

Release Notes for WECC 2026 Common Case

Version 1.5

System Adequacy Planning (SAP) Department

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Executive Summary

The Common Case represents the expected loads, resources and transmission topology 10 years in the future from a given reference year. WECC's 2026 Common Case is based on a reference year of 2016, so it represents loads, resources and transmission topology in 2026. The WECC Common Case is designed to be analyzed with a production cost model (PCM). WECC uses GridView as its PCM tool.

The 2026 Common Case represents the trajectory of recent Western Interconnection planning information, developments and policies looking out 10 years. The Transmission Expansion Planning Policy Committee (TEPPC) stakeholders assisted the WECC System Adequacy Planning (SAP) Department in developing numerous assumptions that depict the Western Interconnection and how it is expected to change over the next 10 years.

A primary goal in developing the Common Case is to define a realistic foundation for the rest of the Year 10 study cases included in TEPPC's annual study program. The case is also used throughout the Western Interconnection for a number of purposes, including: FERC Order 890 and 1000 planning studies by Western Planning Regions, independent transmission developers' studies, market studies (e.g., Energy Imbalance Market) and integration studies, among many others.

The purpose of these release notes is to provide transparency and explanation of the assumptions and modeling in the 2026 Common Case. After the initial release of the 2026 Common Case, subsequent revisions are expected to include improvements over the last. The timing and number of such additional revisions will depend on WECC's and stakeholders' needs for case enhancements, as well as on resource availability for creating additional revisions. These release notes attempt to document all of the assumptions used in the first release (Version 1.0) of the 2026 Common Case. Subsequent versions of the 2026 Common Case will be posted with incremental release notes 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.

The 2026 Common Case data is stored and maintained in ABB GridView (GridView or GV), which is an energy market simulation and analysis software tool distributed by ABB. GridView uses a Microsoft Access database file (GV Case Template.mdb) and numerous text-based shape files (*.DAT) to store the 2026 Common Case information. Stakeholders desiring to perform analyses using the 2026 Common Case in GridView must obtain software licenses from ABB for GridView. All cost values in this document are expressed in 2016 U.S. dollars (2016\$ or \$) unless otherwise as noted.

Electric Topology

TEPPC Load Areas

The “Load Area” topology for the 2026 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 40 areas correlate with the load forecast granularity provided by WECC’s annual loads and resources survey, which is overseen by 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. Figure 1 shows all the load areas for the 2026 Common Case.

TEPPC Regions

The TEPPC regions are defined at an operational level that, in most cases, corresponds to the load areas listed in Figure 1 but with a two-character sub region 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 rates¹ 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

Trading Hubs

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

Currently, the 2026 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.

¹ Hurdle rates represent the cost to deliver surplus energy among different regions.

Operationally, trading hubs are generation free-trading zones with no hurdle-rate barriers. In production cost modeling, the primary purpose of a trading hub is to avoid an unrealistic build-up of hurdle rate

Figure 1. TEPPC Load Areas

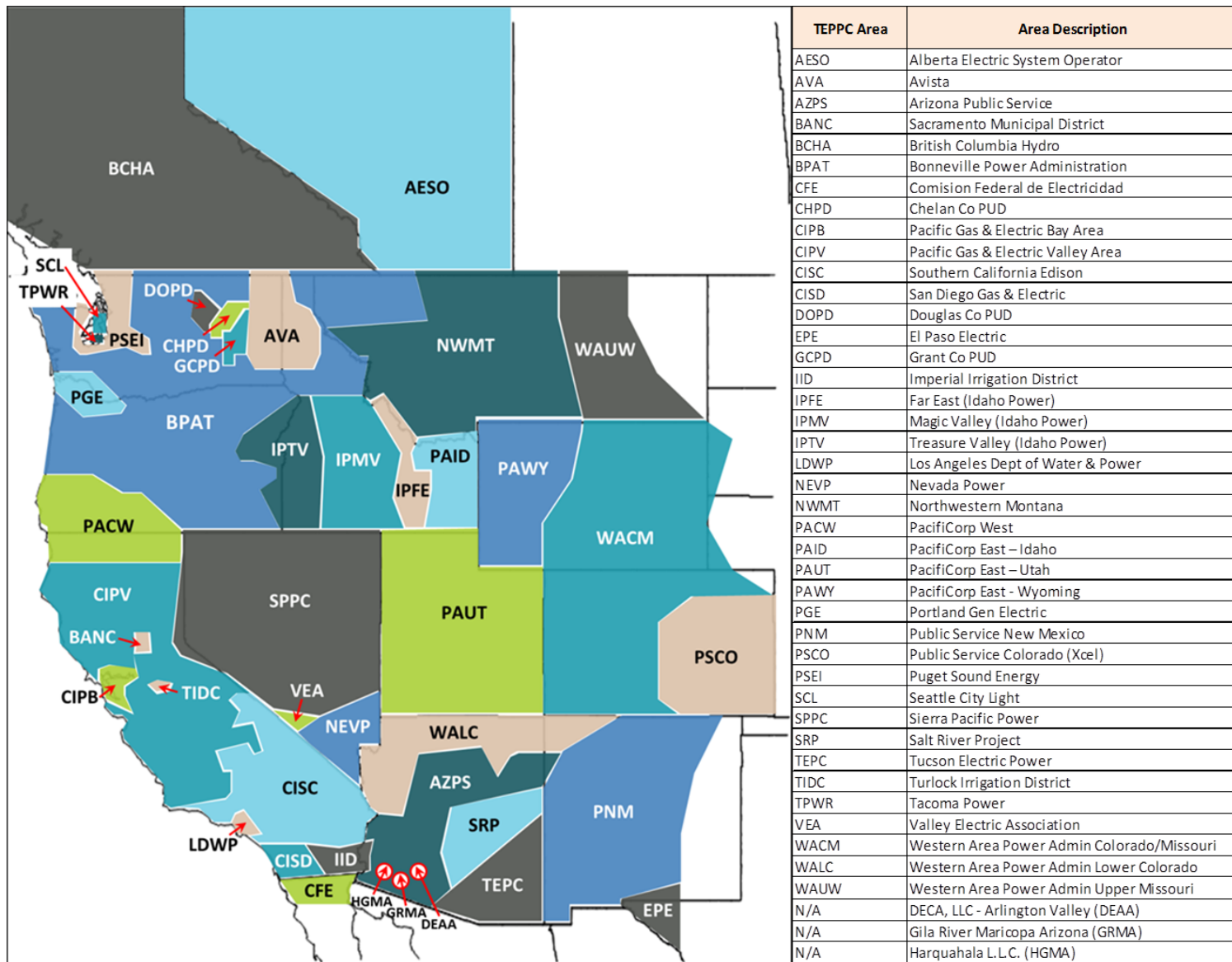
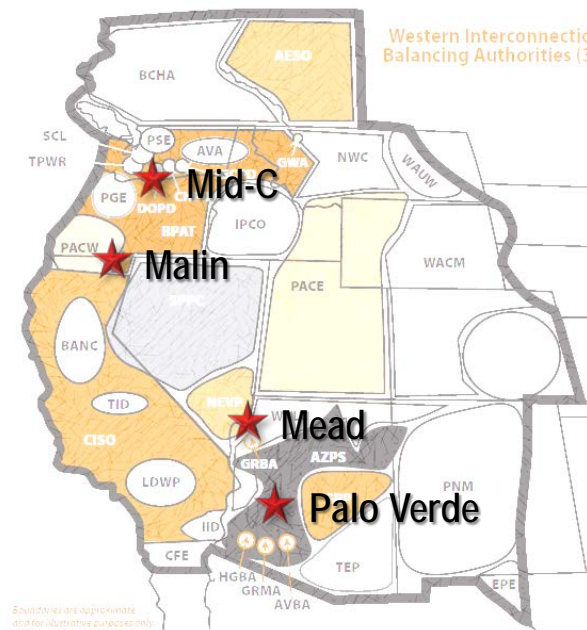


Figure 2. Trading Hubs



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 power imported into a TEPPC region or trading hub does not incur hurdle rates. Figure 3 shows TEPPC regions with a trading hub region interfacing between them.

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

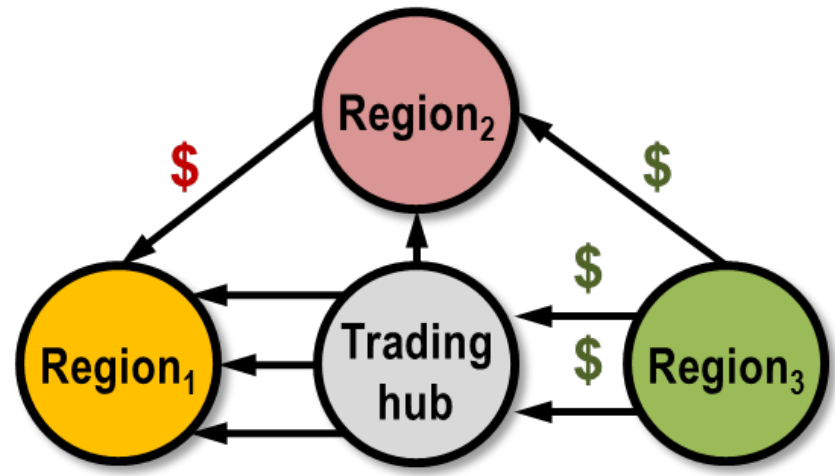


Figure 4 below shows the configuration of the Palo Verde trading hub. In this trading hub, Palo Verde and Hassayampa are two central buses. For generators that are directly connected to the hub, the generation buses are also defined as a part of the trading hub. In addition, Jojoba is also included as a special addition, due to Arizona Public Service Co. (APS), the BA operating these buses, having transmission rights from Jojoba to Hassayampa. The Gila River generation 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

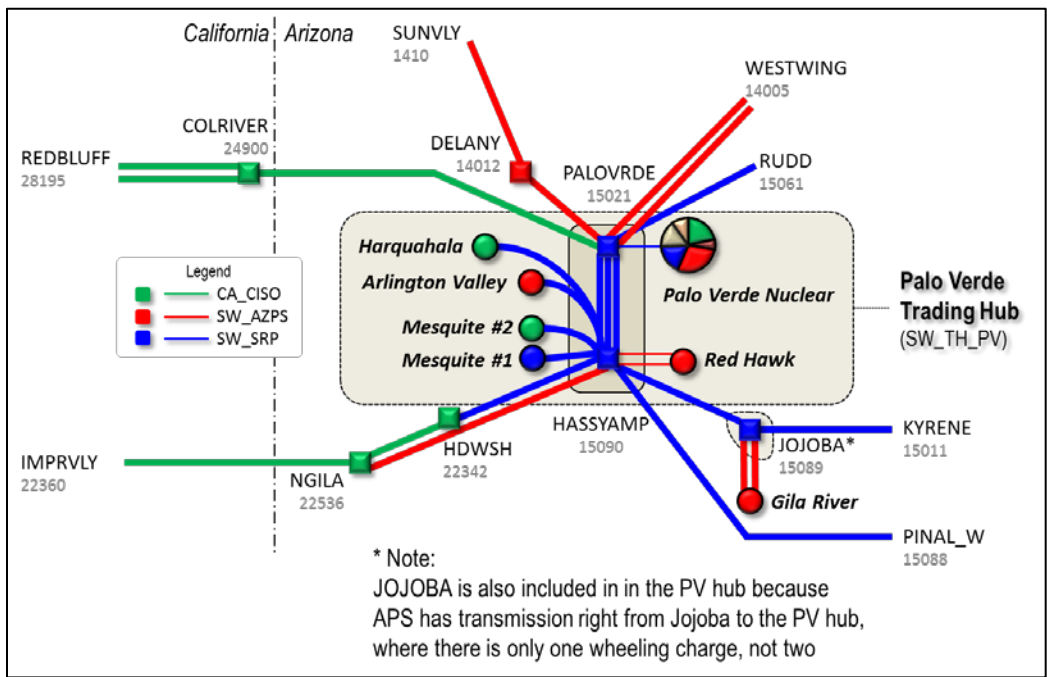


Figure 5 shows the configuration of the Mead trading hub, which consists of Mead 500-kV, 345-kV, and 230-kV buses and the Hoover Power Plant.

