PNNL-36452

Western Interconnection Baseline Study

September 2024

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B&R Code: TF0000000-05300-3123796

Prepared for the U.S. Department of Energy
under Contract DE-AC05-76RL01830

PACIFIC NORTHWEST NATIONAL LABORATORY
operated by
BATTELLE
for the
UNITED STATES DEPARTMENT OF ENERGY
under Contract DE-AC05-76RL01830

Printed in the United States of America

Available to DOE and DOE contractors from
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Pacific Northwest National Laboratory
Richland, Washington 99354

Preface

This report was prepared in connection with the U.S. Department of Energy's (DOE's) National Transmission Planning Study (NTP Study), conducted by the National Renewable Energy Laboratory (NREL) and Pacific Northwest National Laboratory (PNNL). The aim of the NTP Study is to identify transmission that will provide broad-scale benefits to electric customers, inform regional and interregional transmission planning processes, and identify interregional and national strategies to accelerate decarbonization while maintaining system reliability. More information on the NTP Study is available at https://www.energy.gov/gdo/national-transmission-planning-study.

The purpose of the baseline study is to evaluate the degree to which current industry planning processes meet the national 2035 decarbonization goals for the Western Interconnection. This analysis serves as a comparative baseline for the scenario analysis conducted in the NTP Study using a Western Interconnection dataset that is readily available to industry. This baseline analysis differs from the production cost modeling analysis and power flow analysis in the main NTP Study report (forthcoming). In particular, the analysis presented in this report reflects a business-as-usual future with an optimistic build out of specific planned transmission projects and foreseeable generation. In contrast, the NTP Study models a future generation and transmission expansion based on optimization from a capacity expansion model. The analysis presented herein also reflects a 2030 time frame, whereas the main NTP Study production cost modeling analysis and power flow analysis reflect a 2035 time frame. This baseline analysis utilizes industry's most reliable data to account for future transmission projects across various stages of development, with a particular focus on those in the permitting stage. Additionally, it incorporates projections for changes in generation capacity (both additions and retirements). This baseline analysis outlines a probable trajectory, given current process and practice, for the future of the bulk power system with a horizon extending to 2030.

The purpose of this study is twofold:

- Develop a High Renewables case of the Western Interconnection for the year 2030, based on industry transmission and generation trends, and assess its operations with respect to the 2035 zero-emission target using production cost modeling.
- Use power flow modeling to evaluate the reliability and resilience of the High Renewable case with respect to select contingencies.

In addition, there are two other companion reports under the NTP umbrella: the *Interregional Renewable Energy Zones* (IREZ) report (Hurlburt et al. 2024), and the *Barriers and Opportunities To Realize the System Value of Interregional Transmission* (Barriers) report (Simeone and Rose 2024). The IREZ and Barriers reports are intended to review options for achieving the benefits highlighted by the NTP Study. The IREZ report assesses the potential for interregional renewable energy zone corridors to help spur regulatory and financial decision-making. The Barriers report identifies and examines how current market rules and operating practices may negatively impact the potential benefits of existing transmission infrastructure across regions. The Barriers report also provides possible solutions, both incremental and transformative, to realize the full benefits of interregional transmission.

Acronyms and Abbreviations

AC	Alternating current
ADS	Anchor Data Set
B2H	Boardman to Hemingway
BA	Balancing authority
BESS	Battery energy storage system
BPA	Bonneville Power Administration
BTM	Behind-the-meter
BTP	Baseline transmission project
C-PAGE	Chronological AC power flow automated generation tool
CAISO	California Independent System Operator
DC	Direct current
DOE	U.S. Department of Energy
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GDO	Grid Deployment Office
GIS	Geographic information system
HVDC	High-voltage direct current
ID	Identification
LSE	Load-serving entity
NERC	North American Electric Reliability Corporation
NOB	Nevada–Oregon border
NREL	National Renewable Energy Laboratory
NTP	National Transmission Planning
O&M	Operations and maintenance
OASIS	Open Access Same-Time Information System
PAWY	PacifiCorp Wyoming
PNNL	Pacific Northwest National Laboratory
PNW	Pacific Northwest
POI	Point of interconnection
PV	Photovoltaic
ReEDS	Regional Energy Deployment System
reVX	Renewable Energy Potential Exchange Model
SWIP	Southwest Intertie Project
TRC	Technical Review Committee
TWE	TransWest Express
VRE	Variable renewable energy

WECC	Western Electricity Coordinating Council

Acknowledgments

The authors of this report are grateful for the support and feedback provided by both current and former staff of the Department of Energy's Grid Deployment Office (GDO).

