A Green Future for the Los Angeles Department of Water and Power

Phasing Out Coal in LA by 2020

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1. Introduction

In 2010, the Los Angeles Department of Power and Water (LADWP) published an electricity Integrated Resource Plan (IRP). The plan examines the future of electricity use and generation at the utility and proposes several bold new changes in the composition of the electric generating fleet. The changes in the Recommended Scenario include:

- re-building several large gas-fired power plants on the coast to comply with new California statute,
- building over 1,200 MW of new solar and wind facilities through 2030 to meet the California renewable energy standard (RES);
- a new focus on energy efficiency over the next decade, and
- a proposal to end contracts with two major coal plants in 2014 and 2027.

While this plan is significantly more forward-looking than previous plans, the plan still maintains a heavy reliance on imported coal-fired power in the city until 2027, the end of a contract with the Intermountain Power Project (IPP).

Synapse Energy Economics, Inc. was contracted by the Sierra Club to review public documents on the LADWP 2010 IRP, and examine utility assumptions. Based on documents obtained, this paper examines four distinct futures for LADWP, each of which increasingly focuses on reducing the utility's reliance on fossil fuels and reducing regulatory costs for LADWP consumers, while still meeting consumer demand cost-effectively. The futures are:

- The **2010 IRP Recommended scenario**, which gradually phases out LADWP's heavy dependence on coal, replacing it with gas and renewable energy through 2030;
- An alternative **coal-replacement scenario**, which replaces the IPP in 2020, rather than 2027;
- An **efficiency scenario**, which replaces the IPP in 2020 and works to reduce consumer costs and price uncertainty through moderate increases in energy efficiency;
- A **green scenario**, which replaces IPP in 2020, sets an efficiency target consistent with leading states and utilities, and increases LADWP reliance on accessible renewable energy sources.

This report finds that an accelerated replacement of the IPP coal contract does not entail higher costs for consumers relative to the IRP preferred portfolio selected by LADWP.

It is important to note that these futures are not plans in the formal definition as used by utility planners: these scenarios have not been optimized using a build-out model and they have not been examined using a utility-scale production-cost model. Rather, these futures are structured to ask if minor to significant departures from LADWP assumptions might result in lower costs and risks for LADWP customers. The underlying model to these futures is a spreadsheet tool with assumptions pieced together from published and obtained LADWP assumptions. Synapse was unable to obtain formal LAWDP assumptions, model inputs, or model results which would have been required for a formal analysis of these alternatives.

2. 2010 IRP Recommended Scenario

In the 2010 IRP, LADWP proposes a “Recommended Scenario” that, as described above, increases efficiency and renewable energy use, but also maintains a contract with coal generating units through 2027. There are several detail elements of the Recommended Scenario as understood by Synapse that are critical to understanding the alternatives described below. Assumed penetrations of efficiency, the composition of the gas-fired fleet, energy and capacity from renewable resources, and in particular LADWP’s consumption of coal energy and capacity through 2027 all drive our understanding of the costs of the 2010 IRP Recommended Scenario.

Unlike most regulated utility planning processes, in which concerned and public entities are able to review utility assumptions on power requirements, costs, and model inputs, LADWP is not required to undergo a public review process for its power planning purposes. Despite requests, the Sierra Club was unable to obtain formal planning documents from LAWDP, which under other circumstances would have included model assumptions and inputs, as well as detailed outputs from standard electricity models. Instead, Synapse relied on publicly available documentation in the IRP and elsewhere, and a single set of spreadsheets obtained from the utility with “streams” of capacity, energy, and costs for six considered scenarios through 2030.

Due to a lack of information from the utility, this study cannot be a formal evaluation of LADWP build-out or cost assumptions. Instead, Synapse reconstructed estimated utility costs and resource decisions by reverse engineering results and using LADWP published assumptions, where available. We reconstruct the LADWP Recommended Scenario in a spreadsheet-based model, and explore alternatives. Details on the reconstruction of the Recommended Scenario are found in **Section 6**, below.

To our best understanding significant elements of the Recommended Scenario include:

- An energy efficiency ramp rate of just under 1% per year through 2018, resulting in approximately 7% cumulative reduction from baseline load growth;
- An additional 570 MW of wind by 2030 (relative to the amount installed by 2010);
- An additional 650 MW of solar by 2030 (relative to the amount installed by 2010);
- Several new gas-fired generating stations to rebuild (“repower”) old coastal stations: [1] Haynes 1,2, 5 & 6, and Scattergood 3;
- Four additional gas units built between 2021 and 2029;
- The replacement of Navajo in 2014 with a new gas-fired plant; and
- The replacement of IPP in 2027 with two new gas-fired generators.

LADWP’s long-term contract with IPP ostensibly binds the utility to purchase power from the facility through 2027. In several alternative scenarios in the 2010 IRP document, the utility

[1] LADWP owns three coastal gas-fired power plants (Haynes, Harbor, and Scattergood) which are in violation of the State Water Resources Control Board (SWRCB) Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling, effective October, 2010. The policy effectively bans the use of “once-through cooling”, the use of large volumes of water for direct boiler cooling. LAWDP has proposed that the lowest cost solution for compliance with the policy is a gradual replacement of those three plants through 2035.

explores the potential to replace IPP with a natural gas fired power plant before 2027. In this study, Synapse makes the same set of assumptions: presuming that the utility would continue to purchase power from an IPP entity, but that the utility would pay for a replacement unit at the site.

Finally, it should be noted that in the limited documents obtained from the utility showing expected capacity, energy, and cost streams from 2010 to 2030, the model output suggests that the utility can somehow retain peaking capacity from the IPP station through 2027, yet shed both energy and CO_2 obligations from the station on an annual basis. For the purposes of this study, Synapse assumes that in all scenarios, LADWP will obtain both capacity and energy from either the existing or the repowered IPP station, consistent with the long-term contract. For details on this inconsistency, see **Section 6**, below.

3. Scenario Design

The scenarios used in this analysis are designed to examine the persistent assumption that LADWP's dependence on coal is the optimal solution for providing affordable energy to utility consumers. Currently, the utility obtains over 40% of its energy from two coal-fired power plants: Navajo Generating Station on the banks of the Colorado River in Page, Arizona, and via a direct transmission line from Intermountain Power Plant (IPP) in central Utah. These scenarios test assumptions about LADWP's dependence on out-of-state coal and other fossil-fired resources, and the costs of increasing utility efficiency programs and renewable energy.

In the four scenarios, we find:

- The accelerated replacement of the IPP coal contract does not entail higher costs for consumers relative to the preferred portfolio selected by the LADWP;
- The increasing cost of generation in the LADWP service territory is not due to the increasing use of renewable energy, but is rather an expensive regulatory liability from high carbon dioxide (CO_2) emissions at LADWP-owned coal resources;
- Consumers are unlikely to avoid the near-term costs of repowering old coastal gas-fired plants, or the regulatory expense of emitting large amounts of CO_2 from the two coal plants;
- The department can significantly mitigate costs and risks for consumers over the next two decades through prudent investments in achievable energy efficiency and renewable energy, reducing demand and requirements for new gas-fired power plants.

The four scenarios are all modifications of the 2010 IRP Recommended Scenario put forth by LADWP. Major deviations from the IRP Recommended Scenario are as set forth below. Changes in resource online and retirement dates, as well as capacity changes are detailed in **Appendix B**.

Replacement Scenario

The Replacement Scenario is identical to the 2010 IRP Recommended Scenario, with the exception that the IPP coal contract is replaced, on site, in 2020 instead of 2027. As a replacement, two gas-fired generators are placed in service in 2020. Like LADWP, we assume one of these units would be a combustion turbine (a jet-engine like unit capable of reaching peak power quickly) and the other would be a combined cycle (a combustion turbine with an attached steam turbine used to capture waste heat).[2] We assume that the replacement plant is built on the IPP site to allow LAWDP's long-term "take or pay" contract to be fulfilled through 2027. This scenario differs from the IRP recommended scenario in that we assume capacity and energy are both available and purchased in proportion at IPP through at least the 2027 contract end; in contrast, the IRP recommended scenario appears to gradually reduce energy purchases from IPP while maintaining capacity purchases.

Efficiency Scenario

The Efficiency Scenario increases near term energy efficiency assumptions at the utility by a small fraction, from an assumed ~1% incremental savings per year per year through 2016 to 1.2% incremental savings per year. [3].Where the IRP assumes that energy efficiency is no longer available past 2016, this scenario maintains this highly achievable reduction rate through the end of the analysis period, effectively flattening load from 2015 to 2030. The flattened load, which also reduces peak demand, allows us to make additional improvements in the LADWP system, including retiring the inefficient Scattergood gas steam plant in full by 2016, and Haynes Units 1&2 by 2020 (instead of 2027). The significant reduction in new energy demand from this simple change in efficiency allows us to suggest that the Scattergood and Haynes repowering could be achieved with lower cost combustion turbines, and reducing the size of the IPP replacement gas plant by 300 MW.

