2023 Power Integrated Resource Plan

Los Angeles Department of Water and Power

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1 Executive Summary

The Los Angeles Department of Water and Power (LADWP) is submitting this 2023 Integrated Resource Plan (IRP) to the California Energy Commission (CEC) as mandated by California Senate Bill 350 (SB 350). This IRP outlines LADWP's minimum investments needed to achieve the clean energy goals set by California Senate Bill 100 (SB 100) and California Senate Bill 1020 (SB 1020).

1.1 Related Planning Efforts Conducted by LADWP

The 2022 SLTRP envisions a range of scenarios designed to reach an ambitious goal: achieving 100% clean energy by 2035, in alignment with the vision set by the Los Angeles City Council in September 2021. In line with this vision, the 2022 SLTRP's Recommended Case sets a resolute target of reaching 100% clean energy by January 1, 2035. Moreover, recognizing the importance of State of California SB100 energy goals, the 2022 SLTRP thoughtfully evaluated the "SB 100 case" to provide a clear roadmap toward fulfilling these obligations.

It is crucial to underline that LADWP's commitment to meeting the SB 100 RPS Goals of achieving zero-carbon energy by 2045 remains unwavering. While the 2022 SLTRP's Recommended Case offers a conceptual plan, it acknowledges the complexities associated with technology availability, implementation feasibility, system reliability, and affordability. These challenges are recognized as potential risks that may impact the transition to 100% clean energy. LADWP is dedicated to addressing these challenges head-on, and future iterations of the SLTRP will meticulously consider various constraints, ensuring that the path to clean energy remains steadfast, optimizing the Power System resource plan to uphold reliability, resilience, environmental responsibility, and affordability while achieving the ambitious zero-carbon energy goals set forth by SB 100.

1.2 Power System Overview

The Los Angeles Department of Water and Power (LADWP) is the nation’s largest municipal utility with a net maximum plant capacity of 10,664 megawatts (“MW”) and net dependable capacity of 8,101 MW as of August 31, 2022. The Power System’s highest instantaneous peak demand registered 6,502 MW on August 31, 2017. We are responsible for meeting the electric and water requirements of our service area and provide service almost entirely within the boundaries of the City of Los Angeles (LA). This service area encompasses approximately 473 square miles and is populated by approximately 4.0 million residents. In Fiscal Year 2020-2021, LADWP supplied 20,936 gigawatt-hours (“GWh”) to more than 1.55 million residential and business customers, in addition to more than 5,100 customers in California’s Owens Valley.

Commercial, industrial, and governmental customers consumed about 63% of the electricity in Los Angeles. As of Fiscal Year 2021-2022, LADWP had an approved total Power System budget of $4.9 billion, comprised of $1.8 billion for capital projects, $1.6 billion for operations and maintenance, and $1.5 billion for fuel and purchased power.

As shown in Figure 1, LADWP also has vertically-integrated power generation, transmission, and distribution systems that span over five Western U.S. states. Within the Los Angeles Basin, LADWP currently owns and operates four natural gas-fired generating stations (often referred to as the “in-basin” power plants):

- Harbor Generating Station, located near the Port of Los Angeles
- Haynes Generating Station, located in Long Beach
- Scattergood Generating Station, located near Los Angeles International Airport
- Valley Generating Station, located in the San Fernando Valley

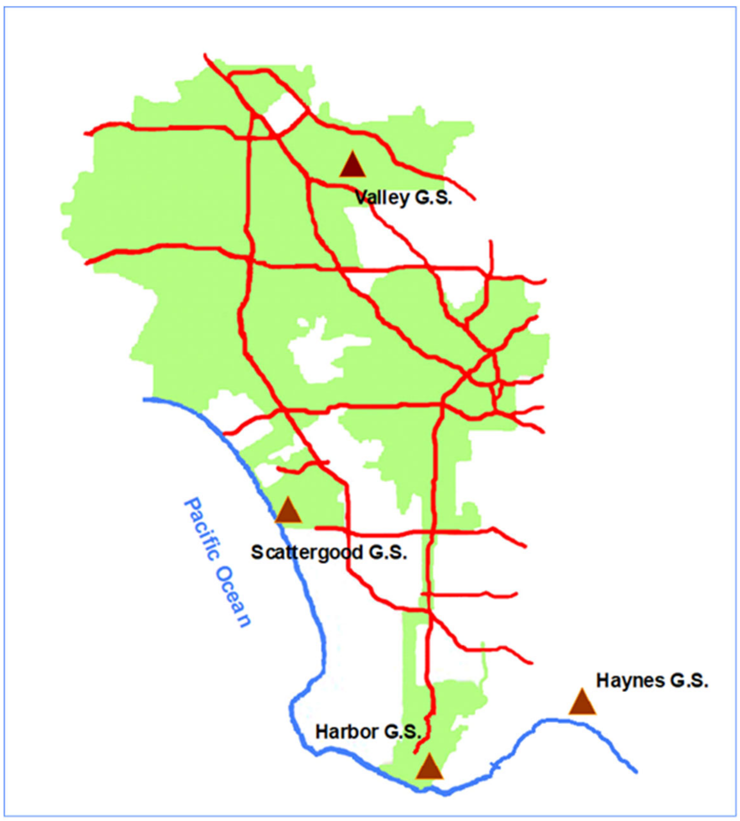


Figure 1. LADWP’s "in-basin" generating stations.

Additionally, LADWP owns and operates the Castaic Power Plant, a 1,320 MW pumped-storage hydroelectric generation facility located in Castaic, California. As of 2021, LADWP has over 550

MW of total installed local solar, leading Los Angeles to be designated the number one solar city in the nation from 2014 to 2016, 2018 to 2020, and once again in 2022.

LADWP also has out-of-state contracts for a portion of the generating capacity from the Intermountain Power Project—a coal-fired power plant located in Delta, Utah set for retirement in 2025, the Hoover Dam hydroelectric power plant in Nevada, and the Palo Verde Generating Station, a nuclear power plant located in Arizona (Figure 6).

On the renewable energy front, LADWP owns and has power purchase agreements for a diverse number of renewable energy generating facilities, including several solar, wind, and small hydroelectric facilities in California's Owens Valley, wind facilities located in Utah, New Mexico, Oregon, Wyoming, and Washington State, and geothermal and solar facilities in California and Nevada (Figure 2). Combined with the in-basin renewable energy generation resources, an estimated 35% of LADWP's power resources in the year 2021 were eligible renewable energy resources, as shown in Figure 3. Furthermore, that number increased to 55% when eligible hydroelectric and nuclear energy were included as part of a broader clean energy category. LADWP has made these substantial achievements in renewable energy procurement in just under two decades and is accelerating the rate of renewable energy adoption.

Figure 2. Red Cloud Wind Project, located in New Mexico.

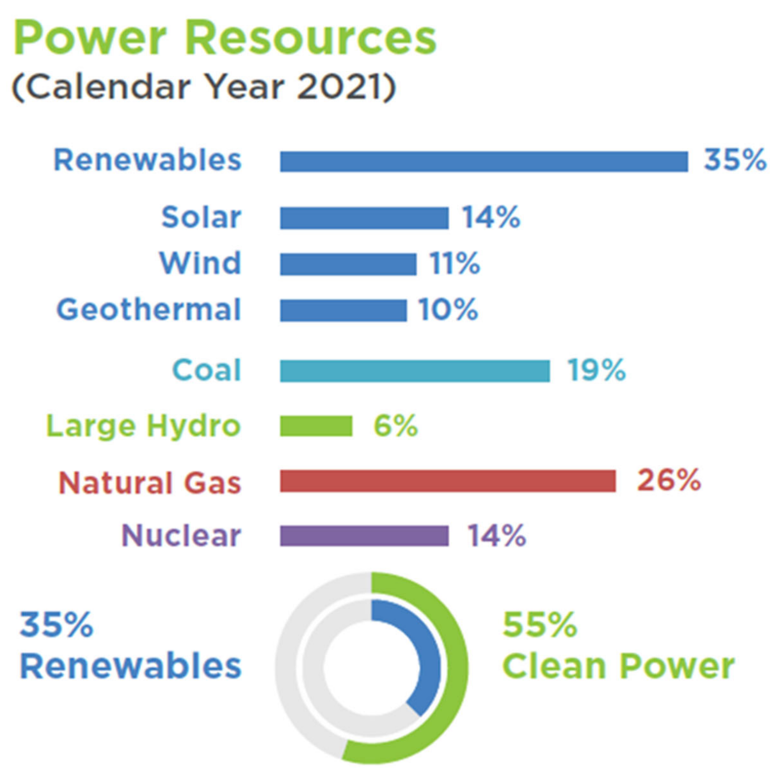


Figure 3. Percentage Breakdown of Power Resources, Calendar Year 2021. Based on energy used to supply retail customer load on an annual basis.

Figure 4. Historical Percentage of Eligible Power System Renewable Energy Resources, 2002-2021. Based on energy used to supply retail customer load on an annual basis.

Figure 4 shows LADWP's historical percentage of eligible renewable energy used to supply retail customer load on an annual basis. As shown in Figure 5, LADWP has achieved significant reductions in reducing greenhouse gas (GHG) emissions through a combination of replacing coal-fired generation, adding more efficient gas generation, expanding energy efficiency, and integrating renewable energy. For example, LADWP achieved and exceeded the GHG emission reduction target set by California Senate Bill 32 to reduce GHG emissions to 40% below 1990 levels by 2030 in 2016, 14 years ahead of schedule. As of 2021, LADWP's GHG emissions were approximately 7.0 million metric tons (MMT), nearly 60% below the 1990 emissions baseline of 17.9 MMT.

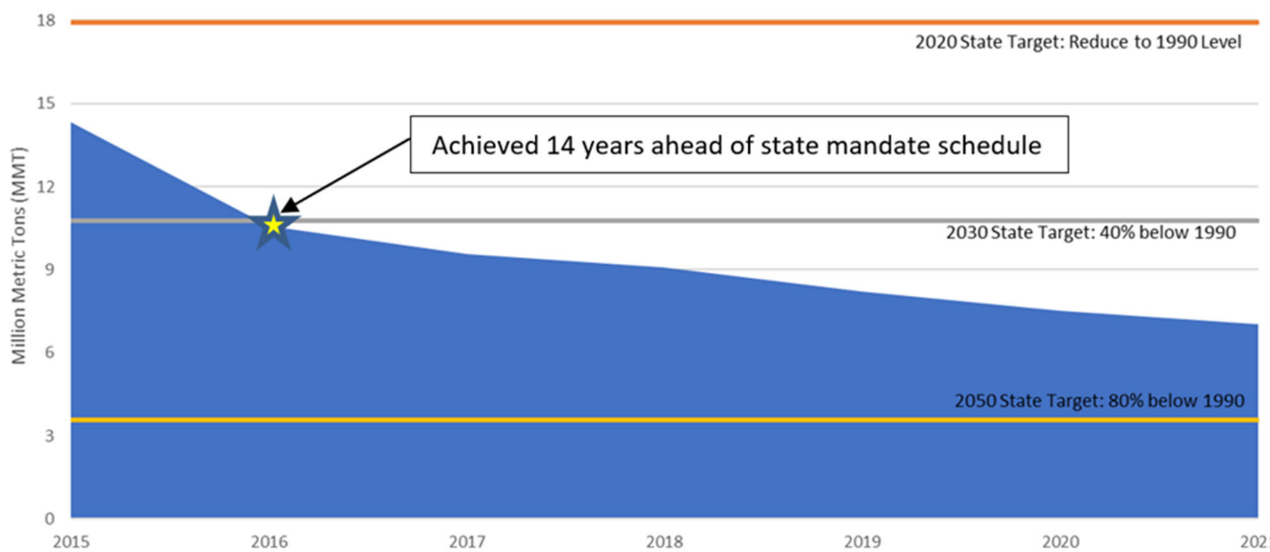


Figure 5. Historical LADWP GHG Emissions, 2015-2021.

As shown in Figure 6, with respect to transmission, LADWP has 4,040 miles of overhead transmission circuits (alternating current and direct current) and 135 miles of underground transmission circuits. On the distribution side, LADWP has 7,265 miles of overhead distribution lines, 3,807 miles of underground distribution cables, and 167 distribution substations. In terms of collaboration with neighboring utilities and system operators, LADWP serves as a balancing authority for the City of Glendale's and City of Burbank's electric utilities, helping balance generation, power flows, and demand across the interconnected systems in real-time. LADWP is also a participant in the California Independent System Operator's Western Energy Imbalance Market (WEIM), which helps electric grid operators in the region share energy reserves and optimize renewable energy resources, helps ensure reliability, lowers costs, and lowers greenhouse gas emissions.

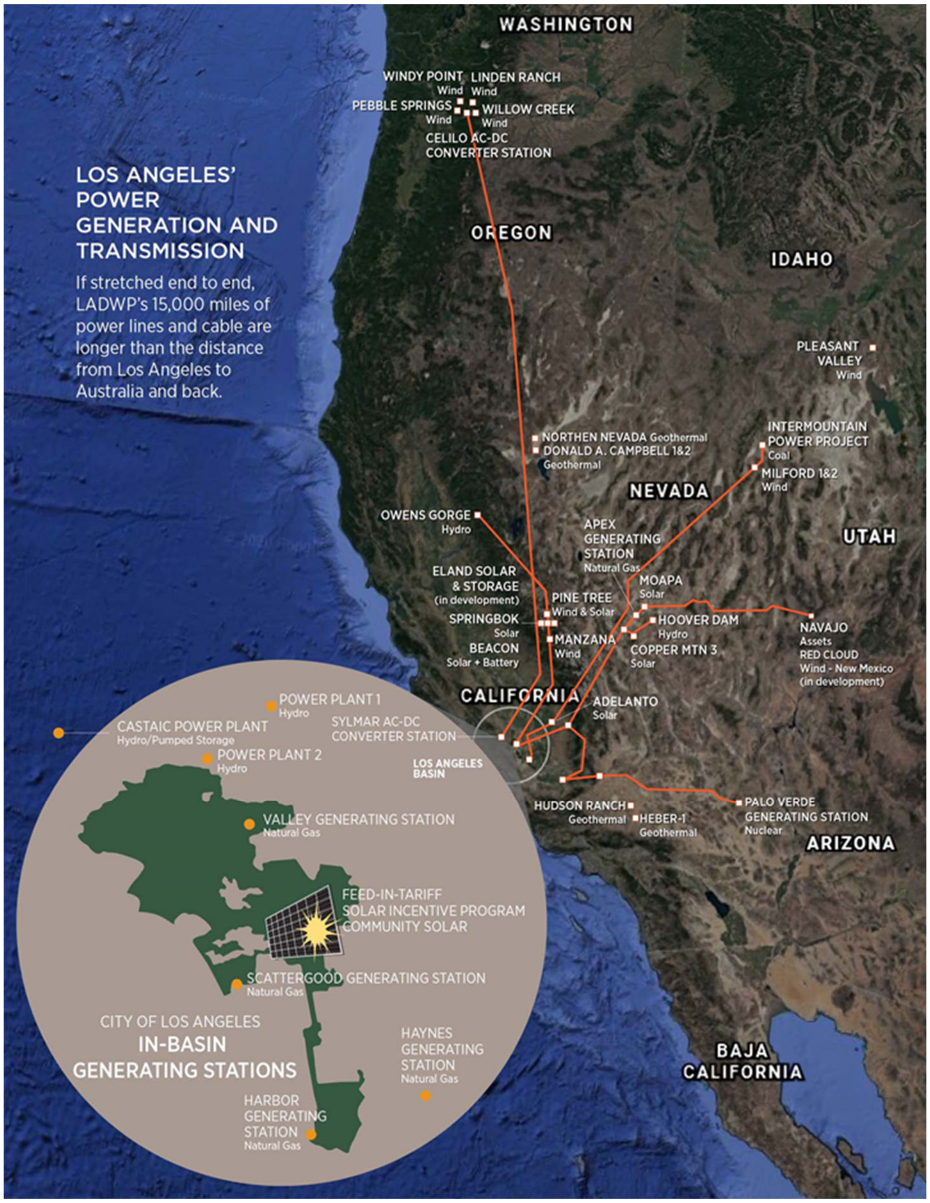


Figure 6. LADWP's generation and transmission resources

1.3 California Senate Bill 100

In 2018, California passed Senate Bill 100 (SB 100). SB 100 requires that all retail electricity sold in California is supplied by renewable and zero-carbon resources by the year 2045. Renewable energy resources include wind, solar, geothermal, and small hydroelectric technologies, while zero-carbon resources include large hydroelectric and nuclear technologies. While not specified in SB 100, it is assumed that combustion resources fueled by biofuels or hydrogen derived from renewable energy resources are also considered zero-carbon resources. It is important to note that while all retail electricity sales in California must be served by renewable and zero-carbon resources by 2045, power losses, mostly in the form of resistive heat from transmission and distribution lines, can still be served by fossil-fired generation.

Along with the 2045 goal of achieving 100% clean electricity, SB 100 also sets forth a 60% renewable portfolio standard (RPS) by the year 2030. This percentage of renewables must be maintained at or above 60% from the year 2030-onward.

The SB 100 Joint Agencies, comprised of the California Air Resources Board (CARB), California Energy Commission (CEC), and the California Public Utilities Commissions (CPUC), conducted computer simulations that revealed several key takeaways:

► Achieving the goals set forth in SB 100 is achievable from a technical standpoint through multiple pathways.

► The procurement and construction of clean electricity generation facilities such as solar, wind, geothermal, small hydroelectric, and biofuels along with energy storage technologies such as batteries, compressed air energy storage, and pumped-hydroelectric energy storage must be sustained at record-setting build rates.

► Geographic and technological diversity of zero-carbon energy resources lowers overall costs and enhances system reliability.

► Natural gas combustion turbines and combined-cycle facilities can act as a bridge to achieving 100% zero-carbon energy by 2045 and help minimize overall costs during the transition.

► Increased use of energy storage can reduce natural gas capacity needs.

► Transitioning to 100% clean energy would have benefits above and beyond the mitigation of greenhouse gasses including:

o Public health improvement

o Energy equity advancement

o Clean energy economy growth

After recognizing that the SB 100 Joint Agency Report was an initial analysis, the Joint Agencies recommended further analysis which includes:

► Verifying that scenario results satisfy the state’s grid reliability requirements

► Evaluating potential effects of emerging resources, such as offshore wind, long-duration energy storage, green hydrogen technologies, and demand flexibility

► Assessing the costs and benefits for environmental, social, and economic factors associated with the additional clean electricity generation capacity and storage needed to implement SB 100

► Supporting the alignment among the joint agencies and continuity between SB 100 reports by holding annual workshops.

1.4 California Senate Bill 1020 (SB 1020)

In September 2022, California Senate Bill 1020 (SB 1020) was enacted. SB 1020 added interim goals to the mandates already established in SB 100. Under SB 1020, at least 90% of all retail sales of electricity in California must be supplied by eligible renewable and clean energy resources by December 31, 2035. By December 31, 2040, 95% of all retail electricity sales must be supplied by eligible renewable and clean energy resources. Additionally, all electricity procured to serve California state agencies must be supplied by renewable or clean energy resources by the end of 2035.

1.5 Computer Modeling

A major component of the IRP process is the modeling of LADWP's Power System through the use of computer models. For long-term planning, computer modeling involves simulating aggregate customer demand, the dispatch of LADWP's various electricity generating assets and energy storage assets, and power flows through the high-voltage transmission system. Such modeling typically does not involve simulating the flow of electricity on LADWP's lower voltage distribution system.

For this iteration of the IRP, the planning horizon was chosen to span between the years 2022 and 2045 to align with California policy objectives. As mentioned previously, high-level assumptions need to be made about which generation, storage, and transmission resources are expected to be available along with their various projected costs.

Computer modeling is a two-step process. The first step involves running a capacity expansion model. A capacity expansion model determines which generation and storage resources should be built and in what quantities, and when and where to build them. As shown in Figure 7, this IRP used Automated Resource Selection (ARS), a proprietary software package provided by LADWP's consultant, Ascend Analytics, for capacity expansion modeling.

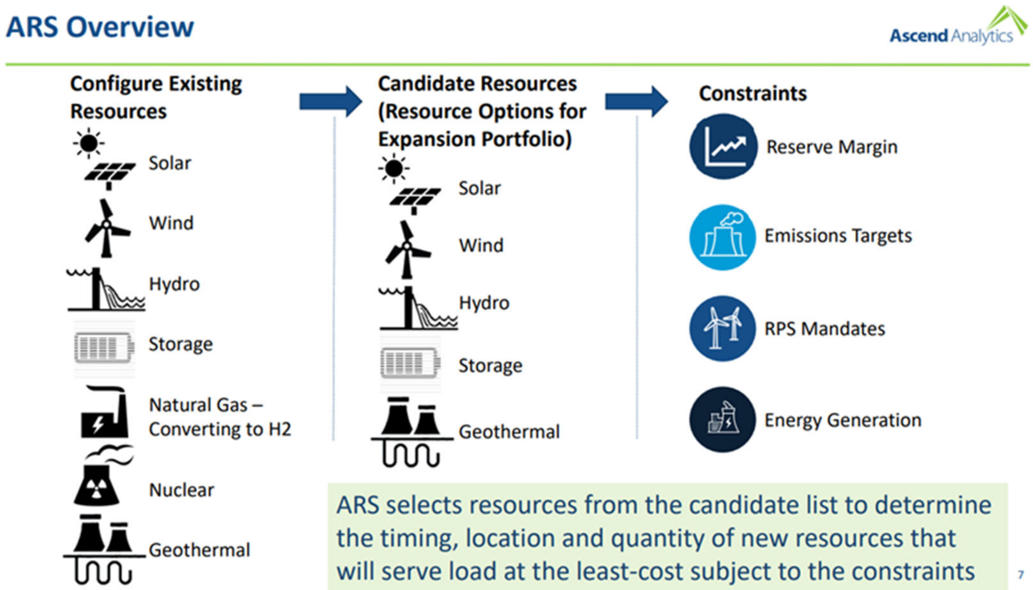


Figure 7. The ARS software package was used for capacity expansion modeling for the 2023 IRP.

The next step in the computer modeling process is running production cost models on the portfolios built by the capacity expansion model. Production cost models use the principle of economic dispatch, which uses the marginal cost of each generation resource to make dispatch decisions.

Production cost models also take into consideration various operational constraints, as illustrated in Figure 8. For example, in order to ensure reliability, LADWP requires a minimum quantity of firm, dispatchable, and readily available generation to support transmission reliability. This dispatchable generation must withhold the ability to ramp up power output on short notice to mitigate any contingencies such as an unexpected outage of a major transmission line. The production cost model ensures such constraints are met at all times.

New to this iteration of the IRP is stochastic Monte Carlo simulation. Several years of hourly weather data from various weather stations within LADWP's service territory as well as data from weather stations near its renewable generation assets were gathered. This hourly weather data was then correlated to historical customer load data and the output from intermittent renewable solar and wind generating stations. Numerous iterations called simulation repetitions (sim reps) were run using varied forecasted weather data. Some sim reps tended to have higher average temperatures, which resulted in higher customer demand, while other sim reps tended to have lower average temperatures, resulting in lower customer demand. Weather also affects production from wind and solar generating stations. For instance, it was determined that the spread between the high and low temperature of the day was highly correlated to wind energy production. By running multiple sim reps with differing weather, each resource portfolio built by the capacity expansion model could be tested against a wide range of conditions.

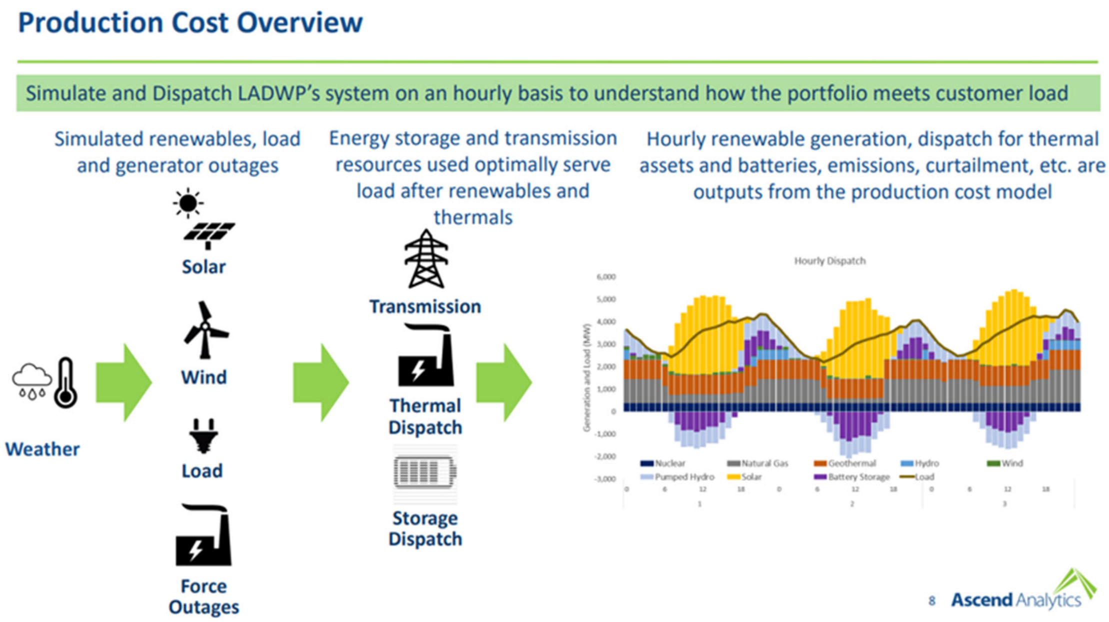


Figure 8. The production cost modeling process used for the 2023 IRP.

1.6 Results

Through the use of computer modeling, metrics such as emissions, costs, reliability, and electricity rates are forecasted for each case and are presented in the following sections.

1.6.1 Greenhouse Gas Emissions

With respect to GHG emissions, this IRP starts below 7 million metric tons in 2022 and by 2025 reduces this by almost half, as can be seen in Figure 9. The single most significant reduction in carbon emissions throughout the entire study horizon results from LADWP fully divesting away from its last remaining coal asset in 2025, as coal-fired generation at the Intermountain Power Project is replaced by cleaner generation from green hydrogen-capable units, which in 2025 operate off a fuel blend capable of 30% green hydrogen and 70% natural gas by volume.

Further reductions can be observed starting in 2030, as substantial amounts of renewable energy are interconnected into LADWP's system, along with energy storage of various technology types and durations.

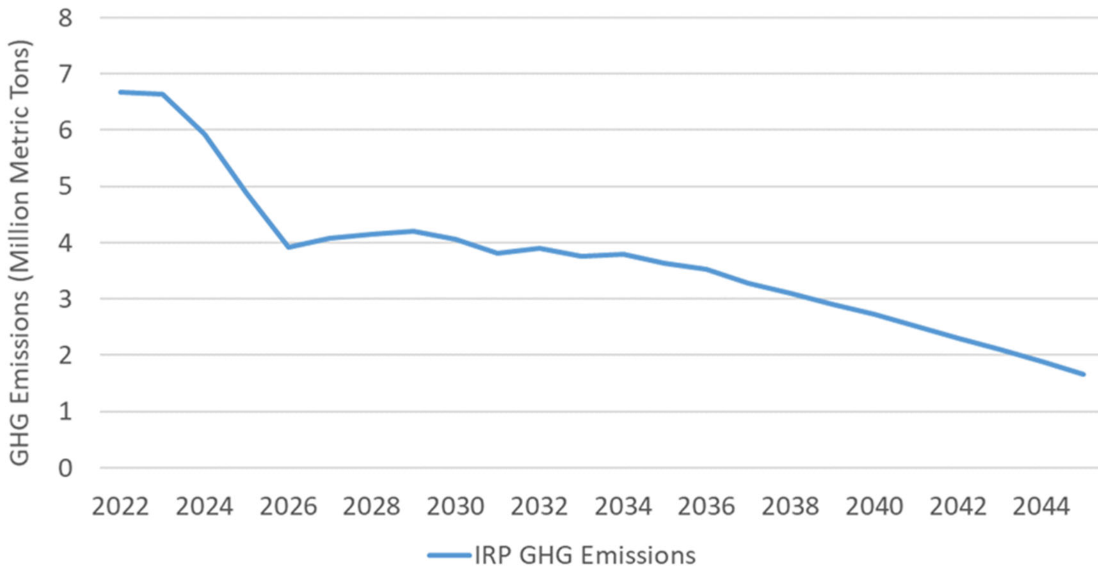


Figure 9. GHG emission from 2022 to 2045.

1.6.2 Cost

With respect to total portfolio costs, the net present value (NPV) is taken of all the fixed costs (including capital, fixed operations and maintenance, power purchase agreements, debt service, and others) and all the variable costs (including fuel, greenhouse gas allowances, nitrogen oxide credits, variable operations and maintenance, and others), across the study horizon from 2022 through 2045 (Figure 10).

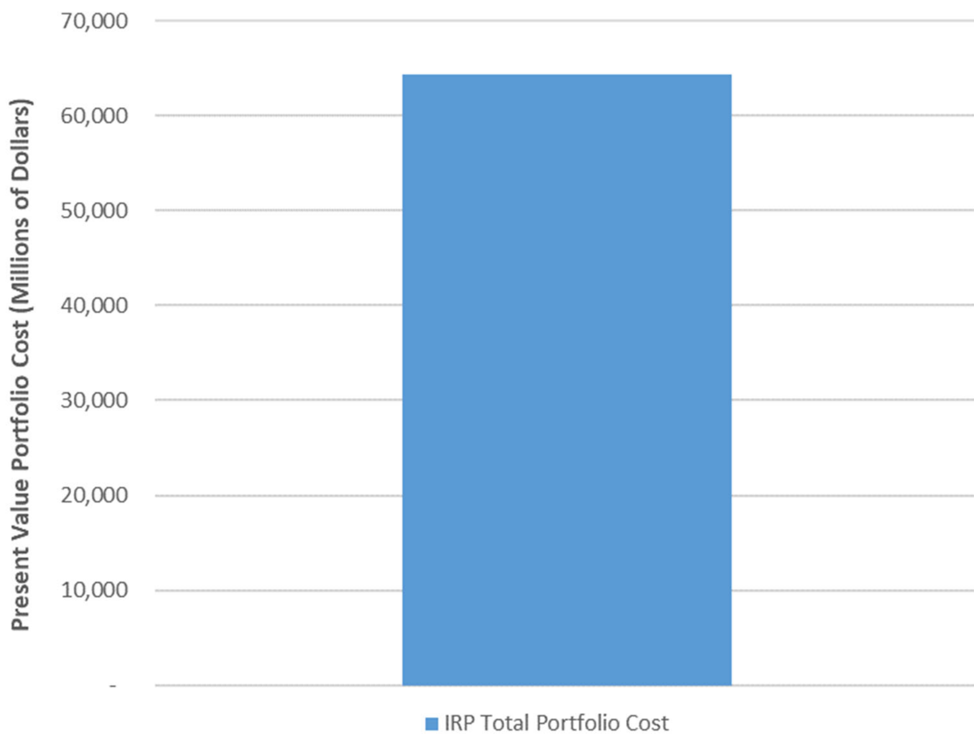
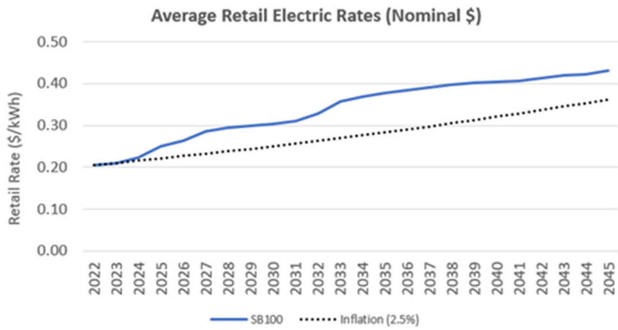


Figure 10. Total Portfolio Costs (net present value) for the IRP scenario.

As can be seen in Figure 10, implementing this IRP has an approximate NPV cost exceeding $60 billion. While showing the total portfolio cost from this financial perspective provides many insights, it must also be noted that there exist nuances and risks that fail to be captured by such financial estimates, such as the significantly challenging prospects for attaining permitting, accommodating required outages, procuring enough equipment, and hiring sufficient personnel to enable the clean energy transition.

1.6.3 Retail Electric Rates

Forecasts of retail electricity rates were also conducted. Figure 11 shows the average retail electricity rate forecasts, forecasted to be $0.30/kWh in 2030 and $0.38/kWh in 2035. By 2035, this represents an average rate increase of 4.8% annually over today's rates.



2023 IRP Scenario	Est. Avg. Retail Rate in 2030 and 2035 ($/kWh)	Est. Avg. Retail Rate Increase (2022-35)	Est. Avg. Retail Rate Increase (2022-45)
SB100	**$0.30, $0.38** *(in 2030, 2035)*	*4.8%*	*3.3%*

Note: Preliminary, subject to ongoing budget estimate and future rate review.

Figure 11. Forecasted average retail electricity rates to meet SB 100 requirements.

LADWP POWER SYSTEM

LADWP is the nation's largest municipal electric utility. In fiscal year 2020-21, we supplied 20,936 gigawatt-hours (GWh) to more than 1.55 million residential and business customers, as well as more than 5,100 customers in the Owens Valley.

We maintain a diverse and vertically integrated power generation, transmission and distribution system that spans five Western states, and delivers electricity to more than 4 million people in The City of Angels.

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Chapter 2

Introduction and Background

DEFINITIONS

AG	Advisory Group
CAISO	California Independent System Operator
CEC	California Energy Commission
City	City of Los Angeles
DCFC	Direct current fast chargers
ECCEJR	Energy, Climate Change, Environmental Justice, and River Committee
EE	Energy efficiency
EIM	Energy Imbalance Market
EJ	Environmental Justice
ELCC	Effective load carrying capability
ERO	Electric Reliability Operator
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FiT	Feed-in Tariff Program
GHG	Greenhouse Gas
GW	Gigawatts
GWh	Gigawatt-hours
HILF	High-impact low-frequency
In-basin	Located within the Los Angeles Basin
IPP	Intermountain Power Project
IRP	Integrated Resource Planning
kW	Kilowatt
kWh	Kilowatt-hour
LA100	LA100 Study
LADWP	Los Angeles Department of Water and Power
LDES	Long-duration energy storage

LADWP	Los Angeles Department of Water and Power
LDES	Long-duration energy storage
LOLH	Loss of load hours
MW	Megawatt
MWh	Megawatt-hour
NEM	Net energy metering
NERC	North American Electric Reliability Corporation
NOx	Nitrous oxides
NREL	National Renewable Energy Laboratory
PPA	Power purchase agreement
RPS	Renewable Portfolio Standard
SB 100	California Senate Bill 100
VoLL	Value of lost load
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market

2 Introduction and Background

The 2023 Integrated Resource Plan (IRP) developed by the Los Angeles Department of Water and Power (LADWP) provides a comprehensive roadmap for meeting the future energy needs, regulatory mandates and clean energy goals for the City of Los Angeles (LA). At LADWP, we strive to achieve all of our planned goals while providing affordable, safe, and reliable power to all our customers. Throughout the planning process, LADWP staff considered all technical requirements, regulatory mandates, and community feedback in order to present a comprehensive and robust long-term plan. The 2023 IRP will synchronize with the annual budget process, which will allow us to update the plan's assumptions and recommend the optimal pathway for achieving 100% clean energy by 2045 with minimal adverse rate impacts. This IRP sets up a framework for LADWP to address key opportunities and risks in order to ensure an effective and equitable clean energy transformation for the City of LA.

2.1 The Power System

LADWP's Power System is the nation's largest municipal electric utility with a net maximum plant capacity of 10,664 megawatts ("MW") and a net dependable capacity of 8,101 MW as of August 31, 2022. The Power System's highest load registered 6,502 MW on August 31, 2017. LADWP provides electric and water service almost entirely within the boundaries of the City of Los Angeles, an area covering approximately 473 square miles. To provide Angelenos with a safe, reliable, and resilient electric grid, LADWP maintains a vast network of overhead transmission and distribution lines, transmission towers, underground cables, power poles, crossarms, transformers, and vaults.

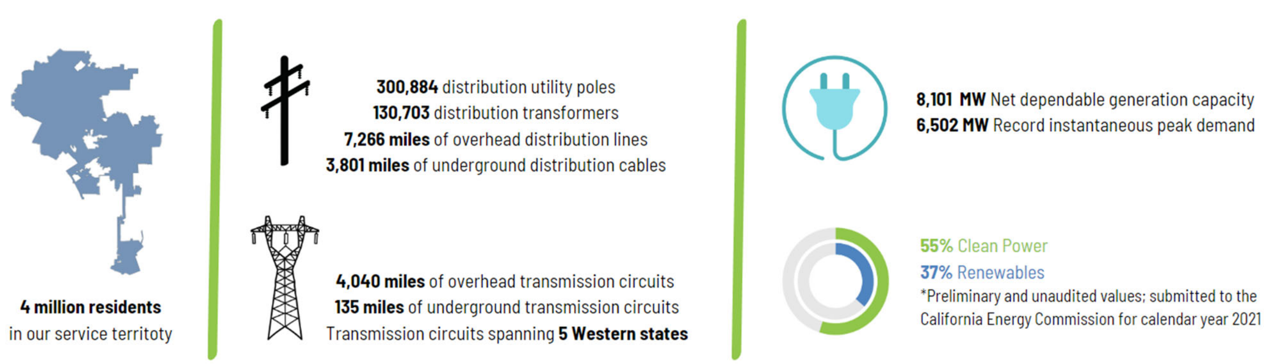


Figure 12. LADWP Quick Facts and Figures.

Additionally, LADWP currently owns and operates four natural gas-fired generating stations located within the Los Angeles Basin (often referred to as the "in-basin" power plants), which are shown in Figure 12:

- Harbor Generating Station, located near the Port of Los Angeles
- Haynes Generating Station, located in Seal Beach
- Scattergood Generating Station, located near Los Angeles International Airport
- Valley Generating Station, located in the San Fernando Valley.

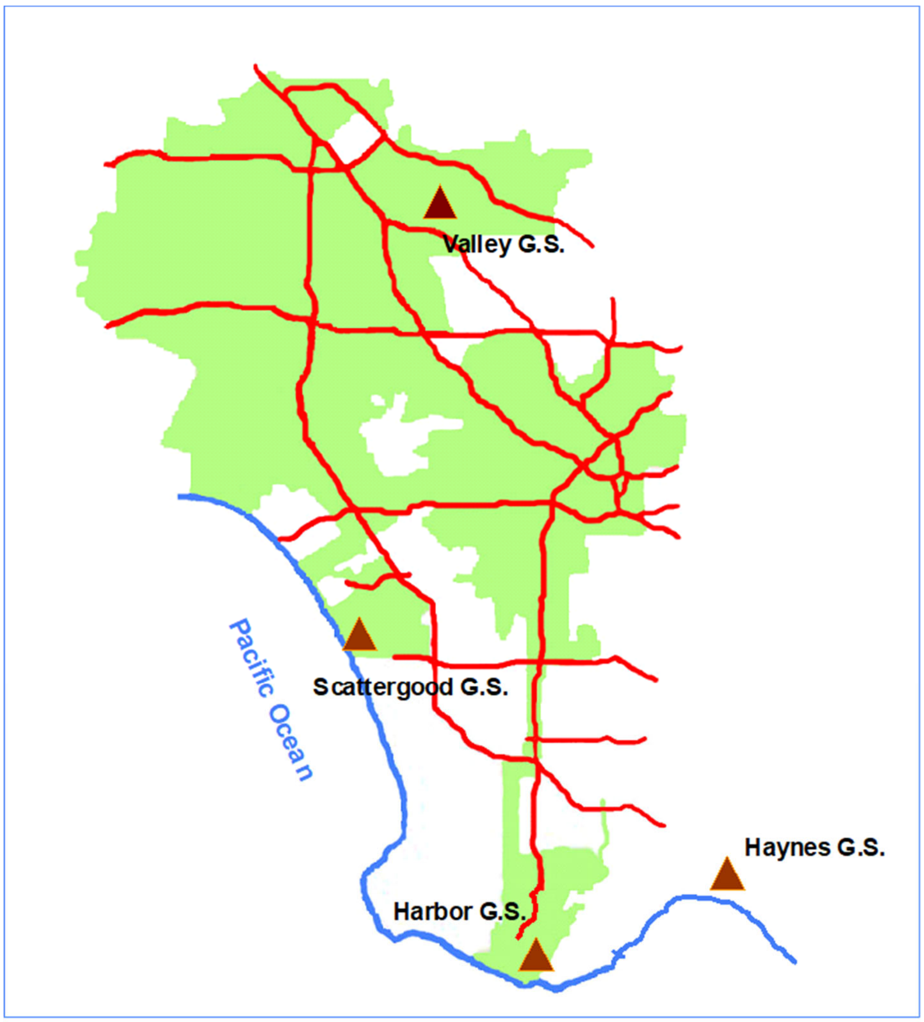


Figure 13. LADWP "in-basin" generating stations.

Additionally, LADWP owns and operates the Castaic Power Plant, a pumped-storage hydroelectric generation facility located in Castaic, California. LADWP also has contracts for a portion of the generating capacity from the Intermountain Power Project (IPP)—a coal-fired power plant located in Delta, Utah set for retirement in 2025; Hoover Dam hydroelectric power plant in Nevada; and the Palo Verde Generating Station, a nuclear power plant located in Arizona.

LADWP also owns or has power purchase agreements for several renewable energy generating facilities, including several solar, wind, and small hydroelectric facilities in California's Owens Valley, wind facilities located in Utah, New Mexico, Oregon, Wyoming, and Washington State, and geothermal and solar facilities in California and Nevada.

2.2 California Senate Bill 100

California Senate Bill 100 (SB 100), or the "100 Percent Clean Energy Act of 2018", sets a 2045 goal of powering all retail electricity sold in California with clean resources, such as solar, wind, hydroelectric, and nuclear power. Additionally, SB 100 mandates that California utilities achieve at least 60% renewable portfolio standard (RPS) by 2030.

