National Transmission Planning Study

Chapter 5:

Stress Analysis for 2035 Scenarios

NREL

Pacific Northwest National Laboratory

GDO Grid Deployment Office

Suggested citation
U.S. Department of Energy, Grid Deployment Office. 2024. *The National Transmission Planning Study*. Washington, D.C.: U.S. Department of Energy. https://www.energy.gov/gdo/national-transmission-planning-study.

Context

The National Transmission Planning Study (NTP Study) is presented as a collection of six chapters, each of which is listed next. The NTP Study was led by the U.S. Department of Energy's Grid Deployment Office, in partnership with the National Renewable Energy Laboratory and Pacific Northwest National Laboratory.

- The **Executive Summary** describes the high-level findings from across all six chapters and next steps for how to build on the analysis.
- **Chapter 1: Introduction** provides background and context about the technical design of the study and modeling framework, introduces the scenario framework, and acknowledges those who contributed to the study.
- **Chapter 2: Long-Term U.S. Transmission Planning Scenarios** discusses the methods for capacity expansion and resource adequacy, key findings from the scenario analysis and economic analysis, and High Opportunity Transmission interface analysis.
- **Chapter 3: Transmission Portfolios and Operations for 2035 Scenarios** summarizes the methods for translating zonal scenarios to nodal-network-level models, network transmission plans for a subset of the scenarios, and key findings from transmission planning and production cost modeling for the contiguous United States.
- **Chapter 4: AC Power Flow Analysis for 2035 Scenarios** identifies the methods for translating from zonal and nodal production cost models to alternating current (AC) power flow models and describes contingency analysis for a subset of scenarios.
- **Chapter 5: Stress Analysis for 2035 Scenarios (this chapter)** outlines how the future transmission expansions perform under stress tests.
- **Chapter 6: Conclusions** describes the high-level findings and study limitations across the six chapters.

As of publication, there are three additional reports under the NTP Study umbrella that explore related topics, each of which is listed next.[1] For more information on the NTP Study, visit https://www.energy.gov/gdo/national-transmission-planning-study.

- **Interregional Renewable Energy Zones** connects the NTP Study scenarios to ground-level regulatory and financial decision making—specifically focusing on the potential of interregional renewable energy zones.

[1] In addition to these three reports, the DOE and laboratories are exploring future analyses of the challenges within the existing interregional planning landscape and potential regulatory and industry solutions.

- **Barriers and Opportunities To Realize the System Value of Interregional Transmission** examines issues that prevent existing transmission facilities from delivering maximum potential value and offers a suite of options that power system stakeholders can pursue to overcome those challenges between nonmarket or a mix of market and nonmarket areas and between market areas.

- **Western Interconnection Baseline Study** uses production cost modeling to compare a 2030 industry planning case of the Western Interconnection to a high renewables case with additional planned future transmission projects based on best available data.

List of Acronyms

AC	alternating current
ADS	Anchor Dataset
B2H	Boardman to Hemingway
BA	balancing authority
BESS	Battery Energy Storage Systems
CA	California
CAISO	California Independent System Operator
CIPB	Pacific Gas & Electric Bay Area
CIPV	Pacific Gas & Electric Valley Area
CISC	Southern California Edison
CISD	San Diego Gas & Electric
C-VOLL	cumulative value of lost load ($)
DC	direct current
DOE	U.S. Department of Energy
EIA	Energy Information Administration
ES	energy storage
FERC	Federal Energy Regulatory Commission
GODEEEP	Grid Operations, Decarbonization, Environmental, and Energy Equity Platform
GT	gas turbine
HTC	hydrothermal coordination
HVDC	high-voltage direct current
ICE	interruption cost estimate

IPCO	Idaho Power Company
IPFE	Far East (Idaho Power)
IPMV	Magic Valley (Idaho Power)
IPTV	Treasure Valley (Idaho Power)
IM3	Integrated Multisector Multiscale Modeling
km	kilometer
kV	kilovolt
kWh	kilowatt-hour
LSE	load-serving entity
M	meter
ML	machine learning
MLP	multilayered perceptron
MT	multiterminal
MW	megawatt
MWh	megawatt-hour
NERSC	National Energy Research Scientific Computing Center
NEVP	Nevada Power
NG	natural gas
NOB	Nevada–Oregon Border
NREL	National Renewable Energy Laboratory
NTP Study	National Transmission Planning Study
O&M	operations and maintenance
PACE	PacifiCorp East
PAID	PacifiCorp East - Idaho

PAUT	PacifiCorp East - Utah
PAWY	PacifiCorp East - Wyoming
PCM	production cost model
PHS	pumped hydro storage
PNNL	Pacific Northwest National Laboratory
PNW	Pacific Northwest
PV	photovoltaic
RCP	representative concentration pathway
ReEDS	Regional Energy Deployment System (model)
reV	Renewable Energy Potential (model)
SAM	System Advisor Model
SPCC	Sierra Pacific Power
TELL	total electricity loads
TGW	thermodynamic global warming
TWh	terawatt-hour
UTC	Coordinated Universal Time
VEA	Valley Electric Association
VOLL	value of lost load ($/kWh)
WECC	Western Electricity Coordinating Council
WRF	Weather Research and Forecasting

Chapter 5 Overview

This chapter presents the study's extreme stress analysis methods and key findings. *Extreme stress* refers to extreme meteorological events such as heatwaves and droughts that can affect grid operations. *Extreme stress analysis* assesses the potential impacts of such meteorological extremes on bulk power systems' reliability and operations. The study used a suite of modeling tools to project extreme events onto future grid scenarios to assess the reliability, economic, and operational impacts of stress conditions under different transmission expansion options. The goal was to analyze how the different transmission planning frameworks influenced grid operations throughout periods of heightened stress and which strategies successfully maintained grid operations. Findings from this extreme stress analysis provide initial regional insights into how grid operations may respond to extreme events based on different transmission characteristics, and the stress analysis approach is offered as a proof-of-concept model for future resource adequacy analyses and transmission planning processes that consider grid reliability under extreme weather scenarios.

The study applied its stress analysis method to two nodal transmission expansion scenarios for the Western Interconnection for the year 2035. The analysis projects spatially defined heat and drought condition impacts on hourly load, wind, solar, and the availability of hydropower during droughts and reveals how extreme events challenge reliable grid operations as regional loads are increased during the heat event while supply decreased because of hydropower reductions. The two nodal transmission scenarios are: 1) the western interconnection 2035 Limited (Lim) scenario and 2) the western interconnection 2035 Alternating Current (AC) scenario.[2] The specific assumptions used for these scenarios are high demand growth[3] and the 90% decarbonization by 2035 emissions constraint.

Four stress cases were defined based on historical events in the West using production cost simulations for the year 2035 for both nodal transmission scenarios to generate 8 simulation results (4 stress cases × 2 scenarios; see Table I). The acronyms "AC" and "Lim" denote the Alternating Current and Limited transmission scenarios, respectively, and "H" and "H+D" represent the heatwave and the combined heatwave and drought events, respectively.

[2] The stress analysis study examined only the Lim and AC scenarios within the Western Interconnection footprint because of study timeline limitations. Future areas recommended for study include conducting additional stress analyses for combined Eastern and Western Interconnection scenarios and expanding the range of threats (e.g., cold snaps) and transmission expansion scenarios (e.g., multiterminal high-voltage direct current [HVDC]).

[3] An increase in peak demand of 21% relative to the 2030 Industry case. For more information regarding the load assumptions, refer to Chapter 1: Introduction (Appendix D), earlier (Round 1) ReEDS Scenario. The nodal realization is explained in Section 4 of Chapter 3: Transmission Portfolios and Operations for 2035 Scenarios.

Table I. Stress Case Scenarios

Stress Case	Stress Event
1	California Heatwave
2	California Heatwave + Pacific Northwest Drought
3	Pacific Northwest Heatwave
4	Pacific Northwest Heatwave + Pacific Northwest Drought

Key Findings

1. **Compounded extreme events lead to higher levels of unserved energy than individual events.** When the California (CA) or Pacific Northwest (PNW) heatwave is combined with the PNW hydropower drought, the resulting unserved energy increases in both regions and across both transmission scenarios (Figure I).

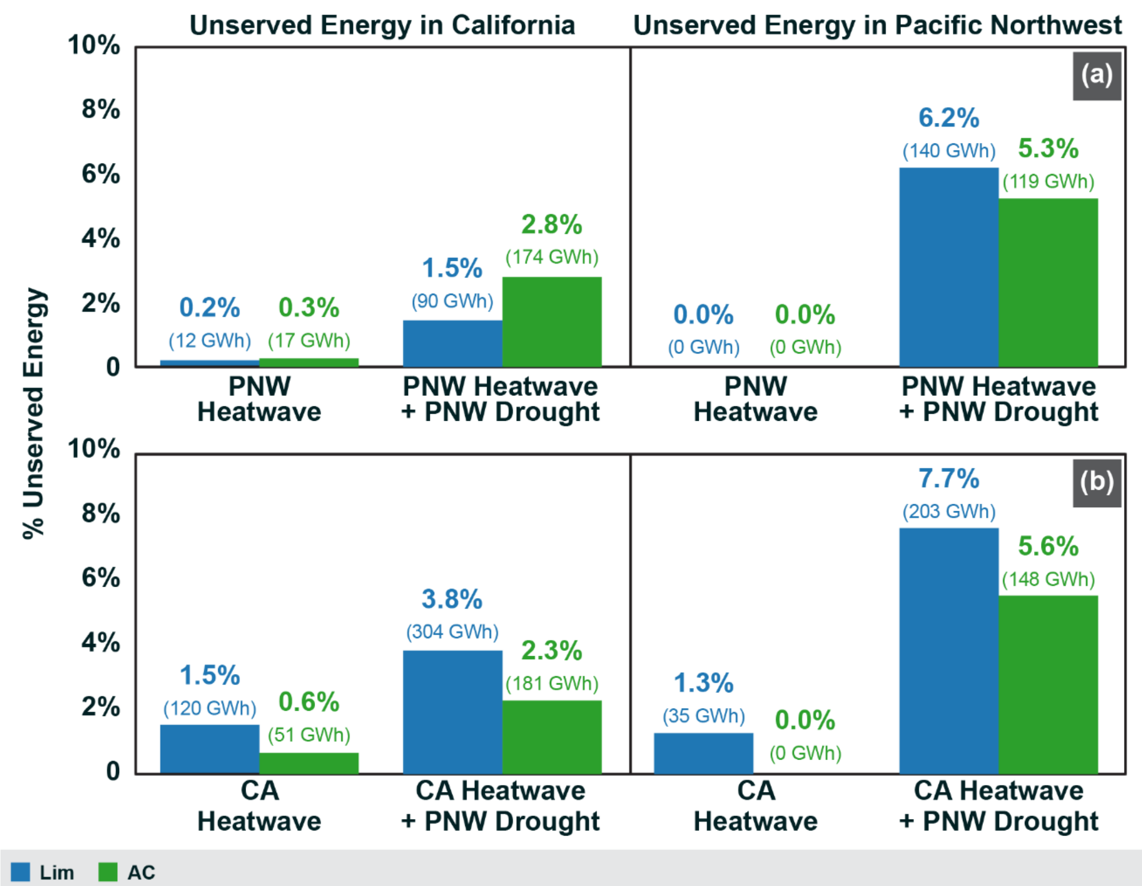

Figure I. Both Lim and AC scenarios show pronounced effects from the combination of a heatwave in (a) the PNW or (b) California and the PNW drought compared to the respective single heatwave events

GWh = gigawatt-hour

2. **The buildout of interregional transmission can support the power system during extreme weather events, decreasing the potential for and amounts of unserved energy.**[4]
   The new interregional capacity (in the AC scenario) within the Western Interconnection region forges a vital corridor for channeling wind resources from New Mexico, Colorado, and Wyoming to meet California's increased demand during the California heatwave and PNW drought. This transmission route is vital to address California's surging demand and compensating for hydropower shortfalls in the PNW (Figure II). As a result, unserved energy is reduced by 1.5% in California (4.2% in Southern California) and 1.9% in the PNW in the AC scenario compared to the Limited scenario.

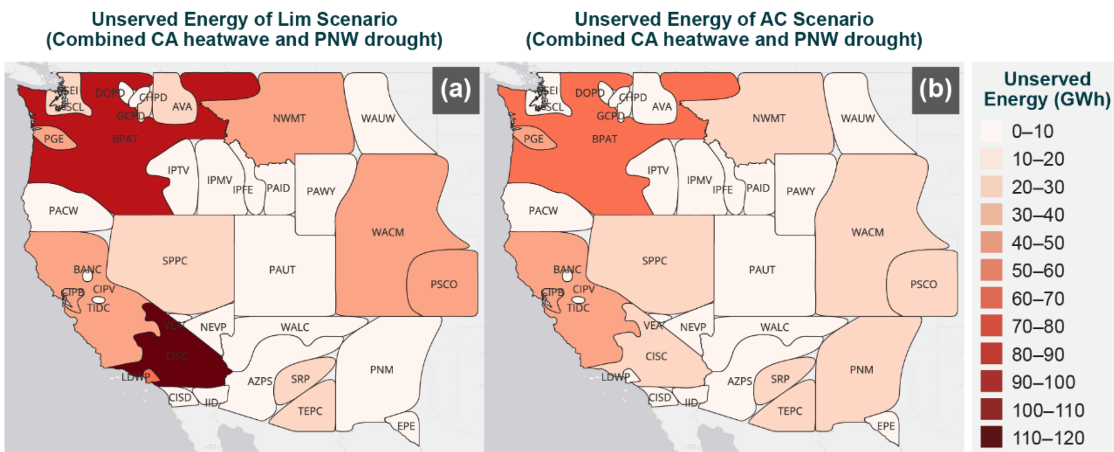

Figure II. The AC scenario (b) significantly reduces the worst regional impacts of combined California heatwave and PNW drought events (the most severe of the stress cases modeled) relative to the Lim scenario (a)

3. **Transmission and resource planners should carefully consider interregional transmission capacity and additional local generation capacity to minimize the risks of extreme stress events.** Both interregional transmission and local generation capacity expansion are needed to manage risk during a variety of extreme stress events, as exemplified by the combined heatwave and drought in the PNW. California reported 1.3% lower unserved energy levels in the Limited scenario than the AC scenario (Figure III), benefiting from its greater installed capacity of local dispatchable resources (such as battery storage and natural gas) (Figure IV) that could support the state's increased load demands amid decreased imports from the PNW. In both scenarios, California is a net exporter, supporting the PNW heatwave and drought.

   This specific case highlights that the attributes of an extreme event—duration, magnitude, type, and location—affect each region's generation availability differently,

[4] Unserved energy is the amount of customer demand that cannot be supplied due to a shortage of available generation resources.

including the ability to transfer power between regions. Hence, depending on the extreme event under study, a system with different levels of interregional transmission capacity may respond differently based on the levels and types of generation and storage resources, including local assets. Therefore, transmission planning solutions will need to carefully consider the attributes of extreme events and how those affect generation availability and transmission utilization.

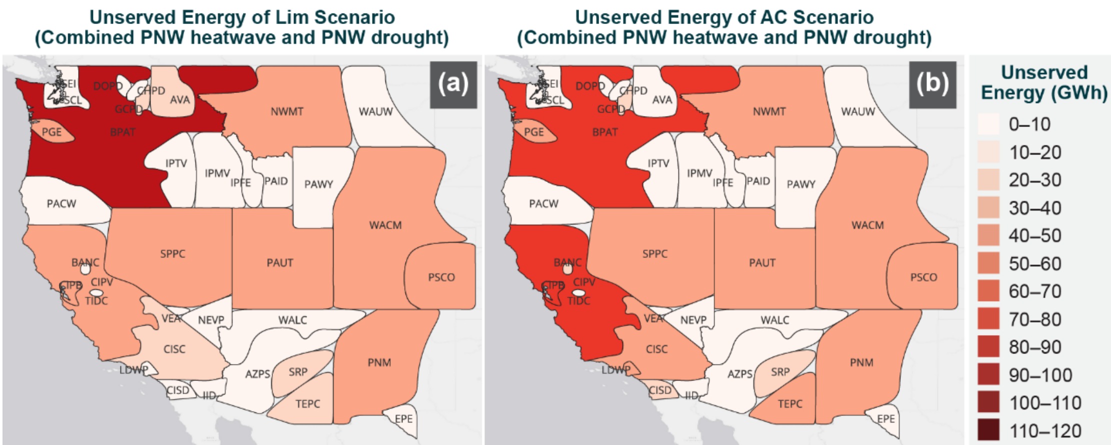

Figure III. In the Lim scenario (a), the greater installed capacity of battery energy storage resources and natural gas turbines in California leads to a 1.3% reduction in unserved energy in California compared to the AC scenario (b)

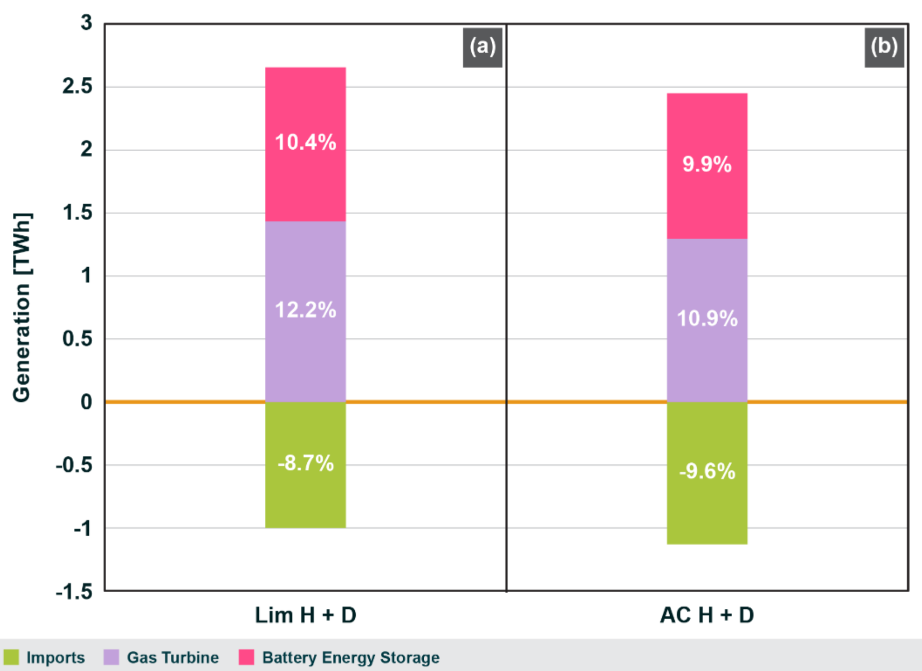

Figure IV. Generation outputs (terawatt-hour [TWh]) in California for the Lim (a) and AC (b) scenarios during the combined PNW heatwave event with PNW drought

In the Lim scenario, there is a greater dispatch of battery energy storage and natural gas turbines, leading to reduced unserved energy in California compared to the AC scenario

4. **The unserved energy peaks in the morning are because of low online energy resource availability and increasing load ramps.** The unserved energy peak coincides with increasing morning load ramp[5] and exhausted battery and pumped hydro energy storage resources (because of the full use of storage to meet the peak load in the late afternoon when solar diminishes), prior to solar generation coming online. The amount of unserved energy is higher in the Lim scenario compared to that in the AC scenario (Figure V), underscoring the importance of interregional capacity (in the AC scenario) in boosting California imports to meet the load during early morning hours.

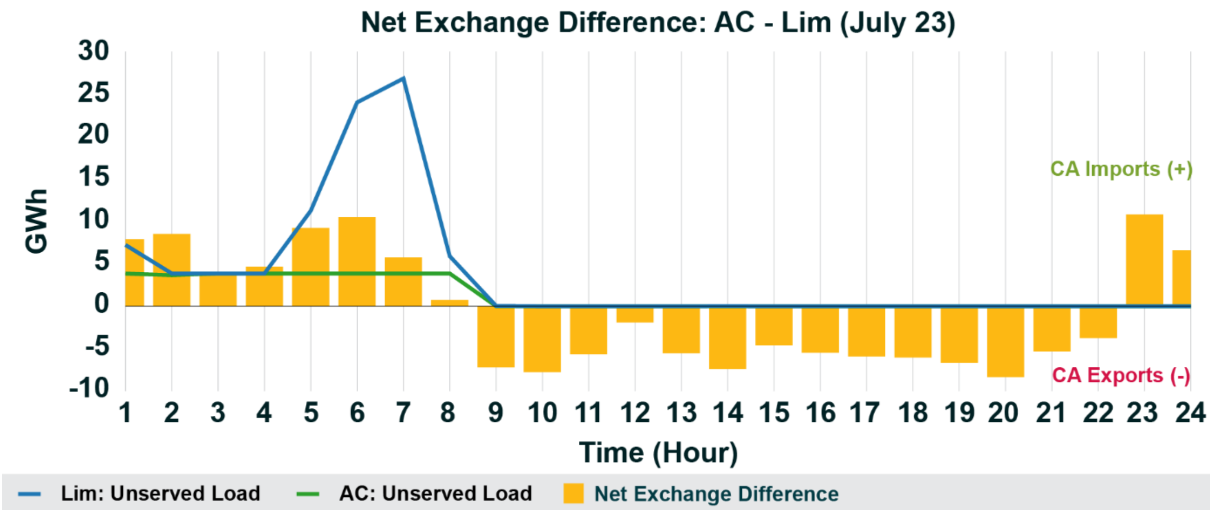

Figure V. Hourly unserved energy during the combined California heatwave and PNW drought; the yellow bars show the hourly net exchange difference between the AC and Lim scenarios, highlighting the interregional support (in the AC scenario) to California (+) during those morning hours

5. **Different transmission topologies provide varying economic benefits of reliability based on extreme event locations and types.** The study revealed the reliability benefits of different transmission topologies are highly dependent on geographic location and stress intensity. The NTP Study estimated economic benefits based on four stress events (PNW heatwave, PNW heatwave with PNW drought, California heatwave, California heatwave with PNW drought), and the transmission topology with greater benefits depends on the location and intensity of the modeled event. Future work should combine estimates of the benefits of preventing outages during extreme events with the probability of event occurrence to obtain expected benefits that can be used to augment a cost-benefit analysis.