Figure 5. Mead Trading Hub

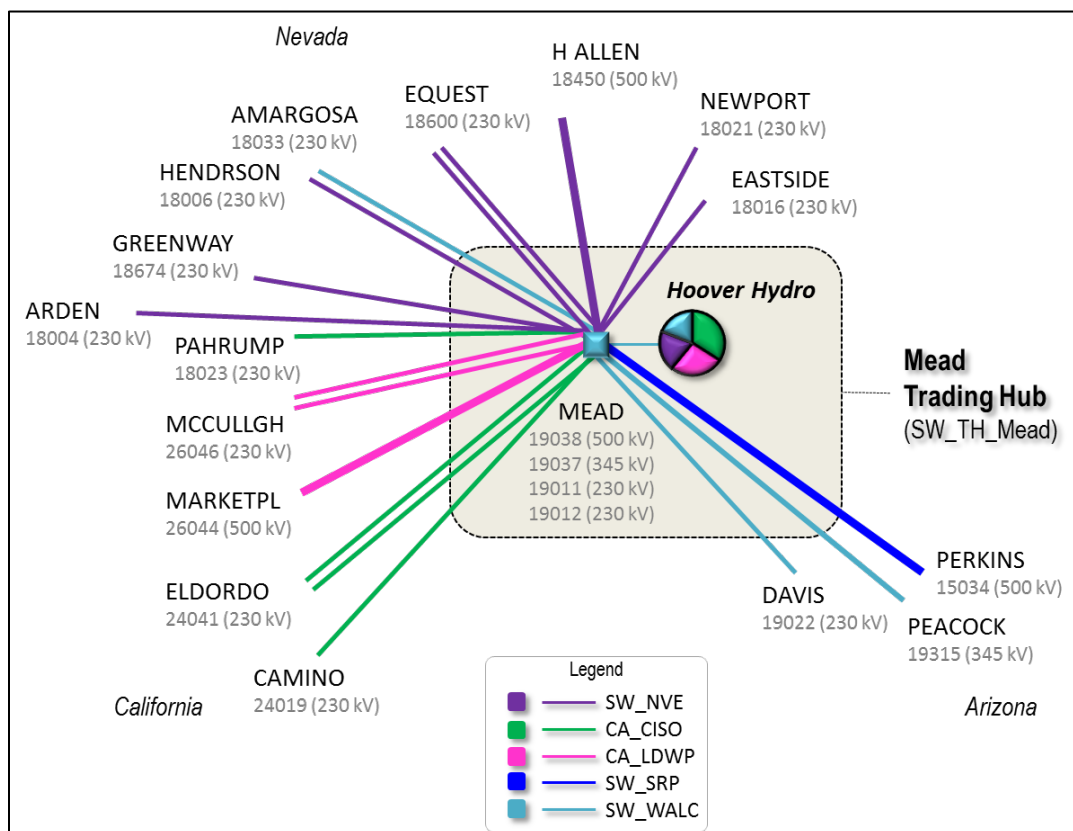
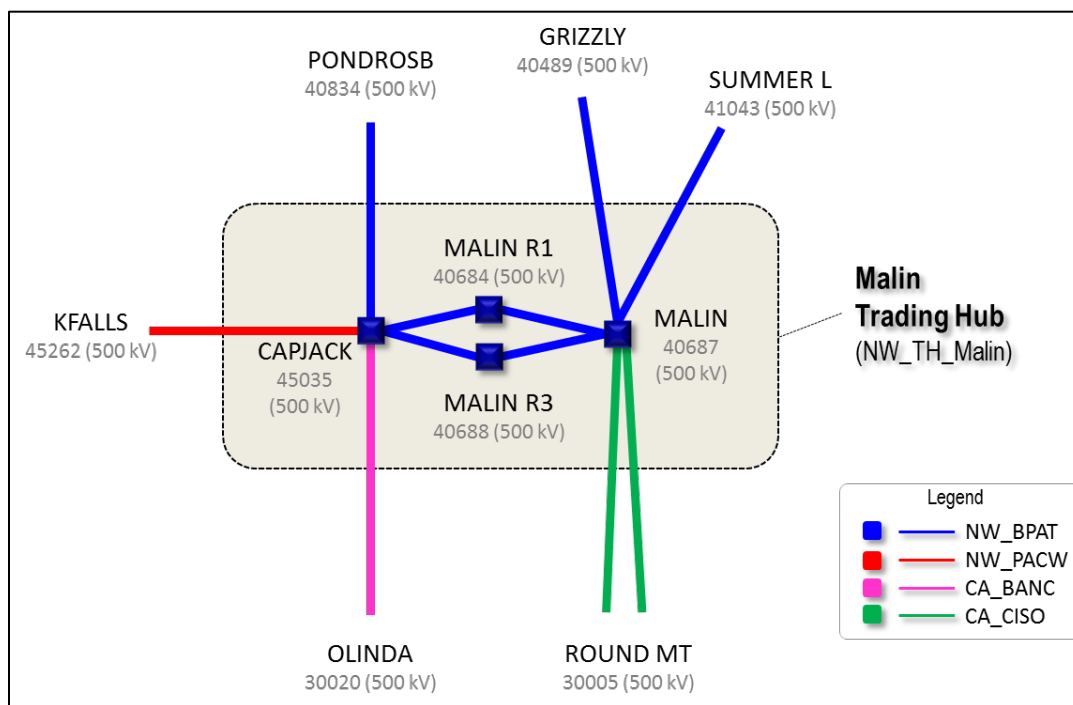


Figure 6 shows the configuration of the Malin trading hub, which consists of the 500-kV intersection of the Bonneville Power Administration, PacifiCorp West, Balancing Authority of Northern California, and the California Independent System Operator (i.e., NW_BPAT, NW_PACW, CA_BANC, and CA_CISO in the 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 2026 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 2015 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 2026 Common Case. These are base values and do not include additional charges associated with the California Global Warming Initiative.

Table 2. 2026 Interregional Hurdle Rates (2016\$)

From	To	Direction		From	To	Direction	
		→	←			→	←
AB_AESO	BC_BCHA	\$2.14	\$7.11	SW_AZPS	CA_CISO	\$3.95	\$10.98
AB_AESO	NW_NWE+	\$2.14	\$4.74	SW_AZPS	CA_IID	\$3.95	\$3.32
NW_AVA	NW_BPAT+	\$2.53	\$1.91	SW_AZPS	CA_LDWP	\$3.95	\$5.84
NW_AVA	NW_PACW	\$2.53	\$3.08	SW_AZPS	SW_PNM	\$3.95	\$4.16
NW_AVA	NW_PGE	\$2.53	\$2.53	SW_AZPS	SW_SRP	\$3.95	\$2.08
NW_BPAT+	BC_BCHA	\$1.91	\$7.11	SW_AZPS	SW_TEPC	\$3.95	\$3.57
NW_BPAT+	CA_BANC+	\$1.91	\$2.53	SW_AZPS	SW_WALC	\$3.95	\$1.91
NW_BPAT+	CA_CISO	\$1.91	\$10.98	SW_NVE	CA_CISO	\$6.96	\$10.98
NW_BPAT+	CA_LDWP	\$1.91	\$5.84	SW_NVE	CA_LDWP	\$6.96	\$5.84
NW_BPAT+	NW_PACW	\$1.91	\$3.08	SW_NVE	SW_WALC	\$6.96	\$1.91
NW_BPAT+	NW_PGE	\$1.91	\$2.53	SW_PNM	SW_EPE	\$4.16	\$4.16
NW_BPAT+	NW_PSEI	\$1.91	\$2.53	SW_PNM	SW_WALC	\$4.16	\$1.91
NW_BPAT+	SW_NVE	\$1.91	\$6.96	SW_SRP	CA_CISO	\$2.08	\$10.98
NW_NWE+	BS_PACE	\$4.74	\$3.08	SW_SRP	SW_TEPC	\$2.08	\$3.57
NW_NWE+	NW_AVA	\$4.74	\$2.53	SW_SRP	SW_WALC	\$2.08	\$1.91
NW_NWE+	NW_BPAT+	\$4.74	\$1.91	SW_TEPC	SW_EPE	\$3.57	\$4.16
NW_NWE+	RM_WACM	\$4.74	\$4.98	SW_TEPC	SW_PNM	\$3.57	\$4.16
NW_PACW	CA_CISO	\$3.08	\$10.98	SW_WALC	CA_CISO	\$1.91	\$10.98
NW_PACW	NW_PGE	\$3.08	\$2.53	SW_WALC	CA_IID	\$1.91	\$3.32
BS_IPCO	NW_AVA	\$2.67	\$2.53	SW_WALC	CA_LDWP	\$1.91	\$5.84
BS_IPCO	NW_BPAT+	\$2.67	\$1.91	SW_WALC	SW_TEPC	\$1.91	\$3.57
BS_IPCO	NW_PACW	\$2.67	\$3.08	CA_CISO	CA_BANC+	\$10.98	\$2.53
BS_IPCO	NW_PGE	\$2.67	\$2.53	CA_IID	CA_CISO	\$3.32	\$10.98
BS_IPCO	SW_NVE	\$2.67	\$6.96	CA_LDWP	CA_CISO	\$5.84	\$10.98
BS_PACE	BS_IPCO	\$3.08	\$2.67	SW_TH_PV	CA_CISO	\$0.00	\$10.98
BS_PACE	CA_LDWP	\$3.08	\$5.84	SW_TH_PV	SW_AZPS	\$0.00	\$3.95
BS_PACE	RM_WACM	\$3.08	\$4.98	SW_TH_PV	SW_SRP	\$0.00	\$2.08
BS_PACE	SW_AZPS	\$3.08	\$3.95	SW_TH_Mead	SW_WALC	\$0.00	\$1.91
BS_PACE	SW_NVE	\$3.08	\$6.96	SW_TH_Mead	SW_NVE	\$0.00	\$6.96
BS_PACE	SW_WALC	\$3.08	\$1.91	SW_TH_Mead	SW_AZPS	\$0.00	\$3.95
RM_PSCO	SW_PNM	\$3.09	\$4.16	SW_TH_Mead	SW_SRP	\$0.00	\$2.08
RM_WACM	RM_PSCO	\$4.98	\$3.09	SW_TH_Mead	CA_CISO	\$0.00	\$10.98
RM_WACM	SW_PNM	\$4.98	\$4.16	SW_TH_Mead	CA_LDWP	\$0.00	\$5.84
RM_WACM	SW_WALC	\$4.98	\$1.91	CA_CFE	CA_CISO	\$2.31	\$10.98

Loads

Load Data Collection and Adjustments

The WECC Loads and resources (L&R) information used for the 2026 Common Case is a combination of loads collected by the 2015 WECC L&R data collection and those collected by the California Energy Commission (CEC). These loads are adjusted for energy efficiency (EE), distributed generation, and pump loads. The final loads are used with a 2009 historical load shape to derive load shapes for the 2026 Common Case.

L&R 2026 Data Extrapolation

Some balancing areas loads are forecasted for 2015 through March 2026. The months of April-December must be extrapolated to create a 2026 full year load forecast, so the missing data is extrapolated using a 3rd degree polynomial fit from the monthly forecasts provided. Table 3 and Table 4 show the results used for extrapolated data calculated for these BAs.

Table 3 Extrapolated 2026 Load Energy (GWh)

BA	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
BCHA	5,840	5,632	5,300	5,611	5,612	5,433	6,003	6,560	7,269
CFE	1,098	1,293	1,496	1,694	1,750	1,524	1,261	1,072	1,049
CHPD	327	319	305	336	332	313	345	382	433
EPE	670	780	954	1,015	1,017	893	750	658	725
PAUT	2,716	2,748	2,972	3,472	3,544	3,079	2,887	2,911	3,103
PAID	445	502	576	660	581	461	445	472	572
PACW	1,658	1,653	1,637	1,863	1,825	1,650	1,679	1,794	2,060
PAWY	937	956	937	997	996	898	984	958	989
PGE	1,902	1,900	1,842	1,995	2,029	1,849	1,896	2,025	2,288
PNM	1,060	1,145	1,262	1,476	1,443	1,264	1,148	1,102	1,309
PSCO	3,287	3,406	3,620	4,145	4,061	3,538	3,442	3,524	3,890
SCL	846	811	777	806	815	786	862	929	1,051
TEPC	1,231	1,448	1,733	1,903	1,860	1,646	1,368	1,216	1,345
TIDC	231	265	295	339	337	296	254	227	238
TPWR	448	427	396	413	416	398	454	522	577
WACM	2,601	2,706	2,808	3,333	3,102	2,697	2,768	2,762	3,069
WALC	1,077	1,177	1,018	907	901	926	806	774	792
WAUW	71	70	72	93	85	69	65	74	92

Table 4 Extrapolated 2026 Load Peak (MW)

BA	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
BCHA	10,309	9,482	9,324	9,685	9,611	9,493	10,776	12,225	13,064
CFE	2,050	2,285	2,663	3,031	3,122	3,028	2,472	1,795	1,762
CHPD	585	530	503	532	522	475	556	664	722
EPE	1,541	1,869	2,063	2,066	2,076	1,937	1,674	1,472	1,547
PAUT	4,315	5,301	6,341	6,880	6,685	6,227	4,950	5,043	5,336
PAID	849	855	1,031	1,089	942	808	858	947	1,040
PACW	3,190	2,924	3,137	3,612	3,516	3,212	3,198	3,490	3,806
PAWY	1,434	1,388	1,494	1,530	1,502	1,428	1,423	1,524	1,527
PGE	3,923	3,770	3,609	3,380	3,366	3,470	3,966	4,026	3,529
PNM	2,270	2,103	1,997	1,914	2,002	2,466	2,966	2,743	2,592
PSCO	5,847	6,198	8,094	8,729	8,340	6,996	6,093	6,141	6,795
SCL	1,541	1,408	1,372	1,414	1,402	1,376	1,519	1,715	1,895
TEPC	2,202	2,062	2,025	2,295	2,864	3,416	3,512	3,342	3,158
TIDC	466	580	708	756	740	672	512	416	417
TPWR	911	837	733	670	669	700	710	840	945
WACM	4,105	4,364	4,194	5,826	5,193	5,080	4,272	4,748	5,226
WALC	1,850	2,049	2,011	1,819	1,841	1,881	1,647	1,337	1,478
WAUW	139	140	157	168	160	146	143	154	163

Energy Efficiency Adjustments

The loads in 2026 Common Case are adjusted for Energy Efficiency (EE) savings. WECC L&R data submitted by the BAs are reviewed by the Lawrence Berkeley National Laboratory (LBNL) for consistency. These adjustments are subtracted from the BA load energy and peak. In the 2015 L&R data submitted, only three BAs required EE adjustments. Table 5 and Table 6 show the LBNL adjustments required for the 2026 Common Case data.

Table 5 LBNL Energy Adjustments (GWh)

BA	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
IPTV	51	45	47	46	52	55	64	61	49	44	45	50
IPMV	17	15	16	16	21	24	25	23	18	15	14	16
IPFE	12	11	12	11	13	15	16	13	11	11	11	12

Table 6 LBNL Peak Adjustments (MW)

BA	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
IPTV	77	77	57	68	79	99	113	82	102	49	75	72
IPMV	25	26	20	24	32	43	44	31	38	17	24	24
IPFE	19	19	14	16	19	26	27	17	22	11	18	17

Behind the Meter PV and Distributed Generation Adjustments

The forecasted Behind the Meter (BTM) PV and DG is added to the loads for each BA. For the 2015 submitted L&R data Table 7 and Table 8 shows the PV embedded in the load forecasts. LBNL has identified net-metered PV embedded in the L&R load forecasts. The net-metered PV is added back into the loads for the 2026 Common Case.

Table 7 Net-Metered PV Embedded in 2026 L&R Forecasts (GWh)

BA	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AZPS	242	255	318	340	338	323	334	337	332	312	261	239
LDWP	29	35	42	49	49	49	55	52	45	38	32	28
NEVP	38	40	50	54	53	51	53	53	53	50	41	38
PSCO	54	58	85	88	94	93	91	89	82	74	57	54
TEPC	28	28	33	37	39	40	37	32	34	35	31	28

Table 8 Net-Metered PV Embedded in 2026 L&R Forecasts (MW)

BA	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AZPS	0	0	0	437	609	757	781	929	750	383	0	0
LDWP	191	215	220	267	261	242	250	256	223	188	180	167
NEVP	0	0	0	69	97	120	124	147	119	61	0	0
PSCO	0	0	0	41	199	194	268	223	218	111	0	0
TEPC	0	1	9	29	32	35	73	51	18	10	0	1

The CEC forecasts for the 2026 Common Case also have the monthly BTM PV forecasts for the mid-demand case added back to the BA's energy and peak loads. Table 9 shows the annual BTM-PV forecast used for 2026 Common Case. Table 10 and Table 11 shows the area forecasts that include these BTM-PV adjustments used in 2026 Common Case.

