March 2003

Clean and Affordable Power

How Los Angeles can reach 20 percent renewables without raising rates

The Center for Energy Efficiency and Renewable Technologies

Environment California Research & Policy Center

Clean and Affordable Power:

How Los Angeles Can Reach 20% Renewables *without* Raising Rates

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Report Produced by:

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and

The Center for Energy Efficiency & Renewable Technologies

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Executive Summary

This study represents an independent analysis of prospects and means for implementing a Renewable Portfolio Standard (RPS) of 20% by 2017 at the Los Angeles Department of Water and Power (LADWP).

When taking into account the declining cost of renewable energy and the steadily rising cost of natural gas, along with the benefits of maintaining a diversified energy portfolio containing fixed price resources, investing in renewable energy becomes a smart business decision. This study finds that implementing an RPS will not raise rates for LADWP customers, and may in fact save money in the long run.

Establishing a renewable target of 20% by 2017, the level recently established by state lawmakers for investor owned utilities, will enhance reliability and may prevent future rate increases by diversifying away from natural gas.

Moving to 20% renewable energy will require 6,209 GWh of generation from renewables by 2017, based on an expected net energy load of 31,040 GWh. This report compares the cost of meeting that amount of energy sales through renewable energy with the cost of meeting it through conventional energy, and finds that renewables can be substituted at comparable costs.

Principal Findings of this Report:

1. There is a good chance that renewable energy will not impose *any* additional costs above conventional energy sources. Taking the conservative numbers used in this report, it is possible that factoring in renewable energy will lead to a net *savings* for Los Angeles. Expected costs for conventional energy sources run from \$44/MWh to \$67/MWh. These are conservative numbers, and do not account for the risk of future carbon regulation. Meanwhile, expected costs for renewable energy sources run from \$38/MWh (10-year landfill gas project) to \$52/MWh (20-30 year geothermal or wind project).

2. The report also evaluates the *Worst-Case Scenario* in which renewable energy costs exceed those for conventional energy, and concludes that these costs would average no more than \$5/MWh of above-market rates over the first 10 years of an RPS. This equates to \$11 million/year, or 0.49% of LADWP revenues at current rate levels. For illustration, if these costs were funded from rate increases alone, the average consumer would see their monthly bill rise by only 38.5 cents.

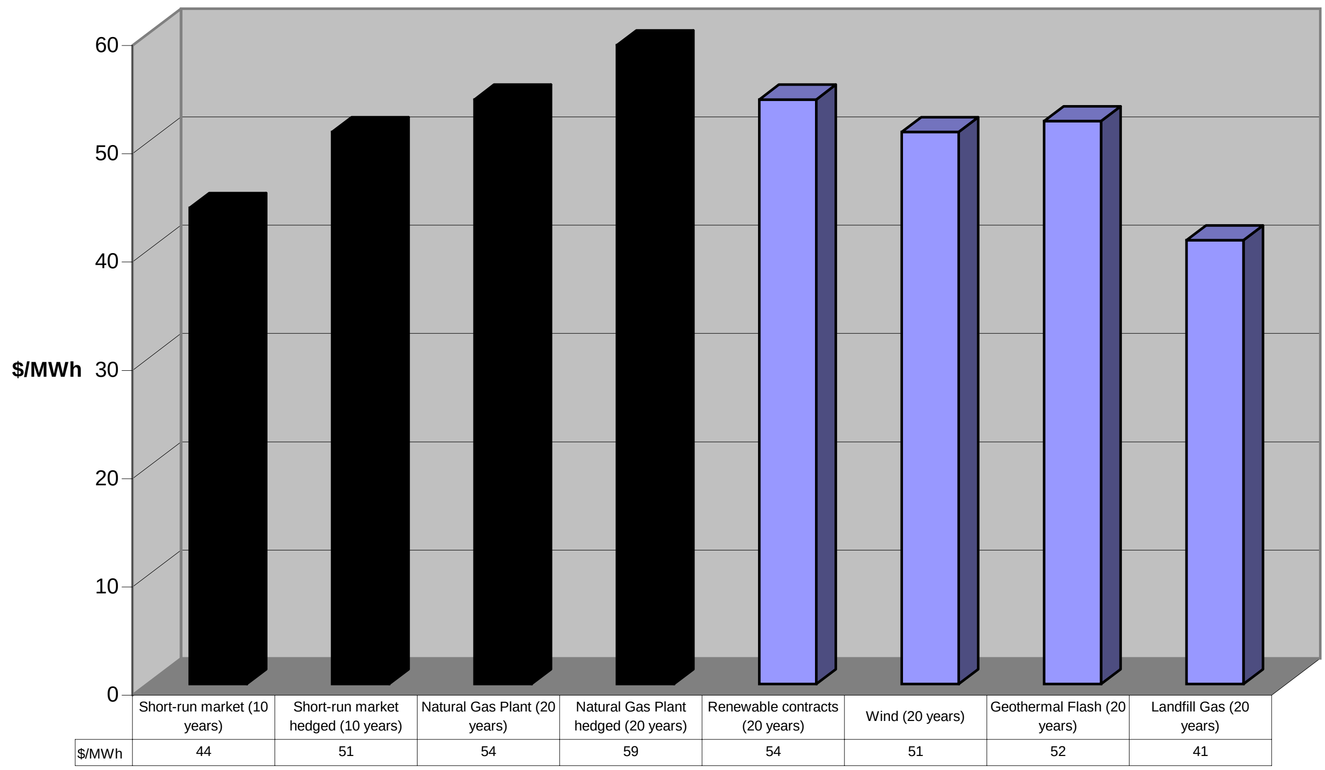
3. DWP has numerous options for funding any worst-case scenario additional costs attributed with meeting a 20% RPS by 2017 without raising rates, including:

    - Reallocate 14% of public goods funding away from lower priority programs, including research, development, and demonstration (RD&D);
    - Slightly increase operations and maintenance (O&M) productivity over time;
    - Apply profits from the sale of 10% of the Mohave coal plant toward the RPS;
    - Accept a 3-4% reduction in equity return, which was \$257 million in 2001-2002;
    - Change the line rate for connecting new construction to the energy grid to value energy efficiency.

4. Meeting a 20% by 2017 standard may save Los Angeles money. Recent forecasts project the cost of natural gas to rise steadily over time. In this

climate, fixed-price renewable energy resources are projected to have prices below natural gas resources in the long run. Furthermore, renewables serve as a hedge against natural gas prices, providing portfolio diversity and actually decreasing demand for natural gas. LADWP currently relies on natural gas power plants to generate 25% of its energy.

Figure 1: Cost Comparison: Natural Gas vs. Renewable Energy



Conclusion

In sum, LADWP can generate and provide the energy Los Angeles needs to live and work from renewables without materially impacting its financial outlook. The City should move ahead quickly to increase its use of renewable energy to 20% over the next 15 years with a minimum 1% ramp up each year, and should buy this energy like any other conventional generation resource. Doing so will provide Los Angeles with added energy reliability, price stability, and independence from fossil fuels.

I. Introduction

Support for greater use of renewable energy has increased steadily throughout California in the wake of the recent energy crisis. An over-dependence on fossil fuels, natural gas in particular, has made the state vulnerable to both natural fluctuations in the price of this finite resource as well as to energy companies who manipulate the energy market for financial gain.

Furthermore, many businesses and energy planners are anticipating increases in the environmental cost of fossil fuels, particularly coal, due to climate change regulations.

In this context, renewable energy has become an attractive alternative to conventional, fossil-fuel resources. By increasing investments in renewable energy, utilities can generate needed electricity and protect against price spikes and blackouts. By diversifying utility energy portfolios, a renewable portfolio standard saves consumers money in the long run, while spurring new industries and job growth. And, renewables help address California's serious air quality problems and reduce dangerous global warming gases.

Although Los Angeles was spared the direct impacts of the energy crisis, Angelinos have equal reason to look to renewables, based on price, stability, and environmental concerns. Recent volatility and price spikes in natural gas along with long-range forecasts have made renewable energy an excellent substitute to over-dependence on fossil fuels. From a reliability standpoint, a diverse energy portfolio that includes electricity from many different sources protects against the possibility of a future energy crisis.

