LOS ANGELES DEPARTMENT OF WATER AND POWER

POWER SYSTEM RATE ACTION REPORT

Chapter 1: Executive Summary

July 2015

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EXECUTIVE SUMMARY

1.1 PURPOSE AND OBJECTIVES FOR THE PROPOSED NEW RATES AND RATE STRUCTURE

The Los Angeles Department of Water and Power (LADWP or the Department) is the nation's largest municipal utility and supplies power to nearly four million citizens of Los Angeles. The Board of Water and Power Commissioners (Board) is currently obligated under Charter Section 609(c)[1] and the Master Resolution to establish rates for electric service (Power Rates) and collect charges in an amount which, together with other available funds, will be sufficient to service the Department's Power System indebtedness and pay the necessary expenses of operating and maintaining the Power System. Necessary expenses include meeting regulatory mandates and investing in infrastructure for better reliability.

LADWP has taken important steps to reduce the need for rate actions since the last power base rate action in 2012, including, but not limited to, negotiating new labor contracts, exploring innovative financing mechanisms and undertaking cost cutting measures. However, the Department is at a point where rate increases are necessary in order to meet its various commitments.

To collect adequate revenue to fund the revenue requirements in a balanced manner while ensuring sustainability objectives are met, the Department is proposing several changes to both its power rates and overall rate structure.

Through the duration of the proposed five-year rate period, revenue collected will allow the Department to improve customer service and achieve the following business goals:

- Infrastructure Reliability—Through the Power System Reliability Program (PSRP), invest approximately $4.5 billion in capital and O&M to improve system reliability including the replacement of 27,000 poles, 60 miles of cables and 3,350 transformers;
- Power Supply Transformation—Invest $5.1 billion[2] to rebuild local power plants and transition off coal while generating 33% of retail sales from renewable energy by 2020;

[1] For full text see: http://www.amlegal.com/nxt/gateway.dll?f=jumplink$jumplink_x=Advanced$jumplink_vpc=first$jumplink_xsl=querylink.xsl$jumplink_sel=title;path;content-type;home-title;item-bookmark$jumplink_d=california(laac)$jumplink_q=[field%20folio-destinationname:%27Ch609.%27]$jumplink_md=target-id=JD_Ch609

[2] This amount does not include the budgeted spending for Customer Opportunities Programs.

- Energy Efficiency—Invest $878 million to expand energy efficiency programs to save 2,489GWhs of energy usage; and
- Customer Solar Programs—Invest $356 million to enable the growth of the Solar Incentive Program (SIP), Feed-In Tariff (FiT) and Utility Built Solar (UBS) programs.

In addition to these goals, the Department is proactively taking initiative to reduce the O&M costs associated with the currently higher than normal level of uncollectible revenue resulting from the recent new customer information system (CIS) implementation. These efforts include increasing self-service options, reducing use of estimated bills, reducing collection thresholds, decreasing call wait times, and other actions that are designed to reduce the level of uncollectible revenue from 1.56% in FY 2014-15 to 1.00% in FY 2019-20.

1.2 REVENUE REQUIREMENT AND RATE DRIVERS

In developing the rate proposal, LADWP was committed to striking the right balance among continuing to meet regulatory requirements, providing reliable service, planning for a sustainable power supply transformation, and maintaining reasonable rates. The key programs and drivers that contribute to the proposed revenue requirements and rates include:

- Infrastructure Reliability (PSRP);
- Power Supply Transformation;
- Customer Opportunities Programs:
    - Energy Efficiency;
    - Local Solar; and
- Fuel Costs.

The Department is planning to spend a total of $13.2 billion in O&M and capital across all the programs mentioned above over the next five years. Current revenues will be inadequate to fund the above programs with a projected shortfall of $900 million (an average of $180 million per year) during the proposed five-year rate period from FY 2015-16 to FY 2019-20. Figure 1 outlines the year-over-year (YOY) impact of each of the rate drivers on the increased revenue requirement and also demonstrates that most of these costs are regulatory driven.

Figure 1: Year-Over-Year Component Breakdown of Proposed Retail Rate and Revenue Requirement Increase Compared to FY 2014-15

Program	Rate Driver	Regulatory (or Other External) Requirement	Average Annual Revenue Requirement Increase ($M)	System Average Annual Increase (¢/kWh)	Avg. Annual Percentage Increase (%)
Power System Reliability Program	Power System Reliability		26	0.11	0.68%
Power Supply Transformation Program	Coal Replacement	✓	17	0.07	0.48%
	Once-Through Cooling	✓	4	0.02	0.09%
	Renewable Energy	✓	36	0.15	0.96%
	Subtotal		57	0.24	1.53%
Customer Opportunities Program	Energy Efficiency	✓	60	0.26	1.54%
	Customer Solar Programs	✓	18	0.07	0.46%
	Subtotal		78	0.33	2.01%
Fuel Costs			18	0.08	0.46%
Total Average Annual Increase			**$180**	**0.76**	**4.68%**[3]

1.3 ASSUMPTIONS AND RISKS ASSOCIATED WITH THE PROPOSED PLAN

The Department's Power System financial plan and resulting proposed rates are based on certain assumptions related to future expenditures and consumption. Figure 2 summarizes some of these assumptions and potential risks.

Figure 2: High Level Assumptions and Risks of Proposed Plan

Assumption	Description	Risk/Implication
Energy Efficiency (EE)	Based on the Board's goal for a 15% reduction in energy usage by 2020	If load growth is greater than reflected in the financial plan, the overall generation supply could be altered resulting in a ripple effect through the RPS projections, fuel demand, and price of electricity. However the risk is mitigated by pass-through adjustment factors in the rate structure, which can be adjusted quarterly to reflect actual costs and other changing conditions.
Regulatory	Assumes known and	Regulatory mandates direct a significant portion of Department

[3] All proposed rates are developed based on Financial Plan Case Number 19.

Assumption	Description	Risk/Implication
Mandates	consistent regulatory obligations for the Department	expenditures. Volatile political environments or changing mandates could force the Department to spend even more to meet legal obligations. Most Department obligations mandate significant structural changes and a timeline of compliance of several years, so compliance will likely extend beyond the rate action time period.
Financial Market Conditions	Assumes current market conditions with low steady inflation, returns on investment and bond rating	If market conditions change, LADWP's decoupled rate structure[4] will likely ensure adequate cost recovery and eliminate over-collection if market conditions become even more favorable.
Adoption of Customer Programs	Assumes projected adoption of customer programs, such as local solar and EE programs	Customer programs such as local solar and EE are significant rate drivers. If adoption of these programs is diminished over the rate period, total program spending and the revenue requirement could be impacted. This effect would largely be balanced through higher electric supply prices and overall load growth.

1.4 COST OF SERVICE STUDY PROCESS AND SUMMARY RESULTS

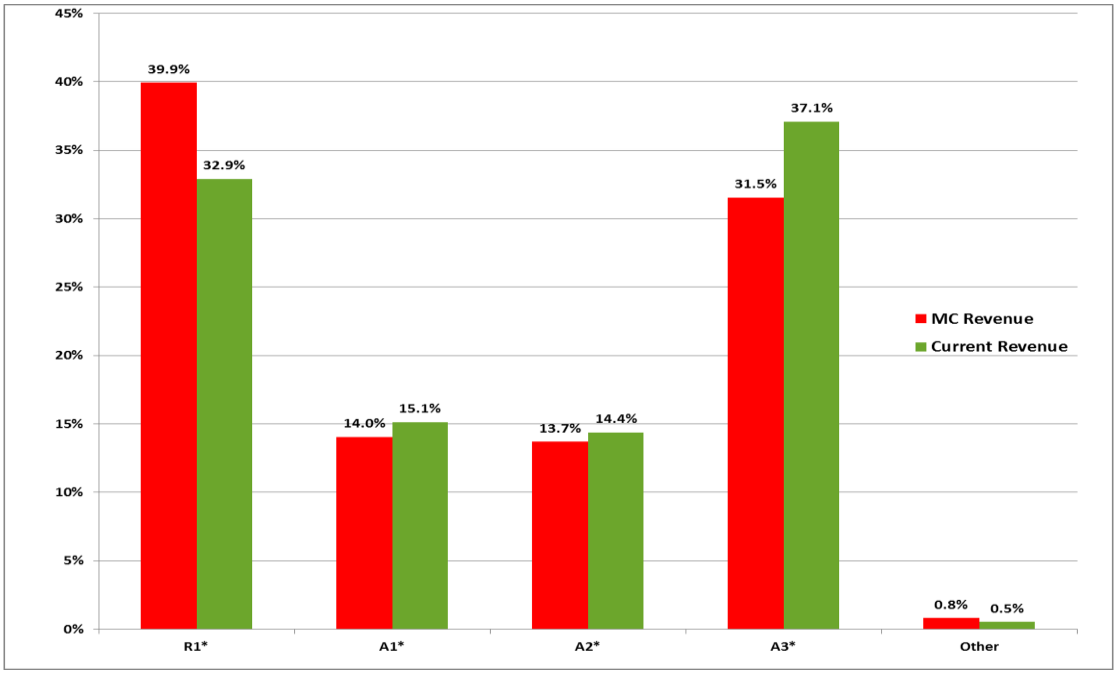
On October 2, 2012, the Los Angeles City Council approved LADWP's Incremental Electric Rate Ordinance No. 182273 to provide incremental rate adjustments for FY 2012-13 and FY 2013-14. In its action to approve LADWP's power rates, the Council, along with other recommendations, requested that LADWP "conduct a new formal cost of service study in order to prepare for future power rate restructuring." Therefore, LADWP has completed a marginal cost of service study for its Power Systemto evaluate the power service cost of service and ensure that rates are cost based.[5]

Figure 3 provides a comparison of the FY 2012-13 test year marginal cost revenue requirement and current revenue percentages for each customer class.

[4] LADWP's proposed approach to decoupling is discussed in Chapter 5.

[5] Even in the absence of the Council's Motion, periodic cost of service studies are a common industry practice.

Figure 3: Comparison of Marginal Cost Revenue Requirement and Current Revenue Percent by Customer Class



Results of the marginal cost of service study indicate the marginal cost revenue requirement percentage for the residential (R1) customer class is 39.9%, while the corresponding percentage of current revenues for FY 2012-13 is 32.9%. Conversely, the Industrial (A3) customer class is allocated a lower revenue requirement of 31.5% compared to 37.1% of the current total revenues. These results were supported by an embedded cost of service analysis, which produced similar customer class percentages as the marginal cost of service study. Marginal cost of service study principles and methodologies are discussed in more detail in Chapter 4 of this report.

The percentages for each customer class as calculated from the marginal cost of service study were used to guide allocation of the total revenue requirement to customer classes through the rate design as discussed in Chapter 5 of this report. Rates for each major class of customers will be designed to recover approximately the portion of the revenue requirement assigned to each class based on the cost of service study results, consistent with legal considerations.

1.5 RATE DESIGN SUMMARY

LADWP proposes changes in the electric rate structure and rates to be implemented in late 2015. The electric rate changes are designed to provide financial stability to support LADWP's efforts to sustainably improve infrastructure reliability, meet renewable energy and energy efficiency goals, and follow legal and regulatory requirements. The Residential customer rate structure is designed to provide a transition to rates that reflect the nature of the underlying costs while encouraging the expansion of customer solar and other distributed generation investments.

1.5.1 Legal Considerations

In its report on the last Power System rate action, the Ratepayer Advocate (RPA) proposed that LADWP reevaluate and consider replacing the surcharge-based restructuring approach with fully restructured permanent rates. The City Council made the same recommendation when it approved the 2012 rate action. Consequently, LADWP has evaluated the current approach to the ordinance structure.

While there may be a desire to undertake a modification of the current rate structure to provide a simpler rate framework, several lawsuits have recently been filed asserting that Proposition 26 does not permit LADWP's annual transfer of monies, financial conditions allowing, from the Power Revenue Fund ultimately to the City's General Fund. The City disputes the merits of those lawsuits. While the transfer is being contested, the City will continue to adopt an electrical rate structure that preserves the rates in effect on November 3, 2010, and layers incremental charges on top of them. Therefore, for purposes of the current rate action, LADWP proposes that the results of the cost of service studies and the impact of the new revenue requirements for power service be applied to only the Incremental Electric Rate Ordinance.

1.5.2 Net Energy Metering and Renewables

LADWP maintains a Net Energy Metering (NEM) rate structure to encourage customers to implement renewable generation such as solar. LADWP's NEM program allows a customer's load from the grid to be offset by the energy delivered by the customer to the grid at the full retail rate for the energy. Customer solar generation at retail energy rates can offset all charges except minimum charges up to the value of the bill. The LADWP NEM program structure provides greater incentive for renewables and distributed generation than many other utilities' programs. LADWP proposes to maintain this structure to provide its customers substantial incentives to install customer owned solar generation.

This aspect of the rate design will help LADWP move toward a more distribution based utility, indifferent to the type or cost of customer generation. In addition, by phasing in the changes to rates, this transition is achieved in a gradual, sustainable way.

1.5.3 Phased in Rate Change

The overall rate changes required to cover the increased cost of necessary power reliability program enhancements, power supply replacement including mandated requirements and customer opportunity programs such as energy efficiency will be phased in over a five-year period. This approach will moderate the effect of the rate increases while ensuring Board approved financial metrics continue to be met. In addition, some changes to the rate design are also required to maintain reasonable and cost based rates for all customers. Figure 4 shows the overall annual rate change by customer class and by year for each year of the proposed five-year rate period.

Figure 4: Proposed Average Electric Rates and Annual Percentage Increase by Customer Class

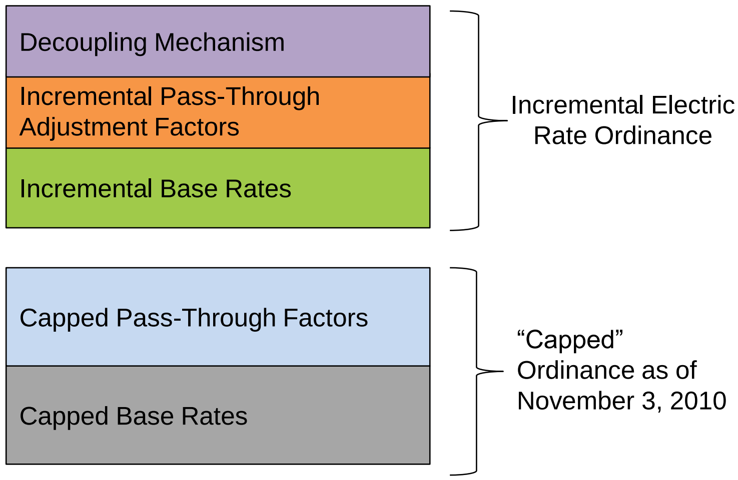
Class	FY 2014-15	FY 2015-16		FY 2016-17		FY 2017-18		FY 2018-19		FY 2019-20		Five-Year Average
	$/kWh	$/kWh	Annual %	$/kWh	Annual %	$/kWh	Annual %	$/kWh	Annual %	$/kWh	Annual %	Annual %
R1A	$0.1515	$0.1595	5.3%	$0.1656	3.8%	$0.1767	6.7%	$0.1849	4.7%	$0.1953	5.6%	5.2%
A1A	$0.1753	$0.1814	3.5%	$0.1862	2.6%	$0.1958	5.2%	$0.2025	3.4%	$0.2112	4.3%	3.8%
A2B	$0.1556	$0.1622	4.2%	$0.1676	3.3%	$0.1777	6.1%	$0.1850	4.1%	$0.1943	5.0%	4.5%
A3A	$0.1391	$0.1447	4.1%	$0.1498	3.5%	$0.1595	6.5%	$0.1662	4.2%	$0.1748	5.2%	4.7%
System Average	**$0.1506**	**$0.1573**	**4.4%**	**$0.1627**	**3.4%**	**$0.1730**	**6.3%**	**$0.1803**	**4.2%**	**$0.1896**	**5.2%**	**4.7%**

1.5.4 Proposed Rate Structure

LADWP has historically employed a structure of base rates and pass-through adjustment factors in combination with a “decoupling” mechanism to isolate the impact of reduced demand from energy conservation on overall revenues and enhance the Department’s financial stability. Pass-through adjustment factors typically reflect costs largely outside LADWP’s control, such as the market driven cost of fuel and regulatory mandates, but can also recover the costs of specific programs such as the PSRP. Employing these mechanisms in the rate design is a standard industry practice for both publicly owned utilities and Investor Owned Utilities (IOUs). The Department proposes only minor changes to the existing structure of the adjustment factors in the proposed rate design.

The base rates correspond to costs over which LADWP does have more control. In addition, decoupling is proposed to ensure the Department has an incentive to undertake conservation and provide incentives for renewable energy without the risk of not covering its largely fixed costs. A decoupling mechanism tracks whether fixed costs are being recovered in base rates and provides a means to adjust rates accordingly to prevent under or over-recovery of costs. This approach is also standard practice for many utilities. Figure 5 provides a visual depiction of this general rate structure.

Figure 5: Proposed Electric Rates Structure



Residential Rate Structure Changes

Changes to the Residential rate structure are meant to provide the correct cost signals for conservation and sustainable technology adaption. The major change is the addition of a new Residential monthly tiered fixed charge tied to the level of monthly consumption by the existing rate tiers. The new tiered fixed charge is based on the same levels of consumption as the current rate tiers and two temperature zones as depicted in Figure 6.

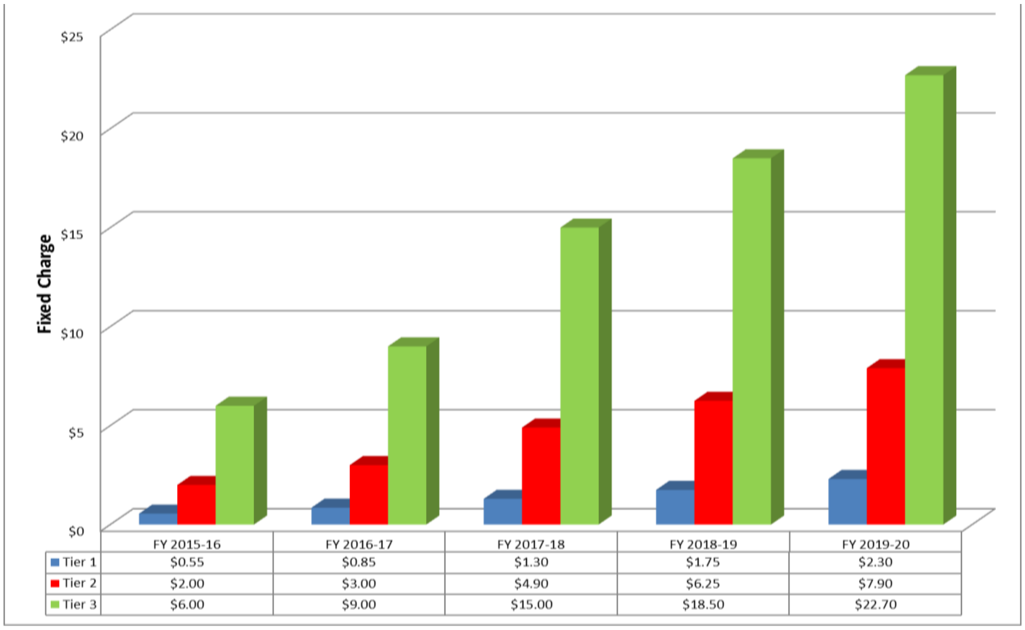
Figure 6: Proposed Thresholds for Residential Monthly Tiered Fixed Charge

	Zone 1 Monthly Usage (kWh)	Zone 2 Monthly Usage (kWh)
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500
Tier 2	350 < and ≤ 1050	500 < and ≤ 1500
Tier 3	> 1050	> 1500

All three major California Investor Owned Utilities (IOUs) are planning to implement substantial increases to their fixed monthly charges or minimum bill charges; however, at the time of this report, the California Public Utilities Commission (CPUC) is still in the process of determining a final ruling (proceeding R-12-06-013).

The implementation of a tiered fixed charge recognizes that a significant amount of a power utility's cost is fixed and that sole reliance on usage based energy charges does not adequately align rates with costs. The new tiered fixed charge will be phased in over five years to provide a gradual transition of rates so that customers can adapt their usage patterns to the new structure and so that lower usage customers do not experience a significant increase in overall rates at any one time. A graphical depiction of the proposed monthly tiered fixed charge increase over the five-year rate period is shown in Figure 7.

Figure 7: Proposed Residential Monthly Tiered Fixed Charge



Commercial and Industrial Rate Structure Changes

The general rate structure of proposed Commercial and Industrial rates will not change but will reflect the need to meet increasing costs over the five-year phase in period. Also, increases in the energy rates over the five-year period reflect anticipated market changes. The service and generation demand rates remain constant as costs are unchanged from previous rates. The facility demand rate increases slowly due to increased costs to help maintain and improve reliability of the distribution infrastructure. These changes are designed to balance increased revenues with providing incentives for solar and other distributive generation technologies. An overview of the elements that make up a Commercial and Industrial customer's rates are shown in Figure 8. Detailed descriptions and rate impacts by customer class are discussed in Chapter 5.

Figure 8: Major Elements of LADWP Electric Commercial and Industrial Rate Design

	Small Commercial (Small General Service A1A)	**Medium Commercial (Primary Service A2B)**	**Large Commercial and Industrial (Sub-transmission A3A)**
Fixed Charges	Service charge	Service charge	Service charge
Capacity Charge ($/KW)	Facilities charge	Facilities charge and monthly demand charge	Facilities charge and monthly demand charge
Energy (Usage) Charges ($/kWh)	Based on season	Based on season and Time of Use (TOU)	Based on season and TOU
Voltage by Class	≤ 4.8 kV	4.8 kV	34.5 kV

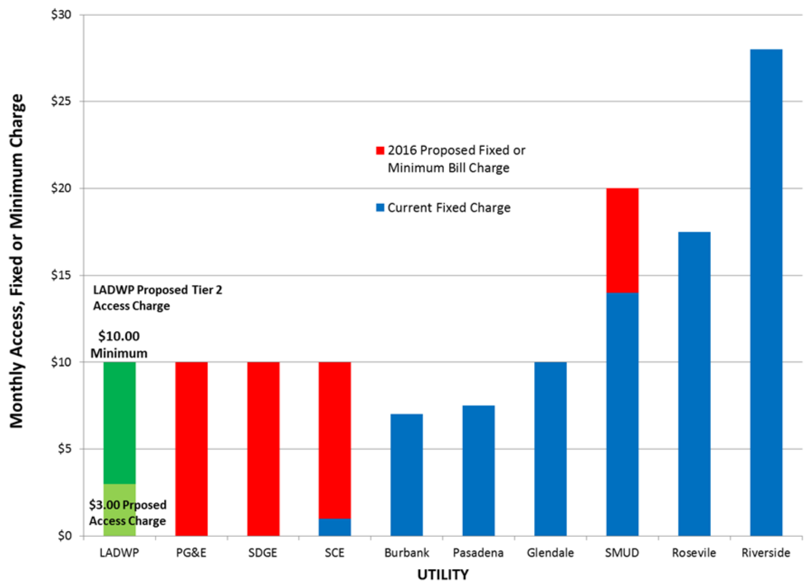
1.5.5 Peer Utility Rate Comparisons

In preparing the rate proposal, LADWP reviewed industry trends and how the proposed rate structure and rates would compare to other utilities. As discussed above, the main proposed structural change is the addition of a new Residential monthly tiered fixed charge.

All three major California Investor Owned Utilities (IOUs) have proposed to implement new customer fixed charges of $10.00 per month by 2017. Other public utilities are also implementing larger monthly charges. It is important to note that LADWP's implementation of a tiered fixed charge avoids the disproportionate effect of a single large monthly charge on lower usage customers. Figure 9 provides a comparison of utility current or proposed Residential fixed charges[6] in 2017 based on current rates or proposed rate changes that have already been announced (based on the proposed tier 2 rate). As shown by the chart, LADWP's monthly fixed charge level is reasonable.

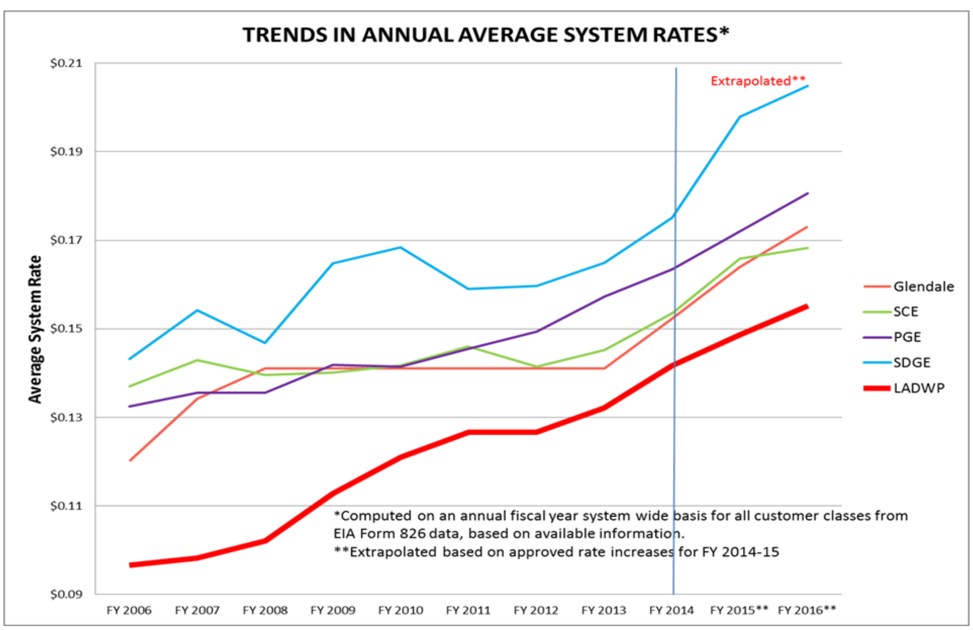
[6] Riverside has a fixed charge of $8.00, plus a reliability charge of $20.00 for a medium-sized residence.

Figure 9: Comparison of Peer Utility Residential Customer Fixed Charges (2017)



The second major change in LADWP's rates is the overall rate change during the five-year period. Figure 10 compares LADWP system average rates (total system retail revenue divided by total retail sales) to the system average rates for several other California utilities. LADWP's system average rates are presently lower than its peers.

Figure 10: Comparison of California Utility System Average Rate Levels



The Department proposes an annual system average rate increase of 4.68% over the five-year rate period.

The three major California IOUs have all increased rates recently and have announced intentions to continue this trend. These utilities have experienced significant cost increases for similar reasons as LADWP, such as compliance with the California renewable energy targets.

1.5.6 Summary of Proposed Rate Changes

The following is a summary of the major changes:

- Phased in rate change over five years averaging 4.68% per year to moderate the impact of the changes on customers;
- Addition of a monthly tiered fixed charge for Residential customers to reflect the industry trend of transitioning the rate structure to be more in line with the cost structure;
- Continuation of decoupling and a combination of base rates and pass-through adjustment factors with only minor changes to help maintain financial stability;
- Continuation of the Incremental Electric Rate Ordinance approach based on legal considerations; and
- Continuation of the current Commercial and Industrial rate design with continued NEM to provide incentives for additional distributed generation programs.

1.6 SUMMARY OF MAJOR ACCOMPLISHMENTS SINCE LAST RATE ACTION

Since the last base rate action in 2012, the LADWP Power System has made significant accomplishments in regulatory compliance, cost reduction and infrastructure investment. These accomplishments include, but are not limited to, the following:

- Working with the Ratepayer Advocate – LADWP has been working closely with the Ratepayer Advocate (RPA), holding bi-weekly meetings since July 2013. In these meetings, many major aspects of LADWP's financial plans have been reviewed, including monthly cash/variance reports, major capital projects, and other major items.
- Labor agreement – In September 2013, union workers approved revisions to the contract between the union and the Department. From October 2014 to September 2017, LADWP will save approximately $456 million from the new contract.
- Cost Reduction Plan and other cost-saving reductions – From February 2011 to June 2014, the Department implemented a multiyear, enterprise-wide cost reduction plan that focused on initiatives that would have a quick and measurable impact on the Department's expenses to help keep rates reasonable in light of industry-wide operational, regulatory and financial challenges, exceeding its original $459 million target by $7.8 million.

- Benchmarking – In February 2015, the Department completed an initial high level benchmarking study. The study identified areas where LADWP is comparable to or better than industry performance and where LADWP has opportunities for improvement. This high level study provided a “roadmap” that will help identify areas for further study and analysis.
- Major Power System investments – Major investments have been made to improve the Power System operations in the areas of renewable energy supply, transitioning off coal, rebuilding local power plants, energy efficiency, infrastructure, and local solar programs.
- Greenhouse gas (GHG) emissions reductions – Through the growth of renewable generation sources, the expansion of energy efficiency and customer solar programs, and several other key environmental initiatives such as electric vehicles, demand response, and smart metering, LADWP has made significant progress in reducing its environmental footprint. GHG emissions levels for 2013 were 14.3 million metric tons (MMT), which is 20% below 1990 levels.
- Electric Vehicles – The Department’s electric vehicle program, “Charge Up LA! - Home, Work, and On The Go” has installed electric vehicle charging stations throughout Los Angeles and awarded thousands of customer and commercial rebates for charging station installation.
- Integrated Resource Planning (IRP) – The IRP was updated in December 2014 and is intended to drive the priorities, financial planning, and budgeting effort for the Power System as it considers a 20-year planning horizon. The overriding purpose is to provide a framework to assure the future energy needs of Department customers are met in a manner that balances superior reliability and supply of electric service, competitive electric rates consistent with sound business principles, responsible environmental stewardship exceeding all regulatory obligations, and a focus on the customer.
- Financial planning to avoid rate increases – Refinancing, regulatory asset treatment, gas hedging, and reduced labor expenses have contributed to reducing the costs of operations.

Many of the benefits realized continue to be ongoing. Process improvements and other cost savings opportunities have become a major strategic focus area for LADWP.

1.7 ANALYSIS OF ALTERNATIVES

In order to understand the sensitivity of the rate plan to the assumptions and risks outlined in Section 1.3 and the potential impact of delaying or altering the proposed rate action, LADWP has developed a series of sensitivity analyses in conjunction with the Ratepayer Advocate. These analyses indicate that the financial plan assumptions and proposed rates are the optimal solution for customers, stakeholders and LADWP itself. Any delays in the rate action would either result in a deterioration of the financial metrics (which would negatively impact the Department’s ability to borrow) or necessitate spending cuts that would prevent LADWP from making critical investments in infrastructure, regulatory mandated programs and sustainable electric transformation. The results of the scenario analyses are summarized in Chapter 3.

1.8 BEYOND THE FIVE-YEAR PROPOSED RATE PLAN

The Department will continue to assess rate and revenue requirements associated with both externally mandated costs as well as various levels of funding for other programs for FY 2020-21 and beyond. Costs for these time periods are still subject to uncertainty but are anticipated to require future adjustments in rates. According to the current financial plan, a system average rate increase would be expected for FY 2020-21 to keep up with increasing revenue requirements that support the programs discussed in this report. However, budgets and other program specifics for FY 2020-21 are currently preliminary.

LOS ANGELES DEPARTMENT OF WATER AND POWER

POWER SYSTEM RATE ACTION REPORT

Chapter 2: Introduction and Background

July 2015

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INTRODUCTION AND BACKGROUND

2.1 PURPOSE AND OBJECTIVES FOR THE PROPOSED NEW RATES AND RATE DESIGN

The Los Angeles Department of Water and Power (LADWP or the Department) is the nation's largest municipal water and power utility and supplies power to nearly four million citizens of Los Angeles through the operation of over 7,640 megawatts (MW) of generation and close to 14,000 miles of power transmission and distribution lines.

The Board of Water and Power Commissioners (Board) is currently obligated under Charter Section 609(c)[1] and the Master Resolution to establish rates for power service (Power Rates) and collect charges in an amount which, together with other available funds, will be sufficient to:

- Service the Department's Power System indebtedness; and
- Pay the necessary expenses of operating and maintaining the Power System.

The obligation of the Department under the Charter and the Master Resolution is known as the rate covenant. Providing reliable infrastructure and meeting regulatory mandates are necessary expenses of operating and maintaining the Power System.

Power Rates are also subject to the approval of the City Council by ordinance (a rate ordinance). The Charter provides that such rates will, except as otherwise authorized by the Charter, be of uniform operation for customers of similar circumstances throughout the City taking into consideration, among other things, the nature of the uses, the quantity supplied and the value of the service.

LADWP has taken important steps to reduce the need for rate actions since the last base rate increase in 2012. However, given the nature of LADWP's obligations and commitments, the Department is at a point where rate increases are necessary to continue and improve system reliability, meet regulatory obligations and maintain a healthy financial standing.

The proposed rate action puts forward an updated rate design, including new rates that will enable the Department to comply with the rate covenant and other legal obligations. The objectives of the proposed rate action include:

- Maintaining affordable power rates;
- Continuing to encourage business development in Los Angeles;

1 For full text see: http://www.amlegal.com/nxt/gateway.dll?f=templates&fn=default.htm&vid=amlegal:laac_ca

- Encouraging the growth of energy efficiency;
- Transforming infrastructure through increasing upgrades to provide reliable service; and
- Promoting the proliferation of local renewable energy supply.

The proposed new rates allow LADWP to meet all of these objectives while continuing to maintain competitive rates relative to peer utilities and benefiting the overall City of Los Angeles. This section outlines the following considerations of the updated rate design:

- Alignment with the Mayor's policy and goals;
- Establishing a pricing policy to transform electric power supply;
- Providing cost recovery for major Department programs;
- Legal considerations; and
- Cost of service alignment confirmation

2.1.1 Alignment with the Mayor's Policy and Goals

The Department operates with goals and visions that align with the Mayor's larger policy goals for the City of Los Angeles. Especially pertinent to the Power System are the Mayor's Budget Policy and Goals.[2]

On September 22, 2014, the Mayor of the City of Los Angeles issued his Fiscal Year (FY) 2015-16 Budget Policy and Goals to the General Managers of all City Departments. The Mayor outlined five "Priority Outcomes" that focus on the results that he believes matter most to the residents of Los Angeles. These outcomes are:

1. Make Los Angeles the best run big city in America;
2. Promote good jobs for Angelenos all across Los Angeles;
3. Create a more sustainable and livable City;
4. Ensure our communities are the safest in the nation; and
5. Partner with citizens and civic groups to build a greater City.

The Department's investments and initiatives outlined in the proposed financial plan and rates were developed with the Mayor's objectives in mind and strongly align with each Priority Outcome. For example, LADWP's significant investments in energy efficiency and customer solar programs help to make Los Angeles more sustainable (Mayor Priority Outcome 3), and the significant planned investments in infrastructure improvements promote economic development, stimulate job growth in the region and improve customer service (Mayor Priority Outcomes 1

[2] See http://sanpedrocity.org/wp-content/uploads/2014/09/FY15-16-Budget-Policy-Letter.pdf

and 2). For more examples of how LADWP's rates are guided by Priority Outcomes, see Chapter 2 - Appendix A.

2.1.2 Establishing a Pricing Policy to Transform Electric Power Supply

The proposed power rates are designed to recover costs associated with the sustainable transformation of the power supply portfolio in a manner designed to minimize the impact on ratepayers while also preserving core Department financial integrity. The proposed rate structure includes base and variable pass-through rate components and a transparent decoupling mechanism that matches costs to rates and ensures recovery of the Department's fixed and variable costs to operate the Power System. A detailed explanation of the Department's proposed rate structure and rates is found in Chapter 5.

In order to transform Los Angeles' power supply and forge a clean energy future, LADWP must replace over 70% of its existing power supply as well as rebuild and modernize much of its aging power grid infrastructure. This effort, much of which is legally obligated, requires significant capital investments, operations and maintenance expenditures, and power purchases which are all factored into LADWP's financial plan and proposed rates.

The power supply transformation plan includes[3]:

- Rebuilding local power plants to preserve oceanic life and comply with regulatory mandates;
- Increasing renewable energy supply to 33% by 2020 as required by State law;
- Transitioning to make Los Angeles coal free by replacing the 39% of coal-fired power supply that LADWP currently receives each year from the Navajo Generating Station (NGS) in Arizona and Intermountain Power Plant (IPP) in Utah;
- Growing customer opportunities programs to reach a 15% energy efficiency target, while also enabling local solar programs and sponsoring emerging technology initiatives; and
- Addressing increases in the price of fuel and increases in the cost of purchased power.

2.1.3 Providing Cost Recovery for Major Department Programs

Sustainability, reliability, and regulatory compliance are top priorities for the Power System. In order to maintain high quality service and electricity, the Power System must complete large, capital-intensive projects. LADWP complies with Federal and State mandates through projects that involve meeting a Renewable Portfolio Standard (RPS), replacement of aging infrastructure, and Once-Through Cooling (OTC) elimination. LADWP's capital improvement plan sets a rigorous schedule for maintenance and replacement of transmission and distribution

[3] See Chapter 3 Section 3.3 for detailed information about the power supply transformation.

lines to reduce system disruptions. LADWP remains committed to improving sustainability through energy efficiency and local solar projects.

The Department's last new electric base rates were approved in FY 2012-13; however, revenue requirements for major programs continue to increase. The proposed rates are designed to meet the obligations associated with operating the Power System. The Power System's major programs include:

- Power System Reliability Program (PSRP): Comprehensive, long-term Power System reliability initiative;
- 33% Renewable Portfolio Standard (RPS): Compliance with State guidelines to have 33% of electricity powered by renewable resources;
- Repowering of Local Power Plants: Replacement of older generating units to eliminate ocean water intake in an effort to comply with OTC regulatory mandates;
- Transitioning off Coal: Divestiture of NGS and elimination of coal-fired generation at IPP; and
- Customer Opportunities Programs: Several programs including the Local Solar Program, incentives for local solar installation and PPA opportunities, and Energy Efficiency, a 15% energy reduction target enabled by energy efficiency programs.

The capital investment in these major programs is expected to increase at a compound annual growth rate (CAGR) of 7.7% from FY 2013-14 to FY 2019-20 as shown in Figure 1. More detail on why these programs are important can be found in Chapter 3, Power Rate Drivers.

Figure 1: Increase in Capital Costs for Major Power System Programs Between Last Base Rate Increase and Last Year of Proposed Rate Action ($M)[4]

Category	FY 13-14	FY 19-20	Net Change	% Change	CAGR[5]
Power System Reliability Program	$256.45	$542.20	$285.75	111.43%	16.15%
33% RPS (Less Local Solar)	$72.22	$331.90	$259.68	359.57%	35.67%
Repowering of Local Power Plants (Including OTC elimination)	$375.93	$183.70	($192.23)	-51.13%	-13.34%
Transitioning off Coal[6]	$0	$0	N/A	N/A	N/A
Customer Opportunities Program (Including	$116.64	$196.60	$79.96	68.55%	11.01%

[4] All budgeted costs and revenue requirement calculations are based on Financial Plan Case Number 19.

[5] The Compound Annual Growth Rate (CAGR) represents an annualized growth rate over the period in question (in this case, five years).

[6] The capital spend for this category is shown a "0" as most of these expenses are incurred by the Department in the form of power purchases at the Apex and other generating facilities.

Category	FY 13-14	FY 19-20	Net Change	% Change	CAGR[5]
Local Solar)					
Total	**$848.94**	**$1,230.00**	**$381.06**	**44.89%**	**7.70%**

All together, the total yearly expense of the Department is known as the "revenue requirement." In general, the revenue requirement is the annual revenue required to fund the Department's obligations and operations, maintenance, cash funded capital, administration, debt service cost and other expenses to provide safe and reliable service to LADWP's customers. These major spending categories are required to meet the obligations defined under the rate covenant.

The Department's annual revenue requirement is determined by the "cash-needs approach" and is comprised of the following:

- Operating & Maintenance (O&M) Expenses: The normal and recurring expenses incurred to run the Power System including, but not limited to, fuel, power, supplies, employee costs, and administrative costs, etc.

- Cash Funded Capital Expenditures: The amount of cash the Department will spend from its operating revenue in a given year on capital after deducting all other funding sources.

- Debt Service Cost: The principal as well as the interest on all outstanding debt for required payments to the Department's creditors.

- Planned Transfer to the City: The planned revenue requirement also includes the cash needed to ensure LADWP satisfies criteria to fund a transfer payment to the City of Los Angeles equal to 8% of prior fiscal year Power System revenue.

The proposed rates are designed to meet the obligations associated with operating the Power System for the five-year period FY 2015-16 through FY 2019-20. This proposed revenue requirement funds critical Department activities, allows the Department to meet legal mandates, and maintains the current fiscal health of the organization.

2.1.4 Legal Considerations

The proposed rates consider many legal obligations set at the Federal, State, and local levels, which provide guidance for rate design and also mandate significant Department capital and O&M expenditures.

2.1.4.1 Legal Requirements Which Guide Rate Design

LADWP must consider applicable legal guidance in developing proposed rates for power service. Potentially applicable guidance includes:

- City Charter Section 676, Rate Setting, which states: "rates shall be of uniform operation for customers of similar circumstances…, as near as may be, and shall be fair and reasonable, taking into consideration, among other things: (1) the nature of the uses; (2) the quantity supplied; and (3) the value of the service"; and

- Proposition 26, which declares that "a charge imposed for a specific government service or product provided directly to the payor shall not exceed the reasonable costs of providing the service or product to the payor."

2.1.4.2 Legal Requirements Which Mandate Department Expenditures

The Department is also required to comply with many complex regulatory and legislative mandates associated with specific Power System programs. Many of these mandates are outside LADWP's control and are direct drivers of the proposed rate action. The legal requirements with significant impact on the Department's Power System costs include:

- Senate Bill (SB) X1-2 – California Renewable Energy Resources Act: State law has established Renewable Portfolio Standard (RPS) mandates for power utilities in the State, including the Department, requiring costly investments in new sources of generation or purchased power. These mandates require that the retail sales of power produced by eligible renewable energy resources must reach the following target percentages: 20% average for 2011 through 2013, 25% by 12/31/16, and 33% by 12/31/20;

- Federal Clean Water Act – Once-Through Cooling (OTC): A mandate that effectively obligates the Department to eliminate OTC from all in-basin thermal generators;

- California Assembly Bill (AB) 32 – Global Warming Solutions Act: A State law that requires utilities to reduce greenhouse gas (GHG) emissions to 1990 levels by 2020, representing a 25% reduction in GHG emissions Statewide;

- California SB 32 – Amendment to the Public Utilities Code, Feed-In Tariff (FiT): A State mandate requiring the Department to develop a 75MW solar (FiT);

- California SB 1368 – Power Plant Emissions Performance Standards: A law that prohibits California utilities from entering into long-term financial commitments for base load generation unless the utility complies with the emissions performance standard;

- Environmental Protection Agency (EPA) – Coal Combustion Residuals (CCR) Regulations: An executive order mandating that by 2010, utilities reduce emissions to 2000 levels; by 2020, utilities reduce emissions to 1990 levels; and, by 2050, utilities reduce emissions to 80% below 1990 levels; and

- California AB 2021 – Energy Efficiency (EE): State legislation that requires utilities, such as the Department, to identify and develop all potentially achievable, cost-effective EE savings and establish annual energy reduction targets. It requires the State's electric utilities to achieve cumulative savings of 10% of total energy consumption levels by 2020.

Detailed information on these laws and other mandates can be found in Chapter 2 - Appendix B.

2.1.5 Cost of Service Alignment Confirmation

In October 2012, the Los Angeles City Council approved LADWP's Incremental Electric Rate Ordinance No. 182273 to provide incremental rate increases for FY 2012-13 and 2013-14. In its action to approve LADWP's power rates, the Council made recommendations, including requesting that LADWP "conduct a new formal cost of service study in order to prepare for future power rate restructuring." In response to this recommendation, LADWP has completed a cost of service study for its Power System to evaluate the power cost of service and ensure that rates are cost based.

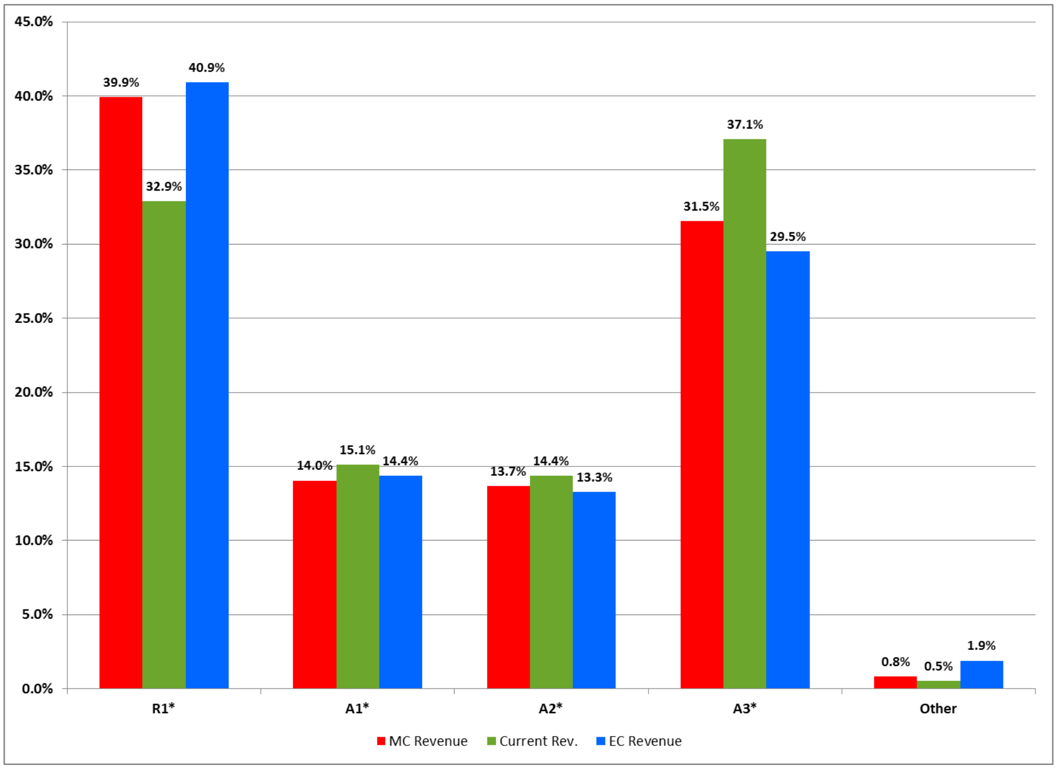
Cost of service analysis constitutes standard utility industry practice for setting power rates. LADWP has utilized the marginal cost study approach to evaluate the cost of providing service to various customer classes and provide guidance for rate design. Marginal cost principles are an accepted methodology for guiding both the allocation of costs to customer classes and the development of power rates. All the major California Investor-Owned Utilities (IOUs) and many Publicly-Owned Utilities (POUs) utilize marginal cost principles for rate design, particularly in the tier design for the residential customer class and time of use (TOU) rates for commercial customer classes.

Figure 2 below illustrates the results of the marginal cost of service study compared to the current revenue percentages for each customer class. The marginal cost revenue requirement percentage for the residential (R1) customer class is 39.9%, while the corresponding percentage of current revenues for FY 2012-13 is 32.9%. Conversely, based on marginal costs, the large commercial and industrial (A3) customer class would be allocated a lower revenue requirement of 31.5% as compared to providing 37.1% of the current total revenues. These results were supported by an embedded[7] cost of service analysis, which produced similar customer class percentages as the marginal cost of service study. The results of the embedded cost of service analysis are also shown in Figure 2.

The marginal cost study results will guide the alignment of the revenue requirements among the customer classes. Marginal cost of service study principles and methodologies are discussed in more detail in Chapter 4 of this report.

[7] Embedded Costs are also referred to as Average Embedded Costs.

Figure 2: Cost of Service Study Results



2.2 BENEFITING CUSTOMERS AND THE OVERALL CITY

A rate increase will benefit present and future citizens of Los Angeles. The proposed rate action will allow LADWP to provide Los Angeles with extensive energy efficiency programs, sustainable clean energy, reliable infrastructure, and improved customer service, thus improving the standard of living for citizens of Los Angeles. Electric power is a fundamental service on which most modern economic activity now relies; LADWP's proposed investments to transform the City power supply will also ensure that the City and citizens of Los Angeles continue to have access to cleaner, reasonably priced sources of sustainable energy in the future.

Inductive economic impact analysis done by the Los Angeles Economic Development Corporation (LAEDC) suggests that Department expenditures for major projects in Los Angeles creates jobs and stimulates additional economic output[8]. The LAEDC estimated that, in FY 2011-12, Power System expenditures, totaling $2.18 billion, supported 27,600 jobs and induced $6.99 billion of additional economic activity and output. If the local characteristics of the current Los Angeles economy have remained similar to the assumptions made by the LAEDC, the average annual Power System spending, of $2.65 billion per year over the five-year rate action,

[8] See Los Angeles County Economic Development Corporation, An Economic Impact Analysis.

will support an average annual 33,321 jobs and induce an average annual $8.39 billion in additional economic activity and output as shown in Figure 3.

Figure 3: Estimate of Economic Impact of Power System Expenditures[9]

		Proposed Rate Period					
Fiscal Year	**FY 14-15**	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**Average Annual**
O&M Expenditures ($M)	*$957*	*$1,010*	*$1,019*	*$1,043*	*$1,074*	*$1,120*	*$1,053*
Capital Investments ($M)	*$1,431*	*$1,598*	*$1,594*	*$1,538*	*$1,593*	*$1,659*	*$1,596*
Total Department Spending ($M)	$2,338	$2,608	$2,613	$2,581	$2,668	$2,778	$2,650
Direct Jobs	*6,865*	*7,411*	*7,441*	*7,442*	*7,682*	*8,004*	*7,596*
Indirect and Induced Jobs	*23,186*	*25,305*	*25,353*	*25,071*	*25,909*	*26,985*	*25,725*
Total Jobs	30,051	32,716	32,794	32,513	33,591	34,989	33,321
Economic Output ($M)	$7,568	$8,215	$8,239	$8,194	$8,463	$8,816	$8,385

2.3 MAJOR ACCOMPLISHMENTS SINCE THE LAST RATE ACTION

Since the last base rate action in FY 2012-13, the Power System has achieved significant accomplishments in many areas of operations that have resulted in cost savings efficiencies and infrastructure investment including, but not limited to:

- Working with the Ratepayer Advocate;
- A new labor agreement;
- Significant cost reduction plan savings;
- Major Power System investments:
    - Renewable Energy Supply;
    - Transitioning off Coal;
    - Repowering Local Power Plants;
    - Energy Efficiency;
    - Local Solar Programs;

[9] Extrapolated per the ratios estimated by LAEDC for the 2012 Power System Work.

  - Power System Reliability Program (PSRP);
- Reduction of greenhouse gas emissions;
- Electric Vehicle programs; and
- Additional business planning to avoid unnecessary rate increases.

This section discusses some of these accomplishments; however, given the nature of these accomplishments, many of the benefits are yet to be realized.

2.3.1 Ratepayer Advocate Input

The Department has been working closely with the Ratepayer Advocate (RPA), holding bi-weekly meetings since July 2013. In these meetings, many major aspects of LADWP's financial plans and actions that require Board approval have been reviewed. Specific topics discussed pertaining to the Power System include, but are not limited to:

- Major initiatives and capital projects;
- Monthly cash/variance reports;
- Financial plans that may potentially be used in the rate action;
- Quarterly Board packages for major program expenditures;
- Marginal cost study results;
- Power rate design options; and
- Various sensitivity cases to stress test the revenue requirement (LADWP has worked with the RPA to develop long-term fiscal outlooks and stress test the proposed plan against dozens of different scenarios).

2.3.2 Labor Agreement and Reduction in Labor Costs

2.3.2.1 Labor Agreement

In September 2013, IBEW union workers approved revisions to the labor contract, or Memorandum of Understanding (MOU), between their union and the Department. Under the proposal, the four-year package freezes salaries for three years and then limits a cost-of-living increase to 2.0% in the final year. It also includes provisions to permit LADWP and IBEW, by mutual agreement through the Joint Labor/Management Resolution Board, to reexamine various existing work rules and pay bonus structures, and it resolves a lawsuit filed by the LADWP pension board over payments to workers who transferred into the utility.

From October 2013 to September 2017, LADWP will save approximately $456 million from the new contract as summarized in Figure 4.

Figure 4: Key Components of the Labor MOU

Key MOU Components	Four-Year Savings Estimate ($M)
Defer Cost of Living Adjustment (COLA) from 10/1/13 to 10/1/16	$385.0
Entry Level Salary Reduction for 34 Common Classes	$15.0
Sick Time Medical Certification Requirement	$12.0
Contracting Out Overtime Restriction - Reduction from 10% to 5%	$3.0
Retirement Plan Tier 2 For All New Hires	$41.0
Total Estimated Savings Over Four Years	**$456.0**

It is estimated the contract will result in a $5 billion savings over 30 years. The contract takes a 2% salary increase to cover employee health care costs. It makes a number of changes to the pension system, including moving the retirement age from 55 to 63 and capping payouts at 80% of the last three years average salary, resulting in an estimated savings of $1.8 billion. The biggest savings, estimated at $4.22 billion, will come from salary savings. Other savings will come from reduced payments to contract out and a change in sick leave.

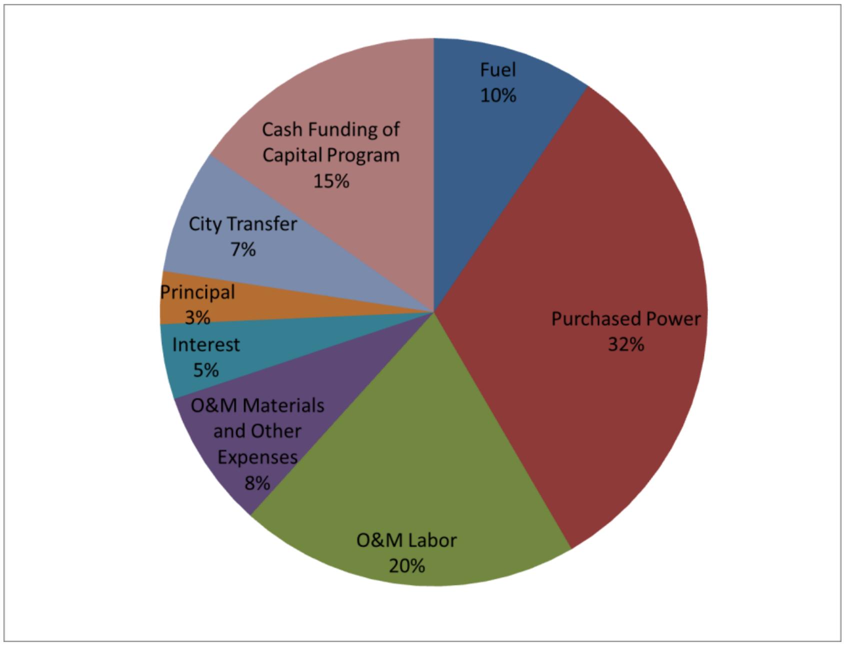
There will also be savings of $180 million to $210 million (from the settlement of reciprocity lawsuit) in the calculations of retirement benefits for employees who transfer into the LADWP system.

LADWP identified a unique opportunity to place new hires in a new Tier 2 pension that provides for a reduced pension calculation. Given its current workplace demographic, over the next four years this is estimated to save the Department $41 million. Approximately 58% of the workforce will be eligible to retire in ten years. Therefore, savings will be significant as more and more new hires take the place of retiring employees.

2.3.2.2 Labor Costs

Recent wage and benefit increases have been somewhat mitigated by the new labor MOU. The Department has separately estimated the impact of inflation and benefit costs (benefits include both pension costs and healthcare costs) on basic operations. Collectively, wages and benefits represent $744 million, or 20%, of the Power System's $3.70 billion revenue requirement for FY 2015-16. Figure 5 shows the current portion of the Power System's revenue requirement represented by wages and benefits in operating and maintenance expenses, inflation (in the form of cost of living adjustments (COLAs)) and pension costs.

Figure 5: Power System FY 2015-16 Revenue Requirement Components[10]



COLA and Inflation

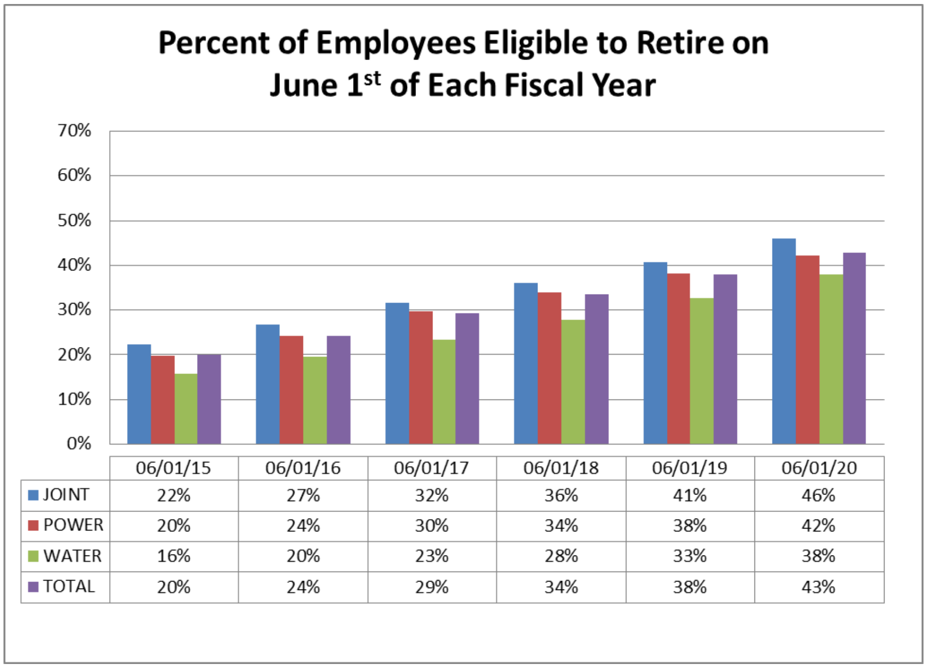
The Department forecasts inflation separately for labor and non-labor expenses. Recent wage and benefit increases have been somewhat mitigated by the new labor MOU with the COLA frozen for the first three years and 2% in the fourth year. However, after this period, the Department's financial plan assumes COLAs will return to the 2.9% level. It also assumes an inflationary impact of about 2.5% per year for non-labor expenses. While the wage cost of living increase for most of the Department's employees is limited until 2017, other employee related expenses, namely health care and pension costs, are expected to continue increasing at or above the level of inflation.

Retirement

Pending retirements present a significant challenge to the Department. As shown in Figure 6, 42% of LADWP's Power System workforce is eligible to retire within the next five years.

[10] The City Transfer is 8% of LADWP's operating revenue but it represents 7% of the overall revenue requirement as indicated by this chart.

Figure 6: LADWP Retirement Eligible Personnel 2015-2020[11]



	06/01/15	06/01/16	06/01/17	06/01/18	06/01/19	06/01/20
JOINT	22%	27%	32%	36%	41%	46%
POWER	20%	24%	30%	34%	38%	42%
WATER	16%	20%	23%	28%	33%	38%
TOTAL	20%	24%	29%	34%	38%	43%

To prepare for the expected retirements and associated loss of institutional knowledge, the Department is increasing recruiting efforts with the goal of having people in place and trained in advance of expected retirements in critical functional areas. The combination of a lengthy recruiting process and a long training period make it imperative that replacement personnel are identified well in advance of retirements. For the Power System, the majority of the new personnel will be assigned to and funded by the specific infrastructure replacement projects discussed in this report. In addition, new hires will enter the Department at a new Tier 2 pension level, which will provide LADWP with additional savings.

Pensions

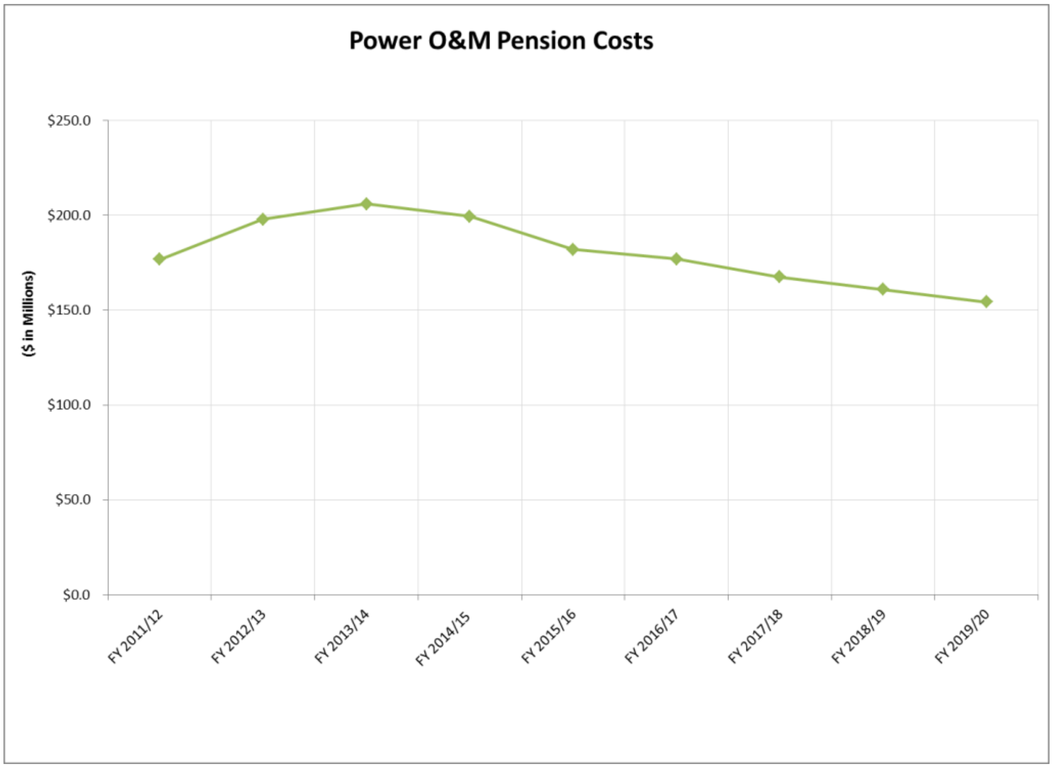
Pension costs contribute to the Department's O&M expenses. Figure 7 below shows the pension expense included in Power System O&M expenses for FY 2014-15 through FY 2019-20.

As discussed previously, the Department is expecting significant savings by placing new hires in a Tier 2 pension category with lower long-term Department costs and by capping pension payouts at 80% of the average of the last three years' salary. The new pension structure is estimated to save the Department $1.8 billion. Beginning in FY 2011-12, LADWP has treated the unfunded pension liability as a regulatory asset, allowing the cost to be amortized over time

[11] Criteria for retirement eligibility are defined as "age 55 with over 30 years of service" or "age 60 with five or more years or service." LADWP data estimated as of June 1st of each year.

rather than being collected in one year. Regulatory asset accounting will benefit LADWP by deferring the impact of pensions on customer rates without impacting the debt to equity ratio.

Figure 7: Power System O&M Pension Costs



Overtime

The original cost reduction plan also targeted significant reductions in overtime. Figure 8 outlines the overtime targets set in 2011, recent results, and future projections.

Figure 8: LADWP Overtime Performance and Targets (Excluding Daily Exempts) Budgeted Overtime as a Percentage of Total Labor Costs

	Average FY 08-09 through FY 10-11	Cost Reduction Plan Target	FY 11-12 through FY 13-14	Average FY 14-15 through FY 19-20
Water System	12.4%	10.0%	12.7%	9.8%
Power System	25.3%	22.0%	20.6%	17.5%
System Support/Shared Services	12.4%	10.0%	12.4%	9.1%

Outside Contracts

As noted in discussion of LADWP's initiatives to respond to the Council's recommendations, LADWP will evaluate each major project to determine the correct mix of outsourcing and internal personnel to complete the project in the most cost-effective way. The Power System has identified additional infrastructure improvement projects that could be implemented if incremental resources and funding are available through either new personnel, overtime, outside contracts or some combination of these sources. On an ongoing basis, the outside contracts will allow LADWP to continue addressing power supply and regulatory requirements while addressing infrastructure improvements at the same time.

Changes to the new MOU give the Department greater flexibility to contract out for labor and services. As shown in Figure 9, the Department anticipates outsourcing an average of 53.5% of the Power system work over the five-year rate period[12].

Figure 9: Power System Capital Work to be Contracted Out (%)

	Proposed Rate Period (Fiscal Year)					
	FY 15-16	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**Five-Year Average**
Power System Capital Work Delivered by Outside Contracts (%)	50.8%	49.2%	52.9%	55.9%	58.1%	53.5%

2.3.3 Cost Reduction Plan Highlights

From February 2011 to June 2014, the Department implemented a multiyear, multimillion dollar, enterprise-wide cost reduction plan that focused on initiatives that would have an immediate and measurable impact on the Department's expenses. This plan included change in areas such as labor, operations and capital expenditures to help keep rates reasonable.

In 2011, the Department examined its portfolio of recurring and non-recurring projects and related labor and non-labor expenses to identify areas to reduce costs in the short-term. The major components identified for the Department's original cost reduction plan were as follows:

- Overtime reductions, vacancy and attrition-based labor cost savings;
- Non-Labor operations savings; and
- Capital cost savings.

[12] Excludes portion of System Support Division (SSD)/shared services work allocated to the Power System.

The cost reduction plan was developed to balance the need to maintain reasonable customer rates and financial stability with LADWP's major Water and Power System initiatives. LADWP exceeded its original $459 million target by $7.8 million. LADWP has saved an estimated $467 million across the entire Department over the three-year period.

Figure 10: Cost Reduction Plan Current Results (Water and Power Systems)

Source	February 2011-June 2014 Savings ($M)
Labor	$230.0
Non-Labor	$142.8
Capital	$94.1
Total	**$466.9**

Though the cost reduction plan was designed as a three-year program, various initiatives have sustainable effects that LADWP expects to realize in the future.

Additional Cost Savings Initiatives

In addition to exceeding the original cost reduction plan target, LADWP has implemented many other initiatives to control or reduce costs further. Highlights of these efforts include the following:

- Overtime: As part of the original cost reduction plan, LADWP established a 22% overtime target for the Power System. The approved budget for FY 2014-15 was 11.3%, and the projected level is expected to be 17.5% on average during the proposed rate period.[13]

- Castaic Power Plant Improvements: The Power System has modernized the Castaic plant to improve overall operating efficiency. The new turbines and other modifications have improved the generating unit output and pumping efficiencies, increasing capacity by approximately 80MW to 90MW for the entire plant. The current effort is focused on automated dispatch for Units 1 through 6 for improved Power System operations.

- Solar Facilities on LADWP Property: The renewable energy program maximized the use of LADWP property and existing electrical infrastructure by building two new 10MW solar power plants at the Pine Tree Wind Farm and Adelanto Converter Station, which are both in service. Solar panels are also being installed on several LADWP-owned buildings and other facilities.

- Power System Reliability Program: The Power System is implementing a new asset management plan to incorporate best practices on new and existing equipment. Through

[13] Similar trends are projected for the Water System and SSD/shared services.

this program, LADWP expects to optimize expenditures for maintenance, reduce life cycle costs, and use best practices for overall equipment maintenance.

- Capital Prioritization: The FY 2014-15 update of the prioritization process for proposed capital projects to ensure best use of capital dollars has been completed. The ranking process was based on a variety of strategic objectives, including reliability, environmental stewardship, and maintaining competitive rates. The current effort to prioritize capital projects for FY 2015-16 is underway with expected completion by the end of March 2015.

- Capital Project Controls: An upgraded Work Management Information System is being deployed to streamline capital project controls and management. Additionally, the Power System is working on improvement of overall project management to ensure proper approval and review processes throughout the life cycle of a project. Training sessions have been held to comply with the processes outlined in the Power System Engineering Process Manual.

- Real Estate Consolidation: LADWP is in the process of acquiring a 17.35 acre property adjacent to the existing 35 acre Valley Center facility to consolidate operations. The consolidated property is expected to provide opportunities to optimize facilities/real estate and reduce staff.

- Procurement Card Program: Tighter internal controls are being implemented on procurement cards so that charges are only authorized on approved contracts, taking advantage of wholesale prices and competitive bidding processes.

- Corporate Performance Improvement: Process improvements and other cost savings opportunities have become a major strategic focus area for LADWP supported by several initiatives, including establishment of a small organization within LADWP responsible for promoting, monitoring, and reporting on performance improvement efforts.

2.3.4 Major Power System Investments

The progress made since the last rate action reflects a commitment to environmental sustainability and system reliability. The Department has made every effort to accelerate programs linked to reducing greenhouse gas emissions and to focus on empowering customers to make their own clean energy choices. The major investments LADWP has made since the last rate action include, but are not limited to, renewable energy supply, transitioning off coal, repowering local power plants, energy efficiency, local solar, and power system reliability.

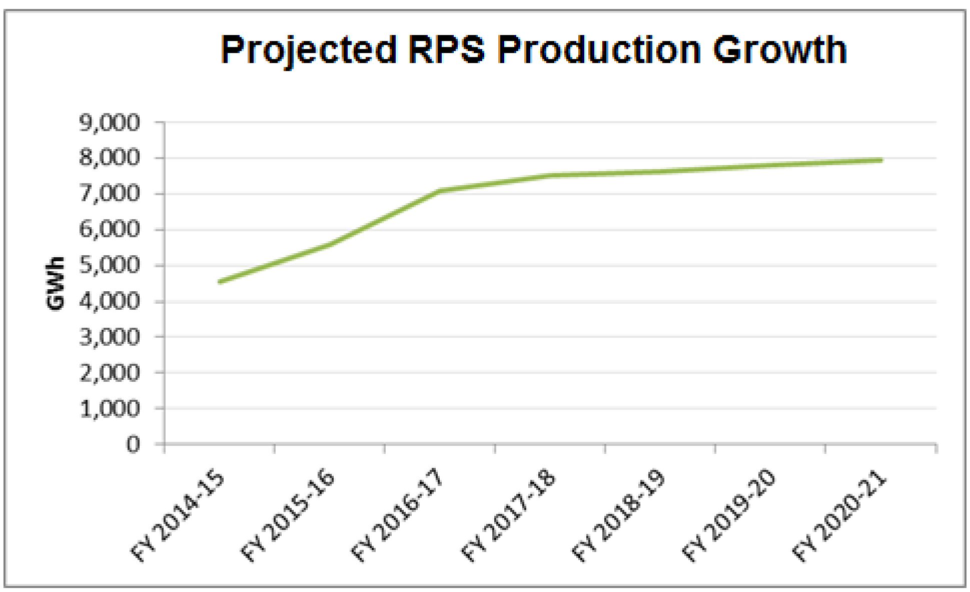
2.3.4.1 Renewable Energy Supply

Through California SB X1-2, the State of California has set Renewable Portfolio Standard (RPS) targets that electric utilities are obligated to meet. Those standards are:

- 20% average RPS for 2011 through 2013;
- 25% RPS by 12/31/16; and
- 33% RPS by 12/31/20.

Since the last rate action, the Department met and exceeded the 20% average RPS and is on track to meet the 2016 and 2020 calendar year targets. In calendar year 2012, 19.5% of the Department's power generation portfolio was renewable; in calendar year 2014, that number increased to a total of 19.9%. To meet this standard, the Department has engaged a broad spectrum of renewable sources, including solar, wind, hydro, geothermal, and generic renewable energy market purchases. The Department's existing renewable resources can provide an average annual 4,643GWh of power through a combination of Department owned facilities, purchase power agreements (PPA) and fuel purchases. The main components are wind, small hydro, solar, biogas, and geothermal resources. Figure 11 shows the forecasted increase of the Department's secured RPS resources over the five-year rate action period.

Figure 11: Projected RPS Production Growth (FY 2014-15 through FY 2020-21)



The Department still has a long way to go to meet future RPS targets and transform the power supply for a sustainable Los Angeles. However, the Department is on track to meet or exceed State guidelines and is proactive in its approach.

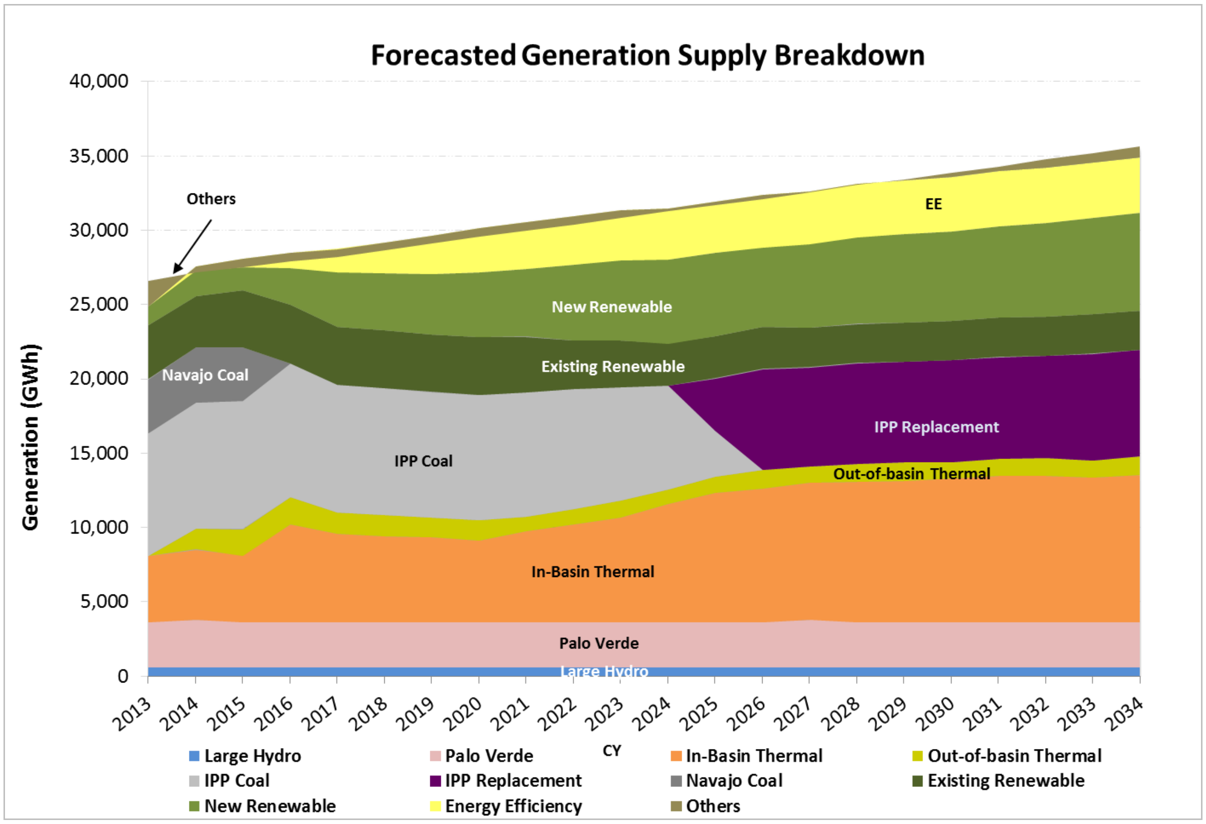
2.3.4.2 Transitioning Off Coal

California Senate Bill 1368 prohibits California utilities from entering long-term financial commitments for base load generation unless the source complies with greenhouse gas (GHG) emissions performance standards. The Department is currently receiving approximately 477MW of capacity from the Navajo Generating Station (NGS) in Arizona and 1200MW of capacity from IPP in Utah. The Department is divesting its stake in NGS prior to the conclusion of its contractual term in 2019. Also, in June 2015, the Board approved a contract amendment to eliminate coal-fired energy production at IPP by 2025. Through these actions, the City of Los Angeles will become the first major city in the United States to commit to becoming coal free.

Pursuant to the Department's accelerated NGS divestment plans, on June 26, 2015, the City of Los Angeles approved a transaction to divest LADWP's 21% interest in the facility by the end of 2016. The accelerated effort is a proactive step in reducing the Department's greenhouse gas contribution. A substantial portion of Navajo supply will be replaced by the Apex gas generating station combined with energy efficiency measures and additional renewable supply.

Forecasts for coal divestiture and the Department generating portfolio are outlined in the current 2014 Integrated Resource Plan (IRP). Figure 12 outlines the forecasted Department generation supply through 2034, illustrating the planned transition off of coal.

Figure 12: Generation Supply Breakdown[14]



2.3.4.3 Repowering Local Power Plants[15]

The Department is currently the owner and operator of four major power plants in 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. These generating stations have aging units that require replacement to bring on-line more efficient combined cycle units with lower NOX emissions.

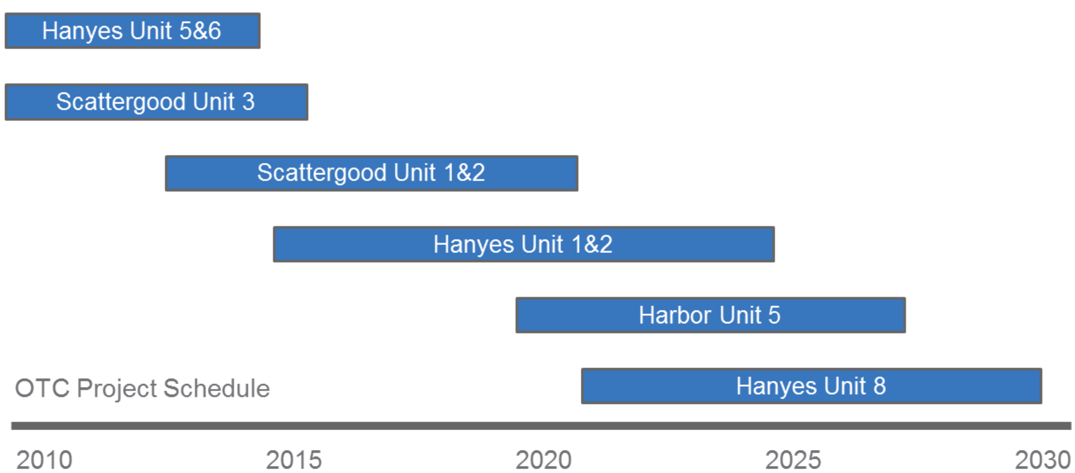
The EPA Clean Water Act mandates that the Department eliminate the intake of ocean water at coastal generating sites which is currently used in a process known as Once-Through Cooling (OTC). Ocean water is cycled through the cooling system of the generators and then deposited back into the ocean, which may have biological impacts. In compliance with the EPA's implementation of the Clean Water Act, the Department is undertaking an extensive effort to rebuild its in-basin thermal plants and eliminate all OTC.

[14] IRP Case Number 3, early divestiture of the Navajo Generating Station.

[15] See Chapter 2 - Appendix C for detailed project information on Once-Through Cooling compliance efforts and current repowering project status.

Each generator replacement timeline is carefully planned to ensure continued access to reliable base load generation for the duration of the compliance project. The Department is on track for completing their repowering efforts and portfolio wide OTC compliance by 2030. The Department has spent $844.3 million since FY 2012-13 to repower generating stations. $755.3 million will be spent on repowering and OTC over the next five years. To date, OTC has been eliminated from Harbor Units 1, 2, 3 and 4; Haynes Units 3, 4, 5 and 6. LADWP is on track to exceed compliance deadlines for several generation unit replacement projects as shown in Figure 13, which provides a high level timeline indicating the planned projects and status for each generator in need of replacement.

Figure 13: Once-Through Cooling Elimination Timeline[16]



Elimination of OTC continues to be a major program in the Department's power supply transformation.

2.3.4.4 Energy Efficiency[17]

California State Assembly Bill 2021 requires publicly-owned utilities such as the Department to identify and develop all potentially achievable, cost-effective energy efficiency (EE) savings and establish annual targets. It requires the State's electric utilities to achieve cumulative savings of 10% of total energy consumption levels by 2020. In 2014, the Board exceeded that mandate by adopting an energy savings target of 15% by 2020, enabled by an aggressive energy efficiency program portfolio[18].

From FY 2009-10 to FY 2013-14, the Department has spent $274 million on EE programs and has achieved 794GWh in net energy savings through several major EE initiatives.

[16] 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. Upgrades at the Harbor facility also include replacement of the aging units 1 and 2 which do not currently use OTC.

[17] See Chapter 2 - Appendix D for detailed EE program information.

[18] See Chapter 2 - Appendix E for the Board Approved Resolution concerning EE targets.

Figure 14: Sample LADWP Energy Efficiency Programs

Small Business Direct Install Program	LAUSD Direct Install Program
Home Energy Improvement Program	Commercial Lighting Efficiency Offer
Low Income Refrigerator Exchange Program	Custom Performance Program
Consumer Rebate Program	LADWP Facilities Upgrade Program
City Plants Program	Energy Efficiency Technical Assistance Program

2.3.4.5 Local Solar Program

The Department has developed multiple options for customers to both install equipment and, in turn, benefit from distributed generation. Customers can sell power to the Department through the Feed-In Tariff (FiT). Customers can credit their bills while receiving an installation incentive through the Solar Incentive Program (SIP).

Solar Incentive Program (SIP): California Senate Bill 1 mandates that all California electric utilities implement a solar incentive program and capped Statewide expenditures at $3.35 billion. Based on its size, the Department is obligated to offer $313 million in incentives to its customers. As of FY 2013-14, 14,461 installations have been awarded $254.3 million in incentives contributing to roughly 2.3% of the RPS composition.

Feed-In Tariff (FiT): The FiT program is designed to encourage the development of distributed generation by offering customers the opportunity to sell energy to the Department at local load centers. There are two major FiT programs - the FiT100 and the FiT50. The FiT100 program is a fixed allocation of distributed solar PPA offers. The FiT50 is a bundled solar program for bidding on the Beacon Solar Project. Since the inception of the program, the Department has achieved several major milestones:

- 130MW of projects reviewed;
- 56MW of projects active;
- 117MW of projects waitlisted;
- 11 FiT projects commissioned totaling 5.4MW;
- 8.2MW of contracts executed and awaiting construction;
- FiT Hotline answers most live calls and responds to messages within 24 hours; and
- FiT50: Board Awarded 22MW to SunEdison and 28MW to Hecate.

2.3.4.6 Power System Reliability Program

In 2014, the Power System Reliability Program (PSRP) was developed by the Department to evolve the Power Reliability Program (PRP) using a more comprehensive approach to maintain system reliability in the short and long-term through the timely replacement of aging infrastructure. The PSRP is an integrated approach to planning capital expenditures for system reliability designed to minimize future outages; it includes all major LADWP power generation and delivery assets affecting reliability. The PSRP focuses on prioritizing the most sensitive capital expenditures that will impact reliability by targeting critical replacement of aging infrastructure. The PSRP is designed to hold O&M costs at current levels while reducing the system wide age of critical assets. It also utilizes metrics and indices to help prioritize infrastructure replacement and expenditures across the supply chain.

The development of the PSRP is a major step in integrating system reliability projects and prioritizing projects given a Department limited budget. Its goal is to maximize reliability within the spending constraints of the Department.

2.3.5 Greenhouse Gas Emissions Reductions

On June 2, 2014, the U.S. Environmental Protection Agency (EPA) proposed a plan to cut carbon pollution from power plants - the Clean Power Plan, which aims at maintaining an affordable, reliable energy system, while cutting pollution and protecting health and the environment. Specifically, the Clean Power Plan proposes state-specific goals for carbon dioxide emissions from the power sector, as well as guidelines for states to follow in developing plans to achieve the state-specific goals.

A major accomplishment for the Department is the reduction of greenhouse gas (GHG) emissions as a product of Department environmental programs. Through the growth of renewable generation sources, the expansion of energy efficiency and customer solar programs, and several other key environmental initiatives such as electric vehicles, demand response, and smart metering, LADWP has made significant progress in reducing its environmental footprint.

GHG emissions levels for 2013 were 14.3 million metric tons (MMT), which is 20% below 1990 levels. This is largely due to the historical elimination of power from the Mojave and Colstrip coal plants, completed repowering of units at Harbor, Haynes and Valley generating stations with cleaner natural gas-fired replacements, and increasing the Department's renewable portfolio from 3% in 2003 to 20% of overall sales, on average, over the period 2011-2013. GHG emissions levels for 2013 show an increase compared to 2012 in which LADWP achieved a 22% GHG emissions reduction below 1990 levels. The reason for the 2012 decrease in GHG emissions levels was due to an anomaly. At the end of 2011, LADWP experienced a major cable failure resulting in damage to equipment at IPP, which took one unit off-line for six months. Since half of LADWP's IPP energy was unavailable, other cleaner burning resources were used. The IPP damage has since been repaired, and the GHG emissions levels for 2013 returned to anticipated quantities[19].

[19] See 2014 Integrated Resource Plan: See 2014 IRP: https://www.ladwp.com/ladwp/faces/ladwp/aboutus/a-power/a-p-integratedresourceplanning/a-p-irp-documents?_adf.ctrl-state=10dc8885y3_4&_afrLoop=113042341268089

The proposed divestment of coal fired generation from NGS and elimination of coal-fired generation at IPP will be a major step in reducing GHG emissions. The accelerated divestment of NGS at the end of 2016 and elimination of coal-fired energy deliveries from IPP in 2025 will put the Department ahead of plan by reducing emissions an extra 5.59MMT of CO2 per year, ahead of schedule.

2.3.6 Electric Vehicles (EV)

The Department anticipates that the electrification of cars will be a significant step toward reducing greenhouse gas emission in Los Angeles and is therefore a major component of the Department's strategic plan. Rebates available to residential and commercial customers are covered by the program "Charge-Up LA! - Home, Work, and On The Go."

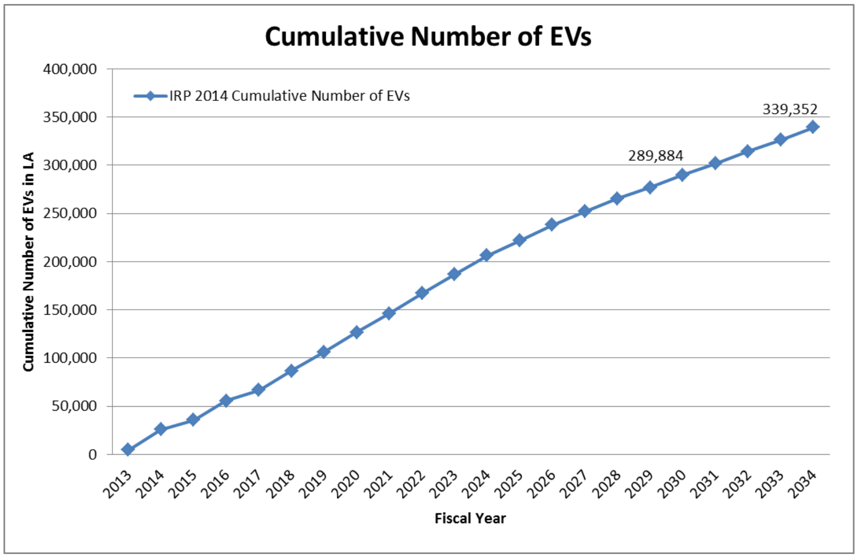
- The residential program provides rebates of up to $2,000 to customers for home chargers and installation costs. The first residential program extended from May 2011 to June 2013. The second round of rebates began in August 2013 and will end June 2015. LADWP has awarded over 1,400 rebates to date.

- Commercial customers can receive up to $750 for hardwired wall-mounted EV chargers and up to $1,000 for stand-alone pedestal chargers. The rebate does not cover the cost of installation. One EV charger rebate is available to commercial customers who have a minimum of five parking spaces available to employees, customers, visitors, and/or tenants. One additional EV charger rebate is available for each additional 20 parking spaces. The first round of rebates was budgeted for $2 million, half of which was paid for by the Department of Energy as part of the Smart Grid Demonstration Program. The second round of rebates is also budgeted at $2 million and is funded by the proceeds for a clean air grant.

- LADWP has worked with customers to upgrade Los Angeles' 350 existing public charging sites, and EV chargers have been installed at high profile locations, such as the LA Convention Center and LAX. To date, LADWP has installed over 300 Level 2 chargers on City properties.

The Department anticipates a significant increase in the number of electric vehicles in the coming years as illustrated in Figure 15.

Figure 15: Cumulative Electric Vehicle Forecast FY 2012-13 to FY 2033-34



2.3.7 Integrated Resource Plan

The Integrated Resource Plan (IRP) is a valuable tool for long-term planning and for reducing fluctuations in Department expenditures due to future uncertainty. One of the major goals of the IRP is to identify a portfolio of generation resources and other Power System assets required to meet the City's future energy needs at the lowest possible cost and risk, consistent with the Department's environmental priorities and reliability standards. Many states and regulatory agencies require development of an IRP prior to approval of procurement programs or electric rate increases. This document goes beyond traditional integrated resource planning and incorporates additional planning elements to form a comprehensive Power System plan. It is intended that the IRP will drive the priorities, financial planning, and budgeting effort for the Power System as it considers a 20-year planning horizon to guide the Department as it executes major new and replacement projects and programs. The overriding purpose is to provide a framework to assure the future energy needs of Department customers are met in a manner that balances the following key objectives:

- Superior reliability and supply of electric service;
- Competitive electric rates consistent with sound business principles;
- Responsible environmental stewardship exceeding all regulatory obligations; and
- Focus on the customer as a primary driver of Department programs.

In an effort to solicit feedback and review from stakeholders in the community, the 2014 IRP includes an Advisory Committee and Public Outreach Process. This helped to establish the goals and objectives of the IRP analysis while incorporating public comment.

The Department finalized the IRP[20] in December 2014. The IRP is published every other year, with true-ups in off years. The 2014 IRP is the most recently completed document since the plan was last published in 2012.

2.3.8 Keeping Rates Competitive and Financial Planning

One of LADWP's main strategic goals is to maintain an overall rate advantage while funding essential utility needs. Developing the proposed rates is a balancing act between the need to plan for a long-term power supply, provide reliable quality service, and continue to meet regulatory requirements and the desire to maintain reasonable customer rates. In addition, contractual obligations for wages, benefits and pensions and the impact of inflation must be considered.

The Department has generally positioned itself well to meet its spending obligations in a sensible and cost effective manner. The Department is expecting $1.60 billion annually in capital expenditures, $1.05 billion annually in O&M expenditures, and a net increase of $3.75 billion in principal debt over the next five years. The bulk of these expenditures are costs related to critical infrastructure reliability programs or are legally mandated programs, such as Renewable Portfolio Standard (RPS) requirements.

This section discusses some of LADWP's efforts to control costs and avoid unnecessary rate increases.

2.3.8.1 Access to Bond Markets

As discussed throughout this report, LADWP has made significant investments in the Power System and requires additional investments in the future. Most of these investments are typically financed through borrowed funds, making it imperative that LADWP have regular and continued access to capital markets at reasonable interest rates. The Department has identified maintaining low cost access to inexpensive capital markets as a core business objective; therefore, maintaining sound financial metrics, and thus quality bond ratings are critical. To keep good ratings, the Department must demonstrate to credit rating agencies quality financial metrics with a low risk profile.

2.3.8.2 Refinancing and Refunding

The Department has taken advantage of its quality credit ratings by engaging in refinancing and refunding activities. Refinancing and refunding activities can take advantage of economic conditions and good interest rates to provide significant savings to the Department. In the current interest rate environment, refinancing and refunding has saved the Department $302.5 million in debt service and interest expenses over the lifetime of its bonds, or $273.0 million in present value dollars since 2009 as outlined in Figure 16.

[20]See 2014 IRP: https://www.ladwp.com/ladwp/faces/ladwp/aboutus/a-power/a-p-integratedresourceplanning/a-p-irp-documents?_adf.ctrl-state=10dc8885y3_4&_afrLoop=113042341268089

Figure 16: Refinancing and Refunding Savings[21]

Year	Power System Savings($M)	Present Value of Savings($M)
2009	$13.28	$7.63
2010	$5.93	$5.00
2011	$107.33	$102.12
2012	$34.36	$25.38
2013	$111.74	$104.73
2014	$29.89	$28.13
Total	**$302.54**	**$272.99**

2.3.8.3 Regulatory Assets

Beginning in FY 2011-12, LADWP has treated several programs, including Energy Efficiency programs as well as the unfunded pension liability, as regulatory assets, allowing the cost to be amortized over the life of the programs' assets rather than being collected in one year in accordance with Generally Accepted Accounting Principles (GAAP). Regulatory asset accounting will benefit LADWP by deferring the impact of these programs on customer rates without impacting the debt to equity ratio. With the growth of the programs, this classification has helped to minimize the immediate rate impact of applicable programs.

2.3.8.4 Fuel Costs and Natural Gas Hedging

A major Department expenditure each year is fuel. The Department must purchase and account for significant volumes of fuel and related fuel costs (as well as its exposure to fuel price volatility) in its budget and recover those costs in its rates. The prices for various fuels are largely outside the Department's control and fluctuate as a result of market forces.

Fuel costs are driven primarily by free market forces and can fluctuate significantly year to year, and within a year. This sort of volatility has a major effect on the customer rates, as fuel costs passed through by the Variable Energy Adjustment factor. The Department proactively mitigates the risk of price volatility through financial hedging programs.

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. Prior to FY 2008-09, LADWP was active in its natural gas hedging program and had hedged up to 50% of its budgeted volume requirements using dollar cost averaging method for up to ten years forward. No new physical or financial hedges were entered into from 2009-2013 due to several factors including (1) falling gas prices, (2) a rate adjustment that allowed pass-through (without caps) of all fuel costs; (3) expected increased production volume from the natural gas reserves in Pinedale, Wyoming and the anticipation of long-term fixed-price biogas contracts as part of its Renewable Portfolio Standards (RPS) program. However, since

[21] See Chapter 2 - Appendix F for yearly bond refinancing information.

gas prices remain the largest driver of unplanned rate volatility, the Department recognized that a properly structured hedging program was in the customer's interest. The Department has recently begun physical hedging, and, though dormant for a while, the Department plans to reestablish a financial hedging program to help mitigate the price volatility of the natural gas it purchases[22].

The main objective of LADWP's hedging program at this time is to mitigate commercial risk by reducing the volatility in the price of natural gas used in the production of electricity to serve retail customers. The program is not designed to necessarily reduce the cost of fuel. LADWP's budgeted spending on natural gas is on the order of $200 million per year, based on the current price and usage outlook, but the amount could be substantially more if prices increase. The Department recognizes that customers appreciate a degree of certainty in their bills enabled by hedging.

A program-wide audit done by the Department's consultant recommended a hedging framework that enables an integrated approach for developing and evaluating hedging strategies. Per the recommendations of the Department's consultant, the Department is moving toward a combination of physical and financial hedging gas contracts for approximately 50% of the required volume over ten-year periods.

2.3.9 High-Level Benchmarking

In February 2015, the Department completed an initial high-level benchmarking study. The study identified areas where LADWP is comparable or better than industry performance and where LADWP has opportunities for improvement. Key findings of the benchmarking study for the Power System are summarized in Figure 17.

Figure 17: Power High-Level Benchmarking Results

Benchmarking Area	Quartile	Notes
Total O&M Costs per Customer	2^{nd}	The Power System total O&M costs per customer are in the 2nd quartile. This is comprised of Generation, Transmission, Distribution, Customer Service, and Administrative and General (A&G) O&M functional costs including labor and benefits. This metric is one of the LADWP's most significant operational metrics.
Distribution O&M Costs	4^{th}	LADWP's lower capital spending may be a contributory factor driving this metric into the 4^{th} quartile. This metric is expected to benchmark better in the future with increases in Distribution capital investments (e.g., PSRP). These higher levels of Distribution O&M may have favorably impacted reliability as evidenced by 1^{st} and 2^{nd} quartile SAIFI and SAIDI benchmarks, respectively.

[22] The hedging program is authorized through sections 10.1.1, 10.5.3 and 23.135 of the Los Angeles Administrative Code, as well as governed by various internal LADWP policies and internal controls.

Benchmarking Area	Quartile	Notes
Customer Service O&M Costs per Customer	1^{st}	LADWP benchmarks favorably in the 1^{st} quartile when compared to peer sets comprised primarily of IOUs.
Reliability (SAIFI and SAIDI)	$1^{st}/2^{nd}$	LADWP ranks in the 1st and 2nd quartile for both metrics, which demonstrates a high degree of system reliability relative to peers nationwide. These results are especially noteworthy given LADWP's historically low capital spending particularly in the distribution area relative to peer utilities.
Transmission and Distribution Line Losses	4^{th}	Energy losses of 13.1% are higher due to significant transmission line losses for generation plants located in remote areas from which approximately 60% of all LADWP's energy is generated. LADWP's lower distribution voltage relative to peers may also be driving this metric higher. Efforts are underway to mitigate any potential "non-technical" line losses such as non-billed customers, fraud and energy theft.
Key Financial Metrics	N/A	LADWP's key financial metrics are in line with industry peer sets.

The high-level benchmarking summary provides a roadmap that will help identify areas for further study and analysis. Some of the processes to study will include, but may not be limited to overtime, outside contracting and salary/pension/healthcare costs. Processes that may present opportunities for improving financial and/or Departmental performance will undergo business process mapping studies. These studies will compare industry best practices and identify next steps for LADWP to move toward best practices.

2.4 CUSTOMER OPPORTUNITIES PROGRAMS

The purpose of this rate increase is to recover increasing O&M and capital costs incurred by the Power System and provide reliable electricity to the citizens of Los Angeles. Though on an average basis, rates may increase, LADWP provides many customer savings programs to mitigate increases in total bills through conservation efforts.

A sample list of programs that are available to LADWP customers include:

- Low Income Refrigerator Exchange Program: This program delivers free new energy efficient refrigerators to low-income and senior/lifeline LADWP customers who have refrigerators meeting a certain criteria. These older, inefficient refrigerators are a major source of electricity consumption as they run all day, every day and are not built to current Energy Star standards. The program ensures that the old refrigerators stay offline and cannot burden the grid by picking them up and recycling them when a new one is delivered.
- Home Energy Improvement Program: This is a free direct install program which targets residential customers. It offers a full suite of free products and services to improve

energy efficiency in the home by upgrading or retrofitting a home's envelope and core systems. Targeted systems include energy efficient upgrades such as lighting systems.

- Local Solar Programs: The Solar Incentive Program and the Feed-In Tariff Program offers customers the opportunity to leverage distributed generation to either reduce costs or sell power back to the Department.

2.5 RESPONSE TO CITY COUNCIL RECOMMENDATIONS

On September 25, 2012, the Los Angeles City Council adopted an amended committee report with ten recommendations associated with LADWP's Incremental Electric Rate Ordinance. LADWP has made significant progress toward addressing the recommendations by working collaboratively with the Ratepayer Advocate, Chief Legislative Analyst, and Chief Administrative Officer. Programs or other activities have been developed to address all of the recommendations. While some activities are ongoing, LADWP has made significant progress in each area. However, the nature of some of the recommendations and the activities to address them are long-term.

Also, the Department has submitted several reports outlining the status of implementation activities for each recommendation; the last report was provided to the City Council in June of 2014. The current status for each item is shown in Figure 18 below.

Figure 18: Council Recommendations Response Status Highlights[23]

Item	Recommendations	Comments
a.	Conduct negotiations with labor to find common ground that allows for greater flexibility to contract out effectively and bring salaries and benefits closer to other power utility providers.	New labor MOU has been implemented through 2017.
b.	Reevaluate and consider replacing the surcharge-based restructuring approach with fully structured rates once legal considerations allow.	LADWP has determined that the conditions underlying the current "surcharge based approach" have not changed such that it should be replaced. Changes to the structure of the surcharge are proposed to reflect current market conditions; the Department's proposed rate structure is outlined in Chapter 5.
c.	Conduct a new formal cost of service study in order to prepare for future power rate restructuring.	A new cost of service study has been completed.[24]

[23] See Chapter 2 - Appendix G for the full response to Council Recommendations.

[24] The new cost of service study is discussed in detail in Chapter 4.

Item	Recommendations	Comments
d.	Conduct a benchmarking assessment to review the cost per project for the repowering program and the Power Reliability Program to ensure cost reasonableness.	The core benchmarking work was completed during the development and procurement phase of the Scattergood Unit 3 repowering project. The Department will embark on another benchmarking and cost estimate for the next repowering project, Scattergood Units 1 and 2. The Power Reliability Program has been renamed the Power System Reliability Program and grown to include the entirety of the system supply chain, including generation assets.
e.	Identify opportunities to contract out and explore the potential savings, including the benchmarking of staffing and outsourcing levels against utility peers.	The Department has completed its initial high-level benchmarking and identified areas where LADWP's performance is good or better than industry norms and where opportunities for improvement may exist. This high-level study provides a "roadmap" for follow-up in-depth studies in certain areas that may be conducted in the future.
f.	Review overtime expense allocation, as well as the Departments contractual requirements that have an impact on overtime.	Overtime requirements were modified as part of the new IBEW MOU.
g.	Complete a rigorous review of the Department's hedging plan to lock in fuel prices.	The Department contracted a consultant to conduct a comprehensive review of LADWP's hedging program, and several of their findings and recommendations have been implemented by the Department. The Department reinstated the gas hedging program and targets 50% of their required gas volume to be hedged.
h.	Establish a plan for energy efficiency that maintains expenditure levels at an achievable and cost-effective level.	The Department has adopted a 15% Energy Reduction target enabled by aggressive energy efficiency programs.[25]
i.	Seek greater Department efficiencies by pursuing process improvement efforts across a range of area and processes.	Identification of efficiency opportunities is underway as a regular part of business.
j.	Submit a semi-annual report to the Mayor and the City Council regarding the status of the Renewable Portfolio Standards program and its impact on rates.	The Department submitted a comprehensive report to the City Council regarding the RPS program. This report provides a current update in Chapter 3 – Section 3.3.2.

A detailed update of each recommendation is included in Chapter 2 - Appendix G.

[25] The Department's Energy Efficiency plan is discussed in detail in Chapter 2 - Appendix D.

2.6 RECENT RATE ACTION HISTORY

LADWP electricity rates have historically been lower than most of its POU and IOU peers in California. A benchmarking analysis comparing LADWP to its utility peers reveals that LADWP's electricity prices from 2009 to 2014 were lower than average and lower than those of nearly all of its POU and IOU peers in California.

In 1998, in response to the deregulation of the electric utility industry for IOUs in California, the Department voluntarily froze its power rates and significantly reduced costs and headcount. Rates remained frozen for eight years; during this period, LADWP's rates became among the lowest in the State.

During the rate freeze time period, the power delivery infrastructure continued to age without any meaningful replacement program. After the rate freeze expired, the Department began the process of developing a financial plan for FY 2007-08 to FY 2009-10 to raise revenues to fund the increasing costs of operations, infrastructure upgrades, and other reliability improvements, and to meet new legal and regulatory mandates. On April 9, 2008, the City Council approved Ordinance No. 179801 for a multiyear revenue/rate increase as follows:

- 2.9% - May 19 2008;
- 2.9% - July 1, 2008; and
- 2.7% - July 1, 2009.

In that rate action, the Council approved the establishment of the Reliability Cost Adjustment (RCA) factor to start funding long delayed upgrades for the Power System's infrastructure reliability. LADWP invested $2.7 billion in infrastructure improvements during FY 2006-07 through FY 2009-10.

In 2010, the Department was facing continued rising costs to achieve continuing aggressive regulatory and legal mandates; to maintain and upgrade the Power System infrastructure; and to meet all other critical needs necessary for operating and providing reliable service. A rate increase for FYs 2010-11 and 2011-12 was planned to continue to provide the funds needed to address these rising costs. However, due to the economic conditions at the time and the impact an increase in rates would have on City residents, the Department suspended any new base rate increases for those two fiscal years. In order to offset the loss of anticipated revenue, the Department reduced capital expenditures by $900 million, postponing reliability improvement programs and preventive maintenance while ensuring funds were still available to meet mandatory regulatory requirements.

The Department subsequently proposed incremental rates for FY 2012-13 and FY 2013-14, which the City Council approved within two ordinances[26] after RPA review and adjustments on October 23, 2012.

These incremental rates were used to finance a variety of critical programs and mandated Department expenditures. The rates funded major capital projects involving repowering as well as expanded energy efficiency programs and steps to meet the intermediate RPS target.

Figure 19 summarizes LADWP's power rate actions from 2003 to 2015.

Figure 19: Recent Rate Action Timeline

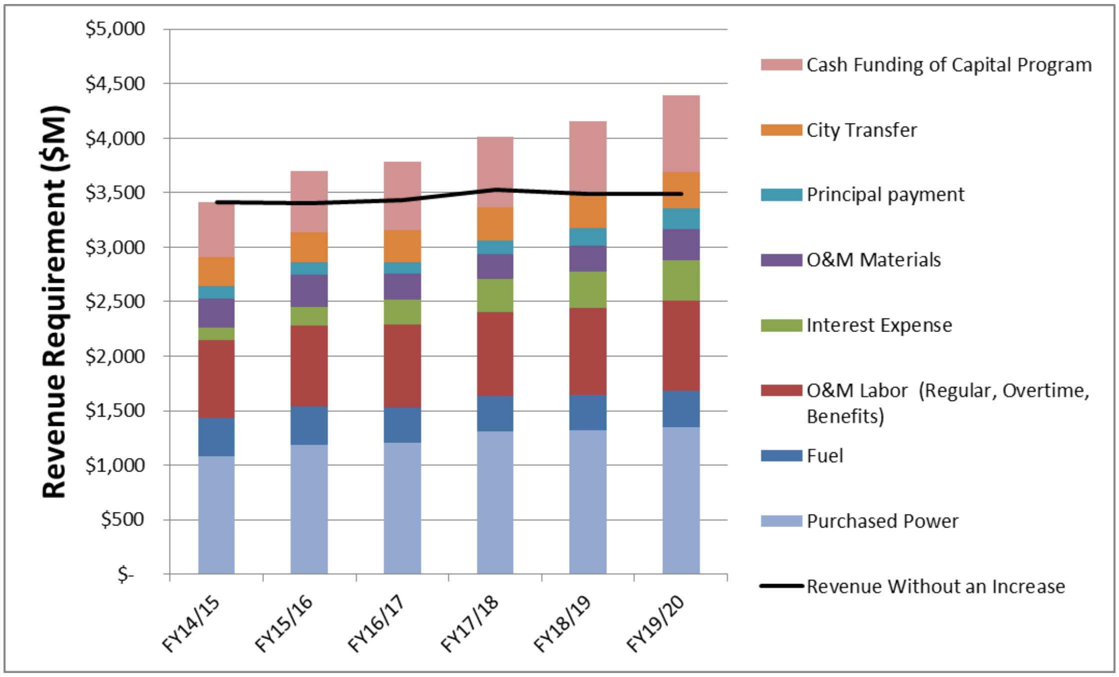
2.7 WHY A RATE INCREASE IS NEEDED NOW?

This report highlights major actions that LADWP has taken to reduce the need for interim rate actions up until this point. However, the Department is at a point where a rate increase is required to improve power system infrastructure, continue to meet regulatory requirements and develop a sustainable electric supply while maintaining a healthy financial standing. This new rate action allows LADWP to meet its objectives and obligations while continuing to maintain competitive rates relative to peer utilities.

Current revenues will be inadequate to fund the major Power System programs as summarized by a graphical representation of the income statement in Figure 20.

[26] Ordinance Nos. 182273 and 182288.

Figure 20: Current Revenue Shortfall (Given No Rate Increase)



* All amounts based on income statement and capital funding include depreciation, net interest expense, and retained earnings.

To meet the Power System's revenue requirement, revenues will have to increase $180 million, on average, per year through the period of FY 2015-16 through FY 2019-20 as reflected in Figure 21.

Figure 21: Year-Over-Year Rate Driver Breakdown of Proposed Retail Rate and Revenue Requirement Increase Compared to Full Year FY 2014-15

Program	Rate Driver	Regulatory (or Other External) Requirement	Average Annual Revenue Requirement Increase ($M)	System Average Annual Increase (Cents/kWh)	Average. Annual Percentage Increase (%)
Power System Reliability Program	Power System Reliability		26	0.11	0.68%
Power Supply Transformation Program	Coal Replacement	✓	17	0.07	0.48%
	Once- Through Cooling	✓	4	0.02	0.09%
	Renewable Energy	✓	36	0.15	0.96%
	Subtotal – Increase		57	0.24	1.53%

Program	Rate Driver	Regulatory (or Other External) Requirement	Average Annual Revenue Requirement Increase ($M)	System Average Annual Increase (Cents/kWh)	Average. Annual Percentage Increase (%)
Customer Opportunities Program	Energy Efficiency	✓	60	0.26	1.54%
	Customer Solar Programs	✓	18	0.07	0.46%
	Subtotal – Increase		78	0.33	2.01%
Fuel Costs			18	0.08	0.46%
Total Average Annual Increase			**$180**	**0.76**	**4.68%**

A rate increase is needed beginning FY 2015-16 to fund critical programs and mandates without risking significant deterioration of the Department's financial profile. However, if incremental revenue is not provided, the Department would likely not be able to meet its mandated regulatory and legislative obligations without significant reductions in the personnel and wages and benefit costs associated with more discretionary programs such as power reliability and customer service. Further consequences of a revenue shortfall could include:

- Failure to meet financial metrics; and
- Not accruing the total revenue requirement to fund system reliability and energy efficiency programs.

The above consequences would be apparent to the credit rating agencies and likely lead to a downgrade or at a minimum, have the Department's bond ratings put on credit "watch" with negative outlook. A downgrade to the Department's Power System bond rating ensures consistently more expensive rates in the long-term.

2.7.1 Financial Metrics

The fiscal health of an organization is often indicated by financial metrics. Financial metrics reflect spending, debt, and revenues to give a snapshot of overall financial performance. The Department must closely manage and monitor the Power System's key financials throughout the five-year rate period to avoid the deterioration of these metrics.

The Department faces a significant challenge in maintaining financial stability while funding both ongoing operations and the additional capital and O&M expenditures. Without a rate increase, the Department credit ratings could be downgraded, resulting in higher borrowing costs and, given the mandates the Department is required to meet, higher customer rates.

Without a rate increase, O&M costs continue to rise and impact important financial metrics:

- Debt Service Coverage (DSC): This is a ratio that 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.

- Capitalization Ratio: Defined as the long-term debt level divided by the sum of long-term debt plus equity. Companies with extraordinarily high capitalization ratio are considered to be a higher risk. Companies with a high capitalization ratio may also find it difficult to secure additional bond issues in the future.

- Operating Cash Target[27]: Minimum target for operating cash reserves (often defined as days cash on hand or a total cash target amount).

- Full Obligation Coverage Rate: Measure of the ability to pay debt service and fixed charges (net off-balance sheet debt service for LADWP); (Funds Available for Debt Service + Fixed Charges – City Transfer) / (Debt Service + Fixed Charges).

2.7.2 Projected Expenditures

The Department has generally planned its financial obligations in a sensible and cost effective manner. For example, the Department owns or has contracted with a portfolio of renewable assets that are fairly diverse (both technologically and geographically), including cost-effective wind and biogas, and generally takes advantage of existing LADWP transmission. To eliminate OTC, 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.

Although necessary and well-conceived, the costs of legal compliance and maintaining reliability are significant, requiring an ever-increasing need for additional debt financing:

- Capital expenditures are projected to average $1.60 billion annually over the five years of the proposed rate plan;

- During the rate request period, long-term debt will increase by $3.75 billion from $10.45 billion in FY 2014-15 to $14.20 billion in FY 2019-20; and

- O&M expenditures are projected to average $1.05 billion annually over the five years of the proposed rate plan.

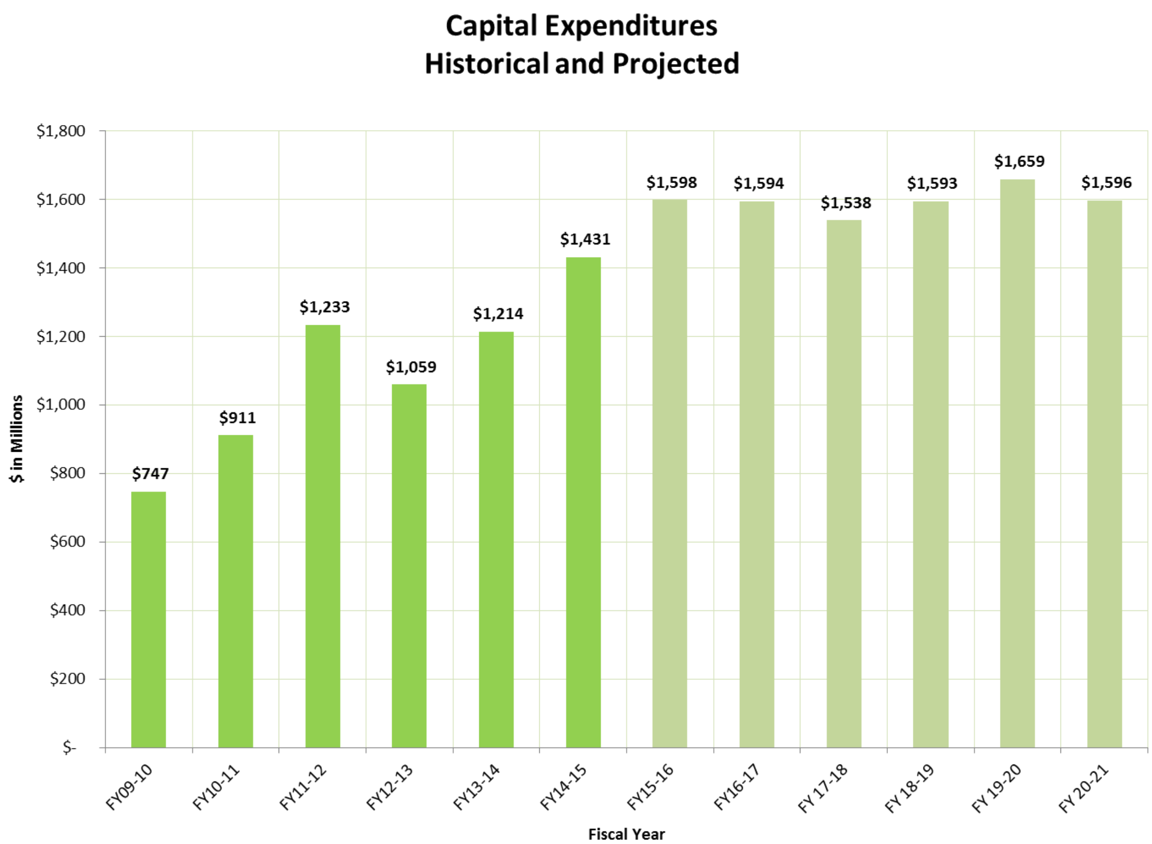
2.7.3 Capital Spending Requirements

As previously discussed, funding Department initiatives to replace aging infrastructure, transform the power supply to meet external mandates, and enhance customer opportunities programs will drive significant increases in Department capital spending. As shown in

[27] For the Power System, this is the cash balance resulting from the financial plan and proposed rates plus the $500 million Debt Reduction Trust Fund (DRTF) which, combined, provide the Department with at least 170 days operating cash.

Figure 22, proposed capital spending will average $1.60 billion annually over the proposed five-year rate period compared to $1.17 billion on average for the previous five years (FY 2010-11 through FY 2014-15), representing a 37% average increase.

Figure 22: Capital Expenditures Historical and Projected



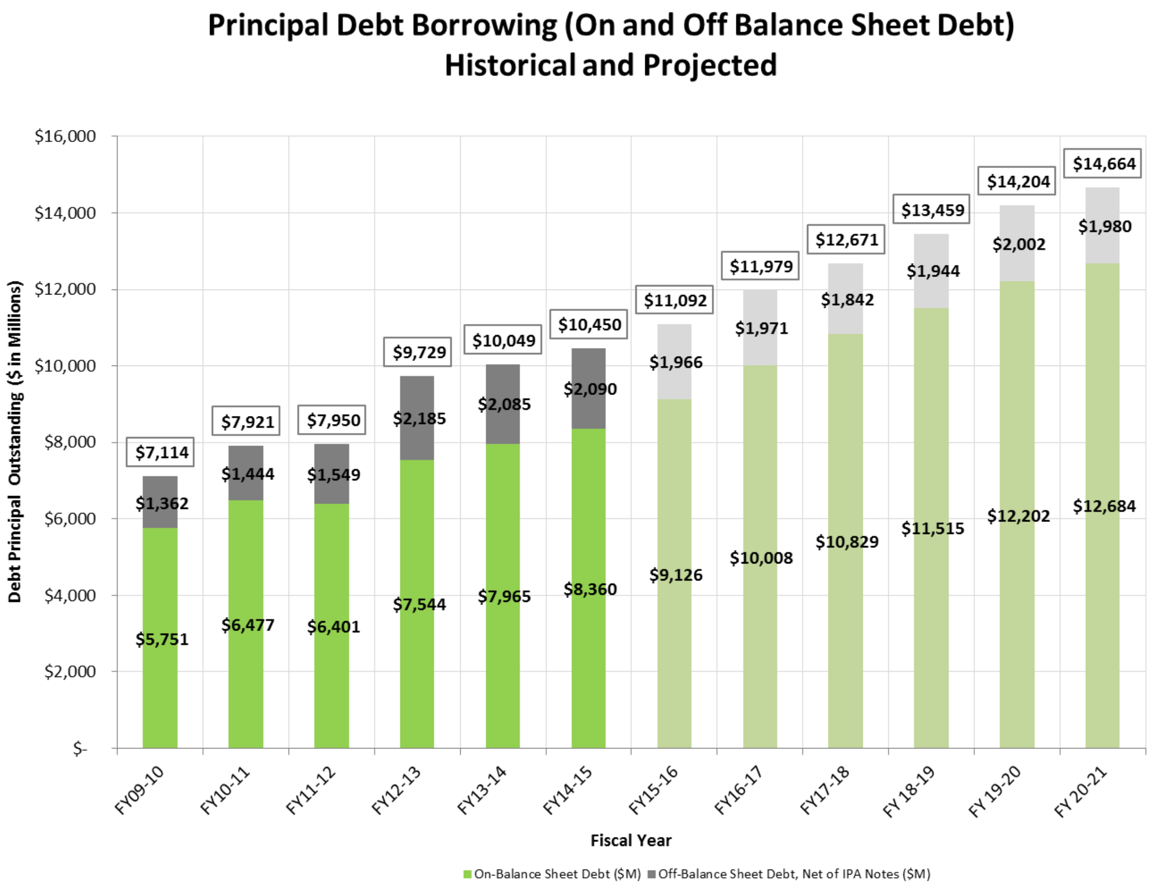
2.7.3.1 Additional Debt

The Department must find the financial resources to fund the capital requirements discussed above. While some funding will come from the increased revenues produced by the proposed rates, the majority will be financed through new debt. As noted above, the Department's on balance sheet debt will grow by $3.75 billion over the five years of the proposed rate plan.

