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# Proposed Inputs & Assumptions

## SERVM 2024 Data Updates in Support of Resource Adequacy (RA) and Integrated Resource Planning (IRP)

March 2024

California Public Utilities Commission

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## List of Acronyms

| | |
|---|---|
| AAEE – Additional Achievable Energy Efficiency | LCR – Local Capacity Requirements |
| AAFS -- Additional Achievable Fuel Substitution | LCT -- Local Capacity Technical Study |
| AB -- Assembly Bill | LDES -- Long-Duration Energy Storage |
| A-CAES -- Adiabatic Compressed Air Energy Storage | LDV -- Light-Duty Vehicle |
| ADS -- Anchor Data Set | LOLE – Loss of Load Expectation |
| ATE -- Additional Transportation Electrification | LESR -- Limited Energy Storage Resource |
| BAA – Balancing Authority Area | LOLH – Loss of Load Hours |
| BANC -- Balancing Area of Northern California | LSE – Load Serving Entity |
| BNEF -- Bloomberg New Energy Finance | LTPP -- Long-Term Procurement Plan |
| BOEM -- Bureau of Ocean Energy Management | MAG -- Modeling Advisory Group |
| BTM – Behind the Meter | MERRA -- Modern-Era Retrospective-Analysis for Research and Applications |

| | |
|---|---|
| CAISO – California Independent System Operator | MMT -- Million Metric Tons |
| CAPEX -- Capital Expenditure | MTR -- Mid-Term Reliability |
| CAPMAX -- Maximum Capacity | MW – Megawatt |
| CARB -- California Air Resources Board | NAMGas -- North American Market Gas-Trade Model |
| CCA -- Community Choice Aggregator | NERC -- North American Electric Reliability Corporation |
| CCGT -- Combined Cycle Gas Turbine | NET -- Negative Carbon Emissions Technology |
| CCS -- Carbon Capture and Storage | NPV -- Net Present Value |
| CEC – California Energy Commission | NQC – Net Qualifying Capacity |
| CHP -- Combined Heat and Power (Cogeneration) | NREL ATB -- National Renewable Energy Laboratory Annual Technology Baseline |
| CPA -- Candidate Project Area | NREL SAM -- National Renewable Energy Laboratory System Advisor Model |
| CPP -- Critical Peak Pricing | OCS -- Outer Continental Shelf |
| CREZ -- Competitive Renewable Energy Zone | O&M -- Operations and Maintenance |
| CT -- Combustion Turbine | OOS -- Out-of-State |
| DAC -- Direct Air Capture | OTC -- Once-Through Cooling |
| D-CAES -- Diabetic Compressed Air Energy Storage | PCAP -- Perfect Capacity |
| DFA -- Development Focus Area | PCM -- Production Cost Model |
| DR -- Demand Response | PEM -- Proton Exchange Membrane |
| DRAM -- Demand Response Auction Mechanism | PPA -- Power Purchase Agreement |
| DRECP/SJV -- Desert Renewable Energy Conservation Plan / San Joaquin Valley | PRM – Planning Reserve Margin |
| EFORd -- Average Forced Outage Rate | PSP -- Preferred System Plan |
| EGS -- Enhanced Geothermal System | PTC -- Production Tax Credit |
| EIA -- Energy Information Administration | PU Code – Public Utilities Code |
| ELCC – Effective Load Carrying Capability | PV -- Photovoltaic Solar |
| EMS -- Energy Management System | RA – Resource Adequacy |
| EO -- Energy-Only Deliverability Status | R&D -- Research & Development |

| | |
|---|---|
| ESP -- Energy Service Provider | RETI -- Renewable Energy Transmission Initiative |
| EUE – Expected Unserved Energy | RPS -- Renewable Portfolio Standard |
| EV -- Electric Vehicle | SB -- Senate Bill |
| EVLST -- Electric Vehicle Load Shaping Tool | SERVM – Strategic Energy Risk Valuation Model |
| FCDS -- Full Capacity Deliverability Status | SMR -- Small Modular Nuclear Reactor |
| FERC -- Federal Energy Regulatory Commission | SNG -- Synthetic Natural Gas |
| FSSAT -- Fuel Substitution Scenario Analysis Tool | SOD - Slice of Day |
| GADS – Generator Availability Data System | SSN -- Secondary System Need |
| GHG -- Greenhouse Gas | ST -- Steam Turbine |
| HEIAWG -- Interagency Working Group High Electrification Scenario | STR -- Storage |
| HSN -- Highest System Need | SUN – Solar PV |
| IAWG -- Interagency Working Group | TAC – Transmission Access Control |
| ICAP -- Installed Capacity | TEPPC -- Transmission Expansion Planning Policy Committee |
| IEA -- International Energy Agency | TID -- Turlock Irrigation District |
| IEPR – Integrated Energy Policy Report | TOU -- Time-of-Use |
| IID -- Imperial Irrigation District | TPP -- Transmission Planning Process |
| IMF -- International Monetary Fund | TRN -- Total Reliability Need |
| IOU -- Investor-Owned Utility | Tx -- Transmission |
| IPP -- Independent Power Producer | UCAP – Unforced Capacity |
| IRA -- Inflation Reduction Act | USGS -- U.S. Geological Survey |
| IRR -- Internal Rate of Return | VEA -- Valley Electric Association |
| ITC -- Investment Tax Credit | VGI -- Vehicle-Grid Integration |
| LADWP or LDWP -- Los Angeles Department of Water and Power | V1G -- VGI shifting load |
| LBNL -- Lawrence Berkeley National Laboratory | V2G -- VGI discharging to the grid |
| LCOE -- Levelized Cost of Energy | WECC – Western Electricity Coordinating Council |
| LCOS -- Levelized Cost of Storage | WRF -- Weather Research and Forecasting Model |

# 1. Introduction

This document describes and updates the key methodologies and sources of inputs and assumptions for the California Public Utilities Commission's (CPUC's) electric system reliability and related modeling and analysis, primarily in support of the Integrated Resource Planning (IRP) and the Resource Adequacy (RA) proceedings. The CPUC also uses this modeling and analysis to support work in other CPUC proceedings such as the Avoided Cost Calculator and Gas System Reliability and Planning. The CPUC expects to update inputs and assumptions annually.

The inputs, assumptions, and methodologies are used in the Strategic Energy Risk Valuation Model (SERVM) to assess CAISO system reliability, production cost, emissions, and other metrics given an assumed electric system, comprised of a resource portfolio, electric demand, and a transmission network. SERVM is often used with the RESOLVE capacity expansion model, the latter determining optimal resource portfolios for the CAISO electric system that reflect projected load growth, technology costs and potential, fuel costs, and policy constraints, and the former determining the reliability of the optimal resource portfolio. The two models share many inputs and assumptions – maintaining and improving upon input and assumptions alignment is key to achieving reasonable agreement in output between the models. This document describes just those used in SERVM. Refer to the RESOLVE-specific Inputs and Assumptions document (expected in Q2, 2024) for descriptions of inputs and assumptions that are common or related between the two models. Furthermore, this document describes the updates and how they will be developed but, in many cases, no quantitative values are provided because the development work is in progress. A final version of this document with quantitative values will be published when all updates have been completed (expected in Q2, 2024).

The prior version of this document is posted to the CPUC's IRP website: Final 2023 Inputs and Assumptions, 10/5/2023. It contained both RESOLVE and SERVM inputs, assumptions, and methods integrated together in one document. The focus at that time was on aligning inputs and improving consistency between the two models for IRP purposes and it was natural to describe both models in one document. However, because of broader analytical needs beyond IRP, going forward staff expects to keep the RESOLVE-specific and SERVM-specific documents separate and have the RESOLVE-specific document reference the SERVM-specific document where common inputs and model alignment are described.

## 1.1 Overview of the SERVM Model

The CPUC uses the Strategic Energy Risk Valuation Model (SERVM) to analyze system reliability. SERVM calculates numerous reliability, production cost, and other performance metrics for a given study year in light of expected weather, economic growth, electric demand, resource generation, and unit performance. For each of these factors, variability and forecasting uncertainties are considered. An individual year is simulated many times over, with each simulation having an assigned probability and reflecting a slightly different set of weather, economic conditions, and unit performance. Unit commitment and dispatch for all hours of the study year are simulated. The current model probabilistic inputs include 23 possible weather years, 23 possible hydro years, five points of economic load forecast error, and multiple unit outage draws, creating thousands of iterations for the simulation. The 23 weather and hydro years are being updated to range from 2000-2022 (from the prior 1998-2020).

Model outputs include probability-weighted expected values as well as the complete distribution of reliability, production cost, and other performance metrics. CPUC staff typically use SERVM to quantify reliability in terms of Loss of Load Expectation (LOLE) and Expected Unserved Energy (EUE), to project production cost, market prices, fuel burn, and emissions, to determine the Planning Reserve Margin (PRM) consistent with a target reliability level, and to calculate Effective Load Carrying Capability (ELCC) by resource class.

### 1.2 Document Contents

The remainder of this document is organized as follows:

- **Section 2 (Electric Demand Forecast)** documents the assumptions and data sources that will be used to derive the electric demand forecast in CAISO, California, and regions outside California, including the impacts of demand-side programs, demand modifiers, and electrification.
- **Section 3 (Baseline Resources)** documents the assumptions and data sources that will be used to update the list of baseline resources, including key attributes such as in-service date, retirement date, technology, maximum output, location, offtaker, and unit name. Baseline resources are existing online units or projects in-development and assumed to be online by the project’s in-service date.
- **Section 4 (Generator Operations and Hourly Profiles)** documents the assumptions and data sources that have been and will be used to characterize hourly electricity demand and variable generation hourly profiles, and the operational attributes and constraints of each of the resource classes that SERVM can model.
- **Section 5 (Resource Adequacy Modeling)** discusses certain proposals and modeling conventions staff will use to conduct analysis to inform policy questions in the Resource Adequacy proceeding.
- **Section 6 (Emissions Accounting)** documents assumptions, data sources, and accounting conventions that will be used to characterize greenhouse gas and criteria pollutant emissions.

### 1.3 Key Data and Model Updates

Since the publication of the "Inputs & Assumptions: 2022-2023 Integrated Resource Planning"[1] in October 2023, CPUC staff have scoped numerous updates to SERVM model functionality, inputs, and assumptions to occur in the first half of 2024 to support LOLE modeling in the RA proceeding[2] as well as the IRP and other proceedings during 2024.

Key updates to SERVM include:

- Deploying and benchmarking a new SERVM client (version 9.25 as of February 2024)
- Updating the baseline generating fleet in SERVM, including aligning with the January 2024 vintage of the CAISO Master Generating Capability List, and in-development[3] resources included in LSE IRP filings and LSE MTR procurement order filings as of 12/1/2023
- Including all existing or under construction non-CAISO units from the 2032 WECC Anchor Data Set (ADS) dated December 8, 2023, and where available, incorporating resource and demand forecast information from the IRPs of neighboring regions. This means updating data on new generators, online or in-development (excluding planned or generic generation) and retiring or terminated generators/projects, as well as updating electric demand peak and energy forecasts for regions outside California.
- Updating the electric demand forecast and GHG emissions price forecast according to the California Energy Commission (CEC) 2023 Integrated Energy Policy Report (IEPR) California Energy Demand Forecast
- Consolidating the SERVM "SMUD" and "TID" regions into one region consistent with the "NCNC" Planning Area of the IEPR demand forecast
- Updating weather data to include historical solar, wind, and electric demand data for 2021-2022, as well as historical hydro data from 2021-2022 to append to the previous

[1] 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

[2] 2024 LOLE Modeling schedule included in the scoping memo for the RA proceeding (Track 2 schedule) linked here: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M521/K589/521589385.PDF

[3] See the Resource Data Template (RDT) user guide for IRP filings: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/rdtv3_userguide_20220923.pdf

weather and hydro dataset. 1998-1999 data will be dropped to keep the size of the dataset at 23 years.

