Release Notes for WECC 2024 Common Case

Accompanies WECC 2024 Common Case, Version 1.5

WECC System Adequacy Planning (SAP) Department

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155 North 400 West, Suite 200

Salt Lake City, Utah 84103-1114

Table of Contents

Forward

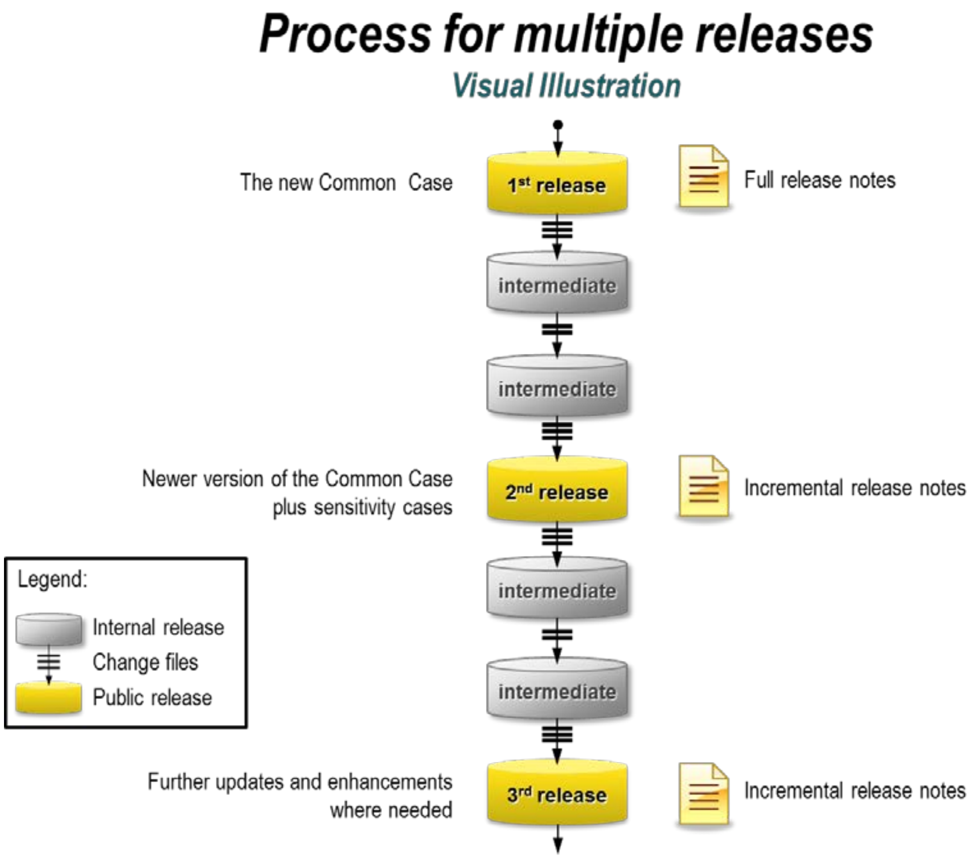
The Common Case is a production cost model (PCM) that serves as the "expected future," 10-year study scenario for the Transmission Expansion Planning Policy Committee (TEPPC). The case represents the trajectory of recent Western Interconnection planning information, developments and policies looking out 10 years. TEPPC stakeholders assisted the WECC Transmission Expansion Planning (TEP) Department in developing the thousands of assumptions that depict the Western Interconnection and how it is expected to change over the next 10 years.

A primary goal in developing a Common Case is to define a realistic foundation for the rest of the 10-year studies. Thus, the 2024 Common Case serves as the starting point for the other 10-year studies conducted as part of the 2013 and 2014 TEPPC Study Programs. The case is also used throughout the Western Interconnection for a number of purposes, including: FERC Order 890 and 1000 planning studies by subregions, independent developer studies, market studies (e.g., Energy Imbalance Market) and integration studies, among many others.

These release notes accompany the 2024 Common Case. The purpose of the release notes is to provide transparency and explanation of the assumptions and modeling in the Common Case. These release notes effectively replace the "assumptions matrix" that was previously used.

Unlike past versions of the Common Case, the 2024 Common Case will feature multiple public versions, each having improvements over the last. This process and its relation to the release notes are illustrated in Figure 1. The first version of the Common Case is released with a significant set of accompanying release notes (this document) that attempts to document all assumptions in the dataset. Subsequent versions will also be posted with release notes; however, these notes are limited to summarizing and explaining the incremental changes between the current and previous dataset releases. The frequency of dataset releases will be determined by need and significance of dataset improvements.

Figure 1. Common Case Version Release Process



The 2024 Common Case is housed and maintained in GridView, which is an energy market simulation and analysis software tool distributed by ABB. ABB GridView (GridView or GV) uses a Microsoft Access database file (GV Case Template.mdb) and numerous text-based shape files (*.DAT) to store the 2024 Common Case information. All of these files are human-readable.

All cost values in this document are expressed in 2014 dollars (2014$ or $).

Electric Topology

TEPPC Load Areas

The “Load Area” topology for the 2024 Common Case is based on the large load centers and, in most cases, is analogous to the Balancing Authority (BA) boundaries or the Load-Serving Entity (LSE) boundaries where more granularity is needed. The forty areas correlate with the load forecast granularity provided by the Loads and Resources Subcommittee (LRS), which has merged into the Reliability Assessment Work Group (RAWG). The generator-only BAs are not modeled as load areas (no load) and their generation is assigned to the closest defined load area.

TEPPC Regions

The TEPPC regions are defined at an operational level that, in most cases, corresponds to the areas listed above but with a two-character subregion added to the front of the name (e.g., the Los Angeles Department of Water and Power (LDWP) area is the CA_LDWP region). For this level, some of the distributed load centers or LSEs are consolidated to model the operational aspects associated with a BA such as hurdle rates and reserve requirements, which are explained later in this document. The regional groupings that include multiple load areas are listed in Table 1.

Table 1: Regional Groupings

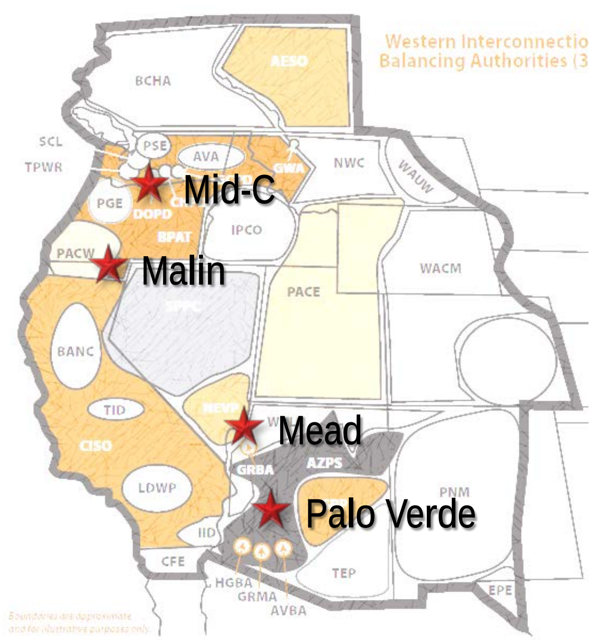
Regional Group	Area Members
BS_IPCO	IPFE, IPMV, IPTV
BS_PACE	PAID, PAUT, PAWY
CA_CISO	CIPB, CIPV, CISC, CISD, VEA
SW_NVE	NEVP, SPPC

See Figure 7 for Area definitions.

Trading Hubs

The TEPPC region level is also used to define trading hubs. There are four trading hubs in the Western Interconnection and shown in Figure 2: Mid-C, Malin, Mead and Palo Verde.

Figure 2. Trading Hubs



Currently, the 2024 Common Case models three trading hubs: Mead (SW_TH_Mead), Palo Verde (SW_TH_PV), and Malin (NW_TH_Malin). When necessary and through further efforts, the Mid-C trading hub can be modeled in a future version of the dataset.

Operationally, trading hubs are generation free-trading zones with no hurdle-rate barriers. In database modeling, the primary purpose of a trading hub is to avoid an unrealistic build-up of hurdle rate charges where large concentrations of generation in one area are committed to serve load in multiple areas.

A trading hub typically has the following characteristics:

1. A large concentration of generation resources serving multiple control areas;
2. A cluster of buses where the buses could be owned by utilities of different regions;
3. When power flows within the cluster of buses, no hurdle rates apply;
4. When power is exported out of the trading hub, no hurdle rates apply;
5. When neighboring regions export power to the trading hub, hurdle rates still apply;
6. Trading hubs are usually located at the boundaries of multiple TEPPC regions.

In database modeling, both TEPPC regions and trading hubs are modeled as regions. The differences are:

- When power is exported from a TEPPC region, hurdle rates apply.
- When power is exported from a trading hub, hurdle rates *do not* apply.

Note that in both cases, power imported into a TEPPC region or trading hub does not incur hurdle rates.

Figure 3 is a conceptual diagram of TEPPC regions with a trading hub region interfacing between them.

Figure 3. Representation of three TEPPC regions interfacing with a trading hub

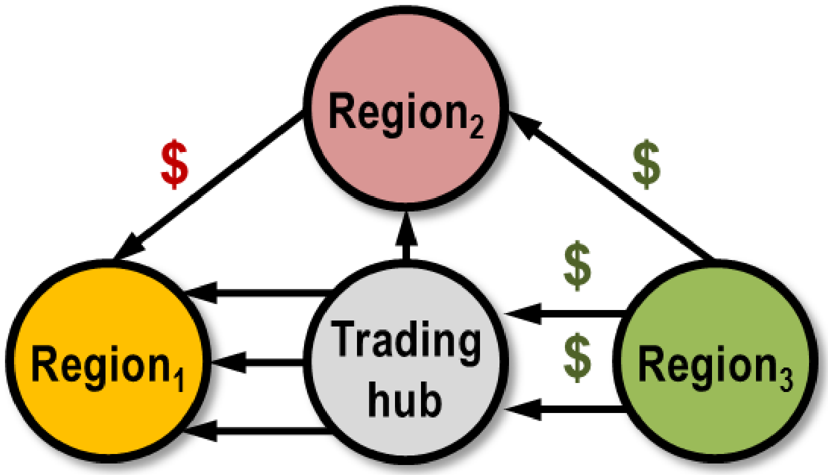


Figure 4 shows the configuration of the Palo Verde trading hub. In this trading hub, Palo Verde (Bus ID 15021) and Hassayampa (Bus ID 15090) are two central buses. For generators that are directly connected to the hub, the generation buses are also defined as a part of the trading hub. In addition to that, Jojoba (Bus ID 15089) is also included as a special addition, due to APS having transmission rights from Jojoba to Hassayampa. The Gila River generation is owned by APS and serves APS, but it would be charged twice by hurdle rates if the Jojoba bus were not included in the Palo Verde trading hub: APS-to-SRP and SRP-to-PV when Gila River supplies to APS.

Figure 4. Palo Verde Trading Hub

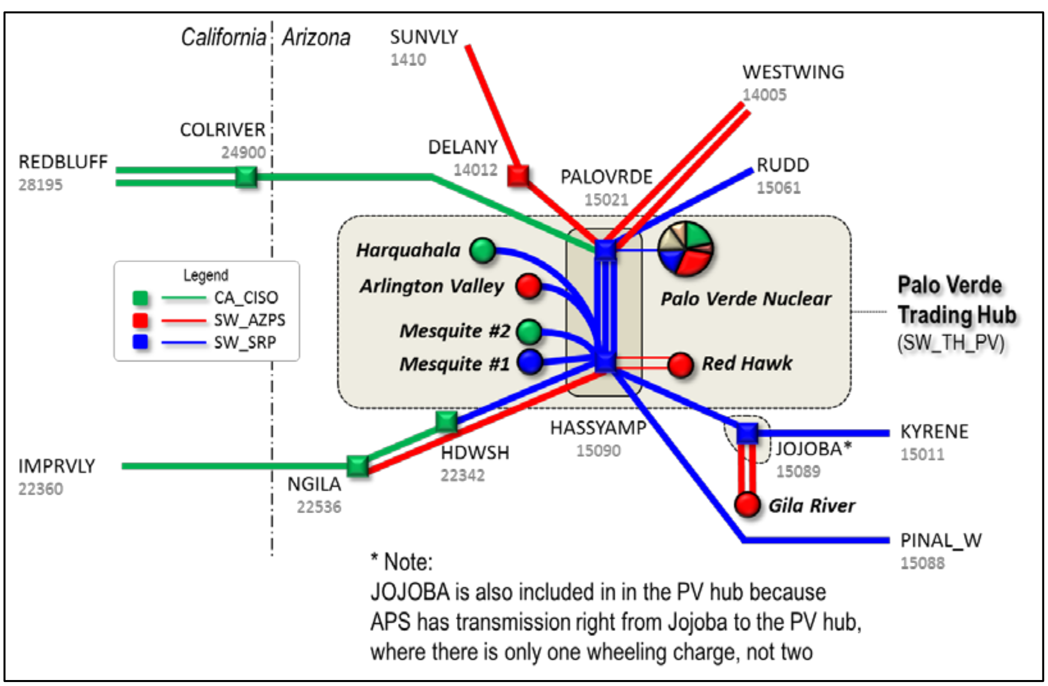


Figure 5 shows the configuration of the Mead trading hub, which consists of Mead 500-kV, 345-kV, and 230-kV buses and the Hoover Power Plant.

Figure 5. Mead Trading Hub

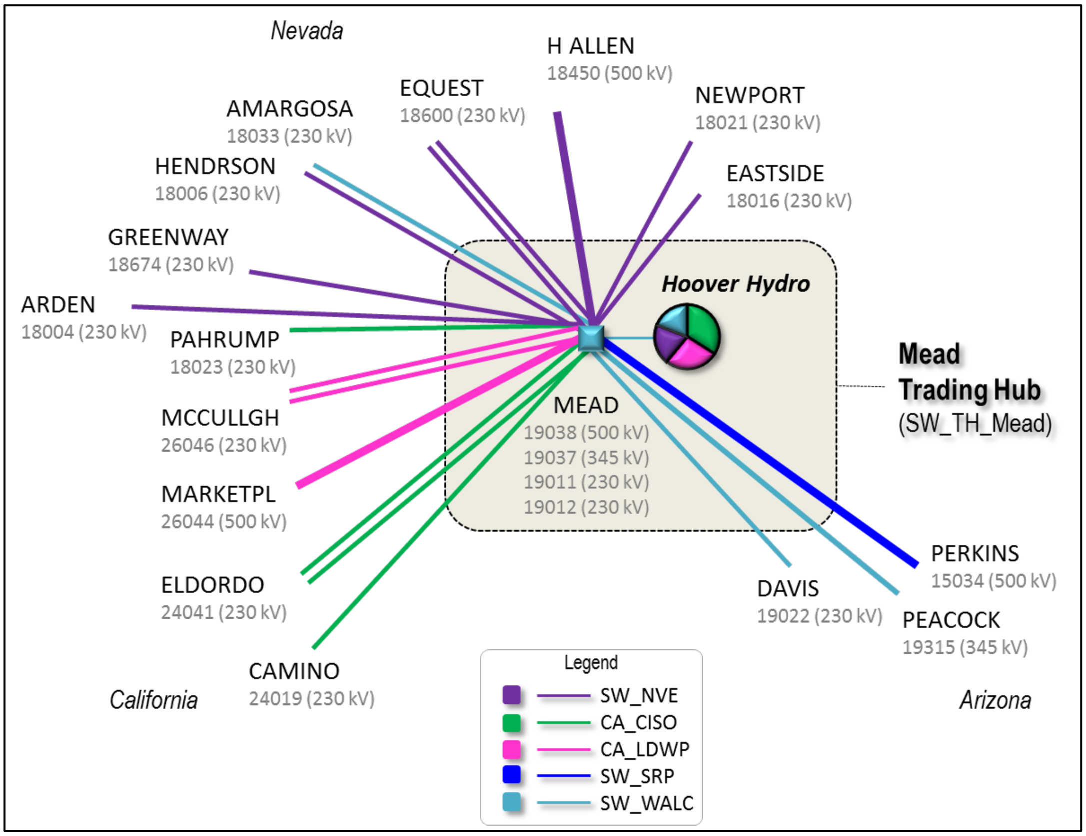
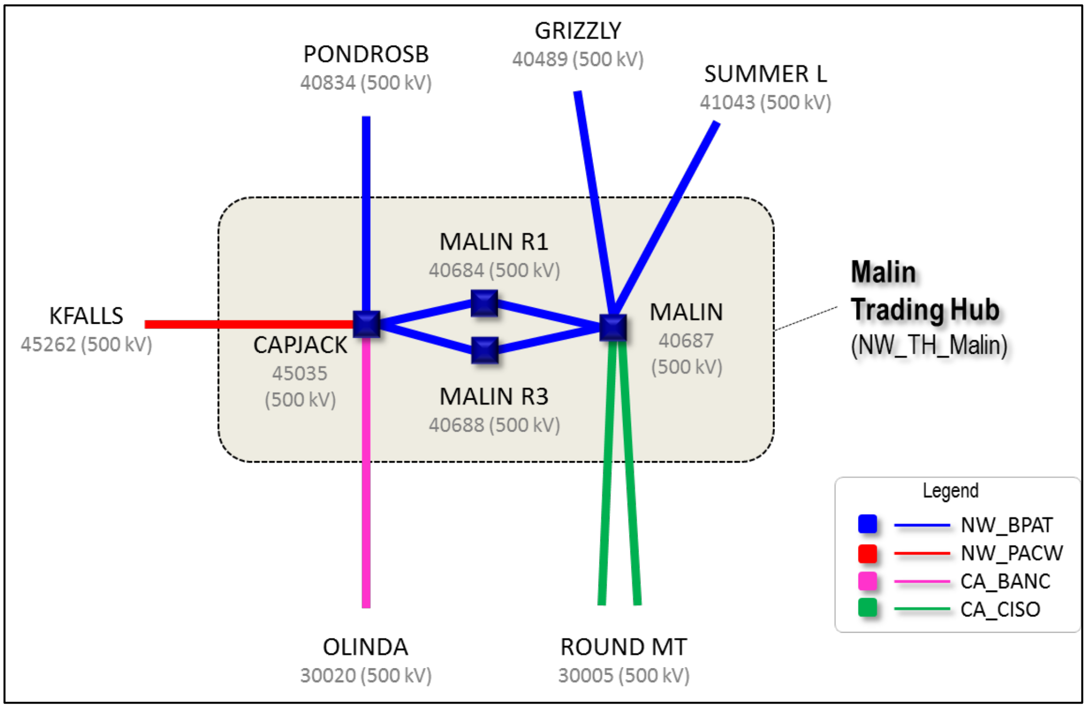


Figure 6 shows the configuration of the Malin trading hub, which consists of the 500-kV intersection of the Bonneville Power Administration, PacifiCorp West, Balancing Authority of Northern California, and the California Independent System Operator (i.e., NW_BPAT, NW_PACW, CA_BANC, and CA_CISO in the model).

Figure 6. Malin Trading Hub



Hurdle Rates

Hurdle rates represent the cost to deliver surplus energy among different regions, and they are called "Wheeling Charges" in GridView. The 2024 Common Case models hurdle rates based on three categories of charges:

1. Tariff rates: trade policy-based charges applied to power transfers between TEPPC regions.
2. Wheeling rates: charges paid to the owner of a transmission line for the right to transport power across the line.
3. Rates per model validation: interregional charges modeled to encourage reasonable interregional transfers. These are set based on stakeholder review of simulation results and their recommendations.

The tariff rates were derived from the 2013 OASIS rates posted by the applicable transmission owners as compiled by the California Independent System Operator (CAISO). Table 2 shows the interregional hurdle rates in the 2024 Common Case. These are base values and do not include additional charges associated with the California Global Warming Initiative.

Table 2. 2024 Interregional Hurdle Rates (2014$)

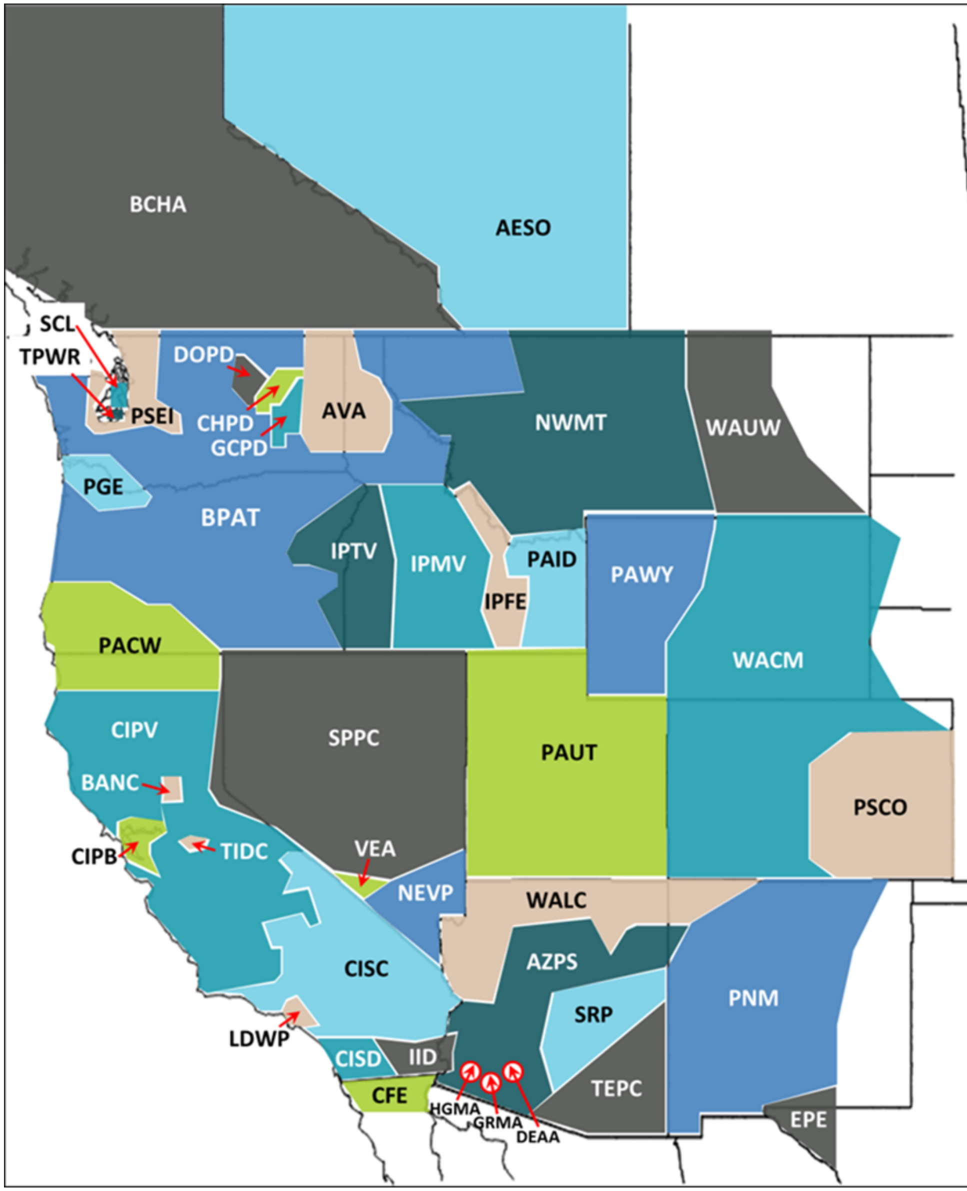
From	To	Direction →	Direction ←	From	To	Direction →	Direction ←
AB_AESO	BC_BCHA	$3.05	$9.10	SW_AZPS	CA_CISO	$3.86	$9.96
AB_AESO	NW_NWE+	$2.09	$4.63	SW_AZPS	CA_IID	$3.86	$4.07
NW_AVA	NW_BPAT+	$2.47	$1.87	SW_AZPS	CA_LDWP	$3.86	$5.71
NW_AVA	NW_PACW	$2.47	$3.01	SW_AZPS	SW_PNM	$3.86	$4.07
NW_AVA	NW_PGE	$2.47	$2.47	SW_AZPS	SW_SRP	$3.86	$1.97
NW_BPAT+	BC_BCHA	$1.87	$6.95	SW_AZPS	SW_TEPC	$3.86	$3.49
NW_BPAT+	CA_BANC+	$1.87	$2.47	SW_AZPS	SW_WALC	$3.86	$1.86
NW_BPAT+	CA_CISO	$1.87	$9.96	SW_NVE	CA_CISO	$6.81	$9.96
NW_BPAT+	CA_LDWP	$1.87	$5.71	SW_NVE	CA_LDWP	$6.81	$5.71
NW_BPAT+	NW_PACW	$1.87	$3.01	SW_NVE	SW_WALC	$6.81	$1.86
NW_BPAT+	NW_PGE	$1.87	$2.47	SW_PNM	SW_EPE	$4.07	$4.07
NW_BPAT+	NW_PSEI	$1.87	$2.47	SW_PNM	SW_WALC	$4.07	$1.86
NW_BPAT+	SW_NVE	$1.87	$6.81	SW_SRP	CA_CISO	$1.97	$9.96
NW_NWE+	BS_PACE	$4.63	$3.01	SW_SRP	SW_TEPC	$1.97	$3.49
NW_NWE+	NW_AVA	$4.63	$2.47	SW_SRP	SW_WALC	$1.97	$1.86
NW_NWE+	NW_BPAT+	$4.63	$1.87	SW_TEPC	SW_EPE	$3.49	$4.07
NW_NWE+	RM_WACM	$4.63	$4.87	SW_TEPC	SW_PNM	$3.49	$4.07
NW_PACW	CA_CISO	$3.01	$9.96	SW_WALC	CA_CISO	$1.86	$9.96
NW_PACW	NW_PGE	$3.01	$2.47	SW_WALC	CA_IID	$1.86	$4.07
BS_IPCO	NW_AVA	$2.61	$2.47	SW_WALC	CA_LDWP	$1.86	$5.71
BS_IPCO	NW_BPAT+	$2.61	$1.87	SW_WALC	SW_TEPC	$1.86	$3.49
BS_IPCO	NW_PACW	$2.61	$3.01	CA_CISO	CA_BANC+	$9.96	$2.47
BS_IPCO	NW_PGE	$2.61	$2.47	CA_IID	CA_CISO	$4.07	$9.96
BS_IPCO	SW_NVE	$2.61	$6.81	CA_LDWP	CA_CISO	$5.71	$9.96
BS_PACE	BS_IPCO	$3.01	$2.61	SW_TH_PV	CA_CISO	$0.00	$9.96
BS_PACE	CA_LDWP	$3.01	$5.71	SW_TH_PV	SW_AZPS	$0.00	$3.86
BS_PACE	RM_WACM	$3.01	$4.87	SW_TH_PV	SW_SRP	$0.00	$1.97
BS_PACE	SW_AZPS	$3.01	$3.86	SW_TH_Mead	SW_WALC	$0.00	$1.86
BS_PACE	SW_NVE	$3.01	$6.81	SW_TH_Mead	SW_NVE	$0.00	$6.81
BS_PACE	SW_WALC	$3.01	$1.86	SW_TH_Mead	SW_AZPS	$0.00	$3.86
RM_PSCO	SW_PNM	$3.02	$4.07	SW_TH_Mead	SW_SRP	$0.00	$1.97
RM_WACM	RM_PSCO	$4.87	$3.02	SW_TH_Mead	CA_CISO	$0.00	$9.96
RM_WACM	SW_PNM	$4.87	$4.07	SW_TH_Mead	CA_LDWP	$0.00	$5.71
RM_WACM	SW_WALC	$4.87	$1.86	CA_CFE	CA_CISO	$2.00	$9.96

Loads

Load Data Collection and Adjustments

The 2012 WECC Loads and Resources (L&R) information, collected by the LRS of the Planning Coordination Committee (PCC), has BA-submitted load forecasts and provides the basis for the loads in the 2024 Common Case. The forecasted loads for 2023 in the 2012 L&R load forecasts were extrapolated into 2024, adjusted to exclude historical 2005 pump loads, and adjusted for energy efficiency savings from federal appliance and lighting standards determined to not be fully reflected in the L&R load forecasts. These resulting 2024 peak demand and energy forecasts were used in conjunction with 2005 historical load shapes to derive the 2024 load shapes for the areas in the 2024 Common Case. Figure 7 shows all the TEPPC load areas included the 2024 Common Case.

