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CITY OF REDDING ELECTRIC UTILITY

2024 | INTEGRATED RESOURCE PLAN

REU | City of Redding Electric Utility

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Acronyms, Abbreviations, and Definitions List

AAEE	Additional Achievable Energy Efficiency
AAFS	Additional Achievable Fuel Switching
AAGR	Annual Average Growth Rate
AB	Assembly Bill
AC	Alternating Current
ACF	Advanced Clean Fleet
AMI	Advanced Metering Infrastructure
Avangrid	Avangrid is an intermediate contracting entity that purchases energy from Big Horn and provides it to M-S-R PPA.
BANC	Balancing Authority of Northern California
Barriers Study	Low-Income Barriers Study, Part A: *Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities*
BE	Building Electrification
BESS	Battery Energy Storage System
BPA	Bonneville Power Administration
BPS	Bulk Power System
CAISO	California Independent System Operator
CalEnviroScreen	California Communities Environmental Health Screening Tool
CalEPA	California Environmental Protection Agency
California ISO	California Independent System Operator, also CAISO
CAPEX	Capital Expenditures
CARB	California Air Resources Board
Carbon Allowance	The amount of carbon allowed to be emitted as authorized by the government; an allowance is commonly one ton of carbon dioxide
CCS	Carbon Capture and Sequestration
CEC	California Energy Commission (also Energy Commission)
CEC Guidelines	The CEC document, *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines* (July 2017)
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
COD	Commercial Operation Date
COI	California-Oregon Intertie

Combined Cycle	A combined-cycle power plant uses both a gas and steam turbine together to produce more electricity from the same fuel
COR	City of Redding
COSL	City of Shasta Lake
COTP	California-Oregon Transmission Project
CPUC	California Public Utilities Commission
CPWC	Cumulative Present Worth Cost
CRAT	Capacity Resource Accounting Table (CEC Standardized Table)
CSD	Community Service and Development
CV	Central Valley
CVP	Central Valley Project
DAC	California-designated disadvantaged communities
DC	Direct Current
Decarbonization	Electrification
Decatherm (Dth)	Dekatherm; Measurement of heat equivalent to one MMBTU
DMS	Distribution Management System
DSM-IRP	Demand-Side Management Integrated Resource Plan
DOE	Department of Energy
DSM	Demand-Side Management; refers to initiatives that encourage consumers to optimize energy usage
Dth	Decatherm (Measurement of heat equivalent to one MMBTU)
Dth/day	Decatherm per Day
EBT	Energy Balance Table (CEC Standardized Table)
EDAM	Extended Day-Ahead Market
EE	Energy Efficiency
EER	Eligible Renewable Energy Resources
EIA	U.S. Energy Information Administration
Energy Commission	California Energy Commission (also CEC)
EPA	U.S. Environmental Protection Agency
ES	Energy Storage
ESA	Energy Savings Assistance
EUE	Expected Unserved Load
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission

Fuel-Substitution	Replacing natural gas, propane, or other heating fuels with electricity (building electrification)
Fuel-Switching	Replacing gasoline or diesel fuels with electricity (transportation electrification)
FY	Fiscal Year (July 1- June 30 for Redding; October 1-September 30 for the US Government)
GEAT	GHG Emissions Accounting Table (CEC Standardized Table)
GHG	Greenhouse Gas
GWSA	Global Warming Solutions Act
HSC	Health and Safety Code
ICE	Intercontinental Exchange
IEPR	Integrated Energy Policy Report
Index+	A contract structure where energy with attributes such as a Renewable Energy Credit is purchased at a price based on a market index plus an additional fixed amount for the attribute. The attribute is assigned to the purchaser and the energy is settled in an energy market at its index price.
IPP	Independent Power Producer
IRP	Integrated Resource Plan
IRP Filing	POU Adopted IRP Accompanied By The Required Supporting Information
JPA	Joint Powers Agency
LCFS	Low Carbon Fuel Standards
LCOE	Levelized Cost of Energy
LD PEV	Light-Duty Plug-In Electric Vehicle
LIEEP	Low-Income Energy Efficiency Program
LMP	Locational Marginal Pricing
Load Factor	A load factor is a measure of the variability in utility load over time
LOLH	Lossof Load Hours
LTP	Long-Term Procurement Requirements
MACRS	Modified Accelerated Cost Recovery System – the current tax depreciation system in the US
MMBTU	One Million British Thermal Units (1,000,000 BTU)
MMT	Millions of metric tons
M-S-R PPA	California Joint Powers Agency, M-S-R Public Power Agency, of which the City of Redding is a member along with Modesto Irrigation District and they City of Santa Clara
M-S-R EA	M-S-R Energy Authority

MT	Metric Ton
MTCO2e	Amount of a Greenhouse Gas whose atmospheric impact has been standardized to one unit mass of carbon dioxide, based on the global warming potential of the gas
MW	Megawatt
MWh	Megawatt-hour
NCPA	Northern California Power Agency
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NO_x	Nitrogen Oxide
OASIS	Open Access Same-Time Information System
OH	Overhead
OMS	Outage Management System
OSI-SCADA	Open Systems International- Supervisory Control and Data Acquisition
PACI	Pacific AC Intertie
PBR	Portfolio Balance Requirements
PEV	Plug-In Electric Vehicle
POU	Publicly-Owned Utility
PPA	Power Purchase Agreement
PRC	Public Resources Code
PUC	Public Utilities Code
PV	Photovoltaic (solar)
RE	Renewable Energy
REC	Renewable Energy Credit (1MWh renewable energy = 1 REC) is a tradable, non-tangible energy commodity representing proof that 1 megawatt-hour (MWh) of electricity was generated from an eligible renewable energy resource
REU	City of Redding Electric Utility
RPS	Renewables Portfolio Standard
RPS Eligible	Renewable resource with under 30MW capacity
RPT	RPS Procurement Table
SAE	Statistically Adjusted End-Use
SB	Senate Bill
SB 100	Senate Bill 100, De Leon. 100 Percent Clean Energy Act of 2018
SB 350	Senate Bill 350 (De León, Chapter 547, Statutes of 2015)
SB 1020	Senate Bill 1020, Laird. Clean Energy, Jobs, and Affordability Act of 2022

SB 1037	Senate Bill 1037. Energy Efficiency (2005)
Scenario	Portfolio expansion plans developed and compared
SMUD	Sacramento Municipal Utility District
SNR	Sierra Nevada
SOTP	South of Tesla Principles
TAC	Transmission Access Charge
TANC	Transmission Agency of Northern California
TE	Transportation Electrification
TPUD	Trinity Public Utilities District
UG	
USBR	United States Bureau of Reclamation
VAR	Volt-Amp Reactive
WAPA	Western Area Power Administration, (also Western)
WECC	Western Electricity Coordinating Council
WREGIS	Western Renewable Energy Generation Information System
ZEV	Zero Emission Vehicle
ZNE	Zero Net Energy

2024 IRP Filing Contents (SB 350 Requirements)

IRP Filing Contents Per CEC Guidelines	Public Utilities Code	Sections in REU IRP
A. Planning Horizon	Section 9621(b) (1) and (2)	IRP's planning horizon is 2023-2045 (Throughout IRP)
B. Scenarios and Sensitivity Analysis	Section 9621 (d)	Section 7, *Modeling Assumptions, Tools, Methodology*
C. Standardized Tables	N/A	Exhibit 9.5 Standardized Tables
1. Capacity Resource Accountable Table (CRAT)	N/A	Exhibit 9.5 Standardized Tables
2. Energy Balance Table (EBT)	N/A	Exhibit 9.5 Standardized Tables
3. RPS Procurement Table (RPT)	N/A	Exhibit 9.5 Standardized Tables
4. GHG Emission Accounting Table (GEAT)	N/A	Exhibit 9.5 Standardized Tables
D. Supporting Information	N/A	Supporting information to supplement data in the Standardized Tables may be found in the charts, graphs, and narratives in the IRP
E. Demand Forecast	N/A	Section 6, *Energy Forecast and System Impacts*
1. Reporting Requirements	N/A	Exhibit 9.5 Standardized Tables
2. Demand Forecast Methodology and Assumptions	N/A	Section 6.2, *Forecast Methodology and Assumptions*
3. Demand Forecast-Other Regions	N/A	Section 6.2, *Forecast Methodology and Assumptions*; and Section 8.4, *Sensitivity Cases*
F. Resource Procurement Plan	Section 9621(b) and (d)	Section 4, *Energy Efficiency, Electrification, and Demand Response Programs*
1. Diversified Procurement Portfolio	Section 9621(d)(1)(D)	Section 7.2, *Modeling Assumptions*; and Section 8.4, *Sensitivity Cases*
2. RPS Planning Requirements	Section 9621(b)(2) and Section 399.11	Section 8.2, *Scenario Analysis*
3. Energy Efficiency and Demand Response Resources	Section 9621(d)(1)(A) Section 9615	Section 4.4, *Energy Efficiency and Greenhouse Gas Reduction*; and Section 4.6, *Demand Response Programs*
4. Energy Storage	Section 9621(d)(1)(B) Chapter 7.7 (commencing with Section 2835) of Part 2 of Division 1	Section 4.7, *Energy Storage*

5. Transportation Electrification	Section 9621(d)(1)(C)	Section 4.2, *Transportation Electrification*
G. System and Local Reliability	Section 9621(d)(1)(E) and Section 9620 (a) and (b)	Section 7.3, *Scenario Design*; and Section 8.2, *Scenario Analysis*
1. Reliability Criteria	Section 9621(d)(1)(E) and Section 9620 (a) and (b)	Section 7.3, *Scenario Design*; and Section 8.2, *Scenario Analysis*
2. Local Reliability Area	Section 9621(d)(1)(E) and Section 9620 (a) and (b)	Section 6.4, *Transmission System Assessment*
3. Addressing Net Demand in Peak Hours	Section 9621(c)	Section 7.2, *Modeling Assumptions*; Section 7.3, *Scenario Design*; and Section 8.2, *Scenario Analysis*
H. Greenhouse Gas Emissions	Section 9621(b)(1)	Section 2, *Purpose and Background*; and Section 4.2, *Transportation Electrification*
I. Retail Rates	Section 9621(b)(3) and Section 454.52.(a)(1)(C) and (D)	Section 8.5, *Impacts to Redding*
J. Transmission and Distribution Systems	Section 9621(b)(3) and Section 454.52.(a)(1)(E) and (F)	Section 5, *Existing System and Resource Description*
1. Bulk Transmission System	Section 9621(b)(3) and Section 454.52.(a)(1)(E) and (F)	Section 5.4, *Transmission Assets*; and Section 6.4, *Transmission System Assessment*
2. Distribution System	Section 9621(b)(3) and Section 454.52.(a)(1)(E) and (F)	Section 5.5, *Distribution Assets and Adequacy*
K. Localized Air Pollutants and Disadvantaged Communities	Section 9621(b)(3) and Section 454.52.(a)(1)(H)	Section 4.8, *Localized Air Pollutants and Disadvantaged Communities*

IRP Project Partners

Ascend Analytics	Modeling software company contracted by REU for portfolio modeling services
Curve Developer	Software developed by Ascend Analytics to forecast market gas and power prices
Dunsky Energy + Climate Advisors	Consultant contracted by REU to develop the Building and Transportation Electrification Forecast through 2045
GreatBlue	2022 Comprehensive Residential and Commercial Customer Survey
Itron, Inc.	Consultant contracted by REU to develop the Utility's comprehensive load forecast
SMUD	(Sacramento Municipal Utility District) Contracted to conduct the Transmission Assessment Study

Summary of Figures

Summary of Tables

1. Executive Summary

This report (Report) presents the Integrated Resource Plan (IRP) for the City of Redding's Electric Department (REU), owner of a non-profit, vertically integrated utility providing electric service to approximately 45,000 customers in and near Redding, California within a service area that covers approximately 61 square miles. REU's vision is to make Redding better by connecting with customers and being their trusted and reliable, community-owned utility. This overarching objective is achieved by providing reliable, cost-effective service, while complying with state and federal mandates and regulations. This Report offers a current and comprehensive examination, analysis, assessment, and selection of the Utility's preferred resource plan, aimed at facilitating REU's vision and enhancing its established goals and objectives.

An IRP is a long-term, comprehensive plan developed to help ensure that REU can meet its customers' annual peak energy needs over the planning horizon in a cost-effective manner, while also meeting system reliability needs, state policy goals, and other targets established for the community. This is not intended as a procurement document, rather, a blueprint for meeting future resource requirements while complying with clean energy mandates and objectives. Acquisitions will be thoroughly evaluated in the normal course and the standard procurement process will be followed.

The 2024 IRP was developed through extensive analysis and benefited from coordination among internal and external partners and stakeholders. This report, and the accompanying appendices, describes the analyses conducted and the underlying assumptions used to produce a 20-year plan to meet customers' energy needs through 2045. Incorporated into the IRP are anticipated changes to the utility industry and California over the planning period.

Although significant changes within the electric utility industry are anticipated to occur over the 20-year planning horizon for the IRP, REU must plan for sufficient supplies of electricity while also maintaining affordable rates and achieving safety, environmental, operational, and reliability goals. During the preparation of the IRP, a wide variety of alternatives that could meet these many supply and demand-side objectives were considered and narrowed down to those that met objectives of the IRP's guiding framework. The IRP process has also taken into consideration the need to establish a plan that will allow flexibility to respond to uncertainty regarding future technology and regulatory change.

1.1 Legislative Requirements and Updates

The initial IRP filed in 2019 was developed in response to the Clean Energy and Pollution Reduction Act of 2015 (California Senate Bill 350; herein SB 350), which established new clean energy, clean air, and greenhouse gas (GHG) reduction goals. SB 350 established requirements for any publicly owned utility (POU) with an average load greater than 700 GWh (in the 2013-16 period) to develop and adopt an IRP by January 1, 2019, and update it with the California Energy Commission (CEC) at least every five years. Redding is the smallest utility in California required to complete an IRP, with an average annual load of approximately 745 GWh.

SB 350 was superseded by Senate Bill 100 (herein SB 100), which updated the State's Renewables Portfolio Standard (RPS) requirements, established carbon-reduction goals, and required the CEC, the California Public Utilities Commission (CPUC), and the California Air Resource Board (CARB) to file a joint policy report on SB 100 by 2021.

California's clean energy mandates have expanded to include, but are not limited to, the following:

- SB 100: renewable energy and zero-carbon resources must supply 100 percent of electric retail sales to end-use customers by 2045
- Renewables Portfolio Standards (RPS): requires that by 2030, at least 60 percent of California's electricity is generated from renewable resources; sets long-term contract requirements
- Energy Efficiency Standards: aims to reduce energy consumption and promote energy-saving practices among utility customers
- Carbon reduction targets established by Senate Bill 1020 starting in 2035
- POUs must develop an IRP that sets forth the plan to achieve the above goals and other objectives such as those related to reliability and cost-effectiveness
- Transportation electrification plans must be included in the IRP

The CEC requires an updated IRP to be filed by 2024; therefore, REU embarked on a comprehensive and inclusive process to update its IRP initially filed in 2019. The IRP process involved a series of studies, assessments, modeling, and stakeholder engagement activities aimed at ensuring that the plan aligns with the organization's goals and effectively addresses the evolving energy landscape and customer needs.

Greenhouse Gas Cap-and-Trade Program (GHG Program)

Program Administration and Oversight

The CARB oversees health and air quality standards for the state. CARB sets the State's air quality standards at levels that protect those greatest at risk, and is the agency tasked with developing policies for combating climate-change through measures that promote a more energy-efficient, carbon-free, and resilient economy. CARB policies typically exceed federal emissions standards. Key activities include:

- Administer Cap-and-Trade and Greenhouse Gas programs (AB 32)
- Developing Scoping Plans (AB 1279) for carbon-neutrality pathways to meet California goals
- Administer the State's Low Carbon Fuel Standards (LCFS) Program

Program Overview

California's cap-and-trade greenhouse gas program is a key component of the State's comprehensive strategy to combat climate change. Under this program, a cap, or limit, is set on the total amount of greenhouse gas emissions allowed from certain sectors of the economy, primarily industries and power plants. These entities are required to hold allowances equal to their emissions, and a portion of these allowances are auctioned by the State.

The program encourages emission reductions by creating a market for emissions allowances, where entities can buy and sell allowances as needed to comply with the cap. Over time, the cap is gradually reduced, leading to a decrease in allowable emissions and incentivizing emissions reduction efforts. Revenue generated from the sale of allowances is reinvested in various programs aimed at further reducing greenhouse gas emissions, promoting renewable energy, and supporting disadvantaged communities disproportionately affected by pollution.

Renewables Portfolio Standards (RPS Program)

Program Administration and Oversight

The California Energy Commission (CEC) began implementing policies in the late 1990s and early 2000s to address environmental concerns, promote clean energy, and reduce greenhouse gas emissions. California passed Senate Bill 1078 in 2002, which established the Renewables Portfolio Standards (RPS) program.

The RPS program is a regulatory policy that mandates utilities and energy providers to procure a specified percentage of their electricity from renewable resources, such as wind, solar, hydro, and biomass. The program's objective is to promote the use of renewable energy resources within the State's electric grid.

Program Overview

When renewable energy is produced, one Renewable Energy Credit (REC) is created for each megawatt-hour (MWh) of electricity generated from eligible renewable resources. REC represent environmental attributes of clean energy production. Utilities can use purchased or generated RECs to demonstrate compliance with renewable energy targets, which are either retired or banked for future compliance. RECs are categorized based on criteria within the regulations, which specify the percentage of each type of REC that can be used to satisfy compliance requirements. Some of the key requirements of the RPS program are:

- Procurement Requirement: At least 60 percent of REU's electric retail sales must be served by eligible renewable resources by 2030
- Long-Term Portfolio Requirement: For the compliance period beginning January 1, 2021, and each compliance period thereafter, at least 65 percent of the electricity products applied toward the RPS procurement target shall be from contracts of 10 years or more in duration or ownership or ownership agreements for eligible renewable energy resources
- Portfolio Balance Requirements: Beginning January 1, 2021, at least 75 percent of RPS procurement shall be from bundled, in-state energy contracts, with a maximum of 10 percent of RPS procurement from out-of-state RECs.

The CEC adopted revised RPS Enforcement Regulations on December 22, 2020. The updated RPS Enforcement Regulations included the revised renewables and emissions targets from SB 100. In March 2023, Redding City Council (Council) approved modifications made to REU's RPS Enforcement Program and Procurement Plan to reflect recent updates to the regulations (Exhibit 9.4). In addition to the updated procurement targets for each compliance period shown in Table 1-1 below, the newest regulations require utilities to meet specific Long-Term Procurement Requirements (LTP) and Portfolio Balance Requirements (PBR).

Table 1-1: SB 100 RPS Procurement Targets

Compliance Period	4		5			6		7	
Year	2023	2024	2025	2026	2027	2028	2029	2030	2031…
RPS Target	41.25%	44.00%	46.00%	50.00%	52.00%	54.67%	57.33%	60.00%	60.00%

Senate Bill 1020

Governor Newsom signed the SB 1020 bill, also known as the 100% Clean Electric Grid bill, on September 16, 2022. This legislation aims to significantly decrease California's reliance on fossil fuels in three stages. According to the policy, the State's goal is to have 90% of all retail sales of electricity supplied by eligible renewable energy resources and zero-carbon resources by 2035. This target will be followed by a 5% increase by 2040, leading to the ultimate objective of achieving 100% clean energy by 2045.

Impacts of Updated Regulations

Recognizing the importance of being flexible and adaptable, REU remains committed to staying informed of evolving clean energy regulations, targets, and objectives in California, and is well-positioned to adapt its portfolio modeling accordingly. The preferred scenario selected in the 2019 IRP no longer aligns with the State's updated regulatory requirements, necessitating the identification of new resources and timelines to ensure regulatory compliance.

REU aims to ensure the IRP remains robust and responsive to changing regulations throughout the planning period. To achieve this, modeling and scenario development methodologies have shifted to one that is centered around compliance requirements rather than renewable resource identification. The scenarios developed for this IRP account for the varying degrees of compliance needed to meet clean energy mandates, with an anticipation of increasingly stringent renewable energy and carbon reduction requirements imposed by regulatory bodies.

Regulatory requirements for clean energy and carbon reduction will likely become more stringent over time. Through continuous monitoring of regulatory developments, engagement with regulatory authorities, and iterative modeling processes, REU remains committed to maintaining compliance with updated clean energy regulations. By incorporating these expectations into the modeling process, the organization can assess the implications on resource selection, investment strategies, and operational plans. This forward-thinking approach positions REU to proactively respond to regulatory changes and achieve long-term sustainability goals while providing reliable and affordable electricity services to its constituents.

1.2 Existing Resources and Energy Forecast

Existing Resources

The electric resources used to meet the power requirements of customers include generation supply resources, renewable resources, contractual power purchases, transmission assets, and natural gas supply facilities. These resources and assets are described in Section 5. REU's generation resources include:

- Redding Power Plant – a 183.1 MW natural gas power plant consisting of combined cycle and simple cycle generators owned by REU
- Whiskeytown Small Hydro – a 3.5 MW eligible renewable hydro generator owned by REU
- Big Horn Wind – a Power Purchase Agreement (PPA) for approximately 70 MW of eligible renewable wind generation from Big Horn Wind Project in Klickitat County, Washington.
- Western Base Resource – a PPA contract for approximately 8% of the Central Valley Project (CVP) hydro generation resources marketed by the Western Area Power Administration (WAPA)
- Renewable Energy Purchases – long-term and short-term PPA's with an Index+ contract structure for eligible renewable energy from various generators in various quantities

In light of the revised clean energy mandates and targets established through the enactment of SB 100 and SB 1020, the preferred resource portfolio identified in the 2019 IRP no longer aligns with the State's requirements concerning renewable energy and carbon mitigation. Table 1-2 below depicts REU's existing energy resources and their contribution to customer load, renewable compliance, and carbon-free targets.

Table 1-2: REU Calendar Year 2022 Energy Resources

	Capacity Available (MW)	Annual Energy (GWh)	Percent of Total Energy
Generated Power			
Redding Power Plant[1] (U1-U6)	183.1	426,918	60%
Whiskeytown (U9)	3.5	25,916	4%
Total Generated Power	**186.6**	**452,834**	**64%**
Carbon-Free Power Purchase Agreements			
WAPA Base Resource[2]	128.5	63,163	9%
Big Horn I Wind Project	23.0	163,586	23%
Total Purchased Power	**151.5**	**226,749**	**32%**
Market Power			
Market Power Purchases	-	149,939	21%
Market Power Sales	-	-117,111	-16%
Net Market Power	**-**	**32,828**	**5%**
Total	338.1	712,411	100%

1. *Capacity listed is nameplate capacity (EIA860 defined) for Redding Power Plant.*
2. *The hydro-based contract with WAPA is for 128.5 MW, but the average summer planning capability is 74 MW.*

Figure 1-1 below illustrates the current portfolio's inability to meet the updated renewable energy requirements beyond 2030.

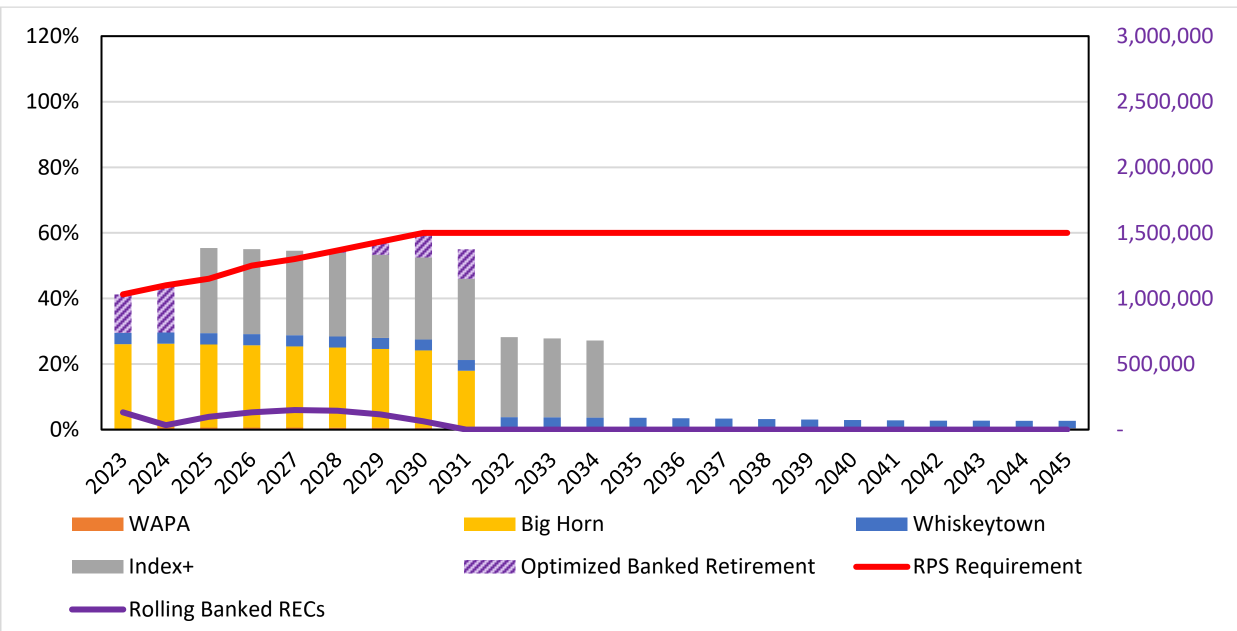


Figure 1-1: REU Current Portfolio RPS Outlook

Based on the current resource portfolio, Figure 1-2 demonstrates the inability to meet newly introduced carbon emissions targets set forth in Senate Bill 1020 starting in 2035.

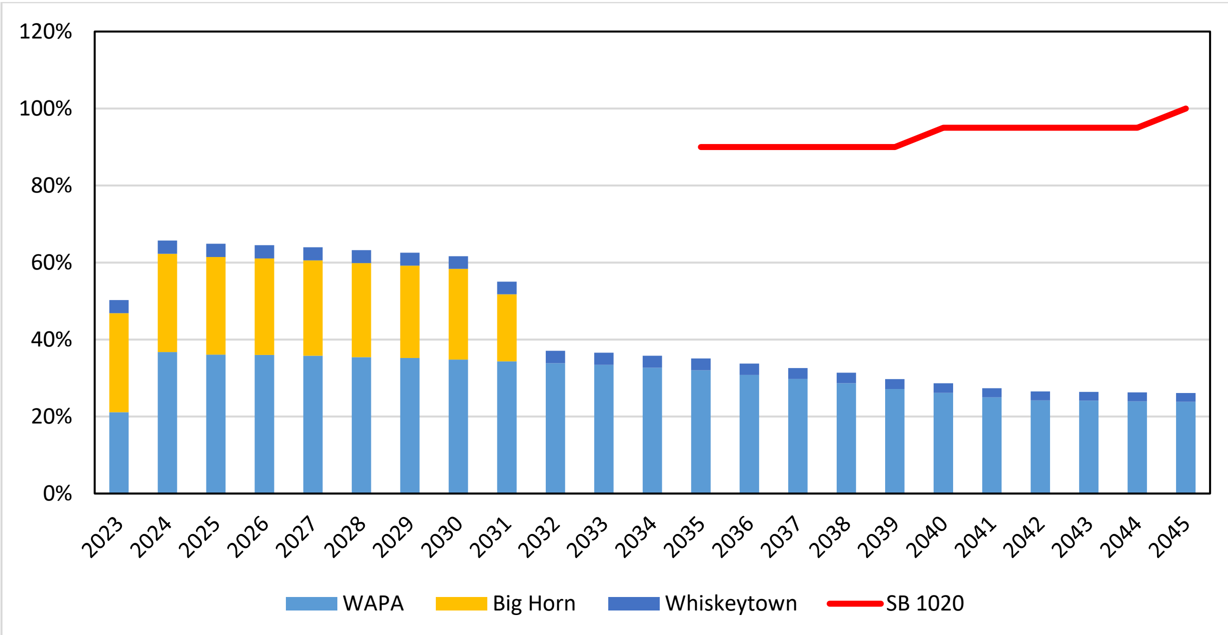


Figure 1-2: REU Current Portfolio Carbon-Free Energy

Energy Forecast

The load forecast developed by Itron, Inc. (Itron), the consultant contracted to provide load forecasting services for REU, and Dunsky Climate + Energy Advisors (Dunsky), the consultant contracted to forecast load impacts from electrification (further described in Section 6.2) is the foundation upon which the IRP was built. REU also contracted with Ascend Analytics (Ascend) to conduct portfolio modeling services.

1.3 Modeling and Resource Selection

As highlighted in Section 8.2 of this report, REU's current portfolio does not align with the State's clean energy mandates. Consequently, scenarios have been formulated within the outlined strategic framework to incorporate future resources aimed at achieving renewable energy compliance and carbon reduction targets. REU collaborated with Ascend, who furnished forecast models to evaluate the diverse attributes associated with each identified technology (Table 1-3). This approach allowed the model to operate without technology constraints, permitting the selection of technologies based on their economic performance within energy markets.

Recognizing the importance of involving diverse perspectives and gathering input from key stakeholders, REU formed a dedicated stakeholder group to review the results and provide insights on the Utility's direction. The stakeholder group consisted of representatives from customer advocacy organizations, environmental groups, regulatory agencies, community organizations, and other relevant entities. This collaborative approach ensured that the IRP development process benefited from the collective expertise and input of a broad range of stakeholders.

This IRP was developed based on the following strategic framework: *The preferred 2024 IRP scenario should meet or exceed the State's clean energy mandates while balancing reliability and affordability.*

Using this framework, REU developed the following scenarios for modeling and evaluation:

- Low Scenario: "Current Portfolio" - does not meet mandates
- Mid Scenario: "Net-Zero Carbon 2045" - meets mandates
- High Scenario: "100% Zero Carbon 2045" - exceeds mandates

REU owns and operates a natural gas fired combined cycle generation plant, Redding Power Plant (the Plant). The specifics of the Plant are described in Section 5.1. The "Net-Zero Carbon 2045" scenario assumes that net-zero carbon can be achieved while continuing to operate REU's natural gas power plant for system reliability. In contrast, the "100% Zero Carbon 2045" scenario assumes that REU will not generate any carbon and could no longer rely on the Plant for reliability.

REU worked with partners and consultants to develop and optimize models and forecasts around these scenarios to determine a preferred approach to resource planning and procurement over the 20-year planning horizon.

Table 1-3: Potential Resources for Selection

Resource	Assumptions	Dispatchable	RPS Eligible	Carbon-free
Solar	Southern California, Northern California	No	Yes	Yes
Wind	Southern California, Northern California, Offshore, New Mexico	No	Yes	Yes
Renewable Gas	REU Prepay Gas Agmt.	Yes	Yes	Yes*
Carbon Capture	REU Prepay Gas Agmt.	Yes	No*	Yes
Hydrogen	Assume NG Retrofit	Yes	Yes*	Yes
Storage	4 Hour Battery, 8 Hour Battery	Yes	N/A	N/A
Geothermal	California	Yes	Yes	Yes
Biomass	California, Assume PPA	Yes	Yes	Depends

** Renewable or Carbon-free eligibility depends on the fuel source*

1.4 Preferred Plan Evaluation

REU worked with a key stakeholder group that unanimously selected the *Net-Zero Carbon 2045 Scenario* as the preferred plan for the 2024 IRP, recognizing the vital role of the Plant in ensuring reliable and affordable energy throughout the planning horizon.

Net-Zero Carbon 2045 Plan Defining Characteristics:

- Allows the continued dispatch of Redding Power Plant with the use of carbon allowances
- To meet SB 1020 targets, the Redding Power Plant is primarily running for peaking load
- To meet planning criteria, the following resources are added:
  - 2031: 150 MW of solar and 25 MW of 8-hr battery storage
  - 2034: 50 MW of solar
  - 2037: 50 MW of solar and 15 MW of 8-hr battery storage
  - 2041: 50 MW of solar and 15 MW of 8-hr battery storage
  - 2045: 40 MW of solar

In total, this results in the addition of 340 MW of solar generation and 55 MW of 8-hour battery storage to the portfolio through the 2045 planning horizon.

The stakeholders strongly encouraged staff to reduce fossil-fuel generation before the 2045 timeframe and seek opportunities to reduce carbon where feasible without compromising reliability. Additional resources and capacities needed to meet demand and clean energy mandates are outlined below in Table 1-4.

Table 1-4: Selected Resources for Scenarios

	Net-Zero Carbon 2045		100% Zero Carbon 2045			
Year	Solar (NorCal + SoCal) MW	Storage (8-hour Battery) MW	Solar (NorCal + SoCal) MW	Storage (8-hour Battery) MW	Natural Gas CCS MW	Hydrogen MW
2031	150	25	200	25	-	-
2034	50	-	-	-	-	-
2037	50	15	25	15	-	-
2041	50	15	35	160	25	95
2045	40	-	-	-	-	-

As seen in Figure 1-3 below, with the additional resources specified in the model's preferred scenario, REU's resource portfolio would meet the State's clean energy mandates, including the SB 1020 carbon targets that begin in 2035 and increase to meet to the 2045 timeline.

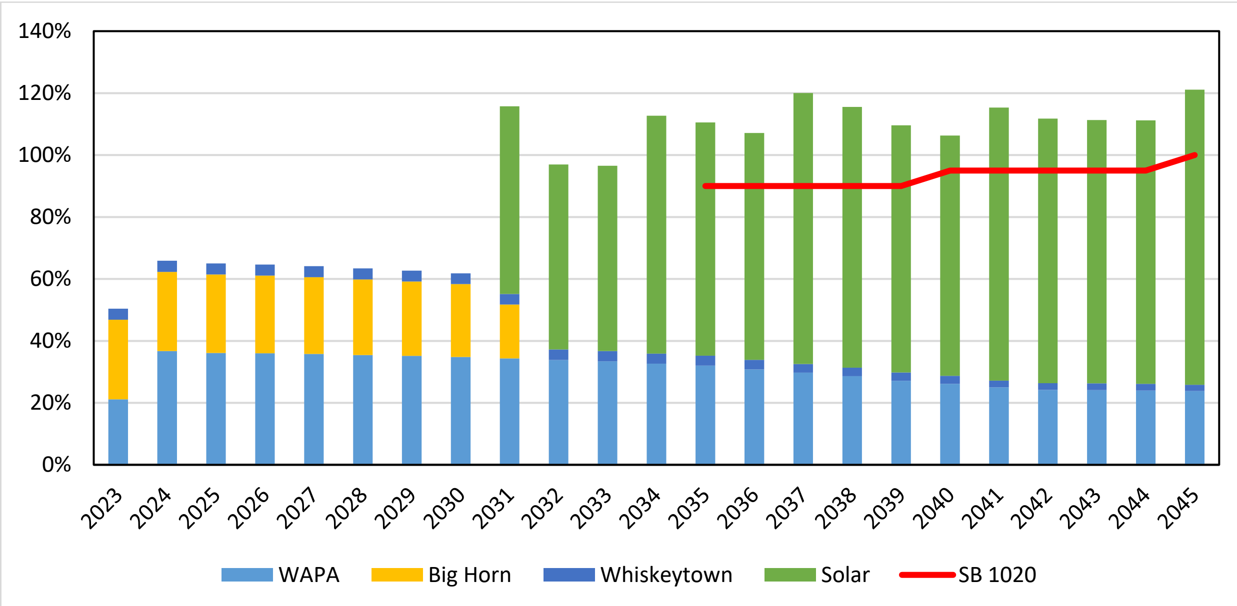


Figure 1-3: Carbon Profile Net-Zero Carbon 2045

Various energy resource technology types identified in the preferred scenario that allow REU to serve customer demand while meeting clean energy mandates are illustrated below in Figure 1-4. While solar is recognized as a cost-effective resource option, given its intermittent attributes, the model employs an approach of overbuilding solar resources to guarantee an ample energy supply for peak load demands. In the figure below, "Out-of-State Imports/Exports" primarily refers to energy sales and purchases from power producers in the Pacific Northwest to serve customer demands.

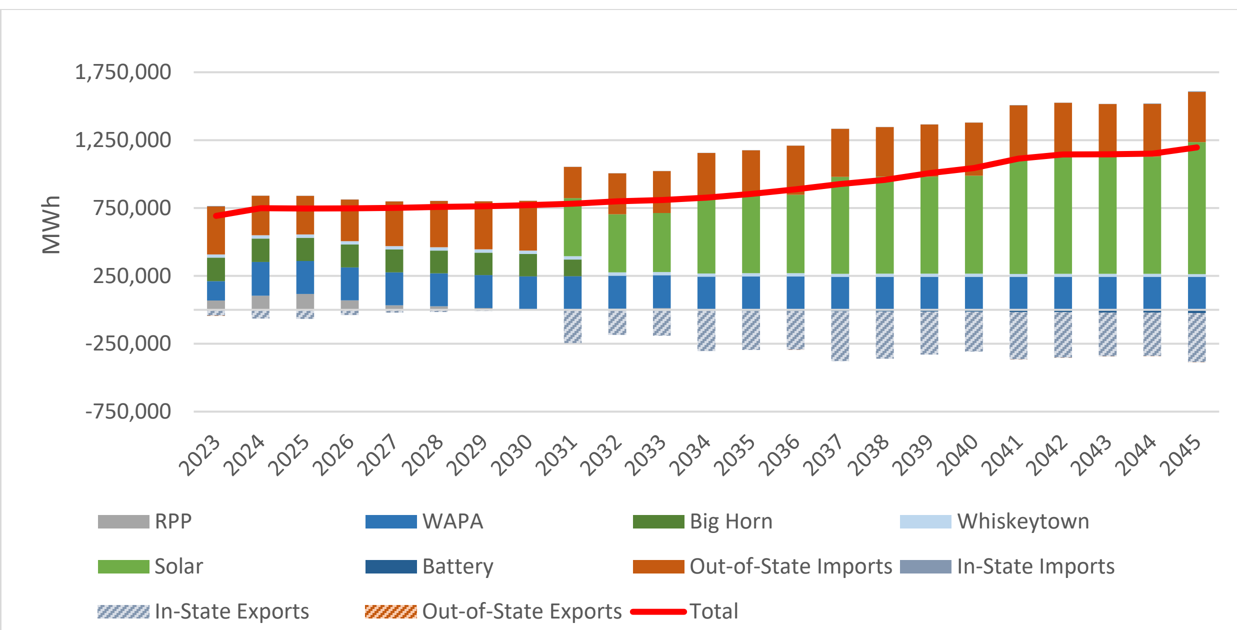


Figure 1-4: Energy Supply Stack – Net-Zero Carbon 2045

Power Supply Cost

A comparison of the cumulative present worth cost (CPWC) across the assessed scenarios, using both total cost and cost per megawatt hour metrics is presented below (Table 1-5). The Net-Zero Carbon 2045 scenario exhibits a slightly reduced portfolio cost when compared to the existing portfolio. Conversely, the 100% Zero-Carbon 2045 scenario demonstrates a notably higher cost in comparison to both the Current Portfolio and the Net-Zero Carbon 2045 Scenario.

Table 1-5: CPWC for Scenarios with Resource Cost

	Current Portfolio	Net-Zero Carbon 2045	100% Zero Carbon 2045
RPP	$14	$13	$15
WAPA	$140	$140	$140
Bighorn	$102	$102	$102
Whiskeytown	$0	$0	$0
Solar	$0	$227	$227
8 Hour Battery	$0	$200	$477
NG with CCS	$0	$0	$83
Hydrogen	$0	$0	$96
Market Imports	$624	$370	$307
Market Exports	-$26	-$205	-$209
Index+ RECs	$23	$23	$23
Total, $M	$878	$870	$1,263
Levelized CPWC, $/MWh	$54.70	$54.25	$79.12

Table 1-6 below provides an estimate of the change in energy costs in 2045 across the modeled scenarios. These are estimates of the levelized energy costs for that year. The CWPC shows an average levelized energy cost over the entire planning horizon. Despite the higher energy cost per kilowatt-hour (kWh) in 2045 compared to the Current Portfolio, the CPWC shows the Net-Zero Carbon 2045 plan is more cost-effective over the entire planning period.

Table 1-6: REU Predicted Energy Cost Rates in 2045

	Current Portfolio	Net-Zero Carbon 2045	100% Zero Carbon 2045
Energy Cost in 2023 ($/kWh)	$0.0574	$0.0574	$0.0574
Energy Cost in 2045 ($/kWh)	$0.0765	$0.0866	$0.2079
Energy Cost Change ($/kWh)	$0.0191	$0.0292	$0.1505

1.5 Conclusion

In summary, the IRP process has been a complex comprehensive journey, resulting in the identification of a Preferred Plan that will ultimately shape Redding’s energy future. The Net-Zero Carbon 2045 plan calls for additional renewable energy resources to satisfy clean energy mandates. Overall, through strategic implementation of those resources, the total portfolio cost to serve retail customers will decrease by $8,000,000 over the 20-year planning horizon. Due to increasing carbon and gas prices, integrating renewable resources in the portfolio reduces power supply costs, as the cost-effectiveness of intermittent resources is move favorable than the thermal generation resources in today’s portfolio.

The preferred Net-Zero Carbon 2045 scenario, as explained in the Report, aligns with the overarching goals and objectives of the IRP and integrates renewable energy resources and sustainable practices into REU's energy portfolio. It represents a flexible and adaptable strategy, preserving the reliability and affordability of energy services while achieving the State's clean energy targets and objectives. The Preferred Plan protects the financial interests of REU's valued customers and signifies a pivotal step forward in the Utility's ongoing journey towards a resilient, responsible, and forward-thinking energy landscape.

2. Purpose and Background

The City of Redding (COR) recognizes the critical role that electricity plays in supporting the growth and vitality of its community. As an essential utility service provider, REU is committed to making informed decisions that address the evolving energy landscape while considering the unique needs of its customers, environmental sustainability, technological advancements, and regulatory requirements.

As a publicly owned utilities (POU), REU is accountable to its ratepayers and stakeholders. In today's rapidly evolving energy landscape, POUs face the responsibility of making informed, forward-looking decisions that balance competing interests: providing reliable and affordable electricity to their communities while simultaneously addressing the complex challenges posed by changing energy markets, technological advancements, and clean energy mandates.

An IRP offers a structured and systematic approach to navigate the complex choices inherent in the provision of electric service providers. The IRP's significance is highlighted by the Utility's ability to meet short-term objectives while paving the way toward ensuring a sustainable, equitable, and resilient energy future. In essence, an IRP demonstrates REU's commitment to serving the community's energy needs while embracing the broader responsibility being conscientious stewards and helping the community thrive.

As demonstrated in this document, the IRP provides an assessment of the future energy needs of customers over the next 20+ years (from 2023 through 2045) and summarizes the preferred plan for meeting those needs in a safe, reliable, cost-effective, and environmentally responsible manner.

2.1 Background

The initial IRP filed in 2019 was developed in response to the Clean Energy and Pollution Reduction Act of 2015 (California Senate Bill 350; herein SB 350), which established new clean energy, clean air, and greenhouse gas (GHG) reduction goals. SB 350 established requirements for any POU with an average load greater than 700 GWh (in the 2013-16 period) to develop and adopt an IRP by January 1, 2019, and update it with the California Energy Commission (CEC) at least every five years. SB 350 was superseded by Senate Bill 100 (SB 100), which updated the state's Renewables Portfolio Standard (RPS) requirements, established carbon-reduction goals, and required the CEC, the California Public Utilities Commission (CPUC), and the California Air Resource Board (CARB) to file a joint policy report on SB 100 by 2021.

California's clean energy mandates include, but are not limited to, the following:

- SB 100: renewable energy and zero-carbon resources must supply 100 percent of electric retail sales to end-use customers by 2045
- Renewables Portfolio Standards (RPS): requires that by 2030, at least 60 percent of California's electricity is generated from renewable resources; sets long-term contract requirements
- Energy Efficiency Standards: aims to reduce energy consumption and promote energy-saving practices among utility customers
- Carbon reduction targets established by Senate Bill 1020 starting in 2035
- POUs must develop an IRP that sets forth the plan to achieve the above goals and other objectives such as those related to reliability and cost-effectiveness
- Transportation electrification plans must be included in the IRP

Goals and Objectives

The overarching objective of the IRP is to foster awareness, preparedness, and strategic planning in an intricate and ever-evolving energy landscape. By doing so, REU ensures its adaptability and responsiveness to developing trends in the energy sector and hedges against risk, resulting in continued cost-effective services. The IRP plays a crucial role in establishing well-defined goals and objectives that will steer the future course of REU's electric utility operations. These goals and objectives encompass multiple dimensions, including but not limited to:

Affordability

Striving to maintain reasonable and cost-effective electricity rates for customers, taking into account the cost of generation, transmission, and distribution, while also considering the long-term financial sustainability of the utility.

Environmental Sustainability

Meeting clean energy mandates by reducing greenhouse gas emissions, minimizing the environmental impact of electricity generation and delivery, and promoting renewable energy sources and energy efficiency initiatives to support a cleaner and greener future.

Reliability

Ensuring a robust and resilient electric grid capable of meeting the community's demand for electricity under normal and emergency conditions with expected load growth from electrification while managing increased saturation of intermittent resources.

Benefits of the Integrated Resource Plan

The development and implementation of the IRP offers numerous benefits to REU, the COR, and its constituents. These benefits include:

- Enhanced Decision-Making: The IRP provides a systematic approach for evaluating various resource options, enabling informed decision-making that aligns with the community's needs, values, and long-term vision.
- Financial Stability: By strategically planning for future electricity supply and demand, the IRP helps mitigate financial risks and uncertainties, supporting the long-term financial stability of REU and ensuring cost-effective electricity services for customers.
- Environmental Responsibility: The IRP promotes the adoption of cleaner and more sustainable energy resources, helping to reduce carbon emissions, improve air quality, and contribute to the state's efforts in combating climate change.

2.2 Overview of IRP Process

REU embarked on a comprehensive and inclusive process to update its IRP filed in 2019. The IRP process involved a series of studies, assessments, modeling, and stakeholder engagement activities aimed at ensuring that the plan aligns with the organization's goals and effectively addresses the evolving energy landscape and customer needs. This section provides an overview of the key steps undertaken during the IRP development process.

Initial Studies and Assessments

To lay the foundation for the IRP, REU conducted a range of studies to gather data and insights into various aspects of electric utility operations. These studies included a customer survey, aimed at understanding customer preferences, expectations, and evolving energy demands. Additionally, a comprehensive transmission system assessment was conducted to evaluate the existing infrastructure's capabilities and identify potential upgrades or expansions needed to support future electricity supply. Furthermore, an electrification forecast study was carried out to anticipate the growth of electric vehicles, electrified heating systems, and other emerging electrification trends within the community.

Integration of Study & Survey Results

The results from the studies were crucial inputs that informed REU's models and load forecast. The load forecast provided by Itron, Inc., coupled with the electrification forecast developed by Dunsky Climate + Energy Advisors, helped project the future demand for electricity within the Utility's service territory. By incorporating the customer survey data, transmission system assessment findings, and electrification forecast into the load forecast, the models developed by Ascend Analytics provided REU with a comprehensive understanding of the factors that would influence its future resource needs. (See *IRP Project Partners* for more information about the consultants identified in this section).

Portfolio Modeling

Ascend Analytics employed a robust forecast modeling process that integrated the study results and load forecast to determine resources needed to meet future demand. This modeling exercise allowed REU's Long-Term Resource Planning team (the Resources Team) to evaluate several resource scenarios based on a variety of clean energy requirements and implementation timelines. Doing so determines the optimal mix of resources needed to meet projected electricity demand while accounting for the State's regulatory requirements around clean energy and renewable resources.

Stakeholder Engagement

Recognizing the importance of involving diverse perspectives and gathering input from key stakeholders, REU formed a dedicated stakeholder group to review the results and provide insights on the Utility's direction. The stakeholder group consisted of representatives from customer advocacy organizations, environmental groups, regulatory agencies, community organizations, and other relevant entities. Staff provided a series of educational workshops to ensure the group was able to make an educated and informed decision when determining the preferred scenario. This collaborative approach ensured that the IRP development process benefited from the collective expertise and input of a broad range of stakeholders.

Review of Model and Resource Selections

Once the stakeholder group reviewed the results and provided their insights, the Resources Team incorporated their feedback into the model and resource selection process. REU carefully considered the stakeholder group's recommendations to ensure that the IRP reflects the collective vision and goals of the community. Various resource options were evaluated, such as renewable energy generation, carbon-free energy, energy storage, and demand response programs, among others, to determine the optimal mix of resources needed to meet the anticipated utility demand over the long term.

Plan Finalization and Implementation

REU finalized the IRP's preferred resource scenario and affirmed the stakeholder group's assessment that Net-Zero Carbon 2045 is the scenario that most closely aligns with the IRP's strategic framework identified by REU leadership.

The Plan outlines the strategic direction, resource allocation, and implementation timelines to meet the community's electricity needs while considering reliability, affordability, clean energy mandates, and customer preferences.

Although the IRP is not a procurement document, the finalized plan serves as a roadmap for REU's future investments, policy decisions, and operational strategies, with the aim of ensuring a reliable, affordable, and sustainable electricity supply for the COR.

2.3 Strategic Framework

Establishing a strategic framework prior to developing the modeling scenarios for the IRP was crucial to ensure a cohesive and effective planning process. The strategic framework serves as a guiding roadmap, outlining the core principles, goals, and priorities that will shape the IRP's direction. By having REU's Leadership Team agree upon this framework, consensus was reached on the fundamental values and objectives that underpin the energy future.

This approach promoted alignment of the IRP with the REU's overarching mission and vision, fostering a coherent and unified approach to energy planning. The agreed-upon strategic framework provided a clear vision which the Resources Team used to assess various modeling scenarios, ensuring that each option considered was in alignment with its long-term objectives.

Moreover, having a well-defined strategic framework facilitated informed decision-making during the modeling process. It helped to focus on exploring viable solutions that not only met REU's energy needs but also aligned with its sustainability targets, reliability commitments, and customer demands.

REU's Leadership Team agreed upon the following strategic framework for the IRP development:

The preferred 2024 IRP scenario should meet or exceed the State's clean energy mandates while balancing reliability and affordability.

Subsequently, REU's Resources Team presented its leadership with a range of proposed modeling scenarios that aligned with the identified framework. The selected scenarios and assumptions were provided to Ascend along with the comprehensive load forecast prepared by Itron and Dunsky for portfolio modeling. The Resources team furnished inputs and constraints for three specific scenarios:

- Low Scenario: Herein "Current Portfolio" - *does not meet mandates*
- Mid Scenario: Herein "Net-Zero Carbon 2045" - *meets mandates*
- High Scenario: Herein "100% Zero Carbon 2045" - *exceeds mandates*

2.4 Scenario Development

With the strategic framework in place, REU's Resources Team rigorously assessed and scrutinized each modeling scenario to ensure it resonated with the established long-term objectives, sustainability commitments, and customer requirements. This process enabled REU to make informed decisions and prioritize options that not only fulfilled customer energy needs but also aligned with the broader vision for a resilient energy future. By anchoring the evaluation process in the strategic framework, the foundation was laid for a well-considered and cohesive IRP that reflects the collective goals and remains committed to addressing the dynamic challenges of the energy landscape.

Does the Scenario Meet or Exceed Clean Energy Mandates?

Different scenarios were modeled with varying levels of constraints to assess their feasibility. The model subsequently determined the optimal combination of energy resources to fulfill the portfolio requirements while adhering to specified criteria.

Does the Scenario Maintain Reliability?

To assess the reliability of the chosen scenario, a study is conducted analyzing each hour of every day throughout the 20-year planning period to calculate the Loss of Load Probability (LOLP) based on the selected resources. This analysis helps ensure that the chosen scenario accounts for the necessary capacity to maintain a reliable power supply.

Does the Scenario Maintain Affordable Rates?

After completing the capacity expansion model, each scenario undergoes analysis using a production cost model. This model calculates the cost of the power supply for each scenario, enabling REU’s Resources Team to evaluate and compare the costs associated with each option.

	Affordability	Reliability	Meets Mandates
Current Portfolio	✓	✓	
Net-Zero Carbon 2045	✓	✓	✓
100% Zero Carbon 2045		✓	✓

Table 2-1: Scenario Development

Scenario Results

Outcomes are illustrated in Table 2-1. The Current Portfolio falls short of meeting carbon targets and requirements; the Net Zero 2045 scenario successfully meets the objectives of the strategic framework; and the 100% Zero Carbon 2045 scenario fails to meet affordability goals by protecting power supply costs.

2.5 Stakeholder Process

REU recognizes the importance of engaging stakeholders in the decision-making process to ensure that the IRP reflects the values, needs, and aspirations of the community. In developing the IRP, REU's Resources team initiated a stakeholder group process, which involved selecting community members representing various groups and organizations and involving them in a series of workshops and discussions.

Identifying the Stakeholder Group

The Resources Team carefully identified and invited representatives from diverse community groups to participate in the stakeholder group. These groups included environmental groups, community organizations, and other relevant entities who represented economic development, small commercial, residential, and minority customers. The selection process aimed to ensure a broad representation of perspectives and expertise, fostering inclusivity and comprehensive input into the planning process.

- Customers: Residential, small and large commercial, and institutional customers who rely on REU's electricity services.
- Environmental Organizations: Nonprofit organizations and advocacy groups focused on environmental sustainability and renewable energy.
- Economic Development: Organizations focused on the economic growth, sustainability, and viability of the community.
- Community and Interest Groups: Organizations representing minority customers with diverse community interests, such as business associations, social justice groups, and more.

Organization	*Representative*
Mercy Medical Center, Redding	Facility Director
Caliber Office Furniture	Owner, Operator
Shasta Builders' Exchange	Executive Director
Redding Rancheria	Special Projects
North State Climate Action	Advocate
Shasta Environmental Alliance	President
Shasta Environmental Development Corporation	President

The Resources Team contacted several low-income advocacy groups and aimed to invite a representative to join the stakeholder group. Many of the organizations that were contacted did not have the resources to spare for this project; therefore, each of the stakeholders involved were asked to consider the vulnerable low-income and disadvantaged communities when evaluating the scenarios presented.

Stakeholder Workshops and Discussions

The stakeholder group was engaged through a series of workshops and discussions facilitated by REU's Resources Team. During these sessions, participants were provided with relevant information about the energy landscape, the study results, load forecasts, regulatory requirements, and various resource scenarios. The workshops offered a platform for stakeholders to ask questions, share insights, and provide feedback on different aspects of the IRP.

Presentation of Scenarios: Net- Zero Carbon 2045 and 100% Zero Carbon 2045

As part of the stakeholder group process, REU's Resources Team presented two distinct scenarios for consideration: Net-Zero Carbon 2045 and 100% Zero Carbon 2045 plans. These scenarios outlined different pathways for achieving carbon reduction goals and transitioning towards cleaner energy sources. The presentations included detailed information on the potential benefits, challenges, costs, and implications associated with each scenario.

Voting and Feedback

Following the series of workshops and presentations, stakeholders were given the opportunity to vote and provide feedback on the two scenarios. Their votes and feedback were sought to gauge their preferences and perspectives on the proposed plans. The stakeholders' input was vital in guiding the decision-making process and shaping the final direction of the IRP.

