Inputs & Assumptions

2024 – 2026 Integrated Resource Planning (IRP)

February 2025

California Public Utilities Commission

Table of Contents

Table of Contents

List of Acronyms

A-CAES	Adiabatic Compressed Air Storage	LDV	Light-Duty Vehicle
AAEE	Additional Achievable Energy Efficiency	LDWP	Los Angeles Department of Water and Power
AAFS	Additional Achievable Fuel Substitution	LFC	Levelized Fixed Cost
AB	Assembly Bill	LFE	Load Forecast Error
ACE	Area of Conservation Emphasis	LIP	Load Impact Protocol
ADS	Anchor Data Set	LOLE	Loss of Load Expectation
AEO	Annual Energy Outlook	LSE	Load Serving Entity
ATB	Annual Technology Baseline	MGC	Master Generating Capability List
BAA	Balancing Authority Area	MMT	Million Metric Tons
BEV	Battery Electric Vehicle	MTR	Mid-Term Reliability
BLM	U.S. Bureau of Land Management	NAMGas	North American Market Gas Trade Model
BOEM	Bureau of Ocean Energy Management	NCNC	Northern California, Non-CAISO
BTM	Behind-the-Meter	NGBA	North of Greater Bay Area
CAISO	California Independent System Operator	NOL	North of Lugo
CAPEX	Capital Investment/Expenditure	NOx	Nitrogen Oxides
CARB	California Air Resources Board	NPV	Net Present Value
CCA	Community Choice Aggregator	NQC	Net Qualifying Capacity
CCGT	Combined Cycle Gas Turbine	NREL	National Renewable Energy Laboratory
CEC	California Energy Commission	NSRDB	National Solar Radiation Database
CES	Clean Energy Standard	NW	Northwest Region
CHP	Combined Heat and Power	OOS	Out-of-State
CPA	Candidate Project Area	PCAP	Perfect Capacity
CT	Gas Combustion Turbine (Peaker)	PEIS	Programmatic Environmental Impact Statement
D/E	Debt-to-Equity Ratio	PGE	Pacific Gas & Electric

DAC	Disadvantaged Communities	PHEV	Plug-in Hybrid Electric Vehicle
DOE	U.S. Department of Energy	PM	Particulate Matter
DR	Demand Response	PNNL	Pacific Northwest National Laboratory
DRAM	Demand Response Auction Mechanism	POU	Publicly Owned Utility
EFORd	Equivalent Forced Outage Rate Demand	PPA	Power Purchase Agreement
EGS	Enhanced Geothermal Systems	PRM	Planning Reserve Margin
EIA	U.S. Energy Information Administration	PSP	Preferred System Plan
ELCC	Effective Load Carrying Capability	PTC	Production Tax Credit
EO	Energy-Only	PV	Photovoltaic Solar
EODS	Energy Only Deliverability Status	REC	Renewable Energy Certificate
EOP	East of Pisgah	RETI	Renewable Energy Transmission Initiative
EPRI	Electric Power Research Institute	RPS	Renewable Portfolio Standard
ESGC	Energy Storage Grand Challenge	SAM	System Advisor Model
ESP	Energy Service Provider	SB	Senate Bill
EV	Electric Vehicle	SCE	Southern California Edison
FCDS	Full Capacity Deliverability Status	SDGE	San Diego Gas & Electric
FO&M	Fixed Operations & Maintenance Cost	SEIA	Solar Energy Industries Association
FSSAT	Fuel Substitution Scenario Analysis Tool	SERVM	Strategic Energy Risk and Valuation Model
GBA	Greater Bay Area	SIP	State Implementation Plan
GETEM	Geothermal Electricity Technology Evaluation Model	SOx	Sulfur Oxides
GHG	Greenhouse Gas	SSN	Secondary System Need
HSN	Highest System Need	ST	Steam Turbine
IAWG	Interagency Working Group	SW	Southwest Region
ICAP	Installed Capacity	T&D	Transmission and Distribution
ICE	Reciprocating Engine	TOU	Time-of-Use
IEPR	Integrated Energy Policy Report	TPP	Transmission Planning Portfolio
IID	Imperial Irrigation District	TRN	Total Reliability Need
IMF	International Monetary Fund	UCAP	Unforced Capacity
IOU	Investor Owned Utility	USFWS	U.S. Fish and Wildlife Service
IPP	Independent Power Producer	USGS	U.S. Geological Survey
IRA	Inflation Reduction Act	VEA	Valley Electric Association
IRR	Internal Rate of Return	VGI	Vehicle-to-Grid Integration
ITC	Investment Tax Credit	VO&M	Variable Operations & Maintenance Cost
LBNL	Lawrence Berkeley National Laboratory	WACC	Weighted Average Cost of Capital
LCOE	Levelized Cost of Electricity	WEA	Wind Energy Area
LCR	Local Capacity Requirement	WECC	Western Electricity Coordinating Council
LCTS	Local Capacity Technical Study	WRF	Weather Research & Forecasting Model
LDES	Long Duration Energy Storage		

1. Introduction

This document describes the key data elements and sources of inputs and assumptions for the California Public Utilities Commission's (CPUC's) 2024-2026 Integrated Resource Planning (2024-2026 IRP) modeling. It summarizes the inputs and assumptions staff developed for the 2025 filing requirements modeling and will be updated for the Preferred System Portfolio modeling in 2026.

The inputs, assumptions, and methodologies are applied to create optimal portfolios for the CAISO electric system that reflect different assumptions regarding load growth, technology costs and potential, fuel costs, and policy constraints. In some cases, multiple options are included for use in developing IRP scenarios and sensitivities modeling.

1.1. Overview of the RESOLVE model

The high-level, long-term identification of new resources that meet California's policy goals is directly informed by use of the RESOLVE resource planning model. The CPUC uses RESOLVE to develop the Load Serving Entities (LSE) Filing Requirements, a look into the future that identifies a portfolio of new and existing resources that meets the Greenhouse Gas (GHG) emissions planning constraint, provides ratepayer value, and responds to reliability needs. The CPUC uses RESOLVE because it is a publicly available and vetted tool. The CPUC uses the process of soliciting party feedback on inputs and assumptions to ensure that RESOLVE contains transparent, publicly available data sources and transparent methodologies to examine the long-term planning questions posed within the Integrated Resource Planning process.

RESOLVE is formulated as a linear optimization problem. It co-optimizes investment and dispatch for a selected set of days over a multi-year horizon to identify least-cost portfolios for meeting carbon emission reduction targets, renewables portfolio standard goals, reliability during peak demand events, and other system requirements. RESOLVE typically focuses on developing portfolios for jurisdictions within the CAISO Balancing Authority Area, but incorporates a representation of neighboring zones in order to characterize transmission flows into and out of the region of interest. Zone in this context refers to a geographic region that consists of a single balancing authority area (BAA) or a collection of BAAs in which RESOLVE balances the supply and demand of energy. The CPUC IRP version of RESOLVE includes seven zones: four zones capturing California balancing authorities, two zones that represent regional aggregations of out-of-state balancing authorities, and one resource-only zone representing dedicated hydroelectric imports from the Pacific Northwest.[1] The CAISO zone consists of the three IOU zones in RESOLVE, representing the CAISO balancing authority area. Other CA zones include IID, LDWP, and NCNC.

RESOLVE can solve for optimal investments in new candidate resources, as well as economic retention of existing resources. Resources and asset types include:

- Thermal generators (e.g., gas, geothermal, biomass)
- Renewable resources
- Energy storage
- Hydropower
- Shift & shed demand response, energy efficiency, and other distributed energy resources (e.g., BTM PV)
- Intra- and inter-zonal transmission

Subject to the following constraints or a subset of them as desired:

- Hourly zonal demand and operating reserve requirements
- An annual constraint on delivered renewable energy and zero-carbon energy that reflects Renewables Portfolio Standard (RPS) policy and the Senate Bill (SB) 100 policy
- An annual constraint on emissions (e.g., GHGs)
- An annual Planning Reserve Margin (PRM) constraint to maintain resource adequacy and reliability
- Technology-specific operational constraints (e.g., ramp rate limits, battery state-of-charge); and
- Constraints on the minimum retention amounts for gas-fired thermal resources, representing resources in local capacity requirement (LCR) areas
- Constraints on the ability to develop specific new resources
- Constraints on transmission deliverability and line upgrade limits
- Interzonal power flow limits and simultaneous flow limits

[1] A seventh resource-only zone was added in the 2019-2021 IRP cycle to simulate dedicated imports from Pacific Northwest hydroelectric resources. This zone does not have any load and does not represent a BAA. Similarly, several zones for remote resources were created for the 2024-2026 IRP cycle.

RESOLVE optimizes the buildout of new resources years into the future, representing the fixed costs of new investments and the costs of operating the CAISO system within the broader footprint of the Western Electricity Coordinating Council (WECC) electricity system.

1.2. Overview of the SERVM Model

The CPUC also uses the Strategic Energy Risk Valuation Model (SERVM) as a separate tool to provide more detailed analysis of factors such as system reliability once a portfolio has been determined. SERVM calculates numerous reliability and cost metrics for a given study year in light of expected weather, overall economic growth, electric demand and resource generation, and unit performance. For each of these factors, variability and forecasting uncertainties are also taken into account. An individual year is simulated many times over, with each simulation reflecting a slightly different set of weather, economic, and unit performance conditions. In contrast to RESOLVE, each single target forecast year is simulated on an hourly basis so that daily and seasonal patterns are analyzed. Probability-weighted expected values are then created from model outputs which reflect twenty-three possible weather years, twenty-three possible years of hydro availability, five points of load forecast error, and multiple unit outage draws, creating thousands of iterations for the simulation.

The results provide a comprehensive distribution of reliability costs, expected unserved energy, and other reliability metrics. Energy Division staff uses these metrics to determine the adequate quantity of effective capacity required to maintain a target Loss of Load Expectation (LOLE).

The 2024-2026 IRP cycle includes activities to align the inputs and outputs of RESOLVE and SERVM, to the extent possible, through the use of common data sources to achieve reasonable agreement in outputs between the models.

1.3 Document Contents

The remainder of this document is organized as follows:

- **Section 2 (Load Forecast)** documents the assumptions and corresponding sources used to derive the forecast of load in CAISO and the WECC, including the impacts of demand side programs, load modifiers, and the impacts of electrification.
- **Section 3 (Baseline Resources)** summarizes assumptions on baseline resources. Baseline resources are existing or in development resources that are assumed to be operational in the year being modeled.
- **Section 4 (Resource Cost Methodology)** describes the financial model used to calculate levelized fixed costs of candidate resources in RESOLVE.

- **Section 5 (Optimized Resources)** discusses assumptions used to characterize the potential new resources that can be selected for inclusion in the optimized, least-cost portfolio. Candidate resources are incremental to baseline resources.
- **Section 6 (Generators Operating Assumptions)** presents the assumptions used to characterize hourly electricity demand and the operations of each of the resources represented in RESOLVE's internal hourly production simulation model.
- **Section 7 (Resource Adequacy Requirements)** discusses the constraints imposed on the RESOLVE portfolio to ensure system and local reliability needs are met, as well as assumptions regarding the contribution of each resource towards these requirements.
- **Section 8 (Greenhouse Gas Emissions and Renewables Portfolio Standard)** discusses assumptions and accounting used to characterize constraints on portfolio greenhouse gas emissions and renewables portfolio standard targets.

1.4 Key Data and Model Updates

Since the publication of the "Inputs & Assumptions: 2022-2023 Integrated Resource Planning"[2] in October 2023, CPUC staff and its consultant Energy and Environmental Economics, Inc. (E3) implemented numerous updates to RESOLVE and SERVM model functionality, inputs, and assumptions.

Key updates to RESOLVE include:

- Updated RESOLVE zonal topology to split CAISO into three zones corresponding to the IOUs (PGE, SCE, SDGE) with transmission flow limits among them.
- Updated to align with the latest CEC Integrated Energy Policy (IEPR) California Energy Demand Forecast Update. (Section 2).
- Updated the Baseline Resource assumptions to the most recent data available on existing and in-development resources including new additions within and outside of CAISO (Section 3).
- Updated forecasted load growth and planned future builds for non-CAISO zones to reflect latest data and updates from utility IRPs and other relevant data sources (Section 3).

[2] Found at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/inputs-assumptions-2022-2023_final_document_10052023.pdf

- Updated the methodology and inputs for creating resource costs for all new candidate resources (Section 4).
- Updated the mapping of candidate resources regions in RESOLVE to align with CAISO study areas (Section 5).
- Enhanced Geothermal (EGS) and Long Duration Storage (LDES) are proposed new default candidate resources, with new EGS resource potential analysis and generic LDES archetypes for 12-, 24-, and 100-hr durations (Section 5).
    - Other emerging technology assumptions have not been updated for filing requirements modeling, but may be updated ahead of the next Preferred System Plan (PSP).
- Updated the environmental screens, resource potential and geographic area of all renewable resources (Section 5).
- Updated candidate resource-transmission deliverability constraints, and added representation of interconnection limits imposed on clusters of candidate resources (Section 5).
- Updated solar, wind, and hydro generation profiles (Section 6).
- Updated RESOLVE sample days (Section 6).
- Added Path 26/Path 15 transmission upgrades as available candidate options to be optimally selected by RESOLVE to increase the transmission flow limit between PGE and SCE (Section 6).
- Updated reliability metrics (Planning Reserve Margin (PRM) and resource Effective Load Carrying Capacity (ELCC)), including a new 3D solar + storage ELCC surface with separate dimensions for 4-hour and 8-hour storage (Section 7).

Key updates to SERVM (since the Commission-adopted IRP 2023 PSP) include:

- Extensive updates to the Baseline CAISO generating fleet in SERVM, aligning with the January 2024 CAISO Master Generating Capability List and expected development resources included in LSE IRP filings and LSE Mid-Term Reliability (MTR) and Supplemental MTR Procurement Orders Filings as of December 1, 2023.
- For the Baseline non-CAISO generating fleet, Staff reviewed the WECC 2032 Anchor Data Set as of December 2023 for updated information on generators projected to come online or retire, including removing previously included projects that are now failed or no longer projected to be online. Staff also gathered available data from non-CAISO LSE IRPs to refine the list of non-CAISO generating units.
- Updated the electric demand peak and energy forecast for California regions, including BTM resource projections, based on the CEC's 2023 IEPR California Energy Demand

Forecast. When complete data from the 2024 IEPR becomes available (in February 2025), staff intends to update the model to match it.

- For non-California regions, staff updated the electric demand peak and energy forecast from non-California LSE IRPs, supplemented with projections developed from FERC Form 714 data. BTM solar projections were extrapolated from EIA Form 861M monthly historical installed capacity data.
- Staff also developed new resource build assumptions for non-CAISO regions incremental to the Baseline assumptions as needed to ensure all modeled regions maintain a reasonable load and resource balance.
- Updated the range of modeled weather and hydroelectric availability to be 2000-2022 instead of the prior 1998-2020. Weather drives modeled hourly solar and wind production, and hourly electric demand. Historical year-based hydroelectric availability is still modeled as decoupled from historical weather year-based electric demand and solar and wind production.
- Staff incorporated for the first time in SERVM the capability to derate output level of thermal generating units based on weather. Only CAISO units are modeled with thermal derating based on weather and location.
- Wind profiles were redeveloped. Onshore wind speed data was sourced from the Copernicus ERA5 dataset and the wind production model was calibrated to be consistent with historical production at a regional level. Offshore wind speed data was sourced from the NREL 2023 National Offshore Wind dataset and the wind production model was updated with NREL turbine response curves.
- Updated generating and storage unit forced outage rates and maintenance rates. Generating unit outage data was derived from NERC Generating Availability Data System (GADS) database. Storage outage data was derived from CAISO's Prior Trade Day Curtailment Reports.
- Updated fuel hub prices and where provided, unit-specific transport costs, to align with the March 2023 version of CEC's 2023 IEPR Preliminary Electric Generation Price Model.

2. Load Forecast

2.1 CAISO Balancing Authority Area

The primary source for CAISO load forecast inputs, for both peak and energy demand, is the CEC's Integrated Energy Policy Report (IEPR) Demand Forecast Update.[3] As of the time of writing, the CEC's 2023 IEPR load forecast scenarios are used in modeling. This will be updated to 2024 IEPR for the filing requirements modeling. Specifically, the IEPR Planning Scenario[4] will be used in core modeling and the IEPR Local Reliability Scenario will also be implemented for potential sensitivity analysis. Although the formally adopted IEPR forecast extends only through 2040, the CEC provided data that includes a longer-term forecast through 2050 and was used to cover the entire modeling timeframe. Therefore, there will be no need for the use of other studies (such as previously used CEC's 2018 Deep Decarbonization in a High Renewable Future report or the 2021 High Electrification Interagency Working Group (IAWG) scenario) for long-term load this cycle. Table 1 presents an overview of different 2023 IEPR scenarios, where each row represents a distinct load component.

Table 1. IEPR scenario description.

Load Component	2023 IEPR Planning Scenario	2023 IEPR Local Reliability Scenario
Baseline Demand Case	Mid Case	Mid Case
Transportation Scenario	AATE Scenario 3	Scenario 3
AAEE Scenario	Scenario 3	Scenario 2
AAFS Scenario	Scenario 3	Scenario 4
CARB SIP NOx Rules (FSSAT)	Included in AAFS	Included in AAFS

[3] Most of the demand data were extracted from IEPR Forms 1.1c, 1.5a, 1.5b, and 1.2. Additional IEPR workbooks, including the breakdown of demand and demand modifier components for the CAISO area, hourly profiles, and installed capacity for BTM resources, were used to develop inputs for RESOLVE modeling.

[4] The 2023 Integrated Energy Policy Report is available at https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2023-integrated-energy-policy-report

Many components of the CEC IEPR demand forecast are broken out so that the distinct hourly profile of each of these factors can be represented explicitly in modeling. The components are referred to in this document as "demand-side modifiers." Hourly profiles for demand-side modifiers are discussed in Section 6.

Demand-side modifiers include the following categories and the data sources for each are discussed in subsequent sections:

- Electric vehicles
- Building & other electrification (Additional Achievable Fuel Substitution (AAFS))
- Behind-the-meter (BTM) PV
- Behind-the-meter (BTM) Storage
- Energy efficiency (Additional Achievable Energy Efficiency (AAEE))

Other load modifiers, such as time-of-use rate impacts, pumping loads, and Non-PV self-generation (predominantly behind-the-meter combined heat and power) are embedded in the baseline load.

Demand forecast inputs are frequently presented as demand at the customer meter. However, our planning models measure demand at the generator busbar. Consequently, demand forecasts at the customer meter are grossed up for transmission and distribution losses. Average losses across the CAISO zone calculated from the 2023 IEPR forecast are 7.97%.

2.1.1 Baseline Consumption

Baseline consumption captures economic and demographic changes in California. In RESOLVE and SERVM the baseline peak and total energy consumption forecast is derived from total load (retail sales + transmission and distribution losses) reported in the CEC's demand forecast data along with accompanying information on the magnitude of demand-side modifiers and behind-the-meter-generation forecast data. In both models, the energy consumption forecasts remove the effects of demand modifiers and demand-side generation that are explicitly modeled; in SERVM this is also reflected in the peak energy consumption. These components are additional achievable energy efficiency (AAEE)[5], additional achievable fuel substitution (AAFS), BTM PV, BTM storage, and light, medium, and heavy-duty electric vehicle charging. In RESOLVE additional components that are reported for emissions and RPS accounting purposes include BTM CHP and Other Self-generation. The various components of the baseline consumption forecast are shown in Table 2.

[5] AAEE refers to efficiency savings beyond current committed programs.

Table 2. Baseline Consumption from the 2023 IEPR Planning Scenario Demand Forecast (GWh)

Component	2025	2030	2035	2040	2045
2023 IEPR Total CAISO Load	214,668	236,405	275,360	314,057	336,874
- Light-Duty EVs[6]	242	20,808	40,913	58,798	72,.636
- Medium/Heavy Duty EVs[7]	845	3,904	9,770	15,100	17,312
- AAFS	391	9,195	23,080	35,725	42,762
+ AAEE	3,110	8,186	10,631	10,664	10,695
+ Behind-the-Meter PV	31,120	47,164	57,758	60,786	64,309
- BTM Storage Losses	71	254	362	390	423
= Baseline Consumption	247,349	257,594	269,624	275,494	278,745

2.1.2 Transportation Electrification

Both 2023 IEPR Scenarios include baseline transportation electrification and use Scenario 3 for additional achievable transportation.

Table 3. Light-duty electric vehicle forecast (GWh)

Scenario Setting	2025	2030	2035	2040	2045
CEC 2023 IEPR Planning Scenario and Local Reliability	5,242	20,808	40,913	58,798	72,636

[6] See Figure 27 of the *Final 2023 Integrated Energy Policy Report Update* for associated vehicle adoption forecast https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2023-integrated-energy-policy-report

[7] See Figure 28 of the *Final 2023 Integrated Energy Policy Report Update* for associated vehicle adoption forecast https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2023-integrated-energy-policy-report

Table 4. Medium and heavy-duty electric vehicle forecast (GWh)

Scenario Setting	2025	2030	2035	2040	2045
CEC 2023 IEPR Planning Scenario and Local Reliability	845	3,904	9,770	15,100	17,312

2.1.3 Building Electrification

The building sector's electrification load is modeled with Additional Achievable Fuel Substitution (AAFS). CEC's 2023 IEPR Planning Scenario that uses Mid forecasts (Scenario 3) will be modeled in the core modeling; however, 2023 Local Reliability Scenario forecasts that include additional building electrification programs (Scenario 4) might be used for potential sensitivity analysis. In later modeling years, the AAFS load in the Local Reliability Scenario is actually lower, because while it has additional electrification above the Planning Scenario, the Local Reliability Scenario also assumes more efficient appliances are adopted.

Table 5. AAFS forecast options for the building sector (GWh)

Scenario Setting	2025	2030	2035	2040	2045
CEC 2023 IEPR Planning Scenario	391	9,195	23,080	36,725	42,742
CEC 2023 IEPR Local Reliability Scenario	841	10,573	21,370	31,909	35,215

2.1.4 Behind-the-Meter PV

Generation data for BTM PV are calculated from IEPR hourly data.[8] In SERVM, the geographically granular breakdown of BTM PV generation and capacity by CEC Forecast Zones is used.[9] In RESOLVE, the energy generation and capacities are aggregated to PGE, SCE, and SDGE. These forecasts exclude the impacts of net-energy-metering regulation changes.

[8] Link to 2023 IEPR data: https://www.energy.ca.gov/data-reports/reports/2023-integrated-energy-policy-report/2023-iepr-workshops-notices-and-2

[9] BTM PV capacity is available at https://www.energy.ca.gov/data-reports/reports/2023-integrated-energy-policy-report/2023-iepr-workshops-notices-and-2

Table 6. Behind-the-meter PV forecast options (GWh)

Scenario Setting	2025	2030	2035	2040	2045
CEC 2023 IEPR Planning Scenario and Local Reliability Scenario	32,120	47,164	57,758	60,786	64,309

2.1.5 Behind-the-meter CHP and Other Non-PV Self Generation

The forecast of non-PV self-generation is based on the CEC 2023 IEPR Demand Forecast. On-site combined heat and power (CHP) that does not export to the grid makes up the majority of this component. Because emissions from BTM CHP are counted towards total electric sector emissions, the portion of BTM CHP is separated from the total non-PV self-generation. CHP units that export energy to the grid are separately discussed in Section 3. Forecasts for BTM CHP and the remaining non-PV non-CHP self-generation are shown in the tables below. Two BTM CHP forecasts are considered: one that assumes BTM CHP remains online through 2045 (similar to the 2021 ATE scenario) and the other that assumes BTM CHP retires by 2040 (similar to the 2021 IEPR Mid) for 2023 IEPR forecasts. It is also assumed that BTM CHP retires linearly between 2035 and 2040. Forecast of non-PV, non-CHP self-generation is the same across IEPR Scenarios.

Table 7. Forecast of Behind-the-meter CHP (GWh)

Scenario Setting	2025	2030	2035	2040	2045
BTM CHP Not Retired	10,667	10,667	10,667	10,667	10,667
BTM CHP Retired by 2040	10,667	10,667	10,667	0	0

Table 8. Forecast of other non-PV on-site self-generation (GWh)

Scenario Setting	2025	2030	2035	2040	2045
CEC 2023 IEPR	449	449	449	449	449

2.1.6 Energy Efficiency

Varying levels of energy efficiency among CAISO load-serving entities is modeled with Additional Achievable Energy Efficiency (AAEE). CEC's 2023 IEPR Planning Scenario that uses Mid forecasts (Scenario 3) will be used in the core modeling.

Table 9. Energy efficiency forecast options (GWh)

Scenario Setting	2025	2030	2035	2040	2045
CEC 2023 IEPR Planning Scenario	3,110	8,186	10,631	10,664	10,965
CEC 2023 IEPR Local Reliability Scenario	2,492	5,642	7,454	7,709	8,783

2.2 CAISO Balancing Authority Area – Peak Demand

2.2.1 Introduction

The magnitude and timing of managed peak demand of the system can significantly impact resource portfolio selection by increasing the value of resources that can produce energy during managed peak periods. The managed peak demand is determined by total energy demand, demand-side modifiers, BTM generation, and underlying demand profiles though it is not itself specifically input into the model.

2.2.2 Gross System Peak

In RESOLVE, gross system peak is calculated directly from CEC IEPR hourly demand data for CAISO as the annual peak of hourly "managed net load" (inclusive of "VEA load") minus hourly "BTM PV" generation demand reduction.[10] RESOLVE instead models BTM PV as a supply-side resource in both hourly dispatch and resource adequacy. RESOLVE assigns an ELCC value to BTM PV to determine its contribution to the numerator of RESOLVE's PRM constraint. Additionally, in RESOLVE modeling, two alternatives are considered for BTM and front-of-meter CHP units; one that assumes CHPs remain online (as assumed for BTM CHPs in the IEPR load forecasts) and the other that assumes CHPs retire by 2040. Thus, for the latter case, gross peak is adjusted for BTM

[10] BTM storage is treated as load modifier because its dispatch profiles from IEPR show negligible impact on system peak.

CHP peak impacts for the 2036-2050 timeline. This adjustment is made by assuming a flat profile for BTM CHP generation.

Gross system peak as defined in RESOLVE is applied to the PRM percentage resulting in the total system perfect capacity need determination. In SERVM, gross system peak is also derived directly from CEC IEPR hourly demand data but is input to SERVM at the IOU planning area level rather than the CAISO as a whole. It is defined as the annual peak of IOU planning area hourly "managed net load" minus hourly demand increases or decreases from BTM PV, AAEE, AAFS, BTM storage, and EV charging. These demand modifiers are separately input to SERVM. As a final step, the SERVM gross system peak inputs of each IOU planning area are calibrated such that the managed net peak of the CAISO as a whole matches that of the CEC's IEPR.

Table 10. CAISO gross system peak forecast in RESOLVE

Scenario Setting	2025	2030	2035	2040	2045
CEC 2023 IEPR Planning Scenario	56,164	60,514	67,563	73,210	77,408
CEC 2023 IEPR Planning Scenario: BTM CHP Retire by 2040	56,164	60,514	67,563	74,533	78,731
CEC 2023 Local Reliability Scenario	56,389	61,347	68,402	73,841	77,411
CEC 2023 Local Reliability Scenario: BTM CHP Retire by 2040	56,389	61,347	68,402	75,164	78,734

2.2.3 Managed Net Peak

The annual CAISO managed net peak forecasts were calculated using the CEC 2023 scenarios hourly load data and are shown in Table 11 for selected years. In RESOLVE, the maximum hourly load in each year (through 2050) was found and reported as managed net peak (inclusive of VEA hourly load.) It is notable that managed net peak is not used for the reliability need determination.

In SERVM, electric demand peak and energy and demand modifiers are explicitly modeled for each of the three IOU planning areas within CAISO (PGE, SCE, and SDGE). SERVM inputs by planning area are calibrated such that the managed peak of the CAISO as a whole matches with the CEC's IEPR forecasted managed peak for CAISO.

Table 11. CAISO managed net peak forecast in RESOLVE

Scenario Setting	2025	2030	2035	2040	2045
CEC 2023 IEPR Planning Scenario	46,284	48,895	54,973	60,001	67,513
CEC 2023 IEPR Planning Scenario: BTM CHP Retire by 2040	46,284	48,895	54,973	61,324	68,836
CEC 2023 IEPR Local Reliability Scenario	46,524	49,729	55,718	60,285	63,749
CEC 2023 Local Reliability Scenario: BTM CHP Retire by 2040	46,524	49,729	55,718	61608	65,072

2.3 Other Zones

RESOLVE and SERVM both use a zonal transmission topology to simulate flows among the various regions in the Western Interconnection. RESOLVE includes five zones outside of CAISO: three capturing California balancing authorities (Northern California Non-CAISO (NCNC), Los Angeles Department of Water and Power (LADWP), and Imperial Irrigation District (IID)), two zones that represent regional aggregations of out-of-state balancing authorities (Northwest (NW) and Southwest (SW)). The constituent balancing authorities included in each RESOLVE zone are shown in Table 83 (Section 6.1)

Demand forecasts for zones outside CAISO are taken from two sources and are presented in Table 12:

- For each of the zones within California (IID, LADWP, and NCNC) but external to CAISO, total energy to serve load forecasts are taken from the CEC's 2023 IEPR Planning Forecast Form 1.5a.
- For the zones outside of California (the Pacific Northwest and the Southwest), available data in non-CA IRPs, supplemented with FERC Form 714 data[11] is used as the basis for load projections. Sales forecasts net of demand-side modifiers are combined with available information related to demand-side modifier and consumption forecasts to reconstitute the consumption forecasts for each region. This data is then aggregated to the RESOLVE zones.

[11] Data available on WECC website: https://www.wecc.org/ReliabilityModeling/Pages/AnchorDataSet.aspx

Table 12. Non-CAISO Net Energy for Load – grossed up for T&D losses (GWh)

RESOLVE Zone	2025	2030	2035	2040	2045
NW	148,213	161,316	174,692	190,362	207,756
SW	123,954	147,768	165,561	184,485	205,291
IID	4,307	4,551	4,783	4,938	5,087
LDWP	28,519	31,438	35,118	39,291	42,011
NCNC	20,405	22,034	23,963	25,396	26,709

SERVM's representation of non-CAISO regions is similar but more geographically granular. Consistent with RESOLVE, SERVM's non-CAISO California load forecasts are drawn directly from the CEC's IEPR. Forms 1.2 and 1.5 and demand modifier hourly and/or annual data by IEPR Planning Area or Forecast Zone were used to develop SERVM's inputs. SERVM also employs a more granular zonal transmission topology than RESOLVE, modeling 6 regions within California plus the 7 nearest external regions. The loads for regions external to California were updated to draw from available data in non-CA IRPs, supplemented with FERC Form 714 data, like RESOLVE.

Table 13. Non-CAISO Zonal transmission topology and load regions represented in RESOLVE and SERVM

RESOLVE Zone	SERVM Regions
NW	BPAT, PACW, PortlandGE
SW	AZPS, NEVP, SRP, WALC
IID	IID
LDWP	LADWP
NCNC	BANC, TID

3. Baseline Resources

Baseline resources are resources that are currently online or are contracted and/or under construction and expected to come online within the planning horizon. Being "contracted" refers to a resource holding signed contract(s) with an LSE(s). The contracts refer to those approved by the CPUC and/or the LSE's governing board, as applicable. These criteria indicate the resource is relatively certain to come online.

The capacity of **baseline** resources is an input to capacity expansion modeling, as opposed to **candidate** resources, which are selected by the model and are incremental to the baseline. For some resources, baseline resource capacity is reduced over time to reflect announced retirements. An estimation of baseline resource capital costs is used when calculating total revenue requirements and electricity rates.

Baseline resources include:

- Existing resources: Resources that have already been built and are currently available, net of expected future retirements.
- Resources in-development: Resources that have contracts approved by the CPUC or the board of a community choice aggregator (CCA) or energy service provider (ESP).

  Future Resources in non-CAISO balancing areas: IRP modeling does not optimize resource additions for balancing areas outside CAISO, but changes in the generation portfolio of balancing areas outside of CAISO may influence portfolio selection within the CAISO area. Consequently, future resource builds derived from non-CAISO IRP reports are added to other balancing areas to contribute to policy and reliability targets outside of CAISO. Future resources are added going out to 2045, the last year in the CPUC IRP modeling horizon, and as such, most of the future resources are generic plans rather than near-term, contracted additions.

Baseline resources are assembled from the primary sources listed in Table 14 and are further described below.

Table 14. Data Sources for Baseline Resources

Zone	Online Status	Dataset used
In CAISO	Existing	CAISO Master Generating Capability List, CAISO Master File
In CAISO	In-development	December 2023 LSE IRP compliance filings
Out of CAISO	Existing and In-development	WECC 2032 Anchor Data Set (ADS)

Out of CAISO	Planned Future Resources (beyond baseline)	Survey of Balancing Area IRPs, extrapolated to 2045 where necessary
In CAISO and Out of CAISO	Retirement Dates	Updated CAISO Mothball/Retirement list, December 2023 LSE IRP filings, WECC 2032 Anchor Data Set (ADS)

- The list of generators currently operational to serve CAISO is compiled from the CAISO Master Generating Capability List as of January 2024.[12] These generators serve load inside CAISO and are composed of renewable and non-renewable generation resources, as well as some demand response resources. The CAISO Master Generating Capability List information is supplemented by the CAISO Master File, a confidential data set with unit-specific operational attributes. Both lists also include information related to dynamically scheduled generators, which are physically located outside of the CAISO but can participate in the CAISO market as if they were internal to CAISO. However, because they have no obligation to sell into CAISO they are modeled as unspecified imports and do not have special priority given to their energy dispatch.
- In-development generators that will serve CAISO load are compiled from the December 1st, 2023 IRP compliance Filings, which list contracts entered into by LSEs and approved by the LSEs' highest decision-making authority as of December 1, 2023. To the extent that any of these resources came online between December 1, 2023 and the publishing of the April 2024 CAISO Master Generator Capability List, the CAISO information is used instead.
- For generators outside of CAISO, including areas within California (IID, LADWP, and NCNC), generator listings and their associated operating information are taken from the WECC's 2032 Anchor Data Set (ADS) v2 as of April 2024.
- Planned future generators for non-CAISO zones, beyond near-term additions in the WECC ADS, are added to the baseline based on the most recent IRP plans from non-CAISO balancing areas, and extrapolated to the final model year of 2045, if necessary.

3.1 Natural Gas, Coal, and Nuclear Generation

3.1.1 Modeling Methodology

Natural gas, coal, and nuclear resources are represented in RESOLVE by a limited set of resource classes by zone, with operational attributes set at the capacity weighted average for each resource class in that zone. The capacity weighted averages are calculated from individual unit

[12] Available at: http://oasis.caiso.com/mrioasis/logon.do

attributes available in the CAISO Master File or the WECC ADS. The following resource classes are modeled: Nuclear, Coal, Combined Cycle Gas Turbine (CCGT), Gas Steam, Gas Peaker, Gas Reciprocating Engine, and Combined Heat and Power (CHP).

Gas generators are further divided into subcategories to reflect different classes of generators. These subcategories are based on natural breakpoints in operating efficiency observed in the distribution of data within class averages:

- The CCGT generator category is divided into two subcategories based on generator efficiency: higher efficiency units are represented as **"CCGT1"** and lower efficiency units are represented as **"CCGT2"**. The division into subcategories does not consider the age of each unit, as there is no real correlation between age and efficiency. Additionally, three generators that are located outside of CAISO, but contracted to import energy to CAISO, are not included in these tranches and instead represented as **"CCGT_Remote"**.
- The Peaker generator category is the aggregation of natural gas frame and aeroderivative technologies and is divided into two subcategories: higher efficiency units are represented as "**Peaker1"** and lower efficiency units are represented as **"Peaker2"**. There is not a strong correlation between the efficiency and age of Peaker units.
- The **"ST"** generator category represents the existing fleet of steam turbines. In CAISO, all remaining steam turbine units were moved into the strategic reserve in 2023 and are not modeled in RESOLVE.
- The **"Reciprocating_Engine"** generator category represents existing gas-fired reciprocating engines.
- The **"CHP"** generator category represents non-dispatchable cogeneration facilities with thermal hosts, which are modeled to provide around-the-clock power production in RESOLVE.

The capacity of fossil-fueled and nuclear thermal generators that have formally announced retirement are removed from the baseline according to the announced retirement schedule.

3.1.2 Economic Retention

RESOLVE determines the optimal level of dispatchable gas resources to retain resources that minimizes overall CAISO system costs but still attains other resource planning objectives such as reliability and GHG reductions.

Fixed operations and maintenance (fixed O&M) costs of baseline gas-fired resources are considered in RESOLVE's optimization logic such that dispatchable gas generators will only be retained by the model, subject to reliability constraints, if it is cost-effective to do so. It is believed that fixed O&M costs for gas generators in the current NREL ATB, which are representative of current and recent commercial offerings,[13] are lower than industry data for existing, older gas generators. For this reason, CEC's *Estimated Cost of New Utility-Scale Generation in California: 2018 Update*,[14] which carries higher estimates for gas fixed O&M costs than NREL ATB, was chosen to represent the fixed O&M costs of existing gas generators in RESOLVE starting in the 2022-2023 IRP cycle (Table 15). This CEC report was used in CPUC's 2021 study *Considering Gas Capacity Upgrades to Address Reliability Risk in Integrated Resource Planning* and aligns with ongoing fixed O&M costs for the existing gas fleet based on other E3 analyses.[15] NREL ATB is used for fixed O&M costs for new (candidate) gas resources, as described in Section 5.2. The following considerations are made in economic gas fleet retention modeling:

- Retention decisions are made for CCGTs, Peakers, and Reciprocating Engines.
- Gas resources located in local areas are assumed to serve local capacity requirements; up to 4 GW of these resource may be replaced with 4-hour Li-ion batteries, but the remaining 14.5 GW must be retained to maintain local reliability (Section 7.2).
- While combined heat and power (CHP) facilities are not subject to economic retention decisions due to the presence of a thermal host, they are assumed to be phased out linearly between 2031 and 2040.

[13] See NREL 2022 ATB webpage on fossil energy technologies: https://atb.nrel.gov/electricity/2022/fossil_energy_technologies.

[14] Considering Gas Capacity Upgrades to Address Reliability Risk in Integrated Resource Planning. CPUC Staff Paper. October 2021. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integratedhttps://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/cpuc-gas-upgrades-staff-paper-october-2021.pdfresource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2021-irp-events-and-materials/cpuc-gas-upgradeshttps://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/cpuc-gas-upgrades-staff-paper-october-2021.pdfstaff-paper-october-2021.pdf.

[15] Found here: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integratedhttps://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/cpuc-gas-upgrades-staff-paper-october-2021.pdfresource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2021-irp-events-and-materials/cpuc-gas-upgradeshttps://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/cpuc-gas-upgrades-staff-paper-october-2021.pdfstaff-paper-october-2021.pdf

Table 15. Fixed O&M costs for baseline gas resources (2022 $)

Resource Type	Fixed O&M Cost ($/kW-yr)
Peaker1 Peaker2 Reciprocating_Engine	$38.74
CCGT1 CCGT2 CCGT_Remote	$48.68

Note that RESOLVE's thermal economic retention functionality assesses whether it is economic to retain gas capacity for CAISO ratepayers but does not assess whether gas capacity should retire. Other offtakers may contract with gas plants balanced by CAISO, even if CAISO ratepayers do not. In addition, gas plant operators may choose to keep plants online without a long-term contract.

3.1.3 CAISO Natural Gas, Coal, and Nuclear Resources

Data for baseline natural gas, coal, and nuclear resources serving CAISO load are drawn from a combination of the CAISO Master Generating Capability List and the CAISO Master File.

Table 16. Total Baseline Conventional Resources in the CAISO balancing area (MW)

Resource Class	2025	2030	2035	2040	2045
CHP*	2,365	2,365	1,183	-	-
Nuclear**	635	635	635	635	635
CCGT1	14,687	14,687	14,687	14,687	14,687
CCGT2	2,550	2,550	2,550	2,550	2,550
CCGT_Remote	933	933	933	933	933
Coal	-	-	-	-	-
Peaker1	2,445	2,445	2,445	2,445	2,445
Peaker2	5,527	5,527	5,527	5,527	5,527
Reciprocating Engine	255	255	255	255	255
ST	-	-	-	-	-
Total	**29,398**	**29,398**	**28,216**	**27,033**	**27,033**

**The remaining CHP units by 2030 are assumed to decommission at a linear rate, with no generators remaining by 2040.*

***Diablo Canyon units are assumed to retire in 2024 and 2025. The share of Palo Verde Nuclear Generating Station capacity contracted to CAISO LSEs is included in all years and is modeled within CAISO in RESOLVE. After retirement of Diablo Canyon in 2025, all remaining CAISO nuclear capacity is from Palo Verde.*

Table 17. Baseline Conventional Resources in CAISO by zone (MW)

Zone	Resource Class	2025	2030	2035	2040	2045
PGE	CHP	1,328	1,328	664	-	-
	Nuclear	-	-	-	-	-
	CCGT1	7,115	7,115	7,115	7,115	7,115
	CCGT2	1,800	1,800	1,800	1,800	1,800
	CCGT_Remote	308	308	308	308	308
	Coal	-	-	-	-	-
	Peaker1	361	361	361	361	361
	Peaker2	2,869	2,869	2,869	2,869	2,869
	Reciprocating Engine	255	255	255	255	255
	ST	-	-	-	-	-
	Subtotal, PGE	**14,036**	**14,036**	**13,373**	**12,709**	**12,709**
SCE	CHP	950	950	475	-	-
	Nuclear	635	635	635	635	635
	CCGT1	5,433	5,433	5,433	5,433	5,433
	CCGT2	750	750	750	750	750
	CCGT_Remote	625	625	625	625	625
	Coal	-	-	-	-	-
	Peaker1	1,602	1,602	1,602	1,602	1,602
	Peaker2	1,712	1,712	1,712	1,712	1,712
	Reciprocating Engine	-	-	-	-	-
	ST	-	-	-	-	-
	Subtotal, SCE	**11,708**	**11,708**	**11,708**	**11,708**	**11,708**
SDGE	CHP	87	87	44	-	-
	Nuclear	-	-	-	-	-
	CCGT1	2,139	2,139	2,139	2,139	2,139
	CCGT2	-	-	-	-	-

	CCGT_Remote	-	-	-	-	-
	Coal	-	-	-	-	-
	Peaker1	481	481	481	481	481
	Peaker2	947	947	947	947	947
	Reciprocating Engine	-	-	-	-	-
	ST	-	-	-	-	-
	Subtotal, SDGE	**3,654**	**3,654**	**3,611**	**3,567**	**3,567**

3.1.4 Other Zones Natural Gas, Coal, and Nuclear Resources

For zones external to the CAISO, the baseline gas, coal, and nuclear generation fleet is based on the WECC 2032 ADS. The ADS is used to characterize the existing and in-development generation fleet in each non-CAISO zone. The ADS uses utility integrated resource plans to inform changes in the generation portfolio, including announced retirements of coal generators and near-term planned additions.

Table 18. Baseline conventional resources in external zones (MW)

Zone	Resource Class	2025	2030	2035	2040	2045
IID	CCGT	442	442	442	442	442
	Peaker	338	338	338	338	338
	ST	87	87	87	87	87
	Subtotal, IID	**867**	**867**	**867**	**867**	**867**
LDWP	Nuclear	326	326	326	326	326
	Coal	-	-	-	-	-
	CCGT	3,083	4,072	4,072	4,072	4,072
	Peaker	1,192	1,192	1,192	1,192	1,192
	ST	134	134	134	134	134
	Subtotal, LDWP	**4,734**	**5,723**	**5,723**	**5,723**	**5,723**
NCNC	CCGT	1,526	1,526	1,526	1,526	1,526
	Peaker	881	881	881	881	881
	Reciprocating Engine	49	49	49	49	49
	Subtotal, NCNC	**2,456**	**2,456**	**2,456**	**2,456**	**2,456**

NW	Nuclear	1,185	1,185	1,185	1,185	1,185
	Coal	-	-	-	-	-
	CCGT	6,648	6,648	6,648	6,162	5,647
	Peaker	947	947	947	947	947
	Reciprocating Engine	269	269	269	269	269
	Subtotal, NW	**9,049**	**9,049**	**9,049**	**8,563**	**8,048**
SW	Nuclear	3,042	3,042	3,042	3,042	3,042
	Coal	2,792	2,792	1,156	1,156	1,156
	CCGT	14,442	14,387	13,798	12,667	12,112
	Peaker	3,983	4,559	4,336	4,336	4,114
	Reciprocating Engine	116	116	116	116	116
	ST	829	595	595	595	595
	Subtotal, SW	**25,203**	**25,490**	**23,043**	**21,913**	**21,136**

3.2 Renewables

Baseline renewable resources include all existing RPS eligible resources (solar, wind, biomass, biogas, geothermal, and small hydro) in each zone. Renewable resources with contracts already approved by the CPUC, CCA boards, or ESP boards (which includes those under development), are accounted for in the baseline as well. All wind in the baseline is onshore.

Baseline behind-the-meter solar capacity is discussed in Section 2.1 above.

3.2.1 CAISO Renewable Resources

CAISO baseline renewable resources include (1) existing resources, whether under contract or not, and (2) in-development resources that have executed contracts with utilities. As described above, information on existing renewable resources within CAISO is compiled from the CAISO Master Generating Capability List and the CAISO Master File.

Information on resources that are under development with approved contracts is compiled from the December 1, 2023 LSE IRP compliance filings. The CPUC maintains a database of the LSE's active and past contracting activities for renewable generation. Utilities submit monthly updates to this database with changes in contracting activities. The baseline renewable resource capacity in CAISO is shown in Table 19.

Table 19. Total Baseline Renewables in CAISO (MW)

Resource Class	2025	2030	2035	2040	2045
Small Hydro*	1,105	1,105	1,105	1,105	1,105
Biomass	542	542	542	542	542
Biogas	284	284	284	284	284
Geothermal	1,774	2,112	2,112	2,112	2,112
Solar	23,160	23,439	23,439	23,439	23,439
Wind	8,034	9,619	9,619	9,619	9,619
Total	**34,899**	**37,101**	**37,101**	**37,101**	**37,101**

**Additional detail on small hydro in Section 3.3. Capacity (MW) values are nameplate. RESOLVE and SERVM use historical monthly weather profiles from 1998 – 2020 to determine energy production from hydro resources.*

Note: Remote renewable units not reported separately in this table.

Table 20. Baseline Renewables in CAISO by zone (MW)

Zone	Resource Class	2025	2030	2035	2040	2045
PGE	Small Hydro	817	817	817	817	817
	Biomass	502	502	502	502	502
	Biogas	108	108	108	108	108
	Geothermal	1,084	1,102	1,102	1,102	1,102
	Solar	6,859	7,048	7,048	7,048	7,048
	Wind	1,727	1,727	1,727	1,727	1,727
	Subtotal, PGE	**17,377**	**17,584**	**17,584**	**17,584**	**17,584**
SCE	Small Hydro	288	288	288	288	288
	Biomass	40	40	40	40	40
	Biogas	167	167	167	167	167
	Geothermal	690	1,010	1,010	1,010	1,010
	Solar	12,929	12,929	12,929	12,929	12,929
	Wind	5,606	7,191	7,191	7,191	7,191
	Subtotal, SCE	**21,480**	**23,385**	**23,385**	**23,385**	**23,385**
SDGE	Small Hydro	-	-	-	-	-
	Biomass	-	-	-	-	

		2025	2030	2035	2040	2045
	Biogas	8	8	8	8	8
	Geothermal	-	-	-	-	-
	Solar	3,372	3,462	3,462	3,462	3,462
	Wind	702	702	702	702	702
	Subtotal, SDGE	**4,082**	**4,172**	**4,172**	**4,172**	**4,172**

A subset of the resources shown in Table 19 have an Energy-Only Deliverability status, as opposed to Full Capacity Deliverability Status (FCDS). The capacity of the energy-only resources is shown in Table 21.

