# North Plains Connector (NPC) Evaluation

## Final Report

5/24/2024

**PREPARED FOR**

***Grid United***

**PREPARED BY**

*Astrapé Consulting*

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# ABBREVIATIONS USED IN REPORT

| | |
|---|---|
| BAA | Balancing Authority Area |
| BPAT | Bonneville Power Administration |
| CT | Combustion Turbine Generator |
| CPUC | California Public Utilities Commission |
| DR | Demand Response |
| EE | Energy Efficiency |
| EFOR | Equivalent Forced Outage Rate |
| EFORd | Equivalent Forced Outage Rate Demand |
| EIA | Energy Information Administration |
| ELCC | Effective Load Carrying Capability |
| FERC | Federal Energy Regulatory Commission |
| GDP | Gross Domestic Product |
| HVDC | High Voltage Direct Current |
| IRP | Integrated Resource Plan |
| IPCO | Idaho Power Company BAA |
| LFE | Economic Load Forecast Error |
| LOLE | Loss of Load Expectation |
| LRZ | MISO Load Resource Zone |
| NPC | North Plains Connector |
| NSRDB | National Solar Radiation Database |
| NWMT | NorthWestern Energy BAA |
| MISO | Midwest ISO |
| MW | Megawatt |
| NOAA | National Oceanic and Atmospheric Administration |
| NERC | North American Reliability Corporation |
| NREL | National Renewable Energy Laboratory |
| NSRDB | National Solar Radiation Database |
| PACE | Pacificorp East BAA |
| PACW | Pacificorp West BAA |
| PGE | Portland General Electric BAA |
| PO | Planned Maintenance Outage |
| SAM | System Advisor Model |
| SPP | Southwest Power Pool |
| TTF | Time to Fail |
| TTR | Time to Repair |
| SAM | NREL System Advisory Model |
| SERVM | Astrapé's Strategic Energy and Risk Evaluation Model |
| SPP | Southwest Power Pool |
| WECC | Western Electric Coordinating Council |
| WACM | Western Area Power Administration – Rocky Mountain Region BAA |
| WAUW | Western Area Power Administration – Upper Great Plains West Region BAA |

# EXECUTIVE SUMMARY

This document provides details concerning a study to evaluate the benefits associated with the addition of the North Plains Connector (NPC) project, a 3,000MW high voltage direct current (HVDC) transmission line between WECC and the Eastern Interconnection (EI) currently being developed by Grid United. The project was modeled as follows:

1. A 1,500MW HVDC transmission line connecting Southwest Power Pool (SPP) Zone 1 to NorthWestern Energy, and
2. A 1,500MW HVDC transmission line connecting Midwest ISO (MISO) Load Resource Zone (LRZ) 1 to NorthWestern Energy.

The following summarizes the results of this study.

## RESULTS

To quantify the capacity value of the LOLE benefit associated with NPC, the Effective Load Carrying Capability (ELCC) of the project was calculated. The NPC ELCC was determined by adding load in the three regions until the regional LOLE returned to their base case LOLE levels. This was an iterative process subject to interzonal and inter-regional impacts that make a precise determination difficult.

The analysis was performed by adding load only to the three zones NPC directly connects to (i.e., NWMT_WAUW, SPP Zone 1, and MISO LRZ 1). The figures below show the final resulting load additions and their impact on zonal and regional LOLE. The ELCC value by region is 1,800 in WECC, 1,350 MW in SPP, and 400 MW in MISO. Because most of the reliability benefit in WECC is during the winter and the east experiences most of its reliability benefit in the summer, the ELCC of the project, if added up individually across the three aggregated regions, is greater than 3,000 MW.

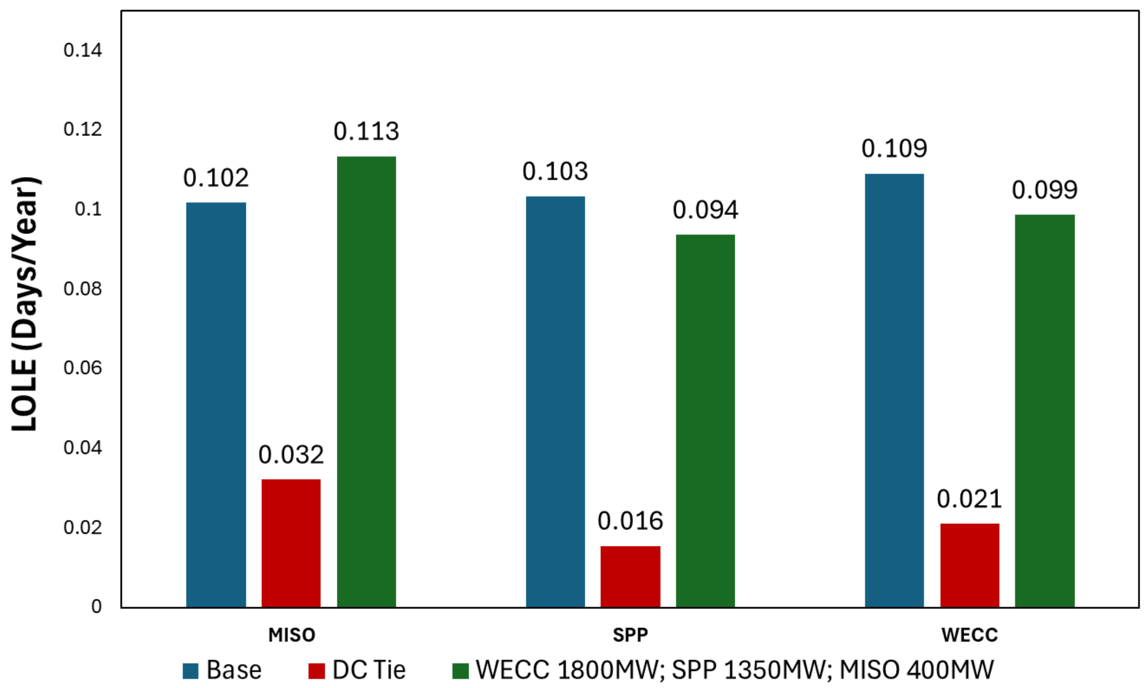


***Figure 1. ELCC Value of NPC***

As shown in the load modeling section, substantial load diversity exists among the zones which translates to the most reliability risk occurring in the summer for SPP and MISO and in the winter for WECC. The tables below show the base case EUE distribution, highlighting the diversity of risk between the three regions.

| WECC | Month | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hour of Day | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| 1 | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.2% |
| 2 | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.4% |
| 3 | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.7% |
| 4 | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 2.3% |
| 5 | 0.3% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.0% | 0.0% | 3.7% |
| 6 | 0.3% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.6% | 0.0% | 0.0% | 5.5% |
| 7 | 0.5% | 0.0% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.4% | 0.0% | 0.1% | 8.2% |
| 8 | 1.1% | 0.3% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.2% | 0.0% | 0.1% | 10.9% |
| 9 | 1.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 4.4% |
| 10 | 0.5% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.0% |
| 11 | 0.4% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.4% |
| 12 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% |
| 13 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 14 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 15 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 16 | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.3% |
| 17 | 0.2% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.0% | 0.0% | 0.0% | 2.0% |
| 18 | 0.8% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.0% | 0.0% | 0.0% | 5.1% |
| 19 | 1.0% | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 6.3% |
| 20 | 1.3% | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 7.2% |
| 21 | 1.2% | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 7.2% |
| 22 | 0.9% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 6.5% |
| 23 | 0.7% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.0% | 5.1% |
| 24 | 0.4% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 4.0% |

***Table 1. WECC Base Case EUE Distribution***

| MISO | | Month | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| Hour of Day | 1 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 2 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 3 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 4 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 5 | 0.0% | 0.5% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.1% | 0.0% |
| | 6 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 7 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 8 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 9 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 10 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 11 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 12 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.4% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 13 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.8% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 14 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 2.2% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 15 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.9% | 1.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 16 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 2.5% | 1.3% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 17 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 6.5% | 6.9% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 18 | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 11.1% | 7.9% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 19 | 0.2% | 0.3% | 0.0% | 0.0% | 0.0% | 0.0% | 6.4% | 4.2% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 20 | 0.1% | 0.9% | 0.2% | 0.0% | 0.0% | 0.0% | 3.0% | 4.4% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 21 | 0.1% | 0.8% | 0.9% | 0.0% | 0.0% | 0.0% | 5.0% | 14.6% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 22 | 0.0% | 0.4% | 0.0% | 0.0% | 0.0% | 0.0% | 2.2% | 3.5% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 23 | 0.0% | 0.3% | 0.0% | 0.0% | 0.0% | 0.0% | 1.4% | 2.7% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 24 | 0.0% | 0.5% | 0.0% | 0.0% | 0.0% | 0.0% | 1.6% | 1.9% | 0.0% | 0.0% | 0.0% | 0.0% |

***Table 2. MISO Base Case EUE Distribution***

| SPP | | Month | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| Hour of Day | 1 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 2 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 3 | 0.4% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 4 | 0.6% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 5 | 0.5% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 6 | 0.3% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 7 | 0.4% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 8 | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 9 | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 10 | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 11 | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.6% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 12 | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 4.8% | 0.9% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 13 | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 9.0% | 2.6% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 14 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 10.4% | 9.6% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 15 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 12.1% | 5.4% | 0.0% | 0.0% | 0.0% | 0.9% |
| | 16 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 9.9% | 2.8% | 0.0% | 0.0% | 0.0% | 1.4% |
| | 17 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 12.1% | 2.2% | 0.0% | 0.0% | 0.0% | 1.3% |
| | 18 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 4.6% | 0.0% | 0.0% | 0.0% | 0.0% | 2.0% |
| | 19 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.9% | 0.0% | 0.0% | 0.0% | 0.0% | 1.8% |
| | 20 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.4% |
| | 21 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 22 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 23 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 24 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |

***Table 3. SPP Base Case EUE Distribution***

# INTRODUCTION

The purpose of this document is to describe the analysis used to determine the resource adequacy value of the North Plains Connector project between Montana in WECC and North Dakota in the Eastern Interconnection.

