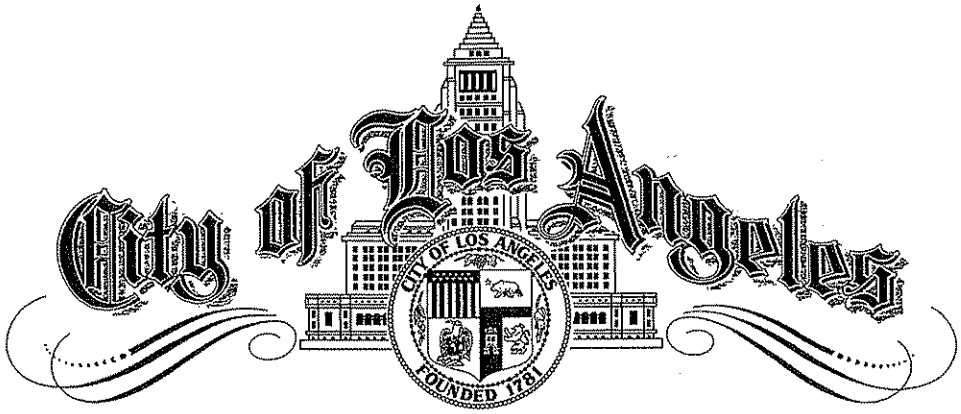

CITY HALL
LOS ANGELES, CALIFORNIA 90012

February 26, 2010

The Honorable Members of the Los Angeles City Council
City Hall
Los Angeles, CA 90012

To the Members of the City Council:

Please find attached the **Independent Fiscal Review of the Los Angeles Department of Water and Power (LADWP) Energy Cost Adjustment Factor (ECAF) and Residential Rate Design Proposals** report. The Fiscal Review was prepared in accordance to Council Action, adopted on September 2, 2009, instructing the City Administrative Officer and the Chief Legislative Analyst to conduct an independent fiscal review the LADWP's proposed Energy Cost Adjustment Factor (ECAF) cap modification proposal (CF# 09-1980-S1) and the Residential Tiered Electric Rate Restructuring proposal (CF# 07-3249). PA Consulting Group (PA) prepared the Fiscal Review through a contractual agreement through our Offices.

The objective of the Fiscal Review of the LADWP's ECAF and the Residential Rate Design proposals is to ensure that the financial interests of the City residents are protected by conducting a rigorous analysis of the financial condition of the Department, the cost of ECAF components, including the Renewable Portfolio Standard (RPS) program, Energy Efficiency (EE) program and related matters. Furthermore, the goal is to provide greater transparency, comprehension and confidence of the costs and impact of these elements prior to consideration of an ECAF and rate restructuring proposal by the City's decision making bodies.

Please note that PA's Review provides the following recommendations:

- A one-time quarterly increase in the ECAF cap to 0.8 cents per kWh to address the current ECAF undercollection, and maintain desired financial ratios and the target debt rating. (At present, the ECAF cap is set at 0.1 cents per kWh per quarter.) PA expects that subsequent quarterly adjustments will be needed which will result in a total increase of 2.7 cents per kWh over the next four quarters.

PA concludes that the first 0.8 increase should be implemented as soon as possible, preferably in time for the April 1, 2010 quarterly ECAF update. PA states that a delay in this timing will result in a growing ECAF undercollection that will eventually need to be addressed by an even higher short-term rate increase.

- Reconstituting the ECAF to focus specifically on volatile fuel and purchased power components only, and removing RPS, EE and city transfer elements, and other components from the ECAF.

  PA maintains that this will provide the Council with greater visibility of the LADWP's cost structure and of the justification for any rate increases. It will clearly identify the Council's actions to stabilize rates and will ensure that controllable costs are subject to appropriate controls.

- Update the Renewable Portfolio Standard (RPS) Plan.

  The Update is needed to reflect modifications and changes to the Plan since its approval in 2005 and to incorporate the Department's direction in the future.

PA's Fiscal Review also evaluates the impact on ratepayers due to this recommended increase and addresses a proposed revision to the prices in the R-1 (residential) rate. Specifically, 1) the impact of a recommended ECAF cap increase on customer classes under the current rate structure, and 2) the impact of a recommended ECAF cap increase under the proposed residential electric rate restructuring.

In conducting this Fiscal Review, every attempt was made to ensure the independence of PA from the LADWP and our Offices. Information was provided by, and verified by the LADWP. PA was tasked with reviewing information, comparing it to other utilities and developing their own analysis and conclusions. In addition, our Offices limited our interaction with PA to clarification of information, formatting, contract compliance and the checking of logic. PA was not directed in the formulation of conclusions and/or recommendations.

Sincerely,

Miguel A. Santana
City Administrative Officer

Gerry F. Miller
Chief Legislative Analyst

CC: Honorable Mayor Antonio R. Villaraigosa
Honorable Board of Water and Power Commissioners

City of Los Angeles

Independent Fiscal Review of the Los Angeles Department of Water and Power Energy Cost Adjustment Factor (ECAF) and Residential Rate Design proposals

February 25, 2010

City of Los Angeles

Independent Fiscal Review of the Los Angeles Department of Water and Power Energy Cost Adjustment Factor (ECAF) and Residential Rate Design proposals

February 25, 2010

Prepared for: City of Los Angeles
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EXECUTIVE SUMMARY

The Los Angeles Department of Water and Power (LADWP or Department) has long been recognized as one of the most unique and respected utilities in the United States. This recognition has been earned due in large part to the strong and consistent financial performance of the Department over-time. LADWP has a long history of low rates, few rate increases, and strong financial ratios exemplified by high credit ratings. The Department's Power System has been a significant contributor to this performance.

The strong and stable revenue stream provided by the Department's customer base, combined with historically low-cost sources of power, has afforded the Department significant financial and operational flexibility and resiliency over the years. The Department has been able to overcome a variety of tests and pursue aggressive strategic goals as a result of this financial strength. However, this record of financial and operational success is currently being threatened by a collection of significant and unprecedented challenges, including:

- Ensuring access to capital for significant capital projects, given the continued challenging economic environment and financial market uncertainty,
- Maintaining the Department's 'AA' bond rating and associated target financial ratios,
- Facing increased scrutiny into the Department's financial and operating performance from rating agencies and other stakeholders,
- Responding to fuel price volatility and changing fuel price dynamics (including natural gas price uncertainty and fundamental shifts in the delivered price of coal),
- Meeting Renewable Portfolio Standards (RPS) in a cost effective and judicious manner, leveraging the Department's existing transmission infrastructure,
- Reducing dependence on current low cost coal generation in advance of California's Global Warming Solutions Act of 2006 (AB 32), and
- Implementing aggressive 10-year Energy Efficiency (EE) targets as outlined in AB 2021.

Managing this collection of challenges to best position the Department for the future – while meeting regulatory and legislative requirements, maintaining high levels of system reliability, mitigating the potential rate impacts to the customer, and maintaining the Department's historical record of financial stability – is the greatest challenge facing the LADWP today.

Utilities meet the requirements of day-to-day operations and large scale capital programs through the derivation and application of rates that are designed for specific customer classes. The manner in which the costs of "doing business" are allocated across the various customer classes is an explicit consideration of all utilities and their oversight bodies. In general, utilities meet revenue requirements through the application of base rates and additional "cost adjustment" charges. Base rates are derived to cover fixed operating and capital costs, while cost adjustment charges are applied to cover special programs and/or more volatile costs. A central feature of all cost adjustment charges is the separation of the

specified cost component from base rates, with the goal of making the cost of certain special programs and/or the most volatile and variable costs distinct and transparent from base rates.

As noted, in addition to special programs, cost adjustment charges are often established to account for more volatile contributions to total cost. One of the most common of these charges is related to fuel costs, which can exhibit tremendous volatility from period to period. Utilities aim to mitigate the impact of more volatile cost adjustment charges through the application of rules that determine how such costs are accounted for and inevitably flow through to the customer. These rules – if well-constructed – can enable utilities to collect requisite revenues, and also dampen the impact of volatility. Increased transparency into the charges that comprise a customer's bill, in combination with the ability to smooth the impact of volatile charges to the customer, make cost adjustment mechanisms commonplace among utilities.

The Department utilizes a variety of such cost adjustment charges, including the principal focus of this Review – the Energy Cost Adjustment Factor (ECAF). The ECAF was initially designed to specifically account for, and provide transparency into the impact of, volatile natural gas and coal commodity costs. However, the composition of the ECAF has changed significantly over time. Specifically, a variety of additional components – including principally the costs of meeting RPS, a Rate Stabilization Fund, and a number of other extraordinary expense items – were included in the ECAF.

Further, how the ECAF has been administered is a critical consideration. The ECAF rate as currently structured is "capped", limiting the amount of the collection or recovery allowable to the Department and limiting the passthrough of higher costs to the customer. Expectations are that typically volatile fuel prices, currently at low levels, will increase over the next several years. At the same time, the Department has taken on a number of commitments, including renewables procurement and enhanced energy efficiency programs, that will lead to predictable increases in energy costs. The cap on rate increases, when combined with higher fuel prices and the additional expenditures associated with new commitments, has created a large and rapidly growing undercollection in the ECAF that is being financed by the Department but must eventually be reconciled.

As part of this Review, PA Consulting Group (PA) has analyzed the Department's five-year financial plan, which includes a 20% renewable energy procurement target, to determine what level of ECAF increase is required to maintain the Department's financial integrity and AA bond rating. Given this analysis and the situation outlined above, we focus two of our primary recommendations on: 1) the Board's proposal to increase the ECAF cap, and 2) the current structure of the ECAF mechanism. In short:

- ***Our independent analysis confirms the need to immediately increase the current ECAF rate under a wide variety of plausible market and operational sensitivities and scenarios***. We recommend an increase in the ECAF cap to 0.8 cents per kWh per quarter to address the current undercollection and to maintain the desired financial ratios and target debt rating. (At present, the ECAF cap is set at 0.1 cents per kWh per quarter.) It is important to note that this is higher than the 0.5 cents per kWh required under the Department's plan. This higher cap incorporates the findings of additional sensitivity analysis performed by PA. We expect this will result in a total increase of 2.7

cents per kWh over the next four quarters, consisting of an increase of 0.8 cents per kWh in April 2010, July 2010 and October 2010, and an increase of 0.3 cents in January 2011.

- ***We recommend reconstituting the ECAF to focus specifically on volatile fuel and purchased power components only, and removing RPS, EE, city transfer elements, and all other components from the ECAF***. We further recommend (consistent with common utility practice) removing the cap on the ECAF and allowing fuel price volatility to "pass through" to customers. This reconstitution should be completed based on a detailed review of alternatives that ensures that the restructure is revenue-neutral, promotes transparency, and complies with all Department accounting, legal, and program requirements.

This Review also evaluates the impact on ratepayers due to this increase and addresses a proposed revision to the prices in the R-1 (residential) rate. Specifically, the Review considers: 1) the impact of a recommended ECAF cap increase on customer classes under the current rate structure, and 2) the impact of a recommended ECAF cap increase under the proposed residential electric rate restructuring.

The Department introduced a tiered or "inverted block" structure for R-1 rates in July 2009. Under that structure, there are two thresholds for customer usage, and as monthly usage passes each threshold, the unit price of additional power goes up. The Department has proposed to revise the tiering, reducing the price for residential customers who use small amounts of power and increasing the price for large users. The Department's goals are to mitigate the impact of an ECAF increase on small users while incentivizing large users to conserve energy. While our analysis indicates the revision achieves these goals, we recommend that any rate revision be part of a larger redesign, along the lines outlined above.

First, assuming a 0.8 cent per kWh per quarter increase in the ECAF cap, *under no rate restructuring*:

- The average Residential customer's monthly payments would increase $11 to $14 over the next four quarters. This is equivalent to 16 to 21% of the current average bill.

- The average low income customer's monthly payments would increase $7 to $9 per month. This is equivalent to 20 to 27% of the current average bill. Similarly, lifeline customers would expect an increase of $8 to $11, or 25 to 34%.

- For Commercial customers, monthly payments would increase 15 to 20%.

Second, *under the proposed restructuring* (and for a 0.8 cent per kWh per quarter increase in the ECAF cap) – *and when compared to LADWP's utility peers* – Southern California Edison (SCE), Pacific Gas & Electric (PG&E), and San Diego Gas & Electric (SDG&E) – PA's analysis reveals that:

- Tier 1 customers realize lower rates than under no rate restructuring, and marginally higher rates than for Tier 1 customers served by the Department's peers.

- Tier 2 customers realize higher rates than under no restructuring, and higher rates than for comparable customers served by the Department's peers.

- Tier 3 customers realize higher rates than under no restructuring, and lower (in some instances, significantly lower) rates than for comparable customers served by the Department's peers.

Even with this restructure and a 2.7 cents per kWh ECAF increase, rates at the highest Tier level will remain lower than the Department's peers. Further, our analysis suggests that the current proposed restructuring yields slightly higher revenue than under current rates. Given the uncertainty inherent in various assumptions in the revenue neutrality analysis, PA believes that it is appropriate that the redesign be slightly revenue-positive but perhaps not as much so as it was in the latest proposal. However, PA recommends that LADWP institute a balancing account to track and true up surpluses and shortages of base rates relative to the current structure or other selected base level.

The results of this Review confirm that the Department and the City are confronted with two significant objectives: determining the rate increase necessary to eliminate the current ECAF undercollection and fund a variety of critical strategic programs while minimizing the impacts of any rate increase to specific customers to the extent practicable. Most principally, the Mayor has stated a goal of meeting – and exceeding – mandated RPS standards. Combined with the need to increase system reliability, implement aggressive EE programs, and replace low cost coal generating units in advance of AB 32, this places significant pressure on the Department. The results of this Review confirm the need for an ECAF rate increase; in the absence of a rate increase, the ability of the Department to meet existing obligations is significantly at risk, and the potential for a credit rating downgrade is significant.

The Department desires to redistribute the costs of these programs among its rate classes – and specifically, away from lower usage Residential classes and toward higher consumption classes. In addition to encouraging energy conservation within this high-usage class, this proposal aims to deflect the more negative impacts of any rate restructuring away from those perhaps least able to handle such a dramatic change (particularly in the current financial environment). These questions are characterized by a variety of complex economic and financial considerations; but fundamentally they describe tradeoffs between competing and incommensurable objectives. The selection and weighting of ratemaking objectives is a matter of public policy, to be deliberated in a transparent manner among the various city stakeholders.

To this end it is important to note that the critical challenges facing the Department must be addressed in an environment that has historically been characterized by limited transparency into both the Department's strategic planning and ratemaking processes, contributing to a strained dialogue between the Department and city stakeholders. In fact, the clear majority of the proposed ECAF cap increase is required to address costs and commitments that have already been made; the manner in which those commitments have been made in the past, and will be made in the future, must be assessed. The recommendations contained in this Review aim to provide the required revenue to the Department to account for the current ECAF undercollection and facilitate more transparent administration of the ECAF going forward. PA believes the risk of inaction to the Department, the City, and the citizen/customer is significant, and that steps must be taken now to improve the administration of the ECAF and communication among all city stakeholders.

TABLE OF CONTENTS

Executive Summary **i**

1. Introduction and Approach **1-1**

2. LADWP Financial Objectives **2-1**
2.1 Ratings considerations 2-1
2.2 LADWP's financial targets 2-5
2.3 Impact of a ratings downgrade 2-9
2.4 Conclusions 2-12

3. Overview of the Energy Cost Adjustment Factor **3-1**
3.1 The Role of Cost Adjustment Factors 3-1
3.2 The ECAF at LADWP 3-2
3.3 Current ECAF costs 3-5
3.4 Historical ECAF undercollection 3-8
3.5 Conclusions 3-9

4. LADWP Reference Case **4-1**
4.1 Natural Gas 4-1
4.2 Coal 4-5
4.3 RPS 4-10
4.4 DSM 4-25
4.5 Operational assumptions 4-29
4.6 Other assumptions 4-29
4.7 Conclusions 4-30

5. Sensitivities Considered **5-1**
5.1 Risk Factors in ECAF projections 5-1
5.2 Derivation of sensitivity values and scenario definition 5-2

6. Results **6-1**
6.1 Reference Case results 6-1
6.2 Sensitivity results 6-6
6.3 Implications for ECAF rate levels 6-10
6.4 Impact of an increase on ratepayers 6-11
6.5 Minimizing ECAF-oriented costs 6-13
6.6 Conclusions 6-15

7. Evaluation of RPS Costs **7-1**
7.1 Cost impact of a 20% RPS target 7-1
7.2 Additional cost impact of reaching a 25% RPS target 7-4

7.3 Conclusions and implications of a 40% RPS goal 7-6

8. Evaluation of Residential Rate Design Proposal 8-1
8.1 Overview of rates 8-1
8.2 Impact of the rate redesign 8-4
8.3 Revenue impact of the rate redesign 8-12
8.4 Comparison of rate structure to other utilities 8-15
8.5 Conclusions 8-20

9. Recommendations and Summary of Findings 9-1
9.1 Recommendations 9-1
9.2 Summary of findings 9-2

Appendices

APPENDIX A: Review of LADWP's financial model

APPENDIX B: RPS Project Descriptions

APPENDIX C: List of Interviews

APPENDIX D: List of Documents

APPENDIX E: Definition of LADWP Peer Group for Financial Analysis

APPENDIX F: Comparison of California Renewables Plans

1. INTRODUCTION AND APPROACH

The Los Angeles Department of Water and Power (LADWP, the Department) generally collects electric revenues through base rates and cost adjustment charges (or "passthrough" costs) – including the Energy Cost Adjustment Factor (ECAF). As currently designed, the primary cost recovery components of the ECAF are:

- Fuel procurement expense,
- Purchased power cost,
- Renewable energy procurement and development,
- Demand Side Management (DSM) program expense,
- DSM revenue loss recovery, and
- The city transfer.

The ECAF is calculated on a quarterly basis based on projected costs, and then adjusted based on actual costs. Under the current authorization, there is a "cap" on allowable cost recovery; customer rates are permitted to increase by a maximum of 0.1 cent per kWh per quarter, or a total of 0.4 cents per kWh per year.

At present, the Department has a significant undercollection of ECAF-related costs that is expected to grow over time due to increasing expenses. The projected drivers for the increase in costs are renewable energy procurement and development, fuel procurement, and the implementation of aggressive DSM programs. With regard to renewable energy procurement, the Department is attempting to meet escalating targets set by the Board of Water and Power Commissioners of the City of Los Angeles (the Board), which call for the LADWP to provide 20% of the power it sells from renewable resources by the end of 2010 and 35% by 2020 (a final goal the Mayor has recently increased to 40%). LADWP has been actively procuring renewable resources to meet these goals.

Given this and other factors, a review of the Power System Financial Planning Criteria conducted in May 2009 found that both the financial integrity and key objectives of the Department (including maintaining target cash reserve and debt coverage ratios) are at risk without an increase to the cap associated with the ECAF. Importantly, a number of additional market and operating risk factors exist that could further increase the current undercollection and threaten the credit rating and financial viability of LADWP.

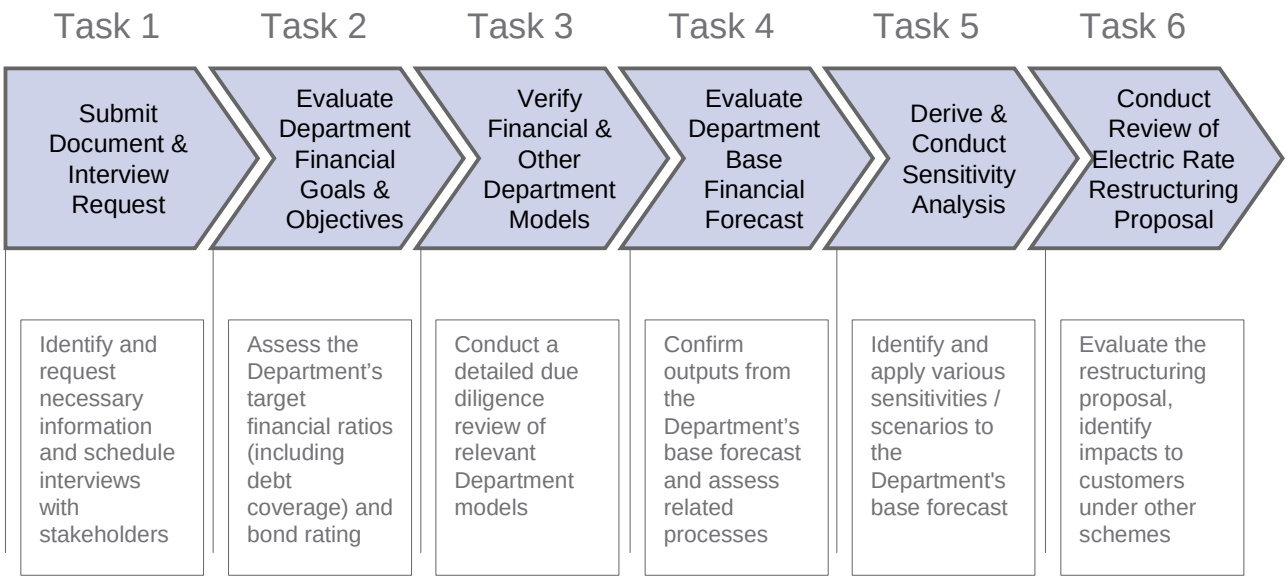
In general, it is believed that the Department's quarterly adjustment limit of 0.1 cent per kWh per quarter: 1) does not properly account for the significant fuel or renewable procurement-related expenses, and 2) increases the probability of a significant rate increase due to the inability to continue financing the undercollected ECAF expenses while ensuring financial integrity. To this end, in August 2009 the Board approved an increase to the current cap on ECAF rate increases. The Board took this action to limit the size of the undercollection and ensure the Department can meet key financial and energy procurement objectives.

In October 2009, the Los Angeles Chief Legislative Analyst (CLA) and City Administrative Officer (CAO), acting on behalf of the City Council, issued a Request for Proposal (RFP) for an independent review of the proposed modification (Review). In November 2009, PA was retained to conduct the Review.

The following Review provides an independent assessment of the proposed:

- ECAF Rate Increase, and
- Residential Electric Rate Restructuring.

Conducting the Review required completion of several key tasks, the conclusions of which form the basis of this report. The following exhibit reflects the key tasks associated with the Review:



Information to complete the Review was primarily derived from two sources: 1) interviews with Department staff and a variety of critical stakeholders, including representatives from the Department, Board, Mayor's Office, and City Council, and 2) documents collected from across the Department and related agencies and organizations. In total, PA conducted 16 interviews and gathered and reviewed approximately 185 critical documents, providing a comprehensive view into the management of the ECAF, electric rates, and Department operations. In addition, PA defined 13 separate sensitivity cases that were analyzed with the support of the Department's financial planning department. During the Review, the Department was very forthcoming and responsive to all of PA's requests for data and additional analysis.

The RFP outlined a variety of questions or focus areas under the two primary topics identified above – ECAF Rate Increase and Residential Electric Rate Restructuring. Many of the focus areas are interrelated and overlap across these topics; therefore, in the interest of clarity this report adopts a different outline than that provided in the RFP. However, all agreed focus areas are addressed herein.

Finally, one of the key questions in the RFP is the impact of ECAF costs under different renewable targets. Early in the Task 2 process, while working closely with the City Council and Department, it was agreed that the Review would focus principally on the Department's known 5-year base financial forecast and 20% renewable plan, with indicative analysis on the impact of a 25% and 40% RPS goal. Additional rigorous analysis of the impact of a 35% and 40% target will be conducted at a later date, when specific Department renewable plans for such targets are derived.

This report is comprised of the following chapters:

- LADWP Financial Objectives: The key financial targets established by the Department, and the impact on the Department of a credit rating downgrade
- Overview of the Energy Cost Adjustment Factor: The role of the ECAF in the Department, an overview of the components that comprise ECAF, and the nature of the current undercollection
- LADWP Reference Case: An evaluation of the Department's base financial plan and Reference Case cost projections that generated the ECAF cap proposal
- Sensitivities Considered: A review of sensitivities used to "stress" the Department's Reference Case, including an assessment of scenario analysis results
- Results: Reference Case and sensitivity analysis results, and the implication of results on ECAF levels and customer costs
- Evaluation of RPS Costs: An assessment of the cost impacts of various RPS targets, including most principally 20%, with directional guidance around 25% and 40%
- Evaluation of Residential Rate Design Proposal: An independent review of the residential rate restructuring proposal, including a discussion on the impact of an ECAF increase under the current rate structure
- Recommendations and Summary of Findings: A discussion of the recommendations emerging from the analysis, including an immediate ECAF cap increase and general restructuring of the ECAF. Also, a summary of key findings with reference to specific questions posed by the City Council as part of their Request for Proposal (RFP) for this Review.

2. LADWP FINANCIAL OBJECTIVES

The Department has identified maintaining its 'AA' debt rating as a core business objective. Maintaining this rating is critical to preserving access to the low-cost debt required to fund the Department's capital programs. Strategic objectives such as meeting renewable portfolio standards and other large scale capital improvement programs are therefore evaluated in the context of this broader objective. To achieve the goal of maintaining its current debt ratings, LADWP has set specific financial targets. This section examines the way in which these targets fit within the broad range of factors considered by ratings agencies and comments on how LADWP's targets compare to agency expectations.

The analysis further describes the evaluation criteria established and utilized by the three most prominent ratings agencies – Standard and Poor's (S&P), FitchRatings (Fitch), and Moody's – to continually assess issuer credit ratings. It also addresses the impact of LADWP's off-balance sheet liabilities and general transfer obligations on these comparisons. Finally, it assesses the financial impact of a ratings downgrade.

2.1 RATINGS CONSIDERATIONS

Ratings agencies assign credit ratings to specific debt instruments and their underlying issuers to provide an indication of the likelihood of default for that given instrument. These ratings are used by purchasers and traders of bonds to help indicate the value of the bond relative to other debt instruments. For a bond of a given term and character, a higher credit rating will typically be associated with a higher bond value and a lower interest rate for the borrower.

The three most prominent credit ratings agencies use very similar scales to indicate the quality of a given debt issue. AAA is the highest rating, followed by AA, A, BBB, and C. Within each class, the ratings agencies further distinguish between quality by indicating a "+" or "-" within each class (for Moody's, a scale of 1 to 3 is used, with 1 the highest subclass).

S&P, Fitch, and Moody's currently rate LADWP at AA-, AA-, and Aa3, respectively. These ratings are at the low end of the "double-A" rating provided by the agencies, one notch above the lower "A" rating level. Maintaining this rating allows LADWP to access low-cost funds in both long-term and short-term financial markets. The debt rating also supports LADWP's long-term purchase agreements and provides a competitive advantage in accessing renewable power projects at the lowest possible rates.

2.1.1 Corporate credit analysis factors

Credit ratings are assigned based on an assessment of the company's financial risk profile (typically indicated by financial ratios) and a more qualitative business risk profile that takes into account other factors that may impact a company's long-term position. As debt instruments may carry a payment obligation of many years, ratings agencies take into account both short-term and long-term factors that could impact a company's ability to repay the obligation.

Each of the three major ratings agencies uses a multifaceted approach to assess these risk profiles. Financial ratios addressing coverage, profitability, capital structure/leverage, and perhaps most importantly cash flow, provide a critical point of reference when assessing financial risk. Ratio medians for a particular rating provide an illustration of where a specific issuer "fits" relative to its peers within a specific industry.

In addition to specific financial ratios, the agencies examine a variety of business risk factors or ratings topics that may impact each rated issuer's ability to make timely payment on principal and interest obligations. Many of these will be specific to a particular industry. For public power utilities, for example, Moody's has laid out 44 separate measurements across 6 broad ratings factors and 22 sub-factors.

Therefore, in addition to financial ratios, assessment parameters include an evaluation of management and governance, the utility's generation portfolio, local government credit characteristics, cost competitiveness, the rate setting process, and the utility's strategic planning process for addressing both traditional power supply as well as emerging issues such as CO_2 reduction and renewables requirements. While numerical ratios play a critical role in outlining the financial risk of a utility, any of these other factors may emerge as a risk that could influence a financial rating. In general, each of the ratings agencies employ quantitative as well as qualitative analyses to derive issuer ratings.[1]

Table 1 below illustrates how these financial and business risk assessments translate into a rating in the case of S&P:

Table 1: S&P Business and Financial Risk Profile Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	Significant	Aggressive	Highly Leveraged
Excellent	AAA	AA	A	A-	BBB	---
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	---	BBB-	BB+	BB	BB-	B
Weak	---	---	BB	BB-	B+	B-
Vulnerable	---	---	---	B+	B	CCC+

Typical range for public power electric utilities

Within the utility space, public power utilities tend to have stronger credit ratings than investor-owned utilities and with few exceptions carry ratings between A- and AA+. This is

[1] See Standard and Poor's, *Corporate Ratings Criteria Methodology*, May 2009; Moody's, *U.S. Public Finance Rating Methodology for U.S. Public Power Electric Utilities*, April 2008. FitchRatings, *Public Power Ratings Guidelines*, June 2009.

due primarily to their unregulated rate setting processes that allow them to set electricity rates independent of federal and state regulation.

2.1.2 Recent downgrades of other municipal utilities

Recently, three other municipal utilities within the State have either been downgraded or put on a negative watch for a possible downgrade. While the specific circumstances of each negative action have been unique, each situation shares some characteristics in common with the current situation at the Department. Each of the three utilities faced declining debt ratios and/or liquidity that suggested the need for increased revenues. In each case, an unwillingness to raise rates in response to these financial pressures resulted in a negative ratings action.

Anaheim Public Utilities (Anaheim): Anaheim Public Utilities provides service to over 110,000 customers in Orange County. In October, 2009, Fitch revised its outlook for Anaheim's AA-rated bonds from Stable to Negative. This reflected financial pressure at the utility in 2008 and 2009 that resulted in the use of reserves to meet Anaheim's debt service coverage target of 1.6. This has resulted in liquidity levels lower than that expected of a AA-rated utility. The lack of any planned base rate increase factored into the negative outlook decision, and it was mentioned that further liquidity declines could prompt a downgrade from its current AA- rating.

Imperial Irrigation District (IID): IID is a community owned utility providing electric service to approximately 140,000 customers in the Imperial Valley and parts of Riverside and San Diego Counties. In May 2009, Fitch downgraded IID's electric system certificates of participation to A+ from AA-. The reasons given were a "tightening of the financial performance of the district, management turnover at senior levels, deepening economic recession in the service territory, sizable capital needs related to generation development and environmental compliance with California's environmental regulations, and outgoing concerns regarding timely cost recovery through rates." In particular, a decision by the Board of Directors to delay a base rate increase led to the downgrade by Fitch.

Modesto Irrigation District (MID): MID provides electric service to over 110,000 accounts in California's Central Valley. In November 2009, Fitch downgraded MID from A+ to A, reflecting declines in financial performance and a decision by the Board of Directors to cancel previously approved rate increases that would have improved key financial metrics.

2.1.3 Recent comments from ratings agencies regarding LADWP

In recent ratings reports, S&P, Fitch, and Moody's have opined on the financial health of LADWP, noting both strengths and challenges that could impact the Department's long-term debt ratings. These reports were issued prior to the most recent set of financial projections prepared by the Department for FY2010.

Strengths noted in recent ratings agency reports on LADWP include:

- A history of sound financial metrics
- Strong liquidity when including the availability of debt reduction reserves

- Unregulated rate-setting authority
- The diversity and health of LADWP's power supply portfolio
- The presence of an Energy Cost Adjustment Factor (ECAF) to pass through increased expenses
- Lower rates relative to other regional utilities

Challenges highlighted in recent reports include:

- An anticipated decline in LADWP's key financial metrics due to an ambitious capital plan
- Additional costs imposed by a renewable energy standard
- Additional costs imposed by climate change legislation and a possible erosion in LADWP's existing rate advantage compared to other California utilities
- Political risk and delays in the rate-setting process
- A potential outage at Intermountain Power Project, the Utah coal-fired facility which accounts for approximately 30% of LADWP's generation portfolio
- Volatile natural gas prices

These conditions speak to the Department's ability to respond to rising costs, including those driven by RPS obligations, volatile fuel prices, potential operational outages, and the Department's base capital program. In the long-run, the impact of CO_2 legislation is also clearly a concern for ratings agencies.

Specifically, the ratings agencies expect the Department to take steps to maintain specific financial targets that are indicative of the ability to address these issues. S&P remarked in a April 2009 report on the Department's Power Revenue Bonds that "if financial pressures increase, the ratings could suffer if LADWP does not provide timely responses that preserve financial margins." Similarly, in a May 2009 report, Moody's suggested that the long-term rating could decline if "debt service coverage falls below peer ratio median or regional competitiveness is impacted adversely by power resource decisions." Moody's further remarked in a July 2008 report on the Department's variable rate bonds that "the credit rating could be lowered should LADWP's debt service coverage ratios fall to a level below the median for Aa-rated electric utilities or should LADWP's system reliability or competitive position be significantly impacted by resource adequacy or regulatory issues." An April 2009 report from Fitch noted that "going forward, Fitch will be monitoring LADWP's rising leverage and projected declines in debt service coverage, given the political sensitivity to raising electric rates and future cost pressures."

In light of these comments, it is reasonable to assume that maintaining appropriate financial targets, most notably debt service coverage, is the single most critical component in maintaining LADWP's AA bond rating. These targets should be based on a comparison to peers and any specific guidelines provided by ratings agencies. Furthermore, demonstrating

the ability to mitigate the risk of rising costs through appropriate ratemaking mechanisms is also important in avoiding a potential ratings downgrade.

2.2 LADWP'S FINANCIAL TARGETS

LADWP has established and communicated a variety of financial targets to ratings agencies and the City, including maintaining a Debt Service ratio of 2.25x, an unrestricted cash balance of $300 million, and a capitalization ratio of no more than 60% debt.

While maintaining LADWP's target ratios is a critical element in maintaining a AA rating, other risk factors facing the Department, as mentioned in recent rating reviews, could still trigger a downgrade. Exposure to fuel price volatility, increasing costs under an RPS program, and possible costs associated with California's AB 32 CO_2 initiative could cause actual values to fall below forecasts. With some key financial targets near historical lows and ratings agency medians, LADWP will no longer have an additional financial cushion to help compensate for these risks. For this reason, demonstrating the capability and willingness to address any changes will also be an important element in maintaining the AA rating.

One mechanism in demonstrating the ability to meet financial targets should be the ECAF. Automatic changes in the ECAF can play an important role in mitigating the risks associated with volatile and unpredictable fuel pricing and in lending confidence that financial targets will be met. However, the current cap of 0.1 cents per kWh on quarterly rate changes is a potential liability that limits the ECAF from adequately serving that function. Another important element is demonstrating the willingness of rate makers to support appropriate revenue increases if required to maintain key ratios.

2.2.1 Debt Service Coverage

a. DEFINITIONS

Given the complexities of debt and other fixed obligations, the components of debt service coverage can be defined in different ways. (For instance, Fitch provides three different definitions which are useful in assessing the ability to repay debt.) However, debt service coverage is generally defined as the ratio of the funds available to pay debt service to the actual debt service itself.

The primary ratio considered is the Debt Service Coverage ratio. This ratio divides the funds available for debt service by the sum of long-term principal and total interest payments. This ratio treats fixed charges other than debt payment as they are shown on the balance sheet, typically as expenses.

Ratings agencies also consider additional debt ratios. Two of these are an Adjusted Debt Service Coverage ratio, which takes into account additional fixed charges not technically classified as debt,[2] and a Coverage of Full Obligations ratio that takes into account both these fixed charges as well as general government transfer obligations.[3]

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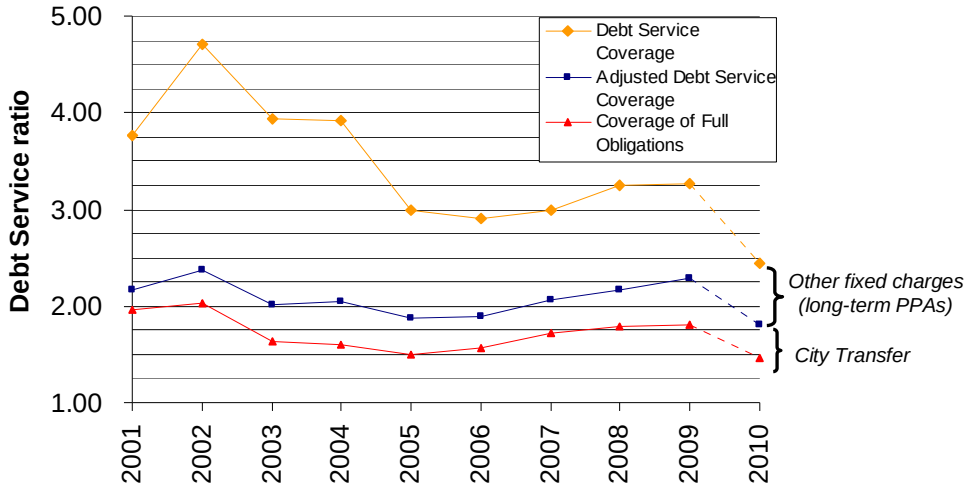
[2] As is the case at many other utilities, LADWP carries significant long-term payment obligations that are not treated as debt payments on the balance sheet. At LADWP, the largest long-term obligations

LADWP has identified its target Debt Service Coverage ratio of 2.25x with consideration to these other metrics.

b. LADWP HISTORY

Since 2001, LADWP's Debt Service Coverage ratio has averaged slightly over 3.5x, largely as a result of relatively low levels of leverage.

Figure 1: 10-year Historical LADWP Debt Ratios



However, ratios in 2010 are projected to dip considerably, with longer-term forecasts showing levels approaching LADWP's target level of 2.25x. This decline is due to a sharp increase in capital spending to support system performance and reliability, and in the short-run is also due also to a projected undercollection of ECAF costs. Given this forecasted departure from historical debt coverage levels, LADWP is operating under tighter financial conditions than it has in years past.

c. PEER COMPARISONS

Understanding the financial ratios maintained by peers and the ratings assigned to them is critical to understanding how ratings agencies will view LADWP's financial ratings. Because LADWP is the largest municipal utility in the United States, it does not have any true peers.

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are for power purchases from IPP and the Southern California Public Power Association (SCPPA), as well as charges associated with transmission built through SCPPA. SCPPA is a joint powers authority, consisting of 10 municipal utilities and IID, through which LADWP procures a significant amount of its renewable energy. Both IPP and SCPPA issue debt that is passed through directly to LADWP as part of its power purchase agreements. The debt associated with theses projects is sometimes referred to as "off-balance sheet" debt.

[3] In the case of LADWP, this is referred to as the City Transfer and represents a transfer of 8% of revenues each year from the LADWP Power Revenue Fund to the City of Los Angeles.

For this comparison, PA has selected municipal retail utilities serving more than 100,000 meters as the peer group for LADWP.

Among peers maintaining an AA rating, the median debt coverage ratio is 2.31x. For this same group, the Coverage of Full Obligations ratio is 1.44x.

Table 2: Median debt service ratios for peer utilities

Peer group defined as Retail municipal utilities, AA+/AA/AA- ratings, > 100,000 meters served			
FY2008 data, median values shown			
# of peers	**Debt Service Coverage**	**Adjusted Debt Service Coverage**	**Coverage of Full Obligations**
Peers	2.31	1.63	1.44
LADWP Target	2.25	~1.75x (implied)	~1.4x (implied)

Source: Fitch Ratings U.S. Public Power Peer Study, June 2009

Based on these comparisons, PA believes that LADWP's target of 2.25x, while slightly below the median of other companies, is reasonable. The appropriateness of 2.25x as a target was also confirmed by LADWP's financial advisors, who conducted their own independent peer analysis and concluded, "We believe the targeted minimum debt service coverage of 2.25x is a prudent policy and is consistent with the level of LADWP's peers."[4]

Regardless, given the change in projected Debt Service Coverage relative to its historical levels, LADWP should expect additional scrutiny from ratings agencies. A level of 2.25x leaves little margin for error, and ratings agencies will look closely for any evidence that management and rate makers are not committed to achieving that stated target.

2.2.2 Cash

A utility's ability to service its debt payments is of paramount importance, but ratings agencies also focus on liquidity metrics such as cash on hand to ensure that an entity can survive short-term volatility in costs and revenues.

In the case of LADWP, the most likely source of such volatility is a sharp increase in purchased power or fuel costs, either due to commodity price increases or an unexpected outage at one of LADWP's low-cost coal or nuclear facilities. This fuel cost increase poses a risk due to delays and caps in passing through short-term increases in ECAF expenses. For example, in the six months ending September 2008, a sharp increase in natural gas prices caused an increase in the ECAF undercollection (and cash impact) of over $150 million.

Even if the ECAF were not capped, short-term spikes still impact cash flows due to the delays in receiving the revenues associated with quarterly ECAF updates. Depending on the timing of a cost increase, it could take up to 6 months before the increase is reflected in the ECAF

[4] Per memo from Gardner Underwood and Bacon LLC to Mario Ignacio, May 11, 2009.

revenues received.[5] It is critical that LADWP maintain ample liquidity to handle situations that include:

- Gas price increases – While LADWP's hedging program helps mitigate the near-term impact of a sharp spike in natural gas prices, such events still need to be planned for. With nearly $400 million per year in natural gas and short-term power purchases, the impact of a short-term doubling in gas prices could result in an unexpected cost of nearly $10 million per month, even with 50 to 75% of the procurement portfolio hedged.

- Unit outages - The cash impact of high gas prices could be even higher in the event of an unexpected operational issue that required significant natural gas or short-term power purchases beyond those expected in LADWP's hedging program. The loss of a unit at IPP, for example, would result in increased costs of $10 to $15 million per month,[6] with the possibility of higher costs given higher gas prices. IPP does not have a history of long unforced outages, but such an event is within the realm of possibility and suggests the need for adequate cash reserves to weather such an event.

Other unanticipated events such as rapid changes in short-term interest rates have a smaller impact but also impact required cash reserves.

LADWP has set a minimum target of $300 million for operating cash reserves. Given the Department's current hedging program and the risks outlined above, this liquidity level should be adequate to cover short-term costs incurred due to fluctuating fuel prices or unit outages. This liquidity is not meant to address longer-term changes in cost structure, which can be measured via the Debt Service Coverage ratio.

This level of liquidity corresponds to slightly less than 50 days of cash given projected 2010 expenses, and can be compared to a median of 102 days for the peers considered by PA and 108 days for the peers considered in a recent analysis by LADWP's financial advisors.[7] This relatively low liquidity position is compensated for by the presence of LADWP's debt reduction trust funds. These accounts were established in 1997 to provide for the payment of principal and interest on long-term debt obligations and purchased power obligations arising from the Department's participation in IPP and SCPPA. As of the end of FY2009, these restricted funds totaled $547 million, providing additional insurance against a potential debt default. While these funds are restricted to repayment of interest and principal, if considered as cash they bring LADWP's minimum targeted liquidity levels to well over 100 days, more in line with comparable peers.

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[5] For example, a cost increase observed in late December would not be included in ECAF rates until April 1. Cash associated with that rate increase would not be received from customers until June or July.

[6] Based on marginal fuel costs of $60/MWh for gas generation and $20/MWh for IPP generation.

[7] Per memo from Gardner Underwood and Bacon LLC to Mario Ignacio, May 11, 2009

Given the short-term liquidity risks presented by a volatile energy market and LADWP's operations, the Department's liquidity position relative to peers, and the stabilizing presence of debt reduction trust funds, LADWP's minimum cash target of $300 million appears to be adequate to maintain its AA rating. This assumes the continuation of a prudent hedging strategy to reduce exposure to short-term gas prices and the presence of LADWP's debt reduction trust funds. Changes to either of these programs could impact the cash levels required to deal with short-term risks.

2.2.3 Capitalization Ratio

In order to keep a manageable level of leverage and maintain balance sheet flexibility while still taking advantage of a relatively low cost of debt, companies often target a capitalization ratio, defined as the long-term debt level divided by the sum of long-term debt plus equity.

LADWP's choice of a capitalization ratio is closely tied to its choice of debt coverage. An increase in capitalization ratio implies that the percentage of debt in the portfolio is increasing and coverage ratios are decreasing. While it is important not to lose sight of the overall structure of the balance sheet, it is important to recognize that maintaining a stable debt coverage ratio should be a primary indicator of a stable Capitalization Ratio.

LADWP has chosen to target a maximum Capitalization Ratio of 60% of total assets: LADWP's current level of debt is 53% but is projected to increase to over 57% over the next five years as over $3 billion in new bonds are issued to fund new capital projects.