[5] Morning load ramp is defined as the transition from relatively lower loads to higher loads in the morning.

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1 Introduction and Background

This section describes the stress analysis of specific transmission expansion scenarios developed for the Western Interconnection in support of the National Transmission Planning Study (NTP Study):

1. **Western Interconnection 2035 Limited (Lim) Scenario**
   Transmission is only developed within Federal Energy Regulatory Commission (FERC) Order No.1000 planning regions; no interregional transmission is included.

2. **Western Interconnection 2035 Alternating Current (AC) Scenario**
   Transmission is developed between adjacent FERC Order No.1000 regions in the Western Interconnection; no transmission is built between the Western and Eastern Interconnections.

To understand the reliability and economic value of transmission expansion scenarios during extreme stress events, it is necessary to perform chronological hourly production cost simulations. These simulations offer insights into how different regions may withstand such events, given their unique generation mixes and transmission capacity. The interplay between these factors is critical, highlighting the importance of extreme stress analysis in understanding the potential benefits of expanding transmission infrastructure.

1.1 Linkage to Other NTP Chapters

This chapter builds on previous chapters of the NTP Study—particularly Chapters 2 and 3—by applying extreme stress events to the nodal transmission scenarios. The NTP Study derived the nodal transmission scenarios starting with the analysis of the zonal capacity results obtained from the capacity expansion model (Chapter 2). The study team then employed a zonal-to-nodal methodology (Chapter 3) to refine the zonal capacity results to a more granular nodal level. The zonal-to-nodal methodology results in two distinct nodal transmission scenarios for the year 2035: the Alternating Current (AC) scenario and the Limited (Lim) scenario.[6] The study team used production cost modeling to simulate these two nodal transmission scenarios under the same stress conditions, derived from a stress case modeling framework. This modeling framework uses a suite of modeling tools to simulate hourly load, wind, and solar time series under varying weather conditions and hydropower availability during droughts.

Figure 1 summarizes how the stress analysis framework referenced in this chapter is related to the initial datasets, capacity expansion modeling, and zonal-to-nodal realization found in other chapters.

[6] This chapter uses the nodal transmission scenarios based on the earlier Regional Energy Deployment System (ReEDS) scenarios (Round 1). For a brief description of the two nodal transmission scenarios, see Section 3 of this chapter. For a more comprehensive description, see Section 4 of Chapter 3.

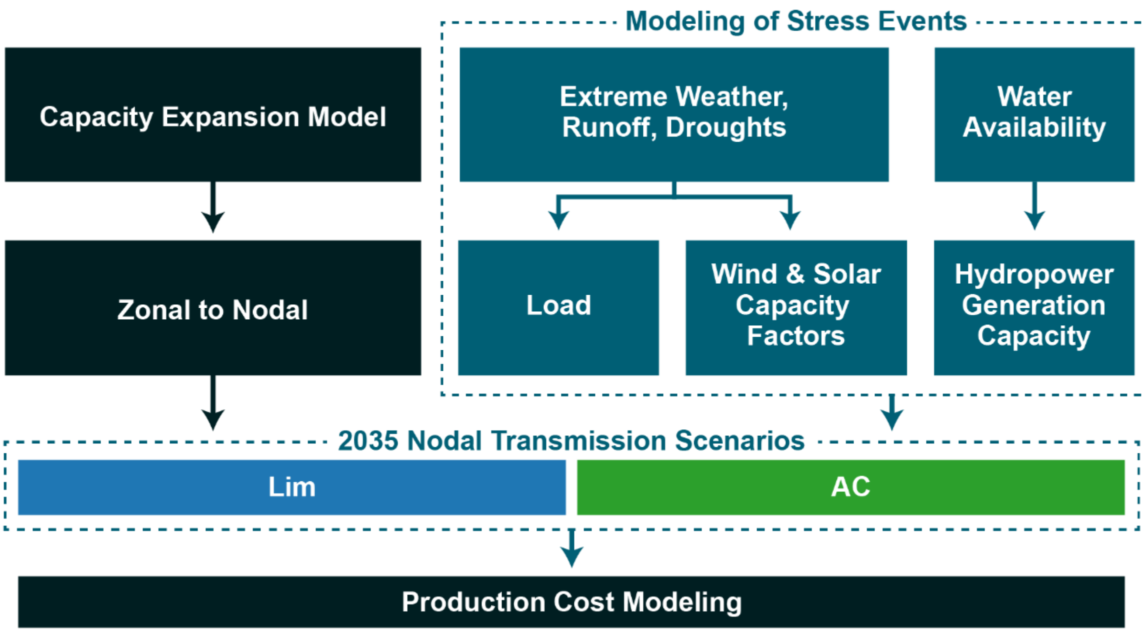

Figure 1. Modeling framework for the stress cases analyzed in the NTP Study

1.2 Motivation

In recent years, the power grid has increasingly faced significant challenges because of the rising frequency and intensity of extreme weather events. Concurrently, the ongoing transition to renewable energy sources—including wind and solar—alongside the increasing electrification of various sectors such as transportation and heating has introduced additional variability into the system. Recent developments, such as those related to climate change, underscore the importance of understanding how extreme conditions, whether occurring individually or in tandem (for example, extreme heat coupled with droughts), can have extensive effects on the grid. In this evolving landscape, new transmission capacity could play a crucial role in diversifying the generation mix in regions affected by extreme stress events by facilitating the transfer of energy from nonaffected regions.

Historically, entities could effectively manage and prepare for rare and mildly disruptive occurrences because they were fairly predictable in the short term with limited impacts. However, climate change effects coupled with increased urbanization and the aging transmission infrastructure have led to a significant increase in the likelihood of severe power system reliability incidents (Auffhammer, Bayliss, and Hausman 2017; Cohen et al. 2022; Do et al. 2023; Dyreson et al. 2022; Lee and Dessler 2022). Unlike before, when such events were isolated and affected only specific areas, these events now often happen concurrently and affect vast regions. An example of this is the simultaneous occurrence of severe droughts, wildfires, and a massive heatwave in the Pacific Northwest (PNW) in June 2021 (Balaraman 2021). Because these events are no longer exceptional or infrequent, power system planners and operators must gain a deeper understanding of how changing weather patterns interact with the modern electrical grid to mitigate the effects of these events.

Concentrating on heatwaves and droughts in the western United States, this chapter investigates 1) how extreme stress events exacerbate strain on the grid by simultaneously increasing demand while diminishing supply and 2) how the two NTP nodal transmission expansion scenarios (i.e., Lim and AC) perform under the influence of such events. In this context, the study team seeks to answer the following questions:

- If part of the Western Interconnection (shown later in Figure 14) experiences an extreme event that includes a simultaneous heatwave and drought, can the Western Interconnection grid avoid unserved energy?
- What is the role of new and existing transmission capacity during extreme stress events across the Western Interconnection?
- How can transmission capacity diversify the generation mix in regions affected by extreme climate events, and why is this diversification critical for highly decarbonized systems exposed to such events?

To address these questions, the study team employed production cost modeling to simulate power grid operations as well as weather-driven modeling tools to generate hourly load, wind, and solar time-series data under varying stress conditions and hydropower availability during droughts. Specifically, GridView—a production cost modeling tool developed by Hitachi Energy (2024)—was used to model the stress cases. GridView is a chronological unit commitment and economic dispatch model that minimizes power systems' operating costs to meet electricity demand and reserve requirements while satisfying various operating constraints. These constraints include unit-specific limitations (such as maximum/minimum capacity limits, minimum up- and downtimes, and ramping limits) as well as systemwide constraints (such as transmission line capacity limits, interface capacity limits, operating reserves, emission constraints, and hurdle rates). Operating costs largely consist of fuel costs, variable operating and maintenance costs, and startup/shutdown costs. The study team imported load, wind, and solar time-series and hydropower energy into GridView to simulate the evolution of the electricity supply and demand during extreme events.

2 Brief Methodology and Datasets

2.1 Types of Threats

This section describes the two types of threats: single- and multievent threats (where two or more weather events coincide).[7] The selected threats are 1) continental heatwaves[8] and 2) combined heatwaves and drought conditions, which are expected to affect the grid in several ways—including hourly load, generation, and water availability, which in turn will affect hydropower generation.

Heatwaves affect the grid by simultaneously increasing the demand for electricity (primarily because of increased demand for space cooling) and reducing supply through the derating of generators and derating transmission capacity (Auffhammer, Bayliss, and Hausman 2017; Sathaye et al. 2013; Bartos et al. 2016). Because they tend to be spatially widespread, heatwaves affect vast regions of the electric grid simultaneously (Sundar et al. 2023), which in turn limits the power grid's ability to alleviate stress during extreme heatwave events. Combined heatwave and drought events can lead to significant generation shortfall risks (Turner et al. 2019).

Solar generation is affected by heatwaves because the efficiency of solar panels decreases as the temperature increases. The exact change in efficiency depends on the panel type but ranges from −0.36%/°F to −0.85%/°F (Dobos 2014). For example, a 45°F above-average heatwave would cause a reduction in efficiency of 4%–9.4%, depending on the panel. Wind generation is affected by heatwaves as well, but the effects are meteorologically and regionally dependent. For example, heat domes are a meteorological phenomenon known to cause extreme heat and suppress wind (White et al. 2023). Not all extreme heat is caused by heat domes, and the wind response during extreme heat can vary widely, depending on the region and the meteorological conditions.

Hydropower generation can be both directly and indirectly affected by heatwaves. Extreme heat can cause unexpected snow melt, increased evaporation losses, increases in stream temperature, and increased load, which necessitate changes in hydropower operations. That said, hydropower is typically resilient to short-term heatwaves. In general, drought conditions lead to a regional decrease in hydropower availability, but systemwide in the Western Interconnection, hydropower is remarkably consistent year to year (PNNL 2022). Heatwaves combined with drought conditions can stress specific hydropower facilities even further—even if the effect is buffered at the Western Interconnection-wide scale.

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[7] This chapter focuses only on two types of threats applied to two considered transmission expansion scenarios (Limited and AC). Future work would include expanding the range of threats (e.g., cold snaps) and transmission scenarios (e.g., multiterminal [MT] high-voltage direct current [HVDC]).

[8] A heatwave event is defined as a period of abnormally hot weather generally lasting more than 2 days. They can cover a large area, exposing a high number of people to hazardous heat.

2.1.1 Continental heatwaves

The study team selected two exemplar case studies: two unique and contrasting historic western U.S. heatwave events. The first occurred for approximately 8 days from roughly June 25, 2015, to July 2, 2015, and covered most of the western United States, including the PNW (Figure 2). The second occurred for approximately 7 days from roughly July 22, 2018, to July 28, 2018, and was most intensive over California and the Desert Southwest (Figure 3). The study team used a unique thermodynamic global warming approach to explore how these two heatwave events may be modified under climate change (Jones 2023). Choosing two heatwaves with different spatial representations allowed the study team to test the ability of expanded transmission to alleviate regional versus widespread stress events.

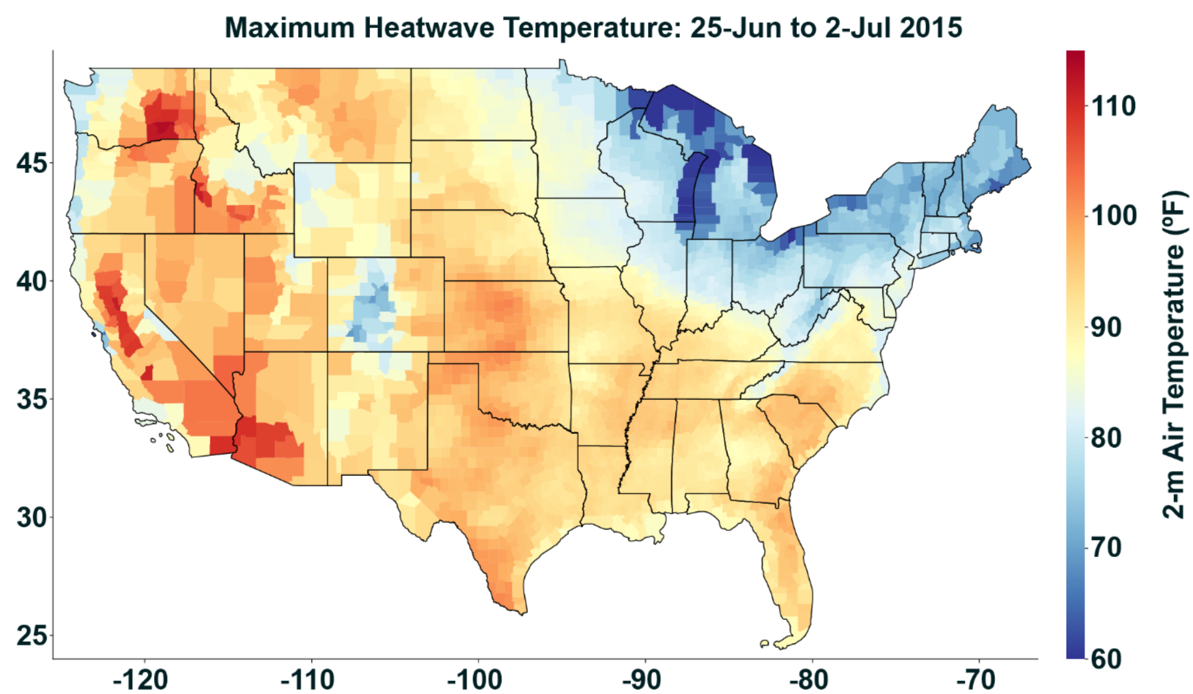

Figure 2. 2015 heatwave event in the PNW

Temperatures in eastern Washington exceeded 112°F during this event. Well above average temperatures extended across much of the West.

m = meter

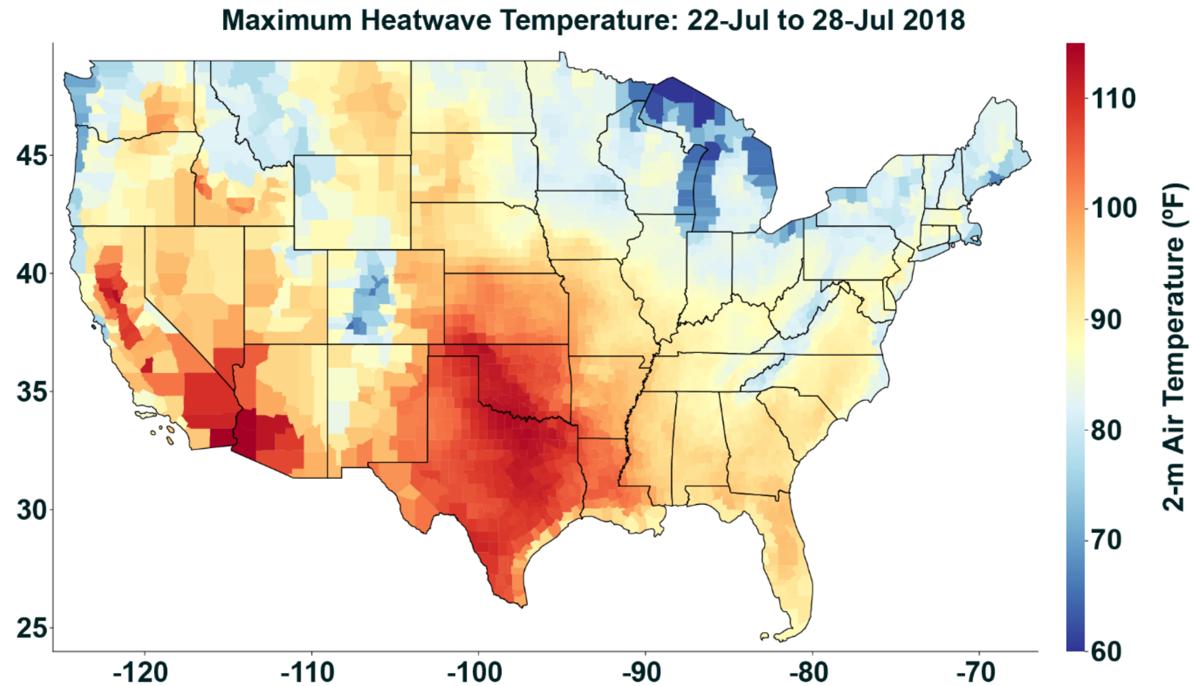

Figure 3. 2018 heatwave event in California and the Desert Southwest

This event was more localized to the central California valley and Desert Southwest, where maximum temperatures exceeded 110°F.

Figure 4 shows the evolution of the daily maximum temperature in the western United States from 2000 to 2019 (Jones et al. 2023). The blue and gray shading in the plot is used to show the timing and magnitude of the 2015 and 2018 heatwave events integrated into the NTP Study. The daily maximum temperatures during both events were 8–10°F above the historical average with slightly warmer values occurring during the 2018 event. In both events, there are only a small number of days in the historical record in which temperatures exceeded the values observed during the heatwaves evaluated in the NTP Study. These intentionally selected heatwaves broke daily temperature records in multiple places.

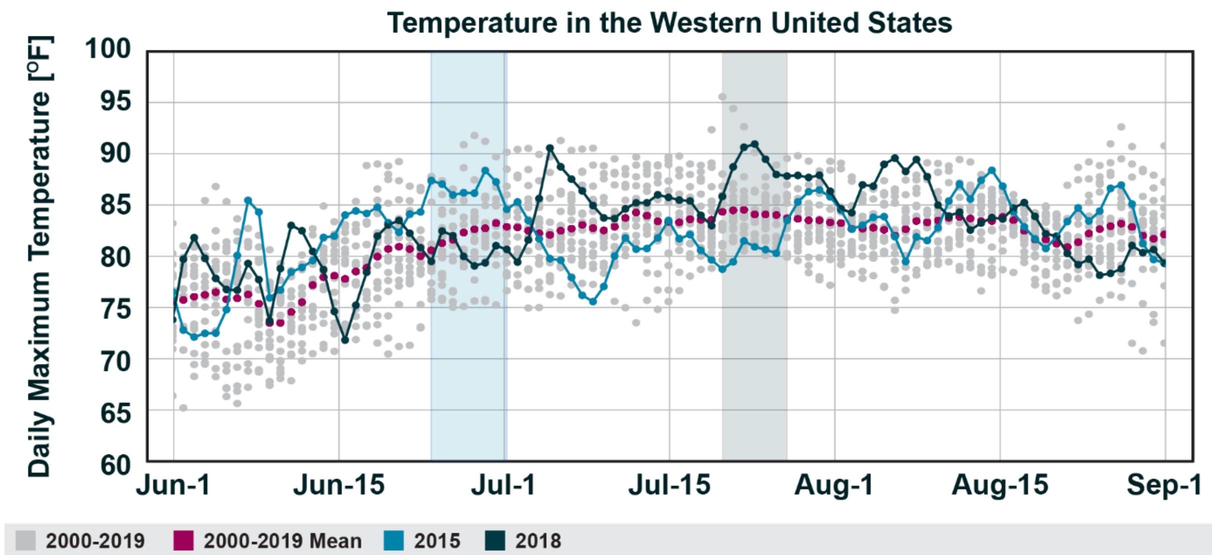

Figure 4. Evolution of the daily maximum population-weighted temperature in the western United States from June through August

Each gray dot shows the daily maximum temperature in a sample year from 2000 to 2019. The magenta dots show the average maximum temperature from 2000 to 2019. The blue and black dots and lines show the evolution of the temperature in 2015 and 2018, respectively. The 2015 and 2018 NTP Study heatwave events are highlighted by the shaded blue and gray boxes, respectively.

The study team acknowledges extreme stress events, particularly heatwaves, can affect the thermoelectric cooling capacity of thermal power generators such as coal and nuclear plants—potentially leading to a decrease in their power output. However, given thermal generation constitutes a small portion of the Western Interconnection generation mix in the two high-renewable transmission scenarios and considering the limited data available on plant-specific thermoelectric cooling technologies, the study team opted to disregard derates of thermal plants during extreme heat.

2.1.2 Hydropower droughts

To model drought, the study team used plant-level water availability information from the year 2001, which is one of the most severe summer droughts across the Western Interconnection over the past 20 years, shown in Figure 5 (Turner et al. 2022). The 2001 drought resulted in the Western Interconnection's worst year for hydropower generation, with total generation approximately 21% below the twenty-first century average. The year 2001 drought was particularly severe in the PNW, where about two-thirds of western hydropower capacity is located.

