EXHIBIT 91

Memorandum

To:	Tertia Speiser, NEPA Compliance Officer, Response and Restoration Division Cybersecurity, Energy Security, and Emergency Response (CESER) U.S. Department of Energy
From:	ICF
Date:	April 19, 2024
Re:	Special Environmental Analysis of Balancing Authority of Northern California (BANC) Operations during 202(c) Emergency Order Operations between September 4, 2022, and September 8, 2022

1 Introduction

On September 4, 2022, U.S. Department of Energy (DOE) issued Order No. 202-22-2 that permitted the Balancing Authority of Northern California (BANC) to operate under Federal Power Act Section 202(c) conditions for a limited period. BANC is a registered Balancing Authority with the North American Electric Reliability Corporation and operates as a neighboring Balancing Authority Area (BAA) to the California Independent System Operator (CAISO) BAA. DOE found that an emergency existed: "California has experienced several periods of extreme heat, drought conditions, and threat of wildfires. Such conditions are expected to occur over the next several days [from September 2, 2022] and threaten the reliable operation of the bulk electric power system in California. The loads from the forecasted heat wave over the next week are expected to push demand for electric energy by BANC members to at or over historical peaks and higher than normally expected planning targets for this time of year." DOE determined that issuance of an Emergency Order would "meet the emergency and serve the public interest." Under the Order NTT Global Data Centers was authorized to operate specific electric generating resources (Covered Resources) located within California outside of the limits of their Title V Operating Permit (Permit No. TV2016-20-01 issued by the Sacramento Metropolitan Air Quality Management District) when directed to do so by BANC, notwithstanding air quality or other permit limitations.

One covered resource was included in the order: NTT Global Data Centers, Americas, located at 1312 Striker Ave, Sacramento, CA 95834. Its generation capacity consists of 48 MW across 24 generators. Each generator is driven by a diesel-fueled internal combustion (IC) engine. As backup capacity the resource is designed to support 26.1 MW of critical data center load with built in redundancy. The 24 generators are collectively known as "CA2".

The Order stated that BANC anticipated that the emergency order it requested "may result in exceedance of National Ambient Air Quality Standards (NAAQS) under the Clean Air Act." The Order also required BANC to inform all affected communities where the Covered Resource operates and clearly explain what the Order allowed BANC to do, including potential impacts to the surrounding community. The Order was limited to a 5-day period and expired on

September 8, 2022. BANC was required to submit a report documenting operations of the covered resources under the emergency order. BANC filed its Final Report on November 14, 2022.

This document summarizes ICF's review of documents BANC provided to DOE regarding its operations under Section 202(c) emergency orders pursuant to the Federal Power Act between September 4, 2022, and September 8, 2022[1] (the "order period"). Specifically, ICF reviewed:

- Operations data from covered generating units to determine the number of engines operating and their hours of operation.
- Emissions data from covered generating units to determine whether any emissions would have caused ambient pollutant concentrations in the region to exceed any NAAQS.
- Location coordinates of the generating units to determine the potential for Environmental Justice impacts on the affected population in the area around the CA2 data center.
- The robustness of community engagement plans.

2 Emissions Evaluation

2.1 Approach

ICF has reviewed the information supplied by BANC for the NTT generating facilities and presents our findings below.

The reporting period for Section 202(c) emergency order was September 4, 2022, through September 8, 2022, though no generating units exceeded their permit limits on September 4 the Order applied to the 24 generating units listed in Table 1.

Table 1. Generating Units at CA2 Covered by DOE 202(c) Emergency Order 202-22-2

Permit No.	Generator ID	Total Operating Hours per Engine During Order Period
21352	41M	17.1
21366	42M	17.0
21367	41U	21.7
21368	42U	21.1
22348	43M	17.1
22349	44M	17.0
21369	43U	21.8

[1] The documents reviewed are posted on the Department of Energy's (DOE) web site at the following link: https://www.energy.gov/ceser/federal-power-act-section-202c-banc-september-2022

Permit No.	Generator ID	Total Operating Hours per Engine During Order Period
21370	44U	16.8
21371	45U	21.9
21372	46U	21.8
22350	47U	9.0
22351	48U	22.1
22352	51M	16.8
22353	52M	16.8
22354	51U	21.4
22355	52U	21.2
22356	53U	21.2
22357	54U	21.2
22358	55U	21.1
22359	53M	16.8
22360	56U	21.0
22361	57U	21.0
22362	58U	18.4
22363	59U	20.9
Total Operating Hours		**462.2**

Source: BANC

The hours of operation per engine on any single day during the Order Period ranged from zero (for several engines) to 7.7 hours (by engine 43U on September 7). The maximum total time of operation for any single engine during the Order period was 22.1 hours (by engine 48U as shown in Table 1). Table A-1 in the BANC Final Report provides further detail on the hours of operation for each engine.

ICF reviewed operating and emissions data provided by BANC for each unit, for each of the 32 hours in which the Order was in effect and operations occurred outside of permit limits (2:00 PM – 10:00 PM PDT on September 5-8, 2022).[2] Meteorological data measured at Sacramento International Airport (SMF), located about 6.1 miles northwest of CA2, provided the average wind direction and speed that occurred for each hour. Based on the wind data the likely locations of potential air quality impacts in the area surrounding CA2 were identified. The likelihood that any impacts would have caused pollutant concentrations to exceed the NAAQS or California Ambient Air Quality Standards (CAAQS) was assessed for each location based on the operational, emissions, and wind data.

The NAAQS and CAAQS are based on specific averaging time periods which range from one hour to one year. For diesel engines the standards that are the most likely to be exceeded are

[2] Several emergency generators also operated between 10:00 and 10:30 PM on September 6 and 7, 2022, due to the generators ramping down from the heat emergency operation.

the NAAQS and CAAQS for the 1-hour nitrogen dioxide (NO_2) standard as a result of operating the diesel generators in excess of the operating permit. Because of the short duration of the Order period, it was not possible to assess impacts for the 24-hour and longer averaging periods. Therefore, direct impacts were assessed primarily in terms of potential 1-hour NO_2 concentrations. Other short-term standards considered but not assessed were the 1-hour carbon monoxide (CO) and sulfur dioxide (SO_2) standards as well as the 8-hour CO standard as the CO emissions from the diesel generators are about half the nitrogen oxide (NO_x) emission rate and the ambient air quality concentration standard is about 30 times higher for CO compared to NO_2. Similarly, SO_2 emission rates are about 1,000 times lower than NO_x emission rates.

Because volatile organic compound (VOC) and NO_x emissions chemically interact in the atmosphere over minutes to hours in the presence of sunlight to produce ozone (secondary formation), the 8-hour ozone NAAQS and CAAQS were also assessed in terms of the potential to cause or contribute to an exceedance of the standards.

2.2 Permit Exceedances

The CA2 engines drive generators that serve as an emergency or backup power supply, meaning that they do not run continuously as in a conventional power plant, but only run for maintenance, repair, or emergency purposes. The engines are permitted by the Sacramento Metropolitan Air Quality Management District (SMAQMD) to operate for a maximum of 50 hours per year for maintenance, and less than 200 hours per year for both emergency and maintenance, per engine.

As noted in the BANC Final Report, NTT exceeded two permit conditions during the Order period. Briefly, these conditions require that a maximum of one engine may operate at a time except under conditions of emergency or for maintenance and repair. These two conditions and the circumstances of exceedance are described in more detail below, per the BANC Final Report.

1. Exceeded Permit Condition: Condition III. 53 of Permit No. TV2016-20-01 states that unless authorized by SMAQMD, for purposes other than emergency operation, only one IC engine may operate at any single time at 1312 Striker Ave. The following exclusions apply to this condition:

a) Facility wide operational test where all or some of the engines operate at the same time occurring no more often than once every calendar year and for less than 30 minutes.

b) Electrical infrastructure upgrades or repairs requiring multiple IC engines to operate.

<u>Manner of Exceedance</u>: Multiple generators ran concurrently on September 5-8, 2022 consistent with the Order: no engines ran on September 4, 17 engines ran concurrently on September 5, 24 on September 6 and 8, and 23 on September 7. Additionally, on September 6-7, 2022, multiple engines operated shortly after the 2 PM - 10 PM period covered by the Order.

2. Exceeded Permit Condition: Per Condition V. B-7.2 and Condition V. B-8.2 of Permit No. TV2016-20-01, the emergency generators at CA2 may only operate for maintenance purposes and/or in an emergency. "Maintenance purposes" is defined as "the operation of an NTT IC engine in order to preserve the integrity of the IC engine and its associated generator, the facility's electrical distribution system or when required by SMAQMD to verify compliance with applicable rules and regulations." "Emergency" is defined as "when electrical service from the serving utility is interrupted by an unforeseeable event."

Manner of Exceedance: The CA2 emergency generators ran during the heat emergency event for purposes other than maintenance or emergency as defined in the permit on September 5-8, 2022. Specifically, the operation from 2 PM to 10 PM on those days did not meet the definition above of emergency; the units were operated in response to the heat emergency. Additionally, several emergency generators operated after 10 PM on September 6 and 7, 2022.

2.3 Analysis of Operations and Emissions

This section summarizes emissions information provided by BANC for those hours during which emissions exceeded the limits in the units' respective air quality permits as described above. The permitted limits on emissions are set on a unit-by-unit basis by SMAQMD at levels that are intended to ensure that ambient concentrations will not violate the NAAQS or CAAQS. NTT reported emissions for CO, NO_X, particulate matter of 10 microns diameter and smaller (PM_{10}), sulfur oxides (SO_X), and VOC. Permit limits were exceeded only for hours of operation (Table 1). NTT did not report any exceedances of permit conditions that limit actual emissions. Table 2 summarizes the reported emissions from the engines for the Order Period.

The emissions in Table 2 represent the total mass (in pounds) of emissions that could have contributed to ambient pollutant concentrations during the Order period. The permits for the CA2 engines do not include limits on the number of pounds emitted per day as shown in Table 2. Rather, the permits limit the mass emissions per unit of work (grams per horsepower-hour), the number of pounds emitted per quarter, and the number of pounds emitted per year. NTT did not report any exceedances of the permit limits for emissions per unit of work, emissions per quarter, or emissions per year. As noted above, permit limits were exceeded only for the number of engines operating at a time (condition 1 in Section 2.2) and for operation for purposes other than maintenance or emergency as defined in the permit (condition 2 in Section 2.2).

Table 2. Emissions (pounds) from CA2 Engines During Order Period

Description	CO	NO_X	PM_{10}	SO_X	VOC
September 4, 2022	0	0	0	0	0
September 5, 2022	649.33	1,198.77	37.46	1.25	249.74
September 6, 2022	2,326.85	4,295.71	134.24	4.47	894.94
September 7, 2022[1]	2,870.88	5,300.09	165.63	5.52	1,104.18
September 8, 2022[1]	1,873.62	3,458.99	108.09	3.60	720.62
Total emissions during Order period	7,720.68	14,253.56	445.42	14.85	2,969.49
Maximum emissions to stay within permit limits (hypothetical scenario of normal operations consisting of 1 engine operating at a time for maintenance/repair/emergency purposes during each hour)	83.20	153.60	4.80	0.16	32.00
Excess emissions due to permit exceedances (emissions during Order period minus hypothetical scenario of normal operations)	7,637.48	14,099.96	440.62	14.68	2,937.48

Source: BANC
[1] Includes operations after 10:00 PM.

2.4 Assessment of Potential Air Quality Impacts

2.4.1 Measured Air District Concentrations in the Region

The SMAQMD operates several air quality monitoring sites in the region that measure concentrations of various pollutants continuously. There are three SMAQMD monitors located within 10 miles of CA2. Table 3 shows the maximum pollutant concentrations measured at each monitor during the Order period. Not every pollutant is measured at each site.

Table 3. Measured Concentrations at SMAQMD Monitors During Order Period

			Maximum Measured Short-Term Concentrations						
Monitoring Site Name	USEPA Site ID	Approx. Distance from CA2 (miles)	CO (1-hr, ppm)	CO (8-hr, ppm)	NO_2 (1-hr, ppm)	PM_{10} (24-hr, μg/m³)	$PM_{2.5}$ (24-hr, μg/m³)	SO_2 (1-hr, ppm)	O_3 (8-hr, ppm)
Bercut Drive	06-067-0015	3.9	1.7	1.6	0.035	NM	11.1	NM	NM
1309 T Street	06-067-0010	5.7	NM	NM	0.030	37.8	10.9	NM	0.079
Del Paso Manor	06-067-0006	7.2	NM	NM	0.019	40	9.4	0.001	0.068
Air Quality Standards									
NAAQS			35.0	9.0	0.10	150	35	0.075	0.070
CAAQS			20.0	9.0	0.18	50	NS	0.25	0.070
Exceedance of standard during Order period?			No	No	No	No	No	No	0.079

Sources: SMAQMD, CARB
hr = hour
μg/m³ = micrograms of pollutant per cubic meter of air
ppm = parts per million
CO = carbon monoxide
NO_2 = nitrogen dioxide
O_3 = ozone
PM10 = particulate matter of 10 microns diameter and smaller
$PM_{2.5}$ = particulate matter of 2.5 microns diameter and smaller
SO_2 = sulfur dioxide
CAAQS = California Ambient Air Quality Standards
NAAQS = National Ambient Air Quality Standards
NM = pollutant not measured at site

NS = no standard established

As shown in Table 3, the nearest air quality monitors to CA2 did not record any exceedances of the NAAQS or CAAQS during the Order period with the exception of O_3. However, because of the distances between CA2 and the monitoring sites, any direct impacts due to CA2 may not be discernible at these monitors and are discussed further below.

2.4.2 Other Measured Concentrations Near CA2

Citizen scientists operate a network of real-time air quality particulate matter sensors focused on $PM_{2.5}$ and the data are reported through the PurpleAir monitoring website. These sensors are not as accurate as the Federal Reference Method (FRM) instrumentation used by SMAQMD monitors but are of sufficient quality to identify areas of high concentrations. PurpleAir measurements have been shown to correlate well with FRM measurements, providing both good accuracy and high precision even under hot and dry conditions.[3]

Four PurpleAir sensors are located within 7,900 feet (1.5 miles) of CA2 with the closest station at 2,500 feet (0.5 miles). Unfortunately, the two closest stations had limited archived data available. However, the most complete dataset collected at 10-minute frequency was the Natomas Clay Way station (# 7278) which, at 4,000 feet (0.8 miles) from CA2, reported data for nearly all of the Order period. The fourth station Natomas Park – Heron is farther from CA2 at 7,900 feet (1.5 miles) but had a nearly complete observation record during the Order period.

None of these stations shows an exceedance of the $PM_{2.5}$ air quality standard but the Natomas Clay Way and Natomas Park Heron both show elevated $PM_{2.5}$ concentrations on Sept 5th starting at around 8 PM and lasting until 11 PM for the Clay Way station, while the Natomas Park Heron measured a longer period of elevated readings from about noon on Sept 5th until 3:00 AM on Sept 6th. No other time periods showed elevated $PM_{2.5}$ concentrations. However, it is unlikely, based on the wind measurement discussed in Section 2.4.4, that these increased concentrations were associated with emissions from CA2.

2.4.3 Likely Pollutant Dispersion at CA2

Buildings and similar structures in the path of air flow create a turbulent wake region on the building roof and the leeward (downwind) side of the building as shown in Figure 1. An exhaust plume caught in the path of this flow is drawn into the wake and is temporarily trapped in a recirculating region or “cavity”. This effect, known as “downwash“, leads to higher ground-level pollutant concentrations near the building than if the building were not present. The CA2 engine stack exits are only a few feet above the roof level. Therefore, it is highly likely the emission plumes are drawn into the wake. Under these conditions the maximum pollutant concentrations will occur within the recirculation cavity and close to CA2, likely within about 120 feet of the building.[4] Beyond the recirculation cavity, concentrations will decrease with increasing distance from CA2.

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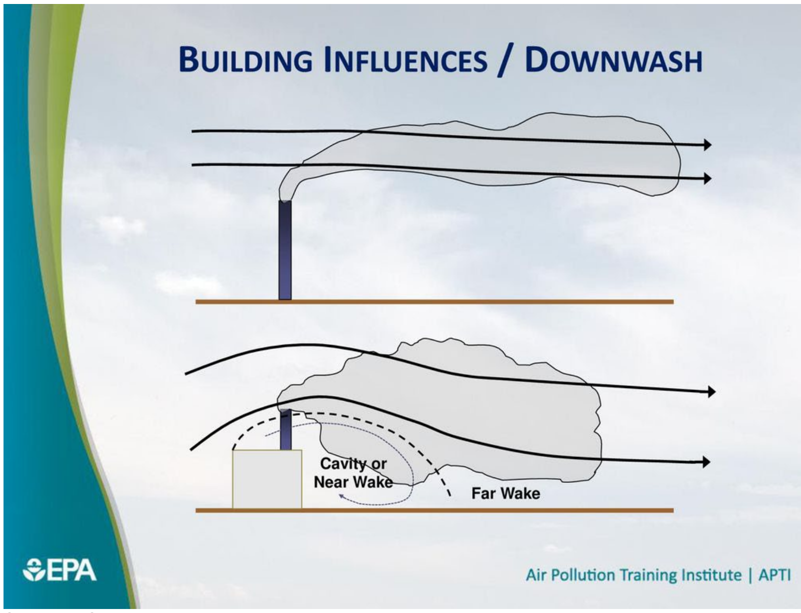
[3] South Coast Air Quality Management District, AQ –SPEC Air Quality Sensor Performance Evaluation Center, 2017. Sensor PurpleAir PA-II.

[4] The USEPA SCREEN3 dispersion model was used to estimate the distance to the maximum pollutant concentration.

Figure 1. Building Downwash Effect



Source: USEPA

2.4.4 Assessment of Direct Air Quality Impacts

Depending on the wind speed and direction, downwash could cause high pollutant concentrations to occur outside the CA2 site but still within a few hundred feet of the building, in areas where the public has access. Although these nearby areas appear to be in industrial/commercial use they include public sidewalks and a vacant lot immediately northwest of CA2 that could be used informally for recreation. Under USEPA policy, these publicly accessible areas are considered "ambient air" and are subject to the NAAQS/CAAQS. Because of the downwash effect and the fact that multiple engines were running simultaneously, it appears that 1-hour NO_2 concentrations likely exceeded the NAAQS or CAAQS in these nearby areas during the Order period.

The exhaust from the engines contains a mixture of nitrogen oxides, primarily nitric oxide (NO) with only a small proportion of NO_2.[5] Once emitted the NO reacts with oxygen in the atmosphere and is converted to NO_2 over time. The conversion time can be seconds to minutes depending on local conditions. As a result, NO_2 concentrations in areas very close to the emission source can be low because the NO has not had time to convert to NO_2. However, because the conversion can occur within seconds, and to avoid underestimating potential impacts, this analysis assumes that most of the NO has converted to NO_2 by the time the emissions reach any locations where impacts are assessed.

Potential concentrations beyond the immediate area of the CA2 site were assessed at the nearest sensitive locations (known as receptors). Sensitive receptors include residences, schools and daycare facilities, health care facilities, and recreational sites. The assessment considered the number of hours that the wind (measured at SMF) blew from CA2 toward each receptor, the wind speeds, the orientation of the units with respect to the wind direction, and the distance from CA2 to the receptor. Based on these factors, the likelihood of a violation of

[5] Air quality studies typically assume conservatively that no more than 10% of the NO_X is emitted as NO_2 in the stack exhaust from diesel generators.

the NAAQS or CAAQS was characterized as three potential options: "unlikely," "possible," or "likely". Table 4 presents the assessment of air quality impacts for each receptor and wind direction combination that occurred during the Order period.

In addition to the SMF meteorological data a personal weather station, at Natomas Park, has hourly meteorological data available through the Weather Underground, a weather station network. This station is located 4,300 feet (0.8 miles) northwest of CA2. Meteorological data from this station was reviewed for possible use in assessing impacts given its proximity to CA2. The data was initially reviewed but had more than half the hours during the Order period with zero wind speed and direction. Further analysis showed the data was likely measuring the wind speed and direction only 10-15 feet above ground level, considerably lower than SMF's 33-foot height. This is important as the wind speed and direction values measured at the lower height are well below the release height of the stacks plus plume rise. In addition, the low measurement height is within the nocturnal boundary layer following sunset while the emissions from CA2 stacks remain well above the surface-based inversion. Data from Natomas Park measured at the lower height, if used in the assessment, would underestimate the wind speeds at the plume height. For these reasons ICF does not include this meteorological data in the air quality analysis.

Table 4. Assessment of Potential Air Quality Impacts at Receptors

Wind Vector Range[1] (degrees)	Wind Speed Range (mph)	Number of Hours[2]	Nearest Downwind Sensitive Receptor from CA2	Minimum Distance to Receptor (ft)	Meets Criteria for 1-hr NO_2 NAAQS Violation?[3]	Meets Criteria for 1-hr NO_2 CAAQS Violation?[4]	Rationale
0-10	6.9-10.4	5	Vacant (possible informal recreation area)	2,300+	Unlikely	Unlikely	Distance from sources; winds moderate during period[5]
20-50	3.5-10.4	7	Residences at Del Paso Rd./Sorento Rd.	3,300	Unlikely	Unlikely, but possible for hour of lowest wind speed	Distance from sources; winds largely moderate during period except 1 hour with low (3.5 mph) wind speed
70-90	3.5-4.6	3	Residences on and east of Bollenbacher Ave.	6,400	Unlikely	Unlikely	Distance from sources; winds low-moderate during period
160-190	0-12.7	8	Residences immediately south of I-80	4,200	Unlikely	Unlikely	Distance from sources; winds largely moderate during period; 3 of the hours have calm wind which will lead to relatively high concentrations.
200-210	6.9-9.2	3	Staybridge Suites Hotel on Promenade Circle	4,900	Unlikely	Unlikely	Distance from sources; winds moderate during period leading to lower concentrations
240	5.8	1	Residences on Golden Cypress Way across stormwater retention pond from CA2	500	Unlikely	Likely	Short distance from sources; moderate wind speed; all of the units are lined up along the south wall of the building which puts them in alignment for producing a high concentration at receptor. Likely to have exceedance of the 1-hour NO_2 CAAQS which would meet criteria for violation. Likely to have exceedance but not a violation of the 1-hour NO_2 NAAQS.[2]
330	6.9	1	Residences on English Elm St.	1,770	Unlikely	Possible	Fairly short distance from sources; winds moderate
340-350	4.6-10.4	6	Natomas Charter School at Del Paso Rd./ Blackrock Dr.	2,400	Unlikely	Unlikely	Distance from sources; winds moderate-high during period

[1] Direction the wind is blowing toward. For example, a wind vector of 0 degrees indicates that the wind is blowing towards due north (i.e., a south wind).
[2] Number of hours wind blew at vectors given in left column.
[3] The 1-hour NO_2 NAAQS is defined statistically: to attain the 1-hour national standard, the 3-year average of the annual 98th percentile of the 1-hour daily maximum concentrations must not exceed 0.10 ppm. Thus, multiple exceedances of the numerical value of the standard can occur before the criteria for a NAAQS violation are met. Source: 40 CFR 50.
[4] The 1-hour NO_2 CAAQS is defined as the value not to be exceeded. Thus, a single exceedance of the numerical value of the standard meets the criteria for a violation. Source: 17 CCR 70200.
[5] If all else is equal, concentrations increase as wind speed decreases, and vice versa.

2.4.5 Assessment of Indirect Air Quality Impacts (Ozone)

An exceedance of both the 8-hour ozone NAAQS and CAAQS occurred during the Order period. The highest measured ozone exceedance was 0.079 ppm occurring between 10 am to 6 pm on September 6^{th} at the T Street monitor. It is likely that CA2 emissions released during the Order period contributed to an exceedance of both the CAAQS and NAAQS within the region, but not in immediate vicinity to CA2 due to the time needed for the photochemistry to take place typically resulting in peak impacts found 2 to 10-km downwind.

2.4.6 Conclusions

Based on the reported emissions, the orientation of the generator stacks, the distances from CA2 to receptors, and the wind speeds and directions during the Order period, it appears likely that the operations that exceeded permit limits at CA2 would have increased ambient concentrations enough to cause or worsen a violation of the 1-hour NO_2 CAAQS, but not the NAAQS, at publicly accessible locations very near CA2 as well as in the area of residences on Golden Cypress Way. It also appears possible that violations of the 1-hour NO_2 CAAQS, but not the NAAQS, could have occurred at residences at Del Paso Road/Sorento Road and at residences along English Elm Street. In addition, it appears likely that the CA2 emissions released during the Order period contributed to an exceedance of both the ozone CAAQS and NAAQS.

Further evaluation could likely refine the extent of this preliminary conclusion. Such evaluation could include further review of meteorological conditions during the reporting period, and air dispersion modeling to quantify the potential ambient air concentrations in the area for NO_2, $PM_{2.5}$, CO and SO_2 and their spatial extent in the region during the Order period.

3 Review of Environmental Justice Implications for Affected Populations

This section highlights the potential environmental justice (EJ) implications for the affected population in the region of interest. ICF's evaluation was based on data from U.S. EPA's EJScreen tool, available at ejscreen.epa.gov/mapper.[6] EPA's EJScreen is a GIS-based mapping tool for evaluating potential EJ impacts across the United States. The tool allows users to combine demographic and environmental information on a user-selected area. The data used for these purposes in EJScreen are based on publicly available data sources, such as the American Community Survey from the Census Bureau for demographic data and various EPA data sources for environmental indicators. ICF used this screening tool for this analysis because it provides a method consistent with EPA's approach for defining EJ vulnerabilities for affected populations.

[6] Another potential source that ICF considered to conduct this analysis is CalEnviroScreen (https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-40. Accessed April 2, 2024). However, due to the familiarity and ease of use of EPA EJScreen's interface and to maintain consistency with a similar analysis conducted for the PJM region, ICF decided to use EPA's EJScreen for both analyses.

3.1 Analyzing Demographic Characteristics of Nearby Populations

To identify the vulnerable population around the CA2 data center that is likely to be impacted by any potential exceedances during the 5-day period in September 2022, ICF extracted the demographic and environmental characteristics of those living within a pre-specified 2-km and 10-km radius around the data center. Since the data center is near a residential part of the city with neighborhoods around, ICF chose the 2-km radius to better isolate the demographic and environmental characteristics of the nearby population. The 10-km radius was chosen to analyze the EJ characteristics in a wider region around the data center.

The EJScreen also identifies if a census tract is designated as a Disadvantaged Community (DAC) in the pre-specified 2-km and 10-km radii.[7] The EPA defines DAC as any census tract that is identified as disadvantaged in the Climate and Economic Justice Screening Tool (CEJST); and/or census block group that is at or above the 90th percentile for any of EJScreen's Supplemental Indexes when compared to the state or nation; and any that are within Tribal lands.[8,9] To calculate a single supplemental index for one block group, EJScreen multiplies the environmental indicator by socioeconomic information. The socio-economic indicators include people of color, low-income, unemployment, limited English speakers, less than high school education, and percent of people under the age of five and percent of people over 64.[10]

Figure 2 below overlays the 2-km circle around CA2 data center. A 2-km radius ensures the neighborhoods around the data center are captured in detail.

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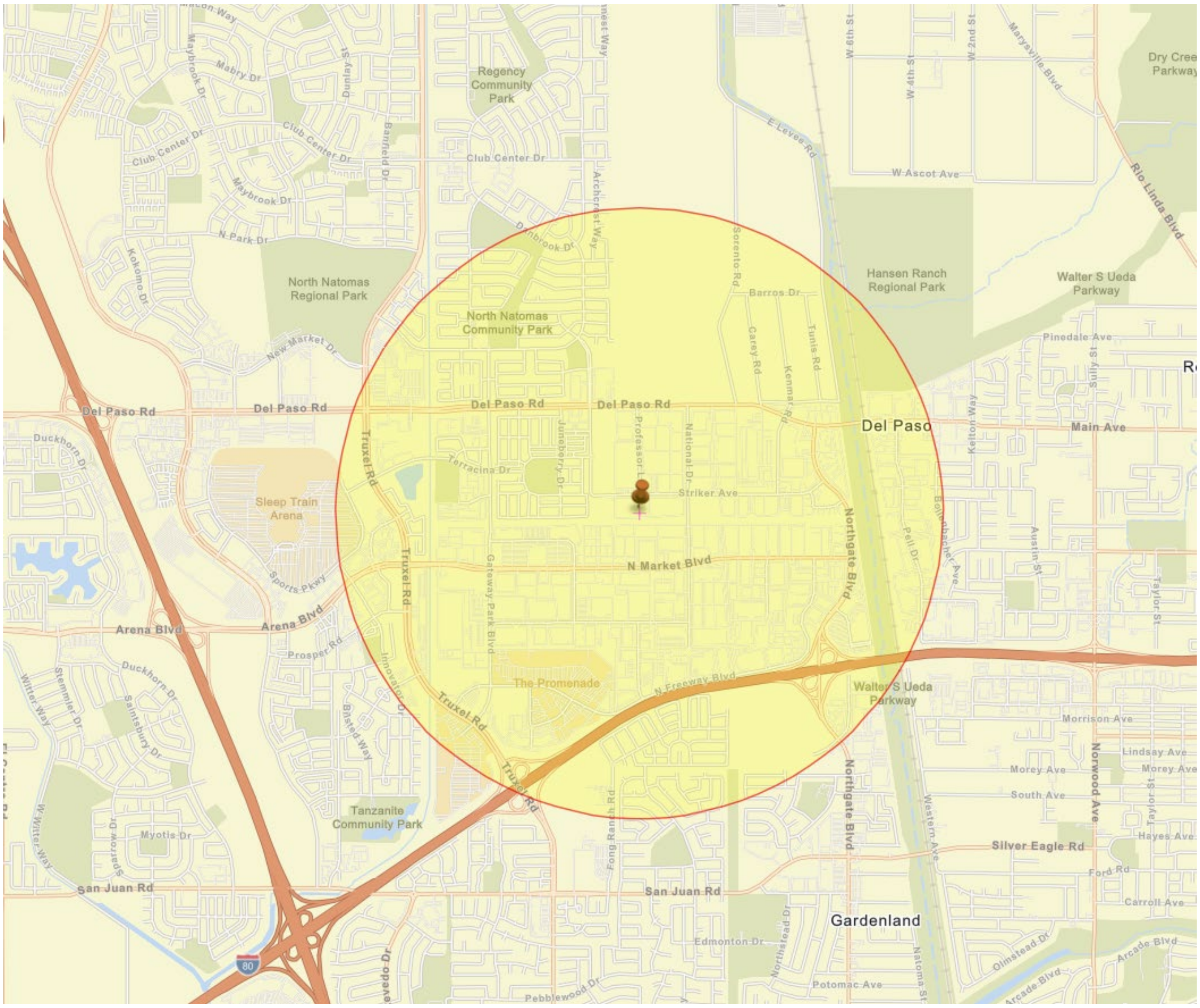
[7] Figure 4 shows DACs located within a 10-km radius around CA2 data center.
[8] U.S. Environmental Protection Agency (EPA), 2023. EJScreen Technical Documentation, https://www.epa.gov/system/files/documents/2023-05/LIDAC%20Technical%20Guidance%20-%20Final_2.pdf. pg. 4. Accessed April 2, 2024.
[9] CEJST considers communities disadvantaged if they are in census tracts that meet the thresholds for at least one of tool's categories of burden, or if they are on land within the boundaries of a federally recognized tribe. Source: https://screeningtool.geoplatform.gov/en/methodology#3/33.47/-97.5. Accessed April 2, 2024.
[10] U.S. Environmental Protection Agency (EPA), 2023. EJScreen Technical Documentation, https://www.epa.gov/ejscreen/ejscreen-map-descriptions. Accessed April 2, 2024.

Figure 2. 2-km Radius Around CA2 Data Center

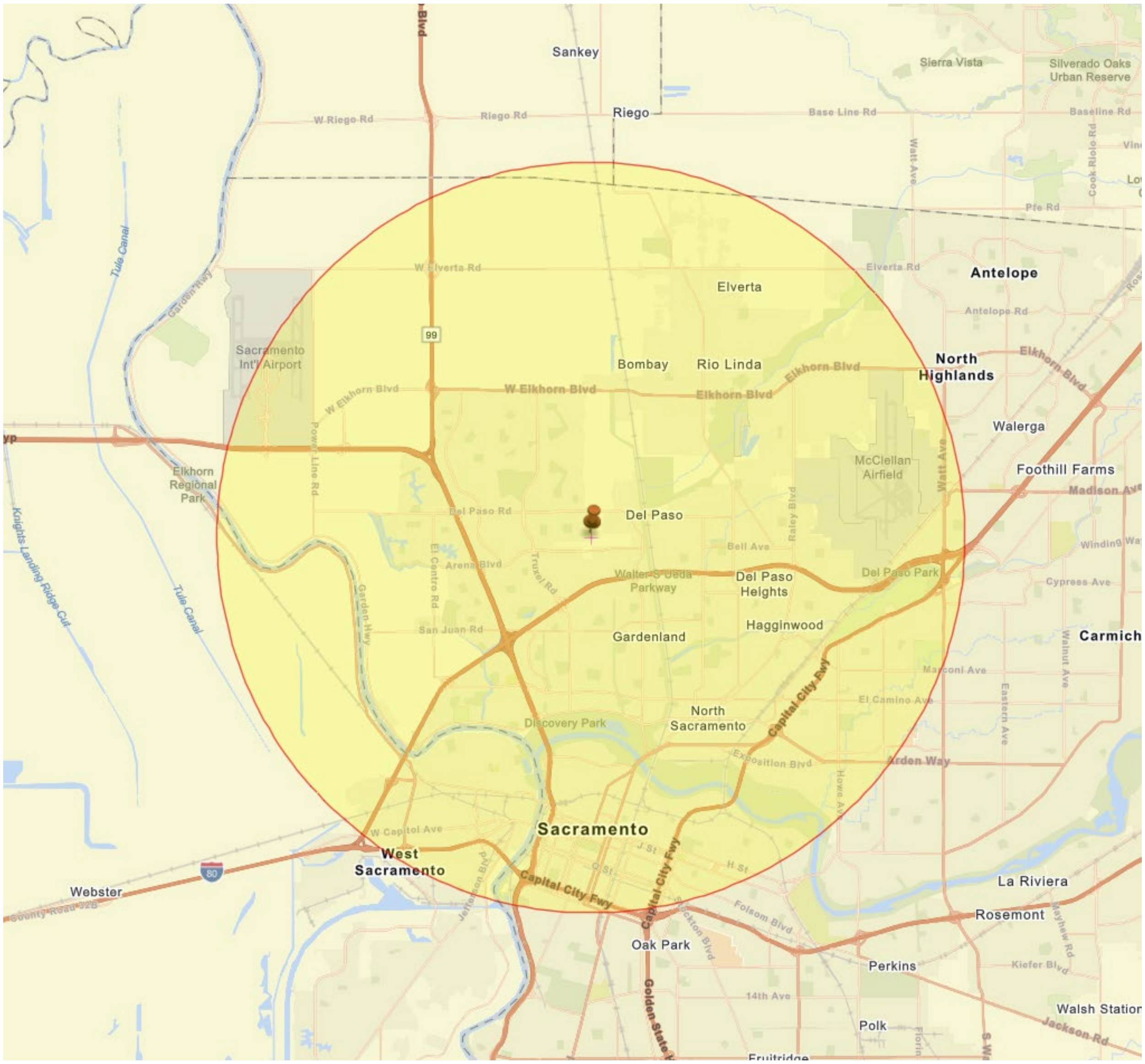


Source: EPA EJScreen[11]

Figure 3 below overlays a 10-km circle around the data center. Using a 10-km radius around the data center captures a greater share of the potentially affected population and is consistent with the air quality analysis discussed above.

[11] United States Environmental Protection Agency. 2023 version. EJScreen. www.epa.gov/ejscreen. Retrieved December 5, 2023.

Figure 3. 10-km Radius Around CA2 Data Center



Source: EPA EJScreen[12]

Using these custom boundaries, ICF extracted the demographic and environmental data from EJScreen to identify the potential EJ vulnerabilities for the population living around the data center. Table 5 indicates the age ranges of population in the 2-km and 10-km radii from the data center.

[12] EJScreen. www.epa.gov/ejscreen. Retrieved December 5, 2023.

Table 5. Distribution of the Affected Population by Age

Age	2-km Radius	10-km Radius
Total Population	**11,223**	**327,136**
1 to 4	7%	6%
5 to 17	21%	17%
18 to 64	63%	65%
65 and up	9%	12%

Source: EPA EJScreen[13]

As shown in Table 5, the largest proportion of population exposed to any potential EJ concerns falls within the 18-64 age group, followed by the 5-17 age group. Note that 28 percent of the total population exposed to any potential EJ concerns in the 2-km radius fall within the 1-17 age group. This age group consists of young children who are likely to be more vulnerable to air toxins.

Table 6. Distribution of the Affected Population by Race

Race	2-km Radius	10-km Radius
Total Population	**11,223**	**327,136**
White	24%	37%
Black	14%	11%
American Indian	0%	0%
Asian	30%	15%
Hawaiian/Pacific Islander	2%	1%
Other race	0%	1%
Two or more races	6%	6%
Hispanic	24%	30%

Source: EPA EJScreen[14]

Table 6 shows the breakdown of the population by race in the 2-km and 10-km radius. Race information is broken down to show population that identify themselves as White, people of color (Black, American Indian, Asian, Hawaiian/ Pacific Islander or other race), or belong to the Hispanic ethnicity.[15] In the area around 2-km radius of the data center, the population that identifies as Asian makes up the majority of the population followed by Hispanic and White. The outlook is slightly different in the area around 10-km of the data center, where the population that identifies as White consists of 37 percent of the total population followed by Hispanic at 30 percent.

[13] EJScreen. www.epa.gov/ejscreen. Retrieved November 11, 2023.
[14] EJScreen. www.epa.gov/ejscreen. Retrieved November 11, 2023.
[15] EJScreen defines people of color as individuals who list their racial status as a race other than white alone and/or list their ethnicity as Hispanic or Latino. Source: U.S. Environmental Protection Agency (EPA), 2023. EJScreen Technical Documentation, https://www.epa.gov/system/files/documents/2023-06/ejscreen-tech-doc-version-2-2.pdf. Accessed December 5, 2023.

Table 7. Demographics of the Affected Population

Demographic Indicators	2-km Radius	10-km Radius	State Average
Total Population	**11,223**	**327,136**	
People of Color[16]	76%	63%	**61%**
Low Income	22%	35%	**28%**
Unemployed[17]	6%	7%	**7%**
Limited English Speaking Households[18]	8%	6%	**9%**
Population with Less Than High School Education[19]	10%	14%	**16%**

Source: EPA EJScreen[20]

As shown in Table 7, 22 percent of the population in the 2-km radius is low-income. Low-income population is defined as those whose household income is less than twice the federal poverty level in the past 12 months. At the 10-km radius, the low-income population increases to 35 percent, higher than the state average of 28 percent. In the 2-km radius around the data center, 76 percent of the population is of color, higher than the state average of 61 percent. However, in the 10-km radius, the percentage of people of color decreases to 63 percent, implying that the population closest to the data center is likely to have a higher proportion of people of color than in the wider radius.

In terms of employment, 6 percent of the population in the 2-km radius is unemployed, which is close to the state average of 7 percent. And according to the education metric, the population in the 2-km and 10-km radius have a lower share of people with less than a high school education compared to the state average. This shows that the area around the data center is ahead in terms of high school educated population as compared to the state average. Thus, while the population likely to be mostly affected by any potential exceedances at the data center may not have any distinguishable difference with the wider state population in terms of their educational attainment and employment status, they are more likely to have been people of color.

Figure 4 below shows DACs located within a 10-km radius around the data center. Census tracts designated as DACs are highlighted in orange. These census tracts are designated as DACs based on the DAC criteria set by EPA as mentioned above. Based on the figure, there are several DACs within the 10-km radius around the data center. This indicates a large share of the population in the area is vulnerable and could be disproportionately affected by any potential EJ concerns that might have been exacerbated by any exceedances at the data center.

