LOS ANGELES DEPARTMENT OF WATER AND POWER

POWER SYSTEM RATE ACTION REPORT

Chapter 3: Rate Drivers

July 2015

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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]

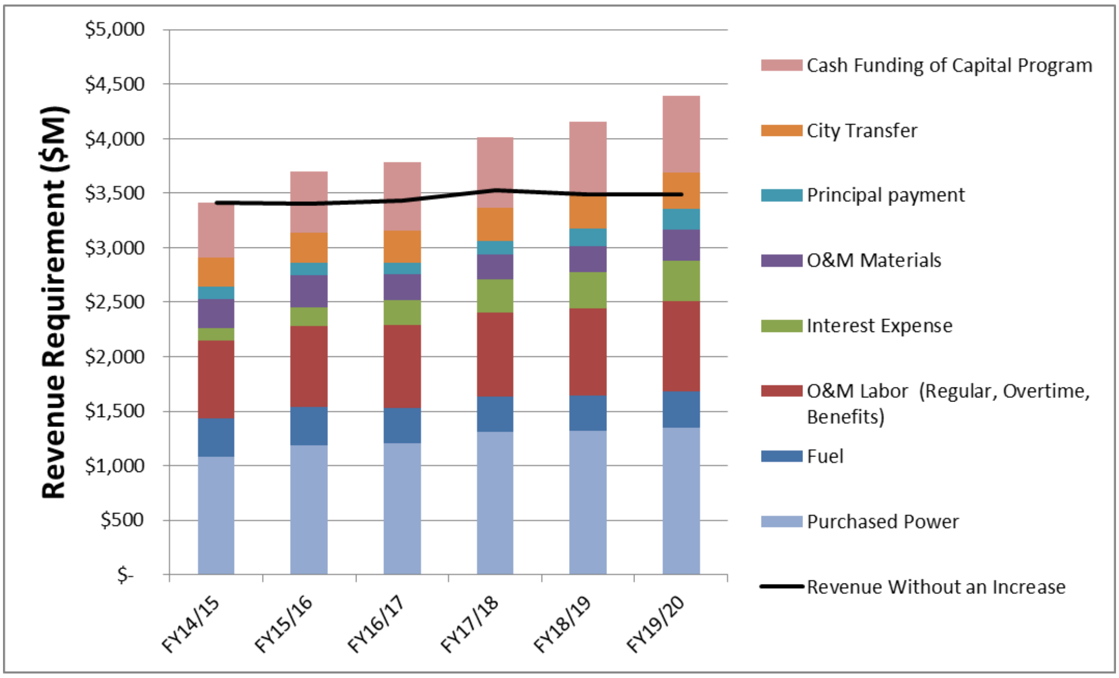


Figure 1 shows a revenue requirement gap of approximately $900 million for FY 2019-20. To meet the Power System's revenue requirement, revenues will have to increase by an average of $180 million per year for the period of FY 2015-16 through FY 2019-20, as reflected in graphically in Figure 1 and numerically 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.

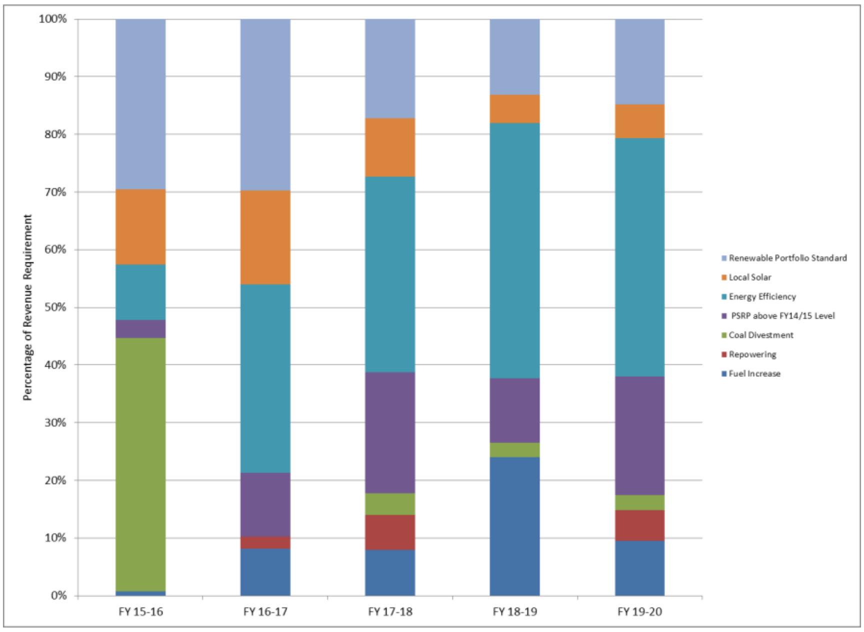
[1] All budget and revenue requirement information is based on Financial Plan Case Number 19 including depreciation, net interest expense, and retained earnings. The full plan can be found in Chapter 3 – Appendix A.

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



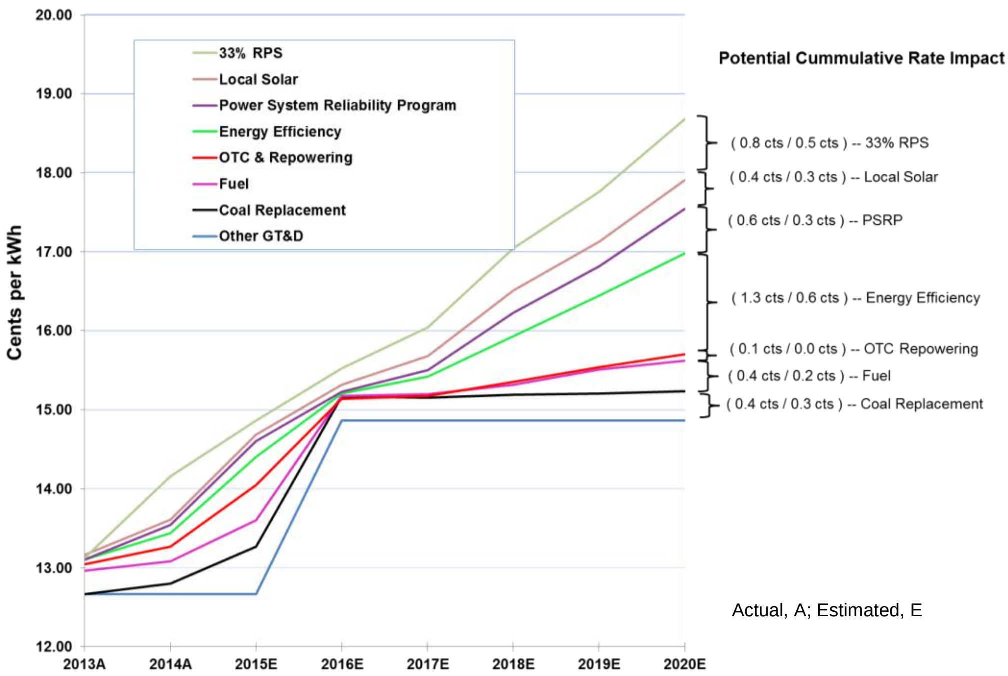
The rate driver contributions in this report are presented in year over year (YOY) format to show the changing impact on the Department's revenue requirement. Throughout this report, we will continue to present YOY numbers. However, in order to understand the potential impact of compounding on the rate 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 average annual 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