A challenge for the Department will be to maintain its strong financial performance and current bond ratings in spite of rising debt. The Department also currently holds about $2.1 billion in off balance sheet net debt driven by costs related to investing through SCPPA, IPP, the Southern Transmission System and RPS pre-payments. This form of financing allows the Department to share costs with other municipal utilities and other entities while maintaining healthy financial metrics and capitalization ratios to ensure bond market access at favorable interest rates to fund its own 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 contribute to additional debt service costs.

Figure 23 summarizes the Power System's on and off balance sheet debt.

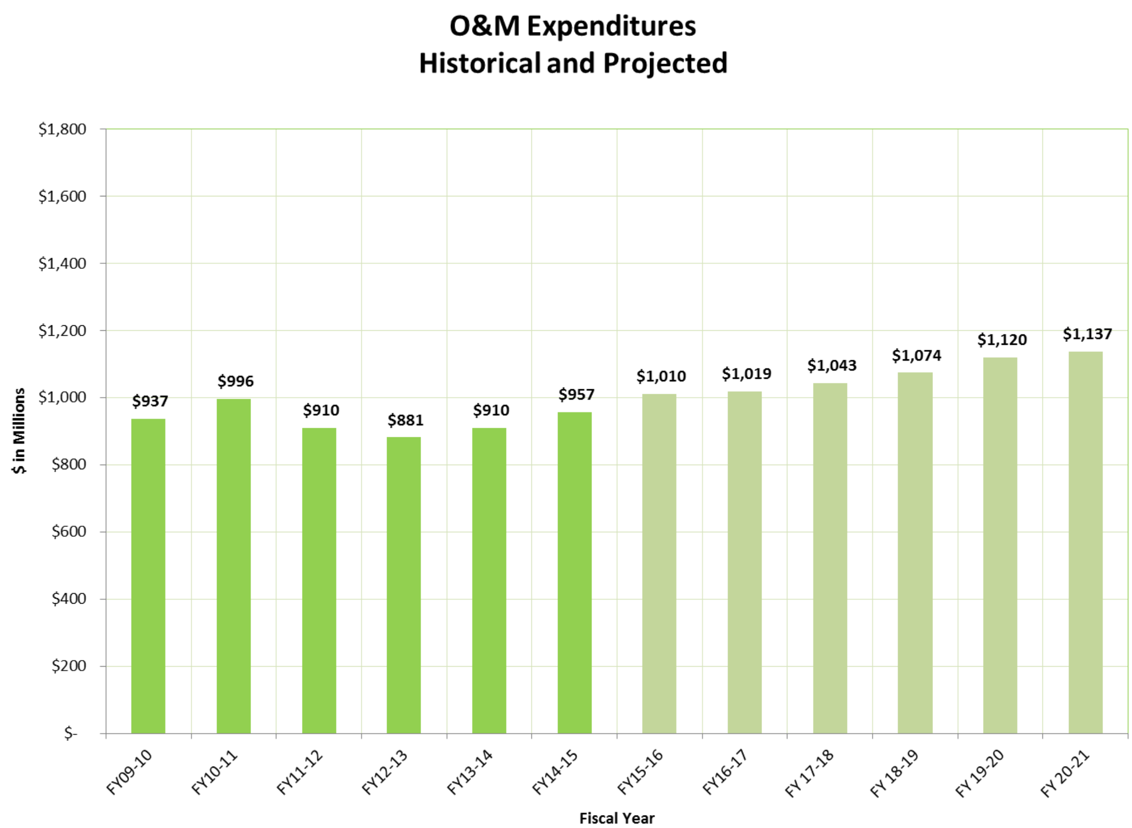
Figure 23: On and Off Balance Sheet Debt, Historical and Projected



2.7.4 Operations and Maintenance Expense Requirements

O&M expenditures will also increase a modest amount. The forecast of O&M expenses, shown in Figure 24, averages $1.05 billion per year for FY 2015-16 through FY 2019-20. In the figure, a noticeable decrease in O&M spending can be seen in FY 12-13. This was due in part to vendor contract expiration and uncertainty related to the time period for which future contracts could be funded. The proposed five-year rate increase is intended to counteract these situations and allow the Department to realize cost savings through longer term contracts and complete the necessary maintenance to ensure reliable service.

Figure 24: O&M Expenditures Historical and Projected



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The proposed increases in capital spending and O&M expenses are required to begin implementing a more sustainable infrastructure and power supply for the future of Los Angeles.

In order to reduce O&M costs, LADWP has also taken significant steps to reduce the higher than normal level of uncollectible revenue that has temporarily resulted from the recent new customer information system (CIS) implementation. Efforts to increase revenue collection include, but are not limited to:

- Implementing on-line, self-service payment options;
- Reviewing bill accuracy;
- Reducing estimated bills to 5% of total bills (which is the current target level);
- Decreasing call wait times to pre-implementation levels; and
- Reducing collection thresholds (amount past due and length of time past due before collection efforts begin).

As system remediation allows, additional payment and other self-service options will be added and budget billing (i.e., level pay) will be introduced. Customer outreach and education plans about programs and services will also be expanded. These efforts are designed to reduce the level of uncollectibles from 1.56% in FY 2014-15 to 1.00% in FY 2019-20 of total operating revenue.

2.7.5 Rating Agency Considerations

The major credit rating agencies – Standard and Poor's (S&P), Fitch Ratings (Fitch), and Moody's – continually assess the credit of entities and ascribe ratings to their bonds. S&P, Fitch, and Moody's currently rate the Power System at AA-, AA-, and Aa3, respectively. Rating agencies assign credit ratings to specific debt instruments, and their underlying issuers, and indicate the likelihood of default for a given instrument. These ratings are used by the marketplace 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 thus a lower interest rate for the borrower.

Financial performance and metric evaluation criteria have been established by these three agencies. Credit ratings are 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 additional factors (such as regulatory and operational restrictions and mandates that may impact its long-term financial position).

2.7.5.1 Financial Risk Profile

Each of the major rating agencies uses a comprehensive approach to assess the risk profiles of a specific debt instrument. Financial ratios that address profitability, capital structure/leverage, and cash flow provide critical points of reference for assessing financial risk. Medians for these ratios provide an illustration of where a specific issuer "fits" relative to its peers within a specific industry.

Public Resources Advisory Group (PRAG) undertook a review of the Power System's financial metrics in June 2013 and found that there was some potential for relaxing the financial metrics for the Power System, which in turn helps to reduce the revenue requirement and customer rates.[28] Based on PRAG's advice, the Board adopted these financial metrics for FY 2014-15 and used them to develop the current financial plan and proposed rates. Figure 25 shows the adopted financial targets.

[28] See Chapter 2 - Appendix H for the full PRAG report recommendations.

Figure 25: Financial Metric Targets

Metric	Current Target (As of May 2014)	Previous Target (Sept 2012)
Operating Cash Target/Days Cash on Hand	170 Days	$300 million[29]
Full Obligation Coverage Rate	1.70	N/A
Debt Service Coverage	2.25	2.25
Capitalization Ratio	Less than 68%	Less than 68%

The Department's financial plan and proposed rates are designed to ensure access to bond markets at the lowest reasonable cost. Figure 26 provides the financial metrics targeted in the Department's financial plan and proposed rates for the next five fiscal years. The Department's projected cash on hand, debt service coverage ratio, and capitalization ratio are shown in Figure 27, Figure 28, and Figure 29.

Figure 26: Financial Metrics of the Proposed Five-Year Rate Plan

	Target	Current Year	Proposed Rate Period					
		FY 14-15	FY 15-16	FY16- 17	FY17- 18	FY 18-19	FY 19-20	Five-Year Average
Operating Cash Target (Days Cash on Hand)	170	170	170	170	170	170	170	170
Full Obligation Coverage Rate	1.70	1.70	1.80	1.70	1.73	1.79	1.85	1.77
Debt Service Coverage	2.25	2.62	2.67	2.66	2.50	2.35	2.32	2.50
Capitalization Ratio (%)[30]	<68.0	60.67	62.48	64.27	65.70	66.74	67.70	65.38

[29] Sufficient operating cash to support operating costs for approximately 170 days.

[30] LADWP continues to evaluate the impact of its capital programs on its capitalization ratio to maintain financial metric targets and ensure that the current bond rating could be maintained.

Figure 27: Operating Cash Target

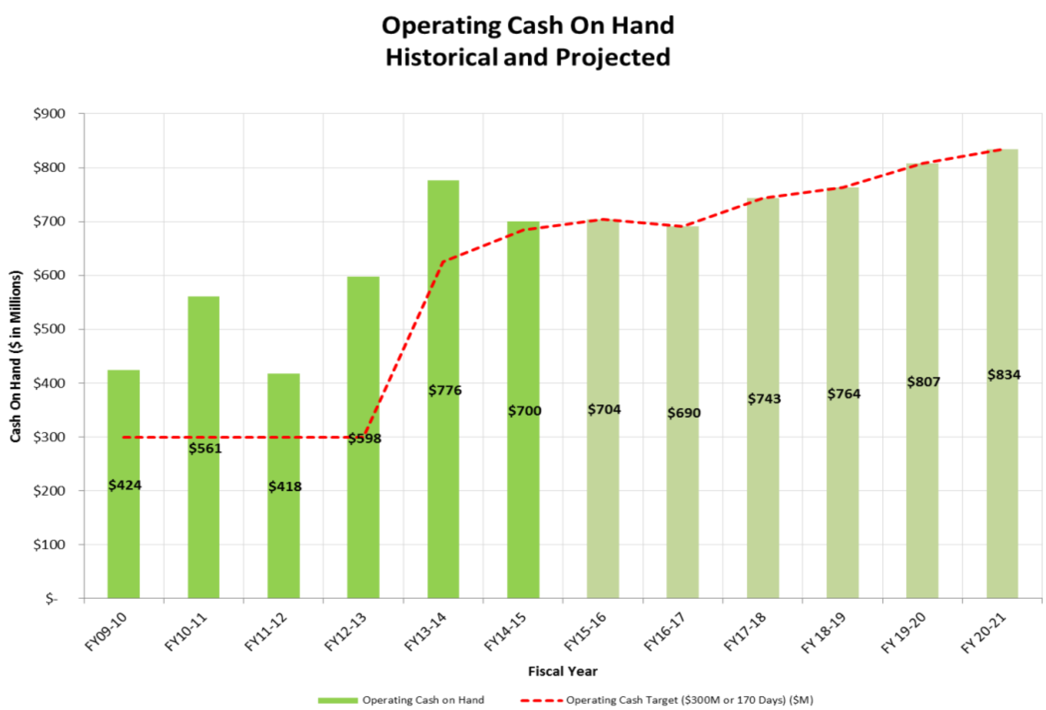


Figure 28: Full Obligation Coverage Rate and Debt Service

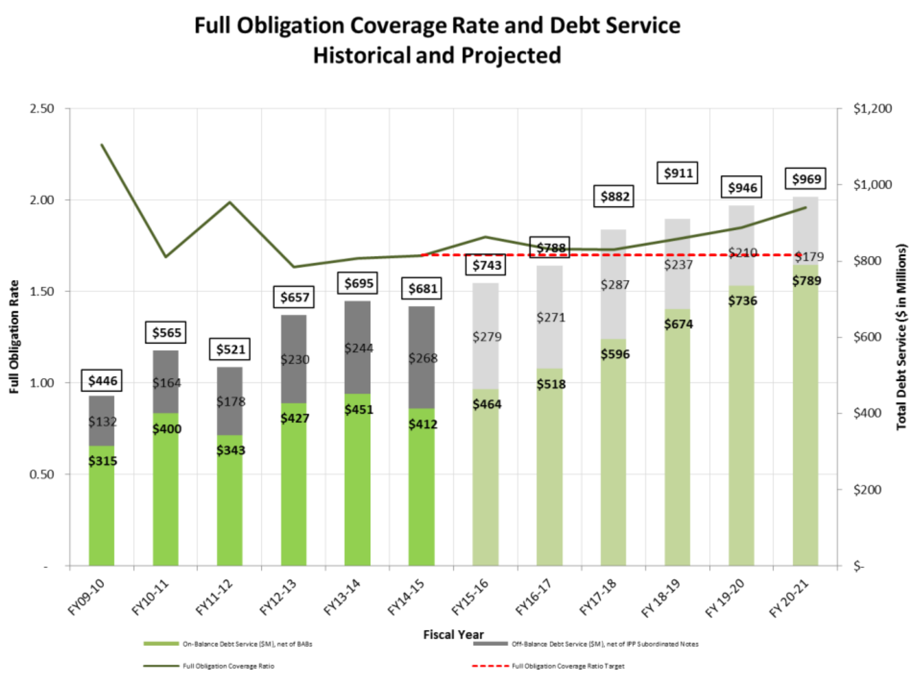
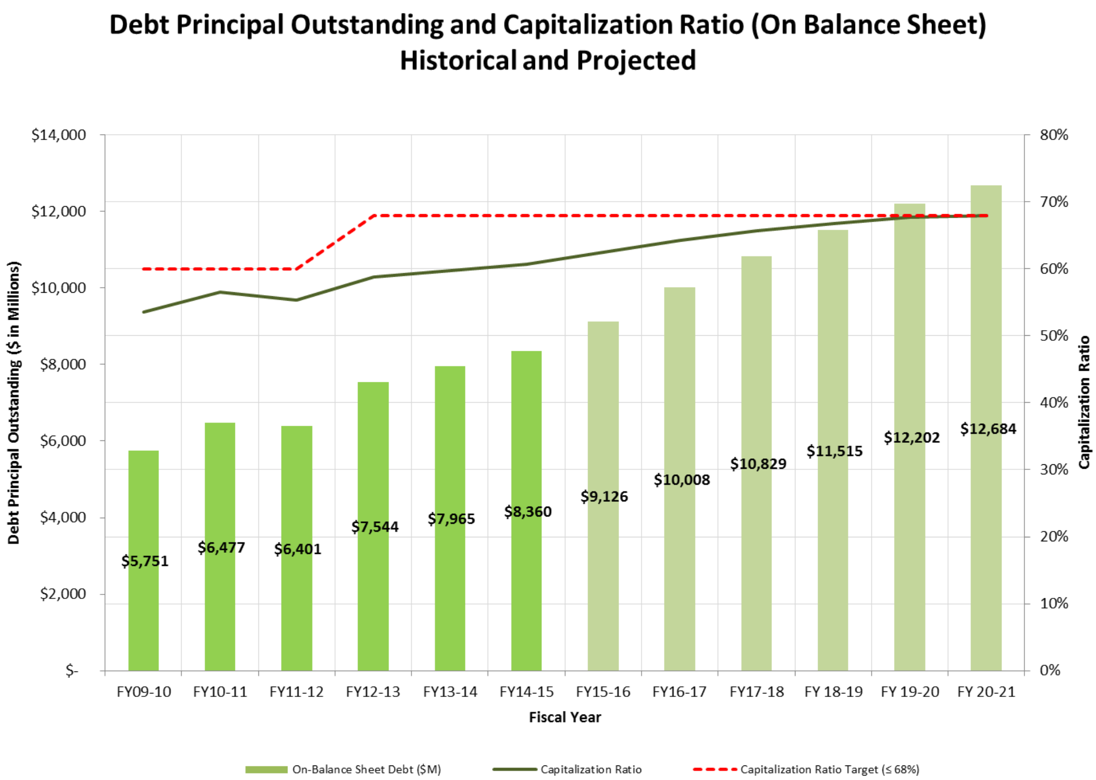


Figure 29: Debt Principal Outstanding and Capitalization Ratio



As actual financial metrics begin to approach the target metrics, more scrutiny will be put on the Department by credit rating agencies. This may indicate the need for additional revenues following the proposed rate action period.

2.7.5.2 Qualitative Factors

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 factors are specific to a particular industry. For public power utilities, for example, Moody's has laid out 9 "Rating Grid Factors" each of which has a number of sub-factors. Five of these rating factors have been identified as "key rating factors":

1. Cost recovery framework within service territory;
2. Willingness to recover costs with sound financial metrics;
3. Management of generation risks;
4. Rate competitiveness; and
5. Financial strength.

In addition, other qualitative factors may also influence a financial rating. These assessments include, but are not limited to:

- 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 CO2 reduction and renewables requirements.

While some qualitative assessments are outside the control of the Department, the Department has managed its financial and operational plans to address these factors. For example, the Department develops contingency plans to respond to unexpected regulatory changes regarding CO2 emissions and has planned for RPS targets as high as 50%. The Department actively compares its own rates to other California utilities and is committed to maintaining competitive prices. The construction work for repowering the Department's thermal generation has been staged to ensure consistent access to requisite generation supply throughout the turbine replacement timeline. The Department takes seriously its qualitative reputation among credit rating agencies and maintains the best possible standards of service.

2.7.6 Risks of Downgrade

If the relaxed financial metrics and/or inability to increase revenues were to result in a ratings downgrade, there would be an increase in borrowing costs.

For the Power System, maintaining its AA- credit rating and preserving inexpensive borrowing costs are critical for maximizing the cost effectiveness of its capital program. Consequently, the Department determines its revenue requirement with an eye toward meeting the debt service coverage, full obligation coverage rate, capitalization ratio, and operating cash target (days cash on hand) metrics that maintain an AA- rating. Lower bond ratings mean higher interest expenses on all borrowing, which can lead to larger customer rate increases. Just as there is a benefit to having a low cost of capital, there is a cost to a downgrade.

A credit rating downgrade for the Power System would have direct and significant impacts on the Department's costs in the form of higher debt service costs. These costs would come in three primary areas:

- 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. As shown in Figure 30, PRAG estimates the impact of a downgrade on interest rates at +15 basis points, but the impact could be +60 basis points in adverse bond market conditions.
- Short-Term Debt: The Power System will maintain $1.2 billion in Variable Rate Demand Revenue Bonds, which are short-term credit facilities that provide the Department access to funds as needed to cover its short-term cash needs and to fund a portion of

the PSRP capital projects. Significant quantities of short-term debt are typically only available to companies with very high credit ratings. Should the Power System credit ratings be downgraded, the majority, if not all, of its low-cost short-term variable-rate debt may have to be refinanced and replaced with higher cost long-term fixed-rate debt for the remaining variable rate debt bonds over the next five years. In addition, any remaining short-term line of credit would carry a higher interest rate with an impact of +25 basis points and as much as +75 basis points in adverse bond market conditions.

- PPA obligations: Many of the 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.

Figure 30: One-Notch Downgrade in Bond Rating from AA- to A+ (S&P)

Scenario	**Long-Term Debt**	**Variable Rate Demand Revenue Bonds**
Current Market	+15 bps	+25 bps
Worst Case Market	+60 bps	+75 bps

The Power System has stress tested the impact of a downgrade to A+ (S&P), under current market conditions and found it would result in an average annual 5.53% to 5.69% rate increase over the next five years as compared to the base case, a 5.20% average annual increase – a net additional 0.33% to 0.49% average annual increase as shown in Figure 31. Customer rates would need to be increased another $57 million to $86 million during the five-year period to recover these increased costs. Therefore, establishing rates to meet the metrics appropriate for the current bond ratings is the best alternative for the Department and customers, as the financial metrics in the proposed five-year rate plan are consistent with published targets for LADWP's current Power System bond ratings.

Figure 31: Impact of a Bond Rating Downgrade (Cumulative Increase)

Cumulative Retail Rates Increase		**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**5-Year Average**
Case 19 (Base Case) Cumulative System Retail Rate Increase		**$159**	**$286**	**$523**	**$693**	**$909**	
Cumulative % Increase		*4.48%*	*8.09%*	*14.90%*	*19.79%*	*26.02%*	*5.20%*
Case #	**Brief Description**						
31	**One-Notch Downgrade in Current Market Condition**	**$185**	**$319**	**$560**	**$753**	**$966**	
	% Increase	*5.22%*	*9.03%*	*15.96%*	*21.50%*	*27.65%*	*5.53%*
	Cumulative Difference to	*$26*	*$33*	*$38*	*$60*	*$57*	

Cumulative Retail Rates Increase		FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	5-Year Average
	Base						
	% Increase due to Downgrade	*0.74%*	*0.94%*	*1.06%*	*1.71%*	*1.63%*	
32	**One-Notch Downgrade in Worst Market Condition**	**$193**	**$331**	**$578**	**$780**	**$995**	
	% Increase	*5.46%*	*9.37%*	*16.44%*	*22.25%*	*28.47%*	*5.69%*
	Cumulative Difference to Base	*$34*	*$45*	*$55*	*$87*	*$86*	
	% Increase due to Downgrade	*0.98%*	*1.28%*	*1.54%*	*2.46%*	*2.45%*	

The impact of a downgrade to the Department's bond rating is substantial and can increase rates significantly in the long-term. Therefore, based on this analysis, the Department believes that adjusting Power System rates and maintaining the current bond rating is in the best interest of the Department's customers.

2.7.7 Delayed or No Rate Action

If there is a delay in the implementation of the proposed rate action, the implication for LADWP and its ratepayers will depend on the length of the delay. For a short delay, the decoupling mechanisms built into the Department's Incremental Electric Rate Ordinance will allow deferral of the revenue shortfall with some rate recovery in the following year. However, for longer delays, it is likely a progressively higher percentage rate increase would be necessary over time to maintain the level of revenue to finance the programs outlined in this report. The longer the delay, the greater the risk for a larger incremental rate increase and curtailment of discretionary program spend, such as energy efficiency.

If incremental revenue is not available, the Department would be in jeopardy of not meeting its mandatory regulatory and legal obligations without a significant deterioration in financial condition. Meeting financial metrics would require significant cuts to important but somewhat more discretionary programs such as the PSRP and energy efficiency as well as reductions to the Department's Customer Service functions. These types of cuts would likely have significant impact on the level of system reliability and customer service.

The Department believes the prudent course of action is to adopt the proposed rate increases. Even after the proposed rates are in effect, LADWP's power service will still be a good value for our customers in relation to peer utilities in Southern California. The Department has developed a five-year rate proposal to provide certainty for customers and to allow LADWP to make long-term contract commitments to obtain the most favorable pricing and terms for construction services and materials.

A. ALIGNMENT OF MAYOR'S PRIORITY OUTCOMES TO LADWP POWER SYSTEM INITIATIVES AND INVESTMENTS

On September 22, 2014, the Mayor of the City of Los Angeles issued his Fiscal Year 2015-16 Budget Policy and Goals to the General Managers of all City Departments. The Mayor outlined five "Priority Outcomes[1]" that focus on the results that he believes matter most to the residents of Los Angeles. These are:

1. Make Los Angeles the best run big city in America;
2. Promote good jobs for Angelenos all across Los Angeles;
3. Create a more sustainable and livable City;
4. Ensure our communities are the safest in the nation;
5. Partner with citizens and civic groups to build a greater City.

The Department's investments and initiatives outlined in this proposed rate plan were developed with the Mayor's objectives in mind and strongly align with each Priority Outcome. Figure 1 provides examples of how the Power System will align to each Priority Outcome through the proposed five-year rate action.

Figure 1: Alignment of Mayor's Priority Outcomes with Department's Initiatives and Investments

Priority Outcome	LADWP Power Rate Action
1. Make Los Angeles the Best Run Big City in America	**Live within our means** • LADWP's rate action considers the continuation of cost reduction initiatives as well as opportunities for process improvements. The creation of the Corporate Performance group will ensure that these process improvements are sustained. • The new rate design builds in adjustment factors that protect LADWP costumers from being over-charged, as LADWP will only seek to recover costs that are actually incurred. **Provide outstanding customer service to our residents and businesses** • LADWP has invested many resources into improving customer services; the proposed financial plan and rates continue to support this trend. • LADWP provides a comprehensive portfolio of energy efficiency and other customer programs to both residents and businesses which help reduce bills, increase sustainability, and help reduce energy use across the board.

[1] See http://sanpedrocity.org/wp-content/uploads/2014/09/FY15-16-Budget-Policy-Letter.pdf

Priority Outcome	LADWP Power Rate Action
	Deploy innovation and the best technology The Power System seeks to invest in the most cost-effective and innovative technologies that are available in order to provide LA with the most reliable and clean energy possible. For example, LADWP has encouraged the adoption of electric vehicles by installing hundreds of charging stations throughout the City and is actively engaging potential energy reduction techniques to reduce peak demand and to smooth the intermittency of bulk renewables available to California. **Restore pride and excellence in public service** The Power System will continue to work with the Ratepayer Advocate (RPA) on major decisions to increase budgeting transparency.
2. Promote Good Jobs for Angelenos All Across Los Angeles;	• LADWP currently employs over 9,100 citizens of Los Angeles and neighboring areas across the Power and Water Systems. When employing contractors, LADWP has a preference for local businesses. • Based on inductive economic analysis done by the Los Angeles Economic Development Corporation (LAEC), it is estimated that Power System capital spending will generate over $8 billion in indirect induced economic activity[2] and over 30 thousand direct and indirect jobs in the Los Angeles local economy.
3. Create a More Sustainable and Livable City;	• The divestment of coal burning generation and the integration of renewables will transform the City's energy footprint. • Local solar programs and electric vehicle incentives will help the City lead the nation in forging a clean energy future. • Infrastructure projects help ensure that poles, transformers, and cable are well-maintained. Less emergency maintenance will be required, decreasing the need for service disruptions and other disturbances.
4. Ensure Our Communities Are the Safest in the Nation;	• To ensure safe communities, the Power System supplies electricity for street lighting throughout Los Angeles, including public parks and public buildings. Access to reliable electricity raises the standard of living for all the communities of Los Angeles. • Availability of electricity is a high priority for the Power System. The Power System is investing many resources to develop local sources of supply through distributed generation, local solar and Feed-In Tariff programs.
5. Partner with Citizens and Civic Groups to Build a Greater City.	• Several of the Power System's investments are joint projects with local and State organizations and are designed to enlist the support of community organizations. For example, the Department supports the City Plants program which plants trees in Los Angeles to increase shade and water/electric conservation. • The Feed-In Tariff is designed to encourage building of local solar facilities to actively transition to a renewable electric future. • LADWP has partnered with other major California Investor Owned Utilities, like Southern California Edison, SoCal Gas, and PG&E to offer energy efficiency programs to customers and help reduce customer bills.

[2] Extrapolated per the ratios estimated by LAEC for the 2012 Power System Work.

B. LEGAL & REGULATORY

The Department is subject to strict legal requirements. Legal requirements for the Power System mandate specific standards and are set at the Federal, State, and local levels. The proposed rate action is designed to meet those standards.

1.1 RATE DESIGN REQUIREMENTS

In designing its proposed power rates, LADWP must consider applicable legal guidance. Potentially applicable legal guidance for the power system rate structure and rates includes:

- *City Charter Section 676; and*
- *California Proposition 26*

Detailed explanations of these requirements follow.

1.1.1 Charter Section 676

According to this section of the City Charter, "rates shall be of uniform operation for customers of similar circumstances…, as near as may be, and shall be fair and reasonable, taking into consideration, among other things: (1) the nature of the uses; (2) the quantity supplied; and (3) the value of the service." A cost of service study helps to evaluate the reasonableness of rates.

LADWP's rate design is guided by the cost of service study based on marginal cost principles. Specific customer class rates will be developed to ensure the revenues from each major customer class based on the new rates in the Incremental Electric Rate Ordinance match the costs of providing service to the respective customer class. Detailed information on the cost of service study can be found in Chapter 4. Furthermore, rates will be established in order to produce revenue in total equal to the Power System's overall revenue requirement.

1.1.2 Proposition 26

In its report on the last Power System rate action, the Ratepayer Advocate (RPA) proposed that LADWP reevaluate and consider replacing the surcharge-based restructuring approach with fully restructured permanent rates. The City Council made the same recommendation when it approved the 2012 rate action. Consequently, LADWP has evaluated the current approach to the ordinance structure.

While there may be a desire to undertake a modification of the current rate structure to provide a simpler rate framework, several lawsuits have recently been filed asserting that Proposition 26 does not permit LADWP's annual transfer of monies, financial conditions allowing, from the

Power Revenue Fund ultimately to the City's General Fund. The City disputes the merits of those lawsuits. While the transfer is being contested, the City will continue to adopt an electrical rate structure that preserves the rates in effect on November 3, 2010, and layers incremental charges on top of them. Therefore, for purposes of the current rate action, LADWP proposes that the results of the cost of service studies and the impact of the new revenue requirements for power service be applied to only the Incremental Electric Rate Ordinance.

1.1.3 Regulatory Mandates

The Department's programs and operations are also required to comply with many complex regulatory and legislative requirements - State, Federal, and local – which are often outside LADWP's direct control. The mandates with significant impact on the Department's Power System costs include:

- *SB X1-2 – California Renewable Energy Resources Act;*
- *Clean Water Act – Once-Through Cooling (OTC);*
- *California AB 32 – Global Warming Solutions Act;*
- *California SB 32 – Amendment to the Public Utilities Code, Feed-In Tariff (FiT);*
- *California SB 1368 – Power Plant Emissions Performance Standards;*
- *Coal Combustion Residuals (CCR) Regulations (Federal - EPA); and*
- *California AB 2021 – Energy Efficiency (EE)*

Detailed explanations of these mandates follow.

SB X1-2 California Renewable Energy Resources Act

State law has established Renewable Portfolio Standard (RPS) mandates for power utilities, including the Department, requiring costly investments in new sources of generation or purchased power. These mandates require that the power sold to customers is produced by eligible renewable energy resources and must reach the following targets:

- 20% average for 2011 through 2013
- 25% by 12/31/16; and
- 33% by 12/31/20.

LADWP has achieved 20% renewable energy delivered to customers, and is on track to meet its RPS requirements.

Clean Water Act – Once-Through Cooling (OTC)

The elimination of OTC stems from the Federal Clean Water Act Section 316(b) and is administered locally by the State Water Resources Control Board (SWRCB). OTC is the process of drawing water from a river, lake, or ocean, pumping it through a generating station's cooling system, and discharging it back to the original body of water. The interpretation of rules and development of guidelines for OTC have been several years in the making. However, the rules are a driving factor behind the conversion of LADWP's Harbor, Haynes and Scattergood power stations, representing 2,839MW of generating capacity, to air cooled units.

California AB32 – Global Warming Solutions Act

State law requires utilities to reduce greenhouse gas emissions to 1990 levels by 2020 representing a 25% Statewide reduction. Compliance with this law requires the Department to divest of its ownership share in the Navajo coal plant, representing approximately 477MW of base load generation, and find alternative sources of power. LADWP plans to replace the Navajo capacity and plan for future growth through a combination of energy efficiency, eligible renewable energy resources and the operation of the Apex Natural Gas Combined Cycle generation station with a base load capacity of 549MW.

California SB 32 and SB 1332– Amendment to the Public Utilities Code, Feed-In Tariff

This is a State mandate requiring the Department to develop a 75MW solar Feed-In Tariff (FiT)[1]. While SB 32 did not specify a deadline for implementation, LADWP adopted a FiT Demonstration Program in March of 2012 and the FiT100 in January of 2013. In September 2012, the State adopted SB 1332, which specified that POUs must adopt a FiT program by July 2013 – several months after LADWP had already adopted its program.

California SB 1368 – Power Plant Emissions Performance Standards

The California Greenhouse Gas Emissions Performance Standard Act, enacted in 2006, prohibits California utilities from entering into long-term financial commitments for base load generation unless the utility complies with the greenhouse gas (GHG) emissions performance standard. SB 1368 established a GHG gas emissions performance standard that limits long-term investments in base load generation by the State's utilities to power plants that meet an emissions performance standard, which was jointly established by the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC). Subsequently, the CEC designed regulations that establish a standard for base load generation owned by, or under long-term contract to publicly owned utilities, of 1,100 pounds of CO2 per megawatt-hour.

Coal Combustion Residuals (CCR) Regulations (Federal – EPA)

In addition to the requirements of SB 1368 above, California's Executive Order S-3-05 signed on June 1, 2005 established the following GHG targets:

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[1] The Feed-In Tariff (FiT) is a program to encourage customers to invest in customer-owned solar facilities; it 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.

- By 2010, reduce emissions to 2000 levels;
- By 2020, reduce emissions to 1990 levels; and,
- By 2050, reduce emissions to 80 percent below 1990 levels.

California AB 2021 – Energy Efficiency (EE)

This is State legislation requiring publicly-owned utilities such as the Department to identify and develop all potentially achievable, cost-effective EE savings and establish annual targets. It 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 EE reduction plan in December 2011, the Department's Board of Water and Power Commissioners (Board) acknowledged that the plan was short of the AB 2021 requirement and requested that management further evaluate energy efficiency program investment options to put the Department on a path to reach the required 10% by 2020. The Board reevaluated this plan in 2014 and adopted new targets to achieve 15% EE through 2020, which exceeds the AB 2021 goal. This target was based on the results of the FY 2013-14 EE Potential Study.

1.1.4 Required Expenditures to Meet Regulatory Mandates

Each of the above mandates has its own capital and operations & maintenance expenditure requirements which will be described in detail in this report. The total capital and O&M expenditures related to regulatory and legal mandates forecasted for the five-year rate period as shown in Figure 1 is over $4.4 billion.

Figure 1: Regulatory Expenditures, Capital and O&M, During the Proposed Rate Period

		Proposed Rate Period						
Program Cost ($M)	**Expenditure Type**	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**Total**	***FY 20-21***
Coal Divestiture	Capital	$322.1	$240.8	$152.3	$125.9	$307.5	$1,148.6	*$428.0*
	O&M	$25.0	$37.1	$40.6	$42.2	$44.3	$198.2	*$45.0*
RPS	Capital	$391.3	$288.0	$177.5	$149.6	$331.9	$1,338.3	*$453.1*
	O&M	$25.0	$37.1	$40.6	$42.2	$44.3	$189.1	*$45.0*
Once-Through Cooling	Capital	$92.2	$21.1	$138.3	$293.4	$183.7	$728.7	*$79.3*
	O&M	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	*$0.0*
Energy Efficiency	Capital	$145.1	$178.0	$194.1	$190.4	$172.1	$879.7	*$169.5*
	O&M	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	*$0.0*
Total Expenditures		**$1,000.8**	**$802.0**	**$743.4**	**$843.7**	**$1,083.8**	**$4,473.6**	***$746.9***

C. ONCE THROUGH COOLING

Once-Through Cooling (OTC) is the process where water is drawn from the ocean, pumped through a generating station's cooling system, and then discharged back to the receiving water source. The 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 Statewide 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 the intake screen, passing into the power plant's cooling system.

The Haynes, Harbor and Scattergood stations all currently employ once-through ocean water cooling. The current combined net capacity of these stations is 2,839MW. 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 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 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 remanded the rule and 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. However, before the Rule was remanded, the Department completed the required Characterization Study to identify baseline biological impacts in order to determine appropriate impingement mortality (IM) and entrainment (E) reduction methods.

The EPA publicly noticed the new proposed Rule for existing facilities on April 19, 2011; subsequently, EPA published two Notices of Data Availability (NODA), on June 11, 2012, and June 12, 2012. The final Rule was published in the *Federal Register* on August 15, 2014. In the meantime, the California SWRCB moved ahead with the adoption of its OTC Statewide Policy to limit the use of OTC for power plants in California prior to the EPA formulating its OTC rules.

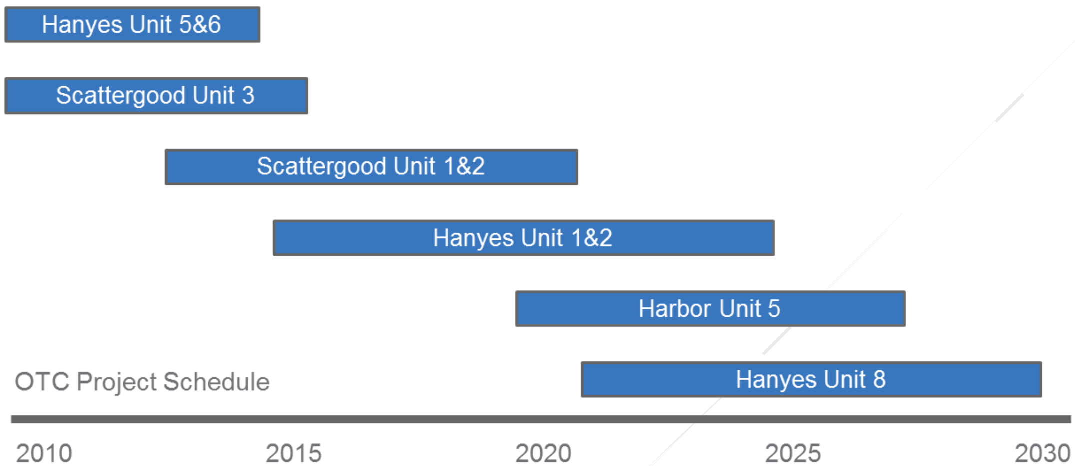
On June 30, 2009, the SWRCB released its draft *Once-Through Cooling Water Policy* for public review and comment, with the accompanying Supplemental Environmental Document released on July 14, 2009. A final Policy version was adopted on May 4, 2010, and became effective on October 1, 2010. The adopted 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 1 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 1 can be demonstrated as “not feasible,” a Track 2 compliance option is available. A Track 2 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 with LADWP’s electrical power supply during implementation of the Policy, 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 as shown in Figure 1. The Department’s financial plan and proposed rates are developed based on this schedule which has been approved by the SWRCB.

Figure 1: OTC Compliance Timeline[1]



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 of the SWRCB 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, 2029.

The Department's repowering program to comply with the SWRCB's Policy by eliminating OTC also addresses 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.

The current status (as of January 2015) of each repowering project is summarized in Figure 2.

[1] 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. Upgrades at the Harbor facility also include replacement of the aging units 1 and 2 which do not currently use OTC.

Figure 2: Repowering and OTC Current Status

Generating Unit	Currently Uses OTC?	Project Status
Harbor Unit 1	No	Repowered and does not use OTC.
Harbor Unit 2	No	Repowered and does not use OTC.
Harbor Unit 3	No	Removed from service.
Harbor Unit 4	No	Removed from service.
Harbor Unit 5	Yes	Steam unit in a combined cycle coupled with 2 gas turbines. Repowering scheduled per Figure 1.
Haynes Unit 1	Yes	Planning and preliminary engineering work is scheduled to start first quarter of 2018.
Haynes Unit 2	Yes	Planning and preliminary engineering work is scheduled to start first quarter of 2018.
Haynes Unit 3	No	Repowered and does not use OTC.
Haynes Unit 4	No	Repowered and does not use OTC.
Haynes Unit 5	No	Repowering completed 12/31/2013 and does not use OTC.
Haynes Unit 6	No	Repowering completed 12/31/2013 and does not use OTC.
Haynes Unit 8	Yes	Steam unit in a combined cycle coupled with 2 gas turbines. Repowering scheduled per Figure 1.
Scattergood Unit 1	Yes	Preliminary engineering and environmental permitting is in progress, and a request for proposal for a design-build contract is scheduled to be advertised in the first quarter of 2017.
Scattergood Unit 2	Yes	Preliminary engineering and environmental permitting is in progress, and a request for proposal for a design-build contract is scheduled to be advertised in the first quarter of 2017.
Scattergood Unit 3	Yes	Engineering and procurement of major equipment are substantially completed and delivered to site, and construction is approximately 50% completed with project scheduled for completion at the end of 2015.

D. ENERGY EFFICIENCY PROGRAMS

1.1 INTRODUCTION

Energy efficiency (EE) is a key strategic element in LADWP's resource planning and is one of the most cost-effective resources within LADWP's power supply portfolio. California Assembly Bill (AB) 2021 calls on publicly-owned utilities (including LADWP) to "identify all potentially achievable cost-effective electricity energy savings and establish annual targets for EE savings and demand reduction for the next ten-year period." In 2012, the Board adopted a target to get on a path to a 10% energy consumption reduction through EE by 2020 and committed to exploring ways to achieve 15% by 2020. In August of 2014, based on a 2014 EE potential study performed by Nexant[1], the Board set additional targets to achieve an energy use reduction through EE of 15% for the ten-year period from FY 2010-11 through FY 2019-20.

EE programs have been employed extensively by LADWP for years to reduce customer electricity usage, power supply costs and carbon emissions. Over the four-year period of FY 2010-11 through FY 2013-14, LADWP spent $215 million on EE ($53.8 million/year on average) and achieved 867,600MWh in net energy savings (216,900MWh/year average). LADWP's current EE goal and corresponding EE spending levels are significantly higher than in the past to achieve the 15% reduction by 2020, placing LADWP on par with California's investor-owned utilities (IOUs) and other utilities in the nation aggressively pursuing EE.

This uptake in spending and annual savings targets to reach the 15% EE goal by 2020 places increasing importance and new challenges on LADWP EE efforts. Programs must therefore have a transparent planning process and plan to verify energy savings, be comprehensive and equitable in nature to cover all customer classes, end-uses and efficiency opportunities, and be effectively delivered through marketing, other community organizations and local workforces.

In response to AB 2021 and the challenge of ramping up EE, the Board of Water and Power Commissioners (Board) adopted principles in 2012 to guide LADWP's EE efforts. These guiding principles are contained in Figure 1 on the next page. In addition to these eight guiding principles adopted by the Board, in the action approving the last Power System rate action in 2012, the LA City Council recommended that LADWP implement recommendations of the Independent Third Party Review, including establishing a plan for EE that maintains expenditure levels at an achievable and cost effective level. The language in the Council recommendation is based on a Ratepayer Advocate (RPA) recommendation to set a firm three-year plan for EE,

[1] This study can be found in Chapter 2 - Appendix E – Energy Efficiency Board Letter.

similar to that of large California IOUs that plan expenditure levels at a realistically achievable tempo according to cost-effectiveness measurements and that includes savings verification.

Figure 1: LADWP EE Guiding Principles

- LADWP will aggressively promote and achieve EE across all customer segments and energy end uses as a key part of LADWP's long-term, supply-side energy procurement strategy.
- Residential customers will be assisted in achieving ultra-high levels of EE in and around their homes with proven economical potential for EE, demand response, and clean energy productions routinely realized on a fully integrated, site-specific basis.
- Commercial customers of all sizes will be assisted in achieving ultra-high levels of EE in and around their businesses with proven economical potential for EE, demand response and clean energy production routinely realized on a fully integrated, site-specific basis.
- Industrial customers will be empowered to demonstrate leadership in proven, economical EE and resource management, which will positively impact their operations.
- Eligible low-income customers will receive tangible economic benefits of EE through the mass adoption of proven, economical low-income EE measures.
- The future benefits of the widespread adoption of EE throughout LADWP territory will be leveraged to support the continued development of quality job opportunities for the local workforce including opportunities at LADWP to address future needs for critical skilled craft positions.
- LADWP is committed to transparency in the administration of its overall EE portfolio, and will report semi-annually on progress towards saving energy, serving a broad range of customers throughout the City, as well as on the training and job creation that results from EE investments. LADWP will provide performance measurement and verification of actual realized energy savings.
- LADWP will collaborate with community organizations to provide outreach and education for its diverse customer base, including hard-to-reach customers such as small business, low-income customers and multi-family units.

1.2 ENERGY EFFICIENCY PORTFOLIO

LADWP created an EE Portfolio Business Plan for FY 2014-15 through FY 2019-20 that contained key information associated with individual programs and the EE portfolio as a whole. LADWP's current EE program portfolio is divided between Mass Market programs (residential and small commercial) and Commercial, Industrial and Institutional (CII), and Cross Cutting (facilities, code, and miscellaneous) programs. A portfolio-approach to EE is important because cost effectiveness may vary widely from program to program. The benefits to some of the less cost effective programs are less financially-tangible in nature; for example, they may be targeted towards low-income or hard-to-reach markets, or they are a part of outreach and education programs. Therefore, providing all services in its portfolio ensures that there are equitable EE programs across all customer classes, and that LADWP continues to approach EE from a holistic point of view.

Figure 2 below shows LADWP's FY 2014-15 EE program portfolio budget organized into Mass Market, Commercial Industrial and Institutional (CII), and Cross-Cutting program types, as well as the necessary program support expenses.

Figure 2: Energy Efficiency Capital Budgets by Program Type

($000)	Current Year	Proposed Rate Period					
	FY 14-15	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**Total**
Mass Market	$48,175	$76,739	$98,297	$100,814	$97,172	$79,395	$452,418
CII	$35,619	$48,456	$56,962	$67,495	$63,094	$58,720	$294,728
Cross-Cutting	$10,187	$9,653	$10,519	$11,482	$12,556	$13,756	$57,965
General Program Support	$7,512	$10,000	$12,000	$14,000	$17,000	$20,000	$73,000
Total	**$101,493**	**$144,848**	**$177,779**	**$193,792**	**$189,822**	**$171,871**	**$878,113**

As shown in Figure 2 above, during the proposed five-year rate period the difference between the combined Mass Market and CII programs budgets (approximately $747 million), and the total EE portfolio budget of close to $878 million, consists of a Cross-Cutting programs budget and a General Program support budget summing to about $131 million. Mass Market programs represent 47% of LADWP FY 2014-15 EE program budget and 36% of overall EE program energy savings. CII programs represent 35% of the budget and 37% of overall EE program savings.

This EE program portfolio budget will prepare LADWP to meet its aggressive 15% goal by 2020. Figure 3 shows the projected EE savings by each program type in the portfolio through the duration of the proposed rate action. Proportionate to the program's budget, the Mass Market programs produce the largest amount of energy savings. In total, the Department estimates achieving an impressive 2,799GWh total of EE savings during the proposed five-year rate period.

Figure 3: Projected Energy Efficiency Savings by Program Type

(GWh)	Current Year	Proposed Rate Period					
	FY 14-15	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**Total**
Mass Market	112.9	202.0	248.9	264.5	274.0	243.8	1,346.1
CII	113.5	148.8	181.0	207.3	188.8	175.0	1,014.4
Cross-Cutting	83.6	91.2	85.2	69.2	57.2	52.2	438.5
Total	**310.0**	**442.0**	**515.0**	**541.0**	**520.0**	**471.0**	**2,799.0**

LADWP's EE Potential Study identifies the commercial sector as yielding the most cost effective energy savings, with over twice the savings potential as the other sectors combined, followed by the residential sector, then the industrial sector. Commercial sector energy savings are found mainly in lighting, cooling and ventilation, and office equipment, with refrigeration and food preparation worth noting. Residential sector savings are found mainly in lighting, electronics and appliances, with cooling and water heating worth noting. Industrial sector savings are mainly associated with machine drives (industrial processes), with lighting and cooling and ventilation worth noting.

LADWP Mass Market programs target difficult to reach low-income, multi-family and small business customers, while CII programs target larger commercial and institutional customers that have a greater array of EE opportunities and economies of scale. As articulated in LADWP's EE Guiding Principles, comprehensiveness and equity considerations compel LADWP to offer EE services to all customer classes. Based on these principles, LADWP has a balanced approach to funding Mass Market and CII programs.

A good portion of LADWP Mass Market program costs pertain to direct install delivery approaches, proven to be effective in reaching low-income, multi-family and small business customers. While less costly financial incentive delivery mechanisms have been tried, none other than direct install has been proven to achieve significant customer participation in these hard to reach markets. Given this situation, and LADWP's desire to address customer needs in these markets for comprehensiveness and equity purposes, delivery efficiencies are particularly important for LADWP to effectively manage costs.

LADWP is aggressively pursuing delivery cost efficiencies, and is forging a relationship with Southern California Gas (SoCalGas) as a significant step forward in doing so. Comprehensiveness and depth of program offerings are enhanced by teaming up with SoCalGas to provide customers with efficiency solutions that cover electricity, water and natural gas. This "one stop shop" concept is a market-oriented approach to program delivery and exemplifies LADWP's interest in comprehensively addressing customer needs. Within LADWP's EE Portfolio Business Plan, there are program strategy tables that summarize the delivery approaches, SoCalGas partnership aspects, and relationship to its guiding principles associated with each program contained in LADWP's overall EE program portfolio.

Figure 4: LADWP Energy Efficiency Program Portfolio

Mass Market Programs	CII Programs	Cross-Cutting Programs
Small Business Direct Install Program	Custom Performance Program (CPP)/CEP	Title 24 and Title 20 Codes and Standards
LAUSD Direct Install	CLIP/CLEO	City Plants Plan
Refrigerator Exchange (LIREP)	Savings By Design (SBD)	LADWP Facilities
Refrigerator Recycling (RETIRE)	Retrocommissioning (RCx)	Program Outreach and Community Partnerships
Home Energy Improvement Program	Refrigeration/Food Service	Emerging Technologies
CA Advanced Homes	Upstream HVAC	
Home Energy Upgrade CA	Energy Efficiency Technical Assistance Program (EETAP)	
Consumer Rebate Program (CRP)		
Energy Service Assistance Program (ESAP) Low Income Multi-Family		
Residential Lighting		
Behavioral-Based		
Consumer Electronics		

1.2.1 Mass Market Programs

Small Business Direct Install Program

The Small Business Direct Install Program (SBDI) is a free direct install program in which the LADWP targets small and medium businesses, offering upgrades to targeted systems, including lights, water and natural gas. The electricity side of the program, which deals with the lighting measures, has been up and running since the first half of 2013 and is currently fully ramped-up.

SBDI is an important program in LADWP's EE program portfolio, currently budgeted for nearly one third of the total EE program budget. It creates a large amount of energy savings and is also a strong job creator, both directly and induced.

LAUSD Direct Install Program

The LAUSD Direct Install Program is a free direct installation program jointly run by LADWP and the Los Angeles Unified School District (LAUSD) and in partnership with SoCalGas. It targets schools in the district in need of energy and water efficiency upgrades, addressing lighting systems, including switches and controls, as well as water efficiency measures.

This program combines the efforts of the LADWP ISS department and LAUSD's maintenance and facilities crew. LADWP provides design assistance and project management experience along with actually doing retrofits for certain types of interventions. LAUSD is LADWP's largest electric customer. Given this relationship, a cost and energy saving partnership between the school district and utility has the potential to greatly benefit both parties.

The program started in the last quarter of 2012 and ramped-up significantly in 2013. The projects included in this program can be complex from logistical and technical standpoints and can take three to six months or more to complete. The LAUSD Direct Install Program is important in LADWP's EE program portfolio, currently budgeted at around 10% of the total EE program budget.

Low Income Refrigerator Exchange Program

The Low Income Refrigerator Exchange Program (LIREP) is a program that delivers free new EE refrigerators to low-income and senior/lifeline LADWP customers who have refrigerators meeting a certain criteria, including being at least ten years old, 14 cubic feet or greater and in working condition. These older, inefficient refrigerators are a major source of electricity consumption as they run all day, every day and are not built to current Energy Star standards. The program ensures that the old refrigerators stay offline and cannot burden the grid by picking them up and recycling them when a new one is delivered.

As part of the effort to promote EE, customers receive four free CFL light bulbs as well when they receive their new refrigerator. This is not considered an added cost to the program because LADWP purchased these bulbs several years ago through another program and they remain available to be provided. As with all of the programs in LADWP's EE portfolio, this program has the dual benefit of lowering demand on the grid while also lowering the customers' bills.

The LIREP is run through a third party contractor, Appliance Recycling Centers of America (ARCA) with just a couple of LADWP employees needed to administer the program for LADWP. ARCA handles the pickup and delivery of the refrigerators, the recycling of the old refrigerators, the program intake and call center, marketing and customer service. This is a mature program that has been around since 2007, but has seen notable variations in the number of annual refrigerator deliveries over the years.

Despite the eponymous implications of its name, the program will start expanding beyond low-income and lifeline customers into other customer segments, including multi-family buildings, schools, congregational institutes, civic and community buildings. While it is a capital-intensive program, with the cost of the refrigerators making up the majority of program costs, the reduction to grid demand is very high and of significant benefit to LADWP.

Refrigerator Recycling (RETIRE)

LADWP offers the REfrigerator Turn-In and REcycle (RETIRE) Program to its residential customers to encourage safe and environmentally friendly recycling of old, energy inefficient refrigerators and freezers. Recycling an old refrigerator/freezer can help customers reduce their energy bill by up to $192 per year. Pick-up and recycling services are offered at no cost to customers, and they receive a $50 rebate.

Home Energy Improvement Program

The Home Energy Improvement Program (HEIP) is a free direct install program which targets residential customers. It offers a full suite of free products and services to improve energy and water efficiency in the home by upgrading or retrofitting a home's envelope and core systems. Targeted systems include lights, water and natural gas. This program is not specifically limited to low-income customers; however, its priority is to serve low, moderate and fixed income customers most in need first.

This program is run directly by LADWP, with the Integrated Support Services (ISS) department handling the assessments and installations and the EE team responsible for program design, management and billing.

CA Advanced Homes[2]

The California Advanced Homes Program (CAHP) was created to help the building industry design and develop more environmentally friendly communities. It highlights best practices in EE, green building and sustainability, and offers generous financial incentives to help builders and architects create environmentally friendly, energy-efficient communities for potential new home buyers. The CAHP is a comprehensive residential new construction concept with a focus on sustainable design and construction. Through a combination of education, design assistance, and financial support, the CAHP works with building and related industries to exceed compliance with the California Code of Regulations, Title 24, 2013 Building Energy Efficiency Standards for Residential and Nonresidential Buildings (Standards), to prepare builders for changes to the Standards and to create future pathways beyond compliance and traditional energy savings objectives. For projects within the City of Los Angeles, the maximum incentive per project is $250,000 (includes incentives and "bonus kickers").

Home Energy Upgrade CA

Through Energy Upgrade California, incentives of up to $6,500 are available to LADWP residential customers with detached single-family units who complete qualifying energy-saving home upgrade projects, including upgrades to air sealing, insulation, windows, cool roofs, and upgrades to heating and cooling systems.

Consumer Rebate Program

The Consumer Rebate Program (CRP) is an incentive based program which pays LADWP customers a fixed amount of money for a short menu of items. This program is intended for residential customers, with the goal of helping consumers choose a more energy efficient option when purchasing certain items. CRP is a mature program with a steady annual amount of

[2] For additional information, see http://californiaadvancedhomes.com/

participation that does not vary greatly except when LADWP makes extra marketing outreach efforts.

Energy Service Assistance Program (ESAP) Low-Income Multi-Family

The Energy Savings Assistance Program provides no-cost weatherization services to low-income households who meet the CARE income guidelines. Services provided include attic insulation, energy efficient refrigerators, energy efficient furnaces, weather-stripping, caulking, low-flow showerheads, water heater blankets, and door and building envelope repairs which reduce air infiltration.

Residential Lighting

The Residential Lighting Efficiency Program (RLEP) will provide light-emitting diode (LED) lamps to customers to assist in reducing their home electrical use. Distribution of the LED lamps will be via two channels: Point-of-Sale (POS) transactions at home improvement stores within LADWP's service territory and through targeted regional distribution, where the lamps will be dispersed door-to-door. The lamps will be dispersed over several years in order to reach the entire targeted audience. This program is currently under development; the anticipated implementation date is June 2015.

Behavioral-Based

The Behavior-Based Efficiency Program (BEP) focuses upon influencing customers to reduce residential electricity usage through changes in behavior. Customers who elect to participate in this program are provided with a Home Energy Saver (HES) report at regular intervals, which is customized for the customer's usage profile. The report also provides energy consumption comparisons to other customers, tips for reducing electric use and referrals to other LADWP energy-saving programs. This program is currently under development; the anticipated implementation date is June 2015.

Consumer Electronics

The Consumer Electronics (CE) Program is a new incentive program that will offer rebates for high efficiency consumer electronics such as televisions, computers, and monitors. This program is currently under development; the anticipated implementation date is June 2015.

1.2.2 Commercial, Industrial, and Institutional Programs

Custom Performance Program

The Custom Performance Program (CPP) is an incentive based program which pays LADWP commercial customers a fixed amount of money for energy savings attained through a range of measures. This program is custom because it focuses on measures not covered by other existing prescriptive programs, often including those measures that go beyond basic turn-key efforts. Retrofits should help buildings go beyond Title 24 requirements or industry standards, and may include measures such as equipment controls, CO monitoring systems, hotel guest room controls, variable frequency drives, cutting edge high-efficiency lighting technologies and other innovative interventions.

Customers' applications include an energy assessment for their building, which helps to guide and inform what measures will be undertaken in the custom retrofit. The assessment estimates the amount of kWh savings achievable through various proposed interventions, and incentive rates are based on a fixed price per saved kWh. LADWP pays out the incentive to customers only after a post-retrofit on-site inspection is made to verify the work. Figure 5 shows the rates paid for the different types of incentives.

Figure 5: Custom Performance Program Incentive Payments

Measure	Incentive Level
Controls/RCx	$0.15/kWh
Plug/Process/Other	$0.15/kWh
Air conditioning and refrigeration	$0.25/kWh
Envelope	$0.25/kWh
Lighting (including LED)	$0.15/kWh
Lighting Controls	$0.10/kWh
Lighting (Lamp Only)	$0.05/kWh
Thermal Energy Storage	Up to $750/kWh

CPP is a mature program generally focused for the most part on larger structures where deep custom retrofits and other installations can help realize substantial energy savings. The program is not limited to these customers; however, the smaller commercial customers have more barriers to entry in terms of project financing and getting over the hurdle of an initial assessment. The program mainly attracts customers through targeted outreach by executive account managers at LADWP. At 18.1% of the overall EE budget, CPP represents an important part of LADWP's EE portfolio, and it plays an even bigger role in terms of its share of energy savings generated in the portfolio.

Commercial Lighting Efficiency Offer

The Commercial Lighting Efficiency Offer (CLEO) is an incentive based program that pays LADWP commercial customers a fixed amount of money to upgrade their lighting to more efficient options. It has historically been one of the most popular and robust commercial EE rebate programs in LADWP's EE portfolio. The incentivized measures in this program each have a set incentive price that was arrived at with consideration for energy savings over a standard time period and the average cost of the measure (material and install).

The menu of items in the program contains a wide variety of high performance lighting measures, including high efficiency fluorescents, CFLs, LEDs and other outdoor pole mounted fixtures. In practice, a large portion of the retrofits consist of some variation of a T12 fluorescent fixture and lamp getting converted to a higher efficiency T8 fluorescent (some variation on a 4 foot fixture). This is attributable to a number of factors. 4-foot and 8-foot T12 fluorescent fixtures were standard in office buildings, warehouses, factories and other commercial structures, so they make up a lot of the stock that needs retrofitting. Additionally, retrofitting one of these fixtures can be simple and cheap, making it a very cost effective intervention. Finally, many of the customers utilizing this program need to get into compliance with California Title 24 standards. Presumably, this pattern will change as the old T12 stock diminishes, new Title 24 standards come along and different interventions become more cost effective (such as LED lamps).

This is a mature program that is seeing some changes in the profile of the typical applicant. In past years of the program, bigger jobs that took longer and had more of a profit margin for a contractor made up the majority of projects in the program. Large office buildings or hospitals would do a complete lighting retrofit. Now, with many larger customers already having performed the retrofits to reach Title 24 compliance, the program is starting to see a change in the model, according to interviews with the program manager. It is now common to see a contractor bundle many smaller retrofits that can be done quickly. Each business will have to apply individually, but generally the contractor will handle all this paperwork and take the incentive money as payment while the business receives the benefit of the energy savings. The contractor in these cases will earn less on each job, making their profit on volume.

Savings by Design (SBD)[3]

Savings by Design encourages high-performance, non-residential building design and construction, and offers a variety of solutions to building owners and design teams including, but not limited to:

- Owner Incentives help offset any additional costs of energy efficient buildings;
- Design Team Incentives reward designers who meet ambitious EE targets;
- Design Assistance supports integration of innovative design technologies into new construction projects; and
- Energy Design Resources offers analysis tools, training, and in-depth information on efficient technologies and strategies.

Retrocommissioning (RCx)

Customers of the Department who own a business, or are a non-residential customer, can qualify for the the RCx program and reduce their electricity and gas usage as well as reduce the cost of building operations. By implementing one or more of the program's 13

[3] For additional information, see http://www.savingsbydesign.com/faqs

retrocommissioning (RCx) measures, customers can save on energy costs and improve building operations. This is a simplified program that requires minimal system data and uses "prescribed" savings calculations, which makes the process much easier. The RCx offers:

- Varying cash incentives per kilowatt hour (kWh) saved (annualized);
- Varying cash incentives per therm saved (annualized);
- Lower energy bills;
- A more productive facility;
- More efficient building operations;
- Longer equipment life;
- A building assessment by qualified engineering professionals; and
- Support throughout the process.

The RCx program has 13 common controls and schedule based commercial building optimization measures divided into three categories.

<u>HVAC Airside Measures</u>

- Reduce supply fan operating schedule
- Adjust airside economizers
- Adjust zone temperature deadband
- Add supply air temperature setpoint reset strategy
- Reduce supply duct static pressure setpoint
- Add supply duct static pressure setpoint reset strategy
- Add/restore supply fan VFD (Requires malfunctioning inlet guide vanes, or malfunctioning VFDs)

<u>HVAC Waterside Measures</u>

- Add/optimize boiler lockout
- Add chilled water supply temperature setpoint reset strategy
- Add condenser water supply temperature setpoint reset strategy
- Restore chilled water pump VFD

<u>Lighting Measures</u>

- Reduce lighting operating schedule
- Restore lighting occupancy sensors

Refrigeration / Food Service

LADWP's Food Service Program helps reduce customers' electricity bills and the cost of new refrigeration equipment by replacing or retrofitting existing refrigeration equipment with state-of-the-art, EE refrigeration technologies. Rebate measures include ice machines, solid and glass refrigerator doors, door gaskets, night covers, strip curtains, vending machine controllers, and other energy efficient measures.

Upstream HVAC

The nonresidential Upstream Heating, Ventilation and Air Conditioning (HVAC) Program is a market transformation oriented program. This program offers incentives to upstream market players who sell qualifying high efficiency HVAC equipment. The logic that underscores this program's design is that a small number of upstream market participants are in a position to impact thousands of customers and influence their choice of equipment by increasing the stocking and promotion of high efficiency HVAC equipment. The upstream model cost effectively leverages this market structure and existing relationships. The upstream program is designed to adapt to market changes, and therefore LADWP will continue working with relevant industry players to continually enhance the program to include new beyond-code upstream incentives.

Energy Efficiency Technical Assistance Program

The EE Technical Assistance Program (EETAP) is an incentive based program which pays LADWP commercial customers to perform an energy audit on their building. The incentive that LADWP pays is based on the projected kWh savings the audit finds. As the name suggests, this program is strictly for technical assistance at the outset of a project, and is a feeder program to the Custom Performance Program (CPP), which incentivizes the actual retrofit. These types of projects are typically very unique, are not necessarily scalable to the average customer, and have savings that are a tremendous benefit to these LADWP customers.

The goal of the program is to help customers get over the initial barrier to entry of doing a deep retrofit. The payment of the incentive depends on the level of energy audit. Fifty percent of the incentive for an American Society of Heating Refrigeration and Air-Conditioning Engineers (ASHRAE) Level 1 Assessment will be paid out after the audit is completed and the rest after the actual retrofit is performed. One hundred percent of the incentive will be paid out after the actual retrofit is performed for an ASHRAE Level 2 or 3 Assessment.

EETAP is a new program, launched at the beginning of February 2014. As of the beginning of May 2014, LADWP had received a limited number of applications and approved the energy audits, but no customers had actually had the audits performed yet. Thus far, the applicants to the program have all opted for an ASHRAE Level 2 or 3 Assessment.

1.2.3 Cross-Cutting Programs

Title 24 and Title 20 Codes and Standards

The Codes, Standards and Ordinances (CSO) Program conducts advocacy activities to improve building, appliance and water use efficiency regulations. These activities include monitoring and active participation in code and standard development, legislative review, sponsorship of local ordinances, and participation in policy efforts with other City departments, State agencies, and utilities. The goal of this program is to promote sustainability with regard to water and energy use. The principal audience includes the LA City Department of Building and Safety, LA City Planning, LA City Department of Public Works, and the LA City Council, who together develop and adopt codes and standards specific to Los Angeles that go beyond State and Federal regulation. Other audiences include State agencies, which conduct periodic rulemakings to update EE and water conservation regulations and standards, and industry groups that conduct research and develop industry specific standards.

City Plants Program

The City Plants program, formerly called Million Trees LA, provides free shade trees for residential customers and property owners and plants street trees around the City of Los Angeles. The program is a public-private partnership between the City of Los Angeles, local non-profit organizations, community groups, residents and businesses. LADWP is City Plants' largest sponsor, and with this partnership, City Plants is able to provide, in addition to the trees, important information on where to plant the trees to maximize EE of buildings.

The program encourages the planting of California Friendly Landscapes trees that are adapted to the region's semi-arid climate and that use less water. Native trees and drought tolerant trees that maximize sustainability are recommended. City residents and property owners are eligible to receive up to seven shade trees to plant on their property. Trees must be maintained by the property owner.

Customers are encouraged to plant the trees on the south or west side of their building if possible. Planting trees on these two sides provides shade during the hottest parts of the day. This cooling effect on the building reduces the need for air conditioning in the home, creating instant energy and cost savings.

This program is primarily run by and is principally handled by the LADWP contractor, the Los Angeles Conservation Corps (LACC). LACC procures the trees and related materials, maintains the trees before they are given away and delivers trees. LACC has several sub-contractors that also handle some of the tree requests/giveaways and delivery. Monthly reports on requests, tree purchases, giveaways and other programmatic details are sent to LADWP.

City Plants is a unique program within LADWP's EE portfolio. While most of the other programs focus on improving the efficiency of a system within a building (i.e. HVAC, lighting) or the actual performance of a building, City Plants improves building efficiency through an external intervention that never touches a building.

LADWP Facilities Upgrade Program

The LADWP Facilities Upgrade Program, as the name indicates, is a program designed to improve the energy and water consumption performance of LADWP facilities. The program was established in 2009 in response to the City of Los Angeles Green LA Directive. Twenty-seven targeted systems include HVAC equipment, lighting fixtures, plumbing fixtures and irrigation equipment.

The three targeted systems in the program — HVAC, lighting and water — are each managed separately. HVAC and lighting projects are administered by the EE department, but the water upgrades are performed by the water side of LADWP and accounted for separately. This program is run directly by LADWP, with projects identified and prioritized and subsequently performed by ISS construction personnel.

In addition to setting a good example and precedent of EE for other City of Los Angeles departments, this program results in reduced electricity and water expenses for LADWP. This ultimately benefits the ratepayer in the form of mitigated costs that otherwise would have been passed along.

Program Outreach and Community Partnerships

The Program Outreach and Community Partnerships Program (Program) is an advocacy program that strives to improve customer awareness among LADWP's "hard-to-reach" customers of electric and natural gas efficiency and water conservation programs through the activities of community-based organizations. In FY 2014-15, this program offers grants to local non-profit organizations that are awarded through a competitive selection process to work in one of the fifteen Los Angeles City Council Districts or on an at-large/city-wide basis to improve community and customer awareness of LADWP's core EE and water conservation programs and free steps they can take to reduce energy and water use.

Emerging Technologies

The LADWP Emerging Technologies Program (ETP) is designed to accelerate the introduction of innovative energy and water efficient technologies, applications, and analytical tools that are not yet widely adopted in California. By reducing both the performance uncertainties associated with new products, as well as institutional barriers, the ultimate goal of this Program is to increase the probability that promising energy and water efficiency technologies will be commercialized and adopted throughout Los Angeles. Activities include supporting the development of the energy and water efficiency technology demonstration features of the La Kretz Innovation Center and partnering with SoCalGas and the Emerging Tech Coordinating Council to assess and introduce new technologies.

1.3 COST EFFECTIVENESS REVIEW

The Department uses a series of industry accepted and CPUC mandated tests called the California Standard Practice Manual (SPM) tests to determine the cost-effectiveness of EE programs. The four tests are:

- Total Resource Test (TRC);
- Program Administrator Cost (PAC);
- Ratepayer Impact Measure (RIM); and
- Participant Cost Test (PCT).

The TRC test is considered as the measurement of the net benefits and costs that accrue to society, which is defined as a program administrator (usually a utility) and all of its customers. It compares the benefits, which are the avoided cost of generating electricity and supplying natural gas, with the total costs, which include program administration and customer costs. The TRC does not include the costs of incentives.

On the other hand, the PAC test does not include the costs incurred by participating customers but does include incentives paid to participating customers. The PAC test measures the benefits and costs that accrue to the program administrator, which is usually, but not always, the utility.[4] Although the TRC has traditionally been the "standardized" metric on which EE programs are evaluated, the Department advocates that the PAC test may give a more accurate view of the levelized energy value of an EE program during its time period of operation.

LADWP EE uses the "E3 Calculator" for examining program cost effectiveness. The E3 Calculator is an Excel-based tool provided by the CPUC and CEC and is used by California IOUs and others to compute the cost effectiveness of EE and other demand-side programs. Inputs to the calculator include the energy savings and costs of each measure proposed in a program, the anticipated installation rate, and costs related to program administration and implementation. The E3 Calculator relies on the CPUC Database for Energy Efficient Resources (DEER) for information on EE technologies and measures. IOU avoided cost models are built into the E3 Calculator to calculate TRC, PAC, and RIM test results. In using the E3 Calculator LADWP EE relies on the Southern California Edison (SCE) avoided cost model to represent LADWP marginal costs.

Recent calculations by LADWP EE show an overall EE portfolio TRC benefit cost ratio of 2.4, indicating that the LADWP EE program portfolio is easily cost effective, with almost two and a half times the avoided cost savings compared to LADWP and participant program costs. LADWP EE programs with the best TRC benefit to cost (B/C) ratios are mainly CII programs, including:

- Custom Performance (3.4 TRC B/C ratio); and
- Commercial Lighting Efficiency (2.56 TRC B/C ratio).

[4] For further information on the SPM tests please see http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Cost-effectiveness.htm

The Mass Market program with the most compelling benefit to cost ratio is Refrigerator Turn In and Recycle (7.1 TRC B/C ratio); however, most programs are cost effective (B/C ratio greater than 1). Programs with lower benefit cost ratios tend to be low-income programs that LADWP will continue for comprehensiveness and equity purposes.

Historically and into FY 2014-15, LADWP's biggest program budget has been for Small Business Direct Install, which is easily considered cost-effective based on total cost (2.7 TRC B/C ratio).

LADWP is currently examining the appropriateness of the ratepayer impact measure (RIM) test given the utility's configuration. The IRP models the net revenue loss from EE by subtracting the avoided supply costs and the fixed billing charges from the gross revenue loss. The IRP indicates demand side programs such as EE primarily reduce the fuel and variable costs of marginal gas fired generation. In addition, this calculation shows that EE is a vital part of the Department's resource portfolio, reducing the energy demand LADWP would otherwise have to meet with additional thermal or renewable generation. Also, EE reduces net customer sales, which in turn means that less renewable energy must be procured by the Department to meet RPS targets.

Within the IRP, net present value (levelized cost) of energy produced by a new combined cycle gas turbine is estimated to be $80/MWh, or 8 cents per kWh. Within LADWP's EE Portfolio Business Plan, the current EE program portfolio is calculated to cost approximately 4 cents per kWh. Therefore, there is a significant positive difference in the cost per kWh between the current EE program portfolio and viable generation resources.

1.4 GHG EMISSIONS

EE is one of the most sustainable and cost effective ways to decrease the Department's greenhouse gas (GHG) emissions. The Department expects to attain significant CO_2 reductions through the expansion of its EE programs. This leads to improving the air quality of the Los Angeles region and contributes to the public health of its residents. As shown in Figure 6, the Department projects a 1,133,504 metric ton CO_2 reduction over the proposed five-year rate period.

Figure 6: Projected CO_2 Reductions from EE (metric tons)

	Current Year	Proposed Rate Period					
	FY 14-15	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**Total**
Mass Market	60,164	107,296	111,763	117,218	119,437	104,080	559,794
CII Programs	60,489	79,039	81,258	91,882	82,315	74,709	409,203
Cross Cutting	44,581	48,425	38,245	30,652	24,920	22,267	164,509
Total	**165,233**	**234,759**	**231,266**	**239,752**	**226,672**	**201,055**	**1,133,504**

E. ENERGY EFFICIENCY BOARD LETTER

This appendix includes the letter that the Department provided to the Board in August 2014 with the new energy efficiency targets of 15% by FY 2020 for approval. It also includes the Nexant Energy Efficiency Territorial Potential studies performed to support this goal.

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Los Angeles Department of Water & Power

RESOLUTION NO. 015 007

AUG 0 5 2014

BOARD LETTER APPROVAL

1- COPY RESO TO PDF- PWR. Chief Sustain. 8/5/14

NANCY H. SUTLEY
Chief Sustainability and Economic Development Officer

RANDY S. HOWARD
Senior Assistant General Manager - Power System

MARCIE L. EDWARDS
General Manager

DATE: July 18, 2014

SUBJECT: LADWP Energy Efficiency Goals for Submission to the California Energy Commission (CEC) as Required by Assembly Bill 2021

SUMMARY

The attached Resolution recommends approval of the Los Angeles Department of Water and Power's (LADWP) annual targets for energy efficiency savings and demand reduction over ten years ending in FY 2022-23, which will be submitted to the California Energy Commission (CEC) pursuant to the requirements of Assembly Bill (AB) 2021 (2006), Sections 2 and 3 (added Section 25310 to Public Resources Code and amended Section 9615 of the Public Utilities Code).

The proposed AB 2021 targets represent a total goal of 3,596 GWh in energy use reduction compared to the baseline forecast over the ten-year period from FY 2013-14 through FY 2022-23, which would result in total cumulative energy savings over the same period of 13.7 percent. This exceeds the minimum AB 2021-required cumulative energy savings goal of 10 percent over the ten-year period by 37 percent. The proposed targets also upwardly revise the most recent set of prior energy efficiency targets, adopted in 2012.

In addition to exceeding state requirements, LADWP also seeks to accelerate program efforts such that the majority of the total savings will be achieved by 2020. Using FY 2010-11 as the starting year, LADWP seeks to build on the actual energy efficiency results of FYs 2010-11, 2011-12, and 2012-13 to achieve cumulative energy savings of

15 percent versus baseline sales projections across the ten-year period from FY 2010-11 through FY 2019-20. This acceleration of savings will result in more customers participating in energy efficiency programs sooner, and thus realizing more energy and bill savings. This will also accelerate delivery of the other benefits of LADWP's energy efficiency programs as specified in the Guiding Principles for the Energy Efficiency Portfolio, adopted by the LADWP (Adopted Board Resolution 013 028, August 7, 2012).

While these targets are aggressive, LADWP expects to achieve them at a levelized cost of $0.042/kWh, which is in line with the energy efficiency portfolios of other large utilities in California, and is also favorably comparable to new generation resources. However, adopting these targets is not without trade-offs or risks. The new energy efficiency targets would require 1.3 percent per year in additional rate adjustments versus a plan that would achieve the 10 percent by 2020 savings required by AB2021. The proposed energy efficiency target will require an additional 0.6 percent per year rate impact above the less aggressive target that was contemplated in the adopted FY14/15 budget, which would have achieved about 12.5 percent energy savings by 2020. These are the net system average rate impacts from factors including reduced power revenue to cover LADWP fixed costs, the cost of the incentives, offset by reduced fuel costs. Individual customers who take advantage of the energy efficiency programs to reduce their consumption can lower their bills despite the slightly higher rates.

Additionally, many external factors may affect LADWP's ability to achieve these targets, such as hiring and staffing limitations; market saturation or customer non-responsiveness to energy efficiency messaging and incentives; uncertainty around future rate increases; etc. Failure to achieve the targets could lead to increased costs as LADWP may need to seek additional generation resources to cover any shortfall or meet state requirements around renewables. LADWP staff will mitigate these risks by constantly monitoring such factors and taking proactive actions to avoid or correct them.

RECOMMENDATION

It is recommended that the Board of Water and Power Commissioners adopt the attached Resolution approving the energy savings shown herein.

BACKGROUND

In accordance with AB 2021, the State Legislature intended that load-serving entities procure all cost-effective energy efficiency savings and specified that each local publicly owned electric utility first acquire all energy efficiency and demand reduction resources that are cost-effective, reliable, and feasible.

Pursuant to AB 2021, each publicly owned utility is instructed to identify all presently achievable, cost-effective efficiency potential on a periodic basis and establish annual targets for the ensuing ten-year period, such that these targets result in cumulative energy savings of at least 10 percent versus baseline sales projections. Originally the periodic basis for identifying energy efficiency potential and setting ten year targets under AB 2021 was every three years; pursuant to AB 2227 (2013) this was extended to every four years, starting in 2017.

Publicly owned utilities are the required to submit the ten-year energy savings and demand reduction targets to the CEC. LADWP presents the targets proposed here for Board adoption for submission to the CEC in satisfaction of the requirements of AB 2021.

ALTERNATIVES CONSIDERED

Summary of Process to Develop Recommended AB 2021 Energy Efficiency Targets. The LADWP hired Nexant, Inc. (Nexant) to conduct an Energy Efficiency Potential Study (Study) for LADWP's service territory to determine the potential energy savings over a 10-year period. The Study was completed in June 2014.

The Study presents a number of energy savings scenarios compliant with AB 2021 requirements and estimates the annual program expenditures levels necessary for achieving the cumulative targets for energy savings and peak demand reduction potential for each investigated scenario. LADWP sought a scenario yielding a high level of total savings across the ten-year planning period while keeping estimated annual expenditures reasonably in line with previous projections.

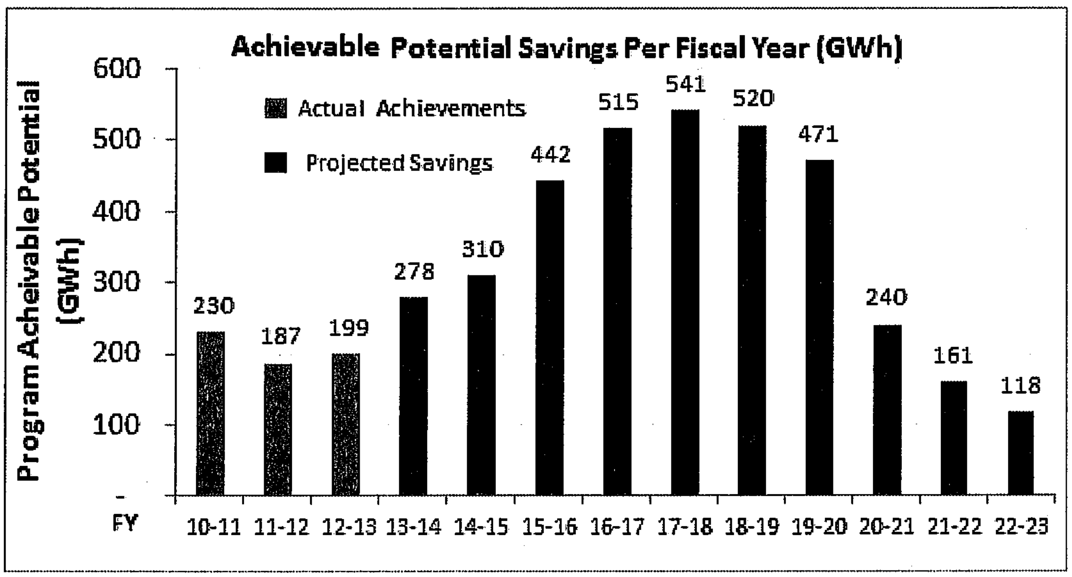
The Study initially analyzed program potential scenarios that represent a broad-brush approach to estimating potential based on assumed incentive and administration/marketing costs. The Study then analyzed, in more detail, ten program planning scenarios to demonstrate how changing assumptions on program delivery, including incentives, administration/marketing, benefit-cost thresholds, and market participation rates can create a range of projected expenditures required to reach the annual savings targets. The energy efficiency savings targets for the ten-year period from FY 2013-14 through FY 2022-23 proposed for submittal to the CEC are based on the Detailed Program Planning Scenario 10 in the Study.

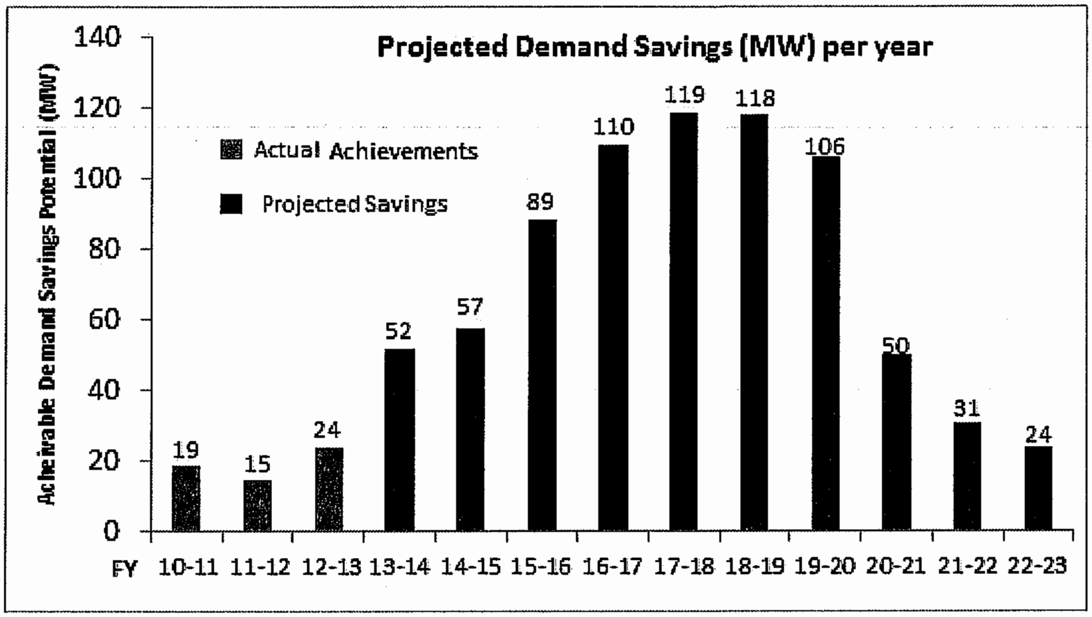
The proposed AB 2021 targets represent a total goal of 3,596 GWh in energy use reduction compared to the baseline forecast over the ten-year period from FY 2013-14 through FY 2022-23, which would result in total cumulative energy savings over the same period of 13.7 percent. This exceeds the minimum AB 2021-required cumulative energy savings goal of 10 percent over the ten-year period by 37 percent.

In addition to exceeding state requirements by setting annual targets that would achieve 13.7 percent across the AB 2021 timeframe of FY 2013-14 through FY 2022-23, LADWP also seeks to accelerate program efforts such that the majority of the total savings will be achieved by 2020. Using FY 2010-11 as the starting year, LADWP seeks to build on the actual energy efficiency results of FYs 2010-11, 2011-12, and 2012-13 to achieve cumulative energy savings of 15% versus baseline sales projections across the ten-year period from FY 2010-11 through FY 2019-20. This acceleration of savings will result in more customers participating in energy efficiency programs sooner, and thus realizing more energy and bill savings. This will also accelerate delivery of the other benefits of LADWP's energy efficiency programs as specified in the Guiding Principles for the Energy Efficiency Portfolio, adopted by the LADWP (Adopted Board Resolution 013 028, August 7, 2012).

Scenario 10 of the Study exceeds the AB 2021 minimum ten-year goal, as well as satisfies LADWP's intent to accelerate savings results by 2020.

LADWP Recommended AB 2021 Energy Efficiency Targets. The charts below shows the energy and demand savings for FY 2013-14 through FY 2022-23 targets for the recommended Scenario 10 from the Study. For reference, actual savings are included on each graph for FY 2010-11 through FY 2012-13. While these targets are aggressive, LADWP expects to achieve them at a levelized cost of $0.042/kWh, which is in line with the energy efficiency portfolios of other large utilities in California, and is also favorably comparable to new generation resources.

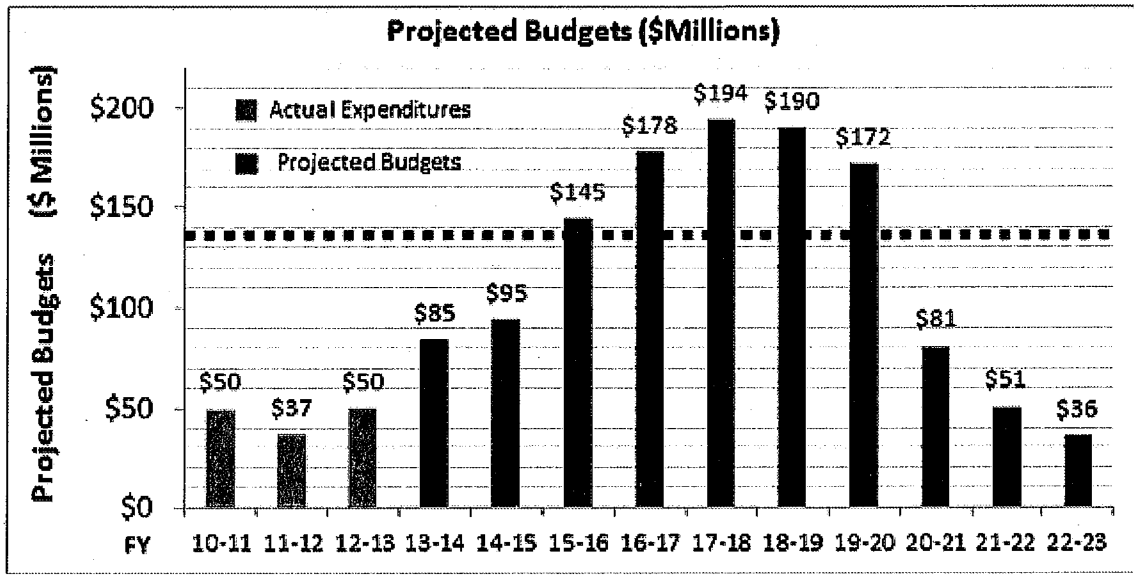




FINANCIAL INFORMATION

The energy efficiency programs required to meet the proposed savings targets totaling 3,596 GWh for the ten-year period between FY 2013-14 and FY 2022-23 will require a substantial investment currently estimated at $1.225 billion over the ten-year period. However, LADWP is not seeking the approval of any additional funding at this time. Annual funding levels allocated for energy efficiency as part of the Power rate increase (Adopted Board Resolution 013 053, September 12, 2012) are expected to be sufficient for at least the first three years of the ten year period. Funding for energy efficiency programs assumes the ability of LADWP to recover revenue losses and other costs for the programs through the Energy Cost Adjustment Factor or other revenue stability means. The new energy efficiency targets would require 1.3 percent per year in additional rate adjustments versus a plan that would achieve the 10 percent by 2020 savings required by AB2021. The proposed energy efficiency target will require an additional 0.6 percent per year rate impact above the less aggressive target that was contemplated in the adopted FY14/15 budget, which would have achieved about 12.5 percent energy savings by 2020. These are the net system average rate impacts from factors including reduced power revenue to cover LADWP fixed costs, the cost of the incentives, offset by reduced fuel costs. Individual customers who take advantage of the energy efficiency programs to reduce their consumption can lower their bills despite the slightly higher rates. Individual customers who take advantage of the energy efficiency programs to reduce their consumption can lower their bills despite the slightly higher rates.

The chart below shows the estimated annual expenditures for FY 2013-14 through FY 2022-23 for the recommended Scenario 10 from the Study. For reference, actual expenditures are included for FY 2010-11 through FY 2012-13. The dotted line represents level to which energy efficiency is currently funded annually as a result of the Power rate increase (Adopted Board Resolution 013 053, September 12, 2012). This level corresponds to an annual funding level of $138 million, and demonstrates that substantive additional funding for energy efficiency is not expected to be needed until FY 2016-17.



RISKS & MITIGATION

The recommended targets are aggressive by the standards of typical utility-administered energy efficiency programs, but are not unprecedented. Several categories of risk accompany the targets. The primary risk to LADWP in adopting these targets is that since they are factored into the Integrated Resource Plan (IRP) as a supply-side resource, if the targets are ultimately not met, LADWP could have to find incremental generating resources to make up for any shortfall. Also, since energy efficiency is a cost-effective strategy to reduce the amount of renewable resources that have to be procured to meet California's Renewable Resource Standard, a shortfall in energy efficiency results could increase the amount of renewables required. LADWP will mitigate both of these risks by assessing energy efficiency program performance versus the targets throughout each year, and adjusting the IRP accordingly on an annual basis. Therefore, any failure to meet an annual energy efficiency target will be identified and incorporated into the IRP immediately, preventing any accumulation of shortfalls that are only identified when it is too late to adjust generation and renewable resources to address them. Nevertheless, as many power resources decisions are made several years into the future, identified shortfalls may need to be addressed through less preferable power supply options such as spot market purchases, which often carry additional costs.

The other category of risk for LADWP in adopting these aggressive targets is that external factors beyond LADWP's control may intercede and preclude achievement of the targets in any given year. Such factors may include, but are not limited to, hiring and staffing limitations; market saturation or customer non-responsiveness to energy efficiency messaging and incentives; uncertainty around future rate increases; regional, state, national or global economic conditions and the financing/investment environment; unforeseen circumstances that necessitate the redeployment of energy efficiency resources to other higher-priority areas; etc. LADWP staff will mitigate these risks by monitoring such factors and taking proactive actions to avoid or correct them. In any year that LADWP does not achieve the energy efficiency target, staff will, in addition to working with the Power System to address the shortfall in the annual IRP, conduct a root-cause analysis of the external factor(s) contributing to the failure to meet the target and propose corrective action(s) to prevent recurrence.

ENVIRONMENTAL DETERMINATION

In accordance with the California Environmental Quality Act (CEQA), it has been determined that Resolution is exempt pursuant to the General Exemption described in CEQA Guidelines Section 15061 (b)(3). General Exemptions apply in situations where it can be seen with certainty that there is no potential that the activity in question may have a significant effect on the environment.

CITY ATTORNEY

The Office of the City Attorney reviewed and approved the Resolution as to form and legality.

ATTACHMENTS

- Resolution
- Energy Efficiency Potential Study (Volume I)
- Resolution 013 028 (Guiding Principles for the Energy Efficiency Portfolio)

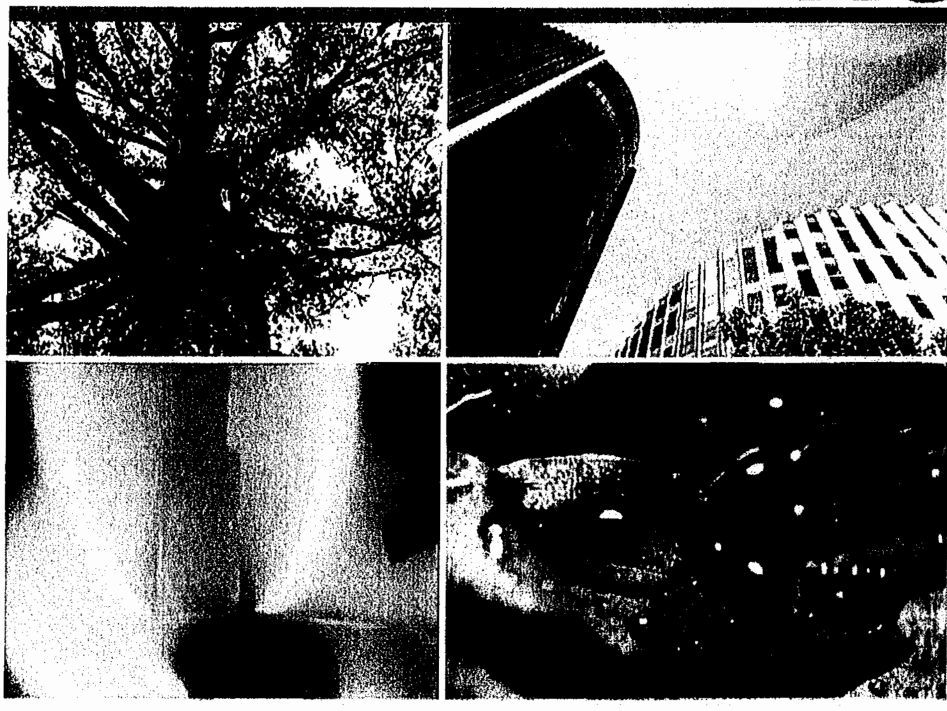
LADWP Territorial Potential
Draft Report
Volume I

Submitted to Los Angeles Department of Water and Power

Submitted by Nexant

In partnership with Cadmus and RetroCom Energy Strategies

June 24, 2014



CONTENTS

VOLUME I

VOLUME II

1 EXECUTIVE SUMMARY

1.1 PROJECT OVERVIEW AND OBJECTIVES

This report summarizes the results of a comprehensive assessment of the long-run electric energy efficiency potential study for the Los Angeles Department of Water and Power (LADWP) territory from 2014-2033[1]. LADWP commissioned this study to support its business plan and energy efficiency goals for 2020. LADWP retained Nexant, in collaboration with its subcontractors Cadmus and RetroCom Energy (the Nexant team), to perform this work. This study encompasses the residential, commercial, institutional (City of Los Angeles buildings and facilities), and industrial sectors.

The results of the study take into account annual program expenditure levels necessary for achieving the cumulative targets for energy savings and peak demand reduction potential, but exclude demand response potential.

Although the timeframe of the study is 20-years, the focus was to estimate cumulative savings potential achievable by 2020 and 2023. LADWP recently adopted a goal of 10% cumulative savings of the load forecast between 2010 and 2020, with an aspirational target of 15%. This study includes an assessment of the feasibility and cost-effectiveness of achieving these savings targets, as well as three additional scenarios, provided below. In addition, the study develops a range of program-level planning scenarios with varying cost and delivery assumptions to identify the range of budgetary requirements to achieve the 15% savings target.

This report presents the results for the study prior to the completion of the potential for energy and demand savings in the City of Los Angeles buildings and facilities, involving 68 site visits to these facilities. The impact of that assessment will be completed in June 2014.

1.2 DEFINITIONS OF ENERGY EFFICIENCY POTENTIAL

The following are the definitions of the types of potentials available in a utility's territory:

- **Technical potential:** The quantification of savings that can be realized if energy efficiency measures passing the qualitative screening are applied in all feasible instances, regardless of cost.

- **Economic potential:** A subset of technical potential, where measures are cost-effective from the Total Resource Cost ("TRC") perspective, without regard to cross-subsidies.

[1] Representing LADWP's fiscal years(FY) 2013-14 to 2032-33

- **Maximum achievable potential:** The energy savings that can possibly be achieved through assuming maximum market penetration of all measures. Individual measures are not necessarily cost-effective in this scenario, though measures with a low TRC benefit-cost ratio are excluded.

- **Program potential:** The energy savings that can possibly be achieved through utility programs or codes and standards. Individual measures are not necessarily cost-effective in this scenario, though measures with a low benefit-cost ratio, as determined through the Total Resource Cost (TRC) test, are excluded.

This study estimated program potential for five top-down policy intervention scenarios, corresponding to varying incentive levels provided to end-use consumers and an acquisition rate of 10 years for retrofit measures, as well as two additional scenarios that considered accelerated acquisition rates under the advanced and extreme scenarios:

- ***Low scenario***: Monetary incentives to customers equaling 25% of incremental costs of energy efficiency improvements[2], and administration and marketing costs equaling 20% of incremental costs. This scenario assumes retrofit opportunities are acquired within 10 years.

- ***Moderate scenario***: Monetary incentives to customers equaling 50% of incremental costs of energy efficiency improvements, and administration and marketing costs equaling 35% of incremental costs. This scenario assumes retrofit opportunities are acquired within 10 years.

- ***High scenario***: Monetary incentives to customers equaling 75% of incremental costs of energy efficiency improvements, and administration and marketing costs equaling 40% of incremental costs. This scenario assumes retrofit opportunities are acquired within 10 years.

- ***Advanced scenario***: Monetary incentives to customers equaling 90% of incremental costs of energy efficiency improvements and administration and marketing costs equaling 65% of incremental costs. This scenario assumes retrofit opportunities are acquired within 10 years.

- ***Advanced accelerated scenario:*** Same incentives and administration and marketing costs as the "advanced scenario", but retrofit opportunities are assumed to be acquired in 8 years.

[2] Incremental costs are either based on the difference between a standard and efficient unit or the total cost to install a measure compared to existing conditions.

- ***Extreme scenario***: Monetary incentives to customers, equaling 100% of incremental costs of energy efficiency improvements, and administration and marketing costs equaling 75% of incremental costs. This scenario assumes retrofit opportunities are acquired within 10 years.

- ***Extreme accelerated scenario:*** Same incentives and administration and marketing costs as the "extreme scenario", but retrofit opportunities are assumed to be acquired in 7 years.

1.3 SUMMARY OF RESULTS

The technical and economic potentials in FY 2032-33 are provided in Table 1-1.

Table 1-1. Technical and Economic Potential

Sector	Baseline Sales (GWh)	Technical Potential			Economic Potential				
		GWh	% of Base Sales	MW	GWh	% of Base Sales	MW	Percent of Technical Potential - Energy	Percent of Technical Potential - Demand
Residential	9,985	3,334	33%	1,940	1,625	16%	471	49%	24%
Commercial	14,798	3,332	23%	851	2,188	15%	505	66%	59%
Institutional	756	143	19%	37	110	15%	27	77%	72%
Industrial	2,195	314	14%	66	265	12%	56	84%	85%
Codes and Standards[a]	N/A	1,690	N/A	312	1,690	N/A	312	100%	N/A
Other[b]	838	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	28,571	8,813	31%	3,205	5,877	21%	1,371	67%	43%

[a]Includes savings from Huffman Bill, Title 24 codes, and Title 20 standards, as well as federal standards not covered by California standards.
[b]Other includes components for which energy efficiency potential was not considered, such as port electrification and rooftop solar. Plug-in electric vehicles were excluded from baseline forecasts

Study results indicate 8,813 GWh of technically feasible energy efficiency potential by FY 2032-33, the end of the 20-year planning horizon, with approximately 5,877 GWh of these resources proving cost-effective. Technical potential amounts to 31% of forecasted load with codes and standards, and 25% of forecasted load without codes and standards. Economic potential represents savings from measures that have a B/C ratio that is greater than or equal to 1.0. By FY 2032-33, savings from these measures can account for 21% of baseline sales with codes and standards and 15% of baseline sales without codes and standards.

The maximum achievable potential, which assumes aspirational levels of market adoption with no infrastructure or resource constraints, is provided is Table 1-2.

Table 1-2. Maximum Achievable Potential

Sector	Baseline Sales - GWh	Maximum Achievable - GWh	% of Base Sales	Maximum Achievable – MW
Residential	9,985	1,830	18%	591
Commercial	14,798	2,998	20%	771
Institutional	756	134	18%	35
Industrial	2,195	306	14%	64
Codes and Standards	NA	1,690	NA	312
Other	838	NA	NA	NA
Total	28,571	6,958	24%	1,773

Finally, Table 1-3 provides the program potentials for FY 2019-20 and FY 2022-23. In addition to the potential, this table also provides the overall benefit-to-cost (B/C) ratio and net benefits, based on a TRC perspective, as well as the portfolio utility levelized cost.

Table 1-3. Program Potential Scenarios

	Low	Moderate	High	Advanced		Extreme	
				Normal	Accelerated	Normal	Accelerated
Target Year 2020: Inclusive of 2010-2011 to 2012-2013 Accomplishments							
Baseline Sales (FY2019-20)	25,388	25,388	25,388	25,388	25,388	25,388	25,388
Cumulative Potential (GWh) FY2019-20	1,947	2,485	2,737	2,933	3,383	3,014	3,825
2010-2011 to 2012-2013 Program Accomplishments	615.6	615.6	615.6	615.6	615.6	615.6	615.6
Potential as % of Baseline Sales without Accomplishments	7.7%	9.8%	10.8%	11.6%	13.3%	11.9%	15.1%
Average Annual Savings as a % of Baseline Sales (2014-2020)*	1.1%	1.4%	1.5%	1.7%	1.9%	1.7%	2.2%
Potential as % of Baseline Sales with Accomplishments	10.1%	12.2%	13.2%	14.0%	15.8%	14.3%	17.5%
Target Year 2023: Excludes 2010-2011 to 2012-2013 Accomplishments							
Baseline Sales (FY2022-23)	26,220	26,220	26,220	26,220	26,220	26,220	26,220
Cumulative Potential (MWh) FY2022-23	2,943	3,714	4,075	4,356	4,357	4,475	4,496
2010-2011 to 2012-2013 Program Accomplishments	615.6	615.6	615.6	615.6	615.6	615.6	615.6
Potential as % of Baseline Sales without Accomplishments	11.2%	14.2%	15.5%	16.6%	16.6%	17.1%	17.1%
Average Annual Savings as a % of Baseline Sales (2014-2023)*	1.1%	1.4%	1.6%	1.7%	1.7%	1.7%	1.7%
Potential as % of Baseline Sales with Accomplishments	13.6%	16.5%	17.9%	19.0%	19.0%	19.4%	19.5%
Scenario Economics (Over 20-Year Study Horizon)							
TRC Benefit Cost Ratio	1.55	1.38	1.33	1.13	1.13	0.90	0.90
Net TRC Benefits ($000s)	$912,082	$978,192	$997,745	$497,037	$497,508	-$517,094	-$535,621
Utility Levelized Cost ($/kWh)	$0.024	$0.046	$0.063	$0.085	$0.085	$0.115	$0.115

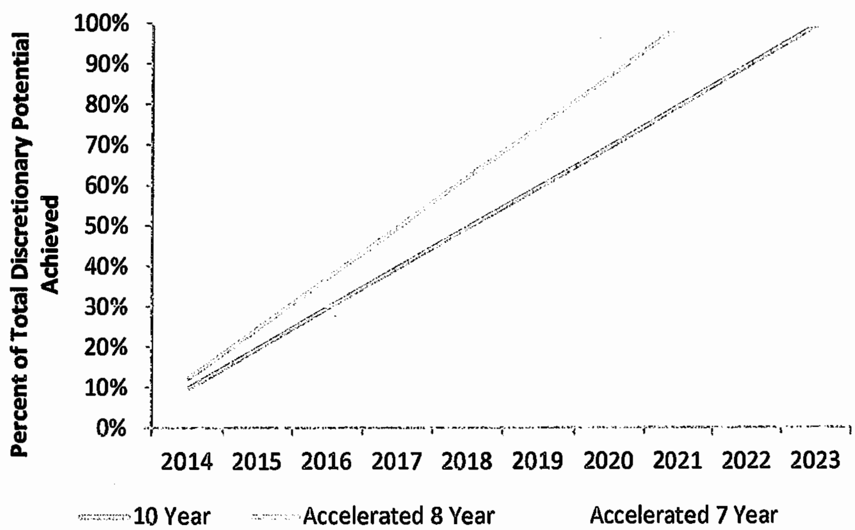
*** These values represent the average annual level of savings required through programs to achieve the potential by the target year.**

1.3.1 Acquisition of Conservation Resources

An assumption of the rate of acquisition for these resources is implicit in the program potential. For equipment measures, the assumption is that they will be adopted when the existing equipment burns out (replace-on-burnout). As such, the acquisition is dictated by the assumed measure life. This is also true for new construction, when the savings can only be realized when the new building is completed. Although retrofit or discretionary measures can theoretically be installed in year one, in reality the adoption of these measures is limited by the existing infrastructure and available resources. Thus the assumed ramp rate for these measures depends on whether the measure is part of a current program, whether it is an emerging technology, and the aggressiveness of the scenario.

Figure 1-1 illustrates the ramp rates for the retrofit measures. The low and moderate scenarios have the same ramp rates where retrofit measures are adopted within 10 years (2023); in order to achieve the advanced and extreme targets, the ramp rate needed to be accelerated to eight and seven years, respectively, for adoption of retrofit measures.

Figure 1-1. Ramp Rates for Discretionary (Retrofit) Measures



1.4 PLANNING IMPLICATIONS

As illustrated in Table 1-3 above, the range of cumulative savings from FY 2013-14 through FY 2019-20 varies from 7.7% to 15.1% of baseline sales depending on the level of program intervention, and identifies that LADWP's aspirational goal of 15% savings as a percentage of FY 2019-20 baseline sales[1] is achievable and cost-effective from the TRC perspective. However, as LADWP develops its program plans, it will not use a single set of incentive rates for all measures, each program will have

[1] 15% savings represents cumulative savings through FY 2019-20 inclusive of program accomplishments from 2010-2013.

unique administration and marketing costs, and the programs may not include all identified measures. To provide some context to the budgetary requirements of actually achieving these savings, the Nexant team explored several scenarios to reach 15% of baseline energy sales by 2020, based on a more granular approach to the assumptions.

With LADWP's guidance, the Nexant team produced ten program planning scenarios to demonstrate how changing assumptions on program delivery, including incentives, admin/marketing, benefit-cost thresholds, and ramp rates can create a range of budgets required to reach roughly 15% savings by 2020. Table 1-4 shows the detailed results for each of these scenarios in FY 2019-20 and FY2022-23, including energy savings, demand savings, average annual budget, benefit cost ratios, and levelized costs.

Table 1-4: Detailed Program Planning Scenario Results (2020 and 2023)

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8	Scenario 9	Scenario 10
Target Year 2019-2020										
Baseline Sales (GWh) FY2019-20	25,388	25,388	25,388	25,388	25,388	25,388	25,388	25,388	25,388	25,388
Cumulative Potential (GWh) FY2019-20	3,094	2,962	2,726	2,859	2,596	2,593	2,601	2,614	2,583	2,610
Cumulative C&S Savings (GWh) FY2019-20	466	466	466	466	466	466	466	466	466	466
2010-2011 to 2012-2013 Program Accomplishments	616	616	616	616	616	616	616	616	616	616
Potential as % of Baseline Sales without Accomplishments	14.0%	13.5%	12.6%	13.1%	12.1%	12.0%	12.1%	12.1%	12.0%	12.1%
Average Annual Savings as a % of Baseline Sales (2014-2020)	2.0%	1.9%	1.8%	1.9%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
Potential as % of Baseline Sales with Accomplishments	16.4%	15.9%	15.0%	15.5%	14.5%	14.5%	14.5%	14.6%	14.4%	14.5%
Cumulative Acquisition Budget ($Million) in FY2019-20	$2,723	$2,280	$1,342	$1,695	$1,250	$1,129	$1,727	$1,567	$1,100	$1,057
Average Annual Acquisition Budget ($Million)	$389	$326	$192	$242	$179	$161	$247	$224	$157	$151
Target Year 2023										
Baseline Sales (GWh) FY2022-23	26,220	26,220	26,220	26,220	26,220	26,220	26,220	26,220	26,220	26,220
Cumulative Potential (GWh) FY2022-23	3,592	3,441	3,166	3,323	3,021	3,015	3,390	3,406	3,038	3,029
Cumulative C&S Savings (GWh) FY2022-23	566	566	566	566	566	566	566	566	566	566
2010-2011 to 2012-2013 Program Accomplishments	615.6	615.6	615.6	615.6	615.6	615.6	615.6	615.6	615.6	615.6
Potential as % of Baseline Sales without Accomplishments	15.9%	15.3%	14.2%	14.8%	13.7%	13.7%	15.1%	15.2%	13.7%	13.7%
Average Annual Savings as a % of Baseline Sales (2014-2023)	1.6%	1.5%	1.4%	1.5%	1.4%	1.4%	1.5%	1.5%	1.4%	1.4%
Potential as % of Baseline Sales with Accomplishments	18.2%	17.6%	16.6%	17.2%	16.0%	16.0%	17.4%	17.5%	16.1%	16.1%
Cumulative Acquisition Budget ($Million) in FY2022-23	$3,165	$2,661	$1,570	$1,990	$1,474	$1,327	$2,261	$2,050	$1,306	$1,225
Average Annual Acquisition Budget ($Million)	$316	$266	$157	$199	$147	$133	$226	$205	$131	$122
Scenario Economics (Over 20-year Study Horizon)										
TRC Benefit Cost Ratio	1.11	1.26	1.20	1.30	1.46	1.35	1.27	1.17	1.37	1.28
Net TRC Benefits ($Million)	$448	$867	$637	$932	$1,129	$930	$869	$599	$958	$775
Utility Levelized Cost ($/kWh)	$0.085	$0.074	$0.050	$0.058	$0.048	$0.043	$0.064	$0.060	$0.042	$0.039

1.5 ORGANIZATION OF REPORT

The report presents the study's findings in two volumes. Volume I (this document), presents methodologies and findings and includes the following sections:

1. Executive Summary
2. General Approach and Methodology
3. Technical and Economic Potential
4. Achievable and Program Potential
5. Planning Considerations

Volume II presents supplemental technical information, assumptions, data, and other relevant details as the following appendices:

- Appendix A: Glossary of Terms
- Appendix B: Detailed Technical and Economic Potential Methodology Appendix C: Detailed Methodology
- Appendix C: Assessment of Previous Study
- Appendix D: Detailed Results by Sector, Segment, and End Use
- Appendix E: Detailed Results for Program Potential Scenarios
- Appendix F: Detailed Results for 15% Program Planning Scenarios
- Appendix G: Measure Performance Data and Costs

2 General Approach and Methodology

2.1 General Approach

2.1.1 Introduction

This report presents findings from the electric energy efficiency technical, economic, maximum achievable, and program potentials study, intended to support LADWPs long-term planning. The study's horizon covers 2014–2033[1], encompassing the residential, commercial, institutional (City of Los Angeles) and industrial sectors.

2.1.2 Objectives

This study includes the following key objectives:

- Estimate cumulative savings potential achievable by 2020, through five scenarios based on utility expenditures through incentives, marketing, and other administrative activities. We also estimated budgets to acquire these resources.

- Estimate cumulative savings potential achievable by 2023, through five scenarios based on utility expenditures through incentives, marketing, and other administrative activities. We also estimated budgets to acquire these resources.

2.1.3 Definitions of Energy-Efficiency Potential

The following are the definitions of the types of potentials available in a utility's territory:

- **Technical potential:** The quantification of savings that can be realized if energy efficiency measures passing the qualitative screening are applied in all feasible instances, regardless of cost.

- **Economic potential:** A subset of technical potential, where measures are cost-effective from the Total Resource Cost ("TRC") perspective, without regard to cross-subsidies.

- **Maximum achievable potential:** The energy savings that can possibly be achieved through assuming maximum market penetration of all measures. Individual measures are not necessarily cost-effective in this scenario, though measures with a low TRC benefit-cost ratio are excluded.

- **Program potential:** The energy savings that can possibly be achieved through utility programs or codes and standards. Individual measures are not necessarily cost-effective in this scenario, though measures with a low TRC benefit-cost ratio are excluded.

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[1] Representing LADWP's FY 2013-14 to 2032-33

This study estimated program potential for five policy intervention scenarios, corresponding to varying incentive levels provided to end-use consumers and an acquisition rate of 10 years for retrofit measures, and two additional accelerated acquisition rates under the advanced and extreme scenarios:

- ***Low scenario***: Monetary incentives to customers equaling 25% of incremental costs of energy efficiency improvements[1], and administration and marketing costs equaling 20% of incremental costs. This scenario assumes retrofit opportunities are acquired within 10 years.
- ***Moderate scenario***: Monetary incentives to customers equaling 50% of incremental costs of energy efficiency improvements, and administration and marketing costs equaling 35% of incremental costs. This scenario assumes retrofit opportunities are acquired within 10 years.
- ***High scenario***: Monetary incentives to customers equaling 75% of incremental costs of energy efficiency improvements, and administration and marketing costs equaling 40% of incremental costs. This scenario assumes retrofit opportunities are acquired within 10 years.
- ***Advanced scenario***: Monetary incentives to customers equaling 90% of incremental costs of energy efficiency improvements and administration and marketing costs equaling 65% of incremental costs. This scenario assumes retrofit opportunities are acquired within 10 years.
- ***Advanced accelerated scenario:*** Same incentives and administration and marketing costs as the "advanced scenario", but retrofit opportunities are assumed to be acquired in 8 years.
- ***Extreme scenario***: Monetary incentives to customers, equaling 100% of incremental costs of energy efficiency improvements, and administration and marketing costs equaling 75% of incremental costs. This scenario assumes retrofit opportunities are acquired within 10 years.
- ***Extreme accelerated scenario:*** Same incentives and administration and marketing costs as the "extreme scenario", but retrofit opportunities are assumed to be acquired in 7 years.

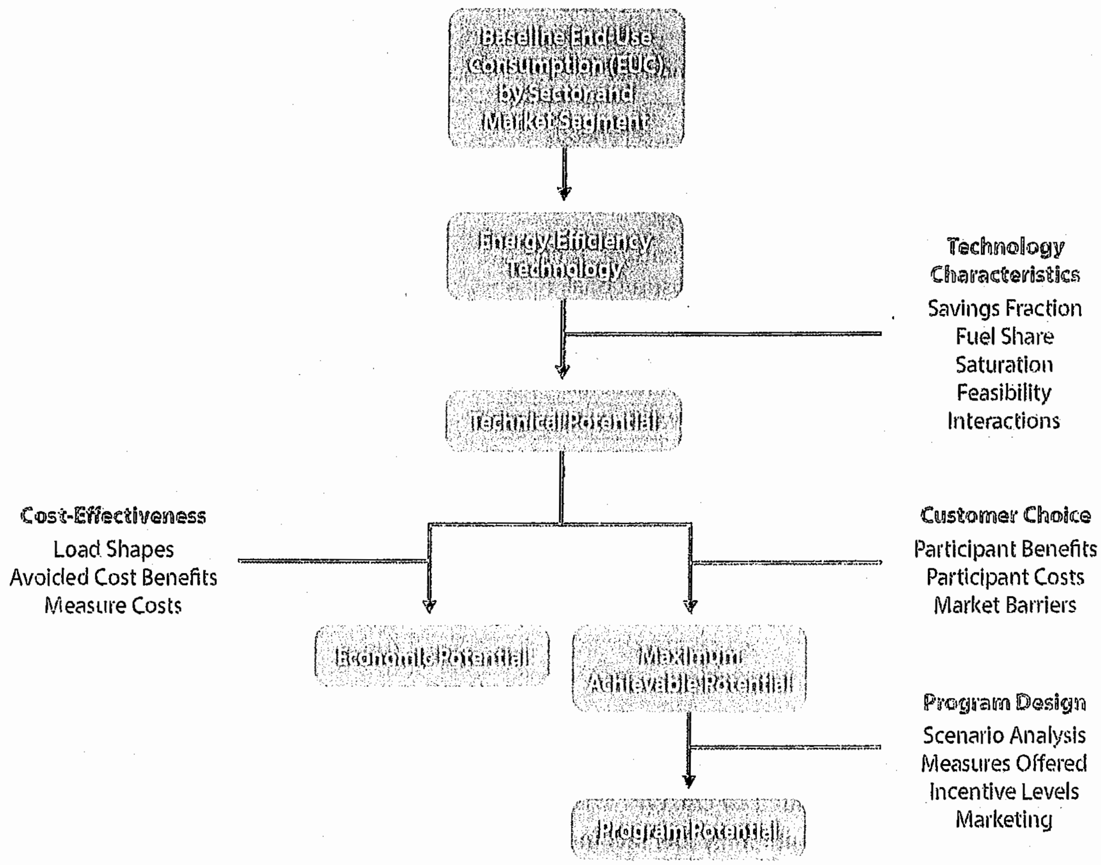
2.2 OVERVIEW

The general methodology is described here, further details are provided in Appendix C. The methodology used can best be described as a hybrid "top-down/bottom-up" approach. As

[1] For this study incremental costs represent the difference in costs between the baseline technology and efficient technology. For equipment replacement measures that are assumed to occur at burnout, when the equipment would naturally be replaced, the incremental costs include the difference between the efficient replacement option and the standard replacement option. For non-equipment measures (such as additional attic insulation) or early retirement equipment measures, incremental costs include the total cost to install a measure compared to existing conditions.

illustrated in Figure 2-1, we began by examining the current energy forecast, and then breaking down the forecast into its constituent customer-class and end-use components. The team then examined the effects for a range of energy efficiency approaches and practices for end use, while accounting for fuel shares, current market saturations, technical feasibility, and costs. We then aggregated these unique impacts to produce resource potentials, estimates at end use, customer class, and system levels.