Table 21. Baseline Energy-only Renewables in CAISO (MW)

Resource Class	2025	2030	2035	2040	2045
Biomass	1	1	1	1	1
Solar	1,596	1,596	1,596	1,596	1,596
Wind	6	6	6	6	6
Total	**1,603**	**1,603**	**1,603**	**1,603**	**1,603**

3.2.2 Other Zones Renewable Resources

3.2.2.1 Other California Entities

For non-CAISO entities in California (those in the balancing authority areas IID, LADWP or BANC), the renewable resource portfolio is derived from the 2032 WECC ADS. RPS-compliant resource portfolios are developed outside of RESOLVE and input to the model – RESOLVE does not optimize renewable resource capacity for non-CAISO BAAs. Baseline renewable capacities for other California entities are shown in Table 22.

Table 22. Baseline Renewables in Other California Entities (MW)

Zone	Resource Class	2025	2030	2035	2040	2045
IID	Biomass	50	50	50	50	50
	Biogas	15	15	15	15	15
	Geothermal	532	576	576	576	576
	Solar	289	289	289	289	289

	Wind	-	-	-	-	-
	IID Total	**886**	**930**	**930**	**930**	**930**
LDWP	Biomass	-	-	-	-	-
	Biogas	4	4	4	4	4
	Geothermal	175	175	175	175	175
	Solar	2,279	2,336	2,336	2,336	2,336
	Wind	420	420	420	420	420
	LDWP Total	**2,878**	**2,935**	**2,935**	**2,935**	**2,935**
NCNC	Biomass	1	1	1	1	1
	Biogas	18	18	18	18	18
	Geothermal	59	59	59	59	59
	Solar	467	467	467	467	467
	Wind	430	430	430	430	430
	NCNC Total	**974**	**974**	**974**	**974**	**974**

3.2.2.2 Non-California LSEs

The portfolios of renewable resources in the NW and SW are based on WECC's 2032 Anchor Data Set, developed by WECC staff with input from stakeholders. Baseline renewable capacities for non-California LSEs are shown in Table 23.

Table 23. Baseline Renewables in non-California LSEs (MW)

Zone	Resource Class	2025	2030	2035	2040	2045
NW	Biomass	686	611	611	611	611
	Biogas	39	39	38	38	38
	Geothermal	4	4	4	4	4
	Solar	1,680	1,860	1,855	1,730	1,565
	Wind	7,673	7,605	7,605	7,555	7,555
	NW Total	**10,082**	**10,119**	**10,112**	**9,937**	**9,773**
SW	Biomass	25	25	25	25	25
	Biogas	39	39	27	27	27
	Geothermal	1,017	1,061	1,061	1,061	1,061
	Solar	8,649	9,199	9,173	8,938	7,687
	Wind	773	908	908	908	908

	SW Total	**10,503**	**11,232**	**11,194**	**10,960**	**9,709**

Resources that have a contract to supply RECs to a CAISO LSE but are not dynamically scheduled into CAISO are modeled as supplying RECs to CAISO RPS requirements, but energy from these projects is added to the energy balance of the zone it is located in. Approximately 2,000 MW of REC contracts, accounting for 2,875 GWh, are modeled as providing RECs to CAISO and energy to other zones.

3.3 Hydro

The existing hydro resources in each zone of RESOLVE and SERVM are assumed to remain unchanged over the timeline of the analysis. The hydro resources in RESOLVE and SERVM are represented as providing energy to the zone they are physically located in, with the exception of Hoover, which is split among the CAISO, LADWP, and SW zones in proportion to ownership shares.

To reflect different attributes of hydro generators in the CAISO zone, CAISO's hydro generators are further divided into subcategories. These subcategories are based on a combination of the units' RPS eligibility and reliability value:

- **"Small"** units have a capacity of 30 MW or less and are RPS-eligible. **"Large"** units are not RPS eligible.
- **"Run-of-River" (ROR)** units are non-dispatchable and have a lower reliability value in RESOLVE. **"Scheduled" (or non-Run-of-River, "non-ROR")** units are dispatchable and have a higher reliability value.

For example, a non-dispatchable, RPS eligible unit would be **"Small_ROR"** Hydro. Hydro units in external zones are not disaggregated because RESOLVE does not model RPS or reliability targets in those zones.

A fraction of the total Pacific Northwest hydro capacity is made available to CAISO as a directly scheduled import. Specified hydro imports from the Pacific Northwest are included in RESOLVE as a reduction in annual electricity supply GHG emissions of 2.8 MMT. RESOLVE modeling will use the same methodology as it has since the 2019-2021 IRP cycle, where specified imports of hydro power from the Pacific Northwest are included as a baseline hydro resource and are dispatched on an hourly basis in RESOLVE (Section 6.2). The quantity of specified hydro imported into California is based on historical import data from BPA and Powerex as reported in CARB's GHG emissions inventory.[16] Annual specified imports (in GWh/yr) are converted to an

[16] CARB GHG Current California Emission Inventory Data available at: https://ww2.arb.ca.gov/ghg-invento-ry-data

installed capacity using the annual capacity factor of NW Hydro – this is for modeling purposes and is not meant to reflect contractual obligations for capacity.

Table 24. RESOLVE hydro installed capacity for CAISO (MW)

Type	PGE	SCE	SDGE	Total CAISO
Small, Run-of-River	206	213	-	**419**
Small, Scheduled	611	75	-	**686**
Large, Run-of-River	-	37	-	**37**
Large, Scheduled	6,279	1,724	-	**8,003**
NW Hydro for CAISO (Large, Scheduled)*	2,730	-	-	**1,861**

**Modeled and reported separately from in-CAISO large, scheduled hydro*

Table 25. RESOLVE hydro installed capacity in external zones (MW)

Region	Total
IID	84
LADWP	854
NCNC	2,768
NW*	30,118
SW	1,458

**Excludes NW Hydro for CAISO*

SERVM has also been updated to model run-of-river and scheduled hydro for CAISO distinctly, as well as mimic the RESOLVE method of separating out NW hydro for CAISO from the rest of NW hydro. The portion of NW hydro for CAISO in SERVM is treated as a remote generator subject to transmission constraints into California but does not incur hurdle rates or GHG emissions.

3.4 Energy Storage

3.4.1 Pumped Storage

Existing pumped storage resources in CAISO are based on the CAISO Master Generating Capability List and shown in Table 26.

Table 26. Existing pumped storage resources in CAISO

Unit	Capacity (MW)	Zone
Eastwood	200	SCE
Helms	1,218	PGE
O'Neil	25	PGE
Total	**1,443**	

The individual existing pumped storage resources shown in Table 26 are aggregated into one resource class.

3.4.2 *Battery Storage*

Baseline storage resources in the 2024-2026 IRP cycle include all battery storage that is currently installed in the CAISO footprint, as well as further battery storage in-development up till the December 2023 IRP compliance filings. The duration of baseline utility scale storage resources will also reflect data from the December 2023 LSE filings. Baseline behind-the-meter storage resources are modeled as a load modifier starting in the 2023 Preferred System Plan (PSP) and are described in Section 2.1.

Baseline battery storage in RESOLVE is disaggregated into two subcategories based on duration to account for the different reliability value of short and long duration storage. Any units with a duration of 6 hours or less are grouped into the "**4-hour**" subcategory, with any other units grouped into the "**8-hour**" subcategory. The actual duration modeled in RESOLVE is a weighted average of each individual unit within the subcategory.

Table 27. Total Baseline battery storage in CAISO (MW)

Battery Storage Resource	2025	2030	2035	2040	2045
4-hour Battery	13,237	14,517	14,517	14,517	14,517
8-hour Battery	293	293	293	293	293
Total	**13,530**	**14,810**	**14,810**	**14,810**	**14,810**

Table 28. Baseline Battery Storage in CAISO by zone (MW)

Zone	Resource Class	2025	2030	2035	2040	2045
PGE	4-hour Battery	3,044	3,204	3,204	3,204	3,204
	8-hour Battery	-	-	-	-	-
	Subtotal, PGE	**3,044**	**3,204**	**3,204**	**3,204**	**3,204**
SCE	4-hour Battery	8,573	9,693	9,693	9,693	9,693
	8-hour Battery	283	283	283	283	283
	Subtotal, SCE	**8,856**	**9,976**	**9,976**	**9,976**	**9,976**
SDGE	4-hour Battery	1,619	1,619	1,619	1,619	1,619
	8-hour Battery	10	10	10	10	10
	Subtotal, SDGE	**1,629**	**1,629**	**1,629**	**1,629**	**1,629**

3.4.3 Other Baseline Storage

A 200 MW, 1600 MWh Adiabatic Compressed Air Storage (A-CAES) unit from the December 2023 IRP Compliance filings is modeled in the baseline in the SCE zone, as a separate technology class in RESOLVE.

3.4.4 Other Zones Storage

For zones external to the CAISO, the baseline storage fleet is based on the WECC 2032 ADS.

Table 29. Baseline conventional resources in external zones (MW)

Zone	Resource Class	2025	2030	2035	2040	2045
IID	4-hour Battery	131	131	131	131	131
	Subtotal, IID	**131**	**131**	**131**	**131**	**131**
LDWP	4-hour Battery	695	695	695	695	695
	Pumped Hydro Storage	1,077	1,077	1,077	1,077	1,077
	Subtotal, LDWP	**1,772**	**1,772**	**1,772**	**1,772**	**1,772**
NCNC	No baseline storage is located in the NCNC zone					
NW	4-hour Battery	64	662	662	662	662
	Pumped Hydro Storage	273	273	273	273	273

	Subtotal, NW	**337**	**935**	**935**	**935**	**935**
SW	4-hour Battery	2,169	2,194	2,194	2,071	2,071
	Pumped Hydro Storage	176	926	926	926	926
	Subtotal, SW	**2,345**	**3,120**	**3,120**	**2,997**	**2,997**

3.5 Demand Response

Shed (or "conventional") demand response reduces demand only during peak demand events. The 2024-2026 IRP cycle treats the IOUs' existing shed demand response programs as baseline resources. Shed demand response procured through the Demand Response Auction Mechanism (DRAM) is included. The assumed peak load impact of demand response is based on final Load Impact Protocol (LIP) reports by the IOUs.[17] Additional interruptible pumping load from the CAISO NQC list is included as baseline shed DR capacity in all years.

Table 30. Baseline shed demand response (Nameplate MW)

Baseline DR Type	PGE	SCE	SDGE	CAISO Total
Utility Programs	487	1,078	110	**1,675**
Interruptible Pumping Loads	1,219	975	-	**2,194**

3.6 External Zone Calibration in RESOLVE

Additional calibration of external (non-CAISO) zones is necessary to reflect planned resource developments outside of CAISO. RESOLVE does not optimize the resource mix in external zones, and there are no candidate resources in these zones that the model can select. The baseline defined by WECC 2032 ADS includes only online resources and specific near-term additions and does not reflect potential future resources that may be necessary to meet loads and policy targets in external zones. This is reflected in RESOLVE's optimized dispatch, which balances loads and resources (including import and export with CAISO) over all zones. In the absence of future resource additions in the external zones, the baseline alone may be insufficient to meet external zones' load, forcing RESOLVE to overbuild within CAISO and export large amounts of energy to

[17] Guide to CPUC's Load Impact Protocols (LIP) Process v3.1. https://www.cpuc.ca.gov/-/media/cpuchttps://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/lip-filing-guide-and-related-materials/lip-filing-guide-v31.pdfwebsite/divisions/energy-division/documents/demand-response/lip-filing-guide-and-related-materials/lip-filinghttps://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/lip-filing-guide-and-related-materials/lip-filing-guide-v31.pdfguide-v31.pdf

external zones to fill the gap. This is an unrealistic outcome, as external LSEs will pursue their own plans rather than rely on CAISO to support them. To properly reflect this in the model, external zones are calibrated for RESOLVE by estimating future resource additions and adding them to the baseline.

Two steps were taken to create a portfolio of future resource additions. First, planned builds from the most recent IRP of each external balancing area were added to the baseline, excluding resources already within WECC 2032 ADS. Second, where IRPs did not extend through 2045, further resource additions were extrapolated based on the balancing area's peak load growth. For any balancing areas that did not have an IRP, future resource additions were estimated using a similar process. First, planned builds from neighbors' IRPs were added on top of the baseline. Second, these planned builds are scaled up or down to meet the peak load of the balancing area (for example, if the balancing area's peak load is 2,000 MW and its neighbors' peak load is 4,000 MW, the builds are multiplied by 50%). Peak load forecasts for balancing areas without IRPs are taken from 2023 FERC Form 714 forecast data.

Future resource additions input into RESOLVE are shown in Table 31. These resource additions are assumed to meet the clean energy policy objectives within each LSE's jurisdiction. RESOLVE can consider these additions when optimizing imports and exports with CAISO. These future resource additions are also modeled in SERVM.

Table 31. Forecasted Future Resource Additions in Non-CAISO Zones for RESOLVE (MW)

Zone	Resource Class	2025	2030	2035	2040
IID	Geothermal	-	11	56	119
	Li-Battery	25	25	215	486
	Solar	-	400	812	1,400
	IID Total	**25**	**425**	**1,039**	**1,942**
LDWP	Geothermal	130	315	365	365
	Li-Battery	-	-	83	453
	Peaker	798	1,778	2,648	2,919
	Solar	-	514	954	1,204
	Wind	-	790	2,375	2,845
	LDWP Total	**928**	**3,397**	**6,425**	**7,786**
NCNC	Geothermal	-	230	253	295
	Li-Battery	257	1,000	1,122	1,246
	Solar	403	1,761	2,330	2,726
	Wind	140	715	836	994
	NCNC Total	**801**	**3,706**	**4,542**	**5,261**

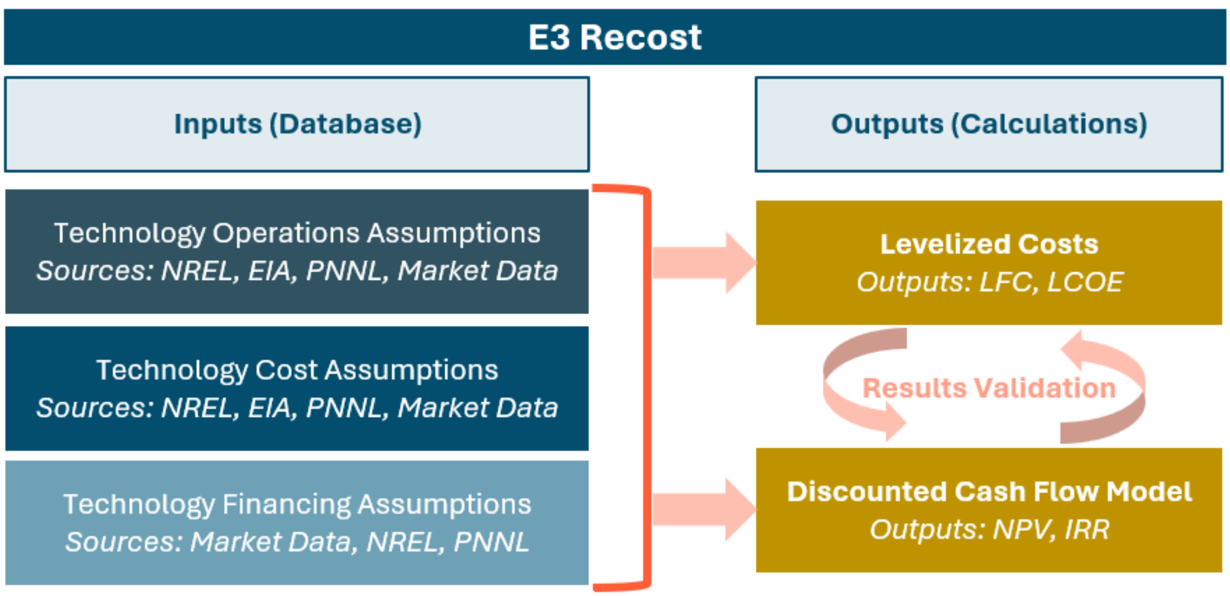
NW	Biomass	-	12	12	13
	CCGT	4	299	310	323
	Li-Battery	662	5,622	6,696	9,912
	Pumped Hydro/Long Duration Storage	5	57	148	319
	Peaker	307	1,015	1,627	5,053
	Reciprocating Engine	181	276	319	378
	Solar	758	5,981	7,970	10,258
	Wind	1,811	6,041	11,748	14,957
	NW Total	**3,728**	**19,302**	**28,831**	**41,212**
SW	Biomass	-	1	51	85
	CCGT	-	15	1,723	1,905
	Geothermal	-	13	64	98
	Li-Battery	2,225	5,901	6,846	10,356
	Pumped Hydro	-	414	1,025	1,708
	Peaker	-	1,006	3,472	5,714
	ST	-	261	261	261
	Solar	2,934	9,853	15,252	22,234
	Wind	378	1,411	3,630	4,331
	SW Total	**5,537**	**18,875**	**32,324**	**46,692**

4. Resource Cost Methodology

4.1 Recost Financial Model

The Recost model is a discounted cash flow model published by E3 that is used to calculate the levelized costs of different candidate resources and develop cost inputs for RESOLVE modeling.[18] Given a set of technology- or project-specific assumptions for system performance and operations, upfront and ongoing costs, and financing parameters, the model computes levelized cost metrics, such as the levelized fixed cost (LFC, $/kW-yr) and levelized cost of electricity (LCOE, $/MWh) for each technology or resource.[19] Ultimately, the results of the Recost calculation are used by RESOLVE to determine which candidate resources will be the most cost-effective to build over the modeling horizon. The key inputs and outputs of Recost are illustrated in Figure 1.

Figure 1. Overview of the Recost Model



To gather location-agnostic technology cost data, Recost primarily leverages public data sources such as the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB)[20]; U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO);[21] and the Pacific

---

[18] E3 Recost Model, https://www.ethree.com/tools/recost-model/

[19] In the RESOLVE context, "technology" is often used to refer to a generic category of resources and is location independent, e.g., "onshore wind" or "utility-scale solar PV." "Resource" is often location-dependent, e.g., "PGE_NGBA_Wind" or "SCE_Arizona_Solar", with regional or locational adjustments to resource characteristics (e.g., capacity factor) and costs (e.g., regional or state cost multipliers) incorporated in their inputs in RESOLVE.

[20] NREL 2024 Annual Technology Baseline (ATB). https://atb.nrel.gov/.

[21] EIA AEO: https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf

Northwest National Laboratory (PNNL) Energy Storage Cost and Performance Database,[22] developed in support of the Department of Energy (DOE) Energy Storage Grand Challenge (ESGC).

Levelized costs (LFC, LCOE) are calculated on a real-levelized basis to yield costs that are flat in real dollars. This approach discounts annual project costs using a nominal discount rate (nominal return on equity) and discounts energy and capacity using a real discount rate (real return on equity). This is a standard approach that yields levelized costs in flat real terms for input to the RESOLVE model. LFC and LCOE are calculated for each resource and commercial operation date (COD) vintage, from 2023 through 2050.

Levelized Fixed Cost (LFC), reported in 2022 $/kW-yr, is used as a direct input in RESOLVE to inform new investment decisions. The components included in LFC are capital cost (CAPEX), including interconnection and interest accrued during construction; fixed operations and maintenance (FO&M), including site control, property taxes, system warranties, and repowering and augmentation costs; the federal Investment Tax Credit (ITC), where applicable; and financing costs (including investor returns on a project). Additional components that impact investment decisions in RESOLVE include variable operations and maintenance (VO&M), fuel costs, and the federal Production Tax Credit (PTC), where applicable.

LFC and LCOE are calculated using a discount rate equal to the cost of equity. Specifically, the LCOE represents the volumetric cost of electricity needed for the candidate resource to recapture its total upfront and ongoing costs over its economic life. At an internal rate of return (IRR) equal to the cost of equity, the net present value (NPV) of a resource that collects revenue on electricity at the LCOE will be zero.

The LCOE is not an input to RESOLVE, but it can be inferred from the model's dispatch results. Nevertheless, LCOE is frequently used to compare resource costs. When doing so, it is important to understand that the results for LCOE reported in this document are illustrative and do not represent actual contract prices for specific resources. Recost does not estimate market electricity prices, contracted PPA electricity rates, nor does it provide forecasts of these market prices or contract rates. Unless otherwise noted, all LCOEs reported under CPUC IRP proceedings are presented as real-levelized values, whereas most PPAs being signed today are flat (nominal-levelized). Additionally, the LCOE in Recost is calculated using production estimates exclusive of curtailment. Since RESOLVE can curtail production for wind and solar resources, LCOE values reported in RESOLVE may be higher than what is reported in this document.

[22] PNNL Energy Storage Grand Challenge (ESGC) Cost and Performance Database: https://www.pnnl.gov/ESGChttps://www.pnnl.gov/ESGC-cost-performancecost-performance.

Recost features several cost methodology updates for the 2024-2026 IRP cycle. These updated cost assumptions are discussed in the following sections:

1. Primary data sources for all technologies updated to NREL 2024 ATB, EIA 2023 AEO, or PNNL Energy Storage Cost and Performance Database (2024) (Section 4.2)
2. Base-year (2023) utility-scale solar, onshore wind, and Li-ion battery CAPEX have been benchmarked to additional recent market reports, resulting in new cost estimates (Section 4.3)
3. Custom CAPEX trajectories for utility-scale solar, wind, and Li-ion batteries have been developed to reflect greater variability in cost forecasts (Section 4.3)
4. New financing assumptions for cost of debt, cost of equity, and WACC have been developed from direct market indicators (Section 4.4)
5. State-specific cost multipliers for CAPEX, FO&M, and interconnection have been updated using latest labor, site control, and interconnection cost estimates (Section 4.5)

Further discussions on the above updates are included in the listed subsections. Candidate resource cost results, including forecasts of CAPEX and LFC/LCOE by project vintage, are reported in Section 5. In addition to LFC, RESOLVE also requires information on variable costs (such as fuel and variable O&M) and resource performance characteristics (such as capacity factor). Fuel costs, variable O&M costs, and capacity factors (modeled through renewable generation profiles) are separately specified in RESOLVE and are discussed in Section 6.

4.2 Resource Cost Data Sources

The public data sources used in Recost to derive resource cost inputs for RESOLVE are summarized in the Table 32 below, including the NREL ATB,[23] PNNL Energy Storage Grand Challenge (ESGC) Cost and Performance Database,[24] and EIA 2023 AEO,[25] among others. These data sources have been used for base year (2023) technology costs, long-term cost forecasts, financing assumptions, and other relevant assumptions.

Table 32. Summary of data sources used to derive RESOLVE technology cost inputs

Category	Data Source
Financing assumptions (Cost of debt, cost of equity, debt fraction)	Custom analysis (Section 4.4)
Thermal technologies (Gas CCGT, Gas CT)	EIA AEO (Gas CT) NREL 2024 ATB (Gas CCGT)

[23] NREL 20243 Annual Technology Baseline (ATB). https://atb.nrel.gov/.
[24] PNNL Energy Storage Grand Challenge (ESGC) Cost and Performance Database: https://www.pnnl.gov/ESGChttps://www.pnnl.gov/ESGC-cost-performancecost-performance.
[25] U.S. Energy Information Administration (EIA) Annual Energy Outlook 2023. https://www.eia.gov/outlooks/aeo/.

Utility-Scale Solar PV	Custom analysis (Section 4.3)
Distributed PV	NREL 2024 ATB
Onshore Wind	Custom analysis (Section 4.3)
Offshore Wind	NREL 2024 ATB (Class 12)
Geothermal (Hydrothermal, Enhanced Geothermal Systems—EGS)	NREL 2024 ATB (Hydrothermal–Binary, EGS–NF–Binary, EGS–Deep–Binary)
Biomass	NREL 2024 ATB
Li-ion Battery	Custom analysis (Section 4.3)
Pumped Hydro Storage (PSH)	NREL 2024 ATB (New Reservoir: Class 8) (Existing Reservoir: Class 3)
Generic 12-hour Storage	PNNL 2024 ESGC (Vanadium Redox Flow, 1,000 MW)
Generic 24-hour Storage	PNNL 2024 ESGC (Compressed Air Energy Storage, 1,000 MW)
Generic 100-hour Storage	LDES Council (Iron-Air Batteries)[26]

Generally, NREL 2024 ATB is used as the main data source for resource costs for most technologies. Within NREL ATB, certain technology classes were used to represent resource costs for the 2024-2026 IRP cycle. Specifically, Offshore Wind Class 12 is used to represent floating offshore wind in California, Pumped Hydro Storage (PHS) New Reservoir Class 8 represents pumped hydro projects requiring construction of two new reservoirs, and Existing Reservoir Class 3 represents pumped hydro projects with at least one existing reservoir. For candidate geothermal projects, including conventional (hydrothermal), near-field enhanced geothermal systems (EGS), and deep EGS, all projects are assumed to be binary systems and use the corresponding cost categories from NREL ATB.

Natural gas combustion turbine (CT) costs for both frame and aeroderivative types were taken from EIA 2023 AEO, reflecting an update to the previous inputs & assumptions. Generic long-duration storage technology costs are taken primarily from the PNNL 2024 ESGC. From that study, vanadium redox flow ("flow") batteries and compressed air energy storage (CAES) are the

[26] "Net-Zero Power: Long Duration Energy Storage for a Renewable Grid." LDES Council, 2021. https://www.mckinsey.com/~/media/mckinsey/business%20functions/sustainability/our%20insights/net%20zero%20power%20long%20duration%20energy%20storage%20for%20a%20renewable%20grid/net-zero-power-long-duration-energy-storage-for-a-renewable-grid.pdf

representative technologies used for generic 12- and 24-hour storage, respectively. For generic 100-hour storage, cost data from a 2021 report published by the LDES Council are used.

Capital costs for utility-scale solar, onshore wind, and Li-ion batteries are derived from a benchmarking analysis over several public data sources, with a full discussion of the analysis in Section 4.3.

Financing costs, including cost of debt, cost of equity, and debt fraction, were derived from public data sources, with a full discussion of the methodology available in Section 4.4.

4.3 Capital Costs for Utility-Scale Solar PV, Onshore Wind, and Li-ion Batteries

The capital cost (CAPEX) assumptions for utility-scale solar PV, onshore wind, and Li-ion batteries in Recost are informed by recent market data and industry reports from 2023-2024. Instead of relying on a single data source for capital cost assumptions, averages are taken across reported values from literature. The data is used to develop estimates for base year (2023) resource CAPEX for utility-scale solar PV, onshore wind, and Li-ion batteries. The data sources and publication years are listed in Table 33 below.

Table 33. Summary of data sources used to derive RESOLVE CAPEX inputs

Publication Name	Publication Year	Technologies
National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB)[27]	2024	Utility-Scale Solar, Onshore Wind, Li-ion Battery
U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO)[28]	2023	Utility-Scale Solar, Onshore Wind, Li-ion Battery
Lazard Levelized Cost of Energy+ (LCOE+)[29]	2024	Utility-Scale Solar, Onshore Wind, Li-ion Battery
Electric Power Research Institute (EPRI) Program on Technology Innovation: Generation Technology Options[30]	2024	Utility-Scale Solar, Onshore Wind, Li-ion Battery

[27] NREL ATB, https://atb.nrel.gov/electricity/2024/technologies

[28] EIA AEO, https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf

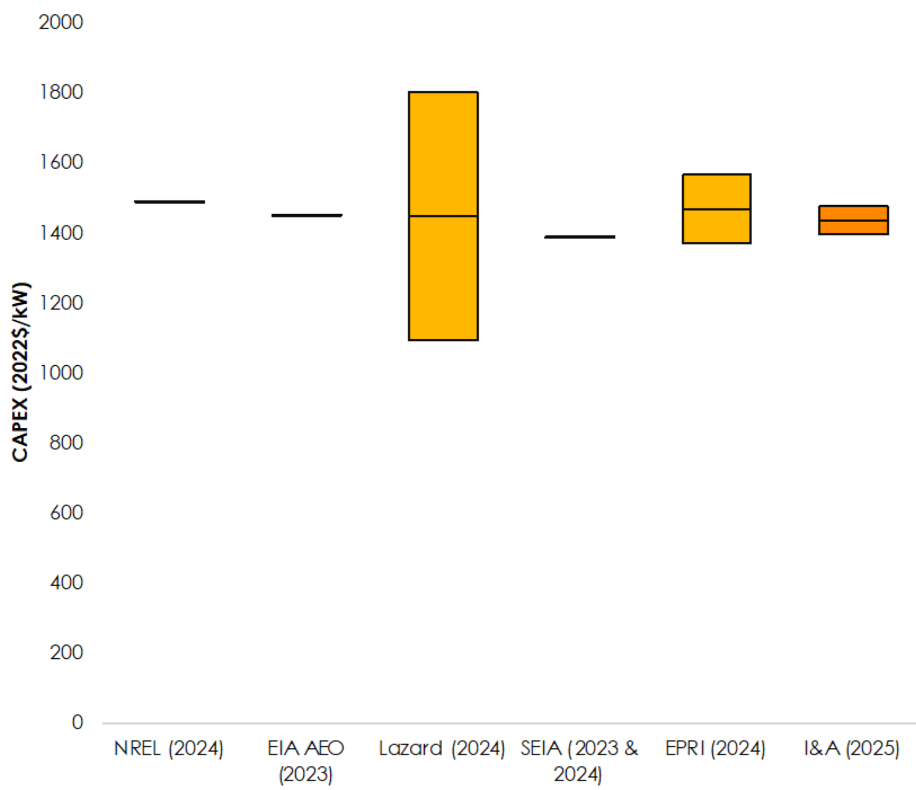
[29] Lazard LCOE+, https://www.lazard.com/media/xemfey0k/lazards-lcoeplus-june-2024-_vf.pdf

[30] EPRI Program on Technology Innovation, https://www.epri.com/research/sectors/technology/results/30002029428

Solar Energy Industries Association (SEIA) Solar Market Insight Report[31]	2024	Utility-Scale Solar
Lawrence Berkeley National Laboratory (LBNL) Land-Based Wind Market Report[32]	2024	Onshore Wind
Pacific Northwest National Laboratory (PNNL) Energy Storage Cost and Performance Database[33]	2024	Li-ion Battery

For each technology, CAPEX values for 2023-2024 are collected, deflated to a common dollar basis year (2022 $), and averaged to produce the base year (2023) estimate. An example of the analysis for utility-scale solar PV is shown in Figure 2 below.

Figure 2. Example of Base Year CAPEX Benchmarking for Utility-Scale Solar PV



[31] SEIA Solar Market Insight Report, https://www.seia.org/research-resources/solar-market-insight-report-q2-2024
[32] LBL Land-Base Wind Market Report, https://emp.lbl.gov/wind-technologies-market-report
[33] PNNL Energy Storage Cost and Performance Database, https://www.pnnl.gov/ESGC-cost-performance

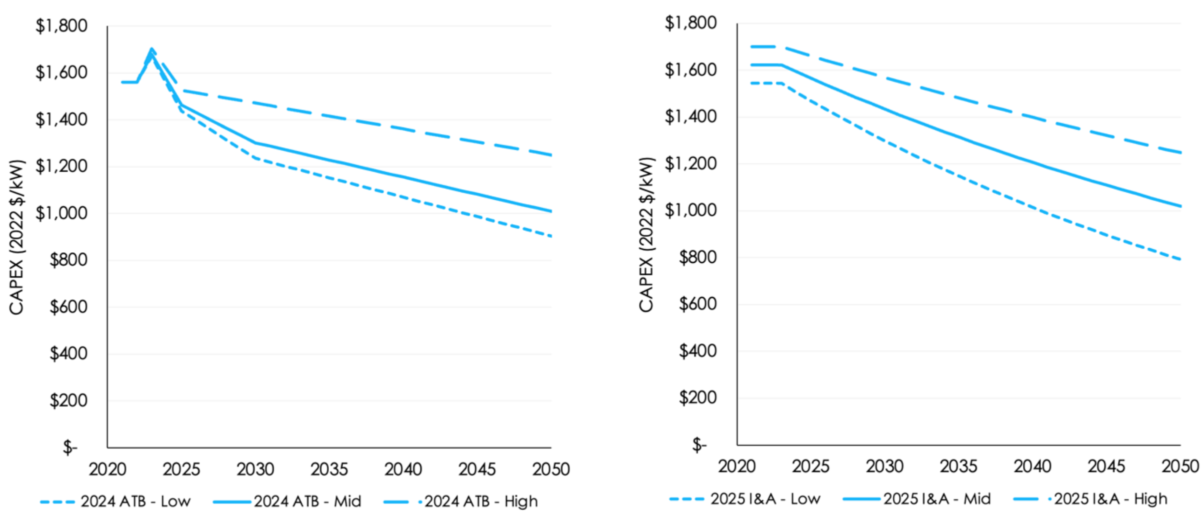
The base year (2023) CAPEX values (2022 $/kW) used in Recost are summarized in Table 34.

Table 34. Base Year CAPEX values for solar, onshore wind, and 4-hr batteries

Technology	Low	Mid	High
Utility-Scale Solar PV	$1,348	$1,387	$1,428
Onshore Wind	$1,457	$1,530	$1,604
Li-ion Battery (4-hr)	$1,163	$1,163	$1,163

In addition to benchmarking the base year CAPEX values to recent publications, the cost trajectories used in Recost reflect a likely range of future costs. Cost trajectories are analyzed in nominal dollars to understand the actual costs that would be paid for resource procurement. Low and high trajectories are developed and applied to the base year CAPEX values to produce a range of expected cost projections. These forecasts reflect a likely range of future costs, but they are not designed to capture all future scenarios with full confidence. A middle forecast, calculated as the average between low and high, is presented as the base assumption for the 2024-2026 IRP cycle. An example of the analysis for onshore wind is shown in Figure 3 below, with the trajectories from NREL 2024 ATB reproduced for comparison.

Figure 3. Onshore Wind CAPEX Trajectory Comparison



Additional tables of CAPEX values developed for utility-scale, onshore wind, and Li-ion batteries for the 2024-2026 IRP cycle are presented in Section 5.

4.4 Financing Costs

The Recost model used for the 2024-2026 IRP cycle assumes that financing is provided by an Independent Power Producer (IPP), reflecting the current development practice of third-party ownership of new resources in California. Market-based financing assumptions are used to ensure that the weighted average costs of capital (WACC) used to levelize candidate resource costs accurately reflect current market conditions and expected ranges of risk. WACC is calculated based on the cost of debt, debt fraction, cost of equity, and effective tax rate for a given state.

Near-term and long-term cost of debt forecasts were developed based on market data in the most recent 90 trading days. The spread of debt cost rates is approximated using borrowing rates captured by the Bank of America US Corporate Index Effective Yield.[34] The long-term rates were adopted from the U.S. Treasury 10-Year Par Yield Curve, with the spread from current rates maintained. The debt fraction is taken from NREL 2024 ATB.

The cost of equity was determined by un-levering sector returns using the sector debt-to-equity ratio (D/E) and re-levering the result using the project debt fractions from NREL 2024 ATB. Sector returns and D/E ratios are taken from publicly available data from various sectors (i.e. utilities, renewable energy, power) to inform spreads of target returns.[35] Distinct ranges of WACC values were developed for three risk classes (i.e. conventional/low risk, moderate risk, and emerging/higher risk technologies), as shown in Table 35 and Figure 4 below.

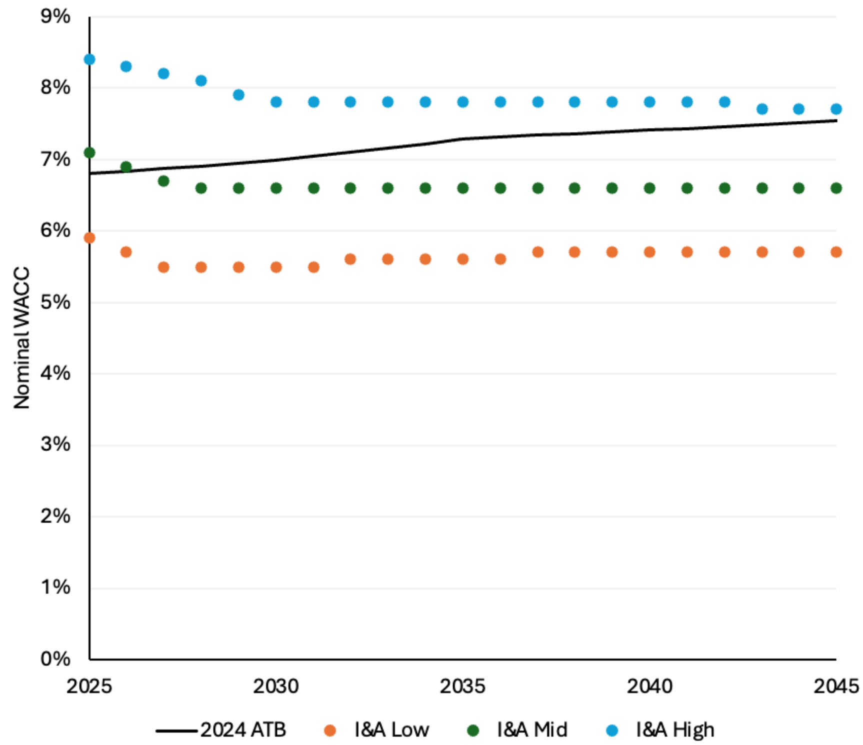
Table 35. Risk Category by Technology Type

Technology	Type	Risk Class
Solar	Utility PV	Low-Risk
Wind	Onshore	Low-Risk
Wind	Offshore	High-Risk
Geothermal	Hydro - Binary	Mid-Risk
Gas	CT - Frame	Low-Risk
Gas	CCGT	Low-Risk
Biomass	Dedicated	Mid-Risk
Li-ion Battery	Utility Standalone	Mid-Risk
Pumped Storage Hydropower	New Reservoir	High-Risk

[34] FRED Economic Data, https://fred.stlouisfed.org/series/BAMLC0A3CAEY

[35] Damodaran Online. https://pages.stern.nyu.edu/~adamodar/. Accessed September 2024.

Figure 4. Utility-Scale Solar PV Nominal WACC (Low-Risk), Recost (2024-2026 IRP cycle) and NREL 2024 ATB



20

4.5 State-Specific Cost Multipliers

State-specific cost multipliers are produced in Recost to reflect state-specific cost conditions for labor, site control, and interconnection.

For a given technology and state, the labor cost multiplier is calculated by applying the state's median construction labor wage, indexed to the U.S. national median, to the percentage of resource capital costs attributable to labor. Labor costs are estimated using the median wages by region for Construction Laborers, as reported by the U.S. Bureau of Labor Statistics.[36] The percentages of resource capital costs attributable to labor are adopted from the 2019 WECC Cost Calculator.[37] For solar and onshore wind only, the site control multiplier is calculated by applying the state's average prime farmland lease rate, indexed to the U.S. national average, to the percentage of resource FO&M attributable to site control. Finally, the interconnection cost

[36] U.S. Bureau of Labor Statistics, Occupational Employment and Wage Statistics, 47-2061: Construction Laborers. https://www.bls.gov/oes/current/oes472061.htm.

[37] WECC 2019 Generator Capital Cost Tool - with E3 Updates. July 2019. https://www.wecc.org/Administrative/E3_WECC_Cost_Calculator_2019-07-02_FINAL.xlsm.

multipliers are calculated by reviewing and benchmarking average project interconnection cost data collected by Lawrence Berkeley National Lab.[38]

The regional cost multipliers are applied to resource CAPEX, FO&M, and interconnection, prior to levelization in Recost. The candidate resource costs by technology, described in Section 5, are inclusive of all state-specific cost multipliers.

4.6 Impacts of Inflation Reduction Act

The Inflation Reduction Act (IRA) may have an extensive impact on climate and energy investments in the U.S. In the context of IRP RESOLVE modeling, the IRA is expected to have the most direct impact on the costs of candidate clean energy resources, primarily via creating new technology-neutral tax credits, which take effect in 2025.

The IRA introduces new tax credit options for both conventional and emerging technologies to encourage new development. Effective immediately, new solar projects under the IRA can now qualify for the production tax credit (PTC) as an alternative to the investment tax credit (ITC). For the 2024-2026 IRP cycle all utility-scale solar resources are assumed to elect the PTC. Another major development arising from the IRA is that standalone storage will have access to the ITC. Previously, storage projects could only receive the ITC if they were paired with on-site renewable generation and constrained to not charge from the grid. With this change, both conventional and emerging energy storage technologies will be eligible to receive these tax benefits without these constraints.

Key details related to implementation and the quantification of costs and benefits from the IRA are subject to pending guidance from the U.S. Treasury Department's Internal Revenue Service. The assumptions and results presented here reflect information available at this time and will continue to be refined as new information and guidance become available.

Under the IRA, projects have access to several tax credit options, with the incentive rate dependent on the number of eligibility requirements met. The different tax credit schedules for utility-scale resources are illustrated in Figure 3. Note that the horizontal axes in the charts in Figure 5 reflect project commercial operation dates, and each data point indicates the tax incentives available to eligible projects that come online in the specified year. The full credit amount (ITC at 30% of qualifying capital expenditure or PTC at $26/MWh (2022 $)[39] of electricity generation) is available to projects only if specific prevailing wage and apprenticeship requirements are met, shown as the "Bonus" option in Figure 5. Otherwise, the credit amount is

[38] LBNL Generator Interconnection Costs to the Transmission System. https://emp.lbl.gov/interconnection_costs

[39] Production tax credit amounts in this section are shown in 2023 dollars.

one-fifth of the full amount ("Base"). To meet the prevailing wage requirement, laborers and mechanics employed in the construction, alteration, or repair of the facility must be paid wages not less than the prevailing wage, as determined by the U.S. Department of Labor. To meet the apprenticeship requirement, a certain number of labor hours for the work must be performed by apprentices.[40] Given the five-fold increase in incentive rate for fulfilling these requirements, it is reasonable to assume that most project developers will strive to meet the prevailing wage and apprenticeship requirements to remain cost-competitive. These requirements are also believed to be actionable for most projects, based on an initial review of current and expected labor cost increases implied by the prevailing wage requirement, although further analysis of net impact on costs is required following initial guidance from the Treasury Department on these requirements. For these reasons, the full IRA credit amount, or the "Bonus" option in Figure 5, is assumed to be the base case IRA scenario for calculating the resource cost inputs.

Tax credits under the IRA are scheduled to expire at the later of (a) 2032, and (b) when the U.S. electric sector achieves 75% GHG emissions reductions relative to 2022 levels, at the national level.[41] Once this condition is met, the credits undergo a three-year phase-out before being retired. Staff expects that the 75% emissions target will not be met until 2045, which is reflected in the timing for the IRA tax credit schedules in Figure 5. Additionally, the IRS has stipulated that offshore wind projects are eligible for a 10-year safe harbor provision to receive the ITC; for this technology only, tax credits are assumed to be monetized through 2050.

In addition to the 30% ITC and $26/MWh "Bonus" credit rates offered under the IRA, certain credit adders are available and may be stacked for projects that meet additional requirements. Beginning in 2025, an extra 10% of ITC or $2.60/MWh of PTC can be claimed by projects that meet the domestic content requirement. The project must source a certain portion of any steel,

---

[40] More details on the IRA tax credits, including the prevailing wage and apprenticeship requirements, and the different tax credit adders, can be found here:

(a) Orrick. IRA Update: What to Know About the New Guidance on Prevailing Wage and Apprenticeship Requirements. December 2022. https://www.orrick.com/en/Insights/2022/12/Initial-Guidance-On-Prevailing-Wage-And-Apprenticeship-Requirements

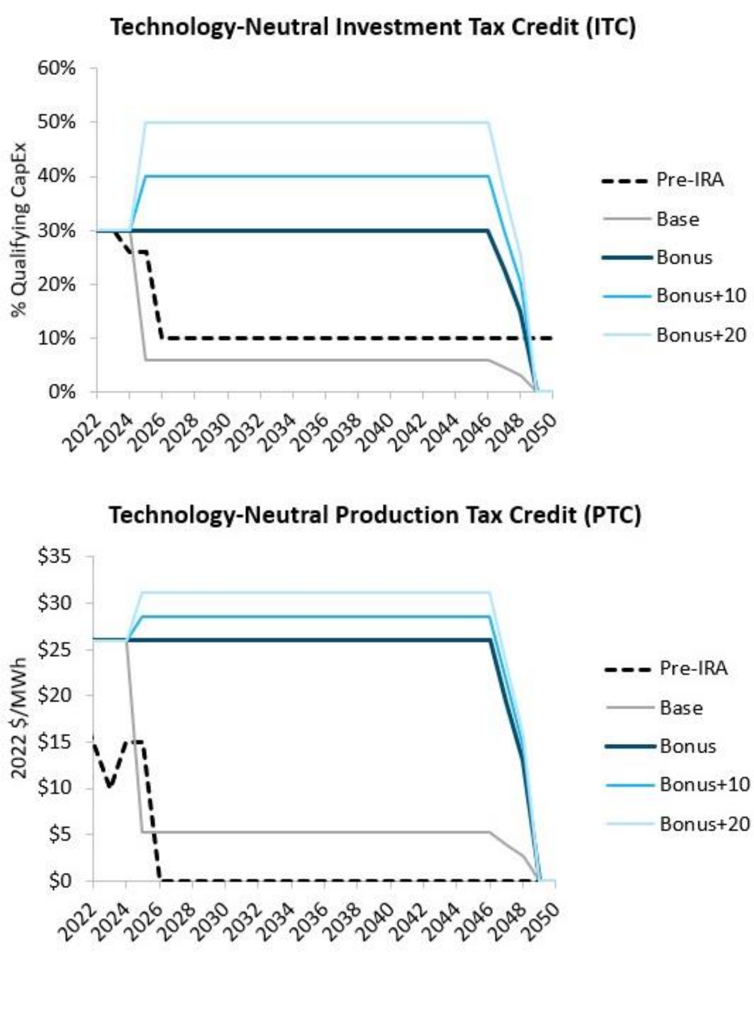
(b) Norton Rose Fulbright. IRS Issues Wage and Apprentice Requirements. November 2022. https://www.projectfinance.law/publications/2022/november/irs-issues-wage-and-apprentice/requirements/ Internal Revenue Service (IRS). Prevailing Wage and Apprenticeship Initial Guidance Under Section 45(b)(6)(B)(ii) and Other Substantially Similar Provisions. November 2022. https://www.federalregister.gov/documents/2022/11/30/2022-26108/prevailing-wage-and-apprenticeship-initial-guidance-under-section-45b6bii-and-other-substantially

(d) McGuireWoods. Inflation Reduction Act Extends and Modifies Tax Credits for Wind Projects. August 2022. https://www.mcguirewoods.com/client-resources/Alerts/2022/8/inflation-reduction-act-tax-credits-for-wind-projects.

[41] Inflation Reduction Act Summary: Energy and Climate Provisions. https://www.energy.gov/sites/default/files/2022-10/IRA-Energy-Summary_web.pdf.

iron, or other manufactured product used to construct the facility in the U.S. to qualify. Another 10% adder can be claimed if the project is in an energy community, which includes regions where employment has historically depended on fossil fuel generation, and fossil fuel brownfield sites. The “Bonus+10” and “Bonus+20” options in Figure 5 illustrate the cases in which an additional 10% and 20% credit are available, respectively, relative to the “Bonus” option. Among these IRA adders, location-specific incentives (e.g., energy community) are feasible and may be worth considering as a sensitivity, given that potential qualification is quite broad in California.[42] The domestic content requirement incentives could also have a significant impact on project economics, although it is more likely to be influenced by uncertainties in the supply chain and will not be considered at this time.