Table 9 CEC BTM-PV Forecasts

BA	Installed PV Capacity (MW)	PV Energy (GWh)	PV Capacity at System Peak
BANC	339	588	120
CISC	4,521	8,074	1,726
CISD	1,312	2,324	0
IID	98	182	0
LDWP	527	899	213

Table 10 CEC BTM-PV Forecasts (GWh)

BA	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CISC	8693	7753	8525	8342	9055	9614	11077	11243	10367	9188	8322	8776

BA	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CISD	1855	1655	1777	1704	1796	1828	2074	2165	2068	1898	1764	1902
BANC	1474	1270	1368	1347	1466	1679	1962	1868	1622	1415	1348	1544
LDWP	2331	2109	2295	2230	2383	2397	2739	2790	2584	2439	2250	2352
IID	283	264	286	317	427	512	573	595	484	370	283	291

Table 11 CEC BTM-PV Forecasts (MW)

BA	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CISC	14918	14539	14601	15821	17923	19166	21242	21989	22522	18417	15227	15638
CISD	3456	3388	3303	3368	3588	3566	4053	4371	4710	3874	3472	3646
BANC	2594	2458	2348	2681	3569	4427	4693	4624	4120	2957	2467	2682
LDWP	5156	5113	5104	5539	6072	6241	7067	7396	7193	6089	5329	5261
IID	594	605	683	894	1162	1341	1400	1449	1297	1081	766	631

Pumping Loads

The individual BAs included pumping loads in their L&R information data submittals and CEC submittals. The 2026 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 12 notes the reduction in energy and peak to the area-level load that contains pumping load. SAP used 2009 historical data to create the reductions in peak and energy.

Table 12 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)	378	309	429	350	435	521	643	643	645	578	566	492
CIPV Pump Energy (GWh)	92	83	124	92	149	173	310	244	185	191	168	136
CISC Pump Peak (MW)	725	606	994	863	971	1047	1165	1187	1188	1164	1168	933
CISC Pump Energy (GWh)	312	276	348	318	410	472	541	528	481	434	544	381
BANC Pump Peak (MW)	53	66	85	69	34	34	100	85	86	86	83	66
BANC Pump Energy (GWh)	29	24	40	19	14	18	58	61	59	59	39	30

Finalized 2026 Common Case Adjusted Loads

The final load energy and peak data for the 2026 Common Case is shown in Table 13-Table 16. The L&R data is adjusted according to LBNL adjustments for EE savings and BTM-PV. The CEC data is revised to reflect CEC BTM-PV adjustments. California load submissions have adjustments for pump loads. The

resulting 2026 peak demand and energy forecasts were used in conjunction with 2009 historical hourly load shapes to derive the 2026 hourly load shapes.

Table 13 L&R Adjusted Energy Loads (GWh)

BA	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AESO	9268	8584	9072	8212	8053	7874	8630	8403	8081	8474	9017	9408
NEVP	2451	2125	2307	2216	2727	3293	3655	3417	2828	2004	2063	2335
SPPC	887	769	835	802	987	1192	1323	1237	1024	726	747	845
AVA	1300	1245	1160	1063	999	1023	1135	1127	1021	1074	1215	1348
AZPS	3024	2604	2750	2729	3343	3935	4646	4578	3878	3033	2724	3067
BCHA	7174	6373	6513	5840	5632	5300	5611	5612	5433	6003	6560	7269
BPAT	5864	5105	5060	4732	4658	4539	4920	4906	4539	4744	5321	5918
CFE	1039	974	1075	1098	1293	1496	1694	1750	1524	1261	1072	1049
CHPD	440	382	373	327	319	305	336	332	313	345	382	433
DOPD	237	188	164	136	136	133	163	158	136	151	186	239
EPE	718	656	676	670	780	954	1015	1017	893	750	658	725
GCPD	501	408	439	439	488	506	579	570	463	461	446	533
IPFE	234	205	212	196	217	260	316	241	211	201	201	244
IPMV	422	364	378	366	485	589	683	601	466	368	356	443
IPTV	1015	865	876	826	897	1004	1318	1185	947	861	867	1086
NWMT	1171	1003	1044	935	948	973	1111	1072	950	991	1033	1146
PACW	2038	1756	1802	1658	1653	1637	1863	1825	1650	1679	1794	2060
PAID	558	510	496	445	502	576	660	581	461	445	472	572
PAUT	3122	2829	2812	2716	2748	2972	3472	3544	3079	2887	2911	3103
PAWY	1004	904	975	937	956	937	997	996	898	984	958	989
PGE	2226	1948	2069	268	240	215	239	266	266	269	272	270
PNM	1270	1090	1183	1060	1145	1262	1476	1443	1264	1148	1102	1309
PSCO	3867	3459	3622	3375	3500	3713	4236	4150	3620	3516	3581	3944
PSEI	3060	2664	2750	2443	2276	2169	2241	2268	2209	2453	2739	3182
SCL	1041	893	936	846	811	777	806	815	786	862	929	1051
SRP	2678	2334	2444	2369	2854	3481	4187	4154	3455	2729	2363	2637
TEPC	1378	1210	1241	1268	1487	1773	1940	1892	1680	1403	1247	1373
TIDC	230	204	225	231	265	295	339	337	296	254	227	238
TPWR	583	516	521	450	427	396	413	416	398	454	523	578
WACM	2901	2527	2732	2601	2706	2808	3333	3102	2697	2768	2762	3069
WALC	724	810	1046	1077	1177	1018	907	901	926	806	774	792
WAUW	87	80	81	71	70	72	93	85	69	65	74	92

Table 14 L&R Adjusted Peak Loads (MW)

BA	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AESO	14196	14319	14035	12710	11941	12384	13447	13184	12597	12625	14391	14472
NEVP	3382	3296	3135	4095	4838	5445	5962	5685	5276	4238	3307	3507
SPPC	1447	1410	1341	1752	2069	2329	2550	2432	2257	1813	1414	1500
AVA	2396	2274	2095	1922	1851	1999	2224	2198	1919	1950	2215	2417
AZPS	5441	5171	4674	5688	7291	8249	9549	9734	8406	6382	4974	5328
BCHA	12472	11811	11232	10309	9482	9324	9685	9611	9493	10776	12225	13064
BPAT	10985	10405	9722	9234	8483	8240	8650	8639	8257	8957	10070	10956
CFE	1738	1737	1787	2050	2285	2663	3031	3122	3028	2472	1795	1762
CHPD	761	689	638	585	530	503	532	522	475	556	664	722
DOPD	451	397	352	330	298	293	323	328	298	341	395	454
EPE	1452	1417	1366	1541	1869	2063	2066	2076	1937	1674	1472	1547
GCPD	843	745	733	758	794	855	935	920	811	749	780	894
IPFE	372	380	352	334	422	544	585	437	437	344	348	387
IPMV	695	689	659	688	969	1215	1266	1097	986	689	646	735
IPTV	1611	1597	1475	1462	1824	2148	2509	2232	2054	1546	1531	1752
NWMT	1869	1691	1603	1459	1483	1845	1992	1891	1702	1532	1677	1781
PACW	3977	3598	3390	3190	2924	3137	3612	3516	3212	3198	3490	3806
PAID	1024	982	872	849	855	1031	1089	942	808	858	947	1040
PAUT	5062	4973	4627	4315	5301	6341	6880	6685	6227	4950	5043	5336
PAWY	1516	1517	1463	1434	1388	1494	1530	1502	1428	1423	1524	1527
PGE	3923	3770	3609	3380	3366	3470	3966	4026	3529	3307	3724	4059
PNM	2270	2103	1997	1914	2002	2466	2966	2743	2592	1973	1941	2274
PSCO	6697	6436	6109	5888	6397	8288	8997	8563	7214	6204	6141	6795
PSEI	5049	4904	4316	3990	3550	3150	3986	3944	3398	4068	5115	5381
SCL	1847	1734	1642	1541	1408	1372	1414	1402	1376	1519	1715	1895
SRP	5312	4957	4552	5435	6697	7884	8443	8473	7669	6295	4825	5229
TEPC	2202	2062	2025	2295	2864	3416	3512	3342	3158	2532	2072	2195
TIDC	403	388	395	466	580	708	756	740	672	512	416	417
TPWR	1052	1047	911	837	733	670	669	700	710	840	945	1036
WACM	4542	4835	4206	4105	4364	4194	5826	5193	5080	4272	4748	5226
WALC	1611	1475	1763	1850	2049	2011	1819	1841	1881	1647	1337	1478
WAUW	171	156	150	139	140	157	168	160	146	143	154	163

Table 15 CEC Adjusted Energy Loads (GWh)

BA	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CIPV	4,463	3,932	4,318	4,331	4,871	5,413	6,099	5,973	5,109	4,542	4,165	4,505

BA	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CISC	8,381	7,477	8,177	8,024	8,645	9,142	10,536	10,715	9,886	8,754	7,778	8,395
BANC	1,445	1,246	1,328	1,328	1,452	1,661	1,904	1,807	1,563	1,356	1,309	1,514
CISD	1,855	1,655	1,777	1,704	1,796	1,828	2,074	2,165	2,068	1,898	1,764	1,902
LDWP	2,331	2,109	2,295	2,230	2,383	2,397	2,739	2,790	2,584	2,439	2,250	2,352
IID	283	264	286	317	427	512	573	595	484	370	283	291
VEA	54	41	41	38	42	58	67	64	55	43	50	64
CIPB	3,639	3,241	3,477	3,310	3,390	3,431	3,613	3,572	3,598	3,529	3,462	3,738

Table 16 CEC Adjusted Peak Loads (MW)

BA	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
						10,97	11,41	10,99				
CIPV	7,083	6,962	6,632	7,456	8,504	0	0	8	9,748	7,688	6,645	7,295
	14,19	13,93	13,60	14,95	16,95	18,11	20,07	20,80	21,33	17,25	14,05	14,70
CISC	3	3	7	8	2	9	7	2	4	3	9	5
BANC	2,541	2,392	2,263	2,612	3,535	4,393	4,593	4,539	4,034	2,871	2,384	2,616
CISD	3,456	3,388	3,303	3,368	3,588	3,566	4,053	4,371	4,710	3,874	3,472	3,646
LDW												
P	5,156	5,113	5,104	5,539	6,072	6,241	7,067	7,396	7,193	6,089	5,329	5,261
IID	594	605	683	894	1,162	1,341	1,400	1,449	1,297	1,081	766	631
VEA	121	103	91	77	97	139	136	134	123	95	120	137
CIPB	7,117	6,826	6,575	6,609	6,929	8,037	8,130	7,934	7,965	6,965	6,874	7,421

Demand Response

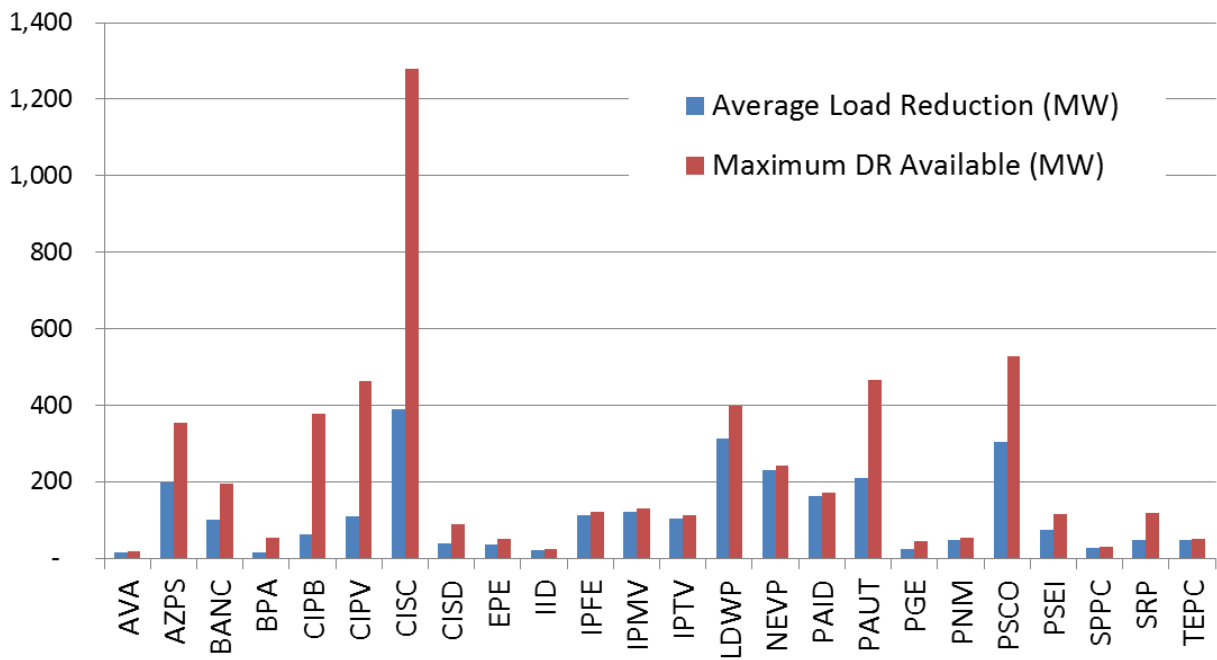
Demand Response (DR) is defined as customer reduction in electricity usage, such that the customer's normal consumption pattern is reduced in response to price changes or incentive payments designed to lower electricity use at times of system stress or high market prices.

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 7 shows the amount of DR reduction to load in the 2026 Common Case dataset as well as the total amount of DR in each BA.

Figure 7. Average Load Reduction and DR Resource Size



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 2026 Common Case; however, they are currently set to zero, as WECC’s Data Work Group (DWG) has determined that at present, WECC lacks the information required to model station service loads correctly. 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 2026 Common Case.

Seasonal Bus Distribution

As mentioned in the Area-Level Loads section of this document, GridView uses the initial power flow 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 seasonally by applying the bus distribution of those seasonal power flow cases. The seasonal bus distributions used in the 2026 Common Case are as follows:

- Summer: 2025HS1a1 Base Case
- Winter: 2015HW1a1 Base Case

Spring and Autumn: 2015HS1a1

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 25 Natural Gas (NG) pricing zones defined in the 2026 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 17.