Capital structures chosen by utilities can vary widely based on the company's liquidity, debt coverage, specific risks, and generation position. The median debt level of the 16 peers considered by PA was 56%. LADWP's choice of a maximum ratio of 60% is not out of line with these comparable companies.

2.3 IMPACT OF A RATINGS DOWNGRADE

2.3.1 Areas of Impact

A ratings downgrade would directly impact LADWP's costs in the form of higher debt service costs. These costs would come in three primary areas:

Short-Term Debt: LADWP maintains nearly $1.2 billion in Variable Rate Demand Obligations (VRDOs), short-term credit facilities that provide LADWP access to funds as needed to cover its short-term cash needs. In today's market, this debt has a very low interest rate. Significant quantities of short-term debt are typically only available to companies with very high credit ratings. Should LADWP be downgraded, a portion of this short-term debt would no longer be available and would need to be replaced with higher-cost long-term debt. Any remaining short-term line of credit would likely carry a higher interest rate than it does today.

Long-Term Debt: A ratings downgrade would also impact the interest rates available for LADWP's long-term debt. While interest payments on all existing long-term debt remain fixed, any new debt issued subsequent to a downgrade would be subject to a higher interest rate. With plans to issue over $3 billion in long-term debt over the next five years, a downgrade could have a substantial and increasing impact on LADWP's cash position.

PPA obligations: Many of LADWP's power purchase agreements (PPAs) are not fixed price PPAs but rather are tied to the actual debt service obligation for the project. PPAs that would be impacted include agreements with IPP as well as any projects funded through SCPPA. Just as LADWP's direct debt contains long-term and short-term components, the debt associated with these individual projects can also contain both. It is important to take the terms of these individual PPAs into account when quantifying a debt downgrade impact.

Hedging costs*:* LADWP has approximately a dozen counterparties with whom it trades swaps and other derivatives as part of the ongoing effort to limit the volatility of its fuel supply costs. The relationship with each of these counterparties includes a credit threshold that dictates the Department's collateral needs with that counterparty. Once the mark-to-market (MTM) value of a position exceeds that threshold, the Department must post collateral to cover it, thereby tying up costly funds in a margin account. In the event of a downgrade, the threshold available to the Department, which is typically $40 million with most counterparties, would be essentially cut in half. As a result, a downgrade could impact short-term cash flows and the cost of the Department's hedging program, particularly in a declining natural gas price environment.

A downgrade to LADWP's credit rating could also impact the perception of the Department as a desirable project partner or counterparty. With the importance of financial flexibility and a low cost of capital in renewable energy procurement today, a ratings downgrade could limit the leadership role taken by the Department at SCPPA and limit access to the best renewable energy resources.

2.3.2 Quantifying the Impact of a Ratings Downgrade

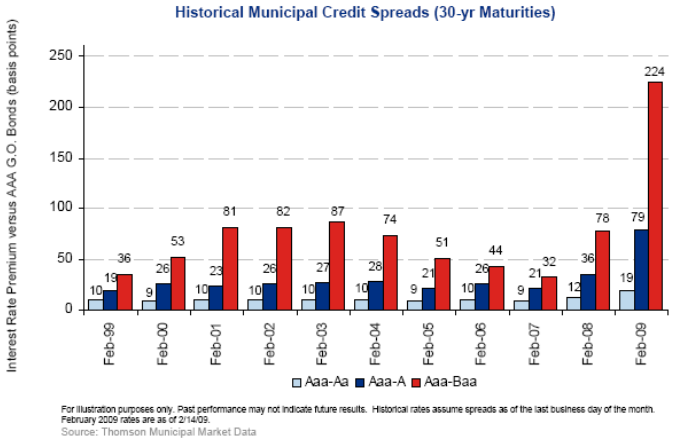
Quantifying the impact of a ratings downgrade requires a detailed description of current debt service by project, a projection of future debt requirements, and an estimation of the impact to each debt instrument in the event of a downgrade. As part of this Review, LADWP provided details on debt instruments held currently as well as its projected 5-year capital investment plans. To estimate downgrade impacts, PA has used existing contracts where applicable and otherwise estimated rate impacts based on current municipal bond rates.

The cost of a downgrade could depend on its timing. Credit spreads, or the difference in interest rates between one bond rating and the next, drive the economic impact of a downgrade. The greater the difference between the rate on a AA-rated bond and an A-rated bond, the greater the cost of a downgrade.

As suggested in Figure 2, credit spreads are significantly higher now than they have been at any point in the past decade, making this a particularly bad time to get downgraded With the credit crisis of late 2008, AA to A spreads that had remained below 20 basis points throughout most of the decade widened to 60 basis points in February 2009. As of today, this spread remains at about 55 basis points (bps) for municipal 30-yr debt,[8] significantly higher than historical levels.

[8] Source: Standard and Poor's Representative Municipal Bond Yields as of 2/9/2010.

Figure 2: Example of historical credit spreads



To estimate the cost of the downgrade from AA to A, PA has considered two cases to represent the likely range of financial impacts on the major classes of LADWP debt and credit facilities. The cases and their assumptions by class of debt are shown in Table 3.

Table 3: Case Assumptions - Analyzing the Cost of a Downgrade

Case	Long-term debt (including off-balance sheet)	Short-term variable rate debt (including off-balance sheet)
Low	55 bps increase, representing the 2/9/2010 spread on 30-yr municipal bonds	64 bps increase, representing the 2/9/2010 spread on 3-month municipal bonds
High	75 bps increase	All short-term debt to be refinanced at today's 4.88% long-term rate.

Source: Standard and Poor's Representative Municipal Bond Yields on 2/9/2010

Results by debt element are shown in Table 4.

Table 4: Cost impact of a Rating Downgrade ($M)

Low Case

Event	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014
LT Debt cost increases by 55 bps	$3.3	$7.7	$14.6	$20.0	$24.7
ST variable rate debt increases by 64 bps	$2.9	$8.6	$8.6	$8.6	$8.6
Off-balance sheet LT debt increases by 55 bps	$1.0	$6.3	$10.4	$18.7	$21.2
Off-balance sheet variable rate debt increases by 64 bps	$0.8	$2.5	$2.5	$2.5	$2.5
Financing cost associated with extra borrowing	$0.1	$1.6	$3.4	$5.8	$8.6
Total Cost of Downgrade	**$8.1**	**$26.6**	**$39.4**	**$55.4**	**$65.5**

High Case

Event	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014
LT Debt cost increases by 75 bps	$4.5	$10.5	$20.0	$27.2	$33.7
ST variable rate debt refinanced at LT fixed rate	$6.4	$19.1	$19.1	$19.1	$19.1
Off-balance sheet LT debt increases by 75 bps	$1.4	$8.6	$14.1	$25.4	$28.9
Off-balance sheet variable rate debt refinanced at LT fixed rate	$2.1	$6.3	$6.3	$6.3	$6.3
Financing cost associated with extra borrowing	$0.7	$2.9	$5.8	$9.6	$13.9
Total Cost of Downgrade	**$15.0**	**$47.3**	**$65.3**	**$87.6**	**$101.8**

In the low case, based on the best expectations as of today, PA projects the cost of a rating downgrade to start at $8 million in FY2010 and increase annually to $66 million by FY2014, with an average annual downgrade cost increase of $39 million. Although representing the low case, note that this cost impact is high by historical standards given the significant spreads on long- and short-term debt instruments.

In the high case, designed to represent the worst case scenario for all debt instruments, costs are projected to start at $15 million in FY2010 and increase annually to $102 million by FY2014, with an average annual downgrade cost increase of $63 million. The higher costs in this case can be attributed to both the higher 75 bps AA-A spreads assumed on long-term debt instruments and also on the assumption that a downgrade could trigger termination events on short-term credit facilities, forcing this borrowing to take place through higher cost long-term instruments.

Over the next five years, a downgrade would cumulatively cost the Department and its customers in the range of $200 to $300 million.

2.4 CONCLUSIONS

LADWP is embarking on a capital investment program requiring the issuance of over $3 billion over the next five years. This capital plan will increase the Department's leverage, as indicated by its capitalization ratio and debt coverage ratio, from historically low levels to levels much closer to the median of its AA-rated peer group, as highlighted in Table 5 below.

Minimizing the interest cost of the increased borrowing will require strict attention to key financial ratios – losing its AA rating would result in additional interest cost increases averaging approximately $40 to $60 million dollars per year over the next five years for LADWP.

Table 5: Summary of Key Financial Ratios

Parameter	LADWP			Peer Median	Comments
	2009	2010 (projected)[9]	Target	**2008**	
Debt Coverage Ratio	3.25	2.44	> 2.25	2.31	*Target is close to median but represents a significant decline from historical levels*
Cash (days of expenses)[10]	63	64	~40	102	*Adequate given debt reduction trust funds*
Capitalization Ratio	53.1%	53.9%	< 60%	56%	*Target is close to median but represents a significant increase from historical levels*

LADWP has targeted a minimum debt coverage ratio of 2.25x, an unrestricted cash level of over $300 million, and a maximum capitalization ratio of 60%. These targets are in line with those of comparable AA-rated municipal utilities, but still leave little room for error. Given the specific risks facing LADWP in California – such as the need to meet RPS generation targets, possible costs introduced by California's AB 32 CO_2 legislation, and the off-balance sheet and general transfer obligations faced by the Department – the 2.25x debt coverage level should be interpreted as the minimum threshold and still does not guarantee that the Department will not be downgraded. As ratios approach the target level, ratings agencies will give more scrutiny than ever to the Department's cost control, strategic plans for meeting new regulatory requirements, and political risks (most notably the City's commitment to maintaining ratios through timely rate actions).

As seen recently at other California utilities, the failure to respond to cost increases in a timely manner by raising rates can lead directly to a ratings downgrade. As described in Sections 4 through 6 of this report, costs at LADWP are expected to rise sharply in upcoming years, driven primarily by costs associated with the ECAF. The inability of LADWP and the City to plan and act in a coordinated manner that supports its targeted financial ratios will almost certainly result in a downgrade.

[9] Assumes increase in ECAF of 0.5 cents/kWh as of April 1, 2010.

[10] Cash calculation based on Revenue Fund balance and total expenses (operating + debt service – depreciation). Excludes debt service reduction funds, which would add approximately 75 days to the LADWP figures.

3. OVERVIEW OF THE ENERGY COST ADJUSTMENT FACTOR

As discussed in Section 1, LADWP generally collects electric revenues through base rates and cost adjustment charges – including the ECAF. Base rates, covering all operations, maintenance, capital depreciation, and other charges not covered under ECAF, still account for the majority of retail revenues. However, the importance of the ECAF has grown over time due to increasing fuel costs and the introduction of additional items to the ECAF account (most notably renewable energy and DSM revenue loss recovery). While the ECAF represented 39% of total Department revenues in 2009, that percentage is expected to grow to nearly 50% of total revenues by 2011.

This section describes the general concept of cost adjustment factors as they have been applied at utilities throughout California. It then provides a history of the growth in scope and cost of the ECAF at LADWP before detailing the composition of current ECAF costs. Finally, the drivers behind the current ECAF undercollection are examined.

3.1 THE ROLE OF COST ADJUSTMENT FACTORS

Designing utility rates is normally a three-step process: *revenue requirement determination*, by which the utility's total costs are estimated; *revenue allocation*, by which the fraction of the total costs attributable to each customer grouping or rate class is calculated; and *rate design*, by which specific prices or rates are set so that the utility can bill and collect an amount equal to the allocated costs. In a regulated environment each of these processes is governed by a formal process – administrative in the case of utilities regulated by the California Public Utility Commission (CPUC), legislative for a municipal utility such as the Department. The purpose is to provide close scrutiny of utility costs and thus to ensure that the utility operates efficiently. Because regulated rate-setting is time-consuming, rates are not redesigned very frequently.

Over the years this process has evolved. An early adjustment was the introduction of the automatic fuel cost adjustment (FCA). The FCA effectively separates the revenue requirement into two different cost components: fuel costs and others. FCAs allow the revenue requirement to be modified more frequently in order to respond to changes in fuel prices, and have generally been used in times of exceptional commodity price volatility. When an FCA is instituted, rules have to be defined for revenue allocation and rate design so that changes in revenue requirements can be immediately translated into rates.

The point of an FCA is to allow retail prices to respond more quickly to commodity price changes. Therefore the costs cannot be examined as closely and at as much length as in normal ratemaking. A basic level of reasonableness review is still necessary, but often the review is limited to making sure that the utility has acted within the bounds of a defined procurement plan. The procurement plan itself is reviewed in a periodic regulatory or legislative process.

The reduced standard of review for an FCA is justified by the costs being out of the utility's control, other than for actions clearly defined within the utility's procurement plan. The utility is assumed to have little impact on wholesale coal or gas prices, since they are set by a much larger market. The same is true for market power purchases, and an FCA therefore often includes both fuel and wholesale power costs.

Fuel cost adjustments were thus intended to allow efficient recovery of costs that were (a) volatile, that is, subject to unpredictable increases (or decreases); and (b) not within the utility's control. Costs that are predictable or within the utility's control would fall under regular ratemaking processes or special review. These include capital investments, long-term commitments for power purchases, or expenditures on programs within the utility's control.

3.2 THE ECAF AT LADWP

According to the City Administrative Officer, "The ECAF operates as a 'pass-through' of renewable energy costs, fuel/natural gas costs, purchased power costs and energy conservation costs as well as providing rate stabilization requirements."[11]

Fuel costs and purchased power costs represent the traditional FCA. These costs are dependent on market prices. While a utility can follow best-practice procurement and hedging plans, it cannot completely control the market price of fuel and purchased power.

Some renewable energy costs are also dependent on market prices (e.g., long-term renewable power contracts whose prices are indexed to gas prices or power prices) but others, such as long term fixed-price PPA costs, prepaid energy costs, transmission costs or the capital costs of LADWP-built renewable resources, are not dependent on market prices and therefore would not typically be part of an FCA.

Energy conservation costs such as the costs of energy efficiency programs are also not part of a typical FCA. On the other hand, revenue losses due to DSM are often considered unpredictable and out of the utility's control. Therefore, in many cases, including that of the California Investor Owned Utilities (IOUs), these losses are passed through by an adjustment mechanism ("revenue decoupling") similar to an FCA.

The ECAF also contains a separate element that accounts for the City Transfer payments that are made as a percentage of total revenues. This adds 8% to all other ECAF costs such that the Department is essentially kept whole on the 8% of ECAF revenues that are transferred to the City as ECAF costs rise and fall. While this makes sense given the way City Transfer payments are calculated today, the fact that City Transfer payments are tied to volatile ECAF revenues at all introduces additional volatility both to customers and to the City, and adds additional complexity to the ECAF balancing account.

Finally, the ECAF is intended to limit the speed at which rates grow. Cost increases in excess of the cap are accumulated in the ECA account and deferred until the quarterly cost increase would otherwise be less than the cap. While this provides a limited amount of rate stabilization (there is also a Rate Stabilization Account used to amortize certain extraordinary items), it is at cross-purposes with the role of the ECAF in enabling a quick response to uncontrollable cost increases. During times when the cap prevents revenues from increasing as quickly as costs, an undercollection of ECAF costs accumulates. This undercollection must be financed by the Department, negatively impacting cash levels as well as debt

[11] Memo to the City Council from Miguel A. Santana, CAO File No. 0160-01536-0000, Council File No. 09-1980, September 1, 2009.

coverage ratios. A well-designed rate stabilization plan usually includes a method to amortize undercollections within a defined time horizon; the ECAF cap can prevent timely amortization.

The ECAF is applied to all rate classes at LADWP with the exception of street lighting and traffic control. The same cost per kWh is applied on a consistent basis across rates, regardless of the base rate differences between rates.

3.2.1 The History of ECAF at LADWP

The definition and implementation of the ECAF at LADWP has changed over the past fifteen years. As of 1997, the ECAF was designed to pass through the cost of fuel, purchased power, and energy conservation. In 1998, the existing ECAF was frozen at 1997 levels in an attempt to prepare for deregulation. At that point, the ECAF rate was 2.94 cents/kWh and accounted for 26% of LADWP's retail revenue.

The ECAF remained frozen for the following eight years. During that time, the Department absorbed fluctuations in actual ECAF costs from year to year while keeping the ECAF rate fixed. However, in 2006 the ECAF was unfrozen to "stabilize LADWP finances in the face of a highly volatile natural gas market."[12] It was noted that continuing to absorb ECAF fluctuations would "potentially contribute to an erosion of the financial integrity of LADWP."

At the same time that the ECAF was unfrozen, several other new categories of charges were introduced to the ECAF account. Most notable was the inclusion of renewable energy costs. At the time, this inclusion was justified by stating that "renewable energy is included as additional funding is needed and the development of renewable energy resources is viewed as a way of offsetting or reducing natural gas requirements. Inclusion of renewable energy is also consistent with the 2003 City Council action conceptually approving a pass-through for renewable energy expense."

In addition to renewable energy costs, a decoupling mechanism for energy efficiency improvements was introduced that incorporated into ECAF a charge for revenues lost due to energy efficiency improvements. This allowed LADWP to maintain base revenue levels even while reducing overall electricity demand. Additional language changes created a small rate stabilization fund, updated language to reflect a 7% City Transfer,[13] expanded decommissioning costs from nuclear facilities to all generation facilities, and specifically included emissions fees, interest expense above 4%, uncollectible bills, asset write-offs, and extraordinary expenses.

While the ECAF was unfrozen, changes in the rate were capped at 0.1 cents per kWh per quarter. This was done despite the concern regarding fuel price volatility and the introduction of multiple new ECAF categories, some of which were expected to grow rapidly over the coming years. Overall, ECAF rates have risen every quarter since 2006 to their current level of 5.09 cents per kWh.

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[12] Memo to the City Council from William T Fujioka, CAO file no 0160-00070-0041, July 31, 2006 "Proposed Power Rate Action for Fiscal Year 2006-07"

[13] The level of City Transfer has since been increased to 8 percent of LADWP revenues.

Since being unfrozen, revenues collected under the ECAF have grown. From 29% of the Department's revenues in 2005, ECAF has grown to account for 39% of revenue in 2009. That growth is expected to continue, with ECAF accounting for nearly half of the Department's revenue by 2011.

3.2.2 Definition of ECAF Components

Per the latest rate ordinance, the ECAF is designed to capture six distinct categories of expenses.[14] These are:

a. FUEL

Includes all costs associated with natural gas, coal, and nuclear fuel procurement. This also includes emissions, greenhouse gas reduction, and retirement costs.

Fuel costs are driven primarily by free market forces, with volatility managed through a mix of hedging programs and long-term fixed price contracts.

b. PURCHASED POWER:

With the exception of RPS (covered below), this includes all purchased power costs, including associated transmission. This covers short-term energy market purchases as well as long-term PPAs such as agreements with IPP and SCPPA.

Purchased power prices are driven primarily by market forces, with long-term PPAs often including a portion of volatile pricing associated with fuel procurement.

c. RPS

Includes all charges associated with renewable resource energy, capacity, RPS-related prepayment expense, operations and maintenance, depreciation, and interest expenses for generation and transmission.

Once constructed, the costs of renewable generators tend to be relatively stable and reflect capital depreciation and O&M costs. PPAs will have a similar structure, with costs representing fixed debt payments and O&M costs. However, the amount of power generated from some RPS resources such as wind and solar can vary from day to day, month to month, and year to year. This means that the cost per kWh of power produced can vary over a contract.

In addition, the market for new RPS generation resources can vary as a function of new technology, local competition, and materials costs. This leads to uncertainty in the cost of new RPS generation builds.

[14] See pages 74-79 of Electric Rate Ordinance 180127 for the technical definition of each component of the Energy Cost Adjustment

d. DSM EXPENSES

Includes qualified DSM costs, defined as costs incurred for the acquisition and installation of devices and systems, including incentive payments, audit costs related to DSM, and administrative costs, which are part of those programs or projects designed to lower and control power system demand or consumption. This is limited to 10% of the fuel, purchased power, and RPS costs described above.

e. DSM REVENUE LOSS RECOVERY:

Set equal to the cumulative energy efficiency savings incurred since July 1, 2006 multiplied by 5.513 cents per kWh of savings. This represents lost revenue due to the implementation of DSM programs and helps to preserve LADWP's rate base as demand is reduced through energy efficiency.

f. CITY TRANSFER:

As described above, a factor of 8% is added to all ECAF expenses to cover the portion of the 8% City Transfer associated with ECAF revenues. This only includes the portion of the City Transfer associated with ECAF revenues and does not include the City Transfer component associated with base rate revenues, which is built into the existing base rate structure.

3.2.3 Calculation of the ECAF Rate

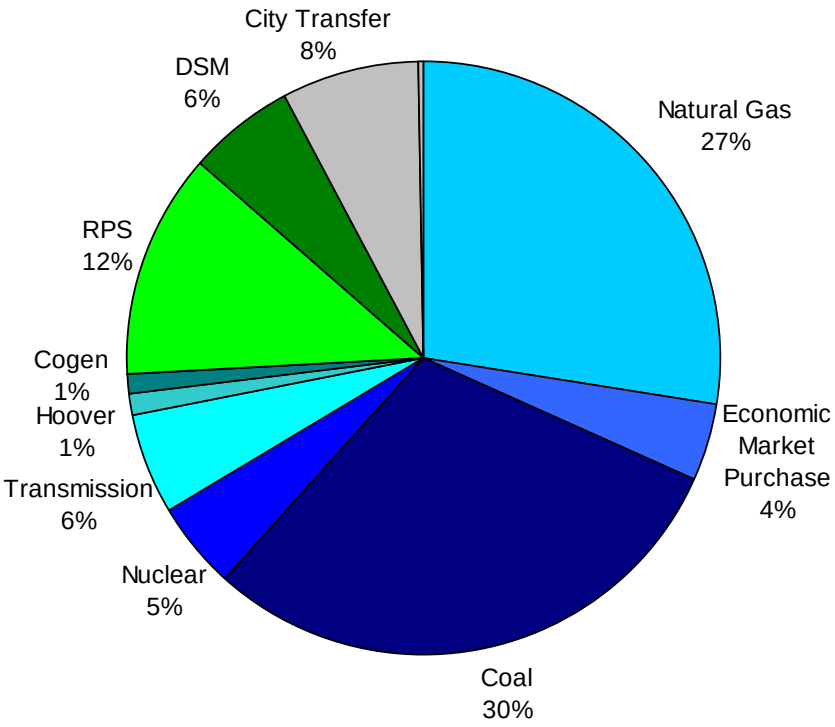
The ECAF rate is calculated on a quarterly basis by estimating the following 12 months of costs described above, adding any previous under or overcollection of ECAF, and dividing by the estimated energy demand for the following 12 months. From this rate, an amount of 1.25 cents/kWh is subtracted to yield the ECAF rate to be charged to customers over the next quarter.

This 1.25 cents is meant to reflect a portion of the ECAF charge that is included in base rates, implying that current base rates are higher than needed to cover base operations.

3.3 CURRENT ECAF COSTS

In FY2009 (ending in June 2009), costs booked to the ECAF account totaled slightly over 1.3 billion dollars.

Figure 3: FY2009 ECAF Cost Breakdown, Total Costs = $1.33 billion



3.3.1 Fuel and Purchased Power

As displayed in Figure 3, over two-thirds of 2009 ECAF costs stemmed from fuel and purchased power costs. These fuel and purchased power costs included:

- ***Natural Gas ($366 million):*** Includes direct fuel and transportation costs for natural gas required to supply LADWP's gas generation assets, including the Haynes and Valley generation assets. 2009 also included a one-time negative adjustment of $67M due to a legal settlement regarding prior fuel charges.

- ***Coal ($401 million)***: Includes $344 million for the full cost of power purchased from IPP in Utah,[15] as well as direct fuel costs for coal required for LADWP's portion of the Navajo generating facility in Arizona.

- ***Nuclear ($61 million)***: Includes $53 million for the full cost of power purchased by LADWP from SCPPA's share of generation from the Palo Verde project in Arizona, as

[15] While LADWP is an owner in the Intermountain Power Agency (IPA), power from IPP is purchased through a separate PPA between LADWP and IPA. Because of this, generation from IPP is considered purchased power, requiring that the full costs of generation (debt service, O&M costs, and fuel costs) are included in the ECAF. In the case of Navajo and LADWP's gas generating assets, LADWP's ownership is held directly on the balance sheet and only fuel costs are included in ECAF. Debt service and O&M are covered by base rate revenues.

well as $8 million for fuel associated with LADWP's direct 6% ownership share in Palo Verde.

- ***Economy Purchase ($57 million)****:* Includes the cost of power purchased on the open market to cover LADWP load requirements. Power is purchased when it is more economic to procure from outside market sources than to use LADWP generation.

- ***Transmission ($73 million):*** Includes transmission costs associated with bringing purchased power into the Los Angeles area. This includes $53 million in payments to SCPPA for the Southwest Transmission System (STS) used to bring power generated at IPP in Utah to LADWP. Additional payments are made for transmission on the Mead-Phoenix, the Southern California Edison (SCE), Mead-Adelanto, and Northern Transmission systems.

- ***Hoover ($16 million):*** Includes power purchased from the Hoover Dam generation facility.

- ***Cogen ($17 million):*** Includes power purchased from qualified cogeneration facilities.

3.3.2 RPS and DSM

18% of FY2009 ECAF expenditures were associated with projects counting towards LADWP's RPS requirement or DSM programs. These costs consisted of:

- ***RPS ($165 million):*** Includes all costs associated with eligible RPS projects, including the full cost of generation owned by LADWP as well as the full cost of any purchased power.[16] $75 million came from short-term renewable energy purchases, $55 million from hydro generation, and $33 million from wind. In 2009, these RPS projects represented 11% of LADWP's retail sales.

- ***DSM ($76 million):*** Includes $69 million of direct expenses under LADWP's demand side management program as well as $6 million in revenue loss recovery. Direct expenses include incentives for refrigerator exchange, commercial and small business lighting programs, and the distribution of compact fluorescent light bulbs.

While these programs totaled only $240 million in 2009, costs are expected to increase dramatically in upcoming years, more than doubling to $550 million in 2011. The drivers and impacts of these increases are described in detail in Section 4 of this report.

3.3.3 City Transfer

Per ordinance, an additional factor of 8% is added to all ECAF expenses to help cover the overall 8% of revenues transferred to the City's general revenue fund each year. Because of this, as other ECAF expenses rise, an additional 8% is added to the total to be transferred to the City.

[16] Unlike other generation, where fuel costs are included in the ECAF while capital and O&M expenses are covered by base rates, all costs associated with RPS generation are included in the ECAF.

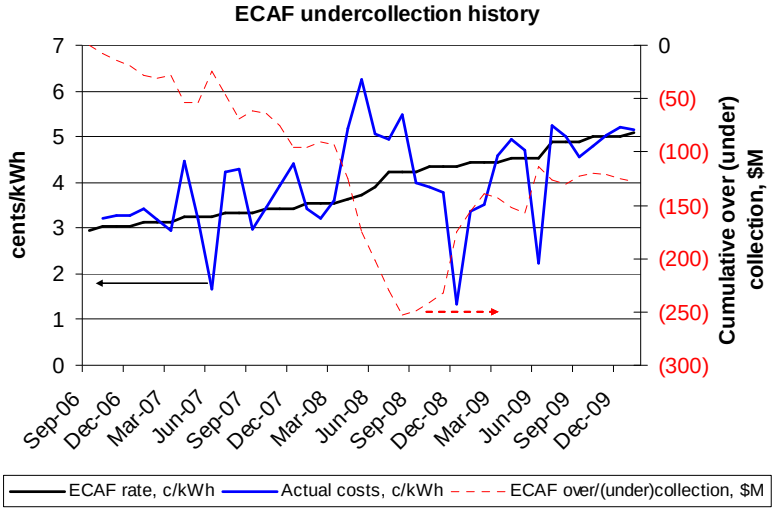
The portion of the City Transfer associated with base rate revenues is not covered by the ECAF; that portion of the transfer is taken out of the existing base rate revenues.

The net impact of this is that the actual amount of the City Transfer rises and falls based on volatile commodity prices. The component of the City Transfer associated with ECAF totaled $100 million in 2009.

3.4 HISTORICAL ECAF UNDERCOLLECTION

The chart in Figure 4 illustrates the relationship between LADWP's ECAF rates and actual costs since 2006. The blue line tracks actual expenses each month, normalized by total demand, to yield a rate in cents per kWh.[17] The black line indicates the actual rate charged by LADWP in any given month. In months where costs exceeded expenses, the ECAF account balance (shown in red) grew more negative. When energy costs exceed the ECAF rate for a sustained period of time, an undercollection results. The cumulative undercollection is shown in the dashed red line. (Note that the arrows indicate the axis that corresponds to the data shown.)

Figure 4: Historical ECAF over/undercollection



Ultimately, customers are responsible for paying the ECAF costs that accumulate in the undercollection balance. As this undercollection accumulates, the Department is in essence loaning those funds to the customer to be paid back at a later date when rate levels eventually catch up to and exceed cost levels. In the meantime, the impact on the Department is to lower cash levels, requiring higher borrowing and lower debt coverage ratios. Over time, an accumulating ECAF undercollection could threaten LADWP's ability to maintain target debt ratios.

[17] Expenses include one-time monthly adjustments such as legal settlements and accounting adjustments. This included a one-time legal settlement impacting fuel in December 2008 and a one-time adjustment for IPP power expense in June 2009.

The majority of the current undercollection was incurred in 2008 when costs exceeded revenues for six consecutive months. During that period, a spike in natural gas prices occurred that could not be fully recovered by the Department. The ECAF undercollection grew to nearly $250 million during this price spike. Natural gas prices declined late in 2008, allowing rates to temporarily climb above costs and partially repay the undercollection in the ECAF.

Since then, costs have increased as gas prices have somewhat recovered and higher RPS and DSM spending have begun to impact costs. As of January 2010, costs exceeded rates and are expected to grow sharply over the next 24 months. This outlook is described in detail in Section 6 of this report.

3.5 CONCLUSIONS

The ECAF as currently constituted at LADWP contains several elements that typically would not be found in a cost adjustment factor. The majority of these were introduced during a sweeping ECAF redesign in 2006 that added renewable energy expenses, revenue loss recovery for DSM energy savings, and a number of other items such as variable rate and extraordinary expenses. At the same time that these large new programs were added to the ECAF, changes in the rate were capped at 0.1 cents per kWh per quarter, limiting the Department's capacity to properly fund these new commitments while still addressing concerns regarding natural gas price volatility. These changes have had several negative impacts.

First, the presence of so many elements into a single cost adjustment factor reduces transparency into the cost drivers behind ECAF increases. Understanding the causes of ECAF increases today requires a detailed decomposition and analysis that is difficult for policy makers, let alone customers, to understand. Fuel and power markets typically move together, allowing a traditional FCA charge to be compared to transparent market prices. When combined with Department programs such as RPS, DSM, and multiple one-time legal settlements and extraordinary items, explanations for ECAF changes become unclear.

Second, the act of bundling market-driven elements with less volatile costs that lie within the Department's control can limit overall transparency and potentially lead to a lack of accountability for those costs. Under the current system, ECAF increases are passed through to customers automatically without detailed rate review. These increases have been partially tied to fuel prices but also to new commitments made by the Department for projects and programs designed to meet RPS and DSM goals. The automatic nature of the ECAF rate increase has removed the need for explicit rate review of these elements.

Third, these long-term commitments have predictable costs. Therefore they can and should be made with specific consideration for their impact on rates. Under the current structure, commitments that are both predictable and within the Department's control can be passed through to ratepayers without review. While this may be appropriate for market-based fuel and purchased power purchases, major capital project commitments represent strategic and not operational decisions.

Finally, rate responses to volatile fuel and purchased power costs should not be constrained by the presence of a very tight cap on ECAF changes. These costs can spike dramatically,

causing rapid growth of an ECAF undercollection and potential deterioration of the Department's financial standing. A prudent procurement and hedging plan should be in place to limit the impact of this volatility. However, as described in Section 4, additional costs and risks limit the practical amount of hedging that can be done. The residual exposure to these market prices should be passed through uncapped to the ratepayer to avoid the potential for financial distress.

The current ECAF design does not provide for adequate oversight and transparency into long-term commitments made by the Department, particularly with respect to RPS and DSM. At the same time, a cap on market-based drivers presents a significant risk to the Department in the event of a market price shock, providing support for the argument that the ECAF should be decomposed into separate elements with their own individual mechanisms for rate review. Any effort to reconstitute the ECAF won't be simple. Any effort to promote transparency must not be at the expense of expediency, and care must be to taken to prevent disproportionate impacts on individual classes of ratepayers.

4. LADWP REFERENCE CASE

LADWP has defined a Reference Case financial plan based on assumptions regarding fuel prices, RPS generation, DSM investment, operating performance, and multiple other variables with a measurable but less significant impact on costs. This section introduces the underpinning assumptions of the Reference Case and offers conclusions with regards to their suitability from a financial planning perspective.

4.1 NATURAL GAS

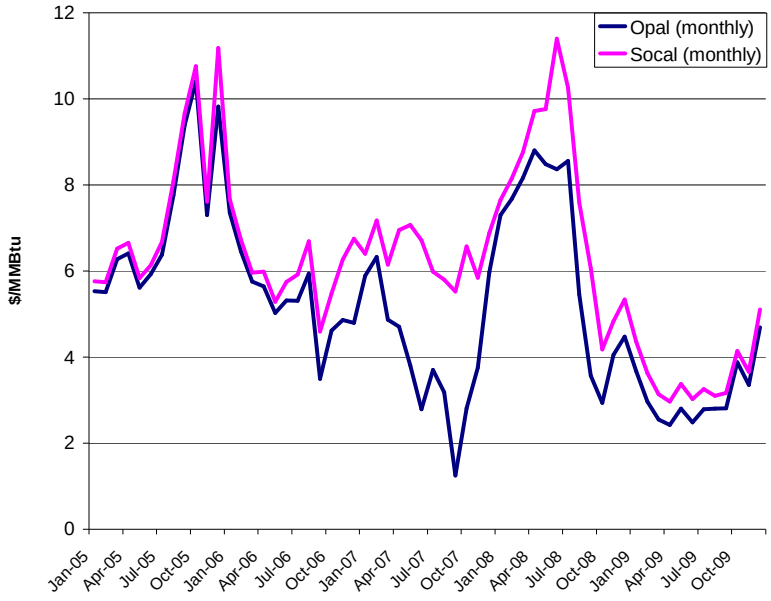
Natural gas prices are the most volatile part of LADWP's ECAF portfolio. Natural gas is traded in a deregulated and liquid market in locations throughout the United States. Prices move with market forces and can vary substantially from day to day, month to month, and year to year. Given the large amount of gas purchases required for LADWP's generation portfolio, this gas price volatility has the potential to substantially impact ECAF costs and rates.

4.1.1 Historical Prices

Since 2005, the price of natural gas in Southern California has averaged slightly over $6 per MMBtu, but monthly average prices have varied from under $3 to over $11 per MMBtu.

LADWP purchases the majority of the gas at the Opal trading location Wyoming. The Department owns firm transportation rights on the Kern River pipeline to move that gas to the local market. From there, the gas is transported through the local Socal system to LADWP's facilities. While prices vary from day to day, the price of the gas transported from Wyoming, inclusive of pipeline charges, is typically lower than purchasing gas in the local Socal market. Historical prices at both Socal and Opal are shown below.

Figure 5: Historical gas prices at Socal and Opal



4.1.2 Natural Gas Hedging

In order to better manage the volatility associated with fuel prices, companies will enter into arrangements to counteract this volatility and limit the effective price paid for fuel. This is generally referred to as "hedging" of fuel costs. When used appropriately, these arrangements can eliminate much of the volatility experienced in the market at a relatively modest cost. However, hedging programs will not eliminate 100% of fuel price volatility and should be designed carefully to limit the introduction of new risks.

a. TYPES OF HEDGING

This may be done by entering into long-term contracts for fuel supply, eliminating the need to purchase gas on a month-to-month basis. This is referred to as physical gas hedging.

Another approach is to enter into a financial hedge. For example, if LADWP projects that it will need to purchase gas at the Opal market hub, it can enter into a financial transaction in the natural gas futures market whereby it makes money if the gas price at Opal rises above a target level and loses money if it falls below a target level. This "swap" arrangement counteracts the financial impact of the price volatility that LADWP experiences when physically purchasing fuel on a month to month basis. The net impact is to limit volatility in the overall cost of the fuel procurement program. Much more complex arrangements also exist, including collars, puts, and calls.

b. HEDGING LIMITS AND CONSIDERATIONS

There are practical limits to fuel hedging. Hedging introduces a new risk associated with estimating actual fuel needs. LADWP's natural gas requirements vary from year to year based on factors such as weather, economic demand, unit outages, and the price of external

market power. Actual fuel needs may be lower or higher than projections. If LADWP were to attempt to hedge 100% of its projected needs, there is a risk that it commits to purchase gas volumes that it physically does not require. These volumes may be worth more or less in the open market than LADWP has committed to pay, creating a new financial risk. To avoid this situation, it is typical for a gas buyer to only enter into hedging arrangements for a fraction of its projected gas usage.

Hedging also comes at a cost, involving banks, traders, or exchanges who earn a margin in the process of matching willing buyers and sellers in the financial or long-term market. While these costs may be modest for relatively simple transactions such as swaps, they increase for more complex transactions or transactions with variable volumes. As hedges are long-term transactions, there is also a chance that the counterparty may not perform as described, creating new credit risk.

Finally, while fuel hedging is helpful in avoiding short-term volatility, it is not necessarily in the interest of LADWP to fix fuel costs over the long-term. In order to ensure that LADWP is competitive with other utilities in the region, long-term natural gas costs should be similar to those of its competition. If LADWP fixes the price for a high percentage of its long-term gas procurement, it takes on the risk that these prices will be higher than the market price, resulting in a higher cost of generation compared to other California utilities.

Because of these considerations, a hedging program should seek a balance of limiting volatility while minimizing costs, limiting the emergence of these new risks, and ensuring competitive, market-based costs over the long run.

c. LADWP'S NATURAL GAS HEDGING PROGRAM

Under section 10.5.3 of the City's administrative code, LADWP has the authority to enter into natural gas hedging transactions for up to 75% of projected requirements. Transactions are to be no longer than ten years in duration (five for physical transactions) and a maximum purchase price of $10 per MMBtu. LADWP's activities under this section are subject to an annual audit, including an assessment of risk management controls and compliance with the provisions of the code.

As implemented, LADWP's hedging program seeks to achieve a balance between volatility and risk by entering into a high percentage (approximately 50%) of natural gas hedges for the current year, falling to zero over the following 10 years. The portfolio of hedges spreads risk between both physical and financial counterparties, focusing on relatively simple transactions transacted at liquid gas trading locations.

Due to lower than expected gas needs and the introduction of additional biogas purchases to meet RPS requirements, LADWP has effectively hedged over 90% of its gas supply needs in FY2010. LADWP has also entered into arrangements for the following eight years, with approximately 50% of projected needs hedged in 2011, declining to approximately 33% of projected needs in 2014 and under 20% by 2018.[18]

[18] Authority and guidelines for this hedging program is set by section 10.5.3 of the Los Angeles administrative code, "Authority of the Board of Water and Power Commissioners to Enter into

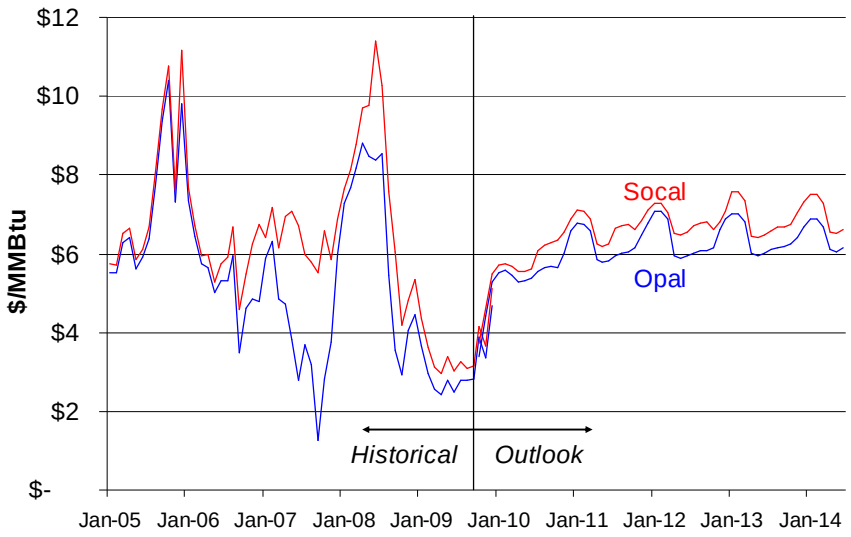
The Department's portfolio includes a combination of physical and financial hedging. LADWP conducts physical hedging through long-term fixed price gas purchases, long-term fixed price biogas purchases, and investment in its own gas reserves at Pinedale. For financial hedging, LADWP employs natural gas swaps at Opal as its primary means for managing prices. LADWP maintains hedging contracts with 11 financial counterparties, including major banks and energy companies. These companies offer a credit threshold of $20 million to $40 million each.

Excluding landfill gas purchases, LADWP's average price for gas hedges between January 2010 and the end of the five-year plan in FY2014 is $6.16 per MMBtu.

4.1.3 Forecasted prices

LADWP bases its natural gas price forecast on prices for purchasing gas for future delivery. These prices reflect NYMEX pricing for gas delivered at Henry Hub, adjusted for the locational price differential between Henry Hub and western markets at Opal and Socal. The forecast used in the financial plan evaluated in this report used prices from October 15, 2009. This forecast is shown in the chart below.

Figure 6: Natural Gas Price Outlook as used in LADWP Financial Plan



4.1.4 Conclusions

LADWP's hedging program for natural gas is reasonable and provides a balance of limiting price volatility while managing the costs and risks of long-term hedging. Increasing current hedging levels may reduce volatility but would introduce the risk of (a) hedging more than

Contracts and Financial Transactions for Natural Gas and the Delegation of Such Authority to the General Manager".

LADWP's gas requirements in future years, (b) locking in long-term prices at levels above other utility costs, or (c) introducing high costs to LADWP's procurement program.

Regarding the program's execution, FY2010's hedging levels exceeded targets due in part to significant purchases of biogas. These were driven by the Department's RPS program and resulted in commitment to an additional 10% of LADWP's projected gas needs. In the future, the Department should strive for better coordination and planning between these RPS requirements and gas procurement in order to avoid potential overcontracting for gas. At the same time, the Department's level of hedging for FY2011 appears to be low (< 50%) and should be increased in a manner consistent with the Department's guidelines.

Regarding fuel price projections, it is typical for energy companies to use forward price projections in Reference Case financial plans. However, it is critical to recognize that natural gas prices change from day to day and that actual gas prices may vary substantially from current forward prices. The comparison of the historical prices and forward outlook illustrated in Figure 6 shows that the volatility present in past prices is not included in the forecast. Future prices will likely include periods of high prices and periods of low prices. If prices rise for an extended period, as seen during 2005 following hurricane Katrina and again in 2008, actual costs may significantly exceed those predicted in the initial forecast.

For this reason, it is important to evaluate alternative financial scenarios that include higher natural gas prices. A failure to do so could limit the Department's visibility of risks that could impact its financial ratios, cash levels, and overall solvency. Reasonable scenarios can be constructed based on historical price behavior and current forward price expectations. Such a scenario is developed in Section 5 of this report.

4.2 COAL

DWP has an ownership interest in and uses power generated by two coal-fired power facilities, the Intermountain Power Project (IPP) and Navajo. Approximately 40% of LADWP's power comes from these plants. Due to the relative stability of coal prices in the United States, and the relatively high percentage of power sourced from these plants, coal has been the largest, but most stable, portion of ECAF expenses. Recent increases in volatility in coal markets and changes in rail freight markets, however, coupled with the expiration of long-term coal supply agreements, have led to expectations of upcoming price changes for IPP with the potential to substantially impact ECAF costs.

4.2.1 Intermountain Power Project

Through its 45% participation in the Intermountain Power Agency (IPA), LADWP is entitled to output from IPP. IPP is an 1800 MW coal fired power plant located in Delta, Utah consisting of two generating units. Other purchasers include other California municipal utilities as well as co-ops, IOUs, and municipal utilities in the state of Utah. LADWP serves as the project manager and operating agent for the plant.

With an all-in cost of power of under $50/MWh, IPP serves as the largest source of baseload generation for LADWP, providing 28% of all power to the system in 2009. LADWP pays for a share of the actual costs incurred at the plant based on its power entitlement and actual power consumption. These costs consist primarily of debt repayment, O&M expenses, and

fuel costs. Power from IPP is treated as purchased power and all of these costs are passed through in the ECAF.