- Revising the electric demand hourly profile weather normalization process for better alignment with the IEPR demand forecast single annual hourly profiles
- Updating onshore wind model for better alignment with historical wind production
- Implementing ambient temperature output derating for thermal generating units
- Proposing a UCAP methodology to characterize the capacity and availability of units based on historical outage performance
- Revising simultaneous net import and export constraints including consideration of monthly-hourly shapes
- Adding Climate-Informed-Forecasting (CIF) augmentation of electric demand shapes and ambient derates for thermal units

# 2. Electric Demand Forecast

## 2.1 California Regions

The CEC 2023 IEPR California Electric Demand 2023-2040 “Planning Scenario” Forecast is the basis for SERVM annual electric demand inputs in California regions. The modeled regions in SERVM correspond to the Planning Areas used in the IEPR as shown in Table 1. The IEPR Managed Forecast[4] can be decomposed into "consumption” and “demand-side modifier” components and represented explicitly in modeling with hourly profiles. For how the hourly profiles for consumption and demand-side modifiers will be developed and used in SERVM, see Section 4.2.

[4] See this presentation for an overview of the structure and components of the demand forecast including a definition of the “managed” demand forecast: https://efiling.energy.ca.gov/GetDocument.aspx?tn=253522&DocumentContentId=88746

*Table 1: Map of SERVM Regions and IEPR Planning Areas*

| SERVM Region | IEPR Planning Area |
|---|---|
| IID | IID |
| LADWP | LADWP + BUGL |
| NCNC | NCNC |
| PGE | PGE |
| SCE | SCE |
| SDGE | SDGE |

Demand-side modifiers explicitly modeled in SERVM follow the categories from the IEPR:

- Electric vehicle charging including baseline and Additional Achievable Transportation Electrification (AATE) from light, medium, and heavy duty vehicles
- Additional Achievable Fuel Substitution (AAFS) which includes building electrification as well as industrial heating
- Behind-the-meter (BTM) PV
- BTM storage
- Additional Achievable Energy Efficiency (AAEE)
- Time of use (TOU) rate impacts

Demand forecast inputs are frequently presented as demand at the customer meter. However, CPUC's system planning models measure demand at the generator busbar. Consequently, demand forecasts at the customer meter are grossed up for transmission and distribution (T&D) losses. To the extent possible, SERVM will use the same loss factor assumptions as the IEPR for each modeled region. The factors are calculated from Form 1.2 of the IEPR.

*Table 2: Modeled T&D Loss Factors by Region*

| Region | IID | LADWP | NCNC | PGE | SCE | SDGE |
|---|---|---|---|---|---|---|
| T&D Loss Factor | 1.128 | 1.129 | 1.064 | 1.091 | 1.069 | 1.082 |

### 2.1.1 Consumption and Demand Modifier Derivation

Consumption represents the fundamental pattern of end-use electricity demand and varies with weather, the economy, demographic changes, and region. In SERVM, consumption is modeled with 23 years of weather normalized hourly profiles to capture weather variability, one set for each region. The median peak and energy of each region's 23 profiles are scaled to match the corresponding CEC IEPR forecasted peak and energy – this captures the economic activity and demographic changes projected in the IEPR. The IEPR's peak and energy consumption is calculated as the total net energy for load (i.e. retail sales grossed up for T&D losses) reported in the CEC's IEPR managed demand forecast data **without** the effects of explicitly modeled demand modifiers (enumerated above). In other words, the demand modifier effects are removed (backed out) from the managed forecast to reconstitute consumption.

Demand modifiers generally represent incremental changes to consumption due to policy and/or technology. With the exception of BTM PV, all of the explicitly modeled demand modifiers are assumed weather independent. Therefore, staff directly translates each demand modifier's peak, energy, and hourly profile attributes from the IEPR into fixed hourly profile "generating" units in SERVM.

### 2.1.2 Behind-the-Meter PV

In SERVM, staff will model BTM PV generation and capacity at the same geographic granularity as the CEC IEPR's Forecast Zones. While the IEPR forecasts single annual capacity and energy values by year and Forecast Zone, SERVM models with 23 weather years and the average capacity factor differs somewhat from the IEPR. Prioritizing energy alignment between the IEPR and SERVM modeling, the average annual energy production of the 23-year distribution will be calibrated to match with the single annual energy value from the IEPR for each Forecast Zone by adjusting the BTM PV installed capacity in SERVM. Calibration factors will be developed for 2022 values and then applied to all years in the forecast as staff experience has shown that the factor by which IEPR energy values differ from the average of SERVM's 23 years of energy values does not vary by forecast year (i.e. installed capacity) but does vary by Forecast Zone.

### 2.1.3 Behind-the-meter CHP and Other Non-PV/Non-Storage Self Generation

The forecast of non-PV/non-storage self-generation in the CEC 2023 IEPR Demand Forecast is not explicitly modeled in SERVM and is generally left combined with consumption. On-site combined heat and power that does not export to the grid (BTM CHP) makes up the majority of this self-generation component3.2. Like the 2022-23 IRP cycle assumptions, staff will continue to assume that BTM CHP retires linearly between 2035 and 2040. Staff assumes the electric demand once served by retiring BTM CHP will return to system electric demand and the model's consumption peak and energy inputs are adjusted upward accordingly between 2035 and 2040. The remainder of non-PV/non-storage self-generation forecasted by the IEPR is unchanged and left combined with consumption demand.

### 2.1.4 Calibration

Although SERVM consumption and BTM PV inputs derive from the CEC 2023 IEPR demand forecast, they cannot fully align because SERVM uses a CPUC staff-developed 23 weather year hourly dataset while the IEPR uses a single hourly dataset.

The SERVM 23 weather year hourly consumption profiles have a slightly different load diversity amongst the three CAISO regions, PGE, SCE, and SDGE, than the single hourly profiles from the IEPR. Thus, the IEPR single CAISO coincident consumption peak and the SERVM median CAISO coincident consumption peak differ even though the medians of the individual PGE, SCE, and SDGE peaks in SERVM are set to match the single PGE, SCE, and SDGE peaks in the IEPR.

The SERVM 23 weather year hourly BTM PV production profiles have a slightly different capacity factor and peak shift impact than the single hourly profiles from the IEPR. Thus, the SERVM median annual energy production differs from the IEPR single annual energy production, and the SERVM median managed peak (both coincident and individual IOU planning area peaks) differs from the IEPR single managed peak even though the installed capacity of BTM PV in SERVM are set to match the IEPR. Recall that the managed peak is consumption **with** the effects of explicitly modeled demand modifiers, and all the other explicitly modeled demand modifiers besides BTM PV are directly used from the IEPR since they are assumed weather independent. Thus, the drivers of managed peak misalignment are the differences between the SERVM 23 weather year hourly BTM PV profiles and the IEPR single hourly profiles.

Prioritizing matching the SERVM median and IEPR single CAISO coincident consumption peaks, staff intends to calibrate the individual consumption peak of each CAISO region in SERVM such that the resulting median CAISO coincident consumption peak matches the IEPR. This means the medians of the individual PGE, SCE, and SDGE consumption peaks in SERVM will no longer match the single PGE, SCE, and SDGE consumption peaks in the IEPR.

Prioritizing BTM PV energy alignment between the IEPR and SERVM modeling, staff will calibrate average annual energy production of the SERVM 23-year distribution to match the single annual energy value from the IEPR for each Forecast Zone by adjusting the BTM PV installed capacity in SERVM. This was already described above in section 2.1.2. The managed peaks in SERVM are left unaligned with the corresponding IEPR managed peaks as staff prioritizes calibrating the CAISO coincident consumption peak to match the IEPR, rather than the managed peak. After development of IEPR inputs for SERVM completion, staff will update this section with quantitative comparisons before and after calibration in the final version of this document.

### 2.2 Other Regions

SERVM uses a zonal transmission topology to simulate flows among the various regions in the Western Interconnection. SERVM will be updated to model six zones (also referred to as regions throughout this document) within California and seven zones external to California.

For the regions outside of California (AZPS, BPAT, NEVP, PACW, PortlandGE, SRP, WALC), WECC's 2032 Anchor Data Set (ADS) PCM V2.4.3 Public Dataset[5] is used as the basis for electric demand projections. Sales forecasts net of demand-side modifiers are combined with available information in the ADS related to demand-side modifier and consumption forecasts to reconstitute the consumption forecasts for each region. The demand forecasts are then grossed up for transmission and distribution losses.

## 3. Baseline Resources

### 3.1 Overview

Baseline resources are resources that are currently online or are contracted 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 both **baseline** and **candidate** resources are inputs to SERVM. In the near-term (e.g. 2-3 years into the future), modeling baseline resources only may result in a sufficiently reliable system, but in the mid to long-term (3 years into the future and beyond) due to load growth and other changes over time, future additional candidate resources may need to be included on top of baseline resources to result in a sufficiently reliable system. Candidate resources are selected using capacity expansion modeling such as RESOLVE or derived from IRPs and other resource projections. For some resources, baseline resource capacity is reduced over time to reflect announced retirements. This document describes the updating process of baseline resources only.

Baseline resources include:

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

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

- Resources under development in non-CAISO balancing areas. These resources come from individual IRP plans filed by Balancing Authorities outside of CAISO and from the WECC ADS. Resources described as “planned” or “generic” are generally excluded.

See the IRP Resource Data Template (RDT) User Guide and workbook[6] for further explanation of criteria for baseline resources including a definition of “in development”. Baseline resources are assembled from the primary sources listed in Table 3 and are further described below.

*Table 3. Data Sources for Baseline Resources*

| Region | Online Status | Dataset Used |
|---|---|---|
| In CAISO | Existing | CAISO Master Generating Capability List and CAISO Master File, both vintage January 2024 |
| In CAISO | In-development | December 1, 2023, IRP Compliance Filings and CAISO POU IRPs. These are tagged as “Development” in the RDT. |
| Out of CAISO | Existing and In-development | 2032 WECC ADS V2.4.3, with supplemental data from non-CAISO LSEs and independent studies for SB100 compliance[7,8,9,10] |
| In CAISO | Retirement Dates | Updated CAISO Mothball and Retirement List, and December 1, 2023, IRP Compliance Filings |
| Out of CAISO | Retirement Dates | 2032 WECC ADS V2.4.3, with supplemental data from non-CAISO LSEs |

- The list of generators currently operational to serve the CAISO area is compiled from the CAISO Master Generating Capability List as of January 2024[11]. WECC ADS information for generation serving the CAISO area is not used, as CAISO information is assumed to be more accurate and current. These generators serve demand inside CAISO and are

[6] IRP Resource Data Template (RDT) User Guide: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/rdtv3_userguide_20220923.pdf

IRP RDT workbook: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/rdtv3_10112022.xlsm

[7] LADWP – LA 100 Study, available at LA100: The Los Angeles 100% Renewable Energy Study and Equity Strategies
[8] SMUD – 2030 Zero Carbon Plan, available at SMUD 2030 Zero Carbon Plan Technical Report
[9] IID – CEC Review of IID 2018 IRP, available at https://efiling.energy.ca.gov/getdocument.aspx?tn=230474
[10] TID – CEC Review of TID 2018-2030 IRP, available at https://www.energy.ca.gov/filebrowser/download/1905
[11] Available at: http://oasis.caiso.com/mrioasis/logon.do

composed of renewable and non-renewable generation resources, as well as some demand response resources. The CAISO Master Generating Capability List information provides a listing of the resources by name and CAISO Schedule Resource ID (CAISO ID) and their Net Dependable Capacity (NDC, used as capmax in SERVM), in-service and retirement dates, and location. Operational data for those generating units come from the corresponding CAISO Master File, a confidential data set with unit-specific operational attributes. Both of these CAISO 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. Nevertheless, information for these dynamically scheduled resources is taken from the CAISO listings rather than those same resources listed in the WECC ADS. Some dynamically scheduled generators also have contracts to provide energy and capacity to CAISO LSEs. Such generators are modeled as specified imports (remote generators) in SERVM.

