LOS ANGELES DEPARTMENT OF WATER AND POWER

2014 Power Service Cost of Service Study

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CONTENTS

FIGURES AND TABLES

FIGURES

1 EXECUTIVE SUMMARY

1.1 Introduction

In October 2012, the Los Angeles City Council approved LADWP's Incremental Electric Rate Ordinance No. 182273 to provide incremental rate adjustments for fiscal years (FYs) 2012-13 and 2013-14. In its action to approve LADWP's power rates, the Council requested that LADWP "conduct a new formal cost of service study in order to prepare for future power rate restructuring".

To meet the Council request and in preparation for its proposed rate action, LADWP has conducted a cost of service study (COSS) using marginal cost principles to evaluate cost structures and ensure that rates are appropriate for each customer class. Cost of service analysis (COSA) constitutes standard utility industry practice for setting power rates. Most utilities, whether Investor Owned Utilities (IOUs) or publicly owned utilities (POUs), conduct cost of service studies when undertaking a rate action. The marginal cost study approach facilitates attaining the following objectives:

- Ensures that rates for each major class of customers recover the costs associated with providing service to that class of customers;
- Encourages efficient system expansion and use of utility facilities and discourages wasteful use;
- Provides efficient price and resource allocation signals; and
- Provides legally defensible foundation for cost based rates.

1.2 Cost of Service Study Approach

Marginal cost of service analysis is the adopted LADWP cost of service study approach. Marginal costs measure the additional costs of providing the next unit of service in the future. The marginal cost method is forward-looking. Cost of new power generation is an example of a marginal cost.

For over twenty years, the California Public Utilities Commission (CPUC) has relied on marginal cost principles for assigning revenue requirements to customer classes, and to guide rate setting for electric utilities.[1] Also, the National Association of Regulatory Utility Commissioners (NARUC) and American Public Power Association (APPA) recognize the use of marginal costs as a valid cost of service methodology.[2] Therefore, the current LADWP cost of service study follows an established framework that is widely utilized across the country.

The ultimate goal of a cost of service study for rate making purposes is to develop the cost of service revenue requirement percentages (as a percent of total utility revenue requirement) for each customer class. The marginal cost of service analysis determines the marginal cost revenue requirements by

[1] In particular, the CPUC has developed 10 Optimal Rate Design Principles, one of which is that "Rates should be based on marginal costs" (OIR at 20-21).

[2] Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, January 1992; Retail Rate Design for public Owned Systems, American Public Power Association, 1992

customer class (i.e., the revenues that LADWP would collect if all customers were charged rates that equal marginal costs).

Marginal cost revenue requirement percentages by customer class are then compared to current revenue percentages (as a percent of total utility revenue) by customer class. Relevant rates would be adjusted to collect customer class revenues appropriate for each class.

A cost of service study is based on a test year; for this study, fiscal year (FY) 2012-13, the most recent year with reliable data at the time of the study, was selected.

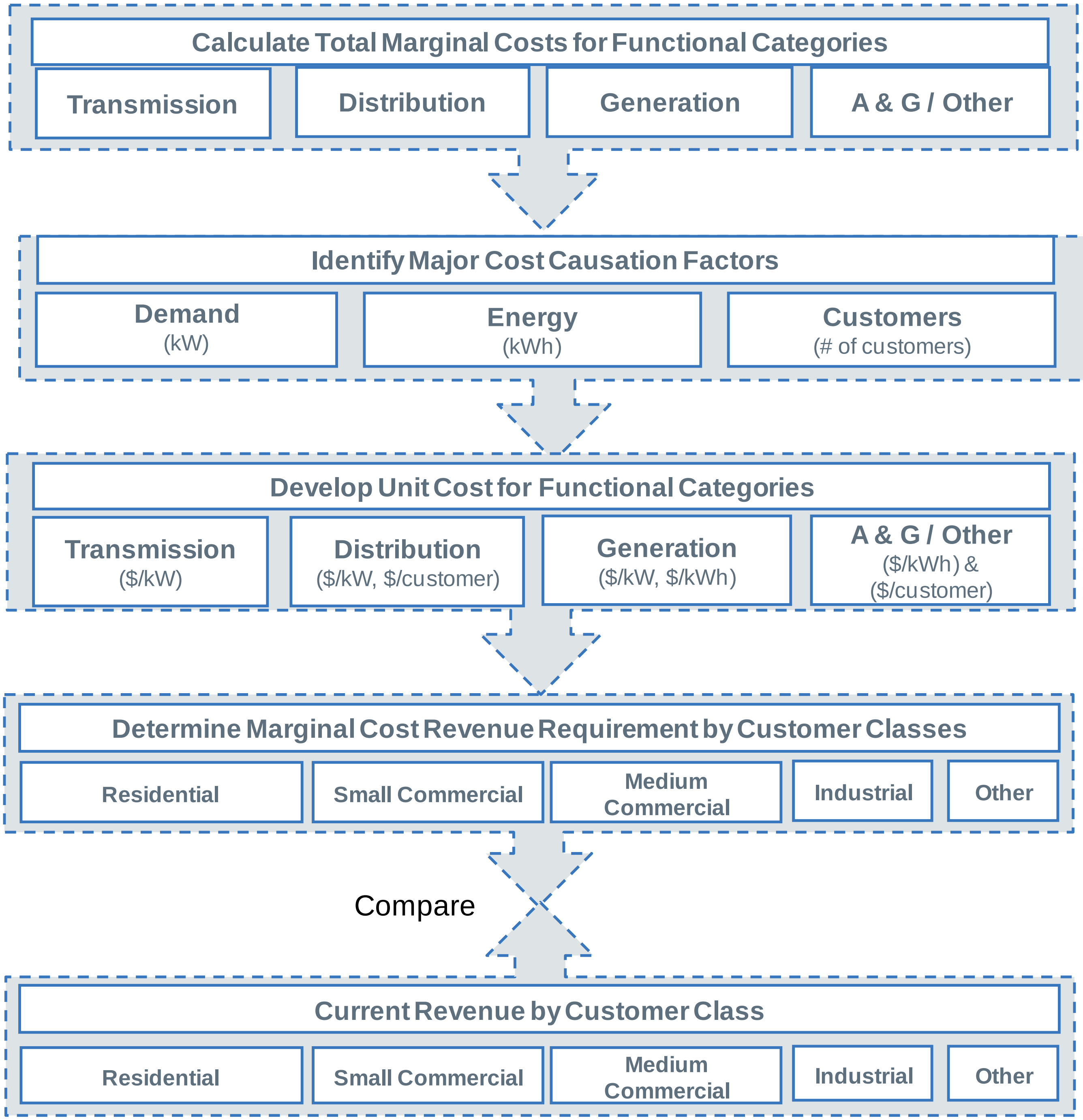
1.3 Marginal Cost of Service Study Methodology

A marginal cost of service study comprises three general steps:

- Functionalization of service costs;
- Development of unit marginal costs/cost drivers for cost causation factors; and
- Determination of marginal cost revenue requirements by customer class.

Each of these steps is explained in more detail in the sections below. Figure 1 summarizes these steps.

Figure 1: Summary of Marginal Cost of Service Study Methodology



1.3.1 Functionalization

The first major step in the marginal cost study is the identification of the various functions performed by LADWP in the provision of electricity services. The goal of the functionalization step is to group costs that have distinct and significant cost drivers. For LADWP, these functional components are:

- **Generation:** the process of generating power from a resource;

- **Transmission:** the bulk transfer of energy from generating stations to electric distribution sub-stations near demand centers;
- **Distribution:** the delivery of electricity received at sub-stations to end-use customers. This power typically goes through three voltage levels, such as 34.5 kV, 4.8 kV and secondary. Distribution also includes reading and maintaining customer meters; and
- **Other Administrative & General (A&G) Functions:** executive management, general supervision, customer service, customer billing, employee administration, etc.

Once the functions have been defined, forward-looking marginal cost revenue requirements for each functional component and their appropriate sub-components are developed. Sub-components are groupings that have distinct cost causation differences, such as voltage level sub-components for the distribution functional area.

1.3.2 Development of Unit Marginal Costs/Cost Drivers

The next major step of the marginal cost study is the identification of the appropriate cost causation factor for each functional and sub-functional cost component. The generally accepted and established industry practices for identifying the appropriate cost causation factors are described below.

- **Demand Related Costs:** These are costs incurred as a result of maximum (peak) power requirements and are utilized to determine marginal cost revenue requirements for the customer classes on the basis of demands in kilowatt (kW) imposed on the system.
- **Energy Related Costs:** Some costs, such as fuel, emissions, impact of renewables, and certain operation and maintenance expenses, are directly related to the quantity of energy in kilowatt hours (kWh) produced.
- **Customer Related Costs:** These costs reflect the marginal costs of customer interconnection to the delivery system and various customer services. These costs are derived for the customer classes on the basis of the number of customers.

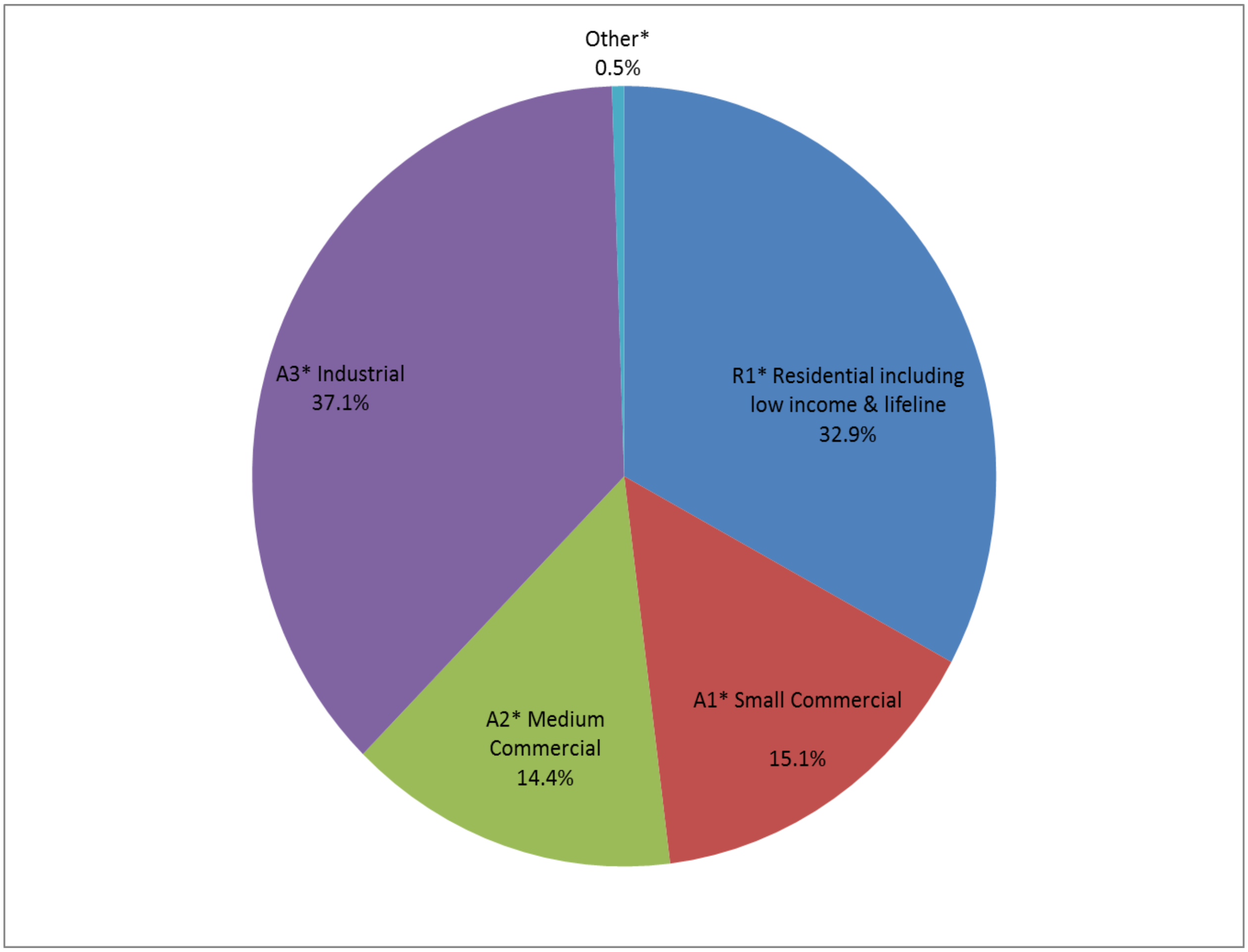
These cost causation factors form the basis for the determination of unit marginal costs for each functional component (and sub-components). Specialized analysis of each component by standard utility techniques results in the estimated unit marginal cost for these drivers.

1.3.3 Determination of Marginal Cost Revenue Requirement by Customer Class

The ultimate goal of a cost of service study for rate making purposes is to develop cost of service revenue requirement percentages by customer class. The marginal cost of service study determines marginal cost revenue requirements by customer class (i.e., the revenues that LADWP would collect if all customers were charged rates that equal marginal costs). The marginal cost revenue requirement percentages are then compared to the actual revenue percentages for each major customer class.

Figure 2 displays the current revenue percentages of current retail revenue collected through LADWP rates for each of the major customer classes for FY 2012-13.

Figure 2: FY 2012-13 LADWP Revenue by Customer Class[3]



Based on the unit marginal cost for each functional component and the corresponding cost causation factor for each customer class, marginal cost revenue requirements are calculated by functional component and sub-component for each customer class. The summation of the marginal cost revenue requirements for all the individual functional components and sub-components comprises the aggregate marginal cost revenue requirement for each customer class.

The marginal cost revenue requirement determination by customer class is summarized by the following equations:

- $Customer\ Class\ MC\ Revenue\ Requirement\ by\ Functional\ Component =$
$Unit\ MC\ for\ Functional\ Component\ times\ Cost\ Causation\ Factor\ (for\ specific\ customer\ class)$
- $Total\ Customer\ Class\ MC\ Revenue\ Requirement =$
$Sum\ of\ all\ MC\ Revenue\ Requirements\ for\ all\ Functional\ Components$

[3] For the LADWP marginal cost study, some customer classes listed here have been combined to maintain consistency for rate design purposes. For instance, the Residential class includes low income and lifeline customers. The asterisk* indicates that multiple classes are included in a listed customer class (e.g., A1 includes A1A and A1B).