Table 17: Natural Gas Burner Tip Pricing Zones (2016\$/MMBtu)

Name in Model	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NG_AB	5.31	4.72	4.29	4.90	4.60	4.91	4.47	4.28	3.98	4.10	4.61	5.47
NG_AZ North	5.05	5.09	4.74	4.84	4.87	4.91	4.98	4.74	4.58	4.80	5.05	5.58
NG_AZ South	5.27	5.31	4.96	5.05	5.09	5.13	5.20	4.96	4.80	5.01	5.27	5.82
NG_Baja	5.37	5.41	5.01	5.12	5.16	5.21	5.28	5.01	4.83	5.08	5.36	5.97
NG_BC	5.36	4.76	4.32	4.94	4.64	4.96	4.51	4.32	4.01	4.13	4.65	5.52
NG_CA PGaE BB	4.89	4.93	4.57	4.67	4.70	4.75	4.81	4.57	4.40	4.63	4.89	5.44
NG_CA PGaE LT	5.60	5.64	5.26	5.37	5.40	5.45	5.52	5.26	5.09	5.32	5.60	6.18
NG_CA SDGE	5.83	5.87	5.46	5.57	5.61	5.66	5.74	5.45	5.27	5.52	5.82	6.47
NG_CA SJ Valley	5.00	5.04	4.67	4.77	4.80	4.85	4.92	4.67	4.50	4.73	4.99	5.56
NG_CA SoCalB	5.09	5.13	4.75	4.85	4.89	4.94	5.00	4.75	4.58	4.81	5.08	5.66
NG_CA SoCalGas	5.99	6.03	5.62	5.73	5.77	5.82	5.90	5.61	5.42	5.68	5.98	6.63
NG_CO	4.96	4.86	4.91	4.70	4.49	4.59	4.53	4.29	4.35	4.57	4.64	5.25
NG_ID North	5.22	4.63	4.19	4.81	4.51	4.82	4.37	4.18	3.87	4.00	4.52	5.39
NG_ID South	5.11	5.01	5.06	4.84	4.63	4.73	4.66	4.41	4.47	4.71	4.78	5.42
NG_MT	5.05	4.95	5.00	4.79	4.58	4.68	4.61	4.37	4.43	4.66	4.73	5.35
NG_NM North	4.89	4.93	4.60	4.68	4.72	4.76	4.82	4.59	4.44	4.65	4.89	5.40
NG_NM South	5.22	5.01	4.91	4.80	4.85	5.04	5.10	4.77	4.63	4.84	5.26	5.29
NG_NV North	5.50	5.39	5.45	5.22	5.01	5.11	5.04	4.79	4.85	5.09	5.16	5.81
NG_NV South	5.08	5.12	4.75	4.85	4.88	4.93	5.00	4.74	4.57	4.81	5.08	5.66
NG_OR	5.54	4.91	4.44	5.10	4.78	5.11	4.64	4.44	4.11	4.24	4.79	5.72
NG_OR Malin	5.05	4.95	5.00	4.78	4.57	4.67	4.60	4.36	4.42	4.65	4.72	5.36
NG_TX West	4.88	4.66	4.57	4.46	4.51	4.70	4.76	4.43	4.29	4.50	4.92	4.95
NG_UT	5.45	5.36	5.41	5.20	5.00	5.09	5.03	4.80	4.85	5.07	5.14	5.74
NG_WA	5.79	5.16	4.69	5.35	5.03	5.36	4.88	4.69	4.36	4.49	5.04	5.96

Name in Model	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NG_WY	4.95	4.85	4.91	4.70	4.49	4.59	4.52	4.29	4.35	4.57	4.64	5.24

Coal Topology and Pricing

There are fourteen Coal pricing zones defined in the 2026 Common Case as presented in Table 18.

Table 18: Coal Pricing Zones (2016\$/MMBtu)

Fuel	Price	Source	Plants
Coal_Alberta	1.31	NPCC	Alberta plants
Coal_AZ	2.52	Ventyx	Apache, Cholla, Coronado, Navajo, Springerville
Coal_CA_South	1.76	NPCC	Ace cogen
Coal_CO_East	1.96	Ventyx	Arapahoe, Cherokee, Comanche, Drake, Noxon, Pawnee, Valmont
Coal_CO_West	1.96	Ventyx	Bonanza, Cameo, Craig, Hayden
Coal_ID	1.33	NPCC	Idaho small coal
Coal_MT	1.14	Ventyx	Colstrip, Corrette
Coal_NM	2.31	Ventyx	Escalante, Four Corners, San Juan
Coal_NV	3.13	Ventyx	North Valmy, Reid Gardner
Coal_PNW	3.10	Ventyx	Boardman, Centralia
Coal_UT	3.12	Ventyx	Carbon, Hunter, Huntington
Coal_WY_E	2.66	Ventyx	Dave Johnston, Laramie River
Coal_WY_PRB	1.13	Ventyx	Wygen, Wyodak, Simpson
Coal_WY_SW	3.28	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 2026 Common Case. These are provided in Table 19.

Table 19: Other Fuel Prices (2016\$/MMBtu)

Fuel	Price	Fuel	Price
Bio_Agri_Res	0.54	Oil_DFO_L	15.36
Bio_Blq_Liquor	0.01	Oil_DFO2	22.94
Bio_Landfill_gas	2.29	Petroleum Coke	1.43
Bio_Other	2.87	Propane	23.55
Bio_Sludge_waste	0.00	Purchased_Steam	1.00
Bio_Solid_waste	0.00	Refuse	0.00
Bio_Wood	2.93	Synthetic Gas	6.99
Geothermal	0.00	Uranium	0.89
Oil_DFO_H	30.58	Waste_Heat	0.00

Emissions Rates by Fuel

Each fuel is modeled with emissions rates for CO₂, NO_x, and SO₂ as shown in Table 20.

Table 20. Emissions Rates by Fuel

Fuel Name	Emission Type	Emission Rate (lb/MMBtu)	Fuel Name	Emission Type	Emission Rate (lb/MMBtu)	
All "Bio_"	CO2	130.00	DefaultFuel	CO2	200.00	
	NOx	0.18		NOx	0.28	
	SO2	0.01		SO2	0.35	
Coal_Alberta	CO2	205.00	Geothermal	CO2	20.00	
	NOx	0.50		NOx	0.18	
	SO2	0.35		SO2	0.01	
Coal_AZ	CO2	205.03	All Natural Gas ("NG_")	CO2	118.00	
	NOx	0.46		NOx	0.08	
	SO2	0.57		SO2	0.00	
Coal_CA_South	CO2	203.53	Oil_DistillateFuel_2	CO2	123.11	
	NOx	0.38	Oil_DistillateFuel_H	NOx	0.18	
	SO2	0.33	Propane	SO2	0.01	
Coal_CO_East	CO2	204.75	Oil_DistillateFuel_L	CO2	144.03	
Coal_ID	NOx	0.55		NOx	0.12	
Coal_MT				SO2	0.00	
Coal_UT	SO2	0.69	Petroleum Coke	CO2	224.00	
Coal_CO_West	CO2	205.20		Purchased_Steam	NOx	0.03
	NOx	0.55				

Fuel Name	Emission Type	Emission Rate (lb/MMBtu)	Fuel Name	Emission Type	Emission Rate (lb/MMBtu)
	SO2	0.69		SO2	0.00
Coal_NM	CO2	203.53	Refuse	CO2	130.00
	NOx	0.38		NOx	0.18
	SO2	0.33		SO2	0.01
Coal_NV	CO2	202.62	Synthetic Gas	CO2	118.00
	NOx	0.35		NOx	0.08
	SO2	0.11		SO2	0.00
Coal_PNW	CO2	205.20	Uranium	CO2	0.00
	NOx	0.29		NOx	0.00
	SO2	0.62		SO2	0.00
Coal_WY_E	CO2	200.00	Waste_Heat	CO2	0.00
	NOx	0.28		NOx	0.00
	SO2	0.46		SO2	0.00
Coal_WY_PRB	CO2	205.20			
Coal_WY_SW	NOx	0.10			
	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 SAP has selected. For example, SAP has asked that all cost data be modeled in 2016 dollars, which requires that many of the costs be converted to 2016 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 2016 through 2026 of 1.9 percent.

Transmission

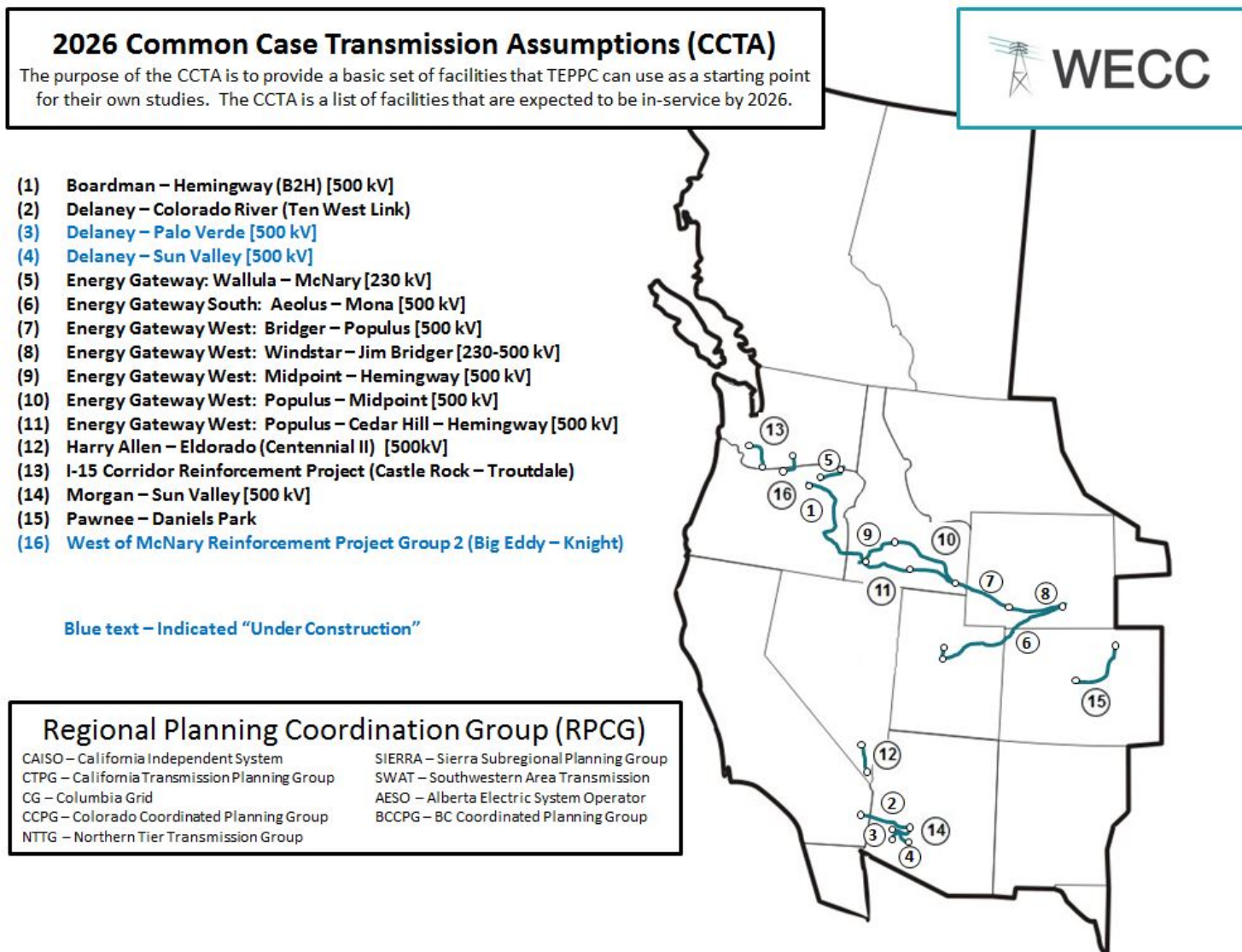
Common Case Transmission Assumptions (CCTA)

The Regional Planning Coordination Group (RPCG) aids the TEPPC planning 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. The RPCG collaborates to develop criteria for determining which projects are included on this list. This list of projects is known as the Common Case Transmission Assumptions (CCTA) and serves as a key input assumption for the 2026 Common Case. The RPCG first developed such a list in 2012 and 2014. The iteration of the list used in the 2026 Common Case is called the 2026 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 2026 CCTA selection process resulted in the inclusion of 16 transmission projects to be on the list.

The purpose of, process of developing, and projects included in the 2026 CCTA are explained in detail in the [RPCG 2026 CCTA Report](#). The projects included in the RPCG 2026 CCTA are shown in the map in Figure 8.

Figure 8. 2026 Common Case Transmission Assumptions



Power Flow Documentation

The 2026 Common Case transmission network is comprised of two main components: the RPCG 2026 CCTA and the WECC Technical Studies Subcommittee (TSS) 2025 HS1A1 Heavy Summer Base Case (2025 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 2025 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 System Adequacy Planning (SAP) Department used the 2025 HS1A1 Power Flow as the foundation of its own 2026 power flow cases. Changes to the 2025 HS1A1 Power Flow were managed within GE’s Positive Sequence Load Flow (PSLF) software through the use of EPCL (*.P) files to create the 2026 Common Case Power Flow and Root Case Power Flow. The two power flow cases are the result of using the 2026 CCTA. The 2026 Common Case was created using the 2025 HS1A1 Power Flow supplemented with a series of transmission additions and removals specified by the projects listed in the [2026 CCTA report](#). The 2026 Root Case, which serves as the power flow case linked to the 2026 Common Case, like the Common Case, supplemented the 2025 HS1A1 case with a series of transmission additions and removals specified by projects in the 2026 CCTAs, but only for CCTA projects that were currently under construction. Table 21 shows the list of CCTA project additions and removals from both 2026 power flow cases. Other changes to the 2025 HS1A1 Power Flow included WECC transfer path fixes, topology changes for a few generators, DC line modeling updates, and islanded bus fixes.