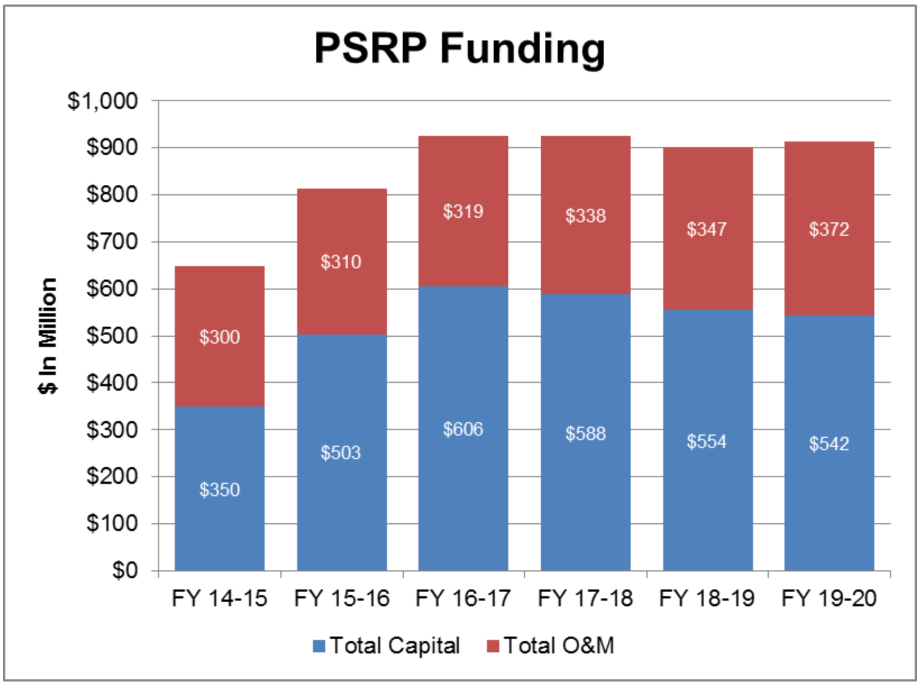
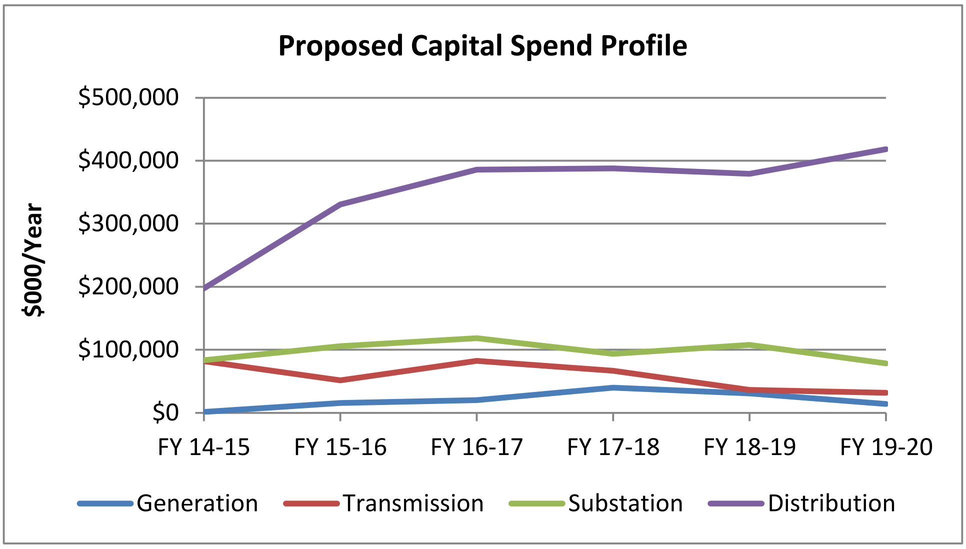


Figure 7 shows a consolidated view of the proposed changes to the individual PSRP programs over the five-year rate period.

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.

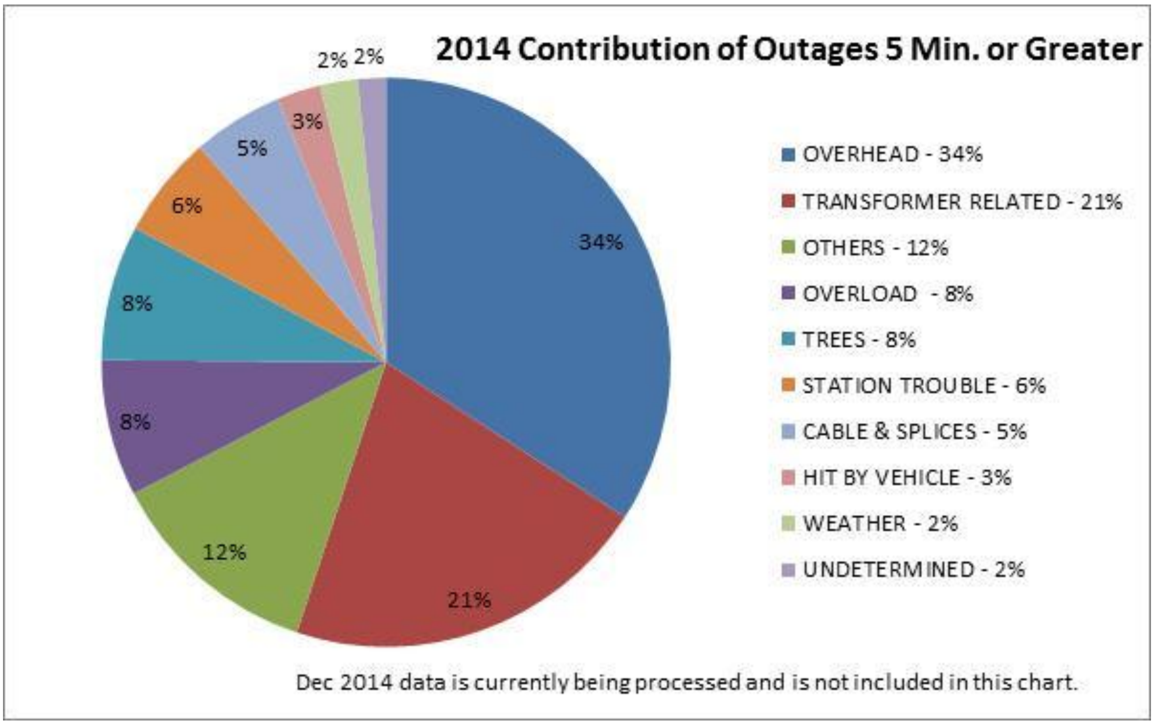
3.2.5.1 Reliability Performance Indicators