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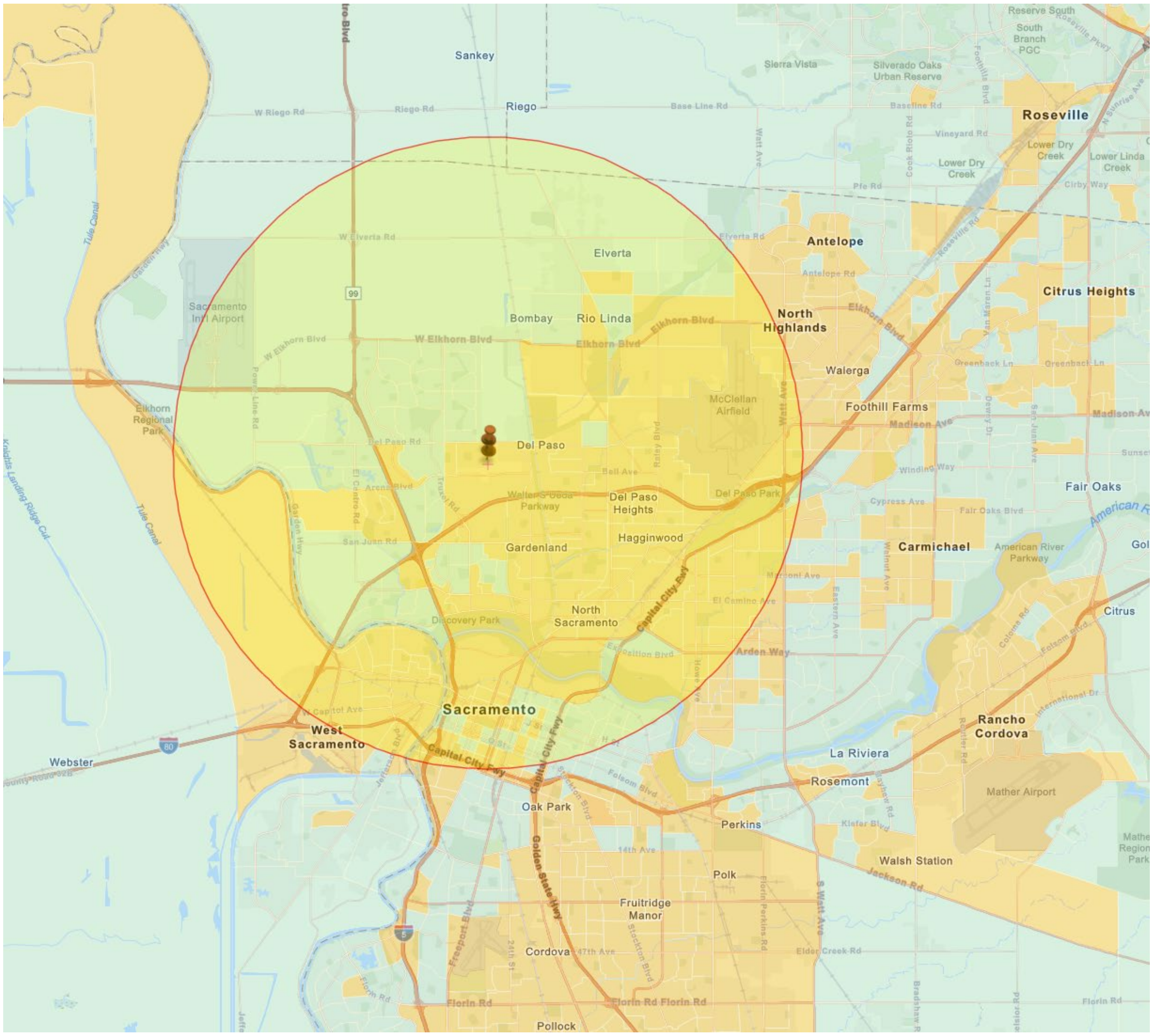
[16] People of color are individuals who list their racial status as a race other than white alone and/or list their ethnicity as Hispanic or Latino. Source: EPA, EJScreen Technical Documentation, https://www.epa.gov/system/files/documents/2023-06/ejscreen-tech-doc-version-2-2.pdf. Accessed April 2, 2024.
[17] Unemployed is defined as individuals who did not have a job during the reporting period, made at least one specific active effort to find a job, and were available to work. Source: EPA, EJScreen Technical Documentation, https://www.epa.gov/system/files/documents/2023-06/ejscreen-tech-doc-version-2-2.pdf. Accessed April 2, 2024.
[18] EJScreen defines limited English-speaking households as a household in which no one over the age of 14 years old speaks only English or speaks a non-English language and speaks English "'very well'" as reported in the American Community Survey. Source: EPA, EJScreen Technical Documentation, https://www.epa.gov/system/files/documents/2023-06/ejscreen-tech-doc-version-2-2.pdf. Accessed April 2, 2024.
[19] EJScreen defines less than high school education as people 25 years or older who did not receive a high school diploma. Source: EPA, EJScreen Technical Documentation, https://www.epa.gov/system/files/documents/2023-06/ejscreen-tech-doc-version-2-2.pdf. Accessed April 2, 2024.
[20] EJScreen. www.epa.gov/ejscreen. Retrieved November 9, 2023.

Figure 4. DACs Within 10-km Radius Around CA2 Data Center



Source: EPA EJScreen[21]

3.2 Combining Demographic Information with Environmental Indicators

To understand the EJ vulnerabilities of the population living around the data center, ICF analyzed the various environmental pollutant indicators from EJScreen and compared their values with the state averages. Table 8 below shows the values of the various environmental indicators of interest (see Table 8 notes for definitions of these pollutant indicators) around the 2-km and 10-km radii of the data center.

[21] EJScreen. www.epa.gov/ejscreen. Retrieved December 5, 2023.

Table 8. Environmental Indicators Data

Environmental Indicators	2-km Radius	10-km Radius	State Average
Particulate Matter (PM 2.5 in ug/m3)	8.52	8.46	**8.65**
Ozone (ppb)	63.3	63.8	**65.9**
Diesel PM (ug/m3)	0.217	0.243	**0.26**
Air Toxics Cancer Risk (risk per MM)	33	38	**27**
Air Toxics Respiratory Hazard Index	0.5	0.56	**0.34**
Toxic Releases to Air	45	57	**780**
Traffic Proximity and Volume	100	540	**510**
Lead Paint	0.026	0.32	**0.31**
Superfund Proximity	0.11	0.14	**0.17**
RMP Proximity	0.92	0.51	**0.57**
Hazardous Waste Proximity	2.9	4.4	**5.9**
Underground Storage Tanks	0.04	1.5	**1.5**
Wastewater Discharge	2.9	1.2	**4**

Source: EPA EJScreen[22]

- Particulate Matter (PM2.5 in ug/m3) —PM2.5 levels in the air, measured in µg/m3 annual average
- Ozone—Ozone annual mean top 10 of daily maximum 8-hour concentration in air
- Diesel PM (ug/m3) —Diesel particulate matter level in the air, measured in µg/m3
- Air Toxics Cancer Risk (risk per MM)—Lifetime cancer risk from inhalation of air toxics
- Air Toxics Respiratory HI—Air toxics respiratory hazard index (ratio of exposure concentration to health-based reference concentration)
- Toxic Releases to Air Indicator (TRI)—Risk Screening Environmental indicators (RSEI) modeled toxicity-weighted concentrations in air of TRI listed chemicals
- Traffic Proximity and Volume—Count of vehicles at major roads within 500 meters, divided by the distance in meters (daily traffic count/distance to road)
- Lead Paint—Percent of housing units built pre-1960, as indicator of potential lead paint exposure
- Superfund Proximity—Count of proposed and listed NPL sites within 5-km, divided by distance in km (site count/km distance)
- RMP Facility Proximity—Count of RMP (potential chemical accident management plan) facilities within 5-km, divided by distance in km (facility count/km distance)
- Hazardous Waste Proximity—Count of hazardous waste management facilities within 5-km, divided by distance in km (facility count/km distance)
- Underground Storage Tanks—Weighted count of USTs per sq. km
- Wastewater Discharge—Toxicity-weighted stream concentrations at stream segments within 500 meters, divided by distance in km (toxicity-weighted concentration/m distance)

As shown in Table 8, the area within the 2-km and 10-km radii of the data center has higher values for Air Toxics Cancer Risk and Air Toxics Respiratory Hazard Index compared to the state averages. This implies the population near the data center is more vulnerable with respect to these two environmental indicators compared to the rest of the state. According to the data from EPA's EJScreen, 11 percent of the population ages 18 and older in the 10-km radius of the data center have asthma, while the state's average is 9.5 percent. Since ozone can reduce lung function and aggravate conditions like asthma, the likely exceedance of ozone emissions during the 5-day period, as mentioned in the air quality analysis above, has the potential to increase the risk of asthma-related health effects during this period.

3.3 Conclusion – Environmental Justice Analysis

Using the data from EPA's EJScreen, it appears the population in the 18-64 age group in the region around the CA2 data center are more vulnerable to EJ concerns compared to the rest of

[22] EJScreen. www.epa.gov/ejscreen. Retrieved December 5, 2023.

California. As discussed in the air quality analysis above, DOE's emergency authorization under Section 202(c) of the Federal Power Act, allowed increased operations of the data center that appears to have exceeded the permit levels and may have caused a violation of the 1-hour NO_2 CAAQS. Analyzing the *baseline*, *business-as-usual* EJ concerns for the population around these data centers indicate that a significant portion of the population surrounding the CA2 data center could be considered to be vulnerable to EJ concerns since there is a large presence of minority population groups, belonging to DAC, with limited socioeconomic opportunities, who could be more susceptible to higher levels of pollution under those baseline conditions. As discussed in Section 2.4.5, further review of meteorological conditions and potentially air dispersion modeling for the relevant time period likely would be required to refine the air quality analysis which would help to determine whether the EJ concerns were exacerbated during those 5 days covered by the 202(c) authorization. BANC is not aware of any action taken by SMAQMD regarding NTT's permit exceedances.

4 Review of BANC Outreach and Emergency Communications

Review of BANC's Community Notice

Order No. 202-22-2 required BANC to "*inform all affected communities where the Covered Resource operates that BANC has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explain clearly what the Order allows BANC to do, including potential impacts to the community where the Covered Resource is located and communities adjacent to the Covered Resource".*[23] BANC enlisted the support of the Sacramento Municipal Utility District (SMUD) to inform affected communities where the Covered Resource operates.

Emergency communications consist of four main components: 1) pre-emergency activities and preparations, 2) creating holding statement(s) during the emergency, 3) monitoring media and stakeholders during the emergency, and 4) post-emergency evaluations. ICF reviewed BANC's summary community outreach efforts related to the order period against this four-part framework. Our review, per the Statement of Work, was limited to documents provided by DOE and available on at the following link: Federal Power Act Section 202(c): BANC September 2022 | Department of Energy. The only additional document identified relative to community outreach is a 17-page document with the name "Final Report of the Balancing Authority of Northern California". Our comments are based on this document, specifically the section titled - Community Notice by Sacramento Municipal Utility District (SMUD) (see Appendix A).

4.1 Review of BANC's Community Engagement

In the summary of its community notice, BANC indicates that "SMUD posted a news release[24] on its website explaining that DOE had issued an order that allowed BANC to call on the Covered Resource through September 8, 2022, under certain conditions." Additionally, "after the issuance of the September 4 order, SMUD contacted customers in near proximity to the Covered Resource via automated phone calls."

[23] https://www.energy.gov/sites/default/files/2022-09/Order%20202-22-2%20Final%20for%20BANC%20.pdf
[24] https://www.smud.org/en/Corporate/About-us/News-and-Media/2022/2022/US-Department-of-Energy-power-generation-order

Based upon a review of BANC's community notice in support of DOE's Emergency Order No. 202-22-2, we found the approach — shown in the Appendix — to be compliant but lacking in efficacy.

In reviewing the communications and outreach channels that BANC employed to inform the impacted citizens of the Emergency Order, it is our assessment that the news release, posted only on the SMUD website, and subsequent automated phone calls were insufficient to reach a large portion of the impacted customers. Based upon an analysis from Critical Mention, it appears that the news release was not picked up by any media outlets, thus further limiting distribution to impacted customers.

Because of the limited information reported, it is unclear if there was additional targeted outreach, such as in-language communications, community event outreach, or communications specifically targeted at hard-to-reach or disadvantaged communities. As such, we offer the following information on best-practices to build a robust and effective emergency response communications strategy.

4.1.1 Strengthening Community Engagement

BANC's outreach effort appears to be only "one-way" communications. The Community Notice did not detail any methods or channels for questions or discussion among the communities or communicating partners. Our typical recommendation would be to include some follow-up with stakeholders to ensure they received and were able to, and did, disseminate the Emergency Order information. These partner organizations may also have events and other opportunities in which BANC could participate to best reach affected communities.

Further, none of the proposed communication tactics identified modes or timing for stakeholder feedback or dialogue, for example, contacting environmental justice organizations every two weeks after initial outreach, or contacting local government weekly after initial outreach. BANC may have planned to solicit such feedback in a separate effort, but nothing in BANC's community notice noted that any feedback or dialogue with stakeholders would happen. This kind of two-way dialogue is helpful in ensuring the impacted communities 1) understand the details of the Emergency Order, and 2) are given an opportunity to ask questions and provide feedback. BANC may have also considered holding community meetings in the impacted areas to allow for stakeholder input; such meetings would also likely garner media coverage.

Additional channels that may add important coverage would be to leverage more of the commercial media market – using public access television channels, as well submitting press releases and information to radio and television networks, to gain earned media coverage that would reach a broader segment of the impacted communities.

There may be language or cultural considerations for reaching the impacted communities that BANC needs to consider in its outreach plans. This was unclear in the current outreach effort information.

4.2 Additional Best Practices for Community Engagement during Emergencies

As previously referenced, successful emergency communications contain four main activities: 1) pre-emergency preparations, 2) creating a holding statement, 3) monitoring media and stakeholders during the emergency, and 4) post-emergency evaluations. We offer the following observations based on these standard practices in emergency communications.

4.2.1 Pre-emergency Preparatory Activities

Primarily, we recommend having several systems and approaches developed prior to crisis events, so that when emergencies occur there are previously approved procedures and communications at the ready, saving time and expediting responses.

For the sake of speed, an organization should proactively draw up a template with potential emergency scenarios, designate the appropriate channels for communication, and then plug in the necessary information if the actual incident occurs. Emergency response communications generally need to be sent to various people in multiple departments. Potential audiences include government agencies and offices (state and local), specific companies or industries impacted by the incident, media, the community, elected officials, and other authorities. The need for cultural considerations e.g., language or manner of contact should also be identified. Modes and processes for follow-up with the various stakeholders during the emergency should also be determined, acknowledging the need for flexibility during the event.

There are unique features of each emergency that may require some communications to be tailored to that event. It is certainly possible that BANC had pre-prepared lists of entities that it tailored when it informed the community in which the covered resources are located about the emergency order. Based on best practice, BANC may consider an annual review of their emergency communications protocol in addition to annual automated messaging tests. BANC may also consider regularly reviewing and updating stakeholder contact information.

4.2.2 Create a Holding Statement

None of the BANC materials indicated that it had pre-prepared holding statements for this emergency order. In an emergency, when minutes count, saying “no comment” in the first wave of press coverage is not an option. To avoid a panic situation when crafting and securing internal approval for an initial response to media or community inquiries, the best practice is to have a holding statement at-the-ready.

The holding statement does not need to be lengthy, nor does it need to address all aspects of what the media is seeking. A few brief sentences grounded in accuracy, BANC’s values, and empathy should be the framework for the statement—and it should be issued quickly. Being timely is critical to controlling the narrative.

BANC may not have had all the information it needed but could let the media and public know that more information will be shared as it becomes available. This approach buys valuable time and credibility with key reporters and important stakeholders. The key is to communicate that the entity is on top of the situation and not making the situation worse.

To implement this strategy, a set of holding statements that address the most likely issues or emergencies should be drafted and pre-cleared through leadership. This will compress the amount of time needed to modify and secure final approval for the statement when the emergency occurs.

Increasingly, organizations communicate directly with affected communities through social media. Similar holding statements created for social media channels and directed at these communities could be developed and pre-cleared through leadership.

4.2.3 Media and Stakeholder Monitoring

It is not apparent that BANC established in advance of the emergency guidance on how media and community stakeholder monitoring would be executed. Once BANC executed its media plan, it would have had to start monitoring the media and communities' responses.

It is vital to establish a protocol in advance of any significant issue or emergency that guides how media and stakeholder monitoring/listening will be executed. The ability to evaluate and review the statements and information being articulated by stakeholders and presented through media channels will inform sound decision making as to whether to issue a holding statement, conduct a press interview, post an update on social media—or not comment publicly.

Each monitoring report should capture and summarize the sources, key articles and stories, amplification, tone/sentiment, reach of the journalists and stakeholders, and patterns of coverage from one report to the next. As social media becomes increasingly important and by-passes traditional media, it is also important to monitor the social media channels of communities affected by the emergency order. It is very possible that BANC had such established monitoring plans, however, they were not included in the materials available for us to review.

4.2.4 Analyzing Effectiveness of Communication

It is not apparent that BANC had a plan to analyze the effectiveness of its communication plan post-emergency. We did not have any materials that discussed whether or how such analysis was done.

It is useful to analyze the effectiveness of communications and engagement during the emergency (as much as possible) and certainly after the event. Providing emergency media coverage and stakeholder/community feedback on social media or through other channels could give BANC information on the effectiveness of its outreach. Such information received in a timely manner could allow for changes in outreach and/or communication efforts.

After an emergency, BANC should evaluate the effectiveness of its outreach. How did the communities and stakeholders feel about the communications? Did they feel informed in a timely manner? Were all the people impacted reached with the information they needed? What was done well? What could have been better? New insights from this post-emergency analysis that lead to improvements should be incorporated into subsequent emergency outreach plans.

4.3 Conclusions

Based on our review, we found BANC's community notice for DOE Order No. 202-22-2 to be compliant, but lacking efficacy. A formal emergency communications plan that establishes protocols for managing emergency situations would benefit BANC. The plan can help establish clear protocols for quickly developing an effective and comprehensive approach to engage and properly inform the impacted communities and stakeholders for emergency events.

The listed distribution channels were inadequate and could have included more public access and earned media channels. It was also unclear if the executed channels effectively reached a majority of impacted customers.

Tailored media, stakeholder, and community engagement are key components of successful emergency operations. It is possible that BANC has a detailed outreach and/or emergency communications plan (not included in the package of materials posted on the DOE website) that includes the best-practices that we provide above.

APPENDIX A

The following information replicates in its entirety the community notice within BANC's Final Report of the Balancing Authority of Northern California.

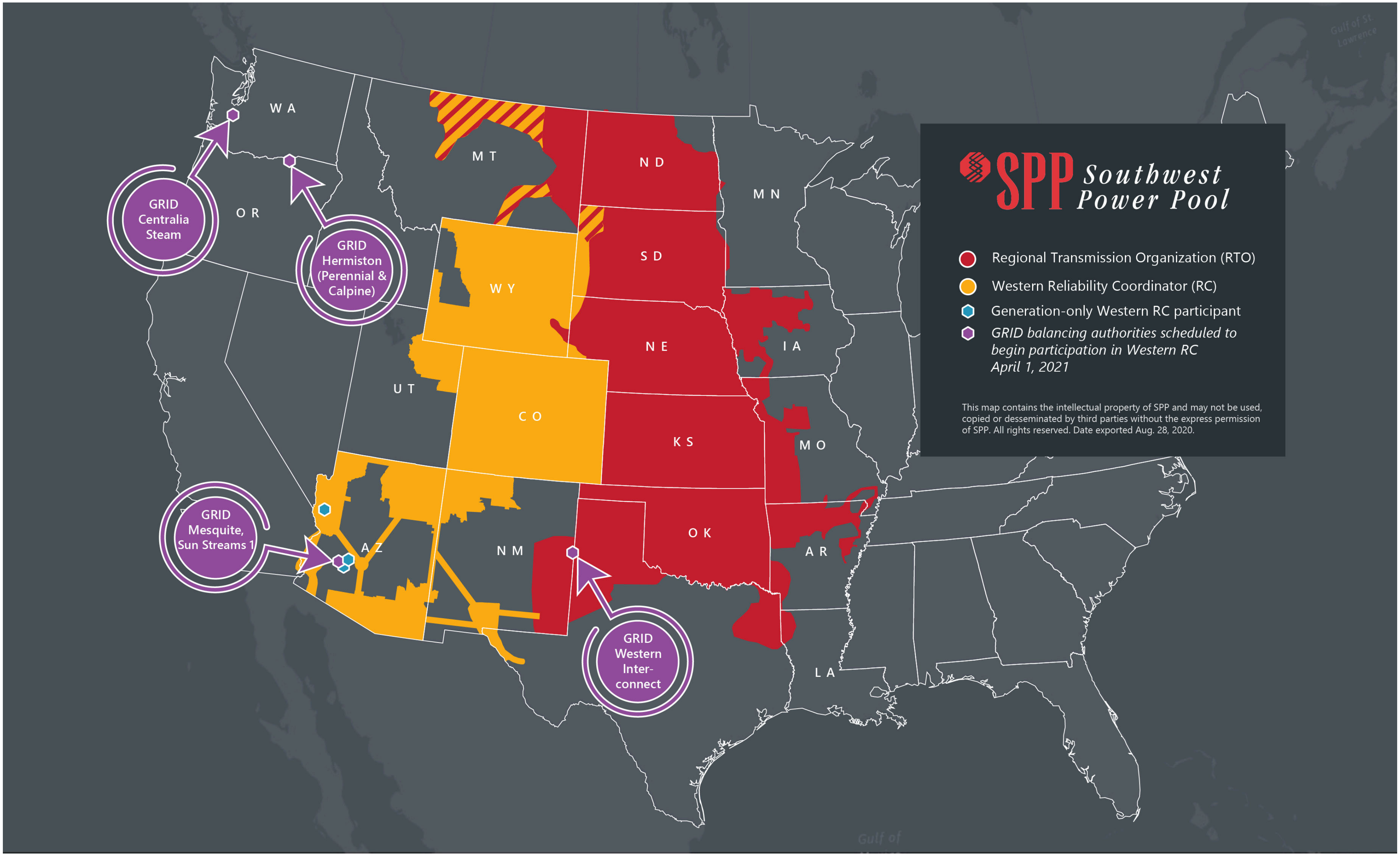
Community Notice by Sacramento Municipal Utility District (SMUD)

Upon issuance of DOE's Order No. 202-22-2 on September 4, 2022, BANC enlisted the support of the Sacramento Municipal Utility District (SMUD) to inform affected communities where the Covered Resource operates.

On September 4, 2022, SMUD posted a news release on its website explaining that DOE had issued an order that allowed BANC to call on the Covered Resource through September 8, 2022, under certain conditions. The news release specified that the Covered Resource may be operated only during a grid emergency between the hours of 2 PM and 10 PM. It also explained that the order authorized generation that would otherwise be constrained by federal air permit limits.

On September 8, following the issuance of DOE's Amendment Number 1 to Order No. 202-22-2, SMUD posted an update on its website explaining the changes resulting from the modified order. In addition, after the issuance of the September 4 order, SMUD contacted customers in near proximity to the Covered Resource via automated phone calls. The calls, which were also placed on September 4, explained that the Covered Resource was participating in a state program to ease stress on the power grid and, if needed, may be called on to run backup generators between the hours of 2 PM and 10 PM.

EXHIBIT 92



SPP Southwest Power Pool
Regional Transmission Organization (RTO)
Western Reliability Coordinator (RC)
Generation-only Western RC participant
GRID balancing authorities scheduled to begin participation in Western RC April 1, 2021
This map contains the intellectual property of SPP and may not be used, copied or desseminated by third parties without the express permission of SPP. All rights reserved. Date exported Aug. 28, 2020.
GRID Centralia Steam
GRID Hermiston (Perennial & Calpine)
GRID Mesquite, Sun Streams 1
GRID Western Inter-connect
WA
OR
MT
ND
SD
MN
WY
IA
NE
UT
CO
KS
MO
OK
AR
AZ
NM
LA

EXHIBIT 93

NCR ID:	**NCR11393**		
Registered Entity Name:	**Gridforce Energy Management, LLC**		
Registered Entity Acronym:	**GRID**		
Reliability Standards Scope:	**Operations & Planning (FERC Order 693) Standards**		
Compliance Monitoring Process:	**Compliance Audit**		
Distribution:	**Public Version. Confidential Information Has Been Removed, Including Privileged and Critical Energy Infrastructure Information.**		
Regional Entity:	**Western Electricity Coordinating Council (WECC)**		
Date of Opening Presentation:	**September 24, 2019**	Date of Closing Presentation:	**September 26, 2019**
Date of Report:	**December 20, 2019**	IP Year:	**2019**
Potential Noncompliance:	**None (zero)**		
Jurisdiction:	**United States**		

Table of Contents

Executive Summary

WECC conducted an Operations & Planning (FERC Order 693) Standards Compliance Audit of Gridforce Energy Management, LLC (GRID), NCR ID NCR11393 from September 24, 2019 to September 26, 2019.

At the time of the Compliance Audit, GRID was registered for the function of Balancing Authority (BA).

The Reliability Coordinator (RC) for GRID is Peak Reliability (PEAK). The Transmission Operators (TOP), Planning Authorities (PA), Transmission Planners (TP), and Resource Planners (RP) for GRID are Bonneville Power Administration (BPA), Public Service Company of New Mexico (PNM), and Salt River Project Agricultural Improvement and Power District (SRP).

The Compliance Audit team (team) evaluated GRID for compliance with Seven (7) Operations and Planning requirements for the 2019 Electric Reliability Organization (ERO) Enterprise Compliance Monitoring and Enforcement Program (CMEP). The team assessed compliance with the NERC Reliability Standards for the period of June 29, 2016 to June 17, 2019.

GRID submitted evidence for the team's evaluation of compliance with requirements. The team reviewed and evaluated all evidence provided to assess compliance with Reliability Standards applicable to GRID at this time.

Based on the evidence provided, no findings were noted for the Reliability Standards and applicable Requirements in scope for this engagement.

There were no open Mitigation Plans; therefore, none were reviewed by the team.

The WECC Compliance Audit team lead certifies that the team adhered to all applicable requirements of the NERC Rules of Procedure (ROP) and Compliance Monitoring and Enforcement Program (CMEP).[1]

Compliance Audit Process

The Compliance Audit process steps are detailed in the NERC ROP. The CMEP generally conforms to the United States Government Auditing Standards and other generally accepted audit practices.

[1]This statement replaces the Regional Entity Self-Certification process.

Objectives

All registered entities are subject to compliance assessments with all Reliability Standards applicable to the functions for which the registered entity is registered[2] in the Region(s) performing the assessment. The Compliance Audit objectives are designed to:

- Provide reasonable assurance of compliance to the identified applicable Reliability Standards;
- Review compliance with applicable NERC Reliability Standards identified for 2019 ERO Enterprise CMEP;
- Review evidence of self-reported violations and previous self-certifications;

Scope

The scope of this Compliance Audit considered the NERC Reliability Standards from 2019 ERO Enterprise CMEP Implementation Plan and Inherent Risk Assessment (IRA) of GRID completed by WECC. In addition, the scope of the Compliance Audit included a review of Mitigation Plans or Remedial Action Directives that were open during the Compliance Audit.

The Reliability Standards and Requirements in-scope for this Compliance Audit are illustrated in **Table 2** Compliance Audit Scope.:

Table 2: Compliance Audit Scope

Standards	Requirement(s)
COM-001-3	R9
COM-002-4	R4
COM-002-4	R6
EOP-008-2	R1
EOP-008-2	R6
EOP-011-1	R2
TOP-010-1(i)	R4

The team did not expand the scope of the Compliance Audit beyond what was stated in the notification package.

Controls

The team reviewed GRID's related internal controls associated with some of the NERC Reliability Standards in scope.

Confidentiality and Conflict of Interest

[2]NERC ROP, Appendix 4C, Section 3.1, Compliance Audits.

Confidentiality and conflict of interest of the team are governed under the Regional Delegation Agreements with NERC, and Section 1500 of the NERC ROP[3] . GRID was informed of Western Electricity Coordinating Council (WECC)'s obligations and responsibilities under the agreement and procedures. The work history for each team member was provided to GRID, which was given an opportunity to object to a team member's participation on the basis of a possible conflict of interest or the existence of other circumstances that could interfere with a team member's impartial performance of duties. GRID had not submitted any objections by the stated objection due date based on the ROP and accepted the team member participants without objection. There were no denials or access limitations placed upon this team by GRID.

Methodology

The ERO Compliance Monitoring and Enforcement Manual (Manual)[4] documents the ERO Enterprise's current approaches used to assess a registered entity's compliance with the NERC Reliability Standards. The ERO Enterprise uses, "to the extent possible, the Generally Accepted Auditing Standards (GAAS), the Generally Accepted Government Auditing Standards (GAGAS), and standards sanctioned by the Institute of Internal Auditors, as guidance for performing activities under the Compliance Monitoring and Enforcement Program (CMEP)."[5] While the ERO Enterprise does not necessarily perform compliance monitoring activities that must be in accordance with these standards recognized in the United States, the ERO Enterprise uses these standards as framework to conduct compliance monitoring activities under the CMEP, and recognizes that these standards provide information used in oversight, accountability, transparency, and improvements in ERO Enterprise operations.

The Western Electricity Coordinating Council (WECC) provided GRID with a Compliance Audit notification package to commence the Compliance Audit. GRID provided evidence at the time requested, or as agreed upon, by Western Electricity Coordinating Council (WECC). The team reviewed the evidence submitted by GRID and assessed compliance with the requirements of the applicable Reliability Standards. Additional evidence could be submitted until the agreed-upon deadline prior to the exit briefing. After that date, only data or information that was relevant to the content of the report or its finding could be submitted with the agreement of the team lead.

The team reviewed documentation provided by GRID and requested additional evidence and sought clarification from subject matter experts during the Compliance Audit. The evidence submitted in the form of policies, procedures, emails, logs, studies, data sheets, etc. were validated, substantiated, and

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[3] See NERC ROP

[4] http://www.nerc.com/pa/comp/Pages/ERO-Enterprise-Compliance-Auditor-Manual.aspx

[5] NERC ROP, Section 1207 and 126 FERC 61,038, Paragraph 3

cross-checked for accuracy as appropriate. Where sampling is applicable to a requirement, the sample set was determined by a statistical methodology, along with professional judgment as mentioned in the Manual.

The findings were based on the facts and documentation reviewed, the team's knowledge of the Bulk Electric System (BES), the NERC Reliability Standards, and professional judgment. All findings were developed based upon the consensus of the team.

Company Profile

Gridforce Energy Management, LLC is a holding company providing Balancing Authority Services under multiple NERC-registered Balancing Authorities inclusive of the NERC-registered entity GRID. GRID as a generation-only Balancing Authority (BA) balances approximately 3,155 MW of generation. GRID balances generation amounts indicated per the following NERC Registered Entity generation entities and generation resource amounts located within the Western Interconnection:

- Calpine Hermiston (NCR00060) (615 MW)
- Perennial Hermiston (NCR5181) (240 MW)
- Centralia Generation Plant (NCR05533) (1,400 MW)
- Mesquite Power (NCR05235) (600 MW)
- Broadview Wind Project (NCR11714) (300 MW)

Compliance Audit Findings

Based on the results of this Compliance Audit, no findings were noted for the Reliability Standards and applicable Requirements in scope for this engagement.

Compliance Culture

GRID's compliance culture was not formally reviewed by the team as part of the compliance audit. Assessment of GRID's internal compliance program will be reviewed by WECC Enforcement on an as-needed basis.

WECC Contact Information

Any questions regarding this Compliance Audit report can be directed to:

WECC

155 North 400 West, Suite 200
Salt Lake City, UT 84103

On behalf of WECC, this report was prepared and reviewed by:

Compliance Audit Team Lead	Date
Senior Compliance Auditor, Operations and Planning	November 4, 2019
Management Rep	**Date**
Compliance Monitoring Manager, Operations and Planning	November 4, 2019

Appendix 1: Compliance Audit Participants

Appendix Table 1: Compliance Audit Team and Appendix Table 2: GRID Participants list all personnel from the team and GRID who were directly involved during the meetings and interviews.

Appendix Table 1: Compliance Audit Team		
Role	Title	Entity
Audit Team Lead	Senior Compliance Auditor	WECC
Team Member	WECC Consultant	WECC
Team Member	Senior Compliance Auditor	WECC
Team Member	Compliance Auditor	WECC
Team Member	Compliance Program Coordinator	WECC

Appendix Table 2: GRID Participants	
Title	Entity
President	Gridforce
Director	Gridforce
Vice President	Gridforce
Security Engineer	Gridforce
System Operator	Gridforce
EMS Engineer 3	Gridforce

EXHIBIT 94

Department of Energy
Washington, DC 20585

Order No. 202-25-14

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists within the Western Electricity Coordinating Council (WECC) Northwest assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

Craig Station (Craig) is an electric generating facility in Craig, Colorado. Craig is operated by the Tri-State Generation and Transmission Association (Tri-State). Craig consists of three coal-fired generation units, Unit 1 (446.4 MW), Unit 2 (446.4 MW), and Unit 3 (534.8 MW), with a combined name plate capacity of 1427.6 MW.[3] Unit 1 and Unit 2 are co-owned by Tri-State, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy (co-owners).[4] Unit 3 is wholly owned by Tri-State. Unit 1 and Unit 2 began operations in 1980 and 1979 respectively. Unit 3 began operations in 1984. Unit 1 is slated to cease operations in December 2025. Unit 2 and Unit 3 are slated to retire in 2028.[5]

EMERGENCY SITUATION

In its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that in the WECC Northwest assessment area, which includes Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming, "[e]nergy variability is greater in the Northwest than other WECC regions due to the large share of wind and hydro in the portfolio." The LTRA notes that:

> [f]ive [gigawatts] of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar, wind, and [battery energy storage systems], further increasing variability in the portfolio. Given the retiring of baseload resources, supply chain issues preventing the construction of [battery energy storage systems] resources are a concern as they assist in meeting demand

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[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] U.S. Energy Information Administration, Form EIA-860, Schedule 3: Generator Data (2024), https://www.eia.gov/electricity/data/eia860/.
[4] Platte River Power Authority, Craig Units 1 & 2 (Yampa Project), https://prpa.org/generation/yampa-project/.
[5] As a coal-fired facility, it would be difficult for the Craig Unit 1 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Tri-State and co-owners were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

during shoulder periods where solar availability is dropping but loads remain high.[6]

The 2024 WECC Western Assessment of Resource Adequacy notes that peak demand in WECC's Northwest-Central subregion, which includes Colorado, is "forecast to grow by 8.5% over the next decade, from 33 GW in 2025 to 36 GW in 2034."[7] Meanwhile, WECC notes that most planned retirements are "baseload generation, such as coal, natural gas, and nuclear."[8]

Since 2019, 571.3 MW of coal-fired generating capacity across six units at three locations have retired in Colorado,[9] leading to a decline in the share of coal-generated electricity from 45% to 28%.[10] Looking forward, by 2029, about 3,700 megawatts of coal-fired generating capacity in Colorado is scheduled to retire according to the Energy Information Administration (EIA),[11] accounting for all but one coal-fired power plant in Colorado. In that same time frame, 675.6 MW of natural gas-fired generating capacity in Colorado will retire as well.[12] In 2025, intermittent wind accounted for over 5,300 MW of Colorado's electricity generating capacity.[13]

Executive orders issued by President Donald J. Trump on January 20, 2025 and April 8, 2025 underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[14] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[15] In a subsequent Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion

[6] *NERC 2024 Long-Term Reliability* Assessment, at 130 (Dec. 2024, corrected Jul. 11, 2025), https://www.nerc.com/globalassets/ourwork/assessments/2024-ltra_corrected_july_2025.pdf.

[7] Western Electricity Coordinating Council, *Western Assessment of Resource Adequacy 2024: Peak Demand by Subregion*, at 2, https://www.wecc.org/sites/default/files/documents/products/2024/WARA%202024%20Peak%20Demand%20by%20Subregion.pdf.

[8] Western Electricity Coordinating Council, *Western Assessment of Resource Adequacy*, https://feature.wecc.org/wara/.

[9] *Id.*

[10] U.S. Energy Information Administration, *Electricity Data Browser, Net Generation for All Sectors Annually from 2019-2024, State: Colorado, (last accessed Dec. 30, 2025),* https://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vtvp&geo=0000000000g&sec=g&freq=A&start=2019&end=2024&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0.

[11] U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of November 2025, Plant State: Colorado, Technology: Conventional Steam Coal* (Nov. 2025), https://www.eia.gov/electricity/data/eia860m/.

[12] U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of November 2025, Plant State: Colorado, Technology: Natural Gas Fired Combustion Turbine and Natural Gas Stream Turbine* (Nov. 2025), https://www.eia.gov/electricity/data/eia860m/.

[13] U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of November 2025, Plant State: Colorado, Technology: Onshore Wind Turbine* (Nov. 2025), https://www.eia.gov/electricity/data/eia860m/.

[14] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[15] *Id.*

of artificial intelligence data centers and increase in domestic manufacturing."[16]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[17]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[18] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Craig Unit 1 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes, and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

I have made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Craig Unit 1 shall be made available for operation until March 30, 2026.

Based on my determination of an emergency set forth above, I hereby order:

A. From December 30, 2025, Tri-State and the co-owners, shall take all measures necessary to ensure that Craig Unit 1 is available to operate at the direction of either Western Area Power Administration (WAPA)—Rocky Mountain Region Western Area Colorado Missouri (WACM) in its role as Balancing Authority or the Southwest Power Pool (SPP) West in its role as the Reliability Coordinator, as applicable.[19] Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry

[16] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[17] U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (Jul. 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[18] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

[19] U.S. Energy Information Administration, Form EIA-860, Schedule 3: Plant Data (2024), https://www.eia.gov/electricity/data/eia860/.

practices.

B. To minimize adverse environmental impacts, this Order limits operation of Craig Unit 1 to the times and within the parameters established in paragraph A. Tri-State shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Craig Unit 1 has operated in compliance with this Order.

C. All operations of Craig Unit 1 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By January 20, 2026, Tri-State, in coordination with the co-owners, is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Craig Unit 1 consistent with this Order. Tri-State and the co-owners shall also provide such additional information regarding the environmental and operational impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Tri-state and the co-owners are directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for Craig Unit 1 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Craig Unit 1 shall not be considered a capacity resource.

H. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 30, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 30, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 7:08PM EST on this 30th day of December 2025.

Chris Wright

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Colorado Public Utilities Commission
Chairman Eric Blank
Commissioner Megan Gilman
Commissioner Tom Plant

EXHIBIT 95

United States Department of Energy

Grid Deployment Office

Research Power Corporation
(formerly known as Centre Lane Trading Ltd.)
GDO Docket No. EA-365-C

Order Authorizing Electricity Exports to Canada

Order No. EA-365-C

October 21, 2025

Research Power Corporation
(formerly known as Centre Lane Trading Ltd.)
Order No. EA-365-C
Authorizing Electricity Exports to Canada

I. BACKGROUND

The Department of Energy (DOE or Department) regulates electricity exports from the United States to a foreign country in accordance with Federal Power Act (FPA) § 202(e) (16 U.S.C. § 824a(e)) and regulations thereunder (10 C.F.R. §§ 205.300 *et seq.*). This authority was transferred to DOE under §§ 301(b) and 402(f) of the DOE Organization Act (42 U.S.C. §§ 7151(b) and 7172(f)). On April 10, 2023, this authority was delegated to the DOE's Grid Deployment Office (GDO) by Redelegation Order No. S3-DEL-GD1-2023.

An entity that seeks to export electricity must obtain an order from DOE authorizing it to do so. Under FPA § 202(e), DOE "shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has discretion to condition the order as necessary or appropriate; the Department "may by its order grant such application in whole or in part, with such modifications and upon such terms and conditions as [DOE] may find necessary or appropriate, and may from time to time, after opportunity for hearing and for good cause shown, make such supplemental orders in the premises as it may find necessary or appropriate." *Id*.

A. Application for Export Authorization

Research Power Corporation (the Applicant) is a power marketer seeking renewal of its authorization to export electric energy to Canada, which was originally granted in Order No. EA-365-A on June 29, 2015, and subsequently renewed (EA-365-B) on April 29, 2020. On December 26, 2024, Centre Lane filed an application with DOE (Application or App.) requesting renewal of its export authority for a five-year term. App. at 1. On July 7, 2025, the Applicant notified DOE of its corporate name change from Centre Lane Trading Ltd. to Research Power Corporation.

According to the Application, Research Power Corporation (formerly known as Centre Lane Trading Ltd.) "is a Canadian Corporation with its principal place of business in Toronto, Ontario" that is "organized under the *Business Corporations Act* of the Province of Ontario, Canada." *Id*. The Applicant states that it "does not own, operate or control any generation or transmission facilities in any region, nor is it affiliated with any entity that owns, operates or controls generation or transmission facilities, and is not affiliated with any franchised public utility." *Id* at 1-2. The applicant further represents that it is a "[Federal Energy Regulatory Commission]-authorized power marketer engaging in the purchase and sale of physical and/or virtual energy in the Day-ahead and Real-time Markets of various Independent System Operators and Regional Transmission Organizations." App at 2.

Research Power Corporation represents that it "has no electric power supply system on which the proposed exports could have a reliability, fuel use system or stability impact." App. at 3. The Applicant states that it "has no obligation to serve native load usually associated with a franchised service area, and, thus, the exports proposed by [Research Power Corporation] will not impair its ability to meet current and prospective power supply obligations." *Id.* The Applicant further affirms that it "will purchase power to be exported from a variety of sources such as power marketers, independent power producers, or U.S. electric utilities and federal power marketing entities as those terms are defined in Sections 3(22) and 3(19) of the FPA" and that "such power is surplus to the system of the generator and, therefore, the electric power that [Research Power Corporation] will export on either a firm or interruptible basis will not impair the sufficiency of the electric power supply within the U.S." *Id*.

The applicant states that it "will make all necessary commercial arrangements and will obtain any and all other regulatory approvals required in order to schedule and deliver power exports." *Id*. The Applicant further states that it will "schedule its transactions with the appropriate balancing authority areas in compliance with the reliability criteria standards and guidelines established by the North American Electric Reliability Corporation[.]" *Id*. Research Power Corporation also attests to not exceed the export limits for the facilities, or otherwise cause a violation of the terms and conditions set forth in the export authorizations for each. App at 4.

B. Procedural History

On December 26, 2024, Centre Lane filed a renewal application with DOE for export authority for a five-year term. *Id* at 1. On June 16, 2025, DOE published notice of Centre Lane's Application in the Federal Register (90 Fed. Reg. 25252) and asked for any interested parties to submit comments on the Application by July 16, 2025. On July 7, 2025, DOE received notice of Centre Lane's corporate name change to Research Power Corporation.

C. Public Comments

No public comments were received.

II. DISCUSSION AND ANALYSIS

DOE is statutorily obligated under FPA § 202(e) to grant requests for export authorization unless the Department finds that the proposed export would negatively impact either: (i) the sufficiency of electric supply, or (ii) the coordination of the electric grid. Regarding the first exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States …." 16 U.S.C. § 824a(e). DOE has interpreted this criterion to mean that sufficient generating capacity and electric energy must exist such that the export could be made without compromising the energy needs of the exporting region, including serving all load obligations in the region while maintaining appropriate reserve levels. *See, e.g.*, *BP Energy Co.*, Order No. EA-314, at 1-2 (Feb. 22, 2007), *renewed*, Order No. EA-314-A, at 2 (May 3, 2012), Order No. EA-314-B, at 2 (Feb. 28, 2017), *renewed,* Order No. EA-314-C, at 4 (Dec. 20, 2021).