Selection of the 2045 Net-Zero Carbon Plan

After carefully considering the votes and feedback received from the stakeholder group, it was determined that the preferred plan moving forward was the *Net-Zero Carbon 2045* scenario. The stakeholders' choice was influenced, in part, by the affordability and reliability considerations associated with operating the Plant. The selected plan reflected the stakeholders' assessment of the balance between environmental sustainability, energy affordability, and the organization's operational capabilities necessary for maintaining its exceptional level of reliability.

Public Survey and Community Agreement

To ensure broad community support and alignment with the stakeholder group's recommendations, REU conducted a public survey to gather feedback on the proposed 2045 Net-Zero Carbon plan. The survey aimed to gauge the community's level of agreement with the plan, including its environmental, economic, and social implications. The results of the survey indicated that the community, as a whole, agreed with the 2045 Net-Zero Carbon plan, validating the stakeholder group's decision and providing further confirmation of community-wide support.

By involving the stakeholder group in a transparent and collaborative process, REU ensured that the IRP incorporated diverse perspectives and reflected the community's preferences. The stakeholder workshops, voting process, feedback collection, and public survey were instrumental in fostering community engagement, building consensus, and ultimately shaping a plan that represents the collective vision for a sustainable energy future in the COR.

3. Legislation & Regulation

In recent years, the legislative and regulatory landscape surrounding energy has evolved significantly, driven, in part, by various state and federal actions. These changes have had a substantial impact on how utilities like REU operate and plan for the future. In the context of these developments, it is crucial to understand the key agencies involved in overseeing and implementing legislative changes, as well as how these changes can affect load forecasting.

REU is subject to oversight from a variety of state and federal agencies. State regulatory oversight bodies include the California Energy Commission (CEC), the California Air Resource Board (CARB), and the California Public Utilities Commission (CPUC). Additionally, the Utility reports to the Western Electric Coordinating Council (WECC), the North American Electric Reliability Corporation (NERC), and the Federal Energy Regulatory Commission. Each of the regulatory oversight bodies monitors various clean energy mandates, safety, security, and reliability standards that REU must abide by. The following section details the oversight and obligations to which REU is accountable.

3.1 State Regulatory Agencies

State-level agencies are given regulatory authority to develop, design, and/or implement various legislative actions from state assembly and senate members, as well as the Governor through executive orders. The following section describes the three primary State regulatory bodies that oversee REU, and their roles in supporting decarbonization efforts. Figure 3-1 shows a diagram of these regulatory and oversight agencies.

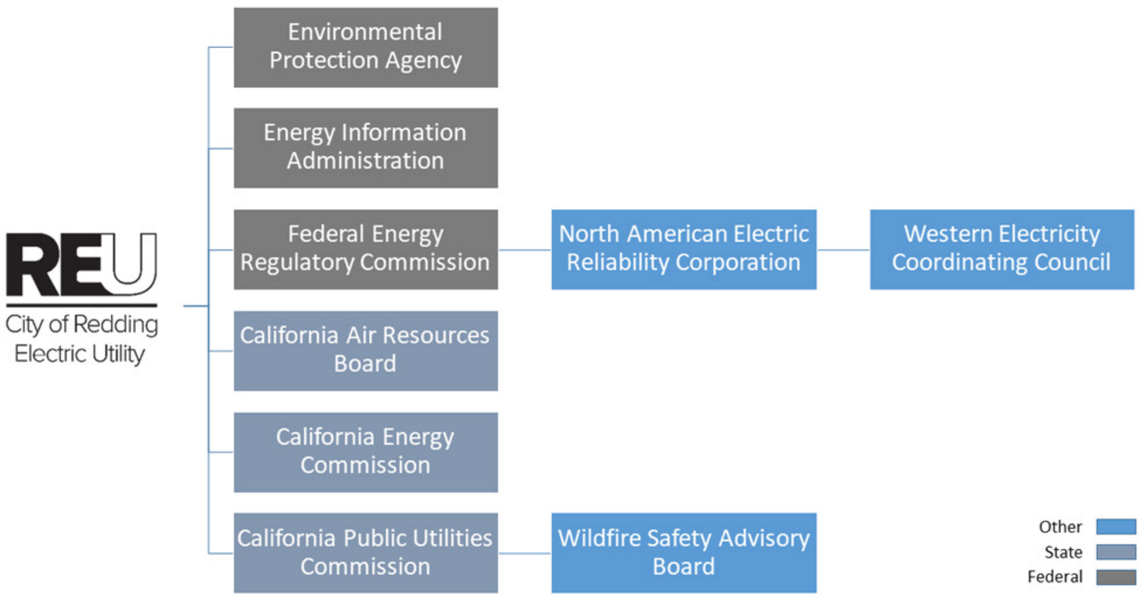


Figure 3-1: Regulatory Oversight of REU

California Energy Commission

The California Energy Commission (CEC) is the state agency that oversees POU activities. The CEC plays a key role in implementing and crafting policies and programs to create a low-carbon economy. Key activities include:

- Developing reporting guidelines and reviewing various reports submitted by POUs, including Integrated Resource Plan, Integrated Energy Policy Report (IEPR), and Annual Energy Efficiency Report (SB 1037)
- Developing and enforcing the State's Renewables Portfolio Standards (RPS) program
- Evaluating and establishing statewide energy efficiency and fuel substitution goals based on POU's Technical and Market Potential Studies results
- Developing Title 24, Part 6 Building Energy Efficiency Standards required for new construction and retrofit projects for residential and commercial buildings
- Evaluate the Power Source Disclosure and Power Content Label programs

REU is subject to the CEC's policies and must consider all current and future policies during the resource planning process. For example, RPS standards were updated to include the accelerated targets, and incorporated long-term contract minimum standards, and portfolio balancing requirements to ensure in-state resources (PCC1) continue to be valued more than out-of-state (PCC2) or unbundled (PCC3) RECs. Additionally, the CEC monitors grid reliability as more renewable energy resources are required through the IEPR process. REU expects the CEC will continue to update existing programs to support SB 100.

California Air Resources Board

The California Air Resources Board (CARB) oversees health and air quality standards for the state. CARB sets the State's air quality standards at levels that protect those greatest at risk, and is the agency tasked with developing policies for combating climate-change through measures that promote a more energy-efficient, carbon-free, and resilient economy. CARB policies typically exceed federal emissions standards. Key activities include:

- Administer Cap-and-Trade and Greenhouse Gas programs (AB 32)
- Developing Scoping Plans (AB 1279) showing carbon-neutrality pathways to meet California goals
- Administer the State's Low Carbon Fuel Standards (LCFS) Program

California's cap-and-trade greenhouse gas program is a key component of the State's comprehensive strategy to combat climate change. Under this program, a cap, or limit, is set on the total amount of greenhouse gas emissions allowed from certain sectors of the economy, primarily industries and power plants. These entities are required to hold allowances equal to their emissions, and a portion of these allowances are auctioned by the State.

The program encourages emission reductions by creating a market for emissions allowances, where entities can buy and sell allowances as needed to comply with the cap. Over time, the cap is gradually reduced, leading to a decrease in allowable emissions and incentivizing emissions reduction efforts.

Revenue generated from the sale of allowances is reinvested in various programs aimed at further reducing greenhouse gas emissions, promoting renewable energy, and supporting disadvantaged communities disproportionately affected by pollution. California's cap-and-trade greenhouse gas program is a market-based approach to limit and reduce carbon emissions from major sectors of the economy, contributing to the State's ambitious climate goals and fostering a transition toward a more sustainable and low-carbon future.

In 2022, CARB's 2022 Scoping Plan for Achieving Carbon Neutrality (2022 Scoping Plan) was issued to lay out additional pathways to achieve carbon neutrality and reduce GHG emissions by 85% below 1990 levels no later than 2045. The results of the report indicated that carbon neutrality is technically feasible by leveraging existing programs (Cap-and-Trade, RPS, etc.), focusing on the balance between carbon sinks (carbon capture, utilization, and sequestration) and sources (fossil fuel production, transportation, etc.), and investing in existing technologies. Continued leadership and climate policy development are also necessary to ensure SB 100 goals are met.

California Public Utilities Commission

While it does not have direct oversight for POUs, the California Public Utilities Commission (CPUC) develops and enforces policies for IOUs that may be passed on to POUs through legislative activities or CEC policy development. The Wildfire Safety Advisory Board, for example, reviews Wildfire Mitigation Plans for both POUs and IOUs, and was originally created as an advisor to the CPUC's Wildfire Safety Division (this has since moved to the Office of Energy Infrastructure Safety under the California Natural Resources Agency). REU and other POUs closely monitor new CPUC policies as they are developed and implemented to ensure POUs are excluded or are provided increased flexibility.

Oversight Agency Coordination

In 2021, the CEC, CARB, and CPUC issued their first SB 100 Joint Agency Report to assess the challenges and opportunities in meeting the zero-carbon target by 2045. The assessment included various scenarios including a zero-combustion, zero-carbon firm resources, and an accelerated timeline to meet the goal by 2035. The results of the report indicated that while the SB 100 target is *technically* feasible, it does not account for grid reliability. The report acknowledges that retaining some natural gas power capacity to minimize the impacts from intermittent renewable resources may be required. Future reports will analyze grid reliability, assess emerging resources (off-shore wind, long-duration storage, etc.), and the environmental, social, and economic costs and benefits from implementing SB 100.

3.2 Federal Oversight Agencies

Federal-level regulators are authorized through various legislative and administrative actions to provide oversight to transmission and energy markets to support the overall grid. The following section provides a brief overview of three primary federal regulatory bodies that oversee REU grid-related activities.

Federal Energy Regulatory Commission

The Federal Energy Regulatory Commission (FERC) is the federal agency responsible for regulating the interstate transmission of electricity, natural gas, and oil resources, and licensing hydroelectric projects. Key activities include:

- Regulating interstate transmission and wholesale energy markets including electricity and natural gas
- Issuing licenses and conducting inspections for hydroelectric projects
- Establishing mandatory reliability standards and approving interstate transmission rates for electricity and natural gas
- Monitors and investigates energy markets

North American Electric Reliability Corporation

The North American Electric Reliability Corporation (NERC) is non-profit regulatory authority responsible for assuring the effective and efficient reduction of risks to the reliability and security of the electric grid. Overseen by the Federal Energy Regulatory Commission (FERC), NERC monitors the bulk power system, develops and enforces Reliability Standards, and assesses seasonal and long-term reliability.

Western Electric Coordinating Council

The Western Electricity Coordinating Council (WECC) is a non-profit, regional entity that supports reliability of the Bulk Electric System in the Western Interconnection. Comprised of 14 Western states, 2 Canadian Provinces, and Northern Baja Mexico, WECC is responsible for compliance monitoring and enforcement, as well as overseeing reliability planning and assessments. WECC is subject to NERC oversight.

WECC is the system administrator for the Western Renewable Energy Generation Information System (WREGIS) which is used for REC accounting for RPS obligations.

3.3 Changes from 2019 IRP

Senate Bill 100

While REU was developing its 2019 IRP, Senate Bill 100 (SB 100) passed legislation and amended the Public Utilities Code (PUC), establishing the newly increased RPS requirements. The PUC's previous renewable energy procurement target required renewable energy to make up 50 percent of retail sales by December 31, 2030. SB 100 accelerated the 50 percent target to 2026 and increased the renewable requirement to 60 percent in 2030.

Additionally, SB 100 reduced the percentage of large hydroelectric generation required to preclude utilities from procuring over a specified amount of renewable generation. Where SB 350 allowed utilities with at least 50 percent of their generation from large hydroelectric resources to reduce the required procurement of renewables by a specified amount, SB 100 reduced the threshold for qualifying utilities to 40 percent.

Finally, SB 100 introduced a new zero-carbon policy not previously required under SB 350. SB 100 requires eligible renewable energy resources and zero-carbon resources to supply 100 percent of retail sales of electricity to California customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045. The bill requires that the achievement of this policy not increase carbon emissions to another place in the western grid. REU is required to incorporate new policy introduced into its long-term planning efforts.

Senate Bill 1020

Governor Newsom signed the SB 1020 bill, also known as the 100% Clean Electric Grid bill, on September 16, 2022. This legislation aims to significantly decrease California's reliance on fossil fuels in three stages. According to the policy, the State's goal is to have 90% of all retail sales of electricity supplied by eligible renewable energy resources and zero-carbon resources by 2035. This target will be followed by a 5% increase by 2040, leading to the ultimate objective of achieving 100% clean energy by 2045.

Renewables Portfolio Standards

The CEC adopted revised RPS Enforcement Regulations on December 22, 2020. The updated RPS Enforcement Regulations included the revised renewables and emissions targets from SB 100. In March 2023, Redding City Council (Council) approved modifications made to REU's RPS Enforcement Program and Procurement Plan to reflect recent updates to the regulations (Exhibit 9.4). In addition to the updated procurement targets for each compliance period shown in Table 3-1 below, the newest regulations require utilities to meet specific Long-Term Procurement Requirements (LTP) and Portfolio Balance Requirements (PBR).

Table 3-1: SB 100 RPS Procurement Targets

Compliance Period	4		5			6		7	
Year	2023	2024	2025	2026	2027	2028	2029	2030	2031...
RPS Target	41.25%	44.00%	46.00%	50.00%	52.00%	54.67%	57.33%	60.00%	60.00%

The RPS established Portfolio Content Categories (PCC) that define renewable energy credits (RECs) and the eligible renewable energy resource products needed to comply with the minimum and maximum values.

- PCC 0: Any contract or ownership agreement executed before June 1, 2010; counts in full toward procurement requirement
- PCC 1: bundled REC + energy at the time of procurement and generated by an eligible renewable resource interconnected to WECC service territory, located within the metered boundaries of a California balancing authority area
- PCC 2: bundled REC + energy at the time of procurement and generated by an eligible renewable resource interconnected to WECC service territory, located outside the metered boundaries of a California balancing authority area
- PCC 3: Unbundled REC procured from eligible renewable energy resources within WECC that do not meet the criteria of PCC 1 or PCC 2

To meet the PBR outlined in Table 3-2, for the compliance period beginning January 1, 2021, and each compliance period thereafter, PCC 1 RECs must account for at least 75 percent of the electricity products applied toward the RPS procurement target. Additionally, no more than 10 percent of the RECs used to satisfy compliance in any given compliance period may be derived from PCC 3 RECs. There is no limit on the number of PCC 0 RECs that can be used in a compliance period, as those RECs are not subject to the PBR.

Table 3-2: SB 100 Portfolio Balancing Requirements

	Compliance Period					
	CP 1 2011-2013	CP 2 2014-2016	CP 3 2017-2020	CP 4 2021-2024	CP 5 2025-2027	CP 6 2027-2030
PCC1 (min)	50%	65%	75%	75%	75%	75%
PCC2 (no restriction)	n/a	n/a	n/a	n/a	n/a	n/a
PCC3 (max)	25%	15%	10%	10%	10%	10%
PCC0	Not subject to portfolio balancing requirements					

Beginning January 1, 2021, with Compliance Period 4, at least sixty-five percent (65%) of REU's RPS procurement for each compliance period must be generated from contracts of 10 years or more in duration or ownership or ownership agreements for eligible renewable energy resources (PUC Sections 399.13(b) and 399.30(d)).

Key modifications to REU's RPS Enforcement Program and Procurement Plan included the following:

- Defined updated procurement targets through 2030
- Addition of Long-Term Procurement requirement starting January 1, 2021
- Included Portfolio Balance Requirement and new Optional Compliance Measure
- Updated notice requirements to the public and CEC as outlined in the new RPS regulations

Updates to the RPS requirements have significantly affected REU's procurement requirements. As a result, the 2019 IRP Scenario H is no longer compliant with current regulations.

Building Energy Code, Title 24 Pt. 6

The Building Energy Efficiency Standards, commonly referred to as Title 24, provides energy and water efficiency requirements for new construction buildings, additions to existing buildings, and alterations to existing buildings. Title 24 is updated every three years and was most recently adopted in 2022. These standards became effective on January 1, 2023.

In addition to general increases in energy efficiency for equipment and buildings, the most significant impact resulting from the 2022 updated standards is the requirement for new construction residential dwellings (Sections 140.10 and 150.1) and nonresidential buildings (Section 170.2) to install onsite or rooftop PV systems Highlights of the PV requirement are as follows:

- Must be sized to offset annual electric usage, providing zero net energy (ZNE)
- Size of the system may be reduced by 25 percent if installed with battery storage system
- Community shared solar, other renewable energy systems, or shared battery systems are options to meet the ZNE requirements under Section 150.1 of Title 24 (note: this option must be approved by the CEC)

Advanced Clean Cars II

California's Governor issued an Executive Order in September 2020, stating that 100 percent of in-state sales on new passenger cars and trucks will be zero-emission by 2035. Additionally, the Executive Order set aggressive goals for zero-emission medium- and heavy-duty vehicles in the state for all operations where feasible by 2045.

Since that time, several major auto manufacturers have pledged to transition to 100 percent electric vehicles or zero-emission vehicle production as early as 2030. While the Executive Order was primarily aimed at auto manufacturers, the Governor required state and local government agencies to work together to develop strategies to provide adequate infrastructure to support the Executive Order's goals. Therefore, utilities across the state are feeling increased pressure to provide infrastructure to support the additional electric vehicles that will be on the road in the foreseeable future.

In 2022, the Executive Order was codified in the Advanced Clean Cars II regulation. By 2035 all new passenger cars, trucks and SUVs sold in California will be zero emissions. The Advanced Clean Cars II regulations take the state's already growing zero-emission vehicle market and robust motor vehicle emission control rules and augments them to meet more aggressive tailpipe emissions standards and ramp up to 100% zero-emission vehicles.

Low Carbon Fuel Standards and Clean Fuel Reward Programs

In 2020, REU opted into the State's Low Carbon Fuel Standards (LCFS) program, which included a provision requiring the Utility to execute a joinder agreement to participate in the State's Clean Fuel Reward (CFR) program. As a program participant, CARB allocates credits to REU based on the saturation of EV charging in its service territory. The credits are issued quarterly and monetized through a competitive bidding process, and revenue is reinvested in the Utility's transportation electrification programs.

LCFS participants are required to contribute a portion of LCFS revenue to the State's CFR program, which was developed to provide rebates to California residents who purchased a qualifying electric vehicle. The CFR program funding has been expended and the program is on hold; however, LCFS program participants are required to continue allocating 25 percent of the revenue from the LCFS proceeds to the CFR program annually.

Each of these programs has a set of corresponding regulatory requirements that participants are mandated to follow, including spending and equity requirements, which impact REU's customer program offerings for transportation electrification.

Advanced Clean Fleet Rule

The Advance Clean Fleet Rule (ACF) rule is a policy aimed at reducing greenhouse gas (GHG) emissions from vehicles and promoting the adoption of cleaner, more sustainable fleet transportation options. The rule sets specific requirements for public fleets to adopt zero-emission vehicles (ZEVs). This requirement is aimed at accelerating the transition to cleaner transportation options in the public sector.

Under the ACF rule, public fleets, including government agencies and departments, are mandated to incorporate a certain percentage of ZEVs into their vehicle fleets. This means that a portion of their vehicle acquisitions or replacements must be zero-emission vehicles, such as battery electric vehicles (BEVs) or fuel cell electric vehicles (FCEVs). Due to more than 90 percent of its fleet residing in a low-population county, the COR is not required to make ZEV purchases until 2027. However, 100 percent of the vehicle purchases must be zero-emission vehicles beginning January 1, 2027.

The inclusion of the public fleet zero-emission vehicle requirement acknowledges the important role of government entities in leading by example and driving the adoption of cleaner technologies. The COR contracted with Frontier Energy, Inc. in April of 2023 to develop a comprehensive City-wide ZEV Fleet Replacement and Infrastructure Plan to fully assess the implications of the regulation on the City's fleet.

Assembly Bill 3232

In addition to the requirement to achieve a reduction in the emissions of greenhouse gases by 40 percent below 1990 levels by 2030, the Clean Energy and Pollution Reduction Act of 2015 (SB 350) established a goal for achieving a cumulative doubling of statewide energy efficiency savings in electricity and natural gas end uses of retail customers by January 1, 2030. AB 3232 directed the CEC, by January 1, 2021, to assess the potential for the state to reduce GHG emissions from residential and commercial building stock by at least 40 percent below 1990 levels by 2030.

The bill requires the CEC to include in their assessment evaluations of the cost to reduce carbon emissions from residential and commercial building stock; cost-effectiveness strategies; challenges with reducing emission from low-income and multi-family housing; load management strategies; potential impacts to ratepayers; and load impacts on infrastructure due to transportation electrification. The CEC was required to submit the findings of the assessment to the Legislature by June 1, 2021. Beginning with the IEPR due on November 1, 2021, and in all subsequent IEPRs, the CEC is required to report on the emissions of GHG related to the energy supply to residential and commercial buildings by fuel type.

Impacts of Updated Regulations

Recognizing the importance of being flexible and adaptable, REU remains committed to staying informed of evolving clean energy regulations, targets, and objectives in California, and is well-positioned to adapt its portfolio modeling accordingly.

The preferred scenario selected in the 2019 IRP no longer aligns with the State's updated regulatory requirements, necessitating the identification of new resources and timelines to ensure regulatory compliance. To achieve this, modeling and scenario development methodologies have shifted to one that is centered around compliance requirements rather than renewable resource identification. The scenarios developed for this IRP account for the varying degrees of compliance needed to meet clean energy mandates, with an anticipation of increasingly stringent renewable energy and carbon reduction requirements imposed by regulatory bodies.

Regulatory requirements for clean energy and carbon reduction will likely become more stringent over time. By incorporating these expectations into the modeling process, the implications of resource selection, investment strategies, and operational plans can be assessed. This forward-thinking approach positions REU to proactively respond to regulatory changes and achieve long-term sustainability goals while providing reliable and affordable electricity services to its constituents.

4. Energy Efficiency, Electrification, & Demand Response

As the state pursues a zero-carbon future, impacts from Customer Program offerings that include energy efficiency, electrification, and demand response activities are increasingly considered critical to decarbonization efforts. The transportation and building sectors are key areas for improvement to meet SB 100 targets. Building code changes support decarbonization by requiring "electric-ready" new construction homes and businesses for future EV and space and water heating equipment, elimination of natural gas subsidies for new construction buildings, and future bans on fossil-fueled appliances. This shift from energy efficiency to decarbonization will contribute to increased energy consumption. Current and future policies on technologies focused on increasing adoption in the transportation and building sectors will also significantly impact the grid's ability to support a zero-carbon future.

REU categorizes program measures as either Committed Savings or Additional Achievable Energy Efficiency (AAEE) or Additional Achievable Fuel-Switching (AAFS). Program measures that were considered in the 2021 Potential Study results are listed as "committed savings" and support REU's approved targets.

The following sections detail the studies and program development for decarbonization programs.

4.1 Demand-Side Management Integrated Resource Plan

Historically, REU has offered energy efficiency programs supporting state goals and regulations, resulting in a lower load forecast over time. With the passing of SB 100, the State began to focus on grid decarbonization rather than relying on energy efficiency to meet clean energy goals. REU developed two reports to address this change:

- 2021 Energy Efficiency Potential Forecast Study (2021 Potential Study)
- Demand-Side Management Integrated Resource Plan (DSM-IRP)

Results from the 2021 Potential Study and the DSM-IRP indicate that electrification programs are expected to increase load over the next ten years. The current load forecast includes results from the Potential Study, whereas results from the DSM-IRP will be incorporated into future load forecasts once programs are fully implemented. Each report's findings are detailed in the following two sections.

2021 Energy Efficiency Potential Study Forecast

Beginning in 2013, and every four years thereafter, REU is required to develop an Energy Efficiency (EE) Potential Study Forecast (Potential Study) that provides a 10-year projection of achievable EE savings. Customer program impacts in the 2019 IRP load forecast were primarily driven by the results of the 2017 EE Potential Forecast (2017 Potential Study) developed for REU by Navigant. Initial findings for that Potential Study indicated approximately 34 GWh of potential EE savings from 2018-2027. These results were incorporated into the load forecast for the 2019 IRP, supporting SB 350 and the state's efforts to double EE savings by 2030.

Results from the 2021 Potential Study forecast (2022-2031), developed for REU by GDS Associates, Inc., identified only approximately 8 GWh of total potential EE from 2022-2031, which is significantly less than the 2017 Potential Study's findings. The differences are attributed to the following factors:

- Updated utility avoided cost rates based on the most recent cost of service study reduced the cost-effectiveness of EE programs
- Increasingly stringent building standards under Title 24 reduced the amount of potential EE savings
- Heavy saturation in the Commercial Lighting Program reduced potential EE savings in future forecasts due to high participation in the early years of the program

On March 2, 2021, Council approved REU staff’s recommendation to update REU's EE goals due to the reduced EE potential identified. The updated goals are listed in Table 4-1, while Figure 4-1 compares the goals from the 2017 and 2021 Potential Studies compared to the CEC’s targets from 2022-2031.

Table 4-1: 2021 REU Council-approved EE Goals

Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
2021 Goals, MWh	1,358	1,305	1,233	1,115	992	755	581	525	439	388

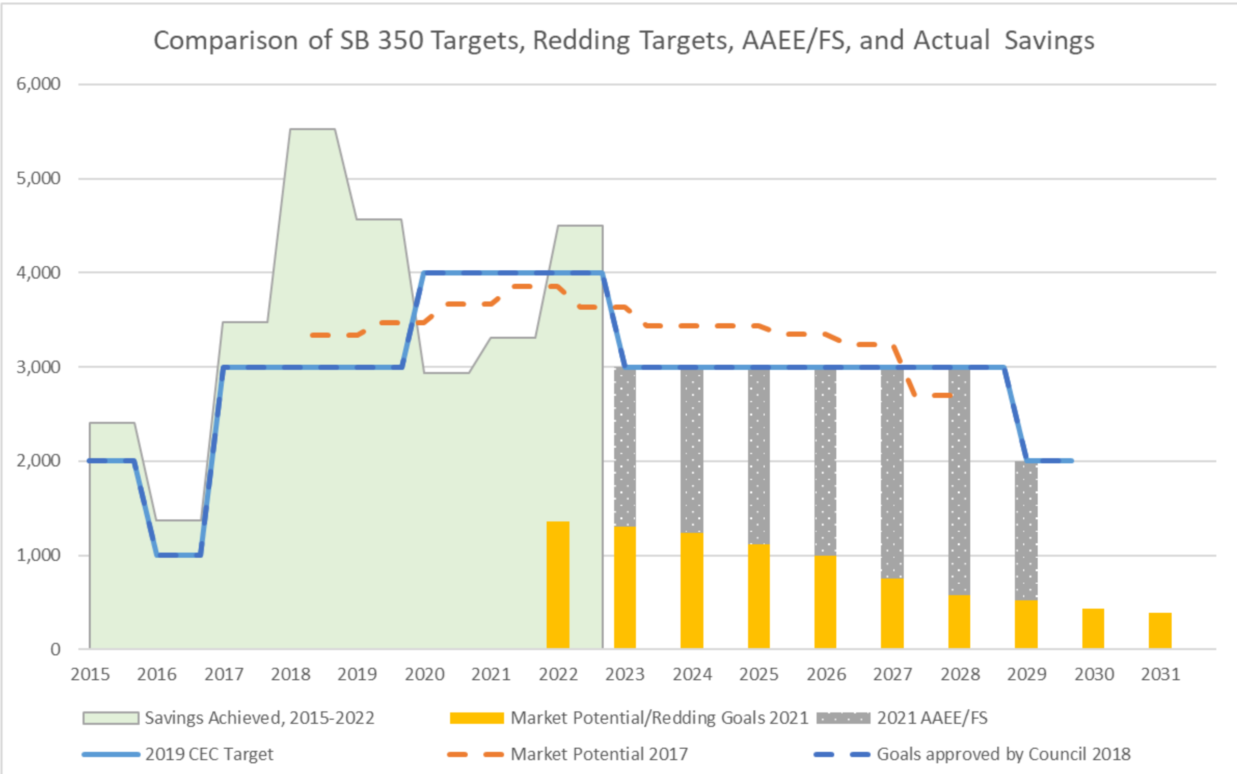


Figure 4-1: CEC Targets, AAEE/FS, and Approved Goals

2021 DSM-IRP Report and Recommendation

The DSM-IRP was developed in response to the 2021 Potential Study results. The planning document sets a framework to identify which programs meet utility goals and establishes a preferred DSM portfolio. REU staff followed a five-step process to structure the DSM-IRP (Figure 4-2). Council approved the report on September 21, 2021.

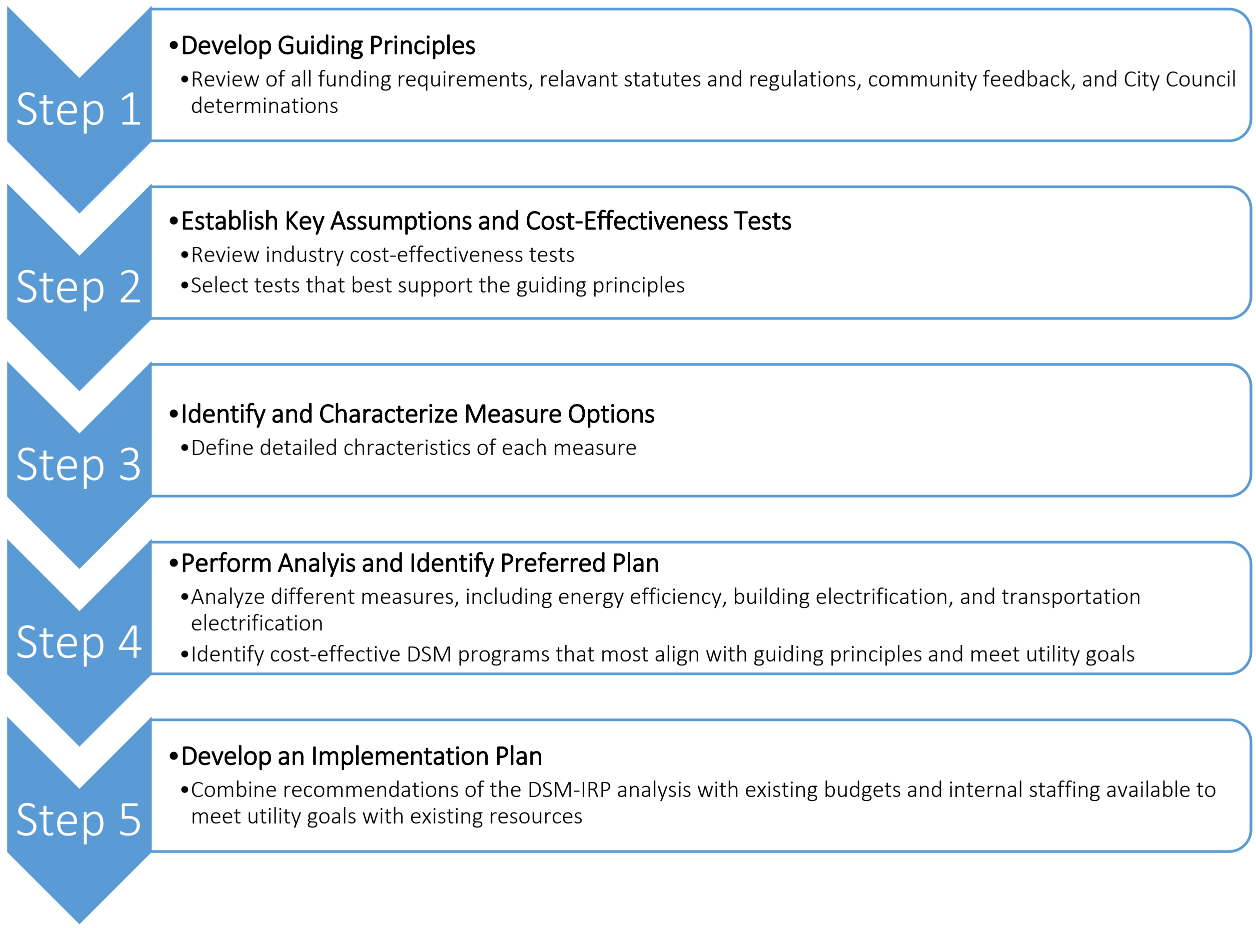


Figure 4-2: DSM-IRP Five-Step Process

Using a five-step approach, staff analyzed hundreds of measures, including energy efficiency, building electrification, and transportation electrification, to determine which measures and programs are most cost-effective. A set of principles were developed to guide the plan, which included the following:

- Offer measures where program participants save money
- Ensure that funds are not transferred from non-participants to participants
- Focus on programs that cost-effectively reduce carbon emissions

From there, three key cost-effectiveness tests were identified that support the guiding principles:

- Ratepayer Impact Measure (RIM, $): The RIM test calculates the utility lifecycle net revenue impacts of a measure. A measure that passes the RIM test provides downward rate pressure and can help identify measures that align with the guiding principles because it provides benefits to both program participants and non-participants.
- Participant Cost Test (PCT, $): The PCT calculates net measure benefits to a customer over the lifecycle of the measure. A measure that passes the PCT test is cost-effective for a customer and can help identify measures that align with the guiding principles.

- Carbon Impact Cost Test (CIT, $/Metric Ton of GHG emissions reduction): The CIT, a City of Redding specific metric, is the ratio of lifecycle rate impacts of a measure to the lifecycle GHG emissions reduction of that measure. The CIT helps identify measures that help cost-effectively reduce carbon emissions. Note that measures with a positive CIT save carbon while providing downward rate pressure.

The components that are included in each cost-effectiveness measure are shown in Table 4-2, where the three metrics that align with the guiding principles are highlighted in blue.

Table 4-2: Cost-Effectiveness Tests Used for Program Evaluation

Test Component	RIM, $	CIT, $/MT GHG	PCT, $
GHG Emissions Reduction		X	
Electric Energy and Capacity Avoided Costs	X	X	
Incremental Costs for Measure and Installation			X
Program Administrator Overhead Costs	X	X	
Incentive Payments Paid by Utility	X	X	X
Customer Bill Impact			X
Utility Revenue Impact	X	X	

The results of the report concluded that building electrification programs and transportation electrification programs best support the guiding principles identified in the DSM-IRP because 1) the recommended electrification programs help maintain low electric rates whereas the historical energy efficiency programs provide upward rate pressure and 2) the recommended electrification programs are a cost-effective way to reduce Greenhouse Gas (GHG) emissions whereas historical energy efficiency programs did not cost-effectively reduce GHG emissions.

Two decarbonization measure types, building electrification (BE) and transportation electrification (TE), were identified as the preferred measures for the DSM portfolio. As a result, REU recommended gradually eliminating EE programs to launch decarbonization programs focused on cost-effective BE and TE measures identified in the analysis. The implementation plan incorporates existing budgets and internal staffing to meet utility goals. Furthermore, it includes education and outreach for customers and contractors to facilitate the transition to decarbonization programs and address all barriers prior to implementation.

REU developed a BE and TE forecast to determine load growth from decarbonization programs based on the DSM-IRP implementation plan. Results from the BE/TE forecast are incorporated into the load forecast for the 2024 IRP.

Shift to Electrification Programs

Since 2017, REU's Customer Program Portfolio (Program Portfolio) has primarily focused on energy efficiency measures that support the State's ongoing climate goals. Programs include energy efficiency equipment rebates for Residential, Commercial, and Low-Income customers. The current Program Portfolio supports the State's energy efficiency doubling goals under SB 350.

Building on the findings of the DSM-IRP, REU transitioned from the current suite of energy efficiency programs to building electrification and transportation electrification programs with a phased approach that will allow time for all stakeholders to adapt to these new types of programs. The energy efficiency programs were terminated effective May 1, 2022, and the first suite of electrification programs was launched on July 1, 2022. Marketing materials, including television and social media campaigns were issued to promote the programs and educate customers on the benefits of electrification.

Methods for reporting electrification program savings relative to the energy efficiency goals are currently under development by California POUs. Existing electrification measures are calculated using energy savings by converting natural gas savings to an electricity-equivalent and subtracting the electricity consumption. This methodology is utilized in the SB 1037 Annual Energy Efficiency report that is submitted by California Municipal Utilities Association.

Redding is required to commit to cost-effective energy efficiency savings. The recommended goals do not achieve the annual SB 350 Targets that were assigned to REU by the CEC from 2023-2026 (Figure 4-3). However, the recommended goals more accurately quantify the cost-effective potential than do the SB 350 Targets. Furthermore, REU expects to meet cumulative goals through 2029 (Figure 4-4), and building electrification will be a significant contributor to energy efficiency in the later years of the forecast. REU will continue to review and identify cost-effective measures that support SB 350 and the State's focus on decarbonization. The results from the 2021 Potential Study are incorporated into the load forecast.

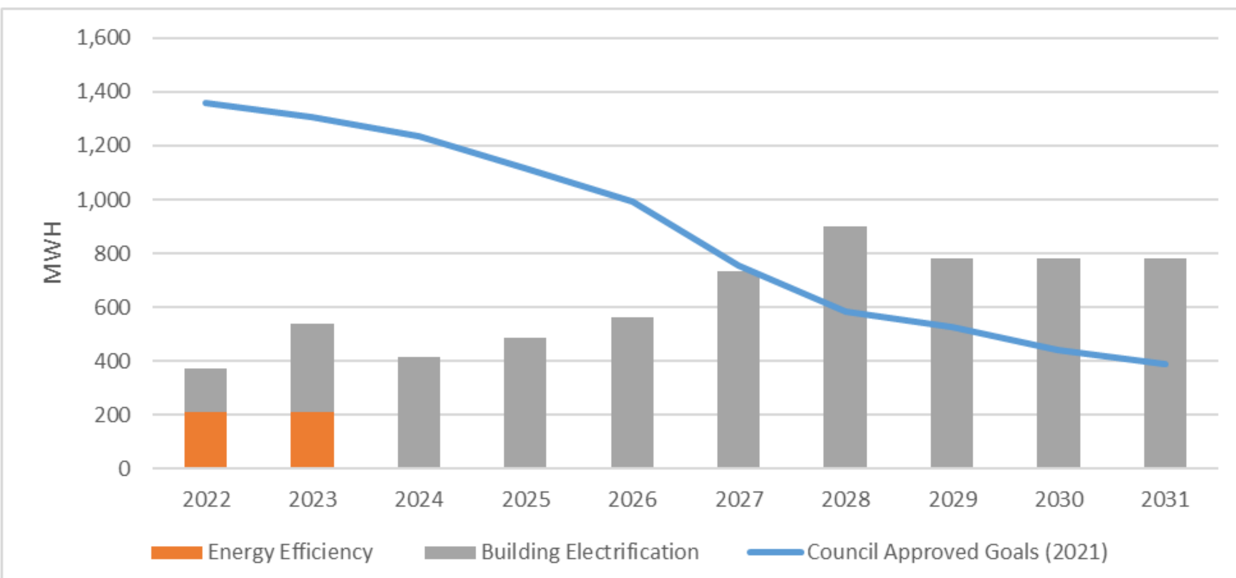


Figure 4-3: City Council Approved Goals vs. Estimated Energy Savings

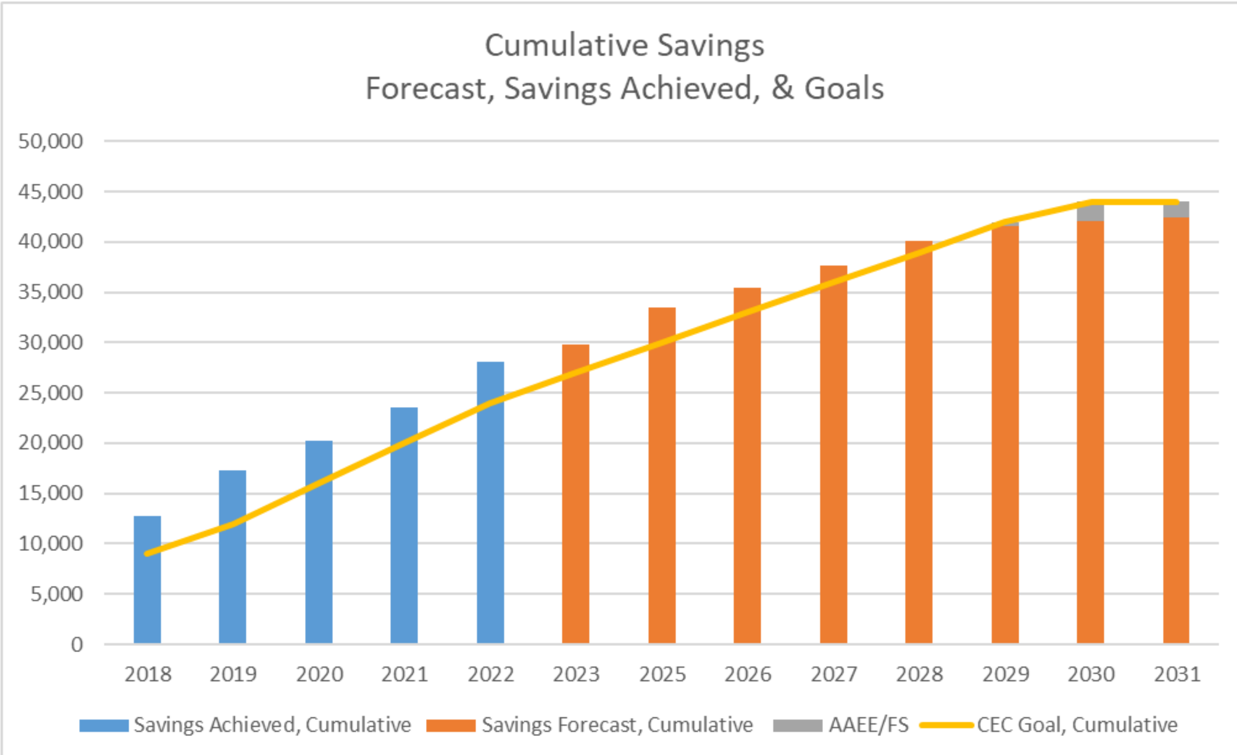


Figure 4-4: Cumulative Savings: Forecast, Savings Achieved, & Goals

4.2 Transportation Electrification

Overview

Various initiatives have been implemented to encourage the adoption of electric vehicles (EVs) and create a supportive infrastructure for EV charging. The COR has been actively engaged in promoting and advancing transportation electrification within its community. To better educate customers, a dedicated online EV hub has been created with customer-facing information including cost calculators, shopping assistance, rebate and incentives programs, charging locators, and contact information for support staff. Additionally, educational materials are provided to customers at various events throughout the year, and promotional advertisements are used to educate the customers about REU's available transportation programs.

The COR has collaborated with local businesses and other stakeholders to install charging stations at key locations, including public parking areas, commercial centers, and recreation facilities. Furthermore, REU has actively participated in regional and state-level programs aimed at expanding the EV charging network and securing funding for EV incentives and infrastructure development.

Alongside its collaboration with EV charging providers, the COR has established an EV Readiness Committee with the purpose of revising and enhancing its design, permitting, and development policies and procedures. The Committee's primary objective is to proactively address barriers to EV adoption and facilitate the necessary investment in EV charging infrastructure throughout the COR. Through this initiative, more customer-friendly policies have been adopted that meet the State's regulatory requirements, encourage the development of EV charging infrastructure, and further support the transition to electric vehicles.

Transportation Electrification Plan

In 2017, Council approved the COR’s first transportation electrification programs, which were funded with revenues from California’s Greenhouse Gas Cap & Trade program. Funding was approved for the following transportation electrification initiatives:

- Residential EV Rebate
- Residential EV Charger Rebate
- Commercial EV Rebate
- COR Fleet EV Charging Stations
- COR Fleet Replacement with EVs
- Public Charging Infrastructure

Subsequently, the COR installed fleet EV charging stations at five of its City facilities, electrified 26 fleet vehicles, invested in electric motorcycles for the Police Department, deployed over a dozen off-road electric vehicles.

After joining the State’s LCFS Program, REU shifted from using Cap-and-Trade funds to using LCFS revenues to support EV programs. As a result of the equity spending obligations mandated by LCFS, a thorough evaluation of the existing programs was conducted, leading to necessary modifications to ensure compliance with the funding requirements outlined by LCFS. By aligning funding priorities with LCFS, REU aims to actively contribute to the reduction of carbon emissions and promote equity within the transportation sector.

REU remains committed to supporting the community's transition to electric transportation and plans to continue its collaboration with other COR departments, leverage existing programs, and to consistently evaluate its programs and procedures to identify and address potential obstacles and barriers to adoption, identify gaps, and seek opportunities for improvement.

Residential Programs

Income-Qualified EV Voucher

The purpose of the program is to reduce or remove barriers to adoption by lowering the down payment amount, the monthly payment amount, and ultimately lowering customers' ongoing fuel and maintenance costs by providing affordable energy that can be used to fuel their vehicles. Funded through LCFS, the Income-Qualified EV Voucher program applies to REU customers who are at or below the Shasta County median income level.

- Income-Qualified EV Voucher Program: applicants can receive a point-of-sale discount off the purchase or lease of a new or used qualifying electric vehicle from a participating retailer.

Income-Qualified e-Bike Voucher

The purpose of this program is to provide clean mobility options and solutions to Redding's most vulnerable community members. Recognizing that the low-income community may not have the ability to invest in an electric vehicle, the Utility is offering an income-qualified electric bike voucher. Customers who are earning an income that is at or below 80% of the Shasta median income can qualify for the voucher.

- Income-Qualified E-Bike Voucher Program: applicants can receive a point-of-sale discount off the purchase of a qualifying e-bike from a participating retailer; additional incentives toward helmet and lock are also available.

Commercial Programs

The Utility has worked in partnership with other COR departments to evaluate the policies and procedures around commercial EV charging infrastructure investments. Policies were updated to comply with the State's charging infrastructure requirements set forth in AB 2127 and AB 970. Additionally, the Utility has implemented a complimentary site assessment service to provide service planning information to customers in an effort to educate customers and encourage investments in public charging infrastructure. A dedicated website has been established allowing customers to find relevant commercial EV charging permitting and building information in one central location.

Commercial DC Fast Charger Rebate

The purpose of this program is to promote the investment and installation of EV fast-charging infrastructure in Redding to support and meet demand for alternative fueling. Many small businesses are interested in installing EV infrastructure, but the initial capital costs can be prohibitive.

- DCFS Rebate Program: applicants can receive a rebate per charging port on qualifying EV charging installations.

Commercial Demand Credit

With the installation of fast charging stations, many small businesses are required to install a second electrical service, which carries an added expense and exposes them to a potentially significant demand fee. Until the charging stations are used regularly and the load factor become favorable, the demand fees can be cost-prohibitive. A demand fee credit can be applied for customers with installations that meet the following criteria:

- Between 50-200kW capacity
- Separately metered stations
- Assign LCFS credits to REU

The demand fee credit can be applied for five years and ramps down by 20% each year before sunsetting.

Transportation Electrification Infrastructure Projects

Public Charging

In 2022, the COR installed four DC Fast Charging stations as a pilot project to encourage third-party investments in charging infrastructure. The COR owns and operates the stations, which are located at the entrance to the Sundial Bridge. Charging rates were established through a public hearing process and are set at $0.20/kWh, REU's cost to provide power, which is significantly lower than typical public charging fees. Adopting affordable charging rates ensures customers have equitable access to public charging.

Since the Sundial Bridge Charging Project was energized, an additional eight super-charging stations have been installed in the same area, and several additional infrastructure projects are currently in the planning, permitting, and construction phases throughout Redding.

To incentivize investments in EV fueling infrastructure, REU has fostered close collaborations with EV charging providers, alongside its partnership with the COR. Together, suitable locations for EV charging stations have been pinpointed and diligently assessed. Through site assessments and circuit impact studies conducted by REU, available capacities have been provided and any essential infrastructure upgrades needed at these locations have been identified. Whenever viable, the COR has taken the initiative to lease properties to third-party charging providers, encouraging the installation of EV charging infrastructure.

City of Redding ZEV Fleet Replacement and Infrastructure Plan

The COR has contracted with Frontier Energy to create a comprehensive City-wide Zero-Emission Fleet Replacement and Infrastructure Plan. The primary objective of this Plan is to carefully assess the electric fuel supply requirements for the future transition of the COR's light-, medium-, and heavy-duty fleets to zero-emission vehicles. However, there are several ancillary benefits that the plan will provide.

- The comprehensive plan will help proactively prepare for the anticipated impacts resulting from the increased adoption of electric vehicles.

- The plan will support applications grant funding opportunities to help with the added cost of infrastructure required to meet the Fleet's electric fuel supply demands.
- Sharing the plan with other agencies impacted by the State's ACF Rule will encourage collaboration and joint infrastructure planning across the region.

Furthermore, this Plan aims to ensure that the COR not only meets but also maintains compliance with regulations while aligning with the State's ambitious goals of significantly reducing transportation emissions.

Electric Vehicle Charging Rates and Managed Charging

REU is in the process updating its 2021 Cost of Service Analysis (COSA), and in the upcoming Cost of Service and Rate Design Study, it is evaluating the potential for creating a new customer class, EV charging rates for Fiscal Year (FY) 2024 and FY 2025. Rates will be designed to follow the Strategic Rate Design document, support the Council's rate philosophy, and closely follow the COSA results by categorizing the customer-, demand-, and energy-related costs for each customer class.

The current rate structure supports the adoption of transportation electrification and EV charging by providing low-cost power to our customers. Low electricity costs can help offset initial investment by reducing the operating costs of EVs, making the cost of charging an EV more affordable than refueling a gasoline or diesel vehicle. Overall, low electricity costs create a favorable environment for transportation electrification by reducing the financial barriers and increasing the economic viability of electric vehicles and charging infrastructure.

The electrification forecast provided by Dunsky evaluated various adoption scenarios including low adoption, high adoption, and managed charging scenarios. This exercise provided REU with valuable insights to use when planning for the increased system demand from electric vehicles. Forecast results indicate implementing managed charging could reduce Redding's peak demand by up to 12MW.

The potential benefits of managed charging have been reviewed. While there are no plans to offer managed charging at this time, REU continues to explore ways to incorporate managed charging strategies into its current customer program portfolio to determine whether that is a technology that would benefit REU and its customers. Additionally, REU is evaluating time-of-use rates and will continue to assess the necessity for managed charging in the event that time-of-use rates are imposed.

4.3 Building Electrification

The Building Electrification program portfolio for both residential and commercial customers aim to simultaneously contribute to the state's goal of doubling statewide energy efficiency savings as codified in SB 350 through traditional EE programs and fuel-substitution (electrification) options, and support decarbonization efforts. To align with decarbonization efforts, REU developed Building Electrification programs to support the conversion of fossil-fueled appliances (natural gas, propane) with electric heat pump technologies.

The following section describes the program offerings.

Residential Programs

Residential Building Electrification Heat Pump Rebates – AAFS

The Residential Building Electrification Heat Pump Rebate program offers prescriptive rebates for residential ratepayers to replace natural gas or propane-fueled appliances with heat pump technology. Selected measures support the DSM-IRP by saving participants money without burdening non-participating ratepayers and has the potential to reduce the overall energy costs. Measure offerings include:

- Heat Pump Clothes Dryers replacing gas appliances
- Heat Pump Water Heaters replacing gas appliances

New Construction Building Electrification – AAFS

The New Construction Building Electrification Rebate Program offers prescriptive rebates for developers to install heat pump equipment instead of natural gas appliances for space and water heating. Measure offerings include:

- Heat pump water & space heating combination

Commercial Programs

Building Electrification Heat Pumps – AAFS

The Commercial Building Electrification Heat Pump Rebate program offers prescriptive rebates for residential ratepayers to replace natural gas or propane-fueled appliances with heat pump technology.

- Heat Pump Water Heaters replacing gas appliances

4.4 Energy Efficiency and Greenhouse Gas Reduction

Investing in energy efficiency has long been recognized as a means of reducing losses on the power distribution system. Such investments have positive impacts on customer rates, the environment, and the lifespan of transmission, distribution, and generating assets. Energy efficiency programs represent significant strides in reducing losses on REU's distribution system. For instance, since the implementation of the street lighting program in September 2015, REU has reduced annual system losses by an average of 1,860,000 kWh by converting high-pressure sodium lighting to LED lighting.

Energy Efficiency Programs

City Energy Efficiency Economic Response Program – Committed Savings

The City's Energy Efficiency Economic Response Program (EEERP) was established in 2020 in response to the Covid-19 Pandemic. The EEERP provides energy efficiency and greenhouse gas reducing measures to COR facilities to help offset utility costs to respective departments. Measures replaced include:

- Replace electric resistance water heaters to heat pumps
- Upgrade to more efficient pool pumps for community aquatic center
- Lighting upgrades for stadiums and city facilities

City LED Streetlight Upgrades – Committed Savings

LED technology consumes nearly two-thirds less energy. The LED Streetlight Replacement Project reduces operational costs, energy consumption, and GHG emissions throughout the city by replacing high-intensity discharge (HID) lights with LED technology. Seventy-seven percent or over 6800 HID streetlights have been replaced with LED fixtures through 2022. REU expects the remaining streetlights to be replaced by 2024.

Greenhouse Gas Programs

Non-Motorized Transportation – GHG Reduction

The Non-Motorized Transportation program provides funding for installation of sidewalks and bike lanes that reduce GHG emissions by improving access throughout City streets to encourage alternatives to traditional transportation methods. Funding also provides the development of additional trail system enhancements throughout the city.

Retired Programs

As discussed, REU has retired several programs as it shifts focus from EE to decarbonization efforts. In addition to energy efficiency programs, GHG programs are also winding down as there is no longer a surplus of GHG allowances available to sell at auction for program proceeds. While this is considered a decarbonization effort, there are fewer funding opportunities to support. REU continues to evaluate programs that can be funded by other means (LCFS, Public Benefits, and ratepayer) to support decarbonization programs. Programs that have been terminated include:

- Residential Energy Efficiency Deemed Rebates
  - Building Envelope (Windows, Ceiling, Floor, & Wall Insulation)
  - Energy Star Appliances (Refrigerators, Room A/Cs, Variable-Speed Pool Pumps)
  - HVAC Systems (Air Conditioning & Space Heating)
  - Water Heater Replacements
- Commercial Energy Efficiency Deemed Rebates
  - Food Service Equipment
  - HVAC Systems (Air Conditioning & Space Heating)
  - Refrigeration Equipment
  - Water Heater Replacements
- Commercial Custom Rebates
- Commercial Lighting Rebates
- Low Income Energy Efficiency & Electrification Programs
- Shade Trees

4.5 Future Programs

REU does not expect to meet the current savings targets due to the shift to electrification. However, REU continues to find opportunities to meet savings targets through electrification programs. Areas of opportunity that may be considered to support electrification, decarbonization, or demand reduction programs included but are not limited to the following:

- Residential and commercial induction cooktop programs
- Residential and commercial heat pump space heating programs
- Residential and commercial behavioral programs
- Panel upgrades
- Low-Income direct-install programs

4.6 Demand Response Programs

Demand Response (DR) programs incentivize customers to reduce the impact of peak demand by load shifting activities, including sending signals to reduce consumption through energy efficiency, appliance adjustments, utilize backup generation, or time-of-use rates. Currently, REU's DR efforts are limited to the CEC's Demand Side Grid Support (DSGS) program, which uses backup generation at certain COR facilities. In Summer 2022, during a period of high demand, the Utility collaborated with other COR departments, specifically the Wastewater and Water Departments, to effectively utilize backup generation. This collaborative effort aimed to alleviate the strain on the grid during peak demand periods, reducing peak demand by 2.54 megawatts.