Figure 2-1. Methodology for Estimating Technical, Economic, Maximum Achievable and Program Potential



2.2.1 Develop Baseline Forecasts

2.2.1.1 Segmenting the Market

The Nexant team's first key activity in assessing the territorial energy efficiency potential was to identify the appropriate level of granularity for the analysis. For this, we utilized the following steps:

1. **Create a model for each sector (residential, commercial, institutional [City of Los Angeles Facilities], and industrial).**

2. **Disaggregate the analysis to specific market segments within each sector (dwelling, business, or industry type).**

Table 2-1 provides the segments by sector.

Table 2-1. Market Segments Included

Residential	Commercial	Institutional	Industrial
Multifamily	Assembly	Assembly	Agriculture
Multifamily Low Income	Education College	Civil Services	Chemical Manufacturing
Single Family	Education Primary (K-12)	Industry	Electronic Equipment Manufacturing
Single Family Low Income	Grocery	Miscellaneous	Food Manufacturing
	Health	Office Space	Industrial Machinery
	Lodging	Park	Lumber Wood Products
	Miscellaneous	Transportation - Institutional	Mining
	Office Large	Utilities	Miscellaneous Manufacturing
	Office Small	Wastewater - Institutional	Paper Manufacturing
	Restaurant	Water - Institutional	Petroleum Refining
	Retail Large		Primary Metal Manufacturing
	Retail Small		Stone Clay Glass Products
	Storage		Street Lighting
	Warehouse		Transportation Equipment Manufacturing
			Wastewater
			Water

The Nexant team relied on housing stock forecasts of residential single family and multifamily units for the City of Los Angeles, provided by LADWP. We disaggregated housing stock forecasts into single family low income and multifamily low income segments by identifying the share of households that fall below the eligibility threshold for LADWP's Low Income Discount Program.[1]

Segmentation of the commercial, institutional, and industrial sectors relied on an analysis of LADWP's customer information system (CIS) data. LADWP provided 2012 sales and customer information for nonresidential customers. The Team first worked with LADWP to identify institutional customers, so we could determine the share of non-residential forecasted sales that institutional customers account for. The Nexant team then identified the appropriate market

[1] U.S. Census Bureau American Community Survey housing microdata for California: http://www2.census.gov/acs2012_5yr/pums/csv_hca.zip

segment for each non-residential customer based on the customers' standard industrial classification (SIC) code.

The Nexant team further segmented each of the identified markets into major end uses, such as lighting, cooling, ventilation, plug load, and other applications expected to be relevant to the estimation of potential. The Nexant team model relied on the following end use data:

- ***Saturations***: For the residential sector, saturations reflect the average number of units in a household. For commercial and institutional sectors, saturations reflect the percent of floor space to which the end use applies (for lighting, this is percent of floor space lit; for heating, this is percent of floor space heated, etc.). The Nexant team relied on the 2009 California Residential Appliance Saturation Survey (RASS) and the California Commercial End Use Survey (CEUS) to calculate residential and commercial/institutional saturations, respectively. For end uses where these sources could not provide saturations, the Nexant team relied on other secondary sources such as Energy Information Agency's (EIA's) Residential Energy Consumption Survey (RECS) and Commercial Building Energy Consumption Survey (CBECS).
- ***Efficiency Shares***: Efficiency shares reflect the current saturation of efficient equipment. The Nexant team consulted a variety of secondary sources, including the California RASS, California CEUS, EIA RECS, EIA CBECS, and the California Statewide IOU[1] Goals and Potential Study. The Team made additional adjustment to the efficiency shares from these sources to account for LADWP's program accomplishments over the last decade.
- ***End Use Consumption***: Residential per-unit end use consumption is expressed in annual kWh per unit. Also referred to as unit energy consumption (UEC), these reflect average annual kWh consumption by end use. The Nexant team relied on the 2009 California RASS and the 2013 California Goals and Potential Study for residential end use consumption. Commercial and institutional end use consumption is expressed as end use intensities (EUIs) which reflect energy consumption per square foot for a given end use. The Team used the 2006 California CEUS, as well as other secondary sources such as the statewide Goals and Potential Study and EIA's CBECS.

[1] Investor-owned utilities

Table 2-2 summarizes the data sources the Nexant team used to disaggregate LADWP's sales.

Table 2-2. Data Sources

Data	Residential	Commercial	Industrial	Institutional
Sales Forecast	LADWP Official	LADWP Official (institutional removed)	LADWP Official (institutional removed)	LADWP Official; Disaggregated from commercial and industrial
Customer Forecasts	LADWP Housing Stock Forecast; U.S. Census Bureau American Community Survey (ACS)	LADWP Floor Space Forecast	N/A	LADWP Floor Space Forecast
Saturations	California Residential Appliance Saturation Survey RASS; EIA RECS	California Commercial End Use Survey (CEUS); EIA CBECS	N/A	California Commercial End Use Survey (CEUS); EIA CBECS
End Use Consumption	California Statewide IOU 2013 Potential and Goals Study; Secondary Sources	California CEUS; California Statewide IOU 2013 Potential and Goals Study; Secondary Sources	EIA Manufacturing Energy Consumption Survey (MECS); Secondary Sources	California CEUS; California Statewide IOU 2013 Potential and Goals Study; Secondary Sources
Efficiency Shares	California Statewide IOU 2013 Potential and Goals Study; California RASS; Adjusted for LADWP Program Accomplishments	California Statewide IOU 2013 Potential and Goals Study; California CEUS; Adjusted for LADWP Program Accomplishments	N/A	California Statewide IOU 2013 Potential and Goals Study; California CEUS; Adjusted for LADWP Program Accomplishments

2.2.1.2 Forecast Baseline Consumption

The Nexant team created the baseline forecast by combining the inputs compiled above to obtain average consumption estimates (by customer segment, construction vintage, and end use) summed up to the sector level. Using the bottom-up forecast, we assumed no future energy efficiency program activity. The Nexant team also used this approach for estimating technical potential for each sector, market segment, construction vintage, and end use, based on the following:

- Current customer counts by sector
- Base-year conditions (equipment and measure saturations, fuel shares, etc.)
- New construction forecasts
- Natural equipment turnover rates

- **Future codes and standards**[1]

The Nexant team calibrated baseline forecasts to LADWP's gross load forecasts. Future programmatic energy efficiency savings were excluded from baseline forecasts to avoid under-estimating potential.

2.2.1.3 Future Codes and Standards

The Nexant team's study will quantify effects of the changes already in place and the changes that have been enacted but have not yet taken effect in their entirety. The most significant changes are these:

- **General service lighting requirements established by the Huffman bill**[2]
- **Commercial lighting efficiency standards set in a 2009 Department of Energy rulemaking**
- **Federal electric water heating standards**
- **Federal standards for appliances, central air conditioners, and heat pumps**

2.2.1.4 Define Efficiency Measures and Technologies

The Nexant team's process begins with compiling a comprehensive database of technical and market data on all energy efficiency measures applicable to all end uses in various market segments, including emerging technologies. We began with the measure list used in the 2013 California Energy Efficiency Potential and Goals Study completed for the California Public Utilities Commission.[3] **We supplemented this list with our own measure databases and input from LADWP staff. The final measure list included 560 unique measures and 6,608 permutations across segments. For this study, we assumed that the 2013 Title 24 standards are in effect from the beginning of the study horizon. As such, any affected measure will assume this standard as the baseline for new construction or replace-on-burnout.**

2.2.1.5 Compile Measure Data and Populate Model

For each end use, the Nexant team populated the database with the following information:

- **Costs (full or incremental, depending on the measure)**
- **Energy and capacity savings as a fraction of end-use consumption (UEC)**

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1 The base-case forecast will include codes and standards already established, even if they do not take effect until future years. It will not, however, attempt to predict how codes and standards may change in the future.

2 California Assembly Bill 1109 (enacted October, 2007): http://www.leginfo.ca.gov/pub/07-08/bill/asm/ab_1101-1150/ab_1109_bill_20071012_chaptered.pdf

3 http://www.cpuc.ca.gov/NR/rdonlyres/29ADACC9-0F6D-43B3-B7AA-C25D0E1F8A3C/0/2013CaliforniaEnergyEfficiencyPotentialandGoalsStudyNovember262013.pdf

- Expected useful life (EUL)
- Applicability (such as technical feasibility and current saturation)
- Adjustments for interactions with other end uses (including lighting and HVAC)
- Competition with other measures (to avoid double-counting of savings)
- Non-energy benefits (such as water savings), if applicable

2.3 ESTIMATING POTENTIAL

2.3.1 Estimating Technical Potential

Technical potential is the theoretical maximum amount of energy and capacity that could be displaced by efficiency, regardless of cost and other barriers that may prevent the installation or adoption of an energy efficiency measure. Technical potential is constrained only by technical factors such as technical feasibility and applicability of measures. In theory, this potential (with the exception of the new construction market) could be acquired immediately by including the early replacement of functioning equipment.

The Nexant team utilizes an industry-standard bottom-up approach for estimating phase-in technical potential. We estimated the phase-in technical potential by introducing all technically feasible measures into the baseline forecast and calculating the resulting impacts. For the purpose of modeling, we will separate measures into two distinct classes:

- **Equipment measures** save energy by upgrading the efficiency of end-use equipment at the time the equipment would naturally be replaced. The technical potential assumes that all customers will install the most efficient, technically feasible option at the time the equipment needs to be replaced.
- **Retrofit measures** save energy by reducing end-use consumption without affecting equipment efficiency. Examples of such measures are insulation, faucet aerators, and lighting controls. For measures that compete for the same savings (e.g., different levels of insulation), the technical potential assumes the most-efficient option is installed, wherever technically feasible to do so.

In developing the end-use level savings, the Nexant team captured the interactive effects associated with installation of multiple measures, both between and within the measure classes described above.

- **The equipment measure analysis accounts for the exclusivity of high-efficiency measure installations.** For example, a residential customer cannot replace a single air conditioner with two air conditioners at different efficiency levels or else potential will be double-counted. The analysis also takes into account the effects that retrofit measures will have on the potential of equipment measures.

- **The retrofit analysis accounts for the reduction in consumption due to high-efficiency equipment installation,** while accounting for the interactive effects and competition between different retrofit measures applied to the same end use.

2.3.2 Estimating Economic Potential

The economic potential is a subset of the technical potential, but only includes measures that have a TRC B/C ratio greater than 1.0. The economic potential assumes that all customers will install the most efficient technically feasible measure available that is also *cost-effective*. For example, the technical potential may assume all customers install a SEER 18 air conditioner, but if that measure is not cost effective and the SEER 16 unit is, the economic potential will assume all customers will install that lower efficiency SEER 16 unit.

2.3.3 Estimating Maximum Achievable and Program Potentials

The maximum achievable potential is also a subset of the technical potential. This potential represents the total potential available when taking market impacts into account. Similar to the approach used in the 2013 California Energy Efficiency Potential and Goals Study of the state's IOUs,[1] this study relaxes the measure-level cost-effectiveness thresholds and focuses on the sector and portfolio level cost effectiveness in determining achievable and program potentials. In order to continue targeting sector and portfolio level cost-effectiveness for the majority of scenarios, applicability adjustments are made to the non-cost effective measures based on their TRC (B/C) ratio. For all except the extreme scenario, measures with a ratio less than 0.3 are excluded. In order to reach the targets of the extreme scenario, this applicability was relaxed to include measures down to a B/C of 0.15 in the commercial, institutional, and industrial sectors. For the residential sector across all scenarios, additional caps were applied so that the sector-level B/C is greater than 1.0. These caps are provided in Table 2-3. In other words, a measure that has a B/C between 0.3 and 0.5 would at most achieve 5% market penetration. These thresholds were developed for this study through an iterative process to ensure the sector-level B/C was greater than 1.0.

[1] http://www.cpuc.ca.gov/NR/rdonlyres/29ADACC9-0F6D-43B3-B7AA-C25D0E1F8A3C/0/2013CaliforniaEnergyEfficiencyPotentialandGoalsStudyNovember262013.pdf

Table 2-3. Applicability adjustments for the residential sector

Benefit-to-Cost Ratio	Applicability Adjustment
Up to 0.3	0%
0.3 to 0.5	5%
0.5 to 0.8	15%
0.8 to 1.0	30%
1.0 and above	100%

The program potential for energy efficiency measures is often analyzed deterministically, ignoring several sources of uncertainty in market conditions that affect utility customers' willingness—and ability—to participate in utility-sponsored energy efficiency programs. One important area of uncertainty concerns the amount of technical or economic potential that may be expected to be achievable, given barriers that may prevent consumers from adopting energy efficiency measures.

Like many studies of energy efficiency potential, achievable potential is based on somewhat arbitrary, fixed values.[1] In this study, we consider the levels of program potential as following a normal market diffusion curve, first introduced in 1963 by Frank Bass. The Bass market diffusion model is one of the most widely used methods for predicting market adoption and diffusion of new products.[2] It provides a framework for estimating future trends in the adoption of innovations, which is also applicable to the adoption of energy-efficient technologies. According to this approach, participation in energy efficiency programs and the adoption of energy efficiency measures and practices are characterized by a logistic (S-shaped) function with the following analytic form:

$$N_t = N_{t-1} + p(m - N_{t-1}) + q\,\frac{N_{t-1}}{m}\,(m - N_{t-1})$$

1 In the Northwest, for example, the Northwest Power and Conservation Council assumes that 85% of economic potential is achievable. Other utilities have used similar static point estimates of about 50% to 70%, depending on incentives and other expenditures.

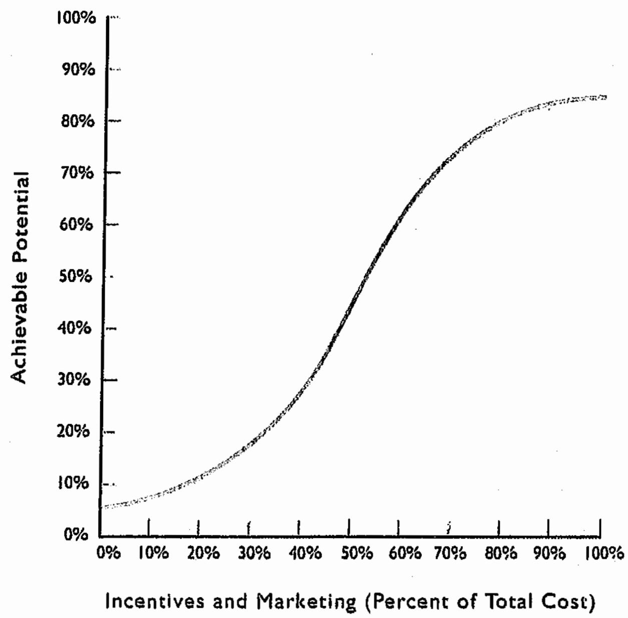
2 The Bass diffusion curve is historically presented as adoption as a function of time; however, this curve more generally represents a logistic function for adoption.

In this formula, N_t indicates the percent of the market adopting the energy efficiency measures. The three critical parameters that define the functional form of this model are:

- m = maximum market potential; the total number of people who will eventually participate in a program – in this study this value is set at 85%, indicating the maximum fraction of the market likely to participate in a program and the starting point of the curve is set at 20%, indicating the current saturation and natural adoption for most measures.
- p= the coefficient of external influence; the likelihood that customers who are not participating in a program will begin to adopt measures due to information and education campaigns sponsored by the utility or other external factors.
- q= the coefficient of internal influence; the likelihood that customers who have not participated in a program will participate due to the influences from those already participating in the program.

The standard market diffusion curve follows a logistic (S-shaped) curve illustrated in Figure 2-2. In this study, it is assumed that the parameters of the model are essentially a function of the utility's marketing efforts (with the effect of raising awareness and providing education) and financial incentives (with the effect of mitigating the importance of upfront cost as a barrier to participation in an energy efficiency program).

Figure 2-2. Typical Market Diffusion Curve



As this graphic illustrates, increases in marketing and incentives will increase adoption, though the relationship is non-linear. That is, above a certain level, increases in expenditures will result in diminishing returns on adoption. This is based on market theory and supported by surveys of willingness to pay.

Note that although marketing plus incentives may be greater than 100%, the scale on the y-axis is indexed to 100%, where the model assumes equal weighting of the two factors.

The program potential scenarios are outlined in Table 2-4.

In this table, the administration/marketing and incentives as a percent of incremental cost scenarios are chosen to represent a spread of expenditures used by utilities around the country. The "high" scenario most closely represents LADWP's current expenditure amounts. It should be noted that at the extremes of expenditure levels, minimal data are available against which to benchmark the adoption.

Table 2-4. Program potential scenarios

Assumption/Scenario	Definition	Low	Medium	High	Advanced	Extreme
Minimum TRC B/C Threshold	Measures below this benefit-cost ratio threshold are excluded from program potential.	0.3	0.3	0.3	0.3	0.15
Incentive as a percent of incremental cost	Measure incentive expressed as a fraction of incremental cost	25%	50%	75%	90%	100%
Administration/Marketing as a percent of incremental cost	Utility marketing and administrative expenditures expressed as a fraction of incremental cost	20%	35%	40%	65%	75%
Program potential as a percent of maximum achievable potential	Program potential, expressed as a fraction of maximum achievable potential. Accounts for market barriers to adoption.	54%	64%	72%	79%	81%
Discretionary ramp rate	Time period over which all retrofit (discretionary) savings are acquired	10 Year	10 Year	10 Year	•2020: 8 Year •2023: 10 Year	•2020: 7 Year •2023: 10 Year

3 TECHNICAL AND ECONOMIC POTENTIAL

3.1 SCOPE OF ANALYSIS

This study separately assessed technical, economic, maximum achievable, and achievable program potential for the residential, commercial, industrial, and institutional sectors. The study further distinguished between applicable end uses within each segment. Analysis began by assessing the technical potential for unique energy efficiency measures, representing a comprehensive set of electric energy efficiency measures applicable to local climate and customer characteristics. Table 3-1 shows counts of the number of unique measures and measure permutations for each sector.

Table 3-1. Counts of Unique Measures and Measure Permutations

Sector	Unique Measures*	Permutations Across Market Segments and Vintages
Residential	88	834
Commercial	121	2,759
Institutional	202	1,574
Industrial	149	1,441
Total	560	6,608

*Represents unique measures within a sector. Institutional sector measures are identical to measures considered in the commercial and industrial sectors.

Consideration of all permutations of these measures, across applicable customer sectors, market segments, fuels, and end uses, resulted in customized data, compiled and analyzed for over 6,600 measures. Appendix G describes all measures analyzed.

3.2 Technical and Economic Potential Results

Table 3-2 shows technical and economic potential for each sector.

Table 3-2. Technical and Economic Energy Efficiency Potential (Cumulative 2033) by Sector

Sector	Baseline Sales (GWh)	Technical Potential			Economic Potential				
		GWh	% of Base Sales	MW	GWh	% of Base Sales	MW	Percent of Technical Potential - Energy	Percent of Technical Potential - Demand
Residential	9,985	3,334	33%	1,940	1,625	16%	471	49%	24%
Commercial	14,798	3,332	23%	851	2,188	15%	505	66%	59%
Institutional	756	143	19%	37	110	15%	27	77%	72%
Industrial	2,195	314	14%	66	265	12%	56	84%	85%
Codes and Standards	N/A	1,690	N/A	312	1,690	N/A	312	100%	N/A
Other	838	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	28,571	8,813	31%	3,205	5,877	21%	1,371	67%	43%

Study results indicate 8,813 GWh of technically feasible energy efficiency potential by FY2032-33, the end of the 20-year planning horizon, with approximately 5,877 GWh of these resources proving cost-effective. Technical potential amounts to 31% of forecasted load with Codes and Standards, and 25% of forecasted load without codes and standards. Economic potential represents savings from measures that have a B/C ratio that is greater than or equal to 1. By FY2032-33, savings from these measures can account for 21% of baseline sales with codes and standards and 15% of baseline sales without codes and standards.

Overall, economic potential is roughly 67% of technical potential. A larger share of technical potential is cost-effective in the industrial and institutional sectors than the commercial and residential sectors. Economic potential accounts for 84% of technical potential in the industrial sector and 77% of technical potential in the institutional sector.

When codes and standards are excluded, the commercial sector makes up 47% of technical potential and 52% of economic potential. Commercial's large share of total potential is largely a function of LADWP's sales. The sector accounts for 51% of total baseline sales, and 53% of baseline sales considered for modeling. The residential sector also accounts for roughly 47% of technical potential, but only 39% of economic potential. This difference is due to lower overall cost-effectiveness in the residential sector.

Appendix D provides detailed summaries of technical potential findings, by sector and end-use.

4 Achievable and Program Potential

4.1 Scope of Analysis

This study considers one maximum achievable scenario and seven program potential scenarios. Maximum achievable potential represents a scenario where the standard measure-level economic screen is relaxed, and only sector level cost-effectiveness is considered. The installation of measures with benefit-cost ratios below one are restricted until each sector's aggregate benefit-cost ratio exceeds one. Section 2.3.3 provides a detailed summary of how the Nexant team applied this approach. Maximum achievable potential provides an upper bound on long-term energy efficiency potential, if LADWP acquired all technically feasible savings, while preserving sector cost-effectiveness.

However, maximum achievable potential does not provide a realistic estimate for planning. Other constraints, such as customers' willingness-to-adopt energy efficiency measures and the maturity of the market for a measure can limit the amount of savings that can be achieved. The Nexant team constructed five program potential scenarios that account for market barriers, and the impact of steps LADWP can take to overcome them, such us spending on incentives on marketing. The five program potential scenarios include:

- **Technical potential:** The quantification of savings that can be realized if energy efficiency measures passing the qualitative screening are applied in all feasible instances, regardless of cost.
- **Economic potential:** A subset of technical potential, where measures are cost-effective from the Total Resource Cost ("TRC") perspective, without regard to cross-subsidies.
- **Maximum achievable potential:** The energy savings that can possibly be achieved through assuming maximum market penetration of all measures. Measures are not necessarily cost-effective in this scenario, though measures with a low TRC benefit-cost ratio are excluded.
- **Program potential:** The energy savings that can possibly be achieved through utility programs or codes and standards. Measures are not necessarily cost-effective in this scenario, though measures with a low TRC benefit-cost ratio are excluded. This study estimated program potential for five policy intervention scenarios, corresponding to varying incentive levels provided to end-use consumers and an acquisition rate of 10 years for retrofit measures, and two additional accelerated acquisition rates under the advanced and extreme scenarios:

- ***Low scenario***: Monetary incentives to customers equaling 25% of incremental costs of energy efficiency improvements[1], and administration and marketing costs equaling 20% of incremental costs. This scenario assumes retrofit opportunities are acquired within 10 years.
- ***Moderate scenario***: Monetary incentives to customers equaling 50% of incremental costs of energy efficiency improvements, and administration and marketing costs equaling 35% of incremental costs. This scenario assumes retrofit opportunities are acquired within 10 years.
- ***High scenario***: Monetary incentives to customers equaling 75% of incremental costs of energy efficiency improvements, and administration and marketing costs equaling 40% of incremental costs. This scenario assumes retrofit opportunities are acquired within 10 years.
- ***Advanced scenario***: Monetary incentives to customers equaling 90% of incremental costs of energy efficiency improvements and administration and marketing costs equaling 65% of incremental costs. This scenario assumes retrofit opportunities are acquired within 10 years.
- ***Advanced accelerated scenario:*** Same incentives and administration and marketing costs as the "advanced scenario", but retrofit opportunities are assumed to be acquired in 8 years.
- ***Extreme scenario***: Monetary incentives to customers, equaling 100% of incremental costs of energy efficiency improvements, and administration and marketing costs equaling 75% of incremental costs. This scenario assumes retrofit opportunities are acquired within 10 years.
- ***Extreme accelerated scenario:*** Same incentives and administration and marketing costs as the "extreme scenario", but retrofit opportunities are assumed to be acquired in 7 years.

Table 4-1 shows maximum achievable potential and program potential for each scenario, by sector. Technical and economic potential are also included, for reference.

[1] For this study, incremental costs represent the difference in costs between the baseline technology and efficient technology. For equipment replacement measures that are assumed to occur at burnout, when the equipment would naturally be replaced, the incremental costs include the difference between the efficient replacement option and the standard replacement option. For non-equipment measures (such as additional attic insulation) or early retirement equipment measures, incremental costs include the total cost to install a measure compared to existing conditions.

Table 4-1. Technical, Economic, Maximum Achievable, and Program Potential by Sector, Cumulative FY2032-33*

Potential Type	Residential	Commercial	Institutional	Industrial	Codes and Standards	Total
Baseline Sales (GWh)	9,985	14,798	756	2,195	-	27,734
Energy Savings (GWh)						
Technical Potential	3,334	3,332	143	314	1,690	8,813
Economic Potential	1,625	2,188	110	265	1,690	5,877
Max Achievable	1,830	2,998	134	306	1,690	6,958
Achievable Low	829	1,351	14	125	1,690	4,009
Achievable Medium	1,150	1,875	36	174	1,690	4,925
Achievable High	1,300	2,121	50	197	1,690	5,358
Achievable Advanced	1,417	2,311	81	214	1,690	5,714
Achievable Extreme	1,541	2,368	96	219	1,690	5,914
Percent of Baseline Sales						
Technical Potential	33%	23%	19%	14%	-	32%
Economic Potential	16%	15%	15%	12%	-	21%
Max Achievable	18%	20%	18%	14%	-	25%
Achievable Low	8%	9%	2%	6%	-	14%
Achievable Medium	12%	13%	5%	8%	-	18%
Achievable High	13%	14%	7%	9%	-	19%
Achievable Advanced	14%	16%	11%	10%	-	21%
Achievable Extreme	15%	16%	13%	10%	-	21%

*Excludes LADWP program accomplishments from 2010-2011 to 2012-2013

For each program potential scenario, the Nexant team considered the following two target years:

1. ***2020 Target Year Scenarios***, which include LADWP's 2010-2011 to 2012-2013 program accomplishments, as well as codes and standards accomplishments in these years.

2. ***2023 Target Year Scenarios***, which *exclude* historic program accomplishments and codes and standards

Table 4-2 summarizes results from these two groups of scenarios. All numbers reflect the target year for which each scenario is based. Benefit-cost ratios reflect the portfolio TRC benefit-cost ratio. The acquisition budgets reflect cumulative spending for FY2013-14 to the target year for the scenario. These were calculated by multiplying program potential in each year by assumed dollar per kWh spending. Dollar per kWh spending changes with each scenario due to changes in assumed administrative and incentive costs. Levelized costs are UCT levelized costs, meaning only utility incentive and administrative costs are considered.

Table 4-2. Program Potential Scenario Summary

	Low	Moderate	High	Advanced		Extreme	
				Normal	Accelerated	Normal	Accelerated
Target Year 2020							
Baseline Sales (GWh) FY2019-20	25,388	25,388	25,388	25,388	25,388	25,388	25,388
Cumulative Potential (GWh) FY2019-20	1,947	2,485	2,737	2,933	3,383	3,014	3,825
2010-2011 to 2012-2013 Program Accomplishments	615.6	615.6	615.6	615.6	615.6	615.6	615.6
Potential as % of Baseline Sales without Accomplishments	7.7%	9.8%	10.8%	11.6%	13.3%	11.9%	15.1%
Average Annual Savings as a % of Baseline Sales (2014-2020)*	1.1%	1.4%	1.5%	1.7%	1.9%	1.7%	2.2%
Potential as % of Baseline Sales with Accomplishments	10.1%	12.2%	13.2%	14.0%	15.8%	14.3%	17.5%
Target Year 2023							
Baseline Sales (GWh) FY2022-23	26,220	26,220	26,220	26,220	26,220	26,220	26,220
Cumulative Potential (GWh) FY2022-23	2,943	3,714	4,075	4,356	4,357	4,475	4,496
2010-2011 to 2012-2013 Program Accomplishments	615.6	615.6	615.6	615.6	615.6	615.6	615.6
Potential as % of Baseline Sales without Accomplishments	11.2%	14.2%	15.5%	16.6%	16.6%	17.1%	17.1%
Average Annual Savings as a % of Baseline Sales (2014-2023)*	1.1%	1.4%	1.6%	1.7%	1.7%	1.7%	1.7%
Potential as % of Baseline Sales with Accomplishments	13.6%	16.5%	17.9%	19.0%	19.0%	19.4%	19.5%
Scenario Economics (Over 20-Year Study Horizon)							
TRC Benefit Cost Ratio	1.55	1.38	1.33	1.13	1.13	0.90	0.90
Net TRC Benefits ($000s)	$912,082	$978,192	$997,745	$497,037	$497,508	-$517,094	-$535,621
Utility Levelized Cost ($/kWh)	$0.024	$0.046	$0.063	$0.085	$0.085	$0.115	$0.115

* These values represent the average annual level of savings required through programs to achieve the potential by the target year.

4.2 DETAILED MAXIMUM ACHIEVABLE POTENTIAL

This section provides the maximum achievable potentials by sector with segment and end-use granularity.

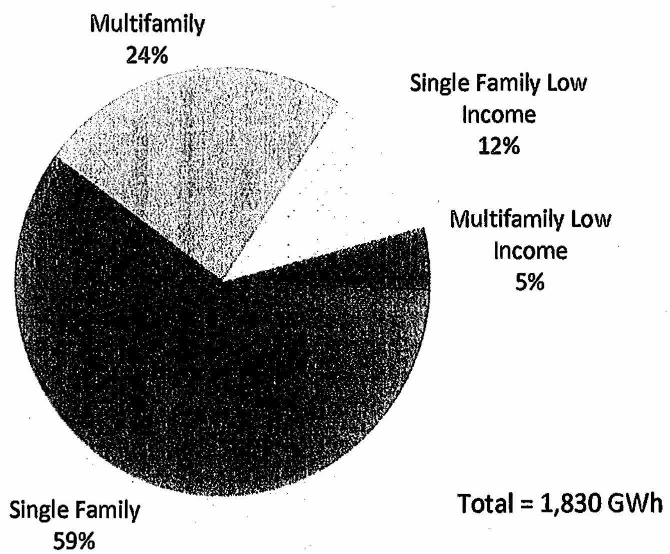
4.2.1 Residential Sector

Study results indicate residential customers account for about 35% of forecasted electricity sales. The Nexant team disaggregated residential sales across four segments: single family, multifamily, low-income single family, and low-income multifamily. Table 4-3 and Figure 4-1 summarize residential maximum achievable potential by segment.

Table 4-3. Residential Maximum Achievable Potential By Segment, Cumulative FY 2032-33

Segment	Baseline Sales (GWh)	Maximum Achievable Potential		
		GWh	% of Base Sales	MW
Single Family	4,820	1,087	23%	336
Multifamily	3,496	445	13%	159
Single Family Low Income	935	211	23%	65
Multifamily Low Income	734	87	12%	31
Total	9,985	1,830	18%	591

Figure 4-1. Residential Maximum Achievable Potential by Segment



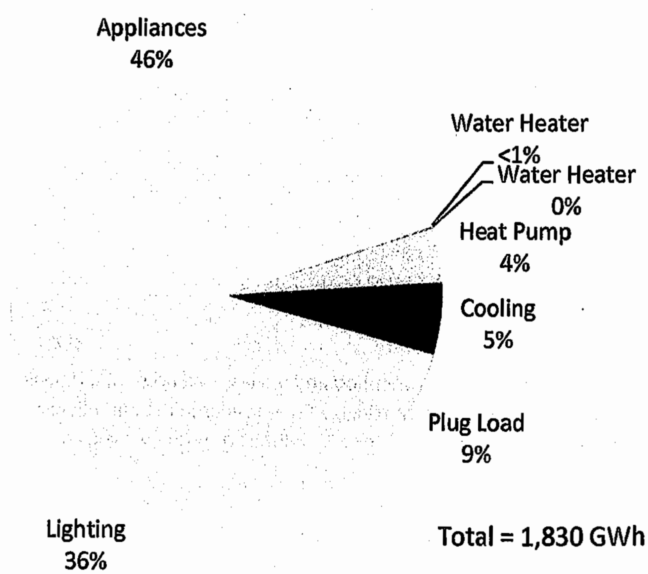
Residential maximum achievable potential amounts to 18% of forecasted FY 2032-33 sales. Single-family homes comprise the majority of the potential (59%), followed by multifamily (24%), with low-income single family and multifamily making up the remainder.

Table 4-4 and Figure 4-2 summarize residential technical and economic potential by end use group.

Table 4-4. Residential Maximum Achievable Potential by End Use

End Use Goup	Baseline Sales (GWh)	Maximum Achievable Potential		
		GWh	% of Base Sales	MW
Appliances	1,997	834	42%	176
Plug Load	2,033	162	8%	19
Cooking	329	0	0%	0
Cooling	2,197	97	4%	182
Heat Pump	222	71	32%	134
Heating	263	0	0%	0
Lighting	1,839	663	36%	79
Other	569	0	0%	0
Water Heater	272	3	1%	0
Pool Pump	264	0	0%	0
Total	9,985	1,830	18%	591

Figure 4-2. Residential Maximum Achievable Potential by End Use



Nearly 82% of maximum achievable potential comes from two end use groups—appliances (46%), lighting (36%). LED lighting across a number of applications (interior, exterior, specialty, pool

lighting, and holiday lights) makes up the majority of lighting savings. High performance T8s make up a smaller share of residential lighting potential, due to the low relative saturation of linear fluorescents. Refrigerator recycling accounts for roughly 82% of total savings in the appliance end use group. Other appliance measures have limited savings for a variety of reasons. For example, emerging refrigerators have reduced savings because of upcoming standards, and efficient clothes washers have limited savings due to the low saturation of electric water heaters.

4.2.2 Commercial Sector

Commercial customers, excluding Los Angeles city facilities, account for 52% of total forecasted FY 2032-33 sales.[1] These customers span multiple broad segments including education, office, storage, and retail, among others. Table 4-5 presents a comprehensive list of the commercial segments the Nexant team considered, and summarizing baseline sales, and maximum achievable potential by segment. Figure 4-3 shows the distribution of commercial technical potential by segment.

Table 4-5. Commercial Maximum Achievable Potential by Segment, Cumulative FY 2032-33

Segment	Baseline Sales (GWh)	Maximum Achievable Potential		
		GWh	% of Base Sales	MW
Assembly	361	61	17%	16
Education College	317	56	18%	13
Education Primary	359	81	23%	19
Grocery	824	262	32%	48
Health	714	86	12%	20
Lodging	333	48	14%	11
Miscellaneous*	5,325	884	17%	244
Office Large	3,106	668	22%	195
Office Small	571	126	22%	37
Restaurant	846	253	30%	46
Retail Large	1,305	316	24%	86
Retail Small	309	80	26%	21
Storage	346	72	21%	16
Warehouse	83	4	5%	1
Total	14,798	2,998	20%	771

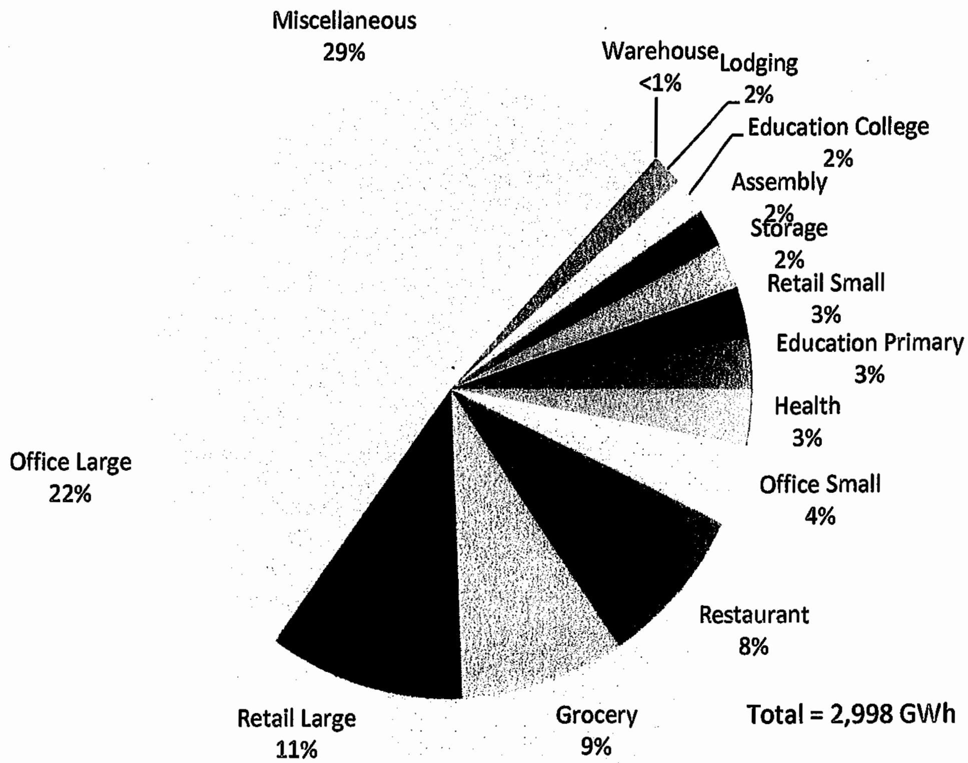
* The miscellaneous sector is composed of both other classified and unclassified accounts. Unclassified accounts did not have a SIC code in LADWP's customer database and represent roughly 60% of sales in the miscellaneous sector. The remaining 40% of the miscellaneous sector are distributed across more than 100 different business types that do not map to a broad segment.

Study results indicate maximum achievable potential can meet 20% of forecasted baseline sales in FY 2032-33. Much of the savings is in the miscellaneous (29% of total), large office (22% of total),

[1] LA facilities are included in the institutional sector.

large retail (11% of total), and grocery (9% of total) segments. This distribution of savings reflects the distribution of baseline sales across the segments. These four segments account for both 71% of baseline sales and 71% of technical potential in FY2032-33. As noted above, the miscellaneous sector is approximately 60% unclassified accounts.[1] The remaining 40% of the miscellaneous sector are distributed across more than 100 different business types that do not map to a broad segment.

Figure 4-3. Commercial Maximum Achievable by Market Segment



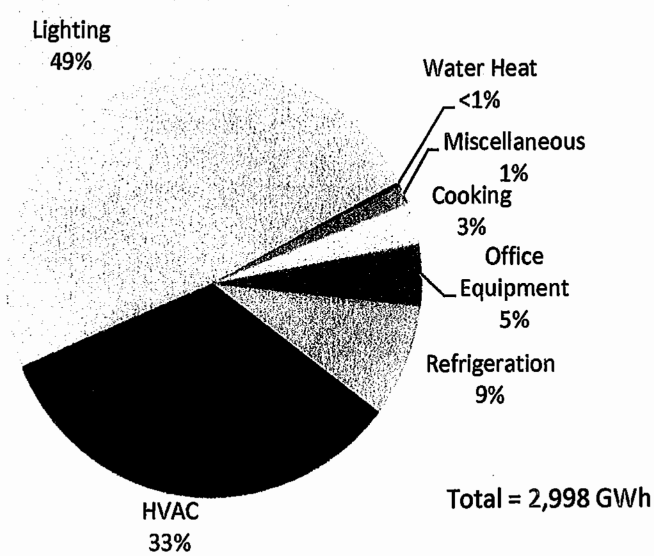
[1] The miscellaneous sector is composed of both other classified and unclassified accounts. Unclassified accounts did not have a SIC code in LADWP's customer data and represent roughly 60% of sales in the miscellaneous sector. The remaining 40% of the miscellaneous sector are distributed across more than 100 different business types that do not map to a broad segment.

Table 4-6 and Figure 4-4 show commercial achievable technical potential by end use group.

Table 4-6. Commercial Maximum Achievable Potential by End Use Group, Cumulative FY 2032-33

Segment	Baseline Sales (GWh)	Maximum Achievable Potential		
		GWh	% of Base Sales	MW
Cooking	474	91	19%	0
HVAC	4,614	1,000	22%	408
Lighting	4,457	1,456	33%	288
Miscellaneous	2,457	43	2%	9
Office Equipment	1,284	139	11%	28
Refrigeration	1,347	256	19%	36
Water Heat	166	11	7%	2
Total	14,798	2,998	20%	771

Figure 4-4. Commercial Maximum Achievable by End Use Group



Savings from lighting measures account for nearly half (49%) of maximum achievable potential in FY2032-33. More than half of lighting savings (55%) comes from the linear fluorescent end use, while high intensity discharge fixtures account for 25% of total lighting savings, interior screw-base fixtures account for 14%, and exterior/other fixtures account for 6%. While the majority of lighting savings comes from the installation of more efficient equipment (80%), a significant share of savings comes from occupancy sensors and improved controls (20%).

4.2.3 Institutional Sector

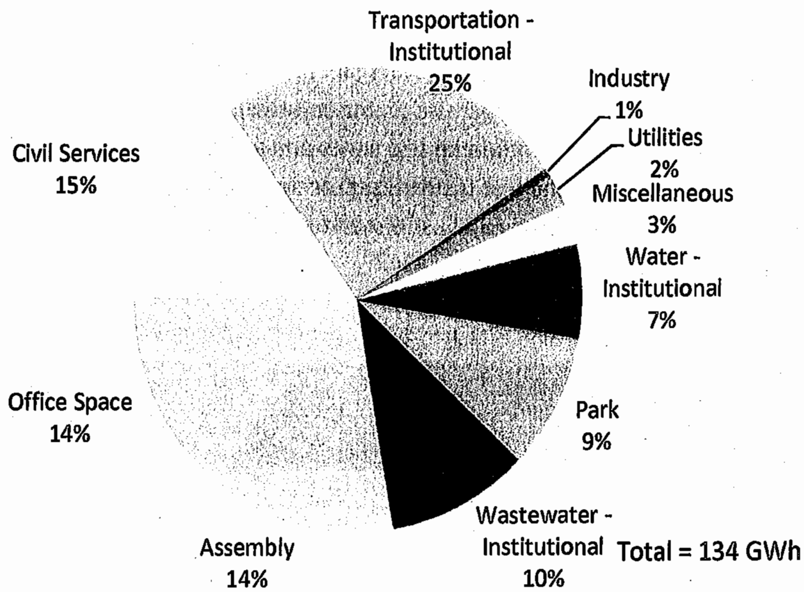
The Nexant team identified LADWP's institutional customers and developed a separate sector for modeling. Institutional buildings have characteristics similar to commercial segments (e.g., office and assembly) and industrial segments (e.g., water and wastewater). The Nexant team employed a bottom-up modeling approach for commercial-like segments and a top-down modeling approach for larger industrial-like accounts. Overall, the institutional sector accounts for nearly 3% of total forecasted baseline sales. Table 4-7 and Figure 4-5 summarize institutional sector maximum achievable potential by segment.

Table 4-7. Institutional Maximum Achievable Potential by Segment, Cumulative FY 2032-33

Segment	Baseline Sales (GWh)	Maximum Achievable Potential		
		GWh	% of Base Sales	MW
Assembly	115	19	16%	5
Civil Services	96	20	21%	6
Industry	5	1	18%	0
Miscellaneous	21	4	18%	1
Office Space	91	19	21%	6
Park	71	13	18%	4
Transportation*	194	34	18%	10
Utilities	17	3	18%	1
Wastewater*	69	14	20%	2
Water*	77	9	11%	2
Total	756	134	18%	35

*Modeled using a top-down approach

Figure 4-5. Institutional Maximum Achievable Potential by Segment



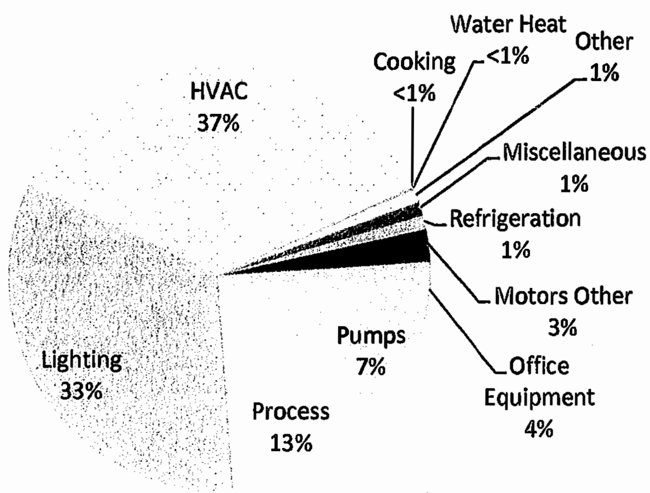
Nearly one-quarter of maximum achievable potential in the institutional sector comes from the transportation segment. This segment includes both the Port of Los Angeles and Los Angeles International Airport; this segment also accounts for roughly one-quarter of baseline institutional sales. Other segments that represent a significant share of savings in the institutional sector include assembly (14%), civil services (15%), and office space (14%).

Table 4-8 and Figure 4-6 show maximum achievable potential by end use group.

Table 4-8. Institutional Maximum Achievable Potential by End Use, Cumulative FY 2032-33

End Use Group	Baseline Sales (GWh)	Maximum Achievable Potential		
		GWh	% of Base Sales	MW
Cooking	7	0	1%	0
HVAC	198	49	25%	20
Indirect Boiler	5	0	0%	0
Lighting	149	45	30%	9
Miscellaneous	72	1	2%	0
Motors Other	64	3	5%	0
Office Equipment	50	6	11%	1
Other	15	1	8%	0
Process	86	18	21%	3
Pumps	85	10	11%	1
Refrigeration	21	1	7%	0
Water Heat	5	0	6%	0
Total	756	134	18%	35

Figure 4-6. Institutional Maximum Achievable Potential by End Use



Lighting and HVAC collectively account for 70% of institutional sector savings. Process, an end use that only applies to the transportation, water, and wastewater segments, accounts for 13% of total institutional maximum achievable potential. Other miscellaneous end uses such as pumps, office equipment, and motors account for the remaining 17% of maximum achievable potential.

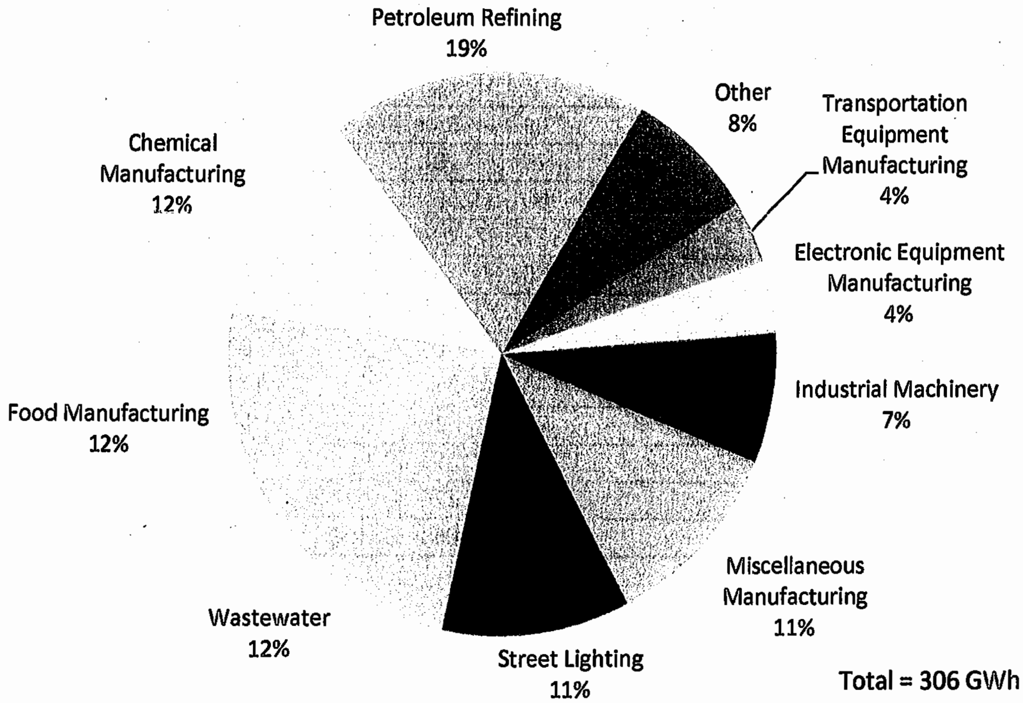
4.2.4 Industrial Sector

Modeling industrial energy efficiency potential presents a unique challenge, due to variability within industrial segments. While a prototypical commercial office, for example, can easily be characterized, it is more difficult to do so for a prototypical industrial segment. For this reason, the Nexant team employed a top-down model to estimate industrial potential, covering a total of 17 industrial segments. Table 4-9 and Figure 4-7 present maximum achievable potential by industrial segment.

Table 4-9. Industrial Maximum Achievable Potential by Segment, Cumulative FY 2032-33

Segment	Baseline Sales (GWh)	Maximum Achievable Potential		
		GWh	% of Base Sales	MW
Agriculture	0	3%	0	0
Chemical Manufacturing	37	14%	7	7
Electronic Equipment Manufacturing	13	20%	3	3
Food Manufacturing	37	18%	7	7
Industrial Machinery	23	17%	7	6
Lumber Wood Products	5	22%	1	1
Mining	1	2%	0	0
Miscellaneous	0	0%	0	0
Miscellaneous Manufacturing	34	18%	10	10
Paper Manufacturing	10	17%	2	2
Petroleum Refining	57	17%	13	12
Primary Metal Manufacturing	1	11%	0	0
Stone Clay Glass Products	2	15%	0	0
Street Lighting	34	20%	7	7
Transportation Equipment Manufacturing	11	18%	3	3
Wastewater	36	20%	5	5
Water	5	11%	1	1
Total	306	14%	66	64

Figure 4-7. Industrial Maximum Achievable Potential by Segment



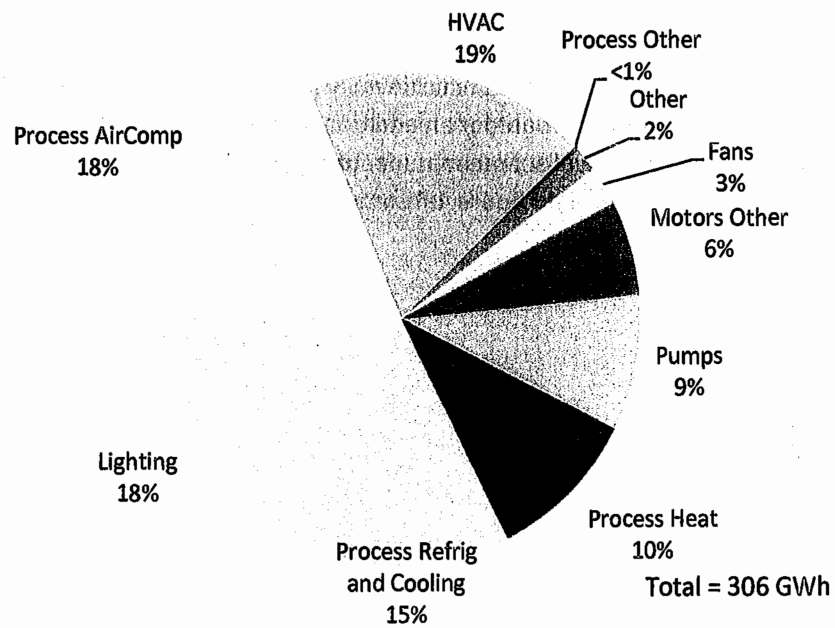
In the figure above, "Other" includes: Miscellaneous, Agriculture, Primary Metal Manufacturing, Mining, Stone Clay Glass Products, Water, Lumber Wood Products, Paper Manufacturing

Petroleum refining makes up nearly 19% of maximum achievable potential. Food manufacturing, chemical manufacturing, and wastewater account for an additional 36% of maximum achievable potential (12% each), and wastewater miscellaneous manufacturing and street lighting each represent 11% of the potential. Table 4-10 and Figure 4-8 summarize maximum achievable potential by industrial end use.

Table 4-10. Industrial Maximum Achievable Potential by End Use, Cumulative FY 2032-33

End Use	Baseline Sales (GWh)	Maximum Achievable Potential		
		GWh	% of Base Sales	MW
Fans	104	8	8%	3
HVAC	264	58	22%	24
Indirect Boiler	29	0	0%	0
Lighting	360	56	15%	11
Motors Other	397	19	5%	3
Other	80	5	6%	1
Process AirComp	277	56	20%	8
Process Electro Chemical	30	0	0%	0
Process Heat	180	31	17%	4
Process Other	21	1	5%	0
Process Refrig and Cooling	217	45	21%	6
Pumps	236	27	12%	4
Total	2,195	306	14%	64

Figure 4-8. Industrial Maximum Achievable Potential by End Use Group



Approximately 37% of industrial savings are in lighting and HVAC end uses. Process end uses represent an additional 43% of total maximum achievable potential (such as process air compression, process refrigeration and cooling, and process heat). The remaining maximum

achievable potential comes from other measures that go to miscellaneous end uses such as pumps, motors, and fans.

4.3 PROGRAM POTENTIAL SCENARIOS

This section provides tabular summaries of each of the seven program potential scenarios. Tables correspond to the scenarios shown in Table 4-11.

Table 4-11. Tables for Program Potential Scenarios

Scenario	Table
Low	Table 4-12
Moderate	Table 4-13
High	Table 4-14
Advanced	Table 4-15
Extreme	Table 4-16
Advanced Accelerated	Table 4-17
Extreme Accelerated	Table 4-18

Table 4-12. Low Program Potential Summary

Category	FY2013-14	FY2014-15	FY2015-16	FY2016-17	FY2017-18	FY2018-19	FY2019-20	FY2020-21	FY2021-22	FY2022-23
Incremental Program Potential (MWh)	186,872	185,834	197,314	198,210	208,202	201,640	210,072	200,330	204,985	196,215
Cumulative Program Potential (MWh)	186,872	372,707	570,021	768,231	976,433	1,178,073	1,388,145	1,588,476	1,793,461	1,989,676
Cumulative Program Potential (MWh) w/ 2011-2013	623,072	808,907	1,006,221	1,204,431	1,412,633	1,614,273	1,824,345	2,024,676	2,229,661	2,425,876
Cumulative Savings from Codes and Standards	195,645	252,234	314,394	374,362	432,266	583,116	738,243	881,024	1,011,821	1,132,324
Baseline Sales (LADWP Gross)	23,969,813	24,109,873	24,301,748	24,552,888	24,837,064	25,113,801	25,387,855	25,746,348	25,985,817	26,219,677
Savings as % of Baseline Sales (no standards)	2.6%	3.4%	4.1%	4.9%	5.7%	6.4%	7.2%	7.9%	8.6%	9.3%
Savings as % of Baseline (with Standards)	3.4%	4.4%	5.4%	6.4%	7.4%	8.7%	10.1%	11.3%	12.5%	13.6%
Savings as % of Baseline Sales Rolling 10-year[1]	3.4%	4.4%	5.4%	6.4%	7.4%	8.7%	10.1%	10.4%	10.9%	11.2%
Incremental Demand Savings (MW)	51	49	52	52	54	53	55	54	54	54
Cumulative Demand Savings (MW)	51	100	152	204	258	311	366	419	473	527
TRC Levelized Cost ($/kWh)	$0.0631	$0.0631	$0.0631	$0.0631	$0.0631	$0.0631	$0.0631	$0.0631	$0.0631	$0.0631
UCT Levelized Cost ($/kWh)	$0.0235	$0.0235	$0.0235	$0.0235	$0.0235	$0.0235	$0.0235	$0.0235	$0.0235	$0.0235

[1] Rolling 10-year savings include the impacts of savings achieved (program accomplishments + codes & standards) starting with the 2010-2011 program year.

Table 4-13. Moderate Program Potential Summary

Category	FY2013-14	FY2014-15	FY2015-16	FY2016-17	FY2017-18	FY2018-19	FY2019-20	FY2020-21	FY2021-22	FY2022-23
Incremental Program Potential (MWh)	259,315	257,874	273,804	275,047	288,913	279,807	291,508	277,989	284,449	272,279
Cumulative Program Potential (MWh)	259,315	517,188	790,992	1,066,039	1,354,952	1,634,759	1,926,266	2,204,256	2,488,705	2,760,984
Cumulative Program Potential (MWh) w/ 2011-2013	695,515	953,388	1,227,192	1,502,239	1,791,152	2,070,959	2,362,466	2,640,456	2,924,905	3,197,184
Cumulative Savings from Codes and Standards	195,645	252,234	314,394	374,362	432,266	583,116	738,243	881,024	1,011,821	1,132,324
Baseline Sales (LADWP Gross)	23,969,813	24,109,873	24,301,748	24,552,888	24,837,064	25,113,801	25,387,855	25,746,348	25,985,817	26,219,677
Savings as % of Baseline Sales (no standards)	2.9%	4.0%	5.0%	6.1%	7.2%	8.2%	9.3%	10.3%	11.3%	12.2%
Savings as % of Baseline (with Standards)	3.7%	5.0%	6.3%	7.6%	9.0%	10.6%	12.2%	13.7%	15.1%	16.5%
Savings as % of Baseline Sales Rolling 10-year[1]	3.7%	5.0%	6.3%	7.6%	9.0%	10.6%	12.2%	12.8%	13.5%	14.2%
Incremental Demand Savings (MW)	71	68	72	73	75	74	76	74	75	75
Cumulative Demand Savings (MW)	71	138	210	283	358	432	508	582	657	732
TRC Levelized Cost ($/kWh)	$0.0732	$0.0732	$0.0732	$0.0732	$0.0732	$0.0732	$0.0732	$0.0732	$0.0732	$0.0732
UCT Levelized Cost ($/kWh)	$0.0459	$0.0459	$0.0459	$0.0459	$0.0459	$0.0459	$0.0459	$0.0459	$0.0459	$0.0459

[1] Rolling 10-year savings include the impacts of savings achieved (program accomplishments + codes & standards) starting with the 2010-2011 program year.

Table 4-14. High Program Potential Summary

Category	FY2013-14	FY2014-15	FY2015-16	FY2016-17	FY2017-18	FY2018-19	FY2019-20	FY2020-21	FY2021-22	FY2022-23
Incremental Program Potential (MWh)	293,221	291,592	309,605	311,011	326,690	316,393	329,624	314,338	321,642	307,881
Cumulative Program Potential (MWh)	293,221	584,813	894,419	1,205,429	1,532,119	1,848,511	2,178,135	2,492,473	2,814,115	3,121,996
Cumulative Program Potential (MWh) w/ 2011-2013	729,421	1,021,013	1,330,619	1,641,629	1,968,319	2,284,711	2,614,335	2,928,673	3,250,315	3,558,196
Cumulative Savings from Codes and Standards	195,645	252,234	314,394	374,362	432,266	583,116	738,243	881,024	1,011,821	1,132,324
Baseline Sales (LADWP Gross)	23,969,813	24,109,873	24,301,748	24,552,888	24,837,064	25,113,801	25,387,855	25,746,348	25,985,817	26,219,677
Savings as % of Baseline Sales (no standards)	3.0%	4.2%	5.5%	6.7%	7.9%	9.1%	10.3%	11.4%	12.5%	13.6%
Savings as % of Baseline (with Standards)	3.9%	5.3%	6.8%	8.2%	9.7%	11.4%	13.2%	14.8%	16.4%	17.9%
Savings as % of Baseline Sales Rolling 10-year[1]	3.9%	5.3%	6.8%	8.2%	9.7%	11.4%	13.2%	13.9%	14.8%	15.5%
Incremental Demand Savings (MW)	80	76	82	82	85	84	86	84	85	84
Cumulative Demand Savings (MW)	80	156	238	320	405	488	574	658	743	827
TRC Levelized Cost ($/kWh)	$0.0766	$0.0766	$0.0766	$0.0766	$0.0766	$0.0766	$0.0766	$0.0766	$0.0766	$0.0766
UCT Levelized Cost ($/kWh)	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627

[1] Rolling 10-year savings include the impacts of savings achieved (program accomplishments + codes & standards) starting with the 2010-2011 program year.

Table 4-15. Advanced Program Potential Summary

Category	FY2013-14	FY2014-15	FY2015-16	FY2016-17	FY2017-18	FY2018-19	FY2019-20	FY2020-21	FY2021-22	FY2022-23
Incremental Program Potential (MWh)	319,613	317,838	337,472	339,004	356,094	344,870	359,293	342,631	350,592	335,592
Cumulative Program Potential (MWh)	319,613	637,451	974,923	1,313,927	1,670,021	2,014,892	2,374,184	2,716,815	3,067,407	3,403,000
Cumulative Program Potential (MWh) w/ 2011-2013	755,813	1,073,651	1,411,123	1,750,127	2,106,221	2,451,092	2,810,384	3,153,015	3,503,607	3,839,200
Cumulative Savings from Codes and Standards	195,645	252,234	314,394	374,362	432,266	583,116	738,243	881,024	1,011,821	1,132,324
Baseline Sales (LADWP Gross)	23,969,813	24,109,873	24,301,748	24,552,888	24,837,064	25,113,801	25,387,855	25,746,348	25,985,817	26,219,677
Savings as % of Baseline Sales (no standards)	3.2%	4.5%	5.8%	7.1%	8.5%	9.8%	11.1%	12.2%	13.5%	14.6%
Savings as % of Baseline (with Standards)	4.0%	5.5%	7.1%	8.7%	10.2%	12.1%	14.0%	15.7%	17.4%	19.0%
Savings as % of Baseline Sales Rolling 10-year[1]	4.0%	5.5%	7.1%	8.7%	10.2%	12.1%	14.0%	14.8%	15.8%	16.6%
Incremental Demand Savings (MW)	87	83	89	90	92	91	93	92	93	92
Cumulative Demand Savings (MW)	87	170	259	349	441	532	626	717	810	902
TRC Levelized Cost ($/kWh)	$0.0908	$0.0908	$0.0908	$0.0908	$0.0908	$0.0908	$0.0908	$0.0908	$0.0908	$0.0908
UCT Levelized Cost ($/kWh)	$0.0850	$0.0850	$0.0850	$0.0850	$0.0850	$0.0850	$0.0850	$0.0850	$0.0850	$0.0850

[1] Rolling 10-year savings include the impacts of savings achieved (program accomplishments + codes & standards) starting with the 2010-2011 program year.

Table 4-16. Extreme Program Potential Summary

Category	FY2013-14	FY2014-15	FY2015-16	FY2016-17	FY2017-18	FY2018-19	FY2019-20	FY2020-21	FY2021-22	FY2022-23
Incremental Program Potential (MWh)	330,360	327,857	348,469	350,474	368,350	357,211	372,291	355,489	363,655	348,074
Cumulative Program Potential (MWh)	330,360	658,217	1,006,686	1,357,159	1,725,509	2,082,720	2,455,011	2,810,501	3,174,155	3,522,230
Cumulative Program Potential (MWh) w/ 2011-2013	766,560	1,094,417	1,442,886	1,793,359	2,161,709	2,518,920	2,891,211	3,246,701	3,610,355	3,958,430
Cumulative Savings from Codes and Standards	195,645	252,234	314,394	374,362	432,266	583,116	738,243	881,024	1,011,821	1,132,324
Baseline Sales (LADWP Gross)	23,969,813	24,109,873	24,301,748	24,552,888	24,837,064	25,113,801	25,387,855	25,746,348	25,985,817	26,219,677
Savings as % of Baseline Sales (no standards)	3.2%	4.5%	5.9%	7.3%	8.7%	10.0%	11.4%	12.6%	13.9%	15.1%
Savings as % of Baseline (with Standards)	4.0%	5.6%	7.2%	8.8%	10.4%	12.4%	14.3%	16.0%	17.8%	19.4%
Savings as % of Baseline Sales Rolling 10-year[1]	4.0%	5.6%	7.2%	8.8%	10.4%	12.4%	14.3%	15.1%	16.2%	17.1%
Incremental Demand Savings (MW)	89	86	91	92	95	94	96	94	95	95
Cumulative Demand Savings (MW)	89	175	266	359	454	547	644	738	833	928
TRC Levelized Cost ($/kWh)	$0.1151	$0.1151	$0.1151	$0.1151	$0.1151	$0.1151	$0.1151	$0.1151	$0.1151	$0.1151
UCT Levelized Cost ($/kWh)	$0.1147	$0.1147	$0.1147	$0.1147	$0.1147	$0.1147	$0.1147	$0.1147	$0.1147	$0.1147

[1] Rolling 10-year savings include the impacts of savings achieved (program accomplishments + codes & standards) starting with the 2010-2011 program year.

Table 4-17. Advanced Accelerated Program Potential Summary

Category	FY2013-14	FY2014-15	FY2015-16	FY2016-17	FY2017-18	FY2018-19	FY2019-20	FY2020-21	FY2021-22	FY2022-23
Incremental Program Potential (MWh)	379,265	378,333	398,353	400,207	417,532	406,769	421,171	404,553	106,303	91,276
Cumulative Program Potential (MWh)	379,265	757,598	1,155,951	1,556,158	1,973,690	2,380,459	2,801,630	3,206,184	3,312,487	3,403,762
Cumulative Program Potential (MWh) w/ 2011-2013	815,465	1,193,798	1,592,151	1,992,358	2,409,890	2,816,659	3,237,830	3,642,384	3,748,687	3,839,962
Cumulative Savings from Codes and Standards	198,577	258,228	323,577	386,861	448,188	602,550	761,266	907,752	1,025,544	1,133,041
Baseline Sales (LADWP Gross)	23,969,813	24,109,873	24,301,748	24,552,888	24,837,064	25,113,801	25,387,855	25,746,348	25,985,817	26,219,677
Savings as % of Baseline Sales (no standards)	3.4%	5.0%	6.6%	8.1%	9.7%	11.2%	12.8%	14.1%	14.4%	14.6%
Savings as % of Baseline (with Standards)	4.2%	6.0%	7.9%	9.7%	11.5%	13.6%	15.8%	17.7%	18.4%	19.0%
Savings as % of Baseline Sales Rolling 10-year[1]	4.2%	6.0%	7.9%	9.7%	11.5%	13.6%	15.8%	16.8%	16.8%	16.6%
Incremental Demand Savings (MW)	102	99	104	105	108	107	109	107	31	31
Cumulative Demand Savings (MW)	102	200	304	409	517	624	733	840	871	902
TRC Levelized Cost ($/kWh)	$0.0908	$0.0908	$0.0908	$0.0908	$0.0908	$0.0908	$0.0908	$0.0908	$0.0908	$0.0908
UCT Levelized Cost ($/kWh)	$0.0850	$0.0850	$0.0850	$0.0850	$0.0850	$0.0850	$0.0850	$0.0850	$0.0850	$0.0850

[1] Rolling 10-year savings include the impacts of savings achieved (program accomplishments + codes & standards) starting with the 2010-2011 program year.

Table 4-18. Extreme Accelerated Program Potential Summary

Category	FY2013-14	FY2014-15	FY2015-16	FY2016-17	FY2017-18	FY2018-19	FY2019-20	FY2020-21	FY2021-22	FY2022-23
Incremental Program Potential (MWh)	437,567	436,179	457,783	460,339	478,590	468,160	482,959	105,855	112,768	97,276
Cumulative Program Potential (MWh)	437,567	873,746	1,331,530	1,791,869	2,270,460	2,738,619	3,221,579	3,327,434	3,440,202	3,537,478
Cumulative Program Potential (MWh) w/ 2011-2013	873,767	1,309,946	1,767,730	2,228,069	2,706,660	3,174,819	3,657,779	3,763,634	3,876,402	3,973,678
Cumulative Savings from Codes and Standards	201,225	263,715	332,110	398,580	463,183	620,890	783,006	913,195	1,030,940	1,138,353
Baseline Sales (LADWP Gross)	23,969,813	24,109,873	24,301,748	24,552,888	24,837,064	25,113,801	25,387,855	25,746,348	25,985,817	26,219,677
Savings as % of Baseline Sales (no standards)	3.6%	5.4%	7.3%	9.1%	10.9%	12.6%	14.4%	14.6%	14.9%	15.2%
Savings as % of Baseline (with Standards)	4.5%	6.5%	8.6%	10.7%	12.8%	15.1%	17.5%	18.2%	18.9%	19.5%
Savings as % of Baseline Sales Rolling 10-year[1]	4.5%	6.5%	8.6%	10.7%	12.8%	15.1%	17.5%	17.3%	17.3%	17.1%
Incremental Demand Savings (MW)	116	113	119	120	123	122	125	32	32	32
Cumulative Demand Savings (MW)	116	229	348	468	591	713	838	870	903	934
TRC Levelized Cost ($/kWh)	$0.1155	$0.1155	$0.1155	$0.1155	$0.1155	$0.1155	$0.1155	$0.1155	$0.1155	$0.1155
UCT Levelized Cost ($/kWh)	$0.1151	$0.1151	$0.1151	$0.1151	$0.1151	$0.1151	$0.1151	$0.1151	$0.1151	$0.1151

[1] Rolling 10-year savings include the impacts of savings achieved (program accomplishments + codes & standards) starting with the 2010-2011 program year.

5 PLANNING CONSIDERATIONS

5.1 SCOPE OF ANALYSIS

The program potential scenarios detailed in Section 4 represent a broad-brush approach to estimating potential based on assumed incentive and administration/marketing costs, and identified that LADWP's aspirational goal of 15% savings as a percentage of 2020 baseline sales[1] is achievable and cost-effective from the TRC perspective. However, as LADWP develops its program plans, it will not use a single set of incentive rates for all measures, and each program will have unique administration and marketing costs. In addition, although all measures with a TRC B/C ratio greater than 0.30 were included in this scenario, not all measures are likely to be included in the programs. To provide some context to the budgetary requirements of actually achieving these savings, the Nexant team explored several scenarios to reach 15% of baseline energy sales by 2020, based on a more granular approach to the assumptions.

LADWP provided the Nexant team with program categories and assigned all measures to these program categories. Example program categories include: Residential Lighting, Residential Envelope, Commercial Refrigeration, and Direct Install (DI). The Nexant team then applied program-specific adoption assumptions to each category. The drivers of the adoption are:

1. Incentive expenditures –varies between 30% to 100% of incremental measure cost
2. Administrative and marketing expenditures – varies between 20% to 60% of incremental measure cost
3. Ramp rates – accounts for program maturity. The ramp rates were designed to accelerate sufficient adoption to reach 15% in 2020 and assume more aggressive market and outreach to reach market saturation of some measures within 7 or 8 years. As such, the majority of the discretionary savings will be captured by 2020, resulting in a drop-off in annual acquisition in later years.

In addition, the codes and standards savings assumptions found through the potential model presented in the prior analysis represent high-level market results that quantify the overall impacts of identified codes and standards that take effect during the planning horizon of this study. However, LADWP programs target specific C&S improvements. For these planning scenarios, the Nexant team used the LADWP expected savings for C&S programs based on LADWP's share of the identified C&S attributable savings for the state.

[1] 15% savings represents cumulative savings through 2020 inclusive of program accomplishments from 2010-2013.

Table 5-1. LADWP Projected Savings from Codes and Standards

Year	GWh	MW
2014-15	76.48	11.6
2015-16	84.41	13.7
2016-17	77.89	13.0
2017-18	62.28	11.3
2018-19	50.18	9.9
2019-20	44.65	9.1
2020-21	38.81	8.3
2021-22	33.34	7.7
2022-23	28.60	7.2

With LADWP's guidance, the Nexant team produced ten program planning scenarios to demonstrate how changing assumptions on program delivery, including incentives, admin/marketing, benefit-cost thresholds, and ramp rates can create a range of budgets required to reach roughly 15% savings by 2020. These scenarios are intended to provide preliminary guidance for LADWP's program planning process but do not represent all possible program delivery options, and input assumptions may be further refined to reflect LADWP's delivery strategy for each program offering. Table 5-2 shows the assumptions, average annual budget, and the cumulative savings as a percent of forecasted baseline sales for each scenario. Table 5-3 shows additional detail for each of these scenarios in FY2019-20 and FY2022-23, including energy savings, demand savings, benefit cost ratios, and levelized costs.

Table 5-2. Program Planning Scenario Assumptions

Scenario	Incentive/Admin Assumption	Minimum B/C Threshold	Ramp Assumption	Average Annual Budget (Million $)	Cumulative Savings as a Percent of Baseline Sales*									
					2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023
1	Incentive 90% of incremental cost; 60% admin – all programs	0.3	Logistic ramp	$389	3.9%	5.3%	7.4%	9.7%	12.2%	14.4%	16.4%	17.3%	17.8%	18.2%
2	Incentive 90% of incremental cost; 60% admin – all programs	0.5	Logistic ramp	$326	3.8%	5.2%	7.2%	9.5%	11.8%	14.0%	15.9%	16.7%	17.3%	17.6%
3	Incentives range from 30% to 100% of incremental cost by program; Admin ranges from 20% to 60% by program	0.3	Logistic ramp	$192	3.8%	5.1%	6.9%	9.0%	11.2%	13.2%	15.0%	15.8%	16.3%	16.6%
4	Incentives Range from 50% to 90% of incremental cost by program; Admin ranges from 40% to 60% by program	0.5	Logistic ramp	$242	3.8%	5.2%	7.1%	9.3%	11.5%	13.6%	15.5%	16.3%	16.8%	17.2%
5	Incentives range from 50% to 100% of incremental cost by program; Admin fixed at 40% for all programs	0.5	Logistic ramp	$179	3.7%	5.0%	6.7%	8.8%	10.8%	12.8%	14.5%	15.2%	15.7%	16.0%
6	Incentives range from 30% to 100% of incremental cost by program; Admin ranges from 20% to 40% by program	0.5	Logistic ramp	$161	3.7%	5.0%	6.7%	8.8%	10.8%	12.8%	14.5%	15.2%	15.7%	16.0%
7	Incentives 100% of incremental cost for all programs; Admin ranges from 20% to 60% by program	0.5	9 Year Linear Ramp	$247	4.3%	6.1%	7.9%	9.7%	11.4%	12.9%	14.5%	15.9%	17.3%	17.4%
8	Incentives range from 50% to 100% of incremental cost by program; Admin ranges from 20% to 40% by program	0.3	9 Year Linear Ramp	$224	4.3%	6.1%	7.9%	9.7%	11.4%	13.0%	14.6%	15.9%	17.4%	17.5%
9	Incentives range from 30% to 100% of incremental cost by program; Admin ranges from 20% to 40% by program;	0.5	8 Year Linear Ramp	$157	4.3%	6.1%	7.9%	9.6%	11.3%	12.9%	14.4%	15.8%	16.0%	16.1%
10	Incentives defined by target incentive rates for program groups	0.5 for direct install; 0 for all other program groups	Logistic ramp	$151	3.7%	5.0%	6.8%	8.8%	10.9%	12.8%	14.5%	15.3%	15.8%	16.1%

*Includes accomplishments from 2010-2013 programs

Table 5-3. Detailed Program Planning Scenario Results (2020 and 2023)

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8	Scenario 9	Scenario 10
Target Year 2020										
Baseline Sales (GWh) FY2019-20	25,388	25,388	25,388	25,388	25,388	25,388	25,388	25,388	25,388	25,388
Cumulative Potential (GWh) FY2019-20	3,094	2,962	2,726	2,859	2,596	2,593	2,601	2,614	2,583	2,610
Cumulative C&S Savings (GWh) FY2019-20	466	466	466	466	466	466	466	466	466	466
2010-2011 to 2012-2013 Program Accomplishments	616	616	616	616	616	616	616	616	616	616
Potential as % of Baseline Sales without Accomplishments	14.0%	13.5%	12.6%	13.1%	12.1%	12.0%	12.1%	12.1%	12.0%	12.1%
Average Annual Savings as a % of Baseline Sales (2014-2020)	2.0%	1.9%	1.8%	1.9%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
Potential as % of Baseline Sales with Accomplishments	16.4%	15.9%	15.0%	15.5%	14.5%	14.5%	14.5%	14.6%	14.4%	14.5%
Cumulative Acquisition Budget ($Million) in FY2019-20	$2,723	$2,280	$1,342	$1,695	$1,250	$1,129	$1,727	$1,567	$1,100	$1,057
Average Annual Acquisition Budget ($Million)	$389	$326	$192	$242	$179	$161	$247	$224	$157	$151
Target Year 2023										
Baseline Sales (GWh) FY2022-23	26,220	26,220	26,220	26,220	26,220	26,220	26,220	26,220	26,220	26,220
Cumulative Potential (GWh) FY2022-23	3,592	3,441	3,166	3,323	3,021	3,015	3,390	3,406	3,038	3,029
Cumulative C&S Savings (GWh) FY2022-23	566	566	566	566	566	566	566	566	566	566
2010-2011 to 2012-2013 Program Accomplishments	615.6	615.6	615.6	615.6	615.6	615.6	615.6	615.6	615.6	615.6
Potential as % of Baseline Sales without Accomplishments	15.9%	15.3%	14.2%	14.8%	13.7%	13.7%	15.1%	15.2%	13.7%	13.7%
Average Annual Savings as a % of Baseline Sales (2014-2023)	1.6%	1.5%	1.4%	1.5%	1.4%	1.4%	1.5%	1.5%	1.4%	1.4%
Potential as % of Baseline Sales with Accomplishments	18.2%	17.6%	16.6%	17.2%	16.0%	16.0%	17.4%	17.5%	16.1%	16.1%
Cumulative Acquisition Budget ($Million) in FY2022-23	$3,165	$2,661	$1,570	$1,990	$1,474	$1,327	$2,261	$2,050	$1,306	$1,225
Average Annual Acquisition Budget ($Million)	$316	$266	$157	$199	$147	$133	$226	$205	$131	$122
Scenario Economics (Over 20-year Study Horizon)										
TRC Benefit Cost Ratio	1.11	1.26	1.20	1.30	1.46	1.35	1.27	1.17	1.37	1.28
Net TRC Benefits ($Million)	$448	$867	$637	$932	$1,129	$930	$869	$599	$958	$775
Utility Levelized Cost ($/kWh)	$0.085	$0.074	$0.050	$0.058	$0.048	$0.043	$0.064	$0.060	$0.042	$0.039

5.2 PROGRAM PLANNING SCENARIOS

This section provides tabular summaries of each of the ten planning scenario summaries. Tables correspond to the scenarios shown in Table 5-4.

Table 5-4. Tables for Program Potential Scenarios

Scenario	Table
1	Table 5-5
2	Table 5-6
3	Table 5-7
4	Table 5-8
5	Table 5-9
6	Table 5-10
7	Table 5-11
8	Table 5-12
9	Table 5-13
10	Table 5-14

See the tables in Appendix F for additional details on methodology, assumptions, and results for each scenario.

Table 5-5. Detailed Results - Scenario 1

Row #	Category	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
1	**Incremental Program Potential (GWh)**	245	275	423	519	568	556	506	239	152	107
2	**Cumulative Program Potential (GWh)**	245	521	944	1,463	2,032	2,588	3,094	3,333	3,485	3,592
3	**Cumulative Program Potential (GWh) w/ 2011-2013**	682	957	1,381	1,900	2,468	3,024	3,530	3,770	3,921	4,028
4	**Incremental Savings from Codes and Standards**	71	76	84	78	62	50	45	39	33	29
5	**Cumulative Savings from Codes and Standards (w/ 2011-2013)**	249	326	410	488	550	600	645	684	717	746
6	**Annual Savings Target (Program + Codes & Standards)**	**317**	**352**	**508**	**597**	**631**	**607**	**550**	**278**	**185**	**136**
7	**Baseline Sales (LADWP Gross)**	23,970	24,110	24,302	24,553	24,837	25,114	25,388	25,746	25,986	26,220
8	**Savings as % of Baseline Sales (no standards)**	2.8%	4.0%	5.7%	7.7%	9.9%	12.0%	13.9%	14.6%	15.1%	15.4%
9	**Savings as % of Baseline (with Standards)**	**3.9%**	**5.3%**	**7.4%**	**9.7%**	**12.2%**	**14.4%**	**16.4%**	**17.3%**	**17.8%**	**18.2%**
10	**Savings as % of Baseline Sales Rolling 10-Year (excludes 2011-2013)**	3.9%	5.3%	7.4%	9.7%	12.2%	14.4%	16.4%	16.4%	16.2%	15.9%
11	**Incremental Demand Savings (MW)**	67	74	115	142	154	154	138	66	40	31
12	**Cumulative Demand Savings (MW)**	67	141	256	398	553	706	844	910	950	981
13	**Total Budget ($000)**	$216,585	$239,542	$372,542	$459,489	$502,774	$486,825	$444,874	$210,642	$135,144	$96,516
14	**TRC Levelized Cost ($/kWh)**	$0.0916	$0.0916	$0.0916	$0.0916	$0.0916	$0.0916	$0.0916	$0.0916	$0.0916	$0.0916
15	**UCT Levelized Cost ($/kWh)**	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855	$0.0855

Table 5-6. Detailed Results - Scenario 2

Row #	Category	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
1	**Incremental Program Potential (GWh)**	235	264	406	497	545	532	484	229	146	103
2	**Cumulative Program Potential (GWh)**	235	499	904	1,401	1,946	2,478	2,962	3,191	3,337	3,441
3	**Cumulative Program Potential (GWh) w/ 2011-2013**	671	935	1,341	1,837	2,382	2,914	3,398	3,627	3,774	3,877
4	**Incremental Savings from Codes and Standards**	71	76	84	78	62	50	45	39	33	29
5	**Cumulative Savings from Codes and Standards (w/ 2011-2013)**	249	326	410	488	550	600	645	684	717	746
6	**Annual Savings Target (Program + Codes & Standards)**	**306**	**340**	**490**	**575**	**607**	**582**	**529**	**268**	**180**	**132**
7	**Baseline Sales (LADWP Gross)**	23,970	24,110	24,302	24,553	24,837	25,114	25,388	25,746	25,986	26,220
8	**Savings as % of Baseline Sales (no standards)**	2.8%	3.9%	5.5%	7.5%	9.6%	11.6%	13.4%	14.1%	14.5%	14.8%
9	**Savings as % of Baseline (with Standards)**	**3.8%**	**5.2%**	**7.2%**	**9.5%**	**11.8%**	**14.0%**	**15.9%**	**16.7%**	**17.3%**	**17.6%**
10	**Savings as % of Baseline Sales Rolling 10-Year (excludes 2011-2013)**	3.8%	5.2%	7.2%	9.5%	11.8%	14.0%	15.9%	15.9%	15.7%	15.3%
11	**Incremental Demand Savings (MW)**	64	70	109	136	147	146	131	63	39	30
12	**Cumulative Demand Savings (MW)**	64	134	244	379	526	672	804	867	905	935
13	**Total Budget ($000)**	$181,811	$199,519	$312,399	$384,336	$422,577	$405,371	$373,611	$178,742	$118,003	$84,357
14	**TRC Levelized Cost ($/kWh)**	$0.0792	$0.0792	$0.0792	$0.0792	$0.0792	$0.0792	$0.0792	$0.0792	$0.0792	$0.0792
15	**UCT Levelized Cost ($/kWh)**	$0.0739	$0.0739	$0.0739	$0.0739	$0.0739	$0.0739	$0.0739	$0.0739	$0.0739	$0.0739

Table 5-7. Detailed Results - Scenario 3

Row #	Category	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
1	**Incremental Program Potential (GWh)**	216	243	373	457	501	490	446	211	135	94
2	**Cumulative Program Potential (GWh)**	216	459	832	1,289	1,790	2,280	2,726	2,937	3,072	3,166
3	**Cumulative Program Potential (GWh) w/ 2011-2013**	652	895	1,268	1,725	2,226	2,716	3,162	3,373	3,508	3,603
4	**Incremental Savings from Codes and Standards**	71	76	84	78	62	50	45	39	33	29
5	**Cumulative Savings from Codes and Standards (w/ 2011-2013)**	249	326	410	488	550	600	645	684	717	746
6	**Annual Savings Target (Program + Codes & Standards)**	**287**	**319**	**458**	**535**	**563**	**540**	**491**	**250**	**168**	**123**
7	**Baseline Sales (LADWP Gross)**	23,970	24,110	24,302	24,553	24,837	25,114	25,388	25,746	25,986	26,220
8	**Savings as % of Baseline Sales (no standards)**	2.7%	3.7%	5.2%	7.0%	9.0%	10.8%	12.5%	13.1%	13.5%	13.7%
9	**Savings as % of Baseline (with Standards)**	**3.8%**	**5.1%**	**6.9%**	**9.0%**	**11.2%**	**13.2%**	**15.0%**	**15.8%**	**16.3%**	**16.6%**
10	**Savings as % of Baseline Sales Rolling 10-Year (excludes 2011-2013)**	3.8%	5.1%	6.9%	9.0%	11.2%	13.2%	15.0%	14.9%	14.7%	14.2%
11	**Incremental Demand Savings (MW)**	54	60	93	115	125	124	111	53	32	24
12	**Cumulative Demand Savings (MW)**	54	114	207	323	447	571	683	736	768	792
13	**Total Budget ($000)**	$107,197	$117,459	$183,961	$225,142	$249,045	$237,734	$221,345	$105,942	$71,921	$50,300
14	**TRC Levelized Cost ($/kWh)**	$0.0684	$0.0684	$0.0684	$0.0684	$0.0684	$0.0684	$0.0684	$0.0684	$0.0684	$0.0684
15	**UCT Levelized Cost ($/kWh)**	$0.0495	$0.0495	$0.0495	$0.0495	$0.0495	$0.0495	$0.0495	$0.0495	$0.0495	$0.0495

Table 5-8. Detailed Results - Scenario 4

Row #	Category	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
1	**Incremental Program Potential (GWh)**	227	254	391	479	526	513	468	222	142	100
2	**Cumulative Program Potential (GWh)**	227	481	873	1,352	1,878	2,391	2,859	3,081	3,223	3,323
3	**Cumulative Program Potential (GWh) w/ 2011-2013**	663	917	1,309	1,788	2,314	2,827	3,295	3,517	3,659	3,759
4	**Incremental Savings from Codes and Standards**	71	76	84	78	62	50	45	39	33	29
5	**Cumulative Savings from Codes and Standards (w/ 2011-2013)**	249	326	410	488	550	600	645	684	717	746
6	**Annual Savings Target (Program + Codes & Standards)**	**298**	**331**	**476**	**557**	**588**	**563**	**512**	**261**	**176**	**129**
7	**Baseline Sales (LADWP Gross)**	23,970	24,110	24,302	24,553	24,837	25,114	25,388	25,746	25,986	26,220
8	**Savings as % of Baseline Sales (no standards)**	2.8%	3.8%	5.4%	7.3%	9.3%	11.3%	13.0%	13.7%	14.1%	14.3%
9	**Savings as % of Baseline (with Standards)**	**3.8%**	**5.2%**	**7.1%**	**9.3%**	**11.5%**	**13.6%**	**15.5%**	**16.3%**	**16.8%**	**17.2%**
10	**Savings as % of Baseline Sales Rolling 10-Year (excludes 2011-2013)**	3.8%	5.2%	7.1%	9.3%	11.5%	13.6%	15.5%	15.4%	15.2%	14.8%
11	**Incremental Demand Savings (MW)**	59	65	101	126	136	135	122	58	36	28
12	**Cumulative Demand Savings (MW)**	59	125	226	352	488	624	745	803	839	867
13	**Total Budget ($000)**	$135,544	$147,384	$232,327	$284,169	$315,217	$299,580	$280,332	$135,482	$93,530	$65,972
14	**TRC Levelized Cost ($/kWh)**	$0.0714	$0.0714	$0.0714	$0.0714	$0.0714	$0.0714	$0.0714	$0.0714	$0.0714	$0.0714
15	**UCT Levelized Cost ($/kWh)**	$0.0582	$0.0582	$0.0582	$0.0582	$0.0582	$0.0582	$0.0582	$0.0582	$0.0582	$0.0582

Table 5-9. Detailed Results - Scenario 5

Row #	Category	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
1	**Incremental Program Potential (GWh)**	206	231	356	435	478	465	425	202	131	92
2	**Cumulative Program Potential (GWh)**	206	437	793	1,227	1,705	2,170	2,596	2,798	2,929	3,021
3	**Cumulative Program Potential (GWh) w/ 2011-2013**	642	873	1,229	1,664	2,141	2,607	3,032	3,234	3,365	3,457
4	**Incremental Savings from Codes and Standards**	71	76	84	78	62	50	45	39	33	29
5	**Cumulative Savings from Codes and Standards (w/ 2011-2013)**	249	326	410	488	550	600	645	684	717	746
6	**Annual Savings Target (Program + Codes & Standards)**	**277**	**307**	**440**	**513**	**540**	**516**	**470**	**241**	**164**	**121**
7	**Baseline Sales (LADWP Gross)**	23,970	24,110	24,302	24,553	24,837	25,114	25,388	25,746	25,986	26,220
8	**Savings as % of Baseline Sales (no standards)**	2.7%	3.6%	5.1%	6.8%	8.6%	10.4%	11.9%	12.6%	13.0%	13.2%
9	**Savings as % of Baseline (with Standards)**	**3.7%**	**5.0%**	**6.7%**	**8.8%**	**10.8%**	**12.8%**	**14.5%**	**15.2%**	**15.7%**	**16.0%**
10	**Savings as % of Baseline Sales Rolling 10-Year (excludes 2011-2013)**	3.7%	5.0%	6.7%	8.8%	10.8%	12.8%	14.5%	14.3%	14.1%	13.7%
11	**Incremental Demand Savings (MW)**	52	56	88	109	118	117	105	51	32	25
12	**Cumulative Demand Savings (MW)**	52	108	196	305	423	540	645	696	728	752
13	**Total Budget ($000)**	$100,337	$108,181	$171,649	$209,267	$233,237	$219,810	$207,410	$101,272	$71,735	$50,607
14	**TRC Levelized Cost ($/kWh)**	$0.0582	$0.0582	$0.0582	$0.0582	$0.0582	$0.0582	$0.0582	$0.0582	$0.0582	$0.0582
15	**UCT Levelized Cost ($/kWh)**	$0.0476	$0.0476	$0.0476	$0.0476	$0.0476	$0.0476	$0.0476	$0.0476	$0.0476	$0.0476

Table 5-10. Detailed Results - Scenario 6

Row #	Category	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
1	Incremental Program Potential (GWh)	206	231	355	434	477	465	424	202	130	91
2	Cumulative Program Potential (GWh)	206	437	792	1,226	1,703	2,168	2,593	2,794	2,924	3,015
3	Cumulative Program Potential (GWh) w/ 2011-2013	642	873	1,228	1,663	2,140	2,605	3,029	3,231	3,360	3,451
4	Incremental Savings from Codes and Standards	71	76	84	78	62	50	45	39	33	29
5	Cumulative Savings from Codes and Standards (w/ 2011-2013)	249	326	410	488	550	600	645	684	717	746
6	Annual Savings Target (Program + Codes & Standards)	**277**	**307**	**440**	**512**	**539**	**515**	**469**	**240**	**163**	**119**
7	Baseline Sales (LADWP Gross)	23,970	24,110	24,302	24,553	24,837	25,114	25,388	25,746	25,986	26,220
8	Savings as % of Baseline Sales (no standards)	2.7%	3.6%	5.1%	6.8%	8.6%	10.4%	11.9%	12.5%	12.9%	13.2%
9	Savings as % of Baseline (with Standards)	**3.7%**	**5.0%**	**6.7%**	**8.8%**	**10.8%**	**12.8%**	**14.5%**	**15.2%**	**15.7%**	**16.0%**
10	Savings as % of Baseline Sales Rolling 10-Year (excludes 2011-2013)	3.7%	5.0%	6.7%	8.8%	10.8%	12.8%	14.5%	14.3%	14.1%	13.7%
11	Incremental Demand Savings (MW)	52	57	89	110	119	118	106	51	31	24
12	Cumulative Demand Savings (MW)	52	109	198	308	427	545	651	702	733	756
13	Total Budget ($000)	$90,485	$98,216	$155,067	$189,060	$210,565	$198,339	$186,951	$90,571	$63,706	$44,528
14	TRC Levelized Cost ($/kWh)	$0.0594	$0.0594	$0.0594	$0.0594	$0.0594	$0.0594	$0.0594	$0.0594	$0.0594	$0.0594
15	UCT Levelized Cost ($/kWh)	$0.0426	$0.0426	$0.0426	$0.0426	$0.0426	$0.0426	$0.0426	$0.0426	$0.0426	$0.0426

Table 5-11. Detailed Results - Scenario 7

Row #	Category	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
1	**Incremental Program Potential (GWh)**	355	351	372	373	389	374	387	370	375	43
2	**Cumulative Program Potential (GWh)**	355	706	1,078	1,451	1,840	2,214	2,601	2,972	3,347	3,390
3	**Cumulative Program Potential (GWh) w/ 2011-2013**	791	1,142	1,514	1,887	2,276	2,651	3,037	3,408	3,783	3,826
4	**Incremental Savings from Codes and Standards**	71	76	84	78	62	50	45	39	33	29
5	**Cumulative Savings from Codes and Standards (w/ 2011-2013)**	249	326	410	488	550	600	645	684	717	746
6	**Annual Savings Target (Program + Codes & Standards)**	**426**	**427**	**457**	**451**	**451**	**424**	**432**	**409**	**409**	**72**
7	**Baseline Sales (LADWP Gross)**	23,970	24,110	24,302	24,553	24,837	25,114	25,388	25,746	25,986	26,220
8	**Savings as % of Baseline Sales (no standards)**	3.3%	4.7%	6.2%	7.7%	9.2%	10.6%	12.0%	13.2%	14.6%	14.6%
9	**Savings as % of Baseline (with Standards)**	**4.3%**	**6.1%**	**7.9%**	**9.7%**	**11.4%**	**12.9%**	**14.5%**	**15.9%**	**17.3%**	**17.4%**
10	**Savings as % of Baseline Sales Rolling 10-Year (excludes 2011-2013)**	4.3%	6.1%	7.9%	9.7%	11.4%	12.9%	14.5%	15.0%	15.7%	15.1%
11	**Incremental Demand Savings (MW)**	98	93	100	100	103	101	103	101	101	13
12	**Cumulative Demand Savings (MW)**	98	191	291	391	493	595	698	799	900	913
13	**Total Budget ($000)**	$235,148	$227,949	$247,314	$249,357	$262,298	$246,259	$259,065	$246,745	$252,958	$33,979
14	**TRC Levelized Cost ($/kWh)**	$0.0644	$0.0644	$0.0644	$0.0644	$0.0644	$0.0644	$0.0644	$0.0644	$0.0644	$0.0644
15	**UCT Levelized Cost ($/kWh)**	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640

Table 5-12. Detailed Results - Scenario 8

Row #	Category	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
1	**Incremental Program Potential (GWh)**	357	353	374	375	391	377	389	372	377	43
2	**Cumulative Program Potential (GWh)**	357	709	1,083	1,458	1,849	2,225	2,614	2,986	3,363	3,406
3	**Cumulative Program Potential (GWh) w/ 2011-2013**	793	1,145	1,520	1,894	2,285	2,661	3,051	3,423	3,800	3,843
4	**Incremental Savings from Codes and Standards**	71	76	84	78	62	50	45	39	33	29
5	**Cumulative Savings from Codes and Standards (w/ 2011-2013)**	249	326	410	488	550	600	645	684	717	746
6	**Annual Savings Target (Program + Codes & Standards)**	**428**	**429**	**459**	**452**	**453**	**427**	**434**	**411**	**410**	**72**
7	**Baseline Sales (LADWP Gross)**	23,970	24,110	24,302	24,553	24,837	25,114	25,388	25,746	25,986	26,220
8	**Savings as % of Baseline Sales (no standards)**	3.3%	4.8%	6.3%	7.7%	9.2%	10.6%	12.0%	13.3%	14.6%	14.7%
9	**Savings as % of Baseline (with Standards)**	**4.3%**	**6.1%**	**7.9%**	**9.7%**	**11.4%**	**13.0%**	**14.6%**	**15.9%**	**17.4%**	**17.5%**
10	**Savings as % of Baseline Sales Rolling 10-Year (excludes 2011-2013)**	4.3%	6.1%	7.9%	9.7%	11.4%	13.0%	14.6%	15.1%	15.8%	15.2%
11	**Incremental Demand Savings (MW)**	94	90	96	96	99	97	99	97	98	12
12	**Cumulative Demand Savings (MW)**	94	184	280	377	475	573	672	769	866	878
13	**Total Budget ($000)**	$212,100	$206,877	$224,381	$226,032	$238,656	$223,204	$235,590	$222,883	$229,116	$30,888
14	**TRC Levelized Cost ($/kWh)**	$0.0705	$0.0705	$0.0705	$0.0705	$0.0705	$0.0705	$0.0705	$0.0705	$0.0705	$0.0705
15	**UCT Levelized Cost ($/kWh)**	$0.0604	$0.0604	$0.0604	$0.0604	$0.0604	$0.0604	$0.0604	$0.0604	$0.0604	$0.0604

Table 5-13. Detailed Results - Scenario 9

Row #	Category	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
1	**Incremental Program Potential (GWh)**	354	350	370	370	385	371	383	366	51	38
2	**Cumulative Program Potential (GWh)**	354	704	1,074	1,444	1,829	2,200	2,583	2,948	2,999	3,038
3	**Cumulative Program Potential (GWh) w/ 2011-2013**	790	1,140	1,510	1,880	2,265	2,636	3,019	3,385	3,436	3,474
4	**Incremental Savings from Codes and Standards**	71	76	84	78	62	50	45	39	33	29
5	**Cumulative Savings from Codes and Standards (w/ 2011-2013)**	249	326	410	488	550	600	645	684	717	746
6	**Annual Savings Target (Program + Codes & Standards)**	**425**	**426**	**454**	**448**	**447**	**422**	**428**	**404**	**84**	**67**
7	**Baseline Sales (LADWP Gross)**	23,970	24,110	24,302	24,553	24,837	25,114	25,388	25,746	25,986	26,220
8	**Savings as % of Baseline Sales (no standards)**	3.3%	4.7%	6.2%	7.7%	9.1%	10.5%	11.9%	13.1%	13.2%	13.2%
9	**Savings as % of Baseline (with Standards)**	**4.3%**	**6.1%**	**7.9%**	**9.6%**	**11.3%**	**12.9%**	**14.4%**	**15.8%**	**16.0%**	**16.1%**
10	**Savings as % of Baseline Sales Rolling 10-Year (excludes 2011-2013)**	4.3%	6.1%	7.9%	9.6%	11.3%	12.9%	14.4%	14.9%	14.4%	13.7%
11	**Incremental Demand Savings (MW)**	90	86	91	92	94	93	94	92	11	10
12	**Cumulative Demand Savings (MW)**	90	176	267	359	453	545	639	731	742	752
13	**Total Budget ($000)**	$149,507	$144,943	$157,496	$158,605	$167,762	$156,450	$165,574	$155,981	$28,773	$21,194
14	**TRC Levelized Cost ($/kWh)**	$0.0585	$0.0585	$0.0585	$0.0585	$0.0585	$0.0585	$0.0585	$0.0585	$0.0585	$0.0585
15	**UCT Levelized Cost ($/kWh)**	$0.0419	$0.0419	$0.0419	$0.0419	$0.0419	$0.0419	$0.0419	$0.0419	$0.0419	$0.0419

Table 5-14. Detailed Results - Scenario 10

Row #	Category	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
1	**Incremental Program Potential (GWh)**	207	233	357	437	479	470	427	202	127	90
2	**Cumulative Program Potential (GWh)**	207	440	798	1,235	1,714	2,184	2,610	2,812	2,940	3,029
3	**Cumulative Program Potential (GWh) w/ 2011-2013**	643	876	1,234	1,671	2,150	2,620	3,047	3,248	3,376	3,465
4	**Incremental Savings from Codes and Standards**	71	76	84	78	62	50	45	39	33	29
5	**Cumulative Savings from Codes and Standards (w/ 2011-2013)**	249	326	410	488	550	600	645	684	717	746
6	**Annual Savings Target (Program + Codes & Standards)**	**278**	**310**	**442**	**515**	**541**	**520**	**471**	**240**	**161**	**118**
7	**Baseline Sales (LADWP Gross)**	23,970	24,110	24,302	24,553	24,837	25,114	25,388	25,746	25,986	26,220
8	**Savings as % of Baseline Sales (no standards)**	2.7%	3.6%	5.1%	6.8%	8.7%	10.4%	12.0%	12.6%	13.0%	13.2%
9	**Savings as % of Baseline (with Standards)**	**3.7%**	**5.0%**	**6.8%**	**8.8%**	**10.9%**	**12.8%**	**14.5%**	**15.3%**	**15.8%**	**16.1%**
10	**Savings as % of Baseline Sales Rolling 10-Year (excludes 2011-2013)**	3.7%	5.0%	6.8%	8.8%	10.9%	12.8%	14.5%	14.4%	14.1%	13.7%
11	**Incremental Demand Savings (MW)**	52	57	89	110	119	118	106	50	31	24
12	**Cumulative Demand Savings (MW)**	52	109	198	307	426	544	650	701	731	755
13	**Total Budget ($000)**	$84,597	$94,742	$144,932	$177,633	$193,758	$189,789	$171,939	$80,876	$50,648	$35,723
14	**TRC Levelized Cost ($/kWh)**	$0.0620	$0.0620	$0.0620	$0.0620	$0.0620	$0.0620	$0.0620	$0.0620	$0.0620	$0.0620
15	**UCT Levelized Cost ($/kWh)**	$0.0394	$0.0394	$0.0394	$0.0394	$0.0394	$0.0394	$0.0394	$0.0394	$0.0394	$0.0394

Nexant

Nexant, Inc.
1255 Crescent Green Drive
Suite 460
Cary, North Carolina 27518
T) (919) 334-7651
F) (919) 851-3006
www.nexant.com

#18

Committees:

Chair
Personnel & Animal Welfare

Vice Chair
Transportation
Ad Hoc on Social Equity

Member
Budget & Finance
Energy & Environment
Ad Hoc on Waste Reduction & Recycling

Website: http://cd5.lacity.org
Email: Paul.Koretz@lacity.org

City of Los Angeles

PAUL KORETZ
Councilmember, Fifth District

City Hall Office:
200 N. Spring Street
Room 440
Los Angeles, CA 90012
(213) 473-7005
(213) 978-2250 Fax

Valley Office:
15760 Ventura Blvd.
Suite 1020
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(818) 971-3088
(818) 788-9210 Fax

West L.A. Office:
822 S. Robertson Blvd.
Suite 102
Los Angeles, CA 90035
(310) 289-0353
(310) 289-0365 Fax

August 4, 2014

President Mel Levine
LADWP Commissioners
111 N Hope Street
Los Angeles, CA 90012

Dear President ~~Levine and~~ Commissioners: Michael –

As you may know, I have introduced a motion to the City Council calling on the City of Los Angeles to reduce its greenhouse gas emissions 80% of 1990 levels by 2050, and on the DWP to reduce its greenhouse gas emissions to 80% of 1990 levels by 2030. Evidenced by increasing extreme storm events around the world, including our own historic drought, the climate crisis is getting worse quickly and, as one of the historically worst polluters, Los Angeles needs to lead the way in addressing and resolving the problem. An essential tool to help us reach those targets will be aggressive and forward-thinking energy efficiency targets.

In 2010, the European Commission for advancement of the European Union economy proposed a 10-year strategy aiming for "smart, sustainable, inclusive growth," which included a target of achieving a 20% increase in energy efficiency by 2020 for the entirety of the 28-nation state Union and its 505,572,500 residents. As Los Angeles is considerably smaller and DWP is more centralized, I believe we can do as well, if not better, in half the time.

When the DWP staff proposes its 10-year energy efficiency targets on August 5th, I urge you to support a target of 15% or higher energy efficiency by 2020. From a fiscal viewpoint alone, it is good policy. The savings will far outweigh the investment. DWP's Territorial Potential Study shows that the utility – just by using existing technology at today's prices – can reduce energy use 15% by 2020. Such an investment would reduce the City's energy bill by around $750 million and produce more than a $1.25 in savings for every $1 invested in the programs.

I urge you to support a "15% or higher by 2020" energy efficiency target.

~~Best regards~~,

Paul

PAUL KORETZ

#18

RECEIVED

AUG 05 2014

Board of Water & Power Com'rs.
CITY OF LOS ANGELES

NURY MARTINEZ
COUNCILWOMAN, SIXTH DISTRICT

August 1, 2014

President Mel Levine
Board of Water and Power Commissioners
111 N Hope Street
Los Angeles, California

Dear President Levine:

As a commissioner guiding the Los Angeles Department of Water and Power (LADWP) into its second century, your leadership can help direct the City and its electricity system toward a more equitable, sustainable, and prosperous future. You will have an opportunity to exercise this leadership later this month, when LADWP staff proposes 10-year energy efficiency targets, which must be submitted to the California Energy Commission under AB 2021. I urge you to support Staff's proposal for a 15% by 2020 energy efficiency target.

LADWP's Territorial Potential Study shows that the utility – just by using existing technology at today's prices – can reduce energy use 14.5% by 2020. Such an investment in energy efficiency would reduce the City's energy bill by around $750 million and produce more than a $1.25 in savings for every $1 invested in the programs.

LADWP can meet these targets by expanding its energy efficiency programs. These programs are benefitting residents and businesses in our community, helping customers manage and reduce their energy bills, and creating jobs. In my district alone, 690 businesses have been assessed for a retrofit under the Small-Business Direct Install program, 623 have enrolled in the program and 428 businesses have completed retrofits. Energy efficiency programs help reduce the need to build and maintain expensive, polluting power plants, and should be our first consideration before we examine rate increases. I urge you to support a "15% by 2020" target.

Sincerely,

Nury Martinez

NURY MARTINEZ
Councilwoman, 6th District

Cc: Commissioner William W. Funderbunk Jr.
Commissioner Jill Banks Barad
Commissioner Michael F. Fleming
Commissioner Christina E. Noonan

City Hall, 200 N. Spring Street, Room 425, Los Angeles, CA 90012
Phone: (213) 473-7006 • Fax: (213) 847-0549
cd6.lacity.org

#10

RECEIVED

AUG 05 2014

Board of Water & Power Com'rs.
CITY OF LOS ANGELES

NURY MARTINEZ
COUNCILWOMAN, SIXTH DISTRICT

August 1, 2014

President Mel Levine
Board of Water and Power Commissioners
111 N Hope Street
Los Angeles, California

Dear President Levine:

As a commissioner guiding the Los Angeles Department of Water and Power (LADWP) into its second century, your leadership can help direct the City and its electricity system toward a more equitable, sustainable, and prosperous future. You will have an opportunity to exercise this leadership later this month, when LADWP staff proposes 10-year energy efficiency targets, which must be submitted to the California Energy Commission under AB 2021. I urge you to support Staff's proposal for a 15% by 2020 energy efficiency target.

LADWP's Territorial Potential Study shows that the utility – just by using existing technology at today's prices – can reduce energy use 14.5% by 2020. Such an investment in energy efficiency would reduce the City's energy bill by around $750 million and produce more than a $1.25 in savings for every $1 invested in the programs.

LADWP can meet these targets by expanding its energy efficiency programs. These programs are benefitting residents and businesses in our community, helping customers manage and reduce their energy bills, and creating jobs. In my district alone, 690 businesses have been assessed for a retrofit under the Small-Business Direct Install program, 623 have enrolled in the program and 428 businesses have completed retrofits. Energy efficiency programs help reduce the need to build and maintain expensive, polluting power plants, and should be our first consideration before we examine rate increases. I urge you to support a "15% by 2020" target.

Sincerely,

Nury Martinez

NURY MARTINEZ
Councilwoman, 6th District

Cc: Commissioner William W. Funderbunk Jr.
Commissioner Jill Banks Barad
Commissioner Michael F. Fleming
Commissioner Christina E. Noonan

#1140

GLOBAL GREEN USA

Tuesday, August 5, 2014

LADWP Board of Commissioners
LADWP, Room 1555-H
111 North Hope Street
Los Angeles, CA 90012

Re: Item 18, Energy Efficiency Goals

Dear President Levine and Board of Commissioners,

Global Green USA, an environmental non-profit organization headquartered in Los Angeles, is writing in regards to the proposed 10-year energy efficiency targets, which will be submitted to the California Energy Commission under AB 2021. We are pleased by the Los Angeles Department of Water and Power's staff recommendation for a target of 15% by 2020, and we strongly urge the Board to approve this goal.

Global Green has long advocated for energy efficiency measures as the first resource used to save energy, as it is the cheapest, easiest, and cleanest option. For years, California has been a leader in approving bold energy efficiency targets; this forward thinking has saved residents billions of dollars and avoided millions of tons of greenhouse gas emissions. While LADWP's investment in energy efficiency has lagged behind other California utilities, LADWP doubled its investment in 2012, which we applaud, and approving today's goals is the logical next step in this decision.

LADWP's own study, as well as independent experts who performed similar analysis, found that the utility can reach a 15% target by 2020 at a budget of $151 million per year, one-half to one-fourth the cost of a new power plant. Energy efficiency savings on this level would also create an estimated 22,000 jobs by 2033, more jobs than any other energy industry. In the long term, it would also save the city $775 million in energy bills.

With a growing population and many more days of extreme heat ahead, the city needs to rethink how we use our energy. Increasing our energy efficiency translates to immediate savings for Angelenos on their utility bills, cleaner air, and increased comfort. We strongly support raising our energy efficiency target to 15% by 2020.

HEADQUARTERS: 2218 Main Street, 2nd Floor | Santa Monica, CA 90405 | Phone: 310.581.2700 | Fax:310.581.2702
WASHINGTON.D.C: 1100 15th Street, NW. 11th Floor | Washington D.C. 20005| Phone: 202.222.0701| Fax:202.222.0703
NEW ORLEANS: 2407 South Broad Street | New Orleans, LA 70125 | Phone: 310.581.2700 | Fax:310.581.2702

Sincerely,

Mary Luévano, Vice President

Global Green USA

HEADQUARTERS: 2218 Main Street, 2nd Floor | Santa Monica, CA 90405 | Phone: 310.581.2700 | Fax:310.581.2702
WASHINGTON.D.C: 1100 15th Street, NW. 11th Floor | Washington D.C. 20005| Phone: 202.222.0701| Fax:202.222.0703
NEW ORLEANS: 2407 South Broad Street | New Orleans, LA 70125 | Phone: 310.581.2700 | Fax:310.581.2702

RE: #18

Moschos, Barbara

From: gstaack24@socal.rr.com
Sent: Monday, August 04, 2014 11:24 PM
To: commission
Subject: Board of Commissioners Website Contact Us

Form for: Board of Commissioners Website Contact Us

Form Data:

First name: Gerald
Last name: Staack
Email address: gstaack24@socal.rr.com
Phone number: 661-424-0262
Subject: Energy efficiency
Comments/Questions: The 15% energy efficiency goal being proposed is a good start.

RE: #18

Moschos, Barbara

From: jdietrick9@gmail.com
Sent: Monday, August 04, 2014 10:04 PM
To: commission
Subject: Board of Commissioners Website Contact Us

Form for: Board of Commissioners Website Contact Us

Form Data:

First name: Jan
Last name: Dietrick
Email address: jdietrick9@gmail.com
Phone number: 805-746-5365
Subject: Energy conservation
Comments/Questions: Kudos to the commission for planning a 15% energy efficiency goal. Many people support it and want to pitch in and make it an example of how conservation is better for the economy than business as usual.

RE: #18

Moschos, Barbara

From:	chergilmore@sbcglobal.net
Sent:	Monday, August 04, 2014 1:24 PM
To:	commission
Subject:	Board of Commissioners Website Contact Us
Follow Up Flag:	Follow up
Flag Status:	Completed

Form for: Board of Commissioners Website Contact Us

Form Data:

First name: Cher
Last name: Gilmore
Email address: chergilmore@sbcglobal.net
Phone number:
Subject: Energy Efficiency Proposal
Comments/Questions: I am writing to thank you and to express my total support for your goal of 15% reduction in energy use by increasing efficiency in your operations. Please continue to do everything you can to reduce our use of fossil fuels, and therefore carbon emissions, so that we can stop global warming.

RE: #18

Moschos, Barbara

From: benjamin.d.fraser@gmail.com
Sent: Monday, August 04, 2014 4:48 PM
To: commission
Subject: Board of Commissioners Website Contact Us

Form for: Board of Commissioners Website Contact Us

Form Data:

First name: Ben
Last name: Fraser
Email address: benjamin.d.fraser@gmail.com
Phone number:
Subject: Energy Efficiency Proposal
Comments/Questions: I am commenting to express support for the energy efficiency proposal that will reduce energy consumption 15% by 2020.

RE: #18

Moschos, Barbara

From: lynne3095@att.net
Sent: Monday, August 04, 2014 10:38 AM
To: commission
Subject: Board of Commissioners Website Contact Us

Form for: Board of Commissioners Website Contact Us

Form Data:

First name: Lynne
Last name: Girdlestone
Email address: lynne3095@att.net
Phone number:
Subject: Energy efficienty goal proposal
Comments/Questions: Dear Commissioners, I would like to express my STRONG support for your adopting the measures that will lead to a reduction in the use of non-renewable energy sources, helping the most-needy Angelinos cope with both the economic and environmental effects of outdated technology, and move us into a CLEANER future. I am deeply concerned about global warming and the impact it is having ALREADY on everyone, everywhere. Please vote in favor of the 15% reduction goal.

RESOLUTION NO. 015 007

WHEREAS, the Los Angeles Department of Water and Power (LADWP) is committed to the promotion of energy efficiency through the sustained implementation of programs and services; and

WHEREAS, there continues to be a statewide need to promote the efficient use of energy and meet the Governor's greenhouse gas reduction targets established in Executive Order S-3-05; and

WHEREAS, the State of California has enacted Assembly Bill (AB) 2021 (2006) (adding Section 25310 to Public Resources Code and amending Section 9615 of the Public Utilities Code) which directs investor-owned utilities and publicly owned utilities to identify achievable, cost-effective efficiency potential periodically and establish annual targets based on that potential for the ensuing ten-year period; and

WHEREAS, the State Legislature intends that load-serving entities procure all cost-effective energy efficiency measures so the State can meet its goal of reducing total forecasted electricity consumption by ten percent over the next ten years; and

WHEREAS, publicly owned utilities are directed to identify efficiency potential and establish draft annual targets for submission to the California Energy Commission (CEC) within 60 days of their adoption dates; and

WHEREAS, in May 2012, the LADWP Board of Commissioners made a commitment, in accordance with Board Resolution No. 012-247, to explore ways to achieve up to 15 percent in energy efficiency savings targets by 2020 by developing a long-term plan and implementing additional programs; and

WHEREAS, in February 2013, the LADWP issued a Request for Proposal (RFP) No. 90113 seeking proposals from qualified firms to conduct an updated energy efficiency potential study, including all City facilities, to determine energy efficiency, and provide support in the development of new energy efficiency and demand response programs based on the findings of the study; and

WHEREAS, the LADWP hired Nexant, Inc. (Nexant) to conduct a study to determine the achievable potential for energy savings; and

WHEREAS, the LADWP acknowledges that adopting aggressive energy efficiency targets is not without trade-offs or risks.

NOW, THEREFORE, BE IT RESOLVED that the Board of Water and Power Commissioners (Board) hereby adopts its ten-year energy efficiency savings targets as shown in the following table.

LADWP ENERGY EFFICIENCY GOALS (AB 2021)

FY	GWh Target	MW Target
2013-14	278	52
2014-15	310	57
2015-16	442	89
2016-17	515	110
2017-18	541	119
2018-19	520	118
2019-20	471	106
2020-21	240	50
2021-22	161	31
2022-23	118	24

BE IT FURTHER RESOLVED, that the General Manager or his designee, and the Secretary, Assistant Secretary or the Acting Secretary of the Board are hereby authorized and directed to execute the necessary documents transmitting the AB 2021 compliance plan to CEC for and on behalf of LADWP resulting from this Board action.

I HEREBY CERTIFY that the foregoing is a full, true, and correct copy of the Resolution adopted by the Board it's meeting held AUG 0 5 2014

Barbara E. Moschos

Secretary

APPROVED AS TO FORM AND LEGALITY
MICHAEL N. FEUER, CITY ATTORNEY

JUL 1 7 2014

BY

WILLIAM H. KYSELLA, JR.
DEPUTY CITY ATTORNEY

F. BOND REFINANCING SAVINGS (WATER & POWER SYSTEMS)

This appendix provides the refinancing savings for both Water and Power System bonds.