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

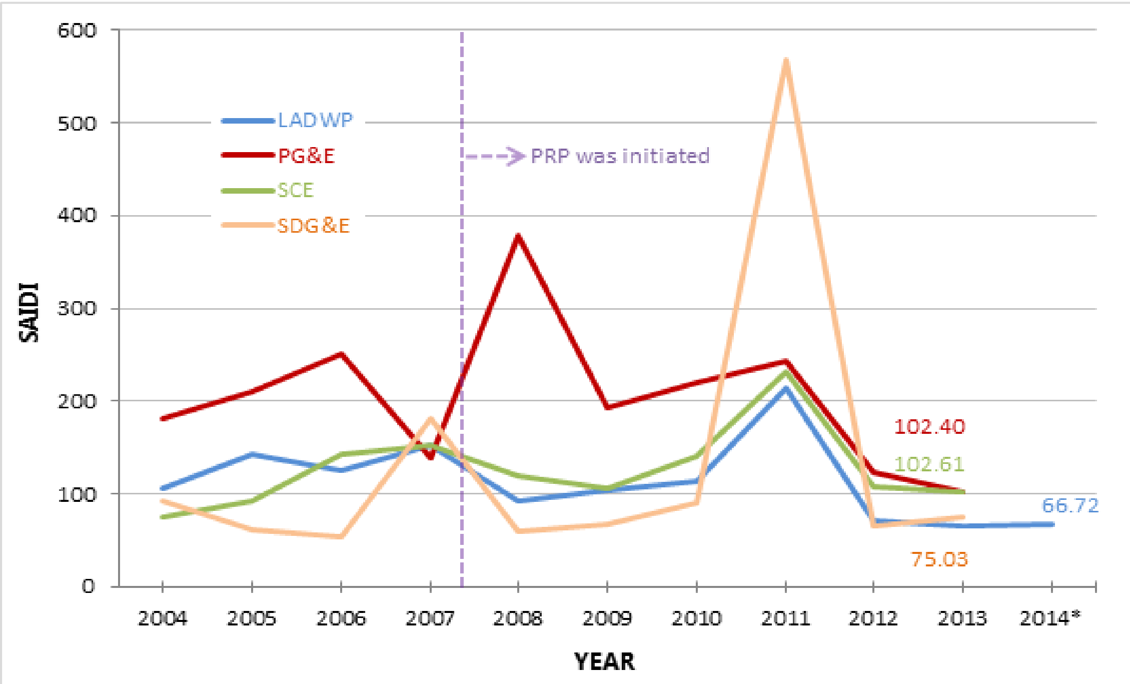


Figure 18: SAIFI Comparison with California IOUs

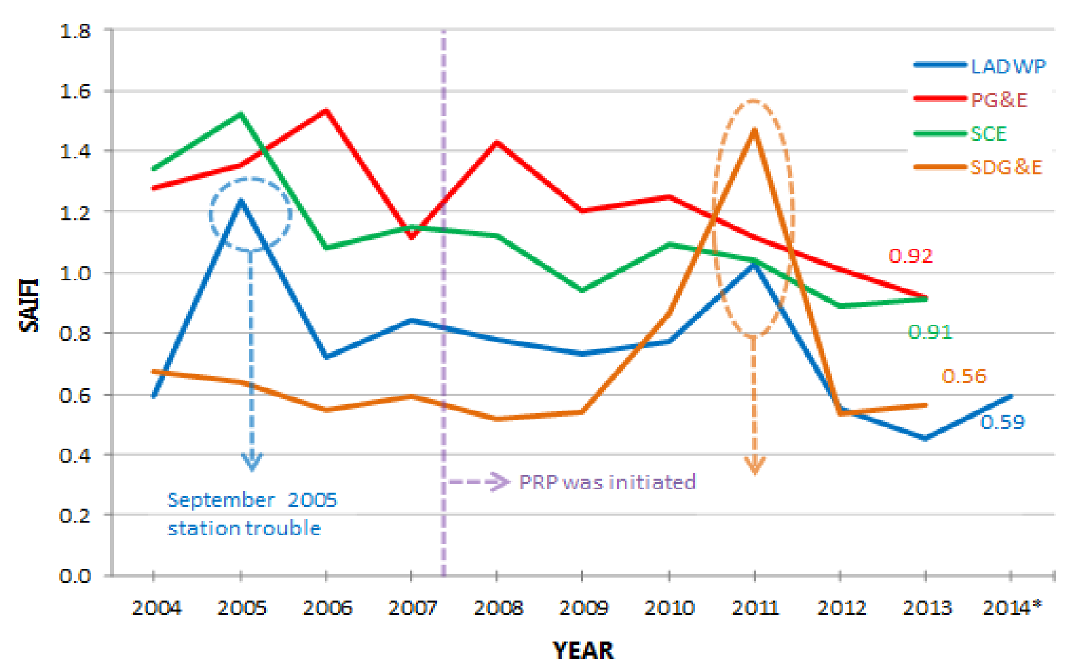
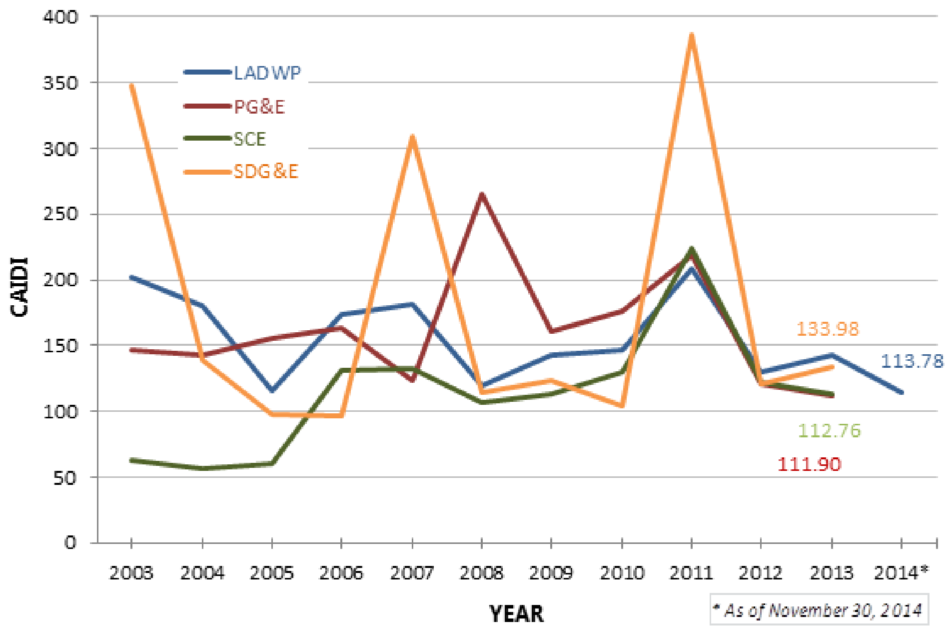