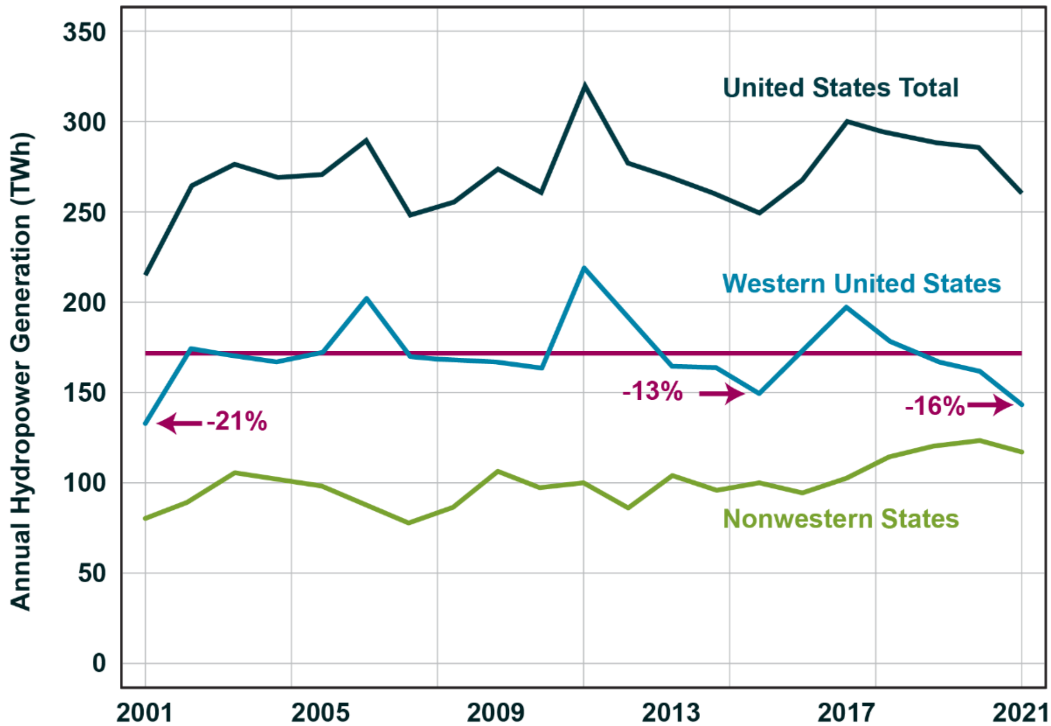

Figure 5. Total hydroelectric power generation in the United States, western U.S. states, and nonwestern states

Western states are defined as Washington, Oregon, California, Idaho, Montana, Utah, Colorado, Nevada, Arizona, Wyoming, and New Mexico. Percentages give the deviation from the mean annual western U.S. generation (solid magenta line). (Data source: Energy Information Administration (EIA) state-level generation reports; Turner et al., 2022)

The study team made a deliberate decision to focus on heatwave events (2015 and 2018) that did not coincide temporally with the drought conditions of 2001. This decision allowed the study team to simulate drought conditions that could induce significant stress on the grid. By using the 2001 hydrologic data, the study team created a multievent threat representing a co-occurrence of significantly reduced hydropower generation capacity alongside the increased energy demand. This allowed the study team to test the NTP Study transmission scenarios under compounded extreme conditions.

2.2 Modeling Inputs for Extreme Stress Events

2.2.1 Hourly load

After selecting the extreme events, the study team simulated how the hourly load evolved during the events. The tool for simulating load is the extensively documented, open-source, Total ELectricity Loads (TELL) model (McGrath et al. 2022). TELL ingests hourly time-series meteorology data at the balancing authority (BA) level[9] and then uses machine learning (ML) to simulate the hourly evolution of total electricity demand within

[9] For more information about the BA's geographical boundaries, see Appendix B.

the BA in response to weather variations. TELL is a nationwide model that works for all BAs in the contiguous United States. Using the weather projections and then scaling to the annual energy values in the 2035 base year loads (Figure 6), the study team used TELL to generate 8,760-hour load profiles for each BA based on the 2015 and 2018 weather years with climate change. Appendix A provides the details of this approach.

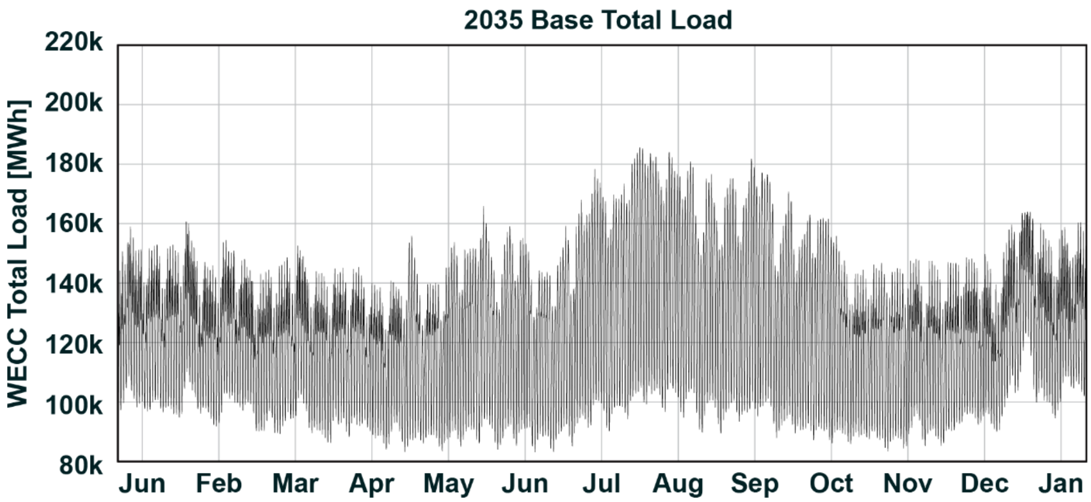

Figure 6. Hourly loads in 2035 in the Western Interconnection for the NTP base year. This load time series is based on the 2009 weather year.

WECC = Western Electricity Coordinating Council; MWh = megawatt-hour

Figure 7 displays the 2035 scaled loads provided by TELL based on the 2015 weather year. The 2015 NTP Study heatwave event is highlighted using blue shading. The total peak load in the Western Interconnection exceeds 210,500 megawatts (MW) during the heatwave period. For reference, the maximum total load in the Western Interconnection is ~185,500 MW in the base 2035 NTP Study loads.

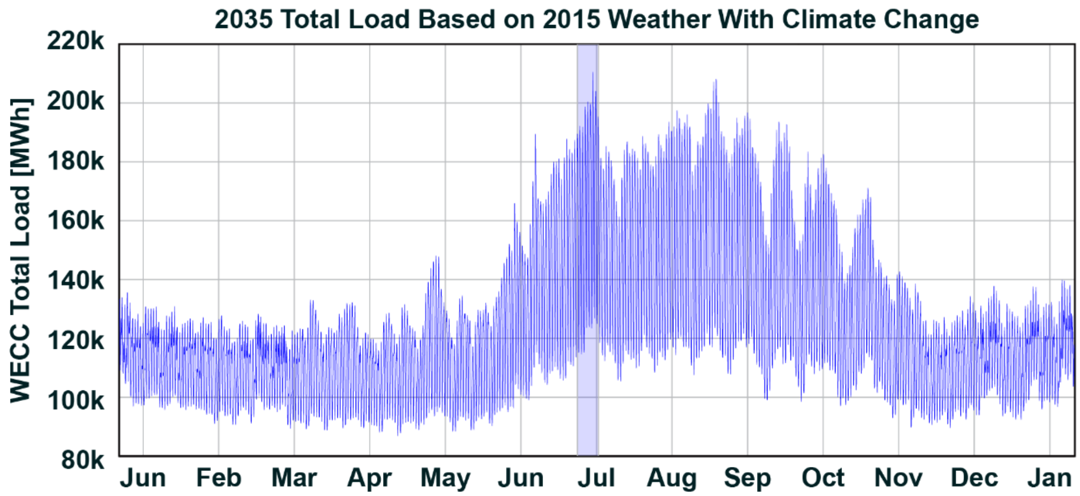

Figure 7. Hourly loads in 2035 in the Western Interconnection based on the 2015 weather year with climate change

The shaded blue box highlights the 2015 NTP heatwave event.

Figure 8 shows the 2035 scaled loads that TELL provided based on the 2018 weather year. The 2018 NTP heatwave event is highlighted using red shading. The total peak load for the Western Interconnection exceeds 217,900 MW during the heatwave period.

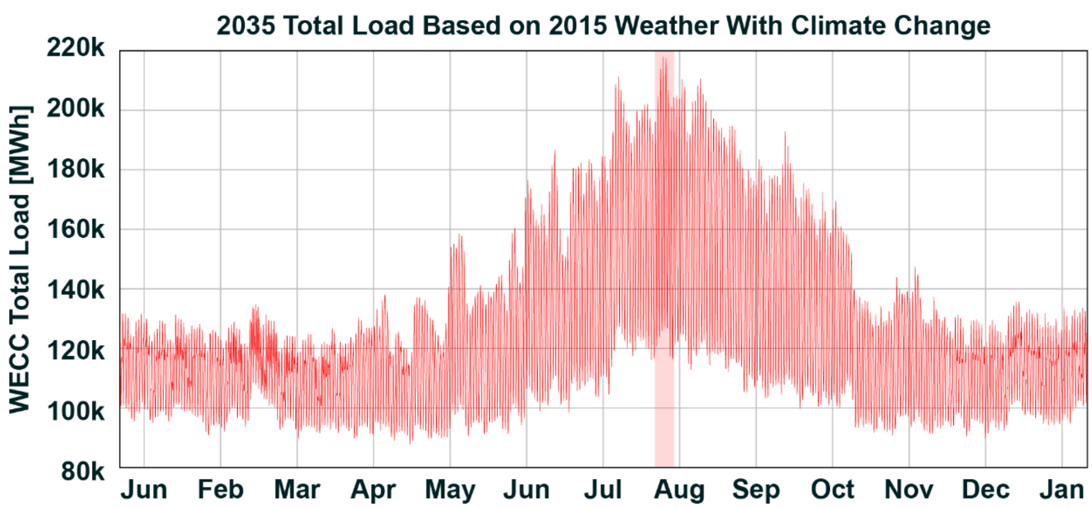

Figure 8. Hourly loads in 2035 in the Western Interconnection based on the 2018 weather year with climate change

The shaded red box highlights the 2018 NTP Study heatwave event.

2.2.2 Hourly solar and wind profiles

The study team developed hourly wind and solar profiles for specific locations associated with solar plants using a gridded generation dataset (Bracken, Thurber, and Voisin 2023) (Figure 9). The study team developed coincident renewable generation profiles for the 2015 heatwave in the PNW and the 2018 heatwave event in California and the Desert Southwest, including profiles reflecting warming consistent with

Representative Concentration Pathway (RCP) 8.5, which were input into GridView. For more details about the process of generating hourly wind and solar profiles, see Appendix B.

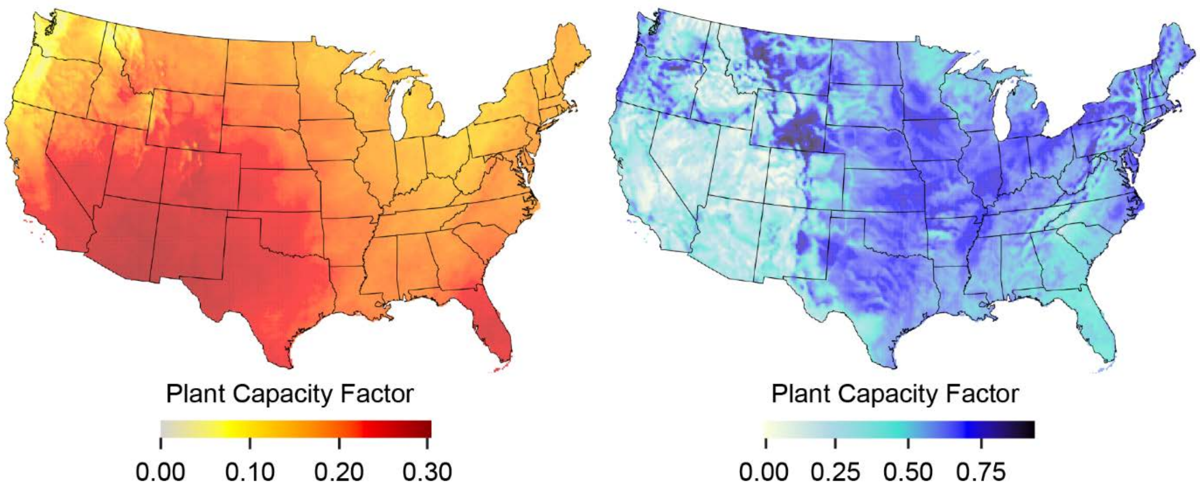

Figure 9. Example of gridded solar (left) and wind (right) generation data

The gridded wind and solar data assume a hypothetical plant located at every grid cell and are derived from downscaled meteorology data (Jones et al. 2023).

2.2.3 Hydropower availability

GridView requires hydropower data in the form of weekly energy targets and constraints that reflect the physical limitations of each hydropower facility. The team used an existing weekly hydropower constraint dataset for 1,500 hydropower plants (Turner et al. 2024). This dataset contains monthly power generation estimates for 1,500 hydropower plants that are disaggregated from annual EIA-923 power generation data using observed streamflow and power production data. The dataset derives hydropower constraints (minimum operating capacity, maximum operating capacity, energy targets, and so on) from disaggregated data based on historical operating ranges and power generation. These data are designed for use in GridView. Figure 10 shows the modeling framework used to produce the weekly hydropower dataset.

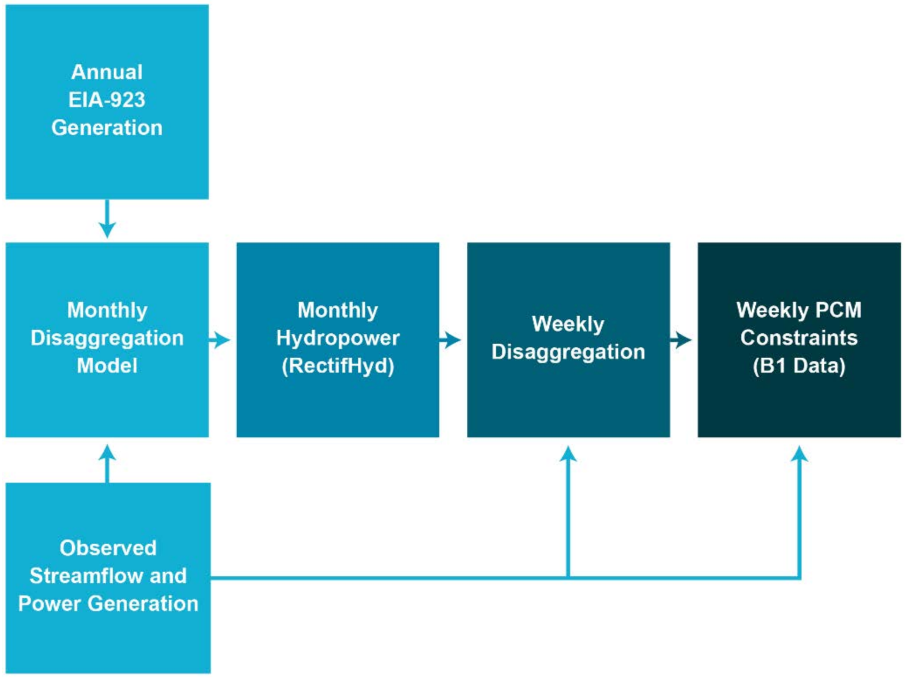

Figure 10. Modeling framework for generating weekly hydropower datasets

PCM = production cost model

The study team used the 2001 hydrologic year, which was historically dry, to represent low hydropower conditions. The study team imported the 2001 water availability—expressed in weekly energy budgets (MWh)—and the weekly operating maximum and minimum MW values into GridView at the individual plant level. The study team then adjusted the hydropower parameters for 1,200 hydropower plants to reflect the 2001 hydrology. Figure 11 shows a representation of the total WECC weekly energy targets for 2001 and 2009 (an average year). The weekly values in 2001 range from 13% above the generation in 2009 to 42% below the generation in 2009, depending on the week. The total generation in 2001 is 17.6% below the generation in 2009. The study team did not include Canadian hydropower plants in this drought parameterization because of the absence of sufficient hydropower data needed to establish monthly energy targets and operating ranges.

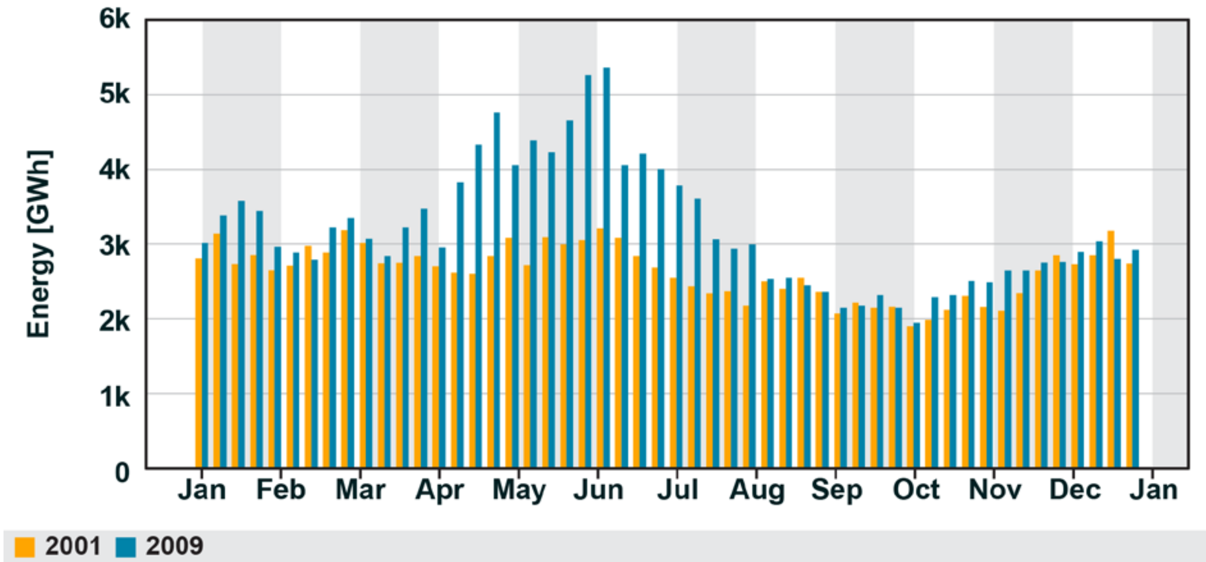

Figure 11. Total WECC weekly energy targets for the drought year under study (2001) and a year with average hydrologic conditions (2009)

GridView dispatches most hydropower plants based on hydrothermal coordination (HTC) logic. Within the HTC logic, GridView conducts hydropower scheduling in response to the net demand (load, wind, solar) of its designated load area. HTC requires the GridView optimizer to be initially run with a hydropower schedule to obtain 24-hour price signals, adjusting this schedule based on these price signals, and then rerunning the unit commitment and economic dispatch with the updated hydropower schedule.

2.3 Methodology for the Economic Analysis Under Extreme Stress Conditions

The study team estimated the economic benefits between the Lim and AC transmission scenarios for the stress events under study. The first type of benefit estimated is the avoided costs of generation; the second type is the reduction in the cumulative value of lost load (C-VOLL) calculated by multiplying the quantity of unserved load by the value of lost load (VOLL). Note the realized economic benefits during extreme stress events cannot be added directly to the economic benefits reported in Chapter 3 without considering the probability of the event occurring, which is beyond the scope of this chapter.

The avoided cost of generation is the difference in generation costs between the Lim and AC scenarios. Extreme events could reduce the generation from hydro, wind, and solar. Other generation types such as fossil fuels replace this lost generation, which incurs additional operating costs. The study team estimated the operating costs using the outputs from the GridView simulations and included changes in fuel costs, startup costs, and variable operations and maintenance (O&M) costs. The extreme event analysis used the same transmission expansion topology as the one in the standard Lim and AC scenarios. Therefore, the generation capital costs—and the transmission capital costs used in this chapter—are identical to those provided in Chapter 3. Thus, the benefits of avoided capital costs are zero for the extreme event economic analysis to avoid double-counting.

The second estimated benefit is the difference in the C-VOLL for the AC topology and the C-VOLL for the Lim topology. The C-VOLL is the quantity of unserved load for each stress event–transmission scenario combination multiplied by the VOLL. The VOLL is a measure of the monetized value lost to residential and nonresidential electricity consumers during a power outage, usually in $/kilowatt-hour (kWh) (Gorman 2022). The VOLL for residential customers evaluates the cost of electricity outages based on survey data collected from residential customers (Baik et al. 2018). Economic loss surveys explore losses from electricity outages across several dimensions, such as lost wages, added travel costs, lodging because of dislocation, dining out, replacing spoiled food, and/or operating a backup generator because of electricity outages. The losses to nonresidential end users include the loss of productivity, the loss of revenues, and the loss of equipment and its cost to replace (Amadi and Okafor 2015). Survey respondents are asked to estimate their losses because of an electricity outage by the duration of an outage. However, the values do not capture indirect losses, supply chain issues associated with outages greater than 24 hours, or the long-duration lost load (Rose et al. 2005). Measuring the value of the long-duration lost load is still in development by other research organizations (Larsen et al. 2019).

The VOLL is not necessarily constant. It can vary by customer type (residential, commercial, and so on), location, time of day, and outage duration (Sullivan et al. 2015). For outages with unserved energy *Q* across location *l*, time of day *t*, and duration *d* and affecting customer type *c*, the study team computed the total C-VOLL using the following equation:

$$C\text{-}VOLL = \sum_{l,t,d,c=0}^{L,T,D,C} Q_{ltdc} \times VOLL_{ltdc}$$

The study team obtained unserved load quantity estimates from the production cost model for each transmission scenario (i.e., Lim and AC) and stress event combination for the Lim and AC frameworks. The study team obtained VOLL estimates from the Interruption Cost Estimate (ICE) calculator (Berkeley Laboratory n.d.). The ICE calculator obtained these VOLL estimates for each load area based on the proportion of the load area within each state. The ICE calculator provides the following VOLL estimates for the Western Interconnection: residential, $5/kWh; small commercial and industrial, $200/kWh; and large commercial and industrial, $90/kWh. The average VOLL is $80/kWh.

As previously mentioned, the realized economic benefits of reliability during extreme stress events cannot be added directly to the economic benefits reported in Chapter 3. To add the reliability benefits to other types of economic benefits (e.g., operating cost and capital cost), the expected value in reliability benefits should be used to estimate an annualized value or net present value[10] of the suitability of different transmission projects. The expected value is calculated by multiplying the realized reliability benefits when the event occurs by the probability of the event occurring. Ideally, the expected value should be computed across a range of extreme events (often called an *all-hazards analysis*) and summed with estimates of other benefit types to obtain the total benefits that can then be used for a cost-benefit analysis (Macmillan et al. 2023). Estimating event probabilities is outside the scope of this study, so the study team did not combine the benefits in this chapter with the general operating benefits presented in Chapter 3. As such, the reader should be cautioned not to add the benefits presented here to other benefit types or directly compare their magnitude to other benefit types.

[10] The net present value provides the discounted benefits of each stress event and transmission scenario combination, including the difference in the transmission and generation capital costs associated with implementing the different generation and transmission scenarios. A positive value would indicate the AC scenario provides a better option than the Limited scenario. Although this chapter does not include net present value calculations, the methodology for computing net present value and the selection of discount rates are discussed in Chapter 3.