Refunding Savings Since June 2, 2009

Adjusted Savings

WATER SYSTEM REFUNDING SAVINGS

Date	Wtr Systm Savings	PV
6/30/2012	956,089.67	882,425.03
6/30/2013	5,976,561.76	5,781,480.71
6/30/2014	6,502,526.26	6,083,251.29
6/30/2015	15,162,286.26	14,342,313.54
6/30/2016	14,205,611.26	13,055,450.29
6/30/2017	2,677,636.26	2,276,617.65
6/30/2018	6,818,792.50	5,491,773.60
6/30/2019	1,895,830.00	1,542,150.95
6/30/2020	1,892,200.00	1,494,778.36
6/30/2021	1,889,487.50	1,448,713.07
6/30/2022	1,891,900.00	1,407,873.77
6/30/2023	4,228,750.00	3,272,645.02
6/30/2024	4,226,468.76	3,193,550.94
6/30/2025	4,214,756.26	3,108,415.36
6/30/2026	4,208,193.74	3,030,723.05
6/30/2027	4,203,887.50	2,956,017.49
6/30/2028	1,214,937.50	687,709.19
6/30/2029	1,215,450.00	663,869.97
6/30/2030	1,215,368.74	640,577.30
6/30/2031	1,214,693.74	617,835.43
6/30/2032	1,213,368.74	595,622.14
6/30/2033	2,996,143.74	1,442,053.59
6/30/2034	2,634,618.76	1,223,052.16
6/30/2035	1,060,343.76	467,963.26
6/30/2036	1,051,787.50	447,150.19
6/30/2037	2,985,487.50	1,247,617.05
6/30/2038	2,982,956.26	1,203,283.76
6/30/2039	2,984,562.50	1,161,940.99
6/30/2040	2,964,862.52	1,114,490.44
6/30/2041	2,957,306.26	1,074,361.39
6/30/2042	2,973,750.00	1,043,959.73
6/30/2043	2,963,000.00	1,004,969.32
6/30/2044	2,960,000.00	969,816.13
	0.00	0.00
	118,539,615.25	84,974,452.16

Adjustments:		
FY 2012	(6,994,270.42)	(6,994,270.42)
FY 2013	527,584.58	527,584.58
Per Pricing Report - Unadjusted		
Total	**125,006,301.09**	**91,441,138.00**

Adjusted Savings

POWER SYSTEM REFUNDING SAVINGS

Date	Pwr Systm Savings	PV
6/30/2010	(337,654.44)	(332,854.08)
6/30/2011	836,265.82	819,734.79
6/30/2012	32,460,363.08	32,246,398.74
6/30/2013	21,389,689.72	20,648,883.55
6/30/2014	26,379,300.01	25,061,475.92
6/30/2015	58,773,349.94	55,455,819.97
6/30/2016	57,156,657.50	52,682,498.93
6/30/2017	47,640,612.50	43,859,053.89
6/30/2018	17,041,843.76	15,590,759.00
6/30/2019	1,973,453.13	1,567,587.61
6/30/2020	1,977,837.51	1,530,601.76
6/30/2021	1,878,740.63	1,408,669.35
6/30/2022	1,881,540.62	1,375,825.46
6/30/2023	6,155,637.50	3,605,963.07
6/30/2024	6,409,075.00	3,704,954.29
6/30/2025	1,748,700.00	1,306,903.55
6/30/2026	1,761,575.00	1,284,906.10
6/30/2027	1,762,275.00	1,254,883.62
6/30/2028	1,758,400.00	1,221,431.41
6/30/2029	1,758,400.00	1,192,826.43
6/30/2030	1,760,650.00	1,166,433.29
6/30/2031	1,739,750.00	1,125,924.98
6/30/2032	1,730,800.00	1,094,267.26
6/30/2033	1,728,750.00	1,067,941.10
6/30/2034	1,724,900.00	1,041,232.80
6/30/2035	1,723,850.00	1,016,921.70
6/30/2036	1,725,000.00	994,526.95
	302,539,762.28	272,993,571.44

Adjustments:		
FY 2013	(2,062,023.17)	(2,062,023.17)
Per Pricing Report - Unadjusted		
Total	**304,601,785.45**	**275,055,594.61**

Adjusted Savings

COMBINED WATER & POWER SAVINGS

Date	Combined Savings	Combined PV
6/30/2012	33,416,452.75	33,128,823.77
6/30/2013	27,366,251.48	26,430,364.26
6/30/2014	32,881,826.27	31,144,727.21
6/30/2015	73,935,636.20	69,798,133.51
6/30/2016	71,362,268.76	65,737,949.22
6/30/2017	50,318,248.76	46,135,671.54
6/30/2018	23,860,636.26	21,082,532.60
6/30/2019	3,869,283.13	3,109,738.56
6/30/2020	3,870,037.51	3,025,380.12
6/30/2021	3,768,228.13	2,857,382.42
6/30/2022	3,773,440.62	2,783,699.23
6/30/2023	10,384,387.50	6,878,608.09
6/30/2024	10,635,543.76	6,898,505.23
6/30/2025	5,963,456.26	4,415,318.91
6/30/2026	5,969,768.74	4,315,629.15
6/30/2027	5,966,162.50	4,210,901.11
6/30/2028	2,973,337.50	1,909,140.60
6/30/2029	2,973,850.00	1,856,696.40
6/30/2030	2,976,018.74	1,807,010.59
6/30/2031	2,954,443.74	1,743,760.41
6/30/2032	2,944,168.74	1,689,889.40
6/30/2033	4,724,893.74	2,509,994.69
6/30/2034	4,359,518.76	2,264,284.96
6/30/2035	2,784,193.76	1,484,884.96
6/30/2036	2,776,787.50	1,441,677.14
6/30/2037	2,985,487.50	1,247,617.05
6/30/2038	2,982,956.26	1,203,283.76
6/30/2039	2,984,562.50	1,161,940.99
6/30/2040	2,964,862.52	1,114,490.44
6/30/2041	2,957,306.26	1,074,361.39
6/30/2042	2,973,750.00	1,043,959.73
6/30/2043	2,963,000.00	1,004,969.32
6/30/2044	2,960,000.00	969,816.13
	420,580,766.15	357,481,142.89

Adjustments:		
FY 2012	(6,994,270.42)	(6,994,270.42)
FY 2013	(1,534,438.59)	(1,534,438.59)
Per Pricing Report - Unadjusted		
Total	**429,109,475.16**	**366,009,851.90**

G. RESPONSE TO COUNCIL RECOMMENDATIONS

On September 19, 2012, the City Council Energy and Environment Committee adopted a report with ten recommendations associated with third party review of LADWP's Incremental Electric Rate Ordinance. The full City Council (Council) adopted the same recommendations in connection with its approval of the Incremental Electric Rate Ordinance on October 2, 2012. Many of these recommendations stemmed from the recommendations found in Appendix E of the "Los Angeles Department of Water and Power (LADWP) - Power System Financial Review and Rate Restructuring Analysis" report issued to the City Council on August 23, 2012 (RPA Power Report) in accordance with Council action of April 8, 2011.

A summary of the activities and status for each of the applicable recommendations is included in this report. LADWP has made significant progress toward addressing each item, including working collaboratively with the Ratepayer Advocate (RPA), Chief Legislative Analyst (CLA) and Chief Administrative Officer (CAO).

As shown in the table below, formal programs or other activities are underway to address all of the recommendations, and LADWP has made significant progress in each area.

Response to City Council Recommendations
a. Conduct negotiations with labor to find common ground that allows for greater flexibility to contract out effectively and bring salaries and benefits closer to other power utility providers.
In December of 2013, the Council approved a new Memorandum of Understanding (MOU) with IBEW Local 18 that provides significant savings to LADWP ratepayers and makes significant progress towards addressing this recommendation. Specifically, the new MOU makes progress in the following major areas: • MOU term was extended from 10/1/14 to 9/30/17 • Defer the existing 2.9% COLA from 10/1/13 to 10/1/16 • Create new lower (Tier 2) pension benefits for new employees • Entry level salaries are reduced for 34 common classes • Contracting out overtime restriction – reduction from 10% to 5% • Sick time medical certification requirement for three days rather than the previous five days As a result of these changes, LADWP is projected to reduce labor costs by $456 million over the

next four years:

Key MOU Components for 10/1/14-9/30/17	Four Year Savings Estimate ($M)
Defer COLA from 10/1/13 to 10/1/16	$385.0
Entry Level Salary Reduction for 34 Common Classes	$15.0
Sick Time Medical Certification Requirement	$12.0
Contracting Out Overtime Restriction - Reduction from 10% to 5%	$3.0
Retirement Plan Tier 2 For All New Hires	$41.0
Total Estimated Savings Over Four years	**$456.0**

b. Re-evaluate and consider replacing the surcharge-based restructuring approach with fully restructured permanent rates once legal considerations allow.

In its report on the last Power System rate action, the Ratepayer Advocate (RPA) proposed that LADWP reevaluate and consider replacing the surcharge-based restructuring approach with fully restructured permanent rates. The City Council made the same recommendation when it approved the 2012 rate action. Consequently, LADWP has evaluated the current approach to the ordinance structure.

While there may be a desire to undertake a modification of the current rate structure to provide a simpler rate framework, several lawsuits have recently been filed asserting that Proposition 26 does not permit LADWP's annual transfer of monies, financial conditions allowing, from the Power Revenue Fund ultimately to the City's General Fund. The City disputes the merits of those lawsuits. While the transfer is being contested, the City will continue to adopt an electrical rate structure that preserves the rates in effect on November 3, 2010, and layers incremental charges on top of them. Therefore, for purposes of the current rate action, LADWP proposes that the results of the cost of service studies and the impact of the new revenue requirements for power service be applied to only the Incremental Ordinance.

c. Conduct a new formal cost of service study in order to prepare for future power rate restructuring.

LADWP has new cost of services studies for both Water and Power. These studies are based on marginal cost principles to allocate the overall water and power revenue requirement to each major customer class.[1] The new costs of services studies by themselves have no impact on the overall revenue requirement; however, they will be used to allocate revenues between customer classes and provide guidance on rate design. This methodology is consistent with industry best practice and leads to the most efficient use of utility resources by LADWP customers.

d. Conduct a benchmarking assessment to review the cost per project for the repowering program and the Power Reliability Program to ensure cost

[1] Embedded cost of service analyses were also developed to verify the results of the marginal cost of service studies.

reasonableness.

Repowering Program

Direct benchmarking assessments for the repowering program are challenging, given the circumstances facing LADWP in the repowering of its coastal gas-fired plants to eliminate Once-Through Cooling (OTC) and maintain a reliable system which is supported by these key generating units. To ensure cost effectiveness, LADWP is relying primarily upon (1) a highly competitive procurement process for the coastal plant repowering and (2) use of new construction bids for similar combined cycle generating units in a separate power plant procurement process underway by LADWP for comparative purposes. Actual awarded prices for the LADWP repowering project came within the median pricing range of the new projects proposed by various competitive proposers for the Navajo replacement project.

The coastal repowering effort is being conducted to comply with the State and Federal, Environmental Protection Agency, requirements to eliminate the use of ocean water for cooling. These plants must be replaced sequentially over a period extending through 2029. Given the program magnitude, significant resources and attention have been allocated to ensure the work is completed timely and cost effectively.

In regard to the overall status of the repowering program and compliance, OTC has been eliminated from Harbor Units 1, 2, 3, and 4; Haynes Units 3, 4, 5 and 6. To ensure cost effectiveness, LADWP is using the following tools to ensure the repowering effort is as efficient as possible:

- Conceptual Cost Estimates: Prior to the development of a repowering project, a conceptual cost estimate is developed based on current pricing trends for similar projects recently built by other generation companies.
- Third Party Reviews: LADWP retains a third party engineering firm to provide a target cost estimate for the project based on similar projects, the specific project attributes, and current market conditions.
- Competitive bidding: To encourage best pricing and performance, contracts are competitively bid through a public process in accordance with the provisions of the Los Angeles City Charter.
- Comparison with Other Projects: The Scattergood Unit 3 project is unique in several aspects, and, therefore, exact project-to-project comparisons are not possible. However, it was of interest to compare costs, while recognizing these limitations. LADWP evaluated a natural gas-fired project and also reviewed an El Segundo plant, located close to the Scattergood site. While not exact comparisons, LADWP used these other plants as benchmarks for some of the market based and other construction costs for Scattergood Unit 3. Based on the comparison of contracts between the El Segundo and Scattergood Unit 3 plants, costs appeared to be within five percent on a per kWh basis.
    - Targeted Outsourcing: To minimize project risk and to keep existing generators functioning during the project, LADWP used a combination of in-house forces and contractors for various aspects of the project.
    - Additional Cost Savings Efforts: To reduce project costs on the repowering projects, LADWP has purchased the turbine/generators separately to eliminate

most of the approximate ten percent mark-up on parts by the Engineer-Procure-Construct (EPC) contractor. In addition, this approach puts the selection of the key components of the project under the control of LADWP to ensure critical materials will be available when required by the project schedule. Typically, the turbine/generators comprise thirty to fifty percent of the overall project cost, and, by LADWP performing the contract administration, the savings can be in the range of $30 to $40 million per project.

The repowering of LADWP's coastal generating units not only ensures that LADWP complies with the State's OTC mandate, but it also has other benefits including operating efficiencies and improved reliability associated with new technologies. As an example, the repowering of Scattergood Unit 3 increased its efficiency by almost 30% (reducing fuel consumption and greenhouse gas emissions) from what was previously in place.

<u>Power System Reliability Program (PSRP)</u>[2]

LADWP has completed several steps toward examining the costs of the PSRP which takes a more comprehensive approach to reliability improvement investments. LADWP retained IEC to assist with a more detailed analysis of the PSRP. As part of IEC analysis, the PSRP business plan has been updated to ensure that expenditures maximize the reliability benefits for customers. The primary goal of the updated PSRP is identify and prioritize all of the projects necessary to improve the reliability of the aging infrastructure – distribution, substation, transmission, and non-RPS generation – in a cost effective manner and consistent with industry best practices.

To that end, IEC has performed an assessment of LADWP's reliability capital program expenditures and methodologies, including a Reliability Benchmark Assessment (RBA) consistent with industry's best practices to ensure that appropriate levels of expenditures are committed to the overall PSRP in regard to distribution, substation, transmission, and generation. The assessment addressed but was not limited to the following issues:

- How LADWP sets priorities or targets;
- Effectiveness of the spending; and
- Spending compared with others in the industry.

Preliminary recommendations are provided in all the major program areas:

- Generation,
- Substation,
- Transmission,
- Distribution,
- Overall capital prioritization methodology, and
- Labor resource planning.

[2] Note that the "Power Reliability Program" has been renamed the "Power System Reliability Program" and has evolved to include all aspects of the power service delivery infrastructure.

e. Identify opportunities to contract out and explore the potential savings, including the benchmarking of staffing and outsourcing levels against utility peers.

As part of the recent LADWP reorganization by the General manager, a new Corporate Performance function has been created. This new function will focus on:

- Initial High-Level Benchmarking: As of February 2015, the Department has completed its initial high-level benchmarking. The study identifies areas where LADWP is good or better than industry norms; and, where there are opportunities for improvement. This high-level study provides a "roadmap" for follow-up in-depth studies to be conducted. Key findings of the study indicate:
    - Total O&M costs per customer are comprised of Generation, Transmission, Distribution, Customer Service, and Administrative & General (A&G) O&M functional costs including labor and benefits. This metric is one of the LADWP's most significant operational metrics. For LADWP, this metric benchmarked favorably in the 2nd quartile.
    - While the Total O&M costs benchmarked favorably, the Power System's A&G O&M and Distribution O&M function metrics benchmarked in the 4th quartile and warrant further analysis.
    - LADWP reliability metrics benchmarked favorably in the 1st and 2nd quartiles.
    - The LADWP's key financial metrics are in line with industry peer sets.
    - Overall Customer Service O&M costs are in the 1st quartile relative to Investor Owned Utilities (IOU) which comprised the bulk of this peer set.
    - LADWP's Uncollectible Expenses (i.e. write-offs of customer payments) of 0.72 percent or approximately $23 million for Fiscal Year (FY) 2012-13 benchmarks negatively in the 4th quartile. If LADWP was at the peer set median, it would result in a savings of approximately $12 million annually.
    - Total power system energy losses of 13.1 percent benchmark in the 4th quartile.
    - Distribution O&M costs benchmark in the 4th quartile.
    - This benchmarking study centralizes all pension/benefit costs into the A&G category consistent with IOU practice. LADWP benchmarked in the 4th quartile for this metric.
- Follow-up In-depth Studies: As a result of the high level benchmarking study, there will be a number of areas that require further study and analysis. While the specific areas to be studied will be identified after completion of the initial benchmarking, some potential components will be:
    - Number of employees and overtime.
    - Contracting amounts as a percent of total for various functions and sub-functions.
    - More detailed salary/pension/healthcare benchmark study with adjustments for cost of living in the greater Los Angeles area.
    - Identification of areas/processes where benchmarking data shows that there is room for improvement. These areas/processes will be the subject of future

Business Process Improvement Studies.

- Determination of the financial impacts of the significant policies that increase LADWP's costs.

- Business Process Mapping Studies: As a result of the above studies, there will be a number of areas that will present opportunities for significantly improving financial and/or Departmental performance. These functions will be the subject of specific business process mapping studies. These studies will compare industry best practices and evaluate what steps need to be taken for LADWP to move toward the best practice.

Additionally, the Department contracts out significant amounts of work as part of its capital and O&M programs. For the current FY 2014-15 Budget, LADWP projects to spend over $2.3 Billion on Power System work. Inductive economic analysis done by the Los Angeles Economic Development Corporation (LAEC) suggests that Department spending in Los Angeles creates jobs and stimulates additional economic output. In FY 2011-12, the LAEDC estimated the impact of Department spending using an industry accepted input-output model that is founded on local economic characteristics. If the local characteristics of the current Los Angeles economy have remained similar to the assumptions made by the LAEDC, in FY 2014-15, the Power System spending will support 30,051 total jobs and induce $7.57 billion in additional economic activity and output. Over the five-year rate action, the average annual Power System spending of $2.65 billion per year will support an annual 33,321 jobs and induce an annual $8.39 billion in additional economic activity and output.

f. Review overtime expenses allocation, as well as the Department's contractual requirements that have an impact on overtime.

The new MOU with IBEW Local 18 has key provisions in it for reducing overtime as a consequence of obtaining contracting services. Overtime at a utility is affected by several factors, many of which are operational in nature and in some cases outside the immediate control of the utility; for example, emergency outage restoration and mandated power supply replacement projects such as the elimination of OTC.

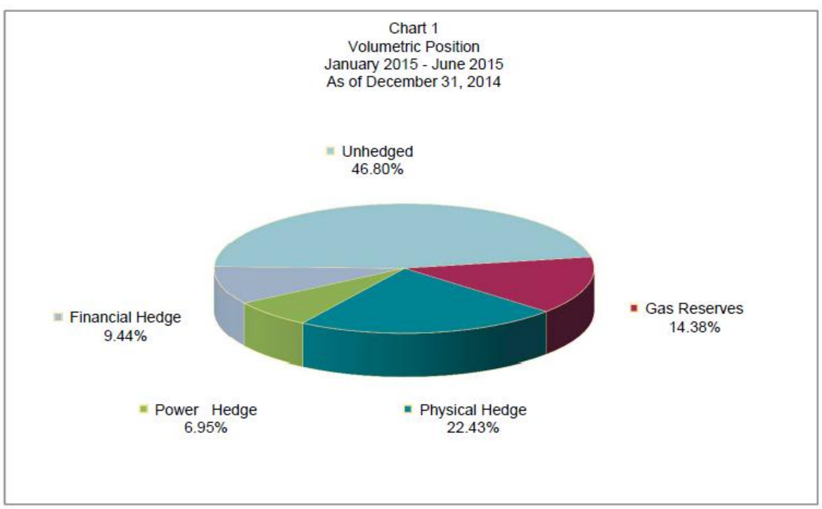
Additionally, overtime is considered a safe and cost effective means of obtaining needed resources when used in moderation. In general, it is good utility practice to use overtime at the rate of roughly 15% of regular labor costs. Currently, LADWP is limited in its ability to recruit replacement employees in a timely manner. These outcomes are resulting in somewhat higher overtime levels. While overtime was higher than the budget at 23.3% for FY 2013-14, this is offset by underspending in regular labor due to the slow hiring process. The approved budget for overtime for the Power System in FY 2014-15 is 10.9% with a proposed five-year average of 16.4%.

g. Complete a rigorous review of the Department's hedging plan to lock in low fuel prices.

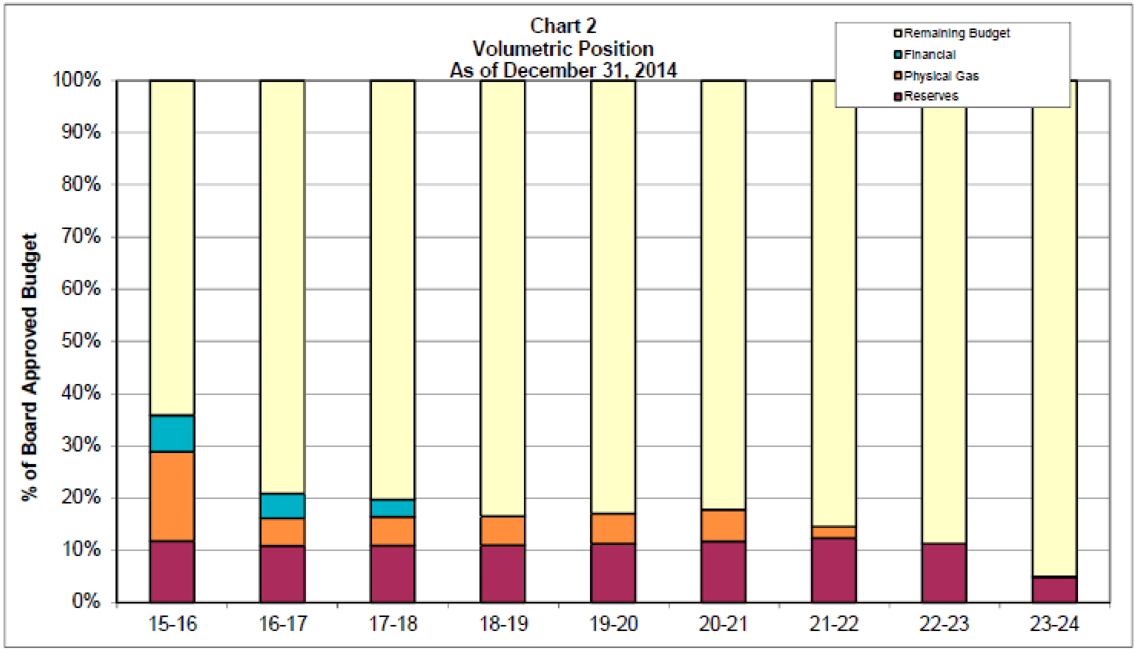
The main objective of LADWP's hedging program is to reduce the volatility in the price of natural gas used in the production of electricity to serve retail customers; the program is not designed to necessarily reduce the cost of fuel. LADWP's budgeted spending on natural gas is on the order of $200 million per year based on the current price and usage outlook, but the amount could be substantially more if prices increase. The Department's rate structure, with the Variable Energy Adjustment (VEA), allows fuel and purchased power costs to be flowed through to customers through quarterly rate adjustments. However, the Department recognizes that customers appreciate a degree of certainty as to what prices will be. The Department would like to minimize unplanned rate changes based on fuel cost fluctuations, and can do so through a fuel hedging program. The hedging program is authorized through Sections 10.1.1 (b), 10.5.3 and 23.135 of the Los Angeles Administrative Code, as well as governed by various internal LADWP policies and internal controls, including its recently approved Dodd-Frank Act compliance policy.

The Department has had a fuel hedging program in place since just after the last energy crisis in FY 2001-02, and prior to FY 2008-09, LADWP was active in its natural gas hedging program and had hedged up to 50% of its budgeted volume requirements using dollar cost averaging method for up to ten years forward. No new physical or financial hedges were entered into from 2009 through 2013 due to several factors, including (1) falling gas prices, (2) the VEA that allowed pass-through (without caps) of all fuel costs; (3) expected increased production volume from the Natural Gas Reserves in Pinedale, Wyoming; and (4) the anticipation of long-term fixed-price Biogas contracts as part of its Renewable Portfolio Standard (RPS) program. However, given the recognition that gas prices remain the largest driver of unplanned rate volatility, the Department recognizes that a properly structured hedging program is in its customers' interests. In 2014, LADWP retained a consultant to review the hedging program to ensure that the goal of reducing rate volatility was most effectively achieved. The Department's consultant recommended a hedging framework that provides an integrated approach for developing and evaluating hedging strategies that satisfies LADWP's stated goal of reducing potential rate volatility.

Staff, during 2014, developed a short term hedging plan and executed hedges related to the current and following fiscal year, with the goal of having the nearest fiscal year 50% hedged. The chart below shows the remaining current fiscal year hedging status, with 53.2% hedged:



The core of the program, however, will be to implement hedges for up to five years out, with decreasing amounts hedged from 50% down to 10% in year five (a "stair step" plan). The following chart shows the Department's current hedged status for future years, and indicates that additional hedges (particularly in the first three years) will be required to achieve these targets.



Such hedges would be added using a dollar cost averaging approach. These longer term hedges will be achieved through either fixed physical contracts or financial contracts. In March 2015, the Board of Water and Power Commissioners (Board) approved a Dodd-Frank Act compliance policy to help ensure its compliance with Dodd-Frank requirements. The Department will begin implementing the hedging strategy for the five-year “stair-step” plan. In addition, the Department has a goal of executing hedges such that unplanned rate changes will not (with a 95% confidence level) vary by more than 1% from the announced level due to natural gas volatility. The Department’s hedging strategy is to be developed by the Power System’s Fuel and Power Purchase Division with oversight of the Energy Services Executive Risk Policy Committee, and approval by the General Manager.

To enhance transparency of the operation and effectiveness of the hedging program, the Department began publishing the Risk Control Reports to the Board. These reports show the Department’s anticipated fuel requirements over ten years, what portion of the requirements are hedged and through what manner, and indicate whether the Department is in compliance with the various ordinance and internal requirements governing the hedging program.

h. Establish a plan for energy efficiency that maintains expenditure levels at an achievable and cost effective level.

LADWP has significantly increased its energy efficiency (EE) program targets and has developed/updated its EE Portfolio Business Plan. For FY 2014-15, the EE program portfolio is consistent with existing approved rates. The Efficiency Solutions Portfolio Business Plan includes a significant ramping up of programs and GWh savings through 2020 consistent with the overall Board-adopted EE plan principles in a manner designed to maximize the savings while minimizing the customer rate impact. Highlights of the new EE Portfolio Business Plans include the following:

- Direct Install Programs: LADWP continues its $60M/year of Direct Install programs, serving residential (HEIP) and small business (SBDI) customers, as well as LAUSD (LAUSD DI)
- Joint Programs with Southern California Gas (SoCalGas): As part of the expanded EE portfolio, LADWP has been entering into joint programs with SoCalGas for residential and commercial new construction programs and a comprehensive home retrofit program. LADWP has also entered into partnerships with SoCalGas on SBDI and LAUSD, as well as a combined effort to provide technical project development assistance to larger, more complex projects. In addition, LADWP and SoCalGas are exploring partnering on a food service program. All of these joint efforts bring economies of scale to both LADWP and SoCalGas.
- Codes and Standards: LADWP is adopting the Codes & Standards methodology used by the Investor-Owned Utilities (IOUs) to account for declining overall savings potential in voluntary EE programs due to increasingly stringent codes and standards.
- Use of bond financing in lieu of customer billings to fund EE programs which allows for lower customer rate impacts and better alignment of the program costs over the life of the EE investments.

LADWP is required by SB 1037 to perform regular measurement and verification on its EE programs to evaluate the performance of EE investments, and commit to applying the feedback received to the portfolio in order to drive continuous improvement in future program design and execution. Therefore, LADWP has and will continue to update the EE Portfolio Business Plans to incorporate refined projections for coming years based on actual performance. The EE potential study has been completed. Results indicated achieving 15% EE by 2020 is both cost effective and achievable. As a result of these findings, the Board has formally adopted the 15% EE goal by 2020.

i. Seek greater Departmental efficiencies by pursuing process improvement efforts across a range of areas and practices.

LADWP has created a new Corporate Performance function. This function will first seek to evaluate the overall performance by conducting a high-level benchmarking study, followed by a more In-Depth Follow-up study to specifically evaluate where there are opportunities to improve cost, reliability, and/or customer service performance of LADWP. Ultimately, the results of these studies will result in a number of Business Process Mapping Studies where LADWP operations can be compared to and moved toward industry best practice. Some potential changes could require the “meet and confer” process, as well as require subsequent MOU changes.

Additionally, consistent with the Mayor’s goal of making City government more efficient and effective, LADWP will be implementing the COMSTAT key performance indicator tool and process throughout the Department, beginning with a soft launch in April 2015. The COMSTAT is built on a single platform with four tiers of performance indicators, each tailored to the appropriate audience. The targeted data monitors and manages dozens of key performance indicators at the Departmental, System, and Division levels, and the integrated COMSTAT platform enables LADWP to evaluate and verify the integrity of the indicators. The goal of the COMSTAT system is to define a “single source of truth” for key indicators and enable transparency for the Mayor, the City, and the public. LADWP expects the COMSTAT tool to be fully operational by the end of 2015.

In FY 2011-12, LADWP initiated a Department wide $459 million, three-year cost reduction program. The final results from the cost reduction plan, concluded in June 2014, exceeded the total $459 million cost reduction plan target. The source of the cost savings has changed somewhat, and the Department has saved more through non-labor and capital budgets; however, LADWP has managed the overall portfolio of savings opportunities to exceed the original target by $7.8 million.

Source	February 2011-June 2014 Savings ($M)
Labor	$230.0
Non-Labor	$142.8
Capital	$94.1
Total	**$466.9**

As a result of these cost reduction efforts, LADWP had no rate ordinance changes for both Water and Power in FY 2014-15. It should be noted that LADWP has used cost containment programs to limit rate actions in the past. Results of this are:

- Water System: The Water System has not had a base rate increase for five years, with the last base rate increase taking place in FY 2009-10. The last rate ordinance change took place with the Water Quality Improvement Adjustment Factor cap increase in FY 2011-12.
- Power System: Over the five-year period, Power System has gone through three of the years (FY 2010-11, FY 2011-12, and FY 2014-15) without any base rate increase. The last rate ordinance change was a two-year rate action for FY 2012-13 and FY 2013-14.

j. Submit a semi-annual report to the Mayor and Council regarding the status of the Renewable Portfolio Standards program and its impact on rates.

LADWP currently reports monthly on the status of the RPS program to the Board. This report provides LADWP's portion of energy derived from renewable sources, the status of the solar incentive program, a listing of projects (current, under-construction, planned and potential), Feed-In Tariff (FiT) information, and their contribution toward RPS goals.

On a quarterly basis, as part of the Energy Cost Adjustment (ECA) calculation, LADWP provides for Board approval costs related to the RPS program, which are allocated to the Variable Renewable Portfolio Standard Energy Adjustment (VRPSEA) and the Capped Renewable Portfolio Standard Energy Adjustment (CRPSEA). In conjunction with this, LADWP is also required to provide one, two, and three-year projections for the CRPSEA factor. If the projected charges do not adequately fund the planned project costs, such that a balance of $50 million to under $100 million is projected, then LADWP must communicate this to the Board and City Council. If the projected balance grows to $100 million or more in the three-year projection, LADWP's Board shall fix rates as necessary. This reporting requirement seeks to ensure that there will be no unexpected rate increase in the future as a result of LADWP RPS projects.

H. PRAG FINANCIAL METRICS

This appendix provides Public Resources Advisory Group's (PRAG's) letter on June 12, 2013 to LADWP regarding financial metrics.

PRAG

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PUBLIC RESOURCES ADVISORY GROUP

Memorandum to: Department of Water and Power of the City of Los Angeles

From: Public Resources Advisory Group

Subject: Financial Metrics

Date: June 12, 2013

At the request of the Department of Water and Power of the City of Los Angeles ("LADWP"), Public Resources Advisory Group ("PRAG") has prepared the following update on setting financial metric targets for the Power and Water Systems. PRAG had previously provided a similar review in a memorandum dated September 12, 2011 (the "2011 Memo"). This memorandum updates our views on the use of financial metrics for internal planning purposes, rating agencies' medians for certain financial metrics, comparisons of LADWP's existing financial metrics to select peer groups, and possible adjustments to the current financial metric guidelines applicable to the Power and Water Systems.

Appropriateness of Financial Metrics. As stated in the 2011 Memo, before relying on financial metrics for planning purposes, it is important to understand these metrics in their appropriate context. There are many metrics that each measure a different aspect of a utility's financial profile. While differing in their precise focus, what the various financial metrics attempt to provide is numerical data which facilitates evaluating the performance of a utility's operations and its long-term sustainability into the future—which effectively equates to evaluating its credit strengths and weaknesses. These areas can include: (1) safety margin for payment of obligations; (2) extent of leveraging; (3) liquidity position; (4) magnitude of potential additional debt necessary to support capital expenditures sufficient to sustain operations; and (5) operating and revenue risk, among other credit factors.

Using financial metrics as a planning tool can be valuable to utilities, especially as rating agencies and investors also look to financial metrics to help evaluate credit ratings and investment decisions, respectively, which can directly impact the cost of borrowing for utilities. However, since financial metrics are basically numbers, relying on them solely for planning purposes should be limited, because they cannot capture the meaningful qualitative aspects of an issuer's situation—including operating, demographic, political, and regulatory risks. In the rating methodology report "U.S. Public Power Electric Utilities with Generation Ownership Exposure" published on November 9, 2011 (the "2011 Methodology Report") by Moody's Investors Service ("Moody's"), it cites financial metrics ("Financial Metrics", referred to as "financial strength" in the report) as one of *five* key rating factors and for which Moody's has assigned a 30% weighting in their credit evaluation methodology, while other non-quantitative factors result in a 70% weighting. Another important consideration is that when comparing financial metrics across issuers, different operating traits and business characteristics can distort their relative credit strengths. As one example, two issuers can be at two different points in their asset lifecycles, and by extension, could have very different levels of outstanding liabilities, which would impact their financial metrics for safety margin for payment and extent of leveraging. As a result, financial metrics, in isolation, can be imprecise measures of credit strength and better serve as general guideposts and as one component of an issuer's benchmarks for planning.

Selecting Financial Metrics and Comparisons. Due to some of the limitations discussed above, it is important, albeit challenging, to select appropriate issuers that LADWP can be compared to in terms of financial metrics. One source for determining suitable comparable issuers is the rating agencies. As a result, for this analysis, PRAG first looked to the rating agencies' published rating criteria, special commentaries, and reports to identify comparable issuers.

The three major rating agencies for municipal bonds—Moody's, Standard & Poor's Financial Services LLC ("S&P"), and Fitch Ratings Inc. ("Fitch")—do not focus on precisely the same metrics, but do share similar core principles. The rating agencies each focus on unique sets of financial metrics (with some overlap) to assess an issuer's creditworthiness and its ability to pay its financial obligations. In general, the rating agencies have focused on: (1) debt service (and also fixed charge, in the case of electric systems to reflect off-balance sheet obligations) coverage ratios; (2) debt-to-capitalization ratios; and (3) liquidity ratios. It is generally acceptable to have trade-offs across these financial metrics. In other words, weakness in one metric may be somewhat offset by strength in another, especially when the weakness is consistent with a fundamental operating characteristic of the issuer. Additionally, because the rating process is to some extent subjective, the precise impact of each financial metric is not an exact science. While rating agencies have, in recent years, increased the transparency of the rating process by providing weighting factors and guidelines for evaluating credits, such as the 2011 Methodology Report, these guidelines themselves frequently include a statement to the effect that other factors or any outlier factors may be considered and given additional weight in evaluating the creditworthiness of a particular issuer. To demonstrate, PRAG compiled actual data as calculated by Moody's for public power issuers and sorted and compared these data points against the range of values for different rating categories as described in the 2011 Methodology Report. The actual data for individual issuers span well beyond the stated range and that even the median values are not necessarily consistent across rating categories. For example, as shown in the following table, the median "Days of Cash" for Aa-rated entities is non-intuitively lower than that for A-rated entities, and median "Debt Service Coverage" for A- and Aa-rated entities are both surprisingly much higher than the range of ratios published in the 2011 Methodology Report.

Financial Metric	Moody's Rating	Stated Range of Ratios	Actual Data by Issuer (3-year average)		
			Low	Median	High
Debt Service Coverage	Aa	2.00x to 2.49x	1.0x	3.1x	53.7x
	A	1.50x to 1.99x	0.6x	2.3x	46.5x
	Baa	1.10x to 1.49x	0.8x	1.4x	3.8x
Debt Ratio	Aa	26% to 50%	3%	36%	573%
	A	51% to 75%	3%	44%	218%
	Baa	76% to 100%	26%	80%	233%
Days of Cash	Aa	150 to 249	15	142	1,455
	A	90 to 149	8	171	1,360
	Baa	30 to 89	10	111	350

Our observations above support the notion that financial metrics should only be considered as one of many credit factors and should be treated accordingly by utility issuers. Rating agencies recognize these limitations and use financial metrics as only one part of their assessment when assigning credit ratings. We note that comparing financial metrics for LADWP specifically is made more challenging as many other utilities have established additional protections for bondholders, such as debt service reserve funds, debt service funds, and greater than "sum-sufficient" rate covenants while LADWP does not provide any of these security provisions.

In addition, it is meaningful to narrow the focus when comparing LADWP to other entities. Given the unique statutory requirements and regulatory environment for utilities in California, it is meaningful to limit comparisons to those other in-state issuers which must abide by similar operating constraints. Additionally, entities should share the same focus on retail customers as LADWP, as wholesalers tend to operate quite differently and their credit ratings are frequently defined by the credit strength of the retail systems they serve. The discussion below focuses the financial metrics comparison for each of LADWP's systems to narrower "peer" groups.

Power System Comparison. For the Power System, the comparison is limited to no more than the 41 public power utilities in California which directly serve retail customers. Many of these utilities are considerably smaller entities with little generation and transmission assets, and are also generally lower rated than LADWP. For the purposes of this analysis, we have restricted the comparison to those larger retail public power utilities in California which, in general, generate or sell at least one million megawatt-hours each year. Consequently, this eliminates most of the issuers in the lowest investment grade category of "triple-B" or below.

However, even the larger utilities in California are generally significantly smaller than LADWP, such that a single generation asset may be sufficient to provide a substantial portion of their energy needs. Therefore, their financial metrics can fluctuate greatly in accordance with the different stages of a single asset's lifecycle. Additionally, different levels of participation in take-or-pay energy arrangements, on-balance-sheet gas-prepayment arrangements, and single project-based financings can distort financial metrics. Keeping in mind these limitations, the table below sets forth four financial metrics for 16 other "large" California retail public power utilities (yellow highlighted entries are "double-A" issuers), using the same general method that is used by the rating agencies to allow the financial metrics to be compared across this diverse peer group of issuers on a relatively consistent basis. This comparison of financial metrics shows that LADWP's Power System is generally (1) stronger than its California peer group members with respect to debt service coverage, (2) about the same with respect to debt ratio and (3) weaker with respect to liquidity.

Utility	Credit Rating			Financial Metric[1]			
	Moody's	S&P	Fitch	Current Debt Service Coverage[2]	Current Fixed Charge Coverage, including Transfers[3]	Debt Ratio[4]	Days of Cash on Hand[5]
LADWP	Aa3	AA-	AA-	3.01x	1.71x	60%	68[6]
Anaheim	A1	AA-	AA-	1.77x	1.20x	73%	39
Burbank	WR	AA-	WR	4.40x	1.43x	34%	116
Glendale	Aa3	AA-	A+	4.76x	1.02x	28%	59
Imperial Irr. Dt.	A1	AA-	A+	1.22x	1.23x	48%	89
Merced Irr. Dt.	Baa2	A	WR	1.99x	1.52x	57%	246
Modesto Irr. Dt.	A2	A+	A	1.62x	1.37x	95%	63
Palo Alto	NR	NR	NR	4.22x	1.63x	1%	581
Pasadena	WR	AA-	AA	3.00x	1.30x	23%	320
Redding	A2	A	A	1.95x	1.22x	64%	73
Riverside	Aa2	AA-	AA-	1.93x	1.20x	62%	296
Roseville	A2	A+	A+	2.66x	1.30x	57%	137
SMUD	A1	AA-	A+	1.80x	1.62x	88%	96
SFPUC	NR	NR	NR	11.52x	6.23x	16%	678
Santa Clara	A1	A+	A+	4.78x	1.90x	28%	382
Turlock Irr. Dt.	A2	A+	A+	0.99x	0.99x	81%	288
Vernon	Baa1	A-	NR	0.65x	0.47x	89%	58
Median	*A1*	*AA-*	*A+*	*1.99x*	*1.30x*	*57%*	*116*
Double-A Median	-	-	-	*3.01x*	*1.25x*	*47%*	*92*
Single-A Median	-	-	-	*1.80x*	*1.30x*	*64%*	*96*

(1) Compiled using information from annual financial statements of each entity for the most recent fiscal year.
(2) Calculated as the sum of net operating income, non-operating interest earnings and other income and depreciation divided by debt service; does not include transfers from rate stabilization or similar funds.
(3) Calculated as the sum of net operating income, non-operating interest earnings and other income, 30% of purchase power cost and depreciation divided by the sum of debt service, 30% of purchased power cost and transfers out.
(4) Calculated as total liabilities divided by total assets.
(5) Calculated as unrestricted cash and investments divided by operating expenses less depreciation.
(6) Does not include Debt Reduction Trust Fund.

Power System Financial Metrics. Based on a review of the data in the table above and assuming LADWP seeks to maintain its current Power System ratings at Aa3/AA-/AA- (Moody's/S&P/Fitch), there may be some ability to modify the long-term financial metric targets. However, we would caution LADWP that changes in financial metrics could result in a change in its credit ratings and that even a single-notch downgrade would place the credit of the Power System in the less than "double-A" rating category. Credit ratings of less than "double-A" are more costly to issuers as it relates to financing costs, specifically, higher fixed rate yields, higher variable rate yields, higher credit enhancement costs, and reduced market access.

Based on the data presented above, the current ratings of the Power System, the anticipation that LADWP's operating expenses will grow significantly over the next few years, the transparency provided by Moody's with the Financial Metrics, including a focus on fixed charge coverage, in PRAG's opinion, LADWP could choose to set its target financial metrics at (1) the current target Debt Ratio of 68% (no change), (2) a Fixed Charge Coverage ratio of 1.70x, instead of a gross Debt Service Coverage ratio of 2.25x, and (3) maintaining 170 days Cash on Hand, inclusive of the Debt Reduction Trust Fund ("DRTF"), and sustain a "double-A" credit rating.

For issuers with off-balance sheet debt and transfers to another entity, the rating agencies view fixed charge coverage as a better measure of safety margin of debt payments. Therefore, with LADWP's obligations to off-balance sheet debt repayments to the Intermountain Power Agency and the Southern California Public Power Authority along with the recurring annual transfers to the City of Los Angeles, a fixed charge coverage target is more appropriate than a gross debt service coverage target. As it relates to the change to 170 days Cash on Hand, as opposed to a fixed dollar amount of $300 million plus the DRTF, a target that increases as operating expenses increase (and vice versa) better reflects the liquidity position of a utility.

With a Fixed Charge Coverage target of 1.70x, PRAG cautions LADWP that Moody's has made recent comments over fixed charge coverages which in recent years have been "…getting closer to falling out of the A rating according to our [Moody's] methodology." It is also important to note that the rating agencies have been very clear and consistent about the need for LADWP to achieve other important operational and policy goals, including instituting timely rate increases. Failure to achieve these other important goals, possibly as a result of adjusting target financial metrics, would more than likely result in rating downgrades to the Power System.

Water System Comparison. Like the Power System, direct comparisons to LADWP's Water System are also difficult. Many of the retail water systems in California consist of only a distribution network with few capital assets. Larger entities with substantial capital assets, similar to LADWP, tend to be wholesale utilities with only agricultural, commercial and/or industrial retail connections. Still other entitites benefit from a disproportionately large supply of water (from historic water rights/ownership and local groundwater sources) and do not require the same levels of operational infrastructure as LADWP. For the purpose of a comparison to LADWP, PRAG identified the ten largest "double-A"-rated water systems in Southern California with a significant number of retail customers, as well as the two largest such systems in Northern California, and six large "double-A" (or slightly higher) rated wholesale entities in Southern California. Similar to the Power System peer group analysis, the table below sets forth three financial metrics for each of these utilities, using the same general method as that used by the rating agencies to allow the metrics to be compared across different issuers on a relatively consistent basis.

Utility	Credit Rating			Financial Metric[1]		
	Moody's	S&P	Fitch	Current Debt Service Coverage[2]	Debt Ratio[3]	Days of Cash on Hand[4]
Retail Systems						
LADWP	Aa2	AA	AA	1.86x	60%	199
Cucamonga Valley Wtr. Dt.	Aa3	AA	WR	1.90x	48%	305
East Bay MUD	Aa1	AAA	AA+	1.12x	69%	475
Eastern MWD	Aa2	AA	AA+	1.37x	41%	401
Imperial Irrigation District	Aa2	AA	WR	8.42x	25%	170
Long Beach	Aa2	AA+	NR	9.84x	15%	268
Pasadena	NR	AA	AA+	3.24x	43%	74
Rancho California Wtr. Dt.	Aa2	AA+	AA+	1.86x	41%	372
Riverside	Aa2	AAA	AA+	2.82x	43%	644
San Diego	Aa2	AA-	AA	1.67x	39%	436
SFPUC	Aa3	AA-	WR	1.53x	93%	124
Santa Ana	Aa2	AA	NR	2.17x	25%	143
Western MWD	WR	AAA	AA	1.58x	34%	316
Median (Retail Systems)	*Aa2*	*AA*	*AA+*	*1.86x*	*41%*	*305*
Wholesale Systems						
Calleguas MWD	Aa2	AAA	NR	2.09x	41%	790
Central Basin MWD	Aa2	AA	NR	0.65x	67%	177
Metropolitan Wtr. Dt. of So. Cal.	Aa1	AAA	AA+	1.83x	46%	208
San Diego County Wtr. Auth.	Aa2	AA+	AA+	1.34x	66%	193
WRD of So. Cal.	NR	AA+	AA+	1.34x	71%	253
West Basin MWD	Aa2	AA-	NR	1.56x	65%	190
Median (Wholesale Systems)	*Aa2*	*AA+*	*AA+*	*1.45x*	*59%*	*200*

(1) Compiled using information from annual financial statements of each entity for the most recent fiscal year.
(2) Calculated as the sum of net operating income, non-operating interest earnings and other income and depreciation divided by debt service; does not include transfers from rate stabilization or similar funds.
(3) Calculated as total liabilities divided by total assets.
(4) Calculated as unrestricted cash and investments divided by operating expenses less depreciation.

Overall, LADWP's financial metrics are seemingly weaker than those of other retail water systems in California, but are more similar to wholesale water systems in Southern California. This can be attributed to the sizeable Water System, inclusive of a large amount of capital assets and related debt, which has similar characteristics to that of a wholesaler, not of a retailer.

Water System Financial Metrics. Based on a review of the data in the table above and assuming LADWP seeks to maintain its current Water System ratings at AA/Aa2/AA (Fitch/Moody's/S&P), there may be some ability to modify its long-term financial metric targets. Once more, we would caution LADWP that changes in financial metrics could result in changes in its ratings, including a possible downgrade which would make certain debt-related costs more expensive, such as higher fixed rate yields and higher credit enhancement costs. In January 2012, the Water System was downgraded from AA+ to AA by Fitch due to "…financial margins that have trended lower over the past few years…" and "The downgrade was triggered by slimmer financial margins." As with the Power System, the anticipated benefit and flexibility afforded by relaxed financial metrics could be partially offset be additional debt-related costs; although, the mid "double-A" ratings of the Water System affords LADWP some flexibility to be aggressive with any adjustments to financial metrics.

Based on the data presented above and the current ratings of the Water System, in PRAG's opinion, LADWP could choose to set its target financial metrics for the Water System at (1) a greater Debt Ratio of 65% versus 60% and (2) a lower Debt Service Coverage ratio of 1.70x versus 2.00x, and (3) maintaining 150 days Cash on Hand, instead of a fixed dollar amount of $200 million which is smaller than 150 days of cash and does not grow as operating expenses increase, and sustain a "double-A" credit rating. The 150 days Cash on Hand would increase the Water System's cash position as the rating agencies have repeatedly cited the weak cash position in the past; however, the lower Debt Service Coverage is a credit negative. Similar to the discussions above for the Power System, other operating factors that result from changing financial metric targets could negatively impact the credit ratings of the Water System.

Summary. As discussed above, while LADWP provides fewer bondholder protections (no debt service reserve funds, no debt service funds, and only a sum sufficient rate covenant) than many other similarly-rated utilities, it may have the opportunity to adjust it financial metric targets as they relate to the Power and Water Systems. With this strategy, however, we believe there is greater risk from being aggressive with financial metrics for the Power System as its ratings are currently just above the "single-A" rating category from all three rating agencies and a single downgrade would likely be costly. With higher ratings, the Water System can afford more aggressive adjustments in its financial metrics. However, LADWP should be aware that negative rating agency reactions are possible since the existing financial metrics were approved by the Board not very long ago and the credibility of any of LADWP's stated policies, in general, may be called into question.

LOS ANGELES DEPARTMENT OF WATER AND POWER

POWER SYSTEM RATE ACTION REPORT

Chapter 3: Rate Drivers

July 2015

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FIGURES AND TABLES

FIGURES

RATE DRIVERS

3.1 OVERALL REVENUE REQUIREMENT AND RATE DRIVER SUMMARY

In the next five years, the Department will continue to address several key issues and programs that are essential to ensure reliability, comply with regulatory mandates and provide services desired by customers. These necessary investments will also help improve the local environment and bolster economic development. The major issues and programs that are driving the proposed changes in rates during the next five years will be discussed in this section and can be summarized as follows:

- Infrastructure and Power System Reliability Program (PRSP): accelerating the replacement of the rapidly aging electric transmission and distribution systems including replacements of distribution stations, transformers, poles, wires, cables, cross-arms and more;
- Power Supply Transformation: programs mainly driven by regulatory and legislative mandates with which the Department must comply, including coal transformation, power plant rebuilds, the Renewable Portfolio Standard, and customer opportunity programs, including energy efficiency (EE) and local solar;
- Customer Opportunities Programs: growing these initiatives to reach a 15% EE target while also enabling local solar programs and sponsoring emerging technology initiatives; and
- Fuel for traditional Power Plants: the variable cost of fuel for the Department's power plants as well as Power Purchase Agreements (PPAs) that LADWP establishes with third parties.

In addition to the major programs noted above, cost pressures related to daily operations such as changes in wages, benefits and pensions of the Department's employees and maintaining access to low cost financing for the capital program each contribute to the proposed rate increase.

The Power System has developed a methodical approach to develop, analyze, prioritize, fund and ultimately implement capital projects. Projects are prioritized based on regulatory/legal requirements, system operations criticality, in-service date, O&M impact and other important criteria. LADWP's approach results in a budget that is developed systematically, regularly reviewed and updated as conditions impacting the financial and non-financial parameters change. This process has allowed LADWP to allocate its limited resources in a manner that maximizes the quantitative and qualitative benefits of investments in recent years without a rate increase. However, current revenues are projected to be inadequate to fund critical planned programs as summarized in Figure 1.

Figure 1: Expense Distribution/Revenue Requirement and Projected Gap from FY 2014-15 to FY 2019-20[1]

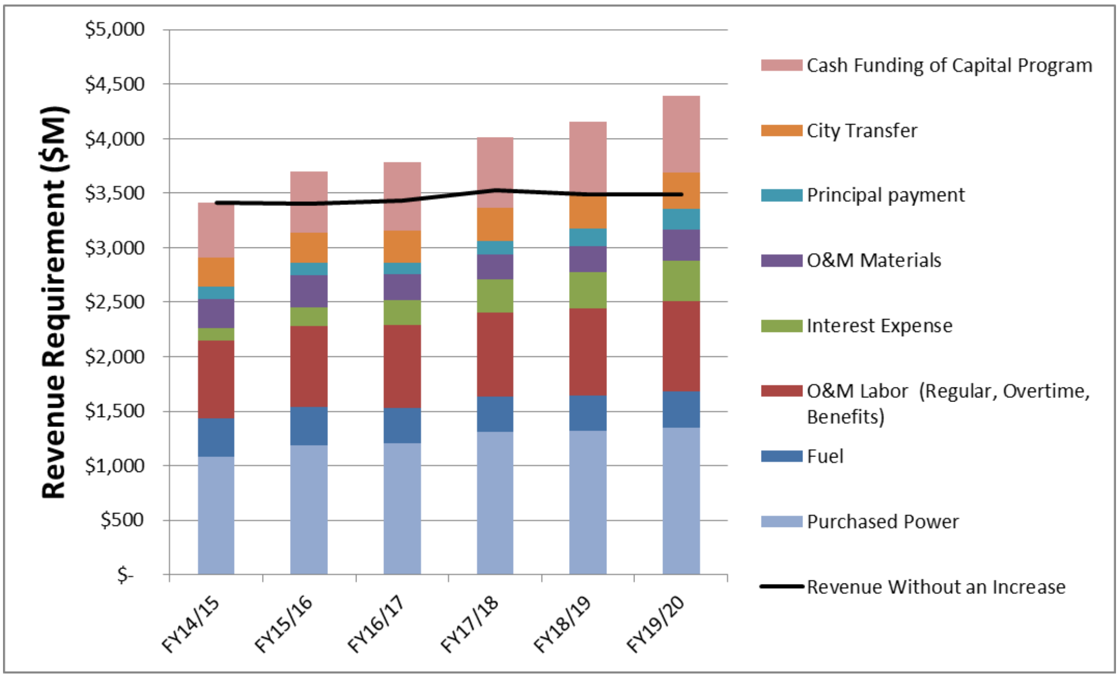


Figure 1 shows a revenue requirement gap of approximately $900 million for FY 2019-20. To meet the Power System's revenue requirement, revenues will have to increase by an average of $180 million per year for the period of FY 2015-16 through FY 2019-20, as reflected in graphically in Figure 1 and numerically in Figure 2. Also recognized in Figure 2 is that a majority of program costs are driven by regulatory mandates or other external factors. To comply with these mandates while providing reliable service and to maintain critical financial metrics established by the Board of Water and Power Commissioners (Board), the Department is requesting an average annual rate increase of 0.76 cents per kWh (4.68%) over the five-year rate period.

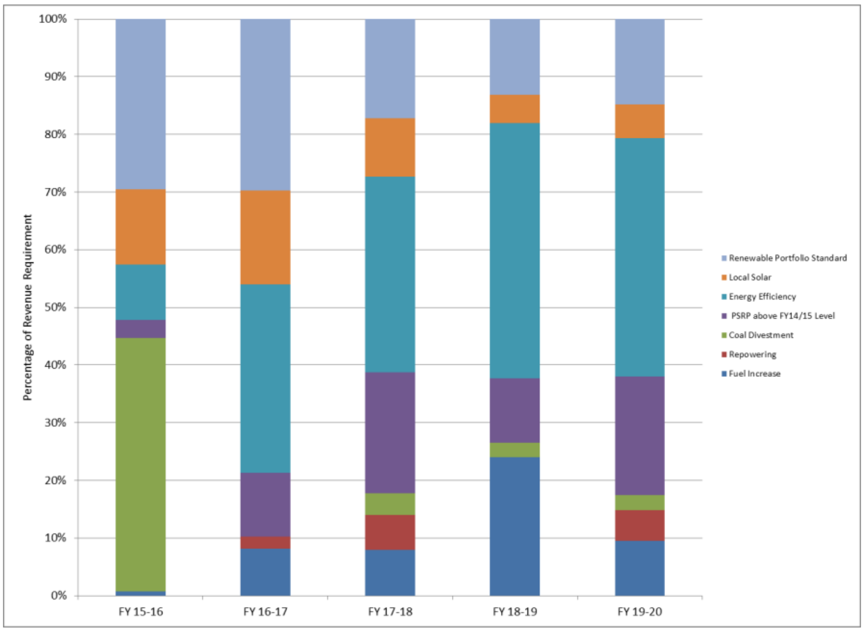
[1] All budget and revenue requirement information is based on Financial Plan Case Number 19 including depreciation, net interest expense, and retained earnings. The full plan can be found in Chapter 3 – Appendix A.

Figure 2: Component Breakdown of Revenue Requirement and YOY System Average Rate Increase for FY 2015-16 Through FY 2019-20 Compared to FY 2014-15

Program	Rate Driver	Regulatory (or Other External) Requirement	Average Annual Revenue Requirement Increase ($M)	System Average Annual Increase (Cents/kWh)	Avg. Annual Percentage Increase (%)
Power System Reliability Program	Power System Reliability		26	0.11	0.68%
Power Supply Transformation Program	Coal Replacement	✓	17	0.07	0.48%
	Once- Through Cooling	✓	4	0.02	0.09%
	Renewable Energy	✓	36	0.15	0.96%
	Subtotal – Increase		57	0.24	1.53%
Customer Opportunities Program	Energy Efficiency	✓	60	0.26	1.54%
	Local Solar Programs	✓	18	0.07	0.46%
	Subtotal – Increase		78	0.33	2.01%
Fuel			18	0.08	0.46%
Total Average Annual Increase			$180	0.76	4.68%

The contributions of certain components to the overall revenue requirement vary year over year, as depicted in Figure 3. The change in yearly contribution of the rate drivers is a true testament to the "balancing act" the Department must perform both proactively and in reaction to a number of factors. In its comprehensive financial plan, the Department has striven to optimally satisfy all stakeholder obligations. The initial focus was on its customers through carefully minimizing overall costs by performing a comprehensive cost of service study to guide rate design and by providing reliable service to each customer segment. The Department still fairly balances its responsibilities to the residents of Los Angeles, Board, City Council, and other stakeholders.

Figure 3: Revenue Requirement - YOY Component Breakdown Over Proposed Five-Year Rate Period



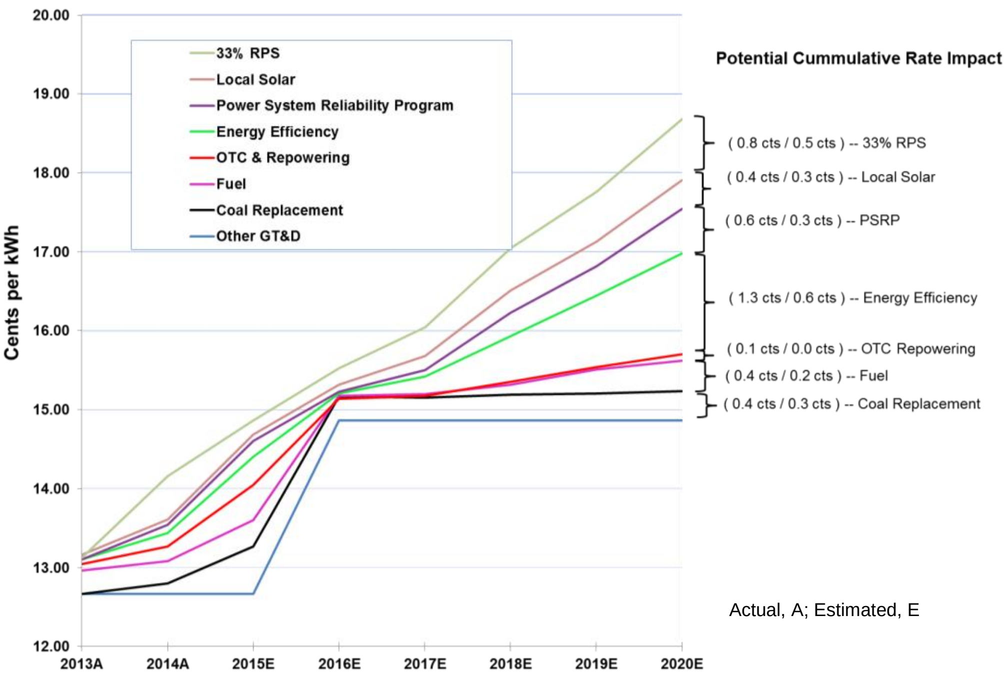
The rate driver contributions in this report are presented in year over year (YOY) format to show the changing impact on the Department's revenue requirement. Throughout this report, we will continue to present YOY numbers. However, in order to understand the potential impact of compounding on the rate drivers by the end of the rate period, the Department has also computed "cumulative" rate increase percentages. Figure 4 compares the percentage rate increases using the two different calculation methodologies. Using the cumulative methodology, the average annual rate increase is 5.13% instead of 4.68%.

Figure 4: YOY vs. Cumulative Average Percentage Rate Increase

Program	Rate Driver	YOY Average Annual Percentage Increase (%)	Cumulative Average Annual Percentage Increase (%)
Power System Reliability Program	Power System Reliability	0.68%	0.75%
Power Supply Transformation Program	Coal Replacement	0.48%	0.49%
	Once- Through Cooling	0.09%	0.11%
	Renewable Energy	0.96%	1.03%
	Subtotal – Increase	1.53%	1.63%
Customer Opportunities Program	Energy Efficiency	1.54%	1.72%
	Local Solar Programs	0.46%	0.50%
	Subtotal – Increase	2.01%	2.22%
Fuel Increase		0.46%	0.25%
Total		**4.68%**	**5.13%**

A visual representation of the cumulative rate FY 2019-20 rate drivers for the proposed power rate increase over the five-year period are depicted in Figure 5. The blue line at the bottom represents the revenue collected from the current rate, with the other lines representing rate driver contributions to the revenue requirement. Higher costs are driven largely by the needs for infrastructure reliability, renewable portfolio standard, EE and local solar.

Figure 5: Cumulative Contribution by Rate Driver to Proposed Rate Increase[2]



3.2 INFRASTRUCTURE AND POWER SYSTEM RELIABILITY PROGRAM (PSRP)

Reliability improvement in light of aging infrastructure and limited resources has become a major challenge for LADWP. Both customers and policy makers are demanding increased reliability levels at the same time that funding for capital replacement and expanded maintenance initiatives is limited due to financial constraints and competing priorities.

LADWP's proposed rate plan balances the appropriate investment levels for infrastructure reliability and compliance with external mandates while minimizing the impact on customer rates. The proposed rates are designed to maintain and improve the level of reliability most efficiently by allocating resources between base labor, overtime, and contractors in the most cost effective manner. The Department has developed its plans for reliability enhancements in a strategic way that is most cost effective and least disruptive to customers by focusing on scheduled planned infrastructure investment projects as opposed to preventative maintenance programs. A systematic replacement program has been shown to be more

[2] The potential cumulative rate impact is calculated by using the annual average values over the proposed five-year rate period.

effective in lowering costs and customer impacts than performing reactive or emergency asset replacement. An example of this is shown in the deferral of the scheduled major overhaul of the OVES Upper, Middle, and Control Gorge (UMC) project from FY 2010-11 to FY 2011-12. Subsequently, a major forced outage of the Control Gorge Unit in January 2012 necessitated the re-conditioning and refurbishment of the generators and turbines at UMC Gorge Power Plants. Completion of the project is expected to be in October 2015. The deferral of this scheduled major overhaul resulted in an additional cost of $50.7 million, for a project that was initially budgeted to cost $9.9 million.

In July 2014, the PSRP was initiated to evolve the Power Reliability Program (PRP). The PSRP focuses on expanding capital expenditures to address the increasing problem of sustainable reliability given an aging infrastructure. The PSRP is designed to mitigate exposure risk by lowering replacement cycles to be closer to actual expected asset life while holding O&M at current levels. The end goal is to achieve asset replacement rates that are more aligned with LADWP asset condition and closer to industry standard. However, financial restrictions and rate pressure will not allow LADWP to raise all of the necessary capital to achieve the desired replacement rates during this rate period. As such, the PSRP will continue to be a long-term investment program which balances available spending with the appropriate reliability improvement programs. The PSRP costs included in the proposed rates help to move LADWP toward the desired asset replacement levels.

The main issues addressed by the infrastructure plan, along with their corresponding PSRP initiative, are:

- Major expansion of maintenance on generation assets to reduce the reliance on out-of-basin generation and maintain voltage stability in the LA area. This program includes the replacement of step up and station service transformers and detailed inspections of the thermal, hydro and pump storage turbine/generator facilities.
- A one-year increase to address underground cable replacement followed by a slow decrease in capital spend for cable. This plan includes underground cable replacement, stop joint replacement, and maintenance hole expansions (access to underground vaults).
- Small increase to the substation asset replacement program to address aging equipment issues on a gradual basis, including transformer, circuit breaker, relay scheme and battery replacements.
- Significant expansion of capital spending on distribution system asset replacement to maintain existing system reliability and improve it in the worst performing areas, including replacement of poles, cross arms, underground cable, transformers, and substructures.
- Maintaining O&M spending at current levels through an ongoing effort to curtail maintenance spend in light of capital replacement projects, which eventually reduce maintenance costs.

The overall proposed funding levels are shown in Figure 6.

Figure 6: PSRP Capital and O&M Costs Over Five-Year Rate Period

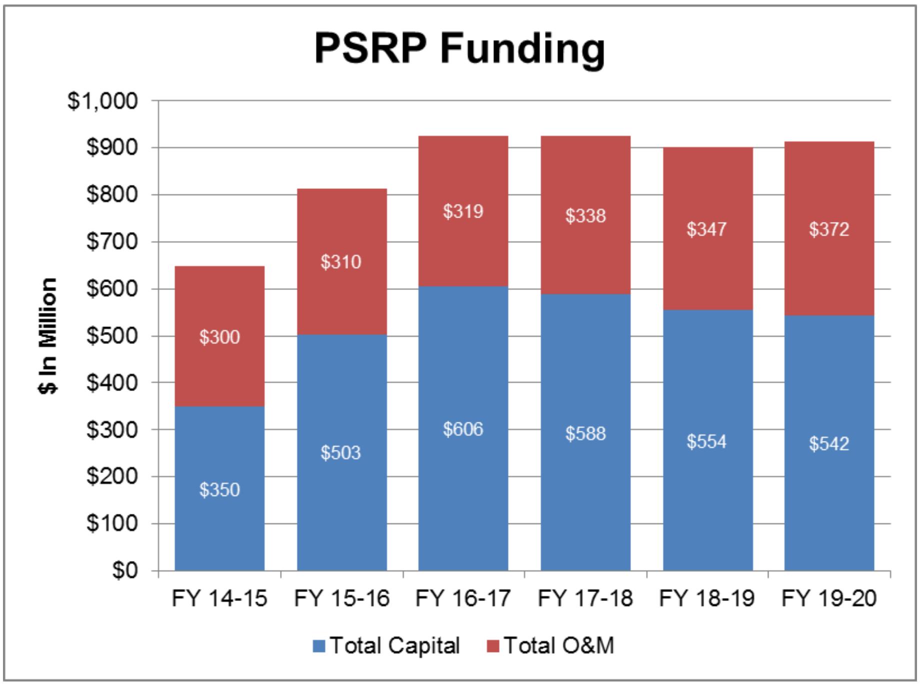
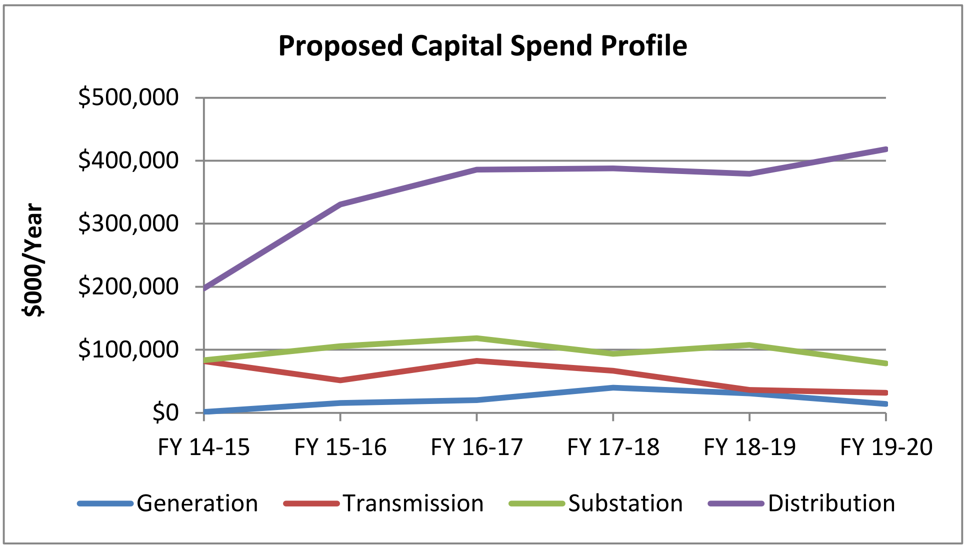


Figure 7 shows a consolidated view of the proposed changes to the individual PSRP programs over the five-year rate period.

Figure 7: Projected Capital Spend by Asset Type



The incremental impact of the PSRP on the Department's revenue requirement is shown in Figure 8.

Figure 8: PSRP Impact on Revenue Requirement and Rates

	Year Over Year Increase						
	FY 15-16	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**Average**	***FY 20-21*[3]**
Total System Revenue Requirement ($M)	5	14	49	19	44	26	*46*
Total System Average Cost per kWh (Cents/kWh)	0.02	0.06	0.21	0.08	0.19	0.11	*0.20*
System Average Annual Percent Increase (%)	0.15%	0.39%	1.31%	0.47%	1.06%	0.68%	*1.05%*

3.2.1 Power System Reliability Program (PSRP) Components

In July 2014, the PSRP was initiated to evolve the Power Reliability Program (PRP). The goal of the PSRP is to allocate limited capital and maintenance dollars to improve the most reliability sensitive portions of the entire electric system. Due to the aging nature of the infrastructure, the core focus of PSRP is the expansion of capital replacement while holding O&M expenses steady. The end result will be a more steady state asset replacement and O&M program over the long-term. However, over the next five years, capital spend will need to increase to fund the replacement of aging and failing assets. The result of lowering the average age of the LADWP electric system will improve reliability and reduce future O&M spend.

The PSRP is divided into four programs:

- Generation Reliability Program (GRP),
- Transmission Reliability Program (TRP),
- Substation Reliability Program (SRP),
- Distribution Reliability Program (DRP).

Each of the above programs has specific asset groups that have been targeted for replacement as shown in Figure 9.

[3] LADWP has analysed expense and revenue requirement projections beyond the five-year timeframe; while additional analysis is required, it is possible further rate increases beyond the current rate period may be necessary.

Figure 9: Assets Recommended for Replacement List[4]

Generation	Transmission	Substation	Distribution
Generator Step Up Transformers	138kV UG Transmission Circuit	High Side Transformers (RS)	Poles
Generation Station Transformers	138kV Stop Joints	Load Side Transformers (RS)	Crossarms
Major Inspection (Thermal)	Maintenance Hole Restraints	Local Substation Transformers (DS)	Lead Cable Miles
Major Inspection (Hydro)		Substation Transmission Breakers	Synthetic Cable Miles
Major Inspection (Pump)		34.5kV Substation Circuit Breakers	Transformers
San Fernando Power Plant		4.8kV Substation Circuit Breakers	Substructures
		Substation Battery Banks	
		Substation Automation	

In addition to systematic asset replacement, LADWP conducts regular scheduled maintenance. These activities include programs such as tree trimming, inspections, and testing. These costs are forecast to remain fairly stable across the next five years.

Figure 10: Projected Capital and O&M Expenses Over Five-Year Period ($M)

	Current	Forecast				
Capital:	**FY 14-15**	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**
Generation	$1.35	$15.5	$20.14	$39.95	$30.98	$14.11
Transmission	$75.96	$51.58	$82.21	$66.83	$36.40	$31.70
Substation	$75.25	$105.63	$118.46	$93.49	$107.84	$78.17
Distribution	$197.10	$330.73	$385.60	$388.05	$379.07	$418.23
Total Capital	**$349.65**	**$503.49**	**$606.41**	**$588.32**	**$554.28**	**$542.21**
O&M:						
Transmission	$26.59	$25.97	$27.24	$32.70	$33.64	$35.42
Substation	$11.91	$10.86	$11.41	$11.81	$12.22	$12.03
Distribution	$188.19	$201.01	$206.97	$219.89	$227.56	$244.02
Journeyman Training	$24.11	$23.76	$25.38	$26.99	$27.75	$28.10
Power System Training	$48.73	$48.89	$47.93	$46.18	$46.11	$52.64
Total O&M	**$299.53**	**$310.49**	**$318.94**	**$337.58**	**$347.29**	**$372.22**

Each of the individual PSRP programs is described in further detail below.

[4] Based on the 2013 PSRP Report.

3.2.2 Generation Reliability Program (GRP)

The Generation Reliability Program focuses on the part of the overall power delivery system that provides cost-efficient electricity to ratepayers by maintaining acceptable levels of electric energy and adequate voltage support to meet local reliability criteria for interconnected system operations. Together, its maintenance and replacement programs are designed to improve system reliability, reduce operating costs and improve the environment.

LADWP generation assets serve the following purposes.

- Provide enough generation to reliably serve the moment-to-moment variability of LADWP's load under projected transmission configuration (this is achieved by Reliability Must Run (RMR) generation assets).
- Provide adequate voltage and VAR support for the LA area.
- Generate power in a cost-efficient manner to meet demand through generator dispatch prioritization procedures.

LADWP's in-State generation system consists of:

- Thermal generation including combined cycle gas turbines (CCs), combustion gas turbine (CT) and Steam Turbines (ST) as base load; and
- Hydroelectric generation including pumped storage and small hydroelectric used as intermediate and peaking plants.[5]

The in-State generation is supported through external generation resources from outside of the State of California which are managed through power purchase agreements. To date, these resources have proven to be extremely dependable, provided there are no interruptions to the fuel supply. However, as discussed later in the chapter, some of these sources are being discontinued over time to help reduce the carbon footprint and comply with a variety of regulatory requirements.

Generation element failures can impact generation resource operation and performance. For that reason, a robust generation system maintenance program aimed at sustaining a continuous and reliable power supply is required. The objectives of the GRP are to:

- Determine and evaluate performance at generation facilities;
- Evaluate the existing generation system maintenance programs;
- Strengthen the existing generation system maintenance programs by proposing meaningful improvement solutions; and
- Provide an evaluation of the overall generation system reliability through benchmarking.

The GRP is a combination of asset replacement and proactive maintenance projects designed to provide improved reliability. The units and unit costs of the GRP are outlined in Figure 11.

[5] RPS sources are not included as these programs are discussed in another section of this chapter. In addition, LADWP also participates in joint generation resources through SCPPA.

Figure 11: Unit Costs and Replacement Units for Generation Reliability Program

	Total Existing LADWP Count[6]	Unit Cost ($000)	Proposed Replacement Units[7]					
			FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20
Generator Step Up Transformer	76	$5,000	0	1	1	2	2	2
Generator Station Transformer	92	$2,000	1	1	1	2	2	2
Major Inspection (Thermal)	24	$4,000	1	4	4	4	4	4
Major Inspection (Hydro)	22	$4,000	1	2	2	2	2	2
Major Inspection (Pump)	7	$4,000	1	1	1	1	1	1
San Fernando Plant	2	$6,600	0	0	1	0	1	0

LADWP has the responsibility to operate and maintain hydroelectric and thermal power units in accordance with established standards and practices and consistent with environmental and flood control regulations. The Power System ensures the safe and sound operation of all structures and equipment associated with the fulfillment of this responsibility. The following programs are in place for generation reliability.

- Spring and Fall Maintenance Outages: Major maintenance outages are periodically performed. Given the plant's present and forecast future operating profiles, it is forecasted that overhauls will be required approximately once every three years or approximately every 25,000 runtime hours. In years in which no major maintenance is due, the station conducts short maintenance outages each spring to prepare for the summer peak season. Work typically accomplished during such short outages includes valve repair, instrument calibration, filter change out, water treatment system cleaning and overhaul, pump-motor repair and alignment and inspections such as of the Heat-Recovery Steam Generators, condenser and fire suppression systems. The station also conducts a similar routine maintenance outage each fall to address concerns noted during the summer peak season.
- Contractual Service Agreement: The Contractual Service Agreement (CSA) provides continuous condition monitoring and warranty coverage of manufacturer's furnished equipment. Under the CSA, the manufacturer also provides major maintenance, including parts, services and repairs of their equipment.
- Major Maintenance Outages Including Overhauls: Under any CSA, and in conformance with manufacturer's maintenance recommendations, the combustion turbines, steam turbines and generators also undergo periodic major maintenance to ensure reliable operations. Finally, key components necessary for the power delivery system are generator step up (GSU) and station transformers. GSU ages range from

[6] This number represents the current number of units the Department has of this equipment.

[7] This number is the planned units to undergo inspection, maintenance, or replacement per the PSRP.

7 to 96 years old. The average age of the generation transformer population is about 48 years. For this proposed rate action, 17 transformers with an average age of 62 years have been identified for replacement.

3.2.3 Transmission Reliability Program (TRP)

The objectives of the Transmission Reliability Program are to:

- Meet FERC, NERC, WECC and LADWP reliability standards;
- Establish asset replacement targets to address aging infrastructure; and
- Develop expansion programs to accommodate future growth.

The TRP includes asset maintenance and replacement with the number of projects per year indicated in Figure 12. In the near term, LADWP will focus on the underground system by replacing self-contained low and medium pressure oil-filled cables.

Figure 12: Unit Costs and Replacement Units for Transmission Reliability Program

	Total Existing LADWP Count	Unit Cost ($000)	Proposed Replacement Units					
			FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20
138kV UG Transmission Circuit	17	$12,600	1	1	2	2	2	2
138kV Stop Joints	31	$300	2	5	5	5	5	5
Maintenance Hole Restraints	238	$27	10	20	30	40	40	40

The older parts of Los Angeles are served by oil-filled underground transmission lines including 138kV and 230kV cable systems. These oil-filled cables were originally placed in service from 1943 to 1959, but are low pressure systems that began failing in 1986 due to age and condition. Another problem with these low pressure cable systems is the use of stop joints. A stop joint is used to divide a cable circuit into independent hydraulic sections, with each section being fed at the stop joint location by gravity fed reservoirs. The stop joint uses a special tube to prevent the oil from passing though the joint. These stop tubes were manufactured between 1943 and 1959; however, due to aging and physical stress, the material becomes brittle and cracks. These cracks allow oil to migrate from high to lower elevations within each cable section which can result in joint failure. Repair and/or replacement of these cables is paramount to improving transmission system reliability, Under the TRP, the oil-filled cables will be replaced with cross linked polyethylene (XLPE or synthetic) cables. This technology was selected for several reasons.

- Oil-filled cables are no longer state-of-the-art technology and are becoming obsolete. Replacement parts are hard to find and expensive, splicing talent is retiring and the oil is becoming increasingly unacceptable as it leaks from the cable systems.
- XLPE cable of the same rating can be installed in existing conduit systems negating the need for subsurface excavation.

3.2.4 Substation Reliability Program (SRP)

The assessment of substation reliability at LADWP includes the evaluation of breakers, power transformers, battery banks, relays, and the substation automation program. The substation reliability program assesses the value of replacement and maintenance costs for four major asset groups:

- Transformers
  - High Voltage Transformers (≤ 230kV)
  - Load Bank Transformers (138kV, 230kV)
  - Local Substation Transformers (34.5kV to 4.8kV)
- Breakers
  - Receiving and Distribution Station Breakers (4.8kV, 34.5kV)
  - Transmission Breakers (>100kV)
- Substation Battery Banks
- Substation Automation Program

The replacement program strategy is to replace aging units using a life cycle approach that replaces units with poor performance to be compliant with NERC/FERC standards. The program includes a regular maintenance program and investigating the use of new technology for transformer remote monitoring. The program is addressed in three steps:

- Immediate replacement of aging substation equipment;
- Life cycle replacement program; and
- Developing a spare parts policy to shorten future outage restoration time, based on critical operation and lead time.

The SRP includes the following asset replacement numbers per year as shown in Figure 13.

Figure 13: Unit Costs and Replacement Units for Substation Reliability Program

	Total Existing LADWP Count	Unit Cost ($000)	Proposed Replacement Units					
			FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20
High Voltage Transformer (RS)	70	$4,000	0	1	1	1	1	1
Load Bank Transformer (RS)	88	$4,500	3	1	1	1	1	1
Local Substation Transformer (DS)	930	$1,200	4	18	18	18	18	18
Substation Transmission Breakers	612	$550	3	6	6	6	6	6
34.5kV Substation Circuit Breaker	1,878	$200	10	10	15	20	20	20

4.8kV Substation Circuit Breaker	2,406	$80	10	20	30	40	40	40
Substation Battery Banks	640	$100	40	64	64	64	64	64
Substation Automation	196	$1,000	0	8	12	12	12	12

3.2.4.1 Transformer Replacement

Based on the 2011 Transformer Assessment, Replacement, and Availability Program study, eight of LADWP's high voltage transformers (>230kV) were over the 50-year useful life period. An additional four units were deemed worst performing for a total of 12 units out of the population of 70 that need replacement. The current PSRP calls for the replacement of five of those transformers over the proposed rate period based on a combination of age and condition.

Based on the same study, 17 of the load bank transformers (138kV and 230kV) were over their useful life of 50 years, and five units were deemed worst performing. These five units are scheduled for replacement through the PSRP by FY 2019-20.

In addition, 290 of the local substation transformers (34.5kV to 4.8kV) exceed their design life of 50 years. Through the PSRP five-year plan, 90 of these transformers will be replaced.

Figure 14: Example of an Old Substation Power Transformer

3.2.4.2 Circuit Breaker Replacement

Circuit Breaker replacement is prioritized by asset criticality and maintenance value as opposed to cost. There are three main categories – transmission (>100kV), sub-transmission (34.5kV), and distribution (4.8kV).

- Transmission Breakers: LADWP has over 600 transmission breakers on its transmission system. Annual short circuit transient studies by the Power System prioritize transmission breaker replacement. Transmission line replacement and upgrade projects also require replacement of the associated breakers. On average, six transmission breakers are planned for replacement annually.
- 34.5kV Breakers: 34.5kV sub-transmission circuit breakers in both receiving and distribution stations include the following types:

- Oil Circuit
- SF6 Circuit
- Air Blast Circuit
- Vacuum Circuit

The current PSRP specifies replacement of these units starting with 10 in FY 2014-15, escalating to 20 in FY 2017-18 and beyond.

- 4.8kV Breakers: A majority of the 4.8kV distribution breakers are over 55 years old with an expected useful life span of 30 years (with proper upgrading and maintenance, this life span can be increased to almost 30 years). On average, about ten 4.8kV breakers are budgeted to be replaced annually. The current PSRP calls for replacement of these units starting with 10 in FY 2014-15, escalating to 40 in FY 2017-18 and beyond.

Figure 15: Example of an Old Oil Circuit Breaker

3.2.4.3 Substation Battery Replacement

Battery banks provide the power to run all of the protection and relaying schemes inside the substation, which in turn control the circuit breakers that protect the transmission and distribution lines and the power transformers inside the substation. Batteries have a fixed life and require replacement every 10–15 years. The SRP calls for replacing 64 banks each year through 2020.

3.2.4.4 Substation Automation

LADWP has multiple programs in place to replace relays and simultaneously increase substation automation. The program calls for the replacement of:

- Obsolete electromechanical 500kV relays to improve reliability and comply with NERC standards (PRC-005-2 & PRC-008-0);
- Obsolete transmission relays between 100kV and 500kV;
- Digital Fault Recorders that are difficult to maintain to comply with NERC standards;

- Distribution 34.5kv and 4.8kV electromechanical relays to improve and expand the substation automation program; and
- Legacy Remote Terminal Units (RTU), Human Machine Interface (HMI) control station, and fiber optic communication.

3.2.5 Distribution Reliability Program (DRP)

Electric distribution infrastructure assets (poles, cables, transformers, etc.) eventually reach the end of their useful lives. Unless they are replaced, they will begin to fail, causing power outages. While the overall number of outages has decreased, LADWP must address the growing backlog of aging assets to maintain, and conceivably continue to improve, the current level of reliability.

The objectives of the Distribution Reliability Program are:

- Meet applicable Institute of Electrical and Electronics Engineers (IEEE) standards, CPUC guidelines, and LADWP reliability standards;
- Establish asset replacement targets to address aging infrastructure; and
- Develop expansion programs to accommodate future growth.

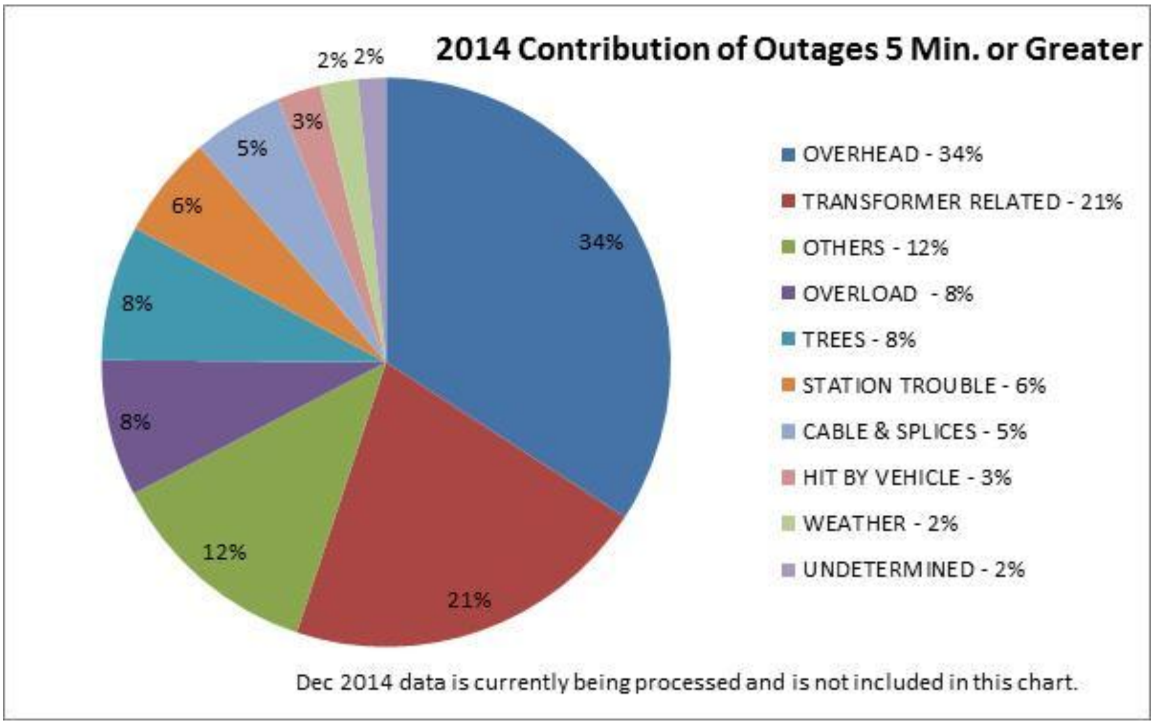
3.2.5.1 Reliability Performance Indicators

LADWP's Power System reliability has consistently placed in the top quartile of the electric utility industry. Reliability is measured in terms of the following metrics.

- System Average Interruption Duration Index (SAIDI) - the average duration of service interruptions per customer during the year. In general, SAIDI is a reflection on the efficiencies of restoring electric service following an interruption. Time to respond, time to repair and speed of notification are part of the different components of SAIDI.
- System Average Interruption Frequency Index (SAIFI) - the average number of service interruptions over five minutes per customer during the year. In general, SAIFI is a reflection on the effectiveness of preventive maintenance on the system to prevent interruptions from occurring in the first place.
- Customer Average Interruption Duration Index (CAIDI) – the average length of an outage for those customers who experienced an outage. Similar to SAIDI, CAIDI is a reflection on the efficiencies of restoring electric service following an interruption. Time to respond, time to repair, speed of notification are part of the different components of CAIDI.

As shown in Figure 16, the Department tracks the cause of each outage to help assess the overall reliability of the electric system.

Figure 16: 2014 Contribution of Outages Greater Than Five Minutes



Note that overhead lines and transformers account for 55% of all outages. Both these asset groups are included in the DRP. This type of information helps LADWP develop the appropriate corrective action work required to address reliability problem areas.

LADWP regularly compares its performance to the other major California utilities in terms of reliability metrics. The charts in Figure 17, Figure 18, and Figure 19 show historical trending for SAIDI, SAIFI, and CAIDI for LADWP, PG&E, SCE, and SDG&E[8].

[8] At the time of this report, data for other California companies for 2014 was not yet available, and data for LADWP is through November of 2014.

Figure 17: SAIDI Comparison with California IOUs

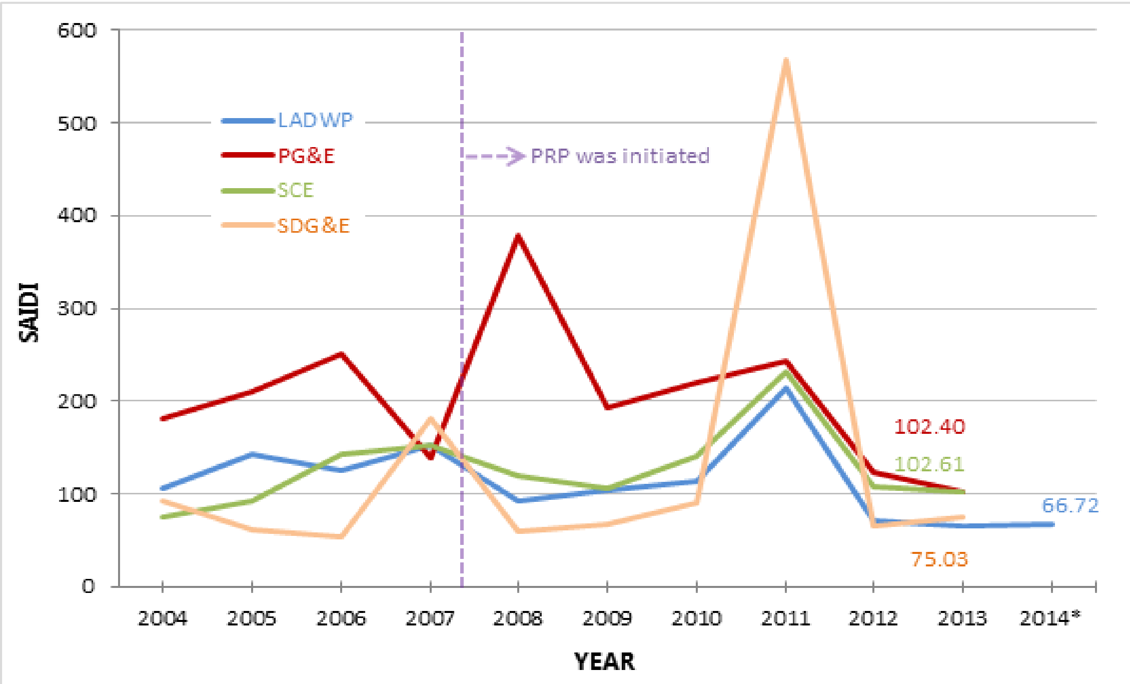


Figure 18: SAIFI Comparison with California IOUs

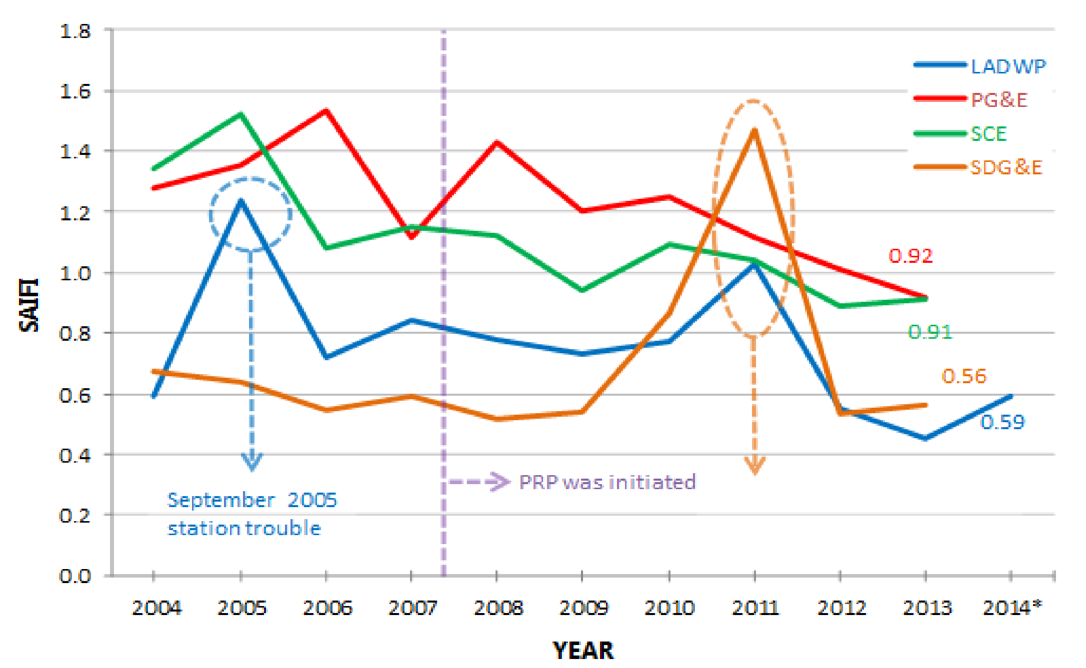
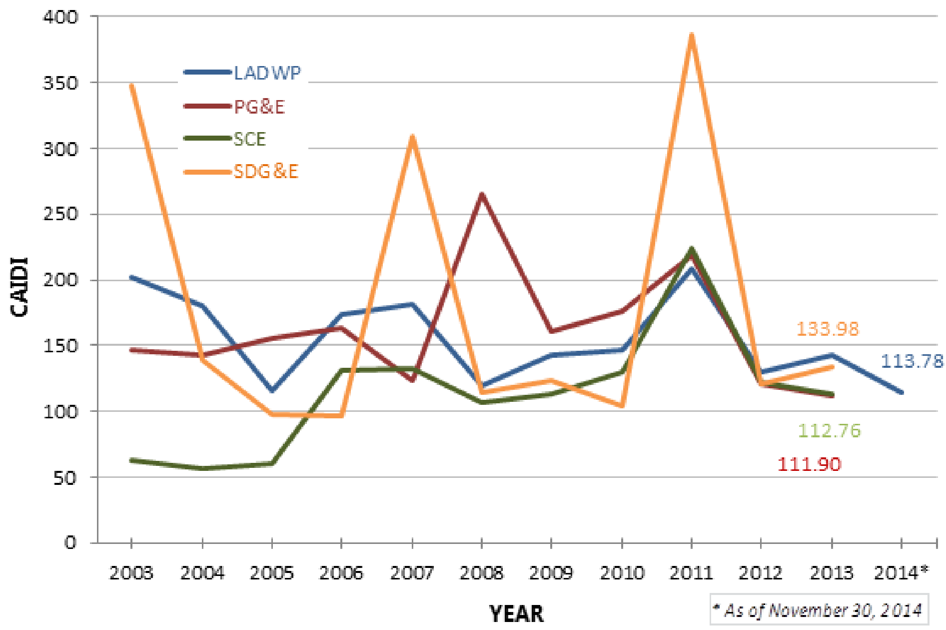


Figure 19: CAIDI Comparison with California IOUs



As can be seen from the above charts, the general trend for reliability is a decreasing SAIFI (fewer interruptions, and/or fewer customers being impacted by interruptions), a fairly flat SAIDI, and an increasing CAIDI. This trend supports the need for infrastructure investments and increased reliability spending. Despite these lower trending metrics, in general, LADWP compares favorably to the other major California electric utilities.

3.2.5.2 Asset Replacement

LADWP tracks the age, condition and impact on reliability for each major type of asset in its infrastructure. Given the number and age of each asset element, a key consideration is to replace assets at a rate that corresponds to their respective service lives. Replacement cycles that exceed the average service life put the system at increased risk of service interruption. Figure 20 shows the proposed annual number of distribution assets replacements through FY 2019-20.

Figure 20: Unit Costs and Replacement Units for Distribution Asset Replacement

	Total Existing LADWP Count	Unit Cost ($000)	Proposed Replacements					
			FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20
Poles	321,780	$45	1,560	4,000	5,000	6,000	6,000	6,000
Crossarms	1,287,120	$4	4,500	7,000	8,000	10,000	10,000	10,000
Lead Cables	1918 miles	$1,000	28	48	48	48	48	48
Synthetic Cables	1679 miles	$800	10	12	12	12	12	12
Transformers	126,000	$20	450	600	700	800	800	800
Substructures	54,099	$400	7	12	16	20	20	20

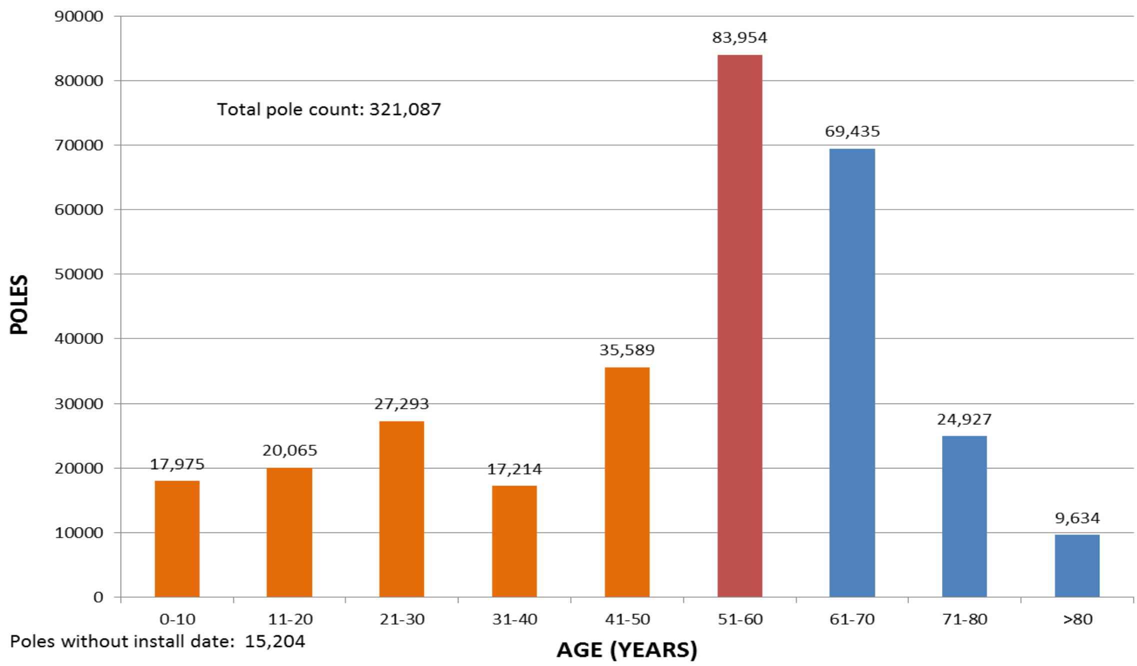
3.2.5.3 Pole Replacement

Since approximately 70% of LADWP's power distribution system is overhead, the maintenance and replacement of poles and cross arms is a major driver of reliability. About 195,000 poles are more than 50 years old; Figure 21 shows an example of a typical old pole in the LADWP system.

Figure 21: Typical LADWP Broken Wood Pole

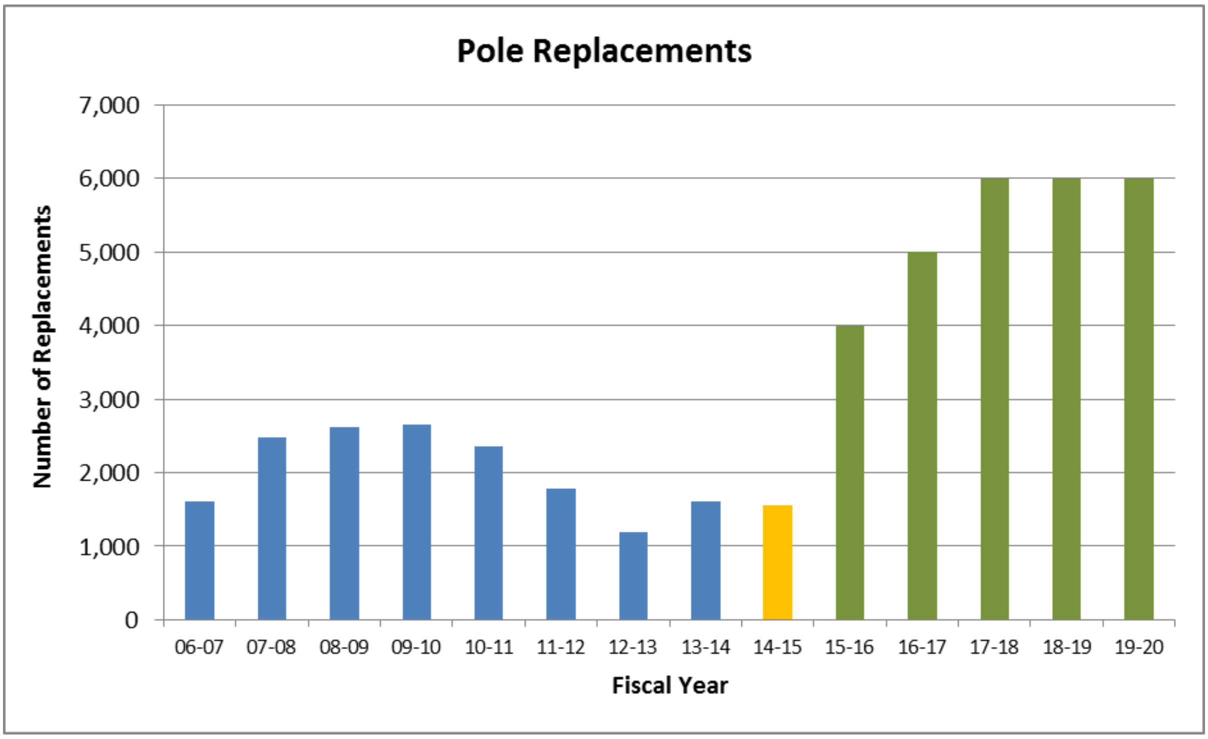
Additional investment in pole replacement is warranted to reduce the age of poles and maintain and improve infrastructure reliability. Figure 22 provides an aging summary for LADWP's poles.

Figure 22: Current Pole Age Distribution



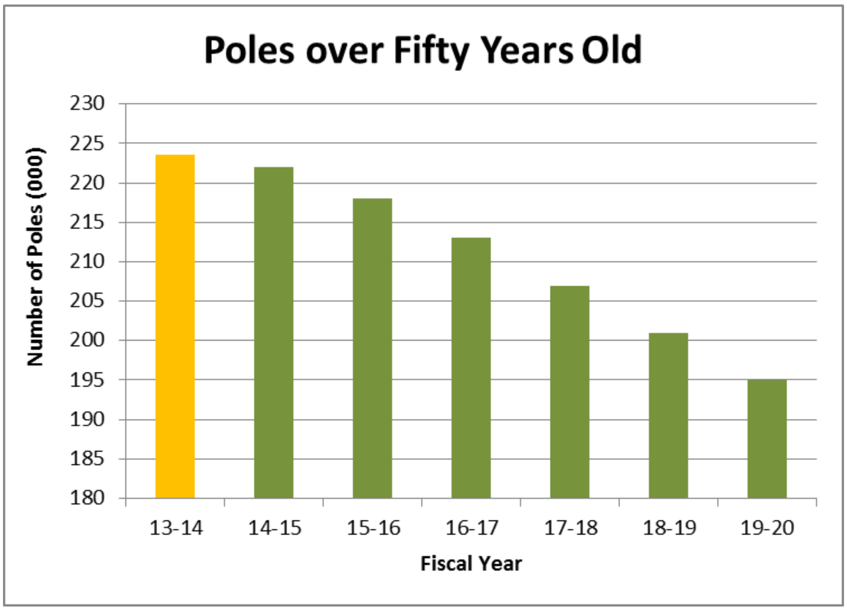
LADWP's financial plan and proposed rates are designed to increase annual pole replacements to 6,000 by FY 2017-18 as shown in Figure 23.

Figure 23: Pole Replacement – Historical and Projected



The current PSRP goals for pole replacements will slowly decrease the average pole age on the system from 54 to 51 by FY 2019-20, but the average pole age will still be above the target age of 50 years. However, as shown in Figure 24, the number of poles over 50 years old will decrease substantially over the proposed five-year rate period.

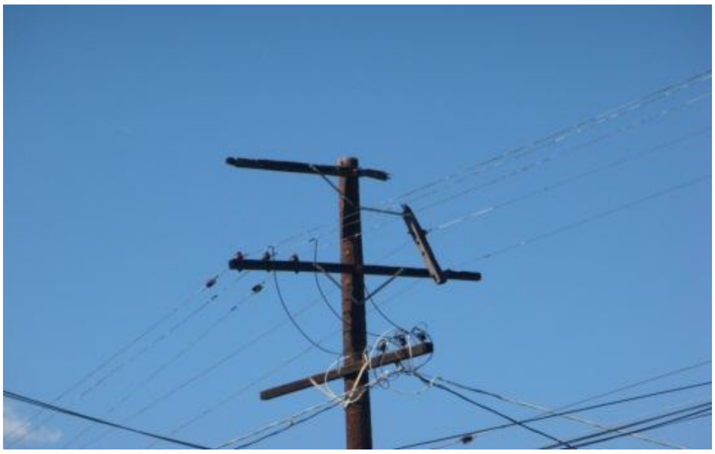
Figure 24: Number of Poles Over 50 Years Old During Proposed Five-Year Rate Period



3.2.5.4 Crossarm Replacements

Crossarms are also a critical part of the pole assembly since they carry the weight of the energized wires and related voltage equipment. Crossarms are typically replaced when the pole is replaced, but there are almost twice as many crossarms as poles that need to be replaced.

Figure 25: Example of Failed Crossarm



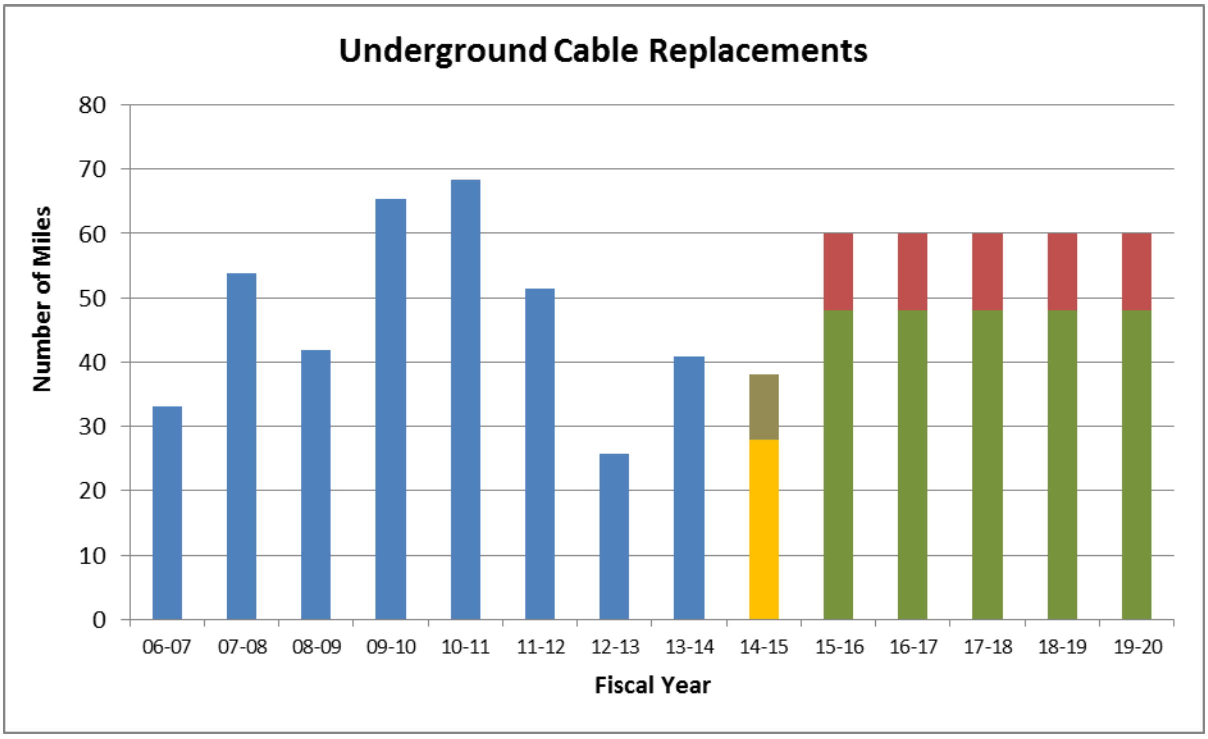
3.2.5.5 Underground Cable (UG) Replacement

LADWP has replaced an average of 48 miles per year of UG cable over the past seven fiscal years. In the same timeframe, UG cable and splice failures have made up, on average, 11.7% of the overall SAIFI and 15.1% of the overall SAIDI results. LADWP employs a Worst-Performing Circuit program to identify UG (and OH) circuits experiencing an abnormal number of outages. Remedial work is then recommended for reliability improvement. While results have varied across all identified circuits, overall improvement is evident.

Figure 26: Example of Failed Underground Splice

In an attempt to maintain an aggressive replacement program, the proposed expenditures are targeting to replace an average of 60 miles of UG cable per year for the next five fiscal years as shown in Figure 27 (Historical and Future Cable Replacements). However, even with the aggressive replacement program, cables will be replaced every 112 years based on LADWP's current replacement cycle, compared to a more ideal level of 75 years. In Figure 27 below, blue is actual historical, yellow is the projected replacement of lead cable for the current fiscal year, olive is the projected replacement of synthetic cable for the current fiscal year, green indicates the forecasted replacement of lead cable and red indicates the forecasted synthetic cable replacement for the five-year rate period.

Figure 27: Underground Cable Replacement - Historical and Projected



3.2.5.6 Distribution Transformer Replacement

There are approximately 128,000 distribution transformers on the LADWP system. Many factors shorten the life of a transformer including corrosion, moisture, heat, loading, and age. From 2009–2012, annual average failure ages were as follows:

- Overhead transformers - 32 years;
- Underground transformers - 25 years; and
- Pad mounted transformers - 29 years.

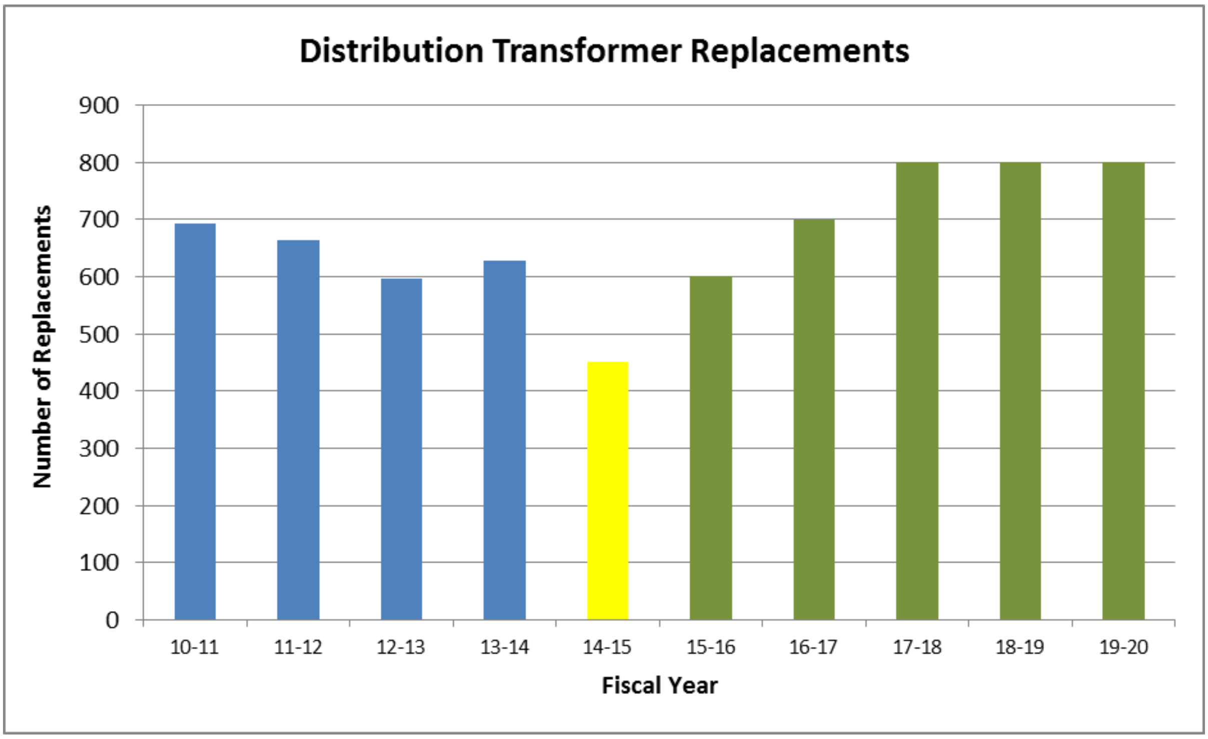
Figure 28 provides an example of an overhead pole mounted distribution transformer.

Figure 28: LADWP Pole Mounted Distribution Transformer

To increase reliability of the overall system, the number of transformer replacements is expected to increase to 800 annually by FY 2017-18 and continue at that level thereafter until FY 2019-20. The tally includes existing units that are replaced due to failure, upgrades due to system growth, and new business installations.

Figure 29 provides the forecasted level of distribution transformer replacements. As seen by the figure, a drop in number of replacements can occur when there is a gap in contract service or reduced funding uncertainty, as experienced in FY 2014-15. The proposed five-year rate action is meant to fund the PSRP in a way that would promote cost savings through predictable longer contract terms and planning.

Figure 29: Distribution Transformer Replacement - Historical and Projected

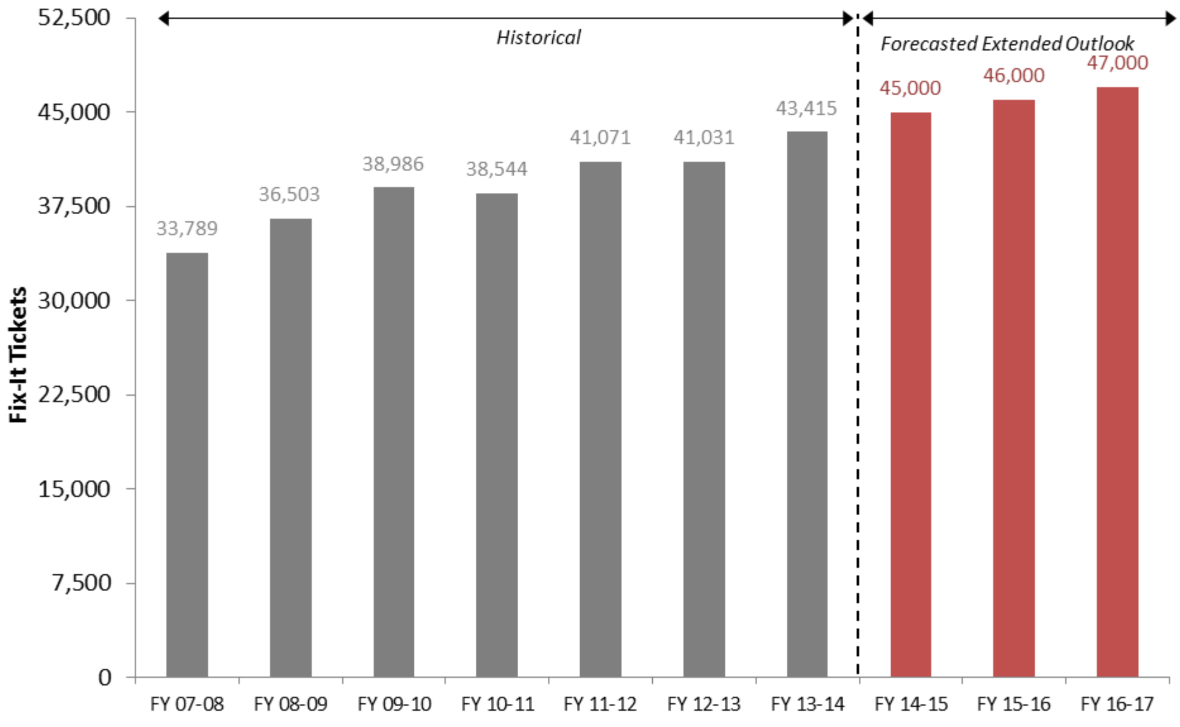


3.2.5.7 Work Backlog

LADWP maintains a list of fix-it tickets, which are distribution system repairs and replacements that were identified through inspections and field work. The size of this backlog has grown in recent years. Reducing the nearly 41,000 repair orders in the queue to a desired level of 2,000 to 5,000 pending work orders every fiscal year would take 3 million work hours to catch up. Due to the magnitude of this situation and to balance work efforts with maintaining reasonable customers' rates, significant resources have not been targeted in this area. Therefore, the repair order backlog is projected to increase to approximately 46,000 tickets in 2017 as shown in Figure 30. However, to begin making progress in this area, LADWP is preparing a plan to field check each ticket to:

- Eliminate duplicates;
- Determine whether the damage or reconfiguration still warrants crew work for corrective action; and
- Determine if the ticket can be deleted since the defect does not present a true risk to reliability.

Figure 30: Fix-It Tickets - Historical and Projected



3.3 POWER SUPPLY TRANSFORMATION

Over the next 15 years, LADWP will need to complete the replacement of over 70% of its existing power supply as well as rebuild and modernize much of its aging power grid infrastructure used to reliably deliver power to its customers. LA's clean energy future – a future with more efficient use of energy, greater reliance on renewable energy, and zero coal – is being built right now through a complete transformation of LADWP's power supply. This effort requires significant capital investments, ongoing operational and maintenance costs, and regular power purchase expenditures,[9] which are all factored into the proposed rates.

The major aspects of the power supply transformation plan include:

- Rebuilding local power plants to preserve oceanic life and comply with regulatory mandates;
- Increasing retail sales from renewable energy to 33% by 2020 as required by State law; and
- Coal transition to make Los Angeles coal free by replacing the 39% of coal-fired power supply that LADWP currently receives each year from the Navajo Generating Station (NGS) in Arizona and the Intermountain Power Plant (IPP) in Utah.

In meeting these objectives, the Department plans to exceed regulatory mandates, deliver economic benefits to the residents of Los Angeles, and exhibit environmental stewardship to proactively decrease GHG emissions. This section will introduce the four key elements of the Department's plan and explain how these cost drivers individually contribute to the proposed rate increase. The expenditures of complying with the legal and regulatory mandates and completing other planned power supply programs are projected to be more than $6.3 billion in capital, O&M, and power purchase expenses over the five-year rate period as shown in Figure 31. The incremental impact of the power supply transformation on the Department's revenue requirement is shown in Figure 32.