## STUDY FRAMEWORK

This study was performed using Astrapé's Strategic Energy and Risk Evaluation Model (SERVM) and its associated study framework. The SERVM framework combines an hourly (i.e., 8760-hour) production cost model coupled with Monte Carlo outage simulations and comprehensive scenario management that considers load and weather uncertainty to determine key reliability parameters such as LOLE. The following describes the key parameters and uncertainties that are considered and how they are applied within the study framework.

### WEATHER UNCERTAINTY

To account for weather uncertainty, SERVM performs hourly production cost simulations using multiple historical weather years. The uncertainties that are modeled for each modeled weather year include hourly load shapes and renewable profiles. Load shapes for each weather year are developed to represent the expected future load response to the historical weather (temperatures). For example, a 1998 weather year represents how loads would respond if 1998 weather were to repeat during the given study year. These load shapes are then scaled so that the median of the peak demands from the various weather year load shapes equals the study year weather normal peak load forecast. For this study, load shapes were scaled such that their forecast matched the median of all available weather years. Similarly, renewable profiles are developed to represent the expected future availability associated with the historical weather profile. For purposes of this study, 43 weather year scenarios were simulated representing weather conditions for the years 1980-2022.

### ECONOMIC LOAD FORECAST ERROR

Economic Load Forecast Error represents the potential error in the weather-normal peak load forecast associated with uncertainty in economic forecasts. Using the Congressional Budget Office's historical forecasts for Gross Domestic Product (GDP), it is possible to predict both the magnitude and probability of error in the forecast of the GDP economic indicator three, four, or five years out into the future. This probability of error can then be converted into a Load Forecast Error (LFE). For this study, five LFE scenarios were chosen. These are described in the Model Development section of this document. Each of the 43 weather year scenarios are combined with each of the five LFE scenarios to create 215 unique load scenarios, or *cases*.

## MONTE-CARLO OUTAGE ITERATIONS

SERVM uses Monte-Carlo techniques to simulate generator outages. Multiple hourly production cost simulations are run for each of the 215 load cases. With each outage iteration, random Monte-Carlo draws are made to determine thermal generation outage profiles associated with that scenario. With enough iterations, the set of random outages for each thermal unit approaches that unit's expected EFOR. For this study, 6 outage draw iterations per case were used. The specifics associated with how these outages were modeled are detailed in the Model Development section of this document.

As shown in the figure below, the SERVM uncertainty framework used for this study required 1,290 hourly (8760-hour) production cost simulations for a single analytical run.

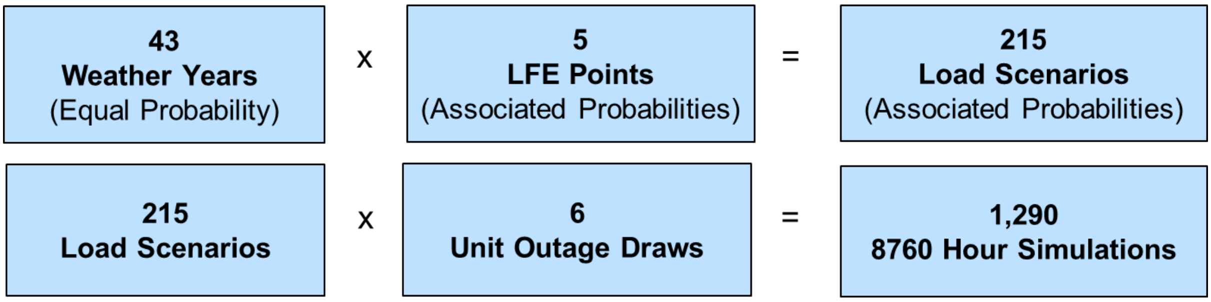


***Figure 2. SERVM Uncertainty Framework***

The Study Methodology section of this document describes the numerous "analytical runs" required to perform the analysis and its associated sensitivities.

# MODEL DEVELOPMENT

The SERVM data model utilized for this study was based upon a large scale, multi-regional model of the Pacific Northwest and Midwest that included the following load zones:

- Portions of the SPP Balancing Authority Area (BAA) that include
    - Zone 1,
    - Zone 2,
    - Zone 3, and
    - Zone 4;
- Portions of the MISO BAA that include
    - LRZ 1,
    - LRZ 2 and LRZ 7 combined,
    - LRZ 3 and LRZ 5 combined,
    - LRZ 4, and
    - LRZ 6;
- The combined areas of NorthWestern Energy (NWMT) and the Western Area Power Administration – Upper Great Plains West (WAUW);
- The combined areas of Bonneville Power Administration (BPAT), Puget Sound Energy, Avista Corporation, and several other smaller load serving entities in northwest Washington;
- Portland General Electric (PGE);
- Idaho Power Company (IPCO);
- Pacificorp East (PACE);
- Pacificorp West (PACW); and
- Western Area Power Administration – Rocky Mountain (WACM).

The figure below shows the topology of the interconnected system.

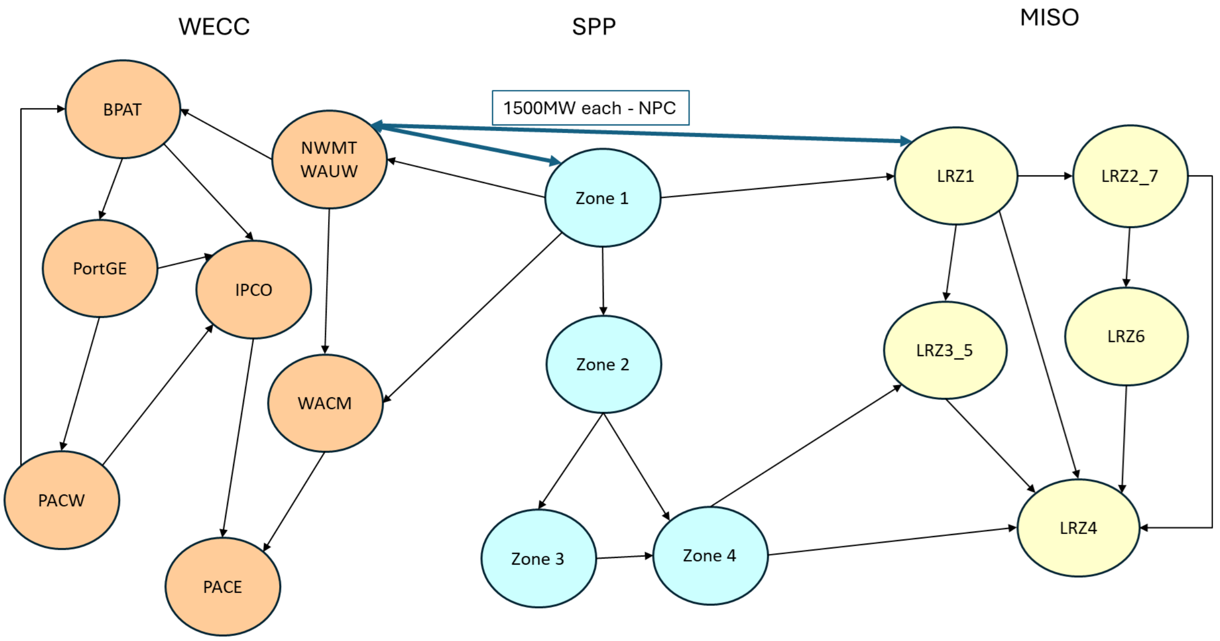


***Figure 3. Topology of the Interconnected System Including NPC***

## BASE CASE MODEL DEVELOPMENT

The basis for the model used for this analysis was a subset of the Astrapé Western Electric Coordinating Council (WECC) and Eastern Interconnection (EI) databases, both of which were developed using publicly available sources.

The WECC SERVM database was developed using the publicly available California Public Utilities Commission (CPUC) SERVM database, with updates as appropriate from the 2032 WECC Reliability Monitoring Anchor Dataset V2.3.2 as well as various publicly available Integrated Resource Plans (IRPs).

The EI SERVM database was developed using publicly available information from the 2022 U.S. Department of Energy's Energy Information Administration (EIA) Form 860, available documents from the North American Reliability Corporation (NERC), various publicly available Integrated Resource Plans (IRPs), and Federal Energy Regulatory Commission (FERC) Forms.

Additionally, for zones within MISO, future generation was established based on the MISO Future 2A expansion plan.

The following sections describe this development process in more detail.

## PEAK DEMAND FORECAST

For the WECC region, peak demand forecasts for 2032 were taken from the load shapes provided as part of the WECC dataset. For those modeled zones that were a combination of two or more BAAs (e.g., the combination of NWMT and WAUW), hourly load shapes from specific zones in the dataset were combined so that a coincident peak load could be determined.

For the SPP region, peak demand forecasts for 2032 were derived from data taken from the “2023 SPP Resource Adequacy Report” published June 15, 2023. From that report, peak demands for each load serving entity within SPP were assigned to their respective zones, and a diversity calculation performed based upon the published SPP-wide peak demand. From those values, peak demands for each of the four modeled SPP zones were calculated.

For the MISO region, peak demand forecasts for 2032 were derived from the MISO Future 2A analysis. These values came from the Long Range Transmission Planning Workshop held on April 28, 2023. The "Futures 2A" forecasts were used and can be found in the document titled "20230428 LRTP Workshop Item 03b All Futures Load Forecast Summary.xlsx" that can be accessed through the MISO website. Zones that were modeled together had their peak demand forecasts combined. A final adjustment was made to the peak loads for EE. EE capacity was subtracted from the peak demand forecasts in each zone. The EE values removed were from the MISO Future 2A found in the "MISO Futures Report Series 1A" published on November 1, 2023.

The figures below show the zonal peak demands modeled for 2032 for each of the three regions.