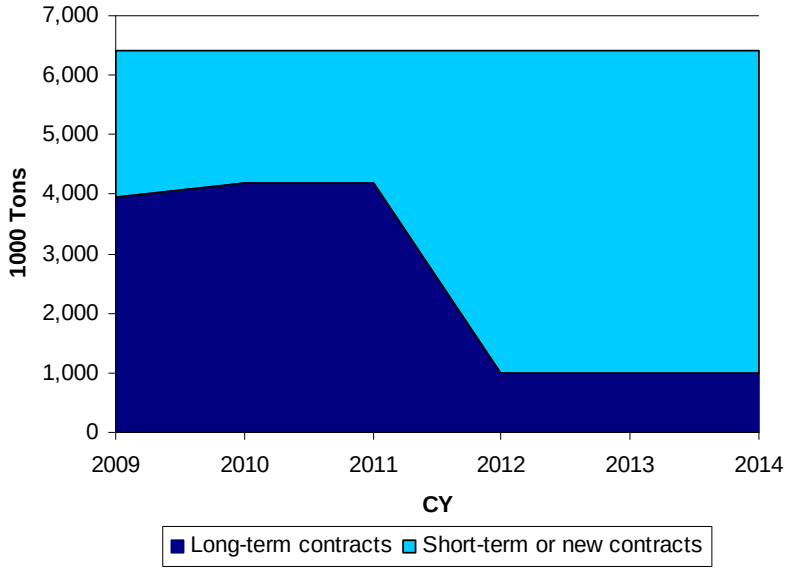
a. COAL SUPPLY

Coal supply costs accounts for ~40% of the total cost of power received from IPP. While debt service and O&M costs may fluctuate from year to year, the cost of coal represents the most uncertain of the three main cost components in forecasting generation costs over the coming five years.

Coal supply for IPP is sourced from a portfolio of mines in Utah, including the Sufco, Dugout Canyon, and West Ridge mines. From the mines, coal is transported via the Union Pacific Railroad to the IPP site.

As is typical in the coal industry, the majority of fuel is procured under long-term contracts with fixed or known prices. Similarly, the coal is delivered by railroad under contract. As these contracts expire and are replaced with new contracts, new prices will be negotiated that are in line with current or expected market prices. The average delivered cost of coal under long-term contract for 2010 (inclusive of freight) is $36 per ton.

Figure 7: Coal quantity under existing supply contracts with IPP



Average coal prices at IPP had been relatively stable for many years, with costs hovering near $35 per ton[19], on average. However, beginning in 2008 there was a significant shift in U.S. coal markets that impacted pricing in the Utah area. This shift was caused by:

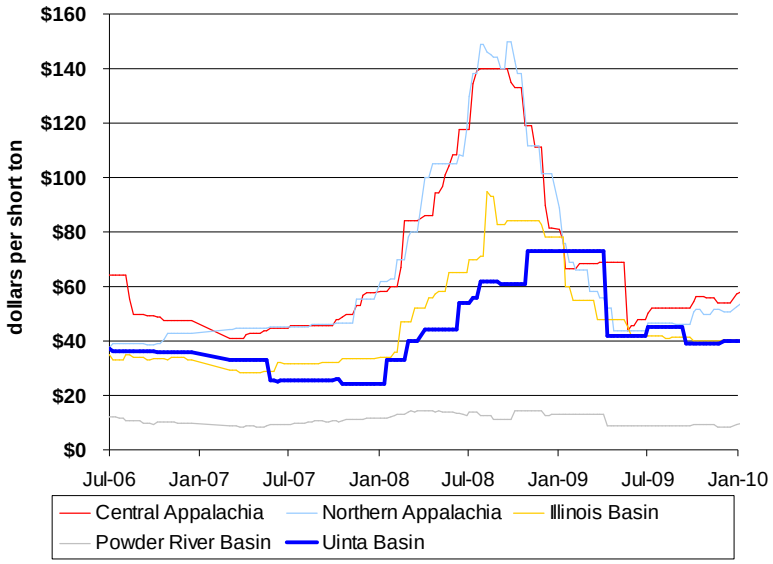
[19] Per PA's interview with Bill Engels at DWP, IPP's average delivered coal prices have generally remained steady at ~$1.50 per MMBtu since 1985. Using a heating value of 11,400 Btu/lb, this is slightly under $35/ton.

- An increase in prices in virtually all U.S. coal markets, coincident with an increase in worldwide coal market prices, which resulted in increased demand for Utah coal from other markets outside of Utah, particularly in the Midwest U.S.

- A decrease in local supply due to the closure of several mines, including the Crandall Canyon mine that suffered a fatal collapse in 2007. EIA estimates that production of coal in Utah declined 11% from 2008 to 2009.

Following the start of the recent global recession in late 2008, U.S. and local Utah coal prices began to moderate and have since returned to near pre-2008 levels. The chart below shows reported spot prices in major U.S. producing basins. Of these reported regions, the Uinta basin, straddling the border of Colorado and Utah, represents the pricing point closest to the mines serving IPP. From this chart, it can be seen that Uinta spot prices more than doubled in 2008, reflecting behavior also seen in the Midwest and Appalachian U.S. markets.[20]

Figure 8: Coal commodity spot prices in major U.S. producing areas



Source: Energy Information Administration

As with most commodity markets, there is uncertainty as to whether spot prices will once again rise as economic growth recovers. While some of the 2008 price increase was likely tied to short-term demand pressure that also impacted other commodities, the local Utah market is likely to also be impacted by the decrease in local supply. For this reason, it is

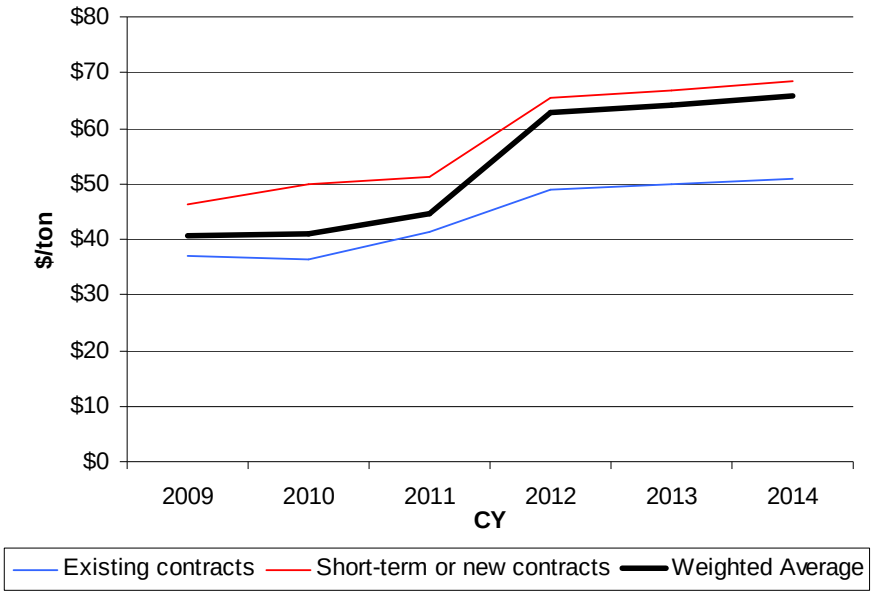
[20] Coal from different basins or mines can have different characteristics such as heating value or impurity content, limiting the substitutability of coal supplies in existing power plants. Coal is also relatively expensive to transport. For this reason it is difficult to compare prices across geographic areas. Spot price markers should be viewed as indicative markers, not actual prices that may be available to a power plant subject to unique quality and transportation constraints.

reasonable to expect that contracts signed during the next few years for future long-term supply at IPP may reflect prices between the current Uinta spot prices and the peak levels experienced towards the end of 2008.

b. DWP'S COAL PRICE FORECAST

LADWP has assumed that new coal deliveries for IPP are recontracted at prices higher than recent historical prices, due both to higher commodity prices in Utah and higher transportation costs. DWP's forecast as used in its financial plan is shown below. The plan assumes that short-term prices increase over time, resulting in an average delivered price of over $65/ton by 2014.

Figure 9: DWP forecast of delivered IPP coal prices



4.2.2 Navajo

The Navajo power plant, located in Northern Arizona, is a coal-fired power plant with 2250 MW of capacity. LADWP owns 22% of the facility. Like IPP, Navajo provides baseload generation for LADWP, accounting for approximately 13% of the Department's total power needs.

Unlike at IPP, LADWP's ownership is accounted for directly. While LADWP still pays debt service, O&M expenses, and fuel costs, only the fuel costs are included in ECAF. Debt service, O&M expenses, and any depreciation are accounted in the same manner as other DWP-owned facilities.

a. COAL SUPPLY

Coal for Navajo is supplied from the Kayenta coal mine operated by Peabody Energy, located on Navajo lands in northeastern Arizona and delivered to Navajo by the Black Mesa and Lake Powell Railroad line, which solely delivers coal over this route. Unlike the competitive

situation experienced by IPP in Utah, the Navajo plant is captive to the Kayenta mine and vice-versa. The Navajo plant has no other reasonable source for coal and the Kayenta mine has no other reasonable market for its coal.

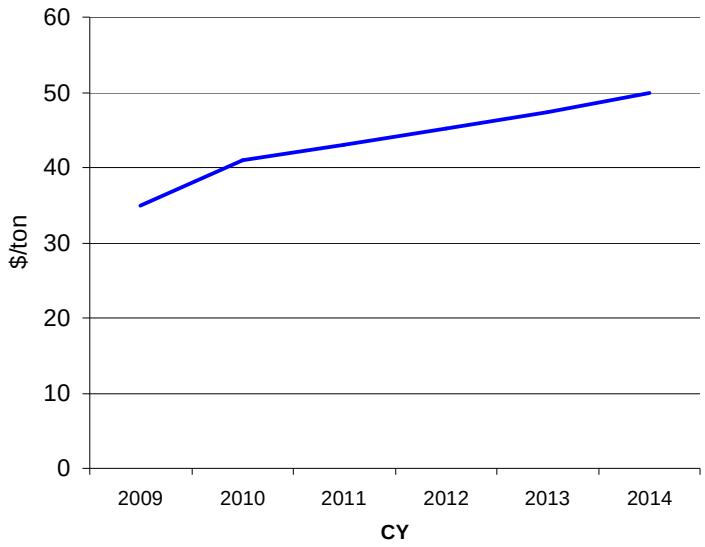
b. PRICING OUTLOOK

Because of this locked-in relationship, the two facilities entered into a long-term agreement for Kayenta to supply coal to Navajo. The current contract has been in effect for nearly 35 years and expires on April 30, 2011. The buyers hold an option to extend for 15 years subject to renegotiation of pricing under certain guidelines described in the initial contract. If the parties do not reach agreement, pricing will be determined in an arbitration proceeding.

Based on cost-plus pricing principles, future pricing for Navajo is likely to fall within a fairly narrow range. Given the current state of negotiations for a contract extension, LADWP estimates that the delivered cost of coal for Navajo will cost between $37.50 and $45 per ton in 2011, with prices escalating beyond that point based on a set of transparent cost indices.

LADWP's current financial plan assumes a cost of $43 per ton in 2011, escalating from that point forward. This is a reasonable assumption given the range of potential negotiation outcomes.

Figure 10: DWP forecast of delivered coal prices at Navajo



4.2.3 Conclusions

LADWP's forecast for coal prices at IPP is near the high end of the range that would be expected given recent and historical price trends. It assumes that the local spot market prices rise as the U.S. economy recovers, causing market prices to return to near 2008 levels prior to significant recontracting of coal at IPP.

In the case that market prices remain relatively close to current spot market conditions, and there is no return to the peak price levels seen in 2008, LADWP has estimated that the delivered price in 2014 would be closer to $55 per ton instead of the $65 per ton used in the current plan. This still represents a significant increase from today's delivered price of $36 per ton, creating an impact on ECAF costs.

LADWP's relatively conservative coal price estimates are appropriate for purposes of planning for an ECAF cap level, because, regardless of near term expectations for coal market prices, the projection is based on market prices experienced in the recent past. However, it is also important to note that, regardless of the trajectory of coal market prices, DWP should not simply accept future cost increases without actively pursuing strategic and tactical options to reduce commodity and transportation prices. A change of $10 per ton in IPP coal prices represents a value of ~$35M per year in ECAF costs. While an ECAF cap may be designed around the higher figure of $65 per ton, lower costs should be pursued as the savings will be passed on to ratepayers through the ECAF passthrough mechanism.

4.3 RPS

In May 2005, the LADWP Board of Commissioners established an RPS requiring that 20% of all retail energy sales be met via renewable energy[21] by 2017. This initial RPS was approved by the City Council in June 2005, and just six months later the Board moved to accelerate the goal, calling for 20% by December 31, 2010, which remains the target today. There is also a non-binding extension set by LADWP's Board calling for an increase to 35% by 2020, and Mayor Villaraigosa has voiced a more aggressive goal of 40% by the same year.

Table 6: Renewable Standards and Goals

Authority	Standard
30+ states	Targets and eligible resources vary significantly, but no state in the lower 48 calls for more than 25% conventional renewables by 2020
California	20% by 2010, goal of 33% by 2020
LADWP	20% by 2010, goal of 35% by 2020
Mayor of LA	40% by 2020

While more than 30 U.S. states feature renewable standards or goals, California's is the most aggressive. In addition, LADWP's 2020 goal (whether 35% or 40%) is even more aggressive than that of the State. Program-to-program comparison is made somewhat difficult by varying targets and eligibility criteria, but LADWP's goals, under any metric, are among the most aggressive in the country.

[21] As amended in 2007, LADWP's RPS establishes renewable energy resources to include: biomass; biodiesel; digester gas; fuel cells using renewable fuels; geothermal; landfill gas; municipal solid waste only if the energy conversion process does not employ direct combustion of solid fuel; ocean wave, ocean thermal, and tidal current technologies; solar photovoltaic; small hydro 30 MW or less, and the Los Angeles Aqueduct hydro power plants; solar thermal; wind; and other renewables that may be defined later.

Effectively meeting its RPS goals requires that LADWP seek transmission solutions, investigate a wide array of rapidly developing technologies, and plan for the integration of intermittent resources to its system. The Department's renewable energy plans continue to evolve, driven by increasing RPS goals, changing strategic objectives, and the rapid rate of change in the nascent renewable energy market.

4.3.1 RPS Compliance Strategy

While the Department continues to define specific project objectives associated with it's 20% RPS plan, it is guided by certain general criteria that appear to drive its efforts. According to the LADWP RPS Policy, as amended in April 2007 and cited in LADWP's 2007 Integrated Resource Plan, the Department's renewable acquisitions will be conducted through a competitive bid process focused on "least cost, best fit criteria," with preference given to projects located within the City of Los Angeles or those to be owned and operated by the Department, thus contributing to the Department's economic development and system reliability goals.

a. RPS STRATEGY – TO PRESENT

LADWP has issued several Requests for Proposals, either through the Department directly or through the SCPPA, operating according to the following strategy:

- Locational diversity – Locational diversity enhances system reliability, reduces system integration issues and costs, and mitigates the RPS compliance risk associated with regional underperformance. Locational diversity is particularly important as penetration of intermittent renewable generation increases. Solar generation is not yet heavily featured in the Department's portfolio, but wind is projected to represent approximately 40% of RPS eligible generation in 2010. With wind projects in multiple areas, LADWP can reduce seasonal volatility (e.g., Tehachapi projects generate more energy in the winter while Pacific Northwest projects tend to generate more in the summer) and minute-to-minute system volatility (e.g., wind speeds do not decrease everywhere at the same time). And by avoiding concentration in a single location, a utility can avoid disproportionate dependence on a single transmission line, which can be important from a reliability perspective and provide a mitigation measure versus RPS compliance risk.

- Project ownership – The amended RPS Policy of April 2007 states that in pursuing its original 20% goal, LADWP will own or have options to own the facilities that account for at least 40% of its RPS eligible energy. And after 2010, LADWP will own or acquire through ownership options at least 75% of the renewable generation needed, either directly or indirectly through off-balance sheet joint powers, until at least 50% of RPS generation is supplied by projects owned directly or indirectly by LADWP. Ownership is important from an economic development perspective (owning and operating generation projects creates jobs), from an expertise perspective (independent operation builds competency), and from a reliability perspective (performance optimization benefits from the ability to maintain and dispatch your facilities according to your own needs).

- Project clusters – The pursuit of project clusters dovetails well with the emphasis on ownership. Clustered generation assets are less costly to own and operate, as scale opportunities can be derived from an owner's ability to devote the same operations and maintenance staff to a greater number of projects. This strategy can be particularly appropriate in wind power, where rapid development and ever-increasing turbine heights have left appropriate cranes in high demand. O&M service agreements may cost as much as $50,000-$75,000 per turbine per year, establishing a clear benefit to the ability to undertake at least a portion of the upkeep independently.

The Department's Reference Case features three geographically distinct clusters of assets, the majority of which are either already owned and operated by LADWP or feature contracts with purchase options.

b. RPS STRATEGY - GOING FORWARD

Having made positive strides towards its initial goals, LADWP now plans certain adjustments to its renewable strategy. The Department has committed to de-emphasizing its locational diversity efforts in favor of rebalancing its current portfolio. Going forward, the Department plans to refocus away from wind and will seek to develop less remote solar and potentially geothermal options, thereby diversifying its technology focus, reducing its dependence on costly external transmission paths, and potentially furthering its own economic development objectives.

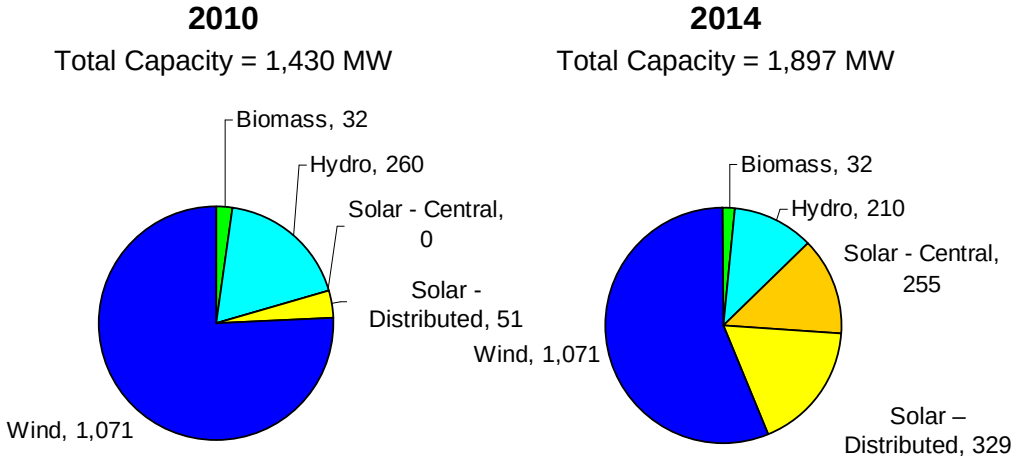
4.3.2 Renewable Energy Portfolio

The Department's current renewable generation project portfolio is a clear product of its original strategy. The map in Figure 11 displays the existing and projected assets identified in the Department's Reference Case. The Department has several small landfill gas assets in and around Los Angeles and 135 MW of LADWP-built and -operated wind at Pine Tree Wind, but will depend primarily on wind assets in the Pacific Northwest, Utah, and Wyoming.

Figure 11: Existing and Proposed RPS Generation and Transmission (Reference Case)

By the close of calendar year 2010, LADWP projects to have 1,413 MW of renewable generation under contract or direct ownership. As indicated in Figure 12, wind will account for 1,071 MW (76%) of this capacity, with the remainder accounted for by 260 MW of hydro (18%), 51 MW of distributed solar (4%), and 31 MW of small local landfill gas driven biomass projects (2%). The generation provided by these sources, along with the additional energy procured through market purchases and large landfill gas deals, accounts for nearly 5,000 GWh of energy generated by wind (43%), hydro (19%), large landfill gas deals (18%), short-term purchases (14%), small local biomass projects (5%), and distributed solar (2%).

Figure 12: RPS Capacity, by Technology – 2010 & 2014 (Reference Case)



The 20% renewable energy target will continue to drive renewable energy investment after 2010. According to the Department's plan evaluated as part of this Review, the Department plans to accelerate its distributed solar programs and has proposed to build central station solar projects at Owens Valley and Niland Solar to meet its ongoing target.[22] These near-term build plans will result in a more diversified portfolio by 2014, as indicated in Figure 12.

Figure 13 shows all RPS eligible energy generated and purchased by the Department over time. Projections show wind generation rapidly increasing through fiscal year 2011 before flattening there. After 2011, increased solar generation is projected to cover the slight RPS requirement increase[23] as well as the void created by the end to short-term purchases and the decline in hydro generation resulting from the December 31, 2011 expiration of the 50 MW Powerex contract for Pacific Northwest hydro power.

[22] The Department's Reference Case, which was finalized in December 2009, included its best estimate of future renewable energy investments. In certain cases, these plans may have since changed. The most prominent example of such potential changes is the 55-MW Niland Solar project. The Reference Case projects Niland to be operating by 2011, but at the time of this report the project has been put on hold indefinitely. PA's assumption in continuing to consider it as part of the analysis is that it will be revisited or replaced by another similar plan. PA has run a number of sensitivities to project any impacts should the actual project pursued result in higher costs to the Department.

[23] LADWP projects demand growth of approximately 1.3% annually between fiscal years 2010 and 2014. However, after significant DSM increases, net sales to customers increase by less than 0.2% annually. In absolute terms, the net sales to customer figure increases by less than 0.7% from 2010 to 2014. The RPS requirement, which is calculated relative to the net sales figure, thus shows very little increase over the same time period.

Figure 13: Actual and Projected RPS Generation (LADWP Reference Case)

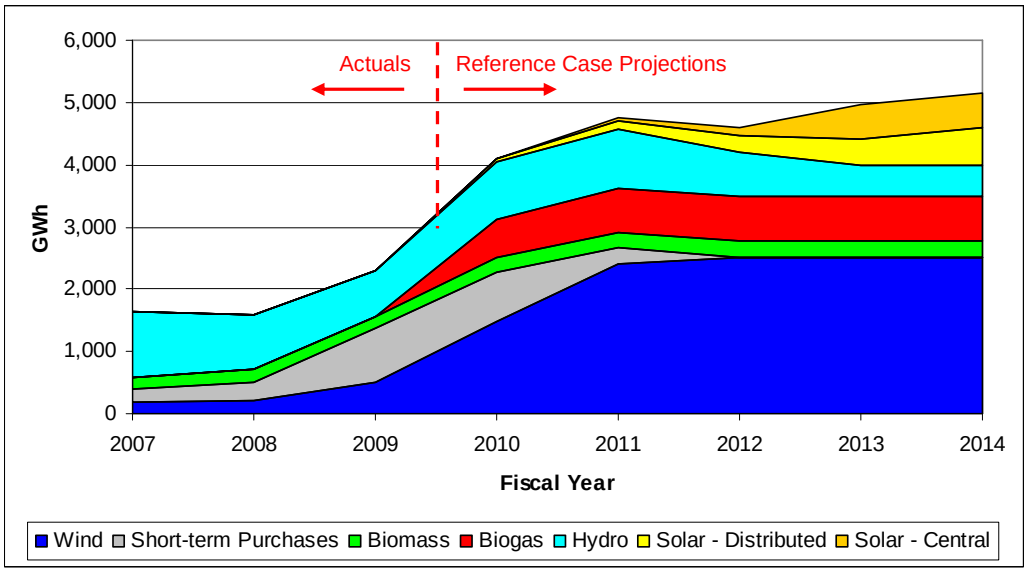


Table 7 presents the operating and cost details as well as the RPS contribution percentage of all plants included in the LADWP Reference Case. The following subsections provide an overview of the various generation sources, by technology. Greater detail on each of the individual assets is available in Appendix B.

Table 7: LADWP Reference Case RPS Facilities

Plant	Technology	Online Date	Capacity (MW)	Generation Cost ($/MWh)	Wheeling and Transmission Cost ($/MWh)	Total Cost ($/MWh)	RPS Contribution (% of CY 2010 Net Sales)	RPS Contribution (% of FY 2014 Net Sales)
Biomass								
Bradley Landfill	Biomass	1/1/2006	6	$52.00	$0.00	$52.00	0.15%	0.15%
Lopez Canyon Landfill	Biomass	4/1/2006	2	$62.00	$0.00	$62.00	0.01%	0.01%
Penrose Landfill	Biomass	5/1/2006	6	$59.00	$0.00	$59.00	0.19%	0.19%
Hyperion Digester	Biomass	7/1/2006	16	$0.00	$0.00	$0.00	0.62%	0.61%
LADWP Biomass	Biomass	12/31/2009	3	$75.00	$0.00	$75.00	0.09%	0.09%
						Total RPS %	**1.06%**	**1.05%**
Hydro								
Aqueduct Hydro Plants	Hydro	1/1/1997	166	$69.77	$0.00	$69.77	1.81%	1.79%
MWD Hydro	Hydro	11/1/2008	8	$91.50	$0.00	$91.50	0.18%	0.17%
Tieton Hydro	Hydro	12/31/2008	6	$85.00	$10.00	$95.00	0.07%	0.07%
Castaic Efficiency	Hydro	7/1/2009	30	$0.00	$0.00	$0.00	0.06%	0.06%
						Total RPS %	**2.12%**	**2.09%**
Solar - Central								
Niland Solar	Solar - Central	12/31/2010	55	$120.00	$35.00	$155.00	0.00%	0.53%
Owens Valley Solar (Ph I)	Solar - Central	7/1/2012	200	$100.00	$0.00	$100.00	0.00%	1.75%
						Total RPS %	**0.00%**	**2.28%**
Solar - Distributed								
Rooftop - Residential	Solar - Rooftop	Various	54	Various	$0.00	$0.00	0.19%	0.47%
Utility-Owned Solar	Solar - Rooftop	Various	275	Various	$0.00	$0.00	0.15%	2.05%
						Total RPS %	**0.34%**	**2.53%**
Wind								
Pleasant Valley Wind	Wind	7/1/2006	82	$63.00	$0.00	$63.00	0.87%	0.86%
Willow Creek Wind	Wind	12/31/2008	72	$77.96	$18.50	$96.46	0.71%	0.71%
Pebble Springs Wind	Wind	2/1/2009	69	$67.30	$28.00	$95.30	0.73%	0.72%
Pine Tree Wind	Wind	7/1/2009	120	$109.67	$0.00	$109.67	1.27%	1.26%
Milford Wind I	Wind	11/15/2009	185	$74.48	$5.00	$79.48	1.64%	1.63%
Windy Point Expansion	Wind	12/15/2009	60	$71.24	$28.00	$99.24	0.59%	0.59%
Windy Point Primary	Wind	12/15/2009	202	$71.24	$28.00	$99.24	2.01%	1.99%
Linden Ranch Wind	Wind	3/31/2010	50	$76.00	$28.00	$104.00	0.41%	0.54%
Milford Wind II	Wind	5/1/2010	66	$80.00	$5.00	$85.00	0.35%	0.52%
Pine Tree Expansion	Wind	6/30/2010	15	$115.88	$0.00	$115.88	0.07%	0.15%
Miller Ranch Wind	Wind	10/31/2010	150	$85.00	$28.00	$113.00	0.26%	1.52%
						Total RPS %	**8.94%**	**10.49%**
Biogas								
Biogas Purchase	Biogas	N/A	0	$0.00	$0.00	$0.00	2.42%	2.99%
						Total RPS %	**2.42%**	**2.99%**

Note: This table displays all assumptions as modeled in the Department's Reference Case.

a. BIOMASS

The assets classified under "biomass" are projected to account for a steady 252 GWh of energy annually throughout 2014 (5% of the requirement). This generation is procured through bilateral contracts with Bradley, Penrose, and Lopez Canyon (each smaller than 6.5 MW) and through digester gas from the Hyperion Treatment Plant, which qualifies for approximately 0.6 percentage points of the 20% RPS target when burned at the Department's Scattergood combined-cycle facility.

Note that the Department's "biomass" assets, as categorized, do not include the more substantial quantity of RPS eligible generation garnered through the purchase of landfill gas through the two large contracts described in the "Biogas" section below.

b. HYDRO

In 2010, hydro is projected to account for 18% of RPS capacity and 19% of eligible energy. Much of this power comes from 166 MW of LADWP-owned small hydro projects in the aqueduct, Owens Valley, and Owens Gorge. Together, these projects account for 430 GWh of generation annually, or 1.8 percentage points of the Department's 20% RPS requirement. The Department projects to receive the same amount of energy annually through its 50 MW contract for Pacific Northwest hydro with Powerex, which operates at a 97% capacity factor. However, the Powerex contract will expire on December 31, 2011, leading to the lower projected 2014 hydro contribution of 10% of eligible energy.

The Department also gets a very small amount of RPS energy through its efficiency project at Castaic. Castaic is LADWP's pumped storage plant that serves as a storage option for off-peak generation. This off-peak generation may include wind energy that cannot be used instantly as generated because insufficient load is available.

Finally, the Department projects to receive a very small amount of energy through the Municipal Water District (MWD) and Tieton Hydro projects, SCPPA projects in which the Department projects to have 8 MW and 6 MW stakes, respectively. The Tieton project requires wheeling and integration charges because the project is in the Pacific Northwest and does not enter LADWP transmission until the Nevada Oregon Border (NOB).

The hydro projects are a cost effective source of RPS eligible energy, averaging less than $75/MWh, including the wheeling and integration costs projected at Tieton.

c. SOLAR

LADWP's current plan calls for approximately 1,280 MW of solar capacity by 2020. As of 2010, the Department has made little progress towards this goal. In this report, the solar efforts have been categorized under two distinct categories: distributed solar (projected to account for 2% percent of the Department's RPS eligible energy in 2010) and central station solar (which is not projected to see any generating capacity until 2011).

<u>Distributed Solar</u>

The distributed solar program includes four elements that have been initiated or are discussed as future contributors:

- Residential solar – LADWP's residential solar incentive program offers rebates to customers who install solar photovoltaics (PV) on their roofs. As of July 2010, 3 MW of residential rooftop solar have been added, a relatively small number relative to the capacity additions projected to occur in future years. By the close of 2014, this program is projected to account for 54 MW of rooftop capacity.

- Utility-owned distributed solar – The utility-owned solar (UOS) program will employ LADWP workers to install PV on municipal property. As with the residential solar program, the UOS program has technically begun, with 2 MW installed as of July 2009. However, the ultimate goals with regard to distributed solar are much more aggressive. Los Angeles Measure B proposed providing 400 MW of distributed solar, enough to meet approximately 14% of the projected 2014 requirement. While

Measure B was narrowly defeated on March 3, 2009, the UOS program remains a key piece of the Department's plans. The Reference Case projects 275 MW of UOS installed by FY2014, enough to meet approximately 10% of the Department's RPS needs.

- Feed-in tariff solar – This is a program being discussed that would allow 3rd party solar developers to install solar PV on private property and sell the power to LADWP at favorable pre-established rates. The plan is still tentative – no feed-in tariff solar is projected to be built in the Reference Case – but any plan could lead to rapid solar construction, as seen under similar programs in Spain and Germany.

- SunShares – The SunShares program, another program that remains in discussion at present, would advance a community solar model by allowing customers to own virtual shares of solar projects. As with the feed-in program, no SunShares additions are projected to occur in the Reference Case.

Combined, the utility-owned and residential programs are projected, by FY2014, to account for more than 600 MW of photovoltaics producing 12% of the RPS eligible energy produced by Department in that year.

Central Station Solar

"Central station" refers to the larger solar projects the Department plans to integrate into its generation portfolio. Currently, LADWP has no such projects existing or under construction. By fiscal year 2014, however, the Reference Case projects 255 MW of central station solar capacity that is projected to generate 11% of the Department's RPS-eligible energy. These 255 MW are projected to be installed across 2 projects: the 55 MW Niland Solar project in the Imperial Valley, projected to be come online on 12/31/2010, and the first 200 MW phase of the proposed Owens Valley solar project.

Overall, solar generation is projected to play a significantly enhanced role in the Department's RPS compliance efforts in coming years. Together, the collective contribution of central station and distributed solar is expected to increase rapidly, rising from 2% of RPS eligible generation in 2010 to 22% by fiscal year 2014. The Department's solar plans do remain highly uncertain, however. If the Department is to realize its Reference Case projection of enough solar capacity to produce 4.8% of net energy sales (nearly a quarter of LADWP's 20% RPS commitment), significant progress must be made in the near term.

d. WIND

By the end of 2010, LADWP projects to own or have under contract 1,071 MW of wind, representing 76% of the Department's projected renewable energy capacity. In spite of its modest capacity factors relative to hydro and landfill gas – LADWP's wind portfolio averages de-rated capacity factors of 23% – wind will represent 43% of the Department's RPS-eligible generation this year. This role will decrease with increased solar penetration over time. Though wind will continue to play a major role for the foreseeable future, generating approximately half of the Department's RPS eligible energy in FY2014, the Reference Case projects a decreasing reliance on wind.

The wind projects contributing to the Department's RPS effort are displayed in Table 8. With expansions at Windy Point, Milford, and Pine Tree counted individually, the Department projects to own or be under contract with 11 operating wind projects by the end of 2010, but does not feature any additional wind build or contracting plans in its Reference Case after this year.

Table 8: LADWP Wind Generation (Reference Case)

Plant	Location	Online Date	Deal Structure	Capacity (MW)	Generation Cost ($/MWh)	Wheeling and Integration Cost ($/MWh)	Total Cost ($/MWh)	2010 RPS Contribution (% of CY 2010 Net Sales)	2014 RPS Contribution (% of FY 2014 Net Sales)
Pleasant Valley Wind	Wyoming	7/1/2006	Prepayment	82	$63.00	$0.00	$63.00	0.87%	0.86%
Willow Creek Wind	Pacific NW	12/31/2008	Prepayment	72	$77.96	$18.50	$96.46	0.71%	0.71%
Pebble Springs Wind	Pacific NW	2/1/2009	Prepayment	69	$67.30	$28.00	$95.30	0.73%	0.72%
Pine Tree Wind	California	7/1/2009	DWP Built/Owned	120	$109.67	$0.00	$109.67	1.27%	1.26%
Milford Wind I	Utah	11/15/2009	Prepayment	185	$74.48	$5.00	$79.48	1.64%	1.63%
Windy Point Primary	Pacific NW	12/15/2009	Prepayment	202	$71.24	$28.00	$99.24	2.01%	1.99%
Windy Point Expansion	Pacific NW	12/15/2009	Prepayment	60	$71.24	$28.00	$99.24	0.59%	0.59%
Linden Ranch Wind	Pacific NW	3/31/2010	Buyout	50	$76.00	$28.00	$104.00	0.41%	0.54%
Pine Tree Expansion	California	6/30/2010	DWP Built/Owned	15	$115.88	$0.00	$115.88	0.07%	0.15%
Milford Wind II	Utah	5/1/2010	Prepayment	66	$80.00	$5.00	$85.00	0.35%	0.52%
Miller Ranch Wind	Pacific NW	10/31/2010	Buyout	150	$85.00	$28.00	$113.00	0.26%	1.52%
Totals				1,071				8.94%	10.49%

The primary explanation for the Department's transition away from wind can be traced at least in part to the characteristics of its current wind portfolio, which feature relatively low generation costs but also low ownership rates, high transmission wheeling and integration costs, and generation profiles that generally do not coincide with that of its demand.

Small hydro and landfill gas options represent the lowest cost RPS-eligible generation options available, but similar opportunities are difficult to find as the Department or its competing utilities have generally taken advantage of these technologies where available. For the near future, the Department will likely achieve additional RPS compliance through a mix of wind, solar, and possibly geothermal. Of these technologies, wind currently represents the cheapest option available to LADWP, particularly from a pure generation cost perspective. In FY2014, the average capacity-weighted generation cost of the Department's wind assets is $79.16, smaller than the RPS portfolio-wide capacity weighted average of $86.54.[24]

Costs cannot be compared across technologies without considering the cost of transmission and portfolio integration, costs that are generally less favorable in the case of wind. The 135 MW of LADWP-owned wind at Pine Tree reside within LADWP's transmission network and thus do not result in wheeling and integration fees,[25] and the low PPM price included in the contract for wind from Pleasant Valley in Wyoming was for delivered energy. However, all other wind assets, totaling 854 MW, include wheeling and integration charges. The Milford assets in Utah incur a $5/MWh charge, and the 600 MW of wind assets in the Pacific

[24] The portfolio-wide average excludes the cost and generation resulting from the "Basin Biogreen" landfill gas purchases.

[25] Wheeling fees represent the expenses paid for the use of transmission outside the LADWP service territory. Integration fees, sometimes called "shaping" fees, are the fees paid to firm the output of otherwise intermittent sources such that the utility receives predictable blocks of power in return.

Northwest incur charges from the Bonneville Power Administration that range from $18.50 to $28.00/MWh. The Department's 11 Reference Case wind assets incur a capacity-weighted average wheeling and integration charge of $16.61/MWh. When combined with the associated generation charges, wind generation costs the Department more that $95/MWh on average. The total cost is still lower than that of solar, but the high wind transmission costs do partially explain the Department's growing preference towards solar.

Another reason for the trend towards solar, ignoring the economic development benefits discussed in Section 6 of this report, relates to the delivery profiles of wind generators. While solar generation occurs during the day when electricity demand is at its peak, the Department's wind-related production tends to be highest at night. This is demonstrated by the indicative data shown below in Figure 14. All else being equal, daytime renewable generation is more valuable because it is displacing higher cost gas-fired generators while renewable generation during lower demand periods at night tends to displace lower cost generation assets.

Figure 14: Example of capacity factor for a wind project by hour of day and month

	HOUR																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	55%	52%	52%	50%	50%	49%	48%	49%	47%	46%	46%	50%	51%	49%	49%	51%	55%	58%	59%	59%	60%	59%	58%	59%
Feb	58%	56%	54%	53%	53%	51%	49%	49%	48%	45%	46%	47%	49%	51%	53%	55%	56%	59%	60%	61%	60%	57%	55%	56%
Mar	57%	56%	49%	49%	54%	52%	50%	49%	51%	50%	45%	50%	48%	53%	58%	62%	56%	60%	58%	53%	54%	61%	59%	62%
Apr	61%	57%	58%	59%	61%	55%	54%	52%	49%	47%	43%	40%	38%	38%	41%	46%	51%	54%	56%	53%	55%	53%	53%	58%
May	50%	54%	54%	52%	48%	49%	48%	47%	45%	45%	43%	45%	47%	44%	47%	49%	53%	50%	48%	52%	57%	54%	53%	51%
Jun	75%	72%	73%	69%	66%	59%	57%	58%	57%	53%	54%	50%	49%	47%	49%	53%	55%	59%	64%	69%	69%	75%	76%	73%
Jul	55%	53%	48%	45%	44%	42%	40%	35%	32%	26%	27%	30%	33%	35%	38%	41%	44%	48%	47%	46%	50%	56%	51%	53%
Aug	69%	68%	70%	69%	66%	64%	60%	59%	56%	51%	49%	50%	50%	53%	57%	59%	60%	64%	66%	64%	65%	67%	69%	72%
Sep	44%	45%	41%	37%	38%	37%	35%	38%	34%	31%	33%	34%	40%	46%	52%	56%	58%	60%	54%	51%	46%	44%	49%	46%
Oct	36%	37%	37%	39%	39%	41%	41%	40%	41%	39%	35%	34%	35%	35%	36%	38%	39%	41%	40%	38%	38%	38%	38%	39%
Nov	37%	35%	33%	31%	30%	31%	30%	31%	32%	32%	31%	31%	32%	33%	35%	37%	38%	39%	41%	42%	38%	37%	37%	37%
Dec	45%	45%	44%	42%	45%	43%	44%	42%	42%	42%	43%	43%	42%	43%	43%	43%	46%	47%	47%	46%	46%	48%	45%	44%

>50% 40% to 50% < 40%

Notes: indicative data from LADWP's Pacific Northwest wind model, built using one year of output from Pebble Springs Wind.
data does not necessarily represent long-term performance of all wind projects

Finally, the Department would prefer to own a greater percentage of its assets, both for the greater dispatch control and the associated jobs creation. While the wind projects generally include ownership options after seven or ten years, only Pine Tree, Linden Ranch, and Miller Ranch project to be LADWP-owned for their entire commercial lifetimes.

e. BIOGAS

LADWP purchases biogas – essentially aggregated landfill gas output – through deals with energy companies that own out-of-state landfill gas resources. These purchases serve as a hedge for natural gas prices, but also help the Department meet its RPS compliance goals.

LADWP commits to buying a certain amount of gas from both counterparties, who provide as high a percentage of certified landfill gas as possible from assorted assets in Texas. The Department pays a fixed $/MMBtu price for the gas, determined according to the 5-yr price strip, and then pays an adder of approximately $4.00/MMBtu for the landfill gas, which qualifies for RPS inclusion.

LADWP is buying gas itself, not electricity, so it must calculate the resulting RPS-eligible energy after the fact in a manner consistent with California Energy Commission (CEC) guidelines. Essentially, the CEC guidelines allow the Department to assume the gas is burned in their lowest heat rate (i.e., most efficient) gas-fired generation unit that is operating at the time of the gas purchase. So, assuming the gas is combusted in a combined-cycle with a 7 MMBtu/MWh heat rate, a $4.00/MMBtu renewable attribute adder for the landfill gas equates to a REC price of $28.00.

In 2010, the energy associated with these deals is projected to account for 18% of the Department's RPS-eligible energy, a number that drops to 14% by 2014 (or about 3 percentage points of the 20% of net sales RPS target).

f. GEOTHERMAL

Though projects continue to be discussed as potential replacement options for Niland Solar, the Reference Case does not include any development of (or long-term contracts with) specific geothermal generation assets.

As present, the only geothermal included in the Reference Case comes from Mexico via the Comisión Federal de Electricidad (CFE). While LADWP would like to convert this to a long-term contract, it is currently short-term only, so the energy purchases through this contract are classified under Short-Term Purchases. In 2009, the Department purchased approximately 100 GWh of geothermal energy, equal to roughly 2% of its renewable energy generation, through this contract. The price paid to CFE includes a renewable energy credit (REC) adder[26] that is confidential but significantly smaller than the $18-20 cost per MWh adder associated with other technology types. All energy is purchased "as available" for now. It tends to flow primarily during the first and second quarters of the year, and to a lesser extent the fourth quarter, but does not provide any energy during the third quarter, when LADWP sees its highest demand.

4.3.3 Conclusions

The Department has made significant strides towards complying with its challenging 2010 RPS target, and has effectively addressed its initial RPS strategy goals of locational diversity, clusters of assets, and project ownership. However, LADWP's ongoing strategy bears careful consideration, particularly as the Department seeks to continue its ownership pursuit and diversification into solar. While both objectives may include long-term benefits and opportunities for local economic development, they are likely to increase costs in the near-term and could potentially lead to RPS shortfalls or forced reliance on short-term market purchases.

The Department's portfolio of existing and signed projects exemplifies its commitment to achieving locationally diverse clusters of renewable generation assets. LADWP has also adhered to its original ownership policy by building and operating Pine Tree Wind, pursuing immediate asset purchase agreements at Linden and Miller, and securing ownership options

[26] The REC cost represents the additional price paid for the renewable energy, over and above the cost of simple "brown" power.

in its other energy prepayment deals. However, LADWP's current portfolio is not without issues. The Department has focused heavily on wind, limiting technological diversity, introducing significant transmission costs, and presenting certain integration challenges. By the end of 2010, wind will represent more than 75% of the Department's owned or contracted capacity. While wind remains the lowest cost renewable resource for utility-scale investment, it also has certain limitations.

California wind building opportunities are limited and costly, and the more remote opportunities that do exist are often accompanied by large integration and wheeling charges. Of the 1,070 MW of wind projected to be owned or contracted by LADWP at the end of 2010, approximately 600 MW are located in the Pacific Northwest, where firming and shaping costs range from $18 to $28 per MWh. The Milford assets in Utah, by contrast, incur only $5 per MWh in fees and the Department's own assets at Pine Tree rely on LADWP transmission only and thus incur zero fees.

The Department's limited technological diversity and the disproportionate reliance on Pacific Northwest assets is not surprising, given the aggressive RPS timing under which the Department operates. With the exception of hydro and landfill gas, each of very limited availability, remote wind has been the least-cost resource available to the Department, and LADWP could not have built much of its own transmission in such a short timeframe.