3 Description of Transmission Expansion Scenarios

Before presenting the results of the extreme stress cases, this section briefly outlines the two nodal transmission scenarios. It provides context for the transmission and generation included in these scenarios, upon which the stress cases were applied.

As described in Chapter 3, the NTP Study used the WECC 2030 Anchor Dataset (ADS) PCM dataset as the starting nodal PCM case for the Western Interconnection. ADS (WECC 2020a, 2020b) is the most reliable forecast for upcoming developments in new generation, generation retirements, transmission assets, and load growth, providing 10-year predictions from specified reference years.

The NTP Study added transmission projects to the 2030 ADS that are either under construction or have significantly progressed through the permitting process and thus are deemed both plausible and likely to materialize. The study team identified additional transmission projects for the year 2035 in the capacity expansion model, which optimizes for the lowest-cost mix of transmission and generation to meet a set of input assumptions and constraints—which is designed to predict future infrastructure and transmission needs (Chapter 2). The study team used a zonal-to-nodal approach (Chapter 3) to build two distinct production cost models for year 2035: the 1) Alternating Current (AC) and 2) Limited (Lim) scenarios. These two scenarios are based on the same high demand estimate[11] and aim to achieve 90% decarbonization by the year 2035, albeit through divergent transmission and generation capacity expansion strategies. The 2035 AC scenario facilitates expansion between transmission planning regions (i.e., Federal Energy Regulatory Commission [FERC] Order No. 1000), whereas the 2035 AC Lim scenario permits transmission buildouts solely within these planning regions. For the Western Interconnection, the FERC No. 1000 regions consist of California Independent System Operator (CAISO), WestConnect, and NorthernGrid; Figure 14 displays the borders of these regions.

Figure 12 and Figure 13 show an overview of the two nodal transmission expansion scenarios.

[11] This represents an increase in peak demand of 21% relative to the 2030 Industry case. For more information regarding the load assumptions, see Chapter 2, earlier (Round 1) ReEDS scenario.

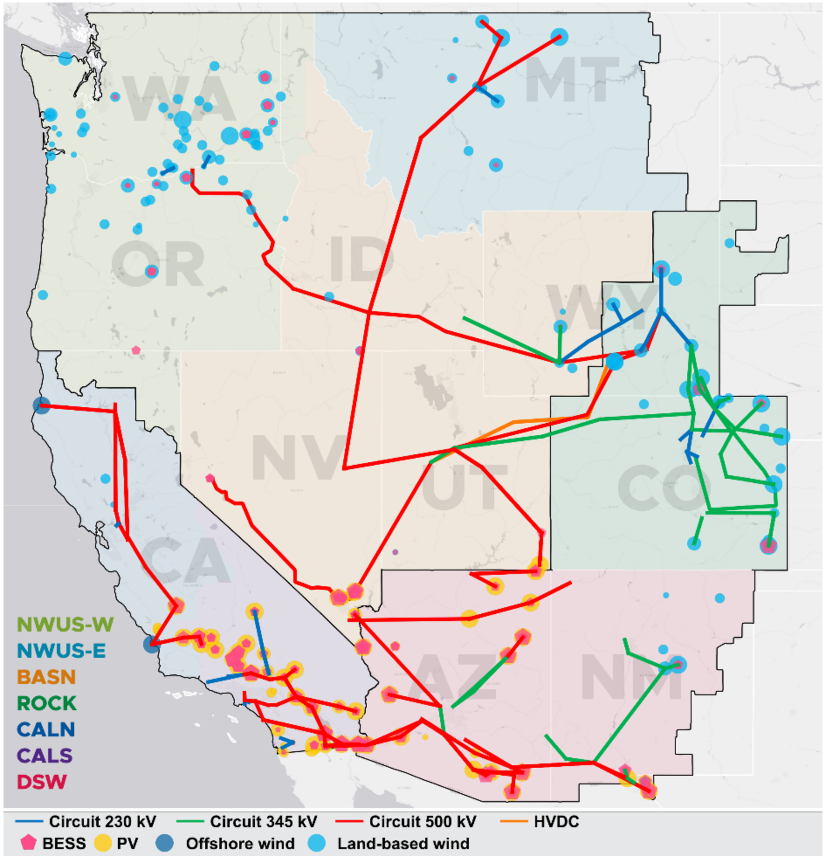

Figure 12. Transmission expansion in the 2035 Lim scenario from the 2030 ADS: 500-, 230-, and 345-kilovolt (kV) circuits are added or updated; new HVDC circuits are added

BESS = battery energy storage systems; PV = photovoltaic

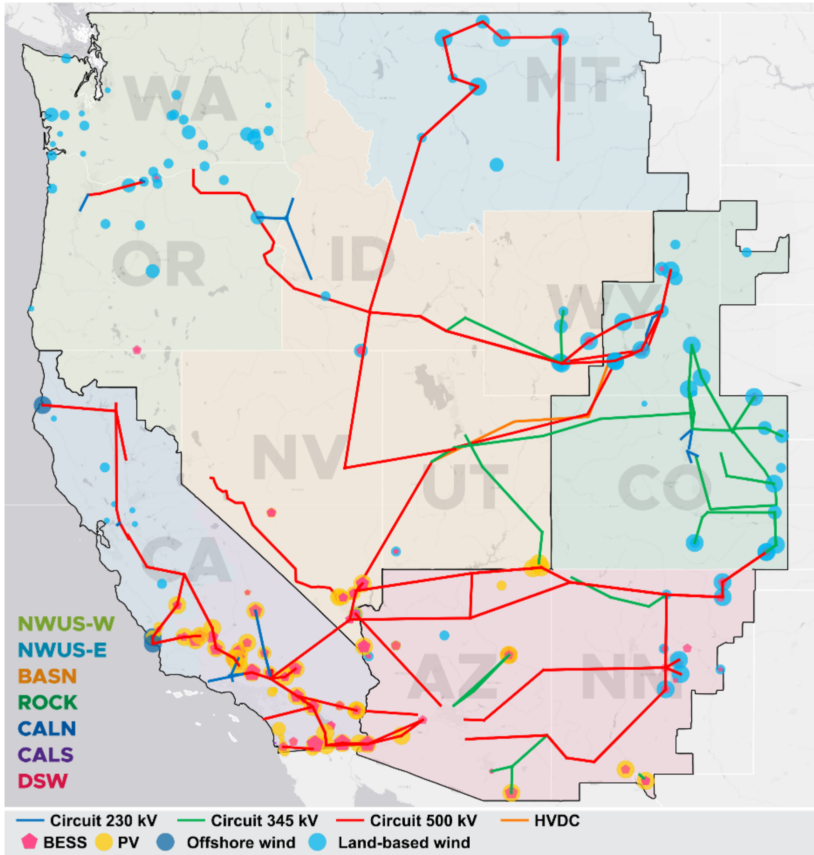

Figure 13. Transmission expansion in the 2035 AC scenario from the 2030 ADS: 500-, 230-, and 345-kV circuits are added or updated; new HVDC circuits are added

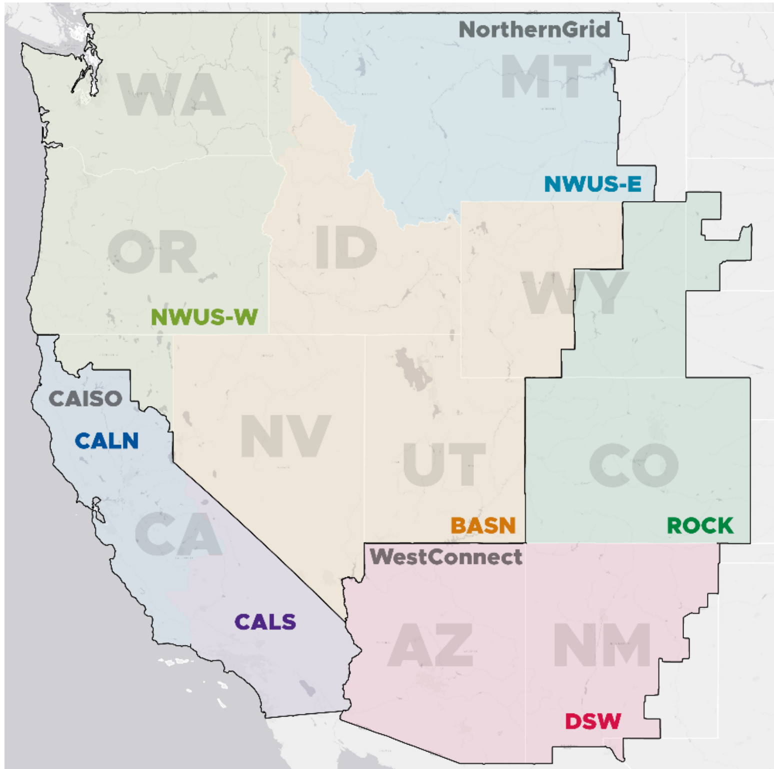

Figure 14. Three FERC Order No.1000 regions: CAISO, NorthernGrid, WestConnect; six WECC regions (excluding Alberta, British Columbia, and Northern Baja California Mexico): Basin (BASN), California North (CALN), California South (CALS), Desert Southwest (DSW), Northwest United States (NWUS), and Rocky Mountain (ROCK)

Figure 15 shows the total installed capacity mix for the two transmission expansion scenarios at both a WECC level (a) and WECC regional level (b), as depicted in Figure 14. Figure 15 also shows the capacity difference between the two scenarios (Lim minus AC capacity) at a WECC level (c) and WECC regional level (d). Solar, wind, and BESS emerge as the primary capacity resources. Solar and battery storage capacity predominantly reside in the California South and Desert Southwest regions for both the Lim and AC scenarios whereas wind capacity is primarily situated in the Northwest and Rocky Mountain regions. The AC scenario exhibits more installed wind capacity, particularly in the Rockies and Basin regions, compared to the Lim scenario, which records higher solar and BESS installed capacity—notably in the Desert Southwest and California South regions.

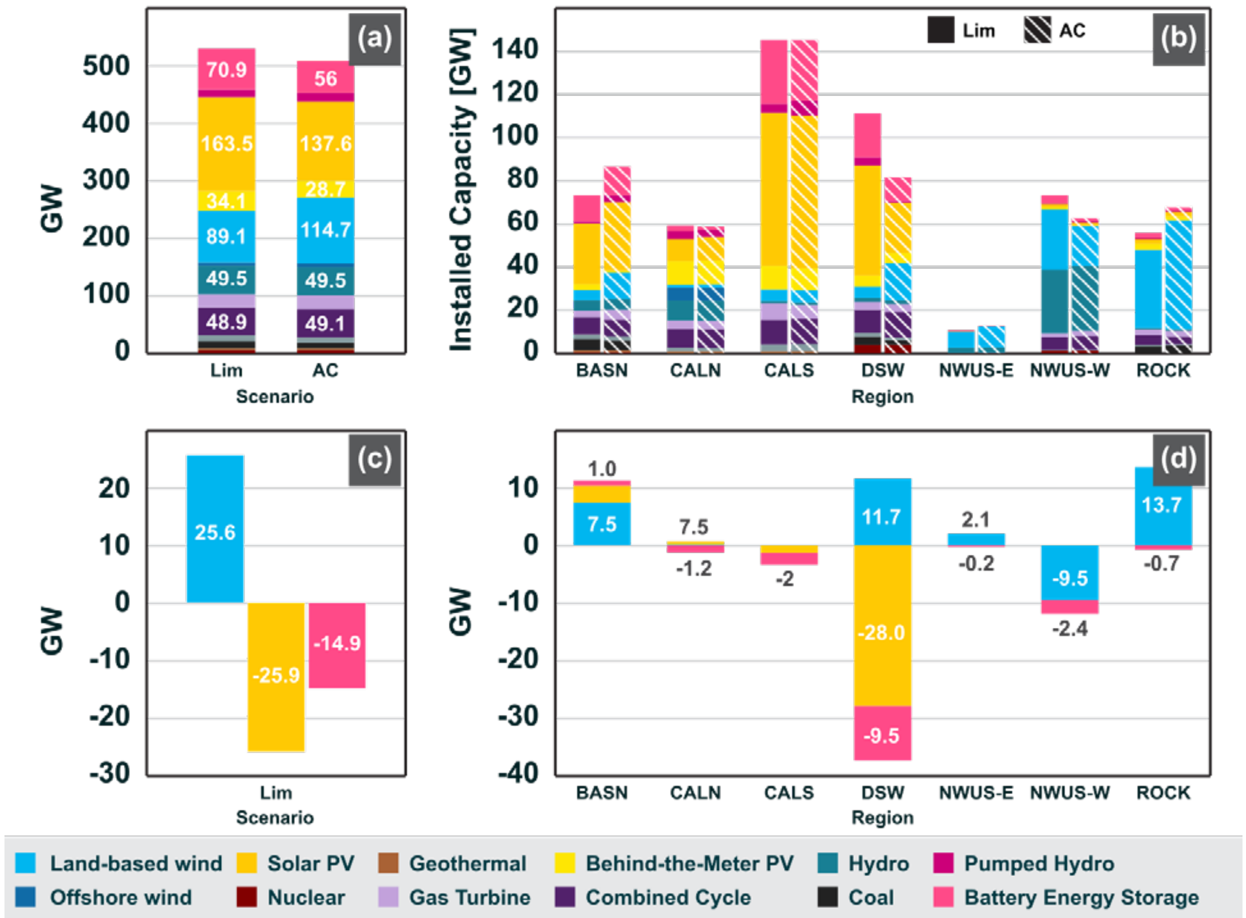

Figure 15. Total installed capacity of the 2035 AC and 2035 Lim scenarios at a WECC level (a) and WECC regional level (b) and their capacity difference (Lim minus AC capacity) at a WECC level (c) and WECC regional level (d)

4 Stress Case Results and Key Findings

The study team defined four stress cases based on historical events in the West and used production cost simulations for both nodal transmission scenarios to generate 8 simulation results (4 stress cases × 2 scenarios; Table 1). As previously stated, this chapter uses the acronyms "AC" and "Lim" to refer to the Alternating Current and Limited transmission scenarios, and "H" and "H+D" to represent the heatwave and combined heatwave and drought events. To simplify the discussion, this chapter refers to these occurrences as the PNW heatwave, representing the 2015 heatwave event, and California (CA) heatwave, representing the 2018 heatwave event, in the following text.

Table 1. Stress Case Scenarios

Stress Case	Stress Event
1	California heatwave
2	California Heatwave + Pacific Northwest drought
3	Pacific Northwest heatwave
4	Pacific Northwest heatwave + Pacific Northwest drought

To evaluate the reliability, economic, and operational impacts of stress cases on the two transmission scenarios, the study team conducted production cost simulations for an entire year for each of the eight stress cases. Unserved energy[12] is the key metric used to quantify the impact of extreme events on grid operations, measured both in energy values (GWh) and as a percentage of total load. In addition, the study team examined the loading of key interface path and transmission lines. The term "key" refers to interface paths where either the starting or receiving endpoints are situated in areas susceptible to extreme stress events. An interface path may comprise multiple transmission lines connecting different areas.

Following are the two main differences between the two transmission scenarios:

- The AC scenario facilitates expansion between transmission planning regions (FERC Order No. 1000). As shown in Figure 13, most of these interregional AC lines serve to connect WestConnect (i.e., Desert Southwest and Rockies) with California, effectively channeling the rich wind energy from New Mexico and Colorado to meet California's substantial demand.
- The Limited scenario features roughly 7.5 GW more installed capacity in California than the AC scenario (Figure 16). This substantial margin is crucial for the forthcoming analysis, especially given half of this capacity is derived from dispatchable sources such as energy storage (ES) and natural gas (NG).[13]

[12] Many factors can cause unserved loads, including capacity shortage, ramping capability shortage, bad commitment decisions (units cannot participate in generation during the minimum downtime), forced generator outages, and transmission limitations.
[13] It is important to note because the capacity mix of each scenario is different, the conclusions on transmission benefits between the two scenarios are not being identified in isolation.

The results are provided at a regional level for PNW and California.

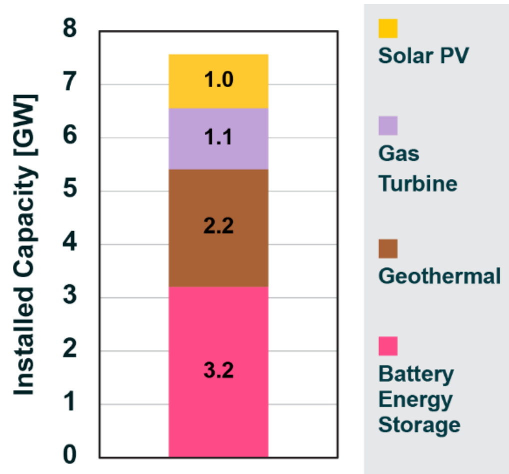

Figure 16. Capacity difference between the Lim and AC scenarios for California

The Lim scenario has roughly 7.5 GW more installed capacity in California than the AC scenario.

4.1 Compounded Extreme Events Lead to Higher Levels of Unserved Energy Than Individual Events

Figure 17 shows the single heatwave event in California leads to unserved energy in both California and PNW, especially under the Lim scenario (1.5% and 1.3% of the total load in California and PNW, respectively), which does not facilitate expansion between transmission planning regions. When the California heatwave is combined with hydro droughts in PNW, the unserved energy increases for both regions and across transmission scenarios. Specifically, in the Lim scenario, unserved energy rises to 3.8% and 7.7% for California and PNW, respectively, during the California heatwave and PNW drought.

Similarly, when the PNW heatwave is coupled with the PNW drought (Figure 18), the unserved energy ranges between 1.5% and 6.2%, depending on the transmission scenario and heatwave region, unlike during heatwave-only scenarios where unserved energy remains below 1%. This finding underscores the profound impact drought conditions have on the reliability of the Western Interconnection, especially in hydropower-dependent areas such as PNW.

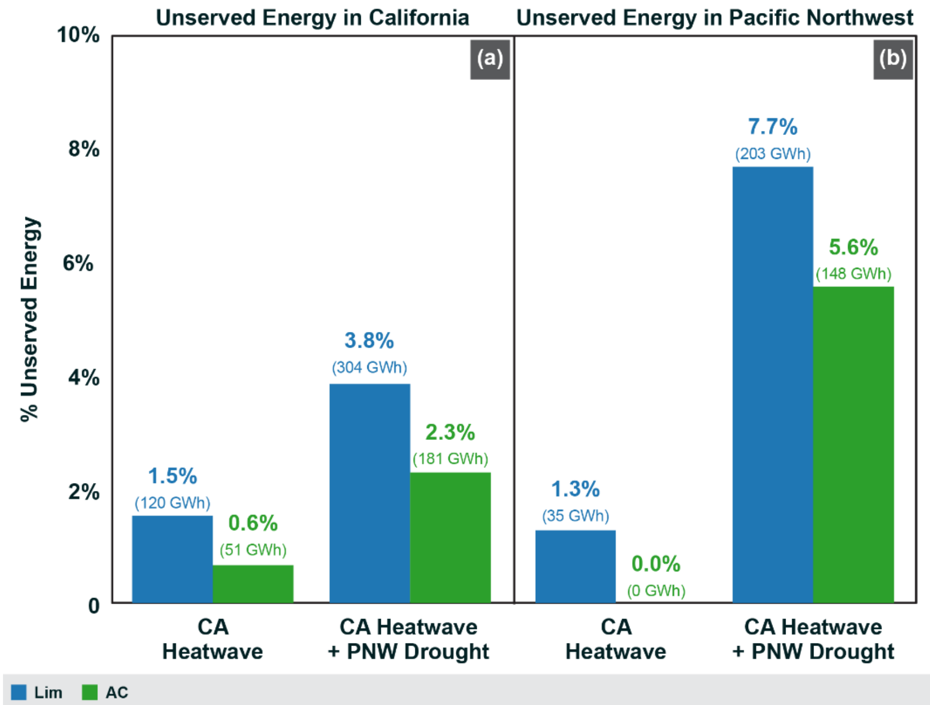

Figure 17. Percent of unserved energy in California (a) and PNW (b) during the California heatwave (July 22–July 28) and combined California heatwave and PNW drought

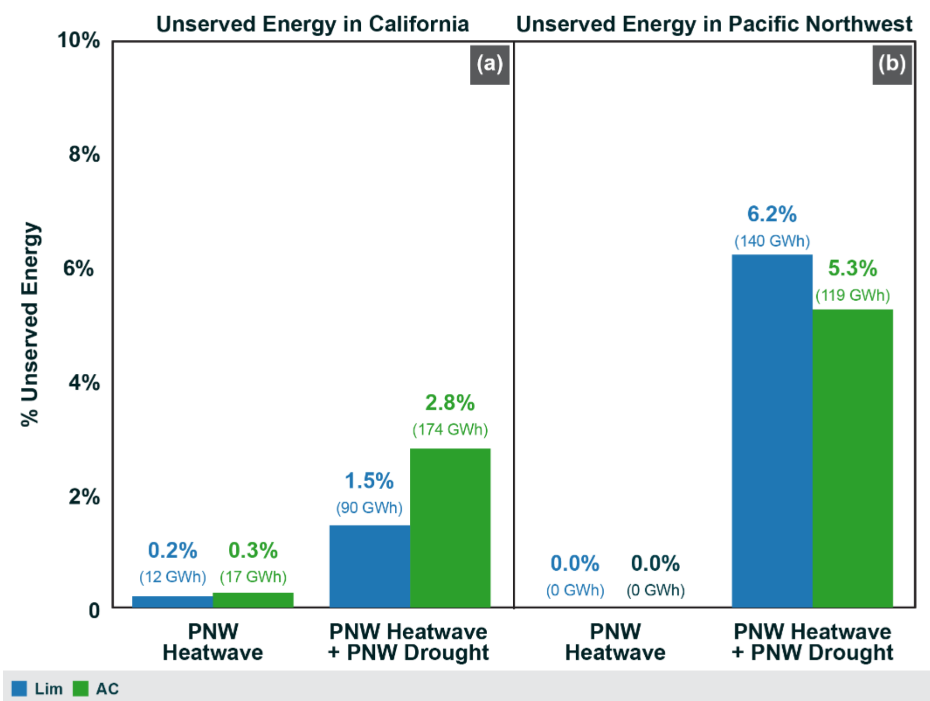

Figure 18. Percent of unserved energy in California (a) and PNW (b) during the PNW heatwave (June 25–July 2) and combined PNW heatwave and PNW drought

The impact of drought is predominantly evident in PNW, with a significant reduction in hydro generation compared to the single-heatwave event across both transmission scenarios and heatwave events, as shown in Figure 19 and Figure 20. There is approximately a 20% reduction during the June PNW heatwave event and a 17% reduction during the July California heatwave event for both transmission scenarios. To compensate for the supply shortfall, both the California and PNW and transmission scenarios (Figure 19 and Figure 20) show increased reliance on NG resources (gas turbines and combustion cycle).

