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2023 Integrated Resource Plan

IRP filing for submission to the

California Energy Commission

Pasadena Water and Power

CITY OF PASADENA INCORPORATED JUNE 1886

PASADENA
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TABLE OF CONTENTS

Additional Attachments:

- Renewable Portfolio Standard Procurement Plan
- Renewable Portfolio Standard Enforcement Plan

Table of Figures

Acronyms Used in PWP's IRP

Figure 1: Acronyms

Acronym	Definition
AAEE	Additional Achievable Energy Efficiency
AAFS	Additional Achievable Fuel Substitution
AATE	Additional Achievable Transportation Electrification
AB	Assembly Bill
ACES	Alliance for Cooperative Energy Services Power Marketing LLC
AMI	Advanced Metering Infrastructure
APPLE	Project Assisting Pasadena People with Limited Emergencies
ATB	NREL's Annual Technology Baseline
BEV	Battery Electric Vehicle
BRP	Business Rebate Program
Btu	British thermal units
C&S	Codes and Standards
CAISO	California Independent System Operator
CalEnvironScreen	CalEPA's California Communities Environmental Health Screening Tool
CalEPA	California Environmental Protection Agency
CAP	City of Pasadena's Climate Action Plan
CARB	California Air Resources Board
CARES	California Alternate Rates for Energy
CEC	California Energy Commission
CED	California Energy Demand Forecast
CES	Clean Energy Standard
CIP	Customized Incentive Program
CMUA	California Municipal Utilities Association
CO2e	Carbon dioxide equivalent
CPM	Capacity Procurement Mechanism
CPUC	California Public Utilities Commission
CRAT	Capacity Resource Accounting Table
CS&R	Codes, Standards, and Regulations
D&C	Distribution & Customer Charge
DAC	Disadvantaged Area Communities
DC	Direct Current
DER	Distributed Energy Resource
DOE	U.S. Department of Energy
DOT	Department of Transportation
DR	Demand Response
E3	Energy and Environmental Economics, Inc.
EAC	Environmental Advisory Commission
EBT	Energy Balance Table

Acronym	Definition
EEI	Edison Electric Institute
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ESAP	Energy Savings Assistance Program
EUAP	Electric Utility Assistance Program
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FY	Fiscal Year
GDS	GDS Associates, Inc.
GEAT	GHG Emissions Accounting Table
GHG	Greenhouse Gas
GPP	Green Power Program
GRI	Global Reporting Initiative
GT	Glenarm
GWh	Gigawatt-hours
HE	Hour Ending
HELP	Home Enhancement Loan Program
HER	Home Energy Reports
HIP	Home Improvement Program
HVAC	Heating/Ventilation/Air Conditioning
IEPR	Integrated Energy Policy Report
IPP	Intermountain Power Project
IRA	Inflation Reduction Act
IRS	Internal Revenue Service
ISO	Independent System Operator
ITC	Investment Tax Credit
kA	Kiloampere
kV	Kilovolt
kWh	Kilowatt-hours
LADWP	Los Angeles Department of Water and Power
LCA	Local Capacity Areas
LCFS	Low Carbon Fuel Standard
LCOE	Levelized Cost of Energy
LCR	Local Capacity Requirements
LDV	Light-Duty Vehicles
LIHEAP	Low-Income Household Energy Assistance
LIHWAP	Low-Income Household Water Assistance Program
LRA	Local Regulatory Authority
LSE	Load Serving Entity
MASH	City's Municipal Assistance, Solutions, and Hiring Program
MDHD	Medium Duty, Heavy Duty

Acronym	Definition
MIP	Mixed Integer Programming
MISO	Midcontinent Independent System Operator
MMBtu	Metric Million British Thermal Unit
MSC	Municipal Services Committee
MVA	Megavolt-ampere
MW	Megawatt – a unit of capacity (similar to the amount of water a hose can push on demand)
MWh	Megawatt-hour – a unit of energy (similar to the amount of water flowing out of a hose)
NBT	Net Billing Tariff
NEM	Net Energy Metering
NERC	North American Electric Reliability Council
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
PBC	Public Benefit Charge
PCC	Portfolio Content Category
PCL	Power Content Label
PDMP	Power Delivery Master Plan
PG&E	Pacific Gas and Electric
PHEV	Plug-in Hybrid Electric Vehicle
POU	Publicly-Owned Utility
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
PSI	Pasadena Solar Initiative
PTC	Production Tax Credit
PTO	Participating Transmission Owner
PUC	Public Utilities Commission
PV	Photovoltaic
PWP	Pasadena Water and Power
RA	Resource Adequacy
REC	Renewable Energy Certificate
RFP	Request for Proposals
RMR	Reliability Must-Run Resources
RPS	Renewable Portfolio Standard
RPT	RPS Procurement Table
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SASB	Sustainability Accounting Standards Board
SB	Senate Bill
SCC	Social Cost of Carbon
SCE	Southern California Edison
SCPPA	Southern California Public Power Authority
SDG&E	San Diego Gas & Electric

Acronym	Definition
SMUD	Sacramento Municipal Utility District
SoCalGas	Southern California Gas Company
SPP	Southwest Power Pool
STAG	Stakeholder Technical Advisory Group
TAC	Transmission Access Charge Area
TCFD	Task Force on Climate-Related Financial Disclosures
TOU	Time of Use (Rates)
TSC	Transmission Service Charge
V2G	Vehicle-to-Grid Charging
WECC	Western Electricity Coordinating Council
WeDIP	Water and Energy Direct Install Program
ZEV	Zero-Emission Vehicle

1. Disclaimer

PWP's 2023 IRP was conducted from January through October 2023. In January 2023, PWP's City Council passed Resolution 9977, which stated that the City Council declares that climate change is an emergency and sets a policy goal to source 100% of Pasadena's electricity from carbon-free sources by the end of 2030. The Resolution directs the City Manager to use the 2023 IRP process to plan multiple approaches to transition to this goal and to optimize affordability, rate equity, stability, and reliability of electricity while achieving the goal. The 2023 IRP was therefore designed to meet CEC requirements under the *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines - Revised Second Edition* and begin investigation into carbon-free pathways.

The 2023 IRP meets the requirements of Resolution 9977, by planning multiple approaches to transition to the goal of 100% carbon-free sources by the end of 2030, while optimizing affordability, rate equity, stability, and reliability of electricity, while satisfying CEC requirements. In its daily business, PWP provides its customers with electric service, in a reliable, affordable, and environmentally responsible manner.

2. Executive Summary

On January 30, 2023, Pasadena City Council passed Resolution 9977, which states that climate change is an emergency. City Council set a policy goal to source 100% of Pasadena's electricity from carbon-free sources by the end of 2030 and direct the City Manager to utilize the 2023 IRP process to plan multiple approaches to transition and to optimize affordability, rate equity, stability, and reliability of electricity while achieving this goal.

PWP conducted its 2023 IRP to meet Resolution 9977 objectives. PWP is also under a regulatory directive to file its 2023 IRP in accordance with CEC's Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines - Revised Second Edition.

PWP began the process in earnest in early 2023 and spent most of the year working on its analysis. PWP engaged with individuals across its organization, as well as with City Council, MSC, EAC, STAG, the public, and two external consultants. PWP is grateful to all that contributed.

PWP modeled five scenarios: three investigated the potential for carbon-free resources to meet load by the end of 2030, one met California requirements, and another met California state requirements and added a carbon tax based on the SCC. PWP stressed the five resulting scenarios to four sensitivities: a month-long heat wave in summer 2030, a loss of Goodrich in 2030, high cost of new resources, and low cost of new resources. PWP also studied the potential of two different types of emerging technologies: an energy efficiency proxy resource and a demand response proxy resource.

PWP faces upcoming energy, capacity, and renewable needs. In 2025, the 108 MW IPP coal contract will be replaced with 50 MW of natural gas, which will then terminate mid-year in 2027. By 2031, the carbon-free scenarios showed that PWP needs between 375 MW and 690 MW of solar, between 0 MW and 60 MW of wind, between 35 MW and 55 MW of geothermal, between 35 MW and 115 MW of fuel cells, and between 305 MW and 685 MW of storage. PWP has a peak of approximately 351 MW in the load forecast by 2031.

Carbon-free represents a portfolio transformation. Such a transformation must be accompanied by considerations of cost, equity, and reliability. A multitude of factors create uncertainty, including, but not limited to, resource costs, resource availability, resource performance under different weather conditions, and load shifts, among others. Cost changes will lead to rate, or rate structure, changes. Such changes must be considered in the context of all PWP ratepayers, including those most at risk.

The scenarios were designed to meet reliability requirements as designed by CAISO. However, requirements may change over time. Glenarm and Goodrich, PWP's local natural gas generation and interconnection to CAISO, play important roles in meeting load under various conditions, but will require major modifications, both physically and operationally, to support a 100% carbon-free model. PWP found that it must further consider these implications in a carbon-free future.

2.1. Waypoint Framework:

After thorough discussion and vetting of the IRP modeling results and analysis during the October 10, 2023, Municipal Services Committee (MSC) meeting, the Committee directed PWP to return with a Waypoint framework, as a more valued methodology for identifying specific near-term actions and longer-term IRP assessments. The Waypoint framework provides alignment with the policy goals of the City of Pasadena, as well as meeting the CEC's requirements, while also providing for a defined re-evaluation point to allow for reassessment of new and emerging technologies that are widely industry accepted to be vital enablers for deeper and broader electric grid decarbonization.

The 2028 Waypoint framework is informed by the modeling results of the Carbon-Free Scenarios 1, 2 and 3; and from a planning perspective is identical to Scenario 2, up-to the 2028 Waypoint. Essentially, the IRP 2028 Waypoint can be loosely attributed to a critical path Carbon-Free pathway or analysis as informed by the IRP modeling results, as Scenario 2 represents the most ambitious of the Carbon-Free Scenarios.

2.2. Procurement Plan through 2028

Resource procurement and implementation planning for the 2023 IRP are defined by the 2028 Waypoint framework. Which among other key value adds, represents a point in time where portfolio planning re-evaluation occurs, and next steps are informed by a variety of considerations, including maturity and feasibility of new and emerging technologies such as carbon-free hydrogen-based generation or long-term battery storage.

The IRP 2028 Waypoint framework and associated implementation plan align with Carbon-Free Scenario 2, and its associated modeling results. Scenario 2 modeling or implementation results emphatically affirm resource quantity, resource type, and timeline along with other attributes needed for optimization. The detailed implementation provisions are provided in greater detail in Section 21, but broadly include resource procurements of utility scale solar, utility scale wind, utility scale storage among other resource types.

When comparing to State mandates and the clean energy plans of other utilities, City Resolution 9977 represents one of the most ambitious decarbonization targets in the USA. The 2023 IRP identified resource needs, reliability implications, cost, and equity considerations involved in a transition. PWP looks forward to continuing to build upon effective planning in the transition to 100% carbon-free electricity.

3. Introduction

3.1. Introduction

The 2023 PWP IRP is a strategic guidance document, compliance report, and initial action plan for developing and maintaining a diverse portfolio of power supply resources. It is a blueprint for meeting PWP's future peak load and energy requirements in a business environment with significant uncertainties and risks. It also reaffirms the City of Pasadena's (Pasadena or the City) commitment to providing reliable, affordable, and environmentally responsible electricity. The IRP also plans multiple approaches to transition to the City Council policy goal to source 100% of Pasadena's electricity from carbon-free sources by the end of 2030 and to optimize affordability, rate equity, stability, and reliability of electricity while achieving this goal, as passed in January 2023 through Resolution 9977. The IRP is a living document subject to frequent revisions and updates to address the City's evolving priorities, technological developments, regulatory requirements, and market changes.

PWP's last IRP, in 2018, was developed through an extensive community stakeholder process. The final report and plan identified resource planning options that would best balance system reliability, fiscal responsibility, and environmental stewardship. The 2018 IRP recommended carbon-free, long-term resource commitments, elimination of coal-fired generation, and aggressive RPS targets and GHG emission reduction targets that exceed state mandates. The 2023 IRP builds on the clean energy goals of the 2018 and earlier IRPs. The 2023 IRP is designed to be flexible and adaptable as it anticipates significant changes in the electric industry and PWP's customer energy requirements over the next 25 years. Future power supply portfolio optimization and regulatory compliance will require frequent reassessment of PWP's electric load, power supply and demand side options, and energy market changes.

The 2023 IRP was created through a collaborative effort under the guidance of the Mayor of Pasadena, City Council, PWP management and staff, Pasadena residents and businesses, and California laws and regulations.

A reference guide showing the locations of where the CEC guidelines are satisfied is shown in Figure 2.

Figure 2: California Energy Commission Guidelines and Location

CEC Guidelines and Location		
Chapter of CEC Guidelines	**Description of Guideline**	**2023 PWP IRP Report Section**
Chapter 2 A	Planning horizon	Planning Horizon (POUs)
Chapter 2 B	Scenarios and sensitivity analysis	Defining Scenarios; Defining Sensitivities; Scenarios and Sensitivities Results

CEC Guidelines and Location		
Chapter of CEC Guidelines	Description of Guideline	2023 PWP IRP Report Section
	Descriptions	Defining Scenarios; Defining Sensitivities
	Results	Scenarios and Sensitivities Results
Chapter 2 C	Standardized Tables	Filed separately; Appendix - Required Tables
Chapter 2 D	Supporting information	Information relevant to IRP creation is included in this document and its Appendices
Chapter 2 E	Demand forecast	Load Forecast; Requirements; Integrated Energy Policy Report and California Energy Demand Forecast
Chapter 2 E 1	Reporting requirements	Load Forecast
Chapter 2 E 1 2	Demand forecast methodology and assumptions	Load Forecast
Chapter 2 E 1 3	Demand forecast- other regions	Load Forecast
Chapter 2 F	Resource procurement plan	Scenarios and Sensitivities Results; Implementation Steps – Carbon-Free Pathways
Chapter 2 F 1	Diversified procurement portfolio	Scenarios and Sensitivities Results
Chapter 2 F 2	RPS planning requirements	RPS (SB 100); Renewable and Zero-Carbon (SB 1020)
Chapter 2 F 2 a	Forecasted RPS Procurement Targets	In RPT (filed separately)
Chapter 2 F 2 b	Renewable Procurement	In RPT (filed separately)
Chapter 2 F 2 c	RPS Procurement Plan	Appended as separate document
Chapter 2 F 2 d	Recommended Information	Greenhouse Gas Emissions
Chapter 2 F 3	Energy efficiency and demand response resources	Energy Efficiency; Demand Response; Integrated Resource Plan Method; Scenario 6: Emerging Technology Study; Scenario 6: Emerging Technologies Study Scenario
Chapter 2 F 3 a	Recommendations for Energy Efficiency and Demand Response Analysis	Energy Efficiency; Demand Response; Integrated Resource Plan Method; Scenario 6: Emerging Technology Study; Scenario 6: Emerging Technologies Study Scenario
Chapter 2 F 3 b	Calculating and Reporting Energy Efficiency Impacts	In CRAT and EBT (filed separately)
Chapter 2 F 3 c	Calculating and Reporting Demand Response Impacts	In CRAT (filed separately)
Chapter 2 F 4	Energy storage	New Resources; Battery Storage
Chapter 2 F 4 a	Recommendations for Energy Storage Analysis	Battery Storage
Chapter 2 F 5	Transportation electrification	In EBT (filed separately); PWP is investigating options concerning community solar, which would allow customers unable to install a personal

CEC Guidelines and Location		
Chapter of CEC Guidelines	Description of Guideline	2023 PWP IRP Report Section
		system to participate in a solar generation project. In a community solar program, the utility has a solar system and sells a portion of the system generation to customers. A constructive complement to community solar, while delivering similar benefits, is the Green Power Program which supports the purchase of renewable energy. Electric Vehicles; Vehicle Electrification
Chapter 2 F 5 a	Recommendations for Transportation Electrification Analysis	Electric Vehicles; Vehicle Electrification
Chapter 2 F 5 b	Calculating and Reporting Transportation Electrification Impacts	In CRAT and EBT (filed separately)
Chapter 2 G	System and local reliability	Resource Adequacy
Chapter 2 G 1	Reliability criteria	System Resource Adequacy and Reserve Margin; Battery Storage; in CRAT (filed separately);
Chapter 2 G 2	Local reliability area	Local Resource Adequacy Capacity
Chapter 2 G 3	Addressing net demand in peak hours	Battery Storage;
Chapter 2 H	Greenhouse gas emissions	Greenhouse Gas Emissions; in GEAT (filed separately)
Chapter 2 I	Retail rates	Retail Rates
Chapter 2 J	Transmission and distribution system	Transmission and Distribution
Chapter 2 J 1	Bulk transmission system	Bulk Transmission System; Bulk Transmission Planning
Chapter 2 J 2	Distribution system	Distribution System Planning
Chapter 2 K	Localized air pollutants and disadvantaged communities	Localized Pollutants and Disadvantaged Communities
Chapter 2 K 1	Reporting Requirements	Localized Pollutants and Disadvantaged Communities
Chapter 2 K 2	Other Recommended Topics	Localized Pollutants and Disadvantaged Communities

3.2. Pasadena Water and Power Department

PWP, a department of the City of Pasadena, has provided its residents and businesses with reliable, affordable, and environmentally responsible electricity since the early 20th century. As PWP continues this tradition, it must plan for the increasing electricity needs of its customers in a dynamic industry environment, while meeting the priorities of City Council for significant emission reductions and complying with current and proposed federal and state regulations. This ensures that PWP can continue to provide reliable, affordable, and environmentally responsible electricity and energy-related services for its customers.

Currently, PWP delivers about 1.1 million MWh of energy annually to approximately 65,000 retail customers. PWP has a historical peak load of approximately 320 MW. PWP has a portfolio of diverse resources including natural gas, hydroelectric, coal, nuclear, solar, wind, geothermal, and landfill gas. PWP owns natural gas-fired units at the Glenarm, a share of the Magnolia natural gas-fired unit in Burbank through an agreement with SCPPA, and the Azusa Hydroelectric Plant. PWP contracts with other resources to benefit from economies-of-scale and to share risks. PWP also has ownership and contract rights on various transmission lines, which were operationally transferred to the CAISO when PWP became a PTO in 2004.

The City Council, PWP, and the Pasadena community share a strong commitment to environmental responsibility and PWP has a history of meeting its customers' electricity needs with affordable and increasingly environmentally friendly resources. Over the past 10 years, the Pasadena City Council has demonstrated an ongoing commitment to environmental stewardship by adopting internal goals for renewable energy and carbon emission reduction targets that exceed state mandates. The City also adopted a Climate Action Plan and is a leader in promoting energy efficiency. The approval of City Council Resolution 9977 declaring climate change an emergency and establishing a policy goal to source 100% of Pasadena's electricity from carbon-free sources by the end of 2030 continues the City's commitment to move beyond current mandates and remain a leader in protecting the environment for future generations.

PWP currently offers several energy efficiency rebate programs for both residential and commercial customers. The average annual energy savings of PWP's past energy efficiency programs is about 175 GWh per year. PWP also offers rebates for EV chargers and has installed several hundred public charging stations in Pasadena.

PWP has historically prioritized providing reliable electricity to its ratepayers. Two standard measures of reliability – SAIFI and SAIDI, shown in Figure 3 – illustrate how PWP's system reliability compares to that of its neighbors. Over the past 10 years (2013-2022), PWP's SAIFI and SAIDI have remained among some of the best in the region. While reconstituting its electricity resource portfolio in accordance with this IRP, PWP maintains its commitment to this high level of reliability performance.

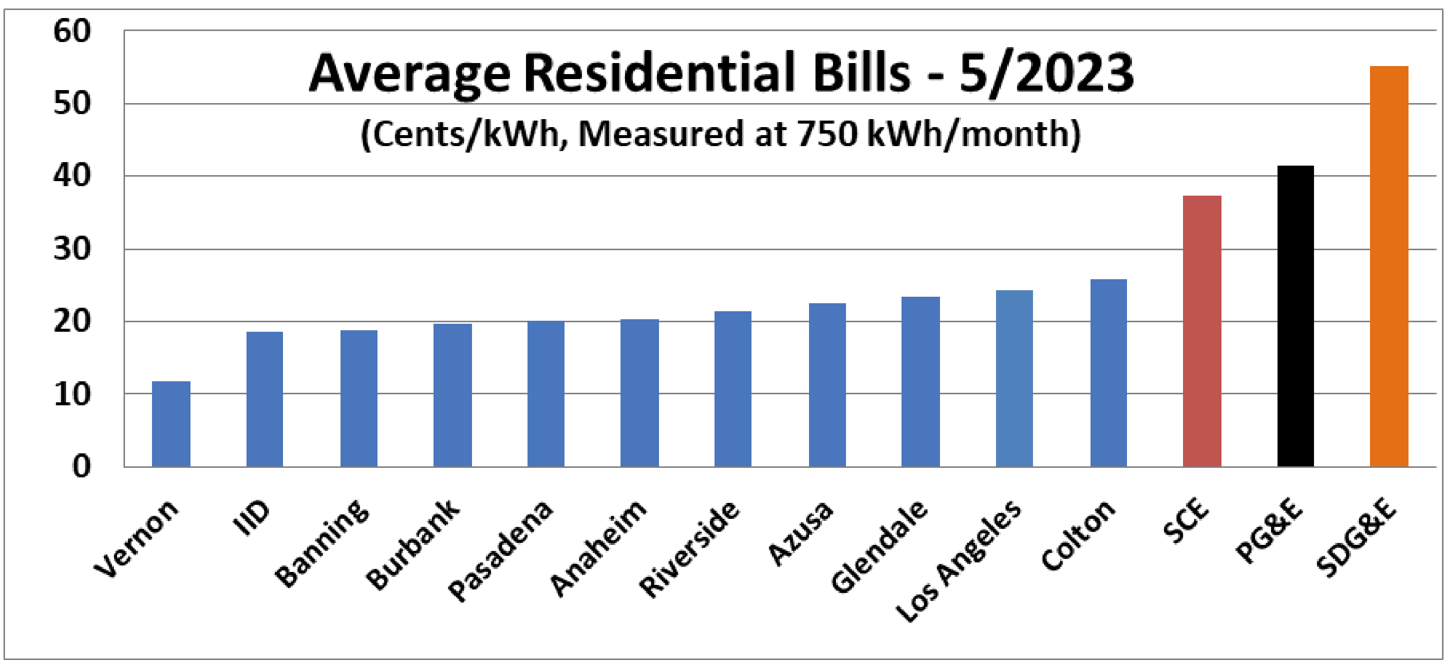
Figure 3: Comparison of System Average Interruption Frequency Index and System Average Interruption Duration Index

SAIFI						
Year	**SCE**	**Pasadena**	**GWP**	**Burbank**	**Anaheim**	**LADWP**
2013	0.85	0.09	0.72	0.19	0.68	0.45
2014	0.84	0.33	0.96	0.24	0.80	0.65
2015	0.83	0.30	0.72	0.17	0.36	0.74
2016	0.95	0.18	1.20	0.39	0.69	0.82
2017	0.84	0.25	1.34	0.52	0.57	0.97
2018	0.71	0.17	1.12	0.33	0.50	0.73
2019	0.85	0.09	1.41	0.32	0.57	0.78
2020	0.85	0.42	1.07	0.38	0.39	0.69
2021	0.96	0.27	0.75	0.31	0.86	0.76

SAIFI						
Year	**SCE**	**Pasadena**	**GWP**	**Burbank**	**Anaheim**	**LADWP**
2022	1.10	0.22	0.86	0.22	0.44	0.74
SAIDI						
Year	SCE	Pasadena	GWP	Burbank	Anaheim	LADWP
2013	92.5	7.4	22.7	16.5	53.0	64.6
2014	91.5	32.6	37.0	10.0	48.5	77.7
2015	98.3	21.4	41.7	4.8	35.0	92.4
2016	106.3	15.4	42.5	19.2	27.1	82,8
2017	90.0	30.6	65.4	12.6	35.0	120.9
2018	70.8	20.0	60.6	11.3	27.4	105.4
2019	89.3	14.3	75.1	4.6	42.1	112.8
2020	89.3	35.9	54.0	8.6	26.4	114.1
2021	102.1	29.5	55.9	16.4	70.9	140.2
2022	131.0	26.0	76.2	4.5	25.5	108.9

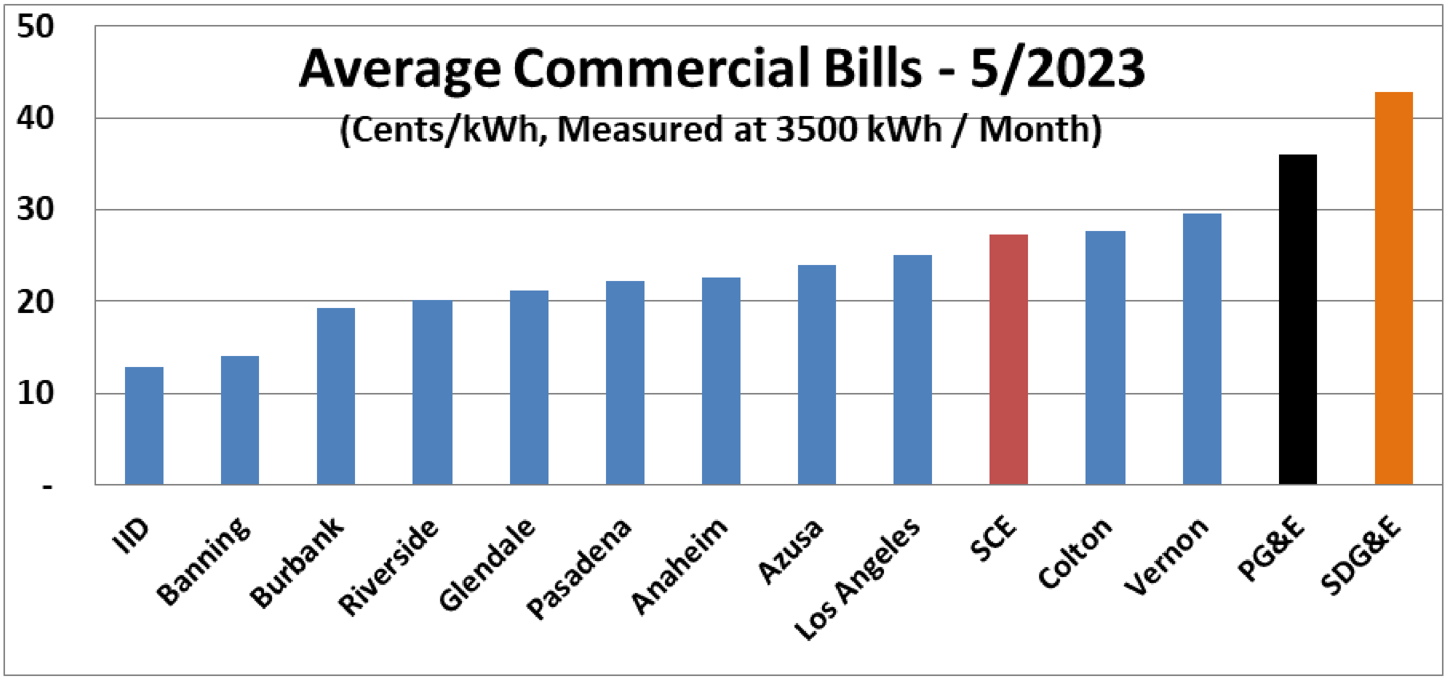
PWP's electric rates are established by the Pasadena City Council after review and input from the MSC. The table in Figure 4 was created by the CMUA and shows average electric rates for residential customers who consume 750 kWh (or 1/1,000 of a MWh) per month. PWP's residential rates are about 45% lower than SCE's rates.

Figure 4: Average Residential Bills, Measured at 750 kWh/Month



PWP commercial rates are also considerably lower than SCE rates.
Figure 5 (also created by CMUA) shows average rates for commercial customers who use 3,500 kWh per month. PWP's commercial customer rate is about 20% lower than SCE for similar customers.

Figure 5: Average Commercial Bills, Measured at 3,500 kWh/Month (May 2023)



PWP offers two optional rate plans to residential and commercial customers: flat seasonal rates and TOU rates. Each customer may choose which plan makes best economic sense for them. PWP also has economic assistance programs for low-income residents and medical device users.

3.2.1. Pasadena Executive Management and Governing Bodies

Pasadena has a Council-Manager form of government that includes seven City Council districts, each with an elected Councilmember serving a four-year term. The Mayor is an elected position that represents the entire City and serves a four-year term. The City Council is responsible for setting policies, passing ordinances, adopting the City budget, appointing committee members, and hiring the City Manager, City Attorney/City Prosecutor, and City Clerk.

As a department of the City of Pasadena, PWP is subject to the authority and oversight of the City Manager, MSC, and City Council. The City Council determines how PWP provides services in the community, including the establishment of priorities, policies, rates, and services.

Development of the 2023 IRP was guided by members of the PWP Executive Management team, including the following:

- General Manager
- Assistant General Manager – Power Supply
- Assistant General Manager – Power Delivery
- Assistant General Manager – Finance and Administration

During the development process for the 2023 IRP, PWP held regular staff meetings to discuss city policy, guiding principles and key IRP components. PWP Executive Management directed and supported staff on all aspects of production.

PWP first presented the 2023 IRP to the MSC for consideration and recommendation. The MSC is a standing committee of four City Council members appointed by Pasadena's Mayor which reviews the City's electric, water, transportation, and sanitation services. Following MSC, the IRP was presented to the City Council for approval and adoption.

3.2.2. Regulatory Agencies

The electricity landscape in California is a complex interaction of many entities. While the Pasadena City Council is PWP's governing body, other state and federal agencies also have regulatory authority.

3.2.2.1. Federal Energy Regulatory Commission

FERC is an independent agency within the U.S. DOE that regulates the interstate transmission of electricity, natural gas, and oil, and approves licenses for hydroelectric projects. FERC oversees related environmental matters. In addition, FERC administers financial reporting regulations and conduct of jurisdictional entities.

3.2.2.2. North American Electric Reliability Council

NERC is a not-for-profit international regulatory authority whose mission is to ensure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces reliability standards, and annually assesses seasonal and long-term reliability. Additionally, NERC monitors the bulk power system, and educates, trains, and certifies industry personnel.

3.2.2.3. California Independent System Operator

CAISO is a non-profit public benefit corporation that manages the flow of electricity across the high-voltage, long-distance power lines that make up 80% of California's power grid. CAISO provides open and non-discriminatory access to the transmission grid and supports a competitive energy market for aggregated resources of one MW or greater.

3.2.2.4. California Energy Commission

The CEC is a state energy policy and planning agency, charged with ensuring a reliable and affordable energy supply. The CEC has the following five major responsibilities:

- Forecasting future energy needs and maintaining historical energy data
- Siting and licensing power plants
- Promoting energy efficiency through appliance and building standards
- Developing energy technologies and supporting renewable energy
- Planning for and directing state response to energy emergencies

3.2.2.5. California Public Utilities Commission

The CPUC regulates privately-owned companies that supply telecommunications, electricity, natural gas, water, railroad, rail transit, and passenger transportation. The CPUC is responsible for ensuring that California utility customers have safe and reliable utility services at reasonable rates and are protected from fraud. PWP is not subject to CPUC oversight.

3.2.2.6. California Air Resources Board

CARB's mission is to promote and protect public health, welfare, and ecological resources through the effective and efficient reduction of air pollutants, while recognizing and considering the effects on the state economy. CARB is responsible for, among other things, administering California's GHG Cap-and-Trade Program.

3.3. Statutory Mandate for Integrated Resource Plans

The CEC creates guidelines for IRP creation and submission for POUs and the CEC's review of those IRPs. PWP files its 2023 IRP under the Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines - Revised Second Edition, from 2018.[1] As of January 2023, there were proposed guidelines titled Draft Commission Guidelines - Publicly Owned Utility Integrated Resource Plan Submission and Review, dated August 2022.[2] Given that the current guidelines are from 2018 and that PWP began its process prior to rule modification, PWP complied with these rules.

According to the CEC, "IRPs are electricity system planning documents that describe how utilities plan to meet their energy and capacity resource needs, policy goals, physical and operational constraints, and other utility priorities (such as reducing rate impacts on customers' bills)."[3] In other words, IRPs are compliance and strategy documents that evaluate a range of risks and opportunities to help a utility plan its next steps. Under PUC Section 9622, the CEC can adopt guidelines to govern the submission of IRP data so it can review the IRP's consistency with the requirements of PUC Section 9621.The requirements from the CEC ensure that IRP analysis is robust and complies with state regulations and directives.

PWP is required to file an IRP with the CEC every five years. PWP's 2023 IRP adoption is due by year end, 2023. PWP needs to file at minimum one scenario, or "a set of assumptions about future conditions used in power system modeling performed to support generation or transmission planning", with the CEC in a document that also lists assumptions, key considerations, and outputs. The IRP filing should include any additional material that supports the CEC's review. Results must be filed in four standard tables in Microsoft Excel templates.

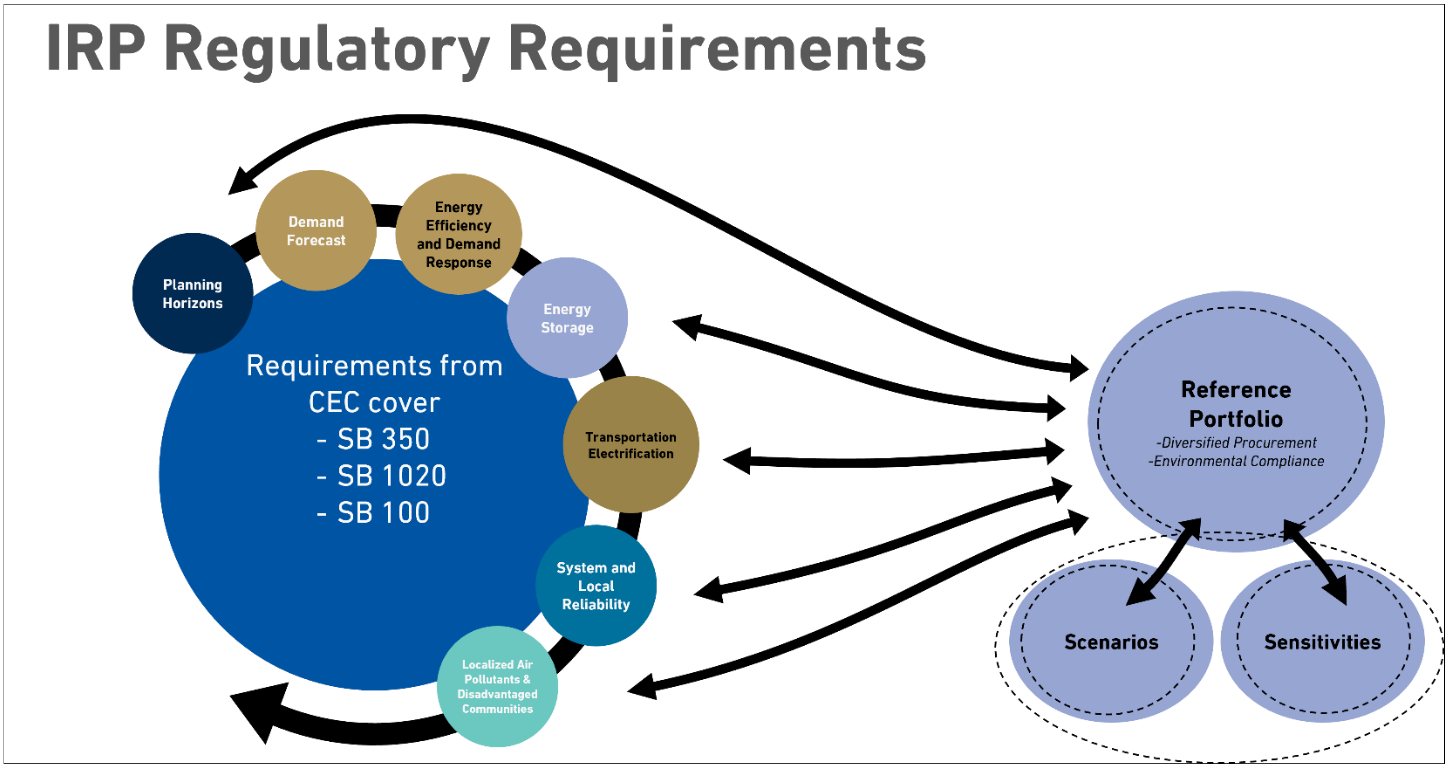
PWP considered multiple scenarios, which are included in this IRP for stakeholder consideration. Requirements from the CEC are shown in Figure 6.

Figure 6: California Energy Commission Requirements

[1] https://efiling.energy.ca.gov/GetDocument.aspx?tn=224889&DocumentContentId=55481

[2] https://www.energy.ca.gov/publications/2022/publicly-owned-utility-integrated-resource-plan-submission-and-review-guidelines

[3] https://efiling.energy.ca.gov/GetDocument.aspx?tn=224889&DocumentContentId=55481



3.4. Community Outreach

PWP is a not-for-profit organization owned and operated by the City of Pasadena, with priorities that include reliability, customer responsiveness, competitive rates, and environmental stewardship. Ongoing engagement with residents, businesses, and civic partners is instrumental to understanding evolving community needs and PWP conducts regular outreach to gauge public opinion on customer satisfaction and expectations.

Stakeholder and community involvement is also fundamental to IRP development; therefore, PWP has implemented an outreach strategy using a multi-media marketing campaign. Communication mediums for the 2023 IRP included website postings, social media, bill inserts, print advertising, digital advertising, City-direct mail newsletters, PWP electronic newsletters, informational videos, press releases, and flyers. PWP also worked closely with the City Manager and the MSC to develop STAG, a diverse cross-section of the Pasadena community that provided input into the 2023 IRP development.

PWP hosted 10 STAG meetings to refine the 2023 IRP analysis, develop energy scenarios and addressed interim comments and questions. PWP also held three Power IRP Community Meetings to ensure that community priorities were also represented in the process. PWP has an extensive history of partnering with the community and appreciates the participation and support of local citizens and businesses in the development of Pasadena's energy resource plan.

3.5. Integrated Resource Plan Objectives

The 2023 IRP sought to optimize PWP's resource mix to achieve a sustainable balance of system reliability, fiscal responsibility, environmental stewardship, and compliance with Council Resolution 9977, SB 350, SB 100, and other applicable legislation and regulatory mandates. Metrics and checklists for these objectives were developed and implemented in this IRP. The following are the components of each objective:

- System Reliability

- Maintain a resource adequacy reserve margin of at least 15%
- Maintain CAISO RA requirements in compliance with the CAISO tariff (including System RA, Local RA, and Flexible RA requirements)
- Preserve, optimize, and enhance local generation to reduce risk of over-reliance on a single transmission tie at the T.M. Goodrich Receiving Station (Goodrich) substation and integrate variable generation, demand-side management and distributed generation

- Fiscal Responsibility
  - Maintain stable, competitive, and affordable rates
  - Minimize the impact of market and price volatility in cost factors like fuel and resource procurement
  - Minimize generation-related direct costs, including GHG compliance costs
  - Provide transparency in expected power-related rates for the average ratepayer

- Environmental Stewardship
  - Plan multiple approaches to transition to sourcing 100% carbon-free electricity supply by the end of 2030 as a policy goal of Resolution 9977
  - Minimize the environmental impact of meeting Pasadena's electric energy needs
  - Comply with all federal, state, and local laws and regulations
  - Meet or exceed required standards for renewables (RPS percentage) as defined by state laws (SB 100)

PWP identified the following four categories for scenario evaluation:

1. Cost
2. Stability
3. Reliability
4. Environment

PWP worked on the IRP from January 2023 through December 2023. Overall, PWP focused on the following two key action items:

1. File an IRP with the CEC to meet state regulatory requirements and guidelines, as mandated by the statute every five years
2. Plan multiple approaches to meet the City's policy goal of sourcing 100% of Pasadena's electricity from carbon-free sources by the end of 2030, optimizing for affordability, rate equity, stability, and reliability

While PWP files this IRP by the end of 2023 to remain in compliance with state regulations, PWP anticipates continuously working on its plans to decarbonize its system.

3.6. Integrated Resource Plan Process and Timeline

SB 350 (De León, 2015) requires that POUs with load greater than 700 GWh, such as PWP, develop an IRP by January 1, 2019, and provide updates every five years thereafter. Compliance is regulated by the CEC.

To assist with the development and preparation of the 2023 IRP, PWP issued a combined RFP in April 2022 for modeling and consulting services. Proposers were given the option of responding to either or both scopes of work. Of the six firms that responded, three offered proposals for both scopes of work. Proposals for each scope of work were separately scored based on criteria described in the RFP. ACES received the highest evaluated score for each of the individual scopes of work, based on a combination of relevant experience, quality of technical proposal, and price proposal.[4]

To ensure transparency in the IRP study results, PWP also contracted with Environmental and Energy Economics Inc. (E3) to review the IRP analysis. A recognized leader in clean energy policy implementation, E3 provides technical, policy, and market analysis, and has worked with clients that include CEC, CPUC, CARB, and a variety of public and private utilities throughout the nation and the world. E3 has also explored higher RPS standards for SMUD, experience that was especially valuable for PWP's project considering the goals of Resolution 9977. A summary of involved consultants and their roles is in the Appendix – Integrated Resource Plan Contract and Resource Roles.

PWP's IRP process evaluates how PWP can serve its customers given uncertainty. PWP must consider different topics, such as electricity market price forecasting; resource and contract valuation; power flow modeling, including transmission constraints; modeling regulatory mandates, including RPS and GHG emissions requirements; among others.

The 2023 IRP process starts with developing and collecting assumptions and baseline data for existing resources and load trends. The next step refines the analysis and develops energy portfolio plans through robust stakeholder input and community engagement to best represent Pasadena's diverse community and ratepayer interests. The process concludes with providing technical analysis and informing policy makers to aid them in determining the best path forward to meeting electricity demands and City objectives over the next 25 years.

3.7. 2023 Integrated Resource Plan Timeline

PWP began the 2023 IRP process in January 2023. Inputs for generation, modeling, analysis, stakeholder engagement, and result documentation continued through October. Approval and filing began in the fall of 2023. The 2023 IRP process, by regulatory requirement, was completed in December. See Figure 7.

Figure 7: PWP's 2023 Integrated Resource Plan Timeline

Category	Action Item	Timeline
Input	Assumption creation	January through May 2023
Input	Inputs Finalized	June 2023
Output	Modeling	July 2023
Output	Report Drafted	August 2023
Output	Report Finalized by PWP	October 2023
Output	IRP Approved by City Council	December 11, 2023
Output	IRP Submitted to CEC	December 31, 2023

[4] https://ww2.cityofpasadena.net/2022%20Agendas/Sep_19_22/Agenda.asp

4. Previous Integrated Resource Plans

Integrated resource planning is a continuous process that requires regular updates and adjustments to address changes in electricity needs, regulations, and the business environment. The 2023 IRP is the latest rendition of PWP's resource planning effort and the 2023 results build upon previous IRP goals, where applicable, while meeting or exceeding the requirements of SB 350, SB 100, and other regulations.

The most recent plans are the 2018 IRP and the 2021 update to the 2018 plan. These can be accessed on PWP's website.[5] Previous IRPs (prior to 2018) are also available at PWP's website.[6]

Figure 8 summarizes progress toward PWP's 2018 IRP goals.

Figure 8: 2018 Integrated Resource Plan Progress

Recommendation	IRP Goal	Status
Increase in Renewable and Zero-Carbon Resources in Portfolio	Ensure all new long-term energy supply contracts are renewable and/or zero-carbon emitting resources	No new long-term fossil-fuel contracts have been added since this policy was adopted in 2018
Reduce fossil fuels in the portfolio	Exit the IPP no later than 2027	The IPP contract terminates effective 6/15/2027; PWP will not participate in the IPP Renewal Project (natural gas and hydrogen blend)
Reduce GHG emissions (specifically carbon) relative to PWP's 1990 level (approximately 198,600 metric tons)	Achieve GHG emissions reduction of at least 75% below PWP's 1990 level by 2030 (reduce to approximately 226,000 metric tons)	Current estimate* is 68% below 1990 levels for 2022, and more than 90%** below by 2030
RPS	Achieve at least 60% RPS by 2030 per requirements of SB 100	Estimated* at 41.25% RPS for 2022 and on track to meet the 2030 state mandate of 60%**

**Current estimate to be updated in the 2022 power content label.*
***Resolution 9977 looks for 100% carbon-free by 2030.*

In the 2021 IRP Update to the 2018 plan, PWP re-evaluated its portfolio to address changes to RA standards. Such changes affect ELCC, which quantifies a resource's ability to contribute to grid reliability. The 2021 IRP Update also more closely examined the need and potential for energy storage as a power supply resource. Based on these considerations, PWP revised the 2018 IRP implementation plan in terms of resource type, size, and timing. Figure 9 summarizes PWP's progress toward the 2021 IRP Update recommendations.

Figure 9: 2021 Integrated Resource Plan Update Progress

[5] https://pwp.cityofpasadena.net/powerirp/.
[6] https://pwp.cityofpasadena.net/powerirparchive/

Recommendation	IRP Goal	Status
Resource Procurement	Procure at least 70 MW of accredited capacity by 2025 for RA	Executed a 15-year 25 MW geothermal and 20-year solar plus battery energy storage system contracts starting in 2027
Energy Storage Study	Investigate storage options to meet 50 MW of installed battery energy storage by 2025	Issued an RFP for construction of a 25 MW utility-owned system at the Glenarm
RPS	Continue efforts to achieve 60% RPS by 2030 and net-zero carbon by 2045	The 2023 IRP optimizes to comply with RPS regulations and seeks to exceed requirements based on City Resolution 9977
Fuel Substitution Study	Examine alternative fuel sources, such as biogas or green hydrogen gas, for the Glenarm local generating stations	Biogas and green hydrogen were considered in the 2023 IRP (See Section 9.4)
EV Study	Refine forecasted growth of EV charging in Pasadena	The 2023 IRP includes the impact of current and expected market penetration rates in the updated Load Forecast

5. Existing Policies and Programs

PWP has developed multiple customer programs to encourage renewable energy generation, increase energy efficiency, provide low-income assistance, and facilitate electrification. The programs are a result of the community's values and the City Council's vision for demonstrating leadership in environmental stewardship and responsible planning.

5.1. Distributed Solar

5.1.1. Current Programs

Pasadena has customer-installed PV solar electric generation, which is primarily rooftop solar. The PSI incentivizes customer PV generation through NEM rates.

5.1.2. Net Energy Metering

NEM is a rate and billing structure that allows customers with qualifying PV systems to receive credit for excess generation. California's first NEM program, referred to as NEM 1.0, was implemented in 1996. This initial program required California electric utilities, including POUs, to provide customers with PV systems at the full retail value of excess generation. A net of total annual PV generation and customer usage resulted in either over-generation or utility-supplied energy and was credited or billed accordingly on an annual basis. The NEM 1.0 program was designed to stimulate the market for renewable energy and help diversify the resource mix in California.

The California NEM program requirement for IOUs was replaced in 2017 with NEM 2.0 and again in April 2023 with NEM 3.0. Both program revisions were intended to address cost inequities. The full retail rate for electricity includes more than just the cost for energy – it includes the costs of capacity, fees, wires, and more. For paying customers the full retail rate is, in effect, a subsidy.

NEM 2.0, also known as the Successor Tariff, was implemented by the CPUC in 2017 to replace NEM 1.0 and applies to IOUs. Primary features include a mandatory one-time interconnection fee, TOU rate requirements, and bypass charges, such as a grid access fee. The program changes were designed to reduce the system cost impacts of large amounts of PV generation on non-PV customers.

In 2023, California implemented NEM 3.0, also known as the NBT. The new tariff was created to further help reduce service inequities between customers with and without distributed generation, and to promote grid reliability, incentivize solar and battery storage, and improve equitable customer electricity costs. According to the CPUC, which regulates IOUs, NEM 3.0 has no impact on existing rooftop solar customers who continue to retain current compensation rates. While POUs are not under CPUC jurisdiction, the topic of rate equity and evolution of rates plays an important role in PWP's future NEM policies.

The goal of the CPUC NEM 3.0 tariff is to promote rate equity by revising rates paid to new solar customers according to the value of the excess energy at the time it is sent to the grid. Typically, when solar is producing midday and there is surplus energy on the grid, the value of solar generation is low. When the distributed solar is not producing (e.g., at night), the value of generation is much higher. This value difference has the effect of incentivizing batteries that can store excess solar energy during the day, then discharge that energy at night when it has more value to the utility. NEM 3.0 was designed to promote this incentive.

Potential revisions to PWP's NEM program to update compensation credits should also include a review of other options and program additions such as virtual or aggregated NEM. Both options allow shared PV systems within customer groups.

All California electric utilities were required to provide NEM 1.0 programs until each met 5% of its total peak demand by solar installations. Once achieved, utilities could transition to a replacement program. At this time, PWP still provides benefits to its customers under the NEM 1.0 construct, but has met the 5% installation cap (specifically, 14.8 MW based on a peak load of 296 MW). With 21 MW of distributed solar (7% of peak demand) in its service territory as of 2022, PWP now has the option of remaining at NEM 1.0 or transitioning to a successor tariff that could include some or all of the provisions of NEM 2.0 or 3.0.

PWP's current NEM program (NEM 1.0) offers three billing options to customers with PV systems: annual billing, monthly billing and bi-monthly. Under the annual option, the customer is billed once a year for electric service. If more electricity is generated than used, the customer may elect to receive compensation for the excess PV generation energy or a credit against future billings.

Under the monthly or bi-monthly option, PWP calculates energy produced on a monthly or bi-monthly basis. A customer that produces more energy than consumed during the billing period is credited for the excess at the energy services charge rate plus $0.025/kWh for the associated RECs. Additionally, because it is less costly to administer, PWP incentivizes the monthly/bi-monthly option with a bonus of an additional $0.066/ kWh.

5.1.2.1. Customer-Generated RECs

PWP does not currently have a mechanism to track customer-generated RECs and, therefore, does not consider residential or commercial generated RECs for RPS compliance purposes. However, it is expected that AMI will be implemented within the next five years, at which point PWP could use the RECs to help meet RPS requirements. Further investigation into compliance with regulation is in progress.

5.1.3. Community Solar

PWP is investigating options concerning community solar, which would allow customers unable to install a personal system to participate in a solar generation project. In a community solar program, the utility has a solar system and sells a portion of the system generation to customers. A constructive complement to community solar, while delivering similar benefits, is the Green Power Program which supports the purchase of renewable energy.

5.2. Electric Vehicles

Transportation accounts for more than 50% of California's GHG emissions and almost 80% of its nitrogen oxide pollutants.[7] Understanding that transportation electrification helps reduce emissions, California recently set a mandate requiring 100% of new car and passenger truck sales in the state to be ZEVs by 2035.

CPUC Section 9621 requires IRPs to discuss how utility rate design and incentives support transportation electrification.[8] Since these efforts have positive community benefits, such as reduced local air pollution, PWP looks to align its transportation electrification programs with state initiatives, laws, and regulations, as well as community priorities. PWP endeavors to study the impact of potential programs on low-income and disadvantaged communities to reduce PWP's system and individual driver costs.

5.2.1. Current Electric Vehicle Incentives

PWP offers the following three EV-related incentives:

- The Commercial EV Charger Rebate Program provides a $3,000 rebate for installed, smart level 2 (240 V) chargers. For Direct Current ("DC") fast chargers, the rebate ranges up to $6,000 per charger, if installing DC fast chargers accessible to students and patrons of accredited schools, as part of income-qualified housing, or in a disadvantaged community. Total incentives are limited to $75,000 per commercial electric customer. For non-network charging stations (not internet-connected), PWP offers a $1,500 rebate per station, up to $15,000 per site/account/customer.[9]
- The Residential EV Rebate Program provides eligible customers rebates of $250 each for the purchase or lease of up to two plug-in EVs per address every three years.[10] Customers can also receive an additional $250 bonus rebate (up to $500) for purchasing or leasing from a Pasadena auto dealer. Customers enrolled in PWP's income-qualified Bill Payment Assistance program are eligible for an additional $1,000 rebate. A customer meeting all requirements could receive a total benefit of up to $1,500 per EV.
- The Residential EV Charging Rebate offers customers $600 for installing a Wi-Fi-enabled EV charger, or $200 for a standard (non-Wi-Fi/non-internet connected) charger.

As of August 2023, PWP has expended almost $2,320,000 on EV incentives.

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[7] https://www.energy.ca.gov/about/core-responsibility-fact-sheets/transforming-transportation
[8] https://openstates.org/ca/bills/20212022/SB437/
[9] https://pwp.cityofpasadena.net/commercialchargerrebate/
[10] https://ww5.cityofpasadena.net/water-and-power/ev/

5.2.2. Current Electric Vehicle Outreach

PWP's website includes a robust menu of EV-related educational material for consumers, including a description of EV features, air quality benefits, home charging tips, potential savings, and tips to enhance the driver experience.[11] Also included are links to additional resources that provide information for potential EV buyers, including a cost comparison calculation for EVs and gasoline-fueled vehicles created by the University of California, Davis, and information about available rebates.[12] In addition to online EV promotion, PWP provides ongoing outreach through various mediums, such as print and digital advertisements, newsletters, press releases, billboards, bus shelter adverting, public service announcements, flyers, events, bill inserts, on-hold messages, and social media.

5.2.3. Current Electric Vehicle Fleet

As of 2022, the City of Pasadena had 9,254 light-duty ZEVs, 98% of which were BEVs or PHEVs registered by citizens. The remainder use hydrogen. Light-duty ZEVs represent about 6.8% of cars on Pasadena roads. In addition, 2,572 new light-duty EVs were sold in 2022, representing 18.8% of the light-duty vehicles sold locally. Overall, EV adoption is steadily increasing, which experts predict will continue across the industry.

Figure 10 and Figure 11 show the composition of the zero-emission vehicles by type by year and the composition of annual sales.

[11] https://pwp.cityofpasadena.net/electrification/; https://pwp.cityofpasadena.net/ev/

[12] https://gis.its.ucdavis.edu/evexplorer/#!/locations/start

Figure 10: Total Light-Duty Electric Vehicles on Grid

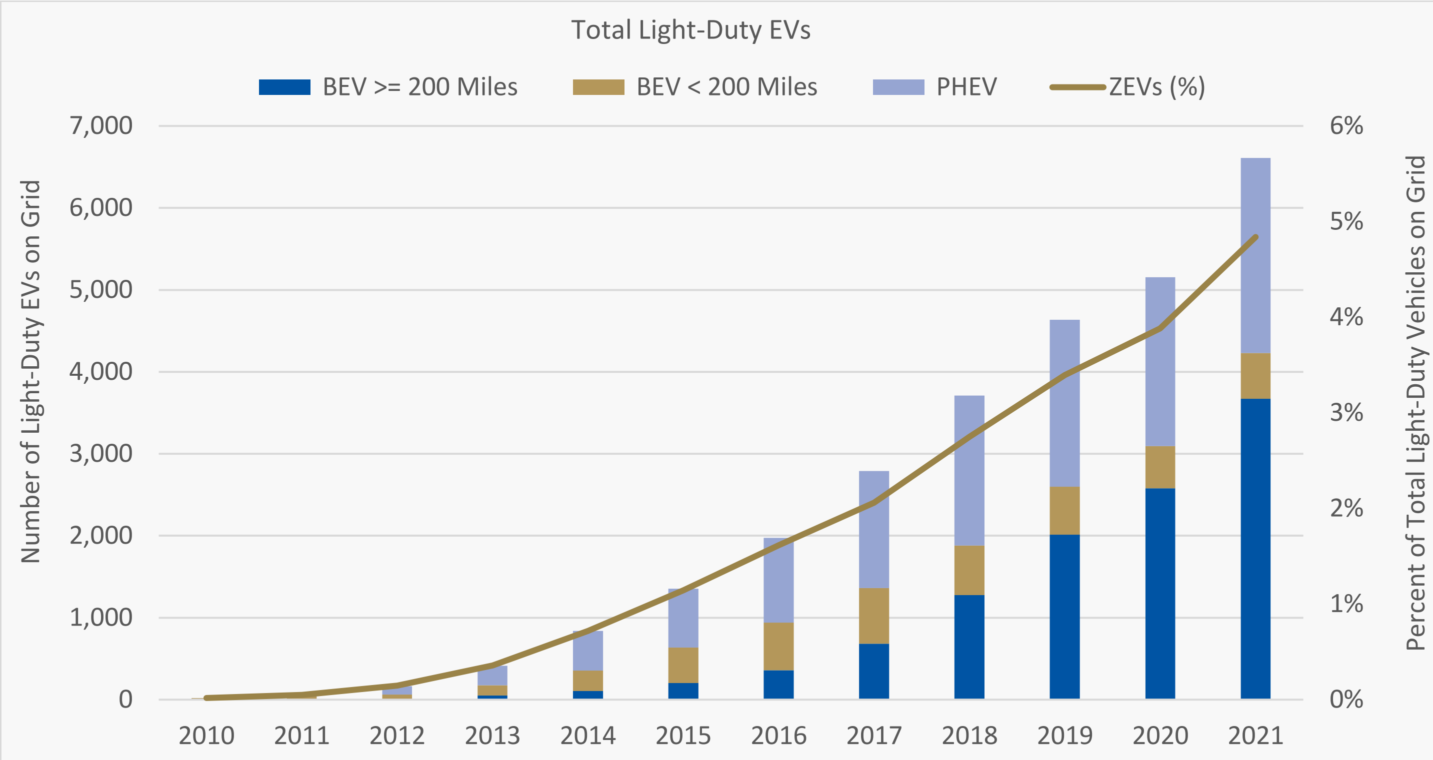
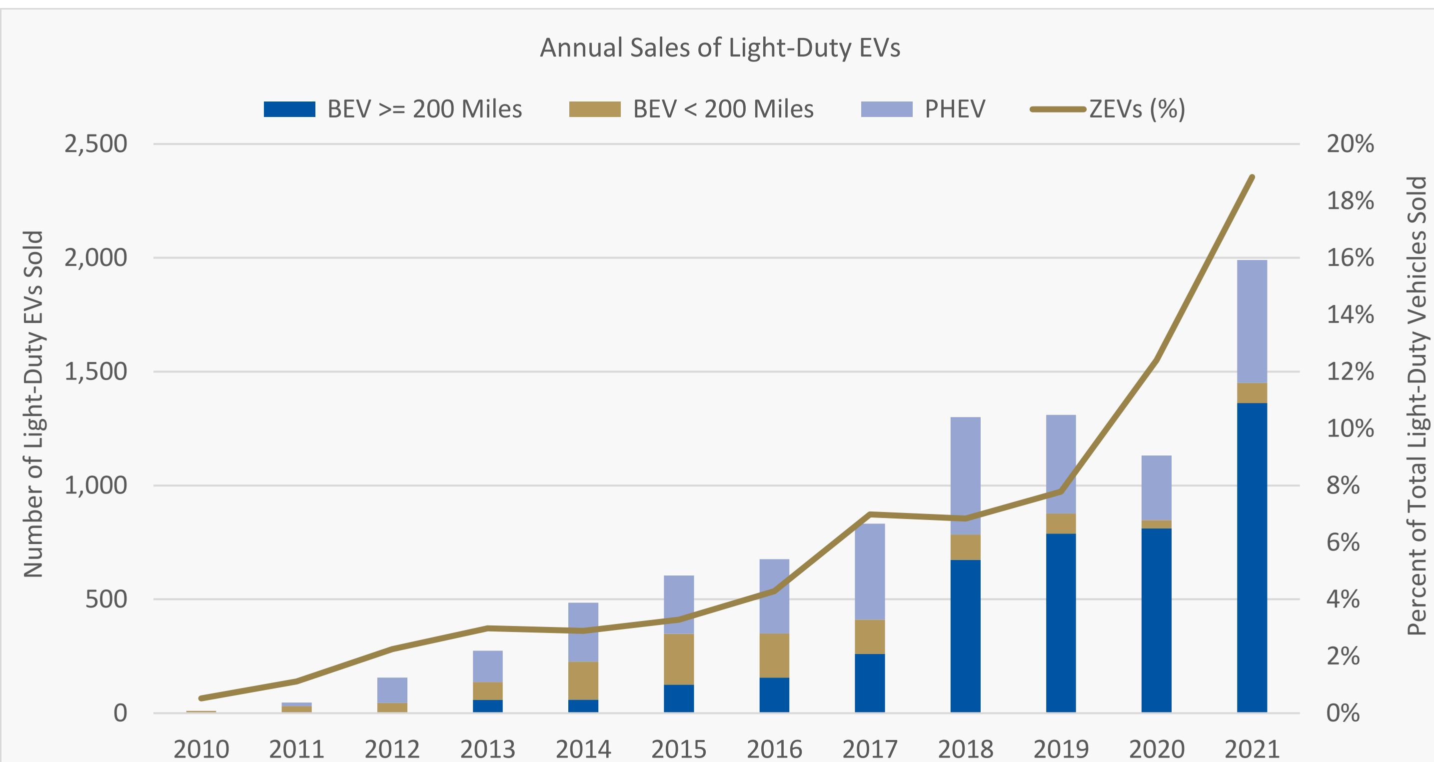


Figure 11: Annual Sales of Light-Duty Electric Vehicles



Medium- and heavy-duty vehicles, by definition[13], weigh more than 10,000 pounds and include vans, buses, and trucks. By spring 2022, there were more than 1,900 medium- and heavy-duty ZEVs on the road in California, 70% of which were buses.[14] In 2023, the City arranged to purchase one electric bus in 2024 that will provide an opportunity to learn more about the benefits and challenges to owning and operating electric busses. As part of its Fleet Replacement Program, the City's DOT is planning a complete conversion to ZEV buses for local services, such as Pasadena Dial-A-Ride and Pasadena Transit by 2033 and 2040, respectively.[15]

5.2.4. EV Charging Stations

In addition to incentives for customer-owned charging stations, Pasadena is committed to developing publicly owned EV charging infrastructure throughout the City. [16] Below is a list of charger types, by level.

- Level 1 Charger
  - A 120-volt (standard house outlet) charger using trickle charging, providing roughly three to five miles of range for every hour charged. A Level 1 charger is typically included in every EV purchase.
- Level 2 Charger
  - A 240-volt charger (using a typical house outlet for dryers, ovens, or heating, ventilation, and cooling). These chargers can charge anywhere from 5.5 miles of range to 60 miles of range per hour of charging, depending on the specific car make and model.
- DC Fast Charger (Level 3 Charger)
  - A DC fast charger differs from the other two levels as it does not need to convert the electricity from AC to DC. Since the battery charges directly from a DC outlet, this results in the fastest charging speed of any chargers on the market today, an estimated 10 miles of range per minute charged. Currently, the only DC charging stations available are those installed by utilities and equipped to convert the distribution grid AC electricity into DC.

The City owns 234 charging stations, of which 203 are Level 2 and 31 are DC Fast Chargers. A map of current and planned charging stations is shown in Figure 12. PWP's website also provides details on where chargers are located.[17]

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[13] Medium and Heavy-Duty Vehicles (ca.gov)

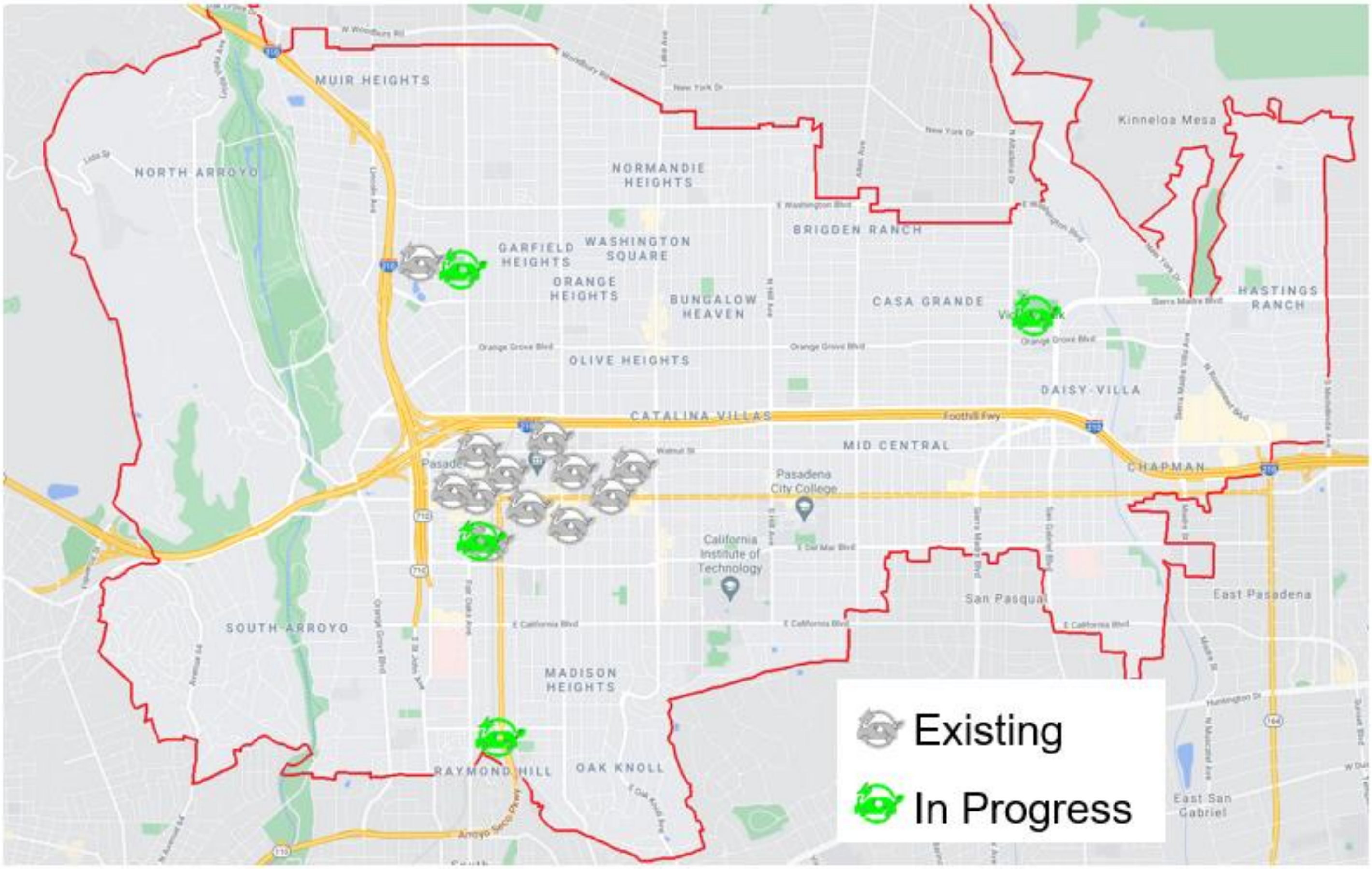
[14] https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics/medium-and-heavy

[15] https://ww2.cityofpasadena.net/2023%20Agendas/Jan_30_23/AR%204%20Attachment%20A_Pasadena%20ICT%20Report_Finalrev.pdf

[16] https://ww5.cityofpasadena.net/water-and-power/ev/

[17] https://pwp.cityofpasadena.net/ev/

Figure 12: Map of Electric Vehicle Chargers in PWP's Territory



5.2.5. Pasadena's Department of Transportation Initiatives

Pasadena's DOT is working to expand its bus fleet to include more ZEVs, such as hydrogen fuel cell or plug-in battery buses. DOT plans to convert its entire fleet to zero-emission by 2040, although additional funding opportunities may accelerate the timeline. Converting the DOT bus fleet to zero-emission will have a large impact on PWP's future load and infrastructure and the departments should collaborate planning to meet this need.[18]

5.2.6. Vehicle-to-Grid Charging

In addition to receiving energy through charging, an EV could deliver energy stored in its battery back to the grid. This is called V2G charging, a form of distributed energy storage that could potentially serve as a resource to a utility. This would require the following:

- Sensors and communication infrastructure to alert the utility when the EV is connected to a charger, as well as the vehicle's state of charge (i.e., how full its battery is)
- Separate metering on the charger

[18] https://ww2.cityofpasadena.net/2023%20Agendas/Jan_30_23/AR%204%20Attachment%20A_Pasadena%20ICT%20Report_Finalrev.pdf

- Minor internal modifications to the EV and charger to allow bidirectional energy flow
- Remote V2G control from the utility to EV via the charger
- An agreement between the utility and EV owner detailing the conditions for the battery energy use, compensation rate, payment method, etc.

PWP could use V2G as a potential distributed energy storage option in Pasadena, possibly beginning with electric transit and school buses, due to the relatively large concentration of battery storage in one location and under a single owner. These conditions would enable PWP to better predict when the vehicles would be connected to chargers and leverage economies of scale when installing associated infrastructure.

5.3. Energy Efficiency

5.3.1. Current Program Incentives

PWP customers pay a PBC, a state-mandated charge that is included on all electric service bills. This charge is currently set at $0.00685/kWh.[19] On average, PWP collects approximately $6.9 million annually through the PBC, which California requires to be allocated to a separate fund and used for the following specific purposes:

- Energy efficiency/demand response programs
- Renewable resources
- Research, development, and demonstration projects
- Low-income rate assistance
- Beneficial electrification, according to the City's Resolution 9977

PBC funds support the commercial and residential programs outlined in the following sections, as well as the three EV programs discussed in Current Electric Vehicle Incentives.

5.3.1.1. Commercial Programs

- The BRP provides rebates for energy efficient equipment installations, including LED lighting, certain commercial restaurant equipment, motor controls, commercial appliances, and HVAC systems.[20] The program is limited to $24,000 per account, with a cap of 25% of total project cost. For each device installed, PWP can claim a predetermined amount of energy efficiency savings.
- The CIP provides savings for customized and/or complicated efficiency projects and covers technology not listed in the BRP.[21] Limited to $50,000 per account, with a cap of 25% of total project cost, customers are provided a $0.05/kWh rebate on energy savings that are higher than California Green Building Standards Code – Part 11, Title

[19] https://ww5.cityofpasadena.net/water-and-power/rates/
[20] https://ww5.cityofpasadena.net/water-and-power/businessrebateprogram/
[21] https://pwp.cityofpasadena.net/customizedincentiveprogram/

24, California Code of Regulations (CalGreen) codes for lighting, non-lighting, and other new construction projects. For fuel switching projects, there is an additional incentive of \$0.15/pound of CO_2 reduction.

- WeDIP applies to small- to medium-sized commercial customers using 50 kW or less.[22] Eligible customers can receive up to \$7,500 of water and energy savings equipment installed at no cost.

5.3.2. Residential Programs

PWP has the following residential programs:

- The Home Energy Rebate Program provides numerous rebates for equipment such as ENERGY STAR-rated refrigerators, dishwashers, ceiling fans, and room air conditioners.
- The HIP is a direct installation program that provides up to \$4,000 in water and energy savings equipment. The program also includes a no-cost, expert water and energy use evaluation and potential installation of devices such as LED light bulbs, advanced power strips, attic insulation, or tune-up of central AC.[23]
- HERs provide customers with a monthly snapshot of personal energy use as it compares to comparable homes in the area. Recipients also receive tips for lower energy usage.[24]
- ESAP is a collaboration with SoCalGas and provides direct installation services for low-income consumers.
- The Residential Electric Panel Upgrade Program provides a rebate for an upgrade to a 200-amp electric panel.[25] This program is intended to assist customers requiring a panel upgrade to support a home EV charger.
- PWP plans to re-launch the Refrigerator Recycling and Exchange Program, which will apply to income-qualified customers only, and will provide a free new replacement refrigerator in exchange for a working refrigerator.

With help from the energy efficiency programs, PWP customers saved approximately 174 GWh per year from FY 2011 through FY 2020. [26] This represents a load reduction of approximately 17.2%. See Figure 13.

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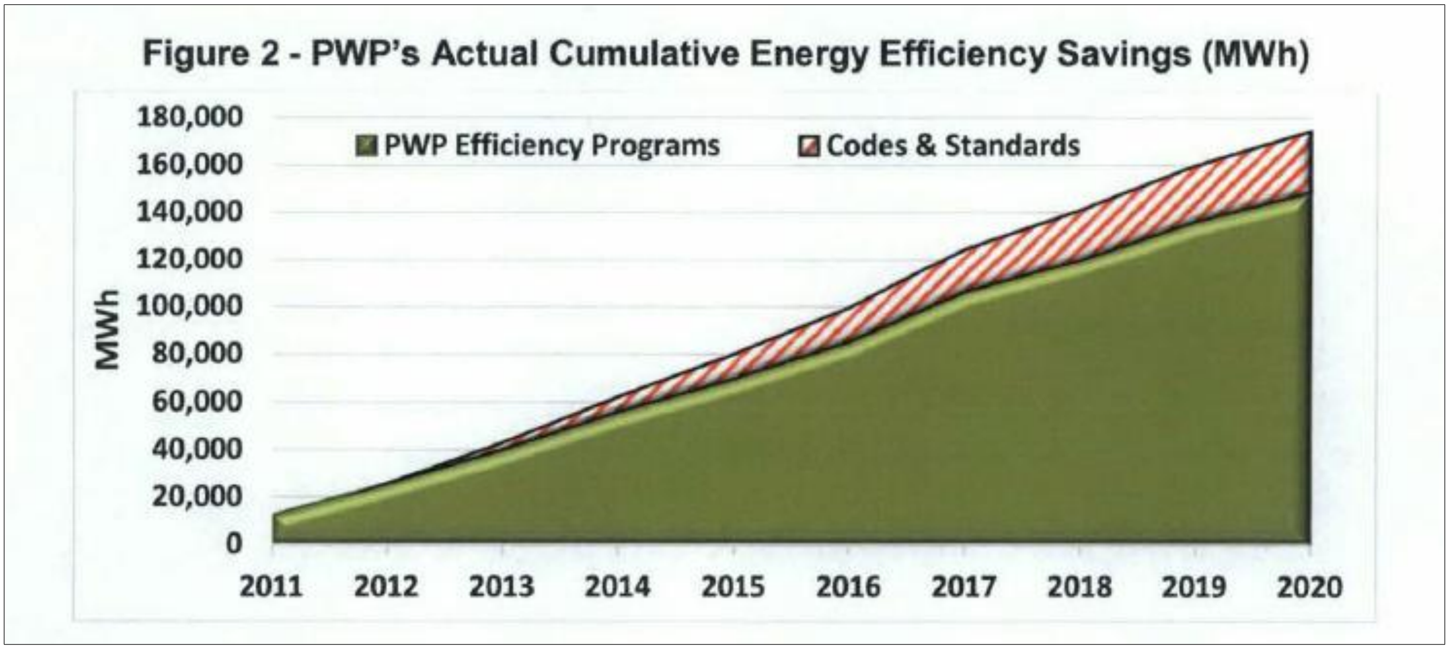
[22] https://ww5.cityofpasadena.net/water-and-power/wedip/
[23] https://ww5.cityofpasadena.net/water-and-power/homeimprovement/
[24] https://ww5.cityofpasadena.net/water-and-power/homereports/
[25] https://pwp.cityofpasadena.net/electricpanelrebate/
[26] May 17, 2021 Agenda Report with the subject “Adopt Ten-Year Energy Efficiency and Demand Reduction Goals for Fiscal Years 2022 through 2031”

Figure 13: PWP's Actual Cumulative Energy Efficiency Savings



5.3.3. Energy Efficiency Regulations

SB 1037 (2005) requires POUs to acquire cost-effective, reliable, and feasible energy efficiency and demand response resources before acquiring other resources.[27] The law also requires annual reporting of savings, expenditures, and cumulative processes to the CEC. CMUA uses economies of scale to help its 45-member POUs submit these reports. PWP's reports are posted by year on its website[28].

Under AB 2021 (2006) and AB 2227 (2012), a POU's governing board (specifically the Pasadena City Council in this case) must adopt 10-year energy efficiency and demand reduction goals every four years. These requirements are codified in PUC Section 9505. The Pasadena City Council adopted its most recent energy efficiency goals in FY 2021. Specifically, the City Council adopted an annual goal of 11,720 MWh per year in savings and 1.8 MW per year in demand reduction for FY 2022 through 2031. This goal represents a 133.4 GWh reduction in sales cumulatively by Fiscal Year 2031, or 11.3% of forecasted sales. Based on model results and historical data, PWP estimates achieving these goals will cost approximately $3 million per year, or about 1.6% of electric rate revenues, which is consistent with recent spending. As a result, PWP anticipates that the $0.00685/kWh PBC charge is currently sufficient.

Figure 14 includes a summary of past PBC budgets.

[27] May 17, 2021, Agenda Report with the subject "Adopt Ten-Year Energy Efficiency and Demand Reduction Goals for Fiscal Years 2022 through 2031"

[28] https://pwp.cityofpasadena.net/eereports/

Figure 14: Past Public Benefit Charge Budgets

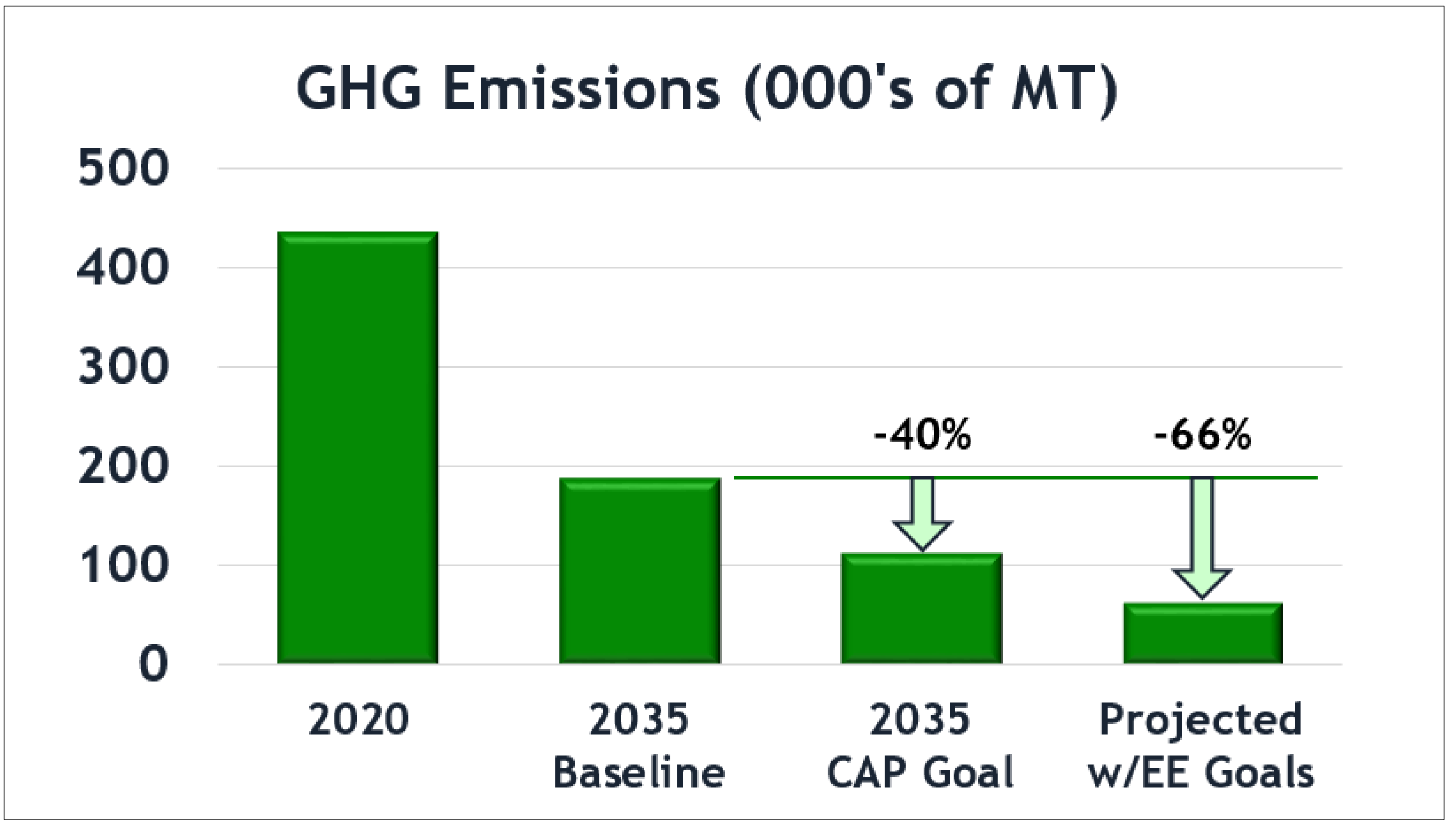
Annual Cost ($000/Year)	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020
Residential Programs	$782	$854	$1,727	$1,935	$1,664
Non-Residential	$2,008	$3,766	$1,267	$1,099	$1,080
Total Program Cost	$2,790	$4,620	$2,994	$3,034	$2,744

The City also refers to energy efficiency in its CAP. Specifically*, Strategy 2: Energy Efficiency and Conservation* discusses prioritization of energy use reduction in existing buildings and new construction. As part of this strategy, CAP Measure E-2.1 sets a target to reduce energy use for existing homes and business by 40% (below 2013 levels) by 2035.

The adopted energy efficiency goals achieve less than 35% reduction, but this comes from electricity only, not from both electricity and natural gas, as in the CAP goal. In fact, the goal was predicted to save 65% more GHG emissions than the CAP goal foresees. See

Figure 15[29]. Overall, PWP is focused on net GHG reduction.

Figure 15: Estimated Greenhouse Gas Emissions from Existing Homes and Businesses



[29] "Adopt Ten-Year Energy Efficiency and Demand Reduction Goals". Item #16 delivered to City Council on May 24, 2021.

In August 2022, the City Council adopted a building electrification ordinance.[30] The ordinance noted that 47% of Pasadena's community-wide GHG emissions come from residential and commercial occupancies. The ordinance requires that existing multifamily buildings, mixed-use buildings, commercial buildings, and larger-scale commercial retrofits be electrified. Exceptions include certain types of food service establishments and essential facilities.

5.3.4. Energy Efficiency Forecast and Goals

In 2021, GDS conducted an energy efficiency potential forecasting study for CMUA, which investigated market potential for residential and nonresidential customers.

GDS performed a study specific to PWP's service territory. As previously stated above, the Pasadena City Council adopted an annual energy efficiency goal of 11.72 GWh from 2022 to 2031, which equates to an average annual target of 1.06% of total energy use avoided per year. This goal was based on GDS' study. These goals appear achievable given Pasadena's current programs and after assuming a GHG adder on avoided costs. While energy savings associated with CS&R constitute about 40% of these total savings, the CEC no longer allows utilities to report on energy efficiency stemming from statewide adoption of new codes and standards. Therefore, CS&R contributions were not considered in setting PWP's goal. For purposes of the IRP, PWP adopted the results of the GDS market potential study, including the GHG adder but not including the potential gains from CS&R advocacy.

PWP's energy efficiency goal in 2017 included CS&R and targeted incremental annual savings of 13,500 MWh in energy efficiency and 2.3 MW of demand reduction per year. If PWP includes CS&R savings in its 2021 goal, PWP's current goals are 19,524 MWh of savings and 3.5 MW of demand reduction per year. PWP remains committed to the cost-effective promotion and adoption of energy efficiency. Programs have become more stringent over time to meet increasingly ambitious goals, as shown in Figure 16 and Figure 17.

Figure 16: Incremental Energy Efficiency Savings (MWh)

Incremental Energy Efficiency Savings (MWh)		
	2017 Goal	2021 Goal
Applicable Years	Fiscal Years 2018 – 2027	Fiscal Years 2022 – 2031
PWP Program Savings	11,338	11,720
CS&R Savings	2,111	7,804
Total Annual Savings	13,500	19,524
Adopted Goal: Total Savings	13,500	11,720

Figure 17: Incremental Energy Efficiency Savings (MW)

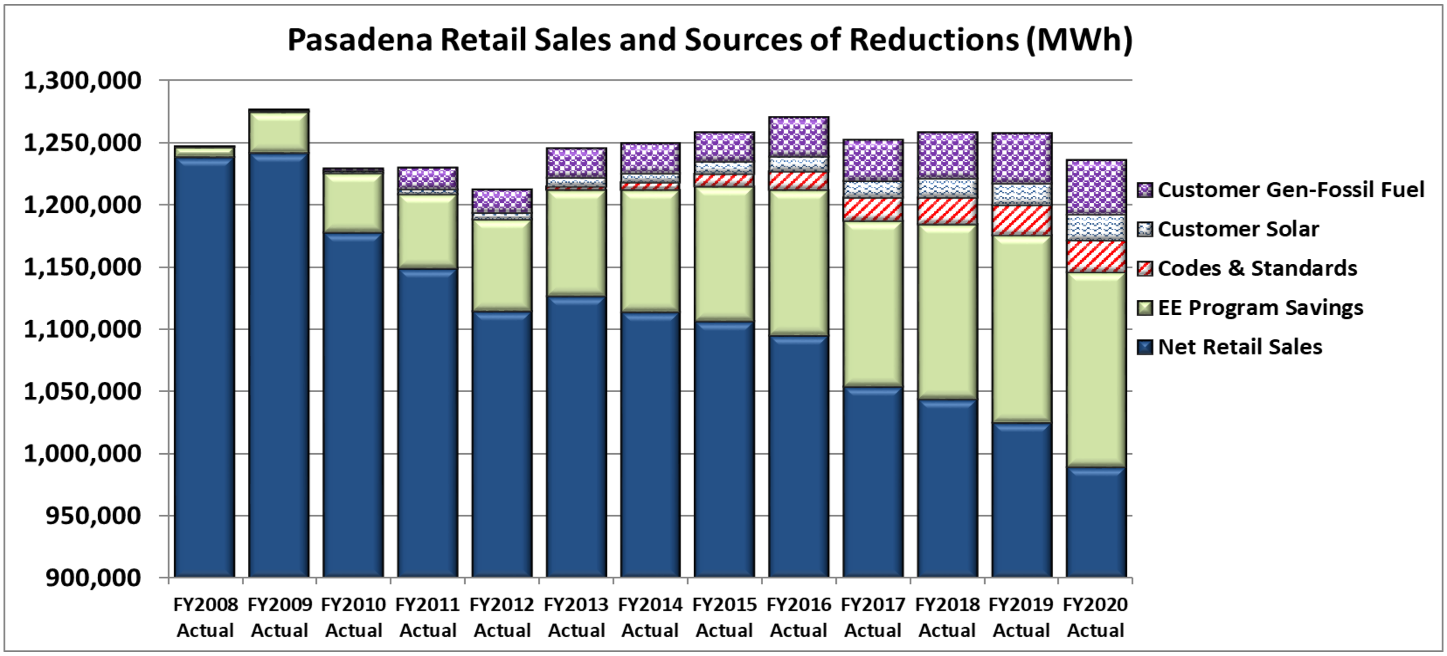
Incremental Energy Efficiency Savings (MW)		
	2017 Goal	2021 Goal
Applicable Years	Fiscal Years 2018 – 2027	Fiscal Years 2022 – 2031
PWP Program Savings	1.6	**1.8**
CS&R Savings	0.7	1.7

[30] Building Electrification Ordinance

Incremental Energy Efficiency Savings (MW)		
	2017 Goal	**2021 Goal**
Total Annual Savings	**2.3**	3.5
Adopted Goal: Total Savings	**2.3**	**1.8**

Reduced electricity usage means that fixed costs need to be recovered from less sales, which may put upward pressure on rates. PWP experienced a net 22% decline in actual retail electricity sales since FY 2008 – a decrease attributed to energy efficiency, CS&R, distributed generation investments, and other factors, including weather and economic activity. See Figure 18. Allocating fixed utility costs – those that do not vary with the volume of sales, such as costs for wires or reliability components – is a question of rate design.

Figure 18: Impact of Energy Efficiency and Customer-Owned Generation on Electric Sales



5.4. Demand Response

5.4.1. Current Demand Response Programs

PWP has one DR program currently active - voluntary load curtailment - with others under development. The current program includes large commercial customers who agree to reduce load by a pre-determined amount upon request. PWP has already identified, tested, and secured more than 2.5 MW of on-call load reduction from 20 of its largest electricity customers.

5.4.2. Future Demand Response Programs

PWP could explore the potential for additional DR programs. Future programs may be feasible when PWP upgrades to AMI in the next few years.

5.5. Green Power Program

The GPP is a voluntary rate structure that offers customers renewable or green electricity produced by technologies such as solar, wind, geothermal, small hydro, and biomass for a price. The GPP accounts for 5% of total load supplied to PWP customers.[31]

5.5.1. Residential Green Power Program[32]

As of 2023, under the Residential GPP, customers have the following three purchase options for green power:

- 200 kWh block for $3.60 a month
- 400 kWh block for $7.30 a month
- 100% of electricity consumed is renewable for $0.018/kWh

PWP currently has 393 residential GPP accounts, which represent 0.6% of all PWP customers.

5.5.2. Commercial Green Power Program[33]

Commercial customers have the following two options when signing up for the GPP:

- 1,000 kWh blocks (any number) for $18 each per month
- 100% of electricity consumed as renewable at $0.018/kWh

PWP currently has 194 commercial GPP accounts, which represents 0.30% of all PWP customers.

5.6. Low-Income Assistance Programs

PWP offers several programs to help customers use energy more efficiently and reduce their utility bills, particularly financially vulnerable households. The assistance programs listed in the following sections represent the majority of PWP's available benefits.

5.6.1. Income-Qualified Programs

5.6.1.1. Monthly Bill Payment Assistance

Low-income customers between the ages of 18 and 61 who qualify according to the table in Figure 19 can receive a $10 bill credit per month.[34]

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[31] https://pwp.cityofpasadena.net/greenpoweroption/
[32] https://pwp.cityofpasadena.net/wp-content/uploads/2017/08/Residential-Green-Power-Option-Fillable-8.2020.pdf
[33] https://pwp.cityofpasadena.net/wp-content/uploads/2020/08/Green-Power-Commercial-App-Fillable-8.2020.pdf
[34] https://pwp.cityofpasadena.net/billassistance/

Figure 19: Low-Income (Electric Utility Assistance Program)

Household Size	1	2	3	4	5	6	Each Additional Person
EUAP income level	$41,700	$47,650	$53,600	$59,550	$64,940	$74,380	+$9,440

Low-income seniors (ages 62 and over) or customers with a permanent disability who qualify according to Figure 20 are eligible to receive a $10 bill credit per month and a waiver of their monthly PBC charge.[35]

Figure 20: California Alternate Rates for Energy (Age or Disability Qualification)

Household Size	1	2	3	4	5	6	Each Additional Person
CARES income level	$41,700	$47,650	$53,600	$59,550	$64,940	$74,380	+$9,440

Low-income seniors (ages 62 and over), and customers with a permanent disability at the income shown in Figure 21 are eligible to receive a $10 bill credit per month and a waiver of their monthly PBC and Utility Users Tax.[36]

Figure 21: California Alternate Rates for Energy Plus (Age or Disability Qualification)

Household Size	1	2	3	4	5	6	Each Additional Person
CARES plus income level	$12,000	$16,000	$20,000	$24,000	$28,000	$32,000	+$4,000

Qualifying residential account holders may apply online at any time, or in person by appointment, and must provide proof of income for all persons living in the household.[37]

5.6.1.2. Other Income-Based Assistance Programs

The following are PWP's other income-based assistance programs:

- Payment Arrangements
  - PWP offers payment arrangements for customers experiencing financial hardship. For more information, or to enroll, customers are invited to call PWP Customer Service at (626) 744-4005.[38]
- LIHEAP
  - This is a federally-funded program administered locally by the Maravilla Foundation. LIHEAP is designed to help low-income households with a one-time payment to help pay heating and cooling bills. This long-standing federal program has helped low-income families nationwide for more than 40 years. More information is available on the Maravilla Foundation website (www.maravilla.org).[39]
- LIHWAP

[35] https://pwp.cityofpasadena.net/billassistance/
[36] https://pwp.cityofpasadena.net/billassistance/
[37] https://pwp.cityofpasadena.net/billassistance/
[38] https://pwp.cityofpasadena.net/paymentarrangement/
[39] https://pwp.cityofpasadena.net/liheap/

- This is also a federally-funded program administered locally by the Maravilla Foundation. This is designed to help low-income households with a one-time payment for outstanding residential water or wastewater bills. The federal government established LIHWAP as part of legislation to ease the financial impacts of the COVID-19 pandemic. LIHWAP expired in August 2023.

5.6.2. General Bill Assistance

PWP also offers non-income-based bill assistance.

Residential electric customers with qualifying electric-powered medical equipment can receive a $10 bill credit per month under the Medical Equipment Assistance program. Qualifying equipment includes aerosol tents, apnea monitors, compressors or concentrators, electrostatic or ultrasonic nebulizers, electric nerve stimulators, hemodialysis machines, kidney dialysis machines, intermittent positive pressure breathing machines, iron lungs, pressure pads, pressure pumps, respirators or ventilators, suction machines, motorized wheelchairs, and electric beds.[40]

The Water Leak Assistance Program assists customers with certain property-related water leaks that result in excessive water waste and high utility bills. The program provides a partial bill adjustment to qualifying customers, in order received, until the $50,000 annual funding cap is reached.[41]

6. Public Participation

A key theme in the development of PWP's 2023 IRP is extensive outreach, coordination, and collaboration between PWP, stakeholder groups, and the Pasadena community. Public participation has been essential to PWP's portfolio refinement efforts and proved especially valuable to the formulation of data assumptions and simulation model inputs for the IRP study.

The Pasadena City Council will utilize the IRP as an information resource to help determine the best policy path forward. With this goal in mind, PWP worked closely with the Pasadena City Manager, City Council, MSC, and EAC throughout the IRP process to ensure that stakeholder and community input were included. PWP provided periodic updates to these governing bodies, which facilitated direct feedback from policymakers and the Pasadena community.

While developing the 2023 IRP, PWP engaged a variety of stakeholders through a comprehensive outreach process to seek input from customers, communities, and policymakers. The outreach process included the following activities listed in Figure 22.

[40] https://pwp.cityofpasadena.net/medical/
[41] https://pwp.cityofpasadena.net/water-leak-assistance-program/

Figure 22: IRP Stakeholders Outreach

Meeting	Date	Topic
STAG #1	December 14, 2022	Introductions
STAG #2	January 18, 2023	Introduction of ACES and IRP Process
STAG #3	February 15, 2023	Decarbonization Pathways
Community Meeting #1	February 22, 2023	Start of IRP Process and Where is PWP Now?
STAG #4	March 1, 2023	Proposed Scenarios and Sensitivity Tests
Municipal Services Committee	March 14, 2023	Informational Update
Environmental Advisory Commission	March 14, 2023	Informational Update
STAG #5	March 15, 2023	Assumption Data Discussion
STAG #6	April 12, 2023	Cost of New Resources
STAG #7	April 19, 2023	Final Scenarios and Sensitivity Tests
Community Meeting #2	April 27, 2023	What will be studied in the 2023 IRP (Scenarios, Sensitivity Tests, and Study)
Municipal Services Committee	May 9, 2023	Informational Update
Environmental Advisory Commission	May 9, 2023	Informational Update
STAG #8	May 17,2023	Load Forecast
STAG #9	August 16, 2023	Results of 2023 IRP Scenarios
Environmental Advisory Commission	September 12, 2023	Informational Update
STAG #10	September 20, 2023	Wrap-up
Virtual Community Meeting #3	September 21, 2023	Results of 2023 IRP and Steps Going Forward
Municipal Services Committee	October 10, 2023 November 14, 2023 December 5, 2023	Recommend Approval and Adoption
City Council	December 11, 2023	Approval and Adoption
Numerous Frequently Asked Questions and Email Communications	December 2022 – October 2023	

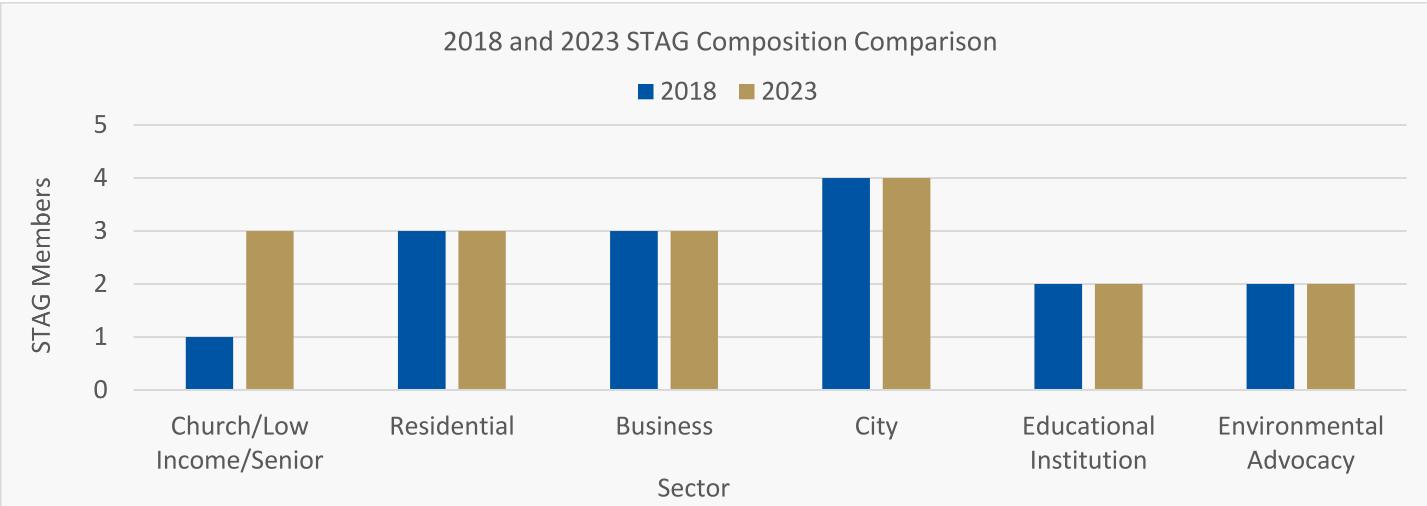
6.1. Stakeholder Technical Advisory Group

Public input and transparency are important aspects of the IRP development process. PWP worked closely with the City Manager and the MSC to assemble the STAG for the 2023 IRP with the goal of recruiting a diverse group of community representatives that could provide input on crucial aspects of the plan including energy supply and power source mixes.

Following the March 4, 2022 website announcement, extensive public outreach was conducted by PWP and City leaders to recruit participation from ratepayers throughout Pasadena.