Computer modeling conducted by the Joint Agencies (CEC, CPUC, and CARB) and their consultants suggests that SB 100 is technically achievable through multiple pathways; however, construction of clean electricity generation and storage facilities must be sustained at record-setting rates. Additional findings indicate that retaining some firm, dispatchable generation capacity such as natural gas-fired power plants may minimize costs and ensure uninterrupted power supply during the transition to 100% clean energy.

2.3 LA100 Equity Strategies

In June 2021, LA100 Equity Strategies was announced to build upon and advance the concepts of the Los Angeles 100% Renewable Energy Study (LA100 Study). LA100 Equity Strategies takes the technical and theoretical results obtained from the LA100 Study and aims to answer how Los Angeles can ensure its clean energy transition is achieved in an equitable manner while all communities share in the benefits and burdens. LA100 Equity Strategies seeks to improve energy equity and justice through community engagement, an Advisory Committee, and a Steering Committee. These groups and their feedback will aid in the development of implementation-ready strategies that can be applied towards intentionally designed policies and programs that help address community priorities relating to energy affordability and burdens, access and use, community health, safety, resilience, and jobs. This effort is ongoing and as outcomes become available, they will be included in future iterations of the IRP.

2.4 The IRP Process

LADWP's Integrated Resource Plan provides a comprehensive roadmap for meeting LA's future energy needs, regulatory mandates, and clean energy goals, while maintaining reliable and affordable power for our customers. To ensure that our plans reflect the input of the communities and customers we serve, the planning process includes an advisory group comprised of various community members and stakeholders. The 2023 IRP will sync with LADWP's budget process with updated assumptions and a recommend the optimal pathway to achieve 100% clean energy by 2045 while also addressing technology risk, minimizing adverse rate impacts, and ensuring an equitable transition to clean energy.

2.5 Case Selection and Assumptions

The first step of the IRP process involves deciding how to develop the IRP using computer modeling to simulate Power System operations. This IRP represents the minimum investments LADWP must make to comply with SB 100, the California state law that mandates utilities achieve 100% clean energy as a percentage of retail sales by 2045, among other clean energy targets.

Once the model for the IRP is determined, the next step in the IRP process is to gather various assumptions to be used as inputs to the computer modeling process. The Integrated Resource Planning Group gathers assumptions from many subject matter experts within LADWP as well as from outside consultants and governmental agencies such as NREL. Assumptions include, but are not limited to the following:

- *Customer demand* – The IRP Group uses a customer demand forecast provided by the LADWP Load Forecasting Group.
- *Fuel Prices* – Natural gas price forecasts spanning several decades into the future are provided by an outside consultant. Coal prices for the Intermountain Power Project, set to retire in 2025, are provided by the LADWP Power External Energy Resources Division.
- *Power Plant Generation Ratings* – Power plant characteristics including megawatt capacity are provided by LADWP Generating Stations and Facilities Engineering.
- *Candidate Resource Pricing* – The IRP Group runs a capacity expansion model that builds out LADWP's future portfolio of generation resources subject to constraints such as RPS goals and reliability metrics while attempting to minimize overall cost. The pricing of future generation resources, such as solar, wind, and geothermal, which are provided as candidate resources from which the capacity expansion model can choose, is provided by NREL's Annual Technology Baseline.
- *Energy Efficiency* – Assumptions regarding the adoption and uptake of energy efficiency measures is provided by the LADWP Efficiency Solutions Group.
- *Building Electrification* – Several scenarios for the adoption of building electrification measures (e.g., converting from gas to electric water heating) are provided by the LADWP Efficiency Solutions Group.
- *Transportation Electrification* – Assumptions regarding the adoption of electric vehicles by customers within LADWP's service territory are provided by the LADWP Electric Transportation Programs Group.

- *Power System Reliability Program* – LADWP is expected to update and upgrade its current distribution system, replacing aging transformers, power poles, and other equipment. These upgrades fall under the Power System Reliability Program. Costs associated with this program are provided by LADWP Power System Engineering. LADWP has incorporated the additional cost in the 2023 IRP to address existing overloads and prepare the grid for future load growth due to electrification.
- *Transmission* – Assumptions regarding transmission line upgrades are provided by LADWP Transmission Engineering.
- *Greenhouse Gas Allowance Pricing* – Pursuant to California law, LADWP participates in the California Cap and Trade Program. Under this program, participants are required to have one greenhouse gas allowance for each metric ton of greenhouse gas emitted. Pricing forecasts for these allowances are provided by the LADWP Air Quality Group based on CARB's forecast.
- *Green Hydrogen* – Price forecasts for green hydrogen fuel are provided by various sources including external consultants and NREL.

The key objectives of LADWP's long term planning efforts, shown in Figure 14, are: (1) maintaining a high level of electric service reliability, (2) exercising environmental stewardship, and (3) maintaining competitive energy rates.

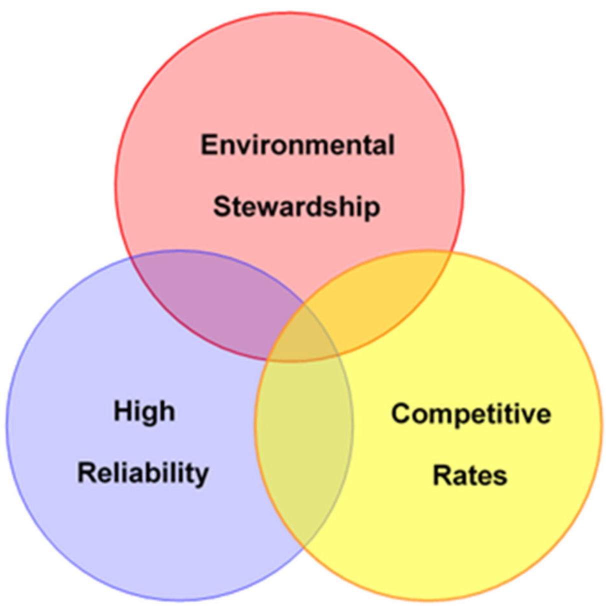


Figure 14. Objectives of this IRP.

Providing reliable electric service to the residents and businesses of Los Angeles has always been a cornerstone of LADWP. Some of the key principles, policies and program areas related to reliability are listed in the following subsections.

2.5.1 Reliability Standards

LADWP continues to follow all applicable Federal Energy Regulatory Commission (FERC)-approved reliability standards regarding bulk power system reliability. With the enactment of the Energy Policy Act of 2005, FERC granted the North American Electric Reliability Corporation (NERC) the legal authority to enforce reliability standards with all users, owners and operators of the bulk power system in the United States. NERC is divided into eight regional electric grids in the United States. The Western Electricity Coordinating Council (WECC), under the delegated authority of NERC, is the regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection, which LADWP is a part of. Both of these regulatory agencies enforce reliability standards on owners, operators and users of the bulk power system.

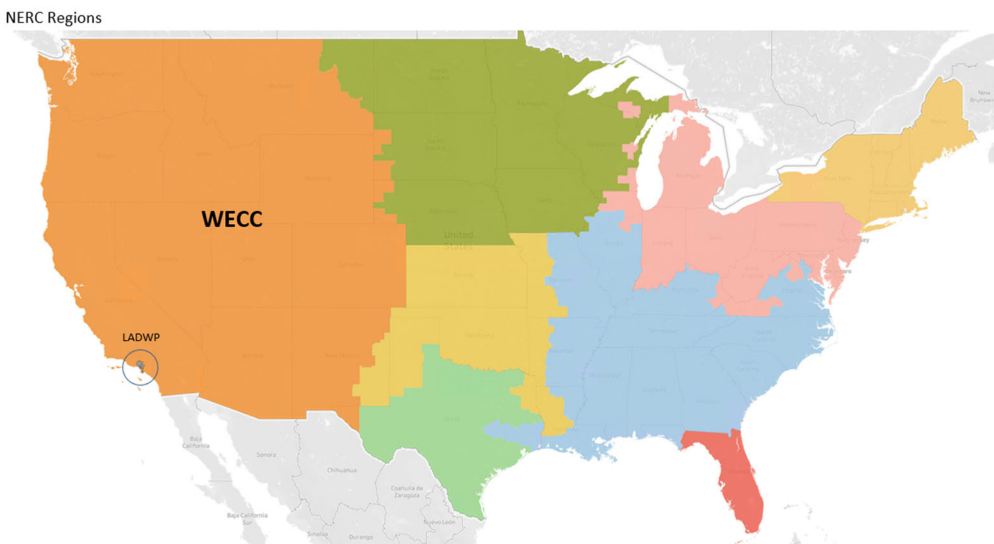


Figure 15. Map of NERC Regions, WECC, and LADWP.

In November 2012, NERC drafted a white paper outlining the need to incorporate risk concepts into the implementation of compliance and enforcement. In the white paper, NERC highlighted that the Electric Reliability Operator (ERO) Enterprise, comprised of NERC and the regional entities, must abandon its “zero tolerance” compliance monitoring and enforcement because it is neither effective nor sustainable. The “zero tolerance” compliance monitoring programs were centered around documenting compliance rather than actually reducing risk and improving the reliability of the bulk electric system. As a result, the ERO Enterprise and industry collaborated to create the Reliability Assurance Initiative (RAI) to identify and implement changes to enhance the effectiveness of the Compliance Monitoring and Enforcement Program (CMEP).

On February 19, 2015, FERC approved the RAI program. The program's transformation for compliance monitoring involves the use of the Risk-Based Compliance Oversight Framework (Framework). The Framework focuses on identifying, prioritizing, and addressing risks to the bulk electric system, which enables NERC and the regional entities to focus resources where they are most needed and effective. The regional entities are responsible for tailoring their approach to compliance monitoring in their specific region in accordance with the processes described in the RAI program.

2.5.2 CAISO

The California Independent System Operator (CAISO) was established in 1998 as part of California's electric utility restructuring effort. CAISO was established as a non-profit public benefit corporation charged with operating the majority of California's high-voltage wholesale power grid and providing equal access to the grid for all qualified users. LADWP is not a member of CAISO, but was certified by CAISO to be a scheduling coordinator in 2012. That certification authorizes LADWP to buy and sell energy and ancillary services directly with CAISO.

In 2019, NERC approved CAISO's registration as reliability coordinator under the name RC West. RC West provides reliability coordinator services to balancing authorities and transmission operators in the Western United States, including LADWP.

2.5.3 CAISO Western Energy Imbalance Market

The CAISO Western Energy Imbalance Market (WEIM) was launched in 2014 to allow non-ISO members in the western region voluntary access to their real-time grid management system, leveraging the power of geographic diversity. In April 2021, LADWP began participating in CAISO's EIM market, and is presently a full participant in the EIM.

2.5.4 Balancing Authority

LADWP is a registered balancing authority with NERC and is responsible for coordinating and balancing the load, generation, and delivery of electricity through its balancing authority area, which includes the Burbank and Glendale power systems. LADWP will continue to serve as a balancing authority in the City of LA, as well as for Burbank and Glendale.

2.5.5 Self-Sufficiency

LADWP maintains a policy of owning or controlling transmission and generation resources independently to serve its native load customers. Augmenting LADWP's self-sufficiency, from time to time, a limited amount of firm energy is purchased from western energy market sellers to bolster LADWP's energy resources during stressed system conditions including those arising from gas curtailments related to Aliso Canyon.

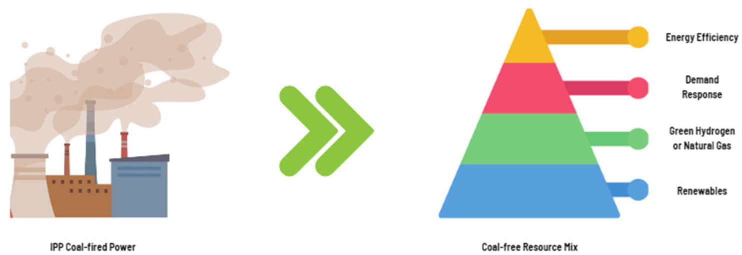
2.5.6 Coastal Power Plants

Figure 16. Scattergood Generating Station.

LADWP owns and operates three coastal natural gas-fired power plants (Haynes, Harbor, and Scattergood) that are critical to its operations. These plants were built beginning from the 1940s up until the 1970s. One of these plants, Harbor Generating Station, was modernized in the 1990s, resulting in increased efficiency and reliability. As a result, LADWP was able to reduce emissions and overall maintenance costs. The modernization of the remaining generation units is a long-term program. LADWP is currently studying various hybrid clean energy options and working to modernize these plants for compliance with environmental regulations, improvements to efficiency, better integration of renewable resources, and expanded transmission import capability.

2.5.7 Intermountain Power Project Replacement

LADWP is committed to a strategy of complete divestment from coal-fired resources by 2025. As a result, LADWP investigated a combination of various alternative energy sources as critical for replacing the coal-fired capacity that the Intermountain Power Project provides. Power System staff has determined that a mix of energy efficiency, demand response, renewable resources (wind, solar and geothermal), and energy from a combined-cycle natural gas or green hydrogen generating facility will be sufficient to replace IPP's capacity. The goal of converting IPP from a coal-fired to combined-cycle natural gas or green hydrogen generating facility is to accelerate LADWP's coal divestiture by two years. In 2015, all 36 IPP participants, including several municipal utilities located in Southern California and Utah, approved an amendment to advance the IPP replacement date to 2025. To achieve the accelerated goal, IPP will be replaced with two combined-cycle natural gas generating units, initially capable of utilizing 30% green hydrogen by volume, totaling 1,200 MW. However, the total project size that is presently being negotiated is approximately 840 MW. The flexible capacity from the repowered IPP units will firm and back up renewable resources and provide a mechanism to reliably integrate renewable resources into LADWP's grid. The accelerated 2025 replacement date—two years ahead of the existing power purchase contract's June 2027 expiration date—is contingent upon several factors including permitting time, material procurement, and final concurrence from all participants. Although LADWP is planning to complete the replacement project by 2025, the commercial operation date could still be delayed due to circumstances beyond LADWP's sole control.



For this IRP, the combined-cycle units replacing IPP are assumed to be green hydrogen-ready, with the capability to use a blend of 30% green hydrogen and 70% natural gas, by volume.

2.6 Computer Simulation

Creating a robust computer model of LADWP's Power System is a crucial component of the IRP process. For long-term planning, computer modeling involves simulating aggregate customer demand, the dispatch of LADWP's various generation and energy storage assets, and our expansive high-voltage transmission system. Typically, such modeling does not involve simulating the flow of electricity on LADWP's relatively low-voltage distribution system.

For this iteration of the IRP, the planning horizon was chosen to span between 2022 and 2045. As mentioned previously, the modeling process requires us to make high-level assumptions about which generation, storage, and transmission resources are expected to be available. Additionally, certain assumptions must be made regarding various projected costs.

Computer modeling is a two-step process. The first step involves running a *capacity expansion model.* This model determines which generation and storage resources should be built, as well as where, when, and to what capacities those resources should be built. Many candidate generation and storage resources are provided as inputs to the capacity expansion model, along with their projected costs. These candidate resources reflect what the IRP Group reasonably believes will be available for development. Our high-voltage transmission system spans several states in the western United States, passing through various regions with, due to their geography, favorable conditions for solar, wind, and geothermal energy production. Candidate solar, wind, and geothermal resources are then provided to the model and situated near these geographical locations within the model. Generally, LADWP prefers to have generation and storage assets located near existing transmission infrastructure in order to reduce costs and minimize environmental impacts. Efficiently sited resources reduce the need to build additional transmission capacity. LADWP's existing generation, storage, and transmission assets are also included as inputs to the capacity expansion model.

Once all assumptions have been submitted into the capacity expansion software, the computer builds a model of LADWP's generation and storage portfolio, all the way up to the 2045 planning horizon. There are several key constraints the model must adhere to:

- ***Customer demand*** – The capacity expansion model must ensure enough generation and storage assets are built each year over the planning horizon to guarantee adequate electricity generating capacity to serve aggregate customer demand. If any year in the planning horizon falls short, the model must build additional generation capacity in that year or prior to that year to mitigate the shortfall.
- ***RPS and clean energy goals and mandates*** – The capacity expansion model must also ensure enough renewable and clean energy resources are built to meet any RPS and clean energy goals and mandates. For example, SB 100 mandates a 60% RPS by 2030. The capacity expansion model must ensure enough solar, wind, and stand-alone energy storage projects are built by 2030 so that this constraint is met and that enough of these resources are built in subsequent years to guarantee LADWP achieves the interim RPS targets set by SB 1020 throughout the planning horizon.

- ***Reliability*** – To ensure customers' lights turn on as expected with the flip of a switch, the capacity expansion model must build out enough generation and storage resources to meet an expected loss of load hours (LOLH) metric. As discussed previously, the capacity expansion must guarantee enough generation and storage resources are built to satisfy customer demand every year; however, customer demand itself can fluctuate, and is highly dependent on weather conditions. Several hundred weather conditions are simulated, along with their effect on customer demand. Hot weather conditions tend to increase customer load due to increased demand for air conditioning, while mild weather reduces demand. A single portfolio must be built by the capacity expansion model that allows for no more than an expected 2.4 LOLH for each year, which is equivalent to NERC's 1-in-10-year industry standard (see BAL-502-RF-03 NERC standard). A loss of load hour is any hour in which customer demand exceeds LADWP's total generation capacity. For example, on a typical hot summer day, LADWP's total aggregate customer demand may reach 6,000 MW during the peak hour of that day. If, for any reason, LADWP did not have 6,000 MW of total generating capacity for that hour (e.g., due to a power plant or transmission line outage), then this would count as one loss of load hour. The industry standard is to plan for an expected LOLH of 2.4 or less.
- ***Cost*** – While adhering to the constraints mentioned above, the capacity expansion model attempts to build a portfolio that minimizes the total cost. Costs include not only capital and construction costs, but also operational costs such as fuel and maintenance.

Once the capacity expansion model creates a resource portfolio, the second step is to run the portfolio through a *production cost model*. The production cost model simulates the dispatch of the generation resources in the capacity model's resource portfolio. Typically, a production cost model uses hourly resolution to simulate dispatch decisions; however, five- and 15-minute resolution can be used as well. The production cost model uses the marginal cost of each resource to determine which resources to dispatch first. The most inexpensive resources are dispatched first, with more expensive resources dispatched subsequently. The model ensures that enough generation resources are dispatched in order to meet the assumed aggregate customer demand in each hour. The production cost model can determine total fuel consumed, emissions produced, and overall system cost, among many other output metrics. The production cost model also simulates planned and unplanned outages for LADWP's generation assets.

2.6.1 Cost

The costs assessed in this IRP are split into fixed costs and variable costs. Fixed costs do not vary with the utilization of an asset. These could be capital costs spent on power plant development and construction (including equipment, permitting, and construction labor), fixed operations and maintenance costs (including routine maintenance, inspection, and monitoring), and costs associated with fixed power purchase agreements, for which LADWP is obligated to purchase a minimum quantity of energy annually. Variable costs are proportional to the quantity of energy generated. The production cost modeling stage of the IRP process provides insight into these costs through hourly simulations of the dispatch of LADWP's generation and energy storage assets. Variable costs include costs for fuel (such as coal or natural gas), greenhouse gas allowances and emission reduction credits (such as those for carbon dioxide and nitrogen oxides), as well as variable operations and maintenance (such as more maintenance and repair of generating units that are used more frequently). Overall, fixed and variable costs are aggregated in the IRP into total portfolio costs. The annual cash flows are discounted through a net present value methodology, which more accurately compares costs among the different cases.

2.6.2 Rate and Bill Impacts

The estimated electric retail rate ($/kWh) and consequent bill impacts ($) in the IRP are preliminary averages and subject to ongoing budget estimates and future rate reviews. The preliminary numbers do not yet reflect the potential cost savings from additional funding sources such as the federal government's Inflation Reduction Act and Bipartisan Infrastructure Law, among others.

The IRP team worked closely with LADWP's Financial Services Organization to determine the volumetric electric retail rate estimates per unit of power sold, deriving estimates for key years such as 2030 and 2035 using the existing LADWP rate structure. The overall total portfolio costs are a key factor in determining rates, as are electric customer retail sales. Building and transportation electrification are examples of negative rate drivers that will help make the per unit cost of power less expensive by increasing the volume of overall retail sales. Examples of positive rate drivers—which make the cost per unit of power more expensive—are programs that reduce overall retail sales, such as net-metered solar and energy efficiency.

We recognize that LADWP customers may currently receive utility bills every other month for electric service combined with charges for water service, sewage, and waste disposal. With respect to average monthly electric retail bill estimates, the values presented in the IRP are for electric service only, and are averaged out over each month. Using this method, we generate an average monthly electric retail bill estimate. Furthermore, the IRP team provides bill estimates for an average residential apartment-sized dwelling and an average residential single-family dwelling. The bill estimate for a residential apartment-sized dwelling assumes an average energy consumption of 300 kWh/month, while the estimate for an average residential single-family dwelling assumes an average consumption of 700 kWh/month.

2.6.3 Emissions

Greenhouse gas (GHG) emissions—often cited in units of million metric tons—as well as emissions from nitrogen oxides (NOx)—often cited in units of tons—are estimated in this IRP scenario at a high-level through production cost modeling. Power plant emissions resulting from the generation process are largely a result of generation efficiency, as well as the emissions intensities of the fuel sources. As an example, for a given quantity of energy produced, natural gas emissions are substantially lower than coal emissions. LADWP will fully divest from all coal resources by 2025. Older generating units are less efficient and produce more GHG emissions per unit of energy produced when compared to newer units, which have greater generating efficiencies as a result of technological advances, among other factors.

2.6.4 Reliability

Reliability in the IRP scenario is quantified using a metric called *loss of load hours (LOLH)*. LOLH quantifies the number of expected hours in which aggregate customer demand exceeds LADWP's total generation and energy import capacity. The North American Electric Reliability Corporation's stated industry standard for LOLH is one day in ten years, which translates to no more than 2.4 loss of load hours per year. Due to this reliability constraint, the resource portfolio for the IRP scenario is built to ensure an LOLH at or below 2.4. Because LADWP is a balancing authority that includes Burbank and Glendale, it is imperative that we not only remain below a 2.4 LOLH, but also strive to maintain the same, exceptional level of reliability we have today—approximately 0.22 LOLH per year.

For this IRP, large quantities of non-dispatchable, variable energy resources such as solar and wind are built. This is due to their declining effective load carrying capability (ELCC), or effective system value, as those types of resources start to become oversaturated in the system. The oversaturation of a resource on the system results in a declining ELCC for these resource types, which indicates that the value to the Power System of each additional unit of capacity (MW) from such a resource becomes lower and lower. One notable example of a resource with declining ELCC in the LADWP system is solar energy, which tends to produce maximum output around the middle of the day and during the spring season in California. Solar energy is often available in abundance during the middle of the day, such that its market price in the real-time market becomes negative; that is, power producers will pay others to use or “off-take” the excess solar energy they produce. Conversely, as solar energy output drops during the darker evening hours, there is a premium price for dependable and dispatchable energy resources that can fill in the supply gap left by low solar generation. We place a high value on flexible resources that can ramp up or down to meet variable demand through the evening hours—something that solar and energy storage assets cannot do.

2.6.5 Curtailment

Energy (GWh) curtailment—which, in the LADWP Power System, most commonly applies to renewable energy—occurs when system constraints do not allow LADWP to take delivery of and integrate all possible renewable energy output. Curtailment can occur due to technical constraints, or when there is an oversupply of renewable energy (renewable energy supply is greater than customer demand). For our Power System, this phenomenon most often occurs with solar energy resources during the spring season, when high solar energy generation during the middle of the day coincides with low electricity demand. It is important to note that in order to get the best possible prices, many of LADWP’s renewable energy projects are power purchase agreements (PPAs) with third-party renewable energy suppliers (as opposed to more expensive, LADWP built capital projects), for which LADWP must pay a fixed price, whether or not we are able to accept all renewable energy production from a given facility. While some PPAs do include clauses allowing a small amount of renewable energy curtailment, as more variable energy resources are interconnected onto the system, the frequency of renewable energy curtailment is expected to increase. Our goal is to keep renewable energy curtailment to a minimum. In order to reduce curtailment from variable energy resources, namely solar and wind, we look to employ strategies such as increased energy storage deployment. Energy storage resources allow us to capture and store renewable energy that cannot immediately be absorbed by system demand. LADWP can then dispatch energy from energy storage resources when the system requires it. Another potential use of normally curtailed renewable energy is electrolytic green hydrogen production, where surplus renewable energy can be used to power an electrolyzer that splits water molecules into oxygen and hydrogen. This green hydrogen, produced entirely using renewable energy, has no carbon emissions and can be stored for long durations (i.e., weeks or months) until needed. Effectively, using green hydrogen, we can deploy a form of "seasonal" energy storage to better take advantage of all our renewable energy resources.

2.6.6 Resilience

Along with reliability, our top priority is to maintain grid resilience amidst increasing extreme weather events—a result of climate change. While grid reliability is centered around having sufficient resources to adequately meet load while accounting for commonly-expected events (e.g., equipment failure or short-duration outages), resilience focuses on high-impact, low-frequency (HILF) events that are often unexpected and can result in long-duration outages. Examples of HILF events include, but are not limited to, wildfires, earthquakes, extreme heat storms (projected to be far more frequent and extreme due to climate change), and even acts of terrorism (both physical and cyber security threats).

Electric grid reliability has widely-adopted, industry-approved metrics and requirements that are often overseen by regulatory governing bodies at various levels of government. However, definitions, metrics, and guidelines for grid *resilience* have not been widely adopted or standardized across the utility industry in the present day. Often, defined resilience standards and metrics are up to each specific organization. Here at LADWP, our working definition of resilience for the Power System is as follows:

The ability of a power system to anticipate, absorb, adapt, and rapidly recover from a certain set of high-impact, low-frequency events, and to supply sufficient capacity, energy, and services to its customers at all times of the year while managing societal impacts and meeting policy objectives.

LADWP has experienced multiple HILF events that have put our grid resilience capabilities to the test. In 1994, the Northridge Earthquake caused widespread damage and power outages across the City of Los Angeles and required the use of black start generators to restore power after widespread outages. The recent California wildfires have also stressed the LADWP grid. The 2019 Saddleridge Fire caused the derating of three critical power transmission paths into the LA basin during a time when several power plants were out-of-service for maintenance. To continue meeting the City's electric demand, LADWP needed to ramp up generation at the remaining in-basin units.

Events that stress the resilience of the grid can be measured using a variety of metrics, such as de-rate factors, outage occurrences, and outage durations for critical power system elements such as high voltage transmission. Other potential metrics include number of customers affected during load shedding or capacity factors of generators during emergency periods with loss of major transmission. Potential future strategies that can help us quantify resilience include assigning monetary values to lost load (VoLL) to calculate the cost-benefit of grid investments or the social burden on communities impacted by potential power outages. These methods can be used to evaluate the costs and benefits of community resilience plans and for physical systems such as microgrids.

2.6.7 Risks

Many potential risks could affect implementation of the IRP. Some of the main risks that we considered during the IRP development process are:

- Required supply resource build rates (MW/year)
- Required customer resource build rates (MW/year dependent on customer participation)
- Required number of transmission builds
- Technological readiness of resources
- Sufficiency of capable workforce and human resources for implementation
- Operations and maintenance personnel required
- Availability of required materials and assets in the market via stable and reliable supply chains
- Streamlining of project permitting for timely completion
- Carefully staging sequence of required outages for system upgrades (critical path/predecessor sequencing, limit of power system elements that can be scheduled for outages at a given time without compromising reliability)
- Maintaining financial health (required capitalization ratios, borrowing ratios, bond ratings, cash-on-hand, etc.)
- Bolstering the Power System to withstand extreme weather events as a result of climate change (black start capability and response time, loss of load hours, geographical diversity of resources, diversity of resource capabilities and characteristics)
- Mitigation of cybersecurity threats
- Potential for high or low loads (impact to rates and amount of required resources to meet demand while maintaining reliability)

Our IRP group works in constant collaboration with other LADWP staff to measure and analyze various metrics in order to assess the aforementioned risks throughout the planning process.

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Chapter 3

2023 Integrated Resource Plan Scenario

DEFINITIONS

BE	Building Electrification
CAISO	California Independent System Operator
CAMR	Comprehensive Affordable Multifamily Retrofits
CDI	Commercial Direct Install
CEC	California Energy Commission
CFL	Compact Fluorescent Light
CII	Commercial, Industrial, and Institutional
City	City of Los Angeles
CLIP	Commercial Lighting Incentive Program
CMUA	California Municipal Utilities Association
CPP	Customer Performance Program
CPUC	California Public Utilities Commission
DCFC	Direct current fast chargers
ECC	Energy Control Center
EE	Energy Efficiency
EIM	Energy Imbalance Market
ELCC	Effective Load Carrying Capability
EPM	Efficient Product Marketplace
ERO	Electric Reliability Operator
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FiT	Feed-in Tariff Program
FYE	Fiscal year ending
GHG	Greenhouse Gas
GW	Gigawatts
GWh	Gigawatt-hours
In-basin	Located within the Los Angeles Basin

IPP	Intermountain Power Project
IRP	Integrated Resource Plan
kW	Kilowatt
kWh	Kilowatt-hour
LA100	LA100 Study
LADWP	Los Angeles Department of Water and Power
LDES	Long-Duration Energy Storage
LED	Light Emitting Diode
LOLH	Loss of Load Hours
MW	Megawatt
MWh	Megawatt-hour
NEL	Net Energy for Load
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NOx	Nitrous Oxides
NREL	National Renewable Energy Laboratory
PEM	Proton exchange membrane
PPA	Power purchase agreement
REP	Refrigerator Exchange Program
RPS	Renewable Portfolio Standard
SB 100	California Senate Bill 100
SB 1020	California Senate Bill 1020
SB 350	California Senate Bill 350
SCE	Southern California Edison
SMUD	Sacramento Municipal Utilities District
TE	Transportation Electrification
TOU	Time of Use
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market

3 2023 Integrated Resource Plan Scenario

This 2023 IRP is based primarily on California Senate Bill 100 (SB 100), with interim clean energy goals for the years 2035 and 2040 as established by California Senate Bill 1020 (SB 1020). This chapter will describe the planning scenario in this IRP in detail along with the many LADWP programs and initiatives that factor into this scenario.

3.1 Scenario Overview

This 2023 IRP is based on SB 100 and SB 1020. SB 100 requires all retail energy sales to be served by clean energy resources by 2045. The term “retail sales” excludes any energy expended in the form transmission and distribution line losses, or otherwise lost during the electricity transmission and distribution process. SB 1020 adds interim renewable and clean energy targets between now and 2045. Per SB 1020, eligible renewable energy resources and zero-carbon resources must supply 90% of all retail sales of electricity to California end-use customers by December 31, 2035 and 95% of all retail sales of electricity to California end-use customers by December 31, 2040. Table 1 provides the input parameters to the 2023 IRP Scenario.

Table 1. 2023 IRP Scenario parameters.

2023 IRP Scenario		
Targets	2030 RPS Target	60% RPS by 2030
	2035 RPS/Clean Energy Target	90% by 2035
	2040 RPS/Clean Energy Target	95% by 2040
	2045 RPS/Clean Energy Target	100% by 2045
Eligible Technologies	Renewables (wind, solar, geothermal, small hydro)	Yes
	Energy Storage	Yes
	Solid Biomass	No
	Biogas/Biofuels	Considered, but not included in final resource portfolio
	Fuel Cells	Considered, but not included in final resource portfolio
	Large Hydro - Existing	Yes
	Large Hydro - New	No
	Natural Gas	Yes
	Nuclear - Existing	Yes
	Nuclear - New	No
Distributed Energy Resources (DERs)	Local Solar	Yes
	Local Energy Storage	Yes
	Energy Efficiency	Yes
	Demand Response	Yes
Renewable Energy Credits (RECs)	Financial Mechanisms (RECs/Allowances)	Yes

3.2 2023 IRP Scenario Description

What follows is a description of the scenario modeled for the 2023 IRP. The SB 100 case, built on the requirements of California Senate Bill 100, which mandates a 60% RPS by 2030 and 100% clean energy by 2045, represents the minimum goals that California utility companies must achieve by law in terms of RPS, mitigating greenhouse gas emissions, and other environmental impacts.

3.2.1 Senate Bill 100

The SB 100 Case represents the minimum goals that LADWP must achieve in order to comply with California State law—namely California Senate Bill 100. SB 100 mandates utilities achieve a 60% RPS by 2030. Furthermore, utilities must achieve 100% clean energy (as a percentage of sales to ultimate customers) by 2045. With the passage and adoption of SB 1020, additional interim 2035 and 2045 renewable and clean energy targets were established.

To build a generation portfolio for the 2023 IRP scenario, we considered renewable technologies including wind, solar, geothermal, small hydroelectric facilities (excluding hydroelectric facilities greater than 40 MW) and biofuels. Solid biomass was not considered due to its relative paucity and lack of availability. In the context of computer modeling, any resources that were "considered" were made available as candidate resources that our capacity expansion model could use to create an optimal generation portfolio. As mentioned previously, the capacity expansion model chooses which resources to build, when to build them, and in what quantities to build them, subject to constraints such as RPS goals and reliability metrics. All this is done while simultaneously attempting to minimize costs.

In terms of non-renewable resources, the construction of new nuclear plants was not considered due to the operational risks and environmental impacts. Additionally, the construction of new large hydroelectric resources (i.e., hydroelectric resources with a capacity greater than 40 MW) was not considered due to the lack of available building sites as well as environmental impacts.

The construction of new gas-fired combustion turbines and combined-cycle plants was considered, along with carbon-free green hydrogen turbines.

In terms of DERs in the 2023 IRP scenario, our assumptions included a buildout of 1,500 MW of local solar, 3,210 GWh of energy efficiency savings, and 576 MW of demand response by 2035.

3.3 Load Forecasting

Utilities are required to forecast energy demand and to determine how that demand will be supplied. Planning the buildout of electric power generating ("supply-side") resources through transmission and distribution systems in order to meet forecasted demand is a vital component of the IRP process. Another key element in our planning process is to determine how we can reduce or control energy demand and increase the efficiency of our customers' electricity use. This process is known as "demand-side resource" planning.

This section and subsequent sections of the IRP address the following:

- Forecasting of future energy demand, including transportation electrification
- Demand-side resources (DSR), including energy efficiency and demand response
- Distributed generation
- Supply-side resources
- Transmission/distribution, including grid reliability
- Advanced technologies, including Smart Grid and energy storage
- Climate change effects on power generation
- Reserve requirements

The discussions include the technical, regulatory, and economic factors that affect LADWP's planning and execution of programs and projects.

Data for this analysis comes from publicly available reports from organizations such as the California Energy Commission (CEC), California Public Utilities Commission (CPUC), the North American Electric Reliability Corporation (NERC), the Federal Energy Regulatory Commission (FERC), other industry forecasts, and internal LADWP sources. In this IRP, we have also highlighted additional studies that are either underway or will be performed in the near future to provide additional clarity regarding the boundaries and needs of the Power System.

3.4 Forecasting Future Energy Needs

Our 2023 IRP utilizes LADWP's official 2021 Load Forecast of customer demand for electricity over the next 20 years.). The 2021 Load Forecast divides customer sales into six separate classes.

- Econometric models are used to forecast sales in the Residential, Commercial, and Industrial classes. Trend models are used to forecast sales in the Streetlight and Owens Valley classes.
- For the Transportation Electrification (TE) sales class, the California Energy Commission EV (Electric Vehicle) Forecast (with adjustment based on Power System's new Electric Vehicle input) is adopted.
- The drivers in the retail sales models include normalized weather, population, employment, construction activity, and personal consumption and income.
- The retail sales forecasted from the class models are adjusted for LADWP programs that affect consumption behind-the-meter such as energy efficiency and net-metered solar generation as well as known state regulations, most notably the Huffman Bill.
- From the sales forecast, a net energy for load (NEL) forecast is developed by applying a normalized loss factor of 12%. NEL is defined as the energy production necessary to serve retail sales and line and distribution losses. Losses can vary in a given year depending on the sources of energy production and other factors. An econometric model is also used to develop weather response functions to forecast peak demand.
- The weather response model includes temperature, heat buildup, and time of the summer, as drivers. Peak demand grows over time as a function of the NEL forecast adjusted for energy efficiency, net-metered solar, residential lighting, and charging of electric vehicles. The NEL forecast is allocated into an hourly shape using the Loadfarm algorithm developed by Global Energy. The inputs into the algorithm are forecasted NEL, peak demand, minimum demand, and historical system average load shape.

3.4.1 2021 Retail Electrical Sales and Demand Forecast

The COVID-19 public health crisis began affecting electricity sales during the third quarter of fiscal year-end (FYE) 2020. Sales for FYE 2020 were 21,115 gigawatt-hours (GWh). This was 3.9% below recorded sales of 21,961 GWh in FYE 2019. The compounded growth rate for sales is estimated to be -0.3% over the five-year budget period. Sales growth will be restrained by accelerated incremental savings from our energy efficiency and solar distributed generation programs. Electric price increases also mean that customers will change their electric consumption behavior to a more conservation-minded approach. The five-year budget period is one of great uncertainty. LADWP is monitoring the sales and load data weekly and will make necessary adjustments for immediate forecast needs.

The LADWP billing system underwent a conversion in September 2013. It is our Load Forecast Group's opinion that sales in FYE 2014 and 2015 are under-reported. In 2017, the billing system reflects amounts related to legal settlements from the billing system conversion. These billing system anomalies from one-off events create noise when performing statistical analysis on historical time series data.

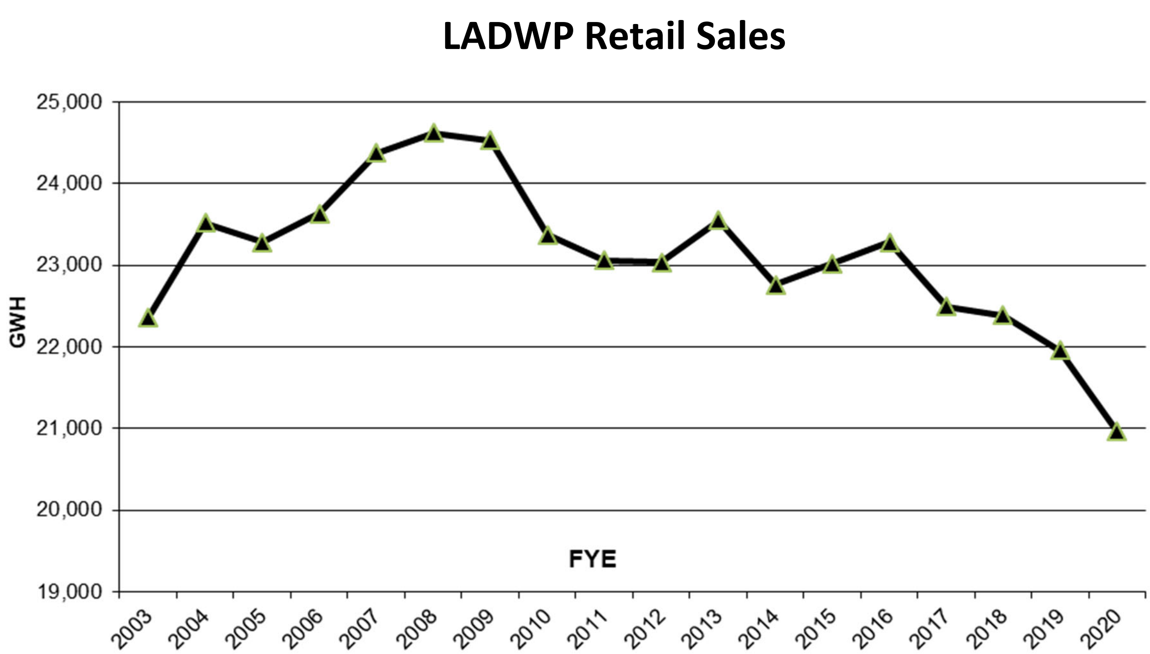


Figure 17. Retail sales net of energy efficiency and distributed generation.

3.4.2 Losses Incurred in Production

In Fiscal Year 2013-14 and 2016-17, percentage losses were the highest recorded since 1981. The formula for percentage losses is ((NEL – Sales) x100) / NEL. Averaged percentage losses are 12.1% with a standard deviation of 1.1% from Fiscal Year 1980-81 to 2019-20. In Fiscal Year 2013-14 and 2016-17 the losses were 14.8% and 15.0% respectively. Figure 18 shows the historical percentage losses.

