2030 Extreme Weather Study

April 2nd, 2024

Participating Members:

- AVA: Avista
- BPA: Bonneville Power Administration
- CHPD: Chelan PUD
- MATL: Montana-Alberta Tie Line
- IPC: Idaho Power Company
- NWMT: NorthWestern Energy
- PGE: Portland General Electric
- PSE: Puget Sound Energy
- SCL: Seattle City Light
- SNPD: Snohomish PUD
- TPWR: Tacoma Power

Table of Contents

List of Figures

1. Introduction and Purpose

The traditional NERC and FERC planning processes currently focus on 10-year planning horizons for normal peak load under normal summer and winter seasonal system conditions. It has been observed that extreme cold and heatwave weather conditions in recent years increasing the peak loads that has never been planned for testing the reliability of the transmission system. Given an increase in extreme weather events around the world impacting the reliability of the transmission systems, there is interest in studying the NorthernGrid footprint transmission systems under the extreme cold, extreme heat, and wildfire conditions and determine the extent of the impact. Given that transmission projects take such a long time to build, there is interest in ascertaining if there are Operational solutions that may help maintain the reliability of the transmission system until such transmission projects are built. The participating utilities in this study have undertaken this study to help identify any non-transmission solutions that can be implemented before 2030 that may help improve the overall reliability of the transmission system, particularly in extreme summer, extreme winter, or wildfire situations.

This study assesses the effects of the following phenomena in the near-term horizon (2030):

- Extreme Temperatures. Should extreme temperatures occur, it will impact:
    1. Utility load-forecasts.
    2. Generator capabilities.
    3. Transmission equipment ratings.
    4. The probability of wildfires, especially around forested areas. Such fires can cause outages on multiple transmission lines simultaneously in areas where lines may share a common corridor.
- Changes in load levels and composition:
    1. The electrification of carbon-emitting sectors such as water and space heating, and transportation has an impact on study load forecasts.
    2. Distributed energy resources and demand-side management will have a net impact on utility load forecasts.

The study scope is included as a report appendix for full details.

2. Executive Summary

In this study, participants created models to represent a 2030 Extreme Summer heatwave condition as well as a 2030 Extreme Winter cold snap condition. The study participants submitted modifications to the starting base cases that included transmission line derates, load increases, and generation redispatch commensurate with the expected study conditions.

The Wildfire cases were built from the prepared 2030 Extreme Summer model. In the wildfire case, corridors of wildfire impact were identified by the study participants and each common corridor outage was applied as the “base” state to imitate a long-term outage due to a wildfire. Study participants developed contingency lists that would typically be analyzed by an operations Real Time Analysis (RTA) desk at their respective organizations, which were then applied on top of each wildfire corridor outage.

Each participant reviewed the results and proposed mitigations to the risks identified if necessary. It was found that there are instances where the observed violations can be mitigated with planned facilities or existing operating actions. The analysis performed resulted in additional Corrective Action Plans (CAP) and operational plans, which are outlined in “3.3 Proposed Extreme Weather Mitigations” and “4.2 Proposed Wildfire Mitigations”.

3. 2030 Extreme Summer/Winter Analysis

3.1. Model Preparation

The seed cases for the analysis are listed below and were sourced from the Western Electric Coordinating Council (WECC). Each of the cases were developed from the 2032 cases indicating that they should have strong representation of the existing transmission topology. Using the existing generation helps ensure a conservative approach to using generation dispatch as a mitigation option. Each participating utility contributed to the modification of load characteristics, generation dispatch, and line rating assumptions through a submit/review process. That submit/review process involved preparing the individual data for compilation and then reviewing the compiled data to ensure consistency with the study scope.

- 2030 Extreme Summer: 2032 Heavy Summer 1a Planning Case
- 2030 Extreme Winter: 2031-32 Heavy Winter 1 Planning Case

The following load forecasts were used by each utility to adjust the planning cases.

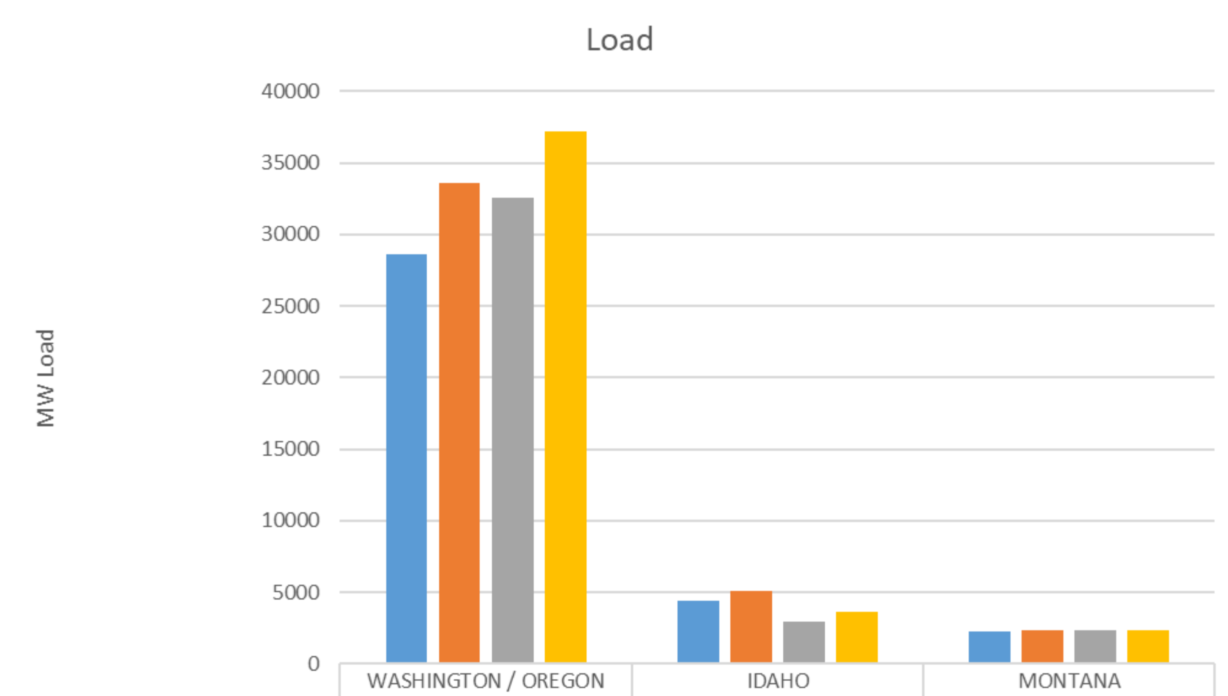
Summer and Winter, One in Twenty Years

- Bonneville, possible range to 1:10
- Montana-Alberta Tie Line
- Idaho Power
- NorthWestern
- Portland General
- Puget Sound
- Seattle (Interpolated between 1:10 and 1:30)
- Snohomish
- Tacoma, flexible

Summer and Winter, One in Ten Years

- Avista, possible range to 1:20
- Chelan, possible range to 1:20

Figure 1 shows how the loads were modified in the 2030 Extreme Summer/Winter (ES/EW) cases, compared to the original seed cases, 2032 Heavy Summer/Winter (HS/HW).