Figure 5. Assumed IRA tax credit availability for technologies by project commercial operation date.



[42] See, for example: S&P Capital IQ. Mapping communities eligible for additional Inflation Reduction Act incentives. October 2022. https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/article?KeyProductLinkType=2&id=72375231.

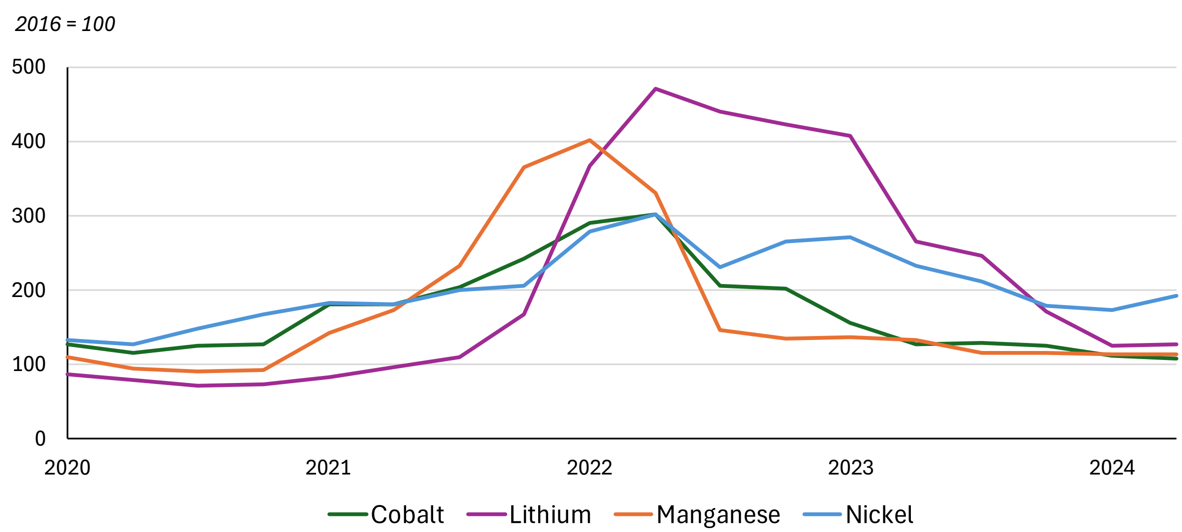
The resource costs for candidate resources presented in Section 5 are inclusive of tax credits (ITC or PTC), Tax credits are assumed to be monetized at a 90% monetization rate.

4.7 Impacts of Commodity Prices on Resource Costs

Between 2020 and 2023, supply chain issues, higher interest rates, inflationary pressures, and other market impacts attributable to the COVID-19 pandemic resulted in observed cost shocks for certain renewable technologies — most notably utility-scale solar PV, onshore wind, and Li-ion batteries.

For Li-ion batteries in particular, commodity price increases for various rare-earth metals resulted in a short-term cost hike between 2021 and 2023. Data reported by the International Monetary Fund (IMF) on feedstock material prices[43] show that since Q1 2020, many rare-earth metals critical to the production of Li-ion batteries, including lithium, manganese, nickel, and cobalt, more than doubled in price during COVID-19. Those price increases were roughly 50% greater than those observed for conventional feedstocks, such as aluminum, iron, and copper. However, since 2023, most of those commodities, particularly lithium, have largely returned to pre-COVID-19 levels, as shown in Figure 6 below.

Figure 6Figure 6. Price Indices for Primary Feedstock Commodities used in Li-ion Battery Manufacturing



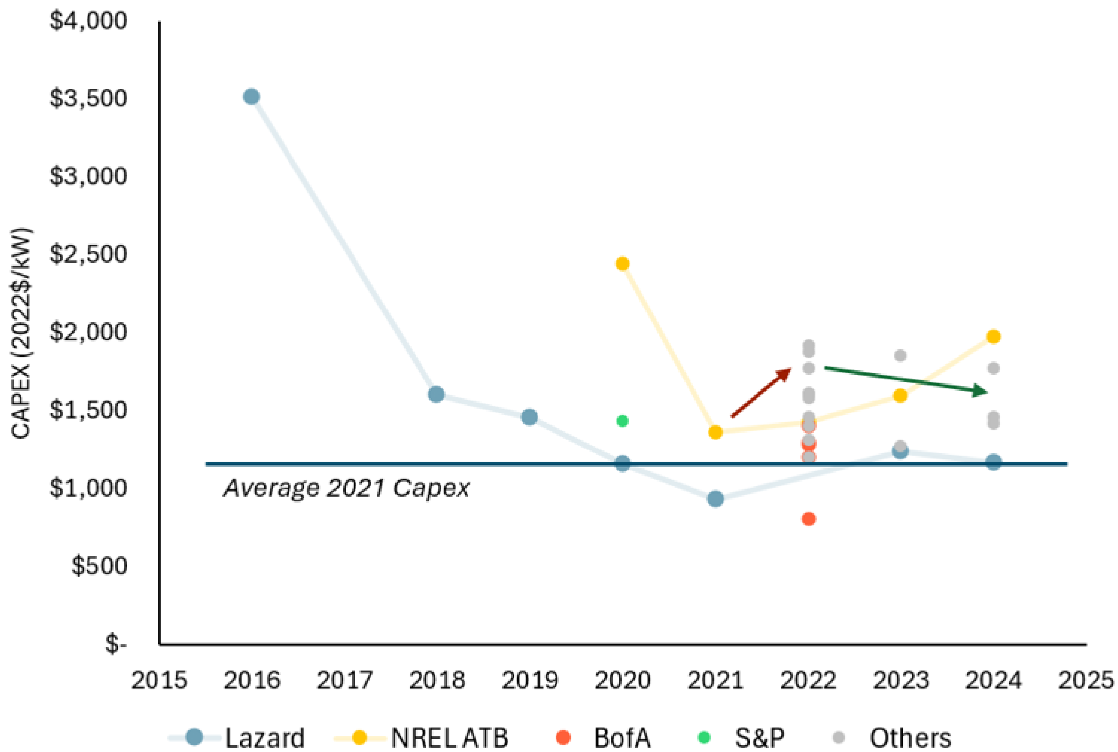
Moreover, over the past year, relaxations of the supply chain constraints and a "soft landing" to inflation have been observed, both of which have helped to lower battery system costs from their pandemic peaks. Reports from NREL, Lazard, S&P, BofA Securities, and others[44] suggest

[43] IMF Quarterly Data, retrieved Q4 2024. https://data.imf.org/?sk=471dddf8-d8a7-499a-81ba-5b332c01f8b9&sid=1547558078595

[44] Additional sources include Wood Mackenzie, Bloomberg New Energy Finance, and Brattle

that estimates for 4-hr battery storage system costs increased at the start of the pandemic and remained elevated through 2023, as shown in Figure 7. NREL ATB and Lazard reported 22% and 35% real cost increases between 2021-2023, respectively. Early market data from 2024, however, suggests that costs have fallen slightly, with Lazard reporting an 8% decrease and other reports showing similar declines. Multiple data sources from 2023-2024 were used to update the base year CAPEX assumption for Li-ion batteries.

Figure 7. Historical 4-hr Li-ion CAPEX by Installation Year and Data Source, $2022/kW



Note: NREL shows a higher cost in 2024 because it relies on an earlier 2023 report for Li-ion battery storage costs.

In the Recost model, market data from recent-year (2023-2024) industry reports for solar, onshore wind, and Li-ion batteries are used to benchmark resource costs. Additionally, the Inflation Reduction Act (IRA) continues to spur demand for clean energy technologies and underpin long-term deployment and cost declines into the future.

5. Optimized Resources

Optimized resources represent the menu of new resource options from which RESOLVE can select to create an optimal portfolio. Optimized resources fall into one of two categories:

- Default candidate resources are optimized resources that are included in all cases, primarily representing established, commercially viable resource technologies.
- Non-default candidate resources are optimized resources that are only modeled in certain sensitivities, including experimental and/or nascent technologies such as shift demand response, emerging technologies, and vehicle-to-grid integration

This document defines guiding principles for a resource to become a default candidate resource in IRP modeling. During each IRP portfolio development, staff evaluates the non-default candidate resources based on these guiding principles and determines if a resource meets the criteria to be a default candidate resource. A default candidate resource must be:

- **Viable:** This resource is a commercialized technology.
- **Scalable:** This resource could be realistically selected at sufficient volume to meaningfully impact California's electric portfolio.
- **Economic:** This resource is projected to be cost competitive within the timeframe of IRP analysis with sufficient publicly available market data to validate those projections.
- **Actionable:** Mechanisms exist, or could be reasonably expected to be put in place, to enable the CPUC to guide procurement of this resource.
- **Timely:** This resource can reasonably be expected to come online within the timeframe of IRP analysis.

The optimal mix of candidate resources is a function of the relative costs and characteristics of the entire resource portfolio (both baseline and candidate) and the constraints that the portfolio must meet. Capital costs are included in the RESOLVE optimization for candidate resources, whereas capital costs are excluded for baseline resources. Generation profiles and operating characteristics are addressed in Section 6.

Other non-optimized resource additions that have prescribed adoption over time from IEPR forecasts, are not represented in RESOLVE as decision variables in the optimization model including energy efficiency, BTM solar and storage.

5.1 Candidate Resources in RESOLVE

The candidate resource technologies represented in RESOLVE are summarized in Table 36 below. For the 2024-2026 IRP cycle, enhanced geothermal (both near-field and deep) and generic long duration storage (12-, 24-, and 100-hr durations) are proposed as new default candidate resources.

Table 36. Summary of candidate resource technologies in RESOLVE

Category	Technology	Resource Potential Approach	Assignment to RESOLVE Zone
Thermal	Combined-Cycle Gas Turbine (CCGT)	Uncapped	One resource per zone (IOU)
Thermal	Combustion Turbine, Frame (CT-Frame)	Uncapped	One resource per zone (IOU)
Thermal	Combustion Turbine, Aeroderivative (CT-Aero)	Uncapped	One resource per zone (IOU)
Thermal	Reciprocating Engine (RICE)	Uncapped	One resource per zone (IOU)
Renewable	Utility-Scale Solar PV	Geospatial analysis	RESOLVE region map (CAISO study area)
Renewable	Distributed Solar PV	Geospatial analysis	One resource per zone (IOU)
Renewable	Onshore Wind	Geospatial analysis	RESOLVE region map (CAISO study area)
Renewable	Offshore Wind	Discrete candidate projects	RESOLVE region map (CAISO study area)
Renewable	Conventional Geothermal (Hydrothermal)	Discrete candidate projects	RESOLVE region map (CAISO study area)
Renewable	Enhanced Geothermal Systems (EGS) – Near Field	Discrete candidate projects	RESOLVE region map (CAISO study area)
Renewable	Enhanced Geothermal Systems (EGS) – Deep	Geospatial analysis	One resource per zone (IOU)
Renewable	Biomass	Discrete candidate projects	One resource per zone (IOU)
Storage	Li-ion Battery (4-hr)	Uncapped	One resource per zone (IOU)
Storage	Li-ion Battery (8-hr)	Uncapped	One resource per zone (IOU)

Storage	Pumped Hydro Storage (12-hr)	Discrete candidate projects	RESOLVE region map (CAISO study area)
Storage	Generic Long-Duration Energy Storage (12-hr)	Uncapped	One resource per zone (IOU)
Storage	Generic Long-Duration Energy Storage (24-hr)	Uncapped	One resource per zone (IOU)
Storage	Generic Long-Duration Energy Storage (100-hr)	Uncapped	One resource per zone (IOU)

For most thermal and energy storage technologies, as well as distributed solar, biomass, and deep enhanced geothermal (EGS), a unique candidate resource is modeled in each RESOLVE zone (IOU); for example, three CCGT resources are modeled, one each in the PGE, SCE, and SDGE RESOLVE zones.

Most utility-scale renewable resources, including solar PV, onshore wind, offshore wind, conventional geothermal, near-field EGS, and pumped hydro storage, are assigned to RESOVLE zones (IOUs) based on the actual locations of likely candidate projects. Those locations are informed either by geospatial analysis or public data on identified candidate projects. In either case, candidate projects are assigned to zones in RESOLVE via the RESOLVE region map. New to the 2024-2026 IRP cycle, this map has been updated to conform with the CAISO Study Areas used in TPP analyses, including busbar mapping and the CAISO 20-Year Transmission Outlook.

The RESOLVE region map is provided in Figure 8 below. The rough mappings of the 2025-26 TPP RESOLVE resource regions to the CAISO study areas used in the 2024-2026 IRP cycle are provided in

Table 37 below; note that these mappings are approximate and the exact region boundaries have changed.

Figure 8. RESOLVE candidate resource regions

Table 37. RESOLVE candidate resource regions

Zone/IOU	2025-26 TPP RESOLVE Regions	CAISO Study Area(s)
PGE	Northern California Solano	PGE North of Greater Bay Area (NGBA) PGE Greater Bay Area (GBA)
	Southern PGAE Central Valley North Los Banos	PGE Fresno PGE Kern

SCE	Tehachapi	SCE Northern
	Greater LA	SCE Metro
	Greater Kramer	SCE North of Lugo (NOL)
	Southern NV Eldorado	SCE East of Pisgah (EOP)
	Riverside	SCE Eastern
	Arizona (Northern Half)	SCE Arizona
SDGE	Greater SD Greater Imperial	SDGE Imperial
	Arizona (Southern Half)	SDGE Arizona

In addition to in-CAISO resources, the CPUC IRP models additional out-of-state wind and geothermal resources in neighboring states with planned or hypothesized transmission pathways to deliver energy to the CAISO system border. Those resources are assigned to RESOLVE zones based on their expected tie-in locations. Out-of-state (non-CAISO) resources are discussed in Section 5.3.2.3.

Within RESOLVE, candidate solar PV resources are represented as either utility-scale or distributed. Utility-scale and distributed solar resources differ in cost (Section 5.3.3.1), transmission (Section 5.5), and performance (Section 6.2) assumptions. There are two types of distribution-level solar resources modeled in RESOLVE.

- **Customer solar** represents behind-the-meter (BTM) rooftop solar and is a mix of mostly residential and some commercial solar resources that benefit from net energy metering (NEM). Customer solar is not modeled as a candidate resource, meaning that its capacity is not optimized by RESOLVE. Rather, the dispatch is modeled like a supply-side resource with a specified generation profile. The installed capacity and energy of customer solar in RESOLVE are consistent with IEPR forecasts.
- **Distributed solar** represents commercial, in-front-of-meter rooftop solar. Distributed solar is available for selection in RESOLVE as a candidate resource that can be optimized. The costs for distributed solar are representative of a 200 kW system.

The CPUC's IRP aims to model utility procurement needs and transmission needs given forecasts of load, energy efficiency, customer solar adoption, etc. Although the CPUC's IRP allows the optimization of conventional demand response, it does not attempt to determine the optimal mix of customer- vs. bulk grid-sited resources for solar and wind resources. In addition, RESOLVE does not capture any transmission and distribution (T&D) benefits of customer-sited resources.

Distributed wind is not included as an optimized resource in the IRP model due to limited potential and higher costs, relative to utility-scale wind projects.

The following sections will discuss the resource potential, first available year, and cost results for natural gas (Section 5.2), renewables (Section 5.3), and storage (Section 5.4) resources.

5.2 Natural Gas

The 2024-2026 IRP cycle includes four technology options for new natural gas generation: advanced combined cycle gas turbines (CCGT), aeroderivative combustion turbines (CT-Aero), frame combustion turbines (CT-Frame), and reciprocating engines. Each option has different costs, efficiency, and operational characteristics. Natural gas generator all-in fixed costs are derived from NREL 2024 ATB[45] and EIA 2023 AEO.[46] Natural gas fuel costs are discussed in Section 6.8. Operational assumptions for these plants are summarized in Section 6.4. The first year that new natural gas generation is assumed to be able to come online is 2030, reflecting a 4-year construction lead-time.

The resource cost estimates for new natural gas generators in 2025 are summarized in Table 38. Although only one row per technology is shown, note that three resources per technology are reflected in RESOLVE, one per zone (IOU), each with the same costs.

Table 38. Capital, FO&M, and levelized fixed costs for candidate natural gas resources in 2025 (2022 $)

Technology	Capital Cost ($/kW)	Fixed O&M Cost ($/kW-yr)	Levelized Fixed Cost ($/kW-yr)
CCGT—Advanced	$1,421	$35	$174
CT–Frame	$1,082	$26	$137
CT–Aero	$1,782	$38	$208
Reciprocating Engine	$2,795	$62	$317

45 NREL 2024 Electricity Annual Technology Baseline. https://atb.nrel.gov/electricity/2024/index
46 U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2023. https://www.eia.gov/outlooks/aeo/

5.3 Renewables

This section covers the assumptions, methodology, and results for resource potential, first available year, and resource cost of candidate renewable energy technologies, including:

- Utility-Scale Solar PV
- Distributed Solar
- In-State Onshore Wind
- Out-of-State Onshore Wind
- Offshore Wind
- Geothermal
- Enhanced Geothermal Systems (EGS)
- Biomass

5.3.1 Resource Potentials and Land Use Screens

To characterize the resource potential available for capacity expansion modeling, geospatial analysis is performed on available land in California and throughout the Western Interconnection to identify potential sites for renewable development. The study includes an assessment of potentially viable project sites, and resource potentials within those sites, to determine an overall potential for each renewable resource in RESOLVE. In the analysis, raw resource potentials are filtered through a set of techno-economic and environmental screens to produce the potential totals. The techno-economic and environmental screens are developed using spatial analysis methods consistent with prior studies.[47, 48, 49, 50, 51, 52] Locations which are

---

[47] https://greeningthegrid.org/Renewable-Energy-Zones-Toolkit/topics/social-environmental-and-otherhttps://greeningthegrid.org/Renewable-Energy-Zones-Toolkit/topics/social-environmental-and-other-impactsimpacts#ReadingListAndCaseStudies

[48] Multi-Criteria Analysis for Renewable Energy (MapRE), University of California Santa Barbara. https://mapre.es.ucsb.edu/

[49] Larson, E. et. al. "Net-Zero America: Potential Pathways, Infrastructure, and Impacts, Interim Report." Princeton University, 2020. https://environmenthalfcentury.princeton.edu/sites/g/files/toruqf331/files/2020https://environmenthalfcentury.princeton.edu/sites/g/files/toruqf331/files/2020-12/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf12/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf.

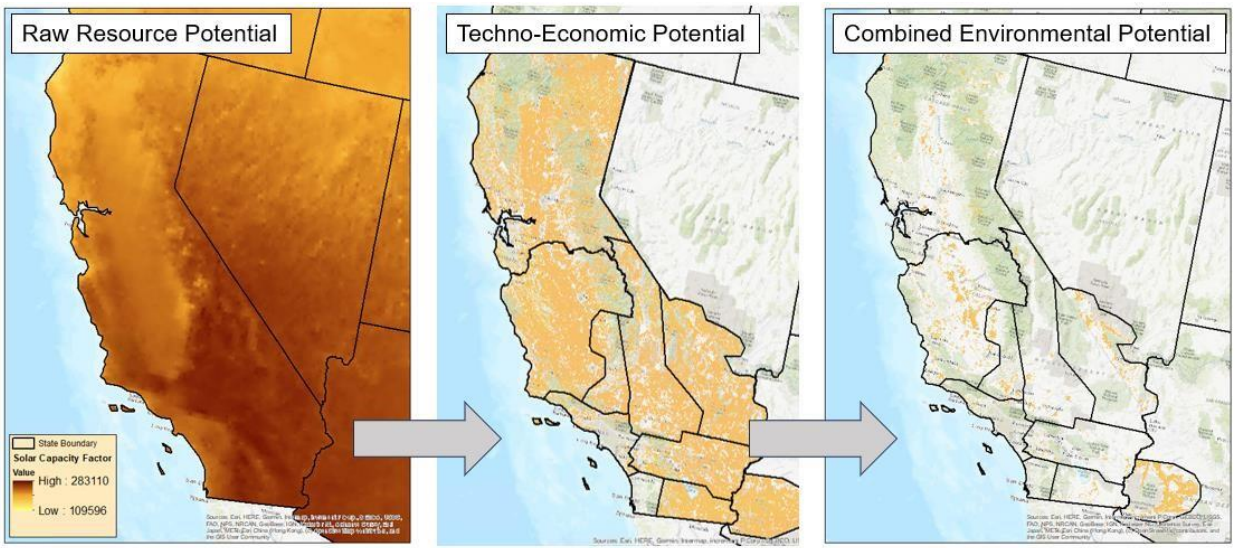
[50] Wu, G. et. al. "Low-Impact Land Use Pathways to Deep Decarbonization of Electricity." *Environmental Research Letters* 15, no. 7 (July 10, 2020). https://doi.org/10.1088/1748-9326/ab87d1.

[51] RETI Coordinating Committee, RETI Stakeholder Steering Committee. "Renewable Energy Transmission Initiative Phase 1B Final Report." California Energy Commission, January 2009.

[52] Pletka, Ryan, and Joshua Finn. "Western Renewable Energy Zones, Phase 1: QRA Identification Technical Report." Black & Veatch and National Renewable Energy Laboratory, 2009. https://www.nrel.gov/docs/fy10osti/46877.pdf.

not suitable for commercial-scale renewable energy development are screened out to produce a set of land use scenarios. There are several types of site suitability criteria which make up the screens: techno-economic criteria, legal prohibitions on development, administratively protected areas, and areas of conservation importance.

Figure 9. Site suitability methods used to identify wind and solar technical resource potential.



The detailed geospatial dataset is aggregated by region to produce resource potentials for each candidate resource in RESOLVE.

5.3.1.1 Raw Resource Potential Rasters

Raw resource potential rasters[53] representing simulated capacity factor data for wind and solar were created from the NREL Wind Supply Curves[54] and NREL System Advisor Model (SAM),[55] respectively. For deep EGS, temperature-at-depth estimates in 1-km bands at 4-km resolution, with depths ranging from 3 km-7 km, were taken from the Stanford Thermal Earth Model.[56] Technology-specific modeling assumptions are made regarding the design and operating characteristics of each technology. These modeling assumptions are described below.

---

53 A raster consists of a matrix of cells or pixels organized into a grid where each cell contains a value representing information.

54 Lopez, A. et. al. "Renewable Energy Technical Potential and Supply Curves for the Contiguous United States: 2024 Edition." NREL, 2024. https://www.nrel.gov/docs/fy25osti/91900.pdf.

55 NREL System Advisor Model (SAM). https://sam.nrel.gov/

56 Aljubran, M. and Horne, R. "Stanford Thermal Earth Model for the Conterminous United States." Stanford, 2024. https://gdr.openei.org/submissions/1592. DOI 10.15121/2324793.

Table 39. Technology configuration modeling assumptions[57]

	Wind	Solar	EGS
Typical nameplate capacity (MW)	4 (Turbine)	50	N/A
Mounting structure	N/A	Single-axis tracking	N/A
Hub height / Rotor diameter	110 m / 150 m	N/A	N/A
Operating losses	16.7%	14%	N/A
Azimuth	N/A	180o	N/A
Ground coverage ratio	N/A	30%	N/A
Inverter loading ratio	N/A	1.34	N/A
Near-field reservoirs	N/A	N/A	Identical to known hydrothermal fields
Deep-field depth	N/A	N/A	3 km-7 km

The capacity factor estimates used in the GIS resource potential and land use screens analysis are used only for estimating available land area and resource potentials; these are not the values that are used in IRP modeling. The capacity factor estimates assigned to each wind candidate potential area are based on the latest gridded mean capacity factor dataset published by NREL.[58] This updated dataset from NREL uses bias-corrected High-Resolution Rapid Refresh (HRRR) wind resource data from 2015-2023 in addition to the previously used 2007-2013 capacity factor data from WTK. The renewable energy profiles used in IRP modeling are discussed in Section 6.2.

The conventional geothermal (hydrothermal) resource potential was estimated using several publicly available data sources. For known hydrothermal fields within California, the CEC database of geothermal resource potential by field is used.[59] This data is informed by earlier studies, including a 2008 report published by the U.S. Geological Survey (USGS).[60] Out-of-state conventional geothermal (hydrothermal) resource potential was based on a 2010 assessment

[57] Conventional geothermal and pumped hydro storage resource potentials are characterized from published results that have already factored in relevant techno-economic data, and are not shown here.

[58] Lopez, Anthony, Gabriel R. Zuckerman, Pavlo Pinchuk, Michael Gleason, Marie Rivers, Owen Roberts, Travis Williams, Donna Heimiller, Sophie-Min Thomson, Trieu Mai, and Wesley Cole. 2025. Renewable Energy Technical Potential and Supply Curves for the Contiguous United States: 2024 Edition. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-91900. https://www.nrel.gov/docs/fy25osti/91900.pdf.

[59] Geothermal Resource Potential by Field. CEC, 2023. https://cecgis-caenergy.opendata.arcgis.com/datasets/32b037f8867f4f2485a77df530a7034f_0/explore?location=36.963735%2C-118.868422%2C6.01. Updated October 2024.

[60] Wiliams, C. et. al. "A Review of Methods Applied by the U.S. Geological Survey in the Assessment of Identified Geothermal Resources." USGS, 2008. https://pubs.usgs.gov/of/2008/1296/pdf/of2008-1296.pdf.

performed for the Renewable Energy Transmission Initiative (RETI)[61] and additional data from the USGS.[62] The resource potential characterization approach entails estimating the area, thickness, and average temperature of the exploitable reservoir in a geothermal area. The potential in megawatts (MW) is then calculated assuming a certain project life and recovery efficiency. Estimation of the amount of electricity that could be generated at various geothermal sites was based on empirically derived formulae relating the estimated amount of heat that can be converted from a site to electrical output.

For EGS, the near-field resource potential is assumed to be equal to the conventional (hydrothermal) potential, effectively doubling the overall potential at those project sites (for increased cost), an assumption that aligns with the 2023 NREL Enhanced Geothermal Shot Analysis.[63] For deep EGS, empirically derived formulae from NREL[64] are used to convert the temperature-at-depth estimates into MW/km^3 estimates, for rock with a minimum temperature of 150^{o}C.

5.3.1.2 Techno-Economic Land Use Screens

The site-suitability criteria included in the techno-economic land use screens for utility-scale solar, wind, and deep EGS are listed in Table 40. As an update from the previous inputs & assumptions and based on analysis using the latest NREL capacity factor data, the minimum capacity factor threshold for wind candidate project areas has been updated to 30%. Since the resource potential for out-of-state wind (NM, ID, WY) is constrained by the availability of new transmission lines required to deliver those resources to CAISO, the land use analysis for out-of-state wind has not been updated for the 2025 I&A. As discussed in the previous section, the conventional geothermal (hydrothermal) and near-field EGS resource potentials were characterized based on published results from earlier studies that already considered equivalent techno-economic criteria such as slope, population density, and existing infrastructure; those assumptions are not presented here.

[61] Lovekin, J. and Pletka, R. “Geothermal Assessment as Part of California’s Renewable Energy Transmission Initiative (RETI). GeothermEx, 2009. http://repository.usgin.org/category/thematic-keywords/reti.

[62] “USGS Western United States Geothermal Favorability.” USGS, 2019. https://www.usgs.gov/tools/western-united-states-geothermal-favorability.

[63] Augustine, C. et. al. “Enhanced Geothermal Shot Analysis for the Geothermal Technologies Office.” NREL, 2023. https://www.nrel.gov/docs/fy23osti/84822.pdf.

[64] Augustine, C. “Update to Enhanced Geothermal System Resource Potential Estimate: Preprint.” NREL, 2016. https://www.osti.gov/biblio/1330935.

Table 40. Techno-economic site suitability criteria and exclusion thresholds

Criterion	Screening Threshold or Exclusion Setback[65]		
	Solar	**Wind**	**Deep EGS**
Slope	> 10°	> 10°	N/A
Population Density	> 100/km²	> 100/km²	> 100/km²
Capacity Factor	< 16% (DC)	< 30%	80th percentile of extractable energy (MW/km³)
Interconnection Distance	> 30 miles	> 30 miles	> 30 miles
Urban Areas	< 500 m	< 1,000 m	< 1,000 m
Water Bodies	< 250 m	< 250 m	< 250 m
Railways	< 30 m	< 250 m	N/A
Major Highways	< 125 m	< 125 m	N/A
Airports	< 1,000 m	< 5,000 m	< 1,000 m
Active Mines	< 1,000 m	< 1,000 m	< 1,000 m
Military Lands	< 1,000 m	< 3,000 m	< 1,000 m
Existing Project Footprints	Excluded	Excluded	Hydrothermal and near-field EGS areas removed

The capacity factor thresholds reported above are only used to inform the GIS resource potential and land use screens analysis; these values are not used in IRP modeling. The renewable energy profiles used in IRP modeling are discussed in Section 6.2. A sensitivity analysis of the wind resource potential resulting from varying capacity factor exclusion thresholds is provided in Section 5.3.1.4.

5.3.1.3 Environmental Land Use Screens

The environmental land use screens used for in-state resources in the 2024-2026 IRP cycle are the CEC Land-Use Screens for Electric System Planning, developed in 2023 for use in IRP modeling.[66] The layers for solar, wind, and geothermal (including EGS) consist of the following environmental criteria:

- Techno-economic land use screen (Section 5.3.1.2)
- Protected Area layer
- Cropland Index Model (Threshold: Mean, 7.7)
- Terrestrial Intactness Model (Threshold: Mean, 0.3)
- Biological Planning Priorities:

[65] Conventional geothermal and pumped hydro resource potentials are characterized from published results that have already factored in relevant techno-economic data, and are not shown here.
[66] https://www.energy.ca.gov/data-reports/california-energy-planning-library/land-use-screens.

- ACE Biodiversity (Rank 5)
- ACE Connectivity (Ranks 4 & 5)
- ACE Irreplaceability (Ranks 4 & 5)
- Wetlands (from CA Nature Habitat and Land Cover)
- USFWS Critical Habitat

For out-of-state resources, including both CAISO-interconnecting regions in Nevada and Arizona as well as wind and geothermal resources in Nevada, Oregon, Idaho, Utah, Wyoming, and New Mexico that do not have existing interconnections to CAISO, the environmental land use screen was created using the Environmental Risk Classes 3 and 4 from the WECC Environmental Data Viewer, which continues to be the most comprehensive environmental land use review of the entire western U.S.[67]

For utility-scale solar, staff also assessed the potential land-use impacts of the Bureau of Land Management (BLM) Approved Western Solar Plan (2024 WSP) and Final Programmatic Environmental Statement (PEIS), approved in December 2024.[68] The intent of the WSP is to limit impacts associated with utility-scale solar energy on lesser-disturbed lands, as well as focusing development into areas closer to the transmission grid. The net impact of excluding these areas on the overall solar resource potential is shown in Table 42.

Staff are also aware of the recent approvals of the Sattitla and Chuckwalla National Monuments and will assess the resource potential and land-use impacts of those new areas once additional geospatial data becomes available.

5.3.1.4 Resource Potential Totals

After application of the techno-economic and environmental land use screens, the remaining areas indicate locations that meet the site suitability criteria for renewable energy development. These areas are then discretized into a grid of 4-km square cells. Each cell in the grid is defined to be a Candidate Project Area (CPA). For each CPA, the following location-specific attributes are calculated: area (km^2), nameplate capacity (MW), distance to nearest substation (km), mean elevation (m), and mean slope. Land use factors of 30 MW/km^2 (8.24 acre/MW) for candidate solar[69] and 6.2 MW/km^2 (40 acre/MW) for candidate wind[70] are assumed. For deep EGS, the land use factors vary with rock temperature, as covered in Section 5.3.

[67] https://www.wecc.org/SystemAdequacyPlanning/Pages/Environmental-and-Cultural-Considerations.aspx.

[68] "Utility-Scale Solar Energy Development PEIS/RMPA." U.S Department of the Interior Bureau of Land Management, 2024. https://eplanning.blm.gov/eplanning-ui/project/2022371/510

[69] Ong, S. et. al. "Land-Use Requirements for Solar Power Plants in the United States." NREL, 2013. https://www.nrel.gov/docs/fy13osti/56290.pdf.

[70] Equivalent to 40 acres/MW; Hossainzadeh, S. et. al. "Land-Use Screens for Electric System Planning: Using

After the CPAs have been characterized, they are grouped to produce the available resource potential for each candidate resource in RESOLVE. For consistency with prior studies and industry standard modeling conventions,[71] a land use discount factor is applied to the solar resource potential to reflect socioeconomic, cultural, or other considerations that will further reduce developable land. For the 2023 PSP, the amount of available land for solar development after applying the environmental land use screens was discounted by 80% to account for these factors. For the 2025 I&A, given the significant reductions to the solar resource potential due to the 2024 WSP, the discount factor has been lowered to 50% and is only applied to modeling regions that were not significantly impacted by the 2024 WSP and/or fall outside the DRECP. Specifically, the available solar resource potential after application of the environmental land use screens and 2024 WSP screen is reduced by 50% for all of PGE, as well as SCE Northern and SCE Metro study areas; no discount factor for solar is applied to other study areas.

During the 2023 PSP, to prioritize the development of in-state, onshore wind resources in areas with high capacity factors, the techno-economic land use screen for in-state wind applied a 28% minimum capacity factor threshold to the CPAs to remove underperforming sites from consideration.[72] For the 2025 I&A, using the updated wind capacity factor data published by NREL in 2024, a sensitivity analysis was performed to understand the trade-offs between this minimum capacity factor threshold and the resulting wind resource potential. First, the capacity factor for each CPA was updated using the new NREL data; then, successive filters at various capacity factor thresholds were applied to the dataset, and the resulting MW totals by region were summed. The results of this analysis are reported in Table 41. To maintain a statewide resource potential for onshore wind that is comparable to the 2023 PSP, Staff recommends a 30% minimum capacity factor threshold using the new NREL data. Additionally, in the 2023 PSP, an 80% discount factor was applied to Southern NV Eldorado Wind, reflecting reduced commercial interest for wind development in this area. For the 2025 I&A, Staff will apply a 50% discount factor to SCE East of Pisgah Wind (previously Southern NV Eldorado Wind), akin to the updated discount rate for utility-scale solar.

Geographic Information Systems to Model Opportunities and Constraints for Renewable Resource Technical Potential in California." CEC, 2023. https://www.energy.ca.gov/publications/2022/land-use-screens-electrichttps://www.energy.ca.gov/publications/2022/land-use-screens-electric-system-planning-using-geographic-information-systemssystem-planning-using-geographic-information-systems.

[71] Wu, G. et. al. "Low-Impact Land Use Pathways to Deep Decarbonization of Electricity." *Environmental Research Letters* 15, no. 7 (July 10, 2020). https://doi.org/10.1088/1748-9326/ab87d1.

[72] The capacity factors used in this analysis are not used elsewhere in IRP modeling. For a discussion on the renewable generation profiles and annual average capacity factors used in the RESOLVE and SERVM models, refer to Section 6.2.

*Table 41. Minimum Capacity Factor Threshold Sensitivity Analysis for In-State, Onshore Wind**

Resource Region	2023 PSP	28%	30%	32%	35%
PGE NGBA	3,405	3,157	2,872	2,166	190
PGE GBA	832	327	231	204	204
PGE Fresno	2,728	2,681	2,228	-	-
PGE Kern	91	91	91	91	91
SCE Northern	1,732	1,701	1,701	1,541	1,467
SCE Metro	-	-	-	-	-
SCE NOL	1,046	1,046	948	756	700
SCE Eastern	165	165	165	165	92
SCE EOP (50% reduction)	711	1,597	1,399	897	641
SDGE Imperial	251	251	251	251	133
SDGE Baja California**	2,473	2,473	2,473	2,473	2,473
Total (with 50% reduction to SCE EOP)	**13,434**	**13,489**	**12,359**	**8,544**	**5,991**

* The capacity factors used in this analysis come from NREL raster data and are not the final resource capacity factors used in RESOLVE or SERVM; see Section 6.2.

** Resource potential for Baja California Wind is taken from the CAISO Interconnection Queue and is not studied as part of this land-use analysis.

For deep EGS, given the large total resource potential across all depths, and the additional costs that would be required to drill to deeper depths, only the potentials at 3-km depth are considered for IRP modeling. If deep EGS is found to be cost-effective in future IRP modeling, additional resource potential at an increased cost will be considered for inclusion.

The resource potentials under the combined techno-economic and environmental land use screens, including the 2024 WSP and additional 50% reductions for select solar resources, a 30% capacity factor threshold for in-state wind, and a 3-km drilling depth for deep EGS, are summarized in Table 42. The resource potentials for out-of-state wind resources reflect the total transmission capabilities of all new transmission lines, both planned and generic, that are assumed to be available to deliver those resources to CAISO by 2045, as discussed in Section 5.5. These values represent the default assumption for RESOLVE.

Table 42. Available in-state (CAISO-interconnecting) resource potential under the techno-economic and environmental land use screens, GW

Technology	Study Area	Resource Potential
Solar	PGE NGBA	55.20
	PGE GBA	18.28
	PGE Fresno	44.96
	PGE Kern	23.58
	SCE Northern	21.84
	SCE Metro	0.51
	SCE NOL	19.88
	SCE Eastern	16.93
	SCE EOP	16.37
	SCE Arizona	33.34
	SDGE Imperial	12.26
	SDGE Arizona	18.34
	PGE Distributed Solar	20.05
	SCE Distributed Solar	15.34
	SDGE Distributed Solar	1.22
	Total	**317.99**
Wind	SDGE Baja California (2)	2.47
	PGE NGBA	2.87
	PGE GBA	0.23
	PGE Fresno	2.23
	PGE Kern	0.09
	SCE Northern	1.70
	SCE NOL	0.95
	SCE Eastern	0.17
	SCE EOP	1.39
	SDGE Imperial	0.25
	Total [73]	**12.36**
Conventional Geothermal	PGE NGBA	0.85[74]
	SCE NOL	0.14

[73] This total includes an additional 50% reduction to the East of Pisgah (SCE EOP) potential to reflect commercial interest.

[74] Excludes 18 MW at the Geysers reported as "In Development" in the CPUC Generator Baseline.

	SCE Eastern	1.88[75]	
	SDGE Imperial	0.53	
	Total	**3.40**	
Enhanced Geothermal (EGS)		Near-Field EGS	Deep EGS
	PGE	0.86	24.92
	SCE	2.07	1.29
	SDGE	0.53	0.44
	Total	**3.46**	**26.65**
Biomass[76]	**PGE_New_Biomass**	**0.93**	
	SCE_New_Biomass	**0.11**	
	SDGE_New_Biomass	**0.09**	

(1) Distributed Solar resource potentials have been disaggregated from the previous IRP cycle based on IOU service territory area.

(2) Wind resource potential for Baja California is equal to the sum of the Net MW to Grid for all projects in the CAISO Interconnection Queue sited in Baja California.[77]

Table 43. Available out-of-state resource potential under the techno-economic and environmental land use screens, GW[78]

	Resource	Resource Potential, MW
Wind	Idaho_Wind	1.10
	New_Mexico_Wind	8.94[79]
	Wyoming_Wind	9.00
	Total	**19.03**
Conventional Geothermal	Nevada Geothermal	1.45
	Oregon Geothermal	0.52
	Utah Geothermal	0.18
	Total	**2.16**
Enhanced Geothermal	Nevada EGS	**12.98**
	Oregon EGS	**6.38**
	Idaho EGS	**10.73**
	Utah EGS	**6.31**
	Total	**36.41**

75 Excludes 44 MW near the Salton Sea reported as "In Development" in the CPUC Generator Baseline.

76 Biomass resource potential is determined from an earlier county-level analysis performed by CPUC and has not been updated for the 2024-26 IRP cycle.

77 Generator Interconnection Queue Report available through the CAISO Resource Interconnection Management System: https://rimspub.caiso.com/rimsui/logon.do. Accessed 4/7/23.

78 Out-of-state resources are subject to additional availability constraints pursuant to transmission deliverability to the CAISO system border. These availability constraints are discussed more in Section 5.5.

79 Excludes 1,585 MW of SunZia Wind reported as "In Development" in the CPUC Generator Baseline.

The resource potentials for candidate renewable resources are subject to additional availability constraints, which are discussed in Section 5.3.2.

Table 44. Summary of Resource Potential by Technology in the Previous and Current Inputs and Assumptions (MW)

Resource	2022-2023 IRP Cycle Resource Potential (MW)	2024-2026 IRP Cycle Resource Potential (MW)
Solar	452,897	281,488
Onshore Wind, In-State	11,424	12,355
Out-of-State Onshore Wind, Out-of-State	13,100 (through 2040) 52,113 (after 2040)	19,036
Offshore Wind	28,925	28,925
Pumped Hydro Storage	3,173	16,473
Biomass	1,156	1,156
Conventional Geothermal	5,522	5,563
Enhanced Geothermal (Near-Field)	Not Modeled	5,619
Enhanced Geothermal (Deep)	Not Modeled	60,827

5.3.1.5 Offshore Wind Resource Potential

The offshore wind resource potential was calculated using the site areas and “High” 5 MW/km^2 area density factor from the June 2022 AB 525 NREL presentation.[80] The Diablo Canyon Dormant Call Area has been removed from RESOLVE modeling. The resulting offshore wind resource potential is summarized in Table 45.

Table 45. Offshore wind resource potential (GW)

Site	Area (sq. km)	Area Density Factor (MW/km^2)	Resource Potential (GW)
Morro Bay WEA (Wind Energy Area)	975	5	4.875
Humboldt WEA	536	5	2.680
Cape Mendocino Study Area	2,072	5	10.360
Del Norte Study Area	2,202	5	11.010
Total	**7,226**		**28.925**

[80] CEC Docket 17-MISC-01. https://efiling.energy.ca.gov/GetDocument.aspx?tn=243707&DocumentContentId=77539

5.3.2 First Available Year and Annual Build Limits

The first available years for candidate renewable resources in the 2024-2026 IRP cycle have been updated to reflect feasible timelines for bringing resources online based on the CAISO interconnection queue, neighboring POU interconnection queues, in-development transmission projects across the WECC, and typical development lead times for resources and transmission. The first available year in RESOLVE is applied on a resource-by-resource basis; accordingly, a range of years applies when summarizing by technology in Table 46.

Table 46. First available year by candidate renewable resource technology

Resource Type	First Available Year
Solar PV	2026
Onshore Wind (in-state)	2026-2030
Onshore Wind (out-of-state)	2026-2040
Offshore Wind	2032-2040
Conventional Geothermal (in-state)	2026-2030
Conventional Geothermal (out-of-state)	2030-2035
Near-Field Enhanced Geothermal (EGS)	2030-2035
Deep Enhanced Geothermal (EGS)	2035
Biomass	2028

In addition to the first available years and annual deployment limits discussed in this section, candidate renewable resources are subject to CAISO transmission constraints, which may further restrict what can be selected in RESOLVE. Transmission representation is discussed in Section 5.5.

5.3.2.1 Solar PV Annual Build Limits

With large representation in the CAISO interconnection queue and strong commercial interest, solar PV is immediately available for selection in RESOLVE. However, based on CAISO Interconnection Queue projected commercial operation dates and historical annual project completion rates, an annual build limit is imposed on candidate solar resources in RESOLVE to ensure that the selected resource additions are feasible. These limits amount to 4 GW of annual capacity additions per year through 2028. After 2028, no restrictions are placed on the selection of additional solar resources. Staff propose raising the previous limit of 3 GW annually to 4 GW because data in the CAISO Master Generation Capability List (MGC)[81] and LBNL Tracking the Sun[82] show that CAISO solar additions have exceeded 3 GW annually starting in 2023.

Table 47. Solar PV annual build limits through 2028, MW

Technology	2026	2027	2028	Total
Solar PV	4,000	4,000	4,000	12,000

5.3.2.2 In-State Wind and Geothermal Availability

The available resource potentials described in Section 5.3, CAISO-interconnecting wind and geothermal are subject to availability constraints through 2030. The schedules reported in Table 48 are the result of staff analysis of the CAISO interconnection queue, commercial interest, and anticipated construction lead times.

Table 48. In-state (CAISO-interconnecting) wind and geothermal annual build limits, MW

<table>
<tr><th></th><th>Resource</th><th>2026</th><th>2027</th><th>2028</th><th>2029</th><th>2030</th></tr>
<tr><td rowspan="9">Onshore Wind</td><td>PGE NGBA</td><td>-</td><td>206</td><td>206</td><td>206</td><td rowspan="9">Full Potential</td></tr>
<tr><td>PGE GBA</td><td>231</td><td>231</td><td>231</td><td>231</td></tr>
<tr><td>SCE Northern</td><td>-</td><td>-</td><td>100</td><td>206</td></tr>
<tr><td>SCE NOL</td><td>-</td><td>212</td><td>212</td><td>312</td></tr>
<tr><td>SCE Eastern</td><td>-</td><td>-</td><td>-</td><td>60</td></tr>
<tr><td>SCE EOP</td><td>-</td><td>308</td><td>308</td><td>408</td></tr>
<tr><td>SDGE Imperial</td><td>63</td><td>63</td><td>63</td><td>63</td></tr>
<tr><td>SDGE Baja California</td><td>353</td><td>353</td><td>353</td><td>1,353</td></tr>
<tr><td>Total</td><td>647</td><td>1,373</td><td>1,473</td><td>2,839</td></tr>
<tr><td rowspan="3">Geothermal</td><td>SCE Eastern</td><td>83</td><td>140</td><td>357</td><td>671</td><td rowspan="3">Full Potential</td></tr>
<tr><td>SDGE Imperial</td><td>-</td><td>83</td><td>83</td><td>83</td></tr>
<tr><td>Total</td><td>83</td><td>223</td><td>440</td><td>754</td></tr>
</table>

[81] https://emp.lbl.gov/utility-scale-solar

[82] http://oasis.caiso.com/mrioasis/logon.do

Out-of-State Geothermal	Nevada (Eldorado)	230	290	290	290	Full Potential
	Nevada (Beatty)	58	97	121	121	
	Utah	-	40	40	80	
	Total	**288**	**427**	**451**	**491**	

5.3.2.3 Out-of-State Wind and Geothermal Availability

The available resource potentials described in Section 5.3, out-of-state wind and geothermal resources will require investments in new transmission to deliver energy and capacity to the CAISO system. Despite additional transmission costs (Section 5.5.4), the chief advantage of out-of-state wind resources is that these resources typically enjoy higher capacity factors than what can be sourced and interconnected directly to the existing transmission system.

Resource availability by year for out-of-state resources reflect CPUC estimates of the transmission project pipeline across the WECC, as well as hypothetical new transmission development to deliver additional resources to the CAISO system border. The analysis accounts for project lead time, likelihood of completion, and availability of line capacities for use by CAISO. The availability of out-of-state resources are summarized in Table 49. Conventional geothermal in Nevada (SCE), Nevada (PGE), Utah, and Oregon are available, unconstrained, beginning in 2032, 2035, 2030, and 2030, respectively. Nevada, Utah, Idaho, and Oregon near-field EGS are assumed to be available in the same years as conventional geothermal (hydrothermal) resources. All deep EGS is assumed to be available starting in 2035. The costs and assumed tie-in locations associated with specific transmission projects that inform these availability assumptions are discussed in Section 5.5.4.

Table 49. Out-of-state wind build limits, MW

	Resource	IOU	2025	2030	2035	2040	2045
Out-of-State Wind	Idaho Wind	SCE	-	1,100	1,100	1,100	1,100
	New Mexico Wind	SCE	-	2,936	2,936	8,936	8,936
	Wyoming Wind	SCE	-	1,500	3,000	5,000	5,000
	Wyoming Wind	PGE	-	-	-	4,000	4,000
	Total		**-**	**5,536**	**7,036**	**19,036**	**19,036**

5.3.2.4 Offshore Wind Availability

The availability of offshore wind reflects an 8- to 15-year lead time and prioritization of the Morro Bay and Humboldt Wind Energy Areas because they are the only resource areas officially recognized by BOEM and for which there are now active leases.