The 2023 STAG, which was established by the City Manager in November 2022, included 13 residents and four City officials representing different interests, sectors, and districts. The STAG included residential customers, small and large businesses, low income/disadvantaged/senior communities, environmental advocacy groups, and educational institutions. Since the IRP is a long-term plan that affects all Pasadena ratepayers, it was important to ensure that PWP's entire customer base would be represented in the group. See Figure 23.

Figure 23: Comparison of the Composition of the 2018 STAG and the 2023 STAG



Using input from the 2023 STAG, PWP developed a variety of IRP data assumptions and model inputs, including environmental assumptions, fuel prices, resource types, new resource costs, load forecast, scenarios, and sensitivity tests. IRP modeling approaches were also discussed with the STAG.

6.2. STAG Meetings

The 10 STAG meetings that were held from December 2022 through September 2023 were instrumental in the IRP development process and analysis. A general outline of discussion topics include:

- The IRP background, goals, and schedule
- PWP's current generation portfolio, customer programs and internal resources
- The electric industry business and regulatory environment and markets
- The process for updating PWP's load forecast for the IRP
- The use of modeling in IRP analysis including scenario development and sensitivity analysis, and resource options and costs
- Approaches and pathways to decarbonization of the electric portfolio

6.3. Community Meetings

PWP hosted three virtual community meetings for residential customers, business customers, and community organizations to introduce the 2023 IRP and collect feedback. The virtual meetings were promoted through a multi-media marketing campaign, including website postings, social media, bill inserts, print and digital advertising, PWP electronic newsletters, press releases, and flyers. The meetings were held on February 22, April 27, and September 21, 2023. In the first two meetings, PWP presented an overview of the IRP process and discussed the use of scenario analysis in resource planning. In the last meeting, PWP presented the preliminary analysis results and potential resource addition and program change recommendations.

6.4. Public Outreach

In April 2022, PWP updated its website to focus on the 2023 IRP process and added electronic links to all past IRPs. To gauge community interest, PWP utilized social media and community events requesting participation in the IRP process.[42]

6.5. Municipal Service Committee and Environmental Advisory Commission Meetings

PWP staff provided updates to the MSC and EAC from November 2022 through November 2023, including status of work performed and next steps. Additionally, PWP received guidance from the MSC on desired direction of the 2023 IRP, as well as public comments. The sentiments and ideas expressed in these meetings helped shape the scope and the analysis of the 2023 IRP.

7. Environmental Regulations and Priorities

7.1. PWP's Environmental Priorities

PWP is committed to reducing GHG emissions through a balanced and sustainable combination of energy sources, planning, and community outreach. In 2018, the City Council approved the Pasadena Climate Action Plan (CAP), which strives for a 52% reduction (compared to 1990 levels) in citywide GHG emissions associated with energy, transportation, water, and solid waste by 2035.[43] By the end of 2021, PWP reduced energy-related emissions by 50% (compared to 1990 levels) and anticipated reaching a 90% reduction by 2030.[44] On January 30, 2023, the City Council adopted Resolution 9977, which declares a climate emergency in Pasadena and sets a policy goal to source 100% of Pasadena's electricity from carbon-free sources by 2030.[45]

7.2. Renewable Portfolio Standard and Zero-Carbon Regulations

More than one-half of U.S. states have an RPS in place.[46] California's RPS was established in 2002 by SB 1078 (Sher) and sparked more than two decades of increasingly aggressive regulatory mandates that increased the required percentage of eligible renewable resources comprising an electric utility's retail sales. Most recently, SB 100 (2018) sets the RPS to be 60% by 2030. The CEC oversees the RPS program, publishes the *RPS Eligibility Guidebook*, and certifies qualifying resources.

SB 100 also stated that 100% should be met with renewable and zero-carbon resources by 2045. In 2022, SB 1020 expanded the 100% by 2045 zero-carbon goal of SB 100 by adding interim targets. A 2021 joint agency report titled *2021 SB 100 Joint Agency Report: Charting a Path to a 100% Clean Energy Future,* issued by the CEC, CPUC, and CARB, identifies

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42 https://pwp.cityofpasadena.net/powerirp/

43 https://www.cityofpasadena.net/planning/planning-division/community-planning/climate-action-plan/

44 https://pwp.cityofpasadena.net/pcl/

45 https://ww2.cityofpasadena.net/2023%20Agendas/Jan_30_23/Agenda.asp

46 https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps/rps-program-overview

zero-carbon resources as energy resources that qualify as renewable according to the most recent *RPS Eligibility Guidebook,* and/or that generate zero-GHG on site.[47] The report acknowledges that even though certain renewable resources (such as geothermal or landfill gas) may produce de minimis carbon emissions, the joint agency study treats them as zero-carbon resources.[48]

Figure 24 illustrates key policies driving California's environmental efforts.

Figure 24: Renewable Portfolio Standard: Key Legislative Actions in California

Senate Bill	Title	Author	Enacted	Percentage of Load That Must be Met by Renewables
1078	Renewable Energy California Renewables Standard Program	Sher	2002	20% by eligible renewable resources by 2017
350	Clean Energy and Pollution Reduction Act of 2015	De León	2015	50% by eligible renewable resources by 2030; 65% must be in long-term contracts
100	California Renewables Portfolio Standard Program: emissions of greenhouse gasses	De León	2018	60% by eligible renewable resources by 2030; 100% by renewable and zero-carbon resources by 2045
1020	Clean Energy, Jobs, and Affordability Act of 2022	Laird	2022	90% by renewable and zero-carbon resources by 2035; 95% by renewable and zero-carbon by 2040; 100% by renewable and zero-carbon by 2045

PWP has set more aggressive environmental targets. Resolution 9977 set a policy goal to source 100% of Pasadena's electricity from carbon-free sources by 2030.[49] Carbon-free resources are not defined by California. Further discussion on how PWP referred to carbon-free resources in the 2023 IRP is included in Section 14.9 of the IRP.

7.2.1. State Compliance

California has both RPS and zero-carbon compliance requirements. The CEC identifies and investigates RPS violations and may refer suspected incidents to CARB for enforcement.

RPS compliance is monitored with RECs. RECs are tradeable instruments representing the environmental attributes of 1 MWh of energy. A REC represents only the environmental quality of the energy, not the energy. As a result, a REC can be sold with electricity (bundled) or sold alone (unbundled).

7.2.1.1. Renewable Portfolio Standards Procurement Quantity Requirement

RPS compliance is evaluated over the span of compliance periods, which are three-year or four-year evaluation periods. Under SB 350, and later updated by SB 100, PWP must supply 44% of its retail sales with eligible renewable resources by

[47] https://www.energy.ca.gov/publications/2021/2021-sb-100-joint-agency-report-achieving-100-percent-clean-electricity
[48] https://www.energy.ca.gov/publications/2021/2021-sb-100-joint-agency-report-achieving-100-percent-clean-electricity
[49] https://ww2.cityofpasadena.net/2023%20Agendas/Jan_30_23/Agenda.asp

the end of 2024, 52% by the end of 2027, and 60% by the end of 2030, with progressively increasing targets in the interim years.

RPS compliance requirements are included in Figure 25 and are reflected in the IRP models.

Figure 25: Senate Bill 100 and Senate Bill 1020 Requirements[50]

Compliance Period (PUC 399.30)	Year	SB 100 RPS%	SB 1020 RPS + Zero-Carbon%
Compliance Period 4	2021	35.75	
	2022	38.50	
	2023	41.25	
	2024	44.00	
Compliance Period 5	2025	46.00	
	2026	50.00	
	2027	52.00	
Compliance Period 6	2028	54.67	
	2029	57.33	
	2030	60.00	
Beyond Current Compliance Periods	2035		90.00
	2040		95.00
	2045		100.00

7.2.1.2. Portfolio Balance Requirement

Pasadena must procure a balanced portfolio of eligible renewable energy resources that covers different classifications of REC products. These are referred to as PCCs. PCC descriptions are included in Figure 26.

Figure 26: Portfolio Content Categories

Type	Definition	Example (Generic)	PWP Portfolio	Share of Overall Requirement
PCC 0	Historical carryover (i.e., grandfathered) contracts or ownership agreements executed before 6/1/2010	A 2009 wind agreement that is still delivering RECs	Chiquita Canyon Landfill, PPM (also called Avangrid, or High Winds Project, or Iberdrola), and Milford Wind	
PCC 1	Bundled RECs; the first point of interconnection is in California, or within a	A project located in California, or in Washington if delivered into California	Puente Hills Landfill, Windsor Reservoir Solar, Antelope Solar, Kingbird Solar, Columbia Two Solar,	At least 75%

[50] https://www.energy.ca.gov/publications/2022/renewables-portfolio-standard-verification-and-compliance-methodology-report

Type	Definition	Example (Generic)	PWP Portfolio	Share of Overall Requirement
	California Electric Balancing Authority Area and transmitted directly into California	without any substitute energy	Summer Solar, COSO Geothermal	
PCC 2	Firmed and shaped outside California and substituted with energy scheduled within California	A project in Washington without transmission to California; generation is firmed and shaped with substitute energy that is scheduled into a California Electric Balancing Authority Area	Avangrid Powerex	No more than 25%
PCC 3	Unbundled (no associated energy)	A renewable energy certificate/ownership of environmental attributes from an RPS-eligible facility	various short-term contracts	No more than 10%

Renewable electricity products acquired after June 1, 2010 are classified by their environmental quality (highest to lowest value).

While the 2023 IRP assumes that PWP will meet all future RPS requirements with California-generated PCC 1 products, the actual PCC 1 supply may be limited, which would result in the need to secure other REC products. Moreover, variations in load and generation may also require procurement of PCC 2 and PCC 3 products to balance PWP's compliance cost-effectively.

7.2.1.3. Long-term procurement requirement

For the compliance period beginning January 1, 2021, and for each compliance period thereafter, at least 65% of the electricity products applied toward RPS compliance must be from long-term contracts (10 years or more in duration).

7.2.1.4. Renewable and zero-carbon requirements

Beginning in 2035, PWP must supply 90% of its electricity from eligible renewable or zero-carbon resources. In 2022, PWP's portfolio consisted of approximately 28% renewable energy, as reported on its Power Content Label (PCL).[51] Note that the PCL reflects a 2019 CEC calculation modification that excludes unbundled/PCC3 RECs. Under the RPS compliance methodology, which involves different disposition requirements and continues to consider PCC 3, PWP's renewables portfolio increases to approximately 40%.

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[51] https://ww5.cityofpasadena.net/water-and-power/pcl/

To help avoid significant environmental performance gaps and to support a smooth transition to zero-carbon sources, PWP modeled an increasing percentage of load that must be met with renewable and zero-carbon sources prior to the 2030 goal. These interim goals are shown in Figure 27. Values in black bold text indicate the requirements, while values in grey italics represent the modeled interim values.

Figure 27: RPS and Zero-Carbon Modeled Requirements

Percent of Load		
Year	**RPS**	**Zero-Carbon**
2022	**38.50**	*37.07*
2023	**41.25**	*41.14*
2024	**44.00**	*45.21*
2025	**46.00**	*49.29*
2026	**50.00**	*53.36*
2027	**52.00**	*57.43*
2028	**54.67**	*61.50*
2029	**57.33**	*65.57*
2030	**60.00**	*69.64*
2031	*60.00*	*73.71*
2032	*60.00*	*77.79*
2033	*60.00*	*81.86*
2034	*60.00*	*85.93*
2035	*60.00*	**90.0**
2036	*60.00*	*91.00*
2037	*60.00*	*92.00*
2038	*60.00*	*93.00*
2039	*60.00*	*94.00*
2040	*60.00*	**95.0**
2041	*60.00*	*96.00*
2042	*60.00*	*97.00*
2043	*60.00*	*98.00*
2044	*60.00*	*99.00*
2045	*60.00*	**100.0**

7.3. Cap-and-Trade Regulation

California's Cap-and-Trade program, which CARB administers, was established in 2006 under AB 32 and phased in from 2013 through 2015.[52] Amended seven times since adoption, the program's current objective is to reduce statewide carbon emissions by 40% below 1990 levels by 2030, as SB 32 (2016) requires. Covering more than 80% of the state's GHG and over 450 different entities, the program establishes an annual cap of allowable emissions which declines over time.

[52] https://ww2.arb.ca.gov/resources/documents/faq-cap-and-trade-program

Covered entities include electric generators, large industrial facilities, transportation providers, and distributors of natural gas or other fuels. Entities that annually produce at least one metric ton (1,000 kilograms, or 2,200 pounds) of carbon dioxide equivalent emissions must acquire an allowance, or a permit to emit. The Cap-and-Trade program measures compliance over distinct time intervals, or compliance periods. Each year, an entity must surrender allowances that represent 30% of its prior year emissions, with the full remainder due at the end of the compliance period.[53] CARB allots a certain number of free, tradeable allowances to specific entities, including electric distribution utilities such as PWP. Other entities can purchase allowances or offsets in auctions that CARB periodically conducts. These auctions are designed to establish stable prices for allowances over time and to help incentivize general investment and movement toward lower-polluting sources.

In practice, awareness of the current allowance price, as determined by trading and auctions, factors into an entity's decision about how to price its generation output. This is how carbon is priced into the electricity sector in California. Future cost estimates for allowances are publicly available on the CPUC's website.[54]

However, for the purposes of the IRP, the Cap-and-Trade program functions as it sounds – as a cap. Each year, PWP may emit from IPP, Glenarm, and Magnolia the amount of carbon corresponding to its current allowances, as prescribed by regulation, without penalty or additional cost.[55] While the Cap-and-Trade program is currently slated to expire in 2030, this IRP assumes that PWP would continue to adhere to the principle of the program. The 2023 IRP therefore ramps down allowed emissions to zero by the mid-2040s. PWP elected to use this modeling method because it limits PWP's emissions during simulated operations.

7.4. Other Environmental Points of Note

7.4.1. Power Source Disclosure Program

PWP reports its PCL every year as required. The PCL is a detailed summary of its power mix and carbon emissions intensity. PCLs are similar in concept and appearance to food nutrition labels, as they provide product health data to the consumer. The PCL is a requirement of the CEC-administered Power Source Disclosure program, which provides easy-to-understand information to consumers about local power sources.[56] Utilities are required to report PCLs annually to the CEC and to make these reports available to customers. PWP's PCL is posted on both the CEC's and PWP's websites.

PWP's 2022 power mix included 27.73% renewable energy: specifically, 5.7% total solar, 13.7% total wind, and 8.3% biomass/biowaste. The balance was comprised of 24.3% coal, 4.2% large hydroelectric, 13.1% natural gas, 8.4% nuclear, and 22.3% unspecified power.[57] Also, as previously noted, unbundled/PCC 3 RECs are not included in the PCL calculation,

[53] Chapter 1: How Does The Cap-And-Trade Program Work?" at https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/about

[54] https://files.cpuc.ca.gov/energy/modeling/EmissionForecast.csv at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/unified-ra-and-irp-modeling-datasets-2022

[55] https://ww2.arb.ca.gov/sites/default/files/2021-02/ct_reg_unofficial.pdf at https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/allowance-allocation/edu-ngs

[56] https://www.energy.ca.gov/programs-and-topics/programs/power-source-disclosure

[57] https://ww5.cityofpasadena.net/water-and-power/pcl/

which, along with different disposition rules, results in a variance from the RPS Compliance report, which shows 40% renewables for the same year. PWP's power mix is impacted by the carbon intensity attributed with the IPP coal contract, which will expire in 2027. After that time, the IPP contract will be fully terminated, eliminating its carbon emitting GHG contribution from the PWP portfolio.

7.4.2. The Cost Impacts of 100% by 2045

Under SB 100, the CEC, CPUC, and CARB were required to issue a joint report by January 2, 2021, and every four years thereafter, to provide policy implementation information.[58] The initial report, which analyzed the required statewide resources and their costs, found that the 100% by 2045 zero-carbon goal would increase system costs by 6% as compared to earlier RPS goals.[59] Furthermore, to reach the target, California must triple its power capacity.[60] Specifically, solar and wind would need to be installed at three times the 2021 pace and batteries at eight times the 2021 pace.

7.4.3. Social Cost of Carbon

For environmental policies that might increase or decrease carbon, government agencies and policymakers may consider the Social Cost of Carbon (SCC). The SCC is an estimated monetary value of the overall downstream impact of emitting an additional metric ton of carbon dioxide. The U.S. EPA established the most recent SCC values in September 2022. [61]

Pasadena considered the SCC in its 2018 IRP and 2021 IRP Update. During simulations, this effectively prevented some generation that would otherwise have been economical. For the 2023 IRP, PWP studied and allocated a scenario specific to model impacts.

It is important to note that carbon is already priced in the electricity generation sector via the Cap-and-Trade and RPS programs. If the SCC were applied as an extra charge to IPP, Magnolia, or Glenarm, the following could occur in the simulation:

- Economical fossil fuel generation would be deployed less because it is now more expensive
- More renewable resources or other resources would be selected

Although the CEC guidelines do not require any use of the SCC, PWP's 2023 IRP modeling includes it in a scenario.

8. Resource Adequacy

RA is a regulatory construct that helps quantify resources' ability to meet energy needs at all times.

PWP is subject to regulatory requirements related to RA. PWP must, at a minimum, meet the planning reserve requirement and reliability criteria assigned to it by the WECC Board of Trustees. Since PWP is a municipal utility, with ultimate governing authority held by its City Council, PWP is its own LRA. An LRA has authority to dictate some RA

[58] https://www.energy.ca.gov/publications/2021/2021-sb-100-joint-agency-report-achieving-100-percent-clean-electricity
[59] https://www.energy.ca.gov/sb100
[60] https://www.energy.ca.gov/publications/2021/2021-sb-100-joint-agency-report-achieving-100-percent-clean-electricity
[61] https://www.epa.gov/environmental-economics/scghg

requirements that must be met by its jurisdictional LSEs. PWP is an LSE because it provides electricity to end users and is regulated accordingly. In short, PWP is both an LRA and an LSE.

Because it participates in the CAISO market, PWP has obligations regarding the following three types of resource adequacy:

- System
  - Ability to meet load, plus an added PRM to cover forecast uncertainty and/or outages
- Local
  - Ability to meet regional load and prevent system overload. CAISO identifies local areas of concern
- Flexible or Flex
  - Ramping capabilities to meet load, especially during the evening hours
  - Since California is now operating a grid with higher levels of renewable resource generation, CAISO finds that flexible resources that can ramp up or down on short notice to meet fluctuation in load and intermittent energy help support reliability

Additional details on how PWP plans to meet System, Local, and Flexible RA capacity requirements during the 2023 IRP study period are described in the following sections.

8.1. System Resource Adequacy and Reserve Margin

PWP has deferred to a PRM of 15% following the CAISO tariff. The PRM is required monthly using a 1-in-2 peak demand forecast, which assumes a 50% probability that forecasted peak will be either greater or less than actual peak.[62] Accordingly, PWP's system RA obligation is equal to its monthly peak load plus the 15% PRM. PWP needs to meet this with a combination of PWP's owned and contracted resources.

Due to increases in renewable resources and the intermittent nature of renewables, reserve margins in markets across the U.S. are increasing. For example, in 2023, MISO released information showing higher seasonal reserve margins, and SPP moved from a reserve margin of 12% to 15%.[63] For 2022, CAISO recommended that the CPUC adopt a 17.5% PRM for its jurisdictional entities. The CPUC adopted a 16% PRM for 2023 and a 17% PRM for 2024, and requested jurisdictional LSEs procure additional resources to meet an effective PRM of 20% to 22.5% for summer 2022 and 2023.[64] CAISO has not yet proposed an increase to the 15% tariff default, but it is presumed to increase in the near future.[65] For the 2023 IRP, PWP elected to model a 15% reserve margin through 2025, increasing to 17.5% for the remainder of the study. PWP believes this reflects market trends.

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[62] https://www.caiso.com/Documents/Resource-Adequacy-Fact-Sheet.pdf
[63] https://cdn.misoenergy.org/20220906%20LOLEWG%20Item%2003%20PY%202023-24%20Preliminary%20LOLE%20Study%20Results626211.pdf; https://www.spp.org/spp-documents-filings/?id=21069
[64] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K540/488540633.PDF; https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M428/K821/428821475.PDF
[65] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M371/K105/371105687.PDF

The installed capacity of a generating resource is not indicative of its ability to support system reliability. For example, a solar resource may be hindered on a cloudy day, or a natural gas plant may experience reduced output due to constraints on natural gas pipelines during cold days. As a result, a resource's reliability contribution is often not equivalent to its installed capacity. RA accreditation for resources is a function of technology type and the ability of the resource to deliver its full capacity onto the grid given fuel, transmission, and other constraints. PWP uses the CAISO net default qualifying capacity for its resources. For the 2023 IRP, PWP assumes that the ELCC of solar specifically, which varies based on month, will decline over time.

In the IRP modeling, PWP assumed monthly accreditation patterns for its resources. This information is based on CAISO data and some of the underlying CPUC data.[66]

Figure 28 shows the annual capacity accreditations for solar in CAISO for select years. In the instance of solar, the more resources online, the later in the day the net peak (actual demand minus renewable resources) occurs. As a result, the hour of operational concern shifts to later in the day when solar is less available.

Figure 28: Solar Resource Adequacy Accreditation

Percent of Installed Capacity Eligible for System/Local RA	
Year	Solar
2025	12.0
2030	9.8
2035	8.7
2040	8.0
2045	7.5

8.2. Local Resource Adequacy Capacity

California's grid contains 10 LCAs. These are areas with transmission constraints that limit power imports, so local generation is required for system reliability. Every year, CAISO performs a Local Capacity Technical Study that evaluates local resource needs for a 1-in-10 peak forecast scenario.[67] It then delegates LCRs to entities within the constrained areas. Based on CAISO tariff Section 40.3.2, PWP's obligation is its proportionate share of SCE's transmission area load at the time of the CAISO's annual coincident peak demand.[68]

The local capacity of each resource is calculated using the same methods as system capacity. All local capacity is system capacity, but not all system capacity is local capacity.

[66] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M452/K750/452750851.PDF; https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K540/488540633.PDF; https://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx; https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M496/K666/496666765.PDF

[67] Calculation includes the impact of storage charging.

[68] https://www.caiso.com/Documents/Final2023LocalCapacityTechnicalReport.pdf

PWP needs these resources to be located in the SCE TAC area. According to Section 40.3.2 of the CAISO tariff: "An LSE or CPE may meet its MW responsibility, as assigned under this Section, by procuring Local Capacity Area Resources in any Local Capacity Area in the TAC Area." The SCE transmission access charge area includes two sub-areas: L.A. Basin and Big Creek/Ventura. PWP meets its local RA requirement with Glenarm, Puente Hills, Chiquita Canyon, Antelope Solar, Kingbird Solar, and Summer Solar resources.

PWP's load is in the L.A. Basin sub-area of the SCE TAC area. Glenarm and Puente Hills are in the L.A. Basin sub-area. Chiquita Canyon, Antelope Solar, Kingbird Solar, and Summer Solar are in the Big Creek/Ventura sub-area. There may be regulatory risk if the location of load and resources in sub-areas diverge, should CAISO decide to pursue a more granular approach to local RA in the future.

Glenarm (with nameplate capacity of 196 MW) that can provide quick ramping support fulfills the need for local and flexible RA requirements. Additionally, it is anticipated that local requirements will likely increase over time. Local RA capacity is currently a scarce product in the market with high prices and less liquidity than System RA capacity. This trend is anticipated to continue as fossil fuel resources in California are decommissioned or reach the end of their natural lives.

8.3. Flexible Resource Adequacy Capacity

The Flexible RA capacity requirement is based on the largest three-hour net load ramp in a month and was implemented in 2015 to address the increased need for grid flexibility given greater renewable resource penetration. CAISO uses load and renewable resource data to determine the overall Flex RA capacity needed for each month, then allocates requirements based on each LRA's contribution to the load ramp under Section 40.10.2.[69] PWP must have sufficient Flex RA from owned and contracted resources to cover its obligations.

CAISO tariff Section 40.10.3 details the following three types of Flexible Capacity: [70]

- Category 1 (Base Flexibility)
    - Available seven days per week, all days per month
    - Must be capable of bidding into the day-ahead and real-time markets from 5:00 a.m. to 10:00 p.m. Pacific Prevailing Time
    - Must be capable of providing energy for a minimum of six hours at capacity
    - Must be able to provide the minimum of two start-ups per day for every day of the month or 60 starts per month, or the number of start-ups allowed by its operational limits, including minimum up and minimum down times
    - No monthly or annual limitations on number of starts or energy limits that translate to less than the daily requirements
- Category 2 (Peak Flexibility)
    - Available seven days per week, all days per month
    - Must be capable of bidding into the day-ahead and real-time markets for a five-hour block that is determined seasonally

[69] http://www.caiso.com/InitiativeDocuments/Final2023FlexibleCapacityNeedsAssessment.pdf
[70] https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Reliability%20Requirements

- Must be capable of providing energy for a minimum of three hours at capacity
- Must be capable of at least one start-up per day
- No monthly or annual limitations on number of starts or energy limits that translate to less than the daily requirements
- Base ramping counts for peak ramping

- Category 3 (Super-Peak Flexibility)
  - Available all non-holiday weekdays per month
  - Must be capable of bidding into the day-ahead and real-time markets for a five-hour block that is determined seasonally
  - Must be capable of providing energy for a minimum of three hours at a capacity
  - Must be capable of at least one start-up per day
  - Must be capable of responding to at least five dispatches per month during the five-hour period of the must-offer obligation
  - Base ramping and peak ramping counts for super peak ramping

Flexible RA capacity is distinct from System RA and Local RA capacity. It has its own accreditation methods. Generally, Flexible RA capacity is bundled with System RA (or Local RA) capacity at a slight premium. It is not generally traded as a stand-alone product since the CPUC requires all Flexible RA to be bundled with System RA for CPUC-jurisdictional entities, and most of the load is served by CPUC-jurisdictional entities. Given that CAISO allows Flexible RA and System RA to be scheduled separately, it is possible that these products could trade separately for non-jurisdictional entities, although that is not currently the common practice.

Glenarm with its unique capabilities such as quick start, ramping ability, minimum run time, and other economics, is highly desirable in supporting forecast dependent resources such as wind and solar and their inherent variability. Glenarm currently provides all of PWP's Flexible RA capacity requirements.

8.4. Slice of Day Proposal

The Slice of Day proposal was adopted by CPUC in the 2022 RA proceeding and is currently applicable only to CPUC-jurisdictional LSEs.[71] Under the Slice of Day construct, an LSE must show that it has sufficient capacity and reserve margin in each hour of the "worst day" of every month. This includes having sufficient energy available to charge energy storage resources. The test year for this construct is 2024, and 2025 will be binding with associated penalties for deficiencies. As of February 2023, the CPUC and stakeholders were still developing the mechanics. While PWP is not directly affected, there may be some aspects that CAISO adopts, though there are no current discussions. The Slice of Day construct may ultimately affect RA trading in the future.

8.4.1. Reliability Must-Run Resources

Some generation is crucial in maintaining system reliability and may not be allowed to retire without a detailed and stringent backup plan. These units are designated as RMR resources. According to CAISO, RMRs are:

[71] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K540/488540633.PDF

"Generation that the CAISO determines is required to be on-line to meet Applicable Reliability Criteria requirements. This includes i) Generation constrained on-line to meet NERC and WECC reliability criteria for interconnected systems operation; ii) Generation needed to meet Load demand in constrained areas; and iii) Generation needed to be operated to provide voltage or security support of the CAISO or a local area."

RMRs are covered in Section 41 of the CAISO tariff.[72]

The Glenarm resource is on the PWP load side of a 280 MW interconnection into CAISO via the Goodrich intertie line. Operations are critical as PWP is a transmission-constrained electric system. Given Glenarm's strategic importance in preventing load shed, any decisions regarding its operations would be subject to CAISO analysis, which is based in part on NERC reliability standards.

The following are the circumstances that cause Glenarm to come online:

- Glenarm helps serve load above the Goodrich intertie limit
- Glenarm is economic enough to provide reliability benefits to the grid
- Goodrich is unavailable due to unexpected failure or needs routine maintenance
- Glenarm alleviates constraints on the distribution system
- One or both 220kV transmission lines from SCE experience unexpected failure or need routine maintenance
- Glenarm provides additional reliability benefits, such as Reactive Power (VAR) support to maintain CAISO-required voltage bandwidth
- Glenarm supports renewable resources and can compensate for their output variability attributed to the uncertainty of wind speeds and solar illumination. The CAISO makes Glenarm unit commitment decisions in these cases where required

PWP is part of CAISO, thus Glenarm is part of CAISO. If Glenarm is online, it is not in complete control of its operations, as it must follow instructions from CAISO. CAISO is similar to a financial clearinghouse; it identifies the most cost-effective sources of power and dispatches them based on physical constraints. Optimizing multiple resources over a wider territory can produce savings for the larger system. CAISO may find that Glenarm is one of the more cost-effective sources of power and call on it to provide energy. Given the lower dispatch of the Glenarm units, it is unlikely that Glenarm will be called on frequently because of economics. It is more likely that CAISO instructs Glenarm to come online to help with grid reliability.

Glenarm helps provide reliability benefits to the grid, as included in its RA characteristics. Under CAISO rules, resources that qualify for RA have to offer in CAISO's day-ahead markets. This is referred to as a must-offer obligation. There are limits to what price a resource can offer in CAISO. These rules exist to prevent market manipulation or an abuse of market

[72] https://www.caiso.com/Documents/Section41-Procurement-of-ReliabilityMust-RunResources-asof-Aug15-2022.pdf

power. Given that Glenarm is an RA resource, it has to offer into the CAISO markets at a reasonable rate, as determined by the CAISO tariff.

9. Model Assumptions

9.1. Planning Horizon (POUs)

In accordance with CEC guidelines, the planning horizon of an IRP must begin no later than January 1 of the year of adoption by a POU's governing board.[73] The 2023 IRP will be presented to the Pasadena City Council for approval in late 2023 and will therefore be considered in effect on January 1 of that year. While current regulations require the planning horizon to run through 2030, the CEC 2022 draft IRP guidelines extend this timeline to 2045, suggesting an attempt to align with evolving clean energy laws and regulations, including the following:

- AB 1279, which expands on SB 32's statewide 40% by 2030 GHG emissions reduction requirement to achieve carbon neutrality no later than 2045 and reduce anthropogenic GHG by 85% compared to 1990 levels.
- SB 1020, which accelerates SB 100's 100% renewable and zero-carbon resources by 2045 requirement for faster adoption by adding interim targets that go beyond 2030.

Also, since resources in the modeled portfolios will likely continue to be operational beyond 2045, the 2023 IRP uses a 27-year planning horizon that starts in 2023 and ends in 2050 (Study Period). While not required by the CEC, it is expected that the longer Study Period will be useful for evaluating capacity and resource performance.

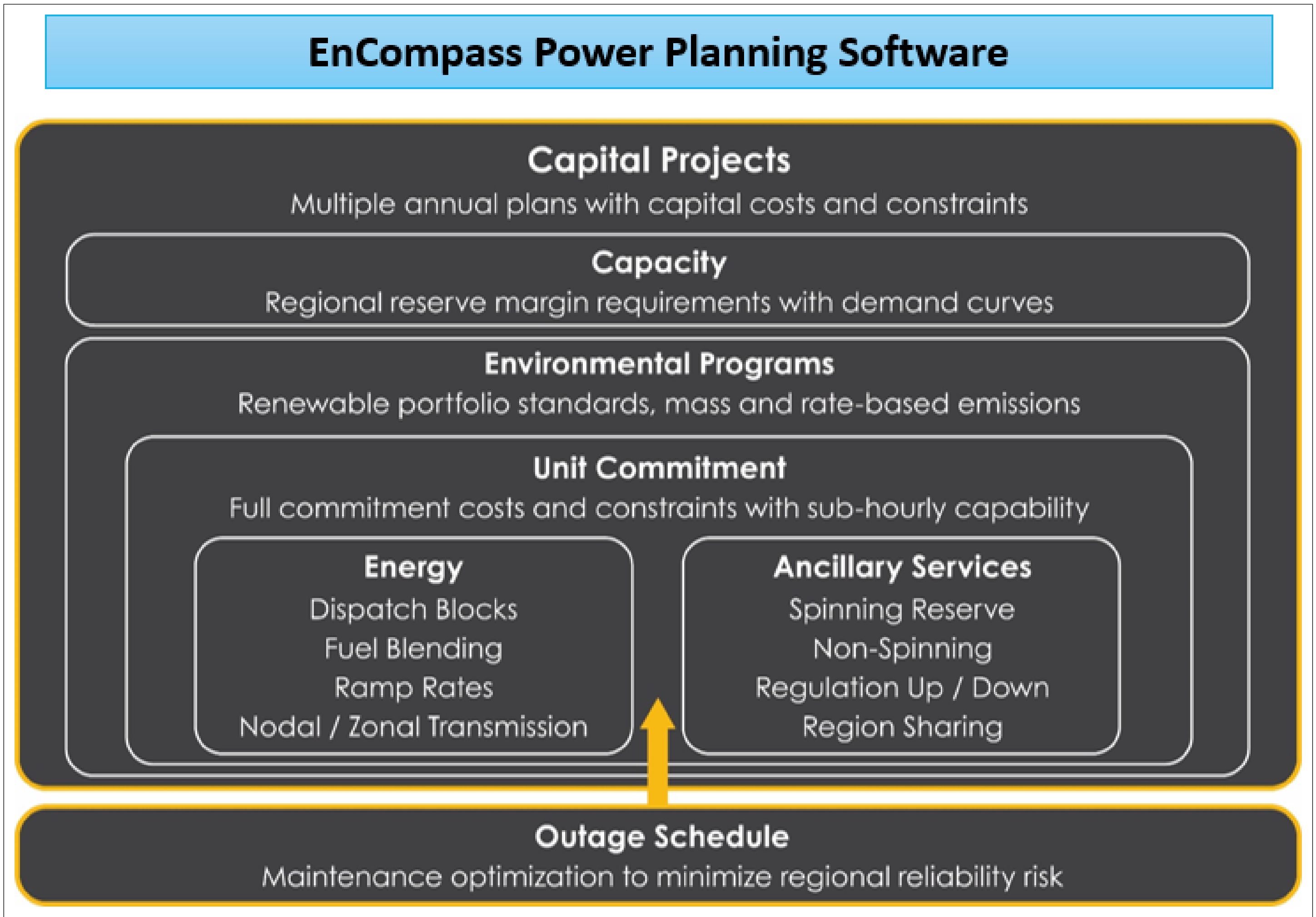
9.2. Model

PWP's IRP leverages Anchor Power's EnCompass software, a premier capacity expansion and production cost modeling software developed and maintained by Anchor Power Solutions.[74] EnCompass is a state-of-the-art power planning simulation software designed for modeling evolving power markets, decarbonization, and sustainability. Encompass was created with enhanced capabilities to evaluate new technologies, assess renewable resources and storage, model reductions in GHG emissions, and optimize decarbonization strategies, and is the industry-model of choice for a variety of entities, including municipal utilities, investor-owned utilities, electric cooperatives, and consultants. It has been the basis for regulatory filings in 17 states.

EnCompass provides capacity expansion, nodal and zonal hourly chronological production cost modeling, risk analysis, scenario analysis, and financial revenue requirement modeling. Figure 29 provides a summary of the model options. The 2023 PWP IRP was modeled using the zonal construct.

[73] https://www.energy.ca.gov/rules-and-regulations/energy-suppliers-reporting/clean-energy-and-pollution-reduction-act-sb-350-0
[74] https://anchor-power.com/encompass-power-planning-software/

Figure 29: EnCompass Power Planning Software



Source: Anchor Power Solutions, developer of EnCompass

EnCompass minimizes total costs and maximizes total revenue of electricity systems, subject to constraints. The model selects and operates the least-cost, best-fit resource mixes given assumptions. In the IRP modeling results, dollars are nominal, unless otherwise noted. The model uses a nominal discount rate of 5% and an annual inflation rate of 2.5%, with results reflected in calendar years. The three critical model constraints used for PWP's IRP are shown in Figure 30.

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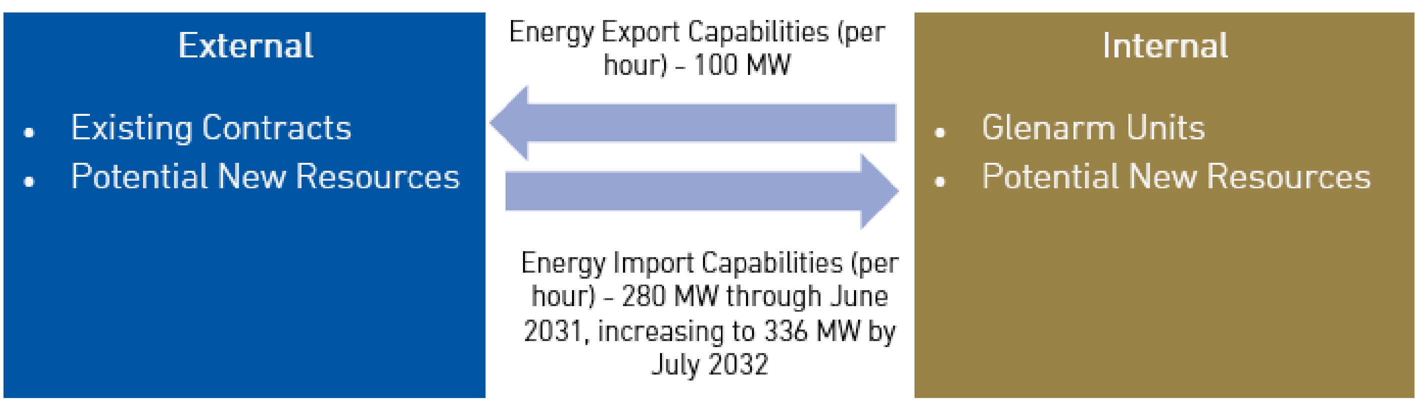
Figure 30: PWP Integrated Resource Plan Critical Model Constraints

PWP IRP Critical Model Constraints		
Energy	**Resource Adequacy**	**Environmental Priorities**
PWP is a transmission-constrained system with limited ability to import energy from outside its service territory. The model considered transmission import constraints when selecting new resources and their preferred locations.	Resource selection is optimized to meet RA requirements. RA is monthly peak load plus a PRM. The PRM is modeled at 15% and increases to 17.5% in 2025. A resource's ability to meet the RA requirements is dependent on resource type. More information is included in Figure 40 and 41.	California RPS regulations require 60% of retail sales to be met with renewable resources by 2030, increasing to 100% renewable and zero-carbon resources by 2045. Carbon emissions must also decline over time in accordance with the Cap-and-Trade Regulation. Pasadena City Council Resolution 9977 declares a climate emergency and sets a policy goal to source 100% of Pasadena's electricity from carbon-free resources by the end of 2030 while optimizing for affordability, rate equity, stability, and reliability.

9.3. Model Topology

PWP's system was modeled according to the topology shown in Figure 31. This setup mimics the system on a transmission level.

Figure 31: Model Topology



PWP serves load within its service territory with internal resources (Glenarm or distributed resources) and by importing energy from CAISO at Goodrich.

PWP is a transmission-constrained electric system. Currently, Goodrich can import up to 280 MW under normal operating system conditions. This is expected to increase to 336 MW in July 2032 with the completion of system upgrades described in Transmission and Distribution. PWP has also executed contracts for resources located outside its service territory. The energy from these external resources moves through the CAISO controlled system and is delivered to the Goodrich substation.

9.4. Power and Fuel Prices

The external area is CAISO. CAISO operates financial markets for electricity and helps ensure reliable power delivery by monitoring and controlling the operation of power plants and transmission lines. [75] CAISO, which PWP joined in 2004, also helps plan with rigorous studies and requirements.

The IRP model uses forecasted power and natural gas prices for the CAISO area surrounding PWP. This accounts for trends in the larger California area. Price trends are based on forecasted resource mixes and include financial and emission factors.

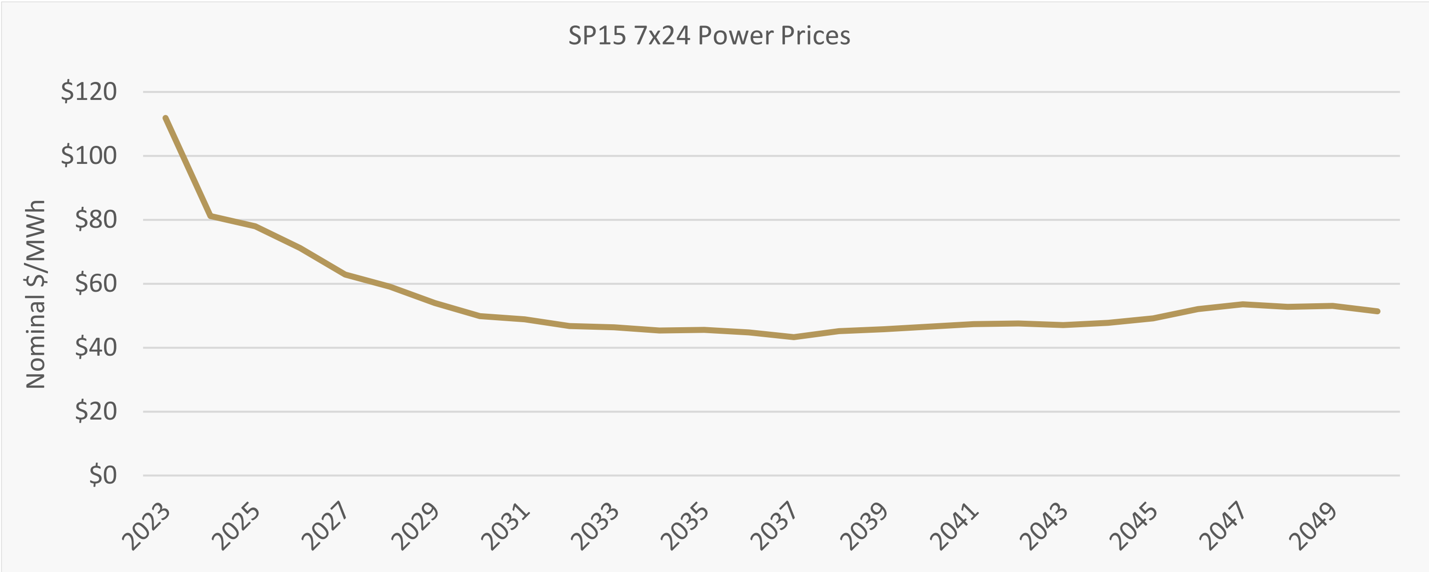
The power prices for SP15 (the CAISO zone for which PWP prefers to price contracts) and the natural gas prices for the Southern California City Gate location come from the Horizons Energy, LLC (Horizons Energy) Fall 2022 Advisory.[76]

Horizons Energy generates fundamental forecasts for 78 North American electricity markets across nine scenarios for energy, fuel, capacity, renewable energy, emissions pricing, and ancillary services.[77] It uses the EnCompass database to create price curves. ACES also uses Horizons Energy data to assist in the management and evaluation of more than 50,000 MW of load and generation for its clients.

For 2023 through 2027, the 2023 IRP uses power and natural gas prices based on market quotes with a trade date of December 30, 2022. This is the latest trade date that allows for full-year 2023 data. Beginning 2028, ACES blended the prices into Horizons Energy price forecast curves at 10% per year, such that prices reflect 100% Horizons Energy data in 2037. This blending process ensures price forecasts in the early years that are as close to actual and executable pricing as possible, with later years mimicking the long-term fundamental price forecast. Power and natural gas pricing are included in Figure 32 and Figure 33, respectively.[78] Prices are normally subject to confidentiality agreements, but Horizons Energy graciously allowed for release.

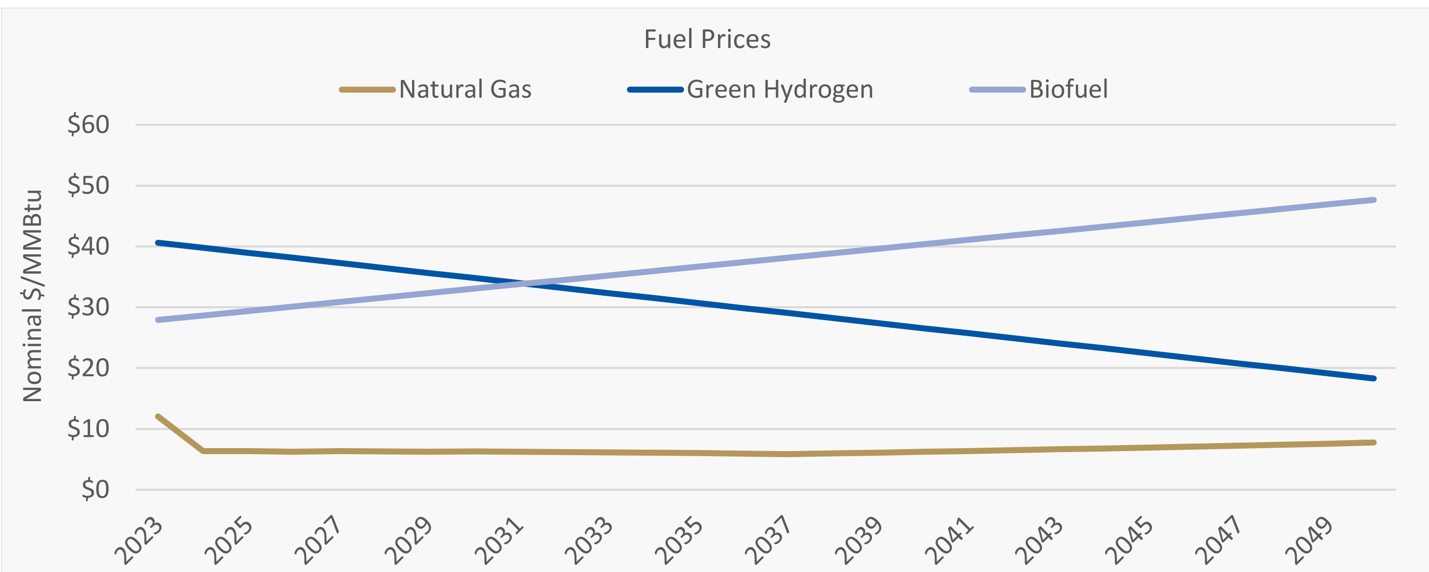
Figure 32: SP15 7x24 Power Prices

[75] https://www.caiso.com/Pages/default.aspx
[76] https://www.horizons-energy.com/
[77] https://www.horizons-energy.com/advisory-services/advisory-service/
[78] The opinions expressed in this report are based on Horizons Energy's judgment and analysis of key factors expected to affect the outcomes of electric power markets. However, the actual operation and results of power markets may differ from those projected herein. Horizons Energy makes no warranty or guarantee regarding the accuracy of any projections, estimates, or analyses, or that such work products will be accepted by any legal, financial, or regulatory body.



Source: Horizons Energy Fall 2022 Advisory

Figure 33: Fuel Prices



Source for Natural Gas: Horizons Energy Fall 2022 Advisory

Figure 34 includes additional estimates of fuel pricing for green hydrogen and biofuel, which were created from publicly available sources.

Figure 34: Fuel Pricing Assumed in PWP's 2023 Integrated Resource Plan

Fuel Pricing Assumed in PWP's 2023 IRP				
Timeframe	**Power**	**Natural Gas**	Biogas	Green Hydrogen
Starting Point	2023 through 2027 based on market quotes with a trade date of December 30, 2022*	2023 through 2027 based on market quotes with a trade date of December 30, 2022*	Assume an initial price of $25/MMBtu[79]	Start at $5.80/kg[80] Convert from gallons to MMBtu[81]
Intermediate Years	Horizons Energy forecast blended at an additional 10% per year	Horizons Energy forecast blended at an additional 10% per year	Price declines linearly through 2040	Price declines linearly through 2050
Ending Point	100% Horizons Energy forecast in 2037 and beyond	100% Horizons Energy forecast in 2037 and beyond	Assume $24/MMBtu (in real 2019 $) in 2040; maintain a linear decline afterwards[82]	Assume a final price of $1.15/kg (in real 2019 $) in 2050[83]

**Last trade date that allows for full 2023 data*

Biofuel and hydrogen may benefit from tax credits under the IRA. Because of the forecast dependency on public source data pre-IRA, such benefits are not directly included. PWP will evaluate the market, public and private sources of information, to investigate these fuels if needed. The IRA is discussed in 11.2.4 of the IRP.

9.4.1. More About Horizons Energy, LLC's Forecasting Method

Horizons Energy uses a fundamentals-based methodology to forecast energy, capacity, environmental and ancillary service prices for 78 North America market areas. Based on Anchor Power's EnCompass power planning model, Horizons Energy simulates the operation of each region of North America. EnCompass is recognized in the industry for its flexibility and breadth of technical capability, incorporating extensive details in generating unit operating characteristics and constraints, transmission constraints, generation analysis, unit commitment/operating conditions, and market system operations. This fundamental approach utilizes the operating characteristics of more than 16,000 generating assets, fuel prices, hourly demand, transmission transfer capabilities, market rules of ISOs and other factors.

The EnCompass power planning model utilizes this database of market information and simulates both annual capital decisions as well as the operational commitment and dispatch of resources. The model simultaneously determines energy,

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[79] https://gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/
[80] https://www.utilitydive.com/news/green-hydrogen-prices-global-report/627776/
[81] https://www.altenergymag.com/story/2020/03/%E2%80%98hydrogen-economy-offers-promising-path-to-decarbonization/32929/
[82] https://gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/
[83] https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf

capacity, environmental and ancillary service prices with hourly resolution and across scenarios. Horizons Energy forecasts market prices throughout North America through the 2050 forecast horizon.

Horizons Energy utilizes a variety of sources like Natural Gas Intelligence (NGI) to obtain forwards and historical costs, the U.S. Energy Information Administration (EIA) Annual Energy Outlook, and other published sources. In the base scenario, Horizons Energy assumes future market prices from NGI for 10 years, then applies a trend thereafter based on internal research and other published sources.

Horizons Energy developed the wind and solar profiles from NREL data. The wind is based on the class of wind and turbine height, whereas solar is based on radiance, fixed or tilt axis, and number of axes.

9.5. Transmission and Congestion

When PWP contracts for new resources, costs associated with congestion and transmission access are generally not included in the contract price.

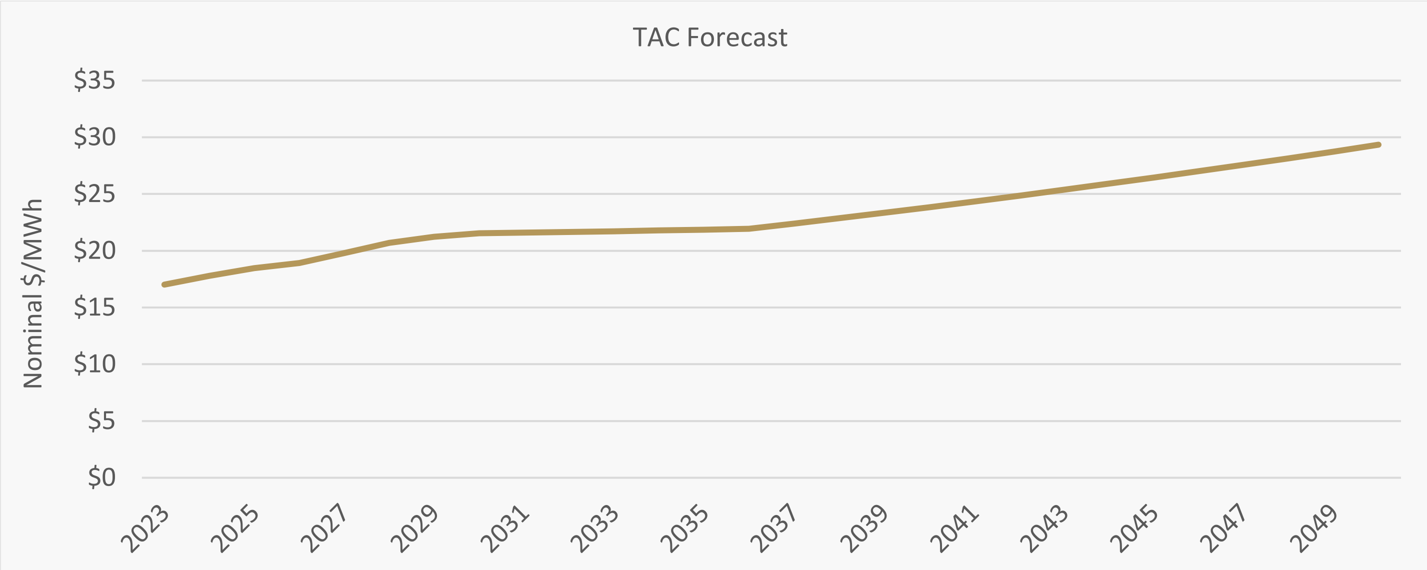
Electric grids are similar to road systems – there are busy roads and costs associated with that congestion. PWP must pay to transport power from where it is generated to where it is needed. Congestion costs are not included in the IRP modeling. However, congestion could be a significant cost in the future, and should be considered when PWP is evaluating contracts.

The TAC is a fee that CAISO charges participants for use of the transmission system. These are general infrastructure usage fees. TAC is separate and distinct from congestion costs. The IRP assumes that the TAC, which applies to external resources and is estimated by CAISO, escalate by 2.1% (the average annual growth rate) after 2036 when the CAISO forecast ends.[84]

Figure 35 shows a forecast of TAC fees.

[84] http://www.caiso.com/Pages/DocumentsByGroup.aspx?GroupID=7A2CFF1E-E340-4D46-8F39-33398E100AE7

Figure 35: Transmission Access Charge Forecast



Electric grids are complex, interconnected systems. Power is injected and consumed across the grid, and transmission lines transport electricity from where it is produced to where it is needed. Additionally, electricity must be produced (or released from storage) the moment it is needed. There are physical (and many other) constraints that underline this system, making long-term planning a multifaceted optimization that considers various factors, such as location, cost, resource type, timing, and environmental impact. Transmission considerations, in terms of availability and cost, are made at the implementation stage, when the relative merits and challenges of specific candidate projects are assessed.

9.6. Load vs. Resources

The following two sections outline PWP's resources and load. Existing Resources (Section 10.1) provides details on PWP's existing resource fleet, while New Resources (Section 10.2) provides information on new resource options.

Overall, resources are located internally (connected electrically anywhere within PWP's power system) or externally (located outside PWP's service territory (i.e., "the grid.")). Figure 36 lists the internal and external resources used in the model, as well as the distributed resources included in the load forecast. Additional details regarding electric load and what is included is shown in the Load Forecast (Section 11) of the IRP. Figure 37 classifies resource size.

Figure 36: Resources by Location

External Resource Options	Internal Resource Options	Included in Load Forecast
• Onshore wind • Onshore wind paired with 4-hour batteries • Offshore wind • Utility-scale solar • Utility-scale solar paired with 4-hour batteries • Geothermal	• Community (utility-scale) solar • 4-hour storage • 6-hour storage • 8-hour storage • 10-hour storage • Commercial batteries • Fuel cells • Residential solar	• Energy efficiency • Distributed solar • Residential storage • Commercial storage

External Resource Options	Internal Resource Options	Included in Load Forecast
• 4-hour storage • 8-hour storage • 10-hour storage • Fuel cells	• Residential batteries • Commercial solar • Commercial batteries • Biogas (defined as renewable)	

Figure 37: Resource Category by Size

Category	Description
Utility-Scale	Large (~1 MW or larger). Lowest costs per unit due to economies of scale. Utility-scale resources are usually large projects located in open areas, such as fields.
Community	Large (often utility-scale) and usually owned/contracted by the utility. Allows consumers with limited roof space to opt-in and get a share of the solar output.
Distributed (Commercial)	Medium (~714 kW); usually owned/contracted by consumer.[85] Examples: panels on a parking garage or on a larger industrial building.
Distributed (Residential)	Small (~6 kW); usually owned/contracted by consumer.[86] Example: panels on a house.

10. Resources

10.1. Existing Resources

PWP has accumulated a diverse mix of resources to reduce its overall portfolio risk. PWP's current resource portfolio consists of City-owned natural gas generation and a variety of contracted energy, capacity, and renewable resources. In 2023, PWP's portfolio included approximately 200 MW of City-owned natural gas generation and 247 MW of other contracted resources. A summary of resources is provided in Figure 38.

Figure 38: Owned and Contracted Resources[87]

Facility	Owned or Contracted	Retirement or Exit Date	Fuel Type	PWP Share (MW)	RA Class	Renewable Class
IPP Coal	Contracted	6/30/2025	Coal	108	System, Flexible	None
IPP Natural Gas	Contracted	6/30/2027	Natural Gas Combined Cycle	54	System, Flexible	None
Glenarm	Owned	Not Applicable	Natural Gas – 132 MW	197	System, Local, Flexible	None

[85] https://atb.nrel.gov/electricity/2022/commercial_pv
[86] https://atb.nrel.gov/electricity/2022/residential_pv
[87] Azusa Hydro, a 15 MW contracted resource, is currently out of service and does not contribute to PWP's resource portfolio

Facility	Owned or Contracted	Retirement or Exit Date	Fuel Type	PWP Share (MW)	RA Class	Renewable Class
			Combustion Turbine and 65 MW Combined Cycle			
Magnolia	Contracted	7/1/2036	Natural Gas Combined Cycle	14	System, Local, Flexible	None
Hoover Hydro	Contracted	(Beyond 2050)	Hydroelectric	14	System	None
Palo Verde Nuclear	Contracted	2045-2047 (3 units)	Nuclear	10	System	None
Milford Wind	Contracted	11/14/2029	Wind	5	System	PCC0
PPM (also called Avangrid, or High Winds Project, or Iberdrola) Wind	Contracted	12/31/2023	Wind	2	System	PCC0
Chiquita Landfill	Contracted	11/22/2030	Landfill Gas	6	System, Local, Flexible	PCC0
Puente Hills Landfill	Contracted	12/31/2030	Landfill Gas	10	System, Local, Flexible	PCC1
Coso Geothermal	Contracted	12/31/2046	Geothermal	10- 20	System	PCC1
Geysers Geothermal	Contracted	12/31/2041	Geothermal	25	System	PCC1
Antelope Solar	Contracted	12/31/2041	Solar	7	System, Local	Solar
Columbia Two Solar	Contracted	12/18/2034	Solar	2	System	PCC1
Kingbird Solar	Contracted	12/31/2036	Solar	20	System	PCC1
Summer Solar	Contracted	12/31/2041	Solar	7	System, Local	PCC1

Facility	Owned or Contracted	Retirement or Exit Date	Fuel Type	PWP Share (MW)	RA Class	Renewable Class
Windsor Reservoir Solar	Contracted	5/30/2031	Solar	1	None	PCC1
Sapphire Solar + Battery	Contracted	12/31/2046	Solar, with Battery Energy Storage System	39 (Solar); 20 (Battery)	System	PCC1

The renewable energy in Figure 39 is identified by category for compliance with California's RPS rules. Further information is available in the IRP and on PWP's website.[88]

Figure 39: Contracts for Renewable Energy

Renewable Category	Quantity (MWh)	Contract Year
PCC1 Bundled Renewable Energy and RECs (Powerex PCC1)	70,000 (Annually)	2020-2030
PCC1 Bundled Renewable Energy and RECs (Avangrid)	10,000	2023
PCC1 Bundled Renewable Energy and RECs (Avangrid)	120,000	2024
PCC2 Bundled Renewable Energy and RECs (Avangrid)	70,000	2023
PCC2 Bundled Renewable Energy and RECs (Powerex)	70,000	2024
PCC3 RECs (STX)	30,000	2023
PCC3 RECs (STX)	35,000	2024

Additional information on owned or contracted resources is outlined in the following sections.

10.1.1. Coal

PWP has a long-term contract for 108 MW of coal-fired power generation from the IPP facility in Utah. Thirty-five participants in six states, including neighboring cities of Los Angeles, Anaheim, Burbank, Riverside, and Glendale, contract for power and capacity from the two-unit, 1,800 MW coal-fired steam plant. PWP's annual share of IPP generation is modeled as 450 GWh of must-take energy which is approximately 39% of PWP's annual load.

IPP will transition from coal-fired generation to natural gas-combined cycle in July 2025 and PWP has contracted for 54 MW of the combined cycle output through the end of June 2027. The repowered facility will provide approximately 375 GWh of energy, or about 33% of PWP's annual load. PWP's share of IPP current and future generation facilities is fixed. PWP's participation in IPP will end in 2027 and PWP will not participate in plans for the facility to transform to a renewable energy and hydrogen hub. [89]

[88] https://ww5.cityofpasadena.net/water-and-power/pwppowersources/
[89] https://www.ipautah.com/ipp-renewed/

10.1.2. Natural Gas

PWP both owns and contracts for a combined total of 264 MW of natural gas energy and capacity.

Like coal resources, natural gas resources have resource-specific carbon-emission factors. The corresponding carbon output for these resources are covered under California's Cap-and-Trade program, and count against PWP's emission allowance. Despite this carbon content, the trajectory has been increasing percentages of clean and renewable energy in PWP's portfolio as incremental renewable procurements have and will occur.

10.1.2.1. Owned

PWP owns 197 MW of natural gas capacity from the Glenarm in Pasadena, which is comprised of four combustion turbines and one combined-cycle unit. These resources are located on the PWP-side of the Goodrich. Goodrich is PWP's interconnection facility with the CAISO transmission system.

Glenarm provides key reliability benefits when PWP system loads exceed the Goodrich transfer limits or when PWP's distribution system reaches internal transfer limits.

The Glenarm units also provide significant resource adequacy capacity that help meet reliability requirements under CAISO's tariff.

10.1.2.2. Contracted

As mentioned above, PWP will begin receiving 54 MW of natural gas-fired generation output from IPP after its conversion from coal in 2025.

PWP has also contracted for up to 14 MW of energy and capacity from the Magnolia in Burbank, California, of which 6 MW is modeled as must-take energy. Any early termination of the Magnolia contract, which currently runs through June 2036, would be subject to the terms and conditions as stated in the contract.

10.1.3. Wind

PWP has contracted for 7 MW of wind capacity from the Milford Wind and PPM Wind Projects.

10.1.4. Landfill Gas

PWP has contracted for 16 MW of landfill gas from the Puente Hills and Chiquita facilities.

10.1.5. Solar

PWP has contracts for 37 MW of solar from five facilities and recently executed an agreement for the Sapphire Solar + Storage Project (Sapphire). Sapphire is slated to begin commercial operations by the end of 2026 and will add 39 MW of contracted installed capacity to PWP's existing 37 MW of installed solar capacity.

10.1.6. Hydro

PWP purchases up to 14 MW of the output of the Boulder Canyon Project at the Hoover Dam. The daily and hourly capacity and energy from Boulder Canyon varies due to river flow requirements. The annual output varies due to hydrology, storage conditions and environmental constraints.

10.1.7. Nuclear

PWP has a long-term contract for 10 MW of the Palo Verde Nuclear facility in Arizona. Palo Verde is modeled as a baseload must-take resource. Its expected output is based on historic generation patterns and its maintenance schedule.

10.1.8. Geothermal

Prior to 2023, PWP contracted for 10 MW of the Coso geothermal facility that is planned to begin delivering to PWP in 2027 and expected to increase to 20 MW of installed capacity in 2037. In 2023, PWP executed an agreement for 25 MW of the Geysers Geothermal Project (Geysers), which will begin delivering to PWP in 2027. Both Coso and Geysers are modeled as must-take baseload resources.

10.2. New Resources

10.2.1. New Resource Options

The IRP simulation model (EnCompass, detailed in Model of the IRP) selects from a variety of resources to provide future energy, capacity, renewable, and zero-carbon energy based on need, location, and economics. For the 2023 IRP, resources are generally modeled in increments of 5 MW or greater. This is considered utility scale, and the increment at which PWP is currently willing to transact. However, PWP would consider smaller increments of distributed resources – commercial and residential solar and batteries are modeled as 1 MW increments. This represents aggregations of smaller projects.

The following are the resource options available in the model are:

- Utility-scale wind
  - Onshore land-based
  - Onshore land-based paired with 4-hour lithium-ion battery storage
  - Offshore
- PV
  - Utility-scale
  - Commercial
  - Residential
  - Utility-scale paired with 4-hour lithium-ion battery storage
- Lithium-ion battery storage
  - 4-hour utility-scale
  - 6-hour utility-scale
  - 8-hour utility-scale
  - 10-hour utility-scale
  - 4-hour commercial
  - 2.5-hour residential
- Utility-scale fuel cells using renewably derived hydrogen
- Utility-scale geothermal

The load forecast includes the impacts of existing and naturally expected forecasted energy efficiency, demand response, distributed solar, distributed storage, electric vehicles, and fuel substitution. See Load Forecast for more details.

Distributed resources, in addition to those included in the load forecast, are optimized as new resource installations. The 2023 IRP assumes, for study purposes, that PWP would finance, control, and register the additional distributed resources as some form of CAISO resource that can provide energy, capacity, and/or renewable benefits.

10.2.2. New Resource Parameters

Resources are modeled with a 20-year contract term and the parameters shown in Figure 40. All resources, except possibly stand-alone batteries, provide renewable and carbon-free energy.

Figure 40: New Resource Parameters

New Resource Parameters				
Resource Type	Size	Capacity Factor	Location	Additional Details
Land-based (onshore) wind	10 MW	35%	External	
Land-based (onshore) wind paired with 4-hour lithium-ion battery storage	10 MW wind and 5 MW storage; interconnection limited at 10 MW	35% for wind; 17% for storage	External	85% roundtrip efficiency for lithium-ion storage; limited to 365 cycles per year[90]
Offshore Wind	10 MW	46%	External	
Utility-scale photovoltaic solar	10 MW	32%	External	
Commercial photovoltaic solar	1 MW	19%	Internal	1 MW represents an aggregation of smaller resources
Residential photovoltaic solar	1 MW	19%	Internal	1 MW represents an aggregation of smaller resources
Utility scale photovoltaic solar paired with 4-hour lithium-ion battery storage	10 MW solar and 5 MW storage; interconnection limited at 10 MW	32% for solar; 17% for storage	External	85% roundtrip efficiency for lithium-ion storage; limited to 365 cycles per year
4-hour utility scale lithium-ion battery storage	10 MW	17%	External and internal	85% roundtrip efficiency for lithium-ion storage; limited to 365 cycles per year

[90] https://atb.nrel.gov/electricity/2022/utility-scale_battery_storage

New Resource Parameters				
Resource Type	**Size**	**Capacity Factor**	**Location**	**Additional Details**
6-hour utility scale lithium-ion battery storage	10 MW	25%	External	85% roundtrip efficiency for lithium-ion storage; limited to 365 cycles per year
8-hour utility scale lithium-ion battery storage	10 MW	33%	External	85% roundtrip efficiency for lithium-ion storage; limited to 365 cycles per year
10-hour utility scale lithium-ion battery storage	10 MW	42%	External	85% roundtrip efficiency for lithium-ion storage; limited to 365 cycles per year
4-hour commercial lithium-ion battery storage	1 MW	17%	Internal	85% roundtrip efficiency for lithium-ion storage; limited to 365 cycles per year; 1 MW represents an aggregation of smaller resources
2.5-hour residential lithium-ion battery storage	1 MW	10%	Internal	85% roundtrip efficiency for lithium-ion storage; limited to 365 cycles per year; 1 MW represents an aggregation of smaller resources
Renewable Hydrogen-Powered Fuel Cells	10 MW	Fuel dependent	External	**6**,469 British thermal units (Btu)/kWh heat rate[91] Burns green hydrogen
Geothermal	10 MW	90%[92]	External	

Monthly capacity accreditation values for different resource types in 2030 are shown in Figure 41. PWP assumed the accreditation for solar was consistent across size. PWP also assumed 100% accreditation for storage

[91] https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf
[92] https://atb.nrel.gov/electricity/2022/geothermal

Figure 41: Resource Adequacy Accreditation for New Resources

Seasonal Qualifying Capacity in 2030 for a 100 MW Installed Capacity Plant (MW)					
Resource Type	January	February	May	August	September
Land-based (onshore) wind	21.90	23.40	21.80	13.80	14.20
Offshore Wind	35.00	39.00	31.00	53.00	43.00
Utility-scale photovoltaic solar	0.27	2.04	4.36	8.44	7.56
Commercial photovoltaic solar	0.27	2.04	4.36	8.44	7.56
Residential photovoltaic solar	0.27	2.04	4.36	8.44	7.56
Renewable Hydrogen-Powered Fuel Cells[93]	99	99	99	99	99
Geothermal	98.30	95.98	92.75	95.09	92.77
4- Hour (or greater) storage	100.00	100.00	100.00	100.00	100.00
2.5-Hour Storage	62.5	62.5	62.5	62.5	62.5

10.2.3. Availability of New Resources

The IRP model can add up to 1 GW of each of the resources listed in Figure 40 to the PWP portfolio each calendar year. At any one point, the model allows a maximum of 2 GW of each new resource type online simultaneously.

All new resource options are available in 2025 except offshore wind and fuel cells. PWP assumes that offshore wind and fuel cells are available for deployment as soon as 2030, which allows additional time for technology maturation.

Given that PWP has a peak of 320 MW in 2023, these build limits in the model are larger than what PWP may be willing to pursue. This currently prevents the model from constraining PWP's potential actions. Market availability will determine when and how much of each different resource type is available. PWP anticipates participating in the market frequently and will adjust procurement based on market intelligence.

PWP assumes that the following resources could be physically located in PWP's service territory:

- 200 MW of 4-hour batteries, or any one of the following:
  - 150 MW of 6-hour batteries
  - 100 MW of 8-hour batteries

[93] This is the weighted average value from Glenarm. Glenarm is a proxy for a dispatchable, fuel-dependent resource.

- 50 MW of 10-hour batteries

- 5 MW of utility scale solar
- 5 MW of fuel cells
- Distributed resources (residential solar, commercial solar, residential storage, commercial storage)

Other resources would be located outside PWP's service territory.

10.2.4. Inflation Reduction Act and Tax Credits

The IRA, which was enacted in 2022, provides for significant investments to promote decarbonization in the U.S. Current assessments of the impact of the IRA indicate up to a 10% decrease in net emissions by 2030 (compared to 2005 levels).[94] The IRA includes $369 billion over the next decade for energy and climate initiatives – the largest investment in climate to date.[95] The majority of this investment will be in the form of tax credits.

The IRA extends and modifies the previously available investment and production tax credits. With the ITC, the credit received is a percentage of the cost of a project. The PTC is similar, but the amount compensated depends on anticipated energy production versus project cost.

The ITC and PTC have been in place for decades in the U.S. and have helped encourage development of renewable generation. While eligibility has historically been limited to certain technologies, under the IRA, the ITC and PTC become new technology-neutral incentives starting in 2025. This is also the first year for addition of new resources in the 2023 IRP; therefore, the technology-neutral incentives will be included in resource costs.

To qualify for the technology-neutral PTC under the new Section 45Y of the Internal Revenue Code, resources must emit zero emissions based on a lifecycle assessment. The 2023 IRP assumes that onshore wind and geothermal projects will incorporate the PTC.

Energy storage now qualifies under the technology-neutral ITC according to the new Internal Revenue Code Section 48D. Previously, storage eligibility required that associated charging be from a renewable resource. That no longer applies. The 2023 IRP assumes that storage, offshore wind, solar, and fuel cells will use the ITC.

The Federal Government revamped the ITC and PTC to support U.S. labor and supply chains. Generally, there is both a base ITC and PTC which are multiplied by a factor of five if developers meet prevailing wage and apprenticeship requirements. There are additional 10% adders if domestic content requirements are met, or if the project is in an energy community. Details on these multipliers appear in Figure 42.[96] Figure 43 shows the general tax credits. The IRP cost inputs assume that prevailing wage and apprenticeship requirements have been met.

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[94] https://rhg.com/research/climate-clean-energy-inflation-reduction-act/
[95] https://www.cohnreznick.com/insights/inflation-reduction-act-renewable-energy-tax-incentives
[96] Jenkins, Jesse D.; Farbes, Jamil; Jones, Ryan; and Mayfield, Erin N. (2022), "REPEAT Project Section-by-Section Summary of Energy and Climate Policies in the 117th Congress," B23 REPEAT Project, http://bit.ly/REPEAT-Policies. doi: 10.5281/zenodo.6993118; https://docs.google.com/spreadsheets/d/1X2PORZp5JzP2yWbdUSbXphEIlGPEOlJNI-T12gz7n1s/edit#gid=1108881515

There are also grants, loans, and loan financing available under the IRA. These may provide opportunities for PWP to reduce or offset future costs. PWP is pursuing grant opportunities while also considering self-build IRA criteria.

Figure 42: Bonus Tax Credits for Renewable Resources

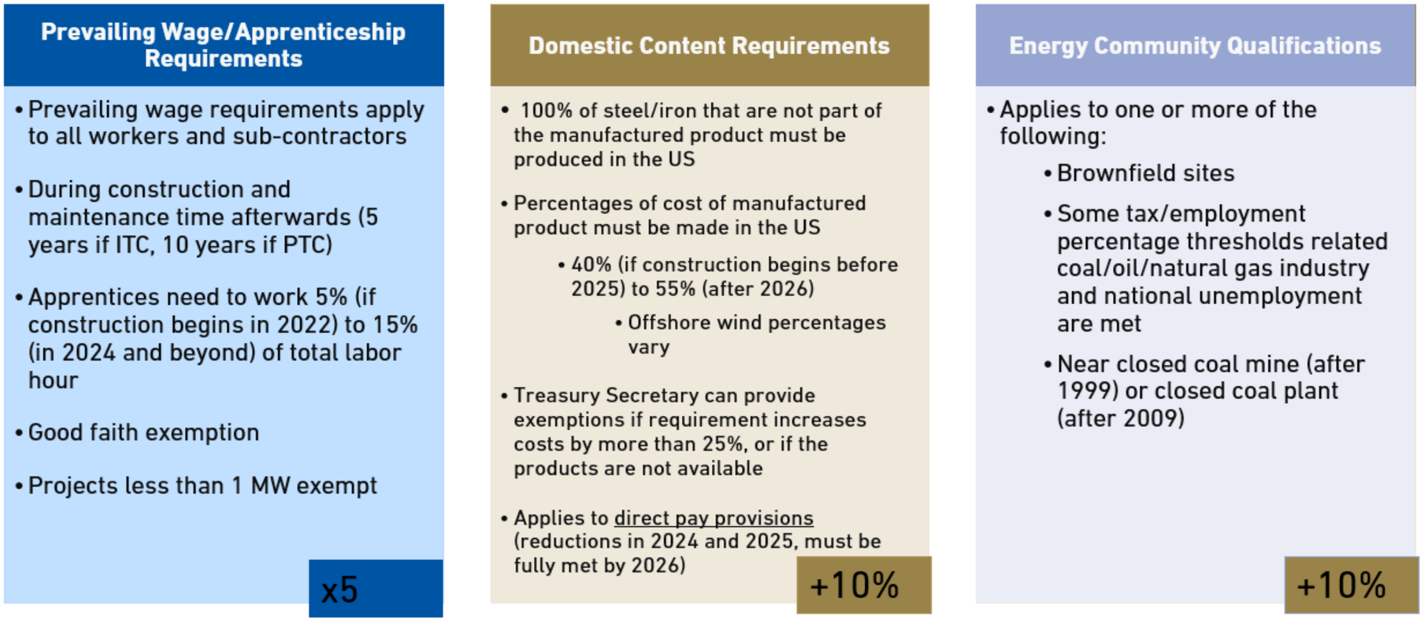


Figure 43: IRA Tax Credits for Projects in Service After December 2024

	Clean Electricity ITC, Section 48D		Clean Electricity PTC, Section 45Y	
	If GHG emissions are zero		*Does not apply to storage*	
	Meet prevailing wage for construction + 1st 5 years of operation	Miss prevailing wage for construction + 1st 5 years of operation	Meet prevailing wage for construction + 1st 10 years of operation	Miss prevailing wage for construction + 1st 10 years of operation
Base Credit	30% ITC	6% ITC	$27.60/MWh (in 2025 $) PTC	$5.52/MWh (in 2025 $) PTC
AND Meet domestic content requirements, or located in an energy community	40% ITC	8% ITC	$30.35/MWh (in 2025 $) PTC	$6.07/MWh (in 2025 $) PTC
OR Meet both	50% ITC	10% ITC	$33.39/MWh (in 2025 $) PTC	$6.62/MWh (in 2025 $) PTC

Credits phase out (100%, 75%, 50%) in following three years when annual greenhouse gas emissions from electricity are 25% of 2022 values, or 2032 (whichever year is later)

Figure 44 summarizes the IRA tax credits applied to new resources in the 2023 PWP IRP study and modeling process.

Figure 44: PWP 2023 Integrated Resource Plan Tax Credit Assumptions

ITC/PTC Component	2025 to 2032	2033	2034	2035	2036+	Notes
PTC Section 45Y (Clean Electricity Production Tax Credit)	100%	100%	75%	50%	0%	Apply to onshore wind, geothermal
ITC Section 48E (Clean Electricity Investment Tax Credit)	30%	30%	22.5%	15%	0%	Apply to solar, storage, fuel cells, offshore wind
Section 25D	30%	26%	22%	0%	0%	• Residential solar and residential storage

ITC/PTC Component	2025 to 2032	2033	2034	2035	2036+	Notes
						• For homeowners that own solar and ≥3 kWh storage systems[97] • This assumes that homeowners will purchase the solar and storage, and that PWP will compensate them

There are various factors that may change tax credit selection and utilization. For example, PWP understands that tax credits may be extended. PWP also may find that solar may elect to use the PTC instead of the ITC. PWP will endeavor to stay abreast of market developments and may study the impacts of various tax credit assumptions.

10.2.5. Contract vs. Ownership and Tax Credits

In the 2023 IRP, modeled resource costs are the estimated price that can be obtained in the market for a PPA. In actual practice. PWP will pursue the most economic option relative to PPA's vs. ownership or self-build. The IRP identifies the best fit resources, without regard for ownership structure. The process for acquiring additional specific resources for PWP's resource portfolio includes evaluation of cost, availability, risk profile, and other factors relevant at the time.

Under the IRA, tax-exempt entities, including government agencies, can receive direct payments from the Treasury Department for technologies such as carbon capture, energy storage, and traditional renewables. Direct pay applies to the new ITC and PTC and includes domestic content requirements. Specifically, for a project to meet the domestic content requirements, iron or steel that is not part of manufactured products must be made in the U.S., and a certain percentage of the total cost of the manufactured products must be made in the U.S. See Figure 45[98]. For projects that begin construction in 2024 or 2025 that do not meet domestic content requirements, the direct pay credit is reduced by 10% and 15%, respectively. The credit is eliminated altogether for non-conforming projects that begin in 2026 or later. Since meeting domestic content requirements adds 10% to the base PTC and ITC, direct pay implies a minimum 40% ITC. The Treasury Secretary can provide exemptions if these requirements increase the overall cost of construction by more than 25% or if the requisite quantity and quality of U.S. products are unavailable. As of early 2022, the IRS is expected to provide additional clarification and guidance on the domestic content requirement of the IRA and Congress has implied it will attempt to address issues that have been identified with implementation of this provision.

[97] https://www.seia.org/initiatives/solar-investment-tax-credit-itc; https://www.mcguirewoods.com/client-resources/Alerts/2022/12/inflation-reduction-act-creates-new-tax-credit-opportunities-for-energy-storage-projects
[98] https://docs.google.com/spreadsheets/d/1X2PORZp5JzP2yWbdUSbXphElIGPEOlJNI-T12gz7n1s/edit#gid=313301748

Figure 45: Domestic Content Requirements

% of the Total Cost of the Manufactured Products That Must Be Made in the U.S.		
Construction Start Date	**Offshore Wind**	**All Other Technologies**
Begin construction before 2025	20%	40%
Begin construction in 2025	27.5%	45%
Begin construction in 2026	35%	50%
Begin construction after 2026	45%	55%
Begin construction in 2027	45%	55%
Begin construction after 2027	55%	55%

10.2.6. Cost of New Resources: The General Market

Estimated resource costs available from public sources are different than actual PPA pricing and project costs. Individual projects have location and technology specific factors, and timelines that influence prices. There has also been exceptional market pressure on costs in the past few years.

Over the past three years, supply chain issues caused by the COVID-19 pandemic have dramatically increased costs in the short term. Additionally, solar has been impacted by the Uyghur Forced Labor Prevention Act in the U.S., which requires verification that there is no forced labor in supply chains. Since most of the solar supply chain is in China, this regulation has reduced U.S. domestic supplies from China. According to a Utility Dive article, "Extreme market conditions in 2021 and the early months of 2022 may have added some 13-15% in costs to solar prices beyond what long-term trends would have predicted, according to NREL's price analysis report for the first quarter of 2022, released Nov. 30."[99]

LevelTen Energy, a firm that provides a central, standardized service for renewable developers to submit project cost data for buyers interested in projects and pricing, publishes a "PPA Index Report" every quarter. While the full report is available only with a paid subscription, the free version provides insights into solar and wind pricing trends.[100] The 25th percentile of CAISO solar bids are in the mid-$40/MWh range, an increase of between 10% and 15% from the previous quarter and an increase of approximately 50% from one year ago. These bids are for future delivery of solar, meaning that the commercial date of operations for the projects is in the 2024-2027 range.

Supply issues caused by COVID-19 and regulatory concerns have also been exacerbated by other market factors. Resources across the grid are retiring. Additionally, non-utilities, such as financial corporations, have entered the market, all contributing to the great demand for projects.

Furthermore, to connect additional renewable energy supply, the grid will require significant transmission upgrades. A study by Princeton University titled *Net-Zero America* found that reaching net-zero GHG emissions by 2050 will require a

[99] https://www.utilitydive.com/news/nrel-benchmark-solar-pricing-cost-report/637919/

[100] https://www.leveltenenergy.com/post/q1-2023-north-america-ppa-price-index

60% expansion of the nation's transmission system by 2030 and 200% by 2050.[101] The costs for transmission additions would be paid by grid users.

10.2.7. Pasadena in the Market

PWP is an active market participant and evaluates new resource offers both independently and through its relationship with SCPPA. SCPPA is a Joint Powers Authority comprised of 11 municipalities and one irrigation district. SCPPA realizes operational efficiencies and cost savings through joint procurement and financing of projects and services. PWP recently executed agreements for additional resources that showed price impacts of market forces such as supply chain constraints, IRA-related tax credits, and other factors. The new agreements are for solar energy paired with storage and geothermal energy from the Geysers in northern California. PWP also evaluated a potential wind energy PPA. The price of these resources is shown in Figure 46.

Figure 46: Reference Market Prices

Market Prices for New Resources		
Type	**Year Online**	**Price**
Land-based onshore wind	2025	\$45.00/MWh – \$70.00/MWh
Utility-scale photovoltaic solar (EDF Sapphire)	2027	\$28.00/MWh – \$35.36/MWh
4-hour utility-scale lithium-ion battery storage (EDF Sapphire)	2027	\$7.00/kW-Month – \$11.70/kW-Month
Geothermal (Calpine Geysers)	2027	\$70.00/MWh – \$110.00/MWh

Another resource cost reference available for use in the 2023 IRP comes from NREL, a national laboratory under the U.S. DOE. Every year, NREL releases its ATB report, a public source for current and future costs according to technology types and locations. NREL provides cost estimates for generic projects.

PWP has observed that current market prices are higher than NREL's near-term estimates. One reason is that NREL provides broad, bottom-up pricing for the U.S. that is not equivalent to actionable project pricing for specific areas. Different ways of quantifying pricing – for example, using the LCOE as a proxy for available prices – come with assumptions on financing, resource performance, and more. Also, NREL has stated in multiple forums, publications, and webinars that its ATB report does not account for near-term market changes. Furthermore, NREL explains, in the context of solar, the purpose of the ATB report and how it may vary from market prices as follows: [102]

> *"It is important to understand what the NREL benchmarks are and are not, and for what purposes they should be used. The benchmarks are bottom-up cost estimates of all major inputs to typical PV and energy storage system configurations and installation practices. Bottom-up costs are based on national averages and do not necessarily represent typical costs in all local markets.*
>
> *The primary purpose of the NREL benchmarks is to provide insight into the long-term trajectories of PV and storage system costs, including which system components may be driving installed prices and where*

[101] https://netzeroamerica.princeton.edu/?explorer=year&state=national&table=2020&limit=200
[102] https://www.nrel.gov/news/program/2022/nrel-tracks-pv-and-energy-storage-prices-in-volatile-market.html

there are opportunities for price reductions. The benchmarks are also used to project future system prices, provide transparency, and facilitate engagement with industry stakeholders.

NREL's benchmarks are often compared with other PV and storage system cost metrics, including reported prices and other modeled benchmarks. However, there is significant variation within and between these metrics because of the various methods and assumptions used to develop them, and different benchmarks are useful for different purposes."

Given this context, NREL's estimates do not reliably reflect actual cost information in the near-term. Adopting NREL's estimates today may drastically understate the actual cost of procuring a resource such as solar in this market environment. Figure 47 and Figure 48 show a detailed example of solar pricing. The pricing is provided in nominal dollars and in real 2023 dollars.

Figure 47: Utility-Scale Solar Nominal Pricing

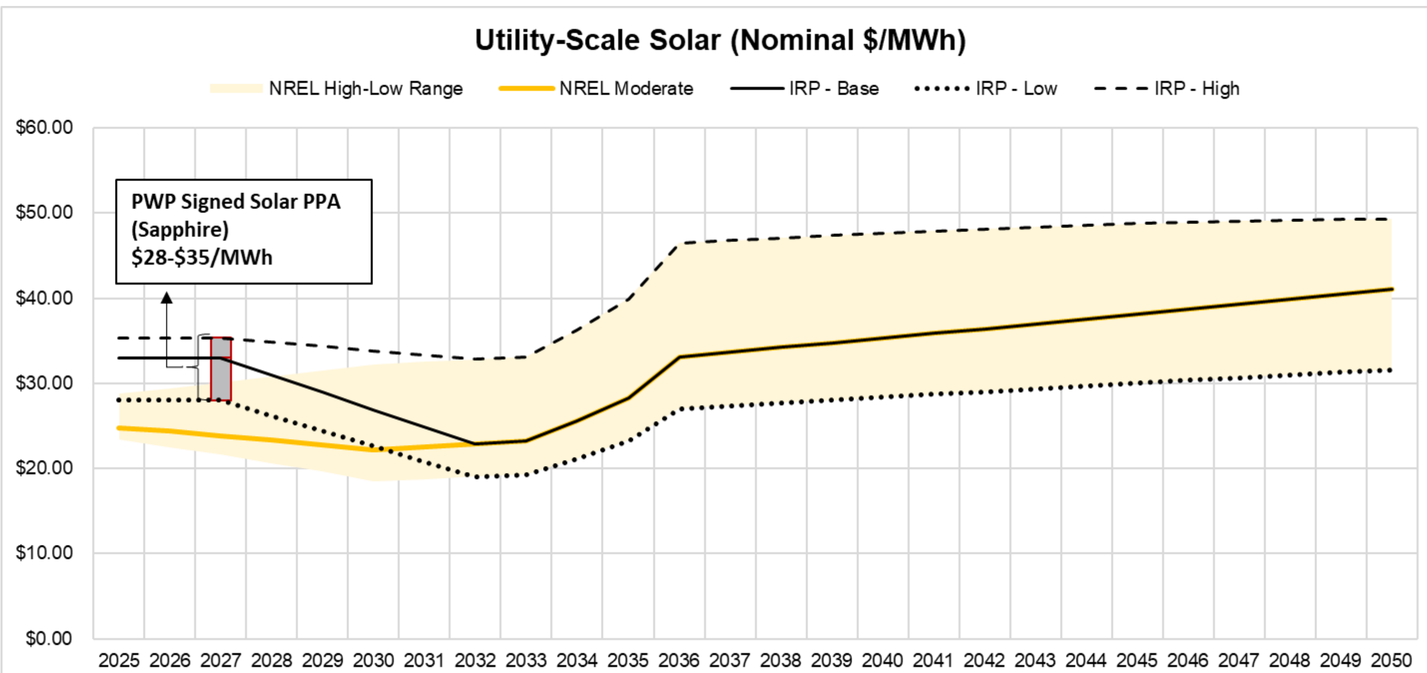
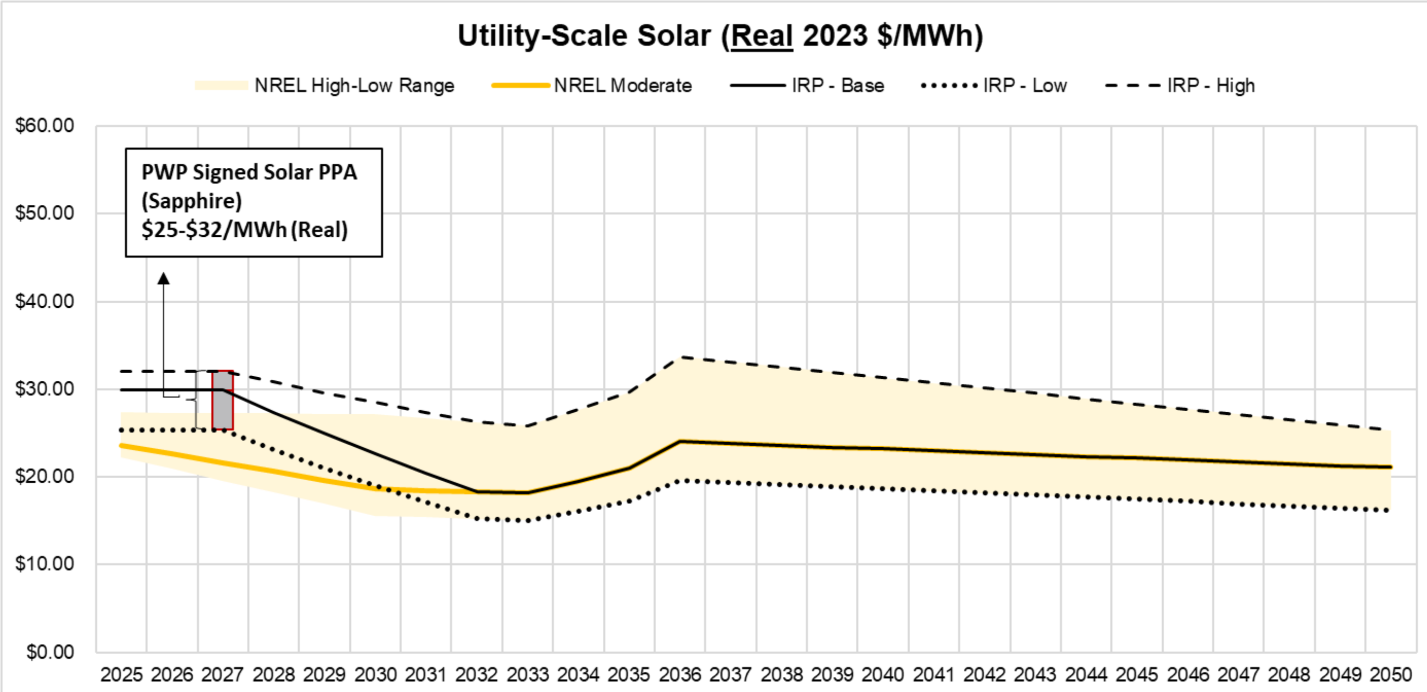


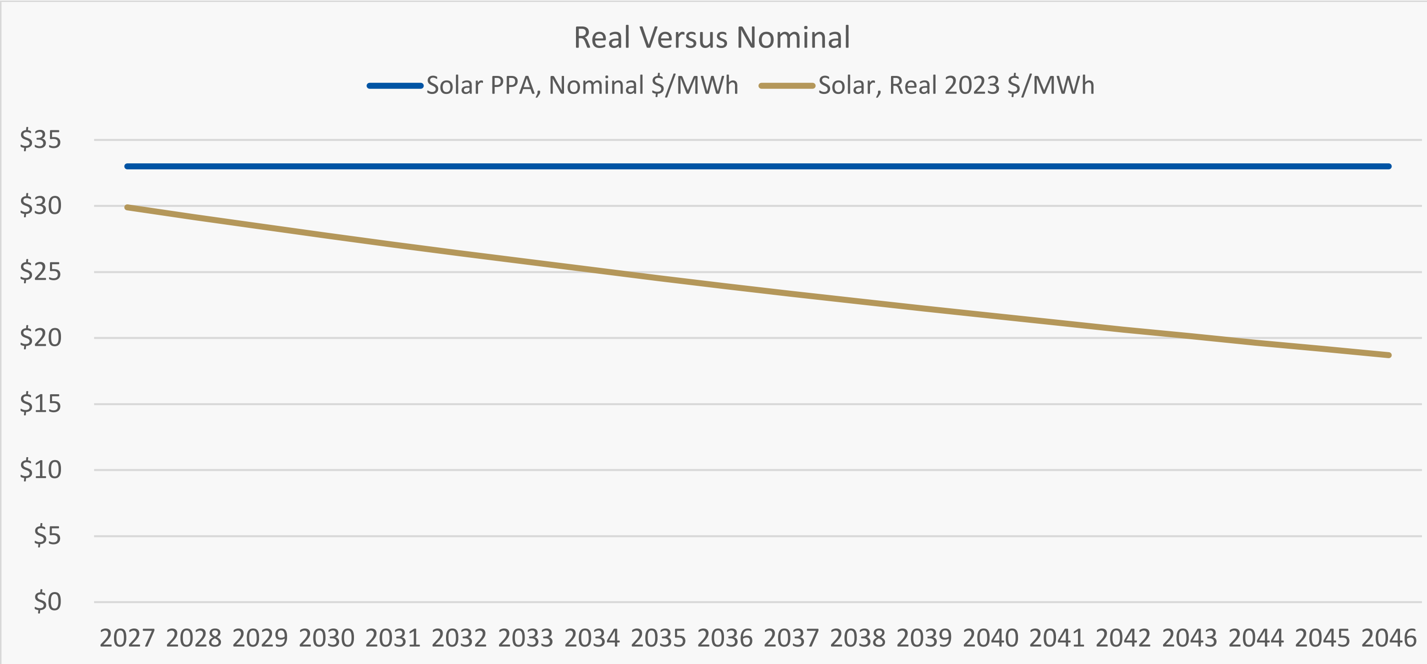
Figure 48: Utility-Scale Solar Pricing in Real 2023 $



Evaluating nominal versus real values can often lead to confusion. See Figure 49 for an example of how real versus nominal values – based on the same data – can appear. Nominal dollars reflect the present value of goods and services exchanged in the marketplace. However, using real dollars gives the true value of goods and services produced or sold because it strips out the effects of inflation. Using nominal costs and discounting at the nominal discount rate is the equivalent of using real costs and discounting at the real discount rate. Using nominal costs and discounting at the nominal discount rate is standard industry practice for IRPs. Market prices for natural gas and electricity are generally quoted in nominal terms. Using nominal dollars is not an artificial impact on costs, rather it shows the cost in a specific future year. NREL provides additional information on real versus nominal dollars.[103] This IRP usually presents the cost of new resources in nominal dollars using the nominal discount rate.

[103] https://youtu.be/v-objUKg3tA?t=1338; https://www.nrel.gov/docs/legosti/old/5173.pdf

Figure 49: Real vs. Nominal Values



It is important to note that nominal values in real dollars are not equivalent to real values in real dollars. See Figure 50. NREL calculates real values in real dollars. The IRP calculates nominal values in nominal dollars and translates them into real dollars.

PWP's 2023 IRP uses the best available information to develop near-term benchmarks for long-term projections for the cost of new technologies. How prices will change in the future is unknown. For example, there could be relaxed financial pressures induced by IRA incentives, or conversely, constraining pressures induced by transmission costs. Because of this uncertainty, once the resource mixes were identified, PWP re-evaluated the costs of new resources using sensitivity tests to quantify potential cost variation.

Figure 50: Real vs. Nominal Levelized Cost of Energy

Real vs. Nominal LCOEs (2030)		
Solar (Utility Scale, Single Axis Tracking)	**Real LCOE**	**Nominal LCOE**
GDP Deflator for Nominal to Real		1.280
Inflation Rate	2.5%	2.5%
Tax Rate (Federal and State)	25.7%	25.7%
Present Value - Depreciation (PV-DEP)	0.875	0.875
Interest During Construction	4.5%	4.5%
WACC	2.44%	5.0%
Recovery Live (years)	30	30
Capital Recovery Factor (CRF)	4.7%	6.5%
ITC (Model Schedule)	30%	30%
Overnight Capital Cost ($/kW-AC)	$734.33	$940.01
Fixed O&M ($/kW-year-AC)	$15.22	$19.48

Real vs. Nominal LCOEs (2030)		
Solar (Utility Scale, Single Axis Tracking)	**Real LCOE**	**Nominal LCOE**
Capacity Factor	32%	32%
Project Finance Factor (No ITC)	1.043	1.043
Project Finance Factor (with ITC)	0.685	0.685
Construction Finance Factor	1.022	1.017
LCOE Calculations		
No ITC	$18.67	$30.09
ITC (Model)	$14.12	$22.14
No ITC (2020 Actual Amount)		$23.51
ITC (2020 Actual Amount)		$17.30

The IRP uses available market cost data and initial project production date to reflect the best-available information of current market conditions. These prices were then blended into NREL estimates over a period of several years. By 2032, these prices fully merge into the moderate cost estimates from NREL. NREL cost estimates have been updated to include the impacts of the IRA. Under the IRA, tax credits will expire when electricity-sector related annual greenhouse gas emissions are less than or equal to 25% of 2022's emissions, or in the year 2032, whichever occurs later. PWP's IRP assumes that tax credits will substantially decrease in 2032 and fully expire by 2036.

PWP provided the Excel files with raw data, citations, and the blending methodology to the STAG in April 2023. The discussion of these costs, and how they were derived, extended over at least two STAG meetings. These meetings generated approximately 20 questions on this topic, and PWP provided the answers to all STAG members. New resources costs are in the Appendix – Cost of New Resources.

However, there remains a great deal of uncertainty on future pricing. In the EDF Sapphire Project (Sapphire), the project developer included a floor and a ceiling price for the solar and storage components. PWP provided details on this to the Pasadena City Council on November 14, 2022.[104] The final contract price is still subject to change as the project advances toward completion. The IRP uses low and high cost curves by blending low and high market prices into NREL's advanced and conservative scenarios. This allows the IRP to run sensitivity tests on portfolios to test how much specific resource mixes could cost if prices change.

10.2.8. Spotlight Technologies

The following subsections provide spotlight information on some technologies.