The Department has rapidly integrated wind assets at respectable costs, and is now right to be considering other options. Wind generation can be more volatile than other renewable technologies and tends to operate at night, when energy demand is lower. While some energy may be used to refill the reservoirs at Castaic, the Department's pumped storage option, excess energy at night can also on occasion result in generation curtailment at IPP or the wind project itself.

LADWP's solution to easing its reliance on wind has been solar. The Reference Case projects nearly 600 MW of solar photovoltaics by FY2014, a sensible build plan if the costs can be contained. First, solar generation coincides more closely with high demand periods, from both a diurnal and seasonal perspective, at least partially offsetting its higher levelized cost.[27] Second, the Department's plans to harness less remote generation options is projected to lead to increased reliance on less costly generation options. Figure 15 reveals less reliance on Pacific Northwest generation (delivered to the LADWP system at the Nevada Oregon Border (NOB)) by 2014, and greater reliance on Inyo-Rinaldi and other LADWP options.[28]

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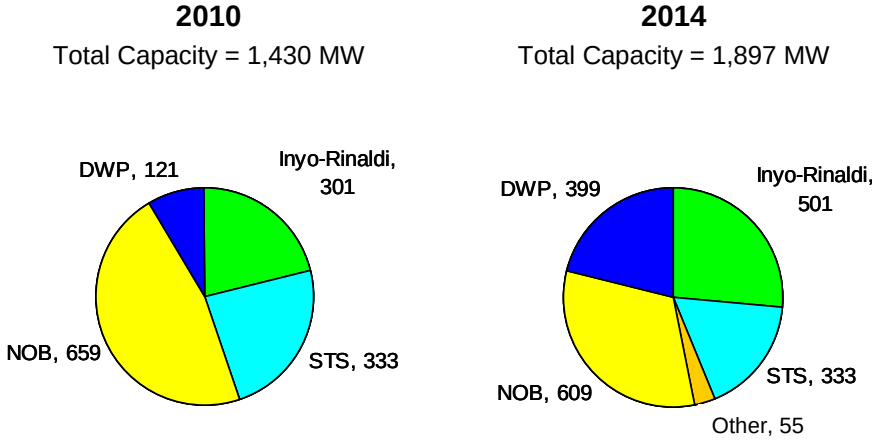
[27] The levelized cost of energy for a given technology represents the present value, on a $ per MWh basis, of building and operating the plant for its entire useful life. A levelized cost analysis will account for all fixed costs, variable costs, any available tax credits, etc.

[28] Note: The 55 MW Niland Solar has been put on hold, at least temporarily, but remains in the LADWP Reference Case. Energy from Niland Solar was originally slated to be transmitted over the Greenpath North Transmission Project, but that line is also on hold and has been excluded in the Reference Case. Should the Niland Solar plan be revived, it is assumed that the energy would travel to the LADWP system through another path (see "Other" in figure).

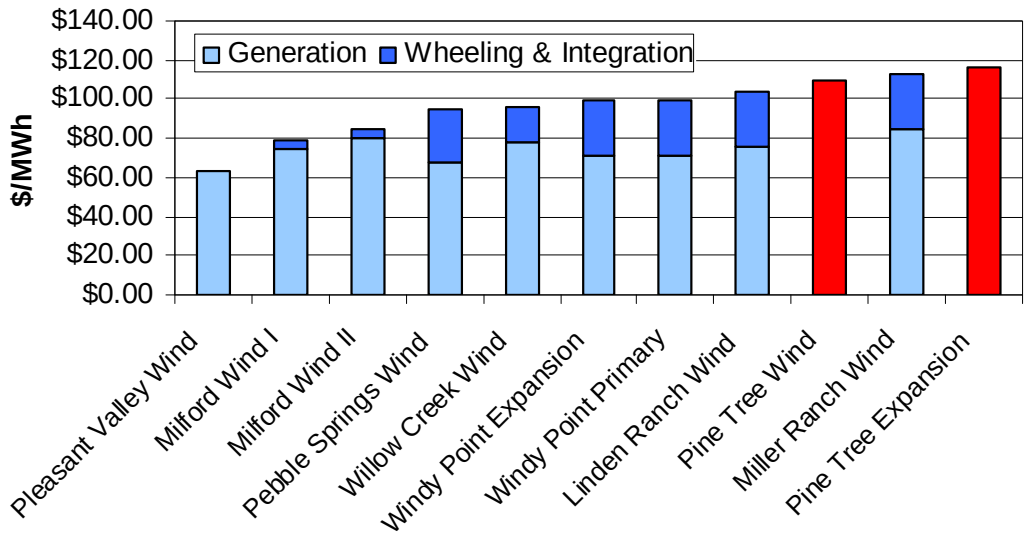
Figure 15: RPS Capacity by Transmission Path - 2010 & 2014 (Reference Case)



LADWP cannot be faulted for considering greater integration of solar resources, a decision also made by each of the three California investor-owned utilities. However, it should be noted that the solar projections in the Department's Reference Case do appear optimistic, both in terms of cost and timing. First, the projected $100/MWh price at Owens Valley Solar, though based on an indicative offer, appears overly optimistic, as do the projections at the other solar installations. And the ability to achieve the aggressive build plan goals will be difficult with Niland Solar on hold and the utility-owned distributed solar plans not proceeding as quickly as initially planned. The ultimate prices achieved will obviously impact the Department's ECAF expenses, but any significant solar build plan delays could also lead to greater than projected ECAF expenses. Solar is projected to account for nearly five percentage points of the Department's 20% RPS target by 2014 – any shortages would likely have to be replaced through short-term purchases to maintain the Department's commitments, which could be costly given the tight market for renewable resources.

LADWP's ongoing strategy to pursue project ownership also bears further consideration. First, to date the cost to the Department of building and owning wind assets has exceeded the cost associated with long-term PPAs. The projected cost of energy from Pine Tree and Pine Tree Expansion, the Department's only built and owned assets, exceeds that of wind acquired from all other projects except Miller Ranch, which includes $28/MWh in wheeling and integration charges and is itself scheduled to be come under LADWP ownership through an immediate asset purchase agreement. See Figure 16.

Figure 16: Generation and Transmission Costs by Wind Project (Reference Case)



The higher levelized cost of energy at Pine Tree stems partially from higher capital costs, which exceeded $3,000/kW, and the inability to capture tax credits.[29] Limiting O&M costs at its facilities will also be a key factor when considering LADWP's desire to be the sole owner of its projects. The Department has not succeeded in meeting its budgeted O&M costs at Pine Tree during the first year of operation; in the first several months of operations, labor costs exceeded budget. As a result, the Department has re-estimated its annual O&M requirement at Pine Tree, moving from the previously approved value of $4.3 million to $5.8 million, an increase of approximately 35% and approximately $5/MWh.

Based on this recent history, it is not clear that the benefits of ownership are large enough to make up for the costs of ownership, particularly in the case of renewable energy. Owning and operating may contribute to the economic development objective through job creation, and there is evidence to suggest that solar could create more local jobs than wind. However, some other traditional benefits of generation ownership may not apply in the case of wind and solar. Relative to fossil-fired generation facilities, which feature high fuel costs and startup costs that contribute to dispatch decisions, wind and solar facilities feature little to no operating expense. With a marginal cost of essentially zero, these assets generally merit operation whenever available. Some benefits to ownership, such as the ability to schedule planned maintenance with consideration to the status of the remainder of your portfolio of assets, would likely be fairly minimal with wind or solar assets.

Given these considerations and recent cost data, it is clear that ownership may not always be in the best interest of the Department and its customers. LADWP should establish clear criteria for when ownership of assets is preferable to entering into long-term power purchase

[29] The Production and Investment Tax Credits (the PTC and ITC), the latter of which currently allows for a cash grant equal to 30% of the project's installation cost, are not currently available to publicly-owned utilities that are already able to use low-cost tax exempt financing.

arrangements. These criteria should take into account the specific costs and benefits involved with each unique renewable project alternative.

4.4 DSM

California Assembly Bill 2021 requires all state utilities, including Publicly Owned Utilities, to identify all potentially achievable cost-effective electricity and natural gas efficiency savings and develop a 10-year energy efficiency savings target. These utility goals were to be established by 2007 and combined by the CPUC into a ten-year statewide estimate with the goal of reducing forecasted energy demand by 10% within 10 years. Once establishing targets, municipal utilities failing to meet their goals may be subject to a charge made by the CEC to fund remedial energy efficiency investments.

In response to California Assembly Bill 2021, LADWP commissioned a 2006 independent study by Quantum (now Itron) to conduct an Energy Efficiency Potential Study. This study identified a maximum achievable reduction of 8% in LADWP's forecasted energy demand. LADWP established a target of 10% by expanding several of the programs suggested by Quantum in their study. This 10% target was submitted to the CEC in September 2007.

This 10% reduction in forecasted electricity consumption represents a cumulative savings of nearly 2500 GWh between 2007 and 2016. LADWP's program to reduce energy consumption is referred to as its DSM program. This program offers residential and commercial energy consumers incentives, rebates, materials, and services designed to encourage energy savings. The direct costs of this program are passed through to customers through the ECAF.

In addition to the direct DSM costs, an additional element is added to the ECAF that attempts to decouple revenues collected by LADWP from actual consumer demand. This "revenue loss recovery" element tracks the cumulative energy savings associated with the direct LADWP spend on energy efficiency. A factor of 5.513 cents/kWh of savings is applied to reflect the Base Revenue not collected by LADWP due to the DSM program. This factor is then added to the ECAF.

While these programs may be reasonable, we do not believe that these costs are best tracked as part of an ECAF account. DSM is one of the few ECAF elements completely within the control of the Department. As such, they should be subject to separate rate review rather rolled into an ECAF that includes automatic rate increases.

The sections below describe LADWP's plans and the projected impacts on DSM costs.

4.4.1 Programs and Direct Costs

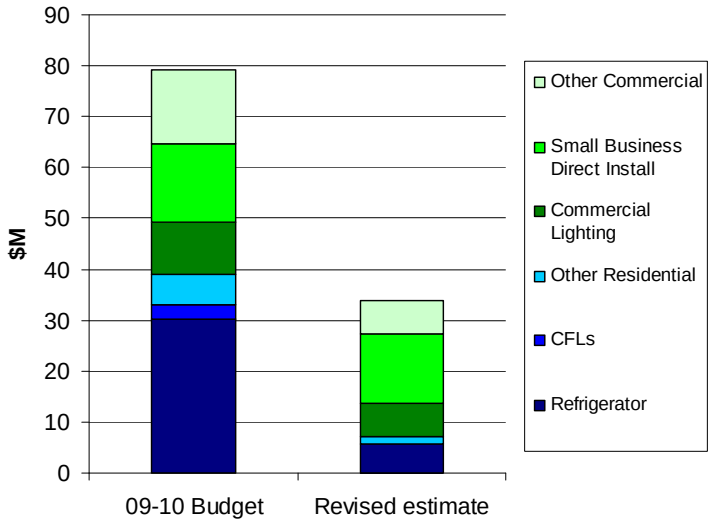
LADWP seeks to fund energy efficiency improvements at a cost below a target representing the marginal cost of generation. This cost target has been estimated at 5 cents/kWh, with an average cost associated with the 2009 budget of 2.5 cents/kWh.

LADWP's plan for DSM expenditures is shown below. Compared to the budget approved in July 2009, LADWP's most recent financial plan reflects a substantial short-term decrease in DSM spending for FY2010. This spending reduction was designed to reduce pressure on

LADWP's short-term financial ratios while preserving the ability to quickly ramp activity back to previous levels once a change in the ECAF cap is approved.

The chart below shows how funds are split between various projects[30].

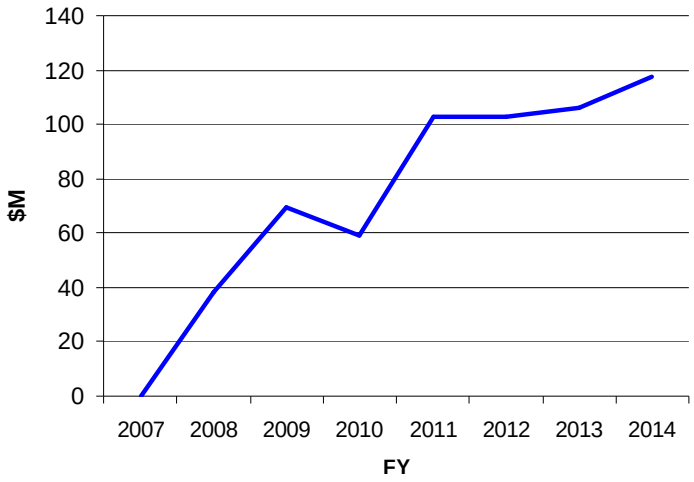
Figure 17: FY2010 Spending for DSM



The revised estimate for 2010 results in an energy efficiency savings estimate of 141 GWh, compared to 300 GWh for the original budget. In order to meet AB2021 commitments, LADWP is required to reduce consumption by an average of 250 GWh per year. For this reason, costs and energy savings are projected to return to the original budgeted numbers for future years. Current forecasted projections, inclusive of administrative costs, are shown below:

[30] Breakdown based on the most recent estimates provided by LADWP considering current spending rates for FY2010. Excludes administrative costs.

Figure 18: Projected DSM Spending



4.4.2 Projected Revenue Loss Recovery

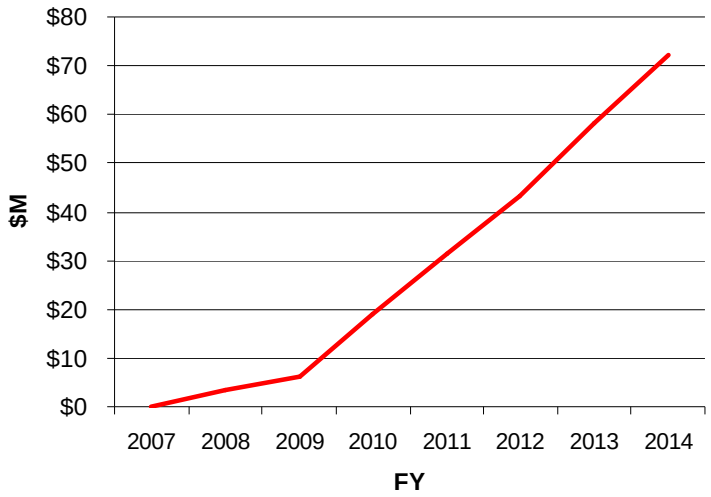
Revenue loss recovery is a direct result of direct energy efficiency spending from prior years. Costs are added to ECAF based on energy savings multiplied by a fixed factor. Due to the difficulty of directly measuring the savings impact of DSM projects, energy savings are tracked on a "deemed" basis based on the projected efficiency improvement and lifetime of specific projects.[31]

As savings are cumulative, the amount charged to the revenue loss recovery factor increases each year.[32] The chart below illustrates the projected cost increase under LADWP's current plan.

[31] These projections are based on guidelines developed by LADWP to be consistent with California Investor Owned Utilities and recommendations from KEMA. The Database for Energy Efficient Resources, developed by the California Energy Commission and California Public Utilities Commission, is used as the source for most energy savings estimates. LADWP's measurement quantification methodology is detailed in an August 27, 2007 internal report.

[32] LADWP tracks the impact of projects over their lifetime, with cumulative savings expiring at the end of the deemed project life. For example, annual savings associated a project with a ten-year life will no longer be counted towards the revenue loss recovery factor after ten years.

Figure 19: Projection of Revenue Loss Recovery



4.4.3 Conclusions

The DSM program, as designed by LADWP, is consistent with its goals to achieve a 10% reduction in energy demand by 2016 while investing in energy efficiency programs below the marginal system cost of generation. While there are potential concerns in using deemed energy savings estimates, including the possibility that projects are not utilized as forecasted in general guidelines, there is no reasonable alternative to measure the impact of distributed DSM programs. In this case, LADWP is using a consistent set of guidelines to determine the energy savings associated with new projects.

While the economics of the projects chosen by LADWP all demonstrate costs under the marginal cost of generation, they do have different costs and paybacks. However, it is likely that all economic options will need to be pursued in order to meet the aggressive demand reduction targets set by LADWP.[33]

Like with RPS, the DSM program was developed in response to a California directive. However, the design of the program, including the actual target adopted, was determined by LADWP. With an annual projected budget of over $100 million, a complex set of methodologies for measuring effectiveness, a diverse set of investment options (including insourcing/outsourcing decisions), and a rate mechanism allowing 100% passthrough via the ECAF, the DSM budget is an area requiring additional scrutiny and strategic planning to ensure that efficiency targets are being met in the most cost-effective manner possible.

[33] A 2006 study performed by Quanta estimated a maximum achievable demand reduction scenario for LADWP of 8%. LADWP increased this target to 10%.

4.5 OPERATIONAL ASSUMPTIONS

The electric power plants operated by utilities and independent generators are not always available for service. They are often not available for maintenance reasons. These planned outages are predictable and are built into annual plans. They also may be unavailable due to unpredicted problems. Estimates for these unplanned outages, sometimes called forced outages, are also built into annual plans. However, they are only estimates based on historical averages. In any year, unplanned outages can be smaller or, in the case of a major problem, much larger than what is planned. LADWP's Reference Case financial plan assumes plant operation at historical capacity factors and availability. The plan does not take into account the possibility of an extended outage at any of the LADWP facilities.

Such an outage could have a substantial impact on ECAF costs. In a worst-case scenario, a low-cost generation source (such as Palo Verde or IPP) would go offline at a time of high natural gas costs. ECAF costs could increase substantially as relatively inexpensive coal or nuclear power is replaced by gas-fired generation or market purchases.

4.6 OTHER ASSUMPTIONS

4.6.1 Nuclear

Nuclear costs are projected to increase from $61 million to $86 million per year between 2009 and 2011 due to an increase in the cost of uranium fuel for Palo Verde.

4.6.2 Economy Purchase

Economy purchases are short-term purchases made when the total cost of purchasing power from external sources is less than the marginal cost of generating power with LADWP assets. The quantity and price of these purchases is estimated based on daily historical heat rates for external market purchases, with quantities constrained by reasonable operating conditions also based on historical data.

As gas prices rise, the cost of economy purchases also increases as market power becomes more expensive. The projected rise in gas prices between 2009 and 2011 drives an increase in economy purchase costs from $57 million to $84 million. As quantities are based on historical observation the annual quantity of economy purchases is roughly unchanged over the time period.

4.6.3 Transmission

The current ECAF includes all transmission charges associated with purchased power, including transmission owned by SCPPA or IPP. These charges are expected to increase from $73 million in 2009 to $80 million in 2011 and on to $90 in 2014.

4.6.4 Hoover

Expenses for power purchased from the Hoover Dam are expected to stay relatively flat from 2009 to 2014.

4.6.5 Legal

Legal costs are expected to increase from zero to $16 million per year due to payments associated with the $160 million settlement of a lawsuit associated with overcharging government entities.

4.6.6 Miscellaneous/Refund

2009 ECAF costs included a one-time refund of $67 million from El Paso to LADWP as well as other minor fuel adjustments and refunds. Future years include other miscellaneous fuel adjustments and refunds but total projections trend to under $1 million per year by 2013. The presence of this one-time refund depressed 2009 ECAF costs, causing a bigger increase between 2009 and future years than otherwise would have been observed.

4.6.7 City Transfer

The City Transfer has been assumed to remain at 8% of the Department's revenues, including ECAF revenues. Therefore, as the other components of the ECAF increase, the City Transfer is projected to increase at the same proportion.

4.7 CONCLUSIONS

In general, LADWP's Reference Case assumptions are reasonable but could benefit from additional sensitivity analysis to better understand the impact of alternative scenarios that have a significant probability of occurrence.

With respect to RPS, LADWP's current project portfolio, consisting primarily of wind, is consistent with the pursuit of low-cost resources. The projected shift over time to additional solar projects has merit given the transmission and integration challenges associated with adding even more wind to the portfolio. However, PA believes that the costs projected for these solar projects have been understated in the Reference Case.[34] While the Department should aspire to achieving these costs, a higher cost projection more consistent with demonstrated project performance would be more appropriate for financial planning purposes.

Moving forward, LADWP's RPS strategy would benefit from a clearer strategic planning process, one that identifies priorities, evaluates and articulates alternatives, and establishes firm decision-making criteria for pursuing specific projects and portfolio adjustments. The lack of such a thorough plan led to significant Department energy and resources being directed towards now abandoned efforts to pursue projects such as Greenpath North and the Measure B solar initiative. Additionally, there remains uncertainty regarding transmission from contracted wind projects in the Pacific Northwest, a situation that introduces additional risks to the Department and may have been better addressed in advance of contracting for the power.

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[34] Since issuing the Reference Case, the Department has raised its estimate Owens Valley costs by 10% to $110/MWh ($150/MWh for the demo units), but these changes are not reflected in the Reference Case analyzed as part of this Review.

While the final cost of the projects chosen by the Department are mainly consistent with expectations, it is likely that a more comprehensive planning process could yield better overall results and allocation of development time. While such a planning effort takes time and may result in a longer planning period prior to contract execution, it is essential to ensuring that customer funds are spent on the optimal mix of resources. A concerted effort to improve this planning process moving forward should be a critical focus of the Department. The current strategy suggested by the Department, including the use of LADWP transmission and development of Owens Valley for the production of solar power, appears reasonable when considered in isolation. However, only a comprehensive Integrated Resource Planning effort can evaluate whether the projected mix of resources is truly best for maintaining and moving beyond a 20% RPS target.

With respect to DSM, the current aggressive plan is consistent with the goal to achieve a 10% energy reduction by 2016. However, the program is new and data on performance is just beginning to accumulate. This suggests a need to revisit the plan and spending requirements frequently to avoid inefficient allocation of funds. In any case, the DSM program should be subject to its own annual review and rate making process outside of ECAF. Rates should only be approved for this program in conjunction with an annual updated plan demonstrating the cost effectiveness and performance of the updated annual strategy.

5. SENSITIVITIES CONSIDERED

ECAF expenses are composed of a wide range of costs, each of which is driven by a number of factors. A nearly infinite number of "what if?" scenarios can be generated that would result in different ECAF costs and rates. The exclusive use of a single Reference Case scenario creates a limited view of costs and fails to address the potential risks facing LADWP. However, the evaluation of unrealistic scenarios or scenarios without material impacts to LADWP is at best a poor use of time and resources and at worst potentially misleading.

To address this issue, PA has:

1. Catalogued the broad range of factors that could impact ECAF performance

2. Identified the factors with the greatest potential to impact ECAF costs due to both the size of their contribution and the uncertainty in predicting their future value

3. Defined realistic but conservative sensitivity values for these factors based on historical analysis and experience as well as forecasts of future changes. These sensitivities include a "stress" scenario that includes simultaneous changes to multiple variables.

This section describes the process of deriving sensitivity values for selected risk factors and defines the scenarios used to evaluate ECAF rate performance.

5.1 RISK FACTORS IN ECAF PROJECTIONS

The costs incurred by LADWP and passed through to ratepayers under the ECAF have the potential to vary substantially from a single projected value. Every factor in the ECAF is subject to some uncertainty. Some large components of the ECAF are relatively predictable (e.g. existing renewable costs, fixed PPA expenses at IPP, DSM expenses); some are predictably unpredictable, that is, their values vary around an average with a known statistical behavior (e.g. natural gas prices, wind energy production); and others may be impacted strongly by discrete events such as regulatory decisions or operational outages.

As the values of these factors change, the costs to LADWP change. In the case of a full ECAF passthrough, this creates risk of rate volatility to ratepayers. In the case of an ECAF with a cap mechanism, this creates the risk of a growing ECAF undercollection and difficulty in meeting target debt ratios or cash levels. Because of these risks, it is critical to recognize which elements have the potential to materially impact ECAF costs, test reasonable alternative scenarios, and mitigate or manage the potential impacts of these scenarios.

In selecting the scenarios with the highest potential to impact LADWP, PA considered risk factors in five general categories:

- *Commodity Prices:* Includes the prices of natural gas, coal, nuclear fuel, and purchased power.

- *Renewables:* Includes the cost of new renewable projects (including the cost of integration and transmission), projected power output, and the power generation shape.

- *Regulatory/Political:* Includes the need to meet RPS targets and energy demand reduction targets, the possibility of climate change legislation impacting the cost of CO_2 emissions, and potential changes in the magnitude of the City Transfer.

- *Macro effects:* Includes impacts on demand due to economic activity or weather and the availability and cost of raising funds in financial markets.

- *Operational:* Includes conventional power plants and transmission outages.

Some of these elements are related and thus have the potential to impact each other. For example, high natural gas prices typically lead to high purchased power prices.

As part of a full risk management program, each element noted above should be evaluated in detail to determine the potential impact on critical financial targets. Given the limited time available for this study, PA evaluated a limited set of scenarios selected based on the magnitude of the potential ECAF impact and the uncertainty of any projection. A total of eight scenarios were selected for inclusion in this report. Three of these, pertaining to the impact of RPS targets on ECAF costs, are analyzed in detail in Section 7. The remaining five scenarios are discussed below.

5.2 DERIVATION OF SENSITIVITY VALUES AND SCENARIO DEFINITION

Based on the considerations discussed above, PA selected five critical risk factors with the greatest potential to deviate from Reference Case projections and impact ECAF behavior. These are natural gas prices, coal prices, renewable energy prices, unit outages, and the introduction of CO_2 legislation that creates a cost for carbon dioxide emissions. Sensitivity values for these factors were selected and packaged into five different scenarios.

These scenarios are summarized in Table 9 below, including the sensitivity values used for each risk factor. The selection of these values is detailed in the following subsections.

Table 9: Overview of ECAF Scenarios

Reference Case assumptions used for all other variables

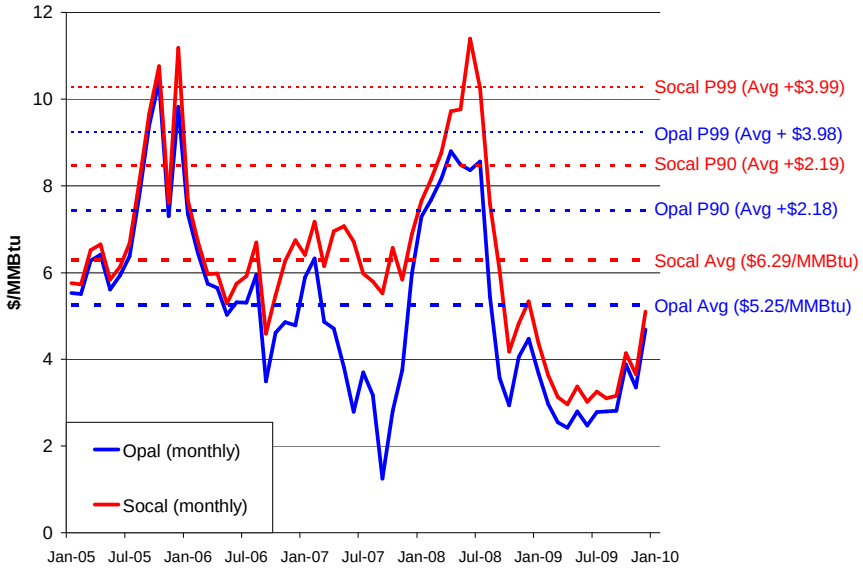
	Stress Case	Historical Peak Gas	High Renewables Prices	Extended Outage	CO_2 Legislation
Natural Gas Prices	**Reference Case + $2.20/MMBtu**	**Reference Case + $4.00/MMBtu**	Reference	Reference	Reference
Coal Prices	**IPP: Reference, Navajo: +$2/ton**	Reference	Reference	Reference	Reference
Wind and Solar prices	**Uncommitted project pricing: Solar ($260/MWh) Wind ($125/MWh)**	Reference	**Uncommitted project pricing: Solar ($260/MWh) Wind ($125/MWh)**	Reference	Reference
Outages	**1 unit of Palo Verde out for 1 year in FY2011**	Reference	Reference	**All of Palo Verde down from FY2011 through FY2014**	Reference
CO_2 Costs	Reference	Reference	Reference	Reference	**High: ~$40/ton in 2012 per EAAC AB32 High estimates** **Medium: ~20/ton in 2012 per EIA Waxman-Markey analysis**

a. NATURAL GAS PRICES

Natural gas prices have historically represented the most volatile portion of the ECAF portfolio. Even with LADWP's existing hedging program, actual natural gas prices can deviate substantially from Reference Case projections. Figure 20 shows historical natural gas prices at Socal and Opal. The distribution of monthly prices suggest that there is a 10% chance that actual prices would be approximately $2.20 over the long-term average (P90

case), and a 1% chance that actual prices would be approximately $4.00 over the long-term average (P99 case).

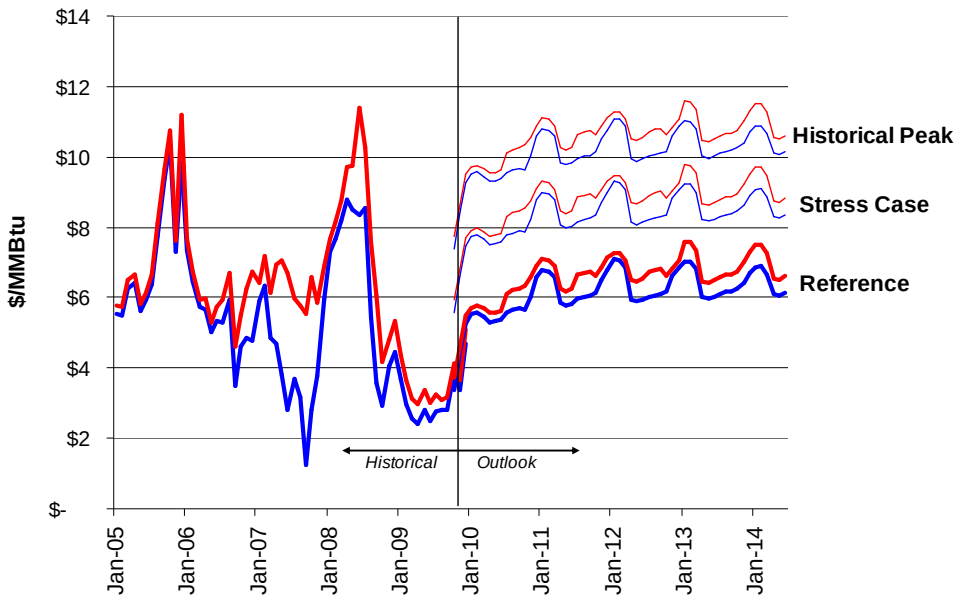
Figure 20: Historical Natural Gas Prices with Summary Statistics



In order to test the impact of gas prices that are higher than the Reference Case, two sensitivity values were selected using this historical price behavior as a basis.

The first sensitivity is included as part of the "Stress Case". It assumes natural gas prices are $2.20 per MMBtu higher than defined in the Reference Case. The second sensitivity is included in an isolated "Historical Peak Gas" case. This adds $4.00 per MMBtu to Reference Case prices. This results in average gas prices of approximately $10 per MMBtu, roughly equivalent to the historical monthly peak gas prices observed at Opal.

Figure 21: Natural Gas Price Outlook by Scenario



b. COAL PRICES

As discussed in Section 4, LADWP's Reference Case IPP coal price assumptions include an eventual return to prices near 2008's historical peak price levels. While it is possible that challenging production conditions and increasing demand for Utah coal could result in even higher levels, the prices in the Reference Case already represent a significant increase from current spot prices. Therefore, PA has made no changes to the Reference Case assumptions for IPP coal when developing the Stress Case.

Navajo coal prices are currently under renegotiation and final prices are expected to be agreed to in a fairly narrow range of $37.50 to $45 per ton. The Stress Case includes an assumption that Navajo coal prices are renegotiated at the high end of estimates provided by LADWP. This results in a 5% increase in price relative to the Reference Case

c. WIND AND SOLAR PRICES

For all renewable energy sources, the Reference Case assumes certain generation costs per MWh. In most cases, these numbers have been established according to signed PPAs, indicating deals that have been consummated and thus are not generally subject to price changes. However, five projects projected to generate RPS-eligible energy prior to the close of FY2014 remain unsigned, and thus remain subject to price fluctuations should the market experience occurrences such as increasing raw materials or commodities costs, labor shortages, or new assumptions regarding production estimation or life of equipment. The five Reference Case projects that are currently unsigned and thus subject to change are displayed in Table 10.

Table 10: Unsigned Reference Case Plants

					Reference Case	
Plant	**Online Date**	**Capacity (FY 2014 - MW)**	**2010 RPS Contribution (% of CY 2010 Net Sales)**	**2014 RPS Contribution (% of FY 2014 Net Sales)**	**Base Generation Cost (2009$/MWh)**	**Generation Cost (FY 2014 - $ millions)**
Milford Wind II	5/1/2010	66	0.35%	0.52%	$80.00	$10.4
Miller Ranch Wind	10/31/2010	150	0.26%	1.52%	$85.00	$31.8
Niland Solar	12/31/2010	55	0.00%	0.53%	$120.00	$16.0
Owens Valley Solar (Ph I)	7/1/2012	200	0.00%	1.75%	$100.00	$42.0
Utility-Owned Solar	Various	275	0.15%	2.05%	$164.98	$81.4
Totals		745	0.77%	6.38%		$181.7

All are projected to make significant contributions to the Department's RPS generation (approximately 6.4% of net sales by FY2014, collectively, or nearly one third of the Department's 20% requirement). This section considers the likelihood of renewable energy cost increases and identifies the methodology used to arrive at the higher generation costs for solar and wind energy to be used in testing the impact of renewable energy cost increases.

i. Wind

The wind industry has matured significantly – key tax credits for wind have been extended through 2012, turbine technologies have become more mainstream with increased operating history, and the increasing domestic turbine manufacturing capacity will help protect against the equipment shortages which precipitated large pricing premiums prior to 2009. However, projects nationwide continue to underperform relative to their projections and high commodity prices could still lead to higher than expected costs, as could any number of site specific problems. Project costs can vary heavily with terrain, any unusual road building or interconnection challenges, and simple public pushback. Therefore, while there is no reason to believe the Department's Reference Case wind price projections are unreasonable, PA has considered higher costs as part of its sensitivity analysis.

As part of the Stress Case, PA has assumed a generation cost for the two currently unsigned Reference Case wind projects of $125/MWh. This figure was derived from the CEC's Cost of Generation model, run using the CEC's standard assumptions for Class 5 wind, including financing terms consistent with that of a publicly-owned utility (POU). The only changes made to the model were to assume a 24% capacity factor, the P-50 projection for Milford II, and an installed cost of $2,750/kW, the average of the projected capital costs at Milford II and Linden Ranch.

ii. Solar

Solar PV costs remain high, but after years of very limited cost improvements, installed costs have begun dropping in recent years with increased polysilicon supply, technology improvements, and general supply-side expansion. These cost declines are projected by most to accelerate and continue over the near term, but these cost improvements should not be taken for granted for two primary reasons. First, costs in California have not yet shown the significant declines projected. A review of January 1 – September 15, 2009 installed cost data for the California Solar Initiative indicates that costs actually increased slightly relative to the 2008 average. And while larger PV projects are generally expected to exhibit economies

of scale, the cost increase was actually most pronounced in projects greater than 100kW, where average costs increased from $7,200/kW to $8,100/kW.[35]

Second, a measure of cost overrun should be expected, given the details associated with two of the major PV projects currently being considered. The installation cost and expense associated with solar PV is generally far less variable from project to project than that of wind, which involves heavier machinery and greater potential for location-driven challenges (e.g. mountain top construction, road building, etc). Panel costs themselves are likely to decline purely as a function of economics, but the labor and other balance of plant costs are more uncertain, particularly with respect to the Owens Valley and utility-owned solar plans, two of LADWP's primary solar initiatives at this point.

The UOS plan would employ LADWP labor to build nearly 200 MW of solar installations on rooftops and other Department property by 2014.

The Owens Valley plan, a tentative plan involving up to 200 MW of thin-film solar at the Owens Lake dust mitigation area by mid-2012, might avoid this potential workforce issue by employing an engineering, procurement, and construction (EPC) firm to build the project. However, the fact that the project has been conceived as an opportunity to both generate RPS-eligible power and further ongoing dust mitigation efforts at Owens Lake suggests the potential for above average build costs and ongoing maintenance needs. The $100/MWh cost projection modeled in the Reference Case would appear to be on the low end of the spectrum, particularly given the unconventional build plan and maintenance needs.

As part of the Stress Case, PA has assumed a generation cost for all solar projects of $260/MWh, a figure derived from the CEC's Cost of Generation model, run using the CEC's standard assumptions for single-axis PV installation, including a mid-range installed cost assumption of $4,534/kW[36] and financing terms consistent with that of a publicly-owned utility.

d. PLANT OUTAGES

IPP, Navajo, and Palo Verde each generate over 10% of LADWP's total electricity needs. As seen in Table 11, these units also represent some of the lowest marginal cost generation in the portfolio.

[35] "Tracking the Sun II: The Installed Cost of Photovoltaics in the U.S. from 1998-2008", Lawrence Berkeley National Laboratory, October 2009, p. 11.

[36] $4,534/kW represents the mid-range installed cost assumption for a 2012 single axis PV project, as specified in the "Renewable Energy Cost of Generation Update", California Energy Commission, August 2009

Table 11: Marginal Cost of Generation at Select LADWP Units

Unit	*$/MWh*
IPP	$22
Navajo	$16
Palo Verde	$12
Natural Gas (average)	$58

FY2010 Reference Case projections, based on fuel cost only

Fixed debt service, O&M, and depreciation costs not included

If one of these three sources experiences a major unexpected outage, generation from those units will need to be replaced by natural gas generation or power purchases. Each MWh of generation replaced will increase ECAF costs by $40 to $50 compared to the Reference Case projections.

While an outage at any of these facilities could impact ECAF costs, recent history suggests that Palo Verde is most likely to experience a significant and prolonged outage. Palo Verde's capacity factor in 2006 dropped to only 70% due to a prolonged outage at one of its three reactors. While IPP and Navajo may experience short-term unplanned outages, it is less likely that a problem at these facilities will result in an outage of long enough duration to materially impact ECAF estimates.[37] Due to the unique issues surrounding nuclear power generation, a prolonged outage at Palo Verde is a scenario that needs to be considered.

PA designed two sensitivities regarding a possible Palo Verde outage. The first assumes that Palo Verde experiences outage in 2011 due to the loss of one unit for one year. This is similar in scope to the outage experienced between 2005 and 2006. This sensitivity is incorporated in the design of the Stress Case described below.

A second "Extended Outage Case" sensitivity was also tested that assumed the full loss of power from Palo Verde beginning in 2011 and extending through 2014. This scenario used Reference Case projections for other factors in order to isolate the impact of the Palo Verde outage on operations.

e. CO2 COSTS

Climate change concerns are driving the consideration of new legislation at both the Federal and State level to regulate CO_2 emissions. Depending on the form of the regulations, the impacts of this legislation on LADWP and the ultimate cost to its ratepayers could vary dramatically. Given the uncertainty, PA has evaluated the costs of CO_2 under two scenarios. In both cases, it has been assumed that LADWP continues to operate its generation portfolio in the same manner as it would without carbon legislation. For this reason the costs should be taken as indicative estimates and not as a forecast of actual LADWP actions.

The first scenario evaluated assumed CO_2 allowance costs equivalent to those forecasted by the Energy Information Administration (EIA) in their analysis of the cap and trade regime

[37] Transmission outages between these large plants and LADWP's service territory also pose a threat to ECAF costs. Such an outage could quickly cause loss of service from the plant.

prescribed under the H.R. 2454 bill sponsored by representatives Waxman and Markey in the U.S. House of Representatives. The "Basic" case described in the EIA analysis[38] forecasts prices of $19.11 per ton of emitted CO_2 in 2012, rising to $22.99 per ton in 2014. For the purpose of this analysis, it was assumed that LADWP would receive no "free" allowances.

The second scenario is based on the high-end forecast for the cost of allowances under California AB 32. The rules governing the implementation of this bill are still under debate. However, the latest draft of recommendations from the Economic and Allocation Advisory Committee (EAAC)[39] to the California Air Resources Board included a range of allowance cost projections, from a number of studies, to establish a projection of $20 to $60 per ton in 2020. They further projected a price trajectory with allowance costs beginning in 2012 and reaching the target value in 2020. As a high CO_2 case, PA adopted the high end of this range, which resulted in prices[40] of $40.12 per ton in 2012, rising to $47.01 per ton in 2014. Again, it was assumed that LADWP would receive no "free" allowances.

Table 12: CO2 cost scenarios

Dollars per metric ton	***2010***	***2011***	***2012***	***2013***	***2014***
CO2, ~$23/ton in 2014	0.00	0.00	19.11	20.92	22.99
CO2, ~$47/ton in 2014	0.00	0.00	40.12	43.35	47.01

[38] A summary of the EIA's analysis and assumptions can be found at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/pdf/sroiaf%282009%2905.pdf

[39] The EAAC is a 17-member committee appointed by the California Secretary of Environmental Protection to advise the State on the implementation of AB32.

[40] EAAC projections are provided in 2007 dollars. These figures assume inflation equivalent to that assumed in the EIA HR 2454 analysis to arrive at cost projections in nominal dollars.

6. RESULTS

This Section summarizes the results of PA's analysis of the Department's Reference Case plan as outlined in Section 4 as well as PA's evaluation of the sensitivities defined in Section 5. The assumptions described in those sections were evaluated to derive forecasts of future ECAF costs, financial ratios, and the rates required to maintain those ratios. The Section then summarizes projected rate impacts, the resulting costs to LADWP's customers, and areas where future rate impacts could be best mitigated.

6.1 REFERENCE CASE RESULTS

6.1.1 Cost Projections

a. COST IMPACTS

The assumptions and plans described in Section 4.1 all suggest that a significant increase in ECAF costs should be expected. Total ECAF cost projections for the FY2010 to FY2014 5-year plan were made using the LADWP financial model[41]. Total costs are shown in the table below.

Table 13: Reference Case ECAF Cost Projections

	2009	***2010***	***2011***	***2012***	***2013***	***2014***
Total ECAF Costs	1333	1579	1845	1916	1995	2043
$M change vs. 2009		246	512	583	662	710
% change vs. 2009		18%	38%	44%	50%	53%

Total ECAF costs are expected to increase by $512 million between 2009 and 2011, a 38% increase from 2009 levels. With a total demand base of roughly 24000 GWh per year, a $512 million increase in costs corresponds to an increase of 2.1 cents per kWh.

While costs continue to increase between 2011 and 2014, the rate of increase slows, with costs increasing an additional $198 million over the next three years. This corresponds to an increase of 0.8 cents per kWh.

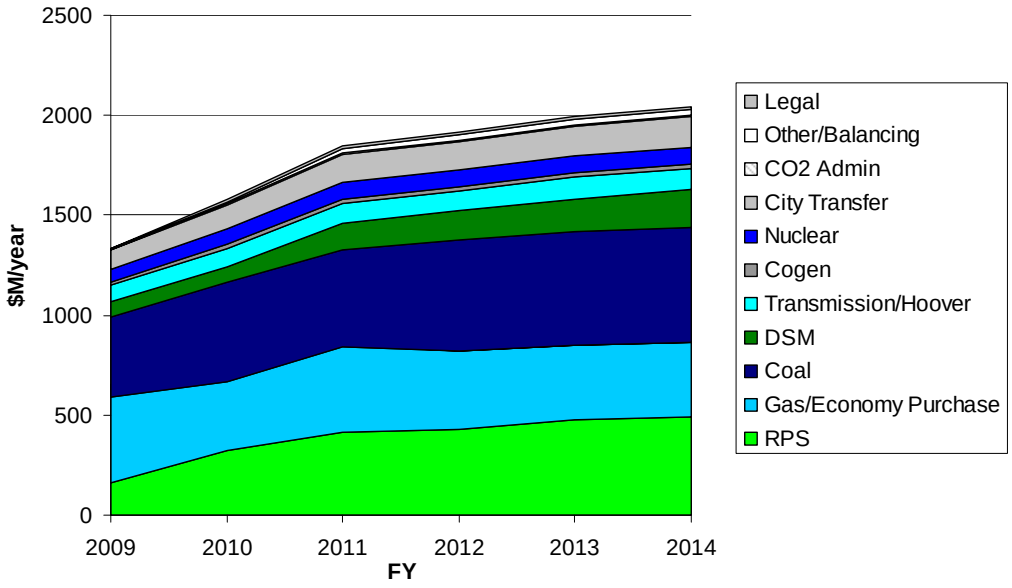
b. COST DRIVERS

In Figure 22 below, the contribution of each ECAF element is shown. RPS costs are projected to increase by over $250 million between 2009 and 2011. This is nearly half of the overall increase expected in that time. However, an increase in RPS generation decreases the reliance on natural gas and market power purchases, partially offsetting this impact. The net cost of RPS is analyzed in detail in Section 7.