The final step of the marginal cost study analysis involves the calculation of marginal cost revenue requirement percentages for each customer class (as a percentage of the total marginal cost revenue requirement). These marginal cost revenue requirement percentages are compared to the corresponding current revenue percentages for each customer class, to determine whether the current rates and rate structure produce revenues for each customer class in the same proportion as the marginal cost revenue requirement. Figure 3 presents this comparison for the LADWP study.

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

Comparisons	Residential	Small Commercial	Medium Commercial	Industrial	Other	Total
Total MC Revenue Requirement	$1,373,625,488	$483,115,979	$470,966,448	$1,085,122,948	$27,827,485	$3,440,658,348
Marginal Cost Revenue Requirement Percentage	39.9%	14.0%	13.7%	31.5%	0.8%	100.0%
FY 2013 Current Retail Revenue	$1,010,099,373	$464,812,908	$441,103,892	$1,138,691,239	$16,187,848	$3,070,895,260
Current Revenue Percentage	32.9%	15.1%	14.4%	37.1%	0.5%	100.0%

For the test year FY 2012-13, the aggregate amount collected through current retail rates for all customer classes, was approximately $3,071 million.

The LADWP marginal cost study calculates the required revenues on a forward-looking basis, using data for the FY 2012-13 test year as a starting point. The revenue requirement based on the marginal cost study generally exceeds the accounting cost based revenue requirement. For the LADWP marginal cost study, the total marginal costs are approximately $3,441 million, which is 12% higher than the FY 2012-13 revenue requirement of $3,071 million.

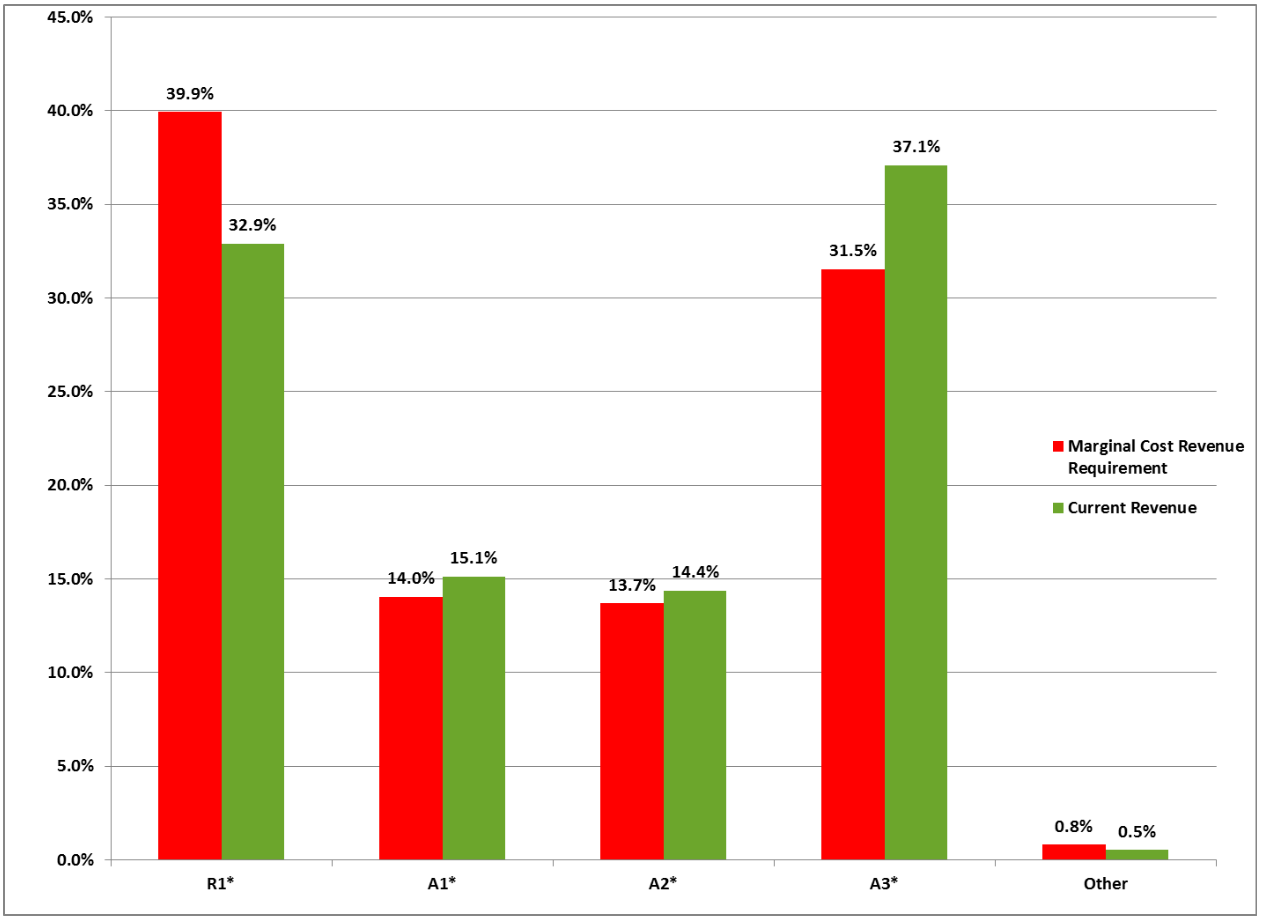
The current customer class revenue percentages in Figure 2 reflect a historical rate structure. Over time, cost structures change; consequently, marginal cost of service studies should be conducted periodically to more accurately reflect forward-looking allocation of costs among customer classes. For example, California legislation and regulations require increased use of renewable energy resources, which will impact electric utility cost of service and the allocation of costs to different classes.

The marginal cost revenue requirement percentage for the residential (R1) customer class is 39.9%, while the corresponding percentage of current revenues for FY 2012-13 is 32.9%. Conversely, based on marginal costs, the Industrial (A3) customer class would be allocated a lower revenue requirement of 31.5% as compared to 37.1%, of the current total revenues. These results were supported by a embedded[4] cost of service analysis, which produced similar customer class percentages as the marginal cost of service study.

The LADWP marginal cost study results therefore demonstrate that a re-alignment of the total revenue requirements among the customer classes is likely warranted. Figure 4 illustrates the differences between the marginal cost revenue requirement and current revenue percentages for the major customer classes.

[4] Embedded Cost studies are also referred to as Average Embedded Cost Studies.

Figure 4: Comparison of Marginal Cost Revenue Requirement and Current Revenue Percent by Customer Class



To avoid over/under collection of costs for one or more customer classes and to more accurately reflect cost causation principles, the marginal cost revenue requirement percentages by customer class can be applied to the approved annual revenue requirement to establish, through rate design, cost based customer rates.

2 MARGINAL COST OF STUDY APPROACH & METHODOLOGY

2.1 Introduction

In October 2012, the Los Angeles City Council approved LADWP's Incremental Electric Rate Ordinance No. 182273 to provide incremental rate adjustments for fiscal years (FYs) 2012-13 and 2013-14. In its action to approve LADWP's power rates, the Council requested that LADWP "conduct a new formal cost of service study in order to prepare for future power rate restructuring".

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Cost of service analysis (COSA) constitutes standard utility industry practice for setting power rates. Most utilities, whether Investor Owned Utilities (IOUs) or publicly owned utilities (POUs), conduct cost of service studies when undertaking a rate action. The marginal cost study approach facilitates attaining the following objectives:

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- Provides legally defensible foundation for cost based rates.

Cost of service analysis is part of the overall utility rate making process. An overview of the typical ratemaking process is shown below in Figure 5**.** Utilization of a marginal cost of service study will ensure rates produce revenue sufficient to recover the costs associated with the provision of electric service. Concurrently, the cost of service study will help ensure rates for each major class of customers recover the costs associated with providing service to that class of customers.

Figure 5: Typical Utility Ratemaking Process

Objectives	• Identify ratemaking objectives
Revenue Requirements	• Calculate revenue requirements (i.e., the amount needed to be billed to customers to cover the utility's costs)
Cost of Service	• Determine overall marginal costs • Functionalize costs • Develop unit costs by cost causation factor • Define customer (or rate) classes • Assign the functionalized costs to customer classes • Calculate marginal cost revenue requirement for each customer class • Compare marginal cost revenue requirement to current revenue by customer class
Rate Design	• Identify revenue constraints • Choose revenue reconciliation method • Evaluate alternative rate designs and choose an approach • Design rates • Determine customer rate and bill impacts • Adjust rate design if needed • Design special rates and contracts if needed

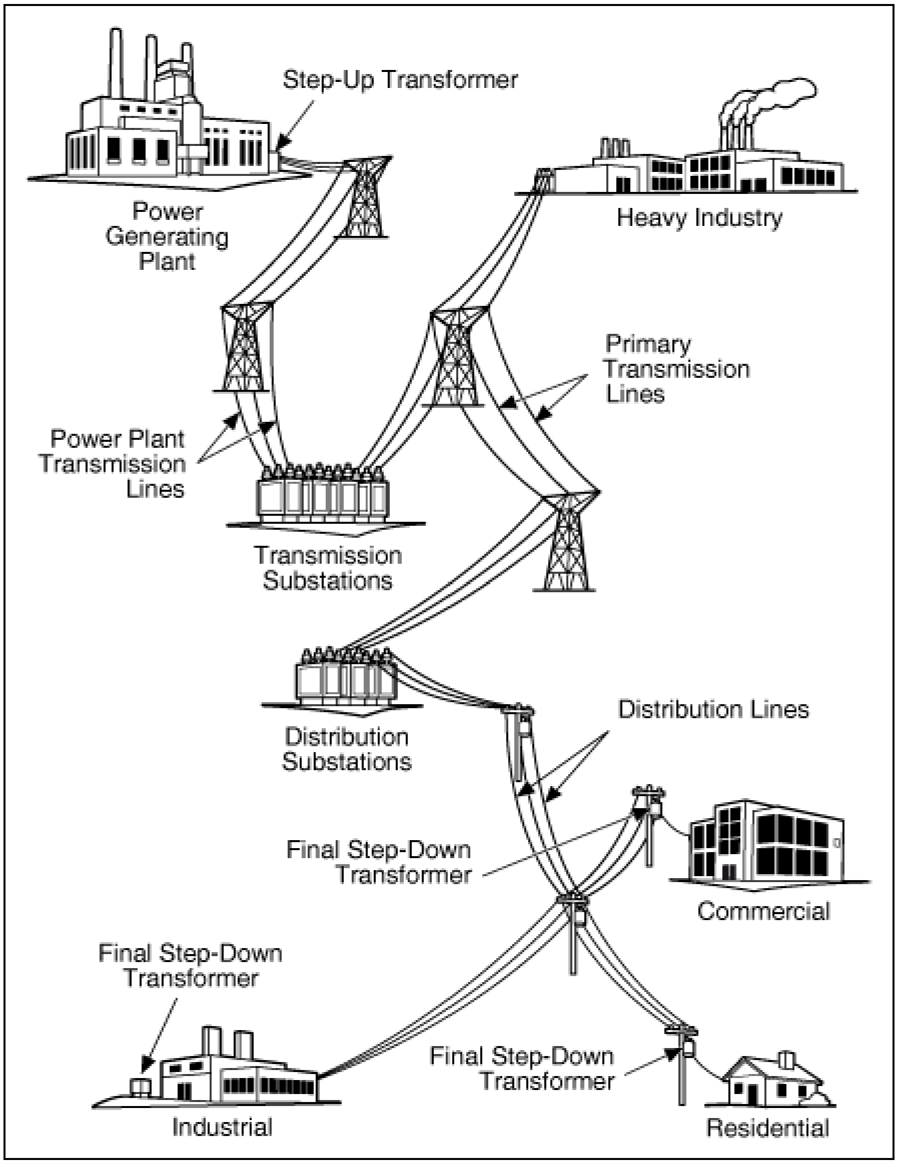
2.2 Electric Supply System Overview

Electric utilities are unique, important businesses that provide electricity to a variety of customers that include commercial, industrial, and residential classes through a system that is generally composed of the following major functional components:

- Generation;
- Transmission;
- Distribution; and
- Administration and General Services supporting those functional components.

Figure 6 provides an illustration of the electric supply system.

Figure 6 Electric Supply System[5]



2.2.1 Functional Components

To obtain a better understanding of the electric system, it can be broken down into functional components:

- **Generation:** The process of producing electrical power from a primary energy source such as natural gas, hydro-electric, solar or wind. A utility may also choose to purchase power from third parties to meet demands of customers. In this case, a third-party generation entity would generate electricity and sell it to the utility; these utility costs would be considered part of the generation function.

[5] Source: http://zone.ni.com/images/reference/en-XX/help/373375B-01/noloc_eps_ep_grids.gif

- **Transmission:** The process of transporting the electricity from generation plants to distribution sub-stations that may be close to the customer. Most transmission lines use high voltage-AC current; power is typically delivered to the transmission system from regional generators or regional interties at 500/230 kV or higher voltages. However, when energy is transported over long distances (often hundreds of miles), DC current is used to reduce losses. Heavy industrial users may receive electricity directly from the transmission lines.
- **Distribution:** The process of distributing the electricity received at the distribution substations to the end-use customer. Distribution substations reduce voltage to a level suitable for use by the applicable customer class. This power typically goes through three stages of transformation on the LADWP system: from 500/230 kV to 34.5 kV (sub-transmission voltage), from 34.5 kV to 4.8 kV (primary voltage), and from 4.8 kV to between 110 and 480 volts at the customer premises (secondary voltage).
- **Administrative and General (A&G):** These functions provide the capability to bill, and provide customer service, accounting and other support services.