Finally, as an environmental leader and the operator of the country's largest municipal utility, Los Angeles has a responsibility to be forward-thinking on alternative energy solutions. Renewable energy will help the city reduce air pollution and meet targets to limit carbon dioxide, while spurring a fast-growing alternative energy industry that the country desperately needs.

For Los Angeles, the pertinent question is how to set a course for this shift from the current, polluting energy to clean, efficient renewable energy. Much concern has been raised over the cost of such a shift, and how LADWP could fund a renewable energy portfolio standard equal to the commitment established by the state – 20% by 2017 – while continuing to offer competitive rates.

In response to these concerns, this report examines the expected future costs of conventional energy and the costs of renewable energy. This study finds that the costs of renewables are comparable to those of conventional sources, and that meeting the statewide renewable energy standard may even result in a net cost savings for consumers.

Given that renewables have achieved cost competitiveness with conventional energy, renewable energy can be funded in exactly the same method as LADWP funds other energy sources, without raising rates. In the short-run, while excess capacity exists, new renewable energy generation will offset costs and allow LADWP to sell excess power, reduce market purchases, scale-down usage of natural gas plants, and sell or retire the oldest and dirtiest plants currently in operation. In the long run, ramping up renewables will give LADWP the ability to meet increased future demand with clean, reliable renewable energy sources.

Even in the Worst-Case Scenario in which renewables cost more than conventional energy sources, LADWP is well equipped to meet these above-market costs. The costs are projected to be an extremely small percentage compared to LADWP's total electric revenues and the utility has numerous methods to meet these small costs without incurring a rate increase.

Among the options available to LADWP, the utility can change the amount of money charged when connecting new construction to its energy grid. It can also apply a small percentage of money from the current public benefits program or from the sale of part of its share of the Mohave Generating Station. Other options include slightly increasing the productivity of operations and maintenance budgets, reducing its overall equity return, and refinancing debt.

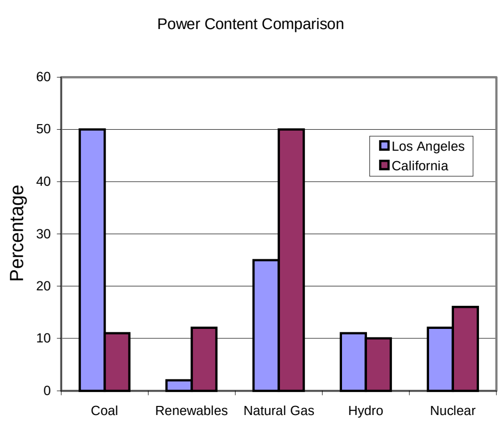
Even if LADWP applied the Worst-Case Scenario costs of the RPS to rates, an unlikely and unnecessary option, the impacts would be minimal. At no point in time would the cost of the RPS ever exceed 0.07 cents/kWh, which means that an average consumer would never see more than a 38.5 cent increase on a monthly bill.

In sum, the shift to a renewable energy portfolio can be achieved in Los Angeles without raising rates, and may help protect the city from the rising and volatile price of natural gas in the future.

II. Amount of Renewables Needed to Reach 20% by 2017

Last fall, the state initiated a requirement for investor owned utilities to achieve an energy portfolio containing 20% renewables by 2017, with an increase of at least 1% each year. The following analysis calculates the amount of renewables needed for LADWP to achieve the same level of renewable energy.

Figure 2: Los Angeles and California Energy Portfolios



As seen in Figure 1 above, Los Angeles currently generates 50% of its energy from coal plants located outside of California. 25% of its energy load comes from natural gas plants in the Los Angeles Basin, with another 12% from nuclear energy and 10% from hydropower. To reach 20% renewables by 2017, LADWP would need to generate or purchase 6209 GWh of renewable energy, a number computed by using LADWP's March, 2002 demand forecast. [1] An illustrative trajectory to reach that goal is shown below (Table 1). This trajectory involves buying an average of 1.3% of load in new renewables in each year through 2017, when 20% is reached. The analysis assumes a baseline of 2.4% of existing renewables.[2] The net energy load is the total amount of energy used by Los Angeles, while the new purchases baseline is the amount of new renewable energy added to the portfolio in a given year to meet the proposed 20% RPS by 2017.

Note on Units

A Megawatt (MW) is a unit of measurement indicating the maximum amount of electricity that a plant can deliver. This is the standard measure of the generating capacity of a power plant. It is also used to determine if the total generating capacity on the grid is enough to satisfy demand at any one time. Megawatt-hours (MWh) are a unit measuring the total amount of electrons produced over some time frame. A 50 MW power plant operating at full capacity for one hour produces 50 MWh of electricity. This is the appropriate unit for talking about how much of the city's electricity is produced by various sources in a given time frame. To measure how much a plant operating at full capacity would produce in one year, simply multiply the capacity by the number of hours in a year (50 MW x 8,760 hrs/yr = 438,000 MWh/yr). 1,000 MWh equals one GWh. The plant's "capacity factor" is the expected energy production of the plant compared to the hypothetical production if it ran 100% of the time.

[1] LADWP, March 2002 Retail Electric Sales and Demand Forecast.

[2] Current renewables percentage provided by LADWP staff at the LADWP Board Workshop on the Status of the Renewable Portfolio Standard (December 3, 2002). This figure does not include LADWP's recent wind acquisition.

The CEC Staff also prepared a load forecast for LADWP through 2013.[3] Extrapolating beyond 2013 to 2017 at the same growth rate as 2008-2013, the CEC's net energy forecast is 30,253 GWh, yielding a renewable component of 6,051 GWh, a difference of about 2.5%, which is not material to this analysis. In both forecasts, the growth in load from 2002 to 2017 is approximately 5,000-5,500 GWh.

The net result is that a minimum of 250 GWh (1% of load in an early year) and an average of 350-400 GWh per year of renewables would need to be added in each year to reach the goal. For comparison, if the average amount were provided purely from wind (at an assumed 35% capacity factor) it would be 114-130 MW nameplate per year. If provided by a baseload technology at a 90% capacity factor (geothermal or biomass), it would be 44-51 MW nameplate per year. A mix of wind and other technologies would be intermediate.

It is appropriate to talk about the need for new capacity because LADWP shows capacity needs later in this decade (based on a 15-20% reserve margin), as demand grows to meet existing capacity of about 7000 MW.[4] In addition, a large block of LADWP's capacity is extremely energy-limited (Castaic pumped storage) or is made up of inefficient peaking natural gas generators.

For example, despite a near-term capacity surplus, LADWP is proposing to expand its fossil fuel investments either through building new combined cycle generation or by keeping the Mohave powerplant in Laughlin, Nevada, in operation. The LADWP is also conducting a feasibility study of a third coal unit at the Intermountain site in Utah.

As Table 1 demonstrates, much of the energy generated from renewables would go to meet expected increases in LADWP load, especially in the long-term. In the short-term, renewable energy could be used to offset market purchases, or facilitate excess energy sales. It could also help expedite the retirement or sale of LADWP's oldest and dirtiest power plants, or reduce the City's natural gas consumption.

Table 1: Renewable Growth Under Proposed Renewable Portfolio Standard (GWh)

	Net Energy Load	Renewable component	% of sales	Annual New Renewables Baseline
2002	25,433	610	2.4%	
2003	24,867	933	3.8%	323
2004	26,392	1,276	4.8%	343
2005	26,947	1,627	6.0%	350
2006	27,379	1,983	7.2%	356
2007	27,829	2,344	8.4%	362
2008	28,296	2,712	9.6%	368
2009	28,709	3,085	10.7%	373
2010	29,062	3,463	11.9%	378
2011	29,353	3,845	13.1%	382
2012	29,606	4,230	14.3%	385
2013	29,892	4,618	15.5%	389
2014	30,158	5,010	16.6%	392
2015	30,416	5,406	17.8%	395
2016	30,720	5,805	18.9%	399
2017	31,040	6,209	20.0%	404

[3] California Energy Commission Staff, California Energy Demand 2003-2013: Draft Report. Publication No. 100-03-002SD, Filed in CEC Docket 02-IEP-01. February 11, 2003, pages A-4 and B-4.