The authors are also grateful to the following PNNL staff who supported this effort:
Steve A. Shankle,
Bharath Kumar Ketineni,
Francis K. Tuffner,
Katherine E. Wolf,
Paul Wetherbee,
Abhishek Somani,
Juliet S. Homer,
Cortland Johnson,
Andrew T. Pitman,
Isaiah P. Steinke,
Slaven Kincic,
Shaobu Wang.

Executive Summary

The Western Interconnection Baseline Study (baseline study) provides an assessment for how potential investments in transmission and renewable generation projects could contribute to achieving future decarbonization goals across the Western Interconnection. By modeling a high renewable generation scenario for the year 2030, the baseline study provides an initial assessment of how transmission lines in advanced permitting stages, combined with anticipated new renewable resources, align with national decarbonization goals. In doing so, it establishes a comparative baseline for transmission and generation expansion scenario analyses in the forthcoming National Transmission Planning (NTP) Study Report.

The baseline analysis for the Western Interconnection consists of two cases: the industry planning (Base) and High Renewables (High RE) cases. Table ES-1 summarizes the two baseline cases. The Base case reflects the Western Electricity Coordinating Council (WECC) 2030 Anchor Data Set (ADS) (WECC 2020a, 2020b). The WECC 2030 ADS is a comprehensive scenario, incorporating input from all member planning regions. The ADS 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 Base case serves as the basis for developing the High RE case. To create the High RE case, the Base case is first augmented with data from 12 future baseline transmission projects (BTPs) that were not already included in the Base case. These BTPs were selected based on their developmental maturity stage and federal permitting status. A two-step methodology then adds new renewables (solar and wind) and energy storage resources to the Western Interconnection, adhering to distance criteria from potential points of interconnections, capacity limits of BTPs, and transmission congestion and renewable curtailment limits.

Table ES-1. Baseline scenarios.

Case	Name	Description
Base	Industry Baseline Case	WECC 2030 ADS
High RE	High Renewables Case	Industry Planning Case + baseline transmission projects + new renewables utilizing existing and new transmission capacity + battery energy storage added to new solar resources

The cases are analyzed in detail using production cost modeling and alternating current (AC) power flow modeling. Production cost modeling is used to understand how the Western Interconnection system will operate at an hourly level to meet electricity demand and reserve requirements for the two nodal baseline cases. Analysis from production cost modeling provides operational insights about the amount of CO_2 emissions, transmission utilization and congestion, the curtailment of wind and solar, and total system costs.

The AC power flow analysis showcases the resilience of the baseline cases against selected contingencies on interregional ties. The developed tools enable the extraction of power flow cases from production cost model simulations, regardless of generation mix, facilitating more in-depth reliability studies. Additionally, the database management system and interactive visualization allow the study team to analyze the system behavior of the baseline cases across numerous AC power flow hourly snapshots and contingencies.

Key findings:

- **Shift in generation mix:** The High RE case displaces 15% of the fossil thermal generation energy with wind and solar. Thermal generation is replaced not only in areas with significant additions of new renewable capacity but also in areas with no or little new renewable capacity enabled by the augmented transmission system.
- **Carbon reduction potential:** The High RE case reduces CO_2 emissions by 73% from 2005 values. The highest percentage of emissions reduction occurs in the central western states (i.e., Utah, Nevada, Wyoming, Colorado, Arizona, New Mexico), where renewable energy replaces large thermal fossil generation.
- **Capacity factor impacts of existing fossil units:** The High RE case decreases the capacity factors of coal and natural gas resources by 33% and 12%, respectively. The low capacity factors may yield early retirements of fossil units because of low utilization and frequent cycling (startups and shutdowns), increasing operations and maintenance (O&M) costs.
- **Renewable curtailments:** Wind and solar curtailment increases in the High RE case by 5.8% and 2.4%, respectively, compared to those in the Base. Renewable curtailment peaks during springtime (i.e., March, April, May) as a result of Northwest hydropower runoffs combined with low-load conditions (due to lower heating and/or air-conditioning electricity demands) and solar overgeneration (due to favorable weather conditions). As more renewables are integrated into the Western Interconnection system, transmission saturation and overgeneration will lead to increased curtailments[1]. Without further enhancements to the transfer capability of the transmission network or the addition of energy storage resources, any new renewable additions will significantly exacerbate curtailment issues.
- **Reduction in generation costs:** Generation operational costs decrease by 32% in the High RE case compared to those in the Base case. Note, however, that capital costs for generation and transmission are not considered as part of this analysis and would be needed for a complete economic evaluation.
- **Shift in energy transfers across regions:** California's annual net energy imports from the Northwest (mainly from Paths 65 and 66) are reduced by ~26% and increased from the Southwest (Basin and Southwest) by ~74% in the High RE case. The BTPs, combined with existing transmission capacity, facilitate increased power transfers to California by accessing newly integrated wind resources from areas with abundant wind, such as Wyoming and New Mexico. This is evidenced by increased power flows on Paths 27 and 46. The increase in power transfers from the Basin region results in California relying less on power imports from the Pacific Northwest (PNW), thus providing congestion relief on Paths 65 and 66.
- **Primary frequency response participation:** The increased contribution from battery energy storage systems in the primary frequency response in the High RE case compared to that in the Base indicates the potentially significant role of this technology for reliability in a high renewables power system.
- **System Resiliency**: The High RE case is resilient enough to withstand selected high-impact contingencies for the power flow hour modeled in this analysis. This finding suggests that the Western Interconnection can be operated reliably and affordably with a high penetration of renewables.

[1] In this report, the term "curtailment" is used synonymously with "spillage."

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1.0 Introduction

The National Transmission Planning (NTP) Study identifies transmission that will provide broad-scale benefits to electricity customers, inform regional and interregional transmission planning processes, and identify interregional and national strategies to accelerate decarbonization while maintaining system reliability. The NTP Study links several long- and short-term power systems models to test numerous interregional and regional transmission buildout scenarios through a wide range of economic, reliability, and resilience indicators on a national scale.

This report covers a baseline analysis for the Western Interconnection, including data development, analysis methodology, and discussion of results. The main scope of the baseline study is to evaluate the degree to which current industry planning processes meet national 2035 decarbonization goals. This analysis forms a baseline for the scenario analysis conducted in the NTP Study. It utilizes industry's most reliable data to account for future transmission projects across various stages of development, with a particular focus on those in the pipeline permitting stage. Additionally, it incorporates projections for changes in generation capacity (both additions and retirements). This baseline analysis outlines a probable trajectory for the future of the bulk power system within the Western Interconnection, with a horizon extending to 2030.

The study begins by compiling a comprehensive database of large transmission projects planned for development across the Western Interconnection by 2030. Following this, it develops a nodal High Renewables (High RE) version of the 2030 industry planning case (Base), which utilizes the Western Electricity Coordinating Council (WECC) 2030 Anchor Data Set (ADS). This High RE version integrates anticipated transmission projects and adds renewable capacity, leveraging both existing and new transmission capacity. Subsequently, the study employs production cost modeling to evaluate the positioning of the 2030 Base and High RE cases with the trajectory towards achieving the 2035 zero-emission target while identifying the potential limitations imposed by the transmission network on progress towards these goals. Lastly, through power flow analysis, the study examines the resilience of both baseline cases against specific interregional tie contingencies, affirming the viability of the baseline scenarios under different contingency events. Figure 1 summarizes the baseline analysis framework.