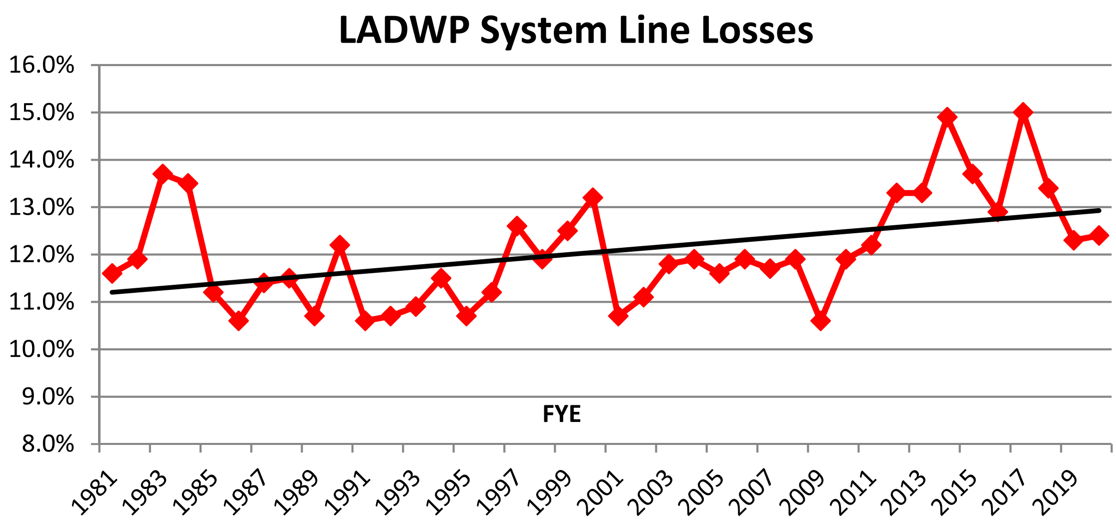
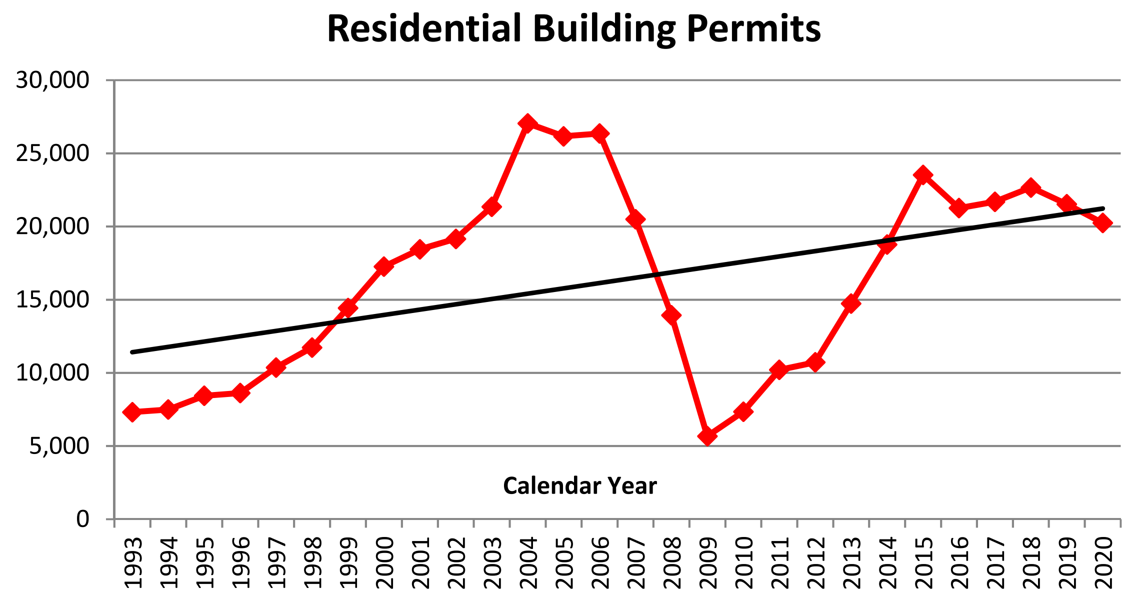


Figure 18.Historical Percentage Losses by Calendar Year.

3.4.3 Economics

In 2021, net migration into Los Angeles County was negative 131,000 people (i.e. the LA County population decreased). The last positive year for net migration in Los Angeles County was 2001. Recent population growth has been due to natural increase (the difference between the number of live births and the number of deaths). The LADWP service area is most commonly modeled as having a constant share of Los Angeles County population. Data at the county level is considered more accurate. All the data and forecasts in Figure 19 below are taken from the 2022 UCLA Anderson Forecast.


Residential Building Permits
30,000
25,000
20,000
15,000
10,000
5,000
0
Calendar Year
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
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2017
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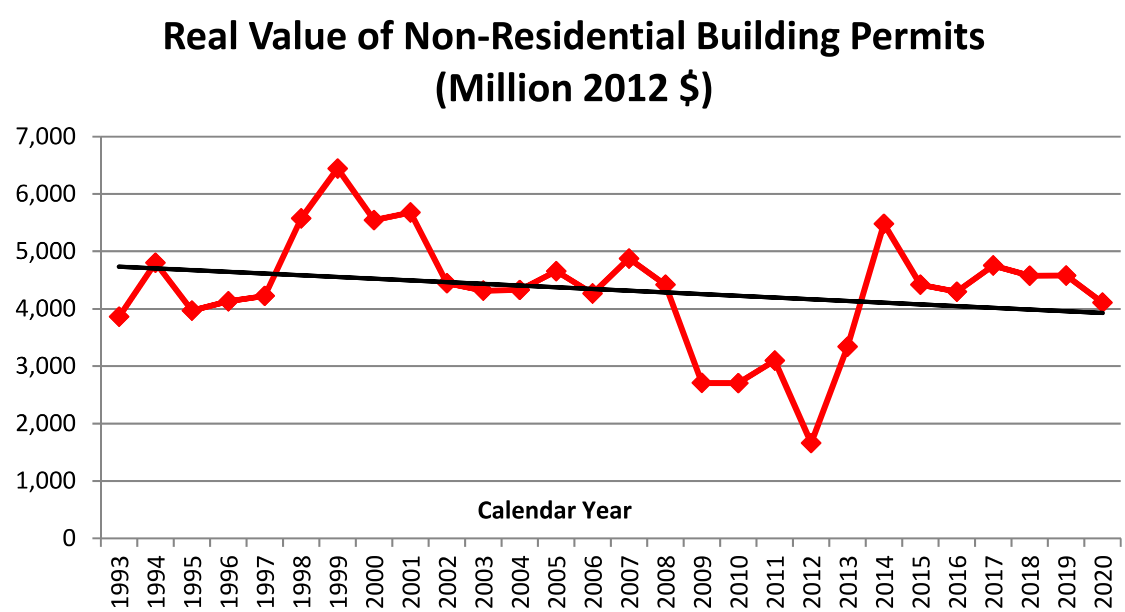
2020


Real Value of Non-Residential Building Permits
(Million 2012 $)
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
Calendar Year
1993
1994
1995
1996
1997
1998
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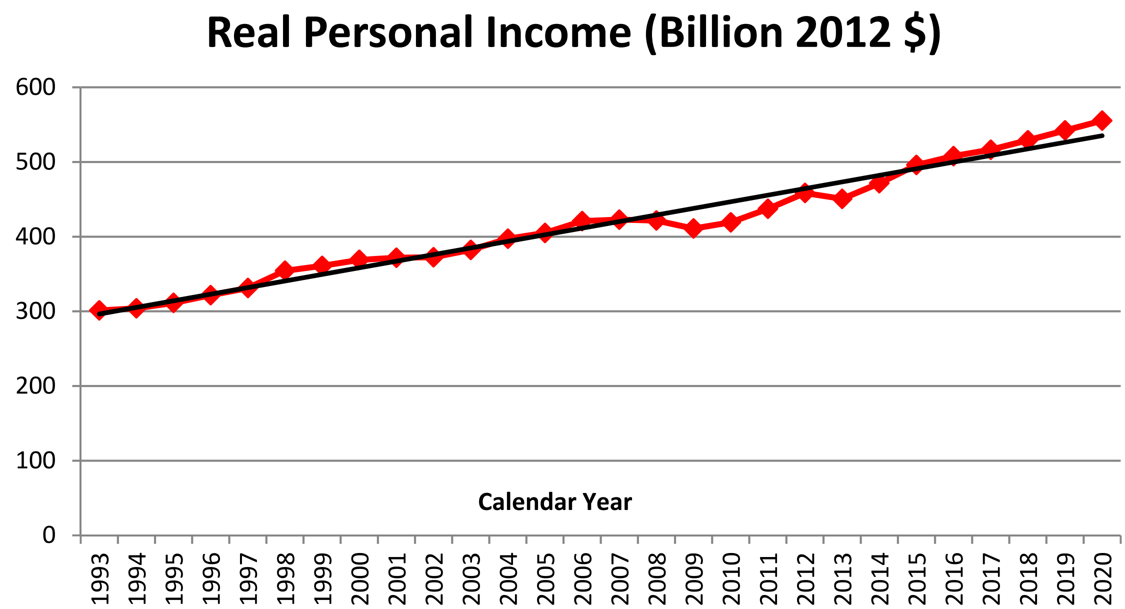


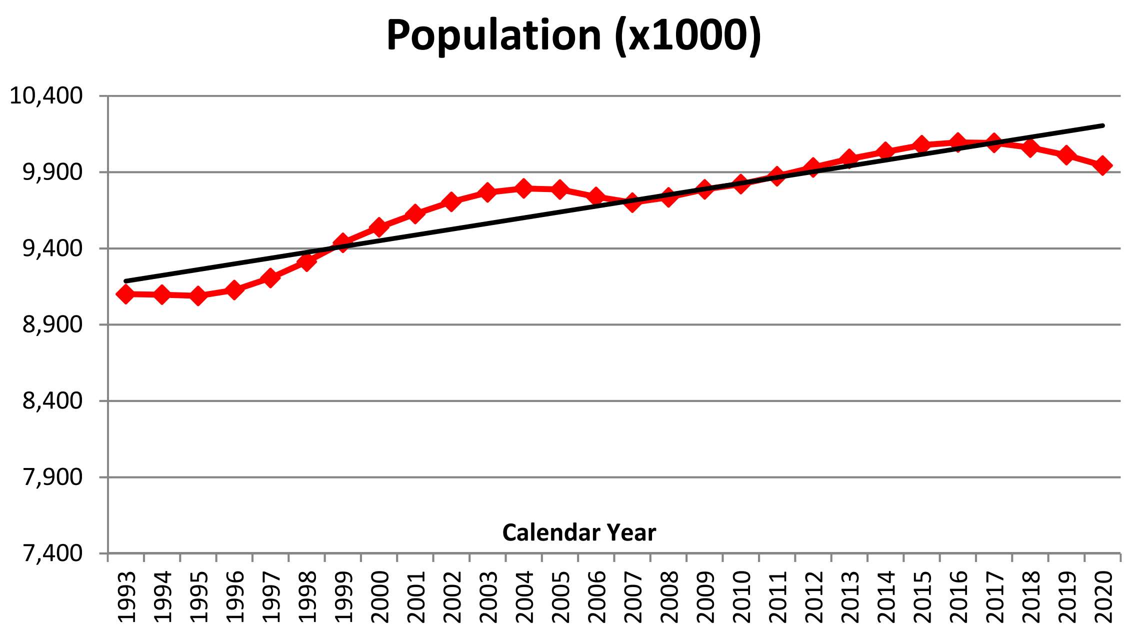


Figure 19. 2022 UCLA Anderson historical inputs for residential building permits, real value of non-residential building permits, real personal income, and population by calendar year.

The electricity consumption within LADWP's service territory is forecasted to decrease 0.3% over the next five years as energy efficiency and customer-installed solar photovoltaic (PV) expansion offsets growth from economic activity. The growth in annual peak demand over the next ten years is predicted to be about negative 0.4% –approximately 20 MW per year—with negative growth over the next few years due to energy efficiency and solar PV programs. Additional load reduction is possible with the implementation of the demand response program which is not presently included in the peak demand forecast, but is considered in this IRP as a resource to serve peak demand.

3.4.4 Forecast Data Sources

The 2021 Load Forecast is LADWP's official Power System load forecast. This forecast is used as the basis for LADWP Power System planning activities including, but not limited to, strategic long-term resource planning, integrated resource planning, transmission and distribution planning, and wholesale marketing. The forecast is a public document that uses only publicly available information.

Table 2 summarizes the data sources used to develop the forecast and where these data sources have been updated from previously published forecasts.

Table 2. Load forecast data sources.

Data Sources	*Updates*
1. Historical Sales through December 2020 were reconciled to the General Accountings Consumption and Earnings Report.	*Historical Sales, Net Energy for Load and weather data is updated through December 2020.*
2. Historical Los Angeles County employment data is provided by the State of California Economic Development Division using the March 2020 benchmark.	*Employment data is updated through December 2020 using the March 2020 benchmark.*
3. The Transportation Electrification Forecast is based on the California Energy Commission Integrated Energy Policy Report forecast with adjustment based on Power System's new Electric Vehicle input.	
4. The LADWP program energy efficiency forecast is based on the AB 2021 goals adopted by Board Resolution on August 5, 2014 and is consistent with the 2017 Strategic Long-Term Resource Plan. Historical installation rates are provided by the Energy Efficiency group.	
5. Projected solar rooftop installations are consistent with the 2017 Strategic Long-Term Resource Plan. Historical installations are provided by the Solar Programs Development Group.	
6. Electric prices are based on approved FY20/21 Final Budget Financial Plan Case-24 developed by Financial Services Organization.	

3.4.5 Five-year Sales Forecast

The 2021 Load Forecast represents total sales that will be realized at the meter while incorporating future savings from known energy efficiency technologies and future loads that are expected to be served by distributed generation. The forecast does not include changes in sales that may result from emerging technologies. Private enterprise and government are both currently funding a wide array of new research primarily in the pursuit of mitigating human-driven climate change. The historical accumulated energy efficiency and solar savings reported in the forecast are from 1999-forward. Historical codes and standard savings for the years 1999 through 2011 are based on California Energy Commission analysis. After 2011, LADWP calculates its share of total savings from codes and standards from reported California savings. True accumulated energy efficiency would more likely be dated back to 1974 when the Warren-Alquist Act was passed in California, but accurate records are not available. In the 2021 Load Forecast, projected energy efficiency and customer-sided solar savings are expected to occur uniformly throughout the year as a simplifying assumption.

Estimated sales for FYE 2021 are 360 GWh, or 1.7% below recorded sales in FYE 2020. The compounded growth rate for sales is estimated to be negative 0.3% over the five-year budget period. This result is mainly attributed to accelerated incremental savings from LADWP's energy efficiency and solar distributed generation programs, and expected increases in real electric rates. In the 2021 Load Forecast, electric rate increases are lagged one year to allow for customer behavior to change.

Historical and future retail sales would be significantly higher absent LADWP energy efficiency and solar distributed generation programs. Based on installed savings, sales have been reduced by 3,652 GWh since FYE 2000 through LADWP-sponsored programs. LADWP is accelerating these savings programs and retail sales are expected to be reduced by another 1,883 GWh over the next five years.

Table 3 shows projections of short-term retail sales and energy efficiency growth.

Table 3.Short-term retail sales ad energy efficiency growth.

Fiscal Year	Retail Sales		Additional Load if not for EE & Solar Savings
Ending June 30	(GWh)	Growth Rate (Year-Over-Year)	(GWh)
2020-21	20,754	-1.7%	3,857
2021-22	20,926	0.8%	4,242
2022-23	20,610	-1.5%	4,664
2023-24	20,671	0.3%	5,092
2024-25	20,834	0.8%	5,535

For IRP modeling and analysis, adjustments are made to the approved load forecast to account for the alternative energy efficiency targets and customer net-metered solar projections.

3.5 LADWP Programs and Initiatives

The following subsections describe the various LADWP programs and initiatives included in the 2023 IRP.

3.5.1 Energy Efficiency

Energy Efficiency (EE) is a key strategic element in LADWP's resource planning efforts. EE serves an important and multi-faceted role in meeting customer demand. A common example of a successful EE measure is the replacement of compact fluorescent lamps (CFLs) with light-emitting diode (LED) lamps. LEDs consume up to 60% less energy than CFLs while producing an equivalent amount of illumination and last up to seven times longer.

EE programs have reduced consumption by approximately 3,275 GWh/yr. LADWP is committed to implementing comprehensive energy efficiency programs with measurable, verifiable goals as well as maintaining an overall cost-effective energy efficiency portfolio.

Under Assembly Bill 2021 (AB 2021), publicly-owned utilities such as LADWP, must identify, develop and implement programs for all potentially achievable, cost-effective EE savings and establish annual targets.

Furthermore, utilities are required to conduct periodic EE potential studies to update their forecasts and targets. LADWP completed and finalized the 2013 EE Potential Study in 2014. The revised energy savings and demand reduction targets, based on the EE Potential Study, were recommended and adopted by the Board of Water and Power Commissioners on August 5, 2014. The next EE Potential study was conducted in 2017, which concluded that LADWP could cost effectively achieve another 15% energy efficiency from 2017 through 2027 in addition to the previously committed 15% from 2010 through 2020. If LADWP keeps the same pace through 2030, we would double our energy efficiency portfolio per SB 350. The following sections describe the various LADWP energy efficiency programs.

2.1.1.1 Comprehensive Affordable Multifamily Retrofits

The Comprehensive Affordable Multifamily Retrofits (the "CAMR") program provides low-income tenants and affordable housing property owners access to energy efficiency retrofits, building electrification measures, and on-site solar installation. The participating housing providers receive free energy assessments and assistance in scoping retrofit projects based on opportunities for energy savings, cost reductions, and GHG emissions reduction. Participating properties contain at least 66% of households at or below 80% of the area median income, consist of five or more units, and install energy improvements that equate to at least 10% in energy savings.

2.1.1.2 Efficient Product Marketplace

The Efficient Product Marketplace (the "EPM") program provides customers an opportunity to research, locate, and purchase energy efficient products from a single website. It offers a point-of-sale credit option to customers during their online purchases, eliminating the need for a rebate application. The EPM also provides customers with the ability to customize a solar system for their home and compare offers from a list of local third-party vendors.

2.1.1.3 Food Service Program

For in-store purchases, the Food Service Program offers an instant rebate as a line item discount directly on their sales invoice for eligible equipment. The Food Service Program is intended to influence commercial food service vendors to stock and sell energy-efficient equipment.

2.1.1.4 Customer Performance Program

The Custom Performance Program (the “CPP”) provides cash incentives for energy savings achieved through the implementation and installation of various energy efficiency measures and equipment that meet or exceed Title 24 or industry standards. Measures may include but are not limited to equipment controls, industrial process, retrocomissioning, chiller efficiency, and/or other innovative energy savings strategies.

The CPP’s Custom Express fast tracks smaller, less energy-intensive projects with deemed energy savings projections to help expedite application processing and get customers paid faster, while the CPP’s Custom Calculated conducts an in-depth energy savings analysis to custom calculate customers’ individual efficiency projects’ energy savings. The CPP has achieved over 586 GWhs of energy savings since 2007.

2.1.1.5 Commercial Lighting Incentive Program

The Commercial Lighting Incentive Program (“CLIP”) offers customers incentives to install newly purchased energy-efficient lighting and controls. CLIP currently provides incentives to customers whose monthly electrical use is greater than 200 kilo-watts (kW). CLIP’s calculated savings approach allows customers to tailor their lighting efficiency upgrades to better meet their lighting needs, attain greater energy savings, and receive higher incentives. Commercial lighting programs have achieved over 748 GWhs of energy savings since 2000.

2.1.1.6 Commercial Direct Install Program

The Commercial Direct Install (“CDI”) Program is a free direct-install program that targets small, medium, and large business customers in the Department service territory. The Department partners with Southern California Gas Company (“SoCalGas”) to offer a tri-resource efficiency program aimed at reducing the use of electricity, water, and natural gas. The CDI program is available to qualifying businesses whose average monthly electrical demand is 250 kW or less. This program has achieved 465 GWhs of energy savings since its inception in 2008.

2.1.1.7 Home Energy Improvement Program

The Home Energy Improvement Program ("HEIP") is a comprehensive direct install whole-house retrofit program that offers residential customers a full suite of free products and services to improve the home's energy and water efficiency by upgrading and retrofitting the home's envelope and core systems. While not limited to low-income customers, HEIP's priority is to serve the most disadvantaged customers.

2.1.1.8 Refrigerator Exchange Program

The Refrigerator Exchange Program (REP) is a free refrigerator replacement program designed to target customers that qualify on either the Department's Low-Income or its Senior Citizen/Disability Lifeline Rates as well as Multi-Residential or Non-Profit customers. The program was expanded to include the following entities: multi-family or mobile home communities, civic, community, faith-based organizations, and educational institutions. The REP leverages a third-party contractor, ARCA (Appliance Recycling Centers of America), to administer the program's delivery and provide energy-efficient refrigerators to replace older, inefficient, but operational models. Additionally, customers can pair the REP with the Window Air Conditioner Recycling Program, which offers a $25 rebate to residential customers to turn-in their old window air conditioners, achieving an energy savings of 104 GWhs since 2007.

2.1.1.9 LED Streetlight Program

The LED streetlight program provided a $48 million loan to the City of Los Angeles to enable it to ultimately install over 180,000 highly energy efficient LED streetlights and reduce its consumption of electricity as a result. This program is now completed, and the loan has been repaid by the City. As a result, this program is being expanded as a $24 million loan to retrofit decorative street lighting with LED streetlights throughout the City.

2.1.1.10 Program Analysis and Development Program

The Program Analysis and Development Program is a non-resource program that covers support activities related to the energy efficiency portfolio, which are not included in individual programs. These activities include but are not limited to, developing new programs, conducting special studies and pilot programs, participation in technical professional groups, and the investment in external studies. The Department has contributed to several research studies as it relates to building electrification, including NBI's Building Electrification Technology Roadmap and E3's Residential Building Electrification in California.

3.5.2 Building Electrification

Starting in 2018, California set forward a number of bills such as AB 3232 and SB 1477 that aim to reduce carbon emissions in the building sector. These policies have not created mandates for any local entity but rather set goals for the CEC and CARB to aim for overall building sector carbon emissions to 40% below 1990 levels. In 2019, sitting Mayor Eric Garcetti released the LA Green New Deal, setting local targets to reduce carbon emissions within the building sector. Specifically, it aims to have net zero-carbon requirements for new buildings by 2030 and all buildings by 2050. Table 4 shows the percentage of the retail price covered by various building electrification incentives.

Table 4. Percentage of retail price covered by various building electrification incentives.

	End Use			
Sector	Water Heating	Space Heating	Clothes Drying	Cooking
Residential	40% coverage	25% coverage	40% coverage	35% coverage
Commercial	30% coverage	10% coverage	N/A	N/A

3.5.3 Distributed Energy Resources

Distributed energy resources are the aggregation and management of smaller demand-side resources that are able to provide utility-scale services. LADWP is evaluating the integration of DERs, such as rooftop solar PV, demand response, energy storage, electric vehicle charging, enhanced energy efficiency technologies, and other modernized smart grid infrastructure.

Each DER has unique operational characteristics that have distinct impacts to power flow. For instance, excess rooftop and distributed solar generation may result in reverse power that can potentially damage distribution equipment designed for one-way flow. The near-term solution would be to offset the solar generation with energy storage or electric vehicle charging, creating an electrical load to absorb excess energy for later use. Communications and intelligent controllers are necessary in order to provide resources like the PV system, the energy storage system, and the electric vehicle charger the appropriate signals to switch on and off. LADWP is currently investigating microgrid control solutions and potential to demonstrate their ability to provide grid operators more visibility and control of DERs, while simultaneously acting as a demand response asset. Figure 20 shows aggregate DER impact on net load.

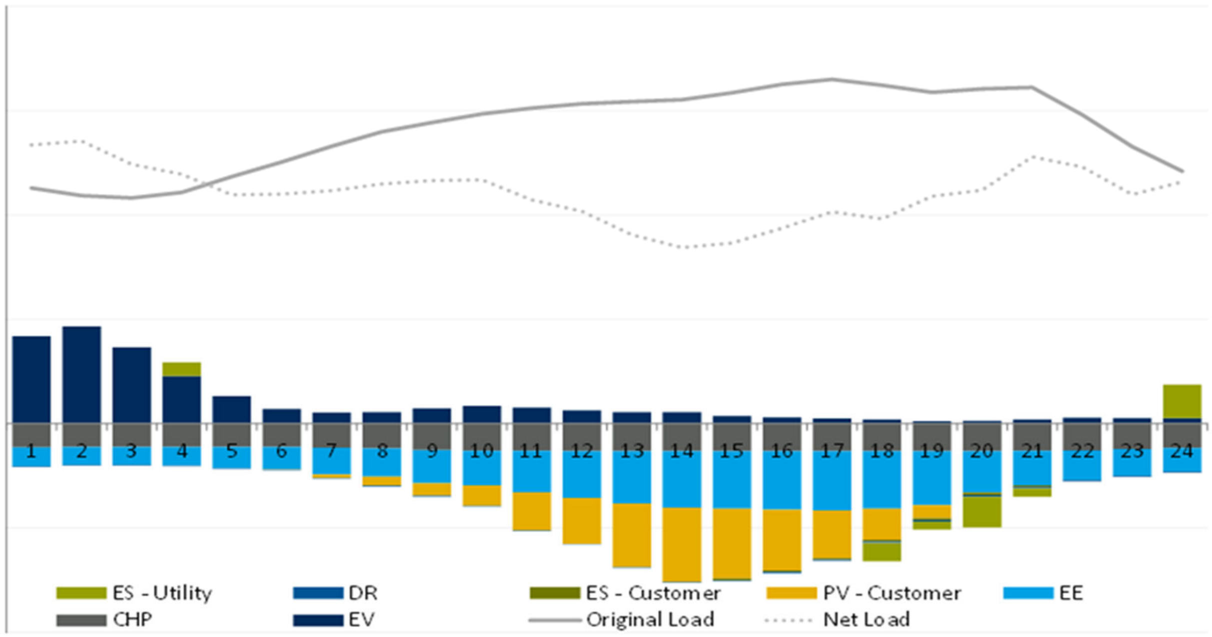


Figure 20. Aggregate DER impact on net load.

The logic required to manage a single location's DERs may be relatively simple, but every on and off operation from each device leaves a small ripple in the power flow. This ripple effect can be amplified by the hundreds of devices on a circuit, or the millions installed across the LADWP power system. The amplified effect can cause grid disturbances, transients, and deteriorating power quality and reliability. LADWP is investigating potential solutions to prevent cascading reliability events before DER adoption reaches critical levels.

Most of the technologies required for a DER-ready distribution infrastructure are emerging in small-scale demonstrations and pilots around the world, but they are not ready for large-scale deployment. These require substantial modernization of distribution infrastructure, including the development of sophisticated distribution operations, communications, and data processing. Although a significant amount of DERs—especially solar PV generation— are currently in service, many installed communication architectures and protocols do not meet utility requirements for monitoring, control, and cybersecurity. We are presently evaluating the requirements to responsibly manage DERs for distribution system optimization and reliability, including interoperability of legacy devices using a DER Management System (DERMS).

A main focus of the LADWP DER program is to understand all potential system impacts. We are attempting to discover how and where these technologies can provide benefits to the grid and our customers. By synchronizing DER incentive programs with power system planning, engineering, and operations stakeholders, we can potentially defer capital infrastructure upgrades and replacements, decrease generation and transmission operating costs, and increase renewable DG integration. Figure 21 shows the various components of LADWP's DER programs.

Figure 21. Components of distributed energy resources.

3.5.4 Demand Response

Demand Response (DR) is an important energy management tool that facilitates the reduction of energy-use over a given time period. These events could be in response to a price signal, financial incentive, or other triggering mechanism. The key objective of DR is to cost-effectively reduce the summer time system peak by avoiding long-term investments in expensive dispatchable power plants (e.g. natural gas and hydrogen) and energy storage assets (e.g. batteries). To meet this objective, customers are incentivized to reduce energy usage at critical peak demand periods in a manner that decreases overall system costs. LADWP's DR programs are based on incentives to encourage customer participation, including reduced rates, rebates, or other financial incentives. The permanent load impacts of EE and temporary load impacts of DR are compared in Figure 22.

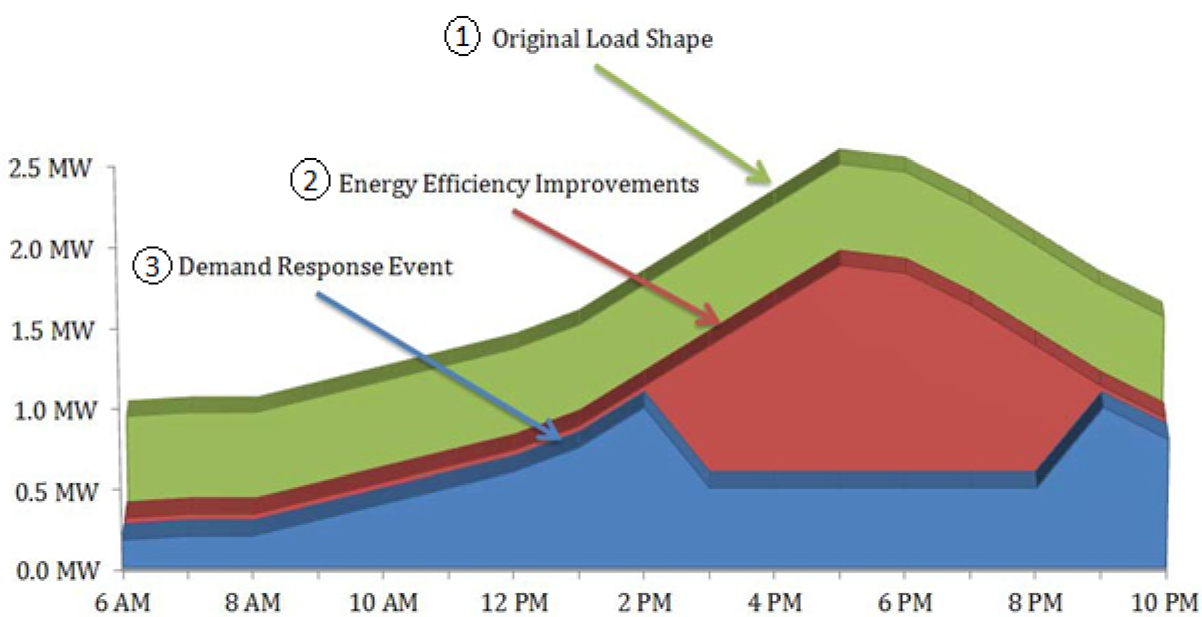


Figure 22. Impacts of energy efficiency and demand response on load.

Figure 22 also illustrates the impact of energy efficiency improvements (2) on the original load shape (1). Energy efficiency improvements reduce the overall original load shape without targeting specific periods of time. In contrast, demand response is effective in reducing energy usage over targeted periods of time and can assist in targeting the peak hours of the energy load shape. The resulting load shape from a demand response event (3) is shown in Figure 22, which targets the hours between 2 p.m. and 9 p.m. and flattens the load shape between those hours. The combination of demand response and energy efficiency complements one another and can be an important resource in reducing overall peak load.

A well designed and cost-effective set of DR programs will benefit both LADWP and its customers through:

- *Reduced System Costs* - DR eliminates or defers the need to build additional power plants and energy storage assets and the associated transmission and distribution infrastructure. Additionally, DR may reduce purchased energy costs by reducing the amount of energy that must be purchased to meet load, especially during the expensive peak demand periods. The overall effect of the cost savings helps maintain low rates for customers.
- *Reduced Customer Bill* - Customers who participate in DR programs will enjoy either reduced rates, rebates, or other financial incentives for reducing energy consumption during peak periods or emergency situations. In addition, cost-effective DR also benefits customers who do not participate, as DR reduces the need for long-term investment in new power plants, transmission, and distribution equipment.
- *Increased Reliability* - The ability to strategically lower energy consumption is one way to help overcome supply-demand constraints and reduce the chance of overload and power failure. This is especially important during those few critical peak times each year when demand is at its highest or when generation units are off-line.
- *Reduced Environmental Impact* - By eliminating or deferring the need to build additional infrastructure, the associated construction and operational impacts are also eliminated or deferred. Furthermore, the reduction in energy usage results in less operational impacts (fuel consumption, carbon emissions, transmission use).
- *Integrating Renewables* - Advanced Automated DR can enable customer loads to respond to fluctuations in generation from wind and solar power. Additionally, as renewable energy continues to become a larger percentage of LADWP’s generation portfolio, there may be times where DR events are initiated to increase demand and absorb the renewable energy, reducing overall system costs.

The updated Title 24 standard that took effect on July 1st, 2014 includes an updated requirement for Automated Demand Response (Auto DR) readiness. Any new building larger than 10,000 square feet and any existing building replacing 10% or more of existing luminaries must enable lighting fixtures to be controllable by a building management system capable of receiving Auto DR signals via the internet. Additionally, HVAC in non-critical zones must also be responsive to Auto DR signals. This regulation is important for the development of the DR portfolio because it may assist LADWP in identifying potential customers who are already capable of participating in future DR programs. Furthermore, the Title 24 updates show a continued commitment by the federal government to promote DR readiness and participation.

The guiding principles for the development and operation of the DR portfolio are:

1. DR will be operated by the Energy Control Center (ECC), managed by the Power System, integrated with billing and customer information systems (CIS), and aligned with Energy Efficiency and Premier Account activities.

2. DR will be customer-friendly through ease of enrollment, flexible participation, incentives and rates transparency, and inclusivity.

3. Load curtailment will be available primarily during summer peak periods, within one to two hours of dispatch, with a significant share of the capacity available within 10 minutes.

4. DR will be treated as a resource by LADWP and included in the IRP process, where the DR goals will be revisited periodically and realigned with projections of supply and demand and changing strategic priorities at LADWP.

LADWP’s focus is on DR resources that are cost-effective and proven. Cost-effectiveness tests determine whether the DR resource is a better investment overall than alternatives for meeting future load growth, given the best available current information. Ramping the program in this manner—gradually and through internal programs—will promote the development of in-house expertise and allow time to deploy the supporting information systems necessary to implement these systems successfully.

In spring 2013, LADWP hired Navigant Consulting to assist with developing a Demand Response Strategic Implementation Plan. The strategic implementation plan serves as LADWP’s near-term and long-term plan for developing a measurable, cost-effective, and customer-friendly DR portfolio. The DR implementation plan provides in-depth details on items such as the estimated DR resources, measurement and verification methods for load and billing impacts, and other requirements. The DR implementation plan is updated annually and is incorporated into LADWP’s IRP. All customer classes and sizes will be eligible to participate in some form of demand response, while the principal sources of load curtailment are provided by the following customers and programs:

1) Commercial, Industrial, and Institutional (CII) Curtailable – Participants receive monthly capacity payments in return for providing guaranteed load reduction of at least 100 kW when requested by LADWP. Additional incentives are provided based on energy reduced during DR events.

2) Residential and Small Commercial Direct Load Control (DLC) – Participants with less than 30 kW peak load receive an annual payment that varies based on their ability and willingness to reduce power consumption from equipment which may include central air-conditioning units, wall-mounted air-conditioning units, pool pumps, and other equipment.

3) Critical Peak Pricing – Residential, small commercial, large commercial, and industrial participants of all sizes will be given a dynamic Time-of-Use (ToU) rate that includes a high "critical peak" price in effect during periods of high energy prices, exceedingly high customer demand, or emergency situations.

4) Electric Vehicle Rider – Participants will have an EV charging station with a separate meter installed. During a DR event, their usage may be curtailed in exchange for a discounted rate while using the charging station.

5) Alternative Maritime Power (AMP) – The California Air Resources Board (CARB) is requiring large vessels docked at the Port of Los Angeles be connected to electric power through LADWP's grid to reduce the emissions caused by on-ship diesel generation. In cases of system-wide emergencies, LADWP system operators may temporarily disconnect AMP customers in order to maintain grid reliability.

2.1.1.11 Implementation Schedule

The initial vision for DR extends through 2026, with the steady growth of CII and mass market load curtailment capability that began in 2014. Early pilot programs have provided real DR capacity and built confidence in the resource, while also refining LADWP's choice of technologies, program designs, and outreach strategies. The first new offerings extended new DR opportunities to large CII customers. Future phases will extend to residential customers with central air conditioning. Once advanced metering infrastructure (AMI) is established within the service territory, residential customers will have additional options via an expanded TOU rate offering and new Critical Peak Pricing (CPP) options.

Currently, LADWP requires customers to have building energy management systems (BEMS), and customers must also commit to a minimum load reduction of 100 kW for each called-for demand response event during the five-month curtailment season of June 15th through October 15th.

With the elimination of coal-fired power plants and the influx of renewable energy, particularly solar photovoltaic, LADWP predicts there will soon be periods where generation will exceed customer demand. Since many utilities are likely to encounter similar imbalances between generation and demand, it is unlikely that LADWP will be able to sell excess generation to neighboring utilities. Curtailing renewable generation is costly and a waste of clean energy, all while the cost-effectiveness of utility energy storage is still unknown. Thus, in the near term, LADWP will study the feasibility of demand response programs to encourage consumption during periods of over-generation.

As LADWP investigates opportunities to address the over-generation challenges described above, customers with significant co-generation capabilities will be engaged to determine capabilities to ramp-up and ramp-down co-generation in response to future periods of over-generation.

Assembly Bill 2514 requires investor-owned utilities (IOUs) procure cost-effective energy storage systems in accordance with CPUC rulemaking. LADWP and other publicly owned utilities will be required to adopt their own energy storage goals and report progress to the California Energy Commission. As details of LADWP's Energy Storage goals develop, staff will identify any coordination opportunities and potential synergies between DR and Energy Storage programs.

3.5.5 Transportation Electrification

State legislation such as AB 32, SB 350, AB 2127, and the California Air Resources Board's Mobile Source Strategy development facilitate increased electrification across various sectors. These initiatives are methods to reduce overall GHG emissions in California and help meet federal air quality standards. This has added a degree of uncertainty to the forecast of future electricity needs in terms of additional resulting load and the speed of implementation of electrification programs.

In the transportation sector, switching from fossil fuels to electric power can result in air quality improvements if the sources of electric power are clean.

The Charge Up LA! Rebate Program provides incentives for participants of our Commercial EV Charging Station, Residential EV Charging Station, and Used EV Rebate Programs. We encourage customers to drive electric with enhanced rebates for all segments. Since 2019, we have allocated $200 million in funding to support residential and commercial EV charging and the purchase of used EVs.

The Level 2 (L2) rebate is geared towards customers with large publicly accessible parking lots which can include apartment buildings, parking lots, mixed-use buildings, and commercial retail spaces. The rebate is $4,000 for an installed L2 charger, or $5,000 if the site is located in a Disadvantaged Community (DAC). There is also a rebate for the installation of additional L2 ports which provides an additional $500 per additional port. LADWP will rebate up to 40 L2 chargers per site which equates to $220,000 in potential rebates for a customer located in a DAC.

The DCFC rebate is geared towards commercial customers that are interested in providing DC fast charging solutions for light-duty EV drivers. The program provides up to $100,000 per installed DCFC, up to 8 per site for installations that are publicly accessible, a total of $800,000 in potential rebates.

The medium-duty and heavy-duty rebate is geared towards commercial customers interested in AC and DC charging solutions for medium-duty and heavy-duty EVs. The program provides up to $125,000 per charger and up to $500,000 per installation site.

The Used Electric Vehicle Rebate Program offers rebates of up to $1,500 for qualifying used electric vehicles (EVs). The Program offers an additional $1,000 rebate for applicants who reside in a home participating in the Lifeline or EZ-SAVE programs, for a total rebate amount of up to $2,500.

The Residential EV Charging Station Rebate Program offers customers rebates to help offset the cost of purchasing and installing eligible charging stations for electric vehicles. Eligible customers may receive a rebate of up to $1,000 for the purchase and installation of a qualified Level 2 (240-volt) charging station. In addition, income-eligible customers participating in LADWP's Lifeline or EZ-SAVE programs are eligible for an additional $500 rebate.

Customers who have EV chargers installed at their residences or businesses can receive an EV rate discount. The EV charger must be separately metered from the main meter, and the EV meter must be on a TOU rate. The EV discount is $0.025 per kWh and applies to base period

(M-F 8pm-10am and weekend) charges. There is no service charge or ESA adjustment factor charge for the EV discount rate.

LADWP's Board approved a five-year Pilot Standard Offer (PSO) Agreement for Commercial Electric Vehicle charging services on September 28, 2021. Eligible customers must sign a PSO Agreement to benefit from this rate. Customers receiving service under this rate benefit from reduced demand charges, reducing a significant barrier to the deployment of EV charging infrastructure as the market develops. The TOU periods under this rate differ from the standard LADWP TOU periods, as to better align with today's grid needs.

Figure 23 shows the projected demand attributed to plug-in electric vehicles.

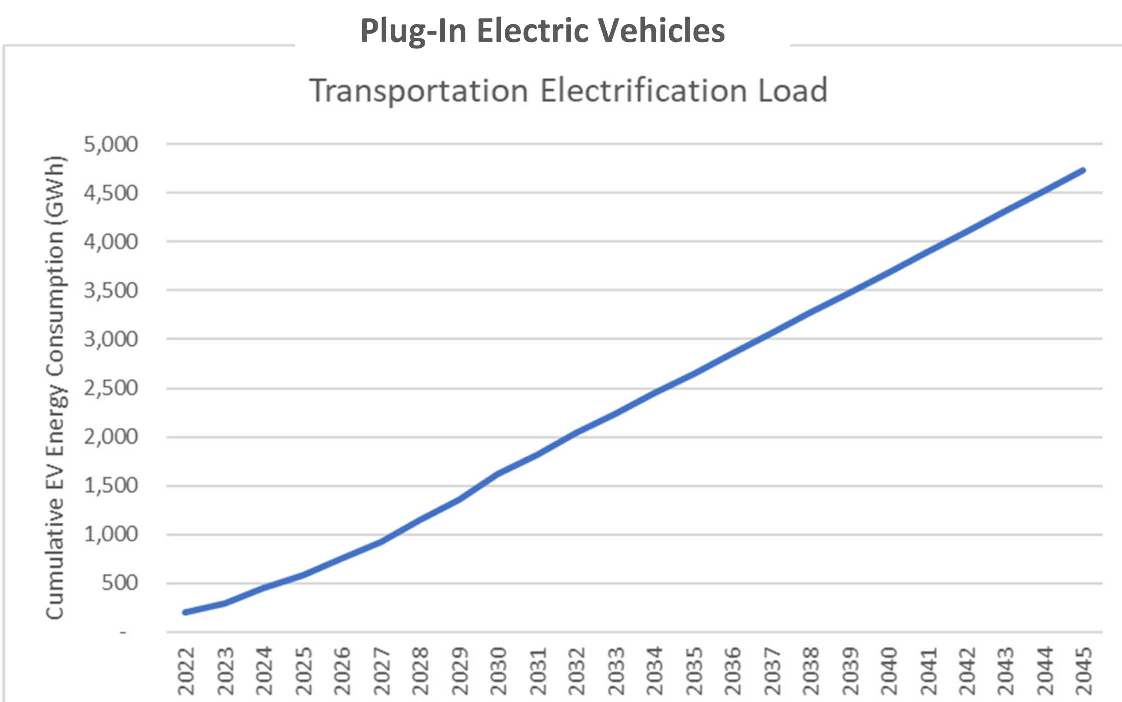


Figure 23. Forecasted energy growth in GWh attributed to plug-in electric vehicles.