Box 1: Efficiency at LAWDP versus Leading Utilities

In recent years, several states have achieved savings which are significantly higher than those proposed by LADWP in the 2010 IRP. For example, Efficiency Vermont reduced consumption in the state by 2.5% in 2008 and 2% in 2009, and plans to maintain the savings level about 2% per year for the next few years.[4]. At least 11 states now have established goals of annual energy savings at or above 2% of retail sales and 4 states established goals to save energy at 1.5%.[5] Historically, leading states and utilities saved energy at or above 1% per year, and there are a few states and utilities even achieved over 2% savings per year. **Table 1** provides examples of such leading states with the maximum achieved savings.[6]

[2] In general, combustion turbines are built to meet peaking requirements, while more expensive combined cycle units are built to handle either intermediate loads (increasing during the day and decreasing at night) or baseloads (on during most hours of the day. In the case of this research, we assume little energy benefit from combustion turbines, and between 30-60% capacity factors (utilization) for combined cycle units.

[3] In this research, as elsewhere, "incremental efficiency" is a measure of savings each year relative to baseline growth. Therefore, if a utility is increasing consumption at a rate of 1.5% per year, incremental efficiency savings of 1.2% per year reduce growth to 0.3% per year. When efficiency savings exceed native growth, the utility sees decreases in consumption. "Baseline growth" is the absolute growth in electricity consumption at a utility, including population changes, changes in per capita consumption, expected regulatory changes, and economic shifts driving industrial, commercial, and residential consumption.

[4] VEIC 2010. Efficiency Vermont Annual Plan 2010- 2011, available at http://www.efficiencyvermont.com/pages/Common/AboutUs/AnnualReport/

[5] MA EEAC 2009. Assessment of All Available Cost-Effective Electric and Gas Savings: Energy Efficiency and CHP

[6] These savings are monitored and verified by third-party auditors responsible for maintaining the integrity of utility efficiency programs.

Table 1. Achieved Efficiency Savings for Selected Entities' Efficiency Programs[7]

Entity	Annual Savings (%)	Year(s)	Source
Interstate Power & Light (MN)	2.6	2006	Garvey, E. 2007. "Minnesota's Demand Efficiency Program."
Efficiency Vermont (VT)	2.5	2008	Efficiency Vermont 2009. 2008 Highlights
Massachusetts Electric Co.(MA)	2.0	2006	EIA 861
Minnesota Power (MN)	1.9	2005	Garvey, E. 2007
Puget Sound Energy (WA)	1.4	2007	Northwest Power and Conservation Council
Connecticut IOUs (CT)	1.3	2006	CT Energy Conservation Management Board (ECMB). 2007
Pacific Corp (ID & WA)	1.3	2007	Northwest Power and Conservation Council
Energy Trust of Oregon (OR)	1.3	2005	Northwest Power and Conservation Council
Pacific Gas & Electric (CA)	1.1	2008	CPUC 2010. Evaluation Reporting Tools (ERT) on 2006-2008 IOUs' EE Programs
Avista Corp (ID, WA, MT)	1.1	2005	Northwest Power and Conservation Council
Idaho Power Co (ID)	1.1	2007	Northwest Power and Conservation Council
Southern California Edison (CA)	1.0	2008	CPUC 2010
PUD No 1 of Snohomish (WA)	1.0	2007	Northwest Power and Conservation Council
Otter Tail (MN)	0.9	2005	Garvey, E. 2007. "Minnesota's Demand Efficiency Program."
Seattle City Light (WA)	0.9	2007	Northwest Power and Conservation Council
MidAmerican (IA)	0.9	2006	Iowa Utilities Board 2009

LADWP has not aggressively pursued energy efficiency in the past, which suggests that City of Los Angeles has more untapped potentials than other areas. In the draft version of the IRP, the utility declared an intent to save approximately 1.2% per year through efficiency programs. However, this reasonable goal was withdrawn in the final IRP.

Green Scenario

The Green Scenario moves LA towards a more aggressive efficiency target, achieving 1.8% incremental efficiency each year, effectively reducing load requirements through 2030. In this scenario, the utility invests in 1,200 MW of wind through 2030, about three times more than suggested in the LADWP IRP Recommended scenario. By increasing energy from wind while reducing demand from efficiency, the utility is able to make all the changes seen in the Efficiency Scenario, and avoid the construction of a large 600 MW of combined cycle gas capacity.

4. Results

The bulk power cost of simply replacing the IPP unit in 2020 rather than 2027 is approximately the same cost as the scenario IRP Recommended for consideration by the LADWP in the 2010 IRP. The bulk cost of supplying power increases markedly in 2012 with the assumed start of carbon prices in California,[8] and then grows steadily with increasing CO_2 and gas prices; there are (relatively) small changes throughout as gas steam units are repowered or retired.

[7] The table is based on Synapse Energy Economics. May 2010 "Beyond Business as Usual: Investigating a Future without Coal and Nuclear Power in the U.S." Savings for California IOUs have been modified based on the most recent EE program evaluation study.

[8] LADWP (and this study) assume that a cost will be imparted upon CO_2 emissions in and associated with electricity entering California as of 2012 with the start of greenhouse gas trading under the Global Warming Solutions Act of 2006. This study uses LADWP's assumed prices for CO_2 emissions (currently unknown), the mid-case starting at $20/ton in 2012 and rising to approximately $50/ton in 2030.

The cost of the two alternative scenarios (Efficiency and Green) do see a significant cost increase in 2012, because the utility cannot quickly purge CO_2 risk prior to the onset of carbon prices in 2012. However, careful planning on the part of the utility could target high-yield efficiency programs at low income consumers in the near term, reducing the bill impact of a rate hike with the onset of carbon prices. As efficiency measures are increased beyond those shown in the IRP and the coal liability is removed in 2020, costs begin to deviate significantly from the IRP Recommended scenario. **Figure 1**, below, shows estimated costs of generation in each scenario over the 20 year analysis period. The reference case is the 2010 IRP Recommended scenario, dotted in a black line.

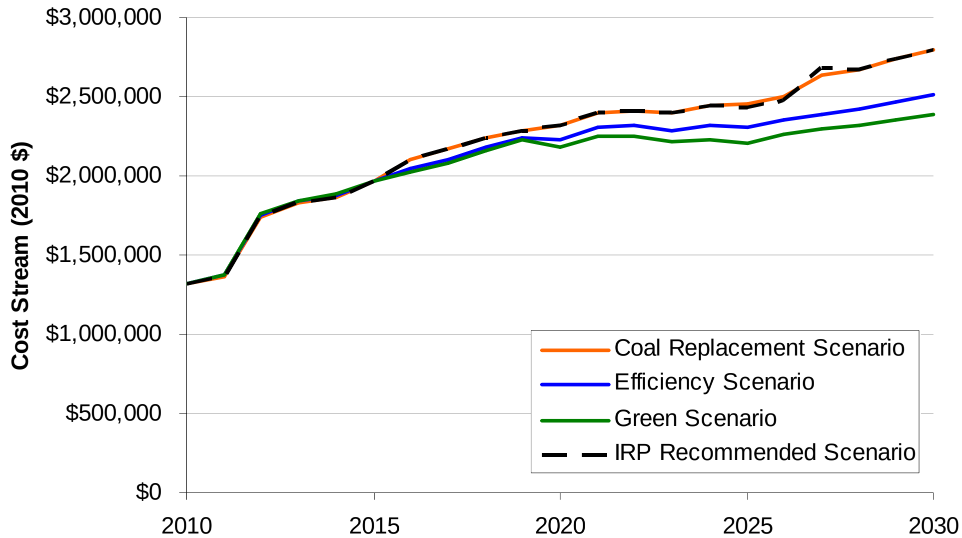

Figure 1. Scenario bulk power costs (in 2010$) . Costs represent generation and carbon emissions prices only.

By 2025, the cost of the Efficiency scenario is $100 million less per year than the IRP Recommended scenario, and by 2030, the Green scenario is $400 million less than the IRP Recommended scenario. The costs given here are all passed directly through to electricity consumers: savings in the operating expenditures of the utility should be realized as lower costs for consumers.[9]

Individual ratepayers benefit from the lower cost of these scenarios, as well as significant reductions in electricity use. The marked increase in the generation component of bills due to CO_2 prices under the Global Warming Solutions Act of 2006 may be unavoidable in the short term, but further increases can be avoided by increasing end-use efficiency and transitioning from high-carbon generation. **Figure 2**, below, shows estimated average residential bills from the

[9] In the case of LADWP, the City of Los Angeles approves utility rates. Utilities and rate-setting entities typically adjust rates as a direct function of the operating expenditures of the utility.

generation component of utility costs.[10] Again, the dotted line is the reference case of the 2010 IRP Recommended scenario.

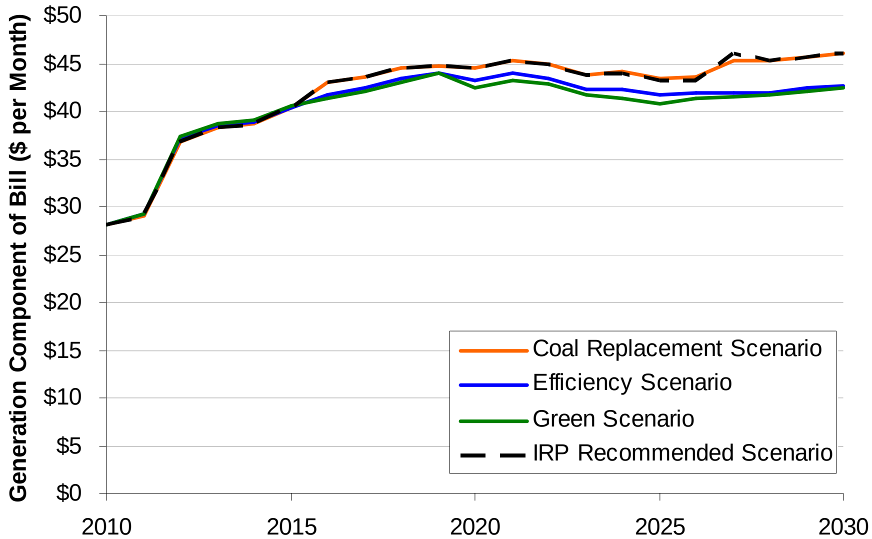

Figure 2. Scenario average monthly residential bills (2010$), generation component of bill only (does not include transmission and distribution).