Under the second exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would … impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has interpreted this criterion primarily as an issue of the operational reliability of the domestic electric transmission system. Accordingly, the export must not compromise transmission system security and reliability. *See, e.g.*, Order No. EA-314-C, at 4.

A. Research Power Corporation Will Not Impair the Sufficiency of the Electric Supply in the United States

Sufficiency of supply, the first exception criterion, addresses whether regional electricity needs are met in the current market. DOE has analyzed this issue from both an economic and a reliability perspective. The economic perspective concerns the supply available to wholesale market participants. The reliability perspective focuses on preventing problems that could result from inadequate supplies. Taken together, DOE examines whether existing electric supply is available via market mechanisms, and whether potential reliability issues linked to supply problems are mitigated by reliability enforcement mechanisms.

From an economic perspective, DOE finds that the wholesale energy markets are sufficiently robust to make supplies available to exporters and other market participants serving United States regions along the Canadian and Mexican borders. Following enactment of the Energy Policy Act of 1992, Pub. L. No. 102-486, which encouraged the Federal Energy Regulatory Commission (FERC) to foster competition in the wholesale energy markets through open access to transmission facilities, energy markets developed across the United States to provide opportunities for a more efficient availability of supply. Subsequently, the Energy Policy Act of 2005, Pub. L. No. 109-58, reaffirmed the Government's commitment to competition in wholesale energy markets as national policy. FERC has continued to encourage the expansion of wholesale energy markets through its orders to remove barriers[1] and to ensure that these markets are functioning properly.[2] As a result, market participants have access to traditional bilateral contracts, as well as organized electricity markets run by regional transmission organizations (RTOs) or independent system operators (ISOs). FERC oversees these interstate wholesale electricity markets across most of the lower 48 states. Absent an indication in the record that the geographic markets relevant to this export authorization analysis are flawed and result in

[1] *See, e.g.*, *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009).

[2] *See, e.g.*, *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *as amended*, 126 FERC ¶ 61,261, *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

uneconomic exports that jeopardize regional supply, DOE finds that the proposed transmission for export does not impair the sufficiency of electric supply within the United States.

From a reliability perspective,[3] DOE focuses on the prevention of cascading outages and other problems that could result from inadequate resources.[4] Reliability oversight is addressed by the authority granted to FERC through the Energy Policy Act of 2005. That Act added section 215 to the FPA, which directed FERC to certify an electric reliability organization and develop procedures for establishing, approving, and enforcing mandatory electric reliability standards. 16 U.S.C. § 824o. FERC certified the North American Electric Reliability Corporation (NERC) in 2006 to develop and enforce reliability standards for the bulk-power system in the United States. *Order Certifying NERC as the Electric Reliability Organization and Ordering Compliance Filing*, FERC Docket No. RR06-1-000, 116 FERC ¶ 61,062 (July 20, 2006). FERC approves these standards, at which point they become mandatory and enforceable. NERC Reliability Standards address areas such as resource and demand balancing, critical infrastructure protection, communications, emergency preparedness and operations, facilities design, transmission operations, transmission planning, modelling, nuclear, personnel performance and training, protection and controls, voltage and reactive, interchange scheduling and coordination, and interconnection reliability operations and coordination.

NERC Reliability Standards are enforceable throughout the continental United States, most of Canada south of the 60th parallel, and the Mexican state of Baja California Norte. Through enforcement by FERC, NERC, and six Regional Entities overseen by NERC,[5] all bulk-power system owners, operators, and users are held responsible for complying with reliability standards. The reliability standards are structured so that many entities have overlapping responsibility for the electric grid, thereby resulting in several layers of reliability monitoring. Entities such as reliability coordinators and balancing authorities coordinate power generation and transmission among multiple utilities to serve demand within an integrated regional wholesale market. One of the principal functions of these entities is to schedule adequate generating and reserve capacity. This allows them to serve demand at the regional level and to ensure that there is sufficient power supply to maintain system reliability. Reliability Standard IRO-001-4 "establish[es] the responsibility of Reliability Coordinators to act or direct other entities to act."[6] Requirement R1 states that "[e]ach Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions."[7] Reliability oversight is designed through coordinated efforts amongst Reliability Coordinators to preserve the benefits of interconnected operations and ensure that operations in one area will not adversely impact other areas.[8] Reliability Standard IRO-014-3 R1 provides that "[e]ach Reliability Coordinator shall have and implement Operating Procedures, Operating

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[3] A related reliability analysis follows in the next section of this Order.

[4] This focus should not be confused with resource adequacy planning and capacity requirements that have traditionally been the domain of state regulatory commissions, NERC-certified Regional Entities, and RTOs/ISOs.

[5] The six entities are the Midwest Reliability Organization, Northeast Power Coordinating Council, ReliabilityFirst Corporation, SERC Reliability Corporation, Texas Reliability Entity, and Western Electricity Coordinating Council.

[6] Standard IRO-001-4 (Reliability Coordination – Responsibilities), at ¶ A.3.

[7] *Id.* ¶ B.R1.

[8] *See* Standard IRO-014-3 (Coordination Among Reliability Coordinators), at ¶ A.3.

Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability."[9]

DOE finds that NERC's FERC-approved comprehensive enforcement mechanism ensures that bulk-power system owners, operators, and users have a strong incentive both to maintain system resources and to prevent reliability problems that could result from movement of electric supplies through export. As a result of this reliability oversight, DOE finds that the sufficiency of supply is not impaired by Research Power Corporation's proposed export authorization.

DOE's sufficiency of supply findings are further supported by the fact that power marketers, such as Research Power Corporation, do not have an obligation to serve a franchised territory. Before the current role of power marketers emerged in the industry, the FPA § 202(e) inquiry into sufficiency of supply had a narrower focus and was designed for an applicant that was a vertically integrated utility[10] with an obligation to serve native load. Under that traditional scenario, the inquiry regarding sufficiency of supply logically sought to confirm that exports would be surplus to the needs of a vertically-integrated utility's native load obligations and reserve margins. As explained in DOE's notice of the first application by a power marketer for export authorization, the sufficiency of supply inquiry became unnecessary when applied to power marketers:

> The Applicant also is required to demonstrate that it would have sufficient generating capacity to sustain the proposed export under the terms and conditions of its export agreement, while still complying with any established reserve criteria.
>
> Since marketers generally could not be seen as having any "native load" requirements, the latter criterion of maintaining sufficient reserve margins appears inappropriate and unnecessary in this instance.

59 Fed. Reg. 54900 (Nov. 2, 1994). Power marketers do not have franchised service areas and, consequently, do not have native load obligations like a traditional local distribution utility that could be impaired by exports.

In sum, market mechanisms and reliability oversight protect against the possibility that Research Power Corporation's exports would jeopardize domestic sufficiency of supply. Therefore, an export by Research Power Corporation would not trigger the first exception criterion of FPA § 202(e) regarding the sufficiency of electric supply within the United States.

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[9] *Id.* ¶ B.R1.

[10] The Supreme Court of the United States has explained: "In 1935, when the FPA became law, most electricity was sold by vertically integrated utilities that had constructed their own power plants, transmission lines, and local delivery systems…[M]ost operated as separate, local monopolies subject to state or local regulation. Their sales were 'bundled,' meaning that consumers paid a single charge that included both the cost of the electric energy and the cost of its delivery. Competition among utilities was not prevalent." *New York v. FERC*, 535 US 1, 5 (2002).

B. Research Power Corporation's Requested Authorization Will Not Adversely Affect Either the Reliability or the Security of the United States Electric Transmission System

Reliability, the second exception criterion under FPA § 202(e), addresses operational reliability and security of the domestic electric transmission system. In evaluating the operational reliability impacts of export proposals, DOE has used a variety of methodologies and information, including established industry guidelines, operating procedures, and technical studies where available and appropriate. When determining these impacts, it is convenient to separate the export transaction into two parts: (i) moving the export from the source to a border system that owns the international transmission connection, and (ii) moving the export through that border system and across the border.

Moving Electricity to a Border System. Moving electricity for export to a border system necessarily involves the use of the bulk-power system. As noted in the preceding section, bulk-power system reliability concerns are addressed under the FPA by FERC and NERC and involve the enforcement of mandatory reliability standards. These standards ensure that all owners, operators, and users of the bulk-power system have an obligation to maintain system security and reliability. The standards are structured so that there are always entities with broader responsibilities than the applicant, such as reliability coordinators and balancing authorities, to keep a constant watch over the domestic transmission system.

To deliver the export from the source to a border system, the applicant must make the necessary commercial arrangements and obtain sufficient transmission capacity to wheel the exported energy to the border system. The applicant would be expected to follow FERC orders regarding open transmission access and to schedule delivery of the export with the appropriate RTO, ISO, and/or balancing authority (formerly the control area operator).

It is the responsibility of the RTO, ISO, and/or balancing authority to schedule the delivery of the export consistent with established and mandatory operational reliability criteria. During each step of the process of obtaining transmission service, the owners and/or operators of the transmission facilities will evaluate the impact on the system and schedule the movement of the export *only* if it would not violate established operating reliability standards. As a failsafe, the reliability coordinator in each region has the authority and responsibility to curtail, cancel, or deny scheduled flows to avoid shortages or to restore necessary energy and capacity reserves. Reliability Standard EOP-011-1 R2 provides that "[e]ach Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area."[11]

Specifically, the reliability coordinator has the authority to suspend exports if the electric energy would be needed to support the regional power grid. *See* Reliability Standard IRO-001-4 R1 ("Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions"), R2 ("Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the

[11] EOP-011-1 (Emergency Operations), at ¶ B.R2.

Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements”), and R3 (“Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1”).

DOE has determined that the existing industry procedures for obtaining transmission capacity on the domestic transmission system (described above) provide adequate assurance that any export will not cause an operational reliability problem. Therefore, Research Power Corporation’s export authorization has been conditioned to ensure that the export will not cause operational issues on regional transmission systems to fall outside of established industry reliability criteria, or cause or exacerbate a transmission operating problem on the United States’ electric power supply system (*see* Order below, Section VII, paragraphs C, D, and I).

Moving Electricity Through a Border System. The second part of DOE’s reliability inquiry, addressing the transmission of the export through a border system and across the border, is a question of whether the border system is reliable and secure. To a large extent, this question is addressed by the jurisdiction of NERC. NERC and Regional Entities—including the Midwest Reliability Organization, the Northeast Power Coordinating Council, and the Western Electricity Coordinating Council—oversee the United States-Canadian border system and a significant part of the United States-Mexican border system. Those border systems are generally subject to the same reliability standards as domestic systems. *See, e.g.*, http://www.ieso.ca/sector-participants/system-reliability/reliability-standards-framework.

DOE also relies on the System Impact Studies submitted in conjunction with an application for a DOE-issued Presidential permit[12] to construct a new international transmission line. As DOE has previously reviewed System Impact Studies submitted with Presidential permit applications,[13] DOE does not need to perform additional impact assessments here, provided the maximum rate of transmission for all exports through a border system does not exceed the authorized limit of the system (*see* Order below, Section VII, paragraph (A)). In its application, Research Power Corporation committed to complying with all reliability limits on border facilities. *See* App. at 3. The second part of the reliability inquiry is therefore satisfied by DOE regulatory oversight, in addition to NERC’s reliability enforcement.

III. FINDINGS AND DECISION

A. Research Power Corporation Meets the Statutory Requirements to Export Electric Energy to Canada

[12] DOE issues Presidential permits pursuant to Executive Order 10,485, as amended by Executive Order 12,038. *See* 10 C.F.R. §§ 205.320-205.329.

[13] *See, e.g.*, *AEP Tex. Cent. Co*., Order No. PP-317, at 2-3 (Jan. 22, 2007); *Mont. Alta. Tie Ltd.*, Order No. PP-305, at 2-4 (Nov. 17, 2008).

As explained above, DOE has assessed the impact that the proposed export would have on the reliability of the United States electric power supply system. DOE has determined that the export of electric energy to Canada by Research Power Corporation, as ordered below, would not impair the sufficiency of electric power supply within the United States and would not impede or tend to impede the coordination in the public interest of facilities within the meaning of FPA § 202(e).

B. Research Power Corporation Qualifies for a NEPA Categorical Exclusion for Exports of Electric Energy

Research Power Corporation's Application qualifies for DOE's categorical exclusion for exports of electric energy under the National Environmental Policy Act of 1969, as amended (NEPA), 42 U.S.C. § 4321 *et seq*. DOE's NEPA Implementing Procedures (June 2025) set forth this categorical exclusion, codified as "B4.2," as follows:

> Export of electric energy as provided by Section 202(e) of the Federal Power Act over existing transmission lines or using transmission system changes that are themselves categorically excluded.

10 C.F.R. Part 1021, App. B, § B4.2.

DOE has determined that actions in this category do not normally have a significant effect on the human environment and that, therefore, neither an environmental assessment nor an environmental impact statement normally is required. 10 C.F.R. § 1021.102(a).

To invoke this categorical exclusion, DOE must determine that, in relevant part, "[t]here are no extraordinary circumstances related to the proposal that may affect the significance of the environmental effects of the proposal." 10 C.F.R. § 1021.102(b)(2). "Extraordinary circumstances" include "unique situations" such as "scientific controversy about the environmental effects of the proposal; uncertain effects or effects involving unique or unknown risks; and unresolved conflicts concerning alternative uses of available resources." *Id*. DOE finds that granting Research Power Corporation's request for export authorization does not present such extraordinary circumstances. Research Power Corporation seeks to deliver electricity over existing international electric transmission facilities, which fits squarely within the B4.2 categorical exclusion. For these reasons, DOE will not require more detailed NEPA review in connection with this Application.

C. Conclusion

DOE grants Research Power Corporation's request for export authorization. Research Power Corporation is authorized to export electricity to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties, subject to the limitations and conditions described in this Order. The authorization shall be effective for a five (5) year term consistent with DOE's standard term for new electricity export authorizations.

IV. DATA COLLECTION AND REPORTING REQUIREMENTS

The responsibility for the data collection and reporting under orders authorizing electricity exports to a foreign country currently rests with the U.S. Energy Information Administration (EIA) within DOE. The Applicant is instructed to follow EIA instructions in completing this data exchange. Questions regarding the data collection and reporting requirements can be directed to EIA by email at EIA4USA@eia.gov or by phone at 1-855-342-4872.

Additionally, any change to the tariff of an entity with an export authorization must be provided to DOE's Grid Deployment Office via email at *electricity.exports@hq.doe.gov*. 10 C.F.R. § 205.308(b).

V. COMPLIANCE

Obtaining a valid order from DOE authorizing the export of electricity under FPA § 202(e) is a necessary condition before engaging in the export. Failure to obtain such an order or continuing to export after the expiration of such an order may result in a denial of authorization to export in the future and subject the exporter to sanctions and penalties under the FPA. DOE expects transmitting utilities owning border facilities and entities charged with the operational control of those border facilities, such as ISOs, RTOs, or balancing authorities, to verify that companies seeking to schedule an electricity export have the requisite authority from DOE to export such energy.

DOE expects Research Power Corporation to abide by the terms and conditions established for its authority to export electric energy to Canada, as set forth below. DOE intends to monitor Research Power Corporation compliance with these terms and conditions, including the requirement in paragraph G of this Order that Research Power Corporation create and preserve full and complete records and file reports with EIA as discussed above.

A violation of any of these terms and conditions, including the failure to submit timely and accurate reports, may result in the loss of authority to export electricity and subject Research Power Corporation to any applicable sanctions and penalties under the FPA.

VI. OPEN ACCESS POLICY

An export authorization issued under FPA § 202(e) does not impose a requirement on transmitting utilities to provide service. However, DOE expects transmitting utilities that own border facilities to provide open access transmission service across the border in accordance with the principles of comparable open access and non-discrimination contained in the FPA and articulated in FERC Order No. 888 (Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, FERC Statutes and Regulations ¶ 31,036 (1996)), as amended. The actual rates, terms, and conditions of transmission service should be consistent with the non-discrimination principles of the FPA and the transmitting utility's Open-Access Transmission Tariff on file with FERC.

All recipients of export authorizations, including owners of border facilities for which Presidential permits have been issued, are required by their export authorization to conduct operations in accordance with the applicable principles of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended. Cross-border electric trade ought to be subject to the same principles of comparable open access and non-discrimination that apply to transmission in interstate commerce. *See Enron Power Mktg., Inc. v. El Paso Elec. Co.*, 77 FERC ¶ 61,013 (1996), *reh'g denied*, 83 FERC ¶ 61,213 (1998). Thus, DOE expects owners of border facilities to comply with the same principles of comparable open access and non-discrimination that apply to the domestic, interstate transmission of electricity.

VII. ORDER

Accordingly, pursuant to FPA § 202(e) and the Rules and Regulations issued thereunder (10 C.F.R. §§ 205.300-309), it is hereby ordered that Research Power Corporation is authorized to export electric energy to Canada under the following terms and conditions:

(A) The electric energy exported by Research Power Corporation pursuant to this Order may be delivered to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties in accordance with the export limits authorized by DOE.

(1) The following international transmission facilities located at the United States border with Canada are currently authorized by Presidential permit and available for open access transmission:[14, 15]

Owner	Location	Voltage	Permit No.[16]
Bangor Hydro-Electric Company	Baileyville, ME	345 kV	PP-89
Basin Electric Power Cooperative	Tioga, ND	230 kV	PP-64
Bonneville Power Administration (BPA)	Blaine, WA	2x 500 kV	PP-10
	Nelway, WA	230 kV	PP-36
	Nelway, WA	230 kV	PP-46
CHPE, LLC	Champlain, NY	±230 kV DC	PP-481[17]

[14] This Order authorizes the export of electricity over any "authorized international transmission facility," which is intended to include both large transmission lines and smaller distribution lines that have received a Presidential permit. However, the list in subparagraph (A)(1) of current facilities only includes transmission lines.

[15] The Applicant submitted a list identifying currently authorized transmission facilities (Attachment 1 of the Application). However, as information about some of those facilities may have changed since the Application was submitted, the table of transmission facilities in this Order may differ from the Applicant's submission to reflect those changes.

[16] These Presidential permit numbers refer to the generic DOE permit number and are intended to include any subsequent amendments to the permit authorizing the facility.

[17] Currently under construction and not yet operational as of September 2025.

Eastern Maine Electric Cooperative	Calais, ME	69 kV	PP-32
International Transmission Company	Detroit, MI	230 kV	PP-230
	Marysville, MI	230 kV	PP-230
	St. Claire, MI	230 kV	PP-230
	St. Claire, MI	345 kV	PP-230
Lake Erie Connector Transmission, LLC	Erie County, PA	320 kV	PP-412[18]
Long Sault, Inc.	Massena, NY	2x 115 kV	PP-24
Maine Electric Power Company	Houlton, ME	345 kV	PP-43
Minnesota Power, Inc.	International Falls, MN	115 kV	PP-78
Minnesota Power, Inc.	Roseau County, MN	500 kV	PP-398
Minnkota Power Cooperative	Roseau County, MN	230 kV	PP-61
Montana Alberta Tie Ltd.	Cut Bank, MT	230 kV	PP-399
NECEC Transmission LLC	Beattie Twp, ME	±320 kV	PP-438[19]
New York Power Authority	Massena, NY	765 kV	PP-56
	Massena, NY	2x 230 kV	PP-25
	Niagara Falls, NY	2x 345 kV	PP-74
	Devils Hole, NY	230 kV	PP-30
Niagara Mohawk Power Corp.	Devils Hole, NY	230 kV	PP-190
Northern States Power Company	Red River, ND	230 kV	PP-45
	Roseau County, MN	500 kV	PP-63
	Rugby, ND	230 kV	PP-231
Sea Breeze Olympic Converter LP	Port Angeles, WA	±450 kV DC	PP-299[20]
TDI New England	Alburgh, VT	±320 kV DC	PP-400[21]

[18] These transmission facilities have been authorized but not yet constructed or placed into operation.
[19] These transmission facilities have been authorized but not yet constructed or placed into operation.
[20] These transmission facilities have been authorized but not yet constructed or placed into operation.
[21] These transmission facilities have been authorized but not yet constructed or placed into operation.

Vermont Electric Power Co.	Derby Line, VT	120 kV	PP-66
Vermont Electric Transmission Co.	Norton, VT	±450 kV DC	PP-76
Vermont Transco LLC	Highgate, VT	120 kV	PP-82
Versant Power	Fort Fairfield, ME	69 kV	PP-497
	Madawaska, ME	138 kV	PP-498
	Easton, ME	7.2 kV	PP-499
	Baileyville, ME	345kV	PP-500

(2) The following are the authorized export limits for the international transmission lines listed above in subparagraph (A)(1):

(a) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on facilities authorized by Presidential Permit PP-64 (issued to Basin Electric Power Coop.) to exceed an instantaneous transmission rate of 150 megawatts (MW). The gross amount of energy that Research Power Corporation may export over the PP-64 facilities shall not exceed 900,000 megawatt-hours (MWH) during any consecutive 12-month period.

(b) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-32 (issued to Eastern Maine Electric Coop.) to exceed an instantaneous transmission rate of 15 MW. The gross amount of energy that Research Power Corporation may export over the PP-32 facilities shall not exceed 7,500 MWH annually.

(c) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-481-2 (issued to CHPE, LLC) to exceed an instantaneous transmission rate of 1,250 MW.

(d) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-230 (issued to International Transmission Company) to exceed a coincident, instantaneous transmission rate of 2.2 billion volt-amperes (2,200 MVA).

(e) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-412-1 (issued to Lake Erie Connector Transmission, LLC) to exceed an instantaneous transmission rate of 1,000 MW.

(f) Exports by Research Power Corporation made pursuant to this Order shall not cause the scheduled rate of transmission over a combination of facilities authorized by Presidential Permits PP-43 (issued to Maine Electric Power Company) and PP-500 (issued to Bangor Hydro-Electric) to exceed 550 MW.

(g) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the combination of facilities authorized by Presidential Permits PP-497 and PP-498 (issued to Versant Power) to exceed a coincident, instantaneous transmission rate of 134 MW.

(h) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-78-1 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 100 MW. Exports by Research Power Corporation may cause total exports on the PP-78-1 facilities to exceed 100 MW only when total exports between the Mid-Continent Area Power Pool (MAPP) and Manitoba Hydro are below maximum transfer limits and/or whenever operating conditions within the MAPP system permit exports on the PP-78-1 facilities above the 100-MW level without violating established MAPP reliability criteria. However, under no circumstances shall exports by Research Power Corporation cause the total exports on the PP-78-1 facilities to exceed 150 MW.

(i) Exports made by Research Power Corporation pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-398 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 750 MW.

(j) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on a combination of the international transmission lines authorized by Presidential Permits PP-45 and PP-63 (issued to Northern States Power Company), PP-61 (issued to Minnkota Power), and PP-231 (issued to Northern States Power Company, d/b/a Excel Energy Inc. (Xcel)), to exceed an instantaneous transmission rate of 700 MW on a firm basis and 1,050 MW on a non-firm basis.

(k) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-66 (issued to Vermont Electric Power Co.) to exceed an instantaneous transmission rate of 50 MW. The gross amount of energy that Research Power Corporation may export over the PP-66 facilities shall not exceed 50,000 MWH annually.

(l) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-56 (issued to NYPA) to exceed an instantaneous transmission rate of 1,000 MW.

(m) Exports by Research Power Corporation made pursuant to this Order shall not cause: (a) the total exports on the facilities authorized by Presidential Permits PP-25, PP-30, PP-74 (issued to NYPA), and PP-190 (issued to Niagara Mohawk Power Corp.) to exceed a combined instantaneous transmission rate of 1,650

MW; and (b) the total exports on the 115-kV facilities authorized by Presidential Permit PP-24 (issued to Long Sault, Inc.) to exceed an instantaneous transmission rate of 100 MW. In addition, the gross amount of energy that Research Power Corporation may export over the PP-24 facilities shall not exceed 300,000 MWH annually.

(n) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on the two 500-kV lines authorized by Presidential Permit PP-10, the 230-kV line authorized by Presidential Permit PP-36, and the 230-kV line authorized by Presidential Permit PP-46 (issued to BPA) to exceed the following limits:

Condition	PP-36 & PP-46 Limit	PP-10 Limit	Total Export Limit
All lines in service	400 MW	1500 MW	1900 MW
1-500 kV line out	400 MW	300 MW	700 MW
2-500 kV lines out	400 MW	0 MW	400 MW
1-230 kV line out	400 MW	1500 MW	1900 MW
2-230 kV line out	0 MW	1500 MW	1500 MW

(o) Exports by Research Power Corporation made pursuant to this Order shall not cause a violation of the following conditions as they apply to exports over the facilities authorized by Presidential Permit PP-76-1, as amended (issued to the Vermont Electric Transmission Company):

Exports Through	NEPOOL Load Condition	Export Limit
Comerford converter	Summer, Heavy	650 MW
Comerford converter	Winter, Heavy	660 MW
Comerford converter	Summer, Light	690 MW
Comerford converter	Winter, Light	690 MW
Comerford & Sandy Pond converters	All	2,000 MW

(p) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-399 (issued to Montana Alberta Tie Ltd.) shall not exceed an instantaneous transmission rate of 300 MW.

(q) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-438 (issued to NECEC Transmission LLC) shall not exceed an instantaneous transmission rate of 1,200 MW.

(r) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-299 (issued to Sea Breeze Olympic Converter LP) shall not exceed an instantaneous transmission rate of 550 MW.

(s) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-400 (issued to TDI-New England) to exceed an instantaneous transmission rate of 1,000 MW.

(t) Exports by Research Power Corporation made pursuant to this Order shall neither cause the total exports on the facilities authorized by Presidential Permit PP-82-6 (issued to Vermont Transco LLC) to exceed an instantaneous transmission rate of 250 MW.

(B) Changes by DOE to the export limits in other orders shall result in a concomitant change to the export limits contained in subparagraph (A)(2) of this Order. Changes to the export limits contained in subparagraphs (A)(2)(l), (m), and (n) will be made by DOE after submission of appropriate information demonstrating a change in the transmission transfer capability between the electric systems in New York State and Ontario and New York State and Quebec, and between BPA and BC Hydro or BPA and West Kootenay Power. Notice of these changes will be provided to Research Power Corporation.

(C) Research Power Corporation shall obtain any and all other Federal and state regulatory approvals required to execute any power exports to Canada. The scheduling and delivery of electricity exports to Canada shall comply with all reliability criteria, standards, and guidelines of NERC, reliability coordinators, Regional Entities, RTOs, ISOs or balancing authorities, or their successors, as appropriate, on such terms as expressed therein, and as such criteria, standards, and guidelines may be amended from time to time.

(D) Exports made pursuant to this authorization shall be conducted in accordance with the applicable provisions of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended.

(E) The authorization herein granted may be modified from time to time or terminated by further order of DOE. In no event shall such authorization to export over a particular transmission facility identified in subparagraphs (A)(1) and (2) extend beyond the date of termination of the Presidential permit or treaty authorizing such facility.

(F) This authorization shall be without prejudice to the authority of any state or state regulatory commission for the exercise of any lawful authority vested in such state or state regulatory commission.

(G) Research Power Corporation shall make and preserve full and complete records with respect to the electric energy transactions between the United States and Canada. Research Power Corporation shall collect and submit the data to EIA as required by and in accordance with the procedures of Form EIA-111, "Quarterly Electricity Imports and Exports Report," and all successor forms.

(H) In accordance with 10 C.F.R. § 205.305, this export authorization is not transferable or assignable, except in the event of involuntary transfer by operation of law. Provided written notice of the involuntary transfer is given to DOE within 30 days, this authorization shall remain in effect temporarily. The authorization shall terminate unless an application for a new export authorization has been received by DOE within 60 days of the involuntary transfer. Upon receipt by DOE of such an application, this existing authorization shall continue in effect pending a decision on the new application. In the event of a proposed voluntary transfer of this authority to export electricity, the transferee and the transferor shall file a joint application for a new export authorization, together with a statement of the reasons for the transfer.

(I) Nothing in this Order is intended to prevent the transmission system operator from being able to reduce or suspend the exports authorized herein, as necessary and appropriate, whenever a continuation of those exports would cause or exacerbate a transmission operating problem or would negatively impact the security or reliability of the transmission system.

(J) Research Power Corporation has a continuing obligation to give DOE written notification as soon as practicable of any prospective or actual changes of a substantive nature in the circumstances upon which this Order was based, including but not limited to changes in authorized entity contact information or NERC compliance registry status.

(K) This authorization shall be effective as of October 21, 2025 and shall remain in effect for a period of five (5) years from that date. Application for renewal of this authorization may be filed within six (6) months prior to its expiration. Failure to provide DOE with at least one hundred and twenty (120) days to process a renewal application and provide adequate opportunity for public comment may result in a gap in Research Power Corporation's authority to export electricity.

Issued in Washington, D.C., on October 21, 2025.

Chris Wright

Chris Wright
Secretary of Energy
U.S. Department of Energy

EXHIBIT 96

ENERGYWIRE

PJM to ratchet down projected AI power demand for eastern US

An updated analysis from the regional grid operator is expected to provide a reality check on data center growth.

BY: **PETER BEHR** | 01/06/2026 06:53 AM EST

A data center is seen under construction last year near the Susquehanna nuclear power plant in Pennsylvania.| Ted Shaffrey/AP

ENERGYWIRE | Across the U.S., energy policymakers and power grid operators have three broad goals at the top of their 2026 priority lists: enable AI dominance. Secure electricity supply. Keep power prices from spiraling.

But hitting those targets is challenged by a simple question that remains hard to answer: What's real and what's hype when it comes to data center demand for electricity?

The dilemma is front and center at PJM Interconnection, the nation's largest regional power grid, serving 67 million people in 13 states from the Atlantic coast to Chicago. Later this month, PJM plans to release an updated estimate of future electricity demand from large users. The report is expected to provide a serious reality check to the projections that developers and utilities make about future data center growth.

PJM Chief Operating Officer Stu Bresler said last month that PJM's overall power demand forecast for the year beginning in mid-2027 will be "appreciably lower" than current projections. PJM wants more evidence on how fast and how large new data centers can actually be built with shortages of chips, electronics and specialized construction teams.

Overestimating AI data center growth threatens to burden consumers with billions of dollars in excessive investments. Underestimating it increases risks of power shortages and blackouts while also undercutting current U.S. leadership as a developer of AI technology.

"At a time when utilities forecast hundreds or thousands of megawatts of growth, improving forecasts by even a few percentage points in the right direction — up or down — can impact billions of dollars in investments and customer bills," said David Rosner, a member of the Federal Energy Regulatory Commission, last year.

"Put simply, we cannot efficiently plan the electric generation and transmission needed to serve new customers if we don't forecast how much energy they will need as accurately as possible," Rosner said.

The most detailed analysis of future U.S. data center demand, issued a year ago by the Department of Energy's Lawrence Berkeley National Laboratory, could not get close to a precise prediction. Instead, it estimated the amount of the U.S. electricity output consumed by data centers in 2028 could range anywhere from 6.7 percent to 12 percent.

"We're all going around trying to solve a problem that we haven't even defined yet," said Caitlin Marquis, managing director of Advanced Energy United, a coalition of clean technology developers and energy users. "It's definitely worthwhile making sure that we know what we're planning for, because the costs of getting that wrong are significant either way."

But a clearer picture may be clouded by consumer resistance that puts some data center projects in doubt, and a fight in Washington over the power of the states to regulate AI.

President Donald Trump's executive order in October declares global AI "dominance" to be a national security imperative and seeks to impose White House control over state AI policymaking.

Governors from both political parties who head AI-leading states oppose Trump's moves. But governors have also been among the biggest AI cheerleaders because of the investment and tax dollars and jobs data centers deliver.

Acting on a directive from the Department of Energy, FERC is trying to forge new rules for assessing data center growth, with an uncertain timetable. PJM is a test case in the debate because of its concentration of existing data centers, the largest in the world by industry estimates.

Forecasts that 'defy logic'

PJM's long-term forecast projected an unprecedented surge in peak power use by data centers, factories and cryptominers that would require adding 32,000 megawatts of new generation, batteries, and demand response between 2024 and 2030. Of this, PJM expected 30,000 MW to come from data centers.

PJM's total generating capacity increased by only about 2,000 MW, or 1 percent, in the past year.

PJM's demand forecasts have been amped up by tech companies plowing billions of dollars into the AI race, joined by investor-backed speculators seeking to secure marketable sites for new centers, according to participants in PJM's review.

The prospect of skyrocketing electricity demand is already showing up on utility bills, according to PJM's independent market monitor, Joseph Bowring of Monitoring Analytics. PJM charges ratepayers for incentive payments to generators to keep plants operating in future years, and those payments have escalated in the past two years because of expected data center construction.

Kent Chandler, a senior fellow at the R Street Institute and a former Kentucky utility regulator, said some PJM officials have acknowledged privately to him that the forecasts coming from utilities "sort of defy logic."

"There just aren't enough transformers and conductors and towers and engineers to accommodate the load growth that some of these utilities are proposing," Chandler said.

That’s true not just within PJM, he said, but across the country.

Potential roadblocks to data center projects are detailed in a new analysis by ICF International. The consulting firm's software mapping program identifies potential data center sites based on key factors like the availability of grid power, favorable zoning and fiber-optic networks. The list of prime data center project locations is shrinking rapidly in Northern Virginia and many other areas, the ICF analysis shows.

“The challenge is knowing which data center is real versus a phantom project,” said Himali Parmar, ICF vice president for energy markets.

Developers are making multiple applications for the same project because it’s relatively cheap to do so, she said. Their applications are shielded by confidentiality agreements that developers demand and utilities accept rather than get in arguments with a potentially huge customer.

“Am I looking at 40 gigawatts of new load requests, or is it 70, or is it 80? That’s a challenge with this lack of transparency,” she said. “PJM does not know what’s coming its way.”

“Utilities have an inherent financial bias to overstate demand” in their forecasts, Chandler said. Strong demand forecasts can move utilities’ stock prices higher and result in increased investment in grid infrastructure that boosts financial returns, grid experts explain.

PJM officials “don't feel comfortable with what utilities are putting in,” Chandler said. “They don't necessarily have the information or expertise [to contradict the utility forecasts]. That’s something they're figuring out now,” Chandler added.

An advance clue to the revisions PJM is preparing may be data from the preliminary report on load growth PJM published last year — the report that will be updated this month.

It showed some utilities in PJM making significantly different assumptions about the reality of utilities’ data center power demand.

An example is the contrast in load growth forecasts from Allentown, Pennsylvania-based PPL Corp., and Dominion Energy Inc., the Richmond, Virginia, power company. Dominion serves “data center alley” in Northern Virginia, the largest cluster of the facilities anywhere. Northeast Pennsylvania, PPL’s territory, is seeing a rush of AI data center development proposals.

PJM published two forecasts. One was a “capacity” figure based on developers’ unverified requests for transmission capacity within PJM to manage the load growth the developers are projecting. The second forecast was the utilities' own estimate of actual load growth.

PPL capacity forecast shows demand soaring more than 3,000 percent to 13,412 MW, in 2029. PPL's own demand estimate indicates that PPL expects about 80 percent of that new data center construction to be completed by 2029.

Dominion, on the other hand, which has the most experience within PJM by far with its track record of data center construction, said that only about 30 percent of the developers' power requests will actually materialize in 2029.

An analysis by ClearView Energy Partners said PJM is very likely to require better forecasting by utilities of data center demand. Its analysts noted that PJM board chair David Mills has suggested PJM could require state officials to review utilities' power demand forecasts and may call for scrutiny of forecasts by outside analysts looking at crucial supply-chain issues that could slow new data center construction.

“We would be better off if operators like PJM got the information directly from the customer and could have a back-and-forth with them to fully understand what they're doing,” Chandler said.

UP NEXT IN **THIS EDITION OF ENERGYWIRE**

Congress would boost oil and gas spending in fiscal 2026 package

BY IAN M. STEVENSON

EXHIBIT 97

UNITED STATES OF AMERICA
BEFORE THE
DEPARTMENT OF ENERGY

	)	
TransAlta Centralia Generation	)	**Docket No.**
	)	

DECLARATION OF ARNE OLSON

I, Arne Olson, declare under penalty of perjury under the laws of the State of Washington, that the following is true and correct:

1. I am over 18 years of age and otherwise competent to make this Declaration.

2. I am the principal author of the Energy and Environmental Economics (E3) study on resource adequacy in the Pacific Northwest to be released in full in the coming weeks.

3. In January 2026, I created the attached spreadsheet with the achieved loss-of-load results from our study for the years 2025-2030. The modeled loss of load expectation for 2026 is 0.15 days/yr., slightly above the common industry target of 0.1. Based on current hydro conditions, the actual risk in winter 2026 is lower. By 2030, the risk grows to 6.01 days/yr., 60 times greater than the industry standard.

DATED this 13 day of January 2026, at San Francisco, California.

ARNE OLSON

EXHIBIT 97-1

(Native Format)

EXHIBIT 98

[Service Date January 9, 2013]

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of	)	DOCKET UE-121373
	)	
PUGET SOUND ENERGY, INC.,	)	ORDER 03
	)	
For Approval of a Power Purchase Agreement for Acquisition of Coal Transition Power, as Defined in RCW 80.80.010, and the Recovery of Related Acquisition Costs	)	FINAL ORDER GRANTING PETITION, SUBJECT TO CONDITIONS
. . . .	)	

***Synopsis**: The Commission approves a power purchase agreement between Puget Sound Energy, Inc. (PSE), and TransAlta Centralia Generation LLC that provides for PSE's acquisition of an average 346 MW of coal transition power, as defined in RCW 80.80.010, over a contract term of 133 months. The Commission determines that PSE is authorized by statute to recover, in addition to its costs of power, equity return in the amount of $1.49 per MWh for all deliveries of power under the contract. This "equity adder," a unique contract incentive provided by statute exclusively for the purchase of coal transition power, will result in PSE receiving $44.12 million in nominal return on equity, having a net present value of $34.15 million over the full term of the contract, without requiring any capital investment by the company.*

The Commission's approval of the agreement is subject to a condition that PSE will file an annual report allowing the Commission to fulfill its obligation on an ongoing basis to regulate in the public interest, as provided by the public service laws, including specifically to effect the purposes of the statute establishing the legal concept of "coal transition power," which has the purpose, among others, of preserving family wage jobs. The report will enable the Commission to evaluate whether the subject power purchase agreement may be found to have lost its character as an agreement for the sale and delivery of coal transition power due to changed circumstances in plant operations, or a failure to satisfy the provisions of RCW Chapter 80.80 on an ongoing basis.

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SUMMARY

1 **PROCEEDING:** On August 20, 2012, Puget Sound Energy, Inc. (PSE or Company) filed with the Washington Utilities and Transportation Commission (Commission) a Petition for Approval of a Power Purchase Agreement for Acquisition of Coal Transition Power, as Defined in RCW 80.80.010, and the Recovery of Related Acquisition Costs (Petition). The subject Coal Transition Purchase Power Agreement (Coal Transition PPA) is between PSE and TransAlta Centralia Generation LLC (TransAlta Centralia).

2 PSE requests an order: (1) approving the Coal Transition PPA, subject to and conditioned upon certain Commission determinations and findings specified in Section VI of the Petition; (2) approving PSE's recovery of the equity component of the Coal Transition PPA as provided in RCW 80.04.570(6); (3) approving deferral of certain costs associated with the Coal Transition PPA throughout the entire term of the Coal Transition PPA including later volume and pricing changes; and (4) finding that the Coal Transition PPA is prudent, regardless of whether the term of the Coal Transition PPA terminates upon its expiration or is terminated prior to its expiration.

3 **PARTY REPRESENTATIVES:** Sheree Strom Carson, Jason Kuzma and Donna Barnett, Perkins Coie, Bellevue, Washington, represent PSE. Simon ffitch and Lisa W. Gafken, Assistant Attorneys General, Seattle, Washington, represent the Public Counsel Section of the Washington Office of Attorney General (Public Counsel). Sally Brown and Greg Trautman, Assistant Attorney's General, Olympia, Washington, represent the Commission's regulatory staff (Commission Staff or Staff).[1]

4 Melinda Davison and Joshua Weber, Davison Van Cleve, Portland, Oregon, represent the Industrial Customers of Northwest Utilities (ICNU). Danielle Dixon, Senior

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[1] In formal proceedings, such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of this proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See* RCW 34.05.455.

Policy Associate, and Nancy Hirsch, Policy Director, Northwest Energy Coalition (NWEC), represent NWEC.

5 **COMMISSION DETERMINATIONS:** The Commission determines that it should approve PSE's Petition, subject to a condition requiring an annual report deemed necessary to protect ratepayers and the broader public interest, as required in the legal and policy environment that establish the concept of "coal transition power." Based on our evaluation of the Coal Transition PPA in the context of Chapter 80.80 RCW, RCW 80.04.570 and the Memorandum of Agreement between TransAlta and the Governor's office that is required under RCW 80.80.100, we find the Coal Transition PPA acceptable and within the bounds the prudence standards that we apply to such an agreement. The Coal Transition PPA, however, includes certain provisions that could give rise to further Commission inquiry if TransAlta substantially limits operation of the Centralia plant.

6 We are concerned specifically with the potential that the power TransAlta commits to deliver could lose its character as "coal transition power," as we understand the term within its statutory definition and other provisions of law that establish its essential characteristics. We are most concerned with two circumstances that are unlikely, according to our record, but nevertheless conceivable, circumstances. One is that, contrary to PSE's expectations,[2] TransAlta will not continue to operate the Centralia Coal Facility and therefore satisfy most, albeit not necessarily all, of its delivery obligations with power from the plant. This could mean, among other things, the loss of family-wage jobs, the preservation of which is one policy goal of the Coal Transition Energy Bill. The other concern is that TransAlta will not continue to provide the financial assistance provided for under RCW 80.80.100 and contractually memorialized in the Memorandum of Agreement (MOA) between TransAlta and the Governor's Office. The legislature expressly contemplates in RCW 80.80.100 that in exchange for the benefits conferred by the Coal Transition Energy Bill will help fund the transition of the local economy in the region that depends on the Centralia Coal Facility as an economic mainstay. Yet, there are various opportunities for TransAlta to terminate the MOA, both as specified in RCW 80.80.100, and otherwise. This means these funds conceivably could be lost.