REU regularly evaluates opportunities for customers to adjust their electricity usage during times of increased demand; however, due to the limited potential for load shifting, there are no current demand response programs or time-of-use rates offered to customers. Programs to incentivize the purchase of DR-capable appliances (heat pump space and water heating, for example) have been considered as an interim step to deploy a full DR program for customers. However, this would need to be supported with time-of-use rates, which would require additional investment. In addition to the existing DSGS program, REU is also evaluating utility-side DR to shift load.

4.7 Energy Storage

REU continuously evaluates the procurement for energy storage requirements. Energy storage (ES) includes batteries and other technologies such as chillers that can store energy for use at a future time. According to the ES Bill (AB 2514, signed into law in 2010), an ES system shall do one or more of the following:

- Use mechanical, chemical, or thermal processes to store energy that was generated at one time for use at a later time.
- Store thermal energy for direct use for heating or cooling at a later time in a manner that avoids the need to use electricity at that later time.

- Use mechanical, chemical, or thermal processes to store energy generated from renewable resources for use at a later time.
- Use mechanical, chemical, or thermal processes to store energy generated from mechanical processes that would otherwise be wasted for delivery at a later time.

ES serves as an efficient means of mitigating system peaks and delivering energy during periods of maximum demand. It can function as an independent asset or be integrated with renewable sources like wind or solar to enhance the reliability of intermittent resources. Notably, the costs associated with energy storage have witnessed substantial reductions in recent years, with the expectation that this trend will persist in the foreseeable future.

AB 2227 required utilities to submit a report on progress toward adopted ES goals. The report, submitted to the CEC on December 29, 2016, showed adequate progress regarding the goals adopted by the Council in 2014. In 2005, REU installed Thermal Energy Storage (TES) systems at various City facilities. TES systems are well-suited for warm climates as they shift electrical demand from peak hours to shoulder or off-peak hours, thereby creating value for customers. REU evaluated and adopted ES procurement targets in response to AB 2514. This resulted in expanding TES installation to commercial customers from 2012 to 2020. REU met its 2020 behind-the-meter (BTM) ES target of 3.6 MW of, therefore satisfying AB 2514 and AB 2227 requirements. The TES systems have reached their useful life and are in process of being decommissioned. Therefore, no additional BTM from TES systems are included in the Itron load forecast.

While BTM storage is no longer included explicitly in the load forecast, REU continues to evaluate ES procurement opportunities on the supply-side as a resource or on the utility's distribution-side as front-of-meter applications. Utility-scale ES can be effective in reducing system peaks and providing energy at the time of day when it’s most valuable. ES costs should continue to decrease and technologies should improve to support utility-scaled needs. Battery storage is an available resource selected in the modeling for the IRP evaluation.

4.8 Localized Air Pollutants and Disadvantaged Communities

The California Environmental Protection Agency (CalEPA) currently identifies disadvantaged communities using the California Communities Environmental Health Screening Tool (CalEnviroScreen). The COR is not an officially designated disadvantaged community (DAC); however, several census tracts within the COR are designated low-income according to California Climate Investments Priority Populations map.

REU recently retired its low-income weatherization program, LIEEP (as mentioned in Section 4.4), which provided energy efficiency and limited electrification upgrades at no cost to low-income customers. REU continues to design and develop programs to support electrification efforts for the low-income community in alignment with the DSM-IRP’s objectives. Current offerings include promoting alternative mobility options for purchasing electric vehicles and electric bikes. Both programs provide point-of-sale discounts to lower the upfront cost barriers that prevent customers from investing in cleaner transportation.

Plans for new or future program developments that aim to educate and assist low-income customers will focus on coordinating with local agencies and leveraging existing programs in other COR departments to ensure the needs to the low-income community are met.

5. Existing System and Resource Description

Redding is rural area located at the northern end of the Sacramento Valley, approximately 160 miles north of Sacramento and 230 miles northeast of San Francisco. As the seat of Shasta County (County), Redding is the major trade and commerce center for the northern central and northeastern portion of California. The city is situated in the midst of a vast recreational area that includes nine national forests, six wilderness areas, two state parks and one national park. Redding experiences hot summers and mild winters with an annual precipitation of approximately 34.2 inches. Elevation within the area varies from 400 feet above sea level to 10,466 feet at Lassen Park, just outside of the County.

Since 1921, REU has provided electric service to its community, and now serves a population of approximately 92,000 through the efforts of 187 employees. The legal responsibilities and powers of REU, including the establishment of rates and charges, are exercised through the five-member Council that is elected City-wide for staggered 4-year terms.

The Utility's electric system (Electric System) includes generation, transmission, and distribution assets. REU also purchases power and transmission services from other entities, referred to as market purchases and sales. For the Fiscal Year ended June 30, 2023, approximately 45,000 customer accounts were served, with a total sale of 738,500 MWh, and realized a peak demand of 234 MW.

The electric resources used to meet the power requirements of customers include generation supply resources, renewable energy resources, contractual power purchases, transmission assets, and natural gas supply facilities. A summary of the power supply resources and the percentage of total energy supplied by each during the calendar year ended 2022, are presented in Table 5-1. These resources are further described in this section.

Table 5-1: Calendar Year 2022 Energy Resources

	Capacity Available (MW)	Annual Energy (GWh)	Percent of Total Energy
Generated Power			
Redding Power Plant[1] (U1-U6)	183.1	426,918	60%
Whiskeytown (U9)	3.5	25,916	4%
Total Generated Power	**186.6**	**452,834**	**64%**
Carbon-Free Power Purchase Agreements			
WAPA Base Resource[2]	128.5	63,163	9%
Big Horn I Wind Project	23.0	163,586	23%
Total Purchased Power	**151.5**	**226,749**	**32%**
Market Power			
Market Power Purchases	-	149,939	21%
Market Power Sales	-	-117,111	-16%
Net Market Power	**-**	**32,828**	**5%**
Total	338.1	712,411	100%

1. Capacity listed is nameplate capacity (EIA860 defined) for Redding Power Plant.

2. The hydro-based contract with WAPA is for 128.5 MW, but the average summer capability is 74 MW.

5.1 Generating Facilities

Redding Power Plant

The Plant is the primary local generation resource, with a total station nameplate capacity of 183.1 MW. The Plant is comprised of: one (1) two-on-one combined cycle power generating station with two Siemens SGT-800 gas turbines (nameplate capacities of 42.5 MW and 40 MW) coupled with a 26.8 MW nameplate capacity GE steam turbine, and three GE Frame 5 simple cycle combustion turbines (combined nameplate capacity of 73.8 MW).

The first SGT-800 gas turbine (Unit 5) was placed into commercial operation in June 2002. The second SGT-800 gas turbine (Unit 6) was placed into commercial operation in August 2011. The Frame 5 combustion turbines were placed into commercial operation in 1996 (Units 1, 2, and 3). All units are currently natural-gas fired only.

The initial steam unit (Unit 4) was acquired and converted from biomass fuel to gas in 1991. Both generator Units 5 and 6 can operate in combined-cycle mode to provide steam to Unit 4. A steam turbine bypass allows either Unit 5 or Unit 6 to operate by sending the generated steam to a secondary steam condenser. When Unit 6 was placed in service, the original fired steam boilers were retired.

On February 9, 2018, testing and verification of a newly installed SCR Dual-function NOx/CO catalyst system was completed for Units 5 and 6, replacing the previously installed SCONOx emissions control system. The catalyst system lowers emissions and increases efficiency. The Station has a cooling tower fed by COR water to meet its cooling needs.

Whiskeytown Project

The COR owns and operates a 3.5 MW hydroelectric generating plant located at the U. S. Bureau of Reclamation Whiskeytown Dam near Redding. This project was completed in 1986 and has produced an average of approximately 26 GWh annually since that time. In some years, temporarily high flow releases have been captured by the flexibility of the dual runners installed in the unit and additional energy has been generated. Under minimum flow release restrictions, it is estimated the facility could produce approximately 10 GWh per year.

In 2021, the controls system for the Whiskeytown station were upgraded to a new programmable logic controller (PLC) system to replace obsolete equipment. The upgrade also allowed remote viewing of the turbine performance from the Redding Power Plant.

The COR has received full CEC certification for the Whiskeytown facility as a California RPS Eligible renewable resource. The facility has been registered with WREGIS, and the associated RECs will either be retained for RPS compliance purposes or utilized for wholesale sales.

The operating license will need to be renewed in 2033. It is expected that the license will be renewed, and Whiskeytown will continue to generate as an eligible renewable resource providing carbon-free power and RECs.

2019 IRP Local Solar Project (Cancelled)

As directed by the preferred portfolio outlined in the 2019 IRP, REU collaborated with NCPA to seek proposals for a 10 MW solar project in REU's service territory in 2019. Despite receiving competitive bids for the project, costs exceeded initial expectations and were higher than those of larger-scale projects. Consequently, the decision was made to prioritize larger-scale projects to fulfill RPS compliance requirements.

5.2 Power Purchase Agreements

In addition to owning and operating generating facilities, REU supplements its energy needs through contractual purchases of energy, transmission, and gas.

Big Horn I Wind Energy Project

The Big Horn I Wind Energy Project (Big Horn) is a 199.5 MW (nameplate capacity) wind project comprised of 133-1.5 MW GE wind turbines, located near the town of Bickleton, in Klickitat County, Washington. As a member of the M-S-R Public Power Agency (M-S-R PPA), a Joint Powers Agency (JPA) with Modesto Irrigation District and the City of Santa Clara, REU receives a 35 percent share of the output from the Big Horn through a power purchase agreement (PPA). REU's share of Big Horn wind energy equates to approximately 70 MW (22 MW firm capacity through a firming and shaping agreement) of the project's output. Power deliveries commenced on October 1, 2006, and will continue through September 30, 2026.

Big Horn interconnects with a high voltage transmission grid through an 11-mile transmission line at Bonneville Power Administration's (BPA) Spring Creek Substation. Through the shaping and firming agreement, Avangrid (owner and operator of Big Horn) receives energy generated from Big Horn, and delivers a firmed and shaped energy product to M-S-R PPA at the California-Oregon border pursuant to firm pre-established delivery schedules. A portion of the California-Oregon Transmission Project (COTP) transfer capability (discussed below) is used to provide for transmission of the output from Big Horn from the California-Oregon border to the COR.

Big Horn is considered an eligible renewable resource by the CEC for California RPS certification. Big Horn has been registered with the WREGIS by Avangrid with BPA acting as the Qualified Reporting Entity. The RECs are transferred from Avangrid, the originator, to M-S-R PPA, and finally to the members of M-S-R PPA. REU retires the RECs towards RPS compliance accounts on an annual basis.

Big Horn Contract Extension

Big Horn's current contract (Initial Term) expires on September 26, 2026; however, there is an option to extend the contract through September 30, 2031, or negotiate a new PPA if the units are repowered. REU staff developed a forecast based on the assumption that Avangrid will exercise the contract extension option (Extension Term) to determine the pricing assumptions and financial impacts.

Currently, the Initial Term variable costs are comprised of the price of energy, plant operations and maintenance (O&M), and the firming and shaping agreement. The Extension Term updates the variable cost components to incorporate the following:

- Monthly Market Index Price (MMIP) + REC pricing as a portion of the cost of energy if it is greater than the contracted price
- O&M costs based on real pricing instead of 2005 nominal value
- Escalation rates to a portion of fixed costs
- Current fixed costs are expected to remain constant

The Extension Term forecast indicates variable costs are higher than what was paid historically due to the O&M costs driving an immediate increase at the start of the new contract term. Furthermore, the addition of the MMIP and REC pricing potentially exposes REU to market volatility. Figure 5-1 highlights the expected increase in variable and fixed costs for Big Horn through the extension contract term.

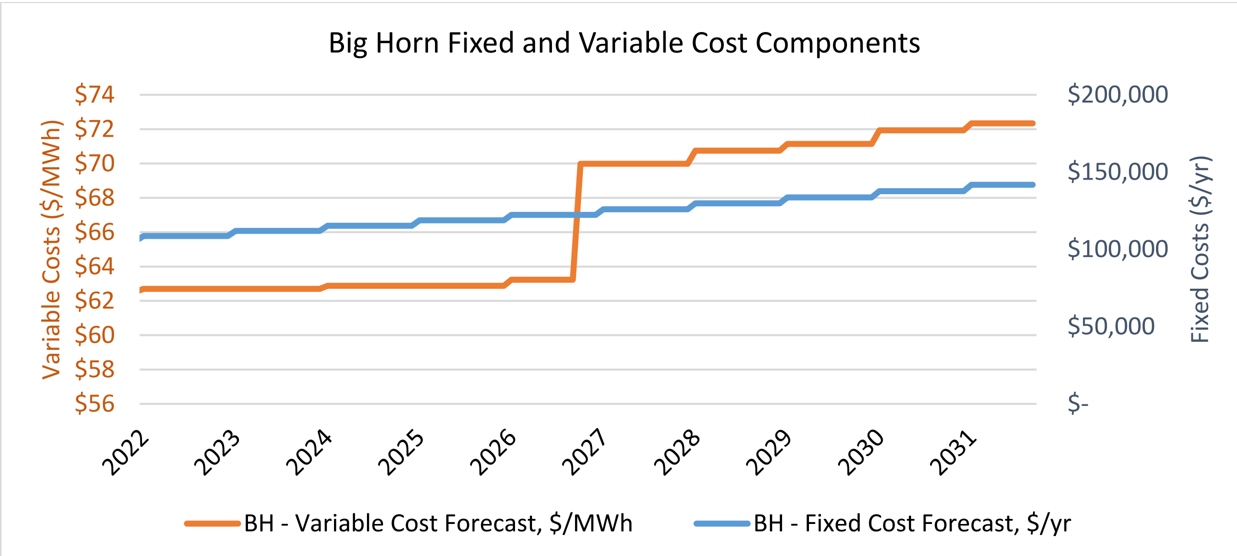


Figure 5-1: Initial Term Costs vs. Extension Term Cost Components

WAPA Base Resource (Hydroelectric Power)

The COR receives a significant portion of its power supply from the Central Valley Project (CVP) pursuant to a contract with the Western Area Power Administration (WAPA). The CVP, for which WAPA serves as marketing agency, is a series of federal hydroelectric facilities in Northern California operated by the U.S. Bureau of Reclamation. Service under the current agreement with WAPA began on January 1, 2005, and continues through 2024. On January 19, 2021, the Council authorized REU to extend the Base Resources contract with WAPA effective January 1, 2025, through December 31, 2054. REU's current allocation is 8.159% of base resource hydroelectric energy generated by WAPA. With the contract extension, REU's allocation of the total CVP generation will be reduced by 2% (from 8.159% to 7.996%) beginning 2025, with an additional 1% reduction (to 7.916%) commencing January 1, 2040.

Delivery of purchased power from WAPA is made at two interconnection points with WAPA: the Keswick Dam Switchyard—a WAPA facility located approximately 0.5 miles from the COR—and at the Airport Substation, located in the southeastern part of the service territory. Power is transmitted to distribution substations over the COR's 115 kV distribution lines.

Energy made available for delivery under its agreement with WAPA is on a pay-and-take basis and is subject to the annual hydrology of the CVP. For planning purposes, WAPA provides estimates of projected deliveries based upon WAPA's assessment of current and expected hydrologic conditions. Deliveries are highly dependent on the hydrologic conditions (rainfall, snowpack, reservoir level, etc.) of Northern California and can vary significantly from year to year. For example, REU received 153 GWh of energy in calendar year 2021 after below-average rainfall in Northern California. In calendar year 2022, REU received 69 GWh of energy – a 45 percent decrease from 2021 – after critically-dry drought conditions remained in Northern California. Deliveries are expected to increase in 2023 due to exceptional rainfall during the year.

While not truly dispatchable, REU is able to shape the daily deliveries of WAPA Base Resource energy within minimum hourly, maximum hourly, and daily total energy. This valuable capability enables REU to align energy scheduling with anticipated load profiles. Looking ahead, this synergy could be particularly advantageous when integrating non-dispatchable renewable resources with predictable generation patterns, such as solar.

REU's contract with WAPA includes power from numerous hydroelectric plants around the Sierra Nevada Region, some of which qualify as a California RPS eligible renewable resource. REU participates in WAPA's Sierra Nevada Region (SNR) REC program to receive the RECs from qualifying hydroelectric projects. RECs from these qualifying hydro facilities (under 30 MW) account for approximately 1.7% of the total allocated Base Resource, supporting RPS targets and the SB 100 requirement to achieve a 100 percent carbon-free resource mix by 2045.

Impact of Drought

In an average water year, approximately one-third of REU's power supply resources are derived from hydroelectric generation, including the Whiskeytown Project and power purchased from WAPA. Hydrology in California can be highly variable from year to year. Table 5-2 indicates, for example, that during four consecutive years of drought, generation received from the WAPA CVP was significantly reduced.

Table 5-2: Historic Deliveries from WAPA CVP

Calendar Year	Energy (GWh)
2018	342
2019	341
2020	253
2021	153
2022	69
Est. 2023	172

In the event of reduced hydroelectric generation, generating additional energy or purchasing additional energy on the wholesale market may be necessary to meet retail sales load obligations, and such actions can significantly increase power supply costs. This is a consideration when planning for future resources and when assessing the risk of renewable energy production from hydro versus other renewable resources such as solar or wind. However, there has been shown to be a direct correlation between the pressure systems that build along the West coast during a drought and the output from wind farms located in the Pacific Northwest. Thus, the impact of drought conditions in the Pacific Northwest tends to also result in decreased wind generation from the COR's share of Big Horn Wind. During such periods, there may be a need to purchase replacement energy from the wholesale market or generate replacement energy at an additional cost.

WAPA Contract Renewal

During the development of the 2019 IRP, Base Resource customers and WAPA were actively negotiating a 30-year contract renewal (Renewal) to continue base resource hydroelectric power after December 31, 2024. REU staff developed the Renewal Forecast to analyze the impacts prior to signing the Renewal, which included:

- Extending the forecast period from January 1, 2025, through December 31, 2054
- Reducing Base Resource allocation by 2% beginning January 1, 2025
- Further reducing Base Resource allocation by 1% beginning January 1, 2040

The Renewal Forecast findings indicate that Base Resource remains a cost-effective resource throughout the forecast period. On January 19, 2021, City Council approved REU staff recommendation to sign the WAPA Renewal based on the assessment. The model incorporated the results from the Renewal Forecast upon approval.

The reduced Base Resource allocation also decreases the cost of the contract for Redding (Figure 5-2). Furthermore, WAPA updated the FY21-FY30 Power Revenue Requirement (PRR) forecast due to adjustments made by the Bureau of Reclamation on operations and maintenance (O&M) costs and project repayments.

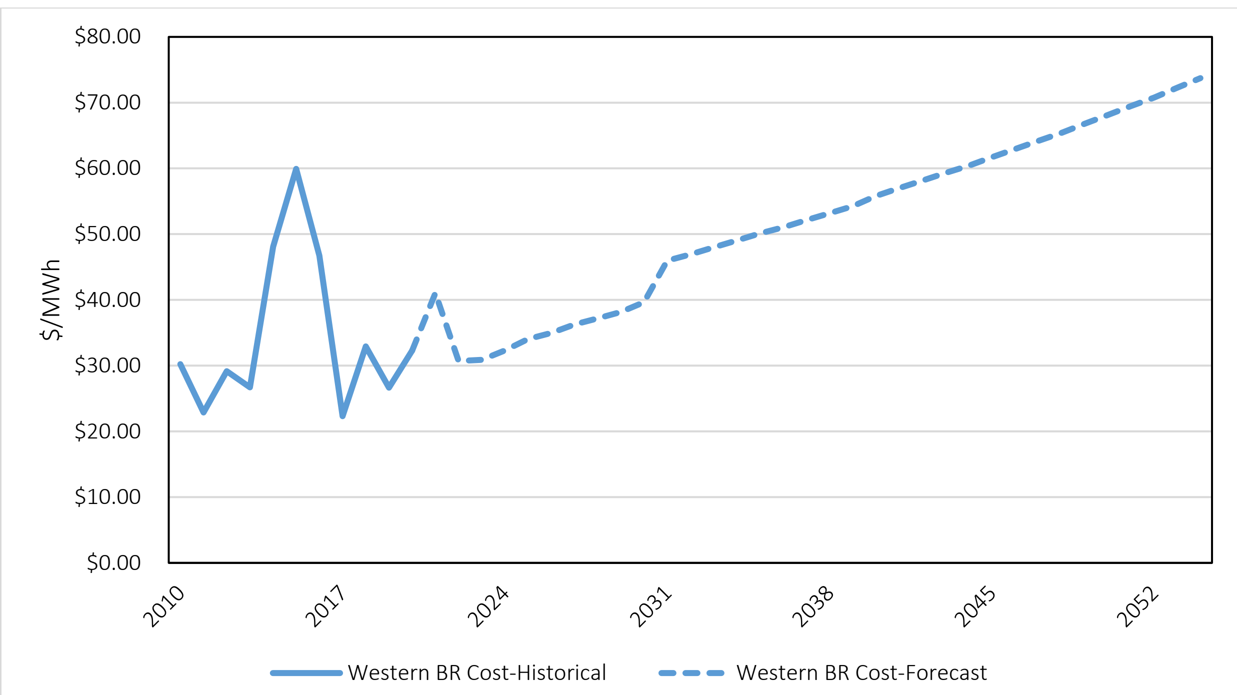


Figure 5-2: WAPA Costs - Historical and Forecast

5.3 Renewable Energy Resources

Since 2003, REU has aggressively pursued cost-effective and self-owned or purchased renewable resources through adopted RPS targets. Currently, REU has a diversified renewable portfolio comprised of the following resources:

- Hydroelectric resources (owned)
- Hydroelectric resources (long-term contracts)
- Wind power (long-term contracts)
- Renewable Energy Contracts (long-term and short-term contracts)

The current resources, which include zero carbon and renewable resources, are summarized in Table 5-3. It is important to note that while WAPA large hydro is considered a zero-carbon resource, it does not qualify as an eligible renewable energy resource. Similarly, behind-the-meter solar does not qualify for utility renewable energy or zero-carbon categorization.

Table 5-3: Current (Calendar Year 2022) Clean Energy Resources

	Resource Type	Capacity Available (MW)	Annual Energy (GWh)	Percent of Retail Sales
Renewable Resources				
M-S-R PPA/Big Horn I Wind Project	Wind	23.0	163	23%
WAPA Base Resource – Small Hydro	Small Hydro	1.3	5	1%
Whiskeytown (U9)	Small Hydro	3.5	26	4%
Total Renewable		**26.5**	**194**	**27%**
Carbon-Free Resources				
WAPA Base Resource – Large Hydro	Large Hydro	128.5	63	8%
Total Clean Energy		155.0	252	35%

Hydroelectric generation has a significant impact on REU's power mix. In 2021, approximately 81 percent of retail sales were supplied by zero carbon resources. However, in 2022, the proportion of zero carbon resources declined to approximately 53 percent due to severe drought conditions affecting hydroelectric generation. This reduction led to an increased reliance on fossil fuel resources to satisfy energy demand.

In 2022, REU received notification from the CEC staff that 121,352 of its RECs, which had been intended for use in Compliance Period (CP) 3 to satisfy Excess Procurement requirements, were rendered ineligible. This ineligibility arose from an administrative error within the reporting tool when the RECs were retired. Consequently, RECs planned for CP 4 compliance were moved into the CP 3 subaccount to satisfy CP 3 RPS requirements for that period, causing a short position for CP 4. Subsequently, REU staff have sought bids to replace those compliance instruments; however, due to elevated market prices, the cost to replace those ineligible RECs would disproportionately impact customers. Figure 5-3 shows the potential impact to RPS obligations due to the ineligible RECs. Note that REU would not Compliance Period 4 (2021-2024) requirements and would potentially have to seek alternative compliance.

As a result, REU is evaluating the potential need to exercise an Optional Compliance Measure to satisfy the RPS requirements for CP 4. To ensure ongoing compliance with SB 100, and meet the RPS targets, REU actively monitors RPS-eligible resources and considers the need for Optional Compliance Measures outlined in its RPS Procurement and Enforcement Plan (Exhibit 9.4).

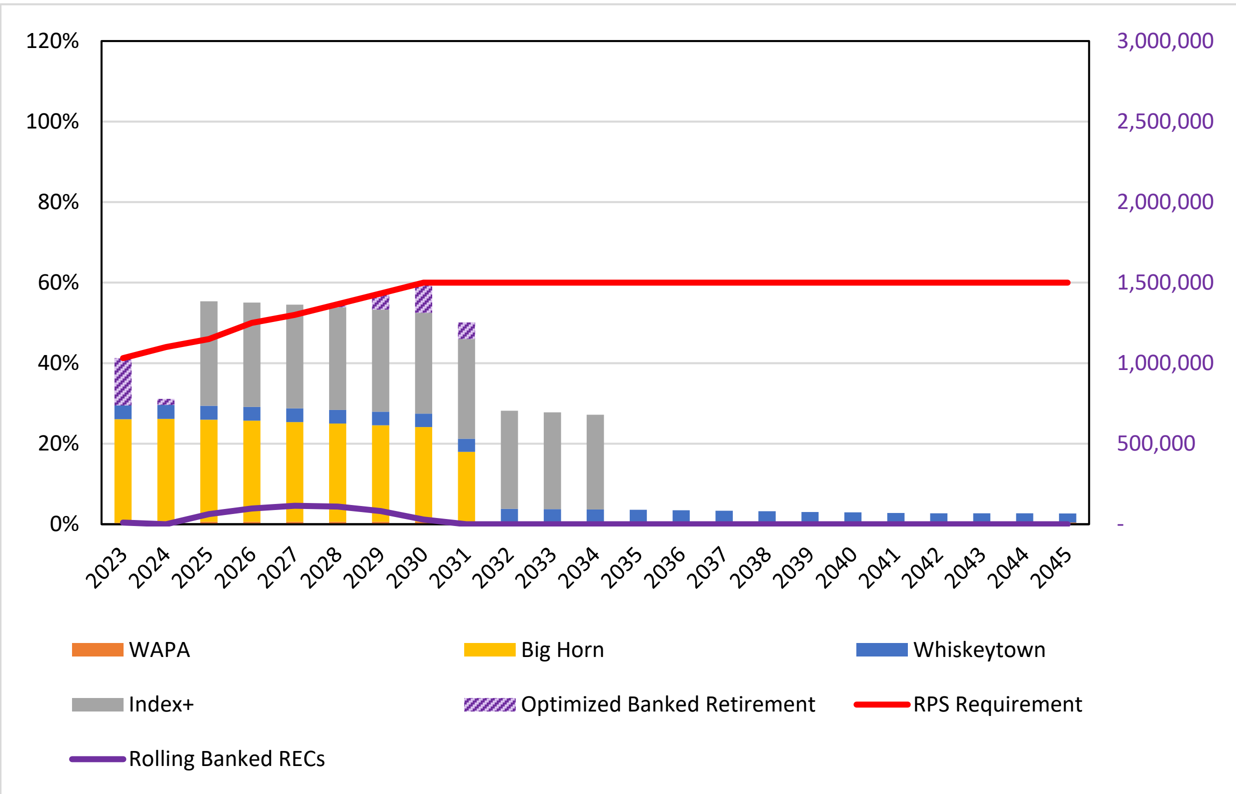


Figure 5-3: 2019 IRP Scenario H v. SB 100 Renewable Requirements with Ineligible RECs Removed

The 2019 IRP's preferred portfolio was devised to align with the renewable energy objectives mandated by SB 350. Initially, REU was tasked with procuring 50 percent of energy supplied to end-use customers from eligible renewable sources by 2030. However, SB 100 subsequently raised the compliance threshold to 60 percent eligible renewables by 2030, introduced long-term contract requirements, and introduced a zero-carbon target for 2045. Concurrently, SB 1020 set interim carbon-free energy targets of 90% in 2035 and 95% in 2040.

The preferred scenario outlined in the 2019 IRP no longer satisfies these updated compliance requirements and targets, as depicted in Figure 5-4. Therefore, it becomes imperative to reassess and adapt this portfolio accordingly.

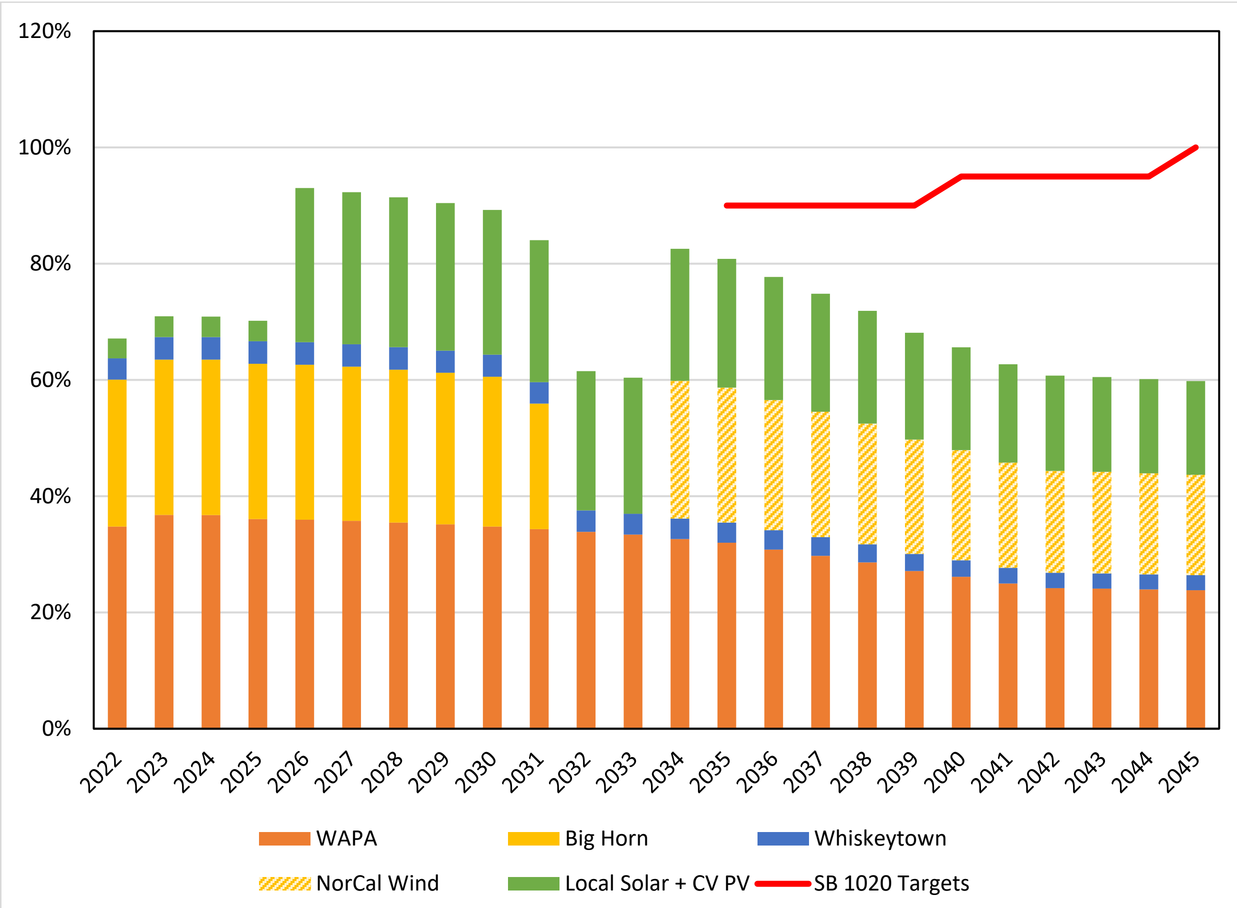


Figure 5-4: 2019 IRP Scenario H vs. SB 1020 Carbon-Free Targets

REU contracted with Ascend to incorporate the adjusted regulatory obligations into its current portfolio scenario to evaluate the long-term effects of the updated requirements. In addition to the stricter energy procurement requirements, there are new Long-Term Procurement and Portfolio Balancing Requirements within the updated RPS regulations that must be adhered to. As such, adjustments to the portfolio included larger eligible renewable project PPAs and earlier procurement target dates.

Renewable Energy Purchases

The preferred plan identified in the 2019 IRP included the addition of 10 MW of local solar generation, originally scheduled to begin operation in 2026, with another Wind Project coming online in 2034. However, updated clean energy mandates rendered the plan non-compliant with new regulatory requirements. To bridge the gap until future renewable projects could be developed, REU executed a short-term, one-year contract for 100,000 MWh of renewable energy, which provided PCC1 RECs to address the shortfall. The long- and short-term contracts will deliver energy with PCC1 RECs according to the schedule in Table 5-4.

Table 5-4: Contracted PCC1 REC Deliveries

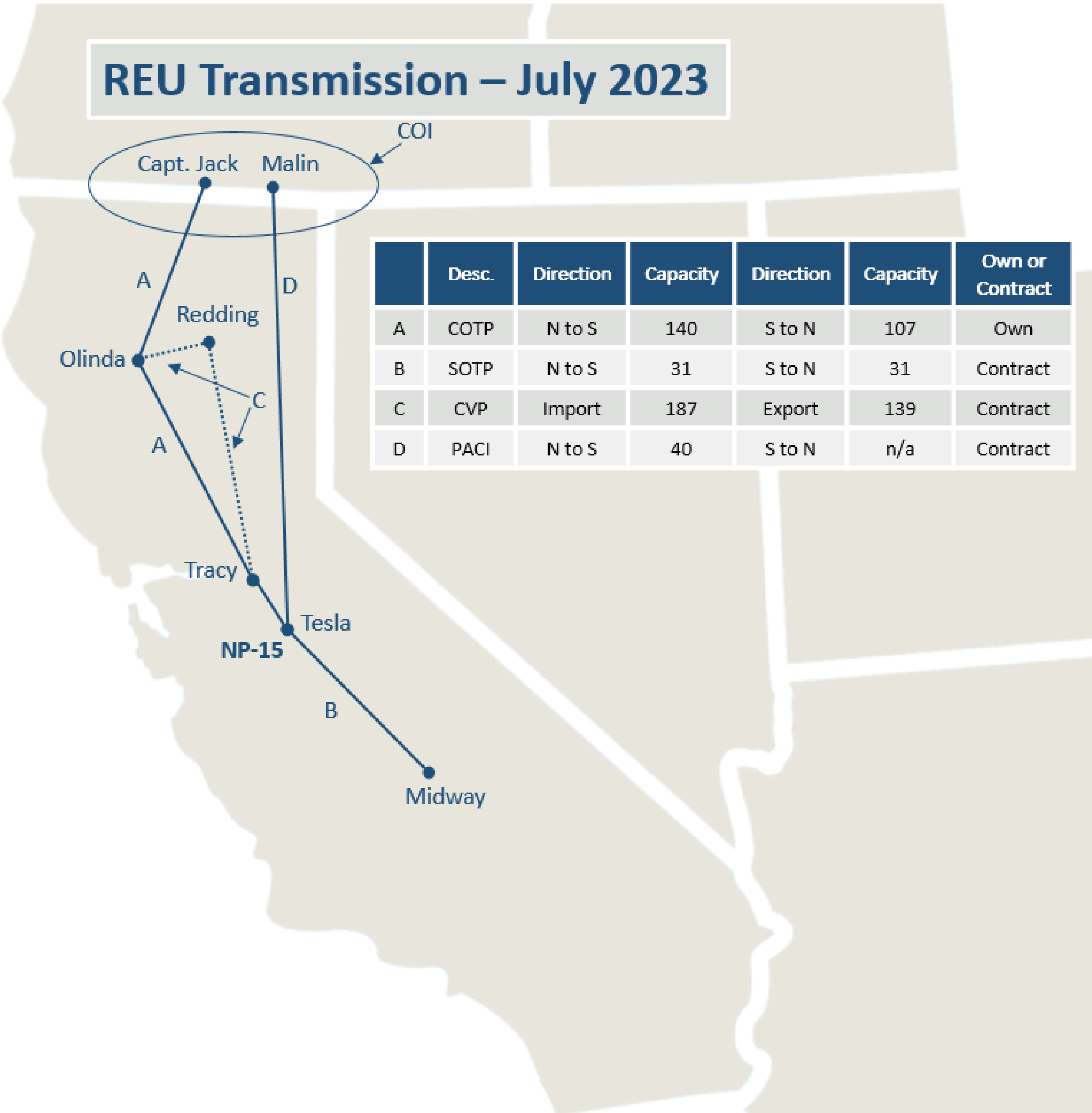
RPS Compliance Period	Calendar Year	Long-Term Contract Energy, MWh	Short-Term Contract Energy, MWh	Total, MWh
5	2025	125,000	50,000	175,000
5	2026	125,000	50,000	175,000
5	2027	125,000	50,000	175,000
6	2028	175,000	0	175,000
6	2029	175,000	0	175,000
6	2030	175,000	0	175,000
7	2031	175,000	0	175,000
7	2032	175,000	0	175,000
7	2033	175,000	0	175,000
7	2034	175,000	0	175,000
	Total	**1,600,000**	**150,000**	**1,750,000**

In addition to the renewable resources listed above, the 2019 IRP preferred plan identified the need for a 60 MW solar project beginning in 2026. As a result, multiple requests for proposals were solicited across various joint powers agencies, and many competitive bids were received. REU worked with Ascend Analytics to evaluate the potential projects and choose the one that satisfied the requirements for renewable compliance and provided the most benefit to REU and its customers.

Based on the analysis of the various proposal received, given the current portfolio needs and compliance requirements, REU selected two Index+ projects to deliver long-term and short-term PCC1 RECs for the years 2025 through 2034. With the Index+ structure, renewable energy is bundled with the RECs. The seller schedules the energy to deliver to the CAISO market, REU receives the renewable attribute, and the seller is compensated by the CAISO for energy delivered.

5.4 Transmission Assets

The transmission facilities owned or contracted for are described in this section. Owned transmission facilities are shown in Figure 5-5.



	Desc.	Direction	Capacity	Direction	Capacity	Own or Contract
A	COTP	N to S	140	S to N	107	Own
B	SOTP	N to S	31	S to N	31	Contract
C	CVP	Import	187	Export	139	Contract
D	PACI	N to S	40	S to N	n/a	Contract

Figure 5-5: REU Existing Transmission

WAPA Transmission Service and BANC

REU is a customer of WAPA, who provides access to their high voltage transmission via an interconnection with its distribution system. Through a transmission service contract, any power needed to meet system loads that are not met by generation assets within the service area can be imported using WAPA's transmission. The transmission agreement, signed August 1995, is effective for 40 years, though either party can opt out after giving a 5-year notice. The contract specifies that WAPA will provide, on a firm basis, both Long-Term Firm Transmission Service and Short-Term Firm COTP Transmission Service, detailed in Table 5-5. The WAPA transmission system is part of the Balancing Authority of Northern California (BANC) balancing authority area (BAA) and interconnects with the California Independent System Operators (CAISO) BAA.

Table 5-5: WAPA Transmission Service Summary Information

Capacity Contract	End Date	Capacity, MW*	Voltage, kV	Delivery Point(s)
Long-Term Firm Transmission				
Contract 1	2035	136.8	230	Olinda, Tracy, Elverta, Airport, Keswick (115 kV)
Contract 2	2035	47.2	230	Delivery: Tracy, Cottonwood Receipt: Airport, Keswick (115 kV)
Short-Term Firm COTP Transmission Service				
Contract 1	By request	By request	230-500	California-Oregon Border, Southern Terminus (500 kV); Olinda, Tracy (230 kV)

**Delivery point capacity after losses*

REU is also a member of BANC, a joint powers authority and balancing area with members that also include the Sacramento Municipal Utility District (SMUD), Modesto Irrigation District (MID), Roseville Electric, Trinity Public Utility District (TPUD), and the City of Shasta Lake (COSL). BANC began its operations on May 1, 2011, and is now the third largest balancing authority in California, serving a peak load of approximately 5,000 MW and 763,000 retail customers. BANC's operations extend from the California-Oregon border to Modesto, California, covering most of the larger utilities in the Central Valley region north of Modesto. A map of BANC members and associated transmission, generation, and interties are in Figure 5-6.

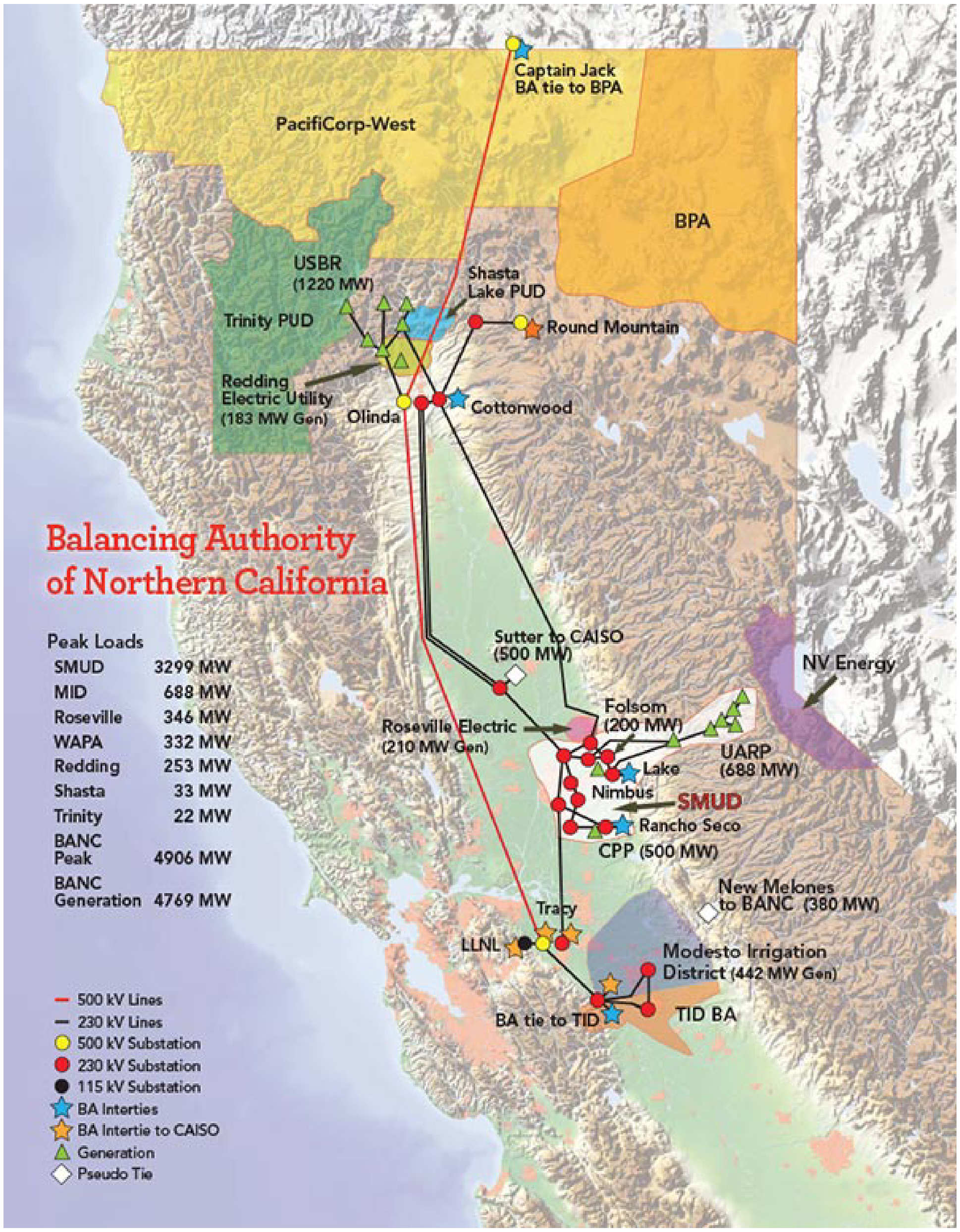


Figure 5-6: Balancing Area of Northern California (BANC) Members

As a member of BANC, REU is responsible for matching customer usage and resources on a moment-by-moment basis. However, BANC operates the transmission system, monitoring power lines to target their operation within the reliable limits of the system, and coordinates operations with neighboring balancing authorities.

SMUD acts as the balancing authority operator and performs balancing authority functions on behalf of BANC. Benefits of being under BANC include direct scheduling of energy transactions over the COTP within the BANC balancing authority area, free of a CAISO tariff or charges, and free from related congestion and encumbrances.

BANC operates under the principle of maximizing consumer value and compliance with NERC reliability standards. The structure provides flexibility to expand and allows members to benefit from potential future savings through the sharing of facility costs.

TANC and California-Oregon Transmission Project

REU, along with fourteen other northern California cities, utility districts, and one rural electric cooperative, are members, or associate members, of a California JPA known as the Transmission Agency of Northern California (TANC). TANC, in partnership with WAPA, two California water districts and PG&E (collectively, the COTP Participants), own the California–Oregon Transmission Project (COTP)—a 339-mile long, 1,600 MW, 500 kV transmission project extending from southern Oregon to central California.

REU is entitled to 8.4119 percent of TANC's share of COTP transfer capability (approximately 115 MW) on an unconditional take-or-pay basis. On April 1, 2005, REU purchased from COSL, its 1.5856 percent ownership interest (approximately 25 MW) in the COTP. As a result, REU participates in the use of the COTP as both a member-participant of TANC (115 MW) and as a direct COTP owner (25 MW); this participation provides a total of 140 MW of firm transmission capability.

Access to the COTP entitlements is gained through a long-term transmission contract with WAPA. Currently, a portion of its COTP transfer capability is used to provide transmission of renewable wind capacity and energy purchased through the M-S-R PPA. The remaining transfer capability is used to make spot market purchases of firm and non-firm energy and as reliability backup for firm power purchases and sales commitments.

In order for TANC members to utilize the full transfer capability of the COTP on a firm basis and to maximize the benefits of the line, the COTP is operated on a coordinated basis with the Pacific AC Intertie (PACI). The PACI is a two-line system that, like the COTP, connects California utilities with other utilities in the Pacific Northwest. The PACI is owned by PG&E, PacifiCorp, and WAPA; it is operated by the CAISO. The three-line system comprised of the COTP and the Intertie is collectively referred to as the California-Oregon Intertie (COI).

Tesla-Midway Transmission Service

The southern physical terminus of the COTP is PG&E's Tesla Substation near Tracy, California. TANC has arranged for PG&E to provide TANC, and certain TANC Members, with 300 MW of firm, bidirectional transmission capacity on its transmission system between PG&E's Tesla Substation and the Midway Substation in Buttonwillow, California (the Tesla-Midway Service) under a long-term agreement known as the South of Tesla Principles (SOTP). The COR's share of Tesla-Midway Service is 31 MW. This transmission service enhances the value of the COTP to TANC and the TANC Participants by increasing opportunities for energy purchases, sales, and other utility arrangements. The full allocation of Tesla-Midway transmission service has been utilized for firm and non-firm power transactions. This service provides value related to the delivery of CAISO renewables.

Other Transmission Assets

Power from sources outside the service territory is delivered to the Airport and Keswick 230/115 kV substations. These two facilities provide a reliable interconnection capacity of 275 MW from WAPA's 230 kV transmission system. WAPA retains ownership of the Airport Substation facilities exclusive of the substation property owned by REU. At the Airport Substation, WAPA owns and maintains the 230 kV related facilities; REU owns the 115 kV facilities, which are maintained and operated by WAPA at REU's expense. At the Keswick Substation, WAPA owns, and is responsible for, all facilities other than the remote terminal unit equipment specific to REU's use at the Keswick Substation.

Transmission Losses

REU contracts with WAPA to settle transmission losses financially. This contract settles losses on all REU transmission, including CVP, COTP, PACI, and SOTP. Through this contract, REU purchases replacement energy in the amount of the assumed losses at the line terminus. This energy is delivered in sync with the scheduled energy so that effective energy at the origin and terminus are the same. The replacement energy for losses is purchased at real-time market rates.

NERC Registration

NERC, the Electric Reliability Organization for North America, has the vital responsibility of safeguarding the reliability and security of the bulk power system (BPS). Its operations fall under the oversight of the Federal Energy Regulatory Commission (FERC). Among the Regional Entities authorized by NERC and FERC, the Western Electricity Coordinating Council (WECC) assumes the role of monitoring and enforcing compliance within the Western Interconnection.

NERC and the Regional Entities have the mandate to identify and register entities that meet the criteria for inclusion in NERC's Compliance Registry. Owners, operators, and users of the BPS must register and adhere to approved Reliability Standards. Entities are categorized into different functional types based on their typical operations and are obligated to comply with the relevant Reliability Standards applicable to their registered functions.

Prior to 2020, REU was registered as a Generator Owner (GO), Generator Operator (GOP), Distribution Provider (DP), and Resource Planner (RP). REU owns 115 kV Facilities that meet the threshold of Bulk Electric System (BES), therefore, in 2019 WECC notified REU that it should either register as a Transmission Owner (TO) or apply for a registration exemption with NERC.

REU pursued a registration exemption by submitting an application to the NERC-led Review Panel. NERC determined that REU has a material impact to the BES and required REU to register as a Transmission Owner (TO), Transmission Planner (TP), and Transmission Operator (TOP). REU completed the implementation of all three registered functions and was officially added to the NERC's Compliance Registry as a Transmission Owner, Transmission Planner, and Transmission Operator in 2020. As a result of the additional functional registrations, REU's compliance obligations increased from approximately 100 Reliability Standard requirements to around 240 requirements. This change also affected the audit cycle, which will require REU to transition from a 6-year audit cycle to a 3-year audit cycle.

5.5 Distribution Assets and Adequacy

Distribution Assets

The COR provides customers with electrical service through a distribution network which includes electric substations, transmission lines, distribution lines, and transformers. A large portion of its electric infrastructure was constructed from the 1950's through the 1980's to serve loads with 12.47 kV, 3-wire overhead service. The infrastructure has since been periodically expanded, updated, and modernized. The most recent modernization program began in 2007 and was completed in 2019, with all substations having received technology and equipment upgrades to improve reliability.

Between 1985 and 2008, commercial developers supported and assisted in funding the expansion of the electric system which more than doubled the 12kV distribution system using underground cabling. Figure 5-7 shows the interface of the 115kV transmission system with the distribution system through 115 kV/12 kV substations.

Figure 5-7: Electric Distribution System

The current transmission and distribution systems consist of the following:

- Service area of approximately 61 square miles
- Approximately 72 miles of 115 kV transmission
- Eleven transmission/distribution substations, one generation step-up substation
- Approximately 740 miles of 12 kV distribution, (OH=300 mi, UG=440 miles)
- Approximately 17,000 poles

Distribution System Adequacy

In 2022, the service availability index achieved an outstanding rating of 99.997 percent, representing an all-time high. This outstanding accomplishment translates to an average customer experiencing only 16.89 minutes without power throughout the entire year (Figure 5-8). The staff's dedication to providing reliable service has resulted in significantly better power availability and minimized disruptions for customers compared to the broader population.

This is a significant improvement from the 2020 average outage time of 52.51 minutes. This impressive performance is notably better than the national average for all Americans where the average power outage duration in 2020 was 116 minutes. The 68 percent improvement in reliability from 2020 can be attributed to the hard work and dedication of staff.

Figure 5-8: Reliability Comparison

For a more localized comparison, in the year 2020, customers of PG&E in the north valley experienced an average of 125 minutes without power while REU customers experienced 52.5 minutes.

The combined strength of its community-owned power plant and diverse grid connections contribute to the continued commitment to high reliability rates. By harnessing these resources and the expertise of dedicated personnel, REU successfully mitigated the impacts of the Carr Fire, a raging wildfire that tore through Shasta County and blazed into Redding's city limits, safeguarding the well-being and comfort of the community during an exceptionally challenging time.

The distribution system conditions are continually evaluated and appropriate adjustments are made as needed to improve and optimize the distribution network. Projects aimed at these improvements are approved and funded through the Electric Distribution Capital Expenditure Plan. Currently, REU is considering the following modifications:

- Replacing aging underground cables in our infrastructure. Our estimates indicate that approximately 790,000 feet (149 miles) of underground cable currently require replacement due to age-related issues, including regular cable failures.
  - Estimated completion by end of 2027
- Upgrading aging circuit breakers and circuit switchers at substations.
  - Estimated completion by end of 2025
- Implementing substation improvements to enhance safety and security. This project will focus on strengthening the physical security of substations throughout our service territory, including upgrades to fences, security cameras, lighting, and other detection methods.
  - Estimated completion by end of 2025
- Conducting line capacity upgrades and Volt-Var Optimization (VVO) for voltage support. These projects involve model validation, analysis, and distribution system improvements through line capacity upgrades and capacitor placement, ensuring sufficient capacity to serve new electric loads with minimal losses.
  - Estimated completion by end of 2027
- Design and construction of a new 115/12kV substation in Stillwater Business Park. This new substation will be in the southeast side of Redding and will increase system capacity and service reliability.
  - Estimated completion date in 2028
- Installing reclosers at Tier 2 or Tier 3 boundaries as part of the fire mitigation plan. This deployment of fast interrupting reclosers at the fire zone boundaries will enhance reliability on circuits outside of Tier 2 and 3 fire zones, eliminating the need to set feeder breaker relays to non-reclosing during periods of increased fire hazard, as required by the state of California.
  - Estimated completion by end of 2027

Furthermore, REU is exploring alternative initiatives aimed at enhancing the communication systems essential for integrating further investments in demand-side energy management. One potential initiative involves the phased installation of optional Outage Management System (OMS) and Distribution Management System (DMS) software. This software would complement the existing system management software, OSI-SCADA, used by Electric Utility Distribution System Operators. By implementing these upgrades, response times are expected to improving, reduced risks of switching errors, and decreased likelihood of unknown equipment overloads.

Phase one of the OMS project has been successfully completed, although additional refinements are still necessary. However, after a comprehensive evaluation and comparison of these projects with the priorities outlined in the 2022 Strategic Plan, it has been decided not to pursue the DMS and network projects during this revision of the IRP.

5.6 Natural Gas Commodity, Transportation and Storage

Natural gas is the primary fuel and the primary variable operating cost of the Plant. The Plant can require delivery of up to 38,000 decatherms (Dth) of natural gas per day, with current average daily requirements of 8,500 Dth per day.

A comprehensive natural gas program has been developed to mitigate the electric retail impacts of gas supply and price volatility. This program includes a gas prepayment arrangement (in which a supply of natural gas can be procured at a discount from the monthly index price), as well as forward purchases of natural gas at fixed prices plus gas storage options.