The costs above represent the annual bulk power costs and estimated costs to consumers in the form of average monthly bills. However, portfolios are also typically examined for the lowest cost solution over a period of time, in terms of a net present value. In the 2010 IRP, various scenarios are compared for a "20 Year Present Value Bulk Power Cost", which are not "bulk power costs," but are instead "average rates" (see Box 2, below) and do not appropriately illustrate the costs of the various plans to average consumers.[11]

Box 2: About Bulk Power Costs, Net Present Value (NPV), Rates, and Bills

The cost of obtaining power can be viewed in four different ways, all of which tell a different story about expected costs. All four of these metrics are important, but each is used for a specific purpose.

Bulk Power Costs are the costs to generate electricity and pay for capital expenditures (such as power plants and transmission lines) on an annual basis. These values are usually given in "real"

[10] Average monthly residential bills assume 500 kWh of consumption by an average residential customer in 2010. Residential consumption is assumed to have no native load growth (i.e. per capita consumption in the reference case would be flat), and is "decremented by incremental efficiency each year" [can we say this differently?]. The rate impact is estimated as the total annual bulk power cost divided by total sales, after efficiency. The generation component of the average monthly bill is estimated as consumption multiplied by the rate.

[11] The "20 Year Present Value Bulk Power Costs" title is a misrepresentation of these graphs. Instead, the graphs show the estimated levelized rate (in $/MWh) faced by consumers over a 20 yr period. Using a rate rather than either total bulk power costs (in millions or billions of constant dollars) or average bills (in $/yr or month) can significantly obscure the benefits of programs such as energy efficiency, which reduce total costs and average bills, but also reduce consumption (MWh) in the denominator, hence increasing the apparent "costs" faced by consumers.

monetary terms (i.e. today's dollars without inflation) and are useful for estimating the relative costs of a plan on a year-by-year basis.

Net Present Value (NPV) is the aggregate cost of a plan as viewed by an investor today. All of the costs are summed, taking into account inflation and a "discount rate", or the loss of value between money invested today versus in a future year. The NPV is usually the most useful way of comparing long-term investment plans.

Electricity **rates** represent the average price of electricity to a given consumer on a per unit energy basis. This value is important to large consumers with fixed energy requirements and a high sensitivity to changes in price.

Electric **bills** are the costs paid by consumers for electricity, multiplying energy consumption times the rate (price). Average bills are a reasonable indicator of the direct economic impact expected on small consumers, such as residential households. Importantly, average bills capture the cost savings to consumers associated with energy efficiency, while rates do not.

In **Figure 3**, we show the net present value (NPV) of the absolute bulk power costs, in billions of net present value dollars over a 20 year period. The IRP Recommended Scenario is almost exactly the same cost as the Replacement Scenario; both exceed the cost of the Green scenario by over $1.3 billion.

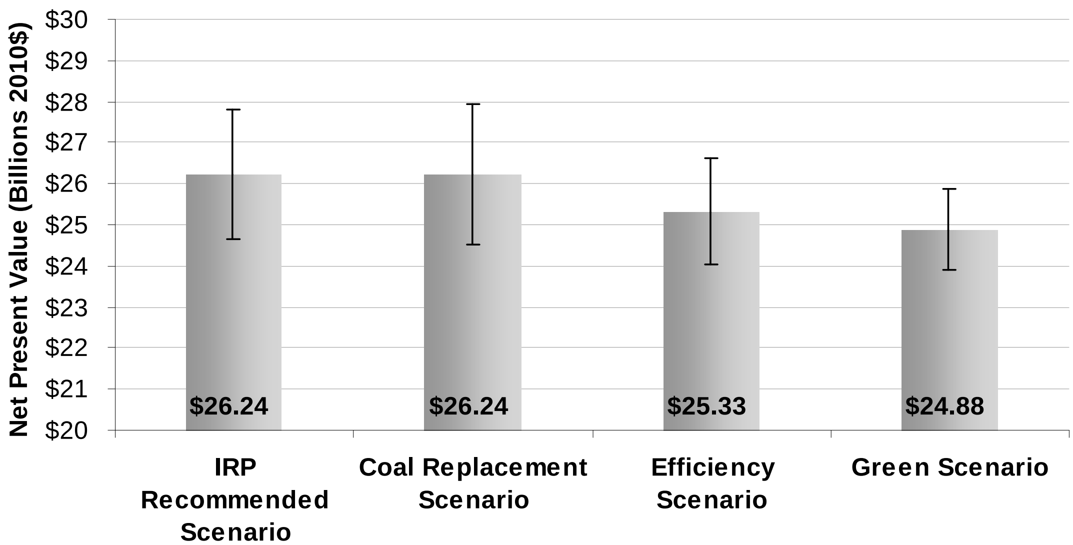

Figure 3. Net present value of alternative scenarios, in billions of 2010$

The error bars on the costs represent uncertainty in future CO_2 prices and gas prices, as represented in the 2010 IRP. The bars show NPV of the scenarios using LADWP-estimated mid gas and CO_2 prices; the high and low bars utilize LADWP-estimated extremes for CO_2 and natural gas prices. The uncertainty in gas and CO_2 prices results in a much wider range of risk for the IRP Recommended scenario ($1.57 billion NPV) than for the Green scenario ($1 billion).[12] The efficiency scenario also has a lower range of risk than the IRP Recommended scenario.

The scenarios can also be examined in context of average residential monthly bills, levelized over the full analysis period (**Figure 4**). We estimate that the IRP Recommended Scenario is approximately $1.30 more expensive for consumers each month than the Green scenario, although the error due to uncertainty in CO_2 and gas prices exceeds this difference for both scenarios.

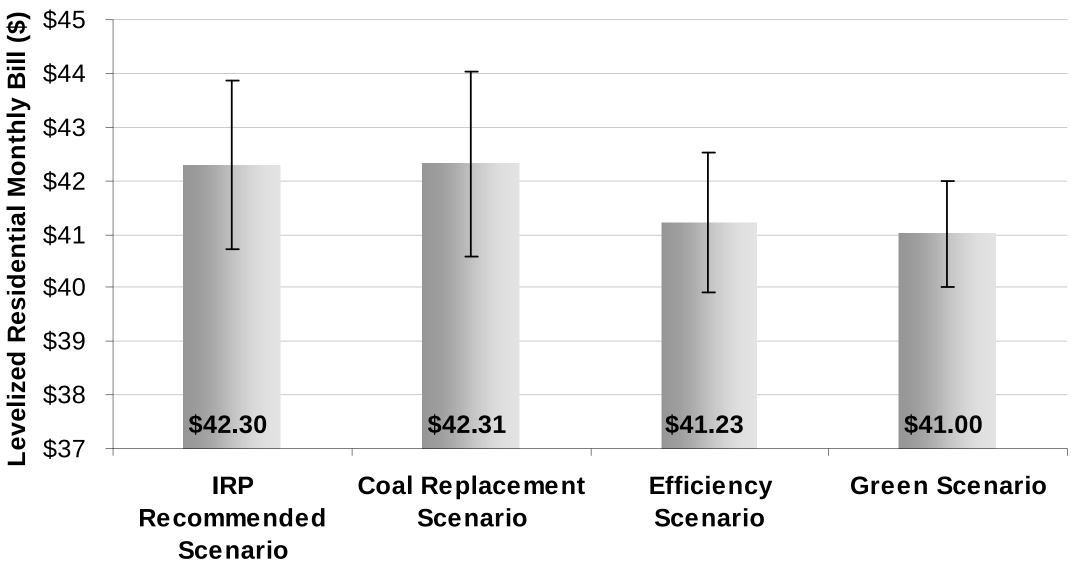

Figure 4. Levelized estimated residential monthly bills, 2010-2030.

The IRP Recommended Scenario appears to slowly ramp down coal generation (see Assumptions and Derivations in later section for details on the assumed ramp-down), gradually replacing the coal generation with natural gas, primarily in the form of combined cycle generators (see **Figure 5**). Energy efficiency trims a small amount of the required energy needs, but does not provide significant savings for consumers past 2018.

[12] The error range is slightly greater on the Replacement scenario than the Recommended Scenario because the impact of uncertain gas prices exceeds the impact of uncertain CO_2 prices in this scenario and time period.