Figure 7. TEPPC Load Areas



TEPPC Area	Area Description
AESO	Alberta Electric System Operator
AVA	Avista
AZPS	Arizona Public Service
BANC	Sacramento Municipal District
BCHA	British Columbia Hydro
BPAT	Bonneville Power Administration
CFE	Comision Federal de Electricidad
CHPD	Chelan Co PUD
CIPB	Pacific Gas & Electric Bay Area
CIPV	Pacific Gas & Electric Valley Area
CISC	Southern California Edison
CISD	San Diego Gas & Electric
DOPD	Douglas Co PUD
EPE	El Paso Electric
GCPD	Grant Co PUD
IID	Imperial Irrigation District
IPFE	Far East (Idaho Power)
IPMV	Magic Valley (Idaho Power)
IPTV	Treasure Valley (Idaho Power)
LDWP	Los Angeles Dept of Water & Power
NEVP	Nevada Power
NWMT	Northwestern Montana
PACW	PacifiCorp West
PAID	PacifiCorp East – Idaho
PAUT	PacifiCorp East – Utah
PAWY	PacifiCorp East - Wyoming
PGE	Portland Gen Electric
PNM	Public Service New Mexico
PSCO	Public Service Colorado (Xcel)
PSEI	Puget Sound Energy
SCL	Seattle City Light
SPPC	Sierra Pacific Power
SRP	Salt River Project
TEPC	Tucson Electric Power
TIDC	Turlock Irrigation District
TPWR	Tacoma Power
VEA	Valley Electric Association
WACM	Western Area Power Admin Colorado/Missouri
WALC	Western Area Power Admin Lower Colorado
WAUW	Western Area Power Admin Upper Missouri
N/A	DECA, LLC - Arlington Valley (DEAA)
N/A	Gila River Maricopa Arizona (GRMA)
N/A	Harquahala L.L.C. (HGMA)

Area-Level Loads

Area-level peak (megawatts) and energy (gigawatt-hours) loads used in the 2024 Common Case are shown in Table 3. For 10-year studies performed in the hourly production cost model environment, load is defined by specifying monthly peak (megawatts) and energy (megawatt-hours) for each of the TEPPC load bubbles. From there, GridView uses a historical or generic hourly load shape to create an 8,784-hour load profile for each load area. This 8,784-hour load profile is a defined load level, in megawatts, for each load area for every hour of the study year. This level of detail is necessary for the hourly production cost model to perform its optimization. For the 2024 studies, TEP used 2005 historical hourly load shapes to create the synthetic 2024 hourly profiles in GridView, which are stored in "Load_*.dat" files. During the production cost simulation, each area's hourly load is disaggregated to load busses within each TEPPC Load Area based on a defined bus load distribution, which results in an hourly load for each load bus in the Western Interconnection. The default bus load distribution is set by the power flow model within the 2024 Common Case; however, multiple power flow cases were used to set the final bus load distribution. Refer to the Seasonal Bus Distribution Power Flow Documentation sections for more details on the bus load distribution and power flow model, respectively.

Table 3. Area Native Loads, excluding pump loads

Area	Energy (GWh)	Peak (MW)	Area	Energy (GWh)	Peak (MW)	Area	Energy (GWh)	Peak (MW)
AESO	113234	15795	IPMV	5055	1160	CISC	114706	25689
AZPS	37184	8831	NEVP	28852	6731	SCL	10636	1867
AVA	14629	2503	NWMT	11923	1855	CISD	25819	5374
BCHA	68154	12296	PAID	4299	1162	BANC	18492	4073
BPA	63752	11836	PAUT	31396	7070	SPPC	15426	2385
CFE	14985	3151	PAWY	10914	1659	SRP	40246	8827
CHPD	4226	755	PACW	22297	4083	TEPC	16624	3813
DOPD	1892	406	CIPB	52214	9597	TIDC	3078	724
IPFE	10786	2317	CIPV	65452	14055	TPWR	5566	1041
EPE	2610	525	PGE	25014	4426	IPTV	11006	2328
GCPD	5036	804	PNM	16076	3057	WACM	33425	5616
IID	4646	1287	PSCO	40016	7909	WALC	12945	2292
LDWP	33317	7584	PSEI	27072	5500	WAUW	750	146

Energy Efficiency (EE) Adjustment

As part of the 2012 LRS data request, BAs were asked to provide projections of the EE program savings incorporated into their LRS load forecast. Lawrence Berkley National Laboratory (LBNL) reviewed these EE savings projections and, with input from the Modeling Work Group (MWG) participants and other state and regional EE experts, assessed the consistency of these projections with applicable statutory and regulatory policies, recent utility integrated resource plans and utility DSM program plans.

LBNL then communicated with load forecasting staff at many of the individual BAs to: 1) clarify any ambiguities in the savings projections submitted through the LRS request; 2) discuss any apparent discrepancies between the submitted savings projection and what would be expected under current policies and program plans; and 3) confirm whether the 2012 LRS load forecasts fully accounted for the expected EE program savings. If the savings projection provided by a BA differed significantly from the expected amount or if the load forecast did not fully account for the BA's savings projection, then the LRS load forecast was adjusted downward accordingly. Table 4 and Table 5 outline EE adjustments by area, expressed as a percent reduction from load.

Table 4. EE Adjustments to Monthly Energy (Percent of L&R Firm + Non-Firm Load)

Load Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
CIPB	-3.9%	-3.9%	-3.9%	-3.9%	-3.9%	-3.9%	-3.9%	-3.9%	-3.9%	-3.9%	-3.9%	-3.9%	-3.9%
CIPV	-3.9%	-3.9%	-3.9%	-3.9%	-3.9%	-3.9%	-3.9%	-3.9%	-3.9%	-3.9%	-3.9%	-3.9%	-3.9%
CISC	-4.0%	-4.0%	-4.0%	-4.0%	-4.0%	-4.0%	-4.0%	-4.0%	-4.0%	-4.0%	-4.0%	-4.0%	-4.0%
CISD	-3.3%	-3.3%	-3.3%	-3.3%	-3.3%	-3.3%	-3.3%	-3.3%	-3.3%	-3.3%	-3.3%	-3.3%	-3.3%
IPFE	-3.5%	-3.9%	-4.2%	-4.5%	-4.5%	-4.0%	-3.5%	-3.6%	-4.0%	-4.4%	-4.0%	-3.3%	-3.9%
IPMV	-3.5%	-3.9%	-4.2%	-4.5%	-4.5%	-4.0%	-3.5%	-3.6%	-4.0%	-4.4%	-4.0%	-3.3%	-3.9%
IPTV	-3.5%	-3.9%	-4.2%	-4.5%	-4.5%	-4.0%	-3.5%	-3.6%	-4.0%	-4.4%	-4.0%	-3.3%	-3.9%
PNM	-4.3%	-4.9%	-4.7%	-4.9%	-4.5%	-4.2%	-3.9%	-4.0%	-4.5%	-4.6%	-4.6%	-4.2%	-4.4%
TEPC	-1.2%	-1.2%	-1.2%	-1.2%	-1.0%	-0.9%	-0.9%	-0.9%	-1.1%	-1.3%	-1.4%	-1.3%	-1.1%

Table 5. EE Adjustments to Monthly Peak (Percent of L&R Firm + Non-Firm Load)

Load Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
CIPB	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%
CIPV	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%
CISC	-4.1%	-4.1%	-4.1%	-4.1%	-4.1%	-4.1%	-4.1%	-4.1%	-4.1%	-4.1%	-4.1%	-4.1%	-4.1%
CISD	-3.8%	-3.8%	-3.8%	-3.8%	-3.8%	-3.8%	-3.8%	-3.8%	-3.8%	-3.8%	-3.8%	-3.8%	-3.8%
IPFE	-3.5%	-3.9%	-4.2%	-4.5%	-4.5%	-4.0%	-3.5%	-3.6%	-4.0%	-4.4%	-4.0%	-3.3%	-3.8%
IPMV	-3.5%	-3.9%	-4.2%	-4.5%	-4.5%	-4.0%	-3.5%	-3.6%	-4.0%	-4.4%	-4.0%	-3.3%	-3.8%
IPTV	-3.5%	-3.9%	-4.2%	-4.5%	-4.5%	-4.0%	-3.5%	-3.6%	-4.0%	-4.4%	-4.0%	-3.3%	-3.8%
PNM	-4.3%	-4.9%	-4.7%	-4.9%	-4.5%	-4.2%	-3.9%	-4.0%	-4.5%	-4.6%	-4.6%	-4.2%	-4.0%
TEPC	-0.9%	-0.9%	-1.2%	-0.5%	-0.5%	-0.6%	-0.6%	-0.7%	-0.8%	-0.8%	-0.8%	-1.4%	-0.9%

Table 6 and Table 7 show the total EE adjustment removed from each areas forecast.

Table 6. Total EE Adjustments to Monthly Peak (megawatts)

Load Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CIPB	411.17	394.39	378.71	393.05	441.18	480.25	502.70	502.70	436.90	394.29	402.36	425.60
CIPV	485.17	485.22	480.60	502.29	570.90	700.44	774.83	775.97	688.77	482.98	472.36	509.41
CISC	691.66	677.61	683.88	758.37	900.64	981.57	1066.13	1137.40	1051.00	876.43	734.99	751.80
CISD	126.73	123.21	123.55	135.73	162.18	178.90	196.19	211.28	193.50	159.76	131.84	138.95
IPFE	12.81	13.48	13.15	13.11	19.41	21.37	18.86	16.55	16.57	13.82	13.52	12.25
IPMV	22.19	23.33	23.31	25.72	41.81	46.94	41.67	38.00	34.84	25.46	22.96	21.78
IPTV	60.85	62.60	62.71	64.76	90.63	88.62	83.61	80.69	79.65	68.99	64.81	60.04
PNM	110.02	120.52	110.75	113.74	116.02	123.57	114.37	127.20	119.92	110.23	119.47	110.52
TEPC	22.03	20.51	29.25	15.33	17.61	22.93	24.89	25.13	24.08	20.34	18.16	34.68

Table 7. Total EE Adjustments to Monthly Energy (gigawatt-hours)

Load Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CIPB	180.62	163.64	176.50	165.54	172.18	174.20	184.11	184.62	177.31	175.14	172.22	184.93
CIPV	208.68	184.37	205.32	206.97	237.88	255.40	298.22	288.83	250.63	224.86	206.11	219.45
CISC	384.56	350.34	383.45	380.05	411.19	430.85	500.15	502.59	462.50	419.15	380.91	394.42
CISD	74.18	66.63	71.11	68.90	71.54	71.87	81.46	85.17	79.06	75.72	70.94	75.55
IPFE	8.28	7.76	8.51	8.38	9.91	10.38	10.30	9.24	8.75	8.44	8.11	8.29
IPMV	14.43	13.56	14.58	15.00	20.22	22.42	22.67	21.35	18.31	14.75	13.92	14.42
IPTV	35.59	32.44	35.15	35.89	39.72	39.95	42.81	42.58	37.02	36.16	34.46	36.00
PNM	61.80	61.39	61.56	61.64	61.85	62.04	62.25	62.29	61.95	61.89	62.03	62.28
TEPC	14.91	12.80	13.80	13.31	14.39	15.55	17.19	17.67	17.10	16.70	16.01	17.04

Pumping Loads

The individual BAs included pumping loads in their L&R information data submittals. The 2024 Common Case models these pumps as generators that have both a positive and negative output. Modeling pumping load as a generator requires that the pumping loads be removed from the BA load forecast. Table 8 notes the reduction in energy (gigawatt-hours) and peak (megawatts) to the area-level load that contains pumping load. TEP used 2005 historical data to create the reductions in peak and energy.

Table 8. Area-level Pumping Load, Peak (megawatts) and Energy (gigawatt-hours)

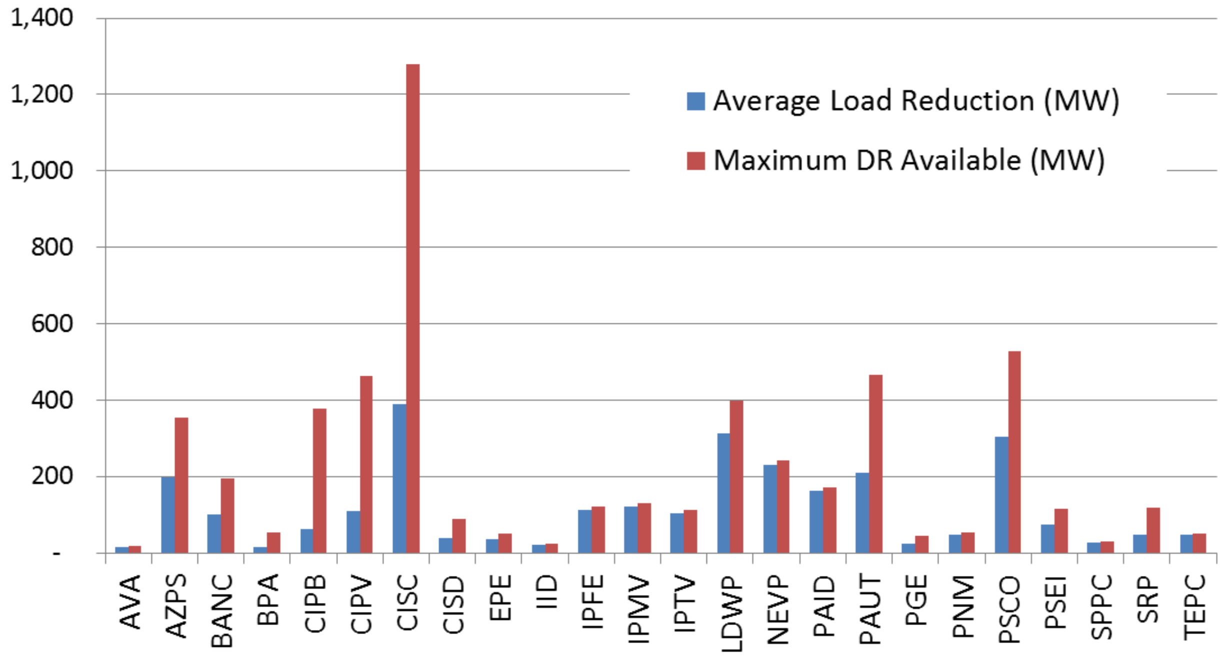
Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CIPV Pump Peak (MW)	496	683	618	690	717	731	738	761	727	702	675	611
CIPV Pump Energy (GWh)	183	216	201	285	214	332	435	378	330	329	281	292
CISC Pump Peak (MW)	961	1028	1113	1250	1231	1251	1250	1209	1215	1214	1240	941
CISC Pump Energy (GWh)	218	334	328	550	506	609	739	609	580	624	584	476
BANC Pump Peak (MW)	86	101	102	56	37	91	93	102	87	93	87	99
BANC Pump Energy (GWh)	61	50	48	29	16	57	63	63	61	62	60	62

Demand Response

Demand Response (DR) is defined as being customer reduction in electricity usage, such that the reduction differs from the customer’s normal consumption patterns and is in response to price changes or incentive payments designed to lower electricity use at times of system stress or high market prices.

Demand Response is modeled as an hourly resource that is fed directly into the model. To develop the hourly DR profiles WECC has used the LBNL Dispatch Tool. The tool requires three user-defined inputs: 1) maximum monthly DR capacity for each (non-interruptible) DR program type and BA; 2) hourly energy load for each BA; and 3) hourly locational marginal prices (LMP) for each BA from GridView. Figure 8 shows the amount of DR reduction to load in the 2024 Common Case dataset as well as the total amount of DR in each BA.

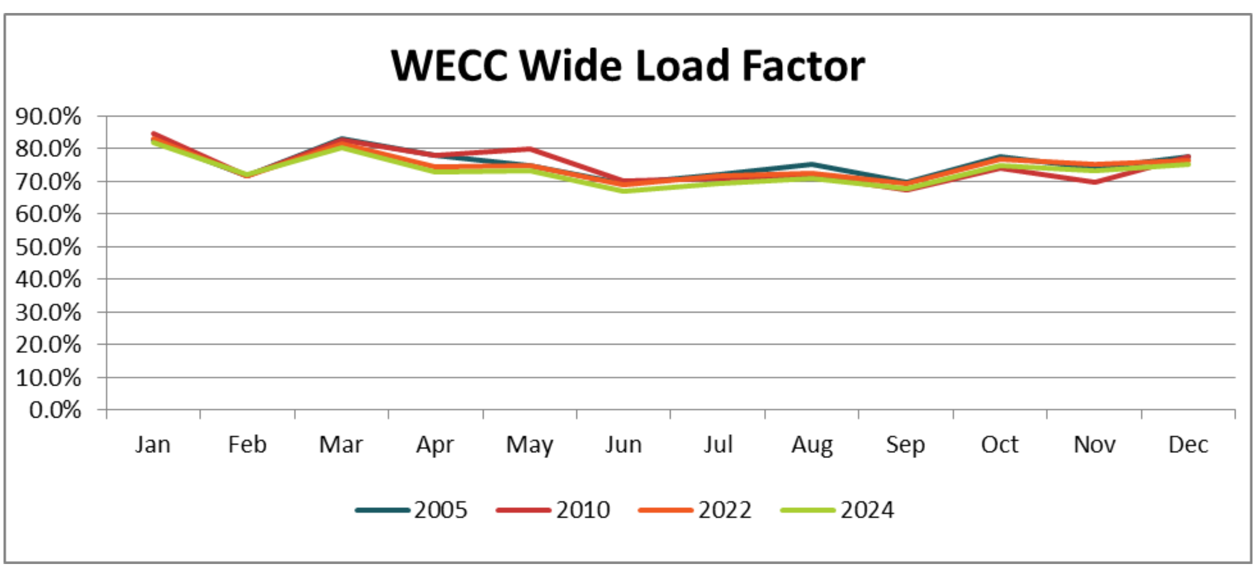
Figure 8. Average Load Reduction and DR Resource Size



Load Factor

Load Factor is defined as the ratio of an area's average load to its maximum load over the same time period. A high load factor indicates that power usage is relatively constant. A low load factor can indicate that occasionally a high demand is set for that given area. Figure 9 shows the 2024 Common Case's Interconnection-wide load factor using non-coincident peak load, benchmarked against 2005 and 2010 historical, and the 2022 Common Case load factors.

Figure 9. WECC Load Factor using Non-Coincident Peak Load



Station Service Loads

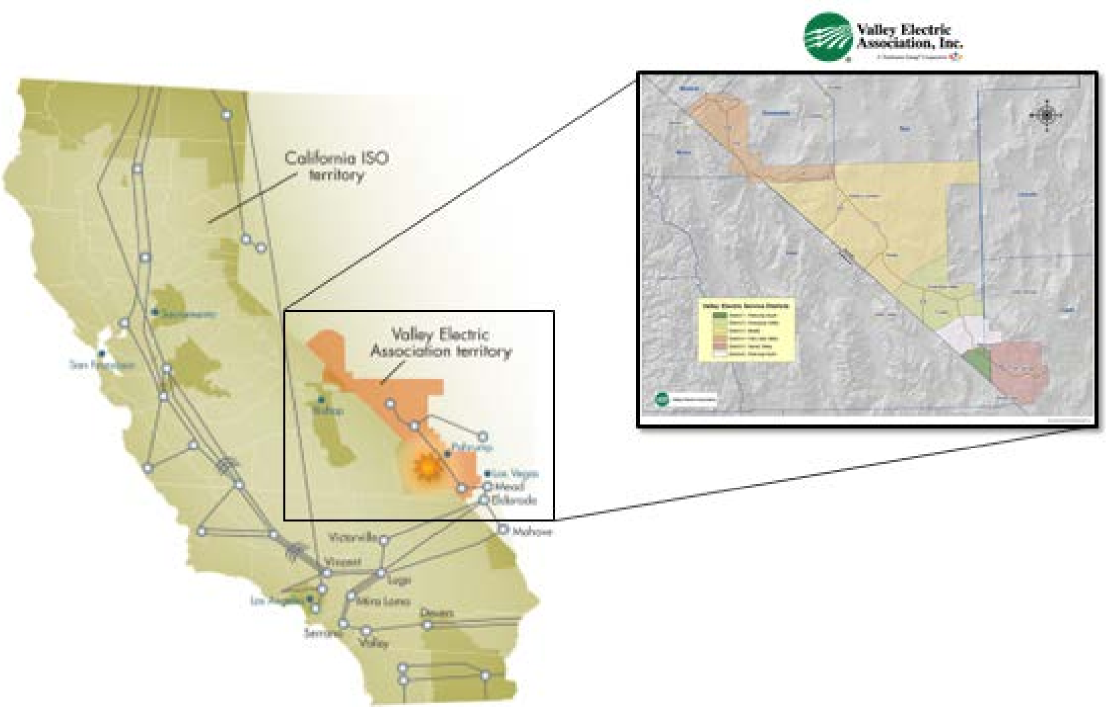
A power plant's station service load consists of all demand within the power plant facility—i.e., local to the facility's generators. The station service loads modeled in the power flow case are included in the 2024 Common Case; however, they are currently set to zero. This assumes the L&R load forecasts do not include station service loads and monthly generator capacity de-rates account for station service in all seasons. Refer to the Resource Modeling Overview section for more details about the monthly generator capacity de-rates and the Power Flow Documentation section for more information about the power flow case used in the 2024 Common Case.

Load Modeling Enhancements

Addition of VEA Load Area

Valley Electric Association (VEA) joined the CAISO on January 3, 2013. In the TEP dataset, VEA is modeled as a load-only area and is the 40th area in the dataset. VEA is a spin-off of the Nevada Power (NEVP) TEPPC load area and accounts for approximately 1.87 percent of the original NEVP load. VEA is located in the CA_CISO region. Figure 10 shows the breakout of VEA on the map.

Figure 10. Valley Electric Association Breakout



Seasonal Bus Distribution

As mentioned in the Area-Level Loads section of this document, GridView uses the initial powerflow case load distribution to determine the transmission topology and to determine the load distribution for which to spread the area-level loads to busses on the system. This distribution is able to be changed on a seasonal basis by applying the bus distribution of those seasonal powerflow cases. The seasonal bus distributions used in the 2024 Common Case are as follows:

- Summer: 23HS1a1 Base Case
- Winter: 13HW2a1 Base Case
- Spring and Autumn: 2013HSP1a1 Base Case

The autumn bus distribution is represented by the spring case because there is not an autumn case available from the same year as the other seasons.

Fuels and Emission Rates

Gas Topology and Pricing

There are twenty-five Natural Gas (NG) pricing zones defined in the 2024 Common Case. The NG price burner-tip forecasts are based on a hybrid model that derives the annual average prices from the California Energy Commission (CEC) North American Market Gas Trade (NAMGas) model and the monthly shapes from the Northwest Power and Conservation Council (NPCC) model. Each gas-fueled generator is assigned an NG fuel zone from the list provided in Table 9.

Table 9: Natural Gas Burner Tip Pricing Zones (2014$/MMBtu)

Name in Model	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NG_AB	5.09	4.87	4.83	4.72	4.67	4.65	4.2	4.19	4.14	4.75	4.78	5.43
NG_AZ North	5.42	5.17	5.06	5.05	5.07	5.3	5.13	5.02	4.64	4.91	4.77	5.8
NG_NM North	5.29	5.06	4.96	4.95	4.98	5.13	4.98	4.88	4.52	4.79	4.66	5.68
NG_CA SoCalB	5.56	5.31	5.19	5.19	5.21	5.4	5.23	5.12	4.71	5.01	4.87	6.01
NG_CA PGaE BB	5.62	5.36	5.24	5.24	5.26	5.45	5.28	5.17	4.76	5.06	4.92	6.07
NG_CA SDGE	5.82	5.56	5.44	5.44	5.47	5.65	5.48	5.37	4.96	5.26	5.12	6.25
NG_CO	5.68	5.43	5.24	4.97	4.79	4.75	4.83	4.6	3.65	4.13	4.86	5.98
NG_BC	5.19	4.86	4.7	4.65	4.56	4.49	4.12	4.14	4.16	4.72	5.23	5.54
NG_MT	5.2	4.97	4.93	4.82	4.77	4.74	4.29	4.28	4.22	4.85	4.88	5.54
NG_ID North	5.13	4.8	4.64	4.59	4.5	4.43	4.06	4.09	4.11	4.67	5.19	5.5
NG_OR Malin	5.18	4.94	4.82	4.82	4.84	5.03	4.87	4.77	4.39	4.67	4.53	5.6
NG_ID South	5.29	5.06	5.01	4.9	4.84	4.82	4.35	4.33	4.28	4.92	4.95	5.63
NG_WY	5.68	5.43	5.24	4.97	4.79	4.74	4.83	4.6	3.65	4.12	4.86	5.98
NG_WA	5.58	5.24	5.07	5.01	4.92	4.84	4.46	4.48	4.5	5.09	5.63	5.95
NG_NV North	6.1	5.84	5.63	5.35	5.16	5.13	5.21	4.97	3.97	4.47	5.24	6.41
NG_NV South	5.56	5.31	5.19	5.19	5.21	5.4	5.23	5.12	4.71	5.01	4.87	6.01
NG_CA SJ Valley	5.53	5.27	5.15	5.15	5.18	5.36	5.19	5.08	4.68	4.98	4.83	5.97
NG_TX West	5.15	4.92	4.82	4.81	4.84	4.99	4.84	4.74	4.37	4.64	4.51	5.54
NG_UT	5.53	5.29	5.1	4.83	4.65	4.61	4.69	4.46	3.52	3.99	4.72	5.83
NG_NM South	5.44	5.21	5.11	5.1	5.13	5.28	5.13	5.03	4.66	4.93	4.8	5.83
NG_CA SoCalGas	5.83	5.57	5.45	5.45	5.48	5.66	5.49	5.38	4.98	5.28	5.13	6.26
NG_CA PGaE LT	5.99	5.73	5.61	5.6	5.63	5.82	5.65	5.54	5.13	5.43	5.28	6.43
NG_Baja	5.77	5.5	5.38	5.38	5.4	5.6	5.42	5.31	4.88	5.2	5.05	6.23
NG_AZ South	5.64	5.4	5.29	5.28	5.31	5.47	5.31	5.21	4.83	5.11	4.97	6.05
NG_OR	5.29	5.06	5.01	4.9	4.84	4.82	4.35	4.33	4.28	4.92	4.95	5.63

Coal Topology and Pricing

There are fourteen Coal pricing zones defined in the 2024 Common Case as presented in Table 10.

Table 10: Coal Pricing Zones (2014$/MMBtu)

Fuel	Price	Source	Plants
Coal_Alberta	1.53	NPCC	Alberta plants
Coal_AZ	2.44	Ventyx	Apache, Cholla, Coronado, Navajo, Springerville
Coal_CA_South	1.79	NPCC	Ace cogen
Coal_CO_East	2.20	Ventyx	Arapahoe, Cherokee, Comanche, Drake, Noxon, Pawnee, Valmont
Coal_CO_West	2.19	Ventyx	Bonanza, Cameo, Craig, Hayden
Coal_ID	1.19	NPCC	Idaho small coal
Coal_MT	1.36	Ventyx	Colstrip, Corrette
Coal_NM	2.25	Ventyx	Escalante, Four Corners, San Juan
Coal_NV	3.18	Ventyx	North Valmy, Reid Gardner
Coal_PNW	2.67	Ventyx	Boardman, Centralia
Coal_UT	1.96	Ventyx	Carbon, Hunter, Huntington
Coal_WY_E	1.52	Ventyx	Dave Johnston, Laramie River
Coal_WY_PRB	0.97	Ventyx	Wygen, Wyodak, Simpson
Coal_WY_SW	2.11	Ventyx	Jim Bridger, Naughton

Other Fuels and Pricing

In addition to the pricing for NG and Coal, prices for eighteen other fuels are modeled in the 2024 Common Case. These are provided in Table 11.

Table 11: Other Fuel Prices (2014$/MMBtu)

Fuel	Price	Fuel	Price
Bio_Agri_Res	0.50	Oil_DFO_L	13.21
Bio_Blk_Liquor	0.01	Oil_DFO2	20.96
Bio_Landfill_gas	2.10	Petroleum Coke	1.31
Bio_Other	2.70	Propane	22.00
Bio_Sludge_waste	0.00	Purchased_Steam	1.00
Bio_Solid_waste	0.00	Refuse	0.00
Bio_Wood	2.68	Synthetic Gas	6.99
Geothermal	0.00	Uranium	0.81
Oil_DFO_H	27.95	Waste_Heat	0.00

Emissions Rates by Fuel

Each fuel is modeled with emissions rates for CO_2, NO_x, and SO_2 as shown in Table 12.