Plug-in Electric Vehicles (PEVs)

Large scale deployment of electric vehicles will significantly affect the way electricity is consumed. It is estimated that by 2030, California will have seven and a half million EVs in deployment, 10% of which are expected to be in the City of Los Angeles. The introduction of electric vehicles in Southern California brings a challenging set of planning, regulatory and cost issues. Because EVs require a unique infrastructure, including specialized charging equipment and adequate electric service, it is essential to anticipate and predict the grid impact in Southern California from the EV deployment.

Regulated utilities in California are now responding to regulatory direction to submit plans for a large-scale EV initiative with full delineation of costs and benefits. This regulatory initiative is an aggressive step, seeking to promote accelerated adoption of EVs. The EV deployments and the associated utility customer features are proceeding throughout the State of California. Energy needed for PEVs will come partially from the utility electric grid. It is expected that the "fuel shift" from traditional transportation fuels will increase customers' demand for electricity from the electric grid.

CARB is currently developing Advanced Clean Fleets, a medium and heavy-duty zero-emission fleet regulation with the goal of achieving a zero-emission truck and bus fleet by 2045 everywhere feasible. Their current priorities lie within certain market segments for earlier application such as last mile delivery and drayage applications. Other agencies in the L.A. air basin also have initiatives underway for "electrification" as they shift towards replacing existing diesel fueled trucks and gasoline powered cars with electric power. In addition, planned expansions to public transportation railways and buses would add additional electric load to the system. Another example of transportation sector electrification is the Clean Air Action Plan developed jointly by the Port of Los Angeles and the Port of Long Beach to reduce air pollution from their mobile and fixed sources. This includes trucks, locomotives, ships, harbor craft, cranes, transportation refrigeration units, and various types of cargo handling equipment. One of the programs, Alternative Marine Power, allows AMP-equipped container vessels docked in-port to "plug-in" to shore-side electrical power instead of running on diesel power while at berth.

2.1.1.12 LADWP Electric Transportation Program

LADWP has recently updated its electric transportation program to align with the electrification goals outlined in the California Energy Commission's AB 2127 Electric Vehicle Charging Infrastructure Assessment. This program brings several benefits, including a significant reduction in greenhouse gas (GHG) emissions and a boost in electricity sales. Additionally, Governor Newsom's Executive Order N-79-20 requires all new vehicles sold in California to be zero-emission vehicles (ZEVs) by 2035. To support the charging needs of these vehicles, LADWP is targeting 45,000 and 120,000 commercial charging stations by 2025 and 2030, respectively. To reach these aggressive targets, key stakeholders must work together to reduce the barriers to charging availability. Various policies, programs, and initiatives must be implemented on a federal, statewide, and local level to contribute towards ensuring L.A. is well positioned to maximize the use of electric transportation for Angeleno and visitors during the planned 2028 Olympic Games and beyond.

The Electric Transportation Program is summarized by the following elements:

- *Program Development* - Develop and implement overall electric transportation program strategies. Assess electrification grid impact and mitigation solutions such as charging management and Vehicle-to-Grid integration. Track EV charging adoption and consumption and report to Sustainability Affairs and various state, federal, and local entities.
- *Education and Outreach* - Increase the percentage of zero-emission vehicles in the city to 25% by 2025, 80% by 2035, and 100% by 2050 in accordance with L.A.'s Green New Deal Sustainability Plan 2019 through increased ride and drive events, social media, and a joint program with other utilities and car dealers.
- *Electrify LADWP and L.A. City Fleet* – 100% of new L.A. City light duty and transit vehicles to be electric by 2028 where technically feasible.
- *Residential Charging Rebates* - Continue LADWP's "Charge Up L.A.!" residential rebates and launch Phase II: Smart Charge Rewards Program.
- *Commercial Charging Rebates* - Provide rebates for multi-unit dwelling, workplace, and public charging. This includes installation costs beyond compliance with Green Building Ordinance which requires newly constructed buildings to supply electric vehicle charging infrastructure.
- *Equitable Transportation Electrification* - Ensure at least 30% (increasing to 50% in 2024) of LCFS holdback credits are used in disadvantaged communities (DAC) and/or low-income communities (LIC). LADWP offers additional used EV and EV charging station rebates to low-income residential customers to address barriers for EV adoption and increase participation within these communities.
- *City EV Charging Infrastructure* - Develop partnerships with State, City, and county agencies in addition to other utilities. Install curbside and parking lot public chargers, City Fleet Chargers, City DC Fast Chargers, and City workplace chargers throughout L.A.

- *Medium- and Heavy-Duty Fleet Charging* - Electrify Port of Los Angeles, Los Angeles World Airports, forklifts, rail, and school and transit busses.

LADWP's Electric Transportation Program clearly illustrates LA's visible support for EV technology through:

- 45,000 City and private commercial chargers for the public, workplace, and City vehicles
- Residential charging support
- Assisting in meeting LADWP's goals of GHG reductions, integration of renewables, better utilization of assets, and customer savings

3.5.6 Power System Reliability Program

To enhance the reliability of its system, LADWP introduced the Power System Reliability Program (PSRP) in 2014. This new multi-year initiative builds upon the previous Power Reliability Program (PRP) and expands its scope. The PSRP encompasses Generation, Transmission, Distribution, and Substation sectors, prioritizing infrastructure replacement expenditures based on established metrics and indices. The main goal is to ensure that all Power System assets affecting reliability are thoroughly assessed, and appropriate corrective actions are proposed to minimize future outages.

Since funding priorities often shift due to regulatory mandates and other demands, competition for limited resources has increased. As a result, there is a need for an expanded Power System Reliability Program and planning process to address these challenges effectively.

The original Power Reliability Program (PRP), which started in 2007, initially focused on enhancing the reliability of the distribution system. However, it has evolved into the more comprehensive Power System Reliability Program (PSRP) as of July 2014, encompassing maintenance and capital work for Generation, Transmission, Substation, and Distribution sectors (see Figure 24).

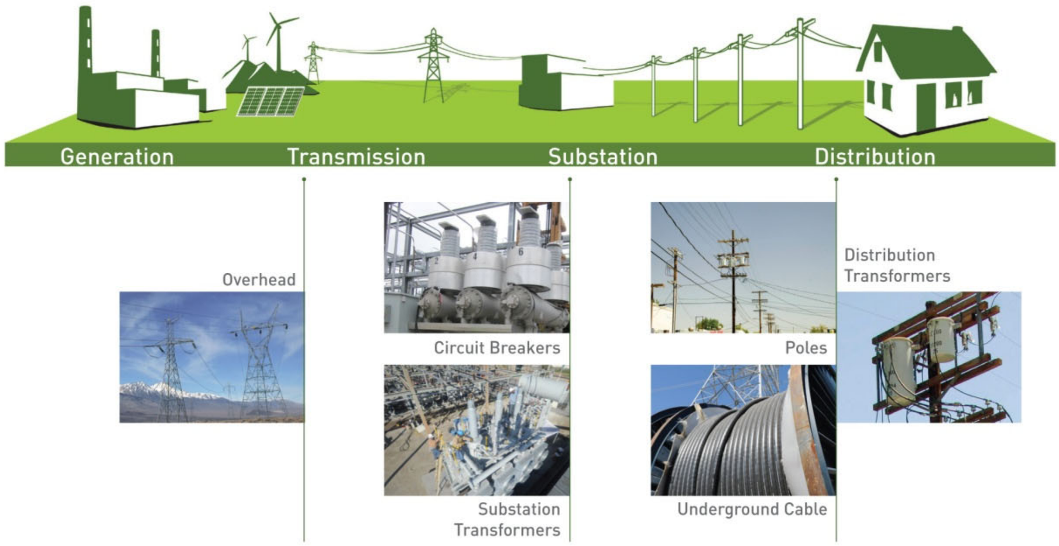


Figure 24. Power System infrastructure assets that provide electricity to customers.

The PSRP is a comprehensive, long-term power reliability program with the following goals:

(a) Address overloaded circuits and stations based on the types of outages and equipment failures specific to the facility

(b) Expedite restoring temporary repairs of equipment failures and target circuits that contribute heavily to LADWP's reliability indices

(c) Commit to proactive maintenance and effective capital improvements needed to expand system capacity and ensure continuance of service

(d) Achieve replacement cycles that align with the assets' respective life cycles, including the replacement of overloaded distribution transformers, worn underground cables, deteriorated overhead poles, and fatigued substation equipment.

The 2022 PSRP Recommended Asset Replacement (Table 5) lists the assets that are prioritized. PSRP targets are expected to be updated on a fiscal-year basis in order to adjust for varying Power System needs, material supply constraints, and human and resource allocations.

Table 5. The 2022 PSRP Report Asset Recommended Replacement List.

2022 PSRP Asset Replacement Categories	
GENERATION	Generation Transformers (GSU & AUX) Major Inspections (Hydro, Pumps and Thermal)
TRANSMISSION	Maintenance Hole Lid Restraints
SUBSTATION	Extra High Voltage Transformers (high side >230-kV) High Voltage Transformers (high side 100-kV to 230-kV) Medium Voltage Transformers (high side <100-kV) Transmission Circuit Breakers (>100-kV) Sub-Transmission Circuit Breakers (34.5-kV) Distribution Circuit Breakers (4.8-kV)
DISTRIBUTION	Cables (34.5-kV & 4.8-kV) Crossarms Poles Substructures Transformers

2.1.1.13 Ongoing reliability challenges

Overall, there has been a reduction in the number of outages since the inception of the PRP and PSRP. However, extreme weather conditions in recent years, coupled with aging infrastructure, have contributed to an increased number of outages for certain years. For example, rain, windstorms, and a station fire all led to an increased number of outages in 2017, while a prolonged heat storm led to an increased number of outages in 2020. Figure 25 shows the number of outages between January 2000 and December 2021.

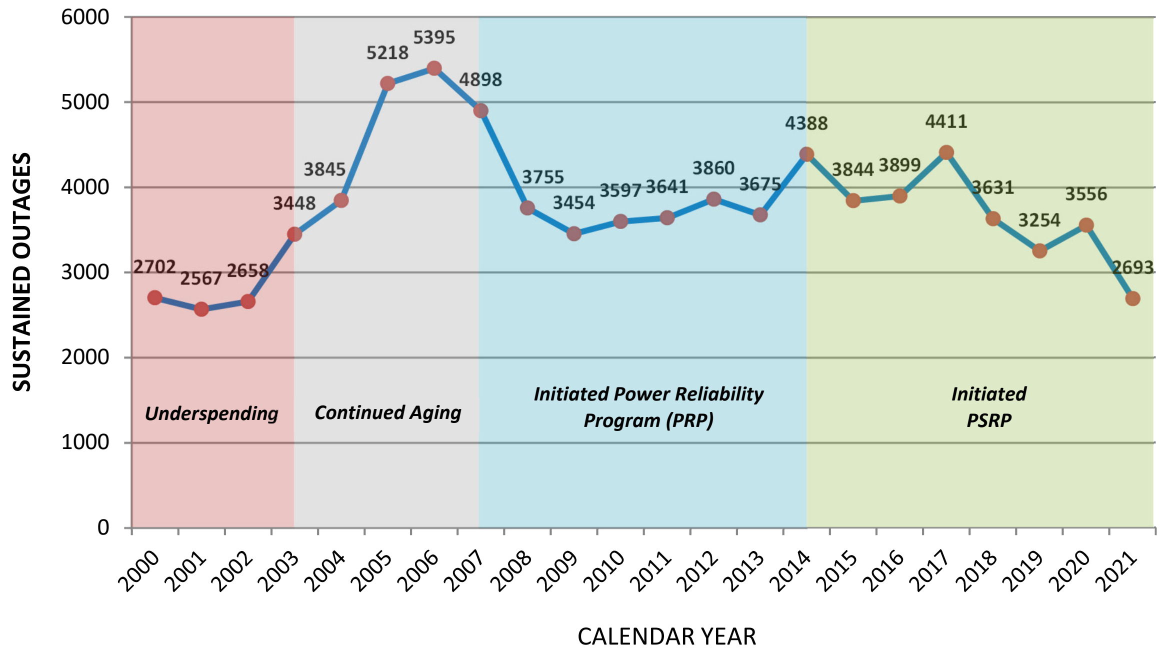


Figure 25. Total sustained outages between January 2000 and December 2021.

3.5.7 Transmission

Electricity from LADWP's power generation sources is delivered to customers over an extensive transmission system. To deliver energy from generating plants to customers, LADWP owns and/or operates approximately 15,000 miles of alternating current (AC) and direct current (DC) transmission and distribution circuits. These transmission and circuit facilities operate at voltages ranging from 120 volts to 500 kilovolts (kV).

In critical times, neighboring utilities look to LADWP's surplus energy and transmission resources to bolster their power system and avoid blackouts. For example, after the nearby San Onofre Nuclear Generating Station retired, the California Independent System Operator has been attempting to secure the delivery of replacement energy from other potentially available generation sources.

Additionally, LADWP annually performs a Ten-Year Transmission Assessment Plan in compliance with the North American Electricity Reliability Corporation (NERC) Compliance Enforcement Program. LADWP's 2022 Ten-Year Transmission Assessment Plan identified a number of transmission improvements that are needed to maintain reliability.

2.1.1.14 Transmission for Renewable Energy

Renewable resources are often located in areas that lack transmission facilities and areas that are far from the City of Los Angeles. Therefore, accessing renewable resources will require extensive infrastructure improvements which includes the construction of new transmission lines, upgrades to existing out-of-basin and local transmission lines, and improvements at transmission facilities and stations to increase their transfer capability.

2.1.1.15 Barren Ridge Renewable Transmission Project

The Barren Ridge Renewable Transmission Project, completed in 2016, increases the capacity of the existing 230-kV Barren Ridge-Rinaldi transmission segment from 450 MW to approximately 1,700 MW. Barren Ridge provides customers access to approximately 1,000 MW of wind and solar power. The resources include, but are not limited to:

- 250 MW from the Beacon solar project
- 60 MW from RE Cinco solar
- 350 MW from the Springbok 1,2, and 3 solar projects

- 143 MW from the combination of Pine Tree solar and Pine Tree wind facility
- Over 100 MW from several of LADWP's hydroelectric plants in the north.

This project also increases the transmission capacity to the Castaic Pumped Storage Power Plant and provides enhanced operational flexibility and integration of variable renewable energy.

Important components of the Barren Ridge Renewable Transmission Project are as follows:

- New Haskell Canyon Switching Station
- New double-circuit 230-kV transmission line from the Barren Ridge Switching Station to the new Haskell Canyon Switching Station
- Expand the existing Barren Ridge Switching Station.

2.1.1.16 Pacific Direct Current Intertie (PDCI) Upgrade

LADWP, along with the other utilities participating in the Pacific Direct Current Intertie, have signed a letter of agreement with the Bonneville Power Administration (BPA) to implement an initial 120 MW capacity increase of the PDCI if the cost is reasonable. In any case, BPA has committed to an extensive overhaul of Celilo HVDC Converter Station which requires coordination at the southern end of the high-voltage direct-current (HVDC) line at Sylmar HVDC Converter Station. BPA's Celilo upgrade project was placed in-service in January 2016. As a result of the Celilo upgrade, plans for an upgrade of the Filter Banks at Sylmar Converter Station were required. The objective of the Sylmar Filters Replacement Project was to replace the old AC and DC filters at Sylmar Converter Station East and West with new filters and to upgrade the control system. LADWP issued a Notice to Proceed to ABB in January 2017 to start the design. Construction of the new AC Filters 3 and 4 began in January 2018 and was commissioned by December 2018.

2.1.1.17 The Haskell Canyon-Olive Transmission Line Project

LADWP plans to reconnect the existing Power Plant 115-kV Transmission Lines 1 and 2 to the new Haskell Canyon Switching Station. Afterwards, we will replace existing double-circuit 115-kV towers with new 230-kV towers from the new Haskell Canyon Switching Station to the north side of the Los Angeles Basin transmission system., One 230-kV circuit will go to a new position at the existing Sylmar Switching Station. This project will maintain system reliability and increase the transfer capability from the new Haskell Canyon Switching Station to the Los Angeles Basin transmission system. It will also assist with supporting 1,700 MW of renewables coming from Owens Valley. In the short-term horizon, we plan to change the circuit rating of Olive-Northridge, Haskell-Sylmar, and Haskell-Olive 230 kV lines in order to support 1,050 MW of renewables from Owens Valley.

2.1.1.18 The Victorville-Los Angeles (Vic-LA) Project

The Vic-LA Projects involve infrastructure and operational improvements between the Victorville area and the Los Angeles Basin. These projects will allow us to add up to 500 MW of transfer capacity, subject to operational requirements. The upgrade work to be performed and scheduled will be determined by a joint Grid Planning and Development Section. The upgrade work could include, but not be limited to, the following work activities:

- Upgrading equipment at Victorville, Mead, and Century Substation including wave traps and capacitor voltage transformer to raise the operating voltage from 287 kV to 300 kV
- Replacing Transformer Bank K and upgrading antiquated equipment at Victorville Switching Station
- Installing shunt capacitors at different strategic locations to improve Los Angeles Basin load power factor
- Replacing Toluca Bank H
- Replacing the 230 kV circuit breakers and the disconnect switches at the Rinaldi Receiving Station
- Reconductoring Valley-Toluca 230 kV circuits and Valley-Rinaldi 230 kV circuits.

2.1.1.19 Los Angeles Basin Projects

The annual Ten-Year Transmission Assessments have consistently identified the need to install Scattergood-Olympic 230kV Cable A for many years now. With each passing year, the urgency becomes more apparent as remedial actions have limited benefit. For this reason, LADWP is moving forward with the installation. With construction that began in 2012, the new 15-mile long Scattergood-Olympic 230kV Cable A in the Westside was placed in service in 2018. Other Los Angeles Basin projects include:

- Upgrading and disconnecting circuit breakers at Receiving Station-U and Receiving Station J.
- Replacing Transformer Banks E and F at Receiving Station K
- Installing 90 MVAR Reactors at RS-D and RS-E
- Reconductoring of the Rinaldi-Tarzana Line 1 and Line 2 230 kV Circuits.

These infrastructure improvements are critical to avoid potential overloads and over-voltage violations on key segments of the Los Angeles Basin transmission system.

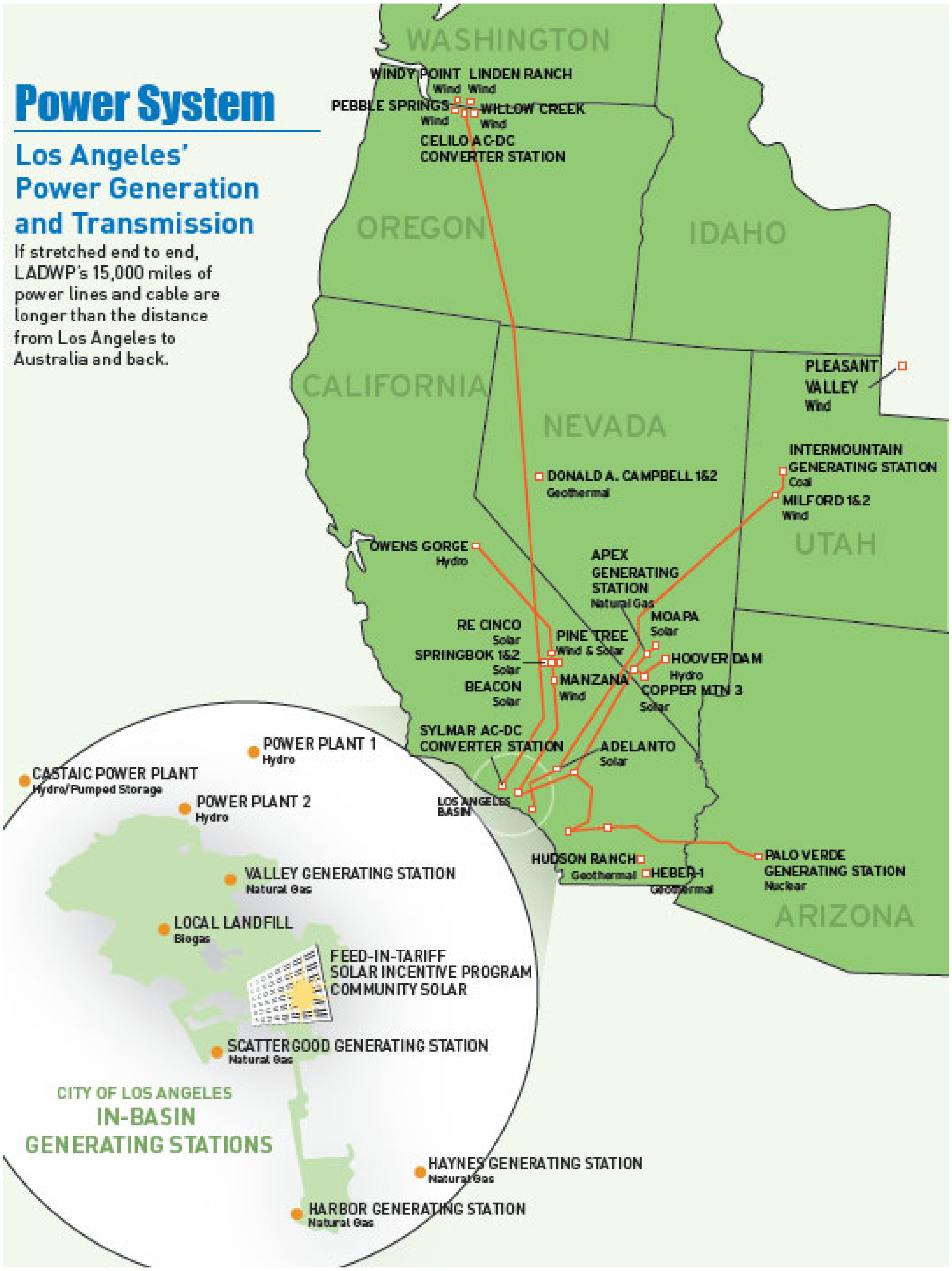


Figure 26. Major in-basin and out-of-basin generating stations and major transmission lines.

3.5.8 Procuring Renewable Energy Resources

Initiatives that utilize renewable resources to generate electricity support the goal of reducing GHG emissions and decreases our reliance upon fossil fuels.

California Senate Bill 2 (1X), which was passed in April 2011 and became effective December 10, 2011, requires utilities to procure eligible renewable energy resources of 33% by 2020. The following interim targets are as follows:

- Maintain at least an average of 20% renewables between 2011 and 2013
- Achieve 25% renewables by 2016
- Achieve 27% renewables by 2017
- Achieve 29% renewables by 2018
- Achieve 31% renewables by 2019
- Achieve 33% renewables by 2020.

California Senate Bill 350, which was passed in September 2015 and became effective October 7, 2015, requires utilities to achieve 50% eligible renewable energy resources by 2030. The following interim targets are as follows:

- Achieve 40% renewables by 2024
- Achieve 45% renewables by 2027
- Achieve 50% renewables by 2030 and maintain this level in all subsequent years.

SB 350 also requires that the energy efficiency of buildings and the conservation savings of retail energy derived from electricity and natural gas end-uses of double by 2030. The law also requires publicly owned utilities to establish annual targets for energy efficiency savings and demand reductions consistent with the statewide goal. The California Public Utilities Commission must also approve programs and investments made by electrical corporations for transportation electrification including electric vehicle charging infrastructure.

California Senate Bill 100, which was passed in August 2018 and became effective September 2018, increased California’s RPS targets to 60% by 2030. The interim targets are as follows:

- Achieve 44% renewables by 2024
- Achieve 52% renewables by 2027
- Achieve 60% renewables by 2030 and maintain this level in all subsequent years.

SB 100 also requires that 100% of retail sales to end-use customers and power services to state agencies are derived from zero-carbon resources by December 31, 2045.

- California Senate Bill 1020 (SB 1020) was signed into law on September 16, 2022 and expanded upon the state's RPS interim targets established by SB 100. These include the following requirements: 90% of electric retail sales to end-use customers from clean energy resources by 2035
- 95% of electric retail sales to end-use customers from clean energy resources by 2040
- 100% of electric retail sales to CA state agencies from clean energy resources by 2045.

These requirements enhance SB 100's original RPS targets by adding 2 new 5-year benchmarks (2035 and 2040) commensurate with SB 100's original RPS target pace for electric retail sales to end-use customers. SB 1020 also added interim targets to SB 100's original target of 100% of electric retail sales to state agencies made from clean energy resources by 2045 with a goal of 90% clean energy by 2035 and 95% clean energy by 2040. To help ensure compliance with these new requirements, SB 1020 would also authorize the CEC and CPUC to disclose confidential information to CAISO, at CAISO's request, regarding power purchase agreements of electric generation and energy storage projects. This should allow for more efficient interagency collaboration to help expedite planning.

California Senate Bill 32 (signed into law on October 11, 2009) and SB 1332 (signed into law on September 27, 2012) requires LADWP to offer a tariff to eligible renewable electric generation facilities until we meet our 75 MW share of the statewide target. Despite the 75 MW requirement, our current target is 135 MW. Through this program, owners or operators of eligible renewable energy systems may sell their energy directly to LADWP. The purchase of this energy will include all environmental attributes, capacity rights, and renewable energy credits which will apply towards our 60% renewable requirement.

California Senate Bill 859 (signed into law on September 14, 2016) requires LADWP to procure a proportionate share of 125 megawatts (14.3 MW) of cumulative rated capacity. The share ratio is based on our peak demand to the total statewide peak demand. This share of capacity must be derived from existing bioenergy projects that commenced operations prior to June 1, 2013 and are subject to terms of at least 5 years.

Former Governor Schwarzenegger signed the California Solar Initiative (CSI) outlined in SB 1, on August 21, 2006. The CSI mandated that all California electric utilities implement a solar incentive program by January 1, 2008. The goal of the CSI is 3,000 MW of net-metered solar energy systems over 10 years with an expenditure cap of $3.35 billion. Expenditures for local and publicly owned electric utilities shall not exceed $784 million. Our cap amount is $320 million, based on us serving 40% of the municipal load in the state.

The LADWP Board of Commissioners adopted a policy to achieve 20% renewables by 2010, and 33% by 2020. The Board and City Council have approved projects and long-term power purchase agreements that achieved the 20% RPS goal in 2010. The policy has been revised to incorporate SB 2 (1X) requirements. Further revisions to this policy are anticipated to maintain continued compliance with any applicable updates to state law and regulations.

SB 2 (1X) also had set certain conditions regarding renewable energy contracts that began on or after June 1, 2010, as shown in Table 6.

Table 6. SB 2 (1X) category requirements for RPS energy contracts.

Portfolio Content Category[1]	RPS % Target		
	Compliance Period 1 (1/1/2011 – 12/31/2013)	Compliance Period 2 (1/1/2014 – 12/31/2016)	Compliance Period 3 (1/1/2017 – 12/31/2020)
1	Minimum 50%	Minimum 65%	Minimum 75%
2	See footnote 2	See footnote 2	See footnote 2
3	Maximum 25%	Maximum 15%	Maximum 10%

[1]Categories are defined as follows:

<u>Category 1</u> = Energy and RECs from eligible resources that

- Have the first point of interconnection with a CA balancing authority or with distribution facilities used to serve end users within a CA balancing authority area; or
- Are scheduled into a CA balancing authority without substituting electricity from another source. If another source provides real-time ancillary services to maintain an hourly import schedule into CA, only the fraction of the schedule actually generated by the renewable resource will count; or
- Have an agreement to dynamically transfer electricity to a CA balancing authority.

<u>Category 2</u> = Firmed and shaped energy or RECs from eligible resources providing incremental electricity and scheduled into a CA balancing authority.

<u>Category 3</u> = Energy or RECs from eligible resources that do not meet the requirements of category 1 or 2, including unbundled RECs.

[2]Remainder % of resources which are neither in Category 1 nor Category 3.

On August 30, 2013, the California Office of Administrative Law (OAL) approved the California Energy Commission's Enforcement Procedures for the Renewables Portfolio Standard for Local

Publicly Owned Electric Utilities (RPS Regulations)[1]. These Regulations first became effective as of October 1, 2013.

On December 22, 2020, the CEC adopted revised RPS Regulations which modified the California Renewables Portfolio Standard Program as amended by SB 350, SB 1393, SB 100, and SB 1110. The revised regulations became effective on July 12, 2021 after approval by the Office of Administrative Law. Modifications include updating the minimum RPS procurement targets and implementing a major provision from SB 350. The major provision pertains to long-term procurement of renewable resources requiring, beginning January 1, 2021, that at least 65% of RPS procurement must be acquired through contracts of 10 years or more, in ownership or ownership agreements.

The CEC verifies that POUs meet minimum RPS procurement requirements such as the Procurement Quantity Requirement, the Portfolio Content Category and Balance Requirement, and the new Long-term Procurement Requirement. California law allows for the California Energy Commission to issue a notice of violation and correction, and the ability to refer all violations to the California Air Resources Board. Failure to meet the targets or comply with provisions of the RPS Regulations may result in significant penalties.

There are various challenges associated with adopting more renewable resources such as wind, solar, and geothermal. For example, we will need to obtain local and environmental permits for transmission and generation infrastructure. We must also ensure the reliable and cost-effective integration of large-scale wind, solar, or other renewable projects. Also, adequate sites for geothermal generation are scarce and geothermal projects require large capital expenditure, impose exploration risks, and have limited transmission line access.

[1] ***Enforcement Procedures for The Renewables Portfolio Standard for Local Publicly Owned Electric Utilities***. California Energy Commission, Efficiency and Renewable Energy Division. Available at: https://www.energy.ca.gov/programs-and-topics/programs/renewables-portfolio-standard/rps-enforcement-regulations-publicly

3.5.9 Early Coal Divestment and Transformation of the Intermountain Power Project from Coal to Green Hydrogen

LADWP's coal generating capacity comes from Intermountain Generating Station (IGS). IGS is also referred to as the Intermountain Power Project (IPP). The amount of capacity available to us from IPP is up to 1,202 MW.

Contractual arrangements for power from IPP will expire on June 15, 2027. LADWP and the other participants at IPP plan to convert the facility to support new efficient units capable of operation on a fuel mixture of green hydrogen and natural gas by July 1, 2025 (two years before the originally scheduled decommissioning date). Although we are planning to complete the conversion by 2025, the commercial operation date of the new generating units may be delayed due to circumstances beyond our control. We are one of thirty-six purchasers of IPP energy.

Effective July 01, 2016, the Department divested its 21.2% generation share (equivalent to 477 MW) from the coal-fired Navajo Generation Station. The divestment was pursuant to the Salt River Project (SRP) Asset Purchase and Sale Agreement (the "Navajo Sale Agreement"). The power instead comes from renewable resources and energy efficiency programs that are backed by natural gas. The backup power resource utilizes natural gas and is located outside the L.A.-basin. Therefore, it is not affected by problems associated with the Aliso Canyon Natural Gas Storage Facility. With the completion of the Navajo transaction, we have reduced coal generated power from 39% to 19% of the City's energy portfolio.

3.5.10 Palo Verde Nuclear Generating Station

LADWP has contractual entitlements totaling approximately 387 MW of capacity from the Palo Verde Nuclear Generating Station (PVNGS). PVNGS, located approximately 50 miles west of Phoenix, Arizona, consists of three generating units. Of the 387 MW capacity available to LADWP, approximately 159 MW are available through a power sales agreement with the Southern California Public Power Authority (SCPPA).

3.5.11 Hydropower

LADWP's large hydroelectric facilities include the Castaic Pumped-storage Hydroelectric Plant and a portion of the capacity of the Hoover Dam. The Castaic Pumped-storage Hydroelectric Plant, located in Castaic, California, is our largest source of hydroelectric capacity and consists of seven units. Hoover Dam, located on the Arizona-Nevada border, consists of seventeen units.

A distinction is made between "large hydro" and "small hydro." According to a provision of SB 2 (1X), small hydro includes facilities which consist of generating units with a nameplate capacity not exceeding 40 MW per unit that is operated as part of a water supply or conveyance system. LADWP's small hydro units are located along the Los Angeles Aqueduct. These units qualify as renewable resources for electricity generation.

3.5.12 Current Renewable Energy Projects

Our renewable resources total over 3,463 MW of existing and planned capacity, and they consist of wind, small hydro, solar, biogas, and geothermal resources.

Here is an outline of our existing renewable energy projects by resource type:

2.1.1.20 Wind

- Linden
- Pebble Springs
- Pine Tree
- PPM Wyoming
- Willow Creek
- Windy Flats
- Milford I
- Milford II
- Manzana
- Red Cloud

2.1.1.21 Small Hydro

- Aqueduct, Owens Valley, and Owens Gorge projects
- Water System Hydro

- North Hollywood
- Sepulveda

2.1.1.22 Solar

- Community Solar/Utility-Built Solar In-Basin/Net Energy-Metered Solar
- Feed-in-Tariff
- Adelanto
- Pine Tree
- Copper Mountain 3
- Moapa Southern Paiute
- Beacon Solar Project
- Springbok 1, 2, and 3
- RE Cinco

2.1.1.23 Geothermal

- Don A. Campbell I and II
- Heber-1
- NV Geothermal Portfolio
- Ormesa

Additional renewable energy comes from market purchases.

3.6 Local Generation and Transmission in the Los Angeles Basin

LADWP owns and operates four generating stations within the Los Angeles Basin. Additionally, there is an extensive buildout of rooftop solar within LADWP's service territory.

3.6.1 Power System Background

Our Power System was designed and has continued to rely upon our four in-basin generating stations: Harbor, Haynes, Scattergood, and Valley. These stations ensure the system remains reliable and resilient while also enabling the import of renewable energy from outside the L.A. Basin. Three out of four of the in-basin generating stations are located on the coast in the southern and western boundaries of the system. These facilities were sited along the coast for access to ocean water which has traditionally been used to cool various processes across the thermal power generation cycle. The southern and western portion of LADWP's service territory form transmission "cul-de-sacs", while electricity imports from outside the LA Basin predominantly flow in from the north. Put simply, this means that renewable power flows from the north and dispatchable, natural gas-fired generation flows from the south. Figure 27 provides a simplified diagram of LADWP's in-basin generation and transmission assets.

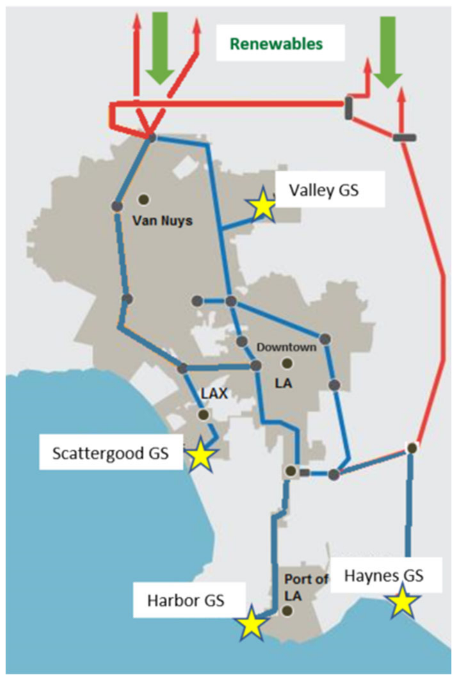


Figure 27. Simplified LADWP Power System with in-basin generating stations.

The need to retain firm, dispatchable, in-basin capacity at the coastal generating stations is paramount in order to meet reliability criteria, demand and reserve power, resource adequacy, contingency reserves, replacement reserves, and system stability. The loss of local, firm capacity would cause violations with the North American Electric Reliability Corporation requirements since we would not be able to fulfill its reliability must run (RMR) obligations. Construction of new transmission lines sited within our local system would satisfy the in-basin generation capacity requirements. However, as a result of the dense urbanization in Los Angeles, the local transmission lines are "locked in." That is to say that there is minimal real estate for adding or moving transmission lines. Alternatively, LADWP is planning various local transmission system upgrades to reduce the needed in-basin generation capacity while still meeting all reliability requirements. These transmission projects require coordination with numerous entities and face significant environmental hurdles which make the projects lengthy and difficult to complete. Maintaining the in-basin generation capacity is extremely important while these transmission upgrades are implemented since the transmission upgrades will require scheduled outages of transmission infrastructure. These transmission outages would cause reliability concerns if it were not for the existing generating units which can provide power locally during times when power distribution is impeded. Upon completion, these planned upgrades will relieve some of the transmission stresses on our system. However, developing local capacity will remain a priority in order to preserve system reliability and resilience.

2.1.2 Need for In-Basin Transmission

Below is a list of ten of the aforementioned transmission projects that are deemed to be necessary within the LA Basin by 2030. These projects, estimated in-service dates, and other transmission upgrades are subject to change as new analyses are performed and updates are incorporated. Table 7 lists the anticipated in-basin transmission upgrades.

Table 7. Anticipated in-basin transmission upgrades.

Project Title	Estimated In-Service Date
Upgrade Scattergood Auto and Phase Shifting Transformer	May 31, 2025
New Valley-Toluca Line 3 & upgrade Valley-Toluca Lines 1, 2	April 1, 2026
Convert Tarzana-Olympic 1A and 1B to 2-230kV lines	April 15, 2026
Upgrade Toluca-Hollywood Line 1 Underground Cable	March 30, 2027
Upgrade Hollywood-Fairfax 138kV Series Reactor	September 30, 2027
New Valley-Rinaldi Line 3 & upgrade Valley-Rinaldi Lines 1, 2	April 1, 2028
New Toluca-Atwater Line 2 & upgrade Toluca-Atwater Line 1	May 1, 2029
Reconductor Rinaldi-Airway Lines 1 and 2	December 31, 2029
New Northridge-Olympic 230kV Cables A/B & Shunt Reactor	December 31, 2029
Upgrade Fairfax-Olympic 138kV Series Reactor	September 30, 2030

3.6.2 Need for Firm Capacity

Long-term, dispatchable power generation is critically relied upon during stressed grid conditions which may be caused by low-probability, high-impact events such as wildfires, earthquakes, or bad actors that disrupt LADWP's ability to import renewable power into the City. Stressed grid conditions may also result from sustained periods of low renewable generation or transmission line maintenance and upgrades which can be exacerbated if they coincide with periods of high electricity demand.

Saddleridge Fire

The Saddleridge Fire was a wildfire that occurred near the northern San Fernando Valley beginning on October 10, 2019. Tragically, the wildfire resulted in one fatality and eight injuries and burned 8,799 acres. During this event, LADWP's import capabilities were significantly impacted. LADWP lost all capacity through the Pacific DC Intertie and Barren Ridge Corridor. Additionally, two out of five lines were lost on the Victorville-Los Angeles transmission path. As such, LADWP dispatched 1,889 MW from the in-basin generating stations to compensate for the lost capacity in the major transmission paths. Thankfully, the wildfire occurred on a relatively low-load day. Customer blackouts would have likely occurred if the load was materially higher. The Saddleridge Fire is one recent example of a low-probability, high-impact event that resulted in stressed grid conditions. As the impacts of climate change make these events more frequent and more severe, it is important that LADWP adequately plan against high-impact outcomes.

LADWP's in-basin generation fleet needs a significant amount of firm capacity—otherwise known as dispatchable capacity—in order to maintain a reliable power supply. NREL defined firm-capacity resources as generation resources whose capacity credits (i.e., dependable capacity ratings) remain effectively constant, regardless of customers' demand patterns and the mix of technologies deployed on the grid. Firm-capacity resources can generate electricity on demand within minutes and run for uninterrupted periods in the range of hours to weeks.

To meet the local firm-capacity requirements, NREL's models determined firm, dispatchable generation is required at LADWP's in-basin generating stations. These units are predicted to be used infrequently compared to today's and are meant to serve load during periods of peak demand and emergency events. They also provide valuable reserve capacity even when they are not running.

Background on LADWP Wildfire Mitigation Measures

Since 2008, LADWP has put in place reliability standards for power equipment that helps mitigate wildfire risks in high-threat fire zones. In addition, the Department has aggressive vegetation management and Power System Reliability Programs, both of which serve to help mitigate wildfires.

LADWP has also worked with the Los Angeles Fire Department (LAFD) to put in place operating protocols and restrictions when working in designated fire threat and brush clearance areas and during Red Flag warning periods. This includes suspending all non-essential work in Tier 2 and 3 zones. When work is completed in these areas, extra precautions are taken to ensure the work performed does not contribute to the risk of ignition.

In 2019, LADWP put new protocols in place to further reduce the risk of wildfires and more are in development under the Department's Wildfire Mitigation Plan. For example, during the recent Saddleridge and Getty Fires, LADWP turned off automatic reclosers on its distribution lines. This step ensured that a power line that experiences a disruption does not automatically re-energize, substantially minimizing the potential for fire ignition. Crews also de-energized power lines directly impacted or threatened by the fire. This allowed staff to work closely with LAFD to eliminate electrical hazards within the path of the fires.

LADWP's Wildfire Mitigation Plan also includes additional measures to harden our system against fire

Chapter 4

Modeling Inputs, Assumptions, and Methodology

DEFINITIONS

ATB	Annual Technology Baseline
BE	Building Electrification
BESS	Battery Energy Storage System
CAPEX	Capital Expenditure
CEC	California Energy Commission
CNM solar	Customer Net-Metered solar
DERs	Distributed Energy Resources
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
FSO	Financial Services Organization
GHG	Greenhouse Gas
GWh	Gigawatt-hours
IEPR	Integrated Energy Policy Report
IRP	Integrated Resource Planning
LADWP	Los Angeles Department of Water and Power
LOLH	Loss of Load Hours
Monte Carlo analysis	A model that uses repeated random sampling to obtain numerical results
NEL	Net Energy for Load
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
PSRP	Power System Reliability Program
Reference Case	SB 100
RPS	Renewable Portfolio Standard

STS	Southern Transmission System
TE	Transportation Electrification
WECC	Western Energy Coordinating Council

4 Modeling Inputs, Assumptions, and Methodology

One of the critical components of the Integrated Resource Plan (IRP) is computer modeling. The IRP Assumptions Package establishes the various inputs to the model, including, but not limited to, assumptions regarding customer demand, fuel costs, and capital costs.