[4] Compare peak demand forecast in LADWP, March 2002 Retail Electric Sales and Demand Forecast to the dependable capacity of 7052 MW shown in Energy Services Department of Water and Power City of Los Angeles, Report and Financial Statements and Required Supplementary Information, June 30, 2002, page 8.

III. Estimate of Costs of Conventional and Renewable Power

The following is an analysis of the benchmark prices for conventional energy resources, natural gas and coal, and those of renewable energy resources such as wind farms, geothermal plants and biomass landfill projects.

Conventional energy prices can be analyzed in two ways: (1) short-run market prices until a need for capacity appears, and (2) the cost of new generation after capacity is needed.

Renewable energy prices can be analyzed by examining the information presented in project bids, and by looking at specific recent municipally financed renewable energy projects.

The following analysis shows that renewable and conventional prices are extremely comparable, and that investing in renewables may result in long-term savings.

A. Short-Run Energy Market Prices

One way to generate a benchmark price of conventional energy is to examine the short-run energy market and forecast its variations over time. The value of energy on the short-run market is dependent on several elements including: (1) the overall dispatch and supply balance of the western U.S. and (2) the price of natural gas. Energy price forecasts are largely confidential, but the California Energy Commission occasionally publishes future energy price scenarios, the most recent for the 2002 Electricity Outlook Report.[5]

The number of powerplants operating has a direct impact on the market price of energy. The CEC created five scenarios related to the number of powerplants that would be on line in future years, with a single gas price forecast. However, the scenario of powerplant availability that the CEC called the "lowest" in 2002 is actually above the CEC's current 2003 forecast of new powerplants in the west.[6] We therefore use the CEC's year 2002 "lowest" forecast as the base case for analyzing future market prices in this analysis, as this most accurately represents the current situation.

The second issue involves the gas price forecast. Current natural gas prices are considerably higher than those used by the CEC in its 2002 report. We show the CEC's 2002 and 2003 forecasts of gas prices below, as well as an "adjusted 2003" forecast that transitions from current spot-market prices in 2003-2004 to meet the new CEC forecast in 2006.[7]

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[5] California Energy Commission, *2002-2012 Electricity Outlook Report*, CEC Publication P700-01-004F, February, 2002, p. 35. See also backup documentation contained in CEC Staff, 2002-2012 Electricity Outlook Report Staff Draft , Powerpoint Presentation to the CEC Electricity and Natural Gas Committee Workshop. December, 11, 2001, page 17.

[6] Compare CEC Staff Electricity Outlook Report Powerpoint Presentation, page 15 with forecasts of new generation in CEC Staff, *Preliminary Electricity and Natural Gas Infrastructure Assumptions*, CEC Publication 100-03-004SD, February 11, 2003, pages 4-20.

[7] The recent CEC gas price forecast (with the exception of 2003) comes from an equilibrium model that does not accurately forecast current prices, projecting a wellhead gas cost of about $3.00/MMBtu in 2003, compared to current wellhead prices in excess of $6. See Richard Ferguson, "Comments of the Center For Energy Efficiency and Renewable Technologies (CEERT) on the December 2002 CEC Staff Paper 'Natural Gas Supply and Infrastructure Assessment'" California Energy Commission Workshop, January 24, 2003. Despite concerns that the model provides too much of a perfect equilibrium and therefore is likely to be low in the long run, we use the CEC's forecast. However, because this forecast has a significant probability of being low, this forecast (even if adjusted in 2003-2005) should be

Table 2: Gas and Electricity Price Forecasts

	Gas Price Forecasts ($/MMBtu)				Electricity Price Forecasts ($/MWh)		
	2002 CEC	2003 CEC	Adjusted 2003	% Increase Over Prev. Forecast	2002 CEC Lowest Gen Additions	Adjusted for Higher Gas Price	% Increase Over Prev. Forecast
2002	$2.99				37		
2003	$3.10	$4.55	$6.00	94%	31	57	83%
2004	$3.21	$4.10	$5.00	56%	29	43	50%
2005	$3.38	$3.94	$4.50	33%	30	39	30%
2006	$3.56	$4.11	$4.11	16%	32	36	14%
2007	$3.73	$4.29	$4.29	15%	34	39	13%
2008	$3.92	$4.50	$4.50	15%	36	41	13%
2009	$4.12	$4.72	$4.72	15%	37	42	13%
2010	$4.33	$4.97	$4.97	15%	39	44	13%
2011	$4.56	$5.25	$5.25	15%	42	48	14%
2012	$4.80	$5.54	$5.54	15%	44	50	14%
2013		$5.83	$5.83				

It should also be recognized that gas prices of less than $4 to $4.50 per MMBtu (adjusted for inflation) over a long period of time are simply not sustainable in light of the major capital investments being proposed in Liquefied Natural Gas and delivery of gas from Arctic sources. Both of these gas sources require extremely expensive infrastructure that can only be financed either through long-term contracts at fixed and relatively high prices or through the expectation of prices high enough to allow a return on these investments.

The CEC also developed information on the relationship between spot market electricity prices and gas prices and found that electricity prices have an elasticity of 0.9 relative to gas prices – i.e., a 10% change in gas prices will cause a 9% change in market energy prices.[8]

From this information, we have prepared a conservative forecast of spot market electric prices (Table 2) to estimate the value of energy from renewables in the absence of a need for capacity. This forecast represents the lowest that energy could be valued; actual prices could certainly range considerably higher. It starts with the CEC's 2002 projections for the lowest amount of generation additions and adjusts the market price forecast upward for higher gas prices. The high prices in 2003-2004 reflect current market prices, and then the forecast transitions to the new CEC forecast in 2006.[9]

The resulting 10-year average market price forecast (2003-2012, using the 2003 Adjusted Gas Price Forecast) is $44/MWh.

We believe that the forecast of electric market prices given here is likely to be conservative for several reasons. First, this forecast of market prices would not yield adequate profit for a new combined cycle

combined with a hedge factor (Section below) if used to compare renewable resources with gas-fired resources.

8 CEC, *2002-2012 Electricity Outlook Report*, page 29.

9 The CEC's 2002 Gas price forecast is calculated from CEC, 2002-2012 Electricity Outlook Report, Appendix A, pp. 120-121. The 2003 gas price forecast is given in CEC Staff, *Comparative Cost of California Central Station Electricity Generation Technologies*: Staff Draft Report, CEC Publication 100-03-001SD, February 11, 2003, Appendix A, page A-1.

generation system to be constructed for spot market use.[10] New generation would have to be committed under long-term contract if this price forecast is correct, in which case the spot market forecast is not an appropriate long-run comparison to use. Therefore, we believe that the estimate of $44/MWh is an absolute lower bound estimate based on the combination of both a low gas price forecast and an electricity price forecast that concludes that new fossil generation will be unprofitable.

B. Cost of New Fossil Fuel Generation

Another method for analyzing the value of renewable energy is to look at the cost of new generation.

1. Cost of Combined Cycle Generation

The cost of fossil fuel-fired combined cycle generation is a critical reference point for LADWP generation. LADWP is conducting several repowers of its existing plants, some of which appear relatively expensive.[11] A new municipal combined cycle plant in southern California is analyzed, using data on the cost of the Southern California Public Power Association's (SCPPA's) Magnolia powerplant from two sources, a recent press release with updated costs[12] and a detailed presentation made to the Pasadena City Council.[13]

Since we are examining a baseload renewable resource cost, the calculation includes only the baseload portion of the combined cycle and excludes duct-firing peaking capacity, which is both cheaper per installed kW and much less efficient in using fuel than the combined cycle and therefore runs at a much lower capacity factor than the base plant. Table 3 gives cost parameters for an unfired combined cycle powerplant.