- Future in-development generators for CPUC-jurisdictional LSEs are compiled from the December 1, 2023, version of IRP filings, which list contracts entered into by LSEs and approved by the LSEs' highest decision-making authority as of August 1, 2023. To the extent that any of these resources came online between August 1, 2023, and the publishing of the January 2024 CAISO Master Generator Capability List, the CAISO information takes precedence.
- For generators outside of CAISO, all identifying information and operating information are taken from the WECC's 2032 Anchor Data Set (ADS) v2.4.3.
- Confirmation of some data regarding in-development resources for CAISO and outside CAISO regions are sourced from Energy Information Administration (EIA) data[12]
- This baseline will replace the prior list dated October 2023[13].
- The baseline update also involves making additions and updates to individual units from the prior baseline list, including updates to operating parameters and maximum capacity. Staff is also updating regions, unit types, and unit categories to correct errors and oversights. Staff will consolidate planned capacity with newly online capacity if a planned project came online, as well as separate 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 names.

[12] EIA December 2023 Monthly Generator Inventory https://www.eia.gov/electricity/data/eia860M/ dated 1/22/24

[13] https://files.cpuc.ca.gov/energy/modeling/2023PSP/SERVM_GeneratorList_20231005.xlsx

- Finally, as part of the baseline resources update, staff are aggregating the SERVM regions SMUD and TID (used in all prior cycles) into one new combined region called NCNC. Electric demand and demand modifiers, all units in the affected regions, and relevant transmission paths will be consolidated. The consolidation will make matching SERVM electric demand and demand modifier inputs with the NCNC Planning Area in the CEC's IEPR demand forecast significantly easier.

## 3.2 Natural Gas, Coal, and Nuclear Generation

Natural gas, coal, and nuclear resources are represented in SERVM as individual units. Unit information such as capacity, operating constraints, and variable costs are drawn directly from the CAISO Master File, the CAISO Master Generating Capability List, or the WECC 2032 ADS v2.4.3[14]. Contracted and under development new generation for the CAISO area is taken from the LSE IRP plans or procurement filings.

For regions external to the CAISO, the ADS is used to characterize the existing and anticipated future generation fleet in each non-CAISO zone. Staff are compiling data from individual non-CAISO LSE IRPs and the EIA to supplement and check that regions to be modeled from the ADS are resource adequate in all future years. Although the ADS is sourced from utility IRPs to track generator additions and retirements as well as projected electric demand changes, the ADS is a snapshot of a single year ten years in the future, and information may be dated.

Details on how SERVM models operating constraints are covered in section 4.3. Units that are contracted to serve load in a region that is different than the units' physical location are virtually assigned to the region holding the contract. For example, the share of Palo Verde nuclear plant that is contracted to SCE is assigned to the SCE region while the share that is contracted to LADWP is assigned to the LADWP region.

### 3.2.1 Retirement Assumptions

Retirement assumptions are drawn from the CAISO Announced Retirement and Mothball List[15], the WECC 2032 ADS v2.4.3, or other public sources. The capacity of fossil-fueled and nuclear thermal generators that have formally announced retirement are removed from baseline thermal capacity using the announced retirement schedule. California steam turbines are all modeled to retire by default at the end of 2023 to achieve compliance with the State Water Board's Once-Through-Cooling (OTC) regulations, even though some of those plants are part of

[14] Data available on WECC website: https://www.wecc.org/ReliabilityModeling/Pages/AnchorDataSet.aspx
[15] Version 9/19/2023 was used. The most recent version is posted at: https://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

California's Strategic Reliability Reserve.[16] Diablo Canyon Nuclear Power Plant (DCPP) is modeled to retire according to its original schedule of Unit 1 in November 2024 and Unit 2 August 2025. Cogeneration (also called combined heat and power or CHP) facilities follow any announced retirement schedule and on top of that, are assumed to be completely phased out by 2040.

#### *3.2.1.1 Diablo Canyon Extension*

SERVM will also be set to model sensitivities strictly in support of the RA proceeding with alternative retirement dates for DCPP to operate through the end of 2026 (Senate Bill 846, which set in motion the potential extension of DCPP, proposed the continued operation of Units 1 and 2 for up to five years, but the current RA analysis time horizon is not beyond 2026). Pursuant to the CPUC's recent Diablo Canyon extension decision that requires Energy Division to allocate the associated credits of Diablo Canyon units to all LSEs using the CAM allocation process, SERVM will be used to conduct reliability analysis to inform an RA 2026 Planning Reserve Margin, with DCPP modeled online for 2026. All other SERVM modeling such as for IRP will adhere to the original DCPP retirement schedule.

## 3.3 Renewables

Baseline renewable resources include all existing biomass, biogas, geothermal, solar photovoltaic (PV), solar thermal, and wind in each region. Small hydro (usually run-of-the-river hydro) is grouped with large hydro and described in section 3.4 below. All wind in the baseline is onshore.

### 3.3.1 CAISO Renewable Resources

CAISO baseline renewable resources include (1) existing resources, whether under contract or not, and (2) resources that have executed contracts with LSEs and have "development" status on LSE IRP filings. As mentioned above, existing CAISO renewable resources are 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 LSE IRP plans as of December 1, 2023.

CAISO renewables also include dynamically-scheduled generators physically located outside the CAISO that have energy and capacity contracts with a CAISO offtaker. These are called "remote

[16] https://www.energy.ca.gov/data-reports/california-energy-planning-library/reliability/strategic-reliability-reserve

generators" and grouped with "direct purchases" (specified imports) in SERVM. The energy and GHG attributes accrue to the "remote region", i.e. the offtaker.

### 3.3.2 Non-CAISO Renewables

For non-CAISO entities in or out of California, the renewable resource portfolio is derived from the WECC 2032 ADS v2.4.3, EIA Monthly Generator Inventory (EIA-860M) data, and available non-CAISO IRPs. Baseline renewable capacities for non-CAISO entities do not include resources physically located in these regions but with energy and capacity contracts with a CAISO offtaker since they are already counted as part of the baseline renewables in CAISO.

## 3.4 Hydro

The existing large hydro resources in each region of SERVM are assumed to remain unchanged over the timeline of the analysis. The large hydro resources in SERVM are represented as providing energy to their local zone, with the exception of Hoover, which is split among the CAISO, LADWP, and AZPS regions in proportion to ownership shares. A single aggregate hydro unit per region is modeled based on all the hydro flows in the region, making no distinction between small and large hydro resources.

Staff sources monthly and hourly hydro unit flow data from EIA Form 906/923, CAISO, and Bonneville Power Administration (BPA). Staff uses the historical hydro data to simulate weather constraints on hydro resources in particular regions, including minimum flows representing Run of River hydro, maximum hydro capacities, and monthly available hydro energy that can be dispatched during a month. See section 4.3.2 for more details on modeling hydro operation.

PGE and SCE regions each have an emergency hydro unit modeled in addition to the aggregate hydro unit representing large and small hydro within each of these regions. The emergency unit represents the ability to borrow from the monthly generation budget under grid stress conditions. The emergency units are modeled to be available only during certain month/hydro year combinations that represent sufficient hydro availability for borrowing. See section 4.3.2 for more details.

Capacity values reported in the table below are the September maximum output from the 2010 hydro year. SERVM characterizes its hydro unit sizes by monthly maximum output across all available hydro years (currently 2000-2022) rather than using the nameplate of each specific hydro unit.

*Table 4. SERVM hydro unit September maximum output under 2010 hydro conditions*

| Unit Name | Region | Maximum Output |
|---|---|---|
| AZPS Hoover Hydro_New | AZPS | 209 |
| BANC Hydro_New | SMUD | 1,350 |
| LADWP Hoover Hydro_New | LADWP | 170 |
| LADWP Hydro_New | LADWP | 562 |
| NEVP Hoover Hydro_New | NEVP | 258 |
| NW Hydro_New | BPAT | 14,057 |
| PACW Hydro_New | PACW | 431 |
| PGE Emergency Hydro_New | PGE | 828 |
| PGE Hydro_New | PGE | 3,244 |
| SCE Emergency Hydro_New | SCE | 172 |
| SCE Hoover Hydro_New | SCE | 466 |
| SCE Hydro_New | SCE | 674 |
| SW Hydro_New | SRP | 1,363 |

## 3.5 Energy Storage

### 3.5.1 Pumped Storage

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

*Table 5. Existing pumped storage resources in CAISO*

| Common Name | SERVM Unit Name | Capacity (MW) |
|---|---|---|
| Eastwood | EASTWD_7_UNIT | 200 |
| Helms | HELMPG_7_UNIT_1<br>HELMPG_7_UNIT_2<br>HELMPG_7_UNIT_3 | 1,218 |
| Lake Hodges | LAKHDG_6_UNIT_1<br>LAKHDG_6_UNIT_2 | 40 |
| O'Neil | ONLLPP_6_UNITS | 25 |
| **Total** | | **1,483** |

Operating characteristics of pumped storage hydro resources (including total energy storage MWh, transition time, minimum pumping and flowing capacity) are taken from the CAISO MasterFile.

### 3.5.2 Battery Storage

Baseline storage resources include all battery storage that is currently installed in the CAISO region, as well as further battery storage listed as "in-development" in the December 1, 2023, LSE filings. Operating parameters for baseline utility scale storage resources come from the CAISO MasterFile and in the case of "in development" storage, from the December 1, 2023, LSE filings. Baseline behind-the meter storage resources are based on CEC's 2023 IEPR demand forecast. Battery storage co-located with a generator (the Paired_BattStorage and Hybrid_BattStorage Unit Categories in SERVM) that meet the baseline criteria are also grouped together with baseline battery storage.

## 3.6 Demand Response

Shed (or "conventional") demand response reduces demand only during peak demand events. Baseline Demand Response resources will consist of IOUs' existing shed demand response programs, shed demand response procured through the Demand Response Auction Mechanism (DRAM), and any third-party Load Impact Protocol (LIP) programs with LSE contracts. The assumed peak load impact of demand response programs are based on final annual LIP reports by the IOUs.[17] Additional interruptible pumping load (mostly Department of Water Resources bulk water pumping load) is also included as baseline shed DR capacity in all years. The total pumping load modeled in SERVM varies by month approximately ranging from 500 to 600 MW and has been derated from source data (CAISO Master Generating Capability List) due to water limits and expected deliveries.

## 3.7 External Region Calibration

To reasonably model grid conditions in external regions and produce a realistic pattern of import exchanges between CAISO and external regions, accurate representations of load and resource balance, projected load growth, and capacity expansion in external areas are vital. However, accurate and detailed data on future loads and resources in external regions may be difficult or impossible to obtain and even if accurate data were available, it may not be desirable to model external regions in detail to reduce model complexity and run time.

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

Staff chose to model only external regions closest to California. Those regions closest to California were maintained in the model while regions further from California were left out. In addition, regions in the Northwest and Southwest were grouped as a co-region to simplify modeling of their dispatch patterns.