	WASHINGTON / OREGON	IDAHO	MONTANA
Heavy Summer (Seed)	28609	4407	2304
Extreme Summer (Modified)	33597	5117	2346
Heavy Winter (Seed)	32565	2925	2345
Extreme Winter (Modified)	37207	3646	2345

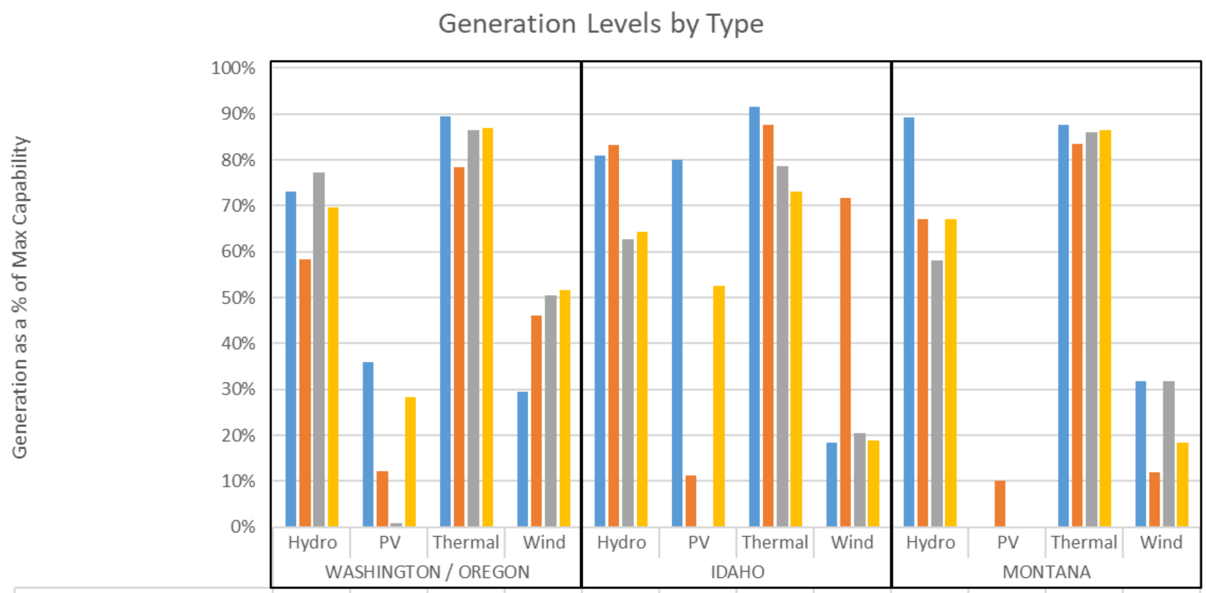
Figure 1: Loads in the seed cases (2032 Heavy Summer/Winter) compared to the 2030 Extreme Summer/Winter models

The rating of transmission equipment tends to decrease during high temperatures due to the lack of cooling from the environment. The following participants de-rated branches to represent higher peak temperatures during an extreme heat event in the 2030 Extreme Summer model:

- Chelan PUD
- Puget Sound Energy

An additional Extreme Summer sensitivity case was run as well, where a generic (flat) transmission line de-rate was applied to the study footprint to represent approximate de-rates due to a 120 degrees Fahrenheit ambient temperature. As of the date of writing, 120 degrees Fahrenheit is the highest recorded temperature within the study footprint and occurred at Hanford, Washington on June 29th, 2021.

With the increased load level, the following resource dispatch was modeled:



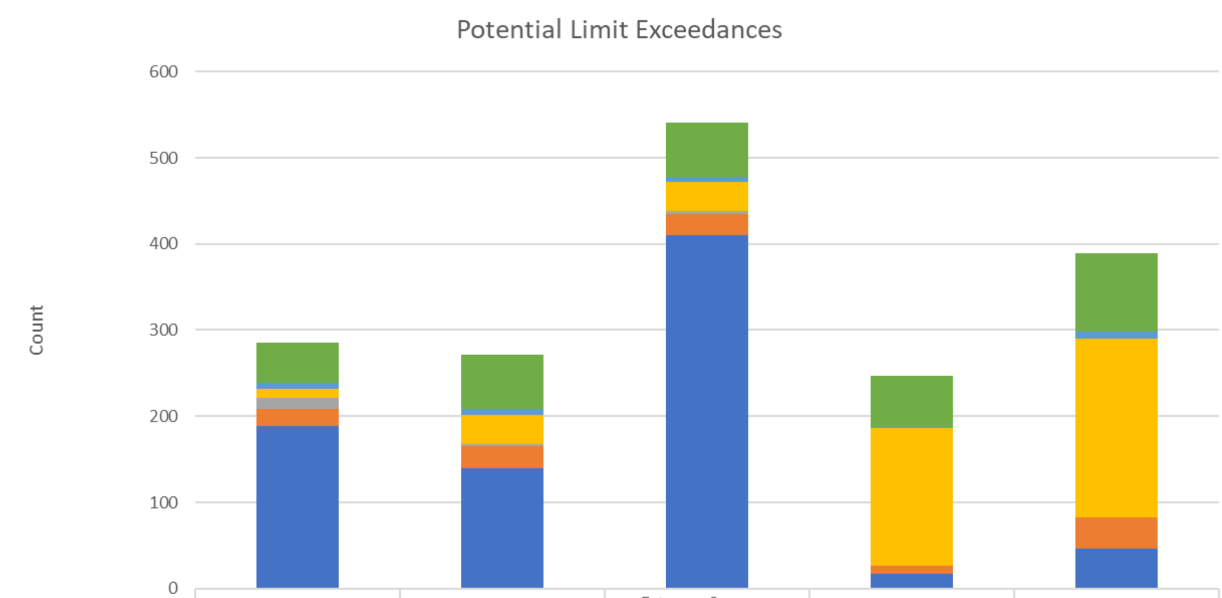
	WA/OR Hydro	WA/OR PV	WA/OR Thermal	WA/OR Wind	IDAHO Hydro	IDAHO PV	IDAHO Thermal	IDAHO Wind	MONTANA Hydro	MONTANA PV	MONTANA Thermal	MONTANA Wind
Heavy Summer (Seed)	73%	36%	89%	29%	81%	80%	91%	18%	89%		88%	32%
Extreme Summer (Modified)	58%	12%	78%	46%	83%	11%	88%	72%	67%	10%	83%	12%
Heavy Winter (Seed)	77%	1%	87%	51%	63%	0%	79%	20%	58%		86%	32%
Extreme Winter (Modified)	70%	28%	87%	52%	64%	52%	73%	19%	67%	0%	87%	18%

Figure 2: Generation in the seed cases (2032 Heavy Summer/Winter) compared to the 2030 Extreme Summer/Winter models

Steady state contingency analysis was then performed on the modeled system by simulating utility provided credible contingency scenarios. Exceedances of seasonal facility ratings were captured and detailed in Section 3.2.

3.2. Results

Below are the counts of observed limit exceedances for each of the cases analyzed, compared against the original WECC seed cases used for the study. Several modifications were applied to the Extreme Summer and Extreme Winter cases, which may have contributed to the reduced count of observed contingency limit exceedances.