2.2.2 Meeting Customer Demand

A core value for LADWP is reliability. Utilities strive to provide electricity reliably to all customers at an affordable price. However, several factors influence the ability to achieve this goal, including:

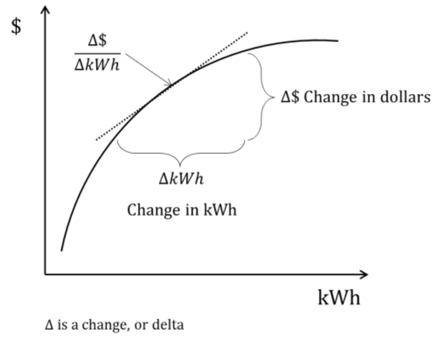
- Patterns of Energy Demand: Utilities must have infrastructure capable of handling different patterns of usage, as well as the peak demand imposed on the system by different customer classes; and
- System Losses: Energy losses throughout the transmission and distribution process.

2.3 Cost of Service Study Approach

The LADWP cost of service study follows a marginal cost methodology. This methodology evaluates the change in cost incurred by a customer class to serve an incremental increase in demand for utility services by that class. Marginal costs measure the additional costs of providing the next unit of service, whether that is the next unit of energy, the additional burden that adding a kilowatt of demand places on the electrical system or the cost of an additional customer.

Marginal costs are calculated for changes in each cost driver, or causative factor. These cost drivers are typically related to demand, energy and/or customer causative factors. The marginal cost is calculated by dividing the change in total cost by the change in the cost driver. For example, the marginal cost of electric generation is calculated for an incremental change in the total cost of generating electricity from a change in load. Figure 7 below illustrates the determination of marginal costs for generating energy (kWh). The vertical axis, dollars ($), represents the total cost of producing energy (kWh). At any point on the production curve, there is a change in dollars that corresponds to a change in energy (kWh) production. The change in cost (delta of $) divided by the change in energy (delta of kWh) is the marginal cost.

Figure 7: Example of Marginal Cost for Generation Given a Generation Production Curve



For over twenty years, the California Public Utilities Commission (CPUC) has relied on marginal cost principles for assigning revenue requirements to customer classes, and as guidance for electric utility rate and rate structure development[6]. Also, the National Association of Regulatory Utility Commissioners (NARUC) and American Public Power Association (APPA) recognize the use of marginal cost as a valid cost of service methodology[7]. Therefore, the current LADWP cost of service study follows an established framework that is widely utilized across the country.

The ultimate goal of marginal cost of service for rate making purposes is to determine the marginal cost percentage of the total revenue requirement for each customer class in rates. The marginal cost revenue requirement percentages are then compared to the percentages of total revenue produced at current rates for each customer class to determine whether an adjustment to the rates is appropriate.

When a difference arises, relevant rates may be adjusted to align revenue percentages with the marginal cost revenue requirement percentages.

2.4 Marginal Cost of Service Study Methodology

Prior to the commencement of the marginal cost study, the appropriate test year has to be established for the analysis. For the LADWP study, FY 2012-13, the most recent period with reliable data at the time of the study, was selected.

The LADWP electric marginal cost of service study comprises three general steps:

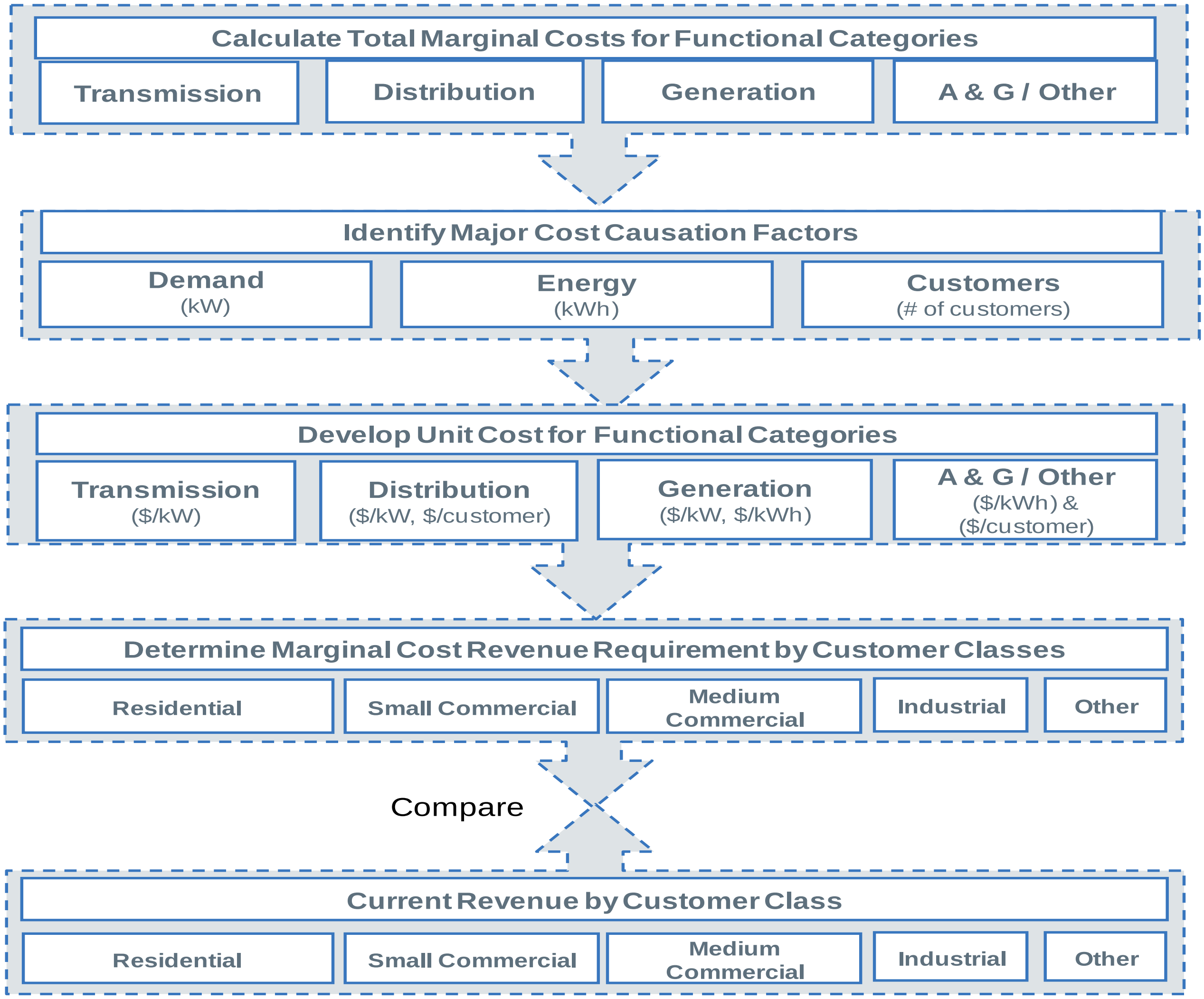
- Functionalization of service costs;
- Development of unit marginal costs/cost drivers for cost causation factors; and
- Determination of marginal cost revenue requirements by customer class.

The graphic in Figure 8 summarizes these three steps.

[6] In particular, the CPUC has developed 10 Optimal Rate Design Principles, one of which is that "Rates should be based on marginal costs" (OIR at 20-21).

[7] Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, January 1992.; Retail Rate Design for public Owned Systems, American Public Power Association, 1992

Figure 8: Marginal Cost of Service Study Methodology



Each of these steps is explained in more detail in the sections below.

2.4.1 Functionalization

The first major step in the marginal cost study is the identification of the various functions performed by LADWP in the provision of electricity services. The goal of the functionalization step is to group costs that have distinct and significant cost drivers. For LADWP, these functional components are:

- **Generation:** the process of generating power from a resource;
- **Transmission:** the bulk transfer of energy from generating stations to electric distribution sub-stations near demand centers;
- **Distribution:** the delivery of electricity received at sub-stations to end-use customers. This power typically goes through three voltage levels, such as 34.5 kV, 4.8 kV and secondary. Distribution also includes reading and maintaining customer meters; and
- **Other Administrative & General (A&G) Functions:** executive management, general supervision, customer service, customer billing, employee administration, etc.

The marginal cost study then develops forward-looking marginal cost revenue requirements for each functional component and their appropriate sub-components. Sub-components are sub-categories that have distinct cost causation differences, such as voltage level sub-components for the distribution functional area.

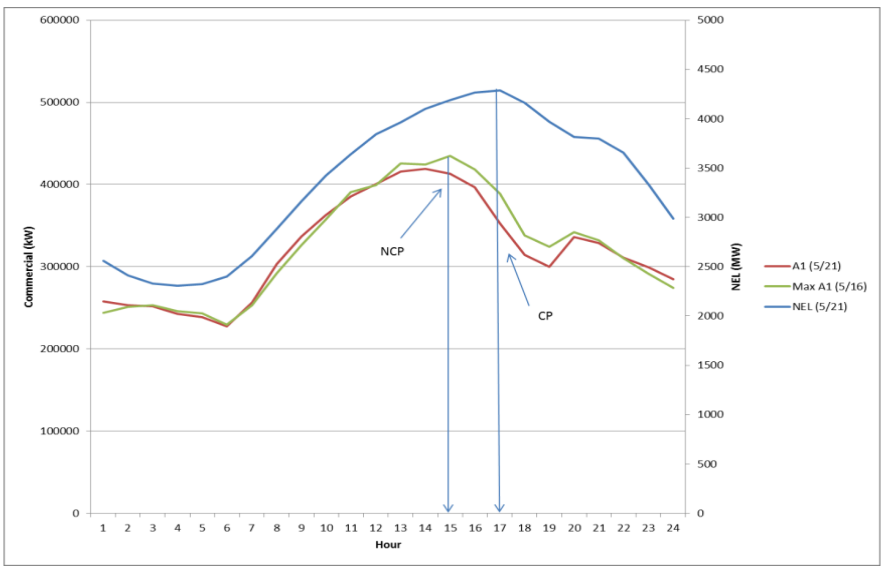
2.4.2 Development of Unit Marginal Costs/Cost Drivers

The next major step in the marginal cost study is the identification of the appropriate cost causation factor for each functional and sub-functional cost component. For example, the cost causation factor for generation capacity costs is the kW demand on the system. The generally accepted and established industry practices for the cost causation factors are described below.

- **Demand Related Costs:** These costs are incurred as a result of maximum power requirements and are utilized to determine marginal cost revenue requirements for the customer classes on the basis of demands (kW) imposed on the system. Two peaks in demand that generally contribute toward system capacity cost causation and ultimately determine how costs get calculated are:
- **System Coincident Peak Demand (CP):** contributions of each customer class coincident with the system peak hour. The Coincident peak demand measurement is used in the calculation of marginal costs for capacity generation, particularly peaking resources, and bulk transmission plant.
- **Class Non-Coincident Peak (NCP):** maximum demand for a class of customers. The hour of occurrence may or may not be the same as the system peak hour. This measurement of demand is used in the calculation of local facility marginal costs such as those of substation and primary distribution facilities.

Figure 9 shows the relationship between system coincident peak demand and class non-coincident peak.

Figure 9: Depiction of System Coincident Peak Demand (CP) vs. Class Non-Coincident Peak (NCP)



- **Energy Related Costs:** Some costs, such as fuel, emissions, impact of renewables, and certain operation and maintenance expenses, are directly related to the quantity of energy (kWh) produced.
- **Customer Related Costs:** These costs reflect the marginal costs of customer interconnection to the delivery system and various customer services. These costs are derived for the customer classes on the basis of the number of customers.

Figure 10 below summarizes the functional cost components and the corresponding cost causation factors for the LADWP cost of service study, based on standard industry practices.

Figure 10: Cost Causation Factor for Each Functional Cost Component

Functional Cost Component	(Cost Causation Factor)	Units
Transmission Capacity	Coincident Peak for each customer class	$/CP kW/year
Transmission Ancillary Services	Coincident Peak for each customer class	$/CP kW/year
Transmission O&M	Coincident Peak for each customer class	$/CP kW/year
Generation Energy	kWh load for each customer class	$/kWh
Generation Capacity	Coincident Peak for each customer class	$/CP kW/year
Generation O&M	kWh load for each customer class	$/kWh
Distribution Capacity	Non-Coincident Peak for each customer class	$/NCP kW/year
Distribution O&M	Non-Coincident Peak for each customer class	$/NCP kW/year
Meter Costs	Number of Customers	$/Customer/year
Customer Account Expenses	Number of Customers (Weighted)	$/Customer/year
Administrative & General Cost Adders	kWh load for each customer class	$/kWh

These cost causation factors form the basis for the determination of unit marginal costs for each functional component (and sub-components).

Specialized analysis of each functional component (and sub-component) based on standard utility techniques results in the estimated unit marginal cost by cost drivers. The specialized analyses are discussed below in Section 3; additional detail for some of the analyses is also provided in Appendices C and D.

2.4.3 Determination of Marginal Cost Revenue Requirements by Customer Class

The third major step in the marginal cost study methodology is to determine whether LADWP recovers from each major class the costs associated with providing service to that class of customers.