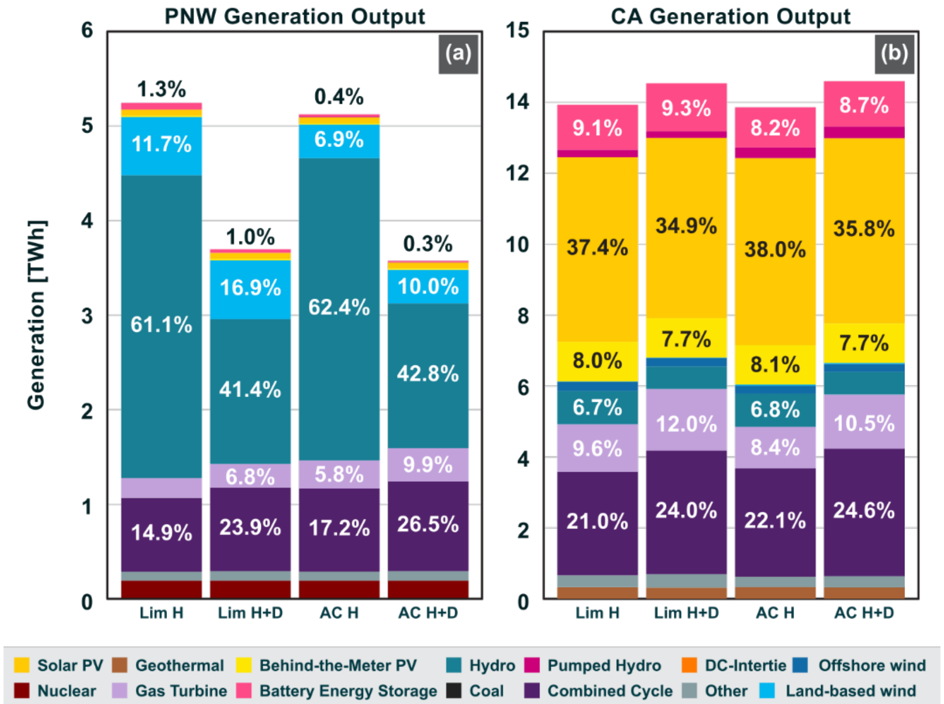

Figure 19. Generation output of PNW (a) and California (b) for the two transmission scenarios (AC and Lim) under stress conditions during the PNW heatwave (H) and combined PNW heatwave and PNW drought (H+D)

TWh = terawatt-hour

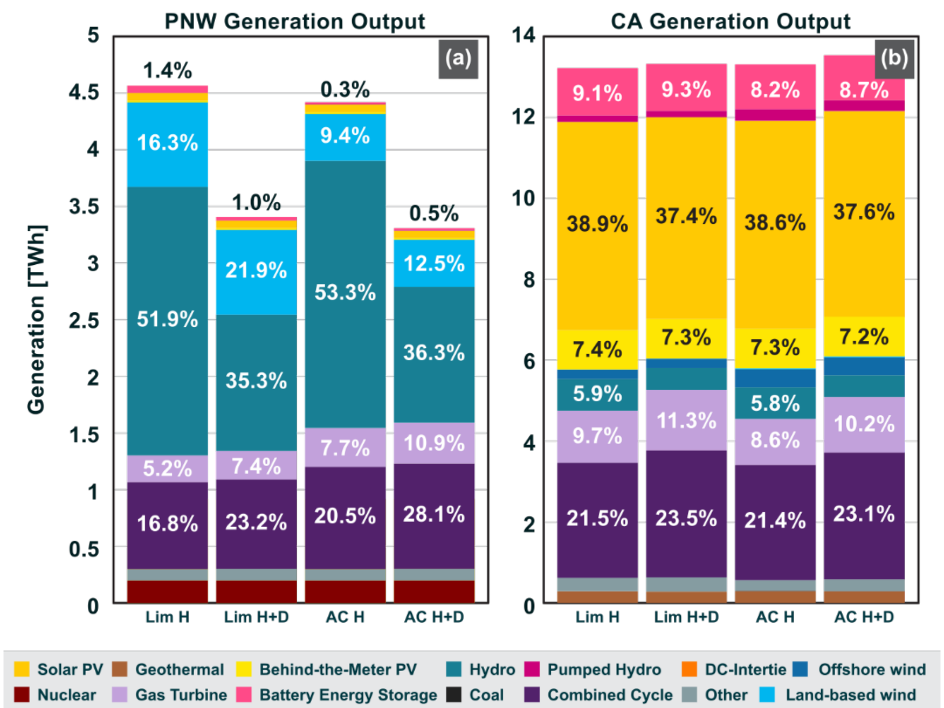

Figure 20. Generation output of PNW (a) and CA (b) for the two transmission scenarios (AC and Lim) during the California heatwave and combined California heatwave and PNW drought (H+D)

4.2 Unserved Energy Peaks in the Morning Because of Low Online Energy Resource Availability and Increasing Load Ramps

The timing of unserved energy is a critical aspect to consider. Figure 21a displays the hourly distribution of unserved energy in California of the two transmission scenarios over a 3-day period (July 22–24) during the combined California heatwave event and PNW drought. Notably, unserved energy peaks during the early morning hours, prior to solar generation coming online, aligning with the morning load ramp and when energy storage—including both systems (BESS and pumped hydro storage [PHS])—is nearly exhausted (Figure 21b, c). The amount of unserved energy is intensified in the Limited scenario, represented by the light blue line in Figure 21a. This outcome underscores the critical importance of interregional capacity in boosting California imports during these early morning hours, significantly reducing unserved energy—although not eliminating it. The scenario where the PNW heatwave is combined with the PNW drought exhibits the same timing of unserved energy.

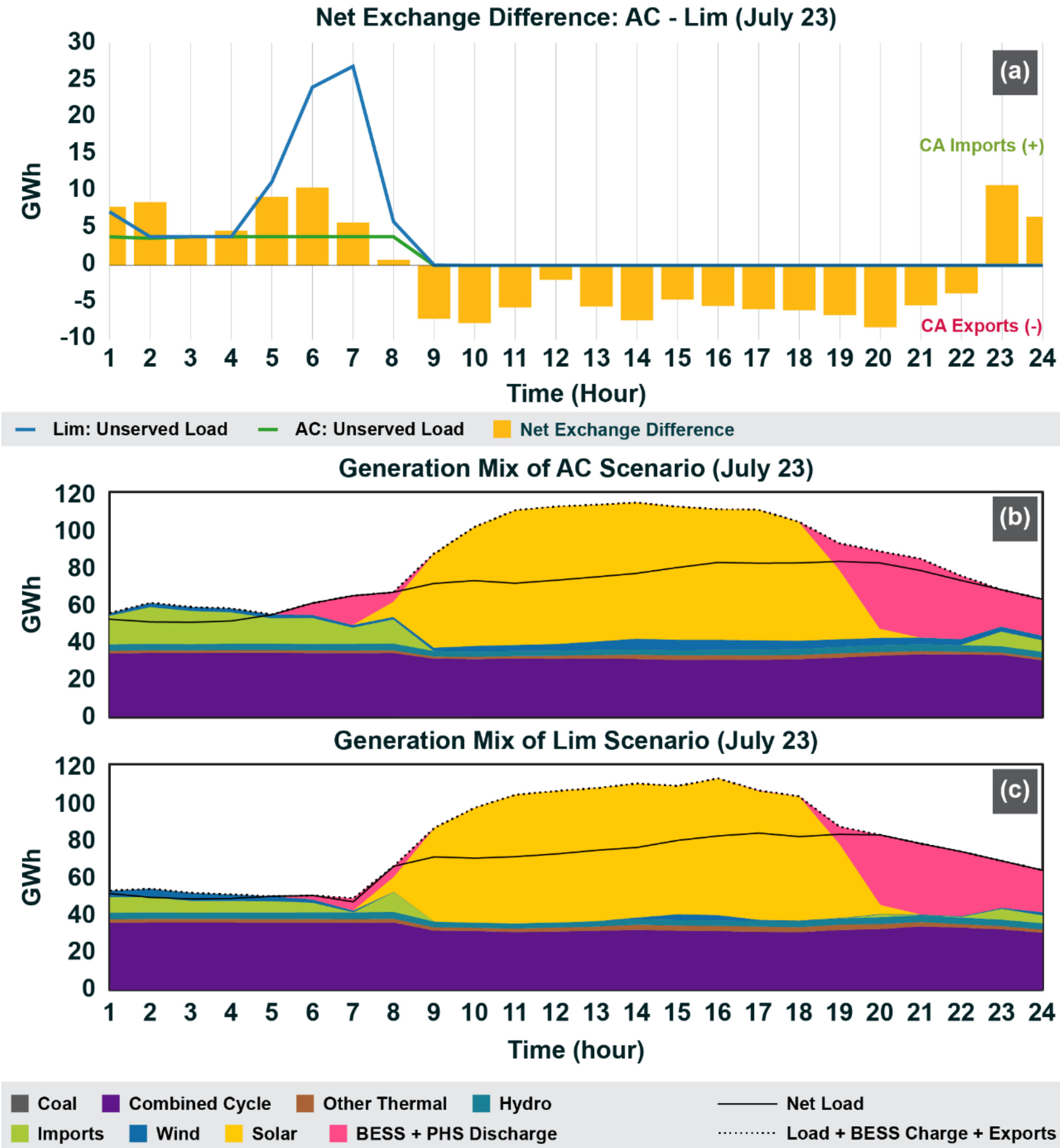

Figure 21. Hourly unserved energy (a) and generation mix (b, c) of the two transmission scenarios during the combined California heatwave (July 23) and PNW drought

In (a), the orange bars show the hourly net exchange difference between the AC and Lim scenarios, highlighting the interregional support to California (+) during those morning hours.

4.3 Interregional Transmission Capacity May Offer Significant Advantages to Regions Affected by Extreme Events by Diversifying Their Energy Resource Mix

During the combined California heatwave and PNW drought, the study team observed the Lim scenario exhibits higher amounts of unserved energy: 7.7% in PNW (Figure 17b) and 3.8% in California (Figure 17a). This is in contrast to the AC scenario, which shows lower levels of unserved energy: 5.6% in PNW (Figure 17b) and 2.3% in California (Figure 17a). This result clearly shows the benefits of the interregional transmission capacity of the AC scenario, which supports serving more energy than the limited within-region topology.

More specifically, the interregional transmission capacity can benefit regions of the system that are experiencing extreme events by diversifying their generation mix both technologically and geographically. This is shown in Figure 22, which demonstrates how wind resources from regions abundant in wind energy, such as New Mexico and Colorado, meet California's heatwave demand through new interregional transmission corridors.

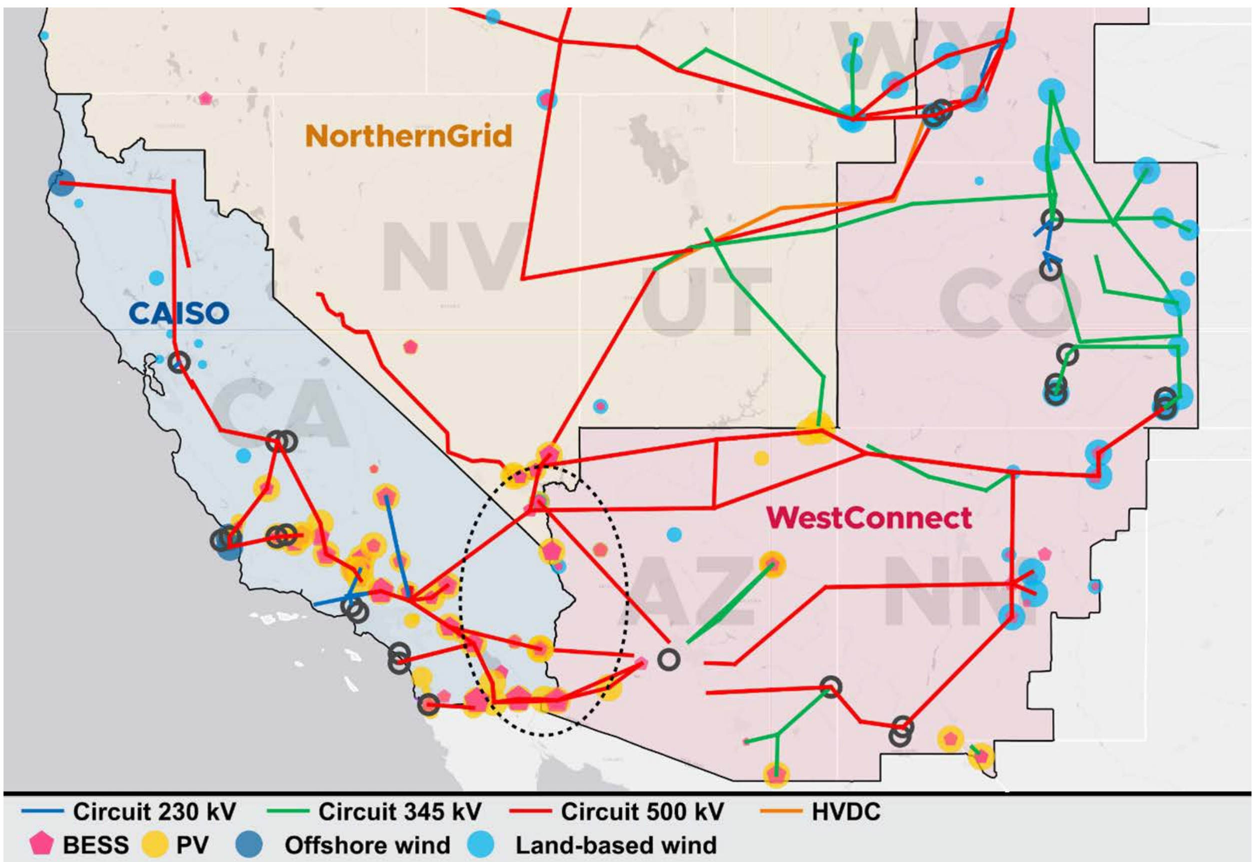

Figure 22. New Interregional AC connections crossing FERC Order No. 1000 borders

The black dotted circle encapsulates the new AC interregional lines crossing WestConnect, CAISO, and NorthernGrid.

Two newly added interregional transmission corridors, which were instrumental in supporting California during the combined California heatwave and PNW drought, connect southern Nevada to southern California via two parallel 500-kV lines and Arizona to the Imperial Valley Area (California), also via two parallel 500-kV lines (Figure 23).

These lines substantially help transfer electricity in southern California during the combined California heatwave and PNW drought. As shown in Figure 24, during the heatwave, California experienced a substantial surge in electricity imports, particularly in the morning hours. This surge is in response to the morning load ramp compounded by the absence of solar generation and depleted energy storage resources (BESS and PHS). Subsequently, the import levels consistently remain above zero for the rest of the day, indicating a sustained need for power.

Figure 24 also illustrates a preheatwave day (July 11) to show the difference in power flows during the California heatwave event (July 23) and slightly before the heatwave (July 11). During the preheatwave day, there is an export of power to the Desert Southwest region at midday, indicating a surplus of solar generation in California.

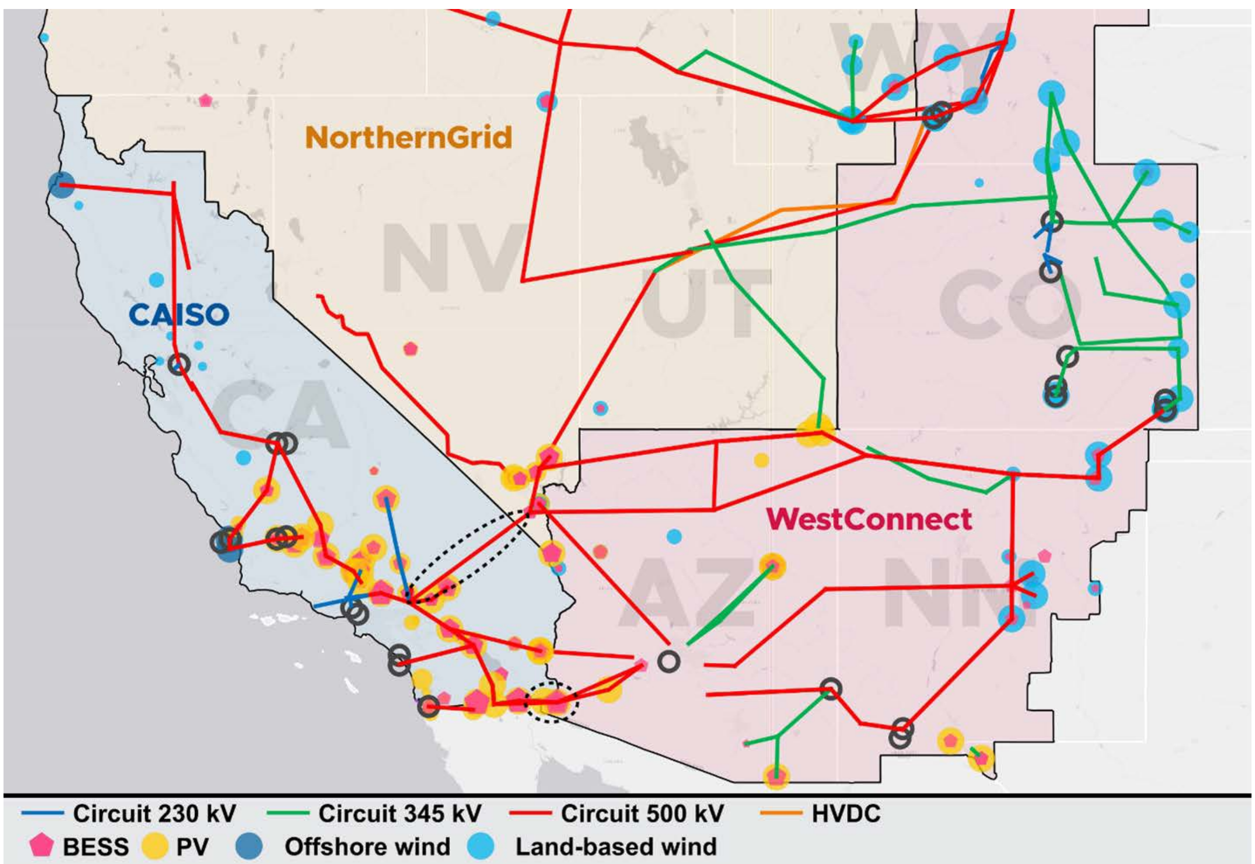

Figure 23. Example of new AC corridors connecting southern Nevada to southern California (indicated by the top black dotted circle) and Arizona to the Imperial Valley Area in California (indicated by the bottom black dotted circle)

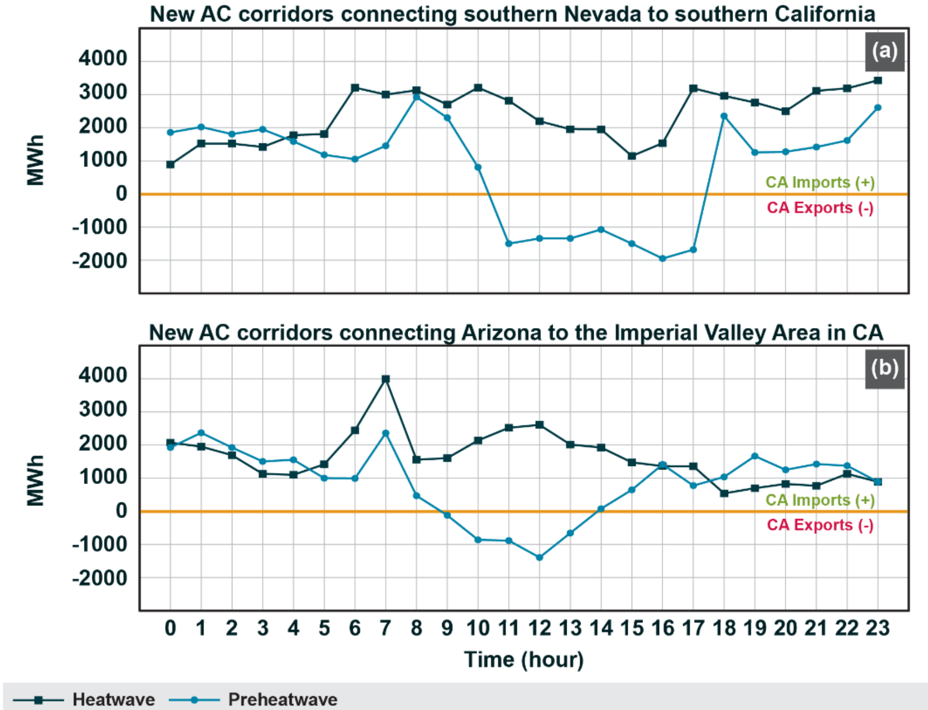

Figure 24. Hourly power flows during heatwave and preheatwave days for the corridors connecting southern Nevada to southern California (a) and Arizona to the Imperial Valley Area in California (b)

The study team observed similar behavior in key interface paths where either the starting or receiving endpoints are in regions affected by extreme stress events, such as PNW and California. These interface paths, numbered 46, 65, 66, 14, and 8 according to WECC, connect the two regions (PNW and California) either themselves or with the rest of the Western Interconnection. For more information about the WECC interface path, see Appendix D.