*Table 6: Non-California Regions Modeled in SERVM*

| SERVM Region | Balancing Area/Utility Name |
|---|---|
| AZPS | Arizona Public Service |
| BPAT | Bonneville Power Administration |
| NEVP | Nevada Power Company |
| PACW | PacifiCorp West |
| PortlandGE | Portland General Electric |
| SRP | Salt River Project |
| WALC | Western Area Power Administration Lower Colorado |

The default amounts of generation and electric demand drawn from available public sources, particularly the WECC ADS as described above, did not result in all regions with 0.1 days/year LOLE level of reliability. To reduce leaning of one region upon another and to model more realistic transfer patterns between regions, additional calibration and research into IRP plans filed by each LSE in an external region are being performed. Including resource additions planned in utility IRPs – beyond the WECC ADS – allows for a "bottoms up" view of regional additions and captures additional relevant mandated or voluntary clean energy policies that will drive the ongoing WECC-wide resource shift away from coal towards clean energy capacity. Where data gaps in IRPs exist, staff will consider the use of heuristics informed by regional growth patterns, or clean energy or reliability requirements. Some calibration of electric demand and/or adding/removing of capacity to/from regions may be needed to tune all regions towards a 0.1 LOLE target. Staff will work to equalize the reliability level across regions by adding perfect load to or removing capacity from external regions whose LOLE is far below 0.1 LOLE and adding perfect capacity to or removing load from external regions whose LOLE is far above 0.1 LOLE. It is difficult and time consuming to iteratively tune many regions to try and get each region close to 0.1 LOLE. Staff will only tune each region towards the 0.1 LOLE target until the point of further tuning having almost no effect on changing the LOLE result for the CAISO region.

# 4. Generator Operations and Hourly Profiles

## 4.1 Overview

SERVM is a full production cost model (PCM) which seeks to completely characterize the electric system with generators represented in an hourly dispatch model. This section describes hourly weather-based electric demand and weather-based generation profiles and non-weather dependent generator operating constraints, and how they are developed and used in SERVM.

## 4.2 Electric Demand and Renewable Production Profiles

Historical weather-based hourly electric demand, and wind and solar production profiles ("shapes") are key inputs to SERVM. The prior cycle of modeling in 2022-2023 used the weather years 1998-2020 as the basis for hourly shapes. In this modeling cycle staff added the two most recent and available weather years and dropped the two years furthest in the past, meaning the 23 years of weather data used in SERVM begin in 2000 and run through 2022. Thus, the overall ensemble of weather patterns tested in SERVM is still 23 years in length but now includes the extreme heat events that occurred in 2020 and 2022.

### 4.2.1 Electric Demand Profiles

Staff developed weather normalized electric demand profiles for SERVM using a weather normalization model and existing temperature and humidity data from 2000-2022 in a two-step process. In step one, staff gathered CAISO region hourly electric sales data from the CAISO's Energy Management System (EMS) and other region data from FERC Form 714 hourly electric sales data[18] and added back the impacts of simulated BTM PV generation, historical demand response (curtailable load) events if any, as well as behind the meter charging, thereby reconstituting the counterfactual consumption demand for the immediately previous three years (2020-2022). In step two, this consumption demand for the previous three years was used to train the Monash[19] regression model which uses historical temperature and humidity to forecast electric demand. That way, the most recent three years of consumption data is used to train a model which is then used to build out 23 years of simulated, weather normalized hourly consumption demand for all regions, corresponding to 2000-2022 weather patterns.

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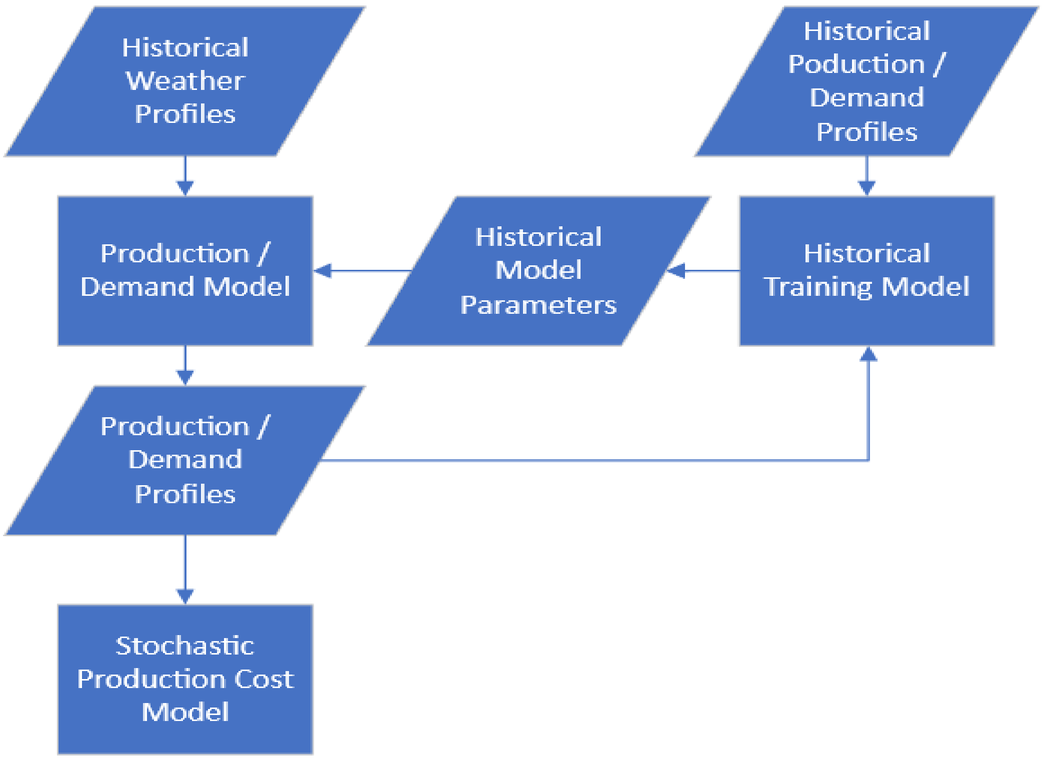
[18] FERC Form 714 data is available at https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-no-714-annual-electric/data up to and including 2020. After 2020, data is available through the FERC ePortal located at https://ecollection.ferc.gov/

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

*Figure 1. Creation of Demand Profiles from Historical Weather*




In leap years of the 2000-2022 weather normalized profiles, February 29 is retained and December 31 is dropped such that the profiles remain 8760 hours long but do not introduce a discontinuity in the weekday/weekend pattern.

Staff also shifted the 2000-2022 weather normalized profiles such that all years start with a Monday (January 1 is a Monday for all years) to ensure each future year only varied from peak, energy, and weather variability, and not from which day-of-week start was used. Staff chose Monday as the uniform start day based on analysis showing that Monday starts was about the median out of the seven possible day-of-week starts in terms of average percentage of peak temperatures occurring on a weekend day.

The resulting weather normalized demand profiles are then input into SERVM and scaled such that the median annual peak and energy of the 23-year distribution matches the single annual peak and energy in the "Planning Forecast" scenario of the CEC's 2023 IEPR consumption electric demand forecast for California regions, or the demand forecast in the WECC 2032 ADS v2 for non-California regions. Refer to section 2.1 above for the definition of consumption electric demand and more details about calibrating the CAISO coincident consumption peak to match with the IEPR.

#### 4.2.1.1 Climate-Informed Approach

When we forecast the behavior of the electric grid looking out to some future target forecast year, we typically make the assumption that weather in the target forecast year behaves consistently with historically observed weather data. For example, electric consumption profiles used within our PCM are currently based on historically observed weather data (temperature and dewpoint) corresponding to the years 2000 - 2022. However, given the rapidly accelerating nature of climate change, it is no longer reasonable to assume that the weather in our target forecast year will behave consistently with historically observed weather data. To realistically forecast the behavior of the electric grid in our target forecast year, we need to account for climate change.

Electric consumption profiles used in our PCM can be thought of as having a normalized hourly shape, and magnitude. The normalized hourly shapes capture the variation in daily and monthly electric consumption, but average to unity per day. In contrast, the magnitude scales the normalized hourly shapes to capture the overall magnitude of the annual electrical consumption. Within our current framework, the CEC IEPR forecast defines the magnitude of electric consumption for each region within California, by specifying an expected peak and average annual demand for each target forecast year. The WECC Anchor Data Set (ADS) specifies the magnitude of annual consumption for all regions outside California. The CEC IEPR and WECC ADS forecasts already incorporate climate change impacts. However, the electric consumption hourly shapes currently used within our model are informed by historical weather data and therefore do not currently reflect impacts of climate change.

Staff has examined the impact of electric consumption shapes on electric grid reliability with and without accounting for climate change. This is accomplished by developing synthetic weather data based on historical data perturbed by differences of ensemble averaged Global Climate Model simulations.[20] Temperature and dew point drive electric consumption, and so synthetic weather data profiles corresponding to warmer climates are developed to make this comparison. These synthetic weather profiles are used to generate electric consumption profiles which are then fed into a stochastic Production Cost Model representing the US western electric grid in the target forecast year of 2035. By comparing the 23 year (1998 – 2020) historical weather data case with the synthetic, climate informed cases we find an additional amount of perfect capacity is needed for each of the warmer climates examined to reach the same level of reliability as the historical reference case. In this approach we fix the magnitude of electric demand in the target forecast year consistent with our alignment with

[20] CPUC Staff Paper, Quantifying the Impact of Climate Change on Electric Grid Reliability Using Historical Weather Data Perturbed by Ensemble Averaged CMIP6 Data, March 2024

the CEC IEPR and WECC ADS forecasts. For the California Independent System Operator footprint, with expected coincident peak demand of 61.2 GW in 2035, we find 825, 1300, and 2350 MW of additional perfect capacity is needed to maintain reliability for climates corresponding to 1.7, 2 and 3 C Global Warming Levels. Given 1.7 C warming is expected under the reference climate forcing in 2035, we recommend using electric consumption shapes informed by climate change in our electric grid reliability modeling.

### 4.2.2 Electric Demand Modifier Profiles

As described in section 2.1 above, SERVM models electric demand modifiers separately from electric consumption demand. Consumption and BTM PV are modeled with the SERVM 23 weather year distribution while all the other explicitly modeled demand modifiers are assumed weather independent and have a single hourly profile for each forecast year. Hourly demand modifier profiles are developed from the "Planning Forecast" scenario of CEC's 2023 IEPR demand forecast for all California regions. This includes AAEE, AAFS, electric vehicle charging demand (both baseline and Additional Achievable), TOU rate impacts, and BTM storage. For non-California regions, only BTM PV generation, if any, is explicitly modeled separately from electric demand.

For non-BTM PV demand modifier profiles, staff directly processes the hourly profiles provided by the CEC's 2023 IEPR demand forecast into normalized profiles for each forecast year paired with the maximum value (whether positive or negative) that together recreate the original IEPR demand modifier profile in SERVM as "fixed profile generator" units, for each forecast year and CAISO region. The 2023 IEPR only provides profiles for the CAISO regions in SERVM (PGE, SCE, and SDGE). For the LADWP, NCNC, and IID regions, staff used the nearest CAISO region's normalized demand modifier profile paired with the IEPR's annual forecast for that particular demand modifier. LADWP uses SCE's normalized profiles, NCNC uses PGE's and IID uses SDGE's. See the next section for how BTM PV profiles are developed.

### 4.2.3 Solar Production Profiles

Weather normalized solar production profiles are created using NREL's PVWATTS Version 5 calculator.[21] The software creates PV production profiles based on historical solar radiation data from the National Solar Radiation Database (NSRDB),[22] and is used to produce both utility-scale and behind-the-meter solar profiles. 2000-2022 NSRDB weather data is used to create the profiles used in SERVM.

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[21] See: https://pvwatts.nrel.gov/downloads/pvwattsv5.pdf
[22] See: https://nsrdb.nrel.gov/current-version

To create solar profiles using the PVWATTS Version 5 calculator, various solar array parameters are determined by fitting historical to modeled solar production data. SERVM simulates solar production profiles for single and double axis tracking configurations as well as fixed axis/tilt configuration. SERVM also simulates production from BTM PV resources with a BTM PV profile using an inverter loading ratio sourced from the CEC's IEPR demand forecast, currently 1.13.