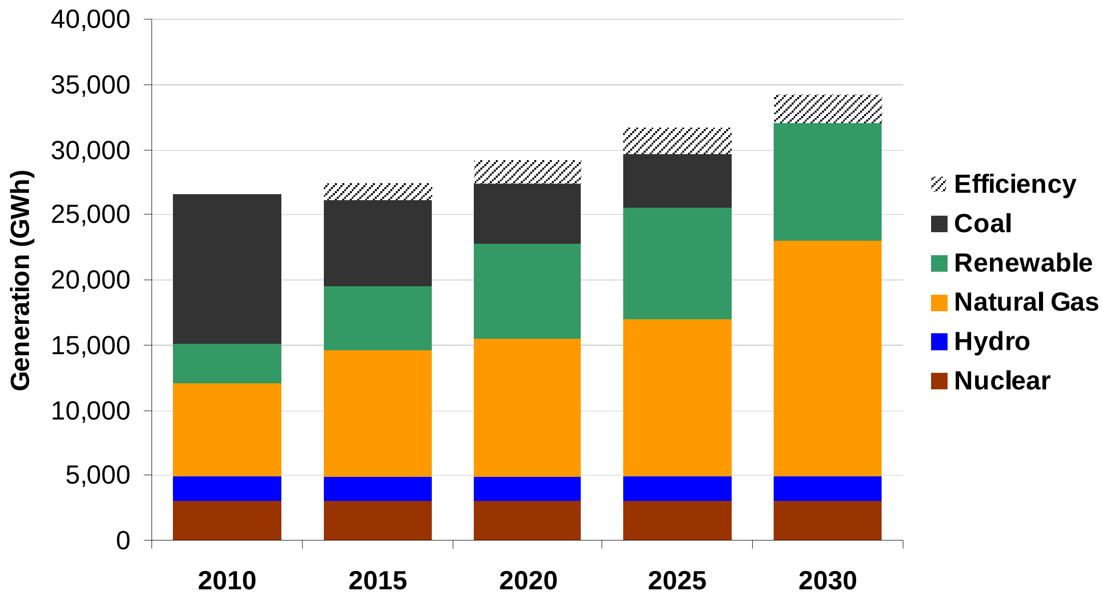

Figure 5. IRP Recommended scenario generation (GWh)

In the IRP Recommended Scenario, costs rise for consumers almost immediately, primarily due to the utility's CO_2 burden. In **Figure 6**, below, CO_2 costs are broken out in a separate category, and clearly cause the sharp increase in near-term costs. The cost of gas and coal are almost perfect substitutes in this analysis (i.e. the sum of the two is a flat line) suggesting that the cost of the overall scenario is *not* governed by a choice to replace coal generation with gas.

Increasing renewable energy use over time to meet RPS requirements do contribute to the overall cost of the scenario, but the costs of solar and wind energy are not significant drivers in this analysis. The large increase in costs in 2027 are associated with a large resource build-out to meet peak capacity requirements at the time of the IPP retirement. The cost of power from IPP coal, however, appears to decrease markedly because it appears to only supply limited energy towards the end of its commission in the late 2020s.

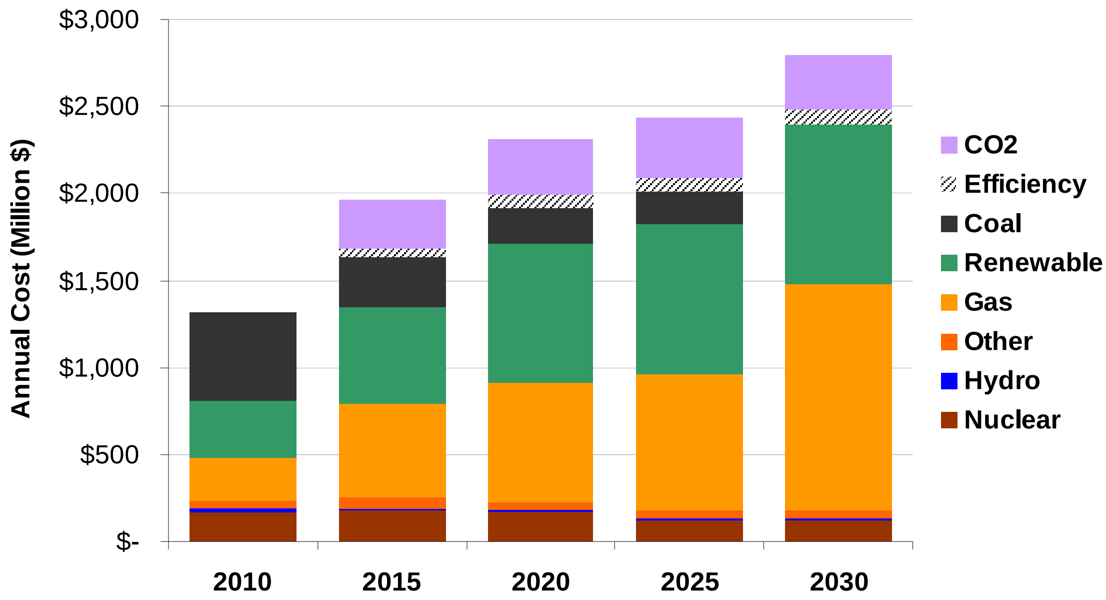

Figure 6. Generation cost components of IRP Recommended scenario (million 2010$)

Energy in the Green scenario (shown in **Figure 7**, below) decreases through the analysis period. This analysis estimates that LADWP can achieve 1.8% annual energy efficiency incremental savings each year through 2030, effectively turning the total load from an increase to a decreasing trend.

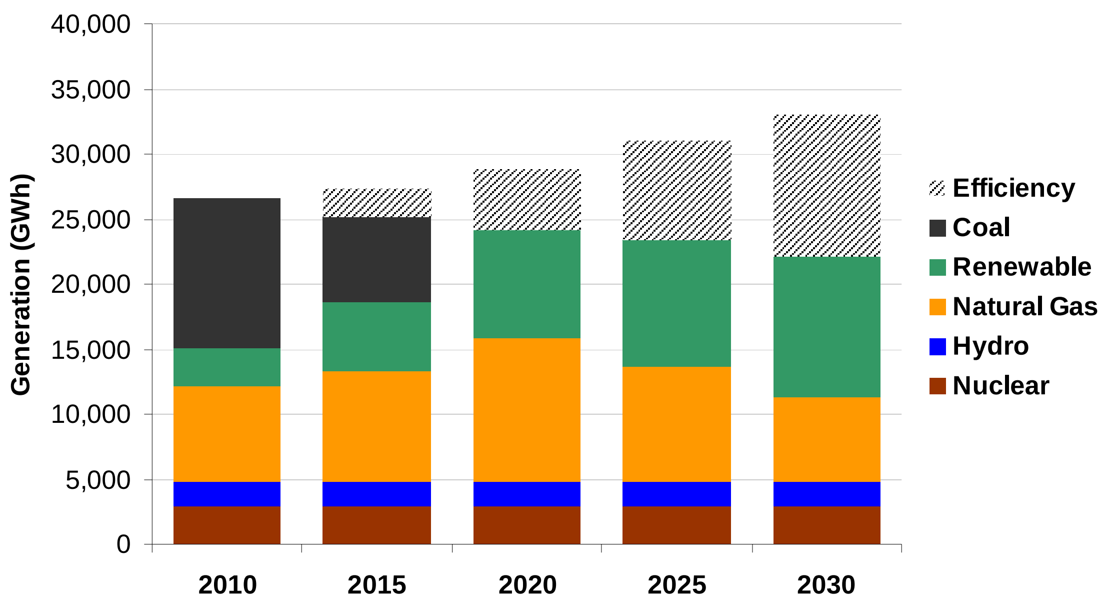

Figure 7. Green scenario generation sources (GWh)

In the Green alternative, the inefficient gas steam units in LADWP service territory are retired by 2020, and replaced in large part by combustion turbines, used to balance an increasing fraction of wind in the LA system. Decreasing load allows more dispatchable resources and the utility's significant pumped hydroelectric facility (Castaic) to be used for balancing intermittent generation. In this scenario, combined cycle units do not exceed 50% capacity factor.

In the Green scenario, the cost of additional incremental energy efficiency is assumed to be 4.0c/kWh; a fairly high cost in comparison to reported values from leading utilities.[13]

The Green scenario achieves a cumulative total of 35% demand reduction from baseline load growth by 2020. This type of aggressive efficiency stance would rigorously target building codes for existing and new construction, broadly expand weatherization and cool-roof projects and incentives, provide programs to replace residential and commercial air conditioners with efficient air-source heat pumps, educate consumers on thermostat control, and target a wide range of lighting uses. Due to decreasing load, the utility reaches nearly 50% renewable energy by 2030.

The costs of the Green Scenario fall below the IRP Recommended Scenario by 2015, as load starts to decrease and some of the new gas plants, such as the Haynes repowering project and part of the IPP replacement plant are no longer required. In particular, although the utility begins with a high CO_2 liability, the footprint decreases dramatically past 2020 (at the retirement of IPP) and most incremental costs are due to efficiency and renewable energy (see **Figure 8**, below).

