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2019 | INTEGRATED RESOURCE PLAN

City of Redding

COOPERATIVELY PREPARED WITH

[redacted]

Ascend Analytics

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Acronyms, Abbreviations, and Definitions List

AAEE	Additional Achievable Energy Efficiency
AAGR	Annual Average Growth Rate
AB	Assembly Bill
AC	Alternating Current
AMI	Advanced Metering Infrastructure
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*
BESS	Battery Energy Storage System
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
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
CEC	California Energy Commission (also Energy Commission)
CEC Guidelines	The CEC document, *Publically 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
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
DC	Direct Current
Decatherm (Dth)	Measurement of heat equivalent to one MMBTU
DOE	Department of Energy
DSM	Demand-Side Management; refers to initiatives that encourage consumers to optimize energy usage
Dth/day	Decatherm per Day
EBT	Energy Balance Table (CEC Standardized Table)
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
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
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
IPP	Independent Power Producer
IRP	Integrated Resource Plan
IRP Filing	POU Adopted IRP Accompanied By The Required Supporting Information
JPA	Joint Powers Agency
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
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
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
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
RPS	Renewables Portfolio Standard
RPT	RPS Procurement Table
SAE	Statistically Adjusted End Use
SB	Senate Bill
SB 350	Senate Bill 350 (De León, Chapter 547, Statutes of 2015)
Scenario	Eight expansion plans developed and compared
SOTP	South of Tesla Principles
TAC	Transmission Access Charge
TANC	Transmission Agency of Northern California
UG	Under Ground
VAR	Volt-ampere reactive; voltage & current out of phase on AC system

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

IRP Project Partners

Ascend Analytics	Modeling software company
PowerSimm	Software developed by Ascend Analytics used to evaluate scenarios for load, resources, cost, risk, and environmental mandates
Curve Developer	Software developed by Ascend Analytics to forecast market gas and power prices
Black & Veatch	Consultant who aided in IRP development ensuring all mandates were met
Itron	Consultant who developed the load forecast

1.0 Executive Summary

This report (Report) presents the Integrated Resource Plan (IRP) for the City of Redding (COR), owner of a non-profit, vertically integrated utility providing electric service to approximately 44,000 customers in and near Redding, California within a service area that covers approximately 61 square miles. COR's vision is to benefit and create value for its electric customers served in the Redding community and to deliver exceptional services through the strength and dedication of its employees. This overarching objective is achieved by providing reliable and safe service at low (cost-conscious) rates, while complying with state and environmental mandates and regulations.

An IRP is a long-term, comprehensive plan developed to help ensure that the COR 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 future resource requirements needed to comply with state mandates. Acquisitions will be vetted in the normal course and the standard procurement process will be followed.

As demonstrated in this document, the IRP provides an assessment of the future energy needs of customers over the next 20 years (from 2018 through 2037) and summarizes the preferred plan for meeting those needs in a safe, reliable, cost-effective, and environmentally responsible manner[2].

This IRP 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, and established a number of requirements for publicly owned utilities (POUs). The most far-reaching goals and requirements include:

- An increase in the procurement of energy from renewable electricity sources, from 33 percent by 2020 to 50 percent by 2030
- Consideration of programs that will help the state double energy efficiency savings in electricity and natural gas end uses by 2030
- A reduction in GHG emissions consistent with the targets set forth by the California Air Resources Board (CARB) in its July 2018 report[1]
- POUs[2] 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. The IRP is to be approved by the respective boards by January 1, 2019, and submitted to the California Energy Commission (CEC) by April 30, 2019

This IRP addresses each of the applicable requirements and targets. The recommended plan meets the 2030 renewable energy (RE) target as well as the intermediate targets; the load forecast reflects a continuation of COR's long history of encouraging energy efficiency and demand reduction; and the recommended plan fits within the CARB's 2030 targets for GHG emissions.

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[1] California Air Resources Board, *Staff Report: Senate Bill 350 Integrated Resource Planning Electricity Sector Greenhouse Gas Planning Targets*, July 2018; SB 350 required CARB to develop recommendations based on the goal of achieving a 40% reduction in GHG by 2030.

[2] SB 350 is reflected in Public Utilities Code (PUC) Section 9621, which applies to POU's with an average electrical demand exceeding 700 gigawatt-hours, based on a three-year average commencing January 1, 2013.

The 2019 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 2037. While the IRP is only required to extend to 2030, the CEC encouraged POUs to consider time periods extending beyond 2030 in its *Commission Guidelines*.[3] 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, COR must plan for sufficient supplies of electricity while also maintaining competitive prices 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. The IRP process has also taken into consideration the need to establish a plan that will allow flexibility to respond to uncertainty regarding technological and future regulatory change. Goals established to guide development of the IRP are presented in Figure 1-1.

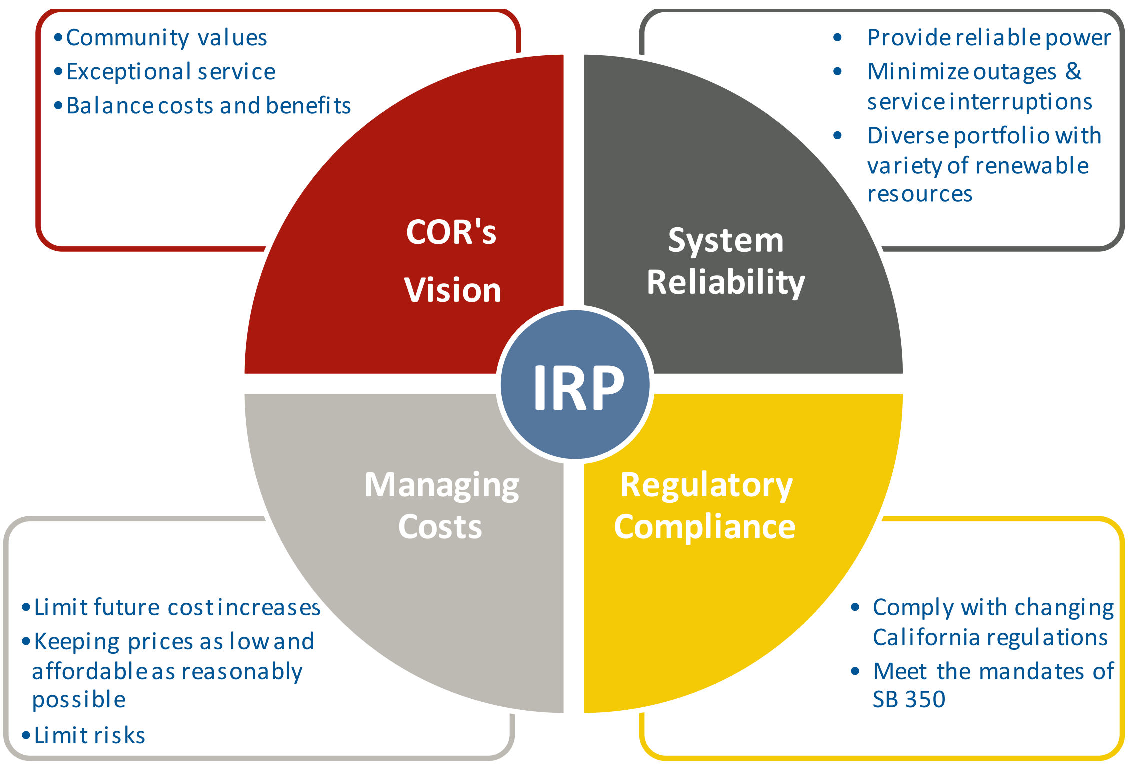

Figure 1-1 IRP Objectives

[3] Vidaver David, Garry O'Neill-Mariscal, Melissa Jones, Paul Deaver, and Robert Kennedy, 2018, *Publically Owned Utility Integrated Resource Plan Submission and Review Guidelines*, California Energy Commission. Publication Number: CEC-200-2018-004-CMD, 2nd Edition, p. 4.

A summary of the 20-Year Resource Plan is provided in Section 1.1. Supporting information, including studies, data, analyses and results, plus associated exhibits for the IRP analysis is provided in the following sections of the Report:

- Section 2.0 Purpose and Background
- Section 3.0 Existing Resources and System Description
- Section 4.0 Energy and Demand Forecast
- Section 5.0 Customer Programs, Energy Efficiency and Demand Response Resources
- Section 6.0 The Need for Additional Resources and Resource Options
- Section 7.0 Modeling Assumptions, Tools, and Methodology
- Section 8.0 Evaluation and Results
- Section 9.0 Conclusions and Recommended Scenario

Standardized tables requested by the CEC are located in Appendix A followed by discussion in Appendix B-F. The organization and contents of this IRP reflect the requirements established in the CEC IRP Guidelines. The major requirements set forth in these guidelines and the primary section in which the required information is provided is shown in Table 1-1.

Table 1-1 Summary of Key IRP Filing Requirements and Location in IRP

ITEM	SELECTED TEXT FROM THE *CEC GUIDELINES*	LOCATION IN IRP
A. Planning Horizon and Objective of Expansion Plan	"adopt an IRP that ensures the utility achieves the specific goals and targets by 2030, including…greenhouse gas emissions reductions of 40 percent below 1990 levels, and…at least 50 percent of eligible renewable resources…The minimum planning horizon…begins no later than January 1 of the year that the POU's governing board adopts the plan and ends no earlier than December 31, 2030…POUs are encouraged to undertake and present analysis….that addresses the post-2030 period"	Section 8
B. Scenarios and Sensitivity Analysis	"IRP Filings….must meet the requirements of PUC Section 9621. POUs are encouraged to also evaluate other scenarios and sensitivity analyses to consider the feasibility and cost-effectiveness (and rate impacts) of alternative resource options."	Section 8
C. Standardized Tables	"POUs must submit the following four Standardized Tables… • Capacity Resource Accounting Table (CRAT) • Energy Balance Table (EBT) • RPS Procurement Table (RPT) • GHG Emissions Accounting Table (GEAT)"	Appendix A
D. Supporting Information	"(1) analyses, studies, data, and work papers, or other material that the POU used or relied upon (including inputs and assumptions) in creating the IRP… and (2) additional information required by these guidelines. Supporting Information supplements the data submitted in the Standardized Tables."	Section 4, 5, 6; all Appendices

ITEM	SELECTED TEXT FROM THE *CEC GUIDELINES*	LOCATION IN IRP
E. Demand Forecast	"1. Reporting Requirements…annual forecasted peak demand (MW) in the CRAT and annual forecasted retail sales, other loads, and net energy for load in the EBT… 2. Demand Forecast Methodology and Assumptions. 3. Demand Forecast – Other Regions. If the POU uses system modeling…the IRP Filing must include the demand forecast assumptions for regions outside the POU jurisdiction."	Section 4, Appendix A
F. Resource Procurement Plan	"…the mix of resources… in the IRP [as]…reported on the CRAT, EBT, and GEAT, and RPS procurement must also be reported on the RPT [along with] all inputs, assumptions, and methodologies …The IRP Filing must address[:] 1. Diversified Procurement Portfolio 2. RPS Planning Requirements 3. Energy Efficiency and Demand Response Resources 4. Energy Storage 5. Transportation Electrification"	Section 4, 5, 8, Appendix A
G. System and Local Reliability	"Filing POUs [must] adopt an IRP to… meets the goal of ensuring system and local reliability…[and report]: 1. Reliability Criteria…the planning reserve margin and how it was determined. 2. Local Reliability Area. The IRP Filing must identify any local transmission constrained areas in the POU service territory…"	Section 4
H. Greenhouse Gas Emissions	"POUs must report in the GEAT estimated emissions intensities (in metric tons of carbon dioxide equivalent [CO_2e] per megawatt hour…for each supply resource reported in the EBT."	Section 8, Appendix A
I. Retail Rates	"…the IRP Filing must include, as Supporting Information, a report or study on rate impacts under the IRP scenario, if that report or study was considered by the local governing authority as part of its IRP planning."	Section 8
J. T&D Systems	"…adopt and IRP [that] achieves the goal of strengthening the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities."	Section 3
K. Localized Air Pollutants and Disadvantaged Communities	"…adopt IRPs to…[achieve] the goal of minimizing localized air pollutants and other GHG emissions, with early priority on disadvantaged communities…[discuss] how current programs and policies in place…address local air pollution…[and] how programs assist and prioritize disadvantaged communities."	Section 8
Summarized from Chapter 2 of Vidaver David, Melissa Jones, Paul Deaver, and Robert Kennedy. 2018. *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines*. California Energy Commission. Publication Number: CEC-200-2018-004.		

1.1 SUMMARY OF THE 20-YEAR RESOURCE PLAN

The IRP, described herein, was based on the load forecast developed by Itron further described in Section 4. The competing expansion plans (Scenarios) were designed to meet the load requirements and other planning objectives stated herein, and each Scenario was rated on various measures to define the preferred Scenario.

Section 6 of this report explains that COR has sufficient generating capacity to meet energy needs through the 2037 planning period; however, an Existing System Scenario is not acceptable as it would fall short of meeting renewable generation and environmental mandates. As a result, several Scenarios were developed that provide additional renewable resources and were evaluated based on the cost and characteristics of select solar and wind options described in Section 6. Centered on these characteristics, as well as additional assumptions and methods described in Section 7, the long-term cumulative present worth cost (CPWC) of eight competing Scenarios were developed and are presented in Section 8. The CPWC includes all incremental costs of the planning period stated on a present worth basis.

The eight Scenarios evaluated each differ in terms of the additional solar and wind resources that comprise the plan. Solar and wind were the only projects evaluated for future resources due to the desires of COR and its customers. The list of projects considered for inclusion in the Scenarios is shown in Table 1-2. The eight Scenarios developed around these projects are shown in Table 1-3. Each of these Scenarios, other than the Existing System Scenario, include the 2021 addition of the 10 MW (Project 1) Solar Project now in Phase II of development—this Phase includes site recommendation, site screening, preliminary development, and early project development and financing.

Table 1-2 Projects Considered in the IRP Scenarios (All Capacities are the Maximum Rated and Not Firm Capacities)

	PROJECT 1	PROJECT 2	PROJECT 3	PROJECT 4	PROJECT 5	PROJECT 6	PROJECT 7
Name	Local PV w/Batt	NorCal/OR PV	AZ PV	CV PV 1	CV PV 2	NorCal/ OR Wind	AZ Wind
Location	Local	OR/NorCal	Arizona	Central Valley	Central Valley	OR/ NorCal	Arizona
Type	PV	PV	PV	PV	PV	Wind	Wind
Capacity (MW)	10	100	100	20	100	100	200
Scalable	No	Yes	Yes	No	Yes	Yes	Yes
AC Capacity Factor (%)	27.9%	27.0%	33.1%	30.6%	29.8%	30.0%	30.0%
Annual Energy (MWh)	24,440	236,520	289,956	53,611	261,048	262,800	525,600
Annual Degradation (%)	0.70%	0.70%	0.70%	0.70%	0.70%	0.00%	0.00%
Energy Storage? (Yes/No/Maybe)	Yes	Not included	Not included	Not included	Not included	Not included	Not included
ES Capacity (MW)	2.50	Not included	Not included	Not included	Not included	Not included	Not included
ES Duration (Hrs)	4	Not included	Not included	Not included	Not included	Not included	Not included
Transmission Requirements	None	To COTP, WAPA	To CAISO, WAPA	NP26, WAPA	To CAISO, WAPA	To COTP, WAPA	To CAISO, WAPA
LMP Market Location (To Value)	NP15	NP15	Palo Verde	ZP26	SP15	NP15	Palo Verde
Transmission Access Charge (TAC) Costs (2018-$/kW/mo)	$0.000	$2.258	$3.137	$0.000	$0.000	$2.258	$3.137
Transmission Costs (2018-$/MWh)	$0.000	$0.000	$11.221	$11.221	$11.221	$0.000	$11.221
Transmission Escalation Rate (%)		5.00%	4.00%	4.00%	4.00%	5.00%	4.00%
There are two methods of accounting for transmission costs: volumetric charges ($/MWh) used by California Independent System Operator, and demand ($/kw-mo). Depending on the location of the project and transmission path, it will be one or the other, or both; the model accommodates both.							

Table 1-3 Projects in the Scenarios Modeled (All Capacities are the Maximum Rated and Not Firm Capacities)

SCENARIO NAME	PROJECT 1: PV	PROJECT 2: PV	PROJECT 3: PV	PROJECT 4: PV	PROJECT 5: PV	PROJECT 6: WIND	PROJECT 7: WIND
A) Base Case	MW: 10 Start: 2021 MWh/yr: 24,440 LCOE: $58						
B) Balanced Mix	MW: 10 Start: 2021 MWh/yr: 24,440 LCOE: $58		MW: 30 Start: 2028 MWh/yr: 86,987 LCOE: $57	MW: 20 Start: 2026 MWh/yr: 53,611 LCOE: $71		MW: 70 Start: 2032 MWh/yr: 183,960 LCOE: $76	
C) Balanced Mix-Alternate	MW: 10 Start: 2021 MWh/yr: 24,440 LCOE: $58	MW: 30 Start: 2029 MWh/yr: 70,956 LCOE: $73			MW: 25 Start: 2026 MWh/yr: 65,262 LCOE: $68		MW: 70 Start: 2032 MWh/yr: 183,960 LCOE: $72
D) Heavy Wind	MW: 10 Start: 2021 MWh/yr: 24,440 LCOE: $58						MW: 85 Start: 2026 MWh/yr: 223,380 LCOE: $68
E) Heavy Wind – Alternate	MW: 10 Start: 2021 MWh/yr: 24,440 LCOE: $58					MW: 85 Start: 2026 MWh/yr: 223,380 LCOE: $72	
F) Heavy Solar	MW: 10 Start: 2021 MWh/yr: 24,440 LCOE: $58	MW: 90 Start: 2026 MWh/yr: 212,868 LCOE: $70					
G) Existing System							
H) Optimized Balanced Mix	MW: 10 Start: 2021 MWh/yr: 24,440 LCOE: $58				MW: 60 Start: 2026 MWh/yr: 156,629 LCOE: $68	MW: 65 Start: 2034 MWh/yr: 170,820 LCOE: $77	

The levelized cost of energy, in $/MWh (LCOE), is measured at the plant and does not include transmission charges. Transmission charges are estimated in Table 1-2

The results of the Scenario analysis are reported in Section 8 and are also summarized in Table 1-4. In this table, the consolidated CPWC results and other key results for the Scenarios evaluated are presented as a “heat map” in which the best Scenario results are shown in green and least favorable results are in red, with varying shades in between. This map clearly illustrates the inadequacies of some Scenarios and highlights those that meet the measured standards. Some plans had a favorable CPWC, but didn’t meet requirements for a balanced renewable portfolio, and alternatively, other Scenarios had a favorable balance of renewable resources, but were considerably higher in cost.

The Base Case Scenario, in which 10 MW of local solar is added in 2021, is listed first in Table 1-4. This Scenario is important as it reflects the addition of the currently-planned Solar Project that is in the second phase of development (See Section 7.0). There are two key conclusions related to the Base Case Scenario.

First, by comparing the Base Case CPWC with the Existing System Scenario (Scenario G) CPWC, it is clear that the Base Case has a lower CPWC. This helps to highlight why adding the 10 MW solar project (Project 1 from Table 1-2) provides an added benefit from a cost perspective, and by adding RE benefits over the Existing System case. This comparison helps to illustrate the reason for selecting the 10 MW Solar Project in 2021 as the next resource addition and why this is considered to be the Base Case rather than Scenario G.

A second, very important conclusion about the Base Case Scenario is that, even though it achieves a higher RE percentage than Scenario G, it still falls short of meeting the 2030 RE target of 50 percent. In fact, it achieves only a 33 percent level in 2030. Moreover, the Base Case Scenario is still very heavily reliant on wind energy (71 percent of all RE) even with the addition of Project 1 in 2021. Due to these results, the Base Case is understood to contain the next project to be undertaken, but it is not the final recommended mix of resources over the entire planning horizon. The need for additional renewable resources beyond 2021 solar addition led to the development of the remaining Scenarios in Table 1-3. With the exception of Scenario G, all Scenarios involved the 2021 solar project, but also included additional RE resources after 2021.

1.1.1 Recommendation

The various modeled Scenarios were rated based on the adopted objectives of maintaining low cost, exceptional reliability, a diverse portfolio, and environmental responsibility. Of the Scenarios modeled, Scenario H is the recommended plan in this IRP as this plan offers the best combination of COR’s goals and includes the practical balance of RE resources (between wind and solar) and the requirements established for POUs by the state. Scenario H calls for the addition of 10 MW (maximum rated capacity, not firm) of new solar purchases in 2021, followed by 60 MW (rated) of solar purchases in 2026 and 65 MW (rated) of wind purchases in 2034. The four detailed tables required by the CEC Guidelines are provided in Appendix A for this preferred Scenario. This IRP, and the recommendation of Scenario H as the preferred plan, was adopted by the Redding City Council (Council) in October 2018.

1.1.2 Merits of Scenario H

The portfolio plan of Scenario H has sufficient generation capacity to meet energy needs throughout the planning horizon, ending with 41 MW of surplus capacity in 2037. While there is a capacity surplus, the IRP must meet requirements for both capacity and energy, particularly eligible RE requirements, simultaneously (see Section 6 for further details outlining this requirement). The plan associated with Scenario H contains three renewable projects additions. At the top right of Table 1-5, the following information about the new renewable project additions are shown:

- 10 MW local Solar PV project (3.5 MW is considered firm capacity), added in 2021 (common to all plans except the Existing System Scenario),
- 60 MW Solar PV project in 2026 (planned to have a firm output of 21 MW), and
- 65 MW wind project (firm output of 7 MW) added in 2034.

COR's energy requirements are met under the plan associated with Scenario H. Under Scenario H, the 1x1 and 2x1 combined cycle (a combined-cycle power station uses both a gas and steam turbine together to produce more electricity from the same fuel) projects are the only two units at the Redding Power Station (Station) generating a significant amount of energy, while all RE projects are actively producing energy consumed by customers or sold into the market. The addition of the three RE projects allows compliance with Renewable Portfolio Standard (RPS) requirements. Details regarding the above mentioned merits of Scenario H as a preferred plan are contained in Section 8.

Scenario H results in a 2030 RE percentage of 54 percent in 2030, exceeding the target of 50 percent. Under this plan, there would be an estimated carbon emissions level of 72,405 $MTCO_2e$ in 2030. This level of emissions is well below the high target of 101,000 $MTCO_2e$ in the CARB staff recommendations for COR (although it is above the 57,000 $MTCO_2e$ set as the lower end of the targeted range). In subsequent years, the $MTCO_2e$ in Scenario H falls below the 2030 level and ends with 73,713 $MTCO_2e$ of emissions in 2037. Details of the cost and revenue projection contributing to the overall CPWC for Scenario H of about $581 million through 2037 are shown year by year in Table 1-5.

Scenario H is quite flexible in that, following the first resource addition in 2021 (common to all plans), projects are layered in over a 20-year period; the next project is expected to be operational in 2026, which brings the following benefits:

- The period between resource additions allows the continued assessment of industry events and system developments in order to adjust the specifics of Scenario H if conditions warrant;
- It provides the ability to increase or decrease the size of the selected RE projects as necessary;
- With the pliability this plan offers, staff can better match resources to comply with any future applicable in-state versus out-of-state requirements, such as those of the California Independent System Operator (CAISO); and
- The plan provides the ability to delay or accelerate the in-service date of the project based on a number of factors such as future legislation and market conditions

While Scenario D may appear to be a less costly option, it offers less flexibility in that, beyond the 2021 solar addition that is also added in Scenario H, the plan consists of only an 85 MW wind addition in 2026. Although it may be economical to add this large wind project, the plan results in an unbalanced mix of solar and wind generation as indicated by the 84 percent wind, 6 percent solar mix of RE for Scenario D indicated in Table 1-4.

Scenario H is within the limit of $MTCO_2e$ recommended by the CARB staff for COR in 2030 (101,000 $MTCO_2e$) and meets the RE targets as is seen in Table 1-6 below. By relying on annual RECs and banked RECs, the plan meets the 2030 RE target of 50 percent and never incurs a negative REC bank balance during the 2018-2037 planning period.

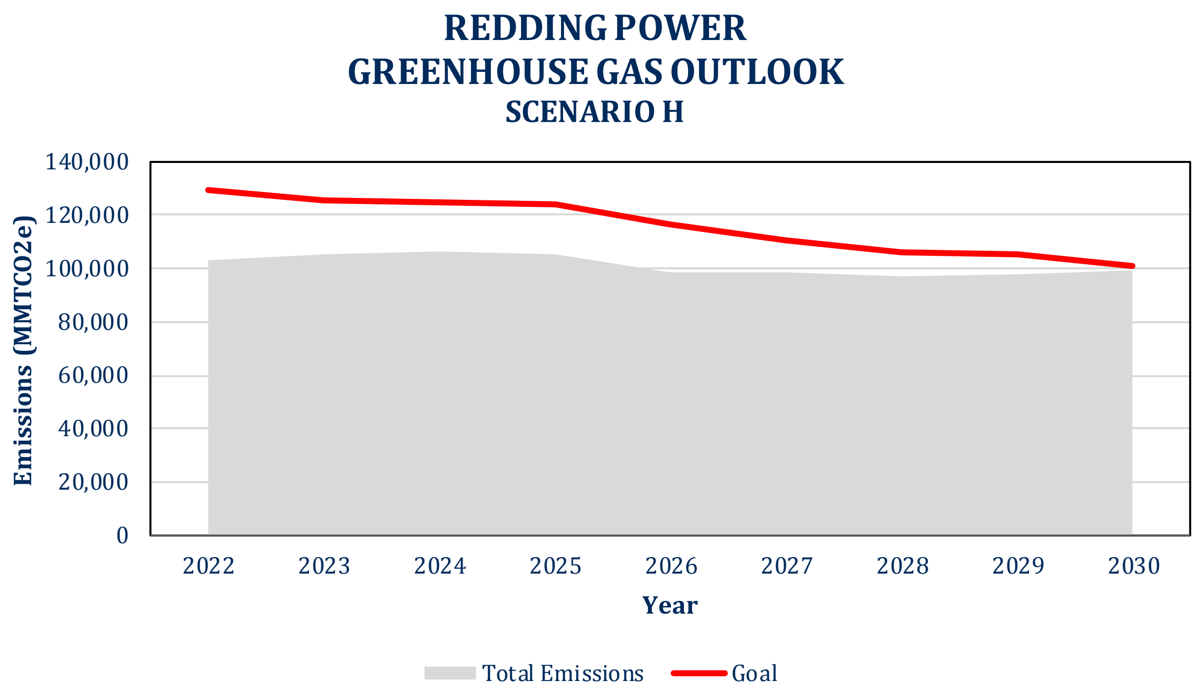

Figure 1-2 GHG Emissions in the Preferred Plan, Scenario H

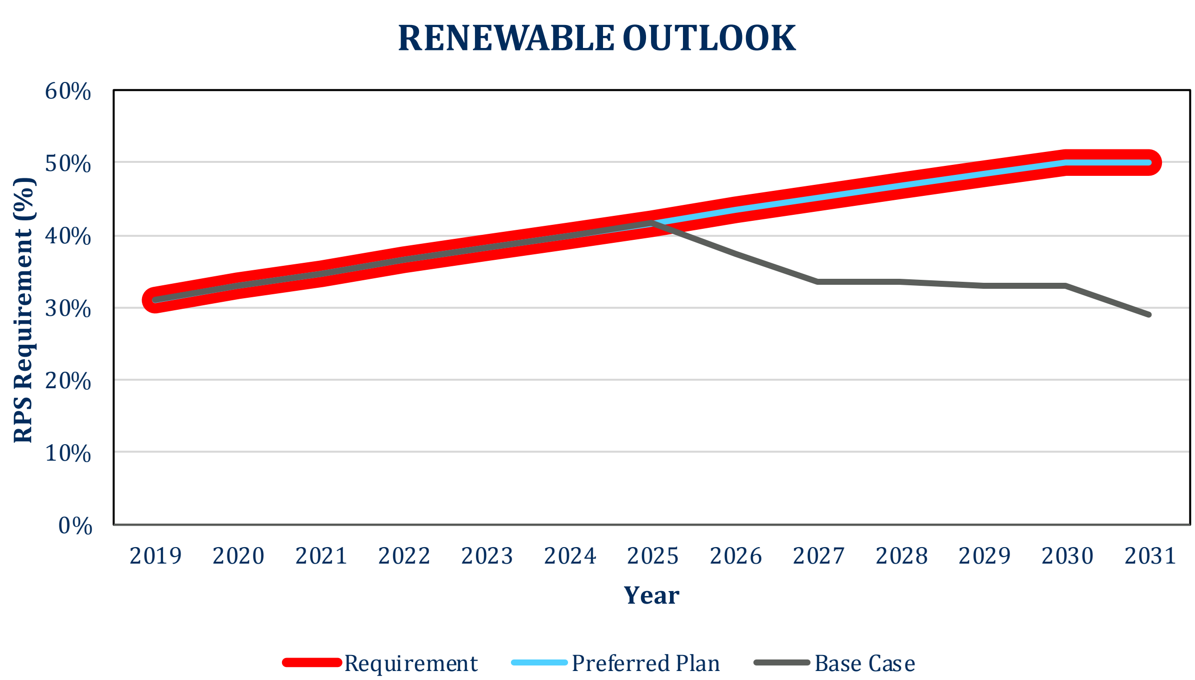

Figure 1-3 Renewable Outlook

1.1.3 Analyses of Alternative Scenarios

Scenario H is the only Scenario identified in Table 1-4 as having green or light green shading in all categories. The plan is within 2.8 percent of the least cost plan; it achieves a 54 percent RE mix in 2030; it achieves all intermediate RE milestones (by relying on banked RECs in some years) and has a reasonably balanced mix of RE contributions from wind (53 percent) and solar (36 percent). Based on the global objective of balancing economic, reliability, and environmental objectives, Scenario H is the best overall plan in the 2019 IRP. Further details about Scenario H are provided in the next Section 8.

In terms of lowest CPWC, Scenario D may appear to be the best overall plan and it also is very good in terms of the 2030 RE level of 65 percent. However, the area where this plan falls short is its lack of resource diversity—the plan is very heavily reliant on wind energy (84 percent of all RE) and contains little solar energy (6 percent). As a result, this plan receives low marks for its inability to achieve a balanced RE portfolio. This assessment is reflective of the preference that several Stakeholders expressed for solar energy and is consistent with the emphasis on a balanced RE portfolio. Relying heavily on one resource can create a reliability issue both with power generation and transmission.

Scenario C also achieves a very high percentage of RE in 2030 (65 percent) but is not economical and also suffers from a high reliance on wind energy. Scenario F is economically competitive and achieves 61 percent RE contribution, but the scenario is over-reliant on wind energy resources.

Scenario E achieves the best overall balance of RE production, with 42 percent coming from wind energy and 47 percent coming from solar energy projects. This plan also achieves all RE milestones and reaches 65 percent in 2030. Nevertheless, the drawback of Scenario E is one of economics—it achieves the favorable RE characteristics at a cost that is 6.5 percent higher than the least cost Scenario D. As a result, it can be concluded that the RE benefits of Scenario E are obtained at a significantly higher cost than the plan having the lowest CPWC (Scenario D). The issue, therefore, is whether a plan could be developed that better balanced cost and environmental benefits. The plan meeting these aims is Scenario H.

Table 1-4 Heat Map Diagram of Scenario CPWC and RE Results

CPWC Summary				2030 Renew-able, % of Retail Sales	Intermediate Milestones for RE Met?	Avg. RE 2018-2030	Achieving RE Balance		
	Description	CPWC ($1,000)	CPWC % Higher				RE from Wind	RE from Solar	RE from Hydro
Base Case	Base Case (with local solar only)	583,833	3.3%	32.8%	No	32.8%	71%	11%	18%
Scenario A	Balanced Mix of Wind/Solar	575,766	1.9%	51.8%	Yes	38.5%	59%	30%	11%
Scenario B	Bal. Mix of Wind/Solar – Alt. Projects	602,421	6.6%	51.3%	Yes	37.9%	60%	29%	11%
Scenario C	Wind Heavy	642,176	13.7%	64.9%	Yes	45.4%	84%	6%	10%
Scenario D	Wind Heavy - Alternate Projects	564,925	0.0%	64.9%	Yes	45.5%	84%	6%	10%
Scenario E	Solar Heavy	601,558	6.5%	61.3%	Yes	44.2%	42%	47%	11%
Scenario F	Early Wind Balanced Mix	566,191	0.2%	59.3%	Yes	41.1%	81%	8%	11%
Scenario G	Existing System without Local Solar	601,957	6.6%	29.6%	No	30.4%	81%	0%	19%
Scenario H	Optimized Balanced Mix	580,966	2.8%	53.9%	Yes	41.2%	53%	36%	11%

*Optimal results are shown in green, unfavorable results in red
** Intermediate Milestones are: 33% by 2020; 40% by 2024; 45% by 2027; 50% by 2030.
***Intermediate Milestones are considered met with the use of banked renewable energy credits

Table 1-5 Detailed CPWC Results for the Preferred Plan, Scenario H

COR V11 Scenario H Mean Results

Desc Optimized Balanced Mix

Economic and Financial Parameters	
CPW Discount Rate:	2.5%
Base Year for CPW $:	2018

Portfolio	Size (MW)	First Year	1st Yr Energy (MWh)	LCOE ($/MWh)
Local PV w/Bat	10	2021	24,440	$ 58.00
NorCal/OR PV				
AZ PV				
Westland PV				
CV PV	60	2026	156,629	$ 68.00
NorCal/OR Wind	65	2034	170,820	$ 77.08
AZ Wind				

		Supply Value/Cost						Wholesale Sales Value/Revenue						Cumulative
Year	System Transmitted Energy GWh	Value[1] of Supply Energy ($1,000)	REU Generation Costs ($1,000)	Hydro Costs ($1,000)	Wind Costs ($1,000)	Risk and Import Costs ($1,000)	Total Purchase + Production ($1,000)	REU Generation Value[1] ($1,000)	Hydro Sales Value[1] ($1,000)	Wind Sales Value[1] ($1,000)	Export Revenue ($1,000)	Total System Cost ($1,000)	Present Worth Cost ($1,000)	Present Worth Cost ($1,000)
2018	767.535	25,503	10,251	4,973	12,239	7,936	60,901	10,561	7,379	5,272	2,178	35,512	35,512	35,512
2019	767.119	24,411	7,054	6,525	12,239	8,909	59,138	7,217	8,523	5,026	1,883	36,488	35,598	71,110
2020	766.632	26,082	8,398	6,788	12,265	8,673	62,206	8,875	9,086	5,478	2,705	36,061	34,324	105,434
2021	763.013	28,227	10,298	7,061	13,507	8,030	67,124	11,286	9,724	7,253	4,425	34,436	31,978	137,411
2022	761.992	29,596	12,496	7,346	13,498	8,286	71,222	14,816	10,247	7,604	7,017	31,538	28,572	165,983
2023	762.510	30,646	13,419	7,642	13,489	9,480	74,676	15,817	10,539	7,855	7,337	33,128	29,281	195,264
2024	767.096	31,690	13,842	7,950	13,509	9,710	76,701	17,128	10,674	8,089	7,981	32,830	28,309	223,573
2025	768.249	32,901	14,180	8,270	13,472	10,713	79,536	18,771	11,150	8,355	8,818	32,442	27,293	250,866
2026	770.535	33,848	13,665	8,603	26,418	9,654	92,188	19,234	11,303	15,315	13,789	32,548	26,714	277,579
2027	773.399	34,785	13,915	8,950	26,414	9,581	93,645	20,329	11,582	15,641	14,364	31,730	25,407	302,986
2028	778.734	35,897	14,153	9,310	26,472	12,050	97,882	19,612	11,838	16,005	13,603	36,824	28,767	331,753
2029	780.769	36,894	15,090	9,685	26,414	12,365	100,449	20,050	12,247	16,360	13,720	38,071	29,015	360,769
2030	782.358	37,897	15,478	10,075	26,420	13,522	103,391	21,901	12,145	16,705	15,001	37,640	27,987	388,756
2031	784.084	38,917	13,482	10,481	23,663	11,895	98,438	24,517	13,203	15,689	16,398	28,631	20,770	409,525
2032	788.191	40,085	15,846	10,903	14,235	17,429	98,499	24,411	13,222	9,172	10,779	40,915	28,957	438,482
2033	789.134	41,143	16,279	11,343	14,217	18,957	101,938	24,413	13,239	9,391	10,512	44,383	30,645	469,127
2034	792.330	42,320	13,158	11,799	32,393	14,010	113,681	24,901	14,097	18,991	18,089	37,603	25,330	494,457
2035	796.280	43,553	14,871	12,275	32,599	15,947	119,245	25,844	13,811	19,435	18,401	41,753	27,440	521,897
2036	802.497	44,988	14,220	12,769	32,885	17,108	121,970	24,429	14,301	19,911	17,188	46,141	29,584	551,481
2037	804.309	46,245	14,388	13,284	33,046	17,601	124,564	24,909	14,822	20,304	17,392	47,136	29,485	580,966
	NPV:	549,144	207,150	143,615	320,874	186,047	1,406,830	290,366	181,805	187,835	165,858	580,966	580,966	580,966

[1] Interim calculation representing the value (either cost or revenue) of the item using a common market base

Table 1-6 Renewable Energy and REC Adequacy in the Preferred Plan, Scenario H

Renewable Energy Achieved (GWh) and Renewable Energy Credits (1,000): Scenario H																				
Redding Electric Utility																				
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Big Horn	180	180	180	180	180	180	180	180	180	180	180	180	180	153	0	0	0	0	0	0
Western Small	5	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Whiskeytown	26	26	26	26	26	26	26	26	26	26	27	26	26	26	26	26	26	26	26	26
Local PV	0	0	0	24	24	24	24	24	24	23	23	23	23	23	23	22	22	22	22	22
CV PV	0	0	0	0	0	0	0	0	155	154	154	152	151	150	149	148	147	146	145	144
NorCal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	176	176	177	176
Total REC Generated	**211**	**212**	**213**	**237**	**237**	**236**	**237**	**236**	**391**	**390**	**390**	**388**	**387**	**358**	**204**	**203**	**377**	**376**	**376**	**374**
Retail Sales, GWh	698	697	694	694	694	695	698	702	704	707	711	716	717	719	722	726	729	733	736	740
RPS Obligation, %	29%	31%	33%	35%	37%	38%	40%	42%	43%	45%	47%	48%	50%	50%	50%	50%	50%	50%	50%	50%
RPS Achieved, %	30%	30%	31%	34%	34%	34%	34%	34%	56%	55%	55%	54%	54%	50%	28%	28%	52%	51%	51%	51%
Required RECs	202	216	229	241	253	266	279	293	305	318	332	346	359	360	361	363	365	366	368	370
Annual REC Balance	9	(4)	(16)	(5)	(17)	(29)	(42)	(57)	86	72	58	42	28	(2)	(156)	(160)	13	10	8	4
REC Bank Balance	**211**	**208**	**191**	**187**	**170**	**141**	**99**	**42**	**128**	**200**	**258**	**300**	**328**	**326**	**169**	**9**	**22**	**32**	**40**	**44**

2.0 Purpose and Background

This section provides an overview of the IRP process—a summary of relevant regulatory policies that guide development of the IRP, including legislation and related regulatory requirements established by the CEC. A summary-level description of the methodology used to perform study evaluations is also provided; the methodology is further described in Section 8.0 of this Report. This section also describes the public stakeholder process conducted to welcome input from consumers into the IRP process.

2.1 OVERVIEW OF THE INTEGRATED RESOURCE PLANNING PROCESS

Integrated resource planning is a process undertaken by utilities to identify the long-term plan that provides adequate resources to meet future peak demand and energy needs, while also achieving other utility goals. These additional goals include maintaining a targeted reserve margin to help ensure system reliability and achieving a reasonable balance between fiscal responsibility and environmental stewardship. In this manner, effective resource planning offers economic benefits to consumers while minimizing environmental impacts. An effective resource plan should also provide the utility with flexibility to accommodate uncertainties and risks related to future conditions, including commodity pricing risk, technological change, and regulatory change.

IRPs require the use of sophisticated analytical tools that allow comparisons of the costs, risk, and benefits among alternative supply-side and demand-side resource options that, together, may constitute a long-term plan. Most commonly, detailed computer models that simulate utility operation on an hour-by-hour basis are used to develop the long-term costs of various Scenarios. Eight Scenarios are developed and compared in an IRP analysis to determine the best long-range plan for the utility. Supply-side options typically include the evaluation of conventional resources, RE resources, and distributed energy resources; however, in the IRP, only RE resources were evaluated based on the RE targets and sufficiency of existing thermal (natural gas-fired) generation. Demand-side options, such as those shown in

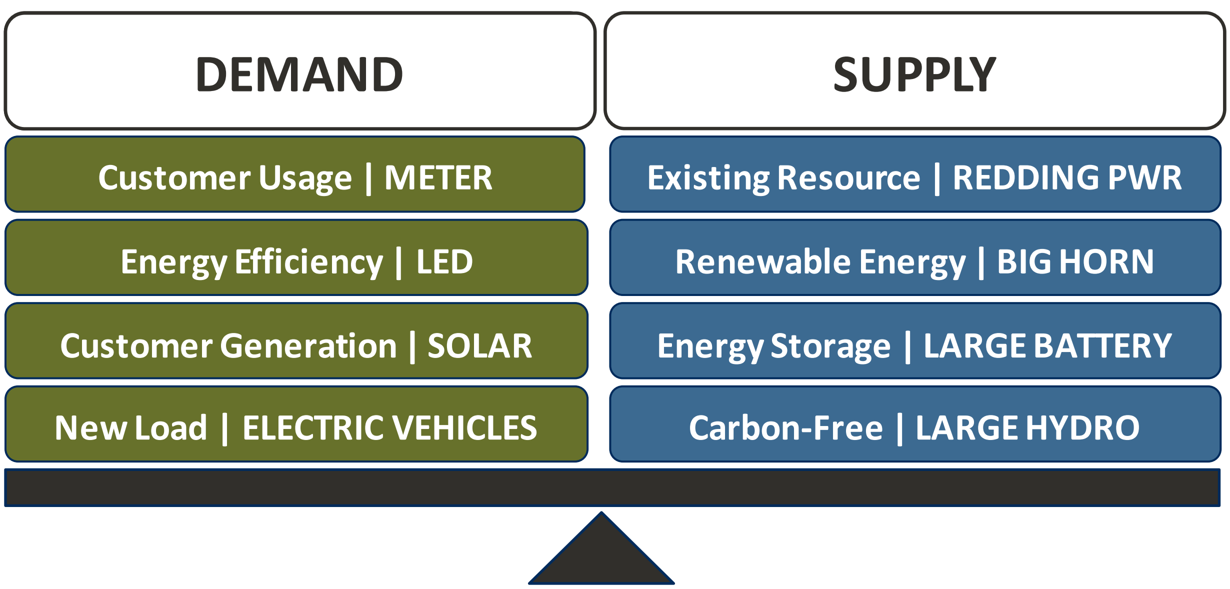

Figure 2-1, can include demand response programs, energy efficiency programs, and other “behind the meter” options, all of which can serve to reduce the overall utility load.

Figure 2-1 COR's Energy Demand and Supply

The key steps of IRP development undertaken are shown in Figure 2-2. These steps were performed over a period of more than one year and were structured to address all regulatory and legislative requirements. Internal IRP approval by the Council is scheduled to occur in October 2018.

Figure 2-2 COR's Integrated Resource Planning Process

2.2 METHODOLOGY

In order to compare the economic and other merits of different resource options and portfolios, IRPs utilize various tools and methodologies to conduct detailed modeling of a power system. Such modeling allows the cost of alternative scenarios to be quantified in terms of present value cost as well as the tracking of whether a portfolio achieves other targets such as GHG and RE goals. It is possible that the least cost portfolio may not be selected if other objectives are not met, or if a slightly more costly portfolio does much better with regard to other goals.

The supply-side evaluations of generating unit alternatives were primarily performed using economic analysis tools developed by Ascend Analytics. The primary tool used in the analysis was PowerSimm, a dispatch optimization and production cost tool that allows the determination of the net cost to serve COR's energy load and tracking of objectives such as RE and emission targets while also considering the volatility of key variables such as fuel price, power price, variability in energy production, outages, weather, and load. Additional detail about PowerSimm and the methodology utilized is provided in Section 7.

2.3 STATE LAWS, POLICY, AND REGULATIONS

Electric utilities are subject to ongoing regulation that can arise from federal, state, and local laws and regulations. This section explains various California laws and regulatory requirements passed in recent years that apply to POUs and is summarized in Figure 2-3. The emphasis will be on legislation, laws, and instructions directly addressing IRP preparation, primarily SB 350, PUC 9621, and the CEC guidelines to POUs for IRP preparation. This is followed by a chronological discussion of other laws, policies, and regulations that also impact long-range planning and influence culminated in the SB 350 and PUB 9621 requirements.

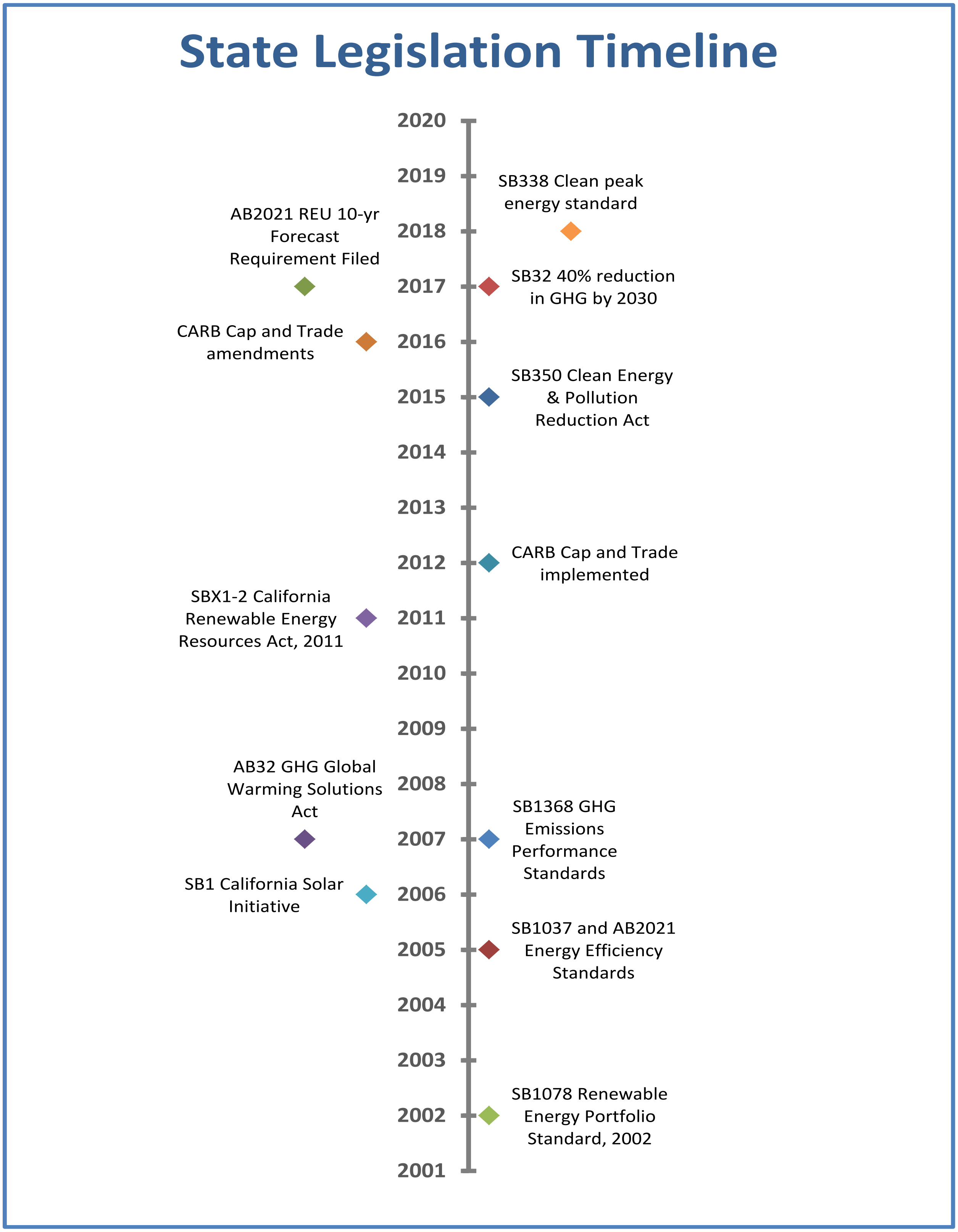

Figure 2-3 Timeline of Key State Legislative Actions Impacting IRP Planning

2.3.1 SB 350 and PUC 9621

This Report is filed in accordance with the mandates of SB 350 (de Leon, Chapter 547, Statutes of 2015) and associated changes to Public Utilities Code (PUC) Section 9621. SB 350, the "Clean Energy and Pollution Reduction Act of 2015," was signed into law by Governor Brown in October 2015 and required POUs with a three-year (2013-2016) average annual energy requirement of greater than 700 GWh to submit an IRP to the CEC—COR is the smallest utility required to file an IRP.