Historical monthly and annual MW capacity and the city at the center of each IEPR Forecast Zone are taken from the IEPR BTM PV forecast. This is used for developing BTM PV profiles reflecting historical weather data, and for reconstituting consumption demand from sales data. Likewise forecasted monthly MW BTM PV capacity by Forecast Zone is based on the IEPR BTM PV forecast. See section 2.1.2 above for how BTM PV annual energy production in SERVM is calibrated to match the IEPR.

The final result is 23 weather years of normalized hourly production profiles representing more than two dozen specific locations ("weather stations") in California and across WECC for each technology class. In SERVM, the normalized hourly profiles (identified by a "weather station" name) get paired with the installed capacity of individual solar units at a specific location, resulting in the final fully scaled hourly solar production profiles for those units at that location. Individual utility-scale solar units as itemized in the set of baseline generators described earlier are modeled. For BTM PV units in California, one aggregate unit for each Forecast Zone of the IEPR demand forecast is modeled.

### 4.2.4 Wind Production Profiles

The CPUC wind model produces 23 years of normalized hourly production profiles (2000 – 2022) for all locations at which wind resources exist within the 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 the installed capacity (in MW) of the resource. Individual efforts were undertaken for each of the Offshore Wind (Offshore) profiles, CAISO onshore profiles (Onshore), and onshore Out of State profiles (OOS) to ensure accuracy.

Normalized hourly wind production profiles are developed in two different ways:

**Velocity**: For regions for which we do not have historical wind production data including some onshore as well as all offshore locations, we are using hourly wind speed data with an appropriate power response curve along with a multiplicative transmission loss factor to create normalized hourly wind production profiles. The power response curve gives normalized production as a function of wind speed. Offshore wind production profiles are calibrated by adjusting the value of the multiplicative transmission loss factor to match simulated capacity factor information[23]. Onshore wind speed profiles are obtained from the Copernicus ERA5 reanalysis dataset[24]. We have moved from the high resolution WRF/ERA5 wind speed dataset to the lower resolution Copernicus/ERA5 dataset since the WRF dataset does not yet contain data past 2020. Offshore windspeed profiles are obtained from the National Renewable Energy Labs (NREL) 2023 National Offshore Wind data set (NOW-23).[25]

**Monte Carlo**: For regions where historical wind production data is available, the process for developing normalized hourly wind profiles is as follows:

a. Map each wind resource to a wind weather station.
b. Aggregate historical hourly wind production to each wind weather station.
c. 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.
d. 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).

For each weather station, choose wind speed profiles from the Copernicus ERA5 dataset that are physically closest to the region centroid, and then resort the Monte Carlo random draws according to the rank order of the historical annual velocity profiles. Choose the single wind speed profile that minimizes the difference between the simulated and historical aggregated monthly and hourly capacity factors. Similar to solar, the normalized hourly wind production profiles (identified by a “weather station” name) get paired with the installed capacity of individual wind units at a specific location, resulting in the final fully scaled wind production profiles for those units at that location.

## 4.3 Operating Characteristics

### 4.3.1 Natural Gas, Coal, Nuclear

SERVM models the thermal fleet individually using actual unit-level data to the extent possible. Principal operating characteristics include Pmax, Pmin, heat rate, start cost, start fuel

23 National Renewable Energy Laboratory National Offshore Wind data set (NOW-23), https://dx.doi.org/10.25984/1821404

24 See: https://cds.climate.copernicus.eu/cdsapp#!/dataset/reanalysis-era5-single-levels?tab=form

25 See: https://data.openei.org/submissions/4500

consumption, ramp rates, minimum up and down times, etc. and are taken from the latest version of the CAISO Master File[26] and the WECC 2032 Anchor Data Set Phase 2 2 V2.3.2.[27]

#### *4.3.1.1 Generator Maintenance and Forced Outage Distributions*

A generator requires maintenance time during the course of a year, and generator owners schedule that maintenance to avoid peak demand times and be available when needed by the system operator to maintain reliability and capture high priced energy hours. Generators are also subject to unplanned forced outages during the course of a year, often depending on age, operating history, and time operating since the last major maintenance. For that reason, generators are given a set maintenance rate which the SERVM model schedules for off-peak times like an owner would likely do, and a stochastic distribution from which SERVM will draw forced outage events. For thermal resources, all this data is drawn from the NERC GADS database.[28]

Maintenance rate data is drawn from GADS data, directly taken from the Unit Year Operational Report in the PC-GAR data application. This rate is a percentage, meant to represent the number of hours in a year the facility is required to undergo maintenance. This is input as a percentage rate applied to each plant individually in SERVM, and each power plant is scheduled for maintenance individually based on monthly demand and resource balance conditions so as to minimize reliability shortages.

Forced outage distributions are likewise sourced from GADS data, and a distribution is created for each class of power plant based on length and frequency of observed forced outage events in the GADS database. Monthly time-to-repair and time-to-fail distributions are created and applied to power plant classes based on EFOR data in the PC-GAR data tool, and the SERVM model then draws from those distributions as the model steps through each hour of the year to simulate the stochastic nature of equipment failure on expected system reliability and operations. Other data include start-up probability, maintenance rate, and partial outage rates and derates are also created from GADS reports. For resources without GADS data available (i.e. storage) those same data parameters will be calculated from CAISO daily curtailment data.[29]

Because powerplant-level GADS data is considered confidential, and to mitigate outliers due to small data sets, staff created groupings of thermal powerplants into unit types and percentile ranges corresponding to high-, mid-, and low-outage resources and applying the aggregate

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[26] See http://oasis.caiso.com/mrioasis/logon.do
[27] https://www.wecc.org/Reliability/2032%20ADS%20PCM%20V2.3.2%20Public%20Data.zip
[28] https://www.nerc.com/pa/RAPA/gads/Pages/GeneratingAvailabilityDataSystem-(GADS).aspx
[29] http://www.caiso.com/market/Pages/OutageManagement/CurtailedandNonOperationalGenerators.aspx

EFORd for each group to its individual powerplants. The aggregated EFORd combined with separately grouped ambient derate values will provide more unique Unforced Capacity (UCAP) values across the thermal powerplant fleet while respecting the confidentiality of outage data reported to NERC.

#### *4.3.1.2 Ambient Derating of Thermal Plants*

CPUC Staff developed a model to derate thermal plants based on ambient temperatures. The model involves regression analyses of historic weather and curtailment data for each thermal plant to determine the best-fit linear coefficients for a set of derating curves, i.e., available percentage of resource capacity as a function of ambient temperature. While the curtailment data include outages due to a variety of factors, only those indicated as “forced” outages which are “ambient due to temperature” are included in the analysis. The model is piecewise-linear, capped at 100% for low temperatures and decreasing linearly above a threshold temperature determined through the regression analysis. Thermal plants are grouped together based on their geographic proximity to a weather station and the plant’s technology, and each group’s derating curve is based on its constituent plants’ historic performance. The derating curves can be used with current- or future-climate weather data to forecast ambient derating factors. The derating factors are then processed into SERVM input files for derating each thermal power plant.

The resulting derate factors for two weather stations are summarized in Figure 2 and Figure 3, showing the monthly distributions of derate statistics for combined cycle and combustion turbine power plants for Sacramento (KSAC), then Santa Barbara (KSBA).

*Figure 2 - Monthly Ambient Derate Statistics for Sacramento*

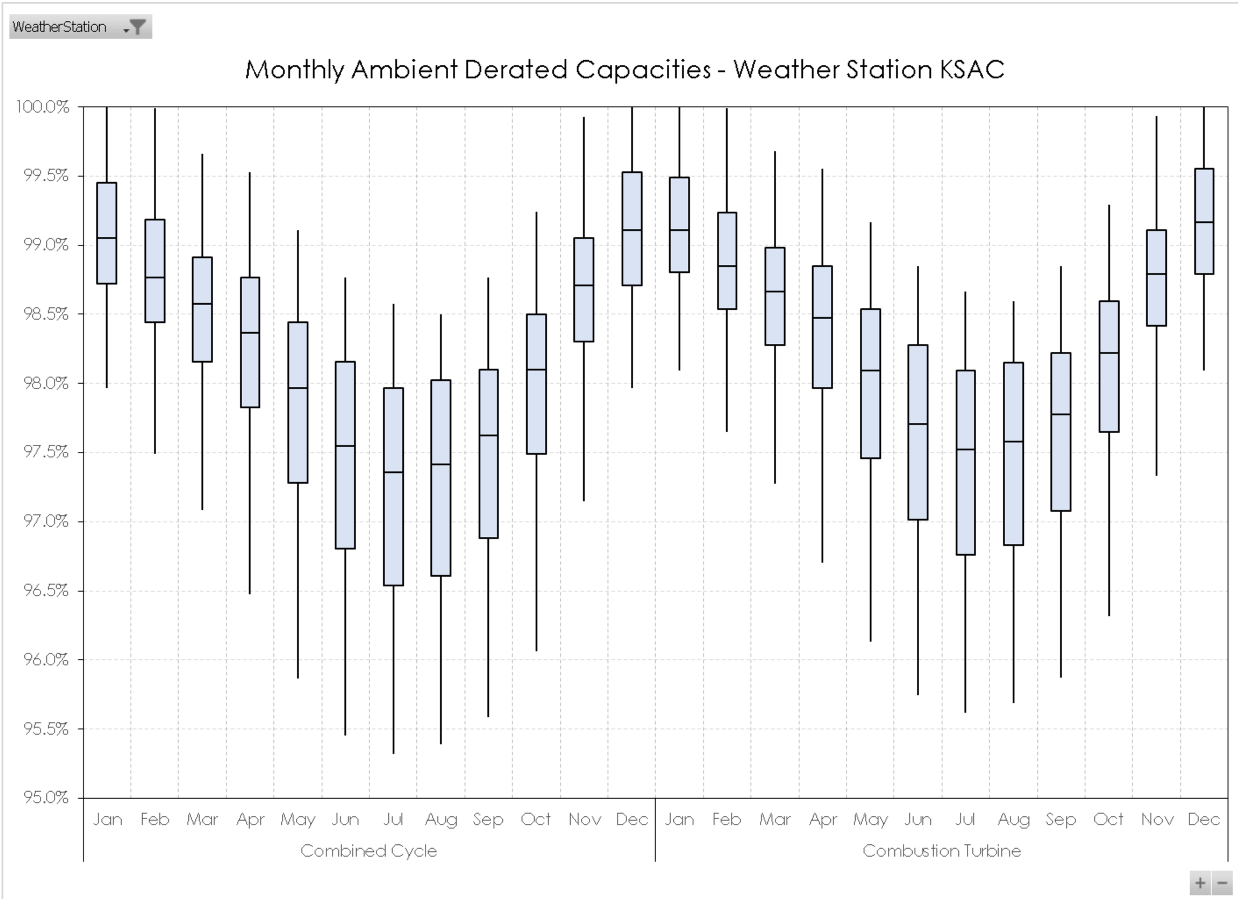
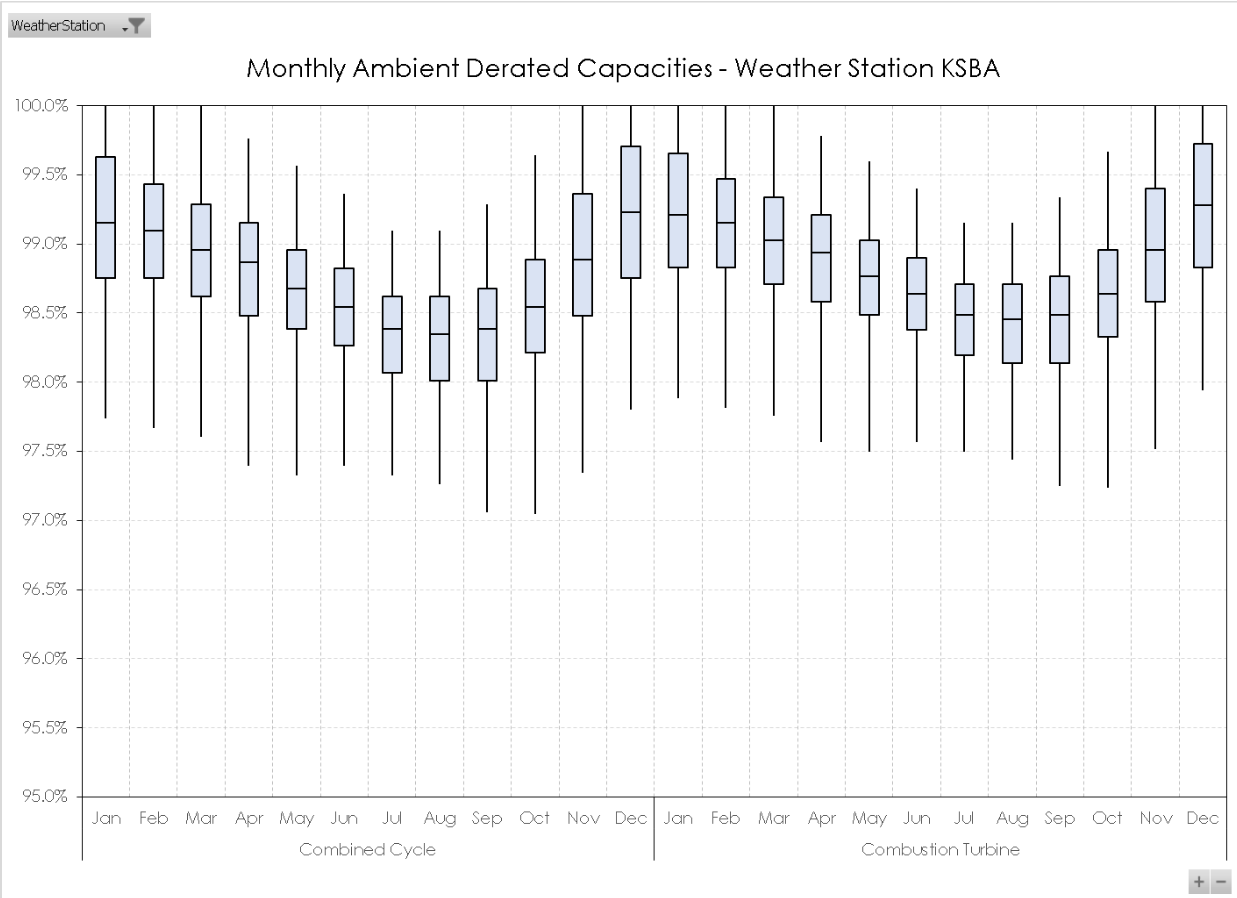