10.2.8.1. Spotlight on Fuel Cells

Like a cross between a natural gas turbine and a battery, a fuel cell consumes hydrogen as fuel and electrochemically transforms that hydrogen fuel into electricity, water, and heat. Fuel cells do not produce carbon emissions or air pollutants

[104] https://ww2.cityofpasadena.net/2022%20Agendas/Nov_14_22/Agenda.asp

that cause smog.[105] If the hydrogen is generated using renewable energy, then fuel cells count as renewable resources in California.[106]

According to the EIA, as of October 2021, there were 166 fuel cell plants with total capacity of 260 MW, the largest of which is 16 MW. All but six use natural gas for the hydrogen source. [107] Fuel cells are an earlier stage generation technology.

NREL does not report on fuel cell costs in the ATB. For PWP's IRP, fuel cell data came from the EIA.[108]

10.2.8.2. Spotlight on Geothermal

Calpine's Geysers project, a geothermal project that PWP contracted for, will begin delivery to PWP in 2027 and is located north of San Francisco. It is the single largest geothermal operation in the world and was the first commercial geothermal plant to operate in the Western hemisphere.[109] According to Calpine, the plants extract hot steam to turn turbines that generate electricity.[110] This appears to match the hydro-flash geothermal technology described by NREL, so PWP's IRP uses that benchmark for future projections.[111]

10.2.8.3. Spotlight on Offshore Wind

Offshore wind may be a key resource to assist with decarbonization. Approximately 80% of the U.S. population lives in coastal areas. Offshore wind also has a generation pattern that may complement that of solar.

Offshore wind is a nascent but growing global industry. According to the DOE, the global installed capacity of offshore wind was more than 50 GW in 2021.[112] For comparison, the size of the entire U.S. grid is 1,144 GW.[113] There are two operational offshore wind farms in the U.S.: the 30 MW Block Island Wind Farm and the 12 MW Coastal Virginia Offshore Wind pilot project.[114] Offshore wind deployment in the U.S. has been spurred by state decarbonization policy. As of May 2022, the pipeline for offshore wind projects in the U.S. was more than 40 GW by 2040 and concentrated across eight states on the East Coast.[115] This does not include California's goal of 5 GW of offshore wind by 2030 and 25 GW by 2045. The Biden Administration has set a 30 GW offshore wind goal by 2030.

When sea depths exceed 60 meters, offshore wind technology changes from fixed-bottom to floating. The Atlantic Coast has shallower waters than the Pacific Coast, which allows for fixed-bottom versus floating technology. As of 2021, more

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[105] https://www.energy.gov/eere/fuelcells/fuel-cells
[106] https://www.energy.ca.gov/programs-and-topics/programs/renewables-portfolio-standard
[107] https://www.eia.gov/energyexplained/hydrogen/use-of-hydrogen.php
[108] https://www.eia.gov/outlooks/aeo/supplement/excel/suptab_55.xlsx; fixed O&M was assumed to be 2.5% of capital costs, which matches NREL's O&M assumption for batteries.
[109] https://www.calpine.com/operations/power-operations/technologies/geothermal; https://geysers.com/
[110] https://player.vimeo.com/video/58388368
[111] https://player.vimeo.com/video/58388368
[112] https://www.energy.gov/eere/wind/articles/offshore-wind-market-report-2022-edition
[113] https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php
[114] https://www.energy.gov/eere/wind/articles/offshore-wind-market-report-2022-edition
[115] https://www.energy.gov/eere/wind/articles/offshore-wind-market-report-2022-edition; https://cnee.colostate.edu/wp-content/uploads/2021/07/OffshoreWind-July-2021.pptx.pdf

than 99% of the global operational offshore wind farms had fixed-bottom foundations. Floating technologies are in earlier development stages. Globally, there is a total of 123.4 MW of installed floating offshore wind capacity.[116] The West Coast must rely on floating technologies due to the depth of the Pacific Ocean in favorable wind resource areas.[117] The Biden Administration is targeting an additional 15 GW of offshore wind in floating technology by 2035 and is looking to support innovation to reduce costs by more than 70% to reach a targeted cost of $45/MWh.[118]

For fixed-bottom technologies online between 2020 and 2025 in the U.S., prices (in 2021 dollars) range from $149/MWh (Skipjack and U.S. Wind) to $75/MWh (Mayflower Wind). Costs could decrease to $60/MWh (in 2021 dollars) for fixed-bottom technologies by 2030.

Floating technologies costs are uncertain given their limited deployment. The DOE currently cites costs from around $200/MWh (in 2021) to between $58/MWh and $120/MWh (in 2021 dollars) by 2030.[119] NREL produced cost projections specific to five offshore areas in California, and assuming PTC eligibility, costs in 2030 are expected to range from $79/MWh to $88/MWh (in 2021 dollars).[120] In 2022, the U.S. Bureau of Ocean Energy Management (BOEM) held an auction for onshore leases for five areas – three in Morro Bay and two in Humboldt County.[121] The CPUC's 2021 Preferred System Plan included 1.7 GW of offshore wind by 2032.[122]

NREL had to make a series of assumptions regarding the price trajectory of offshore wind. For example, it was assumed that port and grid infrastructure is available; therefore, costs for land-based substation or bulk transmission upgrades were not included in pricing. CAISO estimates between $5.8 and $8 billion in upgrade costs for 4 GW of offshore wind in the Humboldt area and $0.11 billion for 6 GW in the Diablo Canyon-Morro Bay areas.[123] California is also investing in the requisite supply chain and port infrastructure.[124] NREL also assumes a 1 GW installation for its California cost estimates and that plants and turbines will get bigger over time, which will lead to cost reductions. Future decreases in costs are also dependent, in part, on lessons learned from fixed-bottom installations on the Atlantic Coast and from other installations around the world. Overall, offshore wind costs are uncertain.

10.2.8.4. Spotlight on Hybrids

Different technology types can be located at the same site, and when they are designed to work together as a single installation, the result is often called a hybrid resource. Simply siting different technology types together (often called co-location) can reduce costs associated with site preparation, site acquisition, site permitting, interconnection upgrades, installation, and hardware, among other costs. Projects usually share an interconnection point and connect to each other.

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[116] https://www.energy.gov/eere/wind/articles/offshore-wind-market-report-2022-edition
[117] https://www.nrel.gov/wind/offshore-resource.html
[118] https://www.whitehouse.gov/briefing-room/statements-releases/2022/09/15/fact-sheet-biden-harris-administration-announces-new-actions-to-expand-u-s-offshore-wind-energy/
[119] https://www.energy.gov/eere/wind/articles/offshore-wind-market-report-2022-edition
[120] https://www.nrel.gov/docs/fy21osti/77384.pdf
[121] https://www.boem.gov/renewable-energy/state-activities/california
[122] https://www.energy.ca.gov/news/2022-08/cec-adopts-historic-california-offshore-wind-goals-enough-power-upwards-25
[123] http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf
[124] https://www.energy.ca.gov/news/2022-03/state-approves-105-million-prepare-port-humboldt-bay-offshore-wind

However, there could be more value from siting resources apart rather than together. For example, storage may unlock more revenue closer to load, and solar in areas with higher irradiance.

Currently, the most common hybrid resources are storage sited with solar. Prior to the IRA, storage had to charge from a renewable resource to be eligible for the ITC, and solar proved to be the market's dominant choice for this application.

In the 2022 NREL ATB, NREL notes that the dominant architecture for solar and storage pairings is still unknown and could evolve over time based on grid composition, performance, and incentives. The PWP 2023 IRP assumes an AC-coupled system when generation and storage form a hybrid installation. In an AC-coupled system the grid has a separate interface with each component (generation and storage). The capital cost of a co-located AC-coupled system is 7% lower than if PV and storage were sited separately, according to NREL. The IRP assumes this capital cost reduction, as well as a 2:1 renewable to storage ratio. PWP's IRP includes both wind and solar paired with 4-hour battery storage.

10.2.9. How Electricity Products Are Priced

Electricity is comprised of different components. Defining the different components, or attributes, ensures reliability and allows the components to be financially traded. See Figure 51 for examples on the different components of electricity (definitions in the table are simplified).

Figure 51: Different Components of Electricity

Part	Simplified Definition	Standard Units
Energy	The flow of energy	MWh
Resource Adequacy	The ability to flow when needed	kW-Month
Renewable	Green	REC
Clean	Zero carbon	MWh

Some technologies are better than others at providing certain attributes of electricity. See Figure 52 for examples. Resources are typically priced in metrics that best reflect their strongest value streams. Wind and solar are common energy resources, so they are priced in terms of energy. Storage is a prevalent capacity resource, so it is priced in terms of capacity. Costs for the 2023 IRP in Figure 53 and Figure 54 are priced at their industry-standard units. Costs are presented in nominal dollars per unit of installed (non-accredited) capacity.

Figure 52: Different Components of Electricity by Resource Type

	The Flow	Stability Assistance	The Ability to Flow When Needed	Green	Zero Carbon
Value	**Energy**	**Ancillary Services**	**RA**	**Renewable**	**Clean**
Wind	✓	✓	✓	✓	✓
Geothermal	✓	✓	✓	✓	✓
Solar	✓	✓	✓	✓	✓
Batteries	✓	✓	✓		✓

	The Flow	Stability Assistance	The Ability to Flow When Needed	Green	Zero Carbon
Value	**Energy**	**Ancillary Services**	**RA**	**Renewable**	**Clean**
Natural Gas	✓	✓	✓		

Figure 53: Cost of New Energy Resources

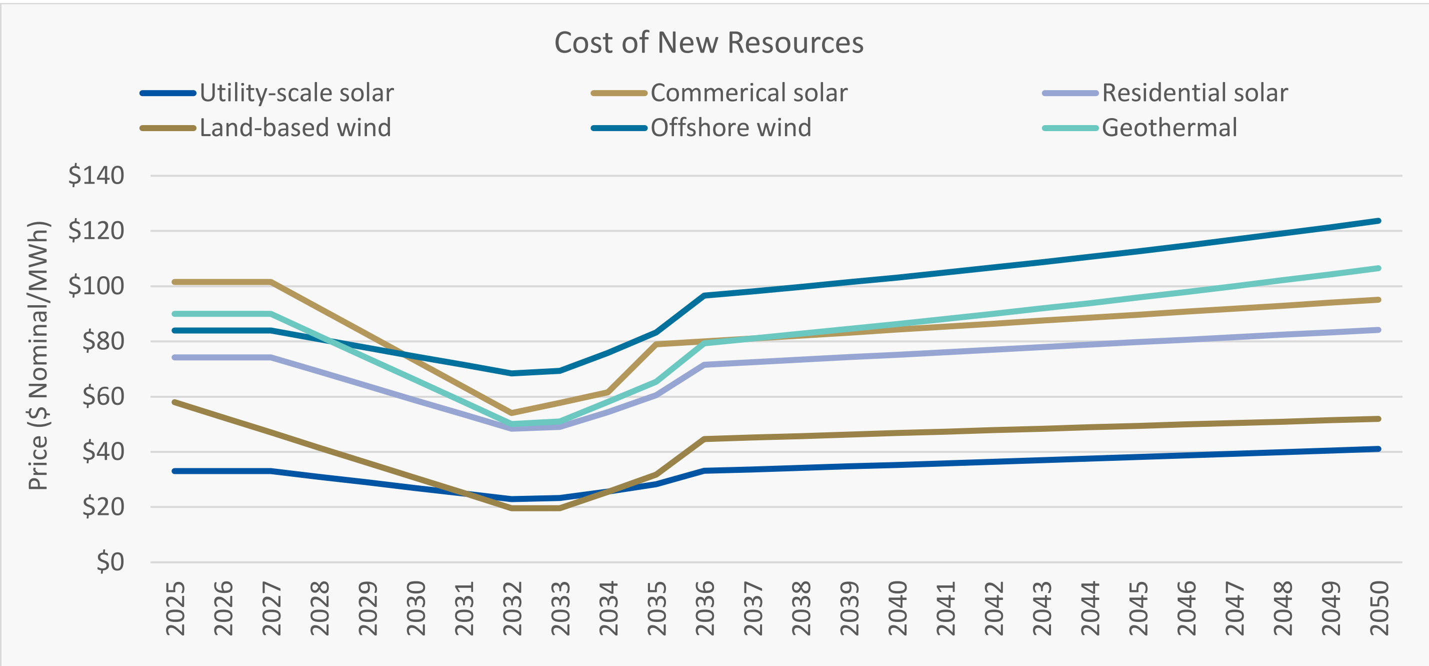
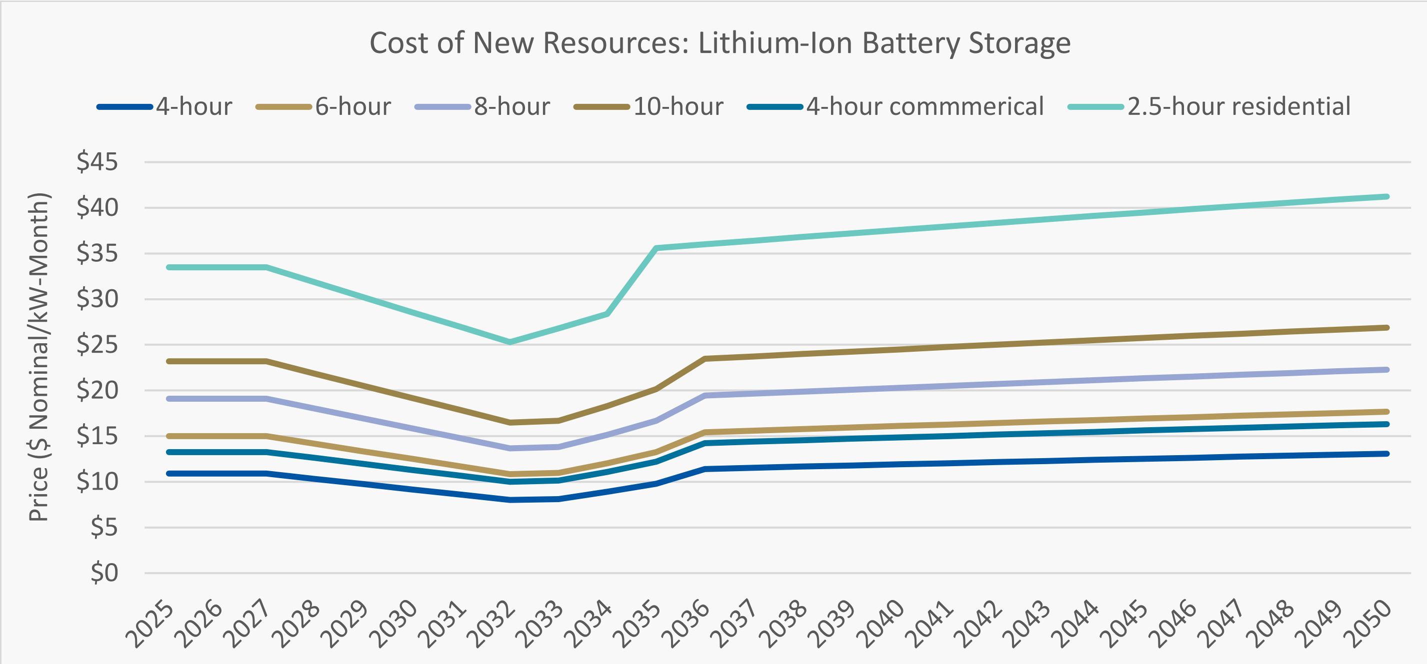


Figure 54: Cost of New Capacity Resources



10.2.10. Cost vs. Value

There is a difference between cost and value. Costs include factors such as capital expenditures, financing, permitting, transmission interconnections, operations, and maintenance. LCOE is a commonly cited industry metric that spreads all the costs for a resource over the lifetime of anticipated generation.

Value is what the resource earns in the energy, ancillary service, RA, renewable, and clean energy markets. Value depends on factors such as grid composition (e.g., percentage of renewable energy), grid location, and time of day. The IRP model optimizes between cost and value. The lowest-cost resources do not always provide the greatest value. Evaluating both cost and value helps explain resource decisions.

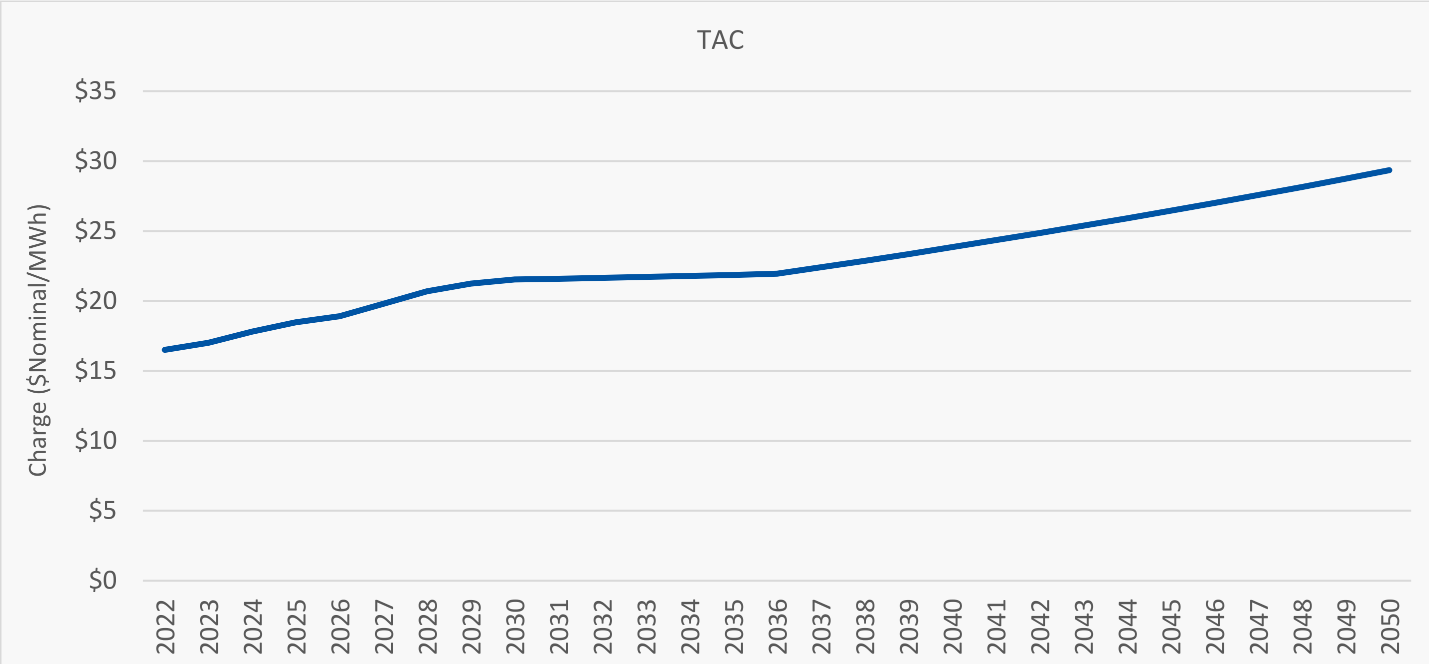
10.2.11. Transmission Access Charge

The TAC is a rate charged by CAISO for transmission use. In the case of Pasadena, this is charged on any load brought into CAISO, or any contracted resources in CAISO. In other words, this applies to everything but resources internal to PWP, including Glenarm, storage located within PWP, or distributed resources. CAISO provides estimates of their TAC.[125]

Figure 55 has the TAC applied to external resources in the IRP model.

[125] http://www.caiso.com/Pages/DocumentsByGroup.aspx?GroupID=7A2CFF1E-E340-4D46-8F39-33398E100AE7

Figure 55: Transmission Access Charge



10.2.12. Exclusions and Other Notes

PWP has excluded the following from consideration in its 2023 IRP:

- New long-term fossil-fueled generation capacity
  - New long-term fossil-fueled generation capacity does not align with PWP's environmental goals
- New nuclear capacity
  - Small modular reactors or new nuclear builds were excluded due to cost, timeline, and location limitations
- Non-lithium-ion storage
  - Limited data is available for modeling alternative battery technologies at this time

As projects are piloted or as costs mature in the markets, PWP will consider all zero-carbon resource alternatives that will support reliability and reduce costs for consumers.

10.3. Diversified Procurement Portfolio

The 2018 CEC guidelines note that "The IRP Filing must address procurement for a diversified procurement portfolio consisting of both short-term and long-term electricity, electricity-related, and demand response products."

As part of the IRP filing, POUs must submit four standardized tables covering capacity, energy, RPS, and GHG emissions. These are filed separately.

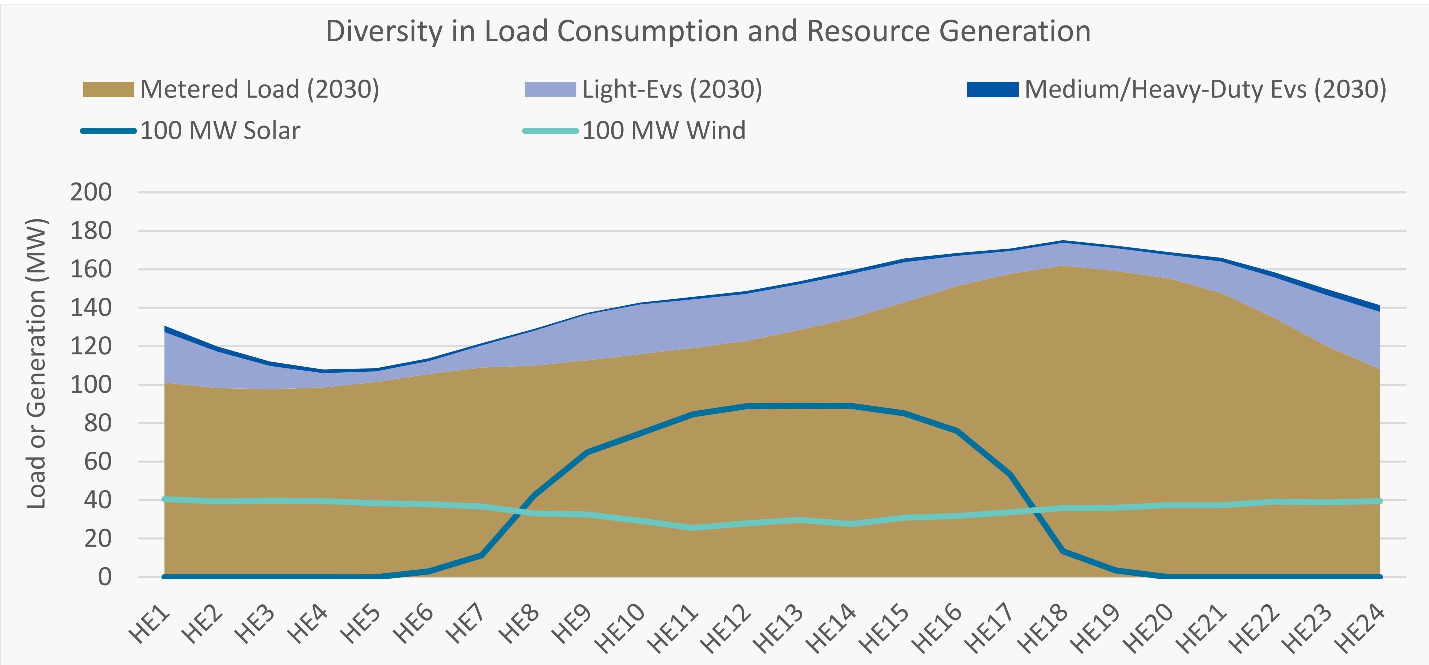
PWP considered the following sources of diversity in its portfolio:

- Resource types

- PWP is committed to supporting a portfolio that includes a variety of resource types. Figure 56 illustrates the different operational profiles of various resources. Resource diversity reduces risk by limiting reliance on the performance profile a particular resource.

- Resource locations
    - Varying resource location is another form of risk reduction. For example, weather events in one area may not affect resources in another area. Different resource locations can also help hedge transmission congestion costs.
- Duration of contracts
    - Contract terms can vary from monthly to annual. Using varying contract terms provides flexibility, particularly in tight resource markets.

Figure 56: Diversity in Load Consumption and Resource Generation



11. Load Forecast

11.1. Requirements

The California Public Utilities Code Section 9621 specifies the process and content of IRPs to meet California regulatory requirements. It requires the development of a load forecast, which is a prediction of energy consumption (in MWh) and peak load demand (in MW). The load forecast is a necessary and critical IRP input because it is the starting point for determining total energy, renewable energy, clean energy, and capacity requirements. The CEC requests that an IRP explain the method and assumptions used to create the load forecast, and that the utility submitting it include public sources in the IRP's supporting material, as applicable.

In its 2017, 2018, and proposed 2022 regulations, the CEC recommends that POUs leverage the CED that is a part of the IERP process. The CED is an hourly forecast of electricity demand in the future. Following CEC recommendations, this IRP derived its load forecast from the California Energy Demand Update, 2022-2035 that is part of the 2022 Integrated Energy Policy Report Update.[126]

11.2. Integrated Energy Policy Report and California Energy Demand Forecast

The CEC produces an IEPR every year, which investigates the state's energy issues and proposes solutions.[127] Under the IEPR process, the CEC must produce forecasts of energy products, including electricity forecasts.

The CEC created the California Energy Demand Forecast Update, 2022-2035, as part of its 2022 Integrated Energy Policy Report Update.[128] The 2022 CED updates economic, demographic, and rate data from 2021, and refreshes the IEPR's methods for scenario design and for modeling the growth of transportation electrification.[129]

The CED has hourly forecasts of electricity demand for four entities: the three investor-owned utilities (PG&E, SCE, and SDG&E) and CAISO. There are two different forecasts: a planning forecast used in RA and IRP planning, with moderate assumptions for most items, and a Local Reliability Scenario that includes higher electrification and lower energy efficiency assumptions used for transmission planning.[130]

The CED forecasts contain hourly estimates of different components of electricity load for 2022 through 2035. These components are shown in Figure 57.

Figure 57: California Energy Demand Forecast Components

CED Update, 2022 - 2035	Description	Treatment in PWP IRP Modeling	Adds to Load?	Subtracts from Load?	Modified in PWP's 2023 IRP?
UNADJUSTED_CONSUMPTION	System load without pumping and with distributed solar load added back in	Native Load	✓		✓
PUMPING		Native Load	✓		
CLIMATE_CHANGE		Climate Change	✓		
LIGHT_EV	CEC uses a demand side model	Light-Duty EVs	✓		✓

126 https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2022-integrated-energy-policy-report-update-2; https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2022-integrated-energy-policy-report-update
127 https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report
128 https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2022-integrated-energy-policy-report-update-2
129 Bailey, Stephanie, Jane Berner, David Erne, Noemí Gallardo, Quentin Gee, Akruti Gupta, Heidi Javanbakht, Hilary Poore, John Reid, and Kristen Widdifield. 2022. Draft 2022 Integrated Energy Policy Report. California Energy Commission. Publication Number: CEC-100-2022001-CMD.
130 https://efiling.energy.ca.gov/GetDocument.aspx?tn=247951&DocumentContentId=82234

CED Update, 2022 - 2035	Description	Treatment in PWP IRP Modeling	Adds to Load?	Subtracts from Load?	Modified in PWP's 2023 IRP?
MEDIUM_HEAVY_EV	CEC uses a demand side model	Medium-/Heavy-Duty EVs	✓		
TOU_IMPACTS	The effect of TOU rates	TOU Rates		✓	✓
OTHER_ADJUSTMENTS	Adds to zero over time	Native Load			
BTM_PV	Photovoltaic Solar generation located behind the meter	Distributed Solar		✓	✓
BTM_STORAGE_RES	Energy storage located behind the meter – residential	Distributed Storage	✓		✓
BTM_STORAGE_NONRES	Energy storage located behind the meter – commercial and Industrial	Distributed Storage	✓		✓
AAEE	AAEE	AAEE		✓	✓
AAFS	AAFS	AAFS	✓		
AATE_LDV	Additional Achievable Transportation Electrification Includes supply-side drivers of adoption.[131]	Light-Duty EVs	✓		✓
AATE_MDHD	AATE	Medium/Heavy-Duty EVs	✓		
MANAGED_NET_LOAD	UNADJUSTED_CONSUMPTION + PUMPING + CLIMATE_CHANGE+LIGHT_EV + MEDIUM_HEAVY_EV + TOU_IMPACTS + OTHER_ADJUSTMENTS + BTM_PV + BTM_STORAGE_RES + BTM_STORAGE_NONRES	Metered Load	✓		✓

131 https://www.energy.ca.gov/event/webinar/2022-11/ca-energy-demand-forecast-aaee-and-aate-results-dawg-meeting

CED Update, 2022 - 2035	Description	Treatment in PWP IRP Modeling	Adds to Load?	Subtracts from Load?	Modified in PWP's 2023 IRP?
	+ AAEE + AAFS +AATE_LDV +AATE_MHD				

11.3. Integrated Resource Plan Method

Following the CEC's recommendation, this IRP is based on the CED and aims to leverage extensive work completed by California to quantify various drivers of electricity demand, including economic and demographic activity, energy efficiency and fuel substitution programs, historical electricity, and natural gas consumption, among other factors. The CEC's website contains additional information on the CED.[132]

The CED does not include a specific forecast for PWP since it is smaller than the other entities explicitly modeled. Instead, PWP's forecast is regarded as part of SCE's.[133] Since the CED's planning forecast is used in other IRP proceedings, PWP's 2023 IRP utilizes the planning scenario forecast for SCE as the reference for PWP's load forecast.

In developing the 2023 IRP, PWP utilized the services of a subcontractor hired by ACES, an external vendor, to generate 2021 hourly load data for SCE and PWP.[134] PWP's load is calculated as a percentage of SCE's 2021 load. As an initial forecast, the resulting hourly percentages were applied to the hourly CED forecast through 2035. Also, since the CED runs through 2035 only, the IRP forecast extrapolates these trends and applies them to the remainder of the forecast through 2050.

Because the CED differentiates the subcategories that comprise the net electricity demand, this method of load forecasting produces estimates for energy efficiency, building electrification, fuel substitution, light-duty EVs, heavy-duty EVs, distributed solar, and distributed storage.

However, historical data and consideration of respective land use/availability shows that PWP's service territory does not precisely mirror the load growth behavior of the larger SCE service territory. Therefore, when investigating the results of certain components, the IRP made modifications to the following:

- AAEE
- Distributed storage
- Distributed solar
- TOU rates
- Light-duty EVs
- Native (remaining) load

[132] https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report/2021-1
[133] https://efiling.energy.ca.gov/GetDocument.aspx?tn=248366
[134] https://www.yesenergy.com/

These changes were necessary to reflect PWP's historical load experience and expectations for the future. Changes to these respective components and the associated impact on the overall load forecast, are detailed in the following subsections.

PWP's annual peak and energy values are shown in Figure 58 and Figure 59. These values are metered at PWP's interface with CAISO, so they include the impact of distribution system losses. PWP considers distribution losses at around 4%.

Figure 58: PWP Peak Demand

Year	Peak (MW)	Reserve Margin (%)	Peak + Reserve Margin (MW)
2023	330.00	15.0%	379.50
2024	332.63	15.0%	382.52
2025	335.26	17.5%	393.93
2026	337.90	17.5%	397.03
2027	340.53	17.5%	400.12
2028	343.16	17.5%	403.21
2029	345.79	17.5%	406.30
2030	348.42	17.5%	409.39
2031	351.06	17.5%	412.50
2032	353.69	17.5%	415.59
2033	356.32	17.5%	418.68
2034	358.95	17.5%	421.77
2035	361.59	17.5%	424.87
2036	363.39	17.5%	426.98
2037	365.21	17.5%	429.12
2038	367.04	17.5%	431.27
2039	368.87	17.5%	433.42
2040	370.72	17.5%	435.60
2041	372.57	17.5%	437.77
2042	374.43	17.5%	439.96
2043	376.30	17.5%	442.15
2044	378.19	17.5%	444.37
2045	380.08	17.5%	446.59
2046	381.98	17.5%	448.83
2047	383.89	17.5%	451.07
2048	385.81	17.5%	453.33
2049	387.74	17.5%	455.59
2050	389.67	17.5%	457.86

Figure 59: PWP Energy

Year	Potential Energy (GWh) Imported into CAISO	Behind-the-Meter Generation (GWh)	Retail Sales (GWh) to End-Users	Retail Sales to End-Users (Accounting for AAEE Impacts)
2023	1,156,320	84,240	1,047,923	1,029,197
2024	1,162,535	84,480	1,059,784	1,034,933
2025	1,173,224	240	1,156,277	1,126,064
2026	1,185,899	-	1,173,515	1,138,463
2027	1,201,519	-	1,192,802	1,153,458
2028	1,220,842	-	1,215,253	1,172,009
2029	1,241,853	-	1,239,018	1,192,179
2030	1,265,577	-	1,265,082	1,214,954
2031	1,290,067	-	1,291,633	1,238,464
2032	1,312,076	-	1,315,006	1,259,593
2033	1,333,660	-	1,338,073	1,280,313
2034	1,352,810	-	1,358,607	1,298,697
2035	1,364,639	-	1,371,814	1,310,054
2036	1,375,921	-	1,384,239	1,320,884
2037	1,386,185	-	1,395,351	1,330,738
2038	1,396,148	-	1,405,369	1,340,302
2039	1,405,362	-	1,414,512	1,349,147
2040	1,414,327	-	1,422,988	1,357,754
2041	1,422,855	-	1,430,986	1,365,941
2042	1,430,863	-	1,438,674	1,373,629
2043	1,438,698	-	1,446,195	1,381,150
2044	1,446,483	-	1,453,669	1,388,624
2045	1,454,323	-	1,461,195	1,396,150
2046	1,462,298	-	1,468,851	1,403,806
2047	1,470,471	-	1,476,698	1,411,652
2048	1,478,887	-	1,484,777	1,419,732
2049	1,487,577	-	1,493,119	1,428,074
2050	1,496,556	-	1,501,739	1,436,694

Other loads will include load from storage charging and will vary based on scenarios. Net energy for load will vary based on storage load and is included in filed charts.

11.3.1. Additional Achievable Energy Efficiency

State minimum requirements are set forth in Title 24 and contains specific regulations for energy efficiency and water conservation. As part of its commitment to environmental stewardship and innovation, PWP is dedicated to expanding its energy efficiency and demand reduction programs whenever new cost-effective and achievable program elements are identified. Details of current PWP energy efficiency and demand response programs are included in Energy Efficiency of the IRP.

PUC Section 9621 requires IRPs for POUs to address the procurement of energy efficiency and demand response as dictated in Section 9651, which states "Each local publicly owned electric utility, in procuring energy to serve the load of its retail end-use customers, shall first acquire all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible."[135] In other words, energy efficiency is the resource of first choice.

In 2021, PWP, through its membership in CMUA, worked with GDS to identify the level of energy efficiency that PWP could cost-effectively support in its territory.[136] This study became the foundation for the energy efficiency goals that the Pasadena City Council adopted in May 2021. For Fiscal Years (FY) 2022 (which began on July 1, 2021) through FY2031 (which began on July 1, 2030), PWP's energy efficiency goal is to achieve 11,720 MWh per year in savings and 1.8 MW per year in demand reduction. The annual energy efficiency and demand reduction goals were derived from the 10-year average of the forecasted figures developed by GDS, in collaboration with PWP. These goals were adopted to represent the AAEE for the 2023 IRP.

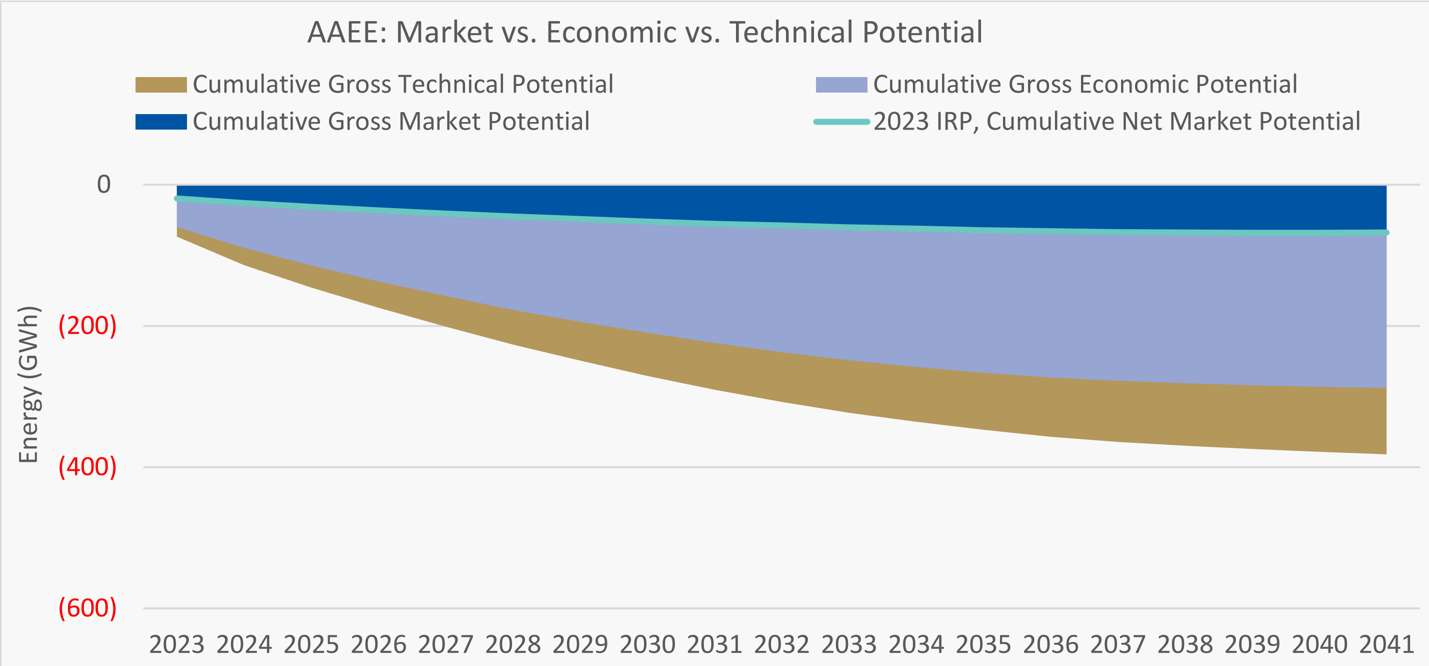
The 2021 GDS energy efficiency study quantified the following three types of potential penetration of energy efficiency: [137]

- Technical (i.e., feasible): savings without regard to economic or other factors
- Economic (i.e., cost-effective): savings when benefit is greater than cost
- Market (both feasible and cost-effective): savings that consider other utility-specific factors, such as existing penetration, past customer behavior, economic conditions, etc.

PWP adopted its goals based on market potential. Figure 60 shows a comparison of the three potential efficiencies.

[135] https://law.justia.com/codes/california/2021/code-puc/division-4-9/section-9615/
[136] https://www.cmua.org/files/CMUA%202020%20EE%20Potential%20Forecast.pdf
[137] https://www.cmua.org/sb1037-reports

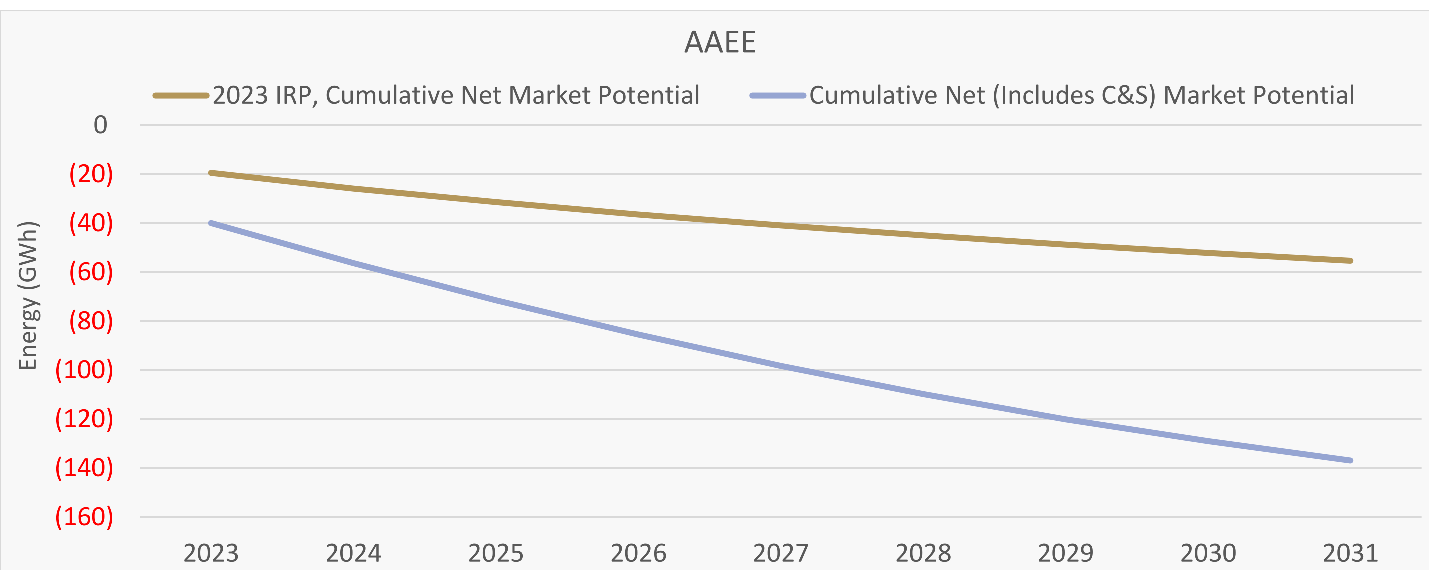
Figure 60: Technical, Economic, and Market Potential for Energy Efficiency



Energy efficiency savings are expressed as either gross (total impact) or net (total impact minus the impact of customers who would have pursued the programs anyway). Programs are also quantified by incremental savings (annual values) or cumulative savings (total savings summed over time). PWP's goal is based on incremental net savings, which are approximately 96% of gross market potential savings.

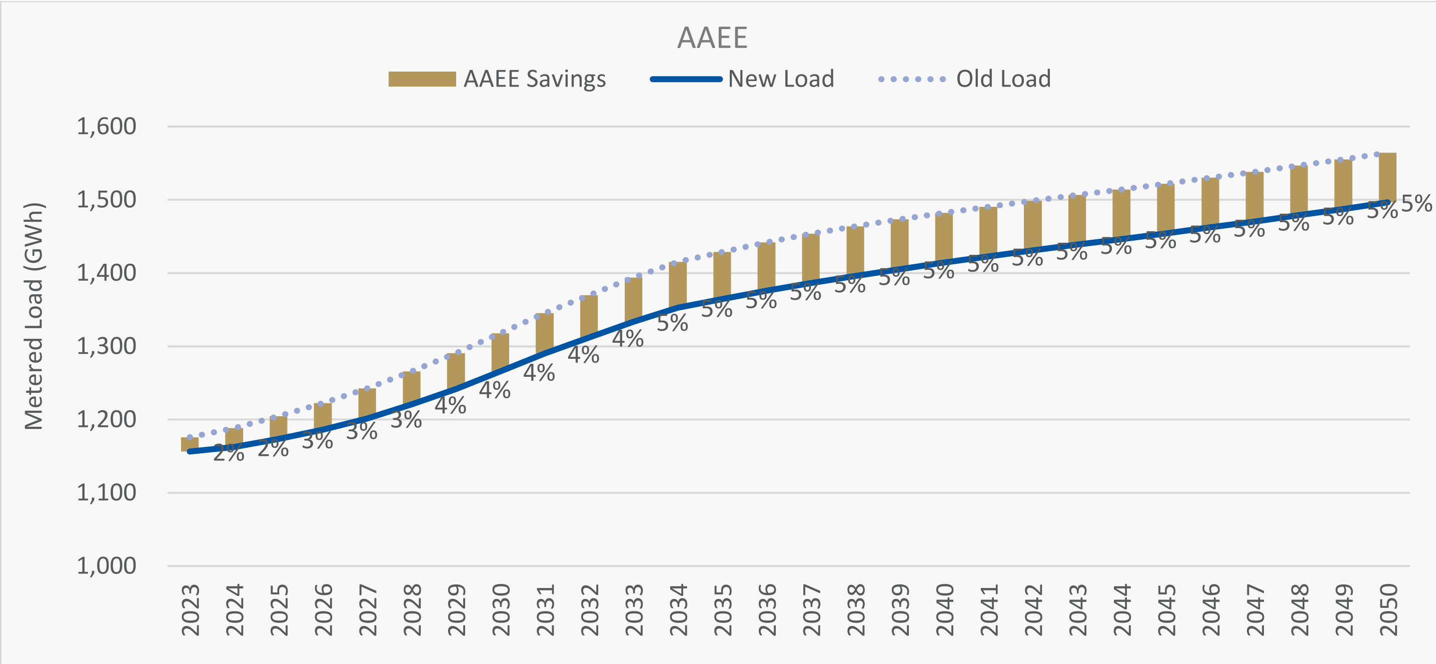
The 2023 IRP uses PWP's energy efficiency goal for its estimate of AAEE through 2031, then 96% of gross market potential for 2032 through 2041 when the goal expires. Since trends are leveling out, suggesting saturation of potential efficiency opportunities, AAEE remains flat from 2042 through the end of the IRP study period in 2050. Figure 61 shows the IRP forecast of AAEE. The negative values on the Y axis indicate energy saved.

Figure 61: Additional Achievable Energy Efficiency in PWP's 2023 Integrated Resource Plan



The percent reduction in load is shown in in Figure 62.

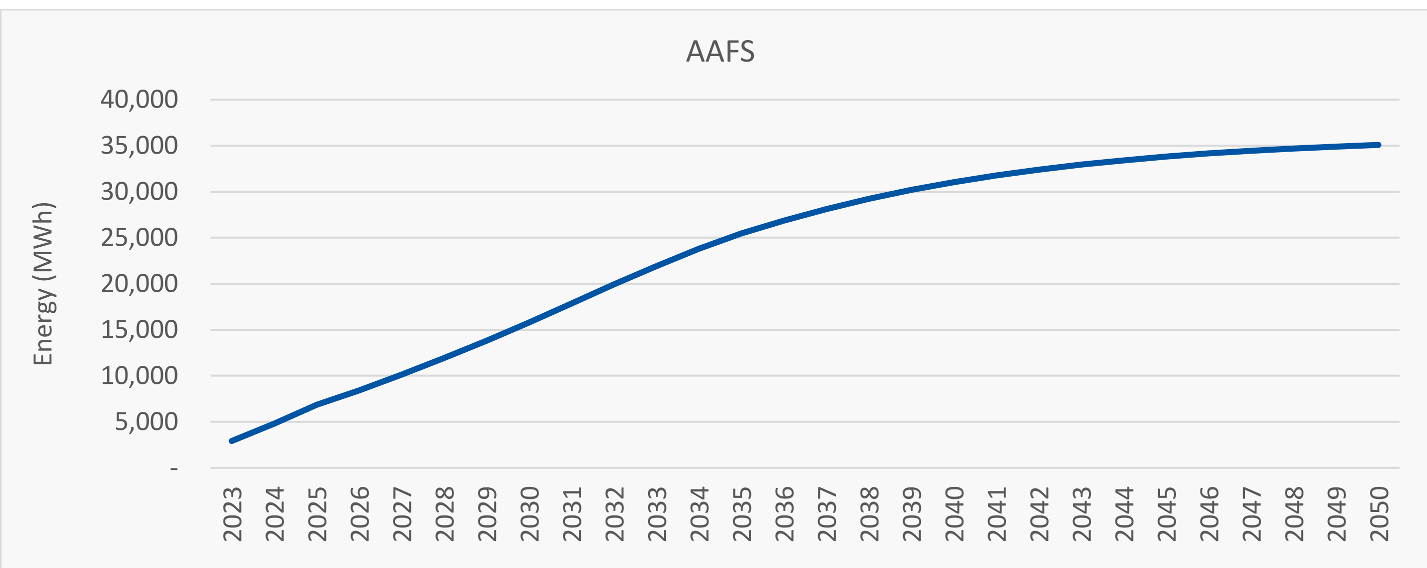
Figure 62: Additional Achievable Energy Efficiency Percent Reduction in Load



11.3.2. Additional Achievable Fuel Substitution

AAFS estimates the impacts of building electrification and fuel substitution on electricity demand and energy consumption and is included in the load forecast. Fuel substitution occurs when a device or system using a regulated fuel (fossil fuel or renewable gas) is replaced with a system using electricity. Replacements under these programs are not yet committed, but likely to occur in the future due to economics or regulation. The 2023 IRP assumes the allocation of AAFS from the CED based on the forecasting methodology outlined in this IRP. AAFS is 2% of CAISO's metered load by the end of the study period. Figure 63 shows an AAFS projection for PWP.

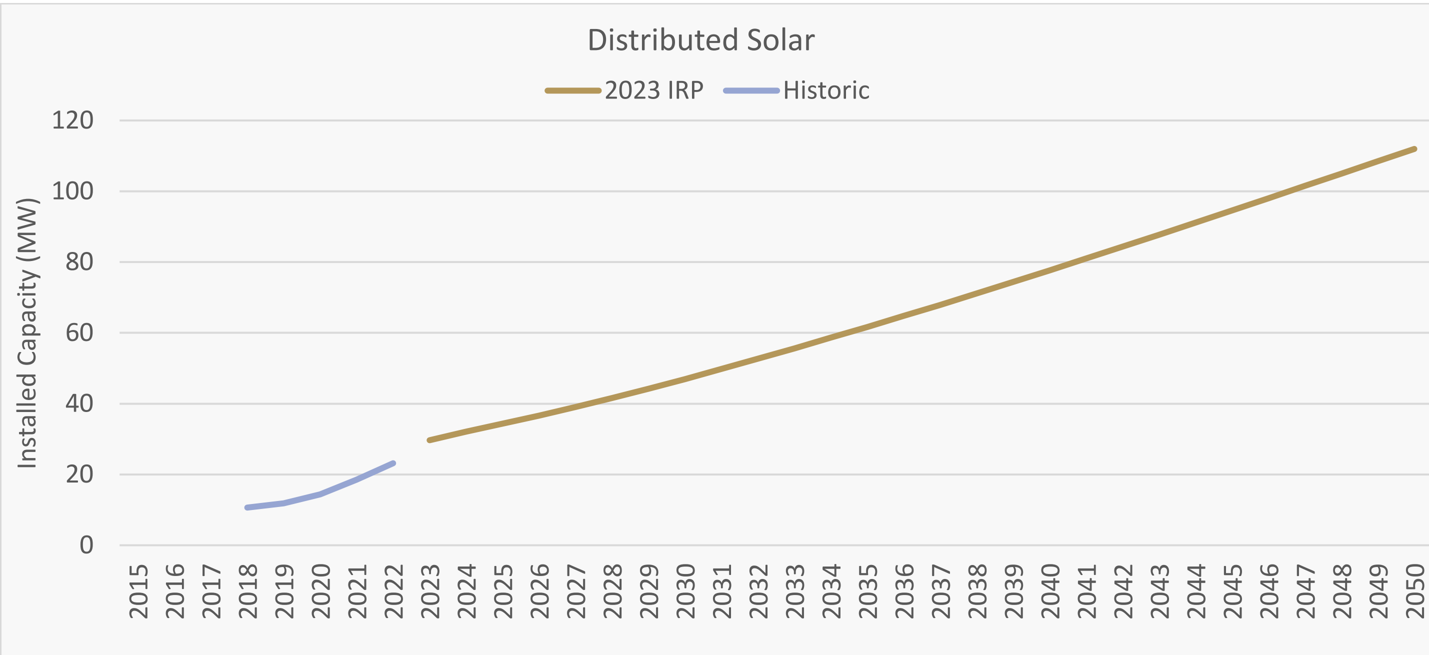
Figure 63: AAFS in PWP's 2023 IRP



11.3.3. Distributed Solar

PWP had 23 MW of distributed solar in 2022. Assuming an average installation size of 7 kW per residential rooftop and 58,291 residential customers, approximately 6% of PWP's households had solar.[138] However, the CED method attributed 52 MW of solar to PWP in 2023. PWP, as a dense urban area, is likely more space-constrained than SCE on average, resulting in actual installations to be less than the CED estimates. PWP's IRP calculated the annual rate of change in the CED and applied it to PWP's 2022 starting point. Extrapolating forward, approximately 12% of households would have solar in 2030 and 23% would have solar in 2045. This is within the range identified for LADWP in 2045 in NREL's LA100 study, and, given uncertainties regarding rooftop solar potential, future rate incentives, and other factors, PWP found these values reasonable for the 2023 IRP.[139] Figure 64 shows the estimated solar capacity included in the IRP load forecast.

Figure 64: Distributed Solar in PWP's 2023 IRP



11.3.4. Distributed Storage

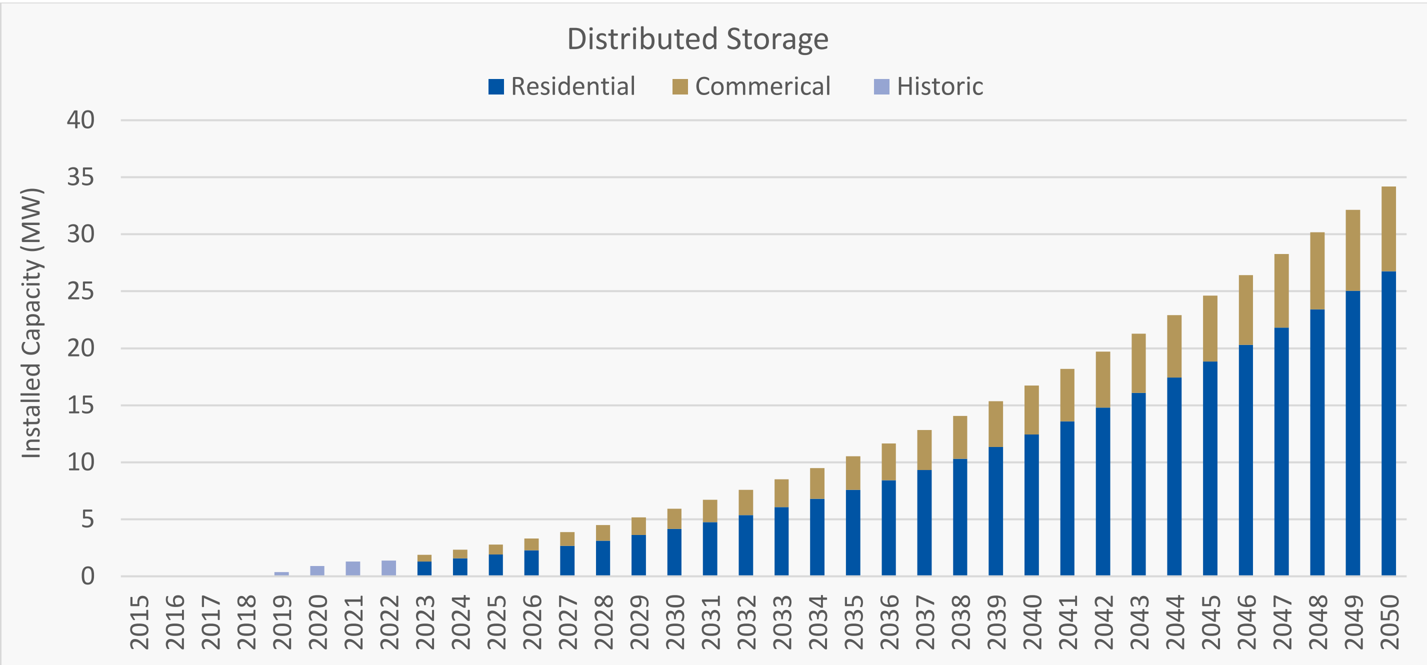
PWP had 1.4 MW of distributed storage in 2022. The CED suggested 0.5 MW across PWP's residential and non-residential sectors in 2023. To calibrate the starting point, PWP's existing penetration was added to the CED forecast resulting in a starting capacity of 1.9 MW of distributed storage.

It is likely that distributed storage will be paired with distributed solar in the future. In the LA100 study, NREL noted that, in 2019, 9.6% of residential PV adopters also installed storage at a storage-to-PV capacity ratio of 0.92.[140] NREL projected that 91% of residential solar adopters would also install storage by 2045. PWP estimated total storage adoption given its anticipated solar penetration using this heuristic and applied the rate of change embedded in that resulting penetration

[138] https://emp.lbl.gov/tracking-the-sun
[139] https://www.nrel.gov/docs/fy21osti/79444-4.pdf
[140] https://www.nrel.gov/docs/fy21osti/79444-4.pdf

to its starting point. Overall, this method generated a larger distributed storage capacity than the CED method estimated, and it produced an estimate more in line with expectations. See Figure 65.

Figure 65: Distributed Storage in 2023 IRP



As a reminder, the method used in PWP's IRP to leverage the CED helps align its load forecast to the CEC's expectations. However, this method is just that – a method. Modifications such as those made for solar and storage adjust the forecast to actual conditions, experience, and expectations specific to PWP.

11.3.5. Time-of-Use Rates

The CED method used in the IRP produced a forecast for the impact of TOU rates. As of 2023, PWP does not have the Advanced Metering Infrastructure (AMI) needed to fully benefit from the implementation of TOU rates. PWP may need to develop some form of TOU rate to facilitate a significant expansion of distributed solar and storage resources and address the resource cost impacts that will occur. PWP currently estimates that AMI will come online in its full capacity around 2030. Therefore, TOU impacts for PWP's forecast are only included in 2030 and beyond. Energy and peak impacts are shown in Figure 66 and Figure 67.

Figure 66: Time-of-Use Rates in PWP's 2023 Integrated Resource Plan

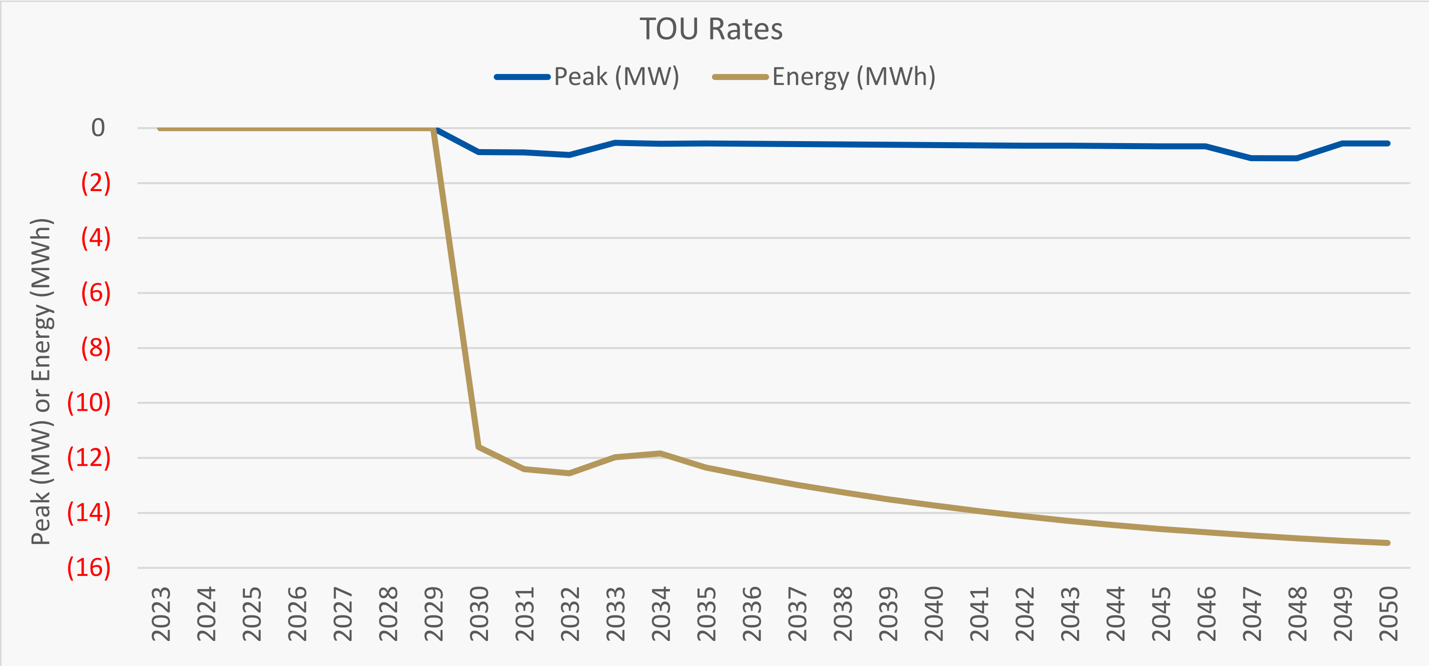
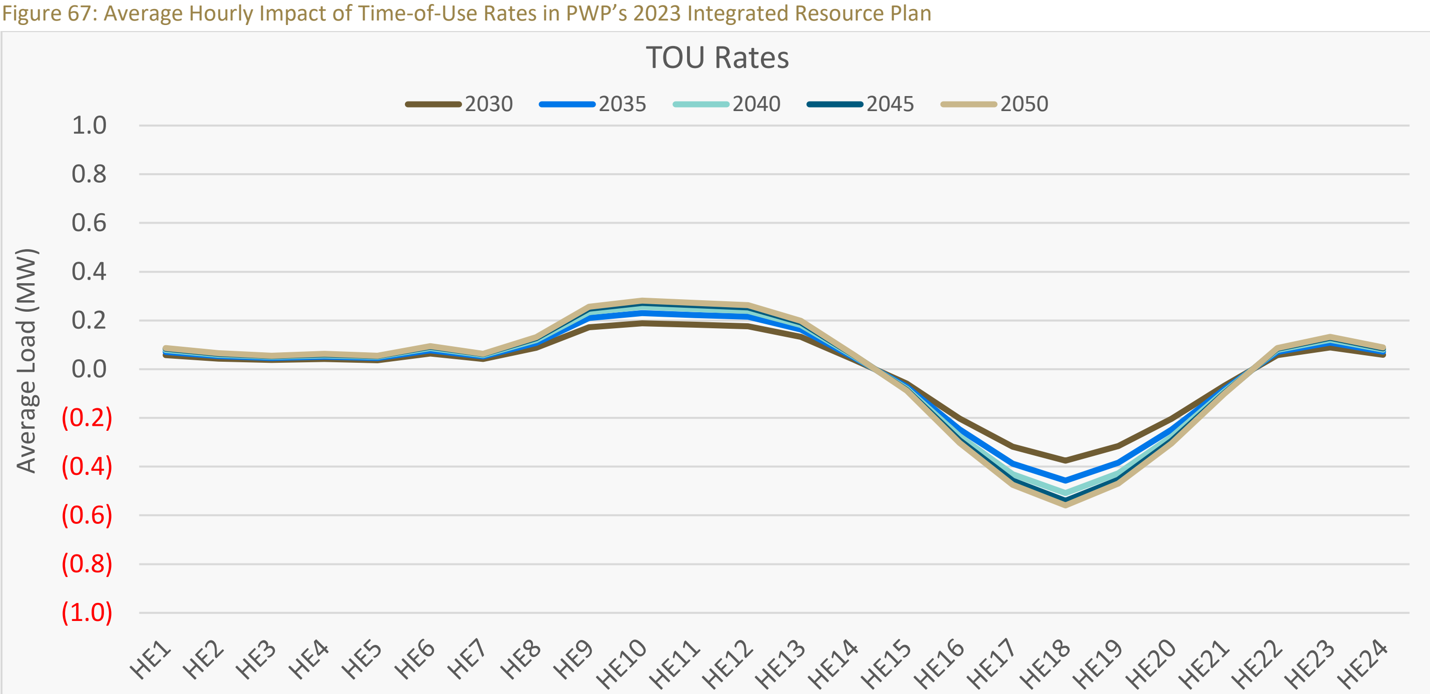


Figure 67: Average Hourly Impact of Time-of-Use Rates in PWP's 2023 Integrated Resource Plan



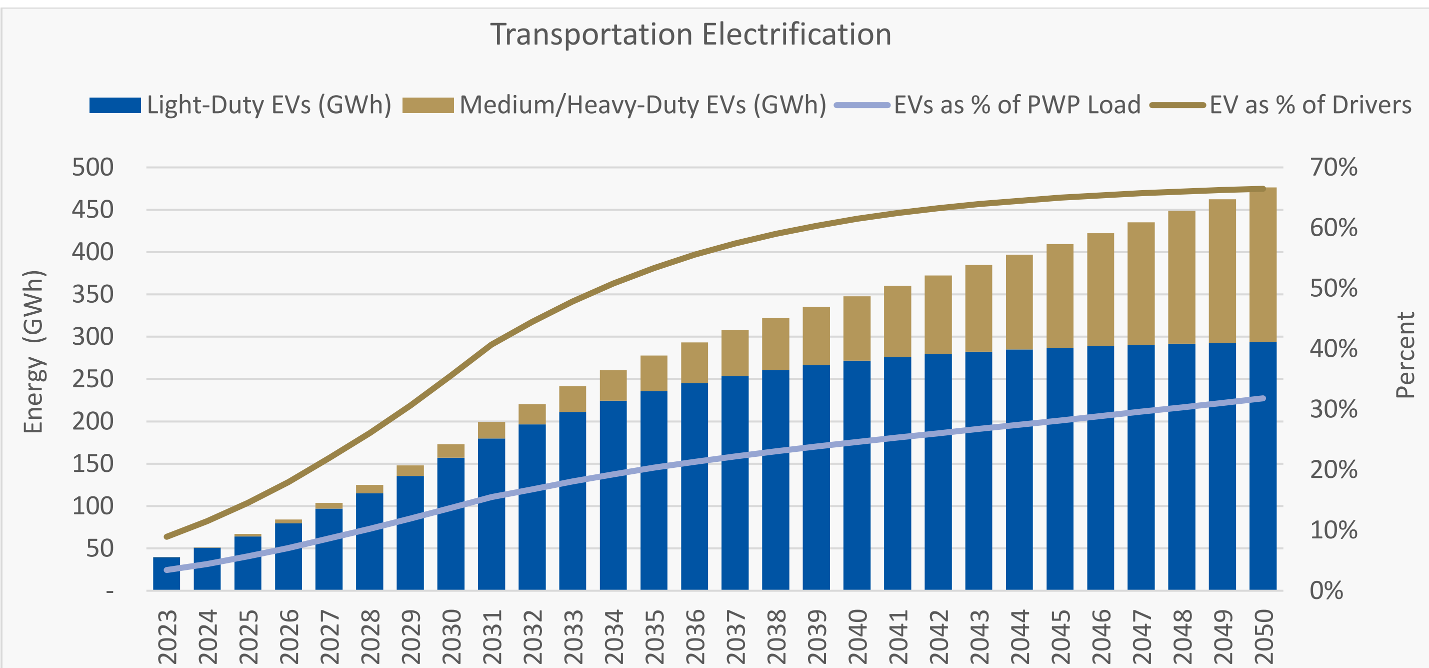
In addition to the impact of TOU rates, AMI could also help enable additional demand response. AMI would potentially allow PWP the ability to aggregate and control the consumption profile of various consumer devices to support savings for all PWP customers.

11.3.6. Vehicle Electrification

Emissions from transportation constitute the largest source of GHGs in California and represent more than double the GHGs associated with the electricity sector.[141] Electrifying transportation can help reduce emissions. California has aggressive transportation electrification goals. Executive Order B-48-18 signed by Governor Brown in 2018 set a target for 5 million zero-emission vehicles and 250,000 public EV charging stations by 2030.[142] In 2020, Governor Newsom set a goal under Executive Order N-79-20 for all in-state sales of new passenger and new medium/heavy-duty vehicles to be zero-emission by 2035 and 2045, respectively. PWP is committed to supporting the transportation electrification goals set by California and align with the GHG emissions reduction targets outlined in the City's CAP.

As of 2022, PWP had 9,254 electric-based (battery EVs, PHEV, and fuel cell EVs) vehicles registered across the eight zip codes in its service territory, which is approximately 7% of all vehicles in PWP's service territory.[143] Assuming around 3 MWh per vehicle, per year (based on assumptions developed in PWP's 2021 IRP Update), PWP's EV load is higher than what the CED would indicate. The IRP load forecast was adjusted to account for the higher initial load in 2023. The 2027 CED forecast was adopted in 2023 and the forecast moved up accordingly. Approximately 36% of light-duty vehicles in PWP's territory are expected to be electric in 2030, and 65% are expected to be electric by 2045. No adjustments were made to the CED's medium/heavy-duty EV forecast. Overall, EV charging is 14% of PWP's CAISO metered energy in 2030 and 28% in 2045, as shown in Figure 68 and Figure 69.

Figure 68: Transportation Electrification in PWP's 2023 Integrated Resource Plan

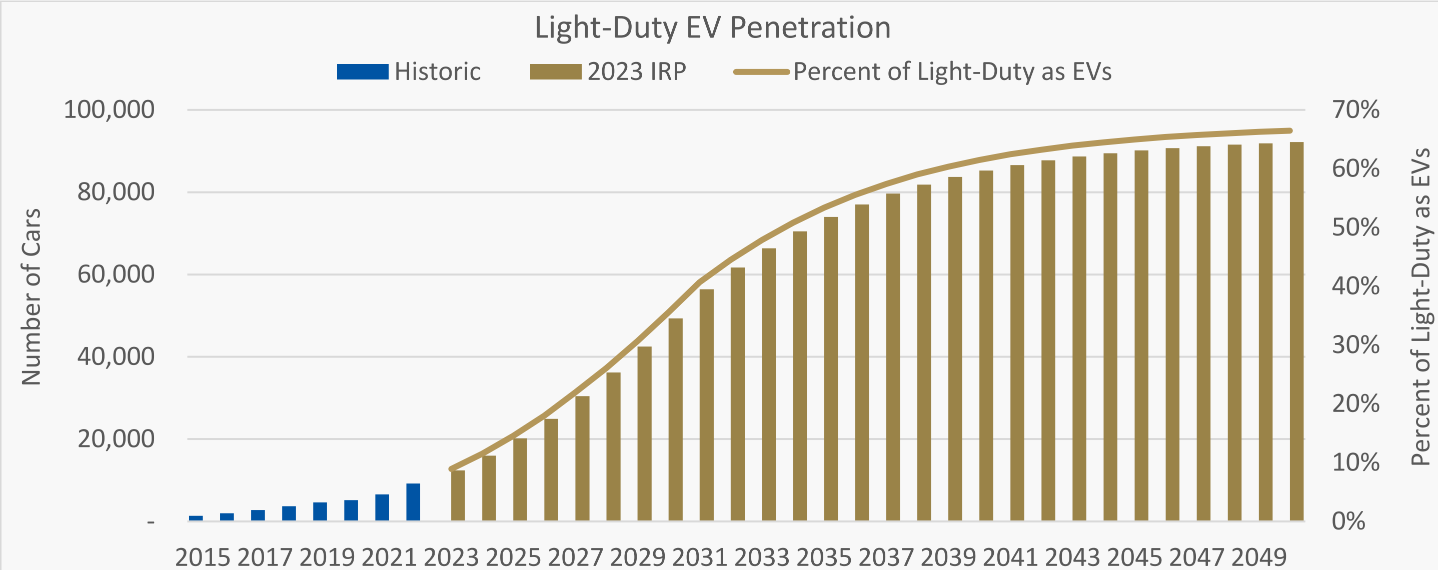


[141] https://ww2.arb.ca.gov/ghg-inventory-data

[142] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/transportation-electrification

[143] https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics/light-duty-vehicle; Used the following zip codes: 91001,91101,91103, 91104, 91105, 91106, 91107, 91123

Figure 69: Light-Duty Electric Vehicle Penetration in PWP's 2023 Integrated Resource Plan



Hourly load shapes for the light- and medium/heavy-duty sectors are shown in Figure 70 and Figure 71. These hourly load shapes come from the CED. EV charging load peaks in hour ending (HE) 24, on average each year. The charging shapes indicate that EVs are charging mid-day and overnight. This could imply, or inform, some form of TOU rate. If EVs were charged during PWP's peak hour, PWP's peak could be 8% higher in 2030 than indicated and 13% higher by 2045. The 2023 IRP assumes that education and voluntary behavior will mitigate the potential impacts of EV charging. However, PWP will keep in mind the potential impacts of EV charging and may further investigate the potential to treat EV charging behavior as a tool to reduce overall portfolio costs.

Figure 70: Average Hourly Shape for Light-Duty Electric Vehicles

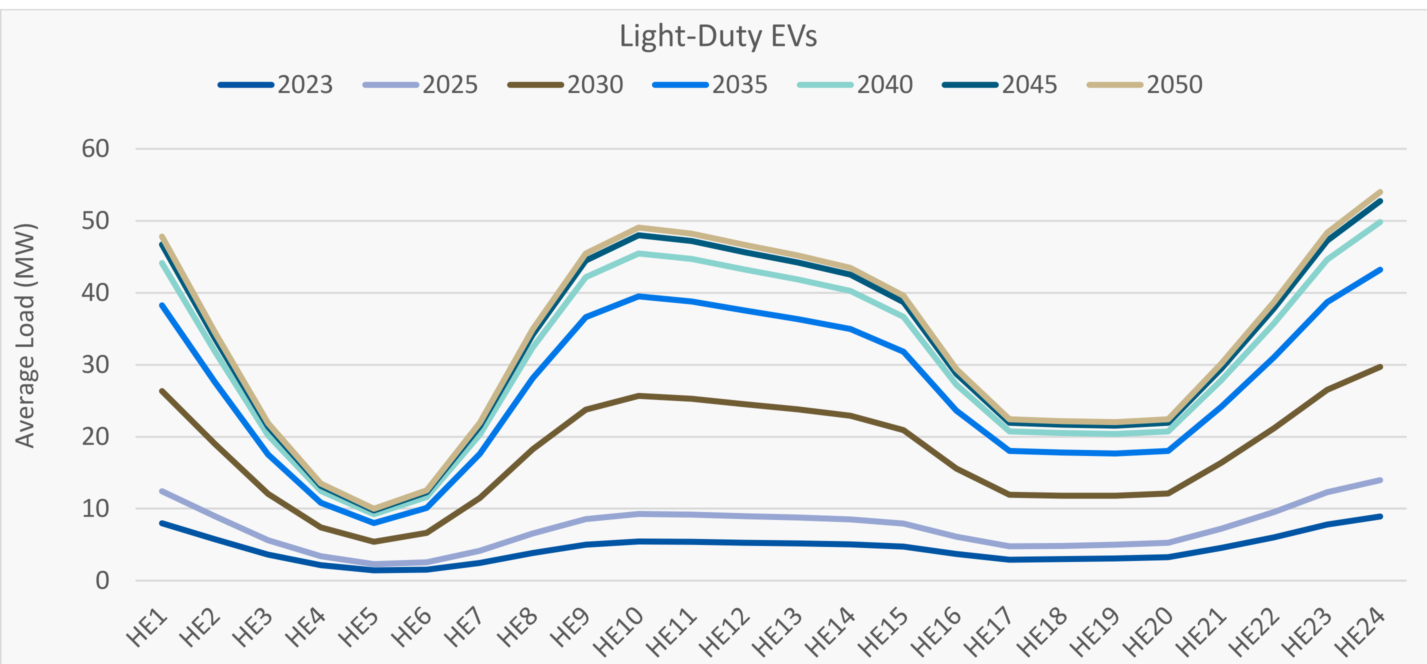
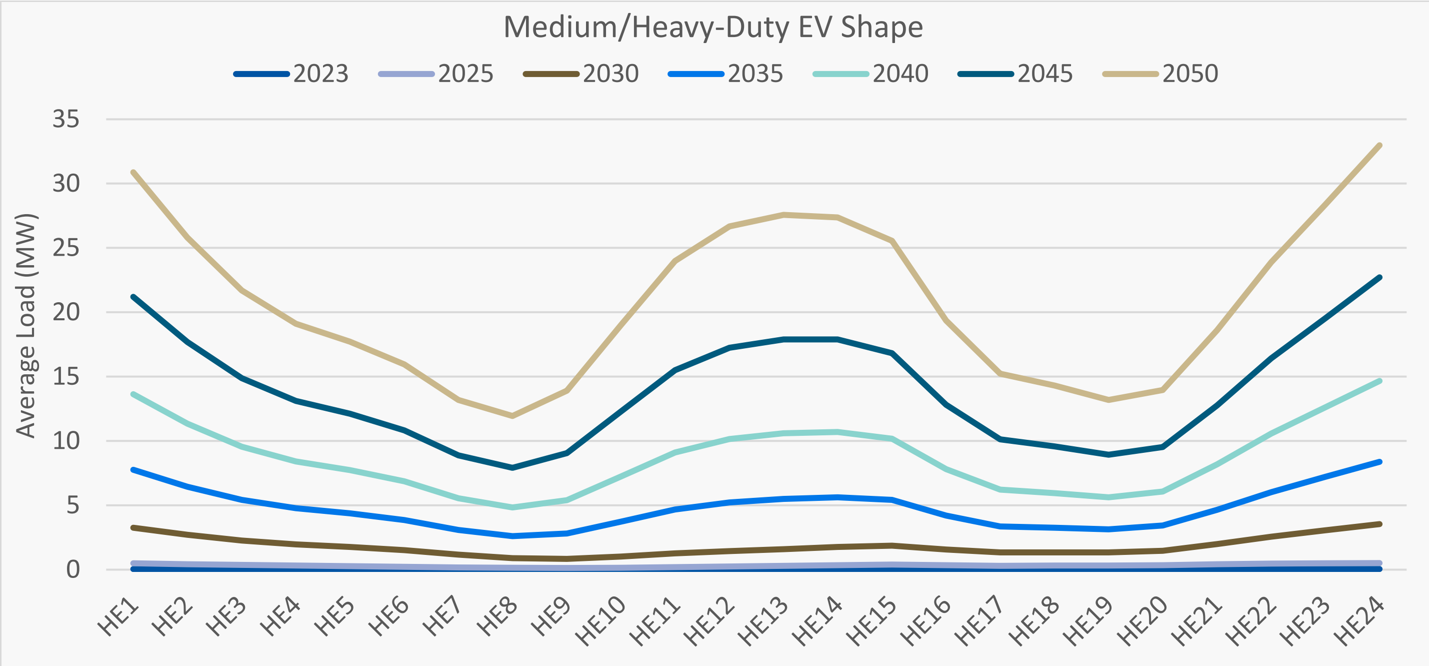
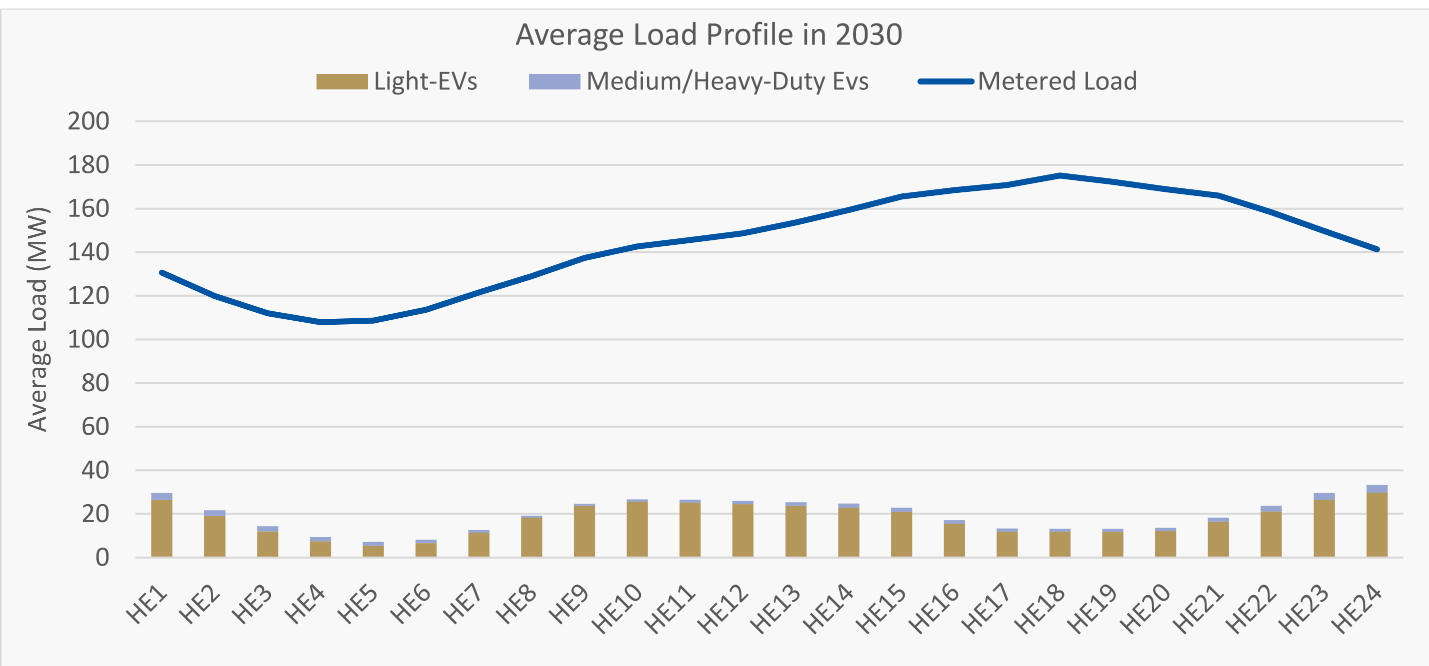


Figure 71: Average Hourly Shape for Medium/Heavy-Duty Electric Vehicles



The average contribution of EV charging to average hourly load in 2030 is shown in Figure 72. EV charging seeks to take advantage of midday opportunities, likely when solar generation is at its highest and market prices are lower. TOU rates can be used to incentivize charging when solar generation is abundant and disincentive it when market prices are high.

Figure 72: Average Hourly Load Profile



PUC Section 9621 requires IRPs to discuss rate design, incentives, education, and outreach to achieve the statewide carbon neutrality goal by at least 2045, as set by the 2018 Executive Order B-55-18.[144] PWP does not currently have transportation-specific rates for electric vehicles. As further detailed in Electric Vehicles, PWP offers rebates to residential customers for both EVs and EV chargers. PWP also offers rebates on EV chargers for commercial customers. PWP's website has additional details on these incentives.[145] However, given planned AMI deployment, PWP could consider implementing rates for the transportation sector. For example, PWP could consider redesigning demand charges, creating EV-specific TOU rates, or developing targeted EV tariffs.

PWP will likely consider rates, incentives, customer education, and customer outreach to support transportation electrification. Electrifying transportation can help achieve California's carbon reduction goals while also aligning with the City's CAP. PWP will aim to design programs that decrease costs for EV customers and the overall grid. PWP is committed to ensuring that potential impacts on low-income customers and disadvantaged communities are a primary consideration when designing such programs.

PWP is also committed to considering the emission reduction opportunities associated with transportation electrification. PWP estimates that by 2030, more than 33% of its light-duty fleet in Pasadena could be electric and approximately 65% could be electric by 2045. If the fossil-fuel vehicles were to remain on the road, the fleet would emit around 0.75 million metric tons of carbon in 2030 and 4.2 million metric tons in 2045.

11.3.7. Climate Change

The CED forecast includes the potential load impacts associated with climate change. Overall, the CED looks at 30 years of history, with recent years selected more often. Per the CED documentation, baseline peak and energy forecasts were weather-normalized, and future years were adjusted for anticipated modifications for climate change. Climate change increases overall load expectations. From 2023 through 2050, the effect of climate change is about 0.3% of annual metered energy.

11.3.8. Native Load

Native load is effectively all load that is not represented in Section 11.3. Figure 73 shows how PWP's native load has decreased over time. The CED generally anticipates increases in energy consumption in the future. Pasadena is relatively fully built and, consequently, expects little load growth from expansion. In the 2023 IRP load forecast, native load is adjusted to match PWP's historical and peak load data, as well as future expectations for its more densely developed system. PWP has a 10 MW distributed generator (a customer-owned distributed energy resource) that has reduced its historical peak load. This facility is anticipated to retire in 2025, so the load forecast was increased by 10 MW in this IRP to reflect the facility's retirement (the facility is modeled as a distributed resource prior to its retirement).

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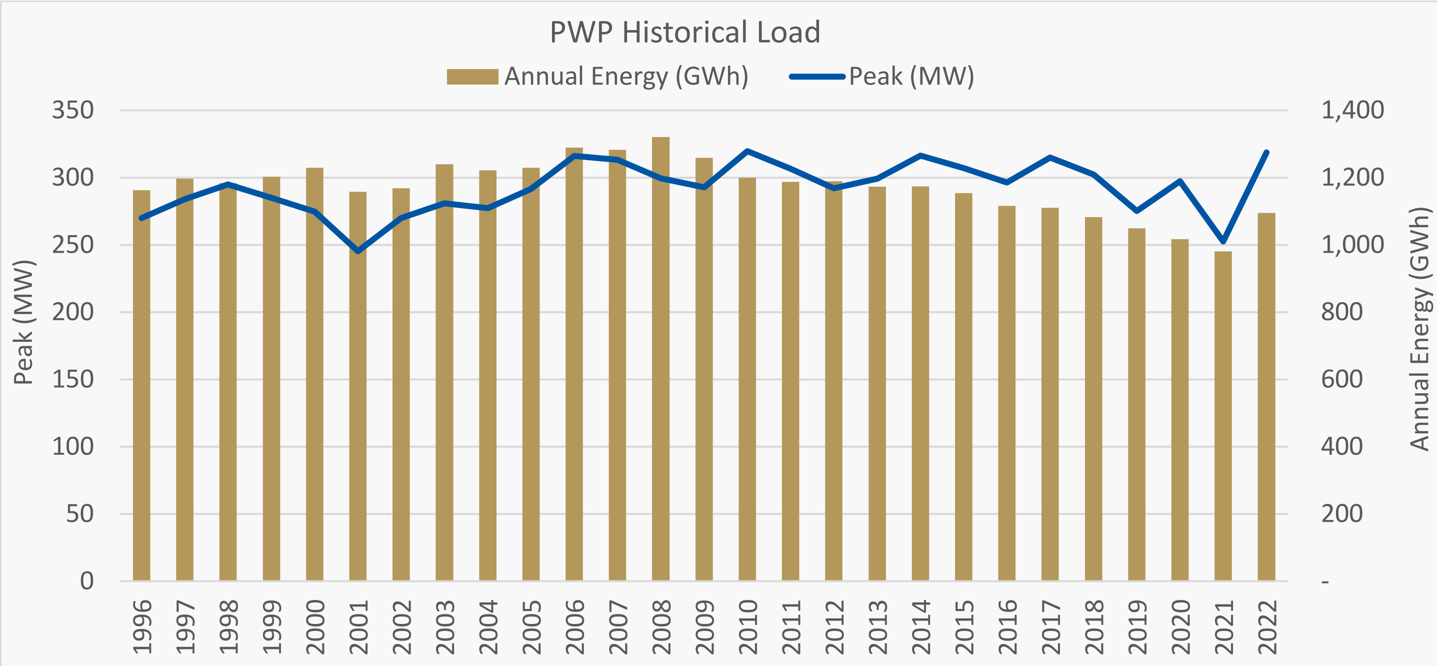
[144] https://codes.findlaw.com/ca/public-utilities-code/puc-sect-9621/; https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf
[145] https://pwp.cityofpasadena.net/residentialevrebate/;

Figure 73: PWP's Historical Load



11.3.9. CAISO Metered Load

Metered load is the load as metered at the transmission interconnection and is the load brought into the CAISO markets.[146] Metered load is higher than retail sales because it includes the impact of losses.

Metered load is calculated according to the following equation:

$$\begin{aligned} Metered\ Load = (&Native\ Load + Light\ Duty\ EVs + Medium\ and\ Heavy\ Duty\ EVs + AAFS \\ &+ Distributed\ Storage\ ) + (TOU\ Rates + AAEE + \ Distributed\ Solar) \end{aligned}$$

Figure 74 shows a comparison between PWP's forecast and SCE's forecast from the CED.

Figure 74: Percent of PWP Peak During Southern California Edison's Peak

Percent of PWP Peak During SCE's Peak													
Month	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	99%	98%	91%	90%	93%	92%	95%	91%	90%	89%	86%	90%	87%
2	99%	100%	98%	97%	96%	97%	86%	87%	99%	99%	88%	83%	77%
3	88%	79%	81%	84%	86%	79%	80%	76%	77%	80%	91%	85%	80%
4	89%	80%	75%	68%	81%	77%	75%	75%	72%	76%	80%	78%	72%
5	89%	62%	62%	59%	76%	74%	56%	63%	68%	64%	67%	70%	73%
6	100%	85%	84%	78%	79%	61%	65%	68%	73%	74%	70%	67%	63%

[146] This is what the CED refers to as managed net load.

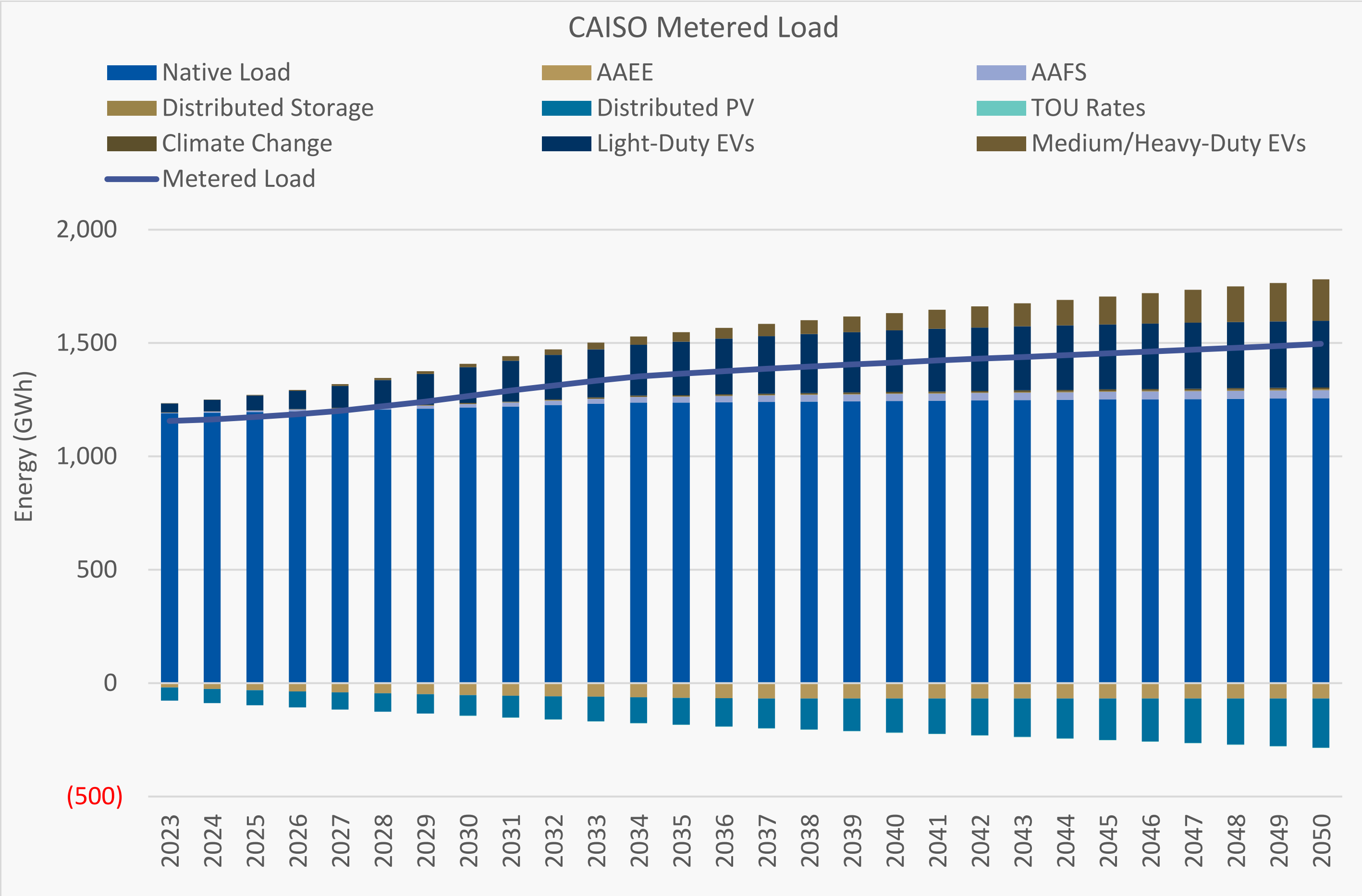
Percent of PWP Peak During SCE's Peak													
Month	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
7	100%	82%	89%	85%	100%	72%	73%	73%	62%	68%	65%	66%	62%
8	100%	81%	81%	98%	97%	68%	62%	53%	62%	64%	68%	64%	54%
9	100%	88%	89%	87%	69%	78%	77%	74%	71%	86%	88%	81%	79%
10	100%	77%	86%	79%	78%	73%	79%	73%	76%	64%	72%	80%	81%
11	100%	94%	96%	91%	87%	90%	81%	90%	91%	82%	83%	81%	68%
12	100%	95%	96%	98%	96%	97%	97%	92%	93%	95%	94%	92%	94%

Figure 75 shows PWP's annual energy and peak forecast. Positive values for energy refer to consumption and negative values refer to avoided energy consumption. Figure 76 provides a graphical representation of CAISO's energy use. PWP has a load factor of approximately 43%, on average, across the study period. Load factor measures actual energy as a fraction of what could occur if PWP experiences peak energy usage every hour.

Figure 75: Load Forecast

Year	Metered Peak (MW)	Peak Hour (HE)	Metered Load (MWh)	Native Load (MWh)	AAEE (MWh)	AAFS (MWh)	Distributed Storage (MWh)	Distributed PV (MWh)	TOU Rates (MWh)	Climate Change (MWh)	Light-Duty EVs (MWh)	Medium/ Heavy-Duty EVs (MWh)
2023	330.00	15	1,156,320.00	1,190,015.58	(19,506.21)	2,914.28	406.89	(57,838.32)	-	657.59	39,427.81	242.38
2024	332.63	17	1,162,534.86	1,193,110.93	(25,886.41)	4,798.36	500.72	(62,350.33)	-	993.75	50,945.23	422.60
2025	335.26	16	1,173,223.68	1,195,460.70	(31,471.95)	6,832.52	590.76	(66,608.08)	-	1,332.50	64,260.02	2,827.21
2026	337.90	17	1,185,898.62	1,198,668.53	(36,512.71)	8,429.86	694.40	(71,103.10)	-	1,676.94	79,439.30	4,605.41
2027	340.53	17	1,201,518.83	1,201,422.94	(40,983.11)	10,124.06	799.01	(75,793.42)	-	2,027.71	96,969.56	6,952.10
2028	343.16	15	1,220,842.31	1,206,299.11	(45,045.88)	11,932.07	914.05	(80,664.81)	-	2,379.37	115,251.26	9,777.13
2029	345.79	18	1,241,853.21	1,210,557.08	(48,790.91)	13,819.78	1,032.05	(85,713.68)	-	2,735.97	135,436.09	12,776.82
2030	348.42	17	1,265,577.17	1,215,678.99	(52,216.66)	15,789.63	1,165.85	(90,950.17)	(11.60)	3,095.60	157,144.46	15,881.07
2031	351.06	17	1,290,066.51	1,219,706.54	(55,384.83)	17,831.60	1,318.96	(96,365.78)	(12.40)	3,457.98	179,725.54	19,788.91
2032	353.69	17	1,312,076.32	1,226,367.29	(57,721.15)	19,923.91	1,472.71	(101,934.12)	(12.56)	3,821.76	196,481.33	23,677.15
2033	356.32	15	1,333,659.83	1,232,249.48	(60,166.46)	21,927.21	1,642.50	(107,616.56)	(11.98)	4,189.34	211,388.76	30,057.54
2034	358.95	15	1,352,809.51	1,238,103.03	(62,405.96)	23,779.00	1,811.55	(113,373.76)	(11.84)	4,559.49	224,442.33	35,905.66
2035	361.59	15	1,364,639.33	1,238,103.03	(64,333.16)	25,448.24	1,997.00	(119,170.35)	(12.35)	4,931.19	235,736.88	41,938.85
2036	363.39	15	1,375,921.35	1,239,341.14	(65,994.23)	26,855.70	2,184.36	(125,152.00)	(12.67)	5,220.75	245,423.99	48,054.33
2037	365.21	15	1,386,185.48	1,240,580.48	(67,305.27)	28,108.82	2,377.28	(131,237.21)	(12.97)	5,483.60	253,680.04	54,510.72
2038	367.04	15	1,396,148.14	1,241,821.06	(67,777.88)	29,215.40	2,575.85	(137,418.52)	(13.25)	5,720.29	260,685.24	61,339.94
2039	368.87	15	1,405,361.54	1,243,062.88	(68,088.44)	30,185.76	2,780.19	(143,688.31)	(13.50)	5,931.99	266,611.15	68,579.82
2040	370.72	15	1,414,326.69	1,244,305.94	(67,952.51)	31,031.63	2,990.49	(150,038.91)	(13.73)	6,120.21	271,614.17	76,269.39
2041	372.57	15	1,422,855.36	1,245,550.25	(67,755.48)	31,765.27	3,206.93	(156,462.57)	(13.93)	6,286.70	275,833.01	84,445.17
2042	374.43	15	1,430,863.42	1,246,795.80	(67,755.48)	32,398.87	3,429.72	(162,951.52)	(14.12)	6,433.32	279,388.36	93,138.46
2043	376.30	15	1,438,697.53	1,248,042.59	(67,755.48)	32,944.10	3,659.06	(169,497.99)	(14.29)	6,561.97	282,383.89	102,373.67
2044	378.19	15	1,446,483.15	1,249,290.64	(67,755.48)	33,411.83	3,895.15	(176,094.26)	(14.44)	6,674.47	284,907.96	112,167.28
2045	380.08	15	1,454,322.83	1,250,539.93	(67,755.48)	33,812.06	4,138.16	(182,732.67)	(14.58)	6,772.57	287,035.34	122,527.49
2046	381.98	15	1,462,298.13	1,251,790.47	(67,755.48)	34,153.77	4,388.48	(189,405.66)	(14.71)	6,857.92	288,829.13	133,454.20
2047	383.89	18	1,470,471.26	1,253,042.26	(67,755.48)	34,444.98	4,646.28	(196,105.77)	(14.82)	6,932.02	290,342.41	144,939.39
2048	385.81	18	1,478,887.37	1,254,295.30	(67,755.48)	34,692.76	4,911.79	(202,825.71)	(14.92)	6,996.24	291,619.76	156,967.63
2049	387.74	20	1,487,576.57	1,255,549.59	(67,755.48)	34,903.32	5,185.25	(209,558.30)	(15.01)	7,051.80	292,698.60	169,516.80
2050	389.67	20	1,496,555.89	1,256,805.14	(67,755.48)	35,082.04	5,466.86	(216,296.59)	(15.09)	7,099.82	293,610.35	182,558.85

Figure 76: CAISO Metered Load by Component



CAISO's metered peak load occurs on the dates and hours shown in Figure 77.