	Heavy Summer (Seed)	Extreme Summer (Modified)	Extreme Summer (Modified) 120f Sensitivity	Heavy Winter (Seed)	Extreme Winter (Modified)
Voltage Deviation	47	63	63	59	91
Unsolved	7	6	6	2	8
Bus Low Volts	11	34	34	159	208
Bus High Volts	12	3	3		
Branch MVA	20	25	25	10	36
Branch Amp	189	140	410	17	46

Figure 3: Steady State Analysis - Violation Counts by Case

3.3. Proposed Extreme Weather Mitigations

Following the development of the base cases, contingency analysis was performed. The study participants then evaluated the analysis and categorized the violations into those that could be operationally mitigated, those that are mitigated by planned upgrades, or new violations that may require new considerations. Section 2.2 focuses on the potential violations that require planned or newly identified upgrades for mitigation.

3.3.1. Extreme Summer Mitigations

- The 2030 Extreme Summer study identified an Idaho Power overload of a Treasure Valley area 230/138 kV transformer for loss of a 230 kV line. This is a localized issue that does not have regional impacts on other entities. Idaho Power will continue to monitor the transformer for overloads in planning studies and has conceptual plans to either install a Remedial Action Scheme (RAS) to back-trip a 230 kV line or install a second 230/138 kV transformer to mitigate the potential overload.
- The 2030 Extreme Summer study identified potential violations in the Puget Sound Energy area that are localized issues with no regional impact. The potential violations identified are alleviated with the following mitigations:
    - Short-term solution: manual load shed in south King County, Long-term solution: Kent/Tukwila Area Project
    - Short-term solution: load shift to south King County through the 115 kV Vashon Tie or manual load drop in Kitsap County, Long-term solution: Kitsap Transmission Capacity Upgrade Project
- The 2030 Extreme Summer study identified two Snohomish contingencies that overloaded local Snohomish lines. System reconfigurations with load reduction through manual operation may be necessary to alleviate power flowing on the remaining line.
- The 2030 Extreme Summer study identified a few violations in the Portland General area that are alleviated through the following planned upgrades:
    - Rebuild of the 230 kV Horizon to Keeler #1 line
    - Install a third bank at the Evergreen substation
    - Reconfiguration of the Sunset bus
    - Reconductor of the 115 kV Bethel to Market #1 line
    - Portland General has planned responses including area sectionalization and load transfer processes that can be implemented until such time as the planned upgrades are installed.

3.3.2. Extreme Winter Mitigations

- The 2030 Extreme Winter study identified two locations in the Bonneville footprint; these potential violations are fixed through the following planned upgrades:
  - Installation of shunt compensation at the Troy 115 kV substation to provide voltage support in the Northern Idaho area
  - Installation of shunt capacitors at the LaPine 115 kV substation to provide voltage support in the Central Oregon area
- The 2030 Extreme Winter study identified potential violations in the Puget Sound Energy area that are localized issues with no regional impact. The potential violations identified are alleviated with the following mitigations:
  - Short-term solution: manual load shed in south King County, Long-term solution: Kent/Tukwila Area Project

4. 2030 Wildfire Analysis

The 2030 Extreme Summer model was used as the starting power flow base case for the 2030 Wildfire Analysis and adjusted to account for the confluence of wildfire and extreme summer conditions.

- Since extreme heat events may be the cause of wildfire events, some participants opted to keep the same high-temperature ratings in the model, while others submitted file updates to return their ratings to normal Summer planning values. Wildfires can cause smog and high winds resulting in a temperature cooling effect in some locations.
- Wildfire corridor events were defined as outlined in this section.
- Analysis of the wildfire events was performed, including:
    1. "State of the system", all components modeled "in-service".
    2. "State of the system" with simulated outages of known or expected corridors that are particularly susceptible to Wildfires.
    3. "State of the system": with simulated outages of known or expected corridors, followed by simulation of outages of operationally credible contingencies to emulate what an operations Real-Time-Analysis desk may have to respond to in an actual event.
    4. Cascading of Variation 3: in some instances, an event called "cascading" occurs. This happens when the alleviation of one violation causes a new violation and so on.

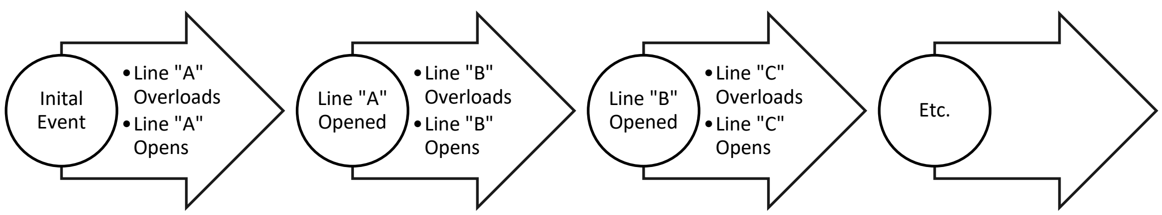


Figure 4: Generic Cascading Example

The following subsections each describe the different transmission paths that were deemed to be of operational interest by the participants. Outages on these paths may lead to operational challenges; this study brings awareness to some of those potential operational challenges. These paths may be WECC-rated paths or subsections of WECC-rated paths.