SB 350 requires POUs to file an IRP consistent with PUC 9621, with the CEC to review and determine IRP consistency. IRPs must be approved by POUs by January 1, 2019, and filed with the Energy Commission by April 30, 2019. The IRP is to be updated at least once every five years thereafter.

PUC 9621 established several targets that affect future resource additions. These include:

- Achieving a statewide target that doubles energy efficiency savings in electricity and natural gas end uses by 2030 to the extent it is cost-effective, feasible, and does not adversely impact public health and safety.
- The development of IRPs that achieve GHG emissions reduction targets established by the CARB, in coordination with the CPUC and the Energy Commission that result in GHG emission reductions of 40 percent from 1990 levels by 2030.

  NOTE: In July 2018 the CARB staff, in coordination with the CEC and CPUC staff, issued targets that were developed around an economy-wide, 260 million metric tons of carbon dioxide equivalent ($MMTCO_2e$) as the mass-based GHG target for the state in 2030.[4] The achievement of this target is spread across all GHG-contributing sectors, with the electric sector targeted to account for a 51 percent to 72 percent reduction from the 1990 GHG emission level of 108 $MMTCO_2e$. This goal is shown in Table 2-1.
- Achieving a renewable resource level of at least 50 percent by 2030 for the amount of electricity generated and sold to retail customers. PUC 9621 also requires compliance with the interim renewable targets in the California Renewables Portfolio Standard Program; for periods beyond the 2018 date of this IRP, the interim targets are 33 percent by the end of 2020, 40 percent by the end of 2024, and 45 percent by the end of 2027.[5] Annual updates must be submitted by the POU.
- These objectives are to be met while also complying with the goals in PUC 454.52 related to serving customers at just and reasonable rates, minimizing ratepayer impacts, ensuring reliability, strengthening the transmission and distribution system, enhance demand-side management, and minimizing pollutants with early priority on disadvantaged communities.,

[4] California Air Resources Board, *Staff Report: Senate Bill 350 Integrated Resource Planning Electricity Sector Greenhouse Gas Planning Targets*, July 2018.

[5] PUC Division 1, Part 1, Chapter 2.3, Article 16, 399.11-399.32, the interim requirements are listed in 399.15(b.2.B) and 339.30 (c, 2).

Table 2-1 Estimated 2030 GHG Emissions by Sector ($MMTCO_2e$)

SECTOR	1990	2030 SCOPING PLAN RANGES($MMTCO_2e$)	% CHANGE FROM 1990 (%)
Electric Power	108	30-53	-72 to -51
Agriculture	26	24-25	-8 to -4
Residential and Commercial	44	38-40	-14 to -9
High GWP	3	8-11	267 to 367
Industrial	98	83-90	-15 to -8
Recycling and Waste	7	8-9	14 to 29
Transportation	152	103-111	-32 to -27
Natural Working Lands Net Sink	-7	TBD	TBD
Subtotal	431	294-339	-32 to -21
Cap-and-Trade Program	n/a	34-79	n/a
Total	431	260	-40
CARB, Staff Report: SB 350 Integrated Resource Planning Electricity Sector Greenhouse Gas Planning Targets, July 2018, p. 23.			

The CARB document also set forth proposed GHG targets for the individual POUs. These targets are shown in Table 2-2 and include a targeted 2030 range of between 57,000 and 101,000 $MTCO_2e$ for COR; this amounts to 0.191 percent of the 2030 electricity sector emissions. CARB has proposed to update these targets on a 5-year basis to coincide with the IRP filing requirements.

Table 2-2 POU Share (in 1,000 $MTCO_2e$) of 2030 GHG Emissions Projected by CARB

POU	2030 ELECTRIC SECTOR EMISSIONS (%)	LOW 2030 TARGET ($MTCO_2e$*)	HIGH 2030 TARGET ($MTCO_2e$*)
City of Redding	0.191	57,000	101,000
City of Burbank	0.430	129,000	228,000
City of San Francisco	0.041	12,000	22,000
City of Anaheim	1.015	305,000	538,000
City of Palo Alto	0.174	52,000	92,000
City of Pasadena	0.426	128,000	226,000
City of Riverside	0.918	275,000	487,000

POU	2030 ELECTRIC SECTOR EMISSIONS (%)	LOW 2030 TARGET ($MTCO_2e$*)	HIGH 2030 TARGET ($MTCO_2e$*)
City of Vernon	0.497	149,000	263,000
City of Glendale	0.396	119,000	210,000
Imperial Irrigation District	1.745	524,000	925,000
L.A. Dept. of Water & Power	8.851	2,655,000	4,691,000
Modesto Irrigation District	1.055	317,000	559,000
City of Roseville	0.452	136,000	240,000
Silicon Valley Power	0.915	275,000	485,000
SMUD	3.621	1,086,000	1,919,000
Turlock Irrigation District	0.629	189,000	333,000
*Low target based on 30 $MMTCO_2e$ for the sector; high target based on 53 $MMTCO_2e$ for the sector. Emission targets for each utility are rounded to the nearest 1,000 $MTCO_2e$.			
CARB, *Staff Report: Senate Bill 350 Integrated Resource Planning Electricity Sector Greenhouse Gas Planning Targets*, July 2018, p. 30.			

2.3.1.1 CEC IRP Guidelines

To facilitate IRP preparation and submittal, the CEC developed IRP guidelines for the state POUs. The guideline document, entitled *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines*, was issued in July 2017 (updated in August and September 2018) and established a number of requirements to be included in the IRP Filing. These requirements include the following:

- POUs must submit the four Standardized Tables to the CEC as part of the IRP Filing. These tables consist of the following:
    1. Capacity Resource Accounting Table (CRAT): Annual peak capacity demand in each year and the contribution of each energy resource (capacity) in the POU's portfolio to meet that demand.
    2. Energy Balance Table (EBT): Annual total energy demand and annual estimates for energy supply from various resources.
    3. GHG Emissions Accounting Table (GEAT): Annual GHG emissions associated with each resource in the POU's portfolio to demonstrate compliance with the GHG emissions reduction targets established by CARB.

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

The four Standardized Tables for the preferred Scenario are presented in Appendix A 8.

- The minimum planning period begins January 1 of the year that the POU's Council adopts the IRP (scheduled for 2018) and must go through 2030, although longer planning periods are encouraged.
- POUs are encouraged to evaluate alternative resource options through various scenarios and sensitivity analyses.
- The IRP Filing must include supporting information used to develop the Standardized Tables and other studies, data, analyses used or relied upon in developing the IRP.
- POUs are required to report the forecasted peak demand, forecasted retail sales, other loads, and net energy for load in the EBT. The IRP must explain the demand forecast method and assumptions utilized. The CEC encourages alternative demand forecast scenarios to be part of the IRP.
- The IRP must report the mix of resources in the required tables; this includes RPS procurement information in the RPT. The mix of resources refers to short-term and long-term electricity, electricity-related, and demand response products. RPS information provided must demonstrate the achievement of the RPS target by listing the RPC procurement targets—the projection of renewables as contained in a RPS procurement plan. The reporting of resource mix must also include the impacts of energy efficiency and demand response resources. Energy storage (ES) and transportation electrification should also be addressed in the IRP and included in the required tables, as appropriate.
- The IRP should address system reliability. This includes explaining how the planning reserve margin was established and a discussion of any local, transmission-constrained areas.
- GHG emission intensities must be reported in metric tons of carbon dioxide equivalent per MWh for each supply resource reported in the EBT.
- The IRP should be consistent with the goal of achieving just and reasonable rates and must include, as Supporting Information, a report on rate impacts under the IRP plan if that report was considered in the IRP planning process.
- The IRP should report on the contribution of the IRP to increasing the diversity, sustainability, and resilience of the transmission and distribution system.
- The IRP should be consistent with minimizing localized air pollutants and other GHG emissions with early priority on disadvantaged communities.

Table 2-3 lists the IRP Filing requirements as listed in the CEC guidelines document and indicates where in this IRP the corresponding information is provided. This table is also provided after the IRP Project Partners table at the beginning of this IRP document.

Table 2-3 Summary of Key IRP Filing Requirements and Location in IRP

ITEM	SELECTED TEXT FROM THE *CEC GUIDELINES*	LOCATION IN IRP
A. Planning Horizon and Objective of Expansion Plan	"adopt an IRP that ensures the utility achieves the specific goals and targets by 2030, including…greenhouse gas emissions reductions of 40 percent below 1990 levels, and…at least 50 percent of eligible renewable resources…The minimum planning horizon…begins no later than January 1 of the year that the POU's governing board adopts the plan and ends no earlier than December 31, 2030…POUs are encouraged to undertake and present analysis….that addresses the post-2030 period"	Section 8
B. Scenarios and Sensitivity Analysis	"IRP Filings….must meet the requirements of PUC Section 9621. POUs are encouraged to also evaluate other scenarios and sensitivity analyses to consider the feasibility and cost-effectiveness (and rate impacts) of alternative resource options."	Section 8
C. Standardized Tables	"POUs must submit the following four Standardized Tables… • Capacity Resource Accounting Table (CRAT) • Energy Balance Table (EBT) • RPS Procurement Table (RPT) • GHG Emissions Accounting Table (GEAT)"	Appendix A
D. Supporting Information	"(1) analyses, studies, data, and work papers, or other material that the POU used or relied upon (including inputs and assumptions) in creating the IRP… and (2) additional information required by these guidelines. Supporting Information supplements the data submitted in the Standardized Tables."	Section 4, 5, 7; all Appendices
E. Demand Forecast	"1. Reporting Requirements…annual forecasted peak demand (MW) in the CRAT and annual forecasted retail sales, other loads, and net energy for load in the EBT… 2. Demand Forecast Methodology and Assumptions. 3. Demand Forecast – Other Regions. If the POU uses system modeling…the IRP Filing must include the demand forecast assumptions for regions outside the POU jurisdiction."	Section 4, Appendix A
F. Resource Procurement Plan	"…the mix of resources… in the IRP [as]…reported on the CRAT, EBT, and GEAT, and RPS procurement must also be reported on the RPT [along with] all inputs, assumptions, and methodologies …The IRP Filing must address[:] 1. Diversified Procurement Portfolio 2. RPS Planning Requirements 3. Energy Efficiency and Demand Response Resources 4. Energy Storage 5. Transportation Electrification"	Section 8, Appendix A

ITEM	SELECTED TEXT FROM THE *CEC GUIDELINES*	LOCATION IN IRP
G. System and Local Reliability	"Filing POUs [must] adopt an IRP to… meets the goal of ensuring system and local reliability…[and report]: 1. Reliability Criteria…the planning reserve margin and how it was determined. 2. Local Reliability Area. The IRP Filing must identify any local transmission constrained areas in the POU service territory…"	Section 4
H. Greenhouse Gas Emissions	"POUs must report in the GEAT estimated emissions intensities (in metric tons of carbon dioxide equivalent [CO_2e] per megawatt hour…for each supply resource reported in the EBT."	Section 8, Appendix A
I. Retail Rates	"…the IRP Filing must include, as Supporting Information, a report or study on rate impacts under the IRP scenario, if that report or study was considered by the local governing authority as part of its IRP planning."	Section 8
J. T&D Systems	"…adopt and IRP [that] achieves the goal of strengthening the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities."	Section 3
K. Localized Air Pollutants and Disadvantaged Communities	"…adopt IRPs to…[achieve] the goal of minimizing localized air pollutants and other GHG emissions, with early priority on disadvantaged communities…[discuss] how current programs and policies in place…address local air pollution…[and] how programs assist and prioritize disadvantaged communities."	Section 8
Summarized from Chapter 2 of Vidaver David, Melissa Jones, Paul Deaver, and Robert Kennedy. 2018. *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines*. California Energy Commission. Publication Number: CEC-200-2017-004.		

2.4 OTHER RELEVANT STATE LEGISLATION AND EXECUTIVE ORDERS

SB 350 and PUC 9621 are, in many ways, the outgrowth of several preceding bills or executive orders affecting the electric utility industry. In general, these bills and orders had the effect of regulating GHG and increasing investment in energy efficiency and environmentally friendly generation and storage alternatives. These objectives were achieved principally through more stringent renewable RPS requirements. The following is a brief summary of key bills and orders, arranged chronologically within the categories of GHG emissions, energy efficiency, RE, and solar power.

2.4.1 Greenhouse Gas Emissions

2.4.1.1 Greenhouse Gas Emissions – Global Warming Solutions Act (AB 32)

On January 1, 2007, Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006 (the GWSA) took effect, prescribing a statewide cap on global warming pollution with a goal of returning to 1990 GHG emission levels by 2020. The law required utilities to report GHG emissions to the CARB, and allowed the CARB to adopt specific regulations for reducing GHG emissions.

On October 20, 2011, the CARB adopted a regulation implementing a Cap-and-Trade Program which became effective on January 1, 2012. The program, which was implemented in phases, covers emissions from electricity generators, electricity importers, large industrial sources, and transportation fuels. The cap on emissions was established in 2013, and was designed to decline every year consistent with reaching the 1990 emission levels by 2020. To achieve the goal, carbon allowances are distributed annually in amounts equal to the cap for that year. Some allowances are given freely, and others are auctioned off. Allowance owners may use allowances to emit carbon or sell the allowances on the secondary market.

CARB held an October 2, 2015 workshop to begin the development of 2016 Cap-and-Trade Program amendments. CARB stated four objectives: (i) to extend the program beyond 2020; (ii) to improve programmatic efficiencies (covering auctions and data reporting); (iii) to better reflect the latest technical data on global warming potential and experiences with other emissions trading programs; and (iv) to maintain the environmental and market integrity of California's program.

The resource plan must ultimately conform to the California GHG emission requirements stated in AB 32. The AB 32 scoping plan regulations require certain economic sectors of California to reduce GHG emissions to 1990 levels by 2020 through a Cap-and-Trade Emissions Reduction Program. As part of this Program, COR must submit "allowances" for its emissions from the Station, as well as a portion of the electricity brought into California over its transmission assets. An allowance represents one metric ton of GHG emissions. The allowances are administered by the CARB.

CARB has provided a set number of "free allowances" each year in order to offset the expected cost burden of the Cap-and-Trade Program. COR has reduced its GHG emissions profile through the following actions:

- Procuring carbon-free energy and making energy purchases that are low in GHG emissions;
- Stepping out of San Juan Coal, which makes Redding 100% coal free;
- Executing a contract with Big Horn before renewables were required;
- Increasing our largest carbon-free asset, WAPA; and,
- Upgrading the Station units 5 and 6 with dual-function catalysts which reduced emissions and increased efficiency

As a result of these emissions reduction efforts, COR has been able to sell a portion of its free allowances in the Cap-and-Trade auction process with total revenues of over $18 million as of March 2018. These funds have been held as restricted reserves, and any revenue received from the sale of these free allowances must be used exclusively for the benefit of the electric utility's ratepayers, consistent with the GHG reduction goals of AB 32. Approximately $10.8 million of these revenues have subsequently been allocated toward funding GHG efforts such as energy efficiency and electric vehicle (EV) programs, as further described in Section 5 of this report.

2.4.1.2 Greenhouse Gas Emissions – Emissions Performance Standard (SB 1368)

Senate Bill 1368 (SB 1368) became law on January 1, 2007. The bill provides for an emission performance standard (EPS), which restricts new investments in baseload fossil fuel electric generating resources that exceed the rate of GHG emissions for existing combined-cycle natural gas baseload generation. SB 1368 allows the CEC to establish a regulatory framework to enforce the EPS for POUs. The CEC regulations prohibit any investment in baseload generation that does not meet the EPS of 1,100 pounds of carbon dioxide (CO_2) per MWh of electricity produced, with limited exceptions for routine maintenance, requirements of pre-existing contractual commitments, or threat of significant financial harm.

2.4.1.3 Greenhouse Gas Emissions: SB 32 and AB 197

SB 32, which was implemented on January 1, 2017, requires the CARB (the designated state agency charged with monitoring and regulating sources of GHG emissions), to ensure that statewide GHG emissions are reduced by at least 40 percent below the 1990 level no later than December 31, 2030.

Companion legislation, Assembly Bill 197 (AB 197), also implemented on January 1, 2017, increases legislative oversight of the CARB. In addition, AB 197 requires that the CARB, if adopting rules and regulations to achieve emissions reductions beyond the statewide GHG emissions limit, protect the State's most impacted and disadvantaged communities, follow specified requirements, consider the social costs of the emissions of GHG, and prioritize emission reduction rules and regulations that achieve specified results.

2.4.2 Renewable Energy

2.4.2.1 Portfolio Standard (SB 350 and SB 1078)

In response to the adoption of Senate Bill 1078 in 2002, a bill establishing the California Renewables Portfolio Standard (RPS) Program, COR first formally adopted a RPS in 2003, which stated that it would meet or exceed a standard of 20 percent of the annual energy needs to be provided by state-qualified renewable resources by 2017. In response to the development by the CARB of a Renewable Energy Standard, the RPS policy was updated in 2011 to include a 33 percent target by 2020. In accordance with the California Renewable Energy Resources Act, enacted in 2011 as Senate Bill X1-2 (SB X1-2), COR was required to complete the following:

(i) Develop and implement a renewable energy resource plan that provides a specified average of the Electric System's retail sales from eligible renewable energy resources. More specifically: the first compliance period was from January 1, 2011 to December 31, 2013, during which an average of 20 percent of the Electric System's retail sales were required to be procured from eligible renewable energy resources.

(ii) During the second compliance period, from January 1, 2014 to December 31, 2016, the Electric System is required to make reasonable progress each year toward a December 31, 2016 goal of 25 percent of retail sales from eligible renewable energy resources.

(iii) During the third compliance period, from January 1, 2017 to December 31, 2020, with the adoption by the CEC of regulations to enforce SBX1-2, the Electric System is required to procure eligible renewable energy resources for 27 percent of its 2017 retail sales, 29 percent of its 2018 retail sales, 31 percent of its 2019 retail sales, and 33 percent of its 2020 retail sales.

(iv) Legislation enacted in 2015, Senate Bill 350 ("SB 350"), requires that electricity generated each year from eligible renewable energy resources be at least 50 percent by December 31, 2030.

2.4.2.2 Renewables Portfolio Standard (SBX1-2)

SBX1-2, the "California Renewable Energy Resources Act," was signed into law by Governor Brown on April 12, 2011. SBX1-2 codifies the RPS target for retail electricity sellers to serve 33 percent of their loads with eligible RE resources by 2020. As enacted, SBX1-2 makes the requirements of the RPS program applicable to POUs.

SBX1-2 requires each POU to adopt and implement a RE resource procurement plan involving the procurement of at least the following amounts of electricity products from eligible RE resources, which may include RE certificates (RECs), as a proportion of total kilowatt hours sold to the utility's retail end-use customers:

(i) over the 2011-2013 compliance period, an average of 20 percent of retail sales from January 1, 2011 to December 31, 2013, inclusive;

(ii) over the 2014-2016 compliance period, a total equal to 20 percent of 2014 retail sales, 20 percent of 2015 retail sales, and 25 percent of 2016 retail sales; and

(iii) over the 2017-2020 compliance period, a total equal to 27 percent of 2017 retail sales, 29 percent of 2018 retail sales, 31 percent of 2019 retail sales, and 33 percent of 2020 retail sales. (More recently, SB 350 increased the statewide RPS to 50 percent by 2030.)

In addition to meeting the RE percent procurement target, the RPS established certain Portfolio Content Categories (PCC) that further divided the eligible RE resources to be procured and established certain limits. The PCCs essentially classify renewable resources into one of four categories based on location of the interconnection and other factors as follows:

PCC1: products must be bundled and the POU may not resell the energy; the resource's first point of interconnection must be to a distribution system serving end-users *within* a California balancing authority area; RE products having a first point of interconnection outside of a California balancing authority area must be scheduled hourly into the area without substituting electricity from another source.

PCC2: products must be bundled and interconnected to a network within WECC; the electricity must be scheduled into a California balancing authority area; the products must have a first point of interconnection *outside* of a California balancing authority area, and the electricity must not be in the portfolio of the POU prior to the date of contract or ownership agreement; the electricity must be scheduled into the California balancing authority area within the same calendar year that the electricity is generated, and the energy may not be sold back by the POU.

PCC3: unbundled RE credits and products that do not meet the requirements of PCC1 or PCC2.

PCC0: RE under contract prior to June 1, 2010, provided that the resource meets the RPS eligibility requirements in effect when the procurement agreement was executed; subsequent amendments do not increase the capacity or production, or substitute a different resource (any such change would be classified into PCC1, 2, or 3 and follow the portfolio balance requirements); and the duration of the contract may be extended if the original contract was for 15 years or more.

For the 2017-2020 period, a minimum of 75 percent of the RE must be classified as a PCC1 resource and a maximum of 10 percent can be a PCC3 resource.

To meet the RPS requirements, the 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. The resolution adopted RPS targets of 20 percent (averaged) from 2011-2013; 25 percent in 2016, and 33 percent in 2020 and thereafter.[6]

In meeting these targets, COR is allowed to apply Excess Procurement (see Appendix E; Optimal Compliance Measures) from one compliance period to subsequent periods and the Council adopted a Cost Limitation such that the annual RPS expenditure should not require rate increases of more than 1.5 percent per year at any time during the life of the considered RPS procurement, and the

[6] RPS Policies & Procedures, *RPS-001 Renewables Portfolio Standard Procurement and Enforcement Plan* (Version 3) REU Resources Division, June 5, 2018, pp. 3-12.

kWh cost of RPS procurement (including delivery, firming, shaping, or storage) should not exceed 75 percent of COR's current kWh retail residential energy charge.

Resolution 2011-197 also adopted the following Enforcement Policies:

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

B. COR will report annually to the City Council on its status of compliance with SBX1-2.

C. COR will notify the City Council of any potential for lack of compliance with the requirements of SBX1-2.

D. COR will explain to the City Council the reason for any noncompliance with SBX1-2 and submit a plan of corrective action.

E. At such time, the City Council will direct staff on its recommended course of action.

2.4.3 Demand Side

2.4.3.1 Solar Power (SB 1)

On August 21, 2006, Governor Schwarzenegger signed into law California Senate Bill 1 (also known as the "California Solar Initiative"). This legislation requires POUs to establish a program supporting the SB 1 goal to install 3,000 MW of photovoltaic energy in California. POUs are also required to establish eligibility criteria in collaboration with the CEC for the funding of solar energy systems receiving ratepayer-funded incentives. The legislation gives a POU the choice of selecting an incentive based on the installed capacity or based on the energy produced by the solar energy system, measured in kilowatt-hours. Incentives would be required to decrease at a minimum average rate of 7 percent per year. POUs also have to meet certain reporting requirements regarding the installed capacity, the number of installed systems, number of applicants, the amount of awarded incentives, and the contribution toward the program's goals.

In response to SB 1, the Council implemented a Solar Rebate Program in 2008. The program was to offer rebates and incentives over a 10-year period beginning in 2008. This program was to be paid for through a rate surcharge of $0.00125 per kWh starting in October, 2007. Aggressive solar rebates were offered through September 30, 2010. In 2010, the Council approved a 700 kW project at the municipal airport and, combined with several other scalable sized projects, effectively exhausted funds available to incentivize solar photovoltaic projects with rebates through July, 2014. In August, 2014, the rebate program reopened with $700,000 in funding; those funds were exhausted in less than two business days through 105 applications with a total installed capacity of 1.3 MW.

Since that time, growth in installed PV systems has continued. On September 13, 2016, the solar rebate program again re-opened, this time providing a $0.50/watt rebate, up to maximum of $5,000. After meeting the goals of SB 1, the new program was closed for new applications on October 31, 2017, with approximately $10.1 million in rebates having been provided over the life of the program which helped to provide more than 8 MW of installed capacity at over 800 customer locations.[7]

As defined by SB 1, COR is fast approaching the 5% net energy metering (NEM) (1.0) cap of 12.7MW and it is anticipated that cap will be reached around the 3rd quarter of 2020. Prior to hitting the cap, a successor policy will be developed and submitted to Council for approval and early adoption to ensure a smooth transition.

2.4.3.2 Energy Efficiency (SB 1037; AB 2021)

Senate Bill 1037 (SB 1037) was signed by then Governor Schwarzenegger on September 29, 2005. The bill requires that each POU, prior to procuring new energy generation resources, first acquire all available energy efficiency, demand reduction, and renewable resources that are cost-effective, reliable, and feasible. SB 1037 also requires each POU to report annually to its customers and to the CEC its investment in energy efficiency and demand reduction programs.

California Assembly Bill 2021 (AB 2021), signed by then Governor Schwarzenegger on September 29, 2006, requires that POUs establish, report, and explain the basis of the annual energy efficiency and demand reduction targets by June 1, 2007, and every three years thereafter, covering a ten-year future horizon. A subsequent bill has changed the time interval for establishing annual targets to every four years. Reporting requirements under AB 2021 include: (i) the identification of sources of funding for the investment in energy efficiency and demand reduction programs; (ii) the methodologies and input assumptions used to determine cost-effectiveness; and (iii) the results of an independent evaluation to measure and verify energy efficiency savings and demand reduction program impacts.

2.4.3.3 Energy Efficiency and Demand Side Management

In addition to the impact on demand from solar power, COR has several ongoing EE and DSM programs that help manage demand on the COR system. These efforts are described in detail in Section 5.0.

2.4.3.4 Peak Demand (SB 338)

SB 338, passed by the California Senate on September 6, 2017 and approved by the Governor on September 30, 2017, requires the PUC Commission and the governing boards of local publicly-owned electric utilities to consider how energy storage, energy efficiency strategies, and distributed energy resources can help utilities meet peak demand electricity needs while reducing the need for new electricity generation and transmission facilities. COR has seen a reduction in peak demand over the last several years and forecasts very little growth from these levels during the planning horizon. As a result, COR currently possesses the required level of resources (including energy storage and energy efficiency programs) to meet future expected peak demand requirements.

2.5 FEDERAL ENERGY LEGISLATION

Currently, the state requirements described above dictate the renewable and emission standards for POUs in California. It is possible that in the future, more restrictive requirements could be mandated at the federal level resulting from new laws or regulations implemented by the U.S. Environmental Protection Agency (EPA).

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[7] *City of Redding Report to Redding City Council, 4.5(b)—Adopt Resolutions to Terminate Solar Surcharge*, November 7, 2017.

In 2009, the EPA issued an "endangerment finding" that, it argued, allowed it to regulate emissions of GHG under existing law. This finding, and other findings and proposed rules, were challenged in court. Ultimately, it was found that the EPA had the authority to regulate GHG emissions from sources that were already covered under other emissions programs. Meanwhile, the EPA developed a set of rules and regulations called the Clean Power Plan ("CPP"), which outlined specific emissions reductions targets for every state and required states to develop their own plans to achieve the targets. The CPP was also challenged in courts, with the result that a "stay," delayed implementation while the CPP worked its way through the courts. Before a decision was reached on the legality of the CPP, the EPA, under the administration of President Trump, announced it would repeal the CPP and replace it with other regulations. The repeal is still at the proposal phase as of the publication of this Report.

GHG regulation at the federal level remains uncertain and, therefore, it is difficult to predict the extent to which future federal policy on the subject could impact operations. This IRP was prepared assuming that California GHG emission reduction requirements would be the most stringent applicable requirements.

2.6 PUBLIC STAKEHOLDER PROCESS

This IRP benefited from the public input process. The stakeholder process involved seeking groups who have an interest in future resource plan (Stakeholders) and inviting their participation such that all relevant issues were identified and addressed. Through this process outlined in Figure 2-4, participants were engaged and involved early in the development. The end result was that the concerns and perspectives of all Stakeholders were considered, with the resulting resource plan achieving what is considered to be an appropriate balance of utility and Stakeholder objectives.

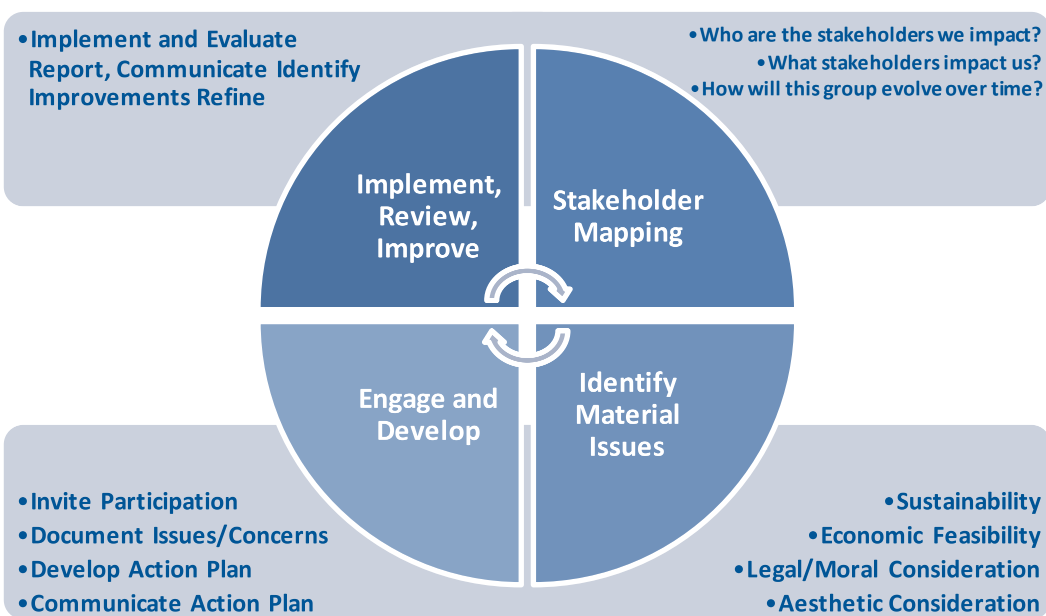


Figure 2-4 Stakeholder Integration Process

In seeking Stakeholders, COR actively sought input and participation from several types of constituents. Actions taken to reach out to potential Stakeholders included a dedicated web page on the COR web site that included information about the process, FAQs, presentations, flyers, feedback forms, surveys and survey results, as well as live recordings of stakeholder meetings.

Stand-alone flyers, bill inserts, radio spots, and social media announcements were used to reach out to customers. A dedicated e-mail was created for customers to contact the IRP team directly.

Participants who joined the stakeholder planning process illustrated in included those involved with economic development and commerce, customers, developers, governmental agencies, consultants, and other interested parties. Stakeholders participated in meetings held in February and June of 2018. Each meeting addressed different aspects of IRP planning. At the first meeting, pictured below in Figure 2-5, the primary objectives included:

- Increasing Stakeholders' understanding of the IRP process, key assumptions, and challenges
- Understanding Stakeholder concerns and perceptions
- Providing a forum for productive Stakeholder feedback at key points in the IRP process to inform decision-making
- Explaining the need to comply with Commission rules and requirements

Figure 2-5 First Stakeholder Meeting | February 23, 2018

At the second meeting, Stakeholders listed in Figure 2-6 responded to the modeling results and overall preference of planning scenarios. In both meetings, there were valuable contributions made by the participants. As part of the public process, a Stakeholder Feedback Form was presented to all participants. The results of these forms were tallied and are included in Appendix B.

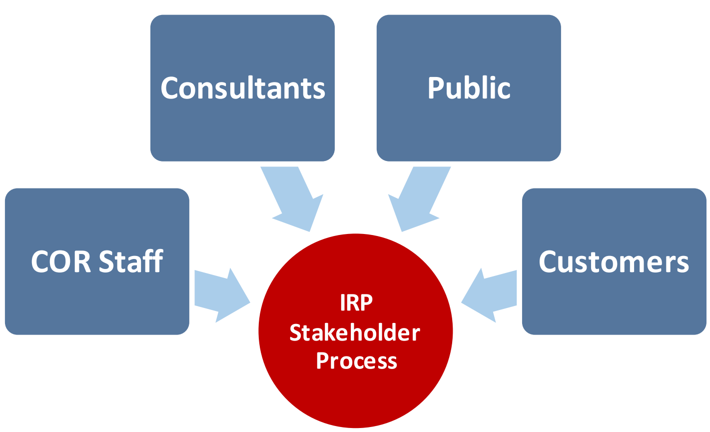


Figure 2-6 Stakeholder Engagement Participants

3.0 Existing Resources and System Description

The city of 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 county 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, the City of Redding Electric Department 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 COR's Electric Department, 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 electric system (Electric System) includes generation, transmission, and distribution assets. COR also purchases electric power and transmission services from others. For the Fiscal Year ended June 30, 2017, approximately 44,200 customer accounts were served, with a total sales of 746,000 MWh, and realized a peak demand of 231 MW.

The electric resources used to meet the power requirements of customers include generation supply resources, RE 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 2017, are presented in Table 3-1. Figure 3-1 shows the location of existing resources and Figure 3-2 shows the mix of energy production in 2017.

Table 3-1 Power Supply Resources (Calendar Year 2017)

SOURCE	CAPACITY AVAILABLE (MW)	ANNUAL ENERGY (GWH)	PERCENT OF TOTAL ENERGY[1]
Generated Power			
Redding Power Station[2] (U1-U6)	183.1	186	25%
Whiskeytown (U9)	3.5	26	3.5%
M-S-R PPA/San Juan[3] *(Now expired)*	0	0	0%
Total Generated Power[1]	**186.6**	**212**	**28.5%**
Purchased Power			
WAPA Base Resource[4]	128.5	369	49.5%
M-S-R PPA/Big Horn I Wind Project	23.0	164	22%
Total Purchased Power[1]	**151.5**	**533**	**71.5**
Total (Generated and Purchased)	**338.1**	**745**	**100.0%**

(1) Totals may not add due to rounding.
(2) Capacity listed is nameplate capacity (EIA860 defined) for Redding Power Station.
(3) The City's interest in San Juan Unit No 4 was terminated effective December 31, 2017.
(4) The hydro-based contract with WAPA is for 128.5 MW, but the average summer capability is 88 MW.

Source: City of Redding

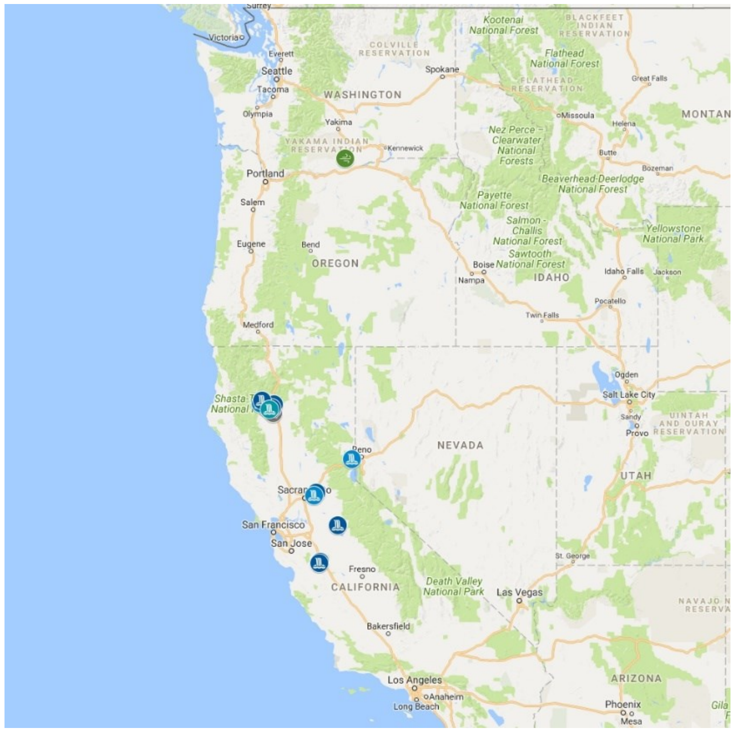


Figure 3-1 Power Resource Locations (Self-Owned and PPA Resources)

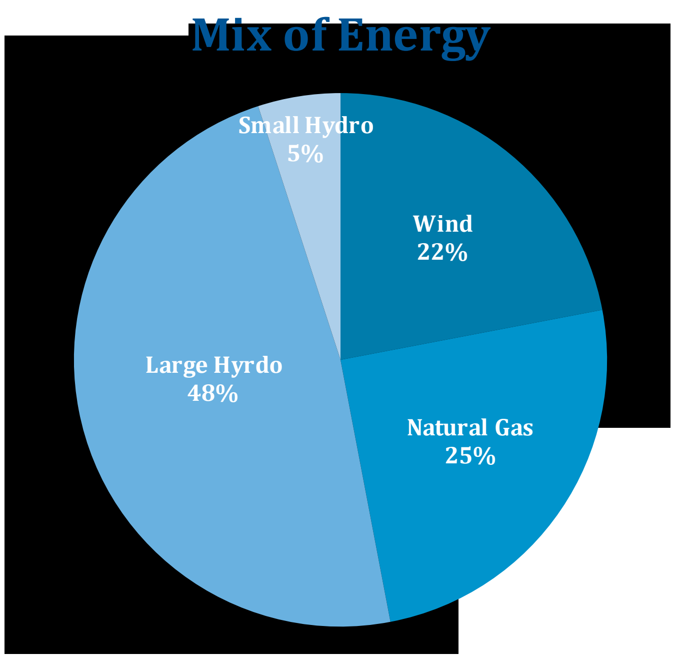


Figure 3-2 Mix of Energy Production by Generation Type, 2017 (Calendar Year)

3.1 GENERATING FACILITIES

3.1.1 Redding Power Station

The Station is the primary local generation resource, with a total station nameplate capacity of 183.1 MW. The Station is comprised of: (1) a two-on-one combined cycle power generating station with two Siemens SGT-800 gas turbines (with nameplate capacities of 42.5 MW and 40 MW, respectively) coupled to a 26.8 MW nameplate capacity GE steam turbine, and three GE Frame 5 simple cycle combustion turbines, with a 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. 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 NO_x/CO catalyst system was completed for Units 5 and 6, replacing the previously installed $SCONO_x$ emissions control system. The catalyst system lowers emissions and increases efficiency. The Station has a cooling tower fed by City water to meet its cooling needs.

3.1.2 Whiskeytown Project

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.

COR has received full CEC certification for the Whiskeytown facility as a California RPS Eligible renewable resource. The facility has been registered with the Western Renewable Energy Generation Information System (WREGIS), and the associated renewable energy credits (RECs) will either be retained for RPS compliance purposes or utilized for wholesale sales.

3.2 RENEWABLE ENERGY RESOURCES

Since 2003, COR has aggressively pursued cost-effective and self-owned or purchased renewable resources through adopted RPS targets. The initial RPS target, in response to SB 1078, was 20 percent of annual energy needs by 2017. Based on the CEC's subsequent Renewable Energy Standard and SBX1-2, the target was modified in 2011 to be 33 percent by 2020 with intermediate targets including 27 percent in 2017, 29 percent in 2018, and 31 percent in 2019. Four years later in 2015, a 50 percent RE target was adopted for the end of 2030 in response to SB 350. Currently, COR has a diversified renewable portfolio comprised of the following resources:

- Hydroelectric resources (owned)
- Hydroelectric resources (purchases)

- Wind power (purchases)
- Local solar projects (customer-owned does not qualify)

Current zero carbon and renewable resources are summarized in Table 3-2. The WAPA large hydro does not qualify as a RE resource but is considered a zero carbon resource. Behind-the-meter solar does not qualify for utility RE. In calendar year 2017, approximately 75 percent of retail sales were supplied from zero carbon resources, in part due to a prolific year for hydropower resources. The current RPS targets under SB 350 are expected to be satisfied for the remaining compliance periods through 2020. With the inclusion of the above-described projects and contracts, current projections indicate that it has sufficient renewable resources to meet the current minimum RE procurement targets mandated by state law through 2024.

Table 3-2 Current (Calendar Year 2017) Zero Carbon and Renewable Energy Resources

SOURCE	TYPE	CAPACITY AVAILABLE (MW)	ANNUAL ENERGY (GWH)	PERCENT OF RETAIL SALES
Renewable Resources				
Whiskeytown Dam	Hydroelectric (Owned)	3.5	26	3.5%
M-S-R PPA/Big Horn I Wind Project	Wind (Purchase)	22.0 (firmed and shaped MW)	164	22%
WAPA Base Resource (Small Hydro)	Hydroelectric (Purchase)		7.6	1%
Zero Carbon Resource				
WAPA Base Resource (Largo Hydro)	Hydroelectric (Purchase)	128.5	361	48.0%
Local Solar Projects (Zero Carbon Resource	Solar PV	10.2	89.4	NA (behind the meter)
Total		**165.2**	**640**	**75%**

As explained in Section 2, the solar initiative program was adopted in 2007 designed to meet SB 1 requirements for the promotion of solar photovoltaic projects through rebates and incentives. Over the last several years, more than 800 solar PV projects have been installed with a combined capacity of over 10 MW. The projects range from 1 kW to 700 kW and are located on City-owned and customer-owned facilities throughout COR's service area and as such, those project have fulfilled the SB 1 requirements.

3.3 CONTRACTUAL PURCHASES

In addition to owning and operating generating facilities, energy needs are supplemented through contractual purchases, as further described below.

3.3.1 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. COR participates in the purchase of a 35 percent share of the output from the Big Horn I Project through a power purchase agreement (PPA) with the M-S-R Public Power Agency (the M-S-R PPA), a Joint Powers Agency (JPA) of which COR is a member along with Modesto Irrigation District and the City of Santa Clara.

COR's share of Big Horn wind energy equates to approximately 70 MW (22 MW firm capacity through a firming and shaping agreement) of the output. Power deliveries commenced on October 1, 2006, and will continue through September 30, 2026, although a five-year extension is possible. If the Big Horn I Project is extended, the M-S-R PPA will have a right of first offer to negotiate a long-term power purchase for such repowered project.

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 between M-S-R PPA and Avangrid Renewables, Inc. (Avangrid is an intermediate contracting entity that purchases energy from Big Horn and provides it to M-S-R PPA), Avangrid receives energy from the Big Horn, as generated, and delivers flat 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 COR.

The Big Horn Project is operated within the BPA balancing authority area. On October 1, 2009, BPA began imposing a wind integration charge for the purpose of recovering its costs to provide within-hour generation balancing services for wind generators. The wind integration charge is currently embodied in BPA's variable energy resource balancing service and the currently applicable wind integration charge is set at $1.48/kW-month. M-S-R PPA has entered into a series of amendments of the PPA with Avangrid whereby M-S-R PPA has agreed to pay, subject to certain caps and limitations, the first $1.20/kW-month of any wind integration charge imposed by BPA, Avangrid has agreed to pay the next $1.20/kW-month, and M-S-R PPA and Avangrid will equally split any wind integration charge exceeding $2.40 per/kW-month.

Through a collaborative effort between Avangrid and M-S-R PPA, Big Horn has obtained California RPS certification as an "Eligible" renewable resource by the CEC. 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, for either retirement or wholesale sales by such members.

3.3.2 WAPA Base Resource (Hydroelectric Power)

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 (an extension beyond 2024 currently in process). As of January 1, 2015, WAPA revised its allocation percentages, and the current allocation of energy available from WAPA is 8.159%. In calendar year 2017, 336.1 GWH of energy were received from WAPA.

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 COR—and at the Airport Substation, located in the southeastern part of the service territory. Power is transmitted to distribution substations over 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. As a result of recent drought conditions in California, deliveries in recent years declined before strongly rebounding in the 2016-2017 Fiscal year.

COR's contract with WAPA includes power from numerous hydroelectric plants around the Sierra Nevada Region, some of which (Nimbus, Stampede, and Lewiston) qualify as a California RPS "Eligible" renewable resource. A contract is in place to receive the RECs from WAPA for the qualifying hydroelectric projects. These RECs aid in meeting RPS targets.

3.3.2.1 Impact of Drought

In an average water year, approximately 32 percent of COR'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 3-3 indicates, for example, that during four consecutive years of drought, generation received from the WAPA CVP was significantly reduced.

Table 3-3 Historic Deliveries from WAPA CVP

FISCAL YEAR (JULY 1-JUNE 30)	ENERGY (GWH)
2012-13	244
2013-14	178
2014-15	158
2015-16	170
2016-17	338
Estimated 2017-2018	237

Source: City of Redding, Fiscal Year, July 1-June 30

Note: COR's allocation increased from 7.74% to 8.20% on Jan 1, 2015.

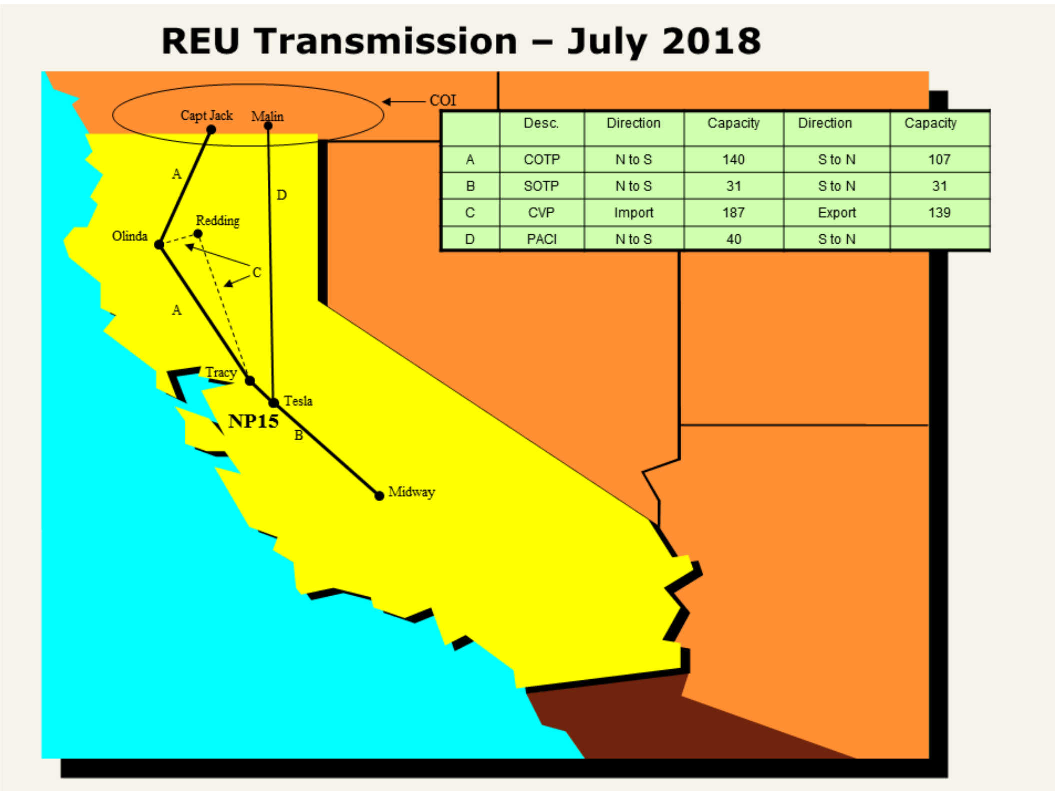
In the event of reduced hydroelectric generation, it is necessary to generate additional energy or to purchase additional energy on the wholesale market to meet its retail sales and load obligations, and such actions can significantly increase costs. This is a consideration when planning for future resources and when assessing the risk of RE 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 COR's share of Big Horn. During such periods, there is sometimes a need to purchase replacement energy from the wholesale market or generate replacement energy at an additional cost.

3.3.3 Other (NCPA)

COR is a member of the Northern California Power Agency (NCPA), which owns certain electric generating projects. COR participates in NCPA's state and federal legislative and regulatory efforts and is currently moving toward participation in a near-term solar project that is anticipated to be in-service in 2021—this project is further described in Section 7.0.

3.4 TRANSMISSION ASSETS AND ADEQUACY

The transmission facilities owned or contracted for are described in this section. Owned transmission facilities are shown in Figure 3-3.



	Desc.	Direction	Capacity	Direction	Capacity
A	COTP	N to S	140	S to N	107
B	SOTP	N to S	31	S to N	31
C	CVP	Import	187	Export	139
D	PACI	N to S	40	S to N	

Figure 3-3 Transmission

3.4.1 WAPA Transmission Service and BANC

COR is a customer of WAPA, who provides access to WAPA's high voltage transmission via an interconnection with the system. Through a transmission service contract, electricity needs that are not met by generation assets within the service area imported. 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 3-4. The details of the contracts are summarized in Figure 3-4. 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.

COR is also a member of BANC, a joint powers authority with members that also include the Sacramento Municipal Utility District (SMUD), Modesto Irrigation District (MID), Roseville Electric, Trinity Public Utility District, 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.