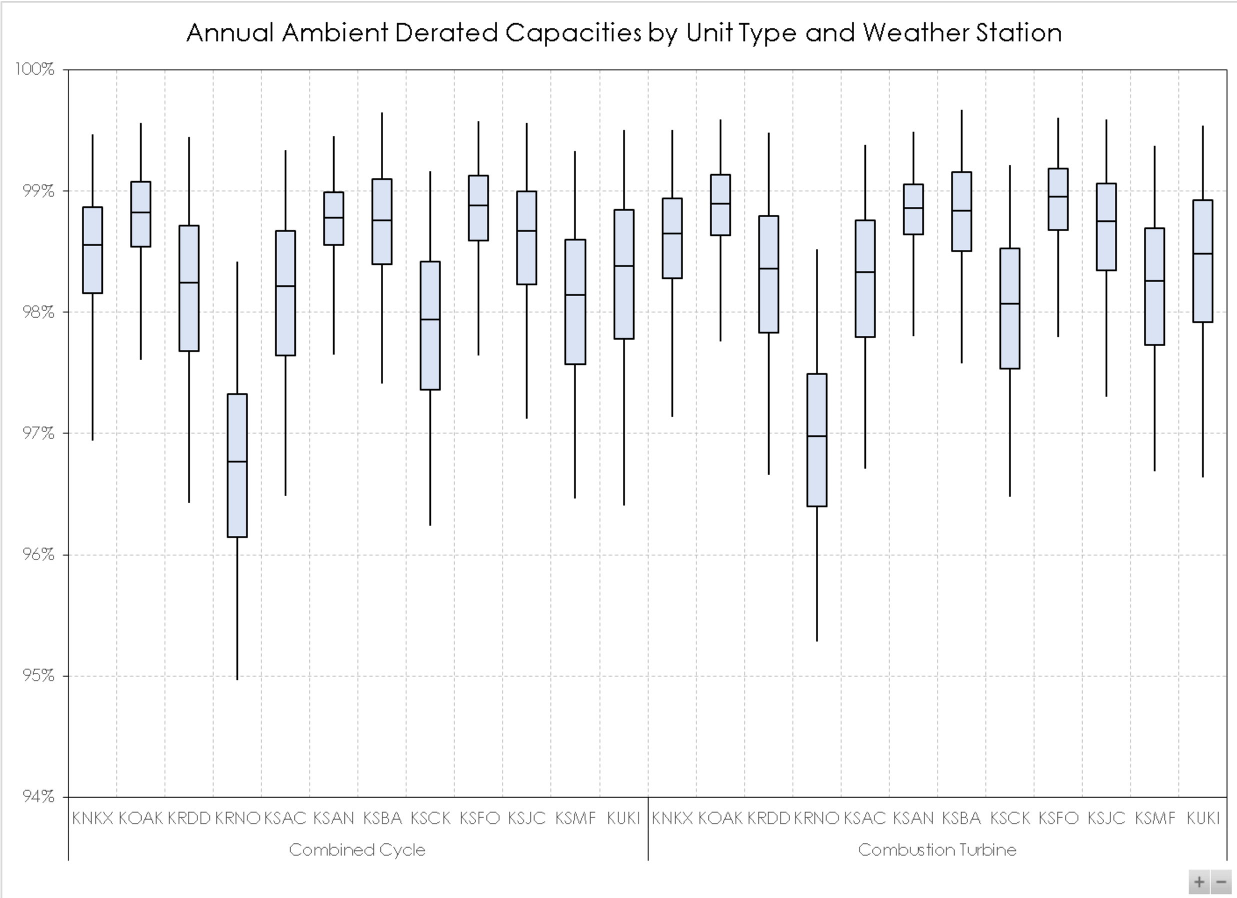
*Figure 3 - Monthly Ambient Derate Statistics for Santa Barbara*




These charts show how the distributions of derates due to ambient temperatures above vary both with month and with location. Sacramento, being more inland than Santa Barbara, generally experiences warmer and more variable temperatures throughout each month, resulting in lower median capacities and wider distributions of derates.

Finally, Figure 4 summarizes ambient derate factors for all twelve weather station and both unit types. The regression parameters determined during analysis yield more significant derates at the same elevated ambient temperatures for Combined Cycle units than for Combustion Turbines, and each weather station reflects its own distribution of temperatures throughout the weather-year.

*Figure 4 - Annual Ambient Derate Statistics*




#### *4.3.1.3 Climate-Informed Ambient Derating*

The ambient derating model for thermal power plants described above can be used with any weather data corresponding to the weather stations used in grouping the power plants. Staff's climate-informed forecasting for weather generates temperature profiles for which, when applied to the derating model, yields climate-informed ambient derate forecasts.

### 4.3.2 Hydro

SERVM models hourly hydro production based on 23 years (2000-2022) of monthly data from EIA Form 906/923 and four years of hourly data collected from the CAISO, BPAT, and EIA. The source data was detrended and translated into monthly generation, daily minimum, average, and maximum generation, and monthly maximum output constraints. SERVM schedules the hydro according to the net load conditions of a given "case" subject to these constraints. A SERVM case is comprised of a particular weather year, hydro year, and economic load forecast uncertainty and will thus have its own hourly hydro dispatch profile.

Hydro variables simulate the annual and seasonal patterns of large and small hydro energy generation in power systems. There is a minimum energy flow, which represents Run of River hydro, that just flows unimpeded each day subject to seasonal water availability, there is a capmax variable which represents the size of the turbines that can generate at maximum hydro flow, and there is an energy variable which represents the energy between minimum flow and max capacity that can be scheduled to meet demand. Each of these variables is entered by month, year, and region reflecting the historical variation in hydro generation in WECC regions.

Hydro operating constraints were aggregated from the actual historical hydro production data for both large and small hydro, by region. Thus, each region that has hydro contains a single aggregate hydro unit. One exception is the shares of Hoover which are modeled as additional units in each region sharing Hoover (AZPS, LADWP, SCE). Another exception is PGE Emergency Hydro and SCE Emergency Hydro which are also modeled as additional units in PGE and SCE, respectively. SERVM has an emergency mode to allow “borrowing” energy from the future dispatch of scheduled hydro up to a certain amount, usually a few hours. For example, “PGE Emergency Hydro_New” can borrow from “PGE Hydro_New” under high price (stress) conditions subject to an energy maximum. These emergency units are defined with a monthly maximum output and availability dependent on hydro year. The emergency unit settings were determined by analyzing historical hydro production data and finding that hydro dispatched higher than average coincident with some high load days when excess hydro production was available.

Staff does not assume that hydro performance (and hydro abundance in general) are tied to other weather dynamics, such as overall temperature, wind, and solar performance. This means that any weather year may be combined with any hydro year to form a particular realization of an operating year in SERVM simulations, e.g. 2010 weather for electric demand and wind and solar production can be combined with 2005 hydro patterns.

### 4.3.3 Energy Storage

In SERVM, storage units can be configured to prioritize energy arbitrage or system reliability and can commit available headroom and footroom to satisfying hourly 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 lack of direct market signals and lack of insight into customer behavior, BTM storage devices are modeled as fixed profiles defined by the 2023 IEPR demand forecast, as described in section 4.2.2 above.

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 storage hydro (PSH) units in SERVM do not have this constraint, though they do have individual charging capmax and discharging capmax values reflecting the individual limitations on the operation of the facility's pumps and turbines.

New planned battery storage is broadly assumed to have round-trip efficiency of 85% while newly built pumped storage is assumed to have round-trip efficiency of 75%. Existing pumped storage facilities however often have round trip cycle efficiencies closer to 60%.

Staff are also using the CAISO curtailment reports to generate seasonal maintenance rates for storage and PSH resources.