The first step in the modeling process involves running a capacity expansion model. Capacity expansion models build or procure sufficient generation resources to meet customer load over the entire planning horizon, subject to any given constraints. In the case of the IRP, the planning horizon stretches from 2022 to 2045. The primary constraints given to the capacity expansion model are renewable portfolio standard (RPS) targets, specified for milestone years across the planning horizon. Our model seeks to minimize the total net present value (NPV) of capital costs and variable costs (e.g. fuel, operations and maintenance, and emissions) over the planning horizon, in order to select the least-cost and best-fit portfolio of generation resources.

The second step is taking the buildout from the capacity expansion model and inputting it into the production cost model. The production cost model simulates the hourly dispatch of the generation portfolio built by the capacity expansion model. The model also performs a Monte Carlo analysis, running up to 250 hourly simulations over the entire planning horizon. The simulations differ in terms of weather, with warmer weather resulting in higher loads and cooler weather resulting in lower loads. The weather simulation also drives the output of solar and wind resources. The Integrated Resource Planning team, in consultation with their consultant, will ensure enough generation resources are built or procured to ensure there are no more than 2.4 hours per year, on average, when customer demand exceeds generation resources. This 2.4 loss of load hours (LOLH) per year is the industry standard and is the threshold most utilities plan for.

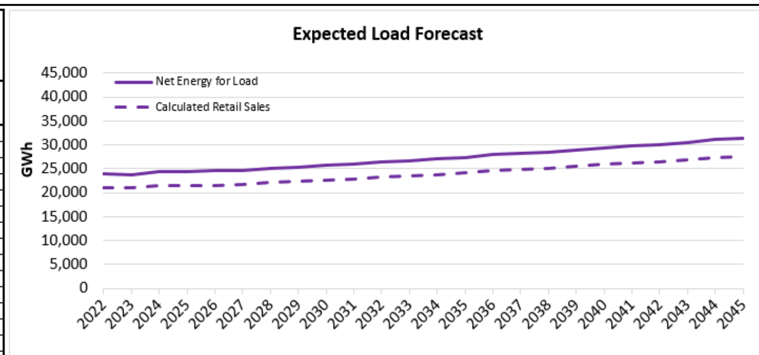
The production cost model also provides numerous output metrics, including but not limited to, total cost, fuel burn, and emissions. This chapter goes into more detail about how modeling assumptions were established and the reason behind their usage. These results are in Chapter 4 of this document.

4.1 Model Input Assumptions

4.1.1 Load Forecast

Expected Load Forecast
Reference Case (SB 100)
Assumes "Reference" Levels of Electrification and Distributed Energy Resources

Calendar Year	Net Energy for Load	Calculated Retail Sales
2022	23,911	21,041
2023	23,786	20,932
2024	24,306	21,390
2025	24,290	21,376
2026	24,512	21,570
2027	24,696	21,732
2028	25,122	22,108
2029	25,349	22,307
2030	25,725	22,638
2031	26,022	22,900
2032	26,443	23,270
2033	26,716	23,510
2034	27,012	23,771
2035	27,407	24,118
2036	27,966	24,610
2037	28,167	24,787
2038	28,487	25,068
2039	28,920	25,450
2040	29,427	25,896
2041	29,765	26,193
2042	30,086	26,476
2043	30,510	26,849
2044	31,039	27,314
2045	31,391	27,624

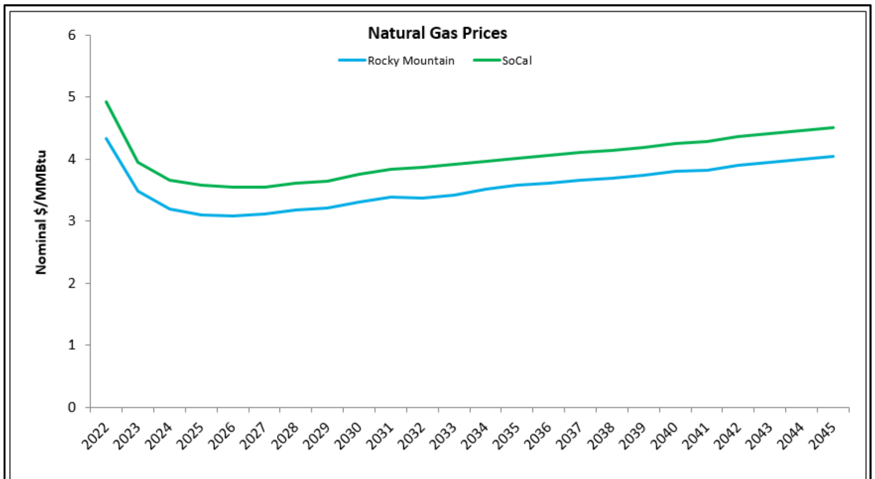


Notes:
1. IRP Net Energy for Load is derived from the IRP Gross Load (inclusive of transportation & building electrification), by reducing from it the expected contributions of Customer Net-Metered Solar (CNM Solar) and Energy Efficiency (EE). An extra 12% energy savings bonus is applied to both CNM Solar and EE, since they do not incur transmission losses due to being located at the load center.
2. IRP Calculated Retail Sales are derived by reducing the IRP Net Energy for Load by 12%, the estimated amount of total average transmission & distribution (T&D) system losses.

Figure 28. IRP Expected Load Forecast. Net Energy for Load (NEL) and Calculated Retail Sales projections.

The IRP Expected Load Forecast (Figure 28) is derived from the LADWP 2021 Retail Electric Sales and Demand Forecast put together by the LADWP's Financial Services Organization (FSO). The IRP Group convened with different program groups to derive projections for varying levels of load modifiers and distributed energy resources (DERs) such as transportation electrification, building electrification, customer net-metered solar, and energy efficiency, to then apply to the IRP modeling. The IRP Expected Load Forecast is shown, which assumes "Reference" levels of transportation electrification (TE), building electrification (BE), customer net-metered solar (CNM solar), and energy efficiency (EE).

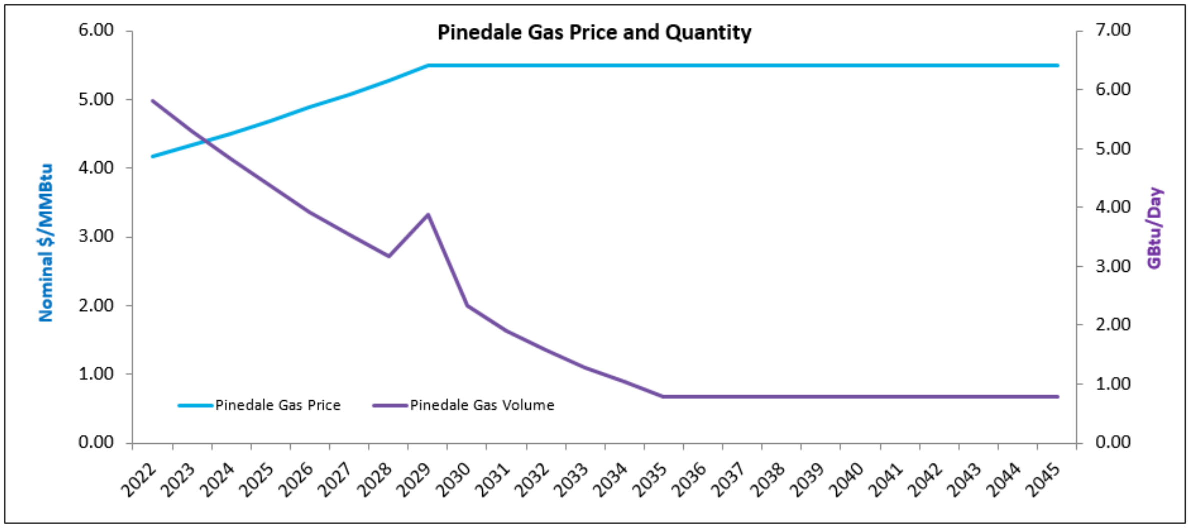
4.1.2 Natural Gas Pricing



Notes:
1. Updated from TRMT (Platts) using data pulled on 10/21/2021
2. Data from 2042-onwards was linearly extrapolated based on trailing fifteen years.

Figure 29. IRP Expected Natural Gas Price Projections. Rocky Mountain and So Cal.

The two main natural gas regional price indices used for the IRP modeling are Rocky Mountain and SoCal (Figure 29). These "Expected" price estimates used for modeling were developed using Platts market data.



Notes:
1. Last updated on 12/06/2021.
2. Uptick in 2029 gas production was confirmed to be correct by the Natural Gas Group.

Figure 30. IRP Natural Gas Price Assumptions.

Pinedale natural gas allocations (Figure 30) are among the first used, as they are relatively inexpensive. After Pinedale natural gas allocations are consumed, the generators use natural gas fuel from Rocky Mountain and SoCal allocations.

4.1.3 Generation Ratings Sheet

Table 8 shows the2022 LADWP Generation Ratings and Capacities of Power Resources Sheet. Ratings for LADWP-owned generating facilities. Information as of January 28, 2022.

Table 8. LADWP Generation Ratings Sheet.

HYDROELECTRIC							
NAME OF GENERATING FACILITY	UNIT NO.	DATE FIRST CARRIED SYSTEM LOAD	GENERATOR NAMEPLATE		NET MAXIMUM UNIT CAPACITY[2] (kW)	NET MAXIMUM PLANT CAPACITY[3] (kW)	NET DEPENDABLE PLANT CAPACITY[4] (kW)
			(kVA)	(kW)			
Upper Gorge Power Plant	1	6/15/1953	37,500	37,500	36,500	[A] 110,500	46,400
Middle Gorge Power Plant	1	5/11/1952	37,500	37,500	37,500		
Control Gorge Power Plant	1	4/01/1952	37,500	37,500	37,500		
Pleasant Valley Power Plant	1	2/05/1958	4,000	3,200	2,700	2,700	[E][F] 5,400
Big Pine Power Plant	1	7/29/1925	4,000	3,200	3,050	[B] 3,050	
Division Creek Power Plant	1	3/22/1909	750	600	680	680	
Cottonwood Power Plant	1	11/13/1908	937	750	1,200	[C] 1,800	
	2	10/13/1909	937	750	1,200		
Haiwee Power Plant	1	7/18/1927	3,500	2,800	2,500	[D] 3,600	
	2	7/18/1927	3,500	2,800	2,500		
San Francisquito Power Plant 1	1A	12/10/1983	25,000	22,500	27,000	[G] [H] 61,000	[K] 41800
	3	4/16/1917	11,720	9,962	11,000		
	4	5/21/1923	12,500	10,625	12,000		
	5A	4/09/1987	25,000	22,500	27,000		
San Francisquito Power Plant 2	1	7/06/1919	17,500	14,000	0		
	2	8/07/1919	17,500	14,000	14,400		
	3	12/02/2006	20,000	18,000	16,000		
San Fernando Power Plant	1	10/22/1922	3,500	2,800	3,250	[I] 6,000	
	2	10/22/1922	3,500	2,800	3,000		
Foothill Power Plant	1	10/06/1971	11,000	8,800	8,600	[J] 8,600	
Franklin Power Plant	1	6/03/1921	2,500	2,000	2,000	2,000	
Sawtelle Power Plant	1	6/05/1986	711	640	650	650	
North Hollywood Pumping Station	1PT2	1/01/1993	2,025	1,800	1,800	4,300	[L] 4,300
	1PT3	1/01/1993	2,025	1,800	1,800		
	3T1	1/01/1993	584	500	500		
	3T2	1/01/1993	231	200	200		
TOTAL HYDROELECTRIC						204,880	97,900

IN-BASIN THERMAL							
NAME OF GENERATING FACILITY	UNIT NO.	DATE FIRST CARRIED SYSTEM LOAD	GENERATOR NAMEPLATE (kVA)	GENERATOR NAMEPLATE (kW)	NET MAXIMUM UNIT CAPACITY[2] (kW)	NET MAXIMUM PLANT CAPACITY[3] (kW)	NET DEPENDABLE PLANT CAPACITY[4] (kW)
Harbor Generating Station	1	7/11/1973	100,400	85,340	73,000	[O] 426,000	425,000
	2	7/09/1974	100,400	85,340	73,000		
	5	7/13/1976	93,750	75,000	60,000		
	10	6/16/1977	71,176	60,500	44,000		
	11	12/16/1977	71,176	60,500	44,000		
	12	8/11/1978	71,176	60,500	44,000		
	13	1/27/1972	71,176	60,500	44,000		
	14	10/22/1922	71,176	60,500	44,000		
Haynes Generating Station	1	9/02/1962	270,000	229,500	222,000	[P] 1,614,200	[Q] [R] 1,512,000
	2	4/07/1963	270,000	229,500	222,000		
	8	1/25/2005	311,000	264,350	250,000		
	9	1/25/2005	215,000	182,750	162,500		
	10	1/25/2005	215,000	182,750	162,500		
	11	6/11/2013	127,282	108,190	99,200		
	12	6/12/2013	127,282	108,190	99,200		
	13	6/12/2013	127,282	108,190	99,200		
	14	6/19/2013	127,282	108,190	99,200		
	15	6/12/2013	127,282	108,190	99,200		
	16	6/12/2013	127,282	108,190	99,200		
Scattergood Generating Station	1	12/07/1958	192,000	163,200	105,000	[S] 778,250	[T] 742,000
	2	7/01/1959	192,000	163,200	156,250		
	4	10/09/2015	255,200	216,920	206,000		
	5	11/15/2015	139,882	118,900	107,000		
	6	8/09/2015	125,765	106,900	102,000		
	7	9/23/2015	125,765	106,900	102,000		
Valley Generating Station	5	8/17/2001	71,176	60,500	44,000	555,000	[U] 532,000
	6	9/04/2003	215,000	182,750	155,000		
	7	9/09/2003	215,000	182,750	155,000		
	8	11/13/2003	311,000	264,350	201,000		
TOTAL IN-BASIN THERMAL (Based on natural gas fuel ratings)						3,373,450	3,211,000

EXTERNAL ENERGY RESOURCES							
NAME OF GENERATING FACILITY	UNIT NO.	DATE FIRST CARRIED SYSTEM LOAD	GENERATOR NAMEPLATE (kVA)	GENERATOR NAMEPLATE (kW)	NET MAXIMUM UNIT CAPACITY[2] (kW)	NET MAXIMUM PLANT CAPACITY[3] (kW)	NET DEPENDABLE PLANT CAPACITY[4] (kW)
Intermountain Generating Station	1	6/09/1986	991,000	950,000	900,000	1,202,000	[V] 1,202,000
	2	4/30/1987	991,000	950,000	900,000		
Palo Verde Nuclear Generating Station	1	1/30/1986	1,559,100	1,413,190	1,333,000	386,690	[W] 380,410
	2	9/19/1986	1,559,100	1,413,190	1,336,000		
	3	1/19/1988	1,559,100	1,413,190	1,334,000		
Apex Generating Station	1A	3/28/2014	239,000	203,150	168075	577,500	[X][Y] 482,600
	1B	3/31/2014	239,000	203,150	168,075		
	STG	3/28/2014	264,000	237,600	229,879		
Hoover Power Plant	(Energy purchased from WAPA through Sep. 2067) [Z]					496,000	267,594
TOTAL EXTERNAL ENERGY RESOURCES						2,662,190	2,332,604

SYSTEM SUMMARY		
SYSTEM SUBTOTAL NET CAPACITY AND ENTITLEMENTS	NET MAXIMUM PLANT CAPACITY[3] (kW)	NET DEPENDABLE PLANT CAPACITY[4] (kW)
Subtotal Net Capacity of the System	7,505,520	6,906,504
California Department of Water Resources (CDWR) Entitlement [AA]	(120,000)	(39,607)
TOTAL NET CAPACITY OF THE SYSTEM	7,385,520	6,866,884

WIND, SOLAR, AND ENERGY STORAGE							
NAME OF GENERATING FACILITY	UNIT NO.	DATE FIRST CARRIED SYSTEM LOAD	GENERATOR NAMEPLATE		NET MAXIMUM UNIT CAPACITY(2) (kW)	NET MAXIMUM PLANT CAPACITY(3 (kW)	NET DEPENDABLE PLANT CAPACITY(4) (kW)
			(kVA)	(kW)			
Linden Wind Power Plant	1-25	6/30/2010	2,189	2,080	2,000	50,000	12,000
Pine Tree Wind Power Plant	1-90	6/14/2009	1,739	1,565	1,500	135,000	32,400
Adelanto Solar Power Plant	1-13	6/30/2012	800	800	800	10,000	2,800
Pine Tree Solar Power Plant	1-17	3/15/2013	500	500	500	8,500	2,380
Beacon Battery Energy Storage System	1-13	8/01/2018	2,083	1,695	1,667	[AB] 20,000	[AB] 20,000
TOTAL WIND, SOLAR, AND ENERGY STORAGE						223,500	69,580

1. Power sources included are LADWP's wholly-owned and operated in-basin gas-fired thermal, pump storage, small hydro (excluding North Hollywood Power Plant), wind (Pine Tree, Linden), and solar (Pine Tree, Adelanto) generation, and battery storage (Beacon). Also included are the following specific jointly-owned and operated power sources acquired through power purchase agreements or entitlements: coal-fired (Intermountain), nuclear-fueled (Palo Verde), gas-fired (Apex) thermal generation, and large hydro generation (Hoover). Renewable power purchase agreements (PPAs), market power purchases, and distributed generation are not included.
2. Maximum Unit Capacity can be attained only when the weather and equipment are simultaneously at optimum conditions. Hydro power plants' Maximum Unit and Plant Capacity are values based on historical data or benchmarking values based on water flow through the turbine. Thermal units Maximum Unit and Plant capacities were provided by Unit Guide Sheet.
3. Net Maximum Plant Capacity for hydro power plants is limited by water flow limits; for in-basin thermal generation and wind power plants, it is determined by the sum of the plant's Net Maximum Unit Capacity; and for external thermal generation it is determined by LADWP's power purchase entitlement share.
4. The Plant Net Dependable Capacity (NDC) reflects year-round output capability. The NDC for small hydro units are calculated from the last five years of net actual generation over the units' available hours. The NDC for the in-basin generating stations are calculated from the top five highest peak load days for the years 2016-2020 where ambient temperatures exceeded 80 degrees Fahrenheit. The NDC for Scattergood Generations Station (SGS), Unit 2 and Haynes Generating Station (HnGS), Unit 1 was determined by the load limits placed on the units by the Energy Control Center/Plant Engineers due to equipment limitations. The NDC for SGS, Unit 1 was calculated utilizing available data during peak day conditions from 2016-2020. The NDC for HnGS, Unit 2 was derived from data following a major rotor repair completed in November 2019. The

NDC for Apex Generating Station was provided in the 2020 Unit Guide Sheet for summer. The plant NDC for the PPAs reflect their associated agreements with LADWP.

A. Upper Gorge (UG) Power Plant is limited to 36.5 MW due to penstock losses. Owens Gorge Power Plants' Net Maximum Plant Capacity of 110.5 MW reflects a maximum generation output at UG of 35.5 MW, and 37.5 MW at Middle and Control Gorge Power Plants each when all three units are running. This is due to a lower effective head from a longer tunnel and venturi losses at UG to which the other two plants are not subjected. All the Owens Gorge Power Plants have black start capability, but they could not send power to the LA basin if the system was in a black out condition.
B. Big Pine Power Plant's Net Maximum Unit Capacity is limited to a maximum flow through penstock.
C. Cottonwood Power Plant, Units 1 and 2 were rewound to a higher Net Maximum Unit Capacity of 1.3 MW each. Net Maximum Plant Capacity is 1.8 MW due to limited maximum flow through the penstock.
D. Net Maximum Unit Capacity for Haiwee Power Plant, Units 1 and 2, is 2.5 MW each when only one unit is running. However, when both units are running and feed is taken from North Haiwee Reservoir, the Net Maximum Plant Capacity is 3.6 MW. Haiwee Power Plant's Net Dependable Capacity is limited by Division of Safety of Dams (DOSD) reservoir level.
E. Division Creek is out of service due to damage caused by a flash flood. Extensive damage was found to the impeller sections of the turbine in Haiwee, Units 1 and 2. ETR for Haiwee is June 30, 2021.
F. Maximum unit and plant capacities are provided by Owens Valley Operations. None of the Haiwee, Cottonwood, Division Creek, Big Pine, and Pleasant Valley Power Plant units have black start capability.
G. San Francisquito Power Plant 1 (PP1), Unit 3 rating is 60 Hz and 11,720 kVA instead of 50 Hz and 9375 kVA as indicated on original nameplate. Unit 3 was rewound in 1980. Units 3 and 4 have black start capability. PP1 and San Francisquito Power Plant 2 (PP2) have a combined maximum net capacity of 61 MW due to downstream flow constraints.
H. PP2, Unit 1 has been out of service since 1996. PP2, Unit 3 has a new generator rated at 18 MW with a refurbished turbine as of December 2, 2006. PP2, Unit 2 has black start capability. PP2 penstock is limited to 400 cfs. Due to penstock limitations, only Unit 2 is operated as a back-up to Unit 3.
I. Net Maximum Plant Capacity for San Fernando Power Plant is 3.5 MW due to the main transformer being placed in open-delate configuration. One of the three transformers was removed because dissolved gases were detected. Unit 2 is out of service for a

generator overhaul, with an expected ETR of April 1, 2022. Plant has no black start capability.

J. Foothill Power Plant Rated Output is 8800 kW but is limited to 8600 kW due to maximum flow through the penstock of 275 cfs. Plant has no black start capability.
K. Castaic Power Plant's Net Maximum Plant Capacity is limited by the maximum flow through Angeles Tunnel. Based on the latest test conducted in November 2011, Net Maximum Plant Capacity was rated at 1265 MW at normal hydraulic head of 1060 ft. Net Dependable Plant Capacity varies based on the Elderberry and Pyramid Lake water levels. The Castaic Power Plant units have completed modernization improvements as follows: Unit 2 in September 2004, Unit 6 in December 2005, Unit 4 in June 2006, Unit 5 in July 2008, Unit 3 in July 2009, Unit 1 in October 2013, and Unit 7 in August 2016. CPP Units 1-6 have black start capability.
L. North Hollywood Pump Station, Turbine 3T1 is rated for two different speeds (500 kW and 200 kW).
M. Castaic Power Plant's Net Maximum Capacity is limited by the maximum flow through Angeles Tunnel. Based on the latest test conducted in November 2011, Net Maximum Plant Capacity was rated at 1265 MW at nominal hydraulic head of 1060 ft. Net Dependable Plant Capacity varies based on the Elderberry and Pyramid Lake water levels. The Castaic Power Plant units have completed modernization improvements as follows: Unit 2 in September 2004, Unit 6 in December 2005 Unit 3 in June 2006 Unit 5 in July 2008, Unit 3 in July 2009, Unit 1 in October 2013 and Unit 7 in August 2016. CPP Units 1-6 have black start capability.
N. Castaic Power Plant's Net Dependable Plant Capacity is limited by the flow through the Angeles Tunnel. Unit 7 is unavailable as a generator and synchronous condenser with an ETR of 12/31/2022. Unit 5 is unavailable from January 4 – December 4, 2021 due to a major overhaul.
O. Harbor Generating Station (HGS), Units 1 and 2 Net Maximum Capacity is approximately 73 MW each due to gas turbine wear. Units 12 and 13 have black start capability.
P. Per the Unit Guide Sheet, HnGS, Units 11-16 Net Maximum Unit Capacity of 595.2 MW is attained when all six units are running as this is when the lowest average auxiliary power is being drawn per unit.
Q. The NDC for HnGS, Units 1 and 2 is limited due to high stator temperatures in the boiler feed pump motors.
R. HnGS Net Dependable Plant Capacity includes operating Units 9 and 10 with duct burners running.
S. SGS, Unit 2 was derated to a gross capacity of 111.8 MW as part of the Unit 3 Repowering Project, and operates at a net maximum capacity of 105 MW. The Net Max

Capacity of the combined cycle is reduced by 2 MW when Unit 4 is run in a 1+1 configuration with Unit 5. None of the SGS units have black start capability.

T. The NDC for SGS, Unit 2 is limited due to low forced draft air fan flow.
U. Valley Generating Station (VGS) Net Dependable Plant Capacity includes operating Units 6 and 7 with duct burners running. Unit 5 has black start capability.
V. The LADWP entitlement for Intermountain Generating Station (IGS) is 44.617% direct ownership, plus a 4% purchase from Utah Power and Light company (UP&L), plus 86.281% of up to 21.057% of muni's and co-op's recallable entitlement, which can vary. IGS Net Dependable Plant Capacity may be less than 1,202 MW due to muni's and co-op's recallable entitlement. None of the Intermountain Generating Station's units have black start capability.
W. LADWP's entitlement is 9.66% of generation comprised of 5.7% direct ownership in Palo Verde Nuclear Generating Station and another 67% power purchase of Southern California Public Power Authority's (SCPPA's) 5.91% ownership of Palo Verde. Units 1,2, and 3 Design Electrical Rating is used for Net Maximum Unit Capacity.
X. Apex Generating Station's Net Dependable Plant Capacity includes operating Units 1A and 1B with duct burners running. Units 1A and STG were originally placed in-service by the original owner on January 13, 2003, and Unit 1B on January 20, 2003. None of the Apex Generating Station's units have black start capability.
Y. SCPPA took ownership of Apex Generating Station on March 26, 2014 and maintains a sales agreement for the station's generated power. LADWP's entitlement is 100% of Apex Generating Station's power produced.
Z. LADWP has a power purchase agreement with the United States Department of Energy Western Area Power Administration (WAPA), the Balancing Authority, for Hoover Power Plant. LADWP's entitlement through September 2067 is 23.9% of the total contingent capacity (2,074 MW) and 14.7% of Firm Energy (approximately 663,283 kWh). Hoover Power Plant output constantly varies due to lower water levels at Lake Mead resulting from drought conditions.
AA. The maximum California Department of Water Resources (CDWR) Entitlement from Castaic Power Plant is 120 MW. This amount varies weekly. The average of FY19-20 was approximately 39.61 MW.

The LADWP Generation Ratings and Capacities of Power Sources (Table 9) Sheet shows key information for LADWP-owned generating facilities of different types, including hydroelectric, pumped storage, in-basin thermal, external energy resources, as well as wind, solar, and energy storage. It is important to note that this Generation Ratings and Capacities of Power Sources Sheet excludes renewable PPAs. Key information found on this document includes names and generating unit numbers, date that a facility first carried system load, generator nameplate ratings, net maximum unit capacities, net maximum plant capacities, and net dependable plant capacities, supported by detailed and individualized footnotes. This document is put together by LADWP's Generating Stations and Facilities Engineering section and is updated annually.

4.1.4 In-Basin Generation & Energy Storage Projects (by 2030)

Table 9. IRP In-Basin Generation and Energy Storage Projects by 2030.

Generation

Project	New Capacity (MW)	Target Comercial Operation Date
Haynes Unit 8 Cooling System Retrofit	565	5/14/2027
Scattergood Hydrogen-Ready Capacity	346	4/1/2029
Valley Units 1–4 Demolition	—	8/31/2025

Energy Storage

Project	New Capacity (MW)	Energy (MWh)	Duration (hr)	Target Comercial Operation Date
Beacon II LDES	50	500	10	12/31/2026
RS-X Li-Ion	60	240	4	12/31/2027
Valley Flow	55	290	5.3	12/31/2029
Scattergood Flow	50	300	6	6/15/2030

The projects shown above (Table 9) reflect planned projects at in-basin generating stations by 2030. Although the new unit at the Scattergood Generating Station is anticipated to be capable of running on 30% green hydrogen by volume, this IRP assumed the unit to run on 100% natural gas to provide a more conservative estimate of overall GHG emissions.

4.1.5 Hoover and Small Hydro

Table 10. IRP Large and Small Hydroelectric Generation Projections. Hoover Power Plant, Owens Gorge, Owens Valley, L.A. Aqueduct.

Hoover			Small Hydro – Owens Gorge, Owens Valley, Aqueduct			
Estimated GWh			Estimated GWh			
	Calendar Year **2021 GWh**	Calendar Year **2022 GWh**	CY	Total	FY	Total
Jan	35.96	28.27	2022	418	2022	436
Feb	32.39	33.24	2023	457	2023	477
Mar	58.01	55.36	2024	492	2024	507
Apr	63.60	56.03	2025	464	2025	421
May	58.79	54.64	2026	411	2026	402
Jun	53.94	51.54	2027	398	2027	393
Jul	49.27	45.43	2028	395	2028	396
Aug	45.81	42.48	2029	398	2029	400
Sep	40.80	37.61	2030	399	2030	398
Oct	34.40	27.87	2031	392	2031	387
Nov	38.32	34.03	2032	384	2032	381
Dec	30.90	29.80	2033	384	2033	387
	542.19	496.30	2034	392	2034	397
			2035	403	2035	409
			2036	415	2036	420
			2037	420	2037	420
			2038	417	2038	413
			2039	413	2039	413
			2040	414	2040	414
			2041	414	2041	414
			2042	414	2042	413
			2043	412	2043	410
			2044	407	2044	405
			2045	404	2045	404

The projections shown above in Table 10 are for the estimated annual generation produced by Hoover Power Plant, a large hydroelectric generating facility, and small hydroelectric generating facilities located in the Owens Gorge, in the Owens Valley, and along the Los Angeles Aqueduct. These projections include the latest available information reflective of on-going drought conditions in the Western United States.

4.1.6 Candidate Resource Prices

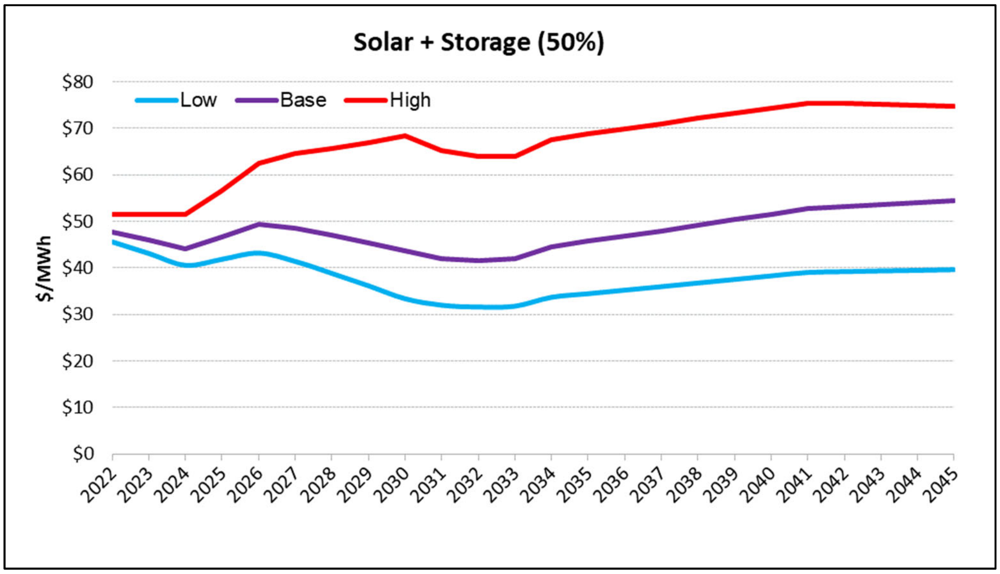


Figure 31. IRP Solar + Energy Storage Price Projections used for capacity expansion modeling; derived from the 2021 NREL ATB.

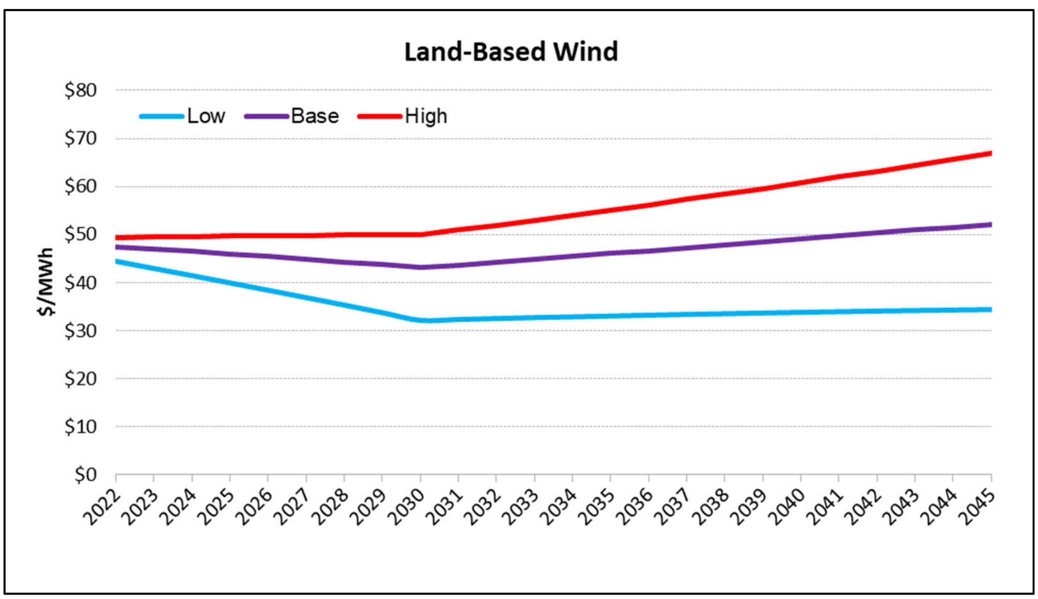


Figure 32. IRP Land-Based Wind Price Projections used for capacity expansion modeling; derived from the 2021 NREL ATB.

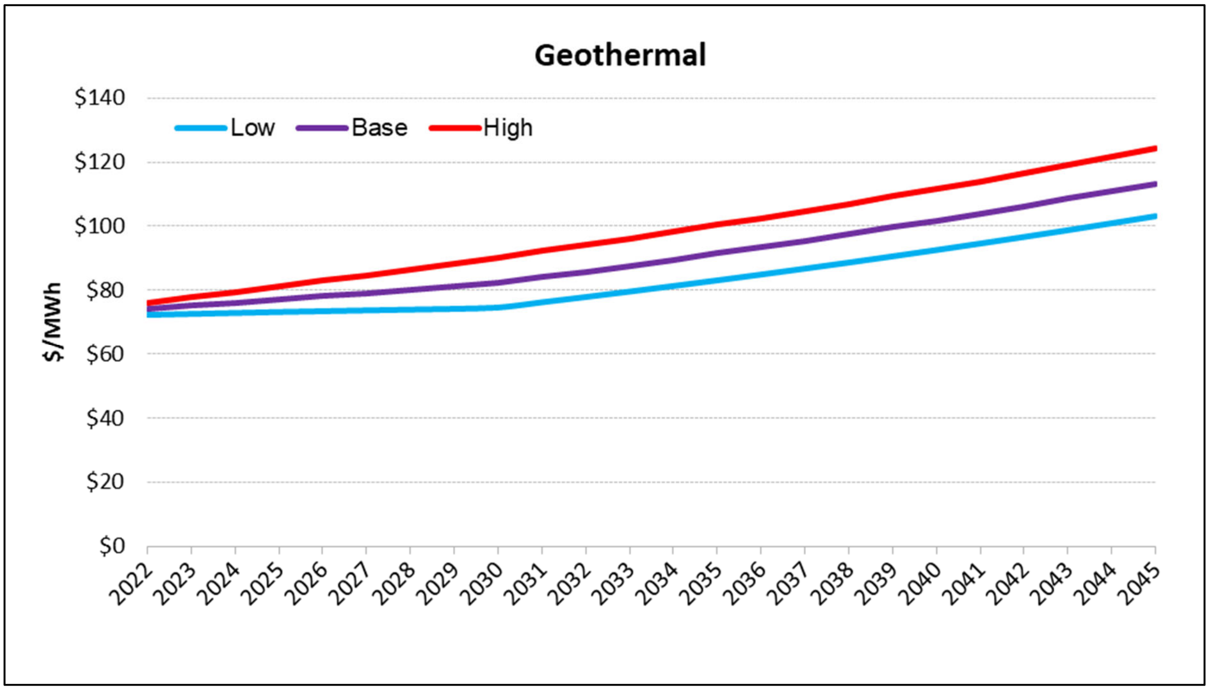


Figure 33. IRP Geothermal Price Projections used for capacity expansion modeling; derived from the 2021 NREL ATB.

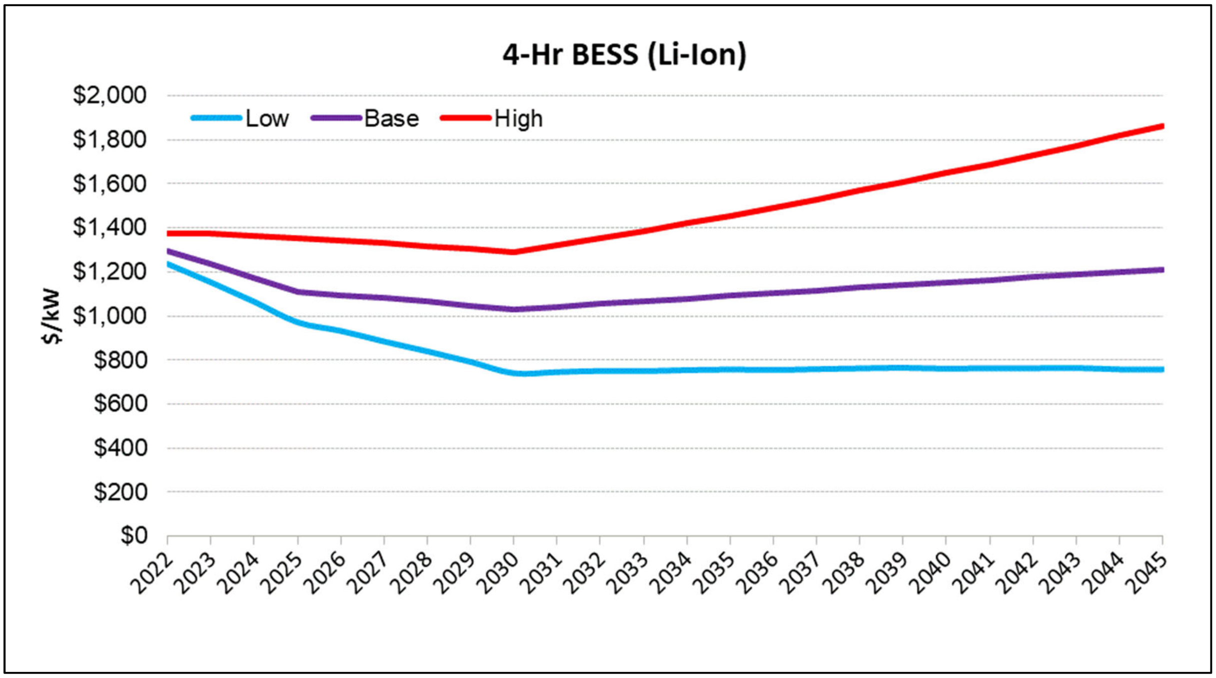


Figure 34. IRP 4-Hour Battery Energy Storage System (BESS) Price Projections used for capacity expansion modeling; derived from the 2021 NREL ATB.

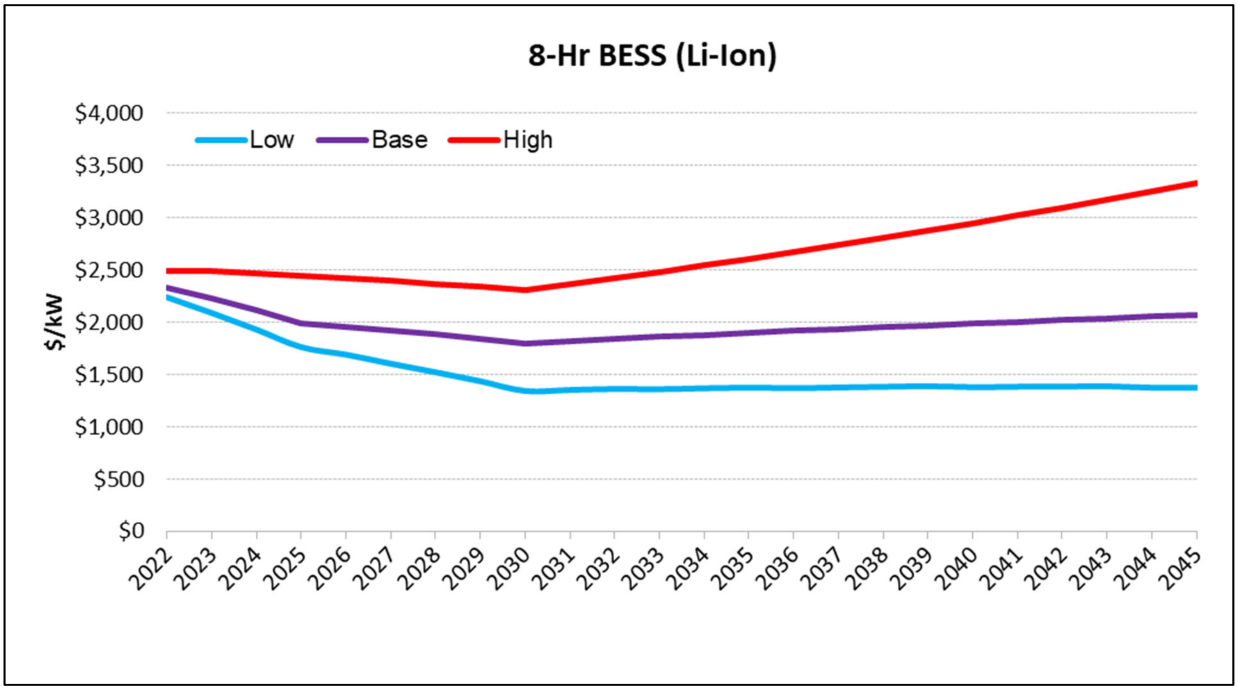


Figure 35. IRP 8-Hour Battery Energy Storage System Price Projections used for capacity expansion modeling; derived from the 2021 NREL ATB.

The candidate resource prices shown above (Figure 31 through Figure 35) represent the estimated average levelized cost of energy (LCOE) for solar + energy storage (assuming coupled energy storage at 50% size of the solar capacity), land-based wind, geothermal, as well as the average capital expenditure (CAPEX) per unit of 4-hour and 8-hour utility-scale energy storage capacity. These price projections were derived from the National Renewable Energy Laboratory (NREL)'s 2021 Annual Technology Baseline (ATB), and are assumed for future generic resources that LADWP has not yet built or contracted for, as recommended by capacity expansion modeling. The IRP used the "Base" price projections.