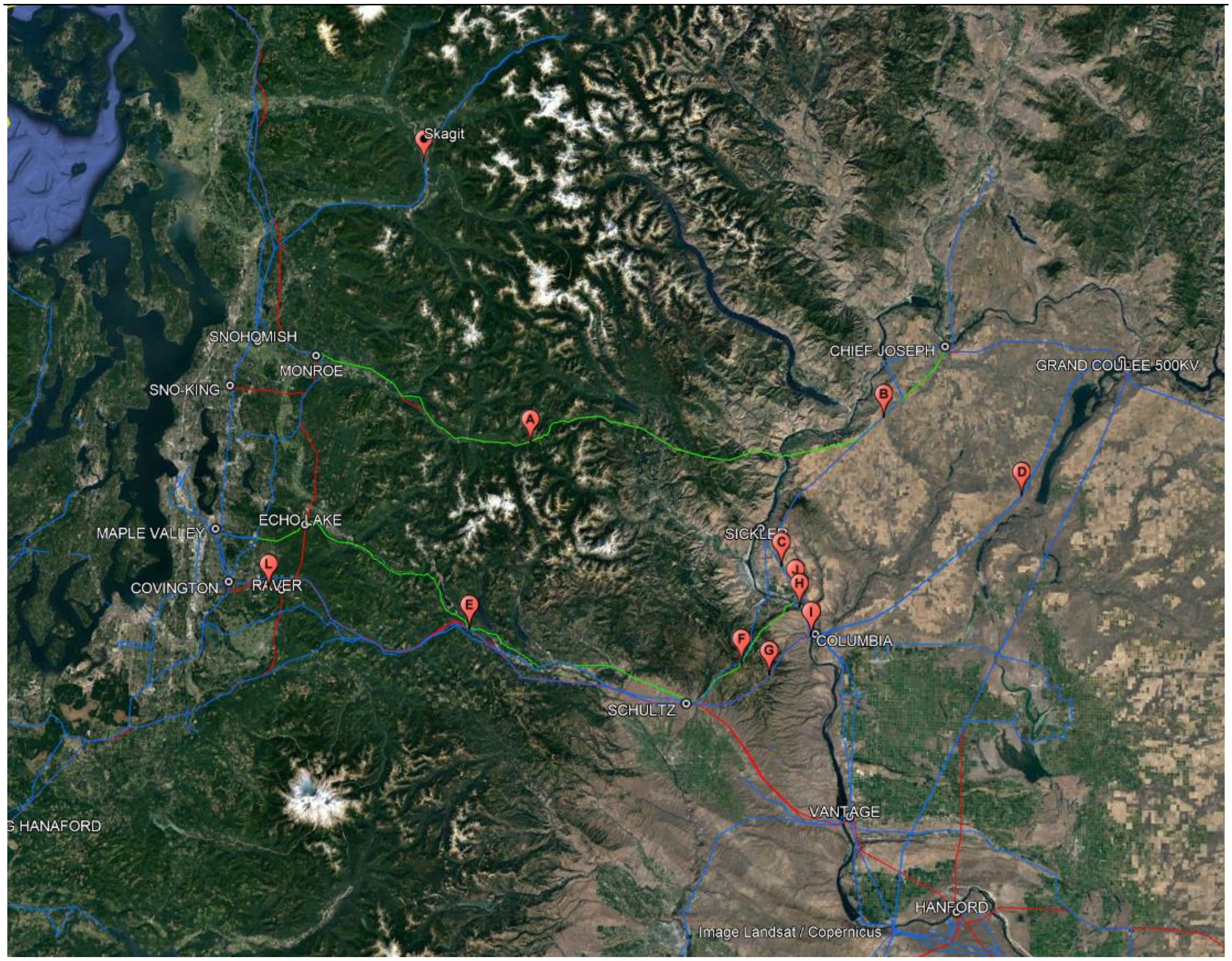


Figure 5: Wildfire Corridors in Washington

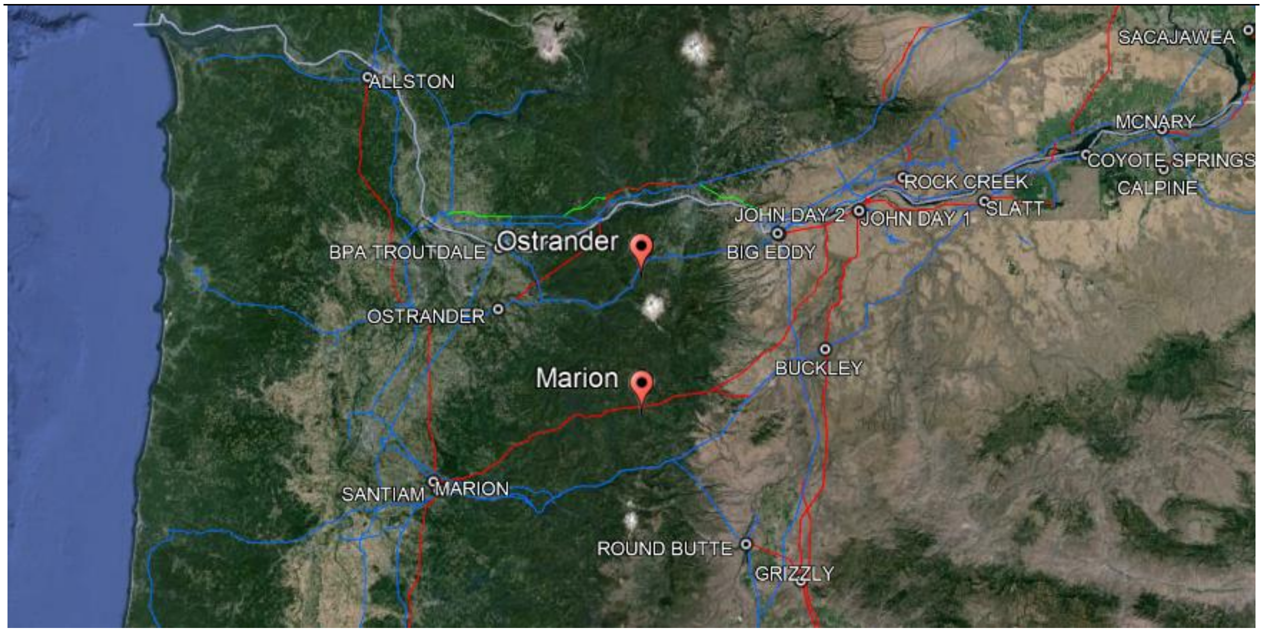


Figure 6: Wildfire Corridors in Oregon

Each of the points identified above represents a transmission line or group of lines that would be out of service in the event a wildfire impacts their respective corridors.

A map of the studied corridors overlaid with the FEMA wildfire risk rating by county is provided in Figure 7.