LADWP serves the following main customer classes[8]:

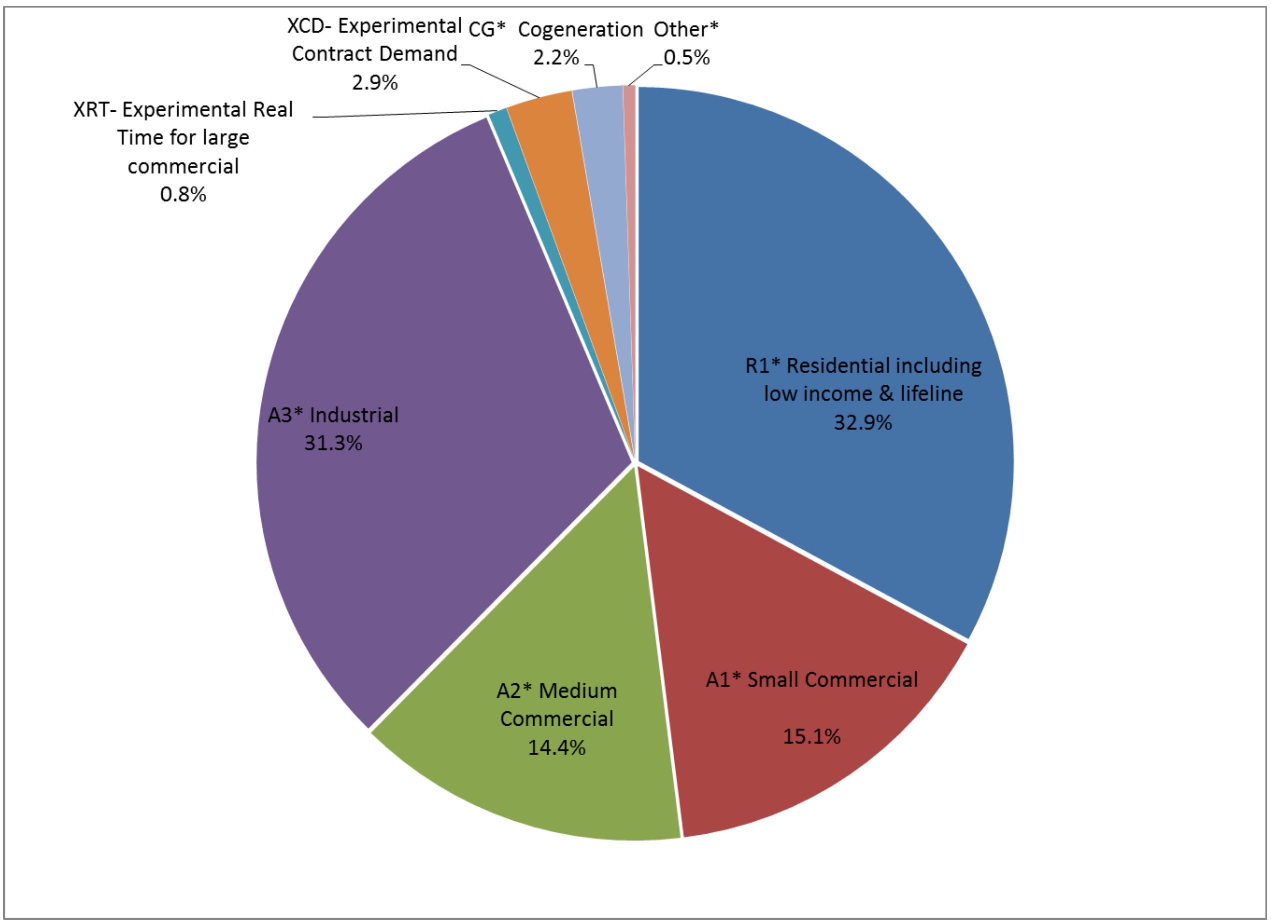
- Residential: Single family and multi-family, including low-income and life-line;
- A-1 Commercial: Smaller office buildings and other commercial real estate, etc;
- A-2 Commercial & Industrial: Commercial & industrial customers who use electricity delivered from the primary voltage system;

[8] Owens Valley customers have been excluded from the marginal cost study analysis, they only constitute about 0.6% of LADWP retail revenues.

- A-3 Commercial & Industrial: Commercial & industrial customers who use electricity delivered from the sub-transmission system;
- Experimental Real Time (XRT): Large, contract commercial & industrial customers with demand of 250 kW or greater with the ability to curtail usage;
- Experimental Contract Demand (XCD): Large, contract commercial & industrial customers with the ability to shift load and maintain high load factors;
- Cogeneration: Customers who own electrical generating facilities that are connected with LADWP's system, but are not subject to Net Energy Metering (NEM) service rider;
- Other: Street, highway lighting, and traffic control.

The actual FY 2012-13 revenues for these major customer classes are displayed in Figure 11. The source for the FY 2012-13 revenues, load and customers is the C&E (Consumption and Earnings) Report FY 2012-13.

Figure 11: FY 2012-13 Revenue by Customer Class



Note that for the LADWP marginal cost study, some customer classes listed above have been combined to maintain consistency for rate design purposes. (For example, the Residential class also includes both low income and lifeline customers in the marginal cost results.) For the LADWP marginal cost study analysis, customer classes have been condensed to five broad categories:

- Residential (R1)
- Small Commercial (A1)
- Medium Commercial (A2)
- Large Commercial or Industrial (A3)
- Other (including Street and Highway Lighting and Port of Los Angeles).

This final step of the marginal cost study analysis determines the aggregate marginal cost revenue requirements for each customer class. This is followed by the calculation of marginal cost revenue percentages for each customer class, as a percentage of the total utility marginal cost revenue requirement.

These marginal cost revenue requirement percentages are then compared to the corresponding current revenue percentages for each customer class to determine whether changes to current rates and rate structures for any of LADWP's customer classes are appropriate. An objective is for rates to produce revenues in the same proportion by customer class as the marginal cost revenue requirements.

The marginal cost revenue requirements for each customer class are calculated by multiplying customer class cost causation factors by functional unit marginal costs. This calculation will produce a system total revenue requirement which will differ from the actual accounting revenue requirement for the system. The marginal cost revenue requirement generally differs from the accounting cost based revenue requirement; for the LADWP marginal cost study, the total marginal cost revenue requirement is $3,441 million, which is 12% higher than the $3,071 million FY 2012-13 revenue requirement.

A summary of the marginal cost of service methodology is provided below:

I. Functionalization

Identify all costs associated with providing electricity service by the following major functional components:

- Generation;
- Transmission;
- Distribution; and
- Customer, Administrative & General.

Within each major functional component, identify particular sub-components that have a distinct cost causation factor (e.g. renewable energy generation costs).

Determine the aggregate marginal costs for each functional component and sub-component.

II. Development of Unit Marginal Costs/Cost Drivers

1. Determine the appropriate cost causation factor or cost driver for calculating a unit marginal cost for each functional component, for example:
    - Proportionate capacity levels (CP or Non-CP) for each customer class;
    - Energy usage (kWh) for each customer class; or
    - Number of customers in each class.
2. Develop a unit marginal cost for each functional component by an individual analysis of each component's marginal cost.

III. Determination of Marginal Cost Revenue Requirements by Customer Class

1. Identify all major customer classes for electric service.
2. Calculate the marginal cost revenue requirement by functional component for each customer class by multiplying the unit marginal cost for each functional component identified in Step II.2 by the total

amount of the corresponding customer class units/cost driver for each customer class identified in Step III.1.

3. Determine the aggregate marginal cost revenue requirement for all customer classes from Step III.2.
4. Calculate the marginal cost revenue requirement percentages (as a percentage of the aggregate revenue requirement) for each major customer class by dividing the customer class amount in step III.2 by the aggregate amount determined in step III.3.
5. Compare the marginal cost revenue requirement percentage for each customer class (step III.4) with corresponding current (FY 2012-13) revenue percentage.

The marginal cost of service study results can then be used to determine whether any changes to rates and/or rate structures are appropriate.

3 CALCULATION OF UNIT MARGINAL COSTS

This section describes the assumptions underlying the marginal unit costs and how the unit costs are calculated.

This section is divided into three major sub-sections:

- Marginal cost study assumptions and data sources;
- Calculation of unit marginal costs for each functional cost component; and
- Summary of unit marginal costs by functional component.

3.1 Marginal Cost Study Assumptions and Data Sources

3.1.1 General Assumptions

The estimation of marginal costs involves a detailed analysis of projected costs of the services provided by utility companies, and it is typically quite sensitive to certain parameters and assumptions, depending on the type of cost being estimated. Some of the key assumptions and data sources for the LADWP marginal cost study are listed below:

- Test year of FY 2012-13 utilized for marginal cost study analysis (most recent year of reliable financial and usage information at the time of the study).
- Current & forecasted LADWP data from 2013 Integrated Resource Plan (IRP), Open Access Transmission Tariff (OATT), Customer Information System (CIS), Consumption and Earnings (C&E) report, and FY 2012-13 General Ledger;
- Operations & Maintenance costs based on FY 2012-13 general ledger;
- Customer counts based on an average for FY 2012-13;
- Load shape by class for calendar year 2012 obtained from the LADWP Rates Department. The calendar 2012 loads were proportioned by hour by customer class to FY 2012-13 levels utilizing the difference between calendar year 2012 loads and C&E Report data for FY 2012-13 ;
- Cost of Capital[9] assumed to be 5.45% based on 2013 IRP;
- Inflation Rate assumed to be 2.5% based on 2013 IRP;
- System losses based on the 2010 Power Loss Study;
- Renewable energy resources of 20%, 25%, and 33% for electricity sales by 2013, by 2016, and in 2020, respectively, to comply with State legislation;
- System lambda based on 2019 Prosym Study forecasts; and
- All marginal cost demand calculations are based on 12CP/12NCP.
- Other key data sources and considerations for calculating the marginal costs are defined below.

[9] The cost of capital of 5.45 % is the appropriate rate for discounting streams of future nominal dollars. This is also referred to as the nominal discount rate.

3.1.2 Integrated Resource Plan

Every other year, LADWP prepares a complete power Integrated Resource Plan (IRP) to provide a 20-year strategy that meets current and future energy needs of the City of Los Angeles. The IRP is refreshed in the years that a complete IRP is not prepared. The IRP lays out alternative strategies for meeting LADWP's regulatory requirements and environmental policy goals for increasing the use of renewable energy and reducing greenhouse gas (GHG) emissions, while maintaining power reliability and minimizing the financial impact on the City's ratepayers. LADWP's 2013 Final Power Integrated Resource Plan was the product of a year-long process that included stakeholder meetings with key business, environmental, and community representatives, a public review of a draft version, and a public workshop. A 2014 update to the 2013 IRP is in process but has not yet been completed at the time of this study.

Since the marginal cost study is forward-looking in nature, many inputs for the calculations have been obtained from the 2013 IRP, and other planning and forecasting data sources.

3.1.3 General Ledger Costs

There were several cost categories for the LADWP Power System that were classified as adders. Since these costs are general in nature and not likely to be significantly different in the future, no specific effort was made to determine forward-looking marginal costs for these categories. Instead, the FY 2012-13 costs incurred by LADWP for these categories were obtained from the General Ledger and included in the marginal cost study calculations. Following is a list of these cost categories, which are discussed in more detail in later sections of this report:

- Generation Operations & Maintenance Expenses;
- Transmission Operations & Maintenance Expenses;
- Distribution Operations & Maintenance Expenses;
- Customer Account Expenses;
- Administration & General Expenses;
- City Transfer Expenses; and
- General Plant Expenses.

3.1.4 Adjustment for System Losses

The total energy sales to ultimate customers for the LADWP system are substantially lower than the net energy load (NEL)[10]. This difference is attributable to power system losses that relate to transmission and distribution line losses and other losses (e.g. metering errors and energy theft).

The demands or loads used for the allocation of generation and transmission costs are the demands at the transmission inlets to the LADWP system, not the demands at the point of delivery to the customer**.** Consequently, an estimate of system losses from the point of supply to the customer's meter, has to be calculated to derive the load at the transmission inlets. These loss factors pertain to both peak demand (kW) and annual energy load (kWh).

For the LADWP system, overall power system losses were determined from the April 2010 Power Loss Study. Each customer class exhibits a different loss factor as displayed in the table below. The higher loss for Residential customers is attributable to the fact that their load is subject to more voltage changes on the distribution lines. LADWP's loss factors are shown in Figure 12.

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[10] Net Energy Load is the actual load at the transmission inlets to the LADWP system, before transmission & distribution & other losses.

Figure 12: LADWP Loss Factors

	R1	A1	A2	A3	Other
Loss Factor	10.46%	10.46%	8.95%	7.45%	10.46%

If marginal costs for the various functional cost components were calculated for the customer classes without consideration of the loss factor, industrial customers would pay too much, while residential customers would pay too little. Therefore, loss factors are incorporated in the marginal cost study calculations for the following cost components:

- Generation & Transmission Capacity costs & Transmission O&M costs (loss factors applied to CP demand for each customer class for marginal cost calculation purposes); and
- Generation Energy (including Renewable & GHG) costs and Generation O&M costs (loss factors applied to kWh load for each customer class for calculation purposes).

To illustrate, generation energy costs are calculated for various customer classes based on the gross kWh load, or load adjusted upward by the corresponding loss factor for each customer class. For example, if the retail load for residential customers is 1,000 kWh, and the loss factor is 10.46%, then load to be used for the marginal cost calculation would be 1,116.8 kWh (1,000/(1-0.1046)) and not 1,000 kWh.

Based on the key factors described above, the marginal cost calculation methodology for each functional component is described in the sections below, including a discussion on the appropriate mode of determining marginal cost revenue requirements for the customer classes.

3.2 Calculation of Unit Marginal Costs for Each Functional Cost Component

3.2.1 Generation Unit Marginal Costs

There are several components in the generation costs: generation capacity, generation energy, renewable energy, and GHG emission costs, as described below.

3.2.1.1 Generation Capacity Unit Marginal Costs

Generation capacity is the need for instantaneous power to meet demand. Traditionally, capacity-related generation marginal costs have been measured by annualizing the expected costs of a utility-built combustion turbine (CT) as a proxy. A combustion turbine or peaker is typically the least cost generation option to provide incremental capacity benefits during the peak demand hours.

The cost for an LADWP owned combustion turbine in the LA region was utilized. This cost for the combustion turbine, included all permitting, financing, development costs, inflation during the construction period, and 15% reserves, was based on estimates in the 2013 IRP. The IRP has estimated the capital cost of a combustion turbine (CT) to be $1,300/kW, with a useful life of 30 years. Using the IRP cost of capital of 5.45%, the total cost of $1,300/kW was then discounted over the 30 year period resulting in an annual cost of $88.95/kW. A fixed annual O&M component of $19.25/kW based on the new CTs at the

Harbor Generating Station was added to the capital cost. The resulting annual cost annuity of $108.20/kW ($88.95/kW +$19.25/kW) represents the unit generation capacity marginal cost per kW.

3.2.1.2 Generation Energy Unit Marginal Costs

Generation energy marginal costs are generally estimated based on the "system lambda". This system lambda is defined as the cost of the next kilowatt-hour that can be produced by an electrical supply system's generating units. As system load increases, the cost of serving incremental loads may increase as more expensive units come on line. The last unit dispatched represents the system lambda.