Table 12. Emissions Rates by Fuel

Fuel Name	Emission Type	Emission Rate (lb/MMBtu)	Fuel Name	Emission Type	Emission Rate (lb/MMBtu)
All "Bio_"	CO2	130	DefaultFuel	CO2	200
	NOx	0.1766362		NOx	0.276
	SO2	0.00579		SO2	0.35
Coal_Alberta	CO2	205	Geothermal	CO2	20
	NOx	0.5		NOx	0.1766362
	SO2	0.35		SO2	0.00579
Coal_AZ	CO2	205.0311	All Natural Gas ("NG_")	CO2	118
	NOx	0.459146		NOx	0.08
	SO2	0.571		SO2	0.0006
Coal_CA_South	CO2	203.5343	Oil_DistillateFuel_2 Oil_DistillateFuel_H Propane	CO2	123.1133
	NOx	0.3824139		NOx	0.1766362
	SO2	0.3303097		SO2	0.00579
Coal_CO_East Coal_ID Coal_MT Coal_UT	CO2	204.7532	Oil_DistillateFuel_L	CO2	144.0294
	NOx	0.552889		NOx	0.116
	SO2	0.6911747		SO2	0.0006
Coal_CO_West	CO2	205.2	Petroleum Coke Purchased_Steam	CO2	224
	NOx	0.552889		NOx	0.028
	SO2	0.6911747		SO2	0
Coal_NM	CO2	203.5343	Refuse	CO2	130
	NOx	0.3824139		NOx	0.1766362
	SO2	0.3303097		SO2	0.00579
Coal_NV	CO2	202.6215	Synthetic Gas	CO2	118
	NOx	0.3485		NOx	0.08
	SO2	0.112818		SO2	0.0006
Coal_PNW	CO2	205.2	Uranium	CO2	0
	NOx	0.288333		NOx	0
	SO2	0.621817		SO2	0
Coal_WY_E	CO2	200	Waste_Heat	CO2	0
	NOx	0.276		NOx	0
	SO2	0.464041		SO2	0
Coal_WY_PRB Coal_WY_SW	CO2	205.2			
	NOx	0.1			
	SO2	0.07			

Costs and Economics

Inflation

Cost data such as fuel prices, variable Operations and Maintenance (O&M) rates, and startup costs are often provided in different year's dollars than what TEP has selected. For example, TEP has asked that all cost data be modeled in 2014 dollars, which requires that many of the costs be converted to 2014 dollars. These conversions were based on the Moody's GDP Inflator/Deflator series, licensed to the CEC. The Moody's series has an average annual inflation from 2014 through 2024 of 1.9 percent.

Transmission

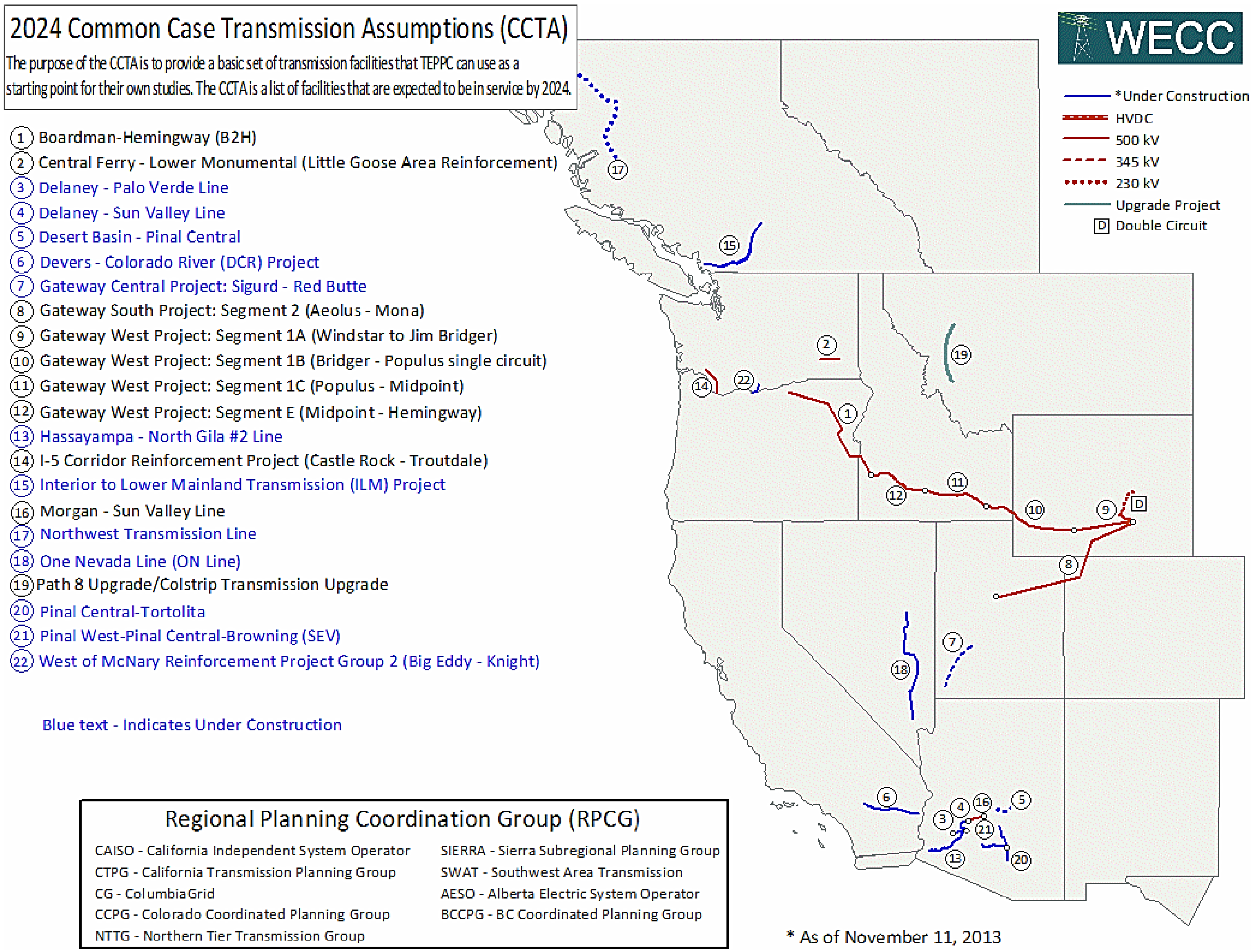
Common Case Transmission Assumptions (CCTA)

The Regional Planning Coordination Group (RPCG) aids the Regional Transmission Expansion Planning (RTEP) process by providing TEPPC with a list of regionally significant transmission projects that have a high expectation of being in-service within a 10-year timeframe given current trends. This list of projects serves as a key input assumption for the 2024 Common Case. The RPCG first assisted in the development of WECC's 10-Year Regional Transmission Plans by providing such a list in 2010 and 2012. This iteration of the list is called the 2024 Common Case Transmission Assumptions.

The WECC Transmission Project Information Portal contains publically available project information for nearly 98 projects currently under development in the Western Interconnection. The RPCG reviewed all of these projects and several others as part of the CCTA selection process. In certain cases, project sponsors provided information directly to the RPCG. The 2024 CCTA selection process resulted in the inclusion of 22 transmission projects to be on the list.

The purpose of, process of developing, and projects included in the 2024 CCTA are explained in detail in the RPCG 2024 CCTA Report. The projects included in the RPCG 2024 CCTA are shown in the map in Figure 11.

Figure 11. 2024 Common Case Transmission Assumptions



Power Flow Documentation

The 2024 Common Case transmission network is comprised of two main components: the RPCG 2024 CCTA and the WECC Technical Studies Subcommittee (TSS) 2023 HS1A1 Heavy Summer Base Case (2023 HS1A1 Power Flow). The TSS manages a central database of technical information about the Western Interconnection transmission system and reliability studies, including power flow models of the Western Interconnection. The 2023 HS1A1 Power Flow case can be downloaded from the WECC Planning Services Base Cases Web page; however, the download is restricted to those that have signed the current WECC Confidentiality Agreement.

WECC's Transmission Expansion Planning (TEP) Department used the 2023 HS1A1 Power Flow as the foundation of its own 2024 power flow cases. Changes to the 2023 HS1A1 Power Flow were managed within GE's Positive Sequence Load Flow (PSLF) software through the use of EPCL (*.P) files to create the 2024 Common Case Power Flow and Root Case Power Flow. The two power flow cases are the result of using the 2024 CCTA. The 2024 Common Case was created using the 2023 HS1A1 Power Flow supplemented with a series of transmission additions and removals specified by the projects listed in the 2024 CCTA report. The 2024 Root Case, like the Common Case, supplemented the 2023 HS1A1 case with a series of transmission additions and removals specified by projects in the 2024 CCTAs, but only for CCTA projects that were currently under construction. Table 13 shows the list of CCTA project additions and removals from both 2024 power flow cases. Other changes to the 2023 HS1A1 Power Flow included WECC transfer path fixes, topology changes for a few generators, DC line modeling updates, and islanded bus fixes.

Table 13. CCTA Mapping and Tracking

Project Name	Included in 23HS1A1 case?	Under construction?	Common Case addition?	Root Case addition?	Root Case removal?
Boardman-Hemingway 500 kV (B2H)	Yes	No	No (included in 23 HS1A1)	No	Yes
Central Ferry - Lower Monumental (Little Goose Area Reinforcement)	Yes	No	No (included in 23 HS1A1)	No	Yes
Delaney-Palo Verde 500-kV Line	Yes	Yes	No (included in 23 HS1A1)	No (included in 23 HS1A1)	N/A
Delaney-Sun Valley 500-kV Line	Yes	Yes	No (included in 23 HS1A1)	No (included in 23 HS1A1)	N/A
Desert Basin - Pinal Central	Yes	Yes	Used EPC to include	Used EPC to include	N/A
Devers - Colorado River 500-kV (DCR) Transmission Line Project	No	Yes	Used EPC to include	Used EPC to include	N/A
Gateway Central Project, Sigurd - Red Butte 345-kV Line	Yes	Yes	No (included in 23 HS1A1)	No (included in 23 HS1A1)	N/A
Gateway South Project – Segment #2 (Aeolus-Mona 500 kV)	No	No	No (included in 23 HS1A1)	No	Yes
Gateway West Transmission Project Segment 1A – Windstar to Jim Bridger 230 kV, 500 kV	No	No	No (included in 23 HS1A1)	No	Yes
Gateway West Transmission Project Segment 1B – Jim Bridger to Southeast Idaho (Bridger – Populus single circuit 500 kV)	No	No	Used EPC to include	No	N/A
Gateway West Transmission Project Segment 1C – Southeast Idaho – South Central Idaho (Populus – Midpoint 500 kV)	Yes	No	No (included in 23 HS1A1)	No	Yes
Gateway West Transmission Project Segment E – South to Southwest Idaho (Midpoint – Hemingway 500 kV)	Yes	No	Used EPC to include	No	N/A
Hassayampa - North Gila 500-kV #2 line	Yes	Yes	No (included in 23 HS1A1)	No (included in 23 HS1A1)	N/A
I-5 Corridor Reinforcement Project (Castle Rock - Troutdale)	Yes	No	Used EPC to include	No	N/A
Interior to Lower Mainland Transmission (ILM) Project	No	Yes	No (included in 23 HS1A1)	No (included in 23 HS1A1)	N/A
Morgan-Sun Valley 500-kV Line	Yes	No	No (included in 23 HS1A1)	No	Yes
Northwest Transmission Line	No	Yes	No (included in 23 HS1A1)	No (included in 23 HS1A1)	N/A
One Nevada Line (ON Line, was SWIP South)	No	Yes	Used EPC to include	Used EPC to include	N/A
Path 8 Upgrade/Colstrip Transmission Upgrade	No	No	No (included in 23 HS1A1)	No	Yes
Pinal Central-Tortolita	Yes	Yes	No (included in 23 HS1A1)	No (included in 23 HS1A1)	N/A
Pinal West-Pinal Central-Browning (SEV)	Yes	Yes	Used EPC to include	Used EPC to include	No
West of McNary Reinforcement Project Group 2 (Big Eddy - Knight)	Yes	Yes	No (included in 23 HS1A1)	No (included in 23 HS1A1)	N/A

Modeling Branch Ratings

WECC models the normal and emergency branch (line or transformer) ratings for each of the four seasons within its GE PSLF power flow model (PFM). In comparison, GridView version 9.0 (as with the Siemens Power System Simulator for Engineering (PSS/E) power flow model) allows the user to model three ratings for each branch and specify summer de-rates for each of these ratings. By default, GridView only imports Ratings 1 and 2 from the PSLF/PFM, as shown in Table 14.

Table 14. GridView version 9.0 interpretation

GE PSLF Branch Ratings (MVA)	GridView Default Interpretation (MW)	GridView Default Summer De-Rate Multiplier
Rating 1: Summer Normal	Rating A: Normal Rating	1
Rating 2: Summer Emergency	Rating B: Contingency Rating	1
Rating 3: Winter Normal	Rating C: Miscellaneous/Special Rating	1
Rating 4: Winter Emergency	N/A	
Rating 5: Autumn Normal		
Rating 6: Autumn Emergency		
Rating 7: Spring Normal		
Rating 8: Spring Emergency		

The following GridView simulation settings determine which branch ratings are used and how there are set in the 2024 Common Case:

- Transmission Constraint Ratings Multiplier: 0.95
  - *Approximates the megawatt equivalent of the megavolt-ampere rating from the power flow model since the production cost simulation only implements an optimized direct-current power flow and can't use the megavolt-ampere rating directly*
- Transmission Constraint Ratings Normal Rating (Commitment & Dispatch): A
  - *Branch rating and summer de-rate multiplier to use in the simulation*
- Summer Period Start/End Dates: June 1st/September 30th
  - *Timeframe in which the summer de-rate is applicable*

Table 15 illustrates how the branch ratings are modeled within GridView so they are consistent with those modeled in the PFM.

Table 15. Modeling Branch Ratings in GridView model based on GE PSLF power flow model

GridView Branch Rating Type	Rating (MW)	Summer De-Rate Multiplier
Rating A	Rating 3 in PFM (Winter Normal)	(Rating 1 in PFM / (Rating 3 in PFM)
Rating B	Rating 4 in PFM (Winter Emergency)	(Rating 2 in PFM / (Rating 4 in PFM)
Rating C	0	1

Paths and Other Transmission Interfaces

In the development assumptions for the WECC transfer path ratings in the 2024 Common Case, the Technical Advisory Subcommittee's (TAS) Studies Work Group (SWG) started with the 2013 WECC Path Rating Catalog and applied modifications to capture operating limits for a number of key paths and to capture rating changes due to the CCTA additions. Any path that had an undefined, unrated, or unstudied secondary limit was set to the negative value of its defined primary limit. Paths with seasonal limits were applied on a monthly basis.

The path limits in the 2013 WECC Path Rating Catalog (PRC), along with the changes listed below, are the basis for the path ratings modeled in the 2024 Common Case. These assumptions are summarized in Table 16.

- Path 4 (West of Cascades-North): The primary and secondary limits were increased from 10,200 MW to 10,800 MW based on feedback from the PRC contact person.
- Path 5 (West of Cascades-South): The primary and secondary limits were increased from 7,200 MW to 7,575 MW based on feedback from the PRC contact person.
- Path 6 (West of Hatwai): The 4,277-MW east-to-west limit was increased to 4,800 MW due to the inclusion of the Path 8 Upgrade project.
- Path 8 (Montana-to-Northwest): The 2,200-MW east-to-west limit was increased to 3,000 MW and 1,350-MW west-to-east limit was increased to 2,150 MW to reflect the inclusion of the Path 8 Upgrade project.
- Path 14 (Idaho-to-Northwest): The 1,200-MW west-to-east limit was increased to 2,250 MW and 2,400-MW east-to-west limit was increased to 3,400 MW to reflect the inclusion of the Hemingway-Boardman project.
- Path 17 (Borah West): The 2,557-MW east-to-west limit was increased to 4,450 MW and 1,600-MW west-to-east limit was increased to 4,500 MW to reflect the inclusion of the Energy Gateway West project.

- Path 19 (Bridger West): The 2,400-MW east-to-west limit was increased to 4,100 MW and 600-MW west-to-east limit was increased to 2,300 MW to reflect the inclusion of the Energy Gateway West project.
- Path 20 (Path C): The 1,600-MW north-to-south limit was increased to 2,250 MW and 1,250-MW south-to-north limit was increased to 2,250 MW to reflect the inclusion of the Energy Gateway West project.
- Path 35 (TOT 2C): The 300-MW north-to-south limit was increased to 600 MW and 300-MW south-to-north limit was increased to 580 MW to reflect the inclusion of the second Sigurd-Red Butte 345-kV line.
- Path 37 (TOT 4A): The 810-MW northeast-to-southwest limit was increased to 1,775 MW to reflect the Energy Gateway West Project.
- Path 38 (TOT 4B): The 680-MW southeast-to-northwest limit was increased to 880 MW and the 829 MW northwest-to-southeast limit was increased to 880 MW to reflect the Energy Gateway West Project.
- Path 39 (TOT 5): The 1,675-MW west-to-east limit was increased to 1,680 MW to reflect the 2013 path rating catalog updated limit.
- Path 42 (IID to SCE): The 600-MW east-to-west limit was increased to 1,500 MW to reflect the Path 42 Upgrade project.
- Path 46 (West of Colorado River or WOR): The 10,623-MW east-to-west limit was increased to 11,200 MW based on feedback from the PRC contact person.
- Path 49 (East of Colorado River or EOR): The 9,300-MW east-to-west limit was increased to 10,200 MW to reflect the inclusion of the North Gila-Imperial Valley project.
- Path 65 (Pacific DC Intertie or PDCI): The 3,100-MW north-to-south limit was increased to 3,220 MW based on feedback from the PRC contact person.
- Path 71 (South of Allston): The 3890-MW north-to-south limit was increased to 4,100 MW to reflect the inclusion of the I-5 Corridor Reinforcement project.
- Path 75 (Hemingway-Summer Lake): The 1,500-MW east-to-west limit was increased to 2,400 MW and 400-MW west-to-east limit was increased to 1,200 MW based on feedback from the PRC contact person.
- Path 81 (Southern Nevada Transmission Interface or SNTI): The path was revised in 2013 with a primary limit of 4,533 MW and a secondary limit of 3,790 MW.
- Path 82 (TotBeast): The path was added in 2013 and defined with 2,465-MW west-to-east and 2,465-MW east-to-west limits.
- Path 83 (Montana Alberta Tie Line): The pat was added in 2014 and defined with 325-MW north-to-south and 300-MW south-to-north limits.

Table 16. Limits of Major Paths and Other Transmission Interfaces

Path #	Path Name	Primary Limit (MW)	Secondary Limit (MW)	Path #	Path Name	Primary Limit (MW)	Secondary Limit (MW)
P01	Alberta-British Columbia	1000	-1200	P50	Cholla-Pinnacle Peak	1200	-1200
P02	Alberta-Saskatchewan	150	-150	P51	Southern Navajo	2800	-2800
P03	Northwest-British Columbia	3000	-3150	P52	Silver Peak-Control 55 kV	17	-17
P04	West of Cascades-North	10800	-10800	P54	Coronado-Silver King 500 kV	1494	-1494
P05	West of Cascades-South	7575	-7575	P55	Brownlee East	1915	-1915
P06	West of Hatwai	4800	-4800	P58	Eldorado-Mead 230-kV Lines	1140	-1140
P08	Montana to Northwest	3000	-2150	P59	WALC Blythe - SCE Blythe 161-kV Sub	218	-218
P09	West of Broadview	2573	-2573	P60	Inyo-Control 115-kV Tie	56	-56
P10	West of Colstrip	2598	-2598	P61	Lugo-Victorville 500-kV Line	900	-2400
P11	West of Crossover	2598	-2598	P62	Eldorado-McCullough 500-kV Line	2598	-2598
P14	Idaho to Northwest	3400	-2250	P65	Pacific DC Intertie (PDCI)	3220	-3100
P15	Midway-LosBanos	5400	-3265	P66	COI	4800	-3675
P16	Idaho-Sierra	500	-360	P71	South of Allston	4100	-4100
P17	Borah West	4450	-4500	P73	North of John Day	8400	-8400
P18	Montana-Idaho	337	-256	P75	Hemingway-Summer Lake	2400	-1200
P19	Bridger West	4100	-2300	P76	Alturas Project	300	-300
P20	Path C	2250	-2250	P77	Crystal-Allen	950	-950
P22	Southwest of Four Corners	2325	-2325	P78	TOT 2B1	600	-600
P23	Four Corners 345/500 Qualified Path	1000	-1000	P79	TOT 2B2	265	-300
P24	PG&E-Sierra	160	-150	P80	Montana Southeast	600	-600
P25	PacifiCorp/PG&E 115-kV Interconnection	100	-45	P81	Southern Nevada Transmission Interface (SNTI)	4533	-3790
P26	Northern-Southern California	4000	-3000	P82	TotBeast	2465	-2465
P27	Intermountain Power Project DC Line	2400	-1400	P83	Montana Alberta Tie Line	325	-300
P28	Intermountain-Mona 345 kV	1400	-1200		AZ-CA	99999	-99999

Path #	Path Name	Primary Limit (MW)	Secondary Limit (MW)	Path #	Path Name	Primary Limit (MW)	Secondary Limit (MW)
P29	Intermountain-Gonder 230 kV	200	-200		COI plus PDCI	7900	-6455
P30	TOT 1A	650	-650		WA-BC East	400	-400
P31	TOT 2A	690	-690		WA-BC West	3000	-2850
P32	Pavant-Gonder InterMtn-Gonder 230 kV	440	-235		WY-UT	1700	-1700
P33	Bonanza West	785	-785		Aeolus South	1700	-1700
P35	TOT 2C	600	-580		Aeolus West	2670	-2670
P36	TOT 3	1680	-1680		AZ Palo Verde East	8010	-8010
P37	TOT 4A	1775	-1775		CA IPP DC South	50000	-50000
P38	TOT 4B	880	-880		CA PDCI South	2780	-3100
P39	TOT 5	1680	-1680		CA PG&E-Bay	99999	-99999
P40	TOT 7	890	-890		CA SCE import	99999	-99999
P41	Sylmar to SCE	1600	-1600		CA SCIT	17700	-17700
P42	IID-SCE	1500	-1500		CA Southern CA Imports	14750	-14750
P43	North of San Onofre	2440	-2440		ID Midpoint West	4400	-4400
P44	South of San Onofre	2500	-2500		NV NV Energy Southern Cut Plane	3500	-3050
P45	SDG&E-CFE	408	-800		OR/WA West of John Day	3450	-3450
P46	West of Colorado River (WOR)	11200	-11200		OR/WA West of McNary	4500	-4500
P47	Southern New Mexico (NM1)	1048	-1048		OR/WA West of Slatt	5500	-5500
P48	Northern New Mexico (NM2)	1970	-1970		WA North of Hanford	4100	-2948
P49	East of Colorado River (EOR)	10200	-10200				

Nomograms

Nomograms are employed where applicable to enforce limits on the summation or subtraction of groups of branches, transfer paths, resources, or aggregate loads. To develop the nomogram assumptions in the 2024 Common Case, the TAS SWG started with the 2022 Common Case and applied modifications to capture changes in topology and generation. Four new nomograms were added in 2024 to implement a 25 percent minimum local generation requirement for California load areas. These four new nomograms use the sum of local thermal generation dispatch in the California load areas to meet at least 25 percent of their local load. The 25 percent minimum local generation nomograms help capture a more realistic thermal commitment that directly impacts economic dispatch and transfer of power between regions. In addition, the 25 percent minimum local generation nomograms are a better estimate of periods and quantity of over generation. All nomogram assumptions used in the 2024 Common Case are summarized in Table 17.

Table 17. List of Nomograms in 2024 Common Case

Nomogram Name	Limit (MW)	Nomogram Name	Limit (MW)
AeolW-Aeolus S	6,458.2	Jday COI PDCI 1	7,650
AeolW-Bonanza W	6,595	Jday COI PDCI 2	7,900
AeolW-TOT1A	17,458	Jday COI PDCI 3	17,115
BrdgW-Aeolus S	12,796	Jday PDCI 1	3002
BrdgW-Bonanza W	10,406	Jday PDCI 3	5,547.21
BrdgW-Path C	16,856	LDWP 25% LocalMinGen	0
COB	5,100	Path 18 Exp	337
COI 1	6,378	Path 18 Imp	256
COI 2	5,923	Path 22	3,113
COI 3	5,726	Path 8	7,925
COI 4	5,549	PG&E Bay 25% LocalMinGen	0
Greater IV-SDGE Area Import	2,830	SCE 25% LocalMinGen	0
IPP DC	361	SDGE 25% LocalMinGen	0
Jday COI 1	4,648.1	SDGE Area Import	3,350
Jday COI 3	9,792.88		

Monitored Lines

Monitored lines are the branches (transmission lines or transformers) whose constraints are imposed in the GridView simulation. TEPPC does not monitor low-voltage transmission and focuses on interregional flows. As a result, the primary criteria for designating monitored lines in the 2024 Common Case is to include all lines at or above 230 kV and all transformers with a lower-side terminal at or above 230 kV. The 2024 Common Case has 3,175 monitored lines. Roughly 3,950 branches met the primary criteria; however, almost 800 branches were removed from the monitored lines, primarily in the Alberta Electric System Operator (AESO) and British Columbia Hydro and Power Authority/BC Hydro (BCHA) areas, because inaccurate resource mapping was causing fictional overloads.

Phase Shifters

The phase shifter modeling was initially set based on the GridView conversion of the 2022 Common Case, which was housed in the probabilistic analysis model (PROMOD). ABB found that a one-to-one conversion was not possible and, as a result, ABB made approximations. The modeling settings were tuned to minimize the number of phase angle change operations during the year, which is typically true of the current and historical phase shifter operations.

Resources

Data Collection and Reconciliation Effort

The 2012 WECC L&R information, collected by the LRS of the PCC, was the starting point for resource information as with past TEPPC PCM datasets. Previous PCM datasets relied on approximate mapping of this resource information to the power flow model; however, one of the primary goals of the 2024 Common Case was to provide a “round trip” capability between the PCM and power flow models, which required more granular resource information than is reported in the L&R information. As a result, TEP began an effort to reconcile resource information provided in a variety of resource databases. This section describes the effort.

Step 1: Building the lookup table within WECC

Table 18 shows the resource databases that WECC used as input into the resource reconciliation effort as well as the field in each that uniquely identified each resource or group of resources within each database. The information in each database was compare with that of the others to build a resource database lookup table that described how a unique identifier in one database was linked to those in all the other databases.

Table 18. Resource databases included in Resource Reconciliation Effort

Resource Database	Unique Identifier Fields	Description
2012 WECC L&R	Unit Name & Unit Number	Information collected by LRS in the 2012 L&R data collection process.
2013 HS2-OP Power Flow[1]	Bus Number & Model ID	2013 Heavy Summer Operating Case meant to represent anticipated operating conditions with heavy flows from the Northwest to California and moderate flows elsewhere. Dated November 30, 2012 and built as part of the TSS 2012 Study Program.
2023 HS1A1 Power Flow	Bus Number & Model ID	2023 Heavy Summer Base Case with typical flows throughout WECC. Dated October 22, 2012 and built as part of the TSS 2012 Study Program.
2022 TEPPC Common Case	Resource Name	The last TEPPC PCM dataset meant to represent the trajectory of recent Western Interconnection planning information, developments and policies looking out 10 years. Dated May 2, 2012.
2011 and 2012 EIA-860	PLANT_CODE & GENERATOR_ID	2011 and 2012 U.S. Energy Information Administration Annual Electric Generator Report (Form EIA-860), which collects generator-level specific information about existing and planned generators.
2013 LBNL IRP Survey[2]	Resource Name	Integrated resource plan (IRP) information collected by LBNL during 2013. It contains the existing resources, planned resources, and planned retirements of Load-Serving Entities responsible for the majority of delivered load across WECC. Dated August 21, 2013.
CAISO NQC List	Generator Name	Net Qualifying Capacity (NQC) List posted by the California Independent System Operator (CAISO).
CAISO Generating Capability List	Generating Unit Name / Description	Master CAISO Control Area Generating Capability List, meant to reflect known CAISO generating resources. Dated December 13, 2013.

Reconciling resource databases beyond the L&R information and power flow models allowed TEP to build links between the L&R information and the power flow models that wouldn't have otherwise been possible. This power flow model contains a lot of information about its generator models; however, multiple fields have to be cross-referenced to determine the generator's "real life" identity.

[1] A WECC member account is required to download power flow base cases directly.

[2] An invaluable effort and source of resource information lead by Peter Larsen who can be contacted at (510) 486-5015 or PHLarsen@lbl.gov.

Listed below are some examples of the difficulty in getting information from the power flow model that can be linked to one or more resources in the L&R information:

- Resource Name: The useable “Long ID” fields in the power flow model house the real-life name of the generators; however, the vast majority of these fields are blank, so TEP had to rely on the “Bus Name,” which only has 8-12 characters.[3] Due to the character limitation, the bus names typically have abbreviated or code names that are difficult to decipher for anyone that didn’t originally create the model in the power flow. TEP leveraged multiple power flow WECC experts to help decipher some bus names.

- Generator and Primary Fuel Type: The “Turbine Type” fields and dynamic models in the power flow model provide some indication of a generator’s type; however, the “Turbine Type” field it isn’t always filled out and even having both pieces of information isn’t always enough identify the primary fuel of the resource. For example, coal-fired, nuclear, and geothermal technologies can use steam turbines but use different primary fuels to create the steam.

- Nameplate/Size: The “PMAX” field in the power flow model represents the maximum real power (megawatts) output capability of the unit. However the station service load for generating facilities isn’t always modeled consistently and may be lumped into the generator model, which alters the generator’s modeled capability.

- Plant configuration: The power flow typically doesn’t do a good job of representing the configuration of generating plants; however, it isn’t immune to aggregation of units. Wind and solar facilities contain a large number of units that are aggregated into fewer generator models and this aggregation can be in any number of ways. Also, small units of various technologies are lumped into a single generator model in some cases. As a result, the number of units in the power flow can be very different from the number of units reported in another resource database.