M-S-R Energy Authority – Gas Prepay

The M-S-R PPA members have formed a JPA known as the M-S-R Energy Authority (M-S-R EA). The M-S-R EA was created for the purpose of entering contracts and issuing bonds to assist M-S-R EA participants in financing the acquisition of supplies of natural gas for use in each participant's electrical generation stations. In 2009, REU participated in the M-S-R EA Gas Prepay Project. The Gas Prepay Project provides, through a Gas Supply Agreement with M-S-R EA (the Gas Supply Agreement), a secure and long-term supply of natural gas of 5,000 Dth daily (or 1,825,000 Dth annually) through September 30, 2039. The Gas Supply Agreement provides this supply at a discounted price below the monthly market index price (the PG&E City Gate index) over the 30-year term. M-S-R EA entered into a prepaid gas purchase agreement with Citigroup Energy, Inc. to provide this gas supply. Under the terms of the Gas Supply Agreement, M-S-R EA bills for actual quantities of natural gas delivered each month on a "take-and-pay" basis. This prepay cannot be used as a financial instrument (i.e. it must be utilized for load only).

Fixed Price Forward Purchases

In addition to natural gas procured through the M-S-R EA Gas Prepay Project, REU also enters fixed price forward gas contracts.

Table 5-6 provides the volume of current fixed price natural gas purchases to which REU has committed.

Table 5-6: Natural Gas Fixed Price Hedges

Year	2023	2024	2025	2026	2027
Decatherm per day (Dth/day)*	9,722	6,538	4,875	2,625	875

**Delivery Point is PG&E City Gate*

Natural Gas Transportation

In order to provide for the transportation and delivery of purchased natural gas, REU entered into an agreement to purchase 7,500 Dth/day of natural gas pipeline capacity in four segments connecting the AECO supply hub and natural gas storage operation located in Alberta, Canada, to California (at the PG&E Citygate) from TransCanada affiliates and PG&E. The contractual obligation for three of the segments expired on October 31, 2015. The remaining contractual obligation for the fourth segment expires on October 31, 2023, but shipping rights for this segment have been assigned to a third party for the remainder of the contract period. In 2022, REU permanently signed over all shipping rights to a third party. When the current contract expires in October 2023, REU will no longer hold any firm gas shipping rights.

Natural Gas Storage

To further manage seasonal, weather, and price volatility, a contract has been executed for natural gas storage within northern California since 2004. In 2010, under a 28-year term contract, REU commenced utilizing storage rights at Gill Ranch Storage—a gas storage facility located in central California. Under the agreement, cushion gas has been leased and Gill Ranch Storage provides approximately 600,000 Dth of natural gas storage. At the end of the contract term in 2038, the cushion gas will be returned.

5.7 Wholesale Energy Trading

REU undertakes extensive planning to select its future conventional and renewable power supplies. Once these resources are available, operation and management of its power supply and transmission resources will be done using an "economic dispatch" model that is designed to produce and deliver energy at the lowest cost that reliably serves consumers.

Like any utility, generation and transmission resource additions may not perfectly align with yearly load projections. To manage this discrepancy, in addition to strategic market purchases when cost-effective, REU leverages its excess capacity and energy by engaging in wholesale energy market trading. This approach aims to maximize the value of its generation assets while minimizing the expenses associated with purchased power.

Furthermore, REU coordinates its gas purchases and sales within the year, taking into account wholesale energy costs. In terms of financial forecasting and planning, only revenues from wholesale trading activities under contract at the time of the forecast are considered. REU remains committed to optimizing its generation and transmission assets within the wholesale market, ultimately benefiting its retail customers. It is anticipated that wholesale sales will continue to play a role in power operations in the future.

5.8 Western Energy Imbalance Market (EIM)

The CAISO Western Energy Imbalance Market (WEIM) is a 5-minute, real-time, bulk power trading market administered by the CAISO. The market utilizes a sophisticated energy model that optimizes the lowest-cost energy to serve real-time customer demand across a wide geographical area.

REU embarked on a trading modernization project to meet the challenges of changing markets and officially joined the WEIM through BANC on April 1, 2021. All future generators installed in the BANC footprint must be bid in the WEIM. The Redding Power Plant is currently bid into the WEIM and responds to signals from CAISO in order to best-utilize the resource.

5.9 Extended Day-Ahead Market (EDAM)

In October 2019, the CAISO initiated the development of a new approach aimed at integrating the CAISO day-ahead market with entities in the WEIM. The WEIM enabled entities to participate in the CAISO day-ahead market without necessitating full integration into the CAISO itself. This approach, known as the Extended Day-Ahead Market (EDAM), represents a significant step forward in regional energy market collaboration and efficiency.

BANC is closely monitoring the ongoing development of the EDAM. They are actively engaged with members to evaluate the feasibility and benefits of potentially becoming part of the integration. This strategic involvement demonstrates BANC's commitment to exploring new opportunities for enhancing energy market operations and achieving more efficient resource planning.

REU anticipates participating in the Extended Day-Ahead Market (EDAM). By doing so, the new market approach can be leveraged to enhance resource planning, optimize energy operations, and ultimately deliver more reliable and cost-effective power to customers.

6. Energy Forecast and System Impacts

A fundamental element of the IRP analysis involves the careful development of long-term projections, spanning the horizon from 2023 to 2045, for both system peak demand and energy consumption. These forecasts serve as the foundation upon which the Utility's strategic planning is constructed. They summarize a comprehensive projection of the capacity and energy needs that the Utility must be prepared to address, either through the development of self-owned generation assets or via strategic power purchase arrangements with external suppliers and joint powers agencies.

These projections are not simply deterministic exercises; rather, they are dynamic statistical representations of the future energy landscape, accounting for a variety of factors, including anticipated population growth, commercial expansion, technological advancements, clean energy mandates and climate initiatives, and evolving energy efficiency and electrification measures. These forecasts evolve in parallel with the ever-changing economic, social, and technological trends, forming a critical component in the REU's ability to proactively and effectively navigate the complex terrain of the energy sector to ensure both reliability and sustainability for the Redding community.

6.1 Historical Energy Use and Peak Demand

Electricity demand exhibits strong seasonal trends, with peak energy requirements driven by air-conditioning use in the summer months and minimum energy use normally occurring during the spring and fall seasons. Demand levels during the summer also tend to exhibit a greater daily variation in load. The seasonal variability is demonstrated in Figure 6-1, which displays the monthly average energy sales for the period of 2018 through 2022. Additionally, Figure 6-2 shows the daily variation in load by month. The summer peak load is roughly three times the magnitude of the base load.

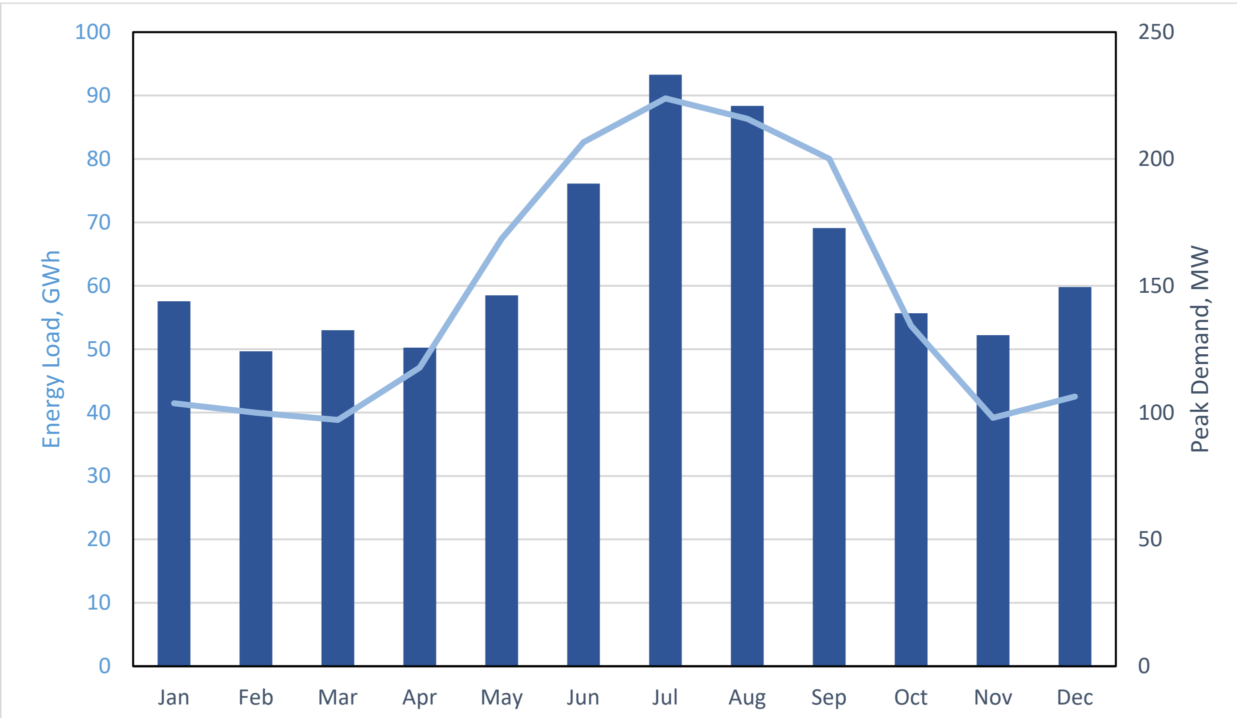


Figure 6-1: 5-Year Average Monthly Energy Sales and Peak Demand (2018-2022)

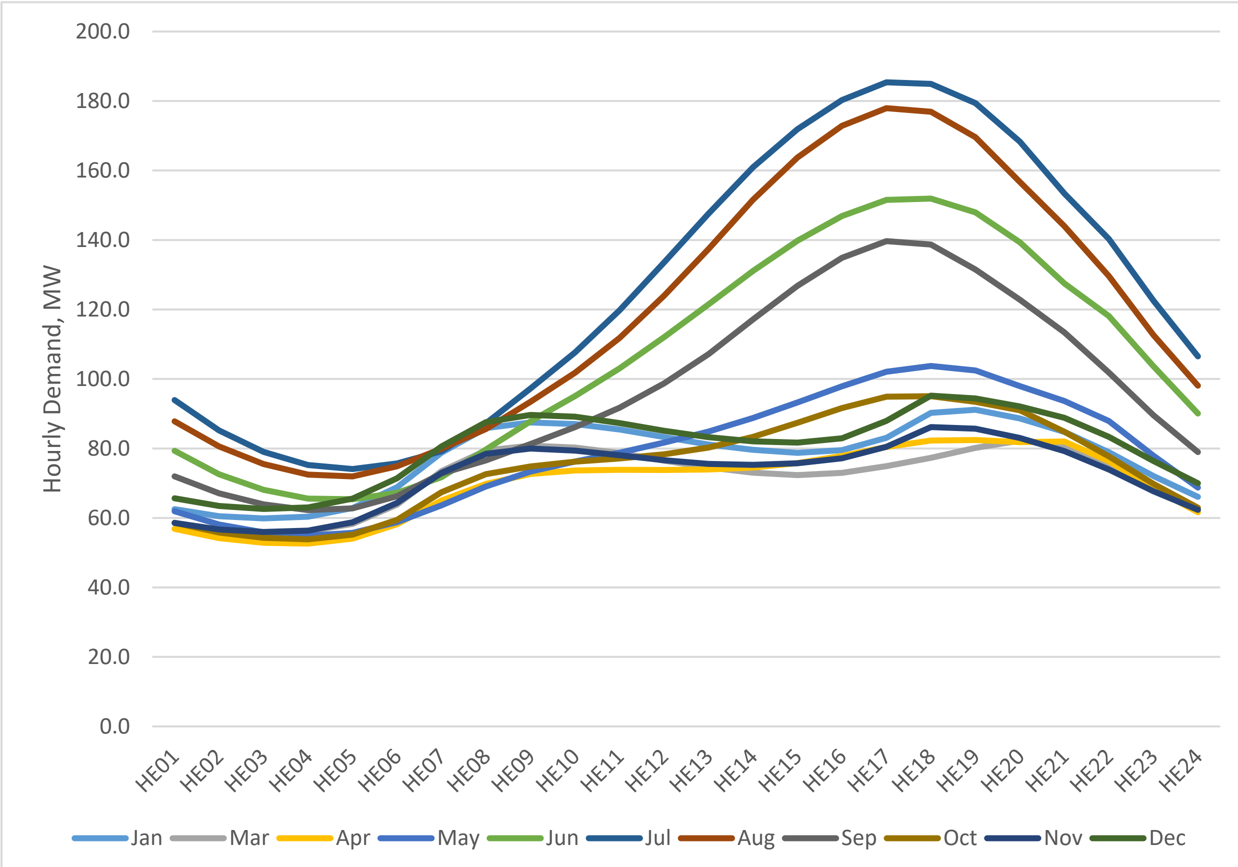


Figure 6-2: Average Daily Load Profile by Month (2018-2022)

Table 6-1 provides a comprehensive overview of historical data spanning the last five Fiscal Years. The data reveals that the combined peak customer demand observed from 2018 to 2022 reached its highest point at 241 MW in 2018, in contrast to 234 MW in 2022. It is important to note that this peak demand is significantly lower than the historical distribution system peak demand of 253 MW, which was recorded on July 24, 2006.

While it is typical for peak demand to occur only once annually, it is crucial to emphasize that resources must be continuously maintained at levels capable of meeting this peak demand throughout the entire year. This ensures the reliability and resilience of the system, even during periods of maximum stress on the infrastructure.

Energy sales exhibited a declining trend from 2018 to 2020. However, there was a significant and notable upturn in energy sales for the years 2021 and 2022. This shift in sales patterns suggests dynamic changes in energy consumption and demand during this period. The sales reduction was expected and aligned with forecast trends. Analysis suggests the sudden increase in energy sales were driven by work-from-home measures implemented during the COVID outbreak. Overall, 2022 sales are 99 percent of 2018 sales.

However, 2020 sales dipped down to only 95 percent of 2018 sales. At the same time, the number of customers has increased by 1.5 percent over the period and reached 44,981 customers in 2022.

Table 6-1: Historic Customer, Sales, and Demand Data

Year	2018	2019	2020	2021	2022
Number of Customers					
Residential	38,088	38,058	38,320	38,587	38,572
Commercial	4,955	4,942	4,972	4,975	5,088
Industrial	326	334	338	353	351
Other	935	930	936	966	970
Total Customers	**44,304**	**44,264**	**44,566**	**44,881**	**44,981**
Megawatt-Hour Sales					
Residential	368,829	356,741	358,510	393,404	375,818
Commercial	323,799	312,484	298,242	302,067	300,597
Industrial	12,626	12,372	12,349	11,552	12,155
Other	41,471	39,765	41,640	50,105	49,924
Total MWh	**746,725**	**721,363**	**710,740**	**757,129**	**738,494**
Peak Demand (MW)	241	228	224	225	234

1. Data is provided for Fiscal Years ending June 30.

2. The values for Number of Customers include every point at which electricity is delivered for end use as of the last month of the Fiscal Year; data does not include sales to COSL.

6.2 Forecast Methodology and Assumptions

The load forecast for the IRP planning period was developed by Itron, Inc. an energy forecasting consultant. Future projections of energy sales and peak demand are developed based on the historical relationship with various socioeconomic factors and temperature data as described further below.

The 2023 load forecast of energy sales and peak demand levels was done by end user class and involved the following customer classes:

- Residential
- Large Commercial Users
- Small Commercial Users
- Fixed Use

The load forecast was developed based on Itron's Statistically Adjusted End Use (SAE) modeling framework, which incorporates models customized for the residential and non-residential sectors. One of the traditional approaches to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, the strength of econometric models is that they are well suited to identify historical trends and to project these trends into the future.

In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the SAE modeling framework captures the strengths of both approaches. For instance, by explicitly introducing trends in equipment saturation and equipment efficiency levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time, and identify end use factors driving those changes.

SAE models leverage the U.S. Energy Information Administration's (EIA) Sector-level End Use Saturation and Efficiency Forecast for the Pacific Region as well as information specific to the COR. The result is a long-term forecasting framework that captures long-term structural changes, short-term driving factors of usage levels such as economic activity, electricity price, and weather, and their appropriate interactions. Furthermore, the framework facilitates the disaggregation of the sector-level sales forecasts into end use-level forecasts in support of further evaluation.

Key considerations and assumptions utilized in preparation of the load forecast are shown in Table 6-2. For the variables listed, those of special importance include assumptions about the future growth of EVs, solar installations, energy efficiency, as well as population growth and the consideration of temperature data.

Table 6-2: Load Forecast Assumptions and Input Considerations

Category	Description
Weather	• Normal Weather for Energy and Peak: (Calculation Range 2013 – 2022)
Economics	• Net Migration Forecast obtained from Woods & Poole Economics, Inc. • High and Low Cases +/- 10% of forecast provided by Woods & Poole Economics, Inc. • Employment Forecast obtained from Woods & Poole Economics, Inc.
End Use Equipment Saturation & Efficiency/ New Technology	• SAE Inputs – Pacific Region Efficiencies from the EIA's 2022 Annual Energy Outlook Forecast • Solar Adoption Forecast • EV Adoption Forecast • Energy Efficiency and Demand Response Forecast
Street Lighting Program	• Extended Street Lighting LED Program Savings through the end of the Forecast Horizon

Weather Normalization

Because energy consumption is heavily affected by weather conditions from year to year, actual energy sales and peak demand data were normalized by Itron as a means of adjusting values to reflect long-term average weather conditions.

Itron developed the peak demand forecast by comparing historical peak demand levels from 1980 through 2022 with the temperature at which annual peak demand conditions occurred, and determining a statistical correlation for that year (for example, the 50^{th} percentile temperature in the 1980-2022 period formed the basis for the "1-in-2 year" case, and the 90^{th} percentile temperature occurring during this period formed the basis for the "1-in-10" year case). The forecast of future peak demand utilized in the IRP base case is the 1-in-2 year forecast, which corresponds to an expected maximum temperature of 111 degrees Fahrenheit.

Service Area Population

An Average Annual Growth Rate (AAGR) for population of less than one percent (0.37 percent) is projected by Woods & Poole Economics, Inc. (the vendor used for the economic driver forecasts) for the forecast period compared to an AAGR of 1.13 percent experienced between 1990 and 2017.

Rooftop solar installations

Recent updates to the Title 24 building code require solar installations on all new residential and commercial buildings that generate 100 percent of the dwelling's annual consumption. This is likely to cause an increase in behind-the-meter solar generation. Concurrently, REU implemented a net-metering rate (commonly referred to as NEM 2.0) for customers with solar. Under this rate, excess generation is credited at the electric utility's avoided cost instead of the retail rate. The new rate is projected to reduce natural adoption of solar resulting from economical choice. As a result, the rooftop solar forecast is largely driven by the expected number of new homes and commercial buildings each year. Due to the rate grandfathering provisions approved by Council, REU received numerous applications before the net metering rate was implemented. a percentage of these are included in the anticipated installations for 2023. As of calendar year 2022, there is 18,076 kW of behind-the-meter solar on REU's system Figure 6-3).

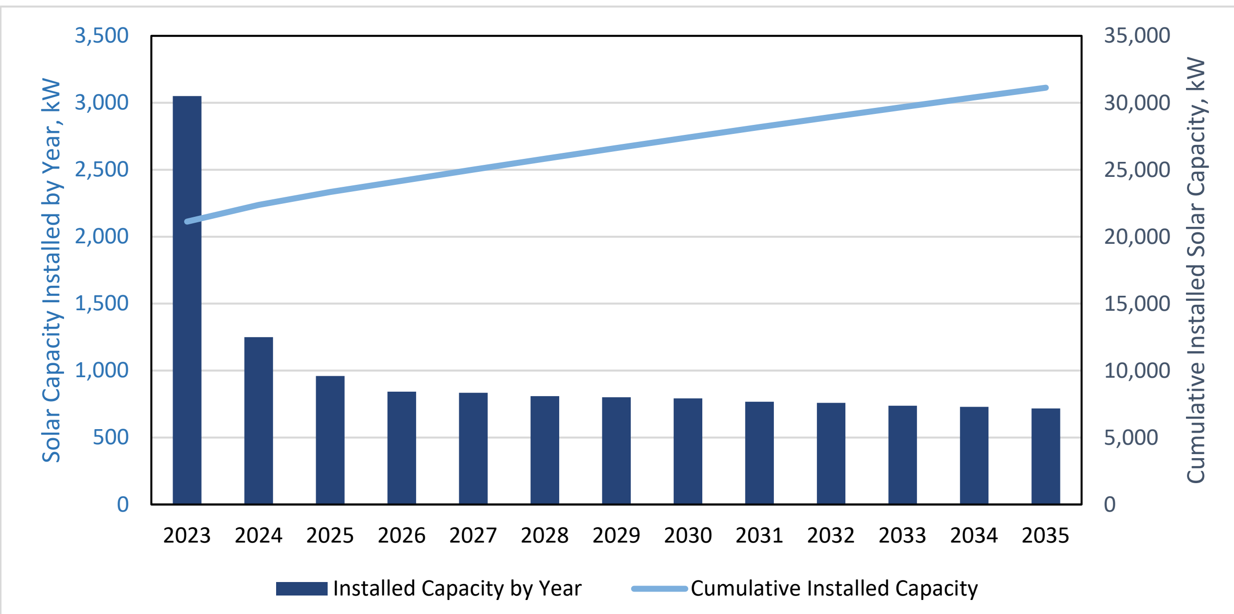


Figure 6-3: Projected Solar Installations

Transportation and Building Electrification Forecast

In preparation for the 2024 IRP update, the Resources Team proactively engaged the expertise of Dunsky. Recognizing the importance of capturing impacts of electrification in forecasting customer demand, Dunsky was contracted to carry out a comprehensive and detailed forecast specifically focusing on building and transportation electrification. This strategic collaboration allowed the Resources Team to gather valuable insights and projections about the future trajectory of electrification in these two critical sectors. By leveraging Dunsky's specialized knowledge and extensive experience, a deeper understanding of the potential impact of electrification on the overall energy landscape was gained.

Dunsky's comprehensive analysis involved assessing various factors such as technological advancements, regulatory frameworks, market trends, and consumer behavior. Through this evaluation, a holistic picture was provided showing potential outcomes and implications of building and transportation electrification.

The findings of this forecast provided the Resources Team with vital information to inform their decision-making process and align their strategies with the emerging electrification trends. With a clearer understanding of the opportunities and challenges associated with building and transportation electrification, staff was better equipped to develop an effective and sustainable roadmap for the 2024 IRP update.

The research objectives for the electrification forecast were to:

1. Forecast service territory-wide adoption of electrified technologies to support REU's long-term planning efforts
2. Consider service territory-wide load impacts of Electric Vehicle (EV) adoption, including annual energy and demand and hourly impacts for a select number of peak and off-peak days
3. Provide results that will integrate with other REU forecasts for the purpose of resource and distribution planning

Based on findings from the electrification forecast, by 2045, up to 24,700 additional units of space heating heat pumps, 11,400 additional units of electrified water heating equipment, and 37,000 additional units of electrified cooking equipment could be seen in Redding. Although variations in near-term market conditions and incentive programs will impact uptake to some degree, regulations will have the greatest influence over adoption levels. Should they be enacted, all-electric new construction codes have the ability to electrify new building stocks while gas appliance bans have the ability to electrify all building types – new and existing.

By 2045, up to 61,000 additional electrified light-duty vehicles and up to 6,400 additional electrified medium-duty vehicles (MDV), heavy-duty vehicles (HDV), and buses may be adopted. As with the building sector, uptake of EVs will be most influenced by regulation. California's light-duty ZEV sales target will require 100% of light-duty vehicles sold in the state to be zero-emission vehicles from 2035 onwards, while other regulations will require zero-emission vehicle adoption by public MDV and HDV fleets and transit buses. By 2045, EV charging could consume up to 490 additional GWh annually and increase demand at the time of current peaks by up to 87 MW.

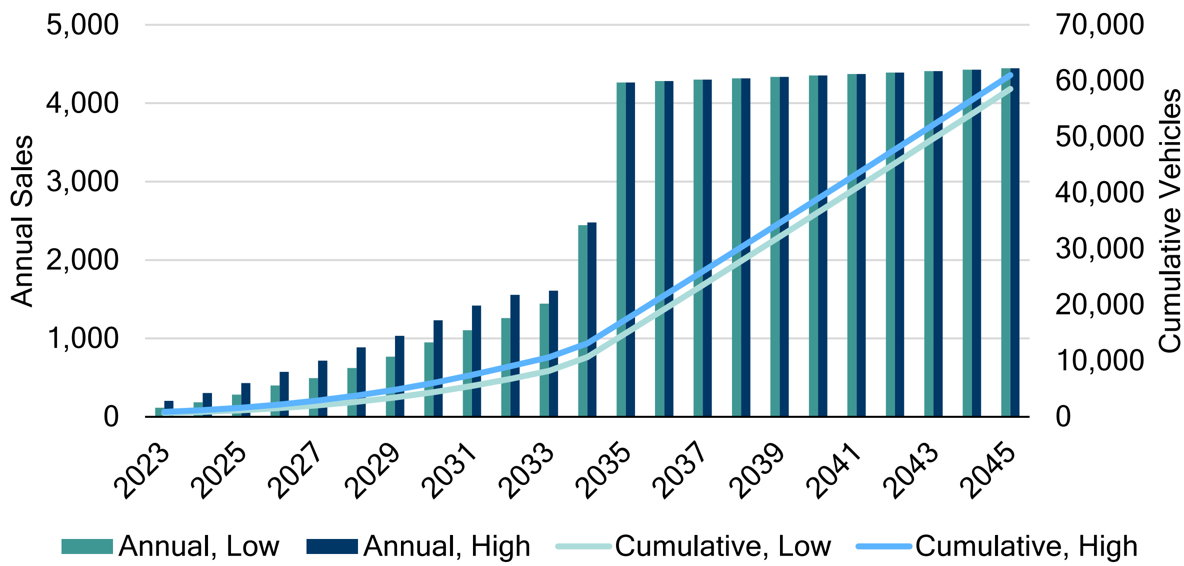


Figure 6-4: Projected Light-Duty Electric Vehicles – REU Service Territory

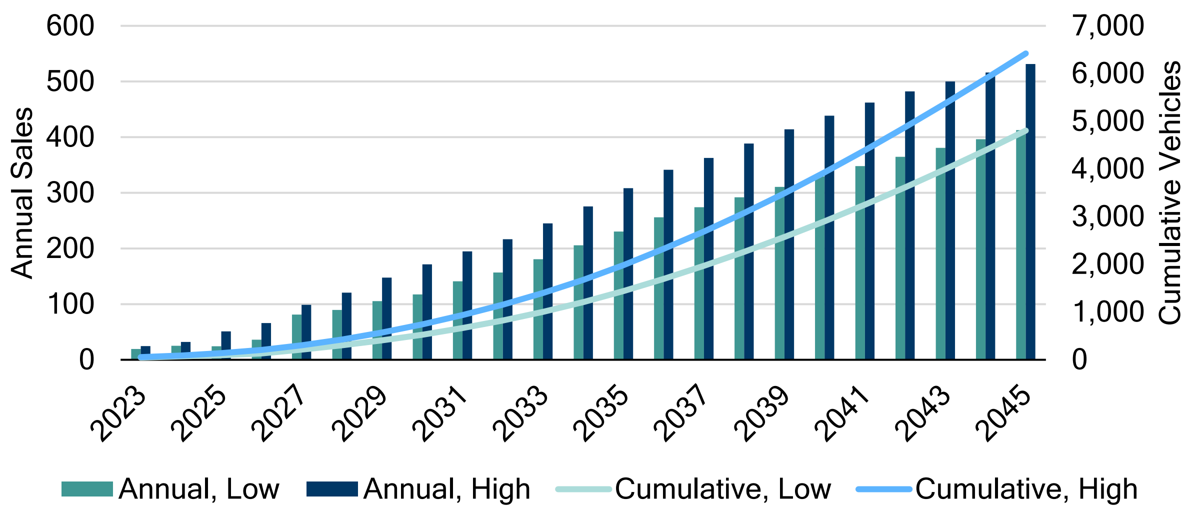


Figure 6-5: Projected Medium Duty Electric Vehicles –REU Service Territory

Energy Efficiency and Demand Response

Previously, Itron's load forecast considered past and current efforts to reduce energy consumption through energy efficiency and GHG-reducing programs. However, with a continued focus on electrification, Itron must now account for increased energy consumption from programs. Itron does not currently disaggregate energy efficiency and building electrification load impacts in the load forecast. Transportation electrification results from the Dunsky forecast study were directly incorporated into the Itron load forecast. The energy requirements and peak demand projections reflect the impact of efforts to reduce energy consumption, system peak, and GHG emissions through the multiple programs described in this section. The load forecast considered a number of energy efficiency and demand reduction measures. These are further described in Section 4.

6.3 Forecast Results

The peak and energy forecast results are presented in this section. The capacity and energy requirement forecasts are also carried forward to the required CEC tables in Exhibit 1.1.

Peak and Energy Forecast

Table 6-3 illustrates the energy and peak demand forecast. In previous studies, the forecast showed a modest decrease in both energy and peak over time due to energy efficiency and conservation efforts. However, with the inclusion of the electrification forecast, which includes both building and transportation electrification, the forecast now shows a steady and significant increase though 2045.

During the forecast period (2023 through 2045), energy requirements for all customer classes are projected to increase from 730,857 MWh in 2023 to 1,101,932 MWh in 2045. For the system, the increase equates to an overall growth of approximately 50.8 percent over the planning horizon and an AAGR of 1.63 percent.

During the forecast period, peak demand is projected to increase, from a value of 224.3 MW in 2023 to 261.4 MW in 2045, equating to an AAGR of 0.75 percent.

System Load Factor

A load factor is a fundamental metric used to assess the variability of utility load patterns over a specific period of time. It provides insights into the overall energy utilization efficiency of a utility system. Specifically, the load factor quantifies the total energy consumed by a utility system relative to the maximum potential energy requirements that would occur if the energy demand at the peak period persisted throughout the entire year.

By expressing the energy requirements as a percentage of the theoretical maximum, the load factor offers a valuable indicator of how consistently and effectively a utility system is utilized. A higher load factor signifies a more balanced energy usage pattern, where the system operates closer to its maximum capacity for longer durations, indicating a higher level of efficiency. Conversely, a lower load factor suggests greater variability in energy demand, with periods of lower consumption relative to peak demand.

Understanding the load factor helps determine the appropriate sizing and capacity requirements for generation, transmission, and distribution infrastructure, ensuring a reliable and cost-effective supply of electricity to customers. Due to the increased electrification in the forecast, the load factor increases from 37.2% in 2023 to 48.1% in 2045. The increase is related to increased winter month usage and off-peak electric vehicle charging. Increased demand from EV charging and building electrification measures results in higher energy consumption and more effective utilization of the grid's capacity. While the increased load factor does mean the electric system will be used more efficiently, it also means that more energy will need to be delivered.

Table 6-3: Projected Net Energy Requirements, Peak Demand Forecast, and Load Factor

	Net Energy Requirements		Peak Demand		
Year	MWh	Percent Change	MW	Percent Change	Load Factor
2022 (Actual)	763,376	-	239.1	-	36.45%
2023	730,857	-4.26%	224.3	-6.19%	37.19%
2024	730,911	0.01%	223.9	-0.17%	37.16%
2025	728,713	-0.30%	223.7	-0.10%	37.18%
2026	729,990	0.18%	223.8	0.03%	37.24%
2027	733,590	0.49%	224.2	0.18%	37.36%
2028	740,293	0.91%	224.8	0.27%	37.49%
2029	744,785	0.61%	225.6	0.34%	37.69%
2030	752,641	1.05%	226.6	0.48%	37.91%
2031	761,774	1.21%	227.9	0.55%	38.16%
2032	772,635	1.43%	229.0	0.49%	38.41%
2033	782,305	1.25%	230.4	0.59%	38.77%
2034	799,534	2.20%	232.3	0.83%	39.29%
2035	825,847	3.29%	235.0	1.19%	40.11%
2036	857,983	3.89%	238.0	1.26%	41.04%
2037	887,123	3.40%	241.1	1.29%	42.01%
2038	921,442	3.87%	244.2	1.31%	43.07%
2039	971,617	5.45%	247.5	1.33%	44.82%
2040	1,007,767	3.72%	250.5	1.22%	45.80%
2041	1,053,926	4.58%	254.1	1.43%	47.35%
2042	1,087,307	3.17%	257.5	1.36%	48.20%
2043	1,090,995	0.34%	258.8	0.50%	48.12%
2044	1,096,450	0.50%	260.1	0.50%	47.99%
2045	1,101,932	0.50%	261.4	0.50%	48.12%
AAGR 2023-2045		**1.63%**		**0.40%**	

Changes to Load Forecast

Figure 6-6 illustrates the forecast trends since 2019, with actual load data through from 2015 through 2022. Compared to the 2018 forecast used for the 2019 IRP, the current 2023 load forecast is four percent lower though 2030; however, it starts dramatically increasing to 11 percent higher by 2038. The current forecast also shows continual growth through 2045. Three prominent drivers are leading to the reduction in the forecast though 2030:

1. Increased behind-the-meter solar adoption
2. Lower overall net migration and economic outlook
3. Assumed efficiency gains of typical household appliances

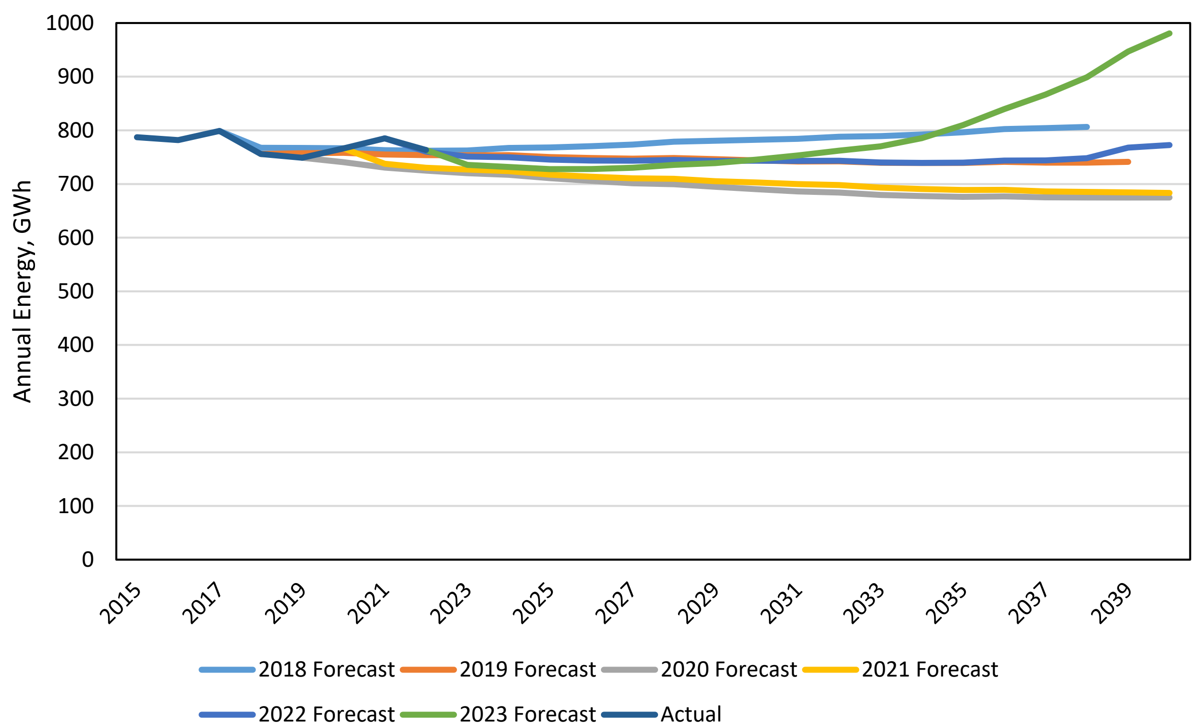


Figure 6-6: Load Forecast Comparison

The historical data shows a consistent year-over-year decrease in actual load, which aligns with the initial forecast. However, a pivotal shift occurs post-2030, driven by the widespread adoption of electric building and transportation technologies. This adoption surpasses any previous efficiency gains or reductions, leading to an unprecedented surge in load. The peak load forecast mirrors this same trajectory as the annual energy consumption pattern (Figure 6-7).

The actual load saw a sharp increase in 2020 partly due to above-average temperatures, coupled with the stay-at-home orders due to COVID-19. It is not conclusive that this is the start of an increasing load trend; however, REU staff continue to evaluate energy trends and future forecasts.

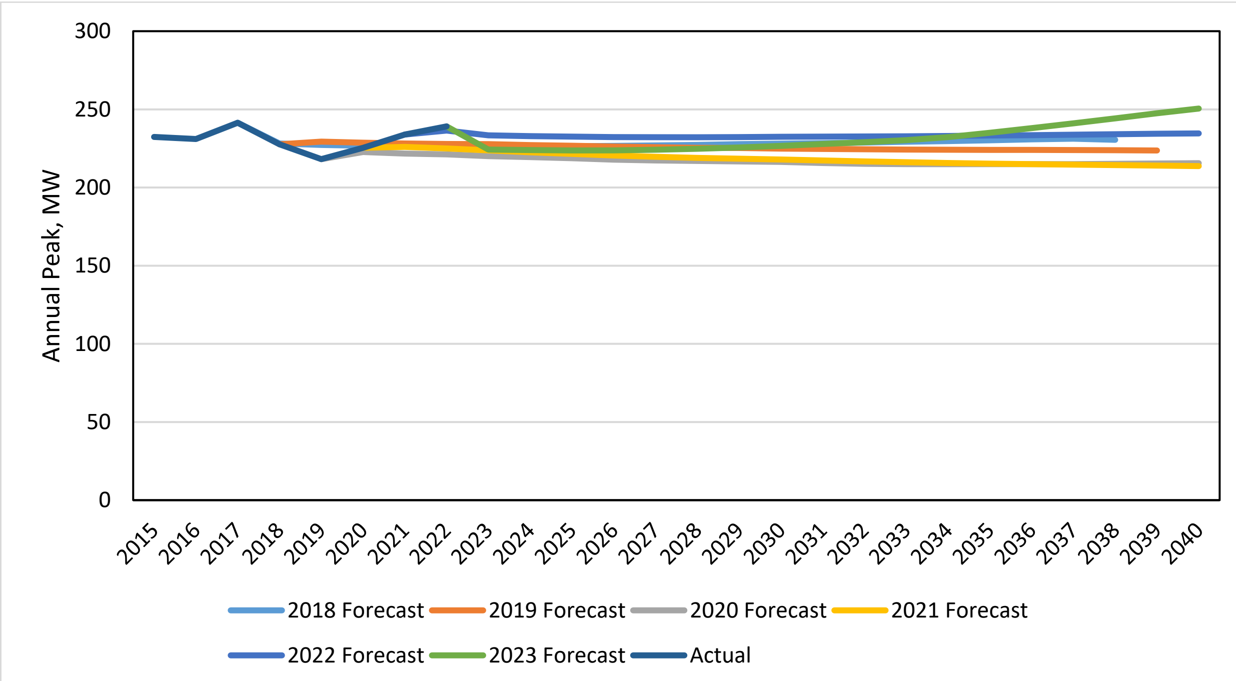


Figure 6-7: Peak Load Forecast Comparison

6.4 Transmission System Assessment

Overview

To accurately capture a zero-carbon scenario within the IRP, the decommissioning of the Plant had to be considered in the portfolio models. This decision prompted REU to carefully assess the resilience and capabilities of its transmission and distribution system to solely rely on imported energy for meeting its load requirements. Additionally, REU needed to evaluate whether the distribution system could effectively operate without on-system generation support to maintain optimal voltage levels.

To address these critical considerations, REU engaged in consultation with the Sacramento Municipal Utility District (SMUD). SMUD embarked on modeling two distinct scenarios to thoroughly assess the potential impacts on REU's transmission and distribution system. These scenarios aimed to uncover potential contingencies, identify necessary mitigations to maintain reliability, and estimate the associated costs required to operate REU's system in the absence of the Plant.

By collaborating with SMUD, REU gained valuable insights into the resilience and reliability of its system under the proposed zero-carbon scenario. The modeling exercises enabled a comprehensive evaluation of various factors, including system stability, load balancing, voltage management, and overall operational feasibility without on-system generation.

Furthermore, the estimated cost of operating without the Plant was also a crucial aspect analyzed in these scenarios. This evaluation allowed REU to gain a comprehensive understanding of the financial implications associated with transitioning to a zero-carbon future and to make informed decisions regarding future investments and resource allocation.

System Study results

Study 1

The initial transmission system study aimed to determine whether REU could meet its projected peak demand without relying on generation from the Plant. REU has a Long-term Parts (LTP) maintenance contract with minimum run-hour constraints. The current LTP agreement is set to expire in 2032, after which there will be no obligation for the Plant to continue operating. Therefore, for SMUD's study, they assumed that the Plant would be taken out of service starting in 2032, and all demand would be met with imported energy. They utilized the 1-in-10-year load forecast from that year to conduct their assessment, with the task of identifying and evaluating any resulting system limitations.

In summary, to serve REU's 2032 forecasted load of 253.73 MW with the Plant out of service, study results concluded REU's transmission system experienced low voltage contingencies at multiple substations. The low voltages fell below current emergency low voltage limits; therefore, REU is not able to serve its year 2032 forecast load reliably and stay above REU's current emergency low voltage limit.

Study 2

The purpose of this study is to ensure REU would be able to serve its load without on-system generation in the event the demand exceeds the forecasted future demand. The second transmission system assessment identified REU transmission system limitations when serving the Utility's load at the maximum reported import level of 350 MVA without the Plant. REU relied on imports to meet its maximum reported import capability without any on-system generation.

In summary, to serve load at REU's maximum import capability, the following system reinforcements must be implemented:

- Convert the Redding Power Plant generator into synchronous condenser for voltage support.
- Loop-in the WAPA's Keswick-Olinda 230 kV Line into the Redding Power Plant (Redding Substation) 115 kV substation as new tie lines for voltage support and eliminating identified thermal overloads.
- Re-rate or replace the Airport 230/115 kV Banks with 140 MVA rating or higher to mitigate identified thermal overloads.
- Re-rate or replace the Keswick 230/115 kV Bank #1 with 110 MVA rating or higher to mitigate identified thermal overload.
- Add a 2nd Moore-Redding 115 kV Line for voltage support.
- Add a 2nd Texas Spring-Redding 115 kV Line for voltage support.
- Loop-in the East Reading-Airport 115 kV Line #1 into the Future South Business Park substation for voltage support.
- Add 35 MVAr of shunt capacitors at Canby 115 kV substation for voltage support.

The facilities with highest thermal violations are for various P6 contingencies are:

- Oregon-Waldon 115 kV Line at 101.8%
- Airport 230/115 kV Bank #1 at 108.46%
- Airport 230/115 kV Bank #2 at 108.46%

REU was able to use the results from the studies to obtain high-level cost estimates of approximately $46 million for the mitigations listed in study one, and input those into the forecast models for the 2045 zero-carbon scenario to capture the capital improvement costs that would be associated with that analysis.

6.5 Comparison to CEC Forecast

As part of the IRP analysis, the energy and peak demand forecasts used in this IRP and prepared by Itron and are compared to the forecasts published by the CEC in its 2022 IEPR Update. While the energy requirements differ between the two forecasts, they are relatively similar in that growth is relatively flat through 2035. Furthermore, the CEC and Itron peak demand forecasts are substantially similar, steadily increasing through 2035. Overall, the forecasts are comparable when looking at the growth rate for energy demand and peak requirements.

Comparing the CEC's forecast of energy requirements to the forecast developed by Itron for the IRP through 2035, the CEC forecast ending (900 GWh) is approximately 9 percent higher than the Itron forecast in 2035 (825 GWh), as seen in Figure 6-8. On average, the CEC forecast of energy requirements is about 15 percent higher throughout the forecast period, while the IRP forecast developed with Itron increases slightly through 2030. However, the average growth rates are virtually the same between the CEC (0.6 percent) and Itron (0.9 percent) forecasts.

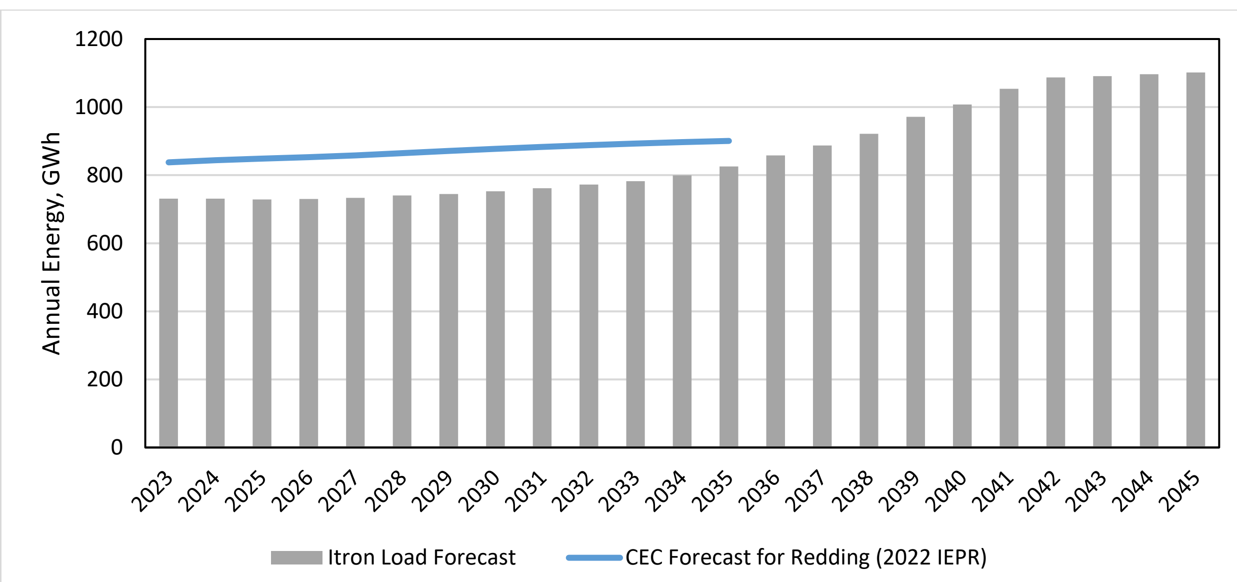


Figure 6-8: Energy Requirements Comparison: REU Forecast vs. CEC Forecast for REU

As seen in Figure 6-9, the anticipated peak demand is comparable between the two forecasts. The CEC reports a higher peak demand for REU, relative to the Itron forecast. In 2035, CEC's peak demand forecast for REU is 239.1 MW, while the corresponding figure in Itron's forecast is 235.0 MW. Similar to the energy demand, the growth rates are also virtually same between the CEC (0.7 percent) and the Itron (0.4 percent) forecasts.

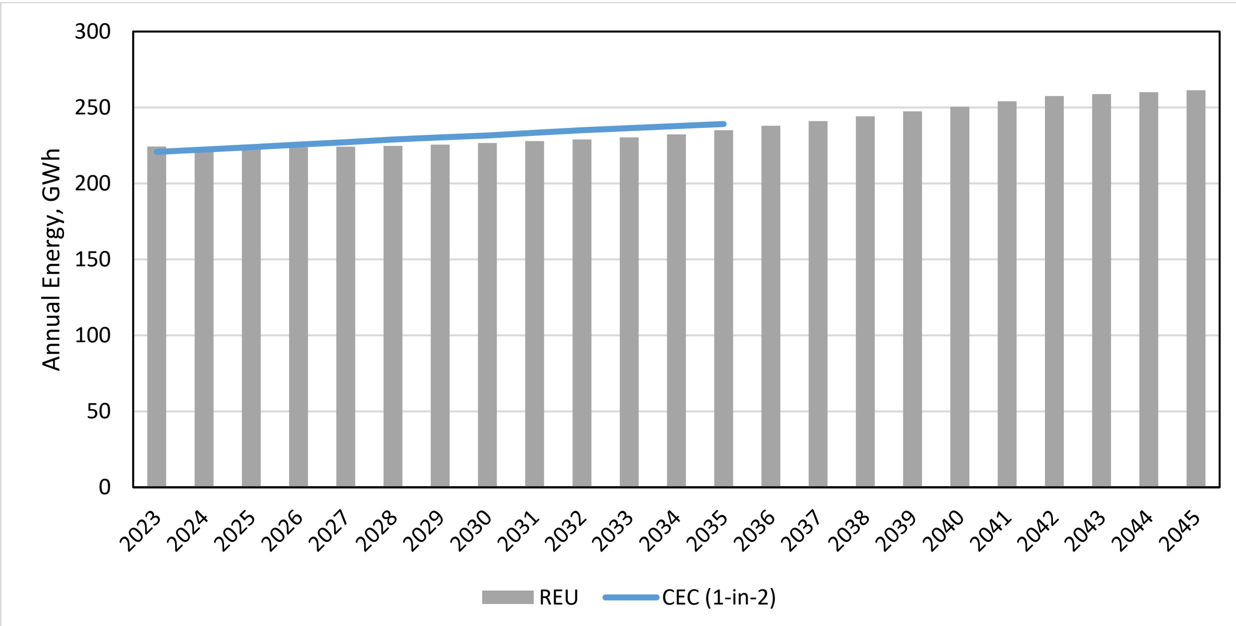


Figure 6-9: Peak Demand Comparison: REU Forecast vs. CEC Forecast for REU

7. Modeling Assumptions, Tools, Methodology

REU engages in a partnership with Ascend Analytics, a provider of resource portfolio modeling services. This collaboration allows REU to make well-informed and strategic decisions regarding the resources necessary to meet future customer demands effectively.

Various modeling tools, including load forecasting models, stochastic simulation models, reliability models, and economic dispatch models were employed to analyze and project energy-related data. Ascend integrates data inputs provided and leverages them with nuanced assumptions concerning future energy markets, constructing a sophisticated, long-term stochastic modeling framework. This model serves as a valuable tool enabling the Resource Team to navigate the intricate landscape of regulatory compliance seamlessly.

Assumptions played a pivotal role, encompassing factors such as energy demand growth rates, natural gas prices, energy policy changes, technological advancements, and clean energy mandates, all of which are described in greater detail below.

This holistic approach ensured that the IRP was well-informed, enabling the Resources Team to make informed and forward-looking decisions regarding its energy portfolio while delivering reliable, cost-effective, and sustainable energy to its customers in the future.

7.1 Modeling Tools

Ascend Analytics' PowerSIMM software was used exclusively for all scenario resource modeling and evaluation.

PowerSIMM Overview

PowerSIMM is a software program used for simulating the performance of an electric power system with high spatial and temporal granularity. This section provides an overview of the key features and capabilities of this simulation software. In the IRP analysis, PowerSIMM was used for the following applications:

1. Production cost modeling – simulates power system operations, inclusive of transmission constraints, on an hourly or sub-hourly timestep for use in decision making for portfolio management or resource planning
2. Capacity expansion optimization – provides a roadmap of future resource procurements to meet policy or reliability needs at the lowest cost
3. Resource adequacy analysis – determines how well a portfolio of resources can serve customer load over a defined period of time on an hourly basis

All applications listed above start with simulations of weather, load, renewables, forced outages, and market prices. The only exception is in resource adequacy models where prices are not used.

Simulations in PowerSIMM

PowerSIMM simulations start with weather as the fundamental driver of load, renewable generation, and market prices. Weather simulations consist of daily maximum and minimum temperatures. PowerSIMM uses historical temperatures to construct future simulations of weather with a time-series model that includes seasonal inputs.

Renewable items require hourly historical generation data coupled with weather data from a nearby station to determine the structural relationship between daily min and max temperatures and renewable generation. PowerSIMM constructs a model for each renewable item using inputs that include daily min and max temperatures, month, and hour. Future simulations are generated with the model using weather simulations as an input. Generation output is scaled to meet future expectations for monthly energy generation and capacity limits.

For load, PowerSIMM creates a structural model using hourly load data, daily min and max temperatures, hour, day of the week, and month. Load simulations are based on weather simulations and scaled to match load forecasts for monthly energy and peak demand.

The simulation of market prices follows a similar construct; however, there are more structural variables observed in both historic and forecast values. There are also more parameters used as inputs. For market price simulations, PowerSIMM adheres to market expectations (i.e. forward prices and option quotes for volatility in prices) by scaling simulations such that the average price exactly meets the forward curves for monthly average prices for natural gas, on peak power, off peak power and carbon. The stochastic price ranges hold to future expectations of price volatility, correlations across time and commodities, and daily price shapes.

Additional details on the model simulations can be found in Exhibit 9.1.

Dispatch in PowerSIMM

Simulations of weather, load, renewables, and spot prices roll into the dispatch module. PowerSIMM models dispatch by optimizing supply resource options in a "dispatch to load" or "dispatch to price" model. In a dispatch to load model, PowerSIMM calculates dispatch decisions to serve load at the least cost, while accounting for transmission system congestion. Market purchases are generally, but not always, included as an option for serving load. The dispatch to price model calculates dispatch decisions to maximize market revenue from generation.

Dispatch calculations rely on inputs to define the physical and economic characteristics of supply resources, including thermal resources, energy storage, hydro resources, or demand-side options. Users can also define transmission lines to represent constraints, such as import or export limits, or line losses. Ancillary services can be included in dispatch models where PowerSIMM will co-optimize supply resources to serve load and fulfill ancillary requirements. PowerSIMM ancillary product dispatch can include regulation up, regulation down, spinning reserves, and non-spinning reserves. PowerSIMM can also perform multiphase dispatch.

PowerSIMM uses a mix-integer linear programming algorithm in the dispatch calculations. The objective function in the algorithm is the minimization of cost to supply energy and ancillary requirements. Included in the total cost are startup costs, variable operations and maintenance (O&M) costs, fixed O&M costs, fuel costs and fuel delivery costs, electric power purchases and power sales. Power sales are treated as negative costs.

The decision variables for the dispatch algorithm include the online state of dispatchable generators, the generation setting for all dispatchable generators, the assignment of ancillary services for units capable of providing ancillary services, the charge or discharge state of energy storage resources, and the amount of market purchases. PowerSIMM iterates over a range of possible values to settle on the decision variables that provide the lowest possible cost within the model constraints.

Dispatch constraints are set for all units in the model such as economic max generation, economic min generation, ramp rates, must run requirements, minimum generation, etc. There are also constraints attributable to transmission limits and the requirement to meet load.

Variable generation from wind, solar and geothermal items are not considered dispatchable, but PowerSIMM may elect to curtail variable resources if system conditions require it. For example, wind generation may be curtailed due to transmission limits.

7.2 Modeling Assumptions

Load Forecast

The load forecast used in the model is described in Section 6.3. A comprehensive description of the technical aspects and implementation of the load forecast in the model is described in Exhibit 9.1.

Forward Curves and Market Pricing

Ascend developed the forward curves for this study. The statistical P5, mean, and P95 values are presented when available to show the general volatility of each curve. Carbon forward curves are represented in Figure 7-1.