Figure 31: Power Supply Transformation Expenditures ($M)

	Cost Type	Current	Proposed Rate Period						*FY 20-21*
		FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Total	
Rebuild Local Power Plants	Capital	286.0	92.2	21.1	138.3	293.4	183.7	728.7	*79.3*
	O&M	-	-	-	-	-	-	-	-
	PPA	-	-	-	-	-	-	-	-
Renewable Portfolio Standards (RPS)	Capital	217.8	322.1	240.8	152.3	125.9	307.5	1,148.6	*428.0*
	O&M	22.3	25.0	37.1	40.6	42.2	44.3	189.1	*45.0*
	PPA	318.1	381.1	473.2	503.6	509.9	524.3	2,392.1	*537.2*

[9] Fuel is a major cost that is associated with LADWP's Power Supply, and is identified as a separate rate driver in Section 3.5.

	Cost Type	Current	Proposed Rate Period						***FY 20-21***
		FY 14-15	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**Total**	
Coal Transition	Capital	357.7	0.0	0.0	0.0	0.0	0.0	0.0	*0.0*
	O&M	40.4	20.3	0.2	0.2	0.2	0.2	21.1	*0.2*
	PPA[10]	190.7	155.8	118.4	118.2	125.0	132.8	650.3	*126.8*
Customer Opportunities Programs	Capital	158.1	214.4	225.2	219.3	214.1	196.6	1,069.6	*359.3*
	O&M	-	-	-	-	-	-	-	-
	PPA	2.2	16.3	35.4	38.2	38.0	37.9	165.9	
Total	**Capital**	**1019.6**	**628.7**	**487.1**	**509.9**	**633.5**	**687.8**	**2,947.0**	***866.6***
	O&M	**62.7**	**45.4**	**37.2**	**40.8**	**42.3**	**44.5**	**210.2**	***45.2***
	PPA	**511.1**	**553.2**	**627.0**	**660.0**	**672.9**	**695.1**	**3,208.3**	***664.1***
Total								**6,365.4**	

Figure 32: Power Supply Transformation Impact on Revenue Requirement and Rates

		Year Over Year Increase						***FY 20-21***
		FY 15-16	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**Average**	
Rebuild Local Power Plants	System Revenue Requirement ($M)	-9	3	14	-1	12	4	*22*
	System Average Cost per kWh (Cents/kWh)	-0.04	0.01	0.06	0.00	0.05	0.02	*0.05*
	Average Annual Percent Increase (%)	-0.25%	0.07%	0.37%	-0.02%	0.28%	0.09%	*0.28%*
Renewable Portfolio Standards (RPS)	System Revenue Requirement ($M)	49	38	40	22	32	36	*61*
	System Average Cost per kWh (Cents/kWh)	0.20	0.16	0.17	0.09	0.14	0.15	*0.26*
	Average Annual Percent Increase (%)	1.38%	1.04%	1.07%	0.55%	0.76%	0.96%	*1.40%*
Coal Transition	System Revenue Requirement ($M)	73	-4	9	4	6	17	*5*

[10] This cost includes the fuel expenditures – coal (Navajo) and natural gas (Apex) during the proposed five-year rate period.

		Year Over Year Increase						FY 20-21
		FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Average	
	System Average Cost per kWh (Cents/kWh)	0.30	-0.02	0.04	0.02	0.02	0.07	*0.02*
	Average Annual Percent Increase (%)	2.05%	-0.12%	0.23%	0.10%	0.13%	0.48%	*1.40%*
Customer Opportunities Programs	System Revenue Requirement ($M)	37	62	104	83	101	78	*105*
	System Average Cost per kWh (Cents/kWh)	0.16	0.26	0.44	0.35	0.43	0.33	*0.44*
	Average Annual Percent Increase (%)	1.05%	1.71%	2.75%	2.08%	2.44%	2.01%	*2.29%*
Total Values	**System Revenue Requirement ($M)**	**150**	**99**	**167**	**109**	**150**	**135**	***192***
	System Average Cost per kWh (Cents/kWh)	**0.63**	**0.42**	**0.71**	**0.46**	**0.64**	**0.57**	***0.34***
	Average Annual Percent Increase (%)	**4.23%**	**2.70%**	**4.43%**	**2.72%**	**3.61%**	**3.54%**	***4.38%***

3.3.1 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.

These four in-basin stations are part of the Department's Reliability Must Run (RMR) generation facilities, which are critical to provide local system reliability. 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.

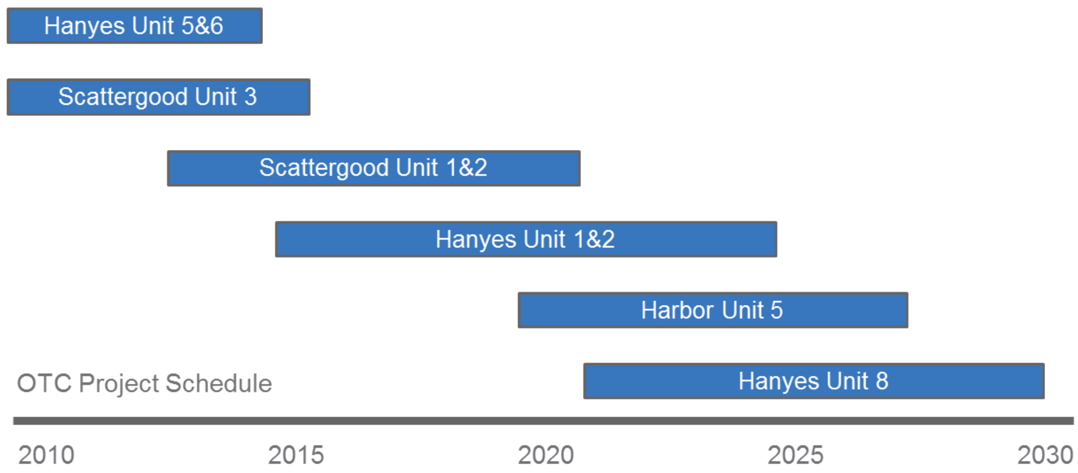
Once-Through Cooling (OTC) is the process where water is drawn from the ocean, is pumped through a generating station's cooling system, and then is discharged back to the receiving water source. OTC is a major regulatory issue, stemming from the Federal Clean Water Act Section 316(b) administered nationally by the Environmental Protection Agency (EPA) and locally by the State Water Resources Control Board (SWRCB). The new

Statewide OTC Policy and EPA rules require cooling towers use either non-ocean water or air for power plant cooling in order to minimize and/or reduce the impacts on marine life. The Policy proposes a two-track compliance pathway.

- Track 1 requires OTC flows to be reduced commensurate with wet closed cycle cooling (CCC) or a 93% flow reduction and effectively requires the installation of cooling towers.
- If Track 1 can be demonstrated as "not feasible," a Track 2 compliance option is available. A Track 2 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.

To prevent disruption in the State's electrical power supply during implementation of the Policy, 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 as shown in Figure 33. The Department's financial plan and proposed rates are developed based on this schedule which has been approved by the SWRCB.

Figure 33: OTC Compliance Time Line[11]



LADWP firmly believes in delivering power to the Los Angeles community in a way that is responsible and preserves our ecosystem. The Department has committed to complete elimination of OTC by 2029, and in the interim must conduct a study or studies, singularly or jointly with other facilities, to evaluate new technologies or improve existing technologies to reduce impact on the marine environment.

The Department will submit the results of the studies and a proposal to minimize marine disturbance to the Chief Deputy Director of the California State Water Resources Control Board no later than December 31, 2015, and, upon approval of the proposal by the Chief

[11] 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. Upgrades at the Harbor facility also include replacement of the aging units 1 and 2 which do not currently use OTC.

Deputy Director, complete implementation of the proposal no later than December 31, 2029. Harbor Units 1, 2, 3, and 4, and Haynes Units 3, 4, 5, and 6 no longer utilize OTC.

Scattergood Unit 3, with engineering and major procurement substantially completed, is currently under construction. Figure 34 shows an aerial view of the Scattergood construction progress and highlights how LADWP is continuing to generate power from existing units while simultaneously constructing the replacement units. A detailed overview of LADWP's OTC projects and their current status can be found in Chapter 2 - Appendix C.

Figure 34: Aerial View of Construction at Scattergood Generating Facility

In the five-year proposed rate period, expenses associated with rebuilding local power plants will be $728.7 million in capital as shown by each generation plant affected in Figure 35.

Figure 35: Rebuilding Local Power Plants - Capital Expenditures ($M)

($M)	Current	Proposed Rate Period						*FY 20-21*
	FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Total	
Haynes Units 1 and 2	0.0	0.0	0.0	2.9	3.9	40.8	47.6	*43.1*
Scattergood	270.6	89.2	19.0	135.4	289.6	142.9	676.2	*36.2*
Castaic[12]	15.0	3.0	2.0	0.0	0.0	0.0	5.0	*0.0*

[12] Castaic is a hydroelectric pump storage plant that is not affected by OTC. However, it is part of the Department's in-basin repowering program, with modernization efforts expected to provide efficiency benefits of up to an extra 80MW.

($M)	Current	Proposed Rate Period						FY 20-21
	FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Total	
Total	**285.6**	**92.2**	**21.1**	**138.3**	**293.4**	**183.7**	**728.7**	***79.3***

Over the five-year proposed rate period, these projects will increase the revenue requirement by an average of $4 million per year and the system average rate by 0.02 cents per kWh (0.09%) as shown in Figure 36.

Figure 36: Rebuilding Local Power Plants Impact on Revenue Requirement and Rates

	Year Over Year Increase						FY 20-21
	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Average	
Total System Revenue Requirement ($M)	-9	3	14	-1	12	4	*22*
Total System Average Cost per kWh (Cents/kWh)	-0.04	0.01	0.06	0.00	0.05	0.02	*0.02*
System Average Annual Percent Increase (%)	-0.25%	0.07%	0.37%	-0.02%	0.28%	0.09%	*0.50%*

3.3.2 Expanding Renewable Energy Supply

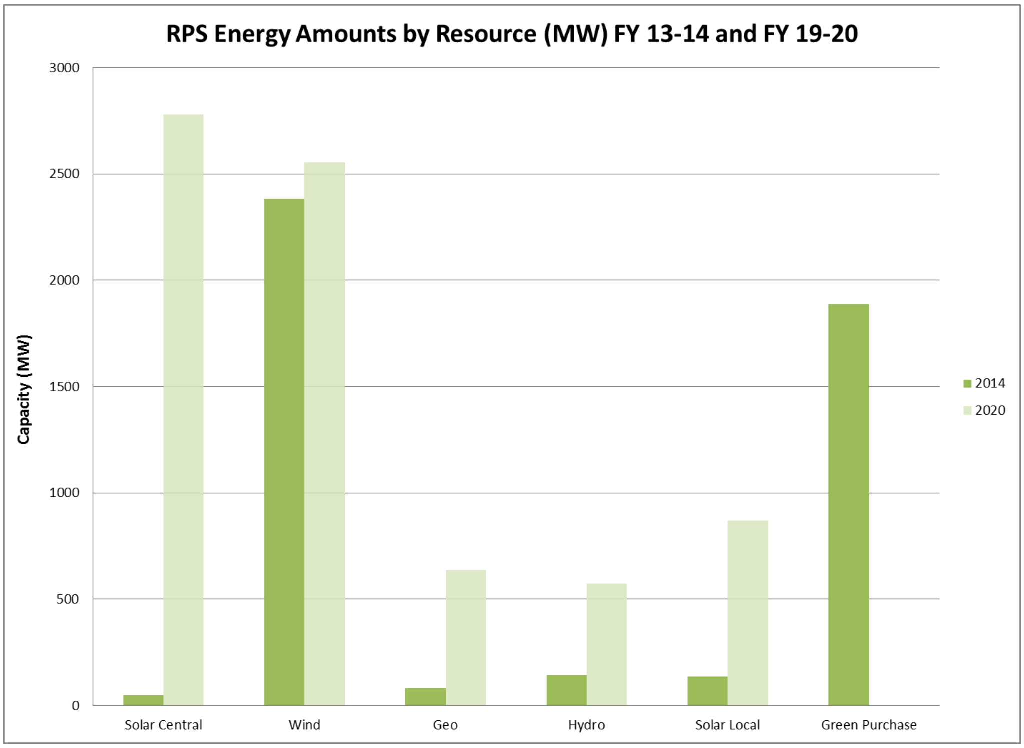
Renewable energy resources are a sustainable way of generating electricity and helping preserve the environment while providing economic and public health benefits. Shifting a greater amount of energy production to eligible renewable energy resources is mandated in California by Senate Bill X1-2. To be compliant with the renewable portfolio standard (RPS) procurement targets, as regulated by the California Energy Commission (CEC), LADWP is required to meet RPS targets of:

- 20% average of its retail sales for the compliance period January 1, 2011 through December 31, 2013 (which has been met);
- 25% of its retail sales by December 31, 2016;
- 27% of its 2017 retail sales;
- 29% of its 2018 retail sales;
- 31% of its 2019 retail sales; and
- 33% of its 2020 retail sales.

The Department's existing secured renewable resources can provide an average annual 4,082GWh of power (15% of total load) through a combination of the Department owned facilities, purchase power agreements (PPA) and fuel purchases. The main components are wind, small hydro[13], solar, biogas, and geothermal resources. By the end of 2015, the Department expects to provide 4,695GWh of power (approximately 20% of load) using renewable energy resources.

The Department's FY 2013-14 renewable energy capacity mix is shown in comparison to the planned FY 2019-20 renewable portfolio below in Figure 37.

Figure 37: FY 2013-14 and Projected FY 2019-20 RPS Energy Mix Comparison



Reaching a 33% RPS procurement target by 2020 is another major power supply investment that influences revenue requirements for the next five fiscal years. The proposed rates will fund the capital and O&M expenses associated with the investments required to meet the targets noted above for the next five fiscal years. The Department will have to make commitments to eligible renewable energy resources during the five-year rate period that will also require additional funding beyond the next five years to meet the targets through 2020. The capital, O&M and PPA expenses associated with the expansion of the Department's currently planned renewable energy portfolio are shown in Figure 38.

Figure 38: Forecasted Costs of Renewable Energy Programs ($M)

RPS Type ($M)	Cost Type	Current	Proposed Rate Period						*FY 20-21*
		FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Total	
Central	Capital	42.2	5.9	16.8	29.9	12.7	12.0	77.3	*12.3*

[13] The CEC's RPS Eligibility Guidebook, 7th ED., implementing SB X1-2 permits the certification of new small hydroelectric generation facilities of 30MW or less, or a small hydroelectric generation unit with a nameplate capacity not exceeding 40MW that is operated as part of a water supply or conveyance system as eligible renewable energy resources.

RPS Type ($M)	Cost Type	Current	Proposed Rate Period						*FY 20-21*
		FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Total	
Solar	O&M	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*0.0*
	PPA	48.4	105.3	184.2	210.0	209.1	208.7	917.3	*207.3*
Central Solar Subtotal		90.6	111.2	200.9	239.9	221.8	220.7	994.6	*994.6*
Wind	Capital	7.7	10.1	14.0	13.4	30.7	23.5	91.6	*138.7*
	O&M	7.9	10.4	22.0	25.6	26.3	27.1	111.5	*27.8*
	PPA	196.8	200.0	200.5	200.9	201.2	201.4	1003.9	*201.3*
Wind Subtotal		212.3	220.5	236.5	239.8	258.2	252.0	1206.9	*367.9*
Geo-thermal	Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*0.0*
	O&M	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*0.0*
	PPA	11.9	19.3	32.6	38.2	43.0	57.6	190.5	*72.1*
Geothermal Subtotal		11.9	19.3	32.6	38.2	43.0	57.6	190.5	*72.1*
Small Hydro	Capital	36.6	25.6	9.9	9.1	18.1	3.0	65.7	*3.1*
	O&M	14.4	14.6	15.0	15.0	15.8	17.2	77.7	*17.2*
	PPA	8.5	12.9	12.0	10.5	12.6	12.5	60.5	*12.5*
Small Hydro Subtotal		59.5	53.2	36.9	34.6	46.5	32.7	203.9	*32.8*
Biogas/ Biomass	Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*0.0*
	O&M	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*0.0*
	PPA	33.4	39.2	39.6	39.6	39.6	39.7	197.7	*39.6*
Biogas/Biomass Subtotal		33.4	39.2	39.6	39.6	39.6	39.7	197.7	*39.6*
Trans-mission	Capital	153.5	280.5	200.2	100.0	64.5	268.9	914.0	*273.8*
	O&M	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*0.0*
	PPA	4.4	4.4	4.4	4.4	4.4	4.4	22.2	*4.4*
Transmission Subtotal		158.0	284.9	204.6	104.4	68.9	273.3	936.2	*278.3*
Generic[14]	Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*0.0*
	O&M	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*0.0*
	PPA	14.7	0.0	0.0	0.0	0.0	0.0	0.0	*0.0*
Generic Subtotal		14.7	0.0	0.0	0.0	0.0	0.0	0.0	*0.0*
Total by	Capital	240.0	322.1	240.8	152.3	125.9	307.5	1,148.6	*428.0*

[14] "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.

RPS Type ($M)	Cost Type	Current	Proposed Rate Period						*FY 20-21*
		FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Total	
Cost Type	O&M	22.3	25.0	37.1	40.6	42.2	44.3	189.1	*45.0*
	PPA	318.1	381.1	473.2	503.6	509.9	524.3	2,392.1	*537.2*
Total		580.4	728.2	751.1	696.5	678.0	876.0	3,729.8	*1,010.3*

The 2014 Integrated Resource Plan (IRP) examines multiple scenarios for expanding renewable resources, with strategic cases of 33%, 40%, and 50% RPS analyzed. In his 2015 inaugural address, Governor Jerry Brown called for an ambitious and unparalleled target of 50% RPS by 2030[15]. The Department continues to project the impacts these requirements would have on other aspects of power supply as well overall LADWP future operations to account for potential future regulatory mandates. Examples of LADWP's existing renewable energy plants are shown in Figure 39.

Figure 39: LADWP's Pine Tree Wind Farm (Left) and Adelanto Solar Plant (Right)

Over the five-year proposed rate period, these projects will increase the revenue requirement by an average $36 million per year and the system average rate by 0.15 cents per kWh (0.96%) as shown in Figure 40.

Figure 40: Expanding Renewable Energy Program Impact on Revenue Requirement and Rates

	Year Over Year Increase						*FY 20-21*
	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Average	
Total System Revenue Requirement ($M)	49	38	40	22	32	36	*61*
Total System Average Cost per kWh (Cents/kWh)	0.20	0.16	0.17	0.09	0.14	0.15	*0.26*

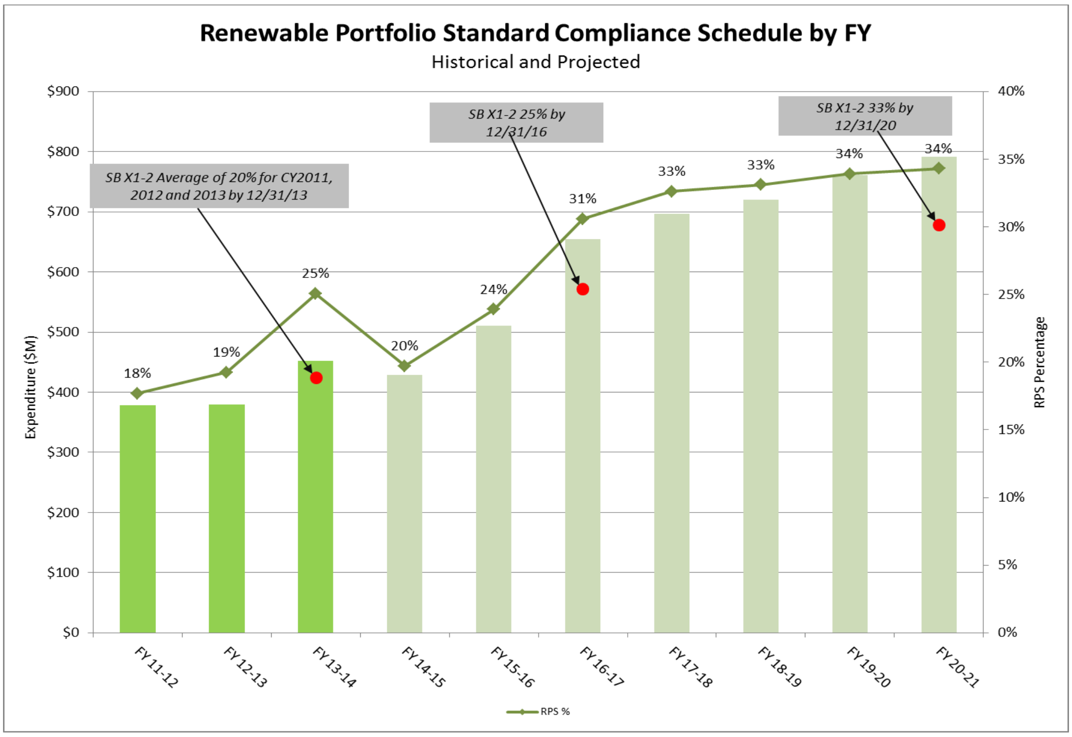
[15] See http://www.latimes.com/local/political/la-me-pc-brown-speech-text-20150105-story.html#page=2

	Year Over Year Increase						FY 20-21
	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Average	
System Average Annual Percent Increase (%)	1.38%	1.04%	1.07%	0.55%	0.76%	0.96%	*1.40%*

In addition to the Department's planned $3.7 billion in direct renewable energy supply capital, O&M, and power purchase expenditures over the next five years, the Department will invest in renewable projects through the Southern California Public Power Authority (SCPPA)[16]. The majority of LADWP's portion of SCPPA's investment will be debt financed; therefore, to meet the RPS procurement targets, the Department must make the investments and start to service the debt before many of the new eligible renewable energy resources are actually producing power for customers and generating revenue.

The rates proposed will allow the Department to meet the 2016 RPS procurement target and maintain a pace of investment to reach the mandated 33% target in 2020 as shown in Figure 41.

Figure 41: Renewable Portfolio Resource Compliance Schedule[17]



[16] For a description of SCPPA and off-balance sheet debt reference Chapter 2, Section 2.7.3.1.

[17] The spike in RPS spending and corresponding RPS mix amounts in FY 2013-14 are attributed to increased "Green Power Purchases" to take advantage of favorable market conditions and ensure compliance with interim and future mandated RPS targets.

This increase in renewable energy will not only ensure the Department complies with regulatory mandates, but also help to preserve the environment by decreasing the amount of greenhouse gas emissions from traditional generation.

3.3.3 Coal Transition Plan

The California Greenhouse Gas Emissions Performance Standard (SB 1368) sets a cap on the level of greenhouse gas emissions from power imported into the State. As coal-fired electricity emits about twice as much CO2 as energy generated with natural gas, early coal replacement options would lower LADWP's GHG emissions levels to comply with SB 1368. The federal government also sets emissions restrictions that LADWP must meet. The Environmental Protection Agency's (EPA) proposed Clean Power Plan is set to be finalized by June 1, 2015, and calls for a 30% cut of GHG emissions from the power sector from 2005 levels[18]. As a result, the Department is required to stop receiving coal power totaling a combined net capacity of approximately 1,677MW from the following two coal-fired generating stations when their current contracts and agreements expire:

- Navajo Generating Station (NGS) in Arizona, with agreement due to expire in 2019; and
- Intermountain Power Plant (IPP) in Utah, with agreement due to expire in 2027.

In June 2015, the Board approved a contract amendment with the Intermountain Power Agency (IPA) that would enable the Department as IPA's operating agent to completely transition out of coal power. In collaboration with participating power utilities, the Department would convert IPP to a smaller natural gas generating station by 2025 at the latest, with efforts to begin that transition by 2020.

In addition, on June 26, 2015, the City of Los Angeles approved a transaction agreement to divest LADWP's 21% interest in the NGS. The NGS and IPP actions are major steps toward the transformation of the Department's power supply to create a cleaner and more sustainable energy future for Los Angeles. Based on the current schedule, LADWP will divest its interest in the NGS by the end of 2016. To account for this lost capacity, in December 2013, the Department, acting through SCPPA, purchased the Apex natural gas combined cycle power plant in Nevada.

Through these actions, the City of Los Angeles will become the first major city in the United States to commit to becoming coal free.

Figure 42 shows the NGS and Apex facilities.

[18] Environmental Protection Agency (EPA), http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule.

Figure 42: The Navajo (Left) and Apex (Right) Generating Facilities

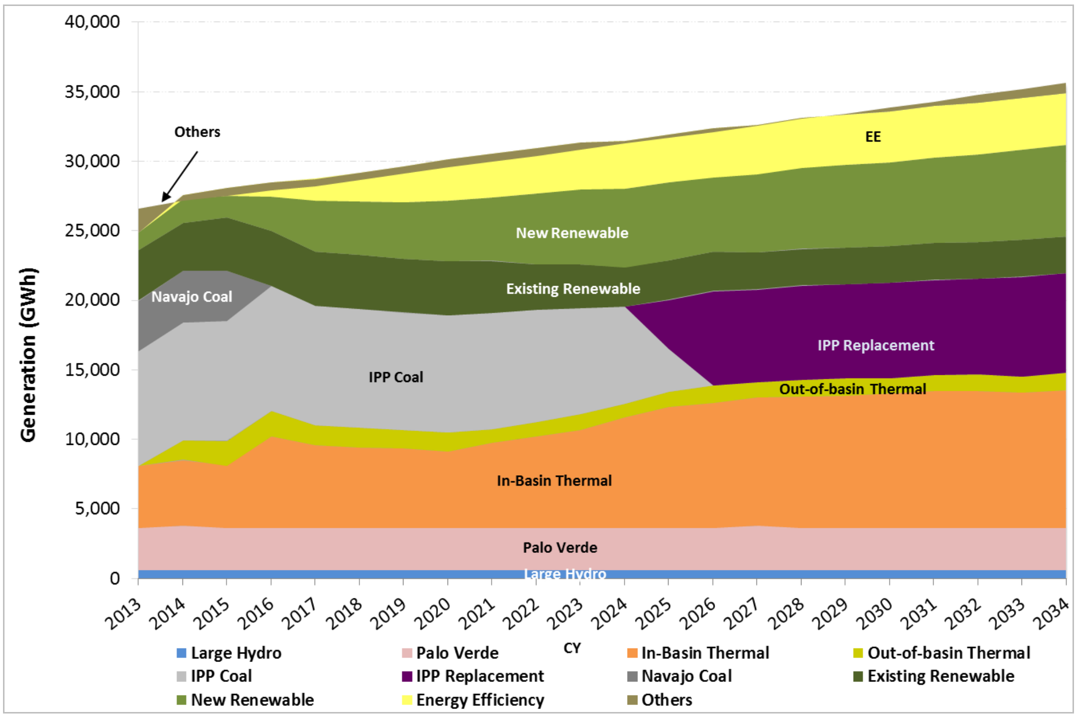
However, this transition poses many challenges and necessitates careful resource planning to maintain a reliable flow of power to Los Angeles. The Department plans to complete this monumental shift out of coal in the most sustainable and cost effective manner through:

- Expanding the use of renewable energy resources;
- Increasing EE to at least 15% by 2020[19]; and
- Using the Apex generation facility, an efficient combined-cycle natural gas plant with a nameplate capacity of 529MW.

The projected plan represents a substantial shift in the Department's power supply capacity, as shown by Figure 43.

[19] EE programs are a part of the Customer Opportunities Programs, which is a rate driver discussed later in this chapter.

Figure 43: 2014 IRP Projected Generation Breakdown[20]



Replacing the NGS results in higher fuel and variable O&M costs, as less expensive coal is substituted with the relatively higher costs of gas-fired energy, EE, and incremental costs of new renewable resources. The Department projects spending approximately $670 million in O&M and fuel associated with the Navajo/Apex generation transition over the five-year rate period, as depicted by Figure 44. The capital cost associated with the purchase of the Apex plant is not included in the below expenditures, as LADWP is able to finance the purchase of Apex with off-balance sheet debt by investing through SCPPA. This arrangement allows the Department to secure favorable interest rates for necessary O&M and capital investments but does contribute to additional debt service costs.

Figure 44: Navajo/Apex Transition Expenditures Required During the Rate Request Period ($M)

	Current	Proposed Rate Period						*FY 20-21*
	FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Total	
Navajo/Apex Transition Expenditures	231.1	176.2	118.6	118.4	125.2	133.0	671.3	*127.0*

Over the five-year proposed rate period, these projects will increase the revenue requirement by an average $17 million per year and the system average rate by 0.07 cents per kWh (0.48%) as shown in Figure 45.

[20] From the 2014 IRP Case Number 3, Navajo 2015, IPP 2025, Adv EE, 33% RPS.

Figure 45: Navajo/Apex Transition Impact on Revenue Requirement and Rates

	Year Over Year Increase						*FY 20-21*
	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Average	
Total System Revenue Requirement ($M)	73	-4	9	4	6	17	*5*
Total System Average Cost per kWh (Cents/kWh)	0.30	-0.02	0.04	0.02	0.02	0.07	*0.00*
System Average Annual Percent Increase (%)	2.05%	-0.12%	0.23%	0.10%	0.13%	0.48%	*0.11%*

Plans and actions to replace coal generation from the IPP and Navajo stations are currently in progress. The Department is planning to stop receiving power from the NGS by the end of 2016, which is three years ahead of the date required by SB 1368. The early divestment of the NGS represents a necessary and cost effective method of reducing GHG emissions. The 2014 Integrated Resource Plan (IRP) calculates that the cost to implement the NGS divestiture in terms of metric tons of GHG removed is $28.9 per metric ton.[21] This represents a reasonable cost as compared to other alternatives to reduce GHG emissions including using EE and integrating more renewables.

3.4 CUSTOMER OPPORTUNITIES PROGRAMS

LADWP offers customer programs that increase ratepayers' choices to reduce and/or control their energy use and in turn lower their electric bill. Across the electric industry, utilities are engaging with their customers through new technologies and offering new services. This section provides an overview of the Department's portfolio of customer opportunities programs:

- Expanding Energy Efficiency: Striving toward a goal of 15% energy reduction through growing the portfolio of Mass Market, Commercial/Industrial/Institutional, and Cross Cutting EE programs;
- Local Customer Solar Programs: Offering incentives for solar installations, customer/developer power purchase contract opportunities, and building new utility owned solar generation.
- Emerging Technology Programs[22] : Driving adoption of Electric Vehicles, implementing a Demand Response plan, and adoption of Smart Grid technology.

LADWP's budget includes $1.07 billion in capital and $166 million in PPAs for the Customer Opportunities Programs in total over the five-year proposed rate period as shown in Figure 46. These programs contribute to the revenue requirement by an average of $78 million

[21] 2014 Power Integrated Resource Plan, Section 4, pg. 171.

[22] These programs are budgeted in the Department's five-year financial plan but are not identified as directly contributing to the overall revenue requirement increase.

annually, resulting in a total system average cost increase of 0.33 cents per kWh (2.01%) per year as shown in Figure 47.

Figure 46: Customer Opportunities Program Expenditures ($M)

($M)	Cost Type	Current Year	Proposed Rate Period						*FY 20-21*
		FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Total	
Energy Efficiency	Capital	101.0	145.1	178.1	194.1	190.4	172.2	879.9	*169.6*
	O&M	-	-	-	-	-	-	-	-
	PPA	-	-	-	-	-	-	-	-
Local Solar	Capital	57.1	69.3	47.1	25.2	23.7	24.5	189.7	*189.7*
	O&M	-	-	-	-	-	-	-	-
	PPA	2.2	16.3	35.4	38.2	38.0	37.9	165.9	*37.7*
Total		**160.3**	**230.7**	**260.6**	**257.5**	**252.1**	**234.6**	**1235.5**	***396.9***

Figure 47: Customer Opportunities Programs Impact on Revenue Requirement and Rates

	Year Over Year Increase						*FY 20-21*
	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Average	
Total System Revenue Requirement ($M)	37	62	104	83	101	78	*105*
Total System Average Cost per kWh (Cents/kWh)	0.16	0.26	0.44	0.35	0.43	0.33	*0.44*
System Average Annual Percent Increase (%)	1.05%	1.71%	2.75%	2.08%	2.44%	2.01%	*2.38%*

3.4.1 Expansion of Energy Efficiency

Energy efficiency (EE) is a cost effective key strategic element in LADWP's resource planning and is one of the most economical resources within LADWP's power supply portfolio. Assembly Bill (AB) 2021 calls on publicly-owned utilities (including LADWP) to "identify all potentially achievable cost effective electricity energy savings and establish annual targets for EE savings and demand reduction for the next ten-year period".

In 2012, the Board adopted a target to get on a path to a 10% energy consumption reduction through EE by 2020 and committed to exploring ways to achieve 15% by 2020. In August of 2014, the Board set additional targets to achieve an energy use reduction through EE of 15% for the ten-year period from FY 2010-11 through FY 2019-20. This goal is both feasible and economically beneficial, as supported by two focal studies:

- *LADWP Territorial Potential Draft Report*[23] *(EE Potential Study*) completed by Nexant in 2014 analyzing the EE potential in the LADWP service territory; and
- *Efficiently Energizing Job Creation in Los Angeles*[24] study by the UCLA Luskin Center estimating the direct, indirect, and induced economic development benefits that LADWP's EE programs could provide.

EE programs have been employed extensively by LADWP for years as a means of reducing customer electricity usage, power supply costs and carbon emissions. Over the five-year period of FY 2009-10 through FY 2013-14, LADWP spent $274 million on EE programs ($54.8 million per year on average) and achieved 794GWh in net energy savings (159GWh per year on average). LADWP's current EE goals and corresponding EE spending levels are significantly higher than in the past, placing LADWP on par with California's investor-owned utilities (IOUs) and other utilities in the nation in aggressively pursuing EE.

This increase in spending and annual savings targets to reach the 15% EE goal by FY 2019-20 places increasing importance and new challenges on LADWP EE operations. These programs will have a transparent planning process and methodology to verify energy savings, be comprehensive to cover all customer classes, end-uses and efficiency opportunities, and be effectively delivered through marketing, community organizations and local workforces. To meet these objectives, LADWP has focused on the following operational parameters in their EE program design and administration:

- Portfolio level EE approach;
- Mass market (residential and small commercial) programs;
- Commercial, industrial, institutional (CII) programs; and
- Cost effectiveness of the overall program.

The Department's current budget and proposed rates include a total of $878.1 million in capital spending for EE programs during the five-year period. By designating these programs as capital expenditures with negligible O&M, the Department is able to decrease the impact on the revenue requirement[25] and rates. As shown in Figure 48, this level of investment is projected to create 2,489GWhs in net energy savings (497.8GWhs per year on average).

[23] Included attached to Chapter 2 - Appendix E – Energy Efficiency Board Letter and Territorial Potential Study.

[24] The UCLA Luskin Center study can be found at: http://innovation.luskin.ucla.edu/sites/default/files/UCLA-LADWP%20EE%20Jobs%20Study_0.pdf.

[25] In the calculation of the revenue requirement, the utility collects a specific portion of its equity through rates, as opposed to operation and maintenance expenses (O&M), which are fully passed down to the revenue requirement.

Figure 48: Total Energy Efficiency Expenses and Usage Savings

	Current	Proposed Rate Period						*FY 20-21*
	FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Total	
Capital Expenditures ($M)	$101.5	$144.8	$177.8	$193.8	$189.8	$171.9	$878.1	*$81*
Incremental Energy Efficiency Savings (GWh)	310.0	442.0	515.0	541.0	520.0	471.0	2,489.0	*240*

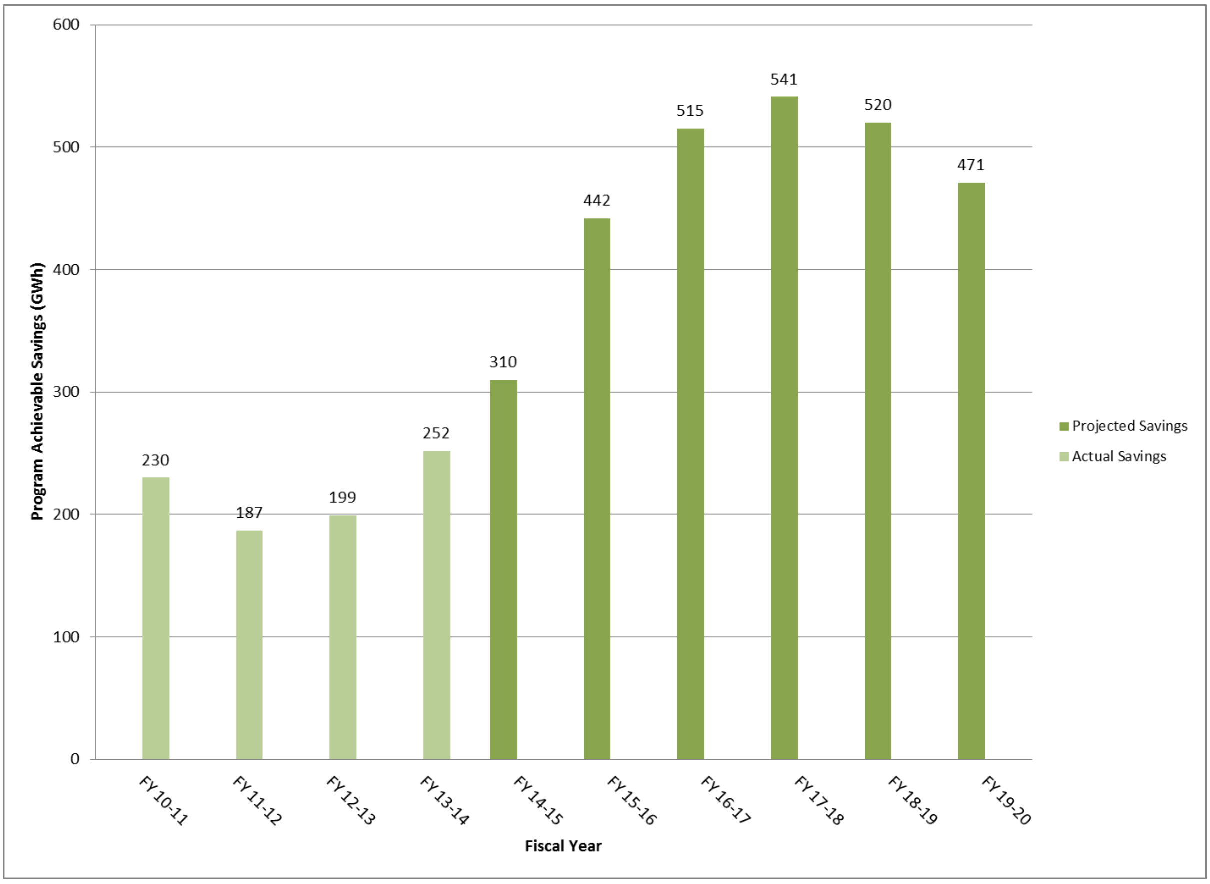
Over the five-year proposed rate period, these energy efficiency projects will increase the revenue requirement by an average $60 million per year and the system average rate by 0.26 cents per kWh (1.54%) as shown in Figure 49.

Figure 49: Energy Efficiency Program Impact on Revenue Requirement and Rates

	Year Over Year Increase						*FY 20-21*
	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Average	
Total System Revenue Requirement ($M)	16	42	80	75	89	60	*94*
Total System Average Cost per kWh (cents/kWh)	0.07	0.18	0.34	0.32	0.38	0.26	*0.06*
System Average Annual Percent Increase (%)	0.44%	1.14%	2.12%	1.87%	2.14%	1.54%	*2.15%*

The actual and projected energy savings are presented below by Figure 50, showing a substantial increase over the proposed five-year rate period. While these targets are aggressive, LADWP expects to achieve them at a levelized cost of $0.042 per kWh averaged across its EE portfolio, which is in line with the EE portfolios of other large utilities in California and is also cost effective as compared to new generation resources.

Figure 50: Historical and Projected Energy Efficiency Savings FY 2010-11 to FY 2019-20



Detailed EE program descriptions and corresponding program level budgets for the five-year rate period are included in Chapter 2 - Appendix D.

3.4.2 Investing in Local Solar Programs

Solar photovoltaic (PV) installations across the United States have increased tremendously in recent years, with 2013 seeing a record capacity of 4.78GW put into service with the State of California accounting for over half.[26] A combination of falling PV equipment prices, creative financing options and regulatory policy has enabled this growth of green power. The Department ensures that its ratepayers can economically participate in this boom by offering eligible customers options for equipment installation or sale of power produced back to LADWP. In addition, LADWP owns and operates multiple solar energy generating facilities. These Local Solar programs consist of:

- Solar Incentive Program (SIP);
- Feed-In Tariff (FiT); and
- Utility Built Solar (UBS).

[26] Greentech Media/Solar Energy Industries Association, "Solar Market Insight Year in Review 2013" http://www.seia.org/research-resources/solar-market-insight-report-2013-year-review

These programs are introduced and discussed in further detail below. Shown in Figure 51 are the total budgeted capital, O&M, and PPA spending for the Local Solar Program. During the proposed rate period the total amount is $355.6 million.

Figure 51: Budgeted Program Expenditures for Local Solar Programs ($M)

	Cost Type	Current	Proposed Rate Period						*FY 20-21*
		FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Total	
Solar Incentive Program (SIP)[27]	Capital	34.9	47.8	26.9	4.4	3.6	3.9	86.5	*3.8*
	O&M	-	-	-	-	-	-	-	-
Feed-In Tariff (FiT)[28]	Capital	-	-	-	-	-	-	-	-
	O&M	-	-	-	-	-	-	-	-
	PPA	2.2	16.3	35.4	38.2	38.0	37.9	165.9	*37.7*
Utility Built Solar (UBS)	Capital	22.2	21.5	20.3	20.8	20.0	20.6	103.2	*21.3*
	O&M	-	-	-	-	-	-	-	-
Total		**59.3**	**85.6**	**82.5**	**63.4**	**61.7**	**62.4**	**355.6**	***62.7***

Providing these programs to customers as well as developing new LADWP owned solar plants will contribute an average annual increase in revenue requirement of $17 million and an average annual increase in the system average rate of 0.07 cents per kWh (0.46%) over the five-year rate period, as shown below in Figure 52.

Figure 52: Local Solar Program Impact on Revenue Requirement and Rates

	Year Over Year Increase						*FY 20-21*
	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Average	
Total System Revenue Requirement ($M)	22	21	24	8	13	17	*10*
Total System Average Cost per kWh (Cents/kWh)	0.09	0.09	0.10	0.04	0.05	0.07	*0.00*
System Average Annual Percent Increase (%)	0.61%	0.57%	0.63%	0.21%	0.30%	0.46%	*0.23%*

3.4.2.1 Solar Incentive Program (SIP)

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. SB-1 established a State-

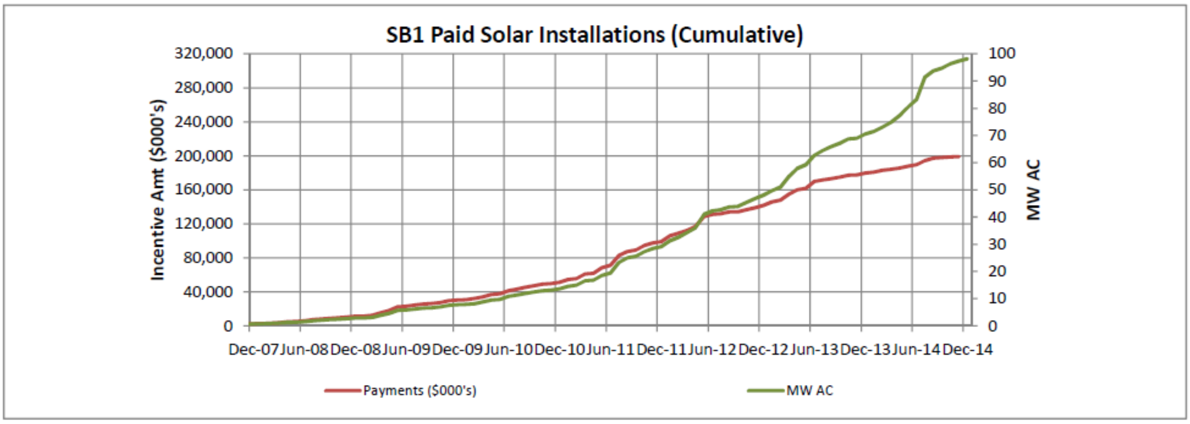
[27] Currently the SIP program is scheduled to close at the end of December 2016. However, to meet its incentive payment obligations the Department has budgeted to make residual payments to customers through the proposed five-year rate period.

[28] The Feed-In Tariff program's operations and maintenance costs are embedded in the customer contract cents/kWh rate for energy under the standard power purchase agreement (PPA) for the FiT.

wide 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. After a slow start, the Solar Incentive Program (SIP) became very popular but required the payment of high incentives to encourage participation due to the Department's low electric rates. Federal tax law credits then facilitated another substantial increase in participation. As a result, the Department's program had to be suspended in April 2011 and recalibrated to lower the incentives to a more sustainable level, thus allowing more customers to participate in the development of renewable energy.

The annual payment budget was doubled to $60 million in FY 2010-11. 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 of the program on September 2011, the program has remained extremely popular. Over $31.7 million in payments were made to customers by LADWP in FY 2013-14. Figure 53 provides the historical results for SIP incentive payments and megawatts (MW) installed.

Figure 53: Solar Incentive Program Historical Payments and MWs Installed



Through the duration of the program, the Department has enabled the installation of roughly 14,000 solar PV systems with a capacity of 118MW. Continuing with this progress, LADWP's goal is to install 280MW by 2016, and 310MW by 2020. In addition to promoting customer owned solar generation, a portion of this capacity is applied to the Department's Renewable Portfolio Standard (RPS) compliance targets.

3.4.2.2 Feed-In Tariff (FiT)

The Feed-In Tariff (FiT) is a program to encourage customers to invest in customer-owned solar facilities; it 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. In addition, since the FiT program encourages local generation projects, it is likely to reduce the use of transmission that would otherwise be required to deliver incremental renewable energy and provide other benefits to the local economy. The Department currently operates two FiT programs.

- FiT100 Program: LADWP offered the first 20MW allocation of solar and other renewable energy during the first quarter of 2013 for the 100MW FiT Program, through which LADWP purchased power from third parties at a fixed price per kWh (starting at $0.17/kWh) under a standard offer power purchase agreement. Since then, two subsequent 20MW allocations have been completed, with the fourth allocation still accepting applications as of February 2015. Figure 54 shows the status of the FiT projects throughout the program period.

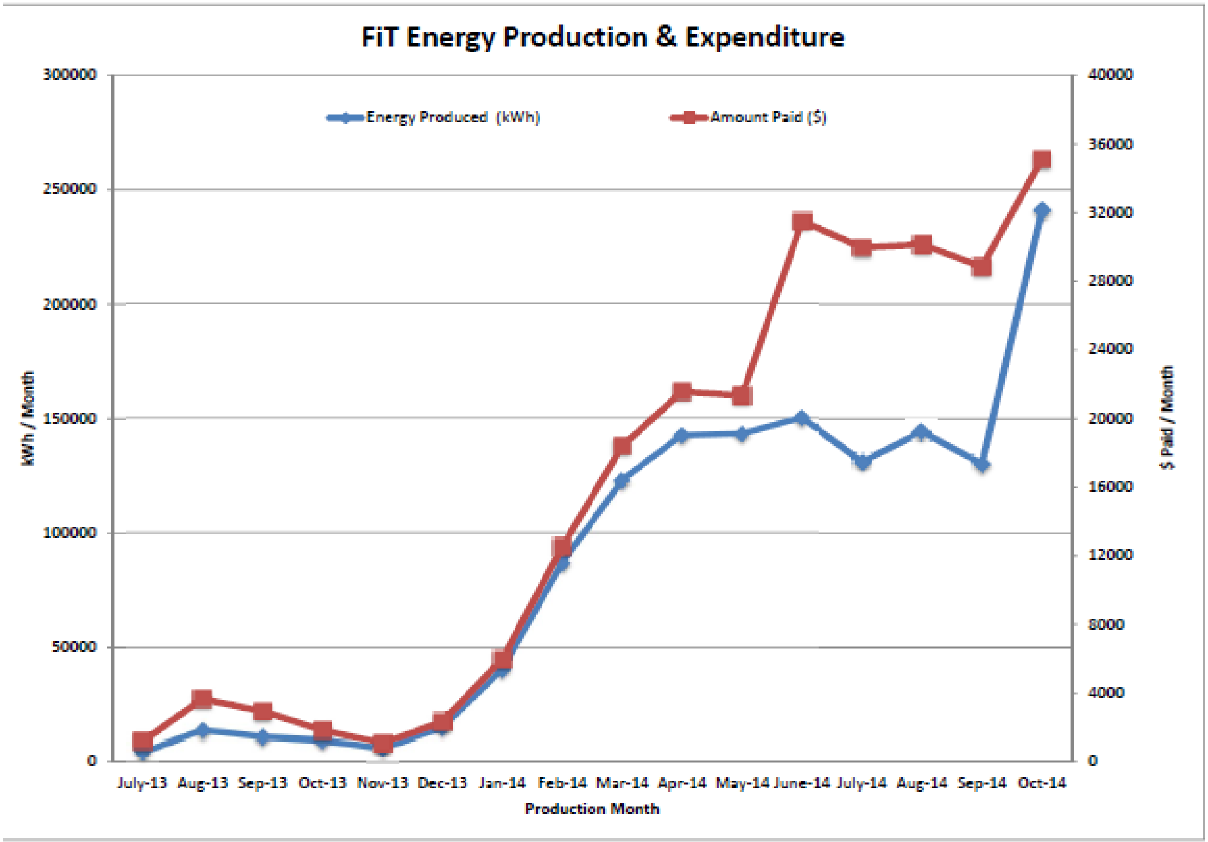
Figure 54: FiT100 Program Allocations

	Offering Date	Offering (MW)	Active (MW)	Waitlist (MW)	Cancelled (MW)	In Service (MW)
Demo Program	5/7/2012	10	1.5	0	5.6	1.6
1st Allocation ($0.17/kWh)	2/1/2013	20	11.9	71.2	28.2	1.6
2nd Allocation ($0.16/kWh)	7/8/2013	20	14.9	32.4	16.5	2.2
3rd Allocation ($0.15/kWh)	8/25/2014	20	14.9	17.9	9.4	0
4th Allocation ($0.14/kWh)	8/25/2014	15	12.5	2.9	0	0
5th Allocation ($0.13/kWh)	Q1 2015	25	-	-	-	-

- FiT50/Beacon Bundled Solar Project: Approved in April 2013, this innovative program bundles 50MW of local FiT solar projects as a requirement for bidding on the large-scale Beacon Solar Project[29], which has a total capacity of 250MW available. This program is aimed at developers interested in building large-scale solar and leveraging their resources to also expand roof top solar projects within the City of Los Angeles.

[29] Beacon Solar is a significant contributor to meeting LADWP's renewable energy goals, providing over 3% toward the State mandates of 25% by 2016 and 33% by 2020. Construction began in July 2014.

Figure 55: FiT Energy Production and Expenditure (January 2015) [30]



3.4.2.3 Utility Built Solar (UBS)[31]

While solar power currently provides approximately only 4% of the Department's RPS mix, the Department plans to increase its reliance on solar power to 49% of the Department's RPS portfolio by the end of FY 2019-20[32]. The Department actively promotes the proliferation of solar power in its service territory, evaluating in-basin local solar projects on LADWP and City of Los Angeles properties. The UBS program looks at potential sites for small scale distributed solar installations to provide sustainable solar power to supplement the Department's large scale generation.

To date, projects totaling approximately 22MW have been put in-service, and a substantial amount of new projects are expected to be put in service by the end of FY 2019-20.

[30] Taken from the LADWP Feed-In Tariff (FiT) Program Dashboard. https://www.ladwp.com/ladwp/faces/ladwp/partners/p-gogreen/p-gg-localrenewableenergyprogram;jsessionid=BCWbJ2lBlrbQTFfSJvGYdxfPG2D3vpTB73fkm8WTs86Jp28505SG!-1496181861?_afrLoop=153355324860904&_afrWindowMode=0&_afrWindowId=null#%40%3F_afrWindowId%3Dnull%26_afrLoop%3D153355324860904%26_afrWindowMode%3D0%26_adf.ctrl-state%3D4dcx6ue8u_4

[31] Although treated as a separate budget item and rate driver from RPS, the installed megawatt capacity from LADWP built solar projects count towards the California mandated 33% RPS target.

[32] Reference Figure 37 in Section 3.3.2.

3.4.3 Emerging Technology Programs

3.4.3.1 Electric Vehicles

The Department is a staunch supporter of the electrification of the transportation sector, believing that this innovation benefits the economy, environment, and public health of the Los Angeles region. Two pioneering programs have been implemented by LADWP to help Electric Vehicle (EV) owners easily install home charging equipment and find reliable public charging stations.

- "Charge Up LA! - Home, Work, and On the Go" Rebate Program: To encourage Angelenos to buy or lease an electric vehicle, LADWP introduced the first two-year Charge Up LA! EV Home Charger Rebate Program in April 2011. The program provided rebates of up to $2,000 to customers for home chargers and installation costs with a $2 million budget and concluded in June 2013.

  In August 2013, LADWP expanded its EV program to implement an additional $2 million "Charge Up LA" rebate program to approved EV customers for large businesses, small businesses, multi-family buildings, and general public use.

- Public Charging Stations: LADWP has worked with customers to upgrade Los Angeles' 350 existing public charging sites located on City of Los Angeles property and at private, publicly accessible locations, and will add new charging locations based on public interest. New EV chargers have also been installed at the LA Convention Center and at LAX. Electrical infrastructure upgrades are also underway to reduce both the frequency and duration of power outages, and to support the increased power demand necessary for EV charging.

LADWP also worked with other City agencies to streamline the process time for permitting and installation of these systems. Figure 56 shows some of the infrastructure installed.

Figure 56: LADWP Fleet and Public Charging Stations Installed Across Los Angeles

3.4.3.2 Demand Response (DR)

Demand Response (DR) programs provide incentives to customers for reducing their electric use (load) when requested by LADWP during periods of high demand or power system emergencies. DR is a cost effective method of protecting grid reliability and deferring the need for additional generation to be built to meet demand.

LADWP has included DR as part of its strategic planning process, with the 2014 Integrated Resource Plan (IRP) incorporating DR into the long range planned capacity mix. The Department has begun implementing a new DR Plan that has the goal of achieving 506MW of load shifting and interruptible load by 2026.

3.4.3.3 Smart Grid Deployment

"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 demand side management (DSM)/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 of 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 nine Smart Grid initiatives.

1. Renewable Integration to support the adoption and utilization of renewable resources.
2. Transmission Automation to better monitor the transmission system to predict instability and take corrective actions before they escalate into major problems.
3. Substation Automation to enable remote monitoring and control of substation feeder lines.
4. Distribution Automation to optimize operational efficiency.
5. Advanced Metering Infrastructure which will enable a number of demand-side capabilities.
6. Demand Response is a tool that will provide reduction of peak loads at critical times to relieve system stress during periods of overload.
7. Advanced Telecommunications will enable real-time control and observation of deployed automation equipment.
8. System and Data Integration will optimize the communications and integration of separate systems and sub-networks.
9. Cyber Security to protect the Smart Grid from physical and cyber-attacks.

These initiatives will also help improve customer service.

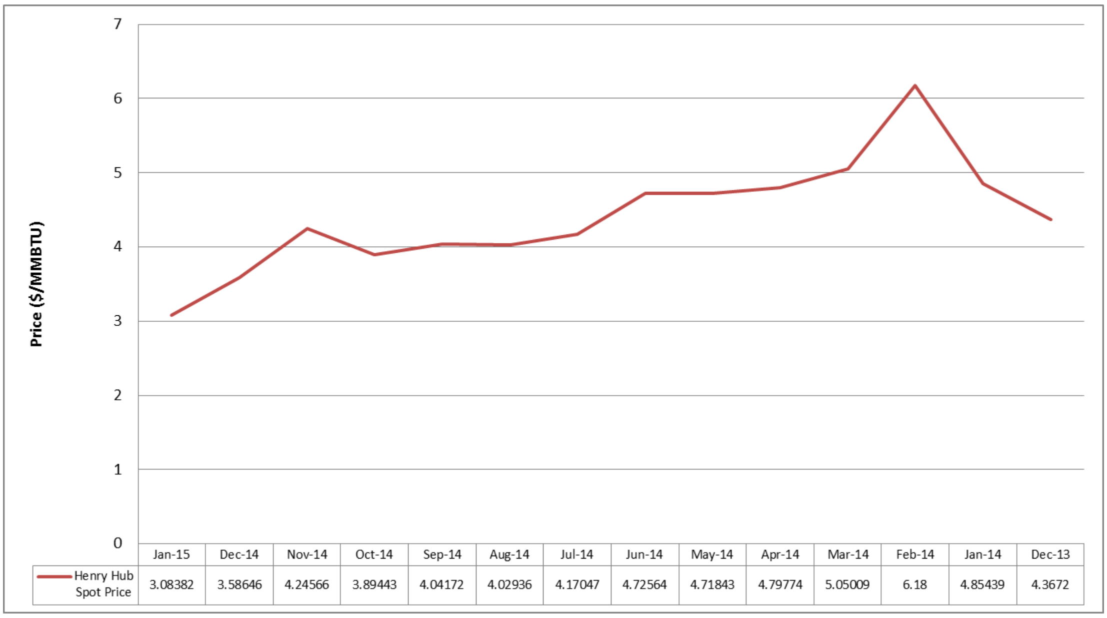
Through a US Department of Energy (DOE) grant in 2009, the Department is also leading a group of local research institutions in a regional demonstration program. The program includes pilot projects in four interrelated areas – Demand Response, Consumer Behavior, Cyber Security and Electric Vehicle Integration.

3.5 FUEL FOR TRADITIONAL GENERATION MIX

The Department must purchase and account for significant volumes of fuel and related fuel costs (as well as its exposure to fuel price volatility) in its budgets and recover the costs in its rates. Fuel in this context includes all costs associated with natural gas, coal, and nuclear fuel procurement; it also includes emissions, greenhouse gas reduction, and asset retirement costs.

Fuel costs are driven primarily by free market forces and can fluctuate significantly year to year, and within a year. In 2014, fuel costs were subject to demand variability in the face of domestic weather events. As a result, the average Henry Hub spot price of natural gas fluctuated between a low of $3.08/MMBTU and a high of $6.18/MMBTU as shown in Figure 57, with the Henry Hub prices representing wholesale and residential retail rates.

Figure 57: Natural Gas Price Index - 2014



This sort of volatility has a major effect on the customer rates, which is passed through by the Variable Energy Adjustment (VEA) factor. The Department proactively mitigates the risk of price volatility through financial hedging programs, owned gas fields, and long-term fixed price gas and power 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 area 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.

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 fixing the price of natural gas at a fixed delivery price. 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 by the Power System's Fuels Management unit. Financial hedging is performed by the Financial Services Organization's (FSO's) Financial Planning unit. The Finance and Risk Control unit serves as the risk controller, assuring that physical and financial gas procurements are made in compliance with Los Angeles ordinances and Department policies. A working group coordinates the activities between the Power System and the FSO. This group provides input to the Energy Services Executive Risk Policy Committee, which makes recommendations to the General Manager.

The Department manages gas price volatility using a variety of tactics including, but not limited to the following approaches:

- Term contracts for physical gas delivery at fixed prices - 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 – the Department strives to reduce the volatility in the price of natural gas used in the production of electricity to serve retail customers; and
- Fleet diversity - 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 and purchased power adjustment factor, the VEA, in the LADWP rate structure, which is separate from the base rate structure. LADWP's proposed rate structure is discussed in Section 3.6 of this chapter and Chapter 5 of this report. All fuel costs, including natural gas and coal prices, have been developed based on the most recent independent market forecasts, current hedging position, and mix of current and planned facilities.

As shown in Figure 58, the Department anticipates fuel costs to decrease during the proposed rate period with costs totaling $1,653.6 million over the five years. Decreases in fuel expenditures are balanced by larger increases in expected purchased power agreement (PPA) expenditures as shown in Figure 59.

Figure 58: Annual Fuel Expenditures ($M)[33]

	Current	Proposed Rate Period						*FY 20-21*
	FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Total	
Biomethane	$33.2	$39.2	$39.6	$39.6	$39.6	$39.7	$197.7	*$39.6*
Natural Gas	$162.9	$186.5	$200.1	$203.3	$213.6	$218.0	$1,021.6	*$228.0*
Gas MTM	$18.9	$17.1	$11.8	$6.4	$0	$0	$35.3	*$0*
Transportation	$45.1	$49.0	$50.1	$49.9	$50.3	$50.1	$249.5	*$50.5*
Coal	$75.6	$40.3	$0	$0	$0	$0	$40.2	*$0*
Nuclear	$19.9	$20.8	$21.1	$21.7	$22.4	$23.2	$109.4	*$23.6*
Total	**$355.7**	**$352.8**	**$322.7**	**$321.0**	**$325.9**	**$331.0**	**$1,653.6**	***$341.8***

Figure 59: Annual Purchased Power Expenditures ($M)[34]

	Current	Proposed Rate Period						*FY 20-21*
	FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Total	
Total Renewables	$287.2	$358.2	$469.0	$502.2	$508.3	$522.5	$2,360.3	*$535.3*
Total Non-Renewables	$794.1	$830.5	$741.0	$807.1	$809.8	$830.4	$4,018.9	*$828.4*
Total	**$1,081.3**	**$1,188.7**	**$1,210.0**	**$1,309.2**	**$1,318.3**	**$1,352.9**	**$6,379.3**	***$1,363.7***

These projected expenditures result in an increase to the annual average revenue requirement of $18 million, leading to an increase in total system average cost of 0.08 cents per kWh (0.46%), as shown in Figure 60.

Figure 60: Fuel for Traditional Generation Impact on Revenue Requirement and Rates

	Year Over Year Increase						*FY 20-21*
	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Average	
Total System Revenue Requirement ($M)	1	10	19	41	20	18	*6*
Total System Average Cost per kWh (Cents/kWh)	0.01	0.04	0.08	0.17	0.09	0.08	*0.02*
System Average Annual Percent Increase (%)	0.04%	0.28%	0.50%	1.01%	0.49%	0.46%	*0.13%*

[33] Excludes fuel related to purchase power agreements.

[34] Excludes direct fuel expenditures.

3.5.1 Natural Gas Hedging[35]

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 program is authorized through sections 10.1.1, 10.5.3 and 23.135 of the Los Angeles Administrative Code, as well as governed by various internal LADWP policies and internal controls. Prior to 2009, LADWP was active in its natural gas hedging program and had hedged up to 50% of its budgeted volume requirements using the dollar cost averaging method for up to ten years forward. However, no new physical or financial hedges were entered into from 2009-2013 due to several factors including, but not limited to:

- A result of the FY 2012-13 rate action that included a charge that allowed pass-through (without caps) of all fuel costs;
- Expected increased production volume from the Natural Gas Reserves in Pinedale, Wyoming; and
- Anticipation of long-term fixed-price Biogas contracts as part of its Renewable Portfolio Standard (RPS) program.

However, since natural gas prices remain the largest driver of unplanned rate volatility, the Department recognized that a properly structured hedging program was in the best interest of customers and reactivated the program in 2014.

The main objective of LADWP's hedging program at this time is to reduce the volatility in the price of natural gas used in the production of electricity to serve retail customers. The Department's hedging program is not necessarily designed to reduce the cost of fuel. LADWP's financial plan includes an average of $200 million annually for natural gas O&M costs over the five-year rate plan, based on the projected price and usage outlook, but the amount could be substantially more if prices increase. As discussed in Section 3.6 below and Chapter 5, the VEA component of the Department's rate structure allows fuel and purchased power costs to be flowed through to customers with quarterly rate adjustments up or down to reflect actual prices. However, the Department recognizes that customers appreciate a degree of certainty as to what prices will be, so LADWP uses the hedging program to minimize unplanned rate changes due to fuel cost fluctuations.

A program-wide audit done by LADWP's consultant in 2013 recommended a hedging framework that provides an integrated approach for developing and evaluating hedging strategies that satisfies LADWP's stated goal of reducing potential rate volatility. The Department uses a combination of physical and financial hedging gas contracts for approximately 50% of the required volume over ten-year periods. The four basic types of positions are:

- Gas Reserves;
- Physical Hedges;
- Financial Hedges; and

[35] A detailed discussion on fuel costs and natural gas hedging is also included in Chapter 2, Section 2.3.8.4.

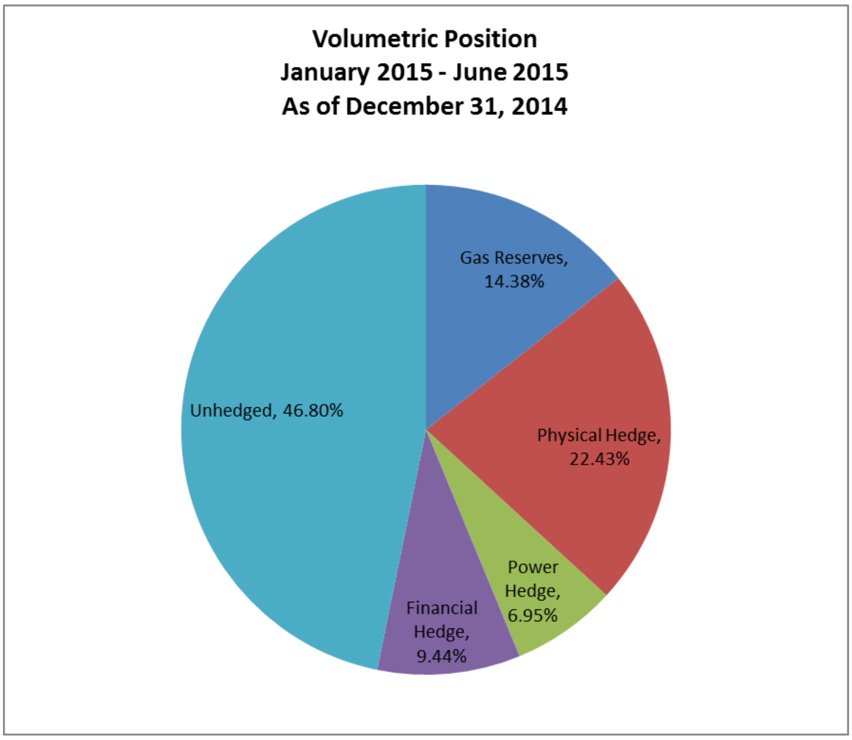
- Power Purchase Hedges.

For financial hedging, the Department utilizes the following standard contracts:

- Variable to fixed price swaps (fixed price forward contracts); and
- Price collars (limits prices within a predetermined range).

As of December 31, 2014, the Department has volumetric positions for January to June 2015 as shown in Figure 61.

Figure 61: Volumetric Positions as of December 31, 2014



The current hedges in place for the Department are shown in Figure 62.

Figure 62: Current Hedges - Natural Gas Volumetric Position in MMBtus (January to June 2015)

Delivery Period	Total Volume Budgeted	Total Volume Hedged	Gas Reserves	Physical Hedge	Power Hedge	Financial Hedge
Jan. 2015 (MMBtu)	4,352,667	2,550,281	684,701	1,085,000	331,080	449,500
Feb. 2015 (MMBtu)	4,120,856	2,303,480	618,440	980,000	299,040	406,000
Mar. 2015 (MMBtu)	5,211,158	2,550,281	684,701	1,085,000	331,080	449.500
Apr. 2015 (MMBtu)	6,333,866	2,468,014	662,614	1,050,000	320,400	435,000
May 2015 (MMBtu)	3,748,108	2,550,281	684,701	1,085,000	331,080	449,500
Jun. 2015 (MMBtu)	4,063,773	2,368,014	662,614	950,000	320,400	435,000
Total (MMBtu)	27,803,428	14,790,353	3,997,773	6,235,000	1,933,080	2,624,500
% of Budget		**53.20%**	**14.38%**	**22.43%**	**6.95%**	**9.44%**

For the duration of the proposed rate period, the Department anticipates approximately 50% of its gas positions will be hedged.

To enhance transparency and effectiveness of the hedging program, the Department began publishing the Risk Control reports to the Board. These reports show the Department's anticipated fuel requirements over ten years and what portions of the requirements are hedged and through what manner and indicate whether the Department is in compliance with the various ordinance and internal requirements governing the hedging program.

3.6 REQUIRED RATE CHANGES VERSUS PASS THROUGH FACTORS

The Department's rate structure is designed to ensure cost recovery of fixed and variable costs. Proposed changes to the rate structure and rates are discussed in Chapter 5 of this report. Existing components of the overall structure are proposed to remain essentially the same and will continue to include the following:

- Variable Energy Adjustment (VEA),
- Variable Renewable Portfolio Standard Energy Adjustment (VRPSEA)
- Capped Renewable Portfolio Standard Energy Adjustment (CRPSEA); and
- Base rates.

In addition, the Department proposes to make the Base Rate Revenue Target Adjustment (BRRTA), which was in place to address FY 2012-13 and FY 2013-14, permanent and introduce an Incremental Reliability Cost Adjustment (IRCA) factor.

This rate structure provides significant transparency to the cost recovery for most LADWP Power System programs as the amounts of the adjustment factors are tied to specific auditable costs. Customers pay for only the amount of cost actually incurred by LADWP. An detailed description of the major cost components that are recovered through these rate elements is provided in Chapter 5.

3.7 IMPACT ON INCREMENTAL VERSUS BASE RATES

In its report on the last Power System rate action, the Ratepayer Advocate (RPA) proposed that LADWP reevaluate and consider replacing the surcharge-based restructuring approach with fully restructured permanent rates. The City Council made the same recommendation when it approved the 2012 rate action. Consequently, LADWP has evaluated the current approach to the ordinance structure.

While there may be a desire to undertake a modification of the current rate structure to provide a simpler rate framework, several lawsuits have recently been filed asserting that Proposition 26 does not permit LADWP's annual transfer of monies, financial conditions allowing, from the Power Revenue Fund ultimately to the City's General Fund. The City disputes the merits of those lawsuits. While the transfer is being contested, the City will continue to adopt an electrical rate structure that preserves the rates in effect on November 3, 2010, and layers incremental charges on top of them. Therefore, for purposes of the current rate action, LADWP proposes that the results of the cost of service studies and the impact of the new revenue requirements for power service be applied to only the Incremental Electric Rate Ordinance.

3.8 ASSUMPTIONS AND RISKS ASSOCIATED WITH THE PROPOSED RATE PLAN

For the proposed rate action, LADWP has based future financial plans on certain assumptions. However, there is always the possibility that these assumptions may change due to unforeseen and/or external events that cannot be predicted at this time. Figure 63 provides a summary of assumptions and identified risks.

Figure 63: High Level Assumptions and Risks of Proposed Plan

Assumption	Description	Risk/Implication
Energy Efficiency	The Board has agreed on a goal of 15% energy reduction by 2020.	If load growth is greater than the projections of the financial plan, the overall generation supply could be altered. This could have a ripple effect through the RPS, fuel demand, and price of electricity; however the risk is mitigated by pass through factors in the rate structure, which can adjust quarterly to changing conditions.
Regulatory Mandates	Assumes consistent regulatory obligations for the Department.	Regulatory mandates direct a significant portion of Department expenditures. Volatile political environments or changing mandates could force the Department to spend even more to meet legal obligations. Most obligations the Department faces mandate significant structural changes and a timeline of compliance of several years, so compliance for significant mandate changes will likely extend beyond the rate action time period.
Financial Market Conditions	Assumes current market conditions with low steady inflation, returns on investment and bond rating.	If market conditions change, LADWP's decoupled rate structure[36] will likely ensure adequate cost recovery and eliminate over collection if market conditions become even more favorable.
Adoption of Customer Programs	Assumes projected adoption of customer programs, such as local solar and EE programs.	Customer programs such as local solar and EE are significant rate drivers. If adoption of these programs is diminished over the rate period, it could affect total program spending and the revenue requirement. This effect would largely be balanced through higher electric supply prices and overall load growth.

As discussed in Section 3.9, in order to understand the impact of these assumptions and implications of changes, LADWP has worked with the Ratepayer Advocate to conduct a sensitivity analysis to measure the impact of these (and other) assumptions on rates.

[36] LADWP's proposed approach to decoupling is discussed in Chapter 5.

3.9 ANALYSIS OF ALTERNATIVES – WHY THE PROPOSED RATE PLAN IS OPTIMAL

The Department has evaluated many different strategic cases to ensure the proposed financial plan and rates provide the optimal solution for customers. LADWP has developed a series of sensitivity analyses while working with the Ratepayer Advocate. These sensitivity analysis scenarios and their outcomes are shown in Figure 64.

Figure 64: LADWP Financial Planning Stress Test Scenario Results

		Five-Year Average Rate Impact (%)	Other Implications
Case No. 19 (Base Case) Final FY 2015-16 Budget		**4.68**	
Case No.	Brief Description		
20	No rate increase for one year with cuts*	4.77	• Major operational impacts and potential for required layoffs. • Additional borrowing of $98M in FY 16-17 to maintain financial metrics.
28	No rate increase for one year without cuts	5.41	• Net income is negative $95M in FY 15-16. • High possibility of downgrade and higher interest costs for bonds issued.
29	No rate increase for five years without cuts*	1.59	• Deterioration of financial metrics, likely bond rating downgrade. • Additional average borrowing of $214M per year to maintain minimum operating cash.
30	No rate increase for five years with cuts*	1.58	• Major operational impacts and potential for required layoffs. • Likely bond rating downgrade.
31	One-notch downgrade in current market condition	5.01	• Revenue increase necessary to meet financial metric targets. • Increased average interest expense of $30M annually over five-year period.
32	One-notch downgrade in high interest rate market condition	5.14	• Revenue increase necessary to meet financial metric targets. • Increased average interest expense of $46M annually over five-year period.
33	Rocky Gas to $7 for five years starting FY 2015-16	5.08	• Increase in fuel and PPA costs of $658M or $132M annually over five-year period.
34	Palo Verde out for two years starting FY 2015-16	4.69	• Increase in fuel and PPA costs by $144M in FY 15-16 and FY 16-17.
35	Rocky Gas to $7 for five years, Palo Verde out for two years starting FY 2015-16	5.01	• Increase in fuel and PPA costs of $913M or $183M annually over five-year period. • Increased average interest expense of $5M

		Five-Year Average Rate Impact (%)	Other Implications
			annually over five-year period.
36	Rocky Gas to $3 for five years starting FY 2015-16	4.58	• Decrease in average annual fuel and PPA costs of $40M over five-year period.
37	Final FY 2015-16 Budget solved using WACC method	6.19	• Stronger financial metrics (well above Board targets). • Decrease in borrowing by $38M annually over five-year period.
41	Cut to 75% of CapEx for five years; cuts distributed to non-mandates; without IRCA pass-through	4.12	• Major impacts on planned capital programs, including meeting infrastructure goals. • Potential for increased service interruptions.
42	Cut to 75% of CapEx for five years; cuts distributed to non-mandates; with IRCA pass-through	4.11	• Major impacts on planned capital programs, including meeting infrastructure goals. • Potential for increased service interruptions and system failures.
43	Cut to 80% of CapEx for five years; cuts distributed to non-mandates; without IRCA pass-through	4.25	• Major impacts on planned capital programs, including meeting infrastructure goals. • Potential for increased service interruptions and system failures.
44	Cut to 80% of CapEx for five years; cuts distributed to non-mandates; with IRCA pass-through	4.25	• Major impacts on planned capital programs, including meeting infrastructure goals. • Potential for increased service interruptions and system failures.
45	Cut to 85% of CapEx for five years; cuts distributed to non-mandates; without IRCA pass-through	4.38	• Major impacts on planned capital programs, including meeting infrastructure goals. • Potential for increased service interruptions and system failures.
46	Cut to 85% of CapEx for five years; cuts distributed to non-mandates; with IRCA pass-through	4.37	• Major impacts on planned capital programs, including meeting infrastructure goals. • Potential for increased service interruptions and system failures.
47	Increase to 105% of CapEx for five years; increase distributed to non-mandates; without IRCA pass-through	5.18	• Additional average borrowing of $62M per year over five-year period. • Increased average interest expense of $16M annually over five-year period.
48	Increase to 105% of CapEx for five years; increase distributed to non-mandates; with IRCA pass-through	5.18	• Additional average borrowing of $62M per year over five-year period. • Increased average interest expense of $6M annually over five-year period.
49	Increase to 110% of CapEx for five years; increase distributed to non-mandates; without IRCA pass-through	5.87	• Additional average borrowing of $114M per year over five-year period. • Increased average interest expense of $16M annually over five-year period.
50	Increase to 110% of CapEx for five	5.87	• Additional average borrowing of $114M per

		Five-Year Average Rate Impact (%)	Other Implications
	years; increase distributed to non-mandates; with IRCA pass-through		year over five-year period. • Increased average interest expense of $14M annually over five-year period.
51	Maintain Gross Sales Volume at FY 2014-15 level for five years	6.00	• Current economic indicators suggest this is an unlikely scenario.
52	Reduce Gross Sales Volume from FY 2014-15 level by 0.5% each year for five years	6.42	• Current economic indicators suggest this is an unlikely scenario.
53	Cut Labor to FY 2012-13 level ($726M) for five years	4.27	• Unlikely scenario due to recent increases in headcount. • May cause major operational impacts and require layoffs.
54	Cut Healthcare to FY 2012-13 level ($125M) for five years	4.34	• Not viable until next MOU in 2017. • Unlikely scenario based on current healthcare industry trends.
55	Cut Pension cost to FY 2012-13 level ($299M) for five years	4.90	• Not viable until next MOU in 2017.
58	Cut PSRP to 75% of budget for five years	4.55	• RCA under-collection will decrease a total of $6M over five-year period.
59	Cut PSRP to 80% of budget for five years	4.59	• RCA under-collection will decrease a total of $6M over five-year period.
60	Cut PSRP to 85% of budget for five years	4.62	• RCA under-collection will decrease a total of $3M over five-year period.
61	Cut PSRP to 105% of budget for five years	4.78	• RCA under-collection will increase a total of $5M over five-year period.
62	Cut PSRP to 110% of budget for five years	4.97	• RCA under-collection will increase a total of $29M over five-year period.

*These scenarios have corresponding O&M, Capital, City Transfer and other impacts that are critical to the scenario evaluation. This detail is included in Chapter 3 - Appendix B.

Completion of these scenarios has provided valuable information to assess alternatives to the Department's proposed financial plan. However, as illustrated by the outcomes above and detailed further in Chapter 3 - Appendix B, none of the alternatives appear to produce a better outcome for customers without significant additional risks for customers, LADWP and its bond investors.

3.10 BEYOND THE FIVE-YEAR RATE ACTION PERIOD

According to the current financial plan, a system average rate increase of 4.68% would be expected over the proposed five-year rate period to cover the revenue requirements that support the programs discussed in this report. This proposed rate increase is intended to ensure the LADWP has sufficient revenue to not only sustain the five-year period, but also make the necessary capital investments to provide reliable and cost effective power to its ratepayers in the future. The Department will continue to assess rate and revenue requirements associated with both externally mandated costs as well as required levels of future rates. Costs beyond the five-year rate plan are still subject to uncertainty but are anticipated to require future adjustments in rates.

Every year, the Department engages in an integrated resource planning effort to enable a long-term view of Department objectives, goals and funding requirements to ensure continued service reliability, compliance with regulatory requirements and availability of programs to help customers manage energy usage and adopt the latest technologies. The 2014 Integrated Resource Plan (IRP) has forecasted modest load grow, with savings in the form of aggressive EE programs. Future rates beyond the next five years will need to take into account the condition of the Department over the long-term. Given the rapidly changing regulatory environment, the Department anticipates changes to regulatory requirements and associated programs, as the State and City seek to accelerate clean energy plans. While the proposed financial plan and rate structure is designed to mitigate current known costs and risks, the power utility industry is changing rapidly, making it difficult to accurately predict long-term requirements in a comprehensive manner. Therefore, the Department will continue to explore further ways to reduce costs, encourage energy conservation, simplify rate structures, and minimize impact on rates.

LOS ANGELES DEPARTMENT OF WATER AND POWER

2014 Power Service Cost of Service Study

July 2015

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1 EXECUTIVE SUMMARY

1.1 Introduction

In October 2012, the Los Angeles City Council approved LADWP's Incremental Electric Rate Ordinance No. 182273 to provide incremental rate adjustments for fiscal years (FYs) 2012-13 and 2013-14. In its action to approve LADWP's power rates, the Council requested that LADWP "conduct a new formal cost of service study in order to prepare for future power rate restructuring".

To meet the Council request and in preparation for its proposed rate action, LADWP has conducted a cost of service study (COSS) using marginal cost principles to evaluate cost structures and ensure that rates are appropriate for each customer class. Cost of service analysis (COSA) constitutes standard utility industry practice for setting power rates. Most utilities, whether Investor Owned Utilities (IOUs) or publicly owned utilities (POUs), conduct cost of service studies when undertaking a rate action. The marginal cost study approach facilitates attaining the following objectives:

- Ensures that rates for each major class of customers recover the costs associated with providing service to that class of customers;
- Encourages efficient system expansion and use of utility facilities and discourages wasteful use;
- Provides efficient price and resource allocation signals; and
- Provides legally defensible foundation for cost based rates.

1.2 Cost of Service Study Approach

Marginal cost of service analysis is the adopted LADWP cost of service study approach. Marginal costs measure the additional costs of providing the next unit of service in the future. The marginal cost method is forward-looking. Cost of new power generation is an example of a marginal cost.

For over twenty years, the California Public Utilities Commission (CPUC) has relied on marginal cost principles for assigning revenue requirements to customer classes, and to guide rate setting for electric utilities.[1] Also, the National Association of Regulatory Utility Commissioners (NARUC) and American Public Power Association (APPA) recognize the use of marginal costs as a valid cost of service methodology.[2] Therefore, the current LADWP cost of service study follows an established framework that is widely utilized across the country.

The ultimate goal of a cost of service study for rate making purposes is to develop the cost of service revenue requirement percentages (as a percent of total utility revenue requirement) for each customer class. The marginal cost of service analysis determines the marginal cost revenue requirements by

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[1] In particular, the CPUC has developed 10 Optimal Rate Design Principles, one of which is that "Rates should be based on marginal costs" (OIR at 20-21).

[2] Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, January 1992; Retail Rate Design for public Owned Systems, American Public Power Association, 1992

customer class (i.e., the revenues that LADWP would collect if all customers were charged rates that equal marginal costs).

Marginal cost revenue requirement percentages by customer class are then compared to current revenue percentages (as a percent of total utility revenue) by customer class. Relevant rates would be adjusted to collect customer class revenues appropriate for each class.

A cost of service study is based on a test year; for this study, fiscal year (FY) 2012-13, the most recent year with reliable data at the time of the study, was selected.

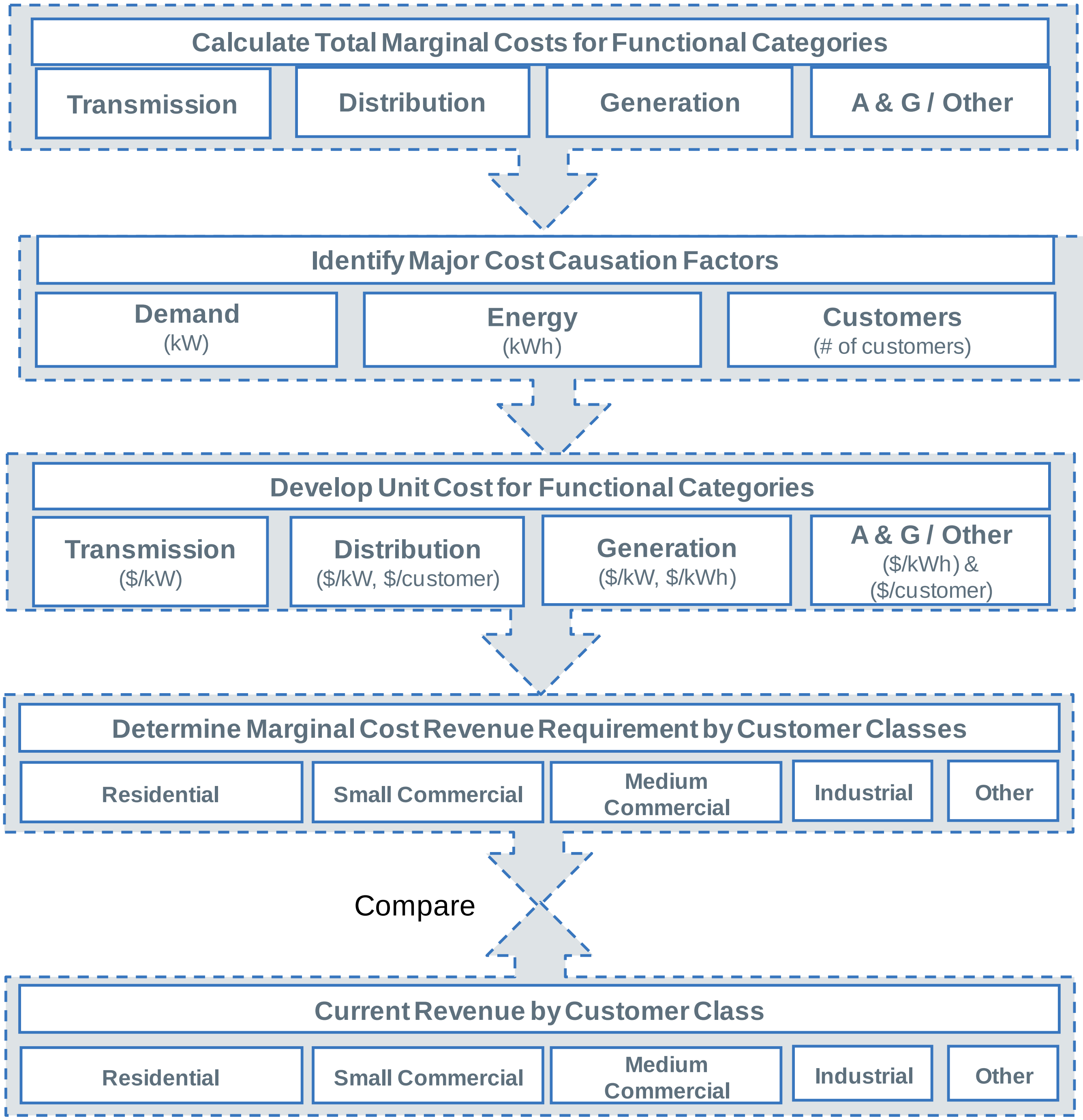
1.3 Marginal Cost of Service Study Methodology

A marginal cost of service study comprises three general steps:

- Functionalization of service costs;
- Development of unit marginal costs/cost drivers for cost causation factors; and
- Determination of marginal cost revenue requirements by customer class.

Each of these steps is explained in more detail in the sections below. Figure 1 summarizes these steps.

Figure 1: Summary of Marginal Cost of Service Study Methodology



1.3.1 Functionalization

The first major step in the marginal cost study is the identification of the various functions performed by LADWP in the provision of electricity services. The goal of the functionalization step is to group costs that have distinct and significant cost drivers. For LADWP, these functional components are:

- **Generation:** the process of generating power from a resource;

- **Transmission:** the bulk transfer of energy from generating stations to electric distribution sub-stations near demand centers;
- **Distribution:** the delivery of electricity received at sub-stations to end-use customers. This power typically goes through three voltage levels, such as 34.5 kV, 4.8 kV and secondary. Distribution also includes reading and maintaining customer meters; and
- **Other Administrative & General (A&G) Functions:** executive management, general supervision, customer service, customer billing, employee administration, etc.

Once the functions have been defined, forward-looking marginal cost revenue requirements for each functional component and their appropriate sub-components are developed. Sub-components are groupings that have distinct cost causation differences, such as voltage level sub-components for the distribution functional area.

1.3.2 Development of Unit Marginal Costs/Cost Drivers

The next major step of the marginal cost study is the identification of the appropriate cost causation factor for each functional and sub-functional cost component. The generally accepted and established industry practices for identifying the appropriate cost causation factors are described below.

- **Demand Related Costs:** These are costs incurred as a result of maximum (peak) power requirements and are utilized to determine marginal cost revenue requirements for the customer classes on the basis of demands in kilowatt (kW) imposed on the system.
- **Energy Related Costs:** Some costs, such as fuel, emissions, impact of renewables, and certain operation and maintenance expenses, are directly related to the quantity of energy in kilowatt hours (kWh) produced.
- **Customer Related Costs:** These costs reflect the marginal costs of customer interconnection to the delivery system and various customer services. These costs are derived for the customer classes on the basis of the number of customers.

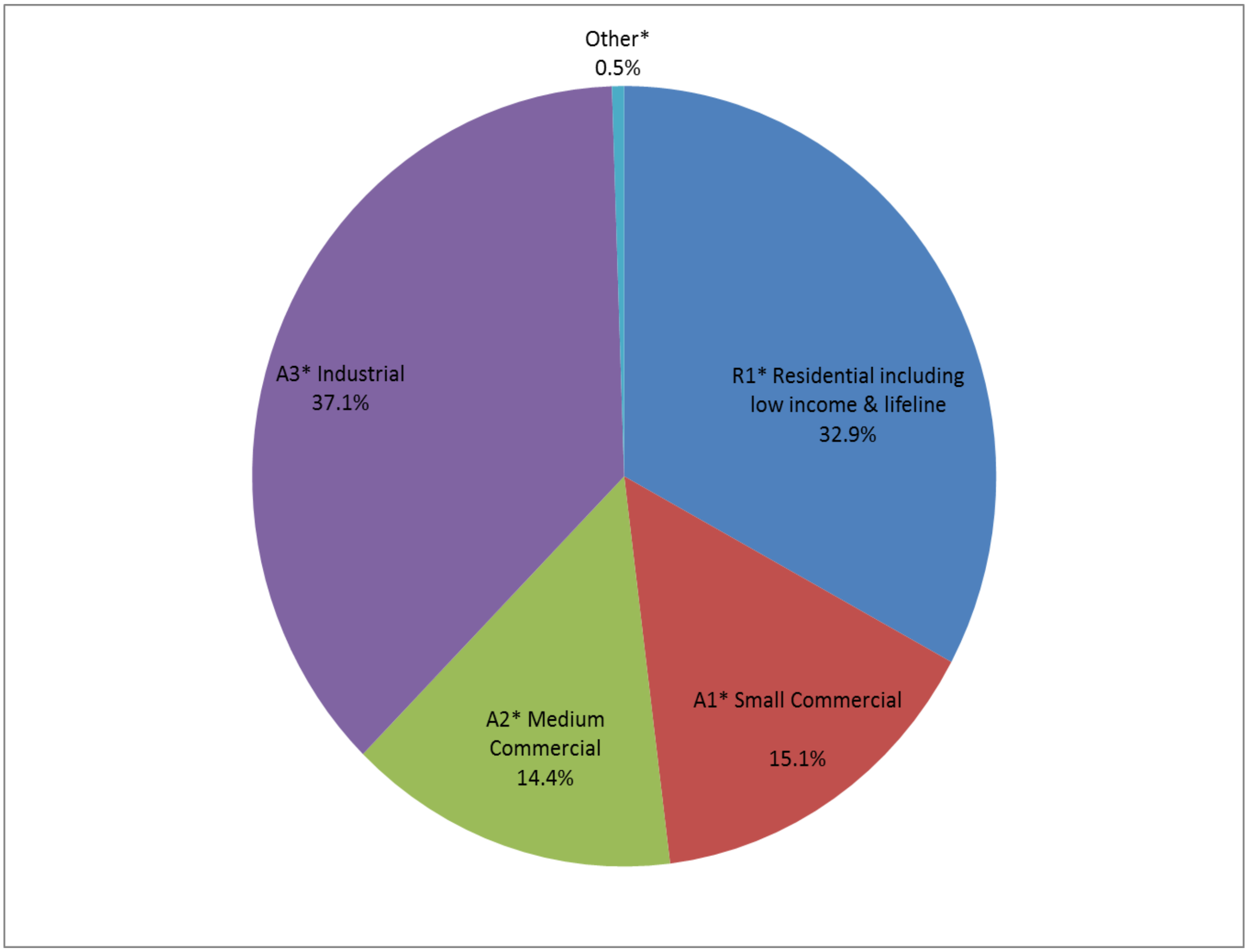
These cost causation factors form the basis for the determination of unit marginal costs for each functional component (and sub-components). Specialized analysis of each component by standard utility techniques results in the estimated unit marginal cost for these drivers.

1.3.3 Determination of Marginal Cost Revenue Requirement by Customer Class

The ultimate goal of a cost of service study for rate making purposes is to develop cost of service revenue requirement percentages by customer class. The marginal cost of service study determines marginal cost revenue requirements by customer class (i.e., the revenues that LADWP would collect if all customers were charged rates that equal marginal costs). The marginal cost revenue requirement percentages are then compared to the actual revenue percentages for each major customer class.

Figure 2 displays the current revenue percentages of current retail revenue collected through LADWP rates for each of the major customer classes for FY 2012-13.

Figure 2: FY 2012-13 LADWP Revenue by Customer Class[3]



Based on the unit marginal cost for each functional component and the corresponding cost causation factor for each customer class, marginal cost revenue requirements are calculated by functional component and sub-component for each customer class. The summation of the marginal cost revenue requirements for all the individual functional components and sub-components comprises the aggregate marginal cost revenue requirement for each customer class.

The marginal cost revenue requirement determination by customer class is summarized by the following equations:

- $Customer\ Class\ MC\ Revenue\ Requirement\ by\ Functional\ Component =$
  $Unit\ MC\ for\ Functional\ Component\ times\ Cost\ Causation\ Factor\ (for\ specific\ customer\ class)$
- $Total\ Customer\ Class\ MC\ Revenue\ Requirement =$
  $Sum\ of\ all\ MC\ Revenue\ Requirements\ for\ all\ Functional\ Components$

[3] For the LADWP marginal cost study, some customer classes listed here have been combined to maintain consistency for rate design purposes. For instance, the Residential class includes low income and lifeline customers. The asterisk* indicates that multiple classes are included in a listed customer class (e.g., A1 includes A1A and A1B).

The final step of the marginal cost study analysis involves the calculation of marginal cost revenue requirement percentages for each customer class (as a percentage of the total marginal cost revenue requirement). These marginal cost revenue requirement percentages are compared to the corresponding current revenue percentages for each customer class, to determine whether the current rates and rate structure produce revenues for each customer class in the same proportion as the marginal cost revenue requirement. Figure 3 presents this comparison for the LADWP study.

Figure 3: Comparison of Marginal Cost Revenue Requirement and Current Revenue by Customer Class

Comparisons	Residential	Small Commercial	Medium Commercial	Industrial	Other	Total
Total MC Revenue Requirement	$1,373,625,488	$483,115,979	$470,966,448	$1,085,122,948	$27,827,485	$3,440,658,348
Marginal Cost Revenue Requirement Percentage	39.9%	14.0%	13.7%	31.5%	0.8%	100.0%
FY 2013 Current Retail Revenue	$1,010,099,373	$464,812,908	$441,103,892	$1,138,691,239	$16,187,848	$3,070,895,260
Current Revenue Percentage	32.9%	15.1%	14.4%	37.1%	0.5%	100.0%

For the test year FY 2012-13, the aggregate amount collected through current retail rates for all customer classes, was approximately $3,071 million.

The LADWP marginal cost study calculates the required revenues on a forward-looking basis, using data for the FY 2012-13 test year as a starting point. The revenue requirement based on the marginal cost study generally exceeds the accounting cost based revenue requirement. For the LADWP marginal cost study, the total marginal costs are approximately $3,441 million, which is 12% higher than the FY 2012-13 revenue requirement of $3,071 million.

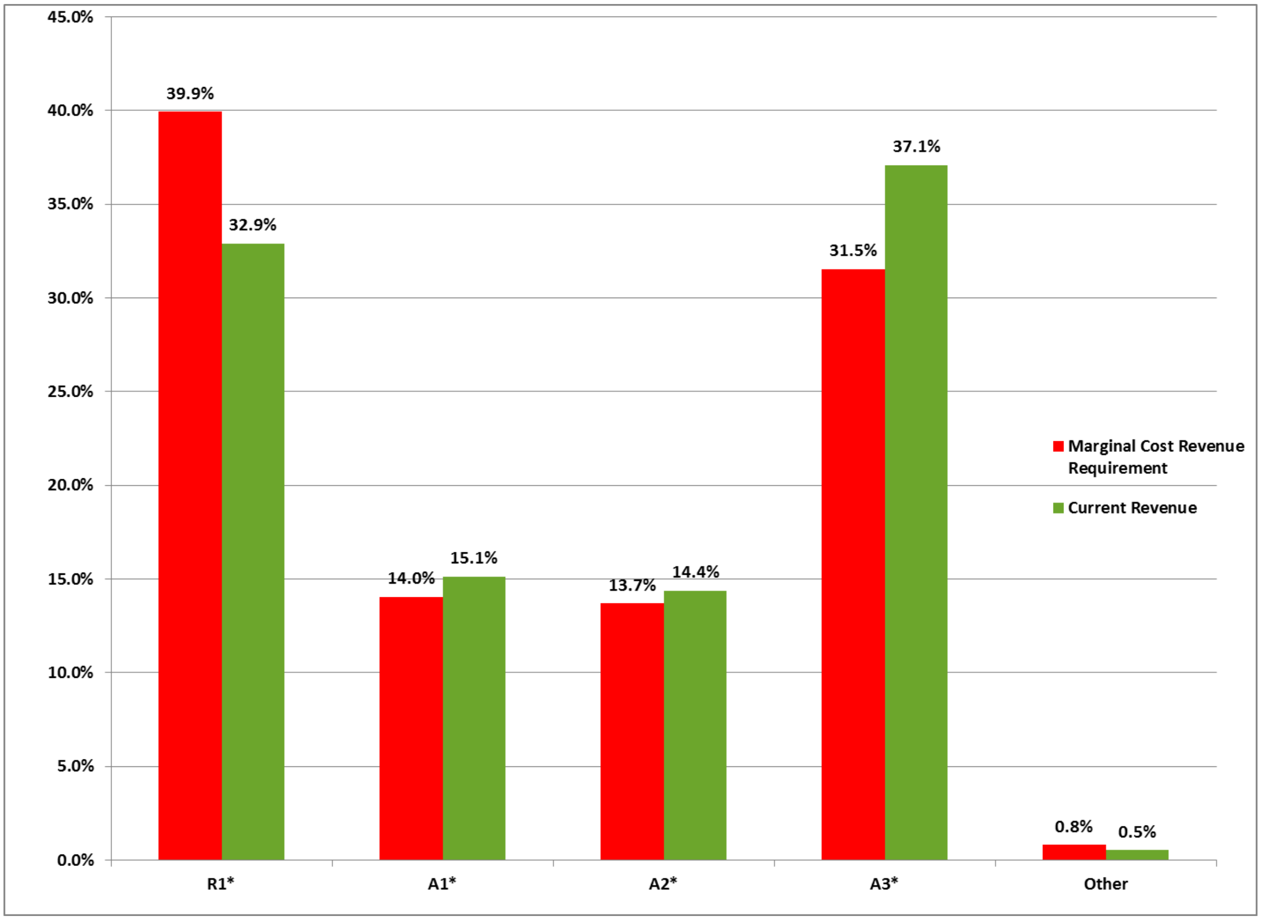
The current customer class revenue percentages in Figure 2 reflect a historical rate structure. Over time, cost structures change; consequently, marginal cost of service studies should be conducted periodically to more accurately reflect forward-looking allocation of costs among customer classes. For example, California legislation and regulations require increased use of renewable energy resources, which will impact electric utility cost of service and the allocation of costs to different classes.

The marginal cost revenue requirement percentage for the residential (R1) customer class is 39.9%, while the corresponding percentage of current revenues for FY 2012-13 is 32.9%. Conversely, based on marginal costs, the Industrial (A3) customer class would be allocated a lower revenue requirement of 31.5% as compared to 37.1%, of the current total revenues. These results were supported by a embedded[4] cost of service analysis, which produced similar customer class percentages as the marginal cost of service study.

The LADWP marginal cost study results therefore demonstrate that a re-alignment of the total revenue requirements among the customer classes is likely warranted. Figure 4 illustrates the differences between the marginal cost revenue requirement and current revenue percentages for the major customer classes.

[4] Embedded Cost studies are also referred to as Average Embedded Cost Studies.

Figure 4: Comparison of Marginal Cost Revenue Requirement and Current Revenue Percent by Customer Class



To avoid over/under collection of costs for one or more customer classes and to more accurately reflect cost causation principles, the marginal cost revenue requirement percentages by customer class can be applied to the approved annual revenue requirement to establish, through rate design, cost based customer rates.

2 MARGINAL COST OF STUDY APPROACH & METHODOLOGY

2.1 Introduction

In October 2012, the Los Angeles City Council approved LADWP's Incremental Electric Rate Ordinance No. 182273 to provide incremental rate adjustments for fiscal years (FYs) 2012-13 and 2013-14. In its action to approve LADWP's power rates, the Council requested that LADWP "conduct a new formal cost of service study in order to prepare for future power rate restructuring".

To meet the Council request and in preparation for its proposed rate action, LADWP has conducted a cost of service study (COSS) using marginal cost principles to evaluate cost structures and ensure that rates are appropriate for each customer class.

Cost of service analysis (COSA) constitutes standard utility industry practice for setting power rates. Most utilities, whether Investor Owned Utilities (IOUs) or publicly owned utilities (POUs), conduct cost of service studies when undertaking a rate action. The marginal cost study approach facilitates attaining the following objectives:

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- Encourages efficient system expansion and use of utility facilities and discourages wasteful use;
- Provides efficient price and resource allocation signals; and
- Provides legally defensible foundation for cost based rates.

Cost of service analysis is part of the overall utility rate making process. An overview of the typical ratemaking process is shown below in Figure 5**.** Utilization of a marginal cost of service study will ensure rates produce revenue sufficient to recover the costs associated with the provision of electric service. Concurrently, the cost of service study will help ensure rates for each major class of customers recover the costs associated with providing service to that class of customers.

Figure 5: Typical Utility Ratemaking Process

Objectives	• Identify ratemaking objectives
Revenue Requirements	• Calculate revenue requirements (i.e., the amount needed to be billed to customers to cover the utility's costs)
Cost of Service	• Determine overall marginal costs • Functionalize costs • Develop unit costs by cost causation factor • Define customer (or rate) classes • Assign the functionalized costs to customer classes • Calculate marginal cost revenue requirement for each customer class • Compare marginal cost revenue requirement to current revenue by customer class
Rate Design	• Identify revenue constraints • Choose revenue reconciliation method • Evaluate alternative rate designs and choose an approach • Design rates • Determine customer rate and bill impacts • Adjust rate design if needed • Design special rates and contracts if needed

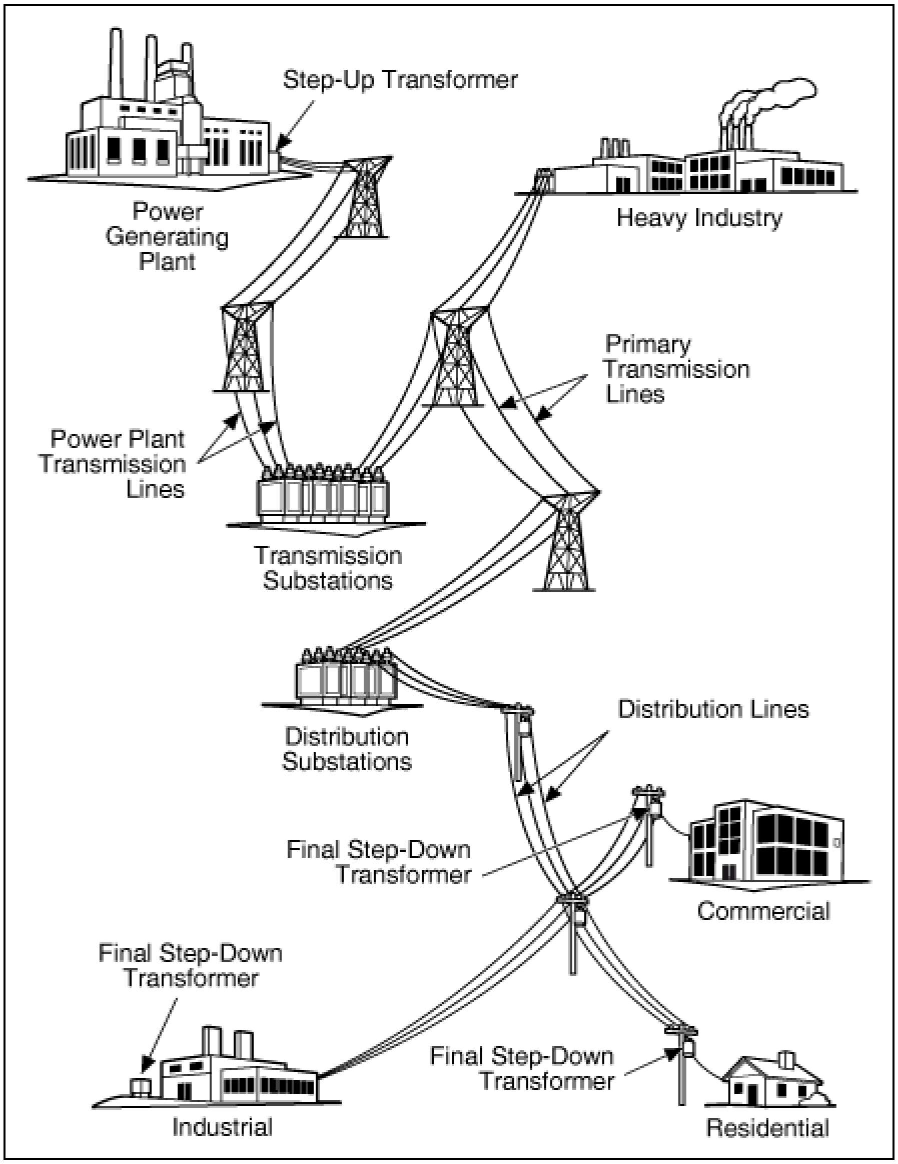
2.2 Electric Supply System Overview

Electric utilities are unique, important businesses that provide electricity to a variety of customers that include commercial, industrial, and residential classes through a system that is generally composed of the following major functional components:

- Generation;
- Transmission;
- Distribution; and
- Administration and General Services supporting those functional components.

Figure 6 provides an illustration of the electric supply system.

Figure 6 Electric Supply System[5]



2.2.1 Functional Components

To obtain a better understanding of the electric system, it can be broken down into functional components:

- **Generation:** The process of producing electrical power from a primary energy source such as natural gas, hydro-electric, solar or wind. A utility may also choose to purchase power from third parties to meet demands of customers. In this case, a third-party generation entity would generate electricity and sell it to the utility; these utility costs would be considered part of the generation function.

[5] Source: http://zone.ni.com/images/reference/en-XX/help/373375B-01/noloc_eps_ep_grids.gif

- **Transmission:** The process of transporting the electricity from generation plants to distribution sub-stations that may be close to the customer. Most transmission lines use high voltage-AC current; power is typically delivered to the transmission system from regional generators or regional interties at 500/230 kV or higher voltages. However, when energy is transported over long distances (often hundreds of miles), DC current is used to reduce losses. Heavy industrial users may receive electricity directly from the transmission lines.
- **Distribution:** The process of distributing the electricity received at the distribution substations to the end-use customer. Distribution substations reduce voltage to a level suitable for use by the applicable customer class. This power typically goes through three stages of transformation on the LADWP system: from 500/230 kV to 34.5 kV (sub-transmission voltage), from 34.5 kV to 4.8 kV (primary voltage), and from 4.8 kV to between 110 and 480 volts at the customer premises (secondary voltage).
- **Administrative and General (A&G):** These functions provide the capability to bill, and provide customer service, accounting and other support services.

2.2.2 Meeting Customer Demand

A core value for LADWP is reliability. Utilities strive to provide electricity reliably to all customers at an affordable price. However, several factors influence the ability to achieve this goal, including:

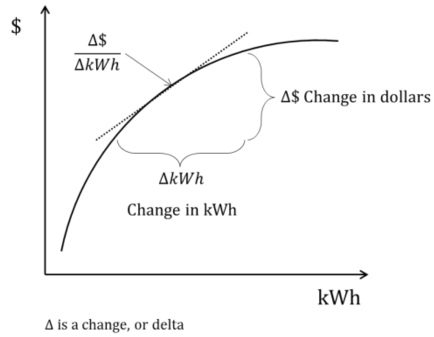
- Patterns of Energy Demand: Utilities must have infrastructure capable of handling different patterns of usage, as well as the peak demand imposed on the system by different customer classes; and
- System Losses: Energy losses throughout the transmission and distribution process.

2.3 Cost of Service Study Approach

The LADWP cost of service study follows a marginal cost methodology. This methodology evaluates the change in cost incurred by a customer class to serve an incremental increase in demand for utility services by that class. Marginal costs measure the additional costs of providing the next unit of service, whether that is the next unit of energy, the additional burden that adding a kilowatt of demand places on the electrical system or the cost of an additional customer.

Marginal costs are calculated for changes in each cost driver, or causative factor. These cost drivers are typically related to demand, energy and/or customer causative factors. The marginal cost is calculated by dividing the change in total cost by the change in the cost driver. For example, the marginal cost of electric generation is calculated for an incremental change in the total cost of generating electricity from a change in load. Figure 7 below illustrates the determination of marginal costs for generating energy (kWh). The vertical axis, dollars ($), represents the total cost of producing energy (kWh). At any point on the production curve, there is a change in dollars that corresponds to a change in energy (kWh) production. The change in cost (delta of $) divided by the change in energy (delta of kWh) is the marginal cost.

Figure 7: Example of Marginal Cost for Generation Given a Generation Production Curve



For over twenty years, the California Public Utilities Commission (CPUC) has relied on marginal cost principles for assigning revenue requirements to customer classes, and as guidance for electric utility rate and rate structure development[6]. Also, the National Association of Regulatory Utility Commissioners (NARUC) and American Public Power Association (APPA) recognize the use of marginal cost as a valid cost of service methodology[7]. Therefore, the current LADWP cost of service study follows an established framework that is widely utilized across the country.

The ultimate goal of marginal cost of service for rate making purposes is to determine the marginal cost percentage of the total revenue requirement for each customer class in rates. The marginal cost revenue requirement percentages are then compared to the percentages of total revenue produced at current rates for each customer class to determine whether an adjustment to the rates is appropriate.

When a difference arises, relevant rates may be adjusted to align revenue percentages with the marginal cost revenue requirement percentages.

2.4 Marginal Cost of Service Study Methodology

Prior to the commencement of the marginal cost study, the appropriate test year has to be established for the analysis. For the LADWP study, FY 2012-13, the most recent period with reliable data at the time of the study, was selected.

The LADWP electric marginal cost of service study comprises three general steps:

- Functionalization of service costs;
- Development of unit marginal costs/cost drivers for cost causation factors; and
- Determination of marginal cost revenue requirements by customer class.

The graphic in Figure 8 summarizes these three steps.

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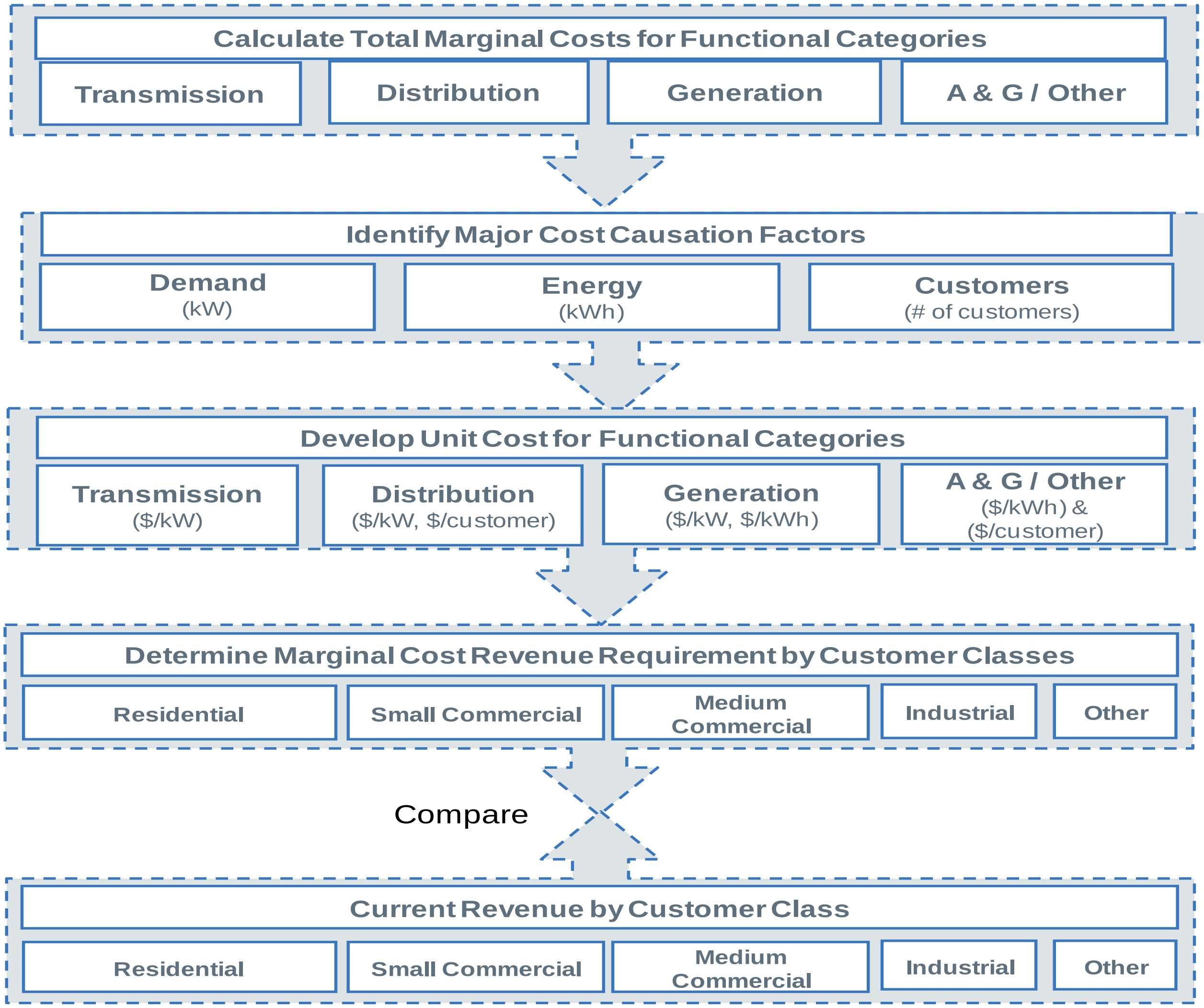
[6] In particular, the CPUC has developed 10 Optimal Rate Design Principles, one of which is that "Rates should be based on marginal costs" (OIR at 20-21).

[7] Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, January 1992.; Retail Rate Design for public Owned Systems, American Public Power Association, 1992

Figure 8: Marginal Cost of Service Study Methodology



Each of these steps is explained in more detail in the sections below.

2.4.1 Functionalization

The first major step in the marginal cost study is the identification of the various functions performed by LADWP in the provision of electricity services. The goal of the functionalization step is to group costs that have distinct and significant cost drivers. For LADWP, these functional components are:

- **Generation:** the process of generating power from a resource;
- **Transmission:** the bulk transfer of energy from generating stations to electric distribution sub-stations near demand centers;
- **Distribution:** the delivery of electricity received at sub-stations to end-use customers. This power typically goes through three voltage levels, such as 34.5 kV, 4.8 kV and secondary. Distribution also includes reading and maintaining customer meters; and
- **Other Administrative & General (A&G) Functions:** executive management, general supervision, customer service, customer billing, employee administration, etc.

The marginal cost study then develops forward-looking marginal cost revenue requirements for each functional component and their appropriate sub-components. Sub-components are sub-categories that have distinct cost causation differences, such as voltage level sub-components for the distribution functional area.

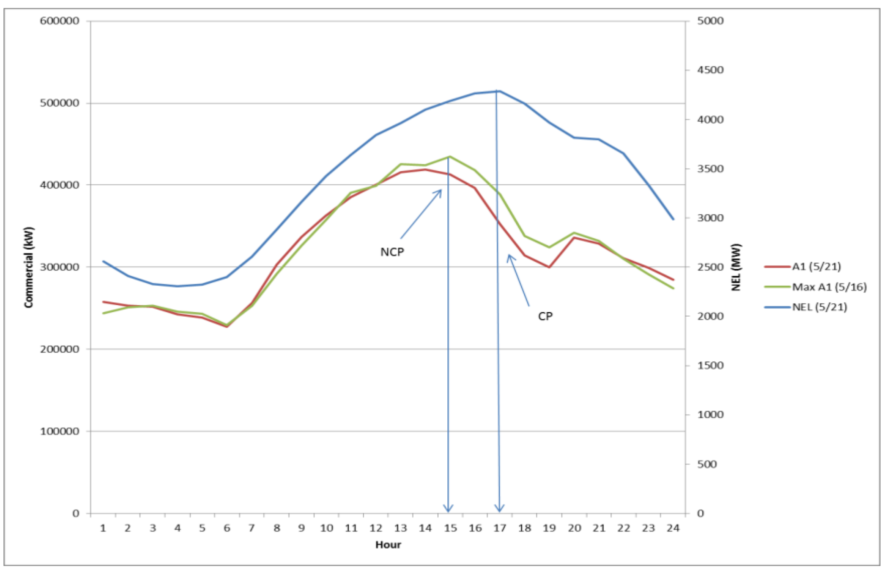
2.4.2 Development of Unit Marginal Costs/Cost Drivers

The next major step in the marginal cost study is the identification of the appropriate cost causation factor for each functional and sub-functional cost component. For example, the cost causation factor for generation capacity costs is the kW demand on the system. The generally accepted and established industry practices for the cost causation factors are described below.