4.1.7 Distributed Solar

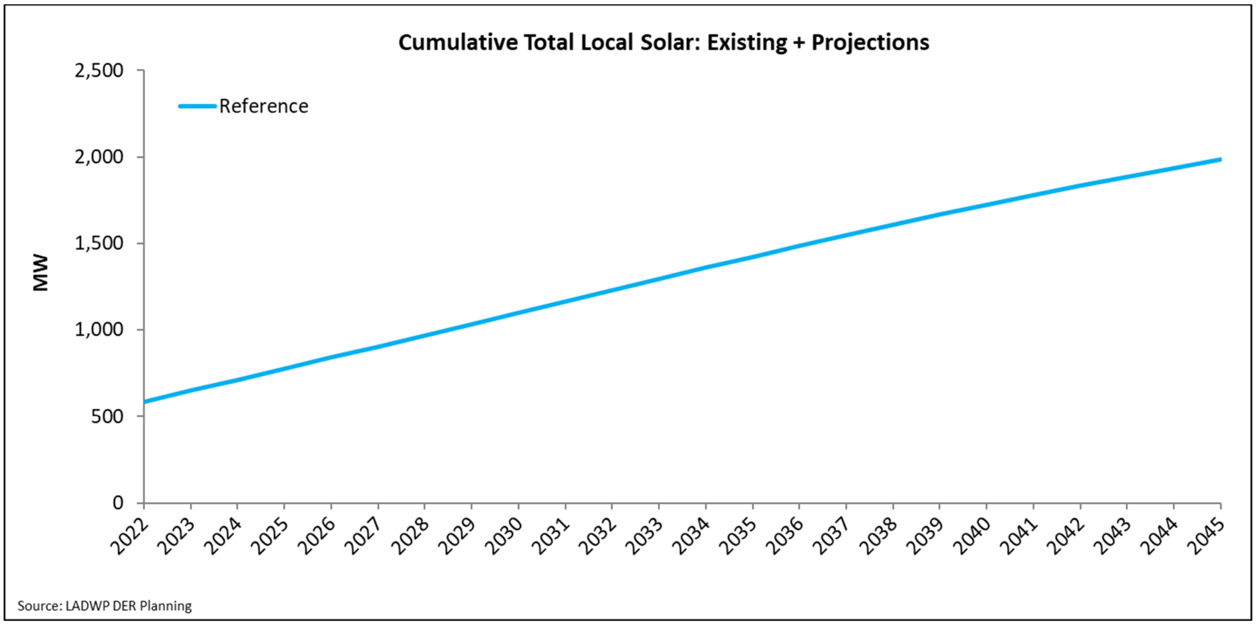


Figure 36. IRP Distributed Solar Capacity (MW) Projections. Project is cumulative and includes existing installations.

The IRP "Reference" level of local (distributed) solar reflects the cumulative total distributed solar capacity that was assumed for the Reference Case, as provided by the LADWP Distributed Energy Resource Planning groups (Figure 36). However, we must upgrade our distribution system to alleviate circuit and feeder overloads and increase distribution system capacity to accommodate higher levels of DERs including distributed solar. It must also be noted that distributed solar adoption also depends on customer participation.

4.1.8 Distributed Energy Storage

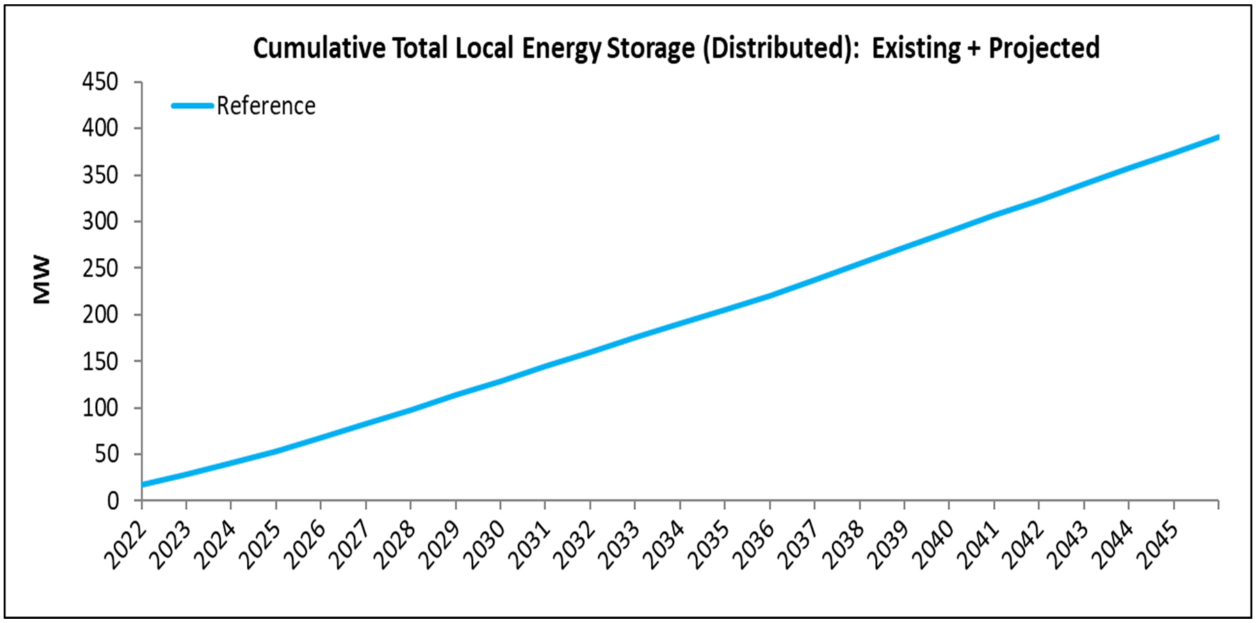


Figure 37. IRP Distributed Energy Storage Capacity (MW) Projection. Projection is cumulative and includes existing installations.

The IRP "Reference" levels of local (distributed) energy storage assume that the majority of the distributed energy storage will be paired with distributed solar (Figure 37). The values shown above reflect cumulative total distributed energy storage capacity that was assumed for the IRP, as provided by the LADWP Distributed Energy Resource Planning groups, however upgrades to the distribution system to alleviate circuit and feeder overloads, as well as increasing distribution system capacity will be necessary to accommodate higher levels of DERs including distributed energy storage. It must also be noted that distributed energy storage adoption also depends on customer participation.

4.1.9 Demand Response

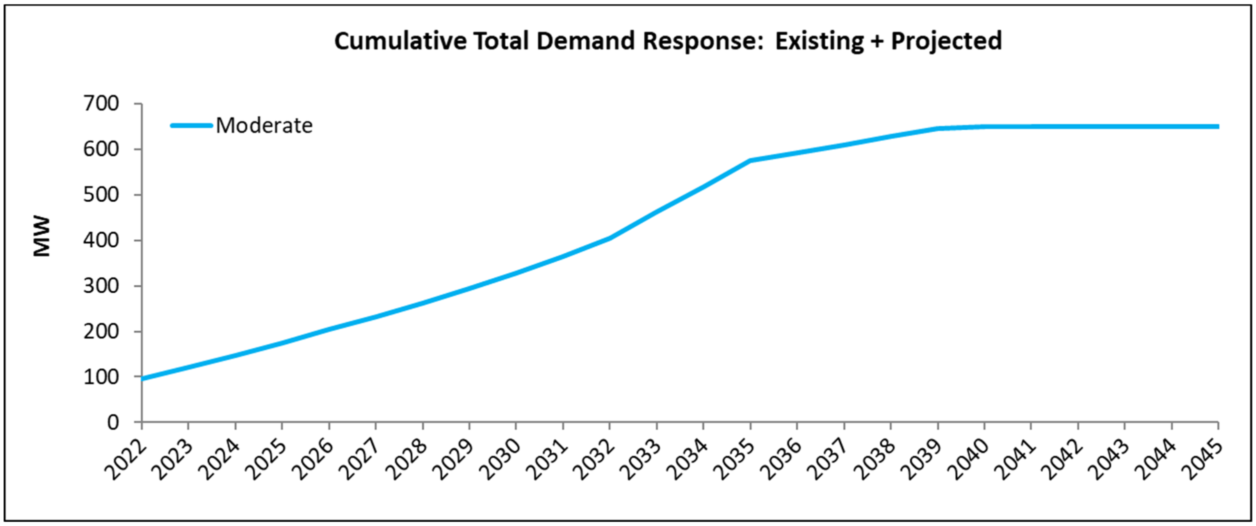


Figure 38. IRP Demand Response Capacity (MW) Projection. Projection is cumulative and includes existing installations.

The levels of demand response (DR) shown above (Figure 38) cumulatively reflect both the existing and planned capacities. For the IRP, "moderate" DR levels were assumed for demand response. It must be noted that DR operates under specific criteria, therefore it may not be available all hours of the year as a resource. Similar to other DERs, DR also depends on customer participation.

4.1.10 Energy Efficiency

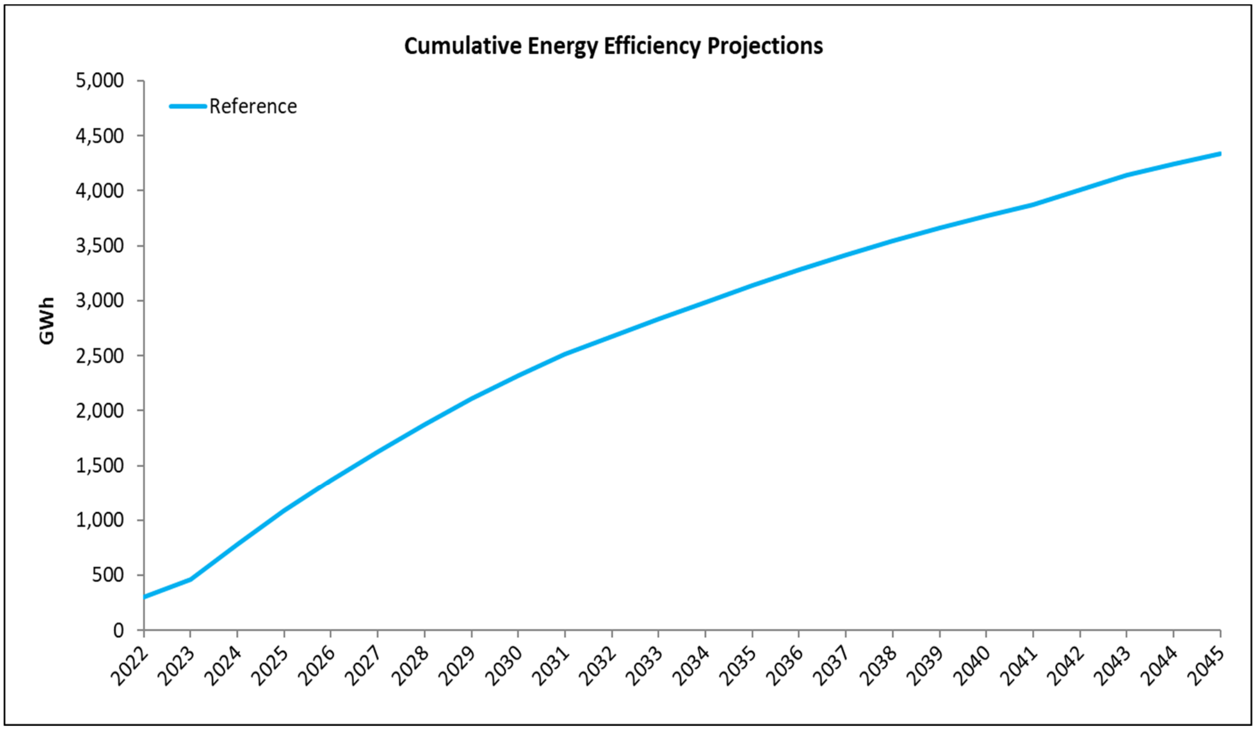
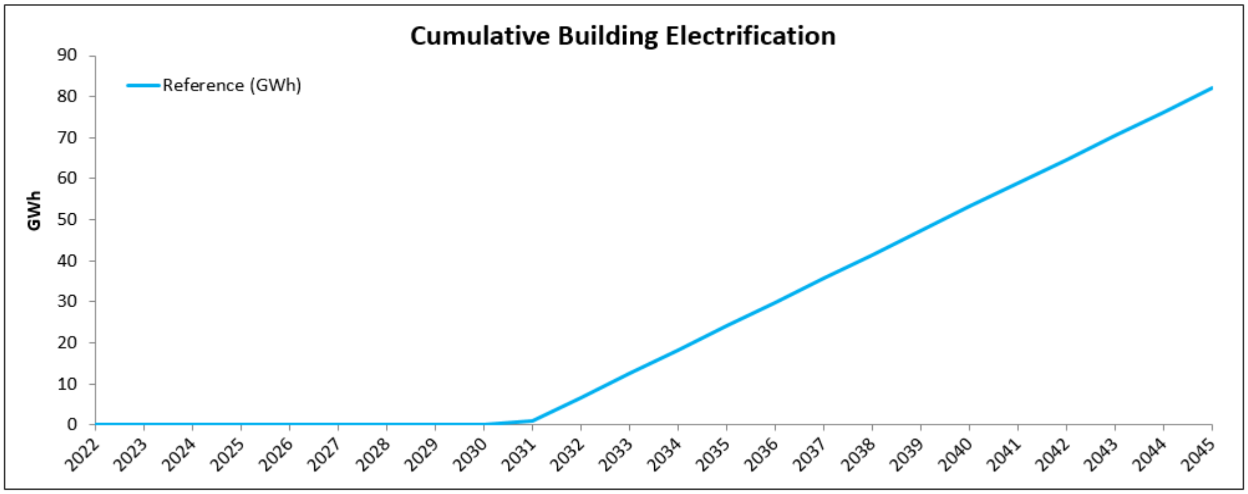


Figure 39. IRP Energy Efficiency Savings (GWh) Projection. Projection is cumulative, reset starting from the year 2021, as historical savings are incorporated into the load forecast.

The levels of energy efficiency shown above (Figure 39) are cumulative projections starting from the year 2022. Per the IRP, SB 100 was modeled using "Reference" levels of EE. EE is also considered a "load reducer" because it lowers the net energy for load and electric retail sales that LADWP ultimately has to meet. Like other DERs, EE depends on customer participation.

4.1.11 Building Electrification



Notes:
1. "Reference" based off CEC 2021 SB 100 modeling (no incremental BE through 2030) assuming LADWP load is ~9% of State load
2. "High" currently reflective of the residential sector only, which will be updated when commercial projections are available.
3. Estimates from 2046-2050 we're linearly extrapolated based on data from trailing five years.
4. Sources: E3, SMUD, SCE, LADWP
5. Last updated 2/2/2022

Figure 40. IRP Building Electrification Load (GWh) Projection. Projection is cumulative, starting from the year 2022.

Per the IRP, SB 100 was modeled using "Reference" levels of building electrification (Figure 40). Distribution system upgrades will likely be necessary to accommodate future levels of building electrification in LADWP's service territory.

4.1.12 Transportation Electrification

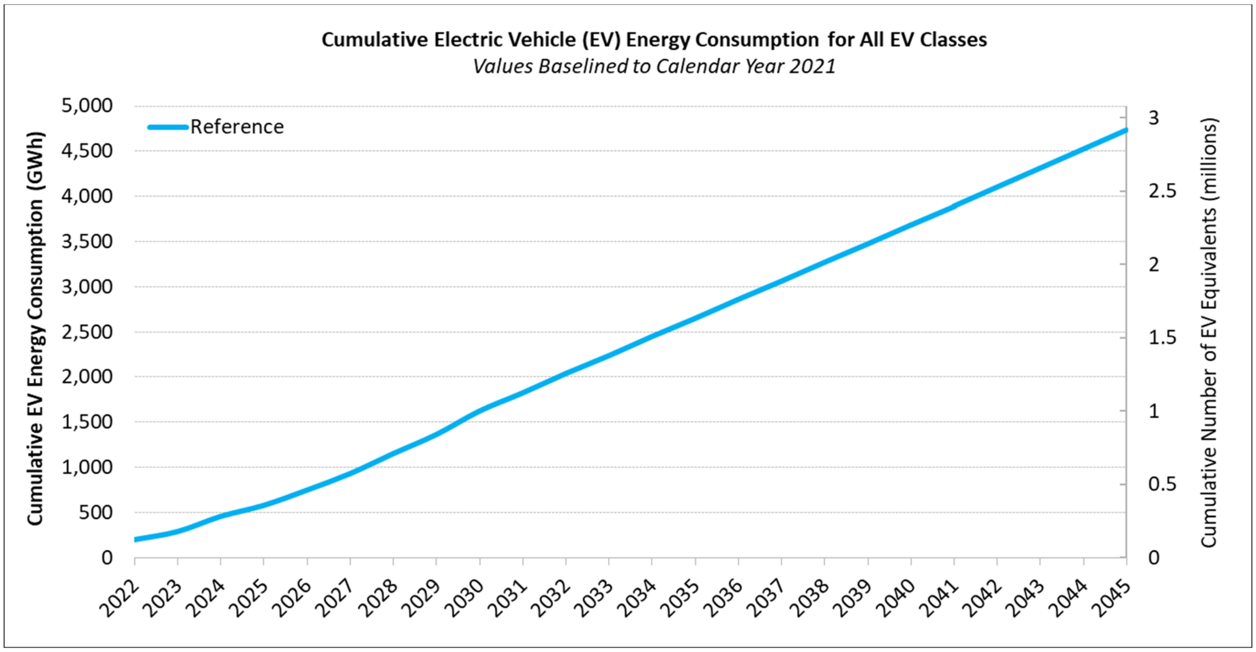


Figure 41. IRP Transportation Electrification Load (GWh) Projection. Projection is cumulative, reset starting from the year 2021, as historical load is incorporated into the load forecast.

The IRP models SB 100 load assuming "Reference" levels of Transportation Electrification shown above (Figure 41).

4.1.13 Power System Reliability Program (PSRP) Re-Vamp

Table 11. IRP Power System Reliability Program (PSRP) Re-vamp Cost Projections. Estimated costs are to address distribution system overloads and expand distribution system capacity.

Case	Reference (SB 100)
PSRP - Capital & O&M	PSRP - Total Annual Fixed Cost ($M)
FY 21/22	$899
FY 22/23	$1,124
FY 23/24	$1,271
FY 24/25	$1,285
FY 25/26	$1,421
FY 26/27	$1,511
FY 27/28	$1,537
FY 28/29	$1,646
FY 29/30	$1,744
FY 30/31	$1,741
FY 31/32	$1,826
FY 32/33	$1,931
FY 33/34	$2,029
FY 34/35	$2,131
FY 35/36	$2,236
FY 36/37	$2,350
FY 37/38	$2,471
FY 38/39	$2,600
FY 39/40	$2,729
FY 40/41	$2,871
FY 41/42	$3,019
FY 42/43	$3,170
FY 43/44	$3,314
FY 44/45	$3,472
Est Totals ($M)	$50,330

The table above (Table 11) reflects cost estimates regarding the revamp of LADWP's Power System Reliability Program (PSRP). A revamp includes alleviating existing distribution system overloads and expanding distribution system capacity to the levels needed to accommodate projections for distributed energy resources and electrification of the transportation and building sectors.

4.1.14 Greenhouse Gas (GHG) Emissions Allowance Prices

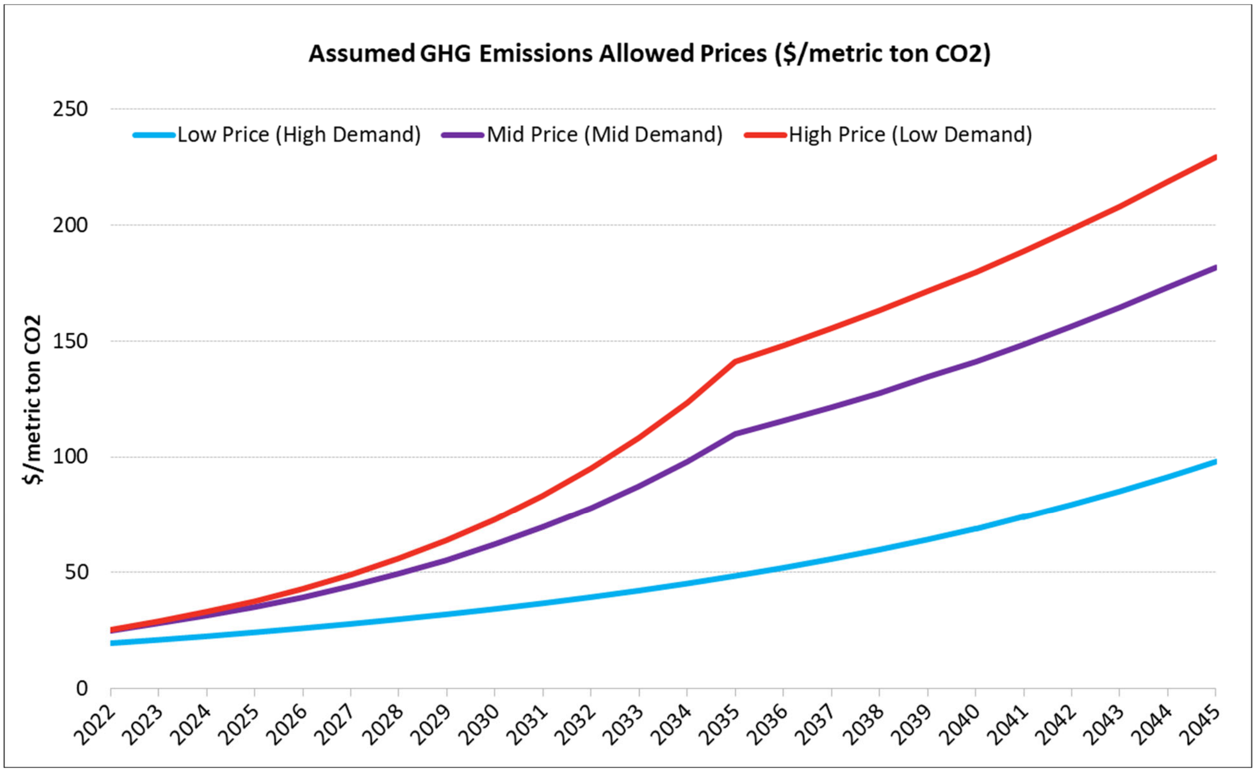


Figure 42. IRP Greenhouse Gas Emission Allowance Price Projection. The "Mid" projection was used for modeling.

The prices above (Figure 42) show projections for greenhouse gas emission allowances, derived from the 2021 California Energy Commission's Integrated Energy Policy Report (IEPR). For the IRP modeling, the "Mid" price was assumed.

4.2 Modeling Methodology and Simulation In-Depth

LADWP contracted with a consultant, Ascend Analytics, to augment its existing computer modeling and simulation capabilities for this IRP. The primary software tool provided by Ascend Analytics is called PowerSIMM. This section describes in detail how PowerSIMM is used as a tool to inform stakeholders in the decision-making process.

PowerSIMM is a software program used for simulating the performance of an electric power system with high spatial and temporal granularity. PowerSIMM's three main applications are for production cost modeling, capacity expansion optimization, and resource adequacy analyses. The PowerSIMM suite of software can be used to inform decision-making over a range of time-steps, from near-immediate decisions on bidding strategies and risk management to long-term resource planning and investment decisions about generation assets.

The overall modeling process is explained below (Figure 43).

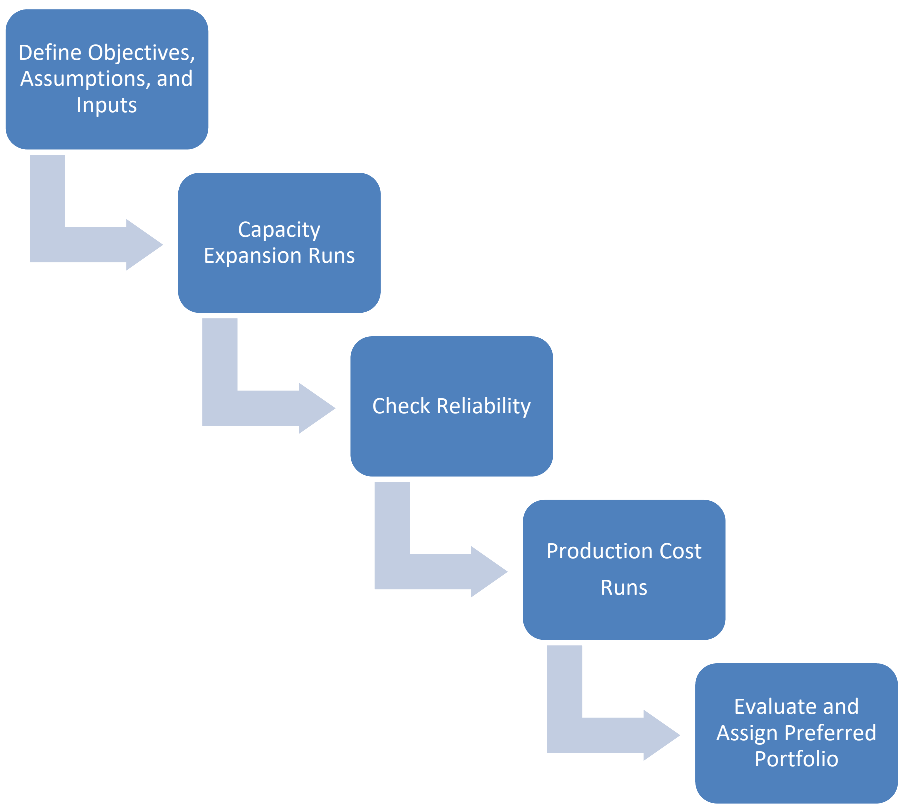


Figure 43. IRP Modeling Process.

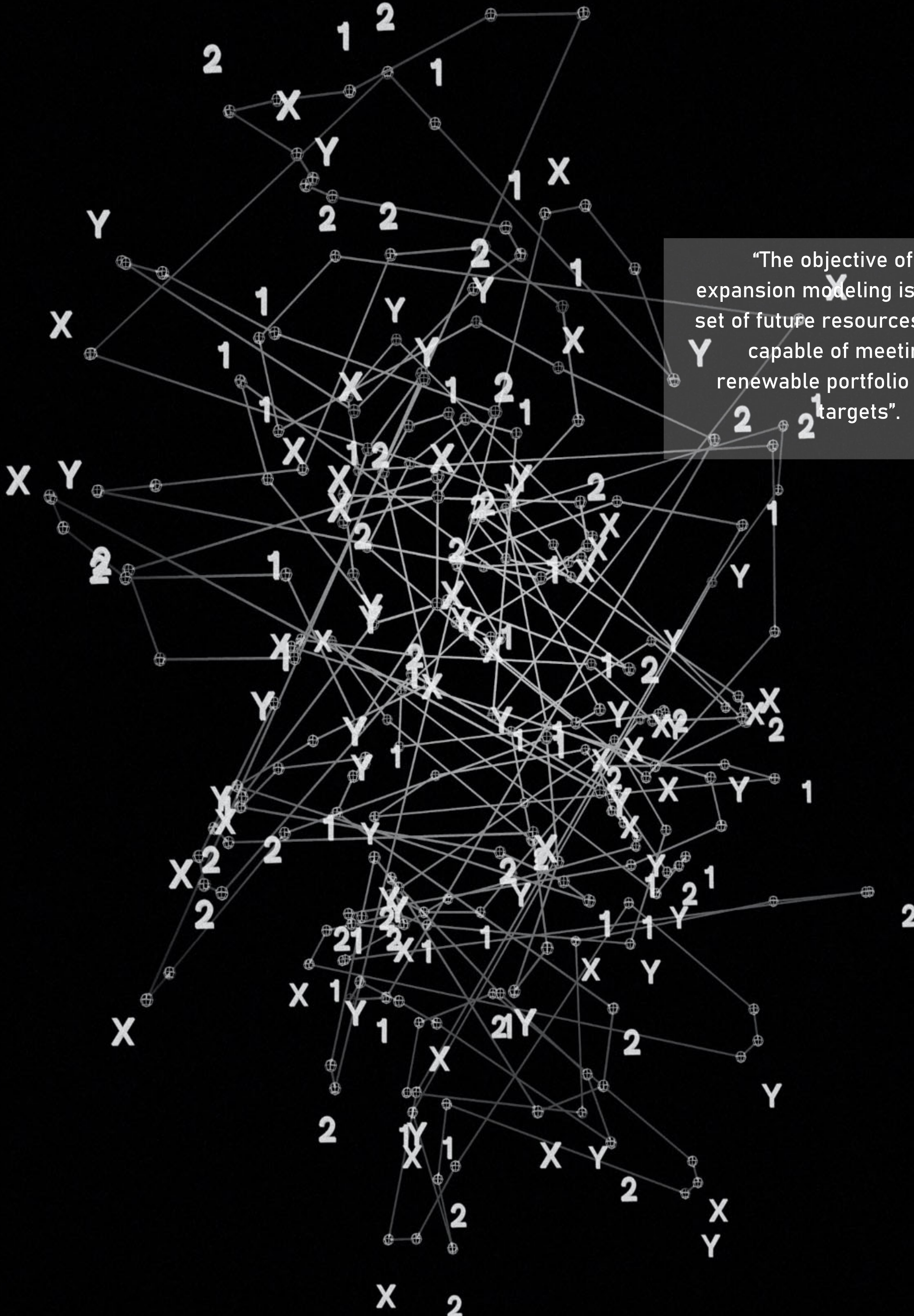
4.2.1 Capacity Expansion

For the IRP, LADWP developed the resource portfolios using capacity expansion, resource adequacy, and production cost models in PowerSIMM. The three types of models play an important role in creating least-cost, reliable resource portfolios. The process of developing resource portfolios starts by defining the objectives, assumptions, and inputs for the capacity expansion model. Primary inputs for the capacity expansion model include the candidate resource options, price forecasts (power, natural gas, coal, carbon), and model constraints such as capacity needs, energy needs, and resource build limitations. The objective of capacity expansion modeling is to select a set of future resources which are capable of meeting the identified renewable portfolio standard targets.

Capacity expansion models provide a least-cost set of resources that meet the constraints defined in the model. Portfolio outputs from the capacity expansion models are then analyzed for resource adequacy. If a portfolio cannot adequately serve load, additional resources must be added. Finally, if portfolios are resource adequate, they are evaluated in a production cost model where they are analyzed to determine production costs and emissions, among other outputs.

The key inputs to the capacity expansion model are capacity values for renewable generation and duration-limited resources such as energy storage, the cost to build new resources, forecast of load, and constraints on carbon emissions. The effective load carrying capability (ELCC) is a measure of the contribution of a power generation asset to serving customer load. ELCC is used in capacity expansion models to adjust the capacity of renewable generation and storage, in order to reflect its ability to improve the reliability of the LADWP Power System. The capital cost to build new resources was developed using the 2021 NREL Annual Technology Baseline. The expected cost to build new resources is a significant factor determining the least-cost portfolio. Expected customer load, electrification load, and demand side management programs were forecasted by LADWP and also programmed as inputs for the capacity expansion model. For carbon emissions, constraints were put in place to reach the SB 100 mandate of 100% clean energy by 2045.

The capacity expansion model takes this set of inputs and optimizes the least-cost portfolio to meet the goals of the IRP, and to reliably serve customer load. To achieve these goals, the IRP capacity expansion models set constraints on the capacity requirements of the overall generation portfolio, renewable generation, and clean energy. The capacity requirements ensure that the LADWP has sufficient capacity to meet customer load, even during extreme events. The renewable generation and clean energy constraints target 100% clean energy by 2045. After selecting the least-cost portfolio, the portfolio is assessed for resource adequacy.



"The objective of capacity expansion modeling is to select a set of future resources which are capable of meeting the renewable portfolio standard targets".

4.2.2 Reliability

Resource adequacy models are used to understand a power system's ability to meet demand. To meet the IRP goal of maintaining reliability though the transition to 100% clean energy, a baseline of the current reliability metrics for LADWP needed to be set. The current portfolio was modeled for 2023 to establish the baseline loss of load hours, which translates to the number of hours across the year that total generation capacity cannot meet customer demand. The resource adequacy for SB 100 was modeled for every fifth year starting with 2025. Through resource adequacy modeling, LADWP showed that the portfolio was able to maintain reliability while transitioning to 100% clean energy. Understanding that the Reference Case achieved sufficient reliability, the final phase of the analysis moved to running the production cost models.

4.2.3 Production Cost Modeling

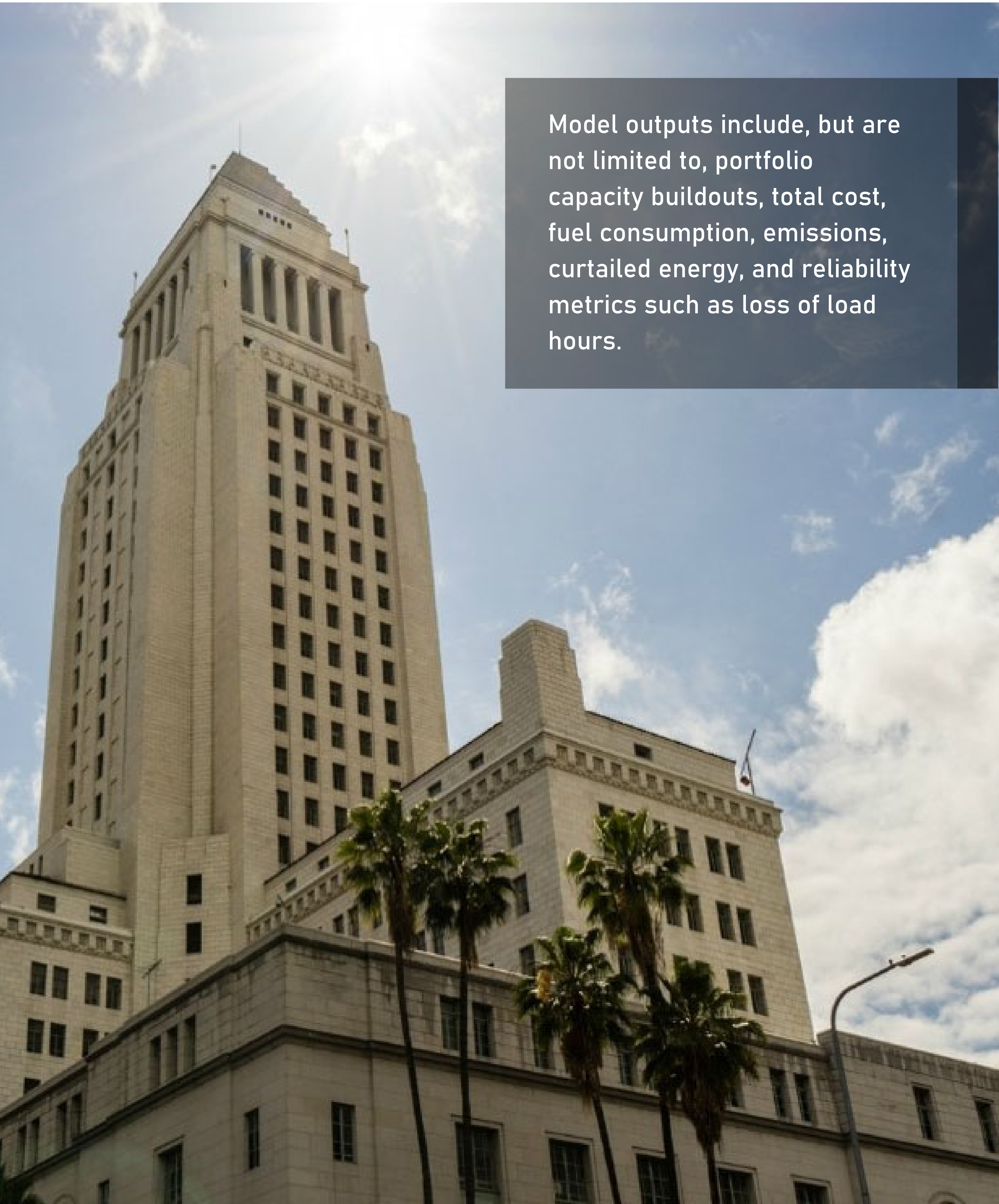
The production cost modeling phase of the IRP was used to quantify how the LADWP Power System was dispatched hourly to serve customer load and the costs associated with operating our existing and future Power System. The outputs from the production cost models were used to calculate metrics such as the total system cost, renewable generation, clean energy generation, carbon emissions, and other figures.

A key feature of the PowerSIMM platform is its simulation engine—the bedrock of any power system model—which explicitly captures the relationships observed in historical data and the correlations among key variables, including geographic and temporal relationships (autocorrelation). The PowerSIMM simulation engine first trains its models on historical data for key variables—weather, loads, renewable generation, and power and fuel prices—using time-series regression techniques. The models use relevant inputs, such as weather for load or renewables, to simulate future values with added calibrated, stochastic terms that create a realistic range of future conditions. This method produces simulations of future conditions whose variation and correlations are meaningful because they are based on information from historical conditions but are not limited to conditions that have occurred previously. The objective of simulating future conditions that fall outside of historical observations (hotter days in the summer, colder days in the winter) allow for power system models that include events and conditions that have not occurred before.

The PowerSIMM platform applies the regression techniques described above to simulations at hourly and sub-hourly time-steps. Simulations of load, renewables, and prices that maintain key structural relationships provide an understanding of the operating characteristics of the types of generation resources that are increasingly common—resources like wind and solar whose variable output is driven by the weather, and flexible resources like battery energy storage that can respond rapidly to changing system conditions.

Chapter 5

Modeling Results



Model outputs include, but are not limited to, portfolio capacity buildouts, total cost, fuel consumption, emissions, curtailed energy, and reliability metrics such as loss of load hours.

DEFINITIONS

ATB	Annual Technology Baseline
BE	Building Electrification
BESS	Battery Energy Storage System
CAPEX	Capital Expenditure
Case(s)	SB 100 Case (i.e., Reference Case), Case 1, Case 2, and Case 3
CEC	California Energy Commission
CNM solar	Customer Net-Metered Solar
Core Case(s)	Cases Modeled Under Their Default Defined Assumptions
DERs	Distributed Energy Resources
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
FSO	Financial Services Organization
GHG	Greenhouse Gas
GWh	Gigawatt-Hours
HVDC	High Voltage Direct Current
IEPR	Integrated Energy Policy Report
In-basin	Located Within the Los Angeles Basin
IRP	Integrated Resource Planning
LA100 Study	The Los Angeles 100% Renewable Energy Study
LADWP	Los Angeles Department of Water and Power
LOLH	Loss of Load Hours
Monte Carlo analysis	A Model That Uses Repeated Random Sampling to Obtain Numerical Results
NEL	Net Energy for Load
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
PPA	Power Purchase Agreement
PSRP	Power System Reliability Program

Reference Case	SB 100 Case
RPS	Renewable Portfolio Standard
STS	Southern Transmission System
TE	Transportation Electrification
WECC	Western Energy Coordinating Council

5 Modeling Results

This chapter presents the results of computer modeling. The new generation and energy storage resources for this IRP were built using the capacity expansion model described in Chapter 3. This model determines the least-cost and best-fit portfolio of generation and energy storage resources. Once the optimal portfolio of resources was determined by the capacity expansion model, detailed hourly production cost models were run on the resource portfolio using a Monte Carlo stochastic method with varying weather conditions.

Model outputs include, but are not limited to, portfolio capacity buildouts, total cost, fuel consumption, emissions, and reliability metrics such as loss of load hours.

5.1 SB 100

This IRP presented by LADWP is based on California Senate Bill 100. This IRP satisfies the mandates established by Senate Bill 100 (SB 100) drafted by the California Senate in an effort to decarbonize California's energy sector. This primarily entails ensuring that LADWP develops a renewable portfolio standard of 60% by 2030 and that 100% of retail sales be supplied using clean energy by the end of 2045. The California Senate subsequently passed Senate Bill 1020 (SB 1020), which includes an interim 90% clean energy target by 2035 and a 95% clean energy target by 2040, with respect to retail sales. While this IRP was conducted to meet mandates established in SB 100, it was found to also meet the new interim clean energy targets established by SB 1020 through the same resource portfolio.

5.1.1 Capacity Expansion

Figure 44 below shows the results of the capacity expansion model. SB 100 mandates that all retail sales of electricity to California end-use customers must be supplied through clean energy resources by 2045. To achieve this, the capacity expansion model builds significant capacities of new solar + storage, wind, and stand-alone energy storage projects.