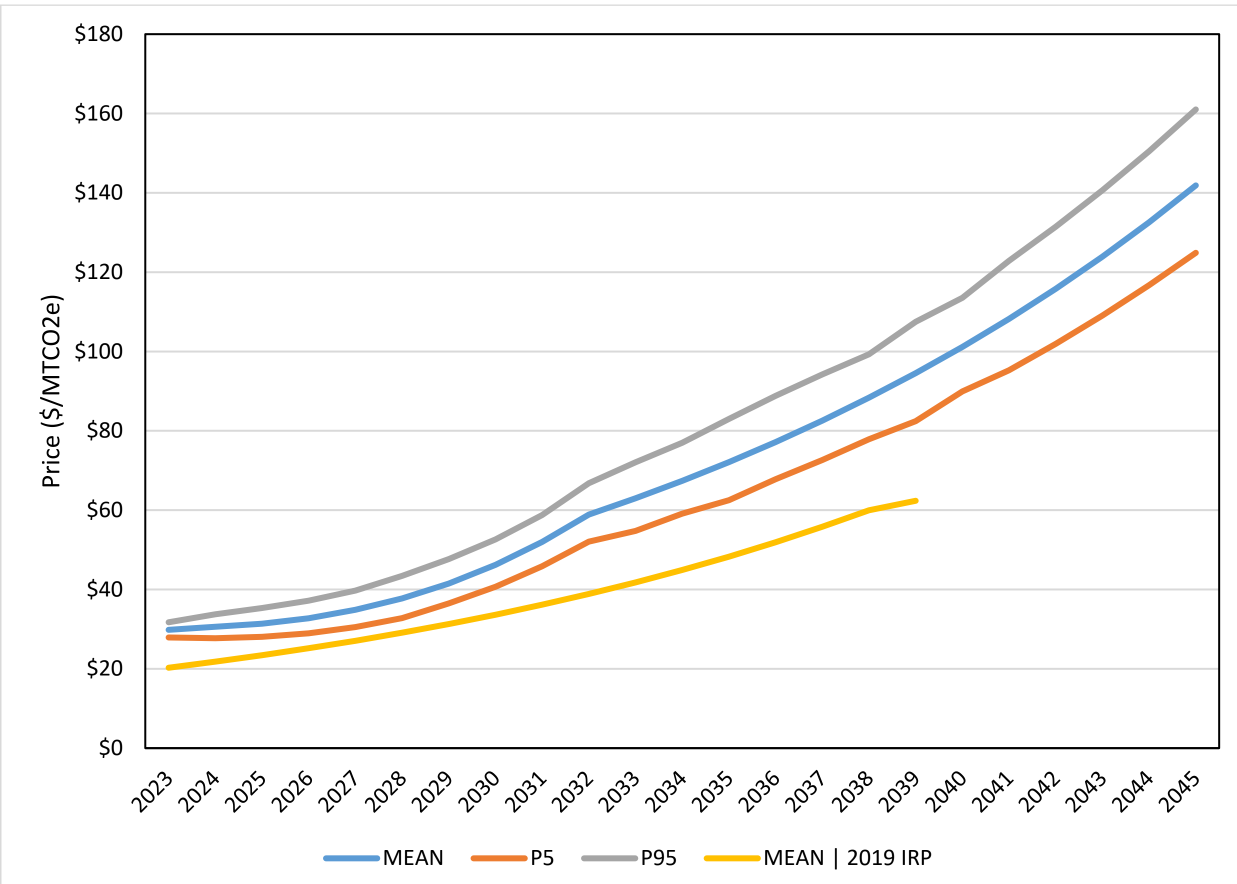


Figure 7-1: Carbon Forward Price

The import and export energy terms are in reference to REU: imports flow to REU and exports flow to energy markets. These curves are adjusted for High-Voltage Wheeling Charges (for imports), grid management charges, transmission losses, and Locational Marginal Pricing based on the CAISO nodes where BANC transacts with CAISO. The import (Figure 7-2) and export (Figure 7-3) energy prices are based on the CAISO NP-15 day-ahead price.

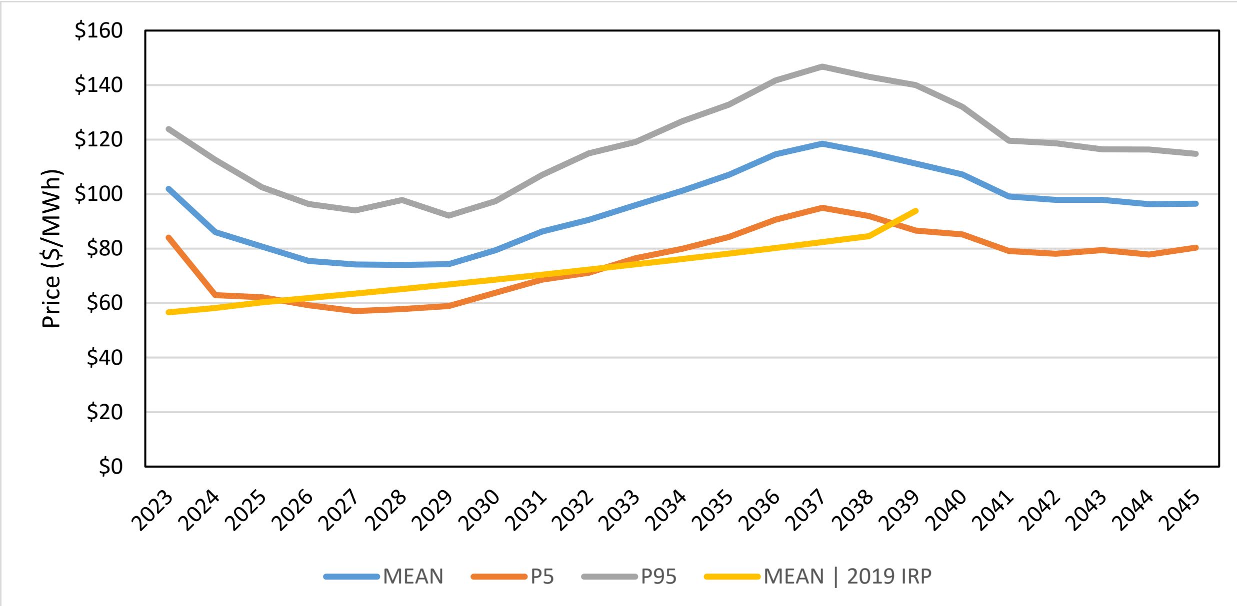


Figure 7-2: In-State Energy Imports Forward Price

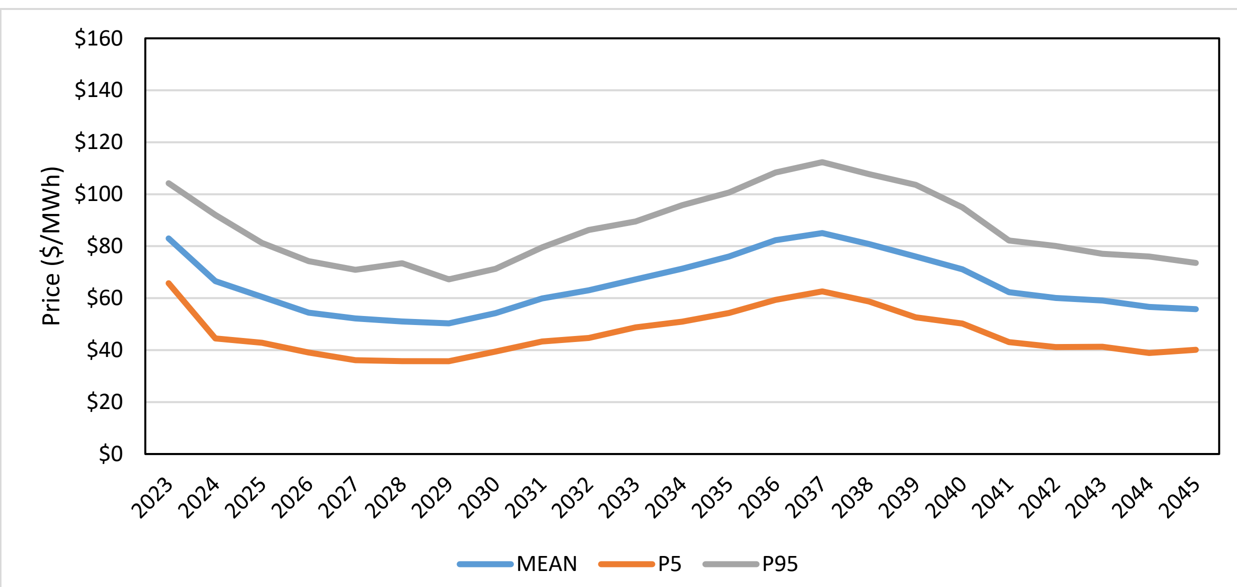


Figure 7-3: In-State Energy Exports Forward Price

Out of state energy refers to the Pacific Northwest markets where REU has access to energy though the COI. These prices are bi-directional and include transmission losses and carbon allowances as required by CARB (Figure 7-4).

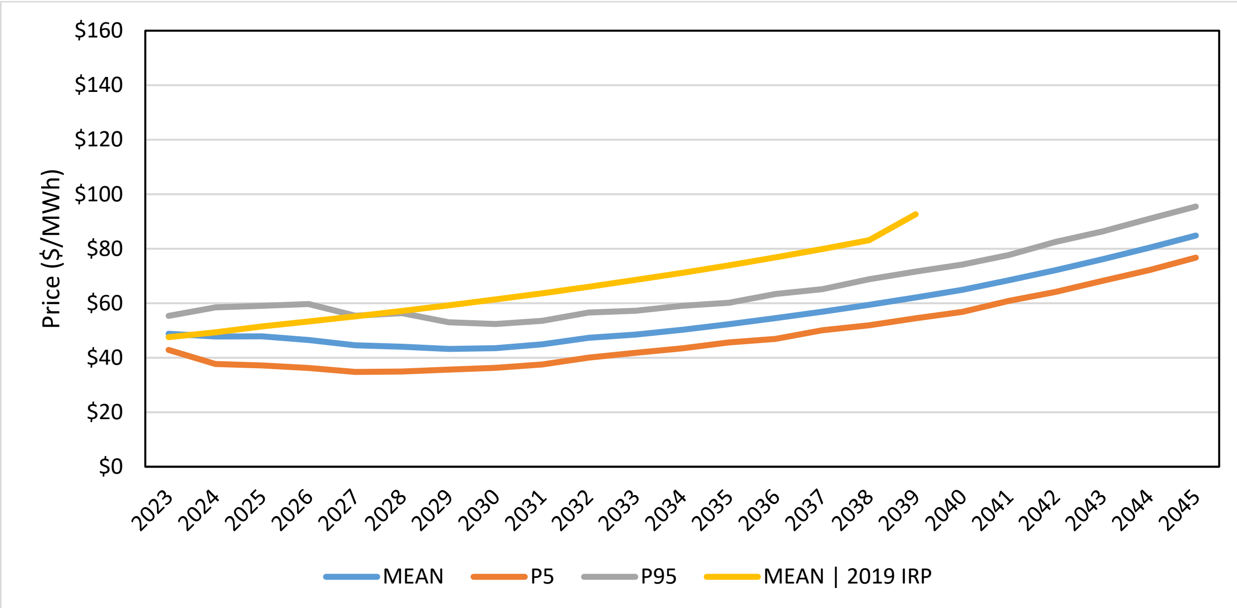


Figure 7-4: Out-of-State Energy Forward Price

Natural gas prices illustrated in Figure 7-5 below are modeled at the PG&E City Gate hub.

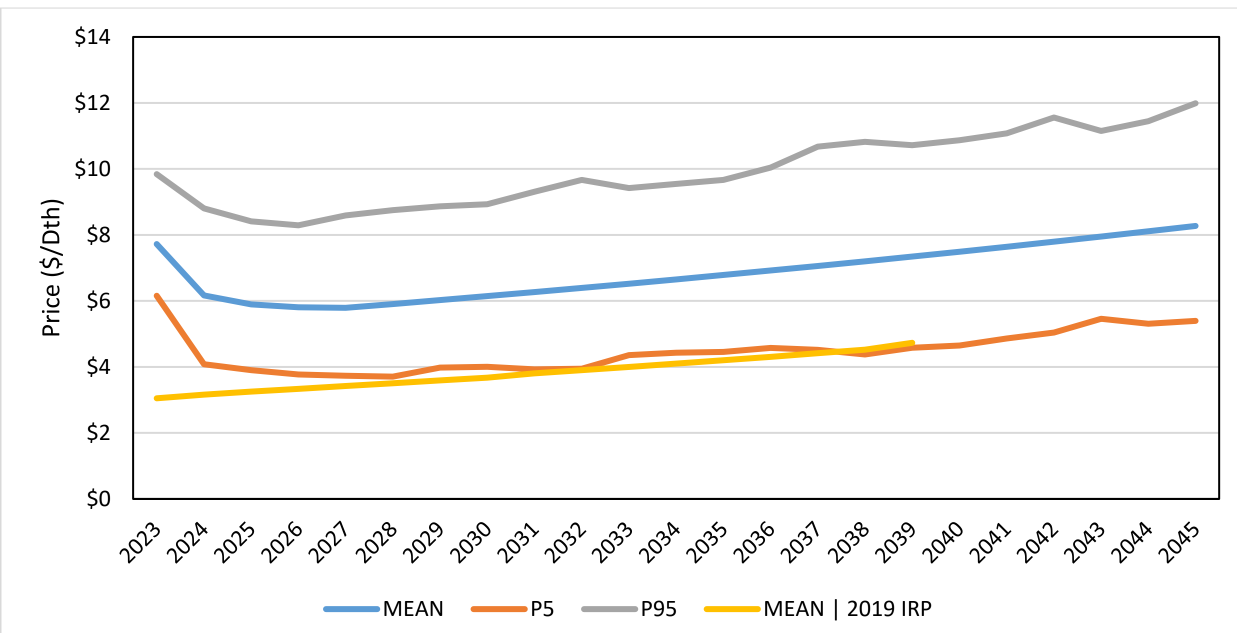


Figure 7-5: Natural Gas Forward Price

The values in Error! Reference source not found. and Error! Reference source not found. represent annualized averages of the forward prices for power, gas, carbon allowances, and renewable attributes used in the model. More information about use of forward curve in PowerSimm can be found in Exhibit 9.1.

Table 7-1: Forward Energy Price Assumptions

Year	Import Energy Price, $/MWh			Export Energy Price, $/MWh			Out of State Energy Price, $/MWh		
	P5	MEAN	P95	P5	MEAN	P95	P5	MEAN	P95
2023	84.00	101.92	123.87	65.74	82.97	104.24	42.86	48.80	55.35
2024	62.90	85.99	112.56	44.51	66.55	92.01	37.71	47.77	58.44
2025	62.13	80.73	102.53	42.85	60.47	81.24	37.14	47.86	59.04
2026	59.22	75.43	96.33	39.09	54.38	74.23	36.23	46.52	59.72
2027	57.06	74.17	94.00	36.10	52.17	70.88	34.78	44.56	55.39
2028	57.77	74.00	97.82	35.75	51.02	73.45	34.96	44.04	56.37
2029	58.90	74.28	92.09	35.72	50.29	67.23	35.64	43.22	53.03
2030	63.76	79.37	97.42	39.41	54.21	71.26	36.31	43.52	52.37
2031	68.58	86.25	107.01	43.30	59.87	79.54	37.52	44.89	53.56
2032	71.09	90.53	114.94	44.69	63.02	86.24	40.06	47.32	56.57
2033	76.44	95.91	119.11	48.76	67.23	89.51	41.78	48.48	57.22
2034	79.89	101.21	126.73	50.97	71.35	95.76	43.47	50.26	59.06
2035	84.24	107.06	132.82	54.28	76.02	100.64	45.63	52.29	60.18
2036	90.60	114.60	141.67	59.36	82.30	108.35	46.90	54.55	63.38
2037	94.95	118.48	146.78	62.60	85.04	112.33	50.05	56.86	65.16
2038	91.95	115.17	143.02	58.71	80.84	107.75	51.88	59.38	68.80
2039	86.61	111.21	139.96	52.62	76.00	103.62	54.48	62.07	71.59
2040	85.21	107.17	132.03	50.23	71.11	94.91	56.79	64.93	74.17
2041	79.10	99.09	119.56	43.09	62.28	82.15	60.85	68.42	77.72
2042	78.11	97.86	118.66	41.14	60.09	80.08	64.17	72.14	82.51
2043	79.46	97.84	116.42	41.29	59.08	77.06	68.19	76.11	86.35
2044	77.82	96.31	116.36	38.86	56.60	76.02	72.13	80.32	90.95
2045	80.30	96.44	114.78	40.10	55.73	73.55	76.73	84.82	95.47

** Average Energy Price data are averages of hourly values*

*** In-State Purchases assumed from CAISO and include High-Voltage Wheeling Charges for energy imports*

+ Out-of-State purchases include the cost of carbon allowances

Table 7-2: Forward Gas, Carbon, and REC Price Assumption

Year	Average* Annual Spot Gas Price, $/Dth			Average* Annual Carbon Allowance Price, $/mTCO2e			Average* PCC1 REC Price, $/REC
	P5	MEAN	P95	P5	MEAN	P95	MEAN
2023	6.16	7.72	9.84	27.90	29.83	31.74	17.25
2024	4.08	6.17	8.80	27.71	30.61	33.77	17.25
2025	3.90	5.90	8.41	28.05	31.37	35.32	19.55
2026	3.77	5.81	8.29	28.95	32.76	37.17	18.76
2027	3.73	5.79	8.59	30.53	34.87	39.73	16.46
2028	3.71	5.91	8.75	32.78	37.76	43.45	14.96
2029	3.98	6.03	8.87	36.50	41.51	47.66	12.32
2030	4.01	6.15	8.93	40.71	46.22	52.63	11.26
2031	3.93	6.27	9.31	45.85	51.97	58.78	11.46
2032	3.95	6.39	9.67	52.06	58.87	66.79	11.27
2033	4.36	6.52	9.42	54.77	62.99	72.07	11.14
2034	4.43	6.65	9.55	59.13	67.40	77.00	10.65
2035	4.46	6.79	9.67	62.53	72.12	82.99	10.87
2036	4.58	6.92	10.04	67.80	77.17	88.80	11.08
2037	4.52	7.06	10.68	72.66	82.57	94.20	11.30
2038	4.38	7.20	10.82	77.86	88.35	99.31	11.53
2039	4.58	7.35	10.72	82.45	94.54	107.48	11.76
2040	4.65	7.49	10.87	89.94	101.15	113.54	12.00
2041	4.86	7.64	11.08	95.27	108.23	122.84	12.24
2042	5.04	7.79	11.56	101.94	115.81	131.44	12.48
2043	5.46	7.95	11.15	109.08	123.92	140.65	13.16
2044	5.31	8.11	11.45	116.71	132.59	150.49	14.23
2045	5.40	8.27	11.99	124.88	141.87	161.02	15.63

** Average data are averages of monthly values*

Potential Resources

Rather than selecting specific projects for evaluation, REU considered potential resources based on their technology type and generating characteristics. The included resources are found in Table 7-3. Ascend provided forecasts for the various attributes for each of these technologies. Each technology was allowed to be selected by the model based on economic performance in energy markets.

Table 7-3: Potential Resources

Resource	Assumptions	Dispatchable	RPS Eligible	Carbon-free
Solar	Southern California, Northern California	No	Yes	Yes
Wind	Southern California, Northern California, Offshore, New Mexico	No	Yes	Yes
Renewable Gas	Assume Tolling Agreement	Yes	Yes	Yes*
Carbon Capture	Assume Tolling Agreement	Yes	No*	Yes
Hydrogen	Assume NG Retrofit	Yes	Yes*	Yes
Storage	4 Hour Battery, 8 Hour Battery	Yes	N/A	N/A
Geothermal	California	Yes	Yes	Yes
Biomass	California, Assume PPA	Yes	Yes	Depends

** Renewable or Carbon-free eligibility depends on the fuel source*

Table 7-4: Renewable PPA Price Forecast, $/MWh

Technology	Solar		Wind				Geothermal
Location	Southern California	Northern California	Southern California	Northern California	Offshore Wind	New Mexico	California
2031	19.56	27.05	46.30	50.51	97.10	39.23	109.38
2032	20.12	27.78	46.65	50.91	97.39	39.50	112.27
2033	20.70	28.53	46.99	51.30	97.78	39.75	115.24
2034	21.29	29.31	47.32	51.69	98.24	40.00	118.29
2035	21.90	30.09	47.65	52.07	98.77	40.25	121.42
2036	22.52	30.90	47.98	52.44	99.36	40.48	124.63
2037	30.20	38.78	53.00	57.51	100.02	45.42	135.35
2038	38.19	46.95	58.20	62.77	110.08	50.54	146.55
2039	46.47	55.44	63.59	68.21	110.91	55.84	158.25
2040	55.08	64.25	69.17	73.84	111.80	61.33	170.47
2041	64.01	73.38	74.94	79.66	112.73	67.02	183.23
2042	73.25	82.85	80.92	85.69	119.03	72.91	196.54
2043	74.90	84.71	81.80	86.63	125.47	73.70	201.74
2044	76.56	86.60	82.69	87.57	132.05	74.50	207.09
2045	78.27	88.52	83.57	88.50	138.79	75.30	212.58

Table 7-5: Renewable Fuel Price Forecast, $/Dth

Year	Hydrogen	Renewable Natural Gas
2031	16.70	30.37
2032	16.27	29.59
2033	15.86	28.83
2034	15.45	28.09
2035	15.05	27.36
2036	14.66	26.66
2037	14.28	25.97
2038	13.92	25.30
2039	13.56	24.65
2040	13.21	24.02
2041	12.87	23.40
2042	12.54	22.80
2043	12.21	22.21
2044	11.90	21.64
2045	11.59	21.08

Table 7-6 below shows the ELCC as a percentage of the nameplate capacity based on resource type. The ELCC assesses the overall capacity and performance of an energy system to ensure that it can reliably deliver electricity to meet the peak demands of consumers under different conditions and contingencies.

Table 7-6: Resource Effective Load Carrying Capability as % of Nameplate Assumptions

Year	Biomass	Geothermal	Thermal Generation (Biomass, RNG, NG+CCS)	Standalone 4HR Battery	Standalone 8HR Battery	Standalone Solar NorCal	Standalone Solar SoCal	Wind - New Mexico	Wind SoCal	Wind NorCal
2031	82%	92%	100%	62%	100%	3%	3%	28%	8%	18%
2032	84%	93%	100%	60%	100%	3%	3%	28%	8%	17%
2033	85%	93%	100%	58%	100%	3%	3%	28%	8%	17%
2034	87%	94%	100%	56%	100%	3%	3%	27%	8%	17%
2035	88%	95%	100%	53%	100%	3%	3%	27%	8%	17%
2036	88%	95%	100%	50%	100%	3%	3%	27%	8%	17%
2037	88%	95%	100%	47%	100%	3%	3%	27%	8%	17%
2038	88%	95%	100%	44%	100%	3%	3%	27%	8%	17%
2039	88%	95%	100%	42%	100%	3%	3%	27%	8%	17%
2040	88%	95%	100%	41%	100%	3%	3%	27%	8%	17%
2041	88%	95%	100%	40%	100%	3%	3%	27%	8%	17%
2042	88%	95%	100%	35%	100%	3%	3%	27%	8%	17%
2043	88%	95%	100%	34%	100%	3%	3%	27%	8%	17%
2044	88%	95%	100%	33%	100%	3%	3%	26%	8%	16%
2045	88%	95%	100%	32%	100%	3%	3%	26%	8%	16%

Table 7-7: Resource Annual Capacity Factor Assumptions

Resource	Biomass	Geothermal	Standalone Solar NorCal	Standalone Solar SoCal	Wind - New Mexico	Wind SoCal	Wind NorCal	Wind Offshore Humboldt	Wind Offshore Morro Bay	Wind Pacific NW
Capacity Factor	70%	92%	33%	34%	47%	31%	25%	55%	46%	24%
MWh/MW nameplate	6,095	8,016	2,857	2,978	4,142	2,734	2,151	4,818	4,070	2,080

Transmission Assumptions

REU is part of the BANC balancing area therefore, any potential projects in CAISO balancing area would incur High Voltage Wheeling Charges to import the energy into REU's system. These charges are significant and make all CAISO projects prohibitively expensive unless REU chooses to liquidate the energy in CAISO, unless the power can be scheduled to REU's system, the power does not have capacity value for REU. Additionally, projects in CAISO can be prioritized for CAISO load, and REU does not consider projects in CAISO as having firm capacity. For the purposes of capacity expansion modeling, all potential resources are assumed to be connected to transmission on which REU has firm rights. For resources that would require additional transmission, that cost would need to be further evaluated.

Discount Rate

The analysis utilized a 2.0 percent discount rate. This discount rate was applied to future costs and revenues to determine estimated future net costs of serving load on a net present value basis.

7.3 Scenario Design

To begin the scenario development process, REU's Leadership Team was asked to identify the goals and objectives of its IRP. Subsequently, the team agreed upon the following strategic framework for the IRP development:

The preferred 2024 IRP scenario should meet or exceed the State's clean energy mandates while balancing reliability and affordability.

Contrary to the 2019 IRP, which focused on developing the most cost-effective and reliable resource mix for meeting the RPS requirements set in SB 350, the 2024 IRP update focuses on meeting reliability and planning capacity requirements with a sufficiently renewable and carbon-free portfolio. This fundamental shift in scenario development strategy will allow REU to maintain awareness of impacts resulting from increasing energy mandates, further enabling its efforts to maintain affordable and reliable rates.

REU's Leadership Team was presented with a range of modeling scenarios proposed by the Resources Team, and chose the following options:

- Low "Base Case" (current portfolio, does not meet mandates)
- Mid "Net-Zero Carbon 2045" (meets mandates and targets)
- High "100% Zero Carbon 2045" (exceeds mandates and targets)

The major distinction between the Mid and High scenarios is the treatment of carbon. Table 7-8 outlines these differences.

Table 7-8: IRP Scenario Comparison

	Low Scenario	Mid Scenario	High Scenario
Primary Objective	Does not Meet Requirements or Targets	Meets RPS Requirements and Carbon Targets	Exceeds RPS Requirements and Carbon Targets
Name	Base Case	Net-Zero Carbon 2045	100% Zero Carbon 2045
Description	• Reference case, assumptions from 2019 IRP	• SB 1020 carbon-free targets (90% by 2035, 95% by 2040, 100% by 2045) • RPP can still run; use offsets for carbon emissions • Carbon-free energy does not need to be brought to load	• SB 1020 carbon-free targets (90% by 2035, 95% by 2040, 100% by 2045) • RPP offline no later than 2045 • Carbon-free energy brought to load (no offsets)

In addition to the regulatory mandates that must be evaluated, typical resource planning criteria must also be considered. Sufficient capacity must be secured to cover projected peak annual demand as well as reserve requirements. PRM is the excess energy above the projected system peak that utilities will plan to maintain in the event that forecasted demand is higher than anticipated due to extreme weather conditions, higher than expected load growth, or in the event that capacity resources are not available due to a forced outage, a transmission line failure, or another unexpected event. A PRM of 15 percent is used in planning based on the requirement set forth for the region by NERC.

Traditionally, a PRM has been considered sufficient to prevent loss-of-load scenarios. However, with the significant penetration of intermittent renewable resources in the bulk power grid, loss-of-load events may occur outside of peak hours. These events are not captured with a planning reserve margin. Using Ascend modeling tools, REU evaluated the scenarios on hour-by-hour basis to ensure that load can be served without relying on market imports. The primary metrics for this study is the Loss-of-Load Hours (LOLH), which gives the average hours in a year that there may be a loss of load. This is described further in Exhibit 9.1.

Each of these scenarios uses the following design constraints and criteria:

- Planning Reserve Margin – sufficient peaking capacity must exist in the portfolio to cover 115% of the annual peak load
- Renewable Energy Compliance – the portfolio must generate enough RECs to satisfy the requirements of SB 100
- Carbon-Free Energy – the portfolio must generate enough carbon-free energy to meet the targets suggested in SB 1020
- 100% Zero-Carbon – no carbon emitting-resources may be procured for the portfolio to be 100% carbon-free
- Reliability – the portfolio must not exceed 2.4 LOLH for any year without using energy imports

- Portfolio Cost– each portfolio will be evaluated for portfolio cost based on the evaluation framework in the Executive Summary.

Low Scenario - Base Case

For the Base Case, there are no constraints and no additional resources added. This scenario represents REU's current system.

Mid Scenario – Net-Zero Carbon 2045

The Net-Zero Carbon 2045 scenario is required to meet the PRM, Renewable Energy, Reliability, and Carbon-Free Energy constraints. The Plant can remain in the portfolio to provide peaking capacity and generate when economically feasible.

High Scenario – 100% Zero Carbon 2045

The 100% Zero Carbon 2045 scenario is required to meet the PRM, Renewable Energy, Reliability, Carbon-Free Energy, and 100% Zero-Carbon constraints; in this scenario, the Plant is not permitted to generate after 2045. The model never naturally selected to retire the Plant economically, so constraints were added, forcing it to retire. In the model, the Plant is forced offline starting in 2040 rather than 2045 to adequately capture the impacts of the retirement. Additionally, all carbon-free energy must be brought to load to be considered carbon-free in the portfolio.

8. Evaluation & Results

The evaluation of IRP scenarios and the preferred plan involved a comprehensive analysis of various strategic options for the Utility. Multiple scenarios were considered, each exploring different resource combinations and strategies to meet future energy demands and regulatory requirements. These scenarios were subjected to rigorous evaluation, considering factors such as cost-effectiveness, environmental impact, reliability, and alignment with clean energy goals.

Ultimately, after a thorough assessment, a preferred plan was identified by the key stakeholder group. This plan was chosen because it effectively balanced the need for reliability and affordability with the imperative of meeting clean energy targets and regulatory mandates. The Resources Team agrees with the stakeholder group's assessment and finds the Net-Zero Carbon 2045 plan represents the most viable and sustainable path forward for the Utility.

8.1 Economic Evaluation Framework

The aim of the economic analysis is to meet the goals and objectives of the IRP as describe in the Purpose and Background, including clean energy mandates, while minimizing the long-term present worth cost of incremental power to customers. This cost is commonly called the cumulative present worth cost (CPWC) of a scenario. The CPWC includes "incremental" costs, which refers to the power supply costs incurred directly or indirectly through interaction with the market and power producers during the 2023-2045 evaluation period. Incremental costs do not include existing fixed costs or common costs such as general and administrative costs, as these are considered common to all future Scenarios. However, the capital costs associated with new resources are included as are variable costs incurred (directly or indirectly) in a resource plan.

8.2 Scenario Analysis

Based on the planning criteria, the software planning tools trended toward a standard set of resources to meet portfolio compliance. REU's portfolio meets capacity and renewable constraints through 2030 and there are no carbon constraints enforced in the model until 2035 to coincide with the targets established in SB 1020. Therefore, no additional resources are selected until 2031 when the Big Horn Wind contract is due to expire.

For renewable and carbon free energy, solar appears to be the most cost-effective option, although it provides very little capacity. For capacity, battery storage appears to be the best option despite not providing energy. These two resources combined provided high value in all scenarios where resources were needed.

As a result, for incremental renewable, carbon, and capacity requirements, solar and 8-hour battery storage were chosen for all scenarios starting in 2031. The solar resources selected are a mix of northern California and southern California projects. The selected resources projects sizes and start year of each are in Table 8-1 below.

In the high scenario, where the goal is 100% Zero Carbon, it becomes imperative to replace the capacity provided by the existing Plant since it would no longer be permitted to generate. However, the model did not naturally retire the Plant because doing so would entail significant costs and necessitate extensive upgrades to REU's distribution system, as elaborated in Section 5.4 of the report.

In response to this challenge, the model pursued a strategy that involved a substantial increase in battery storage, roughly four times the previous capacity. Nevertheless, even with this augmented storage capacity, it remained insufficient to ensure the required level of system reliability. Consequently, the model recommended integrating firm, dispatchable resources to maintain the necessary resource adequacy.

Specifically, the model added 120 MW of thermal capacity to compensate for the retiring Plant. This capacity was comprised of 25 MW generated from natural gas with carbon capture and sequestration (CCS) and an additional 95 MW sourced from hydrogen. This approach aimed to address the immediate need for capacity replacement in a manner consistent with the zero-carbon objectives of the high scenario.

Table 8-1: Selected Resources for Scenarios

	Mid Scenario		High Scenario			
Year	Solar (NorCal + SoCal) MW	Storage (8-hour Battery) MW	Solar (NorCal + SoCal) MW	Storage (8-hour Battery) MW	Natural Gas CCS MW	Hydrogen MW
2031	150	25	200	25	-	-
2034	50	-	-	-	-	-
2037	50	15	25	15	-	-
2041	50	15	35	160	25	95
2045	40	-	-	-	-	-

Carbon-Free Energy

Senate Bill 1020 (SB 1020) introduces interim carbon-free energy targets beginning in 2035, prior to the zero-carbon requirement in 2045. These targets are 90 percent carbon-free from 2035-2039 and 95 percent carbon-free from 2040-2044.

The Low Scenario, or Base Case (shown below) does not meet SB 1020 carbon-free targets. After Big Horn retires in 2031, only WAPA and Whiskeytown will be providing carbon-free energy. As previously mentioned, solar energy was deemed the best value in the model. The unconstrained model deployed an extensive amount of solar due to the relatively low cost comparatively. This resulted in an abundance of renewable and carbon-free energy in both Mid and High scenarios (Figure 8-2 and Figure 8-3).

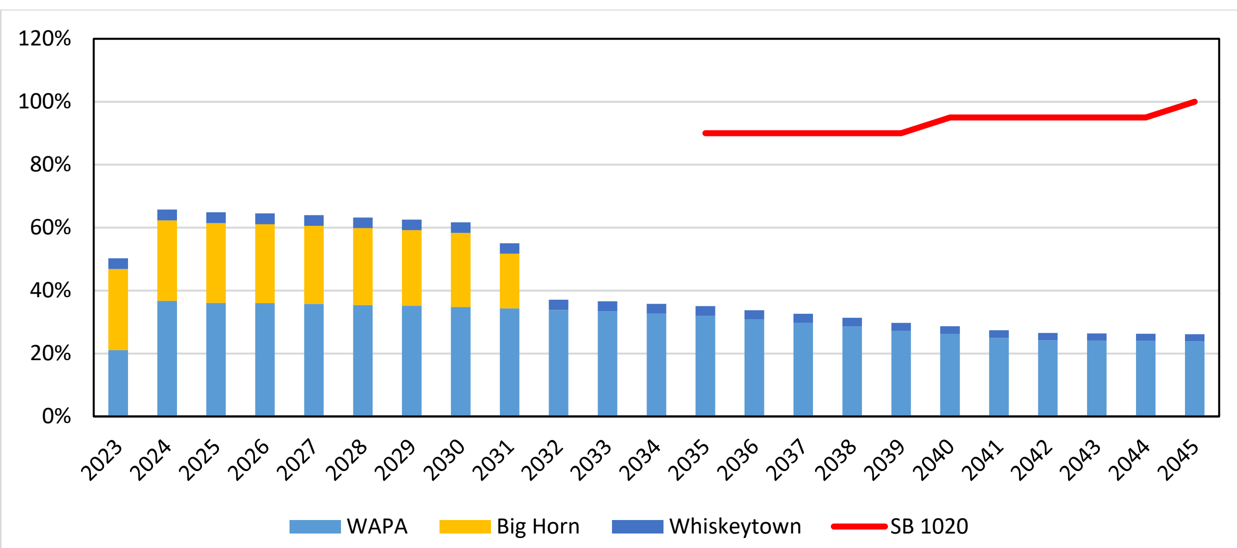


Figure 8-1: Carbon-Free Energy – Base Case

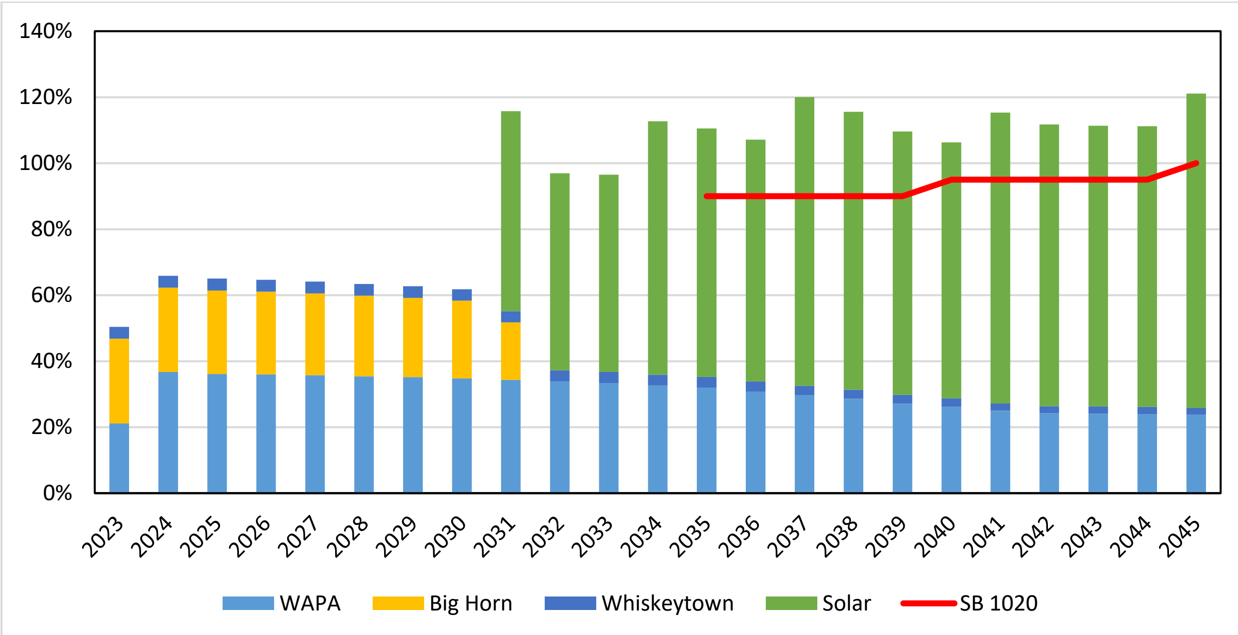


Figure 8-2: Carbon-Free Energy – Net- Zero Carbon 2045

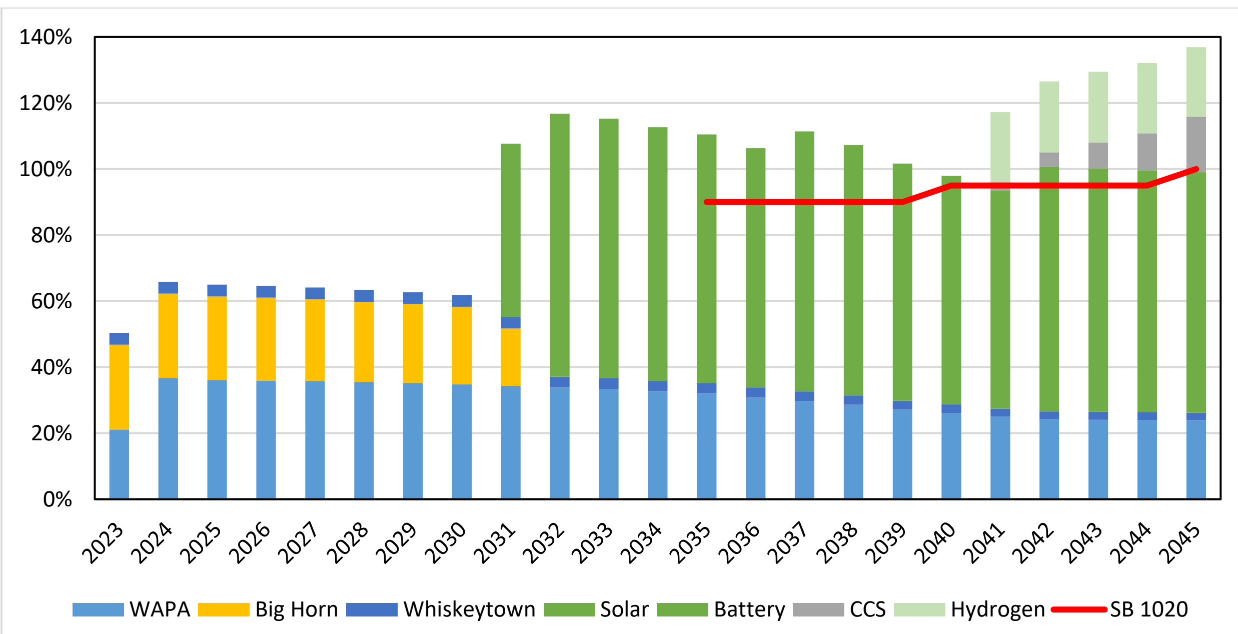


Figure 8-3: Carbon-Free Energy – 100% Zero Carbon 2045

Renewable Energy Compliance

REU's current portfolio is positioned to meet RPS compliance through 2030. The figures below indicate the ability to meet its RPS targets if no additional renewable energy resources are added. In each figure, a year in which a shortfall in RPS compliance occurs is displayed by the stacked bar chart not meeting the red line and by the purple line reaching zero.

As indicated in Figure 8-4 for the Low Scenario, if no additional renewable energy resources are added, there would be an RPS compliance shortfall starting in 2031. The shortfall would become increasingly severe; in 2035 and beyond only the small hydro resources would be contributing renewable energy. Looking at the REC outlook, it is clear that the current portfolio results in a deficiency of RECs.

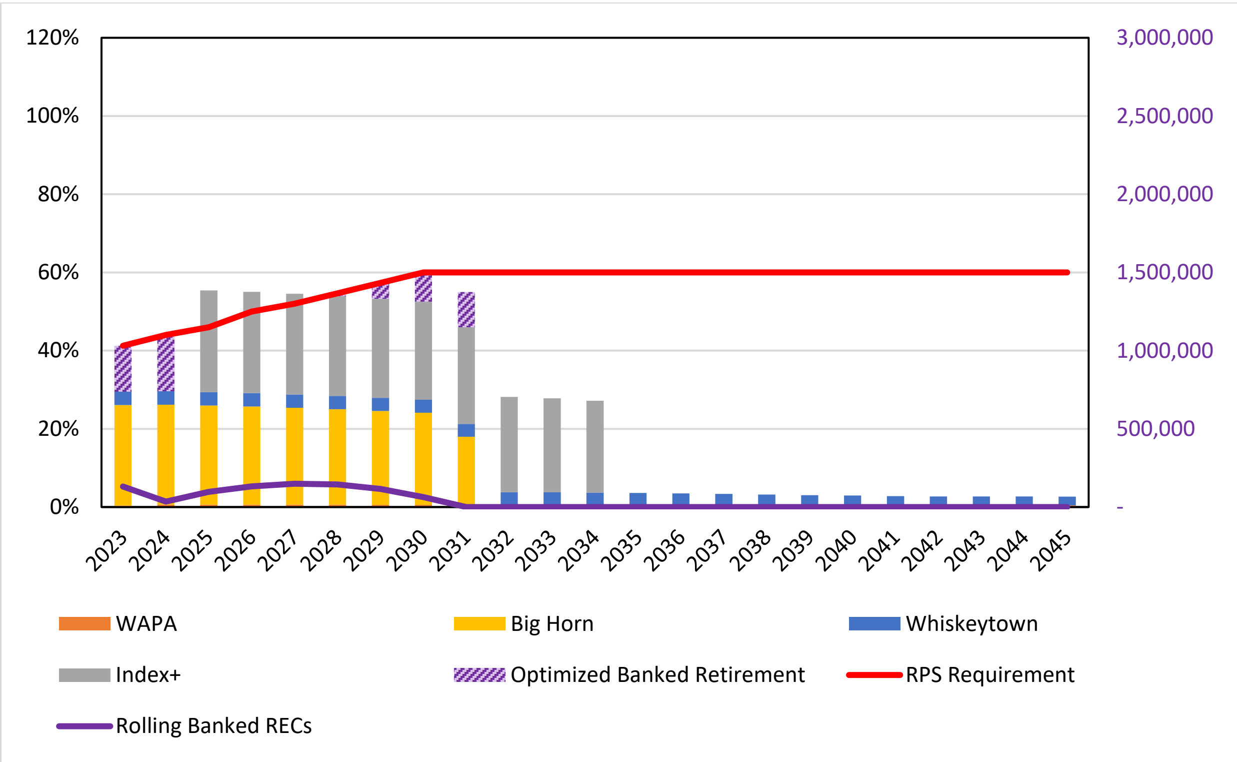


Figure 8-4: Renewable Energy Compliance – Base Case

Both the Mid Scenario (Figure 8-5) and High Scenario (Figure 8-6) exceed RPS requirements for all years and will generate more RECs than needed. The addition of solar in the portfolio starting in 2031 to meet RPS requirements creates a surplus of RECs, and with the focus on carbon-free energy, the renewable energy requirements are easily met. The excess RECs can be marketed; however, revenues from REC sales are not included in this analysis. Additionally, the model indicates that solar projects will become increasingly cost-effective, especially with on-system storage.

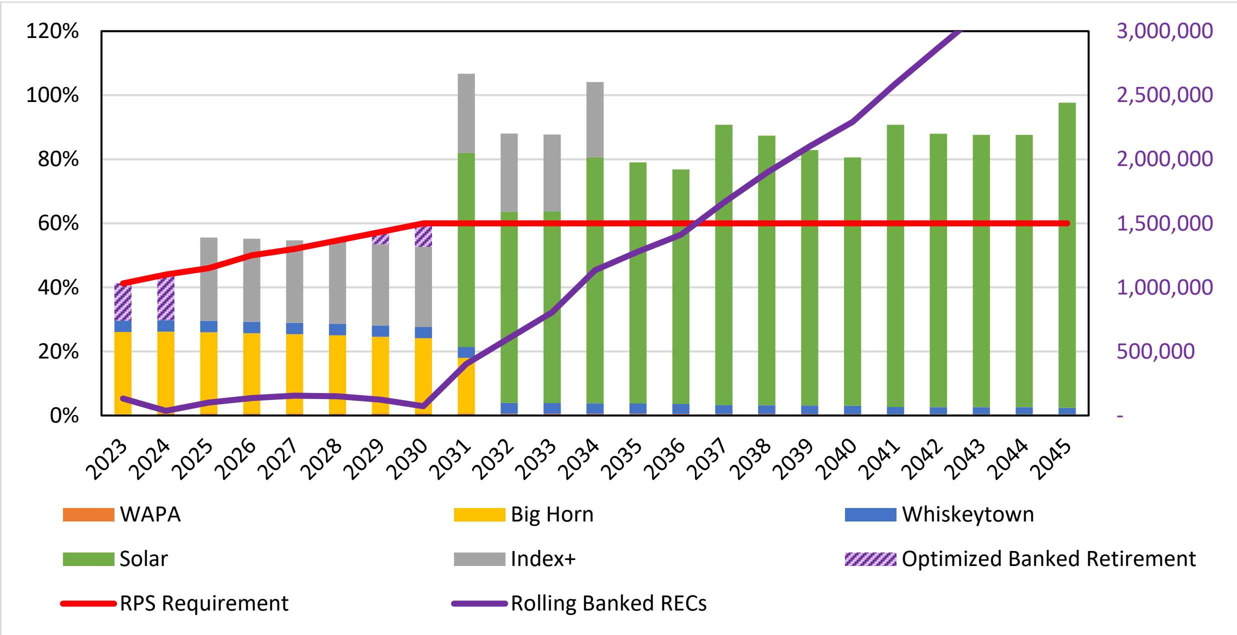


Figure 8-5: Renewable Energy Compliance – Net-Zero Carbon 2045

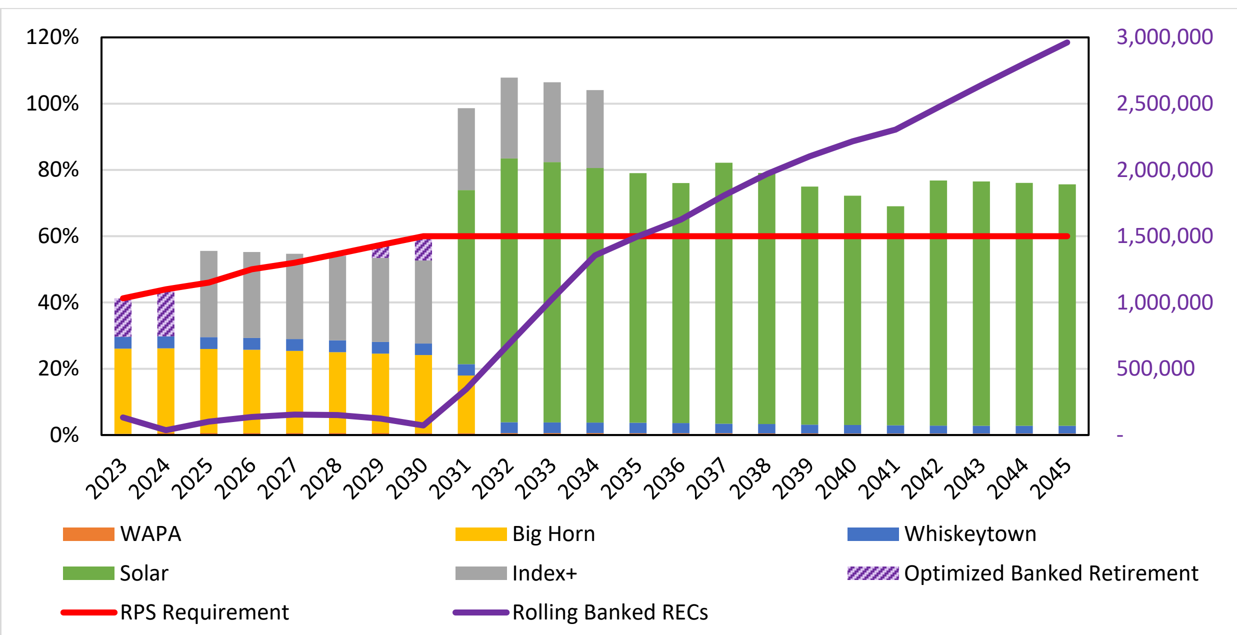


Figure 8-6: Renewable Energy Compliance – 100% Zero Carbon 2045

Planning Reserve Margin

A Planning Reserve Margin (PRM) represents the excess energy that a utility ensures is on standby in case the actual demand for electricity goes beyond what was predicted or expected. Traditionally, REU has relied on a 15 percent PRM to guarantee the reliability of its operations, especially during the hottest summer days. BANC performs an annual study to ensure that all members meet the required PRM. Each resource in the model (existing and potential) is given an Effective Load Carrying Capacity (ELCC), which is the capacity that it is expected to provide during the peak period.

The capacity balance is shown in Figure 8-7 for the Existing System Scenario. This scenario assumes no additional resources are added through 2045 and reflects the expiration of the Big Horn wind resource in 2031. The figure indicates insufficient capacity to meet the PRM after Big Horn wind is retired. Additionally, due to increasing load, there will be insufficient capacity to meet future demand staring in 2039.

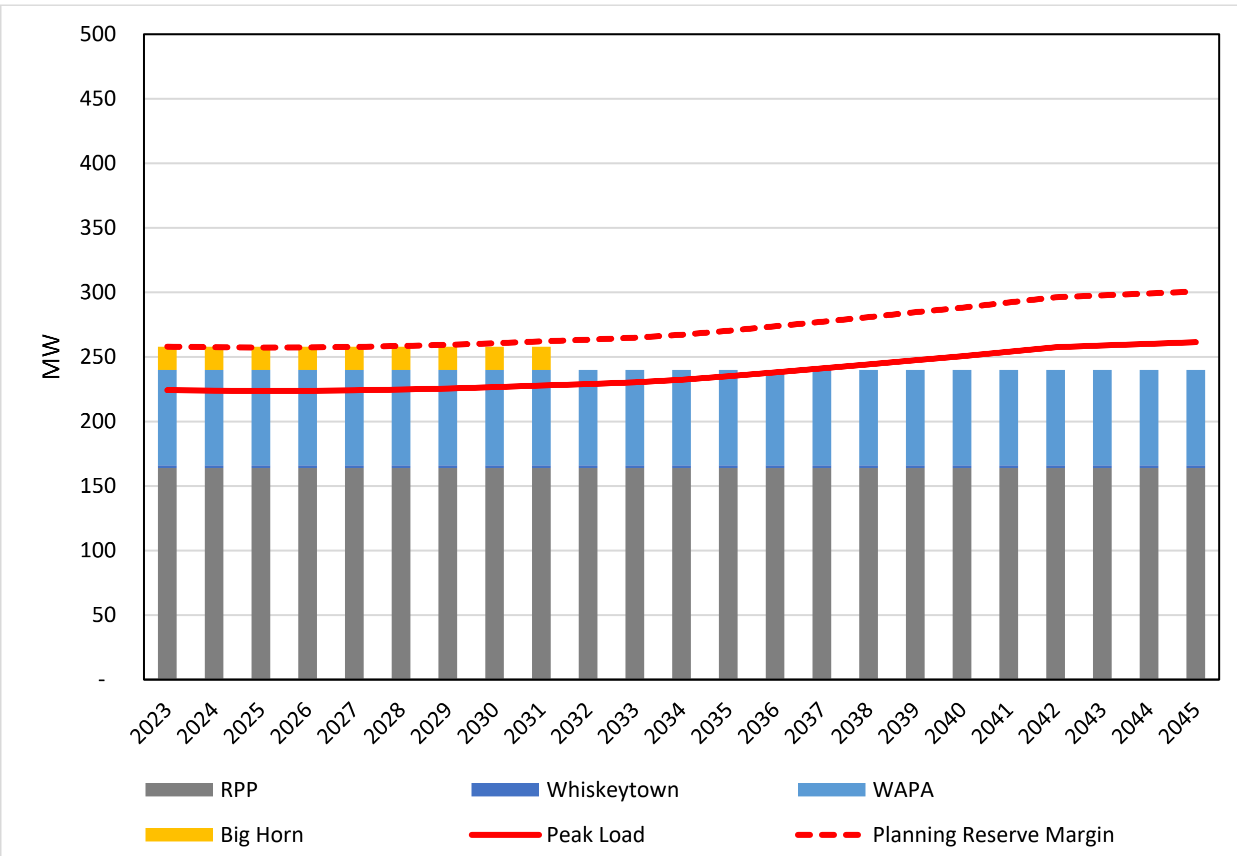


Figure 8-7: Planning Reserve Margin – Base Case

Both the Mid Scenario (Figure 8-8) and High Scenario (Figure 8-9) meet PRM requirements. The High Scenario exceeds the planning reserve margin starting in 2041 due to excessive battery capacity required after the retirement of the RPP in 2040. The excess capacity in the High Scenario is required to maintain reliability at the hourly level. This is discussed in the following section.