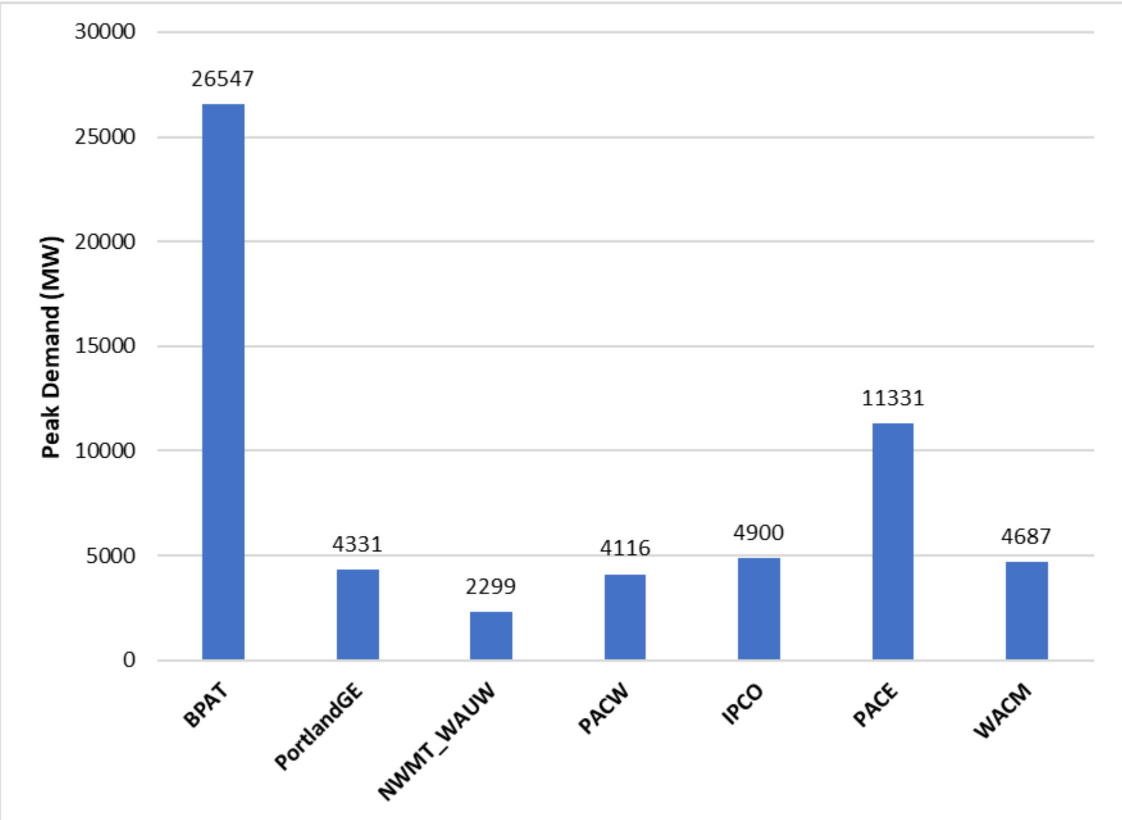


***Figure 4. WECC Modeled Peak Demands***

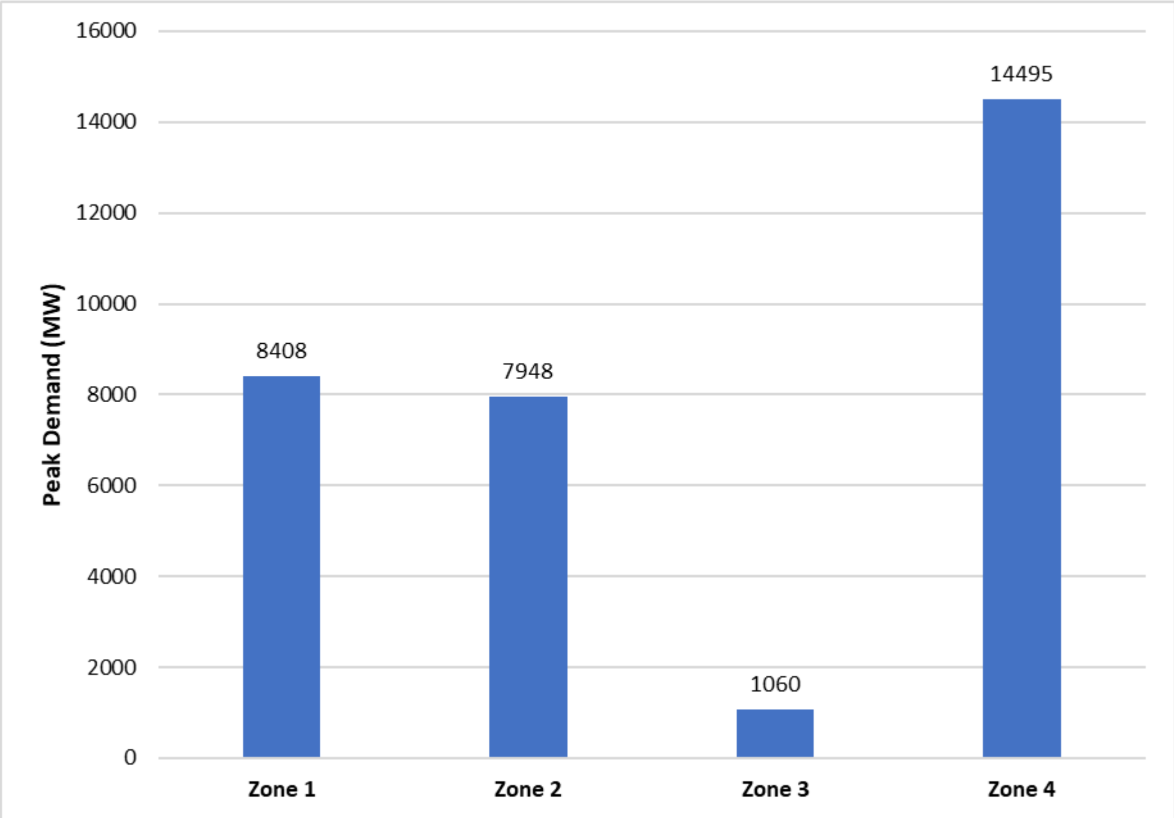


***Figure 5. SPP Modeled Peak Demands***

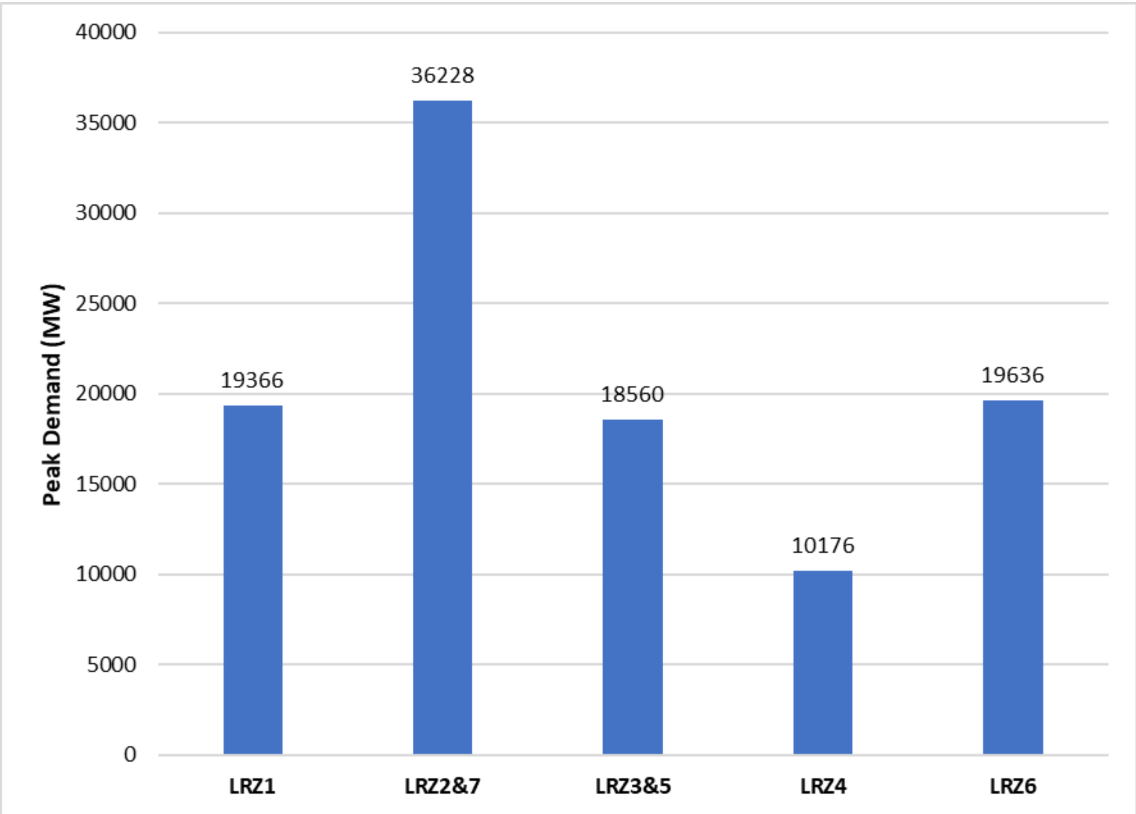


***Figure 6. MISO Modeled Peak Demands***

## LOAD MODELING

As described in the Study Framework subsection above, load shapes were developed for each of the 43 study years 1980-2022 for each zone. For most zones, these load shapes were developed based on trends and relationships between load and weather for the five historical years 2018-2022.

The loads were adjusted to a common economic basis by removing economic bias. This bias was removed from the load shapes by adjusting the loads on a seasonal basis so that the highest load hours of each season were consistent across the historical period.

The five historical load shapes were imported in a neural network that was trained using hourly historical temperatures from the National Oceanic and Atmospheric Administration (NOAA) and other key variables including 8-hour average load, 24-hour average load, 48-hour average load, hour of week, and hour of day. The temperatures used were based on weather stations in major load centers for each zone. The training resulted in neural networks for the summer, winter, and spring/fall seasons.