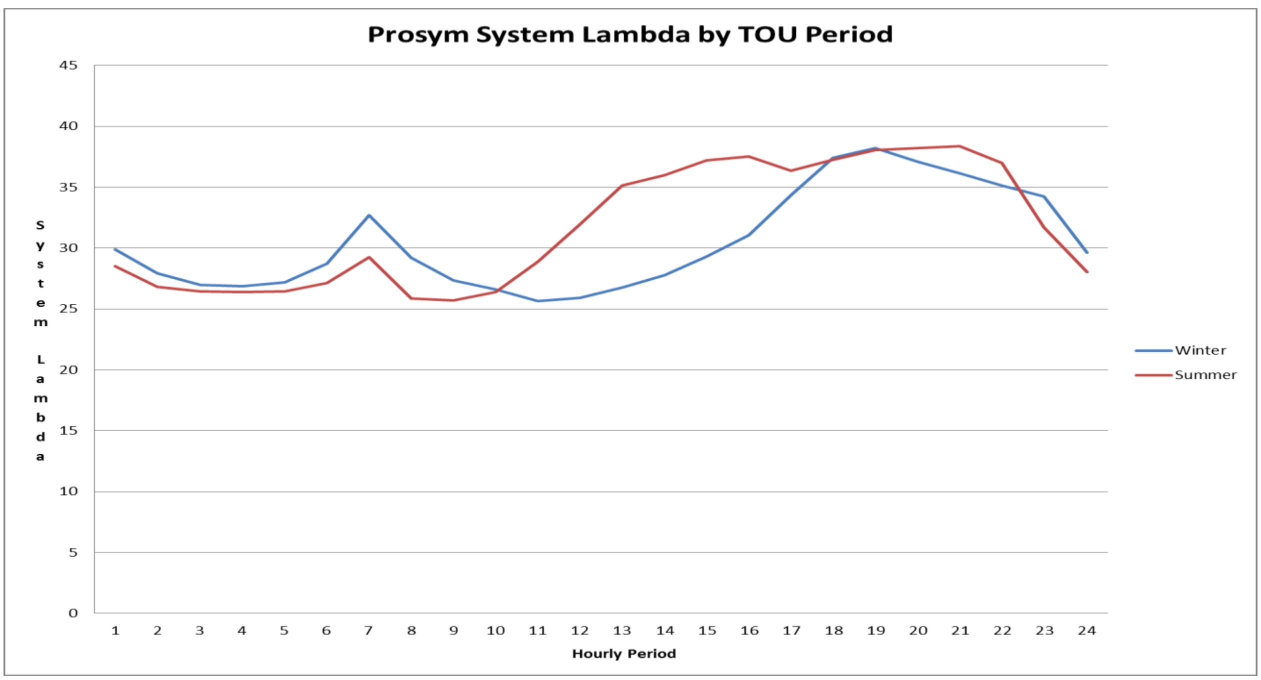
Forward system lambdas are estimated through production simulation models that are utilized to dispatch resource to load on an hourly basis, given available resources and constraints. LADWP utilizes ProSym as the production simulation.

Detailed hourly system lambda forecasts (in $/kWh) for each hour of each day of each month of FY 2018-19 were obtained from the ProSym simulation model. These hourly prices were applied to the corresponding hourly load for FY 2012-13, for each customer class, to derive the marginal generation energy costs.

Consequently, the total generation energy marginal costs were determined directly on an aggregate summation basis across hourly data, and not based on a single unit marginal energy cost.

An illustration of the system lambda, based on the ProSym model is displayed in Figure 13, for a 24-hour period.

Figure 13: LADWP ProSym Model System Lambda by TOU Period



For each customer class, the hourly load for FY 2012-13 (adjusted for system losses for each customer class) was multiplied by the corresponding hourly system lambda price forecast for FY 2018-19 to obtain an hourly generation energy cost for each customer class. FY 2018-19 represents a sufficiently forward look where modeling forecasts variable hourly costs with reasonable certainty. The summation of these hourly costs for the whole year provided the aggregate annual generation energy marginal costs for each customer category. The generation energy unit marginal cost was determined to be $0.034/kWh. In addition to the generation energy costs, the total generation energy marginal cost also includes two components, as described below: renewable energy costs and greenhouse gas (GHG) emissions.

3.2.1.3 Renewable Energy Unit Marginal Costs

Shifting a greater amount of energy production to renewable energy sources is a major environmental policy initiative in California, memorialized by Senate Bill SBX1-2, passed in April 2011. Renewable energy constitutes a major power supply resource addition that influences LADWP revenue requirements for the next several years. SBX1-2 and CEC regulations require LADWP to achieve 20% renewables on average between 2011 and 2013, 25% by 2016, and 33% in 2020. Consequently, the generation energy marginal costs will be impacted by this mandate, since energy from renewables is more expensive than from traditional sources like coal or natural gas.

Solar power through contracts was identified as least cost incremental renewable resource based on the 2013 IRP, and the impact of renewables was estimated as the difference in energy costs between solar power and LADWP's cheapest traditional generation energy source.

This impact of additional costs attributable to renewables was estimated based on IRP data. The cheapest source of solar power based on the LADWP Power Purchase Agreements (PPAs) was estimated to be $83 per MWh (levelized annual cost). The cheapest LADWP source for energy was estimated at $49 per MWh, from generation at the Haynes combined cycle turbine generating plant. Hence, the unit incremental marginal cost per MWh for renewable energy was calculated as the difference between the costs for solar energy minus the cheapest LADWP energy source:

$83 - $49 = $34 per MWh.

Assuming that LADWP reaches a 33% RPS level, the unit incremental cost attributable to renewables was derived as one third of $34 which is $11.2/MWh, or $0.011 /kWh.

3.2.1.4 GHG Emission Unit Marginal Costs

Another factor that impacts marginal energy costs is the State of California GHG policy to price carbon (CO_2) emissions. Currently, the regulation sets the floor price of carbon emission allowances in the California Air Resources Board’s auction process.

A nine year forecast of annual CO_2 costs per ton was obtained from the 2013 IRP. This stream of nine year cash flows was discounted to obtain a net present value of $102.71 in real 2013 dollars; then an annual annuity of $15.94 in CO_2 costs was derived from this for 2013, based on a 5.45% discount rate. This annual CO_2 cost per metric ton per MWh of $15.94 was multiplied by the lowest plant CO_2 emission rate of 38.1% per MWh (which was determined to be for the Haynes CCT generating plant). This analysis resulted in a unit CO_2 emission cost per MWh of $6.07 or $0.0061 per kWh.

3.2.1.5 Generation O&M Unit Marginal Costs

These costs are associated with the operations and maintenance of the LADWP generation facilities and include: operating labor & supervision expenses for operating generation units, generation station expenses, supervision & other maintenance expenses associated with generation plant, etc.

Generation O&M costs were based on the actual 2013 General Ledger account categories associated with the generation functional service component. The amount utilized for the marginal cost study calculations was $150.8 million. This amount was divided by the total system retail load of 23,383 million kWh, resulting in a unit generation O&M cost of $0.006/kWh.

3.2.2 Transmission Unit Marginal Costs

For the LADWP marginal cost study, transmission marginal costs were comprised of three components: transmission capacity, transmission O&M, and ancillary service costs, as described below.

3.2.2.1 Transmission Capacity

A proxy for new transmission capacity was utilized to develop marginal transmission capacity unit cost based on the Barren Ridge project. Renewables are causing incremental marginal transmission requirements on the system, even though load growth itself is slowing and flattening. This analysis is fairly extensive and is shown in detail in Appendix C, Transmission Capacity Analysis. The result of the analysis is the derivation of a unit transmission capacity charge of $45/kW.

3.2.2.2 Transmission O&M

These costs are associated with the general operations and maintenance of the LADWP transmission system, and include: operating expenses for load dispatching labor, transmission station labor, and other operating expenses associated with the transmission lines, maintenance of the overhead & underground lines, station equipment, etc.

Transmission O&M costs were based on the actual FY 2012-13 General Ledger account categories associated with transmission service. The amount utilized for the marginal cost study calculations was $85.7 million and it resulted in the derivation of a unit transmission O&M charge of $22.02/kW.

3.2.2.3 Transmission Ancillary Services

In addition to the incremental cost of new transmission capacity and transmission O&M, transmission also includes the provision of supporting transmission services or ancillary services. These services include but are not limited to:

- Scheduling, System Control & Dispatch service;
- Reactive Supply & Voltage Control (from generation or other source) service; and
- Regulation & Frequency Response service.

The annual marginal cost for these ancillary services, obtained from the Open Access Transmission Tariff (OATT), was $7.64/kW.

3.2.3 Distribution Marginal Costs

Power is typically delivered to the transmission system from generation plants, regional generators or regional interties at 500/230 kV or higher voltages. From the transmission system, this power typically goes through three stages of voltage drops through transformers to the LADWP distribution system: from 500/230 kV to 34.5 kV (sub-transmission voltage), from 34.5 kV to 4.8 kV (primary voltage), and from 4.8 kV to between 110 and 480 volts at the customer premises (secondary voltage).

When there is an increase in the planned level of capacity, additional transformer capacity must be added at each of these steps to accommodate the increased capacity. Additional substation facilities may be required as a result of increases in transformer capacity. Further, an increase in the number of distribution circuits serving a local area may also be required.

3.2.3.1 Voltage level Differentiation

Distribution facilities are specifically assigned to certain customers or classes of customers who use the specific facilities. LADWP customers are differentiated by three voltage levels; therefore LADWP distribution costs have been identified and assigned to the same three levels of voltage:

- Distribution @34.5 kV (sub-transmission);
- Distribution @4.8 kV (primary); and
- Secondary Distribution.

This methodology facilitates the appropriate determination of distribution costs for each customer class based on utilization (or lack thereof) of the distribution facilities by that customer class.

3.2.3.2 Cost Causation Factors

The costs of sub-transmission and distribution capacity are fixed costs and do not vary with the quantity of energy transmitted. Therefore, these capacity-related distribution costs are mainly classified as demand related. Consequently, they are calculated for each customer class on the basis of demands imposed on the system.

The delivery system is designed and constructed to meet the expected peak demand placed on it. This design demand is a localized cost driver; portions of LADWP's delivery system peak at different times depending on the area of the system, as the mix of customers and facilities used also varies by the area of the system. Consequently, non-coincident peak demand (NCP), which represents the maximum demand for a homogenous class of customers, is the most appropriate mode to determine local facility costs such as those of substations and primary and secondary distribution facilities. The use of non-coincident peak demand constitutes standard industry practice for determining distribution costs for customer classes.

The analysis of distribution capacity and O&M costs is extensive and is shown in Appendix D, Distribution Capacity and O&M Marginal Unit Costs.

3.2.4 Customer Related Marginal Costs

Some expenses for the electric system are directly attributable to the number of customers served. For the LADWP marginal cost study, these costs included the provision of customer meters and customer account expenses.

3.2.4.1 Meter Costs

The capital cost of providing a meter for each customer class was based on data received from the LADWP Power System Engineering Department; meters for residential customers are typically less expensive than those provided for commercial and industrial customers. It was assumed that the average life for the meters was 10 years.

Based on the 5.45% cost of capital and a 10 year average life of the meter for each customer class, an annual total unit capital cost for a meter was calculated for each major customer class. For instance, it was estimated that the total capital cost for a residential meter was $50; based on this estimate, the annual annuity cost or the unit marginal cost associated with a residential meter was $6.62. A similar calculation was completed for each other major customer class.

3.2.4.2 Customer Account Expenses

As described above, certain expenses are directly associated with the number of customers on the LADWP system including Customer Records & Collection, Metering Expenses, Meter Reading, etc. For the marginal cost study, these expenses were categorized as Customer Account Expenses and were determined to be $105 million from the FY 2012-13 General Ledger.

A vast majority of customers on the LADWP system (1,275,567 or 86%) are residential. It was determined that compared to a residential account, it involved more time, effort and expense to serve a commercial or industrial account. Consequently, in order to properly reflect this difference, weights were assigned to each customer class (based on service complexity) in the determination of Customer Account

Expenses for each customer class. For example, it was estimated that servicing an A1 (small commercial) customer involved five times the effort required for servicing an R1 (residential) customer. Consequently, a weight of 5 was assigned to the A1 category (compared to a weight of 1 for the R1 category) in the determination of marginal Customer Account Expenses for the A1 customer class. The customer weights used for the marginal cost study are depicted in Figure 14 below. The unit marginal cost for Customer Account Expenses was determined to be $71.26 per customer per year.

Figure 14: Weights for Customer Account Expenses

	R1	A1	A2	A3	Other
Customer Weight	1	5	15	50	15

3.2.5 Indirect General Marginal Costs

LADWP incurs some expenses that are intrinsic to the general operation of the Power System and can be classified as indirect general costs or adders. A brief description of these costs is provided below:

3.2.5.1 General Plant Expenses

These expenses pertain to the depreciation, property taxes and debt servicing costs associated with assets that are utilized in the general operation of the Power System, and not directly tied to the functional components like generation, transmission, distribution, etc.

The total FY 2012-13 expense associated with depreciation, debt and property tax expenses (accounts 503, 505, 507, 530-536) was estimated as $684 million from the General Ledger.

Based on an analysis of General Ledger plant data, it was estimated that general plant assets represented about 9.56% of the total electric plant assets for the LADWP Power System. Therefore, 9.56% of the Total 2013 Depreciation, Property Tax and Interest Expense, or $65.4 million, was assigned to General Plant Expenses and added to the overall plant expense.

A unit general plant marginal cost of $0.0028/kWh was calculated by dividing the $65.4 million general plant adder by the total system retail load of 23,383 million kWh.

3.2.5.2 Administrative & General (A&G) Expenses

These costs refer to the overall general expenses incurred in the administration of the Power System and include expenses for: accounting & collections, sales & marketing expenses, administrative & general salaries and other miscellaneous general expenses. These costs were obtained from the General Ledger (accounts 890-946) and amounted to $166.6 million for FY 2012-13. Dividing this amount by the total system retail load of 23,383 million kWh results in a unit A&G marginal cost of $0.0071.

3.2.5.3 City Transfer Expenses

The City Transfer refers to the annual transfer of funds to the City of Los Angeles, which was $246.5 million for FY 2012-13. This transfer amount was divided by the total system retail load of 23,383 million kWh to determine a unit City Transfer marginal cost of $0.0105/kWh.