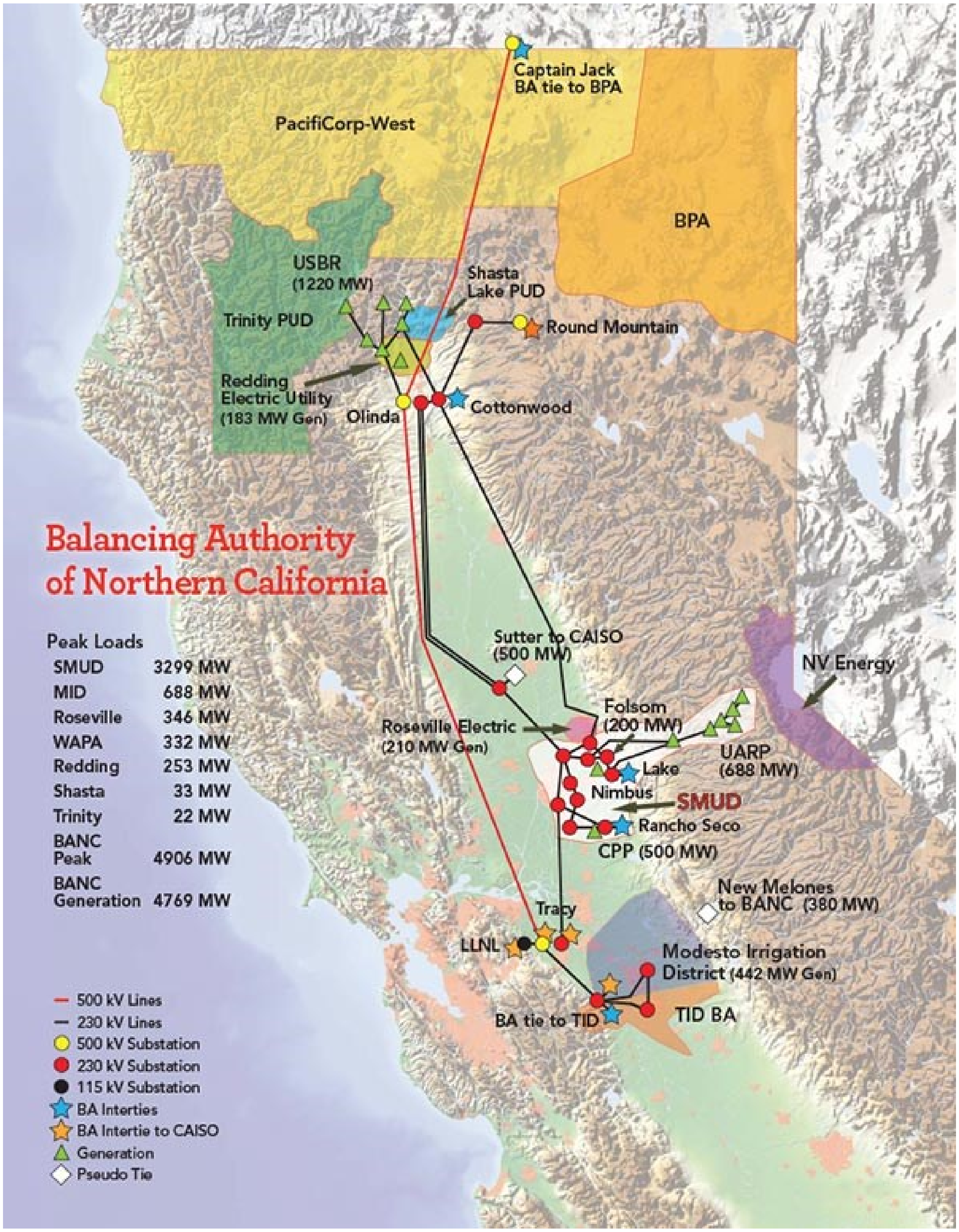


Figure 3-4 Balancing Area of Northern California (BANC) Members

As a member of BANC, COR 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 reliability standards. The structure provides flexibility to expand and allows members to benefit from potential future savings through the sharing of facility costs.

Table 3-4 WAPA Transmission Service Summary Information

CAPACITY CONTRACT	END DATE	CAPACITY (MW)*	VOLTAGE (KV)	DELIVERY/RECEIPT POINTS
Long-Term Firm Transmission Service				
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)*
Source: WAPA/CVP Contract for Transmission Service to the City of Redding, California

3.4.2 TANC and California-Oregon Transmission Project

COR, along with fourteen other northern California cities, utility districts, and one rural electric cooperative, are members or associate members of a California Joint Power Agency (JPA) known as the Transmission Agency of Northern California (TANC). TANC, together with COR, 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.

COR 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, COR purchased from COSL, its 1.5856 percent ownership interest (approximately 25 MW) in the COTP. As a result, COR 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 (the "Intertie"). The Intertie is a two-line system that, like the COTP, connects California utilities with other utilities in the Pacific Northwest. The Intertie 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).

3.4.3 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, bi-directional 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). 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.

3.4.4 Other Transmission Assets

Delivery of power from sources outside the service territory are at 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. COR jointly owns the Airport Substation with WAPA: at the Airport Substation, WAPA owns and maintains the 230 kV related facilities; COR owns, and is responsible for, the 115 kV facilities. At the Keswick Substation, WAPA owns, and is responsible for, all facilities other than the remote terminal unit equipment specific to COR's use at the Keswick Substation.

3.5 DISTRIBUTION ASSETS AND ADEQUACY

3.5.1 Distribution Assets

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 will be 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 12 kV distribution system using underground cabling. Figure 3-5 shows the interface of the 115 kV transmission system with the distribution system through 115 kV/12 kV substations.

Current transmission and distribution system consists of the following:

- Service area of approximately 61 square miles
- Approximately 72 miles of 115 kV transmission
- Eleven distribution substations, one generation station
- Approximately 740 miles of 12 kV distribution, (OH=300 mi, UG=440 miles)

- Approximately 17,000 poles

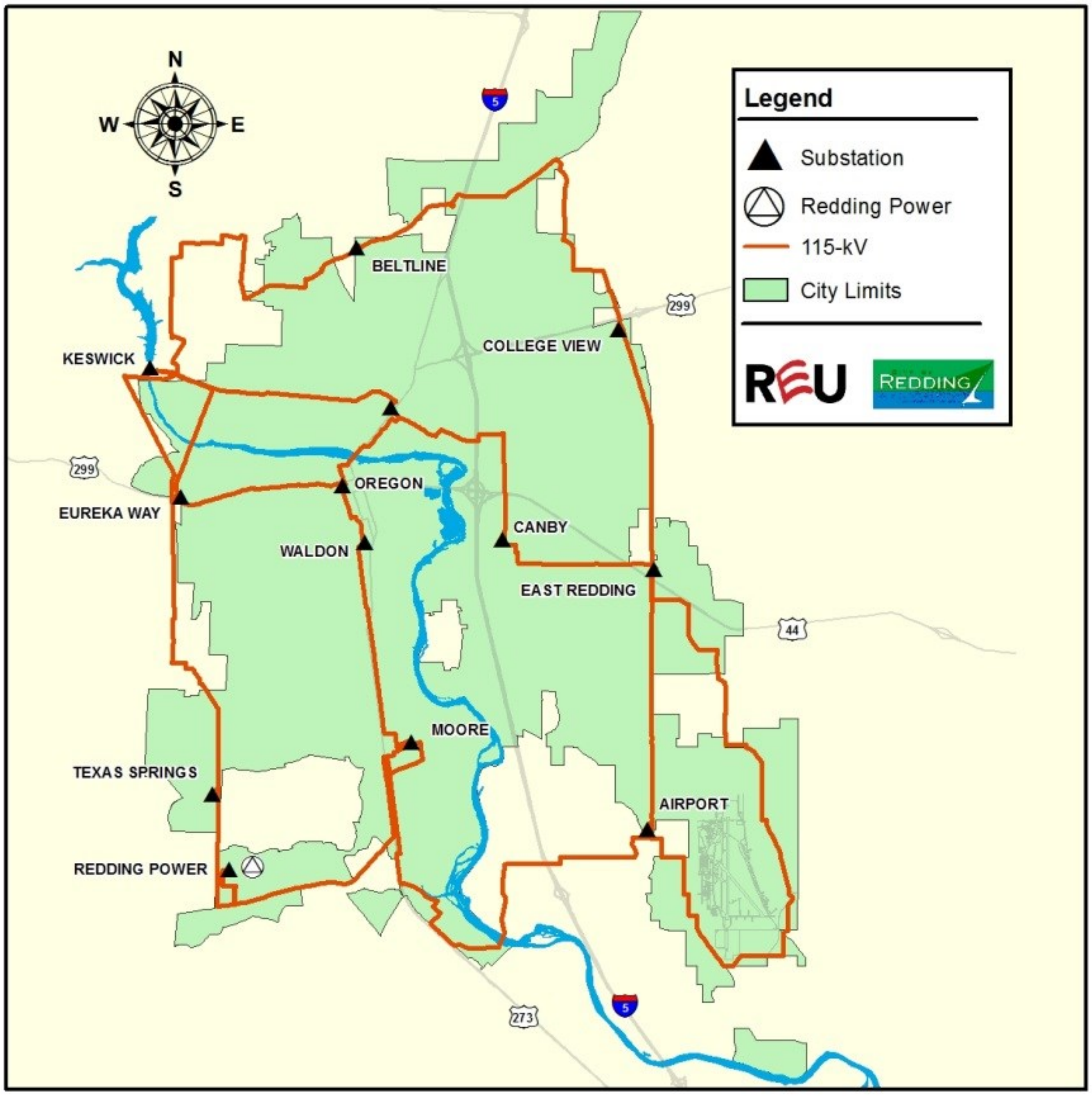


Figure 3-5 Electric Distribution System

3.5.2 Distribution System Adequacy

An all-time high service availability index rating of 99.992 percent in 2017. This means that the average customer experienced only 39 minutes without power over the entire year. This is significantly better than the comparable average for all Americans (130 minutes in 2013), as illustrated in Figure 3-6.

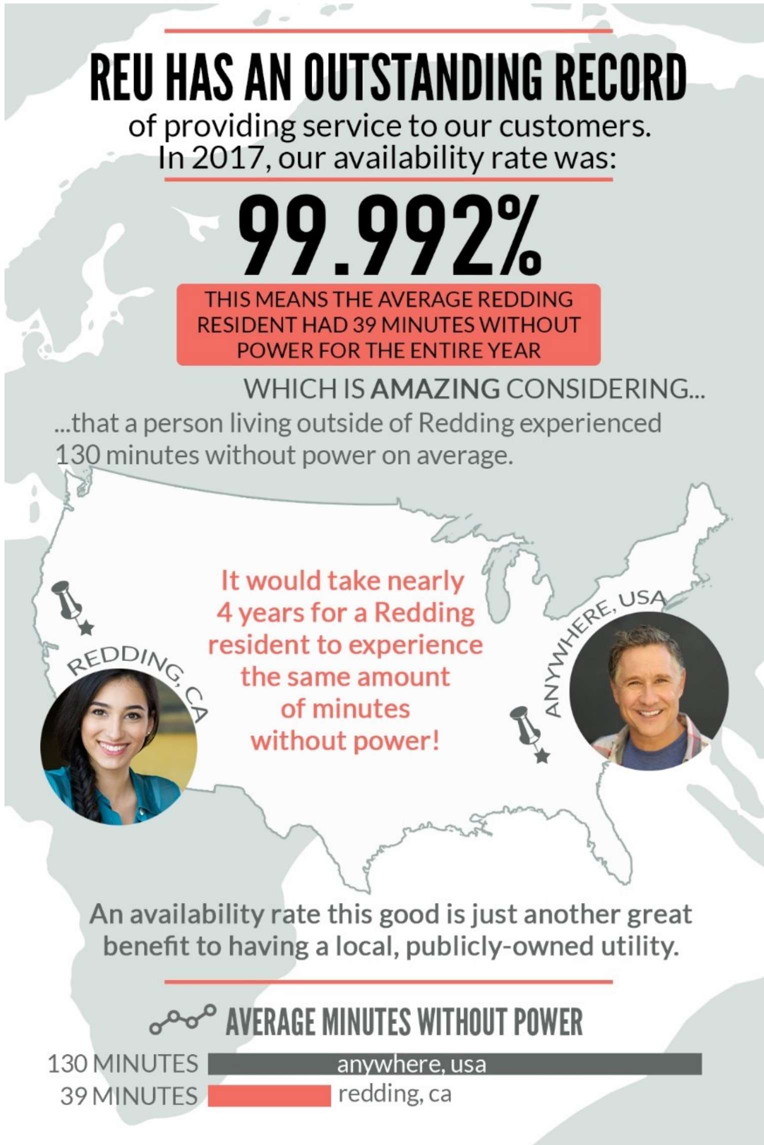


Figure 3-6 Reliability Comparison

For a more local comparison, in 2016, PG&E customers in the north valley had an average of 175 minutes without power.

During the Carr Fire—a raging wildfire that tore through Shasta County and blazed into Redding's city limits—the local transmission system lost 5 out of 6 elements of redundancy. Because of our community-owned generation station and multiple connections to the WAPA grid, our operators were able to avoid a total city-wide blackout.

The distribution system conditions are continually evaluated and appropriate adjustments are made as needed to improve and optimize the distribution network. Projects are approved and funded through the Electric Distribution Capital Expenditure Plan. Current modifications under consideration include:

1. Improved communication for Power and VAR control via local network, installation of additional circuit breaker dedicated to substations.
2. Potential system modifications to accommodate future solar installations are dependent upon site approval/location. Presently 10 MW of additional solar is expected which would equate to a requirement of 475 Amps at 12.47 kV. The majority of this solar generation is anticipated for nearby East Redding Substation and the remainder may split between two other locations. The project completion is planned for year 2021.
3. Re-conductoring of the 115 kV lines between Eureka Way and Oregon substations to increase the line rating. Under certain contingencies that cause increased through-flow, the present line may become overloaded. The project would be completed end of year 2019.
4. Installation of fiber optic communication links between the Plant, Texas Springs Substation, and Moore Road Substation. This will provide high speed tripping capability to increase generator stability as well as redundant substation communication path. The project would be completed end of year 2019.
5. Provide reconfiguration of the lines interconnecting the Plant to the bulk electric system to reduce the system impedance and resultant voltage drop to Canby Substation under certain system contingencies. If approved, the project is proposed to be completed by the end of year 2020.
6. Alternatively (to the reconfiguration project immediately above), provide VAR capacitors at Canby Substation system to reduce the resultant voltage drop to Canby Substation under certain system contingencies. If approved, the project is proposed to be completed by the end of year 2020.

Other projects being considered would provide upgrades to the communication systems necessary to integrate additional demand-side energy management investments. These projects could include:

1. Install city-wide radio network communications in support of a remote commercial metering project. This network will provide open architecture communications for control and monitoring of 12 kV line voltage via capacitor control and commercial remote metering. The project would be completed by the end of 2020.
2. Installation of the optional OMS/DMS software to augment the present OSI-SCADA system used by the Electric Utility Distribution System Operators. This improvement will decrease response times, reduce the risk of switching errors, and reduce the likelihood of unknown equipment overloads. The project would be completed by the end of 2020.
3. Provide System Operator control and monitoring of the utility-owned and large customer-owned solar facilities. This improvement will give the System Operators direct control of solar generation output including MW & Volt/VAR control. The project would be completed by the end of 2022.
4. Upgrade substation communications equipment to automatically retrieve protective relay fault information and display to the System Operator. This improvement will decrease event response times. The project would be completed by the end of 2019.

Finally, it is important to mention that it has been long recognized that reducing losses on the power distribution system through investment in energy efficiency has beneficial impacts on customer rates, on the environment, and it can extend the lifespan of transmission, distribution, and generating assets. Energy efficiency efforts are consistent with goals of reliability, affordability, and sustainability.

In this context, the energy efficiency programs undertaken (and discussed in Section 5) constitute significant steps to reduce losses on its distribution system. For example, since enacting the street lighting program in September 2015, annual system losses have been reduced by an average of 1,231,494 kWh through the conversion of high pressure sodium lighting to LED lighting. The LED lighting technology consumes nearly two-thirds less energy and is estimated, at project completion in 2021, to save over 3,700,000 kWh annually. To date, the project is approximately 33 percent completed with 2,783 LED lights already installed.

3.6 NATURAL GAS COMMODITY, TRANSPORTATION AND STORAGE

Natural gas is the primary fuel and the primary variable operating cost of the Station. The Station 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.

3.6.1 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 into 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, COR 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).

3.6.2 Fixed Price Forward Purchases

In addition to natural gas procured through the M-S-R EA Gas Prepay Project, a number of purchase obligations have been entered into, such as fixed price hedges to purchase natural gas through 2025. Currently, forecasted gas requirements range from approximately 6,000 to 10,000 Decatherms per day ("Dth/day") (a decatherm is equal to one MMBtu) for the next 7 yrs. Table 3-5 provides the volume of current fixed price natural gas purchases to which COR is committed on a yearly basis.

Table 3-5 Natural Gas Purchase Obligations, Fixed Price Hedges

YEAR	2018	2019	2020-2023	2024	2025
Decatherm per day (Dth/day) (Delivery Point is PG&E City Gate)	6,167	5,667	5,000	4,500	4,000

Source: City of Redding

3.6.3 Natural Gas Transportation

In order to provide for the transportation and delivery of purchased natural gas, COR 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.

3.6.4 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, COR 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.

3.7 WHOLESALE ENERGY TRADING

COR 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.

As with any utility, since generation and transmission resource additions do not perfectly match yearly load projections, in addition to making market purchases when economical, excess capacity and energy can be sold. As a result, COR participates in trading in the wholesale energy markets in order to capture the maximum value of its generation assets and to minimize the cost of purchased power. Additionally, coordination of its gas purchases and sales is done within the year in light of wholesale energy costs. For financial forecasting and planning purposes, only revenues from wholesale trading activities that are under contract at the time of the forecast are assumed. Continued optimization of generation and transmission assets is expected in the wholesale market for the benefit of its retail electric customers and it's anticipated that wholesale sales will continue at some level in the future.

4.0 Energy and Demand Forecast

A fundamental element of an IRP analysis is the development of the long-term (2018-2037) system peak demand and energy forecasts. The forecast results in a projection of the capacity and energy requirements on the system that the utility must plan to meet through self-owned generation or purchase arrangements.

Sufficient capacity must be secured to cover projected peak annual demand as well as reserve requirements. Reserves are an amount over and above the projected system peak that utilities will plan to maintain in the event that the forecasted demand is higher than anticipated due to extreme weather conditions or 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 planning reserve margin of 15 percent is used in planning based on the requirement set forth for the region by the North American Electric Reliability Council (NERC).[8]

4.1 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 4-1, which displays the monthly average energy sales for the period of 2013 through 2017.

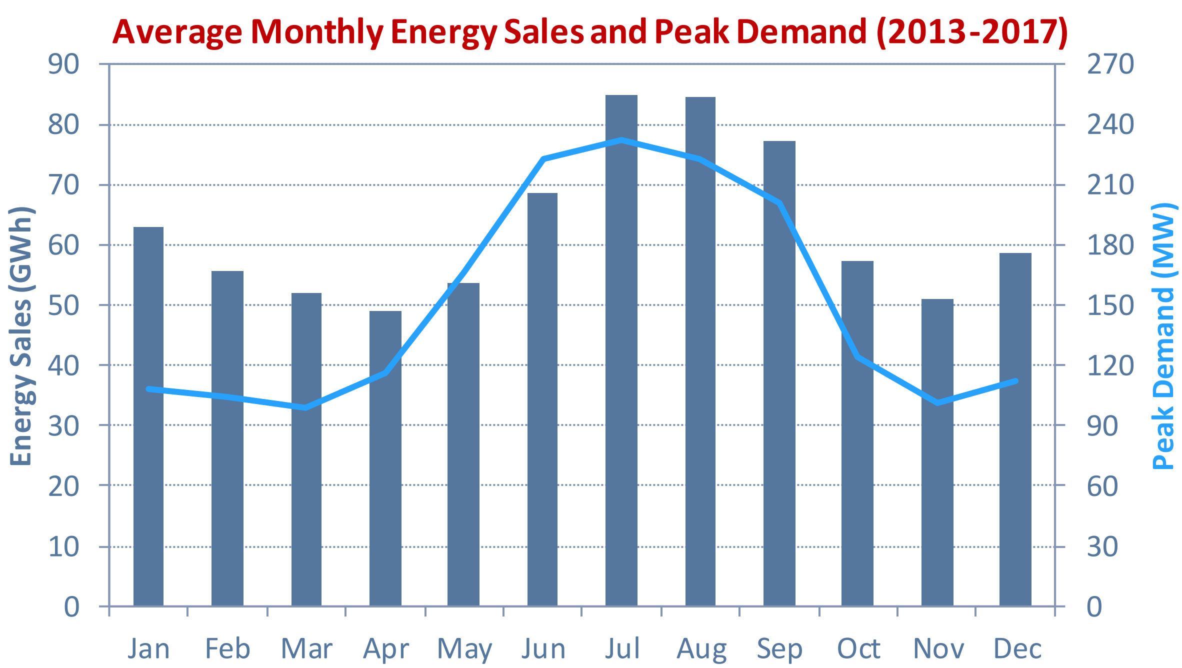


Figure 4-1 5-Year Average Monthly Energy Sales and Peak Demand (2013-2017)

[8] System level Resource Adequacy (RA) requirement of 15 percent above the forecast 1 in 2 peak must be met—sometimes referred to as the 50/50 load forecast.

Table 4-1 lists historical data over the past five Fiscal Years. The table indicates that the combined peak customer demand during the 2013-2017 period reached a maximum of 249.8 MW in 2014 and was 231.0 MW in 2017—well below the historic distribution system peak demand of 253.0 MW recorded on July 24, 2006. Although the peak demand typically only occurs once each year, resources must be maintained to meet the peak year round.

Energy sales also declined over the 2013-2017 period. The 2017 sales of 745,607 GWh were only 96 percent of the 2013 energy sales figure. At the same time, the number of customers has increased by 1.5 percent over the period and reached 44,233 customers in 2017.

Table 4-1 Historic Customer, Sales, and Demand Data

YEAR [1]	2013	2014	2015	2016	2017
Number of Customers [2]					
Residential	37,268	37,387	37,561	37,751	38,015
Commercial	5,022	5,011	5,034	5,025	4,949
Industrial	334	330	322	335	336
Other	927	934	915	928	933
Total Customers	**43,551**	**43,662**	**43,832**	**44,039**	**44,233**
Megawatt-Hour Sales					
Residential	375,606.32	361,105.70	356,070.92	361,427.32	366,353.63
Commercial	338,256.66	336,506.90	338,291.79	332,231.88	324,201.81
Industrial	13,505.87	12,303.01	12,366.15	13,393.83	13,266.38
Other	46,755.68	45,923.16	43,087.05	42,358.33	41,825.28
Total MWh	**774,124.53**	**755,838.77**	**749,815.91**	**749,411.36**	**745,607.10**
Peak Demand (MW)	**235**	**249**	**232**	**232**	**231**

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.
Source: City of Redding

4.2 FORECAST METHODOLOGY AND ASSUMPTIONS

The load forecast for the IRP planning period was developed by Itron; it develops future projections of energy sales and peak demand based on the historical relationship with various socioeconomic factors and temperature data as described further below.

The 2018 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
- Time of 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 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 4-2. For the variables listed, those of special importance include assumptions about the future growth of EV, solar installations, energy efficiency, as well as population growth and the consideration of temperature data.

Table 4-2 Load Forecast Assumptions and Input Considerations

CATEGORY	DESCRIPTION
Weather	• Normal Weather for Energy and Peak: (Calculation Range 2008 – 2017)
Economics	• Net Migration Forecast uses a 10-year historical average (2008 – 2017) in 2017 & 2018 • Net Migration phases into a 20-year historical average (1998 – 2017) by 2023 • High and Low Cases +/- 10% of historical average • Employment Forecast uses post-recession CAGR (2009 – 2017) in 2018 • Employment phases into a long-term growth rate for the 20-64 Age Cohort (0.5%) by 2023)
End Use Equipment Saturation & Efficiency/ New Technology	• SAE Inputs - Pacific Region Efficiencies from the EIA's 2017 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

Source: City of Redding

4.2.1 Rooftop solar installations

Installations of rooftop solar are expected to continue growing within the service area, albeit at a diminishing rate, through 2022. Increases in solar installations for a given year are related to the status of the Investment Tax Credit (ITC), which is scheduled to decline from 30 percent in 2018 to 10 percent by 2023. Figure 4-2 below shows COR's forecast overlaid with the scheduled ITC rates through 2022.

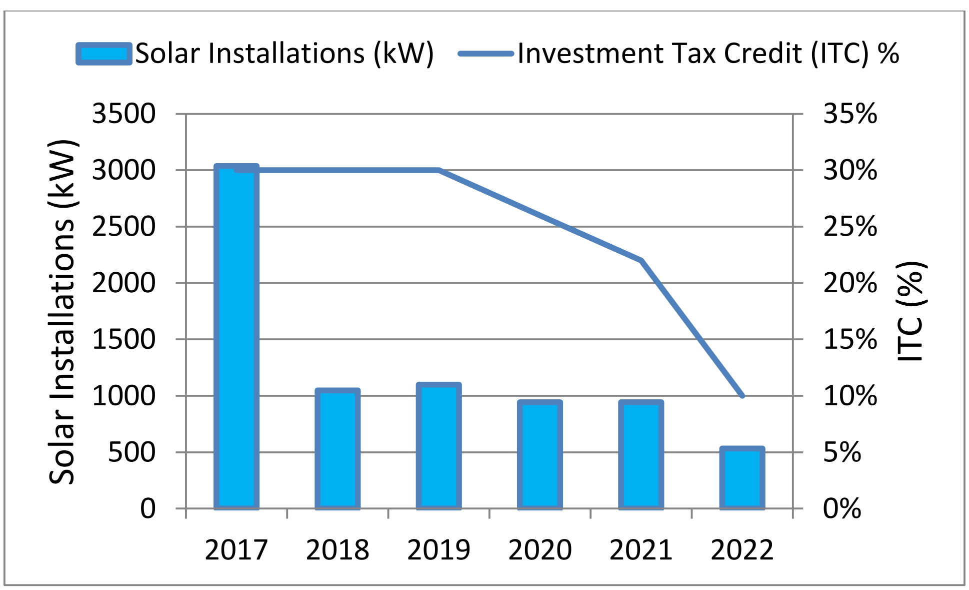


Figure 4-2 Projected Solar Installations vs ITC Tax Credit

4.2.2 The Electric Vehicle Forecast

For the service area, the EV forecast involves a significant increase in the number of vehicles through 2026. Figure 4-3 shows the cumulative number of EVs, including EVs and plug-in electric vehicles (PEVs) that are projected to increase from approximately 200 to more than 2,200 in 2026; this forecast was based on the 2016 Zero Emission Vehicle Action Plan. This rapid growth is also a function of the EV rebate program that went into effect in August 2017. Under this program, commercial incentives of up to $1,000 per vehicle, plus $3,000 are available to commercial customers who install a EV Level 2 charger; residential incentives are $1,000 plus up to $500 for installing a Level 2 charger.[9] It is estimated that the cost of charging under the applicable electricity rate equates to a cost of only $1.08/gallon of gasoline and provides an equivalent environmental benefit to planting more than 100 full grown trees.

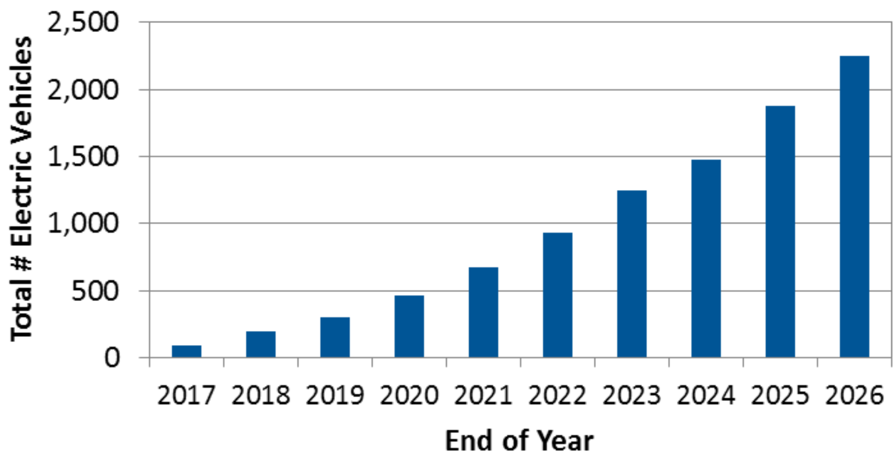


Figure 4-3 Projected Electric Vehicles – COR Service Territory

4.2.3 Energy Efficiency and Demand Response

The load forecast considered a number of energy efficiency and demand reduction measures. These are further described in Section 5.

4.2.4 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 2016 with the temperature at which annual peak demand conditions occurred, and determining a statistical correlation for that year. (For example, the 50th percentile temperature in the 1980-2016 period formed the basis for the "1-in-2 year" case, and the 90th 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.

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[9] A Level 2 charger provides 240 VAC and charges in 4-8 hours, the equivalent of 12-20 miles per hour of charge.

4.2.5 Service Area Population

An average annual growth rate (AAGR) for population of less than one percent (0.49 percent) is projected by Itron for the forecast period compared to an AAGR of 1.13 percent experienced between 1990 and 2017.

4.3 FORECAST RESULTS

The peak and energy forecast results are presented in this section. The capacity and energy requirement forecast is also carried forward to the four required CEC tables in Appendix A.

4.3.1 Peak and Energy Forecast

Table 4-3 shows the energy and peak demand forecast. During the forecast period (2018 through 2037), energy requirements for all customer classes are projected to increase from 767,535 MWh in 2018 to 804,309 MWh in 2037. For the system, the increase equates to an overall growth of approximately 4.8 percent over the planning horizon and an AAGR of 0.24 percent.

During the forecast period, peak demand is projected to increase slightly, from a value of 228.1 MW in 2018 to 231.2 MW in 2037, equating to an AAGR of 0.07 percent.

4.3.2 System Load Factor

Table 4-3 also indicates the projected system load factor. A load factor is a measure of the variability in utility load over time. A load factor measures total energy requirements on a utility system as a percentage of the theoretical maximum energy requirements that would result if the energy requirements at the time of peak demand were required all hours of the year.

Table 4-3 summarizes for each year of the analysis the annual net energy sales forecast and peak demand forecast for the projected system load factor. The projected system load factor remains fairly consistent during the period of analysis, ranging from 38.4 percent in 2018 to 39.7 percent in 2037. The slight increase in load factor and relatively flat peak demand growth rate are reasonable and result from a combination of factors. These results reflect the continued installation of rooftop solar systems by residents or commercial users, programs that may be introduced by State of California to enhance energy efficiency measures to be incorporated into new residential housing and commercial buildings, and assumptions regarding the growth of EVs and demand response.

Table 4-3 Projected Net Energy Requirements, Peak Demand Forecast, and Load Factor

YEAR	NET ENERGY REQUIREMENTS MWH	NET ENERGY REQUIREMENTS PERCENT CHANGE (%)	PEAK DEMAND MW	PEAK DEMAND PERCENT CHANGE (%)	LOAD FACTOR (%)
2017 (actual)	798,960	2.18%	241.4	4.51%	37.8%
2018	767,535	-3.93%	228.1	-5.51%	38.4%
2019	767,119	-0.05%	227.3	-0.37%	38.5%
2020	766,632	-0.06%	226.7	-0.25%	38.6%
2021	763,013	-0.47%	226.2	-0.21%	38.5%
2022	761,992	-0.13%	226.0	-0.12%	38.5%
2023	762,510	0.07%	225.9	-0.01%	38.5%
2024	767,096	0.60%	226.1	0.09%	38.7%
2025	768,249	0.15%	226.4	0.11%	38.7%
2026	770,535	0.30%	226.6	0.11%	38.8%
2027	773,399	0.37%	227.0	0.14%	38.9%
2028	778,734	0.69%	227.3	0.13%	39.1%
2029	780,769	0.26%	227.8	0.24%	39.1%
2030	782,358	0.20%	228.0	0.10%	39.2%
2031	784,084	0.22%	228.4	0.17%	39.2%
2032	788,191	0.52%	228.8	0.17%	39.3%
2033	789,134	0.12%	229.3	0.20%	39.3%
2034	792,330	0.40%	229.7	0.19%	39.4%
2035	796,280	0.50%	230.2	0.23%	39.5%
2036	802,497	0.78%	230.8	0.24%	39.7%
2037	804,309	0.23%	231.2	0.19%	39.7%
AAGR 2018-2037	0.025%		0.071%		

Source: City of Redding

4.4 COMPARISON TO CEC FORECAST

The energy requirements forecast used in this IRP and prepared by Itron can be compared to the forecast published by the CEC in its document *California Energy Demand 2018-2030,* which is developed annually as part of the CEC's Integrated Energy Policy Report.

As seen in Figure 4-4, the CEC forecasts of energy requirements is comparable to the IRP forecast through 2030, with the CEC forecast ending (750 GWh) approximately 4 percent lower than the forecast in 2037 (782 GWh). Overall, the CEC forecast of energy requirements decreases slightly while the forecast of energy requirements increases slightly through 2030.

The peak demand forecast differs slightly in that the CEC reports a lower peak demand in COR, relative to the Itron forecast. In 2018, CEC's peak demand forecast for COR is 212.3 MW. The corresponding figure in Itron's forecast is 228.1 MW.

Similar to the energy demand forecast, the CEC projects declining peak demand through 2030, whereas Itron projects relatively flat demand throughout the forecasted period. Still, the forecasts are substantially similar, especially during the middle years of the projection.

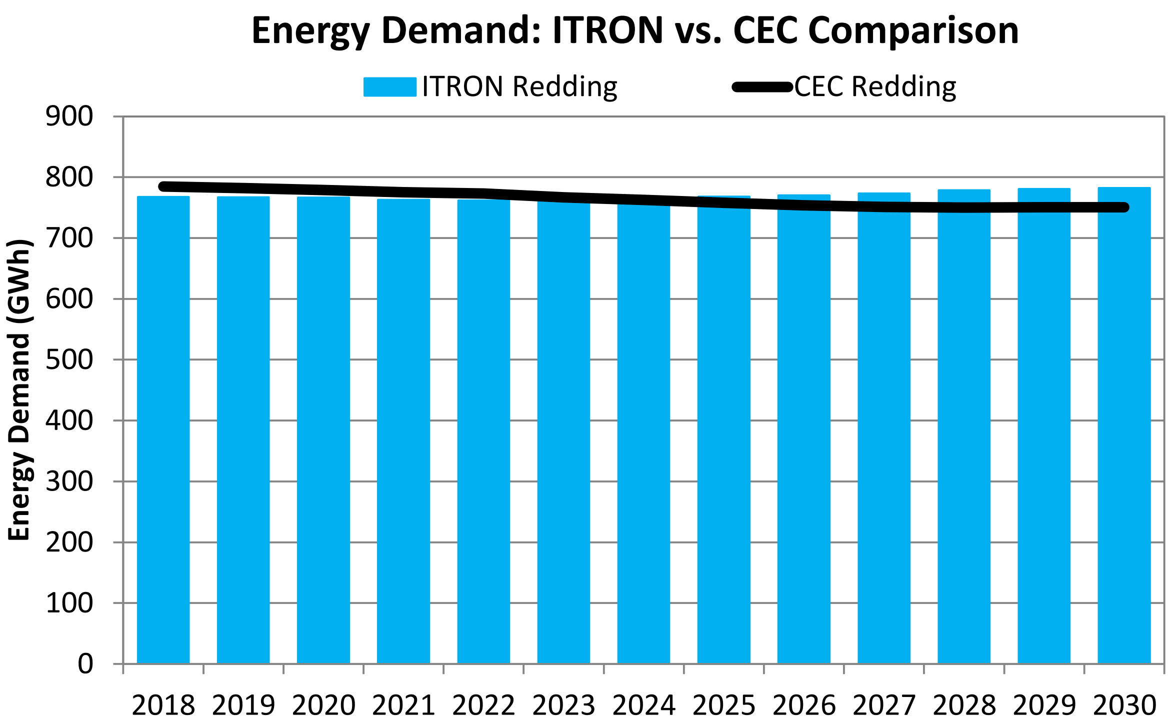

Figure 4-4 Energy Requirements Comparison: COR Forecast vs. CEC Forecast for COR

5.0 Customer Programs, Energy Efficiency and Demand Response Resources

Customer Programs, energy efficiency, and demand response resources are an important consideration in the development of an IRP and PUC regulations require their consideration in resource planning. To the extent that reasonable estimates could be developed, the load forecast by Itron considered past and current efforts to reduce consumption through energy efficiency programs and reduce GHG emissions with electrification programs. The energy requirements and peak demand projections reflect the impact of aggressive efforts to reduce energy consumption, system peak, and GHG emissions through the multiple programs described in this section.

Promoting energy efficiency and demand response programs goes back many years and, in part, has been fostered by the requirements of PUC 9505. Section 9505 required POUs, starting in 2013, to describe and quantify POU investment in energy efficiency and demand reduction programs; to describe the funding for these programs; to explain the method used to estimate cost-effectiveness; and to establish annual energy savings and demand reduction targets and report savings achieved.

This section compares the Additional Achievable Energy Efficiency (AAEE) savings incorporated in the IRP assumptions and the target established under PUC Section 9505. Estimates of market, economic, and technically achievable energy efficiency savings from studies used to establish target savings under PUC Section 9505 are also summarized.

5.1 ENERGY EFFICIENCY PROGRAM BACKGROUND

Targets for energy efficiency programs (and established under PUC section 9505) are based on the net market potential estimated in the Navigant study.[10] The net market potential provides a forecast of market potential for specific utility energy efficiency programs. The net market potential is a subset of the total economic potential and technical potential and recognizes that not all of the impacts that are technically or economically achievable will be realized.

The energy efficiency program portfolio was redesigned in 2016, with a launch of new programs in 2017, and continues to develop new offerings that will help achieve energy efficiency goals over the IRP planning period; those programs are being actively promoted.

During program years 2015-2017, savings achieved exceeded the SB 350 targets set by the CEC (see Figure 5-1). In fiscal years (FY) 2018-2022 and 2027-2028, however, new ways to achieve savings beyond the PUC 9505 target must be explored. New programs have been developed to help fill this gap and have provided new ways to apply, including a new online rebate portal and a rebate catalog scheduled to be released toward the end of 2018.

The AAEE savings assumed in the IRP filing represent the difference between targets established by COR under PUC section 9505 and the annual target set by the PUC in the SB 350 Doubling Report. The relationship between SB 350 targets and the AAEE required to make up the difference is shown in Figure 5-1.

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[10] CMUA, POU Potential and Goals Study, March 2017http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-06/TN217482_20170508T153251_Appendix_B__20182027_Annual_Targets_All_POUs.xlsx.

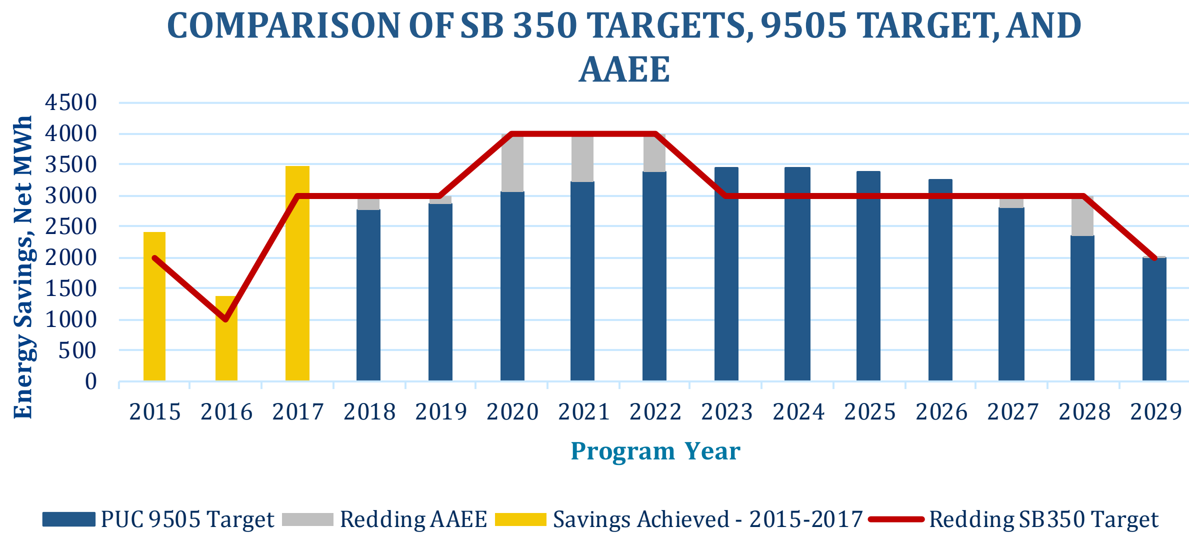

Figure 5-1 Comparison of Energy Efficiency Targets and Historical Achievements

5.2 CURRENT ENERGY EFFICIENCY INITIATIVES

COR maintains a robust suite of energy efficiency programs that will contribute to the state's goal of doubling statewide energy efficiency savings as codified in SB 350. Energy efficiency programs are intended to offer maximum benefit to the community while meeting all regulatory requirements. The regulatory requirements include the following:

- Public Utilities Code § 385 requires that the utilities collect and spend a percentage of their base retail electric revenues on qualified Public Benefits Programs. The customary amount collected by public utilities in California is a minimum 2.85 percent of annual base retail electric revenues. The funds must be spent on programs in four categories including energy efficiency, research and development, RE resource development and low-income assistance.
- Public Utilities Code § 386 requires each local, publicly-owned utility to ensure that low-income families have access to affordable electricity, and the level of assistance reflects the level of need. Furthermore, utilities shall ensure that low-income families have access to low-cost, no-cost measures that reduce energy consumption.
- Public Utilities Code § 454.5 and Public Utilities Code § 9615 both require utilities to address unmet resource needs through energy efficiency and demand response prior to procuring new sources of power.
- Public Utilities Code § 9505 requires each local, publically-owned utility to report annually investments and achievements in energy efficiency and demand reduction programs. Furthermore, utilities must identify all potentially achievable cost-effective electricity efficiency saving and report savings targets to the CEC.
- Public Resources Code § 25305.2 requires the CEC to report to the Legislature a comparison of the annual energy savings targets versus the actual energy efficiency savings and demand reduction for each local POU.

- Public Resources Code § 25310 (c)(1) requires the CEC to set goals that will double statewide energy efficiency savings in California by 2030 and will require specific targets for COR.

A comprehensive list of energy efficiency projects and programs under consideration is described below. The description indicates whether each program was included in the PUC Section 9505 targets, and is, therefore, counted as "committed savings", or whether the program can contribute to future AAEE goals and can support achieving the SB 350 target to double energy efficiency savings.

5.2.1 Current Residential Energy Efficiency Programs

5.2.1.1 Residential Deemed Rebates – Committed Savings

The Residential Rebate Program offers prescriptive rebates for a variety of different measures that work to reduce energy consumption and save customers money. The measures included in the Residential Rebate Program are as follows:

- Energy Star listed Heat Pump Water Heater
- Conventional Storage Water Heater
- Energy Star listed Ceiling Fan
- Energy Star listed Variable Speed Swimming Pool Pump
- Energy Star listed Window and Wall Air Conditioner
- Energy Star listed Refrigerator
- Energy Star listed Wi-Fi enabled smart thermostat
- New Air Conditioner including Split System, Package, and Ductless Systems
- Whole House Fan
- Wall Insulation upgrade
- Ceiling Insulation upgrade
- Dual Pane Windows Replacing Single Pane Windows

5.2.1.2 Residential Weatherization Program - AAEE

To address the needs of income-qualified customers who do not typically participate in utility rebate programs, a Low-Income Energy Efficiency Program (LIEEP) is offered. LIEEP is available to owners and renters residing in single family homes, multifamily dwellings, and mobile homes, who meet the program income eligibility requirements. A trained weatherization contractor conducts program marketing, customer enrollment and income qualification, dwelling assessment, measure installation, and reports program details.

LIEEP utilizes a tiered approach that provides a suite of cost-effective deemed energy efficiency measures (Tier 1) to all participating customers, with a subset of customers who qualify for additional measures (Tier 2). All eligible customers are able to participate in Tier 1 measures that include lighting, appliances, HVAC Retrofits, Wi-Fi thermostats, Tier II smart power strips, and others. However, for more substantial measures such as window replacements, HVAC replacements, duct replacement, heat pump water heaters, etc., an energy audit is performed to verify that the measure is cost-effective in a specific home. This tiered approach provides service to a significant number of customers with Tier 1 measures, while allowing a mechanism to provide significant dwelling upgrades to customers that need improvements the most.

5.2.1.3 Residential Shade Tree Program – AAEE

The Residential Shade Tree Program offers customers an opportunity to reduce energy consumption by planting trees in locations that shade their home. Customers sign up through an online portal and locate the appropriate tree-planting site near their home. Based on the species of tree selected and orientation to the home, the portal, powered by i-Tree software, calculates the energy savings over the life of the tree in a format that is beneficial for integrated resource planning.

5.3 COMMERCIAL REBATES

5.3.1.1 Commercial Deemed Rebates – Committed Savings

A suite of rebates is offered to incentivize building owners to install energy efficiency mechanical equipment, refrigeration equipment, and appliances. The measures included in the commercial deemed rebate program are as follows:

- Auto door closers for walk-in refrigerator and freezer doors
- Anti-sweat door heater controllers
- ECM Fan motors and motor controllers
- Unitary air cooled air conditioners
- Unitary heat pumps
- Packaged Terminal Air Conditioners and Heat Pumps
- Web-enabled programmable thermostats
- Electric food service equipment including refrigerators, freezers, ice machines, steam cookers, convection ovens, fryers, griddles and combination ovens, and vending machine controllers

5.3.1.2 Commercial Calculated Lighting Rebates – Committed Savings

The largest commercial program continues to be the calculated commercial lighting program; this program incentivizes customers to upgrade interior and exterior lighting systems.

5.3.1.3 Commercial Custom Program – AAEE

The commercial custom program serves commercial customers that are performing large projects not addressed by other commercial rebate programs. Incentives are designed to promote comprehensive projects to achieve energy savings over applicable end uses.

5.4 ADDITIONAL PROGRAMS

5.4.1.1 Current Municipal Programs – AAEE

In addition to the residential and commercial programs, this program provides leadership and incentives for projects that reduce operational costs, energy consumption, and GHG emissions. These programs will contribute to AAEE and include the following:

- Retrofit of approximately 7000 existing HID streetlights with new LED fixtures at a rate of approximately 1000 streetlights per year
- Leading a City-wide effort to implement an Energy Savings Performance Contract as allowed by Government Code § 4127. This comprehensive upgrade will cost-effectively reduce energy costs across all City departments

5.4.1.2 Future Programs

Current programs are realizing increased participation rates and improved energy savings rates. These observed trends are consistent with the market potential by end use projected by the Navigant study through 2024, shown in Figure 5-2. Based on these recent successes and programs launched in anticipation of SB 350 doubling requirements, it is projected that new programs launched in 2017 and 2018 will accommodate the AAEE gap and meet or exceed the current savings target.