#### *4.3.3.1 Estimating Energy Storage Forced Outage Rates*

Battery storage resources do not yet report to NERC, and their historic outage data thus is not available through GADS. In lieu of this data, staff propose to analyze CAISO bidding and curtailment data to calculate approximate equivalent forced outage rates (EFOR) as defined in GADS. The formula for EFOR used in the GADS database is as follows:

$$EFOR = \frac{FOH + EFDH}{FOH + SH + Synchronous\ Hrs + Pumping\ Hours + EFDHRS}$$

Where

$$FOH \coloneqq \text{Forced Outage Hours}$$
$$EFDH \coloneqq \text{Equivalent Forced Derated Hours} = \frac{\text{Derating Hours} \times \text{Size of Reduction}}{NMC}$$
$$SH \coloneqq \text{Service Hours}$$
$$EFDHRS \coloneqq \text{Equivalent Forced Derated Hours during Reserve Shutdowns} = \frac{\text{Derating Hours} \times \text{Size of Reduction}}{NMC}$$
$$NMC \coloneqq \text{Net Maximum Capacity}$$

Although the CAISO prior trade-day curtailment reports include outage types (either forced or planned) and natures-of-work that appear to correspond to cause codes reported to GADS, there are some important differences in how and why events are reported to NERC vs. CAISO. Understanding these differences is critical to achieving analogous EFOR values. Staff engaged in a series of meetings to review the CAISO curtailment outage types and natures-of-work with various stakeholders to determine which curtailments should be included in EFOR, eventually agreeing on excluding all "planned" outages and including only "forced" outages with the following natures-of-work:

- ICCP
- METERING_TELEMETRY
- PLANT_TROUBLE
- RIMS_OUTAGE
- RIMS_TESTING
- RTU_RIG
- TECHNICAL_LIMITATIONS_NOT_IN_MARKET_MODEL
- TRANSITIONAL_LIMITATION
- TRANSMISSION_INDUCED

Curtailment reports matching these nature-of-work values will contribute toward the equivalent forced outage hours (EFDH) used in calculating the numerator of EFOR. The distinction between Forced Outage Rate (FOR) and EFOR is that EFOR accounts for partial outages by weighting outage times by the duration. To determine service hours in the denominator, staff analyzed historic CAISO bidding data and summed hours each storage resource has been bid, self-scheduled, or dispatched for residual unit commitment. Similarly, for battery energy storage systems, time spent charging is counted as pumping time for hydro resources, so hours with negative bids will be included in the EFOR denominator.

The EFOR values for storage resources will be evaluated on a monthly basis and aggregated across groups of resources to mitigate outlying resources or outlier data for certain months, and to provide EFOR values for new, not yet online resources with no historic data.

## 4.4 Operational Reserve Requirements

SERVM models reserve products for each hour to ensure reliable operation during normal conditions (regulation and load following) and contingency events (frequency response and spinning reserve). Information on these requirements came from discussions with CAISO staff and is summarized below.

Reserves can be provided by available headroom or footroom from various resources, subject to operating limits (Table 7). 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. Regulation reserves can only be provided by resources that are on Automated Generator Control (AGC). If a resource is not on AGC, it is able to only provide spinning reserve. Further, for storage resources, if they are on AGC they can provide regulation when charging as well as discharging. Individual resources may provide certain reserves, and it is not a good idea to generalize across a technology category. Age, technological limitations, or operator preference can determine which reserve services a generator can provide. Information for individual generators is sourced either from the ADS or CAISO Masterfile database.

*Table 7. Reserve types modeled in 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 SERVM this requirement is equivalent to 3% of hourly demand. Lack of sufficient capacity to provide regulation reserve leads directly to LOLE. | Gas-fired generators on AGC can provide available headroom/footroom, limited by their 10-minute ramp rate. Storage resources and hydro generators on AGC are only constrained by available headroom/footroom. Most other types of resources are not on AGC and cannot provide this service. |
| **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 SERVM this is modeled as 6% of hourly demand each for load following up and down. Load following up and down are targets, not requirements however and do not lead directly to LOLE. | 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. |
| **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 requirement is sourced directly from conversations with CAISO operators. | 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 | This requirement is equivalent to 3% of the hourly CAISO load in SERVM. Lack of | Gas-fired generators can provide all available headroom, limited by their |

| Product | Description | Modeling Requirement | Operating Limits |
|---|---|---|---|
| | resources to replace a sudden loss of power from large generation units or transmission lines. Spinning reserve is a type of contingency reserve. | sufficient capacity to provide spinning reserve leads directly to LOLE. | 10-minute ramp rate. Storage resources and hydro generators are constrained by available headroom/footroom. |
| **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 |

## 4.5 Transmission Topology

SERVM transmission flow limits between regions in each direction were derived from the CAISO's PLEXOS model and Import Allocation process, and further 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 2022 WECC Path Rating catalog. 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. Current transmission path settings between modeled regions in SERVM are posted to the CPUC website.[30] The following illustrative map shows some of the modeled transmission paths in SERVM with some paths modeled as one-way and some as bi-directional.

[30] https://files.cpuc.ca.gov/energy/modeling/2023PSP/RegionTransfer.csv

*Figure 5 – Illustrative Map Showing Abstraction of Transmission Between Regions into Directional Path Limits*


## 4.5.1 Import and Export Constraints

In addition to the physical underlying transmission topology and individual path limits programmed into SERVM, staff uses simultaneous net import and export constraints on the CAISO region. The export constraint is included to model uncertainty in the size of the future potential market for California's exports of surplus renewable power and concerns about whether dispatch patterns and import/export patterns in SERVM are realistic and predictive of future patterns. The CAISO simultaneous net export limit is set at 5,000 MW.

The import constraints are included to cap flows to historically observed levels across different seasons and hours of the day. The intent is to have the model produce realistic interchange patterns with regions neighboring the CAISO and to prevent overly optimistic leaning on other regions to support CAISO reliability. The import constraints cover specified RA imports,[31] unspecified RA imports, and economic imports, but do not cover specified imports from four specific generators. These generators are modeled as generating directly within CAISO even though located outside the CAISO. They are the CAISO LSE shares of Hoover, Intermountain Power Plant, Palo Verde, and Sutter. There are currently two import constraints used in the SERVM model. The first constraint is set at 11,040 MW, derived from CAISO RA import capability reports.[32] The second constraint caps imports at 4,000 MW in June through September from 5pm to 10pm.

Staff are currently conducting analysis of more recent data and revising both import and export constraints. Staff are also creating two scenarios of shaped simultaneous import and export constraints by analyzing recent CAISO data from OASIS and from LSE RA filings that listed firm RA contracted imports. The final version of this document will fully describe the revised constraints to be used in 2024 RA studies.

### 4.5.2 Hurdle Rates

SERVM incorporates hurdle rates for transfers between regions that are intended to capture the transactional friction to trade energy across neighboring transmission systems. Hurdle rates were derived from the CAISO's PLEXOS model and supplemented with information from the CEC's PLEXOS model. Values have been updated to reflect 2022 dollars. Hurdle rates in SERVM do not include any carbon pricing. Instead, carbon prices are assumed to apply to all emitting generators in the model, inside and outside California, uniformly.

## 4.6 Fuel Costs

Monthly natural gas price inputs are derived from the preliminary 2023 IEPR burner tip price estimates from the CEC's North American Market Gas-trade (NAMGas) model runs.[33] SERVM simulates each region individually, and burner tip prices by hub are utilized directly in the model. Individual power plants are linked to their applicable fuel hub from the NAMGas model and monthly commodity price forecasts as well as fuel transportation rates are applied to the production cost of the generator. The 2023 vintage of natural gas price forecast has data

[31] Specified RA imports are modeled in SERVM as "remote" generators, meaning units physically located in one region but contracted for energy and capacity to another region.

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

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

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.[34] Fuel transportation costs are also sourced from the 2023 NAMGas model. The mid scenario will be used as the default fuel costs. Coal and uranium prices are updated using the forecasted prices in the 2023 Annual Energy Outlook[35] using data in that document's Table 3.9 for the Pacific zone and Table 3.8 for the Mountain zone. In SERVM nuclear power plants are currently modeled as a must-run resource;[36] 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.[37]

### 4.6.1 Emissions Price Forecast

Staff intends to be able to model emissions prices to affect the cost of dispatching emitting generation. The GHG Price Projection associated with the CEC's 2023 IEPR Demand Forecast will be used.

# 5. Resource Adequacy Modeling

## 5.1 Overview

The CPUC uses SERVM for resource adequacy and reliability studies across multiple proceedings.[38] In the CPUC's IRP proceeding context, the RESOLVE capacity expansion model and SERVM are used together to develop and test optimal portfolios to ensure that the CAISO system reliability level does not exceed 0.1 day per year Loss of Load Expectation (LOLE), equivalent to satisfying the Commission's 1-day-in-10-year reliability standard in the IRP proceeding. SERVM is used to measure the amount of effective capacity required to meet the 0.1 LOLE reliability standard in the CAISO system. The required level of effective 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

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

[35] Annual Energy Outlook 2023. https://www.eia.gov/outlooks/aeo/

[36] 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.

[37] https://www.energy.gov/sites/default/files/2018/11/f57/robi-biomass.pdf

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

calculated in SERVM. The resulting portfolios are then retested in SERVM to verify they still meet the 0.1 LOLE reliability standard.

In the CPUC's Resource Adequacy (RA) proceeding context, SERVM is used to conduct annual reliability assessments that complement the Slice-Of-Day and monthly Planning Reserve Margin frameworks. SERVM can be used to support ongoing reform under consideration in the RA proceeding, including whether north and south of Path 26 RA requirements for LSEs are necessary and whether the UCAP approach to counting Qualifying Capacity should be adopted.

## 5.2 Path 26 Stress and Wheel Through Sensitivities

Reliability metrics from stochastic reliability modeling such as SERVM include LOLE as well as Expected Unserved Energy (EUE) and Loss of Load Hours (LOLH).[39] Contribution to reliability is measured in terms of ability to reduce LOLE or EUE by adding resources then rerunning the analysis. For this analysis, a 0.1 LOLE target (equivalent to one loss-of-load event every ten years) is used to determine the level of RA resources needed for adequate system reliability.

Staff will perform a Path 26 stress test for study year 2026 while also looking into the constraints that are imposed on Path 26 because of NW to SW wheel throughs. Figure 6 shows the analysis flowchart for these sensitivities. The first step would be to perform an annual LOLE study for year 2026. If LOLE is larger than 0.1, staff will add perfect capacity until LOLE <= 0.1. This is to establish a reference system calibrated to the 0.1 LOLE target reliability that will be the basis to compare sensitivity results against.

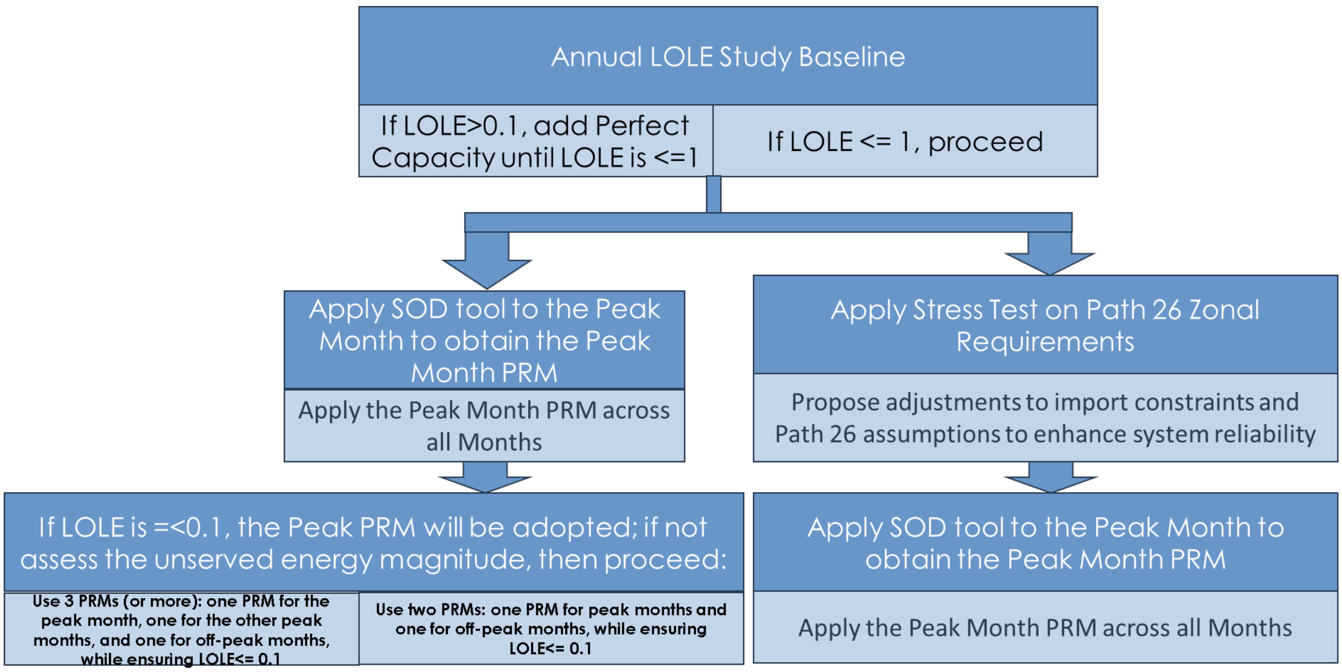
### 5.2.1 Path 26 Stress Test Process

Figure 6 illustrates Staff's proposed order of studies to complete the proposed sensitivities for both Slice of Day (SOD) requirements and Path 26 analysis. Staff begin with the assumption that an efficient CAISO system would have LOLE equal in both the north and south sides of the system, and equalizing LOLE in all parts of CAISO would ultimately minimize need for additional reliability resources by preventing congestion that can trap capacity on one side of Path 26 making it unavailable to meet LOLE events on the other side. Staff will start the study by running SERVM for a LOLE study for year 2026 using only the existing baseline of resources, and no planned or generic resources. If necessary, PCAP will be added to achieve a 0.1 LOLE and that amount will be documented and published for stakeholders. After the initial annual LOLE study is completed, staff will study sensitivities to assess the impact of imbalance or congestion