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[2] *See, e.g., TR. 235:15-239:3; 240:3-8; 241:8-244:16; 259:16-260:11 (Kuzma).*

7 In light of these concerns, we condition our approval of the Coal Transition PPA by requiring an annual report from PSE that will enable the Commission to engage in some ongoing scrutiny of the implementation of the statute and PPA. Given the unique nature of the Coal Transition PPA, we recognize that the Commission may determine at some point in the future that its expectations under the legal and policy environment in which the concept of coal transition power resides are not being met. The Commission may then evaluate whether to revisit some aspects of the Coal Transition PPA.

8 In addition to determining that the Coal Transition PPA should be approved as presented, subject to the imposition of a reporting requirement, we also resolve several issues related to PSE's cost-recovery proposals. We find that the equity adder to which PSE is entitled under RCW 80.04.570(6) should be based on a hypothetical "equivalent plant" cost of $110 million. We accept PSE's proposals to calculate the return amount using its currently authorized 7.24 percent pre-tax weighted average cost of equity over the term of the contract and to levelize the recovery of return using PSE's methodology, which recognizes the time-value of the stream of equity return payments to which the Company is entitled during the life of the contract.

9 As to PSE's request that it be authorized to defer incremental costs that arise between rate proceedings with changes in volume, price or both during the term of the Coal Transition PPA, we think it better to postpone consideration of the issue until PSE seeks recovery of the initial costs of the PPA that it will begin to incur on December 1, 2014. PSE acknowledges that this date, nearly two years from now, leaves ample opportunity for the Company to file either a general rate case or a Power Cost Only Rate Case (PCORC). Either of these proceedings would be a more appropriate one for consideration of cost accounting questions.

MEMORANDUM

I. Background and Procedural History

10 TransAlta Centralia owns and operates a baseload coal-fired electric generating plant of approximately 1340 megawatts of electric generating capacity located at Centralia,

Washington. The plant consists of two generation units and two boilers. The plant is subject to Chapter 80.80 RCW, which imposes an emissions performance standard on baseload electric generation in the State of Washington. Under the statute, as originally enacted, electric utilities such as PSE could not enter into a long-term financial commitment for baseload electric generation from the Centralia plant on or after July 1, 2008, because the generating plant's emissions exceed the emissions performance standard of 1100 pounds of greenhouse gases per megawatt-hour.[3]

11 On May 21, 2009, Governor Gregoire issued Executive Order 09-05, Washington's Leadership on Climate Change, which directed the Department of Ecology to work with TransAlta Centralia to establish an agreed order to apply the emissions performance standard to the Centralia Coal Facility by no later than December 31, 2025. On April 26, 2010, Governor Gregoire and TransAlta Centralia entered into a memorandum of understanding to enter discussions on an agreement to reduce gas emissions from the Centralia Coal Facility and provide replacement capacity by 2025.

12 On April 29, 2011, Governor Gregoire signed Engrossed Second Substitute Senate Bill 5769 (Coal Transition Energy Bill), which provides certain deferrals of the greenhouse gas emissions performance standard to encourage the early closure of coal plants in Washington. As a practical matter, this meant the Centralia facility, the only such plant operating in Washington. The Coal Transition Energy Bill amended RCW 80.80.040 to allow the Centralia facility to comply with greenhouse gas emissions performance standards by shutting down one of its two boilers by the end of 2020 and the other by the end of 2025.[4]

13 The Coal Transition Energy Bill amended RCW 80.80.040 to allow electric utilities such as PSE to enter into new financial commitments for the output from the facility for terms greater than five years. The Coal Transition Energy Bill also established a process that allows such electric utilities to petition the Commission for approval of a power purchase agreement for coal transition power.[5] If such a contract is approved, the utility is allowed to earn and recover the equity

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[3] *See* RCW 80.80.040(1)(a) and RCW 80.80.040(1)(c)(i)(A).

[4] RCW 80.80.040(1)(c)(i)(A).

[5] *See* RCW 80.04.570(6) and WAC 480-100-415.

component of its authorized rate of return in the same manner as if it had purchased or built an equivalent plant and to recover the cost of the coal transition power under the power purchase agreement. This truly unique equity adder is expressly limited to "an agreement for acquisition of coal transition power" and does not apply to "any other power purchase agreement or other power contract." [6]

14 On December 23, 2011, Governor Gregoire and TransAlta Centralia entered into the MOA, which memorialized in contractual form the arrangements set forth in the Coal Transition Energy Bill. [7] The MOA between TransAlta Centralia and the State of Washington is effective as of April 1, 2012 and expires no earlier than December 31, 2025, unless terminated earlier pursuant to its terms.[8]

15 On July 24, 2012, PSE and TransAlta Centralia entered into the Coal Transition PPA that is the subject of this proceeding. It provides that PSE will purchase up to 380 MW of coal transition power from what the PPA refers to as the Centralia Transition Coal Facility (CTCF), with average deliveries over the life of the contract of 346 MW. The contract quantity varies over time and the price increases over time.[9] Starting on December 1, 2014, the initial quantity is 180 MWh/hr. The quantity increases to 280 MWh/hr on December 1, 2015, and to 380 MWh/hr on December 1, 2016. The delivery rate thereafter remains steady through December 31, 2024. On January 1, 2025, the contract quantity decreases to 300 MWh/hr through the termination date, December 31, 2025.

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[6] RCW 80.04.570(8). <u>The Commission is keenly aware that the Legislature strictly limited the applicability of an equity adder concept to coal transition contracts and did not authorize such a feature in connection with any other power purchase agreement or, indeed, any other form of contract for the sale and purchase of electricity. The action we take here, therefore, cannot be considered precedential in any sense or an indication of a change in the Commission's traditional views regarding the regulatory treatment of purchased power.</u>

[7] *See* Exhibit No. RG-8HC at 434-447. *See also* RCW 80.80.100.

[8] *Id.*

[9] *See* Exhibit No. RG-1HCT at 9:1-11:2; *see also* Exhibit No. RG-3C at 16-17 (Coal Transition PPA Section 3.1) and 45 (Exhibit B to Coal Transition PPA). The exact pricing terms are designated "Confidential" under Order 01 Protective Order with "Highly Confidential" Provisions, entered in this proceeding on September 10, 2012.

16 On August 20, 2012, PSE filed its Petition seeking Commission approval of the Coal Transition PPA under RCW 80.04.570.[10] PSE's filing included supportive testimony and exhibits by Ms. Barnard, Mr. Bevil, Mr. Garratt and Ms. Selig.[11]

17 Staff, Public Counsel and NWEC each filed response testimony and exhibits on November 2, 2012. Each party sponsors one witness: Mr. Gomez for Staff, Mr. Woodruff for Public Counsel and Ms. Dixon for NWEC. While it is fair to observe that none of these witnesses flatly opposed Commission approval of the Coal Transition PPA, it is equally fair to observe that none offers unqualified support for PSE's Petition. Although ICNU did not file testimony, its representative participated in oral argument following the evidentiary hearing and supported various positions taken by these parties.

18 Mr. Garratt and Ms. Barnard filed rebuttal testimony for PSE on November 16, 2012. They contest the principal issues raised by the response testimonies and clarify PSE's initial filing with respect to certain secondary issues. Mr. Garrett filed supplemental rebuttal testimony on November 19, 2012 in response to corrections Mr. Gomez filed to his responsive testimony on November 15, 2016.

19 The Commission conducted evidentiary hearings on December 12, 2012. We heard oral argument from all parties on December 20, 2012.

II. Issues

20 The Legislature has set forth the standards, which, if met, mean that we "must approve" the PPA.

> The commission must approve a power purchase agreement for acquisition of coal transition power pursuant to this section only if the

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[10] Petition for Approval of a Power Purchase Agreement for Acquisition of Coal Transition Power, as Defined in RCW 80.80.010, and the Recovery of Related Acquisition Costs.

[11] Ms. Barnard testifies concerning the proposed cost recovery methodology. Mr. Bevil testifies about 2011 RFP process and the quantitative and qualitative evaluation of the TransAlta CTPPA. Mr. Garratt testifies about the IRP and RFP and the Company's internal decision-making processes and about PSE's proposed calculation of the equity component allowed under the statute. Ms. Selig offers a more detailed look into PSE's quantitative analyses.

> commission determines that, considering the circumstances existing at the time of such a review: The terms of such an agreement provide adequate protection to ratepayers and the electrical company during the term of such an agreement or in the event of early termination; the resource is needed by the electrical company to serve its ratepayers and the resource meets the need in a cost-effective manner as determined under the lowest reasonable cost resource standards under chapter 19.280 RCW, including the cost of the power purchase agreement plus the equity component as determined in this section. As part of these determinations, the commission shall consider, among other factors, the long-term economic risks and benefits to the electrical company and its ratepayers of such a long-term purchase.[12]

Further, the Legislature set forth the methodology for determining the "equity component" the utility entering into such a PPA may earn.

> (6)(a) Upon commission approval of an electrical company's power purchase agreement for the acquisition of coal transition power in accordance with this section, the electrical company is allowed to earn the equity component of its authorized rate of return in the same manner as if it had purchased or built an equivalent plant and to recover the cost of the coal transition power under the power purchase agreement. Any power purchase agreement for the acquisition of coal transition power that earns a return on equity may not be included in an imputed debt calculation for setting customer rates.
> (b) For purposes of determining the equity value, the cost of an equivalent plant is the least cost purchased or self-built electric generation plant with equivalent capacity. In determining the least cost plant, the commission may rely on the electric company's most recent filed integrated resource plan. The cost of an equivalent plant, in dollars per kilowatt, must be determined in the original process of commission approval for each power purchase agreement for coal transition power.
> (c) The equivalent plant cost determined in the approval process must be amortized over the life of the power purchase agreement for acquisition of coal transition power to determine the recovery of the equity value.

[12] RCW 80.04.570(4).

(d) The recovery of the equity component must be determined and approved in the review process set forth in this section. The approved equity value must be in addition to the approved cost of the power purchase agreement.[13]

21 No party contests PSE on the question whether the Coal Transition PPA is needed by the Company to serve customers. Mr. Gomez testifies that "Staff stipulates that the [Coal Transition] PPA is needed by PSE to serve its ratepayers over the term of the contract, and that the [Coal Transition] PPA meets this need in a cost-effective manner."[14] Staff and the other parties do not oppose Commission approval of the Coal Transition PPA but recommend that various conditions be imposed to provide "adequate protection to ratepayers," as required under RCW 80.04.570(4).

22 Staff and Public Counsel challenge PSE on the question of what is the cost of an equivalent plant for purposes of determining how much equity return PSE should be allowed to recover under the statute.[15] As summarized below, Staff raises several additional issues related to the "equity adder" proposed by PSE:

- Staff and Public Counsel challenge PSE's proposal to measure the cost of an equivalent plant based on a bid the Company received during its most recent Integrated Resource Plan (IRP) and associated Request for Proposals (RFP) process, but rejected.[16] They contend that, considering the IRP/RFP analyses and results, PSE did not select the "least cost purchased or self-built electric generation plant with equivalent capacity."[17] Staff and Public Counsel propose that the Commission rely on the Company's selection and purchase in November 2012 of the Ferndale Combined Cycle Turbine Cogeneration Facility, which was identified as a least cost option through the 2011 RFP process.

[13] RCW 80.04.579(6).

[14] Exhibit No. DCG-1HCT at 3:16-17. Staff clarified during oral argument that this stipulation depends on the equity adder cost of the contract being based as advocated by Staff, not the higher level based on PSE's proposed "cost equivalent plant."

[15] RCW 80.04.570(6)(a).

[16] By way of shorthand reference in this Order, we sometimes refer to the two-step process as the "IRP/RFP."

[17] RCW 80.04.570(6)(b).

- Staff challenges PSE's proposal to fix the equity return throughout the term of the Coal Transition PPA at 7.24 percent, the Company's currently authorized pre-tax weighted average cost of equity return. Staff argues the return should be adjusted as set in subsequent PSE general rate cases.[18]
- There is a methodological dispute between PSE and Staff concerning the calculation of levelized costs for purposes of setting the equity adder value.
- Staff recommends that the equity adder should be allowed only for power generated by coal fuel at the CTCF or a substitute source of energy if required by an abnormal circumstance of limited duration that prevents delivery from the CTCF.

23 Public Counsel and NWEC both initially recommended that we impose conditions requiring changes in the structure and specific terms included in the Coal Transition PPA. Public Counsel withdrew its proposal during oral argument but NWEC's recommendation remains at issue. NWEC challenges Section 10.1 of the Coal Transition PPA, which implements RCW 80.04.570(2), arguing that it should be revised to establish TransAlta as the assumed risk taker in the event of future greenhouse gas emissions regulations or requirements, while still allowing for a contract reopener at the time of any such regulations or requirements to assess specific details, if needed.

24 Public Counsel initially argued that the Commission should condition approval of the Coal Transition PPA by requiring the contract to be restructured to include a unit contingency requirement (*i.e.,* PSE's obligation to take power at any given time is contingent on the plant actually operating at a certain level) and by giving PSE dispatch rights. During oral argument Public Counsel said it would not urge the Commission to require contract reformation, but instead urged that we recognize the absence of such rights in the Coal Transition PPA make it too reliant on the use of resupply power.[19] Public Counsel recommends that the Commission accept Staff's position that resupply power be narrowly defined and that PSE's right to equity return

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[18] PSE states on rebuttal that while accepting Staff's recommendation will increase the complexity of the return calculation, "PSE can accept the proposal." Exhibit No. RG-10HCT at 33:15-34:2.

[19] *See* TR. 290:23-291:24 (ffitch).

should apply only to power produced by the CTCF and the limited amount of resupply power that would qualify under Staff's proposal.

25 Staff and NWEC recommend that the Commission condition approval of the Coal Transition PPA to protect the relationship between the Coal Transition PPA and TransAlta's obligations to provide financial support to affected communities under the MOA and RCW 80.80.100. Public Counsel subscribed to this position during oral argument.

26 Finally, Staff challenges PSE's proposal to defer certain costs during the life of the Coal Transition PPA.

III. Discussion and Decisions

A. Equity Return

1. What is the Cost of an "Equivalent Plant"?

27 *Commission Determination: We find that the cost of an equivalent plant for purposes of calculating the amount of equity return to which PSE is entitled under RCW 80.04.570(6) is $110 million.*

28 RCW 80.04.570(6)(a) provides that PSE is allowed to earn the equity component of its authorized rate of return on the Coal Transition PPA "in the same manner as if it had purchased or built an equivalent plant." RCW 80.04.570(6)(b) states how the Commission should determine the value of an equivalent plant for purposes of calculating the equity return to which a coal transition power purchaser is entitled under the statute:

> For purposes of determining the equity value, the cost of an equivalent plant is the *least cost* purchased or self-built electric generation plant with *equivalent capacity*. In determining the least cost plant, the commission *may rely* on the electrical company's most recent filed integrated resource plan. The cost of an equivalent plant, in dollars per kilowatt, must be determined in the original

> process of commission approval for each power purchase agreement for coal transition power.[20]

These requirements are by no means prescriptive. They offer guidance but also give the Commission significant latitude to determine the cost of an equivalent plant for purposes of calculating the equity return available for a coal transition power purchase agreement based on the record and the application of informed judgment.[21]

29 Three parties address this issue: PSE, Staff and Public Counsel. These parties all suggest that we should rely on the Company's most recently completed IRP and the associated RFP process in which the Coal Transition PPA and acquisition of Ferndale were selected as providing together the least cost means by which PSE can satisfy its capacity needs in the near to intermediate term. The parties differ, however, in their perspectives on what information garnered during this process should be the focus of our determination and they propose significantly different outcomes.

30 PSE, focusing on a plant acquisition proposal received but rejected during the 2011 RFP process, argues the cost of an equivalent plant is $215 million. Staff and Public Counsel focus on a plant acquisition bid into the 2011 RFP that PSE ultimately purchased in November 2012 for $84.2 million: the Tenaska Ferndale Cogeneration Facility (Ferndale). Staff considers Ferndale's unadjusted purchase price as the cost of an equivalent plant. Public Counsel adjusts for the larger volumes under the Coal Transition PPA relative to Ferndale's capacity and allows for certain transaction costs and costs of improvements, and arrives at $110 million as the cost of an equivalent plant.

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[20] RCW 80.04.570(6)(b) (emphasis added).

[21] This is necessary, among other reasons, because it is highly unlikely that an actual plant available for purchase at any given time will match perfectly in its operating characteristics the purchaser's requirements and seller's obligations under a purchase power agreement. Indeed, PSE's witness, Mr. Garratt, recognizes that "the Coal Transition PPA is a firm, 24x7 product, and the capacity factors of the projects bid into the 2011 RFP are less than 100%." Exhibit No. RG-1HCT at 24:16-17. Public Counsel's witness, Mr. Woodruff, testifies in this vein that "no plant can operate at a 100 percent capacity factor." Exhibit No. KDW-1HCT at 30:17-31:6. Accordingly, he says, "there is arguably no plant that is truly equivalent to the Coal Transition PPA and thus no 'true capital cost of an equivalent plant.'" *Id.*

31 Mr. Garratt explains the method PSE used to determine the equity amount it believes the Company should be entitled to recover under RCW 80.80.570(6).[22] PSE first calculated an equivalent plant size of 346 MW, based on the average volume of power to be delivered during the term of the Coal Transition PPA. PSE then calculated a projected cost of an equivalent plant of approximately $215 million, based on the per kilowatt cost of a plant ownership proposal PSE received in response to its 2011 RFP, but rejected.[23] According to Mr. Garratt, this ownership proposal for the Alternative Plant yielded the least cost purchased or self-built electric generation plant (expressed in dollars per kilowatt) among the proposals that PSE decided not to pursue as a result of the 2011 RFP.

32 Both Staff and Public Counsel contest PSE's exclusive focus on the Alternative Plant ownership proposal as the proper measure of an equivalent plant under the statute. Mr. Gomez testifies that Staff disagrees with the Company's decision to pass over what actually was the least cost purchase offer PSE received in response to its 2011 RFP, the Ferndale[24] project offered for sale by Tenaska Washington Partners. Mr. Gomez says that neither logic nor the law support PSE's view that Ferndale no longer qualifies as a touchstone for making the cost equivalent plant determination because it was chosen in the RFP for acquisition in conjunction with a revised offer PSE received from TransAlta.[25]

33 Mr. Woodruff testifies similarly that the Alternative Plant is not an appropriate measure of an equivalent plant under the statute, for several reasons. First, he

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[22] Exhibit No. RG-1HCT at 24:10-29:3; Exhibit No. RG-9.

[23] The identity of the specific plant is designated "Highly Confidential" under Order 01 Protective Order with "Highly Confidential" Provisions, entered in this proceeding on September 10, 2012. We will refer to it for purposes of this Order as the "Alternative Plant."

[24] Exhibit No. RG-8HC at 372.

[25] Exhibit No. DCG-1HCT at 9:20-12:2. Mr. Gomez also states that "the [Ferndale] plant was not chosen until after the selection of the CTCF." Mr. Garratt says on rebuttal that "PSE made the decision to acquire the Ferndale Cogeneration Station before it determined to enter into the Coal Transition PPA." Exhibit No. RG-10HCT at 26:8-9. In point of fact, it appears that Ferndale actually was chosen in conjunction with the revised Coal Transition PPA that PSE ultimately selected to meet its identified capacity needs through about 2016. *See generally* Exhibit No. CB-3HC.

agrees with Staff that this is not the least cost plant demonstrated by the 2011 RFP to be available to PSE.[26] Mr. Woodruff points out that PSE acknowledged in discovery that the lowest cost option identified in the 2011 RFP was the proposal for Ferndale, which has an estimated cost about one-half of the Alternative Plant cost.[27] He says that PSE, in its response to Staff's discovery, justified choosing the Alternative Plant proposal on the basis that it represents the "*next* lowest capital cost" resource after Ferndale. PSE's discovery response contends Alternative Plant is the "lowest capital cost resource *available* to PSE" because the Company elected to acquire Ferndale.[28]

34 Mr. Woodruff argues that the Alternative Plant is not the least cost alternative either under a plain English reading of the statute or if "least cost" is considered as a term of art in electric utility resource planning nomenclature. He says that "in the electric utility industry, the term 'least cost' refers to the "electric resource(s) expected to provide a utility's customers with reliable service at the lowest overall expected long-term cost."[29] He testifies that PSE itself found that Alternative Plant did not meet this criterion during the 2011 RFP.

35 Mr. Woodruff refers specifically to PSE's July re-evaluation of revised offers it received during the RFP evaluation process showing that the Alternative Plant is not PSE's least cost resource option.[30] The exhibit to which Mr. Woodruff refers shows that in PSE's original optimization results, the Alternative Plant was not selected as part of any least cost portfolio in any of the five analytic scenarios. Indeed, it is the only resource among ten options that was not selected in at least one of the five scenarios.[31] The Alternative Plant also was not chosen in the additional optimization analyses performed on the revised proposals PSE received on June 22, 2012, and July

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[26] Exhibit No. KDW-1HCT at 26:17-31:18.

[27] Exhibit No. KDW-14HC (PSE response to Staff Data Request No. 2).

[28] *See*, Exhibit No. KDW-14HC at 3; *See also*, Exhibit No. RG-1HCT at 25:16-20.

[29] Exhibit No. KDW-1HCT at 27:19-28:3.

[30] *Id.* at 24:4-8 (referring to Exhibit No. CB-4HC).

[31] Exhibit No. CB-4HC at 4 (Figure 2). *See also* Exhibit CB-1HCT at 25:1-3 ("the Alternative Plant ownership . . . price sensitivity analysis [showed that] the Alternative Plant ownership purchase price needed to be reduced by approximately 50% just to be least cost in three of five scenarios."

5, 2012.[32] In addition, PSE found in its qualitative review that the Alternative Plant "[p]roject economics [are] less favorable than alternatives."[33]

36 Both Mr. Gomez and Mr. Woodruff testify that the Alternative Plant also is an inappropriate selection as an equivalent plant because it does not meet the capacity criterion for selection as a resource from which to calculate the equity return component of the Coal Transition PPA.[34] Mr. Gomez testifies that as part of PSE's Phase II Qualitative Risks analysis the Company determined that the "capacity output of [the Alternative Plant] facility is large and would produce a substantial surplus of PSE's capacity need until 2016 based on current load forecast."[35] Mr. Gomez says the Ferndale facility's 280 MW is a closer match for the 327 MW[36] of average energy he calculates will be delivered to PSE from the Coal Transition PPA, and the 221 MW of capacity that was originally envisioned in the 2011 IRP for a self-build single cycle combustion turbine plant.

37 Mr. Woodruff testifies similarly that the capacity of Alternative Plant is considerably greater than the capacity of the Coal Transition PPA, which averages 346 MW and varies between 180 MW and 380 MW.[37] Mr. Woodruff says that while neither Alternative Plant nor Ferndale is precisely the same capacity as the Coal Transition PPA, Ferndale is much closer to the Coal Transition PPA's capacity and hence a better equivalent. Mr. Woodruff also points out that Alternative Plant is not among the four resources found during PSE's reevaluation of proposals to meet the

[32] *Id*. at 5-6 (Figures 3 and 4).

[33] *Id*. at 10.

[34] The Alternative Plant, in fact, is significantly larger than the capacity acquired via the Coal Transition PPA. *See* Exhibit No. DCG-1HCT at 10:16-17; *see also* Exhibit No. KDW-1HCT at 29:9-30:2.

[35] Exhibit No. DCG-1HCT at 10:17-20 (quoting Exhibit No. CB-4HC at 10).

[36] It is not clear how Mr. Gomez calculated this number. Mr. Garratt testifies that the average volume of power to be delivered over the life of the contract is 346 MW. Exhibit No. RG-1HCT at 24:12-13. Mr. Woodruff also finds an average delivery of 346 MW. Exhibit No. KDW-1HCT at 29:9-18.

[37] Exhibit No. KDW-1HCT at 29:7-18.

Company's identified capacity need while both the Coal Transition PPA and Ferndale were determined to meet this need.[38]

38 Mr. Gomez and Mr. Woodruff offer several additional reasons why Ferndale should be considered an equivalent plant rather than the Alternative Plant. Mr. Gomez, for example, points to the RFP scoring results for Phase II showing the Alternative Plant offer as having a *negative* portfolio benefit of $62.4 million, with significantly higher risks associated with the acquisition than the Ferndale plant offer with its portfolio benefit of $96.1 million.[39] Mr. Woodruff testifies additionally that the Company's analyses show it found that there were qualitative risks associated with the condition of the plant, the availability and cost of transmission, the adequacy of the pipeline capacity, and the likely possibility that the plant could not be economically be upgraded to meet Emissions Performance Standards.[40] Thus, Mr. Woodruff concludes, there are a number of quantitative and qualitative reasons that disqualify Alternative Plant from consideration for setting the cost of an equivalent plant under RCW 80.04.570.

39 We find that the facts and analyses available to us from the 2010 IRP/2011 RFP process militate strongly in favor of using Ferndale as a key factor in our determination of a cost equivalent plant for purposes of RCW 80.04.570(6). While PSE originally identified a 500 MW power purchase agreement with TransAlta as a preferred means to meet its near-term resource needs, subsequent developments brought the 280 MW Ferndale plant to the forefront as a way to meet the Company's identified need through 2013 (*i.e.*, 242 MW).[41] The Ferndale acquisition option was selected in conjunction with negotiation of a 380 MW option for coal transition power that would add 180 MW of additional capacity in 2014 and 280 MW in 2015. These incremental increases satisfy PSE's projected needs for capacity additions (*i.e.*, 460 MW in 2014 and 554 MW in 2015). Beginning in 2016, the Coal Transition PPA would add 380 MW of capacity and,

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[38] Exhibit No. CB-4HC (Figure 11).

[39] *See* Exhibit No. DCG-1HCT at 11:3-11 (citing Exhibit No.CB-4HC at 18).

[40] Exhibit No. KDW-1HCT at 30:9-16 (citing Exhibit No. CB-4HC at 10).

[41] *See* Exhibit No. CB-1HCT at 15:6 and related discussion at 14:1-15:14. *See also* Exhibit No. RG-10HCT at 2:1-14.

again in conjunction with Ferndale, would meet much of PSE's identified supply-side capacity requirement (*i.e.,* 728 MW) at that time.[42]

40 In other words, PSE determined on the basis of its own careful analysis during the RFP process that the combination of Ferndale and the Coal Transition PPA represents the 'least cost' alternative to meet the Company's capacity needs as identified in the 2010 IRP load forecast as updated in connection with the 2011RFP process.[43] That is, these are the electric resources expected to provide PSE's customers with reliable service at the lowest overall expected long-term cost.

41 On the other hand, PSE's analyses during the 2011 RFP process showed that the Alternative Plant was not a viable option for meeting these supply side capacity needs. It cannot be regarded as a "least cost" alternative in the context of the IRP/RFP process in which PSE evaluated it. It is not by most, if any, measures equivalent to the Coal Transition PPA. Indeed, by both quantitative evaluations and qualitative considerations it cannot be found to represent the least cost mix of electric resource(s) expected to provide PSE's customers with reliable service at the lowest overall expected long-term cost. The Alternative Plant purchase offer is simply not a good measure, or basis for measurement, of the cost of a plant equivalent to the Coal Transition PPA.[44]

42 Our focus, given the evidence before us, is on what was available for purchase in response to the 2010-2011 IRP/RFP process. Ferndale was available and, indeed,

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[42] *Id.; See also* Exhibit No. RG-10HCT at 3:1 ("The Coal Transition PPA ramps to match PSE's capacity need over time") and 17:3-5 ("PSE concluded that the Ferndale Cogeneration Station ownership offer and the Coal Transition PPA offer are least cost and least risk resources after considering the quantitative and qualitative analyses performed in the 2011 RFP.").

[43] See *Id.* at 17:3-5.

[44] The fact that the Alternative Plant was arguably available as a substitute for the Coal Transition PPA, even if that argument had merit, is simply beside the point. It is entirely conceivable that no actual plant sale, or offer to sell, could be considered to be "the least cost purchased or self-built electric generation plant with equivalent capacity" under RCW 80.04.570(6)(b). In any event, PSE's argument that the Alternative Plant was available to meet the need identified in the IRP/RFP process does not hold up under the Company's own evaluation of alternatives, in which it was rejected as an option.

was selected for acquisition in conjunction with the selection of the Coal Transition PPA. This weighs strongly in favor of using the Ferndale plant cost as the measure of the per kWh price of an equivalent plant for the full capacity acquired to meet PSE's requirements through at least 2016. PSE, in contrast, would have us ignore the transaction it selected as least cost in favor of a transaction it rejected because it was not least cost and was otherwise an unsuitable option for meeting the Company's resource needs.[45] This defies logic.

43 We find that the best evidence for determining the cost of an equivalent plant for purposes of RCW 80.04.570 is the price that PSE paid for Ferndale.[46] PSE determined via the 2011 RFP process that Ferndale is the least cost electric generation plant with capacity that PSE might otherwise have obtained under the original coal transition PPA it evaluated. Although Ferndale's capacity is a bit less than the amount PSE contracted for under the Coal Transition PPA, it is easy enough to adjust for this and determine the full cost of an equivalent plant following PSE's approach. Thus, using 346 MW as the appropriate size plant, considering average deliveries of power over the life of the Coal Transition PPA, coupled with the per kilowatt price PSE paid for Ferndale (*i.e.*, $318/kW), we determine the cost of an equivalent plant is $110 million.[47]

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[45] We note in this connection that there is nothing in RCW 80.04.570 that requires the Commission to base its determination of the cost of an equivalent plant on the bid price of a plant actually available for sale at the time. It is entirely conceivable that no such plant would even exist at the time of the Commission's evaluation.

[46] In the language of property valuation, Ferndale can be regarded as a "comparable sale." The Alternative Plant bid, in contrast, represents nothing more than an offer that did not meet with acceptance in the market.

[47] The $318/kW price was calculated by PSE. *See* Exhibit No. DCG-4HC (PSE Response to Staff Data Request 2). This price includes PSE's estimated costs to effect certain plant improvements "to meet PSE's compliance and design standards," and transaction costs. Staff objects to the recognition of these costs when determining the cost of equivalent plant. *See* Exhibit DCG-1HCT at 11:11-14. We find, however, that it is appropriate to consider these costs and recognize them in making our determination.

2. Should the Rate of Return on Equity be Constant over the Life of the Contract?

44 *Commission Determination: Considering the unique ratemaking requirements imposed by RCW 80.04.570, we find that it is appropriate to accept PSE's proposal to hold the equity return component constant at PSE's currently authorized pre-tax weighted average cost of equity of 7.24 percent for the term of the Coal Transition PPA.*

45 PSE proposes that the Commission set the equity return rate at the currently authorized pre-tax weighted average 7.24 percent for the entire term of the Coal Transition PPA, regardless of what the Commission may allow as an authorized equity ratio or return on equity in future rate proceedings.[48] Mr. Garratt testifies that: "[f]or ease of calculation, this pre-tax weighted average cost of equity remains fixed throughout the term of the Coal Transition PPA."[49]

46 Mr. Gomez testifies that Staff sees no reason why the equity return rate should remain the same throughout the term of the Coal Transition PPA. He contends it should change just as PSE's authorized return on equity applicable to other assets changes from one general rate case to another.[50]

47 Mr. Garratt reiterates on rebuttal that PSE proposed to use its currently authorized pre-tax weighted average cost of equity return for the term of the Coal Transition PPA to simplify the up-front calculation of total equity return, which is required to be recovered on a levelized basis over the life of the contract. Mr. Garratt says that Staff's proposal will increase the complexity of the return calculation but "PSE can accept the proposal."[51]

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[48] This pre-tax weighted average cost of equity of 7.24% reflects the return on equity and equity ratio authorized by the Commission in PSE's most recent general rate proceeding.

[49] Exhibit No. RG-1HCT at 26:18-19.

[50] Exhibit No. DCG-1HCT at 12:4-18.

[51] Exhibit No. RG-10HCT at 34:1-2.

48 Our determination of this issue is influenced by the unique ratemaking requirements imposed by RCW 80.04.570. We are directed to allow PSE to earn return on the Coal Transition PPA based on the cost of an equivalent plant, as if PSE were acquiring a hard asset and adding it to rate base. In the case of a hard asset, PSE's capital investment would be depreciated over a fixed term and PSE is allowed to earn a return on a declining rate base at whatever rate of return on equity the Commission authorized from time to time. This is not an appropriate approach in the case of the Coal Transition PPA because most of the total equity return would be recovered during the early years of the contract, putting customers at risk in the event of early termination of the agreement. This effect is exacerbated by the short duration of the Coal Transition PPA relative to the depreciable life of an actual plant in which PSE makes an actual capital investment. We should avoid risk and uncertainty for PSE's customers who pay the costs of the Coal Transition PPA to the extent this can be accomplished.

49 It is more reasonable, then, for the Commission to determine at the outset the full amount of return PSE will be allowed to recover over the life of the Coal Transition PPA and provide for recovery of the total amount on a levelized basis over the term of the contract. This levelized return, recovered on a per MWh basis, protects customers in the event the contract is terminated early. This is PSE's approach. We find it both simple and sensible. We accordingly determine that it is appropriate in this unique situation to fix the allowed return on the Coal Transition PPA at PSE's currently authorized pre-tax weighted average cost of equity: 7.24 percent return.

50 There is a second factor to consider in this connection, though it was not addressed explicitly by the parties. This is the question of income tax effect. The 7.24 percent pre-tax weighted average cost of equity is calculated using PSE's currently authorized rate of return on equity of 9.8 percent, its currently authorized equity share in the Company's capital structure of 48 percent and the currently effective federal corporate income tax rate of 35 percent. The formula is: (9.8% x 48%)/65% = 7.24%. While we determine PSE's authorized rate of return on equity in general rate cases we have no control over the federal income tax rate. PSE is at risk if the corporate income tax rate increases. Ratepayers are at risk if it decreases. Should the corporate income tax rate change during the term of the Coal Transition PPA, the Commission may consider in an appropriate case whether the equity adder should be adjusted to reflect the new rate.

3. How Should Levelized Cost be Determined?

51 *Commission Determination: We find that PSE's method for levelizing the total equity return over the term of the contract, recognizing the net present value of the stream of payments PSE will receive if the contract runs its full term, is reasonable. We apply this method in conjunction with our $110 million equivalent plant value and determine that the cost to customers of the adder for the equity component will be $1.49/MWh.*

52 Mr. Garratt testifies that a levelized cost approach results in equal (or "levelized") payments over the applicable time period (*e.g.*, the term of a power purchase agreement or the depreciable life of a rate-based asset) and which has an equivalent present value to the present value of the stream of payments based on the traditional, front-end loaded regulatory methodology resulting from earning a fixed return upon a declining asset value.[52] Mr. Garratt says this approach was discussed with stakeholders during the legislative process that led to the coal transition provisions in Chapter 80.80 RCW and RCW 80.04.570 as a way to protect customers in the event of early termination of the Coal Transition PPA.[53]

53 According to Mr. Garratt, PSE calculated the levelized cost of the equity component of the Coal Transition PPA using its currently authorized weighted average cost of capital (*i.e.,* 7.8 percent) as its interest cost. Mr. Garratt testifies that this accounts for the time value of money using a methodology that PSE has used to levelize costs in all of PSE's requests for proposals for the past ten years.[54]

54 Staff, however, uses an interest rate of zero, effectively calculating a simple average by dividing the nominal equity amount by the time period for payments (*i.e.,* 133 months). Thus, Staff ignores the cost of deferring payments by calculating simple average cost rather than the levelized cost of the net present value.[55]

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[52] Exhibit No. RG-15T at 2:23-3:5.

[53] *Id.* at 3:8-10.

[54] *Id.* at 3:13-18

[55] *Id.* at 4:17-18.

55 Mr. Garratt, using PSE's cost equivalent plant value and fixed rate of return, demonstrates that Staff's use of a simple average cost rather than PSE's levelized cost results in a return of $2.57/MWh as compared to the $2.92/MWh result using PSE's methodology.[56] Staff's approach, applied to PSE's return calculation, would mean that the net present value of the stream of equity payments to PSE over the life of the Coal Transition PPA would be $57.39 million. This is significantly less than the $66.76 million net present value of the equity return PSE would realize from a $215 million plant depreciated over the term of the Coal Transition PPA or the $65.26 million net present value calculated using PSE's methodology.[57]

56 We determine that PSE's methodology for levelizing costs is appropriate to use. It would not be fair to PSE to ignore the time value of money in making this determination. Even though it results in PSE recovering more return on a nominal basis over the term of the Coal Transition PPA than the nominal return that would result under traditional ratemaking,[58] PSE's approach protects ratepayers by spreading the authorized return over the entire volume of power deliveries. This means that, consistent with the statutory directive,[59] customers do not bear the risks of early termination.

57 Using the method we approve, coupled with our decisions on the cost equivalent plant and equity return, results in an equity adder of $1.49 per MWh, assuming no change is required in the future due to a change in the federal corporate income tax rate. Equity payments to PSE at this level over the term of the contract have a net present

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[56] Exhibit No. RG-16 (compare Table 1 (Staff method) to Table 2 (PSE method)).

[57] *Id.* Columns B and Rows 26 of each of Tables 1 and 2 in Exhibit No. RG-16 calculate the net present value cost of the monthly equity returns calculated based on the respective levelized cost calculation methodologies. PSE's method results in a present value cost of $65.26 million, which is approximately equal to the original present value cost in Column B, line 16 of each of Tables 1 and 2 (*i.e.*, $66.76 million NPV at 7.8%). Commission Staff's methodology, however, results in a present value (Column B, line 26) of $57.39 million, which is 14% lower than the original present value cost in Column B, line 16 of each of Tables 1 and 2. *See also* Exhibit No. DCG-16CX.

[58] This is illustrated in Exhibit No. DCG-16CCX at 8.

[59] *See* RCW 82.04.570(4) (The Commission must determine that "[t]he terms of such an agreement provide adequate protection to ratepayers and the electrical company during the term of such an agreement or in the event of early termination . . ."_.

value of approximately $34.13 million.[60] The nominal value of this return over the full term of the Coal Transition PPA is about $44.12 million.

4. Should "Resupply Power" be Eligible for Equity Return?

58 *Commission Determination: We find that PSE should be allowed to recover an equity return on the full volume of power TransAlta delivers under the terms of the Coal Transition PPA, including resupply power. However, we will require PSE to monitor, and report to the Commission annually, TransAlta's production levels at the Centralia Coal Transition Facility. PSE will also be required to report whether and, if so, to what extent TransAlta has satisfied any part of its delivery obligations through the use of resupply power. The report must identify the amounts of resupply power by source. Although PSE expects TransAlta to continue to operate the plant in a manner that will result in most power delivered under the Coal Transition PPA being from the Centralia Coal Transition Facility, this is not required under the agreement. It is conceivable that deliveries from the facility will reach a point where the contract may be determined to no longer qualify under the terms of RCW 80.04.570 and related authority as a "coal transition PPA." In such unlikely circumstances, the Commission may initiate a proceeding to consider whether it remains prudent for PSE to continue taking deliveries under the contract and, if so, whether PSE can continue to recover any equity return in association with any volumes delivered under the contract.*

59 PSE's right to recover return is not tied to production from the CTCF under the terms of the Coal Transition PPA. Section 3.2 of the Coal Transition PPA allows TransAlta to provide power from any source or sources if, *for any reason*, the output from the CTCF is reduced or curtailed.[61] This is sometimes referred to as a "resupply provision," though that term is not defined in the Coal Transition PPA. Staff objects that there is nothing in the agreement that prevents TransAlta from cutting back on

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[60] *See* Exhibit No. KDW-1HCT at 32:1-14.

[61] Exhibit No. RG-3C (Coal Transition PPA Section 3.2 (b) (Page 17 of 51) (*emphasis added)*

CTCF power production, delivering to PSE lower cost power from other sources,[62] and then benefiting from the price arbitrage. Mr. Woodruff testifies similarly that:

> During periods when the market prices in the PNW are below Centralia's variable operating costs, TransAlta would be expected to make the economically rational decision to reduce Centralia's output – possibly to zero – and purchase power from other sources to meet its delivery obligations under the Coal Transition PPA. During such periods, this strategy should be quite advantageous to TransAlta.[63]

In addition, Mr. Woodruff makes the point that:

> There are only weak contractual links between the operation of Centralia and the delivery and pricing terms of the Coal Transition PPA. From the perspective of PSE's customers, Centralia is barely relevant to the basic structure of the Coal Transition PPA. PSE customers will be required to purchase fixed amounts of power delivered by TransAlta for every hour from December 1, 2014, to December 31, 2025 at fixed prices regardless of whether the Centralia plant is operating. [64]

60 Staff and Public Counsel both recommend that we condition any approval of the Coal Transition PPA to address these concerns. Staff makes a specific recommendation in which Public Counsel joined during oral argument.[65] Staff argues that the equity adder should be allowed only for power generated by coal fuel at the CTCF or under Staff's proposed definition of resupply. According to Mr. Gomez:

> The proper interpretation of "resupply," as it relates to a power purchase agreement for the acquisition of coal transition power, is a

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[62] Although Staff does not say so, this might include surplus power from BPA that recent events inform us may sometimes be available on the market at no cost or even at a "negative price." Even under more ordinary conditions, it is likely that power will be available on the market from time to time at lower costs than provided under the Coal Transition CTPPA.

[63] Exhibit No. KDW-1HCT at 11:3-8.

[64] *Id.*at 7:18-8:5.

[65] Public Counsel initially recommended contract reformation to resolve this issue, but dropped that position during oral argument in favor of Staff's approach.