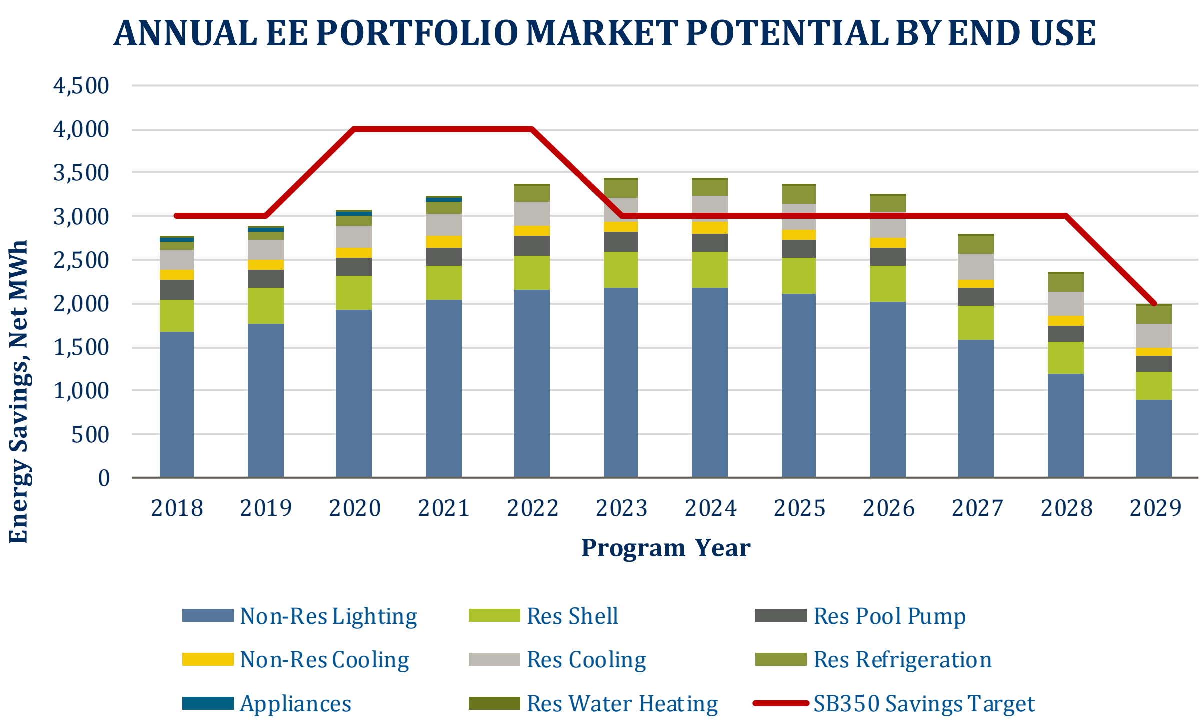

Figure 5-2 Annual EE Portfolio Market Potential by End Use

Although well positioned to meet the current savings targets, it is recognized that unforeseen changes may require future alterations to the program portfolio to better meet community needs, respond to changing statutory requirements, or adapt to technology changes. Throughout the planning horizon, program offerings will be assessed to determine how to provide the best value to customers and optimize energy efficiency impacts. Areas of opportunity that may be considered to increase program energy savings or demand reduction include but are not limited to the following:

- Residential and commercial new construction programs
- Residential and commercial behavioral programs

- Commercial retro-commissioning

5.5 DEMAND RESPONSE PROGRAMS

The CEC encourages POUs to include in the IRP Filing the expected quantitative impacts of planned price-sensitive demand response measures that are proposed, or being considered for future implementation (for example, time-of-use rates), including discussion of POU demand response programs.

Analysis of large customers has been conducted to determine if any have the ability to shift load during periods of high demand. Due to the limited potential for load shifting, there are no current demand response programs or time-of-use rates offered to customers. In the future, time-of-use rates may be offered to non-residential customers; however, the expected impact of new time-of-use rates on peak load are expected to be negligible given the current limited ability of large customers to shift significant amounts of energy load.

5.5.1 Energy Storage

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:

(1) Use mechanical, chemical, or thermal processes to store energy that was generated at one time for use at a later time.

(2) 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.

(3) Use mechanical, chemical, or thermal processes to store energy generated from renewable resources for use at a later time.

(4) 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 can be effective in reducing system peaks and providing energy at the time of day when it is of most value. It can be viewed as a stand-alone resource, or it can be coupled with a renewable resource such as wind or solar and used to “firm-up” intermittent resources to some degree. Costs for ES have decreased significantly in recent years and the cost decrease is expected to continue in the coming years (see Section 6 for assumptions in this IRP).

The first Thermal Energy Storage (TES) system was installed in 2005 (a chiller-based system at Redding Municipal Airport and another direct expansion TES system at the Redding Fire Department). 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 to customers. This participation in the ES market was, in part, a response to AB 2514 and AB 2227.

AB 2514 requires load serving entities to evaluate whether ES procurement targets should be adopted. With approval by the Council in 2012, a contract was executed with a primary TES supplier, Ice Energy, to evaluate the TES capacity that could be cost-effectively installed in COR’s service area. The analysis determined that up to 14 MW of permanent load shifting could be achieved through TES programs.

In 2014, ES targets adopted were 3.2 MW for 2016 and 4.4 MW for 2020. This compares to actual achieved ES capacity of 3.6 MW by mid-2017. Due to changing load conditions (lower sales, reduced peak growth) in the state and service area, in October 2017, it was recommended that the 2020 storage target should be set equal to the 2017 achieved capacity of 3.6 MW.[11] Maintaining this level of TES (3.6 MW) was assumed in the IRP load forecast.

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 with regards to the goals adopted by the Council in 2014. Plans are in place to continue to evaluate the potential benefits of additional ES as part of the IRP process going forward. To date, more than $6 million has been expended on the TES Program.

5.5.2 Additional Solar and Intermittency Analysis

To evaluate the potential benefits of adding ES, Black & Veatch was commissioned to perform a stochastic analysis on the load and generation in order to estimate the deviation of actual hourly load, less generation (Interchange Load), compared to scheduled hourly Interchange Load. In the analysis, Black & Veatch also included a case where a 10 MW Solar PV Project (Solar Project) was included in COR's Interchange Load.

The stochastic analysis was performed utilizing Palisade Corporation's @RISK software; @Risk is a Microsoft Excel add-in used to perform stochastic analyses. The 95 percent confidence intervals with and without the Solar Project were compared to assess whether the addition of the Solar Project impacted deviation from scheduled net interchange.

In comparing the stochastic net interchange deviations from the schedule, with and without the addition of the Solar Project, it was observed, based on the stochastic analysis, that there was not a significant impact to the scheduled interchange deviations when comparing the case with 10 MW of solar PV generation to the case without the Solar Project. It was observed from the modeled results that interchange deviation for cases "with and without" the Solar Project were at times wider than the +/- 8 MW (6 MW, plus 2 MW for the contracted load with COSL) deviation band which COR has contracted with WAPA. A detailed report on the stochastic intermittency analysis is included in Appendix C.

Analysis shows that addition of an ES system would ease decreasing deviations from hourly interchange schedules. Consideration and evaluation of the future addition of ES to smooth load and generation would continue, along with plans to investigate other contractual products which could help manage the cost of scheduled interchange deviations. The impact of future increases in renewable generation, or contracted renewable generation, on Interchange Load deviation from schedule will also be considered. The level of impact on Interchange Load due to the addition of these resources will likely be dependent on the resource scale and level of shaping of the resource (e.g. inclusion of ES in an owned resource or contractual shaping included in a PPA). Determination of the least-cost ES solution will be the subject of a future study.

[11] *City of Redding Report to Redding City Council*, Daniel Beans, September 19, 2017.

5.6 TRANSPORTATION ELECTRIFICATION

A number of studies have been performed and initial steps have been taken to encourage increased penetration of EVs. The highlights of these activities are summarized below:

- A residential EV Rebate Program began in August 2017. Under this Program, incentives of $1,000 per new vehicle purchased or leased is available, and another $500 is available for infrastructure cost of a Level II EV charger is installed at the customer's home.[12] As of May 2018, a total of 34 vehicles qualified for the EV Rebate Program.
- A dedicated webpage has been created, as well as an e-mail address where customers can reach out to staff for questions or comments regarding EVs. During the kickoff of the EV Rebate Program, staff met with local dealers to educate them on EVs and available rebates. A Ride-and-Drive Program is currently in the works as a means to further educate our customers and spark interest.
- A City-wide study to develop an infrastructure plan for the installation of EV charging stations (EVCS) is currently underway and will evaluate the best EVCS locations, optimal number of charging stations, and will estimate power requirements and areas where new or upgraded electrical service is required. Once the study is complete, an implementation plan will be developed and it is anticipated that petrol vehicles will be replaced by EVs where and when it is practical.
- COR has procured or help procure the following:
  - One electric bus for Redding Area Bus Authority – supplied monies to help RABA secure full grant amount
  - Three electric "Mean Green" lawn mowers for the City of Redding Facilities Maintenance Department
  - Three electric carts for the City of Redding Police Department
  - Two electric carts for the City of Redding Parks Department

[12] A Level 2 charger provides 240 VAC and charges in 4-8 hours, the equivalent of 12-20 miles per hour of charge.

6.0 The Need for Additional Resources and Resource Options

The development of the load forecast allows a comparison of capacity requirements with existing and additional near-term resources. The result will highlight the adequacy of existing and near-term additional resources and their ability to meet energy needs and comply with RE requirements during the 2018-2037 planning period; this determination will be done for a scenario that contemplates continued operation of existing resources to meet future requirements.

Sufficient existing and near-term capacity resources exist to meet its projected peak demand and planning reserve requirements over the study period. However, additional RE resources will be necessary to meet RPS requirements and added RE resources will promote further GHG emission reductions. The need for additional renewable resources established in this section leads to the development of several Scenarios that are modeled and presented from an economic cost and RE perspective in Section 8.

6.1 EXISTING SYSTEM CAPACITY BALANCE

Capacity balance is shown in Figure 6-1 for the Existing System Scenario. This Scenario assumes no additions to the system are added through 2037 and reflects the expiration of the Big Horn wind purchase after 2031.

The figure indicates sufficient generation capacity exists to meet capacity needs throughout the planning horizon; the excess generation capacity ranges from a high of 38 MW to 10 MW during the 2018-2037 planning period. (Section 8 will present a similar capacity balance for the preferred plan; the figure is a simplified summary of the CRAT table included in Appendix A for the preferred option.)

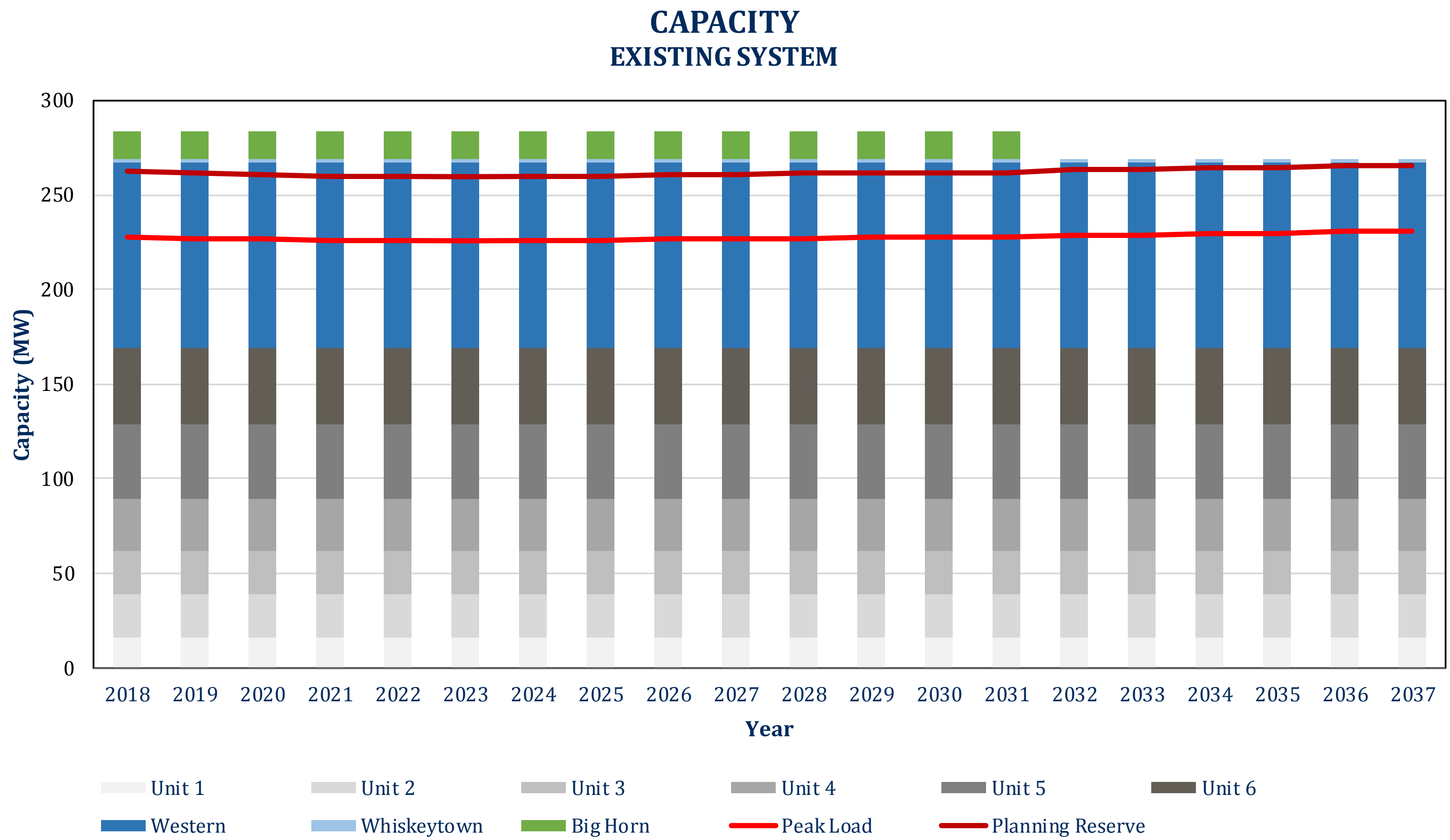

Figure 6-1 Capacity Sufficiency for the "Existing System" Scenario, 2018-2037

6.2 EXISTING SYSTEM SCENARIO ENERGY REQUIREMENTS AND RENEWABLE ENERGY LEVELS

Figure 6-1 provides additional information about the adequacy of the Existing System Scenario. Table 6-1 indicates the total generation from resources, purchases, and sales that occur under the Existing System Scenario. As seen in Figure 6-2, the Station's 1x1 and 2x1 natural-gas fueled combined cycle units are most active in the power market over the planning period, and market purchases account for a significant amount of COR's energy requirements.

Figure 6-3 indicates the ability to meet its RE targets if no additional RE resources are added. In the figure, a year in which a shortfall in RE occurs is displayed by the stacked bar chart not meeting the red line.

As indicated in Figure 6-3, if no additional RE resources are added, RE targets starting in 2019, would not be met and the shortfall would continue through 2037. The shortfall would become increasingly severe, such that in 2030, only a 30 percent RE contribution would be received as compared to the 50 percent requirement. For the remainder of the 2037 study period, the shortage would dramatically increase once the Big Horn wind PPA expiries in 2031. Looking at the REC outlook, it is clear that the Existing System Scenario results in a deficiency of REC.

Figure 6-3 is very significant because it shows that, while the Existing System can meet capacity requirements and energy needs, it is not acceptable in that it does not comply with the obligations necessary to meet the targeted RE levels.

Figure 6-4 lists data pertaining to the GHG emissions under the Existing System Scenario. These emissions are compared to the proposed CARB limits under the low and high targets proposed by CARB staff in July 2018. The 2030 targets proposed are between 57,000 (low target) and 101,000 (high target) of $MTCO_2e$. Figure 6-4 indicates that under the Existing System Scenario, 2030 emissions are projected to be105,408 $MTCO_2e$; this is in excess of the low and high targets proposed by CARB staff. This means that, from an environment and GHG (and RE) perspective, the Existing System Scenario is not a viable plan.

Based on the shortcomings of the Existing System Scenario, several additional Scenarios were developed and evaluated as part of this IRP process. The objective was to balance resource adequacy, economics, stakeholder input, and meet obligations for RE and GHG reductions. These scenarios are presented in Section 8.

Table 6-1 Existing System Energy Sufficiency

Annual Energy Balance of Loads and Resources

Redding Electric Utility

Description		Type	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
System Energy Demand (GWh)			768	767	767	763	762	763	767	768	771	773	779	781	782	784	788	789	792	796	802	804
Energy from REU Units, GWh																						
Unit 1		NG GT	1	0	1	1	2	1	2	2	2	3	3	2	3	3	3	3	4	4	3	3
Unit 2		NG GT	3	2	2	3	6	5	6	7	7	8	8	6	9	9	11	10	11	13	10	10
Unit 3		NG GT	5	2	3	3	7	6	7	7	8	9	9	7	10	10	11	11	12	14	10	11
Unit 4	(Simple Cycle)	SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unit 5	(Simple Cycle)	NG SC	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Unit 6	(Simple Cycle)	NG SC	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
1x1	(Combined Cycle 5 or 6 w/4)	NG CC	191	126	148	169	185	193	189	189	180	179	180	185	174	145	178	179	149	159	157	153
2x1	(Incremental Combined Cycle)	NG CC	15	13	23	37	50	51	53	49	60	56	50	54	54	52	30	33	28	28	27	28
Whiskeytown		Hydro	26	26	26	26	26	26	26	26	26	26	27	26	26	26	26	26	26	26	26	26
Total Generation from REU Units, GWh			242	169	203	238	278	284	286	282	287	285	279	283	279	248	262	264	234	247	235	234
Big Horn		Wind	180	180	180	180	180	180	180	180	180	180	180	180	180	153	0	0	0	0	0	0
Western		Hydro	201	248	248	248	248	248	248	243	243	243	243	243	243	243	243	243	243	243	243	243
Total Generation from Purchases, GWh			382	428	429	428	428	428	429	423	423	423	424	423	423	396	243	243	243	243	243	243
Total Contracted/Installed Generation (GWh)			623	597	631	666	706	712	714	705	710	708	703	706	702	643	505	507	477	490	478	476
Market Sales			(48)	(47)	(64)	(86)	(118)	(119)	(120)	(117)	(127)	(124)	(116)	(116)	(119)	(104)	(49)	(50)	(47)	(47)	(40)	(40)
Market Purchases			193	216	199	183	175	170	174	180	189	191	193	191	200	245	333	333	364	354	365	369
Net Market Purchases (GWh)			144	170	135	97	57	51	54	64	62	67	77	75	81	141	284	283	317	307	325	329
Net System Energy (GWh)			768	767	767	763	763	763	768	769	772	775	779	782	783	785	789	790	793	797	803	805

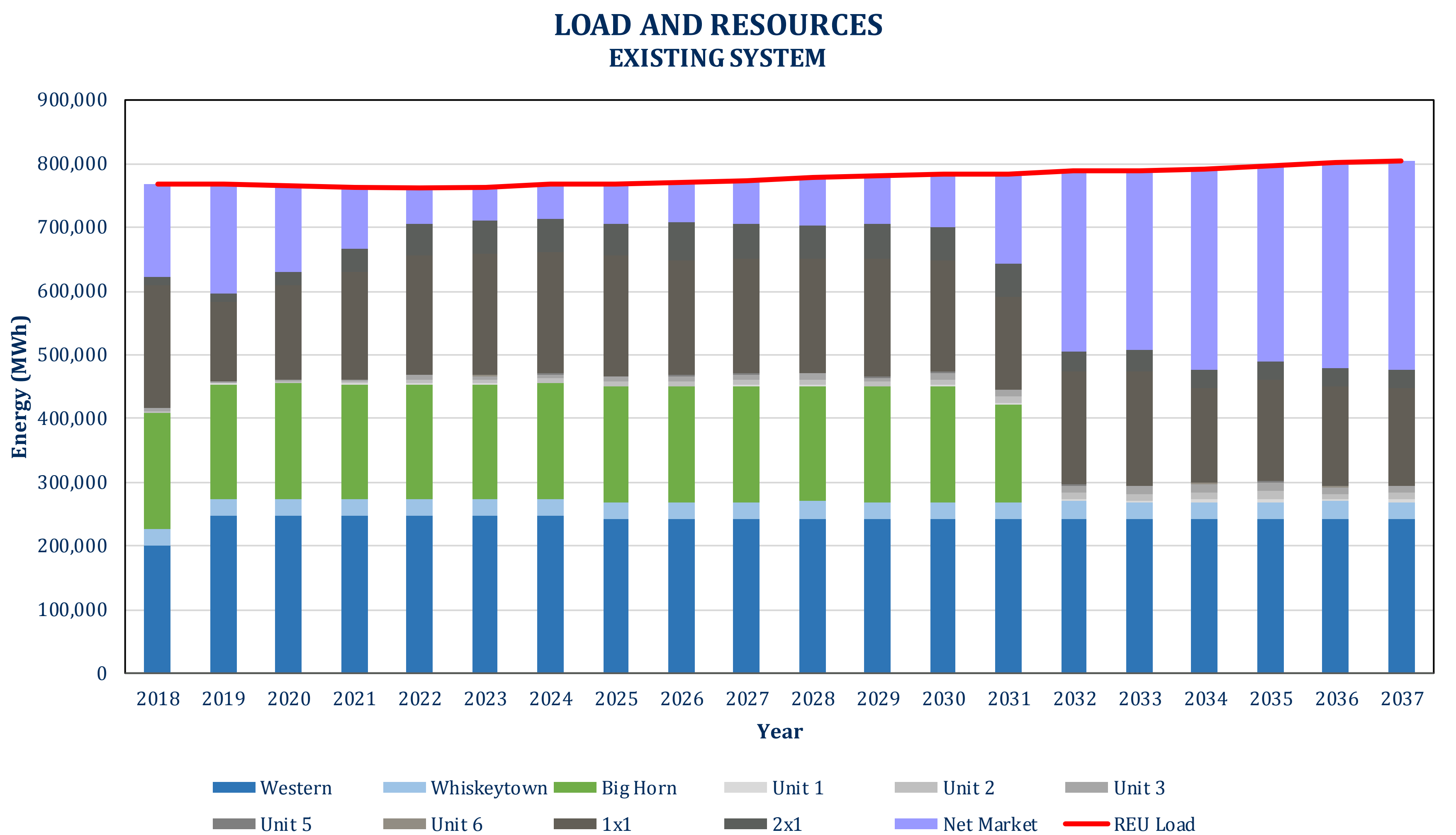

Figure 6-2 Energy Balance for the Existing System, Scenario G

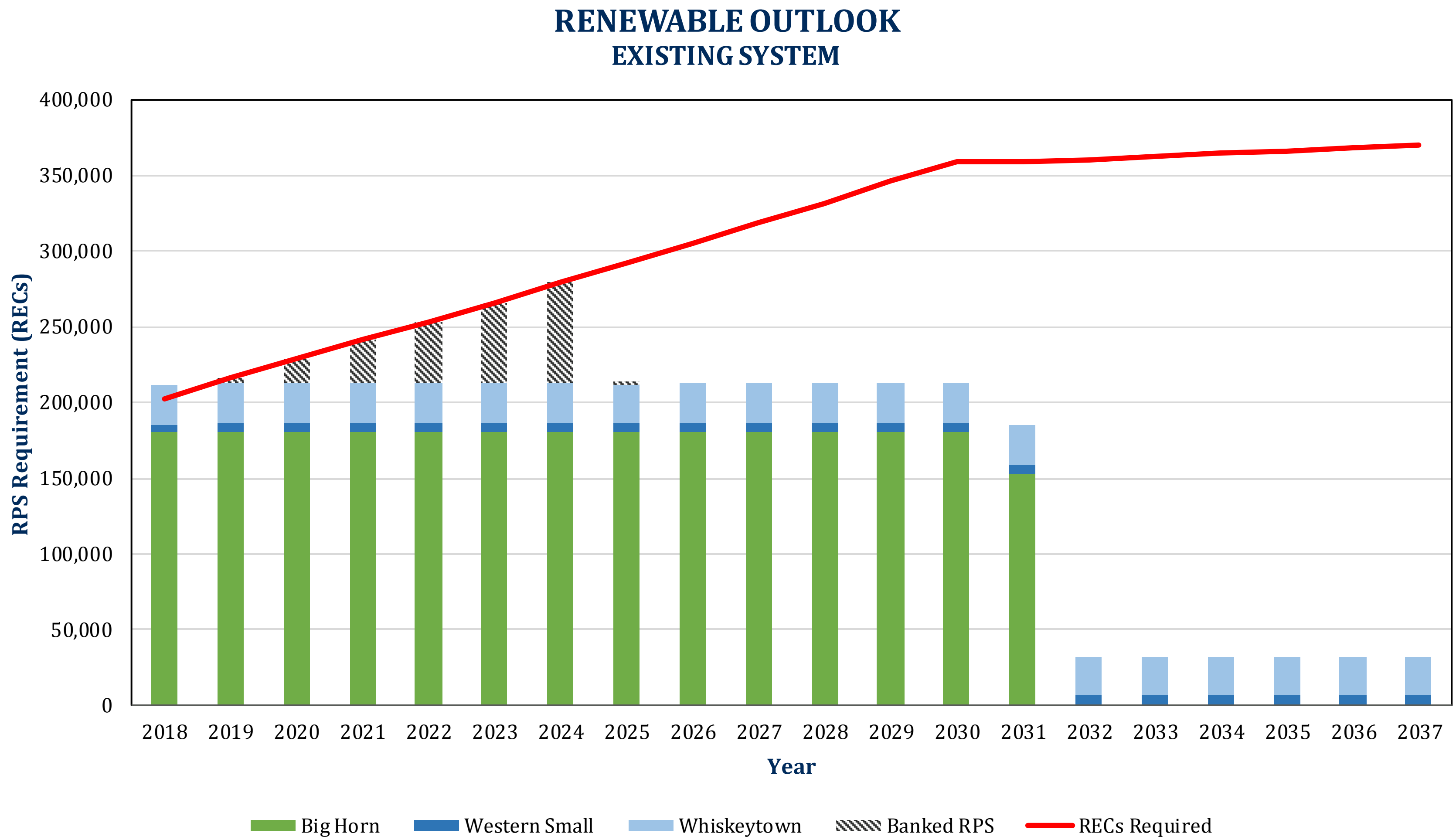

Figure 6-3 REC Adequacy in Existing System Scenario

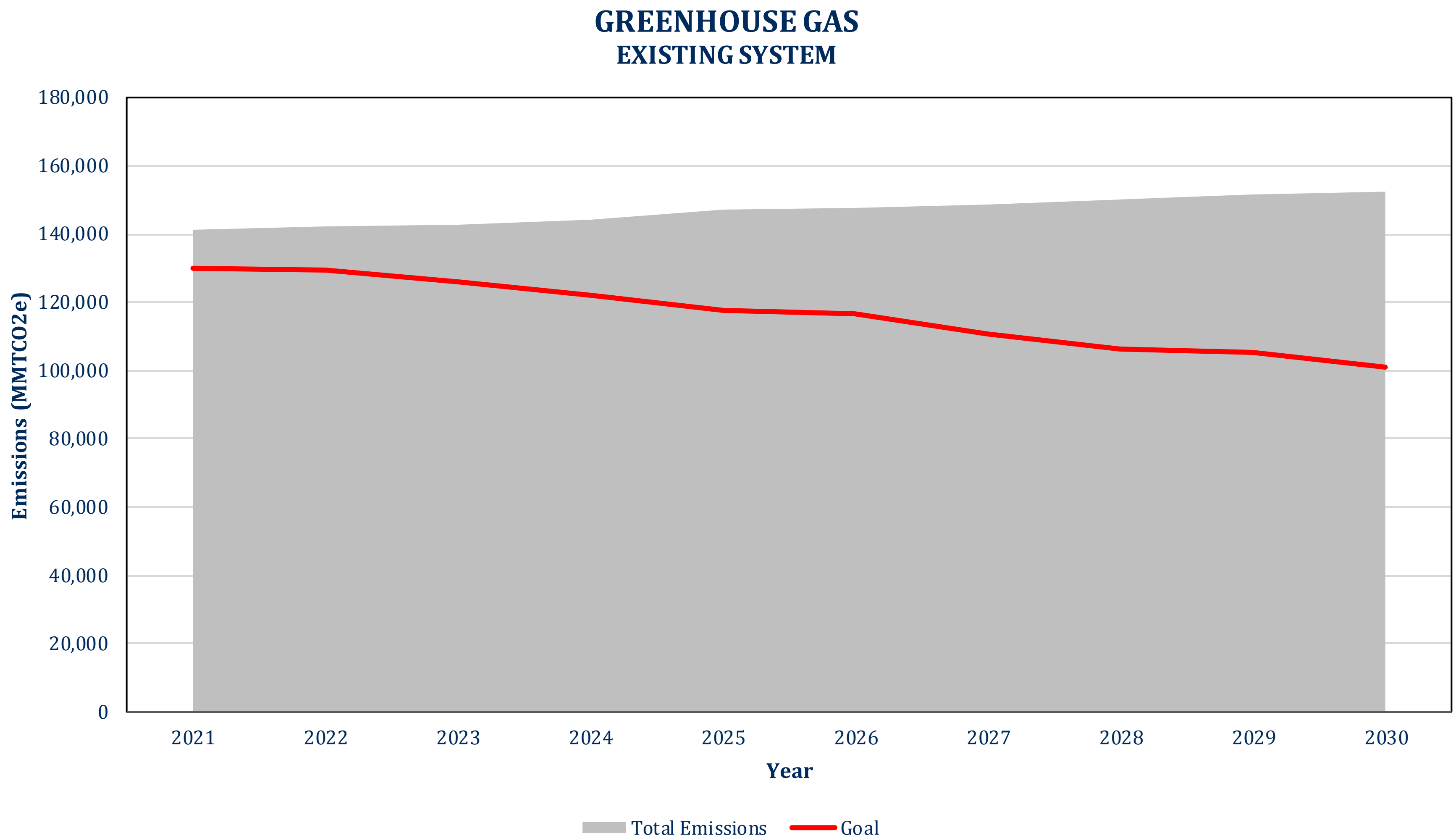

Figure 6-4 Existing System Scenario Projected GHG Emissions

6.3 SUPPLY SIDE RESOURCE TECHNOLOGY COSTS AND CHARACTERISTICS

In consideration of the objective of achieving low electric costs, long-term reliability, and fuel diversity to lower risk of dependence on a single source, a list of multiple resource options were developed to evaluate as candidates to serve future resource needs. All incremental options considered in the analysis were RE solar or wind resources. These options are discussed further in this section.

6.3.1 Renewable Energy

To obtain indicative RE PPA pricing, several locations were selected for modeling, with alternative price and performance estimates developed for each location. In total, five different modeling profiles were developed for different solar projects representing potential project sizes that could be located within each region. The projects are described in Table 6-2 and were sized to reflect sample projects of differing proportions.

The solar projects in Table 6-2 were assumed to consist of single axis tracking systems (SAT). SAT systems tend to have better output in the late afternoons when generation is often the most valuable. The solar production for each location was modeled with SAM's Detailed PV modeling module and used weather data representing each location. The inverter loading ratio (ratio of module capacity to inverter capacity) was assumed to be 1.3. Typical SAT systems have inverts of 1.25 to 1.30 today and are optimized for project location. The capacity factor was calculated based on the AC project capacity. Additionally, the long-term degradation of the systems was assumed to be 0.7 percent per year.

It is noted that, independent of, and prior to the IRP process, analysis indicated that the addition of a 10 MW PV PPA in the 2021 timeframe would be beneficial. The project is being pursued through the NCPA. While the exact cost and performance will be determined through competitive bidding, the Site 1 project in Table 6-2 is considered to be proxy for the project. The Project is currently in Phase Two (out of three) in development and this phase includes all pre-construction engineering, design, and environmental review tasks. On June 5, 2018, the Council approved the Phase Two activities that include the following actions:

(1) Authorize participation in Phase Two of NCPA Solar Project 1 including, approving the Second Phase Agreement, the Power Management and Administrative Services Agreement, and the Amended and Restated Facilities Agreement;

(2) Authorize the City Manager, or designee, to execute the agreements and any associated amendments and administer the project;

(3) Adopt **Resolution** approving the 34th Amendment to City Budget Resolution No. 2017-057 transferring needed funds for phase two. [13]

Due to the relatively advanced stage of this project, all scenarios developed in Section 8 of this IRP incorporate the 10 MW PV project in 2021, with the exception of the Existing System Scenario. The economic analysis in Section 8 will demonstrate that the addition of the project not only contributes to achieving RE and GHG targets, but the project is cost-effective when compared to the Existing System Scenario. For this reason, the addition of the Solar Project in 2021 (and not the

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[13] City of Redding Report to the City Council, 4.5(a)—*Authorization to Participate in Phase Two of NCPA Solar Project 1*, Daniel Beans, Director of Electric Utility,

Existing System Scenario) is considered to be the Base Case Scenario, and additional scenarios are developed around this near-term addition to meet RPS requirements and to evaluate the economics of additional resource options.

Table 6-2 Solar Systems and Modeled Performance

SITE	LOCATION	PROJECT CAPACITY [MWAC]	MODULE CAPACITY [MWDC]	CAPACITY FACTOR (DC)	CAPACITY FACTOR (AC)	DEGRADATION (ANNUAL %)
1	North CA	10	13	21.5%	27.9%	0.7%
2	OR/CA	100	130	20.8%	27.0%	0.7%
3	Arizona	100	130	25.5%	33.1%	0.7%
4	Central Valley	20	26	23.5%	30.6%	0.7%
5	Central Valley	100	130	22.9%	29.8%	0.7%

Source: Black & Veatch

Two wind projects were also evaluated as developments within possible future planning Scenarios. The wind project assumptions are shown in Table 6-3. Wind projects now tend to be 100 MW or more, so it was not realistic to model smaller wind farms. It was assumed, however, that COR could purchase less than the full output of a large wind farm.

Wind capacity factors were derived from analysis performed for various geographic energy zones as part of the California Public Utility Commission's (CPUC) Renewable Portfolio Standard (RPS) Calculator effort, to which Black & Veatch contributed. No degradation was assumed for wind farms.

The location of the solar and wind projects used in this RFP is shown in Figure 6-5. The location impacts the project capacity factor, capital cost, and transmission cost.

Table 6-3 Wind Systems and Modeled Performance

SITE	LOCATION	PROJECT CAPACITY [MWAC]	CAPACITY FACTOR (AC)	DEGRADATION (ANNUAL %)
6	North CA	100	30.0%	0.0%
7	Arizona	200	30.0%	0.0%

Source: Black & Veatch

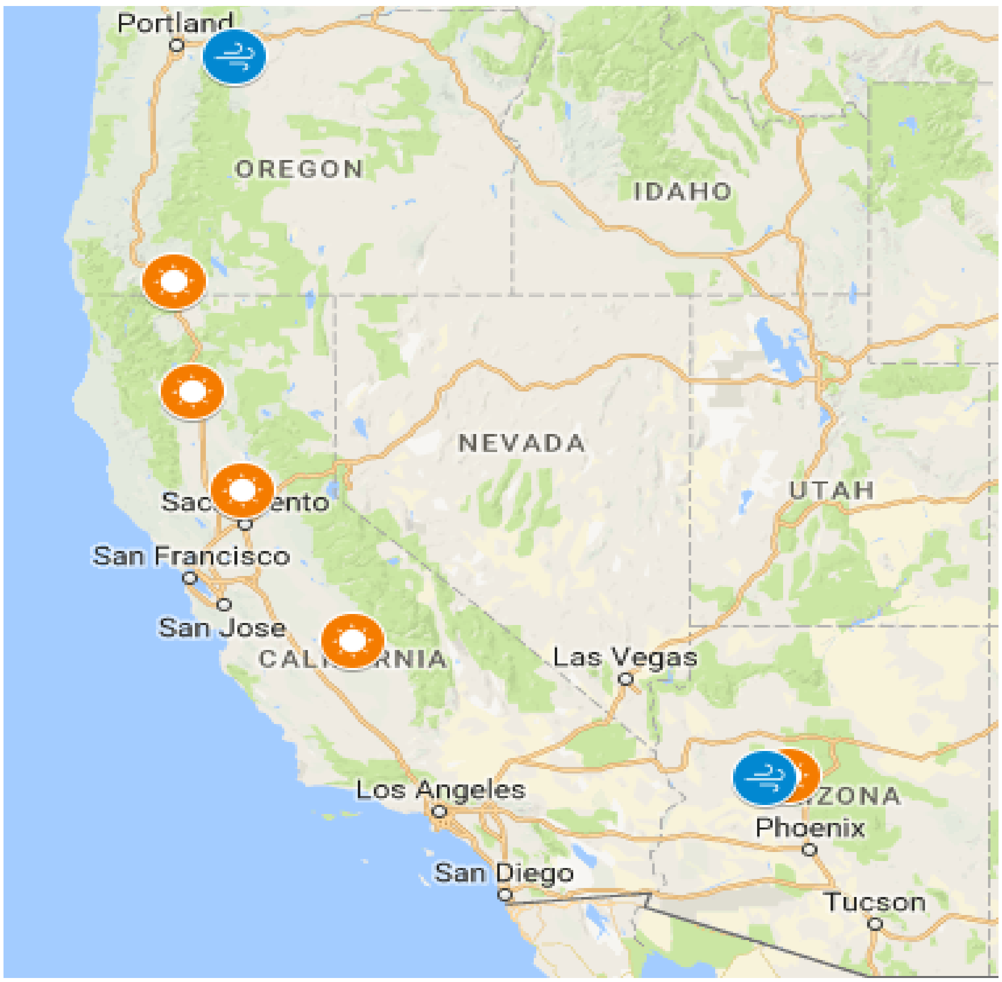

Figure 6-5 Location of Renewable Resource Project Candidate Units in the IRP

6.3.1.1 Cost Assumptions

RE project costs vary depending on system size, year installed, and location costs. The capital costs provided represents an all-in installed cost, or total capital expenditures (CAPEX), including EPC[14], owner's costs, developer fees, interconnection, financing fees, and construction interest. This total cost is used as the capital cost when calculating the levelized cost of energy (LCOE) generation. As part of the CAPEX, Black & Veatch also assumed that interconnection costs for solar and wind would vary by size, as shown in Table 6-4 and Table 6-5. Actual interconnection cost will be highly site specific. The total operating expenses, including O&M, property taxes, equipment replacement, and other administrative costs assumed in the analysis are generic and do not attempt to capture locational differences across the various project's sites.

Table 6-4 2020 Cost Assumptions for Solar SAT Systems (Nominal$)

SITE	LOCATION	PROJECT CAPACITY [MWAC]	INTER-CONNEC-TION COST ($M)	CAPITAL COST [$/KWAC]	CAPITAL COST [$/KWDC]	FIXED O&M COSTS [$/KWAC]	FIXED O&M ESCALA-TION (ANNUAL)
1	North CA	10	$0.5	$1,770	$1,362	$26	2.5%
2	OR/CA	100	$5	$1,440	$1,108	$26	2.5%
3	Arizona	100	$5	$1,380	$1,062	$26	2.5%
4	Central Valley	20	$1	$1,730	$1,331	$26	2.5%
5	Central Valley	100	$5	$1,580	$1,215	$26	2.5%

Source: Black & Veatch

Table 6-5 2020 Cost Assumptions for Wind Systems (Nominal$)

SITE	LOCATION	PROJECT CAPACITY [MWAC]	CAPITAL COST [$/KWAC]	FIXED O&M COSTS [$/KWAC]	FIXED O&M ESCALATION (ANNUAL)
6	North CA	100	$1,700	$35	2.5%
7	Arizona	200	$1,550	$35	2.5%

Source: Black & Veatch

[14] EPC stands for "engineer, procure, and construct". Additional trade tariffs were imposed on imported solar cells in January of 2018, resulting in increases in module costs. However, the new tariffs are set to decline over the next four years, and module costs are expected to continue to fall. Thus, module costs are assumed to be similar to 2017 levels by 2020.

To determine the estimated cost of 2030 projects, it was assumed that capital costs would decline 1 percent per year in real terms for wind and solar technologies amid an inflationary environment of 2.5 percent per year. The escalated technology costs for 2030 are shown in Table 6-6 and Table 6-7 below.

Table 6-6 2030 Cost Assumptions for Solar SAT Systems (Nominal$)

SITE	LOCATION	PROJECT CAPACITY [MWAC]	INTER-CONNEC-TION COST ($M)	CAPITAL COST [$/KWAC]	CAPITAL COST [$/KWDC]	FIXED O&M COSTS [$/KWAC]	FIXED O&M ESCALATION (ANNUAL)
1	North CA	10	$0.64	$2,049	$1,576	$33	2.5%
2	OR/CA	100	$6.4	$1,667	$1,282	$33	2.5%
3	Arizona	100	$6.4	$1,598	$1,229	$33	2.5%
4	Central Valley	20	$1.28	$2,003	$1,541	$33	2.5%
5	Central Valley	100	$6.4	$1,829	$1,407	$33	2.5%

Source: Black & Veatch

Table 6-7 2030 Cost Assumptions for Wind Systems (Nominal$)

SITE	LOCATION	PROJECT CAPACITY [MWAC]	CAPITAL COST [$/KWAC]	FIXED O&M COSTS [$/KWAC]	FIXED O&M ESCALATION (ANNUAL)
6	North CA	100	$1,968	$45	2.5%
7	Arizona	200	$1,794	$45	2.5%

Source: Black & Veatch

6.3.1.2 Levelized Cost of Energy (LCOE)

To model the LCOE of each of the representative projects, Black & Veatch assumed a third-party independent power producer (IPP) structure where PPA pricing is based on the LCOE. A number of financial incentives were incorporated into the modeling, as discussed below. As a tax exempt entity, COR cannot directly use the investment tax credit, however, by contracting with an IPP under a PPA, COR can share in the tax credit through the PPA pricing.

6.3.1.3 Financial Assumptions

The 2018 Tax Reform bill changed the federal corporate tax rate from 35 percent to 21 percent while still allowing state income taxes to be tax deductible, resulting in the composite income taxes for California, Arizona, and Oregon as shown below.

Table 6-8 Assumed Federal and State Income Tax Rates

	CALIFORNIA	ARIZONA	OREGON
Federal Income Tax	21%	21%	21%
State Income Tax	8.84%	6.97%	7.70%
Composite Income Tax	28.0%	26.5%	27.1%

Source: Black & Veatch

6.3.1.4 Tax Credits

The Consolidated Appropriations Act, signed in December 2015, extended the investment tax credits (ITC) that apply to solar technologies and wind. Wind project owners can opt for the ITC in lieu of the production tax credit (PTC), which was also extended, but wind typically benefits more from PTC at better wind sites. The credits do decline over time, as shown in Table 6-9. The availability of tax credits shapes the strategy of purchasing wind and solar from private developers through a PPA instead of self-building since COR is a tax exempt.

- ITC is a credit taken as a percentage against the capital cost of a RE system. The capital cost basis allowed is defined by the IRS. If the project owner opts for the ITC, the depreciation basis will need to be reduced by 50 percent of the ITC (e.g., 30 percent ITC, therefore => Depreciation Basis would be 85 percent of the capital cost)
- PTC is an inflation-adjusted per-kilowatt-hour (kWh) tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year. The duration of the credit is 10 years after the date the facility is placed in service.

For 2020, solar projects can receive a 30 percent ITC against the total capital cost of their project, if the project "begins construction" by the end of 2019. For this analysis, it was assumed that the solar projects begin construction in 2019 and come on-line in 2020 to take advantage of the 30 percent ITC. Otherwise the incentive drops to 26 percent in 2020. By 2030, the ITC drops to 10 percent.

While wind project owners can select between the ITC and the PTC, the drop in the benefits of the ITC occur sooner, so by 2020, there are no incentives available for wind, unless construction started in 2019. In this case, it was assumed that construction starts in 2019 and wind owners take advantage of the PTC at a rate of $9 per MWh, escalated at inflation for the first 10 years of the project. By 2030, wind does not receive any production tax credits, as displayed in Table 6-9.

Table 6-9 Tax Credit Assumptions

TECHNOLOGY (CONSTRUCTION START)	12/31/19	12/31/20	12/31/21	12/31/22	FUTURE YEARS
Solar PV	30%	26%	22%	10%	10%
Large Wind (Estimated PTC per MWh)	$9	N/A	N/A	N/A	N/A

Source: Black & Veatch

6.3.1.5 Accelerated Depreciation

Historically, solar and wind projects have been able to utilize a 5-year accelerated depreciation schedule (MACRS) that helped improve project economics. The 2018 Tax Reform bill now allows RE projects to take 100 percent tax depreciation on the total cost of the project in year 1. Industry experts believe, while quite generous, few investors would be able to take full advantage of this new depreciation schedule, so the modeling in the analysis assumed a 5-year MACRS schedule, where approximately 90 percent of the total capital cost would be depreciable.

6.3.1.6 Cost of Capital

IPPs have multiple methods of funding RE projects. For modeling purposes, it was assumed that the debt/equity structure for both solar and wind projects would be as shown Table 6-10. In recent years, the cost of capital for RE projects has dropped substantially in terms of lower interest rates on debt as well as lower equity return requirements by investors. The debt term was modeled for 20 years, while the life of the project was 25 years in the analysis performed.

Table 6-10 Cost of Capital Assumptions for Solar and Wind

FINANCIAL FACTOR	SOLAR	WIND
Debt Percentage	50	60
Debt Interest Rate (percent)	4.5%	4.5%
Debt term (Years)	20	20
Economic life (Years)	25	25
Cost of equity (after tax) (percent)	10%	10%

Source: Black & Veatch

6.3.1.7 Levelized Cost of Energy

The LCOE for the renewable projects with commercial on-line dates in 2020 and 2030 resulting from the input assumptions and analysis are shown in the tables below. As displayed in Table 6-11, Table 6-12, and Table 6-13, the LCOE represents what is assumed to be a fixed price, 25-year PPA.

Renewable Energy Projects LCOE (Nominal$) 2020 COD

Table 6-11 Renewable Energy Projects LCOE (Nominal$) 2020 COD

SITE	TECH-NOLOGY	LOCATION	PROJECT CAPACITY [MWAC]	CAPACITY FACTOR (AC)	CAPITAL COST [$/KWAC]	ITC OR PTC	NOMINAL LCOE RESULT ($/MWH)
1	Solar SAT	North CA	10	27.9%	$1,770	30%	**$53**
2	Solar SAT	OR/CA	100	27.0%	$1,440	30%	**$48**
3	Solar SAT	Arizona	100	33.1%	$1,380	30%	**$38**
4	Solar SAT	Central Valley 1	20	30.6%	$1,730	30%	**$48**
5	Solar SAT	Central Valley 2	100	29.8%	$1,580	30%	**$46**
6	Wind	North CA	100	30.0%	$1,700	$9/MWh	**$60**
7	Wind	Arizona	200	30.0%	$1,550	$9/MWh	**$56**

Source: Black & Veatch

Table 6-12 Renewable Energy Projects LCOE (Nominal$) 2030 COD

SITE	TECH-NOLOGY	LOCATION	PROJECT CAPACITY [MWAC]	CAPACITY FACTOR (AC)	CAPITAL COST [$/KWAC]	ITC OR PTC	NOMINAL LCOE ($/MWH)
1	Solar SAT	North CA	10	27.9%	$2,049	10%	$85
2	Solar SAT	OR/CA	100	27.0%	$1,667	10%	$75
3	Solar SAT	Arizona	100	33.1%	$1,598	10%	$59
4	Solar SAT	Central Valley 1	20	30.6%	$2,003	10%	$76
5	Solar SAT	Central Valley 2	100	29.8%	$1,829	10%	$73
6	Wind	North CA	100	33.1%	$1,968	$0	$75
7	Wind	Arizona	200	33.1%	$1,794	$0	$70

Source: Black & Veatch

Since the ITC and PTC vary year by year, the following table shows the year by year LCOE for projects that come on-line for that year, assuming construction start dates of the previous year.

Table 6-13 Project Nominal LCOE 2020 to 2030

YEAR	1	2	3	4	5	6	7
	Solar SAT	Solar SAT	Solar SAT	Solar SAT	Solar SAT	Wind	Wind
	North CA	OR/CA	Arizona	Central Valley	Central Valley	North CA	Arizona
2020	$53	$48	$38	$48	$46	$60	$56
2021	$58	$52	$41	$52	$50	$70	$65
2022	$65	$57	$45	$58	$55	$70	$66
2023	$75	$66	$52	$67	$65	$71	$66
2024	$77	$67	$53	$69	$66	$71	$67
2025	$78	$69	$54	$70	$67	$72	$67
2026	$79	$70	$55	$71	$68	$72	$68
2027	$81	$71	$56	$72	$69	$73	$68
2028	$82	$72	$57	$73	$70	$73	$69
2029	$83	$73	$58	$75	$71	$74	$69
2030	$85	$75	$59	$76	$73	$75	$70

Source: Black & Veatch
Note: The above cost only includes energy; transmission is not included

6.4 ENERGY EFFICIENCY

6.4.1 Building Standards

California has continually increased the energy efficiency of new construction and appliances since the Warren Alquist Act (Act) of 1974. These efficiency standards (Title 24) have since been updated to mandate Zero Net Energy (ZNE) residential new construction starting in 2020. ZNE homes require energy efficiency that will be achieved through implementing a high efficiency envelope (insulation, windows, etc.), and efficient Heating, Ventilation, and Air Conditioning (HVAC) units. The remaining energy consumption must be offset by distributed generation, predominantly rooftop solar generation, sized so that the annual building consumption (excluding natural gas) is approximately equal to building's electricity generation. Effective in 2030, all new commercial construction will also be required to meet the ZNE standard. In addition, the Act requires that fifty percent of existing commercial buildings be retrofitted to ZNE by 2030 and fifty percent of new major renovations of state buildings be ZNE compliant by 2025. The increased energy efficiency standards will contribute to a lack of load growth in future years.

6.5 ENERGY STORAGE

As explained in Section 5.5, COR has been heavily involved in the TES market for years and has invested more than $6 million in TES technologies.