[41] PA Consulting's review of the LADWP financial model is described in Appendix A.

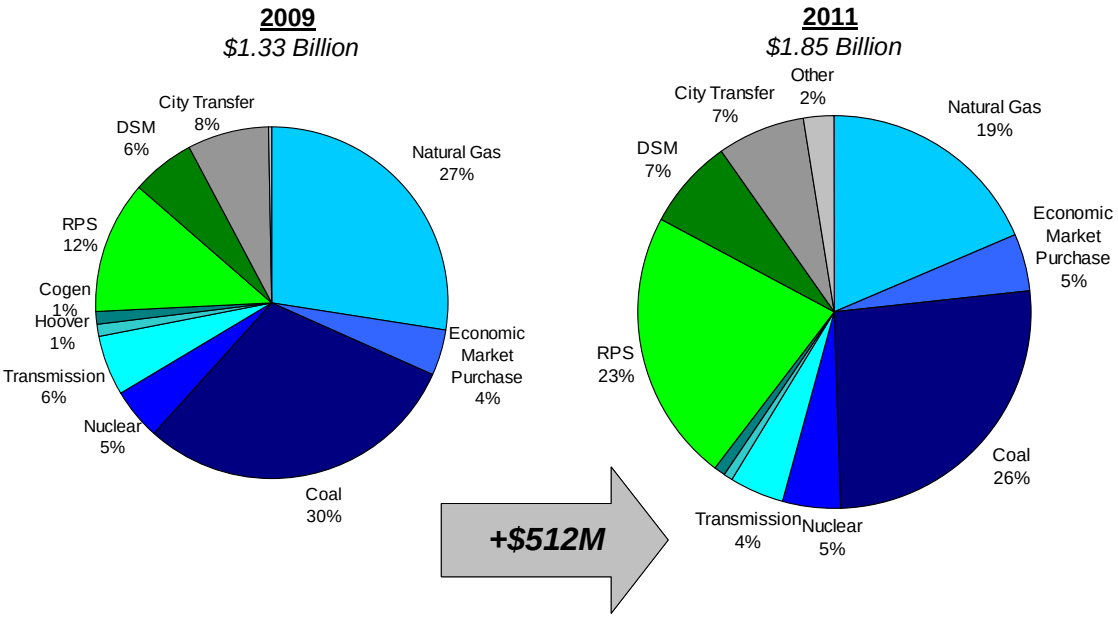
RPS is not the only ECAF component growing over the next five years. Less obvious in the chart are growing contributions from Coal and DSM. The cost associated with coal generation is expected to increase by nearly $175 million per year between 2009 and 2014, driven primarily by higher coal prices. DSM grows by $114 million per year over the same time period. Other components contribute a smaller amount to growing ECAF costs. Details of each component's cost outlook were presented in Section 4.

Figure 22: Reference Case ECAF cost projections by category and year



Looking specifically at the increase in costs between 2009 and 2011, Figure 23 below shows how the contribution of each individual ECAF element has changed over time.

Figure 23: Changes in ECAF costs, 2009 to 2011



Over these two years, RPS costs are expected to grow from 12% to 23% of the overall ECAF portfolio. DSM costs also increase in importance, while the percentage of other costs declines. However, even in 2014, after the full implementation of the 20% RPS plan, traditional power costs still account for over 60% of total ECAF expenses.

c. OBSERVATIONS

While RPS is the single most important factor driving the increase in ECAF costs between 2009 and 2011, much of the increase would still be observed even without the impact of new RPS programs. The ECAF increase is driven not only by RPS, but also by the expectation of higher market prices, increased DSM spending, and multiple smaller contributors.

In addition, the majority of the projected cost increase has either already been committed or is very likely given expectations for market prices. LADWP has already committed to the majority of RPS projects impacting ECAF over the next two years. Coal price and nuclear price increases over that time are based primarily on existing fuel contracts, while some degree of a gas price increase is very likely given the very low price levels seen in 2009. The only significant component in the portfolio that is subject to LADWP control is DSM. However, as discussed in section 4, a failure to adequately invest in DSM could jeopardize the Department's ability to meet its AB2021 commitments.

6.1.2 Financial Performance under Various ECAF caps

The current ECAF structure proposes that the ECAF rate can change by a maximum of 0.1 cents per kWh per quarter, or 0.4 cents per kWh per year. Given the sharp increase in costs projected for the ECAF, this cap increase will not be adequate to prevent a growing undercollection of ECAF costs and an associated failure to meet debt coverage ratios. This

section examines how rates and debt coverage ratios would change under different quarterly ECAF caps.

Under the current ECAF ordinance, any shortfall in ECAF collections each month is added to the ECAF over/undercollection balance. This balance is then incorporated into the next quarter's rates with the intention that any undercollection will be reduced to zero within 12 months. However, if ECAF rates cannot respond to meet changing costs due to the quarterly cap, the undercollection will continue to build until rates are able to catch up to higher cost levels.

As shown in Figure 24, the choice of the quarterly ECAF cap impacts both the pace at which rates increase as well as the ultimate peak rate level. Under the current 0.1 cent/kWh quarterly cap, rates increase continuously. However, they are not able to catch up to actual cost levels, resulting in an undercollection[42] that exceeds $1 billion by the end of the plan period in 2014.

Higher caps help to limit the amount of undercollection. With a cap of 0.5 cents per kWh per quarter, the undercollection is kept below $200 million even during the surge in ECAF costs as rates are increased by 2 cents over the next four quarters. After meeting that initial surge, rates stabilize. This can be also be seen in Figure 24.

The importance of minimizing the ECAF undercollection balance is seen in Figure 25. With caps below 0.5 cent/kWh, debt coverage ratios fall below 2.25 in 2011 as a surging ECAF undercollection limits LADWP's revenue and resulting coverage ratios.

[42] The ECAF undercollection and rates fluctuate on a seasonal basis due to the timing of how charges are booked to the ECAF account.

Figure 24: Projected rates and ECAF undercollection under various quarterly ECAF caps
Reference Case

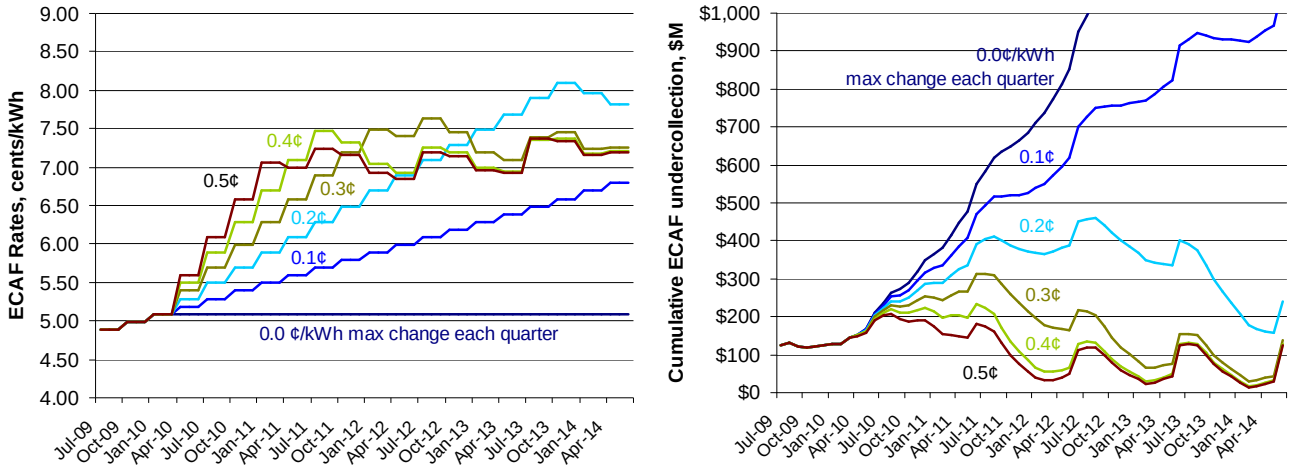
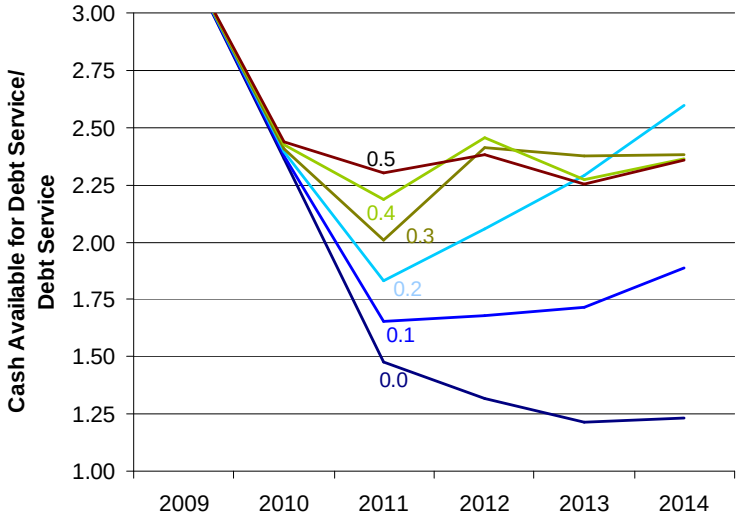


Figure 25: Debt Service Ratios as a function of ECAF quarterly cap
Reference Case projections



Under Reference Case conditions, a rate increase of 2 cents/kWh is required over the next four quarters to avoid a growing ECAF undercollection and maintain the debt service ratios of over 2.25 required to avoid a ratings downgrade. This could be accomplished by raising the quarterly limit on ECAF rate changes to 0.5 cents/kWh per quarter.

However, this rate increase will only be adequate given the LADWP market assumptions described in Section 4. Higher than predicted gas, coal, or renewable energy prices, operational outages, and/or regulatory changes could result in higher ECAF costs than described in the Reference Case. This could lead to growing ECAF undercollections and low debt coverage ratios even with a 0.5 cent per kWh per quarter ECAF increase, exposing

LADWP to a potential ratings downgrade. Section 5 defines a set of alternative scenarios and develops a recommendation for a higher quarterly ECAF cap of 0.8 cents per kWh per quarter that would allow rates to move further if necessary given adverse market conditions.

6.2 SENSITIVITY RESULTS

6.2.1 Costs under market and operational sensitivities

Under the scenarios evaluated by PA, costs in 2011 could be over $200 million more than was predicted in the Reference Case. While each of the individual cases (Historical Peak Gas, Extended Outage, High RPS Prices) shows a significant 2011 impact, it is the Stress Case which has the largest impact.

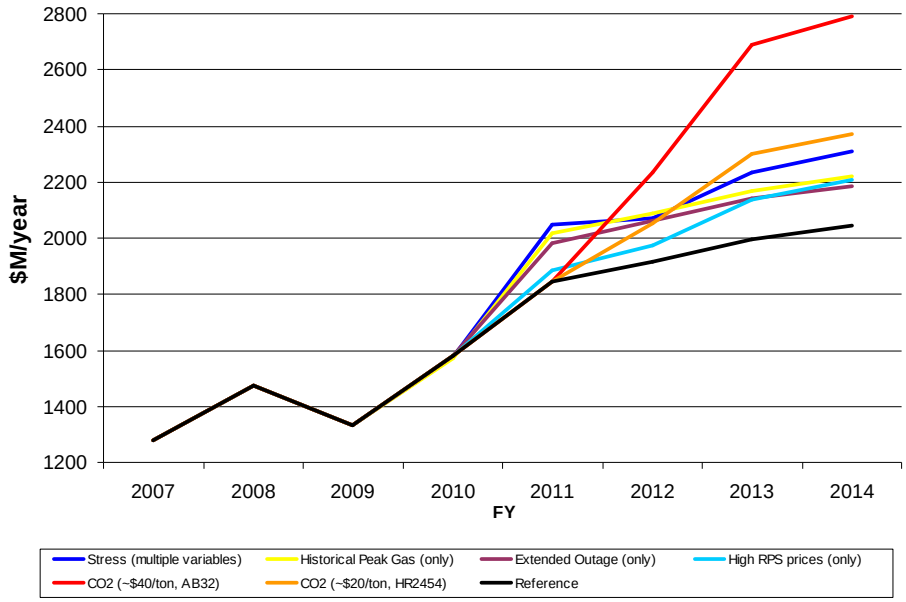
Cases assuming CO_2 costs show no impact in 2011 as these new programs are not assumed to go into effect until 2012. Since 2011 is the critical year for meeting LADWP's debt ratios, CO_2 does not play a role in determining near-term ECAF quarterly rate increases required to get through that period. However, the longer-term impact of various CO_2 scenarios can be seen in 2014.

Table 14: ECAF cost impact of various

$M/year	*2011 Costs*	*vs. Reference*	*2014 Costs*	*vs. Reference*
Reference	1845		2043	
Stress	2047	**201**	2308	**265**
Historical Peak Gas	2020	**174**	2221	**178**
Extended Outage	1982	**137**	2186	**143**
High RPS Prices	1884	**38**	2206	**163**
CO2 (~$47/ton in 2014)	1845	**0**	2792	**749**
CO2 (~$23/ton in 2014)	1845	**0**	2373	**330**

The trajectories of these cost increases are shown in Figure 26 below.

Figure 26: ECAF costs under various scenarios



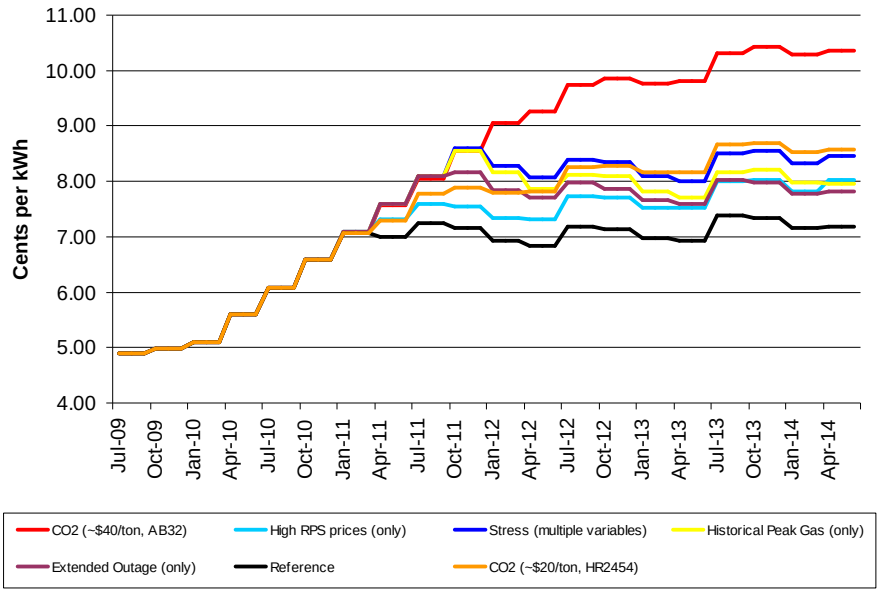
6.2.2 Scenario outcomes under 0.5 cents/kWh quarterly ECAF change cap

The Reference Case forecast projected a required ECAF rate increase of 2 cents per kWh over the next four quarters in order to meet debt ratio targets. The Stress Case, representing a realistic market outcome based on historical pricing, forecasts that $200 million of additional annual revenue could be required by 2011 in order to pay ECAF costs under adverse market conditions. This would require an additional increase in ECAF rates in order to avoid a growing ECAF undercollection and low debt coverage ratios[43].

Section 4 demonstrated that under Reference Case conditions, a 0.5 cents per kWh cap on quarterly ECAF rate changes would result in a 2.0 cents/kWh rate increase over the next four quarters and be just adequate to meet debt coverage ratios. Figures 27 and 28 below illustrate that under these alternative scenarios, rates would be required to increase further.

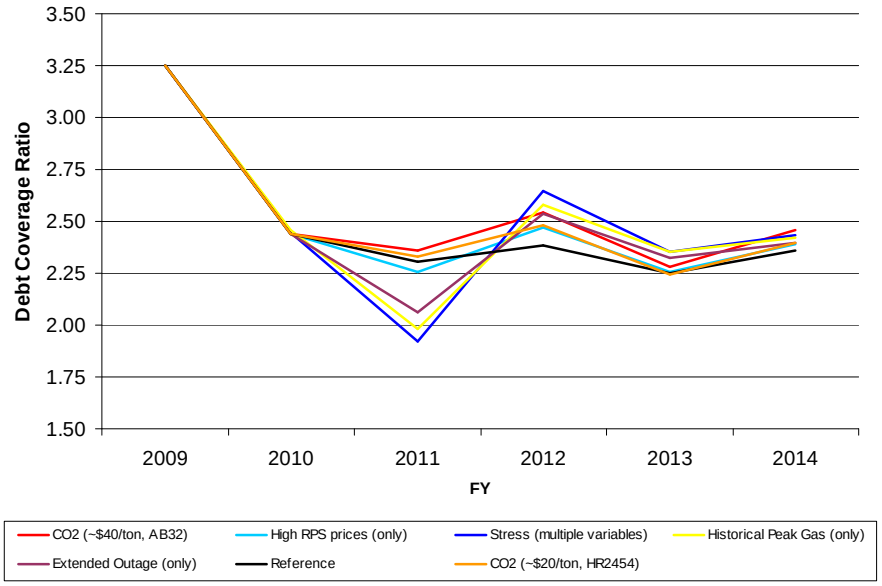
[43] A 1 cent per kWh increase in ECAF rates generates approximately $240 million in revenue each year. The actual rate increase implemented under existing ordinances would vary depending on the size of existing undercollections and caps on quarterly ECAF rate increases.

Figure 27: Projected ECAF rates assuming 0.5 cents/kWh quarterly ECAF change cap



Despite these increases, due to the 0.5 cents/kWh cap, the rates are not able to move fast enough to maintain debt coverage ratios above the target level of 2.25. As can be seen in Figure 28, debt coverage ratios in the Stress Case are projected to fall below 2.0.

Figure 28: Projected Debt Coverage Ratios with 0.5 cents/kWh quarterly ECAF cap



6.2.3 Stress Case performance under various ECAF caps

In order to avoid the possibility of exposure to these debt coverage levels, LADWP requires a higher quarterly ECAF cap that will allow flexibility to adequately pass through increased costs if Stress Case conditions do occur.

Figure 29 demonstrates that under such a Stress Case scenario, a cap on quarterly ECAF changes of 0.8 cents/kWh would be just adequate to maintain a debt coverage ratio of over 2.25 in 2011. Figure 30 shows that at lower cap levels, including the 0.5 cents/kWh each quarter that was adequate in the Reference Case, there is potential for a rapidly growing ECAF undercollection.

Figure 29: Debt Service Coverage Ratios under various caps for quarterly ECAF changes Stress Case projections

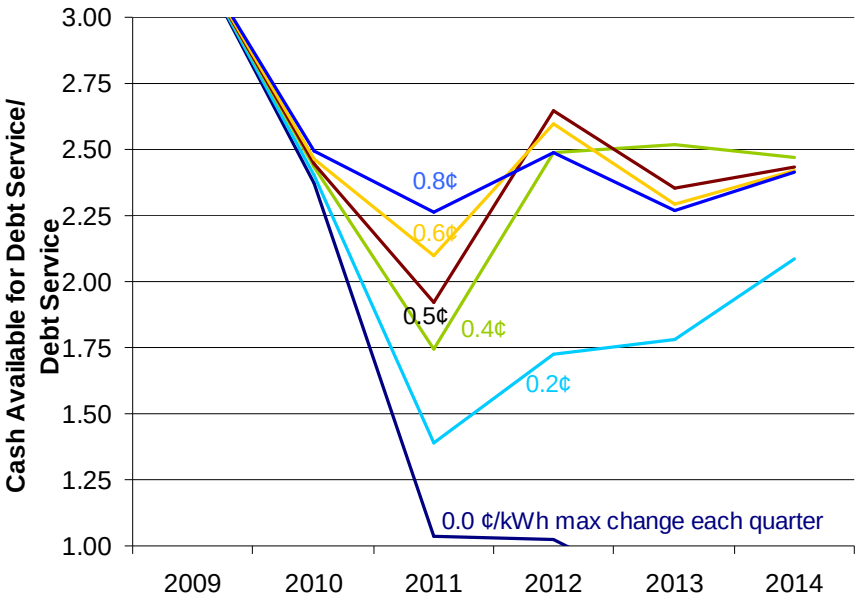
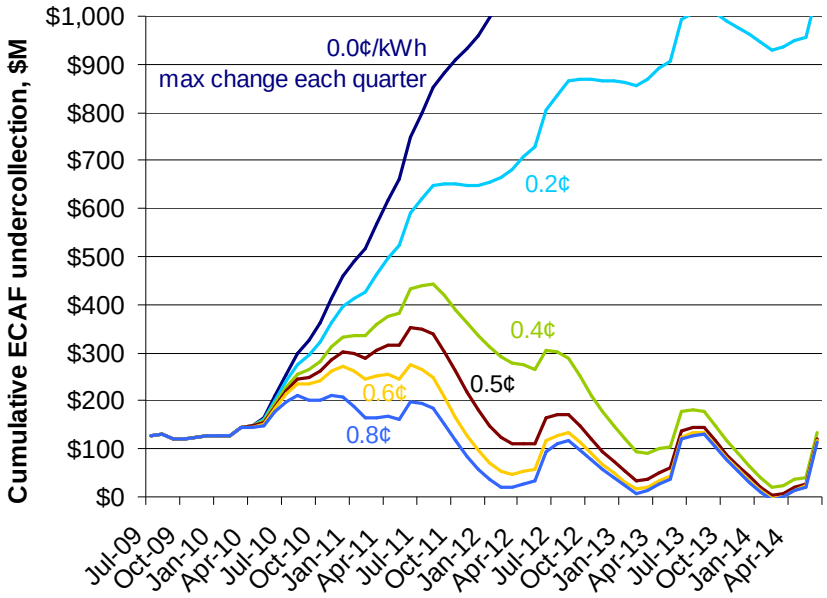


Figure 30: ECAF undercollection under various caps for quarterly ECAF changes
Stress Case projections



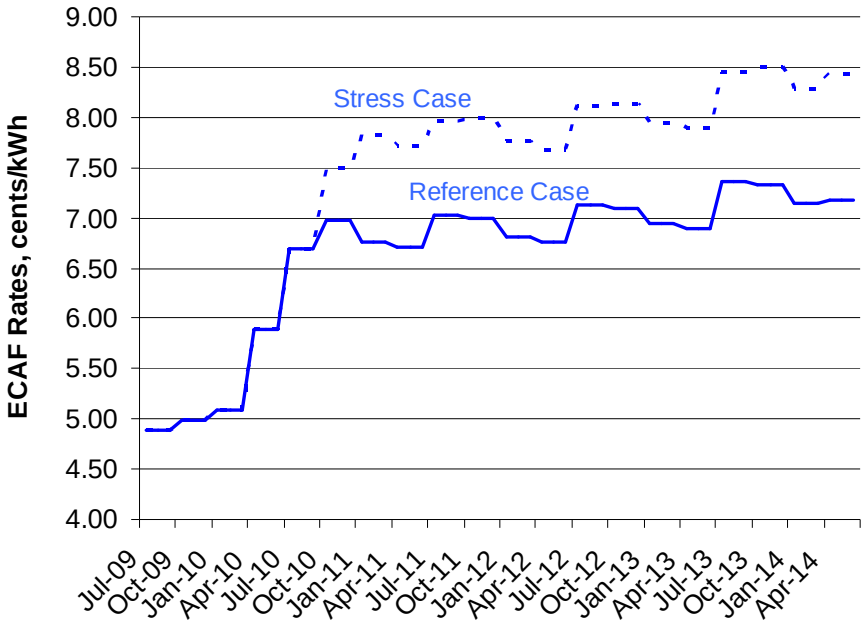
6.3 IMPLICATIONS FOR ECAF RATE LEVELS

ECAF costs are set to rise sharply in 2010, driven not only by increasing costs for RPS generation but also by higher projected fuel costs and increasing costs for LADWP's DSM program. The current 0.1 cent/kWh cap on quarterly ECAF changes is not adequate to respond to these changes without resulting in a sharp increase in undercollections. This undercollection will result in debt ratios below target levels and the likelihood of a downgrade in debt rating.

With the exception of DSM costs, which have been substantially cut from initially planned levels, these costs are associated with commitments that have already been made by LADWP. The costs will start rising in the second quarter of 2010. Without action to change the cap, the ECAF undercollection is projected exceed $500 million by the end of FY2011 and result in a debt coverage ratio below 1.75. In order to maintain the undercollection below the $200 million level that roughly maps to a debt ratio of 2.25, rates need to start increasing in the quarter beginning April 2010. Any delay in a rate increase will result in the need for a higher short-term increase in order to pay back the undercollection accumulated during the delay.

As to the level of increase, a change in the quarterly cap on ECAF changes to 0.8 cents/kWh would allow LADWP to both meet the cost obligations associated with recent commitments but also to weather the conditions outlined in the Stress Case above. Figure 31 below shows that under Reference Case conditions, the total change in rates over the next three quarters would be just under 2.0 cents/kWh. Should Stress Case conditions occur, rates would continue to increase for a fourth quarter, reaching a total increase of 2.7 cents/kWh.

Figure 31: Projected ECAF rates assuming a 0.8 cent/kWh cap on quarterly ECAF changes



6.4 IMPACT OF AN INCREASE ON RATEPAYERS

If the cap on quarterly ECAF changes is raised to 0.8 cents per kWh, rates would increase sharply over the next four quarters in order to cover rising costs. The final amount of an increase depends in part on fuel prices and operational performance. In the two cases outlined in section 6.3, ECAF rates would increase between 2.0 and 2.7 cents per kWh. Given even higher fuel prices than those outlined in the Stress Case, rates could actually increase by as much as 3.2 cents per kWh over those four quarters.

Under the current LADWP rate structure, ECAF is assessed on a cents per kWh to nearly all LADWP ratepayers, regardless of Tier, zone, or type of service. As ECAF increases, ratepayer bills will also increase. However, the amount of increase depends on the amount of power consumed. It is important to note that depending on the class of service, ECAF can comprise slightly more or less of the overall rate charged to customers.

6.4.1 Residential Ratepayers

Residential customers at LADWP are primarily part of rate class R-1.[44] This includes Standard residential service as well as Low-Income and Lifeline Service.

[44] A small number of customers pay for service under schedule R-3, which serves master-metered residential facilities and mobile home parks where the individual single-family accommodations are privately submetered. Similarly, customers in rates class R1-B are metered under Time-of-use service.

All residential customers pay the same rate for ECAF. They also pay two other smaller rate components: an Energy Subsidy Adjustment (ESA) and a Reliability Cost Adjustment (RCA). Furthermore, an energy subsidy of $8.17 per month and $17.71 per month is provided for Low Income and Lifeline customers, respectively. Low Income and Lifeline customers are exempt from paying the ESA and RCA.

Base rates for rate class R1 (which comprises the majority of residential customers) are broken down into three Tiers and two Zones. During the summer months (June-September), higher energy usage is charged in an incrementally higher rate than lower usage. This is done to encourage conservation and is done by breaking usage into three Tiers. Zones are based on the location of the customer, with customers in higher temperature areas (Zone 2) given a higher allotment of power at the lower Tier 1 and Tier 2 energy rates than those living in more temperate areas (Zone 1).

The current R1-A rate structure is shown below in Table 15.

Table 15: R1-A residential rate structure

Base Rates		*kWh/month*		
Season	Tier	Zone 1	Zone 2	Cents/kWh
High	Tier 1	0 to 350	0 to 500	7.02
	Tier 2	350 to 1050	500 to 1500	8.52
	Tier 3	> 1050	> 1500	12.00
Low	Tier 1	0 to 350	0 to 500	7.02
	Tier 2	350 to 1050	500 to 1500	7.02
	Tier 3	> 1050	> 1500	7.02
Other Charges				
Applies to all residential ratepayers			ECA	5.09
			ESA	0.147
			RCA	0.30

** ECA, ESA, and RCA as of January 2010*

While the impact of an ECAF change will depend on each customer's unique usage, the table below shows how average customer bill will be impacted by the ECAF changes suggested in section 6.3. Note that these figures assume that the current residential Tiers are not restructured in any way. Under a separate proposal, LADWP has proposed restructuring rates in Tiers 1, 2, and 3 in order to shift the burden this increase has on Tier 1 customers to customers in Tiers 2 and 3. This proposal is analyzed separately in Section 9 of this report.

Table 16: Impact of ECAF increases on Residential customers (no base rate redesign)

							$ increase		% change	
				Avg kWh	# of meters	Average Bill	+2.0 cents	+2.7 cents	+2.0 cents	+2.7 cents
Residential	**R1-A**	Zone 1	Tier 1	218	184,024	$27	$4	$6	16%	22%
			Tier 2	567	160,599	$72	$11	$15	16%	21%
			Tier 3	1928	30,533	$261	$39	$52	15%	20%
		Zone 2	Tier 1	284	352,318	$36	$6	$8	16%	21%
			Tier 2	807	206,409	$103	$16	$22	16%	21%
			Tier 3	2162	27,573	$286	$43	$58	15%	20%
		Average R1-A		*537*	*961,457*	*$69*	*$11*	*$14*	*16%*	*21%*
Low Income	**R1-D**			348	207,000	$34	$7	$9	20%	27%
Lifeline	**R1-E**			408	93,000	$32	$8	$11	25%	34%

Over the next four quarters, the average residential customer can expect an increase of $11 to $14 in their monthly payments. This is equivalent to 16-21% of the current average bill of $69 per month. Low income customers, who have lower average electricity usage, can expect an increase of $7 to $9 per month. However, since the average bill is lower for these customers, the percentage impact of the ECAF change is higher, ranging from 20% to 27%. Similarly, lifeline customers can expect an increase of $8 to $11, or 25% to 34%.

6.4.2 Commercial Ratepayers

Commercial ratepayers pay under service A-1, A-2, or A-3, depending on service voltage and the amount of electricity consumed. In addition, a higher proportion of these customers receive service under Time-of-Use rates. The impact of ECAF changes on these ratepayers is shown in the table below.

Table 17: Impact of ECAF changes on Commercial customers

					$ increase		% change	
		Avg kWh	# of meters	Average Bill	+2.0 cents	+2.7 cents	+2.0 cents	+2.7 cents
Small General Service	**A1-A**	1123	194,750	$155	$23	$30	15%	20%
Time of Use	**A1-B**	2408	3,977	$304	$48	$65	16%	21%
Primary Service	**A2-A**	13759	10,582	$1,885	$276	$373	15%	20%
Time of Use	**A2-B**	33120	4,981	$4,644	$665	$898	14%	19%
Subtransmission Service	**A3-A**	431901	1,150	$53,487	$8,673	$11,708	16%	22%

Commercial customers would generally expect an increase of 15 to 20% in monthly electricity payments.

6.5 MINIMIZING ECAF-ORIENTED COSTS

ECAF costs derive from a number of sources. Unlike base rate costs, ECAF costs are generally not tied to LADWP labor costs. Instead, they are driven by market forces (fuel and purchased power), the cost of new renewable generation projects (RPS), and DSM programs which are mainly driven by incentives and rebates. Each of these present different opportunities for minimizing future costs.

6.5.1 Fuel and Purchased Power (non-RPS)

Fuel and non-RPS purchased power represent over 50% of ECAF costs and is the obvious place to begin a search for cost reductions. However, the cost of natural gas and economy purchased power is set in liquid markets and is beyond the control of LADWP. Investing in more efficient natural gas plants could theoretically reduce natural gas fuel cost, but only at the expense of a capital investment with the potential to impact base rates. Hedging only impacts cost volatility, not absolute cost levels.

Markets for coal are less liquid and are subject to long-term bilateral negotiations. Projected increases in coal price are a major source of ECAF increases over the next 5 years. While coal commodity markets, freight markets, and cost levels impact these prices, the nature of negotiations suggest a higher ability to influence coal pricing than exists in the gas market. While there has been much discussion about eventually reducing or eliminating coal in

LADWP's portfolio, coal is currently a critical element in meeting the electricity needs of Los Angeles in a cost-effective manner. Because of this, control of rising coal prices should be a near-term strategic focus of LADWP in its efforts to control ECAF costs.

6.5.2 RPS

As described in section 4, LADWP has instituted aggressive targets for renewable energy development. LADWP is attempting to reduce costs by building resources near existing transmission, choosing resources that can be integrated into the existing generation portfolio, maintaining ownership options, and clustering projects together to reduce integration and operating costs. While these are reasonable principles, they fail to take into account the complex tradeoffs in developing RPS resources. These tradeoffs become even more difficult to understand with higher RPS penetrations and a very uncertain regulatory future for carbon regulation.

Therefore, barring a reduction in the overall RPS target, the most critical step to controlling long-term RPS costs is the development of a long-term Integrated Resource Plan that examines the options available for maintaining and increasing levels of RPS generation. This plan should look consider the costs and benefits of these options under various scenarios, including alternative fuel price and carbon regulation scenarios, and make explicit assumptions regarding these scenarios to deliver a strategic plan most beneficial to ratepayers. To the extent economic development is considered as an element in the plan, it should be done in a transparent and explicit manner that allows for policy decisions to be made by rate makers. The lack of such a plan makes it impossible to know that individual projects and proposals put on the table for approval, however promising in isolation, are actually the best projects for ratepayers. Given the rate at which regulations and the renewables market is evolving, this plan should be updated on a regular basis every year.

Once this strategic vision is set, it becomes much easier to execute the supply chain/procurement and financing processes required to optimize costs for specific development plans on behalf of ratepayers. This includes the optimization of tax incentives and grants being offered for renewable projects. Recent transactions have shown an ability to leverage the Department's strong credit rating and innovative financing structures to reduce the cost of RPS power. Retaining this expertise within the Department and continuing to optimize these arrangements will be critical in keeping future ECAF costs low.

6.5.3 DSM

DSM spending is discretionary in the short-run. There are few if any long-term commitments, allowing for immediate reductions in spending levels. However, LADWP has set very aggressive goals for energy demand reduction, exceeding the maximum achievable energy reduction estimates made by its consultants in a 2006 study. In order to reach these goals, it is necessary to invest from year to year in the required efficiency projects and incentives. Also, while they take many years to pay out and require a large upfront investment, DSM projects should be cost effective in the long-run, having been chosen because the average cost of saving the energy is lower than the marginal cost of generation.

The Department has laid out an aggressive spending plan that includes incentives and rebates for refrigerator exchange, efficient lighting, pool pumps, and other energy efficiency

projects. This spending plan shows direct DSM costs rising from $38 million in 2008 to over $100 million in 2011. This ramp-up in activity is indicative of a relatively new program with limited data regarding customer adoption and required incentive levels to achieve this adoption. Therefore, it is critical that the Department's plan be revisited frequently, especially over the next several years, in order to refine its data and priorities in rolling out these programs. Otherwise, incentives may be higher than required for some programs or not high enough for others to reach target adoption levels.

It should be expected that the Department's program will change substantially from year to year. Given the high level of expenses dedicated to the program, careful review of these changing expenses and program results is warranted on a routine basis to maximize the benefits to ratepayers.

6.5.4 LADWP cost reduction efforts

Following the submission of their initial FY2010 budget, LADWP made substantial reductions in forecasted spending in an effort to reduce the need for future rate increases. Major budget reductions included savings from a major labor renegotiation and a rescoping of core utility work. While these programs reduced the levels of potential future base rate increases, they did not directly impact ECAF costs.

The largest changes impacting ECAF costs were a substantial reduction in scope for RPS penetration and a temporary drop in DSM spending. The RPS program was scaled back, with only those projects required to reach and maintain a 20% RPS penetration remaining in the 5-year plan. DSM spending was reduced by $40 million, or 40%.

6.6 CONCLUSIONS

The costs associated with ECAF are set to increase rapidly over the next two years. Without a significant increase in the ECAF rates, this will put significant pressure on LADWP's debt ratios, with the potential that ratios in 2011 will be well under target levels.

Unfortunately, opportunities to avoid these near-term costs are limited. Nearly half of the increase is driven by expected changes in the fuel and power markets. Coal prices are expected to increase as contracts are renewed over the next two years. An anticipated increase in natural gas prices is expected to result in both higher gas costs as well as higher short-term power purchase costs. While market forces may drive these prices down, the most likely case is for a substantial increase, and at this point it is beyond the control of LADWP to impact these near-term prices.

The remainder of the increase is due to RPS and DSM costs, with RPS representing about one third of the increase and DSM representing about 15%. As the 20% RPS goal is to be met by the end of Calendar Year 2010 and these projects require significant lead time, nearly all necessary commitments to meet that goal have been made.[45] As for DSM, short-term

[45] The Department noted in submitting these projects for council approval that there were funds in the Fuel and Purchased Power budget for these projects. In hindsight, this was only true if assuming a substantial increase in ECAF revenue.

reductions have been made and reducing costs further could have a direct impact on the ability of the Department to meet its commitments for energy reduction.

The ability to influence ECAF increases will increase after the initial surge in costs between 2009 and 2011. This includes the recontracting of coal supply at IPP, the selection of additional RPS projects, and the refinement of DSM spending plans. All of these should be a focus of the Department as it seeks to control ECAF increases in the future.

However, today, in order to avoid a substantial ECAF undercollection and maintain target debt ratios, the Department needs to implement a substantial ECAF increase. The alternative is to accept a ratings downgrade that will introduce additional costs to the Department without solving the source of the problem, simply delaying and increasing the size of the eventual increase.

It is critical that any cap on ECAF increases be set high enough not only to handle the increase costs projected in the Reference Case, but also to account for unfavorable pricing or events that are beyond LADWP's control. These are events that could reasonably occur given the known volatility of energy markets and the operating history of physical plants and infrastructure. With a cap designed to maintain target debt ratios during such a "stress" scenario, actual ECAF rates would still only move as much as necessary during more favorable conditions while maintaining the flexibility to manage adverse market shifts.

The Department's Reference Case scenario suggests that a quarterly cap on ECAF increases of 0.5 cents per kWh would be adequate to maintain a target debt ratio of 2.25. However, this assumes that everything goes right and ignores the possibility of reasonable market or operational stresses. The sensitivities designed by PA indicate that under these reasonable Stress conditions a higher cap would be needed in order to maintain the Department's financial ratios and AA debt rating. Based on this analysis, PA recommends that the cap on quarterly ECAF changes be raised to 0.8 cents/kWh beginning in April 2010.

This change will have a substantial impact on ratepayers. Over the next year, average residential bills would increase from current levels by 16 to 21%, or $11 to $14 per month, depending on whether Reference or Stress conditions emerge in the market. Non-residential users would expect a similar increase in percentage terms. The impact on Lifeline and Low Income customers is lower on an absolute basis but higher on a percentage basis.

The Department has separately made a proposal regarding residential rates to shift some of this burden from one set of ratepayers to another. However, the overall bill for power generation remains the same and will need to be funded to avoid a ratings downgrade. This needs to occur as soon as possible given the rapid increases in ECAF costs. If an immediate increase is not approved, a downgrade will result in even higher costs to the Department without solving the cost/revenue mismatch.

7. EVALUATION OF RPS COSTS

RPS compliance represents a significant cost to Los Angeles ratepayers. Most available technologies remain in fairly nascent stages of development, resulting in higher costs, and current infrastructure has been designed with more conventional technologies in mind. This section identifies the annual cost associated with meeting the Department's 20% target, projects the cost associated with executing the Department's plan for reaching 25%, and considers the costs associated with driving towards Mayor Villaraigosa's 40% renewable energy target.

Meeting and maintaining the 20% goal will be costly to ratepayers, and incremental compliance costs are projected to increase should the Department seek to meet more aggressive goals in the near term. Long-term costs, such as that associated with attaining 35% or 40% renewables by 2020, involve a far greater level uncertainty. In the near term, marginal compliance costs will tend to increase as the exhaustion of the less expensive options forces LADWP to develop or contract for more remote, less favorable resources or to integrate more costly technologies. Over time, it is possible that, as technology development and market growth lower the cost of renewable generation and emissions regulations raise the cost of competing fossil-fired options, renewable energy could approach parity with today's more conventional sources of electricity.

7.1 COST IMPACT OF A 20% RPS TARGET

To estimate the cost of complying with the initial 20% RPS target, PA analyzed results from three cases. These cases include the Reference Case, as described in Section 4, and two cases that consider varying treatment of the RPS. The two RPS cases and their underlying assumptions are as follows:

- No RPS (retroactive and going forward) – The No RPS case assumes the complete removal of all renewable projects that would not otherwise have been built without the existence of the original RPS mandate. The Case retains two hydroelectric projects, the residential solar program, and the small landfill gas units, but assumes that any otherwise sub-economic renewable energy projects were never pursued by the Department. The No RPS case is clearly hypothetical, given the retroactive removal of projects that are currently in existence, but is essential to addressing the fundamental questions regarding the total cost of the Department's RPS program.

- No More RPS (going forward only) – The No More RPS case assumes that any currently uncommitted projects do not proceed. Operational projects continue to operate and signed projects come online as scheduled, but any planned projects that are currently unsigned are assumed to be permanently cancelled. This is of course a more realistic case, designed to address questions about the cost of continuing the RPS compliance effort.

The plants included in these two cases and the Reference Case are shown in Table 18. Note that the first tranche of plants represents plants present in all cases, as well as the only eligible renewable facilities included in the theoretical No RPS Case. The second tranche represents the remaining plants that are currently existing or under contract, filling out the balance of the No More RPS Case portfolio and showing what the LADWP portfolio would

look like if it discontinued all non-contracted future renewable energy integration efforts. The final tranche represents the balance of the renewable energy facilities in LADWP's Reference Case, which assumes compliance with the 20% RPS target starting in 2010 and throughout FY2014.