Temperatures from NOAA were downloaded for the remaining weather years (primarily 1980-2017) for each zone. These temperatures, along with the other associated variables developed from them, were then entered into the neural network for the appropriate season to create synthetic load shapes. Because some of the historical weather years may contain extreme temperatures outside the range of the neural networks, loads for extreme temperatures were created using a manually calculated regression trend from the most extreme temperatures in the historical dataset.

The synthetic load shapes were then quality checked against the actual historical shapes to ensure their validity.

The development of the 43 synthetic load shapes results in a diverse set of annual peak loads. Within SERVM, these shapes were scaled such that the median of the peaks from all the weather years would equal the forecasted peak load.

The regional diversity of these loads is illustrated for both the summer and winter seasons in the tables below. The percentage values in the tables represent how far a region is below its peak load during the hours where the specific region listed in each row is at its peak load. For example, in the summer, WECC is 14% below its peak forecasted load during hours when MISO is at peak load for the year.

***Table 4. Summer Regional Load Diversity***

| Summer | System | WECC | MISO | SPP |
|---|---|---|---|---|
| **System is Peaking** | 0% | 8% | 2% | 4% |
| **WECC is Peaking** | 8% | 0% | 16% | 17% |
| **MISO is Peaking** | 3% | 14% | 0% | 8% |
| **SPP is Peaking** | 5% | 15% | 8% | 0% |

***Table 5. Winter Regional Load Diversity***

| Winter | System | WECC | MISO | SPP |
|---|---|---|---|---|
| **System is Peaking** | 0% | 4% | 2% | 4% |
| **WECC is Peaking** | 4% | 0% | 9% | 4% |
| **MISO is Peaking** | 3% | 14% | 0% | 8% |
| **SPP is Peaking** | 2% | 8% | 4% | 0% |

## ECONOMIC FORECAST ERROR

As described in the Study Framework subsection of the Introduction section of this document, five LFE multipliers with their associated probabilities were applied to each of the 43 historical load shapes. The LFE multipliers simulate the expected probability that the peak demand forecast would be missed because of errors in the forecast of economic growth. The multipliers were developed by looking at the historical error in the 4-year out forecast GDP assuming a peak demand sensitivity to changes in GDP of 0.4% per 1% change in GDP. The set of LFE multipliers along with their probability of occurrence used in this study are shown in the table below with a graphic representation in the figure that follows.

***Table 6. LFE Model***

| LFE | Probability |
|---|---|
| -4% | 7.9% |
| -2% | 24.0% |
| 0% | 36.2% |
| 2% | 24.0% |
| 4% | 7.9% |

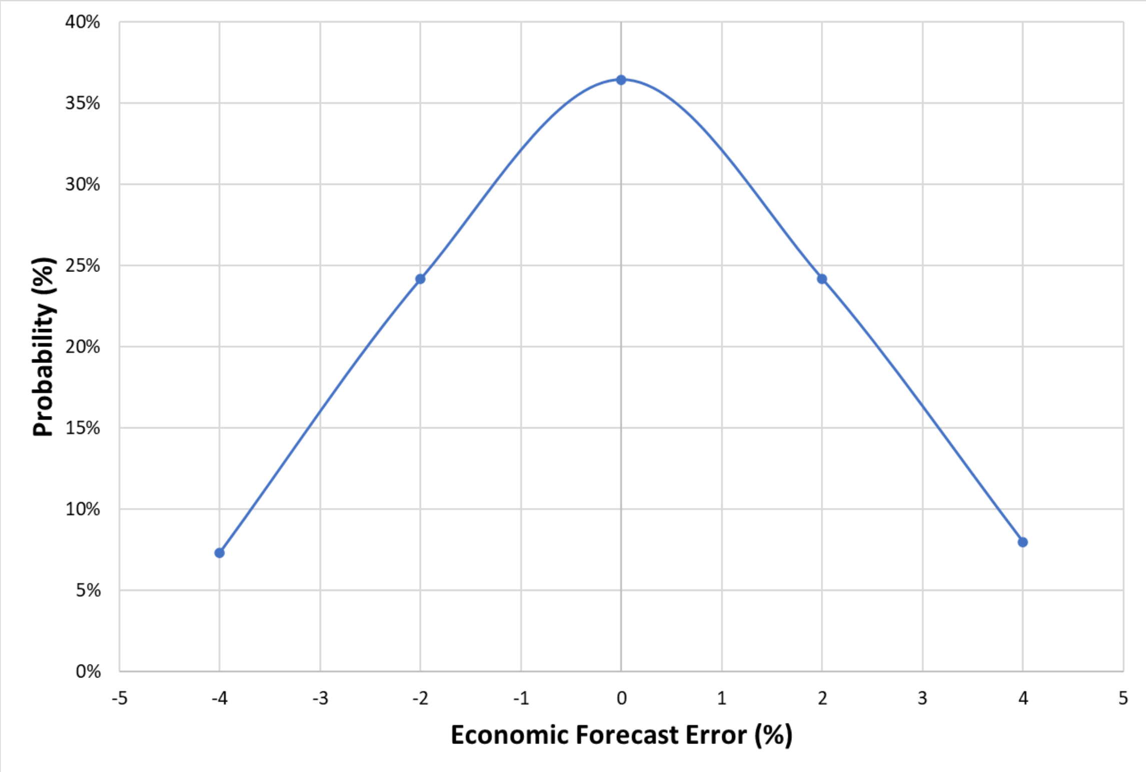


***Figure 7. LFE Model***

## CONVENTIONAL RESOURCE MODELING

As described in the introduction to the Base Case Model Development section above, the list of existing conventional generation facilities came from either the WECC dataset or the EIA Form 860, depending upon the zone. These public sources provided the resource name, minimum and maximum capacity in MW, resource type, in-service date, retirement date if known, and fuel source.

For other variables, such as minimum uptime, minimum downtime, heat rate, startup profiles and cost, etc., generic assumptions were developed by unit size and class. These assumptions were applied consistently across all zones.

The following charts show the zonal capacity mixes of each of three regions followed by a regional generation mix summary.[1] For comparison purposes, the peak load for each zone/region is superimposed on the generation mix graph as indicated.

[1] Charts show final capacity mix after calibration as described in the Study Methodology and Results section.