[10] The CEC's current estimates of required revenue for a merchant plant are $107/kW-year to cover O&M costs, debt service and profit, assuming relatively low plant costs and a relatively leveraged financial structure (CEC Staff, *Comparative Cost of California Central Station Electricity Generation Technologies*, page C-3). A combined cycle operating at 90% capacity factor would yield net revenue of $60-$90/kW-year, assuming an average heat rate of 7000 Btu/kWh and operation 90% of the time.

[11] The addition of 180 MW of capacity at the Valley station was projected to cost $238 million, which provided a total of 500 MW at less cost than a new combined cycle. The 180 MW of new capacity, however, are considerably more expensive than Magnolia. www.construction.com/NewsCenter/Headlines/ENR/20010629a.asp

[12] Magnolia Power Project, California Energy Commission Approves Magnolia Power Project Licensing, March 5, 2003. http://quickstart.clari.net/qs_se/webnews/wed/ch/Bca-magnolia-power.R0kr_DM5.html

[13] City of Pasadena, City Manager, Agenda Report, "Adopt Resolution and Ordinance Approving the Magnolia Power Project Power Sale Agreement…" April 8, 2002. http://www.ci.pasadena.ca.us/councilagendas/2002%20agendas/Apr_08_02/5D1.pdf

Table 3: Combined Cycle Cost Parameters (Magnolia Project)

Cost per kW	$856 per kW[14]
Financing Cost	7.543% of capital cost per year for 30 years principal and interest at 5.04% (SCPPA financing method, including all reserve funds)[15]
Fixed O&M (including Rental)	$7.08 / kW-year[16]
Variable O&M	$2 / MWh[17]
Heat Rate	7200 Btu / kWh[18]
Fuel Prices	Same as Table 3 through 2013 (adjusted CEC figures), rising at 3.5% (inflation plus 1%) after 2013.
Capacity factor	90% (largely baseload)[19]

These figures yield a combined cycle plant cost of $47/MWh for the first year, $47/MWh for ten years levelized; $50 for 15 years levelized, $53/MWh for 20 years levelized, and $59 for 30 years levelized.

[14] $234 million including pollution offsets, less $20 million for duct firing divided by 250 MW without duct firing, from City of Pasadena, Agenda Report, page 4.

[15] $17.65 million per year divided by $234 million, from City of Pasadena Agenda Report, pages 4 and 6.

[16] $2.229 million per year divided by 315 MW (including duct firing) from City of Pasadena Agenda Report, page 6.

[17] Id.

[18] 6800 Btu/kWh for new and clean operation of a combined cycle, with additions for startups, ramping, partial forced outage, degradation between overhauls, and efficiency losses when the temperature exceeds 59 degrees Fahrenheit.

[19] The Pasadena Agenda Package (page 6) shows a capacity factor of 65%, but that was based on total capacity including the duct firing, which would only be used for peaking.

The prices rise over time due to rising natural gas forecasts.

2. Hedging Gas for Combined Cycle Generation

It must also be noted that these combined cycle cost figures are based on gas price forecasts, not fixed prices. One of the major benefits of renewable resources is that they protect ratepayers from gas price spikes through fixed pricing. They also provide physical hedges that reduce the future trajectory of gas prices.

Hedges are not inexpensive. Data provided by Platts and by Lawrence Berkeley Lab both suggest that the cost of hedging gas to obtain a fixed price are in the range of $0.50 to $0.80/MMBtu ($3.50 to $5.50 per MWh at combined cycle heat rates).[20] Southern California Edison, for example, spent approximately $0.80/MMBtu to hedge its exposure to gas costs of its Qualifying Facilities in 2002-2003.

A financial hedge may reduce the exposure to gas prices or spot market power prices for a period of time, but a physical hedge (non-gas resource or efficiency investment) has additional benefits.

1. The lesson of the fall and winter of 2000-2001 is that physical hedges are worth more than financial hedges in the gas market. A contract for gas-fired power as a fixed number of dollars irrespective of gas prices (like Calpine's contracts) hedges against a gas price spike but does nothing to reduce the underlying demand for natural gas. A physical contract for non-gas resources (e.g. renewables) both hedges against the spike and reduces upward price pressure by reducing demand.

2. A second lesson of gas price spikes is that economists often view price excursions as non-recurring events and therefore do not take steps during planning to protect against them. Even when a spike is occurring, the usual advice is for customers to turn the thermostat down, curtail electricity use, and wait out the spike, because nothing can be built fast enough to affect it. Non-gas resources acquired before the price spike would have been far more beneficial, and the true lesson should be to acquire such resources in advance of similar future price spikes.

More importantly when evaluating the difference between physical and financial hedges, the long-run price of natural gas is related to the demand for gas. The Energy Information Administration (EIA) provided powerful evidence to this effect in a recent report relating projections of the future price of gas to the future demand for gas. EIA found that higher demand is consistent with higher long-term prices, with lower demand yielding lower prices.

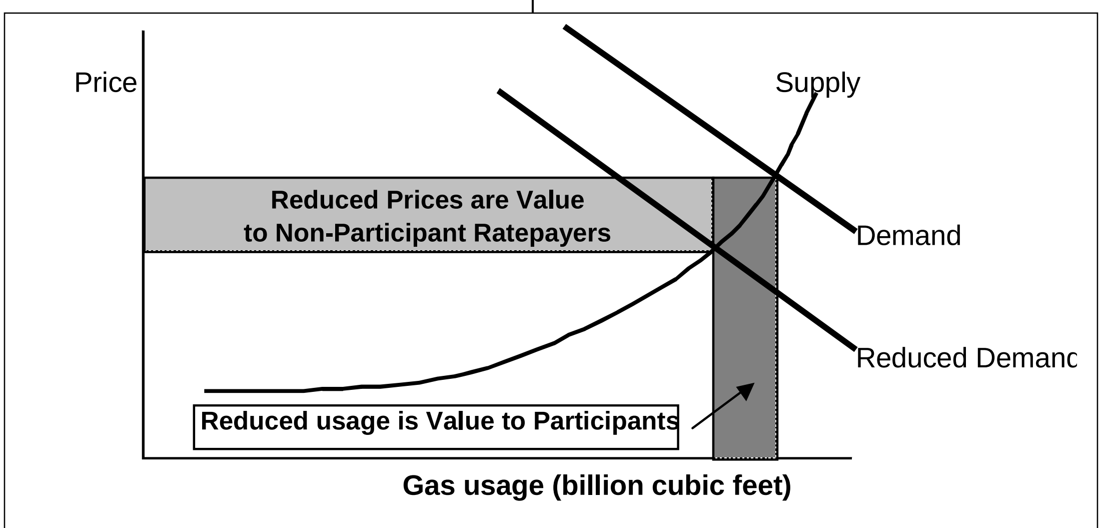
The report specifically found that a national 20% renewable portfolio standard would reduce the use of natural gas by 10% from the base case in 2020. The study also found that the wellhead cost of natural gas would be reduced by 26% from $114 billion to $84 billion per year (2002 dollars in 2020) by

[20] Bollinger and Wyser calculate a hedge cost of $0.50/MMBtu short-term to $0.80/MMBtu long-term. Mark Bolinger and Ryan Wiser, Lawrence Berkeley National Laboratory, "Quantifying the Value that Wind Power Provides as a Hedge Against Volatile Natural Gas Prices," Paper presented at Windpower 2002. Portland Oregon. 2-5 June, 2002. Platt's Research and Consulting estimates a hedge cost for combined cycle generation of $5.20/MWh. Brandon Owens, Platt's Research and Consulting "The Cost of New Gas-Fired Generation: The Value of Renewable Energy Technologies," CPUC Rulemaking 01-10-024, Presentation to Workshop, March 4, 2003, p. 10 Adam Capage and Brandon Owens, Platt's Renewable Power Service, Powerpoint Presentation for Teleconference, February 11, 2003, pp. 9-14.

such an RPS. [21] Buying renewables thus has the strong potential of reducing gas costs not only in the electricity sector, but also reducing the cost of the direct consumption of gas by residential and business customers.