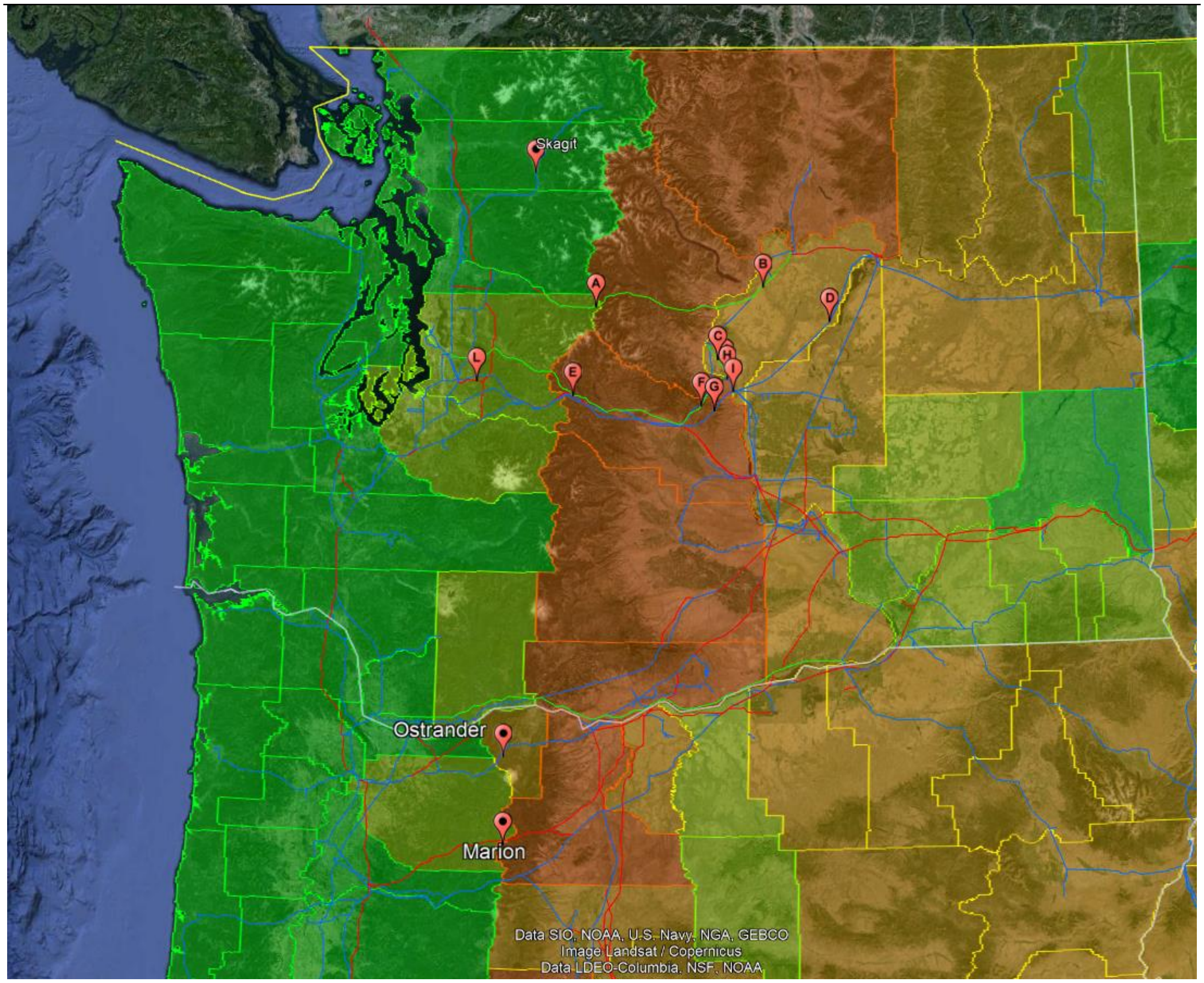
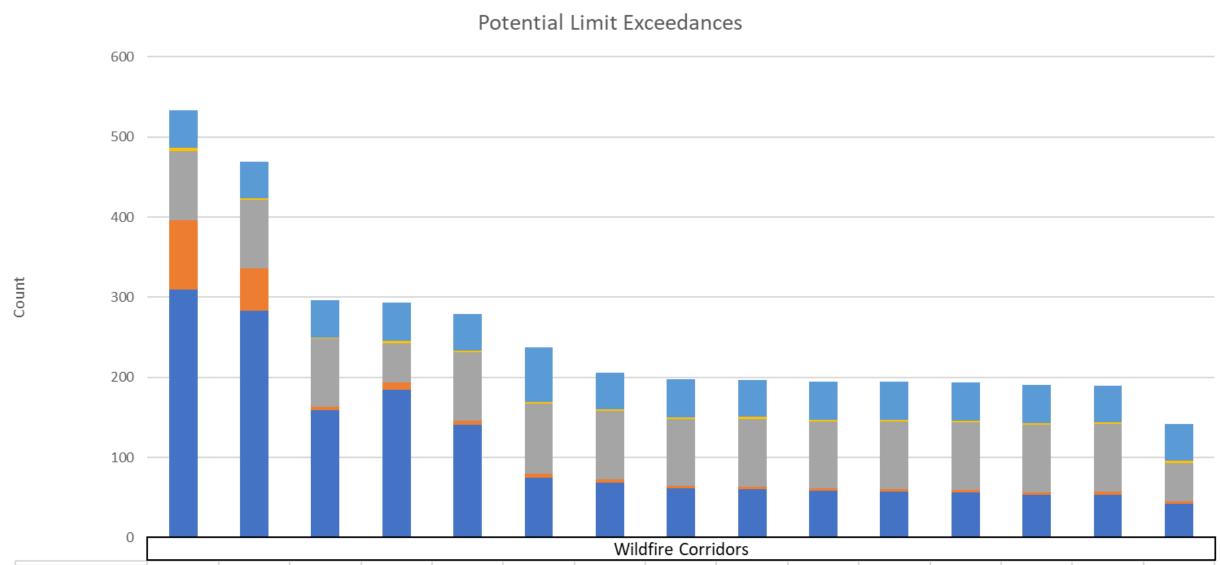


Figure 7: Wildfire Risk by County - Low (Green) to High (Red) (https://hazards.fema.gov/nri/wildfire)

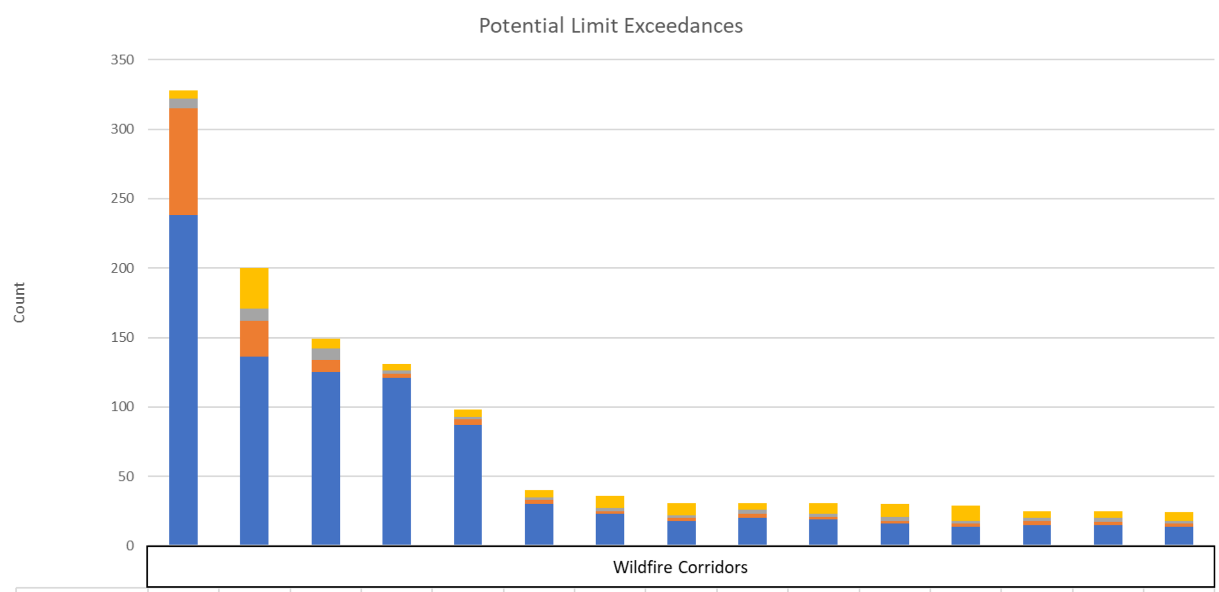
4.1. Results

A summary of the wildfire analysis is provided in Figure 8 (without cascading modelled) and Figure 9 (with cascading modelled).



Voltage Deviation	47	46	46	48	46	68	46	48	46	48	48	48	48	46	46
Unsolved	4	2	2	3	2	2	2	2	3	2	2	2	2	2	3
Bus Low Volts	86	85	85	48	85	87	85	84	85	84	85	85	85	85	48
Branch MVA	87	53	4	10	5	5	4	3	3	3	3	3	3	4	3
Branch Amp	309	283	159	184	141	75	69	61	60	58	57	56	53	53	42

Figure 8: Wildfire contingency violations by scenario, without cascading modelled



Voltage Deviation	6	29	7	5	5	5	9	9	5	8	9	11	5	5	6
Unsolved	7	9	8	2	2	2	2	2	3	2	3	2	2	3	2
Branch MVA	77	26	9	3	4	3	2	2	3	2	2	2	3	2	2
Branch Amp	238	136	125	121	87	30	23	18	20	19	16	14	15	15	14

Figure 9: Wildfire contingency violations by scenario, with cascading modelled

The participant utilities were provided the results from the study in order to produce operations plans, to prepare for these outages ahead of time.

4.2. Proposed Wildfire Mitigations

This section includes a summary of the wildfire plans proposed by the participating members.