Figure 19: CAIDI Comparison with California IOUs



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

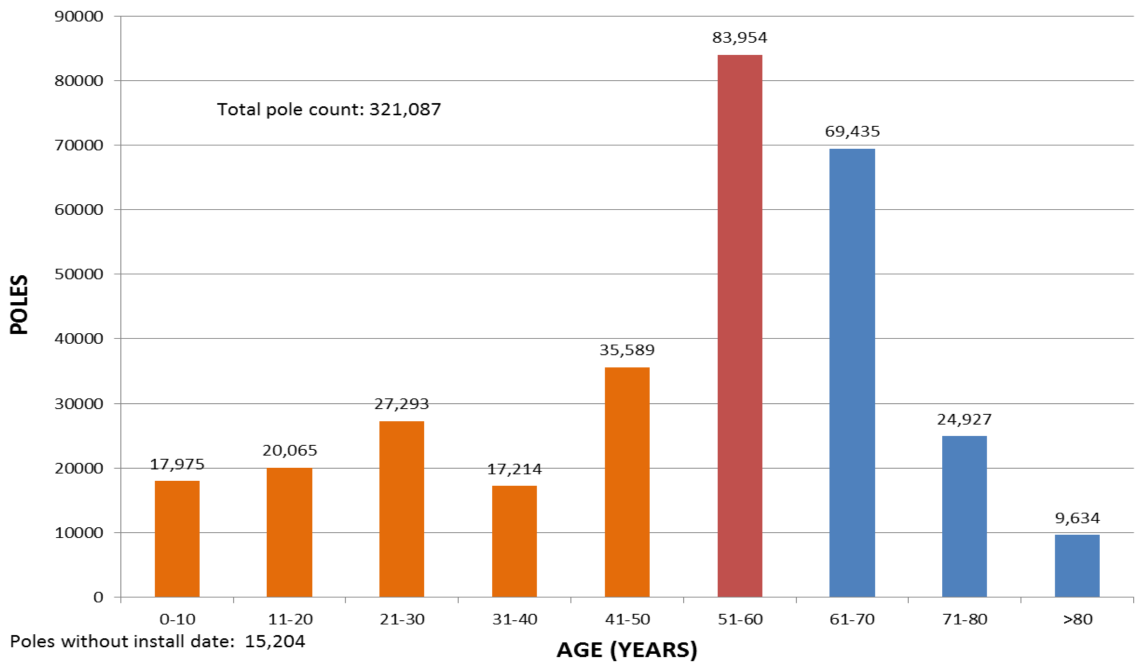
3.2.5.3 Pole Replacement

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

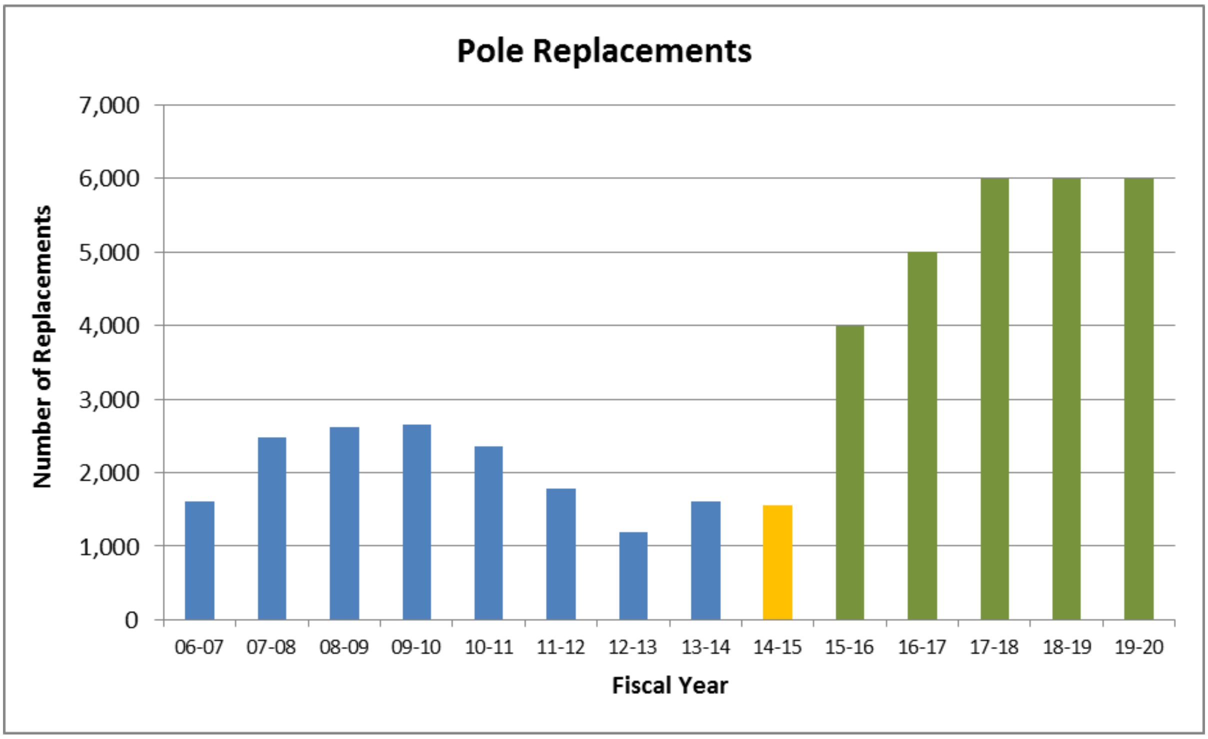
Additional investment in pole replacement is warranted to reduce the age of poles and maintain and improve infrastructure reliability. Figure 22 provides an aging summary for LADWP's poles.

Figure 22: Current Pole Age Distribution



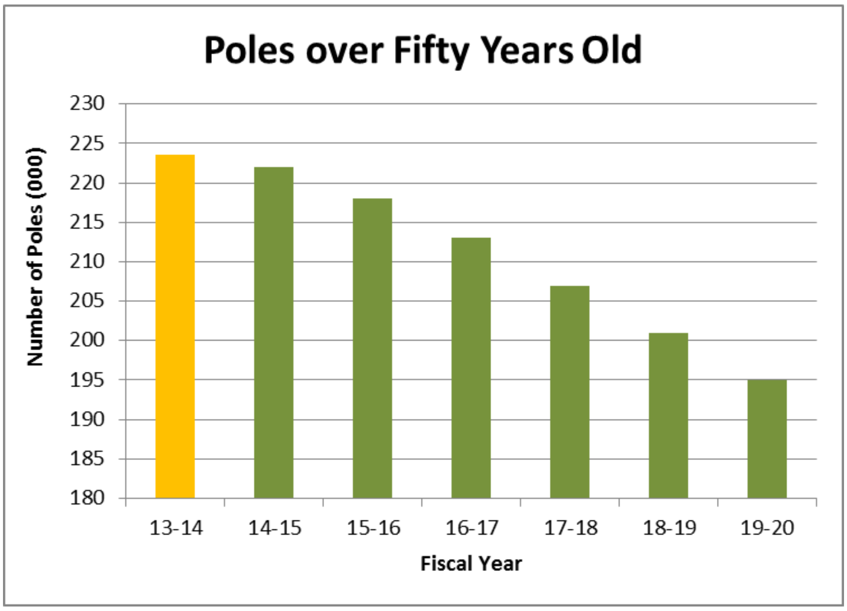
LADWP's financial plan and proposed rates are designed to increase annual pole replacements to 6,000 by FY 2017-18 as shown in Figure 23.

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.

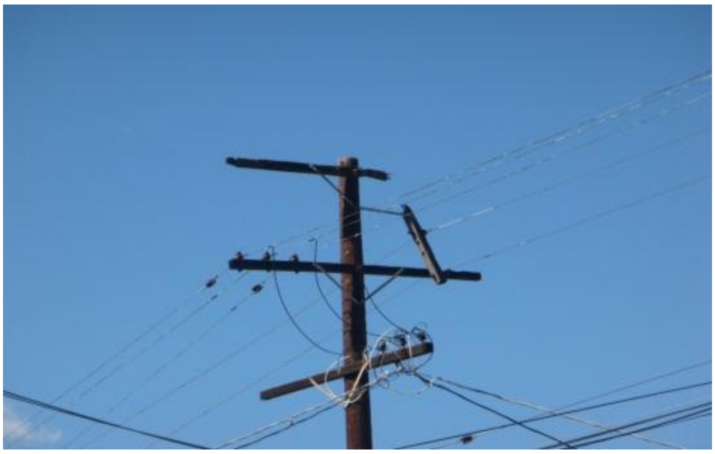
Figure 24: Number of Poles Over 50 Years Old During Proposed Five-Year Rate Period