In other words, renewable energy lowers the overall cost of natural gas, which means the market price does not convey all the information on which consumption decisions should be made. By reducing the long-term demand for natural gas, the long-term price can be reduced, but a large portion of the reduction will flow to society as a whole rather than to the customers who actually change their usage. The chart below shows the effect on a conceptual basis.

Figure 3: Market Price and Value of Gas Demand Reduction



While the EIA estimated in 2002 that the wellhead price of gas will be in the range of $3.22 (year 2001 dollars) in 2020, the impact of reducing or increasing consumption as it affects the gas price is in the range of $8 to $10 per MMBtu of increased or decreased demand. [22] Table 4 (using figures taken from pages 54-55 of the EIA report) provides a more detailed analysis in support of this statement.

[21] Energy Information Administration, Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, and Mercury and a Renewable Portfolio Standard. July 16, 2001, p. 54. It shows that a 20% renewable portfolio standard by 2020 is projected to reduce gas consumption by 11% in 2020 and to reduce the wellhead price of gas by 17% in 2020. Similarly, a set of pollution strategies to reduce emissions of a range of pollutants is projected to increase gas consumption by 9% and increase wellhead gas prices by 17% by 2020. The price elasticity to changes in supply/demand is thus about 1.6 to 1.7 according to EIA.

[22] As discussed above, the EIA 2002 Forecast no longer represents a reasonable gas price forecast. However, the analysis presented here that uses this forecast illustrates the concept of a supply curve – lower demand results in considerably lower prices, with significant savings to consumers, well above the market price of gas.

Table 4: Relation of Gas Demand and Gas Prices from Energy Information Administration

	Integrated SOx NOx, CO2 and Hg reduction case	EIA reference case	20% renewable portfolio standard
domestic production (trillion cubic feet)	30.29	29.47	26.09
imports (trillion cubic feet)	8.16	5.82	5.38
total gas supply (trillion cubic ft.)	38.45	35.29	31.47
wellhead gas price (2001 $/MMBtu)	3.74	3.22	2.66
change in supply from previous case		-8.2%	-10.8%
change in price from previous case		-13.9%	-17.4%
price elasticity from previous case		1.69	1.61
wellhead gas cost (price X supply) $ billions	143.8	113.6	83.7
difference from previous case ($ billions)		30.2	29.9
change in supply/demand from previous case (Tcf)		3.16	3.82
value of gas demand reduction ($/Mmbtu)		$ 9.55	$ 7.83
excess of demand reduction value over price		$ 6.33	$ 5.17
demand reduction value as % of price		296%	294%

Note: calculation based on 1000 Btu/cf

In sum, when buying renewable energy, a hedge value of approximately $5/MWh should be ascribed for a fixed price combined cycle renewable contract in addition to the direct costs outlined above, giving a total renewable benchmark of about $55/MWh over 20 years.[23]

3. Coal Generation Alternatives

A benchmark for renewable energy can also be generated by examining the cost of LADWP coal plants. In addition to gas-fired generation, LADWP has two coal alternatives that could involve large future investments. The first involves the refurbishment of Mohave. Southern California Edison has estimated that the installation of pollution controls and refurbishment of this plant and its associated fuel delivery system will cost from $49 to $56 per MWh.[24] LADWP's costs would probably be about 10-15% less due to municipal financing of the plant. The cost differential at this rate is this small because the complete rebuilding of water and fuel transportation systems would be financed by the coal operator through an increased fuel cost rather than through municipal bond

23 Short-run energy prices are also forecast, and a gas hedge would have a cost of about $6 to $7 per MWh (slightly higher because the market price assumes use of gas at a lower efficiency than a combined cycle plant) to lock in a fixed price for ten years.

24 Harold Ray, Prepared Testimony, CPUC Application 02-05-046, Exhibit SCE-1, May, 2002, pp. 16-18.

financing. The ability to actually rebuild the project is questionable due to extremely large uncertainties surrounding the availability of water and the quality of coal to be burned. The cost may also be underestimated because of water issues and the potential need for future capital additions not included in the estimate.

The second involves the construction of a third unit at Intermountain in Utah. Cost data on this third unit are confidential.[25] However, if we assume that the unit costs approximately the same as the existing units, escalated for inflation, the cost of this new unit will be in excess of $50/MWh by the time it could come on line in 2008.

4. Future Environmental Costs of Fossil-Fuel Resources

In addition to providing a hedge against gas prices, from a strictly business perspective, renewable resources also provide a hedge against future environmental costs associated with conventional, carbon-rich fossil-fuel resources. This analysis has not attempted to include in the costs of conventional resources any future costs from regulation of carbon dioxide and other greenhouse gases.

However, given that there are bills currently pending before Congress that could create a cost for greenhouse gas emissions, it would be both incorrect and imprudent to consider that the expected value over the next 20-30 years of these costs is zero even from a strict financial perspective. Even though the costs are zero now, real costs could potentially be incurred later. Thus, the expected value of future costs is greater than zero.

As a result, LADWP should be valuing the risk of higher costs of global climate change when examining its portfolio of resources. For example, PacifiCorp's recent Integrated Resource Plan (IRP) evaluates the cost-effectiveness of fossil generation based on the assumption that carbon dioxide emissions will cost an average of eight dollars per ton over the plant's lifetime.[26] This represents PacifiCorp's best judgment based on a comparison of regulatory proposals and actions across North America and Europe; other estimates are substantially higher, and PacifiCorp's IRP also included scenarios with the cost of carbon dioxide emissions at $2 per ton, $25 per ton and $40 per ton. Including this real dollars-and-cents risk of using conventional energy would make renewables even cheaper than estimated in this report.

C. Renewable Resource Costs

There are two different methods for analyzing the projected price of renewable resources: to look at information presented in bids and to examine the cost of municipally financed renewables.

From the bid perspective, the California Power Authority recently received bids for over 2500 MW of wind power, with a median price of about $50/MWh. In addition, San Diego Gas and Electric just purchased approximately 4% of its annual load through a renewable resource solicitation on contracts for several different types of resources with terms ranging from 5 to 20 years.[27] While prices are confidential, it is known that all of the accepted offers were cheaper than the California Public

[25] LADWP Approval Board Letter, Approval to Sign Confidentiality Agreements Resulting from the Intermountain Power Project Unit 3 Feasibility Study, January 22, 2003. http://www.ladwp.com/board/020403/Item4.pdf

[26] PacifiCorp, *Integrated Resource Plan 2003*. Available at www.pacificorp.com/File/File25682.pdf

[27] Sempra Utilities, "SDG&E Taps Renewable Energy to Fill Customers' Needs, " Press Release, November 6, 2002. http://public.sempra.com/newsreleases/viewpr.cfm?id=1365

Utilities Commission's interim price target of $53.70/MWh.

Further information was developed by the Colorado Public Utilities Commission, which reviewed data comparing wind and combined cycle project costs and found that wind would be cheaper than combined cycle generation if gas prices exceed $3.50/MMBtu.[28] Based on this finding, GE Wind and Xcel Energy signed a contract to build a 162 MW windfarm in Southeastern Colorado.[29] In California, current gas prices are approximately $5.00-$6.00/MMBtu.

In essence, all of this information shows that a significant number of renewable projects can be readily developed by private merchant plant developers at costs of $55/MWh or less.

A second way to examine these projects is to look at the cost of projects under LADWP ownership, where a developer builds the project, makes some profit from the development and construction, and may hold an O&M contract for it, but the projects are financed on a cost basis either by LADWP or another municipal joint powers entity to which LADWP belongs such as SCPPA. Use of municipal bond financing gives a greater advantage to renewable resources than conventional gas-fired plants because the resources are highly capital intensive. At the same time, however, tax benefits available to a private developer are likely to be lost, because municipalities do not qualify for certain tax incentives when developing renewable resources.