Table 21. CCTA Mapping and Tracking

Project Name	Project line voltage(s)	Estimated In-Service Date	Under Construction ?	Project Status	Included in 2022 CCTA	Included in 2024 CCTA
Abel-Ball	200-300kV AC	4/15/2020	No	Open		
Bighorn-Eldorado	>450kV AC	12/31/2024	No	Open		
Boardman-Hemingway 500 kV (B2H)	>450kV AC	6/1/2020	No	Open	Yes	Yes
Canada – Northern California Transmission Project – Avista	200-300kV AC;#>450kV AC	1/1/2015	No	Cancelled		

Project Name	Project line voltage(s)	Estimated In-Service Date	Under Construction ?	Project Status	Included in 2022 CCTA	Included in 2024 CCTA
Corporation 00/230 kV AC Interconnection						
Canada/Pacific Northwest-Northern California	>450kV AC;#>450kV DC	1/1/2021	No	Cancelled		
Cascade Crossing	>450kV AC	1/1/2023	No	Cancelled	Yes	
Cedar Mountain Loop-in of Moenkopi-Yavapai 500kV Line	>450kV AC	12/31/2011	Yes	Completed		
Centennial II (Amargosa-Northwest)	>450kV AC	12/31/2024	No	Open		
Centennial II (Harry Allen - Eldorado)	>450kV AC	12/31/2024	No	Open		
Centennial II (Northwest - Harry Allen)	>450kV AC	6/1/2024	No	Open		
Centennial West Clean Line	≥450kV DC	12/31/2020	No	Open		
Central Ferry - Lower Monumental (Little Goose Area Reinforcement)	>450kV AC	12/31/2015	No	Open	Yes	Yes
Chinook	≥450kV DC	9/30/2021	No	Open		
Delaney-Palo Verde 500kV Line	>450kV AC	5/1/2016	Yes	Open	Yes	Yes
Delaney-Sun Valley 500kV Line	>450kV AC	5/1/2016	Yes	Open	Yes	Yes
Desert Basin - Pinal Central	200-300kV AC	4/30/2014	Yes	Open		Yes

Project Name	Project line voltage(s)	Estimated In-Service Date	Under Construction ?	Project Status	Included in 2022 CCTA	Included in 2024 CCTA
Devers - Colorado River 500 kV (DCR) Transmission Line Project	>450kV AC	1/31/2014	Yes	Open	Yes	Yes
ECO 500/230/138kV Substation	<200kV AC;#200-300kV AC;#>450kV AC	12/31/2014	Yes	Open		
Gateway Central Project – Mona to Oquirrh 500 kV (Energy Gateway Segment C)	>450kV AC	5/31/2013	Yes	Completed	Yes	
Gateway Central Project – Populus to Terminal 345 kV (Energy Gateway Segment B)	300-450kV AC	1/19/2010	Yes	Completed		
Gateway Central Transmission Project Segment G (Sigurd - Red Butte 345 kV Line)	300-450kV AC	6/1/2015	Yes	Open	Yes	Yes
Gateway South Project – Segment #1 (Mona-Crystal 500 kV)	>450kV AC	12/31/2050	No	Cancelled		
Gateway South Project – Segment F (Aeolus-Mona 500 kV)	>450kV AC	12/31/2022	No	Open	Yes	Yes
Gateway West Transmission Project Segment D – Jim Bridger to Southeast Idaho	>450kV AC	12/31/2023	No	Open	Yes	Yes

Project Name	Project line voltage(s)	Estimated In-Service Date	Under Construction ?	Project Status	Included in 2022 CCTA	Included in 2024 CCTA
(Bridger – Populus single circuit 500 kV)						
Gateway West Transmission Project Segment D (Windstar to Jim Bridger 230 kV, 500 kV)	<200kV AC;#>450kV AC	12/31/2023	No	Open	Yes	Yes
Gateway West Transmission Project Segment E – South to Southwest Idaho (Midpoint – Hemingway 500 kV)	>450kV AC	12/31/2023	No	Open	Yes	Yes
Gateway West Transmission Project Segment E – Southeast Idaho – South Central Idaho (Populus – Midpoint 500 kV)	>450kV AC	12/31/2023	No	Open	Yes	Yes
Gateway West Transmission Project Segment E, Southeast Idaho – South Central Idaho (Populus – Cedar Hill - Hemingway 500 kV)	>450kV AC	1/31/2023	No	Open		
Great Basin HVDC	<450kV DC	12/31/2020	No	Planned		
Harcuvar Transmission Project	200-300kV AC	1/1/2018	No	Open		

Project Name	Project line voltage(s)	Estimated In-Service Date	Under Construction ?	Project Status	Included in 2022 CCTA	Included in 2024 CCTA
Hassayampa - North Gila 500kV #2 line	>450kV AC	5/1/2015	Yes	Open	Yes	Yes
Hemingway-Captain Jack 500 kV Transmission Line	>450kV AC	10/4/2050	No	Open		
High Plains Express Transmission Project	300-450kV AC;#>450kV AC	12/31/2030	No	Suspended		
Hoodoo Wash Loop-in of Hassayampa-North Gila 500kV #1 Line	>450kV AC	12/31/2011	Yes	Completed		
Hughes Transmission Project:	<200kV AC	1/1/2009	No	Completed		
I-5 Corridor Reinforcement Project (Castle Rock - Troutdale)	>450kV AC	6/1/2018	No	Planned	Yes	Yes
Interior to Lower Mainland Transmission (ILM) Project	>450kV AC	10/31/2015	Yes	Open	Yes	Yes
Juan de Fuca HVDC Sea Cable	200-300kV AC	12/15/2015	No	Open		
Juan de Fuca II HVDC Cable	<200kV AC	6/1/2018	No	Open		
Lamar-Front Range	300-450kV AC	12/31/2025	No	Open		
Lamar-Vilas	200-300kV AC	12/31/2025	No	Open		
Lassen 230kV East/West Tie	200-300kV AC	6/1/2018	No	Open		
Lucky Corridor	300-450kV	6/30/2018	No	Open		

Project Name	Project line voltage(s)	Estimated In-Service Date	Under Construction ?	Project Status	Included in 2022 CCTA	Included in 2024 CCTA
Transmission Project	AC					
Montana Alberta Tie-Line	200-300kV AC	9/18/2013	Yes	Completed	Yes	
Morgan-Sun Valley 500kV Line	>450kV AC	6/1/2018	No	Open	Yes	Yes
Mountain States Transmission Intertie (MSTI) (Townsend-Midpoint 500 kV)	>450kV AC	12/31/2017	No	Open		
Navajo Transmission Project Segment #1 (Four Corners - Marketplace 500 kV)	<200kV AC	1/1/2010	No	Suspended		
North Gila - Imperial Valley #2 Project	>450kV AC	12/31/2019	No	Open		
North Gila-Orchard 230kV Line	200-300kV AC	6/1/2016	No	Open		
NorthernLights	>450kV DC	1/1/2015	Yes	Cancelled		
Northwest Transmission Line	200-300kV AC	7/15/2014	Yes	Completed		Yes
NV Energy Robinson - Harry Allen 500 kV Line	>450kV AC	12/12/2024	No	Open		
One Nevada Line (ON Line)	>450kV AC	12/31/2013	Yes	Completed		Yes
Palm Valley-TS2-Trilby Wash 230kV Line	200-300kV AC	6/1/2015	No	Open		
Path 27 Upgrade (Intermountain DC Line)	<200kV AC	1/1/2010	No	Completed		

Project Name	Project line voltage(s)	Estimated In-Service Date	Under Construction ?	Project Status	Included in 2022 CCTA	Included in 2024 CCTA
Path 3 – Northwest to British Columbia – South to North Rating Increase	>450kV DC	8/8/2011	Yes	Completed		
Path 42 Upgrade Project (SCE's Scope of Work)	200-300kV AC	12/31/2014	No	Open		
Path 54 Upgrades- Coronado to Silver King 500kV increase to 1494MW	<200kV AC	12/31/2010	No	Completed		
Path 55 – Brownlee East Increase to 1915 MW	<200kV AC	1/1/2008	No	Completed		
Path 8 Upgrade/Colstrip Transmission Upgrade	>450kV AC	12/31/2017	No	Open	Yes	Yes
Pawnee-Daniels Park	300-450kV AC	10/31/2019	No	Planned		
Pawnee-Smoky Hill	300-450kV AC	6/1/2013	Yes	Completed	Yes	
Pinal Central – Sundance 230kV Line	200-300kV AC	6/1/2026	No	Open		
Pinal Central-Tortolita	>450kV AC	12/1/2015	Yes	Open	Yes	Yes
Pinal West-Pinal Central-Browning (SEV)	>450kV AC	4/30/2014	Yes	Open	Yes	Yes
Renewable Zone 4 to Harry Allen	>450kV AC	12/31/2023	No	Suspended		
RTI Dixie-Oreana	300-450kV AC	12/12/2015	No	Suspended		
San Francisco Bay	≥450kV DC	1/1/2013	No	Cancelled		

Project Name	Project line voltage(s)	Estimated In-Service Date	Under Construction ?	Project Status	Included in 2022 CCTA	Included in 2024 CCTA
Area Bulk Transmission Reinforcement						
San Luis Rio Colorado (SLRC) Project	200-300kV AC	10/30/2017	No	Open		
San Luis Valley-Calumet-Comanche	200-300kV AC;#300-450kV AC	12/31/2030	No	Suspended	Yes	
South Orange County Reliability Enhancement (SOCRE)	<200kV AC;#200-300kV AC	6/1/2017	No	Planned		
Southern Navajo (Path 51) Upgrade Project	<200kV AC	12/1/2010	No	Completed		
Southern Nevada Intertie Project (SNIP)	>450kV AC	12/31/2015	No	Planned		
Southline Transmission Project (Afton-Apache)	300-450kV AC	12/31/2016	No	Open		
Southline Transmission Project (Apache-Saguaro)	200-300kV AC	12/31/2016	No	Open		
Southwest Intertie Project - North (SWIP-North)	>450kV AC	12/31/2016	No	Planned		
Sun Valley – Trilby Wash 230kV Line	200-300kV AC	6/1/2016	No	Open		
Sunrise Powerlink	>450kV AC	6/1/2012	Yes	Completed	Yes	
SunZia Southwest Transmission Project	>450kV AC	6/1/2018	No	Open		

Project Name	Project line voltage(s)	Estimated In-Service Date	Under Construction ?	Project Status	Included in 2022 CCTA	Included in 2024 CCTA
Talega-Escondido / Valley-Serrano 500 kV Interconnect	>450kV AC	12/1/2015	No	Open		
Test	200-300kV AC	12/14/2024	Yes	Open		
Tot 7 Expansion	200-300kV AC;#300-450kV AC	12/31/2030	No	Open		
TOT3 Archer Interconnection Project	200-300kV AC;#300-450kV AC	6/30/2016	No	Open		
TOT3 Upgrade Project – Miracle Mile – Ault Upgrade	<200kV AC	5/1/2010	No	Completed		
Tracy-Viewland 345 kV	300-450kV AC	12/31/2018	No	Suspended		
TransWest Express Transmission Project	≥450kV DC	1/1/2017	No	Planned		
Tres Amigas	300-450kV AC	9/15/2017	No	Planned		
Triton HVDC Sea Cable Project	<200kV AC	6/1/2018	No	Open		
Walla Walla to McNary 230 kV (Energy Gateway Segment A)	200-300kV AC	12/31/2017	No	Open	Yes	
WECC - Eastern Interconnect DC Tie Upgrade Project	200-300kV AC	1/1/2020	No	Open		
West Coast Cable Project	<200kV AC	6/5/2017	No	Cancelled		
West of McNary	>450kV AC	2/28/2012	Yes	Completed	Yes	

Project Name	Project line voltage(s)	Estimated In-Service Date	Under Construction ?	Project Status	Included in 2022 CCTA	Included in 2024 CCTA
Reinforcement Project Group 1 (McNary - John Day)						
West of McNary Reinforcement Project Group 2 (Big Eddy - Knight)	>450kV AC	4/1/2015	Yes	Open	Yes	Yes
West Side Tie	>450kV AC	12/12/2018	No	Suspended		
Western Spirit Clean Line	300-450kV AC	1/1/2018	No	Open		
Westside Tie 345/500 kV	300-450kV AC;#>450kV AC	12/12/2023	No	Suspended		
Wyodak South 230 kV line	<200kV AC	1/1/2010	No	Completed		
Wyoming-Colorado Intertie Project	300-450kV AC	1/1/2017	No	Open		
Zephyr	≥450kV DC	12/31/2020	No	Open		

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 9.5.04 which is used in version 1.0 of the 2026 Common Case (as with the Siemens Power System Simulator for Engineering (PSS/E) power flow model) allows the user to model three ratings for each branch for one season. Since GridView only stores one season's ratings, it uses the winter ratings from GE PSLF and de-rates them for the remaining season's ratings. By default, GridView only imports Ratings 1 and 2 from the PSLF/PFM, as shown in Table 22.

Table 22. 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

GE PSLF Branch Ratings (MVA)	GridView Default Interpretation (MW)	GridView Default Summer De-Rate Multiplier
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 they are set in the 2026 Common Case:

Branch Rating	Setting	Comment
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 1 st to September 30 th	Timeframe in which the summer de-rate is applicable

Table 23 illustrates how the branch ratings are modeled within GridView so they are consistent with those modeled in the PFM.

Table 23. 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)	$\frac{\text{(Rating 1 in PFM)}}{\text{(Rating 3 in PFM)}}$
Rating B	Rating 4 in PFM (Winter Emergency)	$\frac{\text{(Rating 2 in PFM)}}{\text{(Rating 4 in PFM)}}$
Rating C	0	1

Paths and Other Transmission Interfaces

In the development assumptions for the WECC transfer path ratings in the 2026 Common Case, the Technical Advisory Subcommittee’s (TAS) Studies Work Group (SWG) started with the 2015 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 monthly.

The path limits in the 2016 WECC Path Rating Catalog (PRC), along with the changes listed below from 2024 Common Case, are the basis for the path ratings modeled in the 2026 Common Case. These assumptions are summarized in Table 24.

Path 9 (West of Broadview):	Removed
Path 10 (West of Colstrip):	Removed
Path 11 (West of Crossover):	Removed
Path 15 (Midway-Los Banos):	Updated branch assignments
Path 30 (TOT 1A):	Updated branch assignments
Path 31 (TOT 2A):	Updated branch assignments
Path 35 (TOT 2C):	Updated branch assignments
Path 36 (TOT 3):	Updated branch assignments
Path 30 (TOT 5):	Updated branch assignments
Path 43 (North of San Onofre):	Removed
Path 44 (South of San Onofre):	Removed

Table 24. 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	1,000	-1,200	P50	Cholla-Pinnacle Peak	1,200	-1,200
P02	Alberta-Saskatchewan	150	-150	P51	Southern Navajo	2,800	-2,800
P03	Northwest-British Columbia	3,000	-3,150	P52	Silver Peak-Control 55 kV	17	-17
P04	West of Cascades-North	10,800	-10,800	P54	Coronado-Silver King 500 kV	1,494	-1,494

Path #	Path Name	Primary Limit (MW)	Secondary Limit (MW)	Path #	Path Name	Primary Limit (MW)	Secondary Limit (MW)
P05	West of Cascades-South	7,575	-7,575	P55	Brownlee East	1,915	-1,915
P06	West of Hatwai	4,800	-4,800	P58	Eldorado-Mead 230-kV Lines	1,140	-1,140
P08	Montana to Northwest	3,000	-2,150	P59	WALC Blythe - SCE Blythe 161-kV Sub	218	-218
P14	Idaho to Northwest	3,400	-2,250	P60	Inyo-Control 115-kV Tie	56	-56
P15	Midway-LosBanos	5,400	-3,265	P61	Lugo-Victorville 500-kV Line	900	-2,400
P16	Idaho-Sierra	500	-360	P62	Eldorado-McCullough 500-kV Line	2,598	-2,598
P17	Borah West	4,450	-4,500	P65	Pacific DC Intertie (PDCI)	3,220	-3,100
P18	Montana-Idaho	337	-256	P66	COI	4,800	-3,675
P19	Bridger West	4,100	-2,300	P71	South of Allston	4,100	-4,100
P20	Path C	2,250	-2,250	P73	North of John Day	8,400	-8,400
P22	Southwest of Four Corners	2,325	-2,325	P75	Hemingway-Summer Lake	2,400	-1,200
P23	Four Corners 345/500 Qualified Path	1,000	-1,000	P76	Alturas Project	300	-300
P24	PG&E-Sierra	160	-150	P77	Crystal-Allen	950	-950
P25	PacifiCorp/PG&E 115-kV Interconnection	100	-45	P78	TOT 2B1	600	-600
P26	Northern-Southern California	4,000	-3,000	P79	TOT 2B2	265	-300
P27	Intermountain Power Project DC Line	2,400	-1,400	P80	Montana Southeast	600	-600
P28	Intermountain-Mona 345 kV	1,400	-1,200	P81	Southern Nevada Transmission Interface (SNTI)	4,533	-3,790
P29	Intermountain-Gonder 230 kV	200	-200	P82	TotEast	2,465	-2,465
P30	TOT 1A	650	-650	P83	Montana Alberta Tie	325	-300