Starting with Path 46 (West of the Colorado River), which links Desert Southwest (specifically southern Nevada and Arizona) with Southern California, there is a noticeable increase in imports to California during the heatwave day—particularly in the morning hours to mitigate unserved energy (Figure 25).

Transitioning onto Paths 65 (Pacific DC Intertie) and 66 (California Oregon Intertie), which link PNW with Southern and Northern California, respectively, Figure 26 shows an increase in imports to California during the morning and evening hours to support the state during morning and evening load ramps whereas California's exports rise during solar peak hours.

Path 14, which links Idaho and PNW and contains the Boardman to Hemingway (B2H) segment (Figure 27), facilitates an increased flow of power to PNW throughout the day—particularly in the morning hours—and Paths 65 and 66 subsequently channel a portion of this energy to California.

Finally, Path 8 (Figure 28), connecting Montana to PNW, shows increased imports to PNW from Montana during the morning periods of the California heatwave. This bolsters PNW's capacity to cope with the compounded stress of heat and drought.

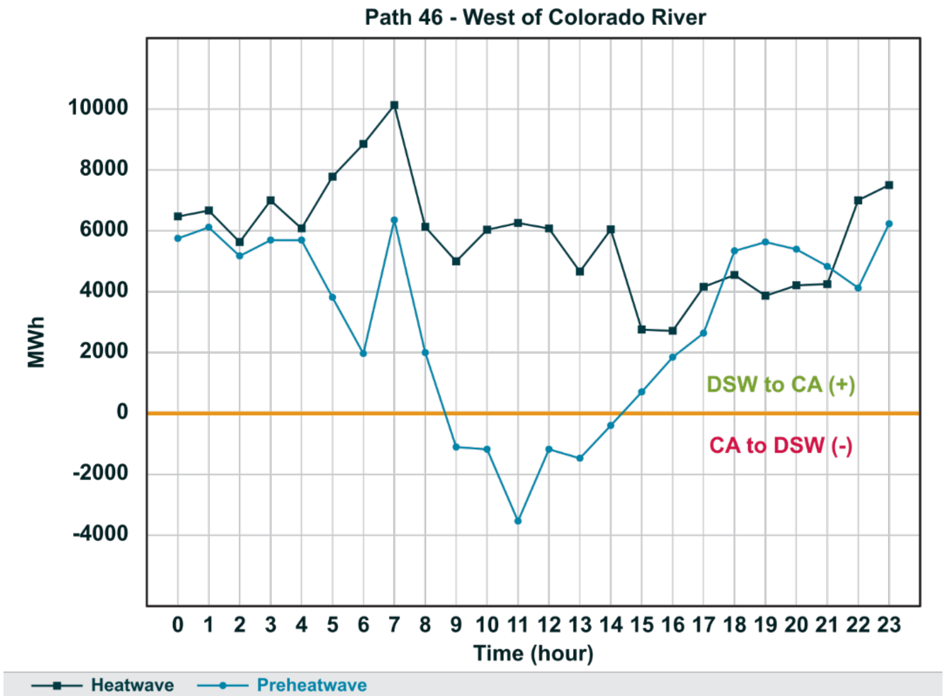

Figure 25. Hourly power flows during the heatwave and preheatwave days for Path 46

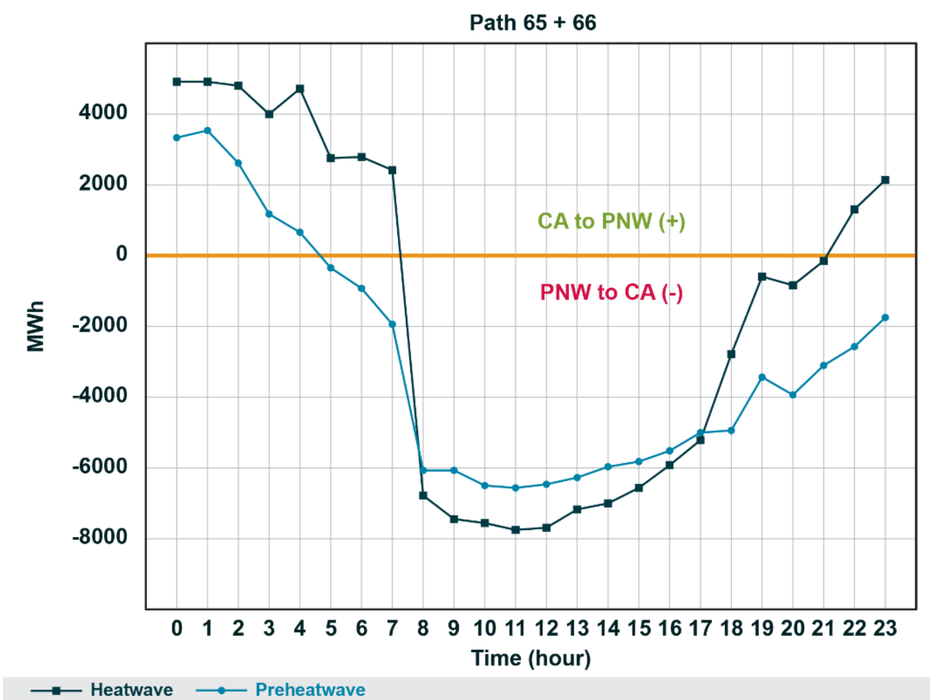

Figure 26. Hourly power flows during the heatwave and preheatwave days for Paths 65 (Pacific DC Intertie) and 66 (California Oregon Intertie)

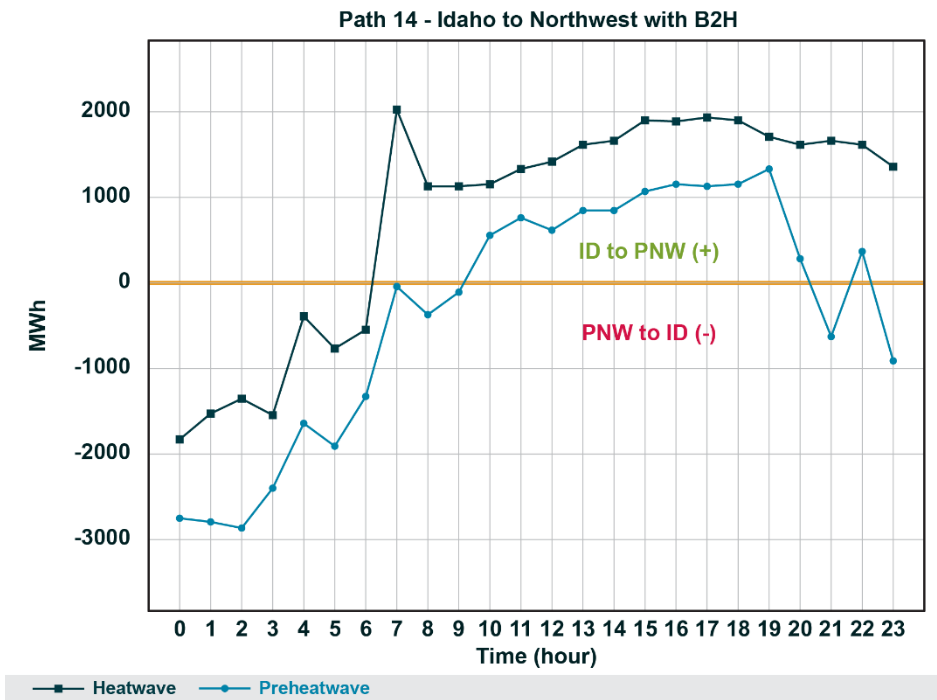

Figure 27. Hourly power flows during the heatwave and preheatwave days for Path 14

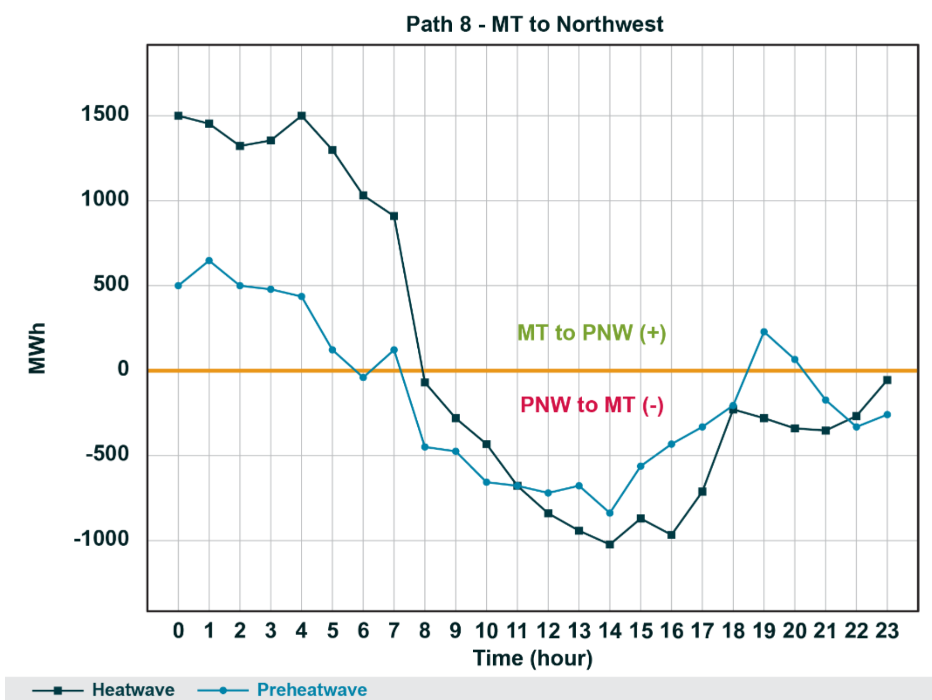

Figure 28. Hourly power flows during the heatwave and preheatwave days for Path 8

In summary, during the combined California heatwave event and PNW drought, all examined interfaces contribute to supporting California by increasing imports—particularly in the early morning hours—to address the challenges of load ramp and capacity shortfalls. In addition, California's exports rise during solar generation hours, both to PNW (via Paths 65 and 66) and to the Desert Southwest (WestConnect) via Path 46.

Figure 29 shows the impact of interregional transmission lines supplying California and PNW in mitigating unserved energy.

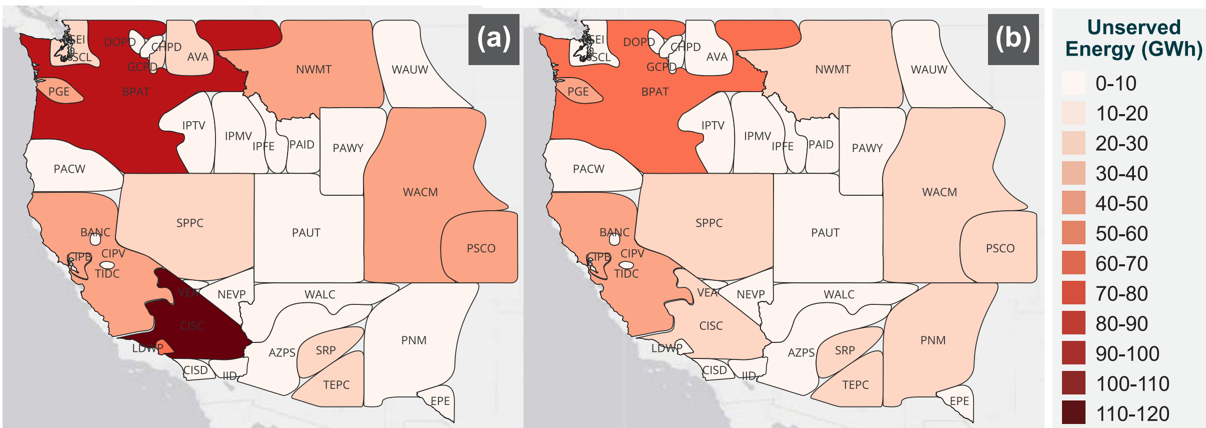

Figure 29. Total unserved energy (GWh) by load area during the combined California heatwave and PNW drought for the Lim scenario (a) and AC scenario (b)

4.4 Transmission and Resource Planners Should Carefully Consider the Interregional Transmission Capacity and Additional Local Generation Capacity When Minimizing Risks of Extreme Stress Events

The combined heatwave and drought in PNW resulted in lower unserved energy in California under the Limited scenario than under the AC scenario. In these two scenarios, when the traditionally exporting region (PNW) was affected by compounding extreme events, the scenario with greater local dispatchable generation and storage capacity within the importing region (California) resulted in greater shortfall mitigation. This outcome suggests attributes of an extreme event—duration, magnitude, type, and location—affect each region's generation and transmission availability differently. Hence, planning studies must carefully consider the attributes of extreme events when considering the topology and capacity of transmission, generation, and storage solutions—whether local or interregional.

This behavior is conceptually shown in Figure 30b. Traditionally, during nonstress periods, PNW primarily serves as a net exporter, leveraging its hydroelectric power resources, while California stands out as a high-demand net importing region (EIA 2023). However, when PNW faces a combined heatwave and drought event, it becomes a net importer (Figure 30b). In such conditions, all neighboring regions strive to assist PNW, whose hydroelectric production is reduced, and almost all PNW generation capacity is allocated mainly to supply the local increased demand. As a result, the new interregional capacity that is present in the AC scenario (Figure 22) and mainly connects the Desert Southwest to California becomes insignificant in supporting California's demand. In contrast, California's greater self-sufficiency in local dispatchable generation capacity (as in the Lim scenario) (Figure 16) might prove more advantageous in mitigating unserved energy in the state.

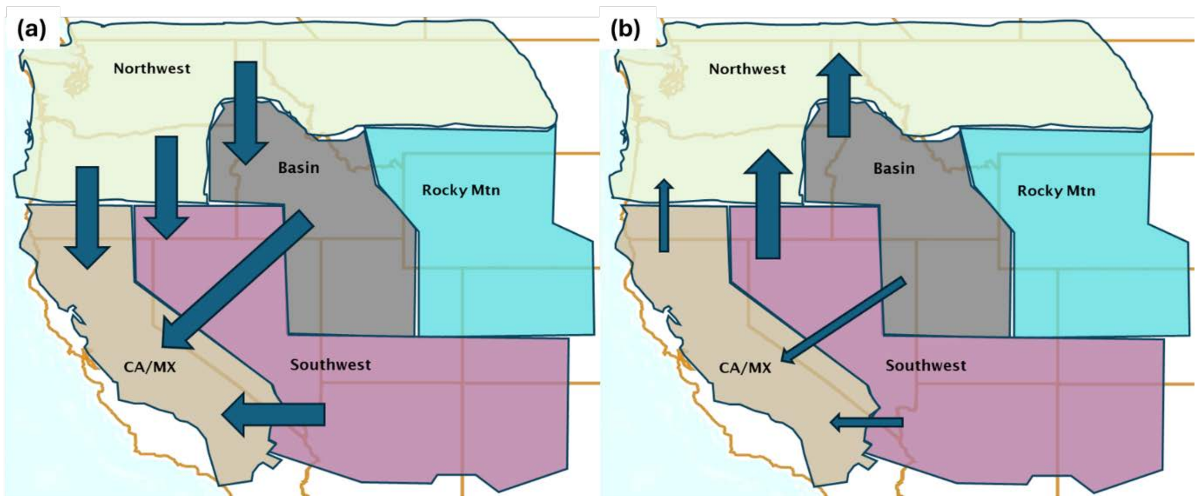

Figure 30. Conceptual representation of net power flows for the Lim scenario during nonstress grid operations (a) and during extreme stress operations when PNW is experiencing a combined heatwave and drought event (b)

The width of the arrow represents the magnitude of the flow, with a larger width indicating higher flows.

Figure 31 depicts the interplay between supplementary transmission capacity (AC scenario) and additional local generation capacity in California (Limited scenario) during the combined PNW heatwave and PNW drought. As expected, the additional installed capacity of local flexible resources such as storage and natural gas (gas turbine [GT]) leads to higher use of these resources in the Limited scenario compared to the AC one, resulting in a 1.3% reduction of unserved energy in the California region, as shown in Figure 32. In contrast, the additional interregional capacity in the AC scenario does not appear to offer practical support to California because exports are comparable between the two scenarios. This suggests in both transmission scenarios, California becomes a net exporter to alleviate stress events in PNW. Consequently, the additional transmission lines proposed to connect the Desert Southwest with California, as suggested in the AC scenario, become underused.

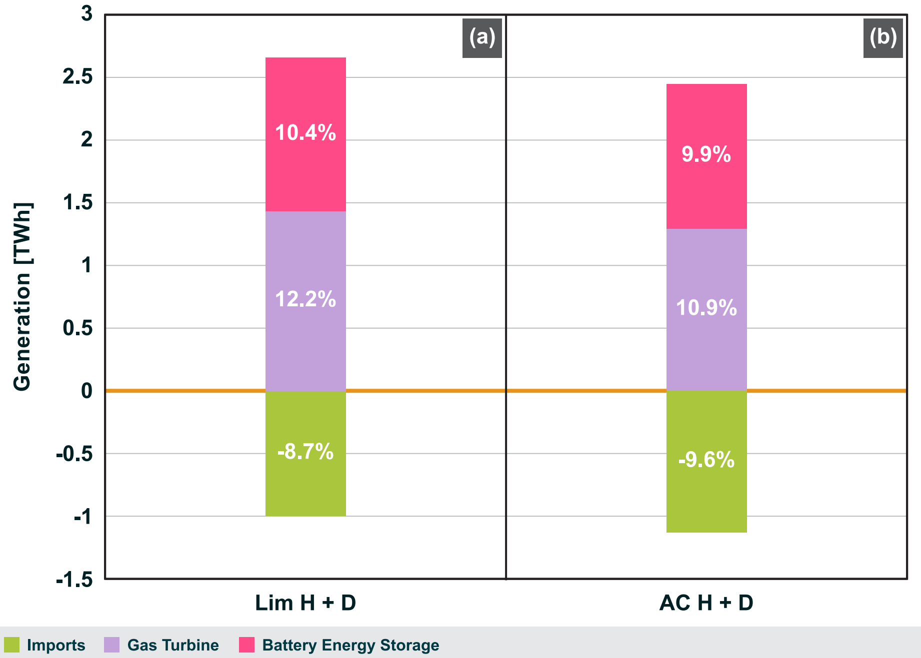

Figure 31. Generation outputs (TWh) in California for the Lim (a) and AC (b) scenarios during the combined PNW heatwave and PNW drought

The Limited scenario shows higher amounts of BESS and GT use, which in turn has resulted in lower unserved energy in California compared to that for the AC scenario.

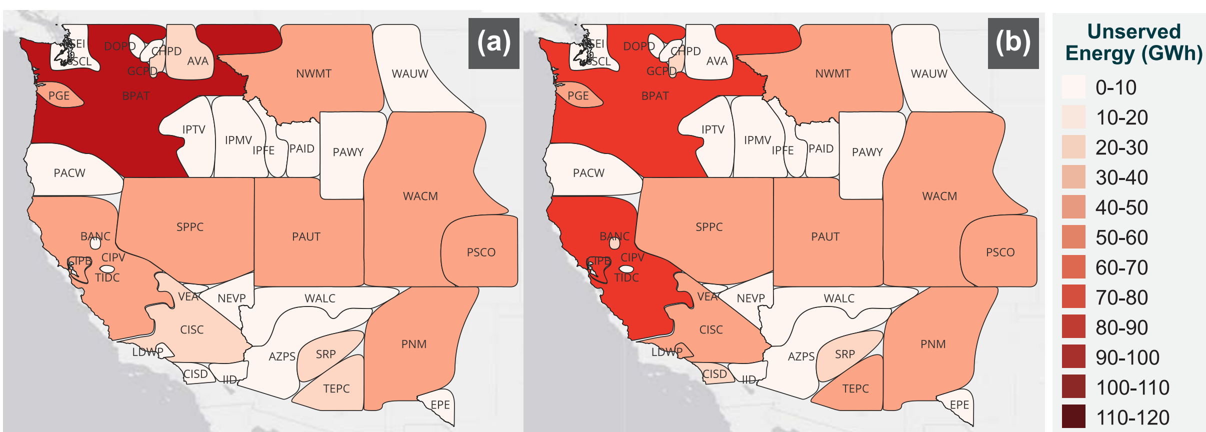

Figure 32. Total unserved energy (GWh) by load area during the combined PNW and PNW drought for the Lim (a) and AC (b) scenarios

4.5 Economic Impacts Differ Based on Transmission Topology and the Location, Type, and Intensity of Extreme Events

The study team compared the benefits of the Limited and AC transmission scenarios. To evaluate these benefits, the study team examined the differences in avoided costs of generation and the C-VOLL between the two transmission scenarios.

Table 2 shows the benefit of avoided generation costs for the two transmission scenarios across all stress events. The generation costs of the AC scenario are lower than those of the Limited scenario for all stress events because of a higher prevalence of low-cost renewable generation in the eastern portion of the Western Interconnection.

Table 2. The Benefit of Avoided Generation Costs Between the Limited and AC Scenarios: Additional Lower-Cost Renewable Generation Favors the AC Topology

Stress Event	Lim Generation Cost ($B)	AC Generation Cost ($B)	Generation Cost Savings of AC ($B)
PNW heat	16.2	15.4	0.7
PNW heat + PNW drought	17.6	16.9	0.7
CA heat	15.7	14.9	0.9
CA heat + PNW drought	17.2	16.4	0.8
Note: Results may not add because of rounding.			

Figure 33 shows the total C-VOLL costs (lower is better) for the two transmission scenarios across all stress events. During the single California heatwave event, the total C-VOLL costs for the AC scenario are lower than the costs of the Limited scenario ($107 billion Limited vs. $85 billion AC). During the combined California heatwave and PNW drought event, the AC scenario results in lower total C-VOLL costs than the Limited scenario ($268 billion Limited vs. $223 billion AC). During the single PNW heatwave event, the Limited scenario results in lower total C-VOLL costs than those of the AC scenario ($54 billion Limited vs. $64 billion AC). Similarly, during the combined PNW heatwave and PNW drought, the Limited scenario records lower total C-VOLL costs than the AC scenario ($156 billion Limited vs. $173 billion AC). Of note is lost load is present in all the extreme events modeled. Different transmission topologies were able to reduce the amount of lost load but not completely prevent it.