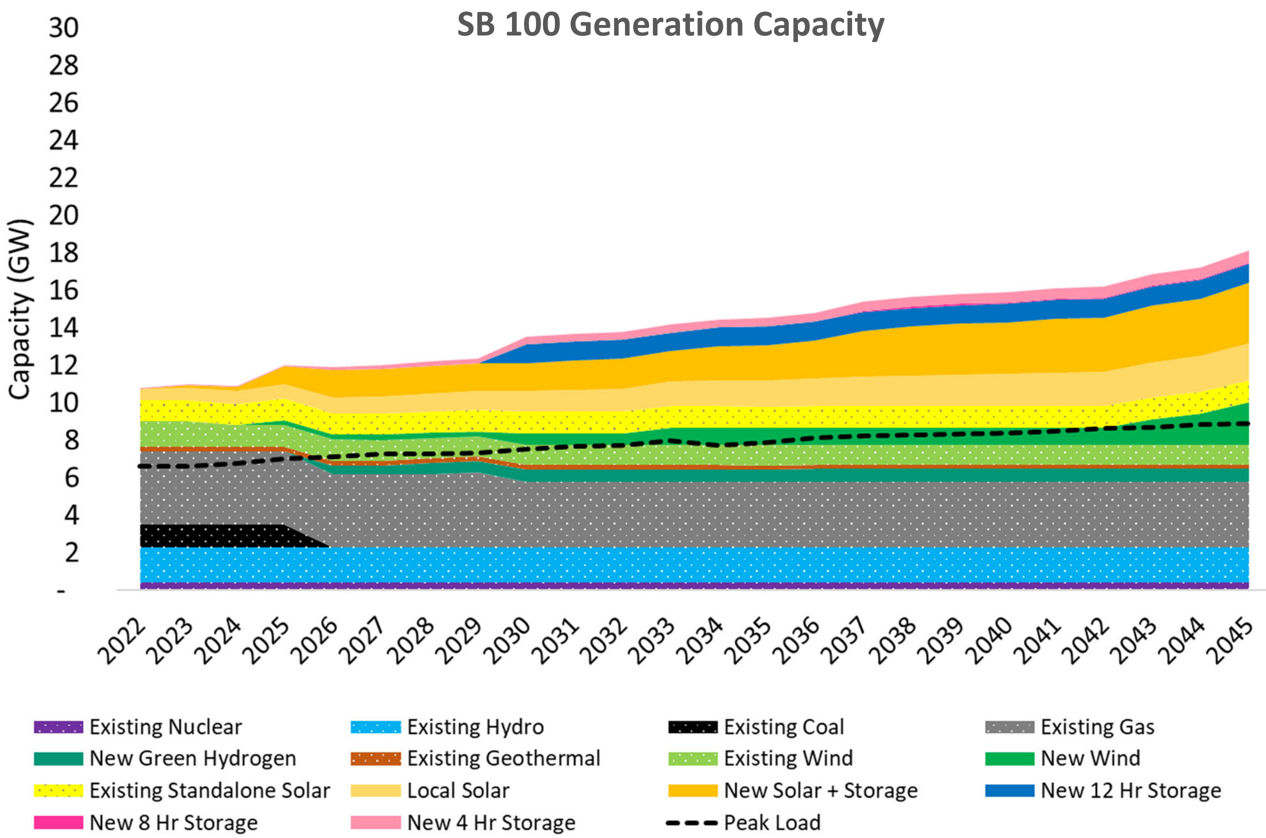


Figure 44. Generation capacity buildout. To achieve the 2045 100% clean energy mandate, significant quantities of new solar + storage, wind, and stand-alone energy storage are built. The dashed line represents annual peak system demand.

As part of the portfolio, several existing natural gas-fired generating units are retained or modernized to eliminate use of ocean water for once-through cooling (OTC). It is important to note that under SB 100, electrical energy losses, which arise primarily through resistive heating in transmission and distribution lines, can be served with fossil-fired generation. LADWP's Power System averages approximately 12% electrical energy losses. In order to minimize total cost, this IRP retains some natural gas-fired generation.

Figure 45 shows the expected energy generation by fuel type. This IRP relies heavily on energy from solar photovoltaic (PV) resources, which include local rooftop and other types of distributed solar, as well as utility-scale solar + storage projects, in order to achieve the 2045 100% clean energy mandate.

5.1.2 Production Cost

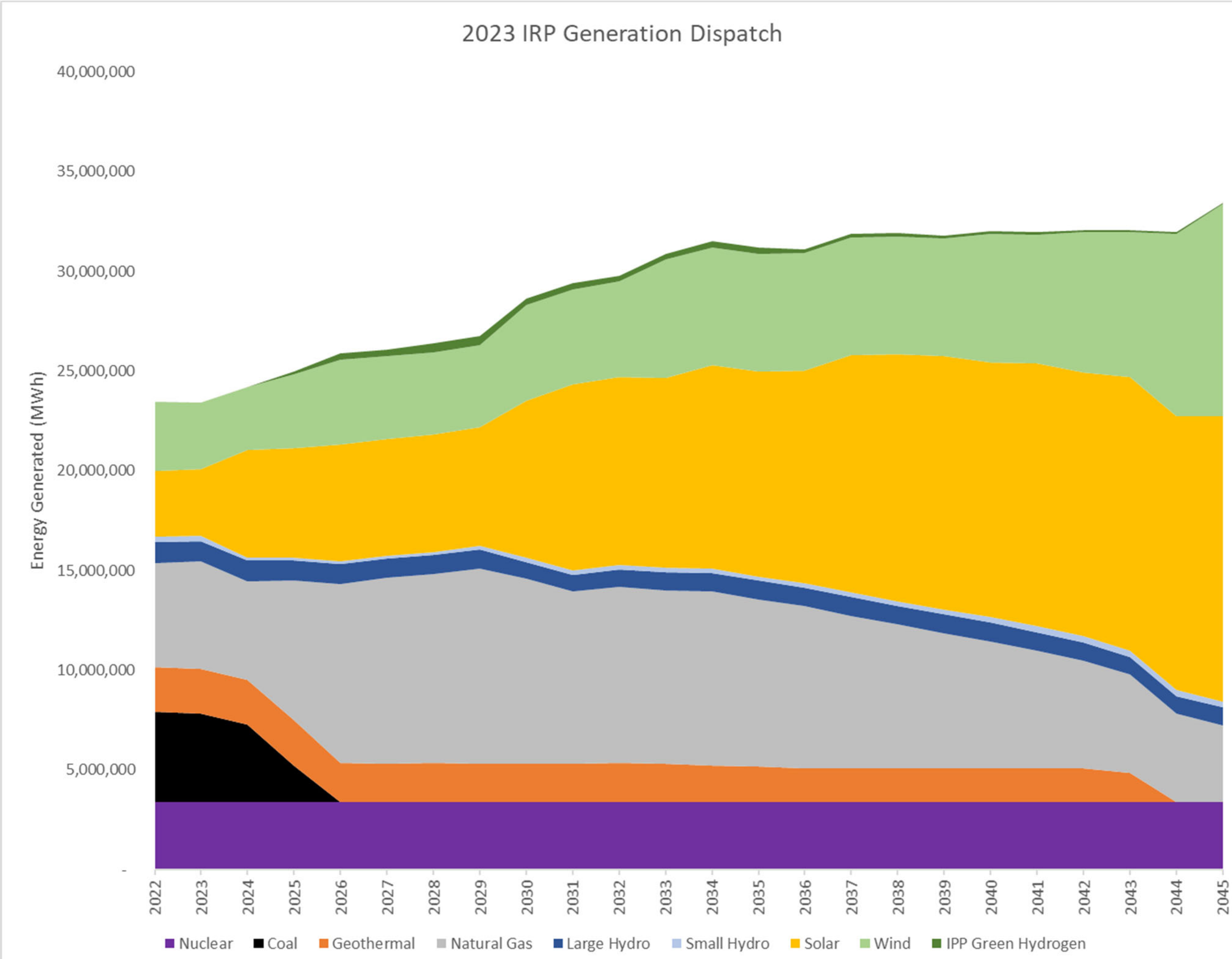


Figure 45. Generation by fuel type. This IRP relies heavily on energy from solar PV, which includes local rooftop solar, as well as utility-scale solar + storage projects, to achieve the 2045 clean energy mandate.

This IRP portfolio also relies on a significant quantity of wind, and smaller amounts of geothermal to meet the 2045 100% clean energy mandate. Figure 45 also shows that more energy is generated each year than is consumed by customers and line losses. This is due to curtailment of intermittent renewable energy resources such as solar and wind. Since these resources are not dispatchable, LADWP must attempt to integrate them into our system as their electricity is generated. However, due to their intermittent nature, the capacity expansion model must overbuild these resources to ensure the 2045 100% clean energy mandate, as shown in Figure 46, can be met under a variety of weather and customer demand situations.

Furthermore, the capacity expansion model overbuilds these resources to provide additional reliability to the system and minimize total loss of load hours. Due to this need to overbuild these intermittent resources, there are times when they produce more energy than what LADWP's system can absorb—either through customer demand or stored for later use, thus resulting in curtailment.

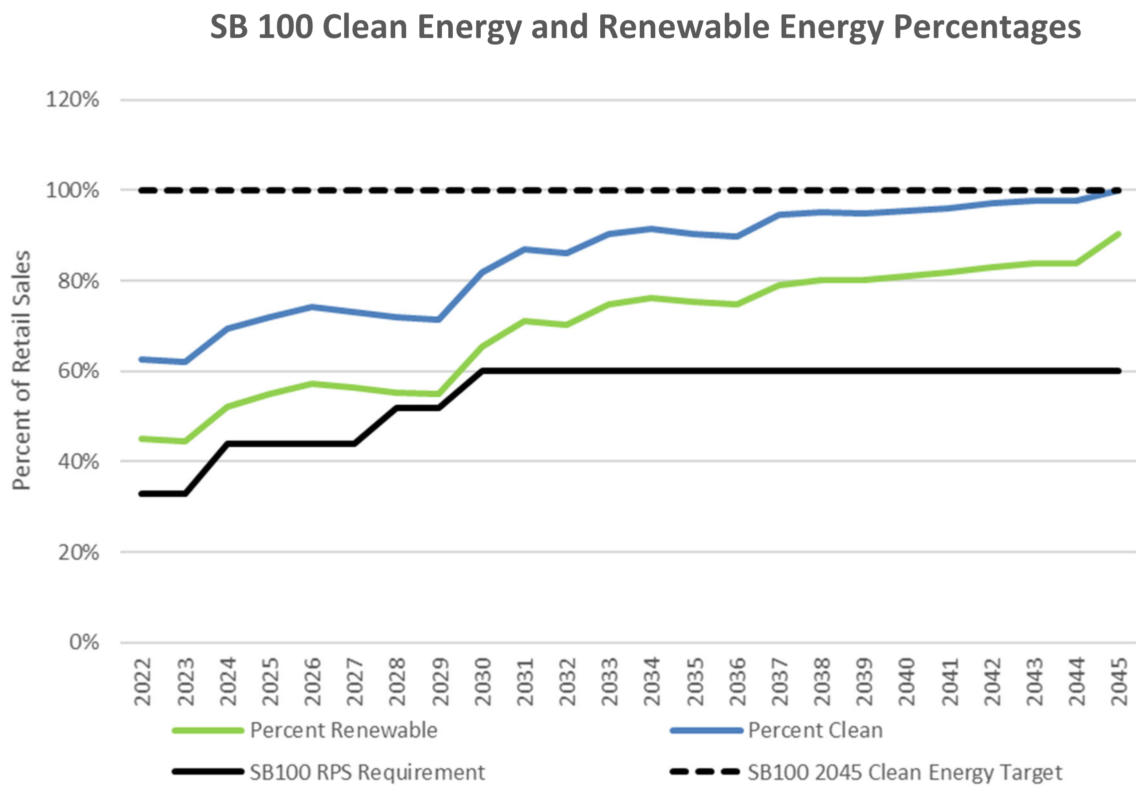


Figure 46. Percent clean (carbon-free) energy, percent renewable energy, and SB 100 RPS requirement. Renewable energy resources (whose percentage is depicted by the green line) can include wind, solar, geothermal, small hydroelectric, and biomass. Clean energy (depicted by the blue line) includes all renewable resources in addition to large hydroelectric and nuclear. SB 100 mandates that utilities achieve and maintain at least a 60% renewable portfolio standard (RPS) by 2030 (depicted by the solid black line). Additionally, SB 100 mandates that utilities achieve 100% clean (carbon-free) energy by 2045 (depicted by the dashed black line).

5.1.3 GHG Emissions

With respect to GHG emissions, this IRP starts below 7 million tons in 2022 and by 2025 reduces this by almost half, as can be seen in Figure 47. The single most significant reduction in carbon emissions throughout the entire study horizon results from LADWP fully divesting away from our last remaining coal asset in 2025, as coal-fired generation at the Intermountain Power Project is replaced by cleaner generation from green hydrogen-capable units, which in 2025 operate off a fuel blend capable of 30% green hydrogen and 70% natural gas by volume.

Further reductions can be observed starting in 2030, as substantial amounts of renewable energy are interconnected into LADWP's system, along with energy storage of various technology types and durations. This energy storage is essential to integrate the renewable energy onto the electric grid in order to reach the state mandate of a 60% renewable portfolio standard by 2030 as required by SB 100. By the 2030 milestone, LADWP significantly increases its renewable portfolio standard percentage from 2022, in less than a decade. Additionally, contributing to emission reductions entering into the 2030s are the retirement of once-through cooling generating units by the end of 2029, in order to comply with state mandates. These retired units are replaced with cleaner energy alternatives, in addition to significant deployment of customer-sided resources such as distributed solar, distributed energy storage, energy efficiency, and demand response, which all play a contributing role in reducing emissions within the Los Angeles Basin.

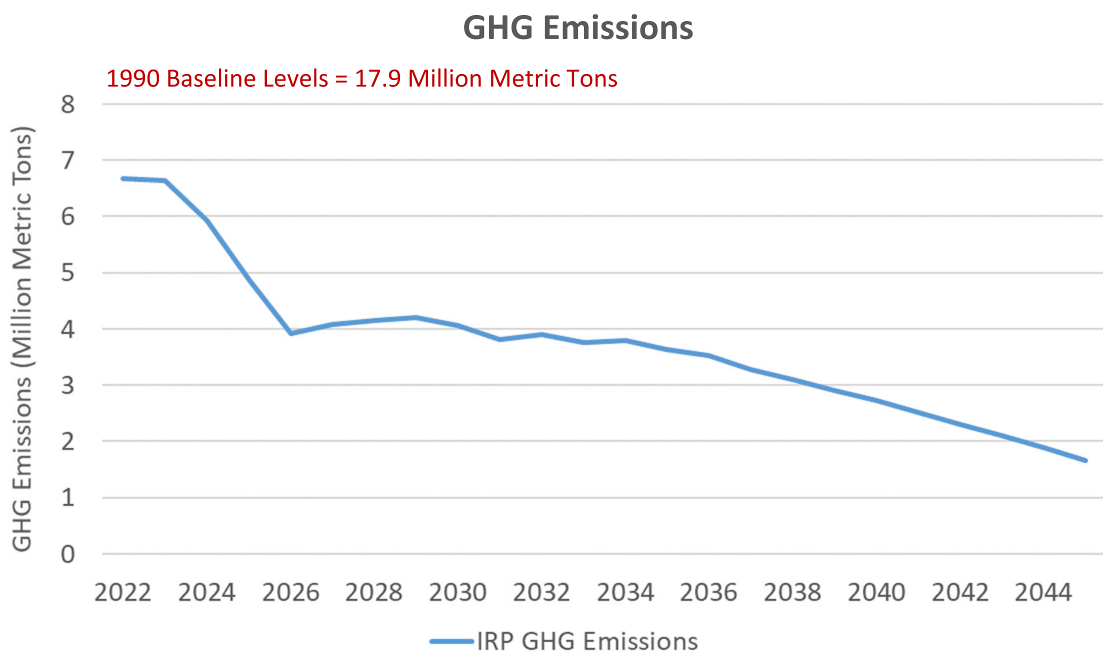


Figure 47. GHG emissions from 2022-2045.

5.1.4 Total Portfolio Cost

With respect to total portfolio costs, the net present value is taken of all the fixed costs (including capital, fixed operations and maintenance, power purchase agreements, debt service, and others) and all the variable costs (including fuel, greenhouse gas allowances, nitrogen oxide credits, variable operations and maintenance, and others), across the study horizon from 2022 through 2045 (Figure 48).

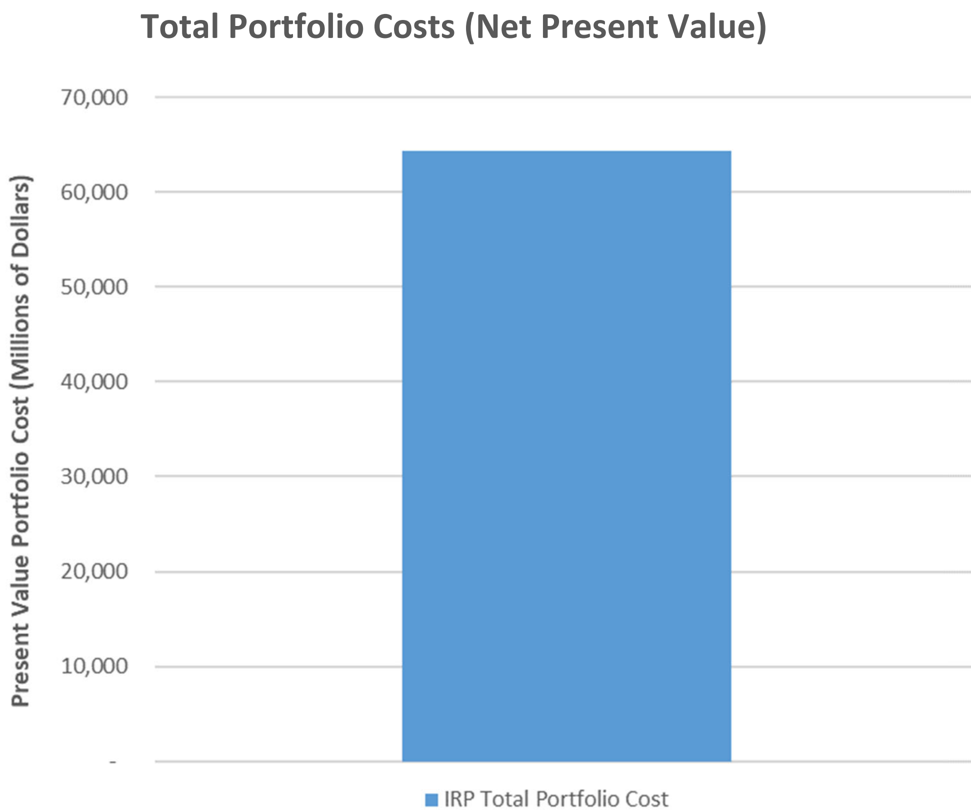


Figure 48. Total Portfolio Costs (net present value) for the IRP scenario.

As can be seen in Figure 48 implementing this IRP has an approximate NPV cost exceeding $60 billion. While showing the total portfolio cost from this financial perspective provides many insights, it must also be noted that there exist nuances and risks that fail to be captured by such financial estimates, such as the significantly challenging prospects for attaining permitting, accommodating required outages, procuring enough equipment, and hiring sufficient personnel to enable the clean energy transition.

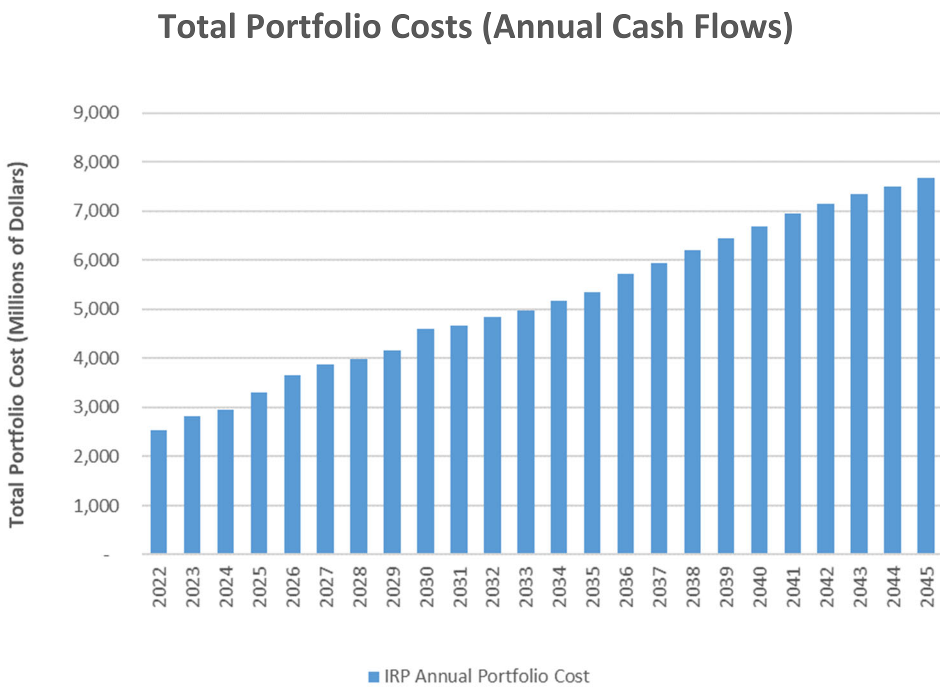


Figure 49. Total portfolio costs (annual cash flows).

When looking at the total portfolio costs from an annual cash flow perspective, it can be seen in Figure 49 that costs start above $2 billion annually and more than triple by the end of the study horizon. The increased costs are largely a result of more aggressive deployment of renewable energy resources, energy storage, infrastructure buildout, and labor, among others. It should also be noted that some of the costs for customer-sided resources such as distributed energy storage, are assumed to be borne by the customer and are not fully represented here.

5.1.5 Implementation Feasibility

Achieving 100% clean energy by 2045 will require a large investment in renewable energy and energy storage, as well as investment in transmission and other resources to ensure reliability. LADWP remains constrained by various factors including, but not limited to, cost and staffing that may limit the maximum quantity of resources that may be procured, built, or otherwise deployed during any given year. Figure 50 shows the annual build rates required to meet SB 100 targets.

The accumulation of capacity using the annual average build rates in Figure 50 shows that in the first decade of implementing this IRP, capacity accumulation of new utility-scale resources would end up above 5,000 MW by 2035 as can be observed in Figure 51.

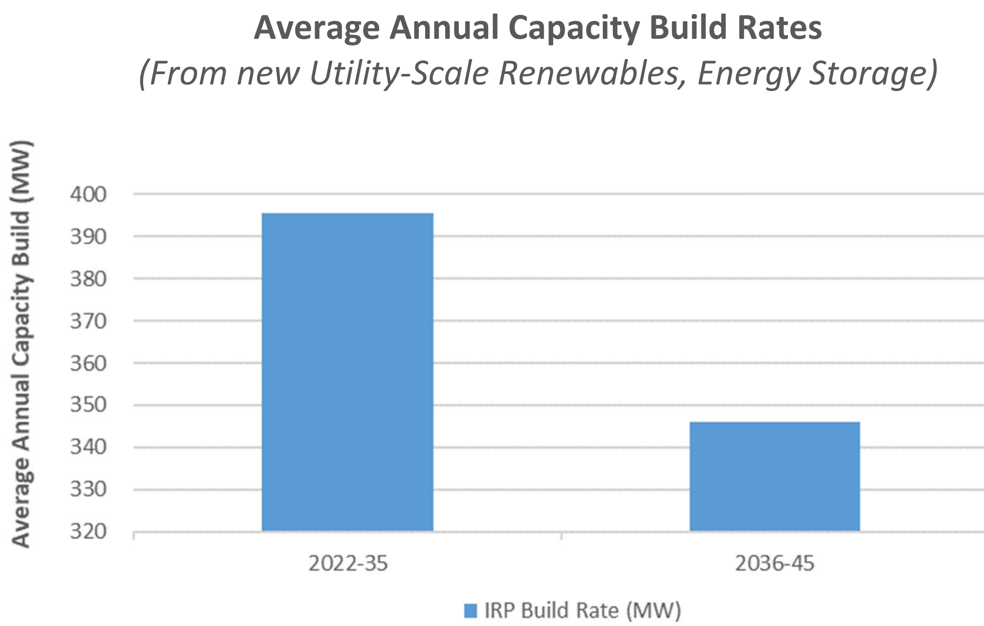


Figure 50. Average annual build rates for new utility-scale resources, 2022-2035 and 2036-2045.

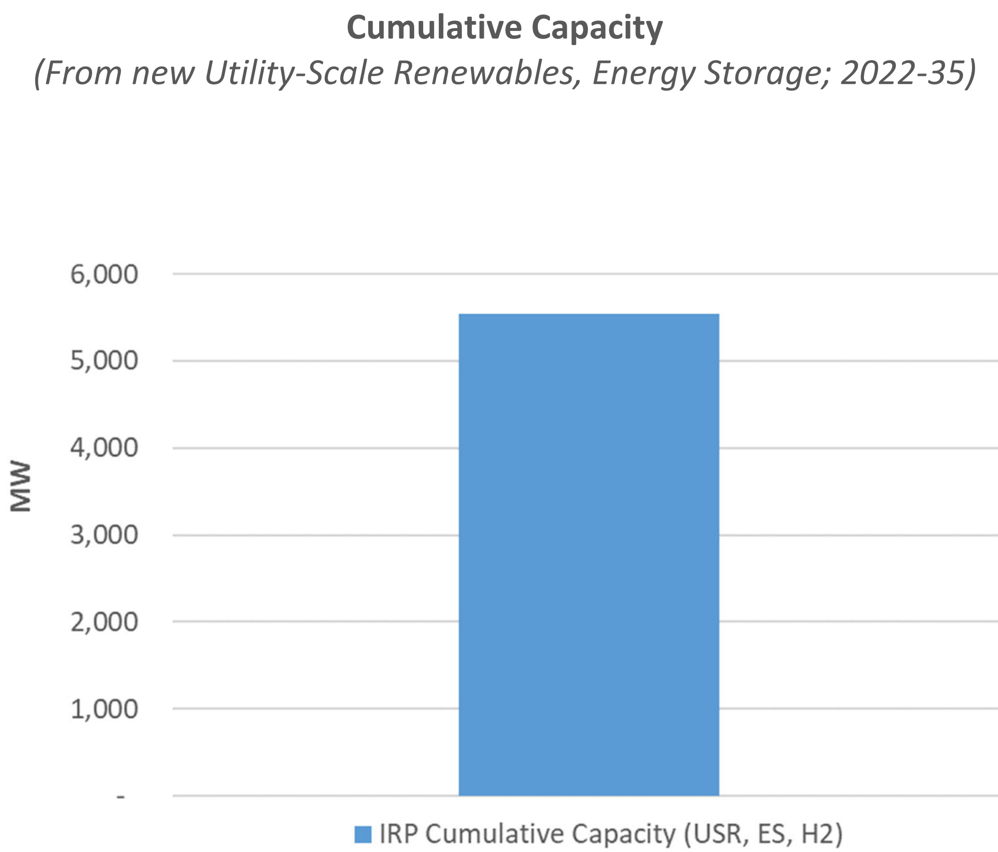


Figure 51. Total cumulative new capacity of utility-scale renewables and energy storage to be built between 2022 and 2035.

The build rates observed in Figure 50 and Figure 51 indicate that the largest portion of new resource buildout will need to occur within the next 10 years. This portion of the buildout will largely involve utility-scale resources like those listed above. Comparatively, the build rates of behind-the-meter resources such as distributed solar, energy storage, and demand response will occur with greater variance over the total transition period with spikes in the early 2030s. This IRP anticipates significant quantities of behind-the-meter resources will be deployed. Figure shows the annual capacity build for distributed solar, distributed energy storage, and demand response resources. Figure 53 shows the cumulative new distributed solar, distributed energy storage, and demand response capacity builds between 2022 and 2045.

Annual Capacity Build Rates

(From Total Distributed Solar, Energy Storage, Demand Response; 2022-45)

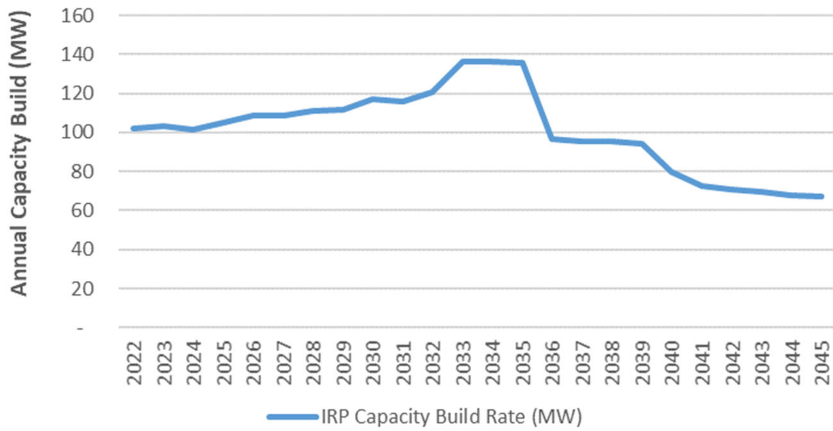


Figure 52. Annual capacity build of distributed solar, distributed energy storage, and demand response resources.

Cumulative Capacity

(From New Distributed Solar, Energy Storage, Demand Response; 2022-45)

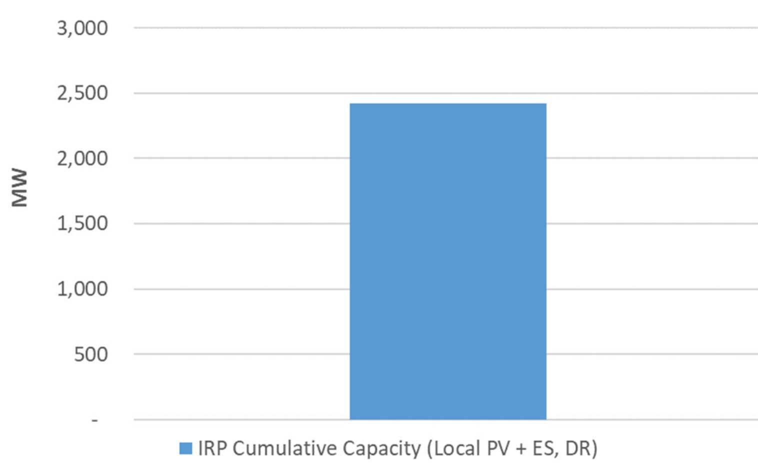


Figure 53. Cumulative new distributed solar, distributed energy storage, and demand response capacity built between 2022 and 2045.

5.1.6 Meeting SB 1020's Requirements

The modeling for this IRP was conducted before the passing of California's Clean Energy, Jobs, and Affordability Act of 2022 (SB 1020) in September of 2022, which introduced new interim renewable and clean energy targets. Starting in 2035, California utilities must ensure that 90% of the retail sales of energy come from renewable and clean energy sources. By 2040, that percentage increases to 95%. While the new targets create more emphasis for LADWP to solidify its energy transition, it has been observed through LADWP's modeling efforts that the interim targets established by SB 1020 will be met, as shown in Figure 54. This in large part thanks to the overbuilding of solar PV resources, including local Feed-in Tariff and utility-scale solar + storage projects. It is also important to note that while generation in previous data sets like Figure 45 shows a use of natural gas resources, these resources would largely be used to serve transmission and distribution losses, as well as other non-retail energy demands. As a result, the SB 1020 targets in question will still be met. Regardless, in future integrated resource plans, LADWP will add constraints which adhere to these new targets and report any changes in the results therein.

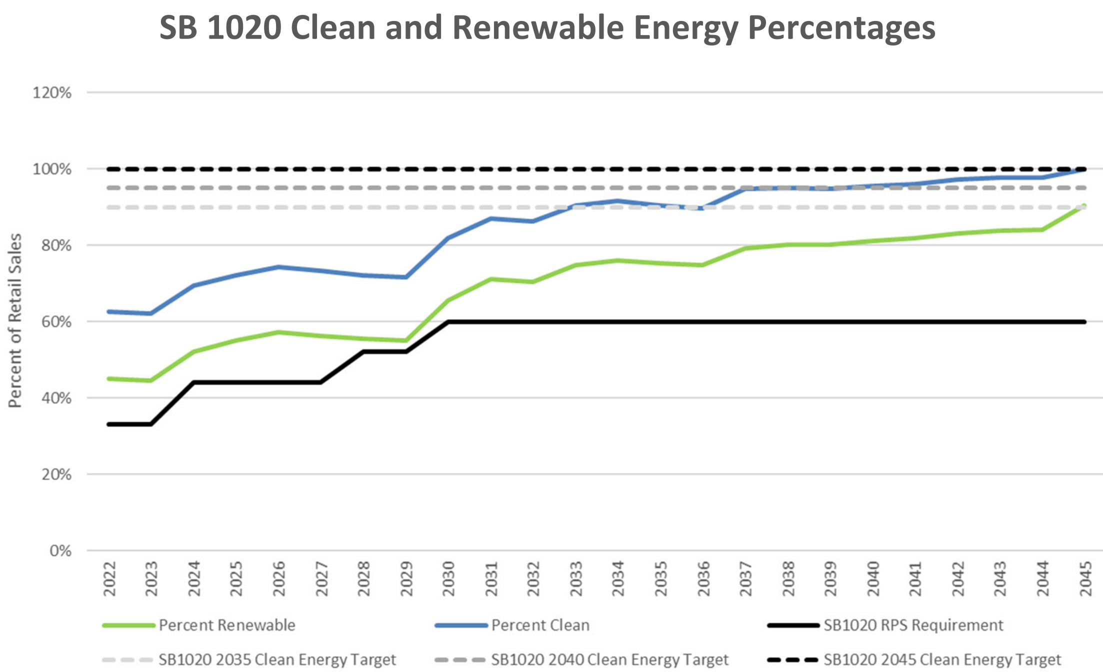
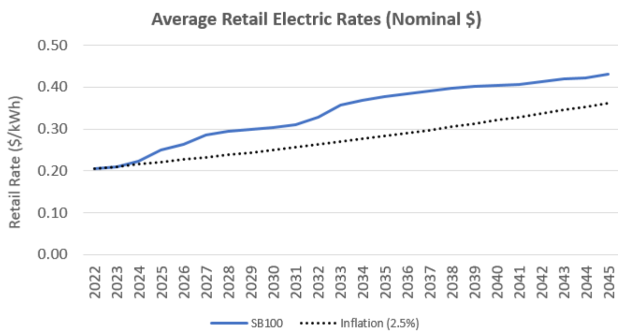


Figure 54. Percent clean (carbon-free) energy, percent renewable energy, and SB 100 RPS requirement compared to SB 100 and SB 1020 requirements. SB 100 mandates that utilities achieve and maintain at least a 60% renewable portfolio standard (RPS) by 2030 (depicted by the black line). Additionally, SB 100 mandates that utilities achieve 100% clean (carbon-free) energy by 2045 (depicted by the dashed line). SB 1020 adds interim targets of 90% clean (carbon-free) energy by 2035, and 95% clean (carbon-free) energy by 2040 for retail sale portions.

5.1.7 Retail Electric Rate and Bill Impact

Forecasts of retail electricity rates were also conducted. Figure 55 shows the average retail electricity rate forecasts, forecasted to be $0.30/kWh in 2030 and $0.38/kWh in 2035. By 2035, this represents an average rate increase of 4.8% annually over today's rates.

Estimated Average Retail Electric Rate Impacts



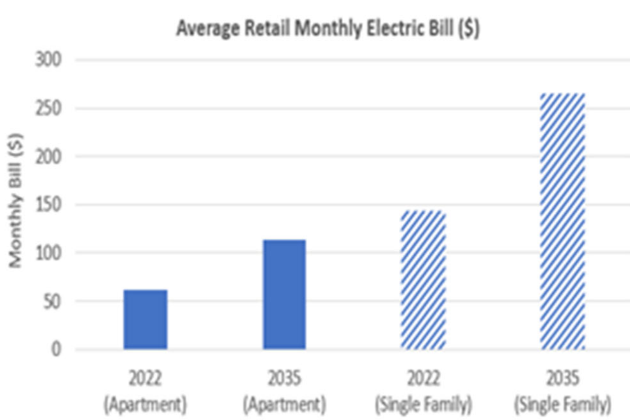
2023 IRP Scenario	Est. Avg. Retail Rate in 2030 and 2035 ($/kWh)	Est. Avg. Retail Rate Increase (2022-35)	Est. Avg. Retail Rate Increase (2022-45)
SB100	**$0.30, $0.38** *(in 2030, 2035)*	*4.8%*	*3.3%*

Note: Preliminary, subject to ongoing budget estimate and future rate review.

Figure 55. Forecasted average retail electricity rates to meet SB 100 requirements.

Figure 56 shows the estimated average monthly customer electric bill impacts for SB 100. Both estimates for single-family and apartment dwellings are included. The estimated average increase in monthly electricity bills is expected to increase by approximately 84% by 2035.

Estimated Average Retail Electric Bill Impacts (2035)



2023 IRP Scenario	Est. Avg. Retail Customer Bill in 2035 (Apartment)	Est. Avg. Retail Customer Bill in 2035 (Single-Family)	% Increase from 2022
SB100	$112	$262	**84%**

Note: Average monthly retail electric bill in 2022 is $61.66/mo. for apartment and $143.86/mo. for single-family home. Average monthly electric consumption is assumed to be 300 kWh/mo. for an apartment, and 700 kWh/mo. for a single-family home. Preliminary, subject to ongoing budget estimate and future rate review.

Figure 56. Estimated average monthly customer electric bill impacts to meet SB 100 requirements. Estimates for single-family and apartment dwellings are included.

Standardized Reporting Tables
for Publicly Owned Utility IRP Filing
California Energy Commission
Energy Assessment Division

POUs must submit the following four Standardized Tables to the Energy Commission as part of the IRP Filing. The Energy Commission encourages POUs to submit data for multiple scenarios, though POUs are only required to submit data for one scenario that meets the requirements of PUC Section 9621. Annual data must be reported in the Standardized Tables through the planning horizon.

Instructions for filling out the tables are in Appendix B Standardized Reporting Tables

Description of Worksheet Tabs

Admin Info: A listing of contact information of the tables' preparer with information for any back-up personnel.

and the contribution of each energy resource (capacity) in the POU's portfolio to meet that demand.

EBT: Energy Balance Table (EBT): Annual total energy demand and annual estimates for energy supply from various resources.

GEAT: GHG Emissions Accounting Table (GEAT): Annual GHG emissions associated with each resource in the POU's portfolio to demonstrate compliance with the GHG emissions reduction targets established by CARB.

RPT: Resource Procurement Table (RPT): A detailed summary of a POU resource plan to meet the RPS requirements.

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
Administrative Information
Form CEC 113 (May 2017)

Name of Publicly Owned Utility ("POU")	Los Angeles Department of Water ahd Power
Name of Resource Planning Coordinator	Jay Lim
Name of Scenario	2023 Integrated Resource Plan

Persons who prepared Tables	**CRAT**	**Energy Balance Table**	**Emissions Table**	**RPS Table**	**Application for Confidentiality**
Name:	Robert Hodel	Robert Hodel	Robert Hodel	Robert Hodel	Robert Hodel
Title:	Mechanical Engineer C	Mechanical Engineer C	Mechanical Engineer C	Mechanical Engineer C	Mechanical Engineer C
E-mail:	robert.hodel@ladwp.com	robert.hodel@ladwp.com	robert.hodel@ladwp.com	robert.hodel@ladwp.com	robert.hodel@ladwp.com
Telephone:	213-367-0553	213-367-0553	213-367-0553	213-367-0553	213-367-0553
Address:	111 N Hope St.	111 N Hope St.	111 N Hope St.	111 N Hope St.	111 N Hope St.
Address 2:	Room 333	Room 333	Room 333	Room 333	Room 333
City:	Los Angeles	Los Angeles	Los Angeles	Los Angeles	Los Angeles
State:	CA	CA	CA	CA	CA
Zip:	90012	90012	90012	90012	90012
Date Completed:	8/17/2023	8/17/2023	8/17/2023	8/17/2023	8/17/2023
Date Updated:	8/17/2023	8/17/2023	8/17/2023	8/17/2023	8/17/2023

Back-up / Additional Contact Persons for Questions about these Tables (Optional):

Name:	Luis Martinez	Luis Martinez	Luis Martinez	Luis Martinez	Luis Martinez
Title:	Electrical Engineering Associate	Electrical Engineering Associate	Electrical Engineering Associate	Electrical Engineering Associate	Electrical Engineering Associate
E-mail:	Luisjose.Martinez@ladwp.com	Luisjose.Martinez@ladwp.com	Luisjose.Martinez@ladwp.com	Luisjose.Martinez@ladwp.com	Luisjose.Martinez@ladwp.com
Telephone:	213-367-5253	213-367-5253	213-367-5253	213-367-5253	213-367-5253
Address:	111 N Hope St.	111 N Hope St.	111 N Hope St.	111 N Hope St.	111 N Hope St.
Address 2:	Room 960	Room 960	Room 960	Room 960	Room 960
City:	Los Angeles	Los Angeles	Los Angeles	Los Angeles	Los Angeles
State:	CA	CA	CA	CA	CA
Zip:	90012	90012	90012	90012	90012

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
Capacity Resource Accounting Table
Form CEC 109 (May 2017)

Scenario Name:

Yellow fill relates to an application for confidentiality.
Units = MW Data input by User are in dark green font.