Technology changes have led to increasing interest in the use of batteries in the energy market. Battery Energy Storage Systems (BESS), which can be independent systems not linked to EVs, can be useful in a broad variety of grid-beneficial applications including use as a capacity resource, for load shifting, and frequency and voltage support.

The CEC has recommended that POU's consider the role of storage in addressing over-generation of RE when solar energy production exceeds local demand. In California, this can occur particularly during the daytime peak solar production periods. If the excess RE is used to charge a BESS system, the stored energy can be used during the evening ramping period and allowing utilities to avoid GHG emissions that would otherwise be produced if the energy demand was met by conventional thermal resources.

A major benefit of BESS is the ability to provide multiple services in one location to meet the needs of the grid. BESS can be configured to respond to grid needs in less than a second, thereby providing the capability for a faster response time than conventional generation resources. Some of the concepts being considered for BESS applications include:

- **Load Shifting:** In load shifting applications, BESS are charged with lower priced energy which can help mitigate curtailment of excess renewable generation—when renewable generation exceeds demand—and the stored energy used at a later time, such as during evening ramping periods.
- **Peaking Supply:** The power output capacity of BESS can be used to meet capacity resource adequacy requirements and replace conventional peaking capacity to provide short-term power needs during periods of peak demand.
- **Frequency Regulation and Voltage Support:** BESS can be used to mitigate load and generation imbalances and maintain grid frequency and voltage needed for grid stability.
- **Spinning Reserve:** BESS can be utilized to provide energy needs within 10 minutes, as an alternative to conventional generation that must be kept online and synchronized to the grid in anticipation of a need.
- **Firming of Intermittent Resources:** BESS can be used to "firm" energy production of a variable energy resource—such as solar or wind generation—and provide a more predictable energy profile to the grid.
- **Transmission Upgrade Deferral:** BESS may offer a way to defer or avoid transmission upgrades.

BESS applications are often selected for primary use in either a power or energy application. Power applications tend to be of shorter duration (approximately 15 minutes to one hour) with operational profiles involving frequent rapid responses or cycles. Energy applications generally require longer duration (approximately 1 hour or more).

6.5.1 Performance and Cost Assumptions for Energy Storage

Because lithium ion batteries are widely accepted as a proven technology for BESS applications, a lithium ion battery was chosen as the technology for this analysis. Table 6-14 highlights the BESS performance parameters used in the IRP analysis.

Table 6-14 Representative Performance Parameters for Lithium Ion Battery Systems

PARAMETER	LI-ION
Facility Capacity Power Rating, MW	5
Discharge Duration at Rated Capacity, hours	4
Facility Energy Rating, MWh[1]	20
Round-Trip Efficiency, percent	85%
Estimated life, cycles	~5,000
Installed Levelized Capital Cost, $/kW-yr[2]	$533
Fixed O&M Costs, $/kW-yr	$20
Variable O&M Costs, $/kWh (charge or discharge)	$0.001 to 0.005

Notes:
1. The rating is based on installed project size.
2. Battery cost scales with MWh, whereas balance of plant and PCS costs tend to scale with power (MW). Because of this, installed costs tend to have a wide array of values.

Source: Black & Veatch

7.0 Modeling Assumptions, Tools, and Methodology

7.1 MODELING ASSUMPTIONS

7.1.1 Load forecasts

The load forecast used for the IRP analysis was presented in Table 4-3 of Section 4.0.

7.1.2 Natural Gas and Average Market Prices

For the purposes of economic analysis, a projection of natural gas fuel prices and power energy prices were required (see Figure 7-1, Figure 7-2, and Figure 7-3). The methods used to produce these prices by Ascend Analytics Curve Developer and PowerSimm software suite are described in Section 7.2 below.

Spot market prices for gas and power are simulated in the PowerSimm construct. Table 7-1 demonstrates the average annual simulated spot gas and power prices (mean, 5th, and 95th percentiles of the simulations) delivered to PG&E City Gate and NP-15 respectively. These prices drive model given that COR dispatches their own units, or transacts with these markets, to find the most economic electricity supply.

Table 7-1 Natural Gas and Market Energy Prices Assumed in the IRP

	SPOT NATURAL GAS PG&E CG $			AVG ANNUAL POWER MARKET ENERGY PRICE* $			AVG CARBON ALLOWANCE PRICE $		
YEAR	5%	MEAN	95%	5%	MEAN	95%	5%	MEAN	95%
2018	2.72	2.91	3.13	35.96	40.38	45.61	14.84	14.99	15.16
2019	2.34	2.82	3.38	25.37	38.50	55.91	15.02	15.59	16.17
2020	2.28	2.80	3.39	26.25	41.36	64.10	15.25	16.23	17.31
2021	2.27	2.87	3.67	25.25	45.05	70.64	15.70	17.06	18.60
2022	2.18	2.96	3.86	26.17	47.75	74.57	17.65	18.86	20.23
2023	2.27	3.05	3.90	29.02	49.74	74.64	18.98	20.27	21.75
2024	2.12	3.16	4.34	30.93	51.59	81.67	20.40	21.79	23.38
2025	2.26	3.25	4.61	30.83	53.87	83.02	21.93	23.43	25.14
2026	2.27	3.34	4.71	31.66	55.76	86.98	23.57	25.18	27.02
2027	2.04	3.42	5.27	35.24	57.73	91.15	25.34	27.07	29.05
2028	1.98	3.51	5.59	35.17	59.78	93.66	27.24	29.10	31.23
2029	2.25	3.59	5.55	38.30	61.94	90.38	29.29	31.29	33.57
2030	1.91	3.68	5.77	37.64	64.21	100.48	31.48	33.63	36.08
2031	1.89	3.81	6.83	36.04	66.57	117.45	33.84	36.15	38.79
2032	2.02	3.90	6.83	38.81	69.07	115.55	36.38	38.87	41.70

YEAR	SPOT NATURAL GAS PG&E CG $			AVG ANNUAL POWER MARKET ENERGY PRICE* $			AVG CARBON ALLOWANCE PRICE $		
	5%	MEAN	95%	5%	MEAN	95%	5%	MEAN	95%
2033	2.05	4.00	6.52	42.49	71.69	111.11	39.11	41.78	44.83
2034	1.95	4.10	7.03	39.63	74.41	121.38	42.04	44.91	48.19
2035	2.04	4.20	8.55	44.99	77.31	123.11	45.20	48.28	51.80
2036	2.04	4.31	8.24	48.73	80.34	123.41	48.59	51.90	55.69
2037	1.95	4.41	7.76	51.97	83.56	126.09	52.23	55.80	59.87

*The Average Market Energy Price data in the last three columns are average annual hourly values.

Source: Black & Veatch

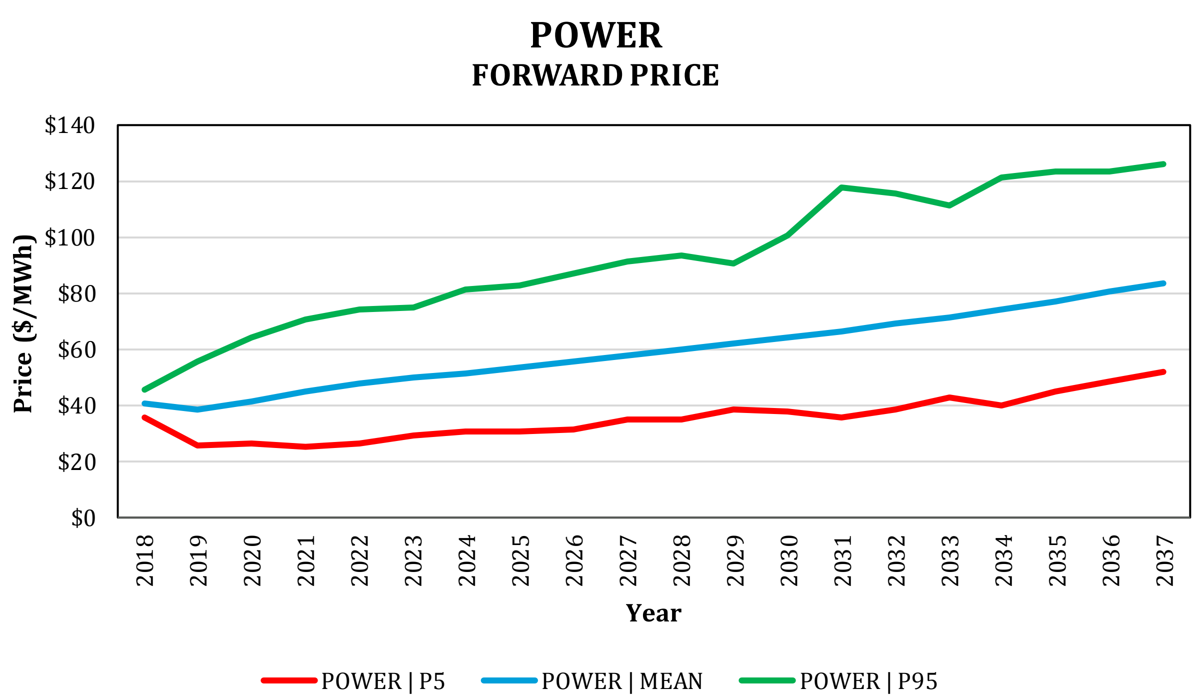

Figure 7-1 Power Forward Price

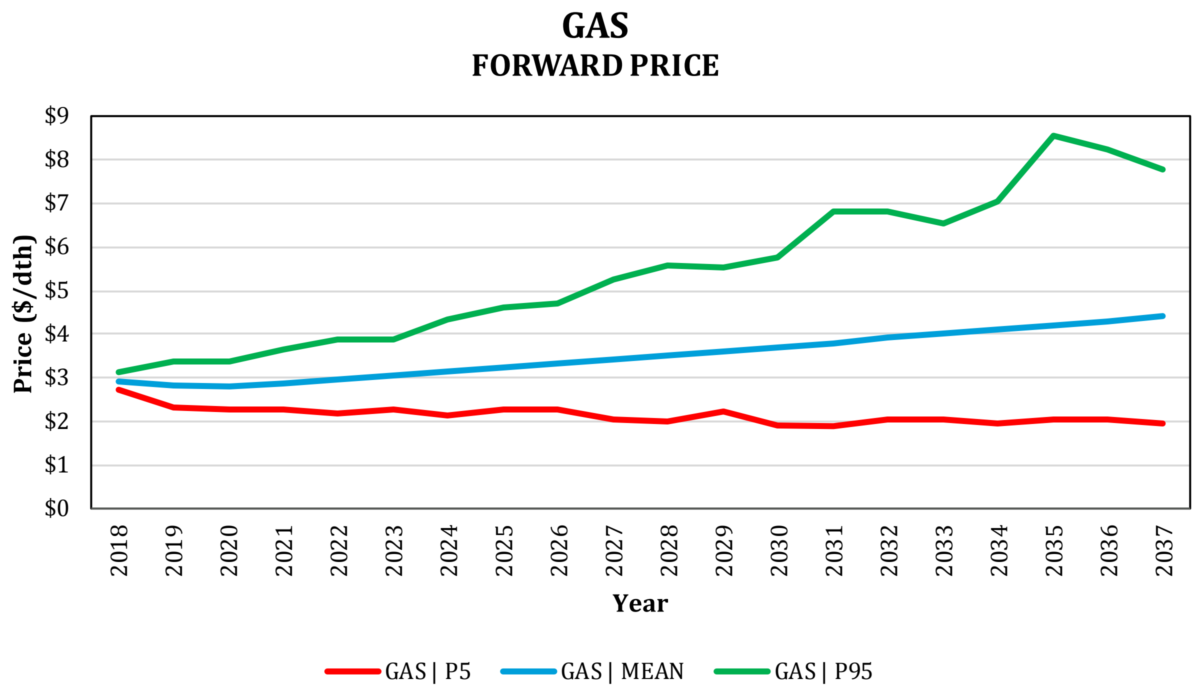

Figure 7-2 **Gas Forward Price**

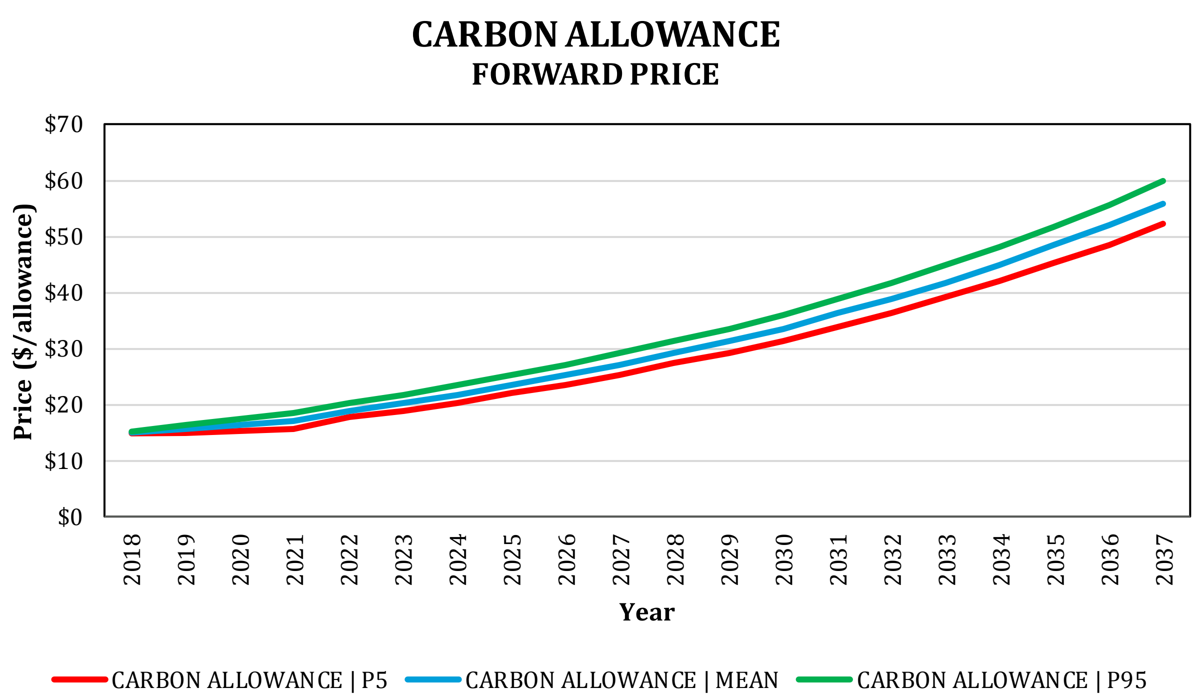

Figure 7-3 **Carbon Allowance Forward Price**

As reported in Table 7-1, these prices are annual equivalents or averages for the stated year. When performing the economic analysis of this report, the actual analysis prices used were hourly, on/off-peak, daily, or monthly as was appropriate and included the natural gas market, electric power market (NP15, COB), and California Carbon Allowance (CCA) market.

7.1.3 Discount Rate

The analysis utilized a 2.5 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.

7.2 ASCEND ANALYTICS PLANNING SUITE – TOOLS FOR MODERN RESOURCE PLANNING

The Ascend Analytics Planning Suite is a set of software programs consisting of Curve Developer (CurveDev) market harvesting and modeling, PowerSimm Planner (PowerSimm) production cost model for system operations simulation, among other tools. The suite is designed, maintained, and supported by Ascend Analytics and was used for the IRP.

7.2.1 CurveDev and PowerSimm – Tools for Market Prices

Forecasting market prices by CurveDev begins by harvesting forward price quotes from the Intercontinental Exchange (ICE). This is done for markets available at PG&E City Gate, California Carbon Allowance, NP15, and MidC. As there are no ICE quotes for COB, this value is derived from historical relationships to the NP15 and MidC price. Beyond the time horizon covered by the harvested broker quotes to the end of the study period, a 2.5% annual increase is used for gas and energy prices and 7.5% for carbon prices. Together, the broker harvest and post processing represents a single price curve for each market and are summarized annually in Table 7-1.

Studies in this report use harvested data as of June 25, 2018. PowerSimm will pull in the latest price curve from CurveDev up until this date, and use this as the mean for all simulated prices. For stochastic studies, PowerSimm also pulls in the 90 business days prior to the June 25th harvest date of the study when simulating prices. The 90 days of data is used to calculate the correlations between markets and dates, as well as the volatility of each market. This information is then used to simulate a distribution of prices that matches the historical correlations and volatilities, while still scaling the mean to the most recent price curve. These prices were rolled-up to produce the annual data as presented in Table 7-1.

Additional information on CurveDev and PowerSimm's methods and capabilities can be found in Appendix D.

7.2.2 CurveDev and PowerSimm – Tools for Modern Resource Planning

Combined, CurveDev and PowerSimm tools form a platform for modern resource planning, in an era of increasing uncertainty in electricity supply driven by the deployment of variable renewable generation. The uncertainty in electric supply brings with it risk that will affect the cost and viability of potential projects needed to meet state-mandated renewable portfolio standards. Not only does PowerSimm provide the appropriate mean cost estimates under multiple correlated scenarios, but is also able to monetize (assess an equivalent cost of) the risk. This assessment, known as the "risk premium", can be equated to an insurance premium used to protect against uncertainty that could be caused by weather, market prices of gas or power, and variability of non-dispatchable resources. While PowerSimm can report an abundance of useful output data, for economic assessments of potential candidate plans, it is sufficient to compare the system annual mean cost and the annual risk premium together.

Additional information on CurveDev and PowerSimm's method and capabilities can be found in Appendix D.

8.0 Evaluation and Results

In this section, the economic analysis performed for the system is described. In general, the analysis is aimed at minimizing system costs—a sentiment that was of utmost importance to Stakeholders—while also meeting the several targets that have arisen under the state RPS and environmental policies described in Section 2, including the following goals:

- Low cost and reliability
- 50 percent renewable energy by 2030 and meet intermediate goals per SB 350
- Increased energy efficiency per SB 350
- 2030 GHG within the July 2018 CARB staff recommended targets (low of 57,000 MTCO2e and high of 101,000 MTCO2e per SB 350)

Based upon past experience and Stakeholder input, an important target has been identified: selecting a resource planning scenario that reasonably balances multiple types of RE resources. Specifically, to achieve a balance in PV and wind resources over the planning horizon is vital as a balanced portfolio may reduce risks associated with over-reliance on a single technology. Portfolio diversity protects customers from contingencies such as market fuel and power prices, fuel and power availability, as well as changes to the load and resources. Also, a balanced wind and solar PV energy generation combination is deemed to be a better fit to hourly system energy demand profile than a plan heavily weighted toward either wind or solar. A balanced wind and solar PV energy generation profile is also considered prudent for a number of other reasons.

As one example, just as there is a reluctance to develop additional hydroelectric renewable resources because of concerns about possible adverse impacts on fish and other wildlife, some industry stakeholders and several COR Stakeholders have expressed concerns about over reliance on wind generation due to the possible impact on avian populations. Thus, in addition to the above bulleted items, staff developed and ranked Scenarios with the objective of achieving a balance between wind and PV RE generation.

8.1 ECONOMIC EVALUATION FRAMEWORK

The aim of the economic analysis is to meet these requirements 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 2018-2037 evaluation period. Incremental costs do not include existing fixed costs or common costs such as general and administrative costs, as these are considered sunk costs or costs 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.

Due to reliance upon interaction with the power market, it is important that an economic analysis projecting future power costs model interaction with the market and project the costs and revenues associated with purchases from, or sales into, the market. A plan that relies heavily on assumed market purchases may incur risks associated with future power energy market prices increasing at a rate higher than assumed in the analysis. Therefore, to reduce the risk of higher retail rates associated with unexpected increases in future power energy market prices, plans with lower market purchases are preferable to plans with higher market purchases, all other factors being equal. Details about the modeling approach used to derive the CPWC are included in Section 8.2.

8.2 SCENARIO ANALYSIS

In the IRP, the CPWCs of several competing Scenarios were determined. A Scenario included one or more of seven potential solar and wind projects, first developed in Section 7, having the specifications summarized in Table 8-1. The selection of projects listed in Table 8-1 was based on the understanding from Section 6 that additional renewable resources will be required.

A total of eight Scenarios were evaluated through detailed modeling; these consisted of the Existing System Scenario (identified as Scenario G), plus seven Scenarios that involved adding RE resources. The various Scenarios evaluated are displayed in Table 8-2, which also lists the specific projects from comprising each Scenario.

Table 8-1 RPS Project Definitions

	PROJECT 1	PROJECT 2	PROJECT 3	PROJECT 4	PROJECT 5	PROJECT 6	PROJECT 7
Name	Local PV w/Bat	NorCal/OR PV	AZ PV	CV PV 1	CV PV 2	NorCal/ OR Wind	AZ Wind
Location	Local	OR/NorCal	Arizona	Central Valley	Central Valley	OR/ NorCal	Arizona
Type	PV	PV	PV	PV	PV	Wind	Wind
Capacity (MW)	10	100	100	20	100	100	200
Scalable	No	Yes	Yes	No	Yes	Yes	Yes
AC Capacity Factor (%)	27.9%	27.0%	33.1%	30.6%	29.8%	30.0%	30.0%
Annual Energy (MWh)	24,440	236,520	289,956	53,611	261,048	262,800	525,600
Annual Degradation (%)	0.70%	0.70%	0.70%	0.70%	0.70%	0.00%	0.00%
Energy Storage? (Yes/No/Maybe)	Yes	Not included	Not included	Not included	Not included	Not included	Not included
ES Capacity (MW)	2.50	Not included	Not included	Not included	Not included	Not included	Not included
ES Duration (Hrs)	4	Not included	Not included	Not included	Not included	Not included	Not included
Transmission Requirements	None	To COTP, WAPA	To CAISO, WAPA	NP26, WAPA	To CAISO, WAPA	To COTP, WAPA	To CAISO, WAPA
LMP Market Location (To Value)	NP15	NP15	Palo Verde	ZP26	SP15	NP15	Palo Verde
Transmission & VERBS Costs (2018-$/kW/mo)	$0.000	$2.258	$3.137	$0.000	$0.000	$2.258	$3.137
Transmission Costs (2018-$/MWh)	$0.000	$0.000	$11.221	$11.221	$11.221	$0.000	$11.221
Transmission Escalation Rate		5.00%	4.00%	4.00%	4.00%	5.00%	4.00%

Source: Black & Veatch

Table 8-2 IRP Scenario and Projects

SCENARIO NAME	PROJECT 1: PV	PROJECT 2: PV	PROJECT 3: PV	PROJECT 4: PV	PROJECT 5: PV	PROJECT 6: WIND	PROJECT 7: WIND
A) Base Case	MW: 10 Start: 2021 MWh/yr: 24,440 LCOE: $58						
B) Balanced Mix	MW: 10 Start: 2021 MWh/yr: 24,440 LCOE: $58		MW: 30 Start: 2028 MWh/yr: 86,987 LCOE: $57	MW: 20 Start: 2026 MWh/yr: 53,611 LCOE: $71		MW: 70 Start: 2032 MWh/yr: 183,960 LCOE: $76	
C) Balanced Mix-Alternate	MW: 10 Start: 2021 MWh/yr: 24,440 LCOE: $58	MW: 30 Start: 2029 MWh/yr: 70,956 LCOE: $73			MW: 25 Start: 2026 MWh/yr: 65,262 LCOE: $68		MW: 70 Start: 2032 MWh/yr: 183,960 LCOE: $72
D) Heavy Wind	MW: 10 Start: 2021 MWh/yr: 24,440 LCOE: $58						MW: 85 Start: 2026 MWh/yr: 223,380 LCOE: $68
E) Heavy Wind – Alternate	MW: 10 Start: 2021 MWh/yr: 24,440 LCOE: $58					MW: 85 Start: 2026 MWh/yr: 223,380 LCOE: $72	
F) Heavy Solar	MW: 10 Start: 2021 MWh/yr: 24,440 LCOE: $58	MW: 90 Start: 2026 MWh/yr: 212,868 LCOE: $70					
G) Existing System							
H) Optimized Balanced Mix	MW: 10 Start: 2021 MWh/yr: 24,440 LCOE: $58				MW: 60 Start: 2026 MWh/yr: 156,629 LCOE: $68	MW: 65 Start: 2034 MWh/yr: 170,820 LCOE: $77	
Levelized Cost of Energy (LCOE) figures at stated at the plant bus bar and do not include transmission costs.							

Source: Black & Veatch

8.3 CONSOLIDATED RESULTS

The consolidated CPWC results for the Scenarios evaluated are shown in Table 8-3. To facilitate interpretation, the results are presented as a "heat map" in which the best Scenario in any category is highlighted in dark green; Scenarios considered favorable but not the best in a category are shaded light green; Scenarios that are significantly less favorable than the best in a category are shaded light yellow, followed by rose colored and red colored shades signifying increasingly significant and unfavorable results compared to the best Scenario result in the category.

The Base Case Scenario in which 10 MW of local solar is added in 2021 is listed first in Table 8-3. This Scenario is important as it reflects the addition of the currently-planned Solar Project that is in the second phase of development (see Section 7). There are two key conclusions related to the Base Case Scenario.

First, by comparing the Base Case with the Existing System Scenario (Scenario G) CPWC, it is clear that the Base Case has a lower CPWC. This helps to illustrate why adding the Solar Project (from Table 8-1) provides benefit from a cost perspective and also by adding RE benefits over Scenario G. This comparison explains the reason for identifying the Solar Project as the next resource addition and why this is considered to be the Base Case rather than the Existing System Scenario.

A second, very important conclusion about the Base Case Scenario is that, even though it achieves a higher RE percentage than Scenario G, it nevertheless falls short of meeting the 2030 RE target of 50 percent. In fact, it achieves only 33 percent RE level in 2030 and also for the 2018-2030 period. Moreover, the Base Case Scenario is still very heavily reliant on wind energy (71 percent of all RE) even with the addition of the Solar Project in 2021. Due to these results, the Base Case is understood to contain the next project to be undertaken, but it is not considered to be the final mix of resources over the planning horizon. The need for additional renewable resources on the system beyond the 2021 solar addition led to the development of the remaining Scenarios in Table 8-3. All of these, with the exception of Scenario G, involved the 2021 Solar Project, but also included additional RE resources after 2021.

Scenario H is the only plan identified in Table 8-3 as having green or light green shading in all categories. Based on the overarching objective to balance economics, reliability, portfolio diversity, and environmental targets, Scenario H is considered to be the best overall plan in the 2019 IRP. The Plan is within 2.8 percent of the least cost plan; it achieves a 54 percent RE mix in 2030; it achieves all intermediate RE milestones (in some years, the plan relies on banked RECs); and has a reasonably balanced mix of RE contributions—53 percent from wind and 36 percent from solar.

In terms of lowest CPWC, Scenario D may appear on its surface to be the best plan as it is both cost-effective and at 65 percent RE, it exceeds the mandated 2030 RE levels. However, this plan falls short in its lack of resource diversity—the plan is very heavily reliant on wind energy (84 percent of all RE) and contains little solar energy (6 percent). As a result, this plan receives low marks for its inability to achieve a balanced RE portfolio. This assessment is reflective of the preference that several Stakeholders expressed for solar energy and is consistent with the emphasis on a balanced RE portfolio.

Scenario C also achieves a very high percentage of RE in 2030 (65 percent) but is not economic and also suffers from a high reliance on wind energy. Scenario F is economically competitive and achieves 59 percent RE contribution, but the scenario is over-reliant on wind energy resources.

Scenario E reaches the best overall balance of RE production, with 42 percent coming from wind energy and 47 percent coming from solar energy projects. This plan also achieves all RE milestones and reaches 61 percent in 2030. Nevertheless, the drawback of Scenario E is one of economics, as it achieves the favorable RE characteristics at a cost that is 6.5 percent higher than the least cost Scenario D.

In least cost planning studies, it is common to consider a CPWC difference between two plans to be in the 1.5 percent to 2.5 percent range. The uncertainties involved in the SB 350 IRPs arguably increases this range, and a CPWC difference of 2.0 percent to 3.0 percent can reasonably be considered within the margin of error. As a result, it can be concluded that the RE benefits of Scenario E are obtained at a significantly higher cost than the plan having the lowest CPWC (Scenario D). The issue, therefore, is whether a plan could be developed that better balanced cost and environmental benefits. The plan meeting these aims is the preferred plan, Scenario H.

Table 8-3 Heat Diagram of Scenario CPWC and RE Results

CPWC Summary				2030 Renew-able, % of Retail Sales	Intermediate Milestones for RE Met?	Avg. RE 2018-2030	Achieving RE Balance		
	Description	CPWC ($1,000)	CPWC % Higher				RE from Wind	RE from Solar	RE from Hydro
Base Case	Base Case (with local solar only)	583,833	3.3%	32.8%	No	32.8%	71%	11%	18%
Scenario A	Balanced Mix of Wind/Solar	575,766	1.9%	51.8%	Yes	38.5%	59%	30%	11%
Scenario B	Bal. Mix of Wind/Solar – Alt. Projects	602,421	6.6%	51.3%	Yes	37.9%	60%	29%	11%
Scenario C	Wind Heavy	642,176	13.7%	64.9%	Yes	45.4%	84%	6%	10%
Scenario D	Wind Heavy - Alternate Projects	564,925	0.0%	64.9%	Yes	45.5%	84%	6%	10%
Scenario E	Solar Heavy	601,558	6.5%	61.3%	Yes	44.2%	42%	47%	11%
Scenario F	Early Wind Balanced Mix	566,191	0.2%	59.3%	Yes	41.1%	81%	8%	11%
Scenario G	Existing System without Local Solar	601,957	6.6%	29.6%	No	30.4%	81%	0%	19%
Scenario H	Optimized Balanced Mix	580,966	2.8%	53.9%	Yes	41.2%	53%	36%	11%

*Optimal results are shown in green, unfavorable results in red
** Intermediate Milestones are: 33% by 2020; 40% by 2024; 45% by 2027; 50% by 2030.
***Intermediate Milestones are considered met with the use of banked renewable energy credits

8.4 DETAILED RESULTS OF THE PREFERRED EXPANSION PLAN

8.4.1 Capacity and Energy Adequacy of Scenario H

Capacity balance for the preferred Scenario H expansion plan is shown in Figure 8-1. This figure is organized in the same manner as was done for the Existing System Scenario in Section 6.

As seen at the top of Figure 8-1 and Figure 8-2, existing sufficient resources and generation capacity are expected to meet energy needs throughout the planning horizon under Scenario H. The excess generation capacity ranges from 18 MW in 2018 to 43 MW in 2034 the planning period, once the RE projects are stated in terms of their firm capacity.

Table 8-4, Figure 8-1, and Figure 8-2 reflect the addition of three renewable projects, the 2021 Solar Project (rated at 10 MW of which 3.5 MW is firm), a second solar project in 2026 having a firm output of 21 MW, and a 2034 wind project having a firm output of 7 MW. The information in this table is simplified but reflects the comprehensive CRAT table included in Appendix A.

Table 8-4 and Figure 8-2 shows how the energy requirements will be met under Scenario H. Under the recommended plan, the 1x1 and 2x1 combined cycle projects are the only two generating units producing a significant amount of energy at the Station, while all RE projects are actively producing energy consumed by customers or sold into the market. Due to this market interaction, net sales are projected into the market starting in 2026 and for several of the subsequent years in planning period. It is seen in the table that the final two RE projects coming on-line in 2026 and 2034 are important contributors to the energy balance as soon as they go into commercial operation.

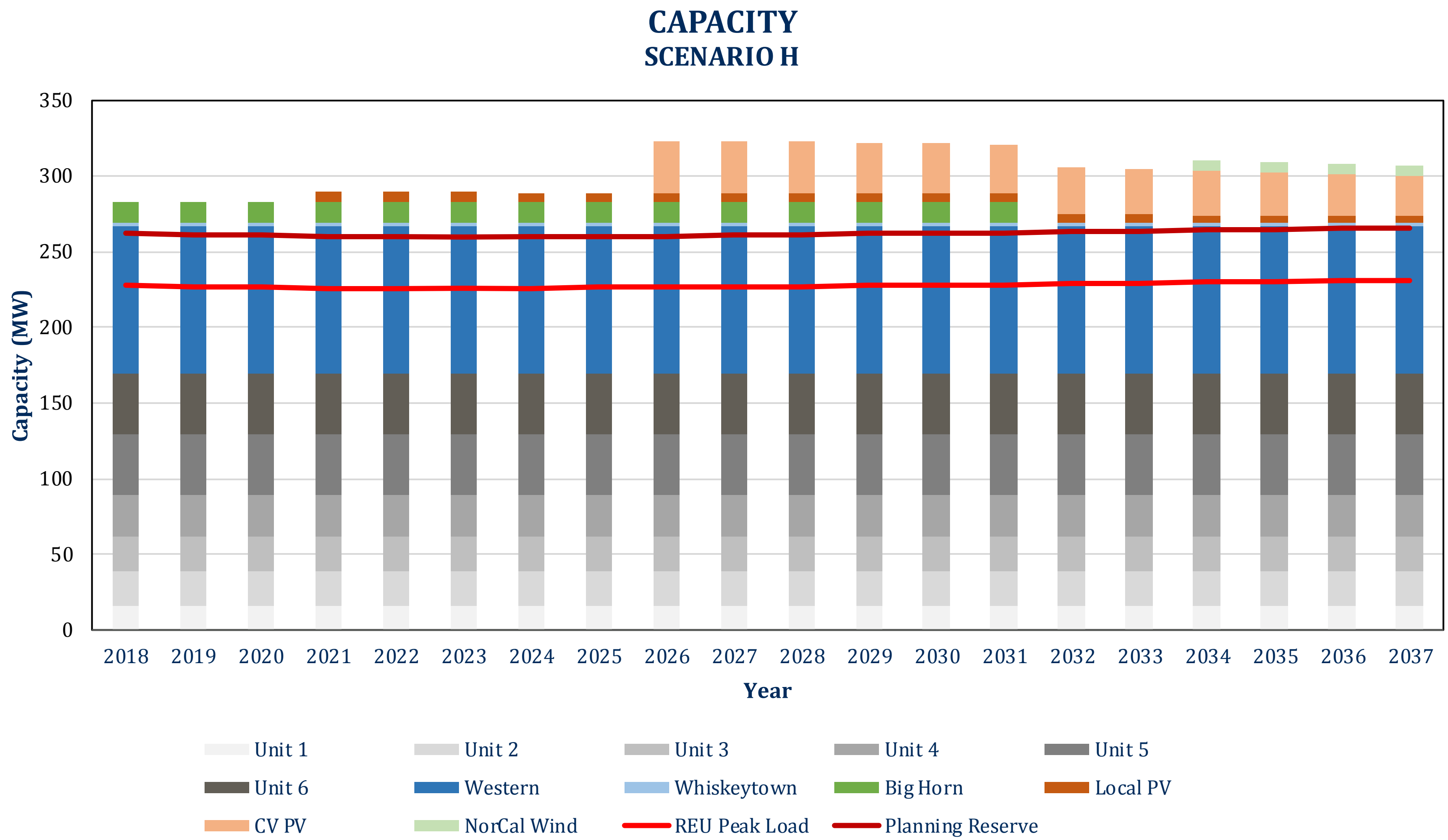

Figure 8-1 Capacity Balance in the Preferred Expansion Plan, Scenario H

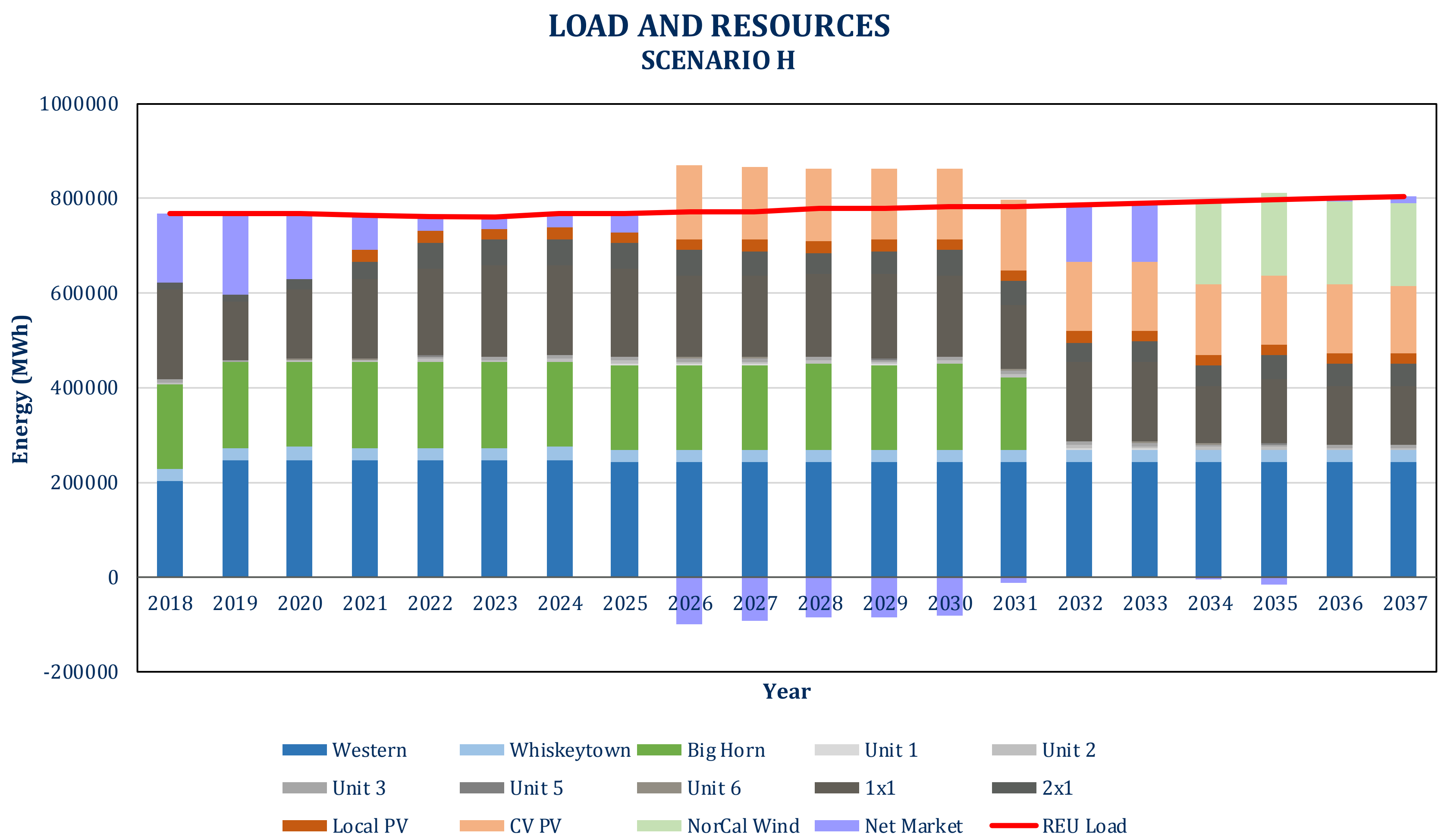

Figure 8-2 Loads and Resources Balance in the Preferred Expansion Plan, Scenario H

Table 8-4 Energy Balance in the Preferred Expansion Plan, Scenario H

Annual Energy Balance of Loads and Resources																					
Redding Electric Utility																					
Description	Type	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
System Energy Demand (GWh)		768	767	767	763	762	763	767	768	771	773	779	781	782	784	788	789	792	796	802	804
Unit 1	NG GT	1	0	1	1	1	1	2	2	1	1	2	1	2	2	2	2	1	1	1	1
Unit 2	NG GT	3	2	2	3	6	5	6	6	6	6	6	4	7	6	7	6	5	5	4	4
Unit 3	NG GT	5	2	3	3	6	5	7	7	6	6	7	5	7	7	7	7	5	6	4	4
Unit 4 (Simple Cycle)	SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unit 5 (Simple Cycle)	NG SC	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Unit 6 (Simple Cycle)	NG SC	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
1x1 (Combined Cycle 5 or 6 w/4)	NG CC	191	126	148	168	184	191	187	187	174	172	173	179	169	138	167	167	121	135	125	125
2x1 (Incremental Comined Cycle)	NG CC	15	13	23	40	53	55	57	53	52	53	46	49	55	48	42	44	45	51	47	45
Whiskeytown	Hydro	26	26	26	26	26	26	26	26	26	26	27	26	26	26	26	26	26	26	26	26
Big Horn	Wind	180	180	180	180	180	180	180	180	180	180	180	180	180	153	0	0	0	0	0	0
Western	Hydro	201	248	248	248	248	248	248	243	243	243	243	243	243	243	243	243	243	243	243	243
Local PV	Solar	0	0	0	24	24	24	24	24	24	23	23	23	23	23	23	22	22	22	22	22
CV PV	Solar	0	0	0	0	0	0	0	0	155	154	154	152	151	150	149	148	147	146	145	144
NorCal	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	176	176	177	176
Total Generation (GWh)		623	597	631	693	731	737	739	730	870	869	864	866	866	798	669	668	794	813	796	792
Market Sales		(48)	(47)	(64)	(97)	(130)	(131)	(132)	(128)	(214)	(212)	(201)	(201)	(205)	(178)	(112)	(114)	(178)	(188)	(173)	(170)
Market Purchases		193	216	199	167	161	157	160	167	115	118	117	117	123	165	232	235	177	172	180	182
Net Market Purchases (GWh)		144	170	135	71	32	26	29	39	(99)	(94)	(84)	(84)	(82)	(13)	120	121	(1)	(16)	8	13
Net System Energy (GWh)		768	767	767	763	763	763	768	769	771	775	780	781	783	785	789	790	793	797	803	805

8.4.2 Renewable Energy and GHG Emissions of Scenario H

The addition of three RE projects in the recommended expansion plan, Scenario H, results in the ability to meet the RPS requirements. This is shown in Figure 8-3 that reports the RE outlook during the 2018 through 2037 planning period.

As seen in the figure, Scenario H remains at or above the goal in all years with the allowances of banking RECs. Importantly, the figure shows that Scenario H maintains a positive REC balance over the entire planning period, meaning that, on the whole, the plan exceeds the cumulative RE credits during the planning horizon and never goes into a cumulative REC deficit in any year during the 2018-2037 planning horizon.

Figure 8-4 shows a projection of the GHG emissions in the form of $MTCO_2e$ during the planning horizon for the preferred expansion plan, Scenario H. Under this plan, there would be 99,335 $MTCO_2e$ in 2030. This level of emissions is below the high target of 101,000 in the CARB staff recommendations for the COR (although it is above the 57,000 $MTCO_2e$ set as the lower end of the targeted range).

8.4.3 The Detailed CPWC Sheet for Scenario H

Table 8-3 presented the CPWC of all Scenarios. The CPWC shown for Scenario H was $580,966,000. In Table 8-8, the derivation of the Scenario H CPWC is shown by year and by the components that contribute to the CPWC of all plans.

At the top of Table 8-5, information about the addition of new renewable projects is listed. The project list for Scenario H includes the 10 MW local PV project added in 2021, the 60 MW PV project in 2026, and the 65 MW wind project added in 2034 (all MW ratings are maximum plant output ratings, reductions are made to arrive at the firm ratings used in the capacity balance). The first year production and levelized cost of energy (LCOE) is also listed in this portion of the table.

Below the input section in Table 8-5 are the yearly cost and revenue components that comprise the annual costs. The categories include supply costs related to self-generation plus power purchase costs (from PPAs and the spot market) and wholesale sales revenue earned from sales into the market. The Total System Cost listed as a column heading includes the net cost once supply costs and wholesale sales are taken into account. Thus, in 2018, the Total System Cost is $35.5 million. Over time, the Total System Costs for each year trend upward, although there are years in which significant market revenues results in a decrease from the previous year (see for example, the year 2031). In the final year of the planning horizon, the 2037 Total System Cost is projected to be $47.1 million.

To derive the CPWC of Scenario H, the Total System Cost for each year is discounted to 2018 at the assumed 2.5 percent discount rate and summed. By the end of the planning horizon, the CPWC of Scenario H is $580.966 million as seen in the bottom of the CPWC column in Table 8-5 and as also reported in Table 8-3.

8.4.4 Additional Discussion of Merits, Scenario H

Section 8.3 explained the development of the competing Scenarios considered and the rationale for selecting Scenario H as the preferred option. Some additional discussion of the Scenario H merits is provided in this section.

While the CEC Guidelines only require the future planning studies to extend to 2030, consideration of additional years beyond 2030 were encouraged. A 20-year plan that has the benefit of measuring the relative merits of various Scenarios beyond the next 12 years until 2030. While the 2037 difference in CPWC between Scenario H and the least cost option, Scenario D from Table 8-3, is 2.8 percent, at the 2030 mark, the difference is only 2.1 percent and well within the range of uncertainty (while there is no definitive rule, in this analysis, CPWC results within no more than 2 to 3 percent are considered to be insignificant differences between plans). Thus, the CPWC results should be interpreted as showing that, while Scenario D is lower in absolute CPWC, the difference with Scenario H is on the margin of insignificance and while the CPWC is an important factor in plan selection, additional non-economic factors play a vital role in the selection of the preferred Scenario.

Scenario H is quite flexible in that, following the first resource addition in 2021 (common to all plans), projects are layered in over a 20-year period, with the next project expected to be operational in 2026, which brings the following benefits:

- The period between resource additions allows the continued assessment of industry events and system developments in order to adjust the specifics of Scenario H if conditions warrant;
- It provides the ability to increase or decrease the size of the selected RE projects as necessary;
- With the pliability this plan offers, staff can better match resources to comply with any future applicable in-state versus out-of-state requirements, such as those of the California Independent System Operator (CAISO); and
- The plan provides the ability to delay or accelerate the in-service date of the project based on a number of factors such as future legislation and market conditions

Scenario D, however, offers less flexibility in that, beyond the 2021 solar addition that is also added in Scenario H, the plan consists of only one 85 MW wind addition in 2026. While economical to add this large wind project, the plan results in an unbalanced mix of solar and wind generation as indicated by the 84 percent wind and 6 percent solar mix of RE for Scenario D as indicated in Table 8-3. It is important to achieve a balance in PV and wind resources over the planning horizon, since a balanced portfolio may reduce risks associated with over-reliance on a single technology. Also, a balanced wind and solar PV energy generation combination is deemed to be a better fit to the hourly system energy demand profile than a plan heavily weighted toward either wind or solar.

As noted earlier, due to reliance upon interaction with the power market, this analysis considers future interactions and estimates the costs and revenues associated with purchases from, or sales into, the market. A plan that relies heavily on assumed market purchases or sales may incur risks associated with future power energy market prices increasing at a rate higher than assumed in the analysis if more heavily reliant on market purchases, or risks associated with future power energy market prices being lower than assumed in the analysis if more heavily reliant on market sales. Therefore, to reduce the risk of higher retail rates associated with unexpected increases or decreases in future power energy market prices, plans with lower exposure to market volatility are preferable to plans with higher market purchases or sales, assuming others factors are equal.

Scenario H is also better than Scenario D with regards to the heavy reliance on wind and the end effects of meeting future RE targets. Scenario D fails to meet the RPS requirements just beyond the planning horizon, ultimately requiring the procurement of an additional renewable project prior to the end of the planning window. For example, Scenario D relies on banked RECs during the last three years of the planning period and additional renewable resources would be required to maintain RPS compliance after 2039. In contrast, Scenario H is above 50 percent in each of the final four years (2034-2037) and meets ongoing RPS requirements in 2038 and beyond.

In summary, Scenario H is expected to have a slightly higher cost than Scenario D, however, it carries less exposure to extreme market conditions, brings less regulatory risk, provides better hourly production, and exhibits more resource diversity, thus meeting portfolio objectives.