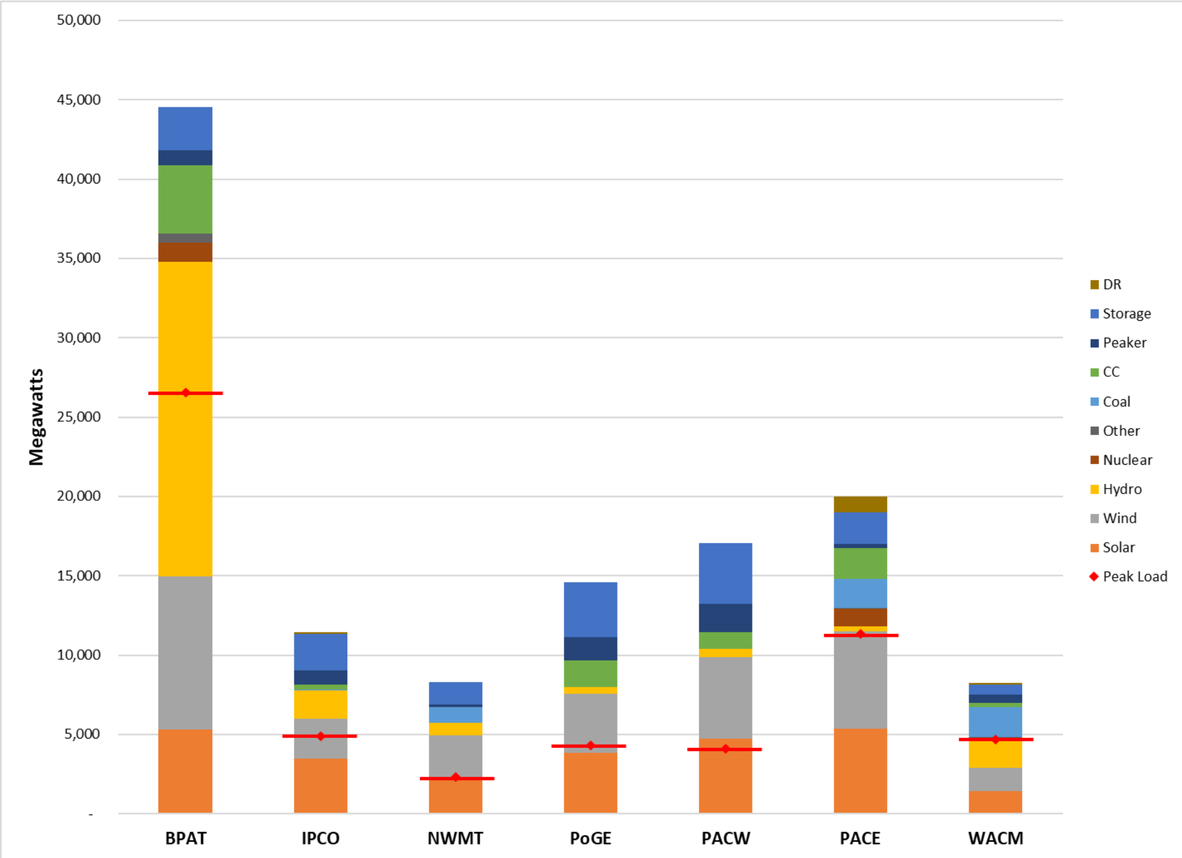


***Figure 8. WECC Zonal Generation Mix***

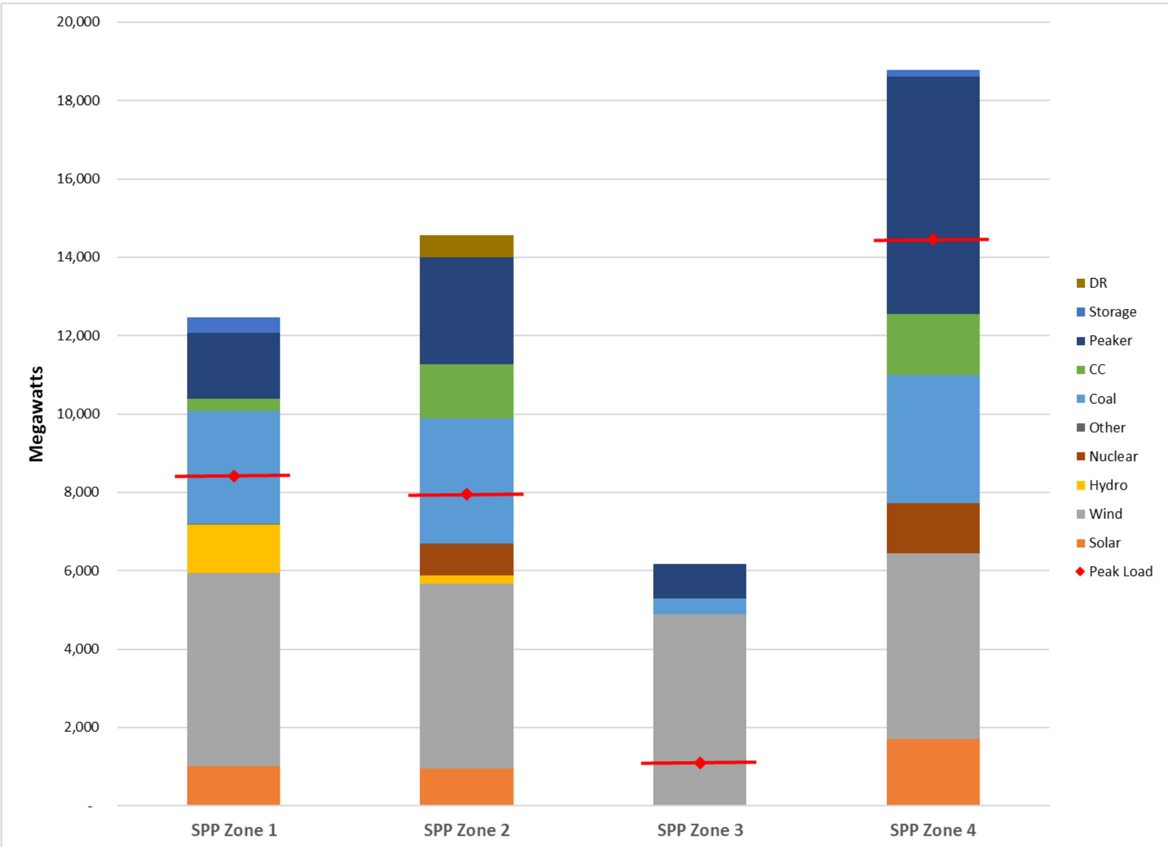


***Figure 9. SPP Zonal Generation Mix***

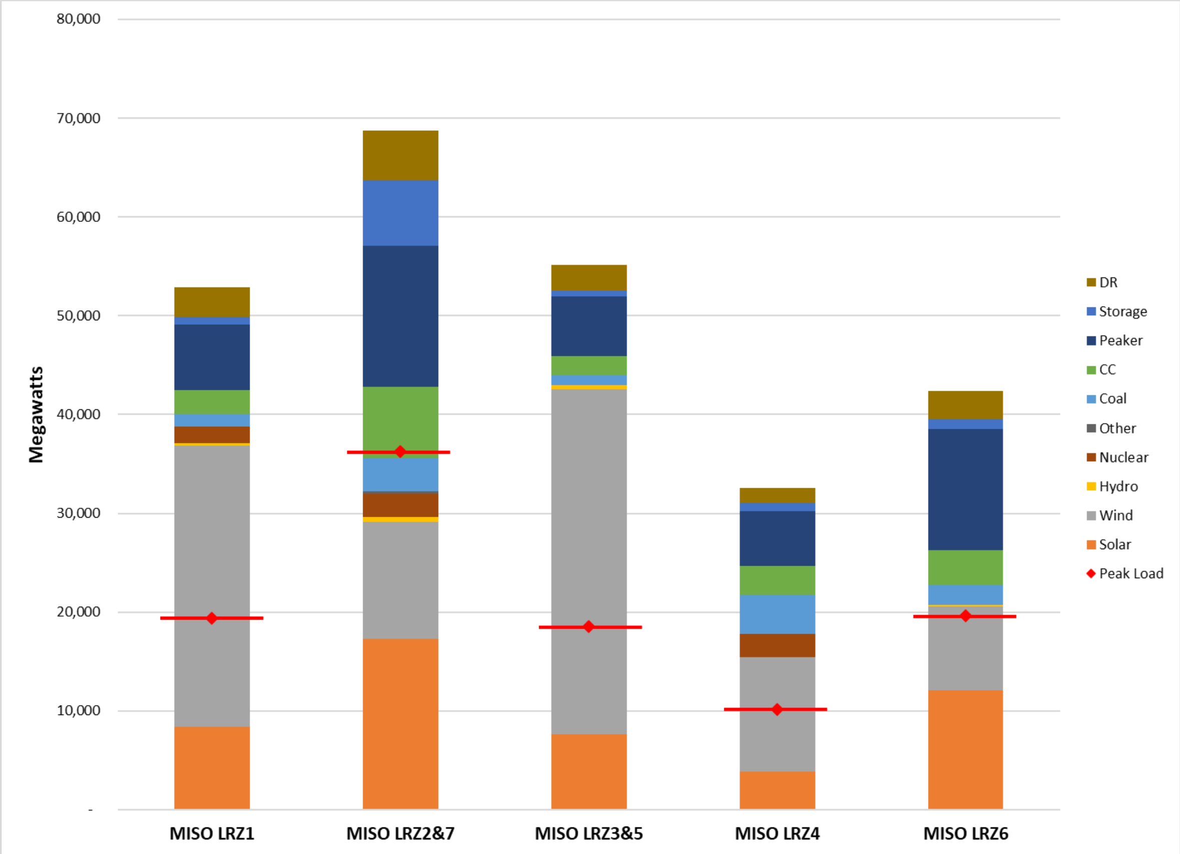


*Figure 10. MISO Zonal Generation Mix*

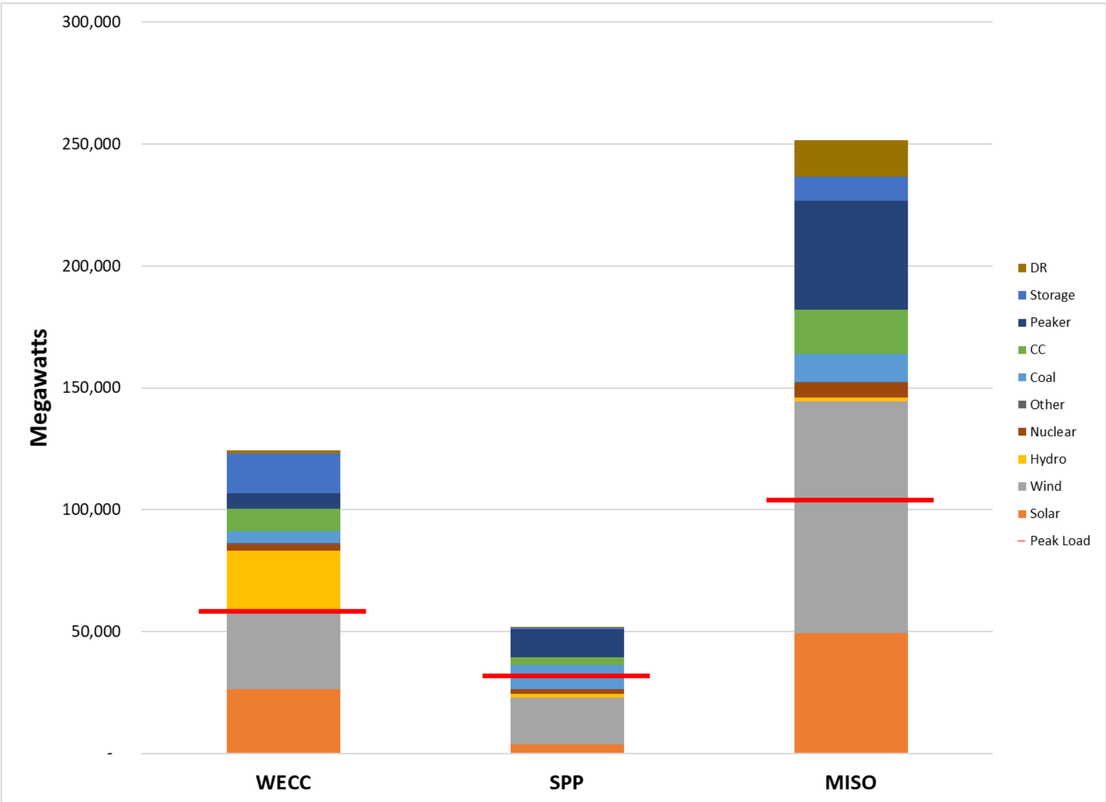


*Figure 11. Regional Generation Mix*

## OUTAGE MODELING

Outage modeling consisted of two primary types of outages, planned maintenance outages (PO), and forced outages.

**Planned Maintenance –** SERVM schedules planned maintenance by finding periods across the year where outage risk is minimized. Maintenance is scheduled such that the total hours offline for maintenance equals the assumed planned maintenance rate. Planned maintenance rates for the thermal resources modeled were based upon class specific rates as reported in the NERC Generating Unit Statistical Brochure for 2018-2202.