[28] Lehr et. Al. "Colorado Public Utility Commission's Xcel Wind Decision." National Renewable Energy Laboratory Publication NREL/CP-500-30551, September, 2001. http://www.nrel.gov/docs/fy01osti/30551.pdf

[29] Land and Water Fund of the Rockies, "Public Utilities Commission Approves Wind Contract." Press Release, October 10, 2002. http://www.lawfund.org/media/pdf/Lamar_Settlement_Release.pdf

The renewable cost estimates below are developed using data from various public sources. The cost of power was based on financing with the same parameters (interest rates, size of reserve funds as a proportion of the project cost, etc.) as the SCPPA financing for the Magnolia project. Property taxes are included for wind and geothermal, because these projects would be built outside the LADWP service area.

Table 5 gives wind project costs for a utility-owned project, starting with the capital costs of the Pine Tree project currently under development for LADWP.

Table 5: Wind Project Cost

Capital	$1350/kW (2004 $) [a]
O&M	$25.85/kW-year (2004 $) [b]
Annual capacity factor	35% [c]
Cost – 30 year levelized	$52/MWh

a. $162 million for 120 MW for Pine Tree Wind Project. "Mayor Hahn Unveils Plan for New LADWP Wind Power Facility," LADWP Press Release, February 3, 2003. http://www5.ladwp.com/whatnew/dwpnews/020303.htm. The 160 MW Desert Sky wind project in Texas has a capital cost of only $1090/kW.

b. $24/kW-year (2001 $) escalated to 2004. Juanita Hayden, ICF Consulting, "Economic Assessment of Energy Efficiency and '10/20' Renewable Goals" prepared for Western Air Partnership, NREL Energy Analysis Forum, May 30, 2002, page 7. http://www.nrel.gov/analysis/pdfs/j_haydel.pdf . GE Wind has a lower estimate of $20/kW (2002 $). Tim Derrick, GE Wind, "The Economics of Wind Energy," Energy 2002 Conference, Palm Springs, CA, June, 2002, page 11. http://www.energy2002.ee.doe.gov/Presentations/renewables/s3-Derrick2.pdf

c. Calculated approximately from carbon savings and gas savings data in "Mayor Hahn Unveils Plan for New LADWP Wind Power Facility," LADWP Press Release, February 3, 2003.

Flash geothermal steam is the cheapest geothermal power technology. Table 6 provides its costs, largely taken from Electric Power Research Institute data.

Table 6: Geothermal Flash Steam Costs[30]

Capital	\$1988/kW (2004 \$) [a]
O&M	2.15 cents/kWh (2004 \$) [b]
Royalty fee	3.5% of gross revenue
Annual capacity factor	92%
Cost – 30 year levelized	\$53/MWh

a. \$1444/kW (1997 \$) escalated at 2.5% per year to 2004 plus 10% development fee for project built under municipal ownership plus \$100/kW for transmission interconnection.

b. 2.0 cents/kWh (2001 \$) escalated at 2.5% per year to 2004.

A third technology, landfill gas, is even cheaper, but is available in relatively small quantities. Its cost data come largely from information provided by the U. S. Environmental Protection Agency. A small royalty fee to the landfill was included. Financing was assumed over only 20 years instead of the 30-year period for other technologies.

Table 7: Landfill Gas Costs[31]

Capital	\$1314/kW (2004 \$)[a]
O&M	1.82 cents/kWh (2004 \$)[b]
Royalty Fee	3.5% of gross revenue
Annual Capacity Factor	85%
Levelized 20 years	\$41/MWh

a. Capital cost from Id. (midrange of \$1100/kW in 2000 \$) escalated to 2004, plus \$100/kW for transmission interconnection.

b. O&M cost from Id. (midrange of 1.65 cents/kWh in 2000\$) escalated to 2004.

30 All data except development fee and transmission interconnection cost from Brandon Owens, "An Economic Valuation of a Geothermal Production Tax Credit" National Renewable Energy Laboratory publication NREL/TP-620-31969, April, 2002, which were in turn taken from Electric Power Research Institute's Renewable Energy Technology Characterization. Development fee added because developer profit would not be present in a municipal ownership case.

31 Costs are taken from Tom Kerr, US EPA, "Landfill Gas to Energy Economics," presentation to Fifth National Green Power Marketing Conference, August, 2000. http://www.eere.energy.gov/greenpower/conference/5gpmc00/tkerr.pdf

D. Summary of Renewable and Conventional Generation Costs

Table 8 shows revenue requirements on a 10, 20, and 30 year levelized basis from the Magnolia combined cycle project and the renewables described above. Given the risk-reducing properties of renewables, a value of about $5/MWh should be considered as the hedge value to be added to Magnolia when comparing it to a fixed price renewable. A hedge value of about $7/MWh would be added to the market price, which is essentially gas based at a higher heat rate than Magnolia.

Table 8: Resource Cost Comparison ($/MWh)

	10 years	20 years	30 years
Short-run market	$44		
Short-run market hedged	$51		
Magnolia	$47	$54	$62
Magnolia hedged	**$52**	**$59**	**$67**
Merchant renewable contracts	< $54 for up to 20 years		
LADWP-Owned Renewables			
Wind	**$50**	**$51**	**$52**
Geothermal Flash	**$51**	**$52**	**$52**
Landfill Gas	**$38**	**$41**	**N/A**

It is evident from this information that on a life cycle basis, municipally owned renewable projects are cheaper than gas-fired generation, although they may be more expensive in some early years. Renewables are a good investment for LADWP ratepayers when compared to conventional generation and should be paid for in power charges. Even typical bids for renewable merchant projects are also within the range of the cost of new gas-fired generation at today's new gas price reality.

There may be some cost increase from renewables in the early years, particularly if an unhedged gas price is used as a point of comparison (because a larger portion of the renewables cost is capital-related than of the gas-fired resources, which have the likelihood of rising fuel costs over the entire life cycle).

However, overall, a good case can be made that at least a large portion of the renewables required for LADWP to meet a goal of 20% renewables by 2017 can be acquired at reasonable prices equivalent to the cost of conventional generation, without the need to tap public goods or other sources of money or to raise rates higher than they would otherwise be in the long run.

IV. Quantifying Worst-Case Renewable Costs in Excess of Market Prices, and Sources of Funds to Pay Potential Costs

The analysis comparing the costs of conventional and renewable energy show that increasing the use of renewables at LADWP will likely not result in additional costs. Indeed, investing in renewable energy may save the city money.

In the event that renewables do cost more than conventional energy, however, LADWP can meet these costs without raising rates.

This section demonstrates that the correct way to consider these costs is as "excess costs," the amount by which they cost more than conventional energy. In a "worst-case" scenario, these costs would not exceed $5/MWh beyond conventional energy over the first 10 years of an RPS.

When leveled out over time, these excess costs are extremely limited. For illustration, if the "worst-case" scenario costs were applied to rates, they would never result in more than a 38.5-cent increase in an average monthly bill. Additionally, LADWP has a number of different options to meet these costs without raising rates, as shown below.

A. Why Costs Are Likely to be Zero

As shown through the cost comparison section, a good case can be made that at least a large portion of the renewables required for LADWP to meet a goal of 20% renewables by 2017 can be acquired at reasonable prices approximately equivalent to the cost of conventional generation and less than the cost of hedged conventional generation. It is unlikely that it would be necessary to raise rates higher than they would otherwise be or to tap into public goods or other sources of money. In other words, a likely scenario is no appreciable cost or even a net savings from buying new renewables.

However, even if there were to be an above-market cost, the amount would be relatively limited. It certainly would not be $150 million per year as informally estimated by LADWP. [32] If public goods money is to be used at all for renewables, it should only be used to defray a small portion of the cost of renewables – the amount by which renewables cost more than $50 to $55/MWh (current dollars), or the cost of conventional resources.

B. Placing a Worst-Case Scenario of "Excess Costs" in Perspective

There appears to be a serious misconception to the effect that 100% of the cost of the renewables should be covered by the public goods charge because renewables are not needed immediately to provide capacity on the LADWP system. This misconception seems to be leading to the flawed conclusion that the RPS is too expensive for LADWP.