Table 18: LADWP RPS Facilities, by Case

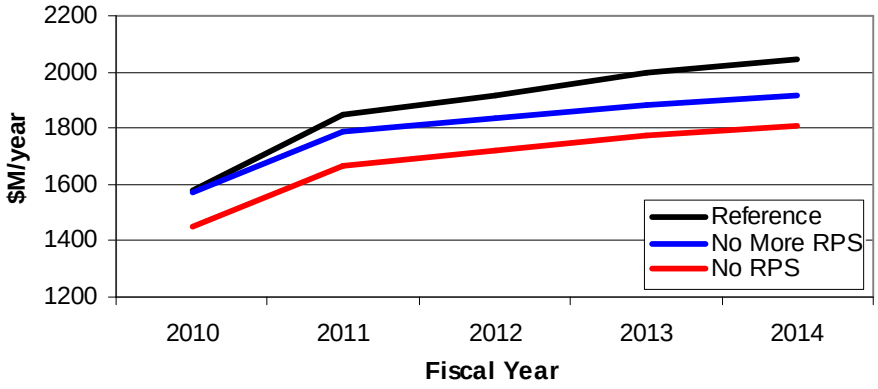
Plant	Technology	Online Date	Capacity online by FY 2014	Generation Cost ($/MWh)	Wheeling and Integration Cost ($/MWh)	Total Cost ($/MWh)	2010 RPS Contribution (% of CY 2010 Net Sales)	2014 RPS Contribution (% of FY 2014 Net Sales)
Plants Included in All Cases								
Aqueduct Hydro Plants	Hydro	1/1/1997	166	$69.77	$0.00	$69.77	1.81%	1.79%
Bradley Landfill	Biomass	1/1/2006	6.4	$52.00	$0.00	$52.00	0.15%	0.15%
Lopez Canyon Landfill	Biomass	4/1/2006	1.5	$62.00	$0.00	$62.00	0.01%	0.01%
Penrose Landfill	Biomass	5/1/2006	6	$59.00	$0.00	$59.00	0.19%	0.19%
Hyperion Digester	Biomass	7/1/2006	16	$0.00	$0.00	$0.00	0.62%	0.61%
Castaic Efficiency	Hydro	7/1/2009	30	$0.00	$0.00	$0.00	0.06%	0.06%
Rooftop - Residential	Solar - Distributed	Various	54	$0.00	$0.00	$0.00	0.19%	0.47%
Short-Term Purchases (1)	N/A	N/A	N/A				2.90%	N/A
Total			**280**				**5.92%**	**3.29%**
					Cumulative RPS %		**5.92%**	**3.29%**
...All Cases Except No RPS								
Pleasant Valley Wind	Wind	7/1/2006	82	$63.00	$0.00	$63.00	0.87%	0.86%
MWD Hydro	Hydro	11/1/2008	8	$91.50	$0.00	$91.50	0.18%	0.17%
Willow Creek Wind	Wind	12/31/2008	72	$77.96	$18.50	$96.46	0.71%	0.71%
Pebble Springs Wind	Wind	2/1/2009	69	$67.30	$28.00	$95.30	0.73%	0.72%
Pine Tree Wind	Wind	7/1/2009	120	$109.67	$0.00	$109.67	1.27%	1.26%
Milford Wind I	Wind	11/15/2009	185	$74.48	$5.00	$79.48	1.64%	1.63%
Windy Point Expansion	Wind	12/15/2009	60	$71.24	$28.00	$99.24	0.59%	0.59%
Windy Point Primary	Wind	12/15/2009	202	$71.24	$28.00	$99.24	2.01%	1.99%
LADWP Biomass	Biomass	12/31/2009	2.5	$75.00	$0.00	$75.00	0.09%	0.09%
Linden Ranch Wind	Wind	3/31/2010	50	$76.00	$28.00	$104.00	0.41%	0.54%
Pine Tree Expansion	Wind	6/30/2010	15	$115.88	$0.00	$115.88	0.07%	0.15%
Powerex Hydro (2)	Hydro	1/12007	0	$75.70	$0.00	$75.70	1.81%	N/A
Biogas Purchase	Biogas	N/A	N/A	N/A	N/A		2.42%	2.99%
Total			**866**				**12.82%**	**11.70%**
					Cumulative RPS %		**18.74%**	**14.99%**
...All Cases Except No RPS and No More RPS								
Milford Wind II	Wind	5/1/2010	66	$80.00	$5.00	$85.00	0.35%	0.52%
Tieton Hydro	Hydro	12/31/2008	6	$85.00	$10.00	$95.00	0.07%	0.07%
Miller Ranch Wind	Wind	10/31/2010	150	$85.00	$28.00	$113.00	0.26%	1.52%
Niland Solar	Solar - Central	12/31/2010	55	$120.00	$35.00	$155.00	0.00%	0.53%
Owens Valley Solar (I)	Solar - Central	7/1/2012	200	$100.00	$0.00	$100.00	0.00%	1.75%
Utility-Owned Solar	Solar - Distributed	Various	275	$0.00	$0.00	$0.00	0.15%	2.05%
Addt'l Biogas Purchase (3)	Biogas	N/A	N/A				1.26%	N/A
Total			**751**				**2.09%**	**6.45%**
					Cumulative RPS %		**20.84%**	**21.44%**

(1) Short-term market purchases are projected to total 689GWh in all cases in CY 2010 but are not projected to occur in 2014 in any of the four cases.
(2) The Powerex Hydro contract expires at the end of 2011, and thus doesn't contribute to RPS compliance in FY 2014.
(3) The Reference Case includes 875 GWh of biogas purchases in 2010, 299 GWh more than the No More RPS Case (576 GWh)

In analyzing this effort, PA has evaluated total ECAF expenses accrued under each of the three cases. Examination of RPS-related cost elements only would be insufficient, as the higher RPS-related costs that come with increasing renewable energy penetration rates will be partially offset by declining fuel expenses (particularly natural gas) as existing fossil-fired generation is displaced by renewable generation (which has a lower marginal cost and thus gets dispatched first).

Figure 32 illustrates the total annual ECAF costs for each of the three cases.

Figure 32: Annual ECAF Costs, by Case



Aside from their varying renewable energy portfolios and any resulting operating adjustments needed at non-renewable facilities to replace the energy from the removed renewable units, the three cases are identical. Therefore, the results speak appropriately to the approximate annual cost of the RPS program as well as the approximate savings to be expected should the Department abandon its RPS efforts going forward. Note that both analyses assume that the remaining variables in all cases remain unchanged. The program cost estimates provided would obviously change if one were to assume changes such as carbon regulation or higher fuel costs (which would reduce the overall cost of RPS compliance) or higher renewables costs or lower renewables performance (which would increase the overall cost of compliance).

7.1.1 Annual cost of LADWP's RPS plan (total)

Annual RPS costs have been calculated as the total ECAF expense in each year from FY2010 through FY2014 under the Reference Case less the total ECAF expenses from the same years under the No RPS Case. The results are shown in Table 19.

Table 19: Total ECAF Expenses, by Year ($M)

	FY 2010	2011	2012	2013	2014
Reference Case	1,579	1,845	1,916	1,995	2,043
No RPS Case	1,448	1,665	1,721	1,775	1,806
Cost Difference	**131**	**180**	**195**	**221**	**237**

These findings indicate that under Reference Case assumptions, the cost of the RPS program, incorporating both actual current commitments and projected future ones, ranges from $131 million in FY2010 to $237 million in FY2014. This equates to an average annual ECAF cost of $193 million, or just under 0.8 cents on the ECAF rate.

7.1.2 Annual cost of continuing LADWP's RPS plan (going forward)

Annual RPS costs going forward have been calculated as the total ECAF expense in each year from FY2010 through FY2014 under the Reference Case less the total ECAF expenses from the same years under the No More RPS Case. The results are shown in Table 20.

Table 20: Total ECAF Expenses, by Year ($M)

	FY 2010	2011	2012	2013	2014
Reference Case	1,579	1,845	1,916	1,995	2,043
No More RPS Case	1,571	1,789	1,834	1,881	1,915
Cost Difference	**8**	**56**	**82**	**114**	**128**

These findings indicate that under Reference Case assumptions, the annual cost of continuing the RPS program as currently planned starts at $8 million in FY2010 and increases to $128 million in FY2014. These figures, which represent the near-term annual cost savings to ratepayers if LADWP were to cancel all uncontracted renewable energy plans, equate to an average annual ECAF cost of $78 million, or approximately 0.3 cents on the ECAF rate.

7.2 ADDITIONAL COST IMPACT OF REACHING A 25% RPS TARGET

PA has also been asked to estimate the annual costs to the Department of attempting to meet a 25% target by 2014. It should be clear that this 25% case does not represent the current plan by LADWP for renewables development. The Department has stated that it does not have a plan to go beyond 20% RPS penetration and is currently developing such a plan. However, it did describe a plan in its original FY2010 budget to reach over 25% RPS penetration by 2014. This budget, assembled in May 2009, included projects in the current LADWP Reference Case as well as several additional proposals.

Using this plan as a basis, PA has worked with the Department to develop a 25% Case, which has updated the Department's May 2009 plan with known changes to project costs to maintain an "apples to apples" comparison with the Reference Case. Aside from the future renewable energy build plan, the 25% Case and the Reference Case were designed to be identical. With all non-build plan characteristics such as unit costs and operating characteristics held constant, comparison of the total annual ECAF expense under the two plans allows conclusions to be drawn about the cost of incremental RPS compliance above 20%.

Table 21 shows the renewable plants assumed to be added in the construction of the 25% Case, which is assumed to build directly off the Reference Case portfolio of renewable assets displayed in Section 7.1. As can be seen in the table, every project in the plan, including a projected solar development in Owens Valley, is projected to cost under $100/MWh, which could be considered aggressive given historical pricing but within cost estimates received by LADWP. For example, in its third quarter 2009 RPS Report to the Legislature, the CPUC stated that "since 2007, nearly half of the projects submitted for CPUC approval have been above the MPR [Market Price Referent]." At that time the CPUC's adopted MPR values for 20-year contracts beginning in the years 2010-2014 ranged from $114/MWh to $129/MWh. In addition, it was assumed based on earlier LADWP plans that additional transmission from Owens Valley would be required to carry electricity to Los Angeles.

Table 21: Additional Plants Added in 25% Case

Plant	Technology	Online Date	Capacity online by FY 2014	Generation Cost ($/MWh)	Wheeling and Integration Cost ($/MWh)	Total Cost ($/MWh)	2010 RPS Contribution (% of CY 2010 Net Sales)	2014 RPS Contribution (% of FY 2014 Net Sales)
Additional Plants included in the 25% Case								
Leaning Juniper Wind I	Wind	12/1/2010	75	$80.00	$0.00	$80.00	0.07%	0.79%
Geothermal Project I	Geothermal	12/31/2010	39	$95.00	$0.00	$95.00	0.00%	1.37%
Leaning Juniper Wind II	Wind	12/31/2010	110	$80.00	$0.00	$80.00	0.00%	1.17%
Geothermal Project II	Geothermal	12/31/2011	16.5	$95.00	$0.00	$95.00	0.00%	0.58%
TI Fuel Cell	Fuel Cell	12/31/2011	1	$75.00	$0.00	$75.00	0.00%	0.03%
Aqueduct Improvement	Hydro	4/1/2012	4	$46.67	$0.00	$46.67	0.00%	0.12%
WS Hydro	Hydro	12/1/2013	4	$91.50	$0.00	$91.50	0.00%	0.05%
Owens Valley Solar (II)	Solar - Central	1/1/2014	200	$100.00	$0.00	$100.00	0.00%	0.87%
Feed-in Tariff Solar	Solar - Distributed	Various	60	$0.00	$0.00	$0.00	0.02%	0.35%
Sunshare Solar	Solar - Distributed	Various	35	$0.00	$0.00	$0.00	0.02%	0.22%
Total (4)			**544**				**0.12%**	**5.56%**
					Cumulative RPS %		**20.96%**	**26.81%**

Note: The 25% Case as run by LADWP included 676 GWh of biogas purchases in FY 2014, 44 GWh less than that included in all other cases. Had the biogas totals been the same in the 25% Case, the total RPS contribution would be 26.99%.

7.2.1 Estimated cost of a 25% RPS plan (going forward)

The annual cost of attaining a 25% RPS has been calculated as the difference between the total annual ECAF costs from the 25% Case and the total annual ECAF costs from the Reference Case.

Table 22: Total ECAF Expenses, by Year ($M)

	FY 2010	2011	2012	2013	2014
25% Case	1,565	1,873	1,976	2,081	2,167
Reference Case	1,579	1,845	1,916	1,995	2,043
Cost Difference	**-14**	**27**	**60**	**86**	**124**

Figure 33: Costs/(Savings) Resulting from 25% RPS Obligation ($M)

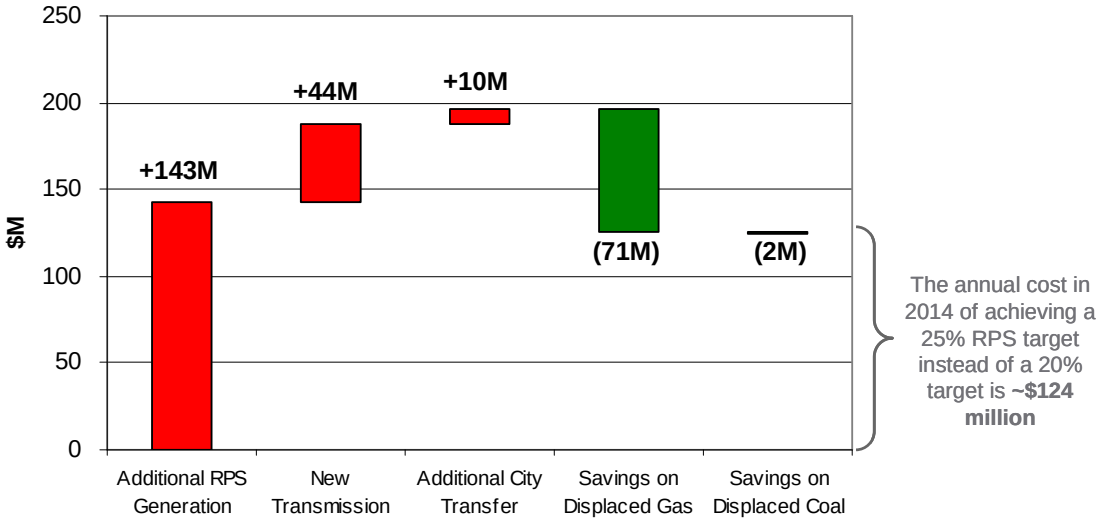
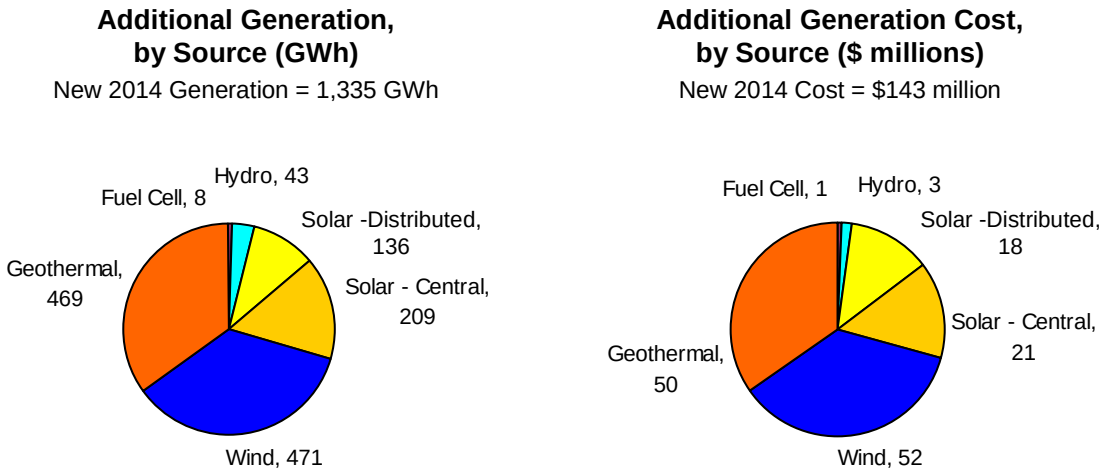


Figure 34: 25% Case – Additional Generation and Cost (2014)

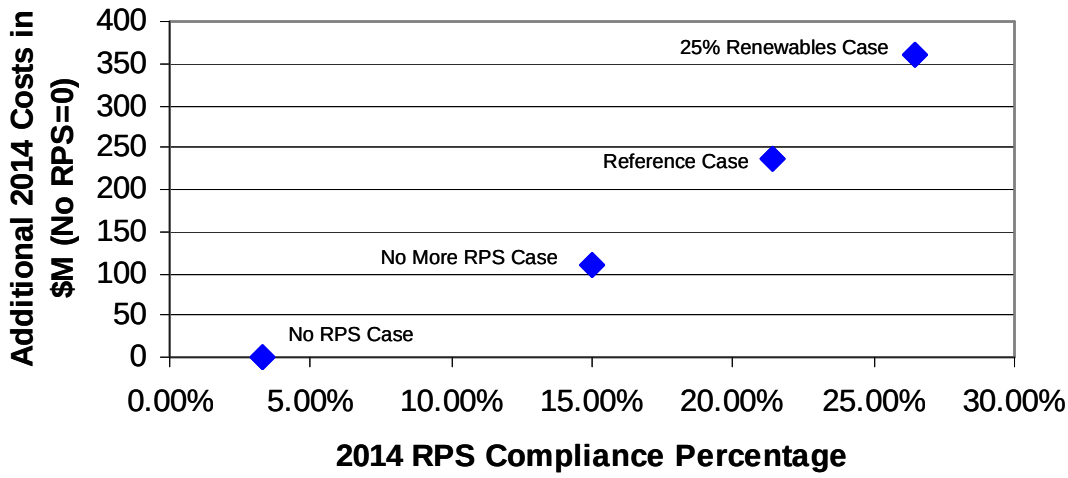


7.3 CONCLUSIONS AND IMPLICATIONS OF A 40% RPS GOAL

7.3.1 Summary of cost impacts

Figure 35 illustrates the ECAF expense associated with achieving varying RPS compliance percentages. Specifically, the graph shows the ECAF cost associated with each of the four cases employed in determining the cost of RPS. The figure sets the cost of No RPS to zero, and thus shows the additional 2014 cost associated with achieving the 2014 RPS percentages achieved by each of the cases 15% (No More RPS), 21.4% (Reference Case), and 26.8% (25% Renewables Case).

Figure 35: 2014 Costs Relative to RPS Compliance Percentages



Of course, total ECAF costs increase with the percentage of renewable energy – the more aggressive the RPS targets, the more expensive the annual costs of the plan. This chart also

indicates, via the steepening slopes as one moves right between case markers, that the *incremental* cost associated with developing and integrating renewable energy into the LADWP portfolio is projected to increase as the percentages increase. Table 23 shows the incremental cost to LADWP, per RPS percentage point added and per MWh added, of pursuing increased renewable energy generation and procurement. As one moves from the lower penetration rate plans to the higher ones, the incremental cost increases, indicating that, under LADWP's Reference Case plans, the cost of procuring the next unit of RPS energy will be more expensive than the last.

Table 23: Incremental Renewable Energy Costs

Increase in RPS % achieved	Total ECAF cost increase per additional % point added (1)	Renewable cost per MWh added (2)
From 3.3% to 15%	$9.3 M	$86/MWh
From 15% to 21.4%	$20.0 M	$136/MWh
From 21.4% to 26.8%	$23.0 M	$145/MWh

(1) Calculated as the additional total ECAF cost incurred in FY2014 divided by the increase in RPS percentage points in FY2014.

(2) Calculated as the additional RPS related expense incurred in FY2014 (including generation cost, transmission investment, O&M, and debt service) divided by the additional MWh of renewable energy generated in FY2014.

These results are not surprising, given the resources and infrastructure requirements needed to execute each of the plans. Getting from 3% to 15%, as indicated by the differences between the No RPS and No More RPS cases, was largely accomplished through the integration of remote wind and even more cost effective resources including landfill gas and small hydro.

The Reference Case reflects a more expensive renewable program as compared to the No More RPS Case, as the Reference Case includes the integration of higher cost solar resources and additional Pacific Northwest wind resources such as Miller Wind which carry high wheeling and integration fees.[46]

The final step, from the 21.4% RPS of the Reference Case to the 26.8% achieved in the 25% Renewables Case, is even more expensive, per unit, for two reasons. First, the build plan in the 25% Renewables Case calls for adding more solar at Owens Valley and contracting with new geothermal projects, which despite aggressive cost estimates relative to historical costs are still more expensive than average Reference Case generation. The second source of increased cost is the transmission added to facilitate the increased capacity of Owens Valley Solar.

[46] Note that the No More RPS Case includes 453 MW of Pacific Northwest wind that carry the same $18 to $28/MWh wheeling and integration cost as Miller Wind. So while the costs associated with Miller Wind are not unprecedented, its addition does still serve to increase the average cost of renewable energy additions.

7.3.2 Different fuel and carbon scenarios

The data presented in this section is based on LADWP's Reference Case plan. This plan assumes natural gas prices are in line with current forward prices and that there is no cost associated with carbon dioxide emissions.

Since renewable resources displace fossil fuel resources, higher fossil fuel prices make renewables appear relatively cheaper. Similarly, lower fossil fuel prices would make the cost of RPS appear relatively more expensive. The introduction of a carbon cost would also impact the relative attractiveness of RPS projects. With higher carbon allowance prices, the cost of RPS decreases.

Due to time constraints, PA has not fully evaluated the scenarios required to quantify the cost of RPS under a range of fossil fuel and carbon price assumptions.

7.3.3 Implications for a 40% RPS goal

Moving beyond 25% towards a goal of 40% introduces more challenges and uncertainties. In addition to the additional fuel and carbon price uncertainty that is introduced over a longer time period, there is also higher project cost and integration cost uncertainty.

A thorough assessment of what it will cost to reach a 40% RPS goal requires a strategic plan from LADWP that takes into account the specific nuances of their generation system, transmission network, and load profile. However, the data here provides a starting point for understanding what a 40% case may look like.

The cost data derived in moving from 15% RPS penetration to 25% RPS penetration provides an indicator for what such a case may look like. Simply extrapolating the data implies that an additional $400 million per year of costs would be incurred in order to reach the 40% penetration level. This would be equivalent to an additional 1.7 cents/kWh in ECAF costs, or roughly $9 on the average monthly residential bill. This extrapolation is shown in Figure 36.

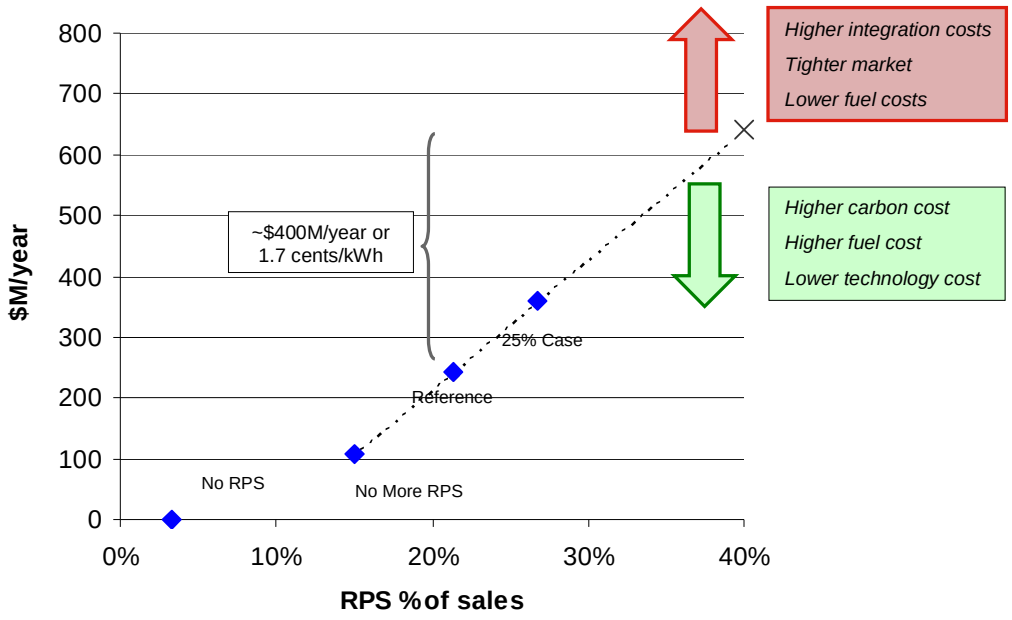
However, such an extrapolation is likely inaccurate as many assumptions may change significantly based on future market or regulatory conditions. Improved technology could drive down the cost of new solar projects beyond the goal of $100/MWh being pursued by LADWP. Higher fuel prices or the introduction of a carbon tax would make RPS look relatively more desirable.

While these and other events may occur to positively impact the cost and desirability of renewables, it is also possible that other events could provide a negative impact. A high penetration of renewables could require higher incremental integration costs, including additional transmission, firming, or energy storage requirements. A tightening of the renewables market or increase in materials costs could offset technology gains. Finally, it is possible that natural gas prices could drop from today's relatively low levels.

Even after a thorough evaluation by LADWP, the cost of RPS commitments will be subject to uncertainty. However, additional study can create a full set of scenarios that will allow policy makers to reach a conclusion regarding the relative costs and benefits of reaching a 40% RPS target. Such a study should model the full LADWP system in detail, taking into account reasonable ranges of fossil fuel prices, carbon prices, renewable development costs, and the

actual cost of integrating renewables while maintaining reliability. This should be part of any long-term Integrated Resource Plan targeting a 40% penetration of renewables.

Figure 36: Extrapolation to 40% RPS case



8. EVALUATION OF RESIDENTIAL RATE DESIGN PROPOSAL

On Sept. 1, 2009, the City Council received two proposals from the Board of Water and Power Commissioners. The first was a proposal to increase the caps on increases in the Energy Cost Adjustment Factor, in order to allow the ECAF to increase by 2 cents per kWh over the course of a year. The second proposal was a revision to the City's Rate Ordinance that would change the tiered prices applicable to residential ratepayers (Rate R-1).

Previous sections of this report have dealt with the Department's ECAF costs and the justification for an increase in ECAF. This section addresses the proposed rate redesign. The Department has stated two goals in restructuring rates. The first is to shift the burden of an ECAF increase to higher-consumption customers (Tier 3). The second is to encourage conservation by widening the difference between Tiers and sending better price signals to customers.

As background we begin with a brief overview of LADWP's rates and the current tiered rate structure. We will then explain the most recent version of the rate revision and display its impact on ratepayers especially when combined with an ECAF increase of the size PA believes may be needed (2.7 cents per kWh). A key question is the extent to which the rate redesign is revenue neutral, that is, whether it results in revenue to LADWP that is higher than under current rates (a surplus) or lower (a shortage). We will then consider possible modifications to the rate design, as well as reporting and oversight mechanisms to mitigate the effect of any surplus.

8.1 OVERVIEW OF RATES

Utility rates are designed around customer classes. A general principle of ratemaking is that similarly situated customers should pay similar prices. A customer class is a group of customers that have some broad similarity, e.g., residential, commercial, industrial, "general service" (a category that can included both commercial and industrial customers), agricultural, public lighting, or "other".

Within a customer class, smaller groups of customers are defined, usually based on characteristics that represent the stress they put on the power system – monthly usage, peak usage, voltage at which they interconnect, etc. These groups of similarly situated customers are the rate classes, and each one has an associated "rate" that defines how they will be charged for their utility usage.

Customers in a given rate class can be provided multiple options, or variant definitions of the way they will be charged, often depending on some demographic distinction or the type of metering. LADWP residential rate options, for example, distinguish some customers demographically (low-income and lifeline customers; customers in Zone 1 vs. customers in Zone 2) and others based on metering (time-of-use).

The bill associated with a utility rate option can be computed from several components. Each component has a billing determinant (a measurement of usage) and a price (the cost per unit associated with that billing determinant). Examples of charges are in the following table:

Table 24: Examples of charges included in utility rates

Charge type	*Typical billing determinant*	*Price*
Customer charge	Customer	Price per customer
Meter charge[47]	Meters	Price per meter
Demand charge	Highest instantaneous usage	Price per kW
Energy charge	Monthly consumption in kWh	Price per kWh
Tiered energy charge	Monthly consumption in kWh	Price per kWh, increasing as consumption grows
TOU energy charge	Monthly consumption at various times of day, in kWh	Price per kWh that varies with time of use

8.1.1 LADWP residential rates

LADWP's residential customers can take service under several different rates. Most residential customers are classified in rate R-1. Rate R-3 is for master-metered multifamily dwellings or trailer parks. Some residential customers can also take power under a "general service" rate, if they have a dedicated transformer. The proposed rate redesign is for the R-1 rate, and in the remainder of this section we will only address R-1 rates.

The R-1 rate has four rate options. R-1B is a time-of-use rate currently used only by a few thousand customers. R-1D (low income service) provides a fixed monthly discount from the R-1A rate. LADWP provided PA a forecast that there would be 182,000 low income customers in fiscal 2010, and 207,000 in fiscal 2011. R-1E (lifeline service) provides a different fixed monthly discount from the R-1A rate. LADWP provided PA a forecast that there would be 93,000 lifeline customers in fiscal 2010 and fiscal 2011. Remaining R-1 customers fall under option R-1A.

In addition to the Base Rate, all customers also pay a equal charge per kWh for the Energy Cost Adjustment Factor (ECAF), which has been covered in detail in this report. R-1A customers pay additional charges for the Reliability Cost Adjustment (RCA), which covers the cost of the Departments reliability program, and the Energy Subsidy Adjustment (ESA), which provides funding for the energy subsidy provided to low income and lifeline customers. R-1D and R-1E customers do not pay the RCA or ESA.

In July 2009 the R-1A base rate, and by association the R-1D and R-1E base rates, became tiered. This means that once monthly usage reaches a certain level, the price of each additional kWh increases. It is the same concept as the marginal tax rates used in income taxes. There are three Tiers. The definition of the Tiers differs, depending on the customer's zip code. Some customers are assigned to Zone 1 and others to Zone 2; Zone 1 is considered to have a milder climate, and the average R-1A customer in Zone 1 uses less electricity that the average R-1A customer in Zone 2.

[47] Differs from the customer charge, if a customer has multiple meters (such as single industrial site with multiple power feeds).

In each case a baseline allowance is set and Tier 1 rates are applied to that allowance. Tier 2 rates apply to power once that baseline has been exceeded, and Tier 3 rates are applied once usage exceeds 300% of the baseline. For Zone 1, the baseline allowance is 350 kWh per month. For Zone 2, the baseline allowance is 500 kWh per month.

The actual prices for each Tier vary by season. The months of October through May are the Low season, and the other months are the High season. The tiered prices are as follows:

Table 25: Definition of current LADWP R-1A rate Tiers

Customers in Zone 1		
Usage	*Low season price*	*High season price*
Up to 350 kWh	$0.0702/kWh	$0.0702/kWh
350-1050 kWh	$0.0702/kWh	$24.57 + $0.0852/kWh for each kWh over 350
Over 1050 kWh	$0.0702/kWh	$84.21 + $0.12/kWh for each kWh over 1050
Customers in zone 2		
Usage	*Low season price*	*High season price*
Up to 500 kWh	$0.0702/kWh	$0.0702/kWh
500-1500 kWh	$0.0702/kWh	$35.10 + $0.0852/kWh for each kWh over 500
Over 1500 kWh	$0.0702/kWh	$120.30 + $0.12/kWh for each kWh over 1500

8.1.2 Proposed rate redesign

Under the proposed rate redesign, base rates for low usage will go down and base rates for high usage will go up. Furthermore, pricing in the Low season will be adjusted to provide different pricing by Tier:

Table 26: Proposed LADWP R-1A Base Rate redesign for rates effective July 1, 2010

Customers in Zone 1		
Usage	*Low season price*	*High season price*
Up to 350 kWh	$0.0602/kWh	$0.0602/kWh
350-1050 kWh	$21.07 + $0.0942/kWh for each kWh over 350	$21.07 + $0.1010/kWh for each kWh over 350
Over 1050 kWh	$30.10 + $0.0942/kWh for each kWh over 500	$91.77 + $0.16/kWh for each kWh over 1050
Customers in zone 2		
Usage	*Low season price*	*High season price*
Up to 500 kWh	$0.0602/kWh	$0.0602/kWh
500-1500 kWh	$30.10 + $0.0942/kWh for each kWh over 500	$30.10 + $0.1010/kWh for each kWh over 500
Over 1500 kWh	$30.10 + $0.0942/kWh for each kWh over 500	$131.10 + $0.16/kWh for each kWh over 1500

These are actually the prices that would come into effect July 1, 2010. LADWP is proposing an additional modification to be effective July 1, 2011 that would further widen the gap between Tiers. We have only considered the impact of the 2010 revision since the rate ordinance may be further amended before the 2011 prices can come into effect.

8.1.3 LADWP's analysis of the rate redesign

One goal of the redesign was to counteract the impact of an ECAF increase on residential ratepayers by shifting the burden to higher-consumption customers (Tier 3). This was done by reducing base rates in Tier 1 and increasing rates in Tier 3 and to a lesser extent Tier 2. LADWP also sought to differentiate the tiered rates in the Low season, which had not been done before.

LADWP attempted to ensure revenue neutrality in the design. However because this is a tiered design, "revenue neutrality" is relative to a particular distribution of bills. LADWP chose the bill distribution of FY2005, as a relatively neutral weather year. PA has been asked to verify revenue neutrality. There are a couple of complexities to that.

LADWP checked revenue neutrality using a distribution of average usages. In other words, they assumed that a customer with an average usage of, say, 340 kWh/month in the high season (a Tier 1 customer) had that usage in every month. In reality, that customer would have lower usage in some months, and higher usage (entering Tier 2) in others. This could have an impact on revenue neutrality.

LADWP also allowed a "cushion", slightly larger than 1%, for loss of revenue due to price responsiveness of load. In reality the price responsiveness could be greater or less.

8.2 IMPACT OF THE RATE REDESIGN

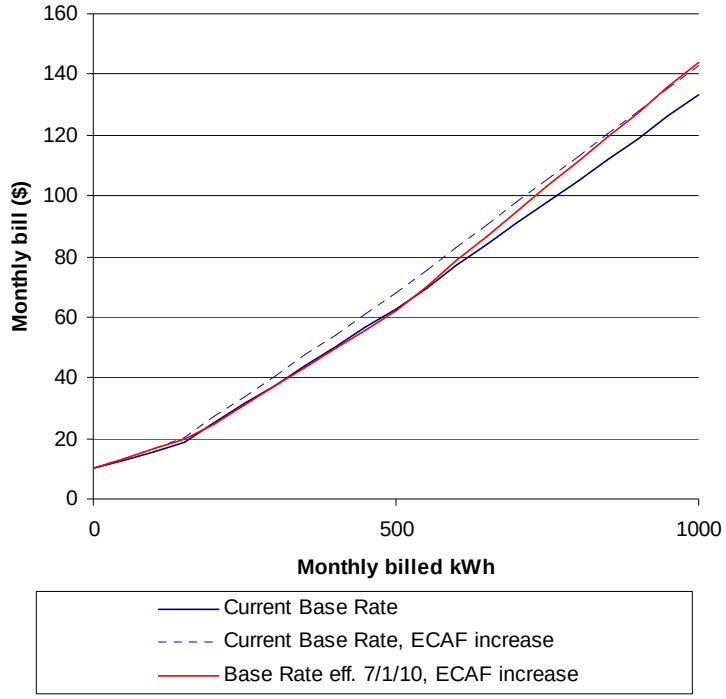
The goal of the proposal is to effectively mitigate the effect of an ECAF increase on low-usage ratepayers. The impact of a 1 cent increase on Tier 1 ratepayers would be eliminated; the impact of a 2 cent increase would be halved.

LADWP has proposed a staged implementation of the rate revision – an initial implementation in 2010 and a further revision in 2011. We believe that the revenue impact of the revision will have to be revisited and this may change the plan for 2011. Therefore we have focused our analysis on the 2010 plan.

8.2.1 Impact on individual customers

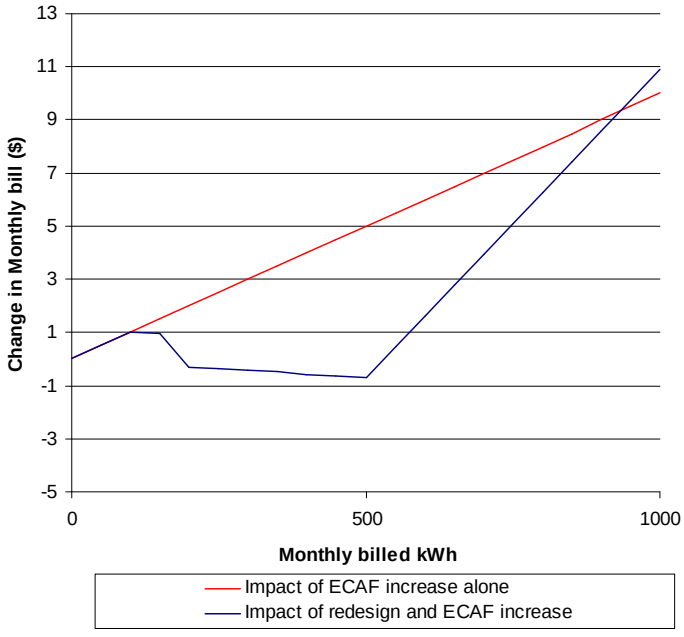
The 2010 revision will offset the impact of a 1 cent ECAF increase on Tier 1 ratepayers. For example:

Figure 37: Impact of 1.0 cent ECAF increase and Rate Redesign, High Season Zone 2



It is easier to see the effect of the base rate increase if one just looks at the change in the monthly bill relative to current rates:

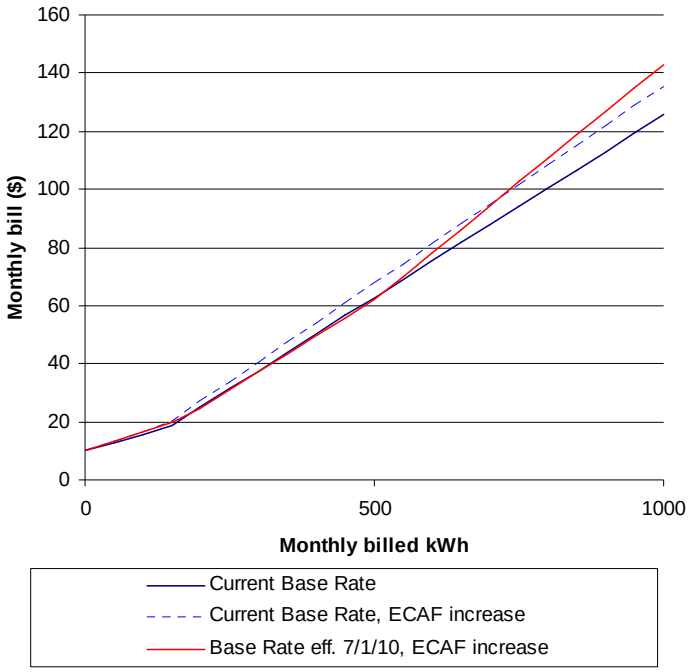
Figure 38: Change in Monthly Bill with 1 cent ECAF increase, High Season Zone 2



There are similar graphs for zone 1 (although the "break" in the graph will be at 350 billed kWh, which is the limit for the first Tier in zone 1).

In the low season, there is a similar impact:

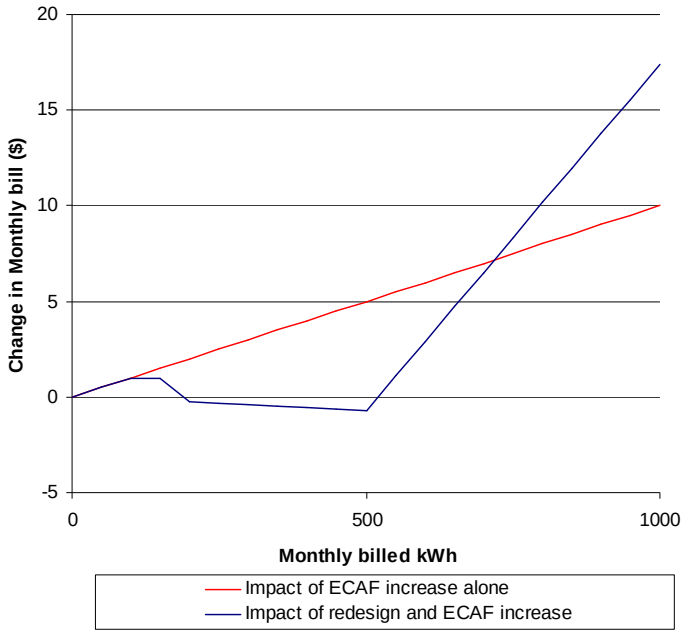
Figure 39: Impact of 1.0 cent ECAF increase and Rate Redesign, Low Season Zone 2



Note in this graph that the red line (with the changed base rate) has a bend at the end of Tier 1 (500 kWh), indicating that Tier 2 consumption will be charged at a higher rate. This is a change from current rates.

It is clear also from the "impact" graph that in the low season, many Tier 2 ratepayers will pay more under the rate revision:

Figure 40: Change in Monthly Bill with 1 cent ECAF increase, Low Season Zone 2



Finally, the rate revision mitigates, but does not eliminate the impact of a larger ECAF rate increase. For example, Tier 1 ratepayers in zone 2 can still wind up with bill increases of $8/month under the 2.7 cents per kWh ECAF increase that PA thinks may be necessary:

Figure 41: Impact of 2.7 cent ECAF increase and Rate Redesign, Low Season Zone 2

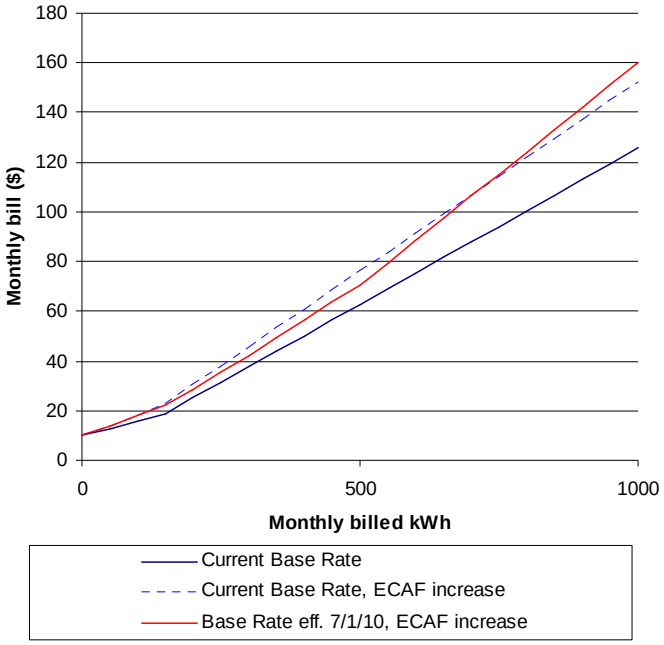
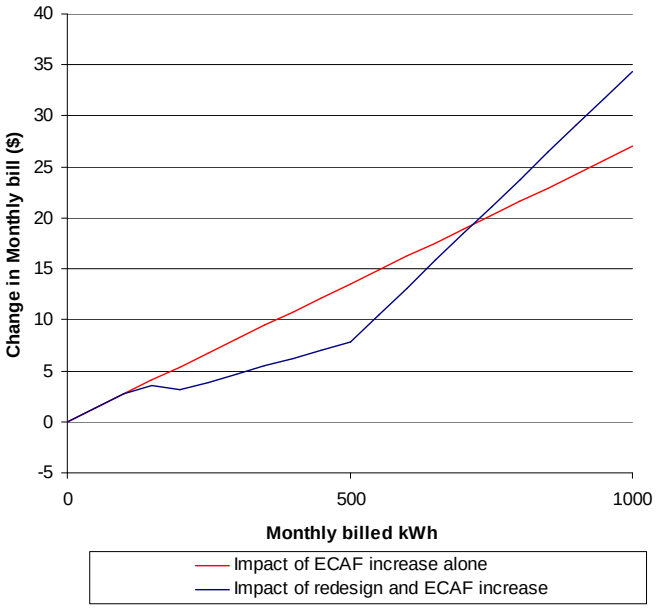


Figure 42: Change in Monthly Bill with 2.7 cent ECAF increase, Low Season Zone 2

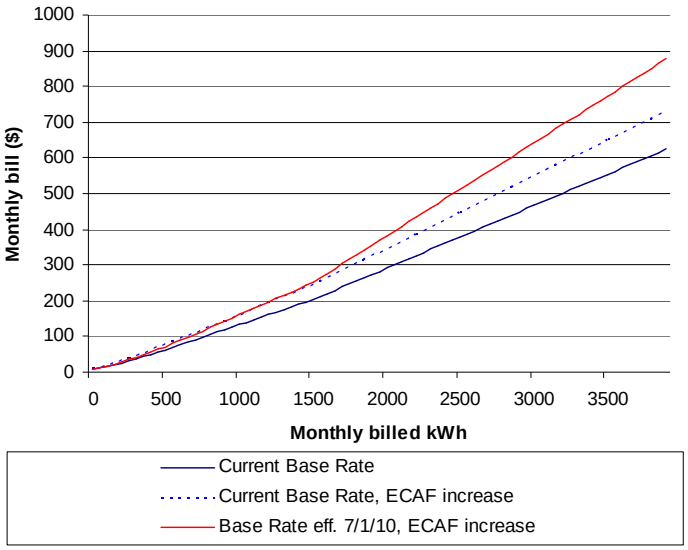


Again, note that in the low season, Tier 2 ratepayers can wind up paying significantly more under the changed design.

These graphs focused on the impacts to Tier 1 and lower Tier 2 customers. As electricity consumption increases, the impacts of the base rate change can become even more

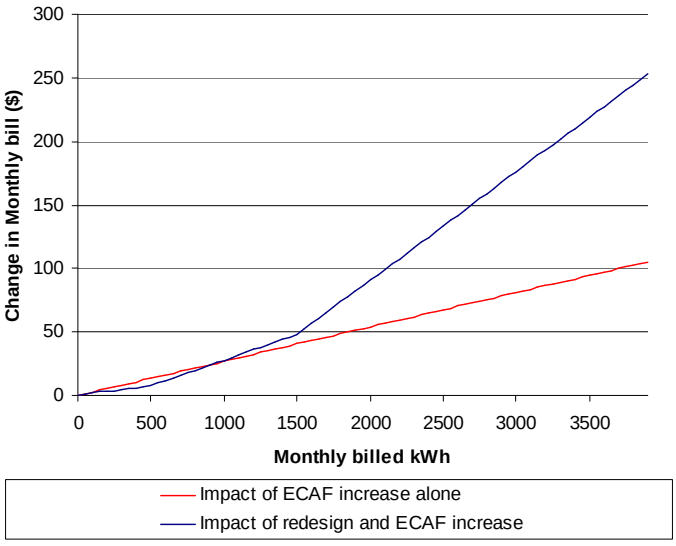
pronounced. The graph below shows the impacts on Tier 3 customers. In Zone 1, these are customers consuming more than 1050 kWh per month. In Zone 2 (shown below), these are customers consuming more than 1500 kWh per month.