3.3 Summary of Unit Marginal Costs by Functional Component

Figure 15 provides a summary of the marginal cost study results. The table lists the unit marginal cost for each functional sub-component, the cost causation factor or billing unit basis for each sub-component, and the methodology and source for determining the marginal costs. The marginal cost revenue requirements and the marginal cost revenue requirements ratios for each customer class are ultimately determined by applying these marginal unit costs to the appropriate customer class units.

Figure 15: Summary of Unit Marginal Costs by Functional Component

Functional Component	Marginal Cost	Billing Units	MC Revenue Determination Method & Source
Transmission			
Transmission Capacity+ losses	$45.12	$/CP kW/yr	Surrogate Transmission Capacity Expansion Project
Integration/Ancillary Services	$7.64	$/CP kW/yr	Open Access Transmission Tariff (OATT)
Transmission O&M	$22.02	$/CP kW/yr	Based on General Ledger (GL) Analysis FY 2012-13
Generation			
Generation Energy + losses	$0.0344	$/kWh	Based on hourly system lambda forecast from ProSym model
Generation O&M	$0.0064	$/kWh	General Ledger Analysis FY2012-13
Renewable Portfolio Standard	$0.0113	$/kWh	2013 IRP estimate
GHG Emission Cost	$0.0061	$/kWh	2013 IRP estimate
Total Generation Energy	$0.0582	$/kWh	
Generation Capacity Plant	$108.20	$/kW/yr	Based on annual cost of combustion turbine from IRP 2013
Distribution by Voltage Level			
Distribution Capacity at 34.5 kV (Sub-tran)	$15.00	$/NCP kW/yr	Analysis of change in real cost versus capacity change
Distribution O&M @ 34.5 (sub-tran)	$11.58	$/NCP kW/yr	Based on General Ledger Analysis FY 2012-13
Distribution Capacity at 4.8 kV	$76.82	$/NCP kW/yr	Analysis of change in real cost versus capacity change
Distribution O&M @ 4.8 kV	$59.31	$/NCP kW/yr	Based on General Ledger Analysis FY 2012-13
Distribution Secondary	$31.43	$/NCP kW/yr	Analysis of change in real cost versus capacity change
Distribution O&M Secondary	$24.27	$/NCP kW/yr	Based on General Ledger Analysis FY 2012-13
Customer Account Expenses	$71.26	$/customer/year	Based on General Ledger Analysis FY 2012-13
Meter Cost by Tariff (average)	$6.72	$/customer/year	Annualized Cost of installing new meters
A&G & Other			
General Plant Costs	$0.0028	$/kWh	Proration of Debt & Depreciation based on Plant ratios from GL
A&G Costs	$0.0071	$/kWh	As an adder; based on General Ledger Analysis FY 2012-13
City Transfer Costs	$0.0105	$/kWh	As an adder; based on General Ledger Analysis FY 2012-13
Total adder	$0.0205	$/kWh	
Inflation Assumption	2.5%		IRP 2013
Cost of Capital , %i	5.45%		Financial Planning Assumption
Average System Marginal Cost in $/kwh	**$0.147**	$/kWh	**Result from Marginal Cost Study**
Average System Current Cost in $/kwh	**$0.131**	$/kWh	**Current average system wide rate**

The average system-wide marginal cost is $0.147 per kWh. This amount represents the summation of the marginal cost revenue requirements for each customer class, divided by the summation of the LADWP system FY 2012-13 kWh load for all customer classes. The corresponding current average system-wide rate is $0.131 per kWh.

4 CALCULATION OF MARGINAL COST REVENUE REQUIREMENT

Marginal cost revenue requirements for each major customer class are determined based on the unit marginal cost for each functional component/sub-component and the corresponding cost causation factor) by functional component for each customer class. Figure 16 provides a list of key cost causation factors for each customer class.

Figure 16: Annual Cost Causation Factors for Each Customer Class

Cost Causation Factors	R1*	A1*	A2*	A3*	Other	Total w/o Owens Valley
NCP12 (kW)	1,755,951	504,779	627,418	1,589,646	41,020	4,518,814
	38.9%	11.2%	13.9%	35.2%	0.9%	100.0%
NCP1 (kW)	2,583,130	608,376	746,909	2,027,460	41,020	6,006,894
	43%	10%	12%	34%	1%	100%
CP 1 (kW)	1,899,043	521,175	612,515	1,678,041	0	4,710,773
	40%	11%	13%	36%	0%	100%
CP 12 (kW)	1,516,369	453,320	514,460	1,393,394	13,673	3,891,216
	39%	12%	13%	36%	0%	100%
Customers (#)	1,275,567	173,462	13,194	5,562	6,525	1,474,309
	86.5%	11.8%	0.9%	0.4%	0.4%	100.0%
Energy @ the Meter (kWh)	7,524,856,175	2,995,566,290	3,202,058,236	9,510,066,485	149,967,510	23,382,514,696
	32.2%	12.8%	13.7%	40.7%	0.6%	100.0%
Energy with Losses	8,311,956,131	3,308,902,524	3,488,749,183	10,218,249,436	157,810,810	25,485,668,085
	32.6%	13.0%	13.7%	40.1%	0.6%	100.0%

The summation of the marginal cost revenue requirements for all the individual functional components and sub-components comprises the aggregate marginal cost revenue requirement for each customer class. The marginal cost revenue requirement determination by customer class is summarized by the following equations:

- $Customer\ Class\ MC\ Revenue\ Requirement\ by\ Functional\ Component =$ $Unit\ MC\ for\ Functional\ Component * Cost\ Causation\ Factor\ (for\ specific\ customer\ class)$
- $Total\ Customer\ Class\ MC\ Revenue\ Requirement =$ $Sum\ of\ all\ MC\ Revenue\ Requirements\ for\ all\ Functional\ Components$

The marginal cost revenue requirement for a particular functional component for a specific class of customer is the unit marginal cost for that component times the customer class cost causation factor for that component adjusted for losses. The cost causation factors by customer class appear above in Figure 16. The unit marginal costs by functional component/sub-component appear in Figure 15.

Figure 17 provides a summary of the marginal cost revenue requirement for each major customer class by functional component.

Figure 17: Summary of Marginal Cost Requirement by Functional Component

FUNCTIONAL COMPONENT	R1* Residential	A1* S Commercial	A2* M Commercial	A3* Industrial	Other	Total w/o Owens Valley	UNIT
Transmission	$ 126,637,360	$ 37,858,334	$ 42,253,447	$ 112,578,690	$ 1,141,897	$ 320,469,729	$/CP kW/yr
Generation Capacity	$ 183,240,190	$ 54,779,792	$ 60,649,274	$ 161,994,433	$ 1,634,210	$ 462,297,899	$/CP kW/yr
Generation Energy & O&M	$ 468,400,282	$ 184,195,056	$ 192,607,354	$ 562,872,410	$ 9,233,871	$ 1,417,308,972	$/kWh
Distribution Capacity & O&M @34.5kV	$ 46,663,847	$ 13,414,359	$ 16,673,453	$ 42,244,353	$ 1,090,082	$ 120,086,093	$/NCP kW/yr
Distribution Capacity & O&M @4.8kV	$ 239,035,951	$ 68,715,167	$ 85,409,902	$ -	$ 5,583,955	$ 398,744,975	$/NCP kW/yr
Distribution Capacity & O&M @Secondary	$ 97,813,300	$ 28,118,186	$ -	$ -	$ 2,284,949	$ 128,216,436	$/NCP kW/yr
Meter Costs	$ 8,441,049	$ 1,147,880	$ 174,675	$ 147,230	$ -	$ 9,910,834	$/Customer
Customer Account Expenses	$ 49,382,347	$ 33,576,978	$ 7,661,847	$ 10,643,390	$ 3,789,137	$ 105,053,699	$/Customer
Admin. & General Costs	$ 53,623,373	$ 21,346,902	$ 22,818,398	$ 67,770,311	$ 1,068,693	$ 166,627,677	$/kWh
General Plant Costs	$ 21,049,321	$ 8,379,514	$ 8,957,135	$ 26,602,560	$ 419,505	$ 65,408,034	$/kWh
City Transfer Costs	$ 79,338,468	$ 31,583,812	$ 33,760,963	$ 100,269,572	$ 1,581,185	$ 246,534,000	$/kWh
Total Marginal Cost Revenue Requirement	$ 1,373,625,488	$ 483,115,979	$ 470,966,448	$ 1,085,122,948	$ 27,827,485	$ 3,440,658,348	
Marginal Cost Revenue Requirement Ratio	39.9%	14.0%	13.7%	31.5%	0.8%	100.0%	

5 MARGINAL COST STUDY RESULTS AND IMPLICATIONS

In today's changing and dynamic business environment, the cost of power production in most instances varies by season, by time of day and by historical periods. Therefore, simply calculating accounting costs is not an accurate way to reflect variations over prolonged time periods; costs based on technology and expenditures from the past may no longer be representative of present conditions.

The marginal cost concept can thus assist the utility in more appropriately allocating and recovering the cost of doing business in the future. The electric power industry is dynamic and highly capital intensive. Marginal cost studies facilitate matching future prices with cost recovery responsibility, which is generally considered to be the most fair and equitable method of electric utility pricing.

This phenomenon is exemplified by the current LADWP marginal cost study results, as explained below.

5.1 Customer Class Impacts

Marginal cost ratemaking concepts have commonly been utilized to promote fairness and equity in rates for customer classes. Through appropriate use of marginal concepts, utilities can appropriately allocate the cost of service among customer classes and then appropriately price services for the customer classes.

LADWP is allowed to recover all necessary costs associated with the provision of electric service to various customer classes. These costs, often referred to as the test year revenue requirement, comprise all costs including capital related costs (depreciation, property taxes, and debt servicing costs), operations and maintenance costs, fuel & power costs, administrative & general costs, etc. For the test year FY 2012-13, this aggregate revenue requirement amount, collected through the retail rates for each customer class, was approximately $3,071 million.

The LADWP marginal cost study calculates the required revenues on a forward-looking basis, using data for the FY 2012-13 test year as a starting point. The revenue requirement based on the marginal cost study generally exceeds the accounting-cost-based revenue requirement. For the LADWP marginal cost study, the total marginal costs are approximately $3,441 million, which is 12% higher than the FY 2012-13 revenue requirement of $3,071 million. Since marginal costs are forward-looking, it is normal for the marginal cost revenue requirement to be higher than the current revenue requirement in total.

Over time, cost structures change, and, as a result, marginal cost of service studies should be conducted periodically to reflect forward-looking allocation of costs among customer classes. For example, California legislation and regulations have increased the required use of renewable resources. The marginal cost of service study allocates these forward-looking renewable costs across customer classes based on cost causation.

The summation of the customer class marginal cost revenue requirements for all the individual functional components and sub-components comprises the marginal cost revenue requirement for each customer class. A marginal cost revenue requirement percent to total is then calculated for each customer class, based on its proportion of the customer class marginal cost revenue requirement to the total LADWP marginal cost revenue requirement.

The marginal cost of service study for LADWP results in a different set of customer class revenue percentages of total revenue, as compared to the current revenue and cost of service structure. For example, based on the marginal cost study results (shown in Figure 18), the marginal cost revenue requirement percent for the residential (R1) customer class is 39.9%, while the corresponding ratio based on current revenues for FY 2012-13 is 32.9%. Conversely, based on marginal costs, the Industrial (A3) customer class would be allocated a lower revenue requirement of 31.5% compared to the current revenue level of 37.1%.

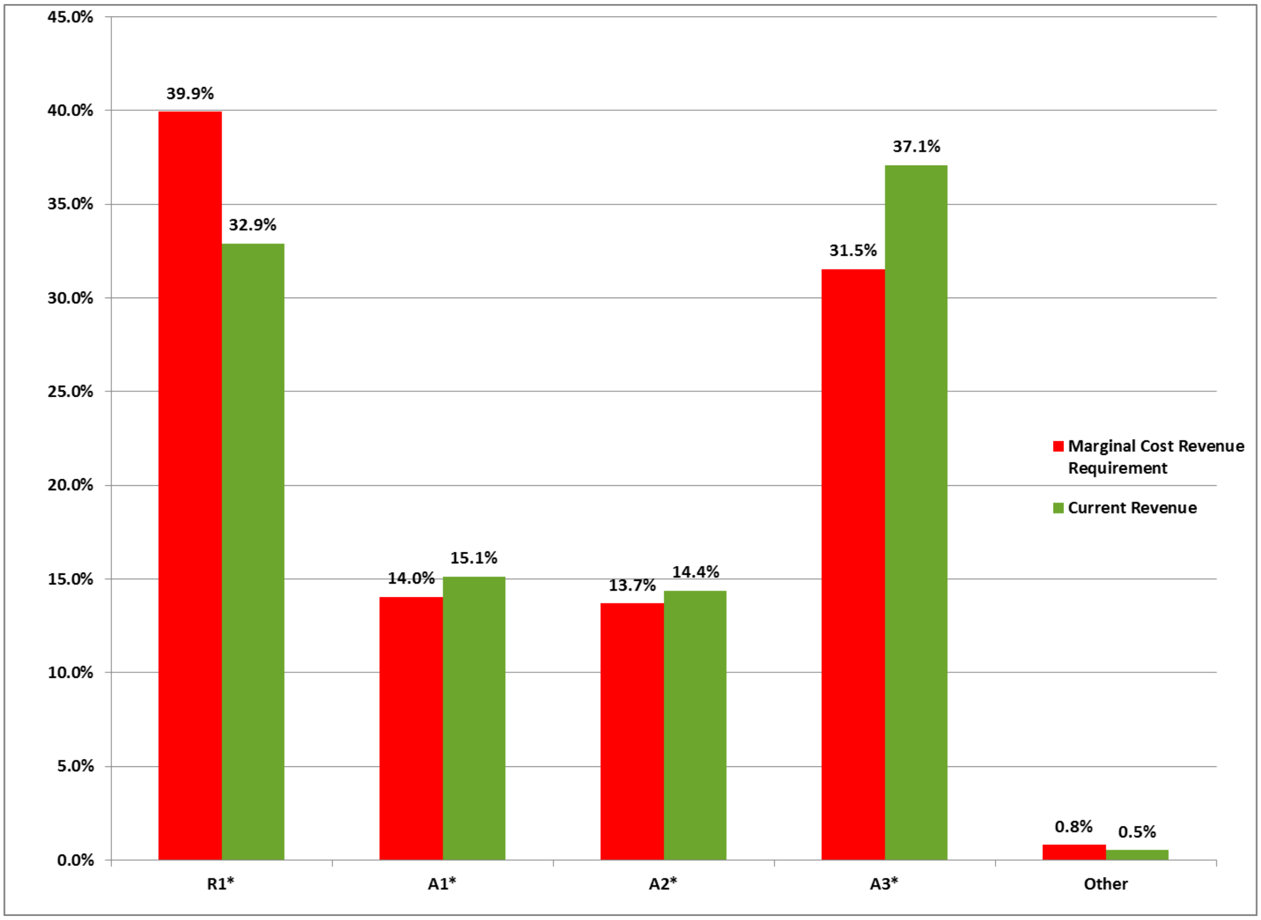
To avoid over/under collection of costs and more accurately reflect cost causation principles, the customer class percentages based on the marginal cost of service study can be applied to the approved annual revenue requirement, to allocate the approved revenue requirement to major customer classes.