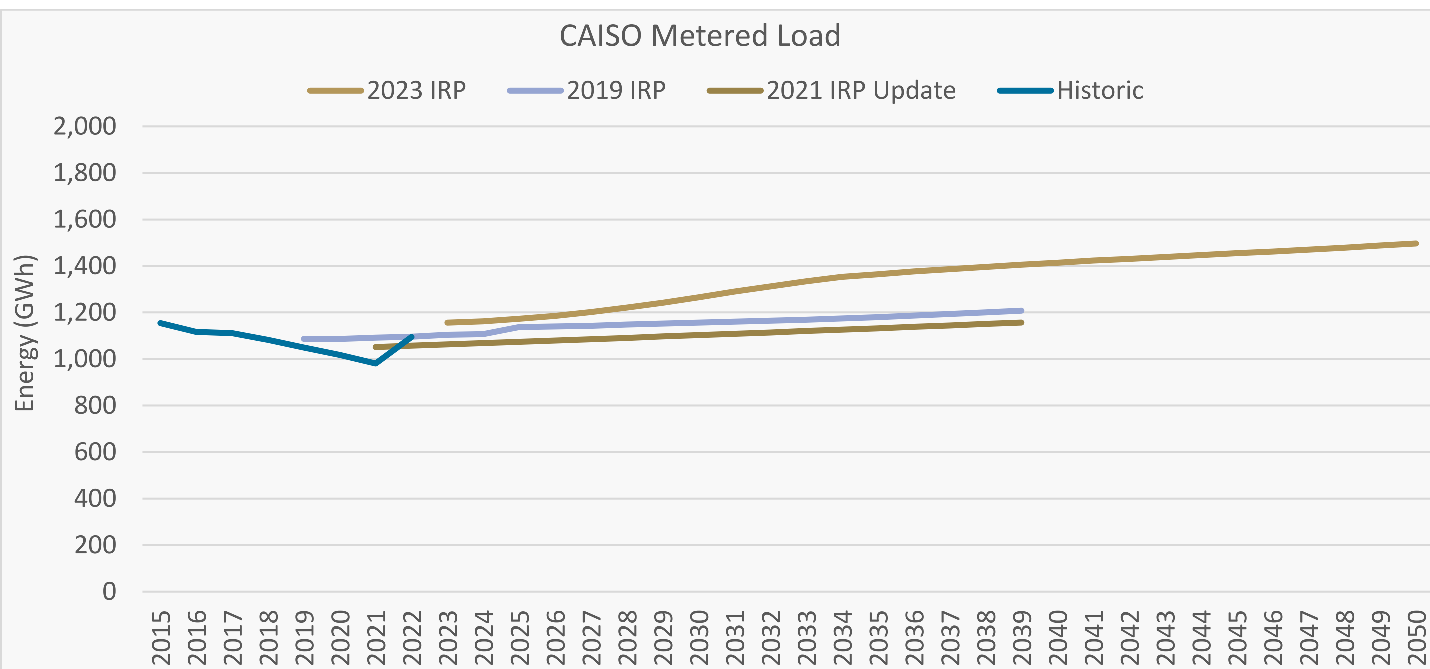
Figure 77: Hour of CAISO Peak Metered Load

Hour of CAISO Peak Metered Load			
Year	**Month**	**Day**	**Hour**
2023	9	5	15
2024	9	13	17
2025	8	28	16
2026	8	27	17
2027	9	7	17
2028	9	5	15
2029	8	30	18
2030	9	13	17
2031	8	28	17
2032	9	7	17
2033	9	6	15
2034	9	5	15

Hour of CAISO Peak Metered Load			
Year	Month	Day	Hour
2035	9	4	15
2036	9	4	15
2037	9	4	15
2038	9	4	15
2039	9	4	15
2040	9	4	15
2041	9	4	15
2042	9	4	15
2043	9	4	15
2044	9	4	15
2045	9	4	15
2046	9	4	15
2047	8	30	18
2048	8	30	18
2049	9	4	20
2050	9	4	20

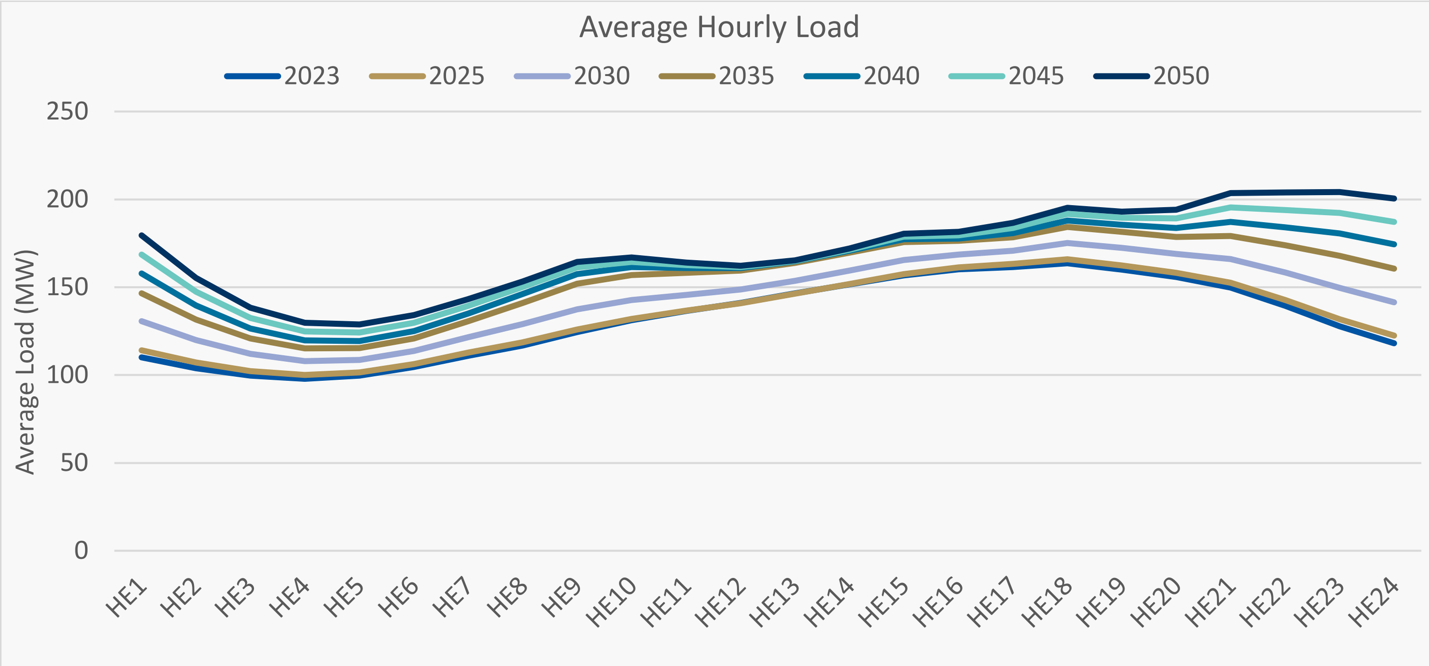
PWP's energy forecast is compared to previous forecasts in Figure 78. By 2030, the energy forecast in the 2023 IRP is 9% higher than predicted in the 2018 IRP forecast due to increased electrification.

Figure 78: PWP Load Comparison



PWP's average hourly load shape for 2023 through 2050 is shown in Figure 79. Load increases in the morning and ramps in the evening. When evaluating future resource potential, PWP will consider its load profile and what resources can help meet load cost effectively.

Figure 79: Average Hourly Load



In addition to average shape, PWP is mindful of the breakdown of its distribution of load, which is shown in Figure 80 and Figure 81.

Figure 80: Load Duration Curve

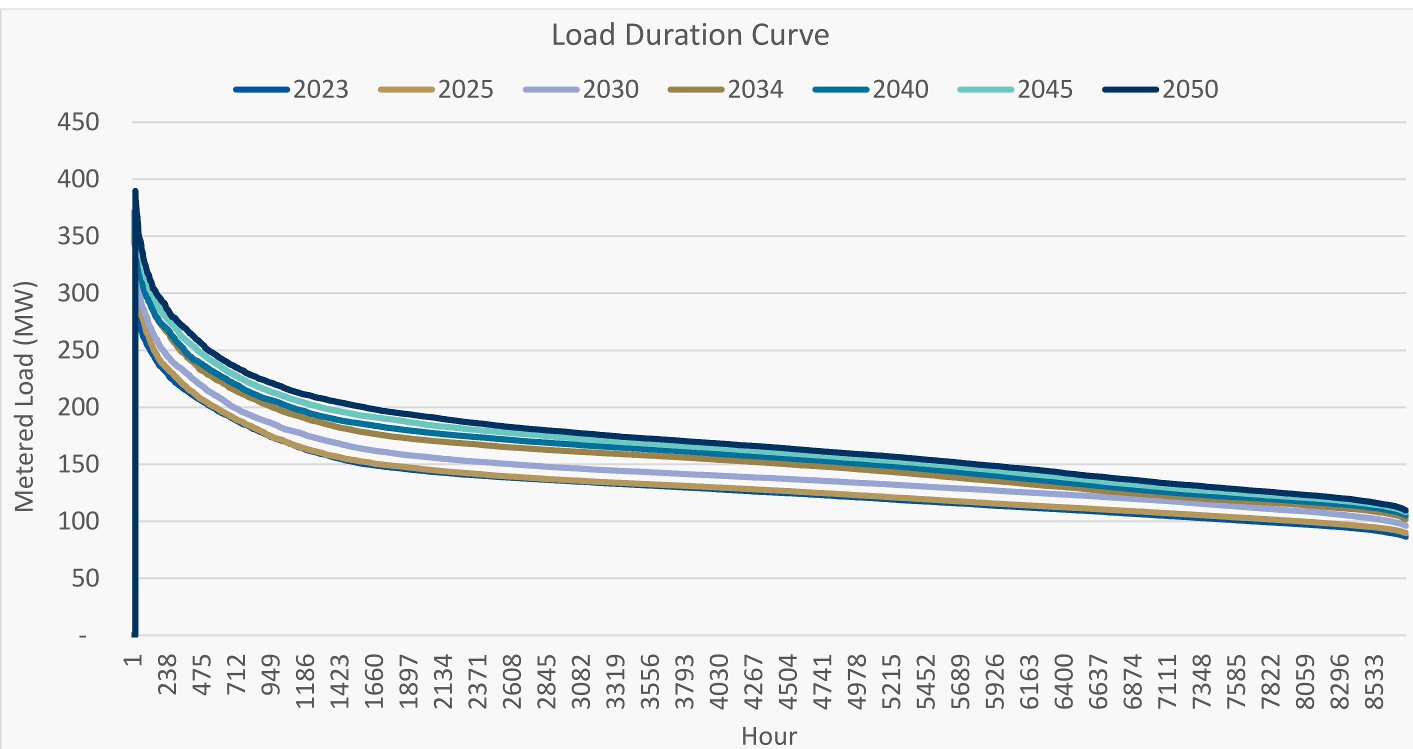


Figure 81: Load Duration Curve Inflection Points

Number of Hours by Year							
Load Equal or Greater Than	**2023**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
185 MW	745	761	954	1,318	1,609	1,988	2,418
280 MW	22	44	73	140	164	204	250
330 MW	1	2	5	25	37	46	55
Percent of Hours by Year							
Load Equal or Greater Than	2023	2025	2030	2035	2040	2045	2050
185 MW	9%	9%	11%	15%	18%	23%	28%
280 MW	0%	1%	1%	2%	2%	2%	3%
330 MW	0%	0%	0%	0%	0%	1%	1%

PWP's system needs to be designed to meet load in all hours. Certain hours of the year can drive resource planning needs.

12. Transmission and Distribution

12.1. Bulk Transmission System

CAISO was created in 1998 to manage the portions of the regional transmission grid owned and operated by the IOUs specifically, PG&E, SDG&E, and SCE. As a CAISO-certified Scheduling Coordinator and PTO, PWP's owned and contracted transmission rights have been delegated to CAISO for operation and planning.

The PWP system interconnects to the CAISO power grid at the T.M. Goodrich substation (Goodrich). Power is received via two 220kV transmission lines from SCE's Mesa and Gould substations, which are located southeast and north of Pasadena, respectively. The 220kV equipment at Goodrich is owned by PWP but maintained and operated by SCE under CAISO's direction. Contractually, the Goodrich interconnection may import up to 336 MW. However, the import capacity is currently limited to 280 MW so that PWP can address N-1 contingency operations under its distribution system limitations. N-1 is an industry planning standard that ensures continued operation in the event a system's single largest element fails.

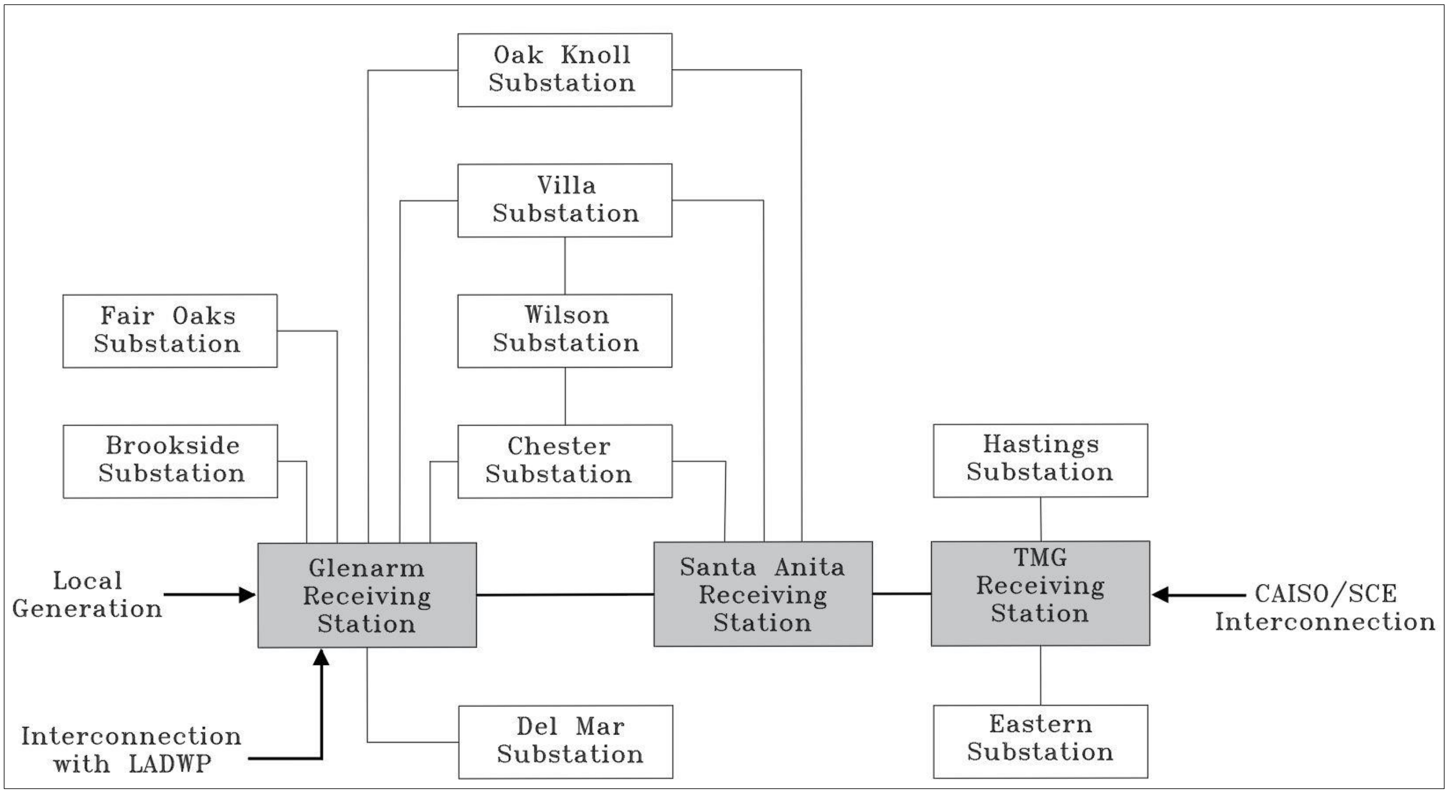
12.2. Bulk Transmission Planning

CAISO's annual transmission plan is an evaluation of grid reliability requirements, upgrades required to achieve State policy goals, and potential projects that could bring economic benefits to consumers. The system reliability assessment included in the 2022-2023 plan raises no concerns that would require any new corrective action plans to meet NERC requirements. Since PWP does not operate any part of the bulk transmission system, there are no identified transmission concerns that need to be addressed in the 2023 IRP.

12.3. Distribution System Planning

PWP's electric distribution system consists of three receiving stations (Goodrich, Glenarm, and Santa Anita) and nine distribution substations. Imported power from CAISO is delivered into the PWP system at Goodrich through three 112 MVA power transformers that step the voltage down from 220kV to 34.5kV. PWP also has a 40 MW, 34.5kV interconnection between Glenarm Receiving Station and LADWP's St. John Receiving Station, which is located west of Pasadena. PWP's Glenarm Power Plant (Glenarm) includes five generating units that connect to Glenarm Receiving Station. The St. John interconnection is currently not synchronized with the PWP distribution system and, therefore, cannot be operated in parallel to PWP’s connection to the CAISO grid. Its use is limited to emergencies or CAISO-mandated load curtailment requirements. See Figure 82.

Figure 82. Simplified Diagram of PWP's Sub-Transmission System



PWP utilizes an underground 34.5kV sub-transmission system, and a combination of overhead and underground 4kV and 17kV systems, to deliver electricity to customers through the distribution substations.

The 73-circuit-mile underground sub-transmission network is comprised of 285 miles of 34.5kV cable. The network includes eight 34.5kV circuits that form the cross-town backbone of the sub-transmission system and connect directly from Goodrich through the Santa Anita Substation to Glenarm Substation. The design of the 34.5kV substations are double bus/double breaker, which provides operating flexibility and a high level of reliability.

In coordination with the 2018 IRP, PWP developed a Power Delivery Master Plan (PDMP), which was approved by the Pasadena City Council in June 2022. The PDMP provides a high-level guide for planning, operating, and maintaining PWP’s electric distribution system over the next 20 years. It describes the utility’s infrastructure, assesses its current condition, and provides an ambitious long-term capital improvement plan of projects designed to enhance reliability, safety, and cost effectiveness. The PDMP describes PWP’s electric distribution system as reliable, despite aging infrastructure, and identifies a few crucial areas that need to be addressed systematically.

The PDMP specifically identifies several improvements directly related to the 2023 IRP. As previously stated, PWP has a contractual ability to import up to 336 MW, but it is limited to 280 MW due to distribution system limitations. The primary limitations are Goodrich transformer capacities, 34.5kV sub-transmission system power flow constraints, and high short circuit duty (~40 kA). The PDMP outlines the following initiatives for implementation on PWP's sub-transmission system to address these issues:

- Within five years, upgrade the capacity and protection of the 34.5kV mini-cross-town sub-transmission lines that connect Glenarm and Santa Anita Receiving Stations through the distribution substations to increase overall system power flow capability. Once the lines are upgraded, they would be reconfigured to create a second cross-town connection for redundancy and improved capacity. This upgrade is necessary before PWP can perform the sub-transmission line replacement work between Glenarm and Santa Anita Receiving Station described in the following bullet.

- Replace/upgrade the four aging 34.5kV cross-town sub-transmission lines between Glenarm and Santa Anita Receiving Stations.

- Upgrade the 220kV/34.5kV Goodrich transformers at the interconnection with CAISO to increase PWP's power import capacity from 280 MW to the contractual 336 MW import limit.

- Reduce the short circuit duty in the 34.5kV sub-transmission system to ~25 kA. To accomplish this, PWP plans to split the 34.5kV sub-transmission system electrically in coordination with the Goodrich transformer upgrades. This would significantly reduce potential damage to PWP's sub-transmission and distribution assets should faults (short circuits) occur.

These projects would not be completed simultaneously, rather they would be completed in operational order and/or in a manner that best minimizes community impacts. The collective scope is expected to be completed within 10 years.

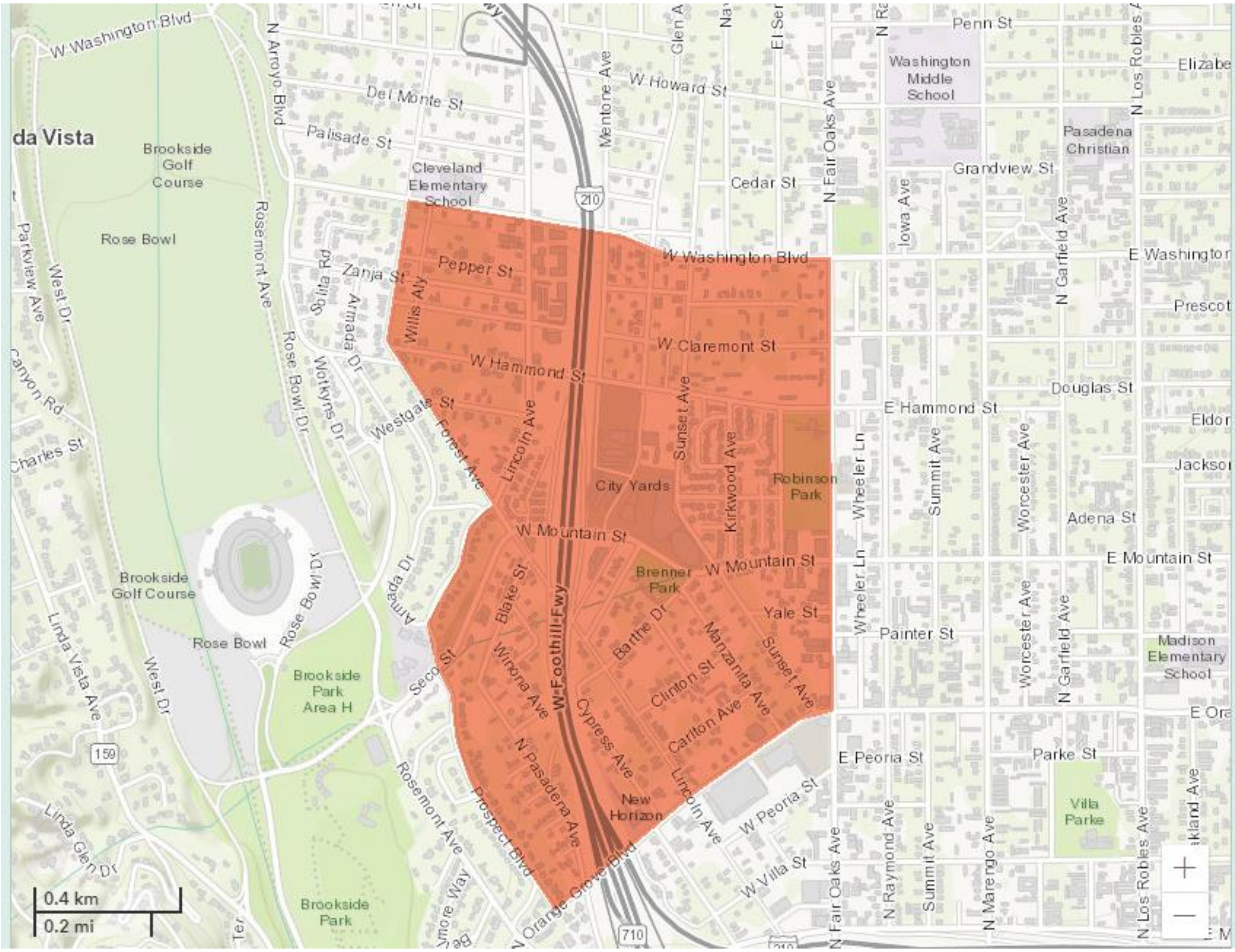
The upgrades would not only improve system reliability and longevity, but also facilitate the growth of DER utility-scale energy storage and utility-side renewable energy projects, such as community solar, within the PWP system. Precise locations, types, sizes and installation dates of new generation and storage projects connected to PWP's distribution system have yet to be determined and will require the PDMP be revised to address distribution system impacts based upon incremental engineering evaluations.

13. Localized Pollutants and Disadvantaged Communities

PWP recognizes that air pollution represents only one of the possible community impacts of supplying electric service to its customers. While the remainder of this section focuses on air quality, PWP remains committed to holistic mindfulness of the communities it serves, including noise and traffic ramifications of its utility operations. In so doing, PWP continually strives to perform as a good neighbor – not only in the present but also in charting and realizing Pasadena's energy future.

As directed by SB 535, the CalEPA defines and designates Disadvantaged Area Communities (DACs) based on geographic, socioeconomic, public health, and environmental hazard criteria. CalEPA's CalEnvironScreen uses U.S. Census data and 21 indicators to identify communities most affected by various sources of pollution. DACs are considered California's most environmentally burdened areas, so CARB's GHG programs such as Cap-and-Trade and the Low Carbon Fuel Standard (LCFS) tend to concentrate their investments in these communities to improve public health, quality of life, and economic opportunities in underserved areas. According to CalEnvironScreen, PWP's service territory includes one DAC. This location, shown Figure 83, encompasses 0.6 square miles in northwest Pasadena and includes a population of more than 6,000 people.

Figure 83: PWP's CalEnvironScreen 4.0 Identified Disadvantaged Area Communities



Source: CalEnvironScreen 4.0

13.1. Emissions Reduction

Glenarm, the only utility-scale generating station in Pasadena for PWP, is located outside this DAC. Nonetheless, PWP has been aggressively reducing its emissions footprint and cutting emissions below the limits set by SB 32 and AB 1279 to benefit all area communities. PWP had reduced emissions from its power supply portfolio by 50% compared to 1990 levels by the end of 2021. In January 2023, the Pasadena City Council adopted Resolution 9977, which sets a more ambitious goal of 100% carbon free energy resources by 2030, thereby accelerating the 2045 state target by 15 years. Resolution 9977 directs PWP to use the 2023 IRP process to define multiple paths to this goal in a way that optimizes stability, service reliability, affordability, and rate equity.

Following its core mission, PWP constructs, operates, and maintains its power system facilities to provide stable and reliable electric service to all its customers, regardless of their respective locations. By also actively promoting rate equity, PWP provides a benefit of special importance to its DAC area. As noted in the IRP Executive Summary, PWP will explore additional actions that would support the overall carbon reduction goals of the IRP including:

- Perform a rate design study that explores various options working to further address rate equity.
- Explore expansion of distributed energy resources, both customer- and utility-owned.
- Evaluate possible changes to customer incentives or subsidies, including low-income assistance.

Prioritizing the DAC and rate equity is essential as PWP undergoes planning and implementation of clean energy projects and programs. Additionally, this effort will be done in compliance with regulatory requirements under SB 32, SB 585, AB 1279, and other applicable statutes.

13.2. Expanding Transportation Electrification in Pasadena's DAC

For more than a decade, PWP has helped support EV adoption in the community by installing EV supply equipment for both fleet and public use. Pasadena has one of the nation's highest percentages of registered EVs.

As a participant in the CARB's LCFS program since 2016, PWP receives credits for usage on EV supply equipment and then can sell credits to transportation fuel producers and importers who have met specified average carbon intensity requirements for fuel according to CARB's regulations. PWP directs a percentage of LCFS program credit proceeds to projects and services that directly benefit qualified DACs and/or low-income customers. In accordance with the LCFS regulation, PWP allocated 30% of LCFS proceeds to qualifying programs and projects in calendar year 2022. This requirement increased to 40% in calendar year 2023 and will increase to 50% in 2024 and subsequent years.

Although pandemic-related supply chain issues have delayed PWP's overall LCFS project timelines, most of these projects progressed in calendar year 2022, including the start of construction of 25 public EV chargers at Robinson Park Recreation Center in northwest Pasadena. The project, which is scheduled to be completed and become operational by December 2023, will provide the DAC with convenient, freeway-accessible charging to encourage EV adoption in the area. PWP has also installed three public chargers at the entrance of the City Maintenance Yards, also located in northwest Pasadena, which is home base for a majority of the heavy-duty and light-duty fleet vehicles that PWP and the Public Works Department operate. These three public chargers add to the 55 existing employee vehicle and fleet chargers located directly on the facility grounds. Moreover, the Advanced Clean Fleets rule recently developed by CARB requires that 50% of new fleet purchases be qualifying zero emission vehicles (ZEV) by 2024. This requirement increases to 100% effective 2027 and will contribute significantly toward overall emissions reduction in the DAC and its surrounding neighborhoods.

Both budgetarily and operationally, PWP is fulfilling its DAC requirements under SB 535 and the LCFS.

13.2.1. EV Rebates and Incentives

To expand interest in EV adoption throughout the community, PWP has long offered incentives for the purchase or lease of an EV or EV equipment, with rebates issued in calendar year 2022 more than double rebates in the previous year. Income-qualified customers are eligible for additional rebates to help improve the affordability of an EV investment. Likewise, commercial customers that install EV equipment in DAC locations and income-qualified structures become eligible for additional incentives to encourage and support EV adoption in Pasadena's disadvantaged communities.

In 2023, PWP launched an e-Bike rebate pilot program, which will further incentivize adoption of affordable clean transportation options. The program was fully subscribed in fall 2023. Looking forward, the City will evaluate the pilot program results, benefits and challenges for future discussion of this and similar programs.

13.2.2. Efficiency and Assistance Programs

PWP offers numerous programs supporting both the DAC and income-qualified customers throughout the community. Section 5 of the IRP (Existing Policies and Programs) outlines these programs. The descriptions in the following subsections highlight several key programs available to these customers. Aside from programs exclusively open to income-qualified customers, PWP offers these programs to all customers. That said, the income-qualified programs particularly benefit DAC/LI customers.

13.2.2.1. Bill Assistance

The EUAP, together with the CARES and CARES Plus programs, provide monthly bill assistance to residents, seniors, and disabled customers who meet income requirements based on household size. Additionally, Project A.P.P.L.E. (Assisting Pasadena People with Limited Emergencies) provides a one-time payment assistance to any income-qualified residential customer who faces the risk of power disconnection due to non-payment. The Medical Equipment Assistance Program provides a monthly bill credit to any residential electric customer who operates eligible electric-powered medical equipment, regardless of income.

PWP also provides information on other available state and federal assistance programs to expand options for those experiencing financial hardships.

13.2.2.2. Energy Efficiency and Electrification Incentives and Services

Residential customers are eligible to receive rebates and services for energy efficient appliances and home improvements that help reduce GHG emissions. The Home Energy Rebate Program (HIP) provides incentives for the purchase of ENERGY STAR®-certified appliances and other qualifying all-electric equipment, as well as home insulation and air conditioning measures. The program also offers additional incentives and benefits to eligible income-qualified customers.

13.2.2.3. Whole House Services

PWP offers various direct installation programs that help qualifying homeowners improve overall home comfort and efficiency. Both PWP's HIP and SoCalGas' ESAP provide no-cost home efficiency evaluations, installations, and upgrades that include LED lighting, air-conditioning tune-ups, weatherization, high efficiency toilets, smart thermostats, and smart irrigation systems. The Under One Roof Program provides qualifying residents with guidance on program eligibility requirements and assistance with service coordination on all City efficiency and home improvement programs.

Income-qualified residents are also eligible to receive general home maintenance services such as painting, wheelchair ramp installations, and broken window replacements through the City's MASH Program. Pasadena's Housing Department has also partnered with Neighborhood Housing Services of Los Angeles County to offer low/no-interest home rehabilitation loans through HELP. Maintenance is an important step in improving home efficiency, and PWP is committed to providing an array of resource and assistance options to all members of the community.

13.2.2.4. Energy and Water Usage Reports

To help residential electric customers gain a better understanding of how personal energy and water consumption compares to that of similar neighborhood residents, PWP provides quarterly home energy and water reports that provide customer-specific savings tips and neighborhood comparisons to motivate efficient practices and behaviors.

13.2.2.5. Commercial Programs

WeDIP, available since 2013, provides no-cost water and energy efficiency upgrades to small business customers who may not have the time or financial resources to participate in PWP's large commercial customer efficiency rebate programs. Through a $1.2 million grant from the California Department of Water Resources, WeDIP was expanded in 2018 to include medium-sized businesses, with 76% of the grant funding directed to small- and medium- sized businesses within a DAC census tract. Additional information on PWP's programs is included on its website.[147]

13.3. Supporting Underserved Communities in the Future

PWP will continue to tailor education, outreach, and programs to engage and benefit low-income customers and its DAC census tract to ensure its customers have the opportunity to help reduce Pasadena's carbon footprint.

14. Defining Scenarios

14.1. Scenarios vs. Sensitivities

PWP is required to file a resource plan with the CEC that complies with various state requirements, including PUC Section 9621. However, the CEC also encourages POUs like PWP to evaluate scenarios and sensitivities to consider the feasibility, cost effectiveness, and rate impacts of alternative options.

In its 2018 IRP guidelines, the CEC defines a scenario as "a set of assumptions about future conditions used in power system modeling performed to support generation or transmission planning" and a sensitivity study as "a technique that determines how scenario analysis changes when an assumption is varied with all other scenario assumptions unchanged." In other words, a scenario produces a combination of resources built over time that aim to optimally meet energy, capacity, and environmental goals. Sensitivities stress scenarios to see how they would perform under different conditions.

In the 2023 IRP, PWP studied five scenarios and one emerging technology scenario. PWP also elected to model the five scenarios under four sensitivities. See Figure 84 for a primer on how PWP regarded the five scenarios versus the emerging technology scenario versus sensitivities.

Figure 84: Scenario vs. Emerging Technology Scenario vs. Sensitivity

Scenario	Emerging Technology Scenario	Sensitivity
• A mix of resources optimized under given conditions	• An avoided cost study • Load is shifted, and new resource mixes are created • The emphasis is not on what is installed, but on the cost differences	• A stress of variables applied to scenarios

[147] https://pwp.cityofpasadena.net/savemoney/

	• This quantifies a potential maximum financial value to PWP for a specified load or peak reduction	

On January 30, 2023, the Pasadena City Council approved Resolution 9977, declaring a Climate Emergency and setting a policy goal to reach 100% carbon-free electricity by the end of 2030. Resolution 9977 further directs PWP to use the 2023 IRP process to plan multiple pathways to meet this goal while optimizing affordability, rate equity, stability, and reliability. As a result of this resolution, the 2023 IRP serves not only to meet CEC obligations but also to launch PWP's investigation into planning and operating a carbon-free system.

PWP has the following two objectives of note for the 2023 IRP:

- File an IRP with the CEC as required by statute every five years
- Plan multiple approaches to transition to the goal of 100% carbon-free sources by the end of 2030, and optimize affordability, rate equity, stability and reliability

The second objective is likely one of the most ambitious decarbonization goals in the world, and far more aggressive than the ambitious California's 100% Clean Energy goals. As identified in the SB 100 Scoping Plan, the State's plan relies upon unprecedented build rates of renewable resources, as well as comprehensive electric grid transmission additions to accomplish a 2045 target implementation date.

PWP acknowledges that working towards achieving such a goal will require intensive and concentrated efforts that stretch across CAISO processes, CEC planning and coordination with government agencies across the state. While PWP must file an IRP by the end of 2023 to remain in compliance with state regulations, PWP anticipates continuing its demonstrated decarbonization trend, as GHG reductions of 68% have been realized as compared to 1990 levels. Therefore, the 2023 IRP represents its initial planning effort to contextualize what a carbon-free transition could entail. PWP will conduct further economic, reliability, rate, environmental, and other studies to help identify risks and opportunities.

14.2. Important Definitions for Scenarios

There are important definitions to note related to scenarios. The scenarios differentiate between internal and external resources. PWP's service territory is internal, whereas the grid outside its territory is external. See Figure 85.

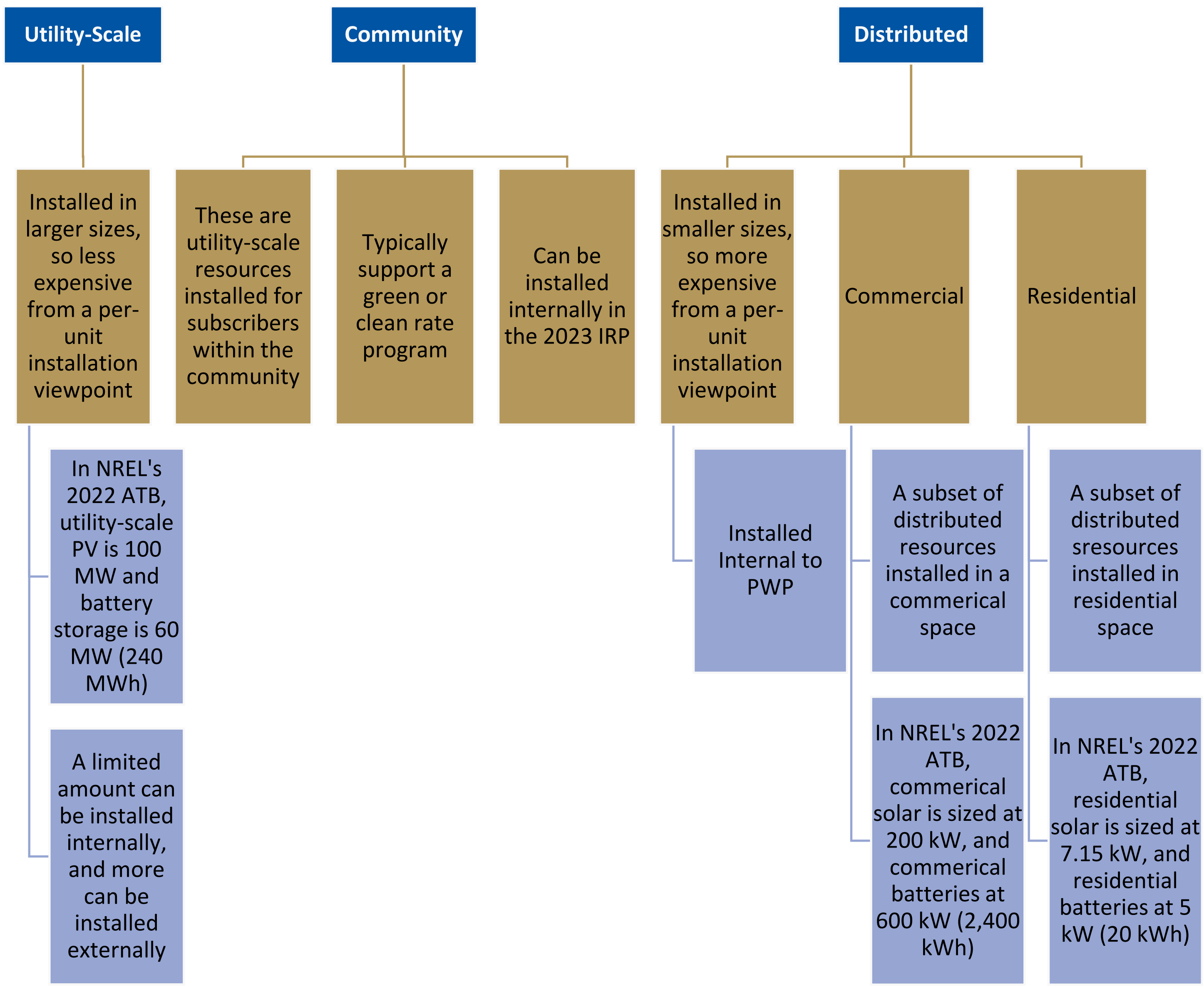
Figure 85: Internal vs. External

Internal	External
PWP is modeled as an area with load and its Glenarm power plant. Load is adjusted to include the impacts of energy efficiency, electric vehicles, distributed solar, and distributed storage. The IRP will refer to everything in this area as “internal.” This area is PWP’s service territory.	Goodrich is PWP’s connection to the larger energy markets within California. Goodrich is modeled as a connection to these larger markets. The larger market is the grid outside of PWP's service territory and is referred to as the external area.

PWP also categorizes resources as utility-scale, residential, commercial, distributed, or community. See Figure 86 for a brief description of each category. Additional information on NREL’s 2022 ATB, as referenced in Figure 86, is available online.[148]

[148] https://atb.nrel.gov/

Figure 86: Utility-Scale or Distributed?



Resolution 9977 requests carbon-free sources by the end of 2030. While renewable and zero-carbon are phrases defined by California, carbon-free is a concept developed by PWP. See Figure 87. PWP defined carbon-free resources as those that do not emit any carbon. This excludes some resources that California defines as renewable and, by that distinction, also as zero-carbon. PWP and its stakeholders also defined the goal as hourly for the purposes of the 2023 IRP. RECs, offsets, or other financial tools were not permitted.

Figure 87: Renewable vs. Zero-Carbon vs. Carbon-Free

	Renewable	Zero-Carbon	Carbon-Free
Who defines this?	California	California	2023 IRP

	Renewable	Zero-Carbon	Carbon-Free
Includes (examples)	Wind, solar, geothermal, renewable-powered fuel cells, landfill gas, biogas	Wind, solar, geothermal, renewable powered fuel cells, landfill gas, biogas, hydroelectric, nuclear, carbon-capture	Wind, solar, geothermal, renewable-powered fuel cells, hydroelectric, nuclear, storage (if charged by carbon-free energy)
Excludes (examples)	Fossil	Fossil	Fossil Landfill gas, biogas, current carbon capture technology
Measured	Annually	Annually	Hourly
Source of Requirement?	SB 100	SB 1020	Resolution 9977

Scenario analysis in the 2023 IRP helps PWP identify risks, opportunities, and inflection points. In the 2023 IRP, PWP assumed different ways to achieve a carbon-free resource portfolio by 2030. Four of the scenarios (including Scenario 6) follow the Resolution 9977 direction to study a carbon-free system, while one scenario (Scenario 4) follows state requirements. Scenario 5 studies the impact of a carbon tax. Figure 88 includes the list of scenarios.

Figure 88: Scenarios

Scenario 1: 100% Carbon Free by 2030 with No Limit on Internal Resources

Scenario 2: 100% Carbon Free by 2030 with a Limit on Internal Resources

Scenario 3: 100% Carbon Free by 2030 with a Limit on Internal Resources and Doubled Distributed Resources

Scenario 4: Reference Case (SB1020)

Scenario 5: Reference Case + Social Cost of Carbon (SB1020 + SCC)

Scenario 6: Emerging Technologies Study Scenario

Each scenario generated a least-cost, best-fit resource mix within the constraints of its assumptions. The IRP used an industry-standard planning model, EnCompass, by Anchor Power Solutions. See Section 9.2 of the IRP for more details on the model. The scenarios are further described in the following subsections.

14.3. Scenario 1: 100% Carbon-Free by 2030 with No Limit on Internal Resources

In addition to all relevant regulatory requirements, PWP will seek to meet 100% of its hourly energy load with carbon-free resources. Carbon-free resources include onshore wind, offshore wind, solar, and renewable hydrogen-powered fuel cells, but do not include natural gas, landfill gas, biofuel, or market purchases. Different durations of battery storage can also meet capacity needs. Battery storage should be charged by carbon-free resources post-2030.

PWP has a limited amount of space available within its service territory to site new generation or storage facilities. However, this scenario allows for a virtually unlimited number of resources to be located internal to PWP. The results of this scenario demonstrate the types and aggregate sizes of resources needed to meet its load every hour with carbon-free resources. This serves as the foundation for what PWP could seek to acquire, in practice. This may also help PWP identify the number, sizes, and scale of facilities needed.

14.4. Scenario 2: 100% Carbon-Free by 2030 with a Limit on Internal Resources

PWP has a limited amount of space available within its service territory to site new generation or storage facilities. Based on best-available information and estimates, PWP believes it can site 200 MW of 4-hour storage, 150 MW of 6-hour storage, 100 MW of 8-hour storage, or 50 MW of 10-hour storage in its service territory. PWP also believes it could site up to 5 MW of hydrogen-powered fuel cells and 5 MW of utility-scale (community) solar. This scenario sets these limits as the maximum amounts of these internal resources that PWP could choose. In other words, the model could elect to install up to those amounts of resources internally. If those limits bind (i.e., if the results maximize any one of those limits), the model would seek to install the next best thing. This could be residential or commercial solar or storage within PWP's service territory, or carbon-free resources located external to PWP that PWP could import through Goodrich. Should the space constraints detailed in Scenario 2 arise in practice, PWP could consider how to proceed.

14.5. Scenario 3: 100% Carbon-Free by 2030 with a Limit on Internal Resources and Doubled Distributed Resources

This scenario copies the carbon-free goals and internal resource availability assumptions mentioned in Scenario 2 but doubles the amount of distributed solar and storage embedded in the load forecast. See Figure 89. The distributed solar and storage capacity embedded in the load forecast represents PWP's estimate of what will happen naturally given current incentives and state trends. In this scenario, PWP also adds that amount online as resources. The doubling of distributed solar and storage assumes a decision to prioritize customer-side resources.

Figure 89: Distributed Resources in Load Forecast

Installed Capacity of Distributed Resources in Load Forecast (MW)		
Year	Distributed Solar	Distributed Storage
2023	30	2
2024	32	2
2025	34	3
2026	37	3
2027	39	4
2028	42	4
2029	44	5
2030	47	6

Installed Capacity of Distributed Resources in Load Forecast (MW)		
Year	Distributed Solar	Distributed Storage
2031	50	7
2032	53	8
2033	56	9
2034	59	9
2035	62	11
2036	65	12
2037	68	13
2038	71	14
2039	74	15
2040	78	17
2041	81	18
2042	84	20
2043	88	21
2044	91	23
2045	95	25
2046	98	26
2047	102	28
2048	105	30
2049	108	32
2050	112	34

Across all scenarios, all resources have associated costs. The IRP presumes that DER already included in the load forecast puts no incremental cost burden on PWP. Additional DER would come at an additional cost, and the IRP identifies this cost component for informational guidance.

14.6. Scenario 4: Reference Case (SB 1020)

This scenario demonstrates PWP's ability to comply, or exceed with all applicable state regulatory mandates, including the following:

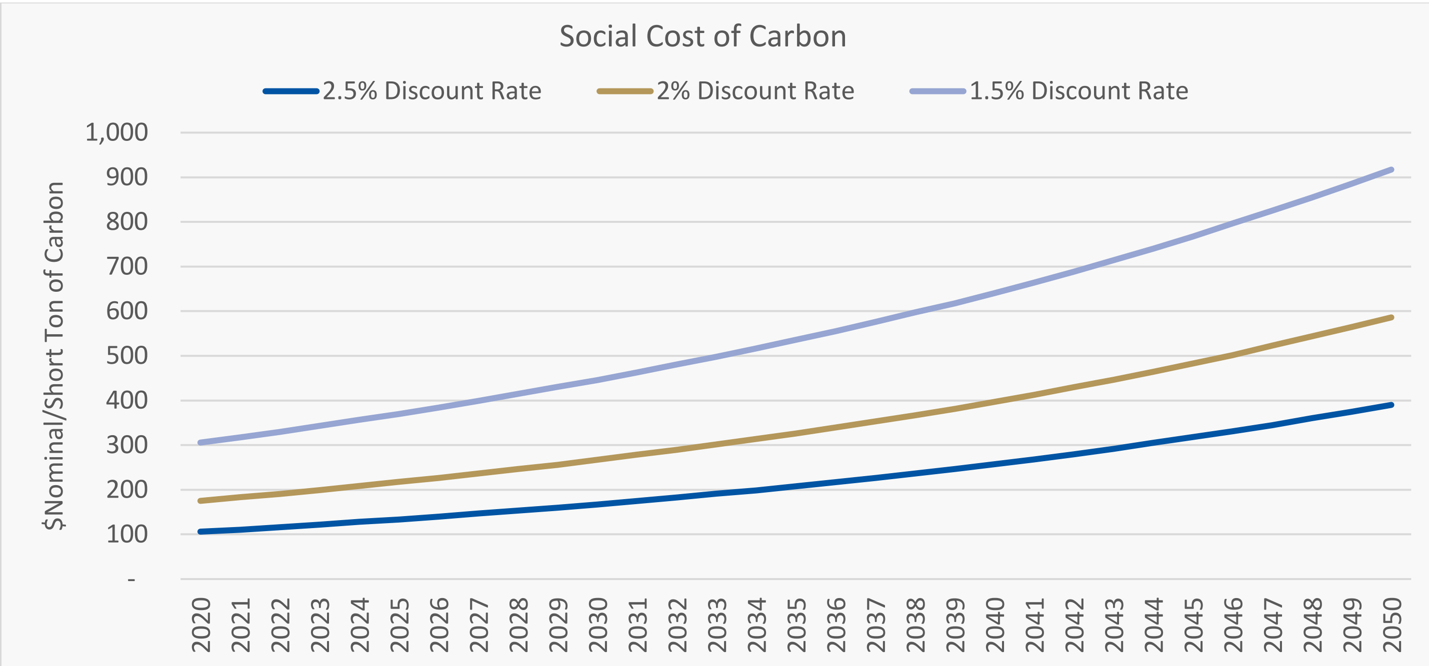
- Utility-specific GHG reduction targets established by CARB that reflect the electricity sector's achievement of economy-wide GHG emissions reductions of 40% lower than 1990 levels by 2030
- Renewable energy procurement target of 60% by 2030
- 100% renewable resource and zero-carbon goal by the end of 2045

Scenario 4 gives PWP a base case against which to compare other scenarios.

14.7. Scenario 5: Reference Case + Social Cost of Carbon (SB 1020 + SCC)

PWP meets all relevant regulatory requirements. Also, a hypothetical additional carbon tax based on the SCC applies to all carbon-generating resources. The SCC is a dollar value estimate of the damage to society caused by CO_2 emissions. PWP referred to an estimate developed by the EPA in 2022. See Figure 90[149]. PWP used the 1.5% discount rate in this estimate, which generates the highest SCC for study purposes.

Figure 90: Social Cost of Carbon



Carbon-producing resources include natural gas, landfill gas, biogas, and market purchases. The IRP assumed that the carbon-intensity of the market declines over time, as carbon-emitting resources are replaced by lower-emitting alternatives. PWP adopted the market estimate using NREL's Cambium 2022 mid-case data, depicted in Figure 91.[150]

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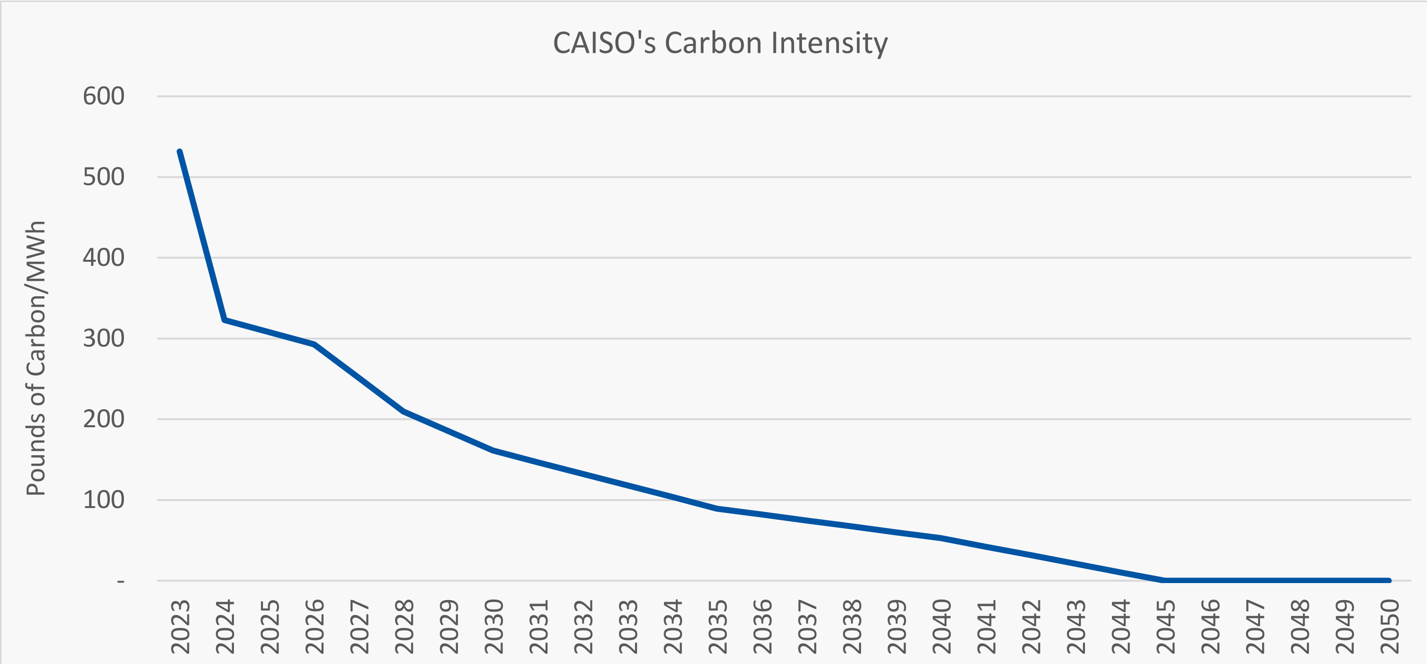
149 https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-issues-supplemental-proposal-reduce

150 https://scenarioviewer.nrel.gov/

Figure 91: Carbon Intensity of CAISO

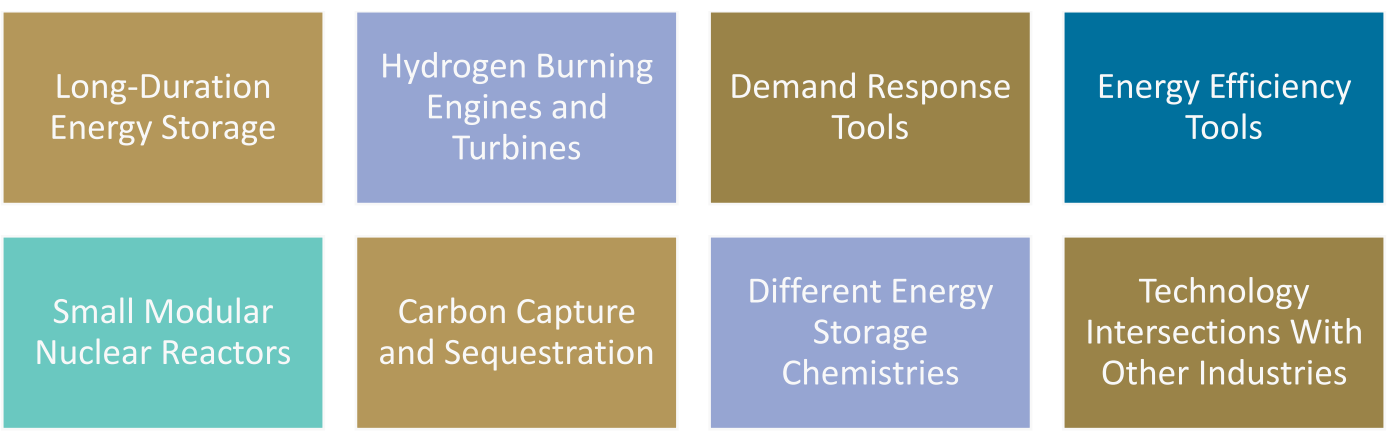


Scenario 5 allows the capacity associated with carbon-producing resources to help meet overall requirements. However, the carbon tax would, in theory, encourage additional renewable generation to replace carbon-emitting resources.

14.8. Scenario 6: Emerging Technology Study

Emerging technologies represent opportunities to achieve carbon-free goals at lower costs and greater reliability. Emerging technologies is a general term referring to technologies that may become available during the IRP Study Period (2023 through 2050). Figure 92 shows examples of potential emerging technologies.

Figure 92: Potential Emerging Technologies



Emerging technologies, by nature, are not currently available commercially. Therefore, PWP does not have the data on costs and operational parameters that it has for more advanced technologies.

PWP seeks to be a leader in making and achieving carbon reduction goals. To support this, PWP ran an Emerging Technology Scenario. This is an additional scenario that evaluates the impacts of emerging technologies on a single given scenario, which is Scenario 2 in this IRP. Scenario 2 is the most constrained in terms of new resources that can be installed. As a result, the value of emerging technologies to PWP may be highest in Scenario 2.

While PWP cannot predict what emerging technologies could best help it achieve its carbon reduction goals cost effectively, the following are two performance traits of particular interest to PWP:

- Less energy usage overall
    - Examples include energy efficiency, distributed resources, a base load plant, etc.
- Less energy usage at net peak load times
    - Examples include demand response technologies, long-duration energy storage, dispatchable clean technologies, etc.

In the Emerging Technology Scenario, PWP sought answers to the following questions:

- What is the proxy value to reduce energy and peak load across all hours of a year by 1%, 2%, or 3%?
- What is the proxy value to reduce the top 0.5%, 1%, and 1.5% of peak load hours each year by 30 MW?

To answer these questions, PWP ran two series of studies: an energy efficiency proxy study and a demand response proxy study.

14.8.1. Scenario 6: Energy Efficiency Proxy

In the first study under Scenario 6, PWP's load is reduced by 0.5%, 1%, and 2% across all hours of the year for a given scenario (in this case Scenario 2). The cost difference between these results and the original scenario result is a potential maximum value to PWP for technologies that reduce overall load.

Scenario 2 is the most constrained scenario, which results in a higher bound of financial value to PWP for an emerging technology that reduces load.

14.8.2. Scenario 6: Demand Response Proxy

In this second study under scenario 6, PWP's load is reduced by 30 MW (approximately 10% of its peak load) across the top 0.5%, 1%, and 2% of load hours each year. The cost differences between these results and that of the original scenario is a higher bound of value to PWP for technologies that reduce load during peak hours. Again, PWP conducted this study on Scenario 2.

14.9. Modeling a Carbon-Free Resource Scenario

Resolution 9977 requests that the IRP plan multiple approaches to meet the City's policy goal of sourcing 100% of Pasadena's electricity from carbon-free sources by the end of 2030. PWP is part of CAISO and, as such, PWP needs to consider its carbon emissions in the context of its interactions with CAISO.

The carbon associated with CAISO market purchases can be assessed in at least the following two ways:

- Average
    - There are different resource types producing energy. The energy generation over one year can translate to an average emission rate. A forecasted estimate of CAISO's carbon intensity is shown in Figure 91.

- Marginal
  - The carbon intensity of CAISO could also default to the carbon intensity of natural gas. This has historically been the last resource to go online to meet load.

Given that the market has embedded carbon, PWP wanted to understand how it could replace market purchases with traceable, carbon-free energy. To be carbon-free on an hourly basis, PWP would need to purchase enough zero-carbon resources to avoid CAISO purchases in each hour of the year.

In modeling PWP's carbon-free system, the 2023 IRP made the following assumptions:

- Glenarm and Magnolia are retired December 31, 2029
  - The debt associated with Glenarm must be repaid. There is an estimated $85 million in outstanding debt associated with Glenarm that was not included in the modeling. Additionally, any decisions regarding Glenarm operations would be subject to CAISO in-depth analysis, which is based in part on NERC reliability standards.
    - Glenarm does not require fuel source modification, adaptation, or conversion for Scenarios 4 and 5. The Carbon-Free Scenarios require Glenarm to be either replaced, converted, or adapted with carbon-free dispatchable alternatives such as carbon capture, green hydrogen, biofuels or other future technologies as they emerge, and prior to 2030

  - Magnolia's contract runs through June 30, 2036. There may be fees, must-take, or other financial obligations associated with an early exit. Participation in this project is through SCPPA and requires an in-depth analysis and potential bilateral negotiations with other SCPPA project participants.
- No biogas as a new resource starting in 2030
- No market access – assume the average emission rate for carbon

From a planning perspective, PWP operationally modeled its system as an island to avoid the markets inherent carbon content (i.e., without CAISO access). However, PWP currently interacts daily with CAISO. The differences between these approaches are shown in Figure 93.

Figure 93: Island vs. Market Access

	Island	Energy Market Access
Modeling	PWP adds resources so it can operate a reliable, 100% carbon-free system on an hourly basis.	Once the resources are selected as though PWP is an island, they can dispatch within the CAISO markets.
Carbon Implications	PWP can meet its load with carbon-free resources each hour.	Resources may dispatch differently given market signals. Market interactions come with carbon implications.
Cost Implications	Scenario costs will appear higher. This is the high bookend. PWP's resources cannot sell excess energy to the market.	Scenario costs will appear higher. This is the low bookend. PWP's resources could sell excess energy to the market. Given that many factors influence revenue earned in the markets, PWP

	Island	Energy Market Access
		may need to study other cost implications to answer the question, "What is excess worth?"

14.10. PWP's Starting Position

PWP has an existing fleet of owned and contracted resources that help meet energy, capacity, and environmental needs. PWP's existing installed capacity is shown in Figure 94.

Figure 94: PWP's Existing Cumulative Installed Capacity

	2023	2024	2025	2026	2027	2028	2029	2030	2031
Total Existing Resources	**407**	**405**	**337**	**337**	**287**	**287**	**287**	**282**	**271**
Existing Coal	108	108	0	0	0	0	0	0	0
Existing Natural Gas Combined Cycle	80	80	130	130	80	80	80	80	80
Intermountain Repower NG	0	0	50	50	0	0	0	0	0
GT - 5	66	66	66	66	66	66	66	66	66
Magnolia	14	14	14	14	14	14	14	14	14
Existing Natural Gas Combustion Turbine	132	132	132	132	132	132	132	132	132
GT - 1	22	22	22	22	22	22	22	22	22
GT - 2	22	22	22	22	22	22	22	22	22
GT - 3	45	45	45	45	45	45	45	45	45
GT - 4	42	42	42	42	42	42	42	42	42
Existing Large Hydroelectric (Hoover)	14	14	14	14	14	14	14	14	14
Existing Nuclear (Palo Verde)	10	10	10	10	10	10	10	10	10
Existing Wind	7	5	5	5	5	5	5	0	0
Milford Wind	5	5	5	5	5	5	5	0	0
PPM (Avangrid) Wind	2	0	0	0	0	0	0	0	0
Existing Landfill	10	10	10	10	10	10	10	10	0
Puente Hills Landfill	4	4	4	4	4	4	4	4	0
Chiquita Landfill	6	6	6	6	6	6	6	6	0
Existing Utility-Scale Solar PV	36	36	36	36	36	36	36	36	36
Antelope Solar	7	7	7	7	7	7	7	7	7
Columbia Two Solar	2	2	2	2	2	2	2	2	2
Kingbird Solar	20	20	20	20	20	20	20	20	20
Summer Solar	7	7	7	7	7	7	7	7	7
Windsor Reservoir Solar	1	1	1	1	1	1	1	1	0
Existing Demand Response	10	10	0	0	0	0	0	0	0
Total New Contracted Resources	**0**	**0**	**335**	**335**	**428**	**478**	**478**	**478**	**478**
New Geothermal	0	0	0	0	35	35	35	35	35
Calpine Geysers	0	0	0	0	25	25	25	25	25
Coso Geothermal	0	0	0	0	10	10	10	10	10
New Utility-Scale Solar PV	0	0	5	5	44	44	44	44	44
EDF Sapphire Solar	0	0	0	0	39	39	39	39	39

	2023	2024	2025	2026	2027	2028	2029	2030	2031
New 4-Hour Storage (projected)	0	0	80	80	100	150	150	150	150
EDF Sapphire Storage	0	0	0	0	20	20	20	20	20
Peak Load (MW)	**330**	**333**	**335**	**338**	**341**	**343**	**346**	**348**	**351**

Installed capacity is not the same as qualifying capacity. Qualifying capacity represents the resources' reliability contributions, which CAISO quantifies. Figure 95 shows PWP's existing RA position without any resource additions.

Figure 95: PWP's Firm Capacity Position without Resource Additions

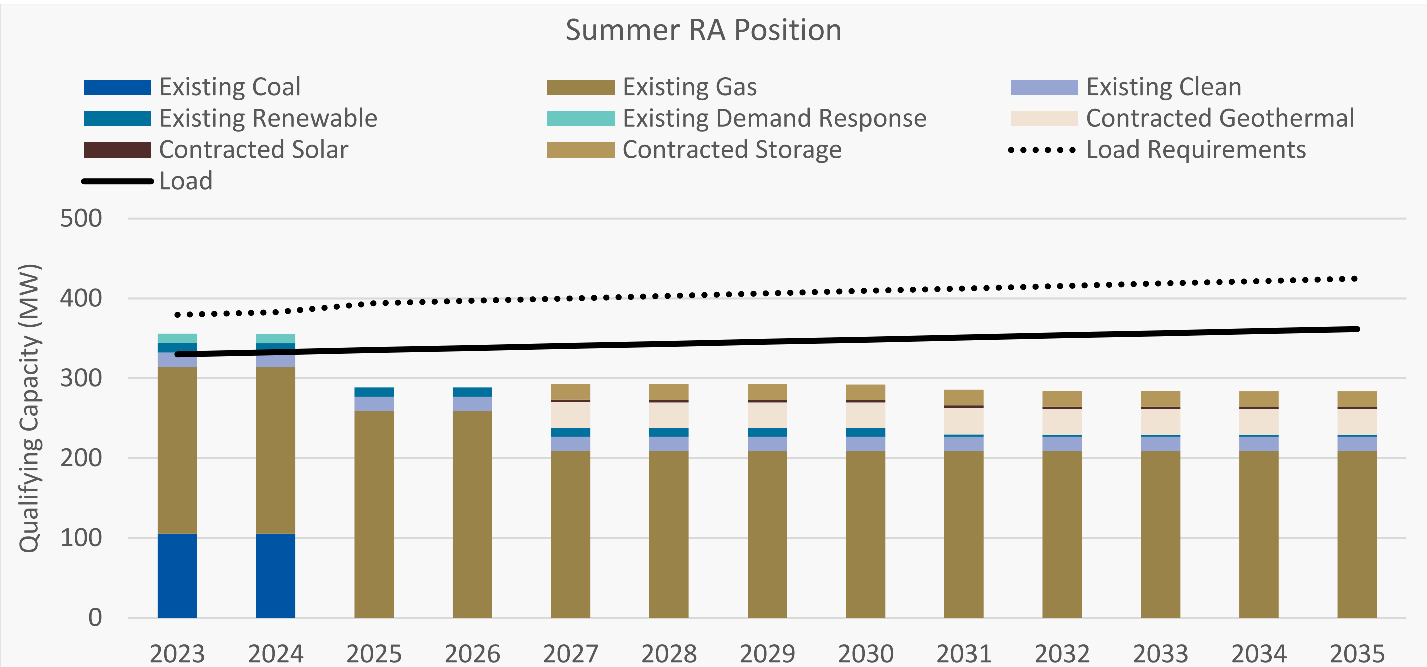


Figure 96 shows the firm capacity of these resources in greater detail.

Figure 96: PWP's Firm Capacity Position without Resource Additions

Monthly Load (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031
July	288	297	311	323	310	297	300	306	322
August	305	323	335	338	334	313	337	330	351
September	330	333	324	322	341	343	346	348	344
Summer Peak Load (MW)	**330**	**333**	**335**	**338**	**341**	**343**	**346**	**348**	**351**
Reserve Margin (%)	15%	15%	18%	18%	18%	18%	18%	18%	18%
Peak Month	09	09	08	08	09	09	09	09	08
Required Reserves (MW)	**50**	**50**	**59**	**59**	**60**	**60**	**61**	**61**	**61**
Summer Load Requirements (MW)	**380**	**383**	**394**	**397**	**400**	**403**	**406**	**409**	**412**
Total Existing Resources	**356**	**355**	**289**	**288**	**238**	**238**	**238**	**237**	**230**
Existing Coal	105	105	0	0	0	0	0	0	0
Existing Natural Gas									
Intermountain	0	0	50	50	0	0	0	0	0
Glenarm	195	195	195	195	195	195	195	195	195

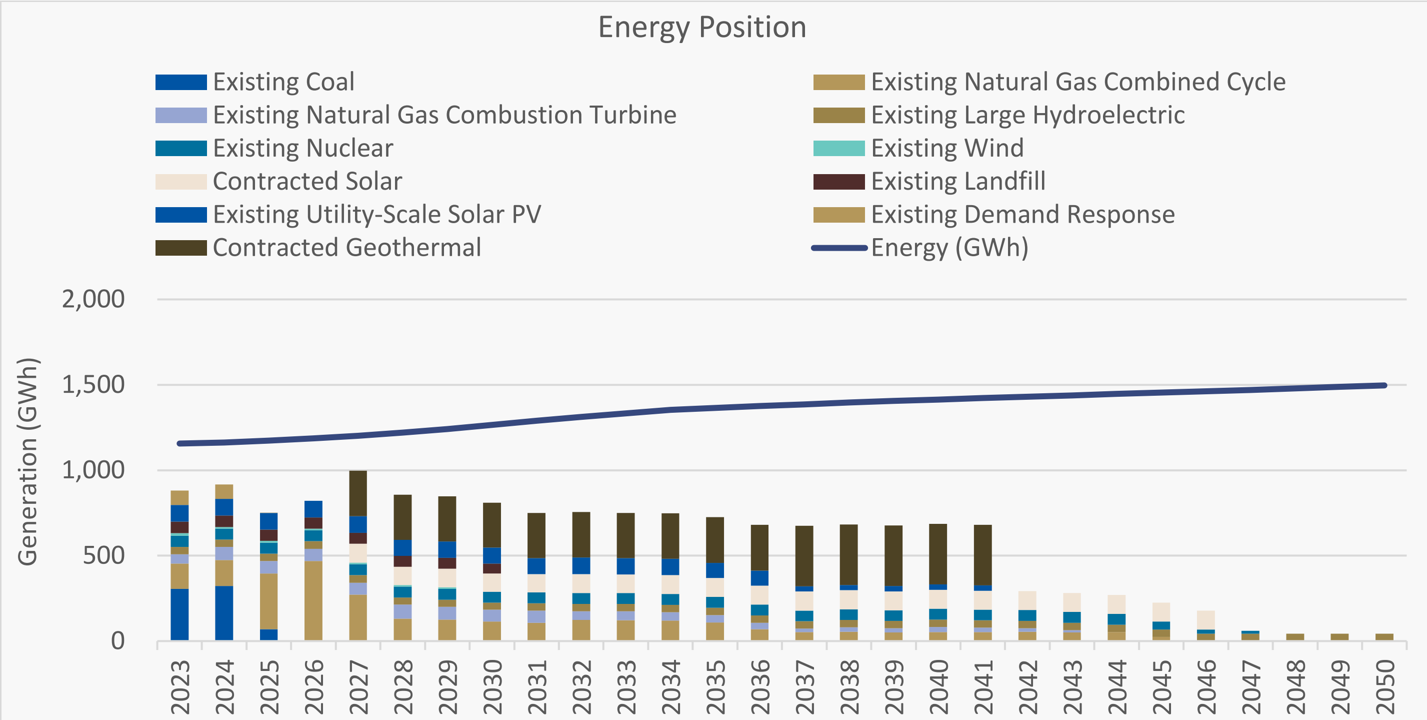
Monthly Load (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031
Magnolia	14	14	14	14	14	14	14	14	14
Existing Large Hydroelectric	9	9	9	9	9	9	9	9	9
Existing Nuclear	9	9	9	9	9	9	9	9	9
Existing Wind	0	0	0	0	0	0	0	0	0
Existing Landfill	8	8	8	8	8	8	8	8	0
Existing Utility-Scale Solar PV	4	4	4	4	3	3	3	3	3
Existing Demand Response	12	12	0	0	0	0	0	0	0
Total New Resources	**0**	**0**	**0**	**0**	**55**	**55**	**55**	**55**	**56**
New Geothermal									
Contracted (Calpine Geysers and Coso)	0	0	0	0	32	32	32	32	33
New Solar									
Contracted (EDF Sapphire Solar)	0	0	0	0	3	3	3	3	3
New Storage									
Contracted (EDF Sapphire Storage)	0	0	0	0	20	20	20	20	20
Length/(Shortage)	(24)	(27)	(105)	(109)	(107)	(111)	(114)	(117)	(127)

Calpine Geysers, Coso Geothermal, and EDF Sapphire Solar were all contracted in 2021 to 2023 to help address upcoming qualifying capacity needs. Without these planned resources, capacity shortages in the summer increase to 105 MW in 2025 and to 162 MW in 2027. Even with these resources, shortages remain at 105 MW in summer 2025 and 107 MW in summer 2027.

Across scenarios, 2025 and 2027 show resource needs because 108 MW of installed capacity from IPP coal retires on June 30, 2025. Approximately 50 MW of installed capacity from IPP natural gas begins on July 1, 2025, and expires on June 30, 2027.

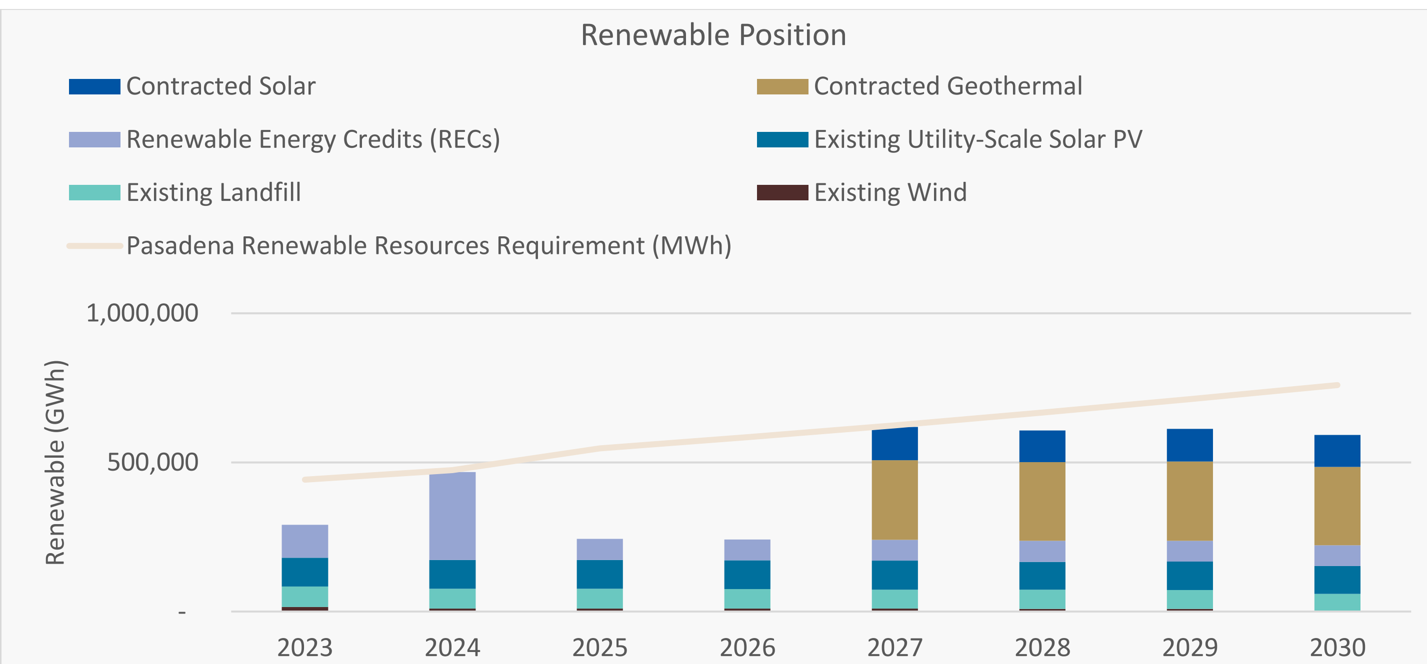
Capacity shortages result in greater net interactions with CAISO's energy markets. Figure 97 shows that PWP will serve approximately two-thirds of its annual energy with contracted resources by 2030, assuming its contracted resources come online as planned.

Figure 97: Energy Position without Resource Additions



Capacity shortages also result in increasing renewable energy needs over time, as shown in Figure 98. As it stands, PWP needs more renewable energy to fulfill its state requirement of 60% renewables by 2030.

Figure 98: Renewable Position without Resource Additions



15. Defining Sensitivities

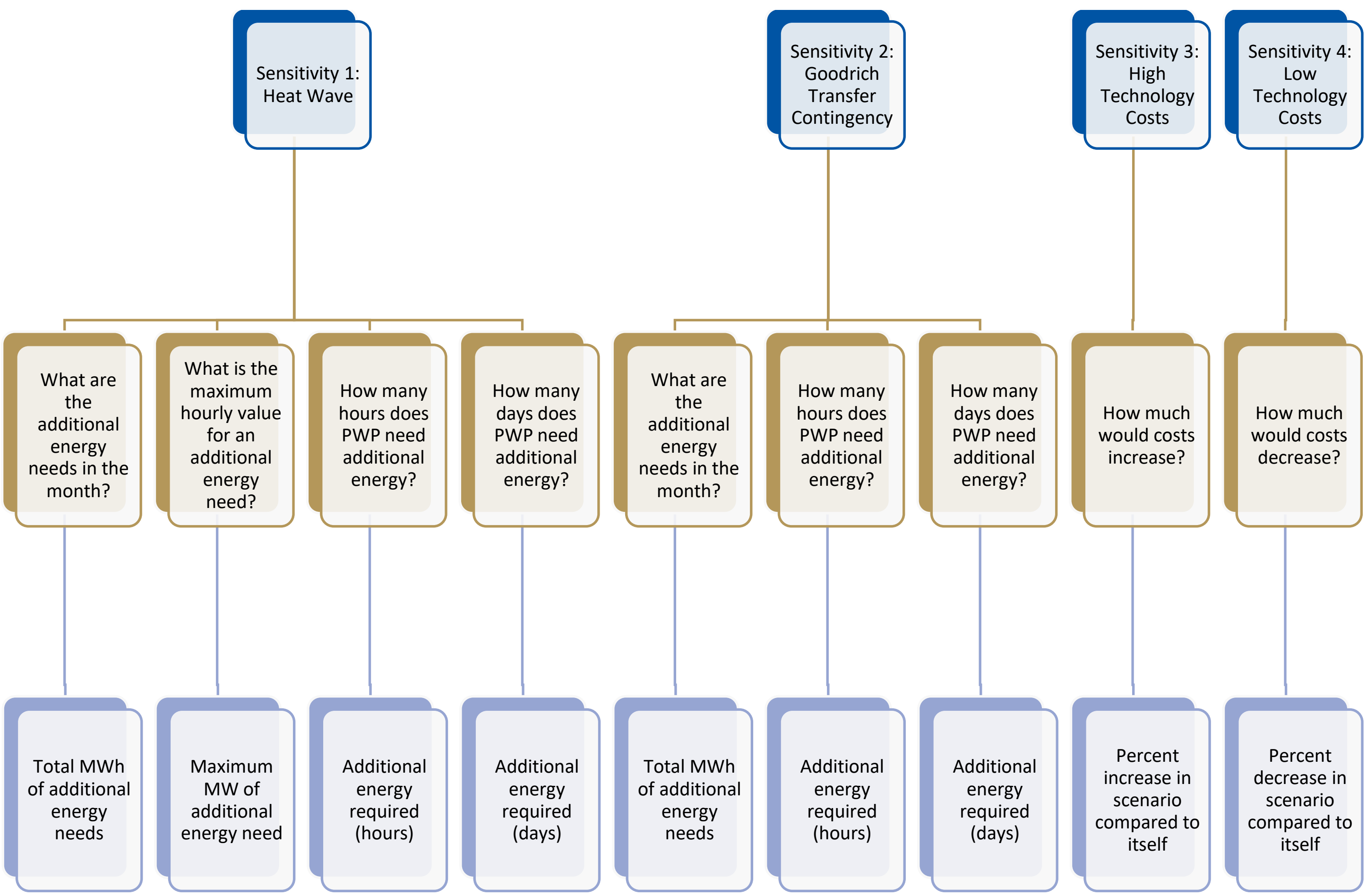
Scenarios are selections of resources optimized to meet capacity, energy, and renewable needs. Sensitivity tests push stressors onto scenarios to determine how the scenarios would perform under different conditions. Scenarios 1, 2, 3, 4, and 5 had the sensitivity tests applied after the initial modeling. These tests help identify potential vulnerabilities and considerations. There are four proposed sensitivities, as shown in Figure 99.

Figure 99: Sensitivities

- Sensitivity 1: Heat Wave
- Sensitivity 2: Goodrich Transfer Contingency
- Sensitivity 3: High Technology Costs
- Sensitivity 4: Low Technology Costs

The sensitivities seek to answer fundamental questions. See Figure 100. Sensitivities 1 and 2 focus on reliability, and Sensitivities 3 and 4 focus on cost.

Figure 100: Sensitivity Metrics



15.1. Sensitivity 1: Heat Wave

This sensitivity tests scenarios against a persistent, record-setting heat wave. Daily temperatures are set between 90 degrees Fahrenheit (°F) and 120°F for four weeks. Power prices, natural gas prices, wind generation, solar generation, and load are all impacted because of the heat. This tests the ability of each scenario to meet load.

In 2030, peak load times occur in late August through early September. See Figure 101. As a result, this scenario ran from August 15, 2030, through September 15, 2030. Dates and times of peak are highly uncertain. This scenario is one estimate of load created for the 2023 IRP.

Figure 101: Peak Load in 2030

Date	Month	Day	Hour Ending	Demand (MW)
September 11, 2030	9	11	17	348
September 11, 2030	9	11	16	343
September 11, 2030	9	11	18	342
September 1, 2030	9	1	17	340
September 1, 2030	9	1	16	332
August 27, 2030	8	27	16	330
September 11, 2030	9	11	15	329
August 25, 2030	8	25	17	328
August 27, 2030	8	27	17	328
September 1, 2030	9	1	18	328

Power prices, natural gas prices, wind generation, solar generation, and load were correlated to heat to create conditions that mimic a heat wave. The explanation in the following subsection provides additional details on the method used to create the data.

15.1.1. Sensitivity 1: Heat Wave: Data Scraping and Cleaning

The following historical hourly data from 2008 to 2022 (excluding 2012 due to irreconcilable inconsistences in the data) came from Yes Energy, subcontracted through ACES:

- Temperature in Pasadena
- CAISO load
- CAISO wind generation
- CAISO solar generation
- Real-time prices at SP-15 Hub
- Daily natural gas price at SoCal City Gate

The data was cleaned by removing missing values and negative solar and wind generation. To compare solar and wind generation across years, the data was converted to a percentage of the maximum generation for the year to estimate capacity factors. This is the cleaned data.

15.1.2. Sensitivity 1: Heat Wave: Normal Data Creation

The wind and solar capacity factors for each hour of the year were averaged from 2008 through 2022. This produced a normal 8,760 capacity factor shape for wind and solar, covering all the hours in a typical year. Hours were then filtered to only the hours in September. The prevailing seasonal and temperature relationships were extracted from the averaged shapes to remove noise, such as historical localized weather patterns. This normal data was used to compare a normal September to the modelled heat wave, and this served as the basis for multipliers derived by dividing the heat wave scenario by the normal scenario, allowing easy switching between the two.

15.1.3. Sensitivity 1: Heat Wave: Training Datasets Creation

Hourly training data is required for the predictions that use hourly granularity (hourly load, power prices, and wind output) and was generated from an August to October subset of the cleaned data (shoulder months are included so that there is more data to enable the model to generate relationships). Hourly data was filtered to isolate only those observations where the temperature is greater than 75°F and the real-time power price and natural gas price are greater than zero. This filtering led to linear trends to use in modeling a heat wave.

Daily training data is required for the predictions that use daily granularity (natural gas and solar output) and was generated from the same subset as the hourly training data. To convert the hourly solar capacity factor into a usable daily metric, a daily maximum was taken as an ordinal variable with 0.05 width bins from 0 to 1. However, the wind capacity factor and the load were converted from hourly values to daily means. As a final step, predictive variables of mean temperature, maximum temperature, and minimum temperature were generated along with temporal variables, such as the year, time of week, and time of year. The hourly training data (and the prediction data in the next step) also included temporal predictive variables with the additional inclusion of the time of day.

15.1.4. Sensitivity 1: Heat Wave: Prediction Data Creation

PWP defined a heat wave as a four-week period when temperatures do not dip below 90°F and do not exceed 120°F during September 2030. By using a sine curve function for daytime warming and a logarithmic decay function for nighttime cooling, hourly temperature estimates were based on an idealized daily temperature curve for a given latitude that interpolates hourly data between the calculated time when the daily minimum and the daily maximum occur.

15.1.5. Sensitivity 1: Heat Wave: Model Creation and Prediction

The load model was trained on the hourly training data. The hourly prediction data was fed into the fitted model to create hourly load predictions. Next, an identical model was created to reflect the exclusion of temperature as a predictive variable, and it was fitted on the cleaned data. The new model predicts normal load for that time of year. By taking the heat wave modeled load and dividing it by the normal load, a multiplier was generated that models the magnitude of change between a normal scenario and a heatwave. This multiplier was also fed into the model.

The wind generation capacity factor model was trained on the hourly training data, then the model was used on the hourly prediction data to predict hourly wind generation capacity factors for the heat wave. These predictions were divided by the normal wind generation capacity values (calculated in a prior step) to generate multipliers.

The solar generation capacity factor model was trained on the daily training data, and then the model was fed the daily prediction data to predict daily maximum solar generation capacity factors; however, the prediction for each of the maximum capacity factors was the same, so only a single multiplier was needed. Therefore, the center of the predicted bin was taken as the single predicted capacity factor and used to rescale the normal data. The original normal data was then divided by the new normal data, and the average was taken to derive a multiplier.

The daily natural gas price model was trained on the daily training data, then the model was used on the daily prediction data to predict daily gas prices for the heat wave.

The real-time pricing model for power prices was trained on the hourly training data, then the model was used on the hourly prediction data to predict hourly power prices values for the heat wave.

For some of the models, a previous model's predictions were used as inputs for its own predictions.

Figure 102: Heat Wave Data Creation

Response Variable	Model Type	Response Transformation	Temporal Granularity	Temperature	Time of Day	Time of Week	Time of Year	Year	Temperature Interaction	Wind Capacity Factor	Solar Capacity Factor	Natural Gas Price	Real-Time CAISO Load
Real-Time CAISO Load	Multivariate Linear	None	Hourly										
Wind Capacity Factor	Multivariate Linear	Logarithmic	Hourly										
Daily Solar Capacity Factor	Multinomial	Ordinal + Maximum	Daily										
SoCal City Gate Natural Gas Price	Multivariate Linear	Logarithmic	Daily										
SP-15 Real Time LMP	Multivariate Linear	None	Hourly										

Overall, assumed temperatures average 104°F, as shown in Figure 103.

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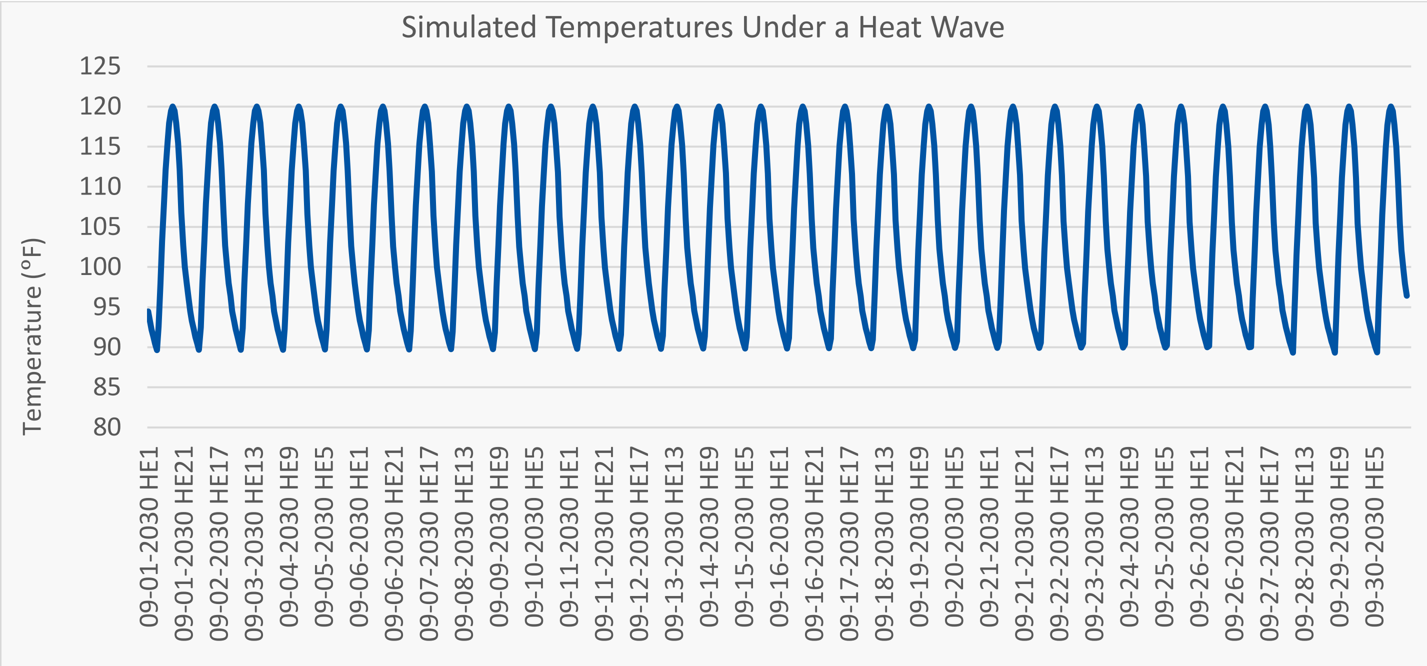
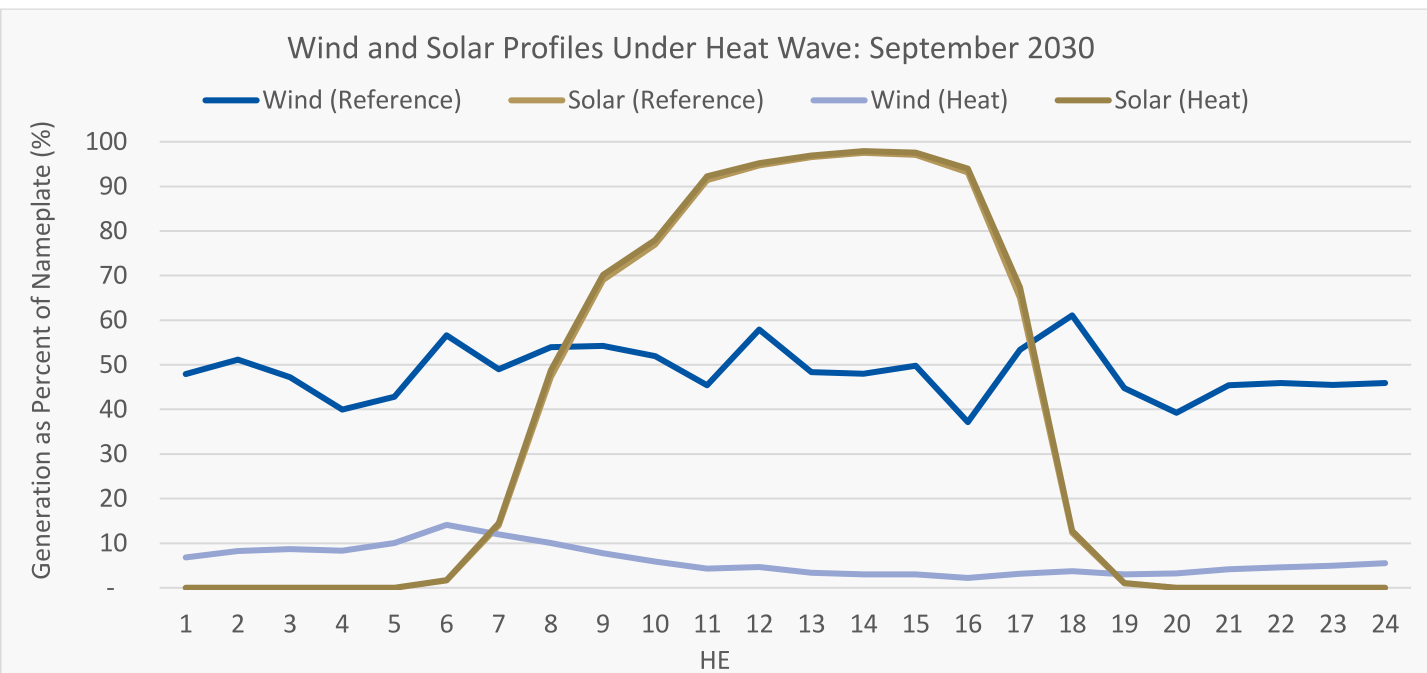
Figure 103: Simulated Temperatures Under a Heat Wave



During a heat wave, renewable output changes. Solar increases by 3.6% and wind is 12% of its normal output. See Figure 104 for details.

Figure 104: Wind and Solar Profiles Under Heat Wave

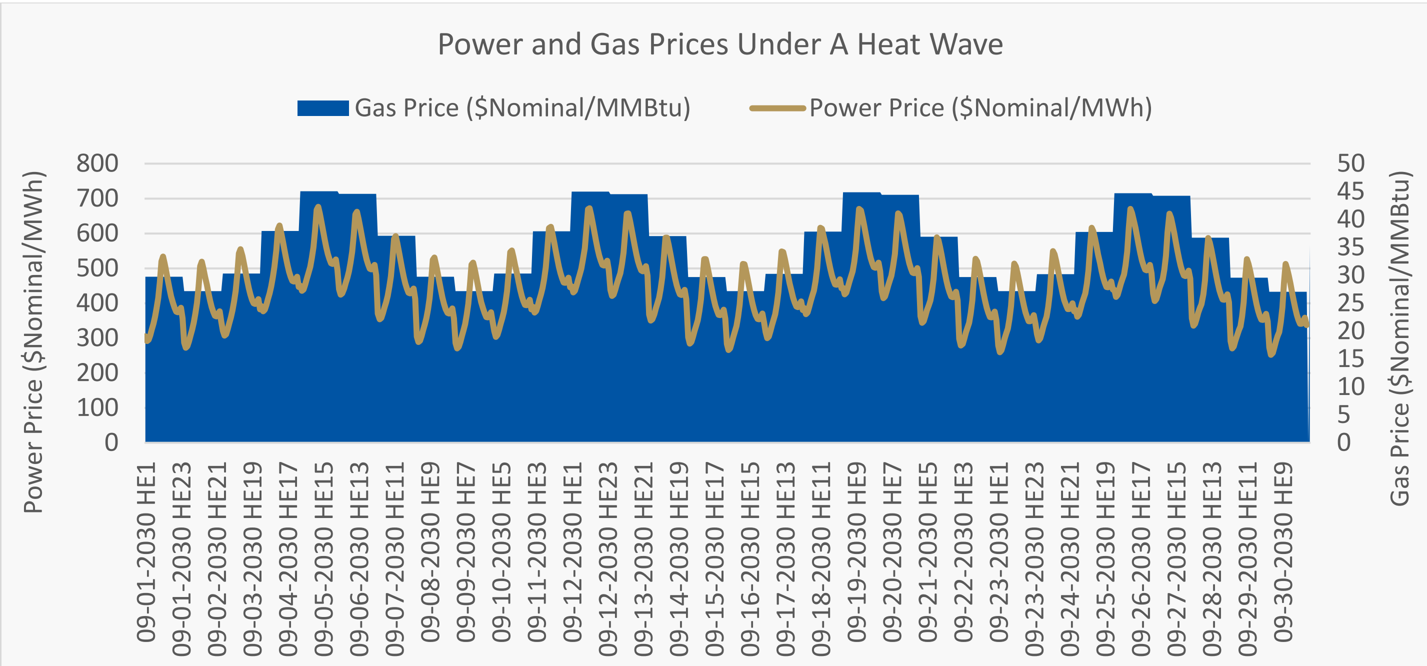


Load increases to approximately 1.5 times its typical amount during a heat wave due to air conditioning demand.

Power and natural gas prices also increase during a heat wave, with natural gas prices averaging $35/MMBtu. In September 2030, the reference forecasted price was $5.50/MMBtu. Figure 105 shows the pricing assumed in the IRP.

Power prices averaged $447/MWh for this sensitivity. For September 2030, the reference case forecasted price was $69/MWh. These prices are in nominal dollars.

Figure 105: Heat Wave Prices



15.2. Sensitivity 2: Goodrich Transfer Contingency

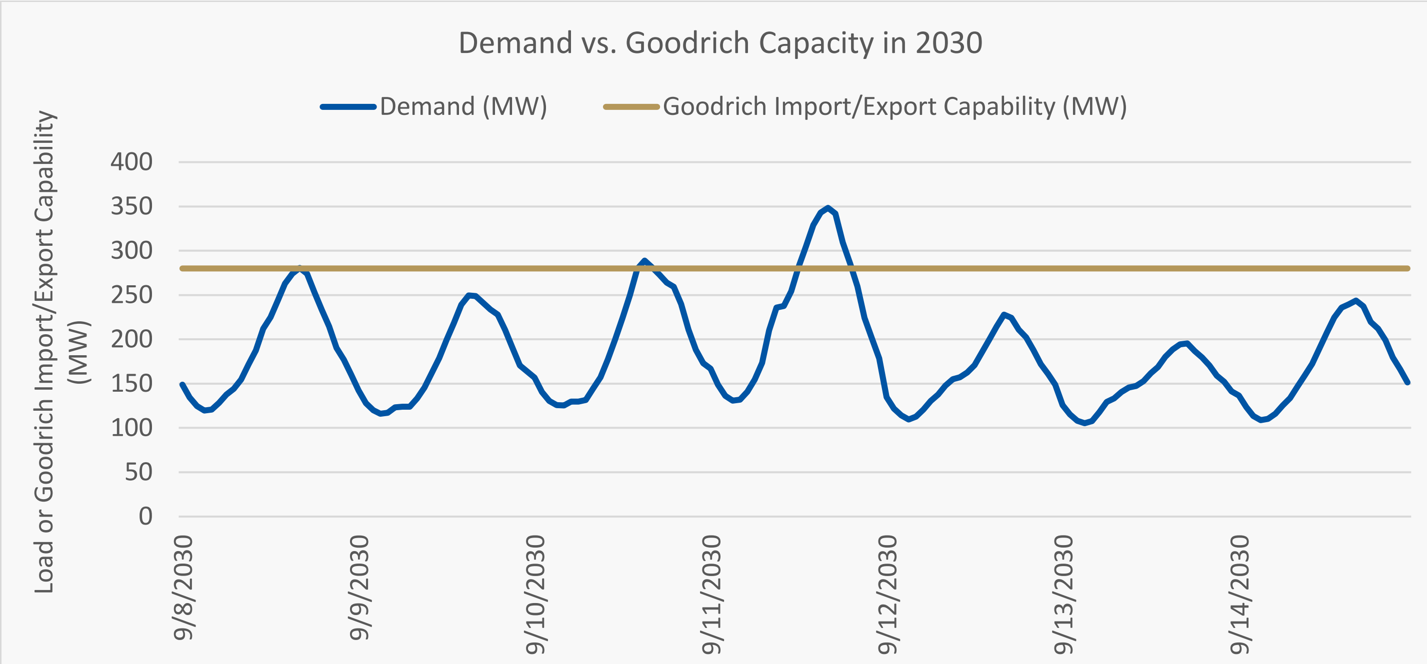
Under normal operating conditions, Goodrich can import up to 280 MW until July 2032. It is anticipated that planned upgrades will allow up to 336 MW thereafter. For purposes of this sensitivity, Goodrich's import capability is reduced by one-half to 140 MW in 2030 to reflect a single transmission line outage into the station for one week during the summer.