4.2.1. Marion Corridor Wildfire

Initial state:

- Marion – Ashe 500, Marion – Buckley 500, Marion – John Day 500-kV lines are out of service due to fire mitigation
- This scenario is similar to one which occurred during the Beachie Creek fire in September 2020 https://www.fs.usda.gov/detailfull/willamette/fire/?cid=fseprd835368

Redispatch generation in the case:

- Reduce West of Cascades South (WOCS) path flow to about 4,300 MW by
    - Increasing US ACE Bonneville generation
    - Increasing available hydro and thermal generation on the I-5 corridor
    - Increasing imports from BC Hydro
    - Decreasing thermal, hydro and wind generation in the lower Columbia area (other than Bonneville)

Real-time operations:

- Real Time Study Engineers, coordinated by RC West and along with BPA, PGE and PacifiCorp, will develop specific operating plans as required by actual operating conditions.

The following planned projects will help with this wildfire scenario in long-term horizon:

- BPA Big Eddy – Chemawa 500-kV upgrade
- PGE Round Butte – Bethel 500-kV upgrade

4.2.2. Ostrander Corridor Wildfire

Initial state:

- Big Eddy - Ostrander 500, Big Eddy – Troutdale 230, Big Eddy – Chemawa 230, Big Eddy – McLoughlin 230 lines are out of service due to fire mitigation

Redispatch generation in the case:

- Reduce West of Cascades South (WOCS) path flow to about 4,650 MW by
  - Increasing US ACE Bonneville generation
  - Increasing available hydro and thermal generation on the I-5 corridor
  - Increasing imports from BC Hydro
  - Decreasing thermal, hydro and wind generation in the lower Columbia area

Real-time operations:

- Real Time Study Engineers, coordinated by RC West and along with BPA, PGE and PacifiCorp, will develop specific operating plans as required by actual operating conditions.

Mid-term solutions:

- Restore BPA North Bonneville – Alfalfa 230-kV line rating to 100C MOT (currently scheduled to be completed by end of 2026)
- Possible upgrade PGE Santiam – Bethel 230-kV line (3.6 mile)

The following planned projects will help with this wildfire scenario in long-term horizon:

- PGE Round Butte – Bethel 500-kV upgrade

5. Conclusions, Next Steps and Opportunities

5.1. Conclusions

The participating members assessed their systems for risks which may occur in an extreme heat wave, and an extreme cold snap, occurring in 2030. The analysis performed resulted in additional Corrective Action Plans (CAP) and operational plans, which are outlined in "3.3 Proposed Extreme Weather Mitigations" and "4.2 Proposed Wildfire Mitigations".

5.2. Next Steps and Opportunities

While performing this analysis, a few parallel efforts have been developing which indicate a need for further work analyzing heat waves and cold snaps.

- FERC 881: Ambient Adjusted Ratings (timeline: July 12th, 2025)
- NERC TPL-008: Transmission System Planning Performance Requirements for Extreme Temperature Events (under development by NERC as of April 2nd, 2024)

When FERC 881 ambient adjusted ratings (AAR) are implemented in operations (July 2025), transmission equipment will be derated hourly based on the local ambient weather conditions within each utility's footprint. While this study did perform a sensitivity with a generic "flat" derate to imitate a 120F (48.9C) temperature across the study region, a 120F temperature may be hotter than what may be experienced locally at each respective utility. In that case, the equipment ratings will likely be higher than what was studied in this report's sensitivity case. On the other hand, the generic derates could also not be low enough, especially in circumstances where transmission lines are limited to a max operating temperature (MOT) below 100C.

Additionally, further assessment of generation derates may be useful in future study efforts. This may include low hydro due to a drought, along with derates of thermal generation due to high ambient air temperatures which result in a lower Carnot efficiency.

The analysis performed in this study may also be useful toward future TPL-008 studies and development of standard extreme weather study practices.

6. Appendix: Corridor Definitions

This section describes all of the common corridors which were analyzed as a part of the wildfire analysis.

6.1. Corridor A: West of Cascades North (WOCN), Highway 2

Approximate Length: 60 miles

Elements:

- Anderson Canyon-Beverly Park 115 kV
- Chief Joseph-Snohomish #4 345 kV
- Chief Joseph-Snohomish #3 345 kV
- Chief Joseph-Monroe #1 500 kV

6.2. Corridor B: Chief Joseph-Central Washington

Approximate Length: 11 miles

Elements:

- Wells-Douglas #1 230 kV
- Wells-Douglas #2 230 kV
- Chief Joseph-Snohomish #4 345 kV
- Chief Joseph-Snohomish #3 345 kV
- Chief Joseph-Sickler #1 500 kV
- Chief Joseph-Monroe #1 500 kV

6.3. Corridor C: East Wenatchee Bench

Approximate Length: 8 miles

Elements:

- Rocky Reach-Columbia #1 230 kV
- Rocky Reach-Jumpoff Ridge #2 230 kV
- Rocky Reach-Maple Valley #1 345 kV
- Sickler-Schultz #1 500 kV
- Lincoln Rock-Urban Industrial 230 kV

6.4. Corridor D: Grand Coulee-Central Washington

Approximate Length: 70 miles

Elements:

- Columbia-Grand Coulee #1 230 kV
- Columbia-Grand Coulee #3 230 kV
- Grand Coulee-Schultz #2 500 kV
- Grand Coulee-Schultz #1 500 kV
- Olympia-Grand Coulee #1 287 kV

6.5. Corridor E: West of Cascades –North (WOCN), I-90

Approximate Length: 10 miles

Elements:

- Cascade-White River 230 kV
- Covington-Bettas Road #1 230 kV
- Cle Elum-Hyak 115 kV
- Rocky Reach-Maple Valley #1 345 kV
- Schultz-Raver #3 500 kV
- Schultz-Raver #4 500 kV
- Schultz-Echo Lake #1 500 kV
- Schultz-Raver #1 500 kV
- Olympia-Grand Coulee #1 287 kV

6.6. Corridor F: Central Washington-Ellensburg-North

Approximate Length: 14 miles

Elements:

- Rocky Reach-Cascade 230 kV
- Rocky Reach-Maple Valley #1 345 kV
- Sickler-Schultz #1 500 kV

6.7. Corridor G: Central Washington-Ellensburg-South

Approximate Length: 23 miles

Elements:

- Columbia-Ellensburg #1 115 kV
- Bettas Road-Columbia #1 230 kV
- Grand Coulee-Schultz #2 500 kV
- Grand Coulee-Schultz #1 500 kV
- Olympia-Grand Coulee #1 287 kV

6.8. Corridor H: North of McKenzie

Approximate Length: 1.4 miles

Elements:

- Jumpoff Ridge-Columbia 230 kV
- McKenzie-Andrew York #1 115 kV
- McKenzie-Jumpoff Ridge #2 115 kV
- Wenatchee-McKenzie 115 kV
- McKenzie-Jumpoff Ridge #1 115 kV
- Rapids-Valhalla 115 kV
- Rapids-Columbia 230 kV

6.9. Corridor I: West of Columbia

Approximate Length: 1 mile

Elements:

- Columbia-Ellensburg #1 115 kV
- Jumpoff Ridge-Columbia 230 kV
- Bettas Road-Columbia #1 230 kV
- Rapids-Columbia 230 kV
- Grand Coulee-Schultz #2 500 kV
- Grand Coulee-Schultz #1 500 kV
- Olympia-Grand Coulee #1 287 kV