PEAK LOAD CALCULATIONS

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	Forecast Total Peak-Hour 1-in-2 Demand	5,598	5,537	5,658	5,646	5,680	5,718	5,832	5,907	6,007	6,089	6,190	6,254	6,322	6,412	6,544	6,595	6,670	6,769	6,882	6,952	7,028	7,126	7,237	7,306
2	[Customer-side solar: nameplate capacity]	476	527	573	618	662	707	753	798	844	889	934	978	1,022	1,065	1,108	1,149	1,190	1,229	1,266	1,302	1,336	1,369	1,400	1,430
2a	[Customer-side solar: peak hour output]	96	106	115	124	133	142	151	160	170	179	188	197	205	214	223	231	239	247	255	262	269	275	281	288
3	[Peak load reduction due to thermal energy storage]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	[Light Duty PEV consumption in peak hour]	30	30	54	67	85	103	125	144	170	186	205	220	238	251	266	278	292	301	310	321	332	341	350	360
5	Additional Achievable Energy Efficiency Savings on Peak	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Demand Response / Interruptible Programs on Peak	95	121	147	175	204	232	263	293	329	364	405	462	519	576	593	610	628	646	651	651	651	651	651	651
7	**Managed Peak Demand (1-5-6)**	**5,503**	**5,416**	**5,512**	**5,471**	**5,476**	**5,486**	**5,569**	**5,614**	**5,678**	**5,725**	**5,785**	**5,792**	**5,803**	**5,836**	**5,951**	**5,986**	**6,043**	**6,124**	**6,231**	**6,302**	**6,377**	**6,476**	**6,587**	**6,656**
8	Planning Reserve Margin*	2,870	3,297	3,025	2,828	2,702	2,701	2,709	3,032	3,368	3,464	3,445	3,539	3,719	3,761	3,753	4,144	4,250	4,272	4,214	4,286	4,260	4,329	4,158	4,352
9	Firm Sales Obligations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Total Peak Procurement Requirement (7+8+9)**	**8,373**	**8,713**	**8,536**	**8,299**	**8,178**	**8,187**	**8,278**	**8,645**	**9,046**	**9,189**	**9,230**	**9,331**	**9,522**	**9,598**	**9,705**	**10,129**	**10,293**	**10,395**	**10,446**	**10,588**	**10,637**	**10,805**	**10,745**	**11,007**

EXISTING AND PLANNED CAPACITY SUPPLY RESOURCES

		Fuel	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
	Utility-Owned Generation and Storage (not RPS-eligible): [list resource by name]	Fuel																								
11a	Harbor	Natural Gas	403	403	403	403	403	403	403	403	188	188	188	188	188	188	188	188	188	188	188	188	188	188	188	188
11b	Haynes	Natural Gas	1,619	1,619	1,619	1,619	1,619	1,619	1,565	1,565	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121
11c	Scattergood	Natural Gas	798	798	798	798	798	798	798	798	514	514	514	514	514	514	514	514	514	514	514	514	514	514	514	514
11d	Valley	Natural Gas	558	558	558	558	558	558	558	558	558	558	558	558	558	558	558	558	558	558	558	558	558	558	558	558
11e	Apex	Natural Gas	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
11f	Castaic	Large Hydroelectric	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226
11g	Palo Verde	Nuclear	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
11h	New Thermal	Natural Gas	0	0	0	0	0	0	0	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346
	Long-Term Contracts (not RPS-eligible): [list contracts by name]	Fuel																								
11i	IPP (Existing Units)	Coal	1,142	1,142	942	475	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11j	IPP (New Units)	Natural Gas	0	0	0	226	458	458	621	621	621	682	682	682	682	717	717	717	717	717	717	717	717	717	717	717
11k	Hoover	Large Hydroelectric	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352
11l	Solar_Distributed_nonRPS_Existing	Unspecified/System Power	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
11m	Solar_Distributed_nonRPS_Planned	Unspecified/System Power	10	20	30	39	49	58	67	77	86	96	105	115	124	133	142	150	159	167	175	182	189	196	203	209
11n	Cogen	Natural Gas	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
11o	Palo Verde (SCPPA)	Nuclear	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159
11p	Planned Energy Storage	Storage	23	29	35	42	50	81	117	125	1,183	1,190	1,198	1,205	1,212	1,220	1,228	1,272	1,280	1,289	1,297	1,305	1,313	1,322	1,330	1,338
11	**Total peak dependable capacity of existing and planned supply resources (not RPS-eligible) (sum of 11a...11p)**		**7,150**	**7,167**	**6,983**	**6,758**	**6,531**	**6,572**	**6,727**	**7,090**	**7,215**	**7,292**	**7,309**	**7,326**	**7,342**	**7,393**	**7,410**	**7,463**	**7,480**	**7,497**	**7,513**	**7,528**	**7,544**	**7,559**	**7,573**	**7,588**
	Utility-Owned RPS-eligible Resources: [list resource by plant or unit]	Fuel																								
12a	Adelanto	Solar PV	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
12b	Pine Tree	Solar PV	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
12c	Castaic_Improvements	Small Hydroelectric	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
12d	Sepulveda	Small Hydroelectric	9	9																						
12e	North Hollywood	Small Hydroelectric	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
12f	Aqueduct_Owens Valley_Owens Gorge	Small Hydroelectric	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
12g	Pine Tree	Wind	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
12h	Linden	Wind	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	Long-Term Contracts (RPS-eligible): [list contracts by name]																									
12i	Wind_PebbleSprings	Wind	69	69	69	69	69	69	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12j	Wind_PPMWyoming	Wind	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12k	Wind_WillowCrk	Wind	72	72	72	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12l	Wind_WindyPoint	Wind	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262
12m	Wind_Milford1	Wind	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
12n	Wind_Milford2	Wind	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
12o	Wind_Manzana	Wind	8	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12p	Wind_RedCloud	Wind	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67
12q	Solar_Distributed_RPS_Existing	Solar PV	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
12r	Solar_Distributed_RPS_Reference_Planned	Solar PV	3	5	9	13	17	21	25	29	33	38	42	46	50	54	58	63	67	71	75	79	84	88	92	96
12s	Solar_PPA_CopperMountain	Solar PV	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
12t	Solar_PPA_Springbok	Solar PV	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
12u	Solar_PPA_Springbok2	Solar PV	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
12v	Solar_PPA_Springbok3	Solar PV	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
12w	Solar_PPA_RecurrentBR	Solar PV	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
12x	Solar_PPA_Kmoapa	Solar PV	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
12y	Solar_PPA_Beacon_1	Solar PV	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
12z	Solar_PPA_Beacon_2	Solar PV	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
12aa	Solar_PPA_Beacon_3	Solar PV	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
12ab	Solar_PPA_Beacon_4	Solar PV	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
12ac	Solar_PPA_Beacon_5	Solar PV	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
12ad	Solar_PPA_2023_Eland1	Solar PV	0	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143
12ae	Solar_PPA_2023_Eland2	Solar PV	0	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163
12af	Geo_DonCamb	Geothermal	14	14	14	14	14	14	14	14	14	14	14	14	0	0	0	0	0	0	0	0	0	0	0	0
12ag	Geo_DonCamb2	Geothermal	16	16	16	16	16	16	16	16	16	16	16	16	16	16	0	0	0	0	0	0	0	0	0	0
12ah	Geo_Herber1	Geothermal	36	36	36	36	36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12ai	Geo_Ormesa	Geothermal	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	0	0	0
12aj	Geo_PPA_NNV_E	Geothermal	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	0	0
12ak	Biomass_ARP_Loyalton	Biofuels	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12al	Biomass_Roseburg	Biofuels	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12am	Planned Utility-Scale Solar	Solar + Storage	0	31	52	52	154	154	154	154	355	417	437	457	641	661	763	1,131	1,273	1,355	1,355	1,477	1,477	1,620	1,620	1,783
12an	Planned Utility-Scale Wind	Wind	0	0	0	55	55	55	55	55	126	126	126	186	186	186	186	186	186	186	216	216	246	281	382	462
12ao	Planned Utility-Scale Geothermal	Geothermal	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	0	0
12	**Total peak dependable capacity of existing and planned RPS-eligible resources (sum of 12a...12ao)**		**1,223**	**1,546**	**1,554**	**1,541**	**1,647**	**1,615**	**1,551**	**1,555**	**1,831**	**1,896**	**1,921**	**2,006**	**2,180**	**2,204**	**2,294**	**2,666**	**2,813**	**2,899**	**2,933**	**3,060**	**3,094**	**3,246**	**3,172**	**3,420**
13	**Total peak dependable capacity of existing and planned supply resources (11+12)**		**8,373**	**8,713**	**8,536**	**8,299**	**8,178**	**8,187**	**8,278**	**8,645**	**9,046**	**9,189**	**9,230**	**9,331**	**9,522**	**9,598**	**9,705**	**10,129**	**10,293**	**10,395**	**10,446**	**10,588**	**10,637**	**10,805**	**10,745**	**11,007**

GENERIC ADDITIONS

		Fuel	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
	NON-RPS ELIGIBLE RESOURCES: [list resource by name or description]	Fuel																								
14a																										
14b																										
14c																										
14d																										
14e																										
14f																										
14g																										
14h																										
14i																										
14j																										
14k																										
14l																										
14m																										
14	**Total peak dependable capacity of generic supply resources (not RPS-eligible)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	RPS-ELIGIBLE RESOURCES: [list resource by name or description]	Fuel																								
15a																										
15b																										
15c																										
15d																										
15e																										
15f																										
15g																										
15h																										
15i																										
15j																										
15k																										
15	**Total peak dependable capacity of generic RPS-eligible resources**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
16	**Total peak dependable capacity of generic supply resources (14+15)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

CAPACITY BALANCE SUMMARY

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
17	**Total peak procurement requirement (from line 10)**	**8,373**	**8,713**	**8,536**	**8,299**	**8,178**	**8,187**	**8,278**	**8,645**	**9,046**	**9,189**	**9,230**	**9,331**	**9,522**	**9,598**	**9,705**	**10,129**	**10,293**	**10,395**	**10,446**	**10,588**	**10,637**	**10,805**	**10,745**	**11,007**
18	**Total peak dependable capacity of existing and planned supply resources (from line 13)**	**8,373**	**8,713**	**8,536**	**8,299**	**8,178**	**8,187**	**8,278**	**8,645**	**9,046**	**9,189**	**9,230**	**9,331**	**9,522**	**9,598**	**9,705**	**10,129**	**10,293**	**10,395**	**10,446**	**10,588**	**10,637**	**10,805**	**10,745**	**11,007**
19	**Current capacity surplus (shortfall) (18-17)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
20	**Total peak dependable capacity of generic supply resources (from line 16)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
21	**Planned capacity surplus/shortfall (shortfalls assumed to be met with short-term capacity purchases) (19+20)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Notes:

*Planning Reserve Margin is based on achieving loss of load hours (LOLH) at or below 2.4 hrs/yr. as determined by Monte Carlo simulations.

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
Energy Balance Table
Form CEC 110 (May 2017)

Scenario Name:

Units = MWh

Yellow fill relates to an application for confidentiality.

NET ENERGY FOR LOAD CALCULATIONS

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	Retail sales to end-use customers	20,534,496	20,253,374	20,620,849	20,589,646	20,690,327	20,855,683	21,330,668	21,817,760	22,356,842	22,803,642	23,264,719	23,703,019	24,099,787	24,574,371	25,144,215	25,530,474	25,946,773	26,450,180	26,945,622	27,408,009	27,826,033	28,330,074	28,820,065	29,275,659
2	Other loads	247,783	248,407	249,034	249,664	250,298	250,934	251,574	252,217	252,863	253,512	254,165	254,820	255,479	256,142	256,807	257,477	258,149	258,825	259,504	260,186	260,872	261,561	262,254	262,950
3	Unmanaged net energy for load	23,616,227	23,297,479	23,785,776	23,681,035	23,796,165	23,984,793	24,595,275	25,079,519	25,692,846	26,201,312	26,796,005	27,224,817	27,676,439	28,216,492	28,934,798	29,304,490	29,778,320	30,351,142	30,984,916	31,441,130	31,916,938	32,490,495	33,118,090	33,566,602
4	Managed retail sales to end-use customers	21,046,719	20,931,777	21,389,562	21,375,617	21,570,301	21,732,103	22,107,714	22,307,499	22,637,822	22,899,709	23,269,962	23,510,378	23,770,892	24,117,846	24,610,260	24,787,183	25,068,349	25,449,813	25,895,834	26,192,995	26,475,577	26,849,183	27,314,261	27,623,696
5	Managed net energy for load	23,916,726	23,786,110	24,306,320	24,290,474	24,511,705	24,695,571	25,122,403	25,349,430	25,724,798	26,022,397	26,443,139	26,716,339	27,012,377	27,406,643	27,966,204	28,167,253	28,486,760	28,920,242	29,427,084	29,764,767	30,085,883	30,510,435	31,038,934	31,390,563
6	Firm Sales Obligations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	**Total net energy for load (5+6)**	23,916,726	23,786,110	24,306,320	24,290,474	24,511,705	24,695,571	25,122,403	25,349,430	25,724,798	26,022,397	26,443,139	26,716,339	27,012,377	27,406,643	27,966,204	28,167,253	28,486,760	28,920,242	29,427,084	29,764,767	30,085,883	30,510,435	31,038,934	31,390,563
8	[Customer-side solar generation]	84,650	179,215	264,203	345,838	428,192	511,153	594,056	677,785	761,683	845,146	927,757	1,009,034	1,089,960	1,169,642	1,247,795	1,323,737	1,398,192	1,470,285	1,539,387	1,604,958	1,667,621	1,727,908	1,785,246	1,840,985
9	[Light Duty PEV electricity consumption/procurement requirement]*	198,334	288,164	456,430	578,535	747,078	929,611	1,150,953	1,362,146	1,621,890	1,822,645	2,037,238	2,235,444	2,447,516	2,647,855	2,858,122	3,059,988	3,268,963	3,471,923	3,681,220	3,891,569	4,101,919	4,312,269	4,522,618	4,732,968
10	[Other transportation electricity consumption/procurement requirement]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	[Other electrification/fuel substitution; consumption/procurement requirement]	0	0	0	0	0	0	0	0	0	864	6,678	12,492	18,306	24,120	29,934	35,748	41,562	47,376	53,190	58,968	64,746	70,524	76,302	82,080

EXISTING AND PLANNED GENERATION RESOURCES

Utility-Owned Generation Resources (not RPS-eligible):
[list resource by name]

			2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
12a	Harbor	Natural Gas	71,139	46,214	98,335	147,354	172,085	124,036	78,677	42,091	255,733	283,802	248,424	158,086	159,626	143,677	160,190	95,643	92,419	81,135	88,835	79,883	81,335	83,450	78,604	78,792
12b	Haynes	Natural Gas	213,433	221,134	317,141	582,286	647,261	986,422	838,368	537,806	1,264,886	1,379,137	1,264,994	832,951	876,047	831,538	975,074	655,328	680,875	623,931	708,394	678,069	660,659	679,668	728,314	627,338
12c	Scattergood	Natural Gas	2,230,069	2,190,889	2,033,342	2,222,382	2,353,531	2,203,147	2,079,962	1,538,633	1,203,543	1,151,640	1,264,890	1,289,041	1,202,857	1,226,911	1,375,674	1,352,487	1,246,927	1,206,182	1,084,933	1,017,765	911,811	816,574	689,240	629,039
12d	Valley	Natural Gas	657,536	728,652	704,389	779,079	886,690	926,094	711,276	573,076	478,312	404,697	434,378	461,689	430,924	506,070	688,392	613,713	517,623	534,529	523,808	493,846	441,532	407,925	392,203	306,445
12e	Apex	Natural Gas	1,872,850	2,041,452	1,612,781	1,807,356	2,063,015	2,324,223	1,856,757	1,618,589	1,421,694	1,409,520	1,460,432	1,593,796	1,701,840	1,667,124	1,827,203	1,742,408	1,723,110	1,596,792	1,474,562	1,345,311	1,215,387	1,095,117	963,547	826,867
12f	Castaic	Large Hydroelectric	485,000	485,000	485,000	485,000	485,000	485,000	485,000	485,000	485,000	485,000	485,000	485,000	485,000	485,000	485,000	485,000	485,000	485,000	485,000	485,000	485,000	485,000	485,000	485,000
12g	Palo Verde	Nuclear	1,997,280	1,997,280	2,002,752	1,997,280	1,997,280	1,997,280	2,002,752	1,997,280	1,997,280	1,997,280	2,002,752	1,997,280	1,997,280	1,997,280	2,002,752	1,997,280	1,997,280	1,997,280	2,002,752	1,997,280	1,997,280	1,997,280	2,002,752	1,997,280
12h	New Thermal	Natural Gas	0	0	0	0	0	0	0	1,477,027	1,638,619	1,530,963	1,624,942	1,624,300	1,648,516	1,558,279	1,538,779	1,573,929	1,445,454	1,337,375	1,216,463	1,107,958	1,003,824	868,185	745,470	654,112

Long-Term Contracts (not RPS-eligible):
[list contracts by name]

			2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
12i	IPP (Existing Units)	Coal	4,529,654	4,415,609	2,883,546	1,851,143	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12j	IPP (New Units)	Natural Gas	0	0	0	1,474,660	2,983,821	2,874,176	4,285,884	4,273,119	3,154,393	2,576,196	2,682,767	2,848,516	2,868,843	2,557,476	1,558,177	1,623,088	1,497,118	1,386,237	1,227,154	1,106,898	1,009,253	864,621	716,470	644,275
12k	Hoover	Large Hydroelectric	369,391	541,765	542,787	510,450	535,942	484,619	483,566	497,638	374,694	351,164	378,347	431,792	439,830	441,214	416,077	466,774	461,267	475,978	467,640	439,942	443,595	415,454	399,862	403,797
12l	Solar_Distributed_nonRPS_Existing	Unspecified/System Power	165,325	165,325	165,325	165,325	165,325	165,325	165,325	165,325	165,325	165,325	165,325	165,325	165,325	165,325	165,325	165,325	165,325	165,325	165,325	165,325	165,325	165,325	165,325	165,325
12m	Solar_Distributed_nonRPS_Planned	Unspecified/System Power	17,692	37,458	55,218	72,280	89,452	106,851	124,158	141,657	159,192	176,634	193,901	210,880	227,802	244,455	260,789	276,661	292,222	307,299	321,732	335,436	348,133	361,133	373,116	384,766
12n	Cogen	Natural Gas	169,940	169,940	170,410	169,940	169,940	169,940	170,410	169,940	169,940	169,940	170,410	169,940	169,940	169,940	170,410	169,940	169,940	169,940	170,410	169,940	169,940	169,940	170,410	169,940
12o	Palo Verde (SCPPA)	Nuclear	1,392,840	1,392,840	1,396,656	1,392,840	1,392,840	1,392,840	1,396,656	1,392,840	1,392,840	1,392,840	1,396,656	1,392,840	1,392,840	1,392,840	1,396,656	1,392,840	1,392,840	1,392,840	1,396,656	1,392,840	1,392,840	1,392,840	1,396,656	1,392,840
12p	Planned Energy Storage	Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	**Total energy from existing and planned supply resources (not RPS-eligible) (sum of 12a…12p)**		14,372,058	14,433,556	13,467,684	13,679,374	13,942,223	14,239,732	14,578,191	14,910,020	14,161,352	13,474,325	13,773,219	13,661,447	13,764,533	13,387,132	13,032,593	12,611,216	12,167,399	11,753,834	11,313,663	10,817,493	10,326,073	9,806,511	9,306,948	8,765,815

Utility-Owned RPS-eligible Generation Resources:
[list resource by plant or unit]

			2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
13a	Adelanto	Solar PV	20,500	20,500	20,500	20,500	20,500	20,500	20,500	20,500	20,500	20,500	20,500	20,500	20,500	20,500	20,500	20,500	20,500	20,500	20,500	20,500	20,500	20,500	20,500	20,500
13b	Pine Tree	Solar PV	18,200	18,200	18,200	18,200	18,200	18,200	18,200	18,200	18,200	18,200	18,200	18,200	18,200	18,200	18,200	18,200	18,200	18,200	18,200	18,200	18,200	18,200	18,200	18,200
13c	Castaic_Improvements	Small Hydroelectric	96,720	97,510	14,180	14,720	16,230	16,420	23,700	26,240	93,070	93,070	93,420	91,730	92,360	91,770	93,460	92,710	93,030	94,400	93,750	95,330	95,370	91,420	88,070	82,200
13d	Sepulveda	Small Hydroelectric	32,500	32,500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13e	North Hollywood	Small Hydroelectric	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300
13f	Aqueduct_Owens Valley_Owens Gorge	Small Hydroelectric	120,989	121,047	121,027	121,513	122,947	123,071	121,200	123,501	121,404	123,373	123,266	121,375	121,625	121,100	122,896	121,735	121,309	121,667	200,134	214,898	211,782	212,715	213,699	212,476
13g	Pine Tree	Wind	248,340	248,340	248,340	248,340	248,340	248,340	248,340	248,340	248,340	248,340	248,340	248,340	248,340	248,340	248,340	248,340	248,340	248,340	248,340	248,340	248,340	248,340	248,340	248,340
13h	Linden	Wind	138,662	138,662	138,662	138,662	138,662	138,662	138,662	138,662	138,662	138,662	138,662	138,662	138,662	138,662	138,662	138,662	138,662	138,662	138,662	138,662	138,662	138,662	138,662	138,662

Long-Term Contracts (RPS-eligible):
[list contracts by name]

			2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
13i	Wind_PebbleSprings	Wind	151,637	151,637	151,637	151,637	151,637	24,511	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13j	Wind_PPMWyoming	Wind	101,608	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13k	Wind_WillowCrk	Wind	166,180	166,180	14,077	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13l	Wind_WindyPoint	Wind	654,006	654,006	654,006	654,006	654,006	654,006	654,006	654,006	654,006	654,006	654,006	654,006	654,006	654,006	654,006	654,006	654,006	654,006	654,006	654,006	654,006	654,006	654,006	654,006
13m	Wind_Milford1	Wind	389,578	389,578	389,578	389,578	389,578	389,578	389,578	389,578	389,578	389,578	389,578	389,578	389,578	389,578	389,578	389,578	389,578	389,578	389,578	389,578	389,578	389,578	389,578	389,578
13n	Wind_Milford2	Wind	195,978	195,978	195,978	195,978	195,978	195,978	195,978	195,978	195,978	195,978	195,978	195,978	195,978	195,978	195,978	195,978	195,978	195,978	195,978	195,978	195,978	195,978	195,978	195,978
13o	Wind_Manzana	Wind	105,941	52,971	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13p	Wind_RedCloud	Wind	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000	1,334,000
13q	Solar_Distributed_RPS_Existing	Solar PV	186,028	186,028	186,028	186,028	186,028	186,028	186,028	186,028	186,028	186,028	186,028	186,028	186,028	186,028	186,028	186,028	186,028	186,028	186,028	186,028	186,028	186,028	186,028	186,028
13r	Solar_Distributed_RPS_Reference_Planned	Solar PV	22,075	47,830	77,263	110,376	147,168	183,960	220,752	257,544	294,336	331,128	367,920	404,712	441,504	478,296	515,088	551,880	588,672	625,464	662,256	699,048	735,840	772,632	809,424	846,216
13s	Solar_PPA_CopperMountain	Solar PV	515,270	515,270	515,270	515,270	515,270	515,270	515,270	515,270	515,270	515,270	515,270	515,270	515,270	515,270	515,270	515,270	515,270	515,270	515,270	515,270	515,270	515,270	515,270	515,270
13t	Solar_PPA_Springbok	Solar PV	282,879	281,464	280,057	278,657	277,263	275,877	274,498	273,125	271,759	270,401	269,049	267,703	266,365	265,033	263,708	262,389	261,077	259,772	258,473	257,181	255,895	254,615	253,342	252,076
13u	Solar_PPA_Springbok2	Solar PV	417,462	415,375	413,298	411,232	409,175	407,129	405,094	403,068	401,053	399,048	397,053	395,067	393,092	391,126	389,171	387,225	385,289	383,362	381,446	379,538	377,641	375,752	373,874	372,004
13v	Solar_PPA_Springbok3	Solar PV	238,800	237,606	236,418	235,236	234,060	232,889	231,725	230,566	229,413	228,266	227,125	225,989	224,860	223,735	222,617	221,503	220,396	219,294	218,198	217,107	216,021	214,941	213,866	212,797
13w	Solar_PPA_RecurrentBR	Solar PV	180,981	180,076	179,175	178,279	177,388	176,501	175,619	174,740	173,867	172,997	172,132	171,272	170,415	169,563	168,716	167,872	167,033	166,197	165,366	164,540	163,717	162,898	162,084	161,273
13x	Solar_PPA_Kmoapa	Solar PV	618,482	618,482	618,482	618,482	618,482	618,482	618,482	618,482	618,482	618,482	618,482	618,482	618,482	618,482	618,482	618,000	618,000	618,000	618,000	618,000	618,000	618,000	618,000	618,000
13y	Solar_PPA_Beacon_1	Solar PV	137,310	136,623	135,940	135,261	134,584	133,911	133,242	132,576	131,913	131,253	130,597	129,944	129,294	128,648	128,005	127,364	126,728	126,094	125,464	124,836	124,212	123,591	122,973	122,358
13z	Solar_PPA_Beacon_2	Solar PV	117,788	117,199	116,613	116,030	115,450	114,873	114,298	113,727	113,158	112,592	112,029	111,469	110,912	110,357	109,806	109,257	108,710	108,167	107,626	107,088	106,552	106,020	105,489	104,962
13aa	Solar_PPA_Beacon_3	Solar PV	137,310	136,623	135,940	135,261	134,584	133,911	133,242	132,576	131,913	131,253	130,597	129,944	129,294	128,648	128,005	127,364	126,728	126,094	125,464	124,836	124,212	123,591	122,973	122,358
13ab	Solar_PPA_Beacon_4	Solar PV	122,385	121,773	121,164	120,558	119,956	119,356	118,759	118,165	117,574	116,987	116,402	115,820	115,241	114,664	114,091	113,521	112,953	112,388	111,826	111,267	110,711	110,157	109,606	109,058
13az	Solar_PPA_Beacon_5	Solar PV	98,157	97,666	97,178	96,692	96,208	95,727	95,249	94,772	94,299	93,827	93,358	92,891	92,427	91,965	91,505	91,047	90,592	90,139	89,688	89,240	88,794	88,350	87,908	87,468
13ad	Solar_PPA_2023_Eland1	Solar PV	0	2,042	745,356	745,356	745,356	745,356	745,356	745,356	745,356	745,356	745,356	745,356	745,356	745,356	745,356	745,356	745,356	745,356	745,356	745,356	745,356	745,356	745,356	745,356
13ae	Solar_PPA_2023_Eland2	Solar PV	0	2,334	851,835	851,835	851,835	851,835	851,835	851,835	851,835	851,835	851,835	851,835	851,835	851,835	851,835	851,835	851,835	851,835	851,835	851,835	851,835	851,835	851,835	851,835
13af	Geo_DonCamb	Geothermal	114,082	114,082	114,082	114,082	114,082	114,082	114,082	114,082	114,082	114,082	114,082	114,082	0	0	0	0	0	0	0	0	0	0	0	0
13ag	Geo_DonCamb2	Geothermal	134,816	134,816	134,816	134,816	134,816	134,816	134,816	134,816	134,816	134,816	134,816	134,816	134,816	95,295	0	0	0	0	0	0	0	0	0	0
13ah	Geo_Herber1	Geothermal	298,593	298,593	298,593	298,593	25,360	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13ai	Geo_Ormesa	Geothermal	209,530	209,530	209,530	209,530	209,530	209,530	209,530	209,530	209,530	209,530	209,530	209,530	209,530	209,530	209,530	209,530	209,530	209,530	209,530	209,530	209,530	0	0	0
13aj	Geo_PPA_NNV_E	Geothermal	1,053,981	1,053,981	1,053,981	1,053,981	1,053,981	1,053,981	1,053,981	1,053,981	1,053,981	1,053,981	1,053,981	1,053,981	1,053,981	1,053,981	1,053,981	1,053,981	1,053,981	1,053,981	1,053,981	1,053,981	1,053,981	1,053,981	0	0
13ak	Biomass_ARP_Loyalton	Biofuels	29,560	9,718	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13al	Biomass_Roseburg	Biofuels	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13am	Planned Utility-Scale Solar	Solar + Storage	0	1,088	458,092	458,092	764,800	764,800	764,800	764,800	2,633,564	4,032,648	4,093,990	4,159,690	4,750,990	4,816,690	5,145,190	6,327,790	6,787,690	7,050,490	7,050,490	7,444,690	7,444,690	7,887,156	7,887,156	8,377,890
13an	Planned Utility-Scale Wind	Wind	0	0	0	574,433	1,139,500	1,139,500	1,139,500	1,139,500	1,811,962	1,811,962	1,811,962	2,942,091	2,942,091	2,942,091	2,942,091	2,942,091	2,942,091	2,942,091	3,507,156	3,507,156	4,072,220	4,309,919	6,193,467	7,700,291
13ao	Planned Utility-Scale Geothermal	Geothermal	432,744	432,744	432,744	432,744	432,744	432,744	432,744	432,744	432,744	432,744	432,744	432,744	432,744	432,744	432,744	432,744	432,744	432,744	432,744	432,744	432,744	432,744	0	0
13	**Total energy from RPS-eligible resources (sum of 13a…13ao, and 13z)**		9,263,872	9,040,041	10,717,341	11,303,257	11,932,999	11,809,126	11,818,365	11,851,589	14,485,974	15,915,494	16,005,587	17,226,386	17,733,076	17,786,772	18,052,136	19,261,057	19,749,606	20,042,927	20,714,644	21,154,062	21,744,964	22,241,536	22,664,986	24,684,481
13z	**Undelivered RPS energy**		135,501	62,689	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	**Total energy from existing and planned supply resources (12+13)**		23,635,930	23,473,597	24,185,025	24,982,631	25,875,222	26,048,859	26,396,556	26,761,610	28,647,326	29,389,819	29,778,807	30,887,833	31,497,608	31,173,904	31,084,730	31,872,273	31,917,004	31,796,761	32,028,306	31,971,555	32,071,037	32,048,047	31,971,934	33,450,296

GENERIC ADDITIONS

NON-RPS ELIGIBLE RESOURCES:
[list resource by name or description]

			2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
15a																										
15b																										
15c																										
15d																										
15e																										
15f																										
15g																										
15h																										
15i																										
15j																										
15k																										
15l																										
15m																										
15n																										
15	**Total energy from generic supply resources (not RPS-eligible)**		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

RPS-ELIGIBLE RESOURCES:
[list resource by name or description]

			2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
16a																										
16b																										
16c																										
16d																										
16e																										
16f																										
16g																										
16h																										
16i																										
16j																										
16k																										
16l																										
16m																										
16n																										
16	**Total energy from generic RPS-eligible resources**		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	**Total energy from generic supply resources (15+16)**		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17z	**Total energy from RPS-eligible short-term contracts**																									

ENERGY FROM SHORT-TERM PURCHASES

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
18	**Short term and spot market purchases:**	640,000	580,000	310,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

ENERGY BALANCE SUMMARY

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
19	**Total energy from supply resources (14+17+17z)**	23,635,930	23,473,597	24,185,025	24,982,631	25,875,222	26,048,859	26,396,556	26,761,610	28,647,326	29,389,819	29,778,807	30,887,833	31,497,608	31,173,904	31,084,730	31,872,273	31,917,004	31,796,761	32,028,306	31,971,555	32,071,037	32,048,047	31,971,934	33,450,296
19a	**Undelivered RPS energy (from 13z)**	135,501	62,689	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	**Short term and spot market purchases (from 18)**	640,000	580,000	310,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	**Total delivered energy (19-19a+20)**	24,140,429	23,990,908	24,495,025	24,982,631	25,875,222	26,048,859	26,396,556	26,761,610	28,647,326	29,389,819	29,778,807	30,887,833	31,497,608	31,173,904	31,084,730	31,872,273	31,917,004	31,796,761	32,028,306	31,971,555	32,071,037	32,048,047	31,971,934	33,450,296
22	**Total net energy for load (from 7)**	23,916,726	23,786,110	24,306,320	24,290,474	24,511,705	24,695,571	25,122,403	25,349,430	25,724,798	26,022,397	26,443,139	26,716,339	27,012,377	27,406,643	27,966,204	28,167,253	28,486,760	28,920,242	29,427,084	29,764,767	30,085,883	30,510,435	31,038,934	31,390,563
23	**Surplus/Shortfall (21-22)**	223,703	204,798	188,705	692,158	1,363,517	1,353,287	1,274,153	1,412,180	2,922,528	3,367,422	3,335,668	4,171,494	4,485,231	3,767,261	3,118,525	3,705,020	3,430,245	2,876,519	2,601,222	2,206,788	1,985,154	1,537,613	933,001	2,059,733

Notes:
*Annual Incremental

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
GHG Emissions Accounting Table
Form CEC 111 (May 2017)

Scenario Name:

Yellow fill relates to an application for confidentiality.

Emissions Intensity Units = mt CO2e/MWh
Yearly Emissions Total Units = Mmt CO2e

GHG EMISSIONS FROM EXISTING AND PLANNED SUPPLY RESOURCES

	Utility-Owned Generation (not RPS-eligible): [list resource by name]	Emissions Intensity	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1a	Harbor	0.71	0.05	0.03	0.07	0.10	0.12	0.09	0.06	0.03	0.18	0.20	0.18	0.11	0.11	0.10	0.11	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06
1b	Haynes	0.50	0.11	0.11	0.16	0.29	0.33	0.50	0.42	0.27	0.64	0.69	0.64	0.42	0.44	0.42	0.49	0.33	0.34	0.31	0.36	0.34	0.33	0.34	0.37	0.32
1c	Scattergood	0.43	0.96	0.94	0.87	0.95	1.01	0.95	0.89	0.66	0.52	0.49	0.54	0.55	0.52	0.53	0.59	0.58	0.54	0.52	0.47	0.44	0.39	0.35	0.30	0.27
1d	Valley	0.44	0.29	0.32	0.31	0.34	0.39	0.40	0.31	0.25	0.21	0.18	0.19	0.20	0.19	0.22	0.30	0.27	0.23	0.23	0.23	0.22	0.19	0.18	0.17	0.13
1e	Apex	0.44	0.82	0.89	0.71	0.79	0.90	1.02	0.81	0.71	0.62	0.62	0.64	0.70	0.75	0.73	0.80	0.76	0.76	0.70	0.65	0.59	0.53	0.48	0.42	0.36
1f	Castaic	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1g	Palo Verde	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1h	New Thermal	0.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.59	0.66	0.61	0.65	0.65	0.66	0.62	0.62	0.63	0.58	0.53	0.49	0.44	0.40	0.35	0.30	0.26
	Long-Term Contracts (not RPS-eligible): [list contracts by name]	Emissions Intensity																								
1i	IPP (Existing Units)	0.98	4.45	4.34	3.82	1.82	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1j	IPP (New Units)*	0.40	0.00	0.00	0.00	0.58	1.18	1.14	1.65	1.69	1.25	1.02	1.06	1.13	1.13	1.01	0.62	0.64	0.59	0.55	0.49	0.44	0.40	0.34	0.28	0.25
1k	Hoover	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1l	Solar_Distributed_nonRPS_Existing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1m	Solar_Distributed_nonRPS_Planned	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1n	Cogen	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1o	Palo Verde (SCPPA)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1p	Planned Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	**Total GHG emissions of existing and planned supply resources (not RPS-eligible) (sum of 1a…1p)**		**6.67**	**6.64**	**5.93**	**4.88**	**3.93**	**4.09**	**4.15**	**4.20**	**4.07**	**3.81**	**3.89**	**3.76**	**3.80**	**3.63**	**3.53**	**3.28**	**3.09**	**2.90**	**2.73**	**2.52**	**2.31**	**2.10**	**1.89**	**1.65**
	Utility-Owned RPS-eligible Generation Resources: [list resource by plant or unit]	Emissions Intensity																								
2a	Adelanto	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2b	Pine Tree	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2c	Castaic_Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2d	Sepulveda	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2e	North Hollywood	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2f	Aqueduct_Owens Valley_Owens Gorge	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2g	Pine Tree	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2h	Linden	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Long-Term Contracts (RPS-eligible): [list contracts by name]	Emissions Intensity																								
2i	Wind_PebbleSprings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2j	Wind_PPMWyoming	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2k	Wind_WillowCrk	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2l	Wind_WindyPoint	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2m	Wind_Milford1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2n	Wind_Milford2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2o	Wind_Manzana	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2p	Wind_RedCloud	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2q	Solar_Distributed_RPS_Existing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2r	Solar_Distributed_RPS_Reference_Planned	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2s	Solar_PPA_CopperMountain	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2t	Solar_PPA_Springbok	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2u	Solar_PPA_Springbok2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2v	Solar_PPA_Springbok3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2w	Solar_PPA_RecurrentBR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2x	Solar_PPA_Kmoapa	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2y	Solar_PPA_Beacon_1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2z	Solar_PPA_Beacon_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2aa	Solar_PPA_Beacon_3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2ab	Solar_PPA_Beacon_4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2ac	Solar_PPA_Beacon_5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2ad	Solar_PPA_2023_Eland1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2ae	Solar_PPA_2023_Eland2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2af	Geo_DonCamb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2ag	Geo_DonCamb2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2ah	Geo_Herber1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2ai	Geo_Ormesa	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2aj	Geo_PPA_NNV_E	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2ak	Biomass_ARP_Loyalton	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2al	Biomass_Roseburg	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2am	Planned Utility-Scale Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2an	Planned Utility-Scale Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2ao	Planned Utility-Scale Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	**Total GHG emissions from RPS-eligible resources (sum of 2a…2o)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
3	**Total GHG emissions from existing and planned supply resources (1+2)**		**6.67**	**6.64**	**5.93**	**4.88**	**3.93**	**4.09**	**4.15**	**4.20**	**4.07**	**3.81**	**3.89**	**3.76**	**3.80**	**3.63**	**3.53**	**3.28**	**3.09**	**2.90**	**2.73**	**2.52**	**2.31**	**2.10**	**1.89**	**1.65**

EMISSIONS FROM GENERIC ADDITIONS

	NON-RPS ELIGIBLE RESOURCES: [list resource by name or description]	Emissions Intensity	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
4a																										
4b																										
4c																										
4d																										
4e																										
4f																										
4g																										
4h																										
4i																										
4j																										
4k																										
4l																										
4m																										
4n																										
4	**Total GHG emissions from generic supply resources (not RPS-eligible)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	RPS-ELIGIBLE RESOURCES: [list resource by name or description]	Emissions Intensity																								
5a																										
5b																										
5c																										
5d																										
5e																										
5f																										
5g																										
5h																										
5i																										
5j																										
5k																										
5l																										
5m																										
5n																										
5	**Total GHG emissions from generic RPS-eligible resources**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
6	**Total GHG emissions from generic supply resources (4+5)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

GHG EMISSIONS OF SHORT TERM PURCHASES

		Emissions Intensity	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
7	**Short term and spot market purchases:**	0.428	**0.274**	**0.248**	**0.133**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

TOTAL GHG EMISSIONS

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
8	**Total GHG emissions to meet net energy for load (3+6+7)**	**6.95**	**6.88**	**6.06**	**4.88**	**3.93**	**4.09**	**4.15**	**4.20**	**4.07**	**3.81**	**3.89**	**3.76**	**3.80**	**3.63**	**3.53**	**3.28**	**3.09**	**2.90**	**2.73**	**2.52**	**2.31**	**2.10**	**1.89**	**1.65**

EMISSIONS ADJUSTMENTS

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
8a	**Undelivered RPS energy (MWh from EBT)**	135,501	62,689	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8b	**Firm Sales Obligations (MWh from EBT)**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8c	**Total energy for emissions adjustment (8a+8b)**	135,501	62,689	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8d	**Emissions intensity (portfolio gas/short-term and spot market purchases)**																								
8e	**Emissions adjustment (8Cx8D)**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PORTFOLIO GHG EMISSIONS

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
8f	**Portfolio emissions (8-8e)**	6.95	6.88	6.06	4.88	3.93	4.09	4.15	4.20	4.07	3.81	3.89	3.76	3.80	3.63	3.53	3.28	3.09	2.90	2.73	2.52	2.31	2.10	1.89	1.65

GHG EMISSIONS IMPACT OF TRANSPORTATION ELECTRIFICATION

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
9	**GHG emissions reduction due to gasoline vehicle displacement by LD PEVs**	**0.12**	**0.15**	**0.19**	**0.22**	**0.27**	**0.31**	**0.37**	**0.43**	**0.50**	**0.55**	**0.61**	**0.66**	**0.72**	**0.77**	**0.82**	**0.88**	**0.93**	**0.99**	**1.04**	**1.10**	**1.15**	**1.21**	**1.26**	**1.32**
10	**GHG emissions increase due to LD PEV electricity loads**	**0.13**	**0.16**	**0.18**	**0.17**	**0.15**	**0.19**	**0.23**	**0.25**	**0.29**	**0.30**	**0.32**	**0.32**	**0.34**	**0.37**	**0.46**	**0.44**	**0.47**	**0.50**	**0.53**	**0.56**	**0.59**	**0.62**	**0.69**	**0.67**
11	**GHG emissions reduction due to fuel displacement - other transportation electrification**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
12	**GHG emissions increase due to increased electricity loads - other transportation electrification**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Notes:

*Assumes a fuel blend comprised of natural gas and 30% green hydrogen by volume

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
RPS Procurement Table
Form CEC 112 (May 2017)

Scenario Name:

Units = MWh

	RPS ENERGY REQUIREMENT CALCULATIONS		**Compliance Period 4**					**Compliance Period 5**				**Compliance Period 6**			
			2021	**2022**	**2023**	**2024**		**2025**	**2026**	**2027**		**2028**	**2029**	**2030**	
1	(Managed) Retail sales to end-use customers (From EBT)		20,658,433	21,046,719	20,931,777	21,389,562		21,375,617	21,570,301	21,732,103		22,107,714	22,307,499	22,637,822	
2	Green pricing program/hydro exclusion*		38,196	42,017	42,017	42,017		42,017	42,017	42,017		42017	42,017	42,017	
3	Soft target (%)		35.75%	38.50%	41.25%	44.00%		46.00%	50.00%	52.00%		54.67%	57.33%	60.00%	
4	Required procurement for compliance period		33,468,491					31,856,442				38,385,607			
	Category 0, 1 and 2 RECs														
5	Excess balance/historic carryover at beginning/end of compliance period**	0					2,949,684				6,076,439				5,774,491
6	RPS-eligible energy procured (copied from EBT)		7,462,571	9,263,872	9,040,041	10,717,341		11,303,257	11,932,999	11,809,126		11,818,365	11,851,589	14,485,974	
6A	Amount of energy applied to procurement obligation		7,385,390	8,102,987	8,634,358	9,411,407		9,832,784	10,785,150	11,300,693		12,085,551	12,789,633	13,582,693	
7	Net purchases of Category 0, 1 and 2 RECs		0	0	0	0		0	0	0		0	0	0	
7A	Carryover and REC purchases applied to procurement obligation		0	0	0	0		0	0	0		0	0	0	
8	Net change in balance/carryover (6+7-6A-7A)		77,181	1,160,885	405,683	1,305,934		1,470,473	1,147,849	508,433		(267,186)	(938,043)	903,281	
	Category 3 RECs														
9	Excess balance/historic carryover at beginning/end of compliance period**	0					0				0				0
10	Net purchases of Category 3 RECs		0	0	0	0		0	0	0		0	0	0	
11	Carryover and REC purchases applied to procurement obligation		0	0	0	0		0	0	0		0	0	0	
12	Net change in REC balance/carryover		0	0	0	0		0	0	0		0	0	0	
13	Total generation plus RECs (all Categories) applied to procurement requirement (6A + 7A + 11)		33,534,142					31,918,627				38,457,876			
14	Over/under procurement for compliance period (11 - 4)		65,651					62,185				72,269			

Notes:
*Assumes constant 2022-onwards

**There is no plan to use excess balance/historic carryover at beginning/end of Compliance Period 4 to meet our compliance targets