There are different circumstances such as planned system maintenance or unplanned (forced) outages that could cause such an event. These could originate at Goodrich, or on the lines feeding into Goodrich. This sensitivity would help PWP compare the value of internal versus external resources.

15.2.1. Sensitivity 2: Goodrich in 2030 Under Forecasted Normal Operating Conditions

The model ran the week of September 8, 2030, through September 14, 2030, when peak loads in 2030 are likely to occur. Figure 106 shows how demand compares to Goodrich's capability.

Figure 106: Demand vs. Goodrich in 2030



15.2.2. Sensitivity 3: High Technology Costs

All scenarios used mid-cost estimates of new resources. However, the 2023 IRP produced low, mid, and high estimates of capital costs for new resources. See Appendix – Cost of New Resources. This sensitivity stresses the results of the scenarios under the high estimates for new resource costs.

15.2.3. Sensitivity 4: Low Technology Costs

This sensitivity tests the results of the scenarios under the low estimates for new resource costs. See Appendix – Cost of New Resources

16. Scenarios and Sensitivities Results

16.1. Scenario 1: 100% Carbon-Free by 2030 (No Limit on Internal Resources)

The installed capacity of new resources in Scenario 1 is shown in Figure 107.

Figure 107: Scenario 1: New Cumulative Installed Capacity

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Total New Resources	**355**	**375**	**468**	**468**	**468**	**788**	**818**	**830**	**899**	**885**
New Wind	0	0	0	0	0	0	0	0	30	30
New Geothermal										
Contracted (Calpine Geysers and Coso)	0	0	35	35	35	35	35	46	0	0
New	0	0	0	0	0	0	0	0	0	0
New Solar										
Contracted (EDF Sapphire Solar)	0	0	39	39	39	39	39	39	39	0

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Utility-Scale Solar	280	300	300	300	300	300	300	300	320	330
Community	0	0	0	0	0	0	0	0	0	0
Commercial	0	0	0	0	0	0	0	0	0	0
Residential	0	0	0	0	0	0	0	0	0	0
New Storage										
Contracted (EDF Sapphire Storage)	0	0	20	20	20	20	20	20	20	0
New 4-Hour Storage	75	75	75	75	75	195	195	195	195	185
New 6-Hour Storage	0	0	0	0	0	80	90	90	90	90
New 8-Hour Storage	0	0	0	0	0	10	10	10	40	30
New 10-Hour Storage	0	0	0	0	0	0	0	0	0	0
New Commercial	0	0	0	0	0	0	0	0	0	0
New Residential	0	0	0	0	0	0	0	0	0	0
New Fuel Cells	0	0	0	0	0	110	130	130	165	220

Figure 108: Scenario 1: Cumulative Installed Capacity by Location

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Total Installed Capacity	**692**	**712**	**755**	**755**	**755**	**859**	**875**	**867**	**919**	**899**
Total Existing Resources	**337**	**337**	**287**	**287**	**287**	**70**	**57**	**37**	**20**	**14**
Total New Resources	**355**	**375**	**468**	**468**	**468**	**788**	**818**	**830**	**899**	**885**
New Onshore Wind	0	0	0	0	0	0	0	0	30	30
New Land-Based External Wind	0	0	0	0	0	0	0	0	30	30
New Offshore Wind	0	0	0	0	0	0	0	0	0	0
New Geothermal	0	0	35	35	35	35	35	46	0	0
Calpine Geysers	0	0	25	25	25	25	25	25	0	0
Coso Geothermal	0	0	10	10	10	10	10	21	0	0
New Utility-Scale Solar PV	280	300	339	339	339	339	339	339	359	330
EDF Sapphire Solar	0	0	39	39	39	39	39	39	39	0
New Internal Solar	270	290	290	290	290	290	290	290	310	320
New Internal Solar (Storage Paired)	10	10	10	10	10	10	10	10	10	10
New PWP-Funded Commercial Solar PV	0	0	0	0	0	0	0	0	0	0
New PWP-Funded Residential Solar PV	0	0	0	0	0	0	0	0	0	0
New 4-Hour Storage	75	75	95	95	95	215	215	215	215	185
EDF Sapphire Storage	0	0	20	20	20	20	20	20	20	0
New 4-Hour Storage (Internal Solar Paired)	5	5	5	5	5	5	5	5	5	5
New 4-Hour Internal Storage	70	70	70	70	70	190	190	190	190	180
New 6-Hour Storage	0	0	0	0	0	80	90	90	90	90
New 6-Hour Internal Storage	0	0	0	0	0	80	90	90	90	90
New 8-Hour Storage	0	0	0	0	0	10	10	10	40	30
New 8-Hour Internal Storage	0	0	0	0	0	10	10	10	40	30
New 10-Hour Storage	0	0	0	0	0	0	0	0	0	0

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
New PWP-Funded Commercial Storage	0	0	0	0	0	0	0	0	0	0
New PWP-Funded Residential Storage	0	0	0	0	0	0	0	0	0	0
New Fuel Cells	0	0	0	0	0	110	130	130	165	220
New Internal Fuel Cells	0	0	0	0	0	110	130	130	165	220
New Biogas Conversion for Glenarm	0	0	0	0	0	0	0	0	0	0
Peak Load (MW)	**335**	**338**	**341**	**343**	**346**	**348**	**362**	**371**	**380**	**390**

PWP adds more than its peak load in installed capacity in 2025. In the same year, the IPP coal resource retires. PWP also increases its reserve margin from 15% to 17.5%, a shift that requires an additional 9 MW.

By 2030, PWP's installed capacity of owned and contracted resources is 859 MW, compared to peak load of 348 MW. In other words, PWP's installed capacity in 2030 is more than 2.5 times its peak load. In Scenario 1, 806 MW of the installed capacity located internal to PWP, which may entail land use issues beyond the scope of this document.

Scenario 1 installs 280 MW of internal, utility-scale solar in 2025. This includes a 10 MW solar facility with attached storage, with a total of 300 MW by 2027 (excluding the EDF Sapphire Solar project). Scenario 1 also installs 75 MW of internal 4-hour storage in 2025, including 5 MW of storage attached to solar, and with 195 MW in total located internally by 2030. Furthermore, there is 90 MW of 6-hour and 10 MW of 8-hour storage by 2035. An additional 110 MW of fuel cells in 2030 also supports reliability, which increases to 130 MW of fuel cells by 2035.

The summer and winter capacity positions are shown in Figure 109, Figure 110, and Figure 111. The renewable category, as annotated by an asterisk, and includes renewable hydrogen power fuel cells and landfill gas, as allowed by the State of California.

Figure 109: Scenario 1: Summer Resource Adequacy

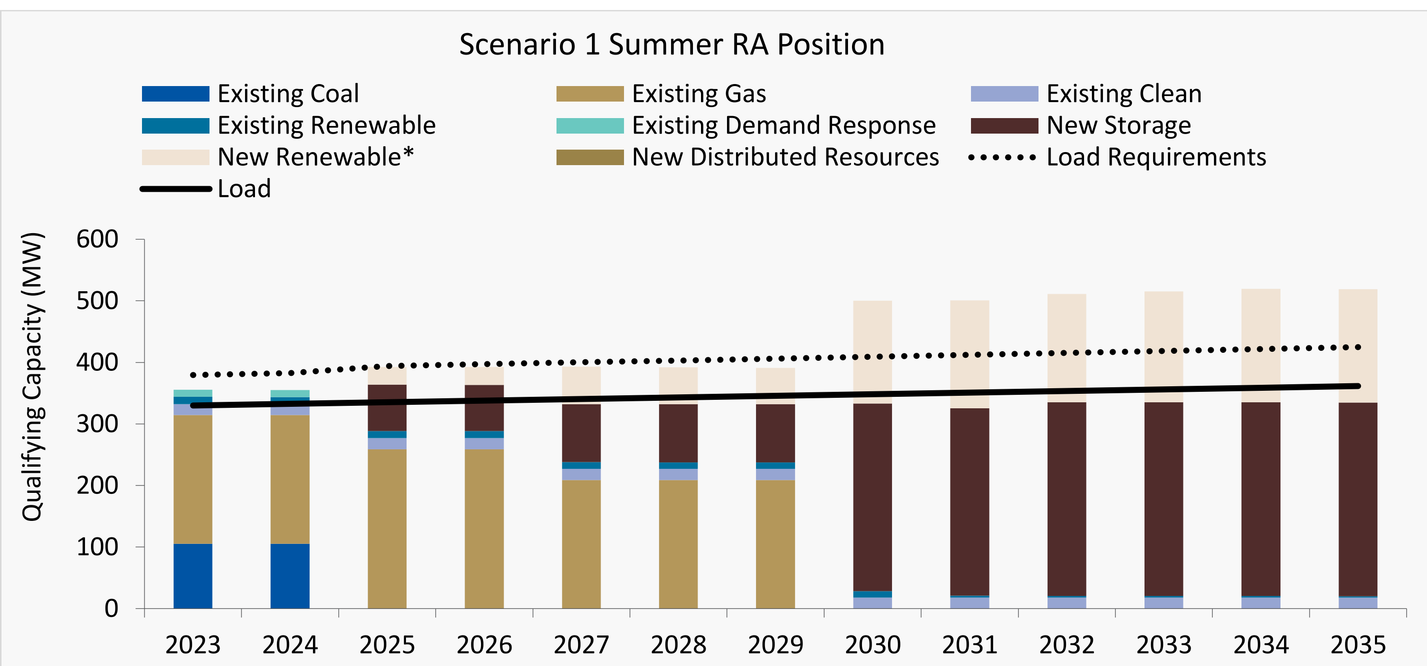


Figure 110: Scenario 1: Winter Resource Adequacy

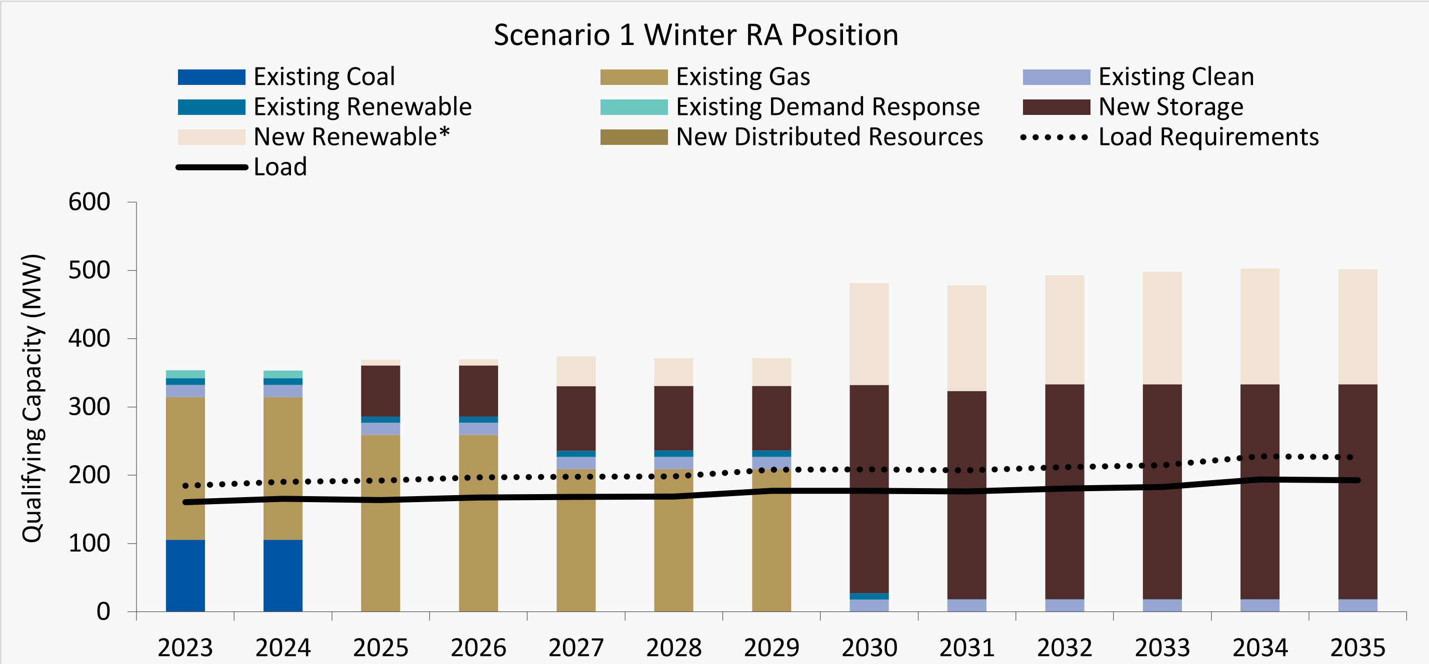


Figure 111: Scenario 1 Resource Adequacy Position

Summer RA Position (MW)												
	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Summer Load Requirements	380	383	394	397	400	403	406	409	425	436	447	458
Existing Resources Qualifying Capacity	356	355	289	288	238	238	238	29	20	19	14	9
Length/(Shortage) Before New Additions	(24)	(27)	(105)	(109)	(162)	(166)	(169)	(381)	(405)	(417)	(432)	(449)
New Resources Qualifying Capacity	0	0	104	104	155	154	153	472	499	511	536	548
Length/(Shortage) After New Additions	(24)	(27)	(1)	(4)	(7)	(11)	(15)	91	94	95	104	99
Winter RA Position (MW)												
	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Winter Load Requirements	185	190	192	197	198	198	208	208	226	236	243	261
Existing Resources Qualifying Capacity	354	353	286	286	236	236	236	27	18	18	18	9
Length/(Shortage) Before New Additions	169	163	94	89	38	38	28	(181)	(208)	(218)	(225)	(252)
New Resources Qualifying Capacity	0	0	83	84	138	135	135	454	483	494	521	535

Summer RA Position (MW)												
	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Length/(Shortage) After New Additions	169	163	177	173	177	174	163	273	275	276	297	284

As shown in the above charts, there is more capacity installed in Scenario 1 than is necessary for RA. Internal fuel cells specifically help serve load under normal operating conditions.

In order to serve load in each hour with carbon-free resources, Scenario 1 requires at least 110 MW of fuel cells in 2030 (compared to the first round of modeling results of 20 MW) and 220 MW of fuel cells in 2050 (compared to the first round of modeling results of 120 MW), as shown in Figure 112 Fuel cells were added to the first round of modeling results because Scenario 1 allowed for unlimited internal resources. Fuel cells are dispatchable, carbon-free resources that can operate for extended periods of time and provide qualifying capacity. Other resources could cover this gap.

Figure 112: Scenario 1: Consecutive Model Runs

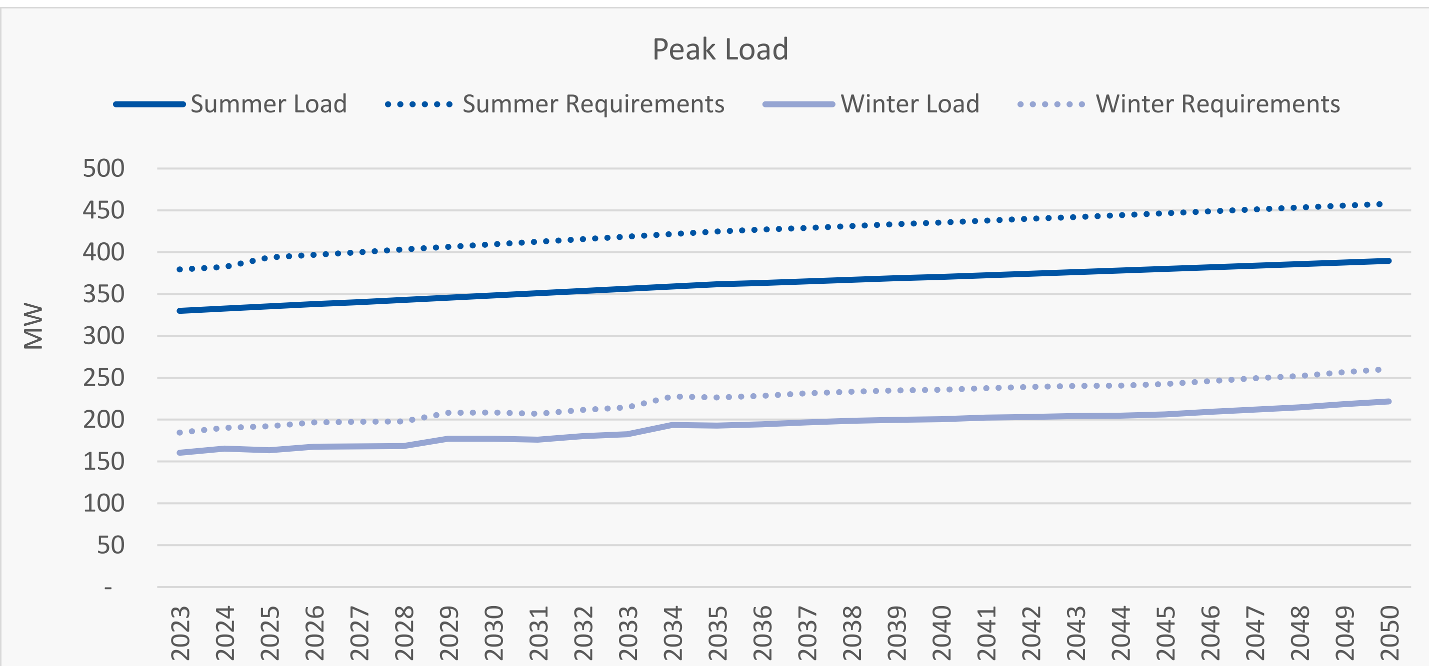
		Additional Energy Needs (MWh)		Additional Energy Needs (% of Total Load)	
Year	Energy (MWh)	With 20 MW Fuel Cells Located Internally at Minimum	With 110 MW of Fuel Cells Located Internally at Minimum	With 20 MW Fuel Cells Located Internally at Minimum	With 110 MW of Fuel Cells Located Internally at Minimum
2023	1,156,000	0	0	0.0%	0.0%
2024	1,163,000	0	0	0.0%	0.0%
2025	1,173,000	0	0	0.0%	0.0%
2026	1,186,000	0	0	0.0%	0.0%
2027	1,202,000	0	0	0.0%	0.0%
2028	1,221,000	0	0	0.0%	0.0%
2029	1,242,000	0	0	0.0%	0.0%
2030	1,266,000	10,960	0	0.9%	0.0%
2031	1,290,000	15,462	0	1.2%	0.0%
2032	1,312,000	9,663	0	0.7%	0.0%
2033	1,334,000	9,890	0	0.7%	0.0%
2034	1,353,000	9,136	0	0.7%	0.0%
2035	1,365,000	12,330	0	0.9%	0.0%
2036	1,376,000	12,814	0	0.9%	0.0%
2037	1,386,000	5,735	0	0.4%	0.0%
2038	1,396,000	7,408	0	0.5%	0.0%
2039	1,405,000	8,781	0	0.6%	0.0%
2040	1,414,000	11,833	0	0.8%	0.0%
2041	1,423,000	15,601	0	1.1%	0.0%
2042	1,431,000	21,173	0	1.5%	0.0%
2043	1,439,000	19,013	0	1.3%	0.0%
2044	1,446,000	20,397	0	1.4%	0.0%
2045	1,454,000	11,656	1	0.8%	0.0%
2046	1,462,000	7,011	1	0.5%	0.0%

Year	Energy (MWh)	Additional Energy Needs (MWh)		Additional Energy Needs (% of Total Load)	
		With 20 MW Fuel Cells Located Internally at Minimum	With 110 MW of Fuel Cells Located Internally at Minimum	With 20 MW Fuel Cells Located Internally at Minimum	With 110 MW of Fuel Cells Located Internally at Minimum
2047	1,470,000	6,625	2	0.5%	0.0%
2048	1,479,000	7,532	2	0.5%	0.0%
2049	1,488,000	7,052	2	0.5%	0.0%
2050	1,497,000	560	0	0.0%	0.0%

This calibration is an indication that alternative ways to evaluate and design opportunities to build and operate a carbon-free system that can be studied. This would include exploring new resource options, identifying ways to incentivize lower load, and consider ongoing feedback from City leaders and the community. Calibration details for the carbon-free scenarios are provided in Appendix - Model Parameters and Additional Reliability Metrics.

Serving load with carbon-free resources leads to excess RA not only in the summer but also in the winter. As shown in Figure 113, peak load in the summer is approximately double the peak load in winter. As shown across all scenarios, meeting summer peaks results in excess RA during the winter.

Figure 113: Summer vs. Winter Peaks



Scenario 1 does not install additional geothermal resources. Since geothermal resources must be located externally in this IRP, they would have to pay the TAC.

The TAC is a CAISO charge that funds transmission infrastructure. This charge is different from congestion; congestion increases (or decreases) the value of energy from a project. Scenario 1 demonstrates a preference for resources installed internal to PWP in part because of this avoided charge. The other reason for this expressed preference is reliability.

No additional commercial or residential solar is installed in this scenario. Cost preferences will defer to utility-scale because utility-scale resources have a lower per-unit cost due to economies of scale.

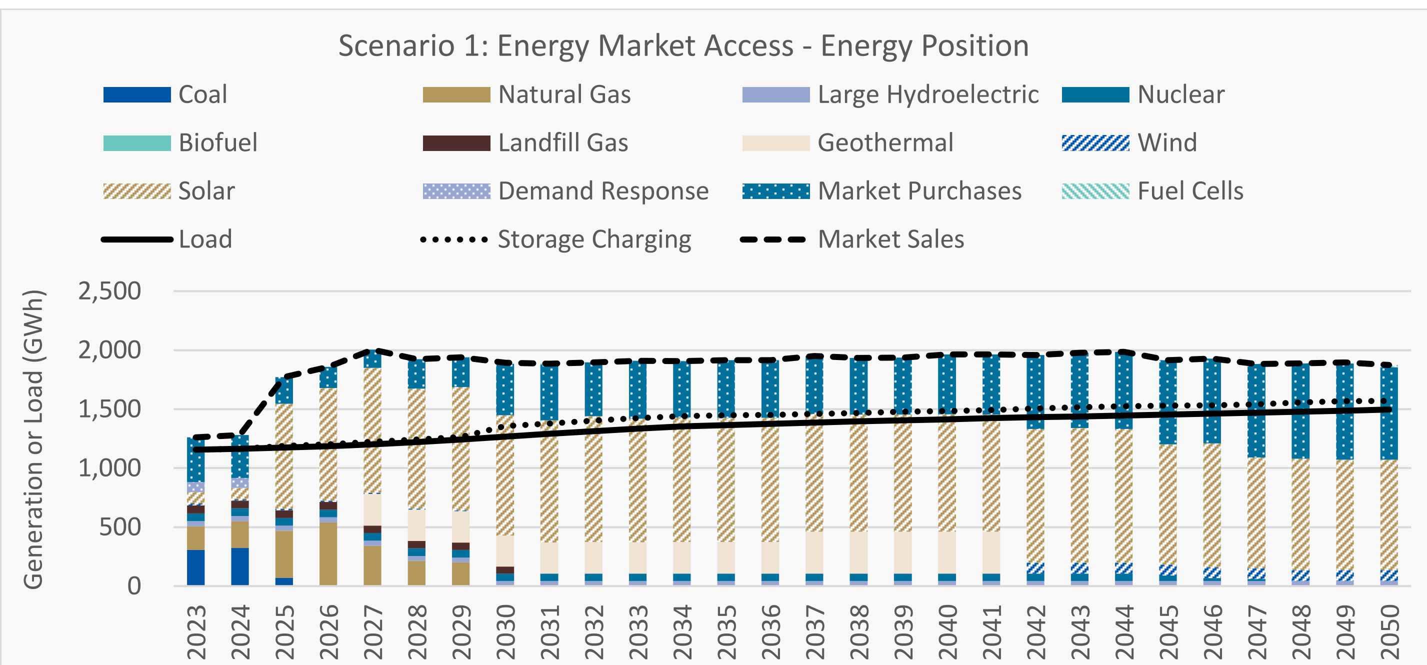
As shown in Figure 114, load in Scenario 1 can be met with carbon-free resources every hour by the end of 2030 (there is landfill gas that expires by the end of 2030). In this scenario, it appears as though PWP operates like an island without interactions in the CAISO markets.

Figure 114: Scenario 1: Island – Resources That Load, Storage Charging, and Market Sales are Served By

Resource Type	2023	2030	2031	2040	2050
Coal	24%	0%	0%	0%	0%
Natural Gas	16%	0%	0%	0%	0%
Large Hydroelectric	3%	3%	3%	3%	3%
Nuclear	5%	4%	4%	4%	0%
Biofuel	0%	0%	0%	0%	0%
Landfill Gas	5%	4%	0%	0%	0%
Geothermal	0%	18%	18%	22%	0%
Wind	1%	0%	0%	0%	6%
Solar	8%	68%	69%	63%	60%
Demand Response	7%	0%	0%	0%	0%
Market Purchases	30%	0%	0%	0%	0%
Fuel Cells	0%	3%	6%	8%	32%

However, PWP will still interact with the CAISO markets in the foreseeable future. See Figure 115.

Figure 115: Scenario 1: Energy Market Access – Energy Position



If PWP does interact in the CAISO markets, excess renewable energy or RA could be sold. What the excess is worth depends on what is going on in the market. Some factors driving value are shown in Figure 116. Market value is uncertain. Financial studies are explored in Section 18, Financial Impacts of the IRP. There are also carbon implications of continued market interactions. See Section 20 of this IRP.

Figure 116: CAISO Excess: What is it Worth?

Energy

- Time of day or year?
- Move market?
- Basis?

RECs

- Type?
- Green or clean?

Capacity

- Month?
- Location?
- Accreditation?

Scenarios 1, 2, and 3 select new resources as though PWP operates like an island. The results of these studies have the "island" label. This is done so that carbon-free resources meet load each hour. These results will present an upper bound of costs because excess renewable energy is not being sold.

However, given that PWP operates within CAISO, Scenarios 1, 2, and 3 are run again with access to CAISO's energy market. This sets a lower boundary of cost estimates, as excess renewable energy is being sold. These results may also report greater carbon emissions because PWP has access to CAISO. These results are referred to as "energy market access".

Figure 117 shows how PWP would meet load if it interacts with the markets. This is different from Figure 114 because market purchases/sales and storage charging can occur at different times.

The modeling of new and installed resources for Scenario 1, was calculated based upon a variety of factors to include RA reliability requirements. The Carbon-Free scenarios require Glenarm to be either replaced, converted or adapted with carbon-free dispatchable alternatives such as carbon capture, green hydrogen, biofuels or other future technologies as they emerge, and prior to 2030. Until such future technologies become available at scale, the availability of the Glenarm facility will be required across all Scenarios.

Figure 117: Scenario 1: Energy Market Access – Resources That Load, Storage Charging, and Market Sales are Served By

Resource Type	2023	2030	2031	2040	2050
Coal	24%	0%	0%	0%	0%
Natural Gas	16%	0%	0%	0%	0%
Large Hydroelectric	3%	2%	2%	2%	2%
Nuclear	5%	3%	3%	3%	0%
Biofuel	0%	0%	0%	0%	0%
Landfill Gas	5%	3%	0%	0%	0%

Resource Type	2023	2030	2031	2040	2050
Geothermal	0%	14%	14%	18%	0%
Wind	1%	0%	0%	0%	5%
Solar	8%	54%	55%	51%	50%
Demand Response	7%	0%	0%	0%	0%
Market Purchases	30%	23%	25%	26%	42%
Fuel Cells	0%	1%	0%	0%	1%

16.2. Scenario 2: 100% Carbon-Free by 2030 – Maximum Limit on Internal Resources

The resources shown in Figure 118 are installed under Scenario 2. By 2030, PWP has 4.3 times its peak in installed capacity.

Figure 118: Scenario 2: New Cumulative Installed Capacity

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Total New Resources	**300**	**300**	**393**	**393**	**403**	**1,418**	**1,493**	**1,505**	**1,542**	**1,550**
New Wind	30	30	30	30	30	30	30	30	60	70
New Geothermal										
Contracted (Calpine Geysers and Coso)	0	0	35	35	35	35	35	46	0	0
New	0	0	0	0	0	10	10	10	30	20
New Solar										
Contracted (EDF Sapphire Solar)	0	0	39	39	39	39	39	39	39	0
Utility-Scale Solar	180	180	180	180	180	180	240	240	220	260
Community	5	5	5	5	5	5	5	5	5	5
Commercial	0	0	0	0	0	400	400	400	400	400
Residential	0	0	0	0	0	0	0	0	0	0
New Storage										
Contracted (EDF Sapphire Storage)	0	0	20	20	20	20	20	20	20	0
New 4-Hour Storage	85	85	85	85	95	265	280	280	290	260
New 6-Hour Storage	0	0	0	0	0	0	0	0	0	0
New 8-Hour Storage	0	0	0	0	0	0	0	0	0	0
New 10-Hour Storage	0	0	0	0	0	0	0	0	0	0
New Commercial	0	0	0	0	0	400	400	400	403	400
New Residential	0	0	0	0	0	0	0	0	0	0
New Fuel Cells	0	0	0	0	0	35	35	35	75	135

Figure 119: Scenario 2: Cumulative Installed Capacity by Location

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Total Installed Capacity	**637**	**637**	**680**	**680**	**690**	**1,489**	**1,550**	**1,542**	**1,562**	**1,564**
Total Existing Resources	**337**	**337**	**287**	**287**	**287**	**70**	**57**	**37**	**20**	**14**
Total New Resources	**300**	**300**	**393**	**393**	**403**	**1,418**	**1,493**	**1,505**	**1,542**	**1,550**

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
New Onshore Wind	30	30	30	30	30	30	30	30	60	70
New Land-Based External Wind	20	20	20	20	20	20	20	20	50	60
New Land-Based External Wind (Storage Paired)	10	10	10	10	10	10	10	10	10	10
New Offshore Wind	0	0	0	0	0	0	0	0	0	0
New Geothermal	0	0	35	35	35	45	45	56	30	20
Calpine Geysers	0	0	25	25	25	25	25	25	0	0
Coso Geothermal	0	0	10	10	10	10	10	21	0	0
New External Geothermal	0	0	0	0	0	10	10	10	30	20
New Utility-Scale Solar PV	185	185	224	224	224	224	284	284	264	265
EDF Sapphire Solar	0	0	39	39	39	39	39	39	39	0
New External Solar	180	180	180	180	180	180	230	230	210	250
New External Solar (Storage Paired)	0	0	0	0	0	0	10	10	10	10
New Community Solar	5	5	5	5	5	5	5	5	5	5
New PWP-Funded Commercial Solar PV	0	0	0	0	0	400	400	400	400	400
New Commercial Solar	0	0	0	0	0	400	400	400	400	400
New PWP-Funded Residential Solar PV	0	0	0	0	0	0	0	0	0	0
New 4-Hour Storage	85	85	105	105	115	285	300	300	310	260
EDF Sapphire Storage	0	0	20	20	20	20	20	20	20	0
New 4-Hour Storage (Land-Based External Wind Paired)	5	5	5	5	5	5	5	5	5	5
New 4-Hour Storage (External Solar Paired)	0	0	0	0	0	0	5	5	5	5
New 4-Hour External Storage	0	0	0	0	0	70	70	70	90	50
New 4-Hour Internal Storage	80	80	80	80	90	190	200	200	190	200
New 6-Hour Storage	0	0	0	0	0	0	0	0	0	0
New 8-Hour Storage	0	0	0	0	0	0	0	0	0	0
New 10-Hour Storage	0	0	0	0	0	0	0	0	0	0
New PWP-Funded Commercial Storage	0	0	0	0	0	400	400	400	403	400
New PWP-Funded Residential Storage	0	0	0	0	0	0	0	0	0	0
New Fuel Cells	0	0	0	0	0	35	35	35	75	135
New External Fuel Cells	0	0	0	0	0	30	30	30	70	130
New Internal Fuel Cells	0	0	0	0	0	5	5	5	5	5
New Biogas Conversion for Glenarm	0	0	0	0	0	0	0	0	0	0
Peak Load (MW)	**335**	**338**	**341**	**343**	**346**	**348**	**362**	**371**	**380**	**390**

Similar to Scenario 1, after the first round of modeling, Scenario 2 required additional internal resources to support load. In Scenario 2, a minimum of 400 MW of commercial storage and 400 MW of commercial solar is needed in 2030 (compared to zero) and in 2050 (compared to 3 MW of commercial storage and 8 MW of commercial solar). This ensures load is served in every hour with carbon-free electricity. Additional details are included in Appendix - Model Parameters and Additional Reliability Metrics.

In 2025, PWP needs 300 MW of installed capacity (in addition to the 50 MW of natural gas from IPP) to cover the 108 MW capacity retirement from IPP. PWP installs 1,015 MW of new capacity in 2030 to replace 212 MW of natural gas. The resulting summer capacity position is shown in Figure 120. Details are quantified in Figure 121.

Figure 120: Scenario 2: Summer Resource Adequacy

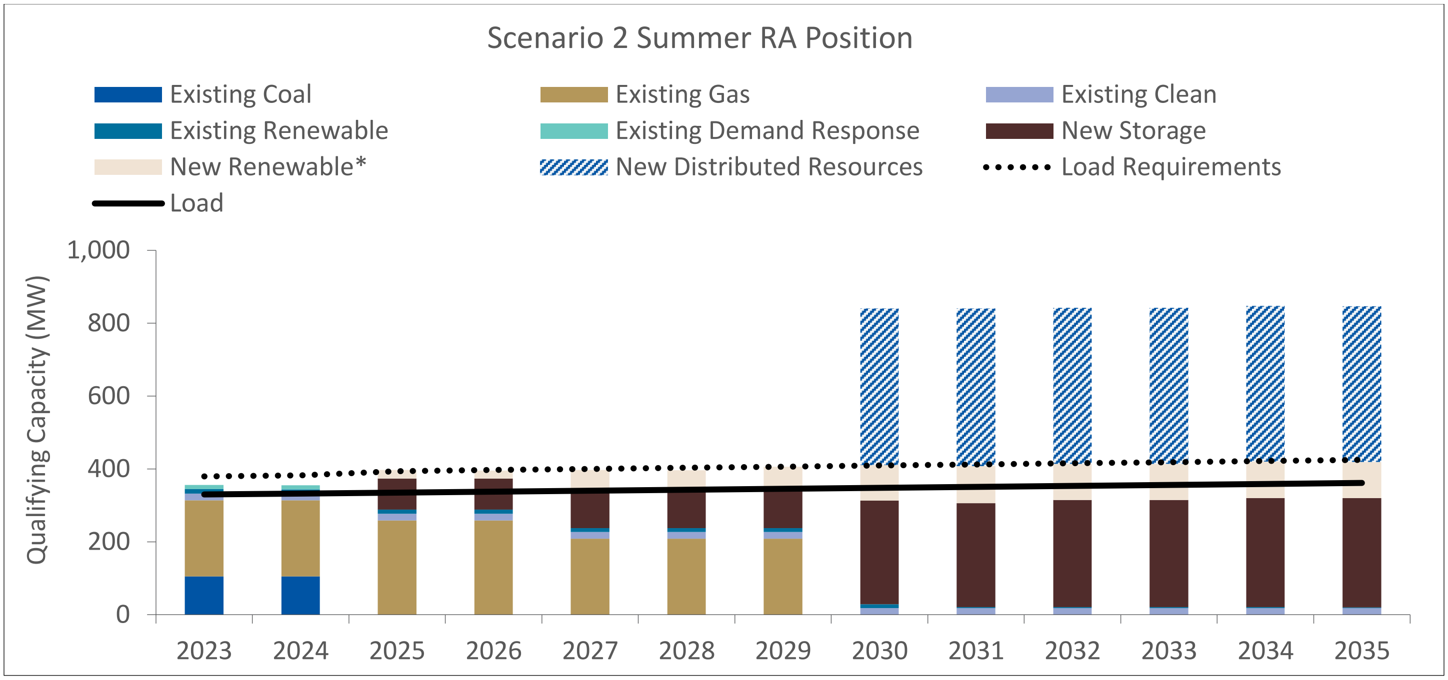


Figure 121: Scenario 2 Resource Adequacy Position

Summer RA Position (MW)												
	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Summer Load Requirements	380	383	394	397	400	403	406	409	425	436	447	458
Existing Resources Qualifying Capacity	356	355	289	288	238	238	238	29	20	19	14	9
Length/(Shortage) Before New Additions	(24)	(27)	(105)	(109)	(162)	(166)	(169)	(381)	(405)	(417)	(432)	(449)
New Resources Qualifying Capacity	0	0	108	107	160	159	169	812	826	839	867	863
Length/(Shortage) After New Additions	(24)	(27)	3	(1)	(2)	(6)	(0)	432	422	423	434	414
Winter RA Position (MW)												
	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Winter Load Requirements	185	190	192	197	198	198	208	208	226	236	243	261
Existing Resources Qualifying Capacity	354	353	286	286	236	236	236	27	18	18	18	9
Length/(Shortage) Before New Additions	169	163	94	89	38	38	28	(181)	(208)	(218)	(225)	(252)
New Resources Qualifying Capacity	0	0	97	97	151	150	160	782	797	807	840	839

Length/(Shortage) After New Additions	169	163	190	186	189	188	188	601	589	589	616	588

Because utility-scale resources are limited in Scenario 2, Scenario 2 leverages distributed resources.

In the 2023 IRP, the qualifying capacity of distributed resources is defaulted to the qualifying capacity of their utility-scale counterparts. The qualifying capacity of distributed resources depends on how they are registered with CAISO. These resources could be classified as demand response resources and collectively registered as a Proxy Demand Response resource. CAISO's tariff sets the rules for how this works. Distributed resources could also be classified as Distributed Energy Resource Aggregations. As of early 2022, these rules remained to be developed between CAISO and entities like PWP. Per FERC's response to CAISO's FERC Order 2222 compliance filing:

> *"Finally, we find AEE/SFP's request that the Commission direct CAISO to take various actions to help enable Distributed Energy Resource Aggregations to provide resource adequacy to be outside of the scope of Order No. 2222. Order No. 2222 requires each RTO/ISO to establish tariff provisions that allow distributed energy resource aggregations to participate directly in RTO/ISO markets, which the Commission defined as "the capacity, energy, and ancillary services markets operated by the RTOs and ISOs."101 The California resource adequacy program is not an RTO/ISO-administered capacity market and, therefore, is outside the scope of the Commission's directives in Order No. 2222. However, we acknowledge CAISO's commitment to continue working with the CPUC and other Local Regulatory Authorities to develop methods for allowing Distributed Energy Resource Aggregations to provide resource adequacy capacity."151*

If distributed resources were not registered as supply side resources, they could reduce the load (and reserve) obligations PWP must cover. There is uncertainty regarding distributed resource accreditation and operation.

Scenario 2 meets its energy obligations with 100% carbon-free energy if it operates like an island (Figure 122). Figure 123 shows how PWP meets is energy obligations if market access is allowed.

The modeling of new and installed resources for Scenario 2, was calculated based upon a variety of factors to include RA reliability requirements. The Carbon-Free Scenarios require Glenarm to be either replaced, converted or adapted with carbon-free dispatchable alternatives such as carbon capture, green hydrogen, biofuels or other future technologies as they emerge, and prior to 2030. Until such future technologies become available at scale, the availability of the Glenarm facility will be required across all Scenarios.

Figure 122: Scenario 2: Island – Resources That Load, Storage Charging, and Market Sales are Served by

Resource Type	2023	2030	2031	2040	2050
Coal	24%	0%	0%	0%	0%
Natural Gas	16%	0%	0%	0%	0%
Large Hydroelectric	3%	2%	2%	2%	2%

[151] http://www.caiso.com/Documents/Jun17-2022-OrderPartialAccepting-RequestingComplianceFiling-FERCOrderNo2222-ER21-2455.pdf

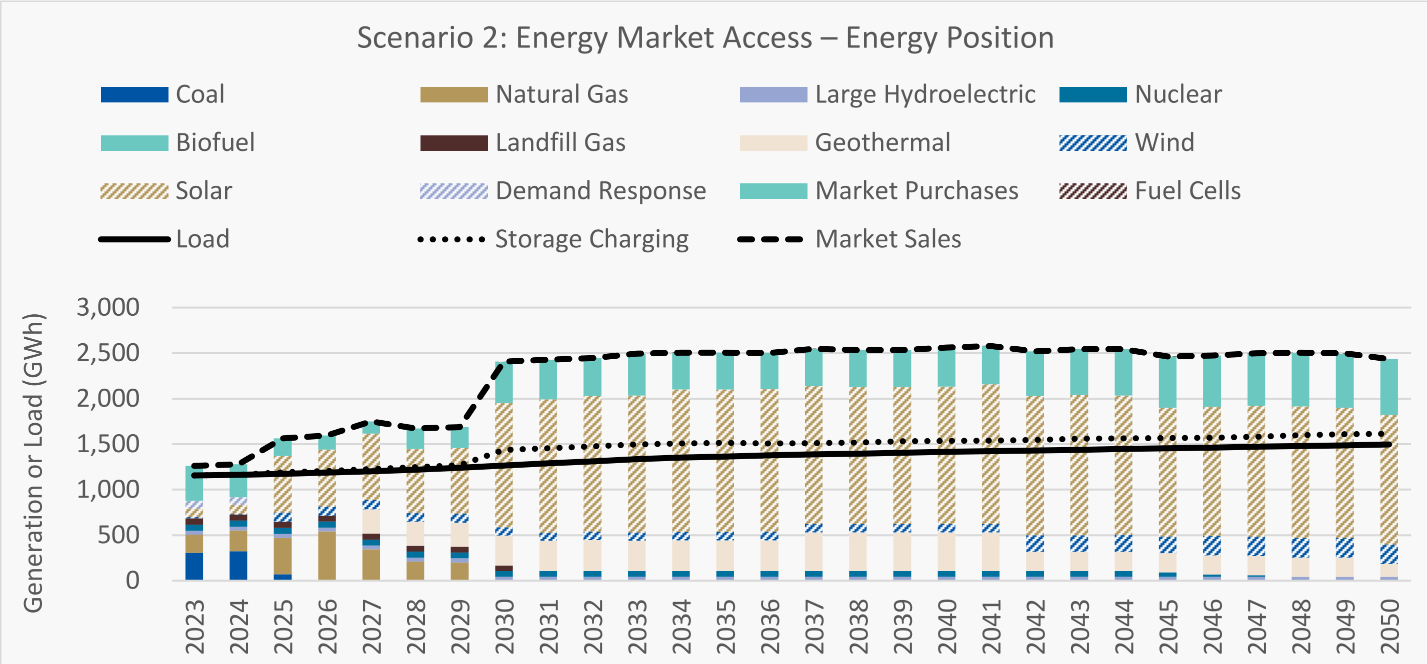
Resource Type	2023	2030	2031	2040	2050
Nuclear	5%	3%	3%	3%	0%
Biofuel	0%	0%	0%	0%	0%
Landfill Gas	5%	3%	0%	0%	0%
Geothermal	0%	16%	16%	20%	8%
Wind	1%	5%	5%	5%	11%
Solar	8%	72%	75%	71%	75%
Demand Response	7%	0%	0%	0%	0%
Market Purchases	30%	0%	0%	0%	0%
Fuel Cells	0%	0%	0%	0%	4%

Figure 123: Scenario 2: Energy Market Access – Resources That Load, Storage Charging, and Market Sales are Served by

Resource Type	2023	2030	2031	2040	2050
Coal	24%	0%	0%	0%	0%
Natural Gas	16%	0%	0%	0%	0%
Large Hydroelectric	3%	2%	2%	2%	2%
Nuclear	5%	3%	3%	2%	0%
Biofuel	0%	0%	0%	0%	0%
Landfill Gas	5%	2%	0%	0%	0%
Geothermal	0%	14%	14%	17%	6%
Wind	1%	4%	4%	4%	9%
Solar	8%	57%	60%	59%	58%
Demand Response	7%	0%	0%	0%	0%
Market Purchases	30%	19%	18%	17%	25%
Fuel Cells	0%	0%	0%	0%	0%

The energy position, assuming energy market access, is shown in Figure 124.

Figure 124: Scenario 2: Energy Market Access – Energy Position



16.3. Scenario 3: 100% Carbon-Free by 2030 (Maximum Limit on Internal Resources and Doubled Distributed Resources)

Scenario 3 evaluates a focused effort into distributed resource deployment on behalf of PWP. Some distributed solar and storage is embedded in the load forecast. This scenario adds that same amount as resources, so the total amount of distributed solar and storage growth each year is double what would have occurred normally in that year. The resources are split between residential and commercial installations.

The installed capacity of resources in Scenario 3 is shown in Figure 125. In 2025, 300 MW are added. In 2030, 859 MW are added to replace 212 MW of natural gas and 5 MW of wind. PWP has 3.9 times its peak in installed capacity by 2030.

Figure 125: Scenario 3: New Cumulative Installed Capacity

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Total New Resources	**300**	**306**	**399**	**410**	**415**	**1,274**	**1,358**	**1,376**	**1,466**	**1,424**
New Wind	60	60	60	60	60	60	80	80	70	70
New Geothermal										
Contracted (Calpine Geysers and Coso)	0	0	35	35	35	35	35	46	0	0
New	0	0	0	0	0	10	20	20	20	10
New Solar										
Contracted (EDF Sapphire Solar)	0	0	39	39	39	39	39	39	39	0
Utility-Scale Solar	100	100	100	100	100	100	120	120	180	200
Community	5	5	5	5	5	5	5	5	5	5
Commercial	31	31	31	31	31	350	357	359	375	350

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Residential	17	21	21	22	22	23	38	39	57	57
New Storage										
Contracted (EDF Sapphire Storage)	0	0	20	20	20	20	20	20	20	0
New 4-Hour Storage	85	85	85	95	95	245	245	245	260	200
New 6-Hour Storage	0	0	0	0	0	0	0	0	0	50
New 8-Hour Storage	0	0	0	0	0	0	0	0	0	0
New 10-Hour Storage	0	0	0	0	0	0	0	0	0	0
New Commercial	1	2	2	2	6	350	360	360	363	350
New Residential	1	2	2	2	3	3	5	8	12	17
New Fuel Cells	0	0	0	0	0	35	35	35	65	115

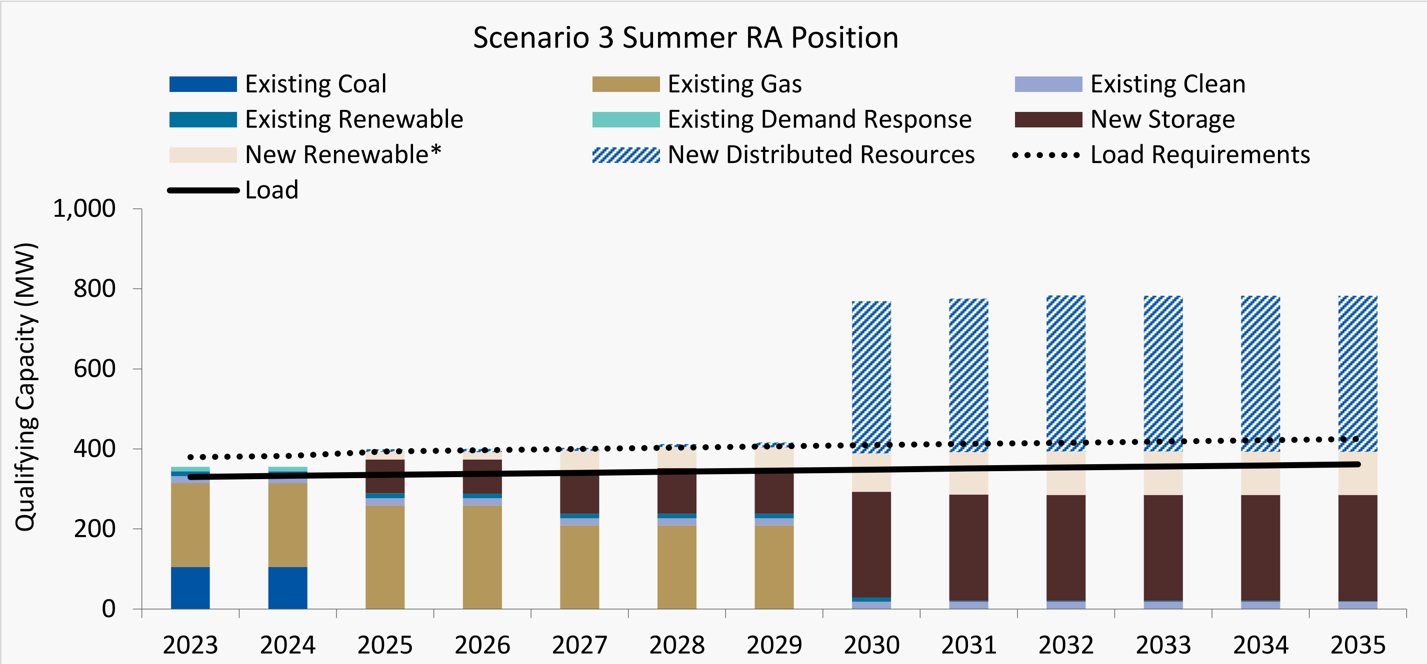
Figure 126: Scenario 3: Cumulative Installed Capacity by Location

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Total Installed Capacity	**637**	**643**	**686**	**697**	**702**	**1,345**	**1,415**	**1,413**	**1,486**	**1,438**
Total Existing Resources	**337**	**337**	**287**	**287**	**287**	**70**	**57**	**37**	**20**	**14**
Total New Resources	**300**	**306**	**399**	**410**	**415**	**1,274**	**1,358**	**1,376**	**1,466**	**1,424**
New Onshore Wind	60	60	60	60	60	60	80	80	70	70
New Land-Based External Wind	60	60	60	60	60	60	80	80	60	60
New Land-Based External Wind (Storage Paired)	0	0	0	0	0	0	0	0	10	10
New Offshore Wind	0	0	0	0	0	0	0	0	0	0
New Geothermal	0	0	35	35	35	45	55	66	20	10
Calpine Geysers	0	0	25	25	25	25	25	25	0	0
Coso Geothermal	0	0	10	10	10	10	10	21	0	0
New External Geothermal	0	0	0	0	0	10	20	20	20	10
New Utility-Scale Solar PV	105	105	144	144	144	144	164	164	224	205
EDF Sapphire Solar	0	0	39	39	39	39	39	39	39	0
New External Solar	90	90	90	90	90	90	110	110	170	190
New External Solar (Storage Paired)	10	10	10	10	10	10	10	10	10	10
New Community Solar	5	5	5	5	5	5	5	5	5	5
New PWP-Funded Commercial Solar PV	31	31	31	31	31	350	357	359	375	350
New Commercial Solar	31	31	31	31	31	350	357	359	375	350
New PWP-Funded Residential Solar PV	17	21	21	22	22	23	38	39	57	57
New Residential Solar	17	21	21	22	22	23	38	39	57	57
New 4-Hour Storage	85	85	105	115	115	265	265	265	280	200

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
EDF Sapphire Storage	0	0	20	20	20	20	20	20	20	0
New 4-Hour Storage (Land-Based External Wind Paired)	0	0	0	0	0	0	0	0	5	5
New 4-Hour Storage (External Solar Paired)	5	5	5	5	5	5	5	5	5	5
New 4-Hour External Storage	0	0	0	0	0	40	40	40	70	60
New 4-Hour Internal Storage	80	80	80	90	90	200	200	200	180	130
New 6-Hour Storage	0	0	0	0	0	0	0	0	0	50
New 8-Hour Storage	0	0	0	0	0	0	0	0	0	0
New 10-Hour Storage	0	0	0	0	0	0	0	0	0	0
New PWP-Funded Commercial Storage	1	2	2	2	6	350	360	360	363	350
New PWP-Funded Residential Storage	1	2	2	2	3	3	5	8	12	17
New 2-Hour Residential Storage	1	2	2	2	3	3	5	8	12	17
New Fuel Cells	0	0	0	0	0	35	35	35	65	115
New Biogas Conversion for Glenarm	0	0	0	0	0	0	0	0	0	0
Peak Load (MW)	**335**	**338**	**341**	**343**	**346**	**348**	**362**	**371**	**380**	**390**

The table shows 942 MW of installed internal capacity beyond that attributable to normal projected DER growth included in the load forecast. In 2030, PWP's peak is 348 MW. The resulting summer capacity position is shown in Figure 127.

Figure 127: Scenario 3: Summer Resource Adequacy



Overall RA is shown in Figure 128.

Figure 128: Scenario 3: Resource Adequacy Position

MW	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Summer Load Requirements	380	383	394	397	400	403	406	409	425	436	447	458
Existing Resources Qualifying Capacity	356	355	289	288	238	238	238	237	229	214	209	204
Length/(Shortage) Before New Additions	(24)	(27)	(105)	(109)	(162)	(166)	(169)	(172)	(196)	(222)	(237)	(254)
New Resources Qualifying Capacity	0	0	115	115	171	221	221	221	222	233	237	251
Length/(Shortage) After New Additions	(24)	(27)	10	6	9	55	52	49	26	11	(0)	(3)
Winter Load Requirements	185	190	192	197	198	198	208	208	226	236	243	261
Existing Resources Qualifying Capacity	354	353	286	286	236	236	236	236	227	213	213	204
Length/(Shortage) Before New Additions	169	163	94	89	38	38	28	28	1	(23)	(30)	(57)
New Resources Qualifying Capacity	0	0	131	131	186	242	242	242	245	256	216	237
Length/(Shortage) After New Additions	169	163	225	220	224	281	271	270	246	233	186	180

A minimum of 350 MW of commercial storage and of commercial solar (compared to 14 MW of commercial storage and 31 MW of commercial solar) is needed in 2030 and in 2050 (compared to 31 MW of commercial storage and 67 MW of commercial solar) to cover additional energy needs.

Scenario 3 can meet its load, sales, and storage charging with zero-carbon resources. Figure 129 and Figure 130 show how PWP meets load as an island and with energy market access, respectively.

The modeling of new and installed resources for Scenario 3, was calculated based upon a variety of factors to include RA reliability requirements. The Carbon-Free Scenarios require Glenarm to be either replaced, converted or adapted with carbon-free dispatchable alternatives such as carbon capture, green hydrogen, biofuels or other future technologies as they emerge, or prior to 2030. Until such future technologies become available at scale, the availability of the Glenarm facility will be required across all Scenarios.

Figure 129: Scenario 3: Island – Resources That Load, Storage Charging, and Market Sales are Served By

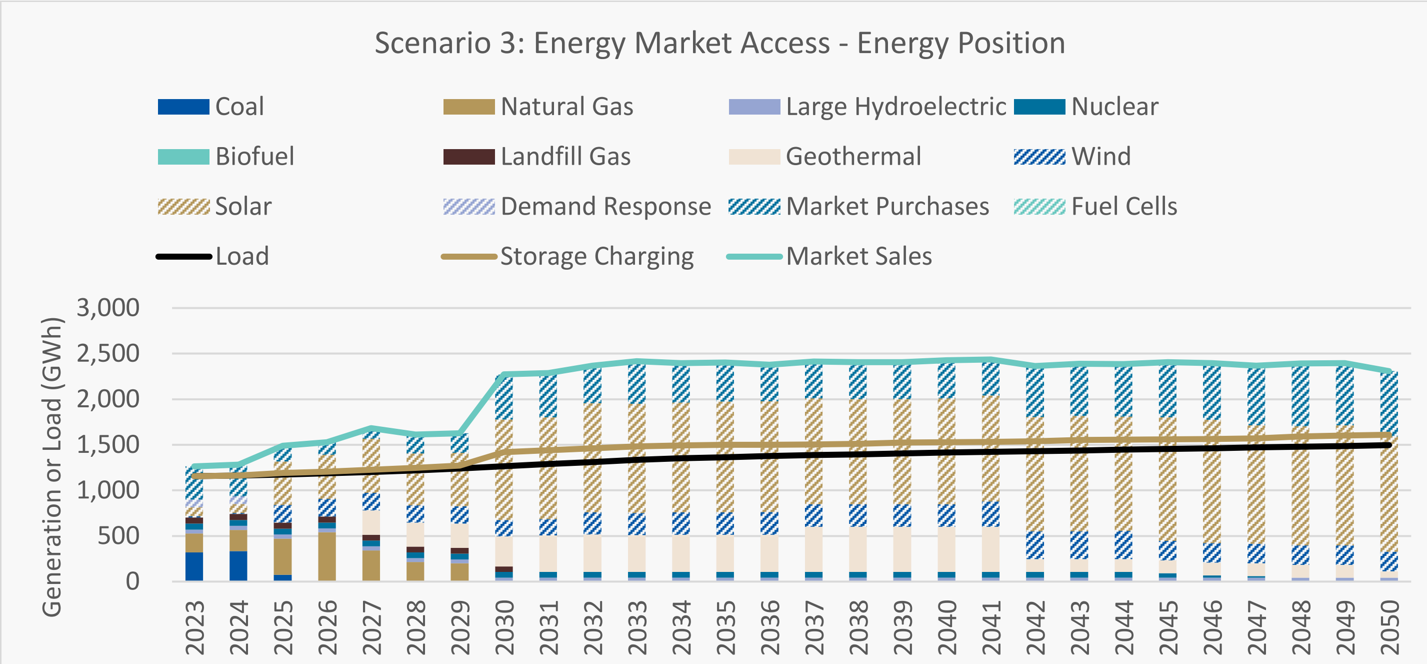
Resource Type	2023	2030	2031	2040	2050
Coal	25%	0%	0%	0%	0%
Natural Gas	16%	0%	0%	0%	0%
Large Hydroelectric	3%	2%	2%	2%	2%
Nuclear	5%	3%	3%	3%	0%
Biofuel	0%	0%	0%	0%	0%
Landfill Gas	5%	3%	0%	0%	0%
Geothermal	0%	18%	22%	24%	4%
Wind	1%	10%	10%	12%	12%
Solar	8%	62%	62%	58%	73%
Demand Response	7%	0%	0%	0%	0%
Market Purchases	29%	0%	0%	0%	0%
Fuel Cells	0%	0%	0%	0%	9%

Figure 130: Scenario 3: Energy Market Access – Resources That Load, Storage Charging, and Market Sales are Served By

Resource Type	2023	2030	2031	2040	2050
Coal	25%	0%	0%	0%	0%
Natural Gas	16%	0%	0%	0%	0%
Large Hydroelectric	3%	2%	2%	2%	2%
Nuclear	5%	3%	3%	3%	0%
Biofuel	0%	0%	0%	0%	0%
Landfill Gas	5%	3%	0%	0%	0%
Geothermal	0%	15%	18%	20%	3%
Wind	1%	8%	8%	10%	9%
Solar	8%	48%	49%	48%	55%
Demand Response	7%	0%	0%	0%	0%
Market Purchases	29%	22%	21%	17%	31%
Fuel Cells	0%	0%	0%	0%	0%

The resulting energy position is shown in Figure 131.

Figure 131: Scenario 3: Energy Market Access – Energy Position



16.4. Scenario 4: Reference Case (SB 1020)

Scenario 4 meets and exceeds state environmental requirements and serves as the basis for comparison for the other scenarios. Installed capacity under this scenario is shown in Figure 132. By 2030, installed capacity is 2.2 times PWP's peak load.

Figure 132: Scenario 4: New Cumulative Installed Capacity

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Total New Resources	**335**	**335**	**428**	**478**	**478**	**478**	**488**	**500**	**698**	**729**
New Wind	250	250	250	250	250	250	260	260	20	70
New Geothermal										
Contracted (Calpine Geysers and Coso)	0	0	35	35	35	35	35	46	0	0
New	0	0	0	0	0	0	0	0	0	0
New Solar										
Contracted (EDF Sapphire Solar)	0	0	39	39	39	39	39	39	39	0
Utility-Scale Solar	0	0	0	0	0	0	0	0	430	440
Community	5	5	5	5	5	5	5	5	5	5
Commercial	0	0	0	0	0	0	0	0	0	0
Residential	0	0	0	0	0	0	0	0	0	0
New Storage										
Contracted (EDF Sapphire Storage)	0	0	20	20	20	20	20	20	20	0
New 4-Hour Storage	80	80	80	130	130	130	130	130	180	210
New 6-Hour Storage	0	0	0	0	0	0	0	0	0	0
New 8-Hour Storage	0	0	0	0	0	0	0	0	0	0

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
New 10-Hour Storage	0	0	0	0	0	0	0	0	0	0
New Commercial	0	0	0	0	0	0	0	0	4	4
New Residential	0	0	0	0	0	0	0	0	0	0
New Fuel Cells	0	0	0	0	0	0	0	0	0	0

Figure 133: Scenario 4: Cumulative Installed Capacity by Location

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Total Installed Capacity	**672**	**672**	**715**	**765**	**765**	**760**	**757**	**735**	**915**	**941**
Total Existing Resources	**337**	**337**	**287**	**287**	**287**	**282**	**269**	**235**	**218**	**212**
Total New Resources	**335**	**335**	**428**	**478**	**478**	**478**	**488**	**500**	**698**	**729**
New Onshore Wind	250	250	250	250	250	250	260	260	20	70
New Offshore Wind	0	0	0	0	0	0	0	0	0	0
New Geothermal	0	0	35	35	35	35	35	46	0	0
Calpine Geysers	0	0	25	25	25	25	25	25	0	0
Coso Geothermal	0	0	10	10	10	10	10	21	0	0
New Utility-Scale Solar PV	5	5	44	44	44	44	44	44	474	445
EDF Sapphire Solar	0	0	39	39	39	39	39	39	39	0
New External Solar	0	0	0	0	0	0	0	0	430	430
New External Solar (Storage Paired)	0	0	0	0	0	0	0	0	0	10
New Community Solar	5	5	5	5	5	5	5	5	5	5
New PWP-Funded Commercial Solar PV	0	0	0	0	0	0	0	0	0	0
New PWP-Funded Residential Solar PV	0	0	0	0	0	0	0	0	0	0
New 4-Hour Storage	80	80	100	150	150	150	150	150	200	210
EDF Sapphire Storage	0	0	20	20	20	20	20	20	20	0
New 4-Hour Storage (Land-Based External Wind Paired)	0	0	0	0	0	0	0	0	0	5
New 4-Hour Storage (External Solar Paired)	0	0	0	0	0	0	0	0	0	5
New 4-Hour Internal Storage	80	80	80	130	130	130	130	130	180	200
New 6-Hour Storage	0	0	0	0	0	0	0	0	0	0
New 8-Hour Storage	0	0	0	0	0	0	0	0	0	0
New 10-Hour Storage	0	0	0	0	0	0	0	0	0	0
New PWP-Funded Commercial Storage	0	0	0	0	0	0	0	0	4	4
New PWP-Funded Residential Storage	0	0	0	0	0	0	0	0	0	0
New Fuel Cells	0	0	0	0	0	0	0	0	0	0
New Biogas Conversion for Glenarm	0	0	0	0	0	0	0	0	0	0
Peak Load (MW)	**335**	**338**	**341**	**343**	**346**	**348**	**362**	**371**	**380**	**390**

In 2025, PWP brings its peak installed capacity online. This is the first year that resources can be installed in the model. Installed capacity totaling 108 MW from IPP coal expires June 30, 2025, and is replaced by 50 MW of natural gas from that facility. Of the 335 MW of new capacity brought online in 2025, 250 MW is wind, 80 MW is storage, and 5 MW is community solar. Due to the RA contribution of renewables being smaller compared to fossil fuels, more installed capacity is needed to replace the coal. In Scenario 4, this is apparent with wind, which does not replace coal at a 1:1 ratio.

PWP has proactively executed contracts for the 93 MW brought online in 2027. The 35 MW of geothermal resources is planned from Coso Geothermal and Calpine Geysers Geothermal, and 39 MW of solar and 20 MW of storage come from the EDF Sapphire Solar project. These resources, in addition to the resources installed in 2025, help cover the loss of 50 MW of installed capacity from the IPP natural gas facility on June 30, 2027. By 2028, there is another 50 MW of new storage installed to assist with the natural gas contract expiration. Then, through the 2030s, retirements and additions are smaller (+/- 15 MW). The resulting capacity position is shown in Figure 134 and Figure 135.

Figure 134: Scenario 4: Summer Resource Adequacy

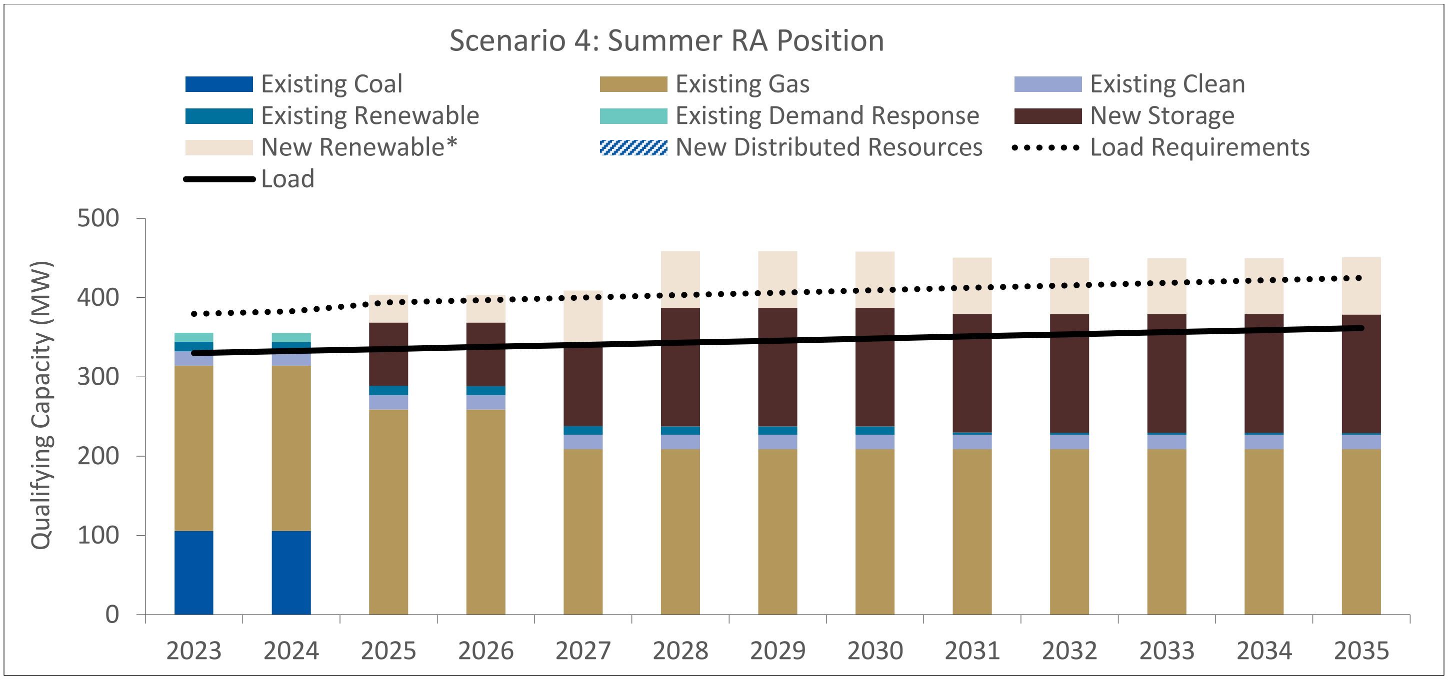
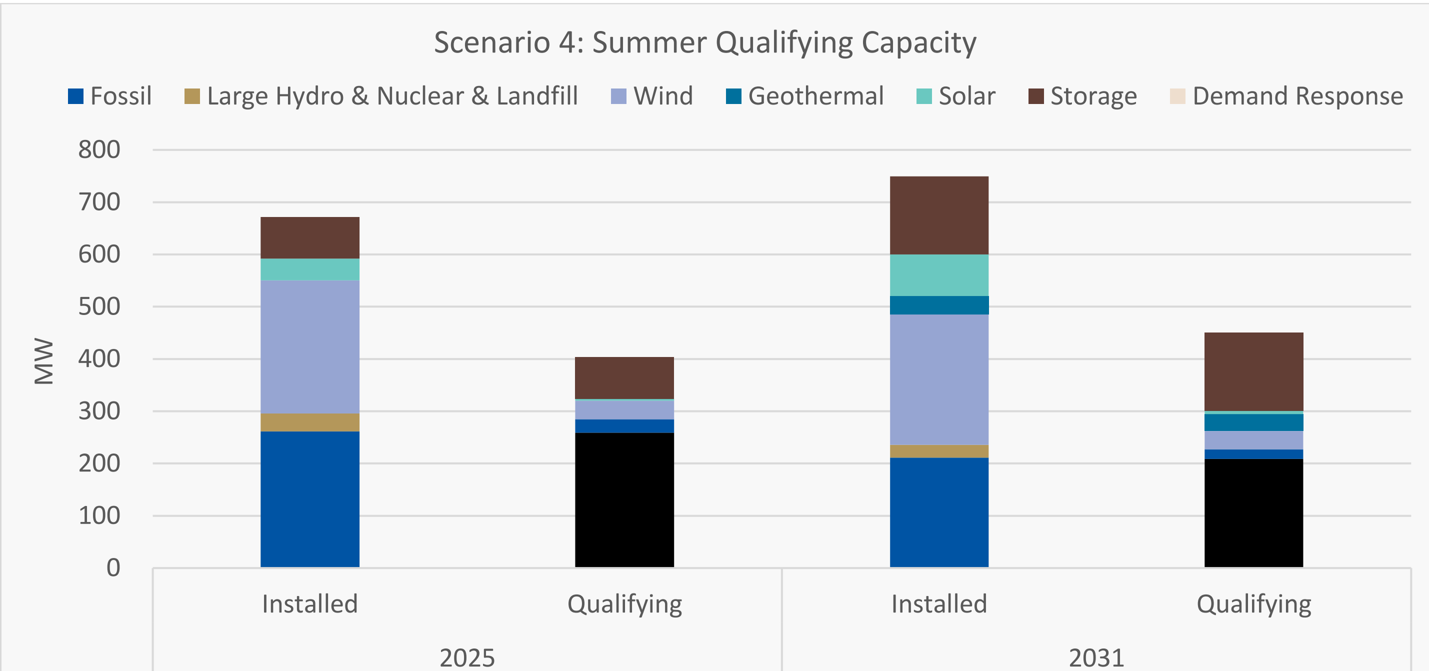


Figure 135: Scenario 4: Resource Adequacy Position

MW	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Summer Load Requirements	380	383	394	397	400	403	406	409	425	436	447	458
Existing Resources Qualifying Capacity	356	355	289	288	238	238	238	237	229	214	209	204
Length/(Shortage) Before New Additions	(24)	(27)	(105)	(109)	(162)	(166)	(169)	(172)	(196)	(222)	(237)	(254)
New Resources Qualifying Capacity	0	0	115	115	171	221	221	221	222	233	237	251
Length/(Shortage) After New Additions	(24)	(27)	10	6	9	55	52	49	26	11	(0)	(3)
Winter Load Requirements	185	190	192	197	198	198	208	208	226	236	243	261
Existing Resources Qualifying Capacity	354	353	286	286	236	236	236	236	227	213	213	204
Length/(Shortage) Before New Additions	169	163	94	89	38	38	28	28	1	(23)	(30)	(57)
New Resources Qualifying Capacity	0	0	131	131	186	242	242	242	245	256	216	237
Length/(Shortage) After New Additions	169	163	225	220	224	281	271	270	246	233	186	180

In this IRP, PWP assumes that storage receives 100% of nameplate capacity in qualifying capacity. This is the current accreditation for 4-hour storage in 2022. As shown in Figure 136, wind receives 14% of its nameplate capacity in qualifying capacity in August. In 2025, solar receives 10% of its nameplate capacity in qualifying capacity in August. This IRP forecasts the qualifying capacity for solar to decrease to 8% by 2031.

Figure 136: Scenario 4: Summer Qualifying Capacity



There is significant uncertainty regarding resources' future qualifying capacity. For example, if the qualifying capacity of storage declines, PWP would need to install or purchase additional capacity. Markets across the country, including California, are considering the long-term qualifying capacity of storage and how it may decline for shorter duration resources. [152]

Figure 137 and Figure 138 show the resources that PWP's load, storage, and market sales are met by under Scenario 4.

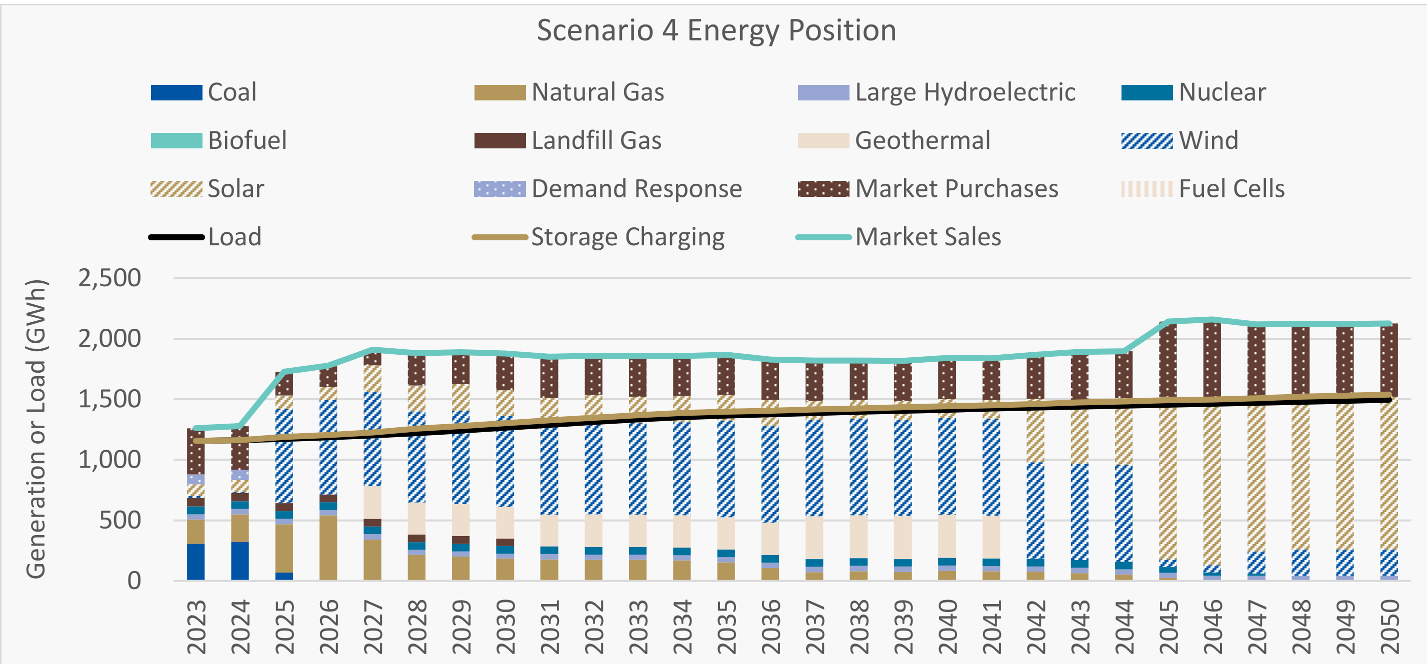
Figure 137: Scenario 4: Resources That Load, Storage Charging, and Market Sales are Served By

Resource Type	2023	2030	2031	2040	2050
Coal	24%	0%	0%	0%	0%
Natural Gas	16%	10%	10%	5%	0%
Large Hydroelectric	3%	2%	2%	2%	2%
Nuclear	5%	3%	3%	3%	0%
Biofuel	0%	0%	0%	0%	0%

[152] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2022-acc-capacity-avoided-cost-v1b.xlsx

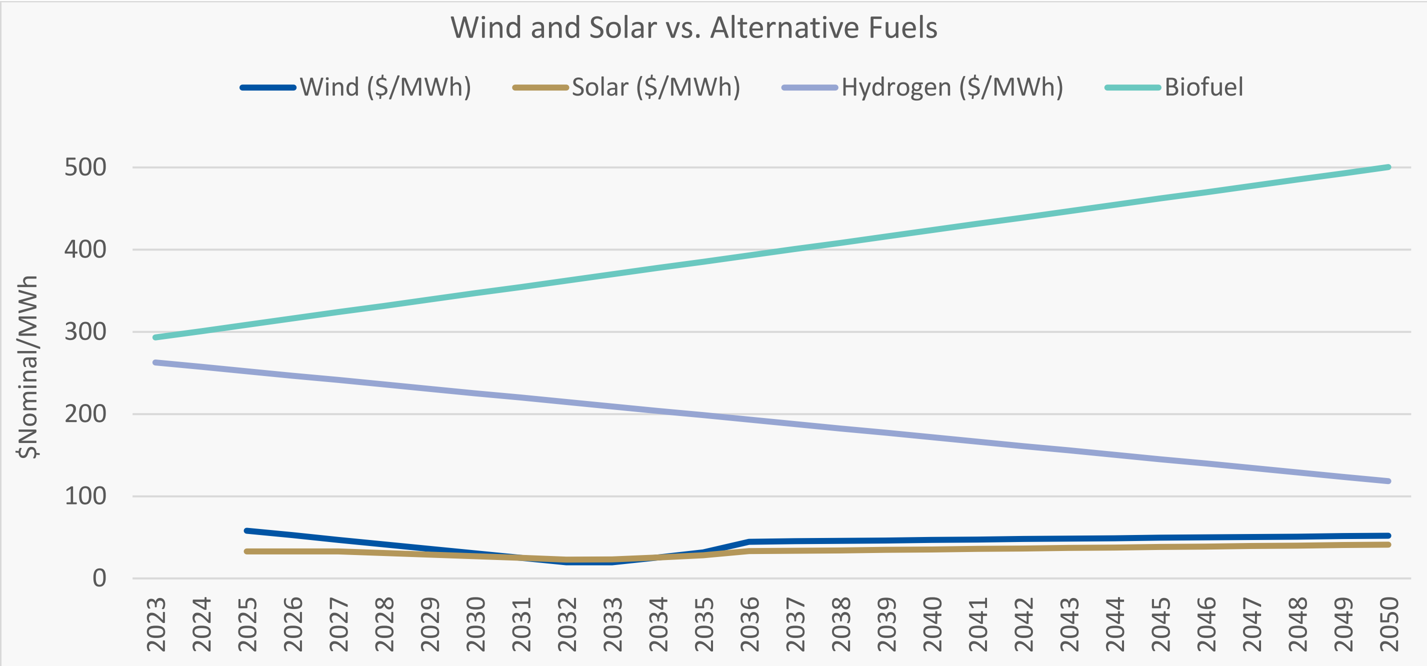
Resource Type	2023	2030	2031	2040	2050
Landfill Gas	5%	3%	0%	0%	0%
Geothermal	0%	14%	14%	19%	0%
Wind	1%	40%	40%	43%	10%
Solar	8%	11%	12%	8%	59%
Demand Response	7%	0%	0%	0%	0%
Market Purchases	30%	16%	18%	19%	28%
Fuel Cells	0%	0%	0%	0%	0%

Figure 138: Scenario 4: Energy Position



Scenario 4 elects to install more wind rather than other combustion resources, such as biofuel or green hydrogen, to meet renewable requirements. Forecasts for hydrogen and biofuel prices were created from publicly available resources. Incentives embedded in new legislation, or local circumstances, may change the economics of these alternative fuels. Figure 139 includes an estimate of costs from hydrogen assuming a 6,469 Btu/kWh heat rate and from biofuel assuming a 10,500 Btu/kWh heat rate.

Figure 139: Wind and Solar vs. Alternative Fuels



16.5. Scenario 5: Reference Case Plus Social Cost of Carbon

Scenario 5 incorporates an additional carbon tax on fossil-fuel, landfill, and market resources. The resulting installed capacity is shown in Figure 140. In 2025, PWP brings 610 MW of wind online, as well as 30 MW of storage and 5 MW of community solar. By 2030, PWP has 3 times its peak capacity in installed capacity.

Figure 140: Scenario 5: Installed Capacity

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Total New Resources	**645**	**655**	**748**	**748**	**748**	**768**	**768**	**800**	**697**	**728**
New Wind	610	610	610	610	610	610	610	610	0	40
New Geothermal										
Contracted (Calpine Geysers and Coso)	0	0	35	35	35	35	35	46	0	0
New	0	0	0	0	0	0	0	0	0	0
New Solar										
Contracted (EDF Sapphire Solar)	0	0	39	39	39	39	39	39	39	0
Utility-Scale Solar	0	0	0	0	0	0	0	0	440	470
Community	5	5	5	5	5	5	5	5	5	5
Commercial	0	0	0	0	0	0	0	0	2	2
Residential	0	0	0	0	0	0	0	0	0	0
New Storage										
Contracted (EDF Sapphire Storage)	0	0	20	20	20	20	20	20	20	0
New 4-Hour Storage	30	40	40	40	40	60	60	80	190	210
New 6-Hour Storage	0	0	0	0	0	0	0	0	0	0

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
New 8-Hour Storage	0	0	0	0	0	0	0	0	0	0
New 10-Hour Storage	0	0	0	0	0	0	0	0	0	0
New Commercial	0	0	0	0	0	0	0	0	1	1
New Residential	0	0	0	0	0	0	0	0	0	0
New Fuel Cells	0	0	0	0	0	0	0	0	0	0

Figure 141: Scenario 5: Cumulative Installed Capacity by Location

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Total Installed Capacity	**982**	**992**	**1,035**	**1,035**	**1,035**	**1,050**	**1,037**	**1,035**	**914**	**940**
Total New Resources	**645**	**655**	**748**	**748**	**748**	**768**	**768**	**800**	**697**	**728**
New Onshore Wind	610	610	610	610	610	610	610	610	0	40
New Land-Based External Wind	610	610	610	610	610	610	610	610	0	30
New Offshore Wind	0	0	0	0	0	0	0	0	0	0
New Geothermal	0	0	35	35	35	35	35	46	0	0
Calpine Geysers	0	0	25	25	25	25	25	25	0	0
Coso Geothermal	0	0	10	10	10	10	10	21	0	0
New Utility-Scale Solar PV	5	5	44	44	44	44	44	44	484	475
EDF Sapphire Solar	0	0	39	39	39	39	39	39	39	0
New External Solar	0	0	0	0	0	0	0	0	440	460
New External Solar (Storage Paired)	0	0	0	0	0	0	0	0	0	10
New Community Solar	5	5	5	5	5	5	5	5	5	5
New PWP-Funded Commercial Solar PV	0	0	0	0	0	0	0	0	2	2
New PWP-Funded Residential Solar PV	0	0	0	0	0	0	0	0	0	0
New 4-Hour Storage	30	40	60	60	60	80	80	100	210	210
EDF Sapphire Storage	0	0	20	20	20	20	20	20	20	0
New 4-Hour Storage (Land-Based External Wind Paired)	0	0	0	0	0	0	0	0	0	5
New 4-Hour Storage (External Solar Paired)	0	0	0	0	0	0	0	0	0	5
New 4-Hour External Storage	0	0	0	0	0	0	0	0	10	10
New 4-Hour Internal Storage	30	40	40	40	40	60	60	80	180	190
New 6-Hour Storage	0	0	0	0	0	0	0	0	0	0
New 8-Hour Storage	0	0	0	0	0	0	0	0	0	0
New 10-Hour Storage	0	0	0	0	0	0	0	0	0	0
New PWP-Funded Commercial Storage	0	0	0	0	0	0	0	0	1	1

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
New PWP-Funded Residential Storage	0	0	0	0	0	0	0	0	0	0
New Fuel Cells	0	0	0	0	0	0	0	0	0	0
New Biogas Conversion for Glenarm	0	0	0	0	0	0	0	0	0	0
Peak Load (MW)	**335**	**338**	**341**	**343**	**346**	**348**	**362**	**371**	**380**	**390**

The installed capacity under Scenario 5 creates the RA position in Figure 142 and Figure 143.

Figure 142: Scenario 5: Summer Resource Adequacy

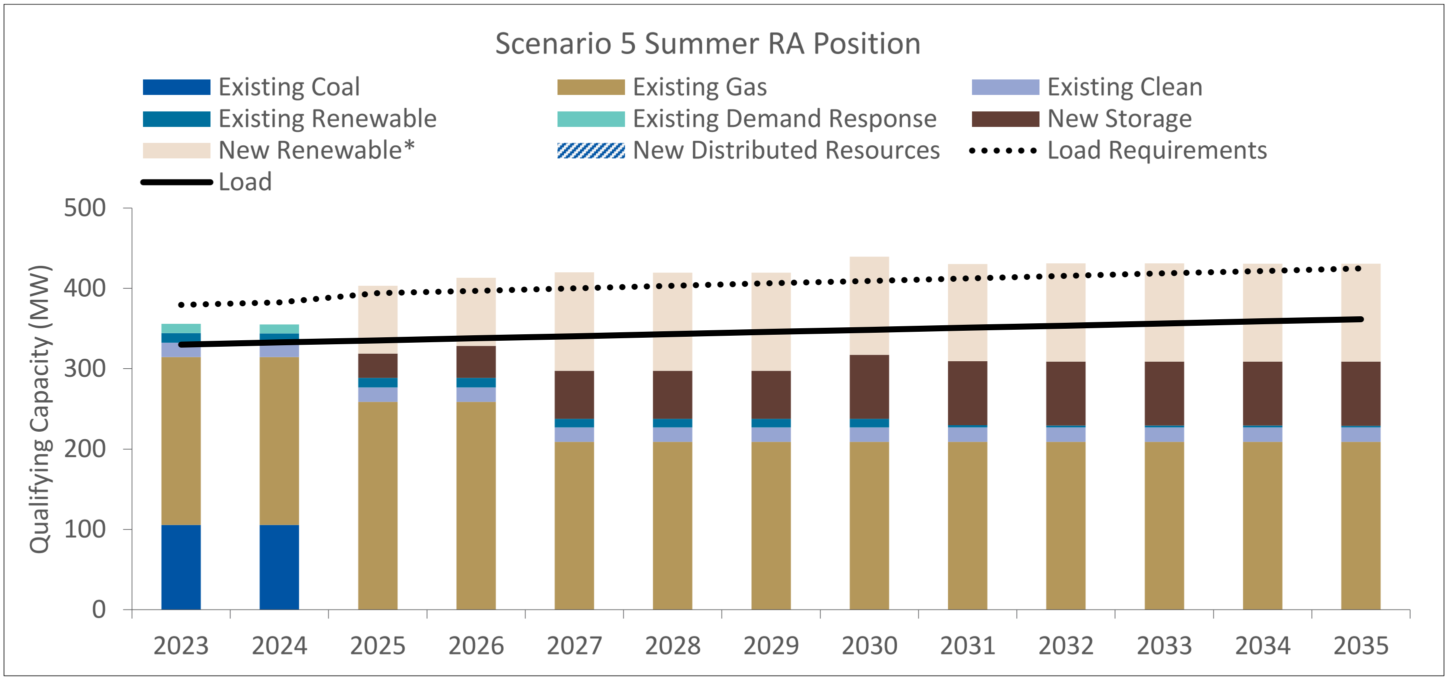


Figure 143: Scenario 5: Resource Adequacy Position

MW	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Summer Load Requirements	380	383	394	397	400	403	406	409	425	436	447	458
Existing Resources Qualifying Capacity	356	355	289	288	238	238	238	237	229	214	209	204
Length/(Shortage) Before New Additions	(24)	(27)	(105)	(109)	(162)	(166)	(169)	(172)	(196)	(222)	(237)	(254)
New Resources Qualifying Capacity	0	0	115	125	182	182	182	202	201	231	242	245
Length/(Shortage) After New Additions	(24)	(27)	9	16	20	16	13	30	6	9	5	(9)

MW	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Winter Load Requirements	185	190	192	197	198	198	208	208	226	236	243	261
Existing Resources Qualifying Capacity	354	353	286	286	236	236	236	236	227	213	213	204
Length/(Shortage) Before New Additions	169	163	94	89	38	38	28	28	1	(23)	(30)	(57)
New Resources Qualifying Capacity	**0**	**0**	**155**	**165**	**220**	**237**	**237**	**257**	**257**	**288**	**218**	**227**
Length/(Shortage) After New Additions	**169**	**163**	**249**	**254**	**258**	**275**	**265**	**285**	**257**	**265**	**189**	**171**

Adding the social cost of carbon (SCC) to carbon-emitting resources incentivizes other renewable resources. The SCC is so high that, in some instances, the model would opt for a $2,000/MWh penalty charge rather than turning on the Glenarm units (Figure 144).

Figure 144: Average Resource Costs with Carbon Tax (SCC)

	Average Cost of Energy ($Nominal/MWh)								New PPAs ($Nominal/MWh)	
Year	GT - 1	GT - 2	GT - 3	GT - 4	GT - 5	IPP Coal	IPP Gas	Magnolia	Wind	Solar
2023		$674.83	$707.78		$385.66	$429.20		$266.28		
2024		$527.20	$574.66		$400.00	$434.82		$229.25		
2025		$578.77			$450.61	$442.78	$208.48	$234.86	$58.00	$33.00
2026		$583.22					$215.28	$240.01	$52.52	$33.00
2027		$535.31	$705.54				$222.72	$250.34	$47.04	$33.00
2028	$503.21	$485.49	$403.27	$408.34	$359.50			$257.91	$41.55	$30.98
2029		$689.04		$538.77	$398.22			$265.40	$36.07	$28.95
2030	$538.41	$515.76	$408.17	$418.79	$377.20			$272.21	$30.59	$26.93
2031		$530.91	$578.07	$461.82	$400.50			$279.28	$25.11	$24.90
2032								$288.07	$19.63	$22.88
2033								$295.63	$19.59	$23.26
2034								$303.66	$25.55	$25.61
2035								$311.27	$31.80	$28.32
2036								$320.62	$44.65	$33.14

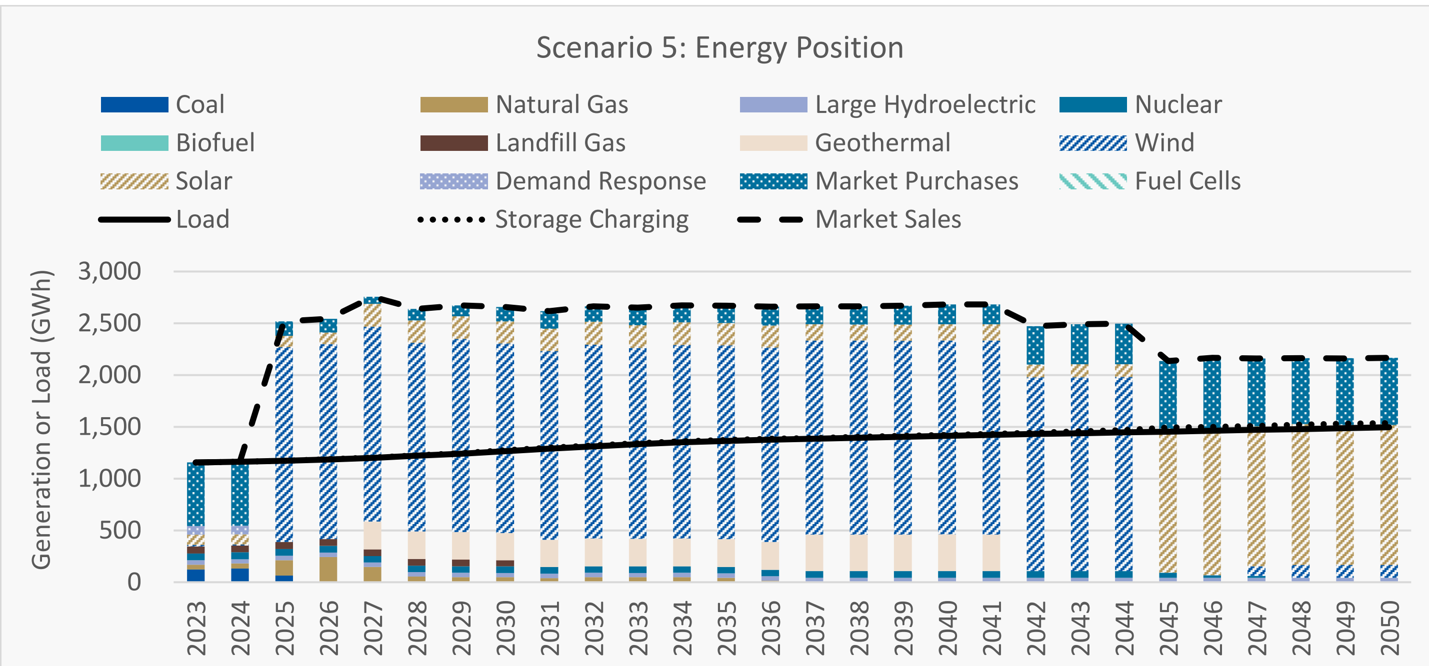
Wind generation helps produce the energy position shown in Figure 146 and Figure 147.

Figure 145: Scenario 5: Resources That Load, Storage Charging, and Market Sales are Served By

Resource Type	2023	2030	2031	2040	2050
Coal	10%	0%	0%	0%	0%
Natural Gas	4%	2%	2%	0%	0%

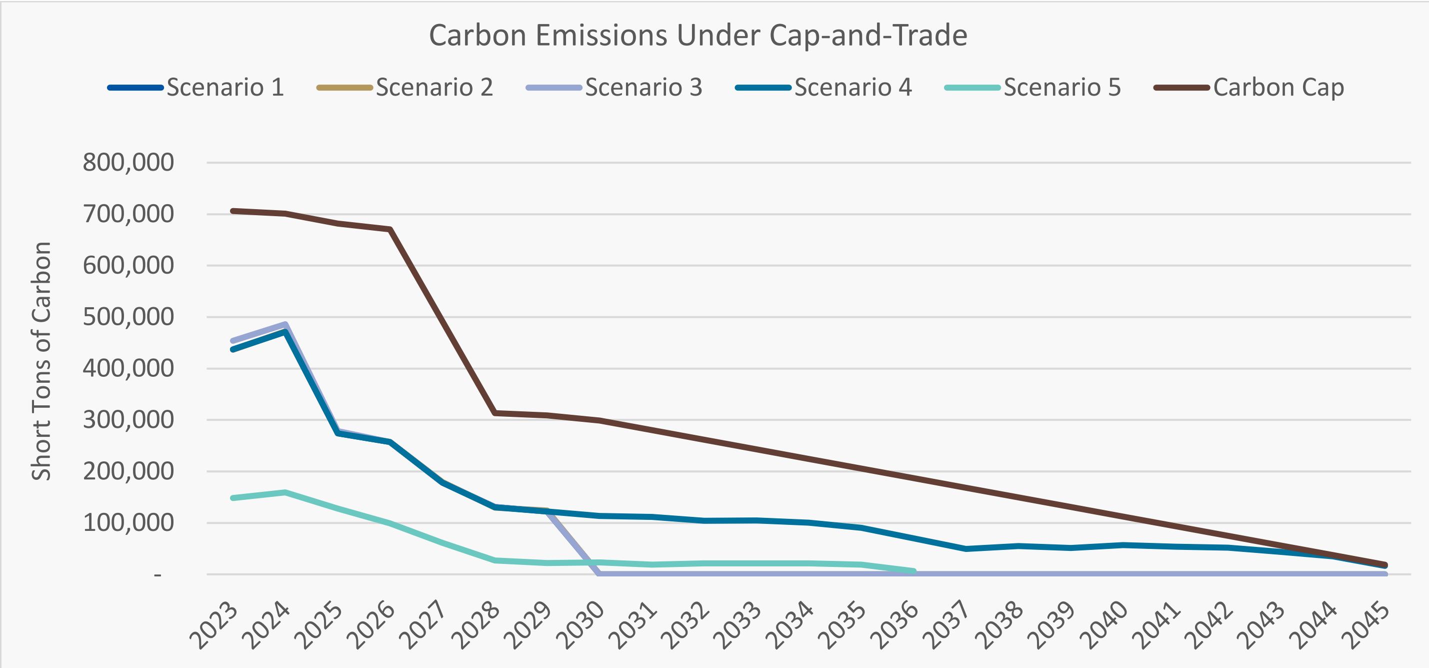
Large Hydroelectric	4%	2%	2%	2%	2%
Nuclear	6%	2%	2%	2%	0%
Biofuel	0%	0%	0%	0%	0%
Landfill Gas	6%	2%	0%	0%	0%
Geothermal	0%	10%	10%	13%	0%
Wind	1%	69%	70%	70%	6%
Solar	8%	8%	8%	6%	62%
Demand Response	7%	0%	0%	0%	0%
Market Purchases	53%	5%	6%	7%	30%
Fuel Cells	0%	0%	0%	0%	0%

Figure 146: Scenario 5: Energy Position



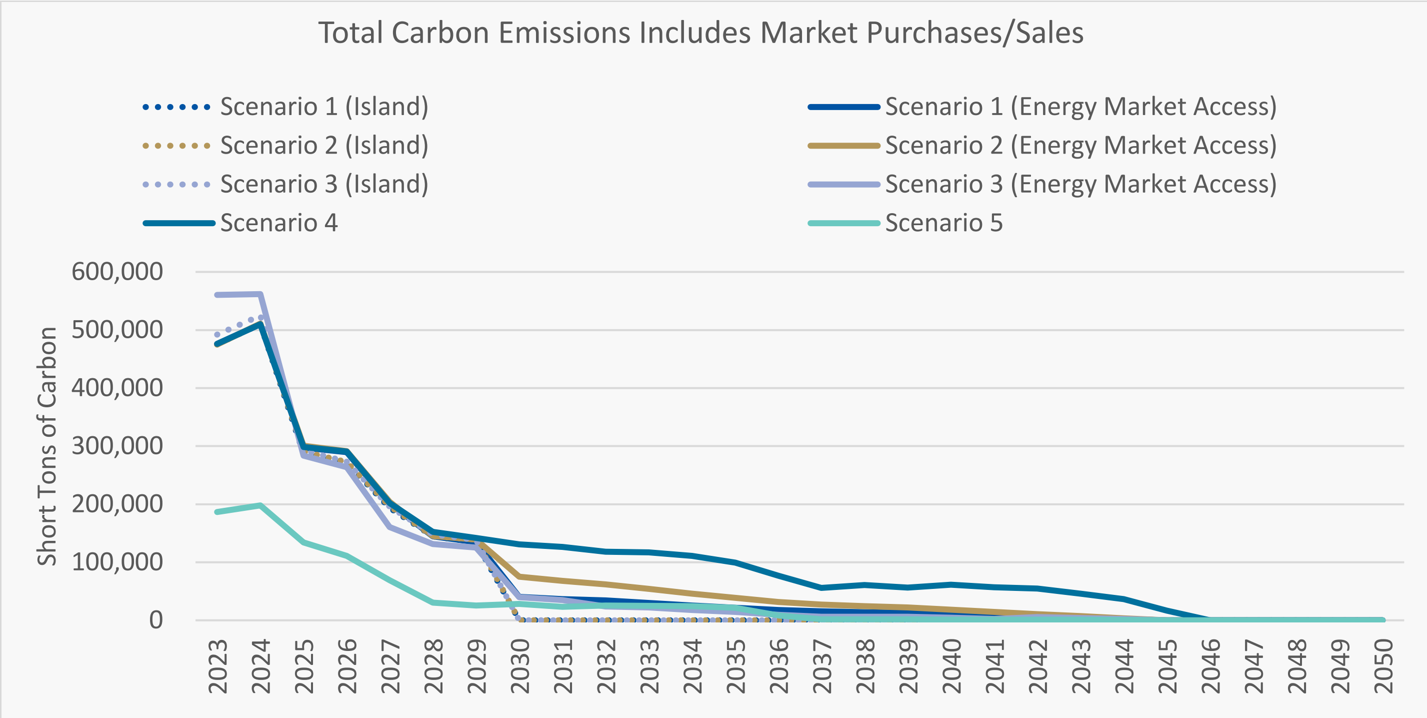
Scenario 5 produces less carbon than Scenario 4 under the Cap-and-Trade Program, which, in this IRP, includes emissions from Glenarm, IPP coal, IPP natural gas, and Magnolia (Figure 147).