6.10. Corridor J: North of Rapids

Approximate Length: 2.6 miles

Elements:

- Rocky Reach-Jumpoff Ridge #2 230 kV
- Pangborn-Rapids 115 kV
- Rocky Reach-Maple Valley #1 345 kV
- Sickler-Schultz #1 500 kV
- Urban Industrial-Rapids 230 kV

6.11. Corridor L: Raver-Covington

Approximate Length: 5.3 miles

Elements:

- Raver-Covington #1 500 kV
- Raver-Covington #2 500 kV
- Tacoma-Raver #2 500 kV
  Raver-Covington #3 230 kV

6.12. Skagit Wildfire

Approximate Length: 85 miles

Elements:

- Diablo-Bothell #1 230kV
- Diablo-Bothell #2 230kV
- Diablo-Bothell #3 230kV
- Diablo-Gorge / Gorge-North Mountain / North Mountain-Snohomish 230kV

6.13. Marion Corridor Fire

Elements:

- Marion – Ashe #2 525kV
- Marion – Buckley #1 525kV
- Marion – John Day #1 525kV

6.14. Ostrander Corridor Fire

Elements:

- Big Eddy – Ostrander #1 525kV
- Big Eddy – Parkdale #1 230kV
- Big Eddy – Chemawa #1 230kV
- Big Eddy – McLoughlin #1 230kV

7. Appendix: 2030 Extreme Study Scope 2022.10.06

Included below this page.

Western Power Pool 2030 Low Carbon, Extreme Weather Study Scope

October 6, 2022

Objective

The 2030 Low Carbon, Extreme Weather study ("Study") is an effort by a group of transmission owners and transmission planners operating in four western U.S. states and the province of Alberta to evaluate issues of common interest, which can best be studied jointly. The objective of the Study is to identify whether near-term transmission constraints exist under low carbon resource requirements and extreme weather. If constraints exist, the Study will identify solutions that may be implemented by 2030.

The participants initiated this Study as a way to facilitate joint sharing of information, increase the efficiency of the planning process in addressing longer-term outlook transmission requirements, and communicate to impacted utility planners, utility operators and regional stakeholders any identified concerns and potential solutions.

Relationship to Other Study Efforts

The purpose of the Study is to evaluate specific conditions and scenarios that are not otherwise already studied through other coordinated efforts. While the participants may freely utilize the Study results to inform other planning analyses, the Study is not intended to fulfill or replace any other transmission planning or resource planning requirements. Specifically, this Study will not address the full suite of NERC TPL-001-4 / TPL-001-5 requirements and Study results are provided in addition to, but not replacing, the participants' FERC Order 890 and 1000 regional planning requirements and NorthernGrid Enrolled Party tariffs. This Study in no way obligates NorthernGrid members to perform future studies as described in this Study scope document.

This Study is not a resource adequacy or economic congestion study. While a goal of the Study is to provide additional context around transmission and resource issues during extreme and highly constrained conditions, the Study is information in nature only and will not result in a regional transmission, local transmission, action, or construction plan.

Study Participants

The Study Participants are Avista, Bonneville Power Administration, Chelan PUD, Montana-Alberta Tie Line (MATL), Idaho Power, NorthWestern Energy, Portland General Electric, Puget Sound Energy, Seattle City Light, Snohomish PUD and Tacoma Power.

Stakeholder Participation

Study participants seek to engage state utility commissions, neighboring utilities and other stakeholders in scope development, assumptions, draft results and proposed solutions through multiple workshops. The goal of stakeholder participation is to help focus, inform and enhance the Study.

Study Horizon

The Study selected a planning year of 2030 to include expected clean energy public policy requirements and expected public policy driven electrification of carbon emitting sectors such as, water and space heating along with transportation. Load forecasting assumptions will include any known or expected customer preference assumptions (e.g. electric ferries, buses, aviation). The Study will also incorporate best estimates of demand side management, time of use pricing and smart charging that are anticipated to be implemented.

Planned Projects

Transmission projects with in-service dates prior to 2030 will be evaluated for inclusion or exclusion from the initial case by the utility or utilities most impacted by the project. Known projects from neighboring utilities outside of the Study footprint will be similarly evaluated. Projects with in-service dates of 2030 or later will be initially offline or removed from cases and evaluated as potential mitigation.

Participant Integrated Resource Plan (IRP) preferred portfolio resources, including resource additions and retirements, will be evaluated for inclusion or exclusion from the initial case by each respective participant. The assumed initial case resources will be documented in the Study report. Resource additions or retirements with action dates of 2030 or later will not be initially modeled but may be evaluated as potential mitigation. Future resources without specific siting locations in IRPs may be modeled at representative buses as determined by Study participants. Any such model assumptions used in the Study will not be indicative of preferred siting, ease of interconnection or feasibility of interconnection.

Low Carbon Assumptions

The Study will incorporate Public Policy requirements and goals such as Washington CETA and Oregon HB 2021, along with individual utility IRP goals and Load & Resource Forecasts, to represent a low carbon future for 2030. As a result of the combined requirements and goals, it is anticipated that electrification of vehicles and heating sources will have a significant impact on load profiles and distribution, as well as changing the coincidence of load peaks across the wider system. The assumptions used in the Study will also incorporate increased inverter-based resource interconnections, distributed energy resources, energy efficiency and demand-side management.

Scenarios

Extreme Heat

The Study will evaluate an extreme heat scenario representing a heat dome event on the west side of the Cascades ("Pacific NW"), concurrent with a widespread peak summer condition in the intermountain ("Inland") region. This scenario case will be developed by modifying the WECC 32HS1a power flow base case to represent 2030 projected load conditions based on a combination of historic load data and stressed (e.g. 1-in-20) utility load forecasts.

In the extreme heat scenario, an imbalance of wind between the Pacific NW and Inland regions will be represented, with minimal wind in the Pacific NW and high wind in select locations throughout the Inland region. Within heavy wind areas, more extreme contingencies may be considered due to potential for forced outages. A low hydro (10^{th} percentile) river availability will be modeled using BPA's power planning models and other data sources to supplement and/or replace ADS hydro assumptions. The Study will also aim to identify any resources that may have restricted or limited output due to the extreme temperatures, particularly wind turbines and solar generation facilities that have cut out ratings at or below 40° C (104° F).

Operationally "always credible" contingencies will be simulated to validate the performance of the system prior to, and following, any proposed system reinforcements. These contingencies will include single transmission lines and transformers, as well as select bus, breaker, overlapping contingencies and common-mode failure contingencies.

Transmission lines and transformers may be evaluated with reduced ratings, as determined by each individual transmission provider's facility ratings practice, for extreme temperature. These derates will be represented in the Study as alarming at a lower threshold. Facility ratings assumptions used in the Study will be documented in the report.

Extreme Cold

The Study will evaluate an extreme cold scenario representing an intense cold snap event in the Pacific NW, concurrent with a widespread peak winter condition in the Inland region. This scenario case will be developed by modifying the WECC 32HW1a1 power flow base case to represent 2029-30 projected load conditions based on a combination of historic load data and stressed (e.g. 1-in-20) utility load forecasts.