- **Demand Related Costs:** These costs are incurred as a result of maximum power requirements and are utilized to determine marginal cost revenue requirements for the customer classes on the basis of demands (kW) imposed on the system. Two peaks in demand that generally contribute toward system capacity cost causation and ultimately determine how costs get calculated are:
- **System Coincident Peak Demand (CP):** contributions of each customer class coincident with the system peak hour. The Coincident peak demand measurement is used in the calculation of marginal costs for capacity generation, particularly peaking resources, and bulk transmission plant.
- **Class Non-Coincident Peak (NCP):** maximum demand for a class of customers. The hour of occurrence may or may not be the same as the system peak hour. This measurement of demand is used in the calculation of local facility marginal costs such as those of substation and primary distribution facilities.

Figure 9 shows the relationship between system coincident peak demand and class non-coincident peak.

Figure 9: Depiction of System Coincident Peak Demand (CP) vs. Class Non-Coincident Peak (NCP)



- **Energy Related Costs:** Some costs, such as fuel, emissions, impact of renewables, and certain operation and maintenance expenses, are directly related to the quantity of energy (kWh) produced.
- **Customer Related Costs:** These costs reflect the marginal costs of customer interconnection to the delivery system and various customer services. These costs are derived for the customer classes on the basis of the number of customers.

Figure 10 below summarizes the functional cost components and the corresponding cost causation factors for the LADWP cost of service study, based on standard industry practices.

Figure 10: Cost Causation Factor for Each Functional Cost Component

Functional Cost Component	(Cost Causation Factor)	Units
Transmission Capacity	Coincident Peak for each customer class	$/CP kW/year
Transmission Ancillary Services	Coincident Peak for each customer class	$/CP kW/year
Transmission O&M	Coincident Peak for each customer class	$/CP kW/year
Generation Energy	kWh load for each customer class	$/kWh
Generation Capacity	Coincident Peak for each customer class	$/CP kW/year
Generation O&M	kWh load for each customer class	$/kWh
Distribution Capacity	Non-Coincident Peak for each customer class	$/NCP kW/year
Distribution O&M	Non-Coincident Peak for each customer class	$/NCP kW/year
Meter Costs	Number of Customers	$/Customer/year
Customer Account Expenses	Number of Customers (Weighted)	$/Customer/year
Administrative & General Cost Adders	kWh load for each customer class	$/kWh

These cost causation factors form the basis for the determination of unit marginal costs for each functional component (and sub-components).

Specialized analysis of each functional component (and sub-component) based on standard utility techniques results in the estimated unit marginal cost by cost drivers. The specialized analyses are discussed below in Section 3; additional detail for some of the analyses is also provided in Appendices C and D.

2.4.3 Determination of Marginal Cost Revenue Requirements by Customer Class

The third major step in the marginal cost study methodology is to determine whether LADWP recovers from each major class the costs associated with providing service to that class of customers.

LADWP serves the following main customer classes[8]:

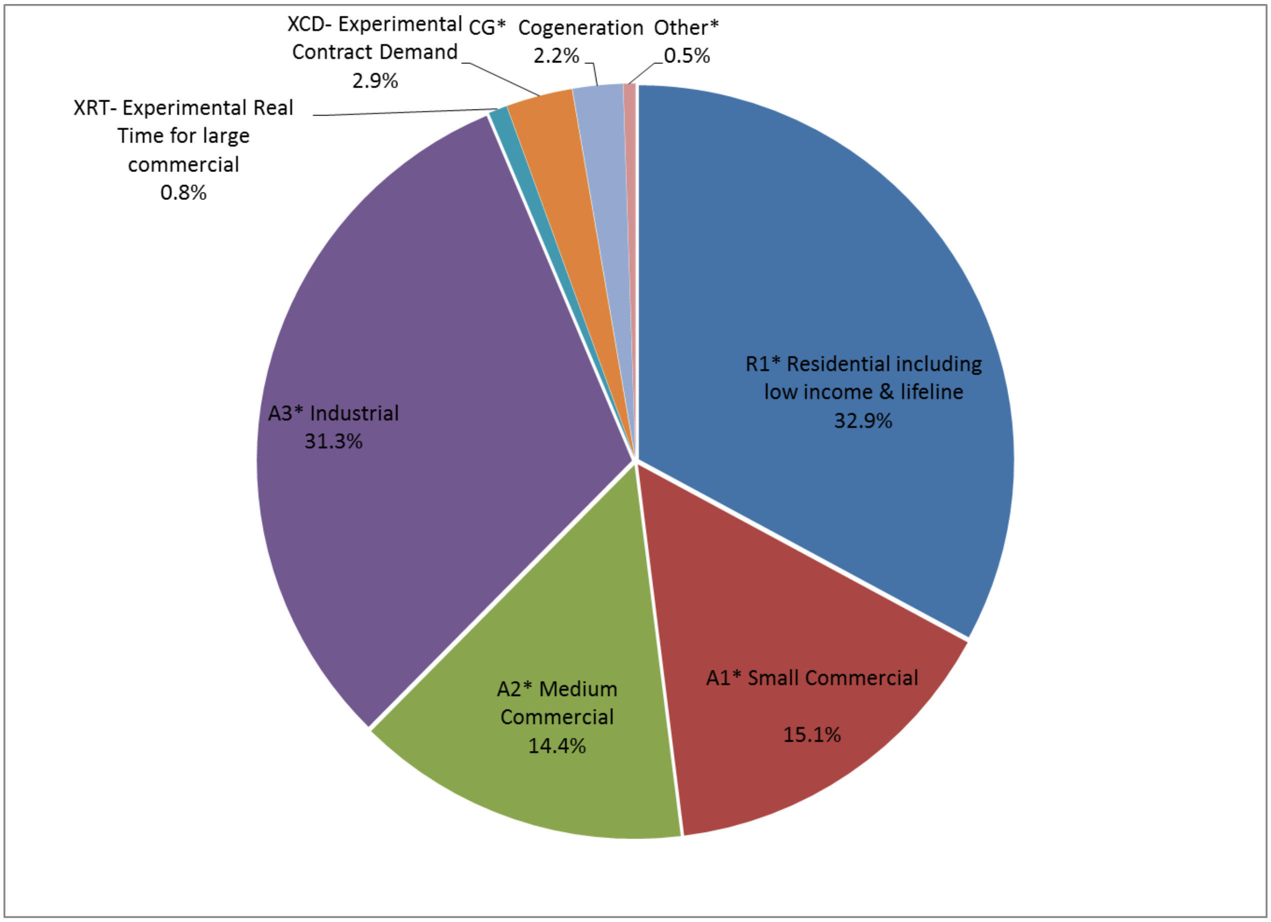
- Residential: Single family and multi-family, including low-income and life-line;
- A-1 Commercial: Smaller office buildings and other commercial real estate, etc;
- A-2 Commercial & Industrial: Commercial & industrial customers who use electricity delivered from the primary voltage system;

[8] Owens Valley customers have been excluded from the marginal cost study analysis, they only constitute about 0.6% of LADWP retail revenues.

- A-3 Commercial & Industrial: Commercial & industrial customers who use electricity delivered from the sub-transmission system;
- Experimental Real Time (XRT): Large, contract commercial & industrial customers with demand of 250 kW or greater with the ability to curtail usage;
- Experimental Contract Demand (XCD): Large, contract commercial & industrial customers with the ability to shift load and maintain high load factors;
- Cogeneration: Customers who own electrical generating facilities that are connected with LADWP's system, but are not subject to Net Energy Metering (NEM) service rider;
- Other: Street, highway lighting, and traffic control.

The actual FY 2012-13 revenues for these major customer classes are displayed in Figure 11. The source for the FY 2012-13 revenues, load and customers is the C&E (Consumption and Earnings) Report FY 2012-13.

Figure 11: FY 2012-13 Revenue by Customer Class



Note that for the LADWP marginal cost study, some customer classes listed above have been combined to maintain consistency for rate design purposes. (For example, the Residential class also includes both low income and lifeline customers in the marginal cost results.) For the LADWP marginal cost study analysis, customer classes have been condensed to five broad categories:

- Residential (R1)
- Small Commercial (A1)
- Medium Commercial (A2)
- Large Commercial or Industrial (A3)
- Other (including Street and Highway Lighting and Port of Los Angeles).

This final step of the marginal cost study analysis determines the aggregate marginal cost revenue requirements for each customer class. This is followed by the calculation of marginal cost revenue percentages for each customer class, as a percentage of the total utility marginal cost revenue requirement.

These marginal cost revenue requirement percentages are then compared to the corresponding current revenue percentages for each customer class to determine whether changes to current rates and rate structures for any of LADWP's customer classes are appropriate. An objective is for rates to produce revenues in the same proportion by customer class as the marginal cost revenue requirements.

The marginal cost revenue requirements for each customer class are calculated by multiplying customer class cost causation factors by functional unit marginal costs. This calculation will produce a system total revenue requirement which will differ from the actual accounting revenue requirement for the system. The marginal cost revenue requirement generally differs from the accounting cost based revenue requirement; for the LADWP marginal cost study, the total marginal cost revenue requirement is $3,441 million, which is 12% higher than the $3,071 million FY 2012-13 revenue requirement.

A summary of the marginal cost of service methodology is provided below:

I. Functionalization

Identify all costs associated with providing electricity service by the following major functional components:

- Generation;
- Transmission;
- Distribution; and
- Customer, Administrative & General.

Within each major functional component, identify particular sub-components that have a distinct cost causation factor (e.g. renewable energy generation costs).

Determine the aggregate marginal costs for each functional component and sub-component.

II. Development of Unit Marginal Costs/Cost Drivers

1. Determine the appropriate cost causation factor or cost driver for calculating a unit marginal cost for each functional component, for example:
    - Proportionate capacity levels (CP or Non-CP) for each customer class;
    - Energy usage (kWh) for each customer class; or
    - Number of customers in each class.
2. Develop a unit marginal cost for each functional component by an individual analysis of each component's marginal cost.

III. Determination of Marginal Cost Revenue Requirements by Customer Class

1. Identify all major customer classes for electric service.
2. Calculate the marginal cost revenue requirement by functional component for each customer class by multiplying the unit marginal cost for each functional component identified in Step II.2 by the total

amount of the corresponding customer class units/cost driver for each customer class identified in Step III.1.

3. Determine the aggregate marginal cost revenue requirement for all customer classes from Step III.2.
4. Calculate the marginal cost revenue requirement percentages (as a percentage of the aggregate revenue requirement) for each major customer class by dividing the customer class amount in step III.2 by the aggregate amount determined in step III.3.
5. Compare the marginal cost revenue requirement percentage for each customer class (step III.4) with corresponding current (FY 2012-13) revenue percentage.

The marginal cost of service study results can then be used to determine whether any changes to rates and/or rate structures are appropriate.

3 CALCULATION OF UNIT MARGINAL COSTS

This section describes the assumptions underlying the marginal unit costs and how the unit costs are calculated.

This section is divided into three major sub-sections:

- Marginal cost study assumptions and data sources;
- Calculation of unit marginal costs for each functional cost component; and
- Summary of unit marginal costs by functional component.

3.1 Marginal Cost Study Assumptions and Data Sources

3.1.1 General Assumptions

The estimation of marginal costs involves a detailed analysis of projected costs of the services provided by utility companies, and it is typically quite sensitive to certain parameters and assumptions, depending on the type of cost being estimated. Some of the key assumptions and data sources for the LADWP marginal cost study are listed below:

- Test year of FY 2012-13 utilized for marginal cost study analysis (most recent year of reliable financial and usage information at the time of the study).
- Current & forecasted LADWP data from 2013 Integrated Resource Plan (IRP), Open Access Transmission Tariff (OATT), Customer Information System (CIS), Consumption and Earnings (C&E) report, and FY 2012-13 General Ledger;
- Operations & Maintenance costs based on FY 2012-13 general ledger;
- Customer counts based on an average for FY 2012-13;
- Load shape by class for calendar year 2012 obtained from the LADWP Rates Department. The calendar 2012 loads were proportioned by hour by customer class to FY 2012-13 levels utilizing the difference between calendar year 2012 loads and C&E Report data for FY 2012-13 ;
- Cost of Capital[9] assumed to be 5.45% based on 2013 IRP;
- Inflation Rate assumed to be 2.5% based on 2013 IRP;
- System losses based on the 2010 Power Loss Study;
- Renewable energy resources of 20%, 25%, and 33% for electricity sales by 2013, by 2016, and in 2020, respectively, to comply with State legislation;
- System lambda based on 2019 Prosym Study forecasts; and
- All marginal cost demand calculations are based on 12CP/12NCP.
- Other key data sources and considerations for calculating the marginal costs are defined below.

[9] The cost of capital of 5.45 % is the appropriate rate for discounting streams of future nominal dollars. This is also referred to as the nominal discount rate.

3.1.2 Integrated Resource Plan

Every other year, LADWP prepares a complete power Integrated Resource Plan (IRP) to provide a 20-year strategy that meets current and future energy needs of the City of Los Angeles. The IRP is refreshed in the years that a complete IRP is not prepared. The IRP lays out alternative strategies for meeting LADWP's regulatory requirements and environmental policy goals for increasing the use of renewable energy and reducing greenhouse gas (GHG) emissions, while maintaining power reliability and minimizing the financial impact on the City's ratepayers. LADWP's 2013 Final Power Integrated Resource Plan was the product of a year-long process that included stakeholder meetings with key business, environmental, and community representatives, a public review of a draft version, and a public workshop. A 2014 update to the 2013 IRP is in process but has not yet been completed at the time of this study.

Since the marginal cost study is forward-looking in nature, many inputs for the calculations have been obtained from the 2013 IRP, and other planning and forecasting data sources.

3.1.3 General Ledger Costs

There were several cost categories for the LADWP Power System that were classified as adders. Since these costs are general in nature and not likely to be significantly different in the future, no specific effort was made to determine forward-looking marginal costs for these categories. Instead, the FY 2012-13 costs incurred by LADWP for these categories were obtained from the General Ledger and included in the marginal cost study calculations. Following is a list of these cost categories, which are discussed in more detail in later sections of this report:

- Generation Operations & Maintenance Expenses;
- Transmission Operations & Maintenance Expenses;
- Distribution Operations & Maintenance Expenses;
- Customer Account Expenses;
- Administration & General Expenses;
- City Transfer Expenses; and
- General Plant Expenses.

3.1.4 Adjustment for System Losses

The total energy sales to ultimate customers for the LADWP system are substantially lower than the net energy load (NEL)[10]. This difference is attributable to power system losses that relate to transmission and distribution line losses and other losses (e.g. metering errors and energy theft).

The demands or loads used for the allocation of generation and transmission costs are the demands at the transmission inlets to the LADWP system, not the demands at the point of delivery to the customer**.** Consequently, an estimate of system losses from the point of supply to the customer's meter, has to be calculated to derive the load at the transmission inlets. These loss factors pertain to both peak demand (kW) and annual energy load (kWh).

For the LADWP system, overall power system losses were determined from the April 2010 Power Loss Study. Each customer class exhibits a different loss factor as displayed in the table below. The higher loss for Residential customers is attributable to the fact that their load is subject to more voltage changes on the distribution lines. LADWP's loss factors are shown in Figure 12.

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[10] Net Energy Load is the actual load at the transmission inlets to the LADWP system, before transmission & distribution & other losses.

Figure 12: LADWP Loss Factors

	R1	A1	A2	A3	Other
Loss Factor	10.46%	10.46%	8.95%	7.45%	10.46%

If marginal costs for the various functional cost components were calculated for the customer classes without consideration of the loss factor, industrial customers would pay too much, while residential customers would pay too little. Therefore, loss factors are incorporated in the marginal cost study calculations for the following cost components:

- Generation & Transmission Capacity costs & Transmission O&M costs (loss factors applied to CP demand for each customer class for marginal cost calculation purposes); and
- Generation Energy (including Renewable & GHG) costs and Generation O&M costs (loss factors applied to kWh load for each customer class for calculation purposes).

To illustrate, generation energy costs are calculated for various customer classes based on the gross kWh load, or load adjusted upward by the corresponding loss factor for each customer class. For example, if the retail load for residential customers is 1,000 kWh, and the loss factor is 10.46%, then load to be used for the marginal cost calculation would be 1,116.8 kWh (1,000/(1-0.1046)) and not 1,000 kWh.

Based on the key factors described above, the marginal cost calculation methodology for each functional component is described in the sections below, including a discussion on the appropriate mode of determining marginal cost revenue requirements for the customer classes.

3.2 Calculation of Unit Marginal Costs for Each Functional Cost Component

3.2.1 Generation Unit Marginal Costs

There are several components in the generation costs: generation capacity, generation energy, renewable energy, and GHG emission costs, as described below.

3.2.1.1 Generation Capacity Unit Marginal Costs

Generation capacity is the need for instantaneous power to meet demand. Traditionally, capacity-related generation marginal costs have been measured by annualizing the expected costs of a utility-built combustion turbine (CT) as a proxy. A combustion turbine or peaker is typically the least cost generation option to provide incremental capacity benefits during the peak demand hours.

The cost for an LADWP owned combustion turbine in the LA region was utilized. This cost for the combustion turbine, included all permitting, financing, development costs, inflation during the construction period, and 15% reserves, was based on estimates in the 2013 IRP. The IRP has estimated the capital cost of a combustion turbine (CT) to be $1,300/kW, with a useful life of 30 years. Using the IRP cost of capital of 5.45%, the total cost of $1,300/kW was then discounted over the 30 year period resulting in an annual cost of $88.95/kW. A fixed annual O&M component of $19.25/kW based on the new CTs at the

Harbor Generating Station was added to the capital cost. The resulting annual cost annuity of \$108.20/kW (\$88.95/kW +\$19.25/kW) represents the unit generation capacity marginal cost per kW.

3.2.1.2 Generation Energy Unit Marginal Costs

Generation energy marginal costs are generally estimated based on the "system lambda". This system lambda is defined as the cost of the next kilowatt-hour that can be produced by an electrical supply system's generating units. As system load increases, the cost of serving incremental loads may increase as more expensive units come on line. The last unit dispatched represents the system lambda.

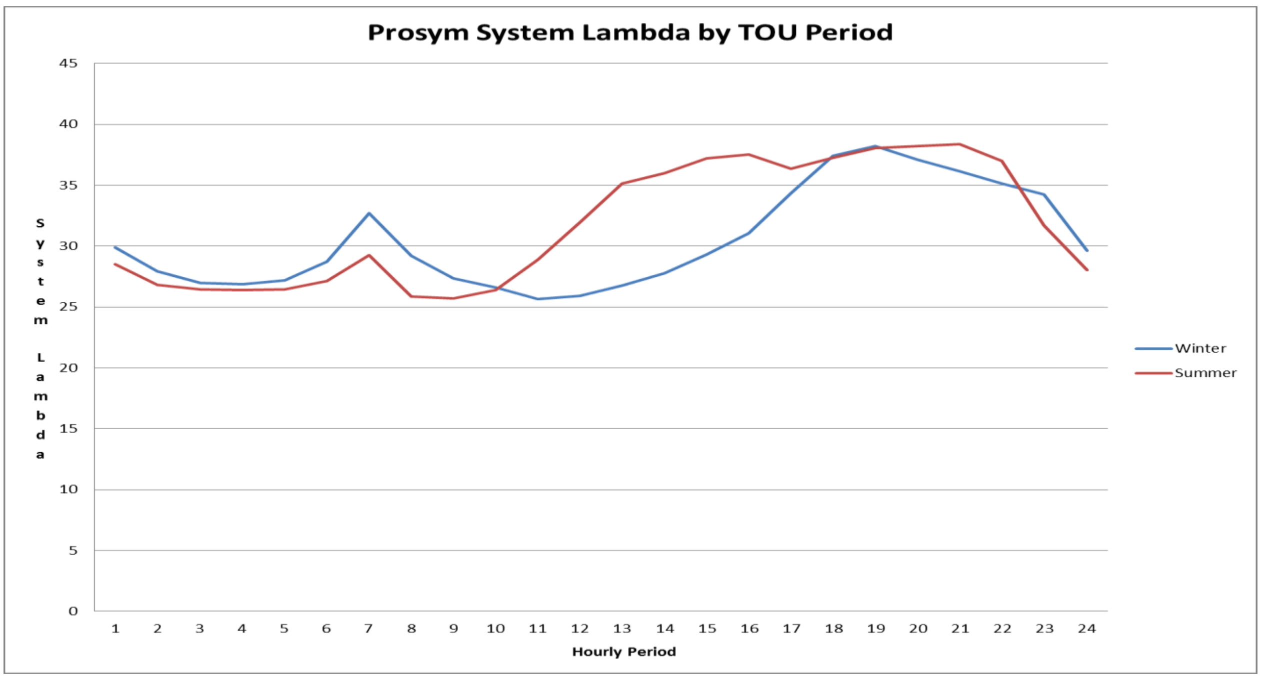
Forward system lambdas are estimated through production simulation models that are utilized to dispatch resource to load on an hourly basis, given available resources and constraints. LADWP utilizes ProSym as the production simulation.

Detailed hourly system lambda forecasts (in \$/kWh) for each hour of each day of each month of FY 2018-19 were obtained from the ProSym simulation model. These hourly prices were applied to the corresponding hourly load for FY 2012-13, for each customer class, to derive the marginal generation energy costs.

Consequently, the total generation energy marginal costs were determined directly on an aggregate summation basis across hourly data, and not based on a single unit marginal energy cost.

An illustration of the system lambda, based on the ProSym model is displayed in Figure 13, for a 24-hour period.

Figure 13: LADWP ProSym Model System Lambda by TOU Period



For each customer class, the hourly load for FY 2012-13 (adjusted for system losses for each customer class) was multiplied by the corresponding hourly system lambda price forecast for FY 2018-19 to obtain an hourly generation energy cost for each customer class. FY 2018-19 represents a sufficiently forward look where modeling forecasts variable hourly costs with reasonable certainty. The summation of these hourly costs for the whole year provided the aggregate annual generation energy marginal costs for each customer category. The generation energy unit marginal cost was determined to be \$0.034/kWh. In addition to the generation energy costs, the total generation energy marginal cost also includes two components, as described below: renewable energy costs and greenhouse gas (GHG) emissions.

3.2.1.3 Renewable Energy Unit Marginal Costs

Shifting a greater amount of energy production to renewable energy sources is a major environmental policy initiative in California, memorialized by Senate Bill SBX1-2, passed in April 2011. Renewable energy constitutes a major power supply resource addition that influences LADWP revenue requirements for the next several years. SBX1-2 and CEC regulations require LADWP to achieve 20% renewables on average between 2011 and 2013, 25% by 2016, and 33% in 2020. Consequently, the generation energy marginal costs will be impacted by this mandate, since energy from renewables is more expensive than from traditional sources like coal or natural gas.

Solar power through contracts was identified as least cost incremental renewable resource based on the 2013 IRP, and the impact of renewables was estimated as the difference in energy costs between solar power and LADWP's cheapest traditional generation energy source.

This impact of additional costs attributable to renewables was estimated based on IRP data. The cheapest source of solar power based on the LADWP Power Purchase Agreements (PPAs) was estimated to be $83 per MWh (levelized annual cost). The cheapest LADWP source for energy was estimated at $49 per MWh, from generation at the Haynes combined cycle turbine generating plant. Hence, the unit incremental marginal cost per MWh for renewable energy was calculated as the difference between the costs for solar energy minus the cheapest LADWP energy source:

$83 - $49 = $34 per MWh.

Assuming that LADWP reaches a 33% RPS level, the unit incremental cost attributable to renewables was derived as one third of $34 which is $11.2/MWh, or $0.011 /kWh.

3.2.1.4 GHG Emission Unit Marginal Costs

Another factor that impacts marginal energy costs is the State of California GHG policy to price carbon (CO_2) emissions. Currently, the regulation sets the floor price of carbon emission allowances in the California Air Resources Board's auction process.

A nine year forecast of annual CO_2 costs per ton was obtained from the 2013 IRP. This stream of nine year cash flows was discounted to obtain a net present value of $102.71 in real 2013 dollars; then an annual annuity of $15.94 in CO_2 costs was derived from this for 2013, based on a 5.45% discount rate. This annual CO_2 cost per metric ton per MWh of $15.94 was multiplied by the lowest plant CO_2 emission rate of 38.1% per MWh (which was determined to be for the Haynes CCT generating plant). This analysis resulted in a unit CO_2 emission cost per MWh of $6.07 or $0.0061 per kWh.

3.2.1.5 Generation O&M Unit Marginal Costs

These costs are associated with the operations and maintenance of the LADWP generation facilities and include: operating labor & supervision expenses for operating generation units, generation station expenses, supervision & other maintenance expenses associated with generation plant, etc.

Generation O&M costs were based on the actual 2013 General Ledger account categories associated with the generation functional service component. The amount utilized for the marginal cost study calculations was $150.8 million. This amount was divided by the total system retail load of 23,383 million kWh, resulting in a unit generation O&M cost of $0.006/kWh.

3.2.2 Transmission Unit Marginal Costs

For the LADWP marginal cost study, transmission marginal costs were comprised of three components: transmission capacity, transmission O&M, and ancillary service costs, as described below.

3.2.2.1 Transmission Capacity

A proxy for new transmission capacity was utilized to develop marginal transmission capacity unit cost based on the Barren Ridge project. Renewables are causing incremental marginal transmission requirements on the system, even though load growth itself is slowing and flattening. This analysis is fairly extensive and is shown in detail in Appendix C, Transmission Capacity Analysis. The result of the analysis is the derivation of a unit transmission capacity charge of $45/kW.

3.2.2.2 Transmission O&M

These costs are associated with the general operations and maintenance of the LADWP transmission system, and include: operating expenses for load dispatching labor, transmission station labor, and other operating expenses associated with the transmission lines, maintenance of the overhead & underground lines, station equipment, etc.

Transmission O&M costs were based on the actual FY 2012-13 General Ledger account categories associated with transmission service. The amount utilized for the marginal cost study calculations was $85.7 million and it resulted in the derivation of a unit transmission O&M charge of $22.02/kW.

3.2.2.3 Transmission Ancillary Services

In addition to the incremental cost of new transmission capacity and transmission O&M, transmission also includes the provision of supporting transmission services or ancillary services. These services include but are not limited to:

- Scheduling, System Control & Dispatch service;
- Reactive Supply & Voltage Control (from generation or other source) service; and
- Regulation & Frequency Response service.

The annual marginal cost for these ancillary services, obtained from the Open Access Transmission Tariff (OATT), was $7.64/kW.

3.2.3 Distribution Marginal Costs

Power is typically delivered to the transmission system from generation plants, regional generators or regional interties at 500/230 kV or higher voltages. From the transmission system, this power typically goes through three stages of voltage drops through transformers to the LADWP distribution system: from 500/230 kV to 34.5 kV (sub-transmission voltage), from 34.5 kV to 4.8 kV (primary voltage), and from 4.8 kV to between 110 and 480 volts at the customer premises (secondary voltage).

When there is an increase in the planned level of capacity, additional transformer capacity must be added at each of these steps to accommodate the increased capacity. Additional substation facilities may be required as a result of increases in transformer capacity. Further, an increase in the number of distribution circuits serving a local area may also be required.

3.2.3.1 Voltage level Differentiation

Distribution facilities are specifically assigned to certain customers or classes of customers who use the specific facilities. LADWP customers are differentiated by three voltage levels; therefore LADWP distribution costs have been identified and assigned to the same three levels of voltage:

- Distribution @34.5 kV (sub-transmission);
- Distribution @4.8 kV (primary); and
- Secondary Distribution.

This methodology facilitates the appropriate determination of distribution costs for each customer class based on utilization (or lack thereof) of the distribution facilities by that customer class.

3.2.3.2 Cost Causation Factors

The costs of sub-transmission and distribution capacity are fixed costs and do not vary with the quantity of energy transmitted. Therefore, these capacity-related distribution costs are mainly classified as demand related. Consequently, they are calculated for each customer class on the basis of demands imposed on the system.

The delivery system is designed and constructed to meet the expected peak demand placed on it. This design demand is a localized cost driver; portions of LADWP's delivery system peak at different times depending on the area of the system, as the mix of customers and facilities used also varies by the area of the system. Consequently, non-coincident peak demand (NCP), which represents the maximum demand for a homogenous class of customers, is the most appropriate mode to determine local facility costs such as those of substations and primary and secondary distribution facilities. The use of non-coincident peak demand constitutes standard industry practice for determining distribution costs for customer classes.

The analysis of distribution capacity and O&M costs is extensive and is shown in Appendix D, Distribution Capacity and O&M Marginal Unit Costs.

3.2.4 Customer Related Marginal Costs

Some expenses for the electric system are directly attributable to the number of customers served. For the LADWP marginal cost study, these costs included the provision of customer meters and customer account expenses.

3.2.4.1 Meter Costs

The capital cost of providing a meter for each customer class was based on data received from the LADWP Power System Engineering Department; meters for residential customers are typically less expensive than those provided for commercial and industrial customers. It was assumed that the average life for the meters was 10 years.

Based on the 5.45% cost of capital and a 10 year average life of the meter for each customer class, an annual total unit capital cost for a meter was calculated for each major customer class. For instance, it was estimated that the total capital cost for a residential meter was $50; based on this estimate, the annual annuity cost or the unit marginal cost associated with a residential meter was $6.62. A similar calculation was completed for each other major customer class.

3.2.4.2 Customer Account Expenses

As described above, certain expenses are directly associated with the number of customers on the LADWP system including Customer Records & Collection, Metering Expenses, Meter Reading, etc. For the marginal cost study, these expenses were categorized as Customer Account Expenses and were determined to be $105 million from the FY 2012-13 General Ledger.

A vast majority of customers on the LADWP system (1,275,567 or 86%) are residential. It was determined that compared to a residential account, it involved more time, effort and expense to serve a commercial or industrial account. Consequently, in order to properly reflect this difference, weights were assigned to each customer class (based on service complexity) in the determination of Customer Account

Expenses for each customer class. For example, it was estimated that servicing an A1 (small commercial) customer involved five times the effort required for servicing an R1 (residential) customer. Consequently, a weight of 5 was assigned to the A1 category (compared to a weight of 1 for the R1 category) in the determination of marginal Customer Account Expenses for the A1 customer class. The customer weights used for the marginal cost study are depicted in Figure 14 below. The unit marginal cost for Customer Account Expenses was determined to be $71.26 per customer per year.

Figure 14: Weights for Customer Account Expenses

	R1	A1	A2	A3	Other
Customer Weight	1	5	15	50	15

3.2.5 Indirect General Marginal Costs

LADWP incurs some expenses that are intrinsic to the general operation of the Power System and can be classified as indirect general costs or adders. A brief description of these costs is provided below:

3.2.5.1 General Plant Expenses

These expenses pertain to the depreciation, property taxes and debt servicing costs associated with assets that are utilized in the general operation of the Power System, and not directly tied to the functional components like generation, transmission, distribution, etc.

The total FY 2012-13 expense associated with depreciation, debt and property tax expenses (accounts 503, 505, 507, 530-536) was estimated as $684 million from the General Ledger.

Based on an analysis of General Ledger plant data, it was estimated that general plant assets represented about 9.56% of the total electric plant assets for the LADWP Power System. Therefore, 9.56% of the Total 2013 Depreciation, Property Tax and Interest Expense, or $65.4 million, was assigned to General Plant Expenses and added to the overall plant expense.

A unit general plant marginal cost of $0.0028/kWh was calculated by dividing the $65.4 million general plant adder by the total system retail load of 23,383 million kWh.

3.2.5.2 Administrative & General (A&G) Expenses

These costs refer to the overall general expenses incurred in the administration of the Power System and include expenses for: accounting & collections, sales & marketing expenses, administrative & general salaries and other miscellaneous general expenses. These costs were obtained from the General Ledger (accounts 890-946) and amounted to $166.6 million for FY 2012-13. Dividing this amount by the total system retail load of 23,383 million kWh results in a unit A&G marginal cost of $0.0071.

3.2.5.3 City Transfer Expenses

The City Transfer refers to the annual transfer of funds to the City of Los Angeles, which was $246.5 million for FY 2012-13. This transfer amount was divided by the total system retail load of 23,383 million kWh to determine a unit City Transfer marginal cost of $0.0105/kWh.

3.3 Summary of Unit Marginal Costs by Functional Component

Figure 15 provides a summary of the marginal cost study results. The table lists the unit marginal cost for each functional sub-component, the cost causation factor or billing unit basis for each sub-component, and the methodology and source for determining the marginal costs. The marginal cost revenue requirements and the marginal cost revenue requirements ratios for each customer class are ultimately determined by applying these marginal unit costs to the appropriate customer class units.

Figure 15: Summary of Unit Marginal Costs by Functional Component

Functional Component	Marginal Cost	Billing Units	MC Revenue Determination Method & Source
Transmission			
Transmission Capacity+ losses	$45.12	$/CP kW/yr	Surrogate Transmission Capacity Expansion Project
Integration/Ancillary Services	$7.64	$/CP kW/yr	Open Access Transmission Tariff (OATT)
Transmission O&M	$22.02	$/CP kW/yr	Based on General Ledger (GL) Analysis FY 2012-13
Generation			
Generation Energy + losses	$0.0344	$/kWh	Based on hourly system lambda forecast from ProSym model
Generation O&M	$0.0064	$/kWh	General Ledger Analysis FY2012-13
Renewable Portfolio Standard	$0.0113	$/kWh	2013 IRP estimate
GHG Emission Cost	$0.0061	$/kWh	2013 IRP estimate
Total Generation Energy	$0.0582	$/kWh	
Generation Capacity Plant	$108.20	$/kW/yr	Based on annual cost of combustion turbine from IRP 2013
Distribution by Voltage Level			
Distribution Capacity at 34.5 kV (Sub-tran)	$15.00	$/NCP kW/yr	Analysis of change in real cost versus capacity change
Distribution O&M @ 34.5 (sub-tran)	$11.58	$/NCP kW/yr	Based on General Ledger Analysis FY 2012-13
Distribution Capacity at 4.8 kV	$76.82	$/NCP kW/yr	Analysis of change in real cost versus capacity change
Distribution O&M @ 4.8 kV	$59.31	$/NCP kW/yr	Based on General Ledger Analysis FY 2012-13
Distribution Secondary	$31.43	$/NCP kW/yr	Analysis of change in real cost versus capacity change
Distribution O&M Secondary	$24.27	$/NCP kW/yr	Based on General Ledger Analysis FY 2012-13
Customer Account Expenses	$71.26	$/customer/year	Based on General Ledger Analysis FY 2012-13
Meter Cost by Tariff (average)	$6.72	$/customer/year	Annualized Cost of installing new meters
A&G & Other			
General Plant Costs	$0.0028	$/kWh	Proration of Debt & Depreciation based on Plant ratios from GL
A&G Costs	$0.0071	$/kWh	As an adder; based on General Ledger Analysis FY 2012-13
City Transfer Costs	$0.0105	$/kWh	As an adder; based on General Ledger Analysis FY 2012-13
Total adder	$0.0205	$/kWh	
Inflation Assumption	2.5%		IRP 2013
Cost of Capital , %i	5.45%		Financial Planning Assumption
Average System Marginal Cost in $/kwh	**$0.147**	$/kWh	**Result from Marginal Cost Study**
Average System Current Cost in $/kwh	**$0.131**	$/kWh	**Current average system wide rate**

The average system-wide marginal cost is $0.147 per kWh. This amount represents the summation of the marginal cost revenue requirements for each customer class, divided by the summation of the LADWP system FY 2012-13 kWh load for all customer classes. The corresponding current average system-wide rate is $0.131 per kWh.

4 CALCULATION OF MARGINAL COST REVENUE REQUIREMENT

Marginal cost revenue requirements for each major customer class are determined based on the unit marginal cost for each functional component/sub-component and the corresponding cost causation factor) by functional component for each customer class. Figure 16 provides a list of key cost causation factors for each customer class.

Figure 16: Annual Cost Causation Factors for Each Customer Class

Cost Causation Factors	R1*	A1*	A2*	A3*	Other	Total w/o Owens Valley
NCP12 (kW)	1,755,951	504,779	627,418	1,589,646	41,020	4,518,814
	38.9%	11.2%	13.9%	35.2%	0.9%	100.0%
NCP1 (kW)	2,583,130	608,376	746,909	2,027,460	41,020	6,006,894
	43%	10%	12%	34%	1%	100%
CP 1 (kW)	1,899,043	521,175	612,515	1,678,041	0	4,710,773
	40%	11%	13%	36%	0%	100%
CP 12 (kW)	1,516,369	453,320	514,460	1,393,394	13,673	3,891,216
	39%	12%	13%	36%	0%	100%
Customers (#)	1,275,567	173,462	13,194	5,562	6,525	1,474,309
	86.5%	11.8%	0.9%	0.4%	0.4%	100.0%
Energy @ the Meter (kWh)	7,524,856,175	2,995,566,290	3,202,058,236	9,510,066,485	149,967,510	23,382,514,696
	32.2%	12.8%	13.7%	40.7%	0.6%	100.0%
Energy with Losses	8,311,956,131	3,308,902,524	3,488,749,183	10,218,249,436	157,810,810	25,485,668,085
	32.6%	13.0%	13.7%	40.1%	0.6%	100.0%

The summation of the marginal cost revenue requirements for all the individual functional components and sub-components comprises the aggregate marginal cost revenue requirement for each customer class. The marginal cost revenue requirement determination by customer class is summarized by the following equations:

- $Customer\ Class\ MC\ Revenue\ Requirement\ by\ Functional\ Component = Unit\ MC\ for\ Functional\ Component * Cost\ Causation\ Factor\ (for\ specific\ customer\ class)$
- $Total\ Customer\ Class\ MC\ Revenue\ Requirement = Sum\ of\ all\ MC\ Revenue\ Requirements\ for\ all\ Functional\ Components$

The marginal cost revenue requirement for a particular functional component for a specific class of customer is the unit marginal cost for that component times the customer class cost causation factor for that component adjusted for losses. The cost causation factors by customer class appear above in Figure 16. The unit marginal costs by functional component/sub-component appear in Figure 15.

Figure 17 provides a summary of the marginal cost revenue requirement for each major customer class by functional component.

Figure 17: Summary of Marginal Cost Requirement by Functional Component

FUNCTIONAL COMPONENT	R1* Residential	A1* S Commercial	A2* M Commercial	A3* Industrial	Other	Total w/o Owens Valley	UNIT
Transmission	$ 126,637,360	$ 37,858,334	$ 42,253,447	$ 112,578,690	$ 1,141,897	$ 320,469,729	$/CP kW/yr
Generation Capacity	$ 183,240,190	$ 54,779,792	$ 60,649,274	$ 161,994,433	$ 1,634,210	$ 462,297,899	$/CP kW/yr
Generation Energy & O&M	$ 468,400,282	$ 184,195,056	$ 192,607,354	$ 562,872,410	$ 9,233,871	$ 1,417,308,972	$/kWh
Distribution Capacity & O&M @34.5kV	$ 46,663,847	$ 13,414,359	$ 16,673,453	$ 42,244,353	$ 1,090,082	$ 120,086,093	$/NCP kW/yr
Distribution Capacity & O&M @4.8kV	$ 239,035,951	$ 68,715,167	$ 85,409,902	$ -	$ 5,583,955	$ 398,744,975	$/NCP kW/yr
Distribution Capacity & O&M @Secondary	$ 97,813,300	$ 28,118,186	$ -	$ -	$ 2,284,949	$ 128,216,436	$/NCP kW/yr
Meter Costs	$ 8,441,049	$ 1,147,880	$ 174,675	$ 147,230	$ -	$ 9,910,834	$/Customer
Customer Account Expenses	$ 49,382,347	$ 33,576,978	$ 7,661,847	$ 10,643,390	$ 3,789,137	$ 105,053,699	$/Customer
Admin. & General Costs	$ 53,623,373	$ 21,346,902	$ 22,818,398	$ 67,770,311	$ 1,068,693	$ 166,627,677	$/kWh
General Plant Costs	$ 21,049,321	$ 8,379,514	$ 8,957,135	$ 26,602,560	$ 419,505	$ 65,408,034	$/kWh
City Transfer Costs	$ 79,338,468	$ 31,583,812	$ 33,760,963	$ 100,269,572	$ 1,581,185	$ 246,534,000	$/kWh
Total Marginal Cost Revenue Requirement	$ 1,373,625,488	$ 483,115,979	$ 470,966,448	$ 1,085,122,948	$ 27,827,485	$ 3,440,658,348	
Marginal Cost Revenue Requirement Ratio	39.9%	14.0%	13.7%	31.5%	0.8%	100.0%	

5 MARGINAL COST STUDY RESULTS AND IMPLICATIONS

In today's changing and dynamic business environment, the cost of power production in most instances varies by season, by time of day and by historical periods. Therefore, simply calculating accounting costs is not an accurate way to reflect variations over prolonged time periods; costs based on technology and expenditures from the past may no longer be representative of present conditions.

The marginal cost concept can thus assist the utility in more appropriately allocating and recovering the cost of doing business in the future. The electric power industry is dynamic and highly capital intensive. Marginal cost studies facilitate matching future prices with cost recovery responsibility, which is generally considered to be the most fair and equitable method of electric utility pricing.

This phenomenon is exemplified by the current LADWP marginal cost study results, as explained below.

5.1 Customer Class Impacts

Marginal cost ratemaking concepts have commonly been utilized to promote fairness and equity in rates for customer classes. Through appropriate use of marginal concepts, utilities can appropriately allocate the cost of service among customer classes and then appropriately price services for the customer classes.

LADWP is allowed to recover all necessary costs associated with the provision of electric service to various customer classes. These costs, often referred to as the test year revenue requirement, comprise all costs including capital related costs (depreciation, property taxes, and debt servicing costs), operations and maintenance costs, fuel & power costs, administrative & general costs, etc. For the test year FY 2012-13, this aggregate revenue requirement amount, collected through the retail rates for each customer class, was approximately $3,071 million.

The LADWP marginal cost study calculates the required revenues on a forward-looking basis, using data for the FY 2012-13 test year as a starting point. The revenue requirement based on the marginal cost study generally exceeds the accounting-cost-based revenue requirement. For the LADWP marginal cost study, the total marginal costs are approximately $3,441 million, which is 12% higher than the FY 2012-13 revenue requirement of $3,071 million. Since marginal costs are forward-looking, it is normal for the marginal cost revenue requirement to be higher than the current revenue requirement in total.

Over time, cost structures change, and, as a result, marginal cost of service studies should be conducted periodically to reflect forward-looking allocation of costs among customer classes. For example, California legislation and regulations have increased the required use of renewable resources. The marginal cost of service study allocates these forward-looking renewable costs across customer classes based on cost causation.

The summation of the customer class marginal cost revenue requirements for all the individual functional components and sub-components comprises the marginal cost revenue requirement for each customer class. A marginal cost revenue requirement percent to total is then calculated for each customer class, based on its proportion of the customer class marginal cost revenue requirement to the total LADWP marginal cost revenue requirement.

The marginal cost of service study for LADWP results in a different set of customer class revenue percentages of total revenue, as compared to the current revenue and cost of service structure. For example, based on the marginal cost study results (shown in Figure 18), the marginal cost revenue requirement percent for the residential (R1) customer class is 39.9%, while the corresponding ratio based on current revenues for FY 2012-13 is 32.9%. Conversely, based on marginal costs, the Industrial (A3) customer class would be allocated a lower revenue requirement of 31.5% compared to the current revenue level of 37.1%.

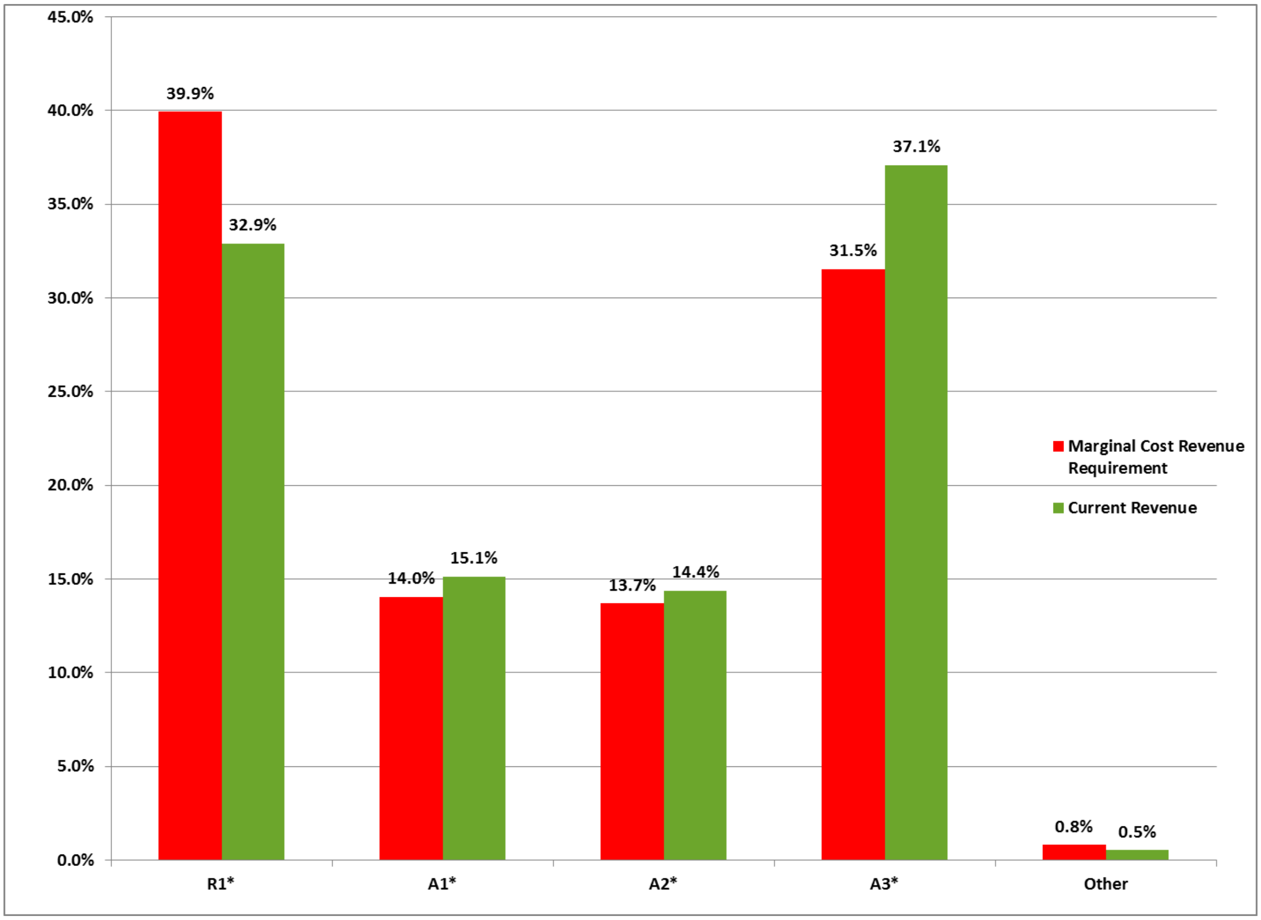
To avoid over/under collection of costs and more accurately reflect cost causation principles, the customer class percentages based on the marginal cost of service study can be applied to the approved annual revenue requirement, to allocate the approved revenue requirement to major customer classes.

Figure 18: Comparison of Marginal Cost Revenue Requirements & Current Revenue by Customer Class

Comparisons	Residential	S Commercial	M Commercial	Industrial	Other	Total
Total MC Revenue Requirement	$1,373,625,488	$483,115,979	$470,966,448	$1,085,122,948	$27,827,485	$3,440,658,348
Marginal Cost Revenue Requirement Percentage	39.9%	14.0%	13.7%	31.5%	0.8%	100.0%
FY 2013 Current Retail Revenue	$1,010,099,373	$464,812,908	$441,103,892	$1,138,691,239	$16,187,848	$3,070,895,260
Current Revenue Percentage	32.9%	15.1%	14.4%	37.1%	0.5%	100.0%

Figure 19 graphically compares the marginal cost revenue requirements ratios and the current revenue ratios for the various customer classes.

Figure 19: Comparison of Marginal Cost Revenue Requirement & Current Revenue Percentages by Customer Class



The current LADWP marginal cost study results demonstrate that a re-alignment of revenue requirements among the customer classes is likely warranted.

These results are supported by an LADWP embedded[11] cost of service analysis, which produced similar customer class percentages as the marginal cost of service study (See Appendix B: LADWP Embedded Cost Analysis).

[11] Embedded Cost analysis is also referred to as Average Embedded Cost Analysis.

APPENDIX A: GLOSSARY OF TERMS

Ancillary Services: Services necessary to support the reliable provision and transmission of energy from resources to loads. These services include regulation, spinning, and non-spinning reserves, replacement reserves, reactive voltage (var) support and black start capability.

Annuity: An annuity is a terminating "stream" of fixed payments, i.e., a collection of payments to be periodically received over a specified period of time. The valuation of such a stream of payments entails concepts such as the time value of money. For the marginal cost study, annuities have been calculated to determine annual payments or annual revenue requirement associated with the determination of marginal costs for capital investments. These annuities have been calculated based on the IRP cost of capital of 5.45%.

Cogeneration: Customers who own electrical generating facilities that are connected with LADWP's system but are not subject to the Net Energy Metering (NEM) service rider.

Coincident Peak Demand: The aggregate demands of a group of customers at a particular time, usually at the time of a customer group's peak or the system peak.

- CP1: Coincident peak one month - represents the system peak in the peak month of the year.
- CP12: Coincident peak 12 months - represents the average of the coincident peaks for each month of the year.

Cost Drivers: Fundamental aspects of customer demand for services that directly cause LADWP to incur costs.

Greenhouse Gas (GHG): Byproduct of the burning of energy generation fuels that is emitted to the atmosphere and absorbs and emits radiation from the atmosphere to cause the greenhouse effect.

Handy Whitman Index: A measure of the annual rate of inflation in capital investments. It is published annually by Whitman, Requardt and Associates, for a wide range of industries and investment categories. Extensively used by the utility industry to gauge the rate of inflation in capital investments by geographic sectors, as well as by asset category like generation facilities, transformers, distribution assets, etc.

Load: The amount of electric power delivered or required at any specified point on an electrical system. Load primarily originates at the power-consuming equipment of the customer.

Marginal Cost: Change of cost that arises from providing an additional unit of a good or service.

Marginal Cost Revenue Requirement: Revenues that would result if all the aspects of electric service were priced to reflect the marginal costs of providing such service.

Net Energy Load: Net Energy Load is the actual load at the transmission inlets to the LADWP system, before transmission & distribution & other losses.

Non-Coincident Peak Demand: The individual customer's peak demand measured irrespective of the time of system peak and irrespective of the peak demand of any other customer or group of customers.

Open Access Transmission Tariff (OATT): The document approved by the Los Angeles City Council on July 1, 2014, which contains the terms and conditions, including rates, under which LADWP makes its transmission facilities available for use by the public after all of LADWP's native load needs are met.

Primary Voltage: Facilities at which electric power is taken or delivered at 4.8 kV.

Present Value: Also known as present discounted value and is a future amount of money that has been discounted to reflect its current value, as if it existed today. The present value is always less than or equal to the future value because money has earning potential, a characteristic referred to as the time value of money. For the LADWP study, present value has been computed by discounting future cash flows by the IRP cost of capital of 5.45%.

ProSym Model: LADWP uses an energy production cost simulation model called ProSym. The ProSym Model is a load dispatch model that computes estimated hourly system lambda costs, and incorporates the future impact of reduced reliance on once-through cooling units and increased generation from solar and wind sources.

Regression Analysis: Statistical process for estimating the relationships among variables for the purpose of predicting future values. It includes many techniques for modeling and analyzing several variables, when the focus is on the relationship between a dependent variable and one or more independent variables. More specifically, regression analysis helps one understand how the typical value of the dependent variable changes when any one of the independent variables is varied, while the other independent variables are held fixed.

Revenue Allocation: The process of assigning the revenue requirement to rate groups or customer classes.

Secondary Voltage: Facilities at which electric power is taken or delivered at or below 480 V and at or above 110 V.

System lambda: The system lambda is defined as the cost of the next kilowatt-hour that can be produced by an electrical supply system's generating unit. It serves as a proxy for the generation energy marginal costs.

System Loss: The loss in load from the point of supply (transmission inlets) to the customer's meter. Power System losses relate to transmission and distribution line losses, and other losses (e.g. energy theft, metering errors, etc.).

Time of Use (TOU) Rates: Rates that are charged for energy depending on the time of day the energy is used.

APPENDIX B: LADWP EMBEDDED COST ANALYSIS

The Department conducted an embedded[12] cost of service analysis utilizing an embedded cost of service model; the results from this model substantiate the conclusions of the marginal cost study. The embedded cost of service methodology was based on standard industry techniques.

The LADWP embedded cost model was based on data provided by the LADWP Budget group; a detailed analysis was conducted by the Budget group to allocate the historical costs on the system to functional components. The embedded cost analysis involves three major steps:

- Functionalizing or unbundling the utility costs according to generation, transmission, distribution, customer or general (based on Budget group analysis);
- Classification of these costs as to whether they were related to demand (kW), energy (kWh) or customer, or a combination thereof.
- Finally, the resulting cost determinations were allocated to the various customer classes, based on appropriate allocation criteria.

Following the steps outlined above, embedded cost revenue requirements were determined for each customer class. An embedded cost revenue requirement percent to total was calculated for each customer class. Figure 20 below displays the results from the embedded cost model. Since the focus of this report is the marginal cost study, the results of the embedded model are simply presented here for comparison purposes only.

Figure 20: Comparison of Embedded Cost Revenue Requirement and Current Revenue by Customer Class

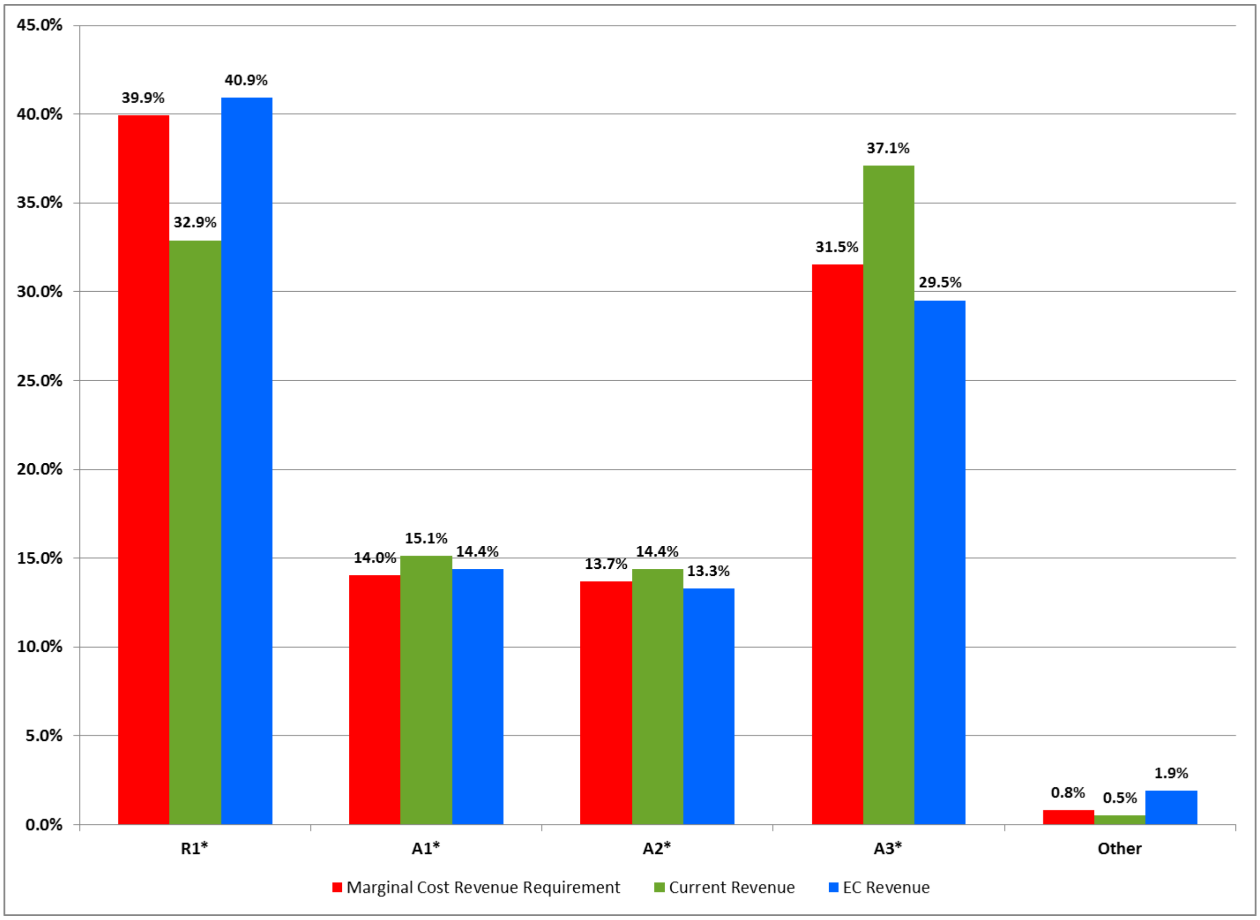
COST STUDIES 2013 Results	R1* Residential	A1* S Commercial	A2* M Commercial	A3* Industrial	Other	Total
Total MC Revenue	$1,373,625,488	$483,115,979	$470,966,448	$1,085,122,948	$27,827,485	$3,440,658,348
Marginal Cost Revenue Percentage	39.9%	14.0%	13.7%	31.5%	0.8%	100.0%
FY 2013 Current Revenue	$1,010,099,373	$464,812,908	$441,103,892	$1,138,691,239	$16,187,848	$3,070,895,260
Current Revenue Percentage	32.9%	15.1%	14.4%	37.1%	0.5%	100.0%
Total Embedded Revenue	$1,273,095,936	$447,346,278	$413,399,145	$918,605,926	$59,100,631	$3,111,547,915
Embedded Revenue Percentage	40.9%	14.4%	13.3%	29.5%	1.9%	100.0%

The results from the embedded cost model are similar to the marginal cost study. For example, the embedded cost and marginal cost revenue requirement percentages for the residential (R1) customer class are 40.9% and 39.9% respectively, while the corresponding ratio based on current revenues for FY 2012-13 is 32.9%. Conversely, based on embedded costs and marginal costs, the Industrial (A3) customer class would be allocated a lower revenue requirement of 29.5% and 31.5%, respectively, compared to the current revenue level of 37.1%. Figure 21 provides a comparison of revenue requirement

[12] An embedded cost analysis is based on historical or "embedded" costs for the electric system.

percentages by customer class for the embedded cost analysis, the marginal cost study and the current revenue.

Figure 21: Comparison of Embedded Cost and Current Revenue Percentages



APPENDIX C: TRANSMISSION CAPACITY ANALYSIS

Transmission capacity marginal costs for the LADWP system were estimated based on a proxy methodology utilizing the new Barren Ridge Renewable Transmission expansion. LADWP is proposing the Barren Ridge Renewable Transmission Project (BRRPT) to access clean, renewable energy resources in the Tehachapi Mountain and Mojave Desert areas of Southern California. This transmission line and substations project will bring renewable energy resources to the City of Los Angeles, and will also enhance power delivery reliability. The project is in Kern and Los Angeles Counties and will consist of:

- Construction of a 230 kilovolt (kV) transmission line from the LADWP Barren Ridge Switching Station to Haskell Canyon on double-circuit structures (involving approximately 13 miles of National Forest System lands and 4 miles of Bureau of Land Management (BLM) managed public lands)
- Addition of a 230 kV circuit on the existing double-circuit structures from Haskell Canyon to the Castaic Power Plant (involving approximately 4 miles of National Forest System lands and 300 feet of BLM managed public lands)
- Upgrade the existing Barren Ridge – Rinaldi 230 kV transmission line with larger capacity conductors between the Barren Ridge Switching Station to Rinaldi Substation (involving approximately 13 miles of National Forest System lands and 4 miles of BLM managed public lands)
- Construction of a new electrical switching station at Haskell Canyon.
- Expansion of the existing Barren Ridge Switching Station.

Although Barren Ridge is a relatively small transmission expansion project, it represents a recent project providing a reasonable basis for estimating an LADWP transmission system capacity expansion. The methodology followed for this analysis was to determine the capital expenditures associated with the Barren Ridge transmission expansion, the corresponding increase in system capacity (per kW) and the resulting transmission capacity unit marginal cost.

The derivation of the unit marginal transmission capacity charge per kW is explained below.

- An expenditure profile was obtained for the Barren Ridge project from the 2013 IRP. Some of the capital costs were incurred prior to 2012; some of the costs are spread over the period 2013-2021, with a majority of the costs expected to be incurred in 2014-2015.
- The estimated project cost was determined to be $184.3 million in 2013 dollars.
- Based on a useful life of 40 years for these facilities and a discount rate of 5.45%, an annual cost annuity for the transmission capacity expansion was determined to be $11.4 million.
- Since the incremental capacity for this project is estimated at 1,900 MW, the annual capacity cost per kW is $6.00 ($11.4 million / 1,900 MW). This incremental cost is incurred for a transmission line expansion of 62 miles representing the Barren Ridge project.
- The total LADWP transmission system comprises 3,747 miles, and the useful life of transmission lines is deemed to be 40 years; therefore, it was estimated that 2.5% of circuit miles, or 93.7 miles, would need replacement annually.

- Since the Barren Ridge project constitutes 62 miles, it was estimated that on average, it would cost 1.51 times more than the Barren Ridge project to undertake an average annual system circuit mile replacement of 93.7 miles.
- Consequently, by extrapolation, the unit marginal cost per kW for the system was obtained as $9.07 per kW, i.e. 1.51 times the unit capacity cost of $6 for Barren Ridge. Assuming an expected loading factor of 20.1% for this project, the final transmission capacity unit marginal cost was estimated to be $45.12 per kW.

APPENDIX D: DISTRIBUTION O&M AND CAPACITY MARGINAL UNIT COSTS

D.1. Distribution O&M Costs by Voltage

Like Transmission O&M costs, Distribution O&M costs are associated with the general operations and maintenance of the LADWP distribution system. These costs include: operating expenses for load dispatching labor, distribution station labor, miscellaneous operation expenses, and maintenance of the overhead conductors, poles, structures, towers, station equipment, etc.

D. 1.1. Determination of Total Distribution O&M Costs

Distribution O&M costs were based on the actual FY 2012-13 General Ledger accounts (G/L Accounts 840-883) associated with distribution service. The cost amount utilized for the study calculations was $281.9 million. These aggregated Distribution O&M Expenses were then allocated to the three voltage levels, as described below.

The General Ledger data is not differentiated by voltage level detail. Consequently, an alternative method was developed to calculate Distribution O&M costs by voltage level. A detailed analysis was conducted to estimate the capital costs of establishing a new LADWP distribution system. Estimates for various components such as poles, conduit, underground cables, overhead conductors, transformers, individual stations, etc. were obtained separately for 34.5kV, 4.8kV and secondary distribution facilities. This aggregate capital expenditure was estimated at a total of $1,081 million.

The estimated capital expenditure ratios for the three voltage levels were then utilized to allocate the total Distribution O&M Expenses to each voltage level. For instance, the capital expenditures estimated for secondary voltage comprised 19.8% of the total expenditures. Consequently, 19.8% (or $55.9 million) of the total Distribution O&M cost of $281.9 million was determined to be attributable to Secondary voltage.

Figure 22 below provides a breakdown of the estimated capital costs for a new distribution system by voltage levels and the allocation of distribution O&M expenses.

Figure 22 Estimated Capital Cost by Voltage Level

Voltage Level	Estimated Capital Costs	Capital Cost Ratio	O&M Expense Allocation
Secondary Distribution	$214,174,218	19.8%	$55,865,257
4.8 kV Distribution	$666,068,221	61.6%	$173,737,404
34.5 kV Distribution	$200,593,200	18.6%	$52,322,781
System Total	$1,080,835,639	100%	$281,925,443

D.1.2. Calculation of Unit Charge

For each voltage level, Unit Distribution O&M marginal costs were then determined. The O&M expenses estimated above for each voltage level were divided by the corresponding NCP kW to obtain a unit marginal O&M cost per kW. The NCP kW utilized for these calculations equated to the summation of the

NCP kW of the customer classes actually using each voltage level. For example, the total NCP level for the LADWP 34.5 kV system for FY 2012-13 was 4,519 MW. However, for secondary distribution, which is not utilized by A2 & A3, the NCP kW level used for the unit cost was 2,302 MW, which excluded the NCP kW for A2 and A3. Therefore, the unit Distribution O&M cost for secondary was calculated as $24.27/kW, or $55.9 million (secondary O&M costs) divided by 2,302 MW (secondary NCP MW).

Figure 23 below illustrates the distribution facility usage levels for each customer class on the LADWP system.

Figure 23 Distribution Facility Usage By Customer Class (FY 2012-13)

Non-Coincident Peak by Voltage Level	R1*	A1*	A2*	A3*	Other*	Total
NCP12 (kW) @ 34.5 kV Sub-Transmission	1,755,951	504,779	627,418	1,589,646	41,020	4,518,814
34.5 kV Ratio	38.9%	11.2%	13.9%	35.2%	0.9%	100%
NCP12 (kW) @ 4.8 kV Primary	1,755,951	504,779	627,418	0	41,020	2,929,168
4.8 kV Ratio	59.9%	17.23%	21.42%	0.00%	1.40%	100%
NCP 12 (kW) @ Secondary	1,755,951	504,779	0	0	41,020	2,301,750
Secondary Ratio	76.3%	21.9%	0.0%	0.0%	1.8%	100%

D.1.3. Calculation of Distribution Capacity Costs by Voltage

The determination of the marginal cost of distribution capacity is based on an estimation of the historical relationship between incremental investments in distribution and distribution capacity.

Standard industry practice for measuring this relationship is to use linear regression analysis, with real capacity cost as a linear function of demand. The slope of the regression line equals the per-unit marginal cost of distribution capacity.

Distribution Capacity marginal costs for the LADWP study were determined based on this regression technique. The historical annual capacity cost increments (adjusted for inflation) were regressed against the amount of capacity available. The slope of the regression line (regression coefficient) constituted the marginal unit cost of distribution.

The cost causation factor for distribution capacity costs is system non-coincident peak. Coincident peak (CP) demand was used for the calculation of the unit marginal costs and then converted to NCP.

The various steps in this calculation are listed below.

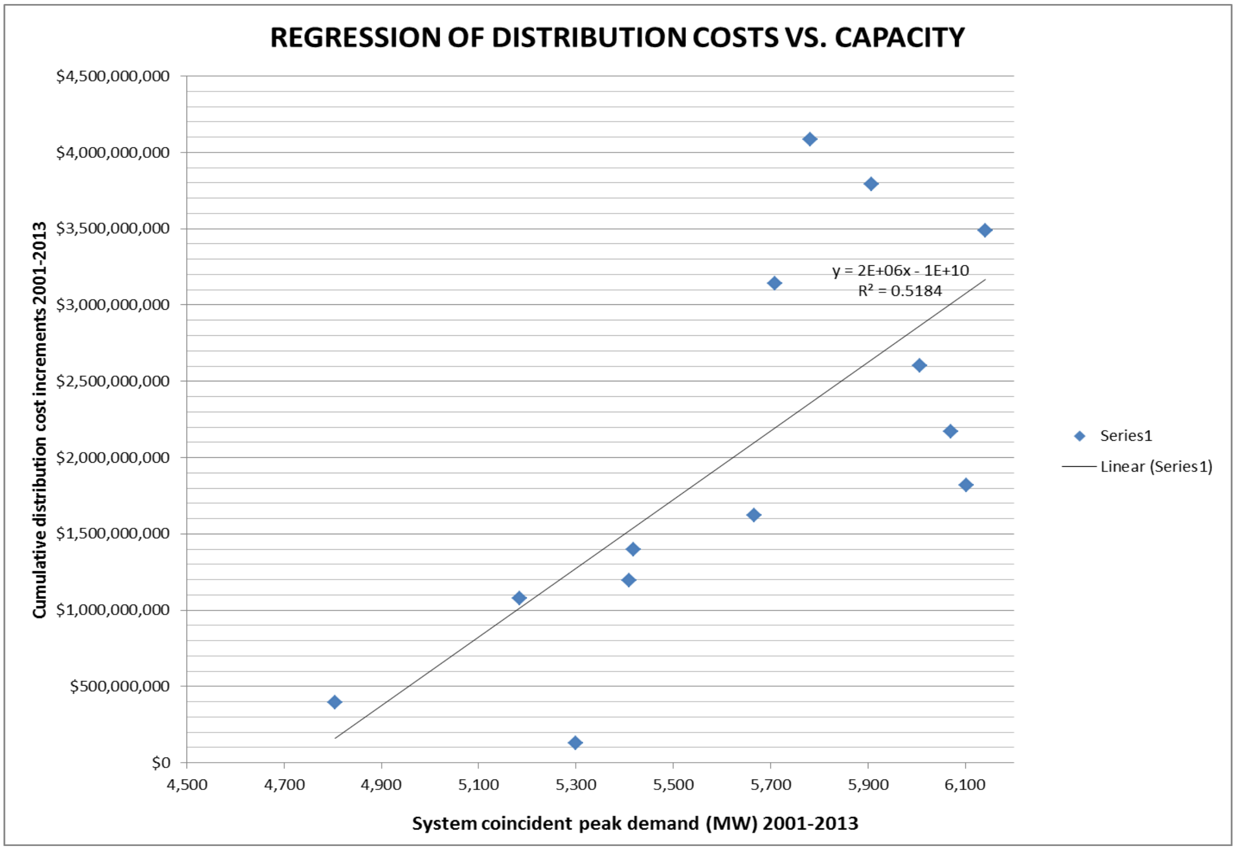
- Distribution gross plant asset data from FY 1999-00 to FY 2012-13 was obtained from the General Ledger by type of account such as poles, towers, overhead & underground conductors, line transformers, etc.
- The annual increments or additions to the distribution gross plant for each year were determined. These historical additions were then converted to current year FY 2012-13 dollars using the Handy Whitman Index for Utility Construction[13].
- Next, the cumulative gross plant additions from FY 1999-00 to FY 2012-13 were determined.
- From historical LADWP load data, the system coincident peak demands in kW were determined for the years 2000 - 2013.

[13] The Handy Whitman Index is a measure of the annual rate of inflation in capital investments, used extensively in the utility industry. It covers different regions as well as different assets like distribution plant, generating units, transmission facilities, etc.

- The cumulative annual gross plant additions (used as a proxy for the capacity costs) were regressed against the annual coincident peak demand in kW (used as a proxy for amount of capacity available).

The regression coefficient or slope of the linear regression equation served as the approximation of the total marginal cost per kW of distribution capacity. This was determined to be $2,247/kW. This total cost was then converted to an annual annuity based on a useful life of 40 years and a 5.45% discount rate, which amounted to $143/kW CP per year. Figure 24 illustrates the relation between the incremental distribution capacity costs and capacity.

Figure 24: Relation of Incremental Distribution Costs and Capacity



This distribution capacity cost per kW for CP was then converted to NCP amounts. The 2013 annual CP demand was 3,891 MW. The aggregate 12 NCP for all customer classes for 2013 was 4,519 MW. Therefore the ratio of NCP/CP amounted to 1.16. Based on this NCP to CP ratio of 1.16, the unit marginal cost of $143/kW CP was converted to a distribution capacity unit marginal cost of $123.25/kW NCP.

Finally, the unit distribution capacity cost of $123.25/kW was allocated to the three voltage levels, based on the percentage of marginal cost estimates for total distribution plant by voltage. By this methodology, the following unit distribution capacity marginal costs were obtained, as shown in Figure 25 below:

Figure 25: Unit Marginal Costs by Voltage (FY 2012-13)

Voltage Level	Estimated Marginal Cost	Unit Capacity Cost $/kW
Secondary Distribution	26%	$31.43
4.8 kV Distribution	62%	$76.82
34.5 kV Distribution	12%	$15.00
System Total	100%	$123.25

D.2. Distribution Capacity Costs by Voltage

Like the distribution O&M costs, distribution capacity marginal costs by voltage are classified as demand related and calculated for the customer classes based on the NCP kW for each customer class. Adjustments are made to the NCP demand factors to account for the fact that some customer classes do not utilize certain distribution facilities. For example, the R1 customer class utilizes all the distribution facilities at all kV levels. Therefore, the bulk of these costs are absorbed by the Residential customer class, as illustrated in Figure 26 below.

As an example, a calculation is illustrated for secondary Distribution Capacity marginal costs in the equation below:

> secondary Distribution Capacity Marginal Costs for R1 = Unit Capacity Cost for Secondary times secondary NCP kW for R1 = $31.43 X 1,755,951 = $55.2 million (which represents 76.3% of total secondary Distribution costs)

In this manner, distribution capacity marginal costs were determined for all three voltage levels for the residential customers, and the summation of these costs constituted the distribution capacity marginal cost for the residential class. The results are displayed in Figure 26 below.

Figure 26: Distribution Capacity MC Revenue Requirements by Customer Class (FY 2012-13)

Voltage Level	R1*	A1*	A2*	A3*	Other*	Total
Secondary Distribution	$55,195,011	$15,866,795	$0	$0	$1,289,373	$72,351,178
Percentage of MC Revenues	76.3%	21.9%	0.0%	0.0%	1.8%	100.0%
4.8 kV Distribution	$134,885,458	$38,775,242	$48,195,904	$0	$3,150,967	$225,007,571
Percentage of MC Revenues	59.9%	17.2%	21.4%	0.0%	1.4%	100.0%
34.5 kV Distribution	$26,331,915	$7,569,581	$9,408,653	$23,838,041	$615,122	$67,763,312
Percentage of MC Revenues	38.9%	11.2%	13.9%	35.2%	0.9%	100.0%
Combined Total Distribution	$216,412,384	$62,211,618	$57,604,557	$23,838,041	$5,055,461	$365,122,062
Percentage of MC Revenues	59.3%	17.0%	15.8%	6.5%	1.4%	100.0%

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LOS ANGELES DEPARTMENT OF WATER AND POWER

POWER SYSTEM RATE ACTION REPORT

Chapter 5: Power Rate Design

July 2015

CONTENTS

FIGURES AND TABLES

FIGURES

POWER RATE DESIGN

5.1 SUMMARY

This chapter discusses the methodology utilized in designing LADWP's electric rates, changes to LADWP's overall rate structure, rates for each major customer class, and trends in the industry.

Rates in this chapter are designed to achieve the following major objectives:

- Affordability;
- Business development;
- Encourage conservation and sustainable customer resources;
- Meet legal requirements;
- Assist in the transformation to a distribution oriented utility;
- Assure financial stability; and
- Utilize marginal cost of service in the rate design.

5.1.1 Introduction

LADWP proposes changes in electric rate design to be implemented for the period beginning late 2015 through June 2020. LADWP proposes three major changes to the rate design:

1. Phased five-year rate change averaging 4.7% per year on a system wide basis[1];
2. Addition of a tiered fixed charge[2] to the Residential (R1A) customer rate structure; and
3. Design of energy charges for all customer classes to encourage distributed generation such as customer-owned solar.

The overall rate structure and rate changes will be phased in over a five-year period to moderate the effect on customers, while continuing to meet financial metric requirements as outlined in Chapter 2. Figure 1 provides a summary of the proposed average customer class rate changes by each fiscal year for the proposed rate period.

[1] All proposed rates are developed based on Financial Plan Case Number 19.

[2] LADWP will present this charge on customer bills as a consumption-based service charge.

Figure 1: Proposed Average Electric Rates and Annual Percentage Increase by Customer Class

Class	FY 2014-15	FY 2015-16		FY 2016-17		FY 2017-18		FY 2018-19		FY 2019-20		Five-Year Average
	$/kWh	$/kWh	Annual %	$/kWh	Annual %	$/kWh	Annual %	$/kWh	Annual %	$/kWh	Annual %	Annual %
R1A	$0.1515	$0.1595	5.3%	$0.1656	3.8%	$0.1767	6.7%	$0.1849	4.7%	$0.1953	5.6%	5.2%
A1A	$0.1753	$0.1814	3.5%	$0.1862	2.6%	$0.1958	5.2%	$0.2025	3.4%	$0.2112	4.3%	3.8%
A2B	$0.1556	$0.1622	4.2%	$0.1676	3.3%	$0.1777	6.1%	$0.1850	4.1%	$0.1943	5.0%	4.5%
A3A	$0.1391	$0.1447	4.1%	$0.1498	3.5%	$0.1595	6.5%	$0.1662	4.2%	$0.1748	5.2%	4.7%
System Average	**$0.1506**	**$0.1573**	**4.4%**	**$0.1627**	**3.4%**	**$0.1730**	**6.3%**	**$0.1803**	**4.2%**	**$0.1896**	**5.2%**	**4.7%**

Changes to the Residential customer rate structure are designed to provide a transition to an enhanced combination of fixed and variable charges that better match costs, while continuing to encourage solar and other distributed generation solutions. Energy rates for most Commercial and Residential classes for peak periods will reach levels that continue to provide incentives to install solar for customers. However, even after the proposed changes, LADWP will continue to have some of the lowest electricity rates in California.

5.1.2 Legal Considerations

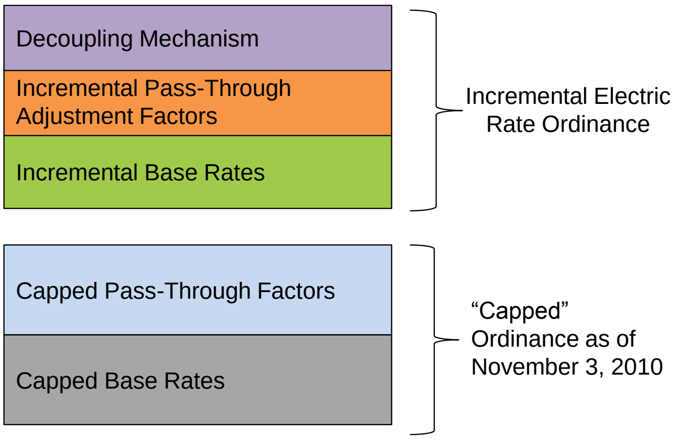
While there may be a desire to undertake a modification of the current rate structure to provide a simpler rate framework, several lawsuits have recently been filed asserting that Proposition 26 does not permit LADWP's annual transfer of monies, financial conditions allowing, from the Power Revenue Fund ultimately to the City's General Fund. The City disputes the merits of those lawsuits. While the transfer is being contested, the City will continue to adopt an electrical rate structure that preserves the rates in effect on November 3, 2010, and layers incremental charges on top of them. Therefore, for purposes of the current rate action, LADWP proposes that the results of the cost of service studies and the impact of the new revenue requirements for power service be applied to only the Incremental Electric Rate Ordinance.

5.1.3 General Rate Structure

The rate structure includes a combination of the electric rate ordinance in effect as of November 3, 2010, No. 168436, as amended (Electric Rate Ordinance), including billing of base rates and pass-through adjustment factors capped at their levels as of November 3, 2010, and an incremental electric rate ordinance, No. 182273 (Incremental Electric Rate Ordinance), with both incremental base rate and incremental pass-through adjustment factors as outlined in Figure 2. LADWP's power rate structure has historically included base rates and pass-through adjustment factors tied to specific costs in combination with some form of a "decoupling" mechanism. Pass-through adjustment factors often reflect costs that LADWP does not control such as fuel costs or regulatory mandates on renewable generation resources. The use of these mechanisms is standard utility practice for both publicly-owned utilities and investor-owned utilities (IOUs).

For LADWP, billing of the base rate and pass-through factors of the Electric Rate Ordinance is limited to their levels as of November 3, 2010. Base and pass-through rates due to the increased revenue requirement since November 3, 2010 are established in the Incremental Electric Rate Ordinance. The incremental structure includes a decoupling mechanism that helps to provide incentives for conservation and expansion of customer-owned solar and other forms of distributed generation by allowing recovery of fixed costs. LADWP proposes to continue this rate structure with some minor adjustments to the adjustment factors.

Figure 2: Proposed Electric Rates Structure



5.1.4 Industry Trends

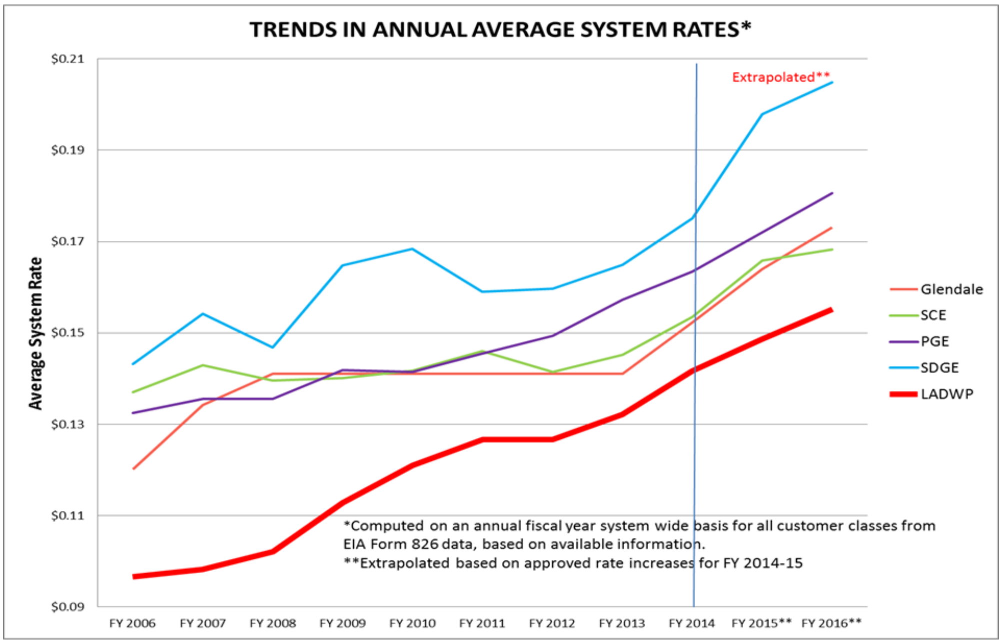
In preparing the rate design proposal, LADWP noted industry trends including, but not limited to the following three major trends:

1. Increasing overall rate levels in California;
2. Implementing fixed charges for residential customers; and
3. Setting higher energy charges during peak periods and promoting net energy metering policies that provide economic incentives for customer-installed solar power generation.

Increasing California Electric Rates

Rate increases have been common for electric utilities in California; this is a trend that is expected to continue in future years. Figure 3 compares LADWP system average rates (total system retail revenue divided by total retail sales) to the system average rates for several other California Utilities. LADWP's system average rates are presently lower than its peers.

Figure 3: Comparison of California Utility System Average Rate Levels



The three major California IOUs have all increased rates recently and have announced intentions to continue this trend. These utilities have experienced significant cost increases for similar reasons as LADWP, such as compliance with the California renewable energy targets.

Most publicly-owned utilities are facing the same cost pressures and increasing rates accordingly. For example, Glendale Water and Power has received approval for a five-year phased in rate change of about 25.4% in total (5.1% on average per year). LADWP proposes a system average rate increase of 4.7% over the next five years. IOU rate trends have recently averaged around the same level and would be expected to continue. Therefore, LADWP is expected to retain its favorable rate levels relative to peer utilities.

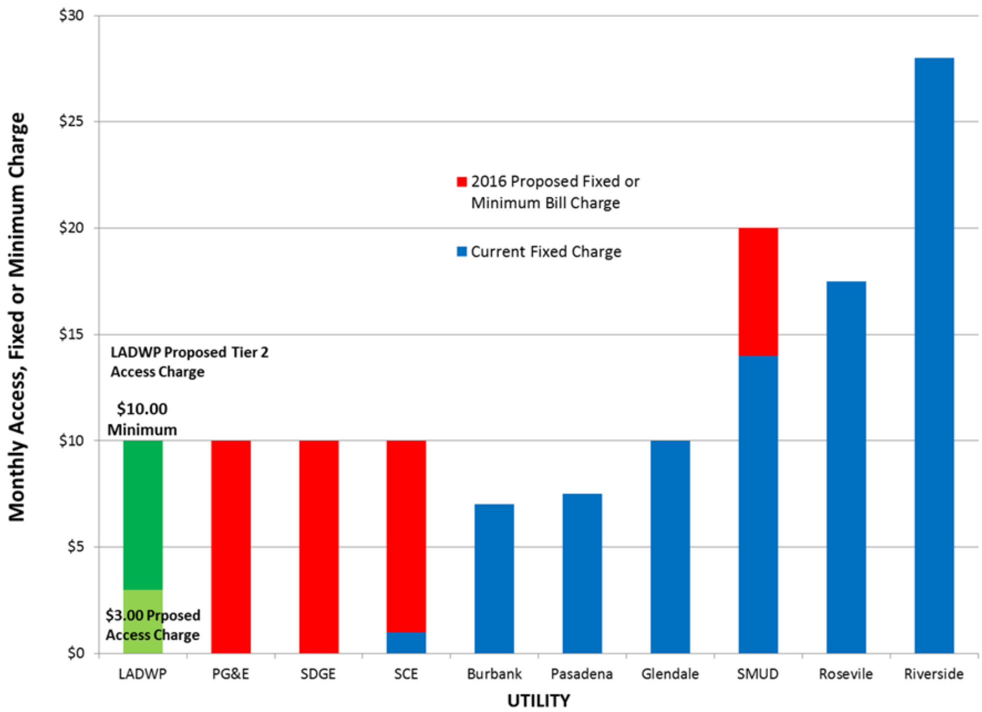
Fixed Charges for Residential Customers

The major structural change in LADWP's proposed rate design is the addition of a new monthly tiered fixed charge for Residential customers. LADWP is proposing to implement a monthly tiered fixed charge which increases based on historical usage in conjunction with the existing minimum charge. This approach is developed to lessen the effect of fixed charges on low usage customers.

Several publicly-owned utilities are also implementing or increasing the level of monthly fixed charges. All three major California IOUs are planning to implement substantial increases to their fixed monthly charges or minimum bill charges; however, at the time of this report, the California Public Utilities Commission (CPUC) is still determining the final nature of the changes (proceeding R-12-06-013). A fixed monthly charge bill component applies a set amount to the customer monthly bill. A minimum base bill amount is charged to the customer unless other charges exceed the minimum bill amount. Both types of charges provide a fixed amount of revenue irrespective of consumption. Fixed monthly charges as well as minimum bill charges are being considered as part of the CPUC process and point toward a growing trend of introducing fixed type charges in the customer bill.

Figure 4 provides an analysis of fixed charges and or minimum bill charges for residential customers in place or announced for a variety of California electric utilities.[3] LADWP's proposed fixed charge for the average residential customer will be the lowest among the peer utilities.

Figure 4: Comparison of Electric Utility Residential Fixed and or Minimum Bill Charges (Planned for 2016)



Energy Charges and Net Energy Metering Policies to Encourage Solar Installation

The three major California IOUs have developed specific rate structures approved by the CPUC to encourage customer-installed solar facilities in the last year. All California utilities, both publicly-owned utilities and IOUs, have some form of net energy metering (NEM). Recent legislation and CPUC rulings have required NEM for most utilities and tightened the NEM requirements.

NEM allows the retail electric rate to be used as a direct incentive for solar generation installation by the customer with some limitations. LADWP's NEM policy and the level of peak period energy rates in this proposal are sufficient to encourage customer-installed solar generation.

[3] The analysis was based on LADWP's proposed tier 2 fixed charge and other utility planned fixed charges or minimum charges proposed for 2016.

5.1.5 Residential Customer Rate Design and Rates

As discussed earlier, the major proposed change to the Residential rate is the implementation of a tiered fixed charge. The proposed rates are designed to recover costs in a manner that allows LADWP to transition to a distribution based utility with back-up generation support that will be indifferent to the use or types of new customer generation. These changes are intended to provide the correct price signals for conservation and sustainable technology adoption. The results of the marginal cost study were used to guide the development of tier thresholds, rates and fixed charges.

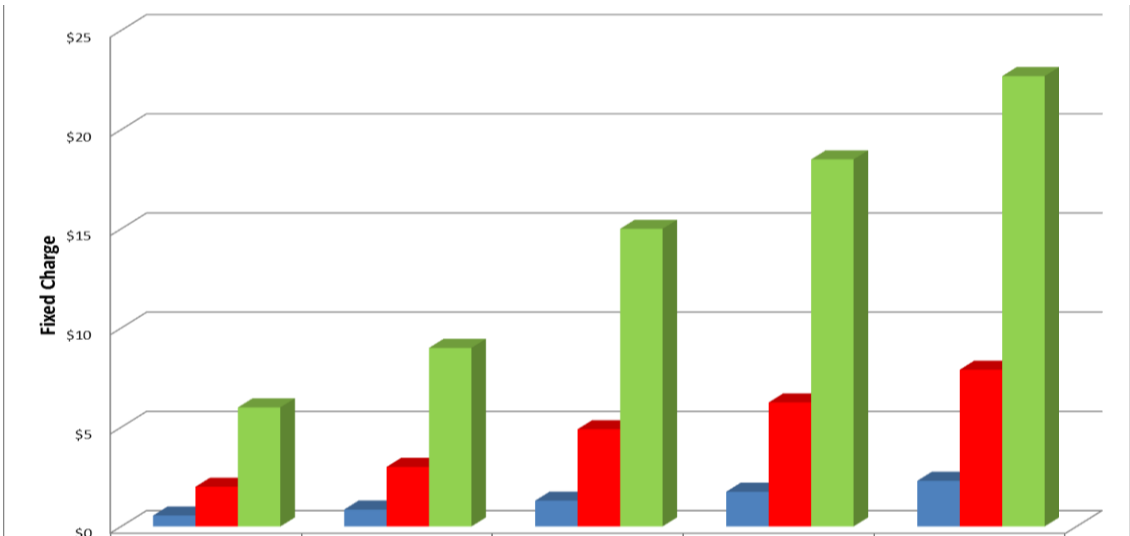
The new Residential monthly tiered fixed charge will be tied to the level of consumption in a similar manner as existing energy charges. Three tiers are proposed with the specific amount based on the customer's highest monthly consumption level (or amount of energy dispatched to the grid for NEM customers) in the prior year. The kWh tier thresholds are the same as the levels currently in place for energy usage. The amount of the fixed charge will vary by tier allotment, which in turn varies based on temperature zones, as shown in Figure 5.

Figure 5: Proposed Thresholds for Residential Tiered Fixed Charge

	Zone 1 Monthly Usage (kWh)	Zone 2 Monthly Usage (kWh)
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500
Tier 2	350 < and ≤ 1050	500 < and ≤ 1500
Tier 3	> 1050	> 1500

The implementation of a tiered fixed charge recognizes that a significant amount of a power utility's cost is fixed and that sole reliance on usage based energy charges does not adequately align rates with costs. The new tiered fixed charge will be phased in over five years to provide a gradual transition of rates, as customers adapt their usage patterns to the new structure. This proposed rate design is also designed to ensure lower usage customers do not experience a significant increase in overall rates at any one time. As shown in Figure 6, the level of the tiered fixed charge is minimal for customers with small amounts of energy consumption.

Figure 6: Proposed Residential Monthly Tiered Fixed Charge



	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20
Tier 1	$0.55	$0.85	$1.30	$1.75	$2.30
Tier 2	$2.00	$3.00	$4.90	$6.25	$7.90
Tier 3	$6.00	$9.00	$15.00	$18.50	$22.70

The proposed energy charges based on the proposed rate design for the Residential (Schedule R1A) class are provided in Figure 7 for the five-year rate period. The proposed class average annual rate increase over the next five years is 5.2%.

Figure 7: Proposed Residential Customer Rates

Tier	Monthly Zone 1 Energy Allocation (kWh)	Monthly Zone 2 Energy Allocation (kWh)	Monthly Tiered Fixed Charge ($)	Summer Energy Charge ($/kWh)	Winter Energy Charge ($/kWh)
FY 2015-16					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$0.55	$0.1494	$0.1494
Tier 2	350 < and ≤1050	500 < and ≤1500	$2.00	$0.1816	$0.1816
Tier 3	> 1050	> 1500	$6.00	$0.2305	$0.1816
FY 2016-17					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$0.85	$0.1524	$0.1524
Tier 2	350 < and ≤1050	500 < and ≤1500	$3.00	$0.1877	$0.1877
Tier 3	> 1050	> 1500	$9.00	$0.2435	$0.1877
FY 2017-18					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$1.30	$0.1577	$0.1577
Tier 2	350 < and ≤1050	500 < and ≤1500	$4.90	$0.1980	$0.1980
Tier 3	> 1050	> 1500	$15.00	$0.2659	$0.1980
FY 2018-19					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$1.75	$0.1606	$0.1606
Tier 2	350 < and ≤1050	500 < and ≤1500	$6.25	$0.2089	$0.2089

Tier 3	> 1050	> 1500	$18.5	$0.2850	$0.2089
FY 2019-20					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$2.30	$0.1640	$0.1640
Tier 2	350 < and ≤1050	500 < and ≤1500	$7.90	$0.2226	$0.2226
Tier 3	> 1050	> 1500	$22.70	$0.3096	$0.2226

As discussed above, the energy rate, in conjunction with NEM, provides substantial incentives for customer-installed solar facilities. The average annual rate increases proposed for each tier are: 2.4% for tier 1, 5.1% for tier 2 and 7.5% for tier 3 (for summer), respectively for the five-year rate period. For instance, as Figure 7 above depicts, tier 3 rates for summer increase from $0.2305/kWh in FY 2015-16 to $0.3096/kWh in FY 2019-20. This approach facilitates minimizing the bill impact on low usage and/or low-income customers. This progression of rate increases by tier levels is also consistent with the Department's rate design objectives of promoting conservation, as well as encouraging solar and other distributed generation, in a gradual, sustainable manner. This structure and rate change methodology will allow LADWP to transition to a distribution utility that is indifferent to either utility or customer generation.

5.1.6 Commercial and Industrial Customer Rate Design

The general proposed rate structure for Commercial and Industrial Customers will not change; however, the rates will increase to reflect the higher costs associated with operating the Power System. The marginal cost of service study was utilized in designing the incremental portion of rates (Chapter 4). In addition, a higher percentage of the incremental revenue requirement will be allocated to the energy charge component over time to provide incentives for customer-installed solar and other distributed generation.

Similar to the Residential customer rate design, the proposed Commercial and Industrial customer rate design is developed in a manner that allows LADWP to transition to a distribution based utility that is indifferent to the use or types of new customer generation.

Figure 8 provides a summary of the major rate design elements for Commercial and Industrial customers. The customer classes considered are Small Commercial (Small General Service A1A), Medium Commercial (Primary Service A2B), and Large Commercial and Industrial (Sub-transmission A3A). The proposed rates can be found in Section 5.5.

Figure 8: Major Elements of LADWP Electric Commercial and Industrial Rate Design

	Small Commercial (Small General Service A1A)	Medium Commercial (Primary Service A2B)	Large Commercial and Industrial (Sub-transmission A3A)
Fixed Charges	Service charge	Service charge	Service charge
Capacity Charge ($/KW)	Facilities charge	Facilities charge and monthly demand charge	Facilities charge and monthly demand charge
Energy (Usage) Charges ($/kWh)	Based on season	Based on season and Time of Use (TOU)	Based on season and TOU

	Small Commercial (Small General Service A1A)	Medium Commercial (Primary Service A2B)	Large Commercial and Industrial (Sub-transmission A3A)
Voltage by Class	≤ 4.8 kV	4.8 kV	34.5 kV

5.1.7 Business Promotion Service Rider[4]

To encourage businesses to locate in the City of Los Angeles, a cost based business promotion service rider has been developed by LADWP to better use generation capacity. Over the next ten years, generation capacity in the Power System is expected to be available to serve new commercial customer load growth. To attract new customers to come to Los Angeles, qualifying new commercial businesses that locate in the City and receive service under General Service Schedule A2, A3, or A4 will be eligible to receive bill credit amounts that will be phased out over three years based on the marginal value of this capacity. The service rider is limited to a total of 80MW of customer load. Qualification and applicability will be developed and communicated by LADWP before the service rider is available sometime in 2016. The available bill credit, as a percent of total, for those that qualify is outlined in Figure 9.

Figure 9: Business Promotion Bill Credit by Year

Year of Location	Credit Amount
1st Year	7.6%
2nd Year	5.0%
3rd Year	2.5%

This approach is designed to encourage and promote business and optimize the utilization of LADWP's generation.

5.1.8 Summary of Proposed Rate Design

LADWP's proposed rate design balances the gradual collection of increased revenue with mechanisms to encourage the use of renewable energy by customers. The main characteristics of LADWP's proposed rate design changes include:

- Strong energy rate incentive in combination with NEM to provide a gradual transition to a distribution based utility where LADWP is indifferent to customer generation;
- Phased in rate change over five years with a system average of 4.7% per year to moderate cost change;
- A realignment of the relevant revenue requirement among the customer classes based on the results of the marginal cost of service study;
- Continued and expanded decoupling and pass-through adjustment factors to better align actual costs and rates while maintaining financial stability;

[4] A service rider works in conjunction with a customer's otherwise applicable rate.

- Addition of a monthly tiered fixed charge for Residential customers similar to other utilities. Unlike the proposed flat fixed charge proposed by IOUs, LADWP is proposing a tiered fixed charge based on usage levels;
- Continued current Commercial and Industrial customer rate structure with an increase in the percentage of revenue requirement allocated to energy charges over time to provide increased incentives for the use of customer-installed renewable generation and energy conservation; and
- Continued Incremental Electric Rate Ordinance approach based on legal considerations.
- To assist and encourage business promotion in the LADWP service area, a new service rider was developed.

5.2 RATE DESIGN OBJECTIVES

The proposed rates are designed to provide a gradual transition to a distribution based utility where LADWP is indifferent to the use or types of customer generation. In addition, the proposed rates are designed to achieve the following major objectives:

- Promote energy conservation, demand response, consistent load usage, and load shifting away from the high peak period;
- Reflect marginal costs;
- Ensure incremental charges to each customer class are proportionate to the cost of providing electric service to that class;
- Maintain rate competitiveness in the region;
- Comply with all applicable legal guidance;
- Provide rate stability;
- Achieve full recovery of costs;
- Minimize individual customer bill impacts, especially for customers who proactively conserve energy; and
- Simplify where possible.

5.2.1 Phased in Rate Change

The overall rate changes required to cover the increased cost of operating the Power System in a sustainable manner while also meeting financial metrics will be phased in over a five-year period to moderate the effect of the cost increases on customers.

Most California utilities are facing cost pressures, resulting in pronounced rate increases. Many municipal utilities have received approval for multiyear rate increases. The large IOUs have recently increased rates and are planning higher rates in the future. Figure 10 below illustrates rate changes approved or proposed at other major California electric utilities in recent years.

Figure 10: Past and Proposed Electric Rate Increases and new Rate Impositions of California Utilities

Utility	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17
LADWP	4.9%*	6.0%	-	4.4%	3.4%
Pacific Gas & Electric (PGE)	2.9%	1%	4.6%	5%	
Southern California Edison (SCE)	5%	6.3%	8%	1.5%	
San Diego Gas & Electric (SDGE)	0%	12.2%[5]	11%	0%	7%
Glendale	0%	8%	7.7%	5.5%	2.2%
Pasadena	2.3%	0%	8.3%	2.4%	2.2%
Burbank	1.75%	1.75%	2.9%		
Sacramento Municipal Utility District (SMUD)	1%	2.5%	2.5%	2.5%	2.5%

*Colors designate the status of the rate increases or impositions: Actual/Approved/Proposed

Changes to the rate design and the allocation of cost recovery among customer classes are consistent with the results of the new marginal cost of service study. These are required to maintain reasonable and cost based rates for all customers. Figure 11 provides the average annual rates and percentage change by customer class for each year of the proposed rate period.

Figure 11: Proposed Average Electric Rates and Annual Percentage Increase by Customer Class

Class	FY2014-15	FY 2015-16		FY 2016-17		FY 2017-18		FY 2018-19		FY 2019-20		Five-Year Average
	$/kWh	$/kWh	Annual %	$/kWh	Annual %	$/kWh	Annual %	$/kWh	Annual %	$/kWh	Annual %	Annual %
R1A	$0.1515	$0.1595	5.3%	$0.1656	3.8%	$0.1767	6.7%	$0.1849	4.7%	$0.1953	5.6%	5.2%
A1A	$0.1753	$0.1814	3.5%	$0.1862	2.6%	$0.1958	5.2%	$0.2025	3.4%	$0.2112	4.3%	3.8%
A2B	$0.1556	$0.1622	4.2%	$0.1676	3.3%	$0.1777	6.1%	$0.1850	4.1%	$0.1943	5.0%	4.5%
A3A	$0.1391	$0.1447	4.1%	$0.1498	3.5%	$0.1595	6.5%	$0.1662	4.2%	$0.1748	5.2%	4.7%
System Average	**$0.1506**	**$0.1573**	**4.4%**	**$0.1627**	**3.4%**	**$0.1730**	**6.3%**	**$0.1803**	**4.2%**	**$0.1896**	**5.2%**	**4.7%**

5.2.2 Legal Considerations

LADWP must consider applicable legal guidance in developing proposed rates for power service. Potentially applicable guidance includes:

- City Charter Section 676, Rate Setting, which states: "rates shall be of uniform operation for customers of similar circumstances…, as near as may be, and shall be fair and reasonable, taking into consideration, among other things: (1) the nature of the uses; (2) the quantity supplied; and (3) the value of the service"; and

[5] Represents a retrospective increase in September 2013, to cover 2012.

- Proposition 26, which declares that "a charge imposed for a specific government service or product provided directly to the payor shall not exceed the reasonable costs of providing the service or product to the payor."

In its report on the last Power System rate action, the Ratepayer Advocate (RPA) proposed that LADWP reevaluate and consider replacing the surcharge-based restructuring approach with fully restructured permanent rates. The City Council made the same recommendation when it approved the 2012 rate action. Consequently, LADWP has evaluated the current approach to the ordinance structure.

While there may be a desire to undertake a modification of the current rate structure to provide a simpler rate framework, several lawsuits have recently been filed asserting that Proposition 26 does not permit LADWP's annual transfer of monies, financial conditions allowing, from the Power Revenue Fund ultimately to the City's General Fund. The City disputes the merits of those lawsuits. While the transfer is being contested, the City will continue to adopt an electrical rate structure that preserves the rates in effect on November 3, 2010, and layers incremental charges on top of them. Therefore, for purposes of the current rate action, LADWP proposes that the results of the cost of service studies and the impact of the new revenue requirements for power service be applied to only the Incremental Electric Rate Ordinance.

5.2.3 Marginal Cost Based Pricing

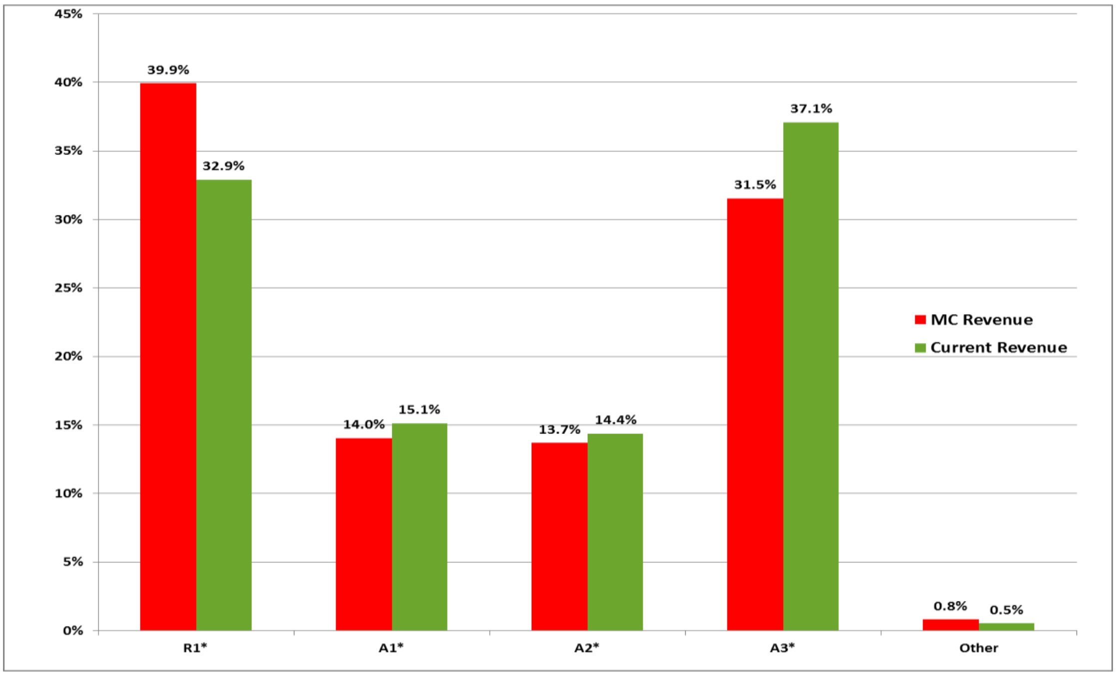
In October 2012, the Los Angeles City Council approved LADWP's Incremental Electric Rate Ordinance No. 182273 to provide incremental rate adjustments for FY 2012-13 and FY 2013-14, resulting in total revenue increase over two years of $328.4 million. In its action to approve LADWP's power rates, the Council, along with other recommendations, recommended that LADWP "conduct a new formal cost of service study in order to prepare for future power rate restructuring." In response to this recommendation, LADWP has completed a marginal cost of service study to evaluate costs of service and ensure that its rates are cost based for each major customer class.

Cost of service analysis constitutes standard utility industry practice for setting power rates. LADWP has utilized the marginal cost study approach to evaluate the cost of providing service to various customer classes and provide guidance for rate design, including rate levels. Marginal cost principles are an accepted methodology for guiding both the allocation of costs to customer classes and the development of power rates. All the major California IOUs and many publicly-owned utilities utilize marginal cost principles for rate design, particularly in the tier design for the residential customer class.

Marginal cost of service study principles and methodologies are discussed in more detail in Chapter 4.

The results of LADWP's new cost of service study indicate that a realignment of the total revenue requirement among the customer classes is warranted. Figure 12 below illustrates the differences between the marginal cost revenue ratios and the current revenue ratios for the various customer classes.

Figure 12: Comparison of Marginal Cost Revenue Requirement and Current Revenue Percent by Customer Class[6]



The results indicate that by applying marginal costs to allocate the total Power System retail revenue requirement, the Residential (R1) customers would be allocated 39.9% of the revenue requirement instead of the current level of 32.9%. Conversely, the Large Commercial and Industrial (A3) customer class would be allocated a lower revenue requirement of 31.5% instead of the current level of 37.1%.

To better align revenues and costs, the base rates in the Incremental Electric Rate Ordinance will be established based on marginal cost results for the major customer classes. The alignment of revenues and costs will be applied to only the Incremental Electric Rate Ordinance in order to preserve the rates in the Electric Rate Ordinance in effect on November 3, 2010. This alignment with the cost study results will be phased in over a five-year period to moderate the impact on the customer classes.

5.3 RATE STRUCTURE OVERVIEW

The primary objectives of this rate proposal are to provide the additional funding necessary for LADWP to increase power reliability program investments, continue the power supply transformation to a more environmentally-friendly generation portfolio while meeting regulatory mandates and expand customer opportunities programs such as energy efficiency and distributed generation. On October 23, 2012, LADWP implemented a new Incremental Electric Rate Ordinance to provide additional revenues for FY 2012-13 and FY 2013-14. In addition, the charges of the Electric Rate Ordinance were capped, and that ordinance

[6] For the LADWP marginal cost study, some customer classes listed here have been combined to maintain consistency for rate design purposes. For instance, the Residential class includes low-income and lifeline customers. The asterisk indicates that multiple classes are included in a listed customer class (e.g., A1 includes A1A and A1B).

continues to be in effect. The proposed rates for FY 2015-16 through FY 2019-20 will require changes to the Incremental Electric Rate Ordinance, but the Electric Rate Ordinance will remain unchanged. The overall rates structure is comprised of the following major components:

- *Base Rates*: Base rates, the portion of rates other than the adjustments, in both the Electric Rate Ordinance and Incremental Electric Rate Ordinance following a tiered/TOU structure based on consumption and/or demand.

Like many other utilities, LADWP has pass-through adjustment factors in addition to the "base" rates. The amounts of these factors are tied to specific costs. More details on these adjustment factors can be found in Chapter 5 – Appendix A.

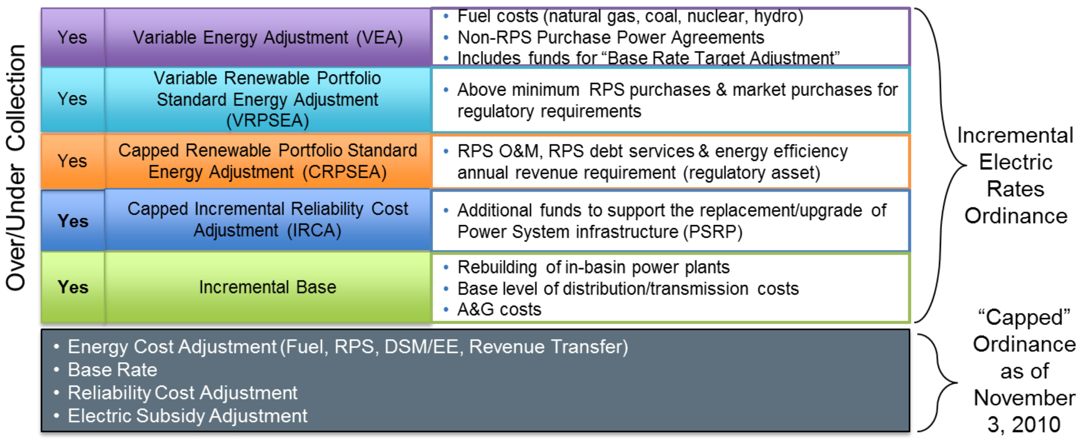
- *Incremental Electric Rate Ordinance Pass-Through Adjustment Factors*: The specific adjustment factors in the Incremental Electric Rate Ordinance include the Variable Energy Adjustment (VEA), Variable Renewable Portfolio Standard Energy Adjustment (VRPSEA), and Capped Renewable Portfolio Standard Energy Adjustment (CRPSEA).
- *November 3, 2010 Pass-Through Adjustment Factors:* Total amount of the pass-through adjustments in the Electric Rate Ordinance.

The total customer rates for almost all customers are determined as the sum of the base and pass-through components in the Electric Rate Ordinance and Incremental Electric Rate Ordinance. Proposed changes to the rate structure and rates pertain only to the incremental base rate and incremental reliability cost adjustment components.

5.3.1 Current Rate Structure

The current rate structure and rates were implemented in October 2012 after review with the RPA and approval by the Board of Water and Power Commissioners (Board) and City Council (Council). At that time, LADWP implemented several changes to the rate design to address industry trends and past Council recommendations to more clearly match rate factors with costs and reflect the uncontrollable nature of some of the costs. Figure 13 shows the current overall rate structure, which includes both the components of the Incremental Electric Rate Ordinance and the Electric Rate Ordinance.

Figure 13: LADWP Current Electric Rate Structure (Detail)



Pass-through factors in the Incremental Electric Rate Ordinance adjusted on a quarterly basis

An important aspect of the current rate structure is the decoupling mechanism built into the Variable Energy Adjustment (VEA) to ensure that shifts in customer usage patterns outside of LADWP's control do not impair base rate recovery of the largely fixed costs designed to be recovered by base rates. As discussed in Chapter 3, LADWP is aggressively pursuing energy efficiency programs. While an estimate of the usage impact of these programs has been built into the financial plan and proposed rates, the actual impact of some of these programs, especially the newer ones, is hard to predict accurately. Therefore, to allow LADWP to continue providing reliable service, the decoupling mechanism ensures base rate revenue will be relatively consistent. This mechanism ensures that base rates recover the designated revenue requirement while protecting customers from over recovery of costs. LADWP proposes to continue this decoupling mechanism.

A complete description of each of the rate components is provided in Chapter 5 - Appendix A.

5.3.2 Proposed Rate Structure

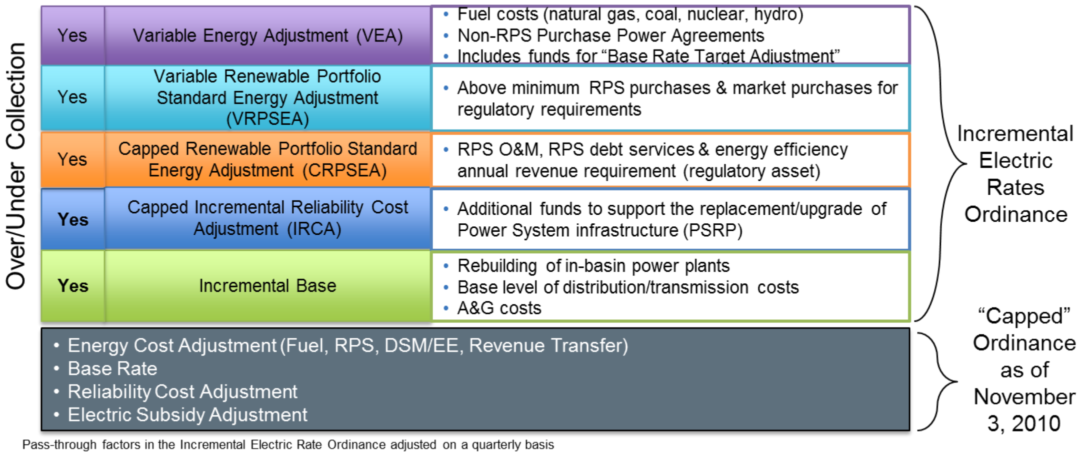
LADWP proposes to retain the overall rate structure implemented in 2012 with only one significant change. As discussed throughout this report, a major component of LADWP's capital improvement program is an increased investment in reliability programs to reduce the frequency and severity of outages and ensure continued system reliability. Over the past two-three years, spending on these programs has been reduced as significant investments have been required to meet regulatory and legal mandates largely associated with renewable energy resources, greenhouse gas reduction and elimination of Once-Through Cooling for LADWP in-basin generation facilities. New revenue has disproportionately been directed to these types of programs in recent years. As a result, LADWP faces a renewed need to invest in reliability improvements through the Power System Reliability Program (PSRP).

The PSRP is a comprehensive program focused completely on infrastructure improvements and designed to continue for many years. While specific projects have been developed to help establish the overall PSRP budget and timing of such projects is based on currently available information, all of the required contracts have not been negotiated. In addition, as has been the situation in the past, LADWP cannot fully predict whether unforeseen outages or other emergency repairs will require a reallocation of resources.

Many of the PSRP projects are long-term in nature requiring LADWP to establish contracts for construction services and materials for items such as poles or transformers covering multiple years. To ensure LADWP receives the best possible terms, larger multiyear contracts are preferred; however, the procurement process for these types of contracts can take six to nine months. Once contracts are in place, if projects are reprioritized and funding is reallocated among projects, significant delays, cost increases or even contract cancellations are possible. In 2011 and 2012, Board approved power reliability program contracts representing $173.5 million were suspended or expired, leaving $95.1 million unspent. LADWP had incurred several unexpected outages, including four major vault failures, largely due to unexpected weather or aging infrastructure failures that required immediate repairs. Since rates in 2012 were set with a two-year period in mind, no alternate sources of funding for these emergency repairs was available, and LADWP had to cancel infrastructure improvement contracts and reallocate resources accordingly.

The proposed overall rate structure will ensure funding availability so that the Department can meet legal mandates and better manage system improvement investment, as shown in Figure 14.

Figure 14: LADWP Proposed Electric Rate Structure (Detail)



5.3.3 Decoupling

Decoupling is a mechanism that encourages conservation while maintaining financial stability for utilities. As there may be variances from forecasted usage and revenue due to conservation, decoupling is a standard utility practice that ensures fixed utility costs are recovered. Conversely, if forecasted usage and revenue is higher than expected, decoupling protects the customer from over-collection.

Conservation is a key element to being a sustainable utility. For both electric and water utilities, there has been a strong trend towards implementing conservation in the last decade. For utilities that plan financial expenditures based upon sales, any conservation effort introduces uncertainty as to the level of customer consumption, which complicates usage forecasting and budgeting. While utilities make every effort to accurately forecast the impact of conservation measures, planned usage reductions may or may not occur, depending on how consumers ultimately respond. Forecasting customer behavior is very difficult to do accurately, so actual conservation levels often do not match forecasts.