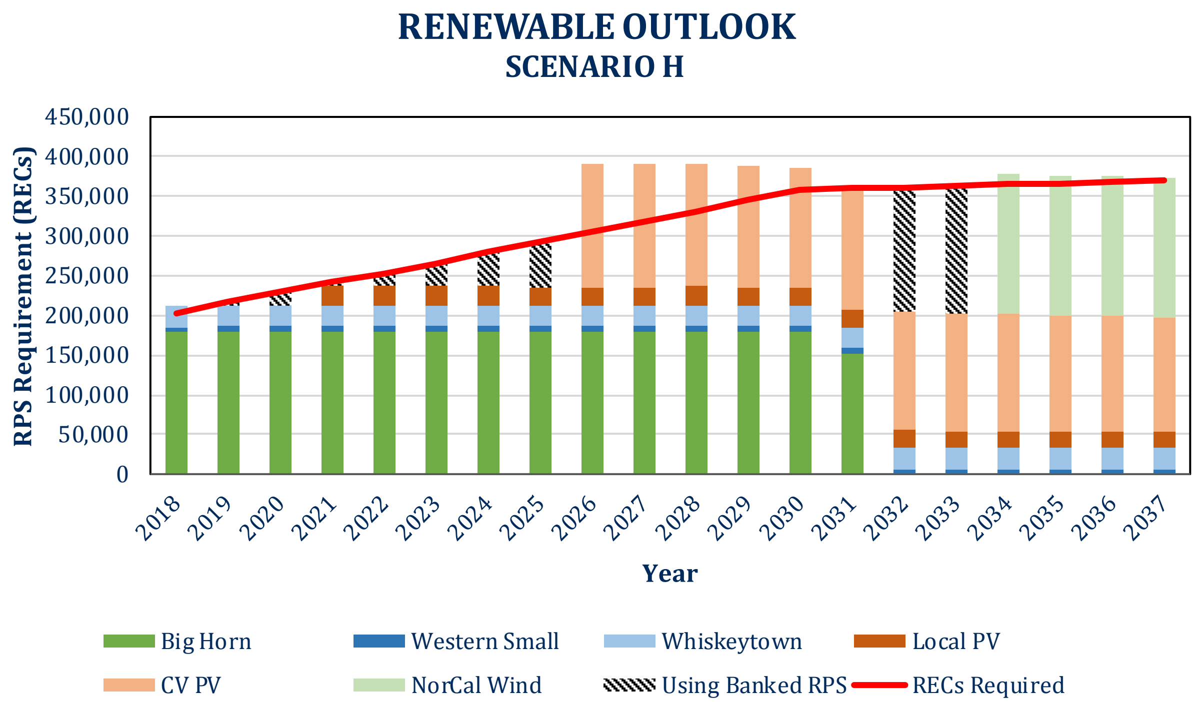

Figure 8-3 Renewable Energy and REC Adequacy in the Preferred Expansion Plan, Scenario H

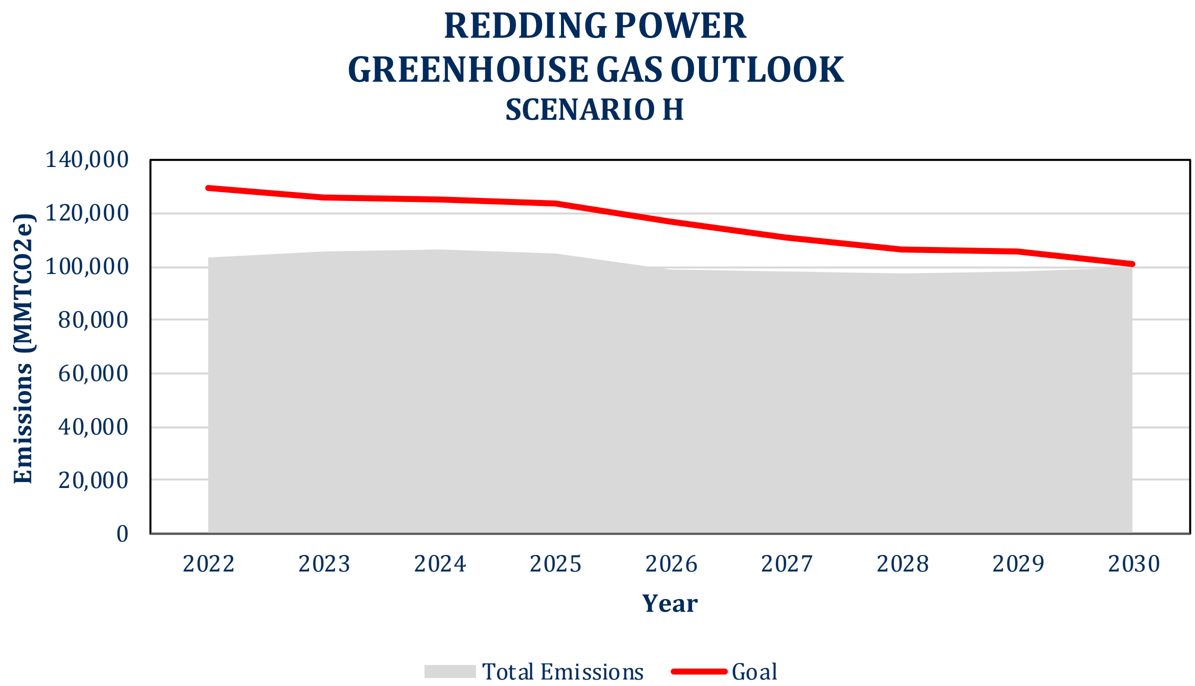

Figure 8-4 GHG Emissions in the Preferred Expansion Plan, Scenario H

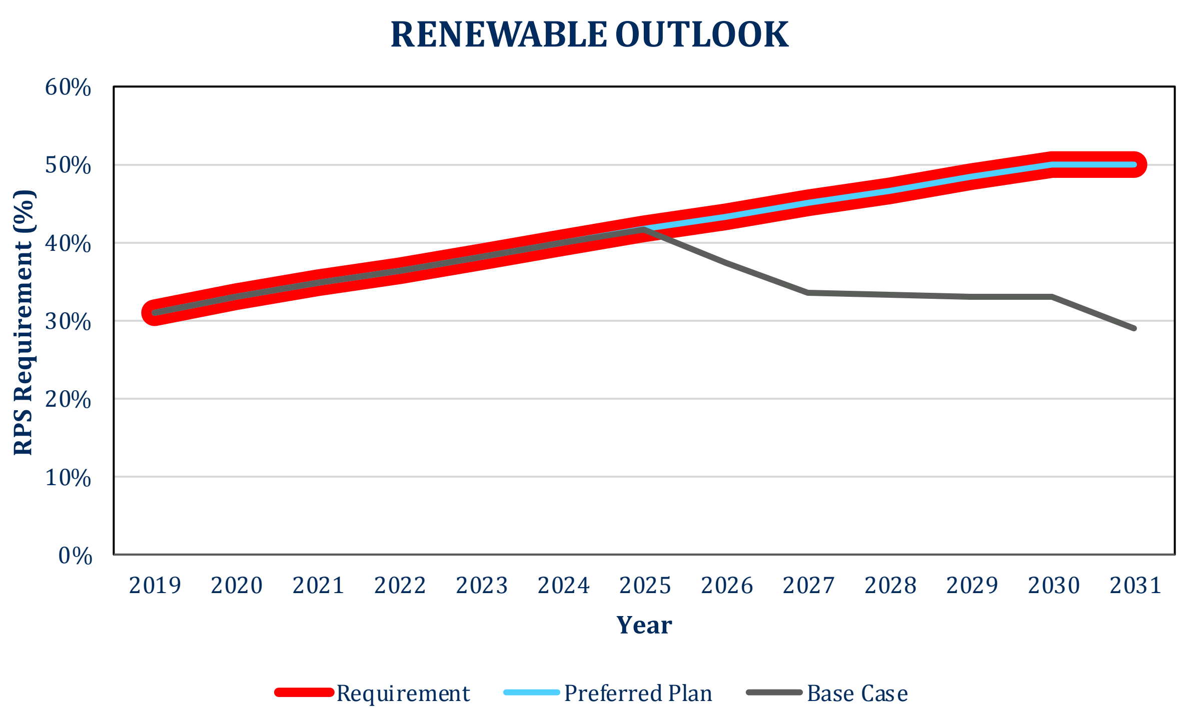

Figure 8-5 Renewable Outlook

Table 8-5 Detailed CPWC Results for the Preferred Expansion Plan, Scenario H

COR V11 Scenario H Mean Results

Desc: Optimized Balanced Mix

Economic and Financial Parameters	
CPW Discount Rate:	2.5%
Base Year for CPW $:	2018

Portfolio	Size (MW)	First Year	1st Yr Energy (MWh)	LCOE ($/MWh)
Local PV w/Bat	10	2021	24,440	$ 58.00
NorCal/OR PV				
AZ PV				
Westland PV				
CV PV	60	2026	156,629	$ 68.00
NorCal/OR Wind	65	2034	170,820	$ 77.08
AZ Wind				

		Supply Cost						Wholesale Sales						Cumulative
Year	System Transmitted Energy GWh	Cost of Supply Energy ($1,000)	REU Generation Costs ($1,000)	Hydro Costs ($1,000)	Wind Costs ($1,000)	Risk and Import Costs ($1,000)	Total Purchase + Production ($1,000)	REU Generation Revenue ($1,000)	Wind Sales Revenue ($1,000)	Generation Sales Revenue ($1,000)	Export Revenue ($1,000)	Total System Cost ($1,000)	Present Worth Cost ($1,000)	Present Worth Cost ($1,000)
2018	767.535	25,503	10,251	4,973	12,239	7,936	60,901	10,561	7,379	5,272	2,178	35,512	35,512	35,512
2019	767.119	24,411	7,054	6,525	12,239	8,909	59,138	7,217	8,523	5,026	1,883	36,488	35,598	71,110
2020	766.632	26,082	8,398	6,788	12,265	8,673	62,206	8,875	9,086	5,478	2,705	36,061	34,324	105,434
2021	763.013	28,227	10,298	7,061	13,507	8,030	67,124	11,286	9,724	7,253	4,425	34,436	31,978	137,411
2022	761.992	29,596	12,496	7,346	13,498	8,286	71,222	14,816	10,247	7,604	7,017	31,538	28,572	165,983
2023	762.510	30,646	13,419	7,642	13,489	9,480	74,676	15,817	10,539	7,855	7,337	33,128	29,281	195,264
2024	767.096	31,690	13,842	7,950	13,509	9,710	76,701	17,128	10,674	8,089	7,981	32,830	28,309	223,573
2025	768.249	32,901	14,180	8,270	13,472	10,713	79,536	18,771	11,150	8,355	8,818	32,442	27,293	250,866
2026	770.535	33,848	13,665	8,603	26,418	9,654	92,188	19,234	11,303	15,315	13,789	32,548	26,714	277,579
2027	773.399	34,785	13,915	8,950	26,414	9,581	93,645	20,329	11,582	15,641	14,364	31,730	25,407	302,986
2028	778.734	35,897	14,153	9,310	26,472	12,050	97,882	19,612	11,838	16,005	13,603	36,824	28,767	331,753
2029	780.769	36,894	15,090	9,685	26,414	12,365	100,449	20,050	12,247	16,360	13,720	38,071	29,015	360,769
2030	782.358	37,897	15,478	10,075	26,420	13,522	103,391	21,901	12,145	16,705	15,001	37,640	27,987	388,756
2031	784.084	38,917	13,482	10,481	23,663	11,895	98,438	24,517	13,203	15,689	16,398	28,631	20,770	409,525
2032	788.191	40,085	15,846	10,903	14,235	17,429	98,499	24,411	13,222	9,172	10,779	40,915	28,957	438,482
2033	789.134	41,143	16,279	11,343	14,217	18,957	101,938	24,413	13,239	9,391	10,512	44,383	30,645	469,127
2034	792.330	42,320	13,158	11,799	32,393	14,010	113,681	24,901	14,097	18,991	18,089	37,603	25,330	494,457
2035	796.280	43,553	14,871	12,275	32,599	15,947	119,245	25,844	13,811	19,435	18,401	41,753	27,440	521,897
2036	802.497	44,988	14,220	12,769	32,885	17,108	121,970	24,429	14,301	19,911	17,188	46,141	29,584	551,481
2037	804.309	46,245	14,388	13,284	33,046	17,601	124,564	24,909	14,822	20,304	17,392	47,136	29,485	580,966
	NPV:	549,144	207,150	143,615	320,874	186,047	1,406,830	290,366	181,805	187,835	165,858	580,966	580,966	580,966

8.5 SENSITIVITY CASES

As discussed previously in Section 8, 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 Figure 7-2 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.

8.6 RETAIL RATES AND THE PREFERRED EXPANSION PLAN

Forecasts project power portfolio costs to increase by approximately $20 million (nominal) from 2018-2037, or 2.25 percent annually (less than 1 percent when adjusted for inflation). Of this $20 million, approximately $15 million is due to the following power purchases related to environmental compliance:

- 60 MW share of Central Valley Solar beginning in 2026; despite the utility owning lower cost thermal generation, additional resources are required to meet state mandates.
- 65 MW share of Northern California/Oregon Wind beginning in 2034 despite the utility owning lower cost thermal generation, additional resources are required to meet state mandates.

Due to forecasted retail sales in 2038 being within 3 percent of 2018 retail sales (energy efficiency measures reducing base load growth), a $20 million increase in annual power portfolio costs represents an increase from today's rates of approximately 15 percent, or less than 1 percent annually (this is less than CPI). Due to the expected limited impact on rates from power supply costs over the forecast period, a separate report or study was not conducted. Any future update to COR's IRP will continue to appropriately evaluate rate impacts related to power supply costs. While Power Supply is a significant portion of the utility's budget (see Figure 8-6), it is not the only driver for rate changes. Other factors not included in this study such as debt service, personnel costs, maintaining the distribution system, and increasing reserves to manage financial risk associated with intermittent resources, will have significant impacts on the revenue requirement. In addition, while the 2018 Carr Fire had a substantial impact on the community, the COR had adequate reserves to fund infrastructure restoration efforts (zero rate impact). Figure 8-7 shows the projected portfolio cost of Scenario H and the level of retail sales through 2037.

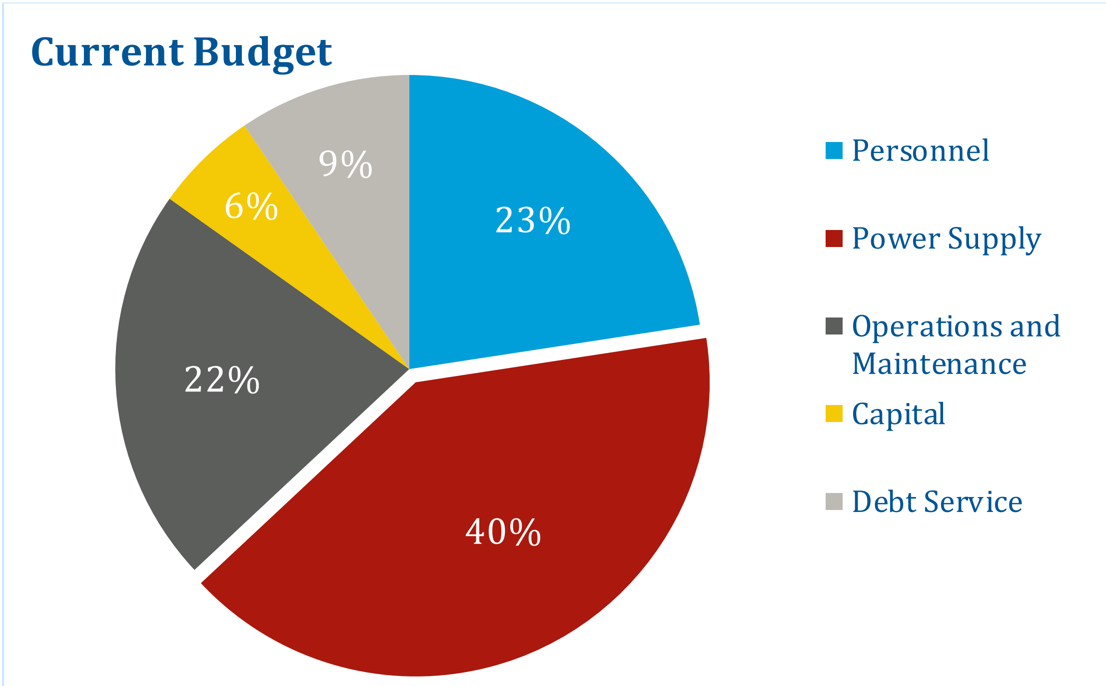

Figure 8-6 **Budget Categories by type in Fiscal Year 2019**

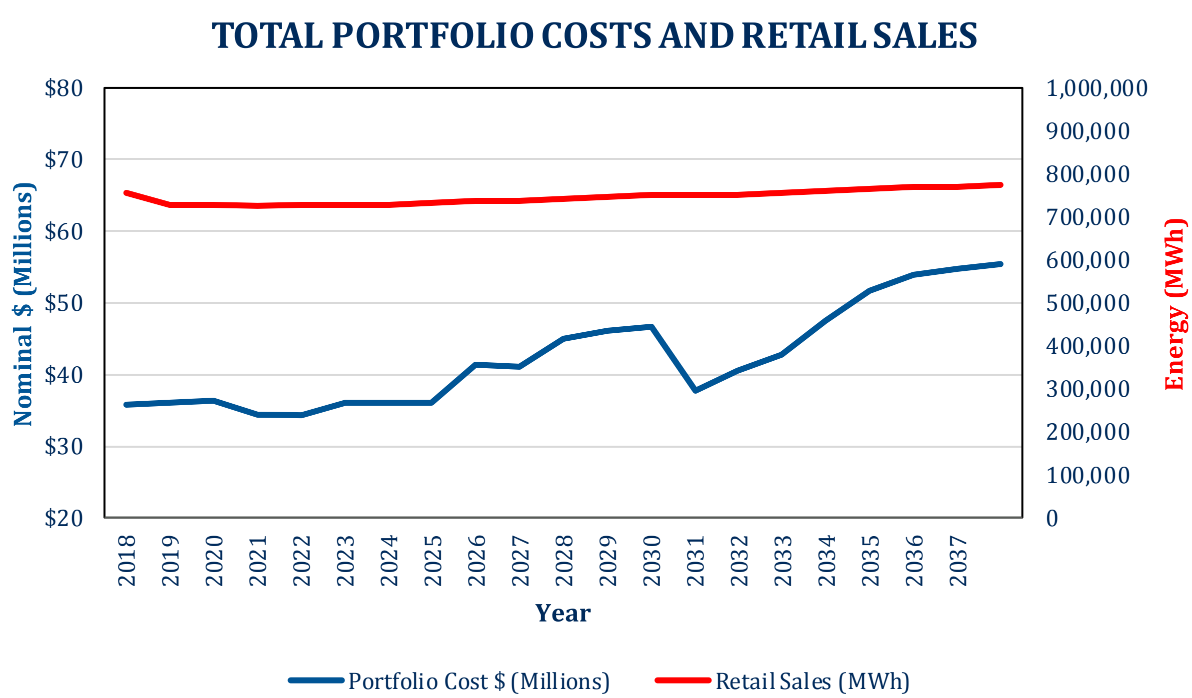

Figure 8-7 **Cost of the Preferred Expansion Plan, Scenario H**

8.7 THE PREFERRED PLAN IN CONSIDERATION OF FUTURE CONDITIONS AND RISKS

A number of factors could emerge in the energy industry, or in the economy, that could impose new conditions or risks not contemplated in this SB 350-based analysis. Some of these factors include new legislation and regulations that impact utility operation and could include the following:

- **SB 100 (The 100 Percent Clean Energy Act of 2017)** – SB 100 further modifies RPS requirements from 50 percent by 2030 (set by SB 350) to 60 percent, and creates the policy of planning to meet all of the state's retail electricity supply with a mix of RPS-eligible and zero-carbon resources by December 31, 2045, thereby achieving a 100 percent clean energy supply.

  On September 10, 2018, SB 100 was signed into law. COR anticipated that SB 100 would likely be signed by the Governor and as such, has begun some preliminary analysis on the potential impacts this law may have on RPS requirements into the planning horizon. The additional analyses, including detailed system modeling, is required to adequately evaluate all the potential impacts of the newly increased RPS obligations.

  SB 100 accelerates the RPS obligations for retail sellers, including POUs as follows:

  - 40 percent to 44 percent by 2024;
  - 45 percent to 52 percent by 2027; and
  - 50 percent to 60 percent by 2030.

  The Bill also states that achieving this policy shall not increase carbon emissions elsewhere in the western grid and shall not involve resource shuffling. SB 100 also requires the CPUC, CEC, the CARB, and other state agencies to incorporate this policy into their regulations and decisions.

  For the last several years, COR's approach to RPS requirements (changes/increases in those requirements) has been to evaluate resources into the future to ensure compliance obligations are fully met. SB 100 carries with it a new level of RPS requirements of over 50 percent by 2030 which presents a more complex balancing of the power supply mix than what COR has considered in the past. SB 100 becomes effective in January 2019 and with that, regular updates to the modeling that supports the power supply strategy will continue and will fully integrate the requirements of SB 100 within that process in 2019 and beyond.

- **AB 813 (Electric Regionalization)** – The bill would open the door for the CAISO to expand its membership to include other balancing authorities across the 14 western states. This regionalization bill would require approval from the state before any California transmission owner, retail seller, or local publicly-owned utility joins a multistate regional transmission system organization. Bill proponents believe regionalization would reduce rates and costs, ensure consistent reporting and tracking of RE targets and achievements, and reduce transmission rates. Opponents believe that the bill would harm the independence of state policy including the progress made in California toward its RE standards, which are generally more aggressive than in other states.

- **SB 1110 (Safeguarding Public Utility Ratepayers from Bond Debt authored by Senator Bradford)** – This bill protects COR from construction debt of power plants built in the early 2000's in response to the energy crisis. In the early 2000's—when many California cities were struggling with how to serve their communities with electricity and experiencing brown outs—Council, with decisive action, approved the speedy construction and operation of the state-of-the-art low emission, gas-fired generation that COR now owns. This action brought safety in delivering electricity, increased reliability, and an enhancement to the local economy with approximately 25 full-time positions earning favorable wages.

  With construction of these safe, efficient, and reliable power generating facilities, debt was incurred. Currently, bond indebtedness is approximately $106 million dollars; which is scheduled to be paid in full by 2030.

  SB 1110 was signed into law on September 20, 2018, providing protection of resource investments as our state traverses the path of 100 percent RE mandates by the 2040's, and would allow the continued operation of these reliable and efficient facilities at a level that would allow us to finish paying for our assets without causing financial harm to our community.

Each of these laws or regulations could impact the decision process, as could economic growth that is significantly higher or lower than anticipated in this IRP. In anticipation of possible changes in future conditions and risks, the IRP has been developed such that it affords flexibility, balance, and margin. The recommended plan does not require an immediate commitment to projects needed well into the planning horizon. In fact, following the 2021 planned addition of the 10 MW Solar Project, incremental RPS resources are not projected to be added until sometime after 2023. The renewable projects under consideration can be developed in a relatively short time; as a result, COR can confirm that future developments identified in this IRP remain beneficial prior to making a firm commitment to these projects.

The recommended Scenario H is balanced in that it mixes solar and wind RE resources better than other Scenarios considered. This is important because, while the economic analysis did incorporate a probability analysis of possible production profiles for these two technologies, there are also non-quantifiable risks that suggest a balanced RE portfolio may help to mitigate future uncertainties. This could include, for example, the possibility of opposition to a renewable technology in the future, that new incentives, taxes, or operational charges (such as integration costs) could materialize and favor one technology over the other. By planning for a balanced portfolio, Scenario H is a way to protect against unforeseen developments that could favor wind over solar, or vice versa.

Finally, the recommended Scenario H provides margin in the sense that, as seen in Figure 8-3, the plan will produce more than the minimum RE required to meet the existing RPS targets. This margin provides a risk reduction benefit should SB 100, or another law or regulation, require a more aggressive pursuit of RE.

8.8 THE PREFERRED PLAN WITH CONSIDERATION OF LOCALIZED AIR POLLUTANTS AND DISADVANTAGED COMMUNITIES

COR is not aware of any officially designated disadvantaged communities in its service territory. Nevertheless, there are many areas served that are considered low income. To help serve the needs of low-income groups, the following strategies are utilized to maximize education and participation of low-income customers in the Low-Income Energy Efficiency Program (LIEEP) program.

Program policies are specifically designed to facilitate coordination with the PG&E Energy Savings Assistance Program and with the California Department of Community Services and Development's (CSD) Weatherization Program. For example, CSD measure feasibility guidelines and installation standards have been adopted, and adopted PG&E ESA and CSD program participation as a categorical qualifier for the LIEEP Program. This seamless integration minimizes duplicative efforts, maximizes return on program marketing efforts, and delivers maximum benefits to our income-qualified customers.

The local non-profit weatherization provider who implements the PG&E ESA Program and CSD programs in Shasta County, also handles implementation of LIEEP.

COR partners with multiple mission driven, non-profit organizations to market the suite of resources available to income qualified customers including weatherization, a rate discount program, and an emergency bill assistance program.

Continuation of these programs, or similar programs and efforts, is anticipated to continue as a means to educate and assist low-income customers in the future. The preferred Scenario H is deemed to be in the interest of low-income customers, and all other customers, in that it achieves a balance between affordability *(having a CPWC less than 3 percent higher than the lowest cost Scenario)* and environmental benefits *(meeting 2030 RPS requirements and within the GHG limits recommended by CARB staff)*.

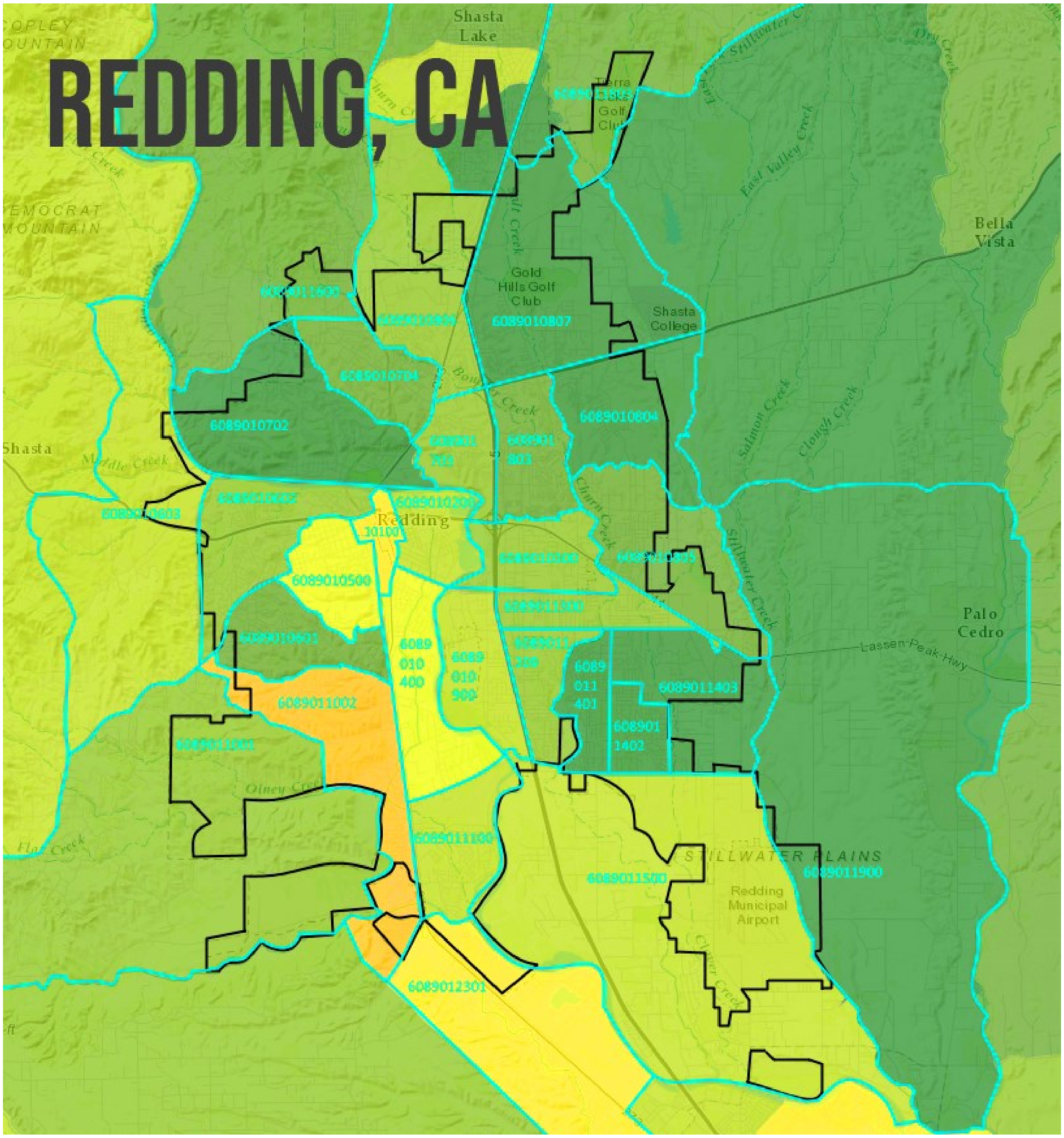

Figure 8-8 Cal Enviro Disadvantaged Communities Map

This figure was created by CalEnviro. For more details, visit https://oehha.ca.gov/calenviroscreen.[15]

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[15] Red represents the most disadvantaged communities while green represents the non-disadvantaged communities.

9.0 Conclusions and Recommended Expansion Plan

This Report discussed the development of the IRP and presented the results. The IRP was developed to benefit and create value for customers and to deliver exceptional services through the strength and dedication of its employees. This overriding objective is achieved by providing reliable and safe service at low (cost-conscious) rates, while complying with environmental mandates and objectives.

The development of the IRP took over one year and was the result of collaborative efforts by COR staff, Black & Veatch, Itron, Ascend Analytics, and Stakeholders. Customers had important input and played a vital role in the planning process. As a result, the recommended Scenario is considered to be a plan that balances many different views and perspectives, and is also a robust plan that will provide low costs, flexibility, environmental compliance, and manageable risks over the 2018-2037 planning period. This Report is designed to be a guiding document, not a procurement plan.

The recommended Scenario is identified in this report as Scenario H. This plan features the addition of the 10 MW (maximum rating, not firm) local Solar Project in 2021, followed by an additional 60 MW of solar capacity in 2026, and a 65 MW wind facility in 2034. This plan is low cost—within 2.8 percent of the lowest overall plan on a cumulative basis but within 2.1 percent through 2030; it allows the flexibility to adjust the size and timings of the 2026 and 2034 resource additions as conditions warrant; it is compliant with the targets for RE (50 percent in 2030 and all intermediate targets), 2030 GHG emissions proposed in the summer of 2018 by CARB; and the plan assumes continued investment in energy efficiency and demand reduction programs.

All of these objectives are met while also providing a reliable power plan that meets the planning reserve requirements. The details of Scenario H are presented in the discussion and accompanying tables and figures in Section 8. The four tables required in the *CEC Guidelines* are provided in Appendix A. These tables support the conclusion that Scenario H is a viable plan that meets the POU objectives and requirements for an IRP.

This IRP will be updated as conditions warrant, most likely every two to three years but, in any case, no longer than the five year limit established in the *CEC Guidelines*. Given the relatively short lead time for RE resources and the dynamics of the power sector, future IRP updates will be able to adjust to changing conditions as needed and will help ensure that the resource plan continues to serve the needs of its valued customers.

Appendix A. CEC Standardized Tables for the Adopted Resource Scenario

The *CEC Guidelines* require four standardized tables to be part of the IRP Filing. The standardized tables presented in this Appendix for the recommended Scenario H are as follows:

- Administrative Information: Summary of contact information for persons who prepared standardized tables
- Capacity Resource Accounting Table (CRAT): Annual peak capacity demand in each year and the contribution of each energy resource (capacity) in the POU's portfolio to meet that demand.
- Energy Balance Table (EBT): Annual total energy demand and annual estimates for energy supply from various resources.
- RPS Procurement Table (RPT): A detailed summary of a POU resource plan to meet the RPS requirements.
- GHG Emissions Accounting Table (GEAT): Annual GHG emissions associated with each resource in the POU's portfolio to demonstrate.[16]

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[16] Page A-4

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	
Name of Scenario	Scenario H

Persons who prepared Tables	**CRAT**	**Energy Balance Table**	**Emissions Table**	**RPS Table**	**Application for Confidentiality**
Name:	Steven B Handy	Steven B Handy	Steven B Handy	Steven B Handy	
Title:	Utility Resource Planner	Utility Resource Planner	Utility Resource Planner	Utility Resource Planner	
E-mail:					
Telephone:	530-339-7309	530-339-7309	530-339-7309	530-339-7309	
Address:	3611 Avtech Parkway	3611 Avtech Parkway	3611 Avtech Parkway	3611 Avtech Parkway	
Address 2:					
City:	Redding	Redding	Redding	Redding	
State:	CA	CA	CA	CA	
Zip:	96002	96002	96002	96002	
Date Completed:	3/7/2019	3/7/2019	3/7/2019	3/7/2019	
Date Updated:					

Back-up / Additional Contact Persons for Questions about these Tables (Optional):					
Name:	Brian Schinstock	Brian Schinstock	Brian Schinstock	Brian Schinstock	
Title:	Utility Resource Planner	Utility Resource Planner	Utility Resource Planner	Utility Resource Planner	
E-mail:					
Telephone:	530-339-7344	530-339-7344	530-339-7344	530-339-7344	
Address:	3611 Avtech Parkway	3611 Avtech Parkway	3611 Avtech Parkway	3611 Avtech Parkway	
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.
Data input by User are in dark green font.

Units = MW

PEAK LOAD CALCULATIONS

			2017	2018*	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Forecast Total Peak-Hour 1-in-2 Demand		241.4	227.7	227.3	226.7	226.2	226.0	225.9	226.1	226.4	226.6	227.0	227.3	227.8	228.0
2	(Customer-side solar: nameplate capacity)		9.0	11.2	11.7	12.7	13.6	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1
2a**	(Customer-side solar: peak hour output)															
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		0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Peak Demand (accounting for demand response and AAEE) (1-5-6)		241	228	227	227	226	226	226	226	226	227	227	227	228	228
8	Planning Reserve Margin	15%	36.2	34.2	34.1	34.0	33.9	33.9	33.9	33.9	34.0	34.0	34.1	34.1	34.2	34.2
9	Firm Sales Obligations															
10	Total Peak Procurement Requirement (7+8+9)		278	262	261	261	260	260	260	260	260	261	261	261	262	262

** 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.

EXISTING AND PLANNED CAPACITY SUPPLY RESOURCES

For fuel type, choose from list or enter value

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

	(list resource by name)	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
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
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
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
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
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
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
11g																

Long-Term Contracts (not RPS-eligible):

	(list contracts by name)	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
11h	Western - Large Hydro	Large Hydroelectric	107.7	109.2	86.2	86.2	86.2	86.2	86.2	86.2	85.3	85.3	85.3	85.3	85.3	85.3
11i																
11j																
11k																
11l																
11m																
11n																
11	Total peak dependable capacity of existing and planned supply resources (not RPS-eligible) (sum of 11a...11n)		277	278	255	255	255	255	255	255	254	254	254	254	254	254

Utility-Owned RPS-eligible Resources:

	(list resource by plant or unit)	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
12a	Whiskeytown	Small Hydroelectric	2.1	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
12b																
12c																
12d																
12e																
12f																
12g																
12h																
12i																
12j																
12k																
12l																
12m																
12n																

Long-Term Contracts (RPS-eligible):

	(list contracts by name)	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
12o	Big Horn	Wind	18.0	19.0	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5
12p	Western - Small Hydro	Small Hydroelectric	2.3	2.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
12q																
12r																
12s																
12t																
12	Total peak dependable capacity of existing and planned RPS-eligible resources (sum of 12a...12t)		22	24	19	19	19	19	19	19	19	19	19	19	19	19
13	Total peak dependable capacity of existing and planned supply resources (11+12)		299	302	274	274	274	274	274	274	273	273	273	273	273	273

GENERIC ADDITIONS

NON-RPS ELIGIBLE RESOURCES:

	(list resource by name or description)	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
14a																
14b																
14c																
14d																
14e																
14f																
14g																
14h																
14i																
14j																
14k																
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	0	0	0	0

RPS-ELIGIBLE RESOURCES:

	(list resource by name or description)	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
15a	Local PV	Solar PV					5.9	5.8	5.8	5.7	5.7	5.6	5.6	5.6	5.5	5.5
15b	CV PV	Solar PV										34.1	33.9	33.7	33.4	33.2
15c																
15d																
15e																
15f																
15g																
15h																
15i																
15j																
15k																
15l																
15m																
15n																
15	Total peak dependable capacity of generic RPS-eligible resources				0	0	6	6	6	6	6	40	40	39	39	39
16	Total peak dependable capacity of generic supply resources (14+15)				0	0	6	6	6	6	6	40	40	39	39	39

CAPACITY BALANCE SUMMARY

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
17	Total peak procurement requirement (from line 10)	278	262	261	261	260	260	260	260	260	261	261	261	262	262
18	Total peak dependable capacity of existing and planned supply resources (from line 13)	299	302	274	274	274	274	274	274	273	273	273	273	273	273
19	Current capacity surplus (shortfall) (18-17)	21	41	12	13	14	14	14	14	13	12	12	12	11	11
20	Total peak dependable capacity of generic supply resources (from line 16)			0	0	6	6	6	6	6	40	40	39	39	39
21	Planned capacity surplus/shortfall (shortfalls assumed to be met with short-term capacity purchases) (19+20)	21	41	12	13	20	20	20	20	18	52	51	51	50	49

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
Energy Balance Table
Form CEC-XXX (Nov 2018)

Scenario Name:

Units = MWh

Yellow fill relates to an application for confidentiality.
Data input by user are in dark green font.

Historical Data: 2017–2018

NET ENERGY FOR LOAD CALCULATIONS

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Retail sales to end-use customers	728,806	689,158	696,626	694,443	694,401	694,010	694,759	697,848	701,978	704,347	707,297	710,693	715,915	717,462
2	Other loads	70,154	66,848	70,493	72,189	68,612	67,982	67,751	69,248	66,271	66,188	66,102	68,041	64,854	64,896
3	Net energy for load	798,960	756,006	767,119	766,632	763,013	761,992	762,510	767,096	768,249	770,535	773,399	778,734	780,769	782,358
4**	Retail sales to end-use customers (accounting for AAEE impacts)	728,806	689,158	696,626	694,443	694,401	694,010	694,759	697,848	701,978	704,347	707,297	710,693	715,915	717,462
5**	Net energy for load (accounting for AAEE impacts)	798,960	756,006	767,119	766,632	763,013	761,992	762,510	767,096	768,249	770,535	773,399	778,734	780,769	782,358
6	Firm Sales Obligations														
7	Total net energy for load (accounting for AAEE impacts) (5+6)	798,960	756,006	767,119	766,632	763,013	761,992	762,510	767,096	768,249	770,535	773,399	778,734	780,769	782,358
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):

No.	(list resource by name)	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
12a	Unit1 - Actuals and Forecast	Natural Gas	335	472	473	523	601	1,466	1,245	1,576	1,723	1,236	1,377	1,758	1,062	1,869
12b	Unit2 - Actuals and Forecast	Natural Gas	934	890	1,658	2,107	2,504	5,672	4,837	5,965	6,219	5,510	5,666	6,250	4,497	6,734
12c	Unit3 - Actuals and Forecast	Natural Gas	1,607	1,077	1,858	2,555	2,918	6,265	5,445	6,504	6,918	6,283	6,459	6,778	5,084	7,192
12d	Unit4 - Actuals (No Forecast as it is part of 1x1 and 2x1 Forecast)	Natural Gas	50,316	68,123												
12e	Unit5 - Actuals (Both Simple Cycle and Combined Cycle)	Natural Gas	74,627	125,239												
12f	Unit6 - Actuals (Both Simple Cycle and Combined Cycle)	Natural Gas	63,333	49,188												
	Unit5 - Simple Cycle - Forecast	Natural Gas			1	16	112	664	583	848	752	912	1,213	824	714	948
	Unit6 - Simple Cycle - Forecast	Natural Gas			1	432	124	710	633	960	971	984	1,055	887	807	1,027
	1x1 - Unit5 or Unit6 in Combined Cycle Mode with Unit4 - Forecast	Natural Gas			125,822	148,209	167,899	184,015	191,231	187,176	186,871	174,055	171,728	173,250	179,252	168,856
	2x1 - Incremental Increase over 1x1 with Unit5 and Unit6 in Combine Cycle Mode with Unit4 - Forecast	Natural Gas			13,373	22,528	39,877	53,179	54,752	56,552	52,550	52,435	53,053	46,004	49,125	54,603
12g																

Long-Term Contracts (not RPS-eligible):

No.	(list contracts by name)	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
12h	Western - Large	Large Hydroelectric	361,466	183,050	241,623	241,923	241,620	241,628	241,634	241,941	236,799	236,788	236,791	237,094	236,787	236,797
12i																
12j																
12k																
12l																
12m																
12n																
12	Total energy from existing and planned supply resources (not RPS-eligible) (sum of 12a…12n)		552,618	428,040	384,808	418,294	455,655	493,589	500,361	501,512	492,803	478,203	477,341	472,846	477,329	478,025

Utility-Owned RPS-eligible Generation Resources:

No.	(list resource by plant or unit)	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
13a	Whiskeytown	Small Hydroelectric	26,439	18,633	26,169	26,207	26,104	26,115	26,181	26,173	26,098	26,180	26,193	26,505	26,208	26,414
13b																
13c																
13d																
13e																
13f																
13g																
13h																
13i																
13j																
13k																
13l																
13m																
13n																

Long-Term Contracts (RPS-eligible):

No.	(list contracts by name)	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
13o	Big Horn	Wind	164,303	175,249	180,078	180,494	180,078	180,078	180,078	180,494	180,078	180,078	180,078	180,494	180,078	180,078
13p	Western - Small	Small Hydroelectric	7,651	6,871	6,195	6,203	6,195	6,196	6,196	6,204	6,072	6,071	6,072	6,079	6,071	6,072
13q																
13r																
13s																
13t																
13	Total energy from RPS-eligible resources (sum of 13a…13t)		198,393	200,753	212,442	212,904	212,377	212,388	212,455	212,870	212,245	212,330	212,342	213,078	212,359	212,563
13x	Undelivered RPS energy															
14	Total energy from existing and planned supply resources (12+13)		751,011	628,794	597,250	631,197	668,032	705,977	712,816	714,382	705,048	690,533	689,683	685,924	689,688	690,588

GENERIC ADDITIONS

NON-RPS ELIGIBLE RESOURCES:

No.	(list resource by name or description)	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
15a																
15b																
15c																
15d																
15e																
15f																
15g																
15h																
15i																
15j																
15k																
15l																
15m																
15n																
15	Total energy from generic supply resources (not RPS-eligible)				0	0	0	0	0	0	0	0	0	0	0	0

RPS-ELIGIBLE RESOURCES:

No.	(list resource by name or description)	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
16a	Local PV	Solar PV					24,379	24,208	24,039	23,924	23,703	23,537	23,373	23,261	23,046	22,885
16b	CV PV	Solar PV										155,422	154,334	153,619	152,181	151,116
16c																
16d																
16e																
16f																
16g																
16h																
16i																
16j																
16k																
16l																
16m																
16n																
16	Total energy from generic RPS-eligible resources				0	0	24,379	24,208	24,039	23,924	23,703	178,959	177,707	176,881	175,227	174,001
17	Total energy from generic supply resources (15+16)				0	0	24,379	24,208	24,039	23,924	23,703	178,959	177,707	176,881	175,227	174,001
17x	Total energy from RPS-eligible short-term contracts															

ENERGY FROM SHORT-TERM PURCHASES

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
18	Short term and spot market purchases:	375,738	252,590	216,453	199,329	167,379	161,419	156,543	160,376	167,049	115,368	117,571	116,561	116,584	122,992
18a	Short term and spot market sales (only report sales of energy from resources already included in the EBT):	327,789	125,378	46,584	63,895	96,777	129,612	130,888	131,586	127,551	214,326	211,562	200,631	200,730	205,223

ENERGY BALANCE SUMMARY

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
19	Total energy from supply resources (14+17+17x)	751,011	628,794	597,250	631,197	692,411	730,185	736,855	738,306	728,751	869,492	867,389	862,804	864,915	864,589
19a	Undelivered RPS energy (from 13x)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Net Short term and spot market purchases (18 - 18a)	47,949	127,212	169,869	135,434	70,602	31,807	25,656	28,790	39,498	(98,958)	(93,991)	(84,070)	(84,146)	(82,231)
21	Total delivered energy (19-19a+20)	798,960	756,006	767,119	766,632	763,013	761,992	762,510	767,096	768,249	770,535	773,399	778,734	780,769	782,358
22	Total net energy for load (from 7)	798,960	756,006	767,119	766,632	763,013	761,992	762,510	767,096	768,249	770,535	773,399	778,734	780,769	782,358
23	Surplus/Shortfall (21-22)	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:

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

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

GHG EMISSIONS FROM EXISTING AND PLANNED SUPPLY

Utility-Owned Generation (not RPS-eligible):

	(list resource by name)	Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1a	Redding Power Plant (Units 1 -6 on CRAT Form)	0.439	99,617	98,376	58,543	71,986	87,001	103,419	105,507	106,446	105,093	98,674	98,561	97,234	97,916	99,335
1b																
1c																
1d																
1e																
1f																
1g																

Long-Term Contracts (not RPS-eligible):

	(list contracts by name)	Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1h	Western - Large	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)		89,617	88,376	58,543	71,986	87,001	103,419	105,507	106,446	105,093	98,674	98,561	97,234	97,916	99,335

Utility-Owned RPS-eligible Generation Resources:

	(list resource by plant or unit)	Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2a	Whiskeytown	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	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2o	Big Horn	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2p	Western - Small	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2q																
2r																
2s																
2t																
2	Total GHG emissions from RPS-eligible resources (sum of 2a...2t)		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)		89,617	88,376	58,543	71,986	87,001	103,419	105,507	106,446	105,093	98,674	98,561	97,234	97,916	99,335

EMISSIONS FROM GENERIC ADDITIONS

NON-RPS ELIGIBLE RESOURCES:

	(list resource by name or description)	Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
4a																
4b																
4c																
4d																
4e																
4f																
4g																
4h																
4i																
4j																
4k																
4l																
4m																
4n																
4	Total GHG emissions from generic supply resources (not RPS-eligible)		0	0	0	0	0	0	0	0	0	0	0	0	0	0

RPS-ELIGIBLE RESOURCES:

	(list resource by name or description)	Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
5a	Local PV	0					0	0	0	0	0	0	0	0	0	0
5b	CV PV	0										0	0	0	0	0
5c																
5d																
5e																
5f																
5g																
5h																
5i																
5j																
5k																
5l																
5m																
5n																
5	Total GHG emissions from generic RPS-eligible resources		0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Total GHG emissions from generic supply resources (4+5)		0	0	0	0	0	0	0	0	0	0	0	0	0	0

GHG EMISSIONS OF SHORT TERM PURCHASES

		Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
7	Net spot market/short-term purchases:	0.429	20,522	54,447	72,704	57,966	30,217	13,613	10,981	12,322	16,905	(42,354)	(40,228)	(35,982)	(36,015)	(35,195)

TOTAL GHG EMISSIONS

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
8	Total GHG emissions to meet net energy for load (3+6+7)	110,139	142,823	131,247	129,952	117,219	117,032	116,487	118,768	121,998	56,320	58,333	61,252	61,901	64,140

EMISSIONS ADJUSTMENTS

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
8a	Undelivered RPS energy (MWh from EBT)	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
8c	Total energy for emissions adjustment (8a+8b)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8d	Emissions intensity (portfolio gas/short-term and spot market purchases)														
8e	Emissions adjustment (8Cx8D)	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PORTFOLIO GHG EMISSIONS

8f	Adjusted Portfolio emissions (8-8e)	110,139	142,823	131,247	129,952	117,219	117,032	116,487	118,768	121,998	56,320	58,333	61,252	61,901	64,140

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.