[39] LOLE equals the expected number of loss-of-load events, regardless of length, in a given year. LOLH equals the expected number of hours with loss-of-load in a year. EUE equals the total MWh of unserved energy in a year. LOLE is a measure of frequency, not duration or magnitude. LOLH is a measure of duration, not frequency or magnitude. EUE is a measure of magnitude, not frequency or duration.

on Path 26 on overall CAISO LOLE. In the event of an imbalance in LOLE between PGE and SCE areas, staff will increase the path rating on Path 26 to facilitate greater transfers. This increase in the path rating will be documented and reported to stakeholders. Average purchases and Binding Hours resulting from these simulations will be statistically analysed to check conformity with LOLE capacity increase/decrease for each region. All modelled regions will be tuned towards 0.1 LOLE target in an attempt to equalize reliability level across regions and model realistic transfer amounts between regions.

*Figure 6: Stress test flow chart including Path 26 sensitivity*




### 5.2.2 Wheel-Through Arrangement Stress Test Process

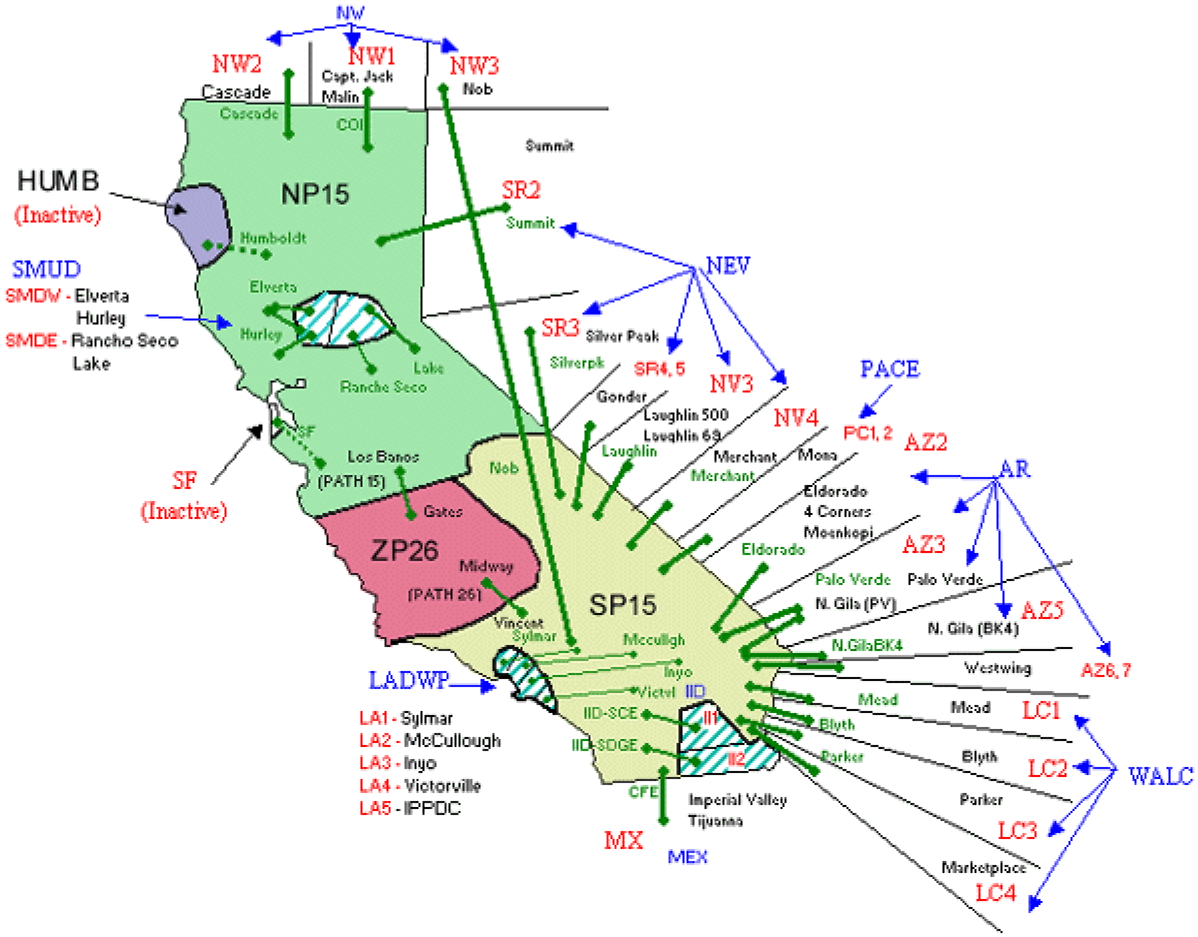
Wheel-Through stress tests are done by adding remote generators that are forced into CAISO areas and forced to flow across Path 26. By this method, these flows would potentially illustrate the congestion that wheel-throughs from NW to SW would create. Available Transfer Capability (ATC) data from the CAISO will be used as the source for wheel-through assumptions (https://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx). Each region's LOLE will be analyzed during this stress test.

Subsequent to the Path 26 sensitivity, Staff then plans to do a sensitivity analysis to better understand the impact that wheel-through transactions, utilizing the Path 26 transmission line, have specifically in creating congestion across Path 26 and exacerbating LOLE in CAISO. In the past few years the number of wheel-throughs flowing North to South over Path 26 have steadily increased. Staff is concerned that oversubscription of Path 26 may increase the planning reserve margin for CPUC LSEs – increasing the reliability cost to meet a 0.1 LOLE standard.

To model this sensitivity, Staff is using historical data from CAISO that appears to illustrate a firm wheel-through arrangement from August 2023 posted on CAISO's reliability requirements website.[40] Staff is only modeling the MWs that are coming in at Malin and Malin/Nob, equal to 1,050 MW, as these amounts reflect the amount of MWs that will flow over path 26 and have sinks at Palo Verde and Mead. Other wheel-through arrangements may exit CAISO via other paths that do not create this type of congestion. Via this sensitivity CPUC staff are analyzing the impact of these wheel-through arrangements like this, and assessing if they complicate existing congestion on Path 26 or exacerbating previously identified reliability constraints. If these arrangements prevent efficient and reliable operation of the CAISO grid, or necessitate a different plan to accomplish resource adequacy, the CPUC may adopt further requirements to mitigate the effect of increased Path 26 congestion.

[40] https://www.caiso.com/Documents/PriorityWheelingThroughTransactionsData.xlsx

*Figure 7 – Illustration of Paths Between California and Neighbors, and within California*




# 6. Emissions Accounting

## 6.2 Greenhouse Gas Accounting

Greenhouse gas (GHG) emissions attributable to entities within the CAISO footprint are tracked using a method consistent with the California Air Resources Board's (CARB) regulation of the electric sector under California's cap & trade program.

### 6.2.1 CAISO Internal Generators

The annual emissions of generators within the CAISO are calculated 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. Generators internal to CAISO are tracked individually and emissions are calculated based on their actual dispatch as all generation from these generators serves CAISO demand.

### 6.2.2 CAISO Imports

Emissions for generation external to CAISO and imported into CAISO is given a 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[41]—a rate slightly higher than the emissions rate of a combined cycle gas turbine.

Specified imports (called direct purchases in SERVM) to CAISO are modeled as balancing CAISO load, therefore any emissions associated with specified imports are included with emissions associated with CAISO generators. Most of the specified imports to CAISO are non-emitting resources, though imports from the coal-fired Intermountain Power Plant are simulated through the mid-2020s.

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 as a reduction in annual electricity supply GHG emissions based on an estimate of hydro generation imported as part of the total unspecified import total. 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.[42] No distinction is made between hydro and other imports from the Pacific Northwest. In other words, hydro imports are combined with unspecified imports. During post processing for calculating GHG emissions, SERVM will use the RESOLVE assumed amount of specified hydro import from the Pacific Northwest to debit from SERVM unspecified imports.

### 6.2.3 BTM CHP Accounting

CARB Scoping Plan electric sector emissions accounting includes emissions from behind-the-meter CHP generation. BTM CHP is represented as a load reduction in SERVM, and therefore emissions from BTM CHP are not explicitly modeled (no fuel is burned in the model corresponding to BTM CHP). To be consistent with CARB's Scoping Plan accounting conventions, staff will estimate BTM CHP emissions from the 2023 IEPR forecast of BTM CHP generation and combine that with modeled emissions from all other generation to determine the GHG emissions total attributed to the CAISO footprint.

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[41] Rules for CARB's Mandatory Greenhouse Gas Reporting Regulation are available here: https://ww2.arb.ca.gov/mrr-regulation

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

## 6.3 Criteria Pollutants Accounting

### 6.3.1 Natural Gas and Coal Plants

Criteria pollutants are calculated in SERVM by dispatching power plants, tracking their emissions on startup and steady state operation, and separating emissions by technology type and operational mode. In the case of SO2 and PM 2.5, emissions are a factor of the fuel consumed, thus tracking emissions is done by tracking fuel consumed in startups and steady state operation. In the case of NOx emissions, there is a separate reaction between the combustion temperature and nitrogen in the ambient air, meaning emissions differ at different levels of operation. Thus, there are different emissions factors for different kinds of startups (cold, warm, hot) and for steady state operations. CPUC staff also report criteria pollutant results in Disadvantaged Community areas (DAC areas) so as to track impact and improvement of impact in pollution over time and IRP cycles.

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 generated.

*Table 8 – NOx emissions factors (lbs/MWh)*

| 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 9 - 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 |

### 6.3.2 Biomass and Biogas Plants

For criteria pollutant analysis, biomass plants were studied separately as the emission factors for biomass and biogas are different. For biomass, criteria pollutant emissions were calculated based on factors estimated by Argonne National Lab and included in a report issued in 2020. The report estimates emissions in g/kWh electricity generation.[43] These values represent a change from the previous IRP Inputs and Assumptions document published in 2023 and are due to ongoing research into emissions factors for electric generators.

*Table 10 - Emission Factors for Biomass (g/kWh)*

| Unit Category | Nox_ g/kWh | PM2.5_ g/kWh | SOx_ g/kWh |
|---|---|---|---|
| BIOMASS/WOOD | 0.752449 | 0.073985 | 0.060309 |

---- DOCUMENT ENDS----

[43] Argonne National Lab report linked here: https://publications.anl.gov/anlpubs/2020/09/162084.pdf

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