TEP used all available information in each database (and extensive Web searching in some cases) to build the lookup table, but cross-referencing the following types of resource information was typically enough to build the link for most resources: generator type, nameplate or size of unit, fuel, BA or TEPPC load area, and U.S. state or Canadian province.

[3] Current power flow models allow up to 12 characters; however, this limit used to be eight characters and few of the old eight-character bus names have been revised to take advantage of the additional 4 characters.

Step 2: Using the lookup table to pull together information

The terms used in each resource database were related to each other by using unique resource identifiers. Table 19 shows 10 samples of the 174 common terms used to define and link together equivalent or related terms used in the different resource databases.

Table 19. Common terms used to link together equivalent terms used in each resource database

Common Term	Equivalent or Related Terms Used in Resource Databases					
	WECC L&R	EIA-860	2013/23 Power Flow Cases	2022 Common Case	LBNL IRP Survey	CAISO GCL
Unit Name	Unit Name	PLANT_NAME		Name	Resource Name	Generating Unit Name / Description
Short Name			Bus Name	Short Name		Resource ID
Zone	ZONE		Zone Name			Demand Zone
BA/Area	BA		Area Name	Area		PTO Area
Org/Owner	Org	UTILITY_NAME	Owner Name	Operator	Utility/LSE	Owner or QF ID
Unit/Turbine Type	Unit Type	PRIME_MOVER	Turb	Category	Resource Type	Unit Type
Primary Fuel	Primary Fuel	ENERGY_SOURCE_1			Fuel Type	Fuel Type
Nameplate	Nameplate	NAMEPLATE		Maximum Capacity (MW)	Nameplate Capacity (MW)	Nameplate Capacity (MW)
SummerCap	Summer Cap	SUMMER_CAPABILITY	PMAX			Net Dependable Capacity (MW)
WinterCap	Winter Cap	WINTER_CAPABILITY				Net Dependable Capacity (MW)

The common terms and the resource database lookup table were used to pull together all the resource information into a single spreadsheet. TEP reviewed the compiled information and determined which single values were the best to use for each common term of each resource. Table 20 shows sample thought processes for determining the reconciled values. TEP attempted to use the information from all resource databases; however, if the information from one or more resource databases conflicted in regard to a given generator or group of generators, then each database's information was prioritizes above or below the others (see the priority list below) while taking into account the respective pros and cons as well as using Web searching to clear up uncertainties.

1. WECC L&R
   - Pros: Recent information, submitted by BAs via a long-standing process.
   - Cons: Contains high-level and often aggregated information that is difficult to disaggregate without information from the other resource databases.
2. EIA-860 (and CAISO GCL for California resources)
   - Pros: submitted by generator owners and, in general, supplement(s) the L&R information very well.
   - Cons: prone to over reporting (i.e., many small, insignificant resources are included and can add confusion) and not as actively reviewed as the other resource databases; therefore, has a lot of outdated information.
3. LBNL
   - Pros: Most recent information and is based on LSEs' IRPs (i.e., what LSEs are currently planning on serving their load now and in the future).
   - Cons: Contains high-level information that can contain duplicative information and contribute to double-counting resources if one isn't careful.
4. 2013 and 2023 power flow cases
   - Pros: Provide detailed plant configuration and generator design-level information.
   - Cons: Contain information of limited scope and are less recent than other resource databases.
5. 2022 Common Case (2022PCM)
   - Pros: Contains information relevant to production cost modeling.
   - Cons: Contains outdated information.

Table 20. Sample thought processes for determining reconciled values

Example Type	Common Term	Compiled Information	Reconciled Value	Thought Process
Numeric Value	Nameplate (MW)	117.847 [LRS] 110 [EIA] 235 [22PCM, Agg of 2] 235 [LBNL, Agg of 2]	117.847	Based on LRS information because it is more recent than EIA. Other sources indicate that the size is roughly half of 235 MW, so 117.847MW is the best value given the information.
Non-Numeric Value	BA/Area	TIDC [LRS] PG AND E [13PF] PG AND E [23PF] TIDC [22PCM]	TIDC	TIDC is and PG&E is not a BA or TEPPC load area; therefore, it is TIDC.
Non-Numeric Value	Unit/Turbine Type	WT [LRS, Agg of 17] Unknown [13PF] Unknown [23PF] Wind [22PCM, Agg of 17] Wind [LBNL, Agg of 17] WIND [CPUC, Agg of 17]	Wind-Onshore	All sources with known type have “Wind”; therefore, it is “Wind-Onshore” to distinguish the type from possible offshore wind.

As indicated in Table 20, TEP defined universal terms for non-numeric values. Table 21, Table 22, and Table 23 show the universal terms used for Generator Type, Primary Fuel and Resource Project Status, respectively.

Table 21. TEP Generator Types, based on merging the EIA-860 Prime Mover and the LRS Unit Type options.

TEP Generator Type	Description
Binary Cycle	Turbines used in a Binary Cycle (such as used for geothermal applications)
Combined Cycle-Duct Firing	Combined Cycle- Duct Firing
Combined Cycle-Gas Part	Combustion unit within a combined cycle plant
Combined Cycle-Single Shaft	Combined cycle plant in which the gas and steam turbines share a single drive shaft
Combined Cycle-Steam Part	Steam unit within a combined cycle plant
Combined Cycle-Whole Plant	Aggregate combined cycle plant – includes the combustion and steam parts
Combustion Turbine-Biomass	Combustion turbine using biomass fuel
Combustion Turbine-Nat Gas-Industrial Frame	Heavy, large, or industrial frame combustion turbine fueled by natural gas
Combustion Turbine-Nat Gas-Aero Derivative	Aero-Derivative combustion turbine fueled by natural gas
Combustion Turbine-Oil	Combustion turbine fueled by oil, diesel, or other distillate fuel
Combustion Turbine-Synth Gas	Combustion turbine fueled by synthetic gas, typically made from coal
Combustion Turbine-Propane	Combustion turbine fueled by propane gas
Combustion Turbine-Other	Combustion turbine not listed above that uses some other fuel

TEP Generator Type	Description
DC Intertie (DCI)	Fictional resource for modeling direct current interties between the Western and neighboring Interconnections
Energy Storage-Battery	Energy Storage, Battery
Energy Storage-Compressed Air Storage	Energy Storage, Compressed Air Energy Storage
Energy Storage-Concentrated Solar Power	Energy Storage, Concentrated Solar Power
Energy Storage-Flywheel	Energy Storage, Flywheel
Energy Storage-Other	Energy Storage not listed above.
Fuel Cell	Fuel Cell
Hydro	Hydroelectric generator
Hydro-RPS	Hydroelectric generator that qualifies toward its state's Renewable Portfolio Standard (RPS)
Hydro-PumpStorage	Reversible hydro turbine, capable of either generation or pumping water to a reservoir for energy storage.
Hydro-PumpStorage-RPS	Pump Storage that qualifies toward its state's RPS when generating
Hydrokinetic-Wave Buoy	Wave generator
Hydrokinetic-Axial Flow Turbine	Hydrokinetic, Axial Flow Turbine
Hydrokinetic-Other	Hydrokinetic not listed above
Internal Combustion Engine (ICE)	Internal Combustion Engine (diesel, piston, reciprocating)
Solar PV-Tracking	Photovoltaic plant with tracking capability, i.e., solar panels track sunlight to maximize their output
Solar PV-Non-Tracking	Photovoltaic plant without tracking capability
Solar Thermal-Storage (CSP6)	Concentrated solar power (CSP) facility (uses mirrors/lenses to concentrate solar energy to create steam and, in turn, produce electricity) with storage capability
Solar Thermal-No Storage (CSP0)	Concentrated solar power (CSP) facility (uses mirrors/lenses to concentrate solar energy to create steam and, in turn, produce electricity) without any storage capability
Steam Turbine-Biomass	Steam turbine fueled by burning biomass
Steam Turbine-Coal	Steam turbine fueled by burning coal
Steam Turbine-Gas	Steam turbine fueled by burning gas
Steam Turbine-Nuclear	Steam turbine fueled by radioactive material
Steam Turbine-Waste Heat	Steam turbine fueled by waste heat, other than those in combined cycle plants that use the waste heat from combustion turbines
Steam Turbine-Other	Steam turbine not listed above that uses some other fuel
Wind-Onshore	Wind generator located on land
Wind-Offshore	Wind generator located off the coast
Various	Used for aggregations that include generators of different types
Other	Other generator types not listed previously

Table 22. TEP Primary Fuel, based on merging the EIA-860 Energy Source and the LRS Primary Fuel options.

TEP Primary Fuel	Description
Biomass-Agricultural	Agriculture Crop Byproducts/Straw/Energy Crops
Biomass-Black Liquor	Black Liquor
Biomass-LandfillGas	Landfill Gas or other material
Biomass-Muni Solid	Municipal Solid Waste
Biomass-Sludge Waste	Sludge Waste
Biomass-Wood-Liquid	Wood Waste Liquids – excludes black liquor but includes red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids
Biomass-Wood-Solid	Wood/ Wood Waste Solids – includes paper pellets, railroad toes, utility pools, wood chips, bark, and wood waste solids
Blast Furnace Gas	Blast Furnace Gas
Biomass-Other	Other biomass gas – includes digester gas, methane, and other biomass gases; other biomass liquids; and other biomass solids not listed above
Coal-Ant	Anthracite Coal
Coal-Bit	Bituminous Coal
Coal-Lig	Lignite Coal
Coal-Sub	Subbituminous Coal
Coal-Synfuel	Coal Synfuel: Coal-based solid fuel that has been processed by a coal synfuel plant; and coal-based fuels such as briquettes, pellets, or extrusions, which are formed from fresh or recycled coal and binding materials
Coal-Other	Waste/Other Coal – includes anthracite culm, bituminous gob, fine coal, lignite waste, waste coal
Demand Response	Demand Response
Electricity-Storage	Electricity used for energy storage
Gas-Kerosene	Kerosene
Gas-Natural Gas	Natural Gas
Gas-Propane	Gaseous Propane
Gas-Synthetic via Coal	Synthetic Gas, derived from coal
Gas-Other Synthetic	Synthetic Gas, other than coal-derived
Gas-Other	Other Gas (coke oven, refinery, etc.)
Geothermal	Geothermal Steam
Jet Fuel	Jet Fuel
Nuclear	Nuclear – includes uranium, plutonium, thorium
Oil-Distillate Fuel	Distillate Fuel Oil – includes Diesel, No. 1, No. 2, and No. 4 Fuel Oils
Oil-Waste-Other	Waste/Other Oil – includes Crude Oil, Liquid Butane, Liquid Propane, Oil Waste, Re-Refined Motor Oil, Sludge Oil, Tar Oil, or other petroleum-based liquid waste
Petroleum Coke	Petroleum Coke

TEP Primary Fuel	Description
Purchased Steam	Purchased Steam
Oil-Residual Fuel	Residual Fuel Oil – includes No. 5, and No. 6 fuel oils, and bunker C fuel oil
Sun	Solar
Tire-Derived Fuel	Tire-Derived Fuels
Waste Heat	Waste heat not directly attributed to a fuel source: Waste heat should only be reported where the fuel source for the waste heat is undetermined and for combined cycle steam turbines that do not have supplemental firing
Water	Water
Wind	Wind
Other	Other generator types not listed previously.

Table 23. Resource Project Status, based on merging the LRS WECC Class Code, NERC Class Code, and other indications of the resource project status (e.g., stakeholder feedback).

Resource Project Status	Description
0	Existing: Existing and commercially operating by 12/31/2013
1	Under Construction: Under active construction and projected to be in-service within the next five years
2	Pre-construction Regulatory Review and/or Approval: Not under active construction, but currently reported to have: • Received regulatory approval, or are undergoing regulatory review; • A signed interconnection agreement; and • An expected on-line date within the next seven years
3	Future-Planned: Reported generation additions that have met the NERC criteria for Tier 1 or Tier 2 Resources but, because of expected on-line requirements, do not qualify as Class 1 or 2 Resources. NERC Future Resource Tiers: - T1 - Tier 1: o Construction is underway or complete (not in commercial operation); o Issued an approved Power Purchase Agreement (PPA); o Designated or approved by a market operator and an Interconnection Agreement has been signed; o Specifically included in an Integrated Resource Plan or under a regulatory environment that mandates a resource adequacy requirement; or o Identified by a Load-Serving Entity (LSE) to meet the obligation to serve load. - T2 - Tier 2: o All regulatory approvals including those for inclusion in the rate base have been requested; or o A Power Purchase Agreement (PPA) or Generation Interconnection has been requested.

Resource Project Status	Description
4	Future-Conceptual: Reported generation additions that are identified and/or announced on a resource-planning basis through one or more of the following sources and meet the NERC criteria for Tier 3 Resources (i.e., they don't meet the NERC criteria for Tier 1 and Tier 2 Resources): - Corporate announcement; - Entered into or is in the early stages of an approval process; - Is in a generator interconnection (or other) queue for study; or - "Place-holder" generation for use in modeling.
5	No Longer Expected: Reported in the past but currently no longer expected to be in-service in the future. This may also include "indefinitely postponed" or "standby" facilities.
Non-WECC	Resource reported to WECC that doesn't actually deliver power to WECC.
Unmapped PF Generator	Generator reported in the power flow model that has unknown status.
Retired	Decommissioned, retired or planned to be indefinitely out-of-service.

Step 3: Stakeholder review of resource reconciliation

TEPPC stakeholders and TSS Area Coordinators reviewed the reconciled resource information. Approximately 15,000 comments and suggested data inputs were received and applied to the TEP resource database. Many comments had conflicting information so TEP collaborated with stakeholders to resolve the conflicts as much as possible given the time constraints.

The California Public Utilities Commission (CPUC) was a key stakeholder in reviewing the resource portfolio. TEP didn't have directly access to the CPUC resource portfolio(s), so those portfolios weren't among the resource databases that were cross-checked in the initial development of the 2024 Common Case. Rather, CPUC reviewed the resource assumptions and advised TEP on what additional resources (especially renewables) should be added to the 2024 Common Case so that the 2024 Common Case includes adequate amounts of CA resources to meet its RPS targets - i.e., in a comparable way to how CPUC's resource portfolio met its projected RPS targets.

Resource Modeling Overview

TEP assigned the generating resources to TEPPC Load Areas and power flow buses based on the resource reconciliation effort previously described. This section describes the power flow bus mapping effort and gives an overview of how the modeling of each resource type was organized.

Assumed Power Flow Mapping

The resource reconciliation effort previously mentioned played a major part in identifying the resources and their location in the power flow model. However, there were still resources missing a link to the power flow model so their power flow location (i.e., bus and ID) were assumed based on the resource's TEPPC Load Area - either on the "swing" bus of, or on a bus local to, the TEPPC Load Area. Table 24 shows the assumed power flow buses for resources in each TEPPC Load Area that did not have a definite power flow location and why the assumption was made.

Table 24. Power Flow Bus Assumptions

TEPPC Load Area	Assumed Bus	Reason/Location?
AESO	54151	Alberta area swing bus
AVA	48271	115-kV bus central to AVA area
AZPS	15926	Arizona area swing bus
BANC	37003	230-kV bus central to BANC & CIPV areas
BCHA	50645	BC Swing Bus
BPAT	40296	Northwest area swing bus
CFE	20008	CFE area swing bus
CHPD	46872	115-kV bus central to CHPD area
CIPB	30000	Pacific Gas & Electric area swing bus
CIPV	37003	230-kV bus central to BANC & CIPV areas
CISC	24004	Southern California area swing bus
CISD	22607	San Diego Gas & Electric area swing bus
DOPD	47031	230-kV bus central to DOPD area
EPE	11135	EPE area swing bus
GCPD	46017	115-kV bus central to GCPD area
IID	21030	IID area swing bus
IPFE	60100	Idaho area swing bus
IPMV	60100	Idaho area swing bus
IPTV	60100	Idaho area swing bus
LDWP	26004	LDWP area swing bus
NEVP	18403	NEVP area swing bus
NWMT	62048	Montana area swing bus
PACW	66055	PACE area swing bus
PAID	66055	PACE area swing bus
PAUT	66055	PACE area swing bus
PAWY	66055	PACE area swing bus
PGE	43761	115-kV bus central to PGE area
PNM	10321	New Mexico area swing bus
PSCO	70120	PSCO area swing bus
PSEI	45705	115-kV bus central to PSEI area

TEPPC Load Area	Assumed Bus	Reason/Location?
SCL	46449	115-kV bus central to SCL area
SPPC	64119	SPPC area swing bus
SRP	15926	Arizona area swing bus
TEPC	16000	500-kV bus central to TEPC area
TIDC	34144	115-kV bus central to TIDC area
TPWR	46631	115-kV bus central to TPWR area
WALC	63005	WAPA UM area swing bus
WACM	73129	WAPA RM area swing bus
WAUW	63005	WAPA UM area swing bus

The assumptions in Table 24 ensured that the output of all resources is applied to the appropriate TEPPC Load Area. Such assumptions, in most cases, are adequate for Interconnection-wide production cost modeling and similar assumptions were made in past TEPPC datasets. The assumed mapping doesn't allow for a solid "round trip" capability between the PCM and power flow models, but such capability is the goal of future versions of the 2024 Common Case rather than its initial version. Swing buses are essential to the power flow model because they provide or absorb whatever power (active or reactive) is needed to stabilize the system. In other words, the swing bus takes up the "slack" in the system to allow the power flow algorithm to determine a solution. The swing buses have generators ("swing generators" or "slack generators") with substantial and flexible capabilities and; therefore, are typically well suited for large injections or absorptions of electric power.

Resource Modeling Categories

TEP grouped the resources into modeling categories based on their operating characteristics. Table 25 shows these categories and gives a brief description of the methodologies used to model the different types of resources. Refer to the next sections for more detail on each resource modeling category.

Table 25. Resource Modeling Categories

Resource Modeling Category	Identification	Modeling Methodology
1. Hourly Renewable	Wind and Solar	Hourly shape based on NREL hourly profiles
2. Hourly Hydro	Hydro insensitive to load or price	Hourly shape
3. PLFHTC[4] Hydro	Hydro sensitive to load and LMP	PLF/HTC
4. Pump Storage	Pump storage or reversible hydro facilities	Pumped Storage
5. Dispatchable Thermal	Conventional resources, such as gas- and coal-fired	Dispatched if it is cost effective and needed
6. Must Run Thermal	Biomass, Biogas, Geothermal, Cogeneration, and Combined Heat and Power (CHP)	Thermal that must run if available, with output typically set to a high minimum value
7. Plant Parts	Operationally tied units, typically units within a combined cycle plant	Same as Dispatchable Thermal
8. DC Line	Power flow resources representing DC lines	Hourly shape based on power flow information and approximations of historical data
9. Motor Load	Negative resources representing pump and other motor loads	Hourly Shape based on historical data
10. Volt-amperes reactive (VAR) Device	Power flow resources representing VAR support devices	Turned off in the model
11. Off-Line	Resources that should be considered off-line (e.g., retired, out-of-service, indefinitely on standby)	Turned off in the model
12. Energy Efficiency/ Demand Response	Resources representing load modifiers such as EE and DR	EE: Hourly shape based on area load shapes DR: Hourly shape based on DR forecasts
13. Generic Storage	Storage facilities with unknown details	Same as Pumped Storage
14. Misc Hourly	Resources that exist or are planned but whose modeling is uncertain or incomplete	“None” (i.e., all zeroes) Hourly Shape and turned off in model

[4] Proportional Load Following Hydrothermal Co-optimization.

Status and Need Categories

TEP considered the following categories of status and need when modeling the resources:

- Existing: those assumed to be online by 12/31/2013. This includes the 0 (Existing) resource project status mentioned previously.
- Incremental: those assumed to be online between 2014 and 2024, inclusively. This includes the 1 (Under Construction), 2 (Pre-Const Reg Approval-Review), 3 (Future-Planned), and 4 (Future-Conceptual) resource project statuses mentioned previously.
- Gap: those added to the dataset to fill any "gaps" with regard to complying with state and federal policy or other directives.

The existing and incremental resources are self-explanatory, but the generic gap resources are more complex as their addition is dependent on a variety of things including, but not limited to:

- Meeting Renewable Portfolio Standard targets;
- Satisfying resource adequacy and planning reserve; and
- Meeting other state-, area-, and region-specific future goals.

Modeling by Resource Category

The following subsections describe the resource categories by which the resources are modeled in GridView. Within the dataset, the "GV SubType" field is used to summarize the TEP Generator Type and TEP Primary Fuel of each resource. Table 26 shows the various values of GV SubType used in the 2024 Common Case and their corresponding TEP Generator Type and TEP Primary Fuel.

Table 26. GV SubType Values in 2024 Common Case

GV SubType	TEP Generator Type	TEP Primary Fuel
Bio-CCWhole	Combined Cycle-Whole Plant-Biomass	Biomass-LandfillGas
Bio-CCWhole	Combined Cycle-Whole Plant-Biomass	Biomass-Sludge Waste
Bio-CT	Combustion Turbine-Biomass	Biomass-LandfillGas
Bio-CT	Combustion Turbine-Biomass	Biomass-Other
Bio-FuelCell	Fuel Cell	Biomass-Other
Bio-ICE	Internal Combustion Engine (ICE)	Biomass-Agricultural
Bio-ICE	Internal Combustion Engine (ICE)	Biomass-Black Liquor
Bio-ICE	Internal Combustion Engine (ICE)	Biomass-LandfillGas
Bio-ICE	Internal Combustion Engine (ICE)	Biomass-Other
Bio-ICE	Internal Combustion Engine (ICE)	Biomass-Sludge Waste
Bio-ST	Steam Turbine-Biomass	Biomass-Agricultural

GV SubType	TEP Generator Type	TEP Primary Fuel
Bio-ST	Steam Turbine-Biomass	Biomass-Black Liquor
Bio-ST	Steam Turbine-Biomass	Biomass-LandfillGas
Bio-ST	Steam Turbine-Biomass	Biomass-Muni Solid
Bio-ST	Steam Turbine-Biomass	Biomass-Other
Bio-ST	Steam Turbine-Biomass	Biomass-Wood-Liquid
Bio-ST	Steam Turbine-Biomass	Biomass-Wood-Solid
CCPart-BioGas	Combined Cycle-Gas Part-Biomass	Biomass-LandfillGas
CCPart-NatGas-Aero	Combined Cycle-Gas Part-Aero Derivative	Gas-Natural Gas
CCPart-NatGas-Industrial	Combined Cycle-Gas Part-Industrial Frame	Gas-Natural Gas
CCPart-Steam	Combined Cycle-Steam Part	Waste Heat
CCWhole-NatGas-Aero	Combined Cycle-Whole Plant-Aero Derivative	Gas-Natural Gas
CCWhole-NatGas-Industrial	Combined Cycle-Whole Plant-Industrial Frame	Gas-Natural Gas
CCWhole-NatGas-SingleShaft	Combined Cycle-Single Shaft	Gas-Natural Gas
CCWhole-SynGas	Combined Cycle-Whole Plant-SynGasViaCoal	Gas-Synthetic via Coal
CrossCompoundPart-Coal	Steam Turbine-Coal	Coal-Bit
CrossCompoundWhole-Coal	Steam Turbine-Coal	Coal-Bit
CT-NatGas-Aero	Combustion Turbine-Nat Gas-Aero Derivative	Gas-Natural Gas
CT-NatGas-Industrial	Combustion Turbine-Nat Gas-Industrial Frame	Gas-Natural Gas
CT-OilDistillate	Combustion Turbine-Oil	Oil-Distillate Fuel
CT-OtherGas	Combustion Turbine-Other	Gas-Other
CT-SynGas	Combustion Turbine-Synth Gas	Gas-Synthetic via Coal
DC-Intertie	DC Intertie (DCI)	N/A
DG-BTM	DG-BTM	DG-BTM
DR	Demand Response	Demand Response
EE	Energy Efficiency	Energy Efficiency
ES-2HR-Generic	Energy Storage-2HR-Generic	Electricity-Storage
ES-4HR-Generic	Energy Storage-4HR-Generic	Electricity-Storage
ES-6HR-Generic	Energy Storage-6HR-Generic	Electricity-Storage
Geo-BinaryCycle	Binary Cycle	Geothermal
Geo-DoubleFlash	Double Flash	Geothermal
Geo-SingleFlash	Single Flash	Geothermal
Geo-ST	Steam Turbine-Other	Geothermal
Hydro	Hydro	Water
Hydro-Netted	Hydro-Netted-From-Load	Water
HydroRPS	Hydro-RPS	Water
ICE-NatGas	Internal Combustion Engine (ICE)	Gas-Natural Gas

GV SubType	TEP Generator Type	TEP Primary Fuel
ICE-OilDistillate	Internal Combustion Engine (ICE)	Oil-Distillate Fuel
MotorLoad	Pumping Load	N/A
MotorLoad	Unknown	Unknown
PS-Hydro	Hydro-PumpStorage	Water-Electricity
PS-HydroRPS	Hydro-PumpStorage-RPS	Water-Electricity
SolarPV-NonTracking	SolarPV-Non-Tracking	Sun
SolarPV-Tracking	SolarPV-Tracking	Sun
SolarThermal-CSP0	Solar Thermal-No Storage (CSP0)	Sun
SolarThermal-CSP6	Solar Thermal-Storage (CSP6)	Sun
ST-Coal	Steam Turbine-Coal	Coal-Bit
ST-Coal	Steam Turbine-Coal	Coal-Lig
ST-Coal	Steam Turbine-Coal	Coal-Other
ST-Coal	Steam Turbine-Coal	Coal-Sub
ST-Coal	Steam Turbine-Coal	Petroleum Coke
ST-NatGas	Steam Turbine-Gas	Gas-Natural Gas
ST-Nuclear	Steam Turbine-Nuclear	Nuclear
ST-Other	Steam Turbine-Other	Other
ST-OtherGas	Steam Turbine-Other	Gas-Other
ST-WasteHeat	Steam Turbine-Other	Purchased Steam
ST-WasteHeat	Steam Turbine-Waste Heat	Waste Heat
UnknownPwrFloMdl	Unknown	Unknown
VAR-Device	STATCOM	N/A
VAR-Device	SVC	N/A
VAR-Device	Synchronous Condenser	N/A
WT-Onshore	Wind-Onshore	Wind

Wind and Solar Facilities

Solar and wind generation are modeled as fixed-shape resources in TEPPC's 10-year production cost model. This means that solar and wind generation is forced into the model as must-take generation because these units have no production cost. The production cost model requires a fixed hourly shape when modeling wind and solar.

Hourly Shapes

The National Renewable Energy Laboratory (NREL), as part of the Western Wind Dataset effort, created hourly solar and wind meso-scale shapes for roughly 30,000 sites throughout the Western Interconnection - refer to the NREL Website for more information. Each NREL profile in the Western Wind Dataset represents a small generation site (2 km by 2 km) and the historical resource availability in that small region. The original data is based on extensive meteorological modeling efforts that result in wind speed or irradiance (in the case of solar) data for the specific region that can then be converted to power output.

TEPPC shapes capture a much larger region and are used to represent a shape that would be more characteristic of an average generation site in that area. Solar and wind shapes used in the TEPPC datasets are created by aggregating NREL profiles. Instead of representing a single 2-km-by-2-km grid, the aggregated TEPPC shapes represent a much larger area. This methodology was adopted for two key reasons:

1) Aggregating NREL profiles to represent regionally based shapes is the most efficient way to accurately assign generators within that region a specific, yet accurate, shape. TEPPC could attempt to develop a shape for each individual generator in the dataset, but this would require a substantial amount of time and effort. Because of this, TEPPC creates aggregated regional shapes that are assigned to plants within that region.

2) Aggregating NREL profiles into a representative TEPPC shape captures the appropriate amount of geographic diversity that is supplied by the resources. Simply taking a single NREL profile and assigning it to a large capacity of resources would result in a shape with overstated variability.

The number of NREL profiles that must be aggregated to produce a single TEPPC profile depends on the capacity of wind/solar within the geographic vicinity for which the TEPPC shape is being created. Each NREL profile has an associated capacity and enough need to be selected to fulfill the required amount of modeled resource capacity within the target geographic vicinity. For example, to model a 300-MW solar or wind plant in the TEPPC dataset, 300-MW worth of NREL solar or wind profiles are selected and aggregated. All plants within the same geographic vicinity are then applied the same (per unit) aggregate shape that gets scaled according to the individual plant's capacity, as previously described. This method more accurately depicts the output of an actual wind or solar site, compared to the alternative option that uses a generic shape. The process for creating solar and wind aggregate shapes is the same for both TEPPC solar and wind profiles, and both wind and solar use NREL 2005 profiles.

Capacity Factors

As part of a stakeholder-requested review of TEPPC wind and solar profiles in the 2022 Common Case, E3 and Black & Veatch found that TEPPC profiles understated the expected output of future and existing wind plants in some states. TAS approved a process where E3 and Black & Veatch would provide capacity factor targets based on U.S. Energy Information Administration (EIA) historical generation data and expected values per the Western Resource Energy Zone (WREZ) report published by the Western Governors' Association and U.S. Department of Energy. These targets were then used as guidance for the TEPPC profile selection process to align TEPPC wind profiles with historical and expected generation throughout the West.