Utility costs are comprised of variable and fixed costs. Conservation can reduce variable costs but does not impact fixed costs. Since fixed costs cannot be changed easily (e.g., power turbine costs) and utility rates are largely usage or consumption based, forecasting uncertainty presents special challenges to utility finances. Revenue targets are typically established using forecasted levels of consumption, which include the impact of expected conservation. Therefore, if conservation is above or below the forecast, the financial condition of the utility and the ability to provide reliable service to customers can be impacted.

Decoupling is the standard utility solution to fixed cost recovery. Decoupling separates fixed cost recovery from the calculated overall rate. If, after accounting for actual usage and revenue, fixed costs are under-recovered, the decoupling mechanism adjusts rates to fully recover fixed costs. This type of adjustment works for over-collection as well. If usage exceeds forecasts, resulting in an over-recovery of fixed costs, customers receive a reduced charge through lower future rates.

5.3.4 Incremental Reliability Cost Adjustment Factor

To ensure that adequate revenue is available for LADWP to implement and maintain the PSRP, LADWP proposes to change the structure of the IRCA to be similar to the current Capped Renewable Portfolio Standard Energy Adjustment (CRPSEA). The revised IRCA will provide the flexibility to reallocate funds between proximate years and within strict dollar limits to allow projects to continue uninterrupted while emergency or other unforeseen repairs are implemented. This approach will not increase the overall amount of funding for the PSRP program over time above the levels in the proposed rate plan. The new IRCA will have the following characteristics.

- Annual changes based on the level of spending for the PSRP.
- For years one (FY 2015-16) through year three (FY 2017-18), caps will be designed to allow unused funds to be applied to the second and/or third year of that range.
- Starting in year four, the increase cannot exceed $0.002 per kWh annually.
- Separate Residential and General Service balancing accounts will be established. Projects (and associated spending) can be reallocated and reprioritized within fiscal years and between proximate fiscal years within the caps and subject to the following reporting requirements:
  - If the projected under-collection is greater than $25.0 million and less than $50.0 million, LADWP will report to the Board and Council to communicate the projected under-collection; and
  - If the projected under-collection is $50.0 million or greater, modified rates shall, if deemed necessary, be fixed by the Board and then approved by an ordinance change.
- General Service IRCA' factor will have both a kW and kWh component.

This approach balances rate certainty for customers with LADWP's flexibility to manage the contracts and other aspects of the PSRP which can be impacted by uncertain weather, material costs or infrastructure maintenance requirements. Combined with a multiyear rate plan, the flexibility inherent in this approach will allow LADWP to plan projects, contracts and investments over several years with a much higher degree of certainty and better economic terms for LADWP's ratepayers. The need for short-term spending reductions merely to manage the Power System's net income will also be reduced. The IRCA will have the same level of transparency as the CRPSEA[7]; if the capped factor does not fully fund the PSRP

[7] LADWP proposes to maintain the current reporting levels for the CRPSEA. Quarterly reports will be provided to the Board and Council to show the projected amount in the balancing account for the next five years if the projected balance for any of

projects (delaying system maintenance), the Board and Council will be made aware of these financial shortfalls in a timely manner.

LADWP's approach will provide the flexibility to pursue longer term projects and contracts with more certainty of funding and give customers a level of certainty about future rate levels associated with the PSRP and infrastructure maintenance.

5.3.5 Net Energy Metering

Net Energy Metering (NEM) is a rate design mechanism that provides an incentive for distributed generation, particularly solar, for retail customers. NEM was conceived in the 1990's as a mechanism to encourage solar and other forms of distributed generation when penetration rates were low for those technologies.

Both LADWP and non-LADWP programs allow customers an offset to their bill for energy generated. For LADWP, the offset is typically based on the value of the energy generated. LADWP has a generous NEM program. Like many other utilities, including the major California IOUs, LADWP's NEM program allows the distributed generation customer's load to be offset by the energy delivered by the customer to the grid at the full retail rate for the energy.

The most important aspect of the LADWP NEM is that, in conjunction with the rate amounts and design, LADWP customers have substantial incentives to install customer-owned solar generation. This aspect of the rate design will help LADWP to move to a distribution based utility, indifferent to the type or cost of customer generation. In addition, by phasing in the changes to rates, this transition is achieved in a gradual, sustainable way.

5.4 RESIDENTIAL (R1A)

Specific modifications proposed for the Residential customer class (R1A) rate design and the impact on rates are discussed in this section.

5.4.1 Residential Customer Current Rate Design Components

The current rate design is comprised of the following components:

- Two geographical areas: Zone 1 (cooler temperature zone) and Zone 2 (hotter zone);[8]
- For each zone, LADWP has a three-tier tariff system with varying tier sizes:
  - Zone 1 customers in the first tier receive a 350kWh baseline usage allocation, representing the minimum level of electricity used by a typical household, that is charged at the lowest tariff rate;

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the five years is greater than $50 million and less than $100 million. If the balancing account is projected to be $100 million or greater, the Board can fix rates, as required, and submit to Council within 180 days.

[8] The LADWP Residential service area has been divided into two temperature zones as supported by a CEC study and using zip codes as a means of granularity. An LADWP 2013 study confirms the previous study. A table showing the current temperature zones by zip codes is in Chapter 5 – Appendix B.

  - Zone 2 customers in the first tier receive a 500kWh baseline usage allocation, representing the minimum level of electricity used by a typical household, that is charged at the lowest tariff rate;
- Tier 2 usage up to 300% of the tier 1 baseline allocation charged at the higher tier 2 rate;
- Usage above 300% of the baseline allocation is billed at the highest tier 3 rate;
- Two seasons:
  - Summer (high season): June – September; and
  - Winter (low season): October – May;
- Constant tier 1 rate for both seasons; and
- Tier 2 and 3 winter season rates equal to the tier 2 summer season rate.

5.4.2 Proposed Changes to LADWP Residential Rate Design

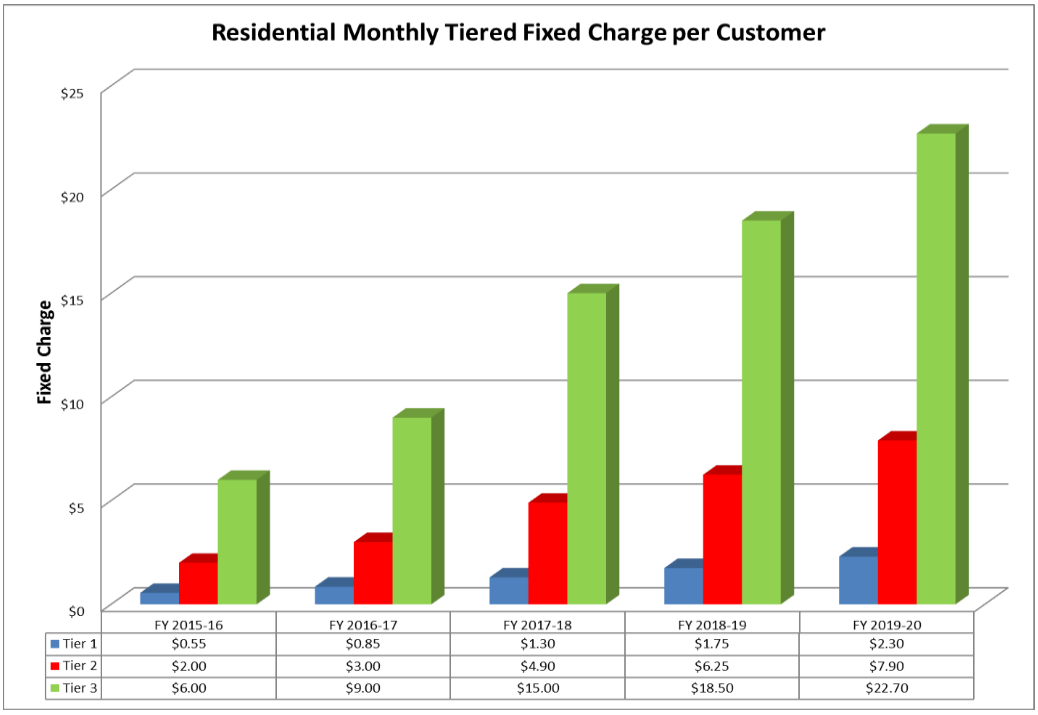
LADWP proposes to implement a tiered fixed charge for Residential customers. Recognizing that significant portions of the cost of delivering electricity are fixed, many electric utilities across the country have traditionally included both fixed charges and usage-based charges in their tariffs. LADWP has had a minimum charge in its Residential customer rate design for many years to partially reflect fixed costs, such as customer service and billing. However, this minimum charge will apply only when the monthly bill is less than ten dollars a month. The proposed fixed charge would be tied to the customer's usage, based on the higher of maximum monthly usage from the grid in the prior year or maximum monthly usage of electricity delivered to the grid in the prior year, as the capacity of the grid is designed based on the peak or maximum expected usage level.

Recently, electric utilities in California have more aggressively been pursuing the use of fixed charges for all customer classes. Several California IOUs and publicly-owned utilities are pursuing new or increased fixed rate infrastructure for Residential customers. A fixed charge component is more appropriate for utilities to recover the often fixed costs of maintaining the distribution infrastructure that enables reliable power delivery through the entire electric grid at all times of the day.

Therefore, while customer usage will always vary, all customers should bear some of the burden of the distribution infrastructure costs.

As more customers generate a portion of their energy needs, a utility's financial survival requires rate design mechanisms to change to ensure all customers continue to contribute to the basic fixed costs of providing electric service. These costs include those of billing, metering, customer care, and part of the distribution infrastructure. As depicted in Figure 15 below, LADWP is proposing a tiered fixed charge that increases gradually to $2.30 for tier 1, $7.90 for tier 2, and $22.70 for tier 3 in FY 2019-20.

Figure 15: Proposed Residential Monthly Tiered Fixed Charge by Year



The tiered fixed charge approach has several benefits, including, but not limited to:

- Ensuring the continuation of the same level of reliability for all customers;
- Encouraging increased energy efficiency measures by linking the three-tiered fixed charge to customer usage levels, as opposed to a single rate for all customers;
- Better matching of cost recovery and cost causation as determined through the new marginal cost of service study;
- Movement toward matching the level of fixed and variable costs with revenue from fixed and usage based rate elements; and
- Minimizing the percentage rate increase for low usage customers or eliminating the impact on low usage customers as the fixed charge is not expected to exceed the current minimum usage charge.

LADWP's Proposal is Balanced

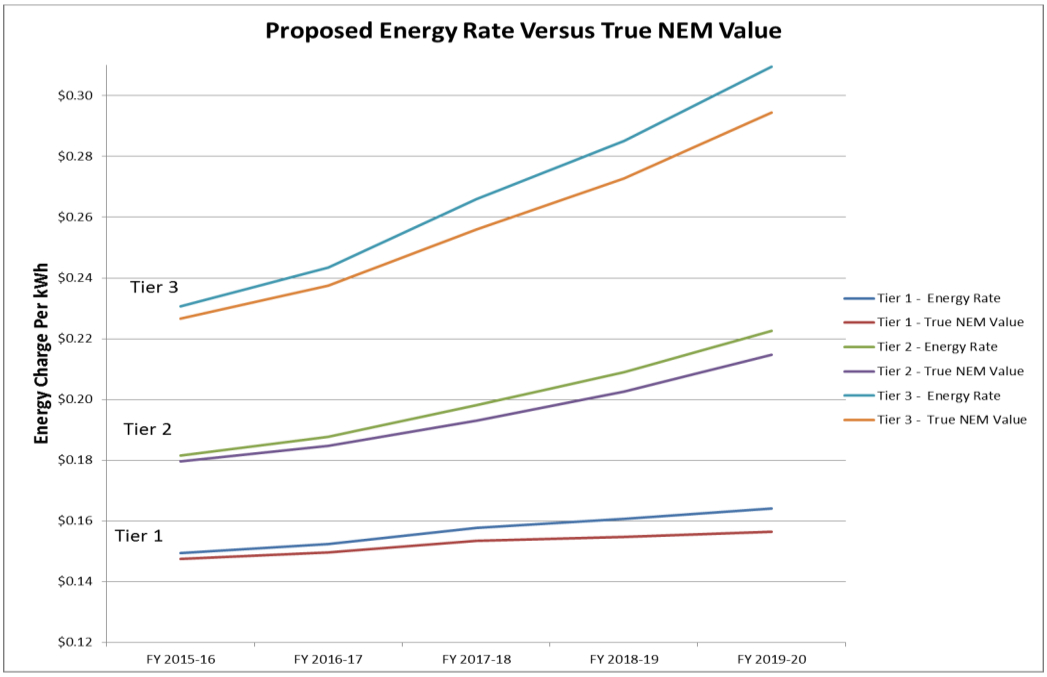
LADWP's proposed monthly tiered fixed charge coupled with increases in the energy rate by tier is equitable and balanced. By assigning a proportionally higher fixed charge to higher usage customers, low usage customers who may not benefit from or be able to afford customer-owned solar are not unduly impacted. LADWP's tiered fixed charge comprises a lower percentage of customers' monthly bills at lower usage levels than if a single fixed charge across all customers was used.

The higher fixed charge for tier 3 customers as a percentage of the total bill is still relatively small. Without fixed charges, energy charges would need to be set higher to recover the full cost of service. LADWP's proposed balance of fixed charges and energy charges is competitive, but still provides an incentive for customer-installed generation. Whether or not a customer installs solar or other generation depends on the "true NEM value" of energy compared to the cost of customer-installed generation. The true NEM value is calculated as the energy rate less the fixed charge for the tier of consumption divided by the kWh of consumption as shown below.

$$\text{True NEM Value} = \text{Proposed Energy Rate} - \frac{\text{Fixed Charge at Tier (given specific kWh Usage)}}{\text{kWh Usage}}$$

Figure 16 presents the proposed Residential energy rate by tier by year compared to the true NEM value for customer-installed generation. The proposed rate by tier is very close to the true NEM value, demonstrating that the fixed charge is a fairly small percent of the total bill. Therefore, the monthly tiered fix charge would not be a deterrent for installation of customer-owned generation.

Figure 16: Residential Customer Proposed Energy Rate Compared to the True NEM Value[9]



Structure of LADWP's Proposed Tiered Fixed Charge

Figure 17 provides LADWP's proposed tier usage thresholds for the fixed charge which mirror the levels for energy usage charges.

Figure 17: Proposed Thresholds for Residential Tiered Fixed Charge

	Zone 1 Monthly Usage (kWh)	Zone 2 Monthly Usage (kWh)

[9] Results calculated using summer rates; however, winter rates show similar results.

Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500
Tier 2	350 < and ≤1050	500 < and ≤1500
Tier 3	> 1050	> 1500

LADWP's Residential customer fixed charge proposal will help balance cost recovery among customers, while recognizing the fixed cost of portions of the electric service delivery infrastructure. This approach is similar to the fixed charges and demand charges for commercial customers. Utility equipment must be on standby for the highest level of energy needs for each customer and all customers collectively to protect against electric outages. Customers with solar and other distributed generation facilities also benefit from the "always" available nature of the utility's service.

5.4.3 Proposed Residential Rates

The components of the proposed LADWP residential rate design are summarized in Figure 18 below:

Figure 18: Proposed Residential Rate Design Components

Tiers	Monthly Zone 1 Usage Allocation (kWh)	Monthly Zone 2 Usage Allocation (kWh)	Monthly Tiered Fixed Charge ($)	Summer Energy Charge ($/kWh)	Winter Energy Charge ($/kWh)
FY 2015-16					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$0.55	$0.1494	$0.1494
Tier 2	350 < and ≤1050	500 < and ≤1500	$2.00	$0.1816	$0.1816
Tier 3	> 1050	> 1500	$6.00	$0.2305	$0.1816
FY 2016-17					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$0.85	$0.1524	$0.1524
Tier 2	350 < and ≤1050	500 < and ≤1500	$3.00	$0.1877	$0.1877
Tier 3	> 1050	> 1500	$9.00	$0.2435	$0.1877
FY 2017-18					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$1.30	$0.1577	$0.1577
Tier 2	350 < and ≤1050	500 < and ≤1500	$4.90	$0.1980	$0.1980
Tier 3	> 1050	> 1500	$15.00	$0.2659	$0.1980
FY 2018-19					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$1.75	$0.1606	$0.1606
Tier 2	350 < and ≤1050	500 < and ≤1500	$6.25	$0.2089	$0.2089
Tier 3	> 1050	> 1500	$18.50	$0.2850	$0.2089
FY 2019-20					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$2.30	$0.1640	$0.1640

Tiers	Monthly Zone 1 Usage Allocation (kWh)	Monthly Zone 2 Usage Allocation (kWh)	Monthly Tiered Fixed Charge ($)	Summer Energy Charge ($/kWh)	Winter Energy Charge ($/kWh)
Tier 2	350 < and ≤1050	500 < and ≤1500	$7.90	$0.2226	$0.2226
Tier 3	> 1050	> 1500	$22.70	$0.3096	$0.2226

In general, proposed increases to tier 2 and 3 prices are higher than proposed increases to tier 1 prices to reflect marginal costs and send a conservation price signal. In addition, the tiered fixed charge increases for higher usage levels. The average annual five-year rate increases proposed for each tier are: 2.4% for tier 1, 5.1% for tier 2 and 7.5% for tier 3 (for summer), respectively. As Figure 18 above depicts, tier 3 rates for summer increase from $0.2305/kWh in FY 2015-16 to $0.3096/kWh in FY 2019-20. This approach facilitates minimizing the bill impact on low usage, low-income customers. Therefore, while the implementation of the fixed charge will impact all customers, generally a larger portion of the proposed revenue increase for the five years will be recovered from customers with higher consumption levels of over 1,000kWh per month. This progression of rate increases by tier levels is consistent with LADWP's rate design objectives of promoting conservation, as well as encouraging solar and other distributed generation. The energy rate levels, in conjunction with NEM, will, therefore, provide economic incentives for customer-installed solar.

5.4.4 Residential Customer Bill Impacts

LADWP's rate design encourages energy conservation. In order to send the proper conservation price signals to customers, electricity rates increase as consumption increases. This approach is consistent with the marginal costs to serve these customers, as well. Therefore, the proposed rate design allocates more of the rate increase to customers that consume higher levels of electricity, and customers at lower consumption levels receive lower relative rate increases.

With respect to customer bill impacts, due to the nature of a fixed charge, when the fixed charge is spread over the relatively low level of usage, lower usage customers will experience a higher percentage increase than other customers, especially in the year the fixed charge is implemented. However, the actual dollar amount of the fixed charge will be significantly more for higher usage customers.

As a result, roughly 80% of all residential customers will see an annual average rate increase below the class average rate increase of approximately 5.3% over the five-year proposed rate period. However, Residential customers with usage of greater than 1,000kWh per month will see an average rate increase greater than the class average to encourage energy conservation measures and behaviors.

As shown in Figure 19, in general, residential customers with lower usage will receive a lower rate increase than customers with a higher usage.

Figure 19: Residential (R1A) Customer Annual Rate Impact by Usage Distribution

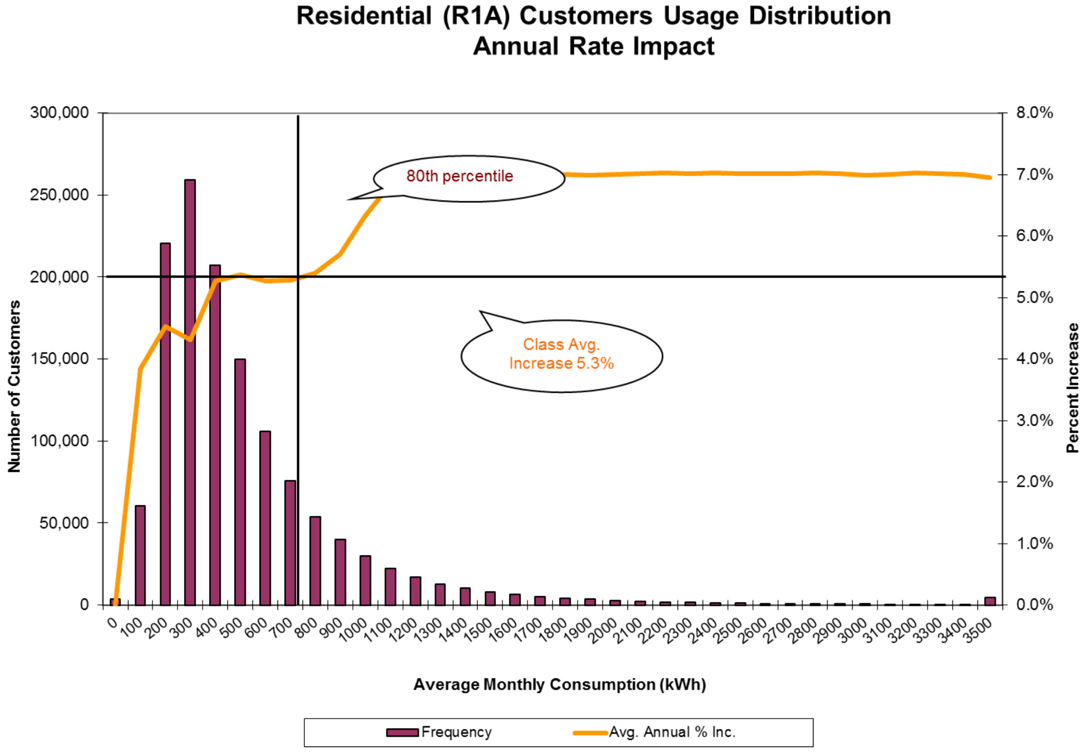


Figure 20 is a tabular representation of Figure 19 that shows the number of customers in each usage band, their proposed average median bill for each of the five years, and the five-year average annual rate increase. The table also includes the cumulative percentage of customers in each customer usage band. For example, at the 500kWh band (which covers all usage above 400 and up to 500kWh), there are 149,560 customers, with a current median bill for FY 2014-15 of $64.57 and a proposed FY 2015-16 bill of $68.18. The five-year average annual increase for this band is 5.4%, and 68.5% of all residential customers have a usage level less than or equal to 500kWh.

Figure 20: Residential (R1A) Customer Bill Impacts by kWh Usage (Detail)

Average kWh	Customers	Average Median Bill						Average Annual % Change	Cumulative %	FY 2019-20 ($/kWh)
		FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20			
0	3708	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	0.0%	0.3%	
100	60596	$11.00	$11.39	$11.68	$12.17	$12.59	$13.12	3.8%	4.9%	$0.1312
200	220476	$20.51	$21.43	$22.14	$23.31	$24.14	$25.15	4.5%	21.7%	$0.1258
300	259076	$33.97	$35.36	$36.50	$38.48	$39.77	$41.30	4.3%	41.4%	$0.1377
400	206920	$48.72	$51.30	$53.16	$56.58	$58.80	$61.54	5.3%	57.1%	$0.1538
500	149560	$64.57	$68.18	$70.65	$75.15	$78.19	$81.92	5.4%	68.5%	$0.1638
600	105846	$81.12	$ 85.49	$88.47	$93.84	$97.71	$102.48	5.3%	76.5%	$0.1708
700	75711	$98.13	$103.38	$106.93	$113.29	$118.10	$124.06	5.3%	82.3%	$0.1772
800	53999	$115.47	$121.88	$126.09	$133.54	$139.41	$146.64	5.4%	86.4%	$0.1833
900	39739	$133.04	$141.01	$146.15	$155.09	$162.17	$170.94	5.7%	89.4%	$0.1899
1000	29704	$150.83	$160.56	$167.10	$178.70	$187.59	$198.52	6.3%	91.7%	$0.1985
1100	22077	$168.81	$180.16	$187.81	$201.62	$212.63	$226.50	6.8%	93.3%	$0.2059
1200	17209	$187.27	$200.16	$208.80	$224.61	$237.14	$252.59	7.0%	94.6%	$0.2105
1300	12908	$205.75	$219.90	$229.48	$246.82	$260.64	$277.80	7.0%	95.6%	$0.2137
1400	10128	$224.83	$240.10	$250.51	$269.19	$284.38	$303.16	7.0%	96.4%	$0.2165
1500	7992	$243.54	$259.84	$271.10	$291.30	$307.86	$328.58	7.0%	97.0%	$0.2191
1600	6298	$262.73	$280.08	$292.21	$313.86	$331.90	$354.31	7.0%	97.5%	$0.2214
1700	5040	$281.95	$300.37	$313.34	$336.43	$355.88	$380.10	7.0%	97.9%	$0.2236
1800	3975	$301.14	$320.66	$334.65	$359.40	$380.33	$406.51	7.0%	98.2%	$0.2258
1900	3375	$320.15	$340.71	$355.49	$381.72	$404.01	$431.97	7.0%	98.4%	$0.2274
2000	2719	$338.99	$360.79	$376.48	$404.23	$427.94	$457.58	7.0%	98.6%	$0.2288
2100	2350	$358.78	$381.63	$398.20	$427.51	$452.84	$484.56	7.0%	98.8%	$0.2307
2200	1910	$377.49	$401.49	$419.03	$450.09	$476.74	$510.09	7.0%	98.9%	$0.2319
2300	1589	$396.32	$421.40	$439.74	$472.02	$500.05	$535.19	7.0%	99.1%	$0.2327
2400	1377	$415.79	$441.77	$461.03	$494.91	$524.51	$561.78	7.0%	99.2%	$0.2341
2500	1112	$435.24	$462.42	$482.56	$517.99	$548.93	$587.90	7.0%	99.3%	$0.2352
2600	955	$453.88	$481.91	$503.02	$540.08	$572.42	$613.09	7.0%	99.3%	$0.2358
2700	859	$472.65	$501.86	$523.72	$561.99	$596.12	$638.52	7.0%	99.4%	$0.2365
2800	737	$492.16	$522.62	$545.39	$585.53	$620.63	$664.98	7.0%	99.5%	$0.2375
2900	620	$510.21	$541.38	$564.98	$606.43	$643.06	$689.27	7.0%	99.5%	$0.2377
3000	577	$530.35	$562.71	$587.28	$630.13	$667.97	$715.76	7.0%	99.5%	$0.2386
3100	470	$548.67	$582.09	$607.48	$651.76	$691.27	$740.68	7.0%	99.6%	$0.2389
3200	460	$567.66	$602.39	$628.52	$674.74	$715.48	$766.93	7.0%	99.6%	$0.2397
3300	365	$587.94	$623.72	$650.79	$698.18	$740.46	$793.98	7.0%	99.6%	$0.2406
3400	370	$605.70	$642.45	$670.20	$718.84	$762.56	$817.82	7.0%	99.7%	$0.2405
3500	4343	$809.65	$857.89	$894.78	$958.31	$1,016.42	$1,090.85	6.9%	100.0%	$0.3117

5.4.5 Residential Comparative Analysis

A comparative analysis of the LADWP rate design with the three large California IOUs and several major California publicly-owned utilities determined that these peer utilities have rate structures similar to LADWP's proposed rate design.

Residential Rate Structure Comparison

Utilities in California have established inverted tier rate designs to promote energy conservation, whereby tier 1 rates are priced lower than other tiers. In addition, tier rates have been guided by marginal costs. Under this approach, tier structures and rates have been largely based on typical consumption and load profiles for Residential customers. The three tier approach also mirrors the high peak, low peak, and base Time of Use (TOU) period concept and provides customers a significant level of control over the cost of electricity. LADWP proposes to continue with this approach, with the addition of a tiered fixed charge. With this change, the revenue requirement for the Residential customer class will be recovered through a combination of the new fixed charge and usage measured on a kWh basis.

Number of Tier Thresholds

In general, IOUs have four tiers and publicly-owned utilities have two to three tiers. However, the IOUs have indicated plans to reduce the number of tiers. Tier sizes vary by utility; the median allotment for the first tier among the utilities studied was 350kWh. Only two California publicly-owned utilities studied (Pasadena and Redding) have one tier and, hence, only one tariff rate.

Usage allocation levels are used to establish the tier thresholds. LADWP's baseline allocations for each tier are more generous than the CPUC mandated baseline allocations for the three major California IOUs, as shown in Figure 21.

Figure 21: Comparison of LADWP and California IOU Residential Tier Structure

Tier	LADWP	California IOUs
1	0% ≤ and ≤ 100% of Baseline	0% ≤ and ≤ 100% of Baseline
2	100% < and ≤ 300% of Baseline	100% < and ≤ 130% of Baseline
3	**>** 300% of Baseline	130% < and ≤ 200% of Baseline
4	N/A	>200% of Baseline

This comparison illustrates that LADWP has larger tier sizes than the IOUs; for LADWP, the top tier tariff is assessed to any load that is over 300% of the baseline allocation, while for the IOUs, the top tier (tier 4) tariff is assessed to any load over 200% of the baseline. These large tier sizes accommodate a rate structure that results in a more gradual progression of tariffs within tiers for LADWP.

As a result of these features, a relatively small proportion of residential customers are assessed the higher tier 3 tariffs. In aggregate, only 6.4% of Zone 1 customers (or 28% of Residential load) and 2.9% of Zone 2 customers (or 13% of Residential load) are assessed the higher tier 3 summer rate. This feature is conducive to supporting conservation and facilitating revenue stability.

In its Residential Rate Reform Proceeding, (R-12-06-013) the CPUC had circulated a draft decision, dated April 21, 2015, that would modify the rate structures of SCE, PG&E and SDG&E (California IOUs) as follows:

- Substantial increases in minimum bill charges to a level of $10 per month by 2016 and possible introduction of fixed monthly charges later;
- Reduction in the number of tiers from the current level of four to two by 2018; and
- Compression of tier rates, such that rate increases are much higher for lower tiers as compared to higher tiers.

At this time, this draft decision is still being reviewed by the Commission. In addition, an alternative proposal has been submitted by a CPUC commissioner, dated May 22, 2015, that will also need to be considered. However, the main trend of higher fixed or minimum bill monthly charges is occurring for the IOUs no matter which proposal is adopted.

In June 2014, IOUs received CPUC approval to implement larger rate increases for the lower two tiers, as an interim step toward flattening of tier rates over four years. These recent developments illustrate the IOU trend toward compression of both the number of tiers and tier rates, which is likely to reduce incentives for conservation.

In contrast, LADWP's proposed rate design will retain the current three tier structure. This methodology is consistent with LADWP's balanced approach to promote conservation measures, while at the same time encouraging customer solar generation through an inverted tier rate structure with progressively higher tier 3 rates.

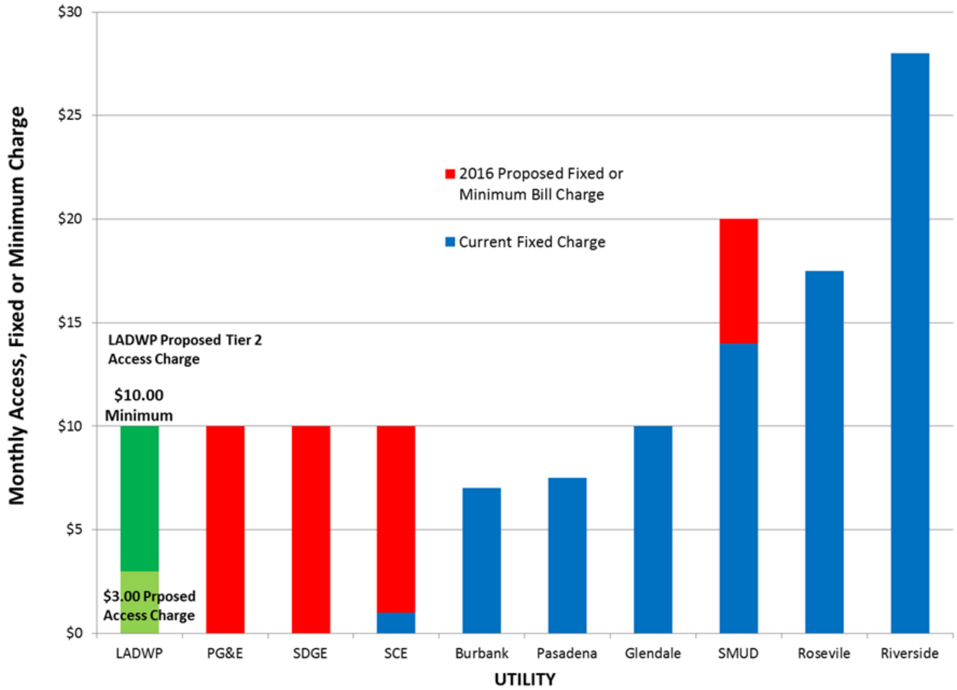
Seasonal Rates

The majority of the utilities have seasonal tariff configuration with winter rates for each tier slightly lower than the corresponding rates in summer.

Fixed Charges

Over 50% of the utilities studied have a fixed monthly infrastructure charge in their rates (currently ranging from $1.00 to $28.00). As discussed earlier, Figure 22 provides a comparison of utility current or proposed residential fixed charges or minimum bill charges[10] in 2016 based on current rates or proposed rate changes that have currently been announced.

Figure 22: Comparison of Electric Utility Residential Fixed and Minimum bill Charges (Planned for 2016)



Several observations can be made regarding electric utility use of fixed charges in California:

- Currently, the California IOUs have either small or no fixed monthly or minimum bill charges in their tariffs but have proposals to implement substantially higher charges of this nature pending the outcome of the CPUC proceeding. Elsewhere in California (and other states), a trend toward introducing and increasing fixed charges or other infrastructure charges is found.
- Roseville increased its monthly fixed charge from $10.00 to $12.00 in 2013 and to $18.00 in 2014.
- At SMUD, for five years starting in 2013, the fixed infrastructure charge will increase every year by $2.00, from $10.00 in 2012 to $20.00 in 2017.
- For several years, Riverside has been assessing a four tiered fixed reliability charge based on size of the residence (as measured by meter size). This reliability charge ranges from $10.00 per month for small residences to $60.00 for very large residences. In addition, Riverside residential customers pay a fixed customer charge of $8.00 per month.

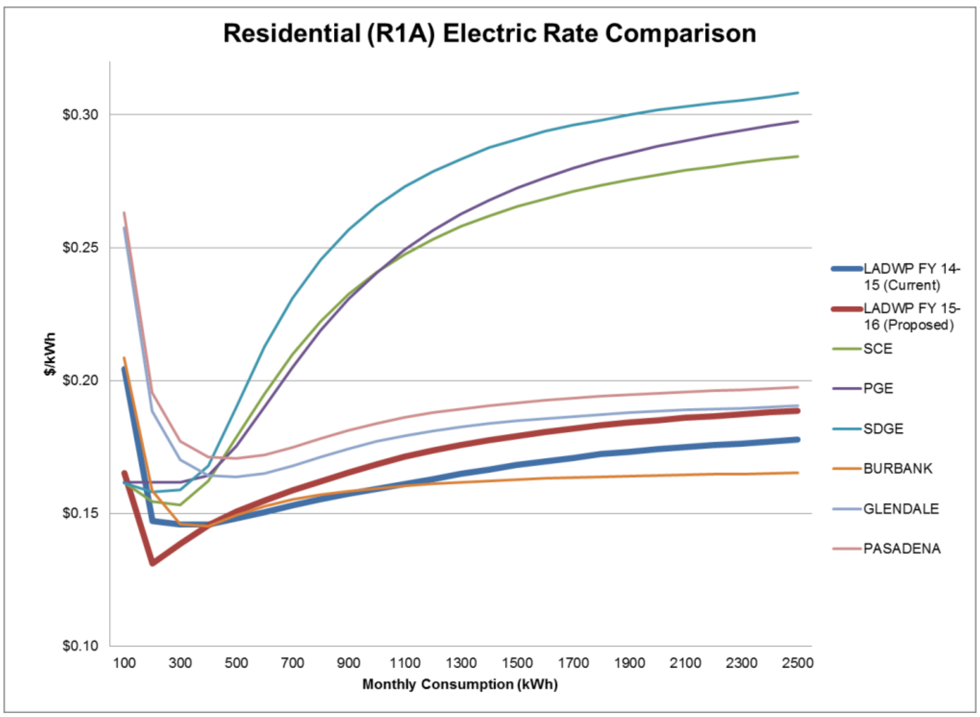
[10] Riverside has a fixed charge of $8.00, plus a reliability charge of $20.00 for a medium-sized residence.

- In October 2014, Pasadena split its residential Distribution and Customer charge into two components: a monthly fixed Customer Charge of $7.80 and a Distribution Charge per kWh based on three usage tiers.

Residential Rate Comparison

LADWP's proposed FY 2015-16 Residential rates for the typical Residential consumption level of 500kWh are less than 15 cents per kWh. As shown in Figure 23, LADWP's proposed Residential rates are competitive at all usage levels when compared to the vast majority of peer utilities and are significantly lower than IOU rates. In addition, these comparisons do not include the impact of rate increases being implemented by other utilities, so the LADWP price favorability is likely to continue and even increase.

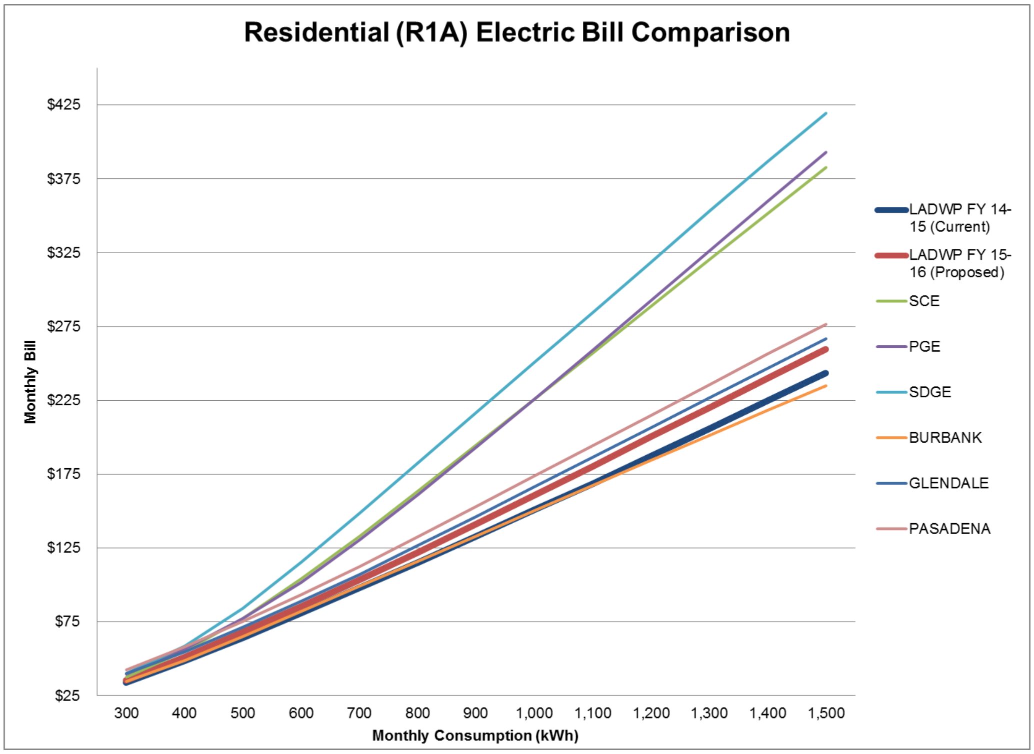
Figure 23: Residential Customer Peer Rate Comparison by Consumption Level ($/kWh)



LADWP's proposed FY 2015-16 typical Residential customer electric bill (based on 500kWh of monthly usage) is the lowest among the peer group, as shown in Figure 24 below. The balanced approach to rate design promotes conservation and encourages distributed generation at the same time. Consequently, LADWP has assigned a larger proportion of the rate increase to higher usage customers. This approach is depicted by the steeper gradient of the LADWP FY 2015-16 proposed residential bill amounts (red line) as compared to current LADWP bills (blue line).

Current and proposed LADWP customer bills are quite similar at lower usage levels; however, proposed LADWP bills are higher than current bills at usage levels above 1,000kWh. Despite this approach, LADWP's bills for customers with higher usage are still much lower than corresponding bills for the IOUs, and also lower than most peer publicly-owned utilities.

Figure 24: Residential Customer Average Monthly Electric Bill Comparison (Total Bill)



5.5 COMMERCIAL AND INDUSTRIAL (A1A, A2B, A3A)

No significant changes are proposed to the rate structure for Commercial and Industrial customers. These tariffs include Small Commercial (A1A), Medium Commercial (A2B), and Large Commercial and Industrial (A3A). The proposed rate increase is assigned across the facilities demand charge, monthly demand charge, and energy charge to align the rate design with cost of service rate design considerations. Due to the variety of load characteristics for commercial and industrial customers, the rate design had to maintain a balance between the energy and capacity characteristics of these customers.

As mentioned earlier in this report, Figure 25 provides a summary of the major rate design elements for LADWP Commercial and Industrial customers.

Figure 25: Major Elements of LADWP Electric Commercial and Industrial Rate Design

	Small Commercial (Small General Service A1A)	Medium Commercial (Primary Service A2B)	Large Commercial and Industrial (Sub-transmission A3A)
Fixed Charges	Service charge	Service charge	Service charge
Capacity Charge ($/kW)	Facilities charge	Facilities charge and monthly demand charge	Facilities charge and monthly demand charge
Energy (Usage) Charges ($/kWh)	Based on season	Based on season and TOU	Based on season and TOU
Voltage by Class	≤ 4.8 kV	4.8 kV	34.5 kV

A steady and consistent load usage pattern allows for economic dispatch of power supply. This is preferred over seasonal or intermittent loads. Commercial and Industrial customer rates are based on required peak capacity, and facilities must be deployed to meet this peak level of demand. The more steady the load, the more economical it is to serve the load. It is also beneficial to the customer and LADWP if their steady load can be shifted away from periods when production costs are high. The proposed Commercial and Industrial rates encourage customers to use energy consistently with less variation. Therefore, customers who have the ability to shift load away from the summer high peak period can avoid paying for higher priced power when production costs are premium, and as a result, LADWP can avoid building expensive peaking units needed when the power system is more constrained by high peak demand.

5.5.1 Commercial and Industrial Proposed Rates

Figure 26, Figure 27, and Figure 28 show proposed rates for Commercial and Industrial customers, which reflect a gradual increase over the five-year rate period. Changes to individual components (energy and demand charges) are guided by cost of service. Increases in the energy rates over the five-year period also reflect anticipated market changes. Except for one initial adjustment to the A1A service charge, the service and generation demand charges remain constant as costs are unchanged from previous rates. The facility demand charge increases slowly due to increased costs to help maintain and improve reliability of the distribution infrastructure. Commercial and Industrial rates, in conjunction with NEM, are set at levels that provide economic incentives and encourage customer solar installation.

Figure 26: Proposed Small Commercial Rates (Small General Service A1A)

	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20
Monthly Fixed Charge	$6.50	$7.00	$7.00	$7.00	$7.00	$7.00
Facilities Charge ($/kW)	$7.48	$7.48	$7.48	$7.98	$8.48	$8.98
High Season Consumption ($/kWh)	$0.14043	$0.14649	$0.15185	$0.15919	$0.16329	$0.16998
Low Season Consumption ($/kWh)	$0.11753	$0.12307	$0.12755	$0.13374	$0.13723	$0.14294

Figure 27: Proposed Medium Commercial Rates (Primary Service A2B)

		FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20
Monthly Fixed Charge		$28.00	$28.00	$28.00	$28.00	$28.00	$28.00
Facilities Charge ($/kW)		$7.48	$ 7.48	$7.48	$7.98	$8.48	$8.98
High Season	**Demand High Peak (HP) ($/kW)** [11]	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00
	Demand Low Peak (LP) ($/kW)	$3.75	$3.75	$3.75	$3.75	$3.75	$3.75
Low Season	**Demand HP ($/kW)**	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75
	Demand LP ($/kW)	$ -	$ -	$ -	$ -	$ -	$ -
High Season	**Consumption HP ($/kWh)**	$0.11818	$0.12522	$0.13059	$0.13876	$0.14405	$0.15132
	Consumption LP ($/kWh)	$0.11091	$0.11795	$0.12332	$0.13149	$0.13678	$0.14405
	Consumption Base ($/kWh)	$0.09018	$0.09722	$0.10259	$0.11076	$0.11605	$0.12332
Low Season	**Consumption HP ($/kWh)**	$0.11184	$0.11888	$0.12425	$0.13242	$0.13771	$0.14498
	Consumption LP ($/kWh)	$0.11184	$0.11888	$0.12425	$0.13242	$0.13771	$0.14498
	Consumption Base ($/kWh)	$0.09391	$0.10095	$0.10632	$0.11449	$0.11978	$0.12705

[11] There are three TOU periods for LADWP Commercial customers, high peak, low peak, and base. High peak represents the highest cost period (weekday afternoon), base represents lowest cost period (late evening-early morning and weekends), low period represents remaining time periods.

Figure 28: Proposed Large Commercial Rates (Sub-transmission A3A)

	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20
Monthly Fixed Charge	$75.00	$75.00	$75.00	$75.00	$75.00	$75.00
Facilities Charge ($/kW)	$6.68	6.68	$6.68	$7.18	$7.68	$8.18
Demand HP Summer ($/kW)	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70
Demand LP Summer ($/kW)	$3.30	$3.30	$3.30	$3.30	$3.30	$3.30
Demand HP Winter ($/kW)	$4.30	$4.30	$4.30	$4.30	$4.30	$4.30
Demand LP Winter ($/kW)	$ -	$ -	$ -	$ -	$ -	$ -
Consumption HP Summer ($/kWh)	$0.11577	$0.12252	$0.12757	$0.13571	$0.14093	$0.14801
Consumption LP Summer ($/kWh)	$0.10951	$0.11626	$0.12131	$0.12945	$0.13467	$0.14175
Consumption Base Summer ($/kWh)	$0.08942	$0.09617	$0.10122	$0.10936	$0.11430	$0.12166
Consumption HP Winter ($/kWh)	$0.11050	$0.11725	$0.12230	$0.13044	$0.13566	$0.14274
Consumption LP Winter ($/kWh)	$0.11050	$0.11725	$0.12230	$0.13044	$0.13566	$0.14274
Consumption Base Winter ($/kWh)	$0.09384	$0.10059	$0.10564	$0.11378	$0.11900	$0.12608

5.5.2 Commercial and Industrial Customer Rate Impacts

Small Commercial Customer (Small General Service A1A)

The proposed rate design encourages Small Commercial customers to use energy consistently with less variation (improve/increase their load factor)[12]. The 3.8% to 4.1% range of annual rate changes for this class is small. Figure 29 provides a graphical representation, and Figure 30 provides a tabular representation of the average annual distribution of bills with proposed rates based on load.

[12] Load Factor is defined as: Total Monthly Average kWh/ (Max High Peak kW for Month * Hours in the Month).

Figure 29: Small Commercial Customer (Small General Service A1A) Annual Rate Impact by Usage Distribution

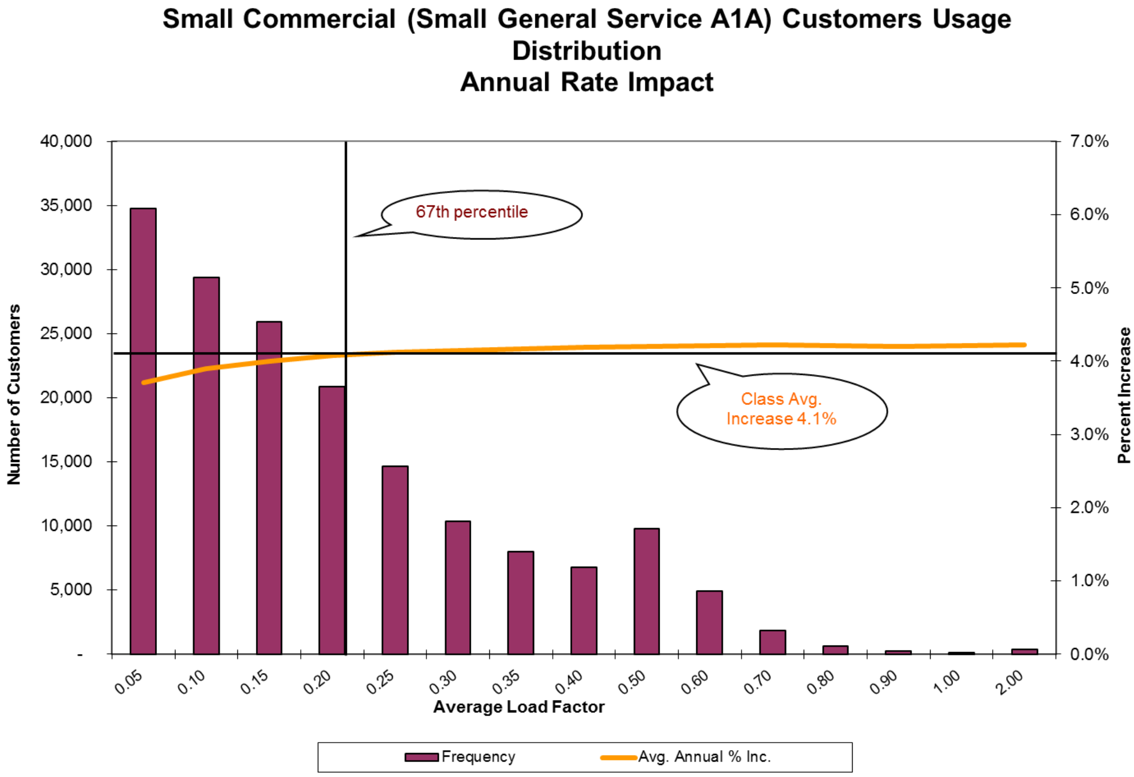


Figure 30: Small Commercial Customer (Small General Service A1A) Bill Impacts by Load Factor (Detail)

Load Factor	Customers	Average Median Bill						Average Annual Increase	Cumulative %	FY 2019-20 $/kWh
		FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20			
0.05	34,780	$44.68	$45.55	$45.86	$48.30	$50.55	$52.95	3.7%	22.8%	$0.790
0.10	29,376	$67.09	$68.97	$70.12	$73.74	$76.66	$80.15	3.9%	39.7%	$0.346
0.15	25,947	$96.74	$99.69	$101.74	$107.02	$111.05	$116.06	4.0%	54.7%	$0.266
0.20	20,867	$147.95	$152.83	$156.52	$164.57	$170.43	$178.11	4.1%	66.7%	$0.233
0.25	14,665	$199.95	$206.92	$212.32	$223.23	$230.86	$241.11	4.1%	75.1%	$0.214
0.30	10,372	$256.47	$265.61	$272.85	$286.83	$296.46	$309.61	4.1%	81.1%	$0.203
0.35	7,960	$324.23	$336.23	$345.86	$363.48	$375.28	$391.85	4.2%	85.7%	$0.194
0.40	6,768	$402.03	$417.39	$429.74	$451.51	$465.92	$486.36	4.2%	89.6%	$0.188
0.50	9,816	$526.08	$546.50	$563.22	$591.67	$610.03	$636.62	4.2%	95.3%	$0.182
0.60	4,891	$627.44	$652.74	$673.34	$707.12	$728.38	$759.72	4.2%	98.1%	$0.177
0.70	1,862	$604.28	$629.01	$649.22	$681.59	$701.76	$731.86	4.2%	99.2%	$0.173
0.80	642	$426.69	$444.45	$458.90	$481.54	$495.51	$516.57	4.2%	99.5%	$0.171
0.90	266	$367.61	$383.12	$395.75	$415.13	$426.90	$444.85	4.2%	99.7%	$0.169
1.00	115	$386.58	$403.03	$416.38	$436.77	$449.10	$467.98	4.2%	99.7%	$0.168
2.00	361	$480.66	$501.39	$518.33	$543.66	$558.76	$582.17	4.2%	100.0%	$0.165

Medium Commercial Customer (Primary Service A2B) Rate Impacts

Similar to the Small Commercial customer class, the proposed rate and rate design encourage Medium Commercial customers to improve their load factor and shift load outside of peak hours. The level of annual rate changes is relatively small for this class; the average annual increase for the vast majority of Medium Commercial customers will range from 2.4% to 6.4%.

Figure 31 and Figure 32 provide graphical and tabular depictions respectively of the average annual distribution of the rate increase based on load factor for the five-year rate period.

Figure 31: Medium Commercial Customer (Primary Service A2B) Annual Rate Impact by Usage Distribution

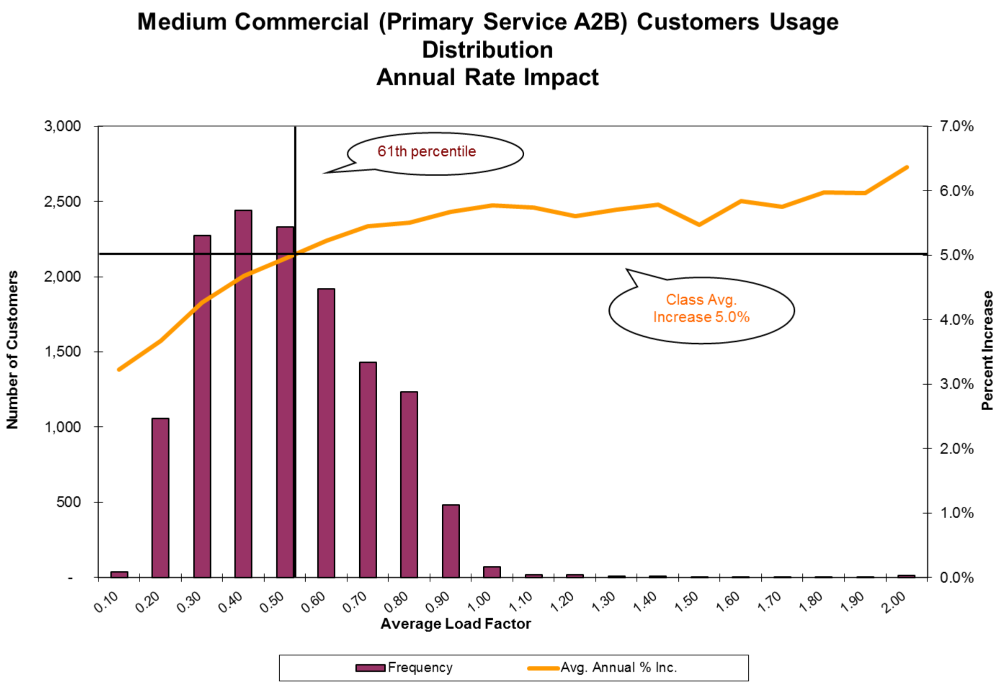


Figure 32: Medium Commercial Customer (Primary Service A2B) Annual Bill Impacts by Load Factor (Detail)

Load Factor	Customers	Average Median Bill						Average Annual Increase	Cumulative %	FY 2019-20 $/kWh
		FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20			
-	59	$248.48	$249.27	$250.39	$265.54	$279.75	$294.61	3.7%	0.4%	-
0.02	12	$736.07	$737.81	$739.13	$777.32	$814.80	$850.95	3.1%	0.5%	$2.500
0.03	12	$927.22	$932.58	$936.66	$971.72	$1,004.58	$1,038.95	2.4%	0.6%	$1.350
0.04	17	$686.56	$692.28	$696.64	$726.81	$754.65	$784.09	2.8%	0.7%	$1.292
0.05	17	$602.04	$605.87	$608.79	$639.01	$667.65	$697.37	3.2%	0.9%	$0.830
0.06	34	$805.23	$814.47	$821.52	$858.81	$890.71	$924.08	3.0%	1.1%	$0.780
0.07	28	$731.33	$742.14	$750.39	$782.92	$811.04	$842.19	3.0%	1.3%	$0.632
0.08	27	$725.20	$737.03	$746.06	$779.98	$809.05	$ 841.46	3.2%	1.5%	$0.554
0.09	43	$956.78	$971.16	$982.14	$1,028.26	$1,068.51	$1,112.80	3.3%	1.8%	$0.536
0.10	39	$815.02	$830.38	$842.10	$879.63	$910.87	$946.44	3.2%	2.1%	$0.467
0.20	1,056	$1,019.09	$1,044.32	$1,064.61	$1,115.66	$1,157.14	$1,206.31	3.7%	9.4%	$0.334
0.30	2,274	$1,412.43	$1,459.87	$1,497.82	$1,578.45	$1,639.10	$1,713.41	4.3%	26.2%	$0.254
0.40	2,441	$1,720.61	$1,790.62	$1,844.77	$1,950.31	$2,026.82	$2,123.29	4.7%	44.1%	$0.217
0.50	2,331	$2,147.49	$2,243.47	$2,319.67	$2,456.53	$2,554.54	$2,679.10	5.0%	61.3%	$0.196
0.60	1,919	$2,434.06	$2,551.64	$2,642.10	$2,805.25	$2,920.28	$3,069.76	5.2%	75.4%	$0.183
0.70	1,431	$2,882.67	$3,031.09	$3,147.38	$3,348.01	$3,487.49	$3,668.19	5.4%	85.9%	$0.175
0.80	1,234	$2,910.16	$3,060.96	$3,177.63	$3,383.61	$3,525.78	$3,711.89	5.5%	95.0%	$0.168
0.90	482	$3,039.72	$3,206.03	$3,332.88	$3,552.62	$3,704.33	$3,902.81	5.7%	98.5%	$0.165
1.00	72	$3,491.39	$3,691.39	$3,843.95	$4,098.47	$4,271.18	$4,500.13	5.8%	99.0%	$0.161
1.10	17	$2,118.08	$2,232.67	$2,320.08	$2,475.72	$2,584.49	$2,725.49	5.7%	99.2%	$0.166
1.20	16	$1,352.72	$1,419.08	$1,471.83	$1,571.34	$1,641.74	$1,732.16	5.6%	99.3%	$0.169
1.30	6	$2,889.58	$3,037.14	$3,149.70	$3,364.27	$3,518.48	$3,714.20	5.7%	99.3%	$0.167
1.40	7	$1,404.48	$1,480.41	$1,538.33	$1,642.75	$1,716.11	$1,810.82	5.8%	99.4%	$0.182
1.50	2	$1,172.42	$1,224.45	$1,264.14	$1,349.91	$1,414.40	$1,493.52	5.5%	99.4%	$0.227
1.60	2	$1,756.52	$1,852.52	$1,925.74	$2,057.55	$2,150.09	$2,269.63	5.8%	99.4%	$0.168
1.70	2	$1,714.96	$1,800.95	$1,866.53	$1,995.84	$2,089.98	$2,208.29	5.8%	99.4%	$0.204
1.80	5	$1,531.83	$1,618.48	$1,684.57	$1,801.58	$1,883.16	$1,989.10	6.0%	99.5%	$0.168
1.90	3	$2,896.84	$3,058.43	$3,181.68	$3,403.46	$3,559.15	$3,760.28	6.0%	99.5%	$0.164
2.00	11	$2,236.65	$2,368.29	$2,468.70	$2,652.40	$2,782.25	$2,949.13	6.4%	99.6%	$0.185

Large Commercial and Industrial Customer (Sub-transmission A3A) Rate Impacts

Similar to the Small and Medium Commercial customers, the proposed rates and rate design encourage Large Commercial and Industrial customers to improve their load factor and shift load outside of peak hours. The range of annual rate changes is also relatively small for this class with increase for the vast majority of customers to range from 4% to 6%.

Figure 33 and Figure 34 provide graphical and tabular depictions respectively of the average annual distribution of the rate increase based on load factor for the five-year rate period.

Figure 33: Large Commercial and Industrial Customer (Sub-transmission A3A) Annual Rate Impact by Usage Distribution

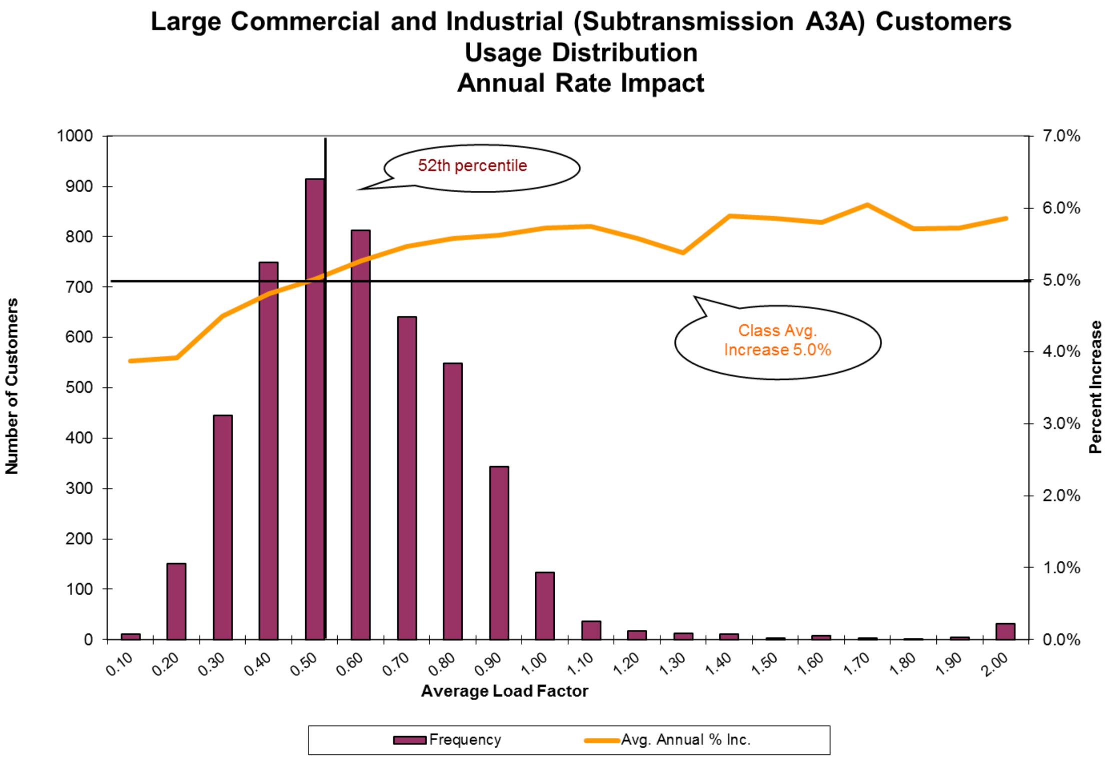


Figure 34: Large Commercial and Industrial Customer (Sub-transmission A3A) Bill Impacts by Load Factor (Detail)

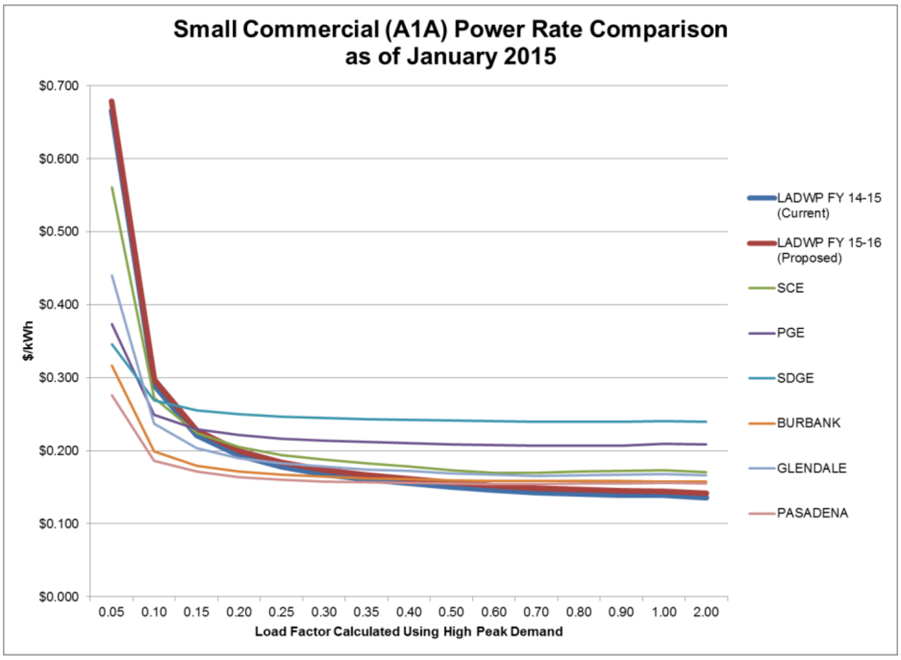
Load Factor	Customers	Average Median Bill						Average Annual Increase	Cumulative %	FY 2019-20 $/kWh
		FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20			
0.00	482	$898.27	$ 956.00	$999.35	$1,069.08	$1,113.61	$1,175.04	6.2%	8.9%	$0.138
0.01	4	$1,520.80	$1,521.57	$1,522.14	$1,580.06	$1,637.65	$1,695.46	2.3%	9.0%	$8.082
0.02	2	$359.12	$360.63	$361.77	$375.55	$388.64	$402.21	2.4%	9.0%	$2.167
0.03	4	$2,278.97	$2,293.60	$2,304.54	$2,397.67	$2,484.40	$2,575.33	2.6%	9.1%	$1.217
0.04	4	$212.26	$213.85	$215.03	$222.54	$229.32	$236.62	2.3%	9.2%	$1.172
0.05	5	$1,410.85	$1,426.32	$1,437.89	$1,497.94	$1,551.18	$1,608.93	2.8%	9.3%	$0.702
0.06	5	$161.34	$162.95	$164.15	$169.99	$175.09	$180.72	2.4%	9.4%	$0.719
0.07	12	$995.11	$1,009.74	$1,020.69	$1,064.94	$1,102.76	$1,144.80	3.0%	9.6%	$0.585
0.08	4	$1,322.53	$1,343.84	$1,359.78	$1,424.64	$1,480.15	$1,541.82	3.3%	9.7%	$0.559
0.09	5	$1,799.24	$1,821.81	$1,838.69	$1,952.64	$2,056.77	$2,167.23	4.1%	9.8%	$0.459
0.10	11	$1,986.91	$2,008.87	$2,025.30	$2,145.11	$2,255.29	$2,371.80	3.9%	10.0%	$0.403
0.20	151	$2,201.65	$2,267.93	$2,317.53	$2,438.01	$2,527.18	$2,632.68	3.9%	12.8%	$0.309
0.30	445	$3,159.70	$3,278.87	$3,368.03	$3,560.58	$3,699.09	$3,870.36	4.5%	21.0%	$0.234
0.40	749	$4,170.95	$4,343.04	$4,471.78	$4,742.10	$4,933.24	$5,173.58	4.8%	34.9%	$0.206
0.50	914	$6,133.61	$6,396.31	$6,592.84	$7,003.48	$7,298.29	$7,669.86	5.0%	51.8%	$0.188
0.60	813	$7,475.75	$7,834.27	$8,102.50	$8,619.00	$8,975.04	$9,443.41	5.3%	66.8%	$0.177
0.70	641	$10,432.78	$10,966.32	$11,365.48	$12,110.09	$12,618.28	$13,284.71	5.5%	78.7%	$0.169
0.80	548	$14,088.77	$14,830.15	$15,384.82	$16,408.17	$17,103.15	$18,017.73	5.6%	88.9%	$0.163
0.90	343	$10,806.46	$11,379.97	$11,809.04	$12,599.05	$13,135.21	$13,840.91	5.6%	95.2%	$0.160
1.00	134	$8,351.72	$8,812.06	$9,156.47	$9,775.22	$10,190.18	$10,741.27	5.7%	97.7%	$0.159
1.10	36	$7,126.57	$7,527.69	$7,827.78	$8,355.70	$8,706.36	$9,175.03	5.7%	98.4%	$0.159
1.20	17	$4,772.67	$5,029.82	$5,182.40	$5,529.14	$5,785.88	$6,102.38	5.6%	98.7%	$0.157
1.30	12	$5,274.29	$5,480.58	$5,634.91	$6,027.92	$6,329.51	$6,692.32	5.4%	98.9%	$0.159
1.40	10	$8,252.33	$8,707.92	$9,048.77	$9,683.08	$10,115.61	$10,683.07	5.9%	99.1%	$0.152
1.50	3	$3,992.02	$4,221.00	$4,392.32	$4,693.66	$4,893.67	$5,161.32	5.9%	99.1%	$0.152
1.60	7	$3,003.38	$3,165.44	$3,286.69	$3,514.53	$3,670.53	$3,874.64	5.8%	99.3%	$0.164
1.70	3	$14,915.77	$15,807.16	$16,474.05	$17,631.20	$18,393.60	$19,419.90	6.0%	99.3%	$0.161
1.80	1	$1,522.26	$1,602.73	$1,662.94	$1,776.78	$1,854.90	$1,957.01	5.7%	99.3%	$0.164
1.90	4	$4,521.76	$4,729.25	$4,884.49	$5,235.46	$5,494.22	$5,815.06	5.7%	99.4%	$0.201
2.00	32	$2,270.63	$2,390.05	$2,479.39	$2,655.02	$2,777.86	$2,935.87	5.9%	100.0%	$0.161

5.5.3 Commercial and Industrial Customer Comparative Rate Analysis

Small Commercial (Small General Service A1A) Comparative Rate Analysis

As discussed earlier, Small Commercial customers with higher load factors use energy more efficiently, resulting in a lower average cost of service. Therefore, Small Commercial customers with high load factors should benefit from lower rates. LADWP's rates for Small Commercial customers are designed to encourage customers with high load factors. Consequently, LADWP's rates for this customer class are lower than most peers at load factors greater than 30%. For Small Commercial customers with a load factor above 50%, LADWP rates are the lowest of the peer utilities as depicted in Figure 35.

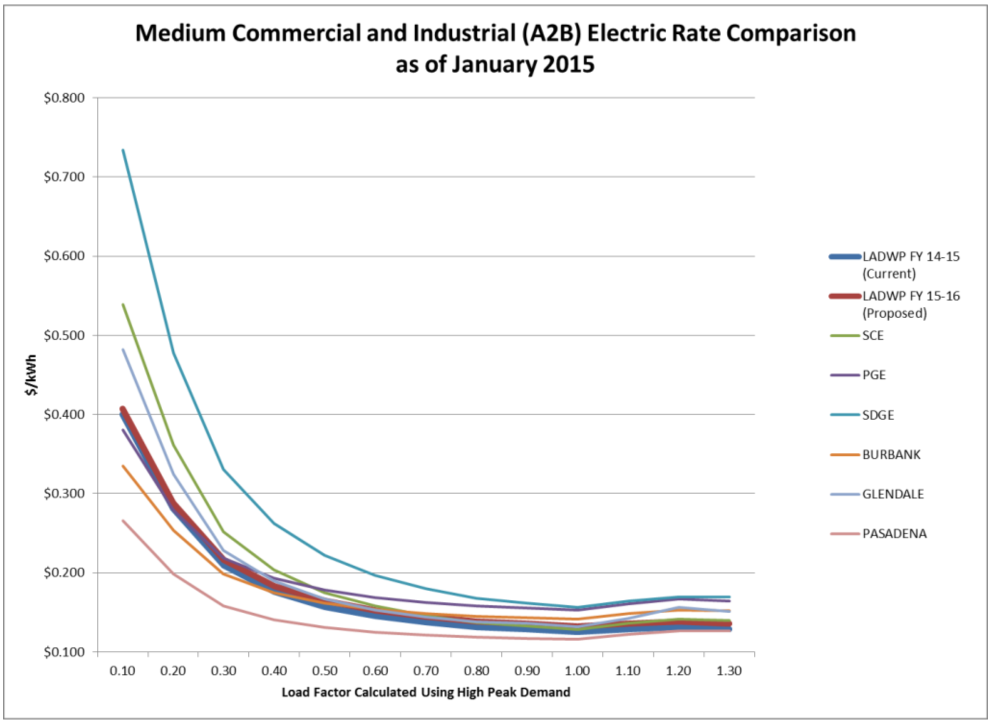
Figure 35: Small Commercial Customer Peer Rate Comparison ($/kWh by Load Factor)



Medium Commercial (Primary Service A2B) Comparative Rate Analysis

LADWP's Medium Commercial customer rates are competitive with the majority of California utilities. In particular, over 70% of LADWP's Medium Commercial customers have a load factor greater than 30%; at these load factor levels, the Department's Medium Commercial customers have rates among the lowest in the peer group, as shown in Figure 36.

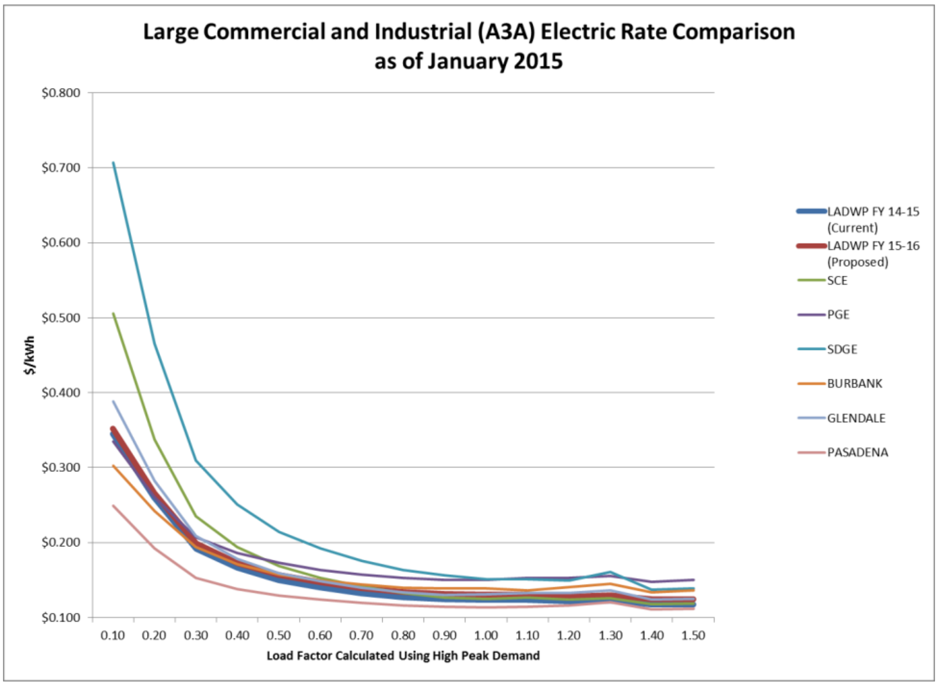
Figure 36: Medium Commercial Customer Peer Rate Comparison



Large Commercial and Industrial (Sub-transmission A3A) Comparative Rate Analysis

For Large Commercial and Industrial customers, LADWP's rates are competitive among other California utilities, as shown in Figure 37.

Figure 37: Large Commercial and Industrial Customer Peer Rate Comparison



5.6 BUSINESS PROMOTION SERVICE RIDER[13]

The City of Los Angeles has actively developed policies to attract new business to the area. One of the five overarching outcomes in the Mayor's FY 2015-16 "Budget Policy and Goals" is to "Promote good jobs for Angelenos all across Los Angeles." Reasonable electricity rates are an important tool to attract new businesses, making it "easier to do business in Los Angeles" and "promote equity, affordability and upward economic mobility", which are additional Mayoral outcomes.

Generally, LADWP's electric commercial rates are competitive. However, as an additional incentive to encourage businesses to locate in the City of Los Angeles, a cost based business promotion service rider has been developed to better use LADWP generation capacity. Over the next ten years, generation capacity in the Power System is expected to be available to serve new commercial customer load growth. To attract new customers to come to Los Angeles qualifying new commercial businesses that locate in the City and receive service under General Service Schedule A2, A3, or A4 will be eligible to receive bill credit amounts that will be phased out over three years based on the marginal value of this capacity. The service rider is limited to a total of 80MW of customer load. Qualification rules will be developed and communicated by LADWP before the service rider is available sometime in 2016. The bill credits, as a percent of total, for those that qualify are outlined in Figure 38.

Figure 38: Business Promotion Bill Credit by Year

Year of Location	Credit Amount
1st Year	7.6%
2nd Year	5.0%
3rd Year	2.5%

5.7 SUMMARY OF ELECTRIC RATE DESIGN

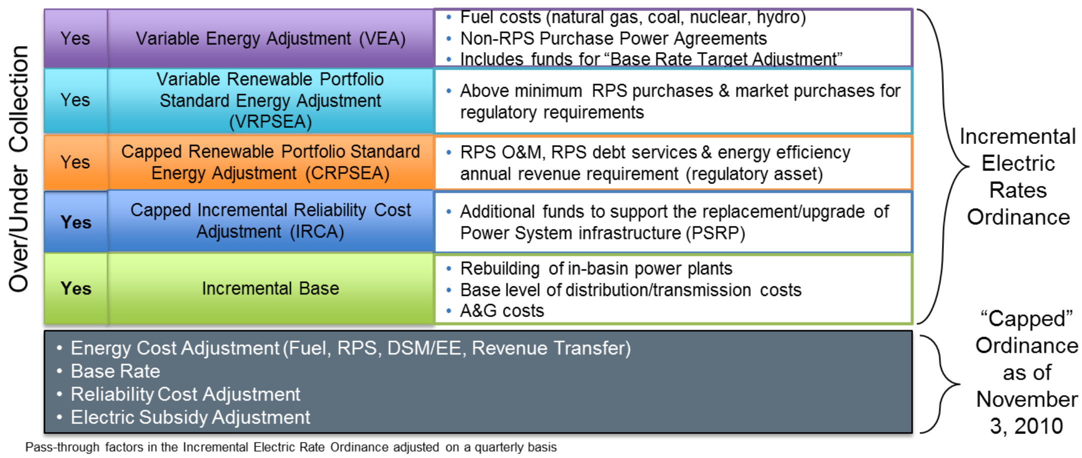
In summary, the main changes to LADWP's electric rate design include a fixed charge for Residential customers, and a phased in system rate change averaging 4.7% per year over five years. Phasing in the proposed changes to the rate structure and rates will moderate the impact on customers, and allow LADWP to achieve its rate objectives (affordability; business development; encourage conservation and sustainable customer resources; meet legal requirements; assist in the transformation to a distribution oriented utility; assure financial stability; and utilize marginal cost of service in the rate design), while allowing LADWP to continue to provide electric service to the citizens of Los Angeles at affordable and competitive prices.

[13] A service rider works in conjunction with a customer's otherwise applicable rate.

A. INCREMENTAL ELECTRIC RATE ORDINANCE COMPONENTS

This appendix provides details for the components of the Incremental Electric Rate Ordinance and the costs that each component is designed to recover.

Figure 1: LADWP Power System Proposed Rate Structure



A.1 Variable Energy Adjustment (VEA) [uncapped]

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. As of April 2015 it is roughly $129.0 million, largely due to the cost of fuel. Through this charge component, the Department intends to collect the legacy under-collection over a ten-year period.

Base Rate Revenue Target Adjustment (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 back to customers if sales exceed forecasted amounts. The base rate revenue target is set in the ordinance for each of the five years.

A.2 Variable Renewable Portfolio Standard Energy Adjustment (VRPSEA) [uncapped]

Purchases for Regulatory Requirements: This charge will recover some costs required to meet legally mandated RPS targets. The cost of market purchases for the 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 from sources in which the Department has an indirect financial ownership above and beyond debt service and O&M, including delivery of excess wind and/or solar power due to climate conditions.

A.3 Capped Renewable Portfolio Standard Energy Adjustment (CRPSEA)

RPS O&M and Debt Service Costs: This adjustment will recover O&M and debt service costs of sources directly and indirectly owned by the Department (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: LADWP will develop a quarterly projection of future under-collections for the next three years. If any projected under-collection is greater than $50.0 million but less than $100.0 million, LADWP will provide a report to the Board and City Council to communicate the under-collection. If any projected under-collection is $100.0 million or greater, if deemed necessary, modified rates will also be fixed by the Board and then approved by ordinance.

A.4 Incremental Reliability Cost Adjustment (IRCA)

Power System Reliability Program: To ensure the continued reliability of the Power System, this adjustment will provide funding for the cash funded portion of capital expenditures for infrastructure replacements and upgrades associated with the PSRP expenditures above $320 million (from Electric Rate Ordinance), as well as for ongoing O&M expenditures above $290 million (from Electric Rate Ordinance).

The new IRCA will have the additional following characteristics.

- For years one (FY 2015-16) through year three (FY 2017-18), caps will be designed to allow unused funds to be applied to the second and/or third year of that range.
- Starting in year four, the increase cannot exceed $0.002 per kWh annually.
- Separate Residential and General Service balancing accounts will be established. Projects (and associated spending) can be reallocated and reprioritized within fiscal years and between proximate fiscal years within the caps and subject to the following reporting requirements:
  - If the projected under-collection is greater than $25.0 million and less than $50.0 million, LADWP will report to the Board and Council to communicate the projected under-collection; and
  - If the projected under-collection is $50.0 million or greater, modified rates shall, if deemed necessary, be fixed by the Board and then approved by an ordinance change.
- General Service IRCA factor will have both a kW and kWh component.

Legacy RCA Under-Collection: The previous RCA factor was established to recover operation, maintenance, and debt service costs of the Power System Reliability Program (PSRP). Current forecasts project the under-collection to reach $89.0 million at the end of FY 2014-15. Within this new adjustment, LADWP will account for the legacy under-collection over a seven-year period.

A.5 Incremental Base Rates

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

B. TEMPERATURE ZONES

This appendix provides the zip codes associated with the temperature zones in LADWP's territory for Residential customers.

Figure 1: Zone 1

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

Figure 2: Zone 2 (Includes Owens Valley)

Zone 2 (Includes Owens Valley)				
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	91602	91604	91605
91606	91607			

LOS ANGELES DEPARTMENT OF WATER AND POWER

POWER SYSTEM RATE ACTION REPORT

Chapter 6: Revised Proposed Rate Plan

December 2015

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FIGURES AND TABLES

FIGURES

REVISED PROPOSED POWER RATE ACTION PLAN

6.1 SUMMARY

In July 2015, the Los Angeles Department of Water and Power (LADWP or the Department) submitted its initial Power System rate action plan[1] to the Ratepayer Advocate (RPA). This plan included proposed new electric rates to provide the necessary additional funding to ensure reliability, comply with regulatory mandates, and provide services desired by customers. Subsequently, a FY 2015-16 Power System budget was approved by the Board of Water and Power Commissioners (Board) and City Council (Council). In addition, LADWP has actively pursued discussions about the proposed rates and underlying rate drivers with the Ratepayer Advocate and other stakeholders. A revised financial plan[2] has now been developed to reflect the approved budget and other changes made in response to stakeholder input. This updated financial plan, provided in Appendix A, underlies the Department's revised proposed Power System rate action plan (revised proposed rate plan).[3]

The purpose of this chapter is to discuss the Department's revised proposed rate plan and explain the major changes from the initial Power System proposed rate plan (initial proposed rate plan). In developing the revised proposed rate plan, the Department has solicited feedback from the public, the Ratepayer Advocate, and other external stakeholders. Modifications to LADWP's financial plan include updates to the Power System Reliability Program (PSRP), certain financial assumptions, rate effective dates, and the proposed power rate ordinance. These changes have had a very slight impact to the overall revenue requirement and associated rate drivers. However, there were no changes to the cost of service study,[4] which is used to allocate rates for each major class of customers to recover approximately the portion of the revenue requirement assigned to each class. The new rates are now expected to take effect around April 1, 2016.

One key change to the proposed rates is a change to schedule R1 Rate A for Residential service; the Department shall measure the customer's maximum historical consumption for determining the power access charge using only the energy delivered to customers instead of measuring the higher of delivered or received energy. This is designed so as not to penalize Residential customers who export large quantities of energy through distributed generation back to LADWP's Power System.

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[1] The initial Power System rate action plan was based on Power Financial Case No. 19.

[2] Throughout this chapter, "revised financial plan" is in reference to Power Financial Case No.143.

[3] The revised Power System rate action plan is based on Power Financial Case No.143.

[4] The Power System Cost of Service Study is presented in Chapter 4.

6.1.1 Major Changes between the Initial and Revised Rate Action Plans

There are several major changes reflected in the revised proposed rate plan as shown in Figure 1. In developing the revised plan, the Department continues to strike a balance between providing reliable service, meeting regulatory requirements, promoting customer choice, and maintaining reasonable rates.

Figure 1: Major Changes between Initial and Revised Rate Plans

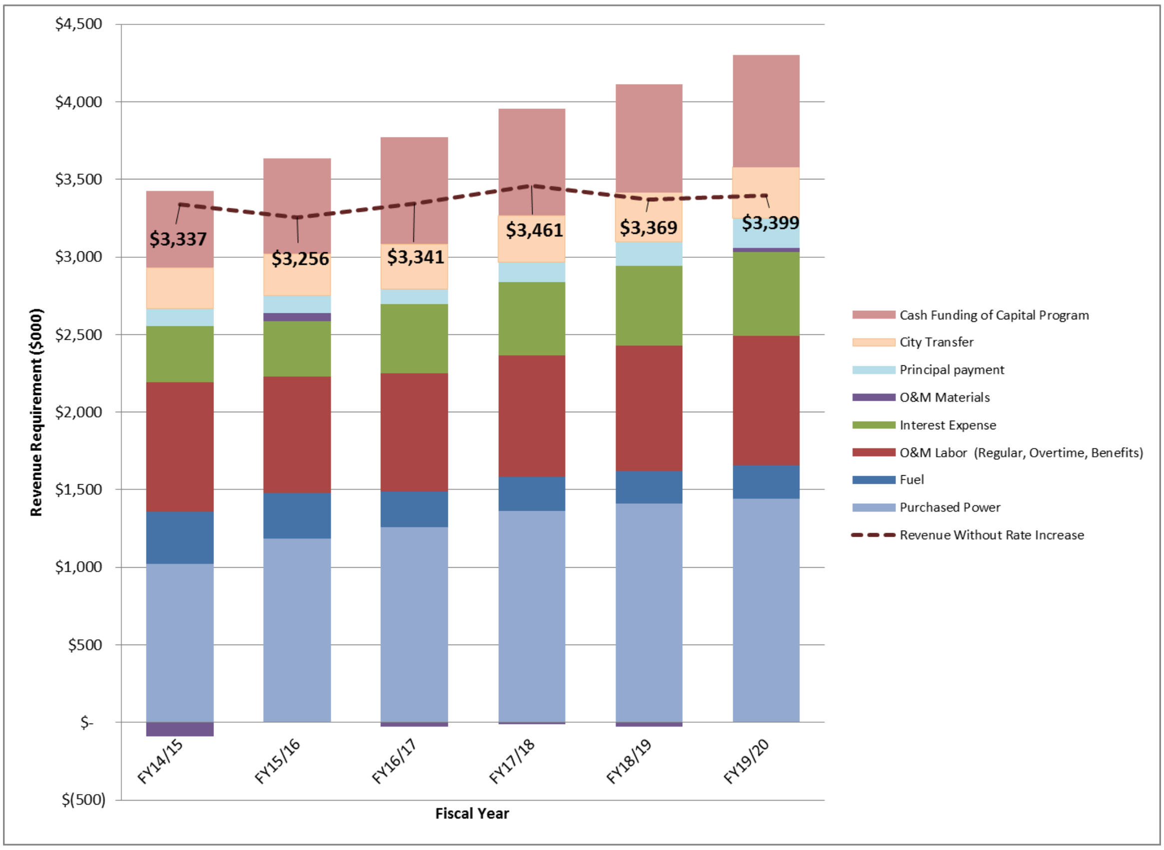
Change	Description
Delayed Rate Action Effective Date	The Revised Proposed Rates will now be effective around April 1, 2016.
Updated FY 2014-15 Financial Results	Actual financial data for FY 2014-15 has been updated as of June 30, 2015.
Approved Power System FY 2015-16 Budget	The Board approved Power System budget is now the basis for the revised financial plan.
Infrastructure and Power System Reliability Program (PRSP) Budget Cuts	In response to input from the RPA, a revised budget for the capital programs geared toward updating and replacing aging electric system infrastructure has been developed.
Fuel and Purchased Power Forecast	The variable cost of fuel for the Department's power plants as well as Power Purchase Agreements (PPAs) that LADWP establishes with third parties have been updated to reflect lower commodity price forecasts.

In addition to the major changes outlined above, this chapter will also address various other miscellaneous changes from the initial proposed rate plan in Section 6.6.

6.1.2 Revised Five-Year Revenue Requirement

The Department's revised financial plan includes several modifications to program budgets and related forecasts which impact the overall revenue requirement as shown in the revised proposed rate plan. The core rate drivers remain the same; however, some of the values have been updated. Figure 2 illustrates the revised potential revenue shortfall the Department expects with no rate increase over the proposed five-year rate period.

Figure 2: Revised Expense Distribution/Revenue Requirement and Projected Gap from FY 2014-15 to FY 2019-20



In comparison to the initial proposed rate plan, the increase in the overall average annual revenue requirement has decreased by approximately $36 million. This change translates into a 0.15 cents per kWh lower system average annual rate increase which equates to an approximately 0.83% lower average annual percentage increase. These changes are relatively minor in light of the Power System's $3.6 billion FY 2015-16 overall revenue requirement. Figure 3 and Figure 4 present the revenue requirement and rate impacts for the initial and revised plans, respectively. In both the initial and revised proposed rate plans, the revenue requirement and average rate increases are presented from a year over year (YOY) standpoint.

Figure 3: Initial Component Breakdown of Revenue Requirement and YOY System Average Rate Increase for FY 2015-16 through FY 2019-20 Compared to FY 2014-15

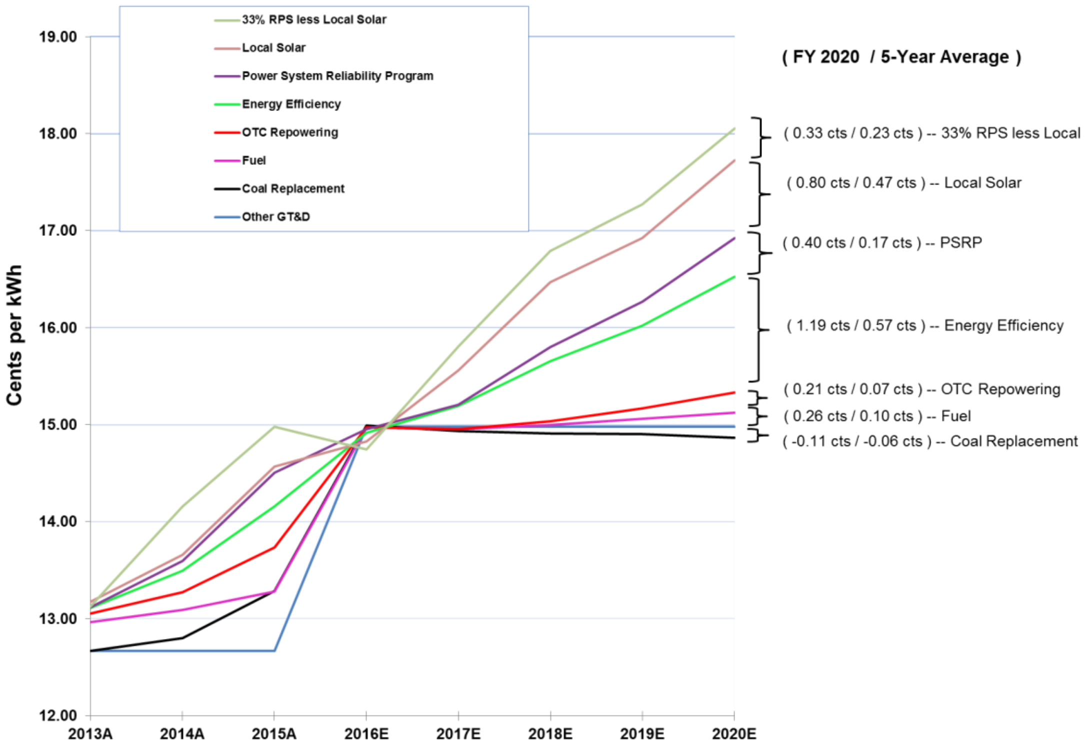
Program	Rate Driver	Regulatory (or Other External) Requirement	Average Annual Revenue Requirement Increase ($M)	System Average Annual Increase (Cents/kWh)	Avg. Annual Percentage Increase (%)
Power System Reliability Program	Power System Reliability		26	0.11	0.68%
Power Supply Transformation Program	Coal Replacement	✓	17	0.07	0.48%
	Once- Through Cooling	✓	4	0.02	0.09%
	Renewable Energy	✓	36	0.15	0.96%
	Subtotal – Increase		57	0.24	1.53%
Customer Opportunities Program	Energy Efficiency	✓	60	0.26	1.54%
	Local Solar Programs	✓	18	0.07	0.46%
	Subtotal – Increase		78	0.33	2.01%
Fuel			18	0.08	0.46%
Total Average Annual Increase			$180	0.76	4.68%

Figure 4: Revised Component Breakdown of Revenue Requirement and YOY System Average Rate Increase for FY 2015-16 through FY 2019-20 Compared to FY 2014-15

Program	Rate Driver	Regulatory (or Other External) Requirement	Average Annual Revenue Requirement Increase ($M)	System Average Annual Increase (Cents/kWh)	Avg. Annual Percentage Increase (%)
Power System Reliability Program	Power System Reliability		19	0.08	0.48%
Power Supply Transformation Program	Coal Replacement	✓	-5	-0.02	-0.14%
	Once-Through Cooling	✓	10	0.04	0.25%
	Renewable Energy	✓	16	0.07	0.44%
	Subtotal – Increase		**20**	**0.09**	**0.55%**
Customer Opportunities Program	Energy Efficiency	✓	56	0.24	1.48%
	Local Solar Programs	✓	38	0.16	1.04%
	Subtotal – Increase		**94**	**0.40**	**2.51%**
Fuel			12	0.05	0.31%
Total Average Annual Increase			**$144**	**0.61**	**3.86%**

Figure 5 illustrates the corresponding cumulative impact of each major program over the proposed five-year rate period.

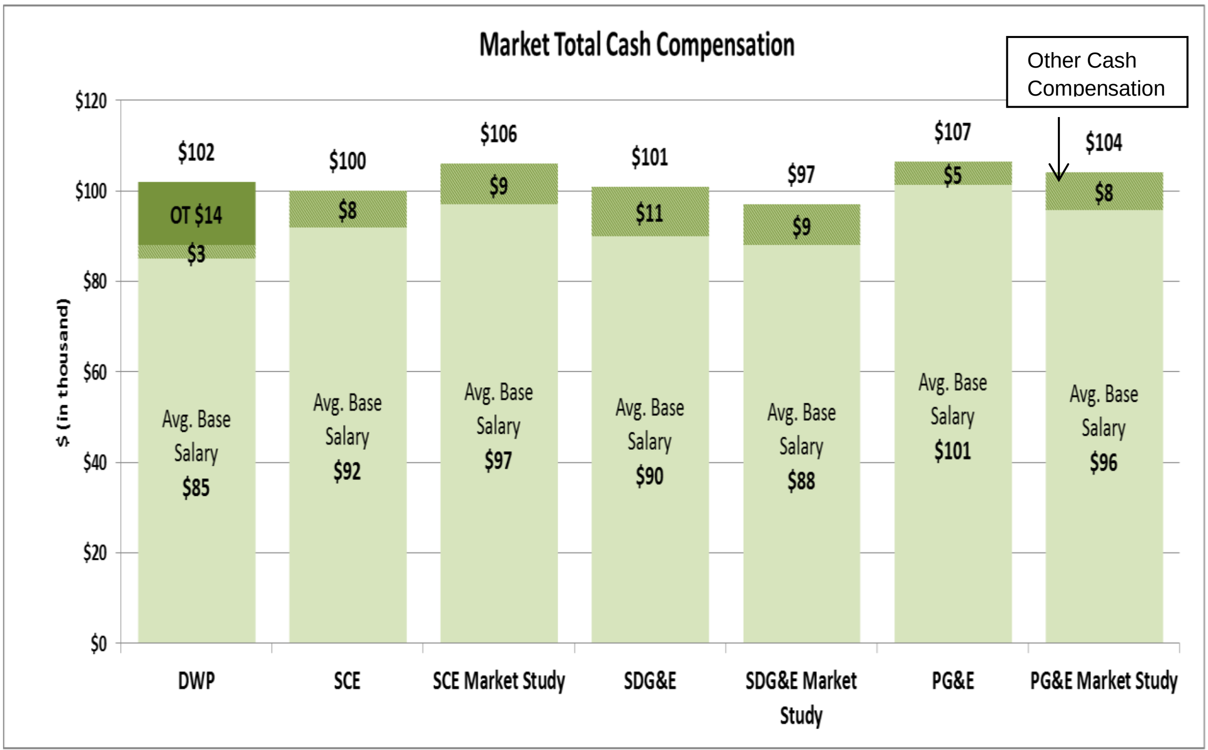
Figure 5: Revised Cumulative Contribution by Rate Driver to Proposed Rate Increase



6.1.3 Comparison of Total Cash Compensation to Neighboring Investor Owned Utilities

Total cash compensation provides one useful measure to compare the LADWP to other similarly situated utilities. The LADWP and others in the utility industry are facing increasing challenges in recruiting and retaining skilled employees. This leads to increased competition for the employees possessing the necessary skills and training. The closest Investor Owned Utilities (IOUs) to LADWP are Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E). As part of their recent rate case filings with the California Public Utilities Commission, both of these utilities were required to file a Total Compensation Study that included actual compensation and a market study of compensation levels for jobs within each of these utilities. While the comparison to data contained in these studies shown below in Figure 6 is not meant to be a comprehensive comparison, it does indicate that LADWP employee total cash compensation is in line with at least two of the large IOUs located in the Southern California area. LADWP intends to work collaboratively with the OPA and their outside expert consultants to perform the second phase of a planned three-phase benchmarking effort.

Figure 6: Labor Cost Comparison Analysis



* SCE data source: p.53 of 2015 General Rate Case for SCE - HR Volume 2, Part 2 - Total Compensation Study/Table D-2 Competitive Analysis - by Total Compensation Dollars (000s) for SCE
* SDG&E data source: Appendix D of SDG&E Direct Testimony of Debbie Robinson Compensation, Health & Welfare - November 2014/Table D-2 SDG&E Study Summary (including Corporate Center): Aggregate Compensation Dollars (000s)
* PG&E data source: Pacific Gas and Electric Company, 2017 General Rate Case, Exhibit (PG&E-8), Human resources, Workpapers Supporting Chapters 5-7, 2017 General Rate Case Total Compensation Study: Volume II - Supporting Documentation - Appndix D, Table D: PG&S Study SummaryL Aggregate Compensation Dollars ($000s)
* LADWP: use class average salary applied to sample of job classes

6.2 UPDATED FY 2014-15 FINANCIAL RESULTS

The revised plan reflects the updated FY 2014-15 financial results, which are now based on close to final audited accounting records. Where applicable, budget data reflects updated actuals as of June 30, 2015, the end of the most recent fiscal year.

6.3 POWER SYSTEM APPROVED FY 2015-16 BUDGET

To complete the final Board approved Power System budget, the Department has undergone a meticulous planning, budgeting, and forecasting process since the submission of the initial proposed rate plan. Completing this effort involves balancing a variety of competing priorities while adhering to the Department's financial planning policies and Board approved financial metrics.

The revised financial plan underlying proposed rates for the five-year rate period is based on the Department's Board approved FY 2015-16 budget. In addition, the revised financial plan includes further changes to certain program assumptions made subsequent to completion of the budget for rate making purposes. These additional changes are discussed separately in this chapter. A comprehensive overview of the revised financial plan is included in Appendix A.

6.3.1 Major Financial Plan Changes

The key financial assumptions that have guided the development of the Department's revised FY 2015-16 financial plan include:

- Updated FY 2014-15 actuals as of June 30, 2015;
- Use of Board approved budget for FY 2015-16;
- Board approved pass-through factors effective in October 2015;
- Rate action effective date of around April 1, 2016 with decoupling for FY 2015-16 under-collection over a two-year period starting January 1, 2017;
- Load forecasts as of October 2014;
- Fuel price forecast as of September 16, 2015;
- Reflected latest refunding bond issue (2015B);
- Updated interest income rate assumptions for IPA subordinated bonds;
- Reflected rate design for adjustment factors (VEA, IRCA, VRPSEA, CRPSEA) and Incremental Base in accordance with the proposed Power Rate Ordinance provided to the RPA;
- Annual Base Rate Revenue Targets set at same values as Financial Case No. 19;
- Net wholesale revenue and contributions in aid of construction (CIAC) exceeding budgeted amounts used to reduce Base Rate Revenue Targets;
- Revised PSRP Program Budgets; and
- Navajo Generating Station (NGS) divestment by the end of FY 2015-16.

These assumptions have governed the development of the revised financial plan, which determines the overall revised revenue requirement.

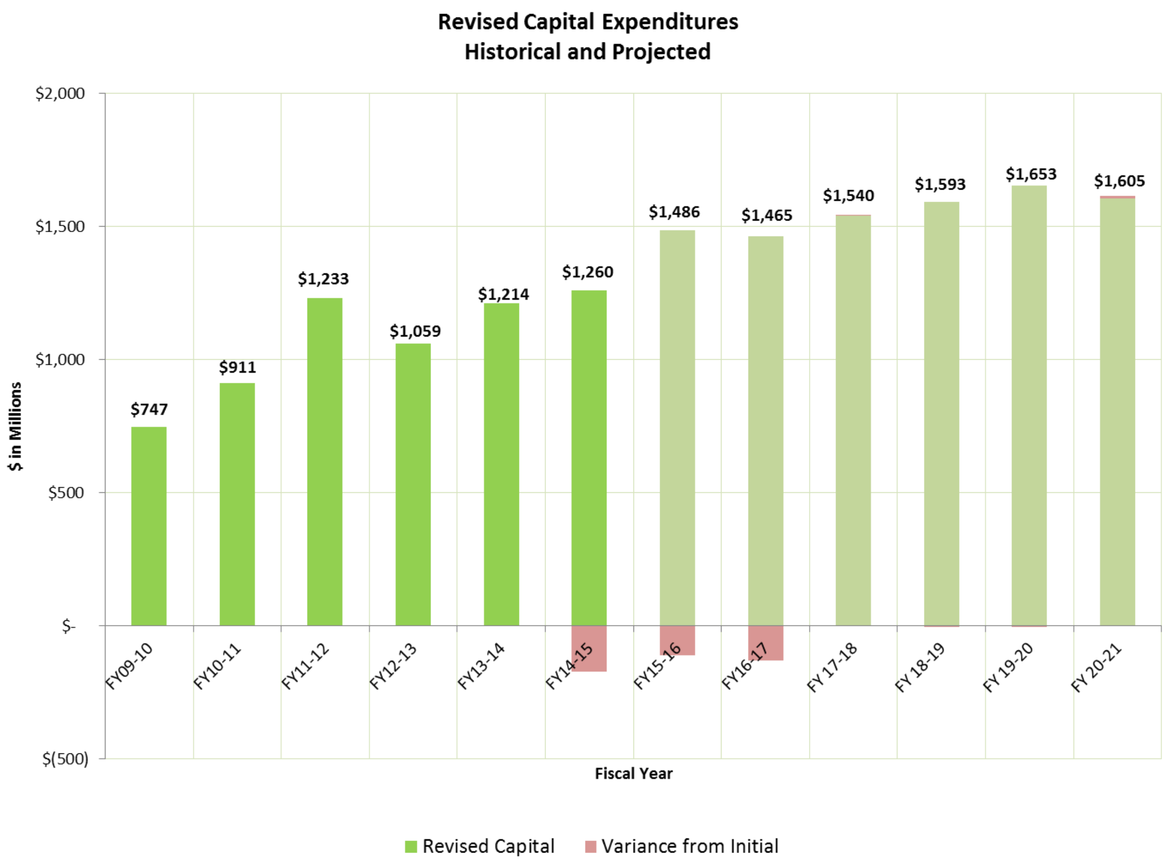
6.3.2 Major Program Budgets

Projected spending for some major programs has been adjusted in the development of the Department's Board approved budget and subsequent updates for the revised financial plan; however, the resulting changes are minor.

Based on the final FY 2015-16 budget, proposed capital spending will increase by an average of $79 million annually over the next five years (FY 2015-16 through FY 2019-20). This annual increase represents overall average annual capital expenditures of $1.55 billion over the next five years. This revised forecast shows minimal variance from the initial proposed rate plan, which proposed an approximate $1.60 billion average annual capital spending budget.

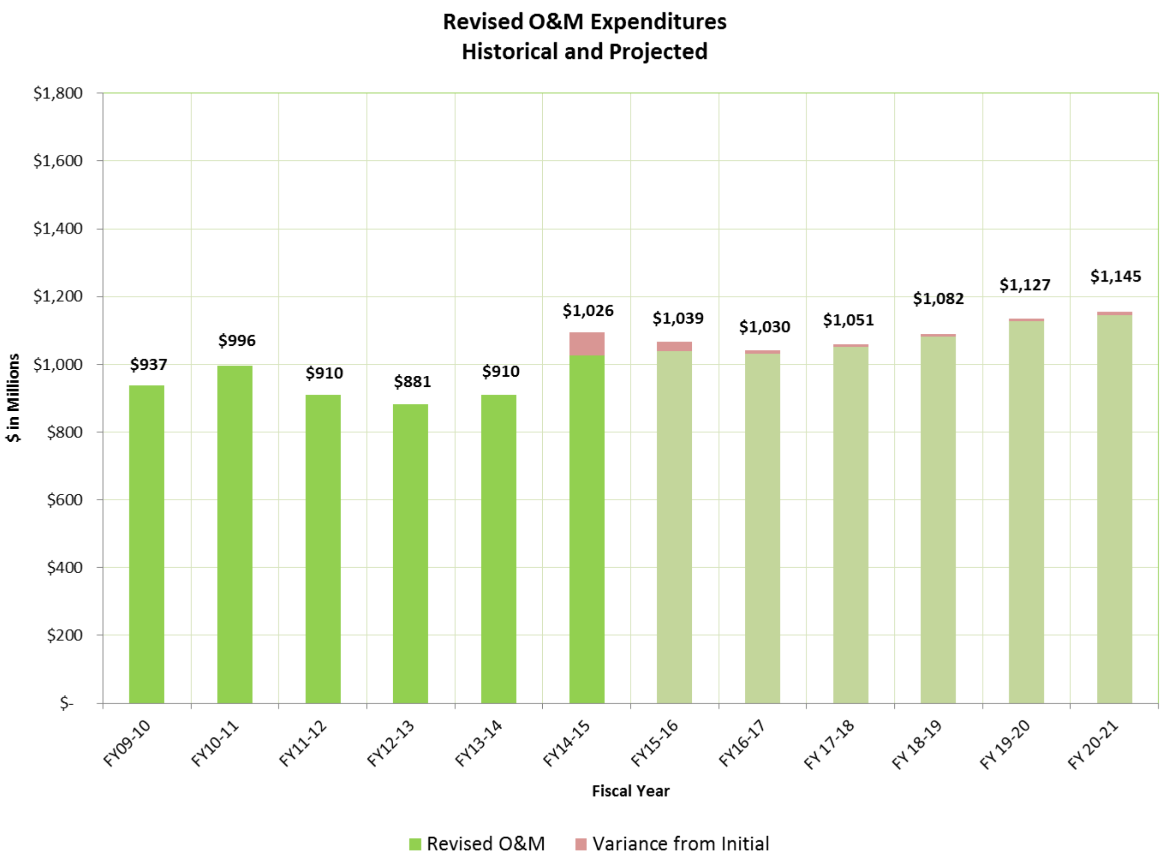
For FY 2015-16, the total Power System projected capital expenditures reflected in the revised proposed rate plan are $112 million less than in the initial rate plan, as shown in Figure 7. This decrease is largely due to an inability to meet planned spending as a result of the delay in securing the needed rate increase.

Figure 7: Revised Capital Expenditures (Historical and Projected)



The revised total Power System O&M expenses, shown in Figure 8, increase at an average annual rate of $20 million per year from FY 2015-16 through FY 2019-20. The average annual increase in O&M expenditures is $13 million more than the initial proposed rate plan. For FY 2015-16, the revised projected O&M expenditures reflected in the revised proposed rates are $29 million more than the initial proposed rate plan. The increased projected O&M spending is partially connected to the reductions in planned capital expenditures as assets no longer scheduled for replacement over the next few years require additional maintenance instead.

Figure 8: Revised O&M Expenditures (Historical and Projected)



6.4 FUEL AND PURCHASED POWER FORECAST

The Department procures, stores, and utilizes various forms of fuel for its portfolio of traditional thermal generation units. LADWP must budget for costs associated with physical commodities including natural gas, coal, and nuclear fuel and power purchase agreements (PPAs). Other considerations are the costs of emissions controls, greenhouse gas reductions, and retirements of assets past their working life.

Free market forces govern the price of these fuels, which exposes LADWP to considerable commodity risk. The Department manages its exposure to price volatility in part through a natural gas hedging program[5].

Natural gas prices have been at historic lows for the past couple of years and are forecasted to maintain a favorable position in the near term, longer than reflected in the initial proposed rate plan. This is beneficial to LADWP, as it maintains and operates a sizable portfolio of peaking and base load natural gas generation assets.

[5] The Department's Natural Gas Hedging Program is discussed in Chapter 3, Section 3.5.1.

The lower fuel costs in the revised financial plan translate into a lower revenue requirement and rates by driving down the fuel cost allocation in the Variable Energy Adjustment (VEA) pass-through rate component. While LADWP is not proposing to change the rates from the initial proposed rate plan, customers will benefit from lower fuel prices through future reductions in the VEA which ensures customers pay only the actual cost for fuel and PPAs. Figure 9 depicts the initial and revised forecasted fuel budgets for the Department during the proposed five-year rate period, along with the variance between the two plans. Notably, the Department forecasts spending 13% less on natural gas during the five-year period in the revised proposed rate plan.

Figure 9: Revised Annual Fuel Expenditures ($M)

($Million)	Current	Initial Proposed Budget[6]						*FY 20-21*
	FY 14-15	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**Total**	
Biomethane	$25.27	$24.12	$24.32	$24.32	$24.32	$24.38	$121.46	*$24.32*
Natural Gas	$129.79	$108.62	$150.13	$145.77	$150.12	$153.43	$708.07	*$172.20*
Gas MTM	$31.56	$27.98	$14.47	$8.17	$0.00	$0.00	$50.62	*$0.00*
Transportation	$41.46	$40.86	$46.58	$44.86	$44.65	$44.56	$221.51	*$46.23*
Coal	$73.58	$77.80	$0.00	$0.00	$0.00	$0.00	$77.80	*$0.00*
Nuclear	$18.18	$18.03	$17.95	$17.41	$17.81	$18.35	$89.56	*$18.85*
Total	**$320**	**$297**	**$253**	**$240.53**	**$236.90**	**$240.72**	**$1,269.00**	***$215.41***
		Revised Proposed Budget						
	FY 14-15	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**Total**	***FY 20-21***
Biomethane	$25.65	$24.12	$24.32	$24.32	$24.32	$24.38	$121.45	$24.32
Natural Gas	$167.48	$100.86	$133.15	$126.25	$129.03	$129.78	$619.06	$143.03
Gas MTM	$22.01	$29.35	$15.04	$8.78	$0.00	$0.00	$53.18	$0.00
Transportation	$38.80	$39.62	$44.78	$42.95	$42.82	$42.35	$212.52	$43.53
Coal	$67.29	$77.80	$0.00	$0.00	$0.00	$0.00	$77.80	$0.00
Nuclear	$14.01	$18.03	$17.95	$17.41	$17.81	$18.35	$89.55	$18.85
Total	**$335.24**	**$289.77**	**$235.24**	**$219.72**	**$213.97**	**$214.87**	**$1,173.56**	**$229.73**
		Percent Difference Between Initial and Revised Budget						
	FY 14-15	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**Total**	***FY 20-21***
Biomethane	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Natural Gas	22.5%	-7.7%	-12.8%	-15.5%	-16.3%	-18.2%	-14.4%	-20.4%
Gas MTM	-43.4%	4.7%	3.8%	7.0%	N/A	N/A	4.8%	N/A
Transportation	-6.9%	-3.1%	-4.0%	-4.4%	-4.3%	-5.2%	-4.2%	-6.2%
Coal	-9.3%	0.0%	N/A	N/A	N/A	N/A	0.0%	N/A

[6] The values presented here are the budgeted fuel expenditures for Case 19, on which the initial proposed rate requirement and rates are based. These values are different than the previously presented fuel expenditures in Chapter 2.

($Million)	Current	Initial Proposed Budget[6]						FY 20-21
	FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Total	
Nuclear	-29.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	**4.6%**	**-2.6%**	**-7.7%**	**-9.5%**	**-10.7%**	**-12.0%**	**-8.1%**	**6.2%**

Figure 10 presents the PPA breakdown for renewable and other sources of power in the revised proposed rate plan.

Figure 10: Revised Annual Purchased Power Expenditures ($M)[7]

($Million)	Current	Proposed Rate Period						FY 20-21
	FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Total	
Total Renewables	$194.0	$373.2	$520.1	$585.7	$615.3	$635.3	$2,729.8	*$649.5*
Total Non-Renewables	$830.0	$814.5	$736.2	$777.5	$793.0	$809.0	$3,930.4	*$792.5*
Total	**$1,024.1**	**$1,187.7**	**$1,256.3**	**$1,363.2**	**$1,408.4**	**$1,444.4**	**$6,660.3**	***$1,442.1***

In the revised proposed rate plan, the projected fuel and PPA expenditures result in an annual average revenue requirement increase of $12 million and an increase in total system average cost of 0.05 cents per kWh (0.31%), as shown in Figure 11. When compared to the initial proposed rate plan, the revised amounts equate to a $6 million lower average annual revenue requirement and 0.03 cents per kWh (0.16%) lower total system average rate.

Figure 11: Revised Revenue Requirement and Rate Impacts from Traditional Generation and Purchased Power Budget

	Initial YOY Increase						FY 20-21
	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Average	
Total System Revenue Requirement ($M)	1	10	19	41	20	18	*6*
Total System Average Cost per kWh (Cents/kWh)	0.01	0.04	0.08	0.17	0.09	0.08	*0.02*
System Average Annual Percent Increase (%)	0.04%	0.28%	0.50%	1.01%	0.49%	0.46%	*0.13%*
	Revised YOY Increase						

[7] Excludes direct fuel expenditures.

	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Average	*FY 20-21*
Total System Revenue Requirement ($M)	-5	10	16	17	23	12	25
Total System Average Cost per kWh (Cents/kWh)	-0.02	0.04	0.07	0.07	0.10	0.05	0.11
System Average Annual Percent Increase (%)	-0.14%	0.27%	0.44%	0.42%	0.57%	0.31%	0.60%
	Difference Between Initial and Revised YOY Increase						
	FY 15-16	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**Average**	***FY 20-21***
Total System Revenue Requirement ($M)	-6	0	-3	-24	3	-6	19
Total System Average Cost per kWh (Cents/kWh)	-0.03	0.00	-0.01	-0.10	0.01	-0.03	0.09
System Average Annual Percent Increase (%)	-0.18%	-0.01%	-0.06%	-0.59%	0.08%	-0.16%	0.47%

6.5 INFRASTRUCTURE AND POWER SYSTEM RELIABILITY PROGRAM (PSRP) BUDGET UPDATES

Investing in reliability improvement to address aging infrastructure remains imperative to the Department. LADWP allocates capital spending for new and updated infrastructure judiciously and strategically, ensuring that funding for replacement and maintenance initiatives is optimal in the face of competing priorities and financial considerations.

The PSRP program is designed to cover a prolonged period with specific projects identified to help develop the overall expected capital expenditure and timelines. These projects are often long-term in nature and require lengthy procurement cycles to contract for materials and construction services. Large multi-year contracts typically provide the best terms for the Department but require sufficient funding to negotiate and execute these contracts and cover any corresponding delays. Also, it is vital to have necessary funding to address unexpected equipment failures and outages.

In their review of the Department's initial proposed rate plan, the RPA recommended that the capital expenditures budgeted for the PSRP during the five-year rate action period be scaled back to less aggressive spending targets that the RPA believed to be more realistic. The RPA also recommended eliminating the cap on the IRCA, the pass-through rate component that provides revenue for the PSRP. These proposals have been reflected in the revised financial plan.

6.5.1 PSRP Cumulative Capital and O&M Budget Updates

Planned PSRP capital spending in FY 2015-16 and FY 2016-17 has been reduced in the revised rate plan to align with the ability to secure resources to perform the work considering the delay in approval of the rates, with greater funding allocated to future years (FY 2017-18 through FY 2019-20). Figure 12 compares the revised capital and O&M spending to the initial proposed rate plan levels during the proposed five-year rate period.