Path #	Path Name	Primary Limit (MW)	Secondary Limit (MW)	Path #	Path Name	Primary Limit (MW)	Secondary Limit (MW)
					Line		
P31	TOT 2A	690	-690		AZ-CA	99,999	-99,999
P32	Pavant-Gonder InterMtn-Gonder 230 kV	440	-235		COI plus PDCI	7,900	-6,455
P33	Bonanza West	785	-785		WA-BC East	400	-400
P35	TOT 2C	600	-580		WA-BC West	3,000	-2,850
P36	TOT 3	1,680	-1,680		WY-UT	1,700	-1,700
P37	TOT 4A	1,775	-1,775		Aeolus South	1,700	-1,700
P38	TOT 4B	880	-880		Aeolus West	2,670	-2,670
P39	TOT 5	1,680	-1,680		AZ Palo Verde East	8,010	-8,010
P40	TOT 7	890	-890		CA IPP DC South	50,000	-50,000
P41	Sylmar to SCE	1,600	-1,600		CA PDCI South	2,780	-3,100
P42	IID-SCE	1,500	-1,500		CA PG&E-Bay	99,999	-99,999
P45	SDG&E-CFE	408	-800		CA SCE import	99,999	-99,999
P46	West of Colorado River (WOR)	11,200	-11,200		CA SCIT	17,700	-17,700
P47	Southern New Mexico (NM1)	1,048	-1,048		CA Southern CA Imports	14,750	-14,750
P48	Northern New Mexico (NM2)	1,970	-1,970		ID Midpoint West	4,400	-4,400
P49	East of Colorado River (EOR)	10,200	-10,200		NV NV Energy Southern Cut Plane	3,500	-3,050
	OR/WA West of John Day	3,450	-3,450		OR/WA West of Slatt	5,500	-5,500
	OR/WA West of McNary	4,500	-4,500		WA North of Hanford	4,100	-2,948

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 2026 Common Case, the TAS SWG started with the 2024 Common Case and applied modifications to capture changes in topology and generation. Two new nomograms were added in 2026 to implement frequency response requirements for CAISO. All nomogram assumptions used in the 2026 Common Case are summarized in Table 25.

Table 25. List of Nomograms in 2026 Common Case

Nomogram Name	Limit (MW)	Nomogram Name	Limit (MW)
AeolW-Aeolus S	6,458	Jday COI 3	9,793
AeolW-Bonanza W	6,595	Jday COI PDCI 1	7,650
AeolW-TOT1A	17,458	Jday COI PDCI 2	7,900
BrdgW-Aeolus S	12,796	Jday COI PDCI 3	17,115
BrdgW-Bonanza W	10,406	Jday PDCI 1	3,002
BrdgW-Path C	16,856	Jday PDCI 3	5,547
COB	5,100	LDWP 25% LocalMinGen	0
COI 1	6,378	Path 18 Exp	337
COI 2	5,923	Path 18 Imp	256
COI 3	5,726	Path 22	3,113
COI 4	5,549	Path 8	7,925
Greater IV-SDGE Area Import	2,830	SDGE Area Import	3,350
IPP DC	361	CAISO Frequency Response	0
Jday COI 1	4,648		

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 2026 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 2026 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 2015 WECC Loads and Resources (L&R) information, collected through the Reliability Assessment Work Group, was the starting point for resource information as well as resources submitted as part of the 2025hs1a1 Base Case..

The 2015 WECC Loads and Resources (L&R) information, collected through the Reliability Assessment Work Group, has BA-submitted load forecasts and provides the basis for the loads in the 2026 Common Case. The forecasted loads for 2025 in the 2015 L&R load forecasts were extrapolated into 2026, adjusted to reflect historical 2005 pump loads being modeled as negative generation, and adjusted for energy efficiency savings from federal appliance and lighting standards determined to not be fully reflected in the L&R load forecasts. The resulting 2026 peak demand and energy forecasts were used in conjunction with 2005 historical hourly load shapes to derive the 2026 load shapes for the areas in the 2026 Common Case.

TEPPC stakeholders and TSS Area Coordinators reviewed the reconciled resource information. Comments and suggested data inputs were received and applied to the SAP resource database. Many comments had conflicting information so SAP staff members collaborated with stakeholders to resolve the conflicts as much as possible given the time constraints.

Planning Regions were key stakeholders in reviewing the resource portfolio. Resource planners reviewed the resource assumptions and advised SAP on what resources (especially renewables) with unspecified locations should be mapped to particular buses the 2026 Common Case.

Resource Modeling Categories

SAP grouped the resources into modeling categories based on their operating characteristics. Table 26 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 26. 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 ² Hydro	Hydro sensitive to load and LMP	PLF/HTC

² Proportional Load Following Hydrothermal Co-optimization.

Resource Modeling Category	Identification	Modeling Methodology
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 generation representing synchronous pump 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	Loads being reduced to reflect 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	Pumped Storage
14. Misc Hourly	Resources that exist or are planned but whose modeling is uncertain or incomplete	Hourly Shape are turned off in model (i.e., all zeroes)

Status and Need Categories

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

- Existing: those assumed to be online by 12/31/2015. This includes the 0 (Existing) resource project status mentioned previously.

- Incremental: those assumed to be online between 2015 and 2026, 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 SAP Generator Type and SAP Primary Fuel of each resource. Table 27 shows the various values of GV SubType used in the 2026 Common Case and their corresponding SAP Generator Type and SAP Primary Fuel.

Table 27. GV SubType Values in 2026 Common Case

GV SubType	SAP Generator Type	SAP 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
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

GV SubType	SAP Generator Type	SAP Primary Fuel
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
ICE-OilDistillate	Internal Combustion Engine (ICE)	Oil-Distillate Fuel
MotorLoad	Pumping Load	N/A
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

GV SubType	SAP Generator Type	SAP Primary Fuel
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 Year 10 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. Updated solar hourly shapes were not available from NREL so the data used in the 2024 Common Case was the most recent dataset available and was utilized in Version 1.0 of the 2026 Common Case. Each NREL profile in the Western Wind Dataset represents a small generation site (2 km by 2 km) and potential wind and solar capabilities calculated by NREL 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 than a single 2-km-by-2-km grid 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 in that area. This methodology was adopted for two key reasons:

1. Aggregating NREL profiles to represent shapes based on region is the most efficient way to accurately assign generators within that region. 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 for the resources while avoiding shapes that would overstate variability.

The number of NREL profiles that are 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 depicts the output of a 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 2026 Common Case, Energy + Environmental Economics (E3) and Black & Veatch, under contract for WECC, found that TEPPC profiles understated the expected output of future and existing wind plants in some states. TAS approved a process in which 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 28 shows the capacity factors of wind profiles used in the 2026 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 "in 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 28. 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%
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 2024 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 derate 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 2026 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 29 shows the resulting capacity factors of solar profiles used in the 2026 Common Case dataset after applying the aligned inverter loading ratios.

Table 29. 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%
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 2026 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 customers would install 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 30 shows the TAS-approved capacity of behind-the-meter (BTM) DG by state as provided by E3, as well as the corresponding capacity in the 2026 Common Case.

Table 30. Behind-the-meter DG in 2026 Common Case, by State

State	2024 Common Case Capacity (MW)	2026 Common Case Capacity (MW)
Arizona	1,401	2,129
California	4,560	12,217.84
Colorado	594	835
Idaho	41	33
Montana	28	33
New Mexico	136	309
Nevada	193	91
Oregon	153	177
Utah	85	175
Washington	72	77
Wyoming	38	29
Total	7,301	16,104

Hydroelectric Facilities

Hydro generation is a significant resource in the Western Interconnection. In the 2026 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 Renewable Portfolio Standard (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. PLF and HTC hydro units 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 unit or plant 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			
		<i>Hourly Shape</i>	<i>PLF</i>	<i>PLF K=0 (Flat)</i>	<i>HTC</i>
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

The PLF/HTC modeling methods were used to model the majority of hydro generation in the 2026 Common Case. PLF constants were obtained by regressing historical data and loads for federal projects, or were supplied by plant operators for non-federal projects. Monthly average generation values for both HTC and PLF plants came from the EIA 906/920 data for 2009. 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. 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).

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).

BC Hydro generation data are determined by BC Hydro’s Generalized Optimization Model using a 2024 load forecast and average inflows (1968 water conditions). TEPPC used the Generalized Optimization Model results to calculate PLF constants for use by the HTC modeling method.

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.

Pumping Loads

Table 32 summarizes the pumping load units and plants modeled in the 2026 Common Case as negative generation and associated reductions to the L&R load forecast. The following subsections provide more details on certain 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. The primary goal of the modeling is to emulate the historical capabilities of the facilities – i.e., meeting or exceeding their historical power consumptions. As a result, the historical hourly shape for 2009 was used as the default.

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 2009 hourly pump load data and then shifting the 2009 hour data to match the 2026 hours. Once the shape files were created, the pump loads were assigned a negative multiplier to represent the resource as a load.

Table 32. Pumping Loads modeled as Hourly Shapes

Plant/Unit Name	Capacity	Total Energy	Load Factor
	(MW)	(MWh)	
SCE Pumped Storage			
Edmonston	-56.39	2,478,056	0.34
Pearblossom	-16.57	297,405	0.22
Eagle Mtn	-8.75	574,863	0.78
Gene & Intake	-6.75	879,065	0.83
Iron Mtn	-7.03	98,927	0.39
Julian Hinds	-8.84	581,745	0.79
OSO	10.93	147,162	0.24
ESRP(Diamond Vly)	-0.93	12,716	0.04
Coulee	-166	55,063	0.38
PG&E Pumped Storage			
Buenavista	-4.58	286,117	0.29
Wheeler Ridge	-6.35	301,369	0.3
Wind Gap	-14.25	641,770	0.29
Dos Amigos	-28.37	249,439	0.16
Delta	-6.78	468,953	0.19
Tracy	-13.63	450,838	0.55

Pumped Storage

Table 33 shows the different pumped storage (PS) facilities that were modeled in the 2026 Common Case. The following subsections provide more detail on each plant such as: Name, Capacity, Total Energy and Load Factor

Table 33. Pumping Storage Facilities

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		<input checked="" type="checkbox"/>
Edward C Hyatt 2, 4, 6	363.45	327.105	CIPV	CDWR	<input checked="" type="checkbox"/>	
Thermalito 2-4	102.3	92.07	CIPV	CDWR	<input checked="" type="checkbox"/>	
Waddell 1, 3, 6-7	30.4	27.36	WALC	CAWC	<input checked="" type="checkbox"/>	
O'Neill 1-6	25.2	22.68	CIPV	CDWR		<input checked="" type="checkbox"/>
W.R. Gianelli 1-8 (San Luis Pumping Plant)	424	381.6	CIPV	CDWR	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>

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 as 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" 2009 historical data - the actual values

are confidential, but Xiaobo Wang of the CAISO provided a “masked” shape based on the actual 2009 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 2026 Common Case.

Thermal Generation Facilities

The operating parameters for the thermal generation were derived from several sources and are listed in Table 34.

Table 34: Thermal Operating Parameters

Parameter	Unit Type	Source	Description
Maximum Capacity	Coal-fired Steam	EIA / LRS / PF	Closest consensus from the common sources including seasonal ratings
	Other Dispatchable	EIA / LRS / PF	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	Columbia Grid	Based on Heat Rates provided by Columbia Grid
	Other Dispatchable	Columbia Grid	Based on Heat Rates provided by Columbia Grid
	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	Stakeholders	Calculated by CEC and Columbia Grid
Ramping Uptime / Downtime	All Thermal	2024 CC	Values from 2024 Common Case; used values from similar types for new generation

Monthly Minimum and De-Rated Maximum Capacity

Table 35 illustrates how the monthly minimum and de-rated maximum capacities were determined for the different thermal generation facilities.

Table 35. Determining Monthly Minimum and De-Rated Maximum Capacity

Resource Modeling Category	Location	Resource Project Status	Minimum Capacity Based on.... (direct link or per similar generator type)	De-Rated Maximum Capacity Based on.... (direct link or per similar generator type)
Dispatchable Thermal	California	0, 1, or 2 (Existing through Pre-Construction)	2024 Common Case modeling	Balancing Authorities' WECC Load and Resource Submittal
	Non-California			
Must Run Thermal	California	Construction)	Average of EIA historical dispatch	CAISO Net Qualifying Capacity (NQC)
	Non-California			Balancing Authorities' WECC Load and Resource Submittal
	Any	3 or 4 (Planned/Conceptual)	84% of Nameplate	85% of Nameplate

Thermal Economic Assumptions

Heat rates:	Calculated by CEC and Columbia Grid
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; and
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	4.30

Generator Type (GT or CC-Gas part)	Average FOR Used (%)
Fuel Cell Natural Gas	3.74
Combined Cycle with Industrial Frame Gas Turbine	3.30
Industrial Frame Gas Turbine (Single or part of Combined Cycle)	5.30
Combined Cycle's Steam Turbine	4.00

Planned Maintenance for most units is 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 maintenance and this option was used to schedule the nuclear refueling outages and a few of the large base-load generators.

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 1.0 of the 2026 Common Case supports limited PCM-PF round-trip capability, so the VAR devices are either not modeled in the dataset or are turned off. This capability is anticipated to be complete in a future version of the 2026 Common Case.

Retirement and Extended Outage Assumptions

Information derived from the LRS data submittals, utility Integrated Resource Plan (IRP) postings, state/federal databases, stakeholders, and other sources was used to develop generation retirement schedules for the 2026 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 36 shows the assumption made for all resources with unknown commission and retirement dates.

Table 36. Assumptions for unknown commission and retirement dates

Resource Project Status	Definition
0	Existing
1	Under Construction
2	Pre-Construction
3	Future-Planned)
4	Future-Conceptual

Resource Project Status	Definition
5	No Longer Expected
	Retired

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 Once-Through Cooling (OTC) in California. The compliance timeline is provided in Figure 9. Note that the generators in red were retired earlier than their designated compliance dates.

The OTC policy recommendation led other California regulating entities to develop a replacement plan that is accelerated due to the early retirement of the San Onofre Nuclear Generating Station (SONGS). TAS elected to use DWG's recommendation based on the latest version of the plan, which is summarized in Table 37.