> seller's right to substitute the source of energy *in the event of an abnormal circumstance of limited duration that prevents delivery from the CTCF*.[66]

Mr. Gomez contends that this definition should be applied to the Coal Transition PPA to provide adequate protection to ratepayers.[67] He says, in addition, that Staff's proposal in this connection "is in keeping with the law's goal of maintaining employment in affected communities."[68]

61 Mr. Garratt does not dispute that the Coal Transition PPA allows TransAlta to obtain power from sources other than the CTCF. Focusing on the several policy goals underlying greenhouse gas emissions and coal transition legislation, however, Mr. Garratt testifies that:

> Allowing resupply upon curtailment "for any reason" promotes the public interests that the Legislature sought to promote. The Legislature found that "an electrical company's acquisition of coal transition power helps to achieve the state's greenhouse gas emission reduction goals by effecting an orderly transition to cleaner fuels and supports the state's public policy." Resupply can help reduce greenhouse gas emissions by replacing coal-fired generation with power from other sources, such as hydropower during high water periods. Resupply can also promote grid stability and reliability, and the integration of wind, solar and other variable renewable energy resources, by allowing TransAlta to reduce facility generation at times when there is excess generation present on the grid.[69]

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[66] Exhibit No. DCG-1HCT at 8:5-14 (emphasis added).

[67] *Id*. at 8:5-14. It is unclear whether relieving PSE's customers from the burden of paying the equity adder would provide adequate protection to ratepayers in circumstances where market power is available at a price lower than TransAlta's variable costs, particularly if this situation persists for significant periods of time during the contract term. During such periods, PSE's ratepayers will capture none of the benefits of the lower cost power. The Coal Transition PPA, viewed as a hedge against higher power prices, may work out to customers' benefit over its full term if such higher prices eventuate. It is also possible, however, that the power prices under the Coal Transition PPA will result in PSE's customers paying more for power than would be the case if PSE had more flexibility under the terms of the contract, or made alternative arrangements to obtain power at prices indexed in one way or another to the market.

[68] *Id.* at 13:14-19.

[69] *Id.* at 30 (quoting RCW 80.04.560). *See also* RCW 80.80.005.

62 NWEC's position supports PSE in this connection. Ms. Dixon testifies that NWEC favors having TransAlta substitute lower carbon emitting sources to meet its power delivery obligations, when feasible. Indeed, Ms. Dixon, focusing on the state's policy goal of reducing emissions, testifies the public interest would benefit if the Coal Transition PPA was amended in such a way as to "incent TransAlta to take advantage of lower GHG emitting resources while still meeting the terms of the contract."[70]

63 Making an additional point, Mr. Garratt refers to an informal opinion letter drafted by the Attorney General's Office and argues that Staff's recommendation is inconsistent with the advice it gives the Governor's Office on this question. Mr. Garratt relates that the Attorney General opined that the inclusion and exercise of resupply rights in a power purchase agreement for coal transition power does not affect the statutory right of the electrical company to recover its costs, including the equity component allowed under RCW 80.04.570(6)(a).[71]

64 We recognize that there may be times when TransAlta will not be able to provide the full volume of power required under the contract from the CTCF. During the last five years of the contract term, for example, when the single generator then operating must be shut down for maintenance, it will be necessary for TransAlta to find replacement power to meet its delivery obligations. At any time during the contract term, there may be unanticipated events that require both generators to be ramped down, or shut down, for brief periods. There may be times when it simply makes sense to shut down the two generators at the same time to conduct routine maintenance. Under these circumstances, there is a reasonable sharing of risks because TransAlta will have to obtain power for delivery to PSE regardless of whether it can do so at prices lower than the variable costs of operating the plant.

65 It would be a different matter entirely, however, if TransAlta elects to shut down production from the CTCF generators and obtain power from other sources for a significant period of time, or permanently, simply because it is financially advantageous to TransAlta to do so. PSE argues, and the weight of the evidence

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[70] Exhibit No. DOD-1-HCT at 11:14-20.

[71] Exhibit No. RG-10HCT at 27:15-28:6 (citing Exhibit No. RG-8HC at 452).

supports, that this is not a likely eventuality.[72] No one denies, however, that TransAlta could continue to meet its delivery obligations using resupply power without violating the terms of the Coal Transition PPA. Were this to occur, the contract between TransAlta and PSE could be found to have lost its status as a coal transition PPA within the meaning of RCW 80.04.570 and Chapter 80.80 RCW. This is because RCW 80.80.010(5) defines "coal transition power" to mean "the output of a coal-fired electric generation facility that is subject to an obligation to meet the standards contained in RCS 80.80.040(3)(c)."

66 The informal opinion letter from the Attorney General's office to which Mr. Garratt refers addresses this concern, recognizing that a strict reading of the statute would allow only the recovery of the output of the plant, and not resupply power. However, the informal opinion rejected that conclusion as "contrary to RCW 80.04.570 as a whole, to general principles of rate-setting, and to the purposes the Legislature identified in enacting E2SSB 5759."[73] As part of its analysis, the opinion letter notes the limited nature of resupply rights, as the opinion "assumes that, given the nature of resupply rights, such rights would be exercised *intermittently* over the multi-year term of a power purchase agreement, on an as-needed basis"[74] It observes that "the actual amounts of resupply power . . . cannot be known at the time the agreement is reviewed by the Commission."[75] Also, the opinion letter explains that while "RCW 80.04.570 does not itself address resupply rights, a related statute contemplates that power purchase agreements may involve some purchased power coming from other sources, as would occur through resupply."[76] The opinion cites RCW 80.80.040(7) which provides:

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[72] *See supra* footnote 2; Mr. Woodruff testifies, for example that TransAlta probably will not opt to meet its delivery obligations entirely without generation from the CTCF. He expects that the cost of generation from the CTCF will be less at times than wholesale electricity market prices in the Pacific Northwest. Under these circumstances, he anticipates that "TransAlta would operate Centralia at high capacity factors to provide the power needed to meet its delivery obligations under the Coal Transition PPA." Exhibit No. KDW-1HCT at 9-15. Mr. Woodruff testifies in addition that "key provisions of the PPA suggest that TransAlta views Centralia as important to its continued performance under the PPA." *Id.* at 9:16-10:3.

[73] Exhibit No. RG-8HC at 453.

[74] *Id.* at 452 (emphasis added).

[75] *Id.* at 454.

[76] *Id.*

> In no case shall a long-term financial commitment be determined to be in compliance with the greenhouse gas emissions performance standard if the commitment includes more than twelve percent of electricity from unspecified sources.

67 The opinion reasons from this provision that :

> A limit on how much power may be supplied from unspecified sources plainly contemplates that agreements may involve power being provided from sources other than the power facility entering the agreement. This would include resupply power once that right is exercised.[77]

Thus, without disputing that the Coal Transition PPA may properly include a resupply provision such as found in Section 3.2 of the agreement, or that PSE may earn equity return on resupply power, we conclude that there may be a limit under the statute on the use of such power. This interpretation is consistent with, and furthers, one of the purposes of the statute. The Legislature was clear that preservation of jobs at the plant was among those purposes. A cessation of plant operations, to the extent such a cessation would result in loss of jobs would be contrary to this purpose. By our interpretation, we seek to minimize that possibility.[78]

68 We need not at this juncture determine definitively the full legal consequences that might flow from these circumstances, if they eventuate. It is better to take a conservative and practical approach than to establish a bright line beyond which the volume of resupply power means the contract between PSE and TransAlta will lose its character as a coal transition power purchase agreement.[79] It is for this reason that we issued Bench Request No. 2, to which PSE responded on December 28, 2012.

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[77] *Id.*

[78] The Legislature found that "coal-fired baseload electric generation facilities are a significant contributor to family-wage jobs and economic health in parts of the state and that transition of these facilities must address the economic future and the preservation of jobs in affected communities." Laws of 2011, ch. 180, § 101(4).

[79] We also need not determine today the full legal consequences of such a finding. We note, however, that it could support a conclusion that PSE is no longer entitled to recover equity return on deliveries under the agreement.

The confidential information PSE provided in its response shows the Historical Generation of the CTCF in GWhs on a quarterly basis from the 1st Quarter of 2008 through the 4th Quarter of 2012, as of the time of the response. These data show that TransAlta's operations of the CTCF are consistently at a level, in all quarters of the year, that would result in all power delivered under the Coal Transition PPA being from the facility.[80] Over the five years reported, had the Coal Transition PPA been in effect, only 10 percent of the deliveries to PSE would have been considered resupply power.

69 We determine that it is necessary to condition our approval of the Coal Transition PPA in connection with this issue only to the extent of imposing a reporting requirement. This will enable the Commission to know if TransAlta exercises its resupply right to a degree that might be found to put the Coal Transition PPA in jeopardy. If Commission Staff's continuing review suggests that the contract has lost its identity as a coal transition agreement, the Commission may initiate proceedings to determine whether this is the case and, if so, what consequences flow from the determination.

B. Contract Structure and Terms

1. Should Section 10.1 of the Coal Transition PPA be Modified to Establish TransAlta as the Assumed Risk Taker in the Event of Future Greenhouse Gas Emissions Regulations or Requirements?

70 *Commission Determination: Section 10.1 of the Coal Transition PPA implements RCW 80.04.570(2) using largely the terms of the statute itself. We reject NWEC's recommendation that we require the PSE and TransAlta to reopen their negotiations and modify the contract to reflect NWEC's policy position, which in this instance is contrary to what the statute provides.*

[80] Section 3.2 of the Coal Transition PPA effectively provides that TransAlta will "supply the Hourly Contract Quantity from the CTCF" unless "the output of the CTCF is reduced or curtailed."

71 NWEC is concerned Section 10.1 of the Coal Transition PPA, which implements RCW 80.04.570(2).[81] Employing the language of the statute, Section 10.1 provides that if new or revised emission performance standards or operational or financial requirements related to greenhouse gas emissions are imposed by law, PSE and TransAlta will initiate a process to modify the agreement to their mutual satisfaction. Any such agreement is subject to Commission review and approval, as expressly required by the statute. Finally, as provided in RCW 80.04.570(2), if PSE and TransAlta cannot agree, either party has the right to terminate the Coal Transition PPA without liability, if the party is adversely affected by the new standard or requirement.

72 Ms. Dixon testifies that NWEC does not support the Coal Transition PPA provisions as written. NWEC's position is that TransAlta should absorb the risk of future GHG emissions regulations. Ms. Dixon says the Coal Transition PPA could establish TransAlta as the assumed risk taker in the event of future greenhouse gas emissions regulations or requirements, while still allowing for a contract reopener at the time of any such regulations or requirements to assess specific details, if needed.

73 It is not entirely clear what NWEC is proposing, but it appears to be that we condition approval of the Coal Transition PPA by requiring the parties to reopen their negotiations now and somehow agree to place the risk of future greenhouse gas emissions requirements on TransAlta. This would, in Ms. Dixon's concept,

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[81] RCW 80.04.570(2) reads:

> Any power purchase agreement for the acquisition of coal transition power pursuant to this section must provide for modification of the power purchase agreement to the satisfaction of the parties thereto in the event that a new or revised emission or performance standard or other new or revised operational or financial requirement or limitation directly or indirectly addressing greenhouse gas emissions is imposed by state or federal law, rules, or regulatory requirements. Such a modification to a power purchase agreement agreed to by the parties must be reviewed and considered for approval by the commission, considering the circumstances existing at the time of such a review, under procedures and standards set forth in this section. In the event the parties cannot agree to modification of the power purchase agreement, either party to the agreement has the right to terminate the agreement if it is adversely affected by this new standard, requirement, or limitation.

"internalize the cost of environmental harm into the cost of [the] product."[82] She acknowledges that if TransAlta assumes the risk of future GHG regulations, the agreed upon power price terms could change.

74 PSE does not address this issue in its rebuttal testimony.

75 As we stated at the beginning of this discussion, Section 10.1 of the Coal Transition PPA tracks very closely the language of the statutory provision that requires it. It is difficult to conceive how PSE and TransAlta could modify Section 10.1 along the lines NWEC suggests without running afoul of what the legislature intended by drafting RCW 80.04.570(2) using the language it chose. In particular, requiring TransAlta to expressly assume the risk of a change in greenhouse gas emission standards would seem to eliminate any claim by TransAlta that it is adversely affected by the change. Thus, TransAlta would not be able to exercise its right, expressly conferred by the statute, to terminate the Coal Transition PPA without liability "if adversely affected by the new standard or requirement, or limitation."[83]

76 The conflict between NWEC's proposal and the requirements of RCW 80.04.570(2), which Section 10.1 of the Coal Transition PPA implements, is reason enough to reject it. In addition, however, we cannot square NWEC's tacit acknowledgement that power prices under the Coal Transition PPA would likely increase if we effectively require TransAlta to internalize now the costs of possibly more stringent environmental regulations in the future, with NWEC's claim that this somehow protects "the interest of PSE customers in avoiding future risk of GHG emissions."[84] Quite the contrary is true. Higher prices under the Coal Transition PPA would simply pass on to ratepayers for the full term of the contract the increased risks TransAlta would assume relative to a change in the law that may or may not occur during its term. We reject NWEC's recommendation.

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[82] Exhibit No. DOD-1HCT at 11:2. Ms. Dixon testifies in addition that modifying Section 10.1 of the Coal Transition PPA as NWEC recommends "could incent TransAlta to take advantage of lower GHG emitting resources while still meeting the terms of the contract." *Id.* at 11:14-20. The specific contract term to which Ms. Dixon refers is Section 3.2, the provision Staff is concerned about in connection with its proposed treatment of "resupply power."

[83] RCW 80.04.570(2).

[84] Exhibit No. DOD-1HCT at 10:19-11:13.

C. Relationship Between the Coal Transition PPA and TransAlta's Performance under the MOA

77 *Commission Determination: We conclude as a matter of law that if TransAlta terminates the MOA prior to the time PSE begins taking power in December 2014, or subsequently, PSE is not relieved of its obligations under the contract.*[85] *Thus, we reject Staff's proposal that we deem the PPA be terminated if the MOA is terminated. We also conclude that the Commission lacks authority to effectively modify the terms of the MOA, as NWEC urges us to do.*

78 *We also determine in this connection, however, that if TransAlta terminates the MOA under Section 8(c), or the MOA is terminated or cancelled by the State of Washington as a result of a failure by TransAlta to satisfy its payment obligations under Section 3 of the MOA the Commission should initiate proceedings to consider whether to require PSE to terminate the Coal Transition PPA to the extent it may do so without incurring liability. Finally, if the MOA is terminated at any time during the term of the Coal Transition PPA, for any other reason, the Commission may initiate proceedings to determine whether the contract retains its identity as a coal transition PPA under RCW 80.04.570 and related authority, and whether PSE should be authorized to continue to recover equity return as authorized under RCW 80.04.570(6).*

79 Staff recommends that the Commission condition its approval of the Coal Transition PPA by requiring that it will terminate if the MOA is terminated. Given its brevity, we quote below Mr. Gomez's entire discussion of this recommendation:

> The MOA specifies the obligations required from each party as a result of the Coal Transition Energy Bill, E2SSB 5769. These obligations include annual payments by TransAlta totaling $55.0 million to fund economic and community development in Lewis and South Thurston

[85] Section 9(d) of the MOA provides: "Termination of this MOA pursuant to Section 8 shall not in any manner impact the validity or enforceability of contracts or agreements entered into by the Parties, other than this MOA, prior to the date of such termination, including Qualified Power Purchase Agreements or other agreements for the sale of electrical output of the Facility."

County. Staff views PSE ratepayers, via the Coal Transition PPA, as a main source of these funds.[86]

80 Ms. Dixon testifies for NWEC that TransAlta's commitment to invest in local economic development and clean energy was a critical element of the negotiations that led to amending the emissions performance standard for coal transition power.[87] This is substantiated, she says, by a legislative finding in ESSB 5769, Sec. 101(4):

> The legislature finds that coal-fired baseload electric generation facilities are a significant contributor to family-wage jobs and economic health in parts of the state and that transition of these facilities must address the economic future and the preservation of jobs in affected communities.

81 Ms. Dixon testifies that the law and the MOA provide both time and funding to help the community succeed in its transition away from operating a coal-fired power plant, which will mean the loss of certain family-wage jobs. Providing educational and retraining opportunities for local workers is a critical piece of ensuring an orderly transition, in NWEC's view. At the same time, dedication of funds to energy efficiency and clean energy technologies will help create new good-paying "green jobs" while providing a path to cleaner power.

82 Ms. Dixon says NWEC's concerns in this area stem from the fact that TransAlta's financial commitments are not assured under the statute or the MOA. RCW 80.80.100(3)(c), for example, provides that the TransAlta is relieved of its obligations if certain tax exemptions currently available to the Centralia coal plant are repealed. In addition, the MOA includes a termination clause that TransAlta can invoke if it fails by December 15, 2013,[88] to execute sufficient long-term coal transition PPAs to

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[86] Exhibit No. DCG-1HCT at 16:9-14.

[87] The MOA provides for $20 million to the affected community for education, retraining, economic development, and community enhancement; $10 million to the affected community for energy efficiency and weatherization; and $25 million for energy technologies with the potential to create considerable energy, economic development, and air quality, haze, or other environmental benefits. *See* Exhibit No. RG-8HC at 2-3 (MOA Section 3).

[88] TransAlta's initial opportunity to terminate the MOA under this provision matured on December 15, 2012, but TransAlta elected to extend the deadline by one year, as allowed under the terms of the agreement.

sell at least 500 MWs of output from the Centralia facility. Because the average volume of power to be delivered to PSE during the term of the Coal Transition PPA is only 346 MW, Commission approval would not preclude TransAlta from invoking its termination rights under the MOA.

83 Even though PSE may terminate the PPA in this circumstance, NWEC is concerned that PSE could decide to continue the Coal Transition PPA without modification even if the MOA ceases.[89] The end result would be that the local community may see no financial support to facilitate the transition to a new economic base.

84 In light of these concerns, NWEC recommends that the Commission condition approval of the Coal Transition PPA by making it contingent on TransAlta committing to invest in at least the proportional level of funding outlined in the MOA that is represented by PSE's acquisition of 346 MW of output. This would provide certainty that at least $13.8 million is invested in local economic development, $6.9 million is invested in energy efficiency and weatherization, and $17.3 million is invested in clean energy technologies. Ms. Dixon testifies that the requirement for financial assistance is part and parcel of the modifications to the emissions performance standard that are allowing PSE to enter into the Coal Transition PPA and it should be a factor in the Commission's determination of public interest.

85 Mr. Garratt points out in rebuttal that neither PSE nor the Commission is a party to the Memorandum of Agreement. He states that "PSE does not know what role, if any, the Commission should play with respect to a contract in which neither PSE nor the Commission is a party."[90] Responding more directly to Staff's recommendation, Mr. Garratt offers two reasons that militate against the Staff's proposal to condition approval of the Coal Transition PPA by requiring that it terminates if the MOA is terminated. First, he relates that TransAlta Centralia can terminate the MOA for reasons unrelated to power sales under the Coal Transition PPA. He cites two examples; TransAlta may terminate the Coal Transition PPA if:

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[89] *See* Exhibit No. RG-10HCT at 40:12-41:6; *See also* Exhibit No. RG-3C at 34 (Coal Transition PPA Section 17.3).

[90] Exhibit No. RG-10HCT at 39:5-8.

- It loses its state sales and use tax exemptions currently available under RCW 82.08.811 and RCW 82.12.811.

- It is not allowed to use the type of air pollution control equipment to which the State of Washington agreed in the MOA.

The MOA, in Mr. Garratt's view, appears to recognize that TransAlta would lose the benefit of its bargain with the State or Washington if either of these things occur and should not have to continue paying the $55 million for promotion of the state's policies.[91]

86 Mr. Garratt testifies also that TransAlta has the right to terminate the MOA if it has not been able to enter into long-term power purchase agreements for at least 500 megawatts of power by December 15, 2012. TransAlta Centralia has informed Governor Gregoire, however, that it will not exercise this option in 2012.[92] However, the effect of this is to extend the MOA for one year, at which time TransAlta again has the option to terminate it. Should this occur during 2013, Mr. Garratt testifies that:

> It is in the best interest of PSE's ratepayers that PSE have the right to decide whether to terminate under these circumstances. If purchases under the Coal Transition PPA remain the most cost-effective resource available, PSE may well decide that, notwithstanding termination of the Memorandum of Agreement, it is in the best interest of ratepayers to continue to make purchases under the Coal Transition PPA.[93]

Thus, PSE would have the Commission reject Staff's recommendation that the Coal Transition PPA be terminated if the MOA is terminated.

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[91] Id. at 39-40.

[92] *See* Exhibit No. RG-14 (letter dated October 24, 2012, from Paul Taylor to Governor Gregoire). The letter states that TransAlta has not yet achieved the 500 MW contracting threshold contemplated in the MOA.

[93] Exhibit No. RG-10HCT at 41:1-6.

87 Although we agree with the policy principles that underlie Staff's and NWEC's advocacy on this issue,[94] we are constrained by the law from accepting their specific recommendations. Insofar as Staff's recommendation is concerned, what we have before us today is a "power purchase agreement for acquisition of coal transition power" within the meaning of RCW 80.04.570. The Coal Transition PPA also is a "Qualified Power Purchase Agreement" as defined in the MOA. As previously noted, Section 9(d) of the MOA provides:

> Termination of this MOA pursuant to Section 8 shall not in any manner impact the validity or enforceability of contracts or agreements entered into by the Parties, other than this MOA, prior to the date of such termination, including Qualified Power Purchase Agreements or other agreements for the sale of electrical output of the Facility.

Because the Coal Transition PPA is a Qualified Power Purchase or other agreement for the sale of electrical output of the CTCF, termination of the MOA cannot be the basis for terminating the PPA except to the extent PSE reserved its rights to do so and elects to exercise them.[95]

88 Insofar as NWEC's recommendations are concerned, they would require us to effectively add provisions to the MOA that are inconsistent with RCW 80.80.100. We are not empowered to do this. Not only is the Commission not a party to the MOA, there is nothing in the MOA, or the applicable statutes, that gives the Commission any express or implied authority to alter this bilateral agreement.

89 Having reached these conclusions, however, we nevertheless conclude that the MOA is an important, if not essential, feature in the legal and policy landscape that gives rise to the very concept of "coal transition power." Absent the amendment of RCW Chapter 80.80 by the Coal Transition Energy Bill during 2011, the contract before us could not have been executed by TransAlta and PSE; there would be no Coal

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[94] We understand this principle to be that the MOA and any agreement for the sale and purchase of coal transition power are so inextricably intertwined that the one should not exist in the absence of the other. The very concept of "coal transition power" depends in significant part on TransAlta's performance under the MOA that provides the funds for the transition.

[95] We note in this connection that the Commission, in a subsequent proceeding, could open the question whether it would be imprudent for PSE to not exercise these rights should the opportunity present itself.

Transition PPA, and we would not be reviewing the contract at all, much less under the special requirements of RCW 80.04.570.

90 RCW 80.80.100 requires the MOA. The statute provides that the MOA may only include the provisions specified in RCW 80.80.100. It sets forth these provisions in detail, including definitive requirements that the facility owner provide two forms of financial support as the coal plant is transitioned into closure:

- $30 million in financial assistance for economic development and energy efficiency and weatherization to the affected community.[96]

- $25 million for energy technologies with the potential to create considerable energy, economic development, and air quality, haze, or other environmental benefits.[97]

These financial benefits specified in the legislation provide an important part of the *quid pro quo* to which TransAlta agreed during negotiation of the MOA in exchange for the right to enter into long-term contracts for the sale of power from the Centralia coal facility even though the plant does not physically meet the state's emission performance standards, and will not do so during the remainder of its operation.

91 The legislature provided an additional benefit to TransAlta by providing an unprecedented inducement to investor-owned utilities such as PSE to enter into such contracts. We refer specifically to the provision included in RCW 80.04.570(6) that requires the Commission to allow such utilities to recover from their customers not only the cost of power provided under a coal transition PPA, but also to recover equity return as if the utility made a capital investment in a hard asset instead of simply entering into a power purchase agreement that requires no such investment.

92 Thus, we see the MOA, RCW Chapter 80.80 and RCW 80.04.570 as three intertwined elements that together establish the concept of coal transition power and define the rights and obligations of TransAlta, PSE and, most important, the people of

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[96] RCW 80.80.100(3).

[97] *Id.*

Washington. The fulfillment of these rights and obligations provides a transition for TransAlta, allowing for an orderly and financially satisfactory retirement of the Centralia coal facility. The fulfillment of these rights and obligations provides a transition for citizens living in the communities most directly affected by the closure, maintaining family-wage jobs and promoting economic development that will substitute for the loss of the plant, which remains an economic mainstay in Centralia and surrounding suburban and rural communities. Finally, it is by the fulfillment of these rights and obligations that the state has provided for the broader public interest to benefit from the assured closure of a significant source of air pollution on a definite schedule.

93 It is true that the MOA and RCW Chapter 80.80 allow for the termination of certain of these mutual rights and obligations upon the occurrence of specified events. We cannot foresee whether any of these events will occur, or evaluate in the abstract the impact any such occurrence relative to the Commission's obligation to "[r]egulate in the public interest, as provided by the public service laws, the rates, services, facilities, and practices of all persons engaging within this state in the business of supplying any utility service or commodity to the public for compensation."[98] We determine, however, that significant changes in circumstances such as a decision by TransAlta to terminate the MOA, or its failure to meet its financial obligations under the MOA as contemplated under RCW 80.80.100, may require a reexamination of the contract between TransAlta and PSE. Should the contract be found under some set of circumstances to have lost its character, and its legal status, as a coal transition PPA, it may be incumbent upon the Commission to initiate proceedings to review the contract and, among other things, consider whether PSE can continue to earn the equity return allowed here, as provided only for a coal transition agreement under RCW 80.04.570.

D. Cost Deferral

94 *Commission Determination: The Commission determines that the question whether PSE should be authorized to defer the incremental costs it incurs as volume and price terms vary from time to time during the life of the Coal Transition PPA should be*

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[98] RCW 80.01.040.

reserved for decision during a rate proceeding in which PSE seeks to recover its initial costs under the Coal Transition PPA, beginning in December 2014.

95 PSE seeks to defer both the contracted purchase price and the costs of the equity return associated with the Coal Transition PPA prior to those costs being included in rates. Additionally, PSE seeks to accrue interest on the deferred amounts, at PSE's net of tax rate of return for the period, currently 6.71 percent. A similar deferral would be used to adjust the yearly increases in contracted power and price increases in the Coal Transition PPA. Ms. Barnard testifies for PSE that:

> PSE would not start booking these deferrals until December 2014 when the contracted volumes begin to flow. A deferral will continue until the date when new rates that address the costs being deferred take effect, and this deferral process will continue throughout the term of the Coal Transition PPA as volumes and prices change in accordance with the terms of the Coal Transition PPA.[99]

96 Staff objects to PSE's proposal to defer costs. Mr. Gomez testifies that this situation is not one such as Goldendale, where PSE had limited control over the timing of the acquisition and was required to immediately borrow the large amount of funds necessary to secure the Goldendale Generating Station opportunity for its customers well in advance of enabling recovery methods. Here, PSE will not take its first delivery of power for nearly two years. This, according to Staff, provides the Company with sufficient time to include the Coal Transition PPA into rates via a Power Cost Only Rate Case (PCORC). Staff does not address specifically the question of deferrals PSE proposes during the term of the Coal Transition PPA as prices and volumes change from year to year.

97 Ms. Barnard focuses on this point in her rebuttal. She testifies that PSE cannot time a general rate case or PCORC filing perfectly to address changes in costs with the Coal Transition PPA that occur throughout its term. Ms. Barnard reiterates the point made in her direct testimony that what PSE proposes to defer are its incremental costs associated with the Coal Transition PPA that are not included in rates.[100] While these

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[99] Exhibit No. KJB-1T at 5:8-12.

[100] Exhibit No. KJB-3T at 3:2-4.

costs change from year to year, the time required to process a general rate case, or even a PCORC, means it is necessary for PSE to maintain a deferral account for these costs or it may lose the opportunity to recover them.

98 PSE acknowledges that it can time the filing of a general rate case or a PCORC so that the costs of the Coal Transition PPA beginning on December 1, 2014, could be recovered in rates.[101] PSE argues, however, that during the subsequent course of the contract, as TransAlta's delivery obligations change from time to time and the power price changes from year to year, it would become difficult to time PCORC and general rate proceedings to include the incremental costs associated with these changes, as they occur. PSE argues that without the authority to defer these costs, the Company would be at risk for losing its ability to recover them. PSE believes this problem would be most significant in the years when the volumes change.[102]

99 As a general matter, it is more appropriate to consider the question of deferral accounting in the context of a rate proceeding. There is ample time for PSE to initiate such a proceeding before the time it begins taking power under this contract in December 2014. We accordingly determine that the Commission will await PSE's initial filing to recover its costs under the Coal Transition PPA to determine this issue.

<u>FINDINGS OF FACT</u>

100 Having discussed above the evidence received in this proceeding concerning all material matters, the Commission now makes and enters the following summary of facts, incorporating by reference pertinent portions of the preceding detailed findings:[103]

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[101] PSE's counsel agreed during oral argument that this is the case: "I believe that PSE probably does not see a need necessarily to defer the first tranche of the agreement, because they will have two years to prepare for that." TR. 255:7-10 (Kuzma).

[102] *Id*. at 225:18-21.

[103] We recognize that certain findings of fact and conclusions of law are mixed findings and conclusions, including findings 2, 4, 5 and 6. In light of their significance relative to the specific statutes governing our review of the Coal Transition PPA, we underscore this point by repeating findings 4, 5 and 6 in the conclusions of law section of this Order.

101 (1) The Washington Utilities and Transportation Commission is an agency of the State of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including electrical companies.

102 (2) Puget Sound Energy, Inc., (PSE) is a “public service company” and an “electrical company,” as those terms are defined in RCW 80.04.010 and as those terms otherwise are used in Title 80 RCW. PSE is engaged in Washington State in the business of supplying utility services and commodities to the public for compensation.

103 (3) On July 24, 2012, PSE and TransAlta Centralia entered into the Coal Transition PPA that is the subject of this proceeding. It provides that PSE will purchase up to 380 MW of coal transition power, with average deliveries over the life of the contract, through 2025, of 346 MW.

104 (4) Considering the circumstances existing at the time of the Commission’s review, the terms of the Coal Transition PPA provide adequate protection to ratepayers and PSE during the term of the Coal Transition Power PPA or in the event of early termination.

105 (5) PSE needs the Coal Transition PPA to serve its ratepayers and the resource meets this need in a cost-effective manner as determined under the lowest reasonable cost resource standards under chapter 19.280 RCW, including the cost of the Coal Transition Power PPA plus the equity component as determined in RCW 80.04.570.

106 (6) The Coal Transition PPA includes termination dates consistent with the applicable dates in RCW 80.80.040(3)(c).

107 (7) The cost of an equivalent plant for purposes of determining the equity return component for the Coal Transition PPA is $110 million, which is a total equivalent plant cost for the Coal Transition PPA of a plant of approximately 346 MW.

CONCLUSIONS OF LAW

108 Having discussed above all matters material to this decision, and having stated detailed findings, conclusions, and the reasons therefore, the Commission now makes the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

109 (1) The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of, and parties to, this proceeding.

110 (2) The Coal Transition PPA is a long-term financial commitment for the purchase of coal transition power, as such terms are defined in RCW 80.80.010(16) and RCW 80.80.010(5), respectively, and as such terms are otherwise used in Title 80 RCW.

111 (3) The Coal Transition PPA is a power purchase agreement for acquisition of coal transition power, subject to the Commission's review and authority under RCW 80.04.570 and as otherwise provided in RCW Chapter 80.80.

112 (4) Considering the circumstances existing at the time of the Commission's review, the terms of the Coal Transition PPA provide adequate protection to ratepayers and PSE during the term of the Coal Transition Power PPA or in the event of early termination

113 (5) PSE needs the Coal Transition PPA to serve its ratepayers and the resource meets this need in a cost-effective manner as determined under the lowest reasonable cost resource standards under chapter 19.280 RCW, including the cost of the Coal Transition Power PPA plus the equity component as determined in RCW 80.04.570.

114 (6) The Coal Transition PPA includes termination dates consistent with the applicable dates in RCW 80.80.040(3)(c).

115 (7) As required under RCW 80.04.570(2), the Coal Transition PPA provides for modification of its terms to the mutual satisfaction of the parties, if a new or revised emission or performance standard or other new or revised operational

or financial requirement or limitation directly or indirectly addressing greenhouse gas emissions is imposed by state or federal law, rules, or regulatory requirements. Under the Coal Transition PPA, such a modification must be consistent with RCW 80.04.570 and is subject to review and approval by the Commission. If the parties cannot agree to modification of the Coal Transition PPA, either party has the right to terminate the Coal Transition Power PPA if such party is adversely affected by the new standard, requirement, or limitation as described in RCW 80.04.570(2).

116 (8) PSE must be authorized to earn the equity component of its authorized rate of return as provided in RCW 80.04.570(6). The rate of return should be fixed throughout the term of the Coal Transition PPA at the Company's currently authorized pre-tax weighted average cost of equity of 7.24 percent, subject to possible adjustment if there is a change in the federal corporate income tax rate.

117 (9) The equivalent plant cost of $110 million, as determined by the Commission to be the least cost purchased or self-built electric generation plant with equivalent capacity, must be amortized over the life of the power purchase agreement for acquisition of coal transition power, which is the term of the Coal Transition PPA (commencing on December 1, 2014, and expiring on December 31, 2025) to determine the recovery of the equity value. Assuming no change in the federal corporate income tax rate, the equity component of PSE's authorized rate of return for the Coal Transition PPA will be earned by PSE and recovered, in an amount equal to $1.49/MWh for each MWh of energy paid for by PSE under the Coal Transition PPA, throughout its term regardless of whether the term of the Coal Transition PPA terminates upon its expiration or is terminated prior to its expiration.

118 (10) The approved recovery of PSE's costs incurred under the Coal Transition PPA should consist of two separate expenses, as proposed by PSE:

- TransAlta Centralia will bill the cost per MWh of energy, and PSE will record this expense in FERC Account 555, Purchase Power. PSE will *pro form* this cost into power costs in the same manner as PSE *pro forms* costs associated with other power purchase agreements and treat this cost in the

Company's Power Cost Adjustment (PCA) mechanism in the same manner PSE treats costs associated with other power purchase agreements.

- PSE will *pro form* the equity return cost per MWh into power costs in general rate case filings. PSE will account for the costs associated with the equity return component on Schedule B-1 of the PCA mechanism.

119 (11) PSE's entry into the Coal Transition PPA is prudent and the associated costs are reasonable for recovery in rates, subject to a future prudence review of PSE's actual power costs as provided in Paragraph 4 of the PCA Settlement Agreement approved in Dockets UE-011570 and UG-011571.

120 (12) The Commission's continuing obligation to regulate in the public interest, as provided by the public service laws, requires the Commission to impose on PSE a reporting requirement so that the Commission can be kept apprised of the operation of the Coal Transition PPA within the legal and policy framework discussed in the body of this Order. PSE should be required to work with Commission Staff to determine the specific form and requirements for an annual report that will include, at a minimum, detailed information on a quarterly basis concerning the operations of Centralia coal transition facility and the sources of power used by TransAlta to fulfill its delivery obligations to PSE. The report also should include data concerning the payments TransAlta makes under the terms of the MOA and a description of the uses to which these funds are dedicated.

121 (13) Commission approval of the Coal Transition PPA, subject to the conditions and requirements of this Order, is in the public interest.

<u>ORDER</u>

THE COMMISSION ORDERS THAT:

122 (1) The Coal Transition Power Purchase Agreement between TransAlta Centralia Generation LLC and Puget Sound Energy, Inc., is approved consistent with and subject to the determination of issues as discussed in the body of this Order.

123 (2) The equity component of PSE's authorized rate of return for the Coal Transition PPA will be earned by PSE and recovered, in an amount equal to \$1.49/MWh for each MWh of energy paid for by PSE under the Coal Transition PPA, throughout its term regardless of whether the term of the Coal Transition PPA terminates upon its expiration or is terminated prior to its expiration, subject to possible revision if the federal corporate income tax rate is changed during the term of the contract.

124 (3) PSE's costs under the Coal Transition PPA, as determined in this Order, are reasonable for recovery in rates, subject to a future prudence review of PSE's actual power costs as provided in Paragraph 4 of the PCA Settlement Agreement approved in Dockets UE-011570 and UG-011571.

125 (4) The approved recovery of PSE's costs incurred under the Coal Transition PPA will consist of two separate expenses, as proposed by PSE:

- TransAlta Centralia will bill the cost per MWh of energy, and PSE will record this expense in FERC Account 555, Purchase Power. PSE will *pro form* this cost into power costs in the same manner as PSE *pro forms* costs associated with other power purchase agreements and treat this cost in the Company's Power Cost Adjustment (PCA) mechanism in the same manner PSE treats costs associated with other power purchase agreements.

- PSE will *pro form* the equity return cost per MWh into power costs in general rate case filings. PSE will account for the costs associated with the equity return component on Schedule B-1 of the PCA mechanism.

126 (5) The Commission's approval is subject to the condition that Puget Sound Energy, Inc., within 30 days after the date of this Order, will enter into good faith discussions and determine in coordination with Commission Staff the content and form of an annual report that will be filed with the Commission under Docket UE-121373, as provided under WAC 480-07-880(3). The report should include monthly data for the preceding 13 months beginning with the period December 1, 2014, through December 31, 2014, and must be provided no later than March 31 of each year, beginning in 2015. The report must include data that show plant operations and the sources of power from which TransAlta satisfies its delivery obligations to PSE under the Coal Transition

PPA, and information concerning the payments and disposition of payments as required under the Memorandum of Agreement between the Governor's Office and TransAlta Centralia entered into on December 23, 2011, memorializing in contractual form the requirements set forth in the Coal Transition Energy Bill, as codified in RCW 80.80.100. The report should include such other data as agreed between Commission Staff and Puget Sound Energy, Inc. These parties should file a detailed description of the report they propose within 120 days after the date of this Order. The proposed content and form of the report is subject to approval by the Commission's Executive Director and Secretary to whom the Commission delegates this responsibility.

127 (6) The Commission retains jurisdiction to effectuate the terms of this Final Order.

Dated at Olympia, Washington, and effective January 9, 2013.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION[104]

JEFFREY D. GOLTZ, Chairman

PATRICK J. OSHIE, Commissioner

PHILIP B. JONES, Commissioner

[104] On January 7, 2013, pursuant to her authority under RCW 80.01.035, Governor Christine Gregoire appointed former Commissioner Patrick J. Oshie, who resigned from office effective January 6, 2013, as Commissioner Pro Tempore for purposes of completing and signing this Final Order.

NOTICE TO PARTIES: This is a Commission Final Order. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 and WAC 480-07-870.

EXHIBIT 99

Near-term winter resource adequacy challenges in the Pacific Northwest

A review of E3's Northwest RA Study Phase 1 and independent evaluation of near-term winter challenges

SYLVAN
ENERGY ANALYTICS

Sylvan Energy Analytics

January 2026

This work was sponsored by GridLAB

Who we are

SYLVAN ENERGY ANALYTICS

Sylvan Energy Analytics is a boutique energy consulting and software firm based in Portland, Oregon.

We specialize in integrated resource planning, capacity expansion and production cost modeling, resource adequacy, clean energy policy, and utility regulation.

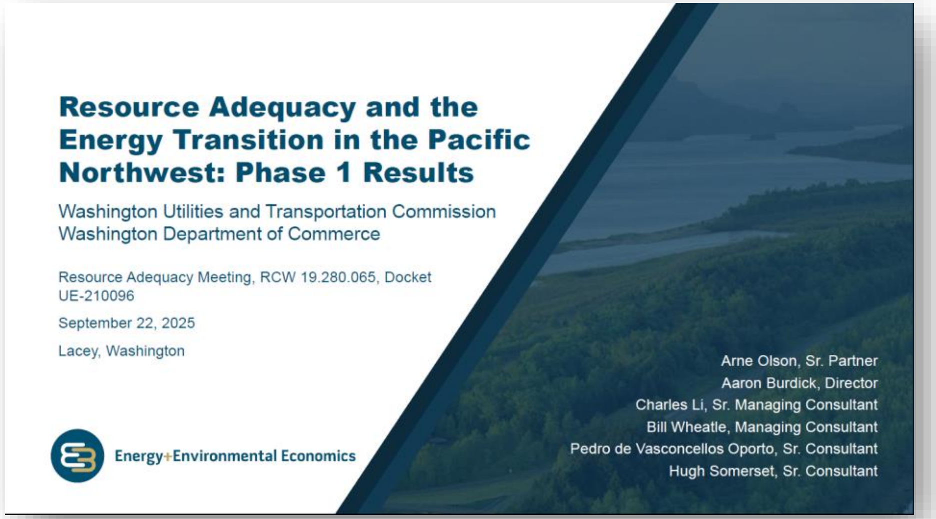
GridLAB

GridLab is a non-profit public interest organization with a mission to provide expertise to enable grid transformation.

GridLab and Sylvan have collaborated on open-source resource adequacy analysis, clean energy planning, and novel resource portfolio optimization techniques.