Table 27 shows the capacity factors of wind profiles used in the 2024 Common Case Dataset. It is important to note there are two different types of profiles used: future and existing.

Future profiles are used to represent wind farms that are not currently on the ground or under construction and they are created using WREZ-expected generation data collected by Black & Veatch.

Existing profiles are used to represent plants that are currently in operation or under construction. These existing profiles are created using EIA historical generation data collected by E3.

Table 27. Existing and Future Wind Profile Capacity Factors

Existing Wind Resources				Future Wind Resources			
Profile Name	**%CF**	**Profile Name**	**%CF**	**Profile Name**	**%CF**	**Profile Name**	**%CF**
WT-E_AB08	35%	WT-E_CO_SE	35%	WT-P_AB08	35%	WT-P_CO_SE	41%
WT-E_AZ_EA	27%	WT-E_CO_SO	37%	WT-P_AZ_EA	29%	WT-P_CO_SO	38%
WT-E_AZ_SO	22%	WT-E_ID_EA	28%	WT-P_AZ_SO	22%	WT-P_ID_EA	29%
WT-E_AZ_WE	28%	WT-E_ID_SO	28%	WT-P_AZ_WE	30%	WT-P_ID_SO	31%
WT-E_BC_NE	29%	WT-E_MT_NO	35%	WT-P_BC_NE	29%	WT-P_MT_NO	40%
WT-E_BC_NO	28%	WT-E_MT_SO	36%	WT-P_BC_NO	28%	WT-P_MT_SO	38%
WT-E_BC_NW	27%	WT-E_NE_SW	28%	WT-P_BC_NW	27%	WT-P_NE_SW	35%
WT-E_BC_WE	27%	WT-E_NM_CE	33%	WT-P_BC_WE	27%	WT-P_NM_CE	33%
WT-E_CA_CE	26%	WT-E_NM_EA	40%	WT-P_CA_CE	36%	WT-P_NM_EA	39%
WT-E_CA_CST	15%	WT-E_NM_SO	27%	WT-P_CA_CST	15%	WT-P_NM_SO	34%
WT-E_CA_DVRS	26%	WT-E_NV_EA	32%	WT-P_CA_DVRS	27%	WT-P_NV_EA	37%
WT-E_CA_LA	26%	WT-E_OR_CE	23%	WT-P_CA_LA	32%	WT-P_OR_CE	34%
WT-E_CA_MTN	26%	WT-E_OR_EA	26%	WT-P_CA_MTN	26%	WT-P_OR_EA	31%
WT-E_CA_NE	31%	WT-E_OR_NO	30%	WT-P_CA_NE	31%	WT-P_OR_NO	34%

Existing Wind Resources				Future Wind Resources			
Profile Name	%CF	Profile Name	%CF	Profile Name	%CF	Profile Name	%CF
WT-E_CA_NO	23%	WT-E_TX_WE	25%	WT-P_CA_NO	24%	WT-P_TX_WE	36%
WT-E_CA_NW	27%	WT-E_UT_NO	24%	WT-P_CA_NW	27%	WT-P_UT_NO	26%
WT-E_CA_SANF	17%	WT-E_UT_SO	26%	WT-P_CA_SANF	18%	WT-P_UT_SO	28%
WT-E_CA_SDSO	31%	WT-E_WA_CE	28%	WT-P_CA_SDSO	31%	WT-P_WA_CE	30%
WT-E_CA_SO	28%	WT-E_WA_EA	27%	WT-P_CA_SO	33%	WT-P_WA_EA	30%
WT-E_CA_SO1	29%	WT-E_WA_SO	29%	WT-P_CA_SO1	29%	WT-P_WA_SO	33%
WT-E_CA_SO2	28%	WT-E_WA_WE	28%	WT-P_CA_SO2	28%	WT-P_WA_WE	32%
WT-E_CA_TEH	39%	WT-E_WY_CE	34%	WT-P_CA_TEH	39%	WT-P_WY_CE	45%
WT-E_CA_THCP	41%	WT-E_WY_SE	35%	WT-P_CA_THCP	41%	WT-P_WY_SE	45%
WT-E_CO_CE	35%	WT-E_WY_SW	34%	WT-P_CO_CE	35%	WT-P_WY_SW	43%
WT-E_CO_NE	27%			WT-P_CO_NE	40%		

E3’s review of TEPPC solar profiles showed that photovoltaic (PV) profiles used in the 2022 Common Case Dataset never exceeded 80 percent of their rated capacity. These TEPPC profiles were found to assume a one-to-one converter loading ratio. Assuming a converter loading ratio of 1.0 forced all of the TEPPC profiles to be capped at 80 percent of their rated capacity due to the NREL de-rate factor of PV profiles. Industry practice for PV installations has been to oversize inverters to compensate for de-rate factors such as AC-DC conversions and losses. Based on E3’s recommendations, TEPPC has decided to align its modeling with that industry practice. The profiles used in the 2024 Common Case assume the following inverter loading ratios.

- Fixed tilt, utility scale: 1.40-1
- Tracking, utility scale: 1.30-1
- Rooftop: 1.20-1

Table 28 shows the resulting capacity factors of solar profiles used in the 2024 Common Case dataset after applying the aligned inverter loading ratios.

Table 28. Percent Capacity Factor of Solar Profiles

Profile Name	% CF	Profile Name	% CF	Profile Name	% CF
CSP0_AZ_WE	26%	PV-Fixed_NM_NO	26%	PV-Rooftop_PSE	14%
CSP0_CA_CE	26%	PV-Fixed_NM_SE	27%	PV-Rooftop_PSEI	14%
CSP0_CA_EA	26%	PV-Fixed_NM_SO	26%	PV-Rooftop_SCE	21%
CSP0_CA_SO	26%	PV-Fixed_NV_SO	26%	PV-Rooftop_SCL	14%
CSP0_CA_SW	27%	PV-Fixed_NV_WE	25%	PV-Rooftop_SDGE	21%
CSP0_NV_SO	24%	PV-Fixed_OR_NW	23%	PV-Rooftop_SMUD	19%
CSP0_OR_NW	25%	PV-Fixed_TX_CE	27%	PV-Rooftop_SPP	22%

Profile Name	% CF	Profile Name	% CF	Profile Name	% CF
CSP6_AZ_SO	40%	PV-Fixed_TX_WE	27%	PV-Rooftop_SPPC	22%
CSP6_AZ_WE	39%	PV-Fixed_UT_CE	23%	PV-Rooftop_TEP	23%
CSP6_CA_SO	42%	PV-Fixed_WA_SO	23%	PV-Rooftop_TEPC	23%
CSP6_CO_SO	35%	PV-Rooftop_AZPS	23%	PV-Rooftop_TIDC	20%
CSP6_NV_WE	38%	PV-Rooftop_BANC	19%	PV-Rooftop_UT	19%
PV-Fixed_AZ_EA	27%	PV-Rooftop_CISC	21%	PV-Rooftop_WALC	23%
PV-Fixed_AZ_NO	26%	PV-Rooftop_CISD	21%	PV-Tracking_AZ_EA	33%
PV-Fixed_AZ_SO	26%	PV-Rooftop_EPE	23%	PV-Tracking_AZ_NO	31%
PV-Fixed_AZ_SW	26%	PV-Rooftop_IID	22%	PV-Tracking_AZ_SO	32%
PV-Fixed_AZ_WE	27%	PV-Rooftop_LDWP	20%	PV-Tracking_AZ_SW	31%
PV-Fixed_CA_NO	24%	PV-Rooftop_NEVP	23%	PV-Tracking_AZ_WE	33%
PV-Fixed_CA_SE	26%	PV-Rooftop_PACW	16%	PV-Tracking_CA_NO	28%
PV-Fixed_CA_SO	27%	PV-Rooftop_PAUT	19%	PV-Tracking_CA_NW	27%
PV-Fixed_CA_SW	26%	PV-Rooftop_PAWY	16%	PV-Tracking_CA_WE	32%
PV-Fixed_CO_CE	26%	PV-Rooftop_PGaE	20%	PV-Tracking_NM_CE	32%
PV-Fixed_CO_SO	20%	PV-Rooftop_PGE	15%	PV-Tracking_NM_NO	32%
PV-Fixed_CO_WE	26%	PV-Rooftop_PGN	15%	PV-Tracking_NM_SE	32%
PV-Fixed_ID_SW	24%	PV-Rooftop_PSC	21%	PV-Tracking_NM_SO	32%
PV-Fixed_NM_CE	27%	PV-Rooftop_PSCO	21%	PV-Tracking_NV_SO	32%

Distributed Generation (DG) Facilities

The TEPPC 2024 Common Case assumes that distributed generation is not included in the L&R load forecasts. TEPPC's definition of DG includes two parts:

- **Behind-the-meter (BTM) DG** – small-scale solar PV installations that individual retail customers would install and own to avoid purchasing electricity from an electric utility.
- **Wholesale DG** – PV systems that are connected directly to the electric distribution network and sell the electricity on the wholesale market, typically 1–20 MW and often procured to meet state DG targets.

Currently DG is being modeled as a resource in the dataset. Behind-the-meter DG is provided by estimates developed by E3 and LBNL and vetted through TAS. These capacities are used to develop "fixed rooftop" solar PV profiles and modeled as a fixed-shape resource. Wholesale DG is provided to the dataset like any other resource—by LRS submittals, the EIA and IRPs—and validated through the generator reconciliation effort. Table 29 shows the TAS-approved capacity of behind-the-meter (BTM)

DG by state as provided by E3, as well as the corresponding energy contributed in the 2024 Common Case. Table 30 shows how the state capacities break out to the different TEPPC load areas.

Table 29. Behind-the-meter DG in 2024 Common Case, by State

State	2022 Common Case Capacity (MW)	2024 Common Case Capacity (MW)	2024 Common Case Energy (GWh)
Arizona	1,960	1,401	2,706
California	4,349	4,560	8,281
Colorado	564	594	999
Idaho	-	41	58
Montana	-	28	42
New Mexico	62	136	262
Nevada	36	193	377
Oregon	76	153	230
Utah	18	85	145
Washington	23	72	105
Wyoming	-	38	55
Total	7,088	7,301	13,259

Table 30. Behind-the-meter DG in 2024 Common Case, by BA and State

State	BA	Ratio	Capacity (MW)
Arizona	AZPS	0.3552	497.64
	SRP	0.3844	538.54
	TEPC	0.1588	222.48
	WALC	0.1016	142.34
California	CIPB	0.1638	746.93
	CIPV	0.2053	936.17
	CISC	0.3598	1,640.69
	CISD	0.081	369.36
	IID	0.0146	66.58
	LDWP	0.1045	476.52
	BANC	0.0579	264.02
	TIDC	0.0097	44.23
	PACW	0.0035	15.96
	BPAT	0	0.00
Colorado	PSCO	0.6445	382.83
	WACM	0.3553	211.05
Idaho	IPTV	0.3693	15.14
	IPMV	0.1696	6.95
	IPFE	0.0876	3.59
	AVA	0.2036	8.35
	PAID	0.1558	6.39
	BPAT	0.0141	0.58
Montana	NWMT	0.7667	21.47
	WAUW	0.0482	1.35
	BPAT	0.1851	5.18
New Mexico	PNM	0.7806	106.16
	EPE	0.1072	14.58
	WALC	0.1122	15.26
Nevada	NEVP	0.6516	125.76
	SPPC	0.3484	67.24
Oregon	PGN	0.3954	60.50
	PACW	0.2555	39.09
	BPAT	0.3272	50.06
	IPTV	0.0218	3.34
Utah	PAUT	1	85.00
Washington	BPAT	0.3676	26.47
	AVA	0.0823	5.93
	PACW	0.0464	3.34
	PSE	0.2501	18.01
	SCL	0.0983	7.08
	TPWR	0.0514	3.70
	CHPD	0.039	2.81
	DOPD	0.0175	1.26
	GCPD	0.0465	3.35
Wyoming	PAWY	0.4899	18.62
	WACM	0.5101	19.38

Hydroelectric Facilities

Hydro generation is a significant resource in the Western Interconnection. In the 2024 Common Case, hydro generation is modeled using a variety of methods that attempt to capture the unique operating characteristics of the resource. A mixture of fixed hourly shapes based on historical time series, a hydrothermal co-optimization (HTC) technique, and proportional load following (PLF) algorithms were used to model hydro generation. Hydro dispatchability constraints due to environmental or other operational factors (e.g., irrigation water deliveries, flood control, environmental release) were captured in the model using minimum and maximum operating levels, monthly energy limits, monthly load proportionality constants (*K* values), and monthly hydrothermal co-optimization fractions (p factors), when applicable.

The initial modeling parameters were determined on a plant level and spread into hydro modeling regions. In all hydro modeling regions, plants were categorized as large (> 10-MW capacity) or small (< 10-MW capacity). The exception to this was in California, which had a special “RPS” category for plants with capacities from 10 MW through 30 MW. Plants smaller than 10-MW capacity were rolled up and modeled as a PLF *K*=0 large plant.

The plant-level modeling was then spread to unit-level modeling. The hourly shapes and energy targets were spread proportionally based on the nameplate of the units in each plant. For PLF and HTC hydro units, they were assigned the same K values and p factors as their plants because these modeling parameters are measures of responsiveness to load levels and locational marginal prices (LMP) rather than parameters that depend on units’ or plants’ size. Table 31 summarizes the number of units using each hydro modeling method.

Table 31. Interconnection-wide Count of Summary of Hydro Modeling Methods, by Hydro Region

Hydro Modeling Region	States/Provinces Included	Number of Units			
		Hourly Shape	*PLF*	*PLF K=0 (Flat)*	*HTC*
Northwest	Oregon, Washington, Idaho, Montana west of the Continental Divide	206	90	243	154
California	California	257	2	131	78
East	Arizona, Colorado, Nevada, New Mexico, Montana east of the Continental Divide, Utah, Wyoming	73	4	71	23
Alberta	Alberta	10	0	0	28
British Columbia	British Columbia	0	0	158	109
Total	**1637**	**546**	**96**	**603**	**392**

Table 32 and Figure 12 show the impact (i.e., capacity and energy) of each hydro modeling method in the 2024 Common Case.

Table 32. Interconnection-wide Impact of Hydro Modeling Methods

Modeling Method	Capacity (MW)	Percent of Total Capacity	Hydro Energy (GWh)	Percent of Total Hydro Energy
UseGivenSchedule	17,735	26.0%	59,715	24.5%
PLF	2,516	3.7%	8,471	3.5%
PLF K=0 (Flat)	5,900	8.7%	24,825	10.2%
HTC	41,990	61.6%	150,769	61.8%
Total	68,141	100.0%	243,779	100.0%

Figure 12. Interconnection-wide Distribution of Hydro Modeling (percent of Total)

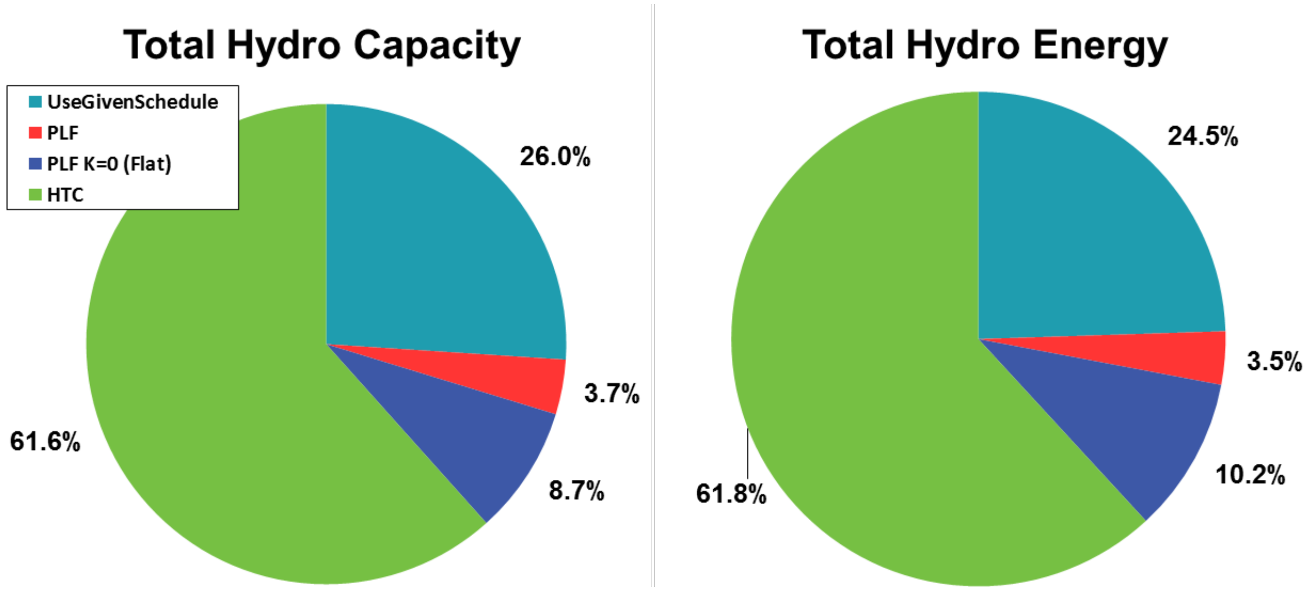
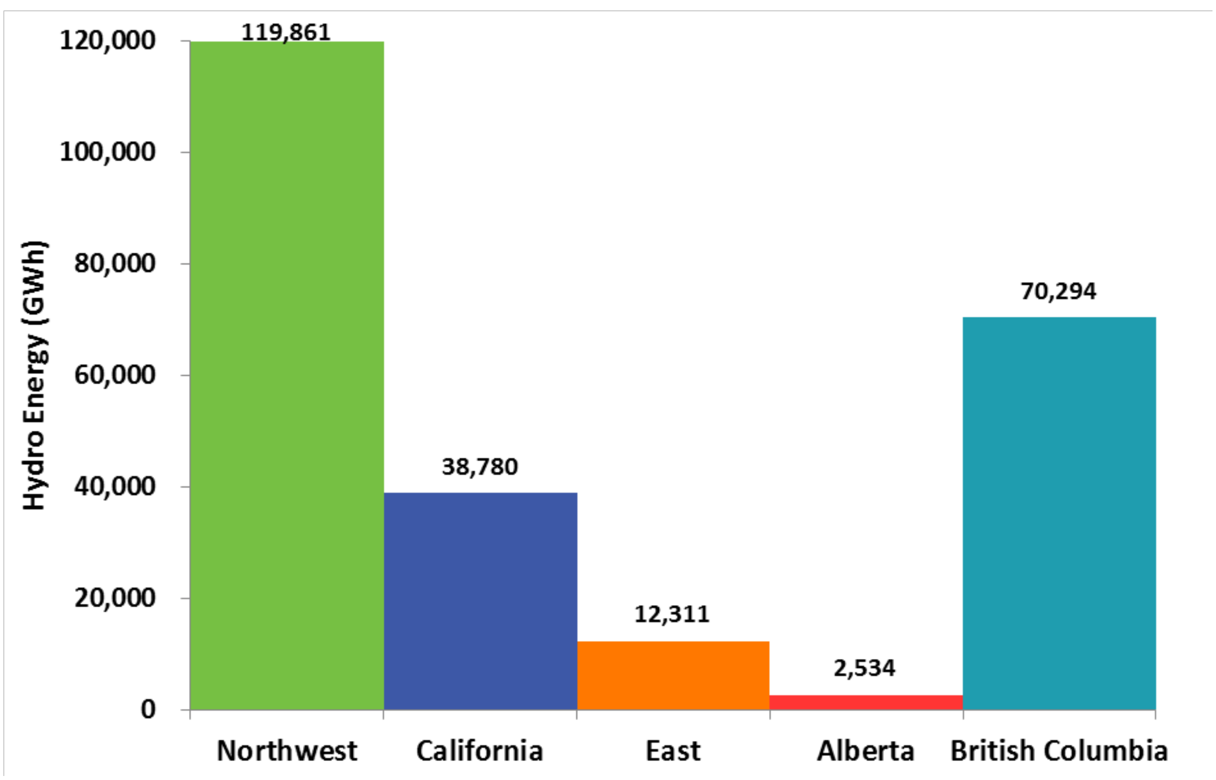


Figure 13 shows the total hydro energy for each hydro region.

Figure 13. Total Annual Energy by Hydro Region



The next sections go into more detail about how the hydro units in each of the hydro modeling regions were modeled.

Modeling Hydroelectric Ramp Rates

Many hydroelectric units are technically capable of extremely quick ramping, able to go from zero to full output in as little as 15 minutes; however, many hydroelectric facilities are limited by environmental water usage restrictions (e.g., allowing for fish migration).

Modeling Hydroelectric Reserve Contributions

All hydro plants and their units are limited in their reserve contribution per the following criteria:

- If there is one unit in plant, then the unit's contribution to reserves is limited to 50 percent of its capacity.
- If there are multiple units in plant, then each unit's contribution to reserves is limited to one over the number of units in the plant (e.g., 1/5 for plants with five units) or 15 percent, whichever is greater.

Northwest Hydro Modeling Region

The Northwest hydro modeling region includes Northwest Federal and Non-Federal, Mid C Non-federal, and PacifiCorp. The PLF/HTC modeling methods were used to model the majority of NW hydro generation in the 2022 Common Case. Plant modeling assumptions are shown in Figure 12.PLF constants were obtained by regressing historical data and loads for federal projects, or were supplied by plant operators for non-federal projects. For Grand Coulee, The Dalles, Chief Joseph, and John Day, average K values were calculated using data years 1999, 2001 to 2003, and 2005 to 2010. Monthly average generation values for both HTC and PLF plants came from the EIA 906/920 data for 2005. Smaller plants were modeled using estimated PLF constants and EIA 906/920 generation values.

Plants determined to not follow load historically were modeled using historical hourly shapes. These included Bonneville, McNary, the lower Snake River, and federal storage plants. Historical data came from the U.S. Army Corps of Engineers and Northwestern Division website for the same years as the EIA data. Wanapum, Priest Rapids and Rock Island data came from the BPA Plant Information (PI) system with concurrence from Grant County and Chelan County PUDs. For Swift 1, Yale, Boyle, Toketee, Lemolo 1 and Merwin generators, 2005 historical data received from PacifiCorp were used. Clearwater 1 and 2 and Slide Creek K values were calculated for 2004 to 2006 and averaged. Plants with nameplate capacities of less than 10 MW were rolled up into state "plants" with summed monthly EIA averages; these state "plants" were modeled using PLF K=0 (flat monthly generation). Unit modeling assumptions are summarized in Table 33.

Table 33. Summary of Northwest Hydro Modeling Methods

Modeling Method	Capacity (MW)	Percent of Total Capacity	Hydro Energy (GWh)	Percent of Total Hydro Energy
UseGivenSchedule	10,067	29.4%	34,979	29.2%
PLF	2,311	6.8%	7,858	6.6%
PLF K=0 (Flat)	2,289	6.7%	9,139	7.6%
HTC	19,519	57.1%	67,884	56.6%
Total	34,186	100.0%	119,861	100.0%

California Hydro Modeling Region

The California hydro data is from the CAISO PI dataset that was aggregated to the river system. "Historical" individual plant data was then disaggregated proportionally to EIA 906/920 monthly generation values. TEP used a combination of historical shapes, PLF and HTC to model California hydro generation. For the few plants not in CAISO's PI system, PLF or HTC modeling using EIA 906/920 data for 2005 were used. California small hydro was disaggregated from the conventional hydro to more accurately track its contribution to RPS requirements (this includes plants from 10- through 30-MW capacity). Plants with nameplate capacities of less than 10 MW were rolled up into operating area "plants" with summed monthly EIA averages; these area "plants" were modeled using PLF K=0 (flat monthly generation), and contributed toward RPS. Unit modeling assumptions are summarized in Table 34.

Table 34. Summary of California Hydro Modeling Methods

Modeling Method	Capacity (MW)	Percent of Total Capacity	Hydro Energy (GWh)	Percent of Total Hydro Energy
UseGivenSchedule	4,822	46.0%	17,016	43.9%
PLF	150	1.4%	463	1.2%
PLF K=0 (Flat)	654	6.2%	2,184	5.6%
HTC	4,863	46.4%	19,117	49.3%
Total	10,489	100.0%	38,780	100.0%

East Hydro Modeling Region

TEP modeled the WAPA plants using 2005 historical hourly hydro data, with the exception of Hoover, Blue Mesa, and Yellowtail, which used PLF/HTC. Non-federal plants were modeled using PLF based on EIA 906/920 data for 2005. Plants with nameplate capacities of less than 10 MW were rolled up into state "plants" with summed monthly EIA averages; these state "plants" were modeled using PLF K=0 (flat monthly generation). Unit modeling assumptions are summarized in Table 35.

Table 35. Summary of East Hydro Modeling Methods

Modeling Method	Capacity (MW)	Percent of Total Capacity	Hydro Energy (GWh)	Percent of Total Hydro Energy
UseGivenSchedule	2,709	49.8%	7,196	58.5%
PLF	56	1.0%	149	1.2%
PLF K=0 (Flat)	268	4.9%	741	6.0%
HTC	2,410	44.3%	4,225	34.3%
Total	5,442	100.0%	12,311	100.0%

Canadian Hydro Modeling Regions

BC Hydro generation data are determined by BC Hydro's Generalized Optimization Model using a 2022 load forecast and average inflows (1968 water conditions). The analysis included Revelstoke 5 and Mica Units 5 and 6. TEP used the Generalized Optimization Model results to calculate PLF constants for use by the HTC modeling method for the G.M. Shrum, Peace Canyon, Site C, Revelstoke, Mica, and small plants. The Arrow Plant and IPP (Independent Power Projects) rollup are modeled with no flexibility (PLF, K=0). BC Hydro provided updated, plant/aggregate-level hydro forecasts for use in the 2024 Common Case.

AESO provided 2005 data that was used as historical data for some plants and to calculate PLF/HTC constants for Bighorn, Bow River aggregate, and Brazeau plants. The historical monthly averages were used as the model energy inputs for the PLF/HTC plants.

British Columbia and Alberta unit modeling assumptions are summarized in Table 36 and Table 37.

Table 36. Summary of British Columbia Hydro Modeling Methods

Modeling Method	Capacity (MW)	Percent of Total Capacity	Hydro Energy (GWh)	Percent of Total Hydro Energy
UseGivenSchedule	0	0.0%	0	0.0%
PLF	0	0.0%	0	0.0%
PLF K=0 (Flat)	2,690	15.7%	12,761	18.2%
HTC	14,392	84.3%	57,533	81.8%
Total	17,082	100.0%	70,294	100.0%

Table 37. Summary of Alberta Hydro Modeling Methods

Modeling Method	Capacity (MW)	Percent of Total Capacity	Hydro Energy (GWh)	Percent of Total Hydro Energy
UseGivenSchedule	137	14.5%	523	20.7%
PLF	0	0.0%	0	0.0%
PLF K=0 (Flat)	0	0.0%	0	0.0%
HTC	805	85.5%	2,010	79.3%
Total	942	100.0%	2,534	100.0%

Pumped Storage Facilities

Table 38 and Table 39 summarize the pumped storage (PS) units and plants modeled in the 2024 Common Case. The following subsections provide more details on certain PS plants. The plants modeled with hourly shapes are either missing information in regard to the plants' operational practices or their operation rarely changes from year to year. In addition, these plants contribute less than 1.0 percent of the annual generation in the 2024 Common Case and; therefore, it was uneconomical to spent exorbitant staff-hours to research such information. The primary goal of the modeling was to emulate the historical capabilities of the facilities – i.e., meeting or exceeding their historical output. As a result, the historical hourly shape for 2005 was used as the default, especially for the smaller facilities.