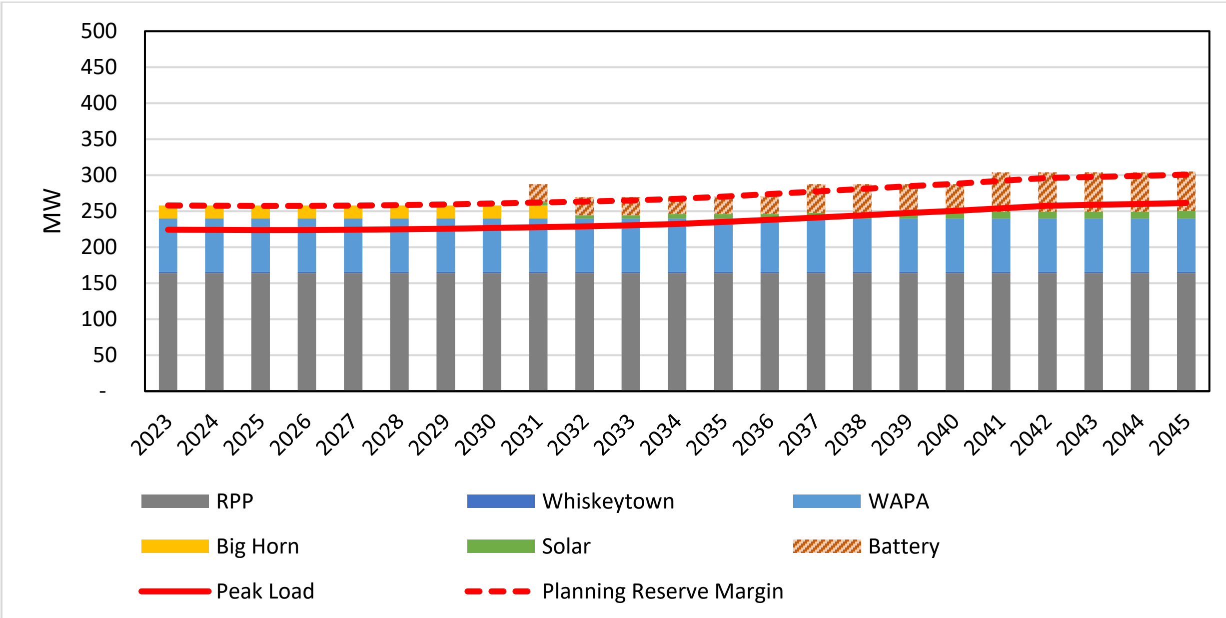


Figure 8-8: Planning Reserve Margin – Net-Zero Carbon 2045

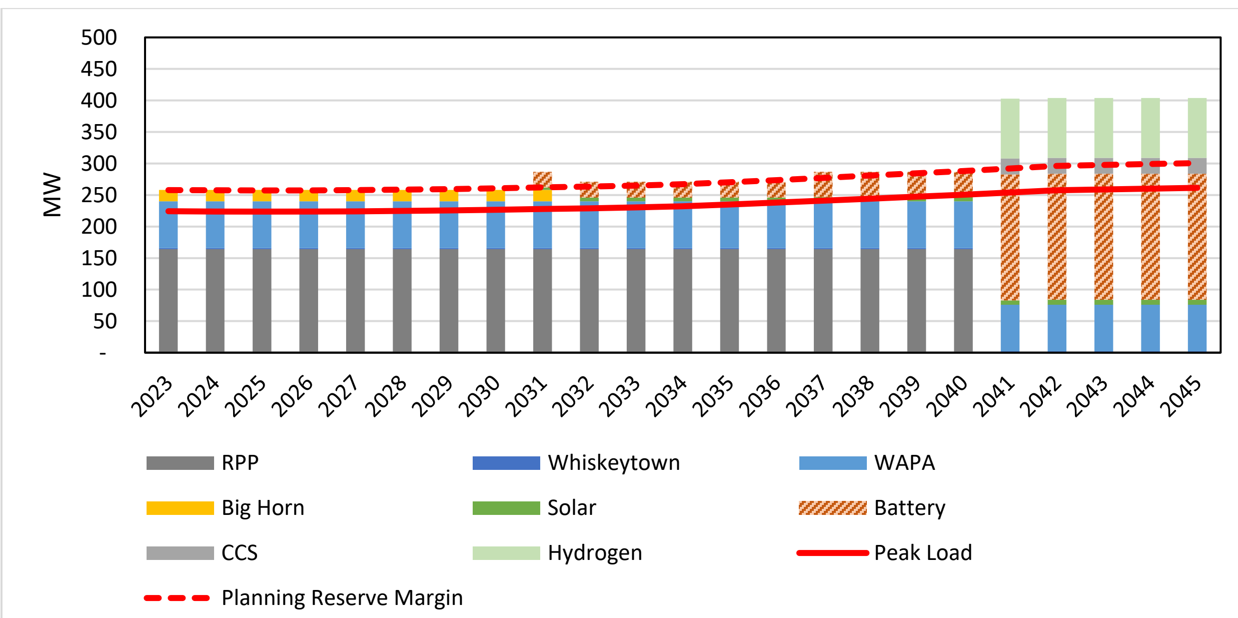


Figure 8-9: Planning Reserve Margin – 100% Zero Carbon 2045

Reliability

With the increase of intermittent renewable resources on the power grid, system reliability has been a growing concern. Traditionally, a PRM on an annual peak demand was used to determine resource adequacy. With the tools provided by Ascend, each of the scenarios was modeled to determine the Loss of Load Hours (LOLH).

- Current Portfolio: REU's Current Portfolio exceeds LOLH targets until 2038, which is the first year that the LOLH is greater than 2.4, per the design criterium (Table 8-2).

Table 8-2: LOLH for Current Portfolio

	Loss of Load hours		
Added Capacity	0 MW	20 MW	40 MW
2023	0.16	0	0
2025	0.06	0	0
2027	0.01	0	0
2028	0.01	0	0
2029	0.01	0	0
2031	0.04	0	0
2032	0.70	0.03	0
2033	0.16	0	0
2034	0.67	0.05	0
2035	0.96	0.06	0
2036	1.10	0.02	0
2037	2.17	0.15	0
2038	2.99	0.24	0
2039	4.56	0.58	0.02
2040	5.92	0.70	0.01
2041	6.88	1.17	0.02
2042	8.19	1.24	0.05
2043	9.97	1.74	0.06
2044	11.12	2.32	0.19
2045	11.27	2.34	0.23

- Mid Scenario (Net-Zero Carbon): Based on the results of these models, there are no concerns with reliability for the Mid Scenario. The Plant provides reliable capacity support and the battery storage provides incremental support as load grows. Batteries are added to the system to meet the PRM constraints, and the LOLH is reduced to zero.

For planning purposes, this study suggests that the 15 percent PRM is sufficient for system reliability and far exceeds LOLH targets.

- High Scenario (100% Zero Carbon): With the absence of the Plant in the 100% Zero Carbon scenario, the 15 percent reserve margin is not sufficient to meet the LOLH planning targets.
    - The capacity expansion model added 200 MW of battery storage to meet planning reserve margin requirements in 2045. However, with the loss of load analysis, additional firm capacity was still needed to meet LOLH targets (Table 8-3).

Table 8-3: LOLH with RPP Removed and 200 MW Battery Storage in 2045

Added Firm Capacity, MW	0	20	40	60	80	100	120	140
Average LOLH	913.5	913.4	909.2	807.2	509.2	167.1	8.7	0.4

As evidenced above, more than 120 MW of firm capacity is required to meet LOLH targets. Beyond a certain threshold, in this case, 200 MW, adding more battery storage capacity showed diminishing benefits in terms of enhancing system reliability. This suggests that while battery storage is a valuable tool for grid stabilization and energy storage, it should be deployed judiciously and in conjunction with other firm capacity resources to maximize its effectiveness. This insight underscores the complexity of energy planning and the importance of balancing various technologies and resources to create a resilient and sustainable energy portfolio.

Energy Supply Stack and Market Energy

The production cost model takes the selected resource scenarios and subjects them to a rigorous economic dispatch model. This sophisticated model is instrumental in estimating the energy output expected from each of the chosen resources within the given scenarios. By doing so, it provides a detailed and quantitative assessment of the performance and contributions of each resource option.

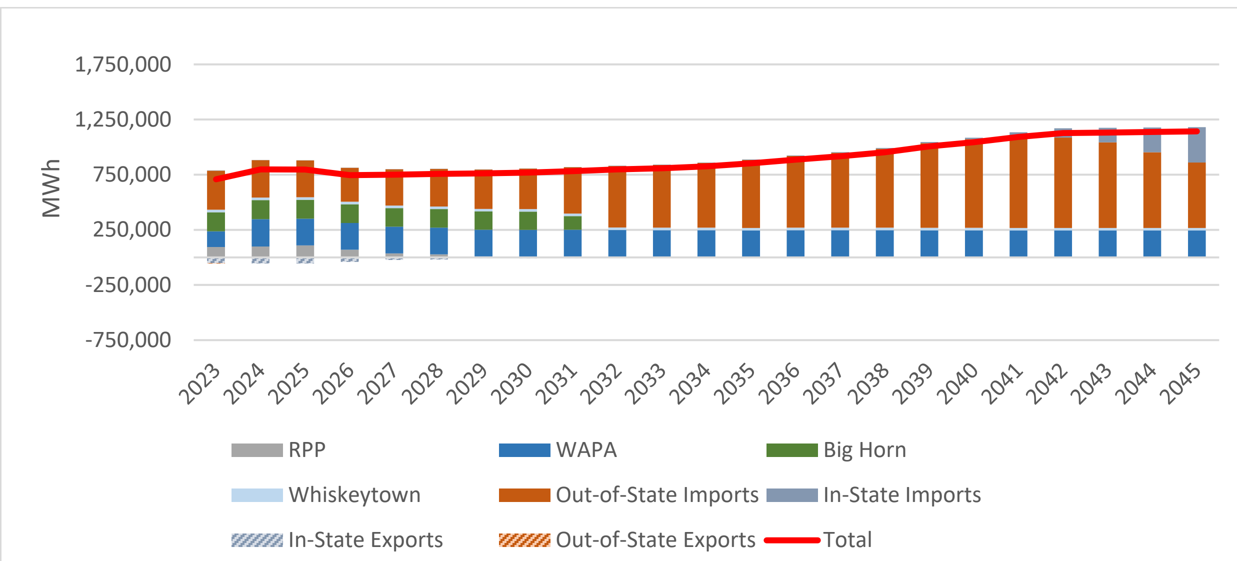


Figure 8-10: Energy Supply Stack – Base Case

Based on this scenario with no added resources, REU would supply most of energy through market purchases. Under this scenario, any increases in forward power prices would be a direct increase in power supply costs.

Both the Net-Zero Carbon 2045 and 100% Zero Carbon 2045 scenarios estimate significant market purchases, though to a much lesser degree. The model was constrained prevent it from simultaneously importing energy from out-of-state and make a market sale in-state. Although the majority of purchases are from out-of-state and the majority of sales are in-state, these are not coincident. The purchases and sales are due to solar generation profiles and economic battery optimization.

The WAPA Base Resource, while not fully dispatchable, can be shaped to fit the daily load profile (Section 5.2), which is difficult to capture in the model. In tandem with battery storage and solar generation, the Base Resource could be used to further reduce market imports. The energy supply stacks for the Net-Zero Carbon 2045 and 100% Zero Carbon 2045 scenarios are shown in Figure 8-11 and Figure 8-12, respectively.

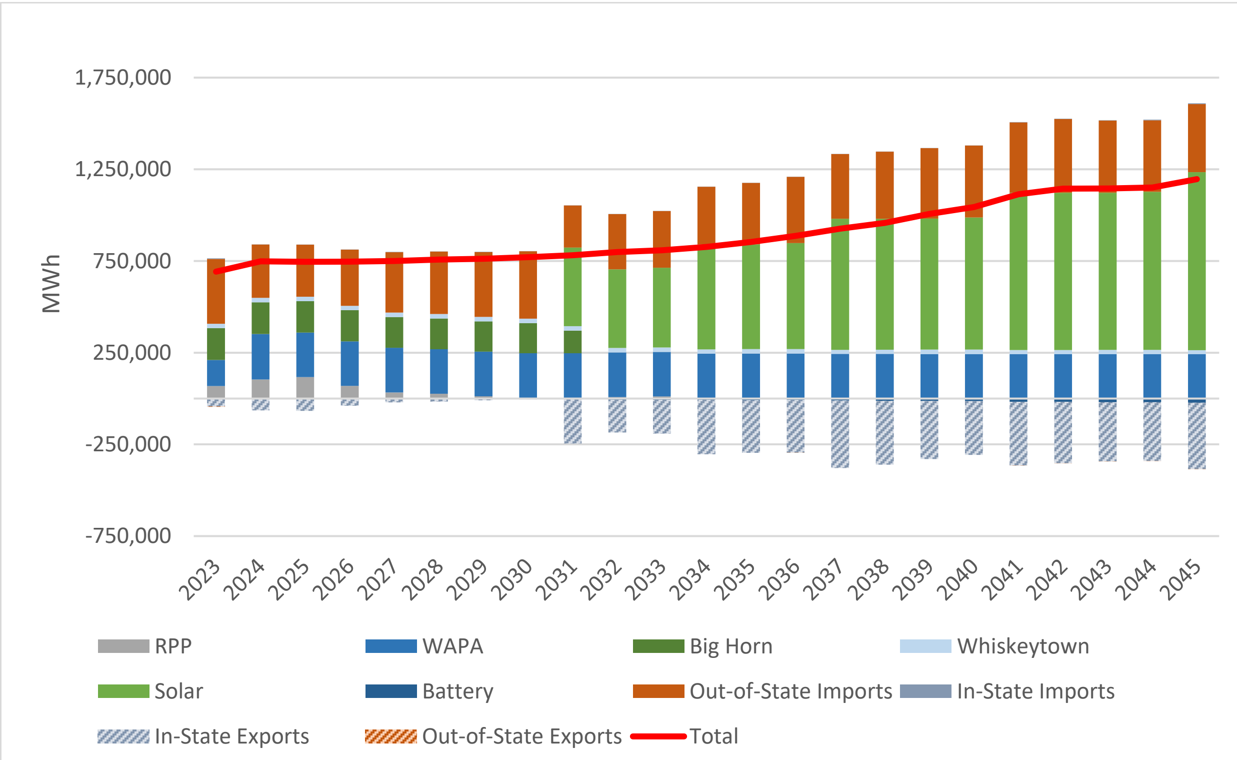


Figure 8-11: Energy Supply Stack – Net-Zero Carbon 2045

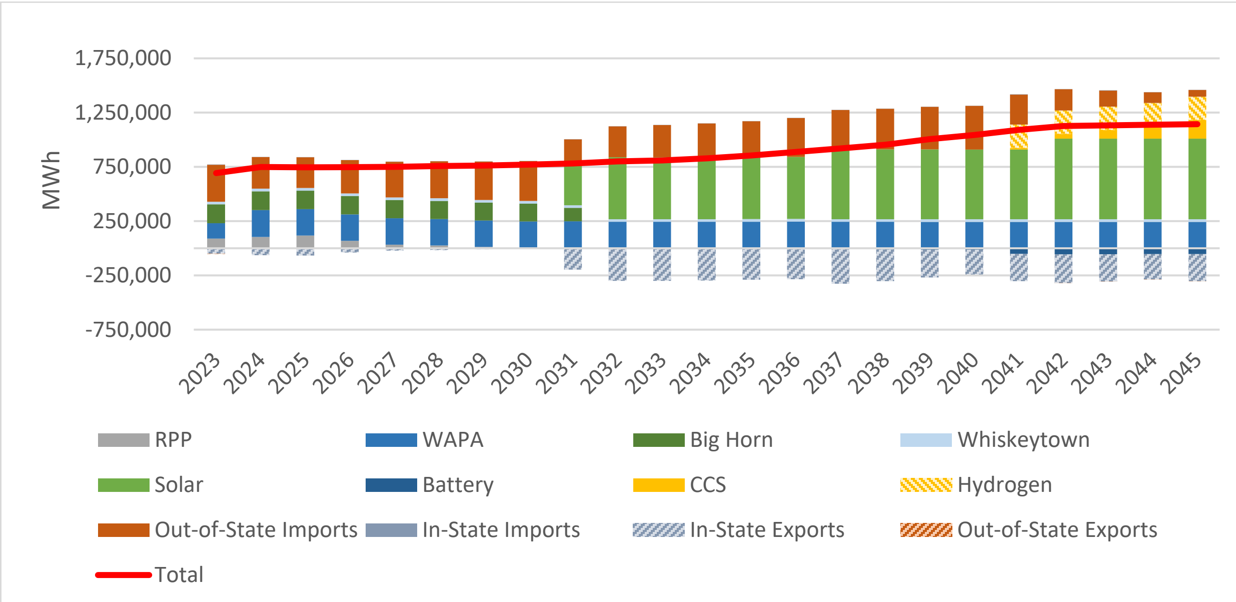


Figure 8-12: Energy Supply Stack – 100% Zero Carbon 2045

With the dispatchable thermal CCS and hydrogen resources added in the 100% Zero Carbon 2045, the market imports are reduced even further.

Portfolio Cost

The total portfolio costs are represented as the cumulative present worth cost (CPWC). These values are broken down by resource and shown in Table 8-4.

Table 8-4: CPWC for Scenarios with Resource Cost

	Current Portfolio	Net-Zero Carbon 2045	100% Zero Carbon 2045
RPP	$14	$13	$15
WAPA	$140	$140	$140
Bighorn	$102	$102	$102
Whiskeytown	$0	$0	$0
Solar	$0	$227	$227
8 Hour Battery	$0	$200	$477
NG with CCS	$0	$0	$83
Hydrogen	$0	$0	$96
Market Imports	$624	$370	$307
Market Exports	-$26	-$205	-$209
Index+ RECs	$23	$23	$23
Total, $M	$878	$870	$1,263
Levelized CPWC, $/MWh	$54.70	$54.25	$79.12

The Net-Zero Carbon 2045 scenario closely aligns with the cost of the Current Portfolio scenario. This cost parity is achieved due to the solar and storage resources acquired for the Net-Zero Carbon 2045 scenario operating at rates very similar to those prevailing in the market. Essentially, this scenario does not incur significantly higher expenses compared to participating in the market without these resources.

In stark contrast, the 100% Zero Carbon scenario presents a notably higher cost profile. This is particularly evident when examining a year-by-year comparison of the levelized CPWC, as illustrated in Figure 8-13. Up until 2040, the three scenarios exhibit minimal cost differences and appear almost identical. However, after 2040, the 100% Zero Carbon scenario faces the necessity of retiring the Plant and procuring substantial additional resources.

The need for such significant procurements post-2040 results in a substantial and abrupt cost escalation for the 100% Zero Carbon scenario. This cost surge is due to the challenge of replacing the Plant's capacity and securing additional resources to maintain grid reliability while adhering to the stringent zero-carbon mandate.

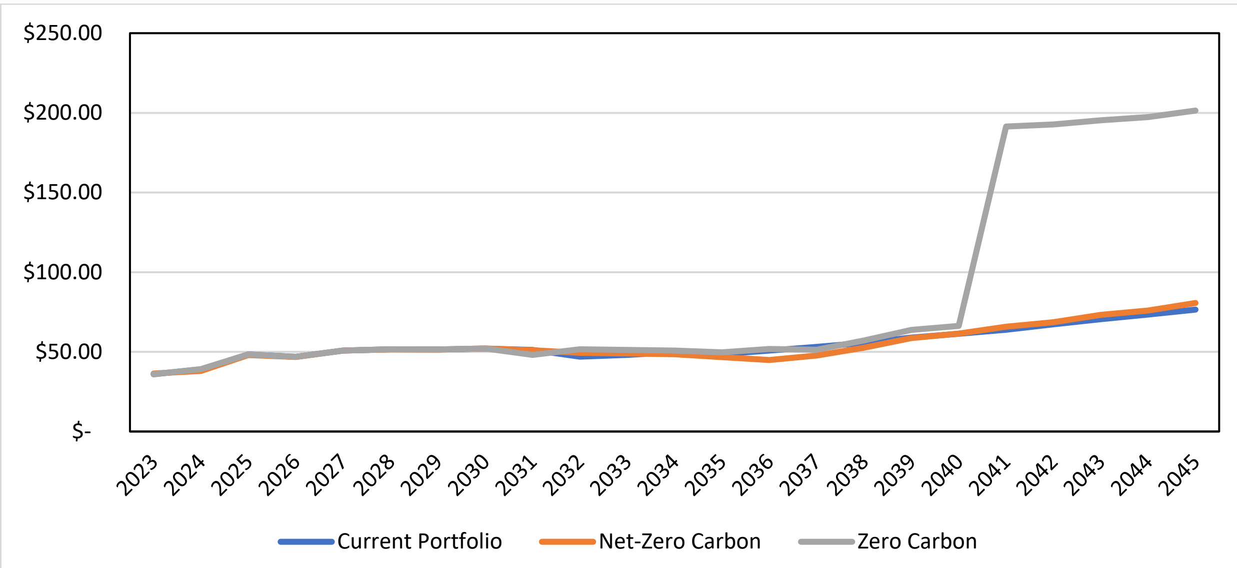


Figure 8-13: Levelized Annual CWPC by Scenario, $/MWh

8.3 Preferred Plan Selection

The key stakeholder working group was tasked with identifying the preferred planning scenario to be used for the development of the 2024 IRP. The primary goal of the scenarios presented was to determine the preferred method for reaching the State's carbon reduction requirements and targets. This decision impacts how REU would account for carbon emissions within its portfolio and ultimately determines whether there is a need to begin planning to retire the Plant to achieve a 100% zero-carbon portfolio.

After thorough consideration, the key stakeholder group unanimously chose the Mid Scenario, Net-Zero Carbon 2045, during the conclusive workshop held on March 23, 2023. This scenario was recognized as the Preferred Plan for the 2024 IRP, with an acknowledgment of the Plant's crucial role in ensuring reliable and affordable energy.

The Preferred Plan recommends procuring large capacities of solar generation to meet renewable and carbon-free energy targets while using 8-hour battery storage for capacity and reliability. Despite the intermittent solar resources, the portfolio still achieves high reliability with fewer than 2.4 loss-of-load hours estimated per year.

In summary, the Preferred Plan has the following characteristics:

- Allows the continued dispatch of Redding Power Plant with the use of carbon allowances
- To meet SB 1020 target, the Plant is primarily running for peaking load and to provide system stability when needed
- To meet planning criteria, the following resources are added:
  - 2031: 180 MW of solar and 25 MW battery storage
  - 2037: 55 MW of solar and 15 MW battery storage
  - 2041: 80 MW of solar and 15 MW of battery storage
- In total, this would add 315 MW of solar generation and 55 MW of 8-hour battery storage to the portfolio though the planning horizon

While endorsing the Net-Zero Carbon 2045 scenario as a means of maintain affordability and reliability, the stakeholders strongly encouraged the staff to explore opportunities for reducing fossil-fuel generation and minimizing carbon emissions without compromising reliability and affordability.

The specific resources selected in each scenario are not the primary focus of this study. The takeaways from the preferred plan as modeled are that REU should focus on cost-effective intermittent resources to

procure renewable and carbon-free energy while leaning on 8-hour battery storage to maintain system reliability and meet capacity planning requirements.

A diverse portfolio is typically preferred to maintain high reliability by not relying heavily on one type of generation resource. As REU seeks to fill these resource requirements, staff will continue to evaluate the portfolio, diversify its resource technology options, and optimize resource selection while adhering to the carbon-free principles established in the preferred plan.

Preferred Plan Reporting

The preferred plan identifies the desired approach to reach zero-carbon goals by 2045 while meeting intermediate renewable requirements and carbon-free targets. Using the resources in the preferred plan, additional models were dispatched to develop a forward outlook that meets the requirements discussed in this report while considering other operational constraints of the Utility and reporting consistent with Form CEC 113, "Standardized Reporting Tables for Public Owned Utility IRP Filing."

The operational constraints relate to obligations under current agreements for minimum operations of REU generation due to the current LTP and prepay gas agreements. While the requirements will still be met under the preferred plan with these constraints, REU staff, under direction of the stakeholder group, is currently evaluating all opportunities to eliminate such operating constraints to further reduce emissions where possible and optimize the resource portfolio to provide the most cost-effective and reliable service.

The annual energy balance for this study is shown in Table 8-5. The forecasted emissions for this plan are shown in Figure 8-14.

Table 8-5: Load and Resource Balance for Preferred Plan with Operating Constraints

Description	Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
System Energy Demand, GWh		731	731	729	730	734	740	745	753	762	773	782	800	826	858	887	921	972	1,008	1,054	1,087	1,091	1,096	1,102
Unit 1	NG GT	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-
Unit 2	NG GT	3	1	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-
Unit 3	NG GT	2	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-
Unit 4	Steam	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Unit 5 (Simple Cycle)	NG SC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Unit 6 (Simple Cycle)	NG SC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1x1 (Combined Cycle 5 or 6 w/ 4)	NG CC	147	147	136	146	140	140	138	139	136	146	133	134	136	132	132	137	99	-	-	-	-	-	-
2x1 (Incremental Combined Cycle)	NG CC	140	139	129	142	133	136	132	132	130	141	128	129	133	127	126	131	96	-	-	-	-	-	-
Unit 9 (Whiskeytown)	Hydro	24	24	24	24	24	24	24	24	24	24	24	24	23	23	23	23	23	23	22	22	21	21	20
Total Energy from REU Generation, GWh		317	313	292	313	298	300	295	296	291	311	286	287	293	282	282	292	218	23	22	22	21	21	20
Big Horn	Wind	173	173	171	169	168	167	166	164	123	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Western	Hydro	142	248	243	243	243	243	243	243	243	243	243	243	243	243	243	243	243	243	243	243	243	243	243
Renewable PPAs	Solar, Wind	-	-	175	175	175	175	175	175	175	175	175	175	-	-	-	-	-	-	-	-	-	-	-
Recommended Renewables	Solar	-	-	-	-	-	-	-	-	371	500	500	515	572	615	644	673	716	773	833	878	907	937	982
Total Generation from Energy Contracts , GWh		316	421	589	587	586	585	584	582	912	918	918	933	815	858	887	916	959	1,016	1,076	1,121	1,150	1,180	1,225
Total Contracted & Installed Generation, GWh		632	733	881	900	884	886	879	878	1,203	1,229	1,204	1,220	1,108	1,140	1,168	1,208	1,177	1,039	1,098	1,142	1,172	1,201	1,245
Market Sales, GWh		(140)	(159)	(318)	(330)	(316)	(316)	(309)	(309)	(535)	(572)	(558)	(564)	(426)	(442)	(444)	(442)	(403)	(331)	(333)	(342)	(346)	(354)	(365)
Market Purchases, GWh		226	200	209	201	208	212	217	226	143	172	194	202	208	229	236	232	279	383	387	397	383	379	366
Net Market Energy, GWh		86	41	(109)	(129)	(108)	(103)	(91)	(83)	(393)	(400)	(364)	(362)	(218)	(213)	(208)	(210)	(124)	53	53	54	37	25	1
Net System Energy, GWh		718	775	772	772	775	783	788	795	810	829	839	858	890	927	961	998	1,053	1,092	1,151	1,196	1,209	1,226	1,247

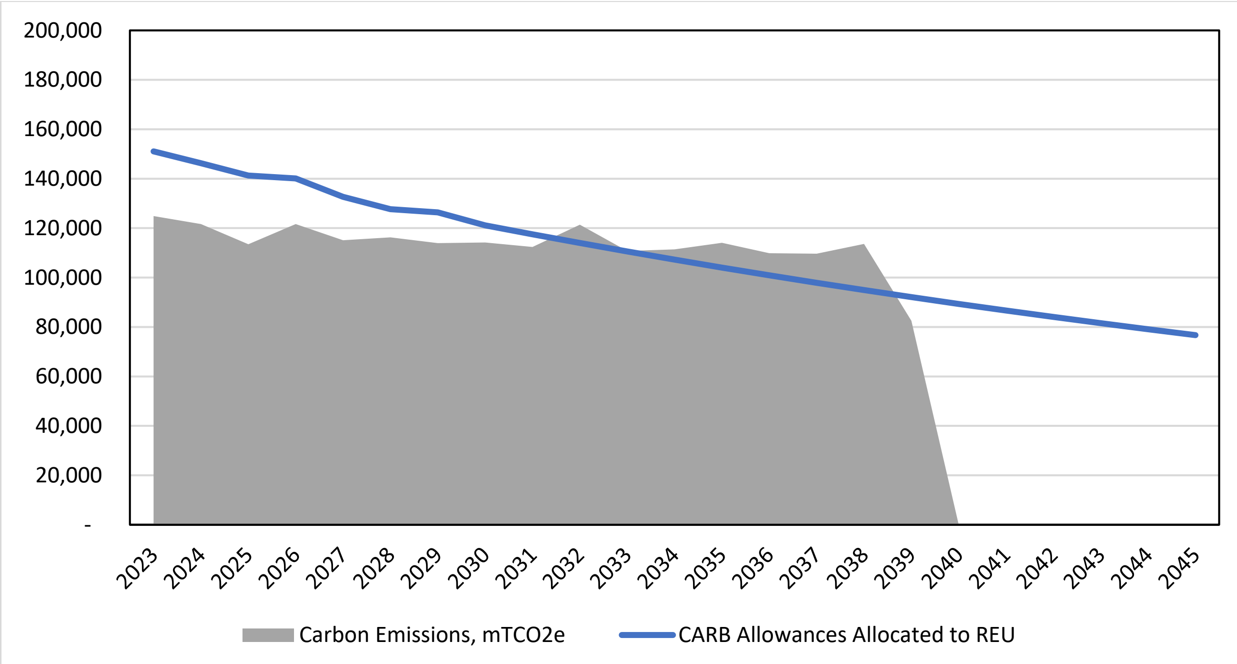


Figure 8-14: Carbon Emission Outlook for Preferred Plan with Operating Constraints

8.4 Sensitivity Cases

As discussed previously in Section 7.1, the PowerSimm Resources Planning Suite, developed by Ascend Analytics, was used to evaluate alternative resource additions to the portfolio that satisfy RPS requirements. PowerSimm employs a probabilistic approach in which the modeling results for a single Scenario include a range of possible outcomes based on agitations of input variables subject to uncertainty and for which correlated probability distributions are generated for the input. This method results in more than single deterministic output variables, but probability distributions on all the key output variables. This means that multiple, single variable sensitivity runs are not needed to understand the impact of uncertainty in one or more key input variables.

For example, regarding fuel prices, the CPWC results reported in Table 8-4 are based on random expected draws of fuel prices, correlated with random expected draws of other input variable, resulting in a 95 percent to 5 percent probability distribution range on the output variables. This means that fuel prices selected in the random expected draws are within a band expected to include the maximum fuel price 95 percent of the time and the low fuel price is not expected to go below the low fuel price more than 5 percent of the time. The results reported in this section are based on the mean results of all runs resulting from multiple draws on the stochastic input variables and simulated by the model.

In addition to the sensitives inherent in the modeling, REU also performed further sensitivity analyses by forcing changes in the modeling assumptions. The primary cases studied were as follows:

- High Load Case – all criteria are the same as the Net-Zero Carbon 2045 scenario, except the load forecast is increased by 10% starting in 2031
- Net-Zero Carbon 2035 – all criteria are the same as the Net-Zero Carbon 2045 scenario, except the portfolio must reach 100% net-zero carbon 2035 instead of 2045
- Net-Zero Carbon Diverse Portfolio – all criteria are the same as the Net-Zero Carbon 2045 scenario, except no new resource technology types can exceed 100 MW

High Load Case

In the High Base Case Scenario, customer demand was assumed increase by 10 percent over the load forecast used in this IRP (Figure 8-15). Although the load was greater, the model did not identify any unique resources. Rather, the already selected solar and battery storage resources were simply scaled up to meet the greater demand, indicating the resource selection is not sensitive to load. The same resources that are most cost effective at the current load forecast will still apply even with increased load. The energy supply stack for this scenario is shown in Figure 8-16.

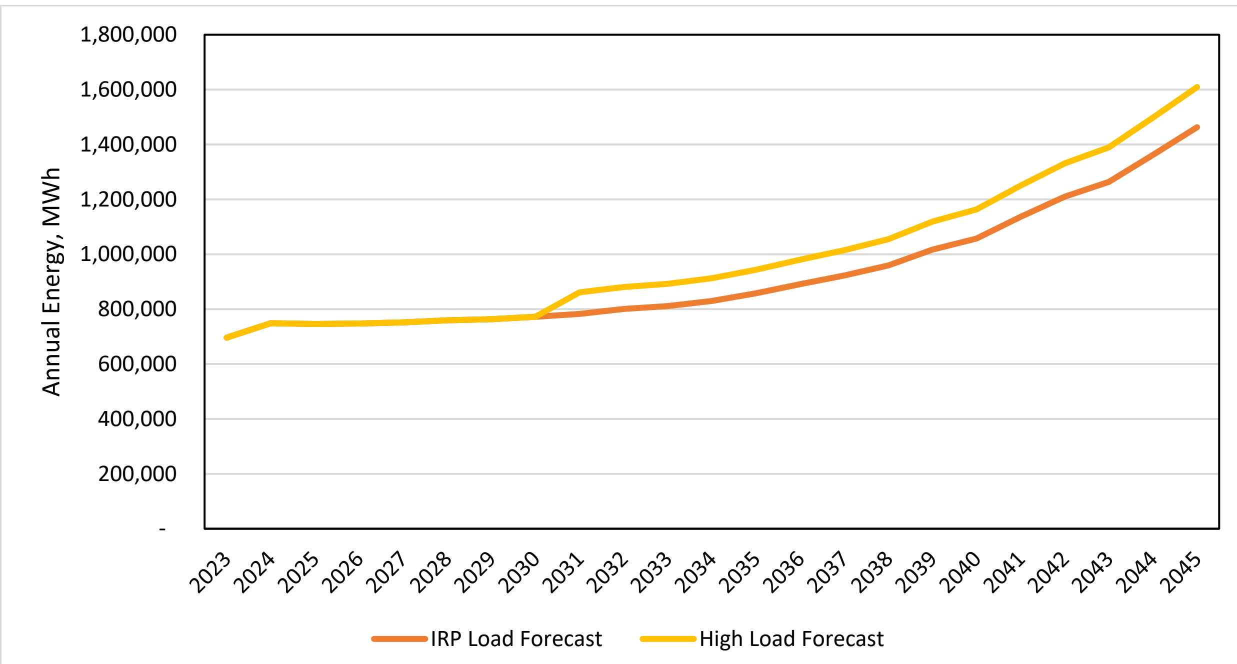


Figure 8-15: High Load Scenario Load Forecast

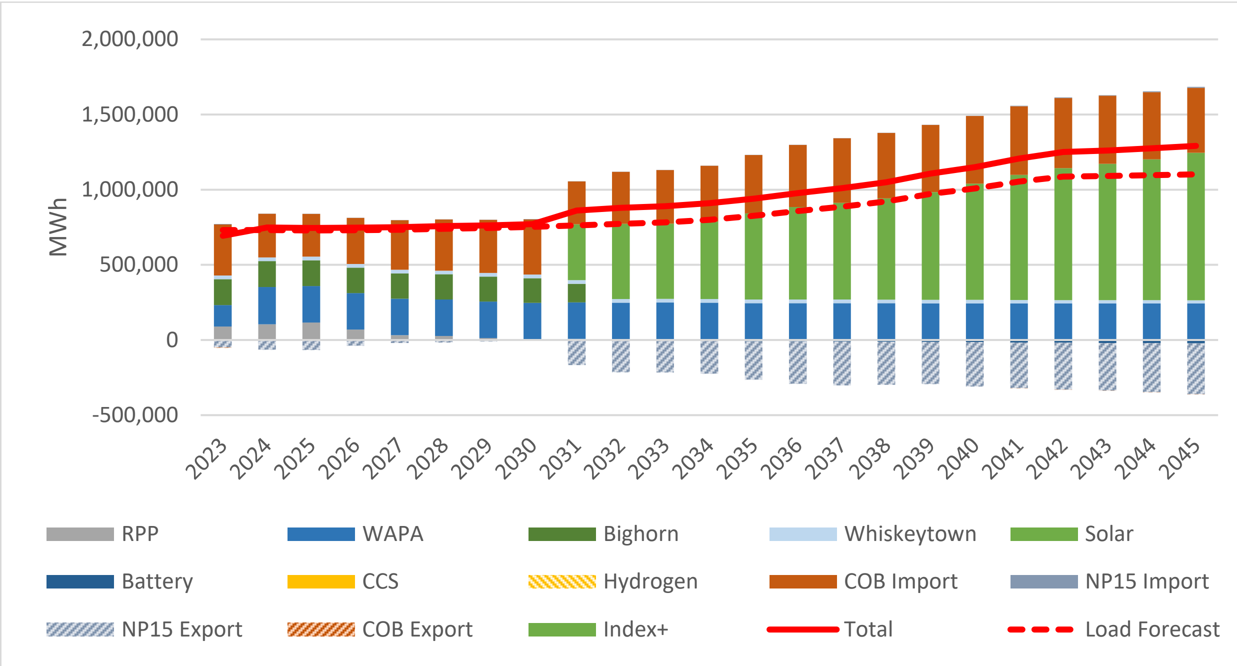


Figure 8-16: Energy Supply Stack – High Load Scenario

Net-Zero Carbon 2035

As shown in Section 7.2, the Net-Zero Carbon 2045 case achieved greater than 100 percent net-zero carbon starting in 2035. Therefore, this accelerated scenario is identical to the preferred scenario chosen for this IRP.

Net-Zero Carbon Diverse Portfolio

The portfolios identified in the mid and high scenarios include large solar projects to reach renewable and carbon-free targets. While resource diversity was a constraint set for the IRP scenario, past experience and prudent planning suggests there is inherent risk in portfolios that rely on a single type of resource. Despite solar is being the least cost resource available to meet renewable compliance and carbon-free targets based on forward cost estimates, a balanced portfolio that includes multiple technologies may reduce risks associated with over-reliance on a single technology. To consider this, the Net-Zero Carbon Diverse portfolio sensitivity scenario limits a single technology type to 100 MW of nameplate capacity.

For this scenario, the model selected wind, solar, and geothermal resources. In this scenario, REU would procure:

- Solar: 100 MW by 2037
- Wind: 100 MW by 2031
- Geothermal: 25 MW by 2043

With the inclusion of geothermal and wind, which both include greater ELCC values than solar, battery storage was no longer selected. The selected resources are shown in Table 8-6 and Planning Reserve Margin

Compliance is shown in Figure 8-17. The Plant and WAPA hydro resources will still serve the majority of REU's peaking capacity.

Table 8-6: Selected Resource Additions for Diverse Portfolio Scenario - Nameplate Capacity, MW

Year	Solar, MW	Wind, MW	Geo, MW
2031	50	100	-
2033	25	-	-
2037	25	-	5
2039	-	-	5
2040	-	-	5
2041	-	-	5
2043	-	-	5

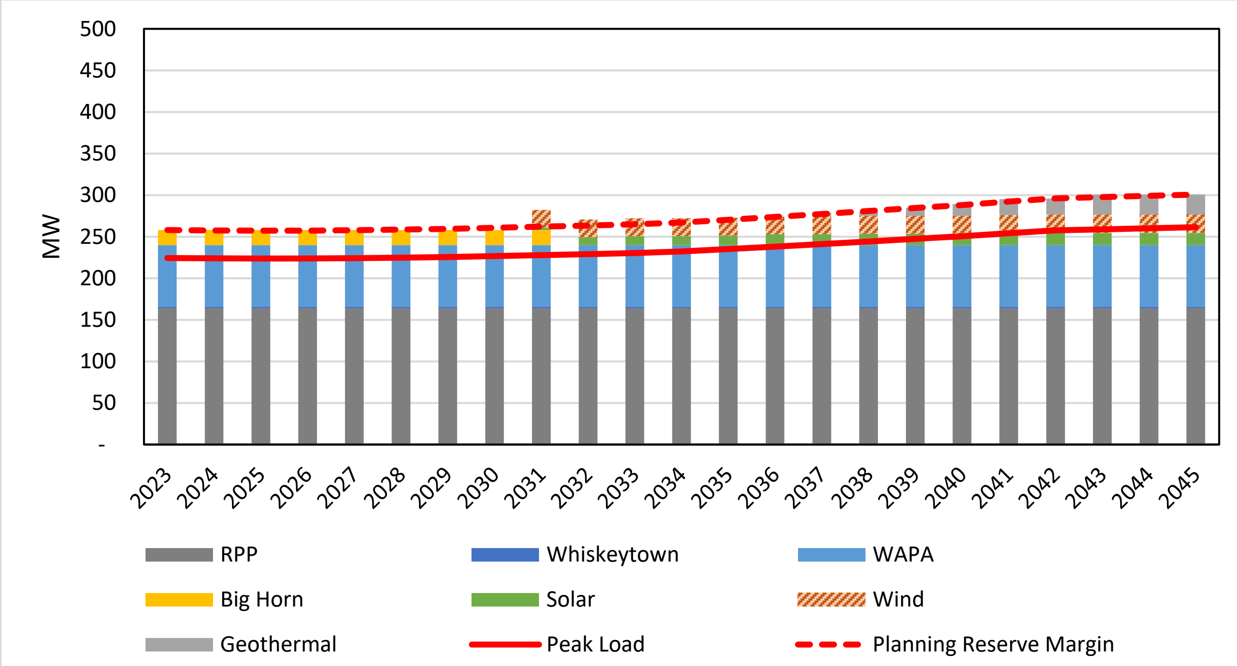


Figure 8-17: Planning Reserve Margin – Net-Zero Carbon Diverse Portfolio

The Diverse Portfolio exceeds RPS compliance requirements and maintains renewable generation greater than 60 percent of retail sales through 2045 as seen in Figure 8-18. The portfolio meets the carbon targets for almost every year, illustrated in Figure 8-19. There is one notable shortage in 2045 where only 95 percent carbon-free energy is achieved. The model had selected a small biomass project to fill in this gap.

In practice, however, REU would likely allow one of the other resources, such as solar or wind, to exceed 100 MW and fill in the resource need.

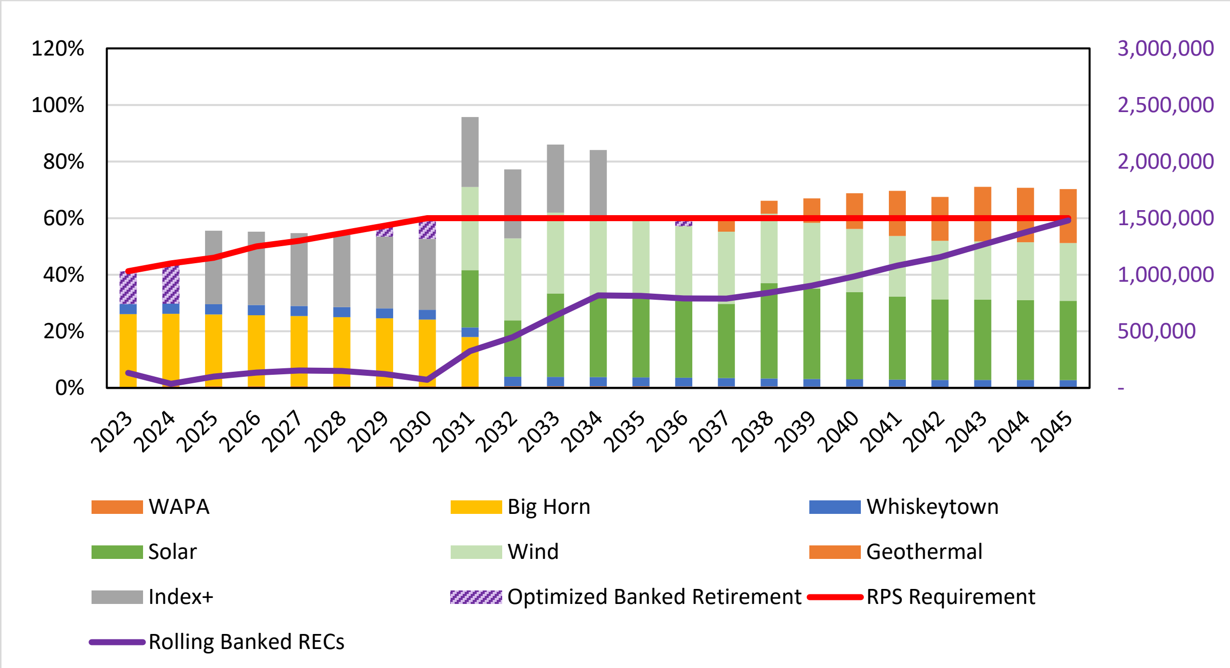


Figure 8-18: Renewable Energy Compliance – Net-Zero Carbon Diverse Portfolio

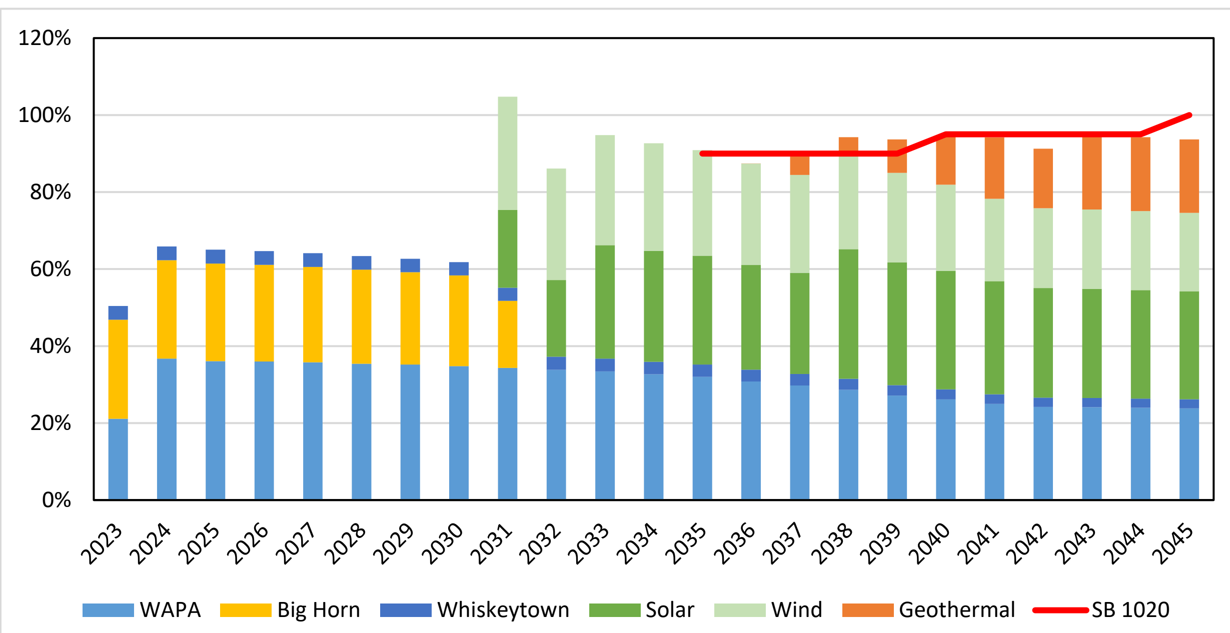


Figure 8-19: Carbon-Free Energy – Net-Zero Carbon Diverse Portfolio

Limiting the allowable solar to 100 MW of nameplate capacity reduces the excess procurement of renewable energy apparent in the preferred scenario. The market and resource price forwards indicate solar is the least cost resource available and provides a positive return. Therefore, limiting this resource increases overall portfolio cost compared to the preferred plan by approximately $49 million, or 5.6 percent. A comparison of the CWPC values for IRP scenarios, including this sensitivity case, are shown in Table 8-7.

Table 8-7: Diverse Portfolio CPWC Comparison to IRP Scenarios

	CPWC	Levelized CPWC
	$ million	$/MWh
Current Portfolio	$878	$54.70
Net-Zero Carbon	$870	$54.25
Zero Carbon	$1,263	$79.12
Diverse Portfolio	$919	$57.70

When selecting future resources, REU must consider these increased costs while weighing the diversity risk; however, this sensitivity analysis provides a comprehensive outlook of a more diverse portfolio that can meet REU's portfolio requirements.

8.5 Impacts to Redding

The extensive modeling provided by Ascend allows for better insights when making future resource portfolio decisions. Weighing not just the carbon emissions, but the reliability and affordability of the given resource options is imperative when meeting customer needs over the planning period.

Future System Modifications

In the scenario favored by the stakeholder group, the modeling predicts a decrease in generation from the Plant. Despite this reduction, studies indicate that the Plant will still be dispatched to meet peak customer demands. REU will evaluate the listed mitigations in Phase I of the Transmission System Assessment study to ensure the Plant can run economically and without voltage support limitations and constraints.

After the adoption of the final 2024 IRP, REU's Transmission & Distribution Assets division aims to create an Integrated Distribution Plan (IDP). The goal of the IDP is to assess the Preferred Plan outlined in the IRP, ensuring that the transmission and distribution system can adequately handle the increased load and identifying any necessary measures for mitigation. Moreover, the IDP will present a comprehensive strategy and timeline for the implementation of system upgrades identified in the Preferred Plan.

Retail Rate Impacts

Table 8-8 below illustrates a comparison of energy rates ($/MWh) for each scenario in the year 2045 and the cumulative present worth cost (CPWC) for each scenario. This comparison provides valuable insights into the relative costs of each scenario over the specified timeframe.

Table 8-8: REU Predicted Energy Cost Rates in 2045

	Current Portfolio	Net-Zero Carbon 2045	100% Zero Carbon 2045
Energy Cost in 2023 ($/kWh)	$0.0574	$0.0574	$0.0574
Energy Cost in 2045 ($/kWh)	$0.0765	$0.0866	$0.2079
Energy Cost Change ($/kWh)	$0.0191	$0.0292	$0.1505
Energy Cost Change Compared to Current Rate*	11%	23%	89%

**REU Current Blended Retail Rate is $0.17/kWh*

The energy rate in 2045 provides insights as to how the retail rates would be affected when a scenario is implemented. However, it is essential to recognize that this does not capture the rate changes that may occur throughout the planning horizon. In 2045, under the current portfolio, retail rates are expected to increase by roughly 11 percent. The Net-Zero Carbon 2045 scenario would lead to a more substantial increase of 23 percent, while the 100% Zero Carbon scenario would result in a significant 89 percent rate hike.

Power supply costs make up a substantial portion, roughly 34 percent, of REU's annual budget, shown in Figure 8-20. Given this significant share, it is imperative to keep power supply costs as low as possible to maintain affordable rates for REU customers. Striking a balance between achieving environmental goals and keeping costs in check is a delicate yet critical aspect of ensuring that energy remains accessible and affordable for the community.

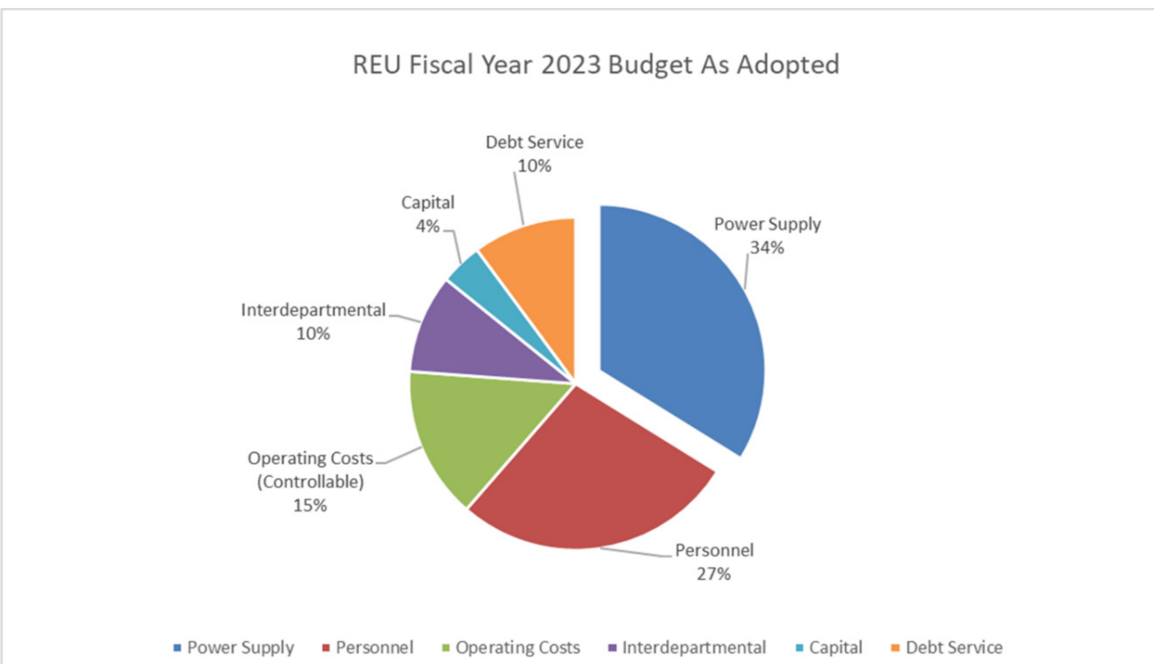


Figure 8-20: REU Fiscal Year 2023 Budget Breakdown

8.6 Conclusion of Evaluation and Results

In conclusion, REU’s IRP update strategy resulted in a comprehensive, all-inclusive process to determine the community's energy future. Through rigorous analysis, stakeholder engagement, and careful consideration of various scenarios, the Net-Zero Carbon 2045 plan has emerged as the Preferred Plan that most closely aligns with REU's goals and objectives.

The Preferred Plan, which meets the compliance requirements while balancing reliability and affordability, is a testament to the Utility's commitment to meeting clean energy targets while ensuring that energy remains accessible to all residents. It not only outlines a strategic roadmap for resource allocation but also emphasizes the importance of adaptability and foresight in navigating the dynamic energy landscape.

The impacts of the IRP are far-reaching and affect nearly every area of the Utility. Beyond the technical aspects of energy planning, they extend to the community, the environment, and long-term sustainability. The chosen plan supports grid reliability and environmental responsibility while also serving as a tool that allows REU to preserve the affordability and accessibility of clean energy for Redding's diverse population.

APPENDIX

9.1 Ascend Analytics Resource Planning Modeling

Ascend PowerSIMM was used to run a variety of models for this resource plan. This section describes the types of models used for the plan.

Production Cost Modeling

The most common application of PowerSIMM in resource planning is as a production cost model, which shows many detailed aspects of system operations over a future time period. Production cost models can run with dispatch modeled across a range of simulated future conditions.

Outputs from production cost models include generation costs, fuel consumption, renewable generation, carbon emissions, and a long list of additional variables used to make investment and operational decisions. Example uses for PowerSIMM include analyzing options to hedge fuel price risk, evaluating new generation resource options, or conducting a study to determine renewable additions for RPS (Renewable Portfolio Standard) mandates.

Production cost model outputs allow users to understand how the system will operate with the assumed inputs. Figure 9-1 shows hourly dispatch results of a production cost model. Comparing outputs from two or more production cost models allows a user to understand how changes in resource mix, price forecast, operational constraints, or other aspects of the system will affect future outcomes.