Background

- In the Fall of 2025, Energy & Environmental Economics (E3) released Phase 1 results of a study examining resource adequacy in the Pacific Northwest
  - The study was sponsored by most of the electric utilities operating in the Pacific Northwest
  - It projected a 9 GW shortfall by 2030 across the "Greater NW," with the potential for multiday supply shortages during winter cold events and shortages as soon as 2026
  - Phase 1 results suggested limited ability for clean resources (wind, solar, and short duration battery storage) to meet the identified needs
  - Phase 2 is underway and is expected to be released in early 2026
- Given the urgency of the Phase 1 findings, Sylvan was engaged by GridLab to review E3's analysis and findings and identify near-term opportunities to support regional RA



Greater Northwest
Total Resource Need and Effective Capacity Contribution from Planned Resources (MW)

System Needs (MW)	2025	2026	2027	2028	2029	2030
Total Resource Need*	49,245	50,737	52,499	54,184	55,879	57,195
Existing Portfolio w/ Retirements	46,716	45,666	45,395	45,388	45,098	44,757
Firm Imports	3,750	3,750	3,750	3,750	3,750	3,750
Reliability Position Surplus (+) / Shortfall (-)	**+1,221**	**-1,321**	**-3,354**	**-5,046**	**-7,031**	**-8,689**
ELCC from "In-Development" Firm Resources	-	296	407	580	770	1,114
ELCC from "In-Development" Wind, Solar and Battery projects	-	645	1,015	1,316	1,508	1,934

** Total Resource Need includes peak load + planning reserve margin as well as obligation to serve the Columbia River Treaty Regime*

We would like to thank E3 and the study sponsors for their time and attention in answering our questions

Overview

Problem statement: If we take the E3 study Phase 1 results at face value, the region needs solutions well before significant amounts of new infrastructure can come online

Objective: Understand what drove E3's Phase 1 findings and explore the potential contributions of near-term solutions that may not be considered in Phase 2 of their analysis

Scope:

- Conduct a methodological review in key areas that could impact RA results, including large load flexibility, hydro dispatch flexibility, imports & coordination with California, and retirements & conversions
- Conduct an independent evaluation of the near-term winter RA challenge in the Pacific Northwest
  - Develop multiple load scenarios based on recent load trends and various projections of future data center demand
  - Examine winter resource adequacy challenges in 2030 based on the weather and hydro conditions experienced in January 2024 (the most recent example of highly constrained winter conditions in the Pacific Northwest)
- Identify near-term opportunities to support regional resource adequacy based on findings

Executive Summary

High level findings from methodological review

Focus area	Findings of methodological review	Potential impact to near-term RA needs
Large load flexibility	• Large load flexibility was not considered in Phase 1 and is not scoped into Phase 2	High
Hydro flexibility	• E3 study may underestimate weekly energy shifting available from hydro dispatch • E3's load following hydro dispatch assumption may overlook contributions from short-duration storage	Uncertain (requires further study)
Imports and coordination with California	• E3 study assumptions may slightly underestimate import winter capability • Winter import capability is limited by transmission, not generation (California has several GWs of unused gas capacity available during PNW winter events)	Low
Retirements and conversions	• Phase 1 results slightly overstated RA challenges by treating coal-to-gas conversions as retirements in initial need evaluation • E3 study Phase 1 did not include Centralia coal-to-gas conversion (it had not yet been announced)	Low-to-moderate

High level findings from methodological review

Focus area	Findings of methodological review	Potential impact to near-term RA needs
Large load flexibility	• Large load flexibility was not considered in Phase 1 and is not scoped into Phase 2	High

Because of the high potential near-term impact of large load flexibility, most of our analysis focuses on these two highly related questions:

1. How much of the projected need is being driven by data centers (i.e., “new large loads”)?
2. What is the potential for management of new large loads to avoid the most catastrophic consequences of potential supply shortages during extreme weather conditions?

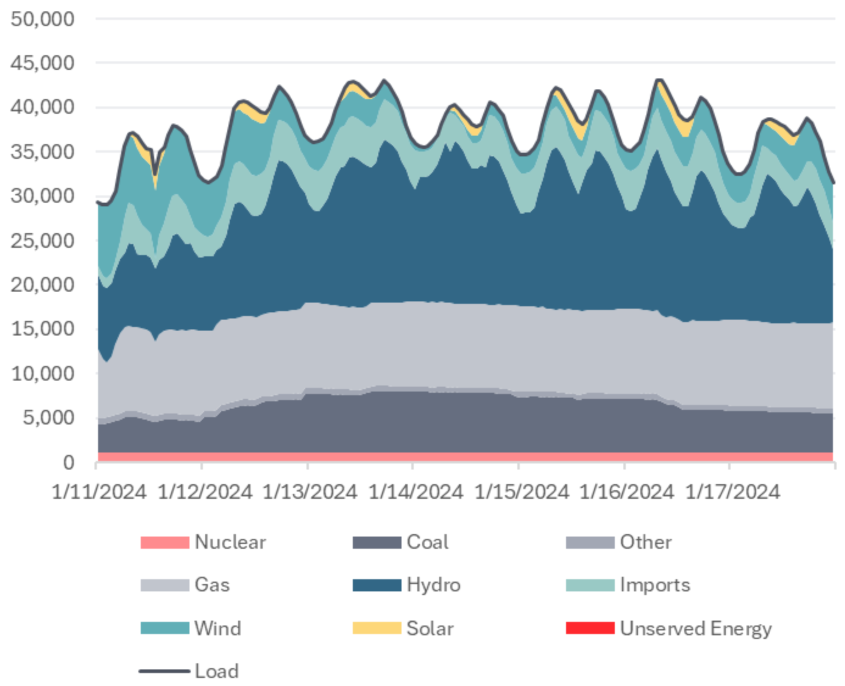
Independent evaluation approach

To better understand the nature of the near-term winter resource adequacy risk in the Northwest and the potential impact of new large loads, we examined how the recent January 2024 winter event might unfold if experienced in 2030 under various scenarios.

GridPath dispatch simulation approach:

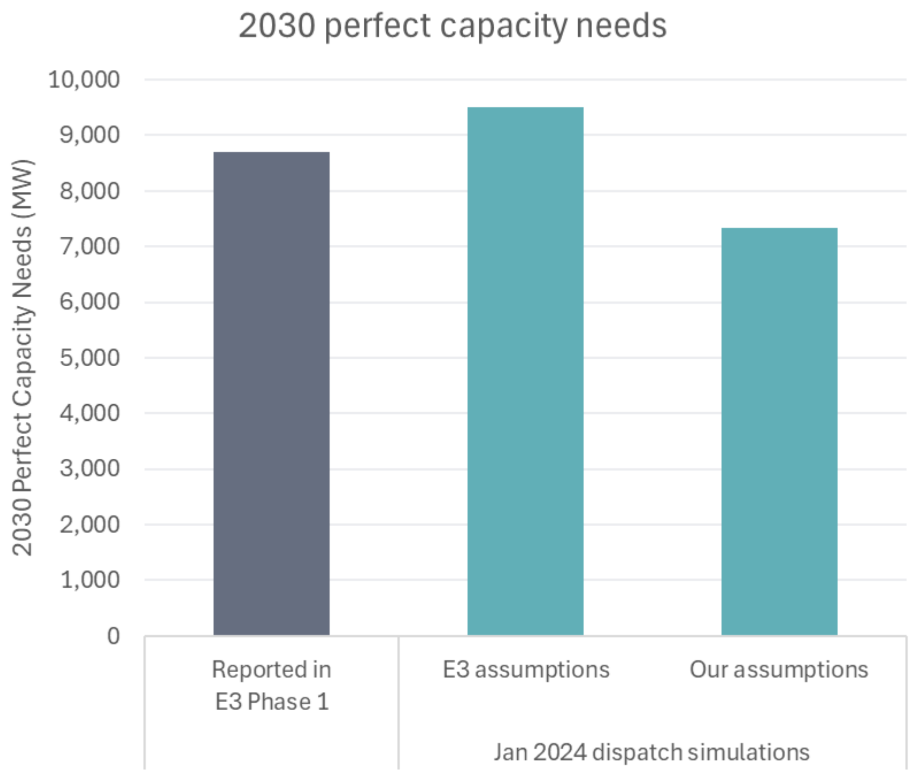
1. Developed dispatch simulation for the "Greater NW" that replicated the weather and hydro conditions from January 2024
2. Ran a benchmark simulation with 2024 historical loads to assess reasonableness of assumptions/constraints
3. Adjusted loads and resources to approximate the 2030 system
4. Identified perfect capacity needs and potential customer outages if unfilled
5. Layered in short-term solutions
   - Resources in development
   - Emergency large load management
   - Additional proposed clean resources

Simulated dispatch in January 2024 benchmarking run



Validating our approach to estimating 2030 winter risk

- To validate our approach, we compared our findings to the Phase 1 reported capacity need in 2030 in two ways:
  - **E3 assumptions:** uses E3's import assumptions (3,750 MW) and coal-to-gas accounting (coal units are retired)
  - **Our assumptions:** uses our import assumptions and our coal-to-gas accounting (coal units are converted to gas), except Centralia 2
- Both simulations assumed loads approximately reflect E3's forecasted load growth rates
- Our dispatch analysis generally corroborates E3's findings when using their load growth rates and gives us confidence that January 2024 conditions serve as a reasonable proxy for estimating winter RA needs
- Differences in import assumptions and coal-to-gas accounting reduce the magnitude of the identified need, but it remains substantial under E3's projected load growth



Alternative 2030 load scenarios

We combined various organic growth and data center load scenarios to explore alternative load growth futures (ranging from 1.5% to 3.2% average annual growth through 2030)

Scenario	Organic Load Growth	Data Center Demand	Total annual average growth rate through 2030
E3 Forecast	High/E3 (~1.8%)	Low/E3 (1,700 MWa)	~2.8%
Baseline Scenario	Baseline (1.4%)	Baseline (3,700 MWa)	3.2%
Low Tech Scenario	Baseline (1.4%)	Low/E3 (1,700 MWa)	2.2%
Low Electrification Scenario	Low (0.9%)	Baseline (3,700 MWa)	2.6%
Low Growth Scenario	Low (0.9%)	Low/E3 (1,700 MWa)	1.5%
Historical growth in electricity sales (2019-2024, excluding 2020)			*1.3%*

All alternative load scenarios envision accelerated load growth relative to the last 6 years

High level findings from independent evaluation

1. The scale and nature of the winter resource adequacy challenge in the Pacific Northwest depends strongly on future load growth, which remains highly uncertain due to both data center demand and electrification trends
2. Large load flexibility could mitigate most or all near-term winter resource adequacy needs under most load scenarios
3. Sustained development of clean resources is well-suited to meeting organic (i.e., non-data center) load growth in the region unless electrification accelerates faster than recent load growth trends suggest
4. Supporting reliable winter data center operations in the Pacific Northwest will likely require resources with more energy availability during challenging winter events
5. In the near term, the ability to curtail large loads first during emergency events can protect other customers from the most catastrophic health and safety consequences of supply shortages
6. In the long term, the need for dispatchable or baseload solutions is not a question of if, but when

Finding #1. The scale and nature of the winter resource adequacy challenge in the Pacific Northwest depends strongly on future load growth, which remains highly uncertain due to both data center demand and electrification trends

We estimate winter capacity needs in 2030 of 1.0 GW – 4.9 GW after accounting for coal-to-gas conversions and resources in development

	Estimated winter perfect capacity needs in 2030 across load scenarios (based on January 2024 weather & hydro conditions)					
	Low Growth (1.5% AGR)	Low Electrification (2.6% AGR)	Low Tech (2.2% AGR)	Baseline (3.2% AGR)	Approximation of E3 Forecast	Reported by E3 in Phase 1
With no new resources	2.9 GW	5.0 GW	4.7 GW	6.8 GW	6.7 GW	8.7 GW
+ Resources in development	1.0 GW	3.1 GW	2.8 GW	4.9 GW	4.8 GW	5.6 GW

Notes: Our estimated capacity needs with no new resources include the impacts of coal-to-gas conversions, including Centralia 2. E3's reported capacity needs with no new resources assume coal units are retired, rather than converted to gas. We estimate this accounts for approximately 1.5 GW of the 8.7 GW of need identified by E3. E3's reported capacity needs with resources in development include coal-to-gas conversions, except for Centralia 2.

Finding #2. Large load flexibility could mitigate most or all near-term winter resource adequacy needs under most load scenarios

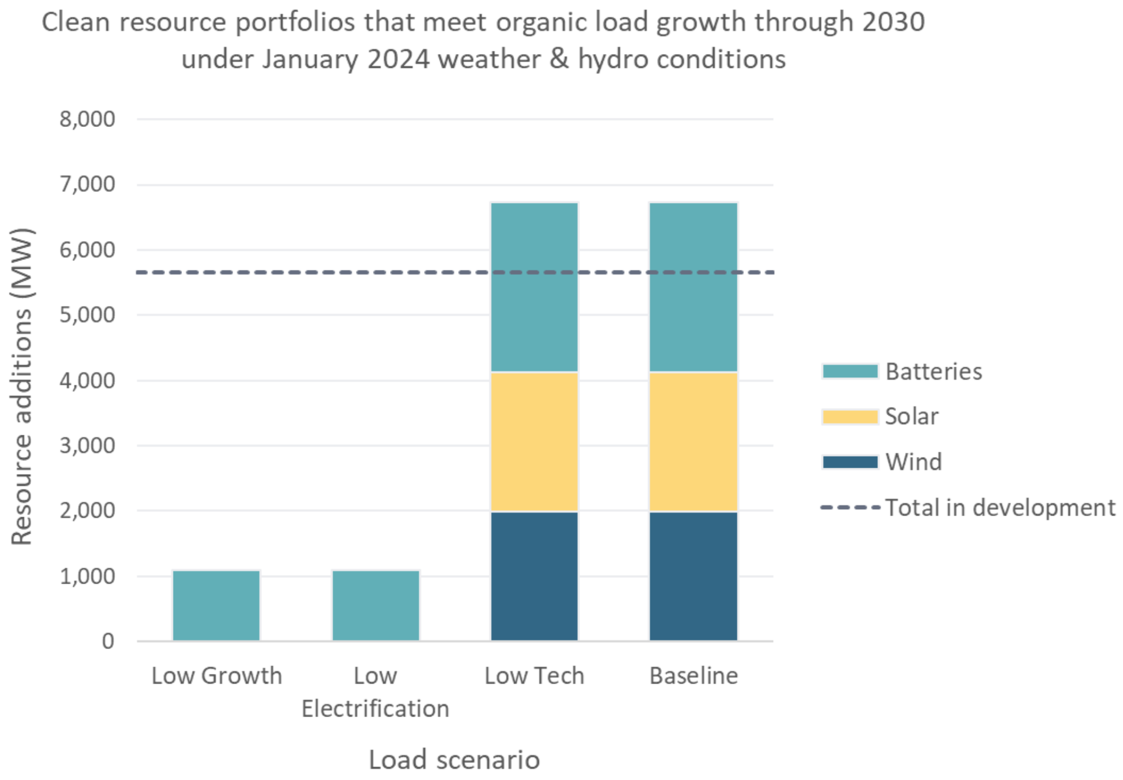
We estimate winter capacity needs in 2030 of 0.0 GW – 3.1 GW to avoid supply shortages if large loads are managed during the most critical winter weather events

	Estimated winter perfect capacity needs in 2030 across load scenarios (based on January 2024 weather & hydro conditions)					
	Low Growth (1.5% AGR)	Low Electrification (2.6% AGR)	Low Tech (2.2% AGR)	Baseline (3.2% AGR)	Approximation of E3 Forecast	Reported by E3 in Phase 1
With no new resources	2.9 GW	5.0 GW	4.7 GW	6.8 GW	6.7 GW	8.7 GW
+ Resources in development	1.0 GW	3.1 GW	2.8 GW	4.9 GW	4.8 GW	5.6 GW
+ Large load flexibility	0.0 GW	0.0 GW	1.1 GW	1.2 GW	3.1 GW	NA

Notes: Our estimated capacity needs with no new resources include the impacts of coal-to-gas conversions, including Centralia 2. E3's reported capacity needs with no new resources assume coal units are retired, rather than converted to gas. We estimate this accounts for approximately 1.5 GW of the 8.7 GW of need identified by E3. E3's reported capacity needs with resources in development include coal-to-gas conversions, except for Centralia 2.

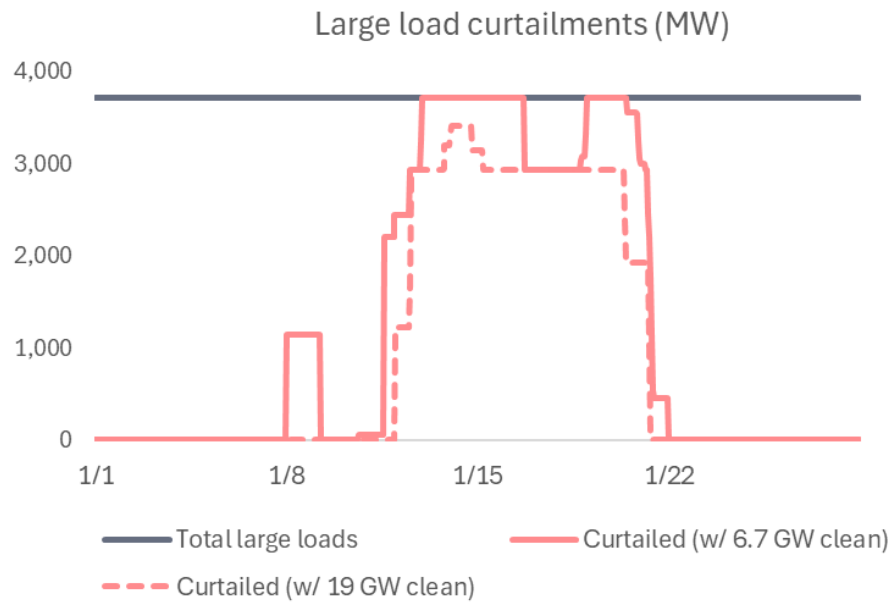
Finding #3. Sustained development of clean resources is well-suited to meeting organic (i.e., non-data center) load growth in the region unless electrification accelerates faster than recent load growth trends suggest

- We estimate that less than 7 GW of new wind, solar, and batteries are adequate to avoid supply shortages among non-data center customers under January 2024 weather & hydro conditions in 2030 across our four load scenarios
- Under the E3 Load Forecast Approximation (with more electrification and fewer data centers than our load scenarios), supply shortages cannot be avoided even if <u>all</u> proposed clean resources (19 GW) come online by 2030



Finding #4. Supporting reliable winter data center operations in the Pacific Northwest will likely require resources with more energy availability during challenging winter events

Without these additional resources, we estimate that large load curtailments could range from 0 hours to 9 days under January 2024 weather & hydro conditions, depending on the load scenario and clean resource buildout



Load scenario	Large load curtailments in 2030 under January 2024 weather & hydro conditions
Low Growth	0 hrs
Low Electrification	2.5 - 4.6 days
Low Tech	2.3 - 6.2 days
Baseline	7.0 - 9.3 days

Note: Clean resource additions range from the greater of the resources under development and the resources needed to meet organic load growth to all proposed clean resources as of December 2024 (19 GW)

Finding #5. In the near term, the ability to curtail large loads first during emergency events can protect other customers from the most catastrophic health and safety consequences of supply shortages

We estimate that large load management could reduce average outages among other customers during critical winter weather conditions from 19 hours to 0.1 hours (assuming only resources already in development come online by 2030)

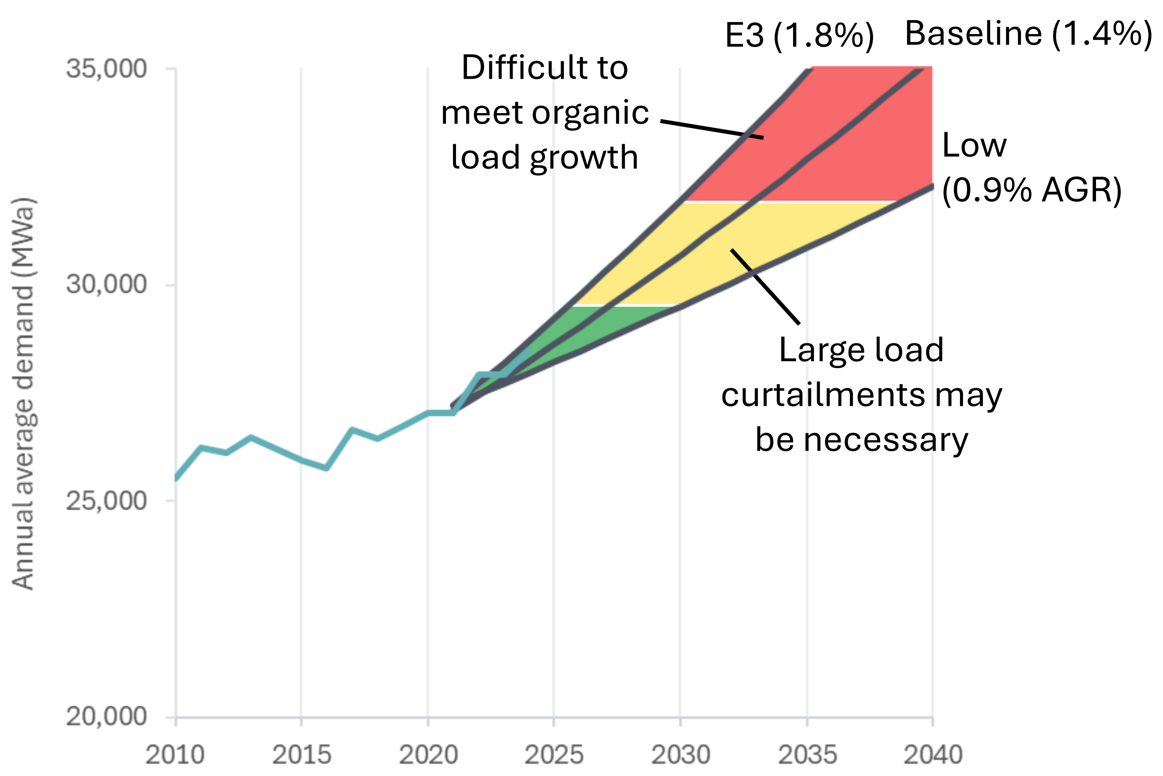
Average customer outage duration in 2030 during January 2024 weather/hydro event under Baseline Load Scenario
(assuming only resources already in development come online)

Strategy	Existing customers	New large loads
Curtail equally across large loads and other customers	**19 hrs**	19 hrs
Prioritize large load curtailment before other customers	0.1 hrs	225 hrs (about 10 days)

Finding #6. In the long term, the need for dispatchable or baseload solutions is not a question of if, but when

- <u>When</u> the region faces the most daunting challenges encountered in our simulations will depend on future load growth (which will depend on economic conditions, electrification, and energy efficiency)
- Pushing these needs out in time creates opportunities for emerging clean technologies to be part of the solution

Extrapolated* organic load growth trajectories and resource adequacy challenges



Cape Lookout State Park, Oregon Coast (source: www.oregonlive.com)

An opportunity to drive innovation

- If subject to flexibility requirements, data center customers will face the most daunting long-duration reliability challenges first and will have an incentive to solve them
- With a desire to move quickly and larger risk appetites than regulated utilities, data center customers could drive innovation in the next generation of clean technologies that serve longer duration needs, accelerating adoption, and driving down costs
- Flexibility requirements can also be leveraged to facilitate more rapid interconnection until new technologies become available

Near-term opportunities identified to support regional RA

Policy

- Consider policies that require large load flexibility or emergency curtailment prior to curtailing other customers to mitigate the most catastrophic health and safety consequences of supply shortages

Planning & Development

- Execute on all clean resource development plans and prioritize or accelerate new resource procurement activities
- Prioritize energy efficiency measures that reduce winter demand (e.g., building shell measures and replacing baseboard heating)
- Prioritize transmission studies and upgrades that support increased South-to-North flows into the Pacific Northwest during the winter
- Schedule coal-to-gas conversion activities to minimize winter downtimes
- Study impacts of natural gas system constraints on electricity reliability

Operations

- Develop emergency conservation programs to discourage EV charging & non-essential energy use, and encourage lower thermostat settings during critical multiday winter events
- Consider day-ahead market designs and market seams solutions that promote resource commitment in California and the Southwest during critical winter events in the Pacific Northwest
- Consider impacts of market participation on the propensity of hydro operators to hold energy in reserve for critical events (e.g., the value of stored water), while respecting all hydro operating limits

Analytical Details

Evaluation approach

To better understand the nature of the near-term winter resource adequacy risk in the Northwest and the potential impact of new large loads, we examined how the recent January 2024 winter event might unfold if experienced in 2030 under various scenarios.

GridPath dispatch simulation approach:

1. Developed dispatch simulation for the Pacific Northwest that replicated the weather and hydro conditions from January 2024
2. Ran a benchmark simulation with 2024 historical loads to assess reasonableness of assumptions/constraints
3. Adjusted loads and resources to approximate the 2030 system
4. Identified perfect capacity needs and potential customer outages if unfilled
5. Layered in short-term solutions
   - Resources in development
   - Emergency large load management
   - Additional proposed clean resources

GridPath

Some technical notes

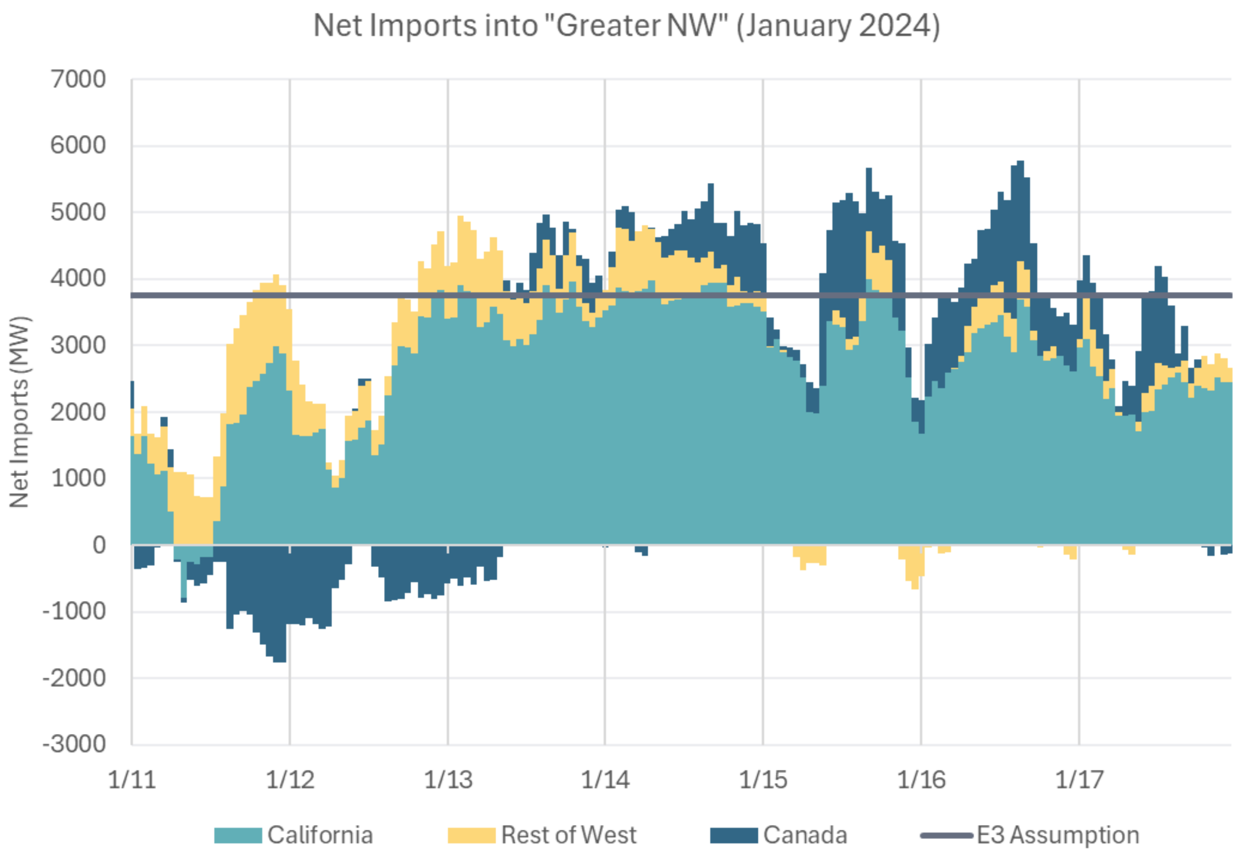
- We did not model full economics due to limited time and data availability, so results are more indicative of what the system *could* do vs. what it *would* economically do
- We have not fully reconciled our “Greater NW” footprint with E3’s due to time and data limitations. Loads and resources likely differ between the analyses and load comparisons focus on load growth rates rather than total loads to account for these differences
- Perfect capacity needs were identified by minimizing the maximum observed unserved energy across the month
- Potential customer outages were identified by equally penalizing total and maximum unserved energy to better reflect operations

Key assumptions

	Our analysis	E3 study
Footprint	BAs in OR, WA, ID, MT + PACE	BAs in OR, WA, ID, MT (excluding WAUW) + PACE
Hydro dispatch	Optimized with weekly energy budgets, minimum, maximum, and ramping constraints based on Jan 2024 hydro dispatch; unconstrained energy shifting allowed between weeks 2 & 3	Load-following heuristic with weekly budgets with up to 5% inter-week energy shifting, minimum and maximum levels based on historical min/max as a function of energy budget
Transmission constraints	2024 benchmark: Constrained flows between PACE and PNW based on high and low observations across January 2024 historical observations 2030 simulations: Added 1,000 MW bidirectional capacity associated with B2H by 2030 (total in 2030: -1,150 MW to +3,410 MW)	None in RA analysis (zonal results are from separate simulations, each assuming a copper plate)
Import constraints	Total: 5,000 MW Into PNW zone (excluding Canada): 3,000 MW Canada to PNW: 1,000 MW Into PACE: 1,000 MW	Total: 3,750 MW
Canadian entitlement	2024 benchmark: 660 MWa net exports into Canada across the month, but allowing Canadian storage to also support imports in any given hour 2030 simulations: Same, but net exports reduced to 590 MWa	590 MW exports to Canada in all hours, no accounting for Canadian storage or import capability from Canada
2030 baseline resource fleet	Existing based on operational resources as of January 2024 (EIA 930), in development resources based on 2024 EIA 860 Dave Johnston 3 retired Coal-to-gas conversions of Centralia 2, Dave Johnston 1 & 2, Naughton 1 & 2	Existing and in development resources based on WECC ADS Dave Johnston 3 and Centralia 2 retired Coal-to-gas conversions of Dave Johnston 1 & 2, Naughton 1 & 2 (however in initial need evaluation, these are retired)
2030 Load	Four load scenarios that combine different outlooks for organic load growth and data center demand, plus a load scenario that approximates E3's forecasted load growth	PATHWAYS-based bottom-up loads with adjustments and internal data center forecast

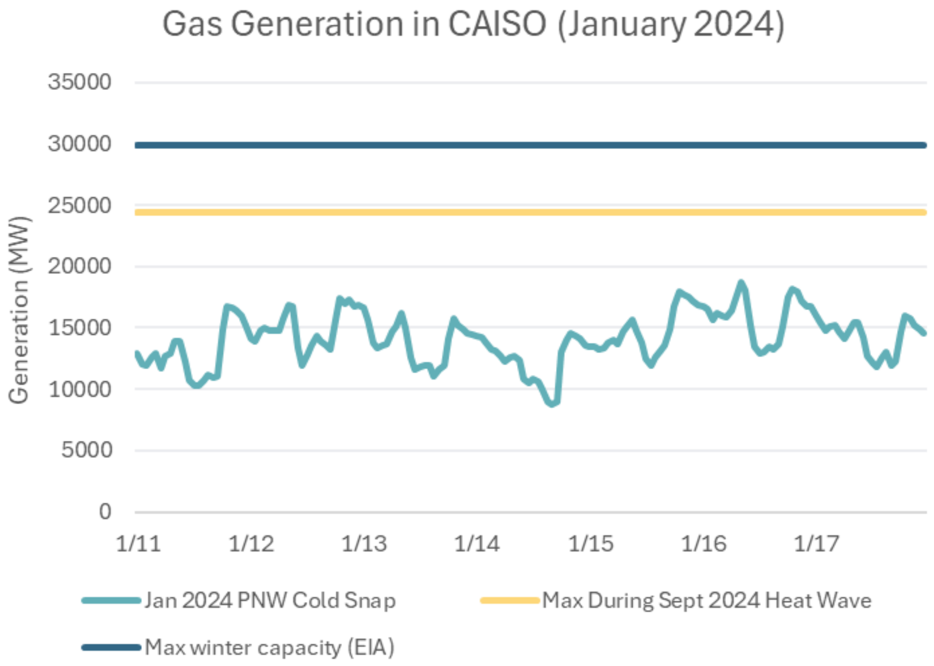
Winter import constraints

- The E3 study assumes 3,750 MW of imports are available in all hours based on imports during the January 2024 cold event
- Net imports into the “Greater NW” exceeded 3,750 MW in 102 hours in January 2024 and exceeded 5,000 MW in the most constrained hours
- The 3,750 MW limit aligns well with imports from California during the event, but may neglect additional import capability from Canada and the rest of the West



Transmission, not available supply, limited imports

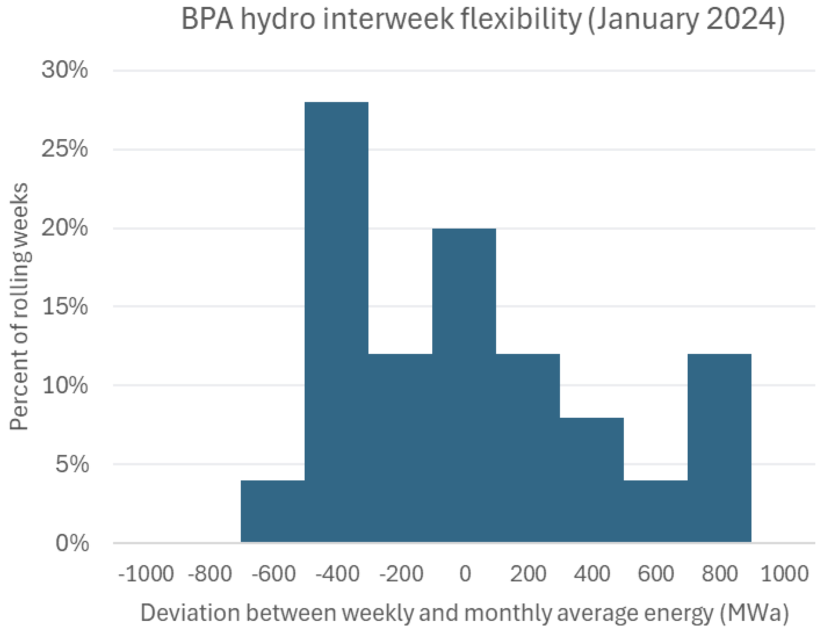
- Much of the gas fleet in California went unused during the January 2024 event (i.e., there was not a shortage of regional generating capacity in the West)
- However, South-to-North transmission flows between California and the Pacific Northwest were constrained by operating limits
- South-to-North operating limits on COI and PDCI are tighter than North-to-South limits
  - Max N-to-S during Sept 2024 heatwave: ~5,500 MW
  - Max S-to-N during Jan 2024 cold snap: ~3,800 MW



Near-term opportunities to support increased imports during winter events:

- ➢ Prioritize transmission studies and upgrades that support increased S-to-N flows into the PNW during the winter
- ➢ Consider day-ahead market designs and market seams solutions that promote resource commitment in California and the Southwest during critical winter events in the Pacific Northwest

Hydropower dispatch



Study review:

- E3 confirmed that they use a load-following heuristic to estimate hydro dispatch in each week and they allow 5% of weekly hydro energy to shift between weeks
- Heuristic dispatch may underestimate the potential of the hydro system to support resource adequacy and may overlook opportunities to co-optimize between hydro and other resources, including short-duration batteries
- Analysis into BPA hydro dispatch in January 2024 suggests that any given week could have access to as much as 880 MWa (14%) of additional hydro beyond the monthly average energy

Outstanding substantives questions:

- How do hydro operators value stored water when dispatching their hydro fleets? Does it adequately account for the value of supporting winter reliability over longer timescales (i.e., future days, weeks, or months) or is hydro dispatch over-optimized for short-term economics?
- How will day-ahead market participation affect this tradeoff between short-term revenues and winter reliability value?

Near-term opportunity:

➢ Consider impacts of market participation on the propensity of hydro operators to hold energy in reserve for critical events (e.g., the value of stored water), while respecting all hydro operating limits

Retirements and conversions

Study review:

- E3 confirmed the 8,689 MW identified need assumes that coal plants retire instead of undergoing coal-to-gas conversions
    - E3 analysis suggests that capacity needs could be 850 MW smaller with coal-to-gas conversions included

Our approach:

- Include all announced coal-to-gas conversions to avoid over-stating incremental needs
    - While conducting the analysis, Transalta announced the conversion of Centralia 2 to gas. This update was incorporated into our final simulations.

	Winter Capacity	E3 initial need evaluation	Our analysis
Dave Johnston 1	99 MW	Retired	Converted to gas
Dave Johnston 2	106 MW	Retired	Converted to gas
Dave Johnston 3	220 MW	Retired	Retired
Naughton 1	156 MW	Retired	Converted to gas
Naughton 2	201 MW	Retired	Converted to gas
Centralia 2	670 MW	Retired	Converted to gas
Total retired		**1,452 MW**	**220 MW**
Total converted to gas		**0 MW**	**1,232 MW**

Outstanding substantive question:

- Some of PacifiCorp's coal-to-gas conversion plans suggest winter downtimes, which may be avoidable by pushing the schedule out or accelerating it by a matter of months. How does winter reliability factor into scheduling for coal-to-gas conversions?