In the extreme cold scenario, the Pacific NW will be modeled at a light-wind condition. Historic records for wind coincidence with cold temperatures will be modeled for Alberta, Montana, Idaho and surrounding Inland regions. A low hydro (10^{th} percentile) river availability will be modeled using BPA's power planning models and other data sources to supplement and/or replace ADS hydro assumptions. This represents a system condition where the Study footprint is potentially reliant on significant imports from surrounding regions and provides the opportunity to evaluate the impacts of that reliance. The Study will also aim to identify any resources that may have restricted or limited output due to the extreme cold temperatures.

The Study will also seek to include any other lessons learned or issues identified for recent Texas events such as planned maintenance practices and generation availability. The Study may also evaluate impacts due to a lack of availability of natural gas (both generation facilities and natural gas pipeline availability) during the extreme cold, to the extent the system could still operate.

Operationally "always credible" contingencies will be simulated to validate the performance of the system prior to, and following, any proposed system reinforcements. These contingencies will include single transmission lines and transformers, as well as select bus, breaker and common-mode failure contingencies. The Study will additionally evaluate select regionally significant extreme contingencies, based on historical data or other known risks, to simulate more extreme events such as ice storms.

Transmission lines and transformers may be evaluated with either increased or decreased ratings, as determined by each individual transmission provider's facility ratings practice, for the extreme temperature and wind conditions. Facility ratings assumptions used in the Study will be documented in the report.

Wildfire Events

The Study will evaluate the potential impacts of widespread wildfire events following proactive Public Safety Power Shutoff ("PSPS") measures and extreme outage conditions. The purpose of this analysis will be to evaluate system integrity on a grid-level, the ability to continue to operate the grid following next contingencies and the risk of Cascading, islanding and uncontrolled separation. The Study will assume that local system restoration may be significantly delayed resulting in significant extended customer impacts. This Study will consider impacts on resource availability and the ability to reliably operate in the post-event state. Importantly, the Study may not address locally significant impacts or the effectiveness of individual utility PSPS plans.

Smog produced by wildfire may cause a temperature cooling effect in some locations. The wildfire case will be developed by modifying the WECC 32HS1a power flow base case to represent 2030 projected 80th percentile loads, or as appropriate based on SCADA and state estimator snapshots of recent historic events. This may be approached as a modification of the Extreme Heat case using simple scaling of loads.

Utility records, WECC reporting and other sources for historical information will be consulted for transmission lines and facilities that have been taken out as PSPS and as result of wildfire damages or power system constraints.

Based on recent wildfire events the Study will evaluate a minimum of two extreme outage condition scenarios. Additional scenarios may be evaluated as determined by Study participants and based on results seen in the extreme heat analysis.

Scenario 1: Forced outage of the Cross-Cascades transmission lines approaching BPA Ostrander substation.

- Simulate operationally "always credible" contingencies, determine how much of I-5 thermal generation is required to maintain reliable load service.

Scenario 2: Forced outage of the Cross-Cascades transmission lines approaching BPA Marion substation out of service (such as occurred in September 2020).

- Simulate operationally "always credible" contingencies, determine how much of I-5 thermal generation is required to maintain reliable load service

Existing Data Analysis

The participants will determine the extreme load level to be modeled by season. SCADA historical data and state estimator snapshots may be used as data sources to help inform the baseline case assumptions. Then the WECC 2032HS1, 2031-32HW1, and 2033LSP1 load levels will be analyzed and adjusted to the agreed extreme. Resources identified in the WECC 2022 Load and Resource data submission that have been added to buses in 2032ADS-Seed_Case will be dispatched based on 1.) the Production Cost Model (PCM) resource dispatch matching the power flow case hours, or 2.) a dispatch level specified by the participants.

Topology

- As determined by each transmission provider, the Study may consider evaluating certain existing planned projects as not being in-service initially, and then evaluating the ability to bring such projects online if the Study shows a need.
- Any planned generation facility retirements or modifications included in utility IRPs for 2030 will be included in the Study. If the Study identifies system constraints resulting from these planned generation facility retirements or modifications during extreme conditions, the constraints will be documented and potential mitigation options identified.
- The Study will consider preferred portfolio resources in 2032ADS-Seed_Case offline initially if case can accommodate and may need to model these preferred portfolio resources online in the initial case due to gas and wind resource availability assumptions. The Study will model transmission upgrades needed to integrate these preferred portfolio resources with the broader transmission grid and document these assumed integration upgrades, but will not seek to determine or model specific generation facility interconnection requirements.

Stressed Conditions

- The Study will consider appropriate interchanges with California and British Columbia based on historic data and entitlement obligations. This may include reduced exports in line with historic peak conditions and any expected changes due to continued energy policy needs. The area interchange assumptions and adjustments made to areas external to the Study footprint will be documented in the Study. While this is not a resource adequacy Study, the Study will seek to identify transmission constraints driven by resource availability internal to the Study footprint. Any potential need for increased reliance on neighboring systems will be documented and mitigation options internal to the Study footprint will be identified as alternatives to this increased reliance.
- Historic data sources for loads and resources may include all or some of the following:
  - PCM data to determine high coincidence conditions.
  - SCADA, PI-historian and other historical data records from participants
  - Temperature data from NOAA and other national weather data sources.

Identification of Transmission Mitigations and Solutions

The participants will propose transmission solutions to resolve reliability issues and transmission availability constraints. Transmission mitigations available by 2030 may include, but are not limited to, transmission rebuilds within existing rights-of-way, transformer additions/replacements, bus reconfigurations and upgrades, other flow control measures. The Study may also identify planned resource retirements or modifications that could result in reliability issues during the evaluated conditions. If the Study identifies system constraints resulting from these planned generation facility retirements or modifications during extreme conditions potential mitigation options may include, but are not limited to, resource additions, resource replacement or transmission reinforcement. Additionally, the ability to charge energy storage solutions will be evaluated to determine if the transmission system is adequate to both deliver power during peak times and supply storage resources during other hours.

The Study may also help to identify further transmission solutions that could provide longer-term mitigation but may require additional time beyond 2030 to fully plan, design, permit and construct.

The proposed mitigations and solutions will be evaluated in the scenarios for effectiveness and limitations. Stakeholder input will be sought on the proposed solutions and used to form the Study results and reporting.

Major Study Milestones

The Study will focus first on evaluation of the extreme heat and extreme cold scenarios and will use the results of those analyses to inform the model assumptions of the wildfire scenario.

Scoping

- Initial Stakeholder Engagement Workshop: August 18, 2022
- Draft Scope: September 8, 2022
- Stakeholder Scoping Workshop: September 22, 2022
- Pre-Final Study Scope: October 6, 2022
- Final Study Scope: October 20, 2022

Extreme Summer and Extreme Winter

- Initial Case Development: November 2022
- Initial Results: December 2022
- Develop Initial Mitigation Solutions: January 2023
- Stakeholder Workshop on Initial Results and Proposed Solutions: February 2023
- Analysis with Proposed Solutions: March 2023
- Draft Final Results and Report Workshop: April 2023
- Final Report: May 2023

Wildfire

- Develop Case from Extreme Summer Scenario: March 2023
- Initial Results, Develop Initial Mitigation Plans: May 2023
- Stakeholder Workshop on Initial Results and Mitigation Plans: June 2023
- Final Analysis: July 2023
- Draft Final Results and Report Workshop: August 2023
- Final Report: September 2023