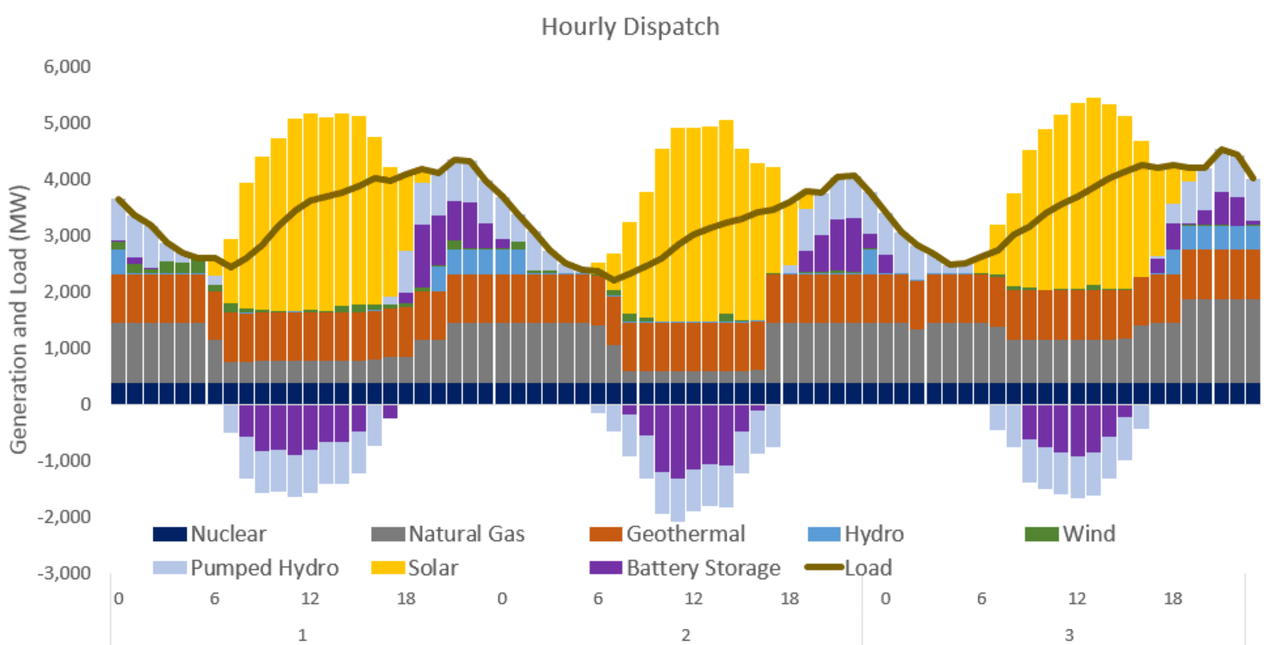


Figure 9-1: Dispatch outputs over a three-day period plotted against load

Key inputs for production cost models include the simulated system conditions[1] and supply resource operating parameters. The operating parameters of dispatchable generation assets in the portfolio—such as ramp rates or start-up times for thermal assets, leakage rates and round-trip efficiencies for battery storage, or spill requirements for hydro—guide dispatch optimization to ensure the model adheres to the actual physical capabilities and attributes of the resources in the portfolio.

Capacity Expansion Optimization

A second common application of PowerSIMM in resource planning is for capacity expansion optimization, which provides the least-cost selection of future resources over time, subject to user-specified constraints. Such constraints may include resource adequacy requirements, annual energy positions, renewable portfolio standards, or carbon emission limits. The Automatic Resource Selection (ARS) module contains the PowerSIMM capacity expansion model. ARS evaluates the performance of a portfolio of existing resources and candidate resources across a range of future operating conditions to assess their likely revenues, costs, and other characteristics (e.g., carbon emissions). Based on the user inputs and constraints, the model determines the optimal resource additions (or retirements) for minimizing total costs while ensuring the generation portfolio can serve load without violating loss-of-load standards or emissions constraints. Figure 9-2 illustrates an ARS model that adds candidate resources to a portfolio to serve load at the lowest cost.

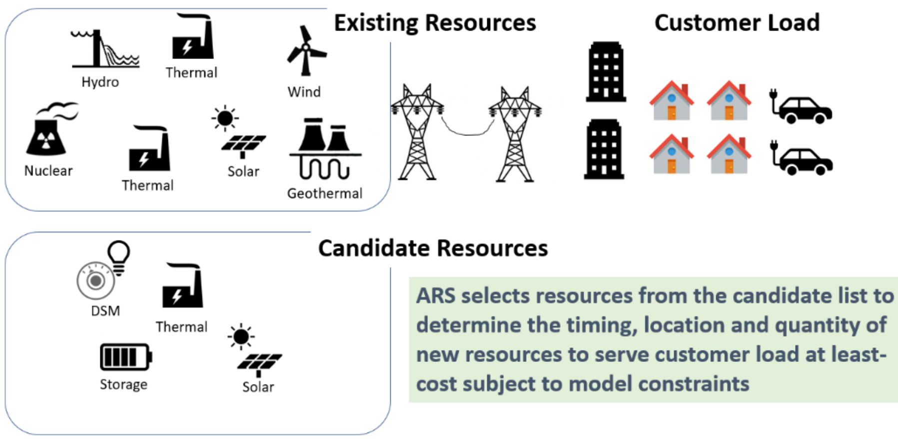


Figure 9-2: ARS Schematic

The portfolio of existing resources and customer load are evaluated with candidate resources across a range of future conditions to select the optimal portfolio composition under input constraints.

The input data requirements for ARS are generally the same as for production cost modeling except for additional project cost information (e.g. new candidate resources), accredited capacity (e.g. existing and new resources), and project specific constraints such as annual build limits for new resources. Users must also define model constraints to apply in the resource selection process, such as requirements for capacity, energy, or renewable generation.

Resource Adequacy Analysis

The third main application of PowerSIMM in resource planning is for resource adequacy analysis, which is used to assess the probability that a system will have adequate generation resources to meet load over a wide range of conditions. Common metrics for this assessment include loss-of-load probabilities (LOLP), expected unserved energy (EUE), and capacity deficit (the amount of additional capacity needed to meet reliability targets), among others. PowerSIMM's resource adequacy module can also be used to assess the capacity contribution from specific resources or technology types, which is typically measured with the effective load-carrying capability (ELCC) metric. As shown in Figure 9-3, PowerSIMM's simulation engine provides simulations of load, renewables, and forced outages used to analyze the ability of a portfolio of resources to serve load. Resource adequacy models may also include transmission constraints.

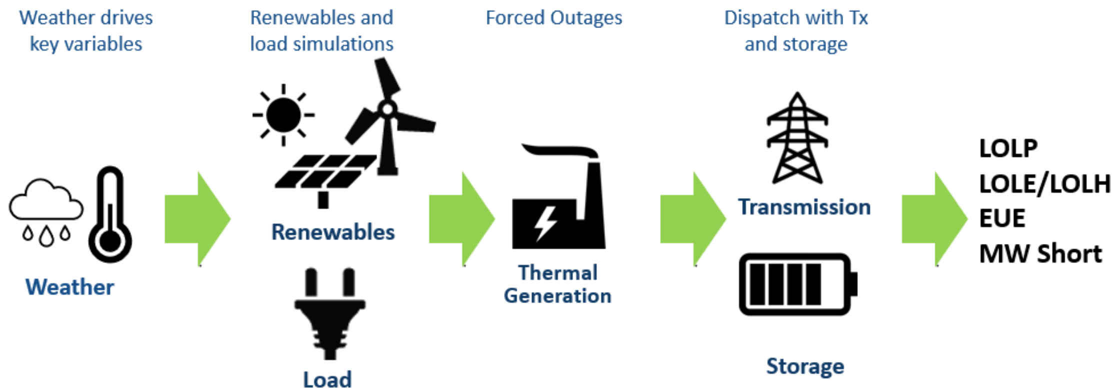


Figure 9-3: PowerSimm Flow Chart

The PowerSIMM resource adequacy model considers weather variability as a key driver to renewable and load simulation. These simulations are coupled with stochastically imposed forced outage in the dispatch module to measure common metrics, including loss-of-load probabilities, expectations, or hours (LOLP, LOLE, or LOLH), expected unserved energy (EUE), and capacity deficit (MW Short).

The dispatch algorithm in a resource adequacy model differs from that used in production cost or capacity expansion models. Resource adequacy models evaluate systems based on how well they can meet system needs, so the ability to import power is typically eliminated (or significantly restricted). The model dispatches resources to minimize load shedding without regard to dispatch cost. Market prices also have no bearing on the dispatch decision in a resource adequacy model. Instead, the important inputs driving resource adequacy results include forced outage rates, correlation between load and renewables, and operational constraints. In each simulated hour of a resource adequacy study, the model calculates hourly load requirements and compares this to the sum of total renewable generation, available thermal capacity (i.e., not on forced or scheduled outage), and available energy in storage (which is charged with excess energy when it is available). The model then dispatches thermal and energy storage resources chronologically (hour-by-hour) to determine how much (if any) load cannot be met in each hour.

Resource adequacy models provide metrics to evaluate the reliability of a system. Additionally, resource adequacy models provide a useful means of determining the capacity contribution of a specific resource, known as the effective load carrying capacity (ELCC). The reliability contribution of the ELCC resource is compared to the reliability contribution from a "perfect" generator to determine the capacity value of the ELCC resource.

Simulation Details

Weather Simulation

PowerSIMM has the ability to simulate weather across dozens of weather variables. Weather simulations in PowerSIMM typically include daily maximum and minimum dry bulb temperatures. These temperatures are then used as fundamental drivers for the load and for alignment with renewable simulations. The weather simulation engine requires historical daily maximum and minimum temperatures from weather stations in proximity to the weather-related resources in the model. PowerSIMM stores historical data for hundreds of weather stations via automated data pulls from the National Climate Data Center. PowerSIMM users select weather stations to create weather zones for use in their specific studies.

PowerSIMM creates weather simulations by decomposing historical daily maximum and minimum temperature data into seasonal and irregular components. The seasonal component represents a smooth function showing how temperature changes over the year. The irregular component captures fluctuations around the seasonal component and represents the day-to-day variability in weather, which is the stochastic part of the weather simulations. The model structure for the irregular component includes 30-day, 60-day, and 90-day moving averages combined in a linear fashion with autoregression and random error terms. Annual patterns drive most of the temperature simulations, but the irregular component of the model allows for deviations from annual and seasonal norms, enabling potential periods of cooler weather in the summer and warmer days in the winter.

PowerSIMM's default method for creating temperature simulations does not use a temperature forecast or include trends in temperature. The result is a set of simulations that resemble historical weather conditions. However, the models can be configured to account for changes in future temperatures to reflect predictions of a changing climate.

The following steps outline the process for creating simulations of daily maximum and minimum temperature:

1. Pull historical weather data – minimum and maximum daily dry bulb temperatures for all selected weather stations.
2. Use an unobserved components model (UCM) to separate temperatures into a seasonal component that captures annual patterns, and an irregular component that captures the uncertainty in temperature data.
3. Apply a transform to the irregular portion of the temperature data to obtain a normally distributed dataset.
4. Fit a Mixed Data Sampling (MIDAS) regression model to the transformed irregular temperature data.
5. Simulate future timeseries for the irregular component of temperatures using the MIDAS model, maintaining the correlations between error terms for each weather station pair.
6. Apply an inverse transformation to the irregular temperature data to bring it back to the original form.
7. Add the seasonal component back into the simulations.

The resulting simulations should reasonably match historical data. Figure 9-4 shows an example of daily max temperature simulations. The stochastic framework captures variations in weather conditions and extreme events. PowerSIMM has the capability to modify the statistical parameters of the temperature distribution to capture extreme events. Ascend runs validations to ensure that simulated temperatures align with historical values at the mean level along with the fifth percentile and ninety-fifth percentile.

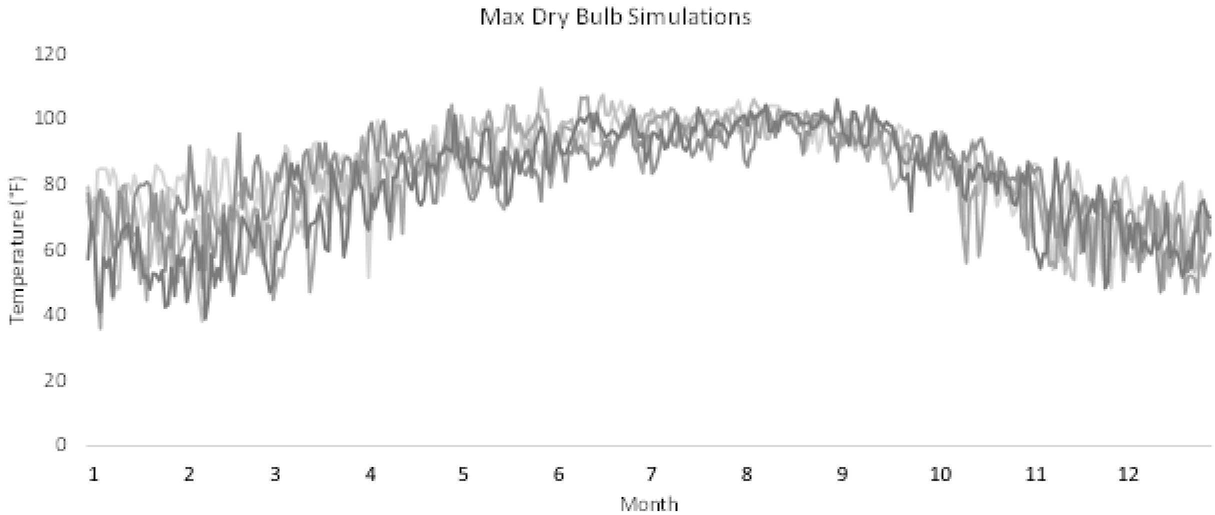


Figure 9-4: Multiple simulations of daily maximum dry bulb temperature across a single year.

Load Simulation

PowerSIMM creates realistic simulations of load that maintain a strong non-linear relationship between load and temperature. The load simulations capture the range of uncertainty exhibited in historical load data. After fitting historical load data to a time series model, PowerSIMM scales the load simulations to match future expectations for energy consumption, peak demand growth, and daily load shapes.

Simulations of load rely on past data to create accurate representation of the utility load that matches historical statistics in the near term while matching the load forecast inputs through the simulation time frame. By scaling load simulations to forecast values, PowerSIMM produces accurate simulations of load that provide a realistic range of future load values around the expected mean. Figure 9-5 shows a time series of multiple load simulations while Figure 9-6 shows the load – temperature relationship maintained in the load simulations.

Load simulations are conducted by using the following steps:

1. Gather historical load data, historic temperature data, and temperature simulations.
2. Perform a log transformation on the historical load data to improve the model fit.
3. Decompose the transformed load data with an unobserved components model into an annual shape, a trend, a cycle, and an irregular component. The decomposed parts will be fit to separate models.
4. Fit a two-component linear regression model to the historical data to determine the break point in the historical load data. The break point is the temperature associated with the lowest load levels where an increase or decrease in temperature results in higher load.
5. The cyclical component of the load data decomposed in the UCM model, found in step 3, is fit to a time series model to determine the effects on load due to the day or week, holidays, temperature (relative to the breakpoint temperature), hour of day, and autoregressive terms. The results provide average hourly load over a variety of conditions.
6. In the load simulations, the output from step 5 provides a method to simulate the cyclical portion of load as a function of the variables estimated in step 5. The cyclical portion is recombined with the annual load trend and shape components determined in step 3 and with a random irregular load component to provide the stochastic nature of the load simulations.
7. An inverse transform applied to the simulations reverses the log transform from step 2.
8. The loads are scaled to match the forecasts input by the user for energy and peak demand.

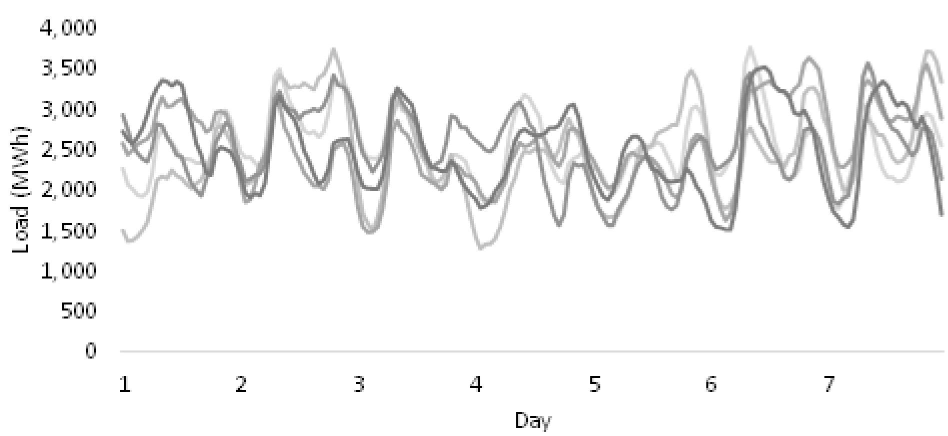


Figure 9-5: Multiple simulations of load over a single week.

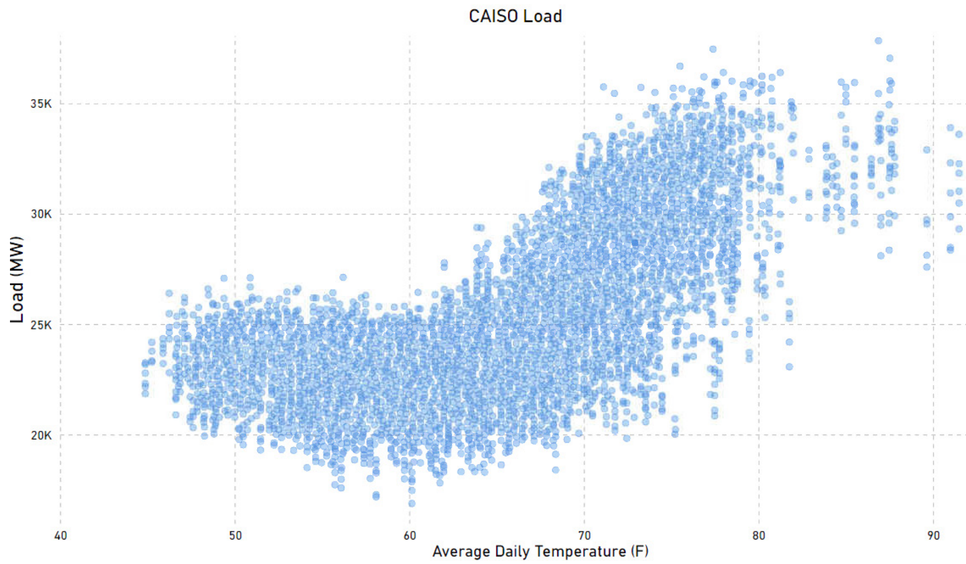


Figure 9-6: Load vs Temperature

Wind and Solar Simulation

PowerSIMM generates simulations of renewables with time series models fit to hourly historical data. Accurate wind and solar generation simulations are an essential part of power system modeling for determining cost of service, loss of load risks, resource valuation, and many other modeling outputs used in utility decision making.

Wind and solar simulation models use a structure that assumes generation is a function of maximum and minimum temperature inputs from the weather simulations. The model also allows structural variables, like time of day and month of year, to affect generation. For example, if generation is typically highest on afternoons in spring, even apart from the influence of temperature, then the model will be able to capture that. Finally, the model includes autoregressive terms to capture the influence of generation in the previous hour to the current hour's generation. In addition to daily temperatures, hour, and month, solar simulations include the solar irradiance calculated at the location of the solar resource. Solar irradiance is a function of the time of day, day of the year, and the longitude and latitude of a project.

PowerSIMM scales monthly wind and solar simulations to match monthly forecasts.

The general simulation process for wind and solar items uses the following steps:

1. Pull historical hourly wind or solar generation and daily minimum and maximum temperature data.
2. Transform the historical generation data by fitting the data to a Beta distribution and mapping to a Normal distribution, resulting in a well-behaved dataset.
3. Fit the transformed data to the time series model.
4. Simulate future wind or solar generation with the temperature simulations used as inputs to the simulations.
5. Perform an inverse transformation on the simulated data to bring it back to the original form of generation.
6. Scale the simulated generation time series so that it matches forecasts on average. For example, the average of all simulations will match the forecast values for energy and expected peak generation. Simulated values will also be kept at or below the input nameplate capacity.
7. For sub-hourly studies, expand hourly simulations with interpolation and added noise at the sub-hourly level.

Realistic simulations of variable renewable energy generation lead to accurate analysis of the value of renewable assets and the effect of renewables in production cost studies, resource adequacy, or capacity expansion. Figure 9-7 and Figure 9-8 provide examples of solar and wind simulations over a week.

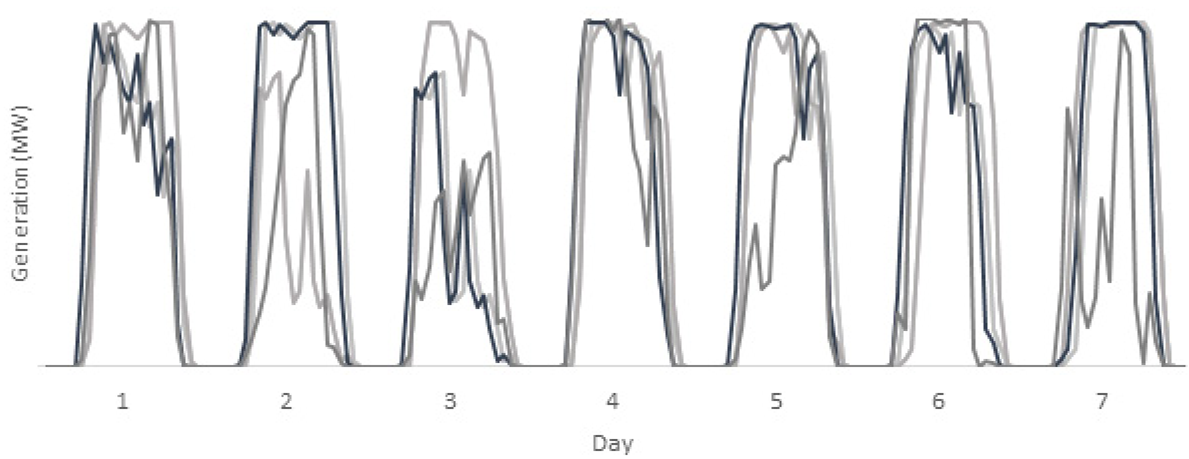


Figure 9-7: Multiple simulations of solar generation over a single week.

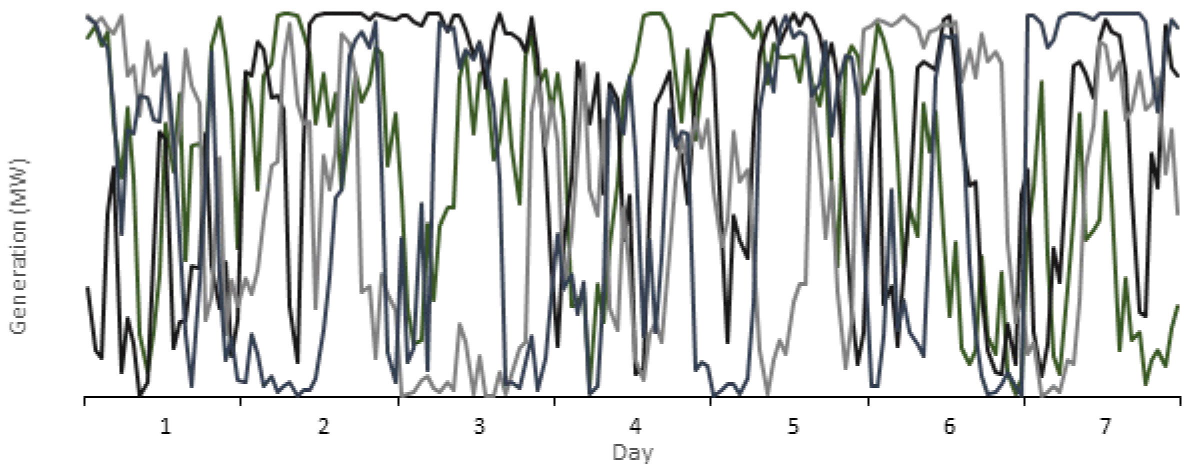


Figure 9-8: Multiple simulations of wind generation over a single week.

Small Hydro Simulation

PowerSIMM models small hydro resources as run-of-the-river hydro. Dispatchable hydro resources are set up as a hydro project in PowerSIMM. Like other variable renewable resources in PowerSIMM, hydro simulations use a time series model fit to historical hourly generation data. The outcome is a set of simulations that capture the full range of potential hydro generation to provide accurate results for utility decision making.

While the structural details of the hydro simulation model differ from the wind and solar simulation models, the general inputs are similar. Hydro simulation models also assume generation is a function of maximum and minimum temperature inputs from the weather simulations. Like wind and solar simulations, the model used for hydro simulations also allows structural variables, like time of day and month of year, to affect the generation. The hydro model also includes autocorrelation terms.

Hydro simulations are scaled to match future expectations for monthly generation and capacity. PowerSIMM ensures that average monthly hydro simulations match the hydro forecast values. Figure 9-9 shows hydro simulations over a one-week period.

The general simulation process for hydro items uses the following steps:

1. Pull historical hourly hydro generation and daily minimum and maximum temperature data.
2. Transform the historical generation data by fitting the data to a Beta distribution and mapping the Beta CDF (Cumulative Distribution Function) to a Normal CDF, resulting in a well-behaved dataset.
3. Fit the transformed data to the time series model.
4. Simulate future hydro generation with the temperature simulations used as inputs for hydro generation.
5. Perform an inverse transformation on the simulated data to bring it back to the original form of generation.
6. Scale the simulated generation time series so that it matches forecasts on average. For example, if the model uses 100 simulations, the average of all simulations will match the forecast values for energy and expected peak generation. Simulated values will also be kept at or below the input nameplate capacity.
7. For sub-hourly studies, expand hourly simulations with interpolation and added noise at the sub-hourly level.

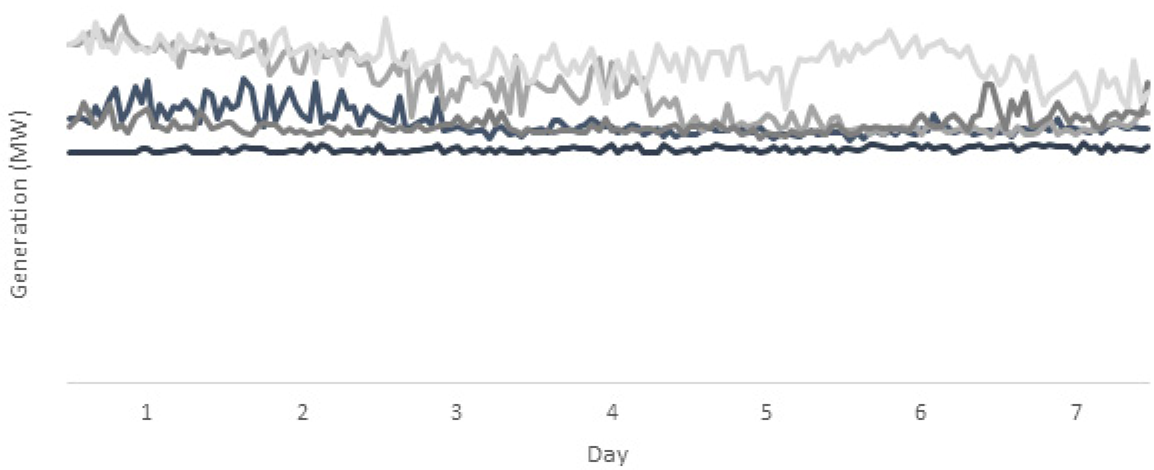


Figure 9-9: Multiple simulations of hydro generation over a single week.

Forward Price Simulation

PowerSIMM simulates forward curves using a stochastic model with parameters derived from recent historical transaction dates and defined user inputs (as applicable). PowerSIMM constructs a system of equations for forward contracts that includes the stochastic component of the forward price, as well as the correlation with neighboring contract months, and other commodities. This framework produces price simulations that are realistic, benchmark well to historical data, and produce a payoff of cash flows consistent with market option quotes at multiple strike prices.

Forward contract prices are modeled with an autoregression, or AR, model with volatilities and correlations maintained in accordance with historical data or with inputs provided in the forward price constraints. PowerSIMM uses an AR lag of one while limiting the coefficient to a value of less than 1. An AR coefficient less than 1 is equivalent to a Geometric Brownian Motion (GBM) model with mean reversion. Thus, the forward prices tend to do a random walk with a constant pull back to the monthly mean values.

Forward simulations are conducted by using the following steps:

1. Calculate the log prices of all historical data.
2. Calculate a target covariance matrix between contracts using historical log price data.
3. Apply any user-input correlation constraints to calculated target covariance matrix (internally stored as a correlation matrix and vector of variances). Correlation constraints in the model force the forward simulations to maintain expected correlations between forward prices for gas, on/off peak power, coal, carbon, and other commodity prices in the model.
4. Fit a time series model with autoregression and moving average terms to the historical log price data (from step 1) while respecting any autoregression or moving average restrictions input by the user. PowerSIMM uses separate models for each commodity (natural gas, on-peak power, off-peak power, coal, etc.).
5. Set the target covariance matrix as the initial residual covariance matrix.
6. Iterate the following steps to construct the forward price simulations while meeting the correlation inputs:
   a) Simulate future forward contract log prices using the autoregressive terms, moving average, and intercept parameters fit above and the current residual covariance matrix. The error terms in these simulations are drawn from a normal distribution, with correlations and variances specified by the residual covariance matrix.
   b) Calculate correlation and variance of simulated price paths.
   c) Adjust current residual covariance matrix based on the difference between:
      i) Simulated correlation and target correlation
      ii) Simulated variances and target variances
   d) Adjust residual covariance matrix to ensure it is positive semi-definite.
7. Calculate volatility of the simulated price paths.
8. Adjust daily log returns of simulated price paths to enforce any volatility constraints.
9. Scale the average of simulated prices to input forecast if indicated by user (those are usually forecasted based on market fundamentals). The mean across all simulations equals to the input forecast.

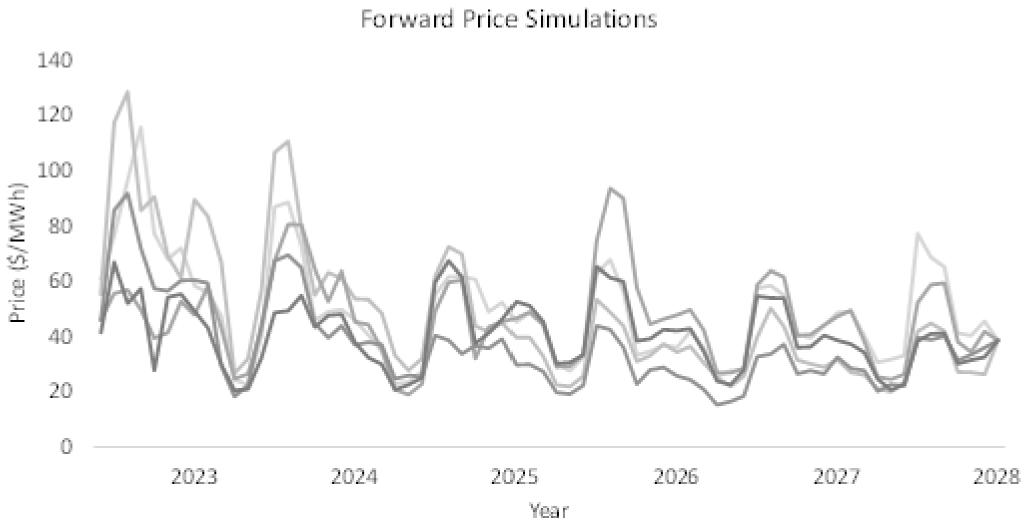


Figure 9-10: Multiple simulations of forward prices.

Spot Price Simulation

PowerSIMM simulates spot prices beginning with the market expectations of monthly blocks of energy represented as the average forward or forecast price over the monthly block. Following the forward price simulations, spot prices are simulated with a hybrid approach that captures the uncertainty in price risk in power markets and trading hubs, including variability in weather, load, renewable output, congestion risk, and LMPs (Locational Marginal Prices), while maintaining consistency with forward price simulations. A sample of hourly spot price simulations are shown in Figure 9-11 over the course of a week.

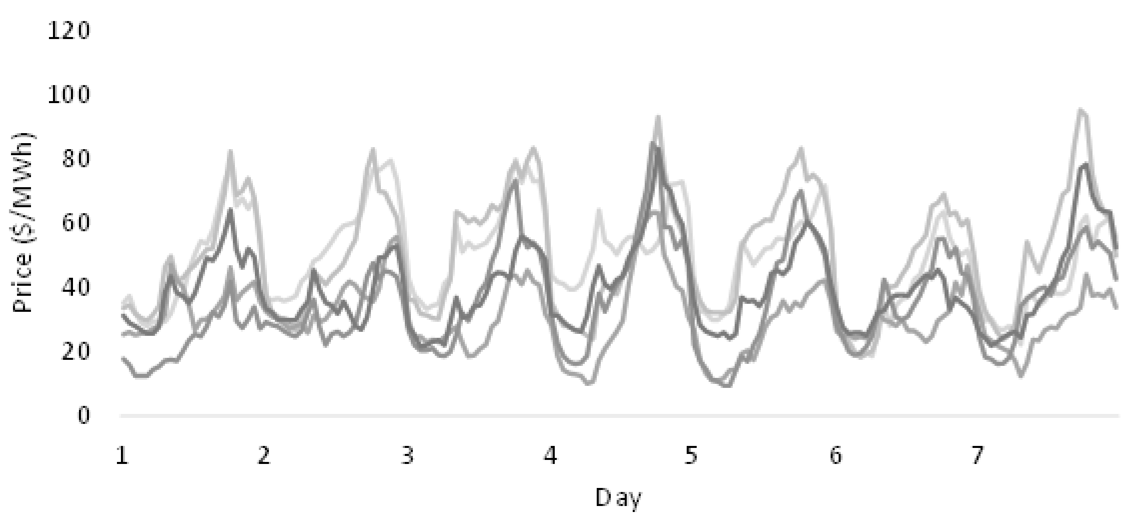


Figure 9-11: Simulations for spot prices over a single week

Basis Price Simulation

Basis price items in PowerSIMM allow for models to contain multiple pricing nodes. The main market configuration in PowerSIMM must select a primary forward price and spot price for use in the price simulations. PowerSIMM derives basis prices as “structural” (regression-based model) or “basic” (random noise) items from the main spot price configured in the model. Basis prices are an important feature of PowerSIMM because they allow for market interactions and simulate locational marginal prices of different nodes.

Scalars applied in the Basis model allow users to set up expected deviations in prices between the basis price (node) and the reference spot price (hub). Users may set up scalars as a constant value across all hours or as random variables where the parameters are a function of time. The Basis module can also be used to produce sub-hourly simulations and ancillary services prices.

Basic model simulations can be broken down into the following steps:

1. Generate a time series of values, drawn from a user defined distribution (such as normal distribution, lognormal, triangular, etc.) with autoregressive and moving average terms included based on the input configuration for that basis.
2. Scale resulting values using input scalers, most often fundamental basis projections
3. Add values from step 2 to reference price to produce final basis price.
4. Output simulated prices to the database.

Structural model simulations can be broken down into the following steps:

1. Gather historical basis price data and simulated and historical main market gas and power price.
2. Transform the historical price data (typically using a power transformation, though log, beta and arcsinh transformations are also available).
3. Fit a daily model to the historical basis price data.
4. For hourly electric basis prices, fit an hourly model to the residuals of the daily basis price model.
5. Simulate daily basis prices and hourly price residuals and sum the hourly residuals to the daily prices to obtain simulated hourly basis prices.
6. Scale prices to the forward curve, which represents the price forecast for the basis node. Recall that scaling a price to a forward curve means the average monthly prices will match the forward prices, while some simulations will be higher, and some will be lower.
7. Summarize to monthly peak period values.
8. Output simulated values to the database.

9.2 Study Summaries

Transmission System Assessment (SMUD)

Executive Summary – Phase 1 Study

This REU Transmission System Assessment (TSA) evaluated and identified the system limitations in the REU system to serve the 1-in-10 year load forecast, year 2032 load with the Redding Power Plant out of service.

Steady State Analysis

Thermal Violations:

- For P0, P1, P2, P3, P4, P5 and P7 contingencies - There are no thermal violations.
- For P6 contingencies (before allowable system adjustments) - There are multiple thermal violations. Per TPL-001-4, system adjustments are allowed between consecutive outages in a P6 contingency.

System Voltage Limits Exceedances:

- For P0, P5 and P7 contingencies - There are no voltage violations.
- For P1 contingencies – The East Redding-Canby 115 kV line outage caused two low bus voltage exceedances at the Canby 115 kV bus (0.9412 per unit) and Sulphur Creek 115 kV bus (0.9448 per unit).
- For P2 contingencies – The East Redding 115 kV bus fault (or equivalent breaker fault) caused the same low bus voltage exceedances at the Canby 115 kV bus (0.9420 per unit) and Sulphur Creek 115 kV bus (0.9458 per unit).
- For P3 contingencies (before allowable system adjustments) – The same low bus voltage exceedances at the Canby 115 kV bus (0.9412 per unit) and Sulphur Creek 115 kV bus (0.9449 per unit). Per TPL-001-4, system adjustments are allowed between consecutive outages in a P3 contingency.
- For P4 contingencies – The same low bus voltage exceedances at the Canby 115 kV bus (0.9409 per unit) and Sulphur Creek 115 kV bus (0.9447 per unit).
- For P6 contingencies (before allowable system adjustments) – There are multiple low bus voltage exceedances. Per TPL-001-4, system adjustments are allowed between consecutive outages in a P6 contingency.

The identified emergency voltage exceedances were based on the REU's current voltage limit of 0.948 per unit post contingencies. If REU lower the emergency low voltage limit to 0.923 per unit according to REU comments received during reviewing the draft TSA report, the emergency system voltage exceedances identified for P1-P4 contingencies would be mitigated. However, even with the revised emergency low voltage limit of 0.923 per unit, the P6 contingencies would still cause low voltage exceedance problem. The allowable system adjustment between consecutive outages may mitigate the emergency low voltage exceedances.

Voltage Deviation Exceedances:

- For P1 contingencies - There are no voltage deviation violations. P2-P7 contingencies are not applicable.

Voltage Stability Analysis

REU's total system load was increased by 5% for P1 contingencies and 2.5% for P7 contingencies. All of REU's P1 contingencies' cases were solved with the 5% increased load. In addition, all of REU's applicable P7 contingency cases were solved with the 2.5% increased load. Results indicated that REU's transmission system still maintains a reasonable reactive margin with the Redding Power Plant out of service to serve year 2032 forecast load.

Q-V margin analyses were conducted based on the worst P1 and P7 contingencies for the 5% and 2.5% increased load base cases. With the worst P1, East Redding-Canby 115 kV line outage, results concluded that there are 85 MVAr of reactive margin at the Canby 115 kV bus and 96 MVAr of reactive margin at the Sulphur Creek 115 kV bus. With the worst P7, Moore-Airport and Redding Power-Moore 115 kV line outage, results concluded that there are 130 MVAr of reactive margin at the Redding Power Plant 115 kV bus.

Dynamic Stability Analysis

Dynamic Stability analyses were performed for P1 and P7 contingencies and stability plots indicated that REU's transmission system remains stable and positively damped.

System Study Summary

In summary, to serve REU's year 2032 forecast load of 253.73 MW with the Redding Power Plant out of service, study results concluded that the REU's transmission system experienced low voltage exceedance problems at the Canby 115 kV bus and the Sulphur Creek 115 kV bus following various contingencies based on the REU's current emergency low voltage limit of 0.948 per unit. Therefore, REU is not able to serve its year 2032 forecast load reliably and meet the REU current emergency low voltage limit.

If REU's emergency low voltage limit would be lowered to 0.923 per unit, the identified low voltage exceedances caused by P1-P4 contingencies would be mitigated, and REU would be able to serve its year 2032 forecast load. It is assumed that allowable system adjustment between consecutive outages may mitigate the emergency low voltage exceedances caused by P6 contingencies.

Mitigations are not being evaluated in this study and it is recommended that REU explores possible mitigation options. Mitigation options may include various combinations of, but not limited to, the following:

- Install reactive support device (capacitors);
- Convert the existing Redding Power Plant into synchronous condenser;
- Install solar and/or battery systems; and
- Possibly increase import capability (add additional transmission ties).

Executive Summary – Phase 2 Study

The Redding Electric Utility (REU) Transmission System Assessment (TSA)[1] Phase II evaluated, identified system limitations, and provided possible mitigations. The proposed mitigations will enable REU's transmission system to have approximately 350 MVA import capability to serve the future year load of 341.53 MW (388.97 includes Shasta and Knauf load) without violations following Categories P1-P7 contingencies of the NERC Reliability Standard TPL-001-4.

REU system load was uninformly increased until an import level of 350 MVA was reached. In addition to the load increased, the REU's new Future South Business Park 115 kV substation was modeled via looping in the East Redding-Airport 115 kV Line #2. Due to to the high level of import and not allowing load dropping for P3 or P6 outages, REU's system reinforcements are necessary to mitigate criteria violations specified within the NERC Reliability Standard TPL-001-4.

System Reinforcements

The proposed system reinforcements or mitigations are as follows based on the results of this study:

1. Convert the Redding Power Plant generator into synchronous condenser for voltage support.
2. Loop-in the WAPA's Keswick-Olinda 230 kV Line into the Redding Power Plant (Redding Substation) 115 kV substation as new tie lines for voltage support and eliminating identified thermal overloads.
3. Re-rate or replace the Airport 230/115 kV Banks with 140 MVA rating or higher to mitigate identified thermal overloads.
4. Re-rate or replace the Keswick 230/115 kV Bank #1 with 110 MVA rating or higher to mitigate identified thermal overload.
5. Add a 2nd Moore-Redding 115 kV Line for voltage support.
6. Add a 2nd Texas Spring-Redding 115 kV Line for voltage support.
7. Loop-in the East Reading-Airport 115 kV Line #1 into the Future South Business Park substation for voltage support.
8. Add 35 MVAr of shunt capacitors at Canby 115 kV substation for voltage support.

With reinforcements of 1-2, there are several thermal violations and low voltage violations. The facilities with highest thermal violations are for various P6 contingencies are:

- Oregon-Waltond 115 kV Line at 101.8%
- Airport 230/115 kV Bank #1 at 108.46%
- Aiport 230/115 kV Bank #2 at 108.46%

- Keswick 230/115 kV Bank #1 at 109.66%.

For emergency low voltage violations, there many bus voltages lower than the emergency low voltage limit of 0.923 per unit. Hence, system reinforcements 3-8 are needed also to mitigate emergency thermal violations and emergency low voltage violations identified above. are as followings based on the TSA:

System Enforcment Steady State Analysis Results

Thermal Violations:

- For P0, P1, P2, P3, P4, P5, P6 and P7 contingencies – There are no thermal violations.

System Voltage Limits Exceedances:

- For P0 - There is no voltage violation.
- For P1-P7 contingencies – There are no emergency low bus voltage exceedances.

Voltage Deviation Exceedances:

- For P1 contingencies - There are no voltage deviation violations.

Voltage Stability Analysis

REU’s total system load of 388.97 MW (341.53 MW without Shasta Lake and Knauf) was increased by 5% for P1 contingencies and 2.5% for P7 contingencies. All of REU’s P1 contingencies’ cases were solved with the 5% increased load. In addition, all of REU’s applicable P7 contingencies’cases were solved with the 2.5% increased load. The TSA results indicated that REU’s transmission system has adequate reactive margin. Table 9-1 below summarizes the system reactive power available due to applicable worst P1 and P7 contingencies.

Q-V margin analyses were conducted based on the worst P1 and P7 contingencies for the 5% and 2.5% increased load base cases. With the worst P1, East Redding-Canby 115 kV line outage, results concluded that there are 40 MVAr of reactive margin at the Canby 115 kV bus and 45 MVAr of reactive margin at the Sulphur Creek 115 kV bus. With the worst P7, Airport-FSBP 115 kV double line outages, results concluded that there are 70 MVAr of reactive margin at Canby 115 kV bus, 73 MVAr at FSBP 115 kV bus, and 83 MVAr of reactive margin at Sulphur Creek 115 kV bus.

Table 9-1: Summary of Reactive Margin

NERC Cat.	Contingency	Bus Monitored	MVAr Margin
P1	East Redding-Canby 115 kV Line	Canby 115 kV	40
		Sulphur 115 kV	45
P7	Airport-FSBP 115 kV Double Lines	Canby 115 kV	70
		Sulphur 115 kV	73
		FSBP 115 kV	83

Dynamic Stability Analysis

Dynamic Stability analyses were performed for P1 and P7 contingencies and stability plots indicated that REU's transmission system remains stable and positively damped.

Summary

With the above proposed system reinforcements, the TSA study results indicated no thermal violations for REU to serve the future load future year load of 341.53 MW (388.97 includes Shasta and Knauf load) with import level of 350 MVA. REU's transmission bus voltages are greater than the emergency low voltage limit of 0.923 per unit following P1-P7 contingencies. In addition, no voltage stability and dynamic stability issues.

Customer Survey (GreatBlue)

Executive Summary

GreatBlue Research was commissioned by the City of Redding Electric Utility (hereinafter "Redding" or "REU") to conduct market research to understand their customers' perceptions of electric resource planning for the future.

The primary goals for this research study were to assess customer sentiments and interest in sustainability and meeting or exceeding clean energy targets and mandates; electric vehicle technology, incentives, customer programs, and charging infrastructure' building electrification measures, electrification benefits, and customer programs; and various types of rate structures.

In order to service these research goals, GreatBlue employed telephone and digital survey methodologies from February 7, 2022, through March 28, 2022, to capture the opinions of residential customers and commercial customers of REU. In total, GreatBlue Research received a total of 641 completed residential customer surveys via digital methodology and 102 completed commercial customer surveys (62 via phone and 40 via digital).

The outcome of this research will enable REU to better understand customer sentiments and interest in various electricity resources, prioritize the potential implementation for those identified resources, and enhance strategic planning to incorporate those resources into REU's Integrated Resource Plans and future customer program offerings.

The REU Ratepayer Survey on electric resource planning leveraged a quantitative research methodology to address the following areas of investigation:

- Level of concern regarding climate change
- Behavioral changes made to reduce energy consumption and likelihood of future behavior modification
- Interest and participation in REU programs
- Interest in, and current usage of, electric vehicles and charging infrastructure

- Awareness, interest, and implementation of building electrification measures
- Interest in various types of utility rate structures and demand response methods
- Preferred methods of communication with REU
- Demographic and firmographic profiles of respondents

Key findings from the study:

Overall, residential customers, particularly low-income (defined as earning $75,000 or less), have a great concern for climate change within the next five years and would consider paying more to exceed goals (100% clean energy). Conversely, despite commercial customers being concerned about climate change over the next ten years, most care about affordability and do not want to pay more to exceed goals.

Electrification Forecast (Dunsky)

Executive Summary

Introduction

This report presents the findings of the Redding Electric Utility (REU) Building and Transportation Electrification Study, which forecasts uptake of key electrified building and transportation technologies in Redding, California over the 2023-2045 study period.

This study provides inputs to the REU 2024-2045 Integrated Resource Plan (IRP). Specifically, the research objectives were to:

- Forecast service territory-wide adoption of electrified technologies to support REU's long-term planning efforts
- Consider service territory-wide load impacts of Electric Vehicle (EV) adoption, including annual energy and demand and hourly impacts for a select number of peak and off-peak days
- Provide results that will integrate with other REU forecasts for the purpose of resource and distribution planning

In addition to these objectives, this work can support future program planning initiatives. High potential program opportunities are highlighted throughout.

Methodology

Market data

The study scope did not include any primary data collection. Market inputs, including baseline building and equipment characteristics, are sourced from existing datasets. The building and vehicle market characterization leveraged the County Metric Database owned and managed by Tierra Resource Consulting (Tierra). The County Metric database is a compilation of publicly available data from Federal, State, and County data sets. Wherever possible, Redding-specific market data is used in the study. When Redding-specific data is not available, county, state, or federal-level data is scaled to Redding's population.

Building Electrification Projections

Building electrification is assessed using Dunsky's Heating Electrification Adoption (HEAT) model. Building electrification is modeled under three scenarios: Low, Mid, and High. Key factors expected to influence adoption are varied among the scenarios: natural gas rates, equipment cost declines, equipment performance improvements, incentive programs, and building regulations.

Transportation Electrification Projections

Transportation electrification is assessed using Dunsky's Electric Vehicle Adoption (EVA) model. Transportation electrification is modeled under two scenarios: Low and High. A third scenario assesses the grid impacts of the High scenario should a managed charging program be established as part of the Grid Impacts of Transportation Electrification component of the study. Key factors expected to influence adoption are varied among the scenarios: fuel (gas and diesel) prices, electric vehicle cost declines, vehicle charging installations, vehicle model availability, and regulation.

Grid Impacts of Transportation Electrification Projections

Annual electricity consumption (GWh) is modeled using the transportation electrification projections developed as part of the study, and using assumptions around vehicle-specific typical driving distances, vehicle efficiencies, and local climate. Annual peak demand (MW) is defined as the incremental demand from EVs at the time of the forecasted system peak. Annual peak demand is calculated using hourly load impacts for each type of EV modeled in this study, and for each type of charging (e.g. home, workplace, commercial fleet, public level 2, and public DCFC). In addition to annual energy and demand impacts from EVs, 24-hour system-wide EV load impacts are assessed for four representative days under each scenario: peak summer day, off-peak summer day, peak winter day, and off-peak winter day. All grid impacts are modeled at the service territory-wide level.

Results

By 2045, up to 24,700 additional units of space heating heat pumps, 11,400 additional units of electrified water heating equipment, and 37,000 additional units of electrified cooking equipment could be seen in Redding. Although variations in near-term market conditions and incentive programs will impact uptake to some degree, regulations will have the greatest influence over adoption levels. Should they be enacted, all-electric new construction codes have the ability to electrify new building stocks while gas appliance bans have the ability to electrify all building types – new and existing.

By 2045, up to 61,000 additional electrified light-duty vehicles and up to 6,400 additional electrified medium-duty vehicles, heavy-duty vehicles, and buses may be adopted. As with the building sector, uptake of EVs will be most influenced by regulation. California's light-duty ZEV sales target will require 100% of light-duty vehicles sold in the state to be zero-emission vehicles from 2035 onwards, while other regulations will require zero-emission vehicle adoption by public MDV and HDV fleets and transit buses. By 2045, EV charging could consume up to 490 additional GWh annually and increase demand at the time of current peaks by up to 87 MW.

Conclusions

Across all end uses, uptake of electrified technologies will present new revenue streams for REU by increasing energy sales. Although regulation alone could drive considerable adoption of these technologies over the study period, the utility can also support adoption – especially in early years – through programming efforts. The utility also has an important role to play in managing emerging loads from electrification, which have the potential to drive considerable increases in peak capacity requirements. Demand management programs targeting thermostats, water heaters, and EV smart chargers can limit increased peak capacity needs and maximize benefits to the utility and its customers.

In the future, more granular geographic assessment of technology uptake and location-specific load impacts will provide insight into how the utility can best prepare for electrification.

9.3 Demand-Side Management IRP (DSM-IRP)

Executive Summary

This report documents the City of Redding Electric Utility Department's (REU) "Demand-Side Management Integrated Resource Plan" (DSM-IRP). The DSM-IRP uses a process similar to Redding's integrated resource planning process but is focused on Demand-Side (behind the meter) resources rather than supply-side resources. The DSM-IRP process helps support REU's mission of providing reliable, cost-effective service by identifying an optimal Demand-Side Management plan that achieves regulatory requirements, community and customer needs, and system reliability.

1.1 DSM-IRP PROCESS AND RECOMMENDATION

The DSM-IRP followed a five-step process described below.

1.1.1 Step 1: Develop Guiding Principles

In Step 1, staff reviewed all funding requirements, relevant statutes and regulations, community feedback, and City Council determinations from the IRP and the NEM 2.0 committee. Based on this information, REU staff developed a set of principles to guide the planning process. These principles are as follows:

- Offer measures where program participants save money
- Ensure customer programs do not cause transfers of funds from participants to non-participants
- Focus on programs that cost-effectively reduce carbon emissions

1.1.2 Step 2: Identify Key Assumptions and Cost-Effectiveness Tests

In Step 2, staff reviewed the industry cost-effectiveness tests and selected the tests that would best reflect the guiding principles. The primary tests evaluated are as follows:

- Total Resource Cost Test (TRC, $): The TRC is the primary cost test used in the evaluation of energy efficiency programs across the nation and within California. The TRC compares the lifecycle avoided utility cost to the installed cost of an energy efficiency measure. The shortcoming of the TRC test is that measures identified by this test as being cost-effective tend to provide upward rate pressure, thereby creating a fund transfer from non-participants to participants. The TRC does not yield results that align with the guiding principles identified in Step 1 and is not used in this analysis.
- Utility Cost Test (UCT, $): The UCT compares the lifecycle avoided utility cost to the utility rebates and program overhead of a measure. Like TRC, the shortcoming of the UCT test is that "cost-effective" measures tend to provide upward rate pressure, thereby creating a fund transfer from non-participants to participants. The UCT does not yield results that align with the guiding principles identified in Step 1 and is not used in this analysis.
- Ratepayer Impact Measure (RIM, $): The RIM test calculates the utility lifecycle net revenue impacts of a measure. A measure that passes the RIM test provides downward rate pressure

and can help identify measures that align with the guiding principles because it provides benefits to both program participants and non-participants.

- Participant Cost Test (PCT, $): The PCT calculates net measure benefits to a customer over the lifecycle of the measure. A measure that passes the PCT test is cost-effective for a customer and can help identify measures that align with the guiding principles.
- Carbon Impact Cost Test (CIT, $/Metric Ton of GHG emissions reduction): The CIT, a City of Redding specific metric, is the ratio of lifecycle rate impacts of a measure to the lifecycle GHG emissions reduction of that measure. The CIT helps identify measures that help cost-effectively reduce carbon emissions. Note that measures with a positive CIT save carbon while providing downward rate pressure.

The three cost-effectiveness tests used in this analysis are the RIM (ensures that non-participants are not negatively affected), the PCT (ensures that participants are not negatively affected), and the CIT (quantifies cost-effectiveness relative to emissions reduction). The components that are included in each cost-effectiveness measure are shown in Table 9-2, where the three metrics that align with the guiding principles are highlighted in blue.