**Forced Outages –** SERVM models forced outages using multiple sets of time to fail (TTF) and time to repair (TTR) inputs for both full and partial outages. Each resource has its own set of TTF and TTR inputs that are used to establish that resource's EFOR. Using Monte-Carlo techniques, a TTF value is chosen randomly for each generating resource. That resource is then allowed to operate until it reaches the TTF threshold, at which point it is forced offline. Once it is forced offline, a TTR value is chosen randomly to determine how long the resource will be unavailable. That resource remains offline until it reaches the TTR threshold, at which point it is once again made available and a new TTF variable is chosen for the resource. With sufficient Monte-Carlo iterations, the EFOR of the resource converges to its expected value.

Targeted EFOR values were developed based on class specific EFOR or in the case of CTs, EFORd, as reported in the NERC Generating Unit Statistical Brochure for 2018-2022. To get desired EFOR rates for batteries across both charging and discharging hours, EFOR targets for batteries were assumed to be 10%. Distributions of TTR and TTF values were created that produced the targeted EFOR values for each thermal and storage resource in the model.

## FUEL COSTS

Fuel costs were based upon the forecasted fuel prices as found in the December 11, 2023 EIA U.S. Regional Natural Gas Prices report (EIA Historical Prices) and the December 11, 2023 EIA Total Energy Supply, Disposition, and Price Summary Report (EIA Forecasted Prices).

Henry Hub nominal forecasted natural gas prices from the EIA Forecasted Prices report were converted into regional natural gas prices based on the ratio of the 2024 project regional prices to the 2024 projected Henry Hub price from the EIA Historical Prices. West Texas Intermediate spot oil prices from the EIA Forecasted Prices report were converted into $/MMBtu delivered oil prices based on MMBtu/Barrel conversion of 5.8. Delivered coal prices were taken directed from EIA Forecasted Prices report.

Because the primary purpose of the study was to understand the physical reliability benefits of the project, the fuel prices and therefore economics are simply incorporated to provide a reasonable commitment and dispatch of resources for each zone.

## SOLAR RESOURCE MODELING

To create the solar profiles for regions in the EI database, irradiance data for multiple locations in each state were downloaded from the NREL National Solar Radiation Database (NSRDB) Data Viewer for the years 1998 to 2017.[2] The data obtained from the NSRDB Data Viewer was input into NREL's System Advisor Model (SAM) for each year and location to generate the hourly solar profiles based on the solar weather data for fixed and tracking solar plants. [3] Solar profiles for 1980 to 1997 and 2018 to 2022 were selected by using the daily solar profiles from the day that most closely matched the region peak load out of all the days +/- 2 days of the source day for the 1998 to 2017 interval. The profiles for the remaining years 1998 to 2017 came directly from the solar shape output data from SAM.

For WECC zones, solar profiles had already been developed by the CPUC for the years 1998-2017. For these zones, Astrapé used the same load matching process to create solar profiles for 1980-1997 and 2018-2022.

## WIND RESOURCE MODELING

Wind profiles were created for WECC, SPP, and MISO regions using historical data and a matching process to cover the entirety of weather years used in the simulation. WECC wind profiles were found on the CPUC website for 1998 to 2020 weather years.[4] SPP profiles were based on hourly data for 2016 to 2018 from the SPP website for all of SPP. MISO profiles are based on historical data for 3 zones (LRZ1, LRZ 2,7, and LRZ3-6) from 2016 to 2018.

Using these historical wind datasets, the profiles were expanded to cover all weather years (1980-2022). To do this, Astrapé used the aforementioned SPP, MISO, and WECC load profiles from 1980-2022. Wind profiles for missing weather years were selected by using the daily profiles from the day that aligned best with the peak load out of all the days +/- 15 days of the source day that was available in the historical data for each region, respectively. The profiles for the years that historical data was present were kept the same. The first two hours and last two hours of each day were smoothed using a rolling average.

## STORAGE RESOURCE MODELING

Battery storage modeling includes relevant unit characteristics such as storage capacity, charging capacity, and round-trip efficiency. If storage capacity was not known, four hours was assumed. Charging capacity was assumed to be the same as nameplate capacity and round-trip efficiency was generally assumed to be 85%.

[2] https://maps.nrel.gov/nsrdb-viewer/
[3] https://sam.nrel.gov/
[4] See the "Normalized Renewable Hourly Profiles" link at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/system-reliability-modeling-datasets-2023

Most battery storage resources were modeled as being available for economic arbitrage. However, during times of reliability risk, the economic arbitrage schedule was allowed to deviate so that the batteries would be discharged to avoid loss of load if storage capacity was available. This deviation was set to occur prior to the calling of demand response resources.

### HYDRO RESOURCES

Available hydro data from 1980 to 2022 was collected from the U.S. Energy Information Administration Form 923. In addition, hourly hydro data was downloaded from each region's website where the information was publicly available. From this data, the average daily minimum and maximum dispatch levels, the total monthly energy, as well as the monthly maximum dispatch levels were identified. Minimum and maximum daily dispatch levels and monthly maximum dispatch levels were defined as a function of monthly total energy and trended. The trended curve fit equations were then applied to historical energy from the monthly energies calculated in the EIA form. For zones where hourly generation was unavailable, the closest zone with hourly hydro generation available was scaled by capacity and then applied to the monthly generation from the EIA form.

SERVM optimally schedules the hourly hydro energy while respecting these constraints. The daily maximum and minimum dispatch and monthly maximum dispatch in conjunction with the total monthly energy are parameters that go into the determination of the hourly hydro schedule. The daily minimum hydro dispatch is scheduled at the minimum load hour of the day, and the daily maximum hydro is scheduled at the maximum load hour of the day. The monthly maximum hydro is scheduled at the max load hour of the month.

### ANCILLARY SERVICES MODEL

For consistency across regions, ancillary services were set as per the table below for all zones.

***Table 7. Ancillary Services Model***

| Ancillary Service | % of Load |
|---|---|
| **Regulating Reserves (Up/Down)** | 1.5 |
| **Spinning Reserves** | 3 |
| **Quick Start Reserves Requirement** | 3 |
| **Quick Start Reserves Target** | 1 |
| **Load Following Reserves** | 3 |

The model was set to maintain both Regulating Reserves and Spinning Reserves during load shed events.

## STUDY APPROACH AND RESULTS

The objective of this study was to determine the capacity benefit associated with adding the 3,000MW North Plains Connector project between the Pacific Northwest and both of SPP and MISO. The project was modeled as two 1,500MW ties: the first connecting SPP Zone 1 to NorthWestern Energy, and the second connecting MISO LRZ 1 to NorthWestern Energy.

## BASE CASE CALIBRATION

To establish a baseline level of reliability, each modeled region (i.e. WECC, SPP, MISO) was calibrated so that its Loss of Load Expectation (LOLE) approximated 0.1 days/year. Because of the interactions between zones within the region, it was impractical to calibrate all zones precisely to 0.1 day/year. Rather, the goal was to get the zones as close to 0.1 as possible.

In the WECC and SPP regions, for those zones that had LOLE greater than 0.1 days/year, calibration was performed by adding a combination of solar, wind, battery, and combustion turbine (CT) resources. This was done on an iterative trial and error basis, with initial emphasis being on solar, wind, and battery until incremental additions provided little additional LOLE benefit. In the MISO region, where the MISO Future 2A plan already considered significant renewable and energy storage additions, CT resources were added to those zones that had LOLE greater than 0.1 days/year. In all regions, for zones that had LOLE less than 0.1 days/year, coal resources were retired until LOLE approached 0.1 days/year.

Once individual zones were within a reasonable range of 0.1 days/year, a weighted average LOLE was calculated for each region (WECC, SPP, and MISO) to facilitate final calibrating as well as for purposes of the NPC analysis. This was done because calibrating on a regional weighted average basis is more stable than doing so on an individual basis.

The figure below shows the final zonal calibrated LOLEs.

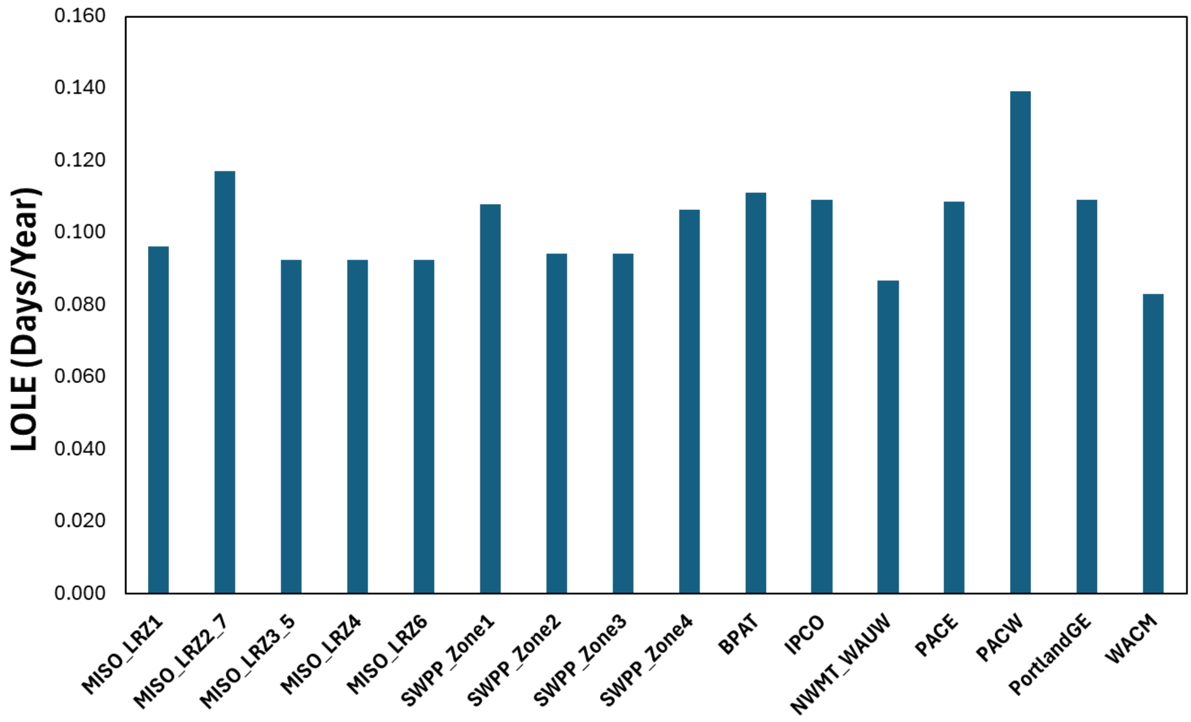


***Figure 12. Base Case Zonal Calibration***

Because SPP and MISO are co-dispatched as single regions, any differences in LOLE between their respective zones are the result of internal transmission limitations. Differences in LOLE between the WECC zones are due to interactions between the zones that make simultaneously calibrating all zones to 0.1 days/year difficult. However, the final results for each zone were near the 0.1 target. Aggregating the LOLE results into regional weighted averages mitigates these impacts.[5] The figure below shows the regional, weighted average LOLE.