Table 38. Pumped Storage Facilities modeled as Hourly Shapes

PS Plant Unit Names			TEPPC Load Area	Operator	Model As….	
Name & Units	Generating Capacity (MW)	Pumping Capacity (MW)			Hydro	Pumping Load
Grand Coulee PG 7-12	499.98	449.982	BPAT	USBR		☑
Edward C Hyatt 2, 4, 6	363.45	327.105	CIPV	CDWR	☑	
Thermalito 2-4	102.3	92.07	CIPV	CDWR	☑	
Waddell 1, 3, 6-7	30.4	27.36	WALC	CAWC	☑	
O'Neill 1-6	25.2	22.68	CIPV	CDWR		☑
W.R. Gianelli 1-8 (San Luis Pumping Plant)	424	381.6	CIPV	CDWR	☑	☑

Table 39. Pumped Storage Facilities modeled as Pumped Storage

Pumped Storage (PS) Units			PS Plants			TEPPC Load Area	Operational Efficiency	Adjustment Factor (CBR in GV)	Modeled Efficiency	Storage Capability	
Name	Generating Capacity (MW)	Pumping Capacity (MW)	Name	Generating Capacity (MW)	Pumping Capacity (MW)					Hours	MWh
Mount_Elbert_1	115.00	103.50	MountElbertPS	230.00	207.00	WACM	75%	0.90	83.3%	20	4,600
Mount_Elbert_2	115.00	103.50									
CabinCreekA	162.00	145.80	CabinCreekPS	324.00	291.60	PSCO	75%	0.90	83.3%	14	4,536
CabinCreekB	162.00	145.80									
LakeHodges1	40.00	36.00	LakeHodgesPS	80.00	72.00	SDGE	80%	0.94	85.1%	14	1,120
LakeHodges2	40.00	36.00									
HelmsPS1	404.00	363.60	Helms_1	1,212.00	1,090.80	PG&E	85%	0.94	90.4%	20	8,080
HelmsPS2	404.00	363.60	Helms_2				75%	0.90	83.3%	20	8,080
HelmsPS3	404.00	363.60	Helms_3				65%	0.95	68.4%	20	8,080
Castaic_1	195.83	176.25	CastaicPS_1-2	1,175.00	968.40	LADWP	85%	0.94	90.4%	20	7,833
Castaic_2	195.83	176.25									
Castaic_3	195.83	176.25	CastaicPS_3-4				75%	0.90	83.3%	20	7,833
Castaic_4	195.83	176.25									
Castaic_5	195.83	176.25	CastaicPS_5-6				65%	0.95	68.4%	20	5,853
Castaic_6	96.83	87.15									
CastaicInflowHydro	99.00	0.00	N/A				N/A	N/A	N/A	N/A	N/A
Horse_Mesa_HM4	119.00	107.10	Hose_Mesa	119.00	107.10	SRP	75%	0.90	83.3%	20	2,380
Mormon_Flat_MF2	57.30	51.57	Mormon_Flat	57.30	51.57		75%	0.90	83.3%	20	1,146
JSEastwoodPS	149.00	134.10	Eastwood_1	149.00	134.10	SCE	75%	0.90	83.3%	20	2,980
JSEastwoodPSInflowHY	50.80	0.00	N/A	50.80	0.00		N/A	N/A	N/A	N/A	N/A

Modeling Multiple PS Units with One Penstock - Helms and Castaic PS

Both the Helms and Castaic pumped storage facilities use a single penstock to feed all of their units. This means that their operational efficiency reduces as more of their units come on-line. To emulate this behavior, the units of these plants were grouped into different efficiency blocks. In GridView, the efficiency is set on the plant-level so the Helms and Castaic pumped storage facilities are modeled with multiple plants, each with different efficiencies.

O'Neill PS Modeling

The purpose of the O'Neil pumped storage facility is to facilitate the exchange of water between the O'Neil Forebay and the California Aqueduct and Delta-Mendota Canal. Historically, the canals have been prone to flood and the O'Neill pumped storage facility has been limited to pumping water out of the canal. As a result, O'Neill is modeled with a historical hourly shape that pumps the entire year as it has never been able to reverse operations and generate like a normal pumped storage facility.

W.R. Gianelli (San Luis) PS Modeling

W.R. Gianelli pumped storage facility is also known as the San Luis Reservoir Pumping Plant and is limited by canal operations. Its pumping/generating cycle is seasonal and reasonably consistent year-to-year. It is modeled with an hourly shape based on "masked" 2005 historical data - the actual values are confidential, but Xiaobo Wang of the CAISO provided a "masked" shape based on the actual 2005 historical data.

Due to confidentiality, it is unclear whether the plant is dispatched based on price signals. The plant provides no spinning reserve or regulation and its efficiency varies with reservoir level. It takes an hour to switch from pump to generate; however, GridView can't explicitly model this switching limitation so it is not reflected in the 2024 Common Case.

Thermal Generation Facilities

The operating parameters for the thermal generation were derived from several sources and are listed in Table 40.

Table 40: Thermal Operating Parameters

Parameter	Unit Type	Source	Description
Maximum Capacity	Coal-fired Steam	EIA / LRS / PF / 2022	Closest consensus from the common sources including seasonal ratings
	Other Dispatchable	EIA / LRS / PF / 2022	Closest consensus from the common sources including seasonal ratings
	Must-run – California	CAISO NQC	Used monthly NQC values
	Must-run - Other	LRS	
Minimum Capacity	Coal-fired Steam	2022	Values from 2022 Common Case (usually 40% of max capacity)
	Other Dispatchable	2022	Values from 2022 Common Case
	Must-run	EIA	Based on the average monthly outputs reported in EIA 923
	Must-run	No EIA	Based on averages for similar types from units with EIA data
Heat Rates	All Thermal	2022	Values from 2022 Common Case; used values from similar types for new generation
Ramping Uptime / Downtime	All Thermal	2022	Values from 2022 Common Case; used values from similar types for new generation

Monthly Minimum and De-Rated Maximum Capacity

Table 41 illustrates how the monthly minimum and de-rated maximum capacities were determined for the different thermal generation facilities.

Table 41. Determining Monthly Minimum and De-Rated Maximum Capacity

<table>
<tr><th>Resource Modeling Category</th><th>Location</th><th>Resource Project Status</th><th>Minimum Capacity Based on....
(direct link or per similar generator type)</th><th>De-Rated Maximum Capacity Based on....
(direct link or per similar generator type)</th></tr>
<tr><td rowspan="2">Dispatchable Thermal</td><td>California</td><td rowspan="4">0, 1, or 2 (Existing through Pre-Construction)</td><td rowspan="2">2022 Common Case modeling</td><td rowspan="2">Balancing Authorities' WECC Load and Resource Submittal</td></tr>
<tr><td>Non-California</td></tr>
<tr><td rowspan="3">Must Run Thermal</td><td>California</td><td rowspan="2">Average of EIA historical dispatch</td><td>CAISO Net Qualifying Capacity (NQC)</td></tr>
<tr><td>Non-California</td><td>Balancing Authorities' WECC Load and Resource Submittal</td></tr>
<tr><td>Any</td><td>3 or 4 (Planned/ Conceptual)</td><td>84% of Nameplate</td><td>85% of Nameplate</td></tr>
</table>

Thermal Economic Assumptions

- Heat rates – copied from 2022 Common Case or similar generator type
- Startup Fuel – derived from Intertek/APTECH data
- Startup Cost – derived from Intertek/APTECH data
- Var. O&M cost – derived from Intertek/APTECH data
- Ramping costs – not implemented in this release

Thermal Outages and Planned Maintenance

Forced outage rates were derived from:

1. Generation Availability Data System rates based on size and vintage.
2. For all other resources, an average forced outage rate (FOR) was used based on comparable generator type:

Generator Type	Average FOR Used (%)
GT Aero-derivative (GT or CC-Gas part)	3.74
Fuel Cell Natural Gas	3.74
Combined Cycle with Industrial Frame Gas Turbine	3.28
Industrial Frame Gas Turbine (Single or part of Combined Cycle)	3.46
Combined Cycle's Steam Turbine	4.00

Planned Maintenance was initially scheduled using the Maintenance Scheduler tool built into GridView that schedules the maintenance for each region based on periods of lower loads. The tool allows for predefining the maintenance and this option was used to schedule the nuclear refueling outages and a few of the large base-load generators.

Pumping Loads

Pumping loads were identified and modeled as negative hourly resources that required creating a positive shape file and applying a negative multiplier for each load. Pump load shape files were created using the 2005 hourly pump load data and then shifting the 2005 hour data to match the 2024 hours. Once the shape files were created, the pump loads were assigned a negative multiplier to represent the resource as a load. The list of pumping load generators can be seen in Table 42.

Table 42. List of Pumping Load Generators

Generator Name	Shape Name	Generator Name	Shape Name	Generator Name	Shape Name
BuenaVistaPump1-1	Pump_BuenaVista	EdmonstonPump1	Pump_Edmonston	JHindPump8	Pump_JHind
BuenaVistaPump1-2	Pump_BuenaVista	EdmonstonPump2	Pump_Edmonston	JHindPump9	Pump_JHind
BuenaVistaPump1-3	Pump_BuenaVista	EdmonstonPump3-3	Pump_Edmonston	OneillPump	Pump_Oneill
BuenaVistaPump1-4	Pump_BuenaVista	EdmonstonPump3-4	Pump_Edmonston	OsoPump1	Pump_Oso
BuenaVistaPump1-5	Pump_BuenaVista	EdmonstonPump4-5	Pump_Edmonston	OsoPump2	Pump_Oso
BuenaVistaPump1-6	Pump_BuenaVista	EdmonstonPump4-6	Pump_Edmonston	OsoPump3	Pump_Oso
BuenaVistaPump2-1	Pump_BuenaVista	EdmonstonPump5-7	Pump_Edmonston	OsoPump4	Pump_Oso
BuenaVistaPump2-2	Pump_BuenaVista	EdmonstonPump5-8	Pump_Edmonston	OsoPump5	Pump_Oso
BuenaVistaPump2-3	Pump_BuenaVista	EdmonstonPump6-10	Pump_Edmonston	OsoPump6	Pump_Oso
BuenaVistaPump2-4	Pump_BuenaVista	EdmonstonPump6-9	Pump_Edmonston	OsoPump7	Pump_Oso
CouleePump1-2	Pump_Coulee	EdmonstonPump7-11	Pump_Edmonston	OsoPump8	Pump_Oso
CouleePump3-4	Pump_Coulee	EdmonstonPump7-12	Pump_Edmonston	PEARBMAP-1	Pump_PEARBM
CouleePump5-6	Pump_Coulee	EdmonstonPump8-13	Pump_Edmonston	PEARBMAP-2	Pump_PEARBM

Generator Name	Shape Name	Generator Name	Shape Name	Generator Name	Shape Name
DeltaPumpA-1	Pump_Delta	EdmonstonPump8-14	Pump_Edmonston	PEARBMAP-3	Pump_PEARBM
DeltaPumpA-2	Pump_Delta	GenePump1	Pump_Gene	PEARBMBP-4	Pump_PEARBM
DeltaPumpA-3	Pump_Delta	GenePump2	Pump_Gene	PEARBMBP-5	Pump_PEARBM
DeltaPumpB-4	Pump_Delta	GenePump3	Pump_Gene	PEARBMBP-6	Pump_PEARBM
DeltaPumpB-5	Pump_Delta	GenePump4	Pump_Gene	PEARBMCP-7	Pump_PEARBM
DeltaPumpC-6	Pump_Delta	GenePump5	Pump_Gene	PEARBMCP-8	Pump_PEARBM
DeltaPumpC-7	Pump_Delta	GenePump6	Pump_Gene	PEARBMCP-9	Pump_PEARBM
DeltaPumpD-8	Pump_Delta	GenePump7	Pump_Gene	TracyPump1	Pump_Tracy
DeltaPumpD-9	Pump_Delta	GenePump8	Pump_Gene	TracyPump2	Pump_Tracy
DeltaPumpE-10	Pump_Delta	GenePump9	Pump_Gene	TracyPump3	Pump_Tracy
DeltaPumpE-11	Pump_Delta	IntakePump1	Pump_Gene	TracyPump4	Pump_Tracy
DiamondValleyLake02	Pump_DiamondValleyLake	IntakePump2	Pump_Gene	TracyPump5	Pump_Tracy
DiamondValleyLake03	Pump_DiamondValleyLake	IntakePump3	Pump_Gene	TracyPump6	Pump_Tracy
DiamondValleyLake04	Pump_DiamondValleyLake	IntakePump4	Pump_Gene	TracyPumpYG	Pump_Tracy
DiamondValleyLake06	Pump_DiamondValleyLake	IntakePump5	Pump_Gene	WheelerRidgePump1-1	Pump_WheelerRidge
DiamondValleyLake07	Pump_DiamondValleyLake	IntakePump6	Pump_Gene	WheelerRidgePump1-2	Pump_WheelerRidge
DiamondValleyLake08	Pump_DiamondValleyLake	IntakePump7	Pump_Gene	WheelerRidgePump1-3	Pump_WheelerRidge
DiamondValleyLake10	Pump_DiamondValleyLake	IntakePump8	Pump_Gene	WheelerRidgePump1-4	Pump_WheelerRidge
DiamondValleyLake11	Pump_DiamondValleyLake	IntakePump9	Pump_Gene	WheelerRidgePump1-5	Pump_WheelerRidge
DiamondValleyLake12	Pump_DiamondValleyLake	IronMountainPump1	Pump_IronMountain	WheelerRidgePump2-1	Pump_WheelerRidge
DosAmigosPump1-1	Pump_DosAmigos	IronMountainPump2	Pump_IronMountain	WheelerRidgePump2-2	Pump_WheelerRidge
DosAmigosPump1-2	Pump_DosAmigos	IronMountainPump3	Pump_IronMountain	WheelerRidgePump2-3	Pump_WheelerRidge
DosAmigosPump1-3	Pump_DosAmigos	IronMountainPump4	Pump_IronMountain	WheelerRidgePump2-4	Pump_WheelerRidge
DosAmigosPump2-1	Pump_DosAmigos	IronMountainPump5	Pump_IronMountain	WindGapPump1-1	Pump_WindGap
DosAmigosPump2-2	Pump_DosAmigos	IronMountainPump6	Pump_IronMountain	WindGapPump1-2	Pump_WindGap
DosAmigosPump2-3	Pump_DosAmigos	IronMountainPump7	Pump_IronMountain	WindGapPump1-3	Pump_WindGap
EagleMountainPump1	Pump_EagleMountain	IronMountainPump8	Pump_IronMountain	WindGapPump2-1	Pump_WindGap
EagleMountainPump2	Pump_EagleMountain	IronMountainPump9	Pump_IronMountain	WindGapPump2-2	Pump_WindGap
EagleMountainPump3	Pump_EagleMountain	JHindPump1	Pump_JHind	WindGapPump3-1	Pump_WindGap
EagleMountainPump4	Pump_EagleMountain	JHindPump2	Pump_JHind	WindGapPump3-2	Pump_WindGap
EagleMountainPump5	Pump_EagleMountain	JHindPump3	Pump_JHind	WindGapPump4-1	Pump_WindGap
EagleMountainPump6	Pump_EagleMountain	JHindPump4	Pump_JHind	WindGapPump4-2	Pump_WindGap
EagleMountainPump7	Pump_EagleMountain	JHindPump5	Pump_JHind		
EagleMountainPump8	Pump_EagleMountain	JHindPump6	Pump_JHind		
EagleMountainPump9	Pump_EagleMountain	JHindPump7	Pump_JHind		

DC Interties (DCI)

The Western Interconnection has eight direct current (DC) interconnections with other regions. Since these DC interconnections can import and export generation, they need to be accounted for in the 2024 Common Case. These interconnections are represented and accounted for as an hourly resource. The nameplate values were determined through the use of historical data and use of the 23 HS1A1 power flow case. Since the DC interties were modeled as hourly resources, shape files were created to represent their import/export characteristics. The Transmission Expansion Planning Department created monthly import/export shapes for all DC Ties since the historical hourly flow data is deemed confidential. The DC Tie shape files characteristics are set to full export, full import, or zero (0) for each given month. The list of DC Tie hourly resources can be seen in Table 43.

Table 43. List of DC Intertie Generators

Generator Name	Nameplate (MW)
DCI_Arteria	200
DCI_BlackWater	200
DCI_Lamar	220
DCI_McNeill	0
DCI_Miles_City	200
DCI_RapidCity	200
DCI_Stegall	110
DCI_VirginiaSmith	200

VAR Devices

The resource reconciliation effort mentioned identified resources meant to represent VAR devices in the power flow. PCM simulations use an optimized DC power flow solution rather than the full AC solution performed by power flow modeling software. As a result, VAR devices do not affect the results of PCM simulations; however, they do come into play when hours of the PCM simulation are exported into the power flow model. Version 1.X of the 2024 Common Case does not support the PCM-PF round-trip capability, so the VAR devices are either not modeled in the dataset or are turned off.

Generic Storage Facilities

The California Public Utilities Commission (CPUC) unanimously approved a 1,325-MW energy storage procurement target for California's largest utilities (CPUC Decision 13-10-040 dated October 17, 2013). The decision required that PG&E, SDG&E, and SCE collectively procure these energy storage resources by 2020 and install them no later than 2024. The CAISO, PG&E, SDG&E, and SCE stakeholders provided preliminary information for modeling these resources in the 2024 Common Case, as shown in Table 44.

The 1,325 MW of generic storage was split into 580-MW, 220-MW, 360-MW, and 165-MW pieces and applied to the CISC, CIPB, CIPV, and CISD load areas.

Table 44. Assumed PG&E, SDG&E, and SCE preliminary plans for procuring 1,325MW of energy storage

<table>
<tr><th>Generator Name</th><th>Capacity (MW)</th><th>Storage Hours</th><th>Reserve Contribution</th><th>TEPPC Load Area</th><th>Point of Interconnection (POI)</th><th>POI Split (MW)</th><th>Total (MW)</th><th>Storage Goal</th><th>Power Flow Bus</th></tr>
<tr><td>OTCR-T1CISC-Stor01</td><td>10</td><td>2</td><td>100%</td><td rowspan="10">CISC</td><td rowspan="10">-</td><td rowspan="10">-</td><td rowspan="10">580</td><td rowspan="5">OTC</td><td>BARRE (24016)</td></tr>
<tr><td>OTCR-T1CISC-Stor02</td><td>10</td><td>2</td><td>100%</td><td>ELLIS (24044)</td></tr>
<tr><td>OTCR-T1CISC-Stor03</td><td>10</td><td>4</td><td>100%</td><td>JOHANNA (24072)</td></tr>
<tr><td>OTCR-T1CISC-Stor04</td><td>10</td><td>4</td><td>100%</td><td>SANTIAGO (24134)</td></tr>
<tr><td>OTCR-T1CISC-Stor05</td><td>10</td><td>6</td><td>100%</td><td>VILLA PK (24154)</td></tr>
<tr><td>CISC-OtherStorage01</td><td>106</td><td>2</td><td>100%</td><td rowspan="5">Other</td><td>BARRE (24016)</td></tr>
<tr><td>CISC-OtherStorage02</td><td>106</td><td>2</td><td>100%</td><td>ELLIS (24044)</td></tr>
<tr><td>CISC-OtherStorage03</td><td>106</td><td>4</td><td>100%</td><td>JOHANNA (24072)</td></tr>
<tr><td>CISC-OtherStorage04</td><td>106</td><td>4</td><td>100%</td><td>SANTIAGO (24134)</td></tr>
<tr><td>CISC-OtherStorage05</td><td>106</td><td>6</td><td>100%</td><td>VILLA PK (24154)</td></tr>
<tr><td>OTCR-CIPB-Stor01</td><td>47</td><td>2</td><td>100%</td><td rowspan="8">CIPB</td><td rowspan="3">Transmission</td><td rowspan="3">118</td><td rowspan="8">220</td><td rowspan="16">OTC</td><td>SANMATEO (30700)</td></tr>
<tr><td>OTCR-CIPB-Stor02</td><td>47</td><td>4</td><td>100%</td><td>NEWARK D (30630)</td></tr>
<tr><td>OTCR-CIPB-Stor03</td><td>24</td><td>6</td><td>100%</td><td>TESLA C (30640)</td></tr>
<tr><td>OTCR-CIPB-Stor04</td><td>28</td><td>2</td><td>50%</td><td rowspan="3">Distribution</td><td rowspan="3">70</td><td>SANMATEO (30700)</td></tr>
<tr><td>OTCR-CIPB-Stor05</td><td>28</td><td>4</td><td>50%</td><td>NEWARK D (30630)</td></tr>
<tr><td>OTCR-CIPB-Stor06</td><td>14</td><td>6</td><td>50%</td><td>TESLA C (30640)</td></tr>
<tr><td>OTCR-CIPB-Stor07</td><td>16</td><td>2</td><td>0%</td><td rowspan="2">Customer</td><td rowspan="2">32</td><td>SANMATEO (30700)</td></tr>
<tr><td>OTCR-CIPB-Stor08</td><td>16</td><td>4</td><td>0%</td><td>NEWARK D (30630)</td></tr>
<tr><td>OTCR-CIPV-Stor01</td><td>77</td><td>2</td><td>100%</td><td rowspan="8">CIPV</td><td rowspan="3">Transmission</td><td rowspan="3">192</td><td rowspan="8">360</td><td>GATES (30900)</td></tr>
<tr><td>OTCR-CIPV-Stor02</td><td>77</td><td>4</td><td>100%</td><td>GREGG (30810)</td></tr>
<tr><td>OTCR-CIPV-Stor03</td><td>38</td><td>6</td><td>100%</td><td>TBL MT D (30300)</td></tr>
<tr><td>OTCR-CIPV-Stor04</td><td>46</td><td>2</td><td>50%</td><td rowspan="3">Distribution</td><td rowspan="3">115</td><td>GATES (30900)</td></tr>
<tr><td>OTCR-CIPV-Stor05</td><td>46</td><td>4</td><td>50%</td><td>GREGG (30810)</td></tr>
<tr><td>OTCR-CIPV-Stor06</td><td>23</td><td>6</td><td>50%</td><td>TBL MT D (30300)</td></tr>
<tr><td>OTCR-CIPV-Stor07</td><td>26.5</td><td>2</td><td>0%</td><td rowspan="2">Customer</td><td rowspan="2">53</td><td>GATES (30900)</td></tr>
<tr><td>OTCR-CIPV-Stor08</td><td>26.5</td><td>4</td><td>0%</td><td>GREGG (30810)</td></tr>
<tr><td>LakeHodges1-2</td><td>40</td><td>14</td><td>100%</td><td rowspan="10">CISD</td><td rowspan="4">Transmission</td><td rowspan="4">80</td><td rowspan="10">165</td><td>Other</td><td>Lake Hodges PS (22625+22626)</td></tr>
<tr><td>OTCR-T4CISD-Stor01</td><td>5</td><td>6</td><td>100%</td><td>OTC</td><td>ECO 138 KV (22932)</td></tr>
<tr><td>CISD-OtherStorage01</td><td>15</td><td>4</td><td>100%</td><td>Other</td><td>San Luis Rey 230 KV (22716)</td></tr>
<tr><td>OTCR-T4CISD-Stor02</td><td>20</td><td>2</td><td>100%</td><td>OTC</td><td>Miguel 230 KV (22464)</td></tr>
<tr><td>CISD-OtherStorage02</td><td>22</td><td>2</td><td>50%</td><td rowspan="3">Distribution</td><td rowspan="3">55</td><td rowspan="6">Other</td><td>Otay 69 KV (22604)</td></tr>
<tr><td>CISD-OtherStorage03</td><td>22</td><td>4</td><td>50%</td><td>EL Cajon 69 KV (22208)</td></tr>
<tr><td>CISD-OtherStorage04</td><td>11</td><td>6</td><td>50%</td><td>Escondido 69 KV (22256)</td></tr>
<tr><td>CISD-OtherStorage05</td><td>10</td><td>4</td><td>0%</td><td rowspan="3">Customer</td><td rowspan="3">30</td><td>Avocado (22020)</td></tr>
<tr><td>CISD-OtherStorage06</td><td>10</td><td>4</td><td>0%</td><td>Rincon (22688)</td></tr>
<tr><td>CISD-OtherStorage07</td><td>10</td><td>4</td><td>0%</td><td>Valley Center (22870)</td></tr>
</table>

Retirement and Extended Outage Assumptions

Information derived from the LRS data submittals, utility IRP postings, state/federal databases, stakeholders, and other sources was used to develop generation retirement schedules for the 2024 Common Case. Ongoing work to identify likely retirements will be important because some generation that is assumed to be available in models will likely be retired for economic or environmental reasons. Failure to capture these retirements may distort the system dispatch. Table 45 shows the assumption made for all resources with unknown commission and retirement dates. For full details regarding the resource project statuses, refer to Table 23.

Table 45. Assumptions for unknown commission and retirement dates

Resource Project Status	Assumed Commission Date	Assumed Retirement Date
0 (Existing)	4/15/2010	4/15/2030
1 (Under Construction)	4/15/2014	4/15/2050
2 (Pre-Construction)	4/15/2016	4/15/2050
3 (Future-Planned)	4/15/2018	4/15/2050
4 (Future-Conceptual)	4/15/2023	4/15/2050
5 (No Longer Expected)	4/15/2030	4/15/2050
Retired	4/15/1986	4/15/2010

The Grand Coulee “Third Power Plant Overhaul Project” is reflected in the 2024 Common Case by the assumptions in Table 46. For each of the time periods in Table 46, the designated unit’s monthly energy target is set to zero.

Table 46. Assumed schedule of the Grand Coulee Third Power Plant Overhaul Project

Grand Coulee Unit	Start Overhaul	Finish Overhaul
Unit 24	3/1/2013	9/30/2014
Unit 23	10/1/2014	3/31/2016
Unit 22	4/1/2016	9/30/2017
Unit 19	1/1/2018	4/30/2020
Unit 20	5/1/2020	8/31/2022
Unit 21	9/1/2022	12/31/2024

Once-Through-Cooling (OTC) Replacement Assumptions

The California State Water Resources Control Board (SWRCB) developed an updated implementation schedule for the coastal generation facilities that use OTC. The compliance timeline is provided in Figure 14. Note that the generators in red were retired earlier than their designated compliance dates.

Figure 14. OTC Compliance Timeline

California Generator Once-Through-Cooling Approved Compliance Timeline

	Compliance Year																			
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
OTC Generators Compliance Dates	Humboldt Bay (135)					El Segundo (670)					Alamitos 1-6 (2010)				Diablo Canyon (2240)					Harbor 5 (228)
						Morro Bay (650)					Huntington Beach 1,2 (450)				Scattergood 1,2 (351)					Haynes 1,2 (444)
		Potrero 3 (206)				Scattergood 3 (445)					Huntington Beach 3,4 (452)									Haynes 8 (585)
		South Bay (311)									Mandalay (430)									
								Contra Costa (674)			Ormand Beach (1516)									
				Haynes 5,6 (682)				Encina (946)			Redondo (1343)									
								Moss Landing (2530)					San Onofre (2246)							
								Pittsburg 5,6 (624)												
Capacity (-)	-135	-517	0	-682	0	-1,765	0	-4,774	0	0	-6,201	0	-2,246	0	-2,591	0	0	0	0	-1,257
Cumulative	-135	-652	-652	-1,334	-1,334	-3,099	-3,099	-7,873	-7,873	-7,873	-14,074	-14,074	-16,320	-16,320	-18,911	-18,911	-18,911	-18,911	-18,911	-20,168

The OTC policy recommendation led the other California regulating entities to develop a replacement plan that is accelerated due to the early retirement of San Onofre. TAS elected to use DWG's recommendation based on the latest version of the plan, which is summarized in Table 47.

Table 47: OTC Replacement Proposal

California OTC Replacement Plan (MW)				
Resource Type	**SCE (CISC)**	**SDGE (CISD)**	**PG&E Bay (CIPB)**	**PG&E Valley (CIPB)**
Incremental EE	855	157.5	0	0
Wholesale Distribution-Level Solar PV	95	17.5	0	0
Energy Storage	50	25	220	360
Conventional	1300	944.02	0	0
Discretionary Conventional	215	0	0	0
Total	2,515	1,144.02	220	360

Renewable Portfolio Standard (RPS) Compliance Check

The RPS compliance check ensures that the resource assumptions in the 2024 Common Case fulfill all applicable state RPS goals, both voluntary and required. The following sections will describe:

- The state RPS targets and how they were determined;
- The RPS fulfillment process used to build up the renewable resource assumptions in the 2024 Common Case; and
- How the 2024 Common Case satisfies the expected 10-year horizon RPS goals.

State RPS Targets

The TAS SWG determined the appropriate state RPS energy targets for each state by pulling together each state's RPS goals applicable to 2024. Table 48 provides a summary of each state's load and corresponding energy sales, and RPS targets based on each state's individual RPS requirements. The amount of behind-the-meter distributed generation (BTM DG) built into the L&R load forecast was not reported with the L&R information so the exact corresponding state RPS targets could not be determined. Ranges of RPS targets were calculated for each state (assuming all and no BTM in the L&R load forecast) and, fortunately, no state RPS target was affected more than 3 percent.

Table 48. Summary of State RPS Targets based on RPS requirements

State	Assuming all BTM DG in L&R Load Forecasts (GWh)			Assuming no BTM DG in L&R Load Forecasts (GWh)			RPS Requirement Details (% of Sales)	Set Asides (% of RPS Target)
	Load (Sales + Losses)	Sales (Load – Losses)	RPS Target	Load (Sales + Losses)	Sales (Load – Losses)	RPS Target		
Arizona	101,982	95,863	8,110	104,688	98,407	8,325	55.1% IOU[5] 39.6% POU 1.5% Fed. 3.8% Co-op	30% DG (2,498 GWh)
California	310,556	275,261	90,836	318,837	282,962	93,377	68.6% IOU 23% POU 0.9% Fed. 0.1% Co-op 0.6% Non-utility 6.8% Energy	N/A
Colorado	61,077	57,413	11,268	62,077	58,352	11,453	56.9% IOU 16.6% POU 0.2% Fed. 25.9% Co-op 0.4% Non-utility	3% DG for IOU RPS (996 GWh)
Idaho	N/A	N/A	No RPS Req.	N/A	N/A	No RPS Req.	N/A	N/A
Montana	15,509	14,578	1,058	15,551	14,618	1,061	48.4% IOU 0.1% POU 3.1% Fed. 28.8% Co-op 19.5% Energy	N/A
New Mexico	20,332	19,112	2,990	20,594	19,358	3,028	67.4% IOU 9.6% POU 3.1% Fed. 28.8% Co-op 19.5% Energy	30% Wind (783 GWh), 20% Solar (522 GWh), 10% Geo/Bio (261 GWh), 3% DG (78 GWh)
Nevada	43,901	41,267	8,337	44,278	41,621	8,410	84.2% IOU 6% POU 0.1% Fed. 5.4% Co-op 4.2% Energy	6% Solar (505 GWh)
Oregon	63,029	59,247	11,550	63,258	59,463	11,593	Utilities > 3% = 74.5% Utilities < 3% = 12% Utilities < 1.5% = 13.5%	N/A
Utah	31,251	29,376	5,473	31,396	29,512	5,498	80.1% IOU 15.8% POU 0.2% Fed. 3.9% Co-op	N/A
Washington	108,140	101,652	12,808	108,245	101,750	12,821	Utilities with > 25k & <25k customers = 84% & 16% (respectively)	N/A
Wyoming	N/A	N/A	No RPS Req.	N/A	N/A	No RPS Req.	N/A	N/A

[5] Investor-Owned Utility.