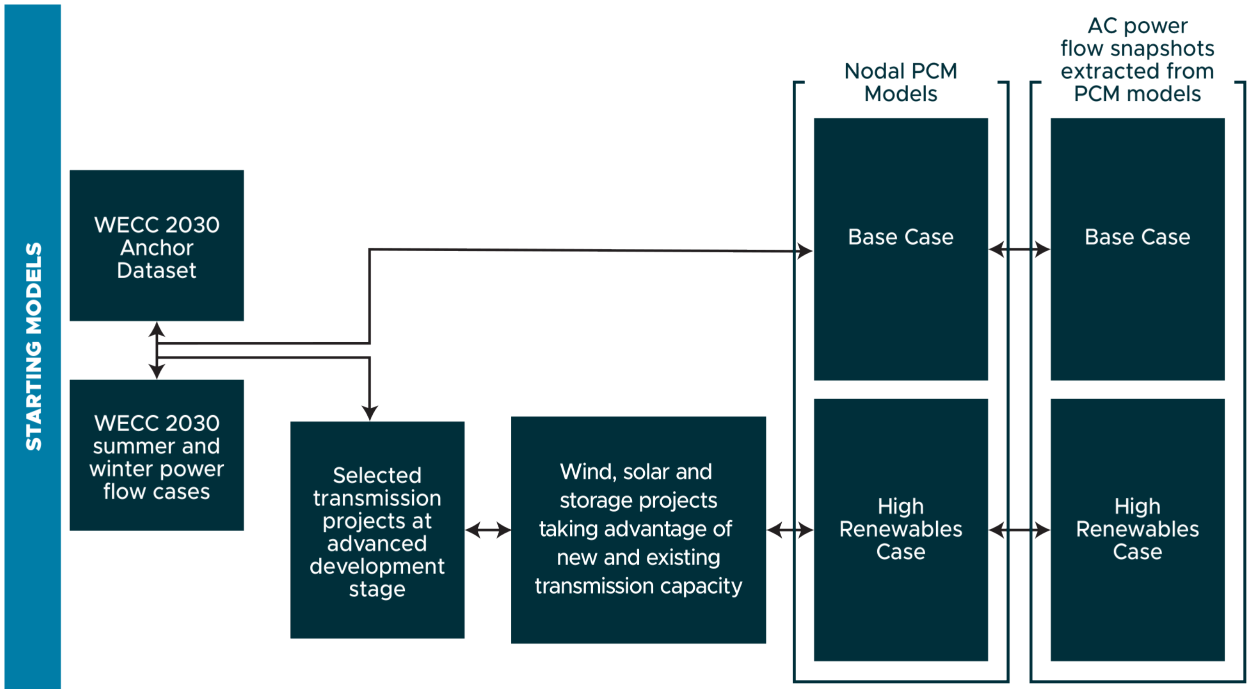


Figure 1. Baseline modeling framework.

2.0 Industry Base Case Background

The WECC 2030 ADS is the base nodal dataset for the Western Interconnection baseline analysis (WECC 2020a). The WECC 2030 ADS is a comprehensive scenario, incorporating input from all planning regions. It aims to project the Western Interconnection's infrastructure for the year 2030, based on the best available knowledge at the time of the case's release as well as existing state and federal laws. The transmission network topology for the WECC 2030 ADS Production Cost Model was carried over from a previous WECC study—the 2030HS (Heavy Summer) Power Flow dataset, which was compiled by the WECC Reliability Assessment Committee using GE PSLF software[2]. The transmission topology was imported into the 2030 ADS Production Cost Model case as the basis for the transmission network topology and represents the best available projection of anticipated new generation, generation retirements, transmission assets, and load growth in the 10-year planning horizon within the WECC grid planning community.

Pacific Northwest National Laboratory (PNNL) uses GridView (Hitachi Energy n.d.), a production cost model designed and marketed by Hitachi, to simulate Western Interconnection power system operations at a highly refined (nodal level) spatial granularity (~22,000 nodes and ~23,000 transmission lines). GridView is a chronological unit commitment and economic dispatch model that minimizes power systems' operating costs of meeting electricity demand and reserve requirements while simultaneously satisfying a wide variety of operating constraints. These constraints consist of unit-specific constraints (e.g., maximum/maximum capacity limits, minimum up and down times, ramping limits) and system-wide constraints (e.g., transmission line capacity limits, interface capacity limits, operating reserves, emission constraints, hurdle rates). Operating costs largely consist of fuel costs, variable operating and maintenance costs, and start-up/shut-down costs. Figure 2 summarizes the key modeling inputs and representative outputs of GridView's production cost modeling analysis.