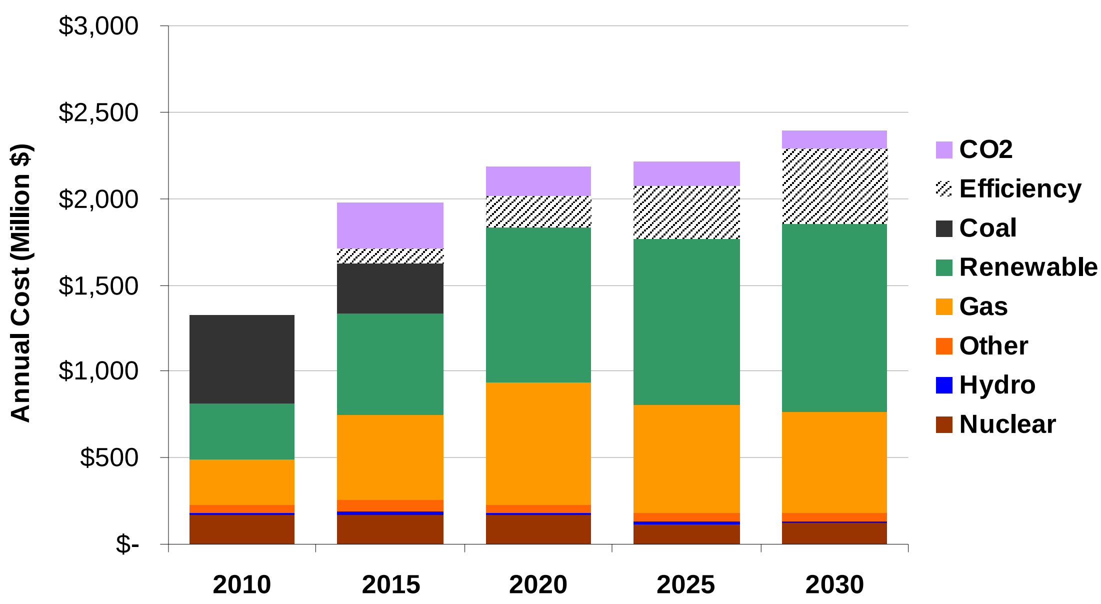

Figure 8. Stream of cost components of Green scenario compared to cost stream from IRP Recommended scenario

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[13] Research by Synapse Energy Economics. K. Takahashi and D. Nichols. 2008. The sustainability and costs of increasing efficiency impacts: evidence from experience to date. ACEEE Conference. August, 2008.

The green scenario may appear to present an unrealistically large fraction of energy from efficiency. In fact, we know that California has historically managed to stabilize per-capita use of energy, and is now working aggressively (along with other states) to decrease energy use through large-scale, deep energy efficiency programs. Historically, technological improvements, behavioral change, and improving building and appliance standards have enabled steep improvements in energy consumption. Used as an aggressive, serious, and targeted system, energy efficiency can reduce consumption, and it is reasonable to consider it as an equal in resource decisions – if it is monitored, verified, and administered well. **Figure 9,** below, shows the trajectory of energy efficiency requirements (in cumulative GWh) targeted by the energy efficiency programs in LADWP's assumed plans (the colored lines) and in our Efficiency and Green scenarios. These scenarios simply carry forward assumptions that it is in the LADWP customer's best interest to pursue all cost effective energy efficiency.

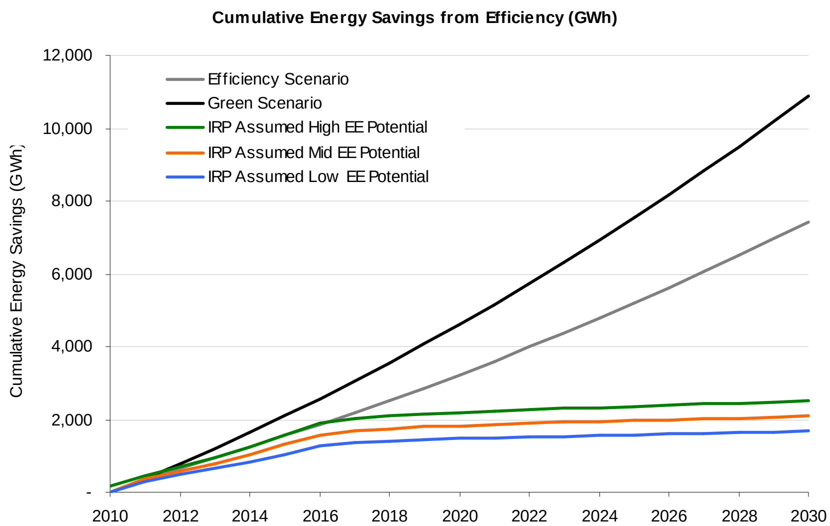

Figure 9. Cumulative energy savings from energy efficiency (GWh)

5. Conclusions

The analysis above demonstrates that under even the most conservative scenarios (a direct one-for-one replacement of coal with gas), LADWP ratepayers will not be penalized for shedding coal by 2020 instead of 2027. If LADWP targets efficiency as a serious, preferred resource rather than a short-term requirement, the city can not only transition off of coal easily, but LADWP customers will see a significant benefit in bills, relative to the plan put forward by the utility. An even more aggressive move towards efficiency and renewable resources can position LADWP as a leading utility in renewable energy and as a low-carbon leader, at even greater savings for the utility's customers.

6. Appendix A: Derivations and Assumptions

The energy, capacity, build-out, and cost estimates used in this analysis are all derived from non-confidential data made available through LADWP as part of, or in addition to, the 2010 IRP process. The data provided in the IRP are insufficient to reconstruct an estimate of the component costs of the 2010 IRP or allow a full evaluation of the decisions and assumptions made in the IRP process. However, LADWP provided a limited dataset of energy, capacity, and resource costs to the Natural Resources Defense Council (NRDC), which was reverse-engineered to estimate the component costs of generation used by LADWP in its 2010 IRP.

The dataset obtained from LADWP from NRDC will be referred to in this document as the "ancillary dataset".

Once the component costs were reverse-engineered, Synapse was able estimate the approximate cost of alternatives, increasing or decreasing specific resources as required to meet a specified portfolio. The following section describes the assumptions and process used to reverse-engineer the LADWP IRP cost estimate data provided to NRDC.

Reverse-Engineering LADWP IRP Cost Estimates

The database obtained from LADWP included annual estimated forward-going capacity (MW), generation (GWh), and costs (000$, assumed nominal) for fuel types of natural gas, coal, nuclear, LG hydro (assumed large hydroelectric), bio gas, geo[thermal], RPS hydro (assumed small hydro, renewable qualified), Solar, Wind, Energy Efficiency, and Other (including DR, losses, and co-generation). Streams of data from 2010 to 2030 were provided for six scenarios presented in the IRP: (a) 20% RPS, (b) 20% RPS with a GHG focus (i.e. early retirement of the IPP plant in 2020), (c) 35% RPS with high wind, (d) 35% RPS high wind with a GHG focus, and (e & f) 35% RPS with solar and solar with a GHG focus, respectively. Capacity, energy, and cost data were *not* provided by LADWP for the IRP Recommended Scenario. For the purposes of this analysis, we derived the costs of scenario (c) the 35% RPS with high wind focus. Once unit costs were established, we were able to re-engineer the IRP Recommended Case, and then the three given scenarios.

The following sections describe the derivation of each major fuel type used. We assumed that nuclear, large hydro, bio gas, geothermal, RPS hydro, and other did not change substantively between the various scenarios, and Synapse did not alter these values. Therefore, we maintained the capacity, energy, and costs as given for these resources.

Load Forecast

A load forecast was used to derive required natural gas capacity factors to meet load requirements, as well as test scenario assumptions about available energy and capacity, estimate transmission and distribution losses, estimate peak reserve requirements, and derive incremental energy efficiency (EE) fractions. The energy and peak load requirements were extracted from the 2010 IRP Table A-1, using the November 2010 Load Forecast. Fiscal year values were translated into calendar year energy and load requirements through interpolation.

Existing Supply-Side Resources

Existing resources (those listed in Appendix A), and their characteristics were derived from various tables in the IRP. Existing resources were listed in IRP Table 2-5. Renewable energy resources were generalized in this table, and so specific existing renewable resources were characterized from IRP Tables F-8 and F-9. All tables listed nameplate capacity, capacity available to LADWP, and "dependable capacity", the fraction of a resource which can be relied upon during peak periods.

Prime mover types, particularly with respect to existing natural gas units, were culled from the US EPA's Clean Air Market (CAM) 2010 "Facility Characteristics" dataset.[14]

Unit heat rates (in MMBTU/MWh) and estimated capacity factors were derived, where available, from public US DOE Energy Information Administration (EIA) data, particularly forms EIA 923 and 860 (fuel consumption and generation, and unit type, respectively). Where heat rates or capacity factors were unavailable, analogous units were used, usually at the same plant.

Carbon dioxide (CO_2) emissions rates were derived from EPA CAM (2010) annual reported emissions and generation.[15]

All units were assumed to operate through the full analysis period (2010 – 2030) unless explicitly marked as retired in a particular year.

New Supply-Side and Demand Response Resources

The 2010 IRP lists new supply-side (including repowers) and demand response resources in IRP Table N-5, including the fuel type, prime mover, online date, capacity, estimated capacity factor, generation, and capital cost (2011 – 2030). This information unto itself is insufficient to re-create the 2010 IRP cost stream and estimated consumer impacts, but can be used to inform the reverse engineering process.

Estimated "dependable fractions" for different resources (particularly stochastic resources such as wind and solar) were assigned from IRP Table L-1.[16] Capacity factors for demand response and wind were assumed at 1% and 27.3%, respectively (the later estimated to generate the correct amount of energy as assumed in the ancillary dataset).

CO_2 emissions rates were assumed to be similar to "best in class" analog units (0.62 tCO_2/MWh for combustion turbines and 0.42 tCO_2/MWh for combined cycle units).

Online dates were assumed to be those shown in IRP Table N-5, even though the total resource mix differs slightly between the IRP Recommended Scenario and the reverse-engineered IRP High Wind scenario.

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[14] US EPA. 2010. Clean Air Markets (CAM) division. Facility Attributes and Contacts. Available online at http://camddataandmaps.epa.gov/gdm/

[15] US EPA. 2010. Clean Air Markets (CAM) division. Unit Level Emissions (2010).