Figure 147: Total Carbon Emissions Under Cap-and-Trade (Scenarios 1 through 5)



Another method of quantifying carbon would be to credit or debit market sales or purchases from PWP's portfolio assuming the carbon intensity of CAISO. PWP would have to be cautious of avoiding any claims to renewable characteristics if the energy is sold. As shown in Figure 148, by that calculation, because of PWP's sales, PWP could offset emissions elsewhere on the grid.

Figure 148: Total Portfolio Carbon Emissions (Netting Market Purchases and Sales)



16.6. Scenario 6: Emerging Technologies Study Scenario

Scenario 6 investigates at what value emerging technologies could provide to PWP. It attempts to answer the following questions:

- If PWP reduces energy load and peak power demand over all hours by 1%, 2%, or 3%, how much would ratepayers save?
- If PWP reduces the top 0.5%, 1%, and 1.5% of peak hours in a year by 30 MW, how much would ratepayers save?

The savings translate into a cost that represents a financial viability point for an emerging technology that could accomplish either of the above two goals. Note that the load forecast already includes resources that are cost effective, such as energy efficiency and demand response.

16.6.1. Scenario 6: Energy Efficiency Proxy

Scenario 2 has the greatest costs because it is the most constrained. Emerging technology would provide the most value under Scenario 2. For the energy efficiency proxy, Scenario 2 is re-run with 1%, 2%, and 3% less load across all hours. New resources can be selected to meet load.

The difference in cost between these model runs can show where a point of financial viability is for this type of resource. For another 1% of energy efficiency in addition to what is in the load forecast, under Scenario 2, a financial viability point is around $259/MWh (in $2030). For the next 1%, a point of financial viability is $127/MWh (in 2030 dollars), and it is not as cost effective afterward in Scenario 2, as shown in Figure 149. Figure 149 also contains the average costs for the entirety of the 1%, 2%, or 3% avoided.

Figure 149: Scenario 6: Energy Efficiency Proxy – Results

20-Year $/MWh Avoided (2030 $, 2030-2049)	Reduce 1% of Load	Reduce 2% of Load	Reduce 3% of Load
Incremental Cost	$259	$127	($140)
Average Cost	$259	$193	$82

16.6.2. Scenario 6: Demand Response Proxy

The same type of study was run for a demand response type of resource. The model is run three times, with load reduced by 30 MW across 0.5%, 1%, or 1.5% of peak hours. The model may build new resources each time. The IRP calculates the difference in cost between each model run. This is how much PWP could be willing to pay for a resource that can reduce peaks across a given number of hours in a year.

From 2030 through 2049, in 2030 dollars, a financial viability point is $12.29/kW-month for 1.5% of peaks, and $10.61/kW-month for 1.0% of peaks. Reducing only 0.5% of peaks each year does not avoid a new resource build during this time under this model run. See Figure 150.

Figure 150: Scenario 6: Demand Response Proxy: Results

Average Cost	0.5% of Peaks	1.0% of Peaks	1.5% of Peaks
20-Year $/kW-Month Avoided (2030 $,2030-2049)	(2.79)	10.61	12.29

The Scenario 6 is run under one set of normal operating conditions under one load forecast. Additional model runs for other scenarios or other conditions may provide a greater range of avoided costs.

16.7. Scenario Comparisons

Across scenarios, the amount of installed capacity by 2031 (the first full year of hourly carbon-free energy) ranges from 750 MW (Scenario 4) to 1,509 MW (Scenario 3). This is equivalent to two to four times PWP's peak load. See Figure 151 and Figure 152. By 2031, PWP needs between 80 MW (Scenarios 4 and 5) and 690 MW (Scenario 2) of solar. By 2031, PWP needs between 0 MW (Scenario 1) and 610 MW (Scenario 5) of wind. By 2031, PWP needs between 80 MW (Scenario 5) and 685 MW (Scenario 2) of batteries.

Figure 151: Installed Capacity of Scenarios

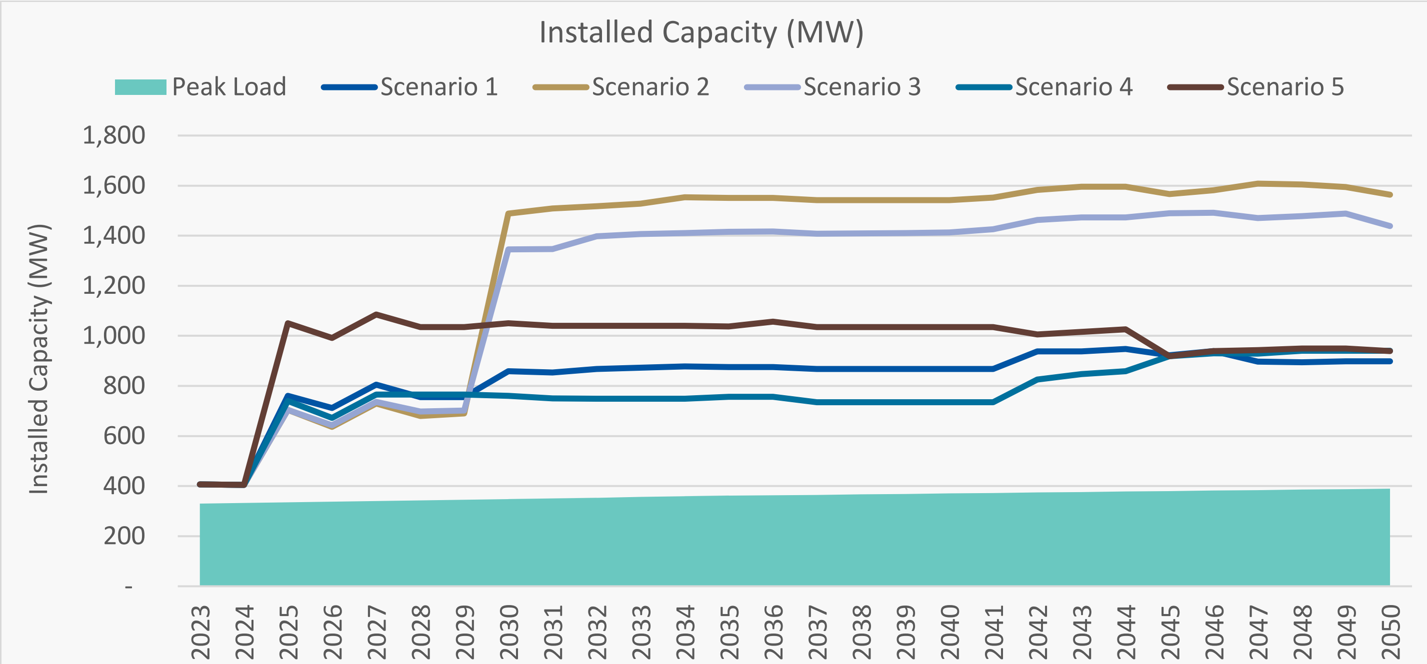
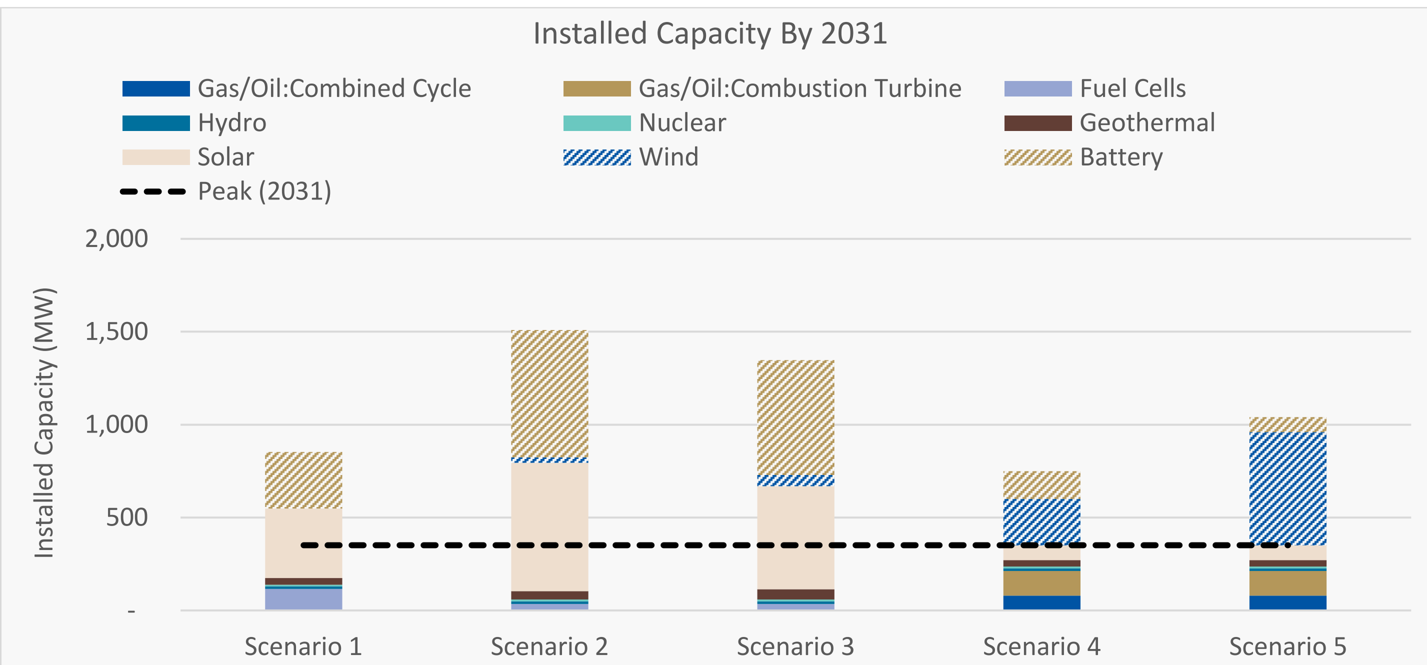


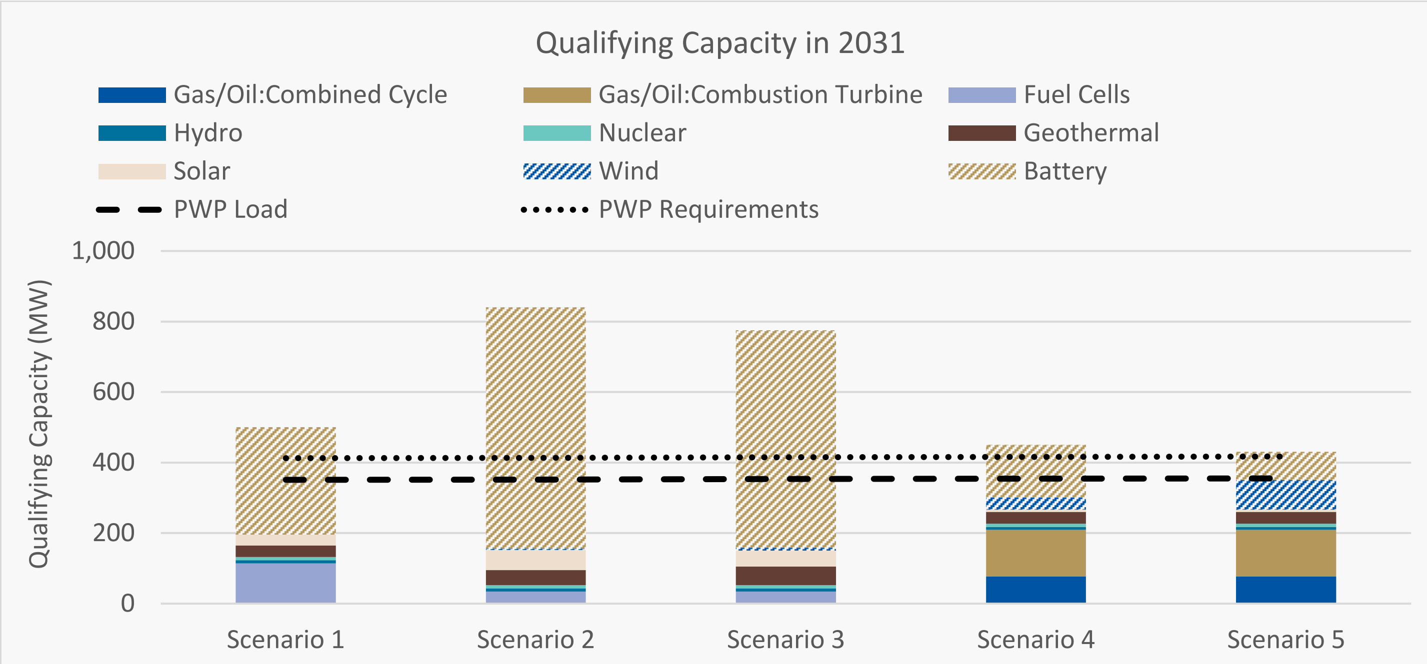
Figure 152: Installed Capacity of Scenarios by Type in 2031



PWP will have to bring online more than its peak in installed capacity. The installed capacity is higher than peak load for two reasons: qualifying capacity and reliability.

RA answers the question: “What reliability contribution does that installed capacity bring PWP?” The contribution of solar has declined over time. It is anticipated that this trend will continue. The qualifying capacity of the installed resources in 2031 is shown in Figure 153.

Figure 153: Qualifying Capacity of Scenarios in 2031



PWP assumes 100% qualifying capacity for storage (of any chosen duration) in this IRP. It is anticipated that the capacity accreditation of storage will decline over time in markets across the U.S. If this occurs, PWP would need additional installed energy and/or storage capacity.

The other reason PWP requires more installed capacity than peak is reliability. Internal resources are required to help serve load reliably given that PWP is a transmission-constrained system. See Figure 154 for a breakdown of resources installed internal to PWP. Additional transmission interconnections would reduce the need for internal resources. PWP is constrained in terms of how many utility-scale resources it can install inside its service territory because the city is mostly developed and densely built.

Figure 154: Internal vs. External Installed Capacity in 2031

Installed Capacity in 2031 (MW)			
	External (CAISO)	Internal (Pasadena)	Total
Scenario 1	153	701	854
Scenario 2	508	1,001	1,509
Scenario 3	408	939	1,347
Scenario 4	417	333	750
Scenario 5	777	263	1,040

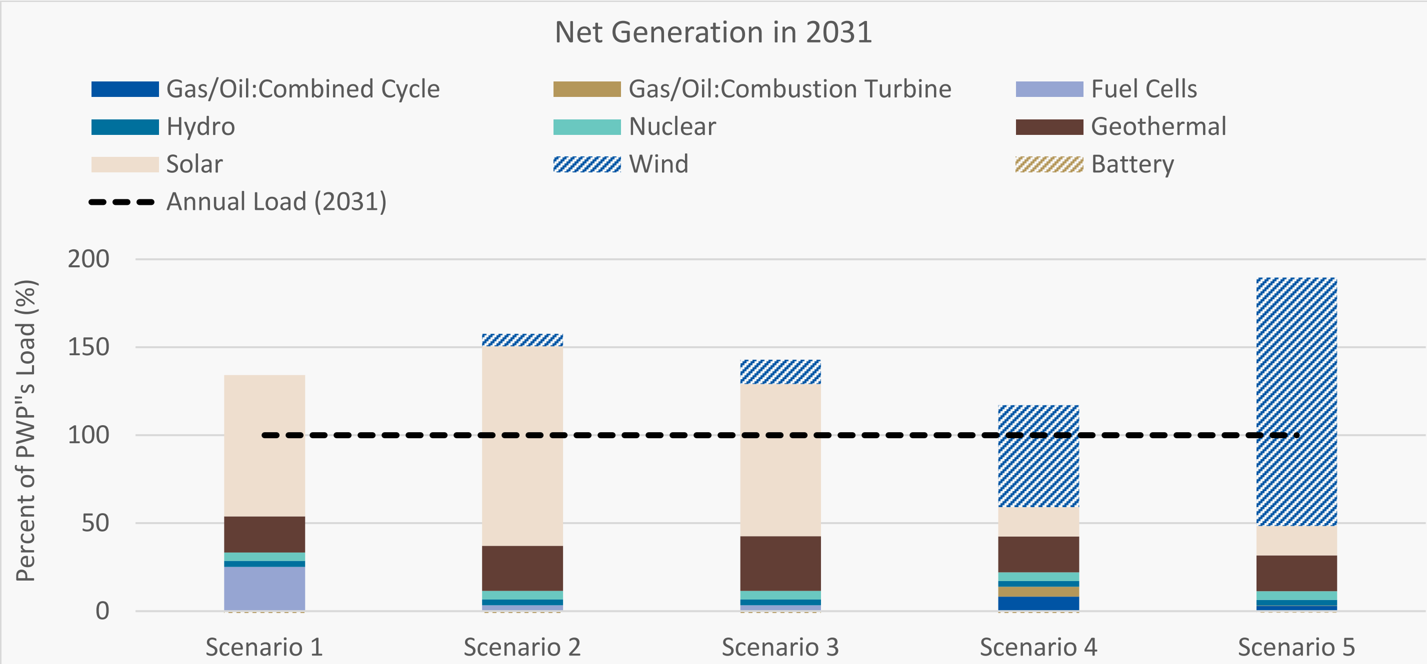
For internal capacity, there are varying amounts of distributed versus utility-scale resources depending on the Scenario (Figure 155).

Figure 155: Installed Capacity Distributed Resources per Scenario – in Addition to Load Forecast

	New 2-Hour Residential Storage (MW)	New 4-Hour Commercial Storage (MW)				New Commercial Solar (MW)			New Residential Solar (MW)
Year	Scenario								
	3	2	3	4	5	2	3	5	3
2025	1		1				31		17
2026	2		2				31		21
2027	2		2				31		21
2028	2		2				31		22
2029	3		6				31		22
2030	3	400	350			400	350		23
2031	3	400	350			400	350		25
2032	4	400	360			400	350		26
2033	4	400	360			400	357		28
2034	5	400	360			400	357		31
2035	5	400	360			400	357		38
2036	6	400	360			400	357		38
2037	6	400	360			400	357		38
2038	7	400	360			400	357		38
2039	8	400	360			400	357		38
2040	8	400	360			400	359		39
2041	9	400	360			400	360		40
2042	10	400	364			400	375		46
2043	11	403	364	2		400	375		46
2044	11	403	364	4	1	400	375		46
2045	12	403	363	4	1	400	375	2	57
2046	13	403	362	4	1	400	375	2	53
2047	14	403	362	4	1	408	375	2	53
2048	15	403	362	4	1	408	375	2	52
2049	17	403	358	4	1	408	381	2	58
2050	17	400	350	4	1	400	350	2	57

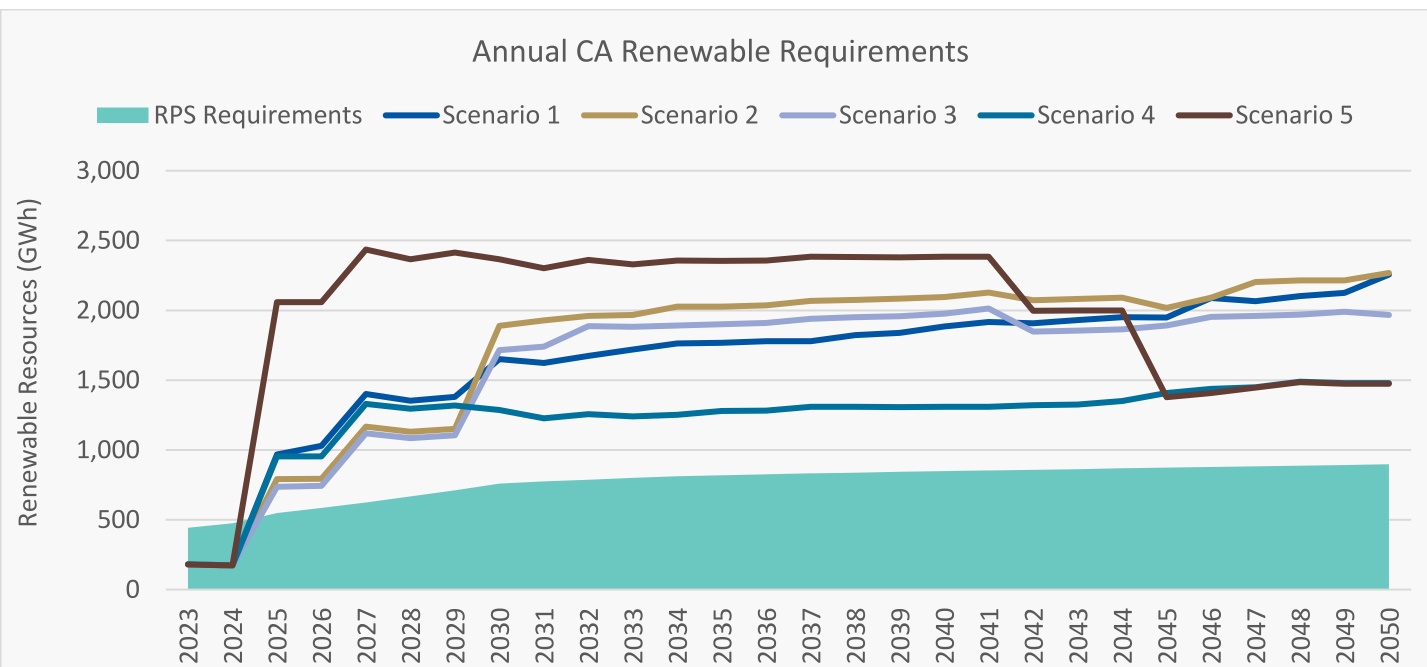
By 2031, PWP is generating between 100% and 200% of its energy needs (Figure 156). Solar is generating between 17% and 113% of PWP's energy annual needs and wind between 0%and 141% because PWP has excess capacity. This would result in overgeneration, but PWP could sell the excess generation in certain hours.

Figure 156: Net Generation of Scenarios in 2031



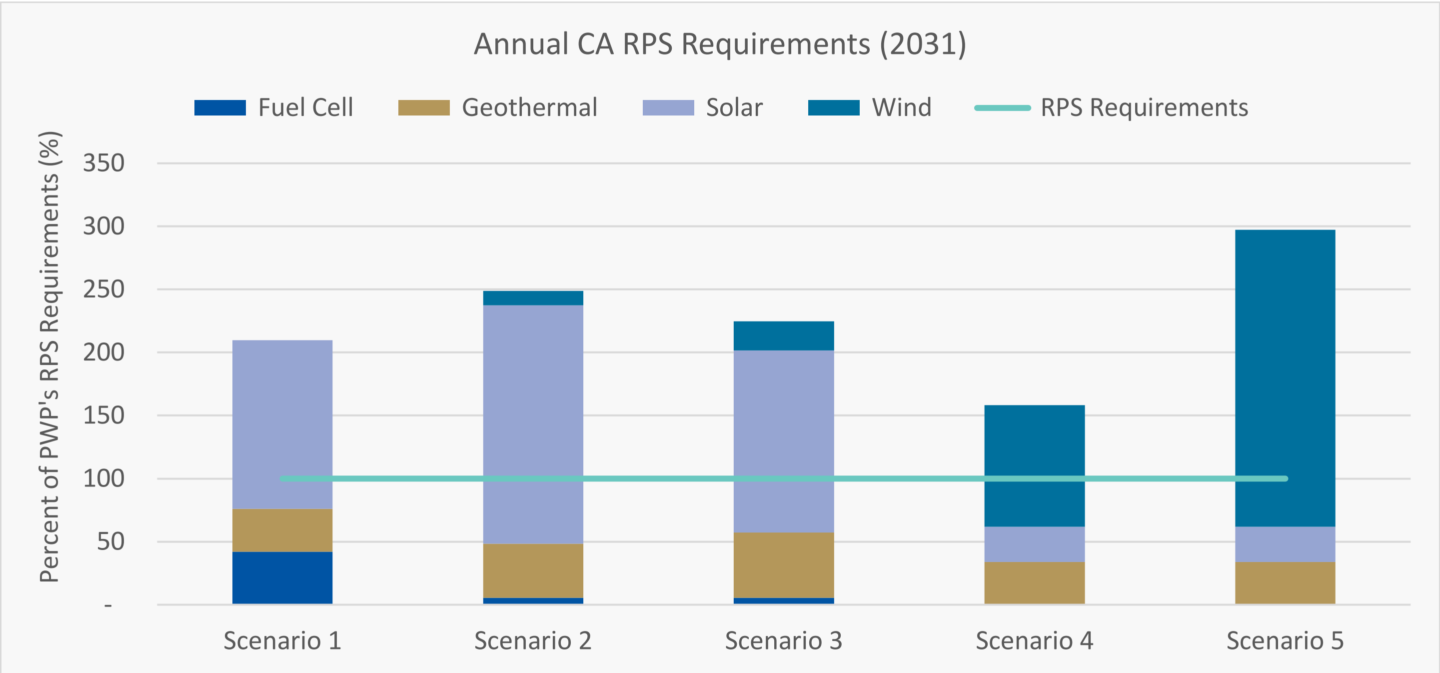
This generation translates into wind and solar generation in excess of PWP's California regulatory renewable requirements. By 2031, PWP is producing two (Scenario 4) to three (Scenario 5) times its 2031 RPS requirements. PWP can exceed its requirement to have 60% of its load covered by renewable energy by two or three times. See Figure 157.

Figure 157: Renewable Compliance Across Scenarios



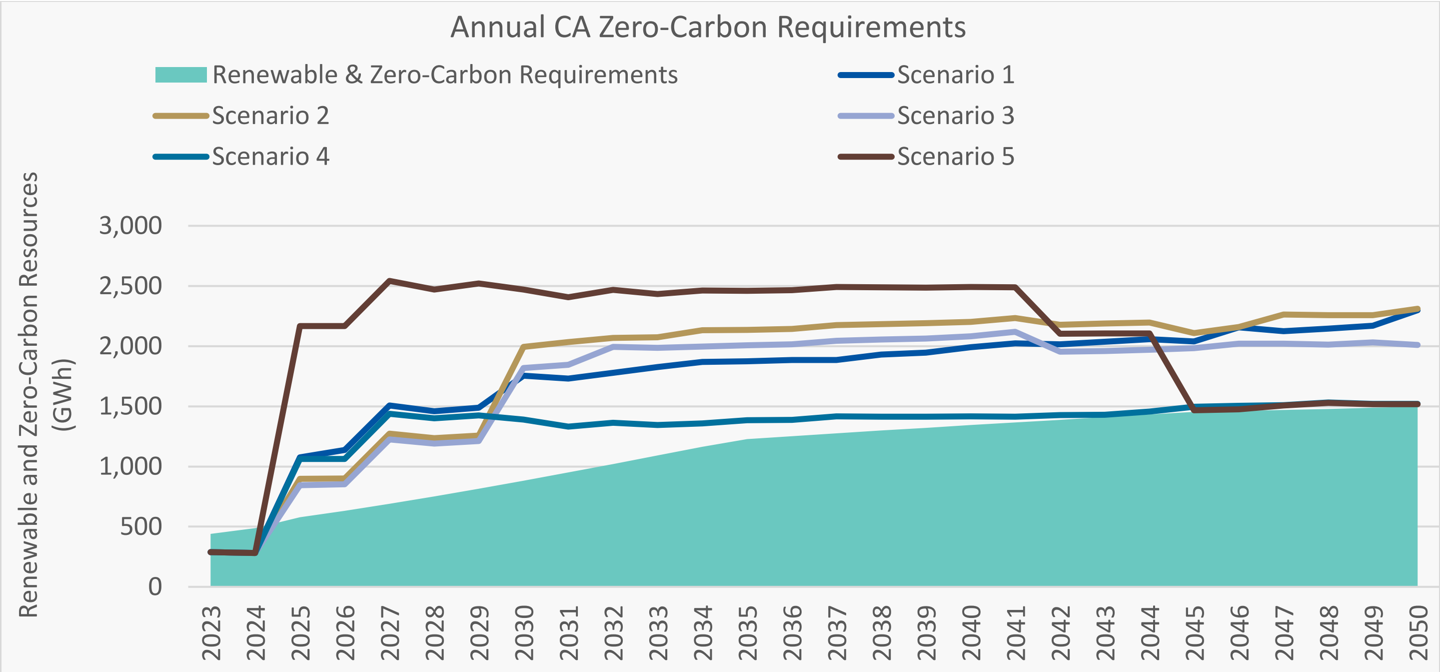
This renewable resource requirement is met not only through wind and solar but also through geothermal and renewable hydrogen fuel cells. By 2031, PWP produces between 28% (Scenario 4) and 189% (Scenario 2) of its RPS requirements in solar and between 0% (Scenario 1) and 235% (Scenario 5) of its RPS requirements in wind. See Figure 158.

Figure 158: Renewable Compliance across Scenarios by Type in 2031



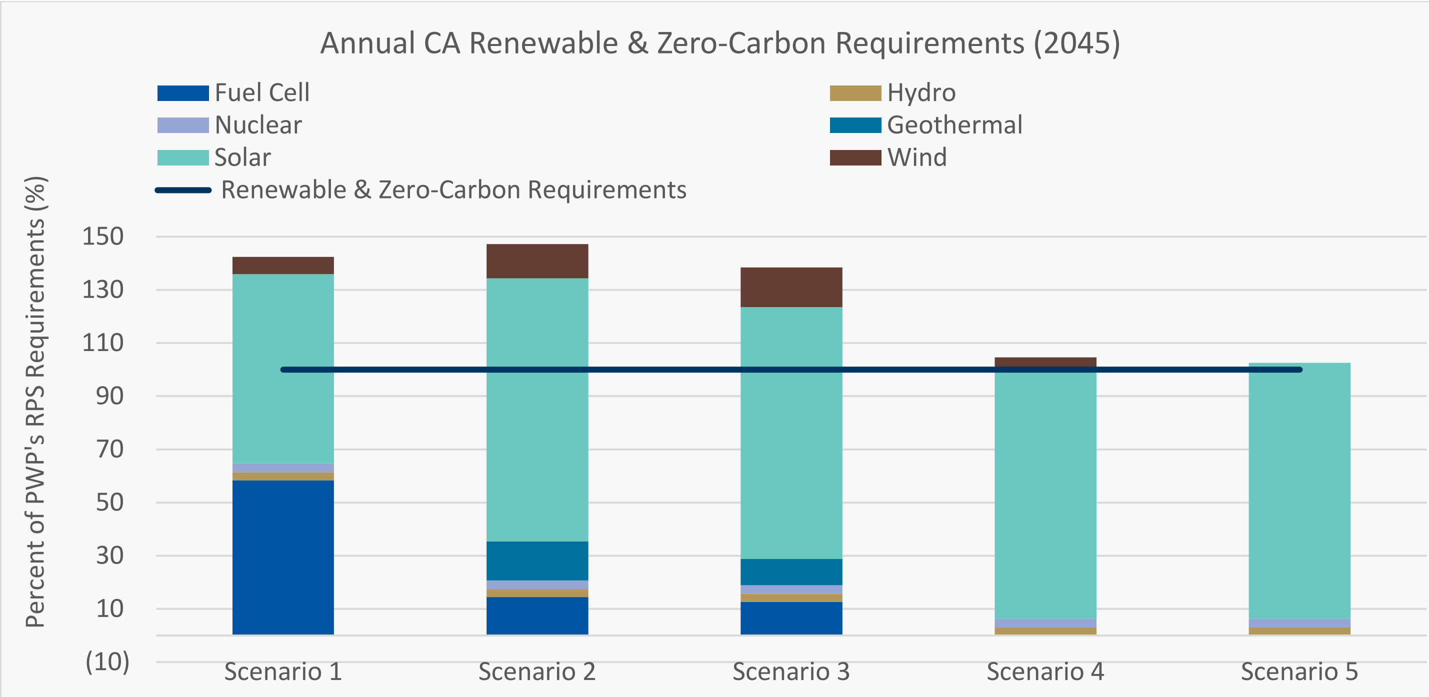
Renewable resources are eligible as zero-carbon resources to meet California's annual State environmental requirements. All scenarios meet California requirements to serve energy with renewable and zero-carbon resources by 2045. By 2045, in the carbon-free scenarios, PWP has excess renewable and zero-carbon energy (Figure 159).

Figure 159: Annual Zero-Carbon Requirements by Scenarios



Those requirements are met by resources like solar (Figure 160).

Figure 160: Zero-Carbon across Scenarios by Type in 2045



By the end of 2030, PWP can operate a 100% carbon-free hourly system under the carbon-free scenarios (Figure 161). PWP has landfill gas that contractually expires toward the end of 2030, so compliance occurs by 2031. Under Scenario 4 PWP can operate above a 60% hourly carbon-free system, and under Scenario 5 above 80%.

Figure 161: Carbon-Free across Scenarios

Year	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
2023	17%	17%	16%	17%	21%
2024	16%	16%	16%	16%	20%
2025	34%	36%	39%	40%	64%
2026	32%	34%	37%	38%	62%
2027	49%	51%	52%	55%	76%
2028	53%	55%	56%	59%	80%
2029	54%	55%	57%	60%	80%
2030	96%	97%	97%	60%	78%
2031	**100%**	**100%**	**100%**	**62%**	**81%**

The information in Figure 161 represents single model runs conducted under normal operating conditions. Sensitivity analyses regarding load, power prices, fuel prices, cost of new resources, and others could provide additional information on capacity and generation required to meet goals.

16.8. Sensitivity 1: Heat Wave

A significant stressor like a heat wave causes reliability concerns. These reliability concerns appear as additional energy needs. These needs are spread across a certain number of hours, and those hours occur across a certain number of days. The IRP model can also identify the maximum hourly demand for additional resource needs. This could be thought of as a potential resource size to help alleviate the reliability concerns.

Scenarios 4 and 5 maximize the Goodrich connection, so additional resources would be needed. For Scenarios 1, 2, and 3, additional utility-scale resources could be located outside PWP and imported over the Goodrich interconnection or located internal to PWP. The last two columns in Figure 162 show the amount of resources that would have to be installed internally and externally.

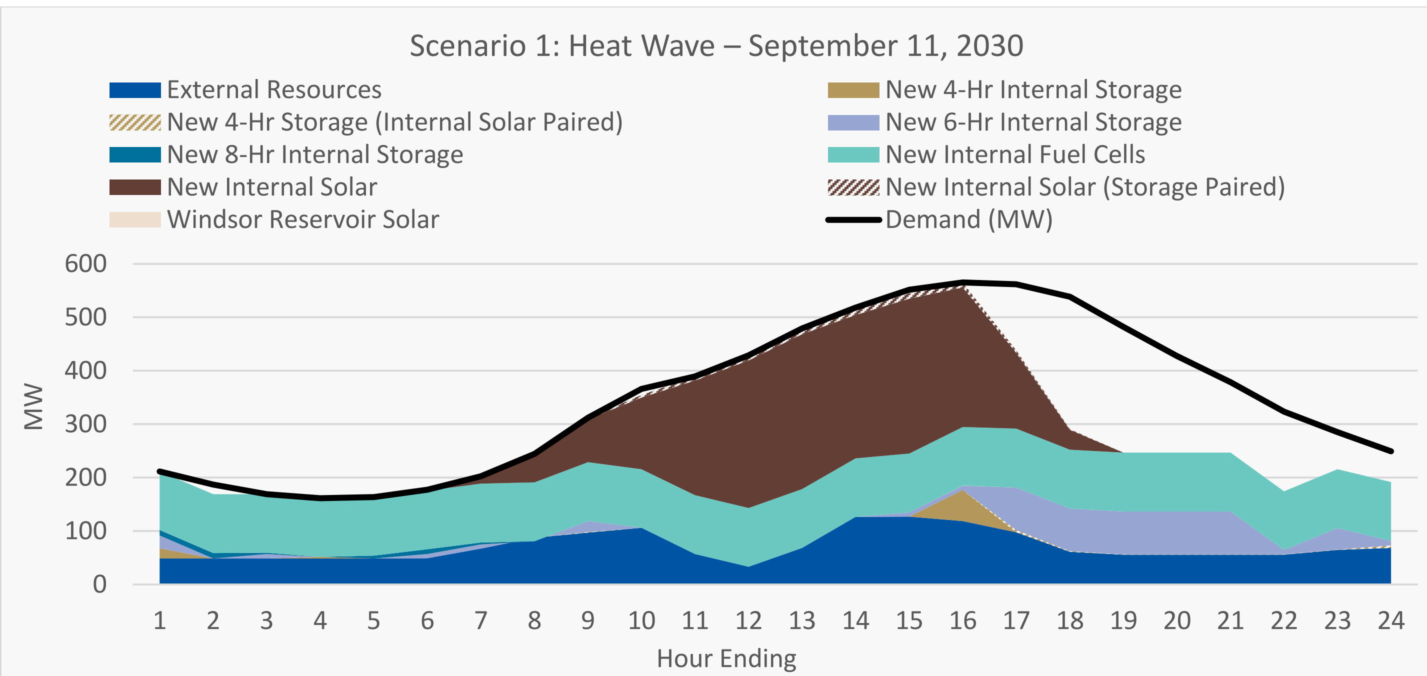
Figure 162: Heat Wave Sensitivity Results

Scenario	Additional Energy Required (MWh)	Additional Energy Required (Hours)	Additional Energy Required (Days)	Largest Hourly Demand for Additional Energy (MW)	Additional Resources That Have To Be Located Internally	Additional Resources That Could Be Located Externally
Scenario 1	1,991	32	9	248	40 MWh total with a 29 MW maximum	1,951 MWh total with a 219 MW maximum
Scenario 2	8,252	188	24	327	1,755 MWh total with a 240 MW maximum	6,497 MWh total with an 87 MW maximum
Scenario 3	22,959	370	30	406	3,041 MWh total with a 241 MW maximum	19,918 MWh total with a 165 MW maximum
Scenario 4	6	8	6	1	6 MWh total with a 1 MW maximum	None (Goodrich is fully importing)
Scenario 5	133	23	12	36	133 MWh total with a 36 MW maximum	None (Goodrich is fully importing)
	This is the total additional energy need in the month.	This is how many unique hours this energy need shows up.	This is how many unique days this energy need shows up.	This is the maximum need in an hour.	The scenarios have the reliability needs indicated in the first four columns. If PWP allows the maximum capacity over Goodrich, this amount would have to be located internally, and the remainder would	For Scenarios 1, 2, and 3, some resources could be located external to PWP. There is still excess capacity over the Goodrich connection.

Scenario	Additional Energy Required (MWh)	Additional Energy Required (Hours)	Additional Energy Required (Days)	Largest Hourly Demand for Additional Energy (MW)	Additional Resources That Have To Be Located Internally	Additional Resources That Could Be Located Externally
					have to be located externally.	

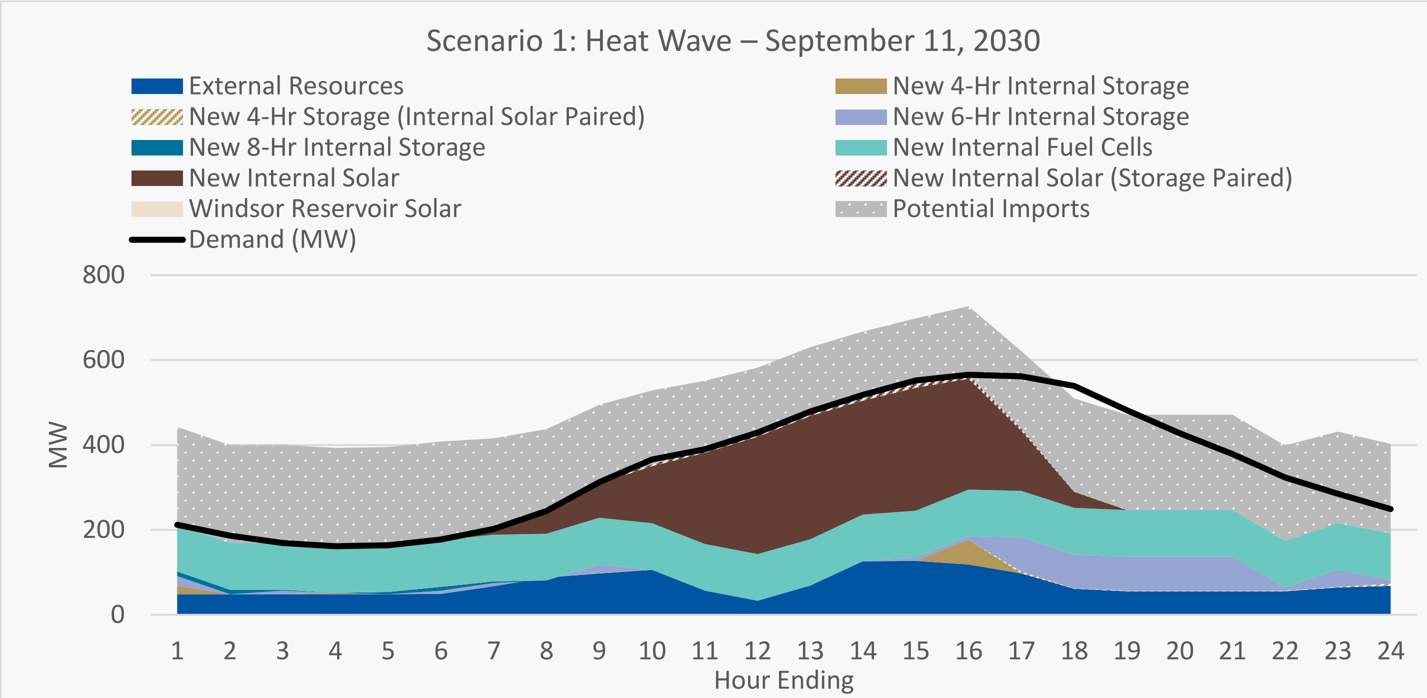
There are 32 hours over nine days in Scenario 1 when there are additional energy needs. Overall, there is a total of 1,991 MWh of additional energy needs in this month under the Heat Wave. The hour with the largest energy need is Hour Ending (HE) 18 on September 11, 2030, when an extra 248 MW is needed. See Figure 163.

Figure 163: Scenario 1: Heat Wave



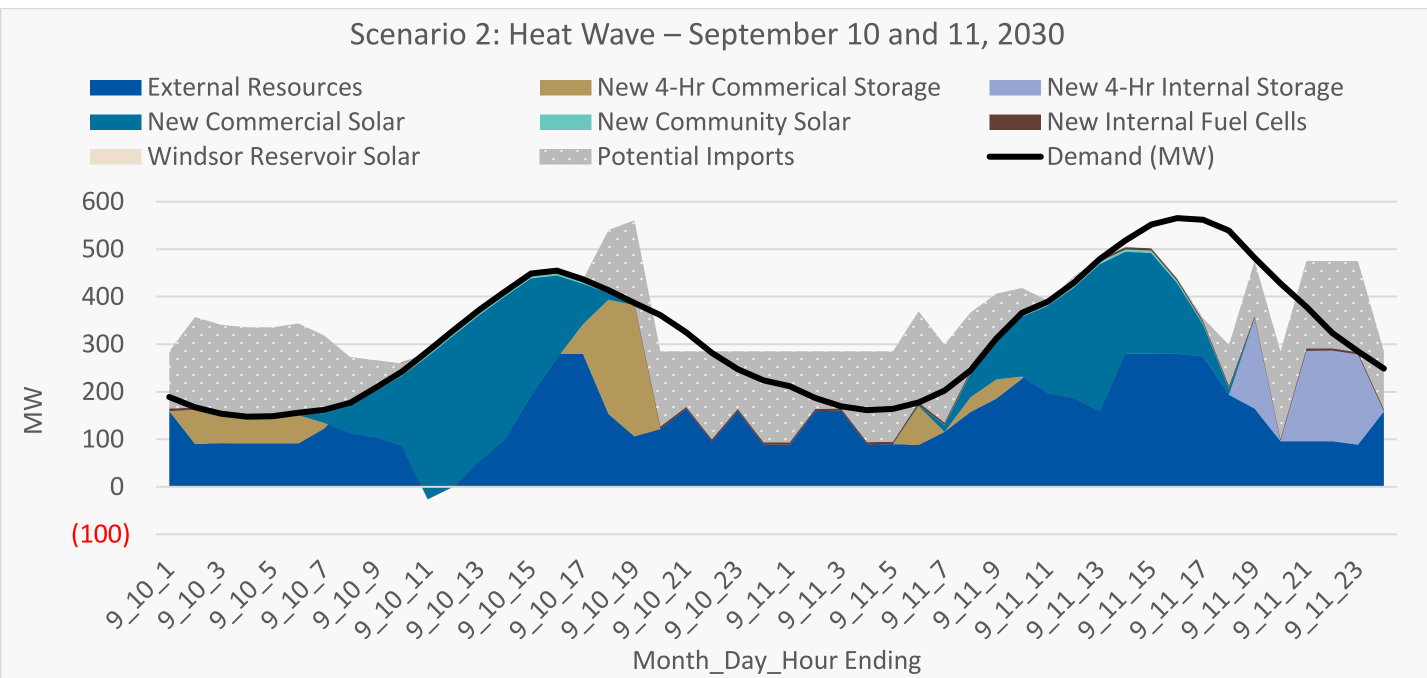
However, PWP could import another 219 MW across Goodrich in that hour. In this case, PWP would need an additional 29 MW located internally. See Figure 164. When Goodrich increases from 280 MW to 336 MW, this capacity could be external.

Figure 164: Scenario 1: Heat Wave with Goodrich Maximized



In Scenario 2, even if Goodrich imports additional carbon-free power up to its maximum potential, PWP could need an additional 240 MW in a given hour to help serve load (Figure 165).

Figure 165: Scenario 2: Heat Wave with Goodrich Maximized



Based on the top 10 hours of additional energy needs in Scenario 3, there are some high-risk days and high-risk hours. The high-risk hours in this forecast are HE 16 though HE 20. See Figure 166.

Figure 166: Scenario 3: Heat Wave Top 10 Additional Energy Need Hours (September 2030)

Scenario 3: Heat Wave – Top 10 Additional Energy Need Hours (September 2030)											
Day	Interval (HE)	Demand (MW)	External Resources (MW)	Distributed Storage (MW)	Distributed Solar (MW)	Utility Solar	New 4-Hour Internal Storage	New Internal Fuel Cells	Additional Energy Needs?	Potential Imports?	Remaining Needs?
6	19	394	96	0	0	0	0	5	293	184	109
10	19	387	97	0	0	0	0	5	285	183	102
11	16	565	248	0	139	5	0	5	169	32	137
11	17	562	187	0	63	3	0	5	305	93	212
11	18	539	115	0	12	1	0	5	406	165	241
11	19	482	95	0	0	0	0	5	382	185	197
11	20	428	98	0	0	0	0	5	325	182	143
21	**17**	**454**	**161**	**0**	**52**	**2**	**0**	**5**	**234**	**119**	**115**
21	**18**	**422**	**102**	**0**	**6**	**0**	**0**	**5**	**309**	**178**	**131**
21	19	386	97	0	0	0	0	5	283	183	101

Scenario 3 shows more additional energy needs under a heat wave than Scenario 2 because of differences in amounts of installed capacity (Figure 167). In 2030, Scenario 2 has 1,001 MW installed internally, while Scenario 3 has 937 MW (64 MW less than Scenario 2). Furthermore, the breakdown of technology types and amounts is different between the two scenarios. Different technology mixes interact differently during a heat wave.

Figure 167: Internal Installed Capacity in 2030 for Scenario 2 and 3

Resource	Scenario 2 (MW)	Scenario 3 (MW)
New 2-Hour Residential Storage		3
New 4-Hour Commercial Storage	400	350
New 4-Hour Internal Storage	190	200
New Commercial Solar	400	350
New Community Solar	5	5
New Internal Fuel Cells	5	5
New Residential Solar		23
Windsor Reservoir Solar	1	1
Total	**1,001**	**937**

Scenario 4 also shows additional energy needs; however, there is availability on the Glenarm units. See Figure 168. In the model, paying a $2,000/MWh penalty is preferable to paying to start the unit given high fuel costs.

Figure 168: Scenario 4: Heat Wave

Day	HE	Demand (MW)	External Resources (MW)	Market Purchases (MW)	Glenarm (GT) (MW)	Other Internal (MW)	Additional Energy Needs? (MW)	GT Spare Capacity? (MW)
1	17	478	128	151	153	44	0	45
8	15	439	132	147	153	5	1	45
10	15	449	150	130	153	16	0	45
14	15	459	127	153	153	26	1	45
14	17	457	115	165	153	24	0	45
21	17	454	108	170	111	62	1	45
21	18	422	86	192	111	30	1	45
28	16	437	147	132	111	45	1	45

Scenario 5 shows additional energy needs ranging from 1 MW to 36 MW across six consecutive hours. Scenario 5 includes 60 MW of installed internal storage by 2030 compared to 130 MW in Scenario 4.

The following are the three primary findings from the heat wave sensitivity test:

- There are additional energy needs.
- There is a need for additional internal resources or increased transmission capacity.
- There are certain hours of interest (HE 15 through HE 18).

16.9. Sensitivity 2: Goodrich Transfer Contingency

PWP is a transmission-constrained system. Goodrich is the one gateway that is currently operating constantly. This sensitivity test evaluates what happens if the capacity at Goodrich is reduced by one-half.

As shown in Figure 169, under a single week of highest demand under normal operating conditions outside the Goodrich contingency, all scenarios can operate reliably.

Figure 169: Goodrich Transfer Contingency Results

	Week of September 8 – 14, 2030			2030 Full Year		
Scenario	Additional Energy Required (MWh)	Additional Energy Required (Hours)	Additional Energy Required (Days)	Additional Energy Required (MWh)	Additional Energy Required (Hours)	Additional Energy Required (Days)
1	0	0	0	0	0	0
2	0	0	0	0	0	0
3	0	0	0	0	0	0
4	0	0	0	2	7	7
5	0	0	0	25	18	28

The carbon-free scenarios have sufficient additional resources installed internally to support reliability. The total amounts of internal resources in 2030 are shown in Figure 170.

Figure 170: Internal Installed Capacity in 2030 Across Scenarios

Installed Capacity (MW)	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Resources in CAISO	163	488	408	427	787
Resources In PWP Service Territory	696	1001	937	333	263

The peak week is not always the week of greatest reliability concern. There can also be reliability needs in winter (February in this IRP). Compared to Scenarios 1-3, Scenarios 4 and 5 do not have the same quantity of internal resources installed, so they may require additional resources to help serve energy needs in February. The monthly needs for Scenarios 4 and 5 are shown in Figure 171.

Figure 171: Scenario 4 and 5: Additional Energy Needs Under Heat Wave

	Scenario 4			Scenario 5		
Month (2030)	Additional Energy Needs (Hours)	Additional Energy Needs (Days)	Additional Energy Needs (MWh)	Additional Energy Needs (Hours)	Additional Energy Needs (Days)	Additional Energy Needs (MWh)
January	1	1	0	4	3	1
February	2	2	1	8	4	19
March	1	1	0	2	2	1
April	0	0	0	0	0	0
May	0	0	0	5	4	6
June	2	2	1	1	1	0
July	1	1	0	1	1	0
August	0	0	0	2	2	0
September	0	0	0	0	0	0
October	0	0	0	0	0	0
November	0	0	0	2	1	2
December	0	0	0	0	0	0

17. Battery Storage

17.1. Storage in the IRP

Battery storage is commercially available peaking capacity. Multiple storage technologies currently exist or have had promising breakthroughs, but lithium-ion remains the most implemented type of battery storage type.[153] PWP included battery storage as a selectable resource in its IRP.

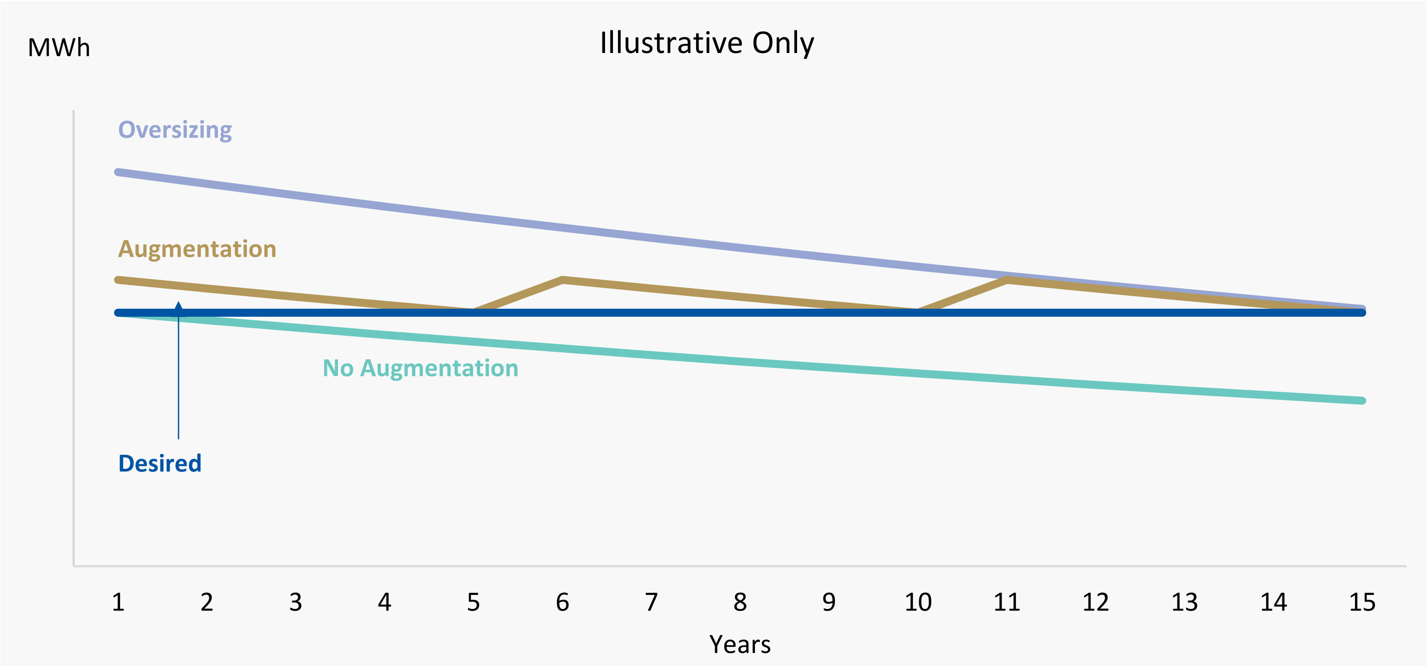
[153] https://www.eia.gov/todayinenergy/detail.php?id=41813

Storage applications are defined by a set of cost and operating parameters, including the following:

- Cost
  - Costs are commonly shown in $/kWh, which can be converted to $/kW by multiplying by the duration of the storage project. For PWP's IRP, all battery costs are assumed to be added via PPAs, so capital and fixed O&M costs were levelized into a flat $/kW-month rate depending on the year of installation. This represents a fixed capacity or demand charge that will be paid regardless of the operation of the battery.
- Size
  - Battery sizes are determined by the installed capacity or inverter size (MW). In the IRP, this value represents how much the battery can inject onto the grid in any given hour. The other size component is the energy (MWh), which is dependent on the installed capacity and the duration. For example, a 4-hour duration battery will be represented by 10 MW/40 MWh. This battery project at full charge can inject 10 MW for four hours before being depleted.
    - PWP modeled different duration types for utility-scale storage in the IRP: 4-hour, 6-hour, 8-hour, and 10-hour. The cost for these durations are scaled linearly based on NREL estimates.
    - Commercial and residential energy storage were also considered as candidate resources for the IRP using cost scalars for early-year installations and blending into the NREL commercial and residential storage costs by the mid-2030s.
- Round-trip efficiency
  - Round-trip efficiency is the measure of how much energy that goes into the battery can be utilized. PWP modeled all battery storage types with an 85% round-trip efficiency in the model.
- Cycle limitations
  - Battery resources were assumed to have an equivalent cycle capability of one cycle per day or 365 cycles per year. This was entered as a capacity factor limit in the model. For example, a 4-hour battery storage project has an upper limit of a 16.67% capacity factor (4 hours/24 hours).
- Augmentation/degradation
  - Similar to the lithium-ion battery in a cell phone, utility-scale batteries can lose energy over time with use. Developers and utilities have several ways to account for this:
    - Assume the battery project will just degrade and that is factored into the cost and forecasted operating capability.
    - Oversize the project so that the desired size is guaranteed throughout the life of the project.
    - Include regular or projected augmentation, or cell replacement, throughout the life of the project.
  - Consistent with NREL, PWP assumed that the PPA includes battery replacement costs such that the energy of the battery stays the same.[154]

[154] https://atb.nrel.gov/electricity/2022/utility-scale_battery_storage#LJT3875D

Figure 172: Illustration of Degradation Strategies for Battery Storage



17.2. Storage: Over-Generation and Evening Ramps

Storage may help store renewable energy when it is not needed and allow for later use. Storage could help meet evening ramps (perhaps with stored solar energy), which may reduce or replace the need for natural gas generation or market purchases.

In the carbon-free scenarios, natural gas was retired, and storage helped replace its capacity. See Figure 173 for installed storage capacity in 2031. The IRP optimized new resource selection, which in most cases, included storage. Storage helped meet reliability and environmental obligations in a cost-effective manner given scenario assumptions. The IRP itself is a quantitative analysis that helps evaluate the cost effectiveness of multi-hour storage compared to other resources.

Figure 173: Installed Storage Capacity in 2031

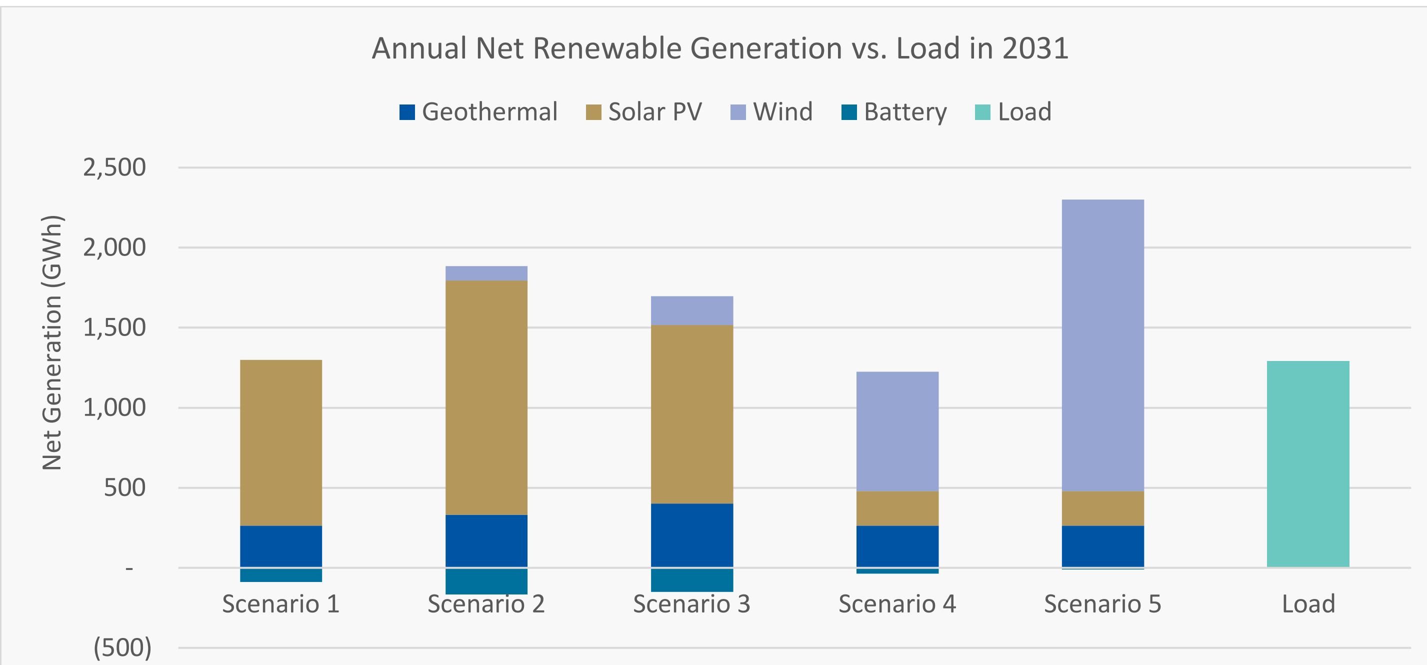
	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Natural Gas/Oil: Combined Cycle				**80**	**80**
Natural Gas/Oil: Combustion Turbine				**132**	**132**
Natural Gas/Oil: Fuel Cell	**115**	**35**	**35**		
New External Fuel Cells		30	30		
New Internal Fuel Cells	115	5	5		
Battery	**305**	**685**	**618**	**150**	**80**
EDF Sapphire Storage	20	20	20	20	20
New 2-Hour Residential Storage			3		
New 4-Hour Commercial Storage		400	350		
New 4-Hour External Storage		70	40		
New 4-Hour Internal Storage	190	190	200	130	60
New 4-Hour Storage (External Solar Paired)			5		

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
New 4-Hr Storage (Internal Solar Paired)	5				
New 4-Hr Storage (Land-Based External Wind Paired)		5			
New 6-Hr Internal Storage	80				
New 8-Hr Internal Storage	10				

RA requirements reflect, in part, the ability of resources to meet peak-hour capacity needs. Storage helps meet PWP's RA requirements.

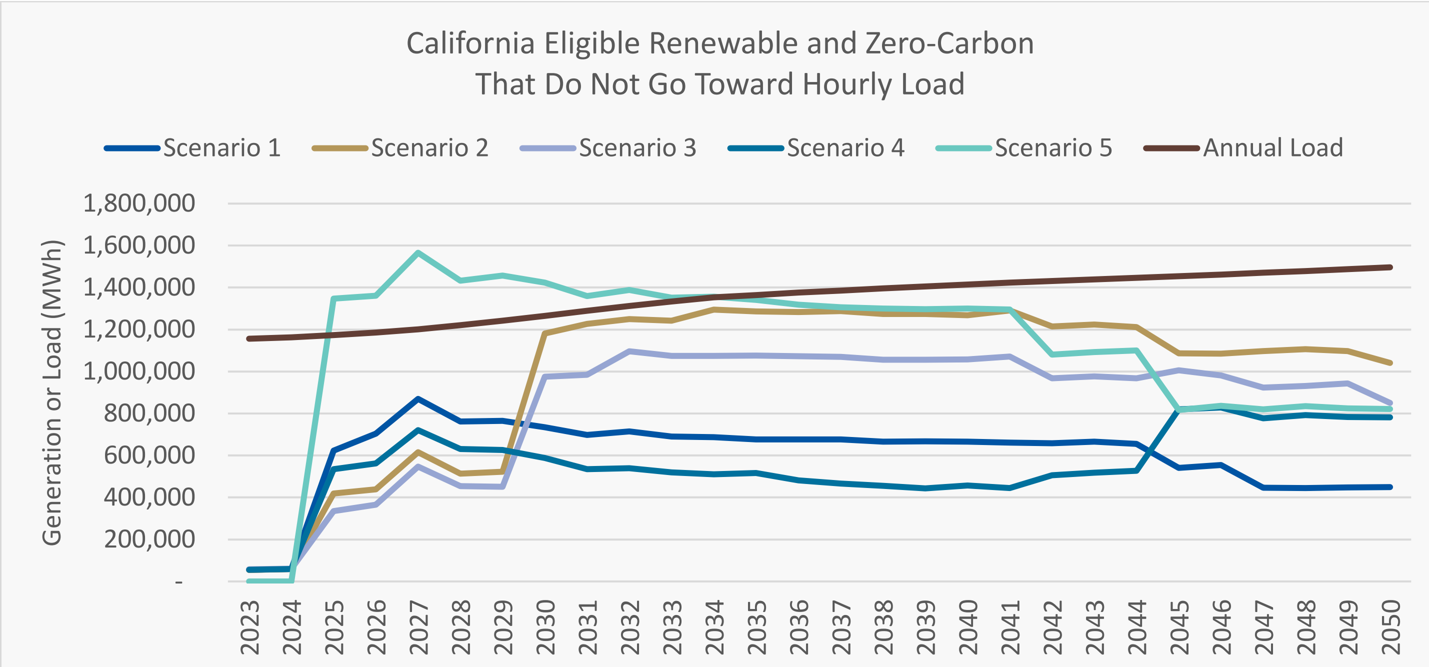
As shown in Figure 174, PWP is producing more energy than needed on an annual basis. Excess could be sold or stored. Batteries are a net consumer of energy due to roundtrip losses. PWP will seek to monitor grid conditions, learn from others, and gain its own experience to understand how excess renewable generation and storage can interact to serve PWP and California customers.

Figure 174: Net Renewable Generation vs. Load in 2031



How much renewable and zero-carbon generation exceeds hourly load? Because PWP is a part of CAISO, allocating what resources go toward load versus elsewhere is a contractual exercise. Post optimization, the amount of California-eligible renewable and zero-carbon energy in excess of hourly load obligations was calculated and summed over the year. Resources were stacked in the order given in Figure 220. See Figure 175 for results.

Figure 175: California Eligible Renewable and Carbon-Free Resources That Do Not Go Toward Hourly



The IRP selected the amount of storage necessary to meet obligations, but PWP is still generating excess. See Figure 176.

Figure 176: PWP is Selling or Curtailing X% of Load in Renewable/Zero-Carbon Resources

PWP is Selling or Curtailing X% of its Load in Renewable/Zero-Carbon Resources	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
2031	56%	98%	79%	44%	110%
2035	50%	94%	79%	38%	98%
2040	47%	90%	75%	32%	92%
2045	37%	75%	69%	56%	56%
2050	30%	70%	57%	52%	55%

PWP will continue to investigate the potential and roles of storage, and how storage could leverage renewable potential.

17.3. Addressing Net Demand in Peak Hours

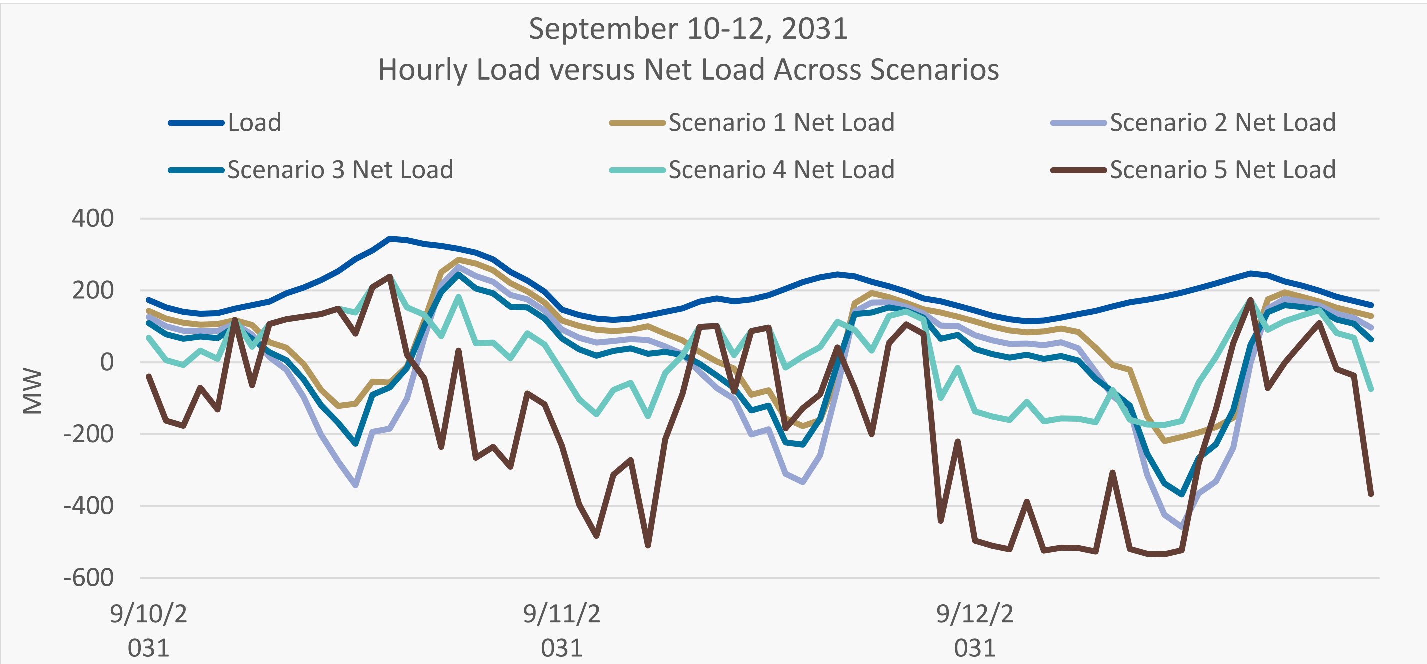
According to the CEC 2018 guidelines, "PUC Section 9621 requires the governing board of a local POU to consider how existing renewable generation, grid operational efficiencies, energy storage, and distributed generation resources, including energy efficiency, will meet energy and reliability needs during the hours of net-peak demand (net of demand met by variable renewable energy resources." The IRP model optimizes to cover obligations, which includes meeting needs during hours of net peak demand through energy and RA obligations.

PWP can consider net peak demand or hourly peak demand minus variable renewable generation. Evaluating September 2031, anywhere from 39% to 65% of hours in the month have negative net peak demand (in other words, hours when wind, solar, and geothermal energy are greater than hourly load). See Figure 177. Figure 178 shows a graphical representation.

Figure 177: Percent of Hours with Negative Net Load in September 2031

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Percent of Hours with Negative Net Load in September 2031	39%	42%	40%	41%	65%

Figure 178: Hourly Load versus Net Load Across Scenarios for Three Days in September 2031



Excess renewable generation that leads to negative net peak demand represents risks and opportunities to the system. PWP may consider further study and investigation of this topic.

18. Financial Impacts

The following sub-sections outline some of the financial implications of the different scenarios.

18.1. Present Value Revenue Requirements

PVRRs are a concept used in IRPs to explain future anticipated costs. PVRR is the current total worth of the expected future revenue requirements associated with a scenario. This IRP analyzes some, but not all, of the cost components involved in PWP's rate structure. Costs in the IRP can be broken into the categories shown in Figure 179.

Figure 179: Components of PVRR

20-Year PVRR (2030 $ in Millions, 2030-2049)	
Expenses ($ in Millions)	
Energy Purchases	Cost of hourly energy purchases from CAISO
Fuel	Cost of natural gas for Glenarm, Magnolia, and IPP
Variable O&M	Variable costs for IPP, Glenarm, and Magnolia; PPA costs; TAC
Fixed O&M	EDF Sapphire Storage capacity charge

20-Year PVRR (2030 $ in Millions, 2030-2049)	
Start Cost	Startup costs for Glenarm
Emissions	REC purchases
Cost of New Resources	PPA costs for new resources
Total Revenue Requirement - Grossed Up	Sum of all expenses
Less: Revenues from Energy and Capacity	Sum of all expenses minus revenue
Energy Revenue ($ in Millions)	Revenue from hourly energy sales to CAISO
Incremental Revenue Requirement	Expenses – energy revenue

The PVRR values for each scenario, under mid, low, and high technology costs, are shown in Figure 180 through Figure 184. Scenarios 1, 2, and 3 have costs associated with an island system and with energy market access.

Figure 180: Scenario 1: PVRR

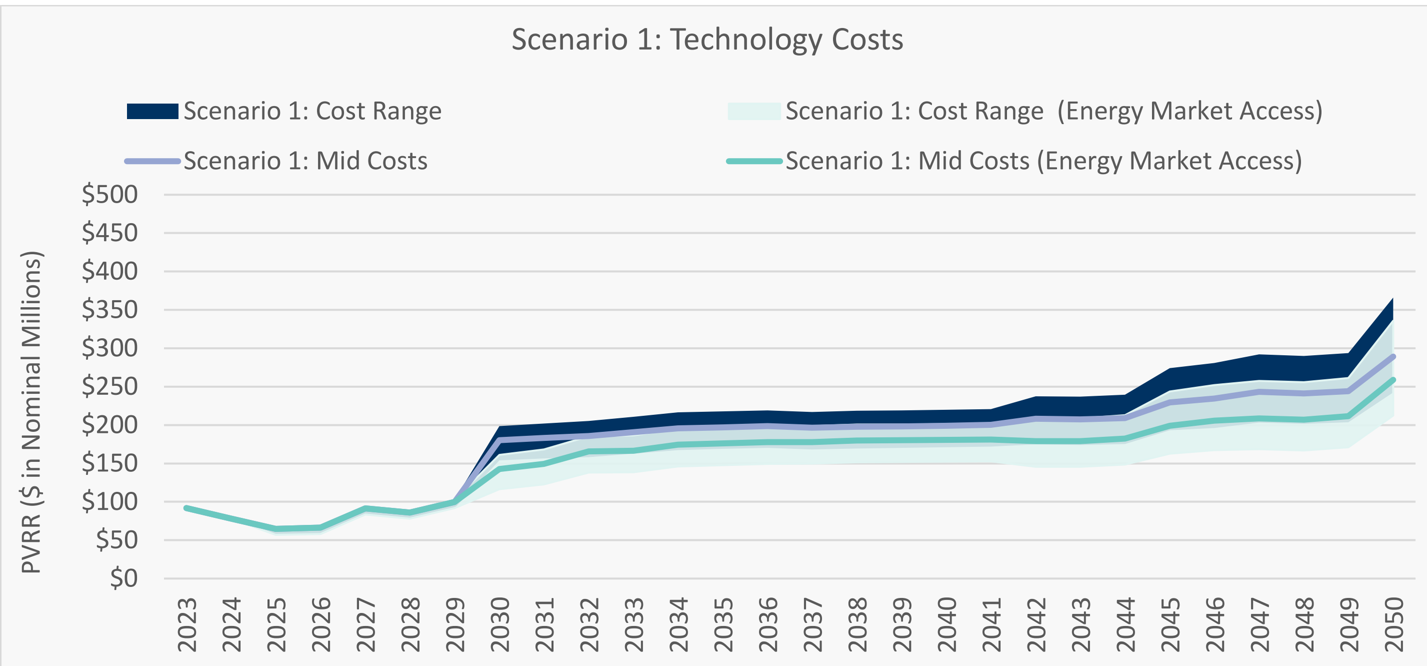


Figure 181: Scenario 2: PVRR

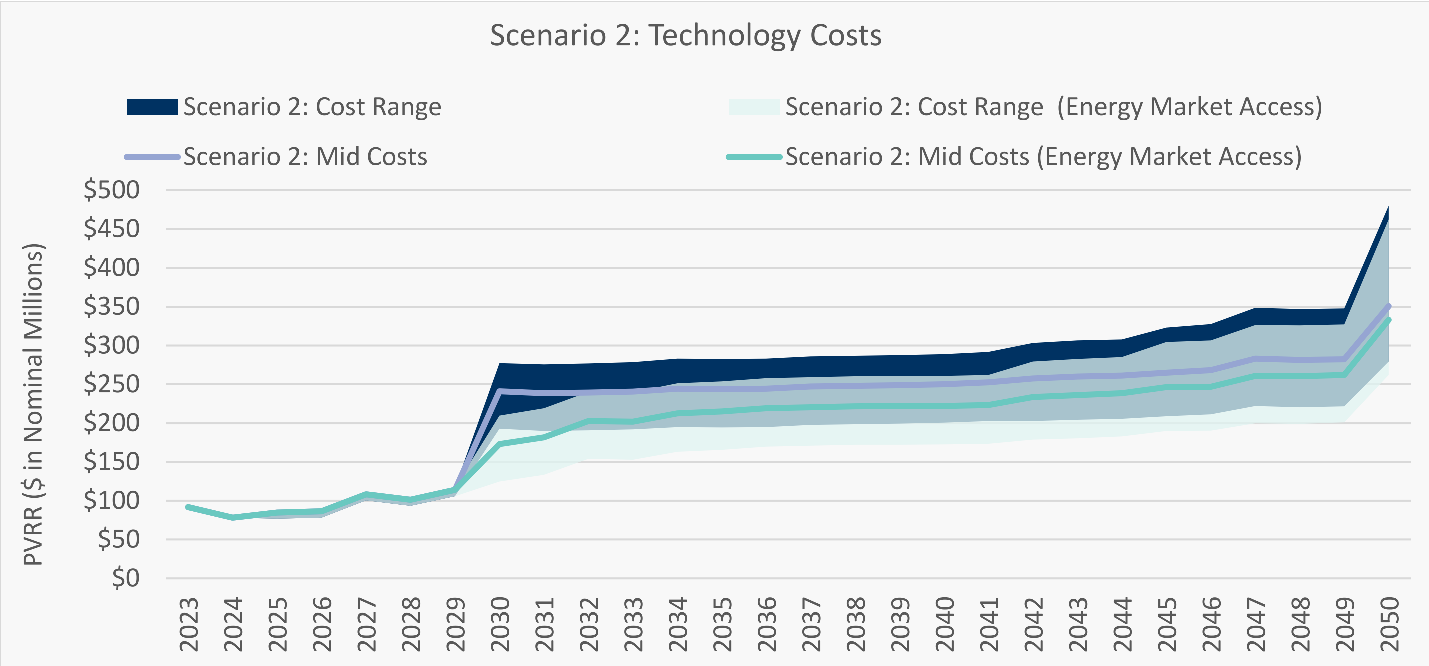


Figure 182: Scenario 3: PVRR

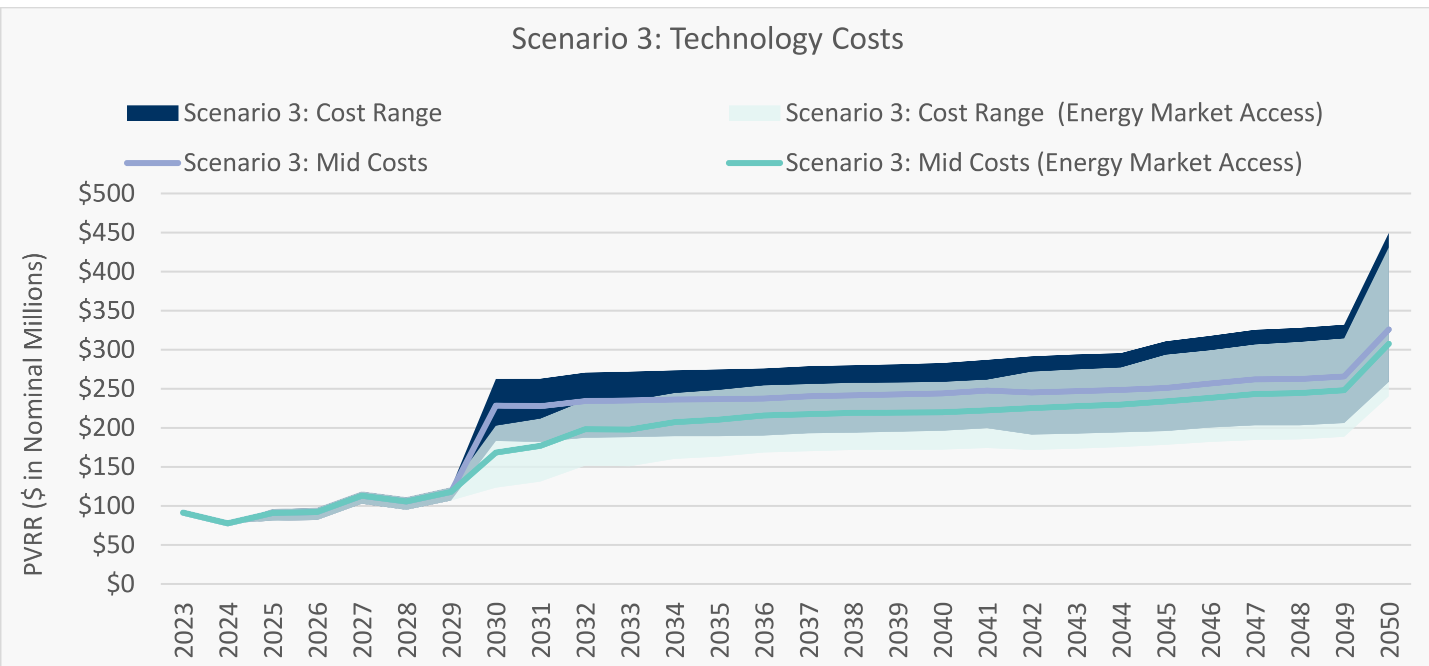


Figure 183: Scenario 4: PVRR

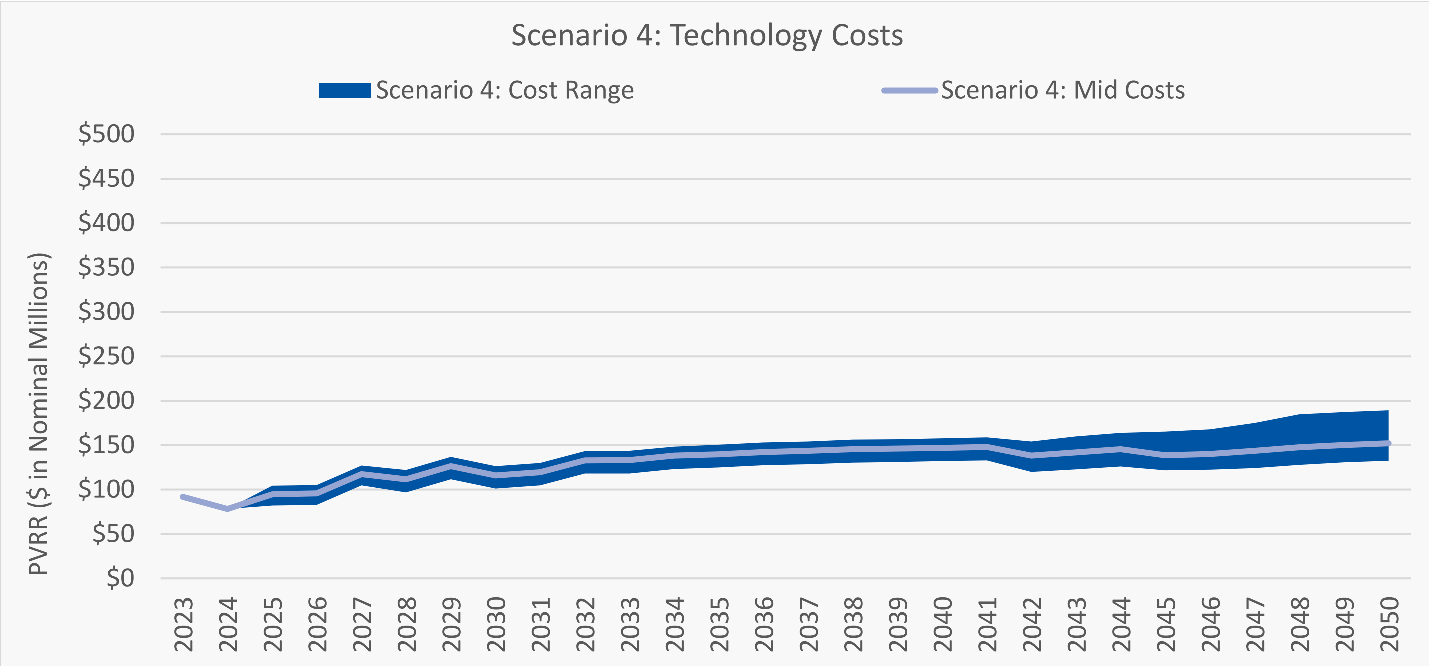


Figure 184: Scenario 5: PVRR

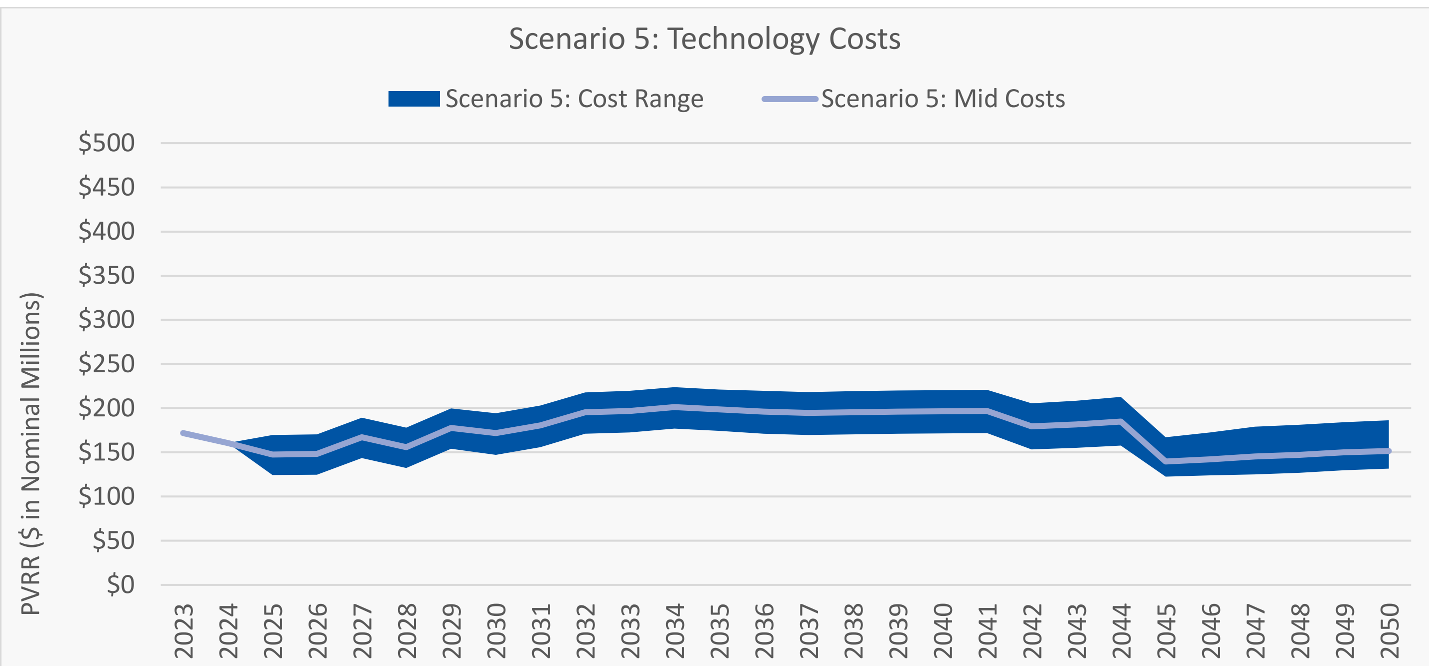


Figure 185 shows the breakdown of costs by type across scenarios.

Figure 185: PVRR By Category Across Scenarios (Mid Costs)

20-Year PVRR (2030 $ in Millions, 2030-2049)								
	Scenario 1: Energy Market Access	Scenario 1: Island	Scenario 2: Energy Market Access	Scenario 2: Island	Scenario 3: Energy Market Access	Scenario 3: Island	Scenario 4	Scenario 5
Expenses ($ in Millions)	$2,611	$2,644	$3,555	$3,289	$3,404	$3,162	$2,080	$2,871
Energy Purchases	$324	$0	$263	$0	$267	$0	$235	$193
Fuel	$5	$362	$1	$16	$1	$36	$76	$11
Variable O&M	$545	$545	$833	$815	$781	$773	$845	$1,087
Fixed O&M	$30	$30	$30	$30	$30	$30	$30	$30
Start Cost	$0	$0	$0	$0	$0	$0	$6	$0
Emissions	$1	$1	$1	$1	$1	$1	$1	$72
Book Depreciation	$1,706	$1,706	$2,426	$2,426	$2,323	$2,323	$887	$1,476
Total Revenue Requirement - Grossed Up	$2,611	$2,644	$3,555	$3,289	$3,404	$3,162	$2,080	$2,871
Less: Revenues from Energy and Capacity								
Energy Revenue ($ in Millions)	$300	$0	$694	$0	$621	$0	$275	$473
Incremental Revenue Requirement	$2,311	$2,644	$2,861	$3,289	$2,782	$3,162	$1,806	$2,398

Overall, the PVRR values (in 2030 dollars) are shown in Figure 186.

Figure 186: PVRRs for Mid, High, Low Costs of New Resources

20-Year PVRR (2030 $ in Millions, 2030-2049)	Low Costs	Mid Costs	High Costs
Scenario 1 (Island System)	2,247	2,644	2,982
Scenario 1 (Energy Market Access)	1,915	2,311	2,650
Scenario 2 (Island System)	2,614	3,289	3,855
Scenario 2 (Energy Market Access)	2,186	2,861	3,427
Scenario 3 (Island System)	2,512	3,162	3,722
Scenario 3 (Energy Market Access)	2,132	2,782	3,342
Scenario 4	1,596	1,806	2,001

20-Year PVRR (2030 $ in Millions, 2030-2049)	Low Costs	Mid Costs	High Costs
Scenario 5	2,084	2,398	2,725

Figure 187 shows the percent increase in costs compared to Scenario 4. Costs increase in the carbon-free scenarios between 28% and 82%.

Figure 187: Percent Costs are Higher in 20 Years Compared to Scenario 4 (Reference Costs)

Percent Costs are Higher in 20 Years Compared to Scenario 4 (Reference Costs)		
20-Year PVRR (2030 $ in Millions, 2030-2049)	Energy Market Access	Island System
Scenario 1	28%	46%
Scenario 2	58%	82%
Scenario 3	54%	75%
Scenario 4	0%	
Scenario 5	33%	

These PVRR costs can be translated into cents per kWh of load served. This can show the costs incurred on top of Scenario 4. See Figure 188.

Figure 188: 2030 $/kWh Costs in Addition to Scenario 4

	Scenario 1		Scenario 2		Scenario 3		Scenario 5
	Energy Market Access	Island	Energy Market Access	Island	Energy Market Access	Island	
2030, $/kWh, 2030 - 2049	$2.77	$4.62	$5.80	$8.21	$5.37	$7.51	$3.33

18.2. Scenario 3 and Distributed Resources

Expected distributed resource deployment is in the load forecast. Those resources are customer-financed resources given business as usual. Resources installed in addition to PWP's load forecast are resources that would require additional incentives from various potential sources. Scenario 3 forced some distributed resources online. The costs of the resources forced online in Scenario 3 are shown in Figure 189. From 2030 through 2049, there is almost $1.4 billion (in 2030 dollars) in costs for these resources.

Figure 189: Costs of Forced Distributed Energy Resources in Scenario 3

Distributed Resource Costs Forced Online	Residential Solar	Commercial Solar	Residential Storage	Commercial Storage
10-Year PVRR (2023 $ in Millions, 2023-2032)	$82.97	$62.37	$21.11	$8.36
20-Year PVRR (2023 $ in Millions, 2023-2042)	$292.34	$247.51	$120.87	$47.23
28-Year PVRR (2023 $ in Millions, 2023-2050)	$418.32	$406.03	$214.01	$105.34
20-year PVRR (2030 $ in Millions, 2030-2049)	$495.33	$479.19	$263.51	$126.42

The costs of the additional distributed resources represent 17% to 23% of the scenario costs in 2030, and 51% to 54% of the scenario costs by 2050.

18.3. Scenario 5 and the Carbon Tax

Scenario 5 assumes that resources that contain carbon (fossil, landfill gas, and CAISO market purchases) are charged a carbon tax based on the EPA's social cost of carbon under a 1.5% discount rate. See Scenario 5: Reference Case + Social Cost of Carbon (SB 1020 + SCC). Scenario 5 optimized new resource builds and resource operations under a carbon tax.

PWP, as a participant of CAISO, needs to follow the rules and regulations of CAISO's tariff; there are rules and regulations regarding how resources can bid into the CAISO markets. These rules exist to prevent manipulation or misuse of market power. PWP would need to further investigate how its carbon preferences would not fall afoul of the CAISO tariff.

Furthermore, CAISO prices carbon through the following three mechanisms at minimum:

- Renewable portfolio standard under SB 100
- Renewable and zero-carbon requirements under SB 1020
- Cap-and-trade regulations under CARB

Any additional pricing of carbon into PWP's rates may be considered as non-cost based. Therefore, that could be a tax, which, under Proposition 26, must be approved by a two-thirds vote of the residents of Pasadena.

Revenue from a carbon tax may be returned to consumers or used to support other activities. The carbon tax, and resulting scenario costs, are given in Figure 190.

Figure 190: Costs of Carbon Tax in Scenario 5

Nominal Millions	Carbon Tax	Scenario 5	Scenario 5 (Carbon Tax Returned)
2023	$64.2	$172.0	$107.8
2024	$70.7	$160.7	$90.0
2025	$47.5	$147.5	$100.0
2026	$38.4	$148.2	$109.8
2027	$25.3	$167.3	$142.0
2028	$12.5	$155.9	$143.4
2029	$10.9	$177.7	$166.8
2030	$12.6	$171.7	$159.2
2031	$10.7	$180.5	$169.8
2032	$12.1	$195.4	$183.3
2033	$12.3	$197.0	$184.6
2034	$12.6	$201.3	$188.7
2035	$11.5	$198.7	$187.2
2036	$4.6	$196.1	$191.5
2037	$0.9	$194.7	$193.8
2038	$0.9	$195.6	$194.6
2039	$1.0	$196.2	$195.1

Nominal Millions	Carbon Tax	Scenario 5	Scenario 5 (Carbon Tax Returned)
2040	$0.9	$196.5	$195.6
2041	$0.8	$196.9	$196.1
2042	$0.9	$179.5	$178.6
2043	$0.8	$181.5	$180.7
2044	$0.5	$184.7	$184.3
2045	$0.0	$139.7	$139.7
2046	$0.0	$142.3	$142.3
2047	$0.0	$145.5	$145.5
2048	$0.0	$147.3	$147.3
2049	$0.0	$150.1	$150.1
2050	$0.0	$151.6	$151.6

Resulting comparisons are in Figure 191.

Figure 191: Present Value Revenue Requirement if Carbon Tax Returned

20-Year PVRR (2030 $ in Millions, 2030-2049)	Mid Costs
Scenario 1 (Island System)	$2,644
Scenario 1 (Energy Market Access)	$2,311
Scenario 2 (Island System)	$3,289
Scenario 2 (Energy Market Access)	$2,861
Scenario 3 (Island System)	$3,162
Scenario 3 (Energy Market Access)	$2,782
Scenario 4	$1,806
Scenario 5	$2,398
Scenario 5 (Carbon Tax Returned)	$2,326

18.4. Scenarios and Cap-and-Trade Interactions

The 2023 IRP designed the scenarios to remain under PWP's allocated allowances. PWP could sell excess allowances. Using low, mid, and high estimates of GHG allowances from the 2022 IEPR shown in Figure 192, scenarios could generate additional savings shown in Figure 193.