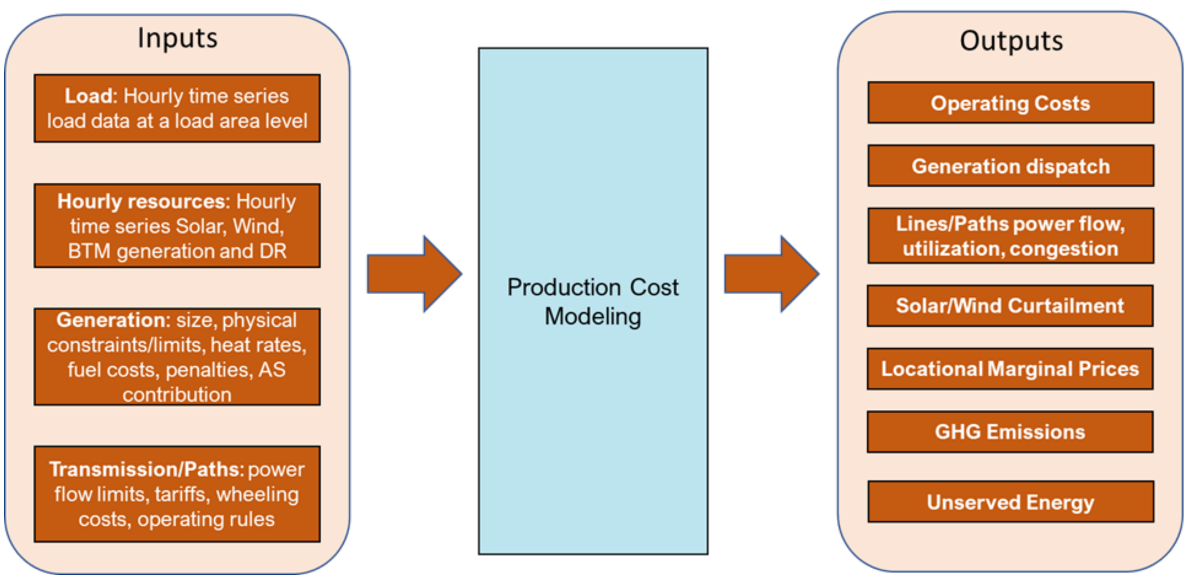


Figure 2. Modeling inputs and outputs of the production cost modeling analysis.

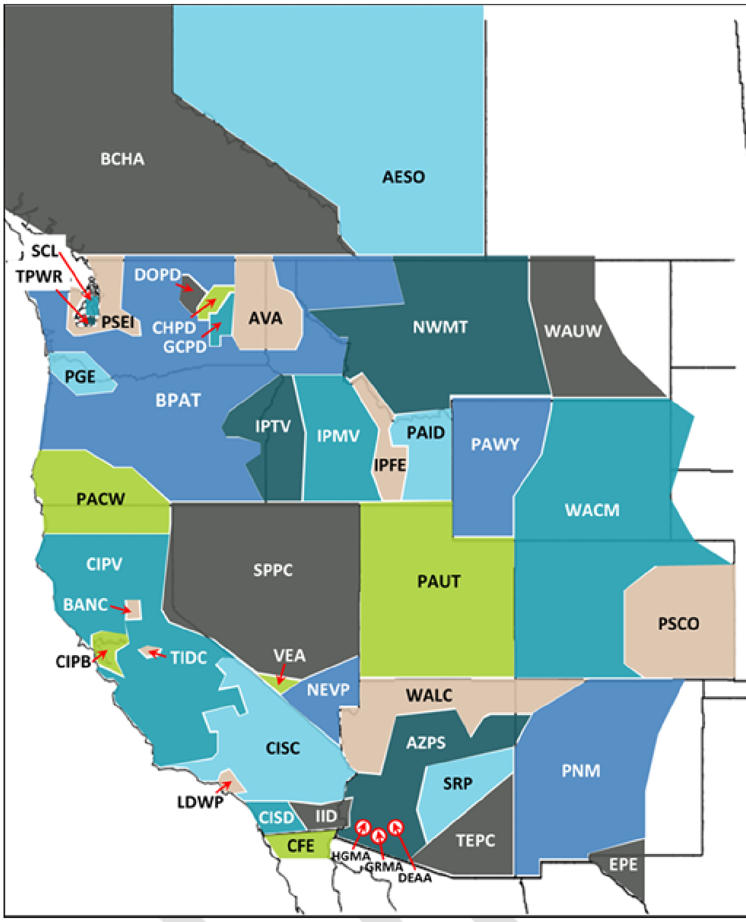
[2] General Electric: PSLF (Positive Sequence Load Flow) Simulation Engine.