[5] Regional weighted averages were calculated as the peak-demand weighted average of the zonal LOLE.

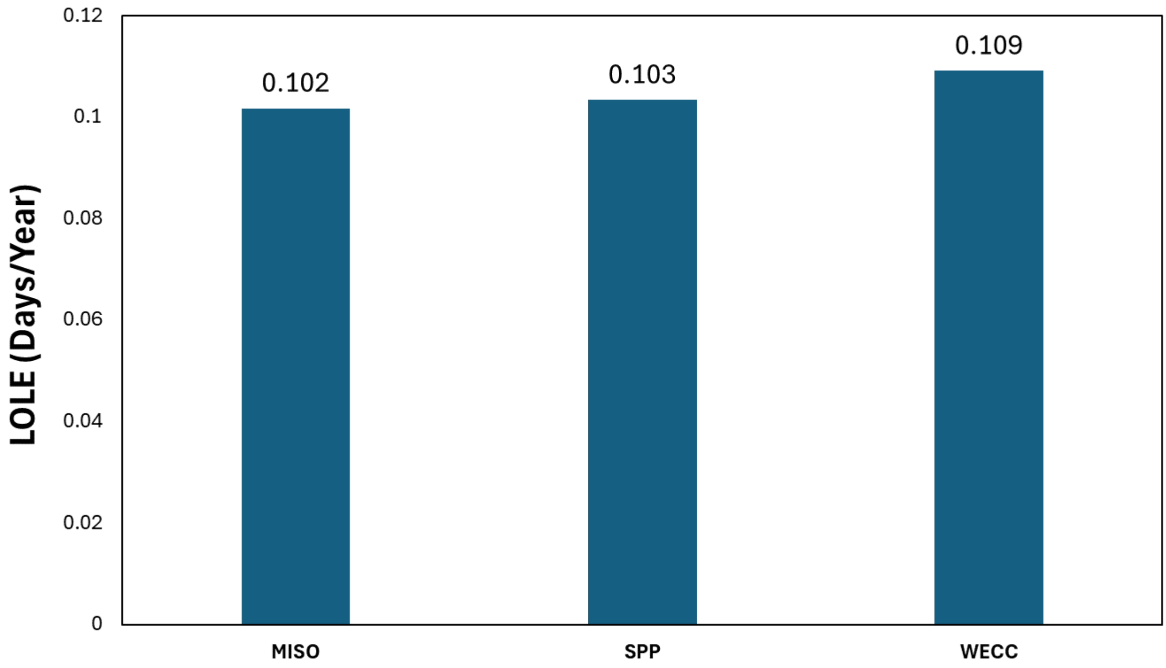


***Figure 13. Base Case Regional Calibration***

## LOLE IMPACT OF NPC

NPC was then added to the calibrated base case to determine the impact the project would have on both zonal and regional reliability. Figures 14 and 15 show the zonal and regional impact of the project as compared to the base case. As expected, given the large footprint the ties are connecting there was significant reliability benefit in all zones.

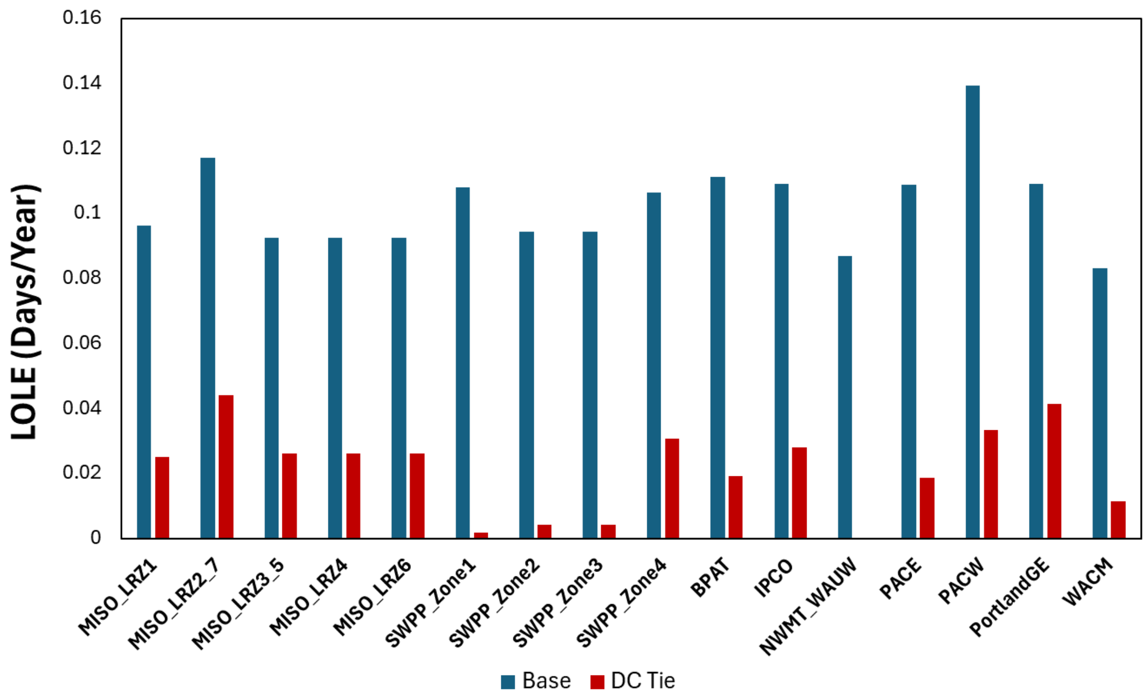


***Figure 14. NPC Zonal LOLE Impact***

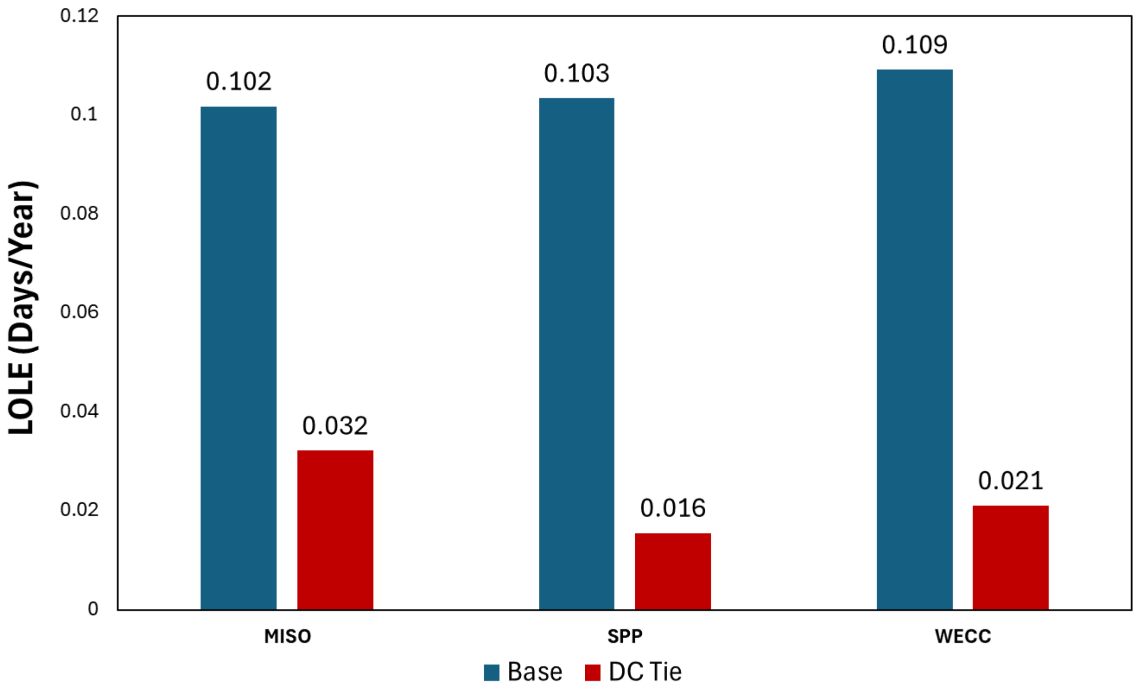


***Figure 15. NPC Regional LOLE Impact***

As shown in the load modeling section, substantial load diversity exists among the regions with most reliability risk occurring in the summer for SPP and MISO and winter risk in WECC. The tables below show the base case EUE distribution, highlighting the diversity between the three regions.

| WECC | | Month | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| Hour of Day | 1 | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.2% |
| | 2 | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.4% |
| | 3 | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.7% |
| | 4 | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 2.3% |
| | 5 | 0.3% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.0% | 0.0% | 3.7% |
| | 6 | 0.3% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.6% | 0.0% | 0.0% | 5.5% |
| | 7 | 0.5% | 0.0% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.4% | 0.0% | 0.1% | 8.2% |
| | 8 | 1.1% | 0.3% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.2% | 0.0% | 0.1% | 10.9% |
| | 9 | 1.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 4.4% |
| | 10 | 0.5% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.0% |
| | 11 | 0.4% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.4% |
| | 12 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% |
| | 13 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 14 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 15 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | 16 | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.3% |
| | 17 | 0.2% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.0% | 0.0% | 0.0% | 2.0% |
| | 18 | 0.8% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.0% | 0.0% | 0.0% | 5.1% |
| | 19 | 1.0% | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 6.3% |
| | 20 | 1.3% | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 7.2% |
| | 21 | 1.2% | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 7.2% |
| | 22 | 0.9% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 6.5% |
| | 23 | 0.7% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.0% | 5.1% |
| | 24 | 0.4% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 4.0% |