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



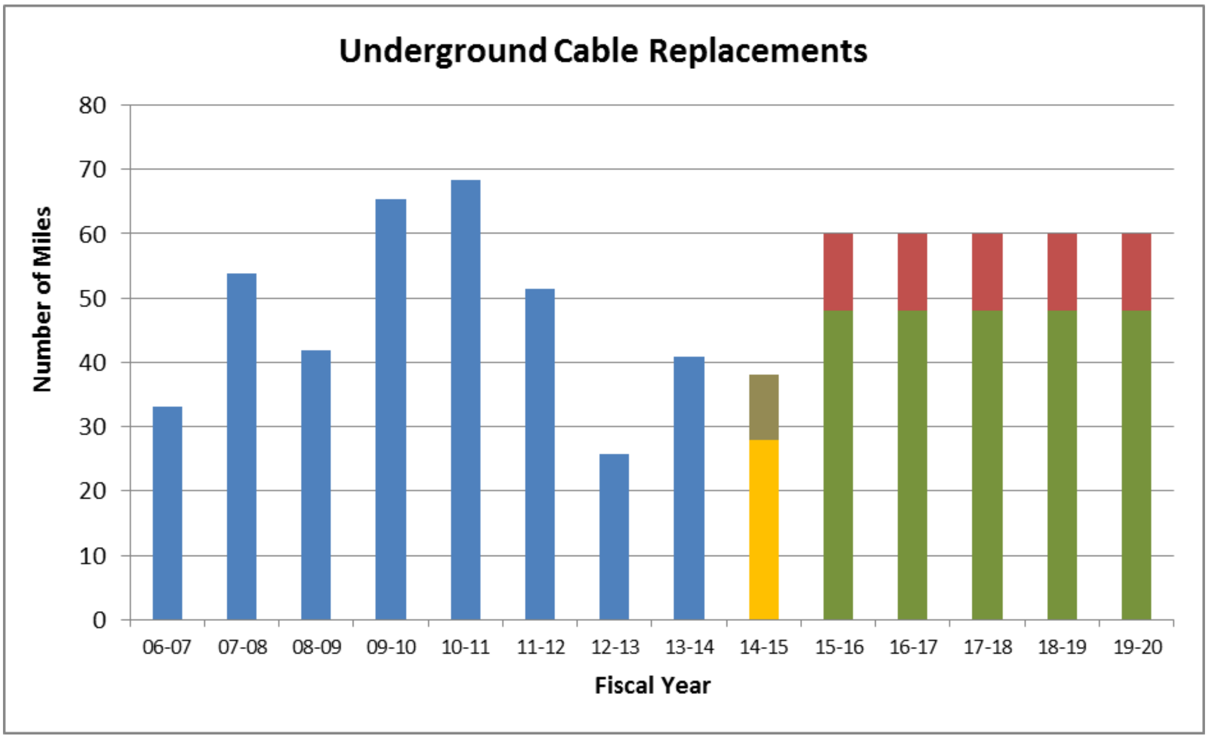
3.2.5.5 Underground Cable (UG) Replacement

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.

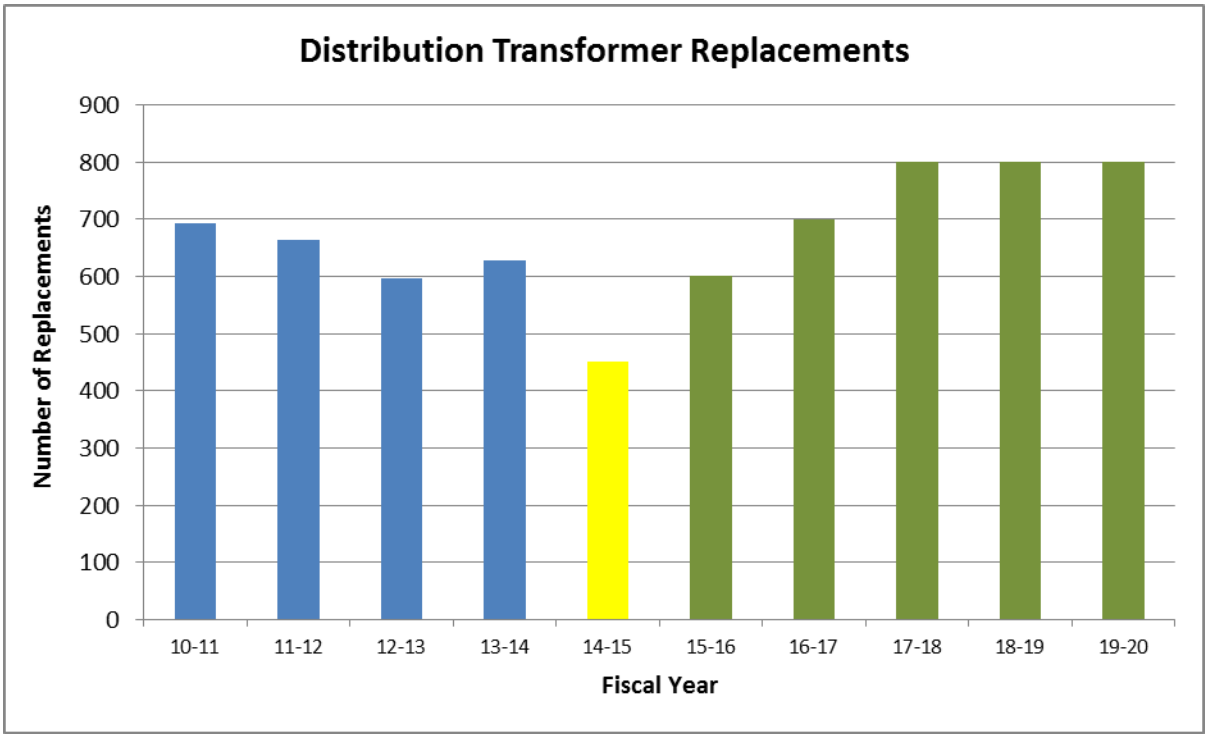
Figure 28 provides an example of an overhead pole mounted distribution transformer.

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

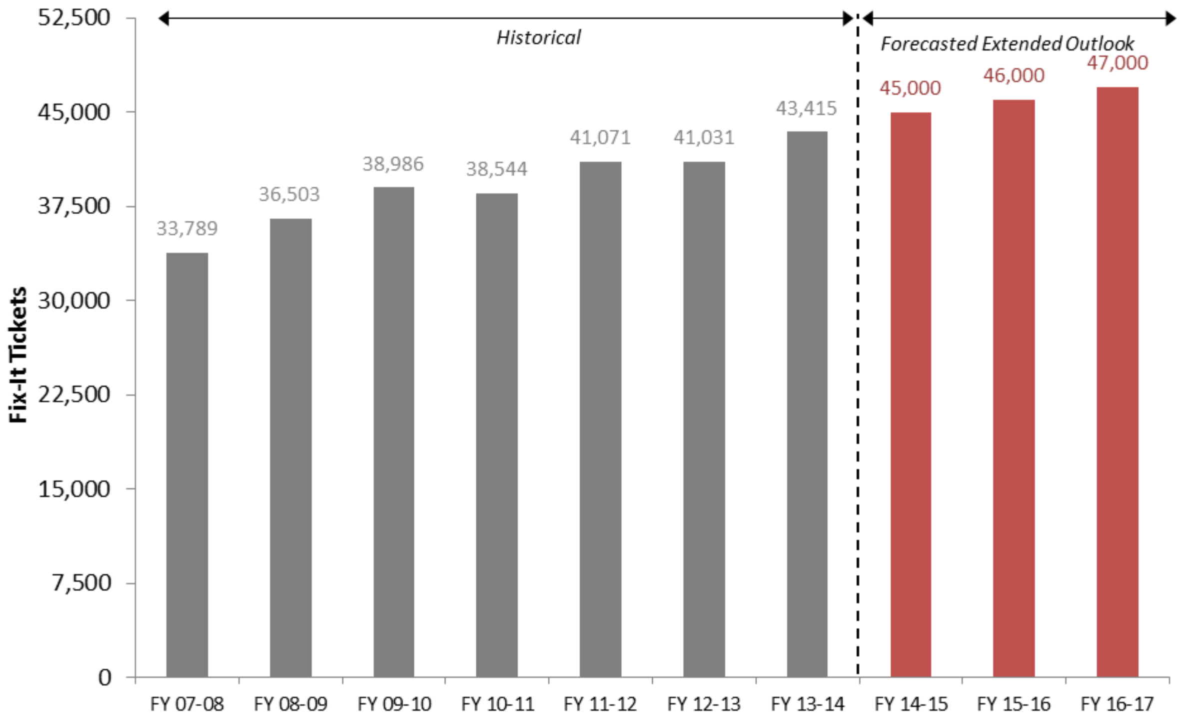


3.2.5.7 Work Backlog

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.