Table 50. Offshore wind first available years

Site	Potential (MW)	First Available Year
Morro Bay	4,875	2032
Humboldt	2,680	2035
Cape Mendocino	10,360	2040
Del Norte	11,010	2040
Total	**28,925**	

5.3.3 Resource Costs

The assumptions for RESOLVE renewable resources are shown in the tables below. While the levelized fixed cost (LFC, $/kW-yr) is used in RESOLVE as the cost to build new resources in a given year; these costs have been translated into the levelized cost of electricity (LCOE, $/MWh) for comparability. The capacity factors used for this conversion are discussed in Section 6.2. The costs reported below reflect custom CAPEX assumptions for solar and onshore wind resources, which are discussed in Section 5.3.3, as well as market-based financing assumptions (Section 4.4) and state-specific cost multipliers (Section 4.5). Incremental costs due to new transmission lines, including long-distance transmission lines for out-of-state resources, are included in the LCOE results for out-of-state resources; those costs are discussed in additional detail in Section 5.5. The costs in these tables reflect the full “Bonus” tax credit incentives under the IRA with 90% monetization.

In this section, updated resource cost assumptions are compared to the assumptions made in the most recent 25-26 TPP. Those costs are identical to the 2023 PSP costs, which are discussed in the 2023 Inputs and Assumptions document.[83]

[83] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/inputs-assumptions-2022-2023_final_document_10052023.pdf

The full resource cost results are made available as part of the supplemental RESOLVE workbooks, including the Resource Cost & Build (RC&B) workbook and the CPUC Pro Forma model.

Table 51. In-state (CAISO-interconnecting) renewable resource cost assumptions by build year

Resource		Capacity Factor	Capital Cost (2022 $/kW)				Levelized Cost of Electricity (2022 $/MWh)			
			2025	2030	2035	2040	2025	2030	2035	2040
Biomass	PGE_New_Biomass	60%	$5,271	$5,026	$4,859	$4,687	$167	$164	$163	$161
	SCE_New_Biomass	60%	$5,271	$5,026	$4,859	$4,687	$167	$164	$163	$161
	SDGE_New_Biomass	60%	$5,271	$5,026	$4,859	$4,687	$167	$164	$163	$161
Conventional Geothermal	SDGE_Imperial_Geothermal	80%	$9,200	$8,522	$8,038	$7,839	$95	$88	$82	$81
	SCE_NOL_Geothermal	80%	$9,200	$8,522	$8,038	$7,839	$95	$88	$82	$81
	SCE_Eastern_Geothermal	80%	$9,200	$8,522	$8,038	$7,839	$95	$88	$82	$81
	PGE_NGBA_Geothermal	80%	$9,200	$8,522	$8,038	$7,839	$95	$88	$82	$81
Solar	PGE_Distributed_Solar	25%	$2,174	$1,859	$1,545	$1,416	$69	$59	$51	$47
	SCE_Distributed_Solar	26%	$2,174	$1,859	$1,545	$1,416	$65	$56	$48	$45
	SDGE_Distributed_Solar	25%	$2,174	$1,859	$1,541	$1,416	$69	$59	$51	$46
	PGE_Fresno_Solar	32%	$1,399	$1,190	$1,014	$865	$36	$28	$22	$18
	PGE_GBA_Solar	31%	$1,399	$1,190	$1,014	$865	$36	$28	$22	$18
	PGE_Kern_Solar	33%	$1,399	$1,190	$1,014	$865	$33	$26	$20	$16
	PGE_NGBA_Solar	31%	$1,399	$1,190	$1,014	$865	$36	$28	$22	$18
	SCE_Arizona_Solar		$1,346	$1,145	$976	$832	$27	$19	$13	$9

	SCE_Eastern_Solar	34%	$1,399	$1,190	$1,014	$865	$31	$24	$18	$15
	SCE_EOP_Solar	33%	$1,399	$1,190	$1,014	$865	$34	$26	$20	$16
	SCE_Metro_Solar	33%	$1,399	$1,190	$1,014	$865	$33	$26	$20	$16
	SCE_NOL_Solar	36%	$1,399	$1,190	$1,014	$865	$29	$22	$17	$13
	SCE_Northern_Solar	36%	$1,399	$1,190	$1,014	$865	$29	$22	$17	$13
	SDGE_Arizona_Solar	32%	$1,346	$1,145	$976	$832	$26	$19	$14	$11
	SDGE_Imperial_Solar	35%	$1,399	$1,190	$1,014	$865	$33	$26	$20	$16
Wind	PGE_Fresno_Wind	29%	$1606	$1471	$1349	$1238	$46	$42	$38	$35
	PGE_GBA_Wind	29%	$1,606	$1,471	$1,349	$1,238	$46	$42	$38	$35
	PGE_Kern_Wind	25%	$1,606	$1,471	$1,349	$1,238	$56	$50	$46	$42
	PGE_NGBA_Wind	26%	$1,606	$1,471	$1,349	$1,238	$53	$48	$44	$40
	SCE_Eastern_Wind	32%	$1,606	$1,471	$1,349	$1,238	$40	$35	$32	$29
	SCE_EOP_Wind	30%	$1,565	$1434	$1,315	$1,207	$38	$33	$30	$27
	SCE_NOL_Wind	25%	$1,606	$1,471	$1,349	$1,238	$56	$50	$46	$42
	SCE_Northern_Wind	25%	$1,606	$1,471	$1,349	$1,238	$56	$50	$46	$42
	SDGE_Baja_California_Wind	32%	$1,606	$1,471	$1,349	$1,238	$40	$35	$32	$29
	SDGE_Imperial_Wind	32%	$1,606	$1,471	$1,349	$1,238	$40	$35	$32	$29

Table 52. Out-of-state renewable resource cost assumptions by build year

Resource		Capacity Factor	Capital Cost (2022 $/kW)				Levelized Cost of Electricity (2022 $/MWh)			
			2025	2030	2035	2040	2025	2030	2035	2040
Geothermal	Nevada Geothermal	80%	$8,855	$8,202	$7,737	$7,545	$106	$97	$92	$91
	Utah Geothermal	80%	$8,846	$8,193	$7,729	$7,538	$99	$91	$86	$85
	Oregon Geothermal	80%	$9,140	$8,466	$7,986	$7,788	$102	$95	$89	$88
	Nevada Near-Field EGS	80%	$11,838	$10,330	$9,318	$9,087	$136	$119	$108	$106
	Utah Near-Field EGS	80%	$11,826	$10,320	$9,309	$9,078	$131	$116	$105	$104
	Oregon Near-Field EGS	80%	$12,219	$10,663	$9,618	$9,380	$135	$119	$109	$107
	Idaho Deep EGS	80%	$15,385	$12,525	$10,972	$10,700	$164	$137	$121	$119
	Nevada Deep EGS	80%	$15,453	$12,581	$11,021	$10,748	$170	$139	$123	$121
	Utah Deep EGS	80%	$15,438	$12,568	$11,010	$10,737	$163	$135	$119	$117
	Oregon Deep EGS	80%	$15,951	$12,986	$11,376	$11,094	$167	$139	$123	$121
Wind	Idaho Wind	28%	$1,560	$1,429	$1,311	$1,203	$66	$61	$58	$55
	New Mexico Wind	38%	$1,554	$1,423	$1,305	$1,198	$49	$45	$42	$40
	Wyoming Wind	40%	$1,564	$1,432	$1,314	$1,206	$53	$50	$47	$45

Note: The out-of-state resource LCOE totals shown above include a transmission cost adder equivalent to the cheapest transmission pathway for each resource among those identified in Section 5.5.

Table 53. Offshore wind resource cost assumptions by build year. Capital cost is exclusive of grid connection costs.[84]

	Resource	Capacity Factor	Capital Cost (2022 $/kW)				Levelized Cost of Electricity (2022 $/MWh)			
			2025	2030	2035	2040	2025	2030	2035	2040
Offshore Wind	Morro Bay Offshore Wind	46%	$7,267	$7,267	$4,894	$3,924	$174	$173	$122	$101
	Humboldt Offshore Wind	49%	$7,267	$7,267	$4,894	$3,924	$164	$163	$115	$95
	Cape Mendocino Offshore Wind	56%	$7,267	$7,267	$4,894	$3,924	$144	$144	$101	$84
	Del Norte Offshore Wind	53%	$7,267	$7,267	$4,894	$3,924	$152	$151	$107	$88

[84] Offshore wind is not available for selection until the mid-2030s.

5.3.3.1 Utility-Scale Solar Cost Assumptions

For the 2024-2026 IRP cycle, new assumptions for base year (2023) and forecasted CAPEX values have been developed pursuant to the methodologies discussed in Section 4.3. The updated CAPEX forecasts for a typical utility-scale solar resource (SCE Northern / Tehachapi area) compared to the assumptions used in the 25-26 TPP are shown in Figure 10 and Table 54.

Figure 10. Cost trajectories for utility-scale solar PV CAPEX

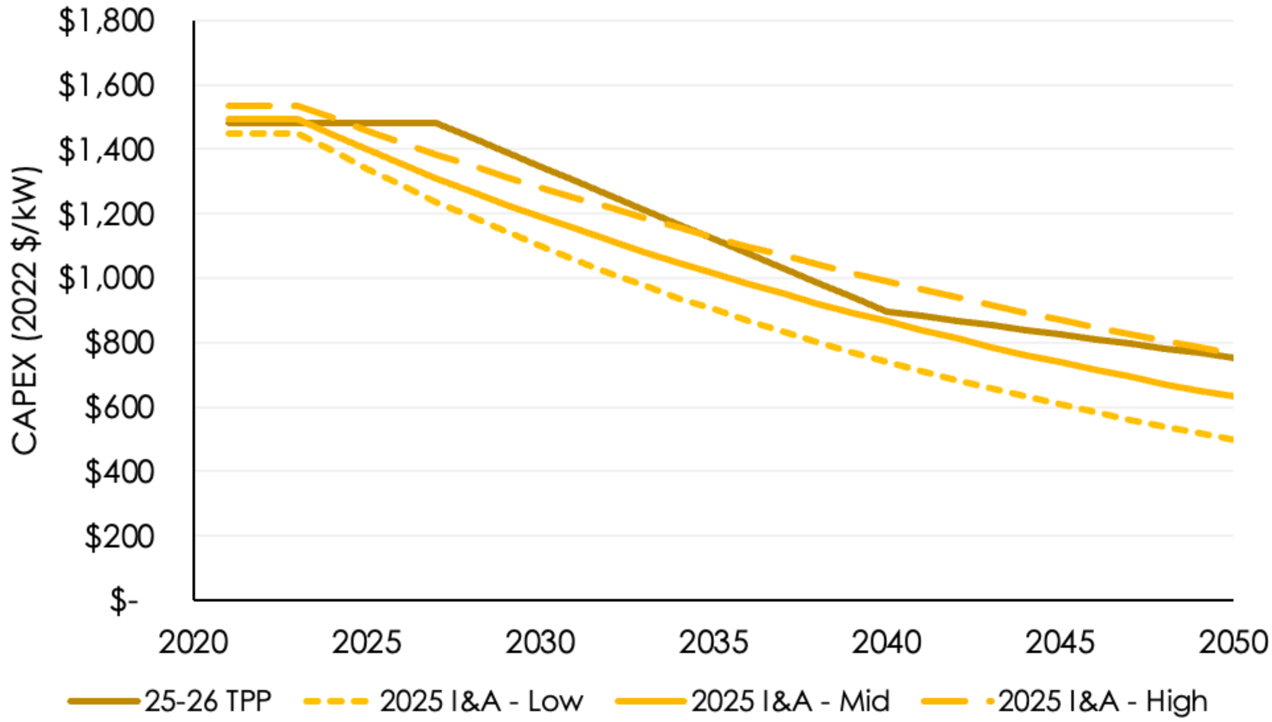


Table 54. Cost trajectories for utility-scale solar PV (2022 $/kWac)

Vintage	2025	2030	2035	2040	2045
25-26 TPP	$1483	$1348	$1122	$896	$825
2025 I&A - Low	$1340	$1099	$902	$740	$607
2025 I&A - Mid	$1399	$1190	$1014	$865	$739
2025 I&A - High	$1459	$1282	$1127	$990	$870

While custom CAPEX trajectories have been developed, NREL 2024 ATB is used to estimate the FO&M of solar PV resources. Regional adjustments to CAPEX, FO&M, and interconnection are made to reflect state-specific conditions, as discussed in Section 4.4. Cost calculations assume a single-axis tracking system with a 1.34 inverter loading ratio for utility-scale solar based on NREL 2024 ATB, and a fixed-tilt system with 1.15 inverter loading ratio for distributed solar based on Lawrence Berkeley National Laboratory's 2019 *Tracking the Sun* study.[85, 86]

Levelized costs are calculated using Recost with an assumed 7.08% nominal WACC (in 2025), 30-year economic life, and selection of the PTC ("Bonus" $27.50/MWh in 2023 dollars) with a tax credit monetization rate of 90%,

5.3.3.2 Onshore Wind Cost Assumptions

For the 2024-2026 IRP cycle, new assumptions for base year (2023) and forecasted CAPEX values have been developed pursuant to the methodologies discussed in Section 4.3. The updated CAPEX forecasts for a typical onshore wind resource (SCE Northern / Tehachapi area) compared to the assumptions used in the 25-26 TPP are shown in Figure 11 and

Table 55.

Figure 11. Cost trajectories for onshore wind CAPEX

[85] https://atb.nrel.gov/electricity/2024/utility-scale_pv.

[86] "Tracking the Sun: Pricing and Design Trends for Distributed Photovoltaic Systems in the United States." Lawrence Berkeley National Laboratory, 2019. https://emp.lbl.gov/sites/default/files/tracking_the_sun_2019_report.pdf.

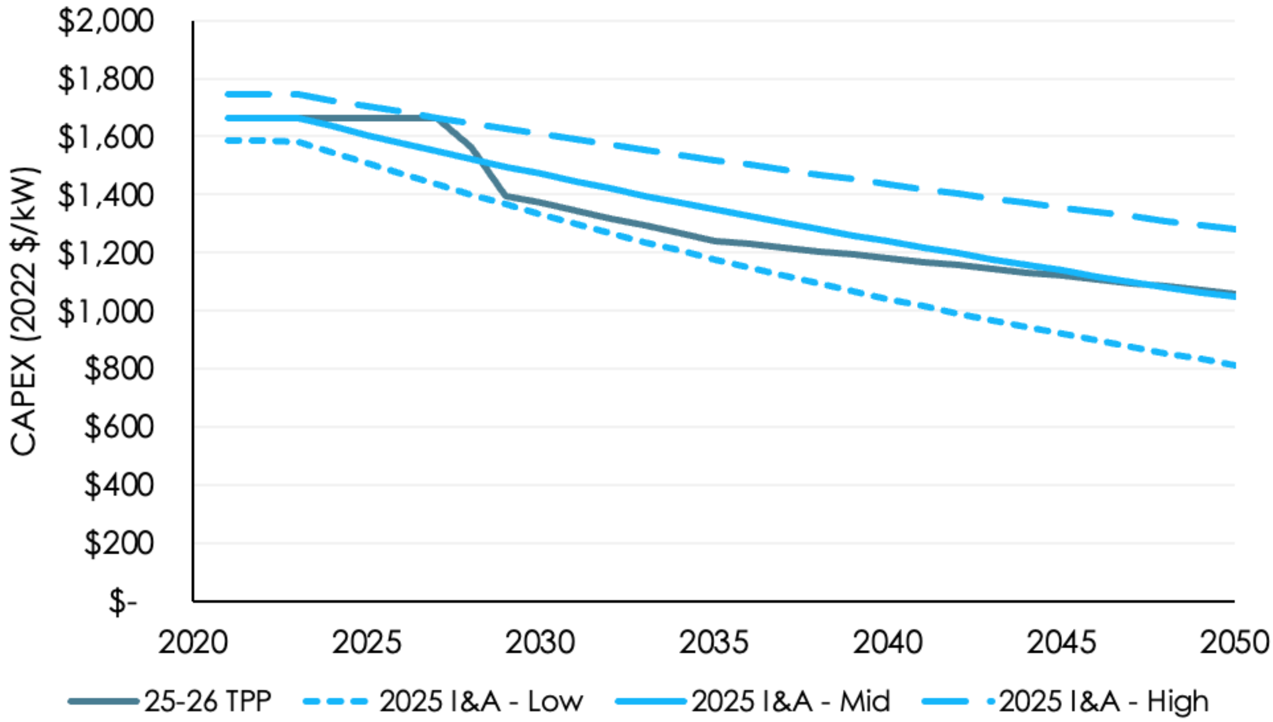


Table 55. Cost trajectories for onshore wind *(2022 $/kW)*

Vintage	2025	2030	2035	2040	2045
25-26 TPP	$1663	$1370	$1242	$1181	$1120
2025 I&A - Low	$1507	$1332	$1178	$1041	$920
2025 I&A - Mid	$1606	$1471	$1349	$1238	$1138
2025 I&A - High	$1704	$1609	$1520	$1435	$1355

While custom CAPEX trajectories have been developed, NREL 2024 ATB is used to estimate the FO&M of onshore wind resources. Regional adjustments to CAPEX, FO&M, and interconnection are made to reflect state-specific conditions, as discussed in Section 4.4.

Levelized costs are calculated using Recost with an assumed 6.99% nominal WACC (in 2025), 30-year economic life, and selection of the PTC ("Bonus" $27.50/MWh in 2023 dollars) with a tax credit monetization rate of 90%,

5.3.3.3 Offshore Wind Cost Assumptions

Staff reviewed the updated methodology for offshore wind published alongside NREL 2024 ATB. The new approach applies an assumed learning rate to present-day pilot project costs of $10,000/kW.[87] This approach aligns with the "Conservative" cost scenario that Staff presented as part of the April 2024 AB 1373 Need Determination Analysis for Centralized Procurement of Specified LLT Resources.[88] Consequently, Staff recommends using NREL 2024 ATB, Class 12 for its offshore wind costs (both CAPEX and Grid Connection Costs). No additional adjustments to offshore wind CAPEX are made.

Figure 12. Cost trajectories for offshore wind CAPEX

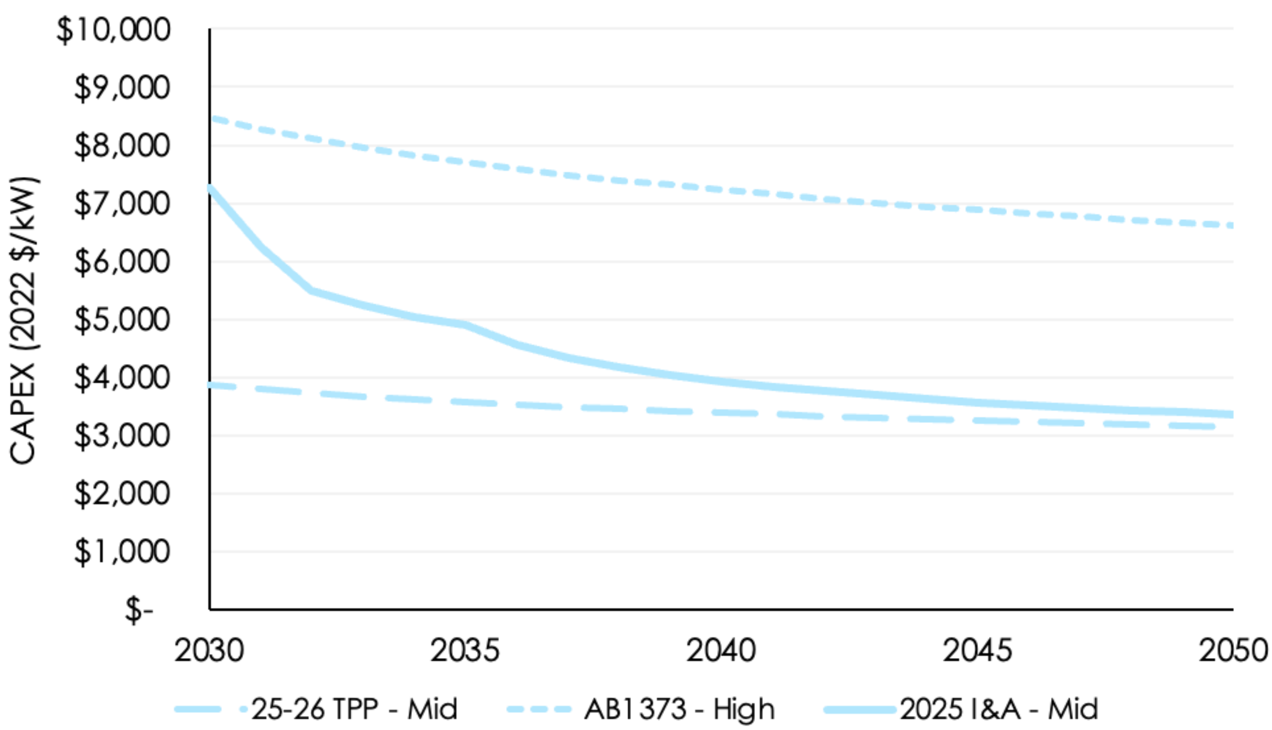


Table 56. Cost trajectories for offshore wind *(2022 $/kW)*

[87] https://atb.nrel.gov/electricity/2024/offshore_wind

[88] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/ab1373/need-determination-analysis-centralized-procurement-of-specified-llt-resources.pdf, Slide 17

Vintage	2030	2035	2040	2045	2050
25-26 TPP	$3,873	$3,572	$3,387	$3,252	$3,146
AB 1373 "Conservative"	$8,468	$7,700	$7,226	$6,882	$6,611
2025 I&A - Mid	$7,267	$4,894	$3,924	$3,568	$3,356

Levelized costs are calculated using Recost with an assumed 8.75% nominal WACC (in 2035), 30-year economic life, and selection of the ITC ("Bonus" 30%) with a 95% CAPEX eligibility basis and tax credit monetization rate of 90%,

5.3.3.3 Geothermal Cost Assumptions

New to the 2024-2026 IRP cycle, near-field enhanced geothermal (EGS), and deep EGS are proposed as new default candidate resources. Conventional geothermal (hydrothermal) will also remain a default candidate resource as it has been in past cycles. The data source for all technologies is NREL 2024 ATB. Reflecting that most new geothermal projects under development today are binary systems, the RESOLVE resource costs for geothermal will use the "binary" technology costs from NREL 2024 ATB. For deep EGS, the resource cost will also depend on drilling depth. To estimate cost multipliers for deep EGS, the Geothermal Electricity Technology Evaluation Model (GETEM) was used.[89]

Levelized costs are calculated using Recost with an assumed 8.75% nominal WACC (in 2035), 30-year economic life, and selection of the ITC ("Bonus" 30%) with a 95% CAPEX eligibility basis and tax credit monetization rate of 90%.

5.4 Energy Storage

Energy storage cost and performance characteristics can vary significantly by technical configuration and use case. To flexibly model energy storage systems of differing sizes and durations, the cost of storage is broken into two components (to the extent that this data is available): capacity (or power, $/kW) and energy (or duration, $/kWh). The capacity cost refers to all costs that scale with the rated installed power (kW) while the energy cost refers to all costs that scale with the energy (kWh) or storage duration (hr) of the storage resource. This breakout is intended to capture the different drivers of storage system costs. For example, a 1 kW battery system would require the same size inverter whether it is a four- or six-hour battery but would require additional cells in the longer duration case.

[89] Geothermal Electricity Technology Evaluation Model (GETEM). Geothermal Technologies Office (GTO), U.S. Department of Energy. https://www.energy.gov/eere/geothermal/geothermal-electricity-technology-evaluation-model.

For pumped storage, capacity costs are the largest fraction of total system cost and include the costs of the turbines, penstocks, interconnection, etc., while energy costs are relatively small and mainly cover the costs of preparing the reservoir. For Li-ion batteries, capacity costs include the cost of the inverter and other power electronics for the interconnection, while the energy costs include the Li-ion battery cells. Starting in the 2022-2023 IRP cycle, energy storage resources are modeled as having fixed durations. This update was made to reflect the practical deployment of energy storage systems, as well as facilitate ELCC modeling for a wider array of energy storage technologies (Section 7.1). For Li-ion batteries, both 4- and 8-hour duration systems will be modeled. For pumped storage, 12 hours of duration is assumed. For generic long-duration energy storage, durations of 12, 24, and 100 hours are modeled, each with unique cost profiles and operating assumptions.

5.4.1 Pumped Hydro Storage

The list of candidate pumped hydro storage projects available in the 2024-2026 IRP cycle is taken from the 25-26 TPP Busbar Mapping dashboard.[90] Projects are classified by whether a reservoir already exists at the project site. The total resource potential by CAISO study area is provided in Table 57 below.

Table 57. Pumped Hydro resource potential by study area

Study Area	Existing Reservoir (MW)	New Reservoir (MW)	Total (MW)
PGE NGBA	393	-	393
PGE GBA	2,400	-	2,400
PGE Kern	2,700	-	2,700
SCE Northern	3,600	5,080	8,680
SCE Eastern	1,800	-	1,800
SDGE Imperial	500	-	500
Total	11,393	5,080	16,473

The capital cost of each candidate pumped storage project is determined based on whether that project has an existing reservoir. From NREL 2024 ATB, Technology Class 8 is used for projects with no existing reservoirs, while One New Reservoir Technology Class 3 is used for projects with at least one existing reservoir. Pumped storage costs in NREL 2024 ATB are represented as a

[90] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/assumptions-for-the-2025-2026-tpp/full-dashboard_25-26tpp_basecase_pd.xlsx, January 2025. Vandenberg and MQR are excluded due to permitting challenges.

single cost in $/kW, with an assumed storage duration of 10 hours.[91] In RESOLVE, candidate pumped storage resources are modeled at a 12-hour duration. The ATB costs are assumed to be valid at 12 hours of duration due to the geographical specificity of the pumped hydro storage resource potential. No learning curve is applied to the NREL ATB costs, and consequently the overnight capital cost and fixed O&M trajectories are flat.

Table 58. Pumped Hydro Storage cost components (2022 $)

Cost Component	Capital Cost – Total, 12-Hour Storage ($/kW)	Fixed O&M Cost ($/kW-yr)
Pumped Hydro, New Reservoir	$4,806	$20
Pumped Hydro, Existing Reservoir	$2,562	$20

Levelized costs are calculated using Recost with an assumed 8.74% nominal WACC (in 2035) and 8.32% nominal WACC, for new reservoir and existing reservoir projects, respectively; 50-year economic life; and selection of the ITC ("Bonus" 30%) with a 95% CAPEX eligibility basis and tax credit monetization rate of 90%, The resulting levelized fixed costs are shown below.

Table 59. Pumped Hydro Storage levelized fixed costs (2022 $)

Levelized Fixed Cost ($/kW)	2025	2030	2035	2040	2045
Pumped Hydro, New Reservoirs	$258	$254	$254	$254	$254
Pumped Hydro, Existing Reservoir	$150	$147	$147	$147	$147

5.4.2 Li-ion Battery Storage

While RESOLVE includes both utility-scale and BTM Li-ion batteries as candidate resources, only utility-scale Li-ion batteries are an optimized resource.

Under the IRA, standalone battery storage can receive the ITC. As a result, the cost benefits of paired battery storage relative to standalone battery storage are diminished. For this reason, paired and hybrid battery storage technologies are not modeled in RESOLVE.

[91] https://atb.nrel.gov/electricity/2023/pumped_storage_hydropower.

For the 2024-2026 IRP cycle, new assumptions for base year (2023) and forecasted CAPEX values have been developed pursuant to the methodologies discussed in Section 4.3. The updated CAPEX forecasts for a typical 4-hr Li-ion battery resource are shown in Figure 13 below.

Figure 13. Cost trajectories for 4-hr Li-ion Battery CAPEX

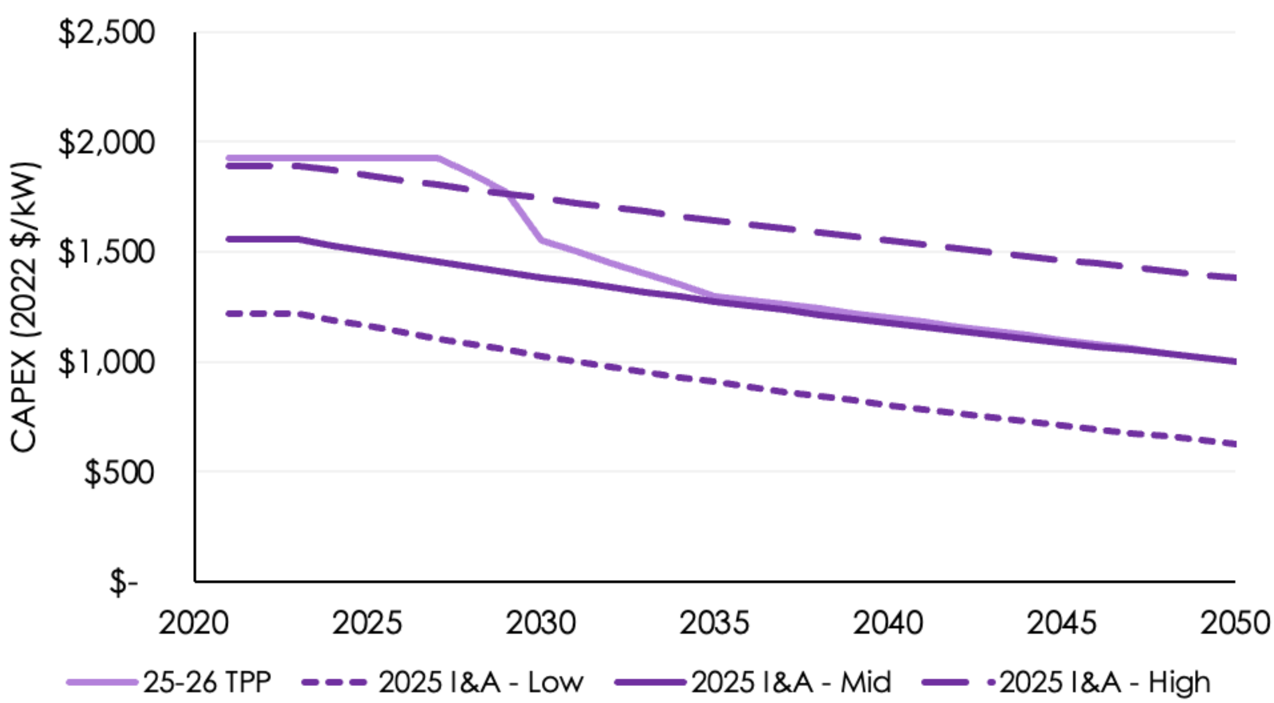


Table 60. Cost assumptions for candidate Li-ion battery resources (2022 $)

Resource	Cost Component	Case	2025	2030	2035	2040
Li-Ion Battery (4-hr)	Capital Cost ($/kW)	Low	$1,116	$986	$872	$771
		Mid	$1,445	$1,330	$1,225	$1,130
		High	$1,775	$1,674	$1,579	$1,490
	Fixed O&M (% of Capital Cost)	All	2.50%	2.50%	2.50%	2.50%
Li-Ion Battery (8-hr)	Capital Cost ($/kW)	Low	$2,009	$1,775	$1,569	$1,387
		Mid	$2,602	$2,394	$2,206	$2,034
		High	$3,194	$3,013	$2,843	$2,681
	Fixed O&M (% of Capital Cost)	All	2.50%	2.50%	2.50%	2.50%

While custom CAPEX trajectories have been developed, NREL 2024 ATB is used to estimate the FO&M of Li-ion batteries. Regional adjustments to CAPEX, FO&M, and interconnection are made to reflect state-specific conditions, as discussed in Section 4.4.

Levelized costs are calculated using Recost with an assumed 8.84% nominal WACC (in 2025), 20-year economic life, and selection of the ITC ("Bonus" 30%) with a 95% CAPEX eligibility basis and 90% tax credit monetization rate.

Table 61. Candidate battery levelized fixed costs – Mid (2022 $)

Resource	Cost Component	2025	2030	2035	2040
Li-ion Battery (4-hr)	Levelized Fixed Cost ($/kW-yr)	$144	$130	$122	$113
Li-ion Battery (8-hr)	Levelized Fixed Cost ($/kW-yr)	$243	$217	$201	$187

RESOLVE does not limit the available potential for candidate battery storage resources.

5.4.3 Generic Long-Duration Energy Storage

The 2024-2026 IRP cycle introduces new generic long-duration energy storage (LDES) archetypes as proposed new candidate resources in the RESOLVE optimization. Three technologies with durations of 12, 24, and 100 hours are represented. The 12- and 24-hour LDES costs come from the PNNL 2024 ESGC Cost and Performance Database.[92] Specifically, the 12-hr LDES resource uses the cost assumptions for vanadium redox flow ("flow") batteries for a 100 MW, 12-hr system configuration, and the 24-hr LDES resource uses the cost assumptions for thermal storage systems for a 100 MW, 24-hr system configuration. These technologies are chosen for their feasibility at each given duration and minimal restrictions for project siting. As a general guiding principle, LDES technology costs should increase with duration, reflecting greater risk and trade-offs between duration and reliability value (ELCC). PNNL provides cost estimates for 2023 and 2030; linear interpolation and extrapolation using these values is assumed. The 100-hr LDES costs used in the "High" cost scenario come from a 2021 LDES Council report, with no assumed learning rate.[93] For the "Low" scenario, costs for 2030 are

[92] https://www.pnnl.gov/projects/esgc-cost-performance/estimates

[93] "Net-Zero Power: Long Duration Energy Storage for a Renewable Grid." LDES Council, 2022. https://www.mckinsey.com/~/media/mckinsey/business%20functions/sustainability/our%20insights/net%20zero%20power%20long%20duration%20energy%20storage%20for%20a%20renewable%20grid/net-zero-power-long-duration-energy-storage-for-a-renewable-grid.pdf.

sourced from a 2023 whitepaper published by Form Energy, with additional 20% reductions by 2040 assumed.[94] The "Mid" costs for 100-hr LDES is taken as the average between "Low" and "High

Table 62. Generic 12-hr LDES CAPEX assumptions (2022 $)

Resource	2030	2035	2040	2045
LDES 12-hr, Low	$3,987	$3,542	$3,147	$2,795
LDES 12-hr, Mid	$4,795	$4,484	$4,286	$4,111
LDES 12-hr, High	$5,426	$5,426	$5,426	$5,426

Table 63. Generic 24-hr LDES CAPEX assumptions (2022 $)

Resource	2030	2035	2040	2045
LDES 24-hr, Low	$1,895	$1,895	$1,895	$1,895
LDES 24-hr, Mid	$3,891	$3,891	$3,891	$3,891
LDES 24-hr, High	$7,039	$7,039	$7,039	$7,039

Table 64. Generic 100-hr LDES CAPEX assumptions (2022 $)

Resource	2030	2035	2040	2045
LDES 100-hr, Low	$2,286	$2,057	$1,852	$1,852
LDES 100-hr, Mid	$2,891	$2,777	$2,674	$2,674
LDES 100-hr, High	$3,496	$3,496	$3,496	$3,496

Table 65. Generic LDES FO&M assumptions, "Mid" Cost Scenario (2022 $)

Resource	2030	2035	2040	2045
LDES 12-hr	$23	$21	$20	$19

[94] Levi, P. et. al. Modeling Multi-Day Energy Storage in New York, Form Energy, 2023.

LDES 24-hr	$54	$54	$54	$54
LDES 100-hr	$29	$29	$29	$29

The levelized costs for each LDES duration are calculated using Recost with an assumed 20-year economic life and selection of the ITC ("Bonus" 30%) with a 95% CAPEX eligibility basis and 90% tax credit monetization rate. The nominal WACC for 12-hr LDES in 2030 is 8.32% under the "Mid" cost scenario, representing the Mid-Risk Class. For 24- and 100-hr LDES with greater associated risk, a nominal WACC is 8.75%, corresponding to the High-Risk Class, is used.

The resulting all-in levelized fixed costs for the "Mid" cost scenario are shown below.

Table 66. Generic Long Duration Storage all-in levelized fixed costs (2022 $)

Resource	2030	2035	2040	2045
LDES 12-hr	$365	$642	$328	$315
LDES 24-hr	$344	$344	$344	$344
LDES 100-hr	$250	$242	$234	$234

RESOLVE does not limit the available potential for candidate long duration energy storage resources.

5.5 CAISO Transmission and Interconnection Representation

With each IRP cycle, CAISO provides transmission capability and cost estimates for use in IRP modeling.[95] The 2024 transmission capability information provided by CAISO for the 2024-2026 IRP cycle includes transmission constraint boundary diagrams,[96] tables of substations and their memberships in constraints,[97] and a whitepaper with a list of electrical zones, transmission capability estimates of the existing transmission system, and the cost and capacity of potential upgrades.[98] This section focuses on the interpretation of this data set and the modeling of candidate resources on CAISO transmission constraints.

Each transmission area constraint studied by CAISO has the following components:

- Assignment to CAISO study area (e.g., PGE Kern)
- Collection of substations (as identified in the constraint boundary diagrams and constraint matrices) that belong to the constraint
- The existing FCDS and EODS transmission capability estimates (in MW) on the constraint

[95] See "Transmission capability information provided to the CPUC": http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx.

[96] https://www.caiso.com/documents/attachment-b2-deliverability-constraint-boundary-diagrams-2024.pdf.

[97] https://www.caiso.com/documents/attachment-b1-v8-constraint-mapping-2024-ipe.xlsx.

[98] https://www.caiso.com/documents/transmission-capability-estimates-white-paper-2024.pdf.

- A proposed transmission upgrade project, with estimated construction lead time, capital cost, and incremental FCDS and EODS transmission capability (MW) delivered by the upgrade.
- Designation of the EODS constraint as a solar- or wind-type area

FCDS ("on-peak") and EODS ("off-peak") are the two types of deliverability conditions that must be satisfied on the transmission constraint. The FCDS capability estimates are used to produce two concurrent constraints in RESOLVE: the Highest System Need (HSN) constraint and Secondary System Need (SSN) constraint. Both constraints utilize the FCDS capability estimates to determine the existing and incremental constraint bounds, but new resource builds may have different contributions towards the HSN and SSN constraints. The EODS capability estimates are used to produce the off-peak constraint. Thus, in general, for each transmission constraint area reported by CAISO, three custom constraints must be represented in RESOLVE: HSN, SSN, and off-peak.

Candidate resources in RESOLVE can be selected as fully deliverable (FCDS), contributing to all three transmission constraints; or energy only (EO)**,** contributing only to the off-peak constraint. FCDS resources are included in RESOLVE's resource adequacy constraint and are counted towards system resource adequacy, as described in Section 7.1. An EO resource is excluded from RESOLVE's resource adequacy constraint, thereby not providing any resource adequacy value. The FCDS or EODS status of a resource does not impact how it is represented in RESOLVE's operational module – the total installed capacity of the resource is used when simulating hourly system operations, regardless of FCDS or EODS designation. Candidate gas-fired thermal resources, conventional geothermal, enhanced geothermal (EGS), out-of-state wind, offshore wind, biomass, and energy storage resources are all required to be FCDS resources and must contribute to all three transmission constraint types. Candidate distributed solar is assumed to be sited near load centers and is not represented on the transmission system.

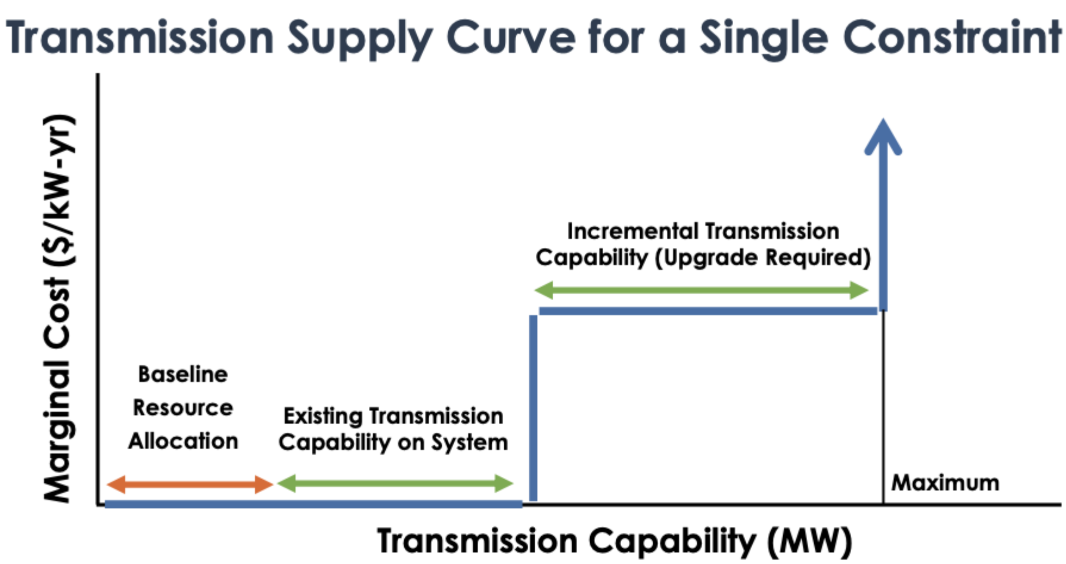
The existing transmission capabilities (FCDS and EODS) of each transmission constraint describe the amount of new resource capacity that can be installed on the existing system (i.e., without requiring upgrades). Resources within each transmission constraint compete with one another for existing, zero-marginal-cost transmission capacity. RESOLVE will typically prioritize FCDS for resources with a higher resource adequacy contribution. Once existing transmission capability (either FCDS or EODS) is exhausted on a transmission constraint, the model must invest in a transmission upgrade to install additional resources. Generally, this will occur if the value of new transmission capacity exceeds the cost of the new transmission investment.

For most of the transmission constraints, CAISO has identified one or more upgrades that can be built to provide incremental capability. These transmission upgrades are modeled in RESOLVE as build assets, with a levelized build cost, resource potential (incremental transmission capability provided by the upgrade), and first available year (calculated using the construction lead time from 2024). Typically, when a transmission upgrade is built in the model, this upgrade will relax all three custom constraints (HSN, SSN, and off-peak) simultaneously. Some transmission upgrades have been identified that relax several constraint areas simultaneously (e.g., the new Collinsville 500 kV substation). RESOLVE allows a single build asset to simultaneously expand the transmission capability of multiple transmission constraints.

The transmission upgrade costs (in real $2022) published by CAISO are converted into levelized, $/kW-yr values by dividing the upgrade cost by the incremental FCDS transmission capability (or EODS capability, if the constraint does not affect FCDS deliverability), and levelizing using a WACC of 7.61% and an economic lifetime of 50 years[99]. This methodology is consistent with previous IRP cycles.

The existing transmission capabilities published in the 2024 CAISO Transmission Capability Estimates whitepaper were calculated from CAISO analysis of the electrical grid as of January 1, 2024. As such, all generators from the resource baseline (Section 3) with commercial operation dates after 1/1/2024 must have their transmission utilizations accounted for in the transmission constraints. This is accomplished by collecting the list of generators with online dates after 1/1/2024, assigning those generators to substations, identifying which constraint(s) are associated with each substation, and subtracting the generators' FCDS and EO capacities from CAISO's transmission capability estimates. Figure 14 provides a generalized view of the marginal cost and utilization of CAISO transmission constraints in RESOLVE.

Figure 14. Conceptual diagram of transmission costs and utilization for transmission constraints in RESOLVE



In the whitepaper, CAISO identifies many transmission constraints within each Study Area. These constraints are sometimes overlapping and sometimes nested, and they represent

99 2023-2024 TPP

multiple concurrent limitations to delivering energy from resource areas to load centers. While only one limit may be binding at a time, all limits must be modeled simultaneously to ensure that no limits are exceeded. In RESOLVE, these constraints are modeled by partitioning the candidate resources into clusters and modeling each cluster on the transmission constraints separately (see Section 5.5.2). By modeling the candidate resources in this way, each resource will contribute towards the FCDS and EODS limits in all the transmission constraints to which it is assigned.

5.5.1 Resource Output Factors

Included in the 2024 CAISO Transmission Capability Estimates whitepaper are a set of resource output factors for each technology type and utility. These factors relate the installed capacity of new resource additions to their utilization of the transmission constraints. While the CAISO no longer studies the SSN deliverability window in their 2024 whitepaper and has not published new output factors since 2023, Staff is continuing to model this window and will retain the 2023 output factors for this cycle.[100] The transmission capacity utilized by a resource is equal to its installed capacity (MW) times the appropriate resource output factor. Unique factors are provided for the HSN, SSN, and off-peak constraints. The off-peak factors are further subdivided into wind- and solar-type area constraints. The latest resource output factors from CAISO are provided in the tables below.

Table 67. FCDS (HSN and SSN) Resource Output Factors

<table>
<tr><th rowspan="2"></th><th colspan="3">HSN</th><th colspan="3">SSN</th></tr>
<tr><th>SDGE</th><th>SCE</th><th>PGE</th><th>SDGE</th><th>SCE</th><th>PGE</th></tr>
<tr><td>Solar</td><td>3%</td><td>10.6%</td><td>10%</td><td>40.2%</td><td>42.7%</td><td>55.6%</td></tr>
<tr><td>In-State Wind</td><td>33.7%</td><td>55.7%</td><td>66.5%</td><td>11.2%</td><td>20.8%</td><td>16.3%</td></tr>
<tr><td>Out-of-State Wind</td><td colspan="3">67%</td><td colspan="3">35%</td></tr>
<tr><td>Morro Bay Offshore Wind</td><td colspan="3">83%</td><td colspan="3">45%*</td></tr>
<tr><td>Humboldt Offshore Wind</td><td></td><td>83%</td><td></td><td colspan="3">45%*</td></tr>
<tr><td>Energy Storage</td><td colspan="3">100%</td><td colspan="3">50%</td></tr>
<tr><td>Firm Resources</td><td colspan="6">100%</td></tr>
</table>

[100] 2023 CAISO Transmission Capability Estimates whitepaper

** The SSN factors for OSW are updated to reflect direct changes from the CAISO*

Table 68. EODS Resource Output Factors by Constraint Area Type

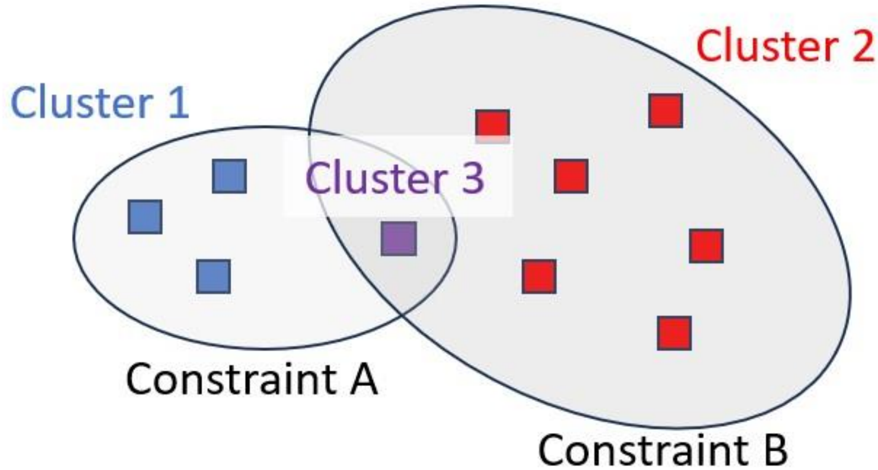
	Wind Area			Solar Area		
Resource Type	**SDGE**	**SCE**	**PGE**	**SDGE**	**SCE**	**PGE**
Solar	68%			79%	77%	79%
In-State Wind	69%	64%	63%	44%		
Out-of-State Wind	67%					
Offshore Wind	100%					
Energy Storage	-100% [1]					
Firm Resources	100%					

[1] Energy storage resources expand the transmission capability of EODS constraints.