Table 9-2: Summary of Cost-Effectiveness Components for Each Measure Test

Test Component	PCT, $	UCT, $	RIM, $	TRC, $	CIT, $/MT GHG
GHG Emissions Reduction					X
Electric Energy and Capacity Avoided Costs		X	X	X	X
Other Fuel Savings (natural gas, fuel oil, propane, etc.)				X	
Non-Energy Benefits (e.g., water, O&M costs, etc.)				X	
Environmental and Health Benefits					
Incremental Costs for Measure and Installation	X			X	
Program Administrator Overhead Costs		X	X	X	X
Incentive Payments Paid by Utility	X	X	X		X
Customer Bill Impact	X				
Utility Revenue Impact			X		X

1.1.3 Step 3: Identify and Characterize Measure Options

In Step 3, staff defined detailed characteristics of each measure, including measure cost, useful life, electricity impacts, fossil fuel impacts, and many others. This information was used to model the impacts and calculate the cost-effectiveness metrics in Step 4.

1.1.4 Step 4: Perform Detailed Analysis

In Step 4, REU staff analyzed hundreds of different measures, including energy efficiency measures, building electrification measures, and transportation electrification measures. The results of this analysis are shown in Table 9-3, which quantifies the performance of past and future programs using the cost tests shown in Table 9-2. Past programs are based on FY 2019 actual results, and future programs are based on measures expected to be installed in FY 2023-2027.

Table 9-3: Program Performance of FY 2019 EE Programs (Historic) vs. Future BE and TE Programs

Program	PCT, $	RIM, $	CIT (RIM/GHG Reduction, $/Ton)	Program Cost, $	Lifecycle Net Revenue Impacts, $	Lifecycle Carbon Savings, Tons
Energy Efficiency Rebates (FY19)	$4,090,000	($4,540,000)	($540)	$950,000	($3,590,000)	8,330
Shade Trees (FY19)	$160,000	($180,000)	($760)	$80,000	($110,000)	240
Low Income Direct Install (FY19)	$460,000	($690,000)	($560)	$500,000	($180,000)	1,230
Residential Energy Discount (FY19)	$2,930,000	($3,010,000)	N/A	$3,010,000	$0	0
Public Streetlights (FY19)	$0	($110,000)	($230)	$210,000	$90,000	500
Building Electrification	$6,860,000	$1,560,000	$70	$1,970,000	$3,530,000	20,780
Transportation Electrification	$1,280,000	$500,000	$110	$500,000	$970,000	7,610

Based on the information in Table 9-3, REU staff found the following:

- All energy efficiency measures and rate assistance fail the RIM test, indicating that these measures create a transfer of funds from non-participants to participants through increased rates.
- Energy efficiency measures are not a cost-effective way to reduce carbon since they are 10-40x more expensive than the current carbon credit allowance price.
- Energy efficiency measures are cost-effective for the customers who participate in the energy efficiency programs, as indicated by a positive participant cost test.
- Building Electrification Measures pass the RIM test, indicating that they will provide downward rate pressure.
- Electrification measures are a cost-effective way to reduce carbon emissions in that they save carbon and provide downward rate pressure. Furthermore, electrification programs are the only programs that create a positive return on the investment of Public Benefits funds.

- Due to Redding's relatively low electric rates and PG&E's relatively high natural gas rates, many customers can save money by switching from existing natural gas space heating and water heating to heat pump space and water heaters.

1.1.5 Step 5: Develop a Recommended Program Plan

Building on the findings of this study, staff recommends ending the current suite of energy efficiency programs, and transitioning to building electrification and transportation electrification programs. To ensure success of the new programs, staff recommends a phased approach that will allow time for all stakeholders to transition from our current EE Portfolio to a new building electrification program. This allows for adjustments to be made as new measures are introduced and allows time for participants and non-participants to become familiar with the new programs. The phased approach includes:

- Introducing the lowest-risk, most cost-effective measures first
- Developing a robust education and outreach program to ensure that all stakeholders have a positive experience
- Ensuring customer satisfaction is tied to the success of the program
- Add new measures as technologies improve and/or participation increases
- Incorporating lessons learned into a continuous program improvement process

Using this phase approach, REU plans to initially offer rebates for the following measures:

- Commercial and Residential Electric Vehicles
- Electric Forklift Rebates
- Low Income Residential Electric Vehicle Rebates
- Residential and Commercial Heat Pump Water Heaters Replacing Natural Gas Water Heaters
- Electric New Home Construction
- Custom Community Projects

REU has identified a budgeted need $2,795,000 between FY 2023-2027. However, REU has identified budget of nearly $7,000,000 for the next 10 years. As these programs mature, building codes change and REU responds to community needs, more programs and measures will be developed and the remaining budget will be allocated. Future measures that may be considered as programs mature include but are not limited to the following:

- Res. and Comm. Heat Pump Space Heaters
- Panel Upgrades
- Induction Cooktops
- Residential and Commercial EV Chargers

9.4 Renewables Portfolio Standard Procurement and Enforcement Plan

<table>
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6</td><td>Approval Date:
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<tr><td colspan="3">Document Owner: Lisa Casner</td></tr>
<tr><td colspan="4">REDDING ELECTRIC UTILITY
Resources Division

RPS-001 Renewables Portfolio Standard Enforcement Program and Procurement Plan</td></tr>
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Lisa Casner (Electric Manager – Resources), Nicholas Zettel (Electric Utility Director)</td></tr>
<tr><td colspan="3">Adopted By: Redding City Council

Date: March 21, 2023</td></tr>
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1. Introduction

Senate Bill 2 in the First Extraordinary Session (SBX1-2)[1] defines the California Renewables Portfolio Standard (RPS) and imposes minimum renewable energy procurement targets for all retail sellers and publicly-owned utilities (POUs), including the City of Redding (Redding). SBX1-2 authorized the California Energy Commission (CEC) to develop procedures for enforcement of the RPS for POUs. As part of that enforcement authority, the CEC adopted "Enforcement Procedures for the Renewables Portfolio Standard for Local, Publicly-Owned Electric Utilities" (RPS Enforcement Regulations) [2] and updated regulations were subsequently adopted in 2021. This document describes Redding's RPS Procurement and Enforcement Plan, as required by the Public Utility Code (PUC) section 399.30(a), which must be approved by the Redding City Council.

1.1 Utility Code

Redding maintains compliance with a multitude of state laws that govern certain aspects of utility energy portfolio requirements. These include the following code sections, which relate to California's Renewable Portfolio Standard:

- Renewable Portfolio Standard requirement PUC § 399.30(a)
- Compliance Period and Procurement Targets PUC § 399.30(b) and (c)
- Portfolio Content Categories PUC § 399.16(b) and (c)
- RPS POU Compliance PUC § 399.30(n)
- Optional Compliance Measures PUC § 399.30(d) and PUC § 399.33

2. RPS Procurement Plan

2.1 Purpose

The purpose of the RPS Procurement Plan is to identify the policies and procedures for Redding to meet the RPS requirements and any future adopted state-defined renewable goals. SB350 was signed by Governor Brown in 2015, mandating that 50 percent (50%) of retail sales must be served by RPS eligible resources by 2030. SB350 also mandated Redding to produce an Integrated Resource Plan that will guide the Procurement Plan as allowed by PUC section 399.17(d). In 2018, SB100 was signed by Governor Brown, which increased the RPS goals to 60% by 2030, and in 2021, the CEC approved updates to the RPS regulations.

[1] SBX1-2 (Simitian, Stats. 2011, Ch. 1) was signed by California's Governor on April 12, 2011.

[2] The CEC adopted the RPS Enforcement Regulations on June 12, 2013, in Order No. 13-0612-5.

2.2 Compliance Periods

Compliance periods are defined by multi-year percentage targets mandated by law. Compliance Periods 1, 2, and 3 have passed; however, they are included below for reference:

A. Compliance Period 1

(1) During Compliance Period 1, January 1, 2011, to December 31, 2013, Redding shall procure, at a minimum, renewable energy resources equivalent to an average of 20 percent of retail sales over the three (3) years of the compliance period.

Expressed as:
$EP_{2011} + EP_{2012} + EP_{2013} \geq .20\ (RS_{2011} + RS_{2012} + RS_{2013})$

Where:
RS_X = total retail sales made by Redding for the specified year X.
EP_X = electricity products procured for the specified year X; this may include excess procurement and historic carryover that the POU has chosen to apply to the compliance period containing year X.

B. Compliance Period 2

(1) For Compliance Period 2, January 1, 2014, to December 31, 2016, Redding shall procure renewable energy resources to meet or exceed the sum of 20 percent of retail sales for each of 2014 and 2015, and 25 percent of retail sales for 2016.

Expressed as:
$EP_{2014} + EP_{2015} + EP_{2016} \geq 0.20\ (RS_{2014}) + 0.20\ (RS_{2015}) + 0.25\ (RS_{2016})$

C. Compliance Period 3

(1) For Compliance Period 3, January 1, 2017, to December 31, 2020, Redding shall procure renewable energy resources to meet or exceed 33 percent of retail sales by 2020. During the intervening years of Compliance Period 3, Redding shall increase procurement to reflect an imputed compliance obligation.

Expressed as:
$$(EP_{2017} + EP_{2018} + EP_{2019} + EP_{2020}) \geq 0.27\ (RS_{2017}) + 0.29\ (RS_{2018}) + 0.31\ (RS_{2019}) + 0.33\ (RS_{2020})$$

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D. **Compliance Period 4**

(1) For the compliance period beginning January 1, 2021, and ending December 31, 2024, Redding shall demonstrate it has procured electricity products within that period sufficient to meet or exceed the sum of 35.75 percent of its 2021 retail sales, 38.50 percent of its 2022 retail sales, 41.25 percent of its 2023 retail sales, and 44.00 percent of its 2024 retail sales.

Expressed as:

$$(EP_{2021} + EP_{2022} + EP_{2023} + EP_{2024}) \geq 0.3575\ (RS_{2021}) + 0.3850\ (RS_{2022}) + 0.4125\ (RS_{2023}) + 0.4400\ (RS_{2024})$$

Redding may not apply Portfolio Content Category 3 RECs in excess of the maximum limit calculated in section 3204 (c)(3)(A) toward its RPS procurement target for this period.

E. **Compliance Period 5**

(1) For the compliance period beginning January 1, 2025, and ending December 31, 2027, Redding shall demonstrate it has procured electricity products within that period sufficient to meet or exceed the sum of 46.00 percent of its 2025 retail sales, 50.00 percent of its 2026 retail sales, and 52.00 percent of its 2027 retail sales.

Expressed as:

$$EP_{2025} + EP_{2026} + EP_{2027} \geq 0.4600(RS_{2025}) + 0.5000(RS_{2026}) + 0.5200(RS_{2027})$$

Redding may not apply Portfolio Content Category 3 RECs in excess of the maximum limit calculated in section 3204 (c)(3)(A) toward its RPS procurement target for this period.

F. **Compliance Period 6**

(1) For the compliance period beginning January 1, 2028, and ending December 31, 2030, Redding shall demonstrate it has procured electricity products within that period sufficient to meet or exceed the sum of 54.67 percent of its 2028 retail sales, 57.33 percent of its 2029 retail sales, and 60.00 percent of its 2030 retail sales.

Expressed as:

$$EP_{2028} + EP_{2029} + EP_{2030} \geq 0.5467(RS_{2028}) + 0.5733(RS_{2029}) + 0.6000(RS_{2030})$$

Redding may not apply Portfolio Content Category 3 RECs in excess of the maximum limit calculated in section 3204 (c)(3)(A) toward its RPS procurement target for this period.

G. Compliance Periods Beginning on and after January 1, 2031

(1) Compliance periods beginning on and after January 1, 2031, shall be three years in length starting on January 1 and ending on December 31. For each compliance period beginning on or after January 1, 2031, Redding shall demonstrate it has procured electricity products within the compliance period sufficient to meet or exceed an average of 60.00 percent of Redding's retail sales over the three calendar years of the compliance period.

Expressed as:

$$EP_{X1} + EP_{X2} + EP_{X3} \geq 0.6000\,(RS_{X1}) + 0.6000\,(RS_{X2}) + 0.6000\,(RS_{X3})$$

Redding may not apply Portfolio Content Category 3 RECs in excess of the maximum limit calculated in section 3204 (c)(3)(A) toward its RPS procurement target for this period.

2.3 Portfolio Content Categories (RPS Enforcement Regulation § 3203)

In addition to meeting the renewable energy procurement target, the RPS established Portfolio Content Categories (PCC) that outline the eligible renewable energy resource products that must be procured to ensure compliance with minimum and maximum values as summarized in Table 2.

A. PCC1: (RPS Enforcement Regulations § 3203(a))

(1) PCC1 electricity products must be bundled at the time of procurement to be classified as PCC1, and the POU may not resell the underlying electricity from the electricity product back to the eligible renewable energy resource from which the electricity product was procured. The electricity products must be generated by an eligible renewable energy resource that is interconnected to a transmission network within the Western Electricity Coordinating Council (WECC) service territory. For purposes of this section 3203, the first point of interconnection to the WECC transmission grid is the substation, or, where generation tie lines interconnect from the eligible renewable energy resource to the network transmission grid.

(a) Electricity products must be generated by an eligible renewable energy resource that has its first point of interconnection within the metered boundaries of a California balancing authority area, or

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(b) Electricity products must be generated by an eligible renewable energy resource that has its first point of interconnection to an electricity distribution system used to serve end-users within the metered boundaries of a California balancing authority area. For purposes of this section 3203, the first point of interconnection to an electricity distribution system is within the service area boundaries of a utility distribution company.

(c) Electricity products from the eligible renewable energy resource with a first point of interconnection outside the metered boundaries of a California balancing authority area must be scheduled into a California balancing authority area without substituting electricity from another source. For purposes of this section 3203, electricity generated by the eligible renewable energy resource must be scheduled into a California balancing authority area on an hourly or sub-hourly basis. The POU's governing board, or other authority as delegated by the POU governing board, must have approved an agreement before the electricity is generated to schedule the electricity from the eligible renewable energy resource into the California balancing authority area on an hourly or sub-hourly basis. If there is a difference between the amount of electricity generated within an hour and the amount of electricity scheduled into a California balancing authority area within that same hour, only the lesser of the two amounts shall be classified as PCC1.

(d) Electricity products must be subject to an agreement between a California balancing authority area and the balancing authority in which the eligible renewable energy resource is located and executed before the product is generated to dynamically transfer electricity from the eligible renewable energy resource into the California balancing authority area.

(3) Electricity products originally qualifying in PCC1 that do not meet the criteria of section 3203 (a)(2)(A) and are resold – (D) shall not be counted in PCC1.

B. <u>PCC2</u>: (RPS Enforcement Regulations § 3203(b))

(1) PCC2 electricity products must be generated by an eligible renewable energy resource that is interconnected to a transmission network within the WECC service territory, and the electricity must be matched with incremental electricity that is scheduled into a California balancing authority area.

(2) PCC2 electricity products must be bundled when procured and must meet all of the following criteria:

(a) The first point of interconnection to the WECC transmission grid for both the eligible renewable energy resource and the resource providing the

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incremental electricity must be located outside the metered boundaries of a California balancing authority area.

(b) The incremental electricity used to match the electricity from the eligible renewable energy resource must be incremental to the POU. For purposes of this section 3203, "incremental electricity" means electricity that is generated by a resource located outside the metered boundaries of a California balancing authority area; prior to the date of contract or ownership agreement, electricity is not in the portfolio of the POU claiming the electricity products for RPS compliance from eligible renewable energy resources with which the incremental electricity is being matched; is executed by the POU, or other authority, as delegated by the POU governing board.

(c) The governing board, or other authority as delegated by the governing board, executes the contract or ownership agreement for the incremental electricity at the same time or after the contract or ownership agreement for the electricity products from the eligible renewable energy resource is executed.

(d) The incremental electricity must be scheduled into the California balancing authority area within the same calendar year as the electricity from the eligible renewable energy resource is generated.

(e) The electricity from the eligible renewable energy resource must be available to be procured by the POU and may not be sold back to that resource.

C. PCC3: (RPS Enforcement Regulations § 3203(c))

All unbundled renewable energy credits and other electricity products procured from eligible renewable energy resources located within the WECC transmission grid that do not meet the requirements of either PCC1 or PCC2 fall within PCC3.

D. PCC0: (RPS Enforcement Regulations § 3202(a)(2))

(1) Any contract or ownership agreement originally executed prior to June 1, 2010, shall count in full toward the procurement requirements if all of the following conditions are met:

(a) The renewable energy resource met the Commission's RPS eligibility requirements that were in effect when the original procurement or ownership agreement was executed.

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(b) Any contract amendments or modifications occurring after June 1, 2010, do not increase the nameplate capacity, expected quantities of annual generation, or substitute a different renewable energy resource.

(c) If contract amendments or modifications after June 1, 2010, increase nameplate capacity or expected quantities of annual generation, increase the term of the contract, or substitute a different eligible renewable energy resource, only the MWhs or resources procured prior to June 1, 2010, shall count in full toward the RPS procurement targets. The remaining procurement that is additional due to the amendment must be classified into a portfolio content category and as long-term or short-term, and follow the portfolio balance requirements and long-term procurement requirement in accordance with RPS Enforcement Regulations section 3204 (c) and 3204 (d).

(d) The duration of the contract may be extended if the original contract specified a procurement commitment of fifteen (15) years or more.

2.4 Procurement Requirements (RPS Enforcement Regulation § 3204)

A. RPS procurement targets for each compliance period

A POU shall demonstrate it has procured electricity products sufficient to meet or exceed the procurement requirements for the respective compliance periods listed below:

	Compliance Period 4				CP 5	CP 6	CP 7
…	2021	2022	2023	2024	…2027	…2030	2031…
…	35.75%	38.5%	41.25%	44%	52%	60%	60%

Table 1: RPS Renewable Requirement

To allow for market and load variations, Redding may procure additional RECs in each Compliance Period above the values listed in Table 1.

B. Exemptions and Adjustments

1. Adjustment for Large Hydroelectric Generation

Consistent with RPS Enforcement Regulations § 3204(b)(8), from January 1, 2019, through December 31, 2030, if Redding receives more than 40 percent (40%) of its retail sales from large hydroelectric generation during a given year of a compliance period, Redding is not required to procure electricity products that exceed the lesser

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of the portion of the POU's retail sales unsatisfied by the POU's large hydroelectric generation, or the soft target for the relevant year of the compliance period.

2. Adjustment for Qualifying Gas-Fired Power Plant

If all requirements in RPS Enforcement § 3204(b)(11) are satisfied, Redding may reduce the amount of eligible renewable energy resources that it procures for a compliance period beginning January 1, 2025, if the gas-fired power plant is operating at or below a 20 percent (20%) capacity factor on an annual average basis during a given compliance period. This amount is calculated by the difference between the gas-fired power plant's actual generation for the compliance period if it had operated at a 20 percent (20%) capacity factor on an annual average during the compliance period. In order to participate, Redding was required to notify the CEC of its intent to act pursuant to this exemption by April 1, 2019. Redding submitted its notification to the CEC on March 12, 2019, and the CEC accepted it on July 31, 2019.

C. Portfolio Balance Requirements

Beginning in Compliance Period 4, at least seventy-five percent (75%) of Redding's RPS procurement shall be from PCC 1 contracts, with a maximum of 10 percent of Redding's RPS procurement from PCC 3 RECs (PUC section 399.16). There is no direct restriction on the percentage of PCC 2.

REC Classification	Compliance Period 1 2011-2013	Compliance Period 2 2014-2016	Compliance Period 3 2017-2020	Compliance Period 4 2021-2024	Compliance Period 5 2025-2027	Compliance Period 6 2027-2030
PCC 1 RECs (Minimum)	50%	65%	75%	75%	75%	75%
PCC 2 RECs (No Direct Restriction)	n/a	n/a	n/a	n/a	n/a	n/a
PCC 3 RECs (Maximum)	25%	15%	10%	10%	10%	10%
PCC 0	Not subject to portfolio balancing requirements					

Table 2: RPS Balancing Requirement

D. Long-Term Portfolio Requirement

For the compliance period beginning January 1, 2021, and each compliance period thereafter, at least 65 percent of the electricity products applied toward the RPS procurement target shall be from contracts of 10 years or more in duration or ownership or ownership agreements for eligible renewable energy resources (PUC section 399.13(b) and 399.30(d)).

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Electricity products will be classified as long-term or short-term based on the contracts, ownership, or ownership agreements through which they are procured. For the purpose of this section 3204 (d) subdivision, long-term procurement refers to procurement from long-term contracts (over ten years in duration), ownership, or ownership agreements, subject to criteria outlined in section 3204 (d).

2.5 Redding's Plan for RPS Compliance

In order to meet the RPS mandates, Redding plans to preserve its existing PCC0 resources, carry forward excess procurement from one compliance period to the next, and look for valuable opportunities to diversify and expand its RPS portfolio while protecting Redding's customers from excessive rate increases that could jeopardize economic growth and viability within the City.

The Integrated Resource Plan (IRP) will be the guiding document and framework used for future RPS energy procurement efforts. The IRP will be used as a procurement guide for RPS resource quantity, timing, location, and generation profiles. The IRP is filed with the California Energy Commission and will follow the required timely updates.

Redding plans to continue evaluating eligible renewable power resources and will initiate any necessary procurement solicitations consistent with the IRP.

3. RPS Enforcement Program

3.1 Enforcement Policy

In compliance with the requirement for the governing board of a POU to adopt a program for enforcement of the legislation prior to January 1, 2012, the Redding City Council passed Resolution 2011-197 "Resolution of the City Council of the City of Redding to Revise the Renewable Portfolio Standard for the City of Redding's Electric System" on December 20, 2011. Resolution 2011-197 adopted the following RPS targets:

- An average of 20 percent in 2011 through 2013;
- 25 percent by 2016; and
- 33 percent by 2020 and thereafter.

Resolution 2011-197 also adopted the following Enforcement Policies:

- Redding will make a reasonable effort in the context of Good Utility Practice to be in compliance with the requirements of SBX1-2.

- Redding will report to the City Council on its status of compliance with SBX1-2 per PUC section 399.13.
- Redding will notify the City Council of any potential for lack of compliance with the requirements that may be considered for a notice of violation and penalty imposition.
- Redding will provide an explanation and analysis to the City Council on such potential for lack of compliance, as well as a plan of corrective action and timeframe for returning the City to compliant status.

The Redding City Council approved updated RPS goals on September 17, 2019, due to the passing of SB 100, which accelerated RPS goals previously established in SB 350 as follows:

- 44 percent by 2024;
- 52 percent by 2027;
- 60 percent by 2030 and thereafter.

The Redding City Council approved the updated RPS procurement plan on March 21, 2023, modifying how Redding utilizes the plan's Optional Compliance Measures.

3.2 Optional Compliance Measures

Specific optional compliance measures are permitted and are adopted by Redding and the City Council. Redding adopts the following optional compliance measures, which may be utilized in the event that factors beyond reasonable control interfere with its ability to meet the procurement requirements set forth in § 3206 of the RPS Regulations.

A. Excess Procurement:

Redding shall be allowed to apply Excess Procurement from one compliance period to subsequent compliance periods using the criteria outlined in § 3206(a)(1) of the RPS Enforcement Regulations.

B. Delay of Timely Compliance:

Enforcement of timely compliance shall be waived if Redding demonstrates that any of the conditions defined in RPS Enforcement Regulations § 3206(a)(2) are beyond the control of Redding, and Redding would have met its RPS procurement requirements but for the cause of delay.

C. Cost Limitations for Expenditures:

The City of Redding's current RPS policy requires that Redding pursue target levels of renewable purchases while ensuring that costs for renewable purchases do not result in disproportionate rate impacts to customers. To ensure customers do not face a disproportionate burden, Redding's City Council has the authority to implement a Cost Limitation, which may result in the temporary suspension of RPS compliance activities.

In this section, Redding establishes a Cost Limitation on the procurement expenditures for all eligible renewable energy resources used to comply with the RPS, consistent with RPS Enforcement Regulations § 3206(a)(3). Potential reliance on this provision for compliance will be consistent with the City's Renewables Portfolio Standard Procurement Plan and the schedule that satisfies the procurement requirements set forth in Section 2.4 of this document.

The following circumstances may result in disproportionate rate impacts to REU customers and may constitute cause for the application of the Cost Limitation Optional Compliance Measure:

(1) An increase to the renewable energy procurement requirements for a given compliance period, as set forth in Section 2.4, not based on a change in electric retail sales, resulting in a deviation from Redding's forecasted renewable energy procurement requirement.

(2) Projected costs to meet renewable energy procurement requirements for a given compliance period exceed the forecasted costs adopted in Redding's renewable energy procurement budget.

When estimating the considered RPS procurement expenditure, the following costs will also be included:

(a) The costs associated with the energy, renewable attribute, firming and shaping, and/or storage, as needed for intermittent resources; and

(b) The costs associated with the delivery of renewable energy.

In the event that renewable energy procurement requirements meet the threshold for application of the Cost Limitation Optional Compliance Measure, Redding shall review its RPS Procurement Plan to ensure that alternatives are not available that would otherwise allow Redding to meet its RPS procurement requirement. Such review shall include an evaluation of:

- current procurement commitments,

- planned procurements,
- long-term commitments, and
- the availability of alternative resources in other portfolio content categories.

Based on this review, Redding reserves the right to refrain from entering into new contracts for renewable energy purchases that meet any of the exemptions listed in its Cost Limitation provisions.

D. Portfolio Balance Requirement Reduction:

The Portfolio Balance Requirement shall be reduced if Redding demonstrates that any of the conditions defined in RPS Enforcement Regulations § 3206(a)(4) are beyond the control of Redding, and Redding would have met its Portfolio Balance Requirements but for the cause of reduction.

4. Review and Updating Requirements (RPS Enforcement Regulations § 3205(a) and (b))

Redding is required to complete an Integrated Resource Plan that will guide the Procurement plan. Redding will provide the following notice regarding new or updated renewable energy resources procurement and enforcement plans:

A. Renewable Energy Resources Procurement Plan

(1) Redding shall post notice in accordance with Chapter 9 (commencing with § 54950) of Part 1, Division 2, Title 5 of the Government Code, whenever the City Council will deliberate in public on the RPS Procurement Plan.

B. Enforcement Plan

(1) Redding shall provide notice regarding new or updated enforcement programs. The enforcement program must be adopted at a publicly noticed meeting offering all interested parties an opportunity to comment.

a. No less than 30 calendar days' notice shall be given to the public of any meeting held for purposes of adopting the enforcement program.

b. If the enforcement program is modified or amended, no less than 10 calendar days' notice shall be given to the public before any meeting is held to make a substantive change to the enforcement program.

Revision No.	Revision Date	Summary of Changes
1	10/15/2013	Original version adopted by City Council on October 15, 2013
2	10/07/2014	Annual update: Removed Lewiston and added Colusa
3	6/05/2018	Combined Procurement and Enforcement plan. Included SB350 updates, removed Colusa biomass project, added cost limitation from stranded assets, and rearranged information for a clearer, concise document.
4	8/26/2019	Updated to include new legislation on: SB100, and SB1110.
5	4/20/2021	Updated to include new RPS regulatory language from updated regulations adopted by CEC in December 2020.
6	3/31/2023	Updated optional compliance measure language and corrected

J:\14_RESOURCES\01_PROCEDURES AND FILINGS\PROCEDURES\RPS-001 RPS PROCUREMENT AND ENFORCEMENT PLAN

9.5 Standardized Tables

State of California

California Energy Commission

Standardized Reporting Tables for Public Owned Utility IRP Filing

Administrative Information

Form CEC 113 (May 2017)

Name of Publicly Owned Utility ("POU")	City of Redding
Name of Resource Planning Coordinator	Lisa Casner
Name of Scenario	Net-Zero Carbon with Operating Constraints

Persons who prepared Tables	**CRAT**	**Energy Balance Table**	**Emissions Table**	**RPS Table**	**Application for Confidentiality**
Name:	Nick Rossow	Nick Rossow	Nick Rossow	Nick Rossow	
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E-mail:	nrossow@cityofredding.org	nrossow@cityofredding.org	nrossow@cityofredding.org	nrossow@cityofredding.org	
Telephone:	530-339-7374	530-339-7374	530-339-7374	530-339-7374	
Address:	3611 Avtech Pkwy	3611 Avtech Pkwy	3611 Avtech Pkwy	3611 Avtech Pkwy	
Address 2:					
City:	Redding	Redding	Redding	Redding	
State:	CA	CA	CA	CA	
Zip:	96002	96002	96002	96002	
Date Completed:	9/13/2023	9/13/2023	9/13/2023	9/13/2023	
Date Updated:					
Back-up / Additional Contact Persons for Questions about these Tables (Optional):					
Name:	Lisa Casner	Lisa Casner	Lisa Casner	Lisa Casner	
Title:	Electric Manager - Resources	Electric Manager - Resources	Electric Manager - Resources	Electric Manager - Resources	
E-mail:	lcasner@cityofredding.org	lcasner@cityofredding.org	lcasner@cityofredding.org	lcasner@cityofredding.org	
Telephone:	530-339-7263	530-339-7263	530-339-7263	530-339-7263	
Address:	3611 Avtech Pkwy	3611 Avtech Pkwy	3611 Avtech Pkwy	3611 Avtech Pkwy	
Address 2:					
City:	Redding	Redding	Redding	Redding	
State:	CA	CA	CA	CA	
Zip:	96002	96002	96002	96002	

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

Scenario Name:

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

PEAK LOAD CALCULATIONS

			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
1	Forecast Total Peak-Hour 1-in-2 Demand	**Note: All line items 2a through 5 have already been incorporated into the load forecast and/or the specified data does not exist therefore can not be reported or forecasted separately and reported here.		239.1	224.3	223.9	223.7	223.8	224.2	224.8	225.6	226.6	227.9	229.0	230.4	232.3	235.0	238.0	241.1	244.2	247.5	250.5	254.1	257.5
2	[Customer-side solar: nameplate capacity]		15.4	18.1	21.1	22.4	23.3	24.2	25.0	25.8	26.6	27.4	28.2	28.9	29.7	30.4	31.1	31.8	32.5	33.2	33.9	34.5	35.2	35.8
2a	[Customer-side solar: peak hour output] [Note 1]																							
3	[Peak load reduction due to thermal energy storage]																							
4	[Light Duty PEV consumption in peak hour]																							
5	Additional Achievable Energy Efficiency Savings on Peak																							
6	Demand Response / Interruptible Programs on Peak																							
7	**Peak Demand (accounting for demand response and AAEE) (1-5-6)**		**0.0**	**239.1**	**224.3**	**223.9**	**223.7**	**223.8**	**224.2**	**224.8**	**225.6**	**226.6**	**227.9**	**229.0**	**230.4**	**232.3**	**235.0**	**238.0**	**241.1**	**244.2**	**247.5**	**250.5**	**254.1**	**257.5**
8	Planning Reserve Margin	15%	0.0	35.9	33.6	33.6	33.6	33.6	33.6	33.7	33.8	34.0	34.2	34.3	34.6	34.8	35.3	35.7	36.2	36.6	37.1	37.6	38.1	38.6
9	Firm Sales Obligations																							
10	**Total Peak Procurement Requirement (7+8+9)**		**0.0**	**275.0**	**258.0**	**257.5**	**257.3**	**257.3**	**257.8**	**258.5**	**259.4**	**260.6**	**262.1**	**263.3**	**264.9**	**267.1**	**270.3**	**273.7**	**277.2**	**280.9**	**284.6**	**288.1**	**292.2**	**296.2**

EXISTING AND PLANNED CAPACITY SUPPLY RESOURCES

Utility-Owned Generation and Storage (not RPS-eligible):

For fuel type, choose from list or enter value

	[list resource by name]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
11a	Unit 1	Natural Gas	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
11b	Unit 2	Natural Gas	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
11c	Unit 3	Natural Gas	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
11d	Unit 4 - Steam Unit used for Combined Cycle with NG Units 5/Unit 6	Natural Gas	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0
11e	Unit 5	Natural Gas	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
11f	Unit 6	Natural Gas	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
11g																								

Long-Term Contracts (not RPS-eligible):

	[list contracts by name]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
11h	Western - Large Hydro	Large Hydroelectric	91.0	66.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0
11i																								
11j																								
11k																								
11l																								
11m																								
11n																								
11	**Total peak dependable capacity of existing and planned supply resources (not RPS-eligible) (sum of 11a...11n)**		**260**	**235**	**243**	**243**	**243**	**243**	**243**	**243**	**243**	**243**	**243**	**243**	**243**	**243**	**243**	**243**	**243**	**243**	**243**	**243**	**243**	**243**

Utility-Owned RPS-eligible Resources:

	[list resource by plant or unit]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
12a	Whiskeytown	Small Hydroelectric	2.7	3.6	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
12b																								
12c																								
12d																								
12e																								
12f																								
12g																								
12h																								
12i																								
12j																								
12k																								
12l																								
12m																								
12n																								

	Long-Term Contracts (RPS-eligible): [list contracts by name]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
12o	Big Horn	Wind	22.0	22.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12p	Western - Small Hydro (Note: capacity is included in 11h)	Small Hydroelectric	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12q	Index+ Renewable PPA - Solar	Solar PV	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12r	Index+ Renewable PPA - Wind	Wind	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12s																								
12t																								
12u																								
12v																								
12w																								
12x																								
12y																								
12z																								
12	**Total peak dependable capacity of existing and planned RPS-eligible resources (sum of 12a…12t)**		**25**	**26**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**
13	**Total peak dependable capacity of existing and planned supply resources (11+12)**		**285**	**261**	**263**	**263**	**263**	**263**	**263**	**263**	**263**	**263**	**263**	**245**	**245**	**245**	**245**	**245**	**245**	**245**	**245**	**245**	**245**	**245**

GENERIC ADDITIONS

	NON-RPS ELIGIBLE RESOURCES: [list resource by name or description]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
14a	8hr Battery Storage	Battery Storage	0	0	0	0	0	0	0	0	0	0	25	25	25	25	25	25	40	40	40	40	55	55
14b																								
14c																								
14d																								
14e																								
14f																								
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14j																								
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14l																								
14m																								
14n																								
14	**Total peak dependable capacity of generic supply resources (not RPS-eligible)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**25**	**25**	**25**	**25**	**25**	**25**	**40**	**40**	**40**	**40**	**55**	**55**

	RPS-ELIGIBLE RESOURCES: [list resource by name or description]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
15a	Solar Resources	Solar PV	0	0	0	0	0	0	0	0	0	0	5	5	5	5	5	5	7	7	7	7	9	9
15b																								
15c																								
15d																								
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15n																								
15	**Total peak dependable capacity of generic RPS-eligible resources**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**5**	**5**	**5**	**5**	**5**	**5**	**7**	**7**	**7**	**7**	**9**	**9**
16	**Total peak dependable capacity of generic supply resources (14+15)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**30**	**30**	**30**	**30**	**30**	**30**	**47**	**47**	**47**	**47**	**64**	**64**

CAPACITY BALANCE SUMMARY

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
17	**Total peak procurement requirement (from line 10)**	**0**	**275**	**258**	**258**	**257**	**257**	**258**	**259**	**259**	**261**	**262**	**263**	**265**	**267**	**270**	**274**	**277**	**281**	**285**	**288**	**292**	**296**
18	**Total peak dependable capacity of existing and planned supply resources (from line 13)**	**285**	**261**	**263**	**263**	**263**	**263**	**263**	**263**	**263**	**263**	**263**	**245**	**245**	**245**	**245**	**245**	**245**	**245**	**245**	**245**	**245**	**245**
19	**Current capacity surplus (shortfall) (18-17)**	**285**	**(14)**	**5**	**5**	**6**	**6**	**5**	**4**	**4**	**2**	**1**	**(18)**	**(20)**	**(22)**	**(25)**	**(29)**	**(32)**	**(36)**	**(40)**	**(43)**	**(47)**	**(51)**
20	**Total peak dependable capacity of generic supply resources (from line 16)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**30**	**30**	**30**	**30**	**30**	**30**	**47**	**47**	**47**	**47**	**64**	**64**
21	**Planned capacity surplus/shortfall (shortfalls assumed to be met with short-term capacity purchases) (19+20)**	**285**	**(14)**	**5**	**5**	**6**	**6**	**5**	**4**	**4**	**2**	**31**	**12**	**10**	**8**	**5**	**2**	**15**	**11**	**7**	**4**	**17**	**13**

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

Scenario Name:

Units = MWh

Yellow fill relates to an application for confidentiality.

Historical Data: 2021–2022

NET ENERGY FOR LOAD CALCULATIONS

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
1	Retail sales to end-use customers	722,772	712,411	673,996	675,142	673,549	675,314	679,158	685,882	690,565	698,375	707,383	717,932	727,465	744,046	758,788	788,916	816,330	848,464	895,345	929,262	972,528	1,004,037
2	Other loads	62,346	50,965	56,861	55,768	55,164	54,676	54,432	54,412	54,220	54,265	54,391	54,703	54,840	55,488	67,059	69,068	70,792	72,978	76,272	78,505	81,398	83,270
3	Net energy for load	**785,118**	**763,376**	**730,857**	**730,911**	**728,713**	**729,990**	**733,590**	**740,293**	**744,785**	**752,641**	**761,774**	**772,635**	**782,305**	**799,534**	**825,847**	**857,983**	**887,123**	**921,442**	**971,617**	**1,007,767**	**1,053,926**	**1,087,307**
4**	Retail sales to end-use customers (accounting for AAEE impacts)	722,772	712,411	673,996	675,142	673,549	675,314	679,158	685,882	690,565	698,375	707,383	717,932	727,465	744,046	758,788	788,916	816,330	848,464	895,345	929,262	972,528	1,004,037
5**	Net energy for load (accounting for AAEE impacts)	785,118	763,376	730,857	730,911	728,713	729,990	733,590	740,293	744,785	752,641	761,774	772,635	782,305	799,534	825,847	857,983	887,123	921,442	971,617	1,007,767	1,053,926	1,087,307
6	Firm Sales Obligations																						
7	**Total net energy for load (accounting for AAEE impacts) (5+6)**	**785,118**	**763,376**	**730,857**	**730,911**	**728,713**	**729,990**	**733,590**	**740,293**	**744,785**	**752,641**	**761,774**	**772,635**	**782,305**	**799,534**	**825,847**	**857,983**	**887,123**	**921,442**	**971,617**	**1,007,767**	**1,053,926**	**1,087,307**
8	[Customer-side solar generation]																						
9	[Light Duty PEV electricity consumption/procurement requirement]																						
10	[Other transportation electricity consumption/procurement requirement]																						
11	[Other electrification/fuel substitution; consumption/procurement requirement]																						

**Note: AAEE have already been incorporated into the load forecast and/or the specified data does not exist therefore can not be reported or forecasted separately here.

EXISTING AND PLANNED GENERATION RESOURCES

Utility-Owned Generation Resources (not RPS-eligible):

	[list resource by name]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
12a	Unit 1	Natural Gas	1,351	1,547	919	281	387	144	41	48	25	44	45	42	81	48	76	88	85	41	26	1	0	0
12b	Unit 2	Natural Gas	3,099	2,690	2,911	1,201	1,687	653	302	223	133	140	198	153	258	195	244	296	260	143	72	2	0	0
12c	Unit 3	Natural Gas	3,229	2,818	2,319	901	1,283	535	210	162	112	133	169	128	196	149	193	227	217	114	64	1	0	0
12d	Unit 4 - Steam Unit used for Combined Cycle with NG Units 5/Unit 6 (Note: Generation is included in 12e and 12f)	Natural Gas	106,795	119,775	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12e	Unit 5	Natural Gas	138,789	175,233	146,617	147,359	136,032	145,634	139,525	139,908	138,447	139,049	136,435	146,150	133,329	133,829	136,139	131,865	132,419	136,872	98,738	0	0	0
12f	Unit 6	Natural Gas	120,666	124,854	139,757	138,876	128,604	141,689	133,352	135,753	132,214	132,393	129,744	141,034	128,126	129,155	132,873	126,689	125,809	131,490	95,901	0	0	0
12g																								

Long-Term Contracts (not RPS-eligible):

	[list contracts by name]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
12h	Western - Large Hydro	Large Hydroelectric	136,862	57,857	139,907	243,752	238,877	238,877	238,877	238,877	238,877	238,877	238,877	238,877	238,877	238,877	238,877	238,877	238,877	238,877	238,877	238,877	238,877	238,877
12i																								
12j																								
12k																								
12l																								
12m																								
12n																								
12	**Total energy from existing and planned supply resources (not RPS-eligible) (sum of 12a...12n)**		**510,792**	**484,775**	**432,430**	**532,370**	**506,871**	**527,532**	**512,307**	**514,970**	**509,807**	**510,636**	**505,468**	**526,384**	**500,867**	**502,253**	**508,402**	**498,042**	**497,666**	**507,538**	**433,679**	**238,882**	**238,877**	**238,877**

Utility-Owned RPS-eligible Generation Resources:

	[list resource by plant or unit]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
13a	Whiskeytown	Small Hydroelectric	18,693	25,916	24,091	24,323	24,248	24,250	24,250	24,322	24,247	24,246	23,949	23,734	23,762	23,723	23,500	23,201	22,993	23,003	23,072	22,953	22,187	21,581
13b																								
13c																								
13d																								
13e																								
13f																								
13g																								
13h																								
13i																								
13j																								
13k																								
13l																								
13m																								
13n																								

	Long-Term Contracts (RPS-eligible): [list contracts by name]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
13o	Big Horn	Wind	191,201	163,586	173,337	172,542	170,746	169,466	168,195	167,424	165,681	164,439	122,979	0	0	0	0	0	0	0	0	0	0	0
13p	Western - Small Hydro	Small Hydroelectric	2,815	5,306	2,420	4,215	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131
13q	Index+ Renewable PPA - Solar (Note: Solar and Wind Generation will vary, all generation included in 13q)	Solar PV	100,000	0	0	0	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	0	0	0	0	0	0	0	0
13r	Index+ Renewable PPA - Wind (Note: Solar and Wind Generation will vary, all generation included in 13q)	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13s																								
13t																								
13u																								
13v																								
13w																								
13x																								
13y																								
13aa																								
13	**Total energy from RPS-eligible resources (sum of 13a…13aa)**		312,709	194,808	199,847	201,081	374,126	372,847	371,576	370,877	369,060	367,816	326,060	202,865	202,893	202,855	27,631	27,332	27,124	27,134	27,203	27,084	26,319	25,712
13z	**Undelivered RPS energy**																							
14	**Total energy from existing and planned supply resources (12+13)**		823,501	679,583	632,277	733,451	880,996	900,378	883,883	885,847	878,867	878,452	831,527	729,250	703,760	705,108	536,033	525,373	524,791	534,672	460,882	265,966	265,195	264,589

GENERIC ADDITIONS

	NON-RPS ELIGIBLE RESOURCES: [list resource by name or description]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
15a	8hr Battery Storage	Battery Storage	0	0	0	0	0	0	0	0	0	0	-4,019	-8,178	-7,894	-7,705	-9,586	-9,316	-11,095	-13,343	-15,141	-14,223	-17,657	-18,123
15b																								
15c																								
15d																								
15e																								
15f																								
15g																								
15h																								
15i																								
15j																								
15k																								
15l																								
15m																								
15n																								
15	**Total energy from generic supply resources (not RPS-eligible)**		0	0	0	0	0	0	0	0	0	0	(4,019)	(8,178)	(7,894)	(7,705)	(9,586)	(9,316)	(11,095)	(13,343)	(15,141)	(14,223)	(17,657)	(18,123)

	RPS-ELIGIBLE RESOURCES: [list resource by name or description]	Fuel type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
16a	Solar Resources	Solar PV	0	0	0	0	0	0	0	0	0	0	371,463	500,046	500,046	514,933	572,081	614,942	643,516	673,291	716,153	773,301	832,851	877,513
16b																								
16c																								
16d																								
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16f																								
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16h																								
16i																								
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16n																								
16	**Total energy from generic RPS-eligible resources**		0	0	0	0	0	0	0	0	0	0	371,463	500,046	500,046	514,933	572,081	614,942	643,516	673,291	716,153	773,301	832,851	877,513
17	**Total energy from generic supply resources (15+16)**		0	0	0	0	0	0	0	0	0	0	367,444	491,868	492,151	507,228	562,495	605,626	632,422	659,949	701,012	759,078	815,194	859,390
17z	**Total energy from RPS-eligible short-term contracts [Note 1]**		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

ENERGY FROM SHORT-TERM PURCHASES

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
18	**Short term and spot market purchases:**	207,958	227,712	225,855	199,588	208,801	200,785	207,526	212,414	217,301	226,037	142,559	171,956	193,624	202,232	208,226	228,548	236,433	232,308	278,683	383,256	386,708	396,736
18a	**Short term and spot market sales (only report sales of energy from resources already included in the EBT):**	246,341	143,919	127,275	202,127	361,085	371,173	357,819	357,968	351,383	351,848	579,756	620,439	607,230	615,034	480,908	501,564	506,523	505,487	468,959	400,532	413,171	433,408

ENERGY BALANCE SUMMARY

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
19	**Total energy from supply resources (14+17+17z)**	823,501	679,583	632,277	733,451	880,996	900,378	883,883	885,847	878,867	878,452	1,198,971	1,221,117	1,195,911	1,212,336	1,098,528	1,131,000	1,157,212	1,194,621	1,161,894	1,025,044	1,080,389	1,123,979
19a	**Undelivered RPS energy (from 13z)**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	**Net Short term and spot market purchases (18 - 18a)**	(38,383)	83,793	98,580	(2,540)	(152,284)	(170,388)	(150,293)	(145,553)	(134,082)	(125,811)	(437,197)	(448,483)	(413,606)	(412,802)	(272,681)	(273,016)	(270,090)	(273,179)	(190,276)	(17,276)	(26,462)	(36,672)
21	**Total delivered energy (19-19a+20)**	785,118	763,376	730,857	730,911	728,713	729,990	733,590	740,293	744,785	752,641	761,774	772,635	782,305	799,534	825,847	857,983	887,123	921,442	971,617	1,007,767	1,053,926	1,087,307
22	**Total net energy for load (from 7)**	785,118	763,376	730,857	730,911	728,713	729,990	733,590	740,293	744,785	752,641	761,774	772,635	782,305	799,534	825,847	857,983	887,123	921,442	971,617	1,007,767	1,053,926	1,087,307
23	**Surplus/Shortfall (21-22)**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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

Scenario Name:

Yellow fill relates to an application for confidentiality.

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

GHG EMISSIONS FROM EXISTING AND PLANNED SUPPLY RESOURCES

Utility-Owned Generation (not RPS-eligible):

	[list resource by name]	Emissions Intensity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
1a	Redding Power Plant (Units 1 -6 on CRAT Form)	0.423	59,738	147,168	124,884	121,677	113,493	121,653	115,104	116,285	113,955	114,204	112,395	121,394	110,755	111,389	114,075	109,840	109,634	113,603	82,507	4	0	0
1b																								
1c																								
1d																								
1e																								
1f																								
1g																								

Long-Term Contracts (not RPS-eligible):

	[list contracts by name] [Note 1]	Emissions Intensity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
1h	Western - Large Hydro	0.000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1i																								
1j																								
1k																								
1l																								
1m																								
1n																								
1	**Total GHG emissions of existing and planned supply resources (not RPS-eligible) (sum of 1a…1n)**		**59,738**	**147,168**	**124,884**	**121,677**	**113,493**	**121,653**	**115,104**	**116,285**	**113,955**	**114,204**	**112,395**	**121,394**	**110,755**	**111,389**	**114,075**	**109,840**	**109,634**	**113,603**	**82,507**	**4**	**0**	**0**

Utility-Owned RPS-eligible Generation Resources:

	[list resource by plant or unit]	Emissions Intensity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
2a	Whiskeytown	0.000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2b																								
2c																								
2d																								
2e																								
2f																								
2g																								
2h																								
2i																								
2j																								
2k																								
2l																								
2m																								
2n																								

Long-Term Contracts (RPS-eligible):

	[list contracts by name]	Emissions Intensity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
2o	Big Horn	0.000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2p	Western - Small Hydro	0.000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
sq	Index+ Renewable PPA - Solar	0.000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2r	Index+ Renewable PPA - Wind	0.000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2s																								
2t																								
2v																								
2u																								
2w																								
2x																								
2y																								
2z																								
2	**Total GHG emissions from RPS-eligible resources**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
3	**Total GHG emissions from existing and planned supply resources (1+2)**		**59,738**	**147,168**	**124,884**	**121,677**	**113,493**	**121,653**	**115,104**	**116,285**	**113,955**	**114,204**	**112,395**	**121,394**	**110,755**	**111,389**	**114,075**	**109,840**	**109,634**	**113,603**	**82,507**	**4**	**0**	**0**

EMISSIONS FROM GENERIC ADDITIONS

NON-RPS ELIGIBLE RESOURCES:

	[list resource by name or description]	Emissions Intensity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
4a	8hr Battery Storage	0.000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4b																								
4c																								
4d																								
4e																								
4f																								
4g																								
4h																								
4i																								
4j																								
4k																								
4l																								
4m																								
4n																								
4	**Total GHG emissions from generic supply resources**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

RPS-ELIGIBLE RESOURCES:

	[list resource by name or description]	Emissions Intensity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
5a	Solar Resources	0.000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5b																								
5c																								
5d																								
5e																								
5f																								
5g																								
5h																								
5i																								
5j																								
5k																								
5l																								
5m																								
5n																								
5	**Total GHG emissions from generic RPS-eligible**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
6	**Total GHG emissions from generic supply resources (4+5)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

GHG EMISSIONS OF SHORT TERM PURCHASES

		Emissions Intensity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
7	**Net spot market/short-term purchases:**	0.428	(16,428)	35,863	42,192	(1,087)	(65,177)	(72,926)	(64,325)	(62,297)	(57,387)	(53,847)	(187,120)	(191,951)	(177,023)	(176,679)	(116,708)	(116,851)	(115,598)	(116,921)	(81,438)	(7,394)	(11,326)	(15,696)

TOTAL GHG EMISSIONS

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
8	**Total GHG emissions to meet net energy for load**	43,310	183,032	167,077	120,590	48,316	48,727	50,779	53,988	56,568	60,357	(74,726)	(70,556)	(66,269)	(65,291)	(2,633)	(7,011)	(5,964)	(3,318)	1,069	(7,390)	(11,326)	(15,696)

EMISSIONS ADJUSTMENTS

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
8a	**Undelivered RPS energy (MWh from EBT)**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8b	**Firm Sales Obligations (MWh from EBT)**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8c	**Total energy for emissions adjustment (8a+8b)**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8d	**Emissions intensity (portfolio gas/short-term and**																						
8e	**Emissions adjustment (8Cx8D)**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PORTFOLIO GHG EMISSIONS

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
8f	**Adjusted Portfolio emissions (8-8e)**	43,310	183,032	167,077	120,590	48,316	48,727	50,779	53,988	56,568	60,357	-74,726	-70,556	-66,269	-65,291	-2,633	-7,011	-5,964	-3,318	1,069	-7,390	-11,326	-15,696

GHG EMISSIONS IMPACT OF TRANSPORTATION ELECTRIFICATION

Note: The data below is not metered actuals or calculations from metered data. It is best estimate using reasonable assumptions which are also used in forecast estimates along with factors from CARB EV GHG Benefits Tool. Line #10 values are already included in System GHG values above.

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
9	**GHG emissions reduction due to gasoline vehicle displacement by LD PEVs**	1,908	2,170	2,651	3,419	4,577	6,196	8,175	10,634	13,619	17,255	21,305	25,814	30,880	39,212	53,228	67,171	80,882	94,392	107,702	120,897	134,049	147,201
10	**GHG emissions increase due to LD PEV electricity**	131	381	526	501	276	385	538	751	1,019	1,385	0	0	0	0	0	0	0	0	133	0	0	0
11	**GHG emissions reduction due to fuel displacement - other transportation**																						
12	**GHG emissions increase due to increased electricity loads - other transportation**																						

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

Scenario Name:

Units = MWh

	RPS ENERGY REQUIREMENT CALCULATIONS	**Beginning balances Start of 2021**	**Compliance Period 4**					**Compliance Period 5**				**Compliance Period 6**		
			2021	**2022**	**2023**	**2024**		**2025**	**2026**	**2027**		**2028**	**2029**	**2030**
1	Annual Retail sales to end-use customers (accounting for AAEE impacts) (From EBT)		722,772	712,411	673,996	675,142		673,549	675,314	679,158		685,882	690,565	698,375
2	Green pricing program Exclusion, (may include other exclusions like self generation exclusion) [Note 1]													
3	Soft target (%)		36%	39%	41%	44%		46%	50%	52%		55%	57%	60%
4	Required procurement for compliance period		1,107,755					1,000,652				1,189,898		
	Category 0, 1 and 2 Resources (bundled with RECs)													
5	Excess balance at beginning/end of compliance period	273,130					19,502				137,398			
6	RPS-eligible energy procured (copied from EBT)		312,709	194,808	199,847	201,081		374,126	372,847	371,576		370,877	369,060	367,816
6A	Amount of energy applied to procurement obligation		312,709	194,808	199,847	201,081		374,126	337,657	353,162		374,972	395,901	419,025
7	Net purchases of Category 0, 1 and 2 RECs		0	0	0	0		0	0	0		0	0	0
7A	Excess balance and REC purchases applied to procurement obligation		0	79,470	78,177	95,982		(64,293)	0	0		0	0	0
8	Net change in balance/carryover (RECs and RPS-eligible energy) (6+7-6A-7A)		0	(79,470)	(78,177)	(95,982)		64,293	35,190	18,413		(4,095)	(26,841)	(51,209)
	Category 3 Resources (unbundled RECs)													
9	Excess balance at beginning/end of compliance period	0					0				0			
10	Net purchases of Category 3 RECs													
11	Excess balance and REC purchases applied to procurement obligation													
12	Net change in REC balance		0	0	0	0		0	0	0		0	0	0
13	Total generation plus RECs (all Categories) applied to procurement requirement (6A + 7A + 11)		1,162,073					1,000,652				1,189,898		
14	Over/under procurement for compliance period (13 - 4)		54,318					0				0		

	Compliance Period 7				Compliance Period 8				Compliance Period 9				Compliance Period 10			
	2031	2032	2033		2034	2035	2036		2037	2038	2039		2040	2041	2042	
	707,383	717,932	727,465		744,046	758,788	788,916		816,330	848,464	895,345		929,262	972,528	1,004,037	
	60%	60%	60%		60%	60%	60%		60%	60%	60%		60%	60%	60%	
	1,291,668				1,375,050				1,536,084				1,743,497			
55,253				866,956				1,451,680				2,030,018				2,849,302
	697,522	702,911	702,938		717,788	599,712	642,274		670,641	700,425	743,356		800,385	859,169	903,226	
	424,430	430,759	702,938		717,788	599,712	642,274		670,641	700,425	743,356		800,385	859,169	903,226	
	0	0	0		0	0	0		0	0	0		0	0	0	
	0	0	(266,459)		(271,360)	(144,440)	(168,925)		(180,842)	(191,347)	(206,148)		(242,828)	(275,653)	(300,803)	
	273,092	272,152	266,459		271,360	144,440	168,925		180,842	191,347	206,148		242,828	275,653	300,803	
0				0				0				0				0
	0	0	0		0	0	0		0	0	0		0	0	0	
	1,291,668				1,375,050				1,536,084				1,743,497			
	0				0				0				0			