Table 37: OTC Replacement Proposal

California OTC Replacement Plan (MW)				
Resource Type	SCE (CISC)	SDGE (CISD)	PG&E Bay (CIPB)	PG&E Valley (CIPB)
Incremental EE	124.21	40	0	0
Demand Response	5	60	0	0
Behind-the-Load Meter PV	38	0	0	0
Energy Storage	264	200	0	0
Gas-Fired Generation	1382	800	0	0
Total	2500	1144	0	0

Figure 9. 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

Renewable Portfolio Standard (RPS) Compliance Check

The RPS compliance check ensures that the resource assumptions in the 2026 Common Case fulfill all applicable state RPS goals, both voluntary and required. The following sections describe:

- The state RPS targets and how they were determined;
- The RPS fulfillment process used to build up the renewable resource assumptions in the 2026 Common Case; and
- How the 2026 Common Case satisfies the expected Year 10 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 2026. Table 38 provides a summary of each state's load and corresponding energy sales, and RPS targets based on each state's individual RPS requirements.

Table 38. Summary of State RPS Targets based on RPS requirements

2026 COMMON CASE: Loads, Sales and RPS Energy Requirements			
State/ Province	2026 Load Forecast (GWh)	2026 Sales Forecast (GWh)	2026 RPS Energy Requirement (GWh)
AB	118,389	111,286	33,386
AZ	97,821	91,952	7,964
BC	72,870	68,498	
CA	279,914	248,582	107,120
CO	65,497	61,567	12,180
ID	30,918	29,063	
MEX	15,325	14,406	
MT	15,501	14,570	1,204
NV	44,036	41,393	9,192
NM	19,184	17,412	2,689
OR	55,524	52,193	10,970
TX	7,458	7,011	379
UT	37,528	35,277	7,028
WA	113,710	106,887	12,719
WY	20,802	19,553	
Total	994,476	919,649	204,830
RPS%	20.6%	22.3%	

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).

Resource Project Status	Description
0	Most Certain (Existing Generation)
1	
2	
3	
4	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 (based on 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 satisfied 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.

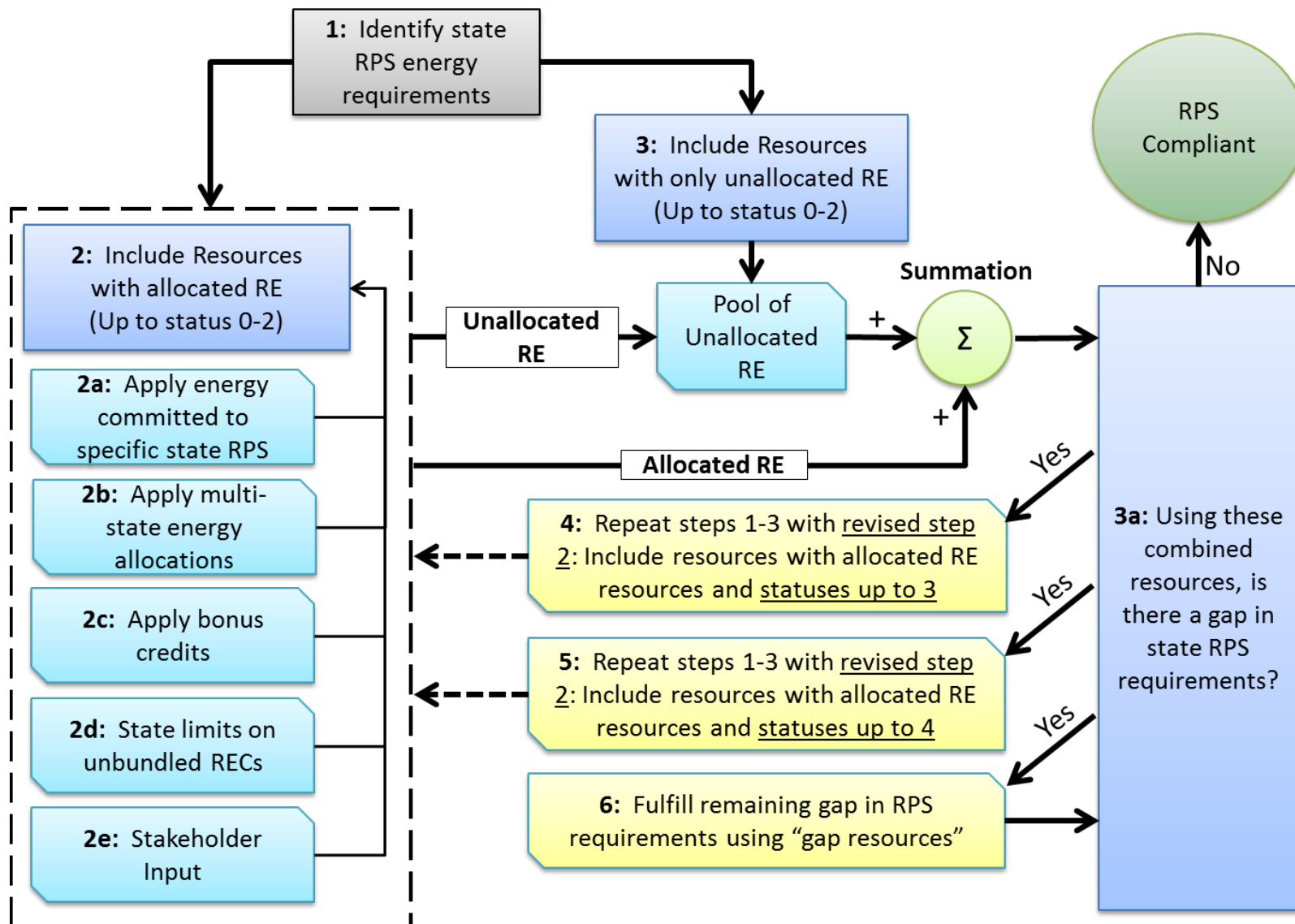
Generators with status 0-2 are of high certainty and are included in the 2026 Common Case. Allocated RE resources with status 3 or above have the next highest certainty as they are less certain per their project status, but the commitment from a buyer increases the chances that they will be developed and may be included. 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 2026 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 10 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 is 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 (status 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 10. Flow chart of the RPS Fulfillment Process



Results of the RPS Compliance Check

Table 39 summarizes the results of the RPS compliance check. The breakdown, by state, of the The summarizes the results of the RPS compliance check for each state. Since the 2026 Common Case has included much of the RPS conceptual resources added for the 2024 Common Case it was determined by the SWG that no additional RPS was required for states to meet there renewable portfolio standard goals.

Table 39. RPS Compliance Check for the 2026 Common Case

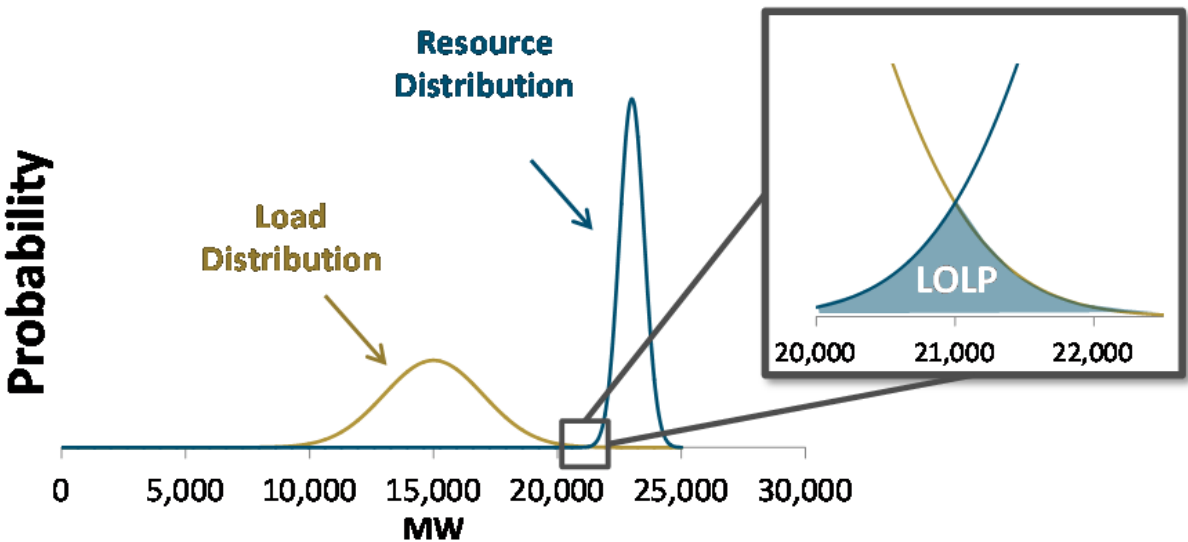
State/ Province	2026 RPS Energy Requirement (GWh)	Cumulative Renewable Generation by Development Status (GWh)					RPS Gap (GWh)
		Existing	Under Construction	Pre-Const Reg Approval- Review	Future- Planned	Future- Conceptual	
Arizona	7,964	4,638	4,673	4,673	7,140	11,329	-3,364
		No	No	No	No	Yes	
California	107,120	64,879	67,905	70,893	97,958	115,348	-8,227
Colorado	12,180	16,000	16,000	16,529	16,544	18,370	-6,190
		Yes	Yes	Yes	Yes	Yes	
Montana	1,204	930	961	961	961	1,004	200
New Mexico	2,689	1,300	1,458	1,458	2,528	3,094	-405
		No	No	No	No	Yes	
Nevada	9,192	5,726	6,164	6,164	8,887	9,170	22
Oregon	10,970	11,127	11,127	11,127	13,621	14,350	-3,380
		Yes	Yes	Yes	Yes	Yes	
Utah	7,028	2,870	2,870	2,870	3,972	4,260	2,768
Washington	12,719	23,059	23,161	24,073	25,382	25,540	-12,821
		Yes	Yes	Yes	Yes	Yes	
Alberta	33,386	5,026	5,026	6,498	7,888	7,888	25,497
Net Gap							-5,901
Unallocated		20,986	23,035	23,810	26,071	26,248	20,346
Total	204,452						

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 2026 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.

Reliability modeling has a long history in electric sector resource planning. Loss of-load-probability (LOLP) modeling, a modeling framework in which the availability of generation resources is compared against potential system load across a broad range of possible conditions, has been established as the industry standard. As tolerance for loss of load due to generation inadequacy is typically very low, a common standard is “one day in ten years”. Reserve margins are planned such that the expected frequency of firm load curtailment due to inadequate capacity resources does not exceed one event in ten years. Such an approach is necessary to capture the tails of the distribution during which loss of load may occur as shown in Figure 11.

Figure 11. Loss of Load Probability Modeling Framework.



For use in the 2026 Common Case WECC has contracted with E3 to conduct a LOLP analysis of the resources in the case using there RECAP tool. The results are outlined below in Table 40.

Table 40. LOLP Modeling Analysis of the Resources

Alberta	AZ-NM-NV	Basin	British-Columbia	CA-North	CA-South	NWPP	RMPA
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	Alberta	AZ-NM-NV	Basin	British-Columbia	CA-North	CA-South	NWPP	RMPA
Net Imports	-	(3,445)	2,255	1,525	500	5,054	(1,525)	625
Hydro	942	1,808	3,475	17,228	7,527	1,916	30,470	1,366
Bio	377	47	65	789	887	559	722	4
CC	4,461	16,370	2,613	265	9,512	12,738	7,276	3,349
ST	5,068	11,816	7,007	23	165	2,308	3,320	6,609
CT	4,696	7,943	1,735	148	4,483	8,105	1,440	2,897
DC-Intertie	-	200	-	-	-	-	200	730
DR	-	759	1,035	-	971	1,297	222	525
EE	-	-	-	-	-	180	-	-
ES	-	-	-	-	-	1,094	-	-
Geo	-	32	911	-	1,034	1,895	-	10
ICE	19	-	160	-	303	2	300	218
MotorLoad	-	-	-	-	(812)	(1,263)	(282)	-
PS	-	207	-	-	2,096	1,448	500	554
Wind & Solar Value **	414	2,929	1,499	208	3,417	6,078	1,307	1,203
sum	15,976	38,666	20,754	20,185	30,081	41,409	43,950	18,090
peak load	14,472	34,482	15,800	13,064	24,911	37,018	33,562	14,823
starting PRM	10%	12%	31%	55%	21%	12%	31%	22%
starting LOLE	18.35	4.75	0.00	0.00	0.27	0.54	0.00	0.07
capacity shortage*	555	602	(2,800)	(6,358)	(1,467)	(1,344)	(6,247)	(1,156)
Target PRM	14%	14%	14%	6%	15%	8%	12%	14%
LOLE at Target PRM ***	3.53	2.27	2.67	3.47	1.43	1.57	2.92	2.20
Wind Installed Capacity (MW)	2,385	2,513	3,068	849	2,390	5,974	10,670	2,797
PV Installed Capacity (MW)		3,954	1,332		9,935	15,228	312	1,156
CSP Installed Capacity (MW)		967	132		6	1,520		
Wind ELCC (MW)	414	606	718	208	1,137	1,039	1,232	679
PV ELCC (MW)		1,668	696		2,279	4,192	74	524
CSP ELCC (MW)		654	86		1	847		
Portfolio Value (MW)	414	2,929	1,499	208	3,417	6,078	1,307	1,203
Wind ELCC (%)	17%	24%	23%	24%	48%	17%	12%	24%
PV ELCC (%)		42%	52%		23%	28%	24%	45%

	Alberta	AZ-NM-NV	Basin	British-Columbia	CA-North	CA-South	NWPP	RMPA
CSP ELCC (%)		68%	65%		21%	56%		

*capacity shortage is the amount of capacity that must be added or subtracted to achieve a reliability target of 0.1 LOLE. A negative capacity shortage indicates surplus.

** approximate breakout by wind and solar is shown below

*** the reliability standard used is a normalized expected unserved energy target of 0.001% across all regions

YELLOW HIGHLIGHT INDICATES RESULTS FROM RECAP

The results of the stochastic reliability assessment for the 2026 Common Case, summarized in Table 40, indicate that each region meets the study's assumed threshold for reliability of LOLF < 0.1 with the exception of Alberta and the AZ-NM-NV regions. The size of these risks is not large enough to necessitate the addition of incremental capacity. Consequently, this modeling effort identifies no need for additional capacity beyond the resources of the Common Case to meet traditional reliability thresholds.

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 41 shows the list of remote generators that were modeled in the 2026 Common Case. Note that the list is dynamic and dependent on stakeholder input.

Table 41. Remote Generators modeled in the 2026 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
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

Remote Generators			
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 2026 Common Case using three grouping tiers, which are shown in Table 42:

1. TEPPC Load Areas;
2. TEPPC Regions; and
3. Combined Areas and Regions.

Table 42 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). The modeling reflects the new FERC Order 789.