In GridView, the hourly load profiles are imported for each of the 40 load areas (shown in Figure 3), which in most cases is analogous to the balancing authority (BA) boundaries or the load-serving entity (LSE). These loads are adjusted for behind-the-meter generation (BTM) to only reflect the native system load. The adjusted hourly load-area profiles are then disaggregated to the nodes of each load area using predefined nodal participation factors adopted by the 2030HS1 power flow case. The final loads are used with a 2009 historical load shape to derive load shapes for the 2030 ADS Production Cost Model. Wind and solar generation are on a fixed hourly schedule specific to each wind and solar generator. The wind hourly generation shapes (MW) use 2009 National Renewable Energy Laboratory (NREL) wind data that are derived by modeling current wind turbine technologies and speed and weather data. Similarly, the solar hourly generation shapes are based on 2009 NREL irradiance and weather data. Hydro resources are modeled using monthly average generation values from the EIA 906/920 data for the year 2009, which is considered an average hydrologic year.

In GridView, ancillary service requirements are applied to each WECC load area through an hourly shape generated using the PNNL tool, GRAF-Plan[3]. The following types of ancillary services are modeled in GridView: (1) Regulation Down/Up, (2) Load Following Down/Up, and (3) Spinning Reserve.

The WECC 2030 ADS projected installed generation capacity is grouped by North American Electric Reliability Corporation (NERC) reliability regions, and the generation type is shown in Figure 4. The 2030 hourly demand profile for the selected regions is given in Figure 5. The total WECC 2030 ADS installed capacity is 307 GW, and the peak demand is 203 GW.

[3] Grid Reserve and Flexibility Planning Tool (Ghosal et al. 2022).



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 3. Western Interconnection load areas. Source: (WECC 2021b).

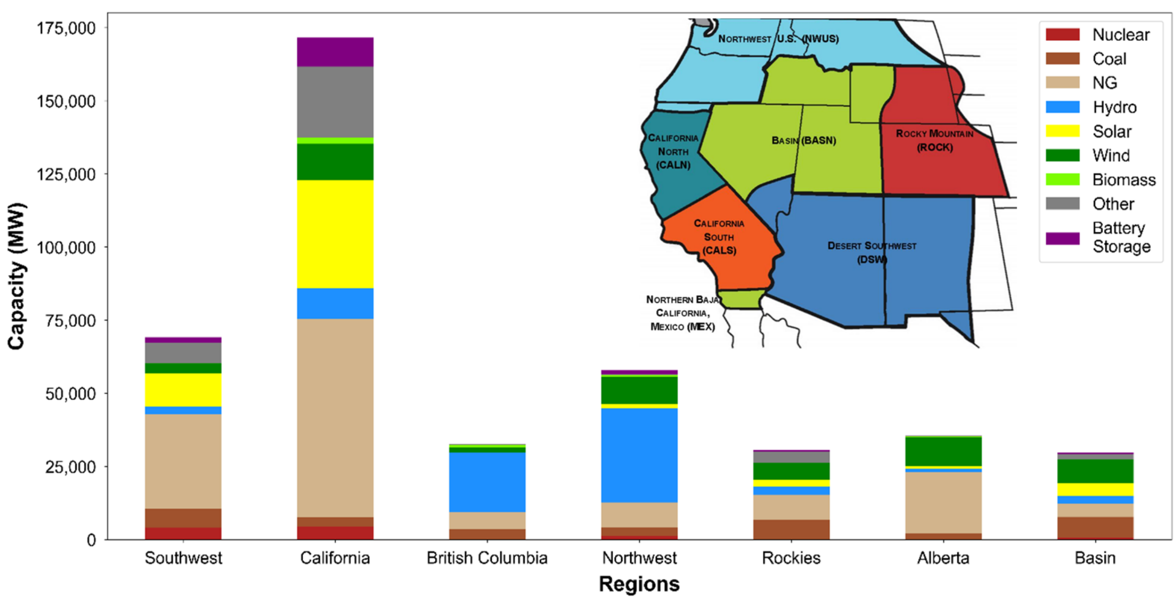


Figure 4. Installed capacity of the WECC 2030 Production Cost Model ADS (grouped by WECC subregion).