RPS Resource Selection

WECC used three core pieces of information to identify the appropriate resources for state RPS requirements:

1. Resource project statuses (0, 1, 2, 3, 4) – provide an indication of the generator's level of certainty. Status 0 is most certain (existing generation) and status 4 is least certain (generators at conceptual planning stages).
2. Generator allocation information – generator resource distribution information provided by state Public Utility Commissions, public utilities, and other planning bodies that have knowledge of which renewable resources are contracted or apply to a specific state's RPS requirement.
3. Information about future hypothetical resources (WREZ zones and NREL profiles) – WREZ zones are areas throughout the Western Interconnection that have both the potential for large-scale development of renewable resources and low environmental impact. NREL profiles, created using historical wind and solar data, help to identify the best locations for generator placement. This option can be used to fill out RPS portfolios if there are not enough resources within the proposed projects.

The above listed pieces of information are strategically combined to create a robust, open, and stakeholder-vetted process through which renewable resources can be assigned to states for RPS compliance purposes.

RPS Fulfillment Process

This section describes a refined method for RPS fulfillment throughout the Western Interconnection. The process is the first of its kind in so much as it attempts to account for both "allocated" and "unallocated" renewable energy (RE), whereas past processes and datasets did not capture the availability and potential RPS impact of unallocated RE. In this context, the "allocated" RE has satisfies a firm commitment to a specific state's RPS requirement (e.g., a wind plant in Wyoming is contractually obligated to provide some or all of its energy toward the California RPS requirement). The commitment information has been provided by public utility commissions (PUC) or other planning bodies and has a high level of certainty. The "unallocated" RE, in contrast, has an undefined destination either because it 1) lacks a firm commitment to RPS goals in specific state(s) and it could be purchased as unbundled Renewable Energy Credit (REC); or 2) the state(s) to which it is firmly committed is unknown (i.e., the commitment information is incomplete).

It is important to note that the allocated and unallocated RE do not directly correspond to bundled and unbundled RECs. Allocated RE corresponds to bundled RECs; however, unallocated RE can correspond to both bundled and unbundled RECs because its destination is left open.

Generators with status 0-2 are of high certainty and are included in the 2024 Common Case by default. Allocated RE resources with status 3 or above have the next highest certainty and they are less certain per their project status, but the commitment from a buyer increases the chances that they will be developed. Unallocated RE resources with status 3 or above are the least certain resources, both per their project status and lack of a firm buyer, and are not included in the 2024 Common Case.

The steps below outline the RPS fulfillment process, which continues through the steps until there is no longer an RPS requirement gap and the dataset is RPS compliant. Figure 15 provides a flowchart of the RPS fulfillment process for illustration.

1. Establish the state and provincial RPS energy requirements (RPS requirements) based on published information.

2. Include all resources with allocated RE and statuses 0-2. In doing so, adhere to the following rules:

    a. When information is available, a generator assigned to a specific state or provincial RPS requirement will be applied to the dedicated state/province RPS requirement regardless of generator location (i.e., a Montana generator can meet California RPS requirements if the information is known). Otherwise, energy from RPS eligible resource will be applied to the resource's local state/province (i.e., the state/province where it is physically located).

    b. Multi-state/provincial allocations are reflected whenever the information is available. For example, portions of a resource's energy may be committed as 10 percent to Oregon, 80 percent to Washington, and 10 percent to Utah.

    c. Bonus/Penalty credits are appropriately accounted for when applicable. For example, in-state solar technologies in Colorado count as 300 percent.

    d. State-specific limits apply on using unbundled RECs to fulfill the state's RPS requirement. For example, Oregon cannot use more than 20 percent unbundled RECs to fulfill its RPS requirement.

    e. Additional requirements per stakeholder input. For example, Arizona PUC prefers that unbundled RECs be avoided, although the regulation does not prevent their use so the decision is up to stakeholders.

3. Include all resources with only unallocated RE statuses 0-2. The so-called "pool of unallocated RE" is comprised of this unallocated RE together with any unallocated RE from the resources

(e.g., from resources that deliver both allocated and unallocated RE to the Western Interconnection).

a. Compare the total RPS “need” to the combination of allocated RE and the pool of unallocated RE: is there a gap in any state’s RPS requirement? Proceed to step 4 if a gap exists.

4. Repeat steps 1-3 above with a revised version of step 2: Include all resources with allocated RE and statuses up to and including 3. The additional status 3 resources should be added as a single block of resources unless stakeholder feedback indicates which status 3 resources are preferred over others (e.g., in-state preferred over out-of-state). Proceed to step 5 if there is a gap in any state’s RPS requirement.

5. Repeat steps 1-3 above with a revised version of step 2: Include all resources with allocated RE and statuses up to and including 4. The additional status 4 resources should be added as a single block of resources unless stakeholder feedback indicates which status 4 resources are preferred over others (e.g., in-state preferred over out-of-state). Proceed to step 6 if there is a gap in any state’s RPS requirement.

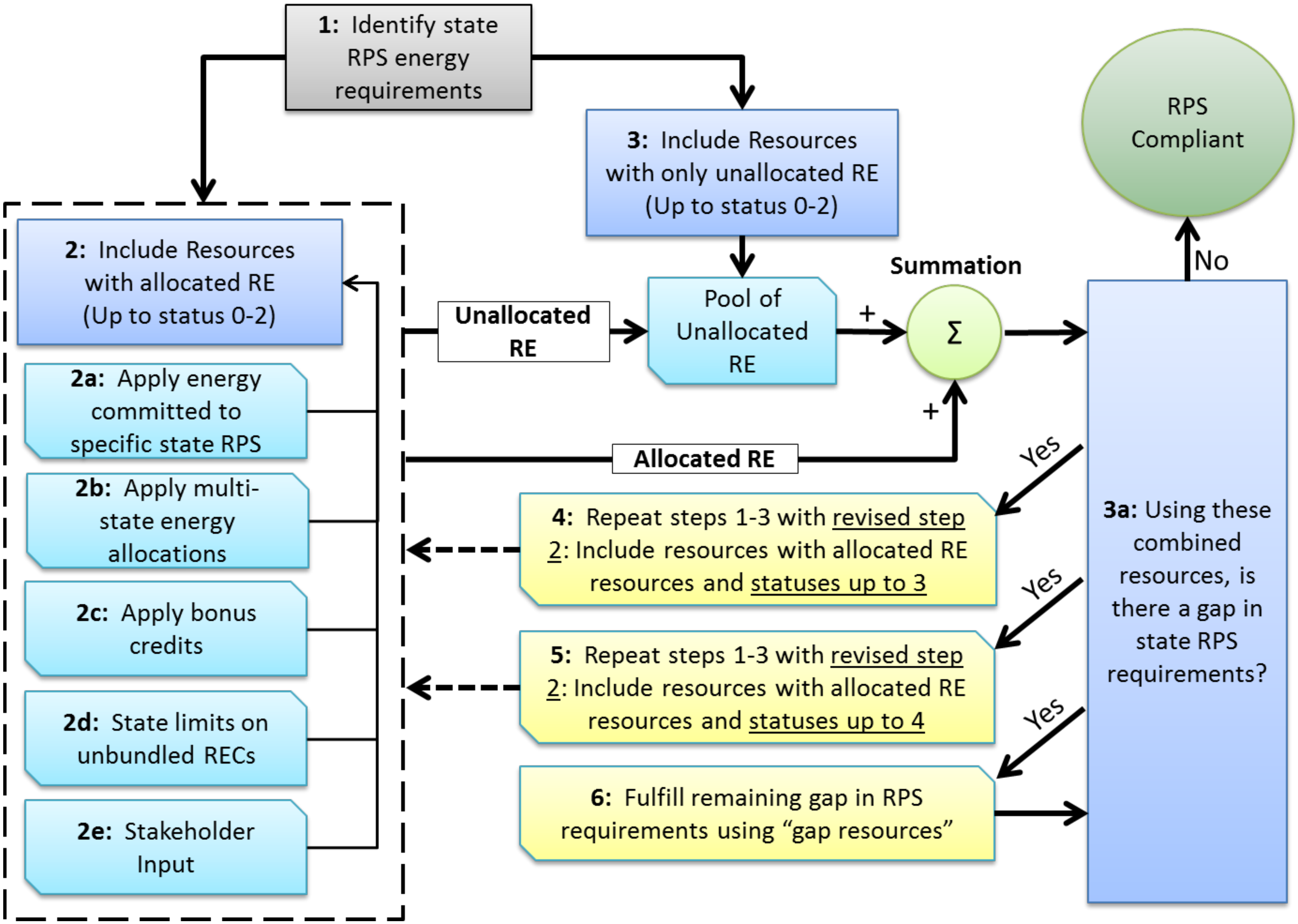
6. Use “gap resources” to fill the remaining RPS requirement gap. These are hypothetical resources that are created by WECC using the following pieces of information:

   a. State preference of resource type – based on the composition of the future (Class Codes 3-4) resources.

   b. WREZ zones – can be used to locate resources and identify economic alternatives.

   c. NREL wind/solar data – can be used to create annual shape and identify best location for generator placement.

Figure 15. Flow chart of the RPS Fulfillment Process



Results of the RPS Compliance Check

Table 49 summarizes the results of the RPS compliance check. The breakdown, by state, of the unallocated RE is provided in Table 50. Note that Table 49 has a “2024 RPS Target Less BTM DG” value. It is provided to show what the 2024 RPS Target would be if the L&R load forecast on which the 2024 Common Case is based included the full amount of behind-the-meter distributed generation (BTM DG) modeled in the 2024 Common Case. BTM DG reduces load and, therefore, reduces the corresponding RPS target. The higher of the RPS targets was used for the RPS compliance check to be conservative.

Step 6 of the RPS Fulfillment Process (in which “gap resources” are added) was not necessary for the 2024 Common Case. In fact, the 2024 Common Case has 16 TWh (or 19 TWh if the lower RPS target is assumed) of renewable energy across the Western Interconnection in excess of the combined 2024 RPS requirements.

As shown in Table 51, the dataset fell short of all RPS requirements with only status 0-2 renewable resources. The status 3 renewable resources were then added to the dataset and all states were able to satisfy their RPS requirements (see Table 52). Per Oregon’s RPS requirements, the status can only use unbundled RECs to meet up to 20 percent. The only status 4 renewable resources added to the dataset were those with allocated RE to Oregon, after which the dataset passed the RPS Compliance Check (see Table 53).

Table 49. RPS Compliance of the 2024 Common Case*

State/Province	2024 RPS Target (GWh)	2024 Common Case Renewable Energy (GWh)	Comparison, % (GWh)	Notes	2024 RPS Target Less BTM DG (GWh)	Comparison, % (GWh)
AZ*	8,325	6,446	22.6% (1,880 GWh) Below Target	Can buy unallocated RE or excess allocated RE	8,110	20.5% (1,664 GWh) Below Target
CA	93,377	95,362	2.1% (1,984 GWh) Above Target	Excess energy available for sale to needy RPS states	90,836	5.0% (4,526 GWh) Above Target
CO*	11,453	10,283	10.2% (1,170 GWh) Below Target	Can buy unallocated RE or excess allocated RE	11,268	8.7% (985 GWh) Below Target
MT	1,061	920	13.3% (141 GWh) Below Target	Can buy unallocated RE or excess allocated RE	1,058	13.1% (138 GWh) Below Target
NM	3,028	2,424	20.0% (604 GWh) Below Target	Can buy unallocated RE or excess allocated RE	2,990	18.9% (566 GWh) Below Target
NV	8,410	10,231	21.7% (1,821 GWh) Above Target	Excess energy available for sale to needy RPS states	8,337	22.7% (1,894 GWh) Above Target
OR	11,593	9,603	17.2% (1,989 GWh) Below Target	Can buy unbundled RECs (within OR's 20% limit)	11,550	16.9% (1,947 GWh) Below Target
TX	429	164	61.8% (265 GWh) Below Target	Can buy unallocated RE or excess allocated RE	429	61.8% (265 GWh) Below Target
UT	5,498	2,205	59.9% (3,293 GWh) Below Target	Can buy unallocated RE or excess allocated RE	5,473	59.7% (3,268 GWh) Below Target
WA	12,821	11,062	13.7% (1,759 GWh) Below Target	Can buy unallocated RE or excess allocated RE	12,808	13.6% (1,746 GWh) Below Target
Allocated RE Subtotal	155,994	148,698	4.7% (7,296 GWh) Below Target		152,859	2.7% (4,161 GWh) Below Target
Remaining RPS Need		7,296				
Unallocated Renewable Energy (RE)		21,433	N/A	Only used unallocated RE from resources up to statuses 0-2		
Total	**155,994**	**170,131**	**9.1% (14,137 GWh) Above Target**	All RPS needs are satisfied by bundled and unbundled RECs within appropriate limits	152,859	11.3% (17,272 GWh) Above Target

* The RPS compliance calculation doesn't currently take into account banking of RE (i.e., excess RE from past years being applied to meet RPS requirement); however, per stakeholder feedback, Colorado and Arizona are likely to use banked RE to ensure RPS compliance.

Table 50. Unallocated RE and Excess Allocated RE that contributed to RPS Compliance of the 2024 Common Case

State/ Province	Unallocated RE (GWh)	Excess Allocated RE (GWh)	Total
AB	7,201	0	7,201
AZ	0	0	0
BC	3,441	0	3,441
CA	0	1,984	1,984
CO	0	0	0
ID	1,824	0	1,824
MT	0	0	0
MX	6,259	0	6,259
NE	0	0	0
NM	0	0	0
NV	0	1,821	1,821
OR	0	0	0
SD	0	0	0
TX	0	0	0
UT	65	0	65
WA	752	0	752
WY	2,727	0	2,727
Total	**22,270**	**3,806**	**26,076**
^Highlighting indicates RPS State			

Table 51. RPS Compliance of the 2024 Common Case with Only Status 0-2 Renewable Resources

State/Province	2024 RPS Target (GWh)	Statuses 0-2		Notes
		2024 Common Case Renewable Energy (GWh)	Comparison, % (GWh)	
AZ	8,325	3,889	53.3% (4,437 GWh) Below Target	
CA	93,377	65,756	29.6% (27,622 GWh) Below Target	
CO	11,453	9,780	14.6% (1,673 GWh) Below Target	
MT	1,061	920	13.3% (141 GWh) Below Target	
NM	3,028	1,324	56.3% (1,704 GWh) Below Target	
NV	8,410	7,467	11.2% (942 GWh) Below Target	
OR	11,593	4,924	57.5% (6,668 GWh) Below Target	
TX	429	140	67.3% (288 GWh) Below Target	
UT	5,498	643	88.3% (4,855 GWh) Below Target	
WA	12,821	9,773	23.8% (3,048 GWh) Below Target	
Allocated RE Subtotal	155,994	104,616	32.9% (51,378 GWh) Below Target	
Remaining RPS Need		51,378		
Unallocated Renewable Energy (RE)		21,433		
Total	**155,994**	**126,049**	**19.2% (29,945 GWh) Below Target**	**Add next Status group**

Table 52. RPS Compliance of the 2024 Common Case with Up to Status 3 Renewable Resources

State/Province	2024 RPS Target (GWh)	Status 3	Up to Status 3		Notes
			2024 Common Case Renewable Energy (GWh)	Comparison, % (GWh)	
AZ	8,325	2,557	6,446	22.6% (1,880 GWh) Below Target	Can buy unallocated RE or excess allocated RE
CA	93,377	29,393	95,149	1.9% (1,772 GWh) Above Target	Excess energy available for sale to needy RPS states
CO	11,453	503	10,283	10.2% (1,170 GWh) Below Target	Can buy unallocated RE or excess allocated RE
MT	1,061	0	920	13.3% (141 GWh) Below Target	Can buy unallocated RE or excess allocated RE
NM	3,028	1,100	2,424	20.0% (604 GWh) Below Target	Can buy unallocated RE or excess allocated RE
NV	8,410	2,764	10,231	21.7% (1,821 GWh) Above Target	Excess energy available for sale to needy RPS states
OR	11,593	4,050	8,975	22.6% (2,618 GWh) Below Target	**Add more - Oregon can only use unbundled RECs to meet up to 20% of its RPS goal**
TX	429	24	164	61.8% (265 GWh) Below Target	Can buy unallocated RE or excess allocated RE
UT	5,498	1,562	2,205	59.9% (3,293 GWh) Below Target	Can buy unallocated RE or excess allocated RE
WA	12,821	1,289	11,062	13.7% (1,759 GWh) Below Target	Can buy unallocated RE or excess allocated RE
Allocated RE Subtotal	155,994	43,240	147,857	5.2% (8,138 GWh) Below Target	
Remaining RPS Need			8,138		
Unallocated Renewable Energy (RE)		837	22,270		No change (Only use up to Class Codes 0-2 for unallocated RE)
Total	**155,994**		**170,127**	**9.1% (14,132 GWh) Above Target**	**Add next Status group for just OR**

Table 53. RPS Compliance of the 2024 Common Case with Up to Status 4 Renewable Resources

State/Province	2024 RPS Target (GWh)	Status 4	Up to Status 4		Notes
			2024 Common Case Renewable Energy (GWh)	Comparison, % (GWh)	
AZ	8,325	0	6,446	22.6% (1,880 GWh) Below Target	No change
CA	93,377	213	95,362	2.1% (1,984 GWh) Above Target	No change
CO	11,453	0	10,283	10.2% (1,170 GWh) Below Target	No change
MT	1,061	0	920	13.3% (141 GWh) Below Target	No change
NM	3,028	0	2,424	20.0% (604 GWh) Below Target	No change
NV	8,410	0	10,231	21.7% (1,821 GWh) Above Target	No change
OR	11,593	628	9,603	17.2% (1,989 GWh) Below Target	**Can buy unbundled RECs (within OR's 20% limit)**
TX	429	0	164	61.8% (265 GWh) Below Target	No change
UT	5,498	0	2,205	59.9% (3,293 GWh) Below Target	No change
WA	12,821	0	11,062	13.7% (1,759 GWh) Below Target	No change
Allocated RE Subtotal	155,994	841	148,698	4.7% (7,296 GWh) Below Target	
Remaining RPS Need			7,296		
Unallocated Renewable Energy (RE)		0	22,270		No change
Total	**155,994**		**170,968**	**9.6% (14,974 GWh) Above Target**	**All RPS needs are satisfied by bundled and unbundled RECs within appropriate limits**

Resource Adequacy (RA) Check

The resource adequacy check is performed on the "pool" level, which is comprised of aggregates of the TEPPC regions that correspond to the granularity of the planning reserve margins taken from the WECC 2013 Power Supply Assessment (PSA). The resource adequacy check is a measure of each pool's ability to meet its peak load with its internal resource capacity and transmission-constrained imports from neighboring pools. The check is used in the 2024 Common Case as a way of identifying pools in the dataset that have the potential for supply shortages based on load, generation and transmission inputs.

Coincident Peak Demand for each Pool

As part of the resource adequacy check, the coincident peak for each pool is calculated for both summer and winter periods by aggregating the hourly load shapes for each TEPPC Load Area. These peak demands are shown in Table 54.

Table 54. Pool Coincident Peak Demand (megawatts)

Name	AZ-NM-NV	Basin	Alberta	British Columbia	CA-North	CA-South	NWPP	RMPA
Summer Peaks	34,652	15,554	14,340	9,034	29,397	43,067	28,053	13,465
Winter Peaks	21,724	12,421	15,795	12,296	20,357	27,738	34,337	11,202

Planning Reserve Targets

As previously mentioned, the resource adequacy check in the 2024 Common Case dataset makes use of the WECC 2013 PSA planning reserve margins for the planning reserve targets. The 2013 PSA is an evaluation of generation resource reserve margins for the WECC summer and winter peak hours from 2014 through 2023, conducted by the Loads and Resources Subcommittee. The planning reserve margins used in the PSA are calculated as a percentage of resources and load, meaning it is the percentage of capacity that is greater than demand. Table 55 shows the resulting planning reserve margins.

Table 55. Definition of Pools and their Planning Reserve Margins

Pool	Corresponding Portions of the Western Interconnection	Summer Margin	Winter Margin
AZ-NM-NV	Arizona, New Mexico, Southern Nevada	13.6%	14.0%
Basin	Idaho, Northern Nevada, Utah	13.7%	13.7%
Alberta	Alberta	12.6%	13.9%
British Columbia	British Columbia	12.6%	13.9%
CA-North	Northern California, San Francisco, SMUD	15.0%	12.1%
CA-South	Southern California Edison, San Diego Gas & Electric, LADWP, Imperial Irrigation District	15.2%	11.0%
NWPP	Pacific Northwest, Montana	17.5%	19.2%
RMPA	Colorado, Wyoming	15%	15.9%

On-Peak Generation Contribution

The on-peak generation contributions used in the resource adequacy check are currently the same as what was used in the 2022 Common Case dataset. These on-peak capacity values are derived using stakeholder input from past and current study programs. These contributions, shown in Table 56, represent the percent capacity that is available from each generator type at the time of summer peak.

Table 56. Percent Contribution to Summer Peak, by Generator Type

Generation Type	AZ-NM-NV	Basin	Alberta	British Columbia	CA-North	CA-South	NWPP	RMPA
Biomass RPS	100%	100%	100%	100%	66%	65%	100%	100%
Geothermal	100%	100%	100%	100%	72%	70%	100%	100%
Small Hydro RPS	35%	35%	35%	35%	35%	35%	35%	35%
Solar PV	60%	60%	60%	60%	60%	60%	60%	60%
Solar CSP0	90%	95%	95%	95%	72%	72%	95%	95%
Solar CSP6	95%	95%	95%	95%	100%	100%	95%	95%
Wind	10%	10%	10%	10%	16%	16%	5%	10%
Hydro	70%	70%	90%	90%	70%	95%	70%	70%
Pumped Storage	100%	100%	100%	100%	100%	100%	100%	100%
Coal	100%	100%	100%	100%	100%	100%	100%	100%
Nuclear	100%	100%	100%	100%	100%	100%	100%	100%
Combined Cycle	95%	95%	100%	95%	95%	95%	95%	95%
Combustion Turbine	95%	95%	100%	95%	95%	95%	95%	95%
Other Steam	100%	100%	100%	100%	100%	100%	100%	100%
Other	100%	100%	100%	100%	100%	100%	100%	100%
Negative Bus Load	100%	100%	100%	100%	100%	100%	100%	100%
Dispatchable DSM	100%	100%	100%	100%	100%	100%	100%	100%

Results of the RA Check: Resulting Planning Reserve Margins (PRM)

The results of the resource adequacy check are shown in Table 57. This overall summary shows the peak load and how that load was met using generation within each pool as well as transfers between neighboring pools. The resulting PRM is the final measure of each pool's resource adequacy.

Table 57. Resource Adequacy Check Results

Overall Summary	AZ-NM-NV	Basin	Alberta	British Columbia	CA-North	CA-South	NWPP	RMPA
Planning Reserve Target (%)	13.6%	13.7%	12.6%	12.6%	15.0%	15.2%	17.5%	14.5%
Peak Load (MW)	34,652	15,554	14,340	9,034	29,397	43,067	28,053	13,465
Gen Requirement (MW) (Peak Load + Reserves)	39,365	17,685	16,147	10,172	33,807	49,613	32,962	15,417
Gen Capacity Available during Summer Peak (MW)	47,206	18,711	15,398	15,409	32,769	38,286	36,193	15,967
Initial Gap (MW)	-7,841	-1,027	749	-5,237	1,037	11,328	-3,231	-549
Gap Adjustment (MW) (Joint Ownership Plants)	4,189	1,194	0	0	0	-5,777	0	394
Gap Adjustment (MW) (Region-Region Transfers)	3,524	-167	-1,200	1,200	-1,037	-5,551	3,231	0
Resulting PRM (%)	14.0%	13.7%	15.7%	57.3%	15.0%	15.2%	17.5%	15.7%
Total Gen (MW)	54,919	19,738	14,198	16,609	31,732	26,958	39,424	16,360

Remote Resources

With the new topology for area loads and regions it is necessary to associate remotely owned (or contracted) resources with the participating areas or regions. This provides the information that GridView needs to count the generation shares for reserves and to deliver the associated energy with no hurdle rate charge (assumes that delivery cost is a fixed cost). Table 58 shows the list of remote generators that were modeled in the 2024 Common Case. Note that the list is dynamic and dependent on stakeholder input.

Table 58. Remote Generators modeled in the 2024 Common Case

Remote Generators			
Agua Caliente Solar	Frederickson CC	Hudson Ranch Geo	Pebble Springs Wind
Apex CC	Gila River CC	Intermountain GS1	Priest Rapids
Argonne Mesa	Goldendale EC	Intermountain GS2	Rattlesnake Road Wind
Arlington Vly CCDF	Goodnoe Hills Wind	Jim Bridger 1	Red Hawk CC
Arlington Vly Solar	Goshen Wind II	Jim Bridger 2	Rock Island
Big Horn Wind	Griffith CC	Jim Bridger 3	Rocky Reach
Biglow Canyon Wind	Harquahala CC_1	Jim Bridger 4	San Juan 1
Campo Verde Solar	Harquahala CC_2	Klondike II Wind	San Juan 2
Centinela Solar	Harquahala CC_3	Klondike III Wind	San Juan 3

Remote Generators			
Centralia 2	Hayden 1	Leaning Juniper Wind	San Juan 4
Chehalis CC	Hayden 2	Linden Wind	Shepherds Flat Wind
Cholla 4	High Lonesome Mesa	Lodi CC	Simpson Tacoma Bio
Colstrip 1	High Wind EC	Lower Snake Rvr Wind	Springerville 3
Colstrip 2	HOOVER	Luna CC	Springerville 4
Colstrip 3	Hopkins Ridge Wind	Mesquite CC1	Star Point Wind
Colstrip 4	Hudson Ranch Geo	Mesquite CC2	Stateline Wind
Comanche 3	Intermountain GS1	Mesquite Solar I	Sutter CC
Cove Fort Geo	Intermountain GS2	Milford Wind 1	Tuolumne Wind
Craig 1	Harquahala CC_1	Milford Wind 2	Valmy 1
Craig 2	Harquahala CC_2	Mint Farm CC	Valmy 2
Dixie Valley Geo	Harquahala CC_3	Navajo 1	Vansycle Wind
Dokie Wind	Hayden 1	Navajo 2	Vantage Wind
Don A. Campbell	Hayden 2	Navajo 3	Wanapum
Dry Lake Wind_1	High Lonesome Mesa	PaloVerd 1	WELLS
Dry Lake Wind_2	High Wind EC	PaloVerd 2	Willow Creek Wind
Four Corners 4	HOOVER	PaloVerd 3	Windy Flats Wind_1
Four Corners 5	Hopkins Ridge Wind	Parker	Windy Flats Wind_2

Reserve Modeling

Reserves are modeled in the 2024 Common Case using three grouping tiers, which are shown in Table 59: 1) TEPPC Load Areas; 2) TEPPC Regions; and 3) Combined Areas and Regions. Table 59 also shows the reserve requirements that are enforced on one or multiple groups of TEPPC Load Areas and Regions. Within the Combined Areas and Regions tier, there are groupings of Reserve Sharing Groups (RSG) that define the more complex reserve requirements (i.e., those that allow several ways in which portions of the Western Interconnection can share resource capacity to ensure reliability of the system).