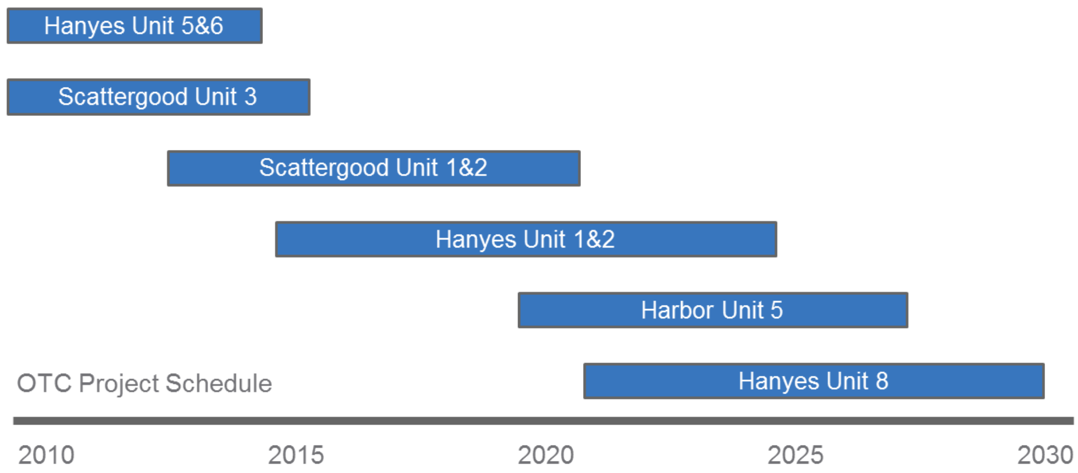
Once-Through Cooling (OTC) is the process where water is drawn from the ocean, is pumped through a generating station's cooling system, and then is discharged back to the receiving water source. OTC is a major regulatory issue, stemming from the Federal Clean Water Act Section 316(b) administered nationally 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

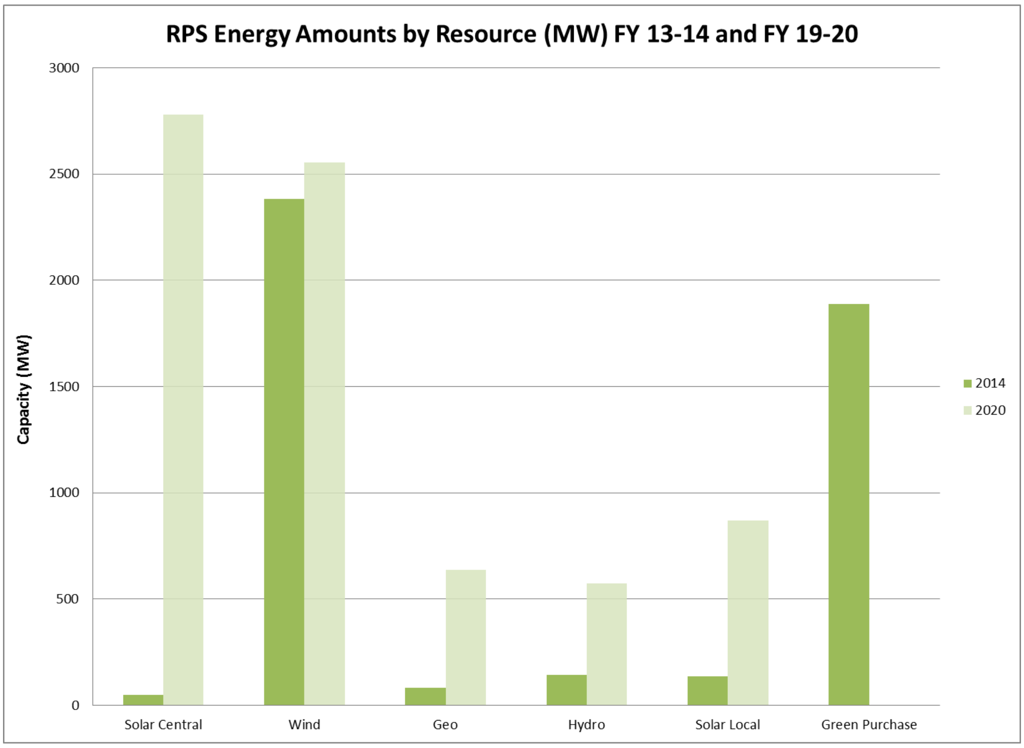
Renewable energy resources are a sustainable way of generating electricity and helping preserve the environment while providing economic and public health benefits. Shifting a greater amount of energy production to eligible renewable energy resources is mandated in California by Senate Bill X1-2. To 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*

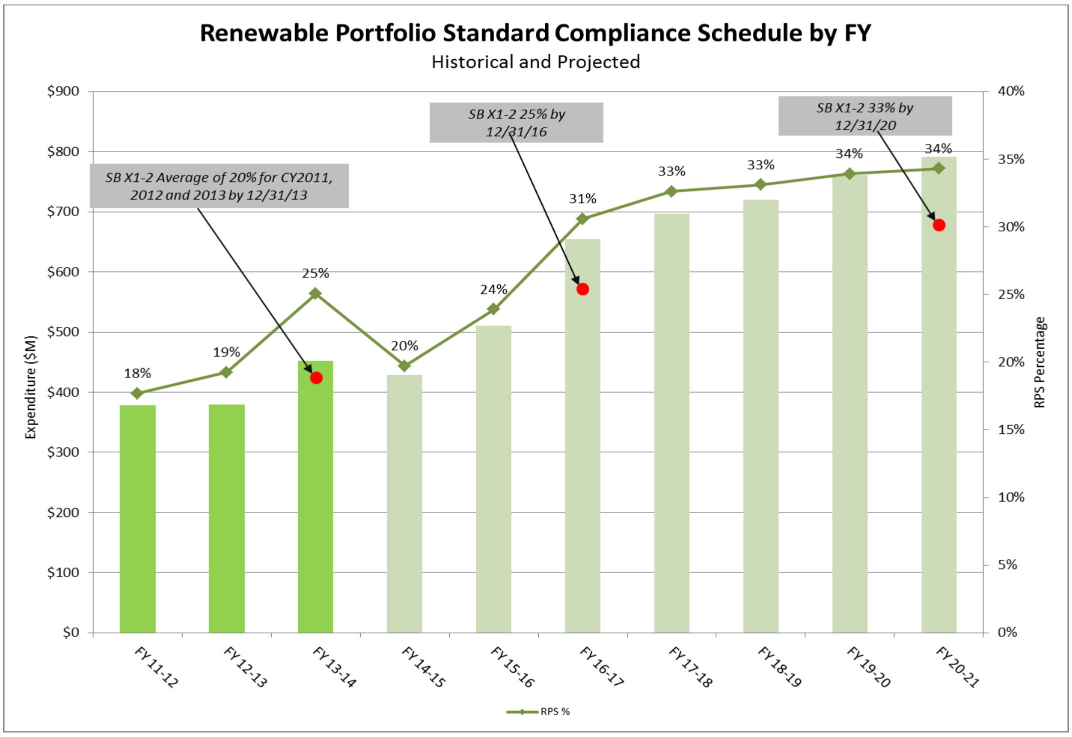
[15] See http://www.latimes.com/local/political/la-me-pc-brown-speech-text-20150105-story.html#page=2

	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.