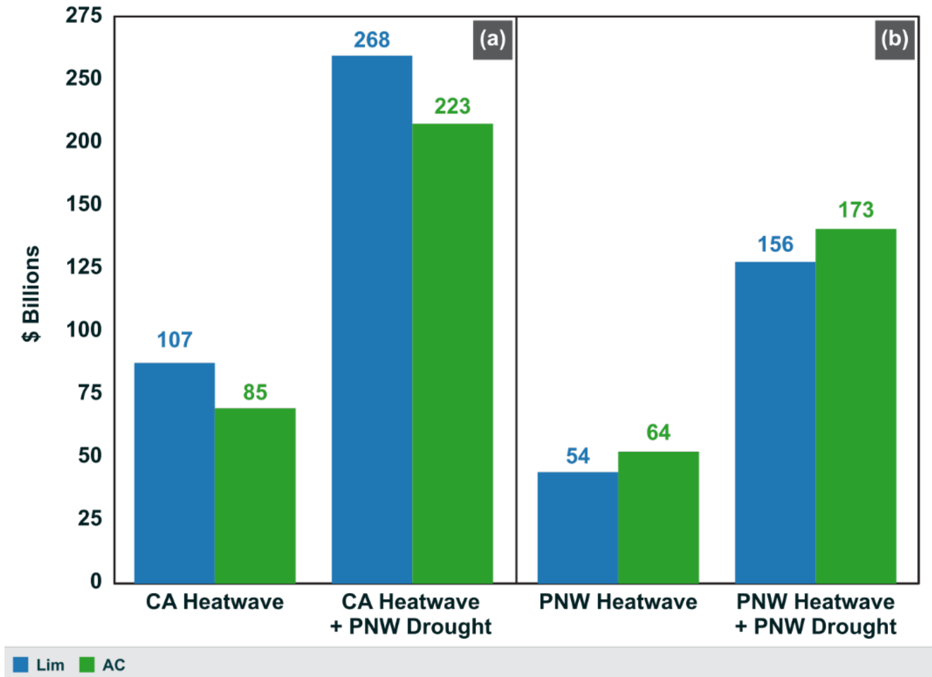

Figure 33. Total C-VOLL costs (TWh × $/TWh) by transmission topology across the Western Interconnection from the combination of a heatwave in (a) California or (b) PNW and the PNW drought compared to the respective single heatwave events.

Figure 34 displays the economic benefit of the AC scenario over the Limited scenario expressed as the difference in C-VOLL costs for each stress event. The AC scenario produces large improvements in total C-VOLL during the California heatwave and the California heatwave plus PNW drought events, with $21 billion and $45 billion less C-VOLL, respectively. The Limited scenario produces C-VOLL improvements during the PNW heatwave event and during the PNW heatwave and PNW drought event with $10 billion and $16 billion less C-VOLL in the Limited scenario.

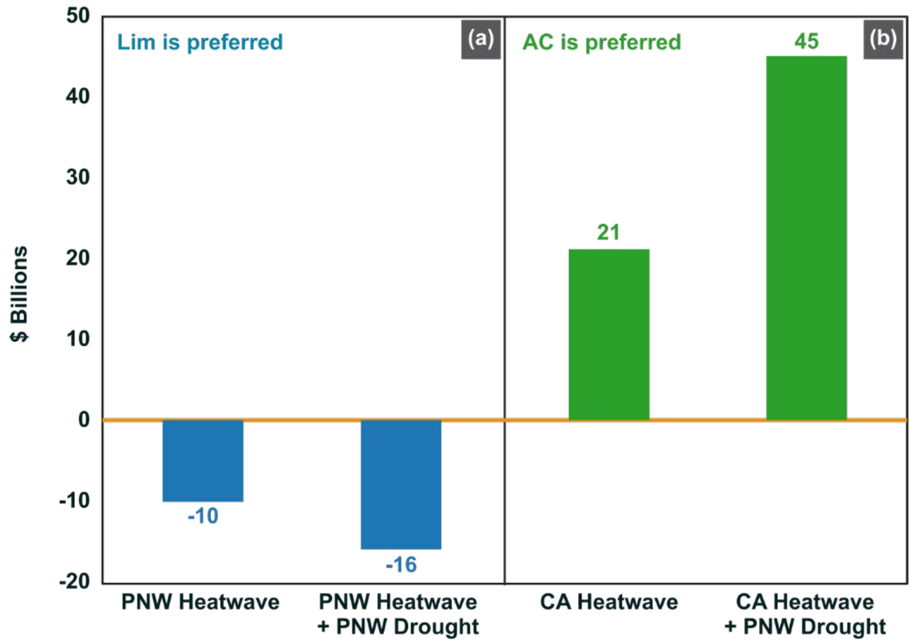

Figure 34. The economic benefit of the AC scenario over the Lim scenario expressed as the difference in C-VOLL

Positive values indicate AC is preferred (a), and negative values indicate Lim is preferred (b).

Comparing the magnitudes of the two benefits (i.e., avoided generation costs and C-VOLL costs), the differences in avoided generation costs (Table 2) are much smaller than the differences in the total C-VOLL costs, shown in Figure 34. This result indicates during extreme events, the end consumers' costs—which result from not serving the load—are much higher than the additional required generation costs. As such, the costs incurred from unserved load could play a critical role in the planning process for future transmission expansion plans.

5 Conclusions

The study team applied a suite of modeling tools for projecting extreme weather events onto future grid scenarios to assess the reliability, operational, and economic impacts of such stress conditions under different NTP Study nodal transmission expansion scenarios. By simulating these scenarios, the study team gained insights into how different regions might fare in the face of extreme events considering their unique generation mixes and the capacity for interregional energy transfers. The interplay between these factors is critical, highlighting the value of extreme event analysis in understanding the potential advantages of expanding transmission infrastructure. This approach underscores the need for strategic planning in the development of transmission capabilities across regions. The stress case analysis takeaways are as follows:

1. Compounded extreme events lead to higher levels of unserved energy than individual events. When the California or PNW heatwave is combined with the PNW hydropower drought, the resulting unserved energy increases in both regions and across both transmission scenarios.
    a. Specifically, in the Limited scenario, unserved energy rises to 3.8% and 7.7% for California and PNW, respectively, during the combined California heatwave and PNW drought, compared to the single California heatwave event, which results in 1.5% and 1.3% unserved energy for California and PNW.
2. The buildout of additional interregional transmission can support the power system during extreme weather events, decreasing the potential for and amounts of unserved energy. This advantage is notably evident during the simultaneous California heatwave and PNW drought.
    a. The new interregional capacity (in the AC scenario) within the Western Interconnection region provides a vital corridor for channeling wind resources from New Mexico, Colorado, and Wyoming to meet the increased demand in California caused by the heatwave and reduced PNW hydropower imports. This strategic transmission route is vital in addressing California's surging demand during the heatwave and compensating for the shortfall in hydropower imports typically received from PNW. As a result, unserved energy is reduced by 1.5% in California (4.2% in Southern California) and 1.9% in PNW in the AC scenario compared to the Limited scenario.
3. Transmission and resource planners should carefully consider interregional transmission and additional local generation capacity when minimizing the risks of extreme stress events.
    a. Both interregional transmission and local generation capacity expansion are necessary to manage risk during a variety of extreme stress events,

as exemplified by the combined heatwave and drought in PNW. California has 1.3% lower unserved energy levels in the Limited scenario than in the AC scenario, benefiting from its greater installed capacity of local dispatchable resources (such as battery storage and natural gas) that could support the state's increased load demands amid decreased imports from PNW. In both scenarios, California is a net exporter, supporting the PNW heatwave and drought.

b. This specific case indicates the attributes of an extreme event—duration, magnitude, type, and location—affect each region's generation availability differently, including the ability to transfer power between regions. Hence, depending on the extreme event under study, a system with different levels of interregional transmission capacity may respond differently based on the levels and types of generation and storage resources, including local assets. Therefore, transmission planning solutions will need to carefully consider the attributes of extreme events and how those affect the generation availability and transmission use.

4. Unserved energy peaks in the morning (5–8 a.m.) because of low online energy resource availability and increasing load ramps.

    a. The unserved energy peak coincides with increasing morning load ramp and exhausted battery and pumped hydro energy storage resources (because of the full use of storage to meet the peak load in the late afternoon when solar diminishes), prior to solar generation coming online. The amount of unserved energy is higher in the Limited scenario compared to the AC scenario, underscoring the importance of interregional capacity (in the AC scenario) in boosting California imports to meet the load during early morning hours.

5. Different transmission topologies provide varying economic benefits of reliability based on extreme event locations and types.

    a. The values shown in this chapter are based on four specific stress events (PNW heatwave, PNW heatwave with PNW drought, California heatwave, and California heatwave with PNW drought) with specific geographical region (California vs. PNW) and intensity characteristics. To understand the overall impact, a more comprehensive analysis including a variety of extreme events must be undertaken.

    b. For each stress event under study, the economic VOLL for these unserved energy periods were in the tens to hundreds of billions of dollars for individual regions (PNW or California). These values are significantly large in that they approach the total cost of the system expansion (transmission and generation) for the Western Interconnection through 2035 (see Chapter 3). However, the reader should be cautioned not to add the benefits presented here to other types of economic benefits or directly compare the magnitude of these benefits with transmission capital costs. This highlights the importance of considering extreme scenarios in addition to the commonly used peak load projections to establish the proper design conditions for capacity expansion and transmission planning processes.

6. Future areas recommended for study could include the following topics:

    a. Conduct additional stress analyses for the Eastern Interconnection by itself as well as for the combined Eastern and Western Interconnection (MT-HVDC) scenarios under both compounded and single stress events. The combined study of the Eastern and Western Interconnections could provide valuable insights into the economic and reliability benefits of transmission planning across seams, allowing affected areas to tap into a more diverse array of generation resources spanning a larger geographic footprint and leveraging variations in time zones.

    b. Expand the range of extreme events considered, such as cold snaps, periods of wind and solar droughts, wildfires, and other potential stressors. By broadening the scope of these analyses, power system planners can gain a more comprehensive understanding of the resilience and vulnerabilities of their grid, informing more robust strategies for mitigating future disruptions and ensuring grid reliability.

    c. The NTP Study built the two nodal transmission expansion scenarios (i.e., AC and Limited) without considering extreme events. A future recommendation is to integrate geographical considerations and account for the magnitude and location of compounding stressors into transmission and generation capacity planning decisions. This stress-informed planning could help build a more robust power system, capable of withstanding a variety of extreme weather stressors.

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Appendix A. Load Modeling

A.1 Selecting Weather Events

The study team chose two unique and contrasting western U.S. heatwave events. The first occurred from roughly June 25, 2015, to July 2, 2015, and covered most of the western United States, including the Pacific Northwest (PNW). The second occurred from roughly July 22, 2015, to July 28, 2018, and was most intense over California and the Desert Southwest. Choosing two heat waves with different spatial extents allows the ability of expanded transmission to alleviate regional versus widespread stress to be tested.

The study team identified and characterized the weather conditions during these events using the Thermodynamic Global Warming (TGW) dataset generated by the Integrated, Multiscale, Multisector Modeling (IM3) project (Jones et al. 2023). The TGW data contains 40 years (1980–2019) of hourly historical meteorology (e.g., temperature and humidity) at a 12-kilometer (km) spatial resolution. Then, the study team repeated the 40-year historical record twice into the future (2020–2059 and 2060–2099) with various levels of additional warming applied to the boundary conditions of the Weather Research and Forecasting (WRF) model used to dynamically downscale the meteorology. The additional warming comes from the average climate model warming levels for two radiative forcing scenarios (Representative Concentration Pathways [RCPs] 4.5 and 8.5) and uses averages for climate models that are colder and hotter than the multimodel mean. This methodology allows historical weather events to be replayed in the future, providing a way to examine how significant historical events such as heatwaves may play out in a warmer future world.

For the 12-km historical and future meteorology data (Jones et al. 2023), the study team postprocessed the data by first spatially aggregating them to the county scale (Burleyson, Thurber, and Vernon 2023a); then, the study team weighted the county data by population to create hourly time series of the meteorology for each balancing authority (BA) in the United States (Burleyson, Thurber, and Vernon 2023b). Figure A-1 shows an example of the TGW temperature evolution in the California Independent System Operator (CAISO) BA.

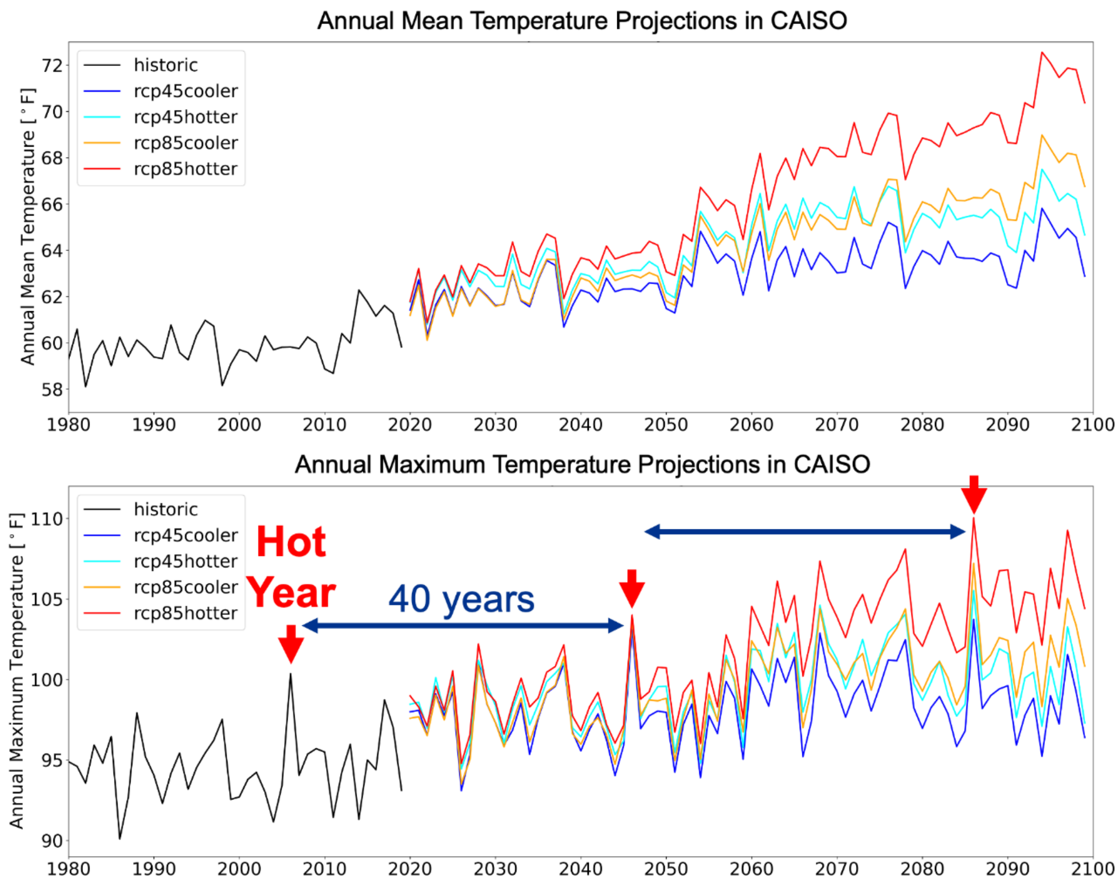


Figure A-1. Evolution of the annual mean (top) and maximum (bottom) temperatures in the CAISO BA service territory

The black lines show the historical values (1980–2019), and the colored lines show the projected values under varying levels of climate change.

In addition, in the heatwave stress analysis, the study team chose to include the effects of climate change on the projected loads. To factor in climate change, the study team used future weather years in the TGW dataset that included the additional thermodynamic deltas applied. That means for the 2015 weather year, the study team used the 2055 (i.e., +40 years) projected weather year meteorology data generated using the RCP 8.5 hotter scenario from the TGW data. For the 2018 weather year, the study team used the 2058 projected meteorology data. The study team intentionally chose to use the hotter scenarios from the TGW data to further stress the grid during the heatwave event. Figure A-2 shows the increase in maximum temperatures because of climate change in each BA during the 2015 and 2018 heatwave events. On average across all BAs, climate change increases the projected maximum temperature during the heatwave periods by +5.5°F and +6.6°F for the 2015 and 2018 NTP heatwave events, respectively. A small number of BAs experience maximum temperature increases approaching +10°F. As expected, no BAs fall below the 1:1 line.

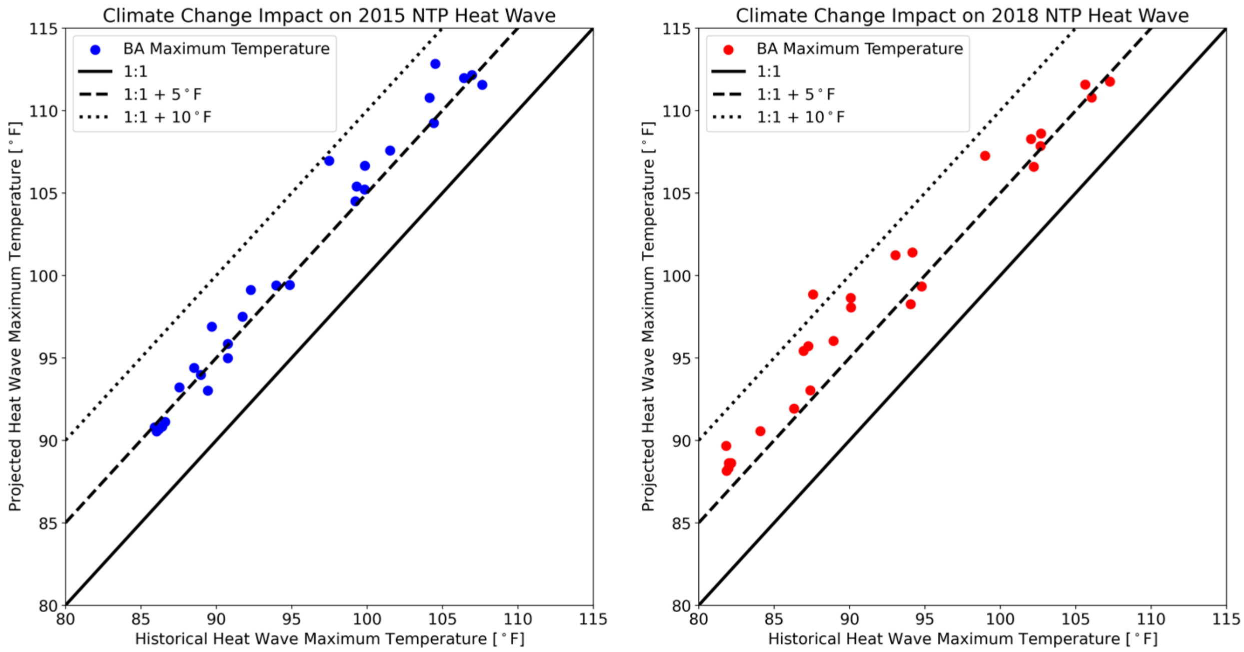


Figure A-2. Observed historical maximum temperature by BA (x-axis) during the 2015 (left panel) and 2018 (right panel) NTP heatwave events

The y-axis shows the projected maximum temperature for the same events under climate change, as derived from the TGW weather dataset.

A.2 Load Projections

Once the study team selected the extreme events, the next step was to simulate how the hourly load, wind, and solar evolved over the course of the events. To do this, the study team borrowed a suite of models and techniques developed by other PNNL projects, including the IM3 project funded by the U.S. Department of Energy (DOE) Office of Science and PNNL's Grid Operations, Decarbonization, Environmental and Energy Equity Platform (GODEEEP) internal investment. The tool for simulating load is the extensively documented open-source Total ELectricity Loads (TELL; https://immm-sfa.github.io/tell/) model developed by IM3 (McGrath et al. 2022). TELL takes as input hourly time series of meteorology by BA and simulates the hourly evolution of the total electricity demand within the BA in response to the variations in weather.

TELL is a machine learning (ML)-based model trained on historical total weather and loads from 2016 to 2018. The historical total loads are from the Energy Information Administration (EIA)-930 dataset, which contains hourly total (net) load observations by BA going back to 2015. TELL trains a unique multilayered perceptron (MLP) model for each BA. The MLP models are accurate (see McGrath et al. 2022 and https://immm-sfa.github.io/tell/user_guide.html). The input variables for TELL are hourly time series of temperature, humidity, shortwave radiation, longwave radiation, and wind speed for each BA. The model also considers the time of day (in Coordinated Universal Time [UTC]), the day of the week, and whether the day was a federal holiday.

One minor thing to note is the load data that TELL was trained on include a slightly different set of BAs in the western United States from the BAs used in the GridView production cost model. TELL models the loads in CAISO, Idaho Power Company (IPCO), Nevada Power (NEVP), and PacifiCorp East (PACE) as a whole, but GridView separates them into subregions. To create the GridView data for these BAs, the study team used the entire BA load simulated by TELL and distributed it to the subregions within the BA using the fractional annual total load in each subregion to portion out the TELL loads. The study team calculated the fractional values using the 2035 National Transmission Planning Study (NTP Study) base year loads. In practice, this means the projected load time series in each of those GridView subregions will have the same temporal variations but different magnitudes. Table A-1 lists the subregions, which are also listed in the code repository containing the Jupyter notebooks used to run TELL for the NTP Study: https://github.com/cdburley/ntp_heat_wave_loads.