Table 59: Reserve Modeling

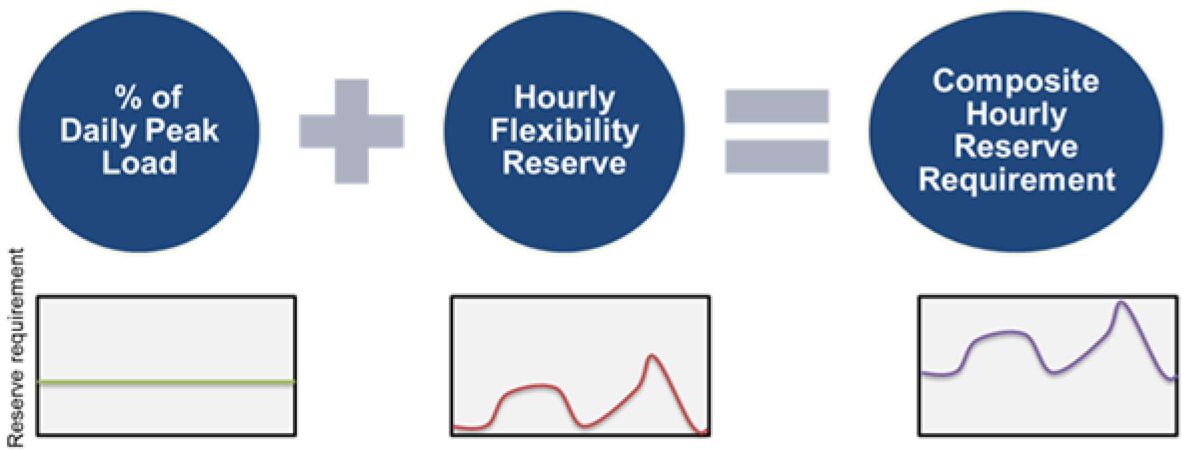
TEPPC Load Area		TEPPC Region		Combined Areas and Regions		Reserve Requirements (FRA = Flex Reserve Adder)		
				RSG Level 1	RSG Level 2	TEPPC Region	RSG1	RSG2
1	AESO	1	AB_AESO	-	-	4% of Load + FRA	-	-
2	BCHA	2	BC_BCH			4% of Load + FRA		
3	BPAT	3	NW_BPAT	RSG1_BPA+	RSG2_NWBS	-	1% of Load	4% of Load + FRA
4	CHPD	4	NW_CHPD					
5	DOPD	5	NW_DOPD					
6	GCPD	6	NW_GCPD					
7	SCL	7	NW_SCL					
8	TPWR	8	NW_TPWR					
9	AVA	9	NW_AVA	-		1% of Load	-	
10	PSEI	10	NW_PSEI			1% of Load		
11	PGE	11	NW_PGE			1% of Load		
12	NWMT	12	NW_NWE			1% of Load		
13	WAUW	13	NW_WAUW			1% of Load		
14	PACW	14	NW_PACW			1% of Load		
15	PAID	15	BS_PACE			1% of Load		
16	PAUT							
17	PAWY							
18	IPFE	16	BS_IPCO			1% of Load		
19	IPMV							
20	IPTV							
21	PSCO	17	RM_PSCO	RSG1_RM	-	3.6% of Load	4% Load + FRA	-
22	WACM	18	RM_WACM			3.6% of Load		
23	SPPC	19	SW_NVE	-	-	4% of Load	-	-
24	NEVP							
25	AZPS	20	SW_AZPS	RSG1_SW	-	3.6% of Load	4% Load + FRA	-
26	SRP	21	SW_SRP			3.6% of Load		
27	TEPC	22	SW_TEPC			3.6% of Load		
28	WALC	23	SW_WALC			3.6% of Load		
29	PNM	24	SW_PNM			3.6% of Load		
30	EPE	25	SW_EPE			3.6% of Load		
31	LDWP	26	CA_LDWP			3.6% of Load		
32	IID	27	CA_IID			3.6% of Load		
33	BANC	28	CA_BANC	RSG1_BANC+	-	-	4% Load + FRA	-
34	TIDC	29	CA_TID					
35	CIPB	30	CA_CISO	-	-	4% of Load + FRA	-	-
36	CIPV							
37	CISC							
38	CISD							
39	VEA							
40	CFE	31	CA_CFE	-	-	4% of Load	-	-

Flexibility Reserve Modeling

Flexibility reserves are defined as the additional reserves required to manage the variability and uncertainty associated with variable generation resources like wind and solar. Given the high penetration of variable generation in the West, including this additional reserve requirement is an important assumption for the PCM studies. The process uses historical load, wind and solar data to derive equations that predict the variability based on statistical analysis of that data.

Flexibility reserves have an hourly dispatch with an operating reserve requirement. The spinning and non-spinning reserve requirements (specified as a percent of daily peak load) are combined with the predefined hourly flexibility reserve to create a composite hourly reserve requirement, as shown in Figure 16. The hourly dispatch of the flexibility reserves was created with ABB's flex reserve tool.

Figure 16. Composite Hourly Reserve Requirement



Advanced Modeling

Transmission Loss Modeling

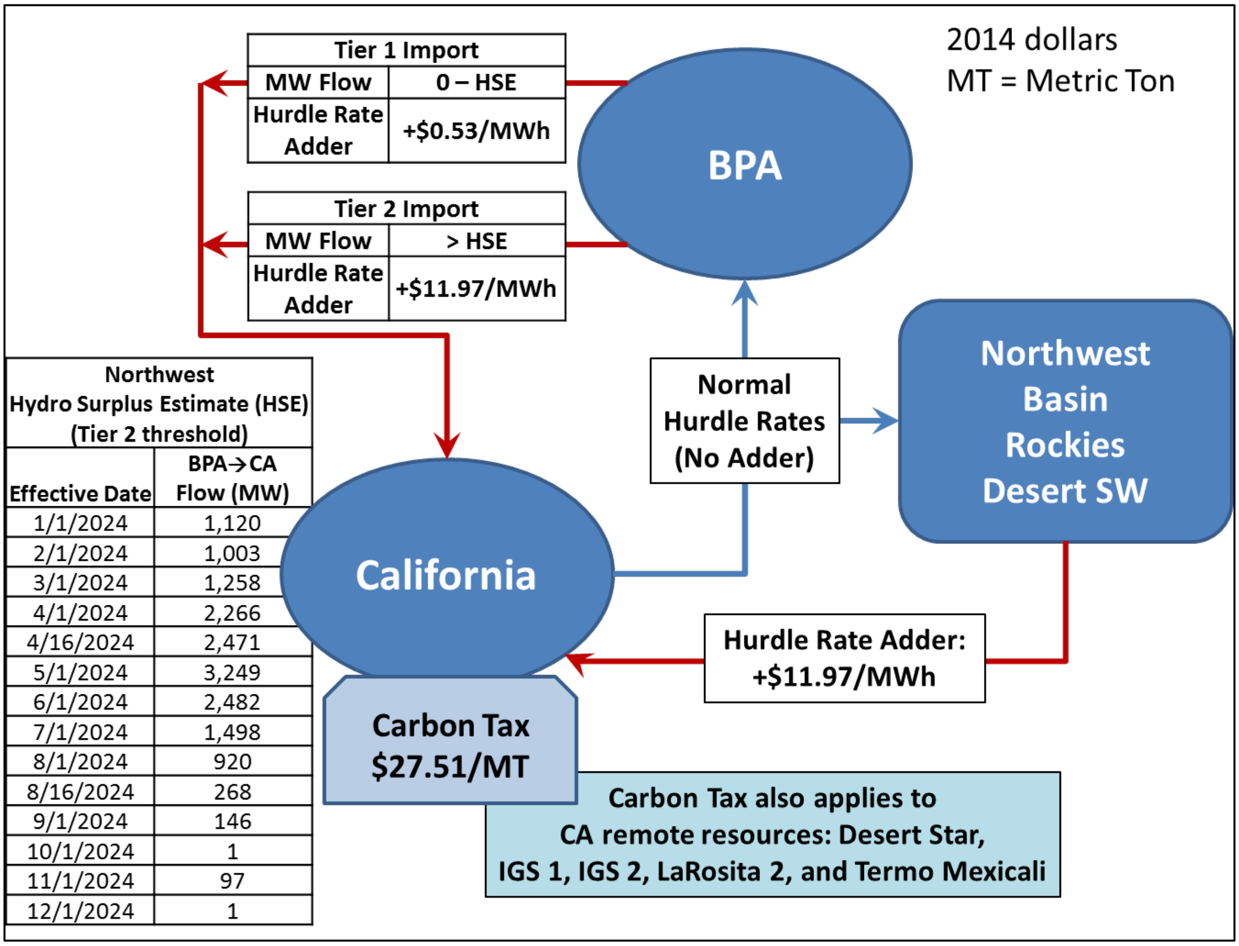
The 2024 Common Case uses GridView's loss model to calculate transmission losses for every hour of the year and adjust the hourly load shapes appropriately. Transmission losses are included in the monthly peaks and energies of the L&R forecast data.

GridView's loss model is based on the load and corresponding transmission loss percentages taken from the imported power flow model. The algorithm uses this information to determine the hour-by-hour transmission losses as the load and generation dispatch changes throughout the simulation.

Modeling the California Global Warming Solutions Act of 2006 (AB 32)

The California Global Warming Solutions Act of 2006 (AB 32) requires California to reduce its greenhouse gas (GHG) emissions to 1990 levels by 2020. Figure 17 provides an illustration of how it is modeled in the 2024 Common Case, which includes a carbon tax on thermal generators within California and additional “emissions reduction” hurdle rates on imports into California.

Figure 17. Illustration of the California Global Warming Solutions Act Modeling



Northwest Hydro Surplus Estimate (HSE) (Tier 2 threshold)	
Effective Date	BPA→CA Flow (MW)
1/1/2024	1,120
2/1/2024	1,003
3/1/2024	1,258
4/1/2024	2,266
4/16/2024	2,471
5/1/2024	3,249
6/1/2024	2,482
7/1/2024	1,498
8/1/2024	920
8/16/2024	268
9/1/2024	146
10/1/2024	1
11/1/2024	97
12/1/2024	1

The CA carbon tax is based on projections given in the preliminary California Energy Commission (CEC) 2013 Integrated Energy Policy Report (IEPR), which stated a CO_2 tax of $26.66 per metric ton for 2024 in 2012 dollars, which is $27.51/metric ton in 2014 dollars. The CA carbon tax is applied to all in-California generation, which is defined by California utilities’ boundaries rather than state lines. This means that generation located outside of but committed to California (like the Intermountain Power Plant or IGS 1-2) are treated as in-California and subject to the CA carbon tax.

The additional “emissions reduction” hurdle rate imposed on imports from the Northwest into California is implemented in two tiers:

(1) Tier 1 imports are subject to a low additional hurdle rate (i.e., +$0.53/MWh) intended to represent the cost of importing Northwest Hydro Surplus Estimate (HSE) energy, which varies monthly and is estimated based on the BPA White Book.[6] Tier 1 imports would ideally include flows correlated to all excess generation from non-CO_2-emitting generators; however, the BPA White Book was the only source found to offer this information and it is limited to just BPA hydro and corresponding imports into California.[7]

(2) Tier 2 imports are subject to the additional hurdle rate equivalent to the CA carbon tax (i.e., +$11.97/MWh).

The California Air Resources Board (ARB) specified the emissions rate for unspecified resources as 0.435 metric ton/MWh.[8] Multiplying this value by the CA carbon tax ($27.51/metric ton) yields the total additional “emissions reduction” hurdle rate: $11.97/MWh. This additional hurdle rate is imposed directly on imports from non-BPA areas into California; however, the ARB has recognized and approved BPA as an asset-controlling supplier (ACS) and BPA imports get special treatment as a result. The ACS System Emission Factor for BPA is 0.0192 metric ton /MWh,[9] which corresponds to the Tier 1 additional “emissions reduction” hurdle rate of $0.53/MWh mentioned above.

Limitations of AB 32 Modeling

There are opportunities to improve the modeling of AB 32 in the future. Listed below are the known limitations of how AB 32 is modeled in the 2024 Common Case.

1. The ARB has recognized and approved both BPA and Powerex as ACS; however, only the additional hurdle rate representing the ACS System Emission Factor for BPA is implemented in the 2024 Common Case. Powerex is the wholly-owned electricity marketing subsidiary of BC

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[6] BPA White Book Reference: "Middle Eighty Percent" of data regarding federal surplus/deficit on page 151 of “2011 Pacific Northwest Loads and Resources Study, Technical Appendix, Volume 1, Energy Analysis.”
http://www.bpa.gov/power/pgp/whitebook/2011/WhiteBook2011_SummaryDocument_Final.pdf
http://www.bpa.gov/power/pgp/whitebook/2011/WhiteBook2011_TechnicalAppendix_Vol%201_Final.pdf

[7] BPA White Book Reference: “2011 Pacific Northwest Loads and Resources Study, Technical Appendix, Volume 1, Energy Analysis.”

[8] Page 56 of the “Proposed Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions”: http://www.arb.ca.gov/regact/2010/ghg2010/ghgisoratta.pdf.

[9] Mandatory GHG Reporting - Asset Controlling Supplier: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/acs-power.htm.

Hydro (Canada's third largest electric utility) responsible for marketing BC Hydro's surplus electricity in the western United States. Determining the amount clean energy component of transferred from Powerex to California is extremely difficult because the BC Hydro region doesn't neighbor any of the California regions.

2. The HSE is, as its name implies, an estimate of the hydro energy in BPA imported to California each month. It is based on the projected "middle eighty percent" surplus from federal hydro plants for years 2020 to 2021.
3. The ACS System Emission Factor for BPA applies to all clean energy in BPA that is imported into California and hydro energy would not be the only clean energy in BPA. As a result, the HSE likely under-estimates the amount of clean energy that would be delivered from BPA to California; however, it is extremely difficult to determine the total clean energy component of transfers from BPA to California.

Disclaimer

Appendix A: RPS and REC Information by State and Province in the Western Interconnection

REC prices depend on a number of factors, including the technology, the vintage (year in which it was generated), the volume purchased, the region in which the generator is located, whether they are eligible for certification, and whether the RECs are bought to meet compliance obligations or serve voluntary retail consumers. Natural gas prices can also affect the cost competitiveness of renewable energy generation, which is reflected in REC prices. For more information, see http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5.

ALBERTA

- No RPS Policy.

ARIZONA

- DSIRE[10] Information:
  - RECs cannot account for more than 20 percent of the annual requirement.
  - May use bundled RECs. Unbundled "paper RECs" will not meet Renewable Energy Standard & Tariff (REST) requirements.
  - Utilities subject to the RES must obtain RECs from eligible renewable resources to meet 15 percent of their retail electric load by 2025 and thereafter. Of this percentage, 30 percent (i.e., 4.5 percent of total retail sales in 2025) must come from DG resources. The DG energy requirement is that 50 percent must come from residential applications and the other 50 percent must come from non-residential, non-utility applications.
- Agency Information (Arizona Corporation Commission):
  - No REC limitation.
  - AZ requires a complete bundled REC package to meet REST requirements.
- Bonus Credits/Multipliers/Other Stipulations:
  - 200 percent credit can be applied to any solar resource.
  - RPS does not apply to the Salt River Project, other publically owned utilities, or cooperatives with more than 50 percent of their customers outside of Arizona.
- Further Reading/Information:
  - The Salt River Project Board of Directors has established an internal renewable energy goal of 20 percent by the year 2020.
  - http://www.srpnet.com/environment/renewable.aspx.

BRITISH COLUMBIA

[10] Database of State Incentives for Renewables & Efficiency.

BRITISH COLUMBIA

- 93 percent renewable energy standard, historically achieved with in-province hydroelectricity.

CALIFORNIA

- DSIRE Information:
  - Plan to reduce unbundled REC use to 10 percent annual RPS target by 2017.
  - Utilities are required to collectively procure 1,325 MW of energy storage by 2020, which will be installed and delivering to the grid no later than the end of 2024.
- Agency Information (California Public Utilities Commission):
  - Bundled RECs account for 65 percent minimum for second compliance period (2014-2016).
  - Unbundled RECs account for 15 percent maximum for second compliance period.
  - Bundled RECs account for 75 percent minimum for third compliance period (2017-2020).
  - Unbundled RECs account for 10 percent maximum for third compliance period.
  - No in-state requirements for bundled or unbundled RECs.
- Bonus Credits/Multipliers/Other Stipulations:
  - N/A.
- Further Reading/Information:
  - RPS/REC procurement rules: http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33RPSProcurementRules.htm.
  - Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities: http://www.energy.ca.gov/2013publications/CEC-300-2013-002/CEC-300-2013-002-CMF.pdf.
  - California Energy Storage Goals: http://www.cpuc.ca.gov/PUC/energy/electric/storage.htm.

COLORADO

- DSIRE Information:
  - Tradable renewable energy credits (REC) may be used to satisfy the standard.
  - For IOUs: 3 percent of retail sales by 2020 must come from distributed generation of which half must be "retail DG" serving on-site load.
  - Cooperatives that provide service to 10,000 or more meters: 1 percent of retail sales by 2020 must come from DG of which half must be "retail DG" serving on-site load.
  - Cooperatives that provide service to less than 10,000 meters: 0.75 percent of retail sales by 2020 must come from DG of which half must be "retail DG" serving on-site load.

COLORADO

- Agency Information (Colorado Public Utilities Commission):
  - No restriction on percentage of RECs used for annual compliance.
  - RES requires IOUs to acquire RECs from different-sized resources:
    - Retail DG (customer site, behind meter).
    - Wholesale DG (< 30 MW).
    - Non-DG (> 30 MW).
- Bonus Credits/Multipliers/Other Stipulations:
  - 300 percent credit for RPS-compliance purposes applies to solar-electric generation before July 1, 2015. Solar electricity generated by a facility that begins operation on or after July 1, 2015 receives 100 percent credit.
  - 125 percent credit for each KWh of eligible electricity generated in-state, other than retail DG.
  - 150 percent credit applies to electricity generated at a “community-based project,” a project not greater than 30 MW in capacity that is owned by individual residents of a community or by an organization or cooperative that is controlled by individual residents, or by a local government entity or tribal council.
  - 200 percent credit for projects up to 30 MW that are interconnected to electrical transmission or distribution lines owned by a cooperative or municipal utility and are installed prior to December 31, 2014 (with the exception of IOUs using this multiplier, it is only available for the first 100 MW of projects statewide).

IDAHO

- No RPS policy.

MONTANA

- DSIRE Information:
  - Utilities and competitive suppliers can meet the standard by entering into long-term purchase contracts for electricity bundled with RECs, by purchasing RECs separately, or by a combination of both.
  - RECs sold through voluntary utility green power programs may not be used for compliance.

MONTANA

- Agency Information (Montana Department of Environmental Quality; Energy and Pollution Prevention Bureau):
    - No limitation on REC usage.
    - RECs used to meet compliance with Montana RPS must come from a Montana Public Service Commission-approved renewable energy development.
    - Energy and RECs do not need to be bundled but it must be demonstrated that it would be possible to obtain the energy and REC as a package if coming from outside Montana.
    - Approved Montana Public Service Commission (MTPSC) developments exist in Oregon, Wyoming, and North Dakota.
    - Stipulation “not of great concern” due to more energy flowing from than into Montana.
- Bonus Credits/Multipliers/Other Stipulations:
    - Community-owned RE set-aside for IOUs of 75 MW for 2015 and beyond.

BAJA CALIFORNIA (CFE)

- No RPS Policy.

NEVADA

- DSIRE Information:
    - Can buy and sell MTPSCs to meet RPS goals.
    - Technology minimum for solar of 5 percent of annual requirement through 2015 (1.2 percent of sales), 6 percent for 2016-2025 (1.5 percent of sales in 2025).
    - Energy efficiency measures can be used to satisfy a portion of the RPS. Limited to no more than 10 percent of the RPS requirement for calendar years 2020-2024 (0 (zero) percent of the requirement for 2025 and beyond).
- Agency Information (Public Utilities Commission of Nevada):
    - No Portfolio Energy Credit (PEC) usage restrictions.
    - Associated electric energy must be delivered to a retail customer in Nevada.
- Bonus Credits/Multipliers/Other Stipulations:
    - 2.4 multiplier for PV systems installed by a retail customer and for which at least 50 percent of energy is used by the customer. A 0.05 adder applies to customer-maintained DG systems, bringing the total to a 2.45 multiplier.

NEW MEXICO

- DSIRE Information:
    - RECs not used for compliance, sold, or otherwise transferred may be carried forward for up to four years.
    - Technology minimum; for IOUs only in 2020:
        - Solar: 20 percent of RPS requirement (4 percent of sales).
        - Wind: 30 percent of RPS requirement (6 percent of sales).
        - Geothermal, biomass, certain hydro facilities and other renewables: 5 percent of RPS requirement (1 percent of sales).
        - Distributed renewables: 3 percent of RPS requirement (0.6 percent of sales).
- Agency Information (New Mexico Energy, Minerals, and Natural Resources Department):
    - No set REC limitation.
    - Can be purchased bundled or unbundled to meet RPS goal.
    - Most RECs used are bundled with renewable energy. Although this is not a standard, it is the preferred method to acquire RECs as outlined by the New Mexico Public Regulation Commission.
- Bonus Credits/Multipliers/Other Stipulations:
    - N/A
- Further reading/information:
    - http://www.nmcpr.state.nm.us/nmac/parts/title17/17.009.0572.htm.

OREGON

- DSIRE Information:
    - Unbundled RECs can only meet 20 percent of a large utility's compliance obligation and 50 percent of a large consumer-owned utility's obligation.
    - RECs procured before March 31 of a given year may be used for a previous year's compliance. RECs may also be banked and carried forward indefinitely for future compliance.
    - Bundled RECs must come from a facility in the U.S. portion of WECC.
    - Utilities with less than 1.5 percent of the state load must meet 5 percent RPS by 2025.
    - Utilities with more than 1.5 percent but less than 3 percent of state load must meet a 10 percent RPS by 2025.
    - A *goal* exists that by 2025, at least 8 percent of Oregon's retail electric load will come from small-scale, community renewable energy projects with a capacity of 20 MW or less.

OREGON

- Agency Information (Oregon Department of Energy/Oregon Public Utilities Commission):
  - "Larger utilities" serving at least 3 percent of Oregon's total retail electric load may use unbundled RECs to meet no more than 20 percent of their annual RPS requirement.
  - "Smaller utilities" serving less than 3 percent of Oregon's total retail electric load have no limits for unbundled RECs to meet RPS goals.
  - "Small utilities" that become "large utilities" (because their load increases to the point that they serve at least 3 percent of Oregon's total retail electric load) may use unbundled RECs to meet no more than 100 percent (years 4-9), and then 75 percent (years 10+).
  - For consumer-owned utilities, the limit on unbundled RECs in a calendar year is 50 percent.
  - RECs that are acquired but not used to meet the RPS in a calendar year can be carried forward indefinitely for future years (banked RECs). Banked RECs have to be used in a "first-in, first-out" order.
- Bonus Credits/Multipliers/Other Stipulations:
  - Double credits for IOUs for PV systems from 500 kW to 5 MW operational prior to January 1, 2016.
- Further reading/information:
  - http://www.oregon.gov/energy/RENEW/RPS/Pages/RPS-RECs.aspx
  - http://energytrust.org/shared-resources/info/green-tags.aspx?src=business

UTAH

- DSIRE Information:
  - Utilities may meet their RPG target by producing electricity with an eligible form of renewable energy or by purchasing RECs (also referred to as "Green Tags").
  - Utilities only need to pursue renewable energy to the extent that it is "cost-effective" to do so.
- Agency Information (American Council On Renewable Energy)
  - No limitation on REC use.
  - RECs produced within the geographical boundary of the Western Interconnection can be used for compliance.
  - Utilities can meet RPS targets by producing electricity from an eligible form of renewable energy or by purchasing renewable energy certificates.
- Bonus Credits/Multipliers/Other Stipulations:
  - 240 percent multiplier for solar-electric.
- Further reading/information:
  - http://www.acore.org/files/pdfs/states/Utah.pdf.
  - http://www.epa.gov/cmop/docs/state-programs.pdf.

WASHINGTON

- DSIRE Information:
    - Utilities subject to the RPS standard must use eligible renewable resources or acquire equivalent RECs, or use a combination of both to meet the annual targets.
    - A utility's failure to meet the energy conservation or renewable energy targets will result in an administrative penalty of $50/MWh (adjusted annually for inflation) paid to the state of Washington. The funds will be deposited in a special account for the purchase of renewable energy credits or for energy conservation projects at public facilities, local government facilities, community colleges or state universities.
- Agency Information (Washington Department of Commerce; State Energy Office):
    - No REC limitation; a utility could rely entirely on RECs to meet its target if necessary.
    - Relevant provision in RCW 19.285.040(2)(a): "[E]ach qualifying utility shall use eligible renewable resources or acquire equivalent renewable energy credits, or any combination of them, to meet … annual targets:"
    - REC synonymous with "Green Tag."
    - RECs generated for compliance cannot be older than the year prior to the compliance year; e.g., for a compliance year of 2014 only RECs generated in 2013 can be used, not RECs generated earlier than 2013.
- Bonus Credits/Multipliers/Other Stipulations:
    - 200 percent credit for Distributed PV. DG must be 5 MW or less to claim the double credit.

WYOMING

- No RPS Policy.

Glossary of Terms and Acronyms

DG: Distributed Generation.

DR: Demand Response.

DSIRE: Database of State Incentives for Renewables & Efficiency (http://www.dsireusa.org/).

DSM: Demand-Side Management.

FERC: Federal Energy Regulatory Commission.

GT: Green Tag. This is synonymous with REC and used in Utah and Washington.

IOU: Investor-Owned Utility.

IRP: Integrated Resource Plan.

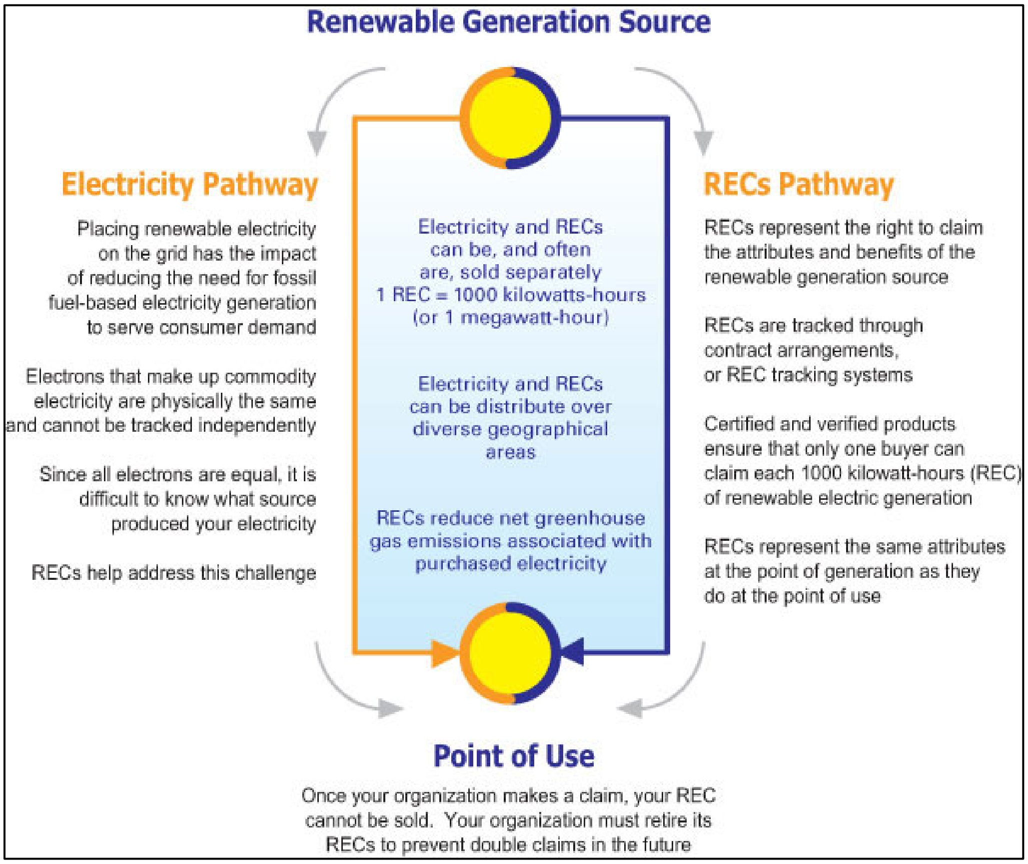
PEC: Portfolio Energy Credit (synonymous with REC, applies in Nevada).

PV: Photovoltaic.

REC: Renewable Energy Certificate. A tradable, non-tangible energy commodity that represents proof that 1 megawatt-hour (equivalently, 1,000 kilowatt-hours) of electricity was generated from an eligible renewable energy resource. *This is interchangeable with* Renewable Energy Certificate, Renewable Energy Credit, Green Tag, Green Ticket, or Renewable Certificate.

REC, Bundled (Bundled REC): A bundled power purchase agreement for both the RECs and energy associated with an eligible RPS facility. Figure 18 shows the REC/Electricity pathway.

Figure 18. Renewable generation REC and electricity pathway (http://www.epa.gov/greenpower/gpmarket/rec_chart.htm)



REC, Unbundled (Unbundled REC): A transaction for the REC only and not the associated electricity. Once the RECs are "unbundled" from the energy, the energy is considered null (non-renewable) power and no green claims can be made for use of this null electricity.

RES: Renewable Energy Standard.

RPG: Renewable Portfolio Goal.

RPS: Renewable Portfolio Standard.

REST: Renewable Energy Standard & Tariff (applies to Arizona).

TREC: Tradable Renewable Energy Credit (synonymous with REC, applies in Colorado).