Figure 192: Carbon Allowance Sale Prices

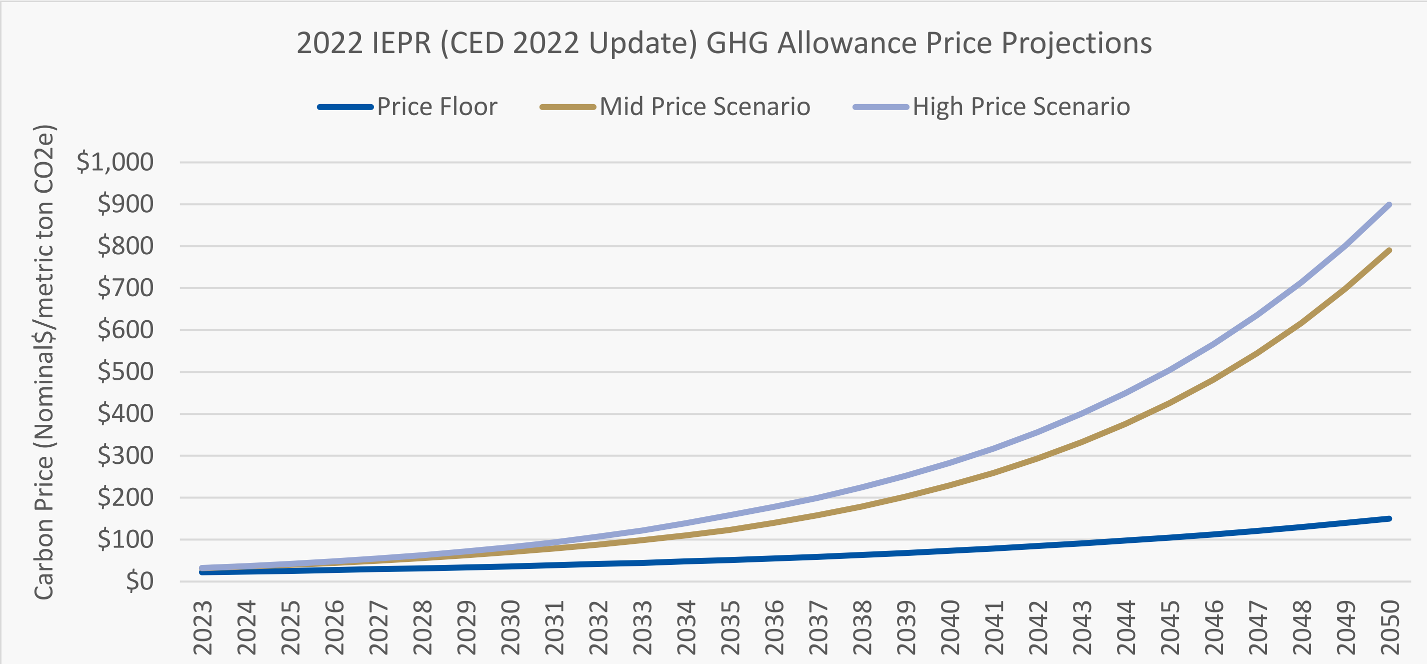


Figure 193: PVRR with Cap-and-Trade Allowance Sales

20-Year PVRR (2030 $ in Millions, 2030-2049)	No Return	Return Price Floor	Return Mid Case	Return High Case
Scenario 1 (Energy Market Access)	2,311	2,218	2,076	2,021
Scenario 1 (Island System)	2,644	2,551	2,408	2,353
Scenario 2 (Energy Market Access)	2,861	2,768	2,625	2,570
Scenario 2 (Island System)	3,289	3,196	3,053	2,998
Scenario 3 (Energy Market Access)	2,782	2,689	2,547	2,492
Scenario 3 (Island System)	3,162	3,069	2,927	2,872
Scenario 4	1,806	1,754	1,679	1,649
Scenario 5	2,398	2,309	2,172	2,119

Overall, Scenario 4 remains the lowest cost. If excess credits under the Cap-and-Trade Program are sold at the price floor, cost increases over Scenario 4 range from 26% to 82%. If estimates of allowances are high, other scenarios become 23% to 82% more costly than Scenario 4.

19. Retail Rates

PWP power resources staff worked closely with PWP finance staff to consider the impact the IRP will have on retail rates for PWP customers. Model outputs provided by the consultant, coupled with additional analysis by PWP staff, were used to develop the cost and rate analysis for the rate components impacted by the IRP. The IRP will increase the rates for customers. As a non-profit, publicly owned utility, rates sustain and reinvest in the operations.

The overall financial impact of the IRP will be fully evaluated after adoption and incorporated into a cost-of-service study expected to begin in 2024.

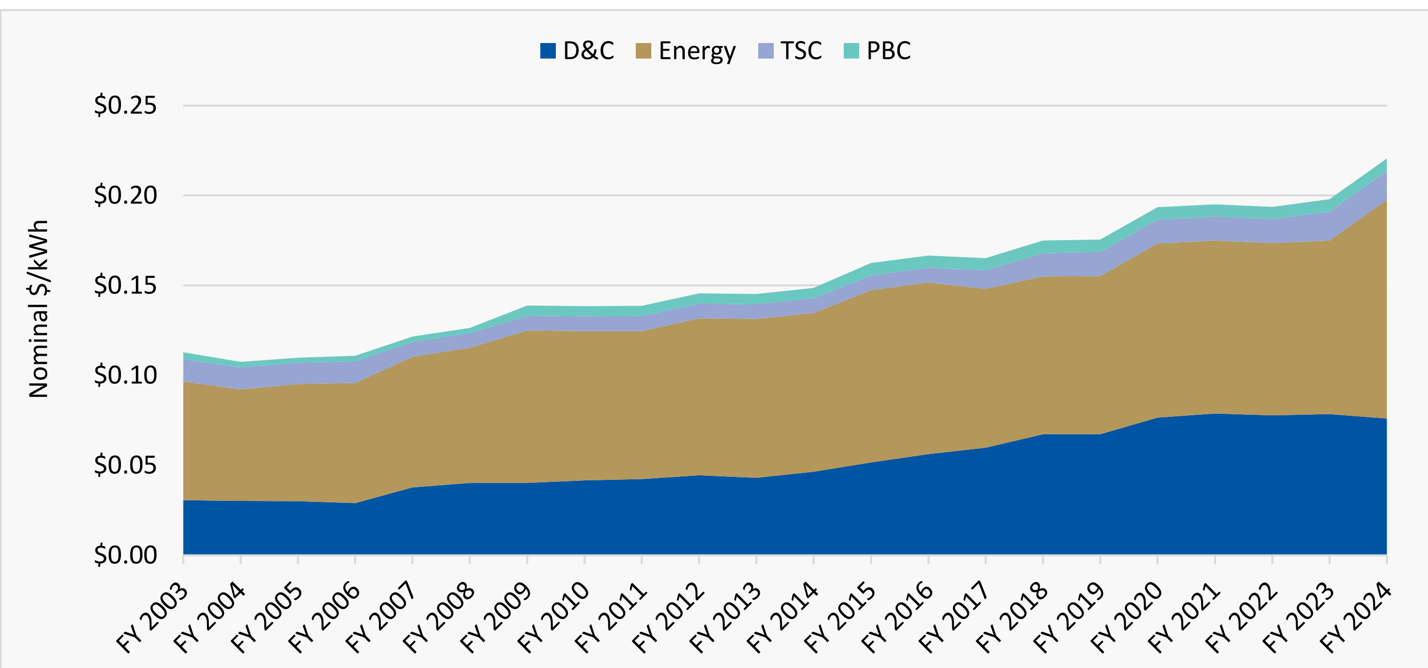
PWP's retail rates primarily consist of the following components:

- *Customer Charge* - A flat fee to recover costs associated with billing metering, customer service and PWP's call center.
- *Distribution Charge* – A volumetric charge to recover the cost of delivering electricity from substations to customers. It includes operation and maintenance, capital investment and debt service.
- *Grid Access Charge* – A flat fee to recover fixed costs associated with the electric grid.
- *Transmission Services Charge* ("TSC") - A volumetric charge to recover costs of delivering electricity from generating plants to sub-stations.
- *Public Benefit Charge* ("PBC") – A volumetric charge to provide funding for incentive and rebate programs for energy efficiency, local solar programs, demand side management and low-income assistance.
- *Energy Services Charge* ("ESC") – A volumetric charge to recover the costs to procure and generate electric resources.

Prior to July 2014, the Distribution and Customer Charge ("D&C") was a combined charge. The charge was separated into two components beginning in July 2014. A Grid Access Charge was implemented in July 2019. The following figures include these three charges combined to illustrate rate trends.

Figure 194 depicts PWP's historical and budgeted rates from 2003 through 2024. Figure 195 shows the breakdown of the rates by percent of total.

Figure 194: PWP Historical and Budgeted Retail Rates (Nominal Dollars per kWh)



The primary focus of the IRP is the energy component of the rate (the ESC) and, particularly, a subset of that energy component that relates to energy production and market purchases and sales. Historically, the costs considered in the IRP represent about 57% of the total costs in the energy rate.

Figure 195: PWP Retail Rate Components as Percent of Total

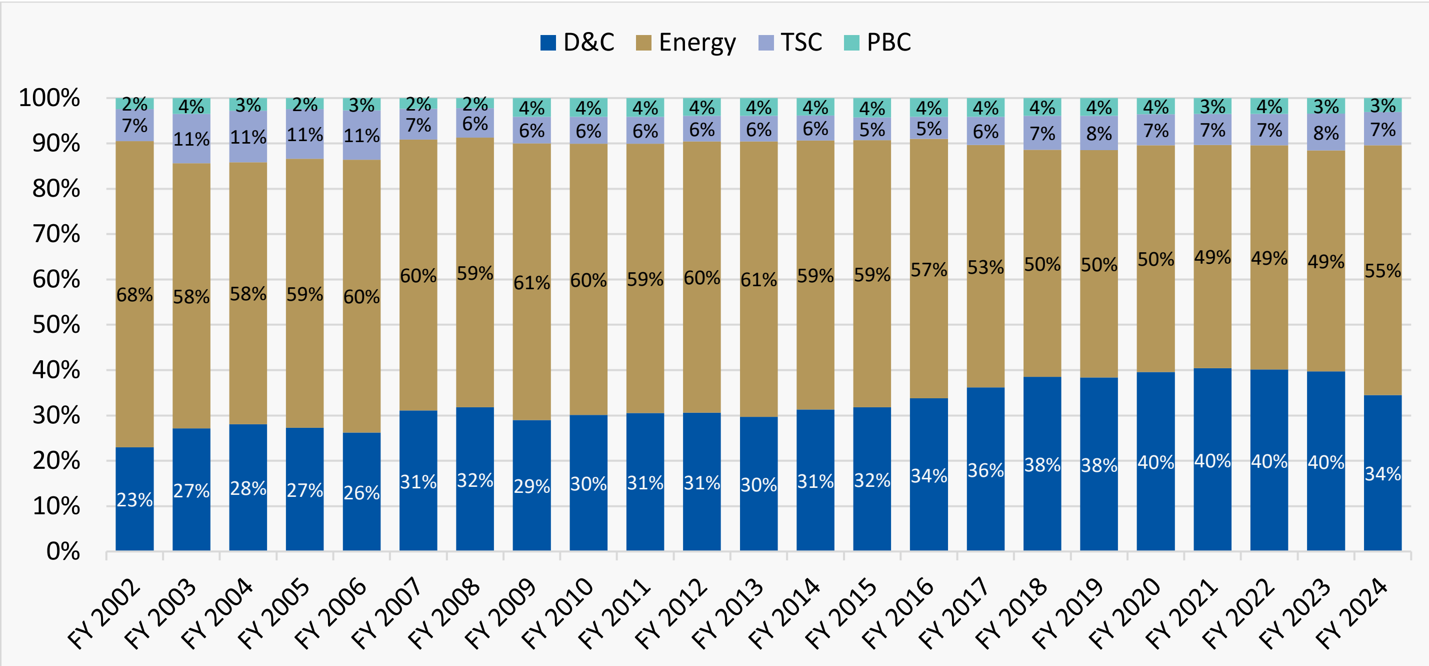


Figure 196 shows the various rate components that are included and excluded in the IRP modeling.

Figure 196: Costs Included and Excluded from IRP Modeling

Included	Excluded

• Fuel costs
• Variable costs
• PPA costs
• TAC costs
• Costs of new resources
	• Congestion costs experienced by resources
	• Other CAISO fees
	• Costs from distribution programs
	  ◆ Distribution cost increases
	  ◆ Transmission cost increases
	• Costs from PWP people operations

There is a significant amount of uncertainty in all rate projections, and a multitude of factors could change the outcome, including, but not limited to, the following for the ESC:

- Procurement costs
  - PPA and/or resource acquisition costs associated with new resources added in each portfolio could be higher or lower than projected.
- Congestion costs
  - If PWP needs to add resources outside its internal load area, PWP could be exposed to congestion costs if PPAs are settled as the busbar of a particular resource. These costs are not included in the IRP.
- Load forecasts

- Changing residential and commercial load patterns could emerge, which would change the resulting resource mix needed.

For the other components of retail rates, that were not studied in this report:

- Distribution and transmission costs
    - Additional costs associated with distribution and transmission beyond the rate of inflation are not considered in this analysis.
    - In 2022, the Power Delivery Master Plan (PDMP) was adopted, with investments totaling $821 Million identified as needed by 2042.
        - These nominal figures do not include the fact that 2021 costs were used, which was prior to increasing costs due to inflation and supply chain issues.
        - The PDMP was also prior to this IRP which includes investments that were not considered or are requiring more projects to be implemented on a tighter timeline. The PDMP was completed prior to the IRP, so feasibility of implementation was not considered nor the impact on the pricing of construction.
    - One such factor is that the IRP calls for extra capital investments required for electrical distribution system support of battery storage infrastructure.
    - CAISO, as the primary infrastructure planner for the state has a proactive approach to meet California's long-term clean energy goals that calls for investments of $7.3 Billion in the approved 2022-2023 Transmission Plan[155]. These investments will have an additive impact to customer rates.
- Other costs
    - Other operating cost to be considered are the finance, administration, information technology and customer service components of expenses.
    - Cost of future debt financing and credit risk.

The tables below show estimated impacts and are intended to provide a sense of the financial implications to the utility and customers based on each scenario. The amounts shown are provided for illustrative purposes only and represent "just in time" rates that would be needed for the different "moderate" and "high" costs in order to recover costs. Varying rate structures, capital financing plans, and rate offsets (such as grant funding) will all be actively pursued but cannot confidently be projected and as such are not included in this analysis.

The Energy Charge projections are based on single-family residential customers on an annual basis. The projections assume usage of 500 kWh per month (6,000 kWh annually). Rates will accelerate during the first seven years of the plan due to cost recovery associated with the compressed timeline and will remain elevated after 2030 to support the portfolio costs.

[155] https://www.caiso.com/Documents/caiso-2022-2023-transmission-plan-approved.pdf

Figure 197: Annual Bill Impacts for Single-Family Residential Customers (Moderate Cost Estimates)

Scenario	Power Supply NPV Moderate Cost ($ in Billions)	Current Energy Charge Portion of Customer Bill in 2023 ($/single family residential customer, Annualized)	Energy Charge Portion of Customer Bill in 2030 ($/single-family residential customer, Annualized)	% Change in Energy Charge Portion of Customer Bill from 2024 to 2030	Energy Charge Portion of Customer Bill in 2045 ($/single family residential customer, Annualized)	% Change in Energy Charge Portion of Customer Bill from 2024 to 2045
1	$2.456	$836.12	$1,254.18	50%	$1,367.06	64%
2	$3.003	$836.12	$1,596.99	91%	$1,549.08	85%
3	$2.926*	$836.12	$1,530.10	83%	$1,484.20	78%
4	$1.937	$836.12	$1,153.85	38%	$1,061.54	27%
5	$2.426	$836.12	$1,588.63	90%	$1,429.77	71%

**The total power supply Net Present Value ("NPV") moderate cost in the table above for Scenario 3 includes the cost of doubling the growth of distributed solar and storage from the load forecast in the amount of $632.33 million. All Scenarios studied in the 2023 IRP have included an embedded Distributed Energy Resource ("DER") growth rate built into the load forecast. Scenario 3 takes this natural growth rate and doubles to study the value of DERs. The IRP modeling captures the estimated costs as they are an additional cost, regardless of the funding source.*

Figure 198: Annual Bill Impacts for Single-Family Residential Customers (High-Cost Estimates)

Scenario	Power Supply NPV High Cost ($ in Billions)	Energy Charge Portion of Customer Bill in 2023 ($/single family residential customer, annualized)	Energy Charge Portion of Customer Bill in2030 ($/single-family residential customer, annualized)	% Change in Energy Charge Portion of Customer Bill from 2024 to 2030	Energy Charge Portion of Customer Bill in 2045 ($/single family residential customer, annualized)	% Change in Energy Charge Portion of Customer Bill from 2024 to 2045
1	$2.728	$836.12	$1,354.52	62%	$1,584.78	90%
2	$3.453	$836.12	$1,806.02	116%	$1,824.08	118%
3	$3.378	$836.12	$1,722.41	106%	$1,774.08	112%

Scenario	Power Supply NPV High Cost ($ in Billions)	Energy Charge Portion of Customer Bill in 2023 ($/single family residential customer, annualized)	Energy Charge Portion of Customer Bill in2030 ($/single-family residential customer, annualized)	% Change in Energy Charge Portion of Customer Bill from 2024 to 2030	Energy Charge Portion of Customer Bill in 2045 ($/single family residential customer, annualized)	% Change in Energy Charge Portion of Customer Bill from 2024 to 2045
4	$2.127	$836.12	$1,220.74	46%	$1,196.32	43%
5	$3.057	$836.12	$1,722.41	106%	$1,205.69	44%

Given that the costs in the IRP are higher than what is currently in the Light & Power Fund Financial Plan, customer retail rates will need to increase to meet the additional revenue requirements. Figures 196 and 197 represent the Energy Charge, just one component of the rates that customers pay for electricity. Other components recover costs for transmission of power to the PWP service area, distribution inside of the service area, customer service, administration, and other factors. All facets of the enterprise require revenue increases to address cost factors such as inflation, high demand, limited supply, supply chain issues, and a competitive job market.

While a full cost-of-service analysis will give more certainty on the exact rate impact, it is possible that bill amounts may double. The current rate is in the 20 ¢ per kWh range and doubling would result in 40 ¢+ in the planning time horizon. By looking at just the Energy Charge in this report, customer will likely see bill in increases in the double digits. Looking to other utilities, who have done full cost analyses and have less ambitious plans and longer lead times, doubling retail rates may also be on the lower end of the spectrum.

20. Greenhouse Gas Emissions

PWP can express its carbon impacts across multiple dimensions, as follows:

- Cap-and-Trade
- Carbon Emissions Netting Market Interactions at CAISO Average Carbon Content
- RPS (SB 100, SB 1020)
- Renewable and Zero-Carbon (SB 1020)
- Carbon-Free (City of Pasadena Resolution 9977)
- Greenhouse gas Emissions Accounting Table (GEAT)

The CEC requirements reference how PUC Section 9621 require POUs to adopt IRPs that ensure the utility achieves specific goals and targets by 2030, including meeting CARB and RPS requirements. PWP exceeds its obligations under both programs as shown in its IRP modeling. PWP seeks to procure renewable energy in excess of requirements to meet its goals for Resolution 9977. There are various factors that may enable or prevent excess renewable energy procurement, including, but not limited to, the following:

- Resource cost and type
- Resource location and transmission congestion considerations
- Competition on supply or demand side
- Resource timing and implications for rates

20.1. Cap-and-Trade Program

This IRP ensures that the utility meets, by 2030, the GHG emissions reduction targets established under the Cap-and-Trade Program, which is regulated through CARB. Post 2030, the carbon-free scenarios have no fossil emissions. See Figure 199. The model optimizes for PWP to operate under its allowance cap and is an assumption included in all scenarios.

Figure 199: Cumulative Emissions Under Cap-and-Trade Program

	Scenario					
	1	2	3	4	5	Carbon Cap
Cumulative Million Metric Tons Emitted (2030 – 2049)	-	-	-	1.00	0.12	2.30

Emissions covered under the Cap-and-Trade Program include the emissions from Glenarm, Magnolia, and IPP.

20.2. Carbon Emissions Netting Market Interactions at CAISO Average Carbon Content

Cap-and-Trade Program allowances are used to cover emissions for the Glenarm, IPP, and Magnolia resources. PWP's portfolio also includes two other sources of carbon that are not a part of the Cap-and-Trade Program modeling, specifically, two landfill gas contracts, which will expire in 2030, and spot market purchases.

There are different ways to think about PWP's total carbon emissions, inclusive of other factors like landfill gas or market purchases that are not covered in the Cap-and-Trade Program. If PWP considers emissions from landfill gas and credits the net of market purchases and sales at the emission intensity of the CAISO market (previously provided in Figure 91), then total emissions could look like Figure 200. Sales (particularly for Scenario 5) create this effect.

Figure 200: Cumulative Portfolio Emissions Netting CAISO Purchases and Sales

2030-2049	Million Metric Tons Emitted from Portfolio	Net Generation (GWh) in Portfolio	Purchases (GWh)	Sales (GWh)
Scenario 1 (Island)	0.00	27,989	0	0
Scenario 1 (Energy Market Access)	0.25	25,403	11,532	8,946
Scenario 2 (Island)	0.00	27,989	0	0
Scenario 2 (Energy Market Access)	0.46	38,022	9,410	19,443
Scenario 3 (Island)	0.00	27,989	0	0
Scenario 3 (Energy Market Access)	0.18	35,170	10,091	17,271
Scenario 4	1.11	29,580	8,188	9,779

2030-2049	Million Metric Tons Emitted from Portfolio	Net Generation (GWh) in Portfolio	Purchases (GWh)	Sales (GWh)
Scenario 5	0.15	43,346	6,495	21,852

If PWP sells the RECs, it may not be able to claim the carbon reduction or renewable energy attributes. Claims must be cautiously made in accordance with regulations and best practices.

Scenario 4 has the lowest cost, with emissions forecasted to be 90% below 1990 thresholds by 2030. PWP can calculate the price for carbon avoided above the carbon reductions found in Scenario 4. The carbon avoided could refer to the carbon avoided under the Cap-and-Trade Program or to the carbon avoided if net market interactions were credited at CAISO's average emission rate. PWP pays between $503/metric ton and $1,616/metric ton to avoid carbon. See Figure 201.

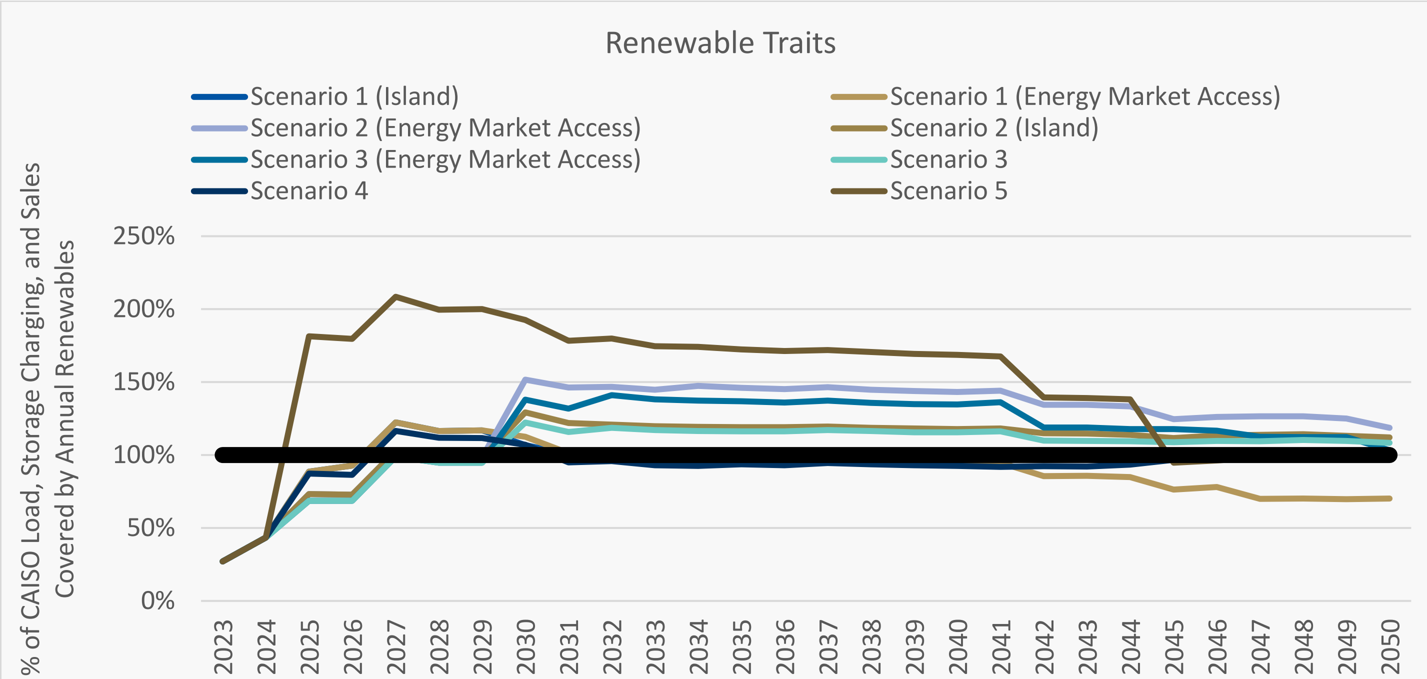
Figure 201: Cost of Avoided Carbon

2030 $/Metric Ton of Carbon (2030 – 2040)	Scenario 1 (Island)	Scenario 1 (Energy Market Access)	Scenario 2 (Island)	Scenario 2 (Energy Market Access)	Scenario 3 (Island)	Scenario 3 (Energy Market Access)	Scenario 5
Using Cap-and-Trade Incremental Avoided Carbon	$835	$503	$1,477	$1,050	$1,351	$972	$669
Netting Market Purchases at CAISO Emission Rate Incremental Avoided Carbon	$756	$592	$1,338	$1,616	$1,223	$1,053	$618

20.3. RPS (SB 100)

Examining the load, sales, and storage charging on the CAISO level (which is the level of modeling in the 2023 IRP) that are met with renewable resources, PWP exceeds 100% clean energy across all scenarios by 2030. See Figure 202.

Figure 202: Renewable Traits



Label #14 on the RPS Procurement Table (RPT) shows the over/under procurement for compliance periods 4. PWP acquires RECs in excess of its obligations under these scenarios. PWP would need purchases prior to 2025, which is the first year that new resources can be installed in the model. See Figure 203.

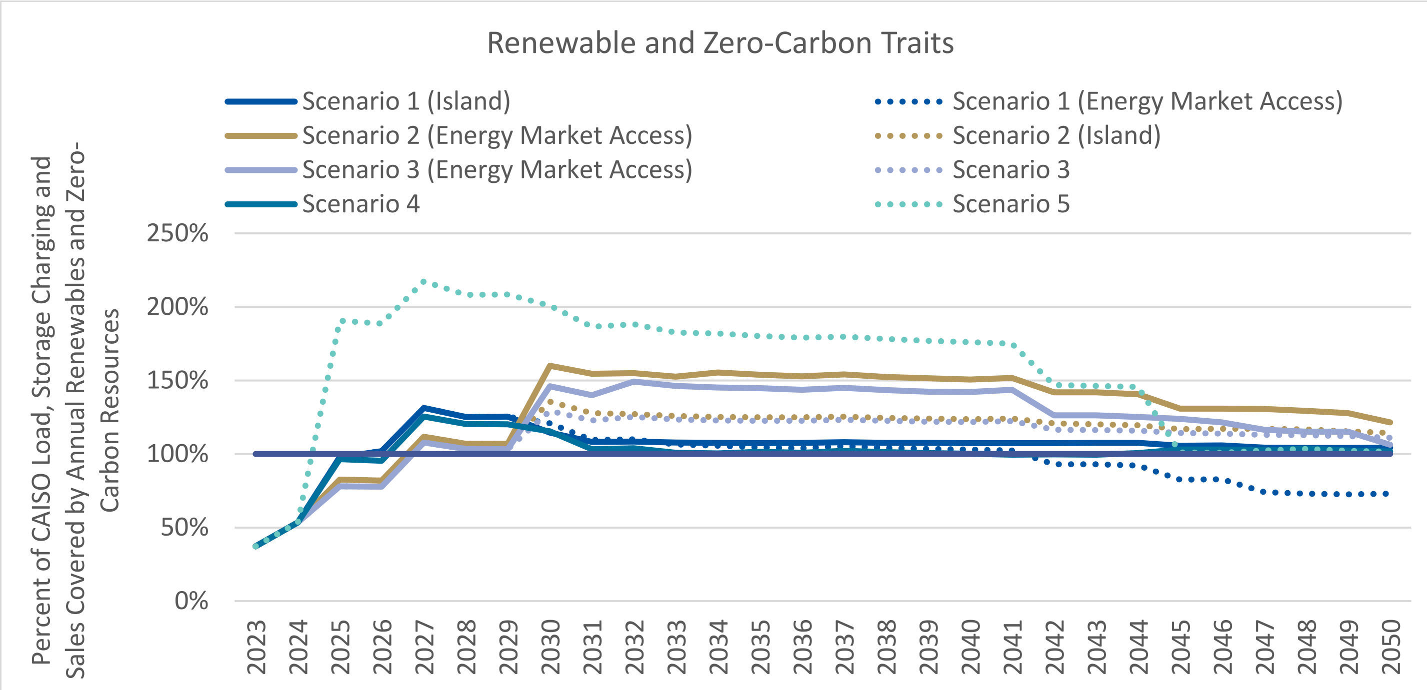
Figure 203: Over/under procurement for compliance period (MWh)

Over/Under Procurement for Compliance Period (MWh)					
	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
2021-2024	(121,488)	(121,488)	(121,488)	(121,488)	(121,972)
2025-2027	1,921,321	1,272,450	1,119,924	1,761,458	5,075,959
2028-2030	2,244,856	2,286,662	2,022,649	2,054,884	5,302,369

20.4. Renewable and Zero-Carbon (SB 1020)

Examining the load, sales, and storage charging on the CAISO level (the level of modeling in the 2023 IRP) that are met with renewable and zero-carbon resources, PWP exceeds 100% clean energy across all scenarios by 2045. See Figure 204.

Figure 204: Renewable and Zero-Carbon Traits



20.5. Carbon-Free Hourly (Resolution 9977)

Scenarios 1, 2, and 3 achieve zero-carbon on an hourly basis without offsets under normal operating conditions by the end of 2030, while Scenario 4 and Scenario 5 exceed 100% clean energy and achieve 62% and 81% of hours in a year with carbon-free energy, respectively. See Figure 205.

Figure 205: Hourly-Carbon-Free Achievements

Percent Zero-Carbon (Hourly) (%)					
	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
2023	17%	17%	16%	17%	21%
2024	16%	16%	16%	16%	20%
2025	34%	36%	39%	40%	64%
2026	32%	34%	37%	38%	62%
2027	49%	51%	52%	55%	76%
2028	53%	55%	56%	59%	80%
2029	54%	55%	57%	60%	80%
2030	96%	97%	97%	60%	78%
2031	**100%**	**100%**	**100%**	**62%**	**81%**

20.6. GEAT

Labeled as #12 on the GEAT, adjusted portfolio emissions in million metric tons of CO2e is shown in Figure 206. The GEAT credits storage charging and market purchases at the emissions intensity of 0.428 Mt CO2e/MWh, which is the value CARB uses for unspecified power imported from out of state.

Procurement in excess of requirements could lead to emissions reductions for the grid as a whole.

Figure 206: Adjusted Portfolio emissions

Adjusted Portfolio Emissions (million metric tons of CO2e)					
Year	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
2023	**0.51**	0.51	0.52	0.51	0.40
2024	**0.53**	0.53	0.54	0.53	0.41
2025	**0.13**	0.21	0.24	0.14	(0.40)
2026	**0.07**	0.18	0.20	0.11	(0.43)
2027	**(0.05)**	0.05	0.08	(0.02)	(0.57)
2028	**(0.01)**	0.09	0.12	0.05	(0.52)
2029	**(0.01)**	0.10	0.12	0.05	(0.53)
2030	**0.17**	0.18	0.21	0.08	(0.49)
2031	**0.20**	0.17	0.20	0.11	(0.45)
2032	**0.21**	0.16	0.15	0.10	(0.47)
2033	**0.22**	0.16	0.16	0.12	(0.44)
2034	**0.22**	0.13	0.15	0.12	(0.45)
2035	**0.22**	0.12	0.14	0.11	(0.44)
2036	**0.20**	0.07	0.10	0.10	(0.44)
2037	**0.18**	0.04	0.07	0.09	(0.45)
2038	**0.18**	0.05	0.08	0.09	(0.44)
2039	**0.19**	0.06	0.09	0.10	(0.44)
2040	**0.19**	0.05	0.07	0.10	(0.43)
2041	**0.18**	0.03	0.05	0.10	(0.43)
2042	**0.26**	0.08	0.16	0.10	(0.25)
2043	**0.26**	0.09	0.17	0.12	(0.23)
2044	**0.27**	0.09	0.17	0.11	(0.22)
2045	**0.33**	0.14	0.16	0.10	0.10
2046	**0.32**	0.13	0.16	0.09	0.11
2047	**0.37**	0.13	0.19	0.09	0.10
2048	**0.40**	0.17	0.23	0.10	0.10
2049	**0.40**	0.17	0.23	0.11	0.11
2050	**0.39**	0.21	0.29	0.11	0.11
Total	**6.50**	**4.09**	**5.06**	**3.50**	**(7.09)**

21. Implementation Steps – Carbon-Free Pathways

In any future resource portfolio, PWP will be required to fill the gap between its current resources and the forecasted quantitative performance requirement associated with each resource attribute (specifically, energy supply, RA, and renewable carbon-free energy content). PWP's challenge will be to augment its portfolio with additional procured and owned resources of various technologies that will fill all three gaps simultaneously, yet cost-effectively.

The 2023 IRP provides the technical objectives, data, information, and pathways needed to achieve 100% carbon-free energy supply by 2030. Furthermore, this IRP identifies optimized renewable portfolio configurations and their associated power supply costs. It also validates and reinforces the understanding that power supply decarbonization will require flexibility in negotiation of renewable contracts as well as employment of all approaches and carbon-free resource types identified in the Scenarios.

The 2023 IRP continues PWP's long-standing goal of reducing carbon from its portfolio in a flexible way so that the current risks and challenges can be carefully addressed. Proactive planning is critical to ensure ongoing safe and reliable electric service while minimizing cost impacts to ratepayers and the environment. Resource planning is a complex process, especially where extreme external volatility exists in the cost and availability of renewable generation resources. Ongoing assessment will be required to ensure that PWP responds to changing conditions while addressing its programmatic priorities and providing rate payer protections.

As with past IRPs, PWP will continue to evaluate the IRP results in consideration of new and changing laws, regulations, resource availability and market conditions, providing updates and performance reporting when needed. The 2023 IRP was developed with a forward-thinking and flexible approach, along with a determination to meet and exceed to California's increasingly aggressive clean energy targets as quickly as possible.

Besides the actual acquisition and development of individual energy and storage resources, the following are some of the additional actions that PWP is considering that would support the overall carbon reduction goals of the IRP:

- Explore expansion of DERs.
- Support mass transit and electric vehicle fleet development and vehicle-to-grid distributed storage opportunities.
- Continue to study the reliability of PWP's evolving resource portfolio.
- Perform a cost-of-service study to identify projected resource portfolio capital expenditures over the next 20 years.
- Evaluate possible changes to customer incentives or subsidies, including low-income assistance.
- Expand Demand-Side Management, expand Energy Efficiency programs, implement Advanced Metering Infrastructure, and explore connection incentives.
- Monitor the actual influence of the City's Building Electrification Ordinance, which becomes effective in 2025.
- Continue to monitor developments in emerging technologies and funding opportunities.

As noted earlier, of the five modeled scenarios, Scenario 2 installs the largest number of new resources and is the most ambitious of the Carbon-Free resource portfolios. This determined approach provides the best planning opportunity for achieving carbon-free electricity by 2030. The resource procurement and development for such a plan will require a level of resource acquisition by the defined 2028 Waypoint, in addition to various actions that support ongoing efforts.

21.1. Waypoint 2028 – Scenario 2 Carbon-Free resource additions:

- 180 MW of new utility-scale solar
- 5 MW of utility/community solar within Pasadena
- 30 MW of new utility-scale wind
- 85 MW of new utility scale storage

The 2028 Waypoint procurement plan is defined by the Scenario 2 modeling results, whereby progress in the evaluation of the maturation of new and emergent carbon-free technologies will be periodically assessed and assessed again at the 2028 Waypoint. The next steps in the Implementation Plan will be formally incorporated into the 2028 IRP, as the Waypoint was strategically selected to align with CEC IRP processes.

The 2028 Waypoint Implementation Plan continues to preserve a pathway to 100% carbon-free electricity by 2030 and leverages existing CEC processes so that updates can be included in the next (2028) IRP. Additionally, the 2028 Waypoint Implementation Plan is in addition to the existing contracted procurements of solar, storage, and geothermal resources prior to, and after 2028; where PWP has previously executed proactive and timely carbon-free resource acquisitions.

Figure 207 provides exact detail of the modeling results for Scenario 2 through the 2028 Waypoint and presents the framework for the detailed implementation plan.

Figure 207 Incremental Installation of Resource Under Scenario 2

	2023	2024	2025	2026	2027	2028
New Utility Scale Solar	-	-	180 MW	-	39 MW (Sapphire)	-
Community Solar (Inside Pasadena)	-	-	5 MW	-	-	-
New Utility-scale Wind	-	-	30 MW	-	-	-
New Utility-scale Storage	-	-	85 MW	-	20 MW (Sapphire)	-
New Geothermal	-	-	-	-	35 (Coso + Geysers)	-

21.2. Waypoint Framework Development:

The Waypoint framework was informed through a thorough examination of the IRP data, analysis, and scenario results. In the most general terms, the IRP Waypoint can be indirectly attributed to a critical path analysis, within a project plan.

The policy goal of the City Resolution 9977 is a primary determinate in both the evaluation and selection of the appropriate Waypoint. To the degree practical, the selection criteria of the Waypoint is strategically designed to align and optimize across the following considerations:

1. The Waypoint will be in alignment with the policy goal of the City of Pasadena Resolution 9977
2. The Waypoint identification will be in alignment with CEC and other regulatory requirements and guidelines including electric system reliability, minimization of impacts to ratepayers, and reduction of GHG emissions.
3. The Waypoint will continue the aggressive trajectory of decarbonization, as affirmed by historical PWP performance.
4. The Waypoint attributes and/or characteristics will generally align with the modeling results of carbon-free scenarios, from a planning and/or implementation plan perspective.

5. The Waypoint identification, from a planning perspective, will ideally provide limited opportunity cost to achieving the policy goal of Resolution 9977 as defined in the scenario modeling results.
6. The Waypoint will have an Implementation Plan that should be defined or informed by the IRP scenario modeling results.
7. The Waypoint should align, support previous or historical decarbonization guidance and directives of the City Council.
8. The Waypoint must provide a reevaluation point to allow for reassessment, specifically related to the maturation of new and emerging technologies. It is widely accepted that such technologies will be required for a full decarbonization transition.
9. The Waypoint aligns with support for energy procurement that is technology-flexible and in line with energy needs, as defined in Pasadena's City Council-approved State Legislative Platform.

21.3. PWP's Proactive Carbon-Free Procurement Actions

PWP anticipates continued load growth, driven primarily by EV adoption and building electrification. This trend, in turn, will increase PWP's need for all three major attributes of a resource portfolio: energy supply, RA, and renewable/zero-carbon /carbon-free energy content. Accordingly, PWP proactively began building its future resource portfolio in 2022 and 2023 with the information outlined in the following paragraphs.

21.3.1. Utility-Scale Photovoltaic Solar + Battery

PWP has contracted for a portion of the Sapphire Project, a hybrid PV solar and battery energy storage facility to be built in Riverside County, California. During the contract delivery period (December 31, 2026, through December 31, 2046) PWP would receive a 39 MW share of the project's solar capability, plus a 19.67 MW share of its battery energy storage system. The contract requires that most of the energy charging the BESS comes from the solar field. This feature would benefit PWP because the presence of the BESS would convert the solar field (by itself, a variable energy resource) to a limited dispatchable resource, thus enabling PWP to store the project's renewable energy until PWP needs it to serve system load.

21.3.2. Geothermal

PWP has secured a 25 MW share of the Geysers, an existing geothermal energy resource comprised of multiple generating facilities in Sonoma County and Lake County, California. PWP plans to use its share of Geysers as a baseload renewable energy resource, meaning it would receive its 25 MW allotment on a full-time basis during the contractual delivery period (January 1, 2027, through December 31, 2041).

21.3.3. Additional Battery (Local)

Foreseeing the need for energy storage resources electrically within Pasadena, PWP has issued a solicitation to install design and to build a 25 MW, 4-hour battery at the Glenarm Power Plant complex. This facility, slated to commence service sometime in 2026 or 2027, could give PWP the ability to store renewable and carbon-free energy generated within the PWP system. PWP will leverage the experience it derives from this pilot project, since a BESS' modular design would enable PWP to adjust its MW throughput capability, and its hours of storage capability, to meet future needs as they arise.

21.4. Resource Procurement Guided by the Results of this IRP

PWP's challenge will be to acquire a diverse collection of procured and owned resources of various technologies that simultaneously, yet cost effectively, fulfills its needs for energy supply, Resource Adequacy, and renewable/carbon-free energy content. The composition of this new resource portfolio, and how quickly PWP needs to assemble it, will depend upon many factors, including, but not limited to, the following:

- The results of this IRP
- PWP's policy directives
- The deliverability of external resource energy to the PWP system
- The commercial availability of resources by type, size, and offered contract duration
- Reliability considerations
- Regulatory requirements
- Rate impacts

Since the IRP study period exceeds most typical contract durations, PWP will likely create its new resource portfolio in pieces over the years, allowing for flexibility, while leveraging all resource types and configurations identified in the Scenarios, while leaving breath to accommodate new technologies as they develop and mature in the future.

Figure 208 below shows the extended study period modeling results, by scenario, of how much cumulative nameplate capacity of wind, solar, storage, and fuel cells are added by 2031. Scenarios 1-3, which all meet 100% carbon-free by the end of 2030, require 700 – 1,300 MW of new installed capacity over the next eight years. Compared to PWP's current resource portfolio of about 400 MW, this represents an extraordinary expansion of resource procurement and capacity additions.

Figure 208: Cumulative New Resource Installed Capacity Through 2031 (MW)

	Solar	Wind	Battery Storage	Fuel Cell	Geothermal	Scenario Total
Scenario 1	300		285	115		700
Scenario 2	615	30	665	35	10	1,355
Scenario 3	480	60	598	35	20	1,193
Scenario 4	5	250	130			385
Scenario 5	5	610	60			675

All of the suggested resource portfolios for Scenarios 1 through 5 include some utility-scale PV solar and some utility-scale battery storage. Before 2030, the smallest amount of utility-scale solar among the carbon-free by 2030 scenarios (Scenarios 1-3) is 300 MW; this is in addition to the Sapphire Solar contract. Utility-scale storage varies among the scenario findings, but a minimum of 60 MW of 4-hour storage prior to 2031 appears across all of the results. This includes the 25-MW, 4-hour facility that PWP is currently soliciting, because the associated contract has not yet materialized.

Note, that these represent potential minimum procurements up to the year 2030; the larger potential procurement strategy is described in the Procurement Plan located in Appendix 28 of this IRP.

21.5. Supplemental Near-Term Actions

In addition to resource acquisition, PWP can take additional measures to support the goals of this IRP, as outlined in the following sub-sections.

21.5.1. Explore DER Expansion and Refine Planning for Internal Resource Sizes and Placement; Revisit the PDMP

The 2023 IRP describes a "Doubled Distributed Solar and Storage" Scenario that envisions over 200 MW of customer-installed photovoltaic solar generation capacity in Pasadena by 2050. Compared to PWP's Load Forecast, this degree of Distributed Energy Resource (DER) growth exceeds what PWP expects to occur naturally. If the City of Pasadena decides to promote such expansion, PWP will need to consider how to achieve this outcome – presumably through some combination of customer outreach/education, equipment rebates, and/or rate incentives. Even considering merely the expected, "normal" growth of DERs in Pasadena (to over 100 MW by 2050), PWP would need to increase its utility-side energy storage capacity to accommodate generation from these resources. This could take the form of expanded BESS facilities at PWP's Glenarm/Broadway complex, plus additional BESS installations at other City-owned locations that PWP would need to identify and to coordinate with the associated City Department(s). Any of these changes could significantly change the topographic loading pattern within PWP's subtransmission and distribution networks, especially in the connected MW of load and internal generation that these networks would face in the future. As PWP develops these internal resources, it will need to update its Power Delivery Master Plan (PDMP) accordingly.

21.5.2. Support Mass Transit and Electric Vehicle Fleet Development, Focusing on Electric Buses (City and School); Pursue Vehicle-to-Grid Charging Opportunities

PWP and other City Departments (Public Works, Police, Transportation, etc.) are at various stages of converting their vehicle fleets to electric vehicles. These fleets encompass both light-duty vehicles (such as sedans) and medium/heavy-duty vehicles (such as transit buses). PWP has supported, and will continue to support, charging facilities in its service area to accommodate this growing number of EVs. This also presents potential opportunities to partner with other City organizations for a symbiotic use of batteries aboard City vehicles and equipment, as they could charge from PWP's distribution system and discharge energy back to the system in times of need. Using central charging facilities at municipal bus yards in a vehicle-to-grid (V2G) mode presents a promising opportunity for symbiotic use of batteries aboard electric buses, as they could charge from PWP's distribution system and discharge energy back to the system in times of need.

21.5.3. Perform a More Extensive Study on the Future of Glenarm

The 2023 IRP study as well as past IRPs, raised awareness of the need to examine the future of PWP's natural gas-fired Glenarm Power Plant, which could take either of two main trajectories:

- Maintain its current operational status.
- Replace, convert, or make adaptations with carbon-free alternative energy and long-term storage resources such as carbon capture and sequestration, green hydrogen, biofuel, or other future technologies that may develop

At 197 MW, Glenarm plays a crucial role in PWP's current resource portfolio. It constitutes PWP's single largest source of RA and contributes to frequency regulation and reliability needs in a transmission-constrained topology. To deliver 100% carbon-free electricity on an hourly basis, as required by the Carbon-Free Scenarios (1 through 3), while maintaining reliability and RA requirements, will require replacing, converting, or making adaptations to Glenarm to an alternative energy and storage resource as described in 22.3.1.. Since these technologies are still being developed and not yet available at scale, they were not studied as part of the IRP process. However, they do represent emergent technologies that PWP could consider in order to achieve 100% carbon-free electricity while also meeting reliability requirements. Further studies of the feasibility, cost, and provisional timeline of these options must be performed to better understand what role they might play in Glenarm's future.

21.5.4. Prepare for a Significant Increase in Expenditures Over the Next 20 Years

Once PWP has defined a specific resource procurement/development program and has secured any alternative funding mechanisms, PWP can then incorporate this information into the power supply portion of future power system budgets. PWP routinely seeks authorization from its City Council before securing any renewable/carbon-free based resource procurement.

21.5.5. Perform a Cost-of-Service Study, Rate Impact Study, and Rate Ordinance Proposal

Several internal PWP financial studies would directly follow from this IRP and the resource procurement that it suggests. PWP's power supply costs include operations and maintenance expenses, as well as capital development costs. To the extent that PWP expects to fund these fiscal requirements through retail revenues, a rate impact study would show how customer rates could change. This process would culminate in a rate ordinance proposal by which PWP requests the Pasadena City Council's approval of changes to its rate structure and/or rates.

21.5.6. Investigate Rate Structure: Time-of-Use Rates, the Next Net Energy Metering Program, Electric Vehicle Charging Rates, Low-Income Assistance, Any Changes to Customer Incentives or Subsidies, Etc.

This IRP envisions an evolution occurring within PWP's connected load, including growth in distributed generation and distributed storage, additional adoption of EVs, and further strides in energy efficiency. Encouraging these developments and accommodating them in an equitable manner may require PWP to consider adjustments to its rate structure. PWP could explore a new TOU rate, a successor to PWP's current NEM program, or EV charging rates. As some of these programs may overlap with existing or proposed customer incentive and subsidy programs, PWP may need to re-evaluate existing programs in the context of other proposed changes. Any resulting rate proposal would need to consider the needs of PWP's low-income customers, incorporating rate equity in the proposal so that PWP's electric service remains affordable to all of its customers.

21.5.7. Expand Demand-Side Management; Explore Advanced Metering Infrastructure Connection Incentives

Section 5.4 of the IRP discusses PWP's current demand-side management efforts to adjust customer load in response to, or in anticipation of, power system contingencies. PWP's AMI network, slated for inauguration as early as 2027, will enable PWP not only to monitor individual customer loads in real time but also, potentially, to control some of those loads with the customers' permission.

21.5.8. Determine the Future of PWP's Green Power Program

As PWP overhauls its resource portfolio, its portfolio content may eventually reach 100% renewable/carbon-free. Before this occurs, PWP would need to re-evaluate the need and future of its existing GPP, which currently places a surcharge on participating customer bills to accomplish this same goal.

21.5.9. Monitor the Influence of the Building Electrification Ordinance After It Becomes Effective in 2025

The 2023 IRP estimates the future impact of Pasadena's Building Electrification Ordinance, which may modify load growth within PWP's service territory. In cooperation with Pasadena's Building & Safety Department, PWP may monitor how its load grows in the future and potentially estimate how much of this load growth is attributable to the ordinance. This field data would help PWP refine AAFS/Building Electrification assumptions for future utility planning, including future IRPs.

21.5.10. Update the Pasadena Utility Code, Electrical Code, and Fire Code (for Batteries, Hydrogen Fuel Cells, etc.)

Emerging technologies may prompt revisions to Codes and Standards (C&S) – for example, PWP's restrictions on types of customer-installed generation, electrical code requirements (which Pasadena's Building and Safety Department administers), and the Pasadena Fire Code (particularly with respect to customer-installed battery systems within enclosed spaces such as garages). Keeping Pasadena's C&S up to date would promote the safe application of these technologies while tapping into their full potential.

21.5.11. Continue to Monitor Emerging Technology Developments

Sections 14 and 16 describe this IRP's Emerging Technologies Scenario. PWP staff continues to identify and to track such developments. As these technologies mature to the point of commercial applicability, PWP could assess if, how, and when to incorporate them into its evolving resource portfolio. This concept is central to the 2028 Waypoint framework.

Each of the above activities will have its own timeline, which will become clear as PWP addresses them individually. Additionally, PWP would present each resulting program to the City Council in a timely manner so that PWP could proceed with appropriate guidance and policy directives. In any event, PWP would likely need to accomplish these activities within five to seven years after issuing this IRP.

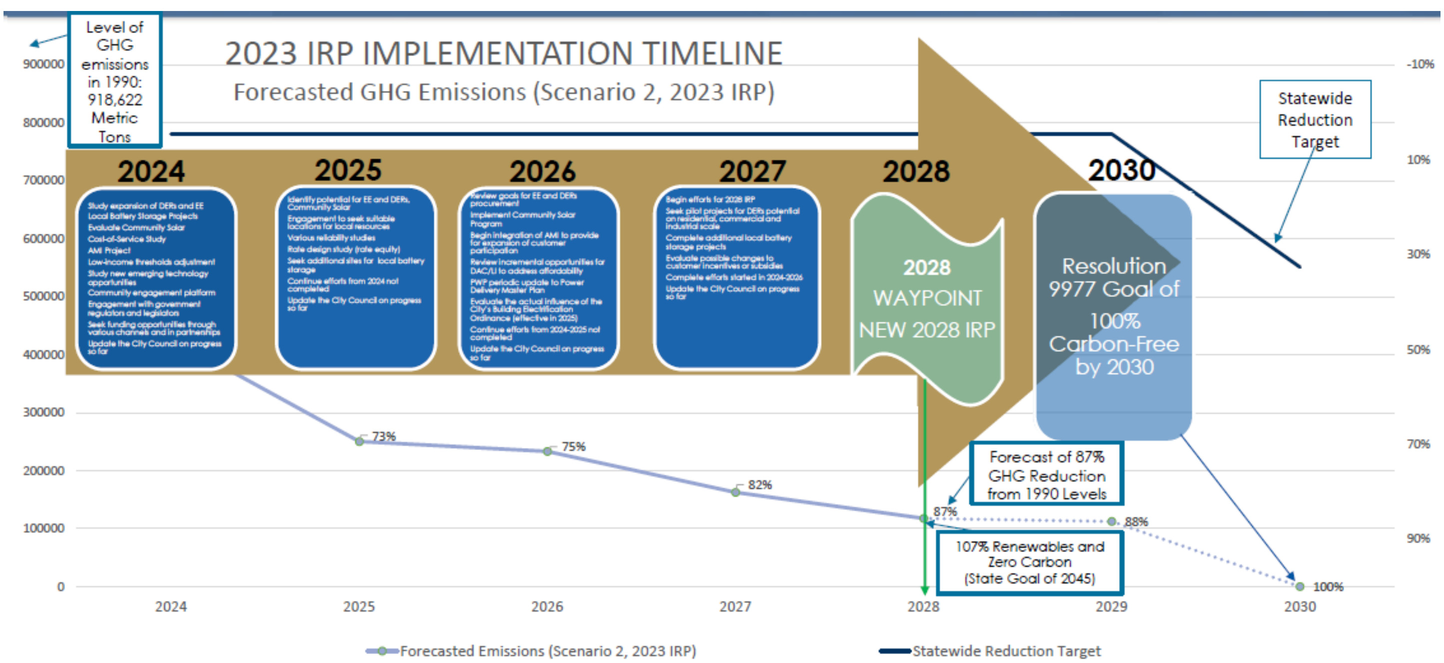
21.6. Timeline The Longer-Range Outlook

Transitioning to a more renewable and carbon-free resource mix would require PWP to ramp up its current long-term contract origination and contract administration activities, with a commensurate increase in its work with SCPPA, which supports PWP in these activities. Conversely, PWP foresees increasing participation in markets for RECs and RA to support interim portfolio balancing during the first five to seven years following this IRP.

The timeline in Figure 209, is a general high-level representation of activities inherent to the 2028 Waypoint framework. While standard utility practices encompass many of the below concepts, other considerations are not included such as energy risk management and mitigation, PPA contract negotiations to capture favorable terms intended to protect rate payer interests, while also strategically sourcing procurements that are less likely to be negatively impacted by inherent CAISO transmission constraints, among other things.

Figure 209: 2023 IRP Implementation Timeline

Figure 210: 100% Carbon – Free Trajectory to Waypoint in 2028



22. Appendix - Required Tables

The required tables are filed separately.

22.1. Capacity Resource Accounting Table

Additional information regarding how the load is calculated in the CRAT is provided in Figure 211.

Figure 211: Capacity Resource Accounting Table Load

	Peak Load C	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
1	Forecast Total Peak-Hour 1-in-2 Demand (7a + 5 – 4)	326	330	343	347	352	356	356	363	364	369	372	376	378	380	383	384	386	388	390	392	394	396	398	399	398	400	399	401
2	[Customer-side solar: nameplate capacity]	30	32	34	37	39	42	44	47	50	53	56	59	62	65	68	71	74	78	81	84	88	91	95	98	102	105	108	112
2a	[Customer-side solar: peak hour output]	20	8	18	12	11	28	4	12	16	15	37	40	40	42	44	46	48	50	52	55	57	59	61	63	9	9	0	0
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	0	0	0	0
4	[Light Duty PEV consumption in peak hour]	4	5	6	8	7	10	15	16	18	20	29	31	31	32	34	34	35	36	36	37	37	38	38	38	32	32	31	31
4a	[Medium/Heavy Duty PEV consumption in peak hour]	0	0	0	1	1	1	1	2	2	2	4	5	5	6	7	8	9	10	11	12	13	15	16	18	14	15	17	18
4d	[TOU rates generation in peak hour]	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
4e	[Distributed storage generation in peak hour]	0	1	0	1	1	0	3	2	2	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	16	17	3	3
4f	[AAFS consumption in peak hour]	0	1	1	1	1	1	1	2	2	3	2	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	5	5
4g	[Climate change consumption in peak hour]	0	0	0	0	1	1	1	1	1	2	2	2	2	2	2	3	3	3	3	3	3	3	3	3	2	2	3	3
4h	[Native load consumption in peak hour]	352	343	354	350	354	370	345	356	360	361	373	376	377	379	381	383	385	387	389	392	394	396	399	401	373	375	348	349
4i	[Distributed natural gas generator in peak hour]	10	10	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	0
5	Additional Achievable Energy Efficiency Savings on Peak	6	8	8	9	11	13	10	14	13	15	16	17	17	17	17	17	18	17	17	17	17	17	17	17	14	14	12	12
6	Demand Response /	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	0	0	0

	Peak Load C	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
	Interruptible Programs on Peak																												
7	**Peak Demand (accounting for demand response and AAEE) (1-5-6)**	**320**	**323**	**335**	**338**	**341**	**343**	**346**	**348**	**351**	**354**	**356**	**359**	**362**	**363**	**365**	**367**	**369**	**371**	**373**	**374**	**376**	**378**	**380**	**382**	**384**	**386**	**388**	**390**
7a	[Metered peak demand in peak hour]	330	333	335	338	341	343	346	348	351	354	356	359	362	363	365	367	369	371	373	374	376	378	380	382	384	386	388	390
8	Planning Reserve Margin	48	48	59	59	60	60	61	61	61	62	62	63	63	64	64	64	65	65	65	66	66	66	67	67	67	68	68	68
8b	Reserve Margin (%)	15%	15%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%
9	Firm Sales Obligations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	**Total Peak Procurement Requirement (7+8+9)**	**368**	**371**	**394**	**397**	**400**	**403**	**406**	**409**	**412**	**416**	**419**	**422**	**425**	**427**	**429**	**431**	**433**	**436**	**438**	**440**	**442**	**444**	**447**	**449**	**451**	**453**	**456**	**458**

22.2. Energy Balance Table (Scenario 4 Example)

Additional information regarding how load is calculated in the EBT is in Figure 212.

Figure 212: Energy Balance Table (Scenario 4) Load

	Net Energy for Load Calculations	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
1	Retail sales to end-use customers (1a + 4a – 1b) *.96	1,047,923	1,059,784	1,156,277	1,173,515	1,192,802	1,215,253	1,239,018	1,265,082	1,291,633	1,315,006	1,338,073	1,358,607	1,371,814	1,384,239	1,395,351	1,405,369	1,414,512	1,422,988	1,430,986	1,438,674	1,446,195	1,453,669	1,461,195	1,468,851	1,476,698	1,484,777	1,493,119	1,501,739
1a	Metered Load	1,156,320	1,162,535	1,173,224	1,185,899	1,201,519	1,220,842	1,241,853	1,265,577	1,290,067	1,312,076	1,333,660	1,352,810	1,364,639	1,375,921	1,386,185	1,396,148	1,405,362	1,414,327	1,422,855	1,430,863	1,438,698	1,446,483	1,454,323	1,462,298	1,470,471	1,478,887	1,487,577	1,496,556
1b	Distributed Generation	84,240	84,480	240	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Other loads	-	-	105,325	117,752	153,124	241,384	246,479	245,473	243,882	242,986	238,602	233,086	228,095	205,042	198,862	193,939	198,942	194,942	190,373	202,111	237,876	235,070	256,827	247,512	257,543	284,078	283,324	285,431
2a	[Storage pumping load]	-	-	-	-	22,845	26,475	28,199	27,839	26,429	23,543	22,129	20,338	18,485	12,748	10,648	10,578	11,407	10,907	10,471	9,858	10,032	9,976	9,655	9,553	-	-	-	-
2b	[Storage pumping load]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,519	2,500	2,389
2c	[Storage pumping load]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,447	2,515	2,612	2,572	2,453
2d	[Storage pumping load]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2e	[Storage pumping load]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

	Net Energy for Load Calculations	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
2f	[Storage pumping load]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2g	[Storage pumping load]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2h	[Storage pumping load]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2i	[Storage pumping load]	-	-	105,325	117,752	130,279	214,909	218,279	217,634	217,452	219,444	216,473	212,749	209,610	192,293	188,214	183,361	187,534	184,034	179,902	192,253	225,114	219,763	242,022	230,601	250,360	273,733	273,056	275,344
2j	[Storage pumping load]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2k	[Storage pumping load]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,730	5,331	5,150	4,912	4,668	5,215	5,195	5,246
2l	[Storage pumping load]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Net energy for load (1a + 4a – 1b +2)	**1,091,586**	**1,103,941**	**1,309,781**	**1,340,163**	**1,395,626**	**1,507,272**	**1,537,123**	**1,563,267**	**1,589,333**	**1,612,784**	**1,632,428**	**1,648,302**	**1,657,067**	**1,646,957**	**1,652,353**	**1,657,865**	**1,672,392**	**1,677,221**	**1,680,984**	**1,700,730**	**1,744,329**	**1,749,309**	**1,778,906**	**1,777,566**	**1,795,770**	**1,830,721**	**1,838,656**	**1,849,743**
4	Retail sales to end-use customers (accounting for AAEE impacts) ((1a – 1b)*.96)	1,029,197	1,034,933	1,126,064	1,138,463	1,153,458	1,172,009	1,192,179	1,214,954	1,238,464	1,259,593	1,280,313	1,298,697	1,310,054	1,320,884	1,330,738	1,340,302	1,349,147	1,357,754	1,365,941	1,373,629	1,381,150	1,388,624	1,396,150	1,403,806	1,411,652	1,419,732	1,428,074	1,436,694
4a	[AAEE generation]	19,506.21	25,886.41	31,471.95	36,512.71	40,983.11	45,045.88	48,790.91	52,216.66	55,384.83	57,721.15	60,166.46	62,405.96	64,333.16	65,994.23	67,305.27	67,777.88	68,088.44	67,952.51	67,755.48	67,755.48	67,755.48	67,755.48	67,755.48	67,755.48	67,755.48	67,755.48	67,755.48	67,755.48
5	Net energy for load (accounting for AAEE impacts) (1a – 1b +2)	1,072,080	1,078,055	1,278,309	1,303,651	1,354,642	1,462,226	1,488,332	1,511,050	1,533,948	1,555,063	1,572,261	1,585,896	1,592,734	1,580,963	1,585,048	1,590,087	1,604,303	1,609,269	1,613,229	1,632,974	1,676,574	1,681,554	1,711,150	1,709,810	1,728,014	1,762,966	1,770,900	1,781,987
6	Firm Sales Obligations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Total net energy for load (accounting for AAEE & AAFS impacts) (5+6)**	**1,072,080**	**1,078,055**	**1,278,309**	**1,303,651**	**1,354,642**	**1,462,226**	**1,488,332**	**1,511,050**	**1,533,948**	**1,555,063**	**1,572,261**	**1,585,896**	**1,592,734**	**1,580,963**	**1,585,048**	**1,590,087**	**1,604,303**	**1,609,269**	**1,613,229**	**1,632,974**	**1,676,574**	**1,681,554**	**1,711,150**	**1,709,810**	**1,728,014**	**1,762,966**	**1,770,900**	**1,781,987**
8	[Customer-side solar generation]	57,838	62,350	66,608	71,103	75,793	80,665	85,714	90,950	96,366	101,934	107,617	113,374	119,170	125,152	131,237	137,419	143,688	150,039	156,463	162,952	169,498	176,094	182,733	189,406	196,106	202,826	209,558	216,297
9	[Total Annual Light Duty PEV electricity consumption/ procurement requirement]	39,428	50,945	64,260	79,439	96,970	115,251	135,436	157,144	179,726	196,481	211,389	224,442	235,737	245,424	253,680	260,685	266,611	271,614	275,833	279,388	282,384	284,908	287,035	288,829	290,342	291,620	292,699	293,610
10	[Total Annual Medium/Heavy Duty electricity consumption/	242	423	2,827	4,605	6,952	9,777	12,777	15,881	19,789	23,677	30,058	35,906	41,939	48,054	54,511	61,340	68,580	76,269	84,445	93,138	102,374	112,167	122,527	133,454	144,939	156,968	169,517	182,559

	Net Energy for Load Calculations	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
	procurement requirement]																												
11	[Total Annual AAFS consumption/ procurement requirement]	2,914	4,798	6,833	8,430	10,124	11,932	13,820	15,790	17,832	19,924	21,927	23,779	25,448	26,856	28,109	29,215	30,186	31,032	31,765	32,399	32,944	33,412	33,812	34,154	34,445	34,693	34,903	35,082
12	[Total Annual TOU rates generation requirement]	-	-	-	-	-	-	-	12	12	13	12	12	12	13	13	13	13	14	14	14	14	14	15	15	15	15	15	15
13	[Total Annual climate change consumption/ procurement requirement]	658	994	1,333	1,677	2,028	2,379	2,736	3,096	3,458	3,822	4,189	4,559	4,931	5,221	5,484	5,720	5,932	6,120	6,287	6,433	6,562	6,674	6,773	6,858	6,932	6,996	7,052	7,100
14	[Total Annual distributed storage consumption/ procurement requirement]	407	501	591	694	799	914	1,032	1,166	1,319	1,473	1,642	1,812	1,997	2,184	2,377	2,576	2,780	2,990	3,207	3,430	3,659	3,895	4,138	4,388	4,646	4,912	5,185	5,467
15	[Total Annual native load consumption/ procurement requirement]	1,190,016	1,193,111	1,195,461	1,198,669	1,201,423	1,206,299	1,210,557	1,215,679	1,219,707	1,226,367	1,232,249	1,238,103	1,238,103	1,239,341	1,240,580	1,241,821	1,243,063	1,244,306	1,245,550	1,246,796	1,248,043	1,249,291	1,250,540	1,251,790	1,253,042	1,254,295	1,255,550	1,256,805

Surplus/Shortfall (21-22) (MWh), labeled as #23 on the EBT, is plus or minus 10 MWh.

23. Appendix – Integrated Resource Plan Contract and Resource Roles

Figure 213: IRP Contacts and Roles

Company	Roles	Contract Details	Representatives
PWP	Represent the utility and best interests of stakeholders	N/A	Sidney Jackson – General Manager of PWP Kelly Nguyen – Assistant General Manager of Power Supply
	Evaluate, communicate, engage, and analyze options for meeting load requirements in compliance with regulations and stakeholder priorities		Robert Castro – Power Resource Planning Manager
	File an IRP to the CEC by December 31, 2023, in compliance with California regulatory requirements		John Hormozi – Principal Power Resource Planner
			Jason Tarasi – Power Resource Planner II
			Christina Schieber – Power Resource Planner I
			Mark Webster – Power Resource Planner I
			Jessica Velazquez - Intern
ACES	Provide consulting services to help PWP meet IRP development and filing requirements in accordance with *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines – Revised Second Edition*	Formal solicitation process, entered December 2022; $277,200 for 2023 IRP modeling and consulting services with optional $150,000 in hourly consulting services to be conducted, if needed, in the post-IRP submission phase; total value of contract not to exceed $427,000	Nette Brocks – Manager of Resource Planning
			Patrick Maguire – Executive Director of Resource Planning
			Todd White – Executive Director of Business Development
			Michael Bloom – Consultant
EE-3	Validate the assumptions data and results.	Informal solicitation, $70,560	Nick Schlag – Partner at E3
			Nathan Lee – Managing Consultant
			Charlie Duff –

Company	Roles	Contract Details	Representatives
			Managing Consultant
			Melissa Rodas – Consultant

24. Appendix – Opportunities for Future Studies and Analysis

Figure 214: Opportunities for Future Studies and Analysis

	What the 2023 IRP Did	Opportunities for Future Study
Planning Horizon	• The IRP guidelines only require present year through 2045, but the 2023 IRP modeled for a Study Period of 2023 through 2050.	
Scenarios and Sensitivity Analysis *"IRP Filings and IRP Filing updates must meet the requirements of PUC Section 9621. POUs are encouraged to also evaluate other scenarios and sensitivity analyses to consider the feasibility and cost-effectiveness (and rate impacts) of alternative resource options. Although not required, POUs are encouraged to submit analyses of alternatives" – 2018 Guidelines*	• While only one scenario is required by the CEC, the 2023 IRP modeled five scenarios, one emerging technology study, and four sensitivities.[156]	• Consider additional or different scenarios and sensitivity tests to evaluate other potential risks and opportunities in future IRPs.
Supporting Information *"Supporting Information for an IRP Filing refers to (1) analyses, studies, data, and work papers, or other material that the POU used or relied upon (including inputs and assumptions) in creating the IRP (such as, but not limited to, market conditions current at the time of the analyses, energy infrastructure, state policies and laws, and needs of the Filing POU) but are not included in the*	• The IRP represented PWP's existing fleet of 20 existing resources/contacts and 4 imminent contracts. • The IRP created low, medium, and high-cost estimates for 16 different technologies using publicly available sources.[157] • The IRP disclosed power prices (while normally subject to a nondisclosure agreement), courtesy of Horizons Energy	• Further consider the impacts of transmission congestion on energy value for existing and new resources external to Pasadena. • Green hydrogen and biogas price forecasts could consider impacts from the IRA.

[156] 34 unique results packages.
[157] 48 unique estimates of resource costs.

	What the 2023 IRP Did	Opportunities for Future Study
IRP itself; and (2) additional information required by these guidelines." – 2018 Guidelines	• The IRP disclosed gas prices (while normally subject to a nondisclosure agreement), courtesy of Horizons Energy. • The IRP created forecasts for green hydrogen and biogas based on public sources of data.	
Demand Forecast "The Energy Commission recommends using the California Energy Demand Forecast developed annually as part of the IEPR." – 2018 Guidelines	• The IRP created hourly load forecasts from 2023 through 2050 for the various components of demand, based upon the IEPR. Hourly forecasts included the following: ○ Native load ○ Additional achievable energy efficiency ○ Additional achievable fuel substitution ○ Distributed (residential and nonresidential) storage ○ Distributed solar ○ Time of use rates ○ Light-duty electric vehicles (EVs) ○ Medium/heavy duty electric vehicles ○ Climate change	• Consider an econometric load forecast in future IRPs. • Consider additional studies regarding distributed resources, EVs, or other components.
Resource Procurement Plan • Diversified Procurement Portfolio • RPS Planning Requirements • Energy Storage and Demand Response Resources • Energy Storage • Transportation Electrification	• The IRP studied three pathways to achieve 100% hourly carbon-free by 2030 without offsets, and one additional decarbonization portfolio looking at the SCC, and compared these results to a reference case that meets state regulatory targets. The results showed a range of resources that could meet environmental goals and requirements reliably and cost-effectively given constraints.	• Update internal practices regarding contract size, contract duration, and resource diversity as market conditions change. • Continue to monitor the potential for long-duration or novel storage technologies applicable to the PWP system. • Study the feasibility of rate mechanisms to incentivize transportation electrification and to avoid the need for additional resources.

	What the 2023 IRP Did	Opportunities for Future Study
	• The IRP documented procedures in place to achieve compliance with State goals. • Energy storage was included as a selectable resource choice; it helps avoid the use of fossil peakers by storing excess renewable energy for later dispatch. • Demand response and energy efficiency were further evaluated in the emerging technology scenario. The load forecast also included impacts. • PWP incorporated light, medium, and heavy-duty transportation electrification into its load forecast.	
System and Local Reliability	• PWP's transmission constrained topology was incorporated into IRP modeling. • PWP considered the impact of Glenarm and Goodrich on reliable operations.	• Conduct further, detailed reliability studies of these two facilities under various load and resource conditions. • Study the distribution system's existing or potential hosting capacity for distributed resources under different conditions in the context of a future PDMP. • Consider operational alternatives at Glenarm (carbon capture, hydrogen, etc.).
GHG Emissions	• The IRP documents CARB compliance. • PWP models carbon emissions from its fossil fleet, landfill/biogas contracts, and net market purchases.	
Retail Rates	• The IRP quantifies the incremental revenue requirement associated with various scenarios and sensitivities. • The IRP conducts a rate examination.	• Conduct a cost of service study in preparation for its next Rate Ordinance proposal. • Further investigate the feasibility of applying AMI to support increased distributed

	What the 2023 IRP Did	Opportunities for Future Study
		resources and demand response. • Investigate alternative rate structures.
Transmission and Distribution Systems	• PWP explains operations and areas of risk and opportunities on PWP's system.	• Consider further studies to explore decarbonization potential with more of a reliability focus.
Localized Air Pollutants and Disadvantaged Communities	• PWP identifies various areas of concern and pathways for mitigation.	• Further research ways to provide tangible benefits targeted to disadvantaged communities.

25. Appendix - Model Parameters and Additional Reliability Metrics

The following constraints are applied when conducting capacity expansion:

- 1,000 MW of new resources can be built each year
- 2,000 MW of new resources can be online at once
- Resources are usually in 10 MW increments, but could be in the following increments:
  - Hybrids are in 15 MW increments (10 MW of solar or wind with 5 MW of 4-hour battery)
  - 5 MW of internal fuel cells in a 5 MW increment
  - 5 MW of community solar in 1 MW increments
  - Distributed resources in 1 MW increments

The capacity expansion was run from 2023 through 2050 to optimize for reliability using capacity derations. A typical day of the week was optimized with 24 intervals in a day over 20 years, with a 10-year expansion period. There was no commitment and mixed integer programming (MIP) stop basis of 200.

Scenario 2 was optimized under an on/off-peak day due to problem size and solve time.

Hourly dispatch runs were run with no maintenance shifts and new outages with convergence. All calendar days with 24 daily intervals over a 7-day optimization period, with a 1-day extension period. Twelve split months were run under full commitment with a MIP stop basis of 25 and a MIP maximum solve time of 120 seconds.

The capacity expansion is optimized with a $2,000/MWh penalty for unserved energy, and a $32.95/kW-month (in 2023, escalating at inflation) penalty for unserved capacity. The energy penalty is based on the soft energy cap for energy at CAISO. The capacity penalty is based on the penalty price for investor-owned utilities. The capacity market can trade at this level.

Scenario 1, 2, and 3 required additional internal resources to meet load with carbon-free resources. Resources are added iteratively, after the initial optimization, to help cover load, as follows:

- Scenario 1: Minimum of 110 MW of fuel cells in 2030 (compared to 20 MW) and 220 MW of fuel cells in 2050 (compared to 120 MW)
- Scenario 2: Minimum of 400 MW of commercial storage and of commercial solar (compared to none) in 2030 and 2050 (compared to 3 MW of commercial storage and 8 MW of commercial solar)
- Scenario 3: Minimum of 350 MW of commercial storage and of commercial solar (compared to 14 MW of commercial storage and 31 MW of commercial solar) in 2030 and 2050 (compared to 31 MW of commercial storage and 67 MW of commercial solar)
- Scenario 4: None
- Scenario 5: None

Additional energy needs were likely due to the difference between a typical week in the capital optimization, and standard hourly day in the dispatch. The energy needs for the capital optimization are shown in Figure 215, the resulting hourly dispatch is shown in Figure 216, and the adjusted dispatch with additional resources are shown in Figure 217.

Figure 215: Reliability Metrics for First Round Scenario Modeling (Capital Expansion)

Capacity Expansion: Additional Energy Needs (MW)					
Year	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
2023	0	0	0	0	0
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	0	0	0	0
2027	0	0	0	0	0
2028	0	0	0	0	0
2029	0	0	0	0	0
2030	224	149	0	0	0
2031	735	2,199	0	0	0
2032	0	0	0	0	0
2033	311	1,488	0	0	0
2034	1,135	1,079	0	0	0
2035	1,433	1,246	0	0	0
2036	195	1,743	0	0	0
2037	0	0	0	0	0
2038	0	0	0	0	0
2039	0	0	0	0	0
2040	606	0	0	0	0
2041	1,575	1,502	0	0	0
2042	4,431	318	1,000	0	0
2043	73	0	0	0	0

Capacity Expansion: Additional Energy Needs (MW)					
Year	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
2044	32	419	0	0	0
2045	0	0	1,031	0	0
2046	0	0	0	0	0
2047	0	0	0	0	0
2048	0	0	0	0	0
2049	0	0	89	0	0
2050	0	0	0	0	0

Figure 216: Reliability Metrics for First Round Scenario Modeling (Hourly Dispatch)

Hourly Dispatch: Additional Energy Needs (MW)					
Year	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
2023	0	0	0	0	0
2024	0	0	0	0	2
2025	0	0	0	0	5
2026	0	0	0	0	14
2027	0	0	0	0	4
2028	0	0	0	0	6
2029	0	0	0	0	12
2030	10,960	5,043	6,209	0	2
2031	15,462	9,111	7,167	0	4
2032	9,663	5,740	1,342	0	1
2033	9,890	9,051	3,642	0	0
2034	9,136	10,627	5,562	0	1
2035	12,330	13,582	7,295	0	0
2036	12,814	16,147	10,010	0	3
2037	5,735	7,284	3,673	0	3
2038	7,408	8,037	4,141	0	0
2039	8,781	10,326	4,151	0	2
2040	11,833	14,332	6,899	0	2
2041	15,601	15,837	7,715	0	0
2042	21,173	6,722	11,832	0	1
2043	19,013	4,569	11,002	0	2
2044	20,397	4,963	11,047	0	1
2045	11,656	4,951	13,725	0	1
2046	7,011	5,140	8,456	0	0
2047	6,625	568	7,054	0	0
2048	7,532	557	7,028	0	0
2049	7,052	1,298	10,173	0	0

Hourly Dispatch: Additional Energy Needs (MW)					
Year	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
2050	560	208	587	0	0

Figure 217: Reliability Metrics for Second Round Scenario Modeling (Hourly Dispatch)

Hourly Dispatch: Additional Energy Needs (MWh) Revamped			
Year	Scenario 1	Scenario 2	Scenario 3
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	0	0	0
2028	0	0	0
2029	0	0	0
2030	0	0	0
2031	0	0	0
2032	0	0	0
2033	0	0	0
2034	0	0	0
2035	0	0	0
2036	0	0	0
2037	0	0	0
2038	0	0	0
2039	0	0	0
2040	0	0	0
2041	0	0	0
2042	0	0	0
2043	0	0	0
2044	0	0	1
2045	1	0	7
2046	1	0	1
2047	2	0	2
2048	2	0	1
2049	2	0	2
2050	0	1	4

Scenario 1 information regarding additions and reliability metrics is described in Figure 112. Scenario 2 information is described in Figure 218. The scenario needs a minimum of 400 MW of commercial storage and 400 MW of commercial solar (compared to none) in 2030 and 2050 (compared to 3 MW of commercial storage and 8 MW of commercial solar). This ensures load is served every hour with carbon-free electricity. The 400 MW of commercial solar and 400 MW of commercial storage helps meet additional energy needs under normal operating conditions.

Figure 218: Scenario 2: Consecutive Model Runs

		Additional Energy Needs (MWh)		Additional Energy Needs (% of Total Load)	
Year	Energy (MWh)	With 400 MW Minimum of Commercial Storage and 400 MW Minimum of Commercial Solar	Without	With 400 MW Minimum of Commercial Storage and 400 MW Minimum of Commercial Solar	Without
2023	1,156,000	0	0	0.0%	0.0%
2024	1,163,000	0	0	0.0%	0.0%
2025	1,173,000	0	0	0.0%	0.0%
2026	1,186,000	0	0	0.0%	0.0%
2027	1,202,000	0	0	0.0%	0.0%
2028	1,221,000	0	0	0.0%	0.0%
2029	1,242,000	0	0	0.0%	0.0%
2030	1,266,000	0	5,043	0.0%	0.4%
2031	1,290,000	0	9,111	0.0%	0.7%
2032	1,312,000	0	5,740	0.0%	0.4%
2033	1,334,000	0	9,051	0.0%	0.7%
2034	1,353,000	0	10,627	0.0%	0.8%
2035	1,365,000	0	13,582	0.0%	1.0%
2036	1,376,000	0	16,147	0.0%	1.2%
2037	1,386,000	0	7,284	0.0%	0.5%
2038	1,396,000	0	8,037	0.0%	0.6%
2039	1,405,000	0	10,326	0.0%	0.7%
2040	1,414,000	0	14,332	0.0%	1.0%
2041	1,423,000	0	15,837	0.0%	1.1%
2042	1,431,000	0	6,722	0.0%	0.5%
2043	1,439,000	0	4,569	0.0%	0.3%
2044	1,446,000	0	4,963	0.0%	0.3%
2045	1,454,000	0	4,951	0.0%	0.3%
2046	1,462,000	0	5,140	0.0%	0.4%
2047	1,470,000	0	568	0.0%	0.0%
2048	1,479,000	0	557	0.0%	0.0%
2049	1,488,000	0	1,298	0.0%	0.1%
2050	1,497,000	1	208	0.0%	0.0%

All scenarios were optimized under the capital expansion with a heat rate of 2,047.2 Btu/kWh for fuel cells. E3 identified this in review. The hourly dispatch was re-optimized with a corrected heat rate of 6,469 Btu/kWh.[158] Fuel cell capacity is in Figure 219. Given the size and importance of fuel cells in meeting reliability, and time constraints, the capital expansion

[158] https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

was not repeated. Since the heat wave and Goodrich sensitivities were focused on reliability, they were kept. The Emerging Technology Sensitivity was also kept because the emphasis was on comparative differences.

Figure 219: Installed Capacity of Fuel Cells

Year	Scenario 1	Scenario 2	Scenario 3
2030	110	35	35
2031	115	35	35
2032	120	35	35
2033	125	35	35
2034	130	35	35
2035	130	35	35
2036	130	35	35
2037	130	35	35
2038	130	35	35
2039	130	35	35
2040	130	35	35
2041	130	35	35
2042	150	65	65
2043	150	65	65
2044	150	65	65
2045	165	75	65
2046	175	75	75
2047	185	95	85
2048	185	95	85
2049	190	95	85
2050	220	135	115

Once the model runs are complete, resources in PWP's portfolio are assigned to load in the order shown in Figure 220. Resources on the top are assigned to load first. Preference is given to dispatchable and internal resources. Assigning resources to load rather than the market helps identify how PWP's carbon-free resources are meeting load.

Figure 220: Resources Toward Load

Resources Toward Load
BTM NG Generator
GT - 1
GT - 2
GT - 3
GT - 4
GT - 5
GT - 1 Biogas
GT - 2 Biogas
GT - 3 Biogas

Resources Toward Load
GT - 4 Biogas
GT - 5 Biogas
New 2-Hour Residential Storage
New 4-Hour Commercial Storage
New 4-Hour Storage (Internal Solar Paired)
New 4-Hour Internal Storage
New 6-Hour Internal Storage
New 8-Hour Internal Storage
New 10-Hour Internal Storage
New Internal Fuel Cells
Intermountain Coal
Intermountain Repower NG
Magnolia
Palo Verde Nuclear
Hoover Hydro
Calpine Geysers
Coso Geothermal
Puente Hills Landfill
Chiquita Landfill
EDF Sapphire Storage
Milford Wind
PPM (Avangrid) Wind
Antelope Solar
Columbia Two Solar
Kingbird Solar
Summer Solar
Windsor Reservoir Solar
EDF Sapphire Solar
New 4-Hour Storage (External Solar Paired)
New 4-Hour Storage (Land-Based External Wind Paired)
New 4-Hour External Storage
New 6-Hour External Storage
New 8-Hour External Storage
New 10-Hour External Storage
New External Fuel Cells
New External Geothermal
New Land-Based External Wind (Storage Paired)
New Land-Based External Wind
New Offshore Wind
New Residential Solar
New Commercial Solar

Resources Toward Load
New Community Solar
New Internal Solar (Storage Paired)
New Internal Solar
New External Solar (Storage Paired)
New External Solar

Curtailments are reported in EnCompass if the price received for generation dips below $100/MWh. This price is a model default that allows for uncertainty. Curtailments across scenarios are shown in Figure 221. Scenario 2 has the greatest amount of curtailment.

Figure 221: Economic Curtailments Across Scenarios (MWh)

Year	Scenario 1 (Island)	Scenario 1 (Energy Market Access)	Scenario 2 (Island)	Scenario 2 (Energy Market Access)	Scenario 3 (Island)	Scenario 3 (Energy Market Access)	Scenario 4	Scenario 5
2023	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-
2028	52,437	52,437	41,131	41,131	38,311	38,311	39,383	72,148
2029	20,675	20,675	15,932	15,932	14,559	14,559	12,761	21,592
2030	187,478	46,734	579,156	50,661	411,034	44,209	34,816	59,833
2031	140,075	28,953	581,054	34,654	401,022	30,358	32,134	61,223
2032	118,726	339	564,742	646	500,999	1,105	2,398	5,265
2033	108,595	13,554	563,308	16,429	488,579	16,391	16,060	31,065
2034	104,325	2,994	601,788	3,552	475,829	2,851	1,339	1,817
2035	99,791	-	583,053	-	467,824	-	-	-
2036	99,746	-	575,057	-	460,519	-	-	-
2037	97,002	-	595,679	-	478,079	0	-	-
2038	91,938	-	579,007	-	464,031	-	-	-
2039	87,286	-	570,236	1	454,676	-	-	-
2040	85,993	-	565,901	-	454,923	-	-	-
2041	83,004	-	582,338	1	476,094	-	-	-
2042	67,652	-	463,746	-	286,794	0	-	-
2043	66,744	-	461,955	0	281,494	1	-	-
2044	63,019	-	454,459	0	280,020	1	-	-
2045	16,538	-	334,621	-	271,617	0	-	-
2046	20,121	-	335,611	0	243,978	0	-	-
2047	4,438	-	337,080	0	194,630	-	-	-
2048	3,239	-	318,606	0	171,392	-	-	-

Year	Scenario 1 (Island)	Scenario 1 (Energy Market Access)	Scenario 2 (Island)	Scenario 2 (Energy Market Access)	Scenario 3 (Island)	Scenario 3 (Energy Market Access)	Scenario 4	Scenario 5
2049	4,394	-	316,677	0	184,534	1	-	-
2050	10,398	-	251,968	0	113,390	-	-	-

Scenarios 1, 2, and 3 select new resources as if PWP operates like an island (i.e., has no market interactions with CAISO). The results of these studies have the "island" label. This is done so that carbon-free resources meet load in each hour. These results provide an upper bound of costs (excluding the separately studied impacts of new resource cost variations) because excess renewable energy is not sold.

However, given that PWP operates within CAISO, Scenarios 1, 2, and 3 are run again with access to CAISO's energy market. This shows a lower bound of cost estimates (again, excluding the separately studied impacts of new resource cost variations), as excess renewable energy is sold. These results may also predict greater CO_2 emissions because PWP has access to CAISO markets. This pertains to the results with the "energy market access" label.