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
9	GHG emissions reduction due to gasoline vehicle displacement by LD PEVs	1,221	1,649	2,144	2,703	3,312	3,962	4,642	5,343	6,057	6,777	7,498	8,215	8,926	9,629
10	GHG emissions increase due to LD PEV electricity loads	610	842	1,114	1,422	1,760	2,123	2,506	2,903	3,312	3,728	4,149	4,570	4,994	5,417
11	GHG emissions reduction due to fuel displacement - other transportation electrification														
12	GHG emissions increase due to increased electricity loads - other transportation electrification														

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

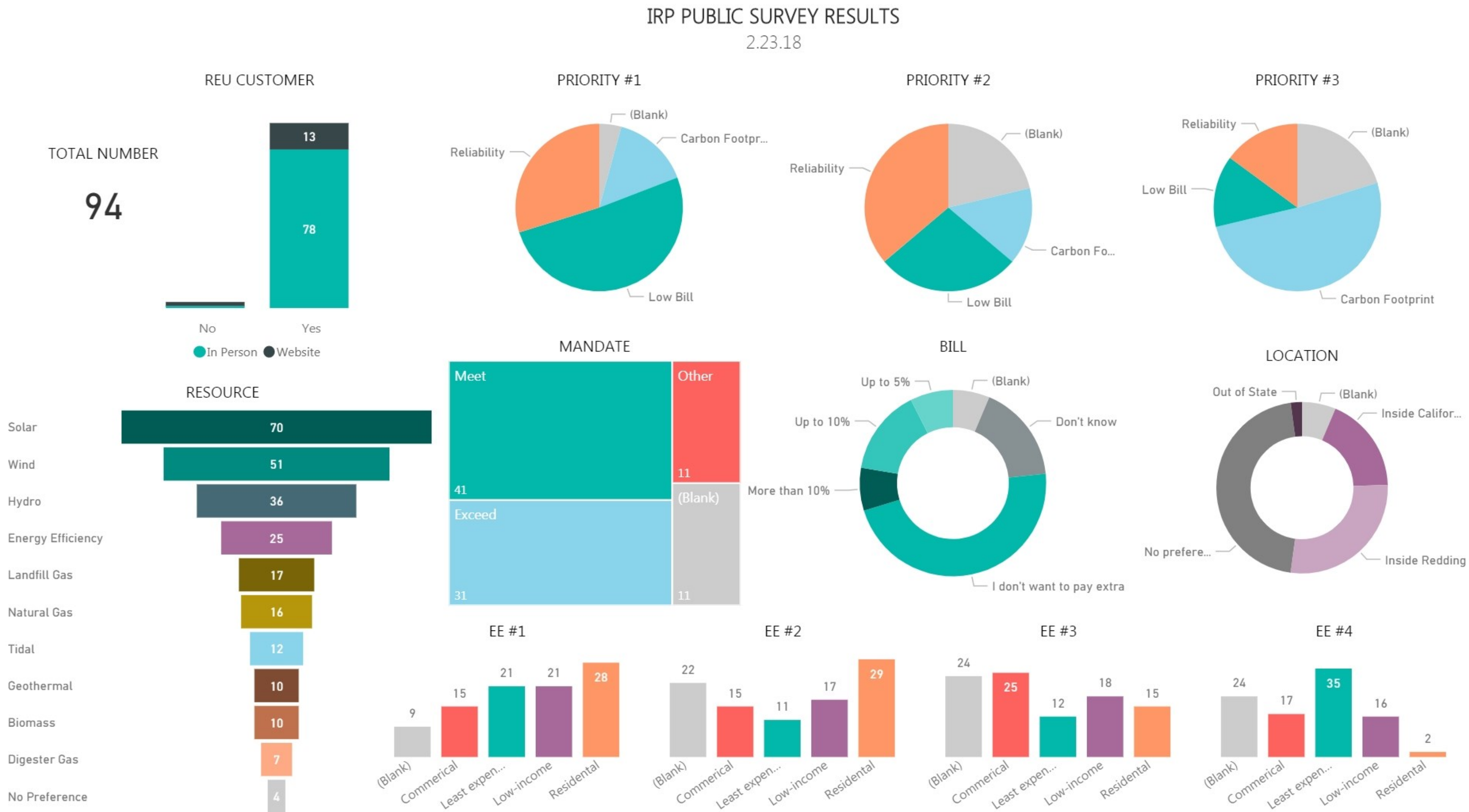
Scenario Name:

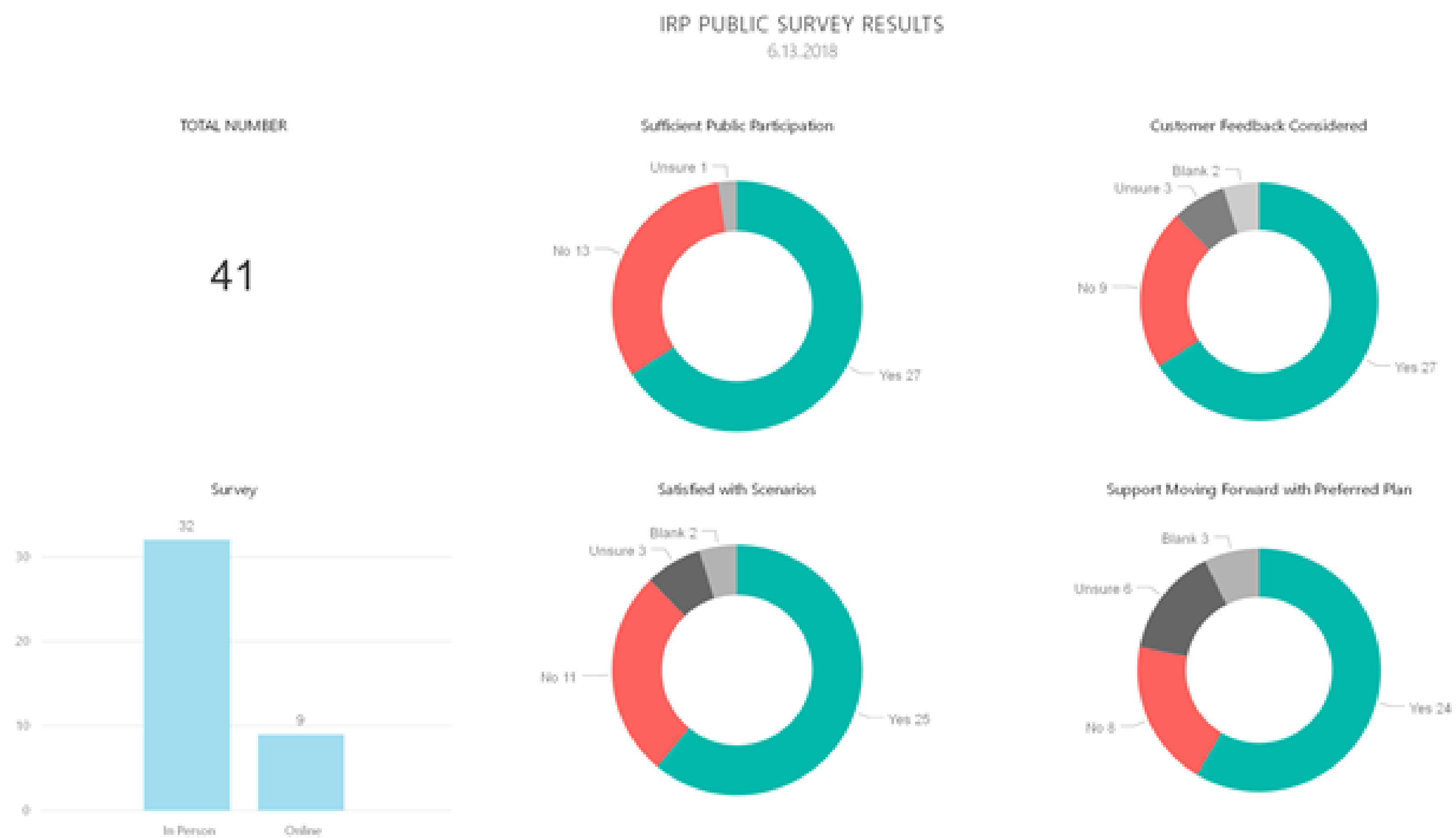
Data input by User are in dark green font.

Units = MWh

	RPS ENERGY REQUIREMENT CALCULATIONS	**Beginning balances Start of 2017**	**Compliance Period 3**					**Compliance Period 4**					**Compliance Period 5**				**Compliance Period 6**			
			2017	**2018**	**2019**	**2020**		**2021**	**2022**	**2023**	**2024**		**2025**	**2026**	**2027**		**2028**	**2029**	**2030**	
1	Annual Retail sales to end-use customers (accounting for AAEE impacts) (From EBT)		728,806	689,158	696,626	694,443		694,401	694,010	694,759	697,848		701,978	704,347	707,297		710,693	715,915	717,462	
2	Green pricing program Exclusion, (may include other exclusions like self generation exclusion)																			
3	Soft target (%)		27.00%	29.00%	31.00%	33.00%		34.75%	36.50%	38.25%	40.00%		41.67%	43.33%	45.00%		46.67%	48.33%	50.00%	
4	Required procurement for compliance period		841,753					1,039,502					915,991				1,036,413			
	Category 0, 1 and 2 Resources (bundled with RECs)																			
5	Excess balance at beginning/end of compliance period	198,401					181,140					88,278				189,572				317,268
6	RPS-eligible energy procured (copied from EBT)		198,393	200,753	212,442	212,904		236,756	236,596	236,493	236,794		235,948	391,289	390,049		389,959	387,586	386,564	
6A	Amount of energy applied to procurement obligation		365,128	0	215,954	260,671		241,304	253,314	265,745	279,139		292,514	305,193	318,284		331,680	346,002	358,731	
7	Net purchases of Category 0, 1 and 2 RECs		0	0	0	0		0	0	0	0		0	0	0		0	0	0	
7A	Excess balance and REC purchases applied to procurement obligation		0	0	0	0		0	0	0	0		0	0	0		0	0	0	
8	Net change in balance/carryover (RECs and RPS-eligible energy) (6+7-6A-7A)		(166,735)	200,753	(3,512)	(47,768)		(4,548)	(16,717)	(29,252)	(42,345)		(56,566)	86,096	71,765		58,279	41,584	27,833	
	Category 3 Resources (unbundled RECs)																			
9	Excess balance at beginning/end of compliance period	0					0					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	0		0	0	0	
13	Total generation plus RECs (all Categories) applied to procurement requirement (6A + 7A + 11)		841,753					1,039,502					915,991				1,036,413			
14	Over/under procurement for compliance period (13 - 4)		0					0					0				0			

Appendix B. Stakeholder Feedback Form Results




IRP PUBLIC SURVEY RESULTS
6.13.2018
TOTAL NUMBER
41
Sufficient Public Participation
Unsure 1
No 13
Yes 27
Customer Feedback Considered
Blank 2
Unsure 3
No 9
Yes 27
Survey
32
9
30
20
10
0
In Person
Online
Satisfied with Scenarios
Blank 2
Unsure 3
No 11
Yes 25
Support Moving Forward with Preferred Plan
Blank 3
Unsure 6
No 8
Yes 24

Appendix C. Intermittency Analysis

Black & Veatch completed a stochastic analysis of COR's load and generation to estimate the 95 percent confidence interval of the deviation of actual hourly load less generation (Net Load) compared to scheduled hourly Net Load. In the analysis, Black & Veatch also included a case where a 10 MW fixed tilt Solar Project (Solar Project) was included in COR's Net Load.

The stochastic analysis was completed utilizing Palisade Corporation's @RISK software; @Risk is a Microsoft Excel add-in which completes stochastic analyses similar to Crystal Ball. The 95 percent confidence intervals with and without the Solar Project were compared to assess if the addition of the Solar Project significantly increased the confidence interval. The key data and assumptions used in the analysis are summarized below.

- Five minute load and generation data for 2014 through 2017 was utilized for the analysis
- The analysis was completed on a monthly basis to consider seasonality of load and generation
- Five minute load data was assumed to follow a normal distribution utilizing the historical mean and standard deviation for 2014 through 2017
- Five minute generation data was assumed to follow a log normal distribution utilizing the historical mean and standard deviation for 2014 through 2017
- The generation from the Solar Project from 2014 through 2017 was estimated using US Climate Reference Network (CRN) data for a site located 20 miles NW of Redding Airport applied in a NREL Solar Advisor Model (SAM) simulation of a 10 MW fixed tilt Solar Project
- Scheduled load and generation for each five minute period was assumed to be the historical mean for 2014 through 2017
- Actual load and generation in each five minute period was estimated stochastically using the distributions defined
- Deviation from schedule on a five minute basis was calculated as the difference between the actual Net Load and scheduled Net Load; actual Net Load greater than scheduled yielded a positive value, actual load less than scheduled yielded a negative value
- The hourly deviation from schedule was calculated as the average of the five minute values
- The stochastic analysis estimated 95 percent confidence intervals for hourly load deviation and hourly load less generation for each month

Further information on the development of the generation data for the Solar Project is included in Attachment A.

Figure C-1 and Figure C-2 below illustrate typical 5 minute input distributions for the COR load and generation; the January 7 a.m. three minute load and generation input distributions without the additional of the generation from the Solar Project have been included.

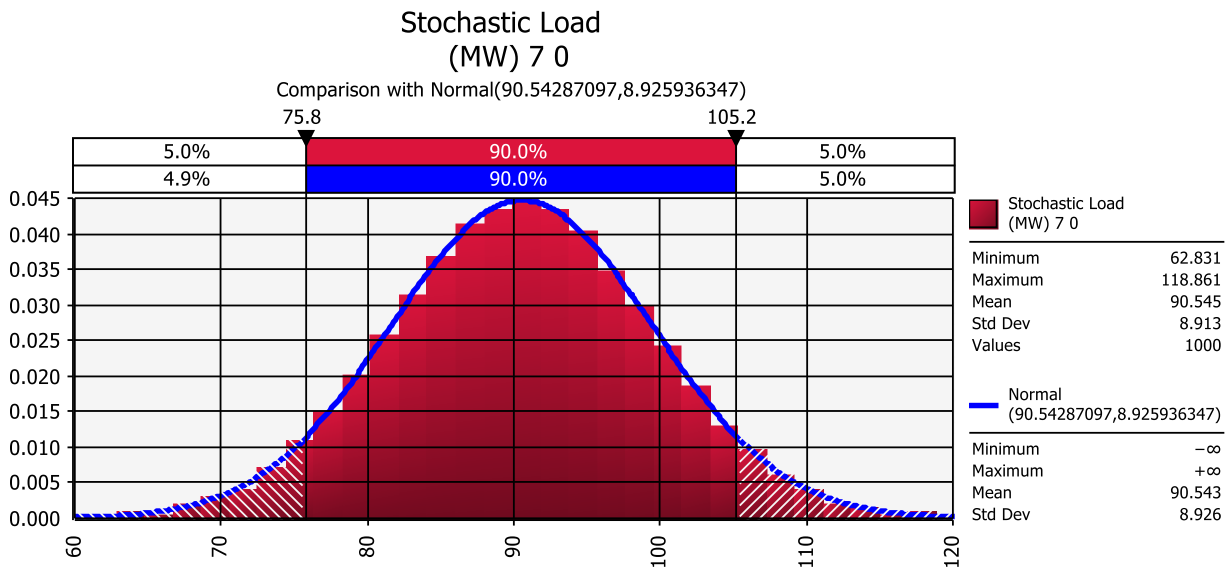


Figure C-1 January 7 a.m. Stochastic Load Distribution

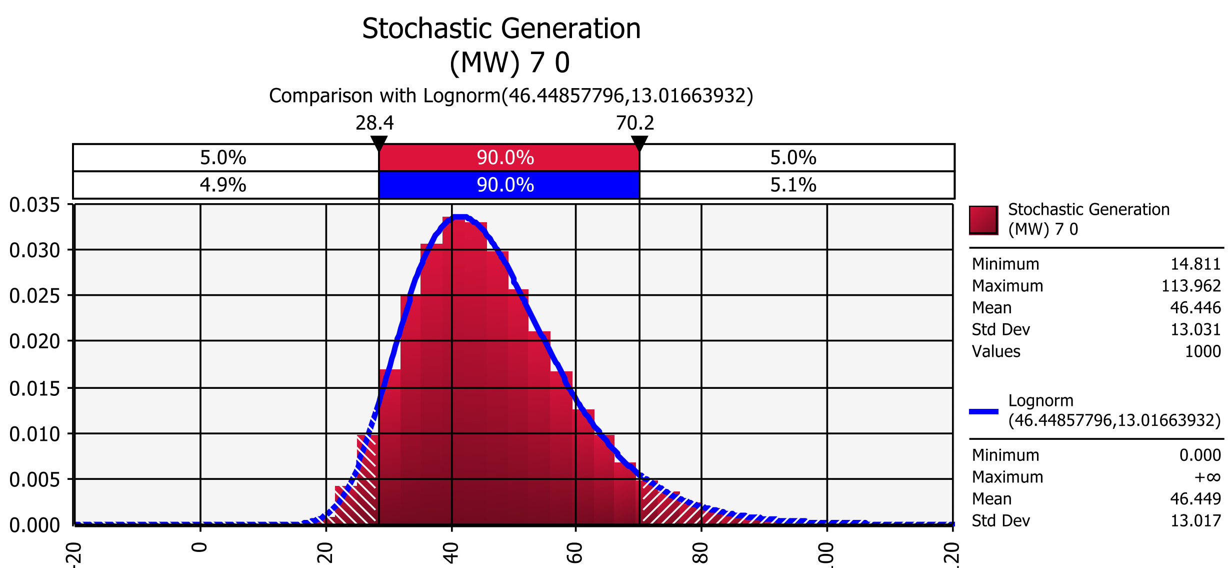


Figure C-2 January 7 a.m. Stochastic Generation Distribution

Figure C-3 and Figure C-4 illustrate representative 95 percent confidence intervals for the actual versus scheduled Net Load; the 95 percent confidence interval for January 7 a.m. Net Load has been included.

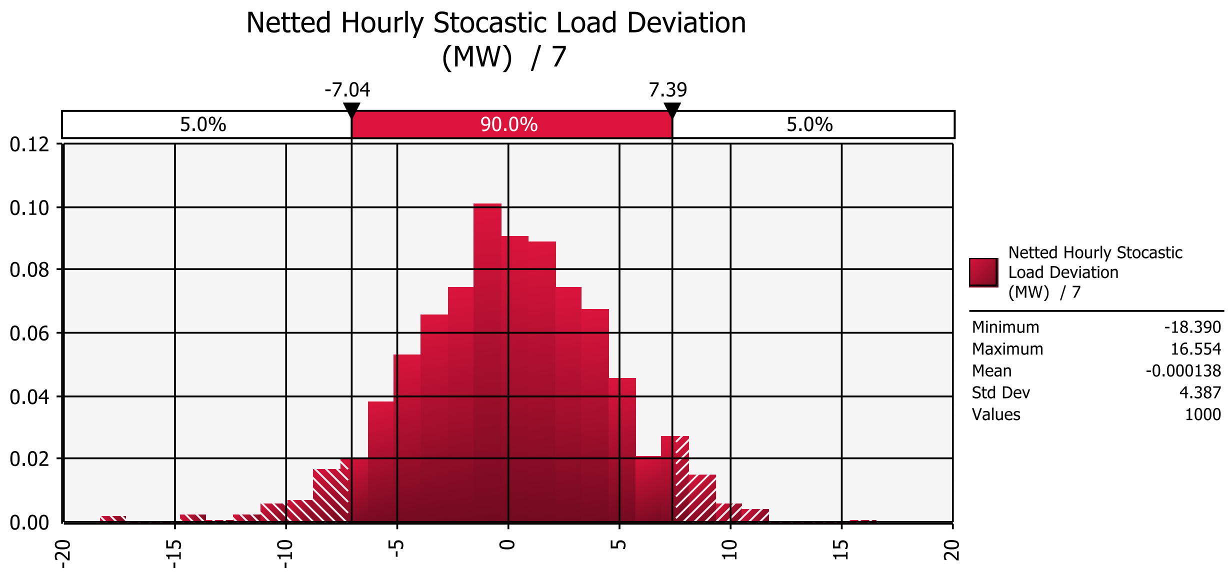


Figure C-3 January 7 a.m. Load less Generation Deviation from Schedule

In comparing the stochastic Net Load deviation from schedule with and without the addition of the Solar Project, in general Black & Veatch found that there was very limited difference between the 95% confidence intervals for each case. Figure C-4 compares the 95% confidence intervals for Net Load with and with and without inclusion of the Solar Project in July; this month was selected as it is a period of high solar generation where it would be expected that the addition of solar would have more influence on the Net Load deviation from schedule.

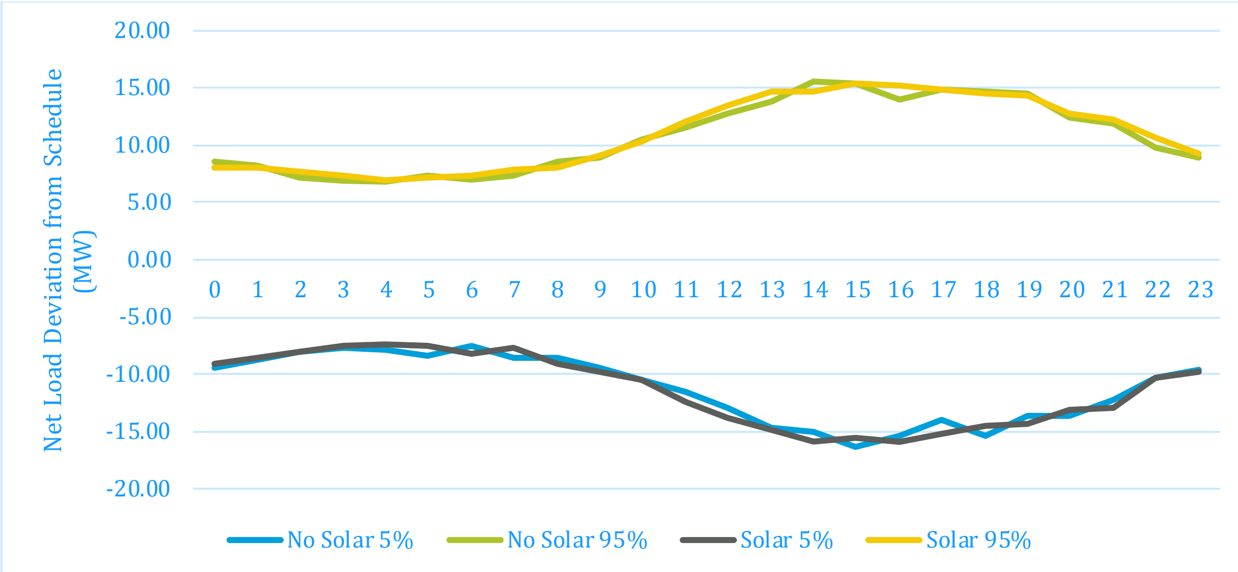


Figure C-4 July Net Load Deviation with and without Solar Project Generation

It can be seen that across the day there is very limited difference between the 95% confidence intervals for Net Load with and with and without inclusion of the Solar Project. Very similar results were seen in the other months of the year; charts for each month are included in Attachment B.

Black & Veatch suggests that a next step could be to schedule a call to discuss the results above and any further analysis which COR would like to complete. Some further analysis which could be completed could include:

- Estimating the impact of increasing solar capacity (e.g. in 10 MW increments) to the results above.

Attachment A: Solar Project Generation Data

INTRODUCTION

Black & Veatch developed a representative historical solar energy production profile for a 10 MW PV plant located in Redding, CA. The historical production was simulated at a sub-hourly level with 5-min time steps for the period of 2014-2017.

SOLAR RESOURCE ASSESSMENT

The historical ground solar resource data accessed in this study is from the US Climate Reference Network (CRN) site located near Redding, CA. The CRN station location is located 20 miles NW of Redding Airport (representative project location) at an elevation of approximately 1440 feet. The US CRN sites measure high quality observations of several meteorological parameters including solar radiation, ambient temperature, wind speed, precipitation etc., at 5-minute intervals. The measured data has been processed for any errors and the quality controlled data was used for the purposes of this study.

USCRN DATA OBSERVATION AND CORRECTIONS

Due to the high elevation of the Redding USCRN location, measured data obtained was reviewed to ensure its compatibility for robust solar energy simulation use. To assess the suitability of solar irradiance data from the CRN location, Black & Veatch compared long term satellite based GHI irradiance for Redding Airport site against the GHI obtained from US CRN site. Long-term trends appeared to be very similar at both these locations. Based on our review of the Redding CRN data the following trends were observed,

- A slightly lower GHI was observed at the CRN site due to more frequent cloud formation associated with closer proximity to the Klamath Mountain range.
- There appeared to be sensor shading due to the Klamath Mountains to the west of the station location and can be noticed on a clear day during late summer afternoons. Therefore, any drop in the simulated production during late afternoon can be attributed to this shading effect in the input irradiance profile and should be taken into consideration when comparing late afternoon PV energy production with coincidental system load data.

This dataset from the CRN site was selected as a representative solar resource dataset due to overall high quality, high temporal resolution and proximity of the location of interest. Additionally, to represent the temperature profile accurately at the airport location an altitude temperature correction of +1.5°C has been applied to the Redding CRN air temperature data to correct for the altitude difference between the Redding CRN and airport site (approximately 1000 ft. altitude difference). No corrections have been applied to the CRN irradiance or wind speed data.

SOLAR PV PRODUCTION MODELING

Black & Veatch used NREL System Advisor Model to simulate the energy production of a 10 MW Solar Project. The system design information assumed during this simulation process is shown in the table below. All the system DC and AC loss assumptions were selected such that it represents a 10 MW ground mount utility-scale project.

System Type and Location	Fixed-Tilt – Redding, CA
System DC Capacity (kWac)	10,000
DC/AC Ratio	1.3
Mounting Type	Fixed – Tilt 30˚ facing south
Ground-Coverage Ratio	33%
Module Type	Crystalline – Silicon (335 W)
Inverter Type	Central Inverters 2000 kW

Based on the analysis, Black & Veatch infers the following:

- The output energy production appears to capture the solar resource variability at the sub-hourly level.
- The output energy production profile does not capture the spatial variability across the entire PV array, and therefore assumes generation to be a point source. This variability however tends to smoothen out as the PV array size increases.
- Due to high temporal resolution of the input temperature profile, high frequency production variation is noticed around solar noon during certain clear sky days. This variation however has very less magnitude and in fact cannot be noticed during the days when project is clipping. This high frequency spikes in production can also be seen in actual production data at sub-hourly level, but this effect is dampened to uneven spatial temperature distribution across the array and data averaging at the meter.

Attachment B: Stochastic Model Results

The stochastic model results comparing the 95% confidence intervals for Net Load with and with and without inclusion of the Solar Project for each month are summarized in the figures below.

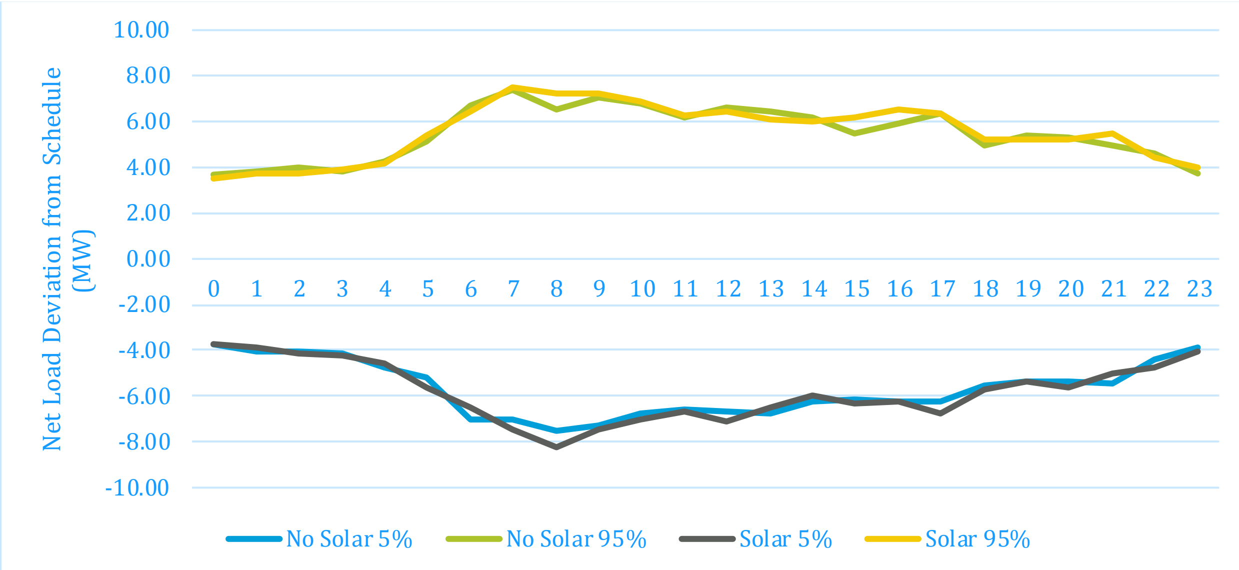


Figure C-5 January Net Load Deviation with and without Solar Project Generation

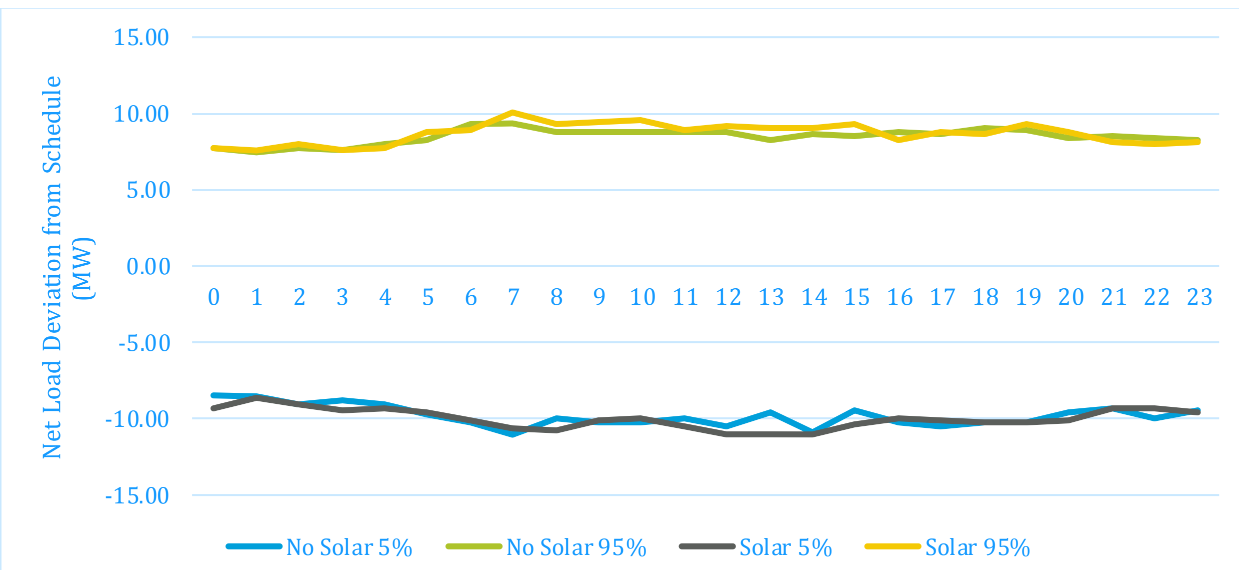


Figure C-6 February Net Load Deviation with and without Solar Project Generation

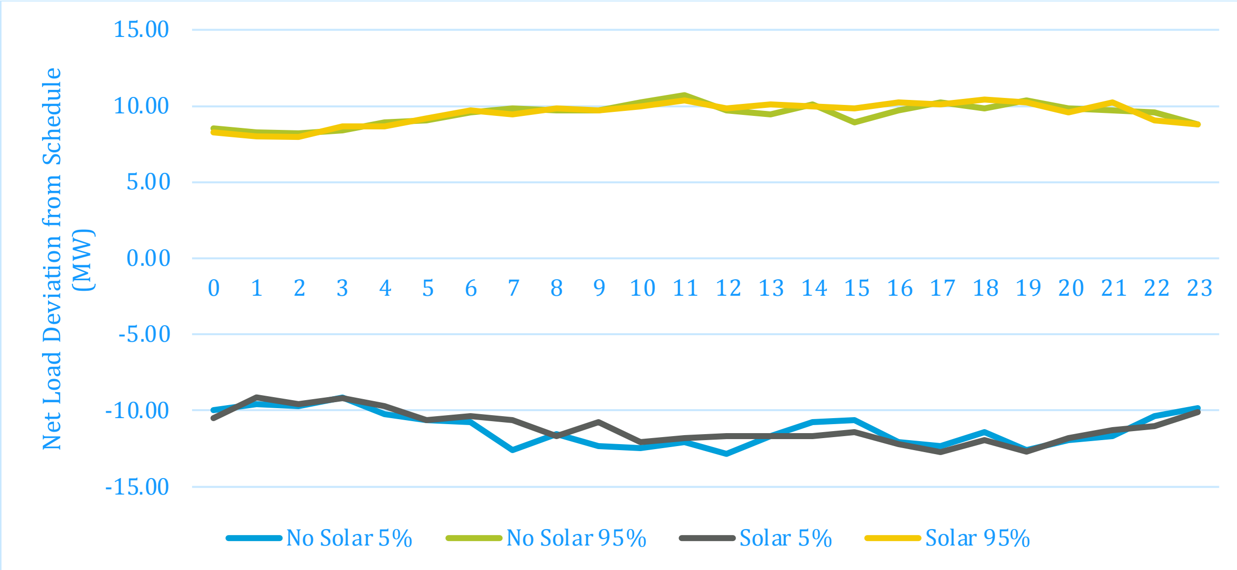


Figure C-7 March Net Load Deviation with and without Solar Project Generation

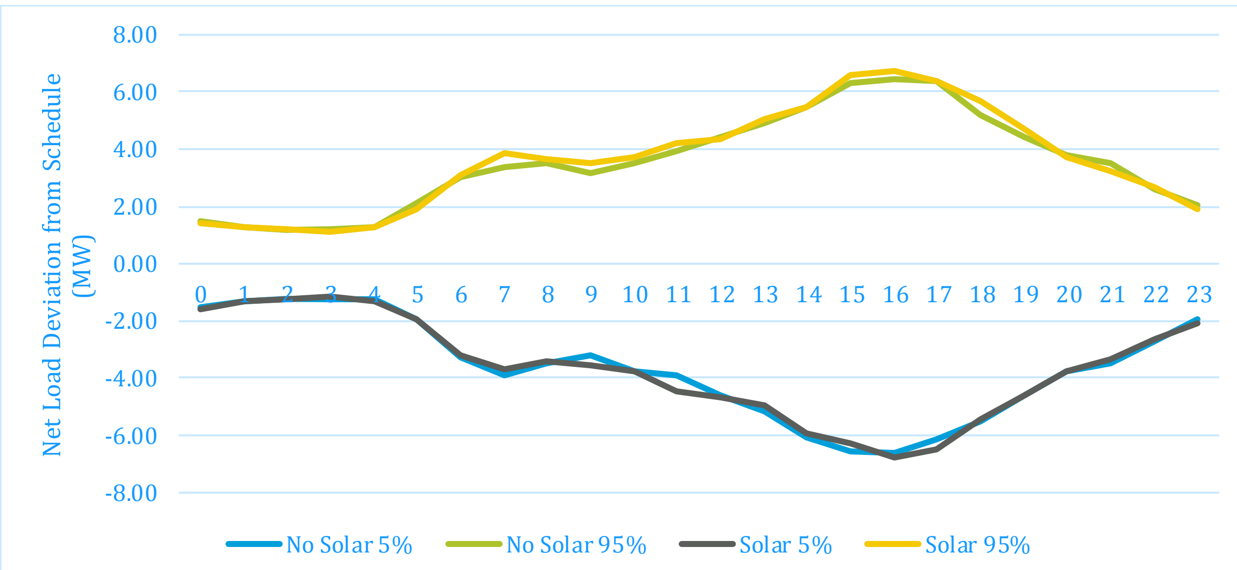


Figure C-8 April Net Load Deviation with and without Solar Project Generation

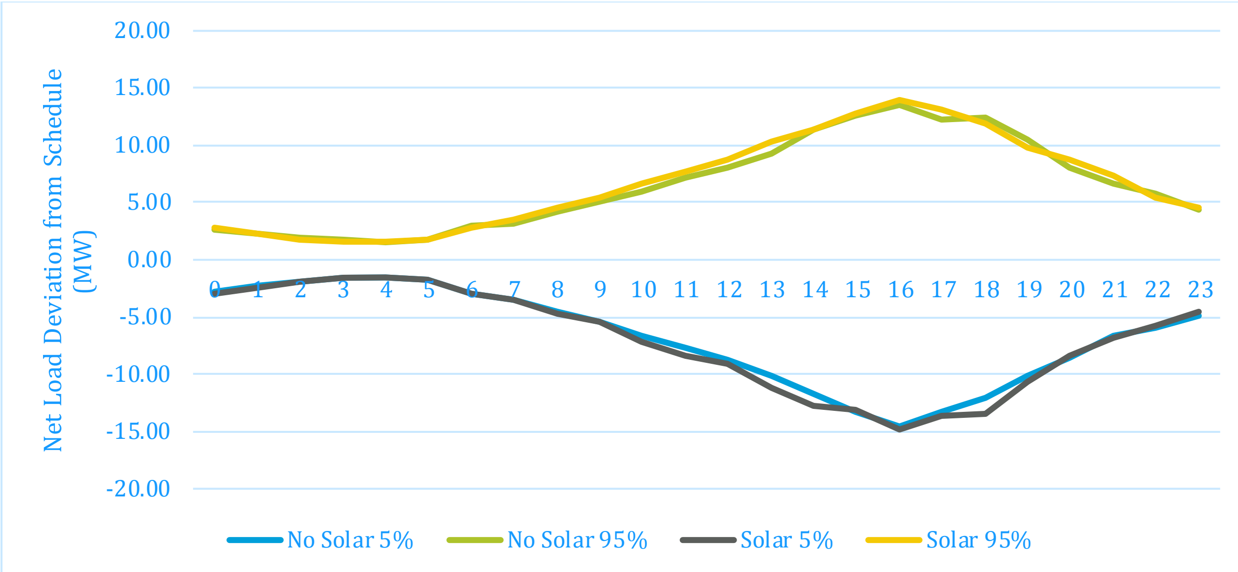


Figure C-9 May Net Load Deviation with and without Solar Project Generation

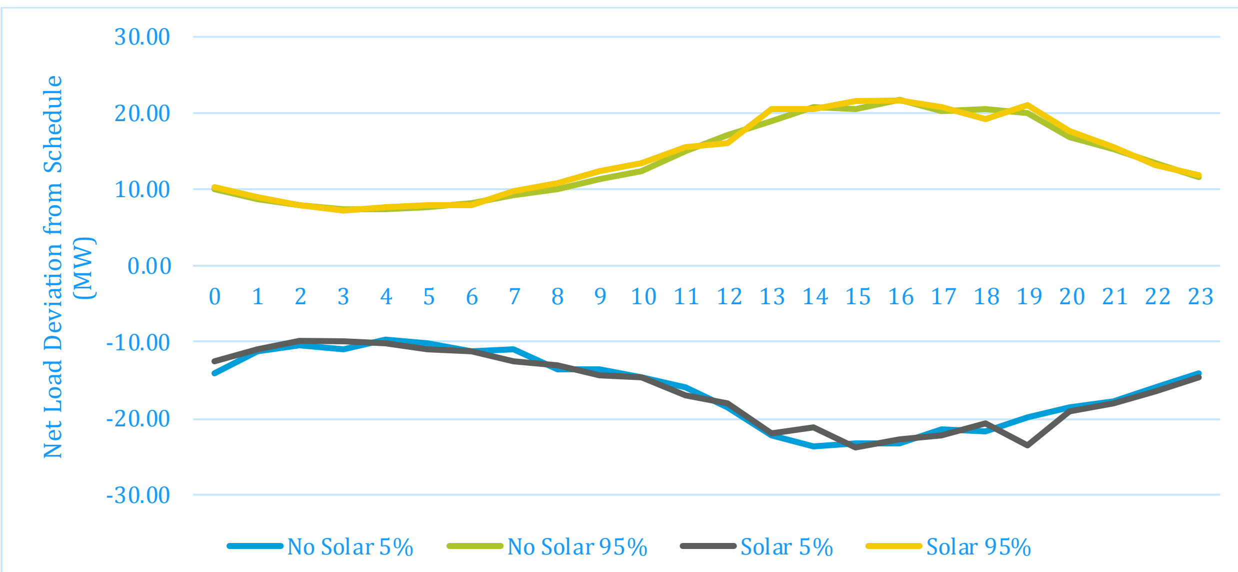


Figure C-10 June Net Load Deviation with and without Solar Project Generation

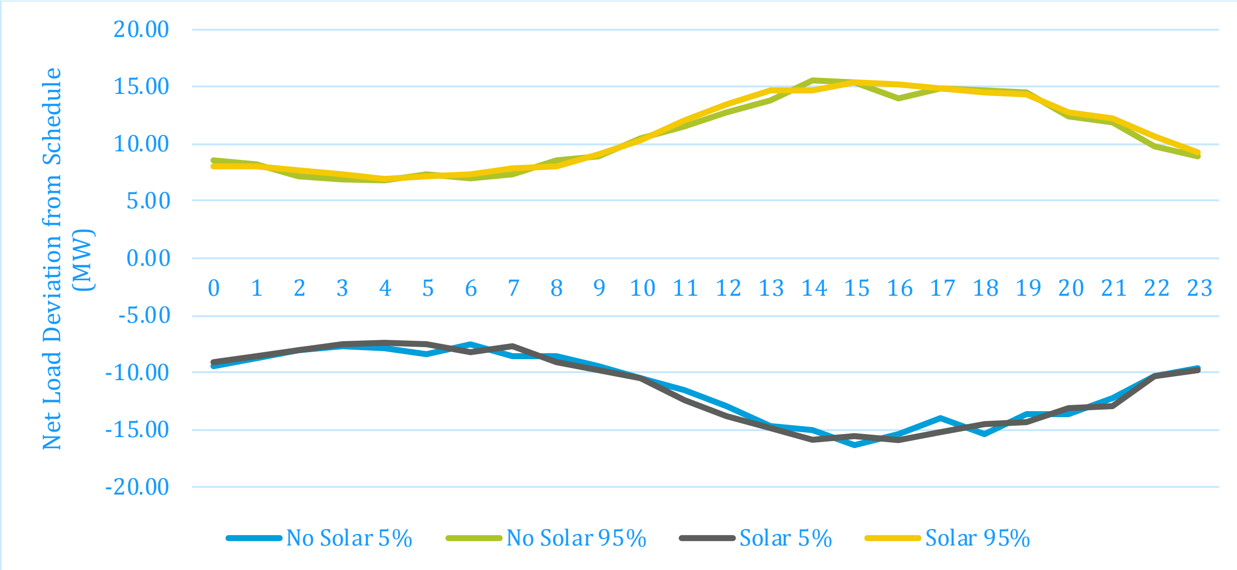


Figure C-11 **July Net Load Deviation with and without Solar Project Generation**

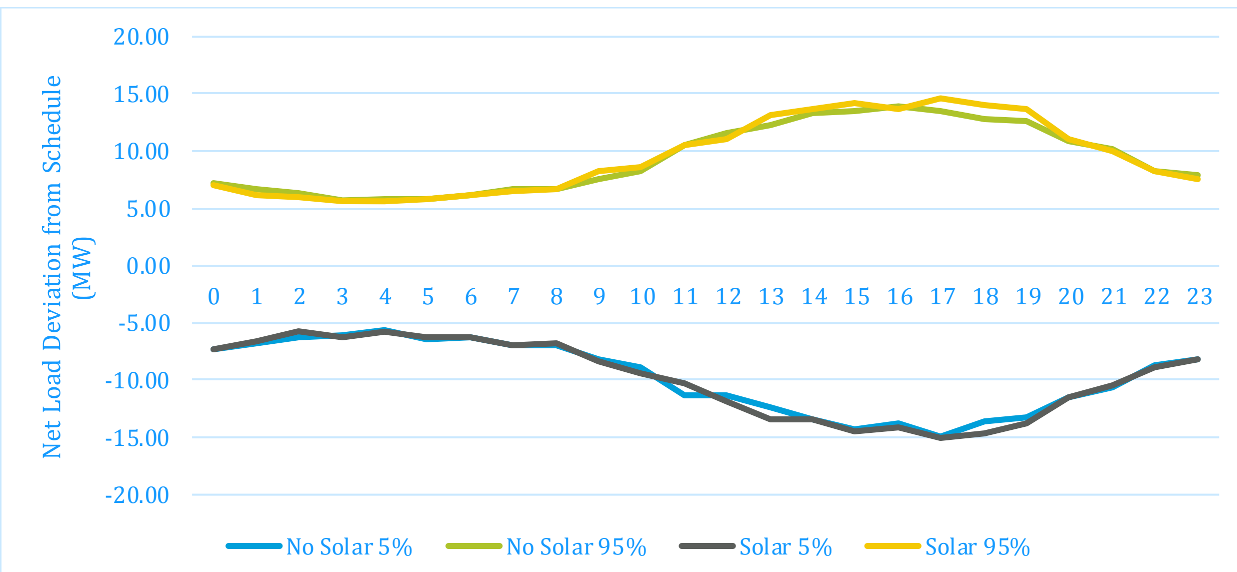


Figure C-12 **August Net Load Deviation with and without Solar Project Generation**

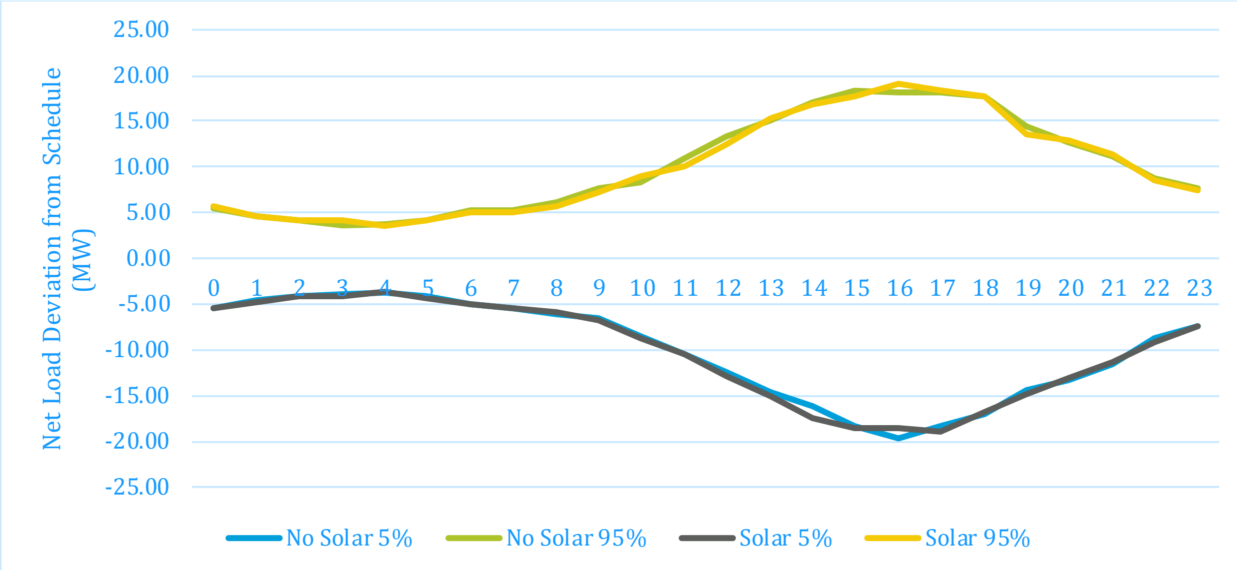


Figure C-13 September Net Load Deviation with and without Solar Project Generation

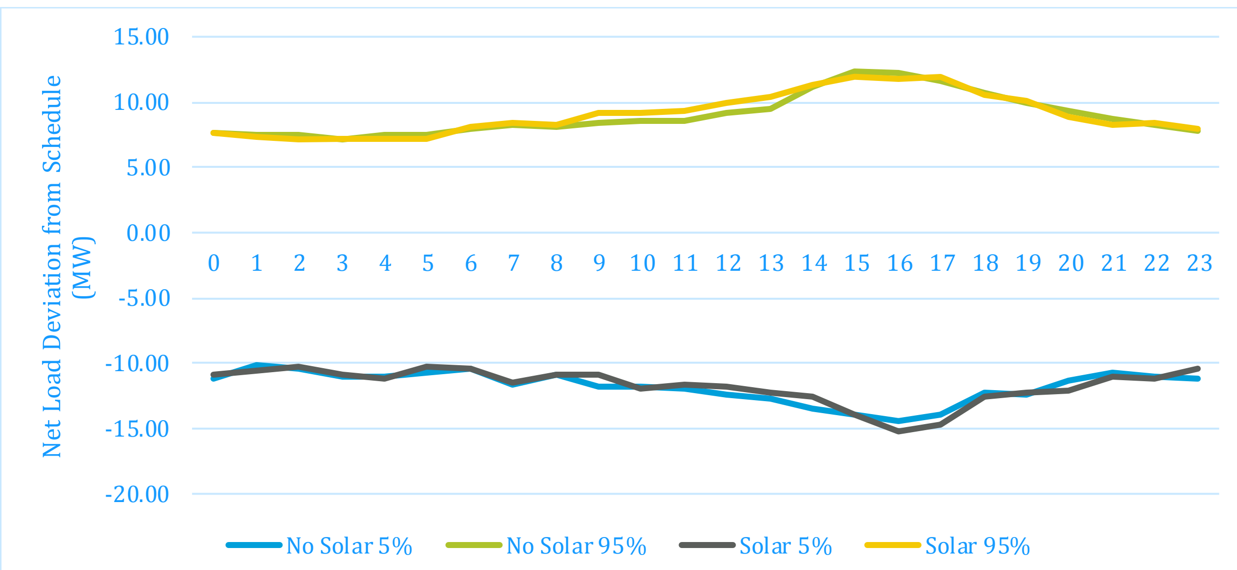


Figure C-14 October Net Load Deviation with and without Solar Project Generation

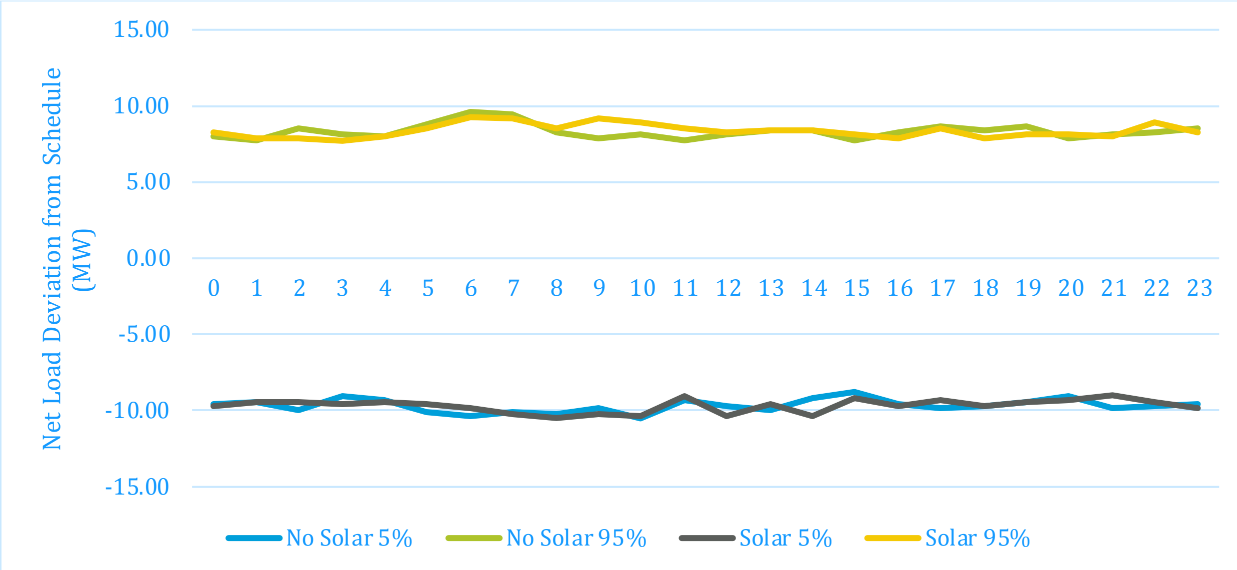


Figure C-15 November Net Load Deviation with and without Solar Project Generation

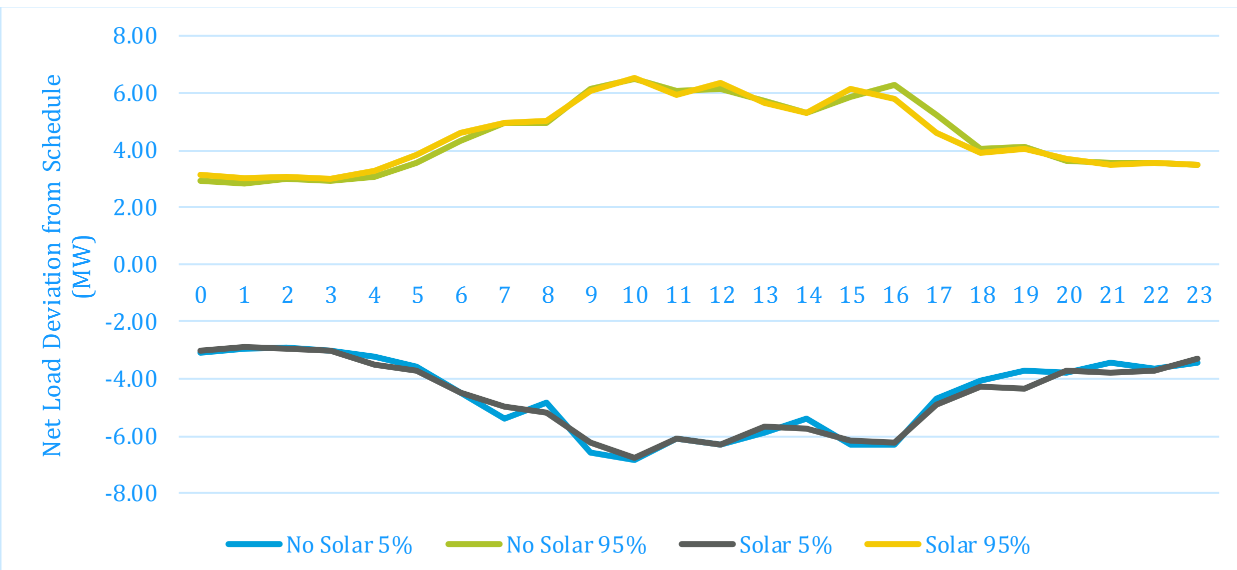


Figure C-16 December Net Load Deviation with and without Solar Project Generation

Appendix D. Ascend Analytics Methodology

FORWARD PRICING

PowerSimm simultaneously simulates multiple strips of forward curves into the future where parameters for the stochastic processes and the covariate factors are estimated from historic data. PowerSimm builds a system of simultaneous equations that captures the stochastic component of each individual forward contract and the covariate relationship between neighboring contract months, other commodities, and other factors (such as interest rates and exchange rates). The state-space modeling framework satisfies the criteria for developing a Cash Flow at Risk solution by producing simulations of prices that are realistic, benchmark well to historic data, and produce a payoff of cash flows consistent with market option quotes at multiple strike prices. The consistency of simulated prices with market expectations remains the principal benchmark criteria for forward market simulations.