5.5.2 Clustering Methodology

For implementation into RESOLVE, the resource potentials from Section 5.3 are assigned to transmission constraints. To represent the CAISO transmission system more accurately in RESOLVE, the candidate resource regions are subdivided into **clusters** via a substation-level analysis of the CAISO transmission system. Clusters are geospatially localized collections of candidate resources and substations within CAISO that have identical memberships in the CAISO transmission constraints (see Figure 15). All substations within a cluster have identical impacts on the transmission system; consequently, candidate resources interconnecting to any of the substations within a cluster will also have identical impacts on the transmission system and will utilize the FCDS and EODS transmission capabilities in similar ways. Grouping the substations into clusters provides a logical basis for representing the CAISO system and ensures that the complexity of nested and overlapping transmission constraints is accurately represented in RESOLVE while reducing the number of decision variables and avoiding substation-level analysis.

Figure 15. Schematic of a transmission system with ten substations (squares) and two constraints (ovals). These ten substations can be aggregated to form three transmission clusters (color-coded). Cluster 1 is comprised of all the substations that are only affected by Constraint A; etc.



Granular representation of the CAISO transmission system is enabled by determining resource potential at the substation level. Using the clusters as the basis for transmission representation in RESOLVE, the candidate resource potentials discussed in Sections 5.3 and 5.4 are subdivided into unique **build assets** by assigning the resource potential to individual substations. At a high level, build assets are *localized* candidate resources in RESOLVE. A build asset is the portion of a candidate resource that interconnects to a specific cluster.

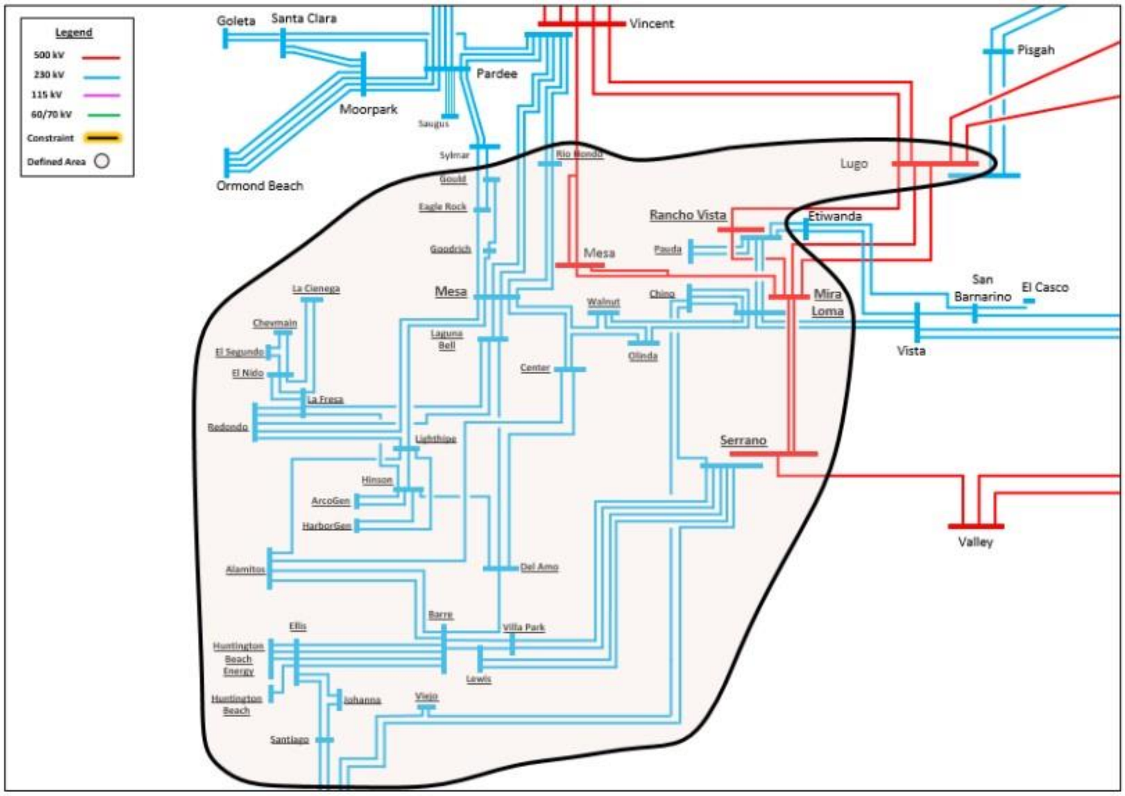
The assignment algorithm can be broken down into several key processes:

1. Assignment of resource potential to substations
2. Assignment of substations to CAISO transmission constraints
3. Aggregation of substations into clusters

By aggregating substations into clusters, and mapping resource potentials to substations, a unique build asset is created for each technology and cluster. The build assets are then used for RESOLVE modeling.

An example of a transmission constraint diagram from the CAISO transmission capability data is provided in Figure 16 below. Each transmission constraint consists of one or several substations among which transmission capability is limited.

Figure 16. CAISO constraint boundary diagram outlining the SCE Metro Area Default Constraint



Two matrices relating substations to their memberships in the transmission constraints were provided by CAISO in the 2024 whitepaper. In total, 93 constraints were included by CAISO and 650 substations with tie-in voltages of 115 kV or higher were included in those constraints.

Once the substation-constraint membership matrix is created, it is used to create the clusters. A cluster is a collection of substations that have identical memberships in transmission constraints. The 650 substations in the matrix were aggregated into 233 unique clusters, with each substation assigned to a single cluster.

To create the build assets for RESOLVE, the resource potentials (Sections 5.3 and 5.4) must be assigned to individual substations. Candidate gas-fired thermal resources, EGS, biomass, and generic LDES were excluded from the transmission analysis since the resource potentials of those technologies do not have a strong geospatial dependency; instead, these technologies are all placed within a single cluster within each zone (IOU) corresponding to the region of the CAISO system least affected by transmission congestion.

The assignment of resource potentials to substations was done over the individual candidate project areas using a nearest-neighbor algorithm via geospatial analysis. Candidate utility-scale solar, in-state wind and geothermal, near-field EGS, and pumped hydro resources were all assigned to substations in this way. Additionally, special assignments were made for the following technologies and resources:

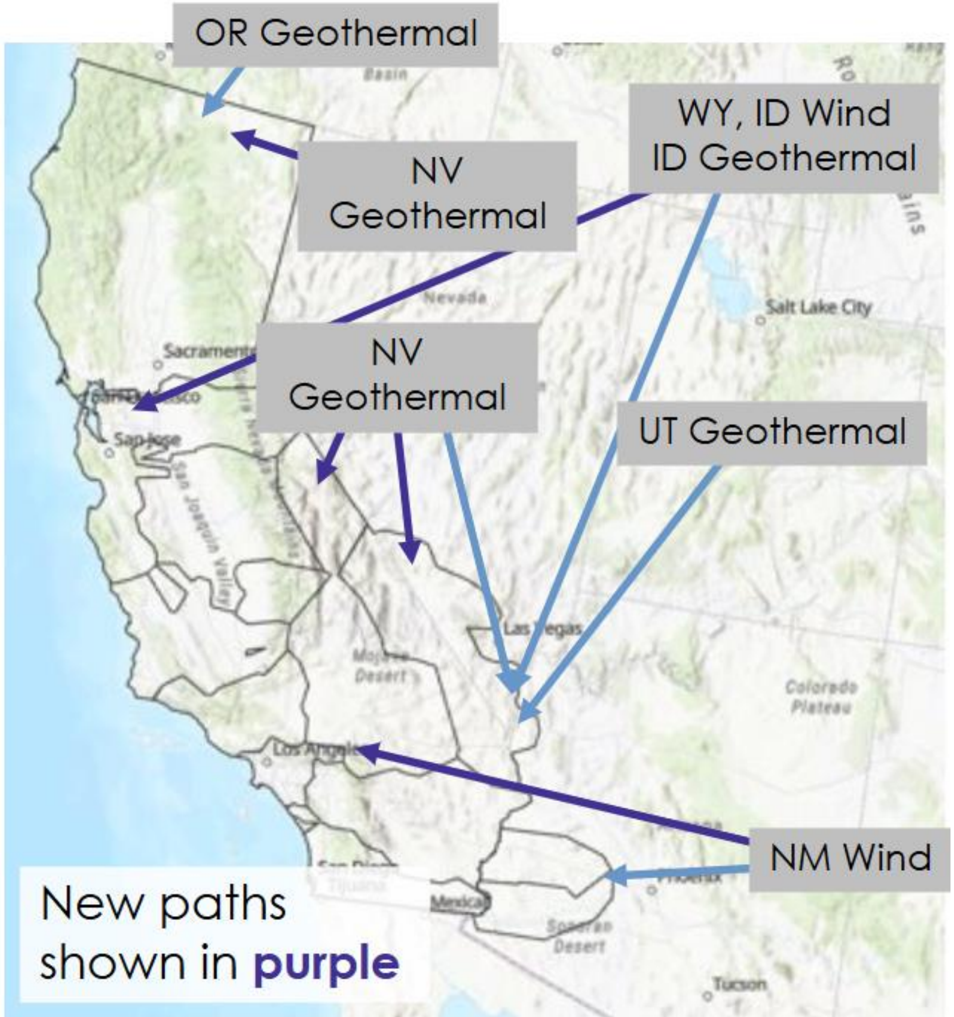
- Geothermal resources in the Imperial Irrigation District (IID) areas of Imperial and Riverside counties are divided between the Imperial Valley and Mirage substations, reflecting ongoing development around the Salton Sea.
- Out-of-state wind and geothermal resources are modeled as interconnecting to the CAISO system at the following substations (see Figure 17). New to the 2024-2026 IRP cycle, the potential of some out-of-state resources is split between multiple substations. Additionally, this update allows for out-of-state wind and geothermal resources to be delivered directly to PGE, reflecting recent planning activities and the identified need for additional high-quality resources to serve Bay Area loads.

Table 69. Substation assignments for resources in other states

Out-of-State Resource	Substation(s)
New Mexico Wind	Palo Verde Lugo
Idaho Wind & Idaho EGS	Harry Allen
Wyoming Wind	Harry Allen (1st 1500 MW from TransWest) Eldorado (2nd 1500 MW from TransWest) Eldorado Tesla
Nevada Geothermal & EGS	Eldorado Control Summit Lugo
Utah Geothermal & EGS	Eldorado
Oregon Geothermal & EGS	Malin

- Morro Bay Offshore Wind is assumed to interconnect to a new 500 kV substation at Morro Bay.
- Other offshore wind resources are assumed to interconnect directly to load pockets in the Bay Area and are excluded from the CAISO transmission constraints.

Figure 17. Assumed tie-in locations for onshore candidate resources requiring new transmission.



Additionally, for every solar build asset, analogous build assets were created to represent 4- and 8-hour Li-ion batteries. In this way, RESOLVE can always choose to pair a solar build with storage, if it is economical to do so. Energy storage creates slack in the off-peak constraints (storage resources are assumed to charge off-peak) and is thus important to include at the same level of granularity as candidate renewable resources. Each storage build asset is assumed to have unlimited resource potential.

RESOLVE chooses to individually build assets using parameters that are specified for each build asset, including the available resource potential (Section 5.3.1), first available year and annual build limits (5.3.2), levelized build cost (5.3.3), minimum build constraints, and transmission constraints. To reduce computational complexity, all build assets within the same resource region or zone share the same production profile and hourly dispatch variables. The build assets carry all the resource potential and cost information, while the dispatch resources only contain operational data. For solar, onshore wind, offshore wind, and geothermal resources, the dispatch resources correspond to the RESOLVE regions introduced in Section 5.1. Candidate gas-fired thermal, biomass, enhanced geothermal, and all candidate storage build assets (Li-ion battery pumped hydro, generic long duration energy storage) are assigned to a single dispatch resource in each RESOLVE zone (IOU) to represent each technology. This reduces the number of candidate storage resources that RESOLVE must optimize when simulating dispatch.

Complete results of the clustering analysis, including the substation-to-transmission cluster mappings, assignment of clusters to resource regions, and complete constraint memberships for all candidate resources, are provided in supporting documentation. The aggregated resources will be incorporated into both the CPUC IRP Resource Potential & Transmission and the CPUC IRP Resource Cost & Build workbook, and shapefiles are provided as supporting information.

5.5.3 Transmission Constraint Data

The amount of new capacity that can be accommodated on each transmission constraint is specified in the attachment A of the 2024 CAISO Transmission Capability Estimates whitepaper.[101] This table includes a listing of transmission constraint names, estimated system capability amounts in MW (existing and incremental), cost of upgrades necessary to accommodate incremental resources, and time to complete the upgrades for each constraint. New to the 2024-2026 IRP cycle, transmission upgrades that have already been approved by CAISO are no longer represented as decision variables with zero upgrade cost, and are instead embedded in the existing capability values in RESOLVE.

While CAISO has included many possible transmission upgrades in their whitepaper, the long-term transmission needs of a highly decarbonized CAISO energy system are not fully known. For this reason, seven generic transmission upgrades are modeled in RESOLVE. Generic transmission upgrades allow RESOLVE to choose resources in excess of the transmission capability and upgrades defined by CAISO. The generic upgrades are meant to represent reinforcements of the main transmission corridors in CAISO. The cost of each generic upgrade was determined by identifying the major archetypal transmission upgrades in the corresponding CAISO study area from the transmission capability estimates whitepaper and averaging the costs of those upgrades. The generic transmission upgrades are first available in 2037, with 500 MW of additional transmission upgrade potential made available to each of the seven generic upgrades per year. Detailed transmission constraint data are provided in the CPUC IRP Resource Potential & Transmission and the CPUC IRP Resource Cost & Build workbook as supplemental information.

5.5.4 Out-of-State Resource Deliverability Costs

New out-of-state resources delivered to the CAISO system are attributed an additional transmission cost to deliver the resource to the CAISO system boundary, representing the cost to wheel power across adjacent utilities' electric systems (for resources delivered on existing

[101] https://www.caiso.com/library/transmission-capability-estimate-inputs-for-cpuc-integrated-resource-plan-aug-29-2024

transmission or already developed transmission lines), and/or the cost of developing a new transmission line (for resources delivered on new transmission). Wheeling costs on the existing system are derived from utilities' Open Access Transmission Tariffs; the costs of new transmission lines are based on assumptions from publicly available transmission development costs. These costs only apply to resources that are modeled as out-of-state and outside of the CAISO system.

Table 70. Wheeling costs for out-of-state resources, 2022 $/kW-yr

Utility	Wheeling Charge
SRP[102]	$30.78
NEVP[103]	$27.65

Resources that require new transmission to reach the CAISO system are assumed to be delivered to a specific CAISO substation (Section 5.5.2). Within the CAISO system, each out-of-state resource must compete for CAISO transmission capability with other candidate renewable resources located within CAISO. The details for transmission projects that would facilitate additional out-of-state capacity to serve the CAISO system are shown in Table 71.

Table 71. Out-of-State Resource Transmission Project Candidates

Transmission Project	Status	RESOLVE Resource	Tie-In Location	First Available Year	Capacity, MW	Total Cost, $/kW-yr
SunZia I (Entitled)	In-Dev[104]	New Mexico Wind	Palo Verde, SCE	2026	546[105]	*76.44*
SunZia I (via SRP)	In-Dev	New Mexico Wind	Palo Verde, SCE	2026	890	*107.22*[106]
SunZia II – RioSol	In-Dev	New Mexico Wind	Palo Verde, SCE	2028	1500	*121.74*
NM to Palo Verde	Generic[107]	New Mexico Wind	Palo Verde, SCE	2035	3000	*132.20*
NM to Lugo	Generic	New Mexico Wind	Lugo, SCE	2035	3000	*100.67*

102 SRP OATT

103 NEVP OATT

104 Estimates for in-dev projects collected from the 2021-2022 TPP and a recent SWIP-N Application Memo

105 Excludes 1,585 MW of in-development SunZia Wind in the CPUC Baseline Generator List

106 Includes SRP OATT

107 Costs reported in CAISO 20-Year Transmission Outlook

SWIP-North	In-Dev	Idaho Wind	Harry Allen, SCE	2027	1100	*62.79*
TransWest Express	In-Dev	Wyoming Wind	Harry Allen, SCE	2029	1500	*100.55*
TransWest Express	In-Dev	Wyoming Wind	Eldorado, SCE	2033	1500	*112.72*
WY to Eldorado	Generic	Wyoming Wind	Eldorado, SCE	2036	2000	*192.33*
WY to Tesla	Generic	Wyoming Wind	Tesla, PGE	2036	2000	*192.33*
WY to Tesla (2nd Tranche)	Generic	Wyoming Wind	Tesla, PGE	2040	2000	*192.33*
NV to Control	Generic[108]	Nevada Geothermal	Control, SCE	2032	unconstrained	*69.03*
Silver Peak to Beatty	Generic	Nevada Geothermal	Beatty, SCE	2032	unconstrained	*69.03*
Robinson Summit to Eldorado	Generic	Nevada Geothermal	Eldorado, SCE	2035	unconstrained	*43.28*
Hilltop to Malin + NVE Wheeling	Generic	Nevada Geothermal	Malin, PGE	2035	unconstrained	*56.22*[109]
Utah to Eldorado	Generic[110]	Utah Geothermal	Eldorado, SCE	2030	unconstrained	*44.63*
Corral to Malin	Generic	Oregon Geothermal	Malin, PGE	2030	unconstrained	*57.69*

Out-of-state EGS (NV, UT, OR, ID) are assumed to be delivered to the same locations as conventional geothermal (or ID Wind) with identical transmission cost adders as those reported above. Near-field EGS is available in the same years as conventional geothermal (as reported above), while deep EGS is available starting in 2035.

5.5.5 Interconnection Constraint and Upgrade Representation

Introduced in the 2025-2026 TPP and new to the 2024-2026 IRP cycle, additional constraints have been added to RESOLVE to represent feasible limits on each candidate resource cluster by interconnection headroom and encourage greater locational diversity in the portfolios selected by RESOLVE. Substations are assigned a default interconnection limit according to its voltage. The total headroom of each cluster is set equal to the sum of the interconnection capacities across all of its substations. Under these new constraints, the total nameplate rating of all resources built within a cluster cannot exceed this value. Additionally, RESOLVE will include interconnection upgrade options

[108] New costs estimated using per-unit cost guides (CAISO 20-Year Transmission Outlook, GLW)
[109] Includes NEVP OATT
[110] 2021-2022 TPP

for clusters at or above a 230 kV rating. These interconnection upgrades will be available starting in 2032, reflecting a 5- to 7-year construction lead-time, and will assume incremental capacities equivalent to the default interconnection capacities. The data corresponding to the interconnection constraints and upgrades is shown in Table 72.

Table 72. Interconnection limits and expansion options (costs in 2022 $)

Voltage, kV	Default Interconnection Capacity, MW	Incremental Capacity, MW[111]	Cost, $MM[112]ye	Levelized Cost, $/kW-yr
115	100	N/A	-	-
138	100	N/A	-	-
161	100	N/A	-	-
230	1,500	1,500	94	4.85
500	3,000	3,000	116	3.03

5.5.6 Offshore Wind Transmission Costs

Offshore wind resources will require transmission upgrades to deliver FCDS capacity to the CAISO system. Assumptions for offshore wind transmission upgrades are adopted from the CAISO 2021-2022 Transmission Plan (TPP)[113], except for Humboldt Bay, which has been updated to match the more recent cost estimate in the 2023-2024 TPP.[114] The size of the offshore wind transmission upgrades are assumed to be equivalent to the resource potential MW totals (Section 5.3).

The Morro Bay upgrade includes upgrades to the Morro Bay 500 kV substation; Morro Bay Offshore Wind is assumed to interconnect to the CAISO system at this new substation and is subject to additional CAISO transmission constraints. The transmission upgrade costs for the other offshore wind resources include the cost of underwater cabling to deliver the resources directly to load centers in the San Francisco Bay Area; as such, these resources are not modeled on additional CAISO transmission constraints.

Table 73. Transmission upgrade data for offshore wind resources

[111] Default and incremental capacity estimates were informed by values reported in an SCE Generator Interconnection Process Presentation, Sept 2021

[112] 20-Year Transmission Outlook (2023-2024), CAISO, July 2024

[113] http://www.caiso.com/InitiativeDocuments/ISOBoardApproved-2021-2022TransmissionPlan.pdf.

[114] https://www.caiso.com/documents/appendix-g-board-approved-2023-2024-transmission-plan.pdf

Resource Name	Total Tx Upgrade Cost ($MM)	Tx Upgrade Costs ($/kW-yr)	First Available Year	Remarks
Morro Bay Offshore Wind	$110	$2	2032	New Morro Bay 500 kV Substation
Humboldt Offshore Wind	$3,471	$101	2035	New 500-kV system upgrades as studied in the CAISO 23-24 TPP
Cape Mendocino Offshore Wind	$20,720	$156	2040	Underwater cabling to Bay Area
Del Norte Offshore Wind	$22,020	$156	2040	Underwater cabling to Bay Area

All costs in real 2022$.

5.6 Demand Response

5.6.1 Shed Demand Response

Shed (or "conventional") demand response reduces demand only during peak demand events. Assumptions on the cost, performance, and potential of candidate new shed demand response resources are based on Lawrence Berkeley National Laboratory's (LBNL) Phase 4 California Demand Response Potential Study for the CPUC.[115] The resource potential supply curve is based on data outputs from LBNL's DRPATH model, with the scenario assumptions outlined below in Table 74. DRPATH potential estimates are not incremental to existing demand response programs. Consequently, LSE demand response programs, including demand response procured through DRAM, are removed from the DRPATH supply curve because these programs are represented as baseline resources (see Section 3.5). On the assumption that lower cost DR has been the focus of LSE DR programs, DR potential is removed from the supply curve in order of least to most expensive. LBNL's supply curve includes pumping loads so the existing interruptible pumping load has also been removed from the lowest cost price tranches of the supply curve. LBNL models DR potential in 2025, 2030, 2040, and 2050. DR potential is linearly interpolated between years as needed. An alternative option, included as an option for sensitivity analysis, explores resource portfolio selection when all shed DR potential is available in all modeled years. Finally, the shed DR potential in the supply curve includes costs as high as $1,000 per kW-year; Figure 18 shows the supply curve through the $250 per kW-year tier.

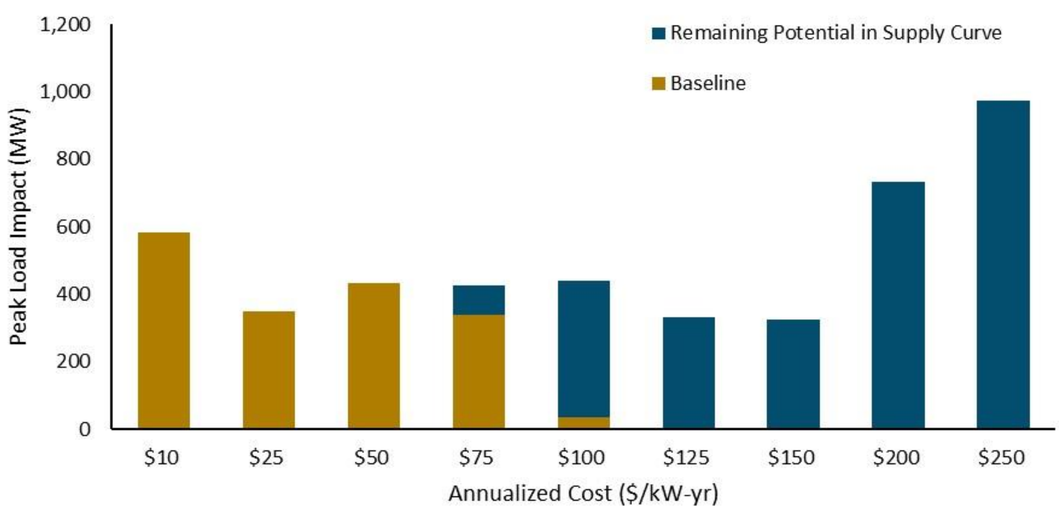
In RESOLVE, DR candidate resources are modeled with a 10-year lifetime as an average estimate on life of service per LBNL inputs. The supply curve costs are modeled as fixed O&M costs representing the annualized cost of equipment and DR program participation costs needed to keep the resources available for load shedding.

[115] Lawrence Berkeley National Laboratory, *Overview of Phase 4 of the California Demand Response Potential Study* (2022). Available at: https://emp.lbl.gov/publications/overview-phase-4-california-demand

Table 74. Scenario assumptions for LBNL's DRPATH model used to generate shed DR supply curve data for IRP modeling.

Category	Assumption
IEPR CED Year	2021
DR Availability Scenario	Medium
Weather	1 in 2 weather year
Energy Efficiency Scenario	Mid AAEE (Scenario 3)
Fuel Substitution Scenario	Mid AAFS (Scenario 3)
Rate Scenario	Rate Mix 1—TOU and CPP (as defined by LBNL report)
Cost Framework	Gross

Figure 18. Conventional demand response supply curve in 2035

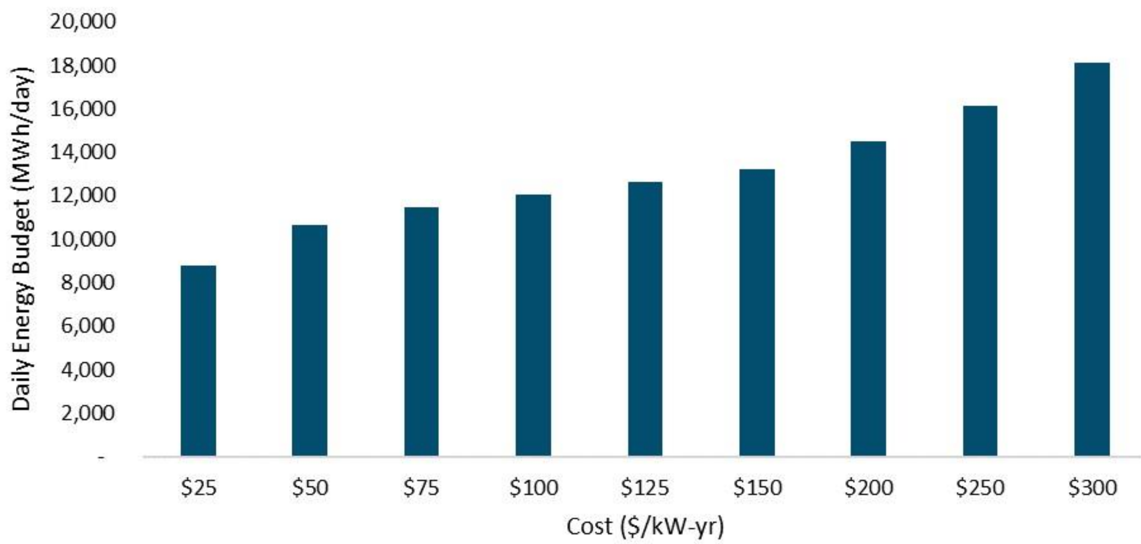


5.6.2 Shift Demand Response

"Shift" demand response (also called "flexible load") in RESOLVE is an energy-neutral resource that can move demand within a day, subject to hourly and daily constraints on the amount of energy that can be shifted. End-use energy consumption in RESOLVE can be shifted, for example, from on-peak hours to off-peak hours; the maximum amount of energy shifted in one day is the daily energy budget. The quantity of shift demand response is reported in units of (MWh/day)-yr, which is the average available *daily* energy budget for a given year. It is currently assumed that the full daily energy budget is available on every day of the year. RESOLVE includes a constraint that sets a maximum quantity of energy that can be shifted in one hour. It is also assumed that there is no efficiency loss penalty incurred by shifting loads to other times of the day.

Assumptions on the cost, performance, and potential of candidate advanced demand response resources are based on Lawrence Berkeley National Laboratory's report for the Phase 4 California Demand Response Potential Study.[116] The resource potential supply curve is based on data outputs from LBNL's DRPATH model, with the same set of scenario assumptions used to create the Shed DR supply curve (see Figure 19).

Figure 19. Shift demand response: total annual costs vs potential daily energy budget in 2035.



5.7 Vehicle Grid Integration (VGI)

According to D.20-12-029[117], Vehicle-Grid Integration (VGI) refers to "any method of altering the time, charging level, or location at which grid-connected electric vehicles charge or discharge, in a manner that optimizes plug-in electric vehicle interaction with the electrical grid and provides net benefits to ratepayers." For the purpose of this IRP cycle, as was the case in the 2022-2023 cycle, VGI is categorized as two main types:

1. VGI included in the IEPR forecast in response to Time-Of-Use (TOU) rates.

2. VGI beyond the IEPR forecast in response to dynamic grid signals and capable of discharging back to the grid (V2G).

[116] Lawrence Berkeley National Laboratory, *Overview of Phase 4 of the California Demand Response Potential Study* (2022). Available at: https://emp.lbl.gov/publications/overview-phase-4-california-demand

[117] Decision 20-12-029. DECISION CONCERNING IMPLEMENTATION OF SENATE BILL 676 AND VEHICLE- GRID INTEGRATION STRATEGIES: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M355/K794/355794454.PDF

The former represents strategies that can be implemented with TOU rates to shift load (V1G), whereas the latter can be actively managed by third-party aggregators or incentivized by dynamic price signals to shift load (V1G) beyond TOU rates or discharge back to the grid (V2G).

V1G in response to TOU rates has already been included in IRP because the IEPR load shapes for light, medium and heavy-duty vehicles used in IRP assume some level of TOU rate responsiveness.

VGI in response to dynamic grid signals is available to estimate the savings from further management of EV charging load beyond TOU rates. For this IRP cycle, as in the 2022-2023 cycle, VGI added in response to dynamic grid signals will focus on only light duty vehicles (LDV), as LDVs are projected to consist of the majority (82%) of transportation load in 2035. VGI is only modeled at residential and workplace locations as vehicles parked at these locations have long enough charging times and relatively predictable charging behaviors for load shifting. Charging at public locations, especially fast charging, usually takes less time, leaving minimal potential to shift load. VGI resources are modeled as statewide aggregated resources with four types:

Table 75. Definition of VGI Resource Types

Resource Types	Definition
V1G Residential V1G Workplace	Shifting EV charging load beyond TOU rates
V2G Residential V2G Workplace	Shifting EV charging load beyond TOU rates + Capable of discharging back to the grid

The study is designed to model VGI in response to dynamic grid signals in a framework similar to a supply-side resource with assumptions in costs in $/kW-yr and potential (MW). This modeling approach is chosen because RESOLVE is a capacity expansion model that cannot directly model retail rates as compensations to resources. This modeling approach does not indicate any CPUC endorsed program design for VGI. The objective of this study is to quantify the value of various V1G and V2G actions in the context of system planning and the impact of VGI on resource portfolio.

To model VGI in response to dynamic grid signals, information on when the vehicles are plugged in is needed to estimate how much load can be shifted beyond TOU rates. Charging behaviors will first be simulated in the EV Load Shape Tool (EVLST) to mimic the latest IEPR load shapes and generate corresponding flexibility parameters with the assumption of around 80% responsiveness to TOU rates. EVLST simulates and optimizes charging behaviors from drivers' perspective to meet driving needs and minimize energy bills. These flexibility parameters will then be used as inputs into RESOLVE to optimize the dispatch of VGI resources in RESOLVE to meet grid needs. The flexibility parameters include windows when charging behaviors can be shifted, the amount of energy that can be shifted in a day, and hourly potential to further increase or decrease EV charging load compared to the TOU baseline.

5.7.1 Resource Potential

VGI resource potential for LDV is developed by estimating the percentage of vehicles with access to residential or workplace Level 2 (L2) chargers and are willing to enroll in VGI programs that involve active management in response to grid signals. The V1G potential is estimated based on the percentage of drivers have access to L2 chargers at residential and workplace and using enrollment curves provided by LBNL from the draft report of the California Demand Response (DR) Potential Study, Phase 4. It is assumed that around 40% of total drivers have access to L2 chargers at home and around 30% of total drivers have access to L2 chargers at the workplace.[118]

Two scenarios, a Mid Enrollment and High Enrollment scenario in residential enrollment curves, will be developed to estimate the low and high bookends of the VGI potential (both V1G and V2G) in the residential sector. Since the enrollment curves were developed based on general DR programs that do not fully reflect VGI-specific enrollment, the original residential enrollment curve provided by LBNL was adjusted for both scenarios with a starting point of the VGI enrollment in the residential sector at around 21%, based on the participation of EV-TOU rates in California in 2021.[119] The reasoning is that VGI programs are less interruptive to customers than DR programs since they are mostly designed not to interrupt drivers' driving needs and change driving behaviors, thus resulting in higher enrollment potential. By the end of 2021, around 21% of EV customers are enrolled in EV-TOU rates without any incentive.[120] These

---

[118] Access to charging is estimated based on a combination of sources including US census data and NREL EVI-Pro2 Input Presentation (https://www.nrel.gov/docs/fy21osti/77651.pdf).

[119] Joint IOU Electric Vehicle Load Research and Charging Infrastructure Cost Report 10th Report Filed on March 31, 2022: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/transportationhttps://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/transportation-electrification/10th-joint-iou-ev-load-report-mar-2022.pdfelectrification/10th-joint-iou-ev-load-report-mar-2022.pdf.

[120] Joint IOU Electric Vehicle Load Research and Charging Infrastructure Cost Report 10th Report Filed on March 31, 2022. Total number of customers on EV rates are calculated by adding the single meter and separately metered accounts in single family and multi-dwelling units in Chart PGE-1, Chart PGE-2, Chart SCE-1, Chart SCE-2a, Chart SDGE-1, Table SDGE-2A and Table SDGE-3. The total number of accounts on EV rates is estimated to be around 151,385 and the total number of EVs in the IOU territories is about 735,348 as of December 2021, which is about 21%.

customers are assumed to be willing to participate in VGI programs, if available, with minimal incentive.

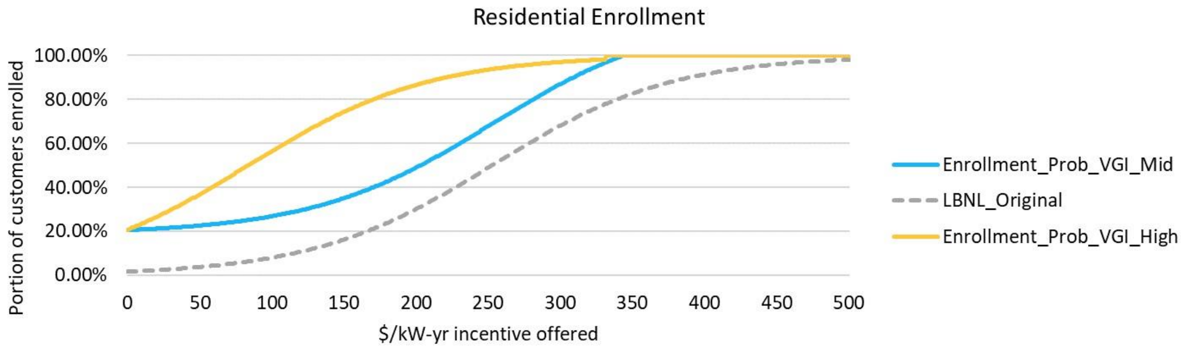
The difference of the Mid Enrollment and High Enrollment scenario comes from how much incremental potential could be induced by higher incentives ($/kW-yr).

- **Mid Enrollment scenario**: shifts the original LBNL enrollment curve vertically by increasing the enrollment potential by 21% at all incentive levels. It results in a relatively low incremental increase in VGI potential at low-cost range. This is consistent with an observation from LBNL that the fraction of the residential program participants within the low-cost range does not increase that much with higher incentives offered.

- **High Enrollment scenario**: shifts the original LBNL enrollment curve horizontally by assuming that VGI enrollment has reached the potential around 21% at $0/kW-yr and could be scaled relatively faster with higher incentives. This is consistent with an observation provided by a stakeholder that their driver propensity is around 98% at a cost range of $200-$400/kW-yr.

The two scenarios mentioned above will only change the assumptions for resource potential but do not change the incentive cost levels and other assumptions. The commercial sector will directly use the original LBNL enrollment curve given its reasonableness and smaller impact on statewide potential compared to the residential sector.

Figure 20. VGI residential enrollment curve for the Mid Enrollment and the High Enrollment scenario



V1G potential modeled for IRP comes from a cost range of $0-50/kW-yr of enrollment curves. Although enrollment curves developed based on existing DR programs may provide some prediction of V1G enrollment at different incentive levels, they are limited in their ability to reflect the enrollment of relatively nascent technologies like V2G and how future VGI policies may look like. Currently, V2G availability is still relatively low at the early stage of the market, and we anticipate that V2G customers expect higher compensation for exporting power than V1G customers expect from managing charging. To account for V2G's higher costs and low penetration at this stage, two major assumptions are made to estimate V2G enrollment:

- A flat cost adder of $50/kW-yr is added to the level of incentives assumed for V1G to reflect the higher payment expected by V2G customers to provide not only load shifting but also discharging services.[121]

- The V2G enrollment potential corresponding to the higher incentive costs is derived from the same function as V1G potential, but it is multiplied by a percentage (%) to reflect V2G potential as a portion of V1G potential at the same incentive level.

The current assumption is that V2G potential starts at 0% of V1G potential in 2025 and grows to 50% of V1G potential in 2050. The starting year of 2025 is set based on a lack of available programs and price signals to allow vehicle discharging in the near term and an estimated timeline when V2G could scale in California. Scaling V2G requires technology readiness, price signals, and policy framework (e.g., FERC Order 2222) in place. CAISO submitted its FERC Order 2222 compliance filling in 2022 and it is expected to take several years to fully implement the policy.[122] The 50% in 2050, an assumption looking decades into the future, is entirely for planning purposes; considering that not all OEMs are willing to enable vehicles to be V2G capable and warranty battery for grid use by 2050 and not all drivers will want to use their

[121] The cost adder of $50 is added to match the level of incentives paid to Demand Response (DR) Programs as V2G is very similar to DR: https://cpowerenergy.com/wp-content/uploads/2020/02/CA_Snapshot_january-2020-Nohttps://cpowerenergy.com/wp-content/uploads/2020/02/CA_Snapshot_january-2020-No-LCR.pdfLCR.pdf.

[122] CAISO FERC Order 2222 Compliance Filing: http://www.caiso.com/Documents/Aug15-2022-ComplianceFiling-FERC-Order-No-2222-ER21-2455.pdf

vehicles as a grid asset. However, sensitivity analysis with higher V2G penetration levels could be explored to inform a broader range of potential VGI outcomes. The VGI potential is calculated as the following:

> VGI Potential by each incentive tranche (%) = % Access to L2 charger * % Enrollment by incentive tranche * % V2G as a percentage of V1G potential.

The percentage of V1G potential by each incentive tranche is derived from the enrollment curves and assumed to be constant throughout all years for a given incentive level. The percentage of V2G potential is modeled as growing each year as V2G as a percentage of V1G potential increases.

Table 76. VGI potential (%) considering both access to L2 chargers and program enrollment probability for the Mid Enrollment scenario.

		Incremental Enrollment at Incentive Levels (%)						
VGI Potential (%)	**Incentive Tranches ($/kW-yr)**	**2024**	**2026**	**2028**	**2030**	**2035**	**2040**	**2045**
V1G_Res_T1	$0	8.6%	8.6%	8.6%	8.6%	8.6%	8.6%	8.6%
V1G_Res_T2	$10	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
V1G_Res_T3	$30	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
V1G_Res_T4	$50	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%
V1G_Com_T1	$0	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%
V1G_Com_T2	$10	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
V1G_Com_T3	$30	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
V1G_Com_T4	$50	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
V2G_Res_T1	$50	0.0%	0.2%	0.6%	0.9%	1.9%	2.8%	3.8%
V2G_Res_T2	$60	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%
V2G_Res_T3	$80	0.0%	0.0%	0.1%	0.1%	0.2%	0.3%	0.4%
V2G_Res_T4	$100	0.0%	0.0%	0.1%	0.2%	0.4%	0.5%	0.7%
V2G_Com_T1	$50	0.0%	0.2%	0.5%	0.9%	1.8%	2.7%	3.7%
V2G_Com_T2	$60	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
V2G_Com_T3	$80	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%
V2G_Com_T4	$100	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.2%

*Table 77. VGI potential (%) considering both access to L2 chargers and program enrollment probability for the High Enrollment scenario (differences in **bold**)*

		Incremental Enrollment at Incentive Levels (%)						
VGI Potential (%)	Incentive Tranches ($/kW-yr)	2024	2026	2028	2030	2035	2040	2045
V1G_Res_T1	$0	8.6%	8.6%	8.6%	8.6%	8.6%	8.6%	8.6%
V1G_Res_T2	$10	**1.2%**	**1.2%**	**1.2%**	**1.2%**	**1.2%**	**1.2%**	**1.2%**
V1G_Res_T3	$30	**3.9%**	**3.9%**	**3.9%**	**3.9%**	**3.9%**	**3.9%**	**3.9%**
V1G_Res_T4	$50	**6.8%**	**6.8%**	**6.8%**	**6.8%**	**6.8%**	**6.8%**	**6.8%**
V1G_Com_T1	$0	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%
V1G_Com_T2	$10	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
V1G_Com_T3	$30	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
V1G_Com_T4	$50	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
V2G_Res_T1	$50	**0.0%**	**0.3%**	**0.9%**	**1.5%**	**3.1%**	**4.6%**	**6.2%**
V2G_Res_T2	$60	**0.0%**	**0.0%**	**0.1%**	**0.2%**	**0.3%**	**0.5%**	**0.6%**
V2G_Res_T3	$80	**0.0%**	**0.1%**	**0.3%**	**0.5%**	**1.0%**	**1.5%**	**2.0%**
V2G_Res_T4	$100	**0.0%**	**0.2%**	**0.5%**	**0.8%**	**1.6%**	**2.5%**	**3.3%**
V2G_Com_T1	$50	0.0%	0.2%	0.5%	0.9%	1.8%	2.7%	3.7%
V2G_Com_T2	$60	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
V2G_Com_T3	$80	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%
V2G_Com_T4	$100	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.2%

The VGI potential (MW) in this study is estimated by the total VGI capable charger capacity, representing smart charger for V1G and bi-directional charger for V2G. To translate VGI potential into MW of capacity, the VGI potential (%) is multiplied by the electric LDV forecast from the 2022 IEPR[130], EV to charger ratio, and EV charger capacity as the following:

VGI potential (MW)[123] = VGI potential (%) * (LDV EV forecast / EV to Charger ratio) * EV charger capacity (kW) / 1000

[123] The nameplate capacity here is defined as the capacity of the charger, which is slightly different from the definition in the 2022 September Inputs and Assumptions Workshop. Stakeholders had complained about the original nameplate capacity definition being confusing. In the 2022 September Inputs and Assumptions Workshop, the nameplate capacity was defined as the capacity to charge or discharge in either direction and was 2x the charger capacity for V2G.

The default EV charger capacity is calculated as a weighted average for Battery Electric Vehicles (BEV) and Plug-in Hybrid Electric Vehicles (PHEV) at around 7kW based on the CEC AB 2127 report.[124] The EV to charger ratio is assumed to be 1 at residential locations and around 25 at the workplace based on the CEC AB 2127 report. The final capacity value will be scaled by the adoption of electric vehicles.

Table 78. VGI potential (MW) for the Mid Enrollment scenario, calculated using EV adoption forecast of 2022 IEPR AATE Scenario 3[125]

VGI Potential (MW)	2024	2026	2028	2030	2035	2040	2045
V1G_Res_T1	1,191	1,897	2,914	4,294	9,212	14,187	18,767
V1G_Res_T2	17	27	42	61	132	203	268
V1G_Res_T3	60	95	147	216	464	714	944
V1G_Res_T4	118	188	289	425	913	1,405	1,859
V1G_Com_T1	45	72	111	164	352	542	717
V1G_Com_T2	0	1	1	2	3	5	7
V1G_Com_T3	1	2	3	5	10	15	20
V1G_Com_T4	2	3	5	8	16	25	34
V2G_Res_T1	0	42	192	472	2,025	4,678	8,251
V2G_Res_T2	0	1	5	13	56	129	228
V2G_Res_T3	0	4	19	46	195	451	796
V2G_Res_T4	0	8	36	89	380	878	1,549
V2G_Com_T1	0	2	7	17	74	170	300
V2G_Com_T2	0	0	0	0	1	2	3

[124] CEC AB2127 report - EV Charging Infrastructure Assessments: https://www.energy.ca.gov/programs-andhttps://www.energy.ca.gov/programs-and-topics/programs/electric-vehicle-charging-infrastructure-assessment-ab-2127topics/programs/electric-vehicle-charging-infrastructure-assessment-ab-2127. This study currently assumes both BEV and PHEV can participate in VGI due to the ease of benchmarking the EVLST load shapes with IEPR load shapes that include both BEV and PHEV charging load. The analysis can be simplified to limit the potential to only BEV. [133] The EV to charger ratio, EV charger capacity and many assumptions are assumed to be static based on assumptions for 2030 for this first round of VGI study given the time limitation to generate flexible parameters across years and the fact that IEPR load shape is based on historical charging session data that does not reflect technology improvement. Future improvements need to be made to make these assumptions time variant. Data for 2030 is chosen because it is the middle of this IRP's core 10-year planning horizon, and it is also the year with the most data availability across multiple sources.

[125] Values have been updated to the 2022 IEPR provided by CEC. Total electric LDV forecasts include electric vehicle adoption under both the Baseline and AATE Scenario 3.

V2G_Com_T3	0	0	0	0	2	5	8
V2G_Com_T4	0	0	0	1	3	8	14

Table 79. VGI potential (MW) for the High Enrollment scenario, calculated using EV adoption forecast of 2022 IEPR AATE Scenario 3. Difference from the Mid Enrollment scenario is highlighted in ***bold****.*

VGI Potential (MW)	2024	2026	2028	2030	2035	2040	2045
V1G_Res_T1	1,191	1,897	2,914	4,294	9,212	14,187	18,767
V1G_Res_T2	**173**	**276**	**423**	**624**	**1,338**	**2,061**	**2,726**
V1G_Res_T3	**534**	**851**	**1,307**	**1,925**	**4,131**	**6,361**	**8,415**
V1G_Res_T4	**945**	**1,504**	**2,311**	**3,405**	**7,305**	**11,250**	**14,882**
V1G_Com_T1	45	72	111	164	352	542	717
V1G_Com_T2	0	1	1	2	3	5	7
V1G_Com_T3	1	2	3	5	10	15	20
V1G_Com_T4	2	3	5	8	16	25	34
V2G_Res_T1	**0**	**68**	**313**	**770**	**3,303**	**7,631**	**13,460**
V2G_Res_T2	**0**	**7**	**32**	**79**	**340**	**785**	**1,385**
V2G_Res_T3	**0**	**22**	**99**	**244**	**1,046**	**2,416**	**4,262**
V2G_Res_T4	**0**	**36**	**167**	**410**	**1,759**	**4,062**	**7,165**
V2G_Com_T1	0	2	7	17	74	170	300
V2G_Com_T2	0	0	0	0	1	2	3
V2G_Com_T3	0	0	0	0	2	5	8
V2G_Com_T4	0	0	0	1	3	8	14

5.7.2 VGI Resource Costs

VGI cost assumptions in IRP reflect the costs potentially paid by utilities or third-party aggregators to enable active management of EV load in response to dynamic grid signals. These costs do not include incremental technology costs to enable VGI capability and are not intended to represent CPUC-endorsed incentives. The costs include fixed O&M costs to reflect the cost of incentivizing active management and administering/marketing the program, and variable O&M costs to reflect the cycling degradation cost only for V2G resources.