[16] "Dependable fraction" is shorthand for effective load carrying capability (ELCC). ELCC describes the maximum expected capacity which can be "depended" upon for meeting peak load requirements. If a wind farm operates intermittently, there is only a small fraction of the farm (or a collection of farms) which can be relied upon during peak hours. While this number is potentially very different for stochastic resources in different areas, utilities often use a single rule of thumb value, such as 10% for wind or solar.

Energy Efficiency

Energy efficiency is represented in the IRP at three different cost levels of availability, at 2.6, 4.0, and 5.6c/kWh; these costs appear to allow LADWP to supply customers with “low”, “most likely”, and “high” levels of energy efficiency, respectively. In the ancillary dataset, total energy offset from energy efficiency appears to correspond with the highest penetration of energy efficiency. However, the costs (normalized to constant 2010$) are inconsistent with the 5.7c/kWh LADWP estimated cost of this “high” level of efficiency. The cost of energy efficiency appears to be assumed to be 2.7c/kWh in the data obtained from the utility, but this is inconsistent with the assumptions listed in the publicly available IRP document.

Instead, the “most likely” penetration of efficiency, coupled with the “most likely” cost of efficiency, at 4c/kWh (a cost higher than in leading utilities, but within a conservative range), produces a cost most closely analogous to the costs seen in the ancillary dataset. Without guidance from the utility, we assumed that the ancillary dataset was erroneous in this matter, and remained consistent with the submitted 2010 IRP.

Figure 10, below, shows the estimated cost streams associated with efficiency from the 2010 IRP (colored lines) and the estimated cost of efficiency in the ancillary dataset (black dashed line).

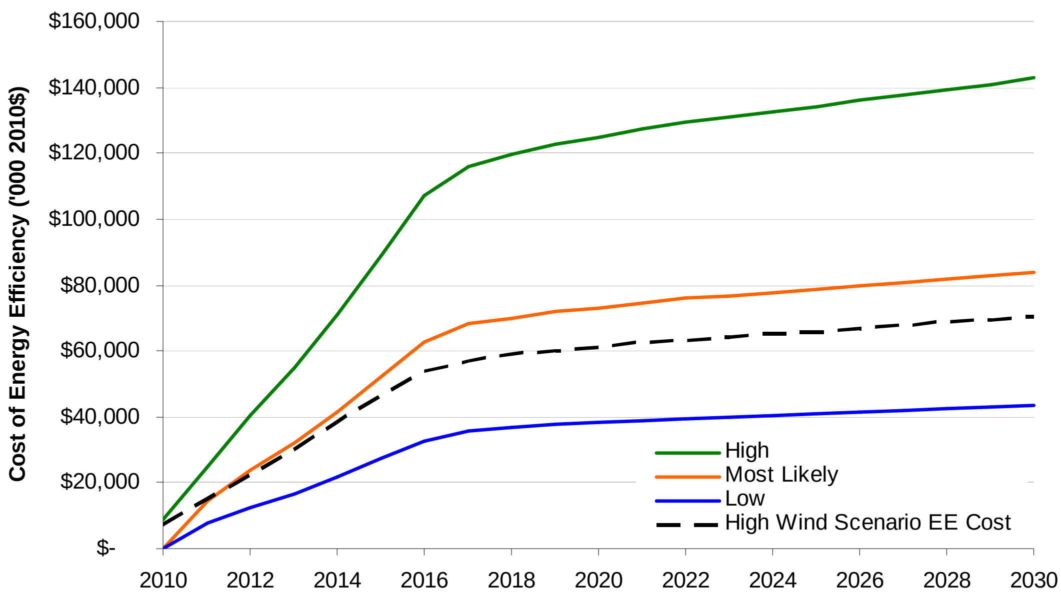


Figure 10. Estimated cost of energy efficiency at low, "likely", and high levels of penetration, and the high wind scenario estimated cost

Energy efficiency in the amount given by the “most likely” scenario was deducted from the total load requirement to yield a net energy demand. Transmission and other losses were then added back in (at 13%, based on Table A-1) to yield an annual generation requirement to meet load (net of energy efficiency). Peak load requirements were reduced by a fraction to account for efficiency savings during peak periods; to accomplish this reduction, we used the effective capacity factor of energy efficiency reported in the ancillary dataset, calculated at approximately 53%. Peak reductions were calculated as (cumulative energy efficiency [in GWh])/(8.76 * 53%).

CO_2 Prices

Prices for greenhouse gas emissions (carbon dioxide equivalent, CO_2) are derived from IRP Figure 3-3, and converted to constant 2010$.

Coal

A total coal energy, capacity, and cost were given in the ancillary dataset. To derive the LADWP estimated unit cost of coal generation and reverse-engineer coal costs, we assumed that:

- The cost of coal energy as given in the ancillary dataset includes the cost of CO_2 emissions;
- The CO_2 emissions rate assumed by LADWP is consistent with the reported rate in CAM 2010;
- The capacity factors for coal are assumed to remain constant at approximately 2008 levels;
- The cost of coal power from Navajo and IPP are approximately the same (given no other information);
- Navajo is taken out of service in the High Wind scenario in 2020 (as stated in the IRP)

Using these assumptions, we derived a unit cost of coal, as shown in **Figure 11**, below. The figure shows the total coal price ($/MWh) before the CO_2 price is removed, after the CO_2 price is removed, and the estimated price used for this analysis.

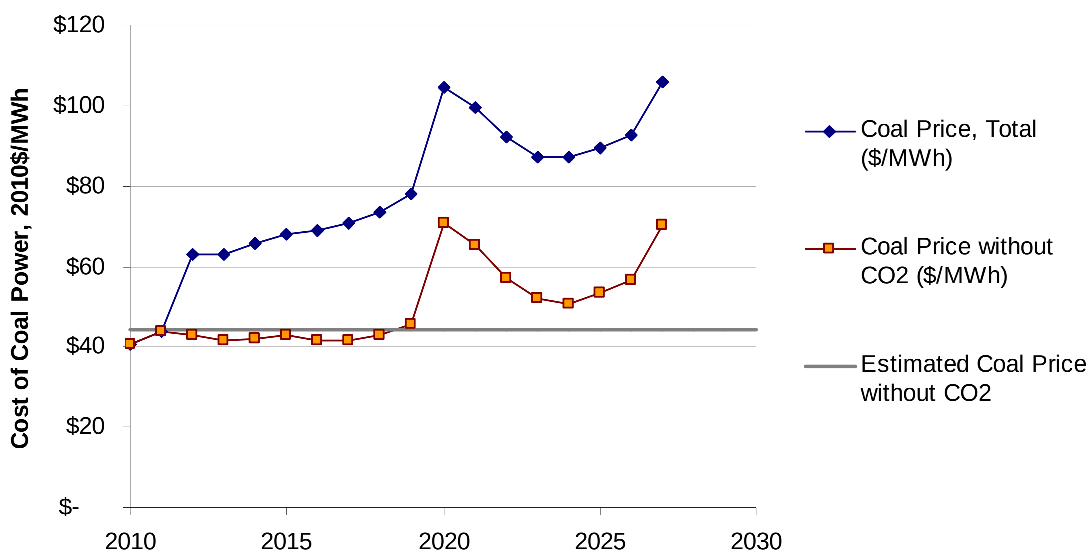


Figure 11. Assumed cost of coal power in 2010 IRP, derived from ancillary dataset.

As can be seen in the figure, the price of coal energy spikes in 2020, and then decreases towards 2025, increasing again thereafter. There is no additional information as to why this spike occurs: we can only surmise that the costs of decommissioning Navajo have been included as a cost to consumers, although the IRP states that the LADWP share of Navajo will be sold, not decommissioned.

The price increase at the end of the series may be a function either of decommissioning IPP, or potentially a price premium paid by LADWP for capacity from the IPP station, while decreasing its take of energy from the plant over time. This capacity / energy discrepancy is described below.

We assume that the cost of coal power in this analysis is approximately $44/MWh.

Coal capacity / energy discrepancy

In the ancillary dataset, coal shows a significant discrepancy between energy served and capacity available from the particular resource. As a rule, we would expect that for a baseload resource such as coal, a full owner (such as LADWP) would access capacity and energy in equal proportion. For example, if an owned 500 MW plant has a capacity factor of 85%, then we would expect an owner to take 3,720 GWh of energy from the plant. If the owner has excess energy, the remainder can be sold on the market, but LADWP's contract with IPP stipulates "take or pay", i.e. that LADWP must purchase the energy from the plant and then sell it. In most frameworks, LA would still be the owner of this coal energy, and hence also the owner of the CO_2 emissions, until IPP is decommissioned.

In the case of the ancillary dataset, the effective capacity factor of coal shrinks from 82% to 70% in 2017, down to 50% by 2026, suggesting that LADWP has constructed a financial process to allow it to take capacity and yet not take responsibility for the coal energy emerging from its IPP resource. It would appear that LADWP also does not then take responsibility for the CO_2 emissions from IPP sales as well. Without further explanation in the IRP, we are left only with supposition. It is unclear if LADWP expects to be able to sell its coal energy outside of California, attempting to circumvent California's efforts to curb greenhouse gas emissions, or if the utility somehow expects to slowly ramp down IPP's output in violation of their long-term contract.