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[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

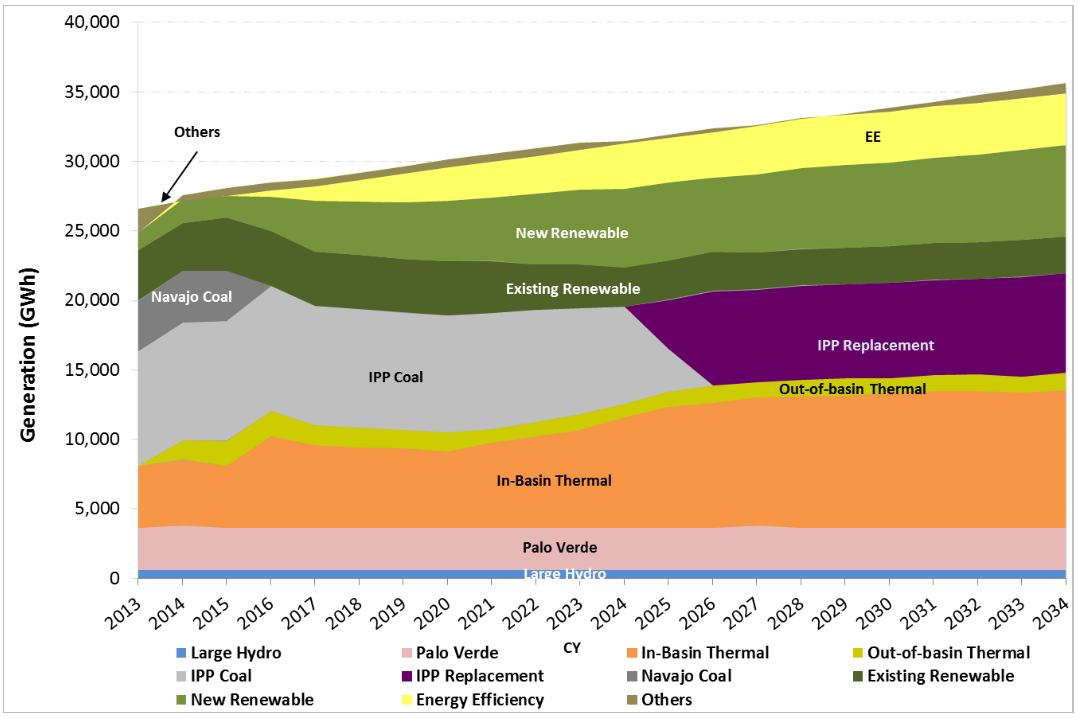
However, this transition poses many challenges and necessitates careful resource planning to maintain a reliable flow of power to Los Angeles. The Department plans to complete this monumental shift out of coal in the most sustainable and cost effective manner through:

- 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*

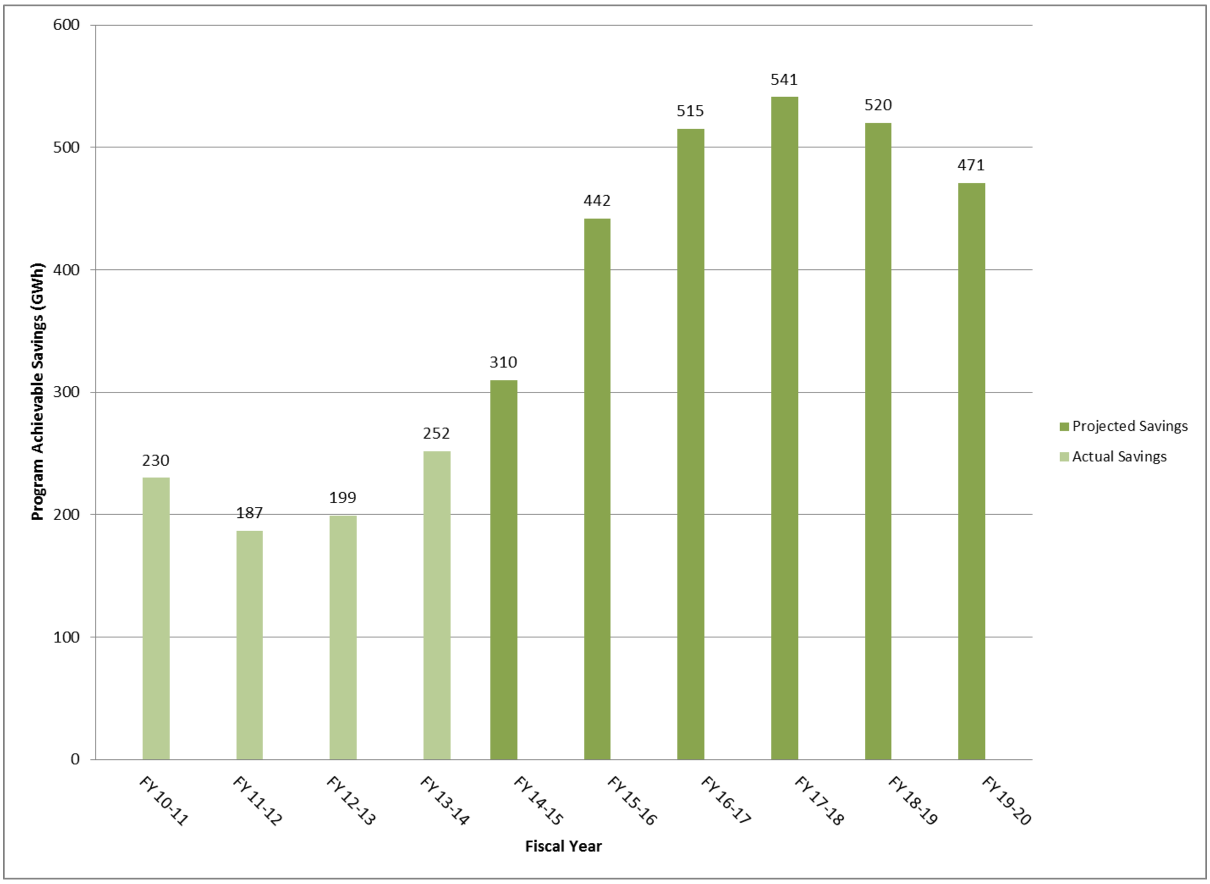
Over the five-year proposed rate period, these energy efficiency projects will increase the revenue requirement by an average $60 million per year and the system average rate by 0.26 cents per kWh (1.54%) as shown in Figure 49.

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-

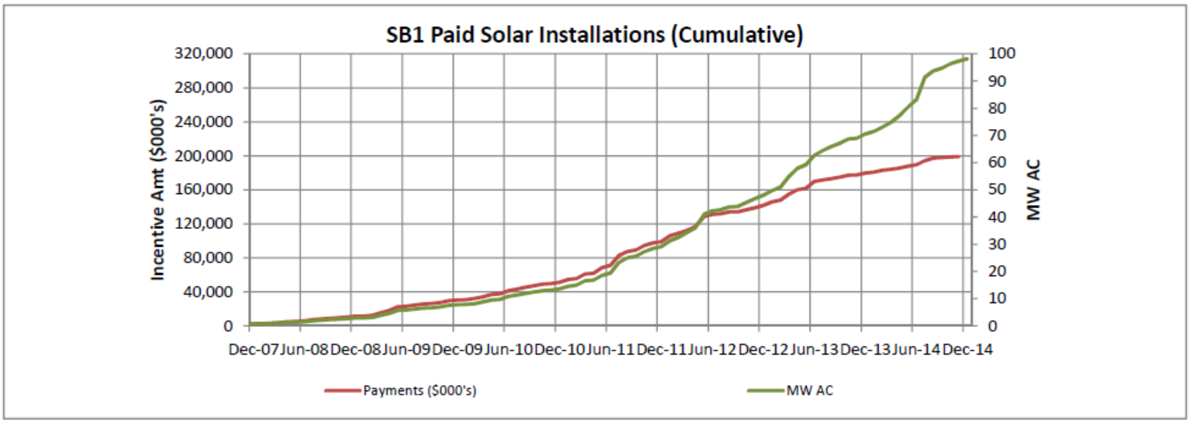
[27] Currently the SIP program is scheduled to close at the end of December 2016. However, to meet its incentive payment obligations the Department has budgeted to make residual payments to customers through the proposed five-year rate period.

[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.