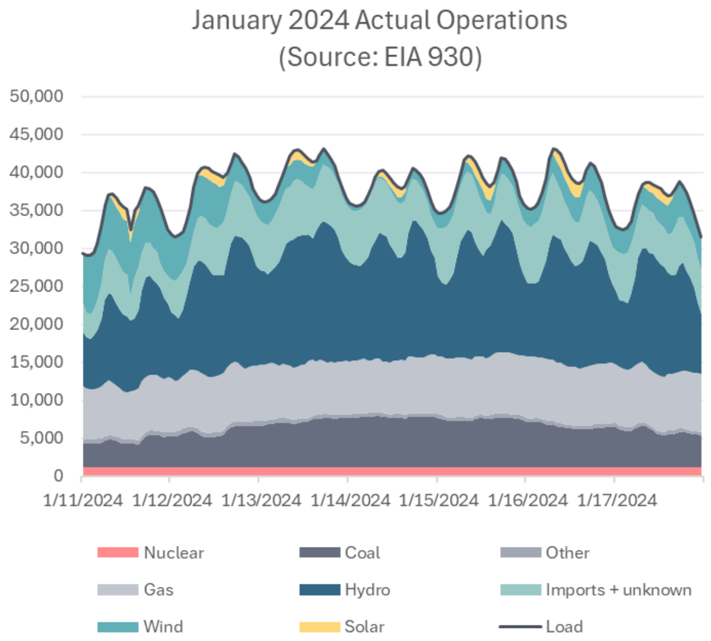
Near-term opportunity:

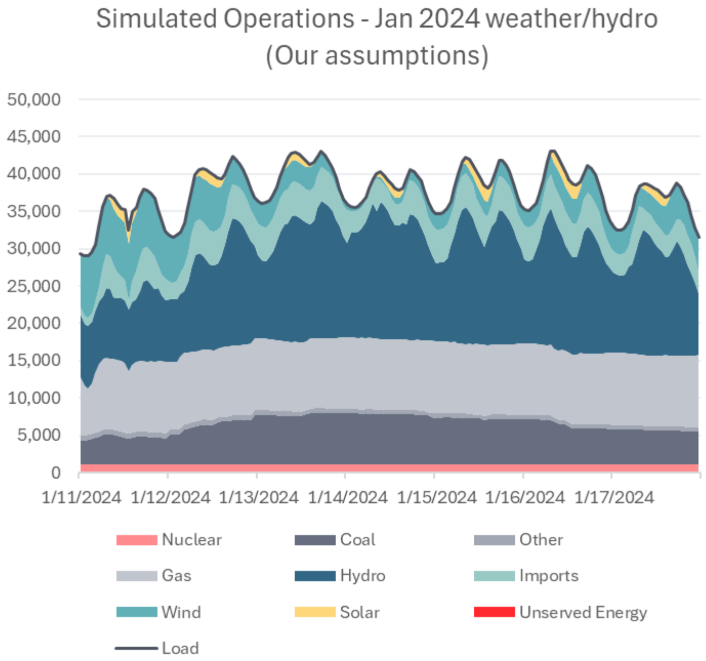
➢ Schedule coal-to-gas conversion activities to minimize winter downtimes

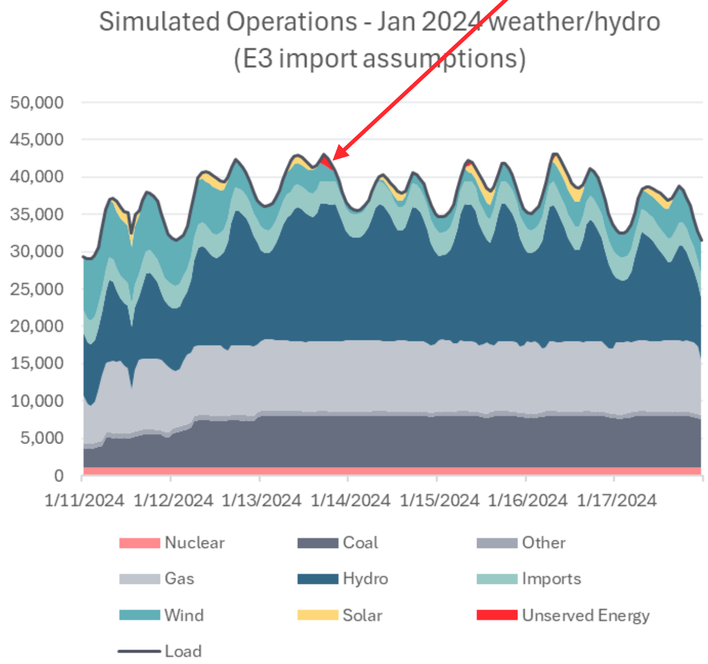
2024 benchmarking

- Tested reasonableness of assumptions by simulating January 2024 dispatch

Applying E3 import constraint yields shortages in 11 hrs, up to 1,400 MW



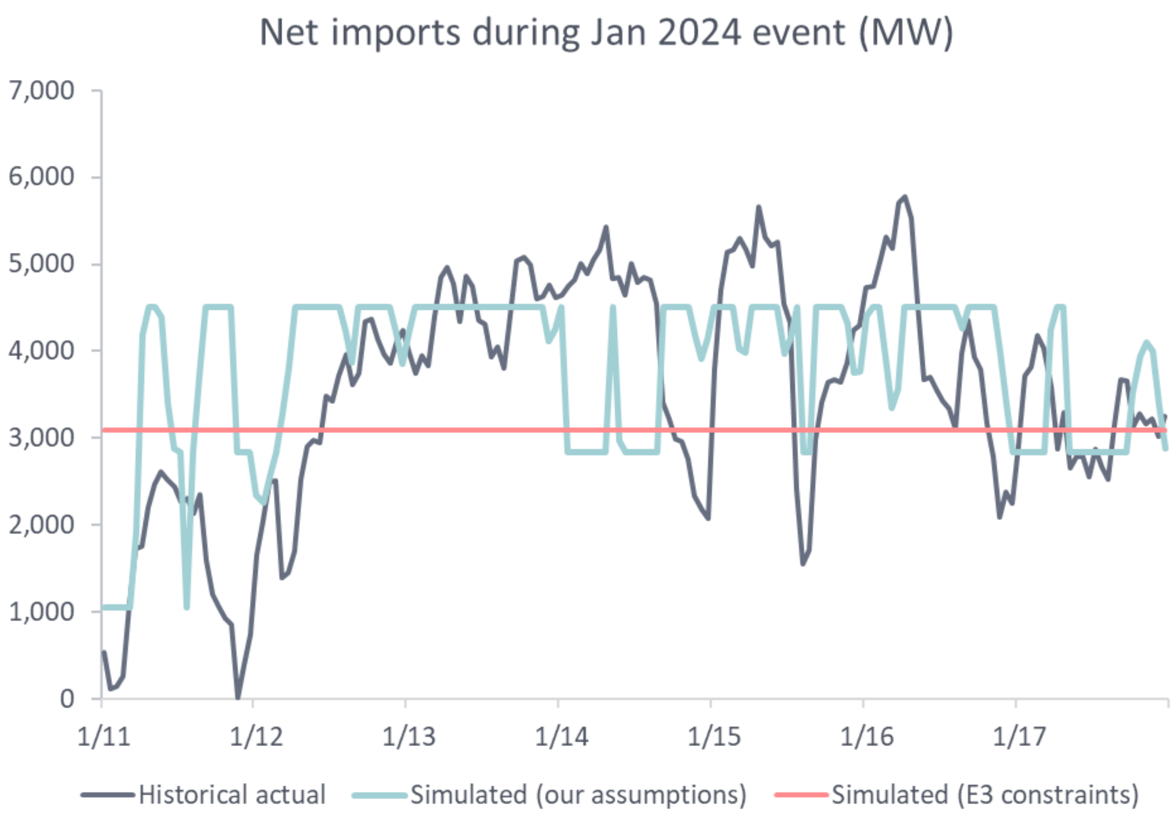




*Actual and simulated operations have different classifications for some resources that are interconnected to BPA, but not reported by BPA (or other BAs) in EIA 930. These resources are simulated explicitly and grouped by technology in the simulated operations plots, but fall within “Imports + unknown” in the actual operations plot (on the left)

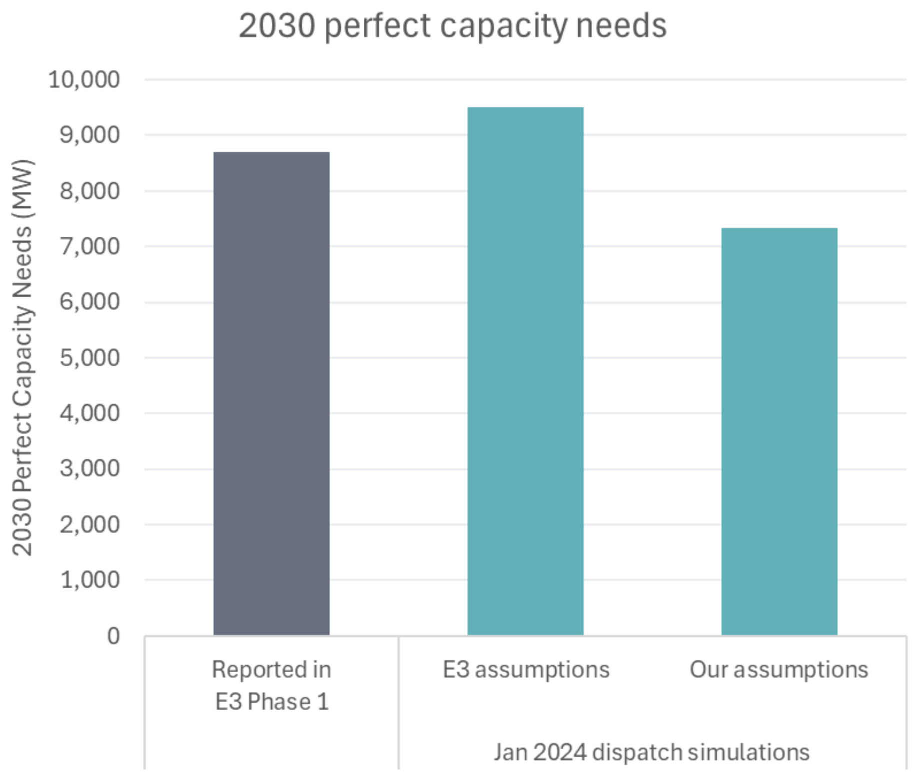
2024 benchmarking

- Additional imports in our assumptions are adequate to clear unserved energy in Jan 2024 benchmarking exercise
- Average net imports between 1/11 and 1/17 are similar across historical actuals and simulations:
    - Historical actuals: 3,508 MW
    - Dispatch simulation with our assumptions: 3,811 MW
    - Dispatch simulation with E3 constraints: 3,090 MW
- Reminder: simulations reflect system capability, not fully economic dispatch



Validating our approach to estimating 2030 winter risk

- To validate our approach, we compared our findings to the Phase 1 reported capacity need in 2030 in two ways:
  - **E3 assumptions:** uses E3's import assumptions (3,750 MW) and coal-to-gas accounting (coal units are retired)
  - **Our assumptions:** uses our import assumptions and our coal-to-gas accounting (coal units are converted to gas, except Centralia 2)
- Both simulations assumed loads approximately reflect E3's forecasted load growth rates
- Our dispatch analysis generally corroborates E3's findings when using their load growth rates and gives us confidence that January 2024 conditions serve as a reasonable proxy for estimating winter RA needs
- Differences in import assumptions and coal-to-gas accounting reduce the magnitude of the identified need, but it remains substantial under E3's projected load growth



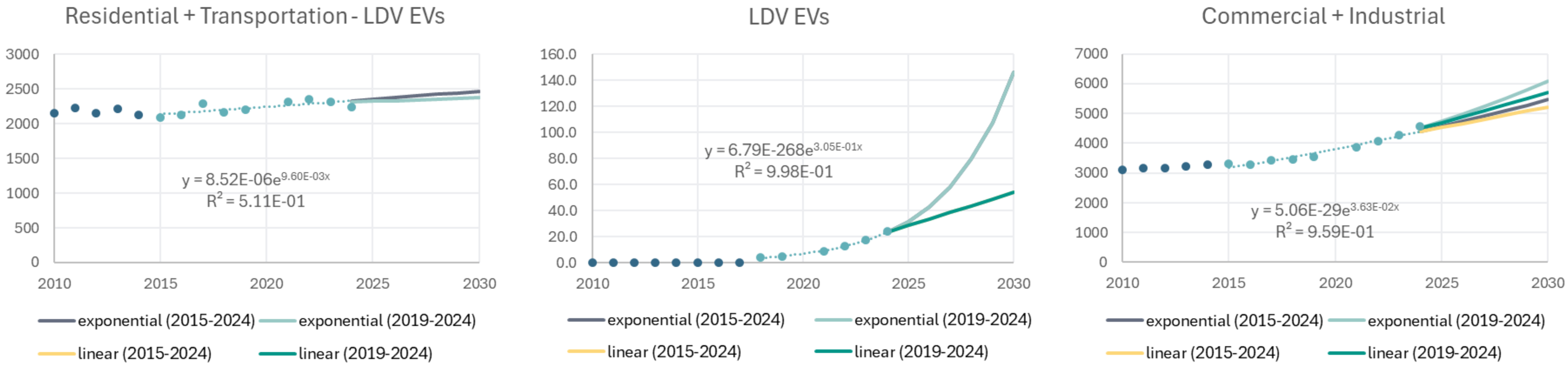
Electricity demand scenarios for 2030

- The E3 study relies on E3's internal load forecast, which comes from their bottom-up PATHWAYS model and internal data center demand forecasts
- E3's annual energy tracks closely with PNUCC's 2025 forecast (with aligned footprints), which is based on utility forecasts and projects 3.2% annual growth
- Data centers vs. electrification
  - E3 suggests that their forecast includes higher EV and electric space heating than the PNUCC forecast, which is potentially offset by a lower data center forecast
  - PNUCC has not collected information from their members to clearly distinguish between organic load growth and data center loads
- To understand the sensitivity of 2030 resource needs to future load growth and data center flexibility, Sylvan developed additional top-down load growth scenarios from available public data

Estimating organic load growth trends

- "Organic" load growth includes everything but new large loads (i.e., includes electrification)
- We estimated plausible ranges of sector-specific loads by fitting linear and exponential functions to recent historical sector-specific loads
- Data sources: EIA historical sales by sector and state, EIA historical LDV EV electricity consumption by state

Example: estimation of organic load growth trends in Oregon



Organic load growth scenarios

- **Baseline organic load growth:** upper bounds of residential and electric vehicle extrapolated trends, plus lower bound of commercial & industrial extrapolated trends (attributes any acceleration of C&I load growth to data centers)
  - Falls between NWPCC "Mixed bag" and "Persistent high growth" load scenarios (excluding data center and H_2 demands)
- **Low organic load growth:** lower bounds of residential and electric vehicle extrapolated trends, plus lower bound of commercial & industrial extrapolated trends (attributes any acceleration of C&I load growth to data centers)
  - Falls just below NWPCC "Mixed bag" load scenario (excluding data center and H_2 demands)
- Note: comparisons are high level and indicative, as footprints vary between forecasts and NWPCC loads assume fixed energy efficiency

Scenario	Average annual organic growth rate through 2030
NWPCC[2] "Persistent high growth"	~1.9%
E3 Forecast[1]	~1.8%
Baseline Organic Growth	**1.4%**
NWPCC[2] "Mixed bag"	~1.0%
Low Organic Growth	**0.9%**
NWPCC[2] "Persistent low growth"	~-0.1%

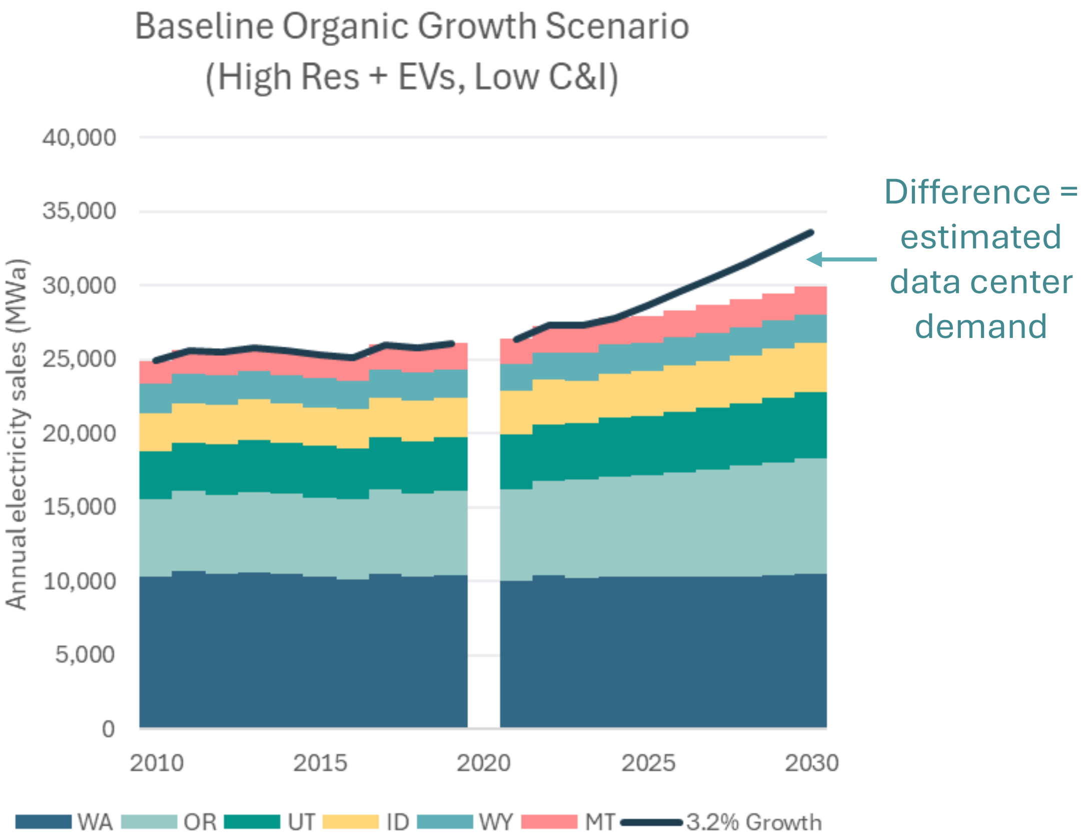
[1]E3 organic growth rate between 2025 and 2030 estimated by subtracting data center demand from total forecasted Greater NW demand reported on slide 24 of Phase 1 Executive Summary

[2]NWPCC growth rates between 2025 and 2030 estimated by subtracting data center and H_2 demand on slide 33 from total forecasted demand scenarios on slide 46 of the Ninth Plan Demand Forecast Part 2 (https://www.nwcouncil.org/fs/19380/2025_0429_2.pdf)

Data center demand scenarios

- **Baseline data center demand:** estimated as the difference between the organic load growth forecast and 3.2% total load growth reported by PNUCC
  - Higher than E3 forecast, between Mid and High forecasts from the NWPCC
- **Low data center demand:** E3 data center forecast

Scenario	PNW MWa (WA, OR, ID, MT)	"Greater NW" MWa (PNW + UT + WY)
Baseline Scenario	**2,931**	**3,717**
Low Scenario (E3 Data Center forecast)	**1,100**	**1,700**
NWPCC Low Tech Load	~1,400	NA
NWPCC Mid Tech Load	~2,200	NA
NWPCC High Tech Load	~4,600	NA



Alternative 2030 load scenarios

We combined various organic growth and data center load scenarios to explore alternative load growth futures (ranging from 1.5% to 3.2% average annual growth through 2030)

Scenario	Organic Load Growth	Data Center Demand	Total annual average growth rate through 2030
E3 Forecast	High/E3 (~1.8%)	Low/E3 (1,700 MWa)	~2.8%
Baseline Scenario	Baseline (1.4%)	Baseline (3,700 MWa)	3.2%
Low Tech Scenario	Baseline (1.4%)	Low/E3 (1,700 MWa)	2.2%
Low Electrification Scenario	Low (0.9%)	Baseline (3,700 MWa)	2.6%
Low Growth Scenario	Low (0.9%)	Low/E3 (1,700 MWa)	1.5%
Historical growth in electricity sales (2019-2024, excluding 2020)			*1.3%*

All alternative load scenarios envision accelerated load growth relative to the last 6 years

Detailed findings

- Resource needs under January 2024 weather/hydro conditions across the 2030 load scenarios
  - With no incremental resources
  - With resources in development as of December 2024 and Centralia 2 coal-to-gas conversion
  - With emergency large load curtailment
- Outage risk to customers with and without large load curtailments
- Contributions of clean energy resources in development and potential from additional proposed clean resources
- High level insights on load uncertainty and how quickly the region may face the most daunting challenges

Detailed findings

- Resource needs under January 2024 weather/hydro conditions across the 2030 load scenarios
  - With no incremental resources
  - With resources in development as of December 2024 and Centralia 2 coal-to-gas conversion
  - With emergency large load curtailment
- Outage risk to customers with and without large load curtailments
- Contributions of clean energy resources in development and potential from additional proposed clean resources
- High level insights on load uncertainty and how quickly the region may face the most daunting challenges

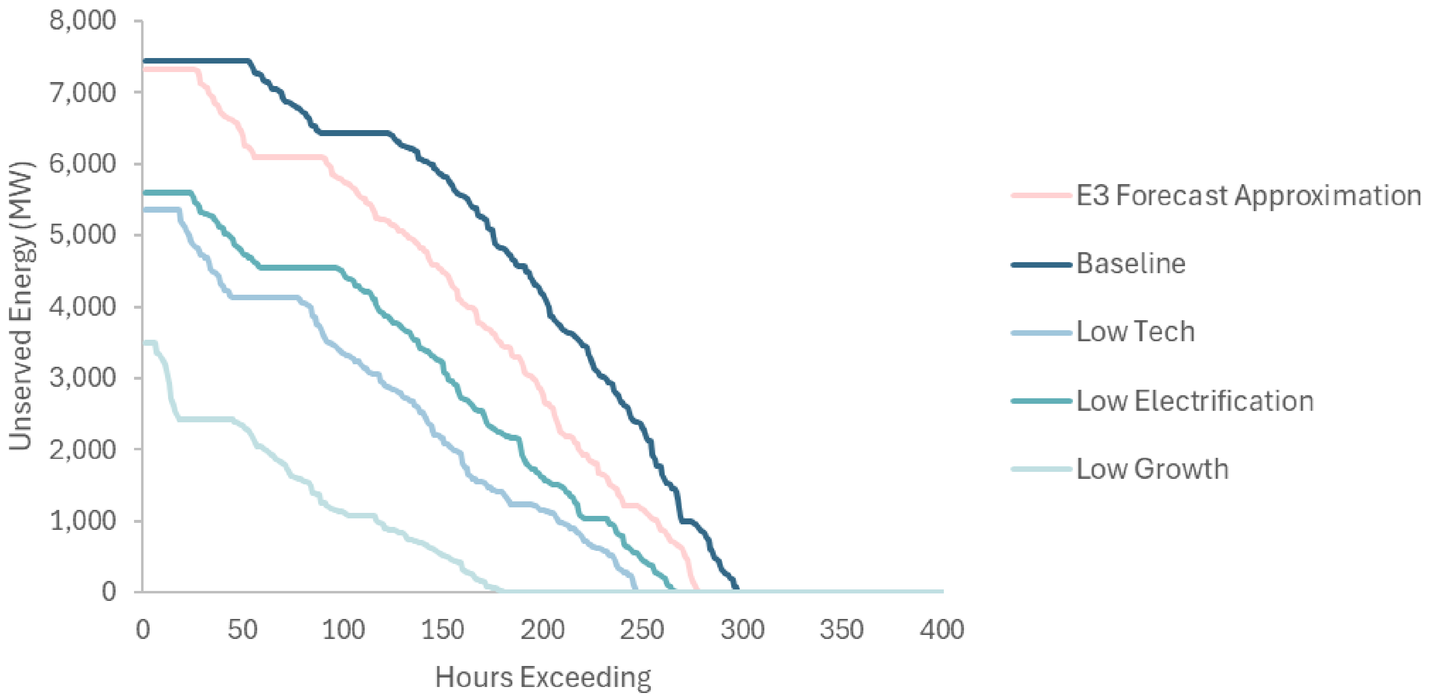
Our findings generally corroborate E3's high level problem statement

Across all load scenarios, unserved energy is observed in large quantities and in several hours if there are <u>no resource additions</u> through 2030, similar to E3's findings

Notes:

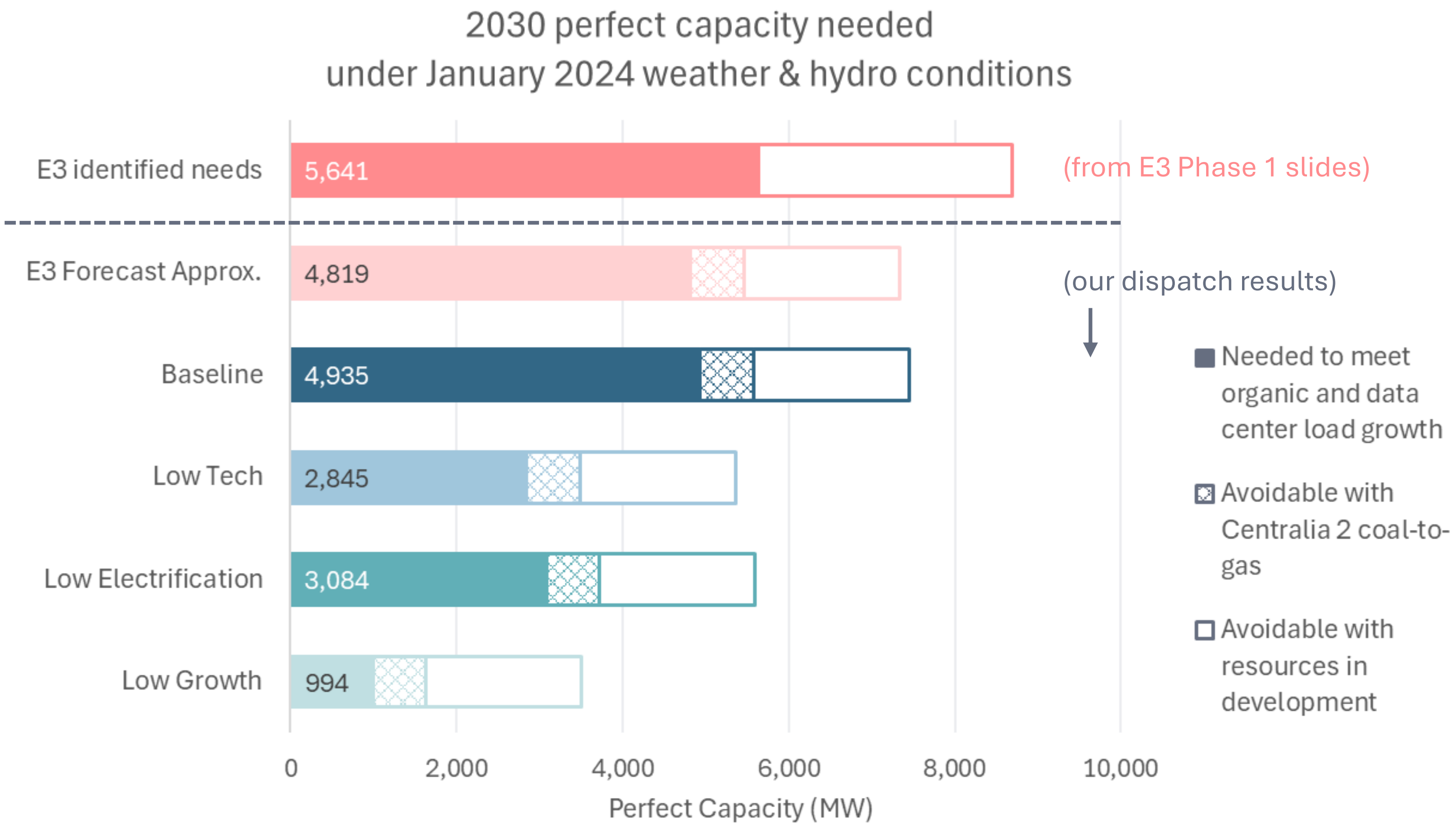
- These results are based on "operational" runs, in which both total and maximum unserved energy are penalized
- Perfect capacity needs (coming up on the next slide) are calculated by minimizing the maximum unserved energy, which can be lower than the maximum values shown on this slide

Simulated unserved energy (sorted from high to low) with no resource additions, before Centralia 2 coal-to-gas conversion



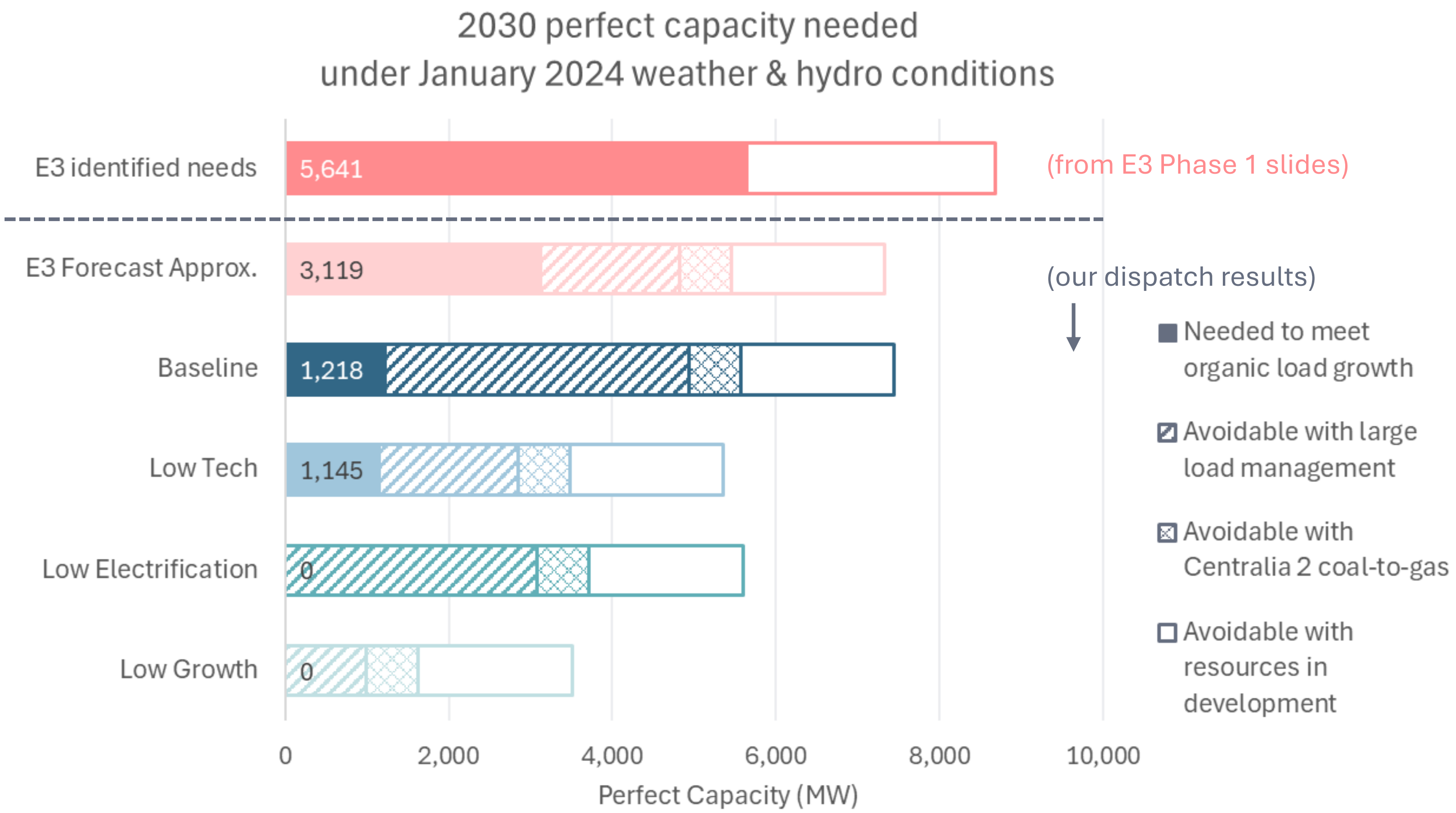
How sensitive are 2030 resource adequacy needs to future load growth?

- No analysis can predict the future and resource needs in 2030 remain highly uncertain, due both to new large loads and electrification trends
- After accounting for resources already under construction or with regulatory approvals in place as of December 2024 according to EIA 860 (“in development”) and coal-to-gas conversion of Centralia 2, estimated remaining 2030 needs range from 1 GW to 5 GW of “perfect capacity” across load scenarios



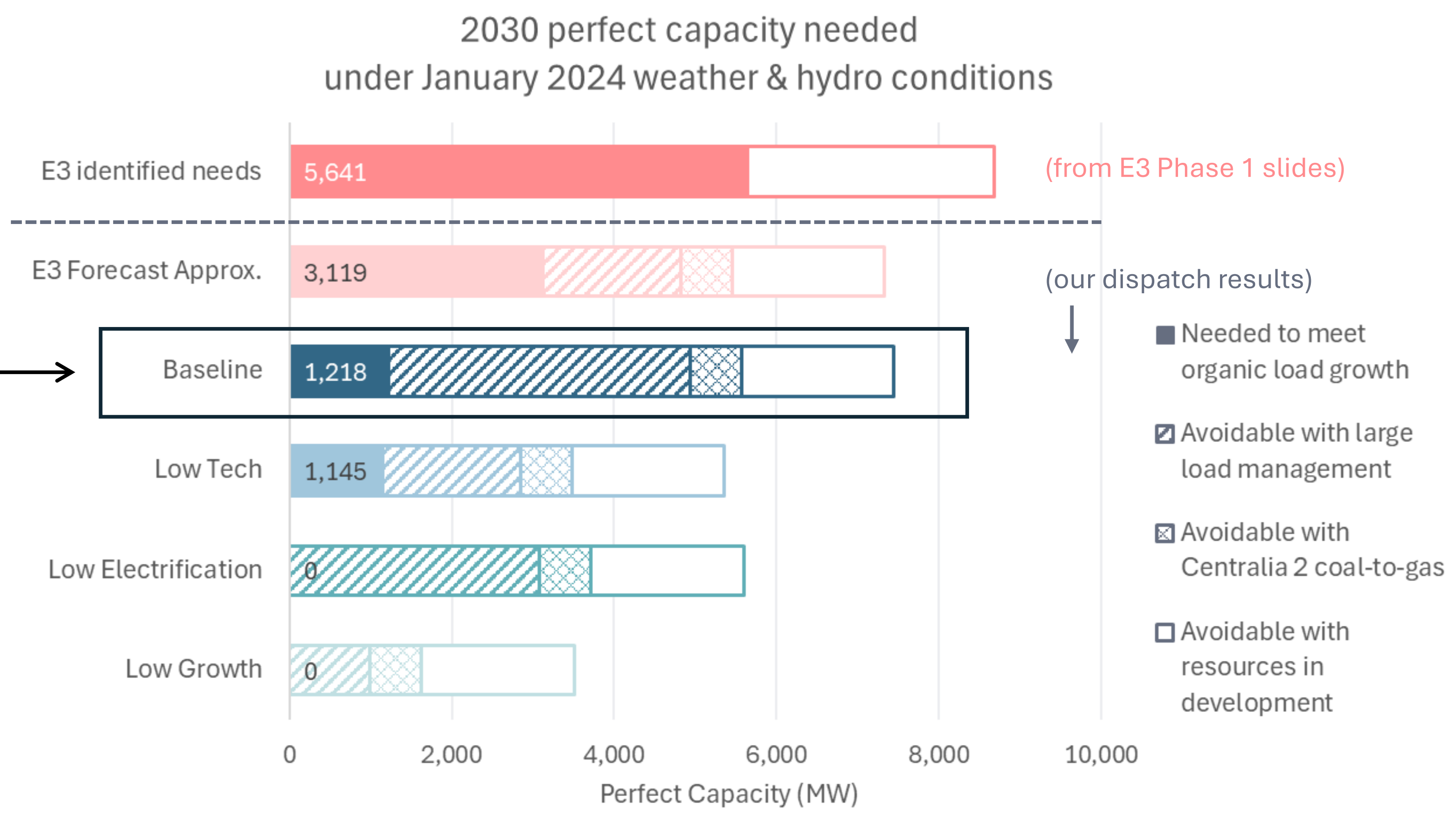
"Connect and manage" for large loads and resource adequacy

- Large loads, which remain highly uncertain in terms of both whether they will materialize and how long they will persist on the grid, are a key driver of near-term needs
- If large loads are interconnected before adequate supply is secured, emergency large load curtailment during extreme weather could mitigate risks to other customers, similar to new requirements in Texas
- If large loads can be managed during extreme weather events, estimated remaining 2030 needs range from 0 GW to 3 GW, depending on organic load growth (including electrification)



"Connect and manage" for large loads and resource adequacy in the Baseline Scenario

Let's dig further into the Baseline Load Scenario



Supply shortages from the customer's perspective

If no additional resources are secured beyond those already in development, what does the shortage under the Baseline Scenario look like from the customer perspective during this event?

Average customer outage duration in 2030 during January 2024 weather/hydro event under Baseline Load Scenario

Strategy	Existing customers	New large loads
Curtail equally across large loads and other customers	**19 hrs**	19 hrs
Prioritize large load curtailment before other customers	0.1 hrs	225 hrs (about 10 days)

Near-term opportunity:

- Consider policies that require large load flexibility or emergency curtailment prior to curtailing other customers to mitigate the most catastrophic health and safety consequences of supply shortages
  - Could be paired with bring-your-own generation strategies
  - Could enable more rapid interconnection

*Resources in development were either under construction or had final regulatory approvals in place as of December 2024

Detailed findings

- Resource needs under January 2024 weather/hydro conditions across the 2030 load scenarios
  - With no incremental resources
  - With resources in development as of December 2024 and Centralia 2 coal-to-gas conversion
  - With emergency large load curtailment
- Outage risk to customers under across the load scenarios with and without large load curtailments
- Contributions of clean energy resources in development and potential from additional proposed clean resources
- High level insights on load uncertainty and how quickly the region may face the most daunting challenges

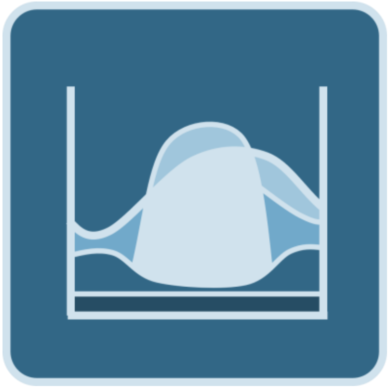
Addressing supply shortages with new clean resources

- Next, we allowed the model to select additional resources from projects that were proposed but did not have regulatory approvals (as of December 2024) to meet demand across the January 2024 weather/hydro conditions under the Baseline Load Scenario
    A. To meet organic load growth; and
    B. To meet all load growth, including data center demand
- Findings are broadly indicative
    - Resource costs were high level and imprecise (i.e., these are not optimal selections)
    - Assumed proposed projects have the same hourly availability as existing projects by technology and zone (i.e., understates diversity benefits)

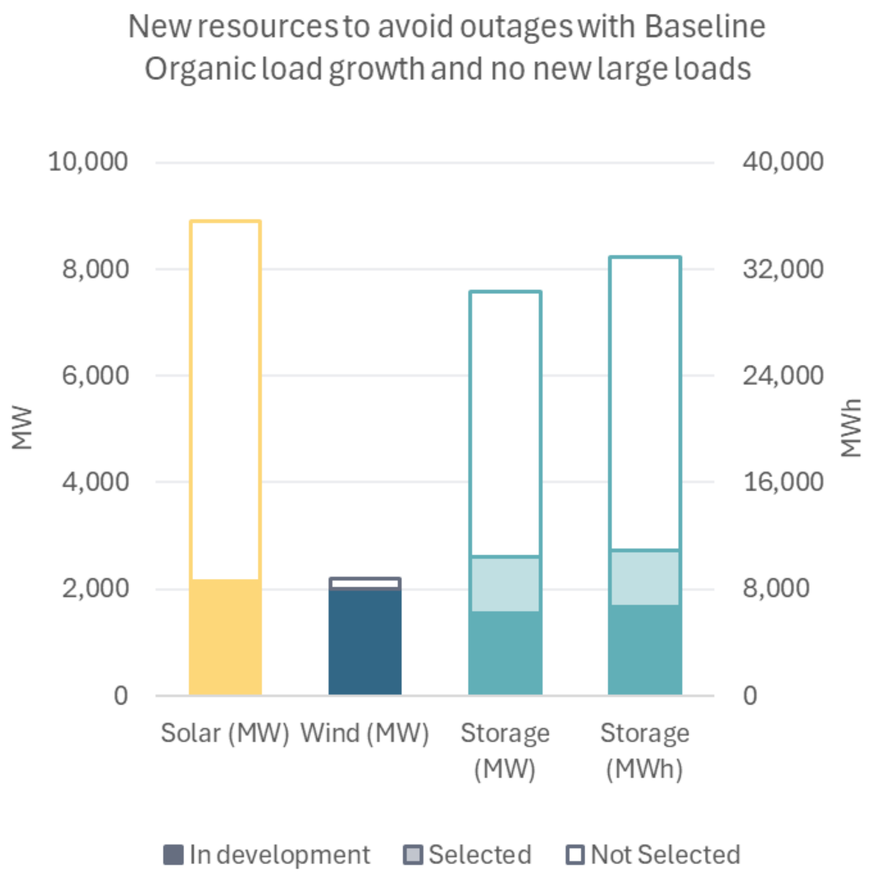
Blended production cost/capacity expansion mode

GridPath

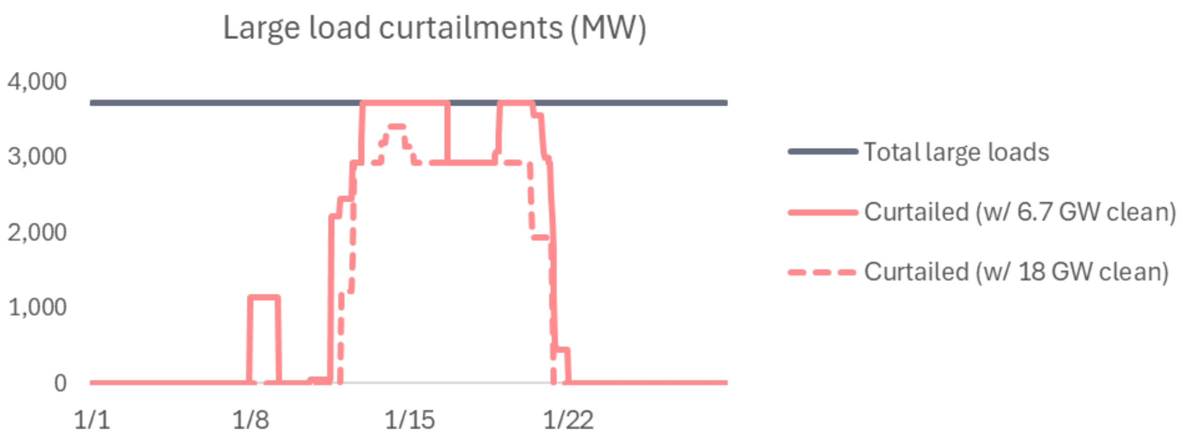
Incorporates investment variables directly into production cost problem to probe resource needs and identify potential solutions



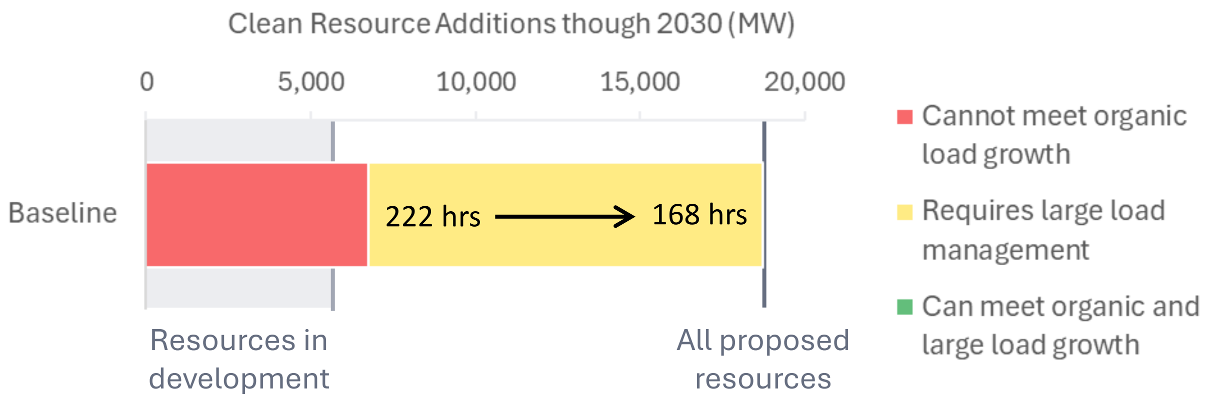
Clean resource additions and large load management in the Baseline scenario



- Clean resources in development (5.7 GW) plus 1 GW of additional short duration storage were adequate to meet Baseline Organic load growth during this event
- With these additional selected resources: large loads experienced 222 hrs (9.25 days) of outages during the event
- When all proposed clean resources were included (19 GW total): large loads still experienced 168 hrs (7 days) of outages during the event