Figure 43: Impact of 2.7 cent ECAF increase and Rate Redesign on higher users, High Season Zone 2



Focusing on the change in monthly bill, it can be seen that the impact of the rate redesign on Tier 3 customers will be very dramatic.

Figure 44: Change in monthly bill, higher users
2.7 cent ECAF increase and Rate Redesign on higher users, High Season Zone 2



8.2.2 Impact on lifeline and low-income customers

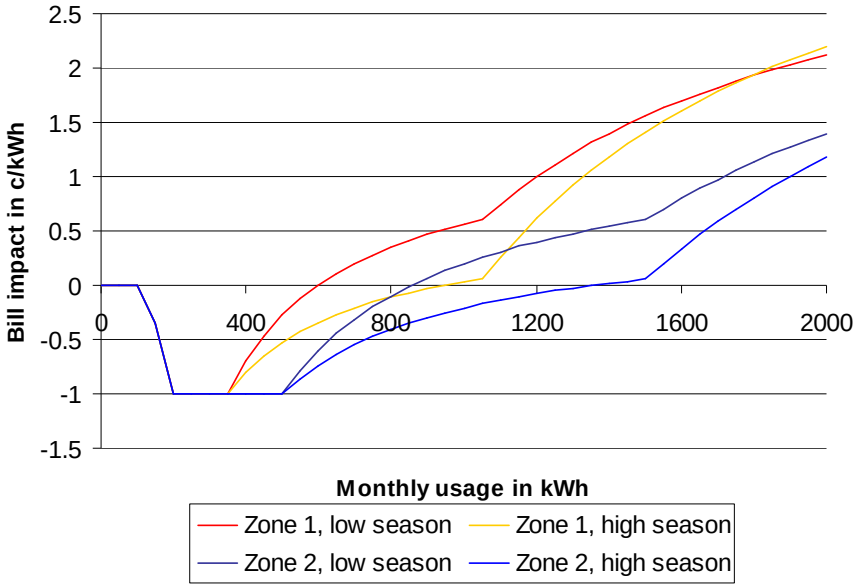
The effect of the rate revision on lifeline and low-income customers is similar to its effect on other R-1A customers. Lifeline and low-income customers receive a fixed rate discount ($8.17/month for low-income customers and $17.71/month for lifeline customers) which is not affected either by ECAF or by the rate revision. However, as this subsidy reduces the amount of a low income or lifeline customer bill, any change in the monthly bill will have a higher *percentage* impact for low income and lifeline customers than it does for R-1A customers.

Low income and lifeline customers could alternatively be protected from ECAF increases by capping the total ECAF rate only as it applies to them. This will fix their rates as ECAF rises. However, the ECAF costs to other ratepayers will increase accordingly. PA's analysis has assumed that total R1-D and R1-E sales in fiscal 2011 will be approximately 1.32 billion kWh. On the other hand, the Department's April 2009 load forecast indicated 23.77 billion kWh in expected retail sales for fiscal 2011. From those figures, if ECAF would otherwise increase 2.7 cents per kWh but is capped for low income and lifeline customers, then ECAF for all other customers would increase instead by 2.9 cents per kWh.

8.2.3 Impact on average rates

The impact on residential customers of the rate revision can be summarized in the following graph, which shows the effect on a customer's monthly bill, depend on monthly usage in kWh, zone and season. Effects are expressed in terms of the average rate (cents per kWh, that is, the change in the bill divided by usage in kWh) to show how large an ECAF change could be counteracted:

Figure 45: Impacts of rate revision on average residential rates



The zero values at low usage levels reflect minimum bills of $10/month under both the old and new rates. At high usage levels the bill impacts will approach 2.4 cents per kWh in the low season and 4 cents per kWh in the high season.

The rate restructuring will reduce the average bill for customers in Tier 1, slightly increase the average bill for customers in Tier 2 (but decrease the average bill for customers on low income rates), and significantly increase bills for Tier 3 customers. But coupled with the expected 2.7 cents/kWh ECAF increase, customers in all tiers will have significant bill increases. Projected impacts in fiscal 2011 are as follows:

Table 27: Bill Impacts of Rate Changes

Rate	Tier	Average monthly bill impact (rate redesign in isolation)	Average monthly bill impact (rate redesign + 2.7cents/kWh ECAF increase)
R-1A	1	-$2.61	$4.45
R-1A	2	$1.26	$20.20
R-1A	3	$37.25	$92.30
Low Income	1	-$2.62	$4.46
Low Income	2	-$0.66	$16.29
Low Income	3	$22.26	$65.53
Lifeline	1	-$2.53	$4.29
Lifeline	2	$0.50	$18.71
Lifeline	3	$25.23	$70.59

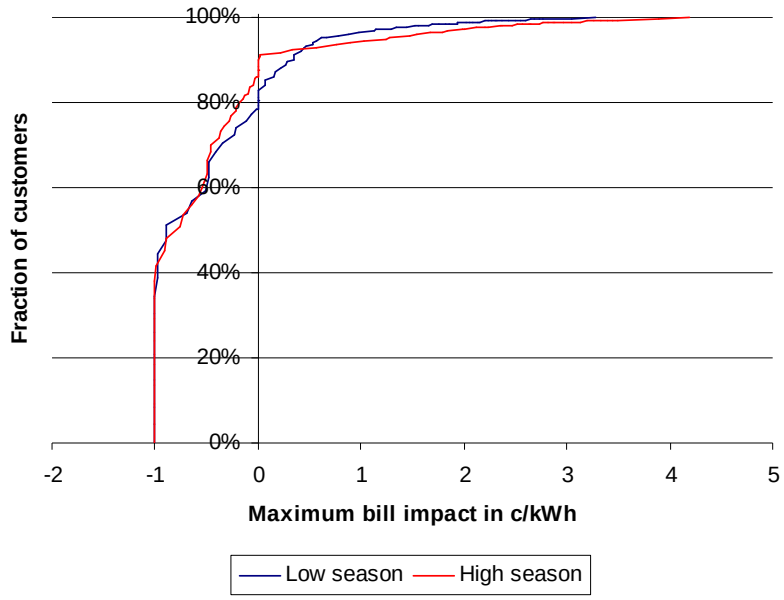
Note that this table is based on average usage levels and does not include the effects of minimum bills. In other words, customers will not see any increases in bills because there bills are at the minimum level, which is above the level that usage alone would indicate.

8.2.4 Distribution of rate impacts

The following figure shows the “cumulative distribution” of those bill impacts expected in FY2010; it is a way of displaying the fraction of customers with a particular average bill impact. For each line, the x coordinate represents the bill impact and the y coordinate is the fraction of customers with that impact *or less*. Thus in both the high and low seasons we expect the rate revision to reduce rates by 1 cents per kWh for about 40% of customers. In the low season about 75% of customers will be beneficially impacted (base rates reduced by the revision) and in the high season about 78% will be.

These impacts are shown *independent* of any increase in the ECAF. An ECAF increase would shift the curves to the right by the amount of the increase.

Figure 46: Cumulative distribution of average rate impacts



8.3 REVENUE IMPACT OF THE RATE REDESIGN

As noted above, LADWP attempted to assure revenue neutrality by estimating total base rate revenues under both the current and the revised base rate structures.

Revenues under tiered rates depend critically on the distribution of usage numbers. LADWP's initial analysis was a based on a study of fiscal 2005 usage by customer and the resulting proportions of Tier 1, Tier 2 and Tier 3 usage. PA updated this distribution by modifying the usages in order to come up with an average usage equal to a forecast of fiscal 2010 average usage. This should have increased the revenue estimated from the revised rate structure.

We believe that LADWP's forecast assumed that each customer's monthly usage equaled their average monthly across the entire season (low or high) in fiscal 2005. PA normalized the histogram separately for each month, to achieve the average usage of that month forecast for fiscal 2010.

LADWP's estimate was that the revised rate structure was not quite revenue neutral, but would return slightly more than 101% of the revenue under current rates. PA believes that this is reasonable and appropriately conservative, given the uncertainty in the estimate, the fact that average usage may be declining, and considering that if the redesign achieves one of its avowed purposes (incentivizing conservation among Tier 3 customers) revenue under the revised rate could be significantly reduced.

PA's own estimation indicated a slightly higher revenue under the revised rates (101.5% of the revenue under current rates). Note, however, that the fiscal 2010 load forecast PA used may not have taken into account the falloff in average usage that occurred in 2009, according to figures filed by LADWP with the federal Energy Information Administration. Such a falloff

would reduce Tier 3 consumption by a greater proportion than Tier 2, and Tier 2 by a greater proportion than Tier 1. Those effects would reduce the surplus estimated by PA.

PA's estimation is summarized in the following table:

Table 28: Revenue effect of rate restructuring

						Base Rate Revenue ($000)		
Rate	Season	Zone	Tier 1 MWh	Tier 2 MWh	Tier 3 MWh	At current rates	At rates eff. 7/2010	Increase / (decrease)
R1A	High	1	428,859	228,655	126,147	64,725	69,095	
		2	903,819	488,717	132,028	120,930	124,895	
	Low	1	856,299	446,052	195,732	105,165	112,005	
		2	1,701,038	601,671	86,905	167,751	167,266	
	Total		3,890,014	1,765,096	540,812	458,571	473,261	3.20%
R1D	High	1	59,006	11,048	412	5,133	4,734	
		2	201,265	35,008	1,349	17,273	15,868	
	Low	1	117,308	22,168	668	9,838	9,213	
		2	374,269	40,951	495	29,183	26,435	
	Total		751,848	109,175	2,923	61,428	56,250	(8.43%)
R1E	High	1	33,176	10,571	1,019	3,352	3,228	
		2	86,579	29,838	3,133	8,996	8,727	
	Low	1	66,479	21,763	1,748	6,317	6,217	
		2	163,444	35,744	1,451	14,085	13,343	
	Total		349,677	97,917	7,350	32,750	31,515	(3.77%)
	GRAND TOTAL		4,991,540	1,972,187	551,086	552,749	561,026	1.50%

8.3.1 Surplus in the revised rate structure

Over the course of a year, and with the assumption that the distribution of usage numbers each month is similar to the distribution of averages in fiscal 2005, this data suggests that the revised rate structure could collect $8.3 million more from LADWP ratepayers than the current rate structure. Given the uncertainty inherent in the distributional and other assumptions, PA believes that it is appropriate that the redesign be slightly revenue-positive. A 1.5% surplus, though, may be too large.

Tier 2 and Tier 3 rates will rise under this redesign. One of LADWP's stated aims is to encourage conservation by Tier 2 and 3 customers and if that actually happens -- if Tier 2 and 3 consumption declines while Tier 1 consumption stays as predicted -- the redesigned base rates will not return as much as the current rate. However, to eliminate the 1.5% surplus, consumption in Tiers 2 and 3 would have to decline by approximately 14%. PA considers a decline of that magnitude to be unlikely.

8.3.2 Revenue Loss Recovery

As explained above (section 4.4), the ECAF includes costs for "revenue loss recovery". The first step of ratemaking is to determine how much revenue the utility needs to cover its costs. A simple way to think of rate design is that the revenue requirement is divided by the projected energy sales to get a price per kWh. If customers install energy efficiency measures, less energy will be sold than had been expected, and revenue will be reduced. To the extent that costs are also reduced, because LADWP does not have to buy or generate power to serve as much load, the revenue reduction will not have any net effect.

However, some costs are incurred regardless of the level of sales, such as the Department's fixed investments. (Recovery of these fixed costs may be included in base rates, not ECAF.) A reduction in revenue will mean that the Department will not cover all its fixed costs. Absent any other action, energy efficiency would lead to a net operating loss that would have to financed, and the costs of doing so are borne by all ratepayers. Instead, the estimated uncollected fixed costs are added to the ECAF, which is also borne uniformly (on an energy basis). The Rate Ordinance quantifies that impact at 5.513 cents per saved kWh.

It may be the case that a tiered rate design leads to increasing the impact of DSM Revenue Loss. The reason is that the usage reductions attributable to energy efficiency occur at the margin. If an energy efficiency measure is implemented by a Tier 3 customer, the revenue reduction is based upon the Tier 3 rate, not the average rate. Under the current tiered residential rates, the highest price (High season, Tier 3) is almost 5 cents per kWh above the average rate; under the rate revision it will be 4 cents per kWh higher still.

PA's computations associated with revenue neutrality indicate an average R-1 base rate (under the current rate structure) of 7.36 cents per kWh. This is significantly below the high season Tier 3 rate. But, a comparatively small fraction of R-1 customers are Tier 3. Furthermore, energy efficiency measures are installed by individual customers, not based on usage; in other words, as usage goes up customers may install more energy efficiency measures but there is no reason the believe the installations increase proportional to usage. The average marginal price in the current rate structure, that is, an average value to which each customer contributes in proportion to the highest price it pays in a given month, is only 7.31 cents per kWh, actually below the average rate. The average marginal price in the revised rate structure is 7.60 cents per kWh.

PA does not believe that the Department has been able to determine the distribution of energy savings over customer Tiers. In the case of many measures, such as broad scale CFL giveaways, it would be impossible to have done so. Therefore we cannot estimate the actually marginal price associated with energy efficiency savings. However, PA believes it is unlikely that the rate revision will create significant additional revenue loss.

8.3.3 Using rate redesign to reduce the impact of an ECAF increase

The City's request for proposal asked its consultant to consider "[w]hether the proposal can be modified in a manner that applies the ECAF equitably across the Tiers and minimizes cost impacts to the ratepayers." In this case "impact" refers to the combined impact of an ECAF rate increase of 2.7 cents per kWh and the rate redesign. There are six things that influence that impact:

1. The absolute size of the increase in ECAF rates (averaging 2.7 cents per kWh)
2. The ECAF increase is applied uniformly across all users
3. The rate redesign applies tiering to low season rates, for the first time
4. The rate redesign reduces Tier 1 rates and increases rates for other Tiers
5. The rate redesign includes a built-in cushion or surplus of 1.5%.
6. The rate redesign is entirely within the residential class, that is, the rate design and ECAF increase do not introduce any subsidization of residential ratepayers by other rate classes, or vice versa.

Item 1 is addressed in the earlier sections of this report. Items 2 through 4 have to do with the equity aspects of the ECAF increase and the rate redesign. There are two key equity principles at issue: that utility rates should reflect the cost of service, and that a basic level of utility service should be affordable to all. These principles are somewhat in conflict, as the first supports a uniform ECAF and the second does not. In several of our interviews, PA attempted to draw out interviewees' views of rate equity, but could not obtain sufficient information to derive a metric of equity.

ECAF reflects energy costs, and energy is a commodity. That means that each unit of each customer's simultaneous consumption costs the utility the same to supply and therefore should be priced equally. That logic is the justification for a uniform ECAF.

On the other hand, it is also now recognized that electricity has become a basic necessity of life, and that a certain level of usage should be protected from the effects of price spikes, or of market power in energy markets. For this reason, when the California Public Utility Commission raised rates for the Investor Owned Utilities (IOUs) by a total of 4 cents per kWh in 2001, the IOUs were also directed to institute a drastic rate tiering so that the price for a baseline level of usage did not rise. The effects of this tiering persist in California IOU rates. As noted below, the standards set by neighboring utilities would support the argument that more steeply tiered LADWP rates would be equitable.

Item 5 represents the one opportunity to reduce the impact of an ECAF increase by reducing the overall level of rates. PA recommends that LADWP recalculate its tiered rates to eliminate the 1.5% cushion. At the same time, though, we recommend that LADWP institute a balancing account, similar to the current RSA, to track and true up surpluses or shortages of base rates relative to the current structure or any other selected base level. The intent of the rate redesign is not to change overall rate revenue, and LADWP's finances should neither benefit nor suffer from fluctuations in the usage distribution or forecasting errors in rate design.

Finally, item 6 is out of the scope of this analysis.

8.4 COMPARISON OF RATE STRUCTURE TO OTHER UTILITIES

One of the benefits often attributed to municipal utility service is to lower rates than are available from investor-owned utilities. These lower rates derive from the municipal utility's lack of a profit motive and ability to issue tax-exempt debt. Therefore, it is instructive to

compare LADWP's residential rates with those of the California Investor-Owned Utilities (IOUs) Southern California Edison (SCE), Pacific Gas & Electric (PG&E) and San Diego Gas & Electric (SDG&E).

Of those, SCE most directly competes with LADWP. However, all of these utilities all have tiered rates that are similar in design to the tiering proposed by LADWP. They are also all subject to many of the same pressures as LADWP in their need to meet RPS targets and the potential for being subject to new carbon regulations imposed by the State of California.

8.4.1 Current rate structures

Tiered rates at LADWP, SCE, SDG&E, and PG&E are all defined relative to a "baseline" (the first Tier), and the baseline usage levels differ. Where LADWP's baseline usages are defined only geographically (2 zones) the investor-owned utilities have different baseline quantities by season, customer type (with or without electric heating) and geography (four zones for SDG&E, nine for SCE and ten for PG&E). Note that the three IOUs each have five rate tiers; LADWP's second rate Tier covers usage in the second, third and fourth IOU Tiers. Because Zone 1 and Zone 2 rates differ only in the identification of the baseline, these tables do not distinguish them.

In Table 29 below, IOU rates are compared with LADWP's current rates, LADWP's current rates plus a projected 2.7 cents per kWh ECAF increase, and LADWP's proposed rate redesign for July 1, 2010 including a 2.7 cents per kWh ECAF increase. Rates shown are for standard Residential service and are inclusive of all charges, including the ECAF.

This analysis indicates that from a competitive standpoint, LADWP's rate tiering is less steep than its rivals' and there is room to make it steeper (as the redesign does). However, it should be noted that the IOUs are now moving in the direction of flattening their rates and in fact certain affluent communities' pursuit of municipalization or community choice may be due to a desire to escape from providing the subsidies inherent in a steeply tiered rate.

The analysis also shows that LADWP's baseline rates today are comparable to SCE's current rates, but the rates for higher usage levels are below SCE's. However, with a projected 2.7 cent/kWh rate increase, these Baseline rates will exceed SCE's, even including the impact of the Department's proposed rate redesign. Rates for higher usage levels are projected to remain below SCE's. The rate redesign will mitigate some of the change in baseline rates, but will increase rates at higher usage levels. Yet, those high-usage prices will still be less than SCE's.

Table 29: Comparison of LADWP rates to California IOUs

Summer (High) Rates		**LADWP**			**SCE**	**PGE**	**SDG&E**
		Current	+ 2.7c ECAF	+ 2.7c ECAF and redesign			
Tier 1	Baseline	0.126	0.153	0.143	0.122	0.119	0.129
Tier 2	100-130%	0.141	0.168	0.183	0.142	0.135	0.150
Tier 3	131-200%				0.210	0.276	0.275
Tier 4	201-300%				0.246	0.406	0.295
Tier 5	>300%	0.175	0.202	0.242	0.282	0.474	0.295

Winter (Low) Rates		**LADWP**			**SCE**	**PGE**	**SDG&E**
		Current	+ 2.7c ECAF	+ 2.7c ECAF and redesign			
Tier 1	Baseline	0.126	0.153	0.143	0.122	0.119	0.129
Tier 2	100-130%	0.126	0.153	0.177	0.142	0.135	0.150
Tier 3	131-200%				0.210	0.276	0.258
Tier 4	201-300%				0.246	0.406	0.278
Tier 5*	>300%	0.126	0.153	0.177	0.282	0.474	0.278

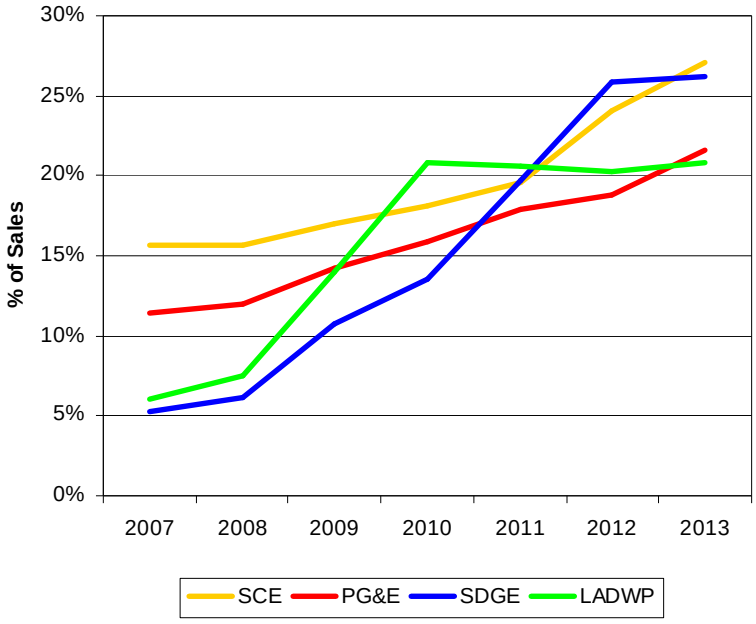
Rates shown are inclusive of Energy and other adjustment costs
*Note that LADWP "Tier 3" rates are equivalent to Tier 5 at California IOUs
Sources: SCE Schedule D 12/29/09, SCE DWR% table, SDG&E Schedule DR 12/29/09
SDG&E Schedule EECC 12/29/09, PG&E Schedule E-1 12/30/09, LA ordinance 180127

8.4.2 Rate outlooks

Looking ahead, three major regulatory changes are likely to further impact these rates. The first is the need for all utilities to reach an RPS level of 20% by 2010. The second is a goal for utilities in California to meet a 33% RPS goal by 2020. The third, and potentially most significant, is the possibility of a significant cost increase due to carbon regulation.

Table 27 included recent costs associated with LADWP's efforts to meet its 20% RPS goals. Figure 47 shows how LADWP's progress towards these goals has compared to these other utilities':

Figure 47: Progress toward 20% RPS, LADWP vs. California IOUs



The information in this figure was drawn from data supplied to PA by the Department, and the three IOUs' most recent RPS Compliance Reports. Information for 2009 and earlier is based on actual deliveries; information beginning with 2010 represents compliance plans.

As the Figure shows, LADWP had a lower RPS penetration in 2009 than either PG&E or SCE but plans to jump to 20% renewable in 2010. This may be a statement of aspirations, as several key projects are not yet in place. While the three IOUs have a directive to achieve 20% by 2010, they are able to comply by "borrowing" against future deliveries, and the Figure indicates they intend to do so.

Table 30 indicates each utility's RPS delivery percentage in 2009, along an estimate of the rate impact of achieving 20%. The rate impact estimates are extremely coarse; they are based on the order-of-magnitude estimates that the utility achieves its objective by replacing fossil power priced at $60/MWh with RPS power priced at $130/MWh. These disparate

estimates were intentionally chosen to show that even if RPS power is much more expensive than fossil power, the rate impacts of RPS alone should be manageable.

Table 30: Rate impact of RPS

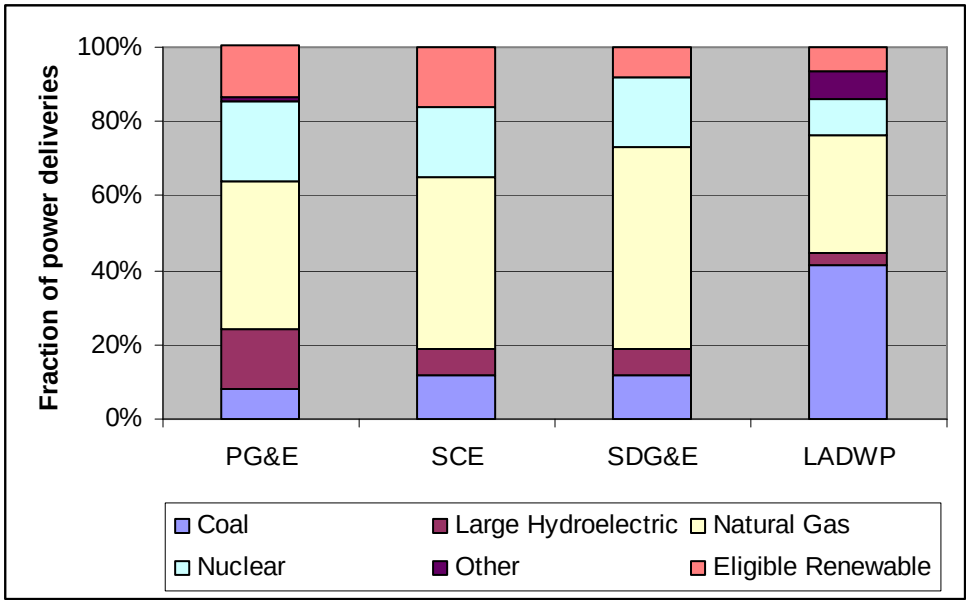
Utility	Estimated 2009 RPS percentage	Estimated rate impact of moving from 2009 levels to 20% RPS (¢/kWh)
SCE	17.0%	0.21
PG&E	14.2%	0.41
SDG&E	10.8%	0.65
LADWP	14.0%	0.42

In general it is difficult to form precise estimates of the rate impacts of renewables. While one can obtain the utilities' renewables percentage for public sources, it is much harder to get public information about actual renewables costs, and very difficult to obtain cost forecasts for renewable contracts that have not yet begun delivery.

The costs of further increases in renewables penetration could be much greater for all three utilities. The State has enunciated a "next stage" goal of a 33% RPS. The California Public Utilities Commission recently sponsored a study that indicated significant costs associated with moving to a 33% standard. Although a number of studies have looked at the costs to integrate up to 20% intermittent renewables, there has not been much work done to evaluate the impacts of higher penetration levels. The California ISO is in the midst of studying the integration of larger volumes of renewables.

Carbon regulation will present a much more difficult challenge to LADWP. Historically LADWP has been the lowest-cost large utility in California and while to some extent that may be attributable to the use of tax-exempt financing, it is probably more due to the Department's relatively heavy reliance on coal. As Figure 48 shows, as of 2008 LADWP power mix was 42% coal-fired while the largest fraction among the IOUs is 12%.

Figure 48: 2009 Power Mix, LADWP vs. California IOUs



A carbon reduction regime will have a very heavy impact on LADWP. The Department will face costs either for emissions permits, for a carbon tax, or for replacing coal generation with other resources. Table 30 showed that even if renewable resources were $70/MWh more expensive than the fossil-fired power they replace, a 20% RPS fraction could probably be attained for less than 1 cents per kWh. On the other hand, if carbon mitigation costs are only $30/MWh, their rate impact on LADWP would be more than 1 cents per kWh, because of the much larger fraction of the Department's power mix that would be affected. The impacts on PG&E, SCE and SDG&E would be much less dramatic.

Shifting carbon generation to other sources, such as natural gas or renewables, will only reduce these impacts if the cost to shift is lower than the cost of paying for carbon allowances. This will depend on the cost of generation as well as the cost associated with carbon allowance purchases. Regardless of the strategy chosen, LADWP will remain at a competitive disadvantage relative to IOUs that already have integrated generation with low carbon content into their existing rates.

8.5 CONCLUSIONS

PA believes that the Department's proposed residential rate restructuring is reasonable and that it meets the goals the Department has set. If a restructuring like this is to be instituted, PA recommends two specific changes: the specific prices should be set in such a way that the restructured rates provide less of a surplus relative to current rates, and a balancing mechanism should be set up to "true up" any surplus or deficit relative to current rates.

But PA also believes that a simple restructuring like this is not really sufficient and that the Department's entire rate structure should be examined. This approach will dovetail with PA's recommended reconstitution of the ECAF, as noted above. There are several additional reasons, over and above those given earlier in the discussion of reconstituting ECAF:

- The issues of rate design that the Department raised in the goals it set for this redesign – protecting baseline customers and encouraging conservation – represent policy statements. Furthermore they conflict to some extent, since conservation by high-usage customers would reduce the ability to subsidize baseline rates. They should be considered in a full ratesetting context.
- Although PA has not proposed a specific metric for measuring the equity of the allocation of ECAF rates, in fact such a metric is not necessary. Equity needs to be considered within the context of the complete rate structure.
- Considerations of equity overall could lead to a change in the uniformity of the ECAF. To the extent that ECAF represents energy costs and developments in wholesale markets, the ECAF component should be applied equally to all "similarly situated kWh". Any differentiation of the ECAF component alone should be on the basis of factors that affect energy prices, not demographic factors. For example, energy prices are known to be higher on peak than off, and higher in the summer than in the winter, so it would be reasonable to differentiate ECAF prices by time of use or season. The first cannot be applied to R1-A customers who lack appropriate metering. Seasonal differentiation of ECAF rates can be done but it would require more frequent updating of ECAF cost computations based on seasonal costs rather than annual ones.
- The Department's rate structure already contains an allowance for rate reductions based on ability to pay, namely the low income and lifeline discounts. A simpler way to protect these most vulnerable customers would be to cap the total ECAF rate only as it applies to them. However, doing so means that the ECAF costs to other ratepayers will increase accordingly. As one can see, even protecting a small group of customers can shift a noticeable cost to all others.

Additional rate equity issues will probably also arise and should be taken up as part of a general rate restructuring.

9. RECOMMENDATIONS AND SUMMARY OF FINDINGS

In examining the issues involving LADWP's proposed ECAF increase and rate restructuring, PA has made a number of conclusions and recommendations throughout this report. This section first provides a summary of key conclusions, focusing on items that are critical to answering the specific questions posed in the RFP for this project.

9.1 RECOMMENDATIONS

9.1.1 Immediate increase in ECAF rate

PA recommends that the current quarterly cap on ECAF rate increases be increased to 0.8 cents per kWh per quarter. Given projected Reference Case costs and the mechanism for ECAF rate increases included in the current ordinance, this will result in a total rate increase of approximately 2.0 cents/kWh over the next three quarters before leveling off. Under a Stress Case scenario with adverse market prices and operating conditions, this rate increase could reach 2.7 cents/kWh over the next four quarters.

This increase should be implemented as soon as possible, preferably in time for the April 1, 2010 quarterly ECAF update. A delay in this timing will result in a growing ECAF undercollection that will eventually need to be addressed by an even higher short-term rate increase.

9.1.2 Decomposition of ECAF and rate restructuring

In parallel with this increase, PA recommends that a new proposal for rate restructuring should be drafted and analyzed. One aspect of this proposal would be to split the current ECAF into several separate rate components. This will provide the Council with greater visibility of LADWP's cost structure and of the justification for any rate increases. It will clearly identify the Council's actions to stabilize rates. It will ensure that controllable costs are subject to appropriate controls. And, by applying to each separate component a review of appropriate detail and frequency, lenders and rating agencies will be able to take comfort in the City's commitment to cost recovery.

Key considerations involved in a decomposition of the current ECAF are:

1. Costs that are clearly out of the LADWP's control, such as short-horizon gas, coal, and power purchases, should remain in the ECAF. "Short-horizon" in this case means not just short-term purchases, but any purchase whose normal sales cycle is short enough to preclude normal rate review.

2. At an appropriate frequency (probably annually or biennially) Council should approve an LADWP procurement plan. LADWP can report its procurement activities regularly, and Council staff can verify that LADWP follows its procurement plan. As long as procurement has been in accord with the plan, ECAF cost recovery should be a pure, uncapped pass-through.

3. Costs that are predictable, such as long-term contract costs or energy efficiency costs, should be removed from ECAF. They should be either part of base rates or part of a separate rate component. For example, long-term renewable PPAs may be

executed on a schedule different from that of a normal rate review, but that does not mean their costs should be passed into rates without review. The rate impact of a contract can be evaluated when it is executed, and Council approval of the contract should mean it will be included in rates when deliveries start. These costs would not be subject to a cap but would receive Council review.

4. Revenue losses attributable to DSM should be passed through without a cap, but as a separate bill component in addition to ECAF.

5. The City Transfer should not be tied to fluctuating ECAF revenues, but rather entirely to more stable base rate revenues. This will create greater certainty of City Transfer payments and remove elements of the City Transfer from the current ECAF structure. While such a change means that the City Transfer will fluctuate as a percentage of total revenue as ECAF revenues change, it will result in lower volatility in rates as well as in payments to the City.

6. The Council should separately define a rate stabilization program that will mitigate or spread out rate increases. Rate stabilization has the effect of financing a cost increase and its impact on City finances and LADWP's capital adequacy should be explicitly considered. The rate stabilization program would combine the functions of the current RSA and the ECAF cap.

An additional consideration in rates restructuring would be to give a complete airing of the issues of equity and fairness in LADWP's rate. In times of increasing costs it is important that the policies underlying rate design be enumerated and that appropriate tradeoffs be determined. A simple concept like "equity" can have several conflicting interpretations – such as cost reflectivity vs. ability to pay – which must be resolved by an appropriate policy-making body.

Given the complexity of the required rate redesign supporting this issue, this process may take several months to fully study and implement. Given the financial pressures facing the department, PA recommends that this process not delay action to increase ECAF rates under the current rate structure.

9.2 SUMMARY OF FINDINGS

a. APPROPRIATENESS OF FINANCIAL TARGETS AND IMPACT OF A DOWNGRADE (RFP QUESTION A1 AND A2, REPORT SECTION 2)

LADWP has clearly communicated a target minimum debt service coverage ratio of 2.25x, a minimum cash level of $300 million, and a maximum capitalization ratio of 60%. While substantially lower than historical levels, the financial targets set by LADWP are within the range expected based on comparable peers and in fact are very close to the median level of these peers. It is critical that management and policy makers demonstrate the willingness and ability to meet those targets. A failure to do so will likely result in a ratings downgrade.

PA has estimated the impact of a downgrade at $40 to $70 million per year, on average, over the next five years. This is due to the impact of higher interest payments on current and future debt. This additional cost is paid directly to lenders and does not resolve any underlying structural cost issues that may cause low debt ratios in the first place. Eventually,

revenues would still need to be brought into line with costs. Otherwise LADWP would face the potential for further downgrades or insolvency.

b. ECAF STRUCTURAL ISSUES AND OTHER VIABLE FISCAL/CAP OPTIONS (RFP QUESTION A3, REPORT SECTION 3)

The ECAF as currently constructed has combined multiple disparate rate elements into one cost adjustment factor, reducing the transparency into LADWP's costs that is necessary to allow policy makers to make informed decisions.

Two other major issues exist with the current ECAF structure. First, predictable long-term cost commitments that LADWP has control over – most notably RPS projects – can be passed through to ratepayers automatically without thorough rate review.

Second, the existing quarterly cap of 0.1 cents/kWh on ECAF changes does not allow LADWP enough rate flexibility to deal with unpredictable and volatile rate components, such as fuel prices, over which it has little control. This leaves LADWP exposed to financial distress in the case of an extended spike in fuel or power prices. The current cap makes the ECAF ineffective in mitigating this risk.

The current ECAF should be decomposed into multiple components. The first should cover market components and be uncapped. Other components, including RPS, DSM, and several other smaller cost elements should be handled in separate cost adjustment accounts with rate changes that are clearly capped or approved on a project-by-project basis.

c. EVALUATION OF LADWP'S REFERENCE CASE PLAN/SOURCES OF ECAF UNDERCOLLECTION (RFP QUESTION A4/REPORT SECTION 4)

The current undercollection in the ECAF account is approximately $125 million. This undercollection resulted from the cap on ECAF changes that failed to allow rates to keep up with rising costs. The majority of the current undercollection resulted from a sharp increase in natural gas prices that was experienced in 2008.

Regarding future projections, PA has reviewed LADWP's Reference Case plan to validate the appropriateness of key assumptions and activities with the potential to impact ECAF costs. Key conclusions include:

- LADWP maintains a natural gas hedging program that balances the desire to reduce price volatility with the need to limit the risks and costs of a long-term hedging program. Natural gas price projections used for financial planning are reasonable and are in line with forward price expectations.

- Coal prices are projected to increase substantially over the next five years, especially at IPP. This has a very strong impact on ECAF costs. While these prices are strongly influenced by market forces, minimizing the extent of these increases should be a major strategic focus of the Department.

- The majority of costs required to meet the Department's 20% RPS goal have already been committed. These costs are reflected in the Department's latest projections. Among those projects required to maintain this 20% level through 2014, PA believes the

Department's assumptions for solar costs, most notably at Owens Valley, to be very optimistic relative to demonstrated performance.

- DSM programs are very aggressive, as required to meet the Department's goal to reduce future energy demand by 10% by 2016. Given the relative immaturity of the program and the large projected expenditures (over $100 million per year of spending projected for FY2011), a thorough review of the Department's DSM spending plans should be undertaken on an annual basis as additional data is obtained to ensure the optimal prioritization of opportunities and allocation of funds.

In general, while the Department's Reference Case plan may be appropriate for a financial projection, it does not adequately take into account potential risks. LADWP should consider critical strategic issues in the context of broader sensitivity analysis to better understand the impact of risks such as volatile fuel prices, plant outages, and higher than expected RPS costs.

d. REQUIRED ECAF CAP LEVELS AND THE FINANCIAL VIABILITY OF LADWP'S PROPOSAL (RFP QUESTION A1/REPORT SECTIONS 5 & 6)

Given the Department's Reference Case assumptions, PA's analysis indicated that an ECAF rate increase of 2.0 cents/kWh would be required to maintain the Department's financial ratios in the face of rising ECAF costs. However, PA evaluated multiple other sensitivities and determined that when considering other potential risks facing the Department, a rate increase of 2.7 cents/kWh could be required.

Given the current ECAF structure, ensuring that the Department can maintaining its target financial ratios over the next two years requires an increase in the cap on quarterly ECAF changes to 0.8 cents/kWh. Depending on market conditions, this will result in a total rate increase of 2.0 to 2.7 cents per kWh over the next four quarters.

e. IMPACT ON LADWP'S RATEPAYERS (RFP QUESTION A3/REPORT SECTION 6.4)

This rate increase of 2.0 to 2.7 cents per kWh will result in a monthly increase of $11 to $14 for the average residential customer. This is an increase of 16 to 21%. General Service customers would expect an increase of 15% to 20% per month, with actual dollar figures varying widely by usage.

Ignoring potential changes to existing residential base rates proposed by LADWP, low income customers would expect an increase of $7 to $9 per month (20% to 27%). Lifeline customers would expect an increase of $8 to $11 per month (25% to 34%).

f. MINIMIZING ECAF-ORIENTED COSTS (RFP QUESTION A7/REPORT SECTION 6.5)

There is little the Department can do to minimize the ECAF-oriented costs driving the 2.0 to 2.7 cents/kWh increase. Many of the increased costs are market driven and nearly all of the RPS commitments driving cost increases have already been made. It is possible to make some savings by further curtailing planned DSM spending but this will impact the Department's long-term goals to reduce energy demand.

Beyond this immediate increase, the Department will have more control. The most important step that LADWP can make is to enhance its strategic planning process. Most important is the development of a long-term Integrated Resource Plan that is updated annually to keep pace with the rapidly changing renewables market.

Beyond RPS, careful optimization of the DSM program is also critical to controlling ECAF costs. Also, while in the long-run the Department has expressed a desire to reduce its dependence on coal-fired power, minimizing upcoming coal price increases and their impact on ECAF costs should be a clear focus.

Streamlining procurement processes, pursuing innovative financing for renewable projects, applying for grants, ensuring proper metering of electricity, and improving customer collections would all also help in reducing costs for all customers. In its recent cost-cutting efforts, the Department has identified many of these potential solutions. However, it is proper management of these larger strategic issues that will have the largest impact on minimizing ECAF costs.

g. COST OF RPS (RFP QUESTION A5/REPORT SECTION 7)

PA has estimated that ECAF costs in 2014 under the Department's 20% RPS case will be $240 million higher than would have been the case if no RPS program was pursued. This is equivalent to a 1 cent/kWh increase in rates or a cost of approximately $5 on the average residential customer bill.

LADWP does not currently have a plan to go beyond this 20% level. However, using a project build plan based on a budget issued by the Department in May 2009, the cost of reaching a 25% level was estimated at an additional $124 million per year, or 0.5 cents/kWh in rates. This would have an additional $2.50 impact on the average residential customer bill.

Moving from 25% to 40% introduces even more uncertainty. Extrapolating these cost impacts to the 40% RPS level, PA has estimated a potential additional cost impact of $400 million per year. With higher fuel costs, the introduction of a cost for carbon, or lower RPS costs than those projected in the near-term, this figure could be smaller. Similarly, it could be higher given higher RPS or integration costs. When the Department has a full plan prepared, PA plans to revisit this analysis to determine the cost to reach 40% under the official LADWP plan.

h. LADWP'S RPS RESOURCE MIX (RFP QUESTION A6/REPORT SECTION 4.3)

Depending on geography and existing generation, utilities in California have chosen different strategies in meeting the State's requirement for 20% RPS generation. However, as can be seen by comparing the plans in Appendix F, there has been a very heavy focus on using wind to meet incremental RPS needs. While some utilities, SDG&E in particular, plan to use solar to increase RPS penetration beyond 20%, none show substantial new non-wind resources as part of their portfolio until 2011 at the earliest.

Utilities have chosen wind to meet this initial ramp-up because (a) there are multiple sites for wind projects accessible to California with a large resource potential, and (b) the cost of wind development today is substantially lower than the development cost for other technologies with a significant resource potential, notably solar energy. However, wind presents

integration challenges for utilities, both in terms of the need to build new transmission once available pathways are full, and also in terms of the need to manage the intermittency of its power once it becomes a substantial part of the portfolio.

For that reason, in moving beyond the 20% goal utilities are increasing turning to solar power as a source for incremental renewable energy. This price of this power, while still more expensive than wind, has been coming down over time. Solar energy also is produced during the day when demand is highest, fitting better with utility load profiles than wind which in many areas blows more strongly at night when demand is lower. PG&E and SDG&E are planning for the introduction of significant solar power beginning in 2011.

LADWP's portfolio is no exception to this trend. In ramping up from only 7% renewable energy content to 20% renewable energy content in only two years, LADWP is relying very heavily on wind. The only exceptions are in short-term purchases that are filling the gap until additional projects can come online, and in the unique purchase of landfill gas from remote sites for use in LADWP's gas combustion turbines. These purchases have been made at very economic levels relative to other renewable options. However, PA does not expect that it will be possible to renew these purchases at similar levels in the future.

Moving beyond the 20% RPS goal, LADWP is, like the IOUs, looking at adding solar energy to its mix of renewables. Under the pricing assumed by the Department, this is a reasonable strategy, as the price assumptions indicate that solar power could be competitive with wind when considering wind's additional integration costs. Given similar power prices among renewable options, it makes sense to pursue a diversity of resources. However, PA believes the pricing being assumed by the Department is aggressive for new solar development and is not consistent with demonstrated performance. While the Department's outlooks are based on actual negotiations with potential vendors, we feel that a more conservative figure should be used for planning purposes even while the Department continues to pursue the best possible pricing arrangements.

Recently, the Department has also adopted several principles to help achieve a more cost-effective portfolio. First among these is to use existing LADWP-owned transmission wherever possible. Additionally, the Department will look to cluster resources near this transmission to improve economies of scale and facilitate possible future ownership of assets by the Department. On the surface, these principles appear to be sound. However, any decision to invest in a project should include a full range of alternatives, including potentially higher quality and less expensive projects further from LADWP transmission.

Evaluating the tradeoffs of these various opportunities requires careful evaluation and is best accomplished as part of an Integrated Resource Planning effort. As described in Section 4, the lack of such a thorough plan contributed to past efforts in developing major projects and plans that were later discarded, possibly reducing the Department's focus on other more desirable projects that would have otherwise been incorporated into the portfolio.

Looking ahead, the Department should use their IRP process to regularly evaluate a full range of renewable projects, including not only solar projects but additional wind, biogas, and geothermal project opportunities. As many renewable project concepts do not reach fruition due to both economic and regulatory concerns, it is critical to maintain a large pipeline of potential opportunities. Similarly, the value of an individual project can only be evaluated in the context of the alternatives, including alternatives that may have been discarded in the

past. The evaluation process for these alternatives should include a full risk assessment of project success, generation costs, and integration costs under a range of potential fuel pricing and regulatory scenarios. Such a process should also include an explicit assessment of economic development and jobs impacts to the extent that is a consideration in making project decisions. Evaluations for major projects should be presented to policy makers in this context to provide assurance that projects coming forward for approval represent the best way for the Department and its customers to invest in renewable power.

i. REVIEW OF DWP'S PROPOSED RATE RESTRUCTURING (RFP B1, SECTION 8)

Provide overall review of the DWP's proposed amendment to the Electric Rate Ordinance to restructure the residential tiered electric rate with emphasis on the following:

- Impact on DWP's ratepayers under each tier, including low income and lifeline customers

Chapter 8 includes a series of graphs illustrating the impact of the rate restructuring on average bills at different usage levels. The rate restructuring will reduce the average bill for customers in Tier 1, slightly increase the average bill for customers in Tier 2 (but decrease the average bill for customers on low income rates), and significantly increase bills for Tier 3 customers. But coupled with the expected 2.7 cents/kWh ECAF increase, customers in all tiers will have significant bill increases. Projected impacts in fiscal 2011 are as follows:

Rate	Tier	Average monthly bill impact (rate redesign in isolation)	Average monthly bill impact (rate redesign + 2.7cents/kWh ECAF increase)
R-1A	1	-$2.61	$4.45
R-1A	2	$1.26	$20.20
R-1A	3	$37.25	$92.30
Low Income	1	-$2.62	$4.46
Low Income	2	-$0.66	$16.29
Low Income	3	$22.26	$65.53
Lifeline	1	-$2.53	$4.29
Lifeline	2	$0.50	$18.71
Lifeline	3	$25.23	$70.59

It would be possible to eliminate the ECAF increase for Low Income and Lifeline customers but those costs would have to be redistributed to other customers, at an average rate of 0.2 cents/kWh (about a dollar per month added to the average bill).