Figure 18: Comparison of Marginal Cost Revenue Requirements & Current Revenue by Customer Class

Comparisons	Residential	S Commercial	M Commercial	Industrial	Other	Total
Total MC Revenue Requirement	$1,373,625,488	$483,115,979	$470,966,448	$1,085,122,948	$27,827,485	$3,440,658,348
Marginal Cost Revenue Requirement Percentage	39.9%	14.0%	13.7%	31.5%	0.8%	100.0%
FY 2013 Current Retail Revenue	$1,010,099,373	$464,812,908	$441,103,892	$1,138,691,239	$16,187,848	$3,070,895,260
Current Revenue Percentage	32.9%	15.1%	14.4%	37.1%	0.5%	100.0%

Figure 19 graphically compares the marginal cost revenue requirements ratios and the current revenue ratios for the various customer classes.

Figure 19: Comparison of Marginal Cost Revenue Requirement & Current Revenue Percentages by Customer Class



The current LADWP marginal cost study results demonstrate that a re-alignment of revenue requirements among the customer classes is likely warranted.

These results are supported by an LADWP embedded[11] cost of service analysis, which produced similar customer class percentages as the marginal cost of service study (See Appendix B: LADWP Embedded Cost Analysis).

[11] Embedded Cost analysis is also referred to as Average Embedded Cost Analysis.

APPENDIX A: GLOSSARY OF TERMS

Ancillary Services: Services necessary to support the reliable provision and transmission of energy from resources to loads. These services include regulation, spinning, and non-spinning reserves, replacement reserves, reactive voltage (var) support and black start capability.

Annuity: An annuity is a terminating "stream" of fixed payments, i.e., a collection of payments to be periodically received over a specified period of time. The valuation of such a stream of payments entails concepts such as the time value of money. For the marginal cost study, annuities have been calculated to determine annual payments or annual revenue requirement associated with the determination of marginal costs for capital investments. These annuities have been calculated based on the IRP cost of capital of 5.45%.

Cogeneration: Customers who own electrical generating facilities that are connected with LADWP's system but are not subject to the Net Energy Metering (NEM) service rider.

Coincident Peak Demand: The aggregate demands of a group of customers at a particular time, usually at the time of a customer group's peak or the system peak.

- CP1: Coincident peak one month - represents the system peak in the peak month of the year.
- CP12: Coincident peak 12 months - represents the average of the coincident peaks for each month of the year.

Cost Drivers: Fundamental aspects of customer demand for services that directly cause LADWP to incur costs.

Greenhouse Gas (GHG): Byproduct of the burning of energy generation fuels that is emitted to the atmosphere and absorbs and emits radiation from the atmosphere to cause the greenhouse effect.

Handy Whitman Index: A measure of the annual rate of inflation in capital investments. It is published annually by Whitman, Requardt and Associates, for a wide range of industries and investment categories. Extensively used by the utility industry to gauge the rate of inflation in capital investments by geographic sectors, as well as by asset category like generation facilities, transformers, distribution assets, etc.

Load: The amount of electric power delivered or required at any specified point on an electrical system. Load primarily originates at the power-consuming equipment of the customer.

Marginal Cost: Change of cost that arises from providing an additional unit of a good or service.

Marginal Cost Revenue Requirement: Revenues that would result if all the aspects of electric service were priced to reflect the marginal costs of providing such service.

Net Energy Load: Net Energy Load is the actual load at the transmission inlets to the LADWP system, before transmission & distribution & other losses.

Non-Coincident Peak Demand: The individual customer's peak demand measured irrespective of the time of system peak and irrespective of the peak demand of any other customer or group of customers.

Open Access Transmission Tariff (OATT): The document approved by the Los Angeles City Council on July 1, 2014, which contains the terms and conditions, including rates, under which LADWP makes its transmission facilities available for use by the public after all of LADWP's native load needs are met.

Primary Voltage: Facilities at which electric power is taken or delivered at 4.8 kV.

Present Value: Also known as present discounted value and is a future amount of money that has been discounted to reflect its current value, as if it existed today. The present value is always less than or equal to the future value because money has earning potential, a characteristic referred to as the time value of money. For the LADWP study, present value has been computed by discounting future cash flows by the IRP cost of capital of 5.45%.

ProSym Model: LADWP uses an energy production cost simulation model called ProSym. The ProSym Model is a load dispatch model that computes estimated hourly system lambda costs, and incorporates the future impact of reduced reliance on once-through cooling units and increased generation from solar and wind sources.

Regression Analysis: Statistical process for estimating the relationships among variables for the purpose of predicting future values. It includes many techniques for modeling and analyzing several variables, when the focus is on the relationship between a dependent variable and one or more independent variables. More specifically, regression analysis helps one understand how the typical value of the dependent variable changes when any one of the independent variables is varied, while the other independent variables are held fixed.

Revenue Allocation: The process of assigning the revenue requirement to rate groups or customer classes.

Secondary Voltage: Facilities at which electric power is taken or delivered at or below 480 V and at or above 110 V.

System lambda: The system lambda is defined as the cost of the next kilowatt-hour that can be produced by an electrical supply system's generating unit. It serves as a proxy for the generation energy marginal costs.

System Loss: The loss in load from the point of supply (transmission inlets) to the customer's meter. Power System losses relate to transmission and distribution line losses, and other losses (e.g. energy theft, metering errors, etc.).

Time of Use (TOU) Rates: Rates that are charged for energy depending on the time of day the energy is used.

APPENDIX B: LADWP EMBEDDED COST ANALYSIS

The Department conducted an embedded[12] cost of service analysis utilizing an embedded cost of service model; the results from this model substantiate the conclusions of the marginal cost study. The embedded cost of service methodology was based on standard industry techniques.

The LADWP embedded cost model was based on data provided by the LADWP Budget group; a detailed analysis was conducted by the Budget group to allocate the historical costs on the system to functional components. The embedded cost analysis involves three major steps:

- Functionalizing or unbundling the utility costs according to generation, transmission, distribution, customer or general (based on Budget group analysis);
- Classification of these costs as to whether they were related to demand (kW), energy (kWh) or customer, or a combination thereof.
- Finally, the resulting cost determinations were allocated to the various customer classes, based on appropriate allocation criteria.

Following the steps outlined above, embedded cost revenue requirements were determined for each customer class. An embedded cost revenue requirement percent to total was calculated for each customer class. Figure 20 below displays the results from the embedded cost model. Since the focus of this report is the marginal cost study, the results of the embedded model are simply presented here for comparison purposes only.

Figure 20: Comparison of Embedded Cost Revenue Requirement and Current Revenue by Customer Class

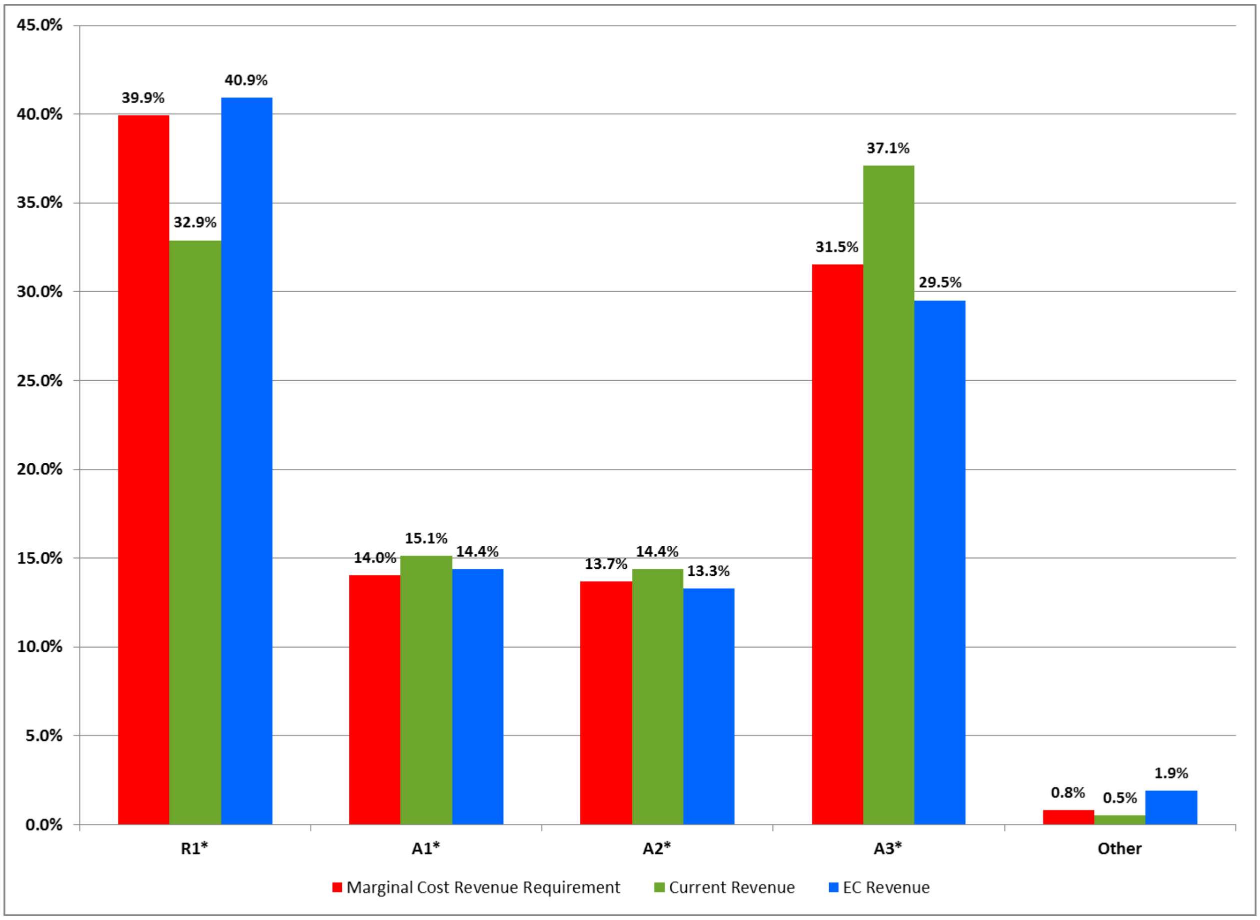
COST STUDIES 2013 Results	R1* Residential	A1* S Commercial	A2* M Commercial	A3* Industrial	Other	Total
Total MC Revenue	$1,373,625,488	$483,115,979	$470,966,448	$1,085,122,948	$27,827,485	$3,440,658,348
Marginal Cost Revenue Percentage	39.9%	14.0%	13.7%	31.5%	0.8%	100.0%
FY 2013 Current Revenue	$1,010,099,373	$464,812,908	$441,103,892	$1,138,691,239	$16,187,848	$3,070,895,260
Current Revenue Percentage	32.9%	15.1%	14.4%	37.1%	0.5%	100.0%
Total Embedded Revenue	$1,273,095,936	$447,346,278	$413,399,145	$918,605,926	$59,100,631	$3,111,547,915
Embedded Revenue Percentage	40.9%	14.4%	13.3%	29.5%	1.9%	100.0%

The results from the embedded cost model are similar to the marginal cost study. For example, the embedded cost and marginal cost revenue requirement percentages for the residential (R1) customer class are 40.9% and 39.9% respectively, while the corresponding ratio based on current revenues for FY 2012-13 is 32.9%. Conversely, based on embedded costs and marginal costs, the Industrial (A3) customer class would be allocated a lower revenue requirement of 29.5% and 31.5%, respectively, compared to the current revenue level of 37.1%. Figure 21 provides a comparison of revenue requirement

[12] An embedded cost analysis is based on historical or “embedded” costs for the electric system.

percentages by customer class for the embedded cost analysis, the marginal cost study and the current revenue.

Figure 21: Comparison of Embedded Cost and Current Revenue Percentages



APPENDIX C: TRANSMISSION CAPACITY ANALYSIS

Transmission capacity marginal costs for the LADWP system were estimated based on a proxy methodology utilizing the new Barren Ridge Renewable Transmission expansion. LADWP is proposing the Barren Ridge Renewable Transmission Project (BRRPT) to access clean, renewable energy resources in the Tehachapi Mountain and Mojave Desert areas of Southern California. This transmission line and substations project will bring renewable energy resources to the City of Los Angeles, and will also enhance power delivery reliability. The project is in Kern and Los Angeles Counties and will consist of:

- Construction of a 230 kilovolt (kV) transmission line from the LADWP Barren Ridge Switching Station to Haskell Canyon on double-circuit structures (involving approximately 13 miles of National Forest System lands and 4 miles of Bureau of Land Management (BLM) managed public lands)
- Addition of a 230 kV circuit on the existing double-circuit structures from Haskell Canyon to the Castaic Power Plant (involving approximately 4 miles of National Forest System lands and 300 feet of BLM managed public lands)
- Upgrade the existing Barren Ridge – Rinaldi 230 kV transmission line with larger capacity conductors between the Barren Ridge Switching Station to Rinaldi Substation (involving approximately 13 miles of National Forest System lands and 4 miles of BLM managed public lands)
- Construction of a new electrical switching station at Haskell Canyon.
- Expansion of the existing Barren Ridge Switching Station.