To match the apparently steadily falling coal energy in the ancillary dataset, we deconstruct the coal power take from IPP into three components, and decrease energy from these components accordingly (see IRP Table F-2). To match energy assumptions in the ancillary dataset, we closed the PPA with UP&L (72 MW) in 2010, decreased the Excess Sales clause (172 MW available) to 100 MW in 2011 and to zero in 2015, and decremented the primary purchase agreement (803 MW) from 2015 to 2019 (to 560 MW), and again from 2024 through 2027 (to zero MW). While this is unlikely the way that IPP will be retired (rather than shares sold or repowered at a single time), this pattern replicates energy and costs accurately for the purposes of re-engineering the IRP (**Figure 12**).

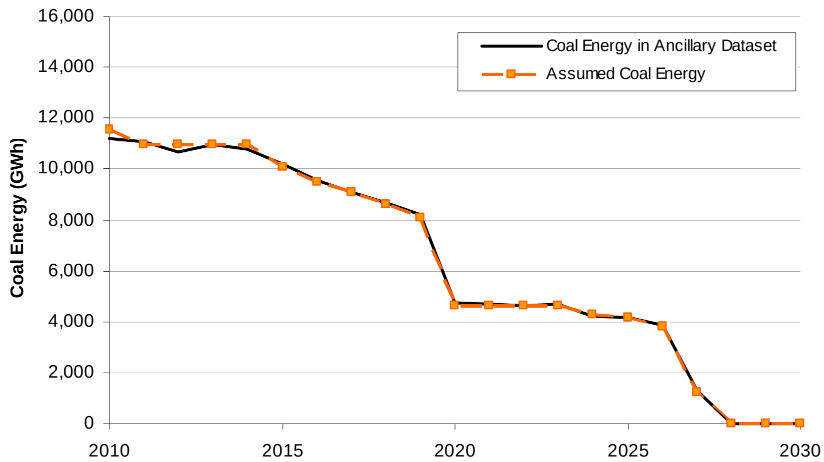


Figure 12. Coal energy in ancillary dataset, and assumed for high wind scenario analog

Natural Gas

We match natural gas capacity, energy, and costs using assumptions culled from the 2010 IRP. Natural gas price forecasts are derived from values shown in IRP Figure 3-2.

New natural gas units are subdivided into combined cycle and combustion turbine units, including repowered gas steam units. We assume that, for the purposes of the high wind scenario analog case, capacity factors are held constant for new units according to assumptions given in IRP Tables 3-4 and N-5. The cost of energy for each given resource is derived from fuel costs (IRP Figure 3-2) and heat rate (IRP Table N-1), as well as variable and fixed O&M costs (IRP Table N-1), and CO_2 prices (IRP Figure 3-3). CO_2 emissions rates are derived from IRP Table N-1. Financial assumptions for amortizing capital costs are derived from IRP Table L-2. We build new units according to the schedule given in IRP Table N-5, and cost them accordingly.

Existing natural gas units are priced according to total heat input for gas steam, combustion turbines, and combined cycle units, and the natural gas price. Combined cycle units are allowed to vary in capacity factor to meet annual energy requirements.

While space was left in the model for fixed and variable O&M costs for existing units, the sum of new unit costs and existing unit fuel costs (and CO_2 costs) almost precisely matched the total sum estimated cost of natural gas energy as given in the ancillary dataset (see **Figure 13**). Therefore, no additional amendments were made to this analysis to account for O&M or remaining plant balances on existing units.

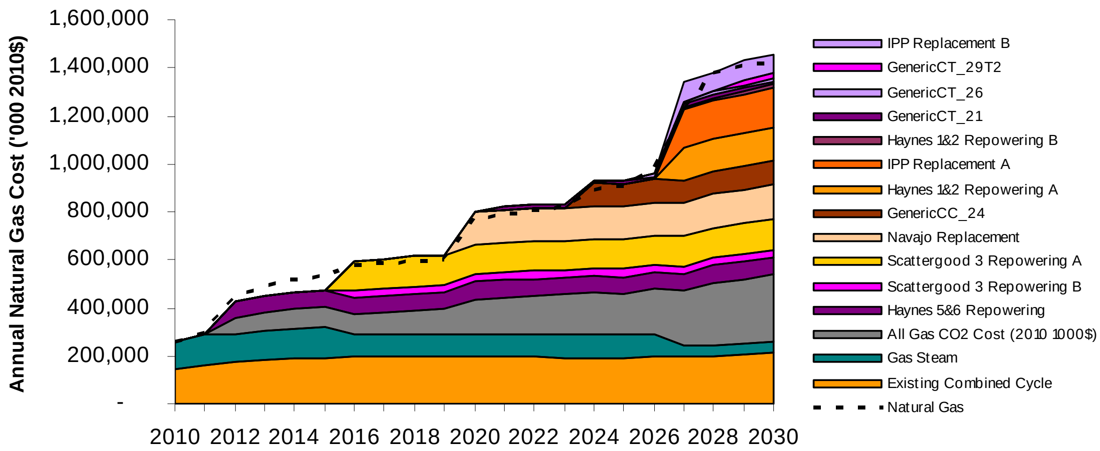
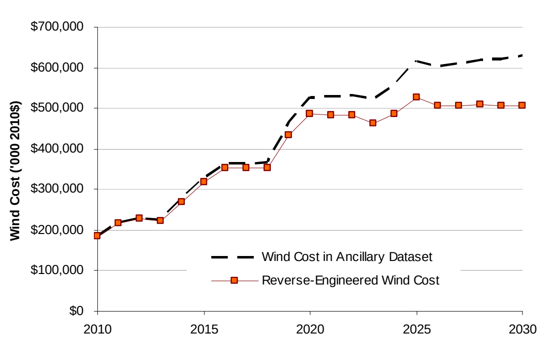


Figure 13. Annual natural gas cost as given in the ancillary dataset (dotted line) and as reverse-engineered (colored wedges), including CO_2 cost in gray.

Wind and Solar

Wind costs were derived from the resources discussed in IRP Table F-8. Because the resources listed in F-8 only apply the IRP Recommended Scenario, we added ancillary wind in the reverse-engineering case only to attempt to match High Wind scenario energy. Incremental wind capacity was added to match the ancillary dataset High Wind case. The costs for this wind energy were simply assigned a levelized cost of $90/MWh according to IRP Table 3-4. The cost of wind energy in the ancillary dataset appears to increase towards the later part of the analysis period (see **Figure 14,** below) for unknown reasons.

Solar costs were derived similarly to the wind costs. New solar resources were derived from the IRP, and then decremented to meet the targets specified in the High Wind case for reverse-engineering purposes. The cost of solar energy was assumed to be the average of the solar PV (PPA), utility in-basin and utility in Owens valley, or $164/MWh (derived from IRP Table 3-4). These costs appear to accurately reproduce the total cost pattern in the ancillary dataset until 2018, when the ancillary dataset appears to choose less expensive resources. With no additional information on the resources chosen in specific years and their estimated costs, we are compelled to accept this error.



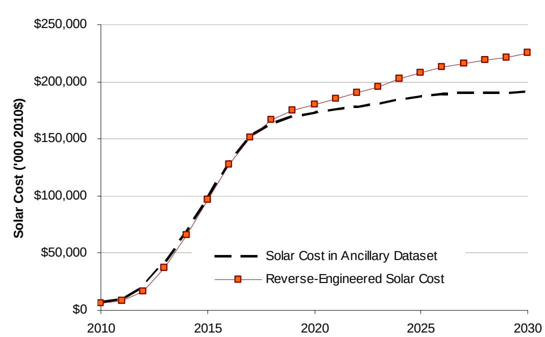


Figure 14. Cost of wind energy (left) and solar energy (right) in ancillary dataset and reverse-engineered

Reverse-Engineered Costs

Costs, capacity, and energy for non-varying resources (geothermal, nuclear, hydroelectric, bio gas and "other") were simply transferred from the High Wind case, and assumed to apply to all other scenarios.

In total, the reverse engineered costs closely approximate the LADWP supplied cost stream, labeled "High Wind Total Cost" in **Figure 15** below. There are numerous patterns in the LADWP supplied data for which we cannot account, but the near approximation allows us to roughly estimate the cost differences which would result from modifications to the IRP Recommended scenario.

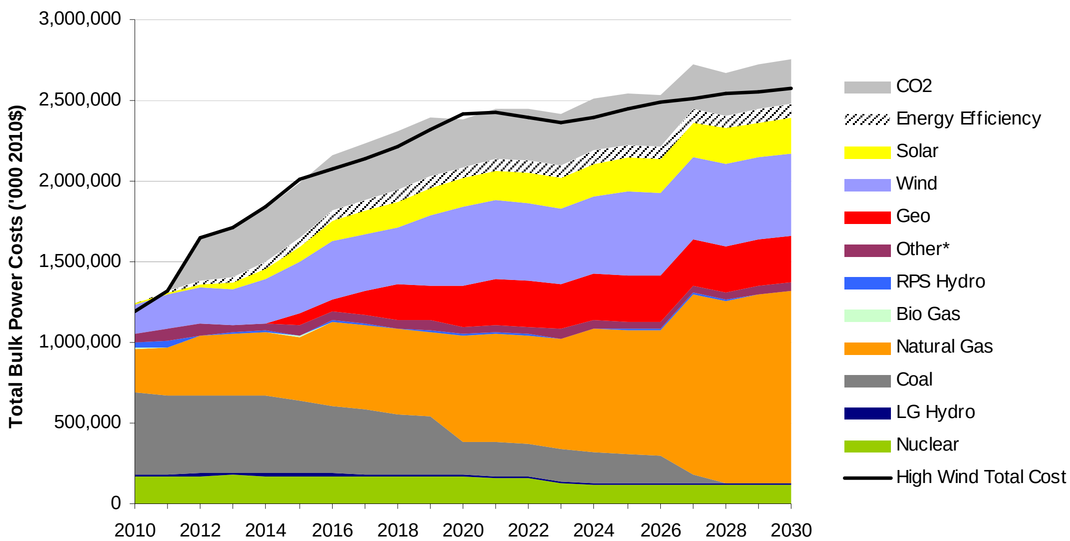


Figure 15. Cost stream of the high-wind case from the ancillary dataset against reverse-engineered costs.