***Figure 16. WECC Base Case EUE Distribution***

| MISO | Month | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hour of Day | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| 1 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 3 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 4 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 5 | 0.0% | 0.5% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.1% | 0.0% |
| 6 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 7 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 8 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 9 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 10 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 11 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 12 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.4% | 0.0% | 0.0% | 0.0% | 0.0% |
| 13 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.8% | 0.0% | 0.0% | 0.0% | 0.0% |
| 14 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 2.2% | 0.0% | 0.0% | 0.0% | 0.0% |
| 15 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.9% | 1.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 16 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 2.5% | 1.3% | 0.0% | 0.0% | 0.0% | 0.0% |
| 17 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 6.5% | 6.9% | 0.0% | 0.0% | 0.0% | 0.0% |
| 18 | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 11.1% | 7.9% | 0.0% | 0.0% | 0.0% | 0.0% |
| 19 | 0.2% | 0.3% | 0.0% | 0.0% | 0.0% | 0.0% | 6.4% | 4.2% | 0.0% | 0.0% | 0.0% | 0.0% |
| 20 | 0.1% | 0.9% | 0.2% | 0.0% | 0.0% | 0.0% | 3.0% | 4.4% | 0.0% | 0.0% | 0.0% | 0.0% |
| 21 | 0.1% | 0.8% | 0.9% | 0.0% | 0.0% | 0.0% | 5.0% | 14.6% | 0.0% | 0.0% | 0.0% | 0.0% |
| 22 | 0.0% | 0.4% | 0.0% | 0.0% | 0.0% | 0.0% | 2.2% | 3.5% | 0.0% | 0.0% | 0.0% | 0.0% |
| 23 | 0.0% | 0.3% | 0.0% | 0.0% | 0.0% | 0.0% | 1.4% | 2.7% | 0.0% | 0.0% | 0.0% | 0.0% |
| 24 | 0.0% | 0.5% | 0.0% | 0.0% | 0.0% | 0.0% | 1.6% | 1.9% | 0.0% | 0.0% | 0.0% | 0.0% |

***Figure 17. MISO Base Case EUE Distribution***

| SPP | Month | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hour of Day | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| 1 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 3 | 0.4% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 4 | 0.6% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 5 | 0.5% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 6 | 0.3% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 7 | 0.4% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 8 | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 9 | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 10 | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 11 | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.6% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 12 | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 4.8% | 0.9% | 0.0% | 0.0% | 0.0% | 0.0% |
| 13 | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 9.0% | 2.6% | 0.0% | 0.0% | 0.0% | 0.0% |
| 14 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 10.4% | 9.6% | 0.0% | 0.0% | 0.0% | 0.0% |
| 15 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 12.1% | 5.4% | 0.0% | 0.0% | 0.0% | 0.9% |
| 16 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 9.9% | 2.8% | 0.0% | 0.0% | 0.0% | 1.4% |
| 17 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 12.1% | 2.2% | 0.0% | 0.0% | 0.0% | 1.3% |
| 18 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 4.6% | 0.0% | 0.0% | 0.0% | 0.0% | 2.0% |
| 19 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.9% | 0.0% | 0.0% | 0.0% | 0.0% | 1.8% |
| 20 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.4% |
| 21 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 22 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 23 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 24 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |

***Figure 18. SPP Base Case EUE Distribution***

## NPC ELCC

To quantify the capacity value of the LOLE benefit associated with NPC, the Effective Load Carrying Capability (ELCC) of the project was calculated. The project ELCC was determined by adding load in the three regions until the regional LOLE returned to their base case LOLE levels. This was an iterative process and, like the calibration process, is subject to interzonal and inter-regional impacts that make a precise determination difficult.

The analysis was performed by adding load only to the three zones NPC directly connects to (i.e., NWMT_WAUW, SPP Zone 1, and MISO LRZ 1). The figures below show the final, resulting load additions and their impact on zonal and regional LOLE. Because most of the reliability benefit in WECC is during the winter and the east experiences most of its reliability benefit in the summer, the ELCC of the project, if added up individually across the three aggregated regions, is greater than 3,000 MW.

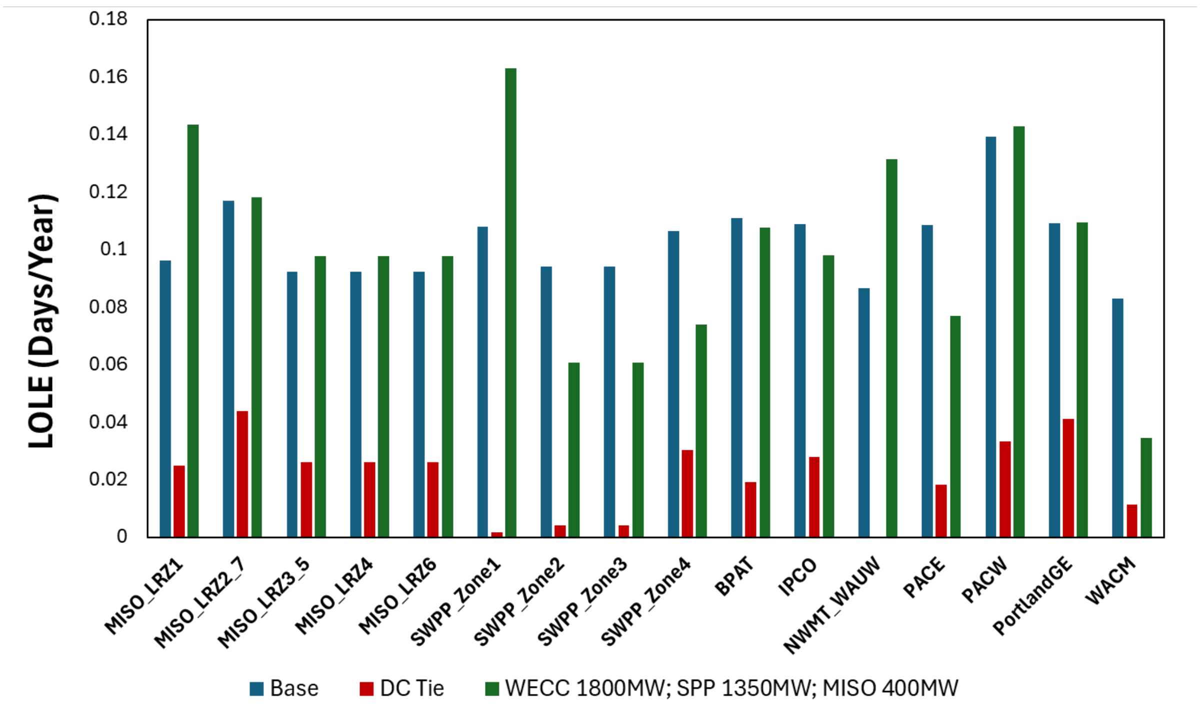


*Figure 19. Zonal ELCC Impact*

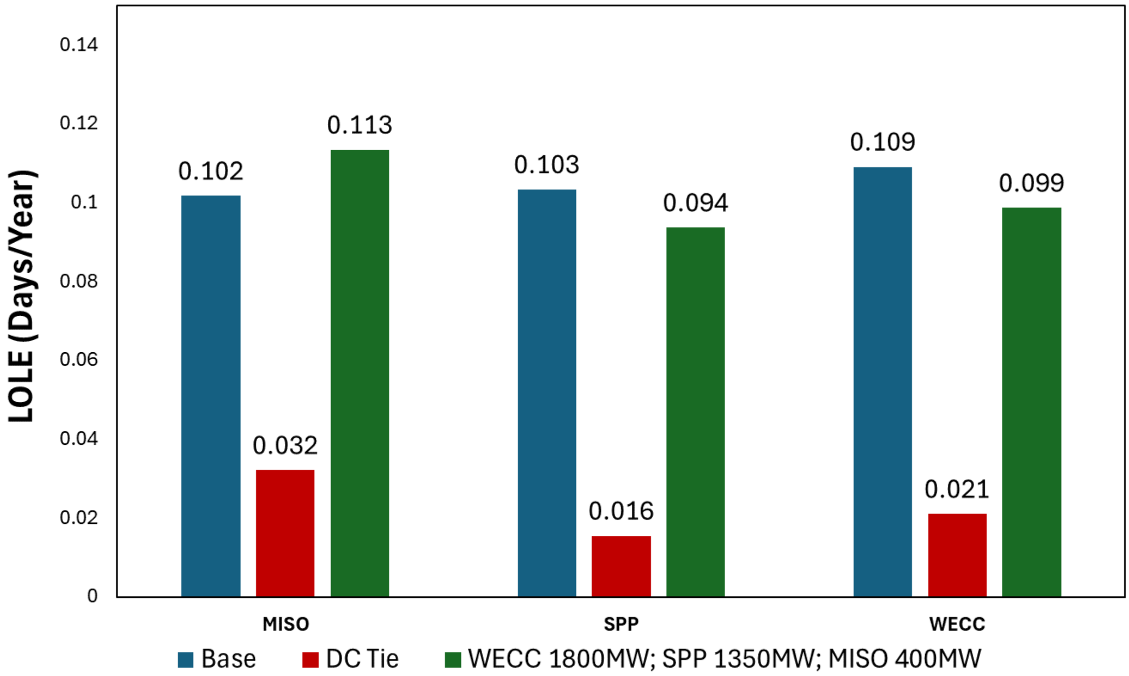


***Figure 19. Regional ELCC Impact***