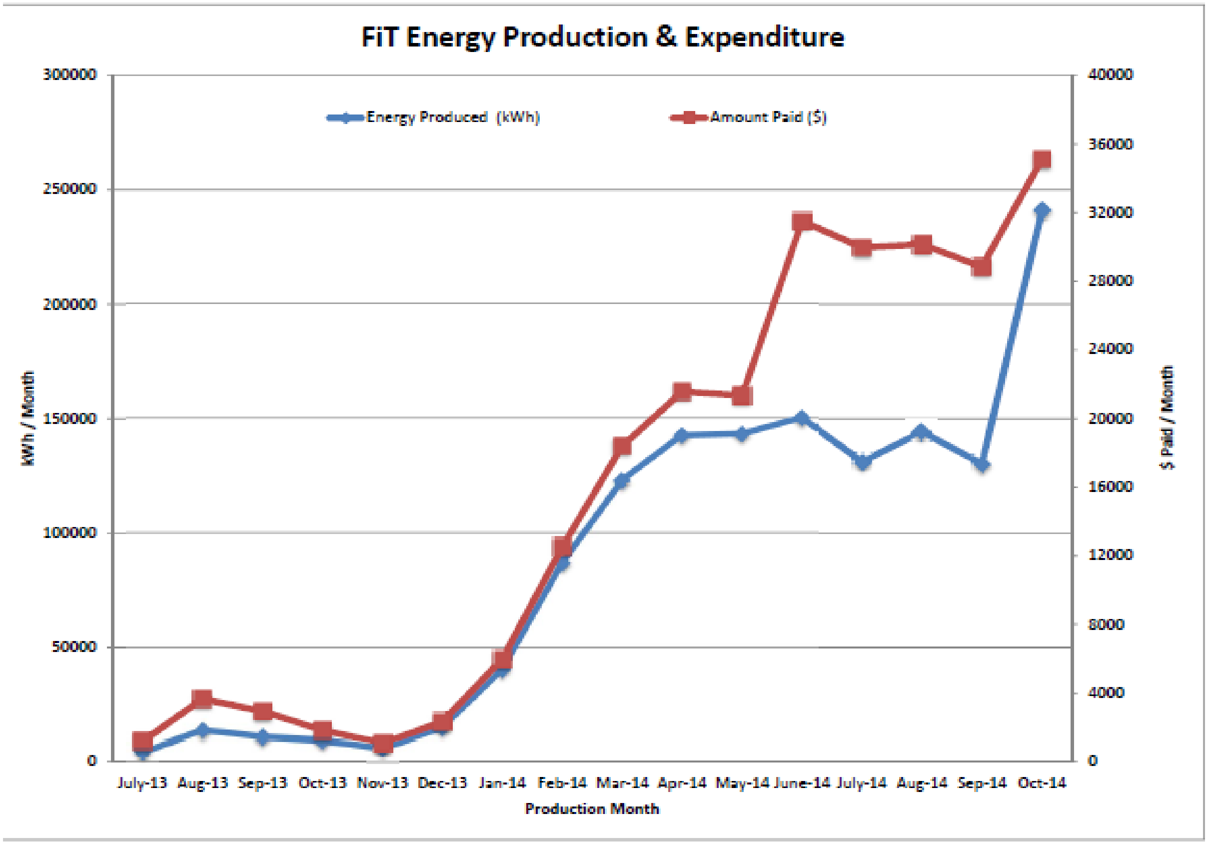
Figure 54: FiT100 Program Allocations

	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.

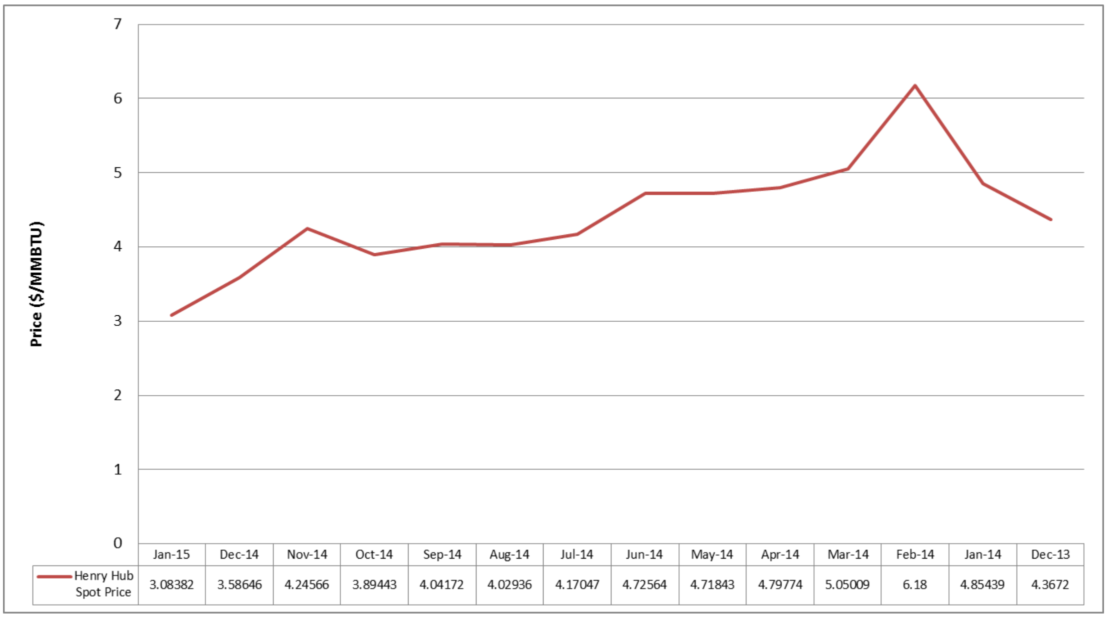
Through a US Department of Energy (DOE) grant in 2009, the Department is also leading a group of local research institutions in a regional demonstration program. The program includes pilot projects in four interrelated areas – Demand Response, Consumer Behavior, Cyber Security and Electric Vehicle Integration.

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.

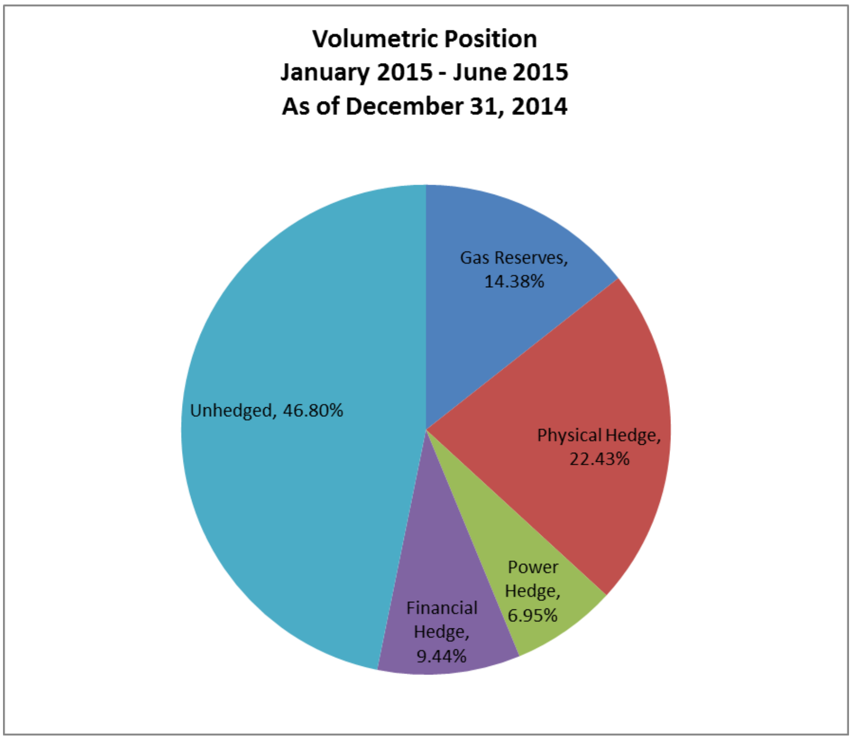
- Power Purchase Hedges.

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.