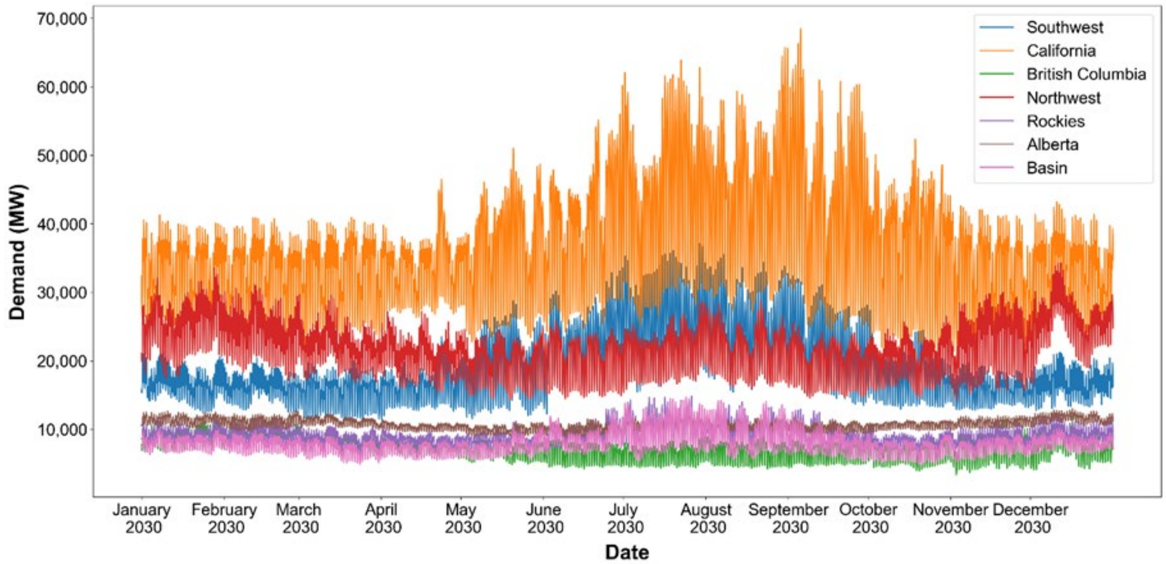


Figure 5. Hourly load profiles for the Western Interconnection (grouped according to NERC reliability region). Source: (WECC 2020a).

3.0 Development of the High Renewables Case

This section describes the methods used to create the production cost and power flow models for the Western Interconnection baseline analysis and introduces and characterizes the baseline cases. The goal of the baseline analysis is to establish the future transmission state that includes transmission projects at advanced stages of permitting. It is used to estimate the sufficiency of current/existing transmission infrastructure expansion plans compared against the Administration's 2035 zero-emission clean grid goal.

Table 1 shows the names and descriptions of the cases used in this study.

Table 1. 2030 Baseline cases for the Western Interconnection.

Case	Name	Description
Base	Industry Baseline Case	WECC 2030 ADS
High RE	High Renewables Case	Industry Planning Case + baseline transmission projects + new renewables utilizing existing and new transmission capacity + battery energy storage added to new solar resources

The WECC 2030 ADS case reflects the Base case, which serves as the basis for developing the High RE case. Figure 6 shows the process of constructing the High RE case starting from the Base case. First, the Base case is augmented with 12 baseline transmission projects (BTPs) (Figure 7), where the latest data on those projects were not already included in the case. Next, new wind and solar projects are incorporated up to the point where significant curtailment (close to 20%) occurs. The placement and sizing of the additional wind and solar capacity require engineering judgment and fine tuning with the production cost model, as it is limited by the transmission capacity to transfer electric energy to the load centers. For more details about the methodology, see Section 3.2. Finally, battery energy storage systems (BESSs) are added for every new solar plant to complete the High RE case. The installed power capacity of each BESS resource was set at 50% of the solar nameplate capacity (i.e., the storage to solar power capacity ratio is 0.5) with 4 hours of charge/discharge duration capability. The following sections present the modeling inputs and data exchange used to update the Production Cost Model database for the High RE case.