Although Barren Ridge is a relatively small transmission expansion project, it represents a recent project providing a reasonable basis for estimating an LADWP transmission system capacity expansion. The methodology followed for this analysis was to determine the capital expenditures associated with the Barren Ridge transmission expansion, the corresponding increase in system capacity (per kW) and the resulting transmission capacity unit marginal cost.

The derivation of the unit marginal transmission capacity charge per kW is explained below.

- An expenditure profile was obtained for the Barren Ridge project from the 2013 IRP. Some of the capital costs were incurred prior to 2012; some of the costs are spread over the period 2013-2021, with a majority of the costs expected to be incurred in 2014-2015.
- The estimated project cost was determined to be $184.3 million in 2013 dollars.
- Based on a useful life of 40 years for these facilities and a discount rate of 5.45%, an annual cost annuity for the transmission capacity expansion was determined to be $11.4 million.
- Since the incremental capacity for this project is estimated at 1,900 MW, the annual capacity cost per kW is $6.00 ($11.4 million / 1,900 MW). This incremental cost is incurred for a transmission line expansion of 62 miles representing the Barren Ridge project.
- The total LADWP transmission system comprises 3,747 miles, and the useful life of transmission lines is deemed to be 40 years; therefore, it was estimated that 2.5% of circuit miles, or 93.7 miles, would need replacement annually.

- Since the Barren Ridge project constitutes 62 miles, it was estimated that on average, it would cost 1.51 times more than the Barren Ridge project to undertake an average annual system circuit mile replacement of 93.7 miles.
- Consequently, by extrapolation, the unit marginal cost per kW for the system was obtained as \$9.07 per kW, i.e. 1.51 times the unit capacity cost of \$6 for Barren Ridge. Assuming an expected loading factor of 20.1% for this project, the final transmission capacity unit marginal cost was estimated to be \$45.12 per kW.

APPENDIX D: DISTRIBUTION O&M AND CAPACITY MARGINAL UNIT COSTS

D.1. Distribution O&M Costs by Voltage

Like Transmission O&M costs, Distribution O&M costs are associated with the general operations and maintenance of the LADWP distribution system. These costs include: operating expenses for load dispatching labor, distribution station labor, miscellaneous operation expenses, and maintenance of the overhead conductors, poles, structures, towers, station equipment, etc.

D. 1.1. Determination of Total Distribution O&M Costs

Distribution O&M costs were based on the actual FY 2012-13 General Ledger accounts (G/L Accounts 840-883) associated with distribution service. The cost amount utilized for the study calculations was $281.9 million. These aggregated Distribution O&M Expenses were then allocated to the three voltage levels, as described below.

The General Ledger data is not differentiated by voltage level detail. Consequently, an alternative method was developed to calculate Distribution O&M costs by voltage level. A detailed analysis was conducted to estimate the capital costs of establishing a new LADWP distribution system. Estimates for various components such as poles, conduit, underground cables, overhead conductors, transformers, individual stations, etc. were obtained separately for 34.5kV, 4.8kV and secondary distribution facilities. This aggregate capital expenditure was estimated at a total of $1,081 million.

The estimated capital expenditure ratios for the three voltage levels were then utilized to allocate the total Distribution O&M Expenses to each voltage level. For instance, the capital expenditures estimated for secondary voltage comprised 19.8% of the total expenditures. Consequently, 19.8% (or $55.9 million) of the total Distribution O&M cost of $281.9 million was determined to be attributable to Secondary voltage.

Figure 22 below provides a breakdown of the estimated capital costs for a new distribution system by voltage levels and the allocation of distribution O&M expenses.

Figure 22 Estimated Capital Cost by Voltage Level

Voltage Level	Estimated Capital Costs	Capital Cost Ratio	O&M Expense Allocation
Secondary Distribution	$214,174,218	19.8%	$55,865,257
4.8 kV Distribution	$666,068,221	61.6%	$173,737,404
34.5 kV Distribution	$200,593,200	18.6%	$52,322,781
System Total	$1,080,835,639	100%	$281,925,443

D.1.2. Calculation of Unit Charge

For each voltage level, Unit Distribution O&M marginal costs were then determined. The O&M expenses estimated above for each voltage level were divided by the corresponding NCP kW to obtain a unit marginal O&M cost per kW. The NCP kW utilized for these calculations equated to the summation of the

NCP kW of the customer classes actually using each voltage level. For example, the total NCP level for the LADWP 34.5 kV system for FY 2012-13 was 4,519 MW. However, for secondary distribution, which is not utilized by A2 & A3, the NCP kW level used for the unit cost was 2,302 MW, which excluded the NCP kW for A2 and A3. Therefore, the unit Distribution O&M cost for secondary was calculated as $24.27/kW, or $55.9 million (secondary O&M costs) divided by 2,302 MW (secondary NCP MW).

Figure 23 below illustrates the distribution facility usage levels for each customer class on the LADWP system.

Figure 23 Distribution Facility Usage By Customer Class (FY 2012-13)

Non-Coincident Peak by Voltage Level	R1*	A1*	A2*	A3*	Other*	Total
NCP12 (kW) @ 34.5 kV Sub-Transmission	1,755,951	504,779	627,418	1,589,646	41,020	4,518,814
34.5 kV Ratio	38.9%	11.2%	13.9%	35.2%	0.9%	100%
NCP12 (kW) @ 4.8 kV Primary	1,755,951	504,779	627,418	0	41,020	2,929,168
4.8 kV Ratio	59.9%	17.23%	21.42%	0.00%	1.40%	100%
NCP 12 (kW) @ Secondary	1,755,951	504,779	0	0	41,020	2,301,750
Secondary Ratio	76.3%	21.9%	0.0%	0.0%	1.8%	100%

D.1.3. Calculation of Distribution Capacity Costs by Voltage

The determination of the marginal cost of distribution capacity is based on an estimation of the historical relationship between incremental investments in distribution and distribution capacity.

Standard industry practice for measuring this relationship is to use linear regression analysis, with real capacity cost as a linear function of demand. The slope of the regression line equals the per-unit marginal cost of distribution capacity.

Distribution Capacity marginal costs for the LADWP study were determined based on this regression technique. The historical annual capacity cost increments (adjusted for inflation) were regressed against the amount of capacity available. The slope of the regression line (regression coefficient) constituted the marginal unit cost of distribution.

The cost causation factor for distribution capacity costs is system non-coincident peak. Coincident peak (CP) demand was used for the calculation of the unit marginal costs and then converted to NCP.

The various steps in this calculation are listed below.

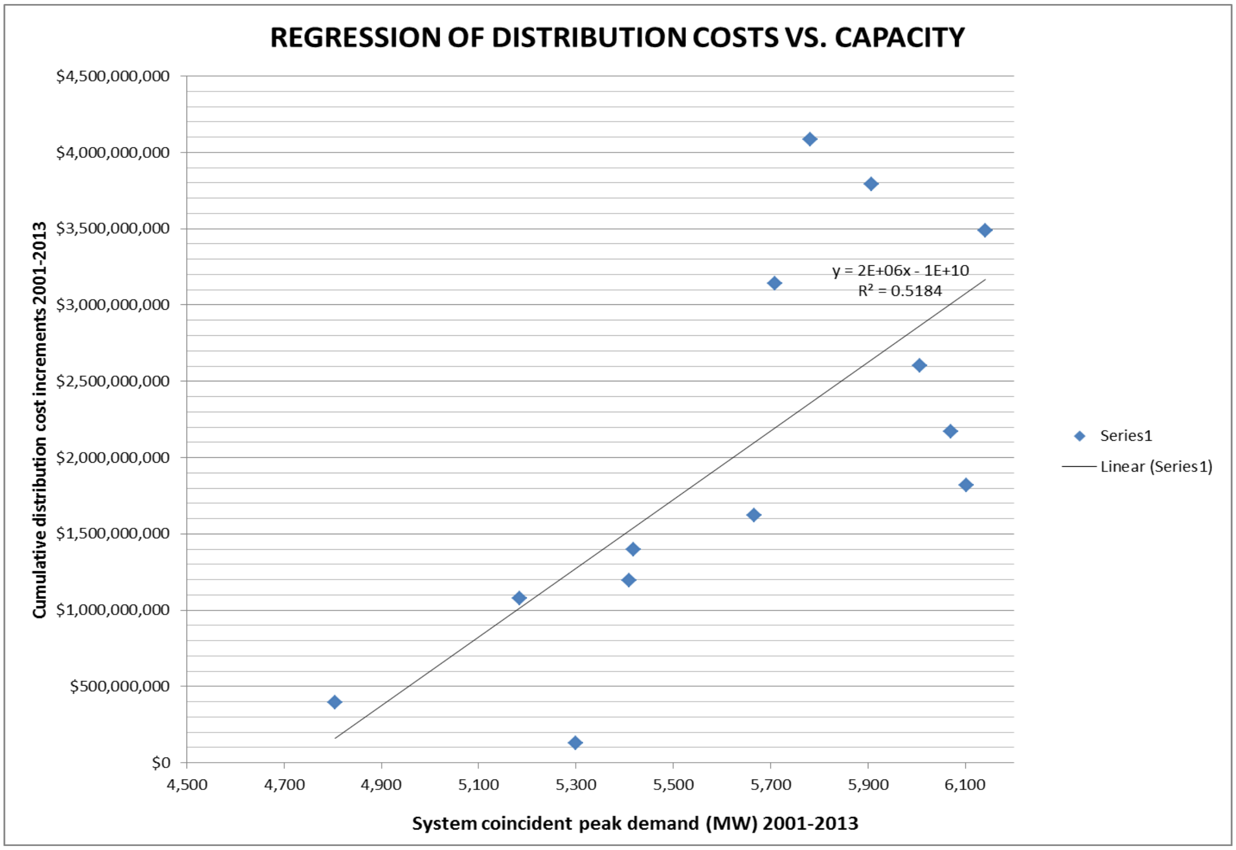
- Distribution gross plant asset data from FY 1999-00 to FY 2012-13 was obtained from the General Ledger by type of account such as poles, towers, overhead & underground conductors, line transformers, etc.
- The annual increments or additions to the distribution gross plant for each year were determined. These historical additions were then converted to current year FY 2012-13 dollars using the Handy Whitman Index for Utility Construction[13].
- Next, the cumulative gross plant additions from FY 1999-00 to FY 2012-13 were determined.
- From historical LADWP load data, the system coincident peak demands in kW were determined for the years 2000 - 2013.

[13] The Handy Whitman Index is a measure of the annual rate of inflation in capital investments, used extensively in the utility industry. It covers different regions as well as different assets like distribution plant, generating units, transmission facilities, etc.

- The cumulative annual gross plant additions (used as a proxy for the capacity costs) were regressed against the annual coincident peak demand in kW (used as a proxy for amount of capacity available).

The regression coefficient or slope of the linear regression equation served as the approximation of the total marginal cost per kW of distribution capacity. This was determined to be $2,247/kW. This total cost was then converted to an annual annuity based on a useful life of 40 years and a 5.45% discount rate, which amounted to $143/kW CP per year. Figure 24 illustrates the relation between the incremental distribution capacity costs and capacity.

Figure 24: Relation of Incremental Distribution Costs and Capacity



This distribution capacity cost per kW for CP was then converted to NCP amounts. The 2013 annual CP demand was 3,891 MW. The aggregate 12 NCP for all customer classes for 2013 was 4,519 MW. Therefore the ratio of NCP/CP amounted to 1.16. Based on this NCP to CP ratio of 1.16, the unit marginal cost of $143/kW CP was converted to a distribution capacity unit marginal cost of $123.25/kW NCP.

Finally, the unit distribution capacity cost of $123.25/kW was allocated to the three voltage levels, based on the percentage of marginal cost estimates for total distribution plant by voltage. By this methodology, the following unit distribution capacity marginal costs were obtained, as shown in Figure 25 below:

Figure 25: Unit Marginal Costs by Voltage (FY 2012-13)

Voltage Level	Estimated Marginal Cost	Unit Capacity Cost $/kW
Secondary Distribution	26%	$31.43
4.8 kV Distribution	62%	$76.82
34.5 kV Distribution	12%	$15.00
System Total	100%	$123.25

D.2. Distribution Capacity Costs by Voltage

Like the distribution O&M costs, distribution capacity marginal costs by voltage are classified as demand related and calculated for the customer classes based on the NCP kW for each customer class. Adjustments are made to the NCP demand factors to account for the fact that some customer classes do not utilize certain distribution facilities. For example, the R1 customer class utilizes all the distribution facilities at all kV levels. Therefore, the bulk of these costs are absorbed by the Residential customer class, as illustrated in Figure 26 below.

As an example, a calculation is illustrated for secondary Distribution Capacity marginal costs in the equation below:

> secondary Distribution Capacity Marginal Costs for R1 = Unit Capacity Cost for Secondary times secondary NCP kW for R1 = $31.43 X 1,755,951 = $55.2 million (which represents 76.3% of total secondary Distribution costs)

In this manner, distribution capacity marginal costs were determined for all three voltage levels for the residential customers, and the summation of these costs constituted the distribution capacity marginal cost for the residential class. The results are displayed in Figure 26 below.

Figure 26: Distribution Capacity MC Revenue Requirements by Customer Class (FY 2012-13)

Voltage Level	R1*	A1*	A2*	A3*	Other*	Total
Secondary Distribution	$55,195,011	$15,866,795	$0	$0	$1,289,373	$72,351,178
Percentage of MC Revenues	76.3%	21.9%	0.0%	0.0%	1.8%	100.0%
4.8 kV Distribution	$134,885,458	$38,775,242	$48,195,904	$0	$3,150,967	$225,007,571
Percentage of MC Revenues	59.9%	17.2%	21.4%	0.0%	1.4%	100.0%
34.5 kV Distribution	$26,331,915	$7,569,581	$9,408,653	$23,838,041	$615,122	$67,763,312
Percentage of MC Revenues	38.9%	11.2%	13.9%	35.2%	0.9%	100.0%
Combined Total Distribution	$216,412,384	$62,211,618	$57,604,557	$23,838,041	$5,055,461	$365,122,062
Percentage of MC Revenues	59.3%	17.0%	15.8%	6.5%	1.4%	100.0%

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