This is an extremely large misconception that, unless corrected, could lead to a very flawed policy decision and the over-reliance on expensive and risky conventional power.

[32] We were informed that LADWP has recently estimated that the cost of the RPS would be about $150 million per year. The only way in which this figure could be developed is to assume that renewables cost somewhere between $50-60/MWh and there are no offsets to that cost for reducing energy generation or purchases, increasing energy sales or reducing gas-fired powerplant construction at some time in the future.

The misconception seems to arise from a confusion regarding energy and generating capacity. Because the utility has adequate capacity at present, though not over the next 20 years, it is incorrectly assumed that energy generated from renewables would have no value. In fact, even if additional capacity is not required immediately, buying renewables will still reduce LADWP's cost of conventional energy year-round.

When energy is delivered to the LADWP system from a renewable resource, it can immediately be used in one of three ways: (1) to reduce LADWP coal or gas generation; (2) to displace LADWP power purchases, or (3) to allow LADWP to sell surplus power on the open market to others in the Western U.S. The ability to do one of these three things creates an energy value even if capacity is arguably not needed. Renewable energy has the same amount of value as energy generated from other sources both on the market and to LADWP customers.

To charge 100% of the cost of a renewable against the public goods charge under these circumstances (or to claim that 100% of the cost of the renewable is an "excess" cost that raises rates) ignores the value of the energy that renewables generate. If LADWP did nothing to increase their renewable portfolio, ratepayers would instead incur the cost of the conventional energy that the utility buys or purchases (or won't receive the benefits of a sale into the open market).

This point can be illustrated with a simple example. Assume for illustration that conventional energy costs $50/MWh. Now let us assume that LADWP buys renewable energy at (again for illustration) $55/MWh. The applicable cost of this renewable energy is ***NOT*** $55/MWh, as has been suggested. It is only ***$5/MWh*** – the ***difference*** between the renewable cost and the conventional energy cost. The value provided by the actual energy *offsets* all costs up to the benchmark.

In sum, it is necessary to compare the cost of renewable energy to the cost of conventional energy to determine any "above market" costs, if any, that would then be funded either from a public goods charge or other sources described below.

For purposes of a **WORST CASE** estimate of the impact on LADWP finances and rates, an above-market payment of $5/MWh (nominal dollars) for the first ten years of each renewable project is used, although it is likely that this estimate is too high. The analysis thus assumes that renewable excess payments are incurred for 24 years (2003-2026), because projects coming on line from 2003-2017 each receive payments for ten years.

Table 9 analyzes the Worst-Case Scenario. The worst-case above-market cost of renewable energy (in nominal dollars) starts at about $1.6 million in the first year, peaks at less than $20 million, and would average $11 million per year from 2003-2026, as shown in the first column. However, these are relatively small numbers when compared to LADWP's electric revenue from its customers, which exceeds $2,045 million in 2003.[33]

[33] On a present-value basis (discount rate 6%), worst-case renewable costs would be $143 million over 24 years, which is 0.49% of the present value of LADWP's revenues at current rate levels without any nominal dollar increase for over 20 years. ($29.1 billion)

Table 9: Impact of <u>Worst-Case Scenario</u> of Excess Renewables Costs ($5/MWh)

	Annual $'000		New Commitment (GWh)	Cumulative Renewable (GWh)	Energy Sales (GWh)	$/MWh	% of current rate revenues		Cumulative ($000)	Cumulative NPV($'000) (6%)
2003	$1,616	$	323	323	22,926	$0.07	0.08%	$	1,616	$1,570
2004	$3,332	$	343	666	23,357	$0.14	0.16%	$	4,948	$4,623
2005	$5,083	$	350	1,017	23,848	$0.21	0.24%	$	10,032	$9,017
2006	$6,863	$	356	1,373	24,231	$0.28	0.32%	$	16,895	$14,614
2007	$8,672	$	362	1,734	24,629	$0.35	0.39%	$	25,567	$21,286
2008	$10,511	$	368	2,102	25,042	$0.42	0.47%	$	36,078	$28,915
2009	$12,377	$	373	2,475	25,408	$0.49	0.55%	$	48,455	$37,390
2010	$14,266	$	378	2,853	25,737	$0.55	0.62%	$	62,721	$46,605
2011	$16,174	$	382	3,235	25,977	$0.62	0.70%	$	78,895	$56,462
2012	$18,099	$	385	3,620	26,201	$0.69	0.77%	$	96,994	$66,867
2013	$18,425	$	389	4,008	26,454	$0.70	0.78%	$	115,419	$76,860
2014	$18,670	$	392	4,400	26,690	$0.70	0.78%	$	134,089	$86,412
2015	$18,896	$	395	4,796	26,918	$0.70	0.79%	$	152,985	$95,533
2016	$19,113	$	399	5,195	27,187	$0.70	0.79%	$	172,097	$104,237
2017	$19,321	$	404	5,599	27,471	$0.70	0.79%	$	191,419	$112,537
2018	$17,482	$	-		27,770	$0.63	0.71%	$	208,901	$119,622
2019	$15,616	$	-		28,073	$0.56	0.62%	$	224,517	$125,593
2020	$13,727	$	-		28,382	$0.48	0.54%	$	238,244	$130,545
2021	$11,819	$	-		28,731	$0.41	0.46%	$	250,063	$134,566
2022	$9,895	$	-		29,094	$0.34	0.38%	$	259,958	$137,743
2023	$7,952	$	-		29,451	$0.27	0.30%	$	267,909	$140,151
2024	$5,991	$	-		29,796	$0.20	0.23%	$	273,901	$141,863
2025	$4,014	$	-		29,922	$0.13	0.15%	$	277,915	$142,945
2026	$2,018	$	-		30,227	$0.07	0.07%	$	279,933	$143,458
Levelized at 6%										$11,431
Average										$11,664

The striking point of this table is that even at $5/MWh for ten years, the excess renewable cost above the cost of conventional energy:

- Is less than 0.05 cents/kWh through 2009;
- Never exceeds 0.07 cents/kWh in any years;
- Never exceeds 0.8% of LADWP's revenue <u>at current rate levels</u>;

In other words, any costs that might arise are relatively small. For instance, a rate hike of 0.07 cents/kWh would increase the average monthly bill by only 38.5 cents.[34]

C. Comparison to Current LADWP Electric Costs and Rates

LADWP's current rates average about 9 cents/kWh on a system-wide basis. The table below shows, in kWh, the California Energy Commission's estimates of LADWP rates and compares them with rates for Southern California Edison. LADWP's rates are considerably less than Edison's, even after Edison's proposed reductions in rates when it pays off its generation-related debt.

[34] Energy Information Administration gives the average California monthly usage as 548 kWh. Average Monthly Bill by Sector, Census Division and State, 1999 Residential by Energy Information Administration Form EIA-861, "Annual Electric Utility Report", 1999 http://www.bluefish.org/elecresi.htm

Table 10: LADWP and SCE Rate Comparison (cents/kWh)

	CEC Retail Price Forecasts			SCE (CPUC App. 03-03-019)	
	LADWP 2003	SCE 2003	SCE 2004	SCE 2003	SCE 2004
Residential	10.44	13.03	11.92	13.69	13.69
Small Commercial	10.84	18.31	16.36	17.49	15.08
Medium Commercial	9.55	14.55	13.05	15.25	11.82
Large Commercial	7.42	11.94	10.41	13.03	9.65

This information shows that even if the small amount of cost from the Worst-Case scenario of RPS costs were applied to rates, rather than recouped through other forms of cost reduction, it would not materially affect LADWP's competitive position.

D. Addressing Worst-Case Scenario RPS Costs Without Raising Rates

As discussed below, LADWP has a number of options for addressing the limited amount of Worst-Case Scenario RPS costs over the next 23 years. LADWP has already slashed its debt costs significantly and sold off assets at a profit. It could make changes to its line extension policy (that would also have the benefit of no longer subsidizing excessive electric use) to raise small amounts of revenue, reduce public goods funding on low-priority research, development and demonstration (RD&D), increase productivity only slightly, or accept a 3-4% reduction in its equity return. Even if some of these actions were required to support the RPS under a Worst-Case Scenario, the additional benefits of renewable energy would still likely outweigh the costs.