26. Appendix – Cost of New Resources

26.1. Utility-Scale Solar

Figure 222: Utility-Scale Solar Nominal Costs

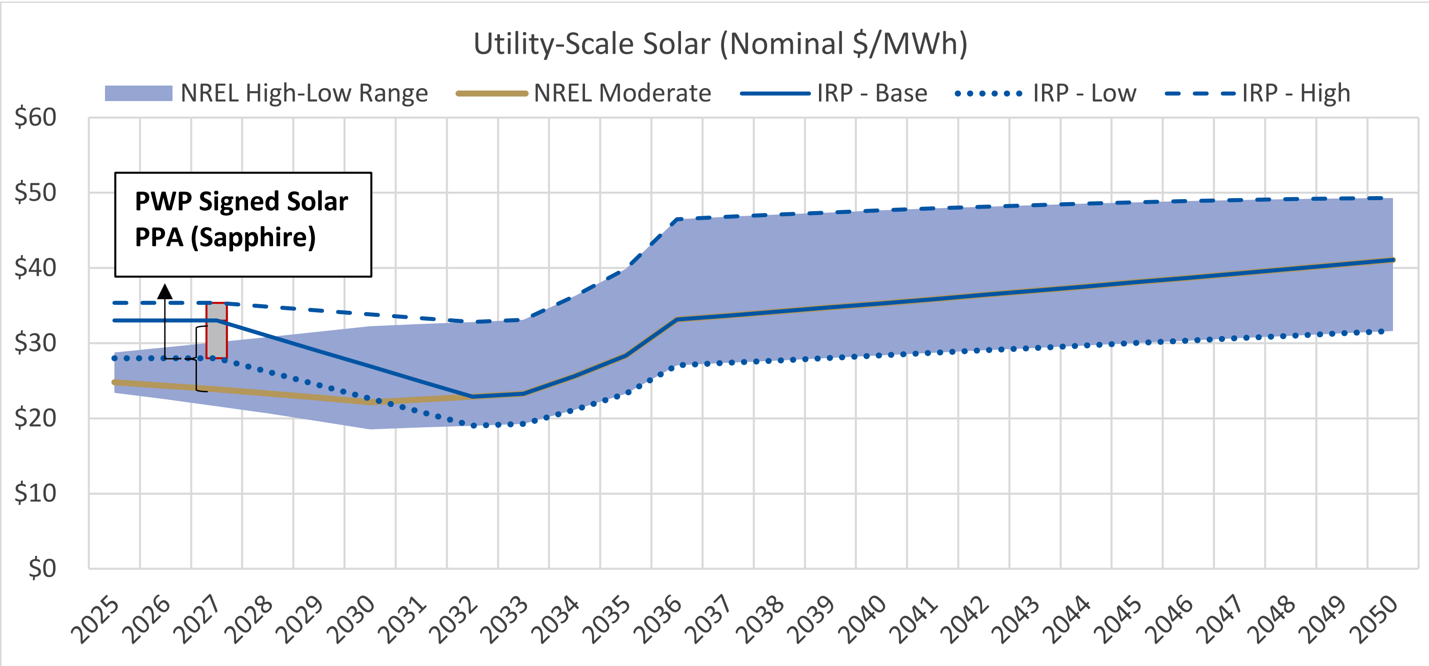
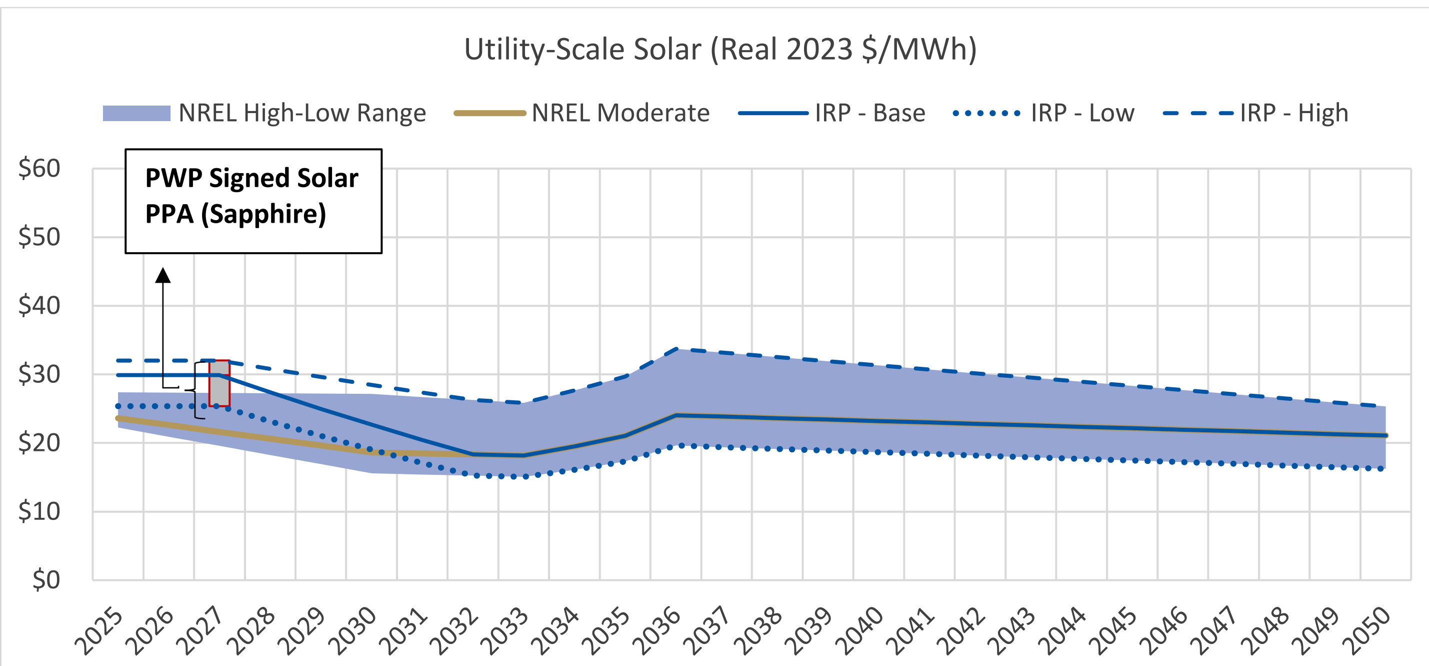


Figure 223: Utility-Scale Solar Real Costs



26.2. Commercial Solar

Figure 224: Commercial Solar Nominal Costs

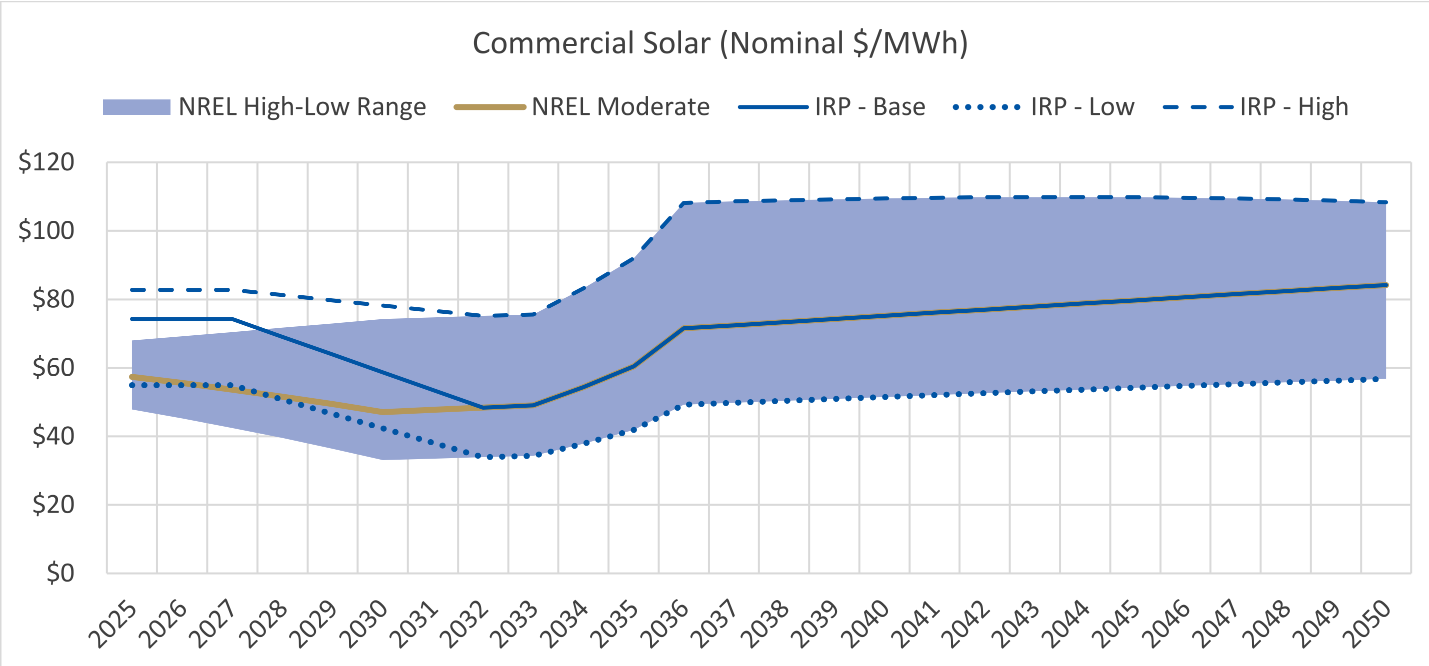
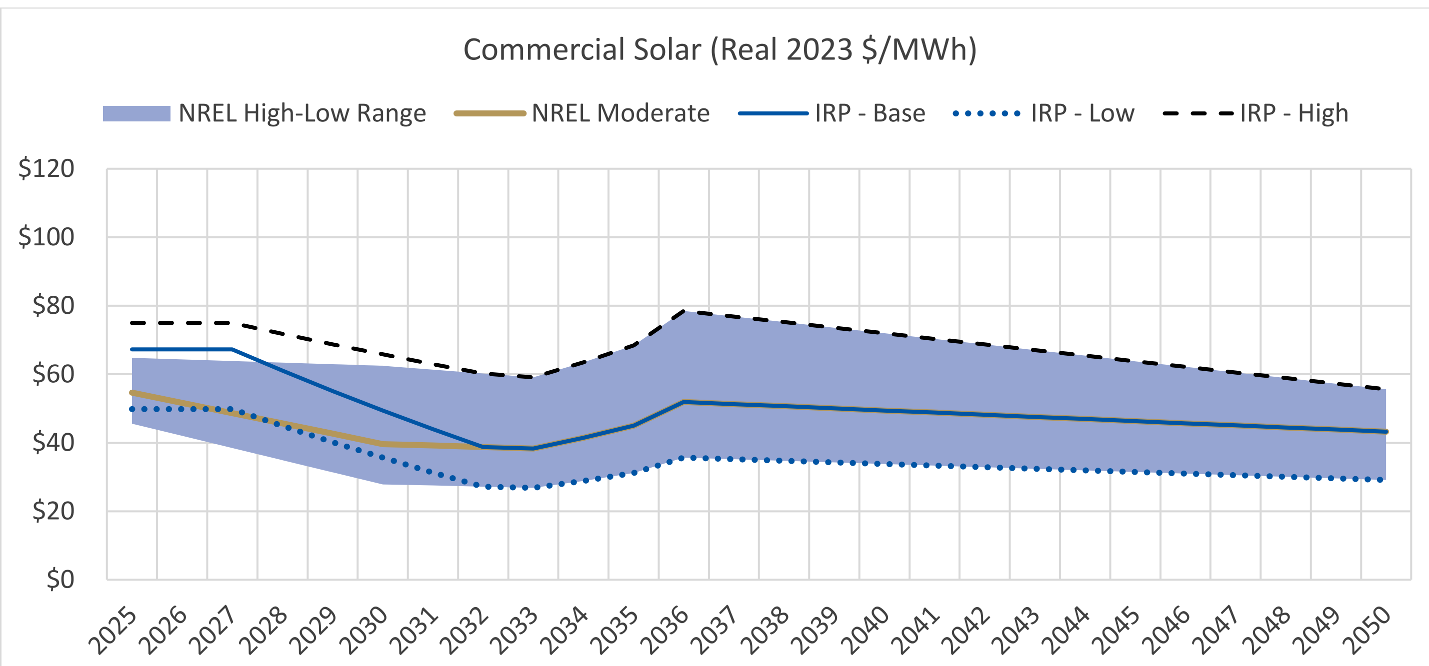


Figure 225: Commercial Solar Real Costs



26.3. Residential Solar

Figure 226: Residential Solar Nominal Costs

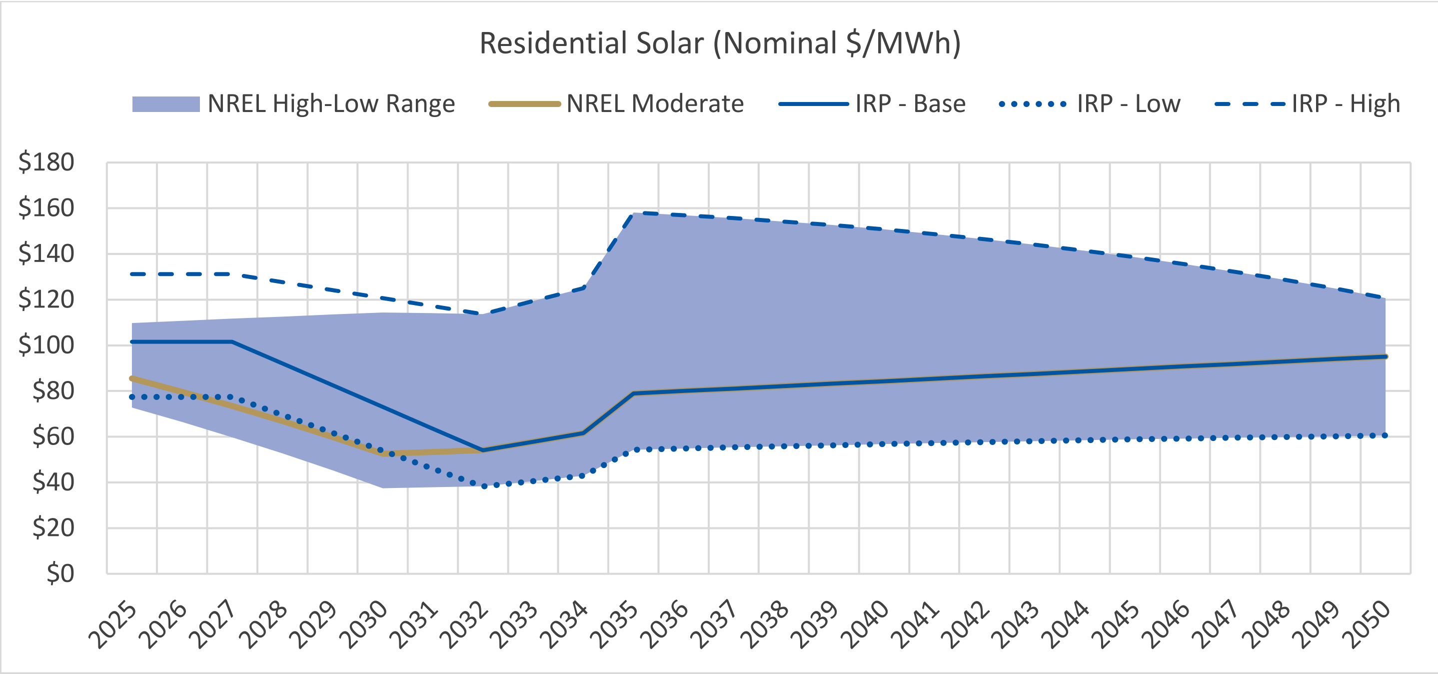
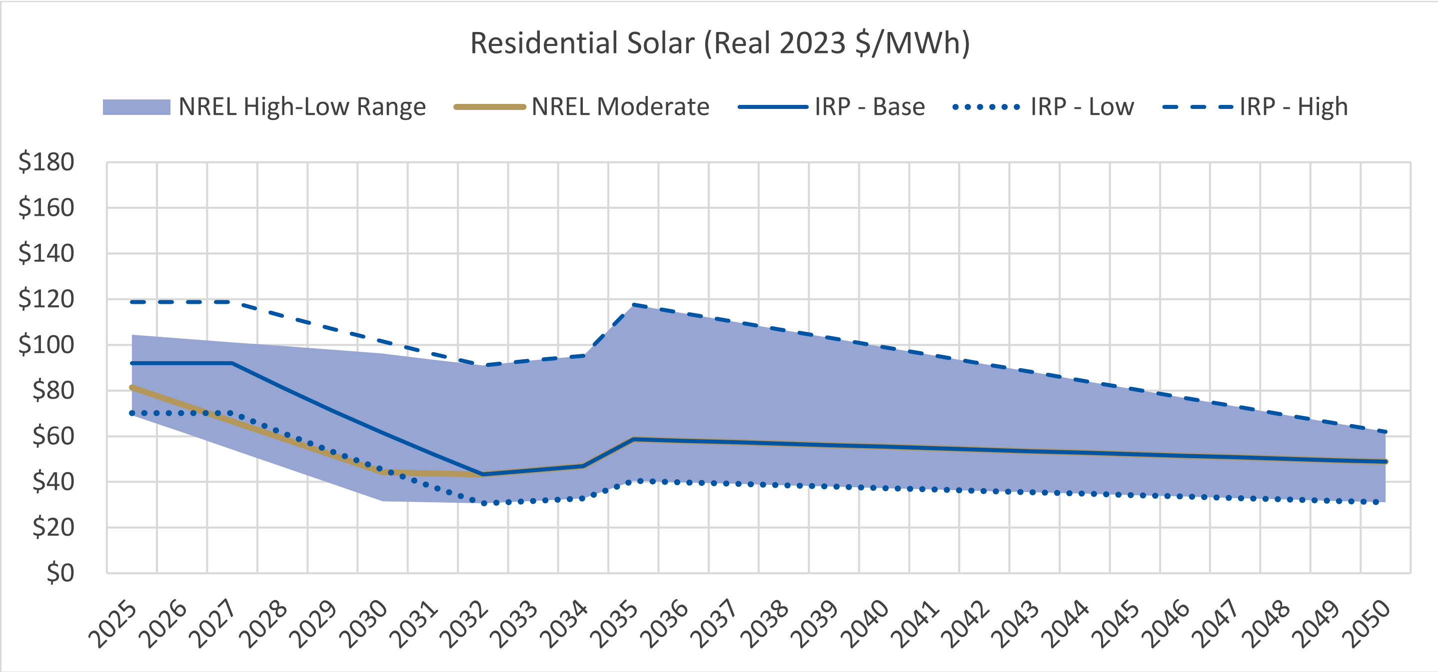


Figure 227: Residential Solar Real Costs



26.4. Utility-Scale 4-Hour Storage

Figure 228: Utility-Scale 4-Hour Lithium-Ion Battery Storage Nominal Costs

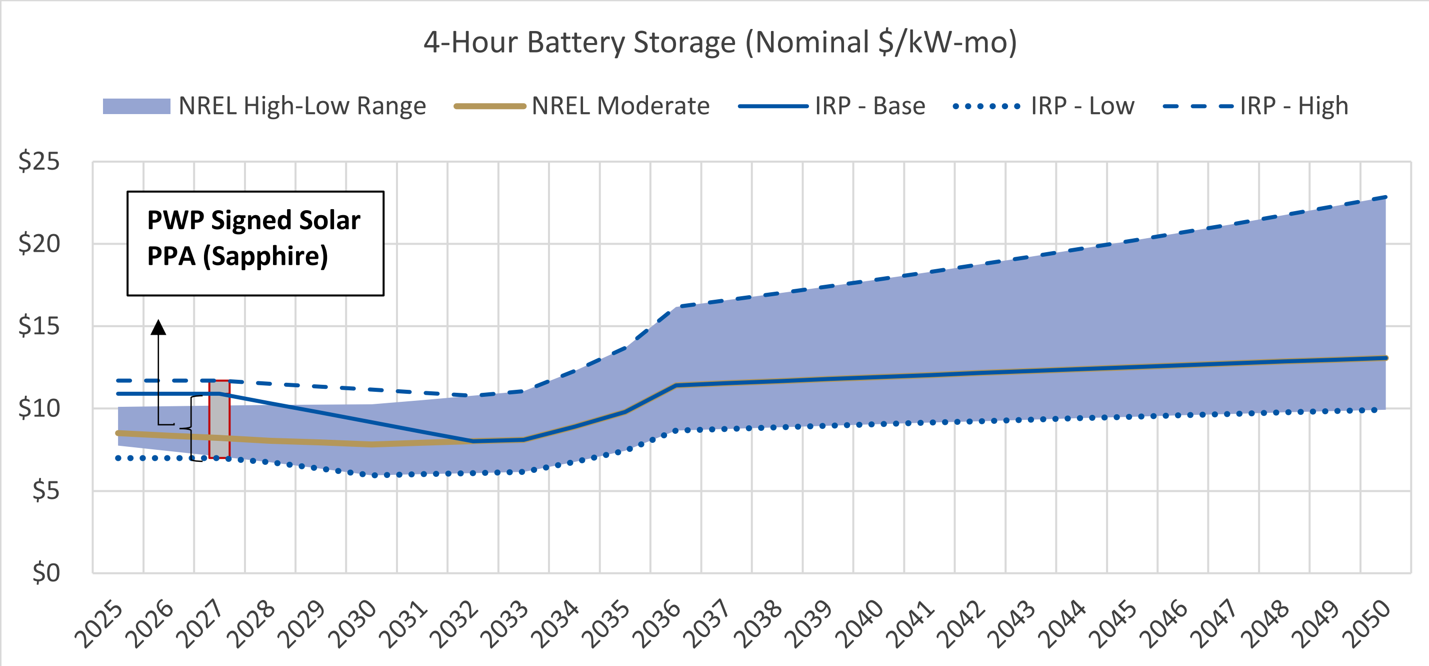
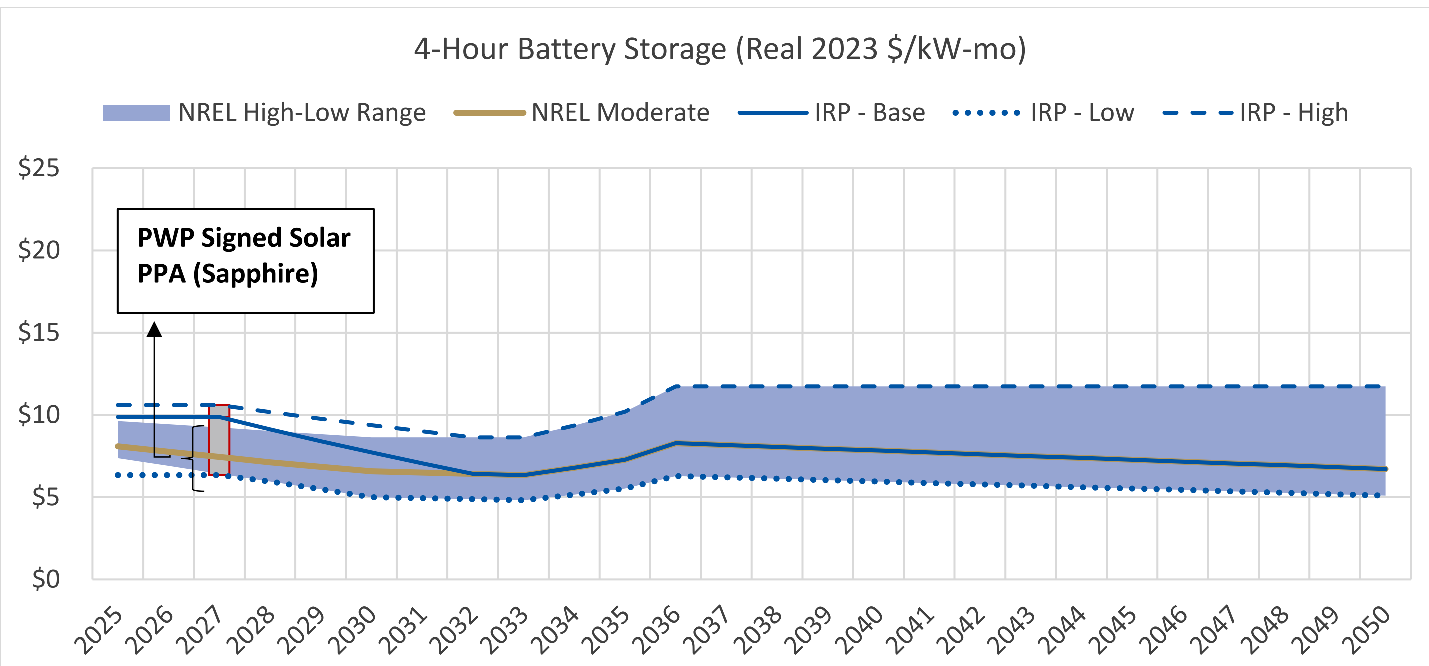


Figure 229: Utility-Scale 4-Hour Lithium-Ion Battery Storage Real Costs



26.5. Utility-Scale 6-Hour Storage

Figure 230: Utility-Scale 6-Hour Lithium-Ion Battery Storage Nominal Costs

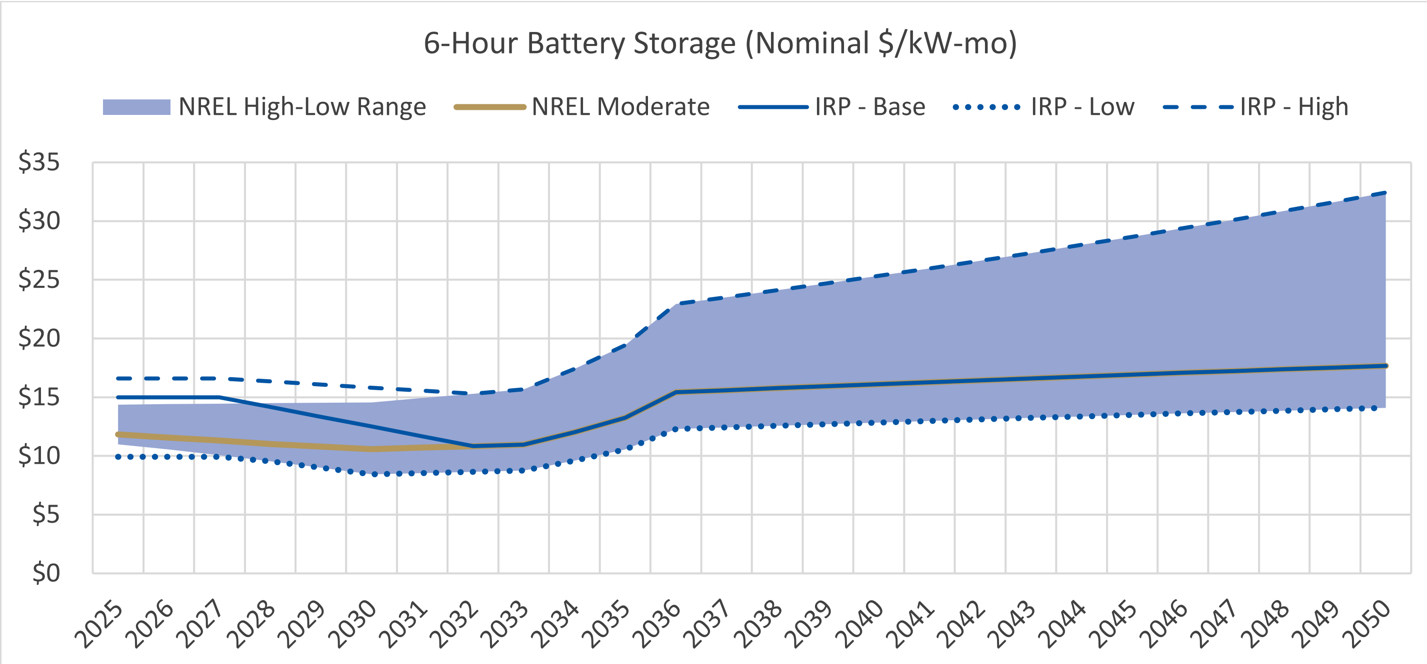
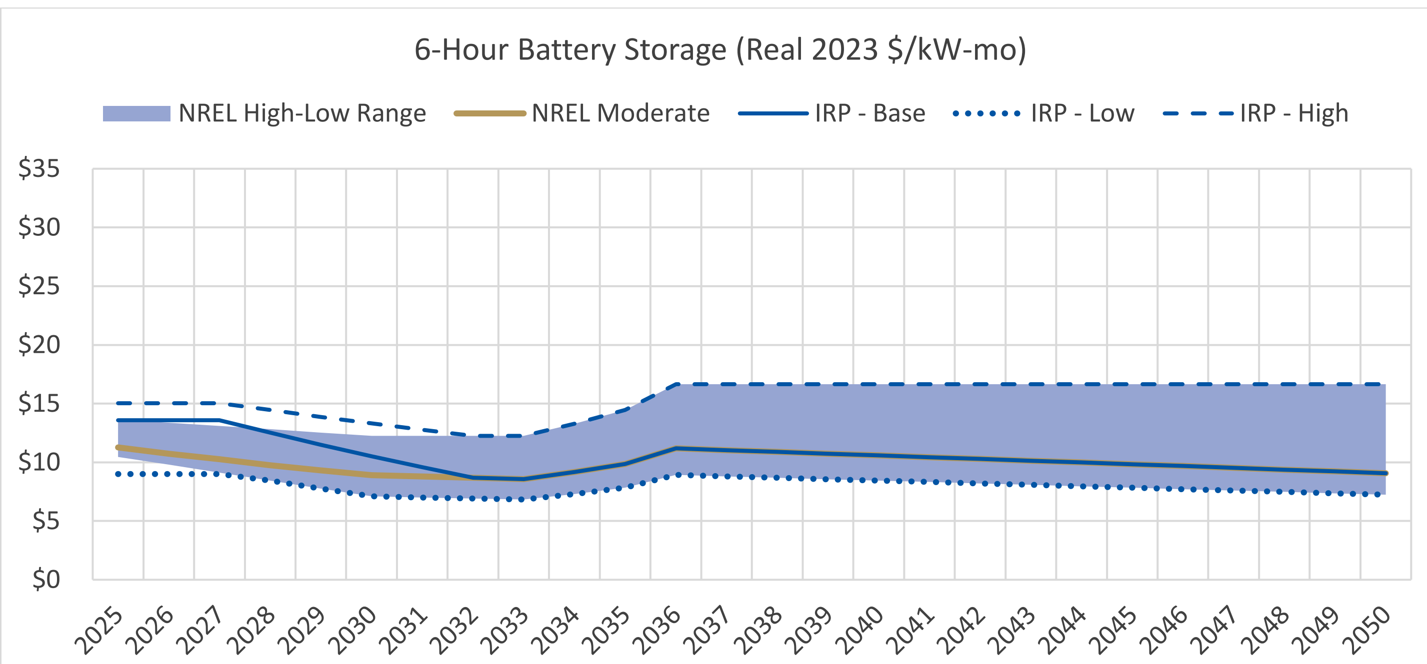


Figure 231: Utility-Scale 6-Hour Lithium-Ion Battery Storage Real Costs



26.6. Utility-Scale 8-Hour Storage

Figure 232: Utility-Scale 8-Hour Lithium-Ion Battery Storage Nominal Costs

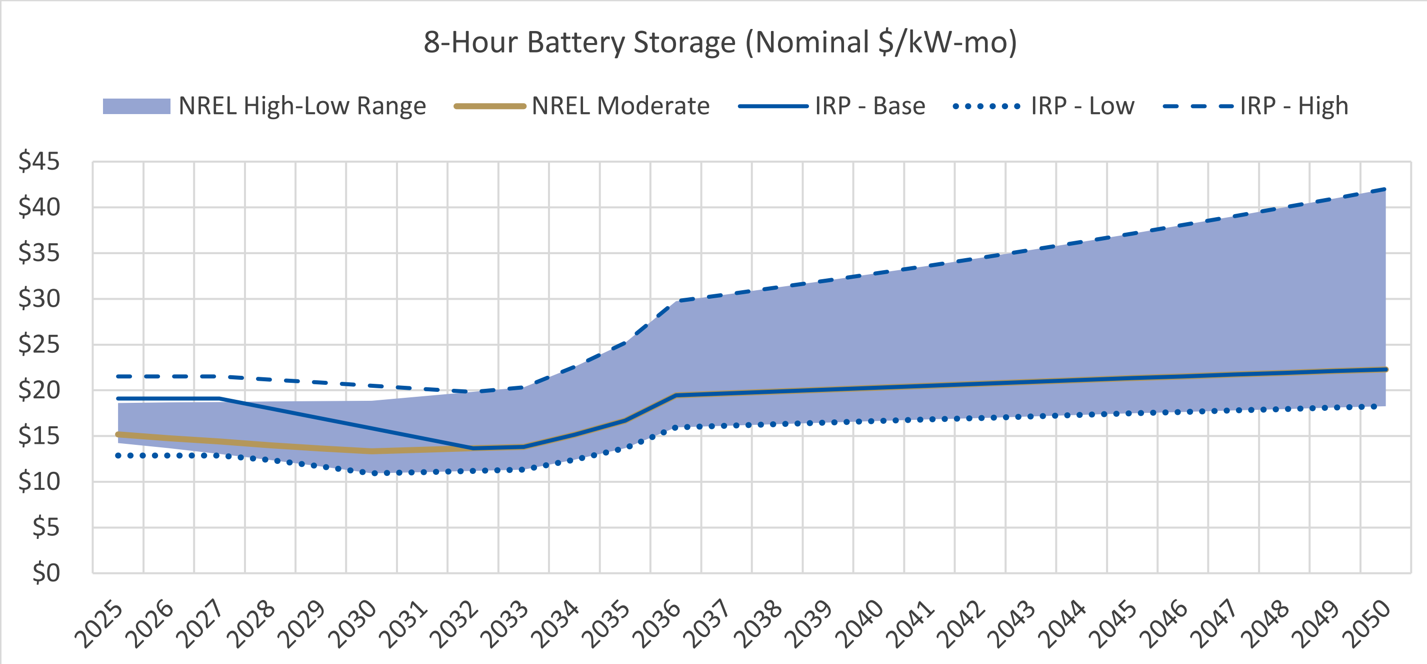
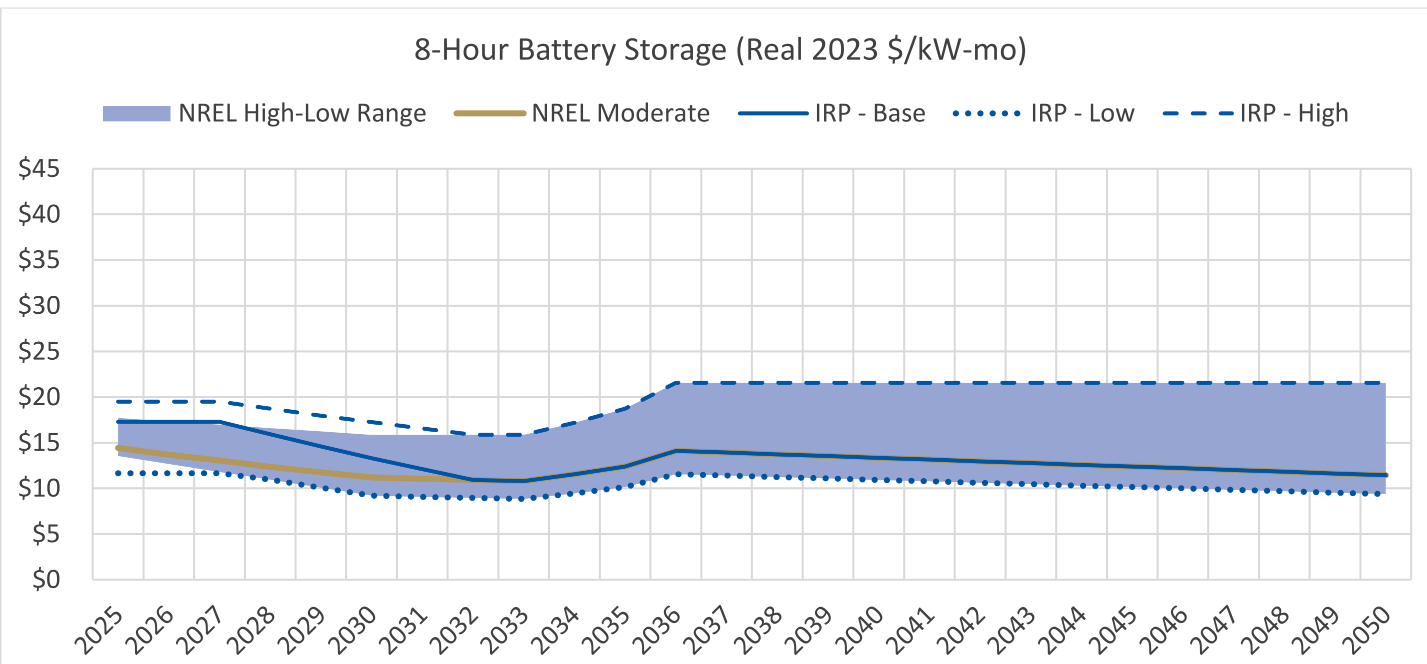


Figure 233: Utility-Scale 8-Hour Lithium-Ion Battery Storage Real Costs



26.7. Utility-Scale 10-Hour Storage

Figure 234: Utility-Scale 10-Hour Lithium-Ion Battery Storage Nominal Costs

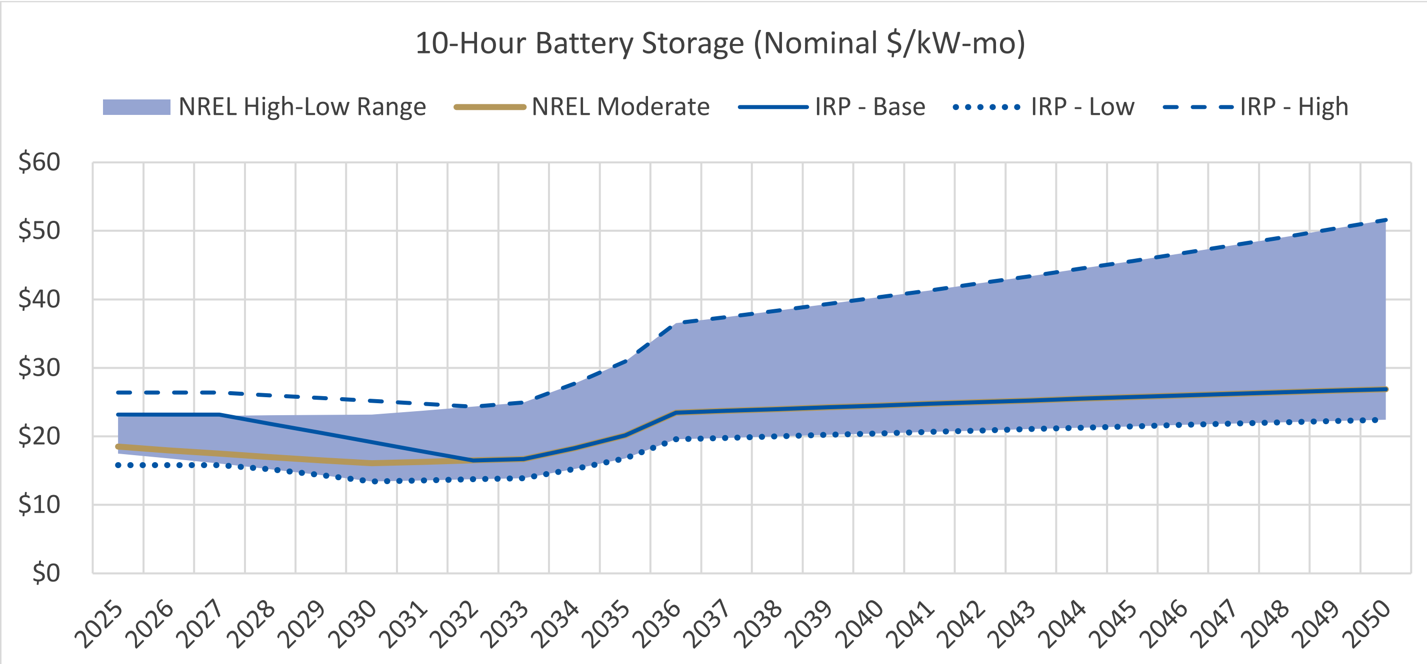
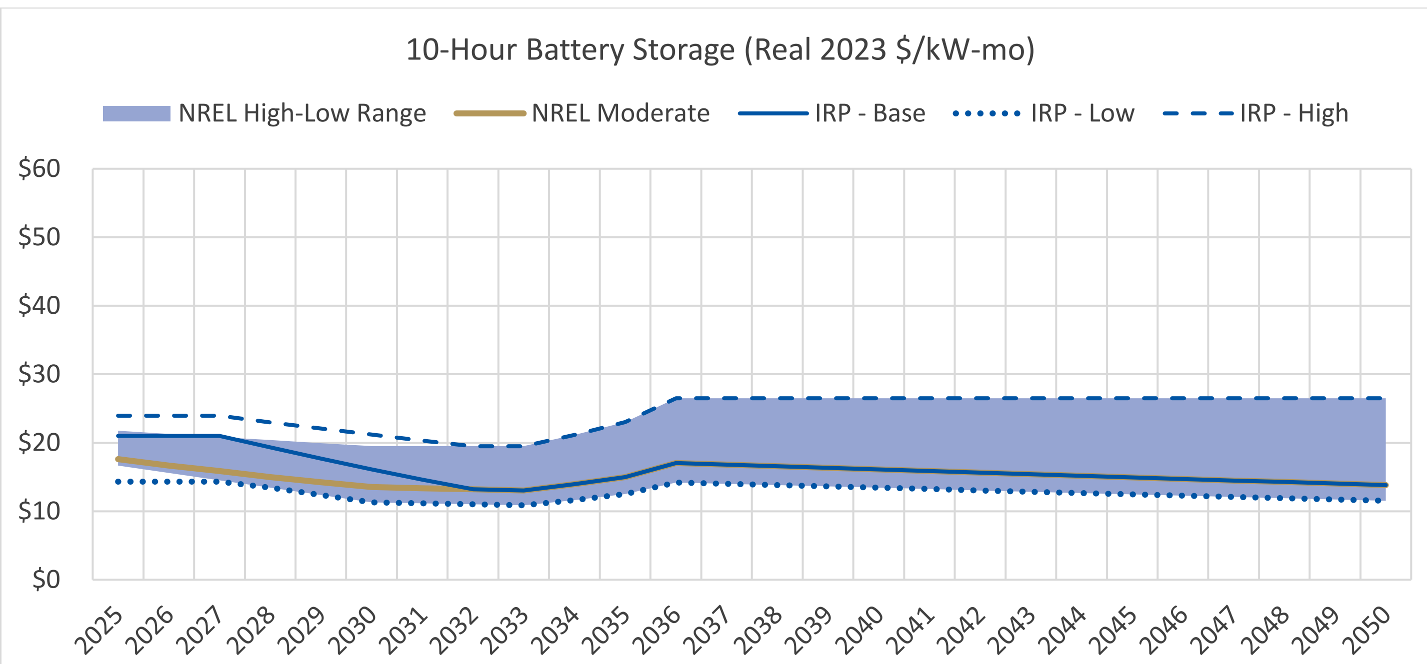


Figure 235: Utility-Scale 10-Hour Lithium-Ion Battery Storage Real Costs



26.8. Commercial 4-Hour Storage

Figure 236: Commercial 4-Hour Lithium-Ion Battery Storage Nominal Costs

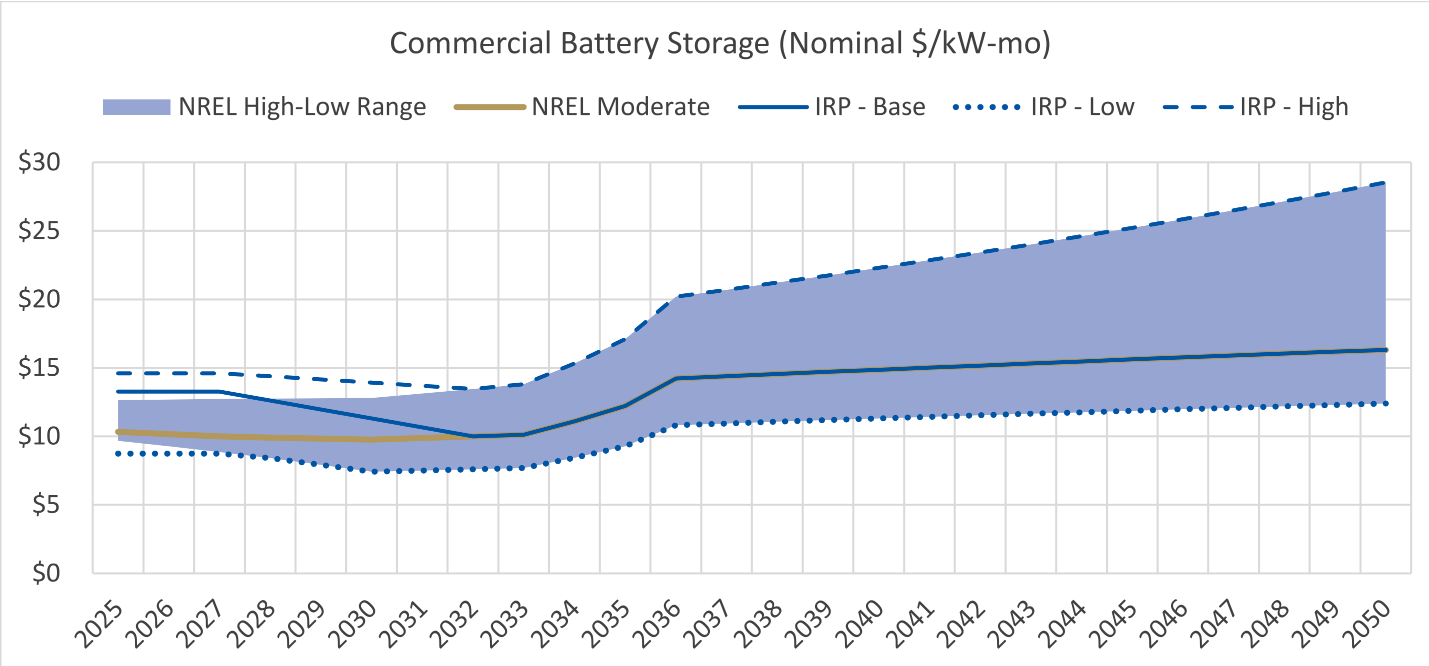
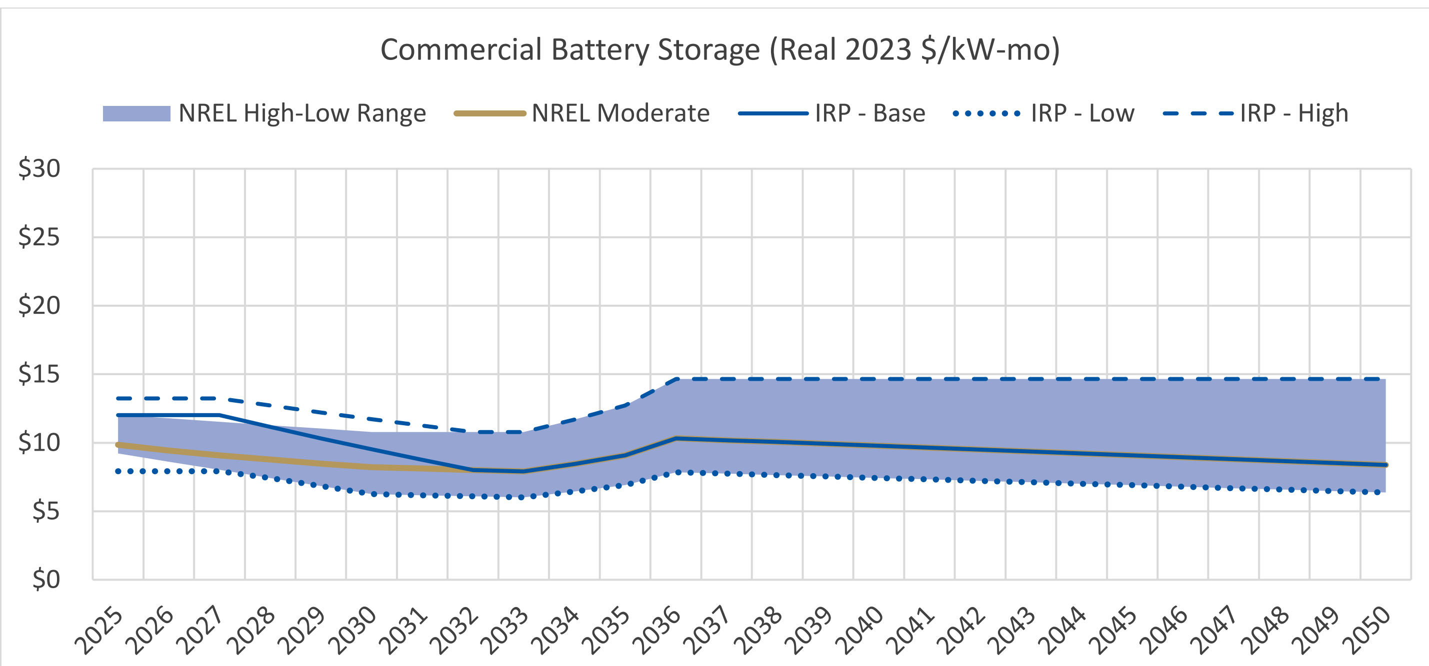


Figure 237: Commercial 4-Hour Lithium-Ion Battery Storage Real Costs



26.9. Residential 2.5-Hour Storage

Figure 238: Residential 2.5-Hour Lithium-Ion Battery Storage Nominal Costs

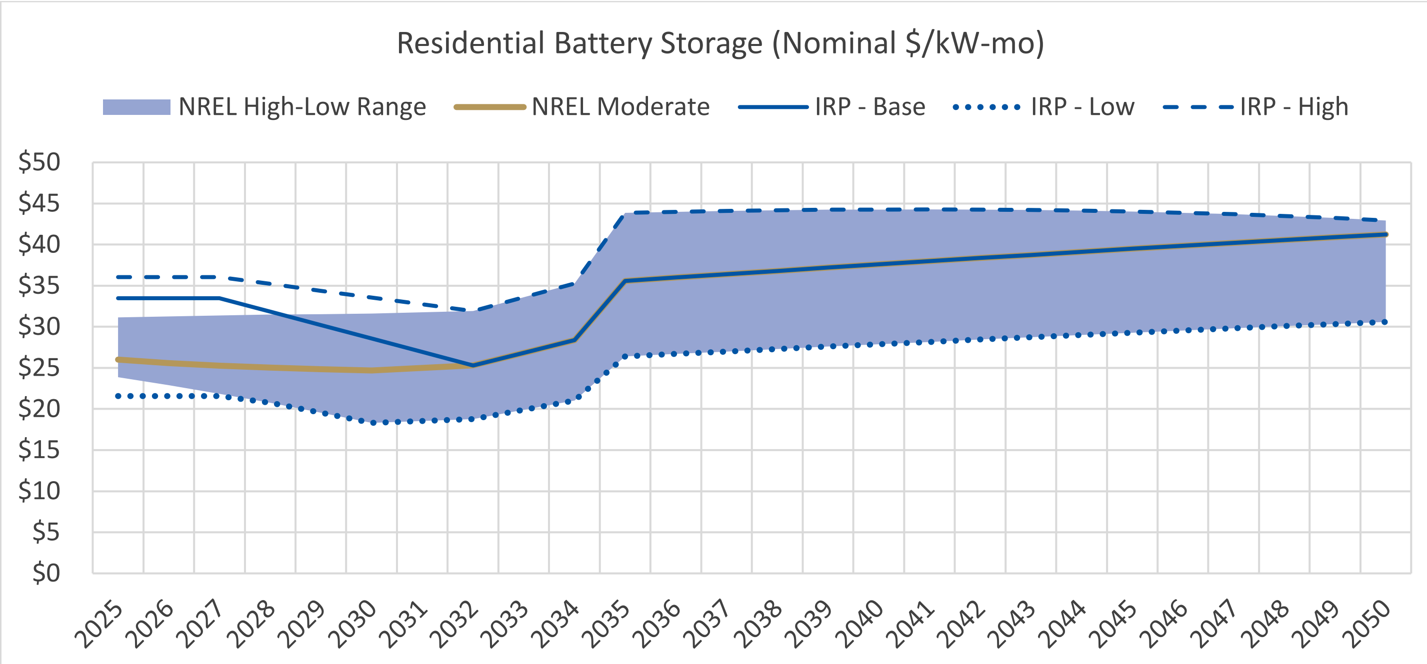
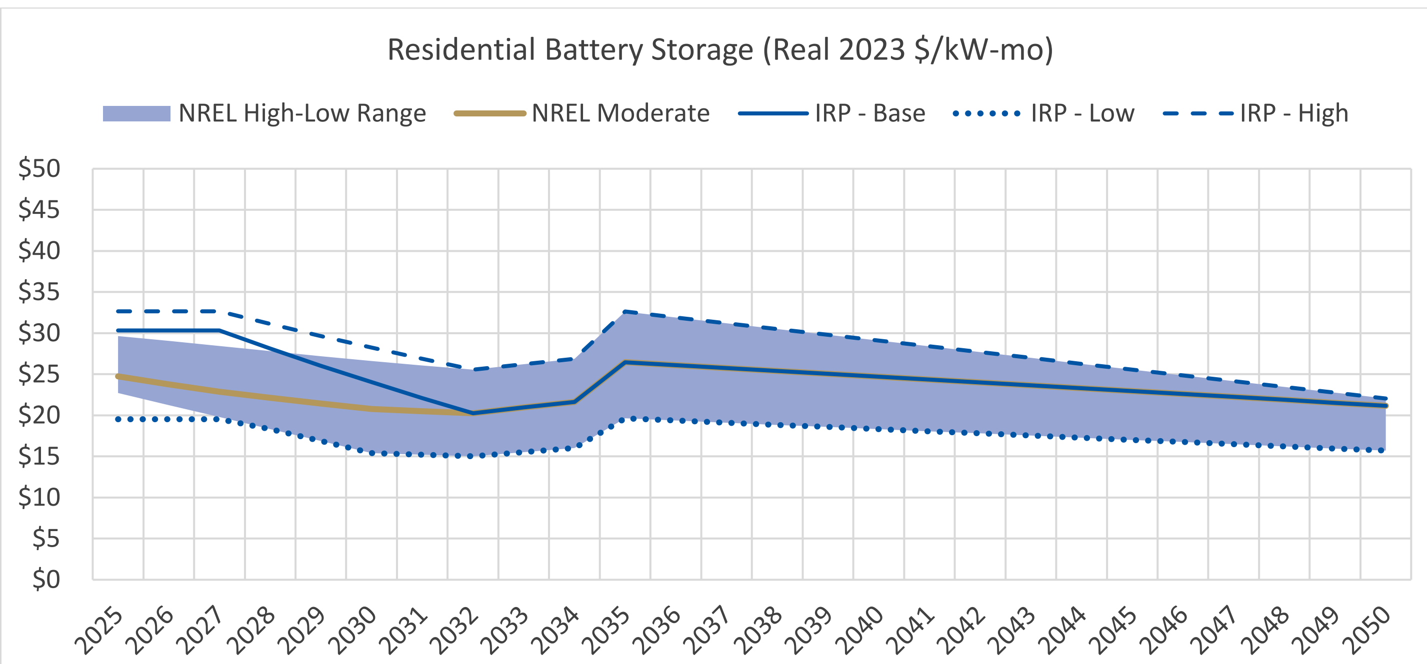


Figure 239: Residential 2.5-Hour Lithium-Ion Battery Storage Real Costs



26.10. Fuel Cells

Figure 240: Fuel Cells Nominal Costs

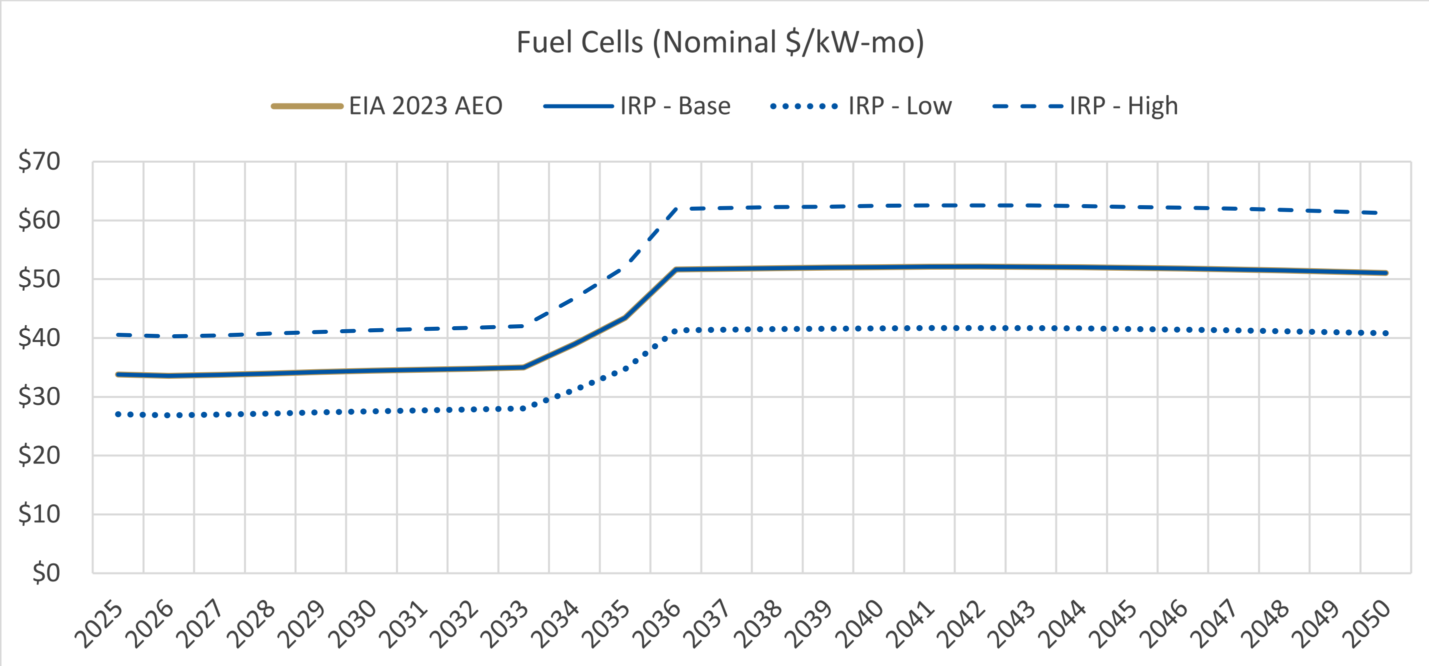
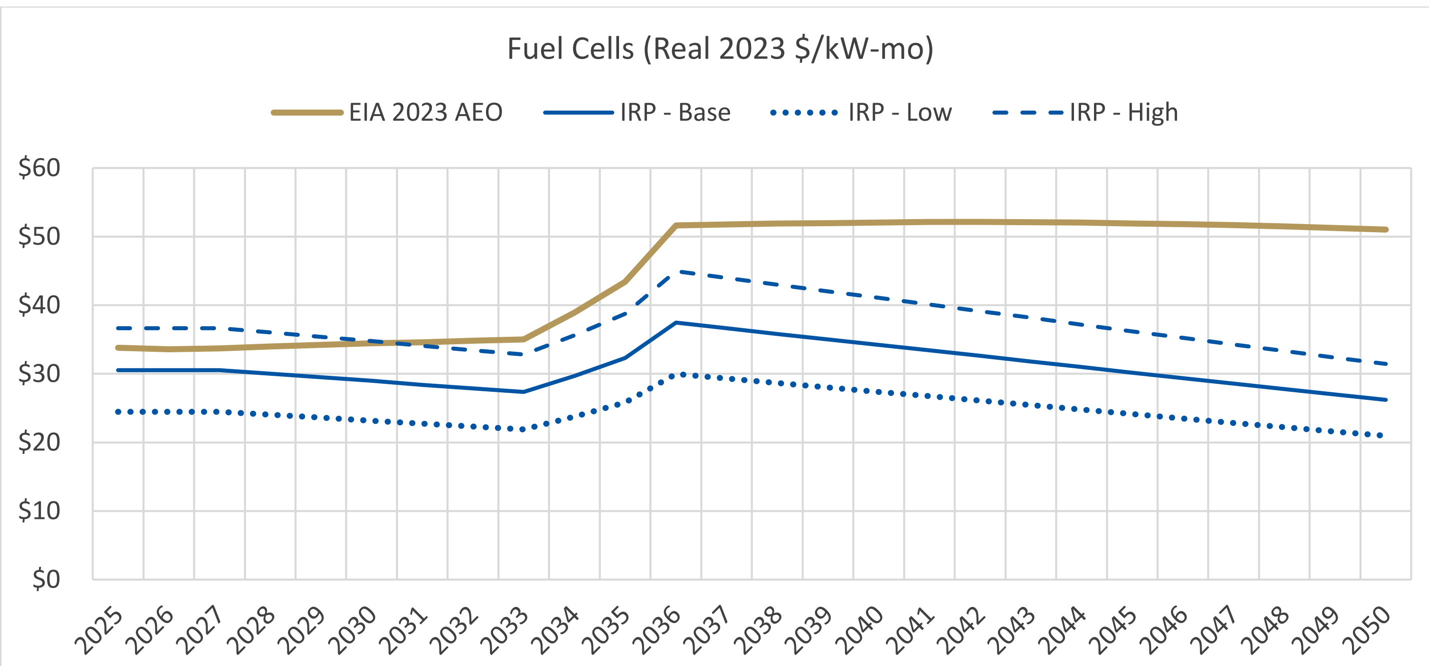


Figure 241: Fuel Cells Real Costs



26.11. Land-Based Wind

Figure 242: Land-Based Wind Nominal Costs

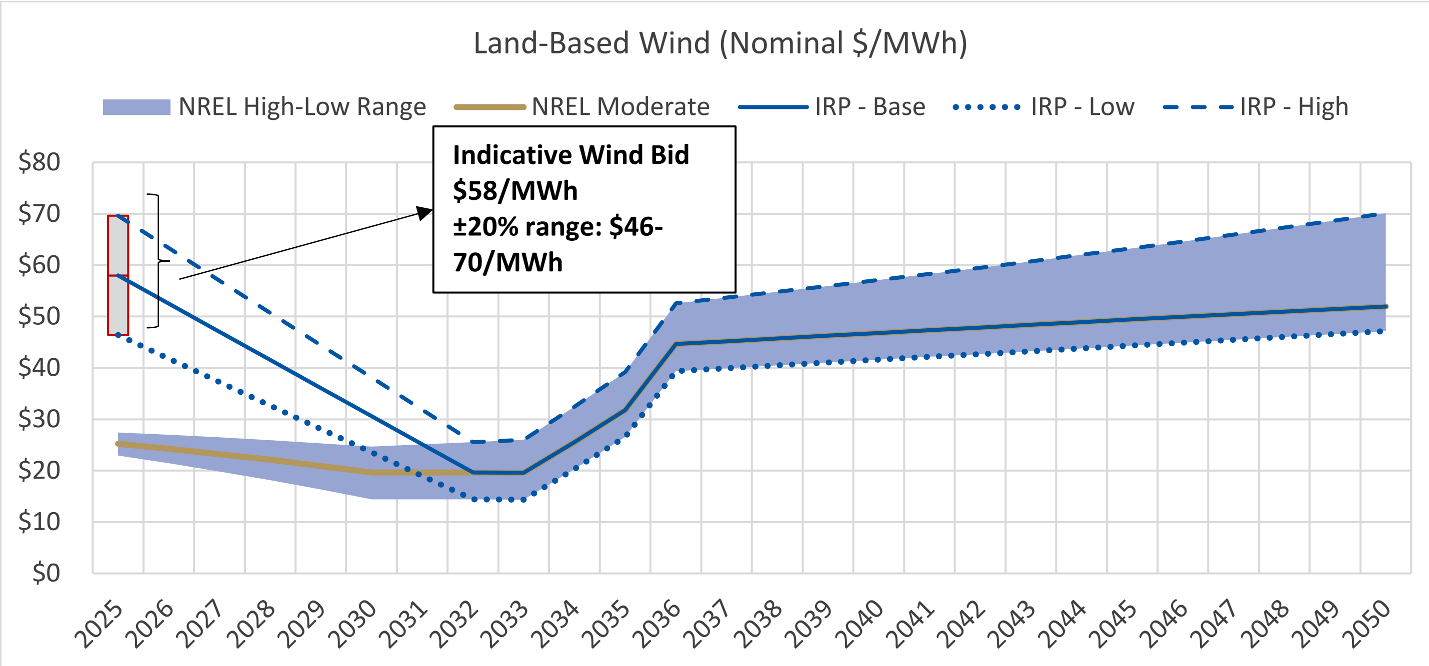
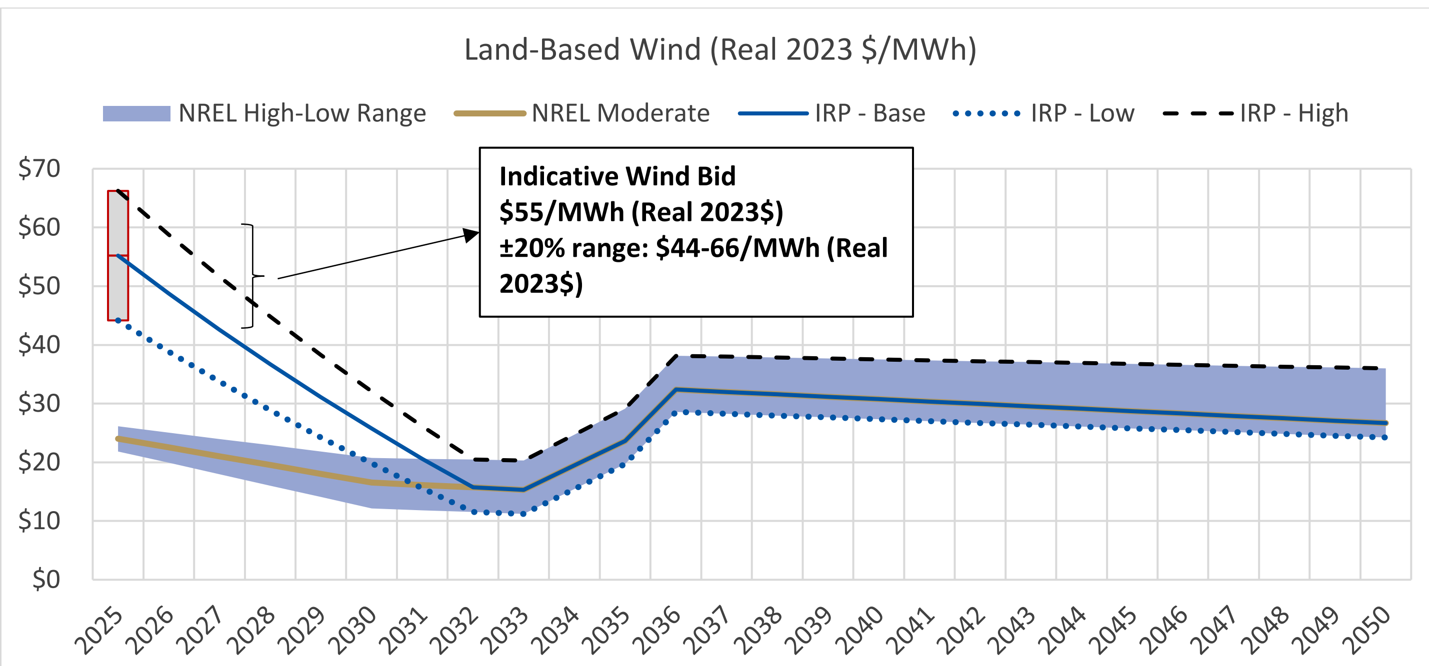


Figure 243: Land-Based Wind Real Costs



26.12. Offshore Wind

Figure 244: Offshore Wind Nominal Costs

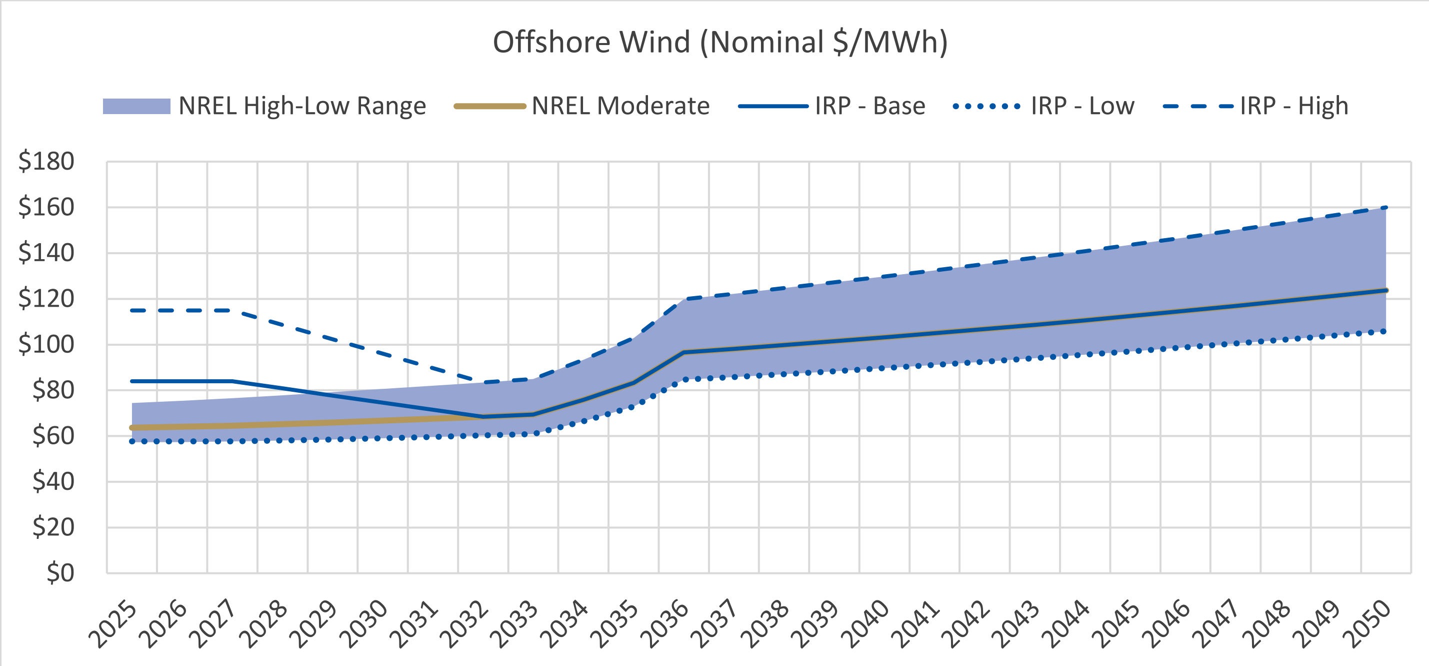
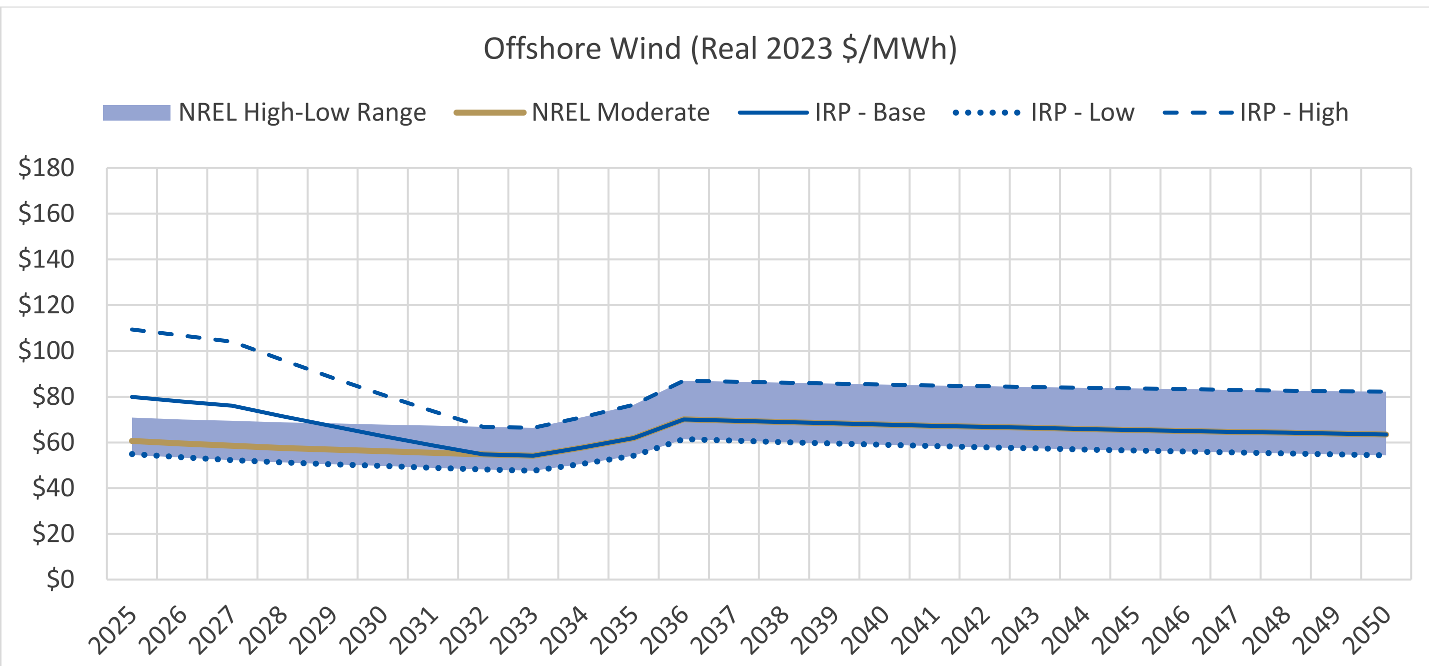


Figure 245: Offshore Wind Real Costs



26.13. Geothermal

Figure 246: Geothermal Nominal Costs

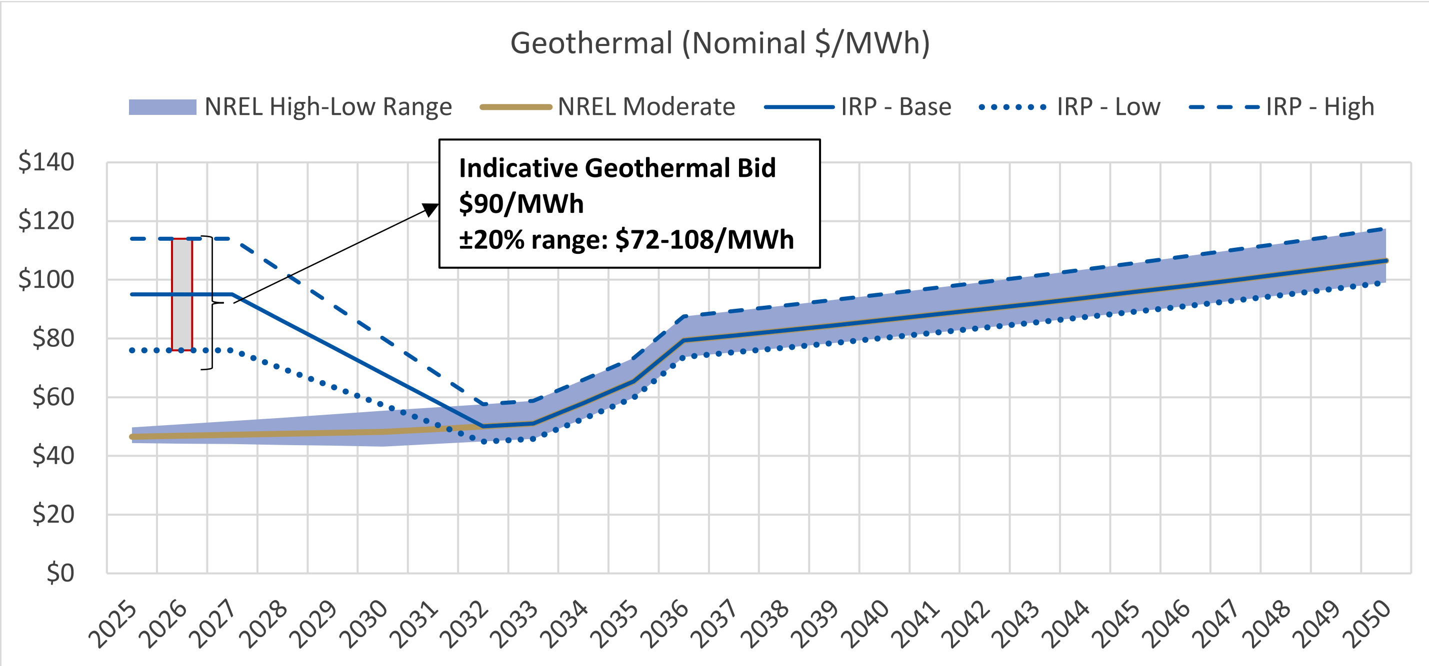
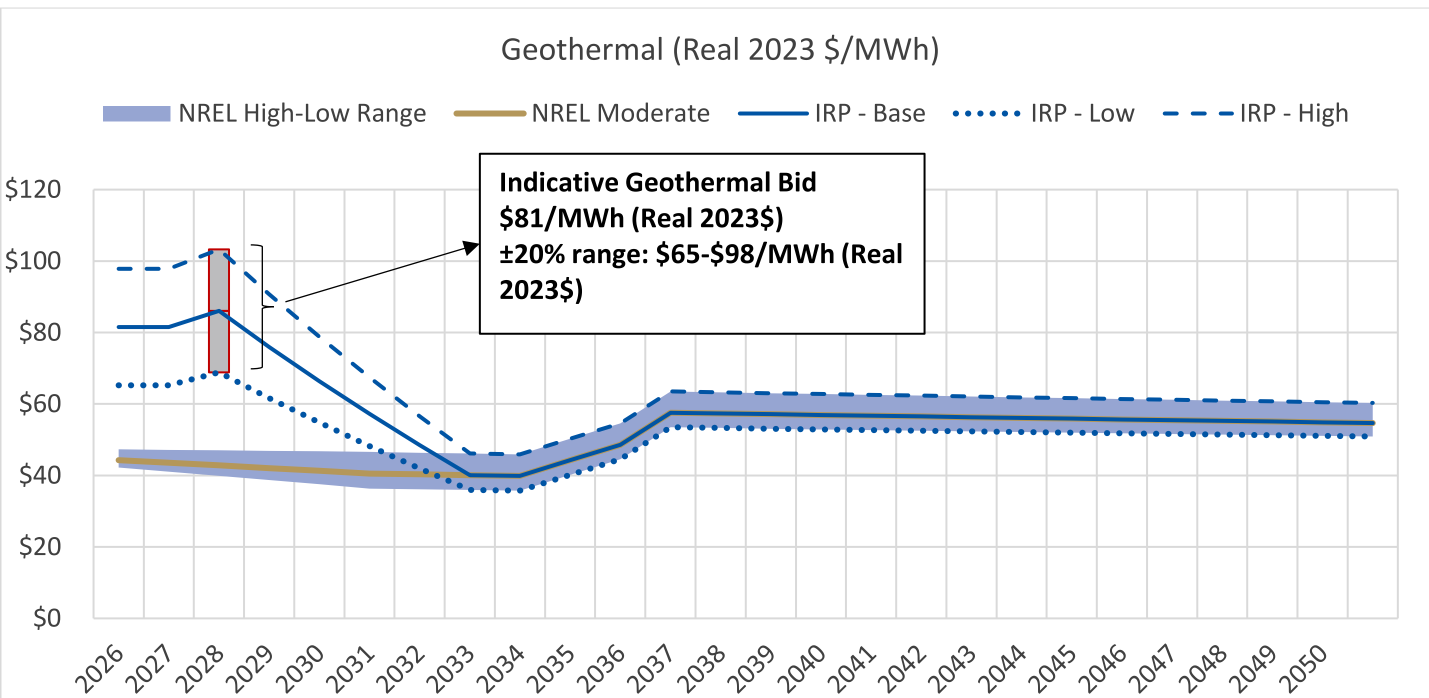


Figure 247: Geothermal Real Costs



27. Appendix - E3 Technical Review of Pasadena Water and Power's Integrated Resource Plan

27.1. Executive Summary

October 31, 2023

Energy Environment and Economics (E3) was contracted by Pasadena Water and Power (PWP) as a technical reviewer to provide validation, critiques, and insights to support the 2023 Integrated Resource Plan (IRP), which explores a set of scenarios to achieve a goal of a carbon-free electricity portfolio by 2030. E3 has worked extensively with utilities throughout North America (and specifically California) to develop high-quality, robust IRPs, providing both direct analytical support and critical analytical review to utilities seeking to decarbonize their portfolios while maintaining reliability.

The scope of this review consisted of a 1) evaluation of the methodology for consistency with industry standards, 2) review of inputs and assumptions, and 3) validation of results and key findings.

Overall, E3 found that the IRP framework as well as inputs and assumptions to be consistent with industry standard practices used by many utilities in long-term planning. Additionally, the results align with common trends seen in other jurisdictions seeking to decarbonize the electricity sector. All scenarios considered, including the Reference Case, reach ambitious carbon reduction goals by 2030 and 2040, achieving 80-100% and 90-100% carbon emissions reductions, respectively.

27.2. Key Takeaways

1) E3 finds that the overall IRP process and methodology is consistent with regulatory requirements and current industry standard practice.

- IRP aligns with the California Energy Commission (CEC) submission guidelines.
- Planning framework is transparent, engages stakeholders, and sets clear objectives.
- Analysis utilizes industry standard capacity expansion and system operation models.

2) E3 finds that the IRP inputs and assumptions, which were accessible for this review, are reasonable long-term planning assumptions, sourced from credible public sources where possible.

- Key sources include the CEC Integrated Energy Policy Report (IEPR) and the National Renewable Energy Laboratory Annual Technology Baseline (NREL ATB).
- Results of the IRP should be interpreted within the context of a rapidly shifting and uncertain market for clean energy; recent increases in PPA pricing provide an indication of directional changes in the industry that will impact costs of future decisions and will warrant continued monitoring as PWP makes progress towards its goals.

3) **E3 concludes that the technical results are generally consistent with studies of ambitious clean energy objectives studied by other utilities and research institutions.**

- All portfolios include a mix of renewables, energy storage, and “firm” resources (resources capable of operating at full capacity over sustained periods of time), following a common blueprint for electricity sector decarbonization observed across a range of studies.
- Scenarios that meet PWP’s 2030 carbon-free goal are more ambitious than most of its peers’ current goals, which requires significant additional resources and results in high costs: the implied cost of carbon abatement in these scenarios exceeds the social cost of carbon
- Reliance on hydrogen fuel cells is a unique aspect of PWP’s carbon-free portfolios; most other plans retain or repurpose natural gas until a commercial “clean-firm” alternative is viable.

While we find the overall IRP analysis and results to be generally reasonable, we also provide PWP with recommendations for future improvements to the IRP. Most importantly, we recommend that PWP continue to refine its forward-looking analysis of its system reliability needs to ensure that any plan developed ensures reliability for its customers.

28. Appendix - Addendum – Supplemental Information

28.1. Introduction

This Addendum satisfies the follow-up documentation and commentary requirements directed by the Municipal Services Committee (MSC) during its November 14, 2023 meeting deliberations. Staff were directed to return with the following supplemental information for further discussion and consideration:

- Create an incremental 2026 Waypoint, allowing for future evaluation and technical analysis of the planned Goodrich Receiving Station upgrades and the required key system modifications as described in the Power Delivery Master Plan (PDMP).
- Provide incremental timeline and detail associated with the planned 2024 PWP’s Electric Rate Study.
- Provide incremental DER and DR information and concepts.
- The Implementation Plan patterned after Carbon Free Scenario 2 modeling results, identifies DER and DR resource types.
- MSC directed staff to provide commentary of dashboard concepts that could be used to assist in the future monitoring and communication.

28.2. Addition of 2026 Waypoint – Goodrich Transfer Station Updates

Consistent with MSC’s directive, a 2026 Waypoint has been added that will provide a specific and pointed opportunity to review the Goodrich Transfer Station required upgrades. Per protocol, the PDMP, which is updated every five years, is a comprehensive 100+ page document that addresses the capital infrastructure, capital investment, and capital replacement planning for the Distribution and Sub-transmission system. The PDMP also includes significant detail specific to the Goodrich Receiving Station.

From a technical perspective, the size, capability, design consideration and megavolt-amperes (MVA) metrics of the power transformers at Goodrich may be of heightened interest, but the overall capabilities of the Distribution and Sub-transmission system capabilities must be jointly and comprehensively considered.

Figure 248: Power Delivery Master Plan

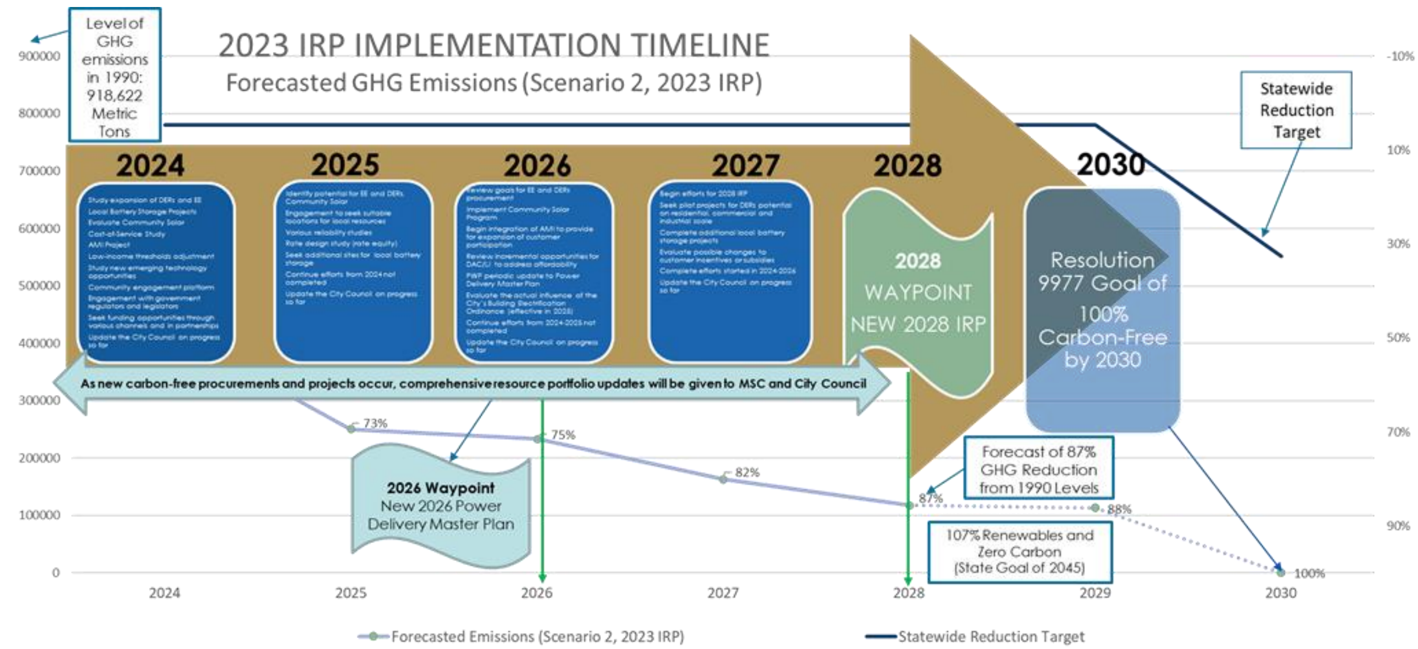
The goals of the PDMP are comprehensive and require infrastructure investment not only to the Goodrich power transformers, but also to the balance of the distribution and sub-transmission networks, which must electrically accommodate the incremental power flows. Engineering review is needed to assure both continued system reliability and ensure electrical protection and preservation of critical system infrastructure.

The five primary goals which are inherent to the Goodrich Transfer Upgrade and the PDWP are as follows:

- Reliability and Safety
- Resiliency
- Power Quality
- Grid Modernization
- Grid Edge (Technology that is customer facing, installed at the “edge” of the grid)

The 2026 Waypoint will be uniquely utilized to provide updated technical reviews and evaluations of the Goodrich Transfer Upgrade, with key considerations that are topical in the present day, and account for developments since the 2022 PDMP.

Figure 249: 2023 IRP Implementation Timeline



28.2.1. PWP is a Transmission-Constrained Electric System

Goodrich plays a key role in supporting reliability in this constrained system. It operates constantly and is the sole interconnection point to the larger CAISO markets. In the review of Goodrich's transfer capabilities, the following key considerations are paramount:

- Improving import capacity up to the 336 MW contractual transmission limit. PWP's ability to use this additional capacity depends on installing larger transformers at the location as well as incremental changes to the 34.5-kv distribution system including upgrading other substations.
- Readying, reviewing, and engineering potential power delivery system modifications to accommodate significant future installations of battery storage capabilities. Engineering studies and associated system impact reviews are required for any significant resource implementation, and the addition of battery storage capacities is no exception.
- The PDMP is updated every five years and driven by the latest IRP. The current plan, which was adopted by the City Council in 2022 and includes the requirements of the 2018 IRP, took 2.5 years to develop and is the culmination of 22 studies on various topics. Accordingly, the next update is planned for 2026 and will require significant modeling and estimating to identify the projects, sequencing, expense, and resources needed to support the 2023 IRP and its 2030 goals.

28.2.2. Cost Considerations – PDMP

Since the adoption of the 2022 PDMP, the price and availability of infrastructure has been dynamically driven, both by pandemic-related events and the scarcity in key metals that are essential to the utility industry.

The initial estimate for the overall PDMP was $821 million, to be distributed over a number of years to lessen rate impacts. This refreshed cost review will consider impacts from expedited scheduling, new resource costs, and the inflationary environment. These characteristics will be addressed within the 2026 Waypoint evaluation.

28.2.3. Supply Chain – Custom Manufacturing

The power transformers at Goodrich will require custom manufacturing. Considering the current transformer backlog that the industry is experiencing, this requirement will be reviewed to assure appropriate actions are taken to include expediting, where might be required, in order to meet Carbon-Free policy goal requirements. This condition will also be specifically evaluated at the 2026 Waypoint.

28.2.4. Construction Schedule: Opportunities to Expedite or Defer Projects

The actual infrastructure upgrades of the Distribution and Sub-transmission system must be carefully coordinated as portions of the existing system will likely be out of service for significant periods of time while new infrastructure is being constructed.

The 2026 Waypoint will be an opportunity to refresh construction schedule assumptions, project planning considerations, and contingency analysis. Moreover, there are coordination and approvals required from the CAISO and/or other regulatory entities, as removing key transmission infrastructure such as Goodrich Receiving Station components may have impact on the surrounding Bulk Electric System.

28.2.5. Summary

The coordination associated with Goodrich Receiving Station will be refreshed in 2026, as part of prudent preparations supporting the 2030 Carbon-Free policy goal. The dynamic considerations noted in this document as well as others, will be part of the 2026 Waypoint analysis specific to the Goodrich Receiving Station Upgrades.

28.3. 2024 Rate Study

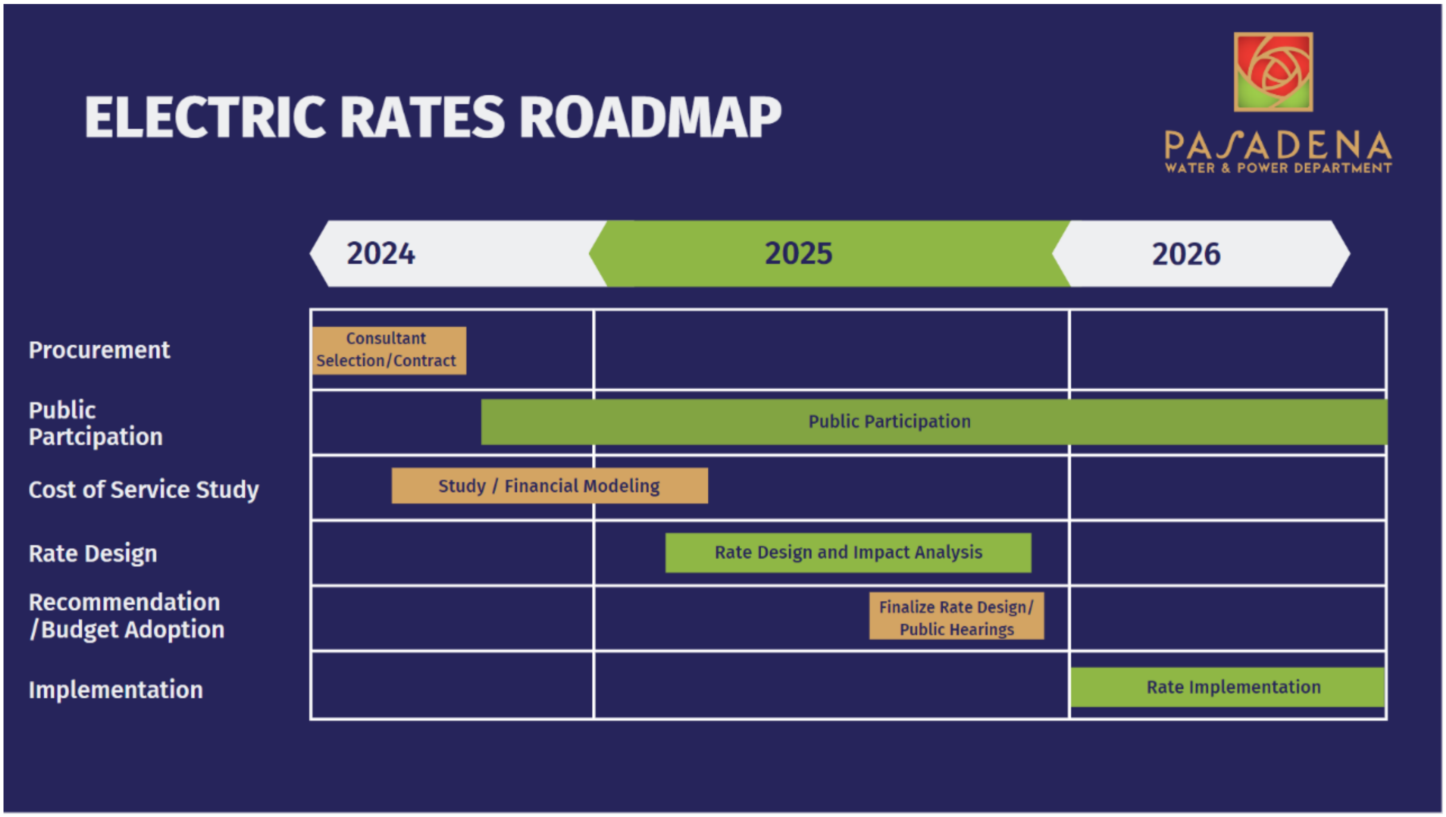
Utility Cost of Service and Rate Design (COS) studies are long-established foundational tools for evaluating, reviewing, and establishing utility rates. PWP is planning a COS in 2024 which will include a comprehensive review of PWP's power system costs, allocations, and budgetary categories. The COS will also examine customer usage behaviors, by customer type, to provide a better understanding of how each would be impacted by various rate structures, while also better documenting how each customer class utilizes and relies upon the PWP system.

The findings of the analysis and proposed rate designs will provide the basis for electric rates for a 10-year period and produce a rate model that can easily be adjusted for changes in energy policy requirements. The model will also help identify rates to support new technologies such as Time of Use (TOU) rates, Net Energy Metering (NEM), Customer Self-Generation, Metered EV rates, and low-income assistance programs.

In order to recover and allocate system costs effectively, several key factors will be considered in the COS modeling including AMI program implementation, DER and DR expansion, Utility-Side Energy Storage, elimination of carbon-based energy supply, stranded investments, expansion of assistance programs, development and implementation of the IRP and PDMP, and regulatory compliance requirements.

A Request for Proposals (RFP) for the COS study is planned for early December 2023. As PWP engages further with respondents leading to eventual selection, a formal project timeline will be produced. However, many COS timelines may involve an 18-month execution window leading to eventual rate approvals.

Figure 250: Electric Rates Roadmap



PWP will fundamentally transform its electricity supply and needs to study the associated customer impacts. Pasadena's goal is to develop and adopt a series of electric rate designs that are based on cost-of-service principles.

The intent of the COS evaluation is:

- To perform a comprehensive review of PWP's power system costs, allocations, and budgetary categories;
- To assess customer characteristics and customer classifications;
- To design various rate structures, and to evaluate their impacts on customers; and
- To develop a flexible, non-proprietary working rate model that will be conveyed to the City of Pasadena.

The working model will be able to accommodate adjustments to factors such as integration of renewable energy sources; rising operating, maintenance, and capital needs; stranded investments; normal to extreme weather patterns; overall sales; and customer demands.

Each rate structure option will adequately balance PWP's short- and long-term financial sustainability. The proposed rate structure must meet the electric utility's ongoing operating expenditures, bond covenants, capital improvement needs, and fund reserve requirements. It must also follow accepted industry standards, best practices, and California law. The recommended rate design will align policy goals with pricing strategies to encourage customer behavior that benefits the utility system.

The findings of the analysis and the proposed rate designs will provide the basis for electric rates for a ten-year period and will be configurable to accommodate evolving energy policy requirements. In developing and updating electric rates, PWP and its consultant will consider the following:

- Time of Use (TOU) rates
- Net Energy Metering (NEM) — with and without Advanced Metering Infrastructure or Time of Use metering
- Customer Self-Generation (Non-NEM)
- Metered Rate for Electric Vehicles (EVs) — Residential and Public
- Recovery Adjustments for new Renewable Energy and Power Purchase Agreements (PPAs)
- A Standby Charge for the recovery of fixed costs necessary to make electricity service available to a distributed generation facility
- Low-Income Assistance Programs

The following are some of the key factors that PWP and the consultant will incorporate into their rate recommendations:

- Advanced Metering Infrastructure (AMI) program implementation and data
- Distributed Solar Energy and Storage Resources, and Demand Response
- Utility-Side Energy Storage
- Value of Good Load Factor (Load Shifting Programs)
- Commercial and institutional customers achieving energy independence
- Stranded investments
- Nonrenewal of carbon-based energy supply contracts
- Expansion of assistance programs, including the Electric Utility Assistance Program (EUAP)
- Power Integrated Resource Plan (IRP)
- Power Delivery Master Plan (PDMP)
- Compliance with California Constitution Proposition 26
- Other issues as appropriate

PWP staff and the consultant will present the findings of the analysis and proposed rate design to City Council Committee(s) and the Pasadena City Council for review and approval.

PWP is planning to publish an RFP for this analysis in early December 2023, with proposal evaluations slated for the end of January 2024. The duration of the project will be approximately 18 months, with quarterly informational items to Council Committee(s) as well as a Public Participation Plan to be developed.

PWP will also dedicate staff hours to working with government entities, nonprofit organizations, and other stakeholders to identify areas of support for its goals.

28.4. Distributed Energy Resources (DERs) and Demand Response (DR) – Project Plan Considerations

The increased penetration of variable resources to the electric grid has introduced a greater need for dynamic responsiveness, which in-part can be resolved with the addition of DER and DR resources. Both Scenarios 2 and 3 call for a significant number of distributed resources installed in the PWP service territory. This includes 350-400 MW of distributed solar and the same amount of distributed battery storage installed in Pasadena.

Resource types of DR and DER's can vary, to include adjustable smart thermostats for air conditioning (A/C) and heating, utility triggered water heating deferrals, utility/commercial/residential partnership in limited duration load curtailment and managed electric vehicle (EV) charging/discharging as potential DR considerations, in addition to the potential levels of commercial/industrial and residential DER levels of solar, wind and storage.

This level of distributed resources will need to be unlocked by re-imagining rate structures, incentive programs, the Green Power program, permitting and interconnection procedures, and metering and billing infrastructure requirements.

PWP will engage in proactive approaches such as conducting a detailed distributed resources Market Potential Study. This will include both energy efficiency and distributed resources. This type of study will help PWP evaluate the upper limit of demand-side resources on the system, as well as use the results to design cost-effective programs.

PWP will also perform a Hosting Analysis, which will help PWP identify the optimal location of distributed resources on the system, as well as identify potential distribution system improvements that could enhance the amount of distributed resources in its service territory.

In addition to the existing Load Curtailment Program, PWP will consider additional approaches for enhancing demand response. For example, when PWP implements advanced metering infrastructure, there will be opportunities to explore automated demand response for residential and commercial customers. In addition, the CEC continues to expand its demand response program offerings including the Demand Side Grid Support (DSGS) Program as well as the Distributed Electricity Backup Assets (DEBA) Program. DEBA incentivizes the construction of cleaner and more efficient distributed energy assets that would serve as on-call emergency supply and/or load reduction for the State's electrical grid during extreme events.

In addition to these action items, PWP will continue to evaluate demand-side resources as part of a broader strategy, and further actions will include:

1. Continued review and coordination of State of California, CAISO, and/or CEC offerings of DER programs that meet the benefit criteria.
2. Continued review of existing PWP programs that currently support thermostat control, or other similar devices such as PWP's WeDIP program and its demonstrated Demand Response contributions.
3. Review and consideration of fiscal incentives that align with principles of equity and fairness as defined in State of California, CEC, and local jurisdictional guidance.
4. Review of Public Benefits capabilities, where enhanced flexibility may exist due to the carve-out prescribed in State of California policy provisions.

With the help of hired consultants, and utilizing the experience of other utilities, PWP will take a proactive approach to distributed resource adoption and demand response programs.

28.5. Dashboard

PWP plans to create future web-based dashboards that will serve to provide status updates similar to other past and present initiatives within the City of Pasadena.

While the exact formats of the dashboard(s) are not yet determined, the general components can be generally summarized from the vast amounts of information already presented as part of the 2023 IRP

Examples of potential Dashboard topics could include:

- Status updates of executed, but not yet commercial projects.
- Commercial Operation Date (COD) projections as well as status of key milestones such as environmental reviews of renewable projects in which PWP may have a commercial interest.
- CAISO updates on policies that are anticipated to change over time, and which may have material impact upon the 2023 IRP process.
- CAISO transmission projects which may have material impacts upon projects that PWP may have commercial interest.
- Rate and/or cost impacts, as they occur dynamically.
- PWP reliability statistics
- State of California renewable percentages and RPS compliance

This dashboard will be updated and dynamically augmented over time. But initial considerations could include some of the aforementioned topics.

Annually, and especially at the 2026 and 2028 waypoints, PWP will report progress relative to the IRP progress and status. These updates will be made to the MSC and/or as designated by Utility governance authorities, to the full City Council. With each energy resource contract or program approval request to the MSC and City Council, which is expected to occur multiple times per year, PWP would also use such opportunities to brief the MSC and City Council on overall resource planning activities, including those mentioned in the timeline below. These are normal and historically established approaches used in project or procurement justifications.

28.6. Summary

All IRPs and associated planning documents rely upon information known at the time or available during the planning horizon, such as energy market conditions, anticipated forward pricing of energy resources, and even regulatory and policy requirements of State, Local and Federal governance.

The electric utility industry must also anticipate, in IRPs, that innovation in a variety of technologies is also likely -- innovations such as storage technology or other carbon-free resources that could unlock additional opportunities for further and faster decarbonization across the industry and the bulk electric grid.

During the MSC meeting of October 10, 2023, staff presented the challenges of the condensed timeline, and the requirement to procure a significant amount of resources of all types needed to meet the policy goal of 100% Carbon-Free by 2030. This time compression, applied to the resource procurement requirements, was further amplified during MSC discussion of November 14, 2023, where focus was upon procurement of DER and DR resources as modeled in the carbon-free Scenario 2 results.

Moreover, during the October 10, 2023 discussion, staff further affirmed that resources are procured in advance of the proposed modeling result implementation or Commercial Operation Date (COD), with most resource types often procured or contracted five years or more ahead of project energization. PWP has been aggressively proactive in the procurement of resources in advance of actual COD or energy delivery dates. For instance:

- Sapphire Solar and Battery Storage – Negotiated, procured, and contracted nearly a half decade ahead of actual COD.
- Coso Geothermal - Negotiated, procured, and contracted more than a half decade ahead of actual COD.
- Calpine Geothermal - Negotiated, procured, and contracted nearly a half decade ahead of actual COD, with energy delivered through 2041, as PWP looks far beyond 2030 in terms of energy and capacity portfolio needs.
- RFP for Battery Storage – Internal to Pasadena. Procurement processes kicking off well ahead of identified need as compared to 2030 carbon-free plans.

In the aggregate, over the last calendar year, PWP has proactively added greater than $500 million of renewable procurement, all of which strategically folds and fits into 2023 IRP considerations.

Additionally, the historical MSC/Council Agenda packages associated with these past energy procurements includes related documentation such as future lookaheads of energy resource needs, as well as applicable commentary on the “fit” of the resource procurement as compared to CAISO resource and associated State regulatory requirements.

PWP shall continue its external market solicitations by engaging with developers for renewable projects that are strategically deliverable to PWP’s region of the CAISO. Competition for renewable resources is anticipated to be more challenging, as increased statewide RPS requirements are enacted by regulatory bodies:

- RPS increases to 41.25% statewide in 2023
- RPS increases to 44% statewide in 2024
- RPS increases to 60% in 2030

PWP needs to monitor potential impacts of CAISO policy continually, as these are critical enablers to the CEC’s Scoping Plan and to achieving statewide carbon-free goals. These considerations include:

- Potential changes to Resource Adequacy constructs designed to enhance grid stability and resiliency.
- The transmission interconnection queue, and transmission projects supporting statewide grid buildout, as detailed in the CEC Scoping Plan.
- Continual monitoring of project deliverability as determined by CAISO transmission analysis.

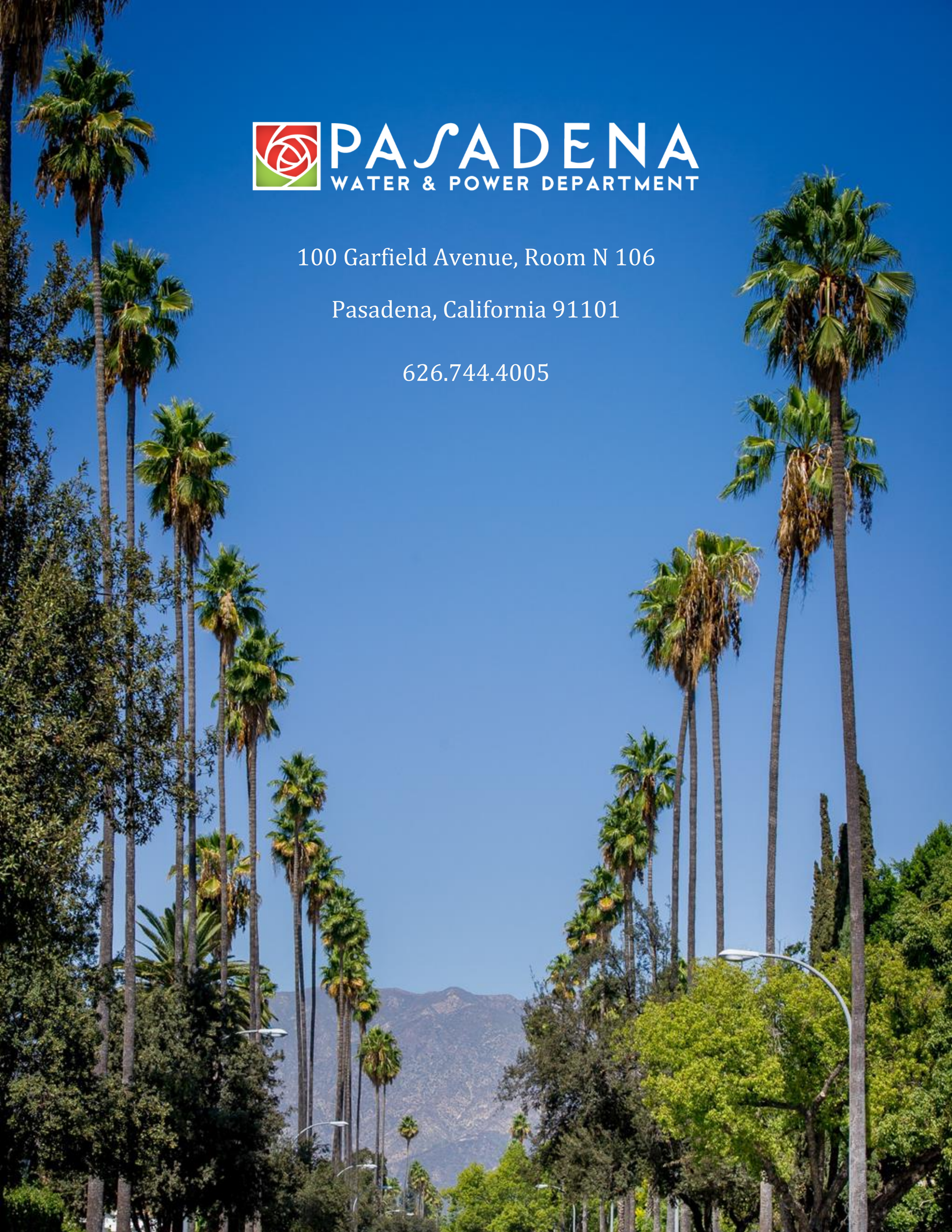
At the same time, PWP must remain mindful of this heightened competition in order to assure price competitiveness balanced with customer protections. With the current supply chain environment and inflationary fiscal spiral, evidence suggests that being awarded renewable contracts is, in part, related to the willingness to be price-aggressive while perhaps accepting more project risk than historical fixed price deliveries would indicate.

To assist in these procurement efforts, PWP may issue an RFP for support services to include portfolio fit/economic analyses of resource offerings. In any case, PWP will continue working in collaboration with regional energy partners, as joint efforts can reduce risk, lower assigned costs, and provide enhanced negotiating power.

PWP shall also maintain constant surveillance for emerging technologies. Upon identifying opportunities suitable for PWP to deploy, staff shall contact/meet vendor representatives to map out next steps.

Community engagement remains an important part of IRP implementation, and PWP shall employ it via a multi-faceted approach. As one of these activities, PWP shall seek and identify opportunities for interorganizational initiatives (e.g., energy efficiency by design, transportation electrification, and vehicle-to-grid energy management) in its pursuit of grant funding; doing so would facilitate joint grant applications with other governmental entities and with non-profit organizations. Meanwhile, PWP will continue its legislative/regulatory analysis and advocacy as needed to support programs requiring outside funding, and to remove regulatory barriers (on both the State and Federal levels) to building a reliable, decarbonized, and cost-effective resource portfolio. Finally, PWP shall develop a comprehensive community engagement plan with formal avenues for input and for progress reports.

All in all, this addendum addresses the interrelationship among the IRP, the PDMP, and the Rate Study. Developments arising from any of these efforts will be reflected in upcoming iterations of this living document.



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