Table 42: Reserve Modeling

TEPPC Load		TEPPC Regions		Regions		Combined Areas and Regions			
Area		(BAAs)		AT BAA Level		RGS Level 1		RSG Level 2	
1	AESO	1	AB_AESO	0.5*(3%G+3%L)		-		-	
2	BCHA	2	BC_BCH	0.5*(3%G+3%L)		-		-	
3	BPAT	3	NW_BPAT	25%*0.5*(3%G+3%L)		Spin_RSG_NW (1 of 3)		0.5*(3%G+3%L)	
4	CHPD	4	NW_CHPD	25%*0.5*(3%G+3%L)					
5	DOPD	5	NW_DOPD	25%*0.5*(3%G+3%L)					
6	GCPD	6	NW_GCPD	25%*0.5*(3%G+3%L)					
7	SCL	7	NW_SCL	25%*0.5*(3%G+3%L)					
8	TPWR	8	NW_TPWR	25%*0.5*(3%G+3%L)					

TEPPC Load		TEPPC Regions (BAAs)		Regions	Combined Areas and Regions	
Area				AT BAA Level	RGS Level 1	RSG Level 2
9	AVA	9	NW_AVA	25%*0.5*(3%G+3%L)		
10	PSEI	10	NW_PSEI	25%*0.5*(3%G+3%L)		
11	PGE	11	NW_PGE	25%*0.5*(3%G+3%L)		
12	NWMT	12	NW_NWMT	25%*0.5*(3%G+3%L)		
13	WAUW	13	NW_WAUW	25%*0.5*(3%G+3%L)		
14	PACW	14	NW_PACW	25%*0.5*(3%G+3%L)		
15	PAID	15	BS_PACE	25%*0.5*(3%G+3%L)		
16	PAUT					
17	PAWY					
18	IPFE	16	BS_IPCO	25%*0.5*(3%G+3%L)		
19	IPMV					
20	IPTV					
21	PSCO	17	RM_PSCO	90%*0.5*(3%G+3%L)	Spin_RSG_RM	0.5*(3%G+3%L)
22	WACM	18	RM_WACM	90%*0.5*(3%G+3%L)		
23	SPPC	19	SW_NVE	25%*0.5*(3%G+3%L)	Spin_RSG_NW (2 of 3)	0.5*(3%G+3%L)
24	NEVP					
25	AZPS	20	SW_AZPS	90%*0.5*(3%G+3%L)	Spin_RSG_SW	0.5*(3%G+3%L)
26	SRP	21	SW_SRP	90%*0.5*(3%G+3%L)		
27	TEPC	22	SW_TEPC	90%*0.5*(3%G+3%L)		
28	WALC	23	SW_WALC	90%*0.5*(3%G+3%L)		
29	PNM	24	SW_PNM	90%*0.5*(3%G+3%L)		
30	EPE	25	SW_EPE	90%*0.5*(3%G+3%L)		
31	LDWP	26	CA_LDWP	90%*0.5*(3%G+3%L)		
32	IID	27	CA_IID	90%*0.5*(3%G+3%L)		
33	BANC	28	CA_BANC	25%*0.5*(3%G+3%L)	Spin_RSG_NW (3 of 3)	0.5*(3%G+3%L)
34	TIDC	29	CA_TID	25%*0.5*(3%G+3%L)		
35	CIPB	30	CA_CISO	0.5%*(3%G+3%L)	-	-
36	CIPV					
37	CISC					
38	CISD					
39	VEA					
40	CFE	31	CA_CFE	0.5%*(3%G+3%L)	-	-

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 12. The hourly dispatch of the flexibility reserves was created with ABB's flex reserve tool.

Figure 12. Composite Hourly Reserve Requirement



Advanced Modeling

Transmission Loss Modeling

The 2026 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.

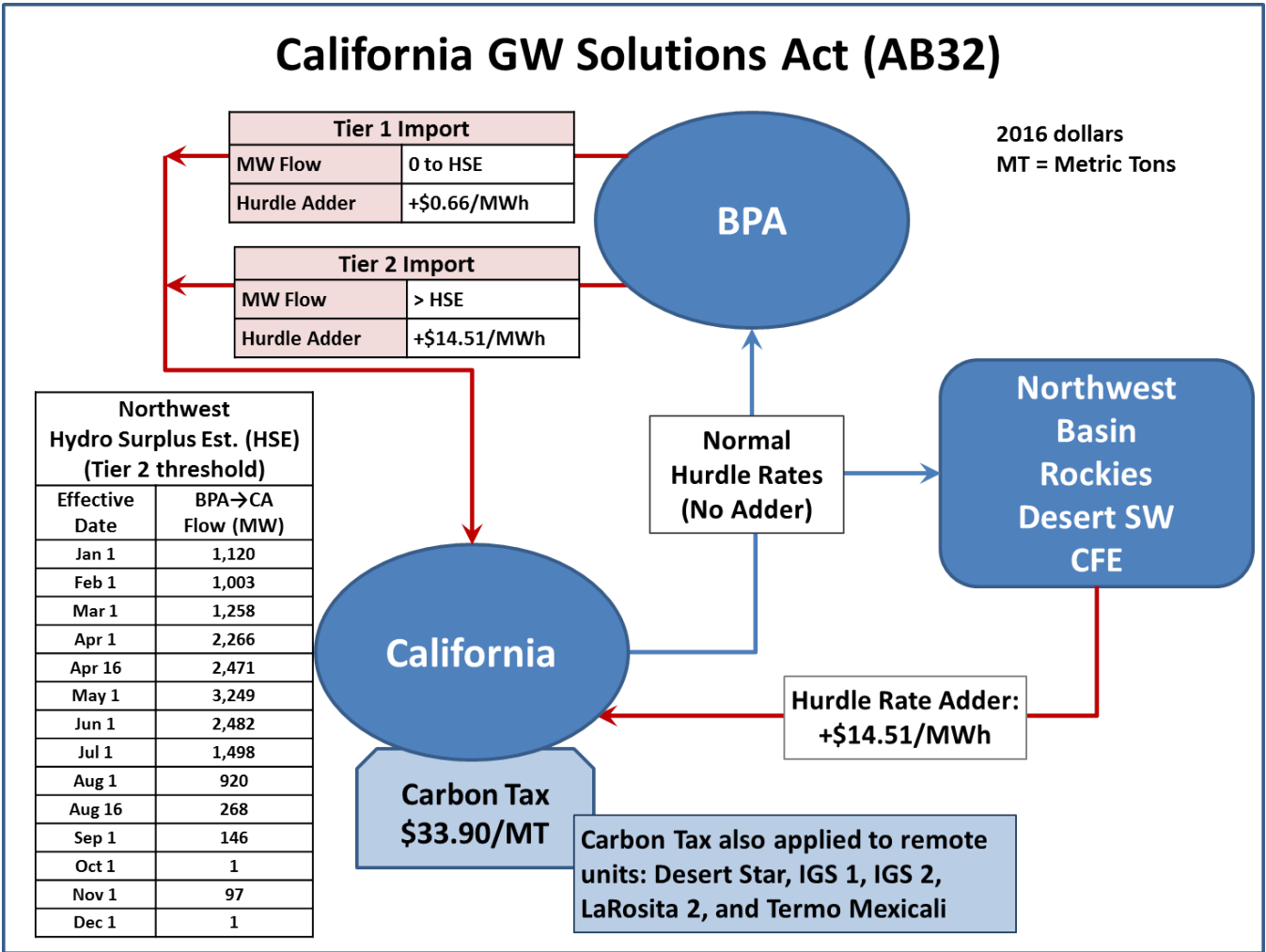
GridView's loss model is based on the load and corresponding transmission loss percentages taken from the imported power flow model. The algorithm uses this information to determine the hour-by-hour transmission losses as the load and generation dispatch changes throughout the simulation.

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 13 provides an illustration of how it is

modeled in the 2026 Common Case, which includes a carbon tax on thermal generators within California and additional “emissions reduction” hurdle rates on imports into California.

Figure 13. Illustration of the California Global Warming Solutions Act Modeling



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 CO₂ tax of \$26.66 per metric ton for 2024 in 2014 dollars, which is \$33.90/metric ton in 2016 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., +\$0.66/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.³ Tier 1 imports would ideally include flows correlated to all excess generation from non-CO₂-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.⁴

- (2) Tier 2 imports are subject to the additional hurdle rate equivalent to the CA carbon tax (i.e., +\$13.85/MWh).

The California Air Resources Board (CARB) specified the emissions rate for unspecified resources as 0.435 metric ton/MWh.⁵ Multiplying this value by the CA carbon tax (\$33.90/metric ton) yields the total additional “emissions reduction” hurdle rate: \$14.51/MWh. This additional hurdle rate is imposed directly on imports from non-BPA areas into California; however, the CARB 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 0.022 metric ton /MWh,⁶ which corresponds to the Tier 1 additional “emissions reduction” hurdle rate of \$0.66/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 2026 Common Case.

1. The CARB 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 2026 Common Case. Powerex is the wholly-owned electricity marketing subsidiary of BC 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.

³ 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

⁴ BPA White Book Reference: “2011 Pacific Northwest Loads and Resources Study, Technical Appendix, Volume 1, Energy Analysis.”

⁵ 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>.

⁶ Mandatory GHG Reporting - Asset Controlling Supplier: <http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/acs-power.htm>.

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

WECC receives data used in its analyses from a wide variety of sources. WECC strives to source its data from reliable entities and undertakes reasonable efforts to validate the accuracy of the data used. WECC believes the data contained herein and used in its analyses is accurate and reliable. However, WECC disclaims any and all representations, guarantees, warranties, and liability for the information contained herein and any use thereof. Persons who use and rely on the information contained herein do so at their own risk.

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

- 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/sustainableplan.aspx>

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 2026.

CALIFORNIA

- 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/RPS_Homepage/
 - California Energy Storage Goals:
 - <http://www.energy.ca.gov/research/energystorage/tour/roadmap/>

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.
- 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).

COLORADO

- 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.
- 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 2020-2026 (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

NEW MEXICO

- 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.
- 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/P-I/Pages/RPS_home.aspx

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>.

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

Acronym	Term	Definition
BA	Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
BTM	Behind the Meter	An energy generating facility that produces power intended for on-site use in a home, office building, or other commercial facility
DSIRE	Database of State Incentives for Renewables and Efficiency	A source of information on incentives and policies that support renewables and energy efficiency in the United States. DSIRE is operated by the N.C. Clean Energy Technology Center at North Carolina State University and is funded by the U.S. Department of Energy. (see http://www.dsireusa.org)
DR	Demand Response	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
DSM	Demand-Side Management	A modification of consumer demand for energy through various methods such as financial incentives and behavioral change through education.
DWG	Data Work Group	A work group under TEPPC that is responsible for collecting and verifying data used in the TEPPC database.
DG	Distributed Generation	Generation that is consumed near the point of generation rather than being transmitted to a remote load
FERC	Federal Energy Regulatory Commission	FERC is a United States government agency, established in 1977 to oversee the country's interstate transmission and pricing of a variety of energy resources, including electricity, natural gas and oil.
GT	Green Tag	This is synonymous with REC and is a term in Utah and Washington

Acronym	Term	Definition
IRP	Integrated Resource Plan	A comprehensive decision support tool and road map for meeting a company's objective of providing reliable and least-cost electric service to all of its customers while addressing the substantial risks and uncertainties inherent in the electric utility business.
IOU	Investor-Owned Utility	A business organization, providing a product or service regarded as a utility (often termed a public utility regardless of ownership), and managed as private enterprise rather than a function of government or a utility cooperative.
LSE	Load-Serving Entity	Load serving entities (LSEs) provide electric service to end-users and wholesale customers.
PV	Photovoltaic	A method for generating electric power by using solar cells to convert energy from the sun into a flow of electrons.
PEC	Portfolio Energy Credit	Synonymous with REC, applies in Nevada.
PSA	Power Supply Assessment	An evaluation of generation resource reserve margins for the WECC summer and winter peak hours for the forecast period.
PCM	Production Cost Model	A modeling tool that dispatches available resources to meet specified load for each of the hours in a year.
PLF/HTC	Proportional Load Following Hydrothermal Co-optimization	A hydro modeling method for improving hourly hydro-generation time series representations in transmission planning studies.
RPCG	Regional Planning Coordination Group	A group consisting of a member from each TEPPC-recognized Regional Planning Group that coordinates planning activities between and among the Regional Planning Groups and TEPPC.
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. <i>This is interchangeable with Renewable Energy Credit, Green Tag, Green Ticket, or Renewable Certificate.</i> A REC may be “bundled” to include

Acronym	Term	Definition
		both the REC and its associated energy, or “unbundled,” to include the REC only but not its associated energy. If the REC is unbundled, the energy is considered null (non-renewable) power and no green claims can be made for use of this null electricity. Figure 14 shows the REC/Electricity pathway.
RES	Renewable Energy Standard	A renewable energy standard (RES) requires utility companies to source a certain amount of the energy they generate or sell from renewable sources such as wind and solar.
REST	Renewable Energy Standard and Tariff (applies to Arizona)	Rules that require that regulated electric utilities must generate 15 percent of their energy from renewable resources by 2025 (applies to Arizona)
RPG	Renewable Portfolio Goal	A regulation that requires the increased production of energy from renewable energy sources, such as wind, solar, biomass, and geothermal.
RPS	Renewable Portfolio Standard	A regulation that requires the increased production of energy from renewable energy sources, such as wind, solar, biomass, and geothermal.
SWG	Studies Work Group	A work group under the TEPPC that is responsible for managing the completion of the study cases defined in TEPPC’s annual study program. It is also responsible for establishing the resource portfolio and transmission network assumptions used in each of the study cases.
TSS	Technical Studies Subcommittee	A WECC subcommittee under the Planning Coordination Committee that manages a central database of technical information about the Western Interconnection transmission system and reliability studies, including power flow models of the Western Interconnection.
TREC	Tradable Renewable Energy Credit	Synonymous with REC, applies in Colorado.
TEPPC	Transmission Expansion Planning Policy Committee	The WECC Committee responsible for overseeing and maintaining public databases for transmission planning; developing, implementing, and coordinating planning processes and policy; conducting transmission planning

Acronym	Term	Definition
		studies; and preparing Interconnection-wide transmission plans.
	TEPPC Load Areas	Topology for 2026 Common Case based on large load centers. Analogous to Balancing Authority boundaries or Load Serving Entity boundaries.
	TEPPC Regions	TEPPC load areas defined at operational level.
	Trading Hubs	Operational region with generation free trading zones and no hurdle rate barriers.

Figure 14. Renewable generation REC and electricity pathway
http://www.epa.gov/greenpower/gpmarket/rec_chart.htm