Table 80. Fixed O&M costs assumptions ($/kW charger-yr)

Category	Fixed O&M Costs ($/kW charger-yr)[126]
Administration Costs	Residential: $2.8/kW/yr Medium commercial: $2.8/kW/yr
Marketing Costs	Residential: $0.1/kW/yr Medium commercial: $0.6/kW/yr
Incentive Costs	$0/kW-yr ~ $100/kW-yr, varying by incentive tranches and by VGI type

Table 81. Fixed O&M costs ($/kW charger-yr) including administration, marketing, and incentive costs.

Fixed O&M ($/kW charger-yr)	2024	2026	2028	2030	2035	2040	2045
V1G_Res_T1	3	3	3	3	3	3	3
V1G_Res_T2	13	13	13	13	13	13	13
V1G_Res_T3	33	33	33	33	33	33	33
V1G_Res_T4	53	53	53	53	53	53	53
V1G_Com_T1	3	3	3	3	3	3	3
V1G_Com_T2	13	13	13	13	13	13	13
V1G_Com_T3	33	33	33	33	33	33	33
V1G_Com_T4	53	53	53	53	53	53	53
V2G_Res_T1	53	53	53	53	53	53	53
V2G_Res_T2	63	63	63	63	63	63	63
V2G_Res_T3	83	83	83	83	83	83	83
V2G_Res_T4	103	103	103	103	103	103	103
V2G_Com_T1	53	53	53	53	53	53	53
V2G_Com_T2	63	63	63	63	63	63	63
V2G_Com_T3	83	83	83	83	83	83	83
V2G_Com_T4	103	103	103	103	103	103	103

[126] Cost information is obtained and estimated from LBNL's DR Potential Study, Phase 4. Fixed O&M costs are assumed to be constant in real terms throughout the study horizon to be consistent with LBNL assumptions.

Table 82. The calculation of variable O&M costs ($/kWh) for V2G resources[127]

	2022	2030	2040	2050
EV Pack and Cell Price ($2022/kWh)	$151	$98	$86	$74
Cycles	3,500	3,500	3,500	3,500
Cost per cycle ($2022/kWh)	$0.04	$0.03	$0.02	$0.02

[127] EV pack and cell price in 2022 are obtained from the BNEF report and it's extrapolated based on the trend of BTM storage cost trajectory from CPUC IRP Pro Forma. BNEF report: https://about.bnef.com/blog/lithium-ionhttps://about.bnef.com/blog/lithium-ion-battery-pack-prices-rise-for-first-time-to-an-average-of-151-kwh/battery-pack-prices-rise-for-first-time-to-an-average-of-151-kwh/. The degradation cost is estimated using stationary storage cycle limit of 3500 cycles, assuming the impact of using EV as a stationary storage resource will have less degradation impact on EVs compared to driving the vehicles. A typical EV warranty cycle limit nowadays is around 100,000 miles, around 500 cycles.

6. Generator Operating Assumptions

6.1 Overview

While RESOLVE is a simplified dispatch model and requires a simpler set of data and constraints, a more expansive set of data assumptions are required for the SERVM model. This section summarizes the sources of data for each of these models.

6.1.1 SERVM Operations

SERVM is a stochastic PCM model which seeks to characterize electric system performance with generators represented in an hourly dispatch model simulated under a range of weather and hydro conditions, load forecast uncertainty, and unit outage draws.

6.1.1.1 Baseline Reconciliation

Staff updated the baseline list of generators during spring 2024 and finalized it in October 2024. This baseline replaces the prior list dated May 2023. Staff added new generators that have come online or were in development as of December 2023. Existing resources in CAISO were sourced from the CAISO Master Generating Capability List as of January 2024. Units in development were sourced from December 2023 LSE IRP compliance filings. Confirmation of some data regarding in-development resources for CAISO and outside CAISO regions were sourced from the CPUC RPS database and current EIA data, as well as the 2032 WECC ADS.

The baseline update also involved making additions and updates to individual units from the old baseline list, including updates to operating parameters and maximum capacity. Staff also updated regions, unit types, and unit categories to correct errors and oversights. Staff consolidated planned capacity with newly online capacity if a planned project came online, as well as separated hybrid units into Limited Energy Storage Resource (LESR) and Solar PV (SUN) portions by creating two units and appending "LESR" or "SUN" to the SERVM Unit IDs.

6.1.1.2 Calibration of imports, simplification of external regions

As was done for the 2023 Preferred System Plan (PSP), to reduce complexity and in recognition of modeling run times and data processing, staff will continue to model only external regions closest to California. Those regions closest to California, listed in Table 83, were maintained in the model while regions further from California were left out. In addition, regions in the Southwest were grouped as a co-region in order to simplify their dispatch patterns. Load, resource, and transmission topology assumptions for external regions are as described elsewhere in this document.

6.1.2 RESOLVE Operations

RESOLVE's objective function includes the annual cost to operate the electric system across RESOLVE's footprint; this cost is quantified using a linear production cost model. Components of RESOLVE's operational model include:

- **Aggregated generation classes:** Rather than modeling each generator independently, generators in each zone are grouped together into categories with other plants whose operational characteristics are similar (e.g., nuclear, coal, gas CCGT, gas peaker). Grouping like plants together reduces the computational complexity of the problem without significantly impacting the underlying economics of power system operations.
- **Linearized unit commitment:** RESOLVE includes a linear version of a traditional production simulation model. In RESOLVE's implementation, the commitment variable for each class of generators is a continuous variable rather than an integer variable. Constraints on operations (e.g., Pmin, Pmax, ramp rate limits, minimum up & down time, start profile) limit the flexibility of each class' operations.
- **Co-optimization of energy & ancillary services:** RESOLVE dispatches generation to meet demand across the Western Interconnection while simultaneously reserving headroom and footroom on resources within CAISO to meet the contingency and flexibility reserve needs of the CAISO balancing authority.
- **Zonal transmission topology:** RESOLVE uses a zonal transmission topology to simulate flows among the various regions in the Western Interconnection. RESOLVE includes eight zones: three zones representing the CAISO IOU planning areas, three zones capturing other California balancing authorities and two zones that represent regional aggregations of out-of-state balancing authorities.[128] The constituent balancing authorities included in each RESOLVE zone are shown in Table 83.

Table 83. Constituent balancing authorities in each RESOLVE and SERVM zone

RESOLVE Zone	Balancing Authorities
PGE	Pacific Gas & Electric (PGE)
SCE	Southern California Edison (SCE)
SDGE	San Diego Gas & Electric (SDGE)
NCNC	Balancing Authority of Northern California (BANC) Turlock Irrigation District (TID)

[128] A seventh resource-only zone was added starting in the 2019 IRP to simulate dedicated imports from Pacific Northwest hydro (NW_Hydro_for_CAISO). This zone does not have any load and does not represent a BAA.

LADWP	Los Angeles Department of Water and Power (LADWP)
IID	Imperial Irrigation District (IID)
NW	Avista Corporation (AVA) Bonneville Power Administration (BPAT) Chelan County Public Utility District (CHPD) Douglas County Public Utility District (DOPD) Grant County Public Utility District (GCPD) Pacificorp West (PACW) Portland General Electric Company (PortlandGE) Puget Sound Energy (PSEI) Seattle City Light (SCL) Tacoma Power (TPWR)
SW	Arizona Public Service Company (AZPS) Nevada Power Company (NEVP) Salt River Project (SRP) WAPA – Lower Colorado (WALC)
Excluded (not modeled)	Alberta Electric System Operator (AESO) British Columbia Hydro Authority (BCHA) Comision Federal de Electricidad (CFE) El Paso Electric (EPE) Idaho Power (IPCO) Northwestern Energy Montana (NWMT) Pacificorp East (PACE) Public Service Company of New Mexico (PNM) Public Service Company of Colorado (PSCO) Tucson Electric Power (TEPC) WAPA – Colorado-Missouri (WACM) WAPA – Upper Plains West (WAUW)

6.2 Load Profiles and Renewable Generation Shapes

Hourly load, wind, and solar generation profiles ("shapes") are key data input to both SERVM and RESOLVE's hourly production simulation model. The following sections describe the sources and assumptions for how these profiles are derived and coordinated between the two models.

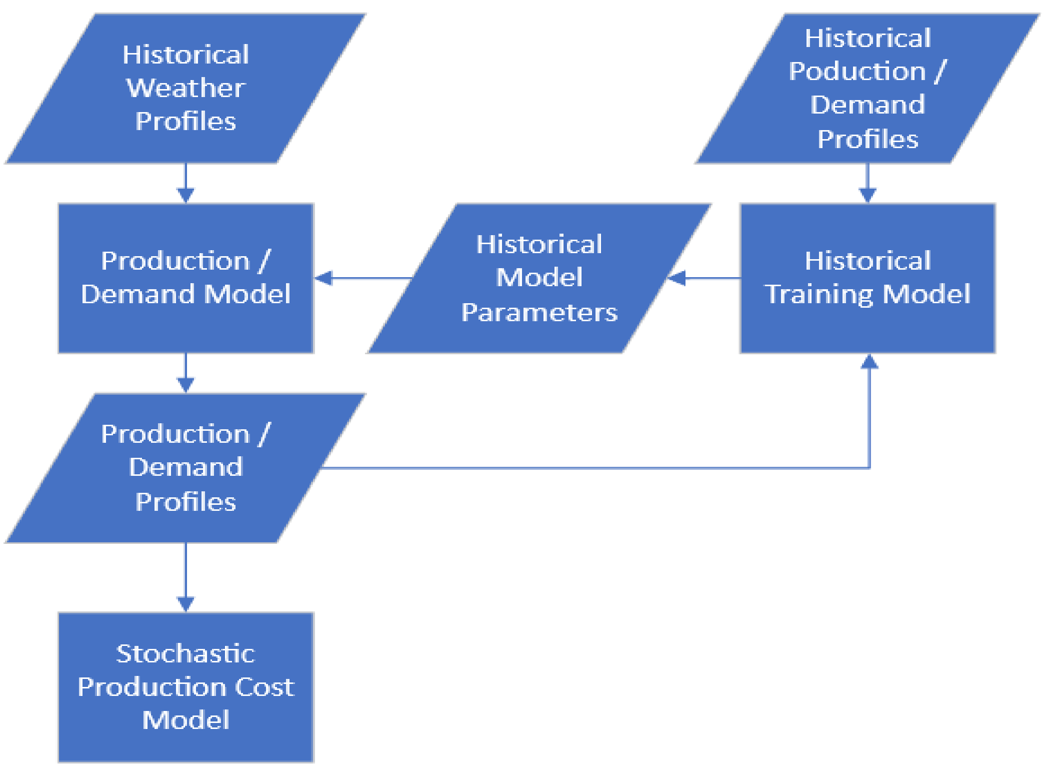
Staff performed updates to add more recent weather years to the model. The range of weather modeled now spans years 2000-2022 instead of the prior 1998-2020 range. This means the extreme weather experienced during 2020 and 2022 are now incorporated into the overall ensemble of weather modeled by SERVM.

6.2.1 Load Profiles

In the past, RESOLVE has sourced load profiles from existing WECC profiles from the years 2007-2009 while the SERVM model has developed electric demand profiles directly using a weather normalization model and historical temperature and humidity data. For the 2024-2026 IRP cycle, Staff have replaced these demand and generation profiles with the current dataset in SERVM. These 23 weather years (2000 - 2022) are the initial dataset from which the representative days are drawn to be used in RESOLVE.

These 23 weather year load profiles are developed in a two-step process. Staff gathered electric sales data from CAISO EMS data and for non-CAISO regions from FERC hourly electric sales data, added back the impacts of simulated BTM PV, actual Demand Response and grid storage charging events. Reconstituted (counterfactual) consumption demand for the most recent three years (2020-2022) was then used to train an implementation of the Monash [129] electric demand model. Once the model is trained on the most recent weather and counterfactual consumption data, the full 23 weather normalized dataset can then be developed.

Figure 21. Creation of Demand Profiles from Historical Weather



The resulting normalized demand profiles are then input into SERVM and scaled to the IEPR peak and energy forecast for California regions. Currently, the 2023 IEPR forecast is available for modeling in SERVM and staff plans to incorporate 2024 IEPR data when it becomes available.

[129] Monash electric demand model is described in a paper here: MEFMR1.pdf (robjhyndman.com)

Electric demand profiles for non-CAISO regions are also developed using the same Monash model approach, using hourly electric demand for the three year training sourced from FERC Form 714 instead of CAISO EMS data, similarly reconstituted to consumption demand using simulated BTMPV generation data for each region. Non-CAISO California regions are scaled to the IEPR peak and energy forecast while non-California regions are scaled according to the non-California peak and energy demand forecast assumptions described elsewhere in this document. Finally, RESOLVE uses this pool of 23 weather year-based demand profiles to develop representative days for its hourly dispatch model.

6.2.1.1 Energy Efficiency Profiles

Energy efficiency is modeled as a demand-modifier (not a candidate resource) with fixed hourly profiles for each forecast year drawn directly from CEC 2023 IEPR AAEE data (and when available, 2024 IEPR). In RESOLVE and SERVM, energy efficiency as well as all other demand modifiers except for BTM PV are drawn directly from hourly profiles provided by the CEC's IEPR and processed into normalized profiles paired with a maximum capacity that together recreate the IEPR demand modifier profile for each forecast year. RESOLVE develops two sets of profiles, one drawn from the IEPR Planning forecast and one drawn from the Local Reliability forecast. SERVM only models the IEPR Planning forecast. In SERVM, the IEPR AAEE data are also modeled for non-CAISO California regions.

6.2.1.2 Electric Vehicle Load Profiles

Light, medium and heavy-duty EV load profiles, residential and commercial, and baseline and Additional Achievable, are all included in the IEPR Demand Forecast and are aggregated into total EV charging fixed hourly profiles for each forecast year. The IEPR includes explicit EV charging data for CAISO regions only.

In RESOLVE, the default assumption is to model these profiles statically with no flexible EV charging allowed except for scenarios where VGI is allowed. However, driver behavior response to TOU rates and other incentives, to the extent captured in the IEPR EV load profiles, is reflected in these static profiles. There are no plans to model VGI profiles in SERVM at this time.

6.2.1.3 Building Electrification Load Profiles

Building electrification load profiles are drawn directly from CEC's IEPR AAFS data. In SERVM, the IEPR AAFS data are also modeled for non-CAISO California regions.

6.2.1.4 Hydrogen Load Flexibility Assumptions

No exogenous hydrogen load flexibility is modeled; instead, hydrogen production load from electrolyzers is modeled endogenously such that the overall system costs for hydrogen production and the electric system are minimized. Essentially the modeling assumes that no hydrogen is produced, carbon-free or otherwise, outside of the system being modeled. All hydrogen used for electricity generation must also be created endogenously by the RESOLVE model through the addition of hydrogen-producing infrastructure to its optimized portfolio.

6.2.2 Solar Profiles

Solar profiles are created using NREL's PVWATTSv5 calculator. The software creates PV production profiles based on weather data from the National Solar Radiation Database (NSRDB), and is used to produce both utility-scale and behind-the-meter solar profiles. NSRDB weather data is used to create the profiles used in SERVM, and these profiles are sampled to create the representative days in RESOLVE.

To create solar profiles using the PVWATTSv5 calculator, parameters are needed that represent north-south single-axis tracking configuration and an inverter loading ratio of 1.3. SERVM simulates solar production profiles for single and double axis tracking configurations as well as a fixed axis configuration. SERVM also simulates production from BTMPV resources. For each of these classes of solar resources, SERVM creates a separate normalized production profile representing hourly weather from 23 weather years and for more than two dozen specific locations in California and across WECC. RESOLVE aggregate profiles are obtained by averaging production profiles across the representative locations. Installed capacity for individual baseline solar installations is used to create a single weighted average baseline CAISO solar profile. Inverter loading ratio for BTMPV resources is sourced from the CEC IEPR information, currently equaling 1.13.

For baseline resources, Staff assigns baseline generators to specific weather station profiles. This mapping and the maximum capacity of each generator is used to construct weighted average profiles for each baseline resource in RESOLVE.

For candidate solar resources, each candidate resource is directly mapped to a weather station. The designated weather station's profile is then used as the profile for that resource to produce RESOLVE aggregated profiles. An inverter loading ratio, equaling 1.3 for utility scale solar and 1.15 for distributed solar, is applied to the solar profiles to reflect AC capacity factors in RESOLVE.

Before the solar profiles can be used in RESOLVE, they are scaled such that the weighted capacity factor of the modeled days matches a long-run average capacity factor. This step is taken to ensure that the day sampling process does not result in over- or under-production for individual solar resources relative to the long-run average. The reshaping is done by scaling the shape up or down until the target capacity factor is met. When scaling up, the maximum capacity factor is capped at 100% to ensure that a profile's hourly production does not exceed its rated installed capacity. The scaling process mimics increasing/decreasing the inverter loading ratio. Solar resource profile capacity factors are scaled using the average simulated capacity factor from the nearest representative weather station from the historical 23-year weather conditions. Solar capacity factors are shown in Table 84. [130]

Table 84. Solar Capacity Factors in RESOLVE

Category	Resource	Capacity Factor
Baseline Resources	PGE_Solar	*30%*
	SCE_Solar	*34%*
	SDGE_Solar	*32%*
	IID_Solar	*30%*
	LDWP_Solar	*28%*
	NCNC_Solar	*31%*
	NW_Solar	*22%*
	SW_Solar	*32%*
Candidate Resources	PGE_Distributed_Solar	*25%*
	SCE_Distributed_Solar	*26%*
	SDGE_Distributed_Solar	*25%*
	PGE_Fresno_Solar	*32%*
	PGE_GBA_Solar	*31%*
	PGE_Kern_Solar	*33%*
	PGE_NGBA_Solar	*31%*
	SCE_Eastern_Solar	*34%*

[130] Note the naming convention for baseline renewable resources is [BAA]_[Solar/Wind]_for_[REC recipient: CAISO or Other]. For example generation from the "CAISO_Solar_for_Other" resource is included in CAISO's load resource balance equation and RECs from this resource are not included in CAISO's RPS constraint. Generation from the "IID_Solar_for_CAISO" resource is balanced by IID and RECs from this resource are included in CAISO's RPS constraint.

	SCE_EOP_Solar	*33%*
	SCE_Metro_Solar	*33%*
	SCE_NOL_Solar	*36%*
	SCE_Northern_Solar	*36%*
	SDGE_Arizona_Solar	*33%*
	SDGE_Eastern_Arizona_Solar	*33%*
	SDGE_Imperial_Solar	*33%*

*Remote solar generators will be modeled with separate profiles, excluded from this table

6.2.3 Wind Profiles

The CPUC 2023 wind model produces 23 years of normalized hourly wind production profiles (2000 – 2022) for all wind resources within our model. For each wind resource in the model, hourly wind production curves (MWh) can be produced by simply scaling the respective normalized hourly production profile closest to the resource by its installed capacity (MW).

Hourly normalized production profiles are developed in two different ways:

1. **Velocity Approach**: For regions where historical wind production data is not available, including some onshore as well as all offshore locations, we build normalized hourly wind production profiles from hourly wind speed data along with an appropriate power response curve and a multiplicative transmission loss factor. The power response curve gives normalized production as a function of wind speed. Developing hourly normalized wind production profiles based on modeled wind speeds supports preservation of correlations with electrical demand and solar production across time and space. Wind speeds are obtained from:
    i. **Offshore Wind Speed Profiles**: Offshore hourly wind speed profiles are obtained from the National Offshore Wind (NOW) data set (https://data.openei.org/submissions/4500). Offshore production profiles are calibrated by adjusting the value of the multiplicative transmission loss factor in order to match simulated capacity factor information (https://www.nrel.gov/docs/fy22osti/82341.pdf).
    ii. **Onshore Wind Speed Profiles**: Onshore wind speed profiles are obtained from the Copernicus ERA5 reanalysis dataset (https://cds.climate.copernicus.eu/cdsapp#!/dataset/reanalysis-era5-single-levels?tab=form).

2. **Monte Carlo Approach**: Where historical wind production data is available, development of wind profiles is informed by historical production data - CAISO production data within CA, and EIA data outside of CA. The process for developing normalized hourly wind profiles is as follows:
    i. Map each wind resource to a wind weather station.
    ii. Aggregate historical hourly wind production to each wind weather station.
    iii. Normalize hourly wind production for each weather station by 1.1 * yearly peak, where the diversity factor of 1.1 accounts for the non-simultaneity of wind production associated with each given weather station. This approach does not require an independent data source for aggregating installed capacity as this is inferred from historical production.
    iv. For each weather station and for each hour of the year, develop Monte Carlo random draws (with replacement) from the historically observed normalized production values for each of the desired weather years (2000 - 2022).
    v. For each weather station, choose wind speed profiles from the Copernicus ERA5 dataset that are physically closest to the weather station centroid, and then resort the Monte Carlo random draws within each month to reproduce the same rank order as the modeled wind speed data. This step imposes temporal and spatial correlation into the Monte Carlo random draws.

The current CPUC 2023 wind model has evolved from previous approaches that have differed in two main ways:

- Reliance on Historical Wind Production: In the current approach, we attempt to make use of historical wind production data, when available. Previous versions attempted to develop normalized wind profiles from velocity profiles and a response function, but the approach tends to systematically undervalue wind production in periods of high load. The NREL NOW dataset will overcome some of these limitations for offshore production since it is based on such detailed studies for a handful of prime offshore locations.
- Aggregated regions: The previous wind model generated wind profile "weather stations" at excessively high spatial resolution, which tends to result in overestimating wind production potential. This can be understood as originating in diversity interactions between production profiles. The current wind model more accurately captures historical production without adding excessive diversity interactions which cause wind production to be overestimated. As a result, the modeled wind production in certain locations has declined from the previous cycle.

Note that we have moved from the high resolution onshore WRF/ERA5 wind speed dataset to the lower resolution Copernicus ERA5 dataset since at the time of development, the WRF/ERA5 dataset did not yet contain data past 2020.

RESOLVE sources wind shapes from the hourly profiles developed for the SERVM model. Profiles are selected from the SERVM model to correspond to aggregated wind resources in the RESOLVE model. The profiles are then scaled using a filter such that the weighted capacity factor of the modeled days matches a long-run average capacity factor. The filter mimics small differences in turbine power curves, slightly increasing or decreasing wind production in a manner that preserves hourly ramps. Baseline wind resources are categorized based on the location of generator units, distinguishing between in-state and out-of-state locations for ELCC and dispatch accounting purposes.

Before the wind profiles can be used in RESOLVE, they are scaled such that the weighted capacity factor of the modeled days matches a long-run average capacity factor. This step is taken to ensure that the day sampling process does not result in over- or under-production for individual wind resources relative to the long-run average. The reshaping is done by scaling the shape up or down until the target capacity factor is met. When scaling up, the maximum capacity factor is capped at 100% to ensure that a profile's hourly production does not exceed its rated installed capacity. The scaling process mimics increasing/decreasing the inverter loading ratio. Wind resource profile capacity factors are scaled using the average simulated capacity factor from the nearest representative weather station from the historical 23-year weather conditions. Wind capacity factors are shown in Table 85.

Table 85. Wind Capacity Factor in RESOLVE

Category	Resource	Capacity Factor
Baseline Resources	PGE_Wind	*29%*
	SCE_Wind	*26%*
	SCE_OOS_Wind (OOS = Out-of-State)	*38%*
	SDGE_Wind	*25%*
	LDWP_Wind	*33%*
	NW_Wind	*26%*
	SW_Wind	*31%*
Candidate Onshore Wind Resources	PGE_Fresno_Wind	*29%*
	PGE_GBA_Wind	*29%*
	PGE_Kern_Wind	*25%*

	PGE_NGBA_Wind	*26%*
	PGE_Wyoming_Wind	*40%*
	SCE_Eastern_Wind	*32%*
	SCE_EOP_Wind	*30%*
	SCE_Idaho_Wind	*28%*
	SCE_New_Mexico_Wind	*38%*
	SCE_NOL_Wind	*25%*
	SCE_Northern_Wind	*25%*
	SCE_Wyoming_Wind	*40%*
	SDGE_Baja_California_Wind	*32%*
	SDGE_Imperial_Wind	*32%*
Candidate Offshore Wind Resources	Cape_Mendocino_Offshore_Wind	*56%*
	Del_Norte_Offshore_Wind	*53%*
	Humboldt_Bay_Offshore_Wind	*49%*
	Morro_Bay_Offshore_Wind	*46%*

*Remote wind generators will be modeled with separate profiles, excluded from this table

6.3 Representative sampling hourly load & generation profiles

RESOLVE differs from production cost models in a sense that production cost models simulate a fixed set of resources, whereas the capacity of new and existing resources can be adjusted by RESOLVE in response to short-run (within year) and long-run (years to decades) economics and constraints. Thus, RESOLVE primarily intends to capture capacity expansion decisions through economic and operational constraints. Simulating detailed investment decisions concurrently with operational characteristics of the electric system necessitates a simplification of production cost modeling to maintain a reasonable runtime. For that purpose, and similar to many other capacity expansion models, RESOLVE optimization uses a down-sampled set of days representing the full range of weather years to maintain a reasonable runtime for while capturing detailed candidate resource options, operational characteristics, regional dynamics and economic variables.

Starting in the 2022-2023 IRP cycle, RESOLVE moved to a new clustering approach to select a subset of 36 sample days from the raw 23-year load, hydro, and renewable profiles in the updated IRP dataset.

The clustering approach used in this analysis relies on features of the load and generation profiles to identify:

a. Sample days (also known as "exemplars", "medoids", or "periods") that best represent the shape of the overall 23-year dataset. In the case of CPUC IRP RESOLVE, these sample days are all 24-hour days, though the algorithm can be configured to select exemplars of other lengths (e.g., sample weeks)
    i. The model employs affinity propagation as the clustering method in this project, using each historical day as a data point, although it does have the capability of employing other methods.
    ii. Affinity propagation algorithm conducts an iterative process that updates the "responsibility" and "affinity" between any two data points. For a particular data point A, if it has high affinity to many other data points, then it would be more responsible/suitable to become an exemplar. Other data points would then reevaluate their affinity towards data point A, based on its updated responsibility. This process iterates until there's only one exemplar remaining for each data point. A detailed process can be found here.[131]
b. A mapping of each sample day back to the original 23-year profile, by providing
    i. A weighting of the sample day, as a percent of the total dataset, used to scale up the expected operational costs for the portfolio from the sample day level to the annual level.
    ii. A reconstruction of a "pseudo-8760" dispatch based on the chronological mapping of which sample day best represents the original date in the profile.

Staff updated the sample day selection in this cycle based on latest load and renewable profiles, and continued to refine the methodology in this process. A more streamlined qualitative evaluation for selected sample days were introduced as a post processing step to validate the quality of the sample days. Staff also made sure that the selected sample days represent a wide range of load and resource conditions.

The specific sample days used in the model are shown in Table 86 below.

Table 86. Representative sample days for 2025 CPUC IRP RESOLVE modeling

#	Historical Date	Weight	#	Historical Date	Weight

[131] https://www.science.org/doi/10.1126/science.1136800

1	1/10/06	2.3%	19	8/5/04	3.0%
2	1/23/05	3.4%	20	8/6/05	2.0%
3	2/26/12	2.5%	21	8/20/05	3.2%
4	3/6/20	4.4%	22	8/23/22	2.1%
5	4/5/21	1.7%	23	8/30/03	3.3%
6	4/7/02	2.9%	24	9/7/06	3.3%
7	4/11/03	3.8%	25	9/22/01	3.0%
8	4/20/14	2.8%	26	9/28/08	4.9%
9	5/3/19	1.7%	27	10/2/05	4.0%
10	5/4/10	1.7%	28	10/29/11	4.0%
11	5/8/18	3.9%	29	11/8/05	3.0%
12	5/15/13	3.5%	30	11/9/01	2.9%
13	5/27/18	0.3%	31	11/20/03	3.9%
14	6/8/11	2.3%	32	11/29/03	2.6%
15	6/20/05	2.6%	33	11/30/13	4.5%
16	7/23/11	2.1%	34	12/5/14	1.7%
17	7/25/12	2.4%	35	12/12/14	0.3%
18	7/31/05	1.5%	36	12/12/16	2.7%

Three primary steps are taken in identifying representative periods:

1. **Input Profiles Correlation Check:** Checking correlation between solar and wind resources narrows down the solution space by only including profiles that are more distinct and dropping the ones that are very similar.
2. **Grid Searching for Weights that "Optimize" Cluster Performance:** Testing different weights for the remaining profiles helps identify a range of weights that minimizes clustering error (i.e., Root Mean Squared Error (RMSE)).
3. **Applying Criteria for "Best Performing" Representative Days:** Statistical analysis and different visualizations are used to assess the efficacy of sample days in capturing the expected variability in load and weather-dependent resource generation across the 23 weather years.

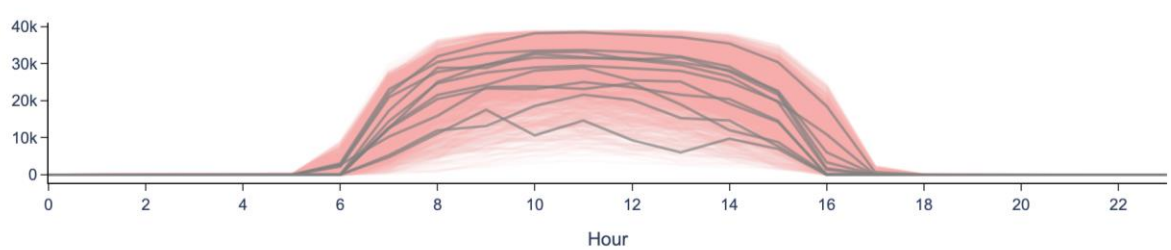
After reviewing a few sets of prospective sample days, the best set of days are identified when the following criteria were satisfied to ensure the validity and efficacy of sample days following criteria are used:

a. Energy representation: ensuring capacity factors in sample days are well within the range of the expected capacity factor in historical weather year data. Sample days are by design the average of clustered historical days; thus, they may represent an average low renewable day instead of the lowest and highest historical renewable days.
b. Calendar distribution: Selected sample days should be distributed across all twelve months and weekdays. For example, it is good practice to at least have one day from each month of the year, a mix of weekend or weekdays, etc.
c. Hydro budget: Sample day profiles should capture hydro year variabilities. Relying on one type of year, such as an extremely low hydro year, may lead to unreasonable investment decisions.
d. Gross load representation: Profiles in sample days should capture patterns in system gross load well enough to ensure that the average expected diurnal and seasonal load patterns are represented. Sample days do not necessarily need to capture 1-2 or 1-10 peaks, since the PRM modeled in RESOLVE is designed to determine the reliability need.
e. Load resource correlation: Sample day profiles should capture the correlation between renewable generation and load. The resulting net load shape should capture the average variation in both renewables and loads.

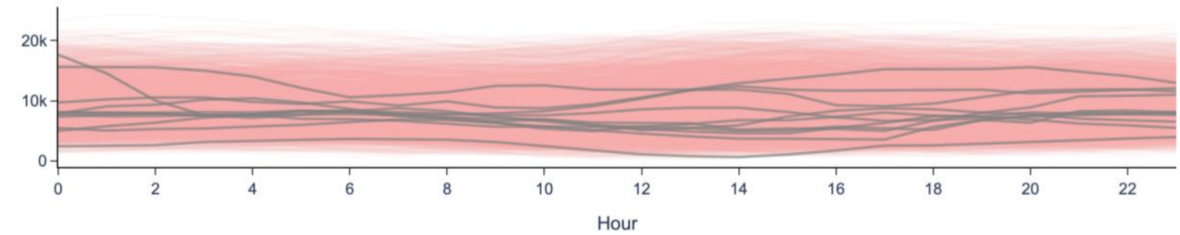
While generally a higher number of sample days could result in better representation of historical variations on load and generation, it was found that when more than 40 sample days are selected, there are only marginal improvements in capturing the historical variability in data. Thus, similar to the 2022-2023 cycle, a set of 36 sample days are identified to be used for IRP RESOLVE modeling. The figures below show the selected days compared to historical observations and demonstrate how average, low and high renewable, loads and hydro conditions are captured in both summer and winter months.

Figure 22. CAISO solar, wind and net load representation in sample days in winter months

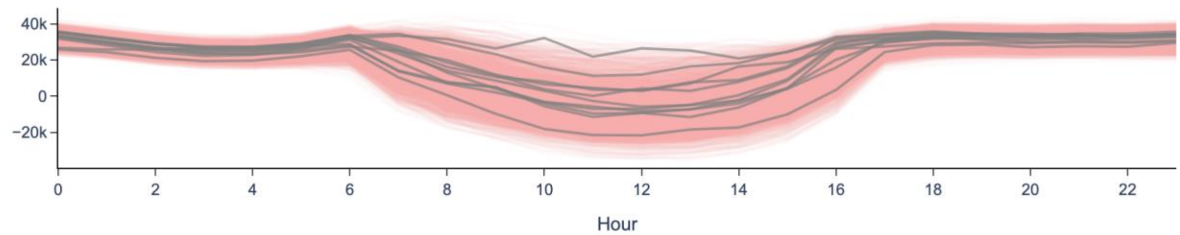
Solar



Wind



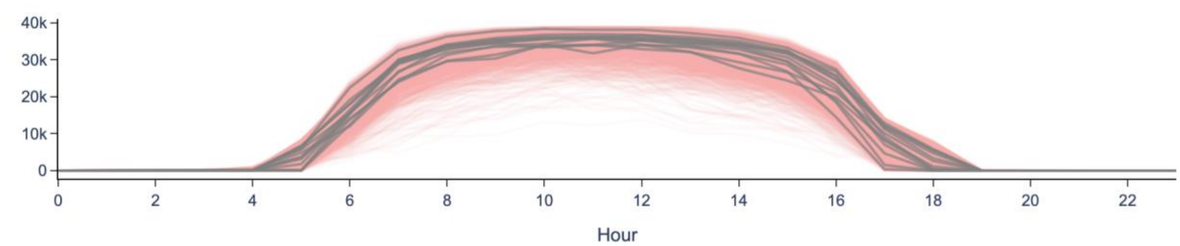
Net Load



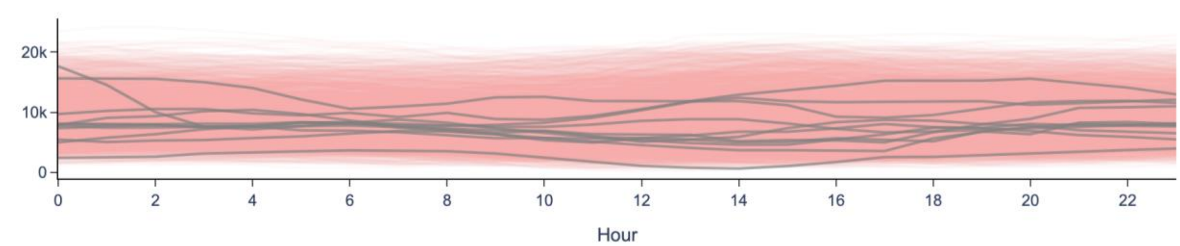
Representative days   Raw historical

Figure 23. CAISO solar, wind and net load representation in sample days in summer months

Solar



Wind



Net Load

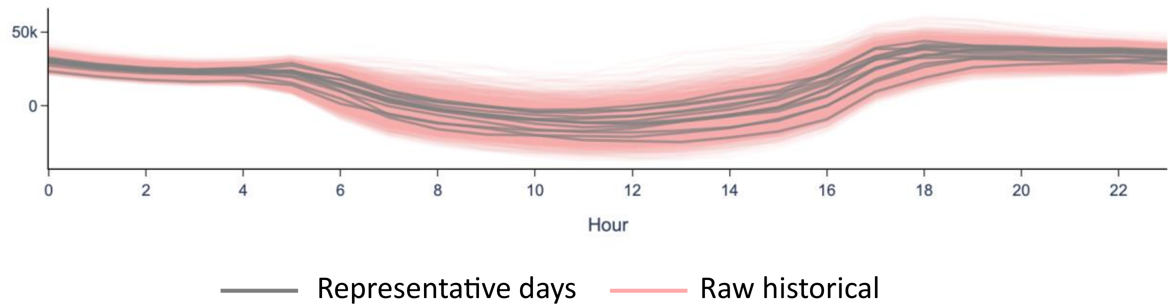
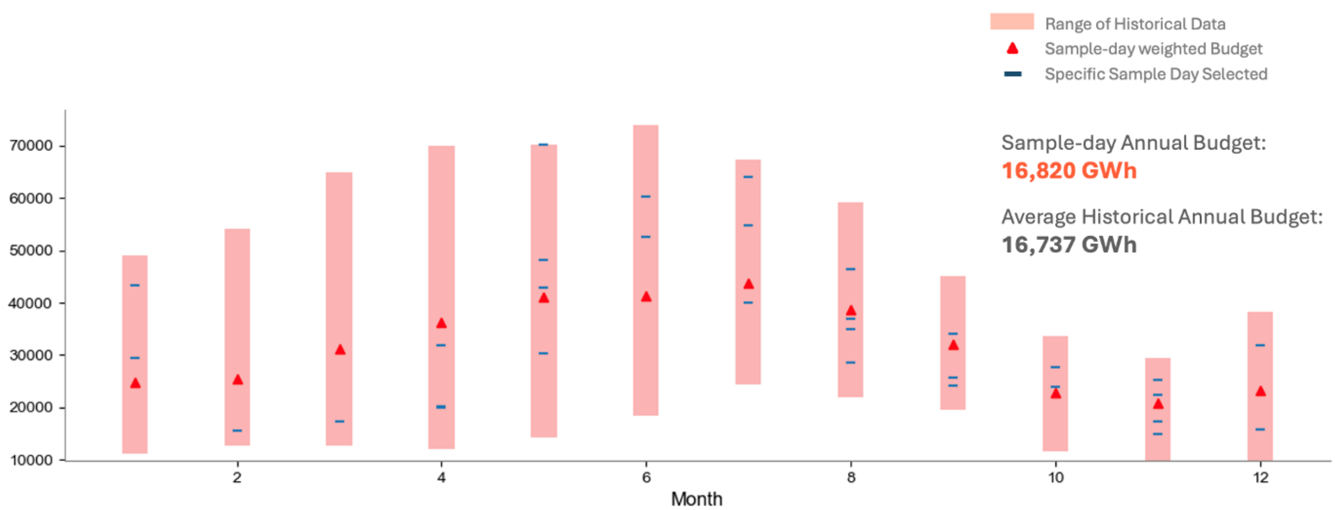


Figure 24. CAISO hydro representation in sample day months



Dispatch in each sample day in RESOLVE are modeled as independent from the other days as a default. In this case, the sample days allow to capture diurnal storage cycles but do not allow for energy to be stored on one day and be discharged on another day. Thus, to characterize the flexibility of storage resources, an inter-day sharing feature is available. This is more important for longer duration energy storage (8+ hrs) and allows for storage to charge over longer periods when excess renewables are available and shift to another day when needed; or allows for discharge of the stored energy across multiple days. To be able to model storage with this level of flexibility, the chronological order of historical days associated with sample days is maintained in the model.

6.4 Operating Characteristics

6.4.1 Natural Gas, Coal, and Nuclear

The thermal fleet is represented by a limited number of resources within each zone. Within each zone, each resource is characterized individually with operating parameters calculated from unit-level data. Constraints on gas and coal plant operation are based on a linearized version of the unit commitment problem. The principal operating characteristics (Pmax, Pmin, heat rate, start cost, start fuel consumption, etc.) for each unit are taken from the latest vintage version of the CAISO Master File and the WECC 2032 Anchor Data Set Phase 2 2 V2.3.2.[132] Variable Operations and Maintenance Costs (VO&M) are sourced from the CAISO Master File. Some plant types are modeled using operational information from other sources:

- The candidate natural gas operating characteristics are based on manufacturer specifications of the latest available models of these classes.

While SERVM simulates each unit individually based on actual unit data, RESOLVE aggregates unit types together into classes of thermal generating units (CCGT, Steam Turbine, Peaker, etc.). and uses weighted average statistics drawn from the unit level data used in SERVM. In RESOLVE, constraints on gas and coal plant operation are based on a linearized version of the unit commitment problem. Monthly derates for each plant reflect assumptions regarding the timing of annual maintenance requirements. Nuclear maintenance and refueling is assumed to be split between the spring (April & May) and the fall (October & November) so that the plants can be available to meet summer and winter peaks (as noted earlier, the modeling assumptions use the current retirement dates for Diablo Canyon Nuclear Power Plan Units 1 and 2). Annual maintenance of the coal and gas fleets in the WECC also occurs primarily during the spring months, when wholesale market economics tend to suppress fossil generator capacity factors due to low loads, high hydro availability, and high solar availability, and well as the fall months, which typically have lower peaks than the winter and summer.

6.4.2 Hydro

Power production from the hydro fleet in RESOLVE in each zone is constrained on each day by three constraints:

Daily energy budget: the total amount of energy, in MWh, to be dispatched throughout the day. These energy budgets are derived from historical monthly average flows from the historical 2000-2022 weather record.

Daily maximum and maximum output: upper and lower limits, in MW, for power production intended to capture limits on the flexibility of the regional hydro system due to hydrological, biological, and other factors.

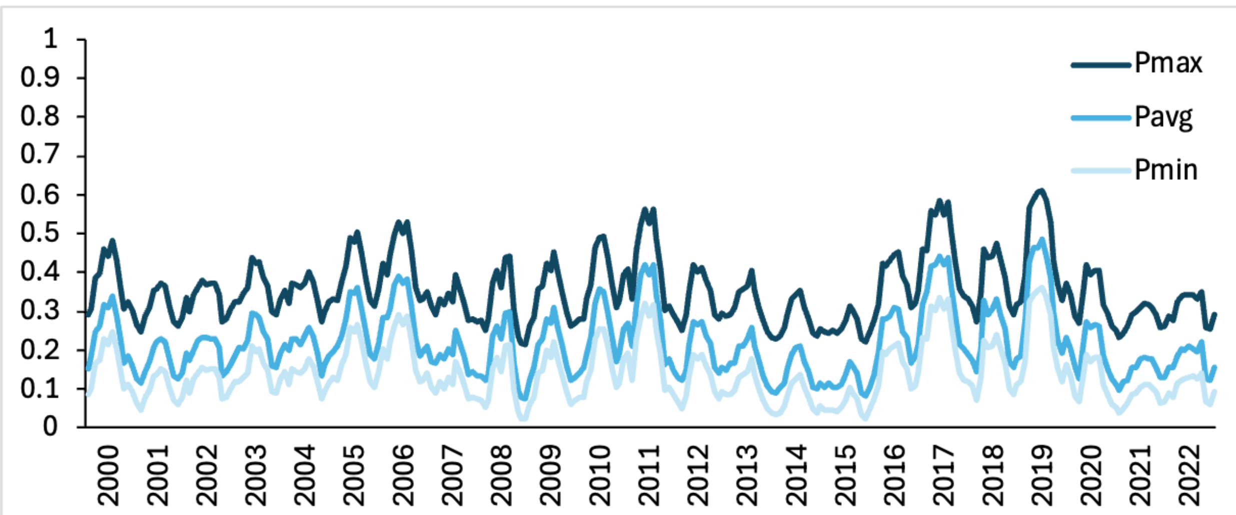
Ramping capability: within CAISO, the ramping capability of the fleet is further constrained by hourly and multi-hour ramp limitations (up to four hours), which are derived from historical CAISO hydro operations.

The RESOLVE parameters have been updated to be consistent with similar parameters in SERVM for the regions that are part of CAISO.

[132] https://www.wecc.org/Reliability/2032%20ADS%20PCM%20V2.3.2%20Public%20Data.zip [145] See http://oasis.caiso.com/mrioasis/logon.do

Outside CAISO, assumed daily energy budgets are derived from monthly historical hydro generation as reported in EIA Form 906/923. Minimum and maximum output for regions outside CAISO are based on functional relationships between daily energy budgets and the observed operable range of the hydro fleet derived from historical data gathered from WECC. The Pacific Northwest Hydro fleet is divided into two resources: **NW_Hydro**, which serves load primarily in the NW and is located in the NW zone, and **NW_Hydro_for_CAISO**, which is modeled as a dedicated import into CAISO. Both hydro resources use the historical maximum and average capacity factor of the NW hydro fleet on the appropriate month and year for each sampled day. To maintain historical streamflow levels for the aggregate fleet of NW hydro generators, fleet-wide minimum output levels are enforced on the NW_Hydro resource.

Figure 25. CAISO Hydro Operating Bounds



In the chart above, P_{max} represents the maximum power output in each month for 1998-2020 hydro years, $P_{average}$ represents the average daily power output in each month (i.e., 24 hours/day x $P_{average}$ = daily energy budget), and P_{min} represents the minimum power output defined by streamflow and other operational requirements.

6.4.3 Energy Storage

In RESOLVE's internal production simulation, storage devices can perform energy arbitrage and can commit available headroom and footroom to operational reserve requirements. For storage devices, headroom and footroom are defined as the difference between the current operating level and maximum discharge or charge capacity (respectively). For example, a 100 MW battery charging at 50 MW has a headroom of 150 MW (100 – (-50)) and a footroom of 50 MW.

Reflecting operational constraints and lack of direct market signals, BTM storage devices in the 2024-2026 IRP cycle can perform energy arbitrage but do not contribute to operational reserve requirements.

For all storage devices, RESOLVE does not by default include minimum generation or minimum "discharging" constraints, allowing them to charge or discharge over a continuous range. For pumped storage, this is a simplification because pumps and generators typically have a somewhat limited operating range. The round-trip efficiency and parasitic (self-discharge) losses for each storage technology (Li-ion, Pumped Storage, and generic long duration) is based on the most recent information in the Lazard's Levelized Cost of Storage report.

Table 87. Assumptions for new energy storage resources

Technology	Round-Trip Efficiency	Duration (hours)
Li-Ion Battery (Utility Scale)	85%	4-hour and 8-hour tranches
Pumped Storage	80%	12
Generic 12-hr Storage	65%	12
Generic 24-hr Storage	60%	24
Generic 100-hr Storage	45%	100

In SERVM, battery storage is modeled with a 90% of nameplate discharge range, except during scarcity hours when full discharge is allowed. This constraint was chosen to reflect real world behavior of operators seeking to avoid increased maintenance from operating batteries at their extremes regularly. Pumped hydro storage units in SERVM do not have this constraint.
In the prior IRP cycle, SERVM used a fixed maintenance rate of 0.0218 for both battery storage and pumped hydro storage. This cycle staff developed seasonal maintenance rates for battery storage from analysis of CAISO Prior Trade Day Curtailment Reports. The current assumptions are shown in Table 88. Pumped hydro storage maintenance rate remains at 0.0218.

Table 88. Battery maintenance rates in SERVM

Season	Maintenance Rate

Summer	0.01
Non-summer	0.0094

In the prior 2022-2023 IRP cycle, SERVM used a fixed 5% Expected Forced Outage Rate (EFOR) for battery storage. This was chosen based on historical battery outage data obtained from CAISO that showed weighted average outage rates of about 5-7%. This cycle staff developed seasonal EFORs for battery storage in low, medium, and high categories from analysis of CAISO Prior Trade Day Curtailment Reports. The current assumptions are shown in Table 89.

Table 89. Battery EFOR rates in SERVM

EFOR Category	Summer EFOR	Non-Summer EFOR
Low	1.12%	1.39%
Mid	3.82%	2.68%
High	7.85%	6.64%

6.5 Operational Reserve Requirements

As described in Table 90 below, both IRP models model reserve products that ensure reliable operation during normal conditions (regulation and load following) and contingency events (frequency response and spinning reserve). Reserves are modeled for each hour in both

RESOLVE and SERVM models. Information on these requirements came from discussions with CAISO staff and are summarized below.