The reverse-engineered costs and prices from this study are used to create the three scenarios explored in this analysis. Using explicit costs of coal, gas, wind, solar, and efficiency, we are able to estimate the costs of replacing IPP and moving LADWP towards a greener future.

		IRP Recommended Scenario		Replacement Scenario		Efficiency Scenario		Green Scenario	
Existing Units	**Unit Type**	**Unit Capacity (MW)**	**Retirement Year**	**Unit Capacity (MW)**	**Retirement Year**	**Unit Capacity (MW)**	**Retirement Year**	**Unit Capacity (MW)**	**Retirement Year**
Harbor 1	Existing Combined Cycle	82	-	82	-	82	-	82	-
Harbor 2	Existing Combined Cycle	82	-	82	-	82	-	82	-
Harbor 5	Existing Combined Cycle	65	-	65	-	65	-	65	-
Harbor 10	Combustion Turbine	47	-	47	-	47	-	47	-
Harbor 11	Combustion Turbine	47	-	47	-	47	-	47	-
Harbor 12	Combustion Turbine	47	-	47	-	47	-	47	-
Harbor 13	Combustion Turbine	47	-	47	-	47	-	47	-
Harbor 14	Combustion Turbine	47	-	47	-	47	-	47	-
Haynes 1	Gas Steam	222	2027	222	2027	222	**2020**	222	**2020**
Haynes 2	Gas Steam	222	2027	222	2027	222	**2020**	222	**2020**
Haynes 5	Gas Steam	292	2012	292	2012	292	2012	292	2012
Haynes 6	Gas Steam	243	2012	243	2012	243	2012	243	2012
Haynes 7	Combustion Turbine	2	-	2	-	2	-	2	-
Haynes 8	Existing Combined Cycle	250	-	250	-	250	-	250	-
Haynes 9	Existing Combined Cycle	163	-	163	-	163	-	163	-
Haynes 10	Existing Combined Cycle	163	-	163	-	163	-	163	-
Scattergood 1	Gas Steam	183	-	183	-	183	**2016**	183	**2016**
Scattergood 2	Gas Steam	184	-	184	-	184	**2016**	184	**2016**
Scattergood 3	Gas Steam	450	2016	450	2016	450	2016	450	2016
Valley 5	Combustion Turbine	43	-	43	-	43	-	43	-
Valley 6	Existing Combined Cycle	159	-	159	-	159	-	159	-
Valley 7	Existing Combined Cycle	159	-	159	-	159	-	159	-
Valley 8	Existing Combined Cycle	215	-	215	-	215	-	215	-
Intermountain 1	Coal	601	2027	601	**2020**	601	**2020**	601	**2020**
Intermountain 2	Coal	601	2027	601	**2020**	601	**2020**	601	**2020**
Intermountain Power Sales Contrac	Coal	803	2020	803	2020	803	2020	803	2020
Intermountain PPA with UP&L	Coal	72	2010	72	2010	72	2010	72	2010
Intermountain Excess Sales	Coal	172	2015	172	2015	172	2015	172	2015
Navajo 1	Coal	159	2014	159	2014	159	2014	159	2014
Navajo 2	Coal	159	2014	159	2014	159	2014	159	2014
Navajo 3	Coal	159	2014	159	2014	159	2014	159	2014
Palo Verde 1	Nuclear	129	-	129	-	129	-	129	-
Palo Verde 2	Nuclear	129	-	129	-	129	-	129	-
Palo Verde 3	Nuclear	129	-	129	-	129	-	129	-
Castaic Var	Hydro	1,247	-	1,247	-	1,247	-	1,247	-
Hoover Var	Hydro	491	-	491	-	491	-	491	-
Aqueduct System Var	Hydro	83	-	83	-	83	-	83	-
Owens Valley Var	Hydro	13	-	13	-	13	-	13	-
Owens Gorge Var	Hydro	113	-	113	-	113	-	113	-
Existing wind, as of 2009 Var	Wind	528	-	528	-	528	-	528	-
New wind in 2010 Var	Wind	327	-	327	-	327	-	327	-
Existing Solar as of 2009 Var	Solar	19	-	19	-	19	-	19	-
RE, minus 2009 existing wind and s	Existing Renewable	142	-	142	-	142	-	142	-
State Capacity 0	State Entitlement	-120	-	-120	-	-120	-	-120	-

		IRP Recommended Scenario		Replacement Scenario		Efficiency Scenario		Green Scenario	
New Units and Projects	Unit Type	Nameplate Capacity (MW)	Year Online	Nameplate Capacity (MW)	Year Online	Nameplate Capacity (MW)	Year Online	Nameplate Capacity (MW)	Year Online
Haynes 5&6 Repowering	Combustion Turbine	600	2012	600	2012	600	2012	600	2012
Scattergood 3 Repowering A	New Combined Cycle	312	2016	312	2016	**500***	2016	**300***	2016
Scattergood 3 Repowering B	Combustion Turbine	200	2016	200	2016	200	2016	200	2016
Haynes 1&2 Repowering A	New Combined Cycle	312	2027	312	2027	**312***	**2020**	**0***	**2020**
Haynes 1&2 Repowering B	Combustion Turbine	100	2027	100	2027	100	**2020**	100	**2020**
DR_Phase 1	Demand Response	50	2011	50	2011	50	2011	50	2011
DR_Phase 2	Demand Response	50	2012	50	2012	50	2012	50	2012
DR_Phase 3	Demand Response	50	2013	50	2013	50	2013	50	2013
DR_Phase 4	Demand Response	50	2014	50	2014	50	2014	50	2014
DR_Phase 5	Demand Response	50	2018	50	2018	50	2018	50	2018
DR_Phase 6	Demand Response	50	2019	50	2019	50	2019	50	2019
DR_Phase 7	Demand Response	50	2020	50	2020	50	2020	50	2020
DR_Phase 8	Demand Response	50	2021	50	2021	50	2021	50	2021
DR_Phase 9	Demand Response	50	2022	50	2022	50	2022	50	2022
DR_Phase 10	Demand Response	50	2023	50	2023	50	2023	50	2023
GenericCT_21	Combustion Turbine	100	2021	100	2021	100	2021	100	2021
GenericCC_24	New Combined Cycle	312	2024	312	2024	312	2024	312	**2050**
GenericCT_26	Combustion Turbine	100	2026	100	2026	100	2026	100	2026
GenericCT_29T2	Combustion Turbine	200	2029	200	2029	200	2029	200	2029
Navajo Replacement	New Combined Cycle	500	2014	500	2014	500	2014	500	2014
IPP Replacement A	New Combined Cycle	520	2027	520	**2020**	520	**2020**	520	**2020**
IPP Replacement B	Combustion Turbine	600	2027	600	**2020**	**300**	**2020**	**300**	**2020**
Generic RPS 1	Generic Renewable	80	2023	80	2023	80	2023	80	2023
Generic RPS 2	Generic Renewable	80	2025	80	2025	80	2025	80	2025
Geo_PG1	Geothermal	80	2015	80	2015	80	2015	80	2015
Geo_PG2	Geothermal	80	2017	80	2017	80	2017	80	2017
Geo_PG3	Geothermal	80	2018	80	2018	80	2018	80	2018
Geo_PG4	Geothermal	80	2020	80	2020	80	2020	80	2020
Solar_FIT	Solar	150	2012	150	2012	150	2012	150	2012
Solar_PPA1	Solar	50	2015	50	2015	50	2015	50	2015
Solar_PPA2	Solar	50	2018	50	2018	50	2018	50	2018
Solar_PPA3	Solar	50	2021	50	2021	50	2021	50	2021
Solar_PPA4	Solar	50	2024	50	2024	50	2024	50	2024
Solar_PPA5	Solar	50	2027	50	2027	50	2027	50	2027
Solar_PPA6	Solar	50	2030	50	2030	50	2030	50	2030
Solar_DWP_Built (In-Basin)	Solar	120	2010	120	2010	120	2010	120	2010
Solar_DWP_Built (Owens)	Solar	200	2013	200	2013	200	2013	200	2013
Solar_Customer_Net-metered	Solar	225	2010	225	2010	225	2010	225	2010
Wind_PG1	Wind	101	2012	101	2012	101	2012	**200**	2012
Wind_PG2	Wind	101	2014	101	2014	101	2014	**200**	2014
Wind_PG3	Wind	130	2019	130	2019	130	2019	**400**	2019
Wind_PG4	Wind	98	2026	98	2026	98	2026	**400**	2026
Wind Pine CYN	Wind	141	2016	141	2016	141	2016	141	2016

* Unit replacement is a peaking combustion turbine rather than the 2010 IRP proposed combined cycle.