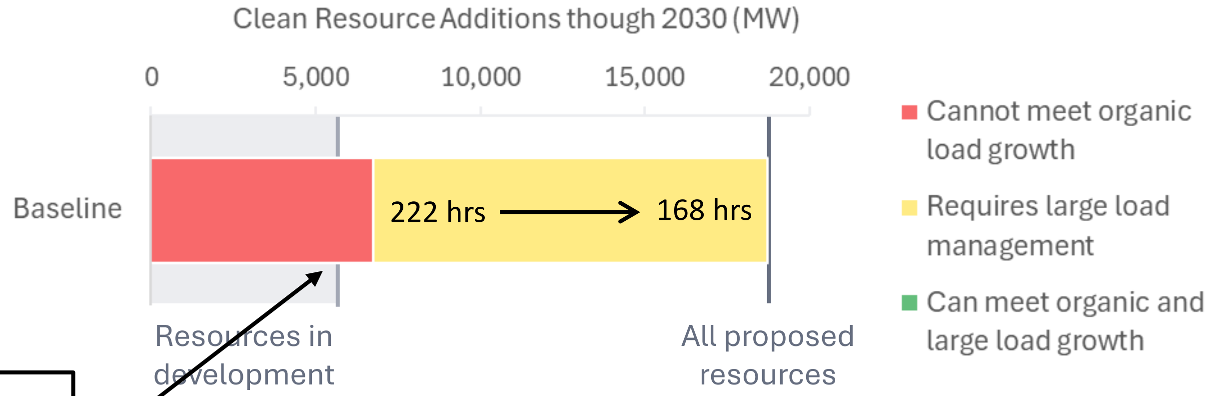


Clean resource additions and large load management across the scenarios



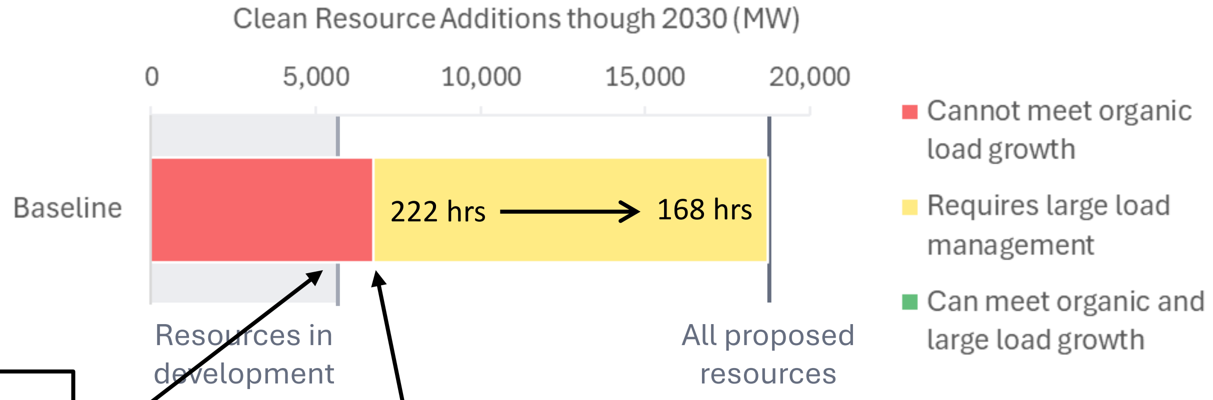
To compare across scenarios, we'll introduce a short-hand for the contributions of new clean resources toward meeting load growth and avoiding large load curtailments

Clean resource additions and large load management across the scenarios



1. Clean resources in development (5.7 GW) <u>are not</u> adequate to meet organic load growth during the event

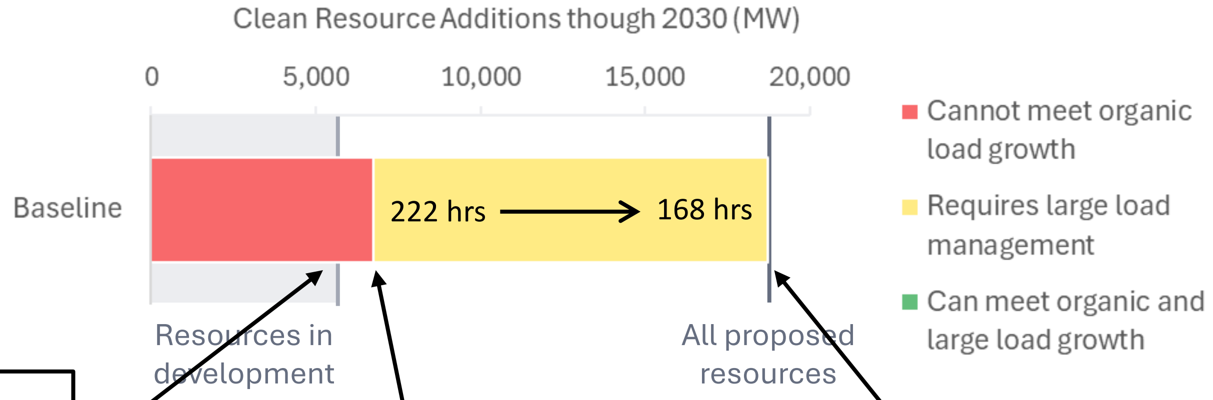
Clean resource additions and large load management across the scenarios



1. Clean resources in development (5.7 GW) <u>are not</u> adequate to meet organic load growth during the event

2. Resources in development plus additional clean resources (6.7 GW total) <u>are</u> adequate to meet organic load growth, but require 222 hrs of large load curtailment

Clean resource additions and large load management across the scenarios

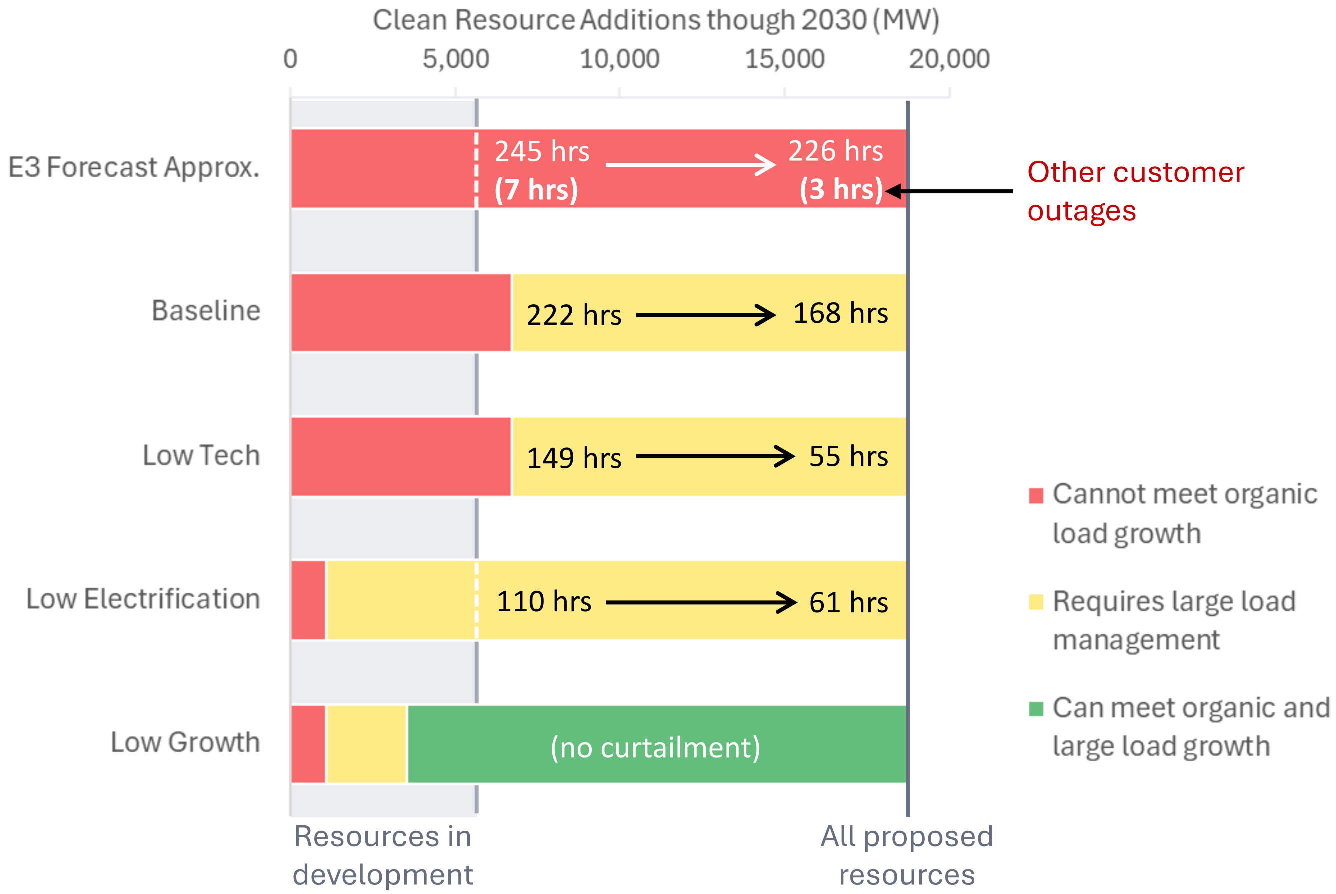


1. Clean resources in development (5.7 GW) <u>are not</u> adequate to meet organic load growth during the event

2. Resources in development plus additional clean resources (6.7 GW total) <u>are</u> adequate to meet organic load growth, but require 222 hrs of large load curtailment

3. With all proposed clean resources (19 GW), large load curtailment persists (168 hrs)

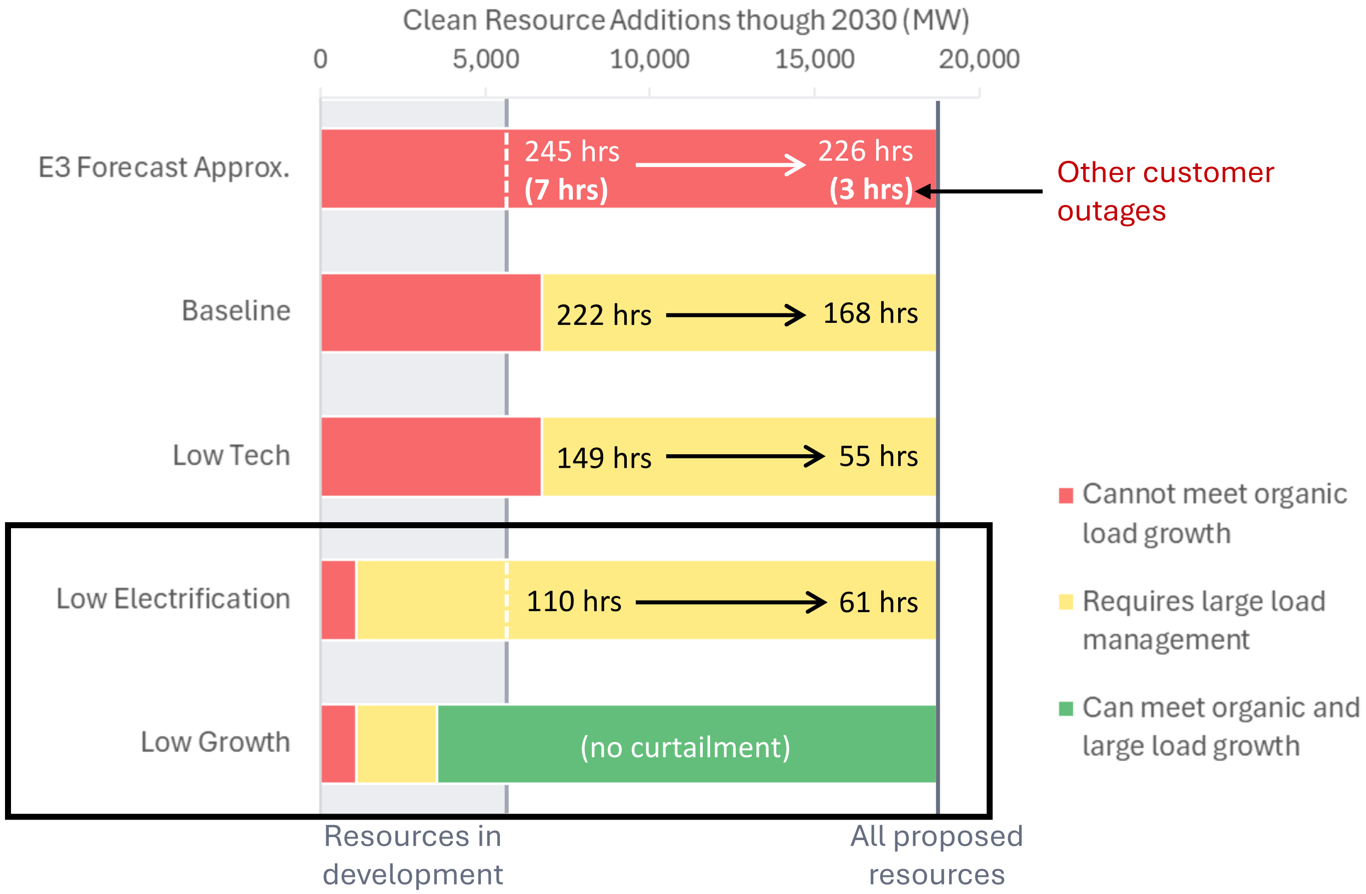
Clean resource additions and large load management across the scenarios



Clean resource additions and large load management across the scenarios

In scenarios without accelerated electrification (Low Electrification and Low Growth):

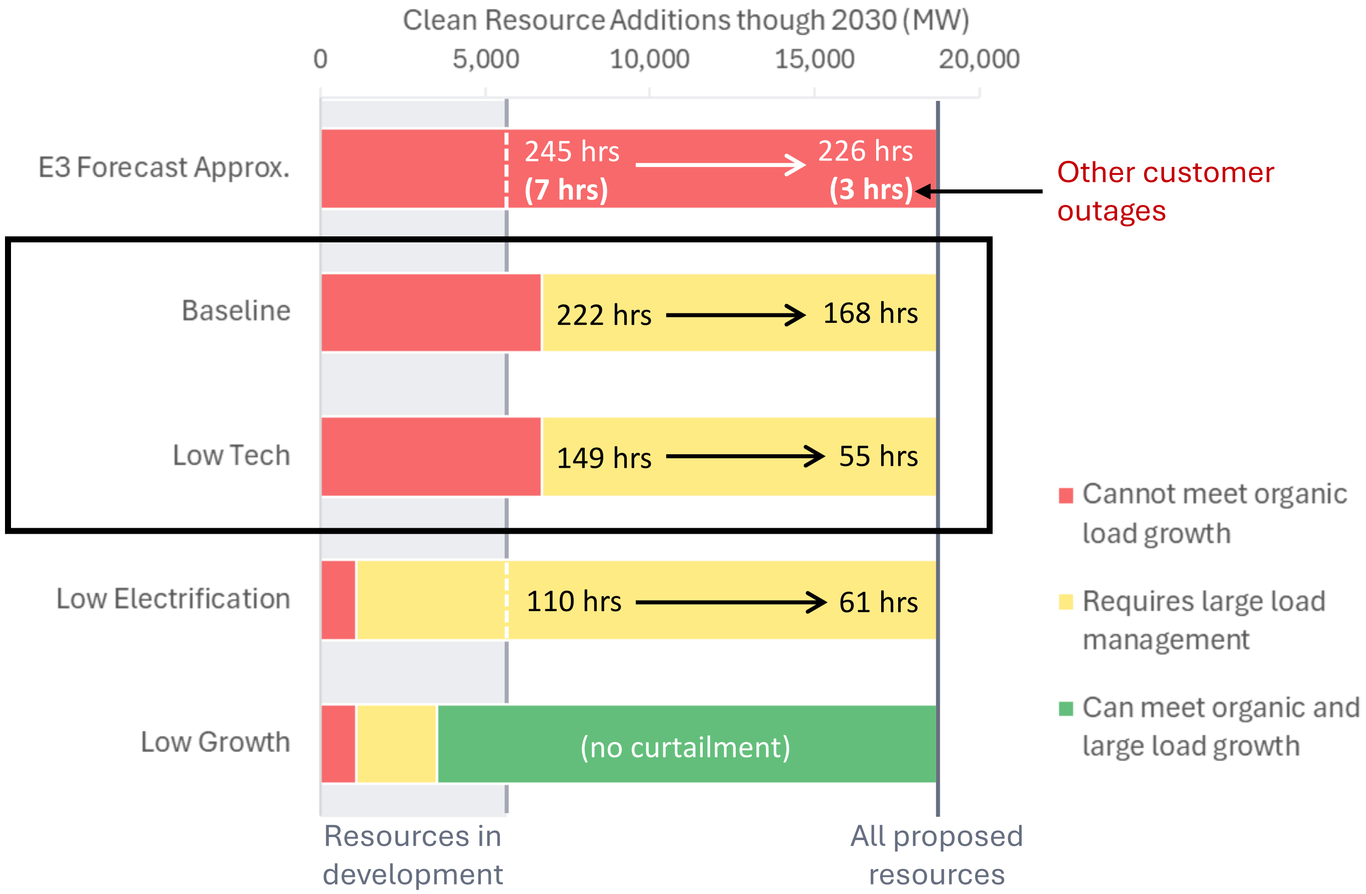
- Clean resources in development are adequate to meet organic load growth during this event
- Large load curtailment will depend on how many large loads materialize and whether they bring additional resources (simulations range from 0 hrs to 110 hrs)



Clean resource additions and large load management across the scenarios

In scenarios that project 1.4% annual organic load growth (Baseline and Low Tech):

- Clean resources in development plus a relatively small amount of incremental resources are adequate to meet organic load growth during this event
- Large load curtailment will depend on how many large loads materialize and whether they bring additional resources (simulations range from 55 hrs to 222 hrs)



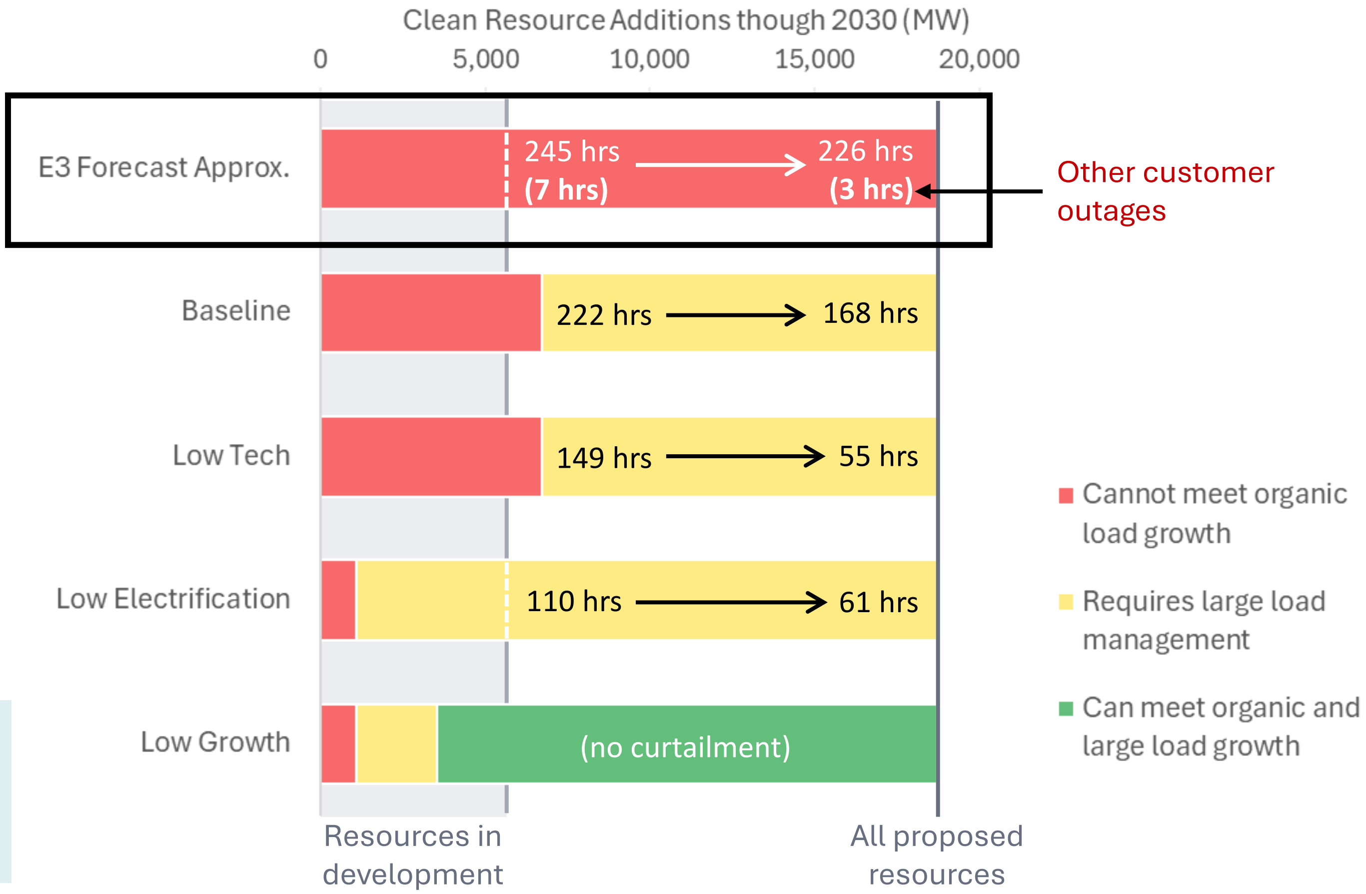
Clean resource additions and large load management across the scenarios

Under E3's load growth scenario, which includes more rapid electrification and relatively low data center demand, the region is in a real bind!

- Resource needs to meet organic growth exceed the quantity of proposed clean projects (19 GW)
- Large load curtailments exceed 100 hrs and other customers may experience rolling brown outs even with large load curtailments unless additional resources can come online
- New gas has been discussed as a solution to this challenge, but the gas system was constrained during the January 2024 event as well

Near-term opportunity:

➢ Study impacts of regional natural gas system constraints on regional electricity reliability

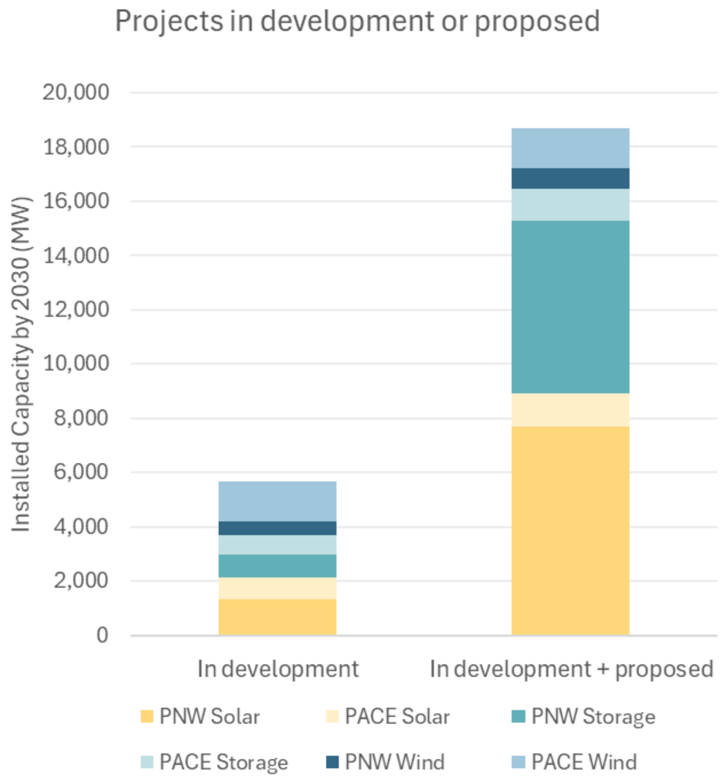


Winter portfolio ELCCs of new clean resources

Winter portfolio ELCCs estimated by calculating avoided perfect capacity during Jan 2024 weather/hydro event (not representative of summer contributions)

Baseline Load Scenario	Installed capacity (MW)	Avoided Perfect Capacity in Jan 2024 conditions (MW)	Approx. Winter Portfolio ELCC
All clean resources in development	5,666	1,875	33%
Additional clean resources pending approvals	13,009	2,473	19%
Total	18,675	4,348	23%

(Calculated before Centralia 2 coal-to-gas conversion and large load curtailments)

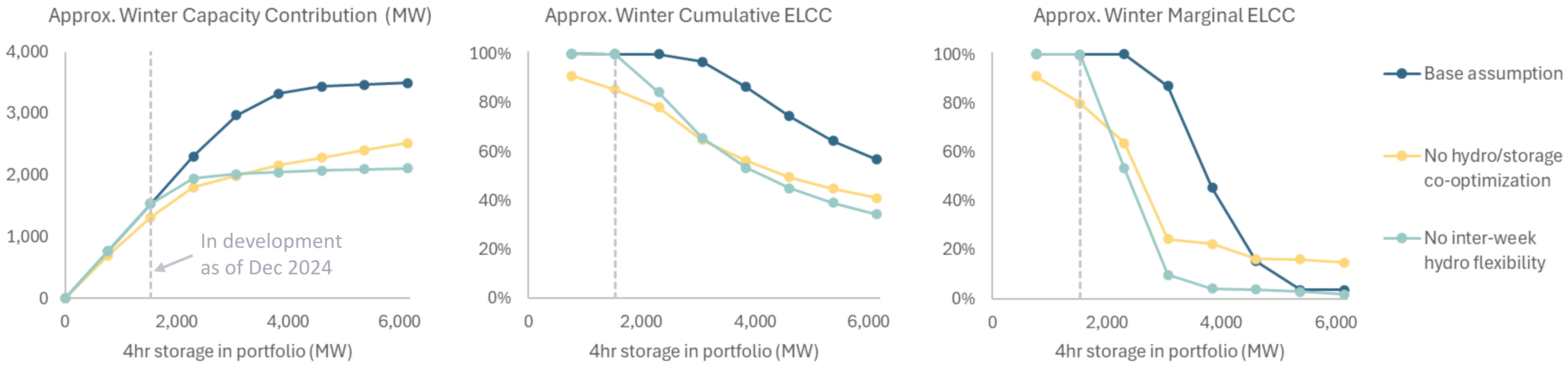


Near-term opportunity:

- Execute on all clean resource development plans and prioritize or accelerate new resource procurement activities

Winter ELCCs of 4hr storage

- Winter ELCCs for 4hr storage could depend strongly on how the hydro system is operated and modeled
- Two assumptions could lead to lower ELCCs and more rapid saturation of short duration storage than our analysis observes
  1. Overly constraining the ability to hold water in preparation for a forecasted or potential future weather event
  2. Load-following or net load-following hydro dispatch that is not co-optimized with battery storage dispatch



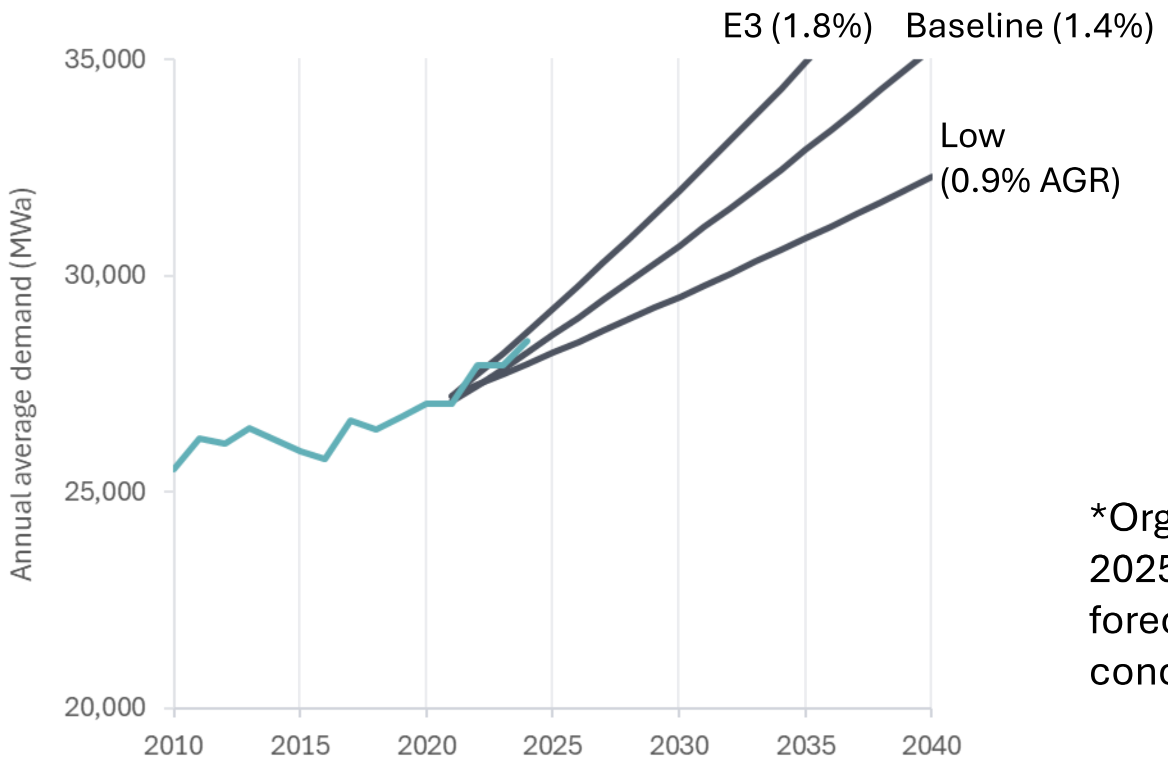
Notes:
- Approximate winter capacity contributions were calculated as the reduction in capacity need during January 2024 weather & hydro conditions under the Baseline load scenario, with wind and solar that is in development and Centralia 2 coal-to-gas conversion
- These values do not account for contributions to resource adequacy in the summer and may not be applicable to individual utilities with unique constraints
- After conducting the analysis, we found that 332 MW of batteries came online in 2024, which were not included in the baseline dispatch simulations because they were not in January 2024 EIA 930 data. This analysis suggests these additional batteries would have reduced capacity needs in all simulations by about 330 MW.

Detailed findings

- Resource needs under January 2024 weather/hydro conditions across the 2030 load scenarios
  - With no incremental resources
  - With resources in development as of December 2024 and Centralia 2 coal-to-gas conversion
  - With emergency large load curtailment
- Outage risk to customers under across the load scenarios with and without large load curtailments
- Contributions of clean energy resources in development and potential from additional proposed clean resources
- High level insights on load uncertainty and how quickly the region may face the most daunting challenges

The need for dispatchable or baseload solutions is not a question of if, but when

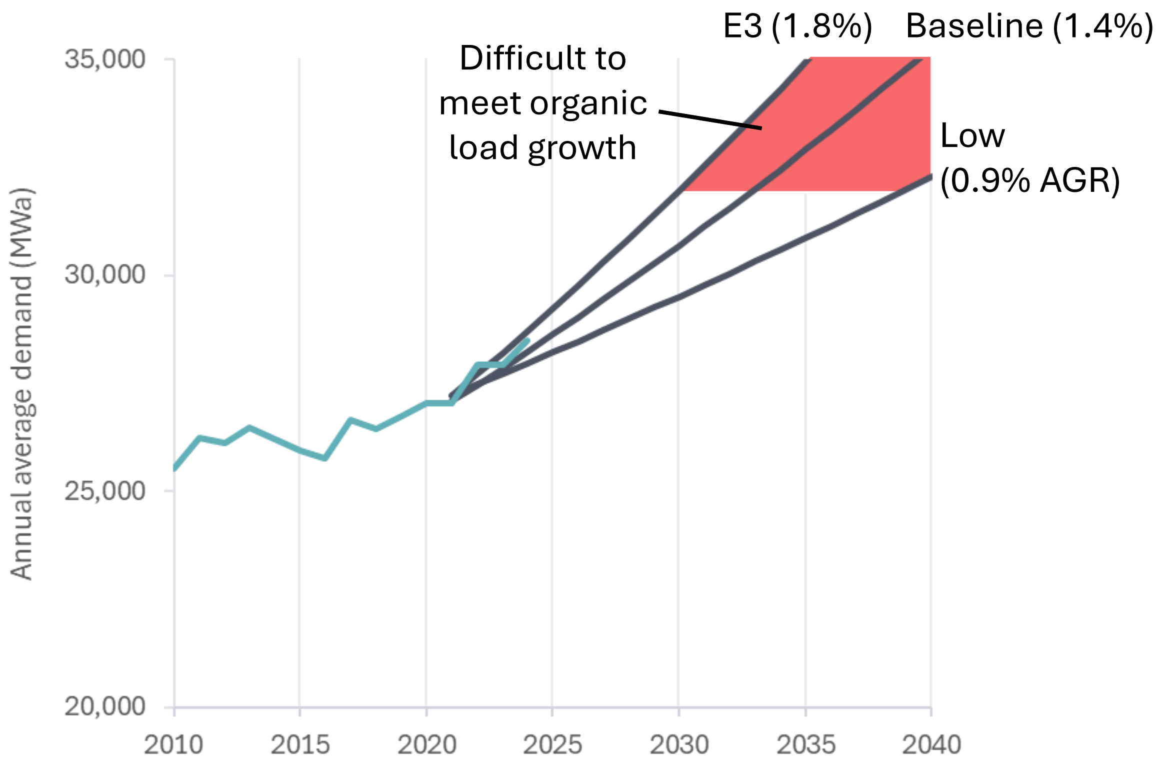
Extrapolated* organic load growth trajectories



*Organic load growth trajectories estimated by applying the 2025-2030 average annual organic load growth rate from each forecast to 2031-2040. This exercise is indicative and conceptual and may not align with actual load forecasts.

The need for dispatchable or baseload solutions is not a question of if, but when

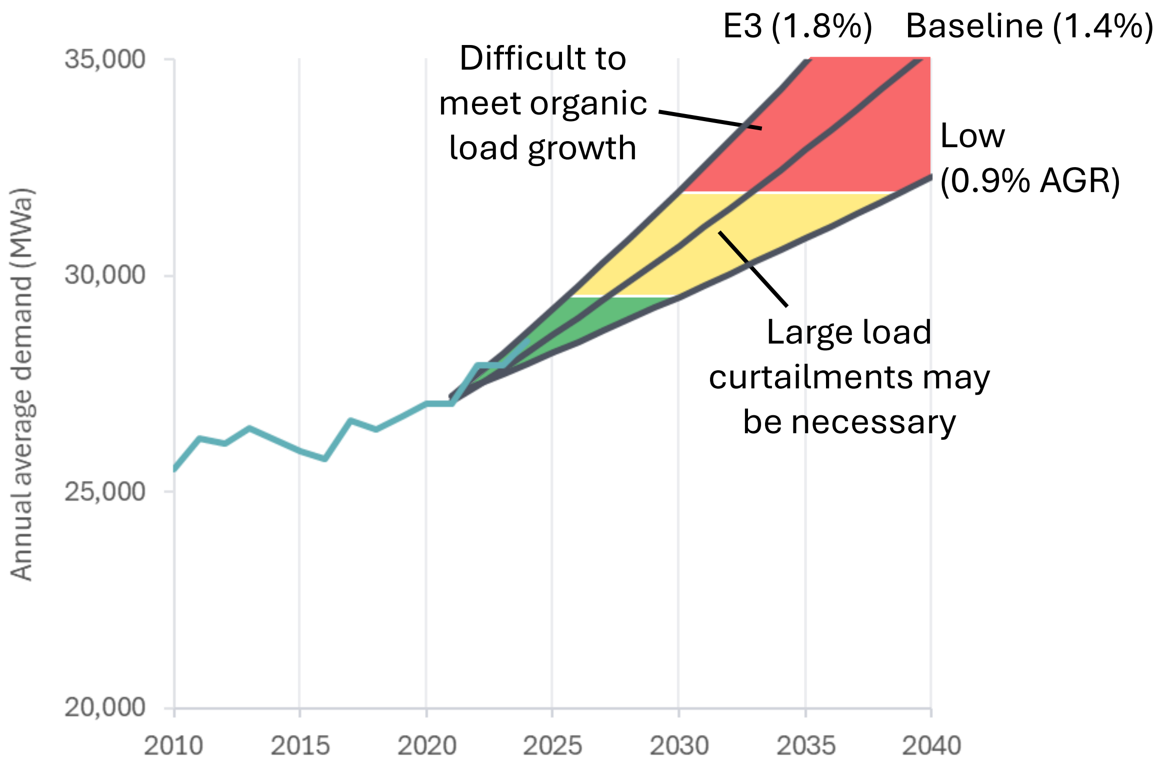
Extrapolated* organic load growth trajectories and resource adequacy challenges



- When the region faces the most daunting challenges encountered in our simulations will depend on future load growth (which will depend on economic conditions, electrification, and energy efficiency):
  - E3 Forecast: By 2030
  - Extrapolated Baseline Forecast: Roughly early 2030s
  - Extrapolated Low Growth Forecast: Roughly late 2030s
- Pushing these needs out in time creates opportunities for emerging clean technologies to be part of the solution

The need for dispatchable or baseload solutions is not a question of if, but when

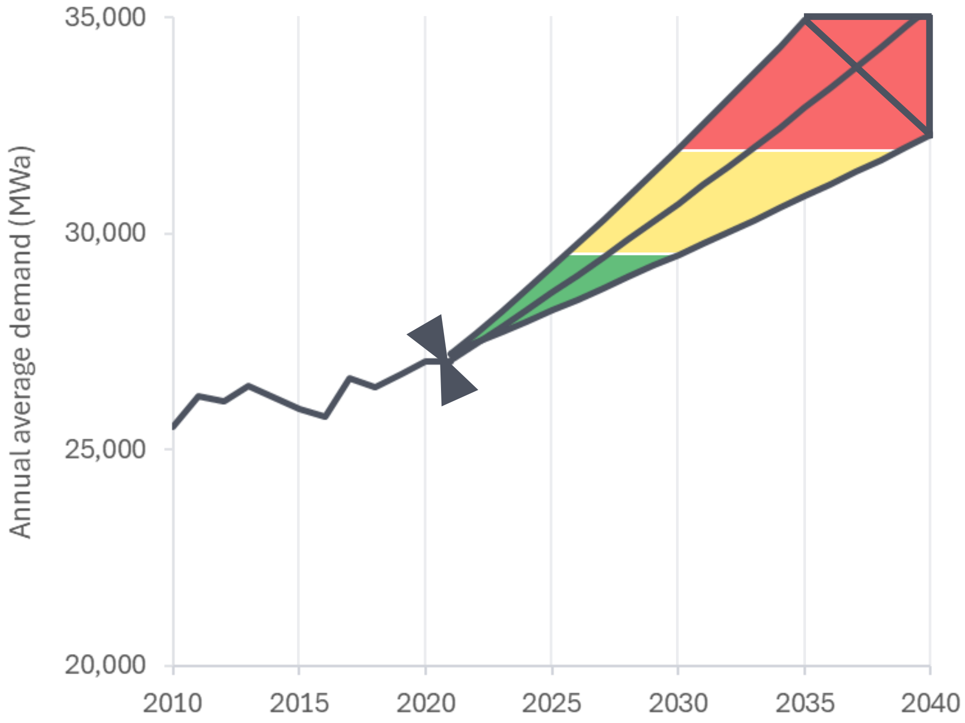
Extrapolated* organic load growth trajectories and resource adequacy challenges



- When the region faces the most daunting challenges encountered in our simulations will depend on future load growth (which will depend on economic conditions, electrification, and energy efficiency):
  - E3 Forecast: By 2030
  - Extrapolated Baseline Forecast: Roughly early 2030s
  - Extrapolated Low Growth Forecast: Roughly late 2030s
- Pushing these needs out in time creates opportunities for emerging clean technologies to be part of the solution
- Large load flexibility requirements provide a crucial backstop across the scenarios

“A kite only flies when it’s tethered”

-Victor Robert Lee



We can’t control the wind (or the economy), but we have some tethers on the demand side that could buy the region some time

Near-term opportunities:

- Develop emergency conservation programs to discourage EV charging & non-essential energy use, and encourage lower thermostat settings during critical multiday winter events
- Prioritize energy efficiency measures that reduce winter demand (e.g., building shell measures and replacing baseboard heating)


Cape Lookout State Park, Oregon Coast (source: www.oregonlive.com)

An opportunity to drive innovation

- If subject to flexibility requirements, data center customers will face the most daunting long-duration reliability challenges first and will have an incentive to solve them
- With a desire to move quickly and larger risk appetites than regulated utilities, data center customers could drive innovation in the next generation of clean technologies that serve longer duration needs, accelerating adoption, and driving down costs
- Flexibility requirements can also be leveraged to facilitate more rapid interconnection until new technologies become available

High level findings from independent evaluation

1. The scale and nature of the winter resource adequacy challenge in the Pacific Northwest depends strongly on future load growth, which remains highly uncertain due to both data center demand and electrification trends
2. Large load flexibility could mitigate most or all near-term winter resource adequacy needs under most load scenarios
3. Sustained development of clean resources is well-suited to meeting organic (i.e., non-data center) load growth in the region unless electrification accelerates faster than recent load growth trends suggest
4. Supporting reliable winter data center operations in the Pacific Northwest will likely require resources with more energy availability during challenging winter events
5. In the near term, the ability to curtail large loads first during emergency events can protect other customers from the most catastrophic health and safety consequences of supply shortages
6. In the long term, the need for dispatchable or baseload solutions is not a question of if, but when

Near-term opportunities identified to support regional RA

Policy

- Consider policies that require large load flexibility or emergency curtailment prior to curtailing other customers to mitigate the most catastrophic health and safety consequences of supply shortages

Planning & Development

- Execute on all clean resource development plans and prioritize or accelerate new resource procurement activities
- Prioritize energy efficiency measures that reduce winter demand (e.g., building shell measures and replacing baseboard heating)
- Prioritize transmission studies and upgrades that support increased South-to-North flows into the Pacific Northwest during the winter
- Schedule coal-to-gas conversion activities to minimize winter downtimes
- Study impacts of natural gas system constraints on electricity reliability

Operations

- Develop emergency conservation programs to discourage EV charging & non-essential energy use, and encourage lower thermostat settings during critical multiday winter events
- Consider day-ahead market designs and market seams solutions that promote resource commitment in California and the Southwest during critical winter events in the Pacific Northwest
- Consider impacts of market participation on the propensity of hydro operators to hold energy in reserve for critical events (e.g., the value of stored water), while respecting all hydro operating limits

Cape Lookout State Park, Oregon Coast (source: www.oregonlive.com)

Thank you!

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SYLVAN ENERGY ANALYTICS