Figure 12: Comparison of Revised and Initial PSRP Capital and O&M Costs Over Five-Year Rate Period

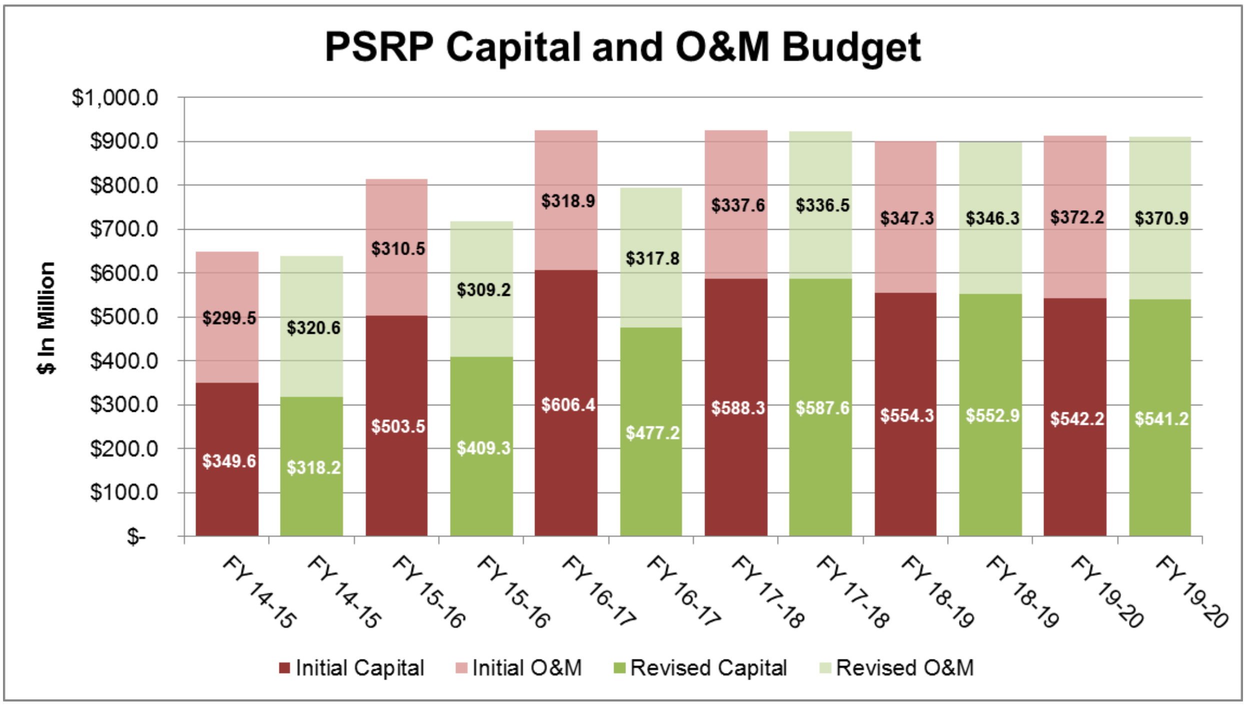
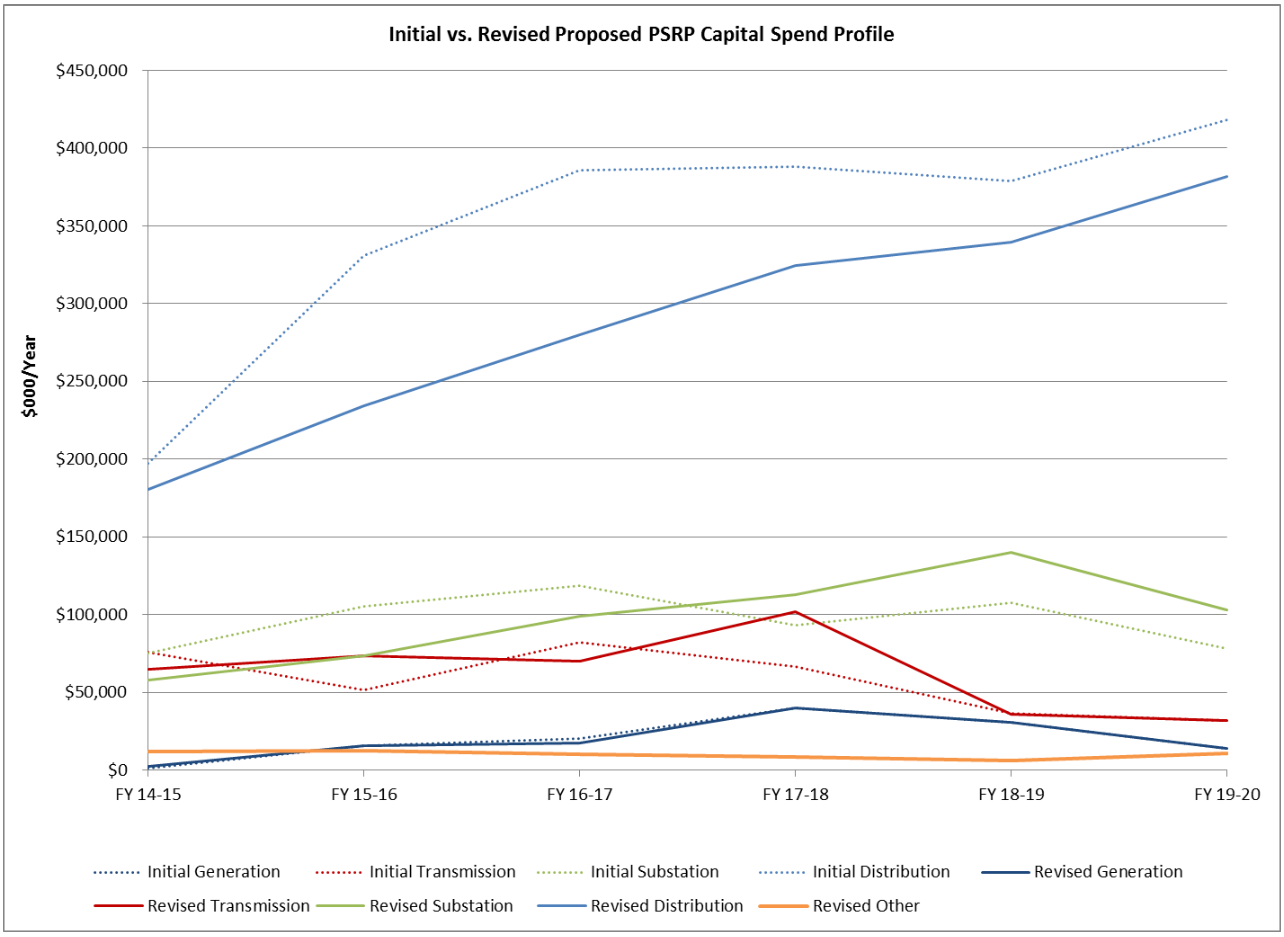


Figure 13 details the revised proposed capital spending profile by asset type over the proposed five-year rate period as compared to the initial plan. While the overall capital spending has been reduced by an average annual amount of $45.3 million over the five-year period, a large portion of the PSRP is still allocated to distribution upgrades to enhance reliability.

Figure 13: Initial vs. Revised Projected Capital Spend by Asset Type



The revised PSRP program level budget is summarized in Figure 14. When compared to the initial proposed plan, the revised plan includes approximately $226.6 million and $5.7 million less capital and O&M expenditures respectively in total during the proposed five-year rate period. This variance represents a relatively minor total spending adjustment, with capital budget cuts in FY 2015-16 and FY 2016-17 making up the vast majority of the difference between initial and revised plans.

Figure 14: Revised and Initial PSRP Capital and O&M Program Budgets

Initial Proposed PSRP Budgets							
($000)	Actuals[8]	Forecast					5-Year Total
Capital:	**FY 14-15**	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	
Generation	$1,347	$15,549	$20,141	$39,954	$30,975	$14,110	$120,729
Transmission	$75,955	$51,583	$82,212	$66,828	$36,399	$31,699	$268,721

[8] Include actuals through September 2014 with estimates through the remainder of the fiscal year.

Substation	$75,245	$105,625	$118,461	$93,485	$107,835	$78,168	$503,574
Distribution	$197,098	$330,729	$385,597	$388,054	$379,074	$418,234	$1,901,688
Total Capital	**$349,645**	**$503,486**	**$606,410**	**$588,320**	**$554,282**	**$542,210**	**$2,794,708**
O&M:							
Transmission	$26,591	$25,970	$27,238	$32,704	$33,637	$35,426	$154,975
Substation	$11,912	$10,860	$11,415	$11,814	$12,222	$12,030	$58,341
Distribution	$188,188	$201,006	$206,966	$219,885	$227,562	$244,020	$1,099,439
Journeyman Training	$24,114	$23,762	$25,383	$26,998	$27,752	$28,100	$131,995
Power System Training	$48,726	$48,891	$47,934	$46,180	$46,111	$52,638	$241,754
Total O&M	**$299,533**	**$310,491**	**$318,937**	**$337,583**	**$347,285**	**$372,216**	**$1,686,512**
Revised Proposed PSRP Program Budgets							
	Actual	**Forecast**					
Capital:	**FY 14-15**	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**5-Year Total**
Generation	$2,175	$15,471	$17,484	$39,928	$30,965	$14,090	$117,938
Transmission	$64,961	$73,570	$70,290	$101,609	$35,719	$31,643	$312,831
Substation	$58,125	$73,570	$99,061	$112,907	$140,273	$103,289	$529,100
Distribution	$180,782	$234,255	$279,982	$324,677	$339,567	$381,506	$1,559,986
Other[9]	$12,145	$12,373	$10,344	$8,482	$6,406	$10,655	$48,260
Total Capital	**$318,189**	**$409,238**	**$477,161**	**$587,604**	**$552,930**	**$541,182**	**$2,568,115**
O&M:							
Transmission	$25,412	$25,448	$26,715	$32,190	$33,122	$34,857	$152,331
Substation	$72,845	$74,324	$74,820	$74,778	$77,086	$90,363	$391,371
Distribution	$142,258	$136,948	$143,227	$156,610	$162,406	$165,250	$764,441
Journeyman Training	$23,695	$23,695	$25,307	$26,926	$27,683	$28,017	$131,627
Power System Training	$47,520	$48,727	$47,773	$46,038	$45,973	$52,461	$240,971
Total O&M	**$311,731**	**$309,141**	**$317,841**	**$336,542**	**$346,269**	**$370,949**	**$1,680,741**
Percentage Difference Between Initial and Revised							
	Actual	**Forecast**					
	FY 14-15	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**5-Year Total**
Capital:							
Generation	61.5%	-0.5%	-13.2%	-0.1%	0.0%	-0.1%	-2.3%
Transmission	-14.5%	42.6%	-14.5%	52.0%	-1.9%	-0.2%	16.4%

[9] This category includes capital costs for IT system investments and other capital expenditures necessary to support infrastructure upgrades and reliability. In the initial proposed rate plan, these costs were appropriated across the various PSRP programs and not represented as a separate budget line item.

Substation	-22.8%	-30.3%	-16.4%	20.8%	30.1%	32.1%	5.1%
Distribution	-8.3%	-29.2%	-27.4%	-16.3%	-10.4%	-8.8%	-18.0%
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Capital	**-9.0%**	**-18.7%**	**-21.3%**	**-0.1%**	**-0.2%**	**-0.2%**	**-8.1%**
O&M:							
Transmission	-4.4%	-2.0%	-1.9%	-1.6%	-1.5%	-1.6%	-1.7%
Substation	511.5%	584.4%	555.5%	533.0%	530.7%	651.1%	570.8%
Distribution	-24.4%	-31.9%	-30.8%	-28.8%	-28.6%	-32.3%	-30.5%
Journeyman Training	-1.7%	-0.3%	-0.3%	-0.3%	-0.2%	-0.3%	-0.3%
Power System Training	-2.5%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%
Total O&M	**4.1%**	**-0.4%**	**-0.3%**	**-0.3%**	**-0.3%**	**-0.3%**	**-0.3%**

6.5.2 Generation Reliability Program (GRP) Update

The Power System has made minor adjustments to planned Generation Reliability Program (GRP) replacement units. The unit level budget for the GRP is presented in Figure 15.

Figure 15: Revised Unit Costs and Replacement Units for Generation Reliability Program

	Total Existing LADWP Count[10]	Unit Cost ($000)	Proposed Replacement Units[11]					
			FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20
Generator Transformer	168	Up to $5,000	0	0 (2)	2	4	4	4
Major Inspection (Thermal)	24	$4,000	1	1 (4)	0 (4)	4	4	4
Major Inspection (Hydro)	22	$4,000	1	0 (2)	2	2	2	2
Major Inspection (Pump)	7	$4,000	1	1	1	1	1	1

(X) – Initial proposed rate plan unit replacement target

[10] This number represents the current number of units the Department has of this equipment.

[11] This number is the planned units to undergo inspection, maintenance, or replacement per the PSRP. These numbers serve as a best estimate to inform PSRP budgeting and forecasting but may change throughout the five-year period due to various financial and operational factors.

6.5.3 Transmission Reliability Program (TRP) Update

The Power System has made minor adjustments to amount of planned Transmission Reliability Program (TRP) replacement units. The unit level budget for the TRP is presented in Figure 16.

Figure 16: Revised Unit Costs and Replacement Units for Transmission Reliability Program

	Total Existing LADWP Count	Unit Cost ($000)	Proposed Replacement Units					
			FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20
138kV UG Transmission Circuit	17	$12,600	1	2 (1)	2	2	2	2
138kV Stop Joints	31	$300	2	5	5	5	5	5
Maintenance Hole Restraints	238	$27	10	20	30	40	40	40

(X) – Initial proposed rate plan unit replacement target

6.5.4 Substation Reliability Program (SRP)

The Power System has made minor adjustments to planned Substation Reliability Program (SRP) replacement units in the revised proposed rate plan, as depicted in Figure 17.

Figure 17: Revised Unit Costs and Replacement Units for Substation Reliability Program

	Total Existing LADWP Count	Unit Cost ($000)	Proposed Replacement Units					
			FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20
Transformer (RS) secondary voltage>138kV	70	$4,000	0	0 (1)	0 (1)	1	1	1
Transformer (RS) secondary voltage>34.5kV	88	$4,500	3	3 (1)	3 (1)	1	1	1
Local Substation Transformer (DS)	930	$1,200	4	12 (18)	16 (18)	18	18	18
Substation Transmission Breakers	612	$550	3	0 (6)	0 (6)	6	6	6
34.5kV Substation Circuit Breaker	1,878	$200	10	4 (10)	21 (15)	20	20	20
4.8kV Substation Circuit Breaker	2,406	$80	10	5 (20)	16 (30)	40	40	40

(X) – Initial proposed rate plan unit replacement target

6.5.5 Distribution Reliability Program (DRP) Updates

The Power System has made minor adjustments to planned Distribution Reliability Program (DRP) replacement units in the revised proposed rate plan. The unit level revised budget for the DRP includes less planned pole and crossarm replacements, as depicted in in Figure 18.

Figure 18: Revised Unit Costs and Replacement Units for Distribution Reliability Program

	Total Existing LADWP Count	Unit Cost ($000)	Proposed Replacements					
			FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20
Poles	321,780	$45	1,560	2,000 (4,000)	2,500 (5,000)	6,000	6,000	6,000
Crossarms	1,287,120	$4	4,500	7,000	7,000 (8,000)	10,000	10,000	10,000
Cables	3597 miles	$1,000	28	46 (60)	48 (60)	60	60	60
Transformers	126,000	$20	450	600	700	800	800	800
Substructures	54,099	$400	7	12	12 (16)	20	20	20

(X) – Initial proposed rate plan unit replacement target

6.5.6 PSRP Budget Impact on Revenue Requirement and Rates

Comparing the total portion of the revenue requirement attributed to the PSRP in the initial proposed rate plan to the revised plan shows minimal variance. Over the five-year proposed rate period, the revised plan forecasts an increase in the revenue requirement by an annual average of $19 million per year and an annual increase in the system average rate of 0.08 cents per kWh (0.48%). Cumulatively over the proposed five-year rate period, these amounts are close to the initial rate plan's average annual revenue requirement increase of $26 million and a 0.11 cents per kWh (0.68%) increase in system average rate. A comparison of the proposed and initial plans' projected PSRP revenue requirement and rate impacts is presented in Figure 19.

Figure 19: Revised PSRP Impact on Revenue Requirement and Rates

	Initial Year Over Year Increase						*FY 20-21*
	FY 15-16	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**Average**	
Total System Revenue Requirement ($M)	5	14	49	19	44	26	*46*
Total System Average Cost per kWh (Cents/kWh)	0.02	0.06	0.21	0.08	0.19	0.11	*0.20*
System Average Annual Percent Increase (%)	0.15%	0.39%	1.31%	0.47%	1.06%	0.68%	*1.05%*
	Revised Year Over Year Increase						
Total System Revenue Requirement ($M)	9	-7	32	25	34	19	*35*
Total System Average Cost per kWh (Cents/kWh)	0.04	-0.03	0.14	0.10	0.15	0.08	*0.15*
System Average Annual Percent Increase (%)	0.26%	-0.20%	0.86%	0.63%	0.85%	0.48%	*0.82%*
	Difference Between Initial and Revised YOY Increase						
Total System Revenue Requirement ($M)	4	-21	-17	6	-10	-7	*-11*
Total System Average Cost per kWh (Cents/kWh)	0.02	-0.09	-0.07	0.02	-0.04	-0.03	*-0.05*
System Average Annual Percent Increase (%)	0.11%	-0.59%	-0.45%	0.16%	-0.21%	-0.20%	*-0.23%*

As noted earlier, since customers will only be charged for the actual amount of the PSRP costs, LADWP is not proposing changes to the customer rates presented in the initial proposed rate plan to reflect the minor changes in the revenue requirement. The decrease in projected PSRP expenditures during the five-year rate period will impact the Incremental Reliability Cost Adjustment (IRCA), the component of the proposed rate design dedicated to collect funds to support the replacement or upgrade of Power System infrastructure. The IRCA will be set and trued up over time based on actual expenditures, ensuring customers pay for only actual PSRP costs.

6.6 OTHER MISCELLANEOUS CHANGES

In addition to the major impacts mentioned previously in Section 6.1.1, several other additional changes that have a minor impact on rates are reflected in the revised proposed rates. These financial assumptions and measures are taken to ensure adequate revenue, maintain the Department's credit rating, and fulfill debt obligations when developing the revised financial plan. These changes include:

- Other rate driver contribution changes from FY 2015-16 revised budget;
- Board approved adjustment factors (effective in October 2015);

- Bond refunding;
- Updated interest income rate assumptions on IPA subordinated notes; and
- Recovery of revenue shortfall for July 2015 – March 2016.

6.6.1 Rate Driver Contribution Changes from FY 2015-16 Revised Budget Allocations

The overall revenue requirement has been reduced, and several components have changed due to projects being implemented and budget allocations being updated since the previous revenue requirement was developed in the initial proposed rate plan. Updates in the revised plan include:

- Coal Transition Plan: The revised proposed rate plan reflects impacts from the divestment of the coal Navajo Generating Station (NGS). Replacing the baseload energy generated by NGS with capacity from the natural gas Apex generating facility has allowed the Department to take advantage of historically low natural gas prices and reduce the expected coal transition plan costs. The revised proposed rate plan forecasts an average annual revenue requirement decrease of $6 million over the five-year period, compared to the initial plan's proposed $17 million average annual increase.
- Renewable Portfolio Standard: To comply with California Energy Commission (CEC) requirements, the Department must substitute a subset of customer sited solar PV capacity due to the CEC's changing RPS guidebook with other renewable resources. Approximately 340 GWh will be replaced with lower cost renewable generation from stations like the Hudson Ranch Geothermal facility for which the Department established a PPA as part of the NGS divestment. Thus, the revised proposed rate plan forecasts an average annual revenue requirement increase of $16 million over the five-year period, compared to the initial plan's proposed $36 million average annual increase.
- Local Solar: The initial plan included a scheduled ramp up of two large LADWP owned solar installations - Moapa and Copper Mountain. These facilities have since gone "on-line." The revised plan now shows an increase in other local solar spending to meet interim and final capacity targets, with an average annual revenue requirement increase of $44 million during the proposed five-year rate period.

6.6.2 Board Approved Adjustment Factors

On December 1, 2015, the Board passed a resolution approving the Energy Cost Adjustment Factor (ECAF) expenditures for the 12-month period commencing January 1, 2016. This action approves cost recovery for fuel, purchased power, demand-side management (DSM), and renewables portfolio standard (RPS) expenditures through a revision to the calculation of Energy Cost Adjustment (ECA), Variable Energy Adjustment (VEA), Capped Renewable Portfolio Standard Energy Adjustment (CRPSEA), and Variable Renewable Portfolio Standard Energy Adjustment (VRPSEA). For the three-month period commencing January 1, 2016, the composite ECAF related costs applied to actual billing of customers will be 6.488 cents per kWh compared to 7.012 cents per kWh for the prior 3 months.

6.6.3 Bond Refunding

Issued on October 1, 2015, the LADWP Power System 2015B bonds are a new debt issue of $269.9 million used to pay the principle of the maturing LADWP 2012C bonds and provide LADWP a more favorable interest rate. Bond refunding allows the Department to take advantage of low interest rate conditions and replace higher-cost bonds with cheaper debt. This process in turn reduces the borrowing costs LADWP incurs to fund infrastructure and other critical investments. It is important to note that such financial measures are made possible by the strong credit rating the Department preserves by maintaining the Board approved financial metrics. Future refunding bond issues are also planned.

6.6.4 Updated Interest Income Rate Assumptions on IPA Subordinate Notes

The Department's short term interest rate income from the debt it is owed from providing financing for the Intermountain Power Plant (IPP) has increased. The additional amount has been reflected in the revised financial plan yielding an additional $92.1 million in projected cumulative net income which will contribute to lowering the revenue requirement over this period. The variable rate and year over year dollar amount is shown in Figure 20.

Figure 20: Revised Interest Income Rate Assumptions and IPA Subordinated Notes

	Proposed Rate Period				
	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20
Variable Rate (%)	1.21%	1.70%	2.12%	2.38%	2.56%
Cash ($M)	$23.1	$35.9	$10.7	$17.9	$4.7

6.6.5 Recovery of Revenue Shortfall for July 2015 – March 2016

The initial proposed rates were based on an effective date of July 2015. To account for the shortage of income from rates during this time period, funds will be recovered through the revenue decoupling mechanism in the VEA adjustment factor over a 2-year period (January 1, 2017 – December 31, 2018).

6.6.6 Net Wholesale Revenue and CIAC

As a result of input from the Mayor, E&E Committee Chair, and the Office of Public Accountability (OPA), LADWP has reduced its proposed rate increase by utilizing any actual amounts exceeding budgeted amounts for the following items to lower the Base Rate Revenue Target Adjustment (BRRTA):

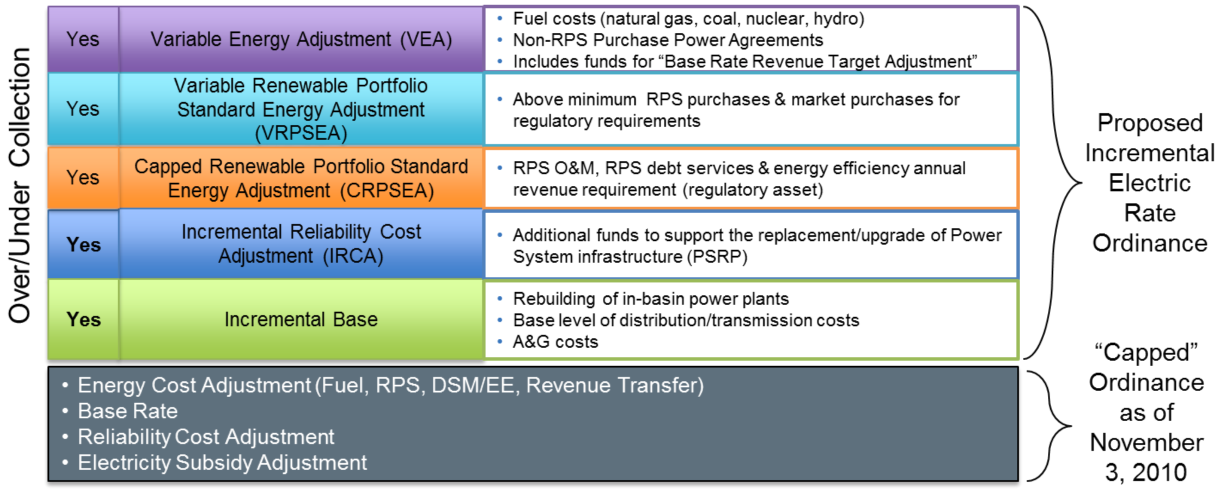
- Net wholesale revenue; and
- Contributions in aid of construction (CIAC), which are basically amounts paid by large customers for upgrades and equipment for new developments.

This is estimated to result in an approximately 0.51% lower system average annual rate increase and equates to a $105 million lower revenue requirement over the five-year period. In the past, LADWP has utilized additional revenues from these sources to cash fund capital expenditures. At the suggestion of the previously mentioned parties, these funds will now be returned directly to customers in the form of lower rates. However, it is important to note that this requires the Department to borrow more money to fund capital projects and is somewhat offset by higher debt service costs.

6.7 KEEPING WITH THE INITIAL RATE STRUCTURE

The proposed rate structure accounts for fluctuating revenues in comparison to forecasted amounts through variable pass-through adjustment factors. Figure 21 shows a visual representation of the Department's proposed rate structure. A detailed presentation of the Department's initial proposed rate structure and rates is contained in Chapter 5.

Figure 21: LADWP Proposed Electric Rate Structure (Detail)



Under the latest proposal, the VEA will be adjusted to account for lower fuel costs and reduced PSRP expenditures will be accounted for through changes in the IRCA that will reflect actual spending during the proposed rate period.

The pass-through adjustment factors are calculated and set on a quarterly basis, with exception of the IRCA that is set annually, to reflect the appropriate level of cost recovery needed.

6.8 FINAL REVISED RATES

As a result of the aforementioned impacts from fuel savings, PSRP expenditure cuts, and other miscellaneous financial plan changes, the revised proposed rates are lower than the initial proposed plan. The updated detail on the revised rates is included in this section.

6.8.1 Revised Proposed Residential Rates and Bill Impacts

The components of the revised proposed LADWP residential rate design are summarized in Figure 22 below.

Figure 22: Revised Proposed Residential Rates

Tiers	Monthly Zone 1 Usage Allocation (kWh)	Monthly Zone 2 Usage Allocation (kWh)	Monthly Tiered Fixed Charge ($)	Summer Energy Charge ($/kWh)	Winter Energy Charge ($/kWh)
FY 2015-16					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$0.55	$0.13617	$0.13617
Tier 2	350 < and ≤1050	500 < and ≤1500	$2.00	$0.16835	$0.16835
Tier 3	> 1050	> 1500	$6.00	$0.21731	$0.16835
FY 2016-17					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$0.85	$0.14557	$0.14557
Tier 2	350 < and ≤1050	500 < and ≤1500	$3.00	$0.18086	$0.18086
Tier 3	> 1050	> 1500	$9.00	$0.23663	$0.18086
FY 2017-18					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$1.30	$0.15066	$0.15066
Tier 2	350 < and ≤1050	500 < and ≤1500	$4.90	$0.19809	$0.19809
Tier 3	> 1050	> 1500	$15.00	$0.25879	$0.19809
FY 2018-19					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$1.75	$0.15103	$0.15103
Tier 2	350 < and ≤1050	500 < and ≤1500	$6.25	$0.19936	$0.19936
Tier 3	> 1050	> 1500	$18.50	$0.27546	$0.19936
FY 2019-20					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$2.50	$0.15283	$0.15283
Tier 2	350 < and ≤1050	500 < and ≤1500	$8.00	$0.21142	$0.21142
Tier 3	> 1050	> 1500	$23.50	$0.29843	$0.21142

The monthly tiered Power Access charge has remained mostly unchanged, with the revised proposed rates reflecting a minor increase in FY 2019 – 20. As with the initial plan, proposed increases to tier 2 and 3 prices are higher than proposed increases to tier 1 prices in the revised plan to reflect marginal costs, which sends a conservation price signal. Overall, the revised proposed rates are lower than those proposed in the initial plan. For example, in the revised plan a typical single-dwelling unit Residential customer (500 kWh average monthly usage) can expect a median monthly bill of $78.75 in FY 2019-20, which represents a 1.56% average annual rate increase. Further details on Residential customer bill impacts from the revised proposed rates are presented in Figure 23.

Figure 23: Revised Residential (R1A) Customer Bill Impacts by kWh Usage (Detail)

Average kWh	Customers	Average Median Bill						Average Annual % Change
		FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	
0	3708	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	0.00%
100	60596	$11.00	$10.89	$11.38	$11.85	$12.12	$12.70	2.90%
200	220476	$20.51	$19.63	$21.20	$22.35	$22.83	$23.80	3.02%
300	259076	$33.97	$32.25	$34.90	$36.83	$37.52	$38.84	2.72%
400	206920	$48.72	$46.88	$50.86	$54.29	$55.57	$57.87	3.50%
500	149560	$64.57	$62.44	$67.68	$72.48	$74.03	$77.15	3.62%
600	105846	$81.12	$78.41	$84.81	$90.94	$92.61	$96.59	3.55%
700	75711	$98.13	$94.96	$102.58	$110.23	$112.03	$117.04	3.59%
800	53999	$115.47	$112.08	$121.04	$130.37	$132.32	$138.47	3.70%
900	39739	$133.04	$129.87	$140.36	$151.77	$154.04	$161.54	3.96%
1000	29704	$150.83	$148.10	$160.67	$175.24	$178.45	$188.22	4.53%
1100	22077	$168.81	$166.41	$180.71	$198.25	$202.79	$215.77	5.03%
1200	17209	$187.27	$185.03	$200.99	$221.11	$226.23	$240.66	5.14%
1300	12908	$205.75	$203.47	$221.01	$243.11	$248.76	$264.66	5.16%
1400	10128	$224.83	$222.31	$241.33	$265.38	$271.47	$288.87	5.14%
1500	7992	$243.54	$240.70	$261.22	$287.19	$294.07	$313.20	5.16%
1600	6298	$262.73	$259.62	$281.65	$309.47	$317.15	$337.83	5.16%
1700	5040	$281.95	$278.56	$302.11	$331.86	$340.17	$362.48	5.15%
1800	3975	$301.14	$297.61	$322.75	$354.68	$363.69	$387.82	5.19%
1900	3375	$320.15	$316.27	$342.87	$376.59	$386.41	$412.16	5.18%
2000	2719	$338.99	$335.05	$363.21	$398.86	$409.30	$436.54	5.19%
2100	2350	$358.78	$354.47	$384.16	$421.89	$433.34	$462.47	5.21%
2200	1910	$377.49	$373.13	$404.42	$444.08	$456.18	$486.84	5.22%
2300	1589	$396.32	$391.63	$424.39	$466.02	$478.56	$510.75	5.20%
2400	1377	$415.79	$410.76	$445.07	$488.58	$502.12	$536.27	5.22%
2500	1112	$435.24	$429.99	$465.84	$511.11	$525.66	$561.52	5.23%
2600	955	$453.88	$448.28	$485.61	$533.29	$548.03	$585.58	5.23%
2700	859	$472.65	$466.90	$505.67	$555.14	$570.82	$609.60	5.22%
2800	737	$492.16	$486.28	$526.70	$578.00	$594.57	$635.09	5.23%
2900	620	$510.21	$503.74	$545.58	$598.67	$615.99	$658.30	5.23%
3000	577	$530.35	$523.69	$567.14	$622.21	$639.78	$683.64	5.21%
3100	470	$548.67	$541.85	$586.63	$643.62	$662.15	$707.26	5.21%
3200	460	$567.66	$560.61	$607.18	$666.14	$685.33	$732.45	5.23%
3300	365	$587.94	$580.52	$628.58	$689.65	$709.49	$758.69	5.23%
3400	370	$605.70	$597.98	$647.13	$710.31	$730.80	$781.32	5.22%
3500	4343	$809.65	$799.03	$864.30	$947.98	$974.19	$1,042.48	5.19%

6.8.2 Revised Proposed Commercial and Industrial Rates and Bill Impacts

Figure 24, Figure 25, and Figure 26 show the revised proposed rates for Commercial and Industrial customers, which reflect a gradual increase over the five-year rate period.

Figure 24: Revised Proposed Small Commercial Rates (Small General Service A1A)

	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20
Monthly Fixed Charge	$6.50	$7.00	$7.00	$7.00	$7.00	$7.00
Facilities Charge ($/kW)	$7.48	$7.48	$7.48	$7.98	$8.48	$8.98
High Season Consumption ($/kWh)	$0.14043	$0.12882	$0.13677	$0.15271	$0.15405	$0.15827
Low Season Consumption ($/kWh)	$0.11753	$0.10540	$0.11247	$0.12726	$0.12799	$0.13123

Figure 25: Proposed Medium Commercial Rates (Primary Service A2B)

		FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20
Monthly Fixed Charge		$28.00	$28.00	$28.00	$28.00	$28.00	$28.00
Facilities Charge ($/kW)		$7.48	$7.48	$7.48	$7.98	$8.48	$8.98
High Season	**Demand High Peak (HP) ($/kW)** [12]	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00
	Demand Low Peak (LP) ($/kW)	$3.75	$3.75	$3.75	$3.75	$3.75	$3.75
Low Season	**Demand HP ($/kW)**	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75
	Demand LP ($/kW)	$ -	$ -	$ -	$ -	$ -	$ -
High Season	**Consumption HP ($/kWh)**	$0.11818	$0.11818	$0.13673	$0.13733	$0.13735	$0.14389
	Consumption LP ($/kWh)	$0.11091	$0.11091	$0.12946	$0.13006	$0.13008	$0.13662
	Consumption Base ($/kWh)	$0.09018	$0.09018	$0.10873	$0.10933	$0.10935	$0.11589
Low Season	**Consumption HP ($/kWh)**	$0.11184	$0.11184	$0.13039	$0.13099	$0.10529	$0.13755
	Consumption LP ($/kWh)	$0.11184	$0.11184	$0.13039	$0.13099	$0.10529	$0.13755
	Consumption Base ($/kWh)	$0.09391	$0.09391	$0.11246	$0.11306	$0.08736	$0.11962

[12] There are three TOU periods for LADWP Commercial customers, high peak, low peak, and base. High peak represents the highest cost period (weekday afternoon), base represents lowest cost period (late evening-early morning and weekends), low peak period represents remaining time periods.

Figure 26: Revised Proposed Large Commercial Rates (Sub-transmission A3A)

	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20
Monthly Fixed Charge	$75.00	$75.00	$75.00	$75.00	$75.00	$75.00
Facilities Charge ($/kW)	$6.68	$6.68	$6.68	$7.18	$7.68	$8.18
Demand HP Summer ($/kW)	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70
Demand LP Summer ($/kW)	$3.30	$3.30	$3.30	$3.30	$3.30	$3.30
Demand HP Winter ($/kW)	$4.30	$4.30	$4.30	$4.30	$4.30	$4.30
Demand LP Winter ($/kW)	$ -	$ -	$ -	$ -	$ -	$ -
Consumption HP Summer ($/kWh)	$0.11577	$0.11577	$0.13400	$0.13460	$0.13485	$0.14200
Consumption LP Summer ($/kWh)	$0.10951	$0.10951	$0.12774	$0.12834	$0.12859	$0.13574
Consumption Base Summer ($/kWh)	$0.08942	$0.08942	$0.10765	$0.10825	$0.10850	$0.11565
Consumption HP Winter ($/kWh)	$0.11050	$0.11050	$0.12873	$0.12933	$0.12958	$0.13673
Consumption LP Winter ($/kWh)	$0.11050	$0.11050	$0.12873	$0.12933	$0.12958	$0.13673
Consumption Base Winter ($/kWh)	$0.09384	$0.09384	$0.11207	$0.11267	$0.11292	$0.12007

Figure 27, Figure 28, and Figure 29 show the revised proposed bill impacts for small, medium, and large Commercial customers. In all cases, the revised proposed rates are lower than the initial proposed rates.

Figure 27: Revised Small Commercial Customer (Small General Service A1A) Bill Impacts by Load Factor (Detail)

Load Factor	Customers	Average Median Bill						Average Annual Increase (%)
		FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	
0.05	34,780	$44.68	$44.37	$44.86	$47.87	$49.94	$52.17	3.2%
0.10	29,376	$67.09	$64.69	$66.48	$72.18	$74.44	$77.32	2.9%
0.15	25,947	$96.74	$92.04	$95.26	$104.24	$107.03	$110.97	2.8%
0.20	20,867	$147.95	$139.25	$144.91	$159.58	$163.32	$169.07	2.7%
0.25	14,665	$199.95	$187.02	$195.34	$215.90	$220.47	$227.99	2.7%
0.30	10,372	$256.47	$238.72	$250.01	$277.08	$282.47	$291.80	2.6%
0.35	7,960	$324.23	$300.61	$315.50	$350.47	$356.68	$368.12	2.6%
0.40	6,768	$402.03	$371.53	$390.65	$434.73	$441.76	$455.73	2.5%
0.50	9,816	$526.08	$484.48	$510.55	$569.10	$577.85	$595.80	2.5%
0.60	4,891	$627.44	$576.11	$607.99	$678.97	$688.39	$709.18	2.5%
0.70	1,862	$604.28	$553.89	$585.10	$654.06	$662.51	$682.25	2.5%
0.80	642	$426.69	$391.03	$413.28	$461.95	$467.58	$481.17	2.4%
0.90	266	$367.61	$337.08	$356.46	$398.24	$402.81	$414.32	2.4%
1.00	115	$386.58	$354.18	$374.79	$418.71	$423.49	$435.61	2.4%
2.00	361	$480.66	$439.00	$465.09	$520.78	$526.14	$540.83	2.4%

Figure 28: Revised Medium Commercial Customer (Primary Service A2B) Annual Bill Impacts by Load Factor (Detail)

Load Factor	Customers	Average Median Bill						Average Annual Increase (%)
		FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	
0.02	12	$5,006.55	$5,006.55	$5,008.97	$5,172.19	$5,335.35	$5,499.35	1.9%
0.03	12	$736.07	$736.07	$740.65	$776.97	$808.58	$848.15	2.9%
0.04	17	$927.22	$927.22	$941.33	$970.63	$984.04	$1,033.30	2.2%
0.05	17	$686.56	$686.56	$701.63	$725.65	$735.50	$778.05	2.5%
0.06	34	$602.04	$602.04	$612.13	$638.23	$653.61	$693.33	2.9%
0.07	28	$805.23	$805.23	$829.59	$856.94	$858.37	$912.51	2.5%
0.08	27	$731.33	$731.33	$759.81	$780.73	$775.56	$830.79	2.6%
0.09	43	$725.20	$725.20	$756.38	$777.57	$768.71	$828.97	2.7%
0.10	39	$956.78	$956.78	$994.68	$1,025.34	$1,038.76	$1,097.61	2.8%
0.20	1,056	$815.02	$815.02	$855.50	$876.51	$857.93	$930.23	2.7%
0.30	2,274	$1,019.09	$1,019.09	$1,086.00	$1,110.79	$1,080.02	$1,181.66	3.0%
0.40	2,441	$1,412.44	$1,412.44	$1,538.26	$1,568.66	$1,487.31	$1,662.18	3.3%
0.50	2,331	$1,720.61	$1,720.61	$1,905.54	$1,935.89	$1,808.11	$2,050.48	3.6%
0.60	1,919	$2,147.49	$2,147.49	$2,398.85	$2,437.36	$2,248.15	$2,582.45	3.8%
0.70	1,431	$2,434.06	$2,434.06	$2,746.28	$2,781.18	$2,539.89	$2,943.59	3.9%
0.80	1,234	$2,882.67	$2,882.67	$3,274.20	$3,317.65	$2,994.60	$3,507.94	4.0%
0.90	482	$2,910.16	$2,910.16	$3,313.77	$3,351.89	$3,014.81	$3,551.81	4.1%
1.00	72	$3,039.72	$3,039.72	$3,477.93	$3,518.84	$3,141.49	$3,727.29	4.2%
1.10	17	$3,491.39	$3,491.39	$4,018.38	$4,057.85	$3,600.07	$4,289.06	4.2%
1.20	16	$2,118.08	$2,118.08	$2,420.02	$2,452.45	$2,203.79	$2,604.56	4.2%
1.30	6	$1,352.72	$1,352.72	$1,533.90	$1,556.89	$1,420.82	$1,657.88	4.2%
1.40	7	$2,889.58	$2,889.58	$3,278.39	$3,334.30	$3,008.03	$3,558.46	4.3%
1.50	2	$1,404.48	$1,404.48	$1,604.56	$1,627.33	$1,445.17	$1,730.68	4.3%
1.60	2	$1,172.42	$1,172.42	$1,309.51	$1,339.34	$1,225.70	$1,438.61	4.2%
1.70	2	$1,756.52	$1,756.52	$2,009.47	$2,038.06	$1,822.19	$2,168.32	4.3%
1.80	5	$1,714.96	$1,714.96	$1,941.52	$1,978.38	$1,800.46	$2,117.55	4.3%
1.90	3	$1,531.83	$1,531.83	$1,747.28	$1,783.98	$1,581.22	$1,897.65	4.4%
2.00	11	$2,896.84	$2,896.84	$3,322.61	$3,370.64	$2,996.87	$3,589.74	4.4%

Figure 29: Revised Large Commercial and Industrial Customer (Sub-transmission A3A) Bill Impacts by Load Factor (Detail)

Load Factor	Customers	Average Median Bill						Average Annual Increase
		FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	
0.01	8	$754.11	$754.11	$755.35	$792.88	$824.90	$857.92	2.6%
0.02	3	$802.21	$802.21	$804.64	$845.72	$886.68	$928.53	3.0%
0.03	6	$988.16	$988.16	$1,000.80	$1,040.29	$1,079.17	$1,122.65	2.6%
0.04	7	$287.65	$287.65	$289.50	$303.31	$317.03	$331.43	2.9%
0.05	7	$508.85	$508.85	$523.42	$539.99	$555.86	$577.03	2.5%
0.06	10	$209.01	$209.01	$214.85	$219.79	$224.45	$231.24	2.0%
0.07	10	$1,926.93	$1,926.93	$1,999.57	$2,062.92	$2,122.81	$2,209.12	2.8%
0.08	7	$1,367.23	$1,367.23	$1,417.95	$1,467.95	$1,515.53	$1,581.56	3.0%
0.09	8	$650.78	$650.78	$679.56	$697.18	$713.43	$740.15	2.6%
0.10	14	$1,622.04	$1,622.04	$1,697.21	$1,737.33	$1,773.87	$1,837.74	2.5%
0.20	166	$1,717.38	$1,717.38	$1,840.96	$1,889.81	$1,932.55	$2,017.15	3.3%
0.30	500	$2,718.78	$2,718.78	$2,980.20	$3,039.73	$3,087.20	$3,226.22	3.5%
0.40	827	$3,181.27	$3,181.27	$3,526.67	$3,587.59	$3,632.72	$3,798.08	3.6%
0.50	1043	$5,223.91	$5,223.91	$5,886.63	$5,966.22	$6,014.19	$6,303.18	3.8%
0.60	945	$7,172.54	$7,172.54	$8,051.54	$8,191.97	$8,290.45	$8,708.62	4.0%
0.70	744	$9,744.63	$9,744.63	$11,086.89	$11,228.89	$11,306.83	$11,872.93	4.0%
0.80	633	$12,896.54	$12,896.54	$14,664.86	$14,863.56	$14,977.87	$15,735.30	4.1%
0.90	361	$11,921.95	$11,921.95	$13,690.08	$13,840.28	$13,906.09	$14,614.94	4.2%
1.00	101	$10,924.19	$10,924.19	$12,578.56	$12,714.26	$12,771.01	$13,429.43	4.2%
1.10	38	$4,821.49	$4,821.49	$5,537.18	$5,595.98	$5,620.62	$5,905.55	4.1%
1.20	11	$3,473.16	$3,473.16	$4,011.38	$4,048.68	$4,060.29	$4,267.64	4.2%
1.30	10	$5,495.36	$5,495.36	$6,094.59	$6,256.69	$6,390.20	$6,741.64	4.2%
1.40	10	$6,974.18	$6,974.18	$8,071.68	$8,144.55	$8,165.04	$8,584.67	4.2%
1.50	4	$1,402.48	$1,402.48	$1,601.58	$1,623.90	$1,636.72	$1,721.95	4.2%
1.60	7	$5,557.63	$5,557.63	$6,460.66	$6,516.45	$6,529.14	$6,870.25	4.3%
1.70	3	$24,571.04	$24,571.04	$28,572.97	$28,811.05	$28,858.14	$30,360.69	4.3%
1.80	1	$899.03	$899.03	$1,042.07	$1,050.78	$1,052.66	$1,106.57	4.2%
1.90	1	$6,302.15	$6,302.15	$7,147.22	$7,300.48	$7,413.42	$7,833.69	4.4%
2.00	16	$2,882.72	$2,882.72	$3,376.82	$3,402.27	$3,404.15	$3,585.72	4.5%

A. POWER SYSTEM FINANCIAL PLAN CASE NUMBER 143

This appendix provides the Power System Financial Plan Case Number 143, the case upon which the revised proposed rates and revised revenue requirement were determined.

POWER -- [FY16] PS Case143 -- Final Rate Case

CASE ASSUMPTIONS

1 Planned Financial Metrics (Manual)

Debt Service Coverage Ratio	2.25
Cash Balance (Revenue Fund + DRTF)	170 Days
Capitalization Ratio	68.0%
Net Income	$75M
Full Obligation Ratio	1.70

2 Load Forecast (Manual)

From Load Forecasting Group	4/15/2014

3 Budget Data for Capital and O&M

IBIS date	4/22/2015

4 Fuel and Purchased Power

Fuel case date	9/16/2015

5 Rate Action Dates

Previous Rate Action Date	11/11/2012
Upcoming Rate Action Date	4/1/16

6 Most Recent Bond Issues (Manual)

	Amount in $M	Date	Issue Name
Refunding	$269.6	10/1/2015	2015B
New Money - Principal	$229.0	1/8/2015	2014E
New Money - Premium (Discount)	$39.2		

7 Future Bond Issues

	FY16	FY17	FY18	FY19	FY20	FY21
Fixed Rate Bond to be Issued	$371.1	$799.6	$717.8	$740.4	$779.8	$603.0
Variable Rate Bond to be Issued	$57.4	$36.7	$156.6	$146.7	$151.3	$158.8
Total Amount	$428.5	$836.3	$874.4	$887.1	$931.1	$761.7

8 Interest Expense - Rate Assumptions

		FY16	FY17	FY18	FY19	FY20	FY21
From Finance (dated 3/31/15)	Variable into Fixed triggered by Downgrade	0.41%	0.88%	1.31%	1.61%	1.75%	1.75%
	Variable	0.41%	0.88%	1.31%	1.61%	1.75%	1.75%
	Fixed	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%

9a Interest Income - Rate Assumptions

9b Interest Income - IPA Subordinated Notes

		FY16	FY17	FY18	FY19	FY20	FY21
9a From Finance (dated 3/31/15)	Variable	1.21%	1.70%	2.12%	2.38%	2.56%	2.56%
9b Interest Income - IPA Subordinated Notes	$M	$23.1	$35.9	$10.7	$17.9	$4.7	-$6.8

10 Rate Stabilization Fund

	($M)	FY16	FY17	FY18	FY19	FY20	FY21
To meet the financial metric (net income)	Deposit	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	Withdrawal	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

11 RCA Legacy Undercollection

	($M)	FY16	FY17	FY18	FY19	FY20	FY21
Amortized over 10 years. Begin amortization in FY13 (50% due to incremental rate ordinance effective in Nov 2012)	Amount	$76.7	$63.9	$51.1	$38.3	$25.6	$12.8

12 ECA Legacy Undercollection

	($M)	FY16	FY17	FY18	FY19	FY20	FY21
Amortized over 10 years. Begin amortization in FY13 and collected in VEAF	Amount	$108.9	$91.7	$74.5	$57.3	$40.1	$22.9

13 Legal Settlement (Barakat) Collection

	($M)	FY16	FY17	FY18	FY19	FY20	FY21
Total costs of $160M that will be collected over 10-yr period. Begin collection in FY15	Amount	$16.0	$16.0	$16.0	$16.0	$16.0	$16.0

14 Energy Efficiency Adjustment

	($M)	FY16	FY17	FY18	FY19	FY20	FY21
IBIS data	Capital	$144.9	$177.9	$193.9	$190.3	$172.0	$169.4
	GWH savings	358	437	479	470	426	201

15 Renewable Portfolio Standard (RPS) Adjustment

	($M)	CY16/FY16	CY17/FY17	CY18/FY18	CY19/FY19	CY20/FY20	CY21/FY21
IBIS data	Capital	$374.7	$287.0	$167.1	$150.8	$333.2	$453.0
IBIS data	O&M	$24.9	$36.9	$40.5	$42.0	$44.1	$44.9
Manual -->	RPS% (CY Basis)	25.1%	32.2%	34.2%	35.2%	35.6%	35.6%
Manual -->	RPS% (FY Basis)	23.6%	30.9%	33.5%	35.0%	35.7%	35.9%

16 Unfunded Pension Liability (GASB68) Adjustment (Manual)

68% of estimated $1.26B to be reported on Balance Sheet per Segal letter dated 10/27/14	FY 15

17 Navajo Adjustments (Manual)

Navajo Coal Generation Divestment Date	7/1/2016
Navajo Coal Generation Sales Price	$1M

18 Sequestration Impact

		FY16	FY17	FY18	FY19	FY20	FY21
BABs, QECB and CREB Subsidy Cut (%)	in %	7.2%	7.2%	7.2%	7.2%	7.2%	7.2%
BABs, QECB and CREB Subsidy Cut ($M)	in $M	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5

19 Burnertip Natural Gas Pricing (Manual)

	FY16	FY17	FY18	FY19	FY20	FY21
FY2015 Budget (4/10/14)	$4.87	$4.86	$4.99	$5.16	$5.37	$5.60
FY2015 Budget (10/10/14)	$4.52	$4.66	$4.83	$5.00	$5.14	$5.29
FY2016 Budget (03/25/15)	$3.43	$3.75	$4.03	$4.22	$4.38	$4.55
Rate Case Budget (9/11/2015)	$3.31	$3.46	$3.61	$3.78	$3.97	$4.13

[FY16] PS Case143 -- Final Rate Case

Fuel Case -->	09/16/15
O&M Case -->	04/22/15

Final Rate Case	3 i-ECAFs	Navajo Coal Out on 7/1/2016	No Downgrade (AA-)	
Final 2016 with 15%EE	EE (15% by 2020)	Low CO2 Price	Pension Return - 7.75 - 7.5% 2Yr Pha	
BR #43	Solar SB-1 (Final 2016)	RPS Excess Credit Sales	Bad Debt as Budgeted	
PSRP O&M Cuts #43	i-RCAF frozen in FY15 only	CO2 Expense - Selective Override	DRTF = $500M	
Non-PSRP O&M Cuts #43	i-RCA Balance Zeroed in FY16	No Load Reduction	No Additional COLA Adjust	
RSF Drawdown #43	i-RCAF = 5.0 cts/kWh	Base Rev Target Preset #2	Var Debt -- PSRP 100%; Other 0%	
		Base Rev Decoupled	w/o CISCON settlement	
iCityXfer = Yes		Base Rev (July - July)	Remit City Transfer	
City Xfer - 8%	ESA split from Base Rate	FY16 BRRTA --> 2 Yrs	PSRP CapEX Debt Funding #3	
Rate action eff 4/1/16	ESAF frozen at 0.147 cts	PHEV --> As Is	with Excess WS & CIAC	

i-RCA Annual Cap -->

FY14/15	0.00	cts/kWh
FY15/16	5.00	cts/kWh
FY16/17	5.00	cts/kWh
FY17/18	5.00	cts/kWh
FY18/19	5.00	cts/kWh
FY19/20	5.00	cts/kWh
FY20/21	5.00	cts/kWh

i-ECA Inc %	5.6%	-2.3%	0.1%	3.3%	0.8%	1.5%	1.4%
i-Base Inc %	0.1%	1.2%	5.1%	2.2%	2.4%	2.8%	4.9%
i-RCA Inc %	0.1%	-0.4%	2.0%	0.7%	-0.3%	0.2%	-0.9%
i-Increase Total %	5.8%	-1.5%	7.2%	6.2%	2.8%	4.6%	5.4%
i-Base + i-RCA %	0.2%	0.8%	7.1%	2.9%	2.0%	3.0%	4.0%
i-ECA Inc $M	181	-81	4	124	32	62	60
i-Base Inc $M	5	40	177	81	93	113	208
i-RCA Inc $M	3	-15	68	27	-14	9	-40
i-Revenue Inc ($M)	189	-55	250	232	111	184	229
i-Base + i-RCA ($M)	8	26	246	108	79	122	168
5 or 6-Yr Simple Avg -->						3.86%	4.11%
5 or 6-Yr Compound Avg -->						4.12%	4.51%

	Final	Final	2014-15 Target (Case 71)	Actuals thru June (3-6)	<====== FORECAST ======>					
FISCAL YEAR ENDING JUNE 30	**2012-13**	**2013-14**	**2014-15**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
1. Retail Sales (GWh)	23,548	22,846	23,774	23,018	24,392	24,620	25,041	25,476	25,895	26,332
Adj. For DSM (GWh)	0	0	(129)	0	(413)	(811)	(1,269)	(1,743)	(2,191)	(2,505)
Adj. For Solar (GWh)	0	0	(12)	0	(115)	(208)	(273)	(291)	(304)	(305)
Adj. due to Others (GWh)	0	0	0	0	0	0	0	0	0	0
Net Retail Sales(GWh)	23,548	22,846	23,633	23,018	23,863	23,601	23,500	23,442	23,399	23,522
2. Operating Revenue:										
Base Revenue	1,558	1,508	1,569	1,523	1,579	1,556	1,546	1,543	1,539	1,545
Energy Cost Adjustment	1,325	1,287	1,339	1,314	1,352	1,337	1,332	1,330	1,327	1,334
Energy Subsidy Adjustment	35	35	36	36	36	36	35	35	35	35
Reliability Costs Adjustment	73	74	75	76	70	69	69	69	69	69
i-Base Revenue	58	173	180	175	223	404	486	577	691	905
i-ECA Revenue	17	102	251	267	205	207	330	360	421	483
i-RCA Revenue	24	56	57	58	54	121	148	134	143	104
Total Retail Revenue ($M)	3,090	3,235	3,506	3,448	3,519	3,730	3,946	4,048	4,225	4,475
Wholesale Sales (Gen. & Trans.)	72	99	44	94	104	102	105	106	108	102
Deferred Revenue - Base Revenue	37	18	(18)	(41)	38	(80)	(78)	(18)	(3)	(1)
Deferred Revenue - Others	(23)	1	(63)	(136)	(15)	8	(12)	(31)	(10)	(7)
Others	(13)	(33)	4	(27)	(13)	(15)	(17)	(18)	(20)	(23)
Total Operating Revenue ($M)	**3,163**	**3,320**	**3,474**	**3,337**	**3,633**	**3,745**	**3,944**	**4,087**	**4,300**	**4,547**
3. Non-Operating Revenue	100	112	155	100	91	94	88	100	88	78
4. Total Revenue	3,262	3,432	3,629	3,437	3,724	3,840	4,032	4,187	4,387	4,625
5. Fuel, Purchased Power & Emissions Expense	1,342	1,414	1,501	1,400	1,511	1,493	1,568	1,607	1,652	1,683
6. O&M Expenditures	903	936	962	1,026	1,039	1,030	1,051	1,082	1,127	1,145
7. Depreciation	418	467	550	496	596	646	679	711	771	830
8. Property Tax	14	14	16	15	17	19	19	19	19	19
9a. Interest Expense	283	278	286	299	308	347	392	440	484	517
9b. AFUDC	(34)	(19)	(57)	(39)	(38)	(18)	(12)	(24)	(29)	(5)
9c. CIAC	(47)	(45)	(20)	(67)	(53)	(53)	(53)	(53)	(53)	(53)
10. Total Expense	**2,879**	**3,044**	**3,237**	**3,130**	**3,380**	**3,464**	**3,644**	**3,782**	**3,972**	**4,137**
11a. Net Income Before City Transfer	**383**	**387**	**391**	**307**	**344**	**375**	**388**	**405**	**416**	**488**
11b. City Transfer	247	253	261	266	267	291	300	316	327	344
11c. Increase in Fund Net Assets	136	134	130	42	77	85	89	89	89	145
12. Capital Expenditures	1,059	1,214	1,476	1,260	1,486	1,465	1,540	1,593	1,653	1,605
13a. Borrowing for CapEx	1,130	567	679	796	428	836	874	887	931	762
13b. Cash on Hand	598	776	654	1,107	695	677	723	756	797	820
13c. Total Debt Service	427	451	436	458	473	499	580	644	717	775
13d. Total Non-Debt Service Expenditures	3,270	3,532	3,918	3,618	3,984	3,939	4,109	4,232	4,383	4,384
14. Financial Ratios (Accrual Basis):										
a. Debt Service Coverage	**2.41**	**2.42**	**2.92**	**2.23**	**2.50**	**2.69**	**2.45**	**2.34**	**2.26**	**2.33**
b. Adj. Debt Service Coverage	1.83	1.86	2.27	1.64	1.93	2.11	1.93	1.85	1.80	1.89
c. Full Obligation Coverage	1.63	1.67	1.87	1.51	1.71	1.77	1.69	1.80	1.83	1.93
d. Capitalization Factor	58.8%	59.7%	61.1%	61.4%	61.8%	63.1%	64.3%	65.4%	66.4%	66.8%
e. Days of Operating Cash (w/o Debt Svc)	176	197	170	242	171	170	170	170	170	170
15. Average Rate (cts/kWh)										
System Average	13.12	14.2	14.8	15.0	14.7	15.8	16.8	17.3	18.1	19.027
Avg. Rate Increase (%)	3.6%	7.9%	7.7%	5.8%	-1.6%	7.2%	6.2%	2.8%	4.6%	5.4%
16a. ECA (Under) Over Collection	(151)	(202)	(153)	(81)	(72)	(85)	(91)	(76)	(76)	(81)
16b. Legacy RCA (Under) Over Collection	(113)	(101)	(89)	(89)	(77)	(64)	(51)	(38)	(26)	(13)
16c. i-RCA (Under) Over Collection	0	0	0	0	0	(7)	(2)	1	(1)	(2)
16d. Total RCA (Under) Over Collection	(113)	(101)	(89)	(89)	(77)	(71)	(53)	(37)	(27)	(15)
17a. PSRP Capital Adds/(Cuts)		**0**	**0**	**0**	**(107)**	**(125)**	**5**	**0**	**0**	**0**
17b. PSRP O&M Adds/(Cuts)		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
17c. Non-PSRP Capital Adds/(Cuts)		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
17d. Non-PSRP O&M Adds/(Cuts)		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
17e. Pension, COLA, RPS Adj for Capital		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
17f. Pension, COLA, RPS Adj for O&M		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
17g. Total Capital Adds/(Cuts)		**0**	**0**	**0**	**(107)**	**(125)**	**5**	**0**	**0**	**0**
17h. Total O&M Adds/(Cuts)		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
18 %CapEx Borrowed		47%	46%	63%	29%	57%	57%	56%	56%	47%
20a. Rate Stabilization Fund Drawdown / (Injection)	(4)	(57)	0	0	0	0	0	0	0	0
20b. Rate Stabilization Fund Balance	117	174	176	174	174	174	174	174	174	174

[FY16] PS Case143 -- Final Rate Case

Fuel Case --> 09/16/15
O&M Case --> 04/22/15

; ANGELES DEPARTMENT OF WATER AND POV
Power System Financial Plan Summary
(In Million Dollars)

i-ECA Inc %	5.6%	-2.3%	0.1%	3.3%	0.8%	1.5%	1.4%
i-Base Inc %	0.1%	1.2%	5.1%	2.2%	2.4%	2.8%	4.9%
i-RCA Inc %	0.1%	-0.4%	2.0%	0.7%	-0.3%	0.2%	-0.9%
i-Increase %	5.80%	-1.51%	7.18%	6.25%	2.83%	4.55%	5.38%
i-Base + i-RCA %	0.23%	0.76%	7.06%	2.91%	2.02%	3.03%	3.97%
i-ECA Inc $M	181	-81	4	124	32	62	60
i-Base Inc $M	5	40	177	81	93	113	208
i-RCA Inc $M	3	-15	68	27	-14	9	-40
i-Revenue Inc ($M)	189	-55	250	232	111	184	229
i-Base + i-RCA ($M)	8	26	246	108	79	122	168

	Final	Final	2014-15 Target (Case 71)	Actuals thru June (3-6)	<====== FORECAST ======>					
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Adj. due to Others (GWh)	0	0	0	0	0	0	0	0	0	0
Net Retail Sales(GWh)	23,548	22,846	23,633	23,018	23,863	23,601	23,500	23,442	23,399	23,522
2. Operating Revenue:										
Base Revenue	1,558	1,508	1,569	1,523	1,579	1,556	1,546	1,543	1,539	1,545
Energy Cost Adjustment	1,325	1,287	1,339	1,314	1,352	1,337	1,332	1,330	1,327	1,334
Energy Subsidy Adjustment	35	35	36	36	36	36	35	35	35	35
Reliability Costs Adjustment	73	74	75	76	70	69	69	69	69	69
i-Base Revenue	58	173	180	175	223	404	486	577	691	905
i-ECA Revenue	17	102	251	267	205	207	330	360	421	483
i-RCA Revenue	24	56	57	58	54	121	148	134	143	104
Total Retail Revenue ($M)	3,090	3,235	3,506	3,448	3,519	3,730	3,946	4,048	4,225	4,475
Wholesale Sales (Gen. & Trans.)	72	99	44	94	104	102	105	106	108	102
Deferred Revenue - Base Revenue	37	18	(18)	(41)	38	(80)	(78)	(18)	(3)	(1)
Deferred Revenue - Others	(23)	1	(63)	(136)	(15)	8	(12)	(31)	(10)	(7)
Others	(13)	(33)	4	(27)	(13)	(15)	(17)	(18)	(20)	(23)
Total Operating Revenue ($M)	**3,163**	**3,320**	**3,474**	**3,337**	**3,633**	**3,745**	**3,944**	**4,087**	**4,300**	**4,547**
3. Non-Operating Revenue	100	112	155	100	91	94	88	100	88	78
4. Total Revenue	3,262	3,432	3,629	3,437	3,724	3,840	4,032	4,187	4,387	4,625
5. Fuel-Related Expenditures										
5a. Fuel and Purchased Power Expen	1,337	1,387	1,460	1,359	1,478	1,492	1,583	1,622	1,659	1,672
5b. Hoover Prepaid Amortization					2	2	2	2	2	2
5c. Legal Settlement Expense	0	0	16	16	16	16	16	16	16	16
5d. CO2 Credit Expense	1	23	23	22	15	1	1	1	1	0
5e. CO2 Credit Revenue	0	0	0	0	(4)	(22)	(39)	(40)	(31)	(13)
5f. Other Emissions Expenses	4	3	4	2	4	4	5	5	5	5
5g. Excess RPS Compliance Credit	0	0	(2)	0	0	0	0	0	0	0
6. O&M Expenditures										
6a. DSM	0	0	0	0	0	0	0	0	0	0
6b. Other Infrastructure	344	362	351	373	368	332	324	334	345	342
6c. Operating Support	251	250	299	303	335	342	348	358	365	375
6d. PSRP	282	295	285	321	309	318	337	346	371	382
6f. Public Benefits	1	1	2	2	2	2	2	2	2	2
6g. RPS	26	28	25	30	25	37	41	42	44	45
6h. RPS (Not Budgeted)	0	0	0	0	0	0	0	0	0	0
6i. IRP (Not Budgeted)	0	0	0	0	0	0	0	0	0	0
6j. PSRP Adds/(Cuts)	0	0.0	0	0	0	0	0	0	0	0
6k. Non-PSRP Adds/(Cuts)	0	0	0	0	0	0	0	0	0	0
6l. Pension Adj	0	0	0	0	0	0	0	0	0	0
6m. COLA Adj	0	0	0	0	0	0	0	0	0	0
6k. O&M Expenditures Total	904	936	962	1,028	1,039	1,030	1,051	1,082	1,127	1,145
7a. Depreciation	407	447	511	468	547	580	598	614	661	705
7b. Regulatory Asset - Solar SB-1	5	7	11	9	12	13	13	13	13	14
7c. Regulatory Asset - EE	7	12	29	20	37	53	68	84	97	111
8. Property Tax	14	14	16	15	17	19	19	19	19	19
9a. Interest Expense	283	278	286	299	308	347	392	440	484	517
9b. AFUDC	(34)	(19)	(57)	(39)	(38)	(18)	(12)	(24)	(29)	(5)
9c. CIAC	(47)	(45)	(20)	(67)	(53)	(53)	(53)	(53)	(53)	(53)
10. Total Expense	**2,880**	**3,044**	**3,239**	**3,132**	**3,380**	**3,464**	**3,644**	**3,782**	**3,972**	**4,137**
11a. Net Income Before City Transfer	**383**	**387**	**391**	**307**	344	**375**	**388**	**405**	**416**	**488**
11b. City Transfer	247	253	261	266	267	291	300	316	327	344
11c. Increase in Fund Net Assets	136	134	130	42	77	85	89	89	89	145
12. Capital Expenditures										
12a. DSM	50	77	101	78	145	178	194	190	172	169
12b. Gas Drilling	15	10	5	2	5	5	5	6	6	6
12c. Other Infrastructure	292	284	303	293	340	362	338	330	366	345
12d. IRP	271	376	279	290	98	23	147	290	173	72
12e. IRP (not budgeted)	0	0	0	0	0	0	0	0	0	1
12f. IRP (moved to OBS)	0	0	0	0	0	0	0	0	0	0
12g. Operating Support	70	98	74	70	113	132	102	73	62	62
12h. PSRP	217	256	364	318	516	603	582	553	541	497
12i. Public Benefits	0	0	0	0	0	0	0	0	0	0
12j. RPS	143	112	349	207	375	287	167	151	333	453
12k. RPS (not budgeted)	0	0	0	0	0	0	0	0	0	0
12l. RPS (moved to OBS)	0	0	0	0	0	0	0	0	0	0
12m. RPS Buyouts	0	0	0	0	0	0	0	0	0	0
12n. PSRP Adds/(Cuts)	0.0	0	0	0	(107)	(125)	5	0	0	0
12o. Non-PSRP Adds/(Cuts)	0	0	0	0	0	0	0	0	0	0
12p. Pension Adj	0	0	0	0	0	0	0	0	0	0
12q. COLA Adj	0	0	0	0	0	0	0	0	0	0
12l. Net Capital Expenditures Total	1,059	1,214	1,476	1,260	1,486	1,465	1,540	1,593	1,653	1,605
13a. Borrowing for CapEx	1,130	567	679	796	428	836	874	887	931	762
13b. Cash on Hand	594	776	654	1,107	695	677	723	756	797	820
13c. Total Debt Service	427	451	436	458	473	499	580	644	717	775
13d. Total Non-Debt Service Expenditur	3,272	3,532	3,920	3,620	3,984	3,939	4,109	4,232	4,383	4,384
14. Financial Ratios (Accrual Basis):										
a. Debt Service Coverage	**2.41**	**2.42**	**2.92**	**2.23**	**2.50**	**2.69**	**2.45**	**2.34**	**2.26**	**2.33**
b. Adj. Debt Service Coverage	1.83	1.86	2.27	1.64	1.93	2.11	1.93	1.85	1.80	1.89
c. Full Obligation Coverage	1.63	1.67	1.87	1.51	1.71	1.77	1.69	1.80	1.83	1.93
d. Capitalization Factor	58.8%	59.7%	61.1%	61.4%	61.8%	63.1%	64.3%	65.4%	66.4%	66.8%
15. Average Rate (cts/kWh)										
System Average	13.1	14.2	14.8	15.0	14.7	15.8	16.8	17.3	18.1	19.0
Avg. Rate Increase (%)	3.6%	7.9%	7.7%	5.8%	-1.6%	7.2%	6.2%	2.8%	4.6%	5.4%
16a. ECA (Under) Over Collection	(151)	(202)	(153)	(81)	(72)	(85)	(91)	(76)	(76)	(81)
16b. RCA (Under) Over Collection	(113)	(101)	(89)	(89)	(77)	(71)	(53)	(37)	(27)	(15)
16c. Baraket Settlement Balance	160	160	144	144	128	112	96	80	64	48

Los Angeles Department of Water and Power
Power System Income Statement
($ in millions)

	Final	Final	2014-15 Target (Case 71)	Actuals thru June (3-6)	FORECAST					
Fiscal Year Ending June 30	**2013**	**2014**	**2015**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Retail Sales (GWh)	23,548	22,846	23,774	23,018	24,392	24,620	25,041	25,476	25,895	26,332
Proj. Energy Eff. Prgm (GWh)	0	0	(129)	0	(413)	(811)	(1,269)	(1,743)	(2,191)	(2,505)
Solar Roof Top	0	0	(12)	0	(115)	(208)	(273)	(291)	(304)	(305)
Reductions from Weather or Actuals (GWh)	0	0	0	0	0	0	0	0	0	0
Net Retail Sales (GWh)	23,548	22,846	23,633	23,018	23,863	23,601	23,500	23,442	23,399	23,522
Revenues:										
Residential	1,014	1,135	1,287	1,239	1,294	1,382	1,472	1,526	1,613	1,720
Commercial	1,816	1,803	1,862	1,897	1,866	1,972	2,075	2,110	2,184	2,306
Industrial	234	262	326	275	326	340	361	373	386	406
Intra - Department	16	17	19	19	19	20	22	22	23	24
Street Lighting	11	17	12	18	14	16	18	18	18	19
Retail Revenue	3,090	3,235	3,506	3,448	3,519	3,730	3,946	4,048	4,225	4,475
Wholesale Sales (Generation)	(21)	5	17	12	14	12	15	16	18	12
Wholesale Sales (Transmission)	93	94	28	82	21	22	22	22	22	22
Excess Wholesale Sales	0	0	0	0	70	69	69	69	69	69
Distribution Other Revenue	10	25	22	(2)	22	22	22	22	22	22
Deferred IPP Revenue	0	0	0	0	7	0	0	0	0	0
Deferred Public Benefit	0	0	0	0	0	0	0	0	0	0
Deferred Rate Stabilization	(4)	(57)	0	0	0	0	0	0	0	0
Deferred SCPPA Credit	27	18	0	0	0	0	0	0	0	0
ECAF (Over)/Under Collection	(42)	52	(51)	(121)	(9)	14	6	(15)	1	4
ESA (Over) /Under Collection	0	0	0	0	0	0	0	0	0	0
RCA (Over)/Under Collection	(6)	(12)	(12)	(12)	(13)	(6)	(18)	(16)	(11)	(12)
Base Revenue (Over)/Under Collection	37	18	(18)	(41)	38	(80)	(78)	(18)	(3)	(1)
Green Power Over/Under Collection	0	0	0	0	0	0	0	0	0	0
Change in Accrued Revenue	2	(0)	0	(3)	0	0	0	0	0	0
Allowance for Legal Settlement	0	0	0	0	0	0	0	0	0	0
Allowance for Bad Debt	(23)	(58)	(18)	(25)	(35)	(37)	(39)	(40)	(42)	(45)
Total Operating Revenue	**3,163**	**3,320**	**3,474**	**3,337**	**3,633**	**3,745**	**3,944**	**4,087**	**4,300**	**4,547**
System Average (cents/kWh)	**13.1**	**14.2**	**14.8**	**15.0**	**14.7**	**15.8**	**16.8**	**17.3**	**18.1**	**19.0**
Retail Rate Increase	**3.6%**	**7.9%**	**7.7%**	**5.8%**	**-1.6%**	**7.2%**	**6.2%**	**2.8%**	**4.6%**	**5.4%**
Fuel Expenses	442	410	420	337	290	235	220	214	215	230
Purchased Power	895	977	1,037	1,020	1,188	1,256	1,363	1,408	1,444	1,442
Hoover Prepaid Amortization		1	2	2	2	2	2	2	2	2
Legal Settlement Expense	0	0	16	16	16	16	16	16	16	16
CO2 Credit Expense	1	23	23	22	15	1	1	1	1	0
CO2 Credit Sales Revenue	0	0	0	0	(4)	(22)	(39)	(40)	(31)	(13)
Other Emissions Expense	4	3	4	2	4	4	5	5	5	5
Excess RPS Compliance Credit	0	0	(2)	0	0	0	0	0	0	0
O & M Expenses	904	936	960	1,024	1,037	1,029	1,049	1,080	1,125	1,144
Demand Side Management (Exld. PB)	(3)	0	0	0	0	0	0	0	0	0
Public Benefit	3	(0)	2	2	2	2	2	2	2	2
Prepaid Public benefit	0	0	0	0	0	0	0	0	0	0
Depreciation - Regular Asset	407	447	511	468	547	580	598	614	661	705
Depreciation - Solar	5	7	11	9	12	13	13	13	13	14
Depreciation - EE	7	12	29	20	37	53	68	84	97	111
Property Taxes	14	14	16	15	17	19	19	19	19	19
TOTAL OPR EXPENSES	**2,677**	**2,830**	**3,028**	**2,937**	**3,163**	**3,189**	**3,317**	**3,419**	**3,570**	**3,677**
Operating Income	486	489	446	400	470	557	627	669	730	870
Gain/Loss On Asset Sales	0	0	64	0	0	(22)	0	0	0	0
Other Income/Expenses, Net	100	112	91	100	91	116	88	100	88	78
Income Before LT Debt Expenses	585	601	601	500	561	651	715	768	817	948
Interest on Fixed Rate Bonds	297	318	323	347	354	381	418	452	483	512
Interest on Variable Rate Bonds	1	0	3	0	6	13	20	27	32	35
Debt Issuance Cost	0	0	3	0	2	3	3	4	4	3
Amortization of Debt Expenses	(15)	(41)	(42)	(48)	(54)	(51)	(50)	(43)	(35)	(33)
Total Debt Expenses	283	278	286	299	308	347	392	440	484	517
AFUDC	(34)	(19)	(57)	(39)	(38)	(18)	(12)	(24)	(29)	(5)
Net Debt Expenses	249	259	229	260	270	329	380	417	455	513
Contributions in Aid of Construction (CIAC)	47	45	20	67	22	23	23	24	15	15
Excess CIAC					31	30	30	29	38	38
Change in Fund Net Assets Before Transfer to the City	**383**	**387**	**391**	**307**	**344**	**375**	**388**	**405**	**416**	**488**
City Transfer	247	253.0	261	265.6	267.0	291	300	316	327	344
Extraordinary loss										
Increase in Fund Net Assets	**136**	**134**	**130**	**41.7218**	**77**	**85**	**89**	**89**	**89**	**145**
Addtn'l Bond Test Ratio: (prev / max)	1.85	1.94	1.90	2.03	1.89	1.96	1.99	1.97	1.96	2.00
Financial Ratio (Current/Current)										
Debt Service Coverage	**2.41**	**2.42**	**2.92**	**2.23**	**2.50**	**2.69**	**2.45**	**2.34**	**2.26**	**2.33**
Adj. Debt Service Coverage	1.83	1.86	2.27	1.64	1.93	2.11	1.93	1.85	1.80	1.89
Full Obligation Coverage	1.63	1.666	1.87	1.51	1.71	1.77	1.69	1.80	1.83	1.93
Capitalization Ratio	58.8%	59.7%	61.1%	61.4%	61.8%	63.1%	64.3%	65.4%	66.4%	66.8%
Interest Coverage	3.46	3.43	3.62	2.93	3.28	3.41	3.24	3.14	3.14	3.30

Los Angeles Department of Water and Power
Power System Balance Sheet
($ in millions)

	Final	Final	Actuals thru June (3-6)	Forecast					
FY ENDING JUNE 30	2013	2014	2015	2016	2017	2018	2019	2020	2021
Plant in Service	14,273	14,983	15,694	17,633	18,661	19,679	21,216	22,273	23,821
Nuclear Fuel - Net	45	43	39	39	39	39	39	39	40
Natural Gas Field	272	249	229	211	193	174	154	133	112
C W I P	884	1,236	1,726	1,051	1,214	1,485	1,303	1,687	1,509
Gross Plant	15,474	16,511	17,688	18,935	20,107	21,376	22,713	24,133	25,482
Accum. Depreciation	6,854	7,298	7,760	8,249	8,771	9,311	9,867	10,471	11,119
Net Plant	8,621	9,213	9,927	10,686	11,336	12,065	12,845	13,662	14,363
Restricted and Other Investment:									
Nuclear Decommissioning Fund	123	127	129	132	135	138	141	144	148
Debt Reduction Trust Funds	490	497	500	500	500	500	500	501	501
Sinking Funds for CREBs	0	0	0	0	11	21	32	44	56
Post Retiree Benefit Fund	0	0	0	0	0	0	0	0	0
Natural Gas Hedging Trust Fund	0	0	0	0	0	0	0	0	0
Hazardous Waste Treatment TF	2	2	2	2	2	2	2	2	2
Other Investment	19	14	10	5	0	0	0	0	0
Total Restricted and Othr Invs.	634	640	642	640	648	662	676	692	707
Current Assets									
Construction Fund	448	194	85	0	0	0	0	0	0
Revenue Fund - Unrestricted	594	773	1,104	692	674	720	752	794	817
Revenue Fund - Working Funds	3	3	3	3	3	3	3	3	3
Bond R&I Fund	280	270	288	276	332	373	429	473	508
Insurance Funds	134	144	154	164	174	184	194	204	204
Account Receivable	539	570	516	524	561	578	596	624	657
Accrued Revenue	176	175	171	171	171	171	171	171	171
Material & Supplies	154	153	155	156	157	158	159	160	161
Fuel Inventory	9	11	10	10	10	10	10	10	10
Other Prepayments and assets	82	107	107	46	46	46	46	46	46
Bond Issue Costs	32	(0)	0	0	0	0	0	0	0
Total Current Assets	2,452	2,399	2,593	2,042	2,129	2,244	2,361	2,486	2,577
Regulatory Asset - CISCON Settlement	0	0	0	0	0	0	0	0	0
Regulatory Asset - Barakat Settement	160	160	144	128	112	96	80	64	48
Regulatory Asset - Solar Incentives	120	148	164	201	214	206	196	186	176
Regulatory Asset - DSM	99	160	217	325	450	576	682	757	816
Post Retirement Healthcare Assets	652	668	670	672	672	670	665	657	645
Pension Assets	(51)	(86)	(145)	(145)	(145)	(145)	(145)	(145)	(145)
Regulatory Asset - Pension Liabilities				748	618	491	373	260	151
Long - Term Notes Receivable	815	745	658	569	554	502	372	210	55
Regulatory Asset - Hoover Prepayment		25	22	20	18	15	13	11	9
Losses due to Debt Refunding		27	30	27	23	20	17	14	12
Prepaid Public Benefit	0	0	0	0	0	0	0	0	0
Total Assets	13,503	14,099	14,923	15,912	16,629	17,402	18,136	18,854	19,413
Retained Earnings	4,568	4,625	4,600	4,624	4,656	4,692	4,728	4,764	4,855
Acc. CIAC	623	668	735	788	841	894	947	1,000	1,053
Equity	5,191	5,294	5,335	5,413	5,497	5,586	5,675	5,764	5,908
Bonds & Notes	7,544	7,965	8,598	8,856	9,544	10,233	10,920	11,622	12,132
Bonds to be Defeased			0	0	0	0	0	0	0
LT Debt Due in 1 Yr	132	111	113	94	132	155	191	217	238
Non - Current Debt	7,412	7,854	8,485	8,762	9,412	10,079	10,729	11,405	11,894
Current Liabilities									
LT Debt Due in 1 Yr	132	111	113	94	132	155	191	217	238
Revenue Certificates	200	200	200	200	200	200	200	200	200
Accrued interest	145	160	171	181	200	219	238	256	270
Accounts Payable	333	394	335	341	339	358	369	381	375
Payable to City's Reserve Fund	0	0	0	0	0	0	0	0	0
Payable to Water System	43	57	73	18	18	18	18	18	18
Accrued Payroll & Others	104	108	115	85	85	85	85	85	85
Potential Refund	0	0	0	0	0	0	0	0	0
Total Current Liabilites	958	1,030	1,007	920	974	1,034	1,101	1,157	1,185
Pension Liabilities				748	618	491	373	260	151
Long -term accrued liabilities	7	5	4	2	0	0	0	0	0
Deferred Public Benefit	0	0	0	0	0	0	0	0	0
ECAF Over (Under) Collection	(151)	(202)	(81)	(72)	(85)	(91)	(76)	(76)	(81)
ESA Over (Under) Collection	0	0	0	0	0	0	0	0	0
RCA Over (Under) Collection	(113)	(101)	(89)	(77)	(71)	(53)	(37)	(27)	(15)
Base Revenue Over (Under) Collection	(37)	(55)	(14)	(52)	28	106	123	126	127
Deferred Rate Stabilization	117	174	174	174	174	174	174	174	174
Green Power Over (Under) Collection	3	3	3	5	5	5	5	5	5
Deferred Revenue - Others	(0)	0	0	0	0	0	0	0	0
Workers Comp Liability	52	57	55	55	56	56	57	57	58
Discount on Notes	45	42	38	35	21	16	12	10	8
Deferred Credit (SCPPA)	18	0	0	0	0	0	0	0	0
Deferred IPP Credit	0	0	7	0	0	0	0	0	0
Total Liabilities and Equity	13,503	14,099	14,923	15,912	16,629	17,402	18,136	18,854	19,413

Los Angeles Department of Water and Power
Power System Source of Funds
($ in millions)

	Final	Final				Forecast			
FY ENDING JUNE 30	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Beginning Cash									
Revenue Fund	418	598	776	1,107	695	677	723	756	797
Construction Fund	21	448	194	85	0	0	0	0	0
Sinking Fund for CREBs/QCEBs	0	0	0	0	0	11	21	32	44
DWP Debt Mang.	246	246	249	251	249	245	240	234	228
SCPPA Debt Mang.	39	39	40	40	40	41	42	43	44
IPA Debt Mang.	205	205	208	209	211	215	219	224	229
Total	929	1,536	1,466	1,692	1,195	1,188	1,245	1,288	1,342
Cash Avail. From Operations	345	369	485	434	643	646	611	602	713
Cont. In Aid of Const.	47	45	67	53	53	53	53	53	53
Bond Proceeds for CapEx	1,130	522	679	428	836	874	887	931	762
Bond Premium Proceeds from Issuance	167	45	117	0	0	0	0	0	0
Bond Refunding Proceeds	631	0	719	0	0	0	0	0	0
Bond Refunding Premium Proceeds	126	0	105	0	0	0	0	0	0
Rev. Certificate Proceeds	0	0	0	0	0	0	0	0	0
Asset Sales Proceeds for Debt Defeasance	0	0	0	0	0	0	0	0	0
Use of Funds for Regulatory Asset				0	0	0			
Change in Current Assets	(98)	(71)	27	52	(104)	(67)	(79)	(76)	(56)
Rate Stabilization Account	(0)	(0)	(0)	0	0	0	0	0	0
Bond R&I Fund	(9)	10	(18)	12	(56)	(42)	(56)	(44)	(34)
Insurance Funds	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	0
Account Receivable	(60)	(31)	54	(9)	(37)	(17)	(17)	(29)	(32)
Accrued Revenue	(2)	0	4	0	0	0	0	0	0
Material & Supplies	7	1	(3)	(1)	(1)	(1)	(1)	(1)	(1)
Fuel Inventory	(0)	(1)	0	0	0	0	0	0	0
Other Prepayments and assets	(3)	(25)	(0)	61	0	0	0	0	0
Post Retirement Healthcare Assets	(21)	(16)	(1)	(2)	(0)	2	5	8	12
Prepaid Public Benefit	0	0	0	0	0	0	0	0	0
Prepaid Hoover Debt Purchase		(25)							
Receivable from ISO	0	0	0	0	0	0	0	0	0
Long Term Notes Receivable	74	70	87	89	16	52	130	162	155
Change in Liabilities	(82)	93	(33)	(71)	2	33	27	28	6
Accrued interest	5	14	11	10	19	19	19	18	14
Accounts Payable	(9)	61	(59)	6	(2)	19	11	12	(6)
Payable to City's Reserve Fund	0	0	0	0	0	0	0	0	0
Payable to Water System	(83)	15	15	(55)	0	0	0	0	0
Accrued Payroll & Others	2	3	7	(30)	0	0	0	0	0
Potential Refund	0	0	0	0	0	0	0	0	0
Long term accrued liabilities	(2)	(2)	(2)	(2)	(2)	0	0	0	0
Green Power Over (Under) Collection	0	(0)	(0)	2	0	0	0	0	0
Workers Comp Liability	9	4	(2)	1	1	1	1	1	1
Discount on Notes	(5)	(3)	(4)	(3)	(14)	(5)	(4)	(2)	(3)
Sales of Assets	0	0	0	0	0	0	0	0	0
Bond Issue Costs	(2)	(2)	(3)	(2)	(3)	(3)	(4)	(4)	(3)
Bond Premium (Discount)	5	0	0	0	0	0	0	0	0
Refunding	(757)	0	(824)	0	0	0	0	0	0
Clearing Depreciation	0	0	0	0	0	0	0	0	0
Cash/Accrual Adjustment	76	69	55	0	0	0	0	0	0
AFDC	0	0	0	0	0	0	0	0	0
Retained Sinking Fund Payment	0	0	0	0	10	10	10	10	10
Change in investments	4	4	5	4	5	0	0	0	0
Total Sources	2,595	2,680	2,952	2,681	2,653	2,785	2,881	2,995	2,982
Capital Expenditure (Gross)	1,059	1,214	1,260	1,486	1,465	1,540	1,593	1,653	1,605
Ending Cash	1,536	1,466	1,692	1,195	1,188	1,245	1,288	1,342	1,376

Los Angeles Department of Water and Power
Power System Operating Result
($ in millions)

	Final	Final		Forecast					
FY ENDING JUNE 30	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Retail Revenue	3,090	3,235	3,448	3,519	3,730	3,946	4,048	4,225	4,475
Wholesales Revenue	72	99	94	104	102	105	106	108	102
Distribution Other Revenue	10	25	(2)	22	22	22	22	22	22
Change in Accrued Revenue	2	(0)	(3)	0	0	0	0	0	0
Allowance for Legal Settlement	0	0	0	0	0	0	0	0	0
Allowance for Bad Debt	(23)	(58)	(25)	(35)	(37)	(39)	(40)	(42)	(45)
Total Non-Accrual Revenue	3,151	3,300	3,512	3,610	3,817	4,034	4,136	4,313	4,555
Operating Expenses:									
Fuel & Purchased Power	1,313	1,365	1,338	1,454	1,468	1,559	1,597	1,633	1,645
CO2 Credit Expense	1	23	22	15	1	1	1	1	0
CO2 Credit Sales Revenue	0	0	0	(4)	(22)	(39)	(40)	(31)	(13)
Other Emissions Expense	4	3	2	4	4	5	5	5	5
Excess RPS Compliance Credit	0	0	0	0	0	0	0	0	0
O & M Expenses	903	936	1,026	1,039	1,030	1,051	1,082	1,127	1,145
Property Taxes	14	14	15	17	19	19	19	19	19
Total O & M Before Depr.	2,235	2,342	2,404	2,526	2,501	2,595	2,665	2,754	2,802
Cash Adj. for Pension Expense	3	2	0	0	0	0	0	0	0
Other Income / Expenses, Net	100	112	100	91	116	88	100	88	78
Total Other	102	114	100	91	116	88	100	88	78
Cash Avail. for Debt Svc.	1,019	1,073	1,208	1,175	1,432	1,526	1,571	1,646	1,831
Interest on Debt	298	319	347	360	394	438	479	516	547
Bonds Maturities	129	132	111	113	94	132	155	191	217
Transfer to Sinking Fund - CREBs	0	0	0	0	10	10	10	10	10
Total Debt Services	427	451	458	473	499	580	644	717	775
Cash Available after D.S.	592	622	751	701	933	946	927	929	1,057
Transfer to City	247	253	266	267	291	300	316	327	344
Cash Available from Operations	345	369	485	434	643	646	611	602	713

Los Angeles Department of Water and Power
Power System Financial Ratios
($ in millions)

Cash / Accrual for Revenue -->	0	1 = Cash, 0 = Accrual
Net of Bond Subsidies -->	0	1 = Net, 0 = Do Not Net

	Final	Final			Forecast				
FY ENDING JUNE 30	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Debt Service Coverage (Current / Current)									
Revenue:									
Operating Revenue Prior to Adjustment	3,163	3,320	3,337	3,633	3,745	3,944	4,087	4,300	4,547
Less Deferred Revenue:									
Deferred - IPP Revenue	0	0	0	0	0	0	0	0	0
Deferred - Public Benefit	0	0	0	0	0	0	0	0	0
Deferred - Rate Stabilization	0	0	0	0	0	0	0	0	0
Deferred - SCPPA Credit	0	0	0	0	0	0	0	0	0
Deferred - Energy Cost Adjustment	0	0	0	0	0	0	0	0	0
Deferred - Energy Subsidy Adjustment	0	0	0	0	0	0	0	0	0
Deferred - Reliability Cost Adjustment	0	0	0	0	0	0	0	0	0
Deferred - Base Revenue	0	0	0	0	0	0	0	0	0
Deferred - Green Power	0	0	0	0	0	0	0	0	0
Total Deferred Revenue	0	0	0	0	0	0	0	0	0
Non-Operating Revenue	100	112	100	91	116	88	100	88	78
Total Revenue	3,262	3,432	3,437	3,724	3,861	4,032	4,187	4,387	4,625
Less Operating Expenses	(2,677)	(2,830)	(2,937)	(3,163)	(3,189)	(3,317)	(3,419)	(3,570)	(3,677)
Adj. for Depreciation Expense	418	467	496	596	646	679	711	771	830
Adj. for NG Depletion Expense	25	24	20	23	23	24	25	26	27
Adj. for Hoover Preapid Amortization	0	1	2	2	2	2	2	2	2
Adjustment for Non-Cash Expense:									
Adj. for Pension GASB 27 (Extra Funding over Expense)	0	0	0	0	0	0	0	0	0
Adj. for Healthcare GASB 45 (Extra Funding over Expense	0	0	0	0	0	0	0	0	0
Less Adjustment for Bond Interest Subsidies									
BAB, CREB and QECB Subsidies	0	0	0	0	0	0	0	0	0
Funds Balance Avail for Debt Service	1,029	1,092	1,018	1,182	1,344	1,421	1,507	1,617	1,808
Debt Service Payment									
Interest on Fixed Rate Debt	297	318	347	354	381	418	452	483	512
Interest on Variable Rate Debt	1	0	0	6	13	20	27	32	35
Principal Maturities	130	132	111	113	94	132	155	191	217
Sinking Fund Payment for CREBs	0	0	0	0	10	10	10	10	10
less BAB, CREB and QECB Subsidies	0	0	0	0	0	0	0	0	0
Net Debt Service	427	451	458	473	499	580	644	717	775
Debt Service Coverage Ratio	**2.41**	**2.42**	**2.23**	**2.50**	**2.69**	**2.45**	**2.34**	**2.26**	**2.33**
Additional Bond Test Ratio (Prev / Max) -- Must Exceed 1.25									
Net Income	383	387	307	344	375	388	405	416	488
LT Debt Expense	283	278	299	308	347	392	440	484	517
Depreciation	418	467	496	596	646	679	711	771	830
Adjusted Net Income	1,084	1,132	1,102	1,248	1,368	1,459	1,556	1,671	1,836
Max Debt Service	558	558	558	584	638	688	740	793	834
Additional Bond Test Ratio (Previous Period Adj. Net Income / Max Debt Service)	**1.85**	**1.94**	**2.03**	**1.89**	**1.96**	**1.99**	**1.97**	**1.96**	**2.00**
Capitalization Ratio									
Non-Current Debt	7,412	7,854	8,485	8,762	9,412	10,079	10,729	11,405	11,894
Retained Earnings	4,568	4,625	4,600	4,624	4,656	4,692	4,728	4,764	4,855
Accum. CIAC	623	668	735	788	841	894	947	1,000	1,053
Equity	5,191	5,294	5,335	5,413	5,497	5,586	5,675	5,764	5,908
Non-Current Debt + Equity	12,603	13,148	13,821	14,174	14,909	15,665	16,404	17,169	17,803
Capitalization Ratio (NC Debt / (NC Debt + Equity))	**58.8%**	**59.7%**	**61.4%**	**61.8%**	**63.1%**	**64.3%**	**65.4%**	**66.4%**	**66.8%**
Days of Operating Cash									
Fuel, Purchased Power & Emission Expense	1,342	1,414	1,400	1,511	1,493	1,568	1,607	1,652	1,683
Barrakat Settlement Expense (included in FPPB)	0	0	(16)	(16)	(16)	(16)	(16)	(16)	(16)
O&M Expense	903	936	1,026	1,039	1,030	1,051	1,082	1,127	1,145
Property Tax	14	14	15	17	19	19	19	19	19
Capital Expenditures	1,059	1,214	1,260	1,486	1,465	1,540	1,593	1,653	1,605
CIAC	(47)	(45)	(67)	(22)	(23)	(23)	(24)	(15)	(15)
Total Non-Debt Service Expenditures	3,270	3,532	3,618	4,015	3,969	4,139	4,261	4,421	4,422
less Capital Expenditures	(1,059)	(1,214)	(1,260)	(1,486)	(1,465)	(1,540)	(1,593)	(1,653)	(1,605)
less CIAC	47	45	67	22	23	23	24	15	15
Operating Expense	2,258	2,364	2,425	2,552	2,527	2,622	2,692	2,783	2,831
Daily Operating Cash Needs	6.2	6.5	6.6	7.0	6.9	7.2	7.4	7.6	7.8
Cash Target	598	776	1,107	695	677	723	756	797	820
Cash from DRTF	490	497	500	500	500	500	500	501	501
Total Equivalent Cash	1,088	1,273	1,607	1,195	1,177	1,223	1,256	1,298	1,321
Days of Operating Cash	176	197	242	171	170	170	170	170	170
Other Ratios									
Cash Balance Avail for Debt Service	1,029	1,092	1,018	1,182	1,344	1,421	1,507	1,617	1,808
Interest on Fixed Rate Debt	297	318	347	354	381	418	452	483	512
Interest on Variable Rate Debt	1	0	0	6	13	20	27	32	35
Interest Coverage Ratio	**3.46**	**3.43**	**2.93**	**3.28**	**3.41**	**3.24**	**3.14**	**3.14**	**3.30**
Off-Balance Sheet Debt Svc($M)	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Conventional									
IGS (IPA) - Issued	171.8	196.4	186.2	209.7	121.4	171.2	185.4	168.3	123.1
NTS (IPA) - Issued	5.6	6.4	6.1	6.9	4.0	5.6	6.1	5.5	4.0

Los Angeles Department of Water and Power
Power System Financial Ratios
($ in millions)

Cash / Accrual for Revenue -->	0	1 = Cash, 0 = Accrual
Net of Bond Subsidies -->	0	1 = Net, 0 = Do Not Net

#	FY ENDING JUNE 30	Issue Yr	Issue Amt	Final 2013	Final 2014	2015	2016	Forecast 2017	2018	2019	2020	2021
	STS (SCPPA) - Issued			53.6	48.5	48.7	48.8	47.6	47.0	47.0	47.0	47.0
	STS Upgrade - Issued			4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
	Mead-Adelanto (SCPPA) - Issued			8.2	8.1	8.1	7.7	7.7	7.7	7.7	7.7	0.0
	Mead-Phoenix (SCPPA) - Issued			2.0	1.7	1.7	1.6	1.6	1.6	1.6	1.6	0.0
	PV (SCPPA) - Issued			8.7	8.6	8.6	8.6	8.6	0.0	0.0	0.0	0.0
	Asset or Prepay RPS											
	Linden (SCPPA) - $135M - Issued			8.3	8.3	8.2	8.2	8.2	8.2	8.2	8.2	8.2
	Milford I (SCPPA) - $219M - Issued			17.2	17.2	17.1	17.1	17.0	17.0	17.0	17.0	17.0
	Windy Point (SCPPA) - $512M - Issued			40.4	40.4	40.2	40.3	40.1	40.1	40.0	40.0	39.9
	Milford II (SCPPA) - $155M Prepay - Issued			11.1	11.7	11.7	11.7	11.6	11.6	11.6	11.6	11.6
	APEX 2014A Tax-Exempt (SCPPA) - $153M			0.0	2.0	7.6	7.6	7.6	7.6	7.6	7.6	7.6
	APEX 2014B Taxable (SCPPA) - $167M			0.0	1.3	14.4	14.3	14.3	14.3	14.3	14.3	14.4
	Future IRP and RPS Projects	Issue Yr	Issue Amt									
1	Geo1 25/200	2023	$158.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Geo2 25/200	2024	$80.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Geo3 25/200	2025	$40.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Geo4 25/200	2026	$41.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	GeoPPA 2015OW 14/114	2011	$0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	GeoPPA 2013OH 35/291	2011	$0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Generic Geo Various (100MW)	2011	$0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Generic Geo Various (100MW)	2011	$0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Generic Geo Various (100MW)	2011	$0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	SolarPPA 2015B 200/430	2011	$0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	SolarPPA 2015B 200/430	2011	$0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	SolarPPA 2015CM 210/453	2011	$0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	SolarPPA 2015CM 210/453	2011	$0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	SolarPPA 2014K 250/557	2011	$0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	SolarPPA 2014K 250/557	2011	$0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Owens Valley Solar (SCPPA)	2021	$149.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.2
17	Owens Valley Solar (SCPPA)	2023	$231.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Owens Valley Solar (SCPPA)	2025	$197.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Owens Valley Solar (SCPPA)	2011	$0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20												
21												
22												
23												
24												
25												
26												
27												
28												
29	IPP CC 2-575	2024	$1,884.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	IPP CT 6-100	2011	$0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Future RPS Buyouts											
1												
2												
3												
4												
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20												
	Gross Off-Balance Sheet Debt Service ($M)			331.2	355.1	362.9	386.9	294.3	336.4	351.0	333.2	283.4
	Less IPA Subordinated Notes ($M)											
	IPA Notes - Interest Payment			(39.1)	(36.7)	(30.9)	(23.1)	(35.9)	(10.7)	(17.9)	(4.7)	6.8
	IPA Notes - Principal Maturities			(62.1)	(74.8)	(69.4)	(88.9)	(15.6)	(51.5)	(130.1)	(162.0)	(155.4)
	Total Income from IPA Notes			(101.2)	(111.5)	(100.3)	(112.0)	(51.5)	(62.2)	(148.0)	(166.6)	(148.6)
	Net Off-Balance Sheet Debt Service ($M)			**230.1**	**243.6**	**262.6**	**274.9**	**242.8**	**274.2**	**203.0**	**166.5**	**134.8**
	Adjusted Debt Service Ratio											
	Funds Available for Debt Service			1,029	1,092	1,018	1,182	1,344	1,421	1,507	1,617	1,808
	less City Transfer			(247)	(253)	(266)	(267)	(291)	(300)	(316)	(327)	(344)
	Adj. Funds Available for Debt Service			782	839	753	915	1,054	1,121	1,191	1,290	1,464
	On-Balance Sheet Debt Service, net of Bond Subsidies			427	451	458	473	499	580	644	717	775
	Adjusted Debt Service Ratio, net of Bond Subsidies & IPA N			**1.83**	**1.86**	**1.64**	**1.93**	**2.11**	**1.93**	**1.85**	**1.80**	**1.89**
	Full Obligation Coverage Ratio (Net of IPA Notes)											
	Funds Available for Debt Service			1,029	1,092	1,018	1,182	1,344	1,421	1,507	1,617	1,808
	Gross Off-Balance Sheet Debt Service			331	355	363	387	294	336	351	333	283
	less IPA - Interest Portion			(39)	(37)	(31)	(23)	(36)	(11)	(18)	(5)	7
	less City Transfer			(247)	(253)	(266)	(267)	(291)	(300)	(316)	(327)	(344)
	Adj. Funds Available for Debt Service			1,075	1,158	1,085	1,279	1,312	1,447	1,524	1,619	1,754
	On-Balance Sheet Debt Service			427	451	458	473	499	580	644	717	775
	Off-Balance Sheet Debt Service			331	355	363	387	294	336	351	333	283
	less IPA Notes - Interest + Principal			(101)	(111)	(100)	(112)	(52)	(62)	(148)	(167)	(149)
	Full Obligation Ratio			**1.63**	**1.67**	**1.51**	**1.71**	**1.77**	**1.69**	**1.80**	**1.83**	**1.93**

Los Angeles Department of Water and Power
Power System
On and Off Balance Sheet Debt Summary

Fiscal Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
On-Balance Sheet ($M)								
- Debt Issuance (Fixed Rate)	0	0	371	800	718	740	780	603
- Debt Issuance (Variable Rate)	0	0	57	37	157	147	151	159
- Debt Issuance	522	679	428	836	874	887	931	762
- Debt Outstanding (Non-Current)	7,854	8,485	8,762	9,412	10,079	10,729	11,405	11,894
- Debt Outstanding (Current)	111	113	94	132	155	191	217	238
- Debt Outstanding (Total)	7,965	8,598	8,856	9,544	10,233	10,920	11,622	12,132
- Debt Outstanding (Fixed Rate)	6,595	7,229	7,429	8,080	8,613	9,153	9,705	10,057
- Debt Outstanding (Variable Rate)	1,369	1,369	1,427	1,463	1,620	1,767	1,917	2,075
- Debt Outstanding % (Fixed Rate)	83%	84%	84%	85%	84%	84%	84%	83%
- Debt Outstanding % (Variable Rate)	17%	16%	16%	15%	16%	16%	16%	17%
- Gross Debt Service	451	458	473	499	580	644	717	775
less Bond Subsidy	0	0	0	0	0	0	0	0
- Net Debt Service	451	458	473	499	580	644	717	775
- On-Balance Sheet DS as % of Total DS	64.9%	63.5%	63.3%	67.3%	67.9%	76.0%	81.1%	85.2%
- On-Balance Sheet Debt Outstanding as % of Total Debt	79.2%	81.6%	82.9%	85.6%	87.3%	88.6%	89.7%	89.6%
Off-Balance Sheet ($M)								
- Debt Issuance (Fixed Rate)	0	0	0	0	0	0	0	149
- Gross Debt Outstanding (Non-Current)	2,590	2,336	2,249	1,940	1,729	1,539	1,289	1,273
- Gross Debt Outstanding (Current)	306	348	228	303	346	326	336	267
- Gross Debt Outstanding	2,895	2,685	2,477	2,243	2,075	1,865	1,625	1,540
- less IPA Notes Outstanding	(809)	(740)	(651)	(635)	(584)	(453)	(292)	(136)
- Net Debt Outstanding	2,086	1,945	1,826	1,608	1,491	1,411	1,333	1,404
- Net Debt Outstanding (Fixed Rate)	1,810	1,721	1,662	1,456	1,352	1,286	1,240	1,336
- Net Debt Outstanding (Variable Rate)	277	224	164	152	139	125	93	68
- Net Debt Outstanding % (Fixed Rate)	87%	88%	91%	91%	91%	91%	93%	95%
- Net Debt Outstanding % (Variable Rate)	13%	12%	9%	9%	9%	9%	7%	5%
- Gross Debt Service	355	363	387	294	336	351	333	283
less IPA Notes	(111)	(100)	(112)	(52)	(62)	(148)	(167)	(149)
- Net Debt Service	244	263	275	243	274	203	167	135
- Off-Balance Sheet DS as % of Total DS	35.1%	36.5%	36.7%	32.7%	32.1%	24.0%	18.9%	14.8%
- Off-Balance Sheet Debt Outstanding as % of Total	20.8%	18.4%	17.1%	14.4%	12.7%	11.4%	10.3%	10.4%
On and Off-Balance Sheet ($M)								
- Total Debt Issuance	522	679	428	836	874	887	931	911
- Total Debt Service	695	720	748	742	854	847	883	909
- Total Debt Outstanding	10,051	10,544	10,682	11,152	11,724	12,331	12,956	13,536
- Total Debt Outstanding (Fixed Rate)	8,405	8,950	9,091	9,536	9,965	10,440	10,945	11,393
- Total Debt Outstanding (Variable Rate)	1,646	1,593	1,590	1,616	1,759	1,892	2,010	2,143
- Total Debt Outstanding % (Fixed Rate)	84%	85%	85%	86%	85%	85%	84%	84%
- Total Debt Outstanding % (Variable Rate)	16%	15%	15%	14%	15%	15%	16%	16%

Comparison of Current Case vs Reference Case

	[FY16] PS Case143 -- Final Rate Case							Reference: [FY16] PS Case19 -- Final 2016 Budget							Variance of Selected Case vs Case 19						
i-ECA Inc %	5.6%	-2.3%	0.1%	3.3%	0.8%	1.5%	1.4%	4.9%	-0.3%	0.7%	3.0%	1.9%	1.9%	1.2%	0.7%	-2.0%	-0.5%	0.3%	-1.1%	-0.3%	0.2%
i-Base Inc %	0.1%	1.2%	5.1%	2.2%	2.4%	2.8%	4.9%	0.0%	4.7%	1.6%	2.2%	2.3%	2.8%	3.6%	0.1%	-3.6%	3.5%	0.0%	0.1%	0.0%	1.3%
i-RCA Inc %	0.1%	-0.4%	2.0%	0.7%	-0.3%	0.2%	-0.9%	-0.1%	0.0%	1.2%	1.0%	0.0%	0.6%	0.0%	0.2%	-0.4%	0.7%	-0.3%	-0.4%	-0.3%	-1.0%
i-Increase Total %	5.8%	-1.5%	7.2%	6.2%	2.8%	4.6%	5.4%	4.8%	4.5%	3.5%	6.3%	4.3%	5.2%	4.8%	1.0%	-6.0%	3.7%	0.0%	-1.4%	-0.6%	0.6%
i-Base + i-RCA %	0.2%	0.8%	7.1%	2.9%	2.0%	3.0%	4.0%	-0.1%	4.8%	2.8%	3.3%	2.4%	3.3%	3.6%	0.3%	-4.0%	4.3%	-0.4%	-0.3%	-0.3%	0.4%
i-ECA Inc $M	181	-81	4	124	32	62	60	165	-10	24	114	76	77	52	16	-72	-20	10	-44	-16	8
i-Base Inc $M	5	40	177	81	93	113	208	1	168	58	84	92	115	157	3	-128	120	-3	1	-2	51
i-RCA Inc $M	3	-15	68	27	-14	9	-40	-5	0	45	39	2	24	2	8	-15	23	-12	-15	-15	-42
i-Revenue Inc ($M)	189	-55	250	232	111	184	229	161	159	127	237	170	216	211	27	-214	123	-5	-59	-32	18
i-Base + i-RCA ($M)	8	26	246	108	79	122	168	-4	169	103	123	94	139	159	11	-143	143	-15	-15	-16	10
					5 or 6-Yr Simple Avg -->	3.86%	4.11%					5 or 6-Yr Simple Avg -->	4.74%	4.75%					5 or 6-Yr Simple Avg -->	-0.88%	-0.63%
					5 or 6-Yr Compound Avg -->	4.12%	4.51%					5 or 6-Yr Compound Avg -->	5.20%	5.34%						-1.09%	-0.83%
	Actuals thru June (3-6)	<====== FORECAST ======>						Actuals thru Sep '14	<====== FORECAST ======>							<====== FORECAST ======>					
FISCAL YEAR ENDING JUNE 30	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
1. Retail Sales (GWh)	23,018	24,392	24,620	25,041	25,476	25,895	26,332	23,997	24,442	24,664	25,092	25,523	25,937	26,371	(979)	(50)	(44)	(51)	(47)	(42)	(39)
Adj. For DSM (GWh)	0	(413)	(811)	(1,269)	(1,743)	(2,191)	(2,505)	(117)	(413)	(811)	(1,269)	(1,743)	(2,191)	(2,505)	117	0	0	0	0	0	0
Adj. For Solar (GWh)	0	(115)	(208)	(273)	(291)	(304)	(305)	(76)	(166)	(253)	(323)	(338)	(346)	(345)	76	50	44	51	47	42	39
Adj. due to Others (GWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Retail Sales(GWh)	23,018	23,863	23,601	23,500	23,442	23,399	23,522	23,804	23,863	23,601	23,500	23,442	23,399	23,522	(786)	0	0	0	0	0	0
2. Operating Revenue:																					
Base Revenue	1,523	1,579	1,556	1,546	1,543	1,539	1,545	1,578	1,579	1,559	1,550	1,543	1,539	1,545	(55)	0	(3)	(3)	0	(0)	(0)
Energy Cost Adjustment	1,314	1,352	1,337	1,332	1,330	1,327	1,334	1,349	1,352	1,337	1,332	1,330	1,327	1,334	(35)	0	(0)	(0)	0	0	0
Energy Subsidy Adjustment	36	36	36	35	35	35	35	36	36	36	35	35	35	35	0	(0)	(0)	(0)	(0)	(0)	(0)
Reliability Costs Adjustment	76	70	69	69	69	69	69	70	70	69	69	69	69	69	6	(0)	(0)	(0)	(0)	(0)	(0)
i-Base Revenue	175	223	404	486	577	691	905	181	350	404	486	577	691	852	(6)	(127)	0	(0)	0	(0)	53
i-ECA Revenue	267	205	207	330	360	421	483	271	262	283	396	471	548	603	(4)	(57)	(76)	(67)	(111)	(127)	(119)
i-RCA Revenue	58	54	121	148	134	143	104	53	54	98	137	139	162	165	4	(0)	23	11	(4)	(19)	(61)
Total Retail Revenue ($M)	3,448	3,519	3,730	3,946	4,048	4,225	4,475	3,539	3,704	3,787	4,006	4,164	4,371	4,602	(91)	(185)	(56)	(59)	(116)	(146)	(127)
Wholesale Sales (Gen. & Trans.)	94	104	102	105	106	108	102	44	35	39	43	46	50	53	50	69	63	62	61	58	50
Deferred Revenue - Base Revenue	(41)	38	(80)	(78)	(18)	(3)	(1)	(49)	(28)	20	3	(1)	(0)	0	8	66	(99)	(81)	(17)	(3)	(1)
Deferred Revenue - Others	(136)	(15)	8	(12)	(31)	(10)	(7)	(93)	0	(42)	(18)	(33)	(11)	(15)	(44)	(15)	50	6	2	1	7
Others	(27)	(13)	(15)	(17)	(18)	(20)	(23)	(31)	(15)	(16)	(18)	(20)	(22)	(24)	4	2	1	1	1	1	1
Total Operating Revenue ($M)	3,337	3,633	3,745	3,944	4,087	4,300	4,547	3,410	3,696	3,787	4,016	4,156	4,388	4,616	(73)	(63)	(42)	(71)	(69)	(88)	(69)
3. Non-Operating Revenue	100	91	94	88	100	88	78	92	84	125	123	118	109	103	8	7	(30)	(35)	(18)	(21)	(24)
4. Total Revenue	3,437	3,724	3,840	4,032	4,187	4,387	4,625	3,502	3,780	3,912	4,138	4,274	4,496	4,719	(65)	(57)	(72)	(106)	(87)	(109)	(94)
5. Fuel, Purchased Power & Emissions Expense	1,400	1,511	1,493	1,568	1,607	1,652	1,683	1,483	1,569	1,530	1,618	1,632	1,681	1,722	(83)	(58)	(36)	(50)	(26)	(29)	(39)
6. O&M Expenditures	1,026	1,039	1,030	1,051	1,082	1,127	1,145	957	1,010	1,019	1,043	1,074	1,120	1,137	69	29	11	8	8	7	8
7. Depreciation	496	596	646	679	711	771	830	545	585	636	680	722	799	862	(49)	11	9	(1)	(11)	(27)	(32)
8. Property Tax	15	17	19	19	19	19	19	16	17	19	19	19	19	19	(0)	0	0	0	0	0	0
9a. Interest Expense	299	308	347	392	440	484	517	257	311	378	433	475	512	543	42	(3)	(31)	(41)	(35)	(28)	(26)
9b. AFUDC	(39)	(38)	(18)	(12)	(24)	(29)	(5)	(53)	(39)	(20)	(12)	(24)	(29)	(5)	14	1	2	0	0	0	0
9c. CIAC	(67)	(53)	(53)	(53)	(53)	(53)	(53)	(20)	(20)	(20)	(20)	(21)	(12)	(12)	(47)	(33)	(33)	(33)	(32)	(41)	(41)
10. Total Expense	3,130	3,380	3,464	3,644	3,782	3,972	4,137	3,185	3,433	3,541	3,760	3,878	4,089	4,266	(55)	(53)	(77)	(117)	(95)	(117)	(129)
11a. Net Income Before City Transfer	307	344	375	388	405	416	488	317	348	371	378	396	408	453	(10)	(4)	5	10	8	8	36
11b. City Transfer	265.6	267	291	300	316	327	344	265.6	273	296	303	321	333	351	0	(6)	(5)	(3)	(6)	(6)	(7)
11c. Increase in Fund Net Assets	42	77	85	89	89	89	145	52	75	75	75	75	75	102	(10)	2	10	14	14	14	43
12. Capital Expenditures	1,260	1,486	1,465	1,540	1,593	1,653	1,605	1,431	1,598	1,594	1,538	1,593	1,659	1,474	(171)	(112)	(129)	2	(1)	(5)	132
13a. Borrowing for CapEx	796	428	836	874	887	931	762	556	927	1,021	981	883	907	645	239	(498)	(184)	(107)	4	24	116
13b. Cash on Hand	1,107	695	677	723	756	797	820	700	704	690	743	764	807	834	406	(9)	(13)	(20)	(8)	(10)	(14)
13c. Total Debt Service	458	473	499	580	644	717	775	412	464	517	596	674	736	788	46	9	(18)	(15)	(30)	(19)	(13)
13d. Total Non-Debt Service Expenditures	3,618	3,984	3,939	4,109	4,232	4,383	4,384	3,851	4,158	4,125	4,182	4,282	4,450	4,323	(233)	(174)	(187)	(73)	(50)	(67)	61
14. Financial Ratios (Accrual Basis):																					
a. Debt Service Coverage	2.23	2.50	2.69	2.45	2.34	2.26	2.33	2.62	2.67	2.66	2.50	2.35	2.32	2.38	(0.40)	(0.18)	0.04	(0.05)	(0.01)	(0.07)	(0.05)
b. Adj. Debt Service Coverage	1.64	1.93	2.11	1.93	1.85	1.80	1.89	1.98	2.08	2.09	1.99	1.87	1.87	1.94	(0.34)	(0.15)	0.02	(0.06)	(0.02)	(0.07)	(0.05)
c. Full Obligation Coverage	1.51	1.71	1.77	1.69	1.80	1.83	1.93	1.70	1.80	1.73	1.73	1.79	1.85	1.92	(0.19)	(0.09)	0.03	(0.04)	0.01	(0.02)	0.01
d. Capitalization Factor	61.4%	61.8%	63.1%	64.3%	65.4%	66.4%	66.8%	60.7%	62.5%	64.3%	65.7%	66.7%	67.7%	68.0%	0.7%	-0.7%	-1.1%	-1.4%	-1.3%	-1.3%	-1.2%
e. Days of Operating Cash (w/o Debt Svc)	242	171	170	170	170	170	170	180	170	170	170	170	170	170	62	1	(0)	0	0	0	0
15. Average Rate (cts/kWh)																					
System Average	15.0	14.75	15.81	16.79	17.27	18.1	19.0	14.9	15.52	16.04	17.05	17.76	18.7	19.6	0.1	(0.77)	(0.24)	(0.25)	(0.49)	(0.6)	(0.5)
Avg. Rate Increase (%)	5.8%	-1.6%	7.2%	6.2%	2.8%	4.6%	5.4%	5.0%	4.4%	3.4%	6.2%	4.2%	5.2%	4.7%	0.8%	-6.0%	3.8%	0.0%	-1.4%	-0.6%	0.6%
16a. ECA (Under) Over Collection	(81)	(72)	(85)	(91)	(76)	(76)	(81)	(122)	(134)	(92)	(95)	(77)	(76)	(75)	41	62	7	4	1	(0)	(6)
16b. Legacy RCA (Under) Over Collection	(89)	(77)	(64)	(51)	(38)	(26)	(13)	(89)	(78)	(66)	(54)	(42)	(30)	(18)	0	1	2	3	3	4	5
16c. i-RCA (Under) Over Collection	0	0	(7)	(2)	1	(1)	(2)	0	(0)	(11)	(3)	0	(2)	(0)	0	0	4	1	1	1	(2)
16d. Total RCA (Under) Over Collection	(89)	(77)	(71)	(53)	(37)	(27)	(15)	(89)	(78)	(77)	(56)	(42)	(32)	(18)	0	1	6	3	4	5	3
17a. PSRP Capital Adds/(Cuts)	0	(107)	(125)	5	0	0	0	0	0	0	0	0	0	0	0	(107)	(125)	5	0	0	0
17b. PSRP O&M Adds/(Cuts)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17c. Non-PSRP Capital Adds/(Cuts)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17d. Non-PSRP O&M Adds/(Cuts)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17e. Total Capital Adds/(Cuts)	0	(107)	(125)	5	0	0	0	0	0	0	0	0	0	0	0	(107)	(125)	5	0	0	0
17f. Total O&M Adds/(Cuts)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 %CapEx Borrowed	63%	29%	57%	57%	56%	56%	47%	39%	58%	64%	64%	55%	55%	44%	24%	-29%	-7%	-7%	0%	2%	4%
20a. Rate Stabilization Fund Drawdown / (Injection)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20b. Rate Stabilization Fund Balance	174	174	174	174	174	174	174	174	174	174	174	174	174	174	0	0	0	0	0	0	0
21a. City Transfer from legacy Revenue	*227*	*252*	*241*	*238*	*241*	*244*	*244*	*238*	*234*	*243*	*240*	*239*	*238*	*239*	*(12)*	*18*	*(1)*	*(2)*	*2*	*6*	*6*
21b. City Transfer from i-Revenue	*40*	*39*	*59*	*77*	*86*	*100*	*119*	*27*	*39*	*53*	*63*	*82*	*95*	*113*	*13*	*(0)*	*5*	*14*	*4*	*6*	*7*
21c. 21b. as a % of Total City Transfer	*15%*	*13%*	*20%*	*24%*	*26%*	*29%*	*33%*	*10%*	*14%*	*18%*	*21%*	*25%*	*29%*	*32%*	*5%*	*-1%*	*2%*	*4%*	*1%*	*1%*	*1%*