Table A-1. BAs in GridView That Do Not Directly Match What Is Simulated by TELL

TELL Balancing Authority	GridView Subregions*
CAISO	CIPB, CIPV, CISC, CISD, VEA
IPCO	IPFE, IPMV, IPTV
NEVP	NEVP, SPCC
PACE	PAID, PAUT, PAWY

* Abbreviations: CAISO = California Independent System Operator; CIPB = Pacific Gas & Electric Bay Area; CIPV = Pacific Gas & Electric Valley Area; CISC = Southern California Edison; CISD = San Diego Gas & Electric; IPCO = Idaho Power Company; IPFE = Far East (Idaho Power); IPMV = Magic Valley (Idaho Power); IPTV = Treasure Valley (Idaho Power); NEVP = Nevada Power; PACE = PacifiCorp East; PAID = PacifiCorp East – Idaho; PAUT = PacifiCorp East – Utah; PAWY = PacifiCorp East – Wyoming; SPCC = Sierra Pacific Power; VEA = Valley Electric Association

Because the NTP Study is considering a future projection of the electric grid (e.g., the grid as it may exist in 2035), the loads must be grown to reflect the natural long-term growth of energy demand between when the TELL MLP models were trained (2016–2018) and 2035. The study team implemented this growth by scaling the raw output from TELL to match the total annual energy for each BA in the base 2035 NTP loads. These 2035 annual energy values in NTP are based on the 2009 weather year. The goal of scaling to match the annual energy in each BA is to mimic the slow, long-term growth trends in loads that are not captured by TELL.

A.3 Load Analysis

The projected loads based on the 2015 and 2018 weather years are not intended to be directly compared to the 2035 NTP Study base loads. They are based on different weather years with different heatwaves (both locations and magnitudes) and use fundamentally different methodologies to project the loads forward to 2035. However, the study team performed basic analyses of the changes in the minimum and maximum loads to provide a basic understanding of the differences in the base case loads and the heatwave loads that were intentionally designed to stress the system.

Figure A-3 shows the annual minimum and maximum loads by BA for the 2015 and 2018 weather years compared to the 2035 base case values. The solid, dashed, and dotted lines show the 2035 base case values ±0%, ±10%, and ±20%. Across all BAs, the annual minimum loads using the TELL projection methodology are all within ±20% and are most often within ±10% of the 2035 base case values. The same is mostly true for the annual maximum loads, which tend to be (by design) higher using the TELL methodology but still generally comparable to the 2035 base case values, which were derived for a different weather year and do not include the amplification of loads because of climate change. The largest differences are on the order of +20%.

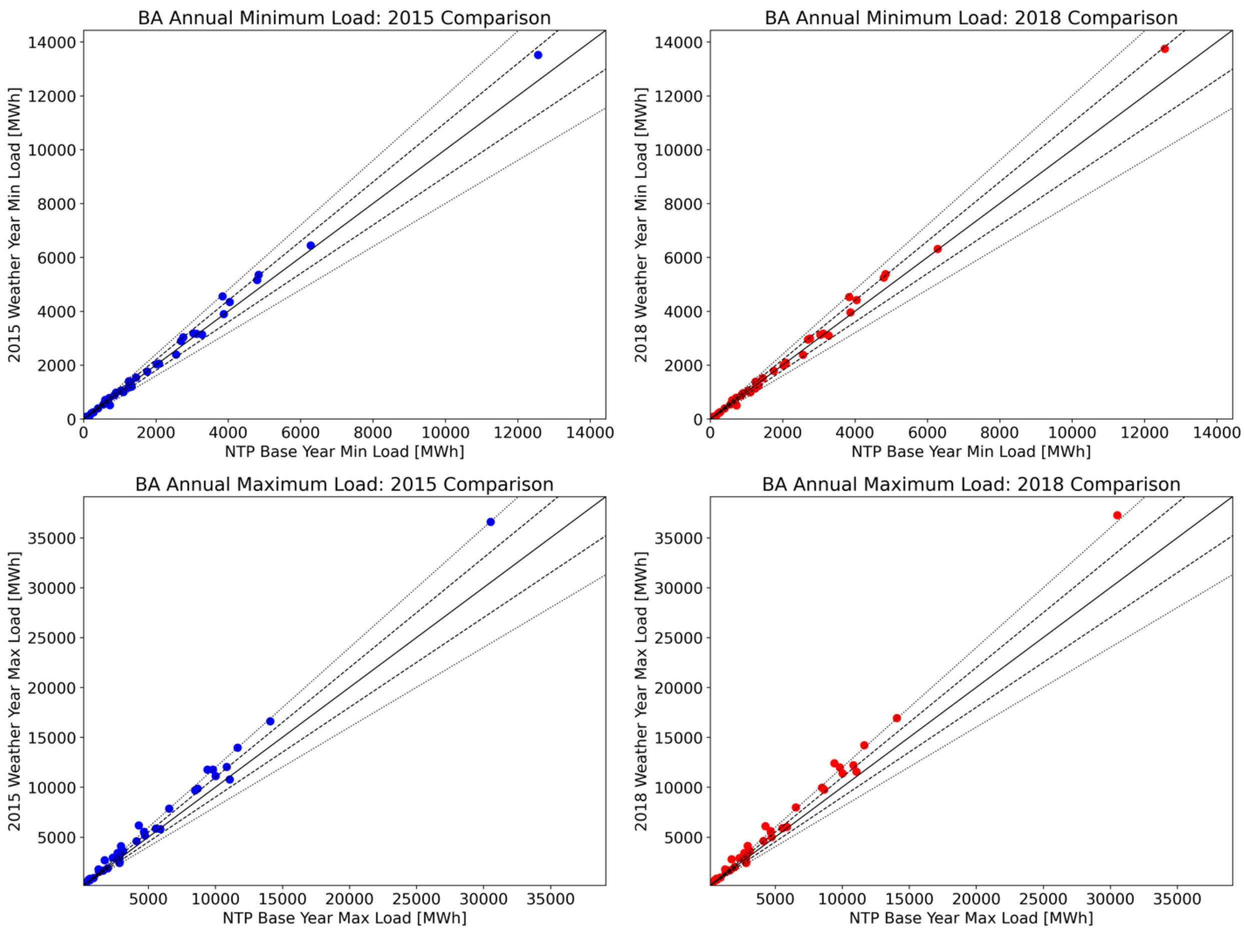


Figure A-3. Scatterplots showing the relationship between the annual minimum (top row) and maximum (bottom row) load values by BA

The study team derived the x-axis values from the 2035 NTP Study base year loads. The y-axis values are those derived from the 2015 (left column) and 2018 (right column) weather year loads with climate change. In each plot, the solid line shows a 1:1 relationship, and the dashed and dotted lines show 1:1 ±10% and 1:1 ± 20%, respectively.

MWh = megawatt-hour

The methodology used by the study team also allows the impact of climate change on loads to be decomposed. By comparing the output of TELL from the 2015 and 2018 weather years without climate change to those with the climate change signal added, the impact of the decision to include climate change on the load projections can be quantified. Figure A-4 shows the load time series from TELL with and without the climate change impact included. Ignoring the spurious signals every 7 days because of differences in weekdays and weekends between 2015 and 2035, the dominant (and expected) signal is for lower wintertime loads and higher summertime loads when using the weather data with the climate change signal included. The absolute difference is approximately −5,000 to −10,000 MWh in the winter and approximately +5,000 to +10,000 MWh in the summer. This corresponds to about a 5%–7% suppression of loads in the winter and a 4%–5% enhancement of loads in the summer. A similar pattern emerges when analyzing the 2018 weather year (not shown).

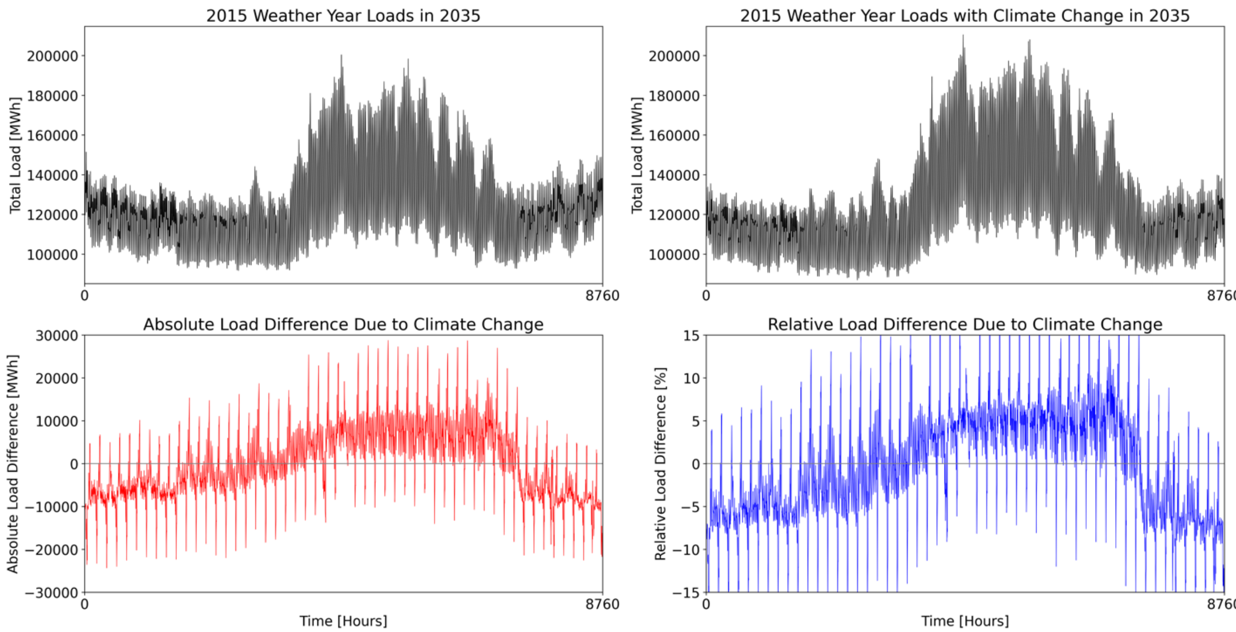


Figure A-4. Hourly loads in 2035 summed across all BAs in the western United States based on the 2015 weather year without (top left) and with (top right) climate change; the absolute difference between the two is shown in the bottom left, and the relative difference is shown in the bottom right

Spurious positive and negative changes every 7 days are because of differences in weekdays and weekends between 2015 and 2035.

Appendix B. Wind and Solar Profiles

To develop hourly solar and wind profiles for the National Transmission Planning Study (NTP Study), the study team leveraged work by the Grid Operations, Decarbonization, Environmental and Energy Equity Platform (GODEEEP) project (http://godeep.pnnl.gov), which produced hourly wind and solar generation at every Thermodynamic Global Warming (TGW) grid cell. The study team performed the computation using the Perlmutter system at the National Energy Research Scientific Computing Center (NERSC), which was supported by the Integrated, Multiscale, Multisector Modeling (IM3) project. At every 1/8th degree grid cell, the study team extracted relevant meteorological data and preprocessed these data for use with the National Renewable Energy Laboratory (NREL) Renewable Energy Potential (reV) model (Maclaurin et al. 2021). reV is an interface to the System Advisor Model (SAM)—a collection of models for renewable energy. The study team used generic configuration options, such as a commonly used turbine hub height and panel array type, to describe the hypothetical power plant in each grid cell. Because of the way the study team constructed the TGW data with the historical period being replicated twice with additional warming applied, the future wind and solar years used here were 2055 and 2058. The study team used the RCP 8.5 hotter warming scenario to represent the most extreme case for the grid and scaled the wind and solar data to remove alternating current (AC)/direct current (DC) losses prior to being imported into GridView. Figure B-1 presents a summary of the workflow methodology.

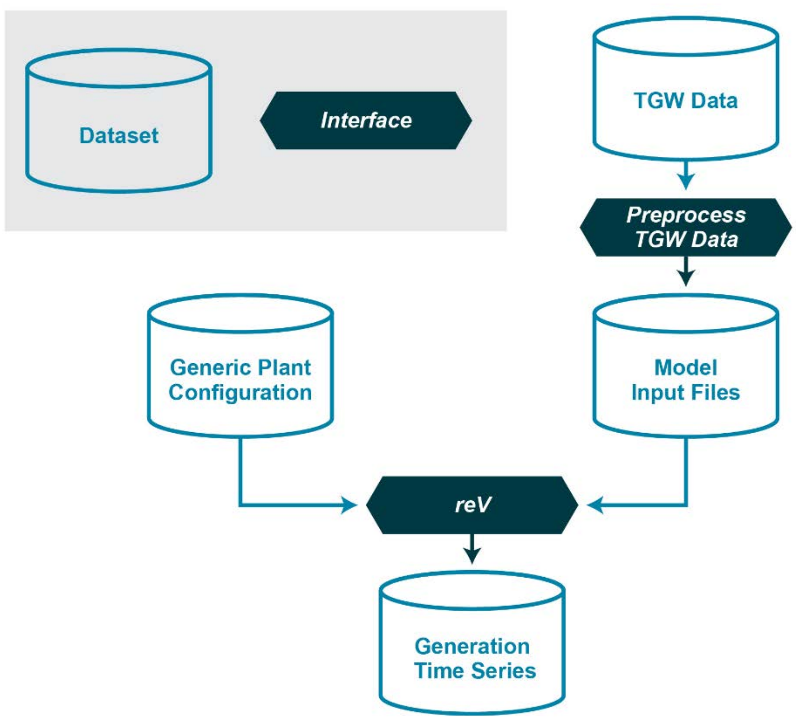


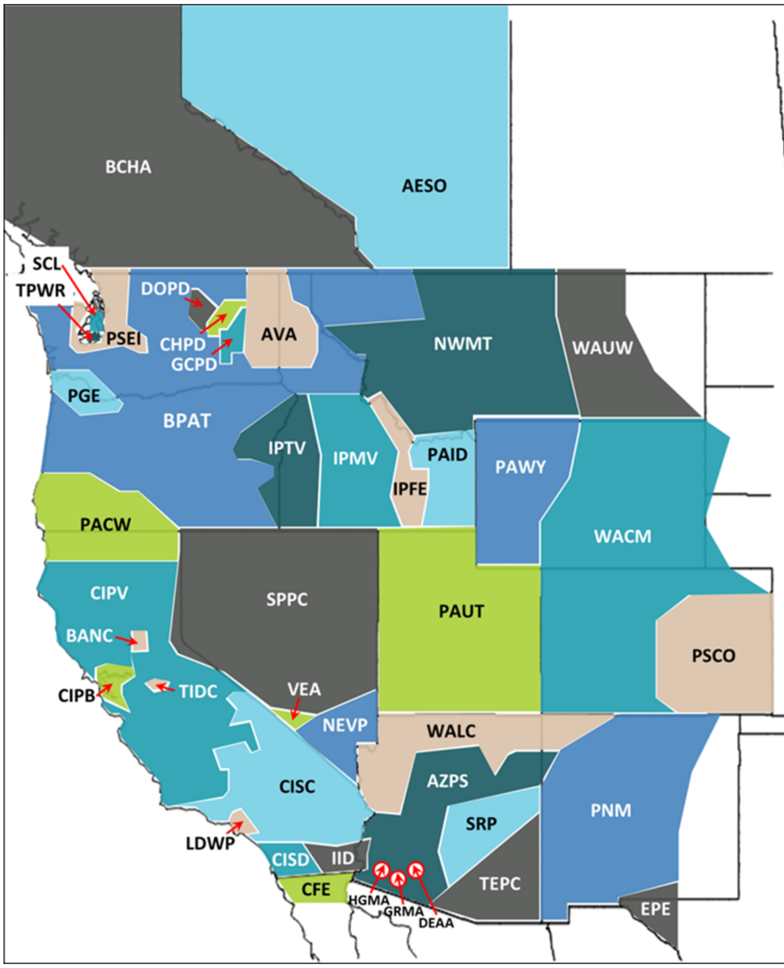
Figure B-1. Workflow for producing wind and solar generation data

TGW is the meteorological dataset, and reV is the renewable generation model used.

Appendix C. Western Electricity Coordinating Council Load Areas

Figure C-1 shows the 40 load areas that, in most cases, are analogous to the balancing authority (BA) boundaries or the load-serving entity (LSE) (WECC 2020b). As previously noted, the study team incorporated the TELL heatwave loads from 2018 in California and 2015 in the Pacific Northwest (PNW) into the production cost model analysis for each respective load area. For presenting the unserved energy results of the production cost model for the stress case analysis, the study team grouped the following Western Electricity Coordinating Council (WECC) load areas to represent the California and PNW regions:

- The California region consists of the following eight WECC load areas, defined in the figure: CIPV, BANC, CIPB, TIDC, CISC, LDWP, CISD, and IID. The CFE is the electric commission for the country of Mexico and is therefore excluded from the analysis.
- The PNW region consists of the following WECC load areas (also defined in the figure): SCL, TPWR, PSEI, DOPD, CHPD, GCPD, PGE, BPAT, and AVA. The study team excluded the Canadian authorities (BCHA and AESO) from the analysis.



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

Figure C-1. WECC load areas (WECC 2020b)

TEPPC = Transmission Expansion Planning Policy Committee

Appendix D. Western Electricity Coordinating Council Interface Paths

Figure D-1 illustrates all Western Electricity Coordinating Council (WECC) transmission paths (WECC 2007), with those analyzed highlighted in green.

Path 65 (Pacific DC Intertie) transfers electricity from Northwest (Celio substation) to Southern California (Sylmar substation). The PDCI line is a ±500-kilovolt (kV) direct current (DC) multiterminal system. This system is divided into the northern and southern systems; the demarcation point is the Nevada–Oregon border (NOB). The north-to-south limit is 3,220 megawatts (MW) whereas the south-to-north limit is 3,100 MW.

Path 66 (California–Oregon Intertie) consists of three transmission lines that interconnect Oregon with Northern California. The north-to-south limit is 4,800 MW whereas the south-to-north limit is 3,675 MW.

Path 46 (West of the Colorado River) interconnects southern Nevada and Arizona with Southern California and is a key corridor for importing electricity to Southern California. It consists of 12 transmission lines and has an 11,200-MW transfer limit.

Path 14 (with Boardman to Hemingway [B2H]) connects eastern Oregon (Northwest) with southwestern Idaho. It consists of five transmission lines including the new B2H line. It has an east-to-west transfer limit of 2,400 MW and a west-to-south transfer limit of 1,340 MW.

Path 8 connects western Montana and the Northwest United States. The 10 lines involved in this path have an east-to-west transfer limit of 2,200 MW and a west-to-east transfer limit of 1,350 MW.

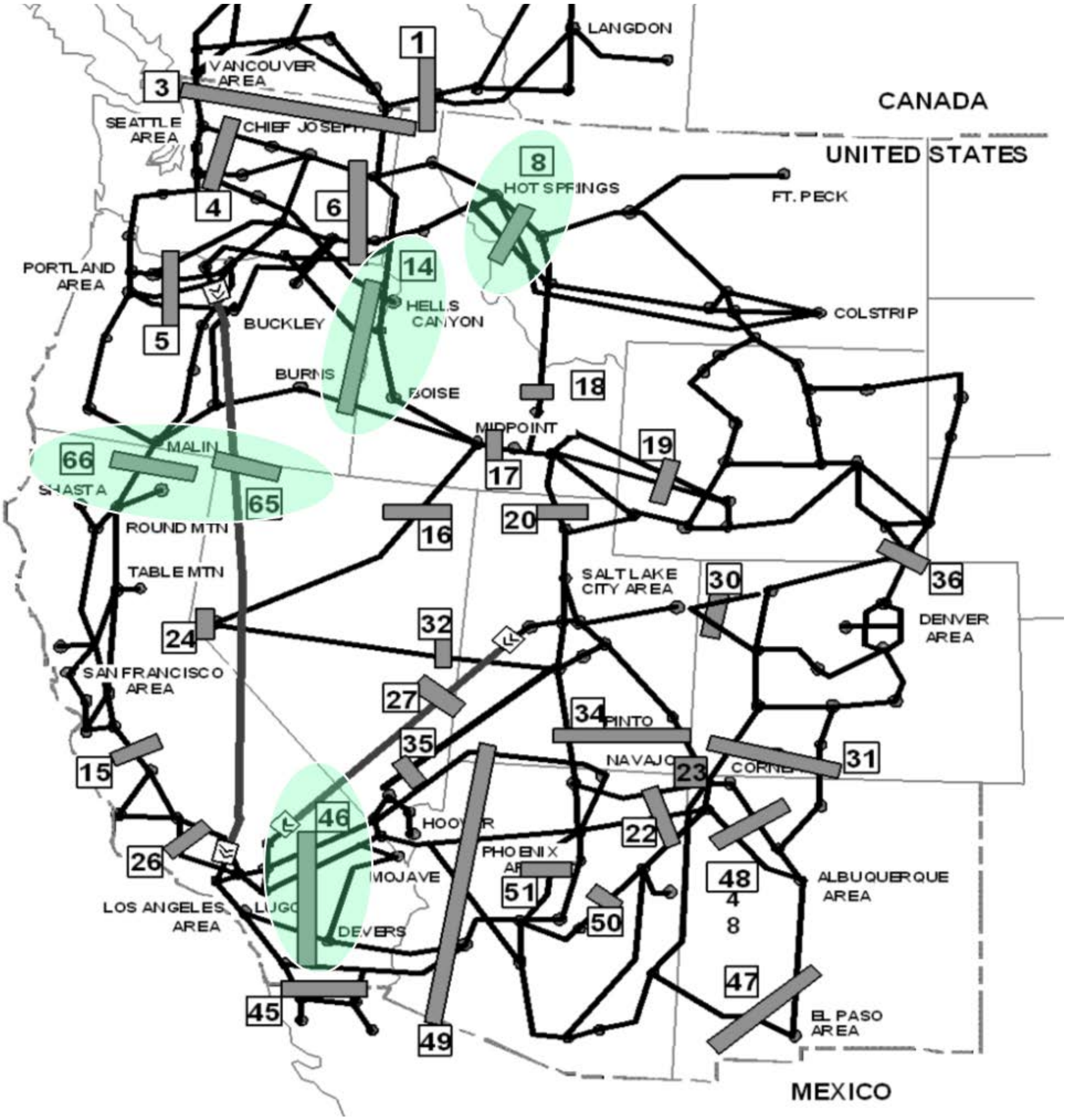


Figure D-1. WECC transmission paths (WECC 2007)

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