Reserves can be provided by available headroom or footroom from various resources, subject to operating limits. For generators, headroom and footroom represent the difference between the current operating level and the maximum and minimum generation output, respectively. For storage resources, the operational range from the current operating level to maximum output (headroom) and maximum charging (footroom) is available, subject to constraints on energy availability. Reserves are modeled as mutually exclusive, meaning that headroom or footroom committed to one reserve product cannot be used towards other requirements.
While SERVM is able to simulate requirements across all regions in the model, in RESOLVE reserves are only modeled for the CAISO zone due to computational limitations.
Geothermal and biomass resources are not modeled as providing reserves.

Table 90. Reserve types modeled in RESOLVE and SERVM

Product	Description	Modeling Requirement	Operating Limits
Regulation Up/Down	Frequency regulation operates on the 4-second to 5-minute timescale. This reserve product ensures that the system's frequency, which can deviate due to real-time swings in the load/generation balance, stays within a defined band during normal operations. In practice, this is controlled by generators on Automated Generator Control (AGC), which are sent a signal based on the frequency deviations of the system.	In RESOLVE the requirement varies hourly and is formulated using a root mean square of the following values for each hour: 1% of the hourly CAISO load; a 95% confidence interval (CI) of forecast error of the 5-minute wind profile within a given season-hour; and a 95% CI of the forecast error of the 5minute solar profile within a given season-hour. The calculation is performed separately for regulation up and regulation down. In SERVM this is modeled as 3% of hourly demand. Lack of sufficient capacity to provide regulation reserve leads directly to LOLE.	Gas-fired generators can provide available headroom/footroom, limited by their 10-minute ramp rate. Storage resources and hydro generators are only constrained by available headroom/footroom.
Load Following Up/Down	This reserve product ensures that sub-hourly variations from load, wind, and solar forecasts, as well as lumpy blocks of imports/exports/generator commitments, can be addressed in real-time.	In RESOLVE hourly requirements are based on a 95% CI of the sub-hourly net load forecast error within a given season-hour. The calculation is performed separately for load following up and load following down. In SERVM this is modeled as 6% of hourly demand each for load following up and down. Load	Gas-fired generators can provide all available headroom/footroom, limited by their 10-minute ramp rate. Storage resources and hydro generators are only constrained by available headroom/footroom.

		following up and down are targets, not requirements however and do not lead directly to LOLE.	
Frequency Response	Resources that provide frequency response headroom must increase output within a few seconds in response to large dips in system frequency. Frequency response is operated through governor or governor-like response and is typically only deployed in contingency events.	770 MW of headroom is held in all hours on gas-fired, conventional hydroelectric, pumped storage, and battery resources. At least half of the headroom (385 MW) must be held on gas-fired and battery resources. This is the same in both RESOLVE and SERVM.	Reflecting governor response limitations, gas-fired generators can contribute available headroom up to 8% of their committed capacity. Wholesale battery storage, pumped storage, and conventional hydroelectric resources are constrained by available headroom.
Spinning Reserve	Spinning reserve ensures that enough headroom is committed on available resources to replace a sudden loss of power from large generation units or transmission lines. Spinning reserve is a type of contingency reserve.	The requirement is 3% of the hourly CAISO load in both RESOLVE and SERVM. Lack of sufficient capacity to provide spinning reserve leads directly to LOLE.	Gas-fired generators can provide all available headroom, limited by their 10-minute ramp rate. Storage resources and hydro generators are constrained by available headroom/footroom. RESOLVE ensures that storage has enough state-of-charge available to provide spinning reserves, but deployment (which would reduce the state-of-charge) is not explicitly modeled.
Non-Spinning Reserve	Ensures that enough headroom is committed on available resources to replace spinning reserves within a given timeframe	Not modeled due to small impact on total system cost	N/A

In RESOLVE, the energy impact associated with deployment of reserves is modeled for regulation and load following. The default assumption for deployment of these reserves is 20%. In other words, for every MW of regulation or load following up provided in a certain hour, the resource providing the reserve must produce an additional 0.2 MWh of energy (and vice versa for regulation / load following down). For storage resources, reserve deployment changes the state of charge of the storage device. For thermal resources, reserve deployment results in increased or decreased fuel burn depending on the direction of the reserve. Conventional hydro resources are constrained by a daily energy budget, so reserve deployment will result in dispatch changes in other hours of the same day. Deployment is not modeled for spinning reserve and primary frequency response because these reserves are called upon infrequently. It is assumed that variable renewables (wind and solar) can provide load following down, but only up to 50% of the load following down requirement. This allows renewables to be curtailed on the subhourly level to provide reserves. Wind and solar resources are not assumed to provide any reserve product other than load following down.

CAISO hour-ahead forecasts and 5-minute actual values of load, wind, and solar are used to develop the load following and regulation requirements for RESOLVE. Reserve requirements use profiles that represent the production *potential*, so wind and solar curtailment is added back to historical profile data before performing the reserve requirement calculations. Requirements from the previous IRP cycle[133] are approximated as a linear combination of the following values:

- A percentage of hourly load
- A percentage of hourly wind output
- A percentage of solar nameplate capacity, differentiated by season and hour of day

Separate percentage values are determined for regulation up, regulation down, load following up, and load following down. Load following percentages were adjusted to reduce forecast bias. The wind and solar (utility-scale and BTM) resource capacity in each future year from the 2022 LSE filings requirement[134] in conjunction with the IEPR Planning Scenario load forecast, is used to calculate reserve requirements for each hour of every year through the end of the study period.

6.6 Criteria Pollutants Emissions Factors

Criteria pollutants are calculated from SERVM results. Power plant fuel burn and emissions are grouped by startup and steady state operation, and power plant locations are overlayed with maps of Disadvantaged Communities (DAC) in California. In the case of SO2 and PM 2.5, emissions are only a factor of the fuel consumed, thus tracking emissions is done by tracking total fuel consumed from startups and steady state operation. In the case of NOx emissions, emission rates vary at different levels of operation. Thus, there are different emissions factors for different kinds of startups (cold, warm, hot) and for steady state operations.

SOx and PM 2.5 emissions factors are presented as lbs per MMBtu of fuel burned, while NOx emissions factors are presented as lbs per MWh.

Table 91. NOx emissions Factors (lbs/MWh)

[133] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resourcehttps://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/inputs--assumptions-2019-2020-cpuc-irp_20191106.pdf p. 78-81plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/inputs--assumptions-2019https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/inputs--assumptions-2019-2020-cpuc-irp_20191106.pdf p. 78-812020-cpuc-irp_20191106.pdf p. 78-81. 2030 regulation and load following requirements are used to determine parameters.

[134] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/zipped-files/RESOLVEpublic-release--public-release-
2022-06-23-lse-plans-filing-requirements.zip

Unit Category	steady_state_nox_ef lbs/mwh	hot_start_ef lbs/mwh	warm_start_ef lbs/mwh	cold_start_ef lbs/mwh
CC	0.081	0.256	0.837	1.417
CT	0.171	0.154	0.739	1.323
ICE	0.500	0.154	0.739	1.323
Cogen	0.241	0.154	0.739	1.323
Steam	0.150	0.154	0.739	1.323
Coal	0.713	2.469	2.965	3.461

Table 92. SOx and PM2.5 Emissions Factors (lbs/MMBtu)

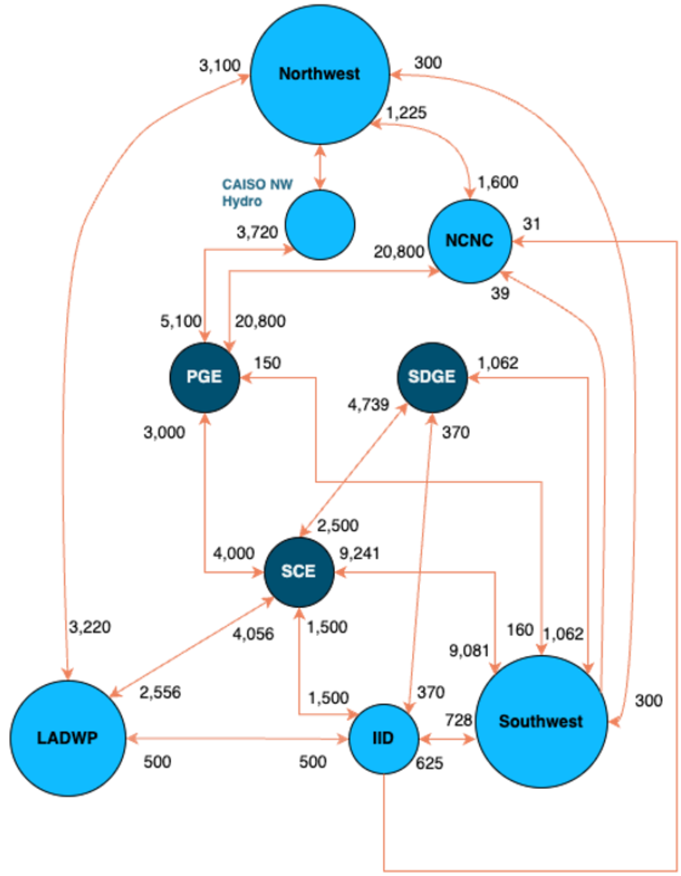
Unit Category	SO2 lbs/MMBtu	PM2.5 lbs/MMBtu
CC	0.001	0.007
CT	0.001	0.007
ICE	0.001	0.010
Cogen	0.001	0.007
Steam	0.001	0.008
Coal	0.085	0.020

6.7 Transmission Topology

Transmission flow limits between RESOLVE BAAs are the sum of flow limits between individual BAAs in the CPUC's SERVM model. SERVM flow limits were in-turn derived from the CAISO's PLEXOS model and supplemented with information from the CEC's PLEXOS model. CAISO's PLEXOS production cost model uses nodal flow ratings from the WECC 2032 ADS 2.0 dataset and path limits from the WECC ADS. The CEC's PLEXOS model was used as a supplemental data source for paths that did not have enough geographic resolution in CAISO's dataset.

Starting in the 2024-2026 IRP cycle, RESOLVE now models the individual CAISO IOUs (PGE, SCE, and SDGE) and the associated impacts of increasing granularity in capacity expansion modeling. The information in this section represents the interzonal transmission simultaneous flow limits, and is different from the transmission deliverability and interconnection data discussed in Section 5.5.

Figure 26. Transmission topology used in RESOLVE (transfer limits shown in MW)

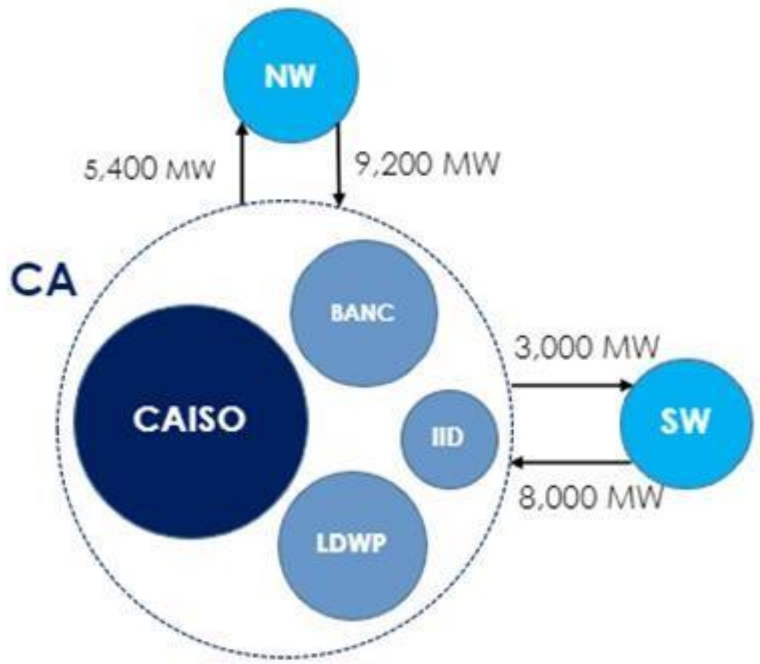


In addition to the physical underlying transmission topology, RESOLVE also includes constraints on simultaneous net imports into, and exports out of CAISO (PGE, SCE, SDGE). The net export constraint is included to capture explicitly the uncertainty in the size of the future potential market for California's exports of surplus renewable power. The net import limit reflects the limit on simultaneous imports into CAISO, and accounts for resources that are external to CAISO but modeled within CAISO in RESOLVE. Those include the CAISO LSE share of specified imports. This MW limit is taken from the total import capability of 11,040 MW from CAISO RA import capability reports.[135] The CAISO simultaneous export limit is set at 5,000 MW. The simultaneous net import/export limit applies to all hours of the year. The contribution of all import capacity to the CAISO PRM is set at 4,000 MW to reflect additional, non-modeled constraints on import availability during peak hours. In addition to CAISO, two other simultaneous flow constraints are added for California to and from SW and NW zones. These values are shown in Figure 27 below.

[135] CAISO Import Allocations, "Step 6: Assigned and Unassigned RA Import Capability on Branch Groups." http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

In SERVM, RESOLVE's non-modeled constraint on import contribution to meeting the CAISO PRM is modeled as an explicit additional simultaneous import constraint for flows into CAISO. The 4,000 MW constraint is enforced during peak hours between 4pm and 10pm in June through September and ramps up to or down from the default total import capability of 11,040 MW in all other hours.

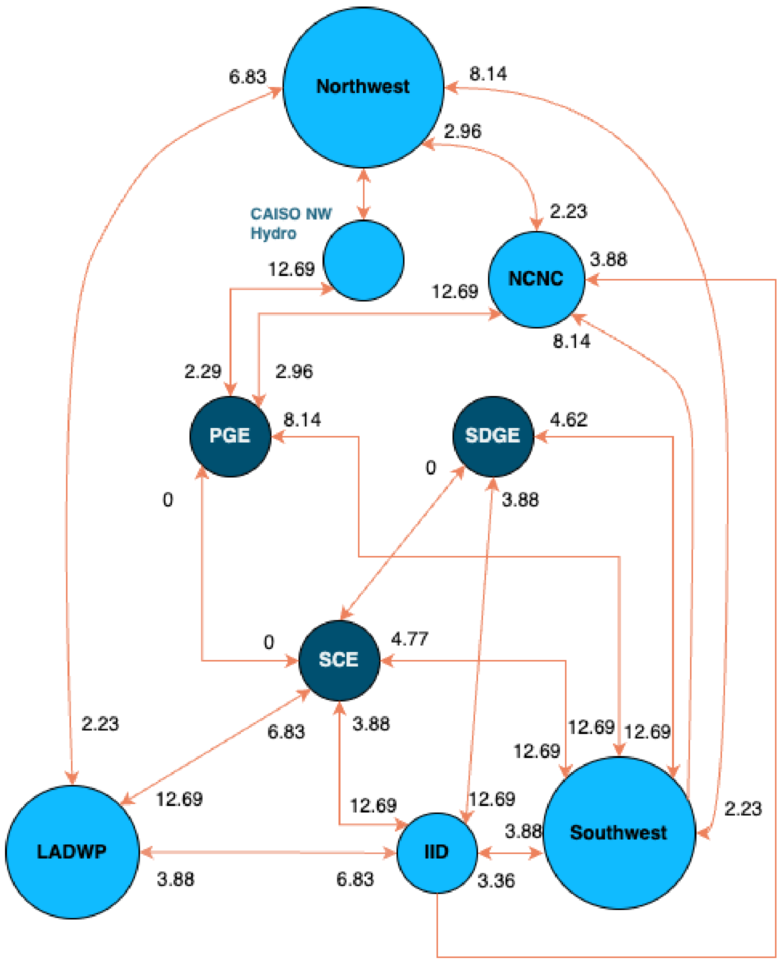
Figure 27. Assumed California to NW and Southwest net export and net import limits.



6.7.1 Hurdle Rates

RESOLVE incorporates hurdle rates for transfers between zones; these hurdle rates are intended to capture the transactional friction to trade energy across neighboring transmission systems. Hurdle rates in RESOLVE are tied to the zone of export and are derived from the hurdle rates used in the SERVM model. SERVM hurdle rates were in-turn derived from the CAISO's PLEXOS model and supplemented with information from the CEC's PLEXOS model. RESOLVE's NW and SW zones represent an aggregation of multiple BAAs, making it likely that the transmission systems of multiple BAAs would be used to export energy from these regions to CAISO. Consequently, hurdle rates to export from the NW and SW are calculated as the capacity-weighted average export hurdle of the constituent BAAs, and in SERVM there is an additional hurdle for a zone adjacent to CAISO added: Arizona Public Service (AZPS) for the SW and Bonneville Power Administration (BPAT)N for the NW. As shown in Figure 28, there is no hurdle rate between CAISO zones.

Figure 28. Hurdle Rates in RESOLVE (2022$/MWh)



In addition to cost-based hurdle rates, an additional cost from CARB's cap and trade program is added to unspecified imports into California; this cost is calculated based on the relevant year's carbon allowance cost and a deemed rate of 0.428 metric tons/MWh.[136] For carbon costs, the 2024-2026 IRP cycle assumptions include three options. Each option is based on CED 2022 Update GHG Allowance Price Projections.[151] RESOLVE only applies these carbon prices to resources in California, as well as unspecified imports into CAISO. The 2024-2026 IRP cycle inputs also include the option to run RESOLVE without a carbon price via the "Zero" trajectory. The "Low" trajectory is used by default which represents the price floor.

[136] Based on CARB's rules for CARB's Mandatory Greenhouse Gas Reporting Regulation, available at: https://ww2.arb.ca.gov/mrr-regulation

Table 93. Carbon Cost Forecast Options (2022$/tonne $CO_2$$)

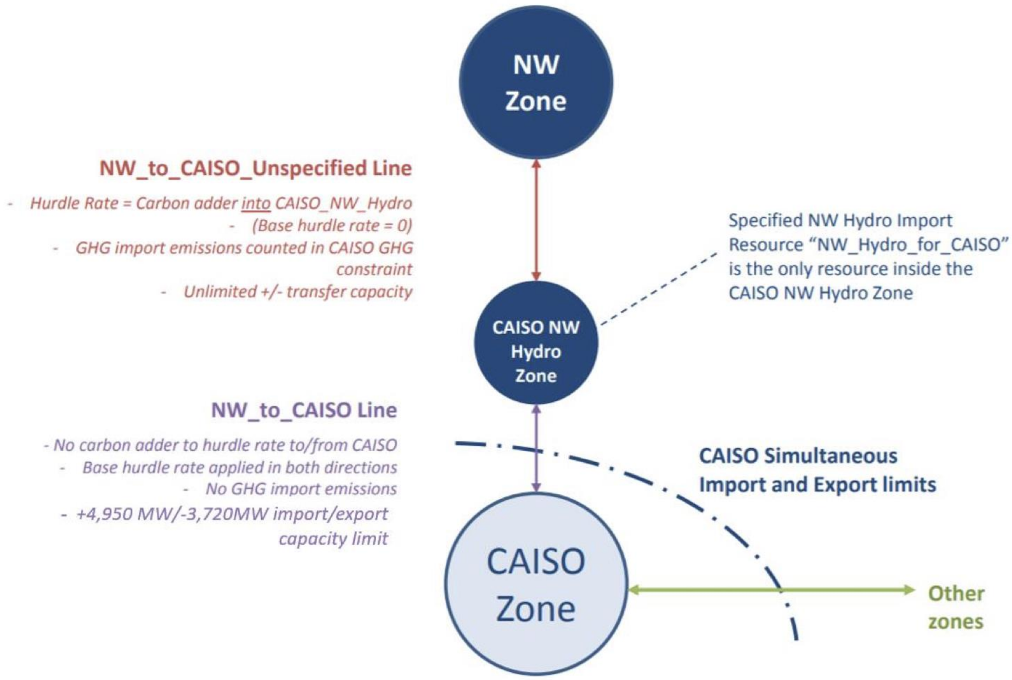
Fuel Type	2025	2030	2035	2040	2045
Low	$24.39	$31.46	$40.47	$52.11	$67.43
Mid	$37.97	$60.80	$97.06	$162.78	$273.43
High	$40.23	$70.94	$124.72	$200.86	$324.01
Zero	-	-	-	-	-

SERVM also models carbon costs in a similar manner to RESOLVE with some small differences. SERVM adds the CED 2022 Update GHG Allowance Price Projections "Mid" trajectory price to the operating cost of natural gas power plants in California while all plants outside California do not have a carbon cost. The "Mid" trajectory price was chosen for modeling in SERVM because its near-term values match reasonably well with carbon pricing observed recently in the CAISO market. SERVM also adds the same carbon costs to the hurdle rates for all transmission paths crossing into California, in other words, imposing the carbon price on all unspecified imports into California.

6.7.2 RESOLVE Transmission Topology for Specified Imports of NW Hydro

As shown in Figure 29, the 2024-2026 IRP cycle RESOLVE model continues to reflect specified hydro imports from the Pacific Northwest on an hourly basis. The resource **NW_Hydro_for_CAISO** is located in a zone called **CAISO_NW_Hydro**. The CAISO_NW_Hydro zone is contained within the NW zone and does not have any load. CAISO can receive unspecified imports from the NW to CAISO and from the CAISO_NW_Hydro to CAISO transmission paths, while exports can only go from CAISO to NW, excluding the CAISO_NW_Hydro zone. Emissions from unspecified imports from the NW are counted towards CAISO's GHG limit and incur CARB cap and trade emission permit costs using CARB GHG intensity for unspecified imports. Transfer limits into and out of CAISO are applied to both transfers to the NW zone and the CAISO_NW_Hydro zone. Essentially, both NW_to_CAISO line and the CAISO_NW_Hydro line are subject to the simultaneous import and export limits between California and the Northwest. Under the updated CAISO topology in the 2024-2026 IRP cycle, the transmission connection CAISO_NW_Hydro to CAISO specifically feeds into the PGE zone, the northernmost of the three CAISO zones.

Figure 29. Transmission Topology of NW Hydro Imports in RESOLVE



6.7.3 Other Specified Imports

Specified imports that deliver both energy and firm RA to CAISO are modeled as if the generator is located within CAISO. The CAISO simultaneous import limit is adjusted to account for the existing specified imports, as described earlier in Section 6.7.

As in previous IRP cycles, the existing specified imports to CAISO are the CAISO LSE shares of Hoover, Intermountain Power Plant, Palo Verde, and Sutter. For the 2024-2026 IRP cycle, two in-development units with contracts for firm RA or transmission will also be modeled as specified imports: SunZia Wind and Cape Station Geothermal. The RA status of these units will be reevaluated when they are online to ensure they should continue to be modeled as specified imports.

Additionally, out-of-state candidate resources in RESOLVE (for example, New Mexico Wind) are treated as specified imports with new firm transmission to deliver energy and RA to CAISO.

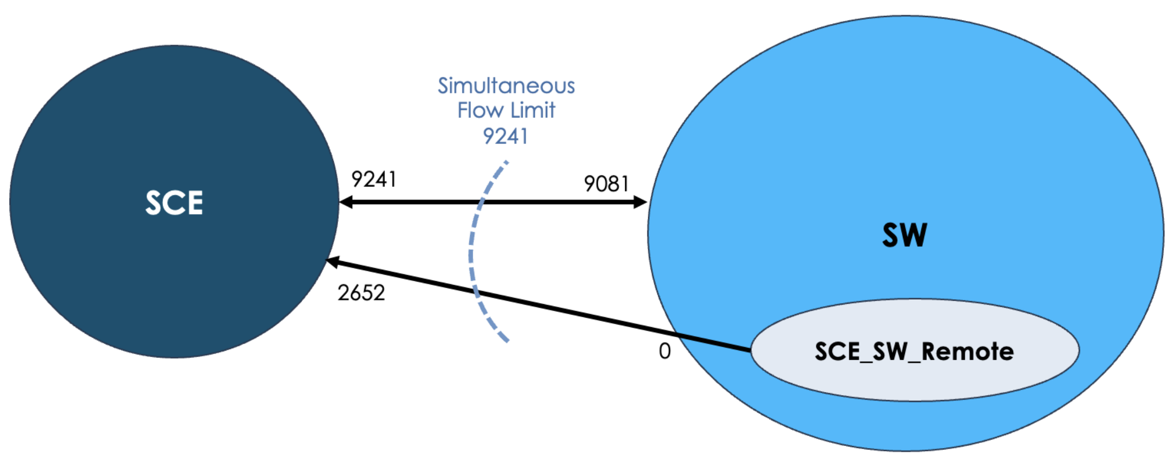
6.7.4 Remote Generators

Remote generators are units that are physically located outside of CAISO, but are contracted to deliver energy to CAISO LSEs. In contrast to specified imports, remote generators are not modeled with firm RA and are considered within unspecified imports for reliability modeling (see section 7 for details). In RESOLVE, remote generators are modeled as outside of CAISO and use transmission to deliver contracted energy to CAISO.

For the 2024-2026 IRP cycle, RESOLVE's representation of remote generators has been improved to align with SERVM and account for these units' transmission utilization. To ensure any energy produced by remote generators is transmitted to the contracted zone, remote generators are placed in special "remote zones" with no load and a one-way transmission path to the contracted zone. The maximum flow of the transmission path from each remote zone to CAISO is equal to the total nameplate capacity of the remote generators in the given zone, and no hurdle rate is applied to this transmission. A remote zone has been created for every combination of contracted zone and physical zone. For example, the remote zone "SCE_SW_Remote" is used for remote generators physically located in the SW zone but contracted to serve energy to the SCE zone.

Remote generators share transmission with other unspecified imports (i.e. imports from resources located in, and contracted to, non-CAISO zones). Remote generators and other imports are both subject to a simultaneous flow constraint, equal to the flow limit between the physical zone and contracted zone, which are shown in Figure 26 above. Essentially, transmission for remote generators is treated as a subset of the transmission path between the physical and contracted zone. An example is shown in Figure 30.

Figure 30. Example of Remote Generator Transmission Topology in RESOLVE



6.7.5 RESOLVE Transmission Path Upgrades

In RESOLVE, the IOUs within CAISO (PGE, SCE, and SDGE) are modeled individually, as are the transmission lines connecting them to each other and the non-CAISO zones. This zonal disaggregation enables 1) modeling of load-resource balance in three zones, instead of a single CAISO zone, with more precision, 2) better alignment with SERVM topology, 3) minimization of post-processing RESOLVE portfolios to balance siting between southern and northern California, and 4) exploration of alternative capacity expansion plans that may include the expansion of the north to south inter-zonal path rating.

As shown in Figure 26 above, there is initially a limit on the path between SCE and SDGE. However, starting in 2034, path limits between SCE and SDGE are eliminated through planned transmission upgrades. Additionally, upgrades to the PGE and SCE constraint (in both directions) are available for RESOLVE to optimally select. Three sequential tranches of upgrades are available:

1. A first tranche with 1,000 MW incremental transmission capacity, consisting of a new 500 kV line from Windhub to Midway[137].
2. A second tranche with 1,500 MW incremental transmission capacity, consisting of a new 500 kV line from Whirlwind to Midway, plus a Path 15 upgrade to deliver the energy to load centers (Alternative 6 from the 23-24 TPP congestion study)[138].
3. A third tranche with 3,000 MW incremental transmission capacity, consisting of three new 500 kV lines (one from Lugo to Vincent and two from Vincent to Midway), plus a Path 15 upgrade to deliver the energy to load centers (Alternative 8 from the 23-24 TPP congestion study)[139].

Table 94. Summary of PGE<>SCE transmission (Path 26/15) upgrade options in RESOLVE

Transmission Upgrade Tranche	Cumulative Upgrade (MW)	Total Path Rating After Upgrade (MW)	Total Cost ($MM)	Levelized Cost ($/kW-yr)	First Available Year
Tranche #1 (+1000 MW)	1000	4000 (SCE to PGE) 5000 (PGE to SCE)	$640	$49.95	2033-2034
Tranche #2 (+1500 MW)	2500	5500 (SCE to PGE) 6500 (PGE to SCE)	$2464	$128.20	2035-2037
Tranche #3 (+3000 MW)	5500	8500 (SCE to PGE) 9500 (PGE to SCE)	$5893	$155.65	2037-2039

All costs in 2022$

6.8 Fuel Costs

Monthly natural gas price inputs are derived from the 2023 IEPR burner tip price estimates from the CEC's North American Market Gas-trade (NAMGas) model runs.[140] In SERVM, each power plant is assigned to a fuel hub and transportation cost, consistent with the NAMGas model outputs to the extent possible. Monthly costs are used directly in SERVM.For RESOLVE, gas fuel

[137] Costs sourced from CAISO 22-23 TPP: 2022-2023 Transmission Plan Appendix F

[138] Costs sourced from CAISO 23-24 TPP and per-unit cost guide: https://www.caiso.com/documents/appendix-g-board-approved-2023-2024-transmission-plan.pdf; https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/20-Year-transmission-outlook-2023-2024

[139] Costs sourced from CAISO 23-24 TPP and per-unit cost guide: https://www.caiso.com/documents/appendix-g-board-approved-2023-2024-transmission-plan.pdf; https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/20-Year-transmission-outlook-2023-2024

[140] https://www.energy.ca.gov/programs-and-topics/topics/energy-assessment/natural-gas-electric-generationhttps://www.energy.ca.gov/programs-and-topics/topics/energy-assessment/natural-gas-electric-generation-prices-california-andprices-california-and

prices for each zone are aggregated from NAMGas burner tip information using the weighted average of gas capacity mapped to each hub in the zone of interest. The 2023 vintage of natural gas price forecast has data through 2059 with three forecasts available, i.e., High Demand, Mid Demand, and Low Demand, corresponding to Low, Mid, and High natural gas prices, respectively.[141] Fuel transportation costs are also sourced from the 2023 NAMGas model. For IRP modeling, the mid scenario will be used as the default fuel costs. The gas price forecasts for the three scenarios are shown in Table 95. Coal prices use a forecast developed by the CEC and uranium prices are updated using the forecasted prices in the EIA 2023 Annual Energy Outlook[154] using data in Table 3.9 for the Pacific zone and Table 3.8 for the Mountain zone. It is notable that coal and nuclear power plants are currently not considered as candidate resources in IRP modeling. As such, coal and uranium fuel prices do not impact resource build results. Further, nuclear power plants are currently modeled as a must-run resource;[142] therefore, uranium fuel prices do not impact nuclear generation dispatch results. Biomass fuel costs of $15/MMBtu were taken as the median of the value range provided in an NREL Biomass technology report.

For RESOLVE modeling needs, in addition to annual fuel price forecast, monthly price shapes are calculated from 2023 IEPR burner tip price estimates to capture seasonal variations in fuel prices which mainly impacts natural gas fuels. These shapes are shown in
Table 97.

Table 95. Natural Gas Fuel Price Forecast Scenario Options ($/MMBtu, 2022$)

Scenario	Region	2025	2030	2035	2040	2045
2023 IEPR – Low	PGE	5.70	5.88	6.13	6.44	6.83
	SCE	5.48	5.58	5.73	5.92	6.16
	SDGE	5.39	5.47	5.58	5.74	5.94
	IID	6.12	6.23	6.40	6.61	6.88
	LDWP	5.54	5.63	5.78	5.98	6.24
	NCNC	6.14	6.35	6.64	7.01	7.46
	NW	4.64	4.62	4.60	4.59	4.58

141 Data can be accessed from https://www.eia.gov/outlooks/aeo/tables_ref.php.

154 Annual Energy Outlook 2023. https://www.eia.gov/outlooks/aeo/

142 Nuclear power plants are characterized by high capital costs relative to fuel costs and are therefore, economically incentivized to run at high-capacity factors. This is likely true for more operationally flexible nuclear generator types (e.g., small modular reactors) as well based on existing cost data.

	SW	4.55	4.51	4.48	4.47	4.46
2023 IEPR – Mid	PGE	6.21	6.41	6.66	6.97	7.36
	SCE	5.89	5.99	6.13	6.27	6.47
	SDGE	5.91	6.01	6.15	6.29	6.48
	IID	6.47	6.59	6.74	6.91	7.14
	LDWP	5.94	6.04	6.17	6.33	6.54
	NCNC	6.62	6.85	7.15	7.51	7.96
	NW	5.06	5.04	5.02	5.02	5.02
	SW	5.05	5.03	5.02	5.07	5.08
2023 IEPR – High	PGE	6.74	7.04	7.40	7.83	8.30
	SCE	6.58	6.85	7.10	7.40	7.71
	SDGE	6.49	6.75	6.97	7.23	7.49
	IID	7.12	7.41	7.67	7.99	8.34
	LDWP	6.62	6.90	7.16	7.47	7.79
	NCNC	7.12	7.45	7.84	8.32	8.86
	NW	5.50	5.56	5.63	5.71	5.83
	SW	5.59	5.73	5.86	5.95	6.14

Table 96. Coal, Uranium, and Biogas Fuel Price Forecasts for CAISO ($/MMBtu, 2022$)

Fuel Type	2025	2030	2035	2040	2045
California Coal*	1.90	1.90	1.90	1.90	1.90
SW Coal	1.90	1.90	1.90	1.90	1.90
Uranium	0.71	0.71	0.71	0.71	0.71
Biomass	15.00	15.00	15.00	15.00	15.00

**SCE and LDWP; all coal serving California LSEs retires by 2025*

Table 97. Monthly Price Shape as Percentage of Annual Price

Fuel Type	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Natural Gas – PGE	104%	103%	96%	95%	98%	99%	100%	99%	100%	99%	103%	104%
Natural Gas – SCE	105%	103%	96%	95%	97%	99%	100%	99%	100%	99%	103%	104%
Natural Gas – SDGE	105%	103%	96%	95%	97%	99%	100%	99%	100%	99%	103%	104%
Natural Gas – IID	104%	103%	96%	95%	98%	99%	100%	99%	100%	100%	103%	104%
Natural Gas – LDWP	105%	103%	96%	95%	97%	99%	100%	99%	100%	99%	103%	104%
Natural Gas – NCNC	104%	102%	97%	96%	98%	99%	100%	99%	100%	100%	103%	103%
Natural Gas – NW	106%	103%	95%	94%	97%	99%	100%	99%	100%	99%	104%	105%
Natural Gas – SW	105%	103%	95%	94%	97%	99%	100%	99%	100%	99%	104%	105%
Biomass	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Coal	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Uranium	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

7. Resource Adequacy Requirements

7.1 System Resource Adequacy

To ensure that the optimized resource portfolio is sufficient to meet resource adequacy[143] needs throughout the year, IRP planning models (both RESOLVE and SERVM) perform assessments to ensure that total available generation capacity (measured in effective load carrying capability, i.e., ELCC) plus available imports in each year meets or exceeds a reserve margin above the annual 1-in-2 gross peak demand. IRP modeling is designed to ensure that the CAISO system would not be expected to endure more than one loss of load event in ten years, satisfying the Commission's 1-day-in-10-year loss of load expectation (LOLE) reliability standard, as formally adopted in the IRP proceeding via D.24-02-047 (1-day-in-10-years = 0.1 days/yr LOLE).

SERVM is utilized for resource adequacy and reliability studies. A study is performed to measure the amount of perfect capacity required to meet the 0.1 LOLE reliability standard in the CAISO system. The required level of perfect capacity (or perfect capacity equivalent) is a measure of the system's Total Reliability Need (TRN). Portfolios selected in RESOLVE's capacity expansion module are constrained to meet or exceed the TRN calculated in SERVM. RESOLVE calculates TRN endogenously using a perfect capacity (PCAP) based PRM (calculated in SERVM) above SERVM's median gross peak.[144]

7.1.1 Setting the Total Reliability Need and the Associated Planning Reserve Margins

The TRN is the total effective capacity needed to reach a system's probabilistic reliability standard. In the past, the CPUC has used installed capacity (ICAP) based accreditation methods, which count firm capacity resources (gas, nuclear, etc.) at their installed capacity and count non-firm resources (hydro, solar, wind, etc.) using either heuristics or their ELCC. This method does not explicitly quantify the impact of firm plant forced outages in the reliability need determination, indirectly increasing the reserve margin required to account for the risk of those outages. However, this can create an un-level playing field between resources, whereby thermal resources are accredited at a value higher than their actual reliability contribution (i.e., their ELCC), while non-firm resources – including new carbon-reducing resources – are accredited at their ELCC.

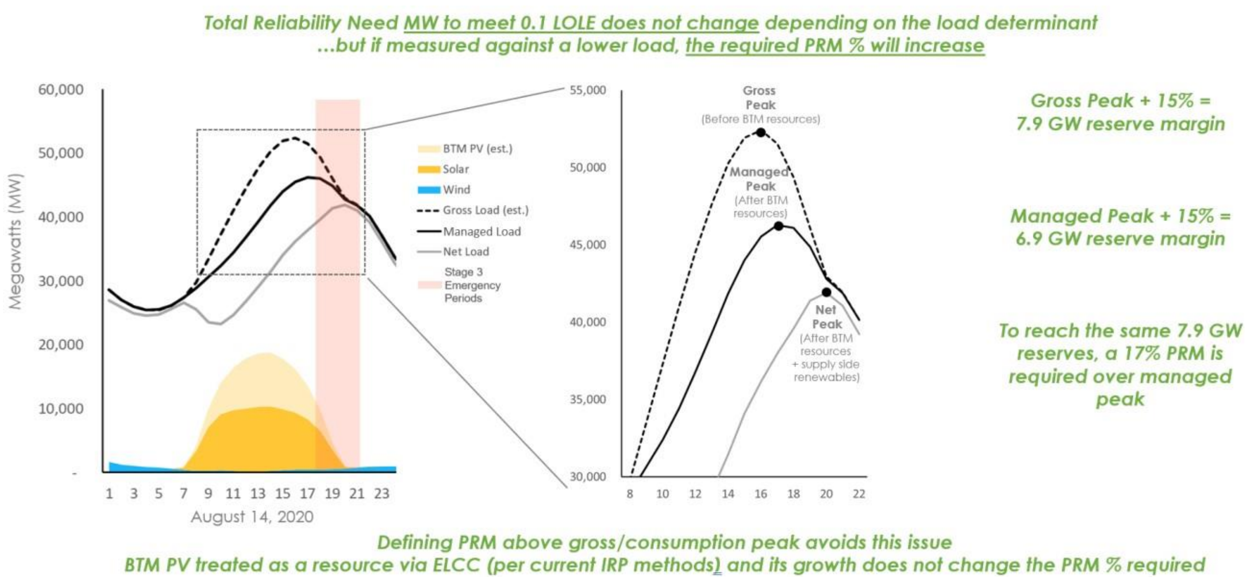
[143] Resource adequacy is referred to here in a broad sense, rather than with specific reference to the CPUC RA program.

[144] The 2023 IEPR in SERVM was calibrated to the IEPR's median managed peak (after all load modifiers). For IRP modeling, we define the gross peak as the managed peak plus the BTM PV output added back in (i.e. peak prior to the BTM peak shift). Calibrating to the IEPR managed peak results in a different SERVM gross median peak than the median gross peak implied by IEPR hourly data, so therefore the SERVM gross median peak is used directly as the basis for measuring the planning reserve margin to meet the TRN.

Similar to the 2022-23 IRP cycle, the planning reserve margin is calculated from the total reliability need (TRN), as derived from SERVM model simulations using the most recent IEPR data. This ties the reliability need definition to the fundamental weather, load, and operating reserve drivers that create reliability risk in SERVM's loss of load probability modeling, using the most recent data available on past historical weather conditions. The 2024-2026 IRP cycle uses historical weather conditions from 2000-2022.

The reliability need definition is defined in total ELCC MW, i.e., total perfect capacity equivalent MW, using "PCAP" accounting. This puts all resources on a level playing field within RESOLVE's economic optimization as it requires that all resources are counted at their ELCC. It also provides a more durable reliability need determination across the planning horizon, because the PCAP total reliability need (and therefore the PCAP PRM) is not dependent on the resource portfolio, but instead on load shapes, load variability, and operating reserve requirements. This PCAP PRM is lower than the ICAP PRM used in IRP cycles prior to the 2022-23 cycle, because no resources are accredited higher than their PCAP equivalent. The PCAP PRM is measured above the gross median system peak, i.e., the IEPR managed peak before BTM PV peak reduction, as calculated in SERVM. A PRM measured at the gross (higher) peak is a lower percentage than a PRM measured at the managed (lower) peak because the same total reliability need MW can be obtained with a lower percentage margin when multiplied by a higher (gross) peak.

Figure 31. Gross vs. Managed vs. Net Peak and the impact on PRM %



A "perfect capacity" generator is a theoretical concept, representing a firm generator that has no outages, fuel constraints, or other availability limitations. Since no resource provides perfect capacity, as shown in

Figure 32, the perfect capacity concept is simply a useful metric for which to measure all resources on a level playing field. ELCC studies are performed to calculate the perfect capacity equivalent MW, i.e., the ELCC for each resource.

Figure 32. Comparing Variable, Use-limited, and Firm Capacity to "Perfect" Capacity

The TRN measures the necessary accredited capacity to meet a target reliability standard. When all resources are counted at their ELCC, the total reliability need for the CAISO system can be expressed as the total ELCC MW required to maintain a 0.1 days/year loss of load expectation reliability standard. For example, the results of the most recent SERVM simulations on the 2035 CAISO system are shown in Figure 33 below. They indicate that, in 2035, 72.4 ELCC GW are necessary to achieve the 0.1 days/yr standard. This is equivalent to a ~14.9% PCAP planning reserve margin above the 63.0 GW gross peak. The translation of TRN MW to a PRM is shown in Figure 34. TRN simulations were performed in SERVM for 2026, 2030, 2035, and 2040, with differences in load shape components (e.g., growth of electric vehicles) impacting the required planning reserve margin.

The updated PCAP PRM in this cycle was calculated using the 2023 IEPR forecast. The PCAP PRM is 15.6% in 2026, 14.5% in 2030, 14.9% in 2035, and 14.1% in 2040. Values in between years were interpolated and the 2040 PRM was maintained in future years.

SERVM loads are calibrated to the IEPR Managed System Peak to calculate the TRN, which is done to facilitate Resource Adequacy (RA) program studies that base RA requirements on reserves in excess of the IEPR Managed Peak. CPUC RA requirements do not explicitly give credit to BTM PV or other demand side modifiers for meeting RA requirements, thus requirements need to be shown after output of demand side modifiers. Since IRP includes an ELCC surface that counts BTM PV reliability contributions, it defines the PRM above the gross peak and counts the ELCC from BTM PV.

Figure 33. SERVM Total Reliability Need (TRN) Simulation Results (2035)

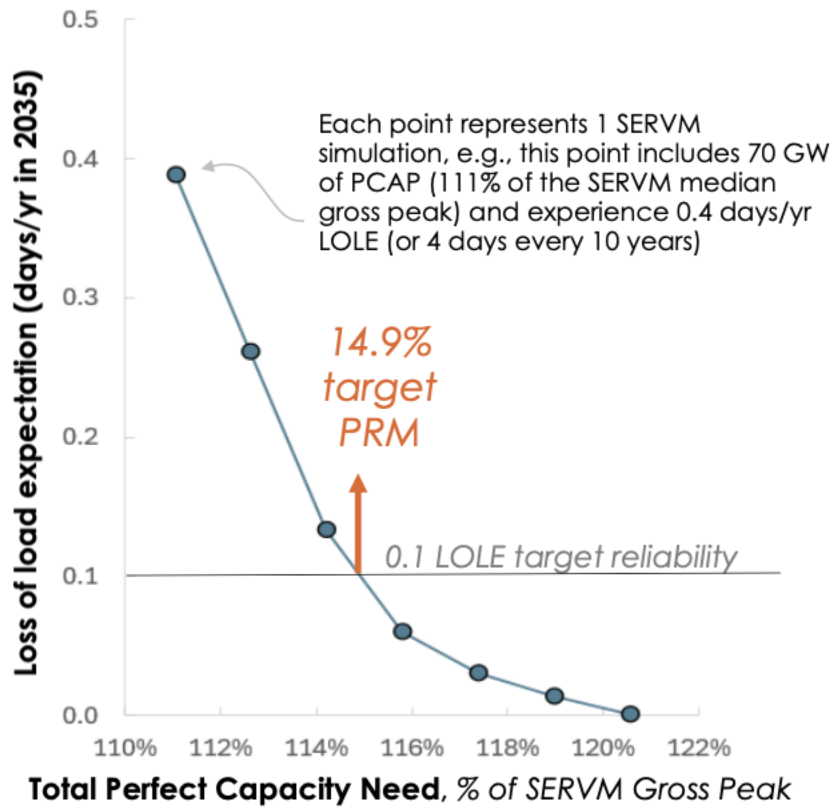
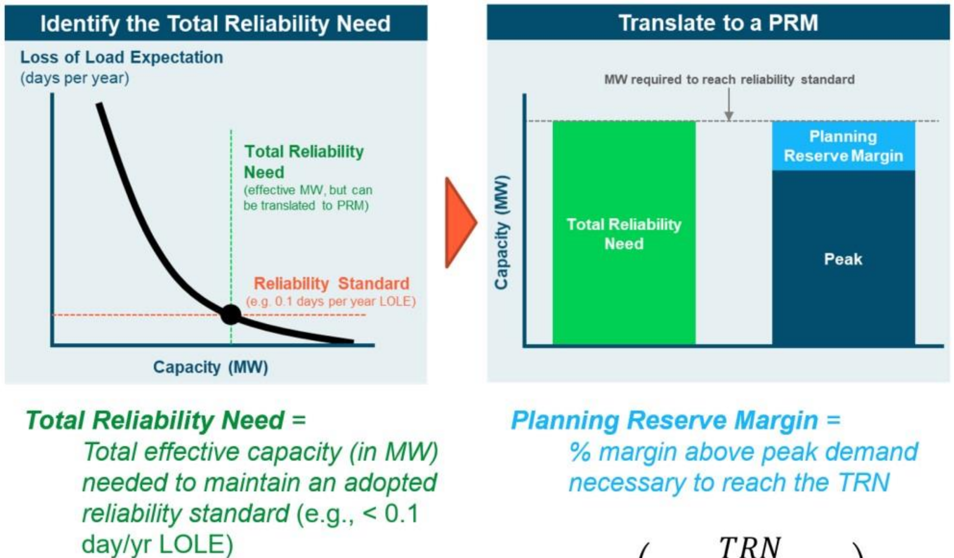


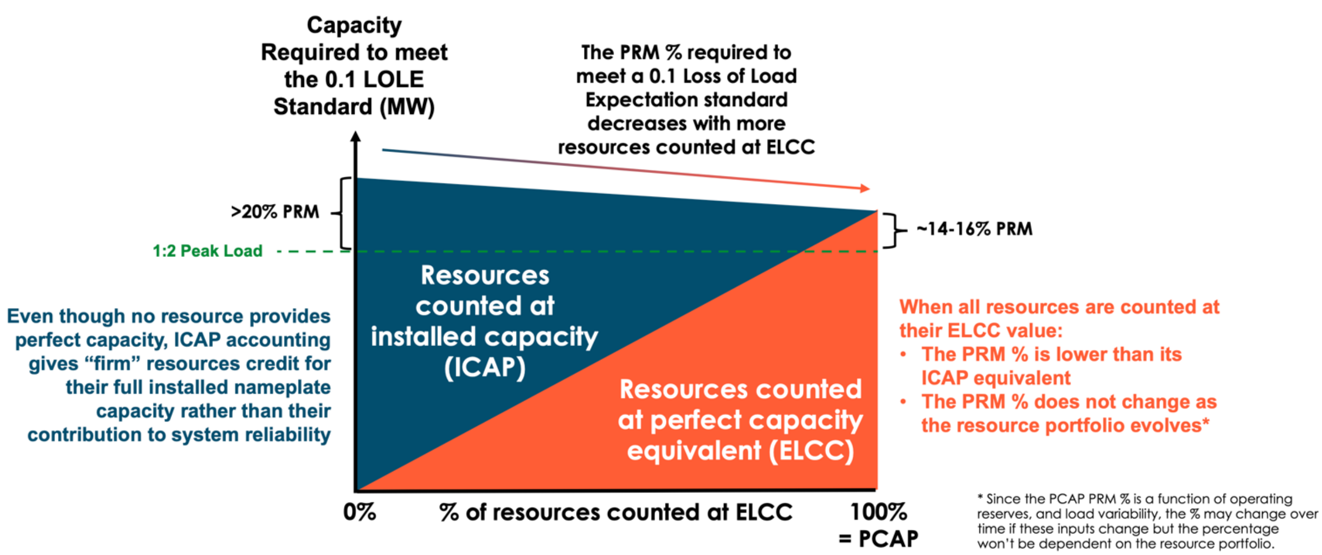
Figure 34. Translating Total Reliability Need MW into a Planning Reserve Margin Percentage



$$PRM\ \% = \left(\frac{TRN}{Peak\ Demand}\right) - 1$$

A PCAP PRM cannot be compared to a single ICAP PRM data point, because the ICAP PRM is inherently dependent on the resource portfolio, whereas the PCAP PRM is not. Figure 35 shows an indicative visual representation of how the ICAP PRM declines as the share of resources counted at their ELCC increases, until the share counted at their ELCC becomes 100%, which is the PCAP PRM.