1. Reallocate Public Goods Funding (LADWP option)

LADWP has suggested that the entire public goods charge might be needed to fund RPS costs, canceling spending for solar photovoltaic and energy efficiency programs. This drastic option has been shown in Section B above to be incorrect, once the proper evaluation method is used – to only charge a public goods fund or other source of funding for the **excess** cost of renewables over conventional energy.

Once the issue is examined in this way, the amount of public benefit funding required becomes much more limited. Public benefits funding is about 3.6% of total revenue.[35] On a life-cycle basis, the Worst-Case Scenario RPS costs are 0.49% of total revenue, even assuming the unlikely scenario of no rate increases at all through 2026, or about 14% of public benefits costs at current rate levels.

The recent program evaluation of LADWP's public benefits programs conducted by NRDC suggests that a number of programs, particularly relating to RD&D, LADWP's own electric transportation activities, and several other activities, should be funded through other sources than the public goods charge.[36] With these actions, funding even Worst-Case Scenario RPS costs through the remainder of the public goods charge would not have the draconian impacts suggested by LADWP of forcing the shutdown of conservation and photovoltaic programs. In addition, there are other sources of funds

[35] Devra Bachrach, Natural Resources Defense Council, *Program Evaluation of the Los Angeles Department of Water and Power Public Benefit Programs*, January, 2003, page 1 and Appendix.

[36] Id., pages 35-41.

besides tapping the existing public goods charge that should be considered. These funding sources are described below.

2. Use $67 Million Profit from Mohave Sale to Fund Half of the Worst-Case Scenario Costs

LADWP received a $67 million book profit from selling a 10% share of the Mohave powerplant to the Salt River Project.[37] This non-operating profit is equal to almost half of the net present value of the excess cost under the Worst-Case Scenario of $143 million. In other words, LA could pay for almost half of the above market price of the RPS under the Worst-Case Scenario with the profits from its sale of Mohave.

3. Apply Operations and Maintenance Productivity Savings

LADWP's Operations and Maintenance (O&M) budget (excluding fuel and purchased power) has increased from $525 million in 1999-2000 to $545 million in 2000-2001 to $598 million in 2001-2002.[38] To analyze the ability to absorb the worst-case costs of an RPS through O&M productivity, a baseline analysis was conducted assuming that O&M costs would increase with inflation (assumed 2.5%) plus one-half of load growth. A further calculation was made of the amount of additional productivity that would be required to achieve a net present value of $144 million in savings over the period from 2003-2026 (compared to a net present value baseline O&M budget under these assumptions of about $11 billion).

The analysis showed that funding the worst-case excess renewable cost would require additional O&M productivity of only **0.13% per year** over the next 23 years.

4. Debt Payoff and Refinancing Creates Room to Pay for Worst-Case Scenario Costs

LADWP has a goal of reducing its generation-related debt to zero by the end of 2003, and is within $1 billion of that goal as of the latest reported information in August, 2002.[39] The reduction in debt and refinancing of bonds will reduce LADWP's expenses by well over $100 million per year.[40] Any potential Worst-Case Scenario costs from the RPS are an order of magnitude less than the savings already realized through the refinancing and defeasance of debt.

5. Change Line Extension Policy to Raise Revenue and Stop Rewarding High Electric Use

While there is not a large amount of construction of new residential dwellings in the City of Los Angeles, LADWP's line extension allowances (amounts that utility ratepayers must pay for new construction) are not only extremely generous to developers, when compared to those of Southern California Edison Company, but they promote the use of electricity in inefficient applications such as space heating, water heating, and cooking by giving greater allowances to developers who install these electric uses. LADWP's allowances also give developers incentives to install inefficient air conditioners, by tying the allowance to the amount of connected air conditioning load.[41] This

37 Energy Services, Department of Water and Power, City of Los Angeles, "Report and Financial Statements and Required Supplementary Information," Fiscal Year Ending June 30, 2002, p. 14.

38 Id., p. 17.

39 "LADWP to Sell $400 Million of Variable Rate Bonds. Press Release, August 20, 2002. http://www6.ladwp.com/whatnew/dwpnews/082002.htm

40 $4 billion in debt multiplied by 5% average interest rate would be $200 million annually.

41 http://www6.ladwp.com/rules/RULES96.htm#Rule15.

method of using allowances to promote electrical use was rejected by the California PUC in the mid-1990s, and allowances are instead tied to average residential revenue. Edison's allowances are $1247 regardless of the dwelling's projected electric use (based on the average cost of distribution) and include not only primary and service lines but the cost of transformers as well. [42] A change in LADWP's line extension policy to be closer to that of Edison would raise several million dollars per year of additional revenue to offset the worst-case cost of the RPS, while improving overall environmental quality by ending rewards to customers that encourage increased electricity use.

6. Slightly reducing equity return (not payment to City)

LADWP's equity return, <u>after payment to the City of Los Angeles</u> was $257 million in 2001-2002.[43] Paying for the worst-case RPS cost would average about $11 million per year over the next 23 years and about $7 million per year through 2010. These figures are 4.5% and 3.1% respectively of the year 2001-2002 equity return.

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[42] Footnote to Edison Rules 15 and 16.

[43] It is recognized that LADWP both had $67 million of unusual income (from the Mohave sale) in 2001-2002 and increased its payment to the City of Los Angeles from about $120 million in 2000-2001 to about $190 million in 2001-2002. Therefore the net comparison

V. Conclusion

Rising and uncertain fossil fuel costs combined with declining renewable prices have made renewable energy a smart investment for LADWP. In fact, investing in renewables may even result in a net savings for Los Angeles.

Even if renewable prices do exceed those of conventional energy, LADWP can meet Worst-Case Scenario costs without raising rates.

Given these factors, and the many benefits that renewables have regarding job creation, reliability, environmental performance and energy independence, LADWP should establish a renewable portfolio standard of 20% by 2017.

Overall, this study has made several key findings:

1. The recent market reality of gas prices suggests a large and permanent increase in the cost of gas, which will seriously impact the price of energy on the short-term market as well as the cost of building and operating a new natural gas power plant.

2. Given these increases, renewables are no longer more costly than gas. The cost of renewable resources, in the range of $50-$55/MWh both with merchant contracts or with municipal ownership and financing, is approximately comparable to the cost of existing gas-fired resources hedged to reduce price volatility and less than the long-run cost of new powerplants.

3. It is possible that increasing the use of renewable energy at LADWP to 20% by 2017 will result in no additional costs or a net savings to ratepayers.

4. A "Worst-Case Scenario" of cost increases from a 20% RPS by 2017 was developed ($5/MWh over 10 years for new resources). This Worst-Case Scenario will increase LADWP's costs by no more than 0.5% of its existing rate levels over 24 years. These increases would have rate impacts of less than 0.07 cents/kWh in all years, and in the unlikely event that all costs were passed on to consumers would increase the average monthly bill by only 38.5 cents.

5. A number of sources of funds for meeting "Worst Case Scenario" cost increases resulting from the RPS have been identified other than raising rates. These include use of 14% of public goods funds, use of profits from the sale of part of LADWP's interest in the Mohave powerplant, changes in line extension policy, small increases in productivity, small portions of future savings from the retirement and defeasance of debt, and small decreases in LADWP's target return on equity.

6. It is simply wrong to ascribe 100% of the cost of meeting the RPS to the public goods program or to assume that 100% of these costs will result in rate increases. Such a position erroneously assumes that even though renewables provide energy, there will be no savings from reducing the use of natural gas and/or the construction of new powerplants over the next 30 years or from selling excess energy.

In sum, meeting the California Renewable Portfolio Standard is roughly economically equivalent to pursuing conventional generation to meet increased demand while at the same time providing additional benefits to LADWP customers by reducing their exposure to gas price volatility and environmental risks associated with other forms of generation.

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