Forward contracts may have institutionally determined and specified drift terms. The drift term is a percent change from the current forward price to the final evolved forward price. For example, a forward contract with a current price of $50 and a drift of 10% would have a final evolved price of $55.

As a base simulation assumption, PowerSimm creates convergence between the initial forward price and the final forward price. This is the equivalent of a zero drift term. Even with a very limited number of assumptions the convergence criteria of $F_0=F_T$ will be satisfied.

The process flow for forward price simulation is shown in Figure D-1.

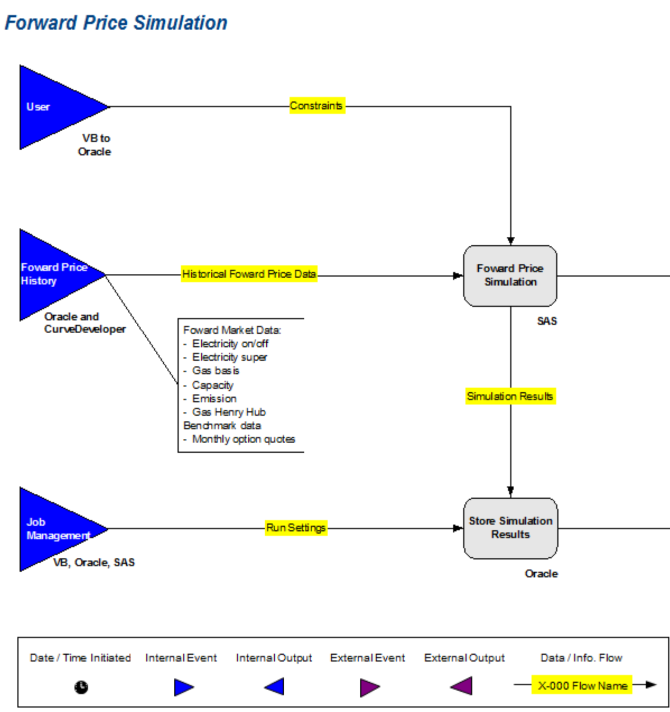


Figure D-1 Forward Price Simulation Process

Input Data

PowerSimm requires a history of forward price quotes for each delivery month to simulate market prices into the future. A minimum of 30 transaction dates for each delivery date is required for forward curve simulation.

PowerSimm has the ability to weight the historic data used in the parameter estimation process to give more weight to more recent events or reduce the impact of outlier events. The default historic weighting formula for forward market data used for parameter estimation follows a linearly declining function. It provides a weight of 1095 for the most recent observation, 1094 for the second most recent, and so on, until it reaches a value of 365 (which corresponds to three years). All historic quotes older than three years old receive a value of 365. Thus, yesterday's quote receives three times the weight in the parameter estimation process as a value that is three years old.

Output Data

Output from the forward price simulation consists of fully evolved forward prices for each forward curve, simulation repetition, and delivery date in the study. The mean forward price for each delivery date is scaled to match the most recent available market forward curve data as of the run time of the study.

SPOT ELECTRIC PRICES

Methodology

The application of the fundamental drivers of electricity has influence on the daily and hourly formation of prices.

Regional electricity prices are primarily a function of daily gas prices and daily reserve margins as shown in Figure D-9. Each variable explains about 50% of the variability in prices and jointly they explain about 90% of the variability. The split regression of Figure D-9 contains a relatively modest amount of noise in the electricity price of +/- $5/MWh when reserves are greater than 15%. When daily reserves are less than 6 percent, the unexplained noise "switches" to a higher regime and captures uncertainty in prices of +/- $40/MWh. High electricity prices can also be caused by spikes in daily gas prices. The spikes in daily gas price carry a direct linear relationship to electricity prices. The joint relationship between high gas prices and low reserve margins follows from regional analysis.

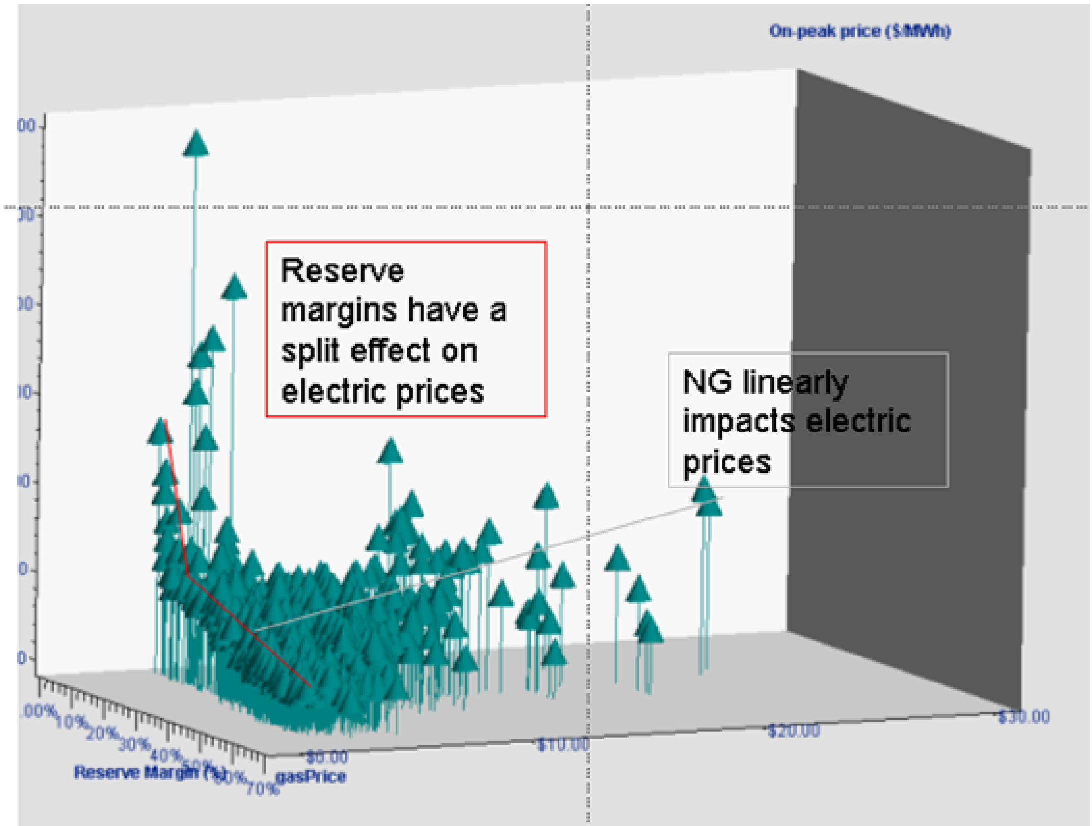


Figure D-2 **Joint relationship of daily reserve margins and gas prices to electric prices**

Simulation of spot electricity prices includes three key components:

1. Simulation of the uncertainty in the parameter estimates and the covariate relationship of uncertainty in the parameter estimate;
2. Simulation of the exogenous variable through a series of simultaneous vector auto-regressive equations;
3. Simulation of residual error.

Variables describing the supply stack, such as the percentage of gas fired generation were determined to be statistically insignificant and were removed from the model.

The simulated values for price are conditional upon the path-dependent weather and load simulations. The mean or median of the realized daily on-peak and off-peak spot prices are bucketed into monthly time steps and scaled so that the mean is equal to the monthly forward price.

Spot electric prices are typically simulated once a week, as new utility and system load values become available. The job management system oversees the appropriate execution of the simulations by way of the Process Flow Editor in the PowerSimm UI.

Process Flow

The process flow for simulation of electric market prices is shown in Figure D-3. The triangles on the left of the figure represent the historic data from which relationships between fundamental variables and electricity prices are determined. The linked simulations of each predictive variable are shown in the rectangular boxes to the right of the triangular inputs. Explanatory variables are linked to electricity prices through a structural state space model.

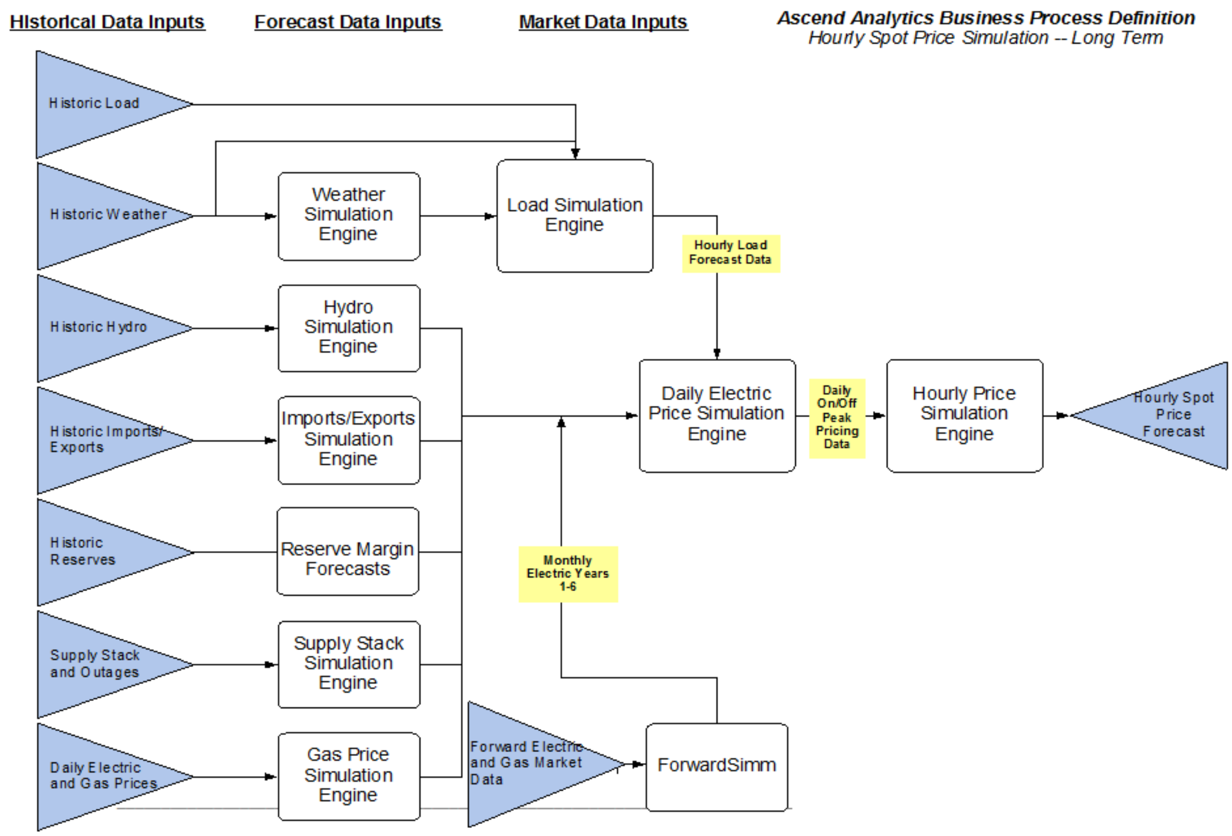


Figure D-3 PriceSimm Process Overview Diagram

Input

The input data consists of the following:

- Historic hourly load data
- Historic hourly or daily hydro generation
- Daily gas prices
- Transmission imports and exports (optional)
- Daily reserve margins (optional)
- Supply stack characteristics (optional)

Weighting of Input Data

The default function for the weighting of historic spot market data used for parameter estimation is flat weighting (all historical data is weighted equally). Alternatively, the historical spot prices can be weighted according to a linearly declining function. This weighting system provides an initial weight for the most recent input spot prices of 730 and 729 for the two-day-old prices. The weights decline daily under the same pattern for two years until they reach a value of 365. All historic quotes older than two years receive a value of 365. Thus, yesterday's quote receives twice the weight in the parameter estimation process as a value that is two years old. Users can adjust the default weighting formula through the UI

Output

The hourly spot price simulation produces daily on-peak and off-peak electric prices and hourly spot electric prices. The prices that are output are scaled to the final evolved forward prices from the corresponding forward price simulation module. More specifically, the average monthly spot price by peak period will be equal to the market forward price as of the scheduled run time of the study in which the forward price simulation was run.

SPOT GAS PRICES

Design Definition

Developing accurate spot gas price simulations is critical for determining the cost of service, risks, and hedging strategies. A simulation approach is advantageous where a specified number of likely events (realizations) can be used in conjunction with exogenous system shocks such as extreme weather events. The combination of market electric prices and spot gas prices is critical to accurately capturing the cost of generation and driving dispatch of generation assets. For each portfolio in PowerSimm, there will be only one central gas delivery point. The other points will be treated as basis points from the delivery point. In most cases, this construct will lead to Henry Hub as the central gas delivery point.

Operational Business Process and Schedule

The generation of new spot prices is run approximately once every month or quarter as new utility and system hydro data becomes available. The Job Management system oversees the appropriate execution of the simulations and provides users with summary statistics based on the last updated input data.

Process Flow

The process flow for gas price simulation is shown below in Figure D-4.

Spot Gas Price Process Flow

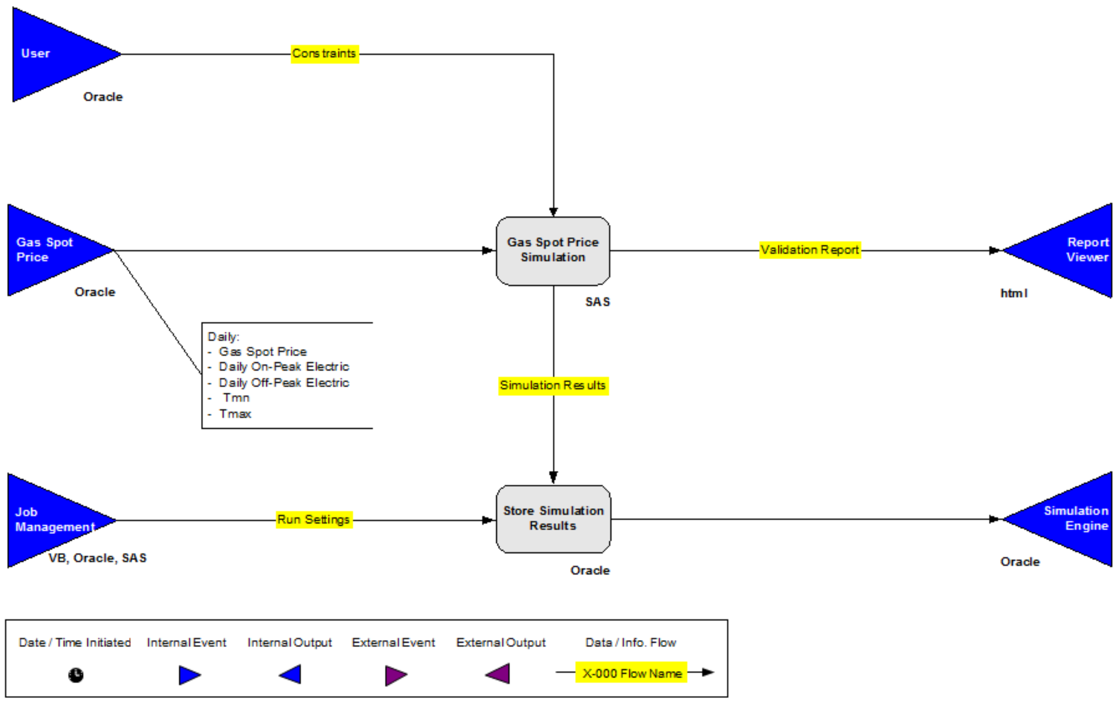


Figure D-4 Spot Gas Price Process Flow

Input Data

Estimation of the parameters to simulated spot gas prices utilizes input of historical gas spot prices, weather, and daily on-peak and off-peak electric prices. The simulated weather is input into the model on a simulation basis.

Output Data

The output data is identical to the daily historic input dataset except that it includes the requested number of spot price simulations for the requested simulation length. This dataset also includes the simulation date and time update along with a link table to describe the parameters used to run the simulation.

Weighting of Data

The historic spot market data used for parameter estimation follows a linearly declining function. The weighting system for market data provides an initial weight for the most recent input spot prices of 730 and 729 for the two-day-old prices. The weights decline daily under the same pattern for three years until they reach a value of 365. All historic quotes older than two years receive a value of 365. Thus, yesterday's quote receives twice the weight in the parameter estimation process as a value that is two years old. Users can adjust the default weighting formula to their own weighting function through the UI.

Reporting Requirement

SimEngine produces daily spot gas price simulations over the forecast horizon. The summary statistics can be viewed in the standard output reports, which focus on the mean, 5th, and 95th percentile simulation results.

LMP & BASIS PRICE SIMULATION

Design Definition

LMP hourly prices and spot gas basis prices share the same simulation structure. Prices are measured in terms of the difference from a central hub. By treating LMP prices as basis prices, we focus on capturing the uncertainty in basis prices between the delivery point and the hub price while maintaining the same correlation between nodal points and the central hub. Simulation of basis addresses market conditions where historic data exists to support estimation of time series relationships. For markets with historic data, it is important to preserve the time series relationships between structural variables such as system load and spot prices.

Operational Business Process and Schedule

Approximately once every month or quarter, generation of new basis prices is run as new utility and system hydro data becomes available. The job management system oversees the appropriate execution of the simulations to provide users with summary statistics based on the last updated input data.

Process Flow

The process flow for spot basis price simulation is shown below in Figure D-5.

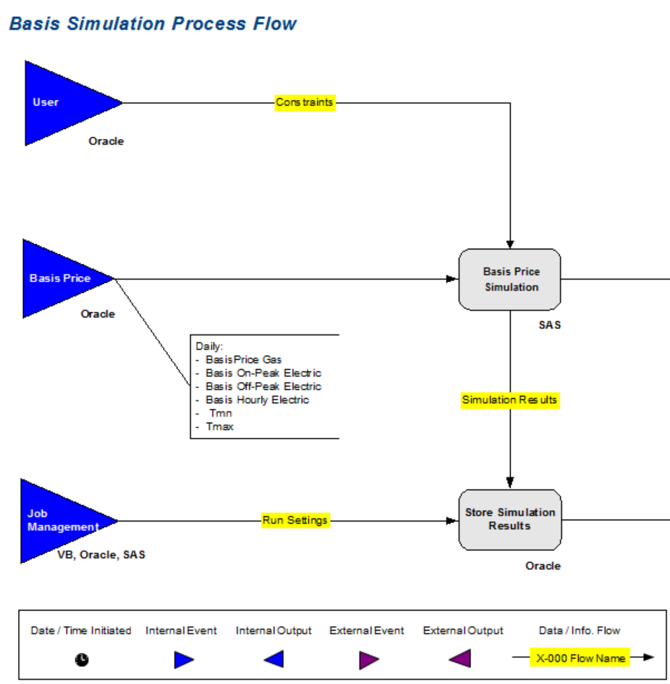


Figure D-5 Spot Basis Price Process Flow

Input Data

Simulation of spot gas prices requires input of historical gas spot prices and daily on-peak and off-peak electric prices.

Output Data

The output data is identical to the daily historic input dataset except that it includes the requested number of basis simulations for the requested simulation length. This dataset also includes the simulation date and time update along with a link table to describe the parameters used to run the simulation.

Methodology

Gas Basis and Daily Electric Prices

Daily gas prices are linked to daily electric on-peak and off-peak prices through the residual error structure.

Hourly Electric Basis

The simulation of hourly electric basis prices follows the following time series model structure where each hour has its own equation.

Hour1 = Lag1(Hour24) + OffPeakPrice + OnPeakPrice + DayOfWeek + MA1 + error

Hour2 = Hour1 + OffPeakPrice + OnPeakPrice + DayOfWeek + MA1 + error

Hour3 = Hour2 + OffPeakPrice + OnPeakPrice + DayOfWeek + MA1 + error

Hour4 = Hour3 + OffPeakPrice + OnPeakPrice + DayOfWeek + MA1 + error

Hour5 = Hour4 + OffPeakPrice + OnPeakPrice + DayOfWeek + MA1 + error

Hour24 = Hour23 + OffPeakPrice + OnPeakPrice + DayOfWeek + MA1 + errorand similarly for OffPeakPrice.
Hour1 + Hour2 + Hour3 + Hour4 + Hour5 + Hour6 + Hour23 + Hour24 = OffPeakPrice

The series of equations for hourly spot prices are estimated with different parameters for each month to capture seasonal effects.

Weighting of Data

The default weighting of historic spot market data used for parameter estimation follows a linearly declining function. The default weighting system for market data provides an initial weight for the most recent input spot prices of 730 and 729 for the two-day-old prices. The weights decline daily under the same pattern for three years until they reach a value of 365. All historic quotes older than two years receive a value of 365. Thus, yesterday's quote receives twice the weight in the parameter estimation process as a value that is two years old. Users can adjust the default weighting formula to their own weighting function through the UI.

Reporting Requirement

SimEngine produces basis price simulations over the forecast horizon. The summary statistics can be viewed in the standard output reports, which focus on the mean, 5th, and 95th percentile simulation results.

POWERSIMM PLANNER – SIMULATION TO CAPTURE MEANINGFUL UNCERTAINTY

PowerSimm is a dispatch optimization and production cost tool. The tool is comprised of two major elements, the Sim Engine and Dispatch Optimization, that work together to systematically bridge the physical and financial dimensions of electricity provision. PowerSimm uses a simulation-based approach to perform decision analysis for portfolio risk management and considers the volatility in important variables such as load, fuel price, power price, weather, renewable generation, load and system constraints, and outages.

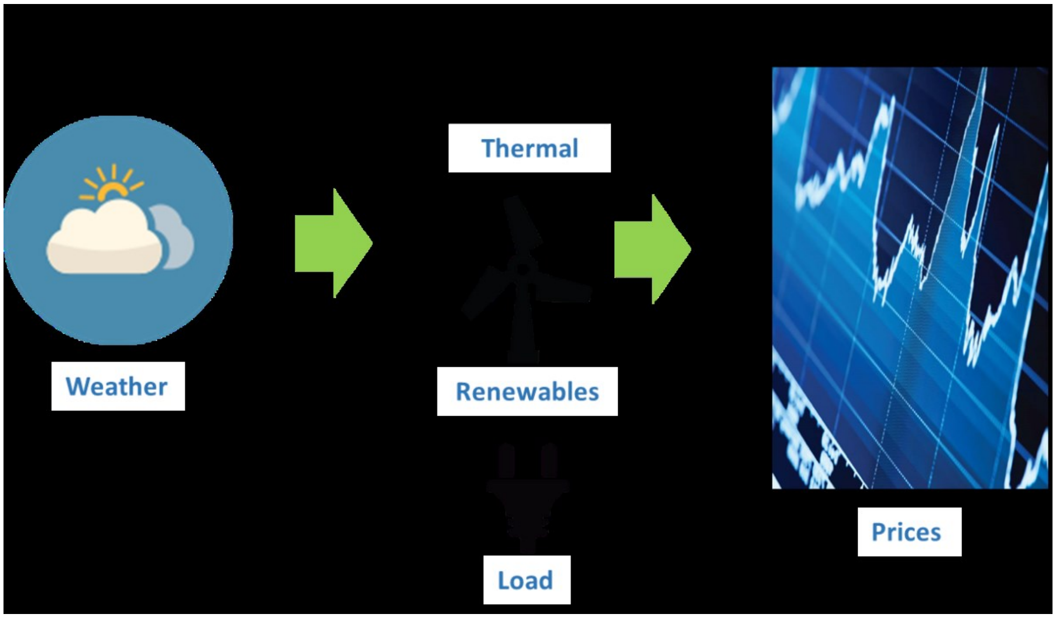


Figure D-6 **PowerSimm's Sim Engine captures "Meaningful Uncertainty" in weather, load, renewables, and prices**

The simulation of uncertainty with respect to weather is becoming ever more critical because weather conditions can be thought of as a new vital parameter in California's emerging high-renewables system. To capture the changing market dynamics with renewables, PowerSimm simulates weather conditions to capture the effect on renewable output and its effect on energy price formation. This is part of the process of characterizing meaningful uncertainty by considering realistic paths of weather that, in turn, drives renewable production, market prices, and net utility loads.

PowerSimm is a stochastic construct model and each expansion plan simulation actually includes 100 or more simulations that allow all possible future states specified through (appropriately correlated) model inputs and forecasts to be considered probabilistically. Figure D-7 demonstrates the value of PowerSimm's stochastic approach. The orange line represents the result of a single deterministic (non-probabilistic) run that would have been calculated based on single values for model inputs such as load and market price. Conversely, using the probabilistic approach, PowerSimm models multiple possible outcomes stochastically, as represented by the blue bar plots in Figure D-7, and characterizes a full distribution of possible outcomes of portfolio cost. This enables the determination of the most likely cost (black bar in the figure representing the mean results) associated with the input variables and forecasts. PowerSimm can make resource decisions based not only on the mean of the distribution, but also by risk considerations informed by the 5th and 95th percentiles. Therefore, the model can solve for the optimal resource portfolio that strikes the best balance between cost and risk.

Using the probabilistic approach, the modeling results for a single run produce a range of possible outcomes for variables subject to uncertainty and for which a probability profile is entered. This means that multiple, single variable sensitivity runs need not be performed to understand the impact of uncertainty in one or more variables. For the simulations, a single cost result was generated for each of the Scenarios evaluated, and no additional sensitivity analyses were performed as is typically done in deterministic modeling approaches.

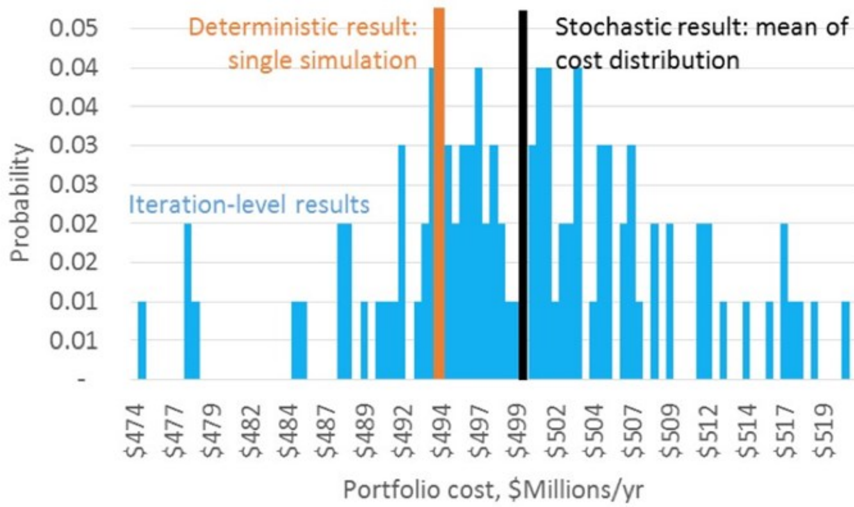


Figure D-7 The Value of Stochastic Analysis in Resource Planning

Using Risk Premium for Resource Decision Making

PowerSimm also identifies the risk associated with each energy portfolio option, quantifying this as the "risk premium." Since different energy portfolios have different simulated cost distributions, the risk premium will be larger for wider cost distributions, or riskier portfolios, and smaller for narrower cost distributions, or less risky portfolios. Ascend then adds the risk premium variable to the expected value to put all energy portfolio options on the same playing field. The factors that drive risk in total portfolio cost include fuel price risk, carbon price risk, and other influential inputs that face uncertainty.

The risk premium is defined as the probability-weighted average of costs above the median, and this concept is illustrated below in Figure D-8:

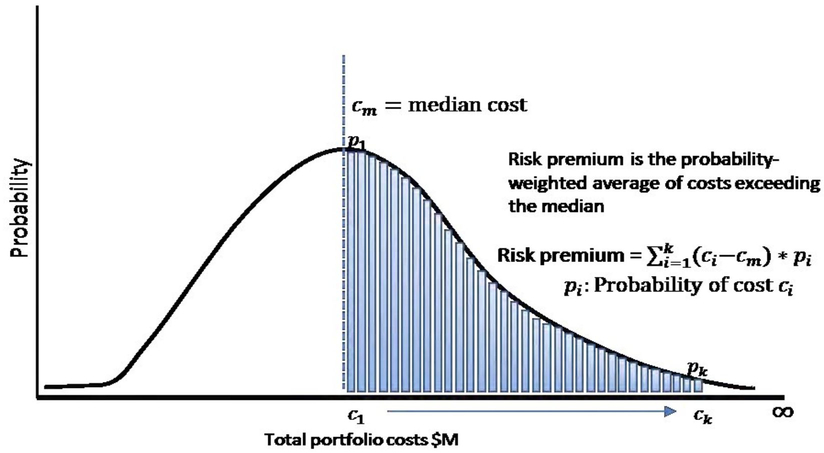


Figure D-8 **Risk Premium is an Economic Concept Measuring how Prone a Portfolio is to Higher than Expected Costs**

PowerSimm planner monetizes risk through applying an actuarial option approach where the value of risk (the risk premium) is calculated as the integral of the cost distribution from the mean to the upper tail of costs, reflecting the downside risk to ratepayers. The underlying cost distribution follows from production cost modeling determined through input simulations of market fuel prices and weather->load->renewables. These underlying simulations are developed to satisfy a long set of validation criteria to ensure "meaningful" uncertainty is reflected in the final distribution of costs.

Appendix E. RPS Compliance and Enforcement Document

<table>
<tr><td>Procedure No:

RPS-001</td><td>Version:

3</td><td>Approval Date:

06/05/18</td><td rowspan="3">RPS Policies & Procedures</td></tr>
<tr><td colspan="3">Effective Date: June 5, 2018</td></tr>
<tr><td colspan="3">Document Owner: Nick Zettel</td></tr>
<tr><td colspan="4">REDDING ELECTRIC UTILITY
Resources Division

RPS-001 Renewables Portfolio Standard Procurement and Enforcement Plan</td></tr>
<tr><td colspan="2" rowspan="2">REU
Redding Electric Utility</td><td colspan="2">Reviewed By:
Nick Zettel (Electric Manager – Resources), Bill Hughes (Electric Manager – Resources), Dan Beans (Electric Utility Director)</td></tr>
<tr><td colspan="2">Adopted By: Redding City Council

Date: June 5, 2018</td></tr>
</table>

TABLE OF CONTENTS

1. Introduction

Senate Bill 2 in the First Extraordinary Session (SBX1-2)[17] 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).[18] This document describes Redding's RPS Procurement and Enforcement Plan, as required by the Public Utility Code, which must be approved by Redding's City Council.

1.1 Utility Code

REU must comply with many state laws that govern certain aspects of utility operations. These include the following code sections, which relate to California's Renewable Portfolio Standard:

- Renewable Portfolio Standard requirement Public Utilities Code (PUC) § 399.30(a)(1)
- 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)

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. The most recent adoption, SB350, mandates that 50 percent of retail sales must be created by eligible renewable energy sources by 2030. SB350 also requires Redding to produce an Integrated Resource Plan that will guide the Procurement Plan.

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[17] SBX1-2 (Simitian, Stats. 2011, Ch. 1) was signed by California's Governor on April 12, 2011, and made significant revisions to Public Utilities Code §s 399.11-399.32, the California Renewables Portfolio Standard Program. Various provisions of § 399.11, *et seq*., were subsequently modified.

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

2.2 Compliance Periods and Procurement Targets

Compliance periods are multiyear, required targets. Although Compliance Periods 1 and 2 have passed, 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:

10.0 EP 2011 + EP 2012 + EP 2013 ≥ .20 (RS 2011 + RS 2012 + RS 2013)

Where:

RS X = total retail sales made by POU 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:

11.0 ***EP 2014 + EP 2015 + EP 2016 ≥ 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)
≥ 0.27 (RS 2017) + 0.29 (RS 2018) + 0.31 (RS 2019) + 0.33 (RS 2020)

D. Compliance Periods beyond 2020

(1) Compliance periods beyond 2020 are not formally established; however, SB350 requires a 50 percent renewable standard by 2030.

The following table summarizes the annual "soft" targets, but compliance is determined over the entire compliance period using the formulas above.

Compliance Period 3					
…	2017	2018	2019	2020	…2030

…	27%	29%	31%	33%	50%

Table 1: RPS Renewable Requirement

2.3 Portfolio Content Categories

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 other facility, 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.

(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. PCC2: (RPS Enforcement Regulations Section 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 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 section 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 section 3204(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.

(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 must be classified into PCC1, 2, or 3, and follow the portfolio balance requirements in accordance with RPS Enforcement Regulations section 3204 (c).

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

	Compliance Period 1 2011-2013	Compliance Period 2 2014-2016	Compliance Period 3 2017-2020
PCC1 (Minimum)	50%	65%	75%
PCC2 (No Direct Restriction)	n/a	n/a	n/a
PCC3 (Maximum)	25%	15%	10%
PCC0	Is not subject to portfolio balancing requirements		
Beyond 2020 is to be determined			

Table 2: RPS Balancing Requirement

2.4 Redding's Plan for RPS Compliance

2.4.1 Existing Eligible Renewable Resources

Redding currently has the following renewable energy resources under contract and/or ownership that meet the RPS eligibility requirements:

Wind

Big Horn Wind Project (PCC0) - In 2006, Redding entered into a 20-year contract with possible 5-year extension for wind energy through the M-S-R Public Power Agency by participation in the Big Horn Wind Project. Redding has contracted for 70 MW of capacity that yields approximately 180,000 MWh of eligible renewable energy annually.

Hydro (<30MW)

Whiskeytown Hydro (PCC0) - In the mid-1980s, Redding invested in small hydro-generation at Whiskeytown Dam. The Whiskeytown Project has a capacity of approximately 3 MW and yields roughly 26,000 MWh of eligible renewable energy annually.

WAPA Small Hydro Program (PCC0) - Redding participates in WAPA's Small Hydro Program; this contributes approximately 6,000 MWh of eligible renewable energy to Redding annually.

2.4.2 Procurement Plan for Future Renewable Resources

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 will be the guiding document and tool for choosing the optimal plan.

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:

A. An average of 20 percent in 2011 through 2013;

B. 25 percent by 2016; and

C. 33 percent by 2020 and thereafter.

Resolution 2011-197 also adopted the following Enforcement Policies:

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

B. Redding will report annually to the City Council on its status of compliance with SBX1-2.

C. Redding will notify the City Council of any potential for lack of compliance with the requirements of SBX1-2 that may be considered for a notice of violation and penalty imposition.

D. Redding will provide an explanation and analysis to the City Council on such potential for lack of compliance with SBX1-2, as well as a plan of corrective action and timeframe for returning the City to compliant status.

E. At such time, the City Council will direct staff on its recommended course of action.

3.2 Optional Compliance Measures

Specific optimal 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 Public Utilities Code §399.30 and § 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 beginning on January 1, 2011, and shall be calculated as set forth in RPS Enforcement Regulations § 3206(a)(1)(D).

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:

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).

The Cost Limitation applied to each RPS procurement expenditure will consider the following:

(1) Incorporating the annual RPS expenditure into Redding's current portfolio should not require rate increases of more than 1.5 percent per year at any time during the life of the considered RPS procurement.

(2) The per-kilowatt-hour cost of the considered RPS procurement expenditure should not exceed, nor be projected to exceed, 75 percent of Redding's current per-kilowatt-hour retail residential energy charge.

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

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

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

In the event that procurement expenditures exceed the adopted Cost Limitation, Redding shall re-evaluate its RPS Procurement Plan to ensure that other options are not available that would otherwise allow Redding to meet its RPS procurement requirement. Such review will include a re-evaluation of current procurement commitments, planned procurements, long-term commitments, and the availability of alternative resources in other portfolio content categories.

D. Portfolio Balance Requirement Reduction:

Redding shall be allowed to reduce the portfolio balance requirement for Procurement Content Category 1[19] for a specific compliance period if conditions beyond the control of Redding occur that warrant a delay in timely compliance (as adopted under § 2.2 (B) of the RPS Enforcement Program) as defined in § 3206(a)(4) of the RPS Enforcement Regulations.

If Redding uses this reduction measure, Redding will update its RPS Procurement Plan with the adjusted information and submit such updated plan to the CEC.

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

Redding is required to complete an Integrated Resource Plan that will guide the Procurement plan.

A. Redding will provide the following notice regarding new or updated renewable energy resources procurement plans:

(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.

(2) Along with the posting of the notice of a public meeting to consider the RPS Procurement Plan, Redding shall notify the CEC of the date, time, and location of the public meeting to consider the RPS Procurement Plan. This requirement is satisfied if Redding provides the CEC with the uniform resource locator (URL) that directly links to the notice for the public meeting. Alternatively, an e-mail with information on the public meeting in Portable Document Format (PDF) may also be provided to the CEC.

[19] Procurement Content Category 1 is defined in § 3203 (a) of the RPS Enforcement Regulations.

(3) Redding will notify the CEC if any URL provided by Redding no longer contains the correct link, and Redding will send the CEC a corrected URL that links to the information, or a PDF containing the information, as soon as it becomes available.

(4) If Redding distributes information to its City Council related to its renewable energy resources procurement status, or future procurement or enforcement programs for the City Council's consideration at a public meeting, Redding shall make all relevant information available to the public at the same time it is distributed to City Council, and shall provide an electronic copy of that information to the CEC for posting on the CEC's website.

(a) This requirement is satisfied if Redding provides the URL that directly links to the documents or information regarding other manners of access to the documents to the CEC. Alternatively, an e-mail with the information in PDF may also be provided to the CEC.

(b) Redding will notify the CEC if any URL provided no longer contains the correct link, and Redding will send the CEC a corrected URL that links to the information, or a PDF containing the information, as soon as it becomes available.

5. Review and Revision History

Revision Number	Revision Date	Summary of Changes
1	10/15/2013	Original version adopted by City Council Date: October 15, 2013
2	10/07/2014	Annual update: Removed Lewiston and added Colusa
3	06/05/18	Combined Procurement and Enforcement plan. Included SB350 updates, removed Colusa biomass project, and rearranged information for a more clear, concise document.

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

Appendix F. Energy Storage Compliance Plan

Procedure No: ESCP - 02	Version: Draft 1	Approval Date: September 19, 2017	Energy Storage Compliance Plan (ESCP)
Effective Date: **October 1, 2017**			
Document Owner: **Lowell Watros**			

REDDING ELECTRIC UTILITY

Energy Services Division

ESCP-02 Energy Storage Compliance Plan (AB 2514 & AB 2227– Public Utilities Code Sections 2835-2839)

REU Redding Electric Utility	Reviewed By: **Lowell Watros (Resource Planner – Enterprise Services), Nick Zettel (Manager – Enterprise Services), Dan Beans (Interim Electric Utility Director)**
	Adopted By: **Redding City Council** Date: September 19, 2017

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Introduction/Background

Redding Electric Utility (REU) started analyzing energy storage technologies in 2004. In 2005, REU installed its first thermal energy storage (TES) devices within its service territory (a chiller-based TES system at Redding Municipal Airport and a direct expansion TES system at the Redding Fire Department).

Subsequent to REU's continued pursuit of cost-effective TES installations throughout the Utility's service territory, Assembly Bill (AB) 2514 (Energy Storage Bill) was introduced to the California Legislature by Assembly woman Skinner in 2010. This bill passed and was signed into law (Public Utilities Code Section 2835-2839) by Governor Arnold Schwarzenegger September 29, 2010.

This energy storage law requires the governing board (City Council) of a local, publicly- owned electric utility by March 1, 2012, to open a proceeding to determine appropriate targets, if any, for the utility to procure viable and cost-effective energy storage systems and, by October 1, 2014, to adopt an energy storage system procurement target, if determined to be appropriate, to be achieved by the utility by December 31, 2016. The law includes a second target to be achieved by December 31, 2020. The law further specifies:

Section 2836 - As part of this proceeding, the governing board may consider a variety of possible policies to encourage the cost-effective deployment of energy storage systems, including refinement of existing procurement methods to properly value energy storage systems.

- The governing board shall adopt the procurement targets if determined to be appropriate pursuant to paragraph (1) by October 1, 2014.
- The governing board shall reevaluate the determinations made pursuant to this subdivision not less than once every three years (in September 2017 and September 2020).

Section 2836.4 - An energy storage system may be used to meet the resource adequacy requirements established by a local, publicly-owned electric utility pursuant to Section 9620 if it meets applicable standards.

Section 2836.6 - All procurement of energy storage systems by a load-serving entity or local, publicly-owned electric utility shall be cost-effective.

Energy Storage Procurement Plan

2.1 Plan Overview

The purpose of the ESCP is to identify the policies and procedures for REU to meet the requirements set forth with AB 2514 and the Energy Storage section of the Public Utilities Code (Sections 2835-2839).

a) The ESCP incorporates REU's TES Program with the legislative mandate requiring utilities to review various energy storage technologies and to set procurement and periodic review targets.

b) Under AB 2514, each utility is to review the applicability of various storage technologies to their local operating requirements and identify which of those, if any, would benefit the utility's electric service requirements. REU has completed an assessment of its TES Program and determined the Program to be beneficial in assisting the overall operating conditions of the Utility.

Under ESCP-01, REU had a procurement target of 3.6 MW to be installed and operational by July 1, 2017. That target was obtained and REU is now in the Operations and Maintenance (O&M) phase for the TES Program as it is now configured. Due to the current (no growth) load forecast and adequate power supplies available for the foreseeable future, no further additions to REU's energy storage capabilities are contemplated at this time. During the next review period, as part of ongoing Integrated Resource Plan (IRP) efforts, REU will analyze the value of all qualified energy storage technologies as defined by AB 2514, including TES. The existing TES assets are expected to have an effective 20-year plus life span. While the TES systems have been proving to be quite reliable, some routine maintenance will be needed over the multi-year time period that the equipment is expected to be in service.

Compliance Periods

AB 2514 established the following compliance periods:

1. On or before March 1, 2012, REU must initiate a proceeding to determine appropriate storage targets.
2. Procurement targets must be adopted by October 1, 2014.
3. Review initial storage targets by September 2017.
4. Review the storage targets set in September 2017 by September 2020.

AB 2227 established the following compliance periods:

1. On or before January 1, 2017, REU must report to the California Energy Commission (CEC) demonstrating that it had complied with storage targets adopted by City Council on October 1, 2014.
2. By January 1, 2021, in similar fashion as Item 1 above, again file a progress report with the CEC, related to City Council adopted targets on October 1, 2017.

Definitions of Energy Storage Technologies

AB 2514 specifically defines what constitutes and qualifies as an energy storage system. The definition as stated in the law (section 2835 (a)(1) – (2)(A)) is: "commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy." An "energy storage system" shall do one or more of the following:

(1) Use mechanical, chemical, or thermal processes to store energy that was generated at one time for use at a later time.
(2) 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.
(3) Use mechanical, chemical, or thermal processes to store energy generated from renewable resources for use at a later time.
(4) Use mechanical, chemical, or thermal processes to store energy generated from mechanical processes that would otherwise be wasted for delivery at a later time.

ESCP Review Requirements

Redding adjusts its load forecast annually. This forecast will be used to anticipate the ESCP's needs in future years. This ESCP will be updated as appropriate to reflect Redding's periodic review of loads and available power resources, including energy storage technologies.

a) Redding will review the initial procurement targets set in September 2014 no later than September 2017, and again no later than September 2020.

AB 2227 added to the requirements of AB 2514 minimally in that local, publically-owned electric utilities, such as REU shall submit a report to the Energy Commission demonstrating it had complied with the energy storage system procurement targets and policies adopted by the City Council in September 2014 by January 1, 2017, and in similar fashion by January 1, 2021. Basically, AB 2227 provides for routine progress reports to the CEC.