Figure 35. How an ICAP PRM Percentage Decreases with Higher Shares of ELCC Resources



The PCAP PRM study can be repeated each IRP cycle to update RESOLVE's reliability need, incorporating the latest IEPR load shapes as well as additional more recent weather years into SERVM simulations. These may cause minor updates to the total reliability need, for instance, when additional years of historical weather conditions are added to SERVM (as was the case for adding 2021 and 2022 weather in this cycle) or if climate impacts are incorporated to adjust the SERVM weather dataset.

To ensure resource capacity counting is aligned with a PCAP PRM, all resources must be counted at their ELCC value. As discussed below, the contribution of each resource to the total reliability need requirement depends on its performance characteristics, the availability to produce power during the most constrained periods of the year, and interactive effects with other resources. The sections below describe the resulting ELCCs.

7.1.2 Adjusting Total Reliability Need to Reflect CPUC Procurement Orders

To ensure the RESOLVE portfolio reflects the procurement ordered by recent Commission IRP Mid-Term Reliability (MTR) procurement orders (D.21-06-035, D.23-02-040, and D.24-02-047, respectively), a modification is made to RESOLVE's reliability need. An adjustment to reliability constraints is necessary to ensure RESOLVE builds enough new capacity to meet the cumulative 15.5 GW NQC from the MTR orders.

The total ELCC MW from the cumulative MTR orders amounts is calculated as a minimum total ELCC MW of new zero-emission resources RESOLVE must cumulatively build in each respective year. Additionally, RESOLVE must comply with the MTR requirement for Long Lead-Time resources for 1 GW of firm zero-carbon resources and 1 GW of long duration storage (8-hour duration or greater) by 2031. Resources are counted toward this requirement based on ELCCs calculated by the MTR Incremental ELCC Study.[145] For resource types not addressed by the Study, RA program NQCs are used. For years in which the total MTR ELCC MW new procurement requirement above baseline resources is higher than the PCAP PRM requirement, RESOLVE will build additional capacity to comply with the MTR procurement orders. If MTR creates a surplus of capacity, RESOLVE may choose to retain existing resources to meet reliability needs later in the planning horizon, or may find it more economically optimal to not retain those resources.

7.1.3 Approach to Calculating Resource ELCCs

ELCC modeling was performed in SERVM to accredit all existing resources and parameterize a set of curves and an ELCC surface to capture reliability contributions for new resources. These ELCC studies considered interactions between resources classes so that ELCC accounting in RESOLVE did not over- or under-credit certain resource classes with strong interactive effects. This was achieved by studying the ELCC of the thermal fleet as a first-in ELCC, then hydro as a second-in ELCC, then existing pumped hydro as a third-in ELCC, followed by existing DR and flexible pumping loads as a fourth-in ELCC. Atop those existing resources, a variety of studies were performed to capture the incremental benefits of solar and storage (via a 3-dimensional solar, 4-hr storage, and 8-hr storage surface), long duration

[145] 20230210_irp_e3_astrape_updated_incremental_elcc_study.pdf (ca.gov)

storage and new demand response (via a set of multipliers to the 8hr storage dimension of the ELCC surface), and wind (via three ELCC curves for onshore wind, for out-of-state wind, and for offshore wind). ELCC studies were performed using 2035 loads and resources to capture a midpoint in the planning horizon. Note that BTM storage is modeled as a load modifier based on the IEPR's hourly charging and discharging shapes. This is because the IEPR's shapes generally show a low capacity value for the BTM storage discharge, hence modeling it as a supply side battery resource would overstate its value relative to the IEPR.

7.1.4 Firm Resource Contributions (Gas, CHP, Coal, Nuclear, Biomass/gas, Geothermal)

The contribution of firm capacity resources was developed by calculating in SERVM the "first-in" ELCC of the entire firm resource fleet: gas, CHP, coal, nuclear, biomass/gas, and geothermal resources. This was done using 2035 CAISO loads and resources. This firm fleet ELCC MW was then allocated across each firm fleet resource category based on the relative EFORd[146] outage rates. In unforced capacity (UCAP) accounting used in some eastern RTO resource adequacy programs, UCAP MW is based on nameplate capacity * (1 – EFORd). However, the ELCC de-rate is higher than the EFORd value, because the EFORd value is an average outage rate value whereas in LOLP modeling a distribution of outages for the firm fleet are considered in a Monte Carlo simulation. During some periods at the tails of these distributions, many units are simultaneously on full outage. These simultaneous outages simulated in LOLP modeling can create loss of load events, hence they reduce the ELCC of the firm fleet relative to its UCAP value based only on an EFORd derate. This can be considered an "outage asymmetry" portfolio effect, because the tail of the distribution with more outages has a higher impact on increasing LOLE than the tail of the distribution with few outages has on decreasing LOLE. Figure 36 below shows a schematic of how a PCAP/ELCC accounting approach captures the full "generator performance impact" that includes both the EFORd and the outage asymmetry impact. For now, this example does not illustrate the effect of ambient derates related to extreme heat events.

Figure 36. Firm Resource Outage Treatment in ICAP, UCAP, and PCAP PRM Accounting

[146] Equivalent Forced Outage Rate demand (EFORd) is a SERVM output characterizing class average forced outage rates during operating hours using generator performance data.

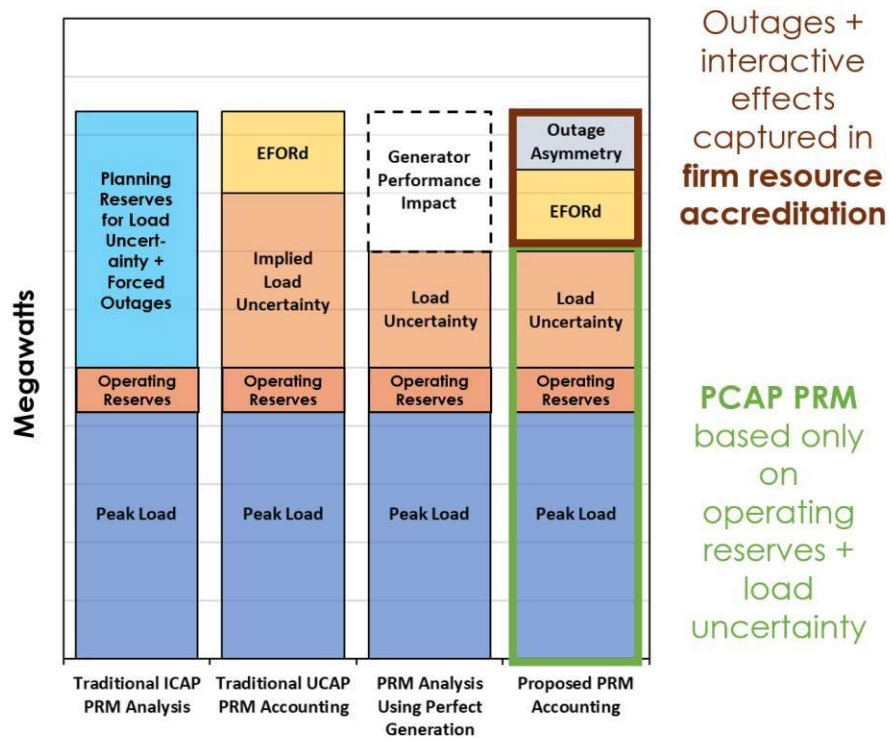


Table 98 shows the EFORd values[147] for each firm resource sub-class, the UCAP values, and the ELCC values that result when scaling up the EFORd de-rate so that the total firm fleet de-rate is equivalent to the ELCC MW calculated in SERVM.

Table 98. Firm Resource Outage Rates and ELCCs

Resource Class	EFORd (Equivalent Forced Outage Rate Demand)	UCAP (1-EFORd) (% of Nameplate)	ELCC for Resolve (% of Nameplate)	ELCC for Resolve after NQC Adjustment (% of Nameplate)
Biogas	1.2%	98.8%	98.6%	72.9%
Biomass	3.7%	96.3%	95.8%	75.5%
Combined Cycle	7.2%	92.8%	92.0%	
Combined Heat and Power (CHP)	4.1%	95.9%	95.4%	70.2%
Combustion Turbine (Peaker)	17.0%	83.0%	80.9%	
Geothermal	0.9%	99.1%	99.0%	94.6%
Nuclear	0.0%	100%	100%	
Reciprocating Engine	3.3%	96.7%	96.3%	

[147] These are sourced from SERVM simulations based on the forced outage rate input data developed for SERVM from the NERC GADS database.

An additional adjustment was made for CHP, biomass/biogas, and geothermal resources. In the RA program[148], these resources are accredited based on historical analyses of resource availability and/or bid behavior. This results in a lower RA-program accredited NQC MW than the SERVM ELCC MW calculated for those resources and this additional availability de-rate was applied for those resources classes (on top of their forced outage ELCC derate), using the ratio of Sept NQC MW to nameplate MW.

7.1.5 Hydro

The ELCC of hydroelectric resources is based on SERVM's "second-in" ELCC calculation. The full ELCC of all classes of CAISO hydro (exlcuding NW_Hydro_for_CAISO, which does not provide RA capacity in RESOLVE) in 2035 was 5,100 MW, for an ELCC of 56%.

7.1.6 Existing Pumped Hydro Storage

Existing pumped hydro storage was calculated as the "third-in" ELCC after the firm fleet and hydro. This calculation in SERVM resulted in a 100% ELCC, as there was no saturation of the storage ELCCs for this first initial tranche of capacity.

7.1.7 Existing Demand Response

Existing demand response was calculated as the "fourth-in" ELCC after the firm fleet, hydro, and pumped hydro storage. This calculation in SERVM resulted in a 97% ELCC. For interruptible pumping load DR units, a similar adjustment as CHP, biomass/biogas, and geothermal (see Section 7.1.4) was done to account for their RA-program accredited NQC MW, resulting in an 61% ELCC for the combined existing demand response and pumping loads capacity. This value is kept constant since RESOLVE currently does not consider retirement of existing DR resources. New DR is accredited differently, as described below.

7.1.8 Wind

Renewable resources with FCDS status are assumed to contribute to system resource adequacy requirements.

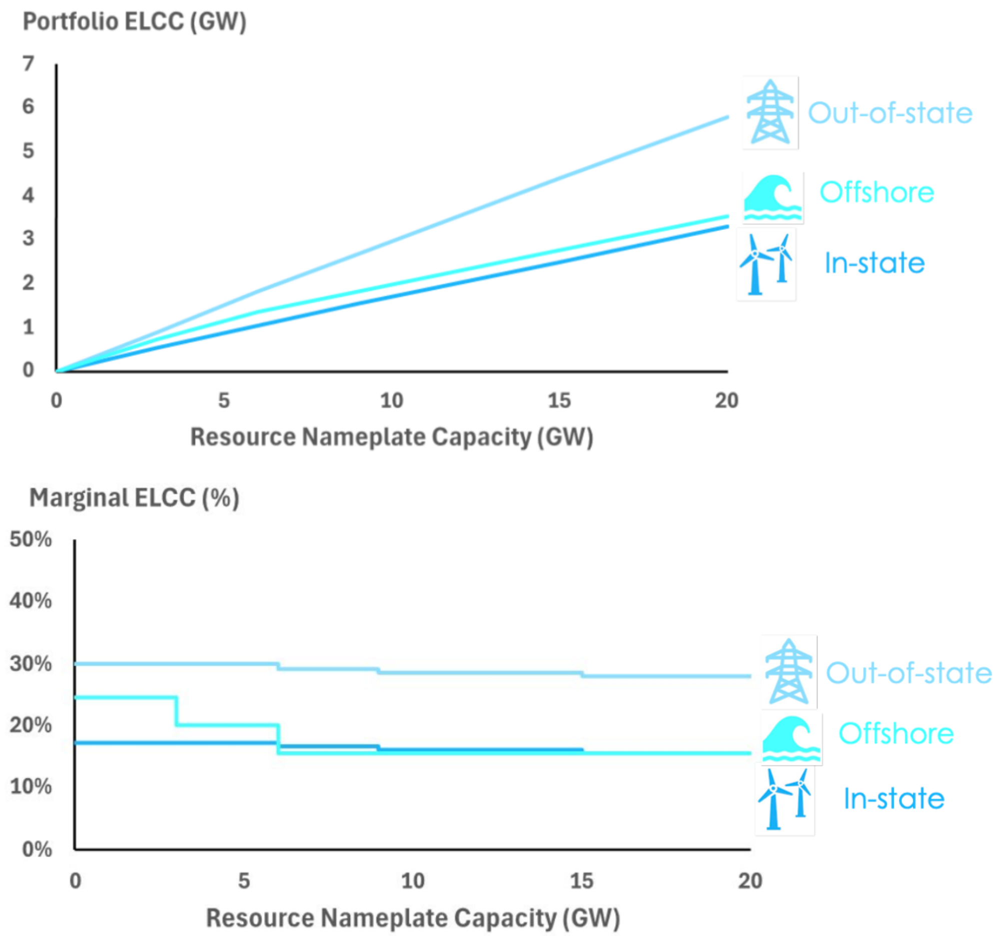
Wind ELCCs are calculated in SERVM as three separate one-dimensional penetration curves for in-state, out-of-state, and offshore wind. This was done for two reasons. First, wind ELCCs increase as the net load is pushed further into the evening by solar, but most of this effect has already occurred by 2022-2024. Therefore, a one-dimensional wind curve is sufficient to capture this interactive effect, when that curve is calculated on top of the 2035 portfolio from the 25-26 TPP that has significant solar and storage growth in it. Second, staff tested the correlations between in-state, out-of-state, and offshore wind and found that they were sufficiently

[148] The values shown here are based on the CPUC's 2022 NQC list.

uncorrelated to warrant separate penetration curves. Hence, three different curves were developed as shown in

Figure *37* below.

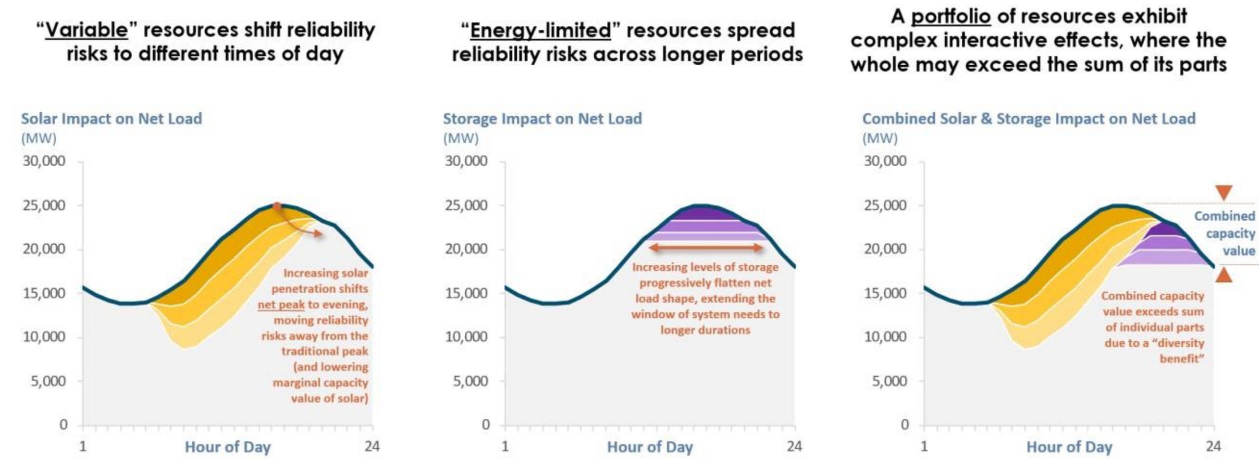
Figure 37. Wind ELCC Curves



7.1.9 Solar and Battery Storage

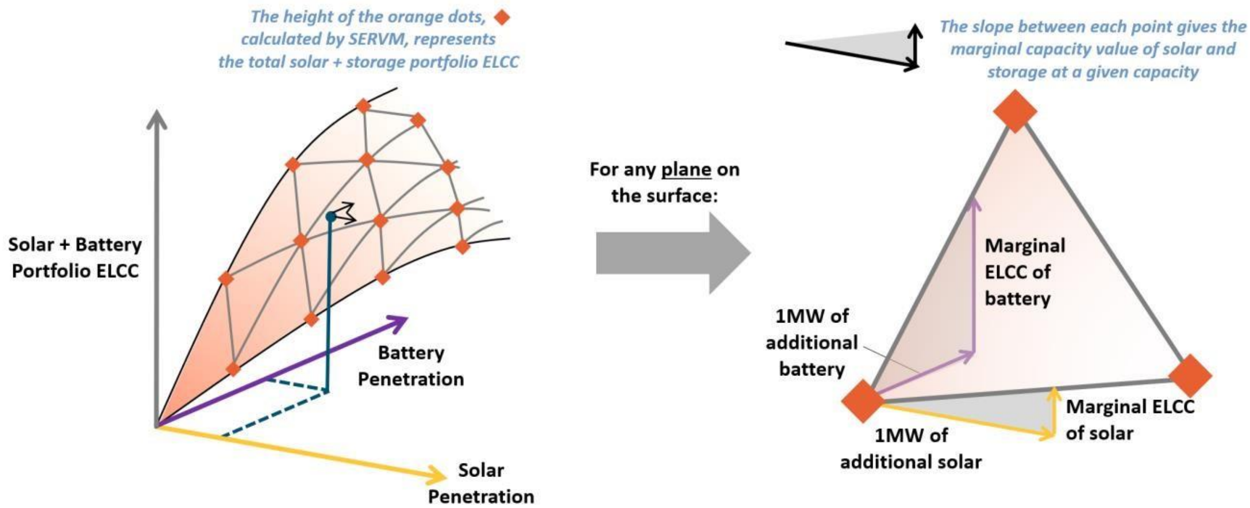
The three-dimensional solar and storage ELCC surface is developed to reflect that solar and battery storage resources of different durations have the most important interactive effects that should be captured in long-term capacity expansion studies. This synergistic interactive effect is illustrated in Figure 38 below. Solar and battery storage additions to the CAISO have been very large in past IRP cycles. Solar shifts and narrows the net peak into the evening hours and provides mid-day charging energy for new batteries. Batteries shift and extend the net peak back into the mid-day solar hours.

Figure 38. Solar and Storage Interactive Effects (illustrative)



To capture these interactive effects, an ELCC surface was generated using SERVM ELCC studies that analyzed the portfolio ELCC of various levels of solar and battery storage additions on top of the 2030 PSP portfolio. A schematic of the surface is shown in Figure 39 below. Solar penetration is one dimension, 4-hr battery storage penetration is another dimension, and the combined portfolio ELCC is the third dimension of the surface. Since the entire surface cannot practically be mapped, specific points are sampled and the marginal ELCC between the points is calculated, as shown on the right side of the figure.

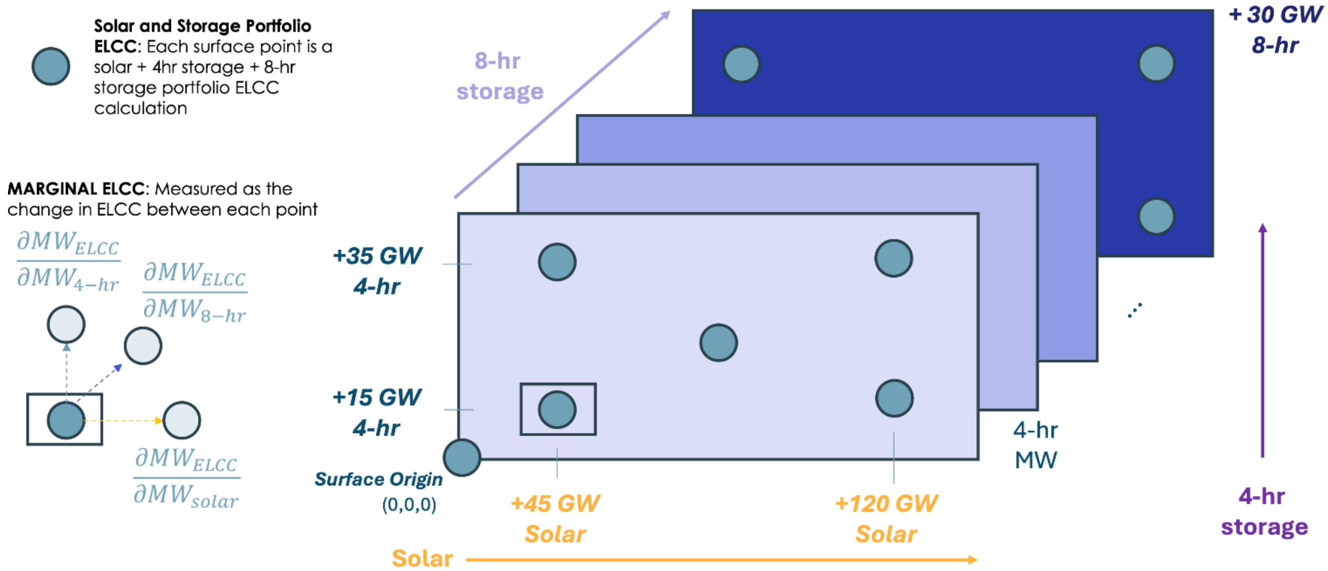
Figure 39. Solar and Storage 2-D ELCC Surface Schematic



Each facet i on the surface is a multivariate linear equation of the form $f_i(PV,STR) = a_iPV + b_iSTR + c_i$, where $f_i(PV,STR)$ is the total ELCC MW provided by solar and battery storage and PV and STR represent the MW capacity of solar and battery storage, respectively. Because of the declining marginal ELCC of solar and battery storage (and the corresponding convexity of this surface), the cumulative ELCC for any penetration of solar and battery storage can be evaluated as the minimum of all linear equations: $F(PV,STR) = \min[f_i(PV,STR)]$.

The surface for this cycle added a third dimension of 8-hr li-ion battery storage to the other dimensions of solar and 4-hr li-ion battery storage penetration. This enables more precise measurement of the interactive effects for both capacity and energy efficiency from a portfolio of 4-hr and 8-hr storage resources, recognizing that these two storage resources were the primary resources selected by RESOLVE in the previous 2022-2023 IRP cycle.

Figure 40. Solar, 4-hr Storage, 8-hr Storage 3-D ELCC Surface Schematic

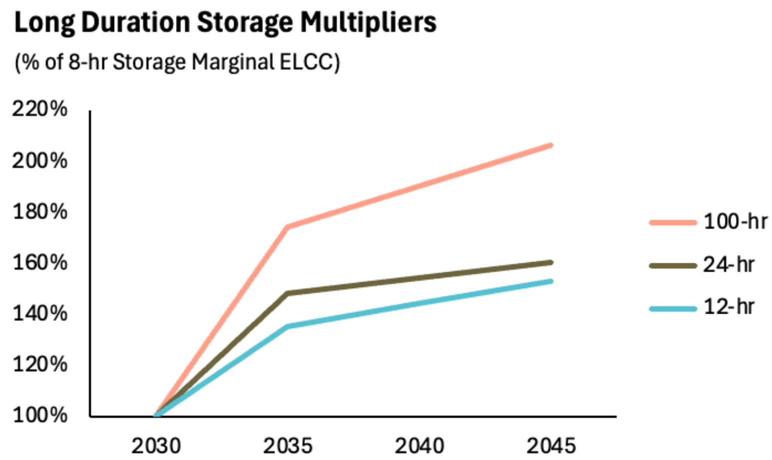


To reflect the dynamic that a solar resource's reliability contribution will typically scale with capacity factor, the capacity (in MW) of individual solar resources used in the multivariate linear equations is scaled by the ratio of each solar resource's capacity factor to that of the solar resource capacity factor used in the SERVM ELCC simulations.

7.1.10 Candidate Long-Duration Storage

Candidate long-duration energy storage (LDES) resources are accounted for on the 8-hr storage dimension of the solar + storage ELCC surface. The nameplate capacities of candidate storage resources with durations of 12 hours or longer are counted on the surface and multiplied by scalar factors (> 1) to reflect the greater reliability contribution of longer duration storage resources relative to the 8-hour duration battery storage resource represented on the ELCC surface. The multipliers were calculated by estimating the ratio of LDES marginal ELCC to 8-hour storage marginal ELCC at various penetrations of solar and 8-hour storage on the solar + storage surface. This ratio provides an “exchange rate” of reliability value between storage resources of different durations. The key assumption underlying this methodology was that the solar + storage surface would have approximately the same shape or form regardless of the duration of the storage resource represented by the surface, with the main difference being that longer duration storage resources’ ELCCs decline more slowly with increasing storage penetration. The multipliers used to model long-duration storage ELCC in RESOLVE vary by year based on the expected level of 8-hour storage penetration on the CAISO system each year. The multiplier values for 12-hour, 24-hour, and 100-hour duration storage resources are shown below. Candidate pumped hydro storage is modeled on the solar + storage ELCC surface as a 12-hr resource, with the respective multiplier.

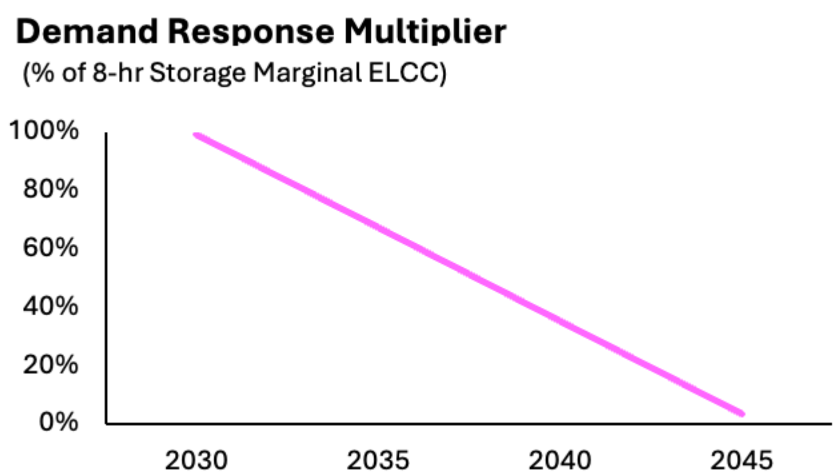
Figure 41. Nameplate Multipliers for Long-Duration Storage ELCC Accounting on Solar + Storage Surface



7.1.11 Candidate Demand Response

Candidate shed demand response resources are modeled on the 8-hr storage dimension of the solar + storage ELCC surface. This enables RESOLVE to capture the antagonistic interactive effect between use- and duration- limited demand response with energy and duration limited battery storage resources. Marginal ELCCs were calculated for additional demand response at various points on the solar and storage surface corresponding to the installed capacity in various years in recent IRP modeling, including the 2023 PSP and 25-26 TPP. These marginal ELCCs were compared to the 8-hour battery storage marginal ELCCs at that point on the surface and a de-rate factor was calculated. For example, if battery storage provides an 80% marginal ELCC and demand response provides a 60% marginal ELCC, then the 8-hour battery equivalent de-rate factor is 60%/80% = 75%. Figure 42 shows the demand response de-rate factor used for each year.

Figure 42. Demand Response Marginal ELCCs Relative to 8-hr Battery Storage



Candidate shift demand response resources are also modeled on a solar + storage ELCC surface. A scaling factor is also applied to the ELCC to account for the availability of shift demand response relative to an equivalent capacity of battery storage. This scaler is calculated as the average amount of shift down potential during the critical evening net peak hours of 6 to 10 P.M. divided by the "nameplate capacity" of the shift DR resource.

7.1.12 VGI Reliability Contribution

Newly-added VGI resources are put on the 4-hr storage dimension of the solar + storage ELCC surface to account for the interactive effect between grid storage and VGI. Given that VGI is not as fully available as grid-scale storage to provide power at its nameplate capacity in every single hour, a scaling factor will be applied to normalize VGI shift down capability relative to its "nameplate capacity" during the 4-hr evening net peak (e.g., 6-10pm)

The scaling factor calculates the total shift down potential (kWh) over the charger's nameplate energy capacity (kWh) during the net peak hours. [149]The final 4-hour battery equivalent capacity of VGI is calculated as follows. VGI will be put on the storage dimension of the solar + storage ELCC surface, together with storage and shed demand response, to determine its ELCC value.

> Battery (4hr) Equivalent Capacity of VGI (MW) = VGI Nameplate Capacity of Chargers (MW) * VGI Scaling Factor (%)

7.1.13 Imports

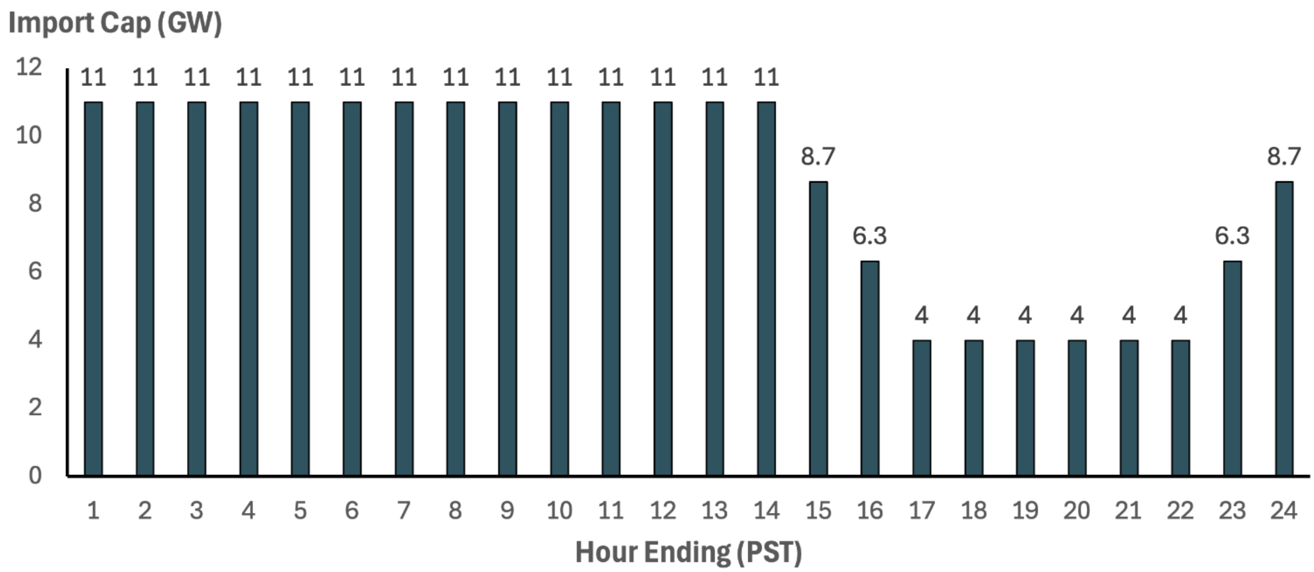
RESOLVE models an amount of "Unspecified" imports as firm imports that count towards supporting reliability in the CAISO. 4,000 MW is the default value for unspecified firm imports modeled in RESOLVE. This excludes "specified" imports that count towards supporting reliability in the CAISO, which are modeled as in-CAISO resources using the relevant ELCCs by resource type. These "specified" imports include the CAISO share of Hoover, Palo Verde, Intermountain Power Plant, Sutter, SunZia wind, and Cape Station geothermal. In SERVM, all units outside CAISO that may deliver energy to CAISO load are subject to SERVM's simultaneous import constraint, which is configured as 4,000 MW during peak hours (5pm to 10pm) in June through September, and as 11,040 MW (reflective of the current CAISO maximum import limit) during all other hours. A ramp between those two limits is parameterized per Figure 43. As solar and storage shift the critical hours in and out of the capped import period, the marginal value of imports may be higher than 4,000 MW (for instance, if the critical hours shift outside of HE17-22). An adjustment was made to the solar and storage surface to account for this dynamic,

---

[149] The nameplate capacity here is defined as the capacity of the charger, which is slightly different from the definition in the 2022 September Inputs and Assumptions workshop. Stakeholders has complaint about that original nameplate capacity definition being confusing. In the 2022 September Inputs and Assumptions workshop, the nameplate capacity was defined as the capacity to charge or discharge in either direction and was multiplied by 2 for V2G.

recognizing that incremental solar and storage capacity will inform this potential additional value, and therefore that the ELCC value should be reflected in the solar and storage surface.

Figure 43. Maximum CAISO Import Capacity Modeled in SERVM

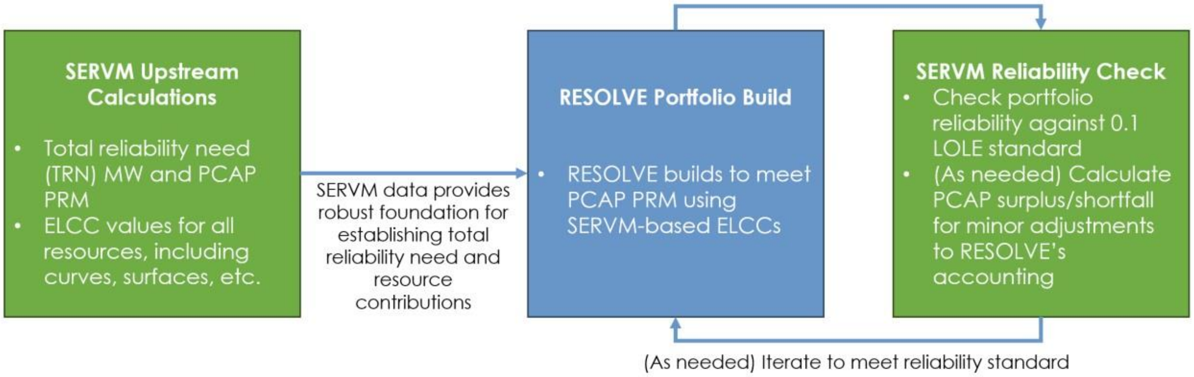


In SERVM, loads and resources for the non-CAISO regions are simulated directly, in addition to the import cap. Through these simulations, there may be periods when less imports are available in certain hours than the maximum import cap. For example, during a WECC-wide simulated weather event, neighboring regions may have less than 4 GW available to import into CAISO during HE17-22, a dynamic captured through SERVM simulations of the broader Northwest and Southwest regions.

7.1.14 Additional Adjustments to CAISO Load/Resource Balance

As needed, additional ad hoc adjustments are made to the CAISO reliability need or resource contributions modeled in RESOLVE. As shown in Figure 44 below, additional calibration adjustments are made through iteration between RESOLVE and SERVM to result in reliable portfolios across the planning horizon. These may account for resource interactive effects beyond those captured in the ELCCs (e.g., higher wind and solar/storage effects beyond the 2035 values assumed in the ELCC surface and wind curves, additional interactions between shaped imports and CAISO resources, load shape changes over time, etc.).

Figure 44. RESOLVE-SERVM reliability-related process flow



7.2 Local Resource Adequacy Constraint

In addition to System Resource Adequacy requirements developed by the CPUC, CAISO identifies Local Capacity Requirements (LCR) that define minimum local resource capacity required in each local area to meet established reliability criteria. These LCRs reflect that electrical areas and sub-areas throughout the state have limited transmission import capabilities. Since the 2019-2021 IRP cycle, the CPUC IRP has assumed that a minimum amount of gas resource capacities located in local areas must be maintained for local reliability needs (see 7.2.1), though CPUC staff continue work on a more granular analysis to capture LCR need (see 7.2.2).

7.2.1 Minimum Retention of Gas-Fired Resources in Local Areas

Many dispatchable gas plants that would potentially not be economically retained by RESOLVE are currently serving local capacity needs. For instance, the 2025 and 2029 CAISO Local Capacity Technical Study (LCTS)[150] indicate that multiple local areas are deficient in at least one year from 2025 to 2029. For this cycle, the CPUC IRP assumes that storage that is built for other system needs (e.g., PRM) can be located in local areas as needed to also mitigate local capacity needs identified. CPUC Staff analysis uses the LCTS and the CAISO Net Qualifying Capacity (NQC) list[151] to determine the minimum generation capacity that must be retained on the CAISO system. The RESOLVE optimization enforces the minimum retention values (Table 99) for each class of generator in each year, and resource replacements by local 4-hour battery storage will be determined by RESOLVE.[152]

[150] https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/Local-capacity-requirements-process-2025

[151] https://www.caiso.com/generation-transmission/resource-adequacy

[152] The maximum potential for 4-hr batteries to replace LCR capacity is based on the 2029 LCTS study (https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/Local-capacity-requirements-process-2025)

Table 99. Minimum CAISO gas retention

RESOLVE Resource	Baseline Capacity (MW)	Gas Contributing to Local Capacity Requirements (MW)	Minimum Retained Existing Gas Capacity (MW)[153]
CCGT1	14,688	9,578	7,546
CCGT2	2,551	2,503	1,747
Peaker1	2,447	2,377	1,786
Peaker2	5,530	4,815	3,319
Reciprocating_Engine	256	212	123
Total	**25,472**	**19,485**	**14,521**

7.2.2 Development of Additional Local Resource Adequacy Modeling

Additionally, CPUC staff and E3 are in the process of developing a new, experimental local capacity module of RESOLVE that seeks to simulate the CAISO's deterministic local reliability planning standard. This tool will consider the local area planning load forecast under binding conditions identified via the CAISO's Local Capacity Technical Studies (LCTS) and be capable of optimizing a least-cost portfolio that meets local capacity requirements considering local resource additions, retirements, and transmission upgrades. Early versions of this module may be limited to modeling one individual local area at a time. This modeling will also seek to connect to the RESOLVE system optimization to ensure the proper feedback loop between resources needed for local reliability and those needed for system reliability. Stakeholders will be able to provide feedback on the proposed approach and data inputs for this new local capacity functionality at a later date.

[153] RESOLVE may replace with local 4-hr batteries.

8. Greenhouse Gas Emissions and Clean Energy Policies

8.1 Greenhouse Gas Constraint

RESOLVE includes optionality to enforce a greenhouse gas (GHG) constraint on CAISO emissions. For the 2024-2026 IRP cycle, for the modeling periods through 2035 the modeling will incorporate the GHG trajectories established in the April 2022 Administrative Law Judge's Ruling Establishing Process for Finalizing Load Forecasts and Greenhouse Gas Emissions Benchmarks for 2022 Integrated Resource Plan Filings[154], which adopted the statewide GHG emissions planning trajectories for 2030 and through 2035 shown in Table 100 below. The baseline emissions are benchmarked to the power sector emissions of 59.5 MMT in 2020 in California, based on the 2022 California's Greenhouse Gas Inventory by Scoping Plan Category.[155] The emissions trajectory from 2023 to 2029 is linearly interpolated between the emissions in 2020 and the target in 2030. Similarly, the 2040 value is a straight-line interpolation between the 2035 value and the CAISO footprint of the energy-related statewide 2045 target from the 2022 CARB Scoping Plan.[156] As in the previous IRP cycles, the statewide emissions of the electricity sector are multiplied by 82%—the share of ARB's forecasted 2030 allocation of emissions allowances to distribution utilities within the CAISO footprint[157]—to yield a target for CAISO LSEs.

It is notable that the 25 MMT and the 30 MMT by 2035 are the new trajectory names replacing the previous 30 MMT and 38 MMT by 2030 trajectories and have the same 2030 and 2035 statewide emissions targets. Both of these trajectories reach the same 8 MMT by 2045 statewide emissions target. Lower long-term emissions targets might be used in some sensitivity analysis.

Table 100. Options for GHG emissions constraints (million metric tons – CAISO footprint)

Scenario Setting	2025	2026	2028	2030	2035	2040	2045
25 MMT by 2035 statewide & 8 MMT by 2045	36.5	34.1	29.2	24.3	20.3	13.7	7.1
30 MMT by 2035 statewide & 8 MMT by 2045	39.9	38.2	34.6	31.1	24.8	16.0	7.1

[154] Found here: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M469/K615/469615281.PDF
[155] https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/ghg_inventory_by_scopingplan_00-20.xlsx

[156] Found here: https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp.pdf
[157] CARB's allowance allocation to distribution utilities from 2021-2030 is available here: https://www.arb.ca.gov/regact/2016/capandtrade16/ attach10.xlsx

8.2 Greenhouse Gas Accounting

RESOLVE tracks greenhouse gas emissions attributed to entities within the CAISO footprint using a method consistent with the California Air Resources Board's (CARB) regulation of the electric sector under California's cap & trade program.

8.2.1 CAISO Generators

The annual emissions of generators within the CAISO are calculated in RESOLVE as part of the dispatch simulation based on (1) the annual fuel consumed by each generator; and (2) an assumed carbon content for the corresponding fuel.

8.2.2 Imports to CAISO

RESOLVE attributes emissions to generation that is imported to CAISO based on the deemed emissions rate for unspecified imports as determined by CARB. The assumed carbon content of imports based on this deemed rate is 0.428 metric tons per MWh[158]—a rate slightly higher than the emissions rate of a combined cycle gas turbine.

Specified imports to CAISO are modeled as if the generator is located within CAISO, therefore any emissions associated with specified imports are included with emissions associated with CAISO generators. Likewise, any emissions from remote generators are included with CAISO generator emissions, and no carbon content is applied to imports on transmission lines from remote generator zones (see section 6.7.4 for further detail on remote generator topology). The majority of specified imports and remote generators to CAISO are non-emitting resources.

8.2.3 Behind-the-meter CHP Emissions Accounting

CARB Scoping Plan electric sector emissions accounting includes emissions from behind-the meter CHP generation. BTM CHP is represented as a reduction in load in IRP, and therefore emissions from BTM CHP are not directly captured in RESOLVE's generation dispatch.[159] To continue to retain consistency with CARB's Scoping Plan accounting conventions in the IRP, emissions associated with BTM CHP generation are included under the GHG constraint, thereby reducing the emissions budget available for supply-side resources. BTM CHP emissions are calculated from CEC IEPR, averaging about 4.0 MMT/yr.

[158] Rules for CARB's Mandatory Greenhouse Gas Reporting Regulation are available here: https://ww2.arb.ca.gov/mrr-regulation

[159] Due to these accounting discrepancies, in 2017 there was an estimated 4 MMT difference between RESOLVE and the Scoping Plan. Specifically, a 42 MMT target in RESOLVE was equivalent to a 46 MMT in the Scoping Plan.

8.3 Clean Energy Policies

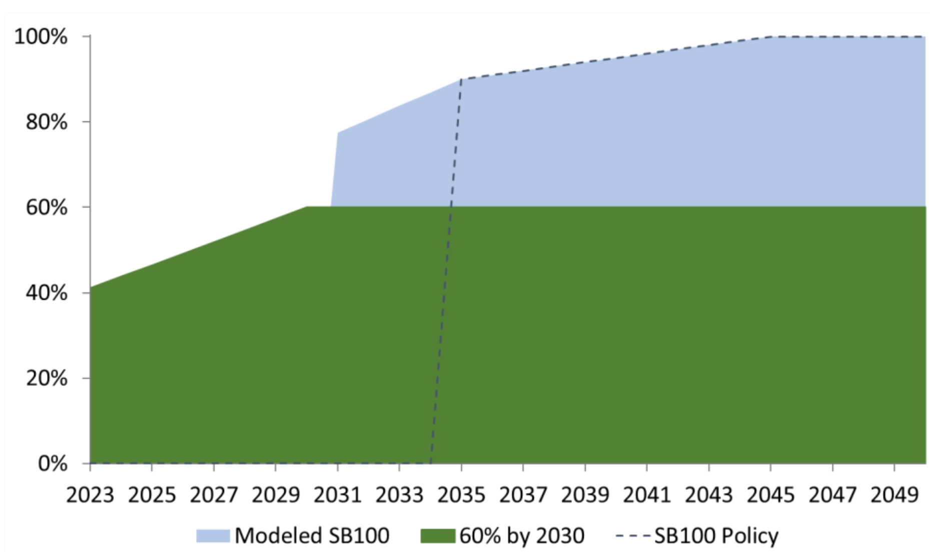
8.3.1 RPS requirement

RESOLVE includes a constraint that enforces RPS compliance in CAISO in all modeled years. Since SB100 policy is modeled separately, this results in the selection of a least-cost portfolio of candidate renewable resources to meet RPS compliance, while satisfying any additional constraints. Enforcing the RPS and/or greenhouse gas constraints (discussed in the previous section) typically results in selection of candidate renewable resources.

8.3.2 SB100 Policy

Senate Bill 100 (SB100) increased the state's renewable portfolio standard to 60% by 2030 and set a goal to supply 100% of retail electricity sales from carbon-free resources by 2045. SB-1020 Clean Energy, Jobs, and Affordability Act of 2022 added two additional clean energy retail sales targets of 90% by 2035 and 95% by 2040.[160] In the PSP modeling, the SB100 clean retail sale targets are applied starting from 2031 (modeled earlier than the first target year to allow for a much smoother compliance), and in addition to RPS eligible resources, electricity generation from resources such as large hydro, nuclear (Palo Verde) and specified hydro imports from NW are eligible to contribute to. For interim years, the target is linearly interpolated between the two consecutive target years.

Figure 45. RPS and SB100 compliance



[160] Bill Text - SB-1020 Clean Energy, Jobs, and Affordability Act of 2022. (ca.gov)

8.3.3 RPS Banking

As a compliance option for CAISO's RPS requirement, includes the ability to retire banked Renewable Energy Certificates (RECs), renewable generation in excess of an LSE's RPS compliance requirements that can be redeemed during subsequent compliance periods, as an adjustment to the RPS target. The volume of RECs that are banked at any point in time can be material, and the timing of REC redemption may significantly impact the selection of candidate resources in the years that the RPS constraint is driving renewable investment. For the 2024-2026 IRP cycle, models a bank redemption of 5,044 GWh per year until 2034, representing a median forecast for banked REC spend, with no banked RECs remaining after 2034.

---- DOCUMENT ENDS----

Energy Division staff and Energy Division's consultants contributors (in alphabetical order): Nathan Barcic, Donald Brooks, Aaron Burdick (E3), Kevin Carden (Astrapé), Alex Dombrowsky (Astrapé), Mounir Fellahi, Jared Ferguson, Behdad Kiani, Emily Leslie (Montara Mountain Energy), Ruoshui Li (E3), Madeline Macmillan (E3), Brendan Mahoney (E3), David Miller, Aditya Nathan (Astrapé), Neil Raffan, Morgan Santoni-Colvin (E3), Samuel Schreiber (E3), Aneri Shah (E3), Sierra Spencer (E3), Joshua Spooner (E3), Andys Theocharous (E3), Karl Walter (E3), Manfei Wu (E3), Patrick Young, Ye Zheng (E3), Angineh Zohrabian (E3).

Project Managers: Sarah Goldmuntz, Manfei Wu (E3), and Joshua Spooner (E3)