- What percent of residential customers are positively and negatively affected by the allocation of ECAF revenue to all tiers (1, 2 and 3)?

Since ECAF revenue is allocated uniformly, all customers' rates are equally affected. In both the high and low seasons we expect the rate revision to reduce rates by 1 cents per kWh for about 40% of customers. In the low season about 75% of customers will be beneficially impacted (base rates reduced by the revision) and in the high season about 78% will be. However, this will have to be combined by the increase in ECAF, which PA expects to be 2.7 cents/kWh.

- Whether the proposed residential electric rate tier restructuring is revenue neutral (e.g., no increase or decrease in total DWP revenues).

PA's analysis indicates that absent additional conservation by Tier 3 customers, the rate redesign will produce approximately 1.5% more revenue than current rates. PA recommends that LADWP recalculate its tiered rates to eliminate the 1.5% cushion. At the same time, though, we recommend that LADWP institute a balancing account, similar to the current RSA, to track and true up surpluses or shortages of base rates relative to the current structure or any other selected base level.

- Whether the proposal can be modified in a manner that applies the ECAF equitably across all tiers and minimizes costs impacts to the ratepayers. And if so provide an alternative proposal.

There are two key equity principles at issue: that utility rates should reflect the cost of service, and that a basic level of utility service should be affordable to all. These principles are somewhat in conflict, as the first supports a uniform ECAF and the second does not. In several of our interviews, PA attempted to draw out interviewees' views of rate equity, but could not obtain sufficient information to derive a metric of equity. These issues represent policy decisions. Equity needs to be considered within the context of the complete rate structure and in a full ratesetting context.

- Review the current and proposed tiered-electric rate to determine its effect on energy conservation as well as the customer feedback regarding the current tiered electric rates.

The tiered rate has only been in effect since July 2009, during which overall usage has declined due to the larger economy. It has not been possible to separately analyze the effect of the tiering on conservation. LADWP reported that it received no "feedback" on the tiered rate, only calls asking for explanations.

- Review the impact of the Demand-Side Management Program savings, which result in a revenue loss to the DWP and the effect on the ECAF. Determine any methods available by which DWP can avoid an increase in the ECAF which essentially results in an increased pass-through charge to the ratepayers decreasing the savings achieved in their previous bills.

PA does not believe that the Department has been able to determine the distribution of energy savings over customer tiers. In the case of many measures, such as broad scale CFL giveaways, it would be impossible to have done so. Therefore we cannot estimate the actually marginal price associated with energy efficiency savings. However, PA believes it is unlikely that the rate revision will create significant additional revenue loss.

PA's conclusions regarding the avoidability of ECAF costs are presented above.

APPENDIX A: REVIEW OF LADWP'S FINANCIAL MODEL

In order to carry out the ECAF review in a reasonable amount of time, PA utilized the existing LADWP Financial Model in carrying out its ECAF evaluation. This model is used by LADWP for generating financial plans and creating the Department's budget. LADWP made critical staff available for providing explanation of all model inputs, calculations, and outputs. LADWP personnel also generated model results based on alternative inputs provided by PA as part of its sensitivity analysis.

Before using the results of the model to generate analysis and conclusions, PA carried out a comprehensive review of the model's integrity to ensure that projected financial outcomes were consistent with inputs and plan assumptions. This review focused first on ECAF elements. PA took input assumptions provided by various LADWP departments, verified they were correctly incorporated into the model, independently checked calculations to calculate ECAF costs, and verified that these outputs were correctly included in summary reports. Figure 49 below details the major ECAF elements investigated in the model review.

In addition to the detailed examination of ECAF elements, PA also validated the critical assumptions and inputs impacting the calculation of LADWP's financial ratios. As these ratios cover costs and revenues beyond the ECAF, it required that PA investigate elements of Base revenues, debt payments, capital expenses, O&M expenses, and the roll-up of these elements into overall financial ratios. These are detailed in Figure 50 below.

In the course of this review, several minor inconsistencies were found between inputs and outputs. These were corrected in the model as they were found. One material error was discovered in the LADWP model regarding the treatment of coal costs. This was corrected prior to the use of data in this report.

When evaluating sensitivities, PA performed additional checks on key outputs and inputs to verify that the model reflected inputs. In the course of running these sensitivities, multiple issues were uncovered highlighting the manual nature of changing inputs and challenge in managing changes to multiple inputs within the current platform.

In general, the current process used by LADWP is very manual and relies very heavily on one very capable staff member to maintain the integrity of calculations across the entire enterprise. The majority of confusion and minor inconsistencies were a result of conducting multiple updates and iterations of the FY2010 budget over the past several months. The introduction of RPS into the portfolio and resulting need to track RPS generation costs and percentages has also put a large burden onto the existing process.

While PA is confident in the results generated in both Reference Case and sensitivity projections, the normal financial modeling process could benefit from more formal process and controls to ensure that model inputs are consistent with endorsed assumptions, calculations are checked and then locked down within the model to ensure integrity, and outputs are generated and displayed on a consistent basis. This may require not only the migration to a different modeling platform, but the implementation of new control processes and additional staff to support the existing team.

Figure 49: Checklist for verification of ECAF input and output calculations in Financial Model

Component	Input Source(s)	Calculation checks	Output
Natural Gas	Gas price Hedge MTM Forecasted usage (Prosym)	*Check gas price at each facility* *Check hedge treatment in ECAF* *Check Prosym backcast*	ECAF $/year spend / ECA reimbursement
Coal	Coal price Forecasted usage (Prosym)	*Check coal price at Navajo* *Check Prosym backcast*	ECAF $/year spend / ECA reimbursement
IPP power	Coal price IPP costs Forecasted power use (Prosym)	*Check coal price at IPP* *Verify IPP worksheet* *Check Prosym backcast*	ECAF $/year spend / ECA reimbursement
Economic purchase power	Historical usage and price	*Verify model reflects total forecast*	ECAF $/year spend / ECA reimbursement
Nuclear	Fuel price Palo Verde PPA terms Forecasted power (Prosym)	*Verify model reflects total forecast*	ECAF $/year spend / ECA reimbursement
RPS - Own build	Actual costs	*Verify depreciation and interest accurately modeled*	ECA $/year reimbursement
RPS - Long-term PPA	Project costs & PPA passthrough	*Verify $/MWh estimates of power cost* *Verify total cost reflected in model* *Verify consistency of power production assumptions*	ECAF $/year spend / ECA reimbursement
RPS - Short-term PPA	PPA terms Landfill gas terms	*Verify $/MWh estimates of power cost* *Verify total cost reflected in model* *Verify landfill gas costs properly accounted for in model*	ECAF $/year spend / ECA reimbursement
DSM Spend	DSM budget and plan	*Verify total costs match DSM plan*	ECAF $/year spend / ECA reimbursement
DSM lost revenue	DSM budget and plan Forecasted MWh savings ECAF ordinance	*Verify calculations are consistently applied in model*	ECA reimbursement
Other	City Transfer Cogen Hoover Legal/Bad Debt	*Document input sources and verify calculations*	ECAF $/year spend / ECA reimbursement

Figure 50: Checklist for verification of key Financial Ratio inputs

Financial Ratios

Component	Input Source(s)	Calculation checks	Output
Debt Service	Debt forecast	*Verify total debt service matches inputs*	Debt payment schedule
Capital Expense	Capex forecast	*Verify capex forecast matches inputs*	Capital costs
O & M	O & M forecast	*Verify O&M forecast matches inputs*	O&M costs
Revenue	Demand Rates	*Verify demand matches forecast* *Verify that rate assumptions match actual* *Verify that financial model matches revenue model*	Revenue forecast
Total consolidation	Non-cash adjustments Off-balance sheet debt Calculations	*Understand sources of adjustments* *Understand sources of off balance sheet debt*	
Ratio definition		*Verify ratio definitions and calculations*	

APPENDIX B: RPS PROJECT DESCRIPTIONS

Figure 51 below summarizes RPS projects that are not owned outright by LADWP, organized by the status of the project. Details of these projects are provided in the remainder of this Appendix.

Figure 51: RPS Projects, by Contract Status

Project Status	Plant	Technology	Online Date	Capacity online by FY 2014	Annual Cost to LADWP ($M)	2014 Generation Cost ($/MWh)	2010 RPS Contribution (% of CY 2010 Net Sales)	2014 RPS Contribution (% of 2014 Net Sales)
Signed, online	Penrose Landfill	Biomass	5/1/2006	6	$3.35	$59.00	0.19%	0.19%
	Pleasant Valley Wind	Wind	7/1/2006	82	$17.50	$63.00	0.87%	0.86%
	MWD Hydro	Hydro	11/1/2008	8	$5.42	$91.50	0.18%	0.17%
	Willow Creek Wind	Wind	12/31/2008	72	$18.00	$77.96	0.71%	0.71%
	Tieton Hydro	Hydro	12/31/2008	6	$1.23	$85.00	0.07%	0.07%
	Pebble Springs Wind	Wind	2/1/2009	69	$13.60	$67.30	0.73%	0.72%
	Milford Wind I	Wind	11/15/2009	185	$2.00	$74.48	1.64%	1.63%
	Windy Point Expansion	Wind	12/15/2009	60	$1.20	$71.24	0.59%	0.59%
	Windy Point Primary	Wind	12/15/2009	202		$71.24	2.01%	1.99%
	Total				**$62.30**		**6.98%**	**6.93%**
Signed, under development	Linden Ranch Wind	Wind	3/31/2010	50	10.1	$76.00	0.41%	0.54%
	Total				**$10.10**		**0.41%**	**0.54%**
Unsigned, under negotiation	Milford Wind II	Wind	5/1/2010	66	0	$80.00	0.35%	0.52%
	Miller Ranch Wind	Wind	10/31/2010	150	0	$85.00	0.26%	1.52%
	Total				**$0.00**		**0.61%**	**2.04%**
On Hold	LADWP Biomass	Biomass	12/31/2009	2.5	0	$75.00	0.09%	0.09%
	Niland Solar	Solar - Central	12/31/2010	55	0	$120.00	0.00%	0.53%
	Total				**$0.00**		**0.09%**	**0.62%**

Notes: 1. Had the biogas totals been the same in the 25% Case, the total RPS contribution would be 26.99%.
2. Biogas purchase, short-term purchases, and Powerex Hydro are not included in this graph

PENROSE LANDFILL

Signed, online

Technology	Location	Online Date	Capacity (MW)	Generation Cost ($/MWh)	Wheeling and Integration Cost ($/MWh)	RPS Contribution (% of 2014 Net Sales)
Biomass	Sun Valley, CA	5/1/2006	6	$59.0	$0	0.19%

Financing Details and Status		Notes:
Counterparty	Penrose Landfill Gas Conversion LLC (PLGC)	• PLGC has maintained a connection contract with LADWP since 1984 for energy transfer to SCE through the LADWP connection and paying a fee for the transfer of energy
Project Manager	LADWP	
Contract Structure & Term	PPA, 7 years	
Financing Arrangement	SCPPA	
Total Cost to DWP	$23.45M	
Annual DWP payment	$3.35M	
Project Status	Signed, online	

PLEASANT VALLEY WIND

Signed, online

Technology	Location	Online Date	Capacity (MW)	Generation Cost ($/MWh)	Wheeling and Integration Cost ($/MWh)	RPS Contribution (% of 2014 Net Sales)
Wind	Uinta County, WY	7/1/2006	82	$63	$0	0.86%

Financing Details and Status		Notes:
Counterparty	PPM Energy	• Municipal partners: City of Burbank, City of Glendale, City of Anaheim along with other municipalities in Utah • An “excess power clause” was negotiated in the agreement which provides LADWP with the option to terminate the agreement should the meter output of energy exceed 110%
Project Manager	LADWP	
Contract Structure & Term	16 years	
Financing Arrangement		
Total Cost to DWP	Not to exceed $280M if new transmission capacity is needed ($238M if transmission costs remain constant)	
Annual DWP payment	$17.5M	
Project Status	Signed, online	

MWD HYDRO

Signed, online

Technology	Location	Online Date	Capacity (MW)	Generation Cost ($/MWh)	Wheeling and Integration Cost ($/MWh)	RPS Contribution (% of 2014 Net Sales)
Hydro	Los Angeles, CA	11/1/2008	8	$91.50	$0	0.17%

Financing Details and Status		Notes:
Counterparty	MWD	• LADWP pays $2 less per MWh than the most recently published CPUC market price referent (MPR) for RPS energy as of the effective date of the PPA. • Termination rights of both parties: The MWD and LADWP may terminate the agreement after the first sixty months of the term upon 48 months advance written notice to the other party if given during the first 5 years of the term or 24 months if given after the first five years.
Project Manager	SCPPA	
Contract Structure & Term	PPA, 15 years and 2 mos.	
Financing Arrangement	SCPPA	
Total Cost to DWP	$82.2M	
Annual DWP payment	$5.42M	
Project Status	Signed, online	

WILLOW CREEK WIND

Signed, online

Technology	Location	Online Date	Capacity (MW)	Generation Cost ($/MWh)	Wheeling and Integration Cost ($/MWh)	RPS Contribution (% of 2014 Net Sales)
Wind	Morrow and Gilliam Counties, OR	12/31/2008	72	$77.96	$18.50	0.71%

Financing Details and Status		Notes:
Counterparty	Invenergy	• Although the contract cost was dependent on three scenarios, due to the COD and Invenergy's intention to retain the asset, Scenario I was taken as given (15 year PPA with an annual cost of $18M for a total of $271M over the 15 year period.) • Willow Creek Energy LLC provided LADWP with a financial guarantee with a cap of $5.2M to cover any payments that Willow Creek will be expected to pay LADWP.
Project Manager	LADWP	
Contract Structure & Term	PPA, 15 years	
Financing Arrangement		
Total Cost to DWP	$271M (includes an annual escalation of 2.25%)	
Annual DWP payment	$18M	
Project Status	Signed, online	

TIETON HYDRO

Signed, online

Technology	Location	Online Date	Capacity (MW)	Generation Cost ($/MWh)	Wheeling and Integration Cost ($/MWh)	RPS Contribution (% of 2014 Net Sales)
Hydro	Yakima Country, WA	12/31/2008	6	$85	$10	0.07%

Financing Details and Status		Notes:
Counterparty	Tieton Hydropower LLC	•The City of Burbank made an $8M earnest money deposit to Tieton, however it backed out of the deal and the backup PPA between SCPPA and Tieton was put into effect. •LADWP's MW allocation is based on 33.6% energy allocation and capacity. Should LADWP acquire 50% share, then the capacity allocation would be 10MW •Under the PPA with SCPPA, Tieton has the right to terminate anytime until 12/31/11 if Tieton finds a 3rd party to purchase all Tieton's assets and membership interests •BPA expenses and transmission charges are estimated at $17.27MWh, which would bring the total cost to $30.1M (33.6% share) or $45.2M (50% share) •A fixed energy price of $65/MWh for the first 400,000 MWh of energy generated, $85/MWh thereafter.
Project Manager	SCPPA	
Contract Structure & Term	PPA, 20 years	
Financing Arrangement	SCPPA	
Total Cost to DWP	$24.6M (33.6% share) or $36.9M (50% share)	
Annual DWP payment	$1.23M (33.6% share) or $1.84M (50% share) excluding transmission costs	
Project Status	Signed, online	

PEBBLE SPRINGS WIND

Signed, online

Technology	Location	Online Date	Capacity (MW)	Generation Cost ($/MWh)	Wheeling and Integration Cost ($/MWh)	RPS Contribution (% of 2014 Net Sales)
Wind	Gilliam County, OR	2/1/2009	69	$67.30	$28.0	0.72%

Financing Details and Status		Notes:
Counterparty	Pebble Springs Wind LLC	
Project Manager	LADWP	
Contract Structure & Term	18 years	
Financing Arrangement	SCPPA (w. Burbank (10 MW), Glendale (20 MW))	
Total Cost to DWP	$306.65M over the 18-year PSA	
Annual DWP payment	$13.6M for energy + $3.3M for transmission costs with a max of $17.03M annually	
Project Status	Signed, online	

MILFORD WIND I

Signed, online

Technology	Location	Online Date	Capacity (MW)	Generation Cost ($/MWh)	Wheeling and Integration Cost ($/MWh)	RPS Contribution (% of 2014 Net Sales)
Wind	Beaver and Millard Counties, UT	11/15/2009	185	$74.48	$5	1.63%

Financing Details and Status		Notes:
Counterparty	UPC Wind Management	• Modified COD is 11/16/2009 • Scenario I: $33.214/yr for 20 yrs if buy option not exercised • Scenario II: $35.027/yr for 20 yrs if buy out option is exercised at 10th year • Scenario III: $36.262/yr for 20 yrs if 1-yr period invoked, higher annual number under the PTC keep-whole option • The project capacity is 200MW, with the participants as follows: - LADWP – 185 MW or 92.5% - City of Burbank – 10MW or 5% - City of Pasadena – 5MW or 2.5%
Project Manager	LADWP	
Contract Structure & Term	Prepayment, 20 years, 3 scenarios	
Financing Arrangement	SCPPA	
Total Cost to DWP		
Annual DWP payment	$40M over 20 years	
Project Status	Signed, online	

WINDY POINT & WINDY POINT EXPANSION

Signed, online*

Technology	Location	Online Date	Capacity (MW)	Generation Cost ($/MWh)	Wheeling and Integration Cost ($/MWh)	RPS Contribution (% of 2014 Net Sales)
Wind	Klickitat County, WA	1/15/2010	202	$71.24	$28	1.99%

Financing Details and Status		Notes:
Counterparty	Windy Flats Partners LLC	•Windy Point Expansion will deliver an additional 60 MW, the expected date of service is 6/30/2010. COD'd but has yet to receive FAA certification •The guaranteed generation is 636,000 MWH per year. •LADWP has an EBO at end of 6th year or BO option at the end of 20 year term. • Termination is allowed under the following circumstances: -Early termination due to delay in COD – by the provision of a 30 day notice -Early termination by default – upon occurrence of a default, the non-defaulting party may terminate agreement -Early termination by mutual agreement -Early termination for failure to receive cash grants
Project Manager	LADWP	
Contract Structure & Term	20 years, three scenarios	
Financing Arrangement	SCPPA, City of Glendale	
Total Cost to DWP	Scenario I: $63.7M/yr for 20 years or $1.2M/yr during the life of the project Scenario II: If BO option exercised at 6th year, $63.9M/yr for 20 years or $1.28M over life of agreement Scenario III: If BO exercised at COD, $73.5M for 20 years or $1.469M over life of agreement	
Annual DWP payment	Maximum of $73.5M per year for 20 years	
Project Status	*Signed, Phase I online	

LINDEN RANCH WIND

Signed, under construction

Technology	Location	Online Date	Capacity (MW)	Generation Cost ($/MWh)	Wheeling and Integration Cost ($/MWh)	RPS Contribution (% of 2014 Net Sales)
Wind	Klickitat County, WA	3/31/2010	50	$76	$28	0.54%

Financing Details and Status		Notes:
Counterparty	EnXco	• Delayed COD 6/1/2010 • Termination is allowed under the following circumstances: - Early termination by mutual agreement – by mutual written agreement - All bonds and interest have been paid in full or adequate provision for such payment has been made and the bonds are no longer outstanding • The proposed payment schedule consists of 6 payments related to project milestones • Municipal partner: City of Glendale (5MW)
Project Manager	LADWP	
Contract Structure & Term	Asset Purchase Agreement, 20 years	
Financing Arrangement	SCPPA	
Total Cost to DWP	A maximum of $139.95M	
Annual DWP payment	$10.10M	
Project Status	Signed, under construction	

MILFORD WIND II

Unsigned, in negotiation

Technology	Location	Online Date	Capacity (MW)	Generation Cost ($/MWh)	Wheeling and Integration Cost ($/MWh)	RPS Contribution (% of 2014 Net Sales)
Wind	Beaver and Millard Counties, UT	5/1/2010	66	$80	$5	0.52%

Financing Details and Status		Notes:
Counterparty	First Wind	• Modified COD is 10/1/2010, contract term of 20 years, and capacity of 90 MW (89%) • SCPPA prepayment amount is $420M, LADWP's share is $373.8M • LA City Council has not approved any RPS projects since September of 2009 pending resolution of LADWP's ECAF increase request • Project capacity share is as follows: LADWP – 65.17%, Pasadena – 9.95%, Anaheim – 24.88%; LADWP has option to receive part or all of Anaheim's share of output • Scenario I, Prepayment: $89.91/MWh excluding RECs and transmission costs, environmental attributed $16.50/MWh; Scenario II, Prepayment with EBO: $89.76/MWh excluding O&M and RECs
Project Manager	LADWP	
Contract Structure & Term	Prepayment, 20 years, two scenarios	
Financing Arrangement	SCPPA	
Total Cost to DWP	Scenario I: $12.3M/yr for 20 yrs if BO not exercised or $259.9M total over 20 yrs Scenario II: $12.4M/yr for 20 years or $260.1Mif purchased exercised at 7th, 8th, 9th, or 10th year.	
Annual DWP payment	n/a	
Project Status	Unsigned, in negotiation	

MILLER RANCH WIND

Unsigned, in negotiation

Technology	Location	Online Date	Capacity (MW)	Generation Cost ($/MWh)	Wheeling and Integration Cost ($/MWh)	RPS Contribution (% of 2014 Net Sales)
Wind	Klickitat County, WA	10/31/2010	150	$85	$28	1.52%

Financing Details and Status		Notes:
Counterparty	Northwest Wind Partners LLC	• Modified COD of 12/31/2010, contract term of 20 years, capacity of 100 MW (67%) and a cost of $76 • LA City Council has not approved any RPS projects since September of 2009 pending resolution of LADWP's ECAF increase request • SCPPA prepayment amount is $157M, thus LADWP's share is $105M • If the project developer is not able to secure financing, LADWP will be in the buyout position rather than prepay position, which is expected to be larger than the prepay amount.
Project Manager	LADWP	
Contract Structure & Term	20 years	
Financing Arrangement	SCPPA	
Total Cost to DWP	n/a	
Annual DWP payment	n/a	
Project Status	Unsigned, in negotiation	

LADWP BIOMASS

On hold

Technology	Location	Online Date	Capacity (MW)	Generation Cost ($/MWh)	Wheeling and Integration Cost ($/MWh)	RPS Contribution (% of 2014 Net Sales)
Biomass		12/31/2009	3	$75	$0	0.09%

Financing Details and Status		Notes:
Counterparty		• Note that this project is included in the LADWP Reference Case but is no longer expected to proceed.
Project Manager	SCPPA	
Contract Structure & Term	30 years	
Financing Arrangement		
Total Cost to DWP		
Annual DWP payment		
Project Status	Signed, in negotiation	

NILAND SOLAR

On hold

Technology	Location	Online Date	Capacity (MW)	Generation Cost ($/MWh)	Wheeling and Integration Cost ($/MWh)	RPS Contribution (% of 2014 Net Sales)
Solar	Imperial County, CA	12/31/2009	55 MW	$120	$35	0.53%

Financing Details and Status		Notes:
Counterparty	Niland Solar Farm LLC	• Note that while this project was included in the LADWP Reference Csae, it was disapproved by the City Council on Dec 16, 2009 and has been put on hold and may not proceed. • Scenario I: $15.3M/yr for 30 years Scenario II: At start of 8th year, LADWP to purchase Niland for $165M and $1M annual O&M Scenario III: Total cost of plant could amount to $323M including the costs of the first 9 years of PPA
Project Manager	LADWP	
Contract Structure & Term	PPA, 30 years, three scenarios	
Financing Arrangement		
Total Cost to DWP	Up to $323M	
Annual DWP payment	See notes	
Project Status	Unsigned, on hold	

APPENDIX C: LIST OF INTERVIEWS

C.1 LADWP INTERVIEWS

During the course of this project, PA Consulting conducted interviews with multiple staff within the Department of Water and Power. These interviews served to validate and explain data provided by the Department.

Table 31: List of interviews

Interviews with LADWP staff			
Interview	*Area/Title*	*Subject*	*Date(s)*
Ben Truong	Financial Analysis	Project coordination and Financial plan	Multiple
Jimmy Lin	Financial Analysis	Financial plan, sensitivities, detailed model review	Multiple
Jeff Peltola	CFO	Financial plan	Multiple
Greg Black	Rates and Budgets	Financial plan	Multiple
George Chen	Rates	Rate Design	Dec 3, Jan 13
Mario Ignacio	Assistant CFO & Treasurer	Financial ratios and debt	Dec 8
Bill Engels	Coal Supply	Coal procurement	Dec 9
John Aguilar	Coal Supply	Coal procurement	Dec 9
Robert Pettinato	Natural Gas	Gas procurement	Dec 10
Michael Webster	Renewables	Renewables	Dec 15
Brad Packer	Operations	Renewables	Dec 15
Mo Beshir	Integrated Resource Planning	Transmission/IRP	Dec 15
Tom Gackstetter	Demand Side Management	DSM and EE	Dec 15
Brian Koch	Renewables	Renewables contracts	Dec 17, Jan 13
Robert Espinosa	Renewables	Renewables contracts	Jan 13
Mike Cockayne	Rates	Demand forecasting	Jan 28

APPENDIX D: LIST OF DOCUMENTS

D.1 DATA REQUEST

The following is a list of documents gathered from LADWP as part of this study. Additional public documents and references were gathered independently and are referenced as footnotes throughout the report.

Table 32: List of documents

Topic	*Description*	*Files*
ECAF	ECAF presentations and packages	ECAF Board Letter_111909 rev2 ECAF Presentation Brief 11232009COOREVISIONS ECAF Question and Answer – Nov 19 2009 ECAF Resolution – Nov 19
	ECAF data for various cases and dates	ECAF Breakdown 2009-11-19_ Board Package with RPS@20%) ECAF Forecast_Support Details ECAF Rate Outlook thru 1314FY Fin_PS_ 2009-12-10_ECAF effective April 09 ECAF Breakdowns 2009-12-10 ECAF forecast_support details 2009-12-10 ECAF Breakdowns_Approved 0910FY Budget Case 2010NS_RPS20Pct 2009-10-30 Actual GWh and Expense FY03-FY09 Resource stacking 2009-05-28 2010NS_Native Load_Approved Budget 2010WS_wwholesale_Approved Budget 2008 NS (Native Load Only) 2007-05-29 PS Fin Plan Rating Agency 11-19.pdf
	Testing of power simulation model performance	Backcast of Fuel Expense_0304FY thru 0910FY
Economy Purchase	Model for projecting purchase volume and price	EconPurch Model (Budget2010)
Natural Gas	Price outlook	Fuel, Emission Price 2009-11-20
	Contract summaries	Contract Status 11-25-09 Contract Status FP 11-25-09 Email from Bob P_112509 Pinedale Allocation 6-09 XXXXXXX 1-Year NAESB XXXXXXX 5-Year NAESB
	Historical gas transactions 2007 through 2009	PA Gas Transaction 12-10-09
	Pinedale	Pinedale Cost Forecast 12-10-09 Pinedale Reserve Forecast 12-10-09
	Hedging	Hedging Summary 2009-09-16 Natural Gas Hedging Authority GCAR 2009-08-11 GCAR 2009-08-12 Natural Gas Transactions FY 09-10 Natural Gas Transactions FY 10-11 Natural Gas Transactions FY 11-12 Natural Gas Transactions FY 12-13

Topic	*Description*	*Files*
Natural Gas		Natural Gas Transactions FY 13-14 MTM Porfolio 2009-10-15
	Hedging counterparty information	ISDA Contracts Information.xls ISDA Counterparty Ratings and Credit Exposure Info ISDA and Powerex Contracts- Credit Scenarios
Coal	IPP	Email from Bill Engels_112509 IPP Coal Contract Summary Sheet Re-issuance of coal price projection KPMG memo to file – IPP deferred revenue June 1 2005 LADWP board budget memo – June 21 2005
	Navajo	070512 Portions of CSA and MOU for extension Amended Navajo-Peabody Coal Supply Agreement 1987 Memorandum of Understanding (NGS)
	Costs and debt projections	IPP and Navajo Coal Related Info IPP Debt Service Pro-rata calculation 2009-04-07
Nuclear	Ownership	Coal Nuclear Ownership Percentage 2009-12-22
	Cost forecasts	PV forecast Jan 09 PV SCPPA and PV Costs 2009-03-24
	Operational forecast	Palo Verde Capacity Factor
CO2	LADWP assessment of CO2 scenarios	CO2 Impact at Federal Level_2009-12-14 CO2 Impact at State Level_2009-12-11
RPS Summary	Summary cost data for various times and cases	003 RPSProjects_%_GWH_$_111909.pdf RPS Master Table 2009-10-19 (20%RPS, 33%RPS, p90) RPS Master Table 2009-09-06_Approved Budget RPS Master Table 2009-12-06 (20%RPS; 33%RPS, p90)_Updated RPS Main Input Confirmation for Barclays 1-14-10 RPS_%_Gwh_$_$perMWH_2009-12-06 RPSProjects_%_GWH_$_111909.pdf
	Plan for 2008 approved budget	RPS Master Table 2007-05-02 (Budget FY2008)
RPS – Short Term	Contracts and project descriptions	PM09-012 UPL suit PM09-014 CAG UAMPS suit PM08-018 COR GR NOB JUL08 TO DEC09 PM09-018 BUR TEITON NOB Q2Q3Q4 2009 PM09-019 COR GREEN MEAD Q3Q4 2009 PM09-049 CITI PV Q4 09 PM09-058 IBR(PPM) GREEN PV Q4 09 PM09-061 IES GREEN MED Q4 09 Transaction ticket NOV09 LADWP PPA A PWX- BP05-020-A Email from John Hormozi_112509 20091124173759100
Solar	Contracts and project descriptions	Owens Valley Solar offer sheet http://www.LADWP.com/LADWP/cms/LADWP000787.jsp http://www.LADWP.com/LADWP/cms/LADWP008237.xls
Wind	Contracts and project descriptions	Linden Pricing July 6 2009 with 33-3 GCF Final SCPPA Milford II_ITC_3 Tier Escalation 102MW v8 (Internal)

Topic	*Description*	*Files*
Wind		Linden_09-1833_rpt_bwp_7-22-09 MWD_SCPPA_Final Board Letter May 2008 MWD-SCPPA PPA May08 Pebble Springs_PPA_SCPPA UPC-Milford PSA SCPPA-LADWP Execution Copy Final 2 9-24-07 Willow Creek_ PPA 08-2186_rpt_LADWP_8-8-08 Windy Point_Board Letter Windy Point_Layoff Agreement Windy Point_PSA WINDY POINT-FLAT PPA BETWEEN SCPPA AND LADWP 2009 PPM Wind 96 125-77
	Performance	Pacific NW Wind Model 2009-10-08 Wyoming Wind Model 2009-10-08 Tehachapi Wind Model 2009-10-08 Wind Capacity Factor 2009-12-10 RPS Estimate of LADWP Owned RPS resources Pine Tree O&M FYTD vs Budget
Hydro	Performance	Historical Hydro Data 1997-2009
	Contracts and project descriptions	PPA 8-19-09 Tieton Board Letter Final
Geothermal	Contracts and project descriptions	Pre-Paid Phase I PPA_Raser_Draft
Biogas	Contracts and project descriptions	Penrose Landfill Agreement BP 05-012 Bradley Landfill_LADWP No BP 05-014 – Agreement
	Landfill gas purchase transactions	Biogas Transaction 2009-11-23 Biogas ECAF impact 2009-12-10 Atmos Landfill Final Confirm Atmos Landfill Final Confirm #2 Shell Confirm 7-27-09 Shell LADWP Cover 7-27-09 Shell Final Confirm Biogas Transactions 2009-11-23
	Treatment of landfill gas for RPS	Gas Pipeline Memo
DSM	Project plans	EE Pgms Briefing for the Mayor 8-6-09 EE svgs-costs 00-01 thru 08-09 CHARTS Email from Tom Gackstetter_112509
	Budget data	EE 09-10EE Pgm Budget Reductions – ECAF 0910 Metrics Matrix EE 09-10 EE Pgm EOY Estimate 12-7-09.pdf Email from Tom Gackstetter_121409
	AB2021 goals	AB2021 Presentation (TG) 9-04-07 FINAL v2 RKR ltr ctr re AB2021 EE Targets 9-28-07
	Measurement methodology	EE Measure Qualification Methodology
Debt and Financials	Description of debt	LADWP Debt Details 2009-12-21 Commercial Paper Cost of Funds – as of 9.30.09 Debt Service Schedule – Power System Debt Service Schedule – Water System Liquidity Facilities (SBPA)- Program Fact Sheet

Topic	*Description*	*Files*
Debt and Financials		State Revolving Fund Loans Water 2009 Series B and Series C – Debt Service Schedule Power System – Variable Rate Program Fact Sheet Sample Debt Fees
	Data on peers and comps	Moody's Public Power Medians 200804 FitchPublicPowerPeerStudy200906
	LADWP financial advisor memos	Mitigation of LADWP transfer increase – PRAG Gardner Memo Re LADWP Credit Ratings.pdf
	LADWP analysis of downgrade scenarios	Rating Downgrade Impact_2009-12-12
	Historical LADWP performance and debt ratios	Financial History for PA 2010-01-29.xls
Demand	Sales forecasts	Customer Sales Forecast & Revenue Support Details April2009Net LADWP April 2009 forecast document October 2008 Forecast Final 012709 R-1B Cons Rate 04 Rate 26 Rate 87 Rate 91 Rate 94 Rate 95 Rate Other Residential Rate 01, 06, and 86 Forecast and Alloc
	Historical data	Green Power Revenue_12_1_08_11_30_09 Low Income_Lifeline Data
	Residential histogram data	Power Monthly Residential Usage by Range_Rate_Zone
Rates	Current rate descriptions	Electric Rates-Ordinance 180127(Approved Aug2008) Rates Classification Scheme
	LADWP analysis of rate restructuring	Charts Item 22 Email From George_112309 ResDesign Model
	Updated LADWP analysis for April 1 rate change	PA Audit File (Jan 14) residential restructure 011410.pdf
	Historical rate information	Rate ordinance 168046 Email from George C_121509 17H PA Data Request rate restructure board packag april 25, 2008.pdf
	LADWP presentations on past rate restructurings	Proposed Tiered Rate Structure Temperature Zone Analysis April 22 2008 - facts on rate increases and restructuring
Budget Cuts	Description of cuts and cost reduction efforts	Cost Reduction Efforts 2009-12-10 Board Letter 2009-10 Budget Amendment_121609 LADWP Budget Cut Summary_121609_Board Package 2009-10 Budget Amendment 122209_v2
	Budget cut details	LADWP Capital Budget Cuts_120709 Decreased Labor costs_120709

Topic	*Description*	*Files*
	Additional scenarios	Cuts if ECAF increase denied 2009-12-12
Expenses	Detailed capital and O&M expenditures	Power_Category_FI Power_Category_FI_Job
Operations	Outage data and projections	2009-12 - Ten Yr Unplanned Outage Data for FSO 2009-03-Outage-Rates-Final-to-FSO(R0 03-16-09).xls
Transmission	Description of key transmission projects	PA Request
	Outlook for costs	Cost Deprecation Debt Service of RPS Transmission Transmission Cost

D.2 SENSITIVITY FILES

In addition, LADWP assisted in evaluating 13 separate scenarios, or sensitivities, as part of the PA analysis. PA prepared the description of each sensitivity and financial forecasts were generated using LADWP's financial model. For each scenario, a complete set of ECAF financial data was generated. The results from ten of these sensitivities judged to be most critical were presented in sections 6 and 7 of this report. The final three sensitivities were later revised or were judged to be not critical to the final report findings.

Table 33: List ot sensitivities

Sensitivities	
Case description	***LADWP file name***
Reference Case	PA Post Budget IPP Corrected
Stress Case	PARevisedHighCase
High RPS prices	PAHighRPSCost
Historical Peak gas	PAVeryHighGas
Extended Palo Verde Outage	PAXtdOutage
CO2 - AB32 (approximately $40/ton)	PABasePlusCO2Cost
CO2 - HR2021 (approximately $20/ton)	PABasePlusCO2Cost-II
RPS frozen at 2008 levels	PA No RPS
RPS frozen Dec 2009	PA No More RPS
25% case based on 7/09 LADWP budget with updated project assumptions	PANew25PctRPS
Stress Case (later revised to include higher RPS costs)	*PA High Case*
25% case based on 7/09 LADWP budget without project updates	*PABudgeted25PctRPS*
Stress Case with RPS frozen Dec 2009	*PA High Case No More RPS*

The list of files generated for each of these cases is detailed below. These files contain the detailed cost and performance information required to perform the analyses described in sections 6 and 7:

Table 34: Files provided for each sensitivity

Files prepared for each case
ECAF Breakdowns 2009-12-30
ECAF Forecast_Support Details 2009-12-30
Fin_PS 2009-12-30 ECAF at 0.1 Cts
Fin_PS 2009-12-30 ECAF at 0.5 Cts on April 2010
2010NS_PAPostBudget 2009-12-30
2010WS_PAPostBudget 2009-12-30
RPS Master Table 2009-12-30 (20%RPS; 33%RPS, p90)

APPENDIX E: DEFINITION OF LADWP PEER GROUP FOR FINANCIAL ANALYSIS

Table 35: List of utilities selected for peer analysis

Utility	Current Fitch Rating	# of Customers
San Antonio (Texas) (CPS Energy)	AA+	673,980
Chattanooga - Electric Power Board (Tenn)	AA	157,227
Colorado Springs Utilities	AA	208,054
Lincoln (Neb.) Electric System	AA	126,033
Memphis (Tenn) - Memphis Light, Gas, and Water	AA	412,204
Nashville (Tenn) - Electric System	AA	353,187
Omaha Public Power District (Neb)	AA	335,990
Orlando Utilities Commission (Fla)	AA	188,284
Springfield (Mo) - City Utilities (electric)	AA	106,251
Anaheim Public Utilities Department (Calif)	AA-	111,543
Austin Combined Utility System (Texas)	AA-	390,361
JEA (Fla) Electric	AA-	413,644
Riverside Public Utilities	AA-	105,397
Snohomish County Public Utility District #1 (Wash)	AA-	315,437
Tallahassee (Fla) Energy System	AA-	112,152

Sources: FitchRatings, EIA form 826 data.

APPENDIX F: COMPARISON OF CALIFORNIA RENEWABLES PLANS

Below is a comparison of renewable plans submitted by California IOUs as part of their latest RPS compliance report filings with the California Public Utilities Commission in August 2009.

Figure 52: Summary of LADWP Renewables Plan (Source: LADWP)

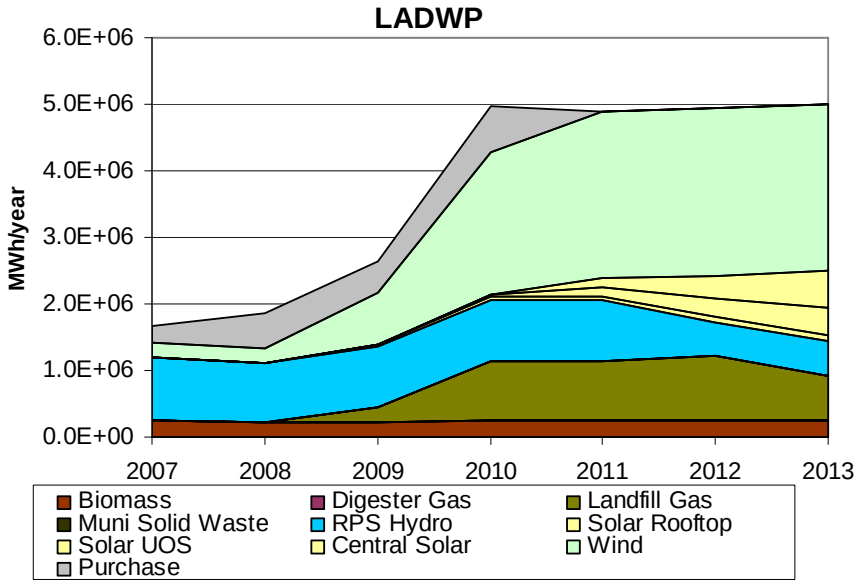


Figure 53: Renewable Plan for PG&E (Source: RPS Compliance Report)

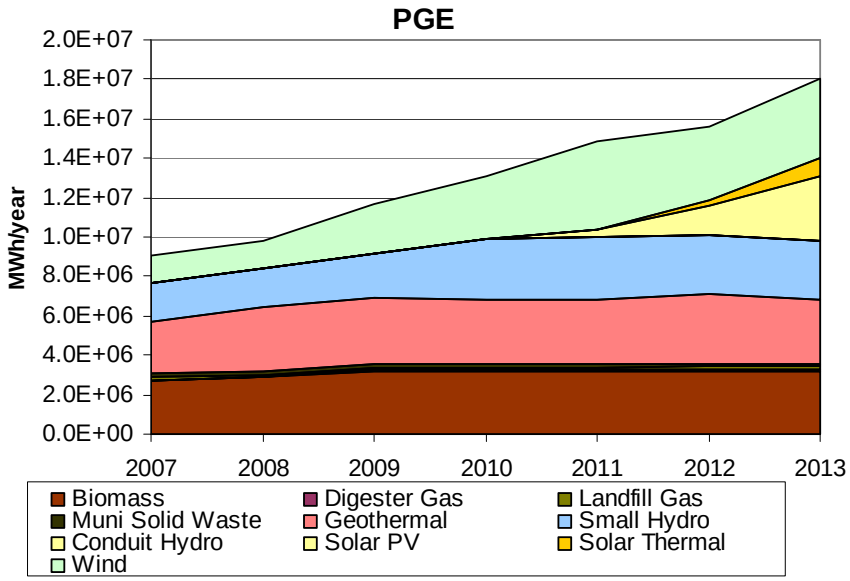


Figure 54: Renewable Plan for SDG&E (Source: RPS Compliance Report)

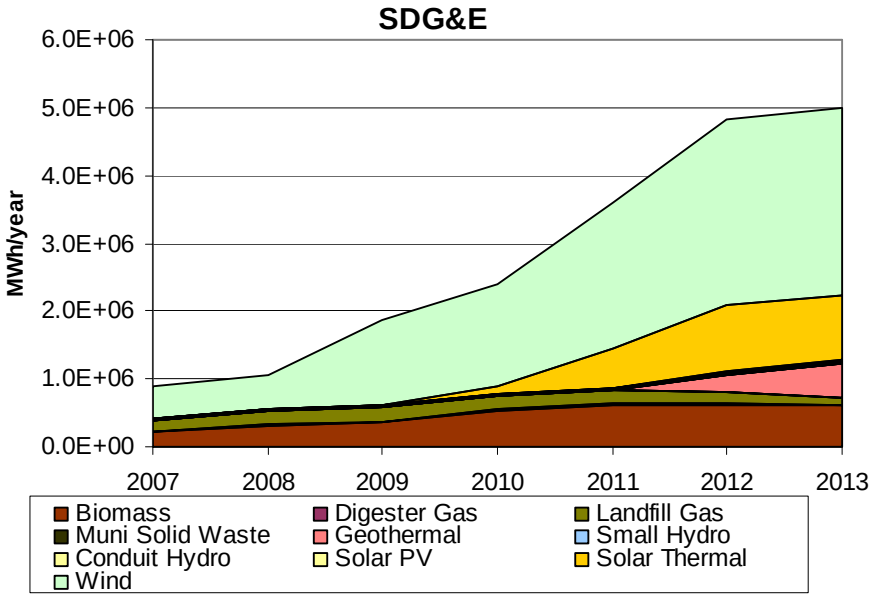


Figure 55: Renewable Plan for SCE (Source: RPS Compliance Report)