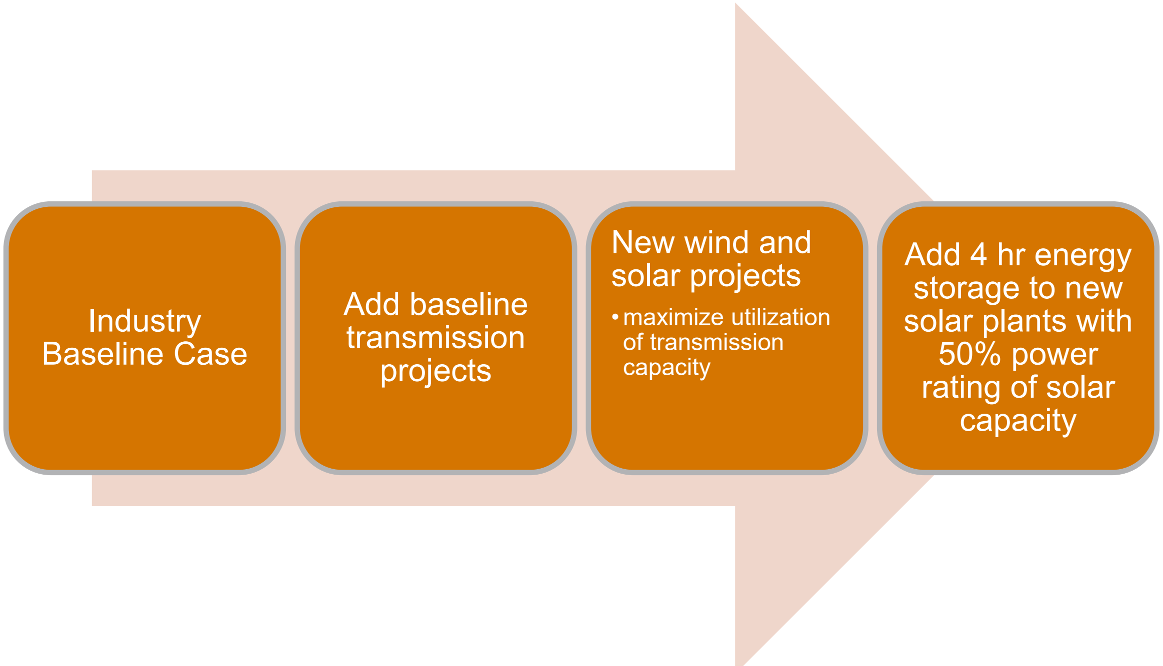


Figure 6. Process flow diagram for developing the High RE case.

3.1 Selection of Baseline Transmission Projects

All transmission capacity enhancements that exist in the baseline analysis are referred to as BTPs.

Specifically, BTPs meet the following requirements:

- They are sufficiently far along in the development pipeline[4].
- They are high capacity (≥345 kV).
- They are least 70 miles long.

BTPs may or may not already be in the Base case. The 12 included BTPs are listed in Table 2 and shown on the map in Figure 7.

Table 2. Selected baseline transmission projects.

Transmission Project	Reference
Boardman to Hemingway (B2H)	(NorthernGrid 2022), (CAISO 2022)
Ten West Link	(CAISO 2022)
Gateway West	(NorthernGrid 2022), (CAISO 2022)

[4] Projects were screened to meet two or more of the following criteria: (1) construction is underway, (2) developers are in active communication with Federal Energy Regulatory Commission (FERC) Order 1000 entities and are providing transmission line visibility/impact studies and power flow data, (3) developers are actively/successfully acquiring federal and/or state permits, (4) developers are actively/successfully securing power purchaser commitment for the proposed line, and (5) developers are actively/successfully engaging the public to address concerns and gain acceptance.

Transmission Project	Reference
Gateway South	(CAISO 2022)
Southwest Intertie Project-North (SWIP-North)	(NorthernGrid 2022), (CAISO 2022), (GDO n.d.)
TransWest Express DC and AC (TWE)	(CAISO 2022)
Cross-Tie	(NorthernGrid 2022), (CAISO 2022), (GDO n.d.)
SunZia DC	(CAISO 2022)
Greenlink Nevada West	(NorthernGrid 2022), (CAISO 2022)
Greenlink Nevada North	(NorthernGrid 2022), (CAISO 2022)
Colorado Power Pathway	(WestConnect 2023)
Southline	(GDO n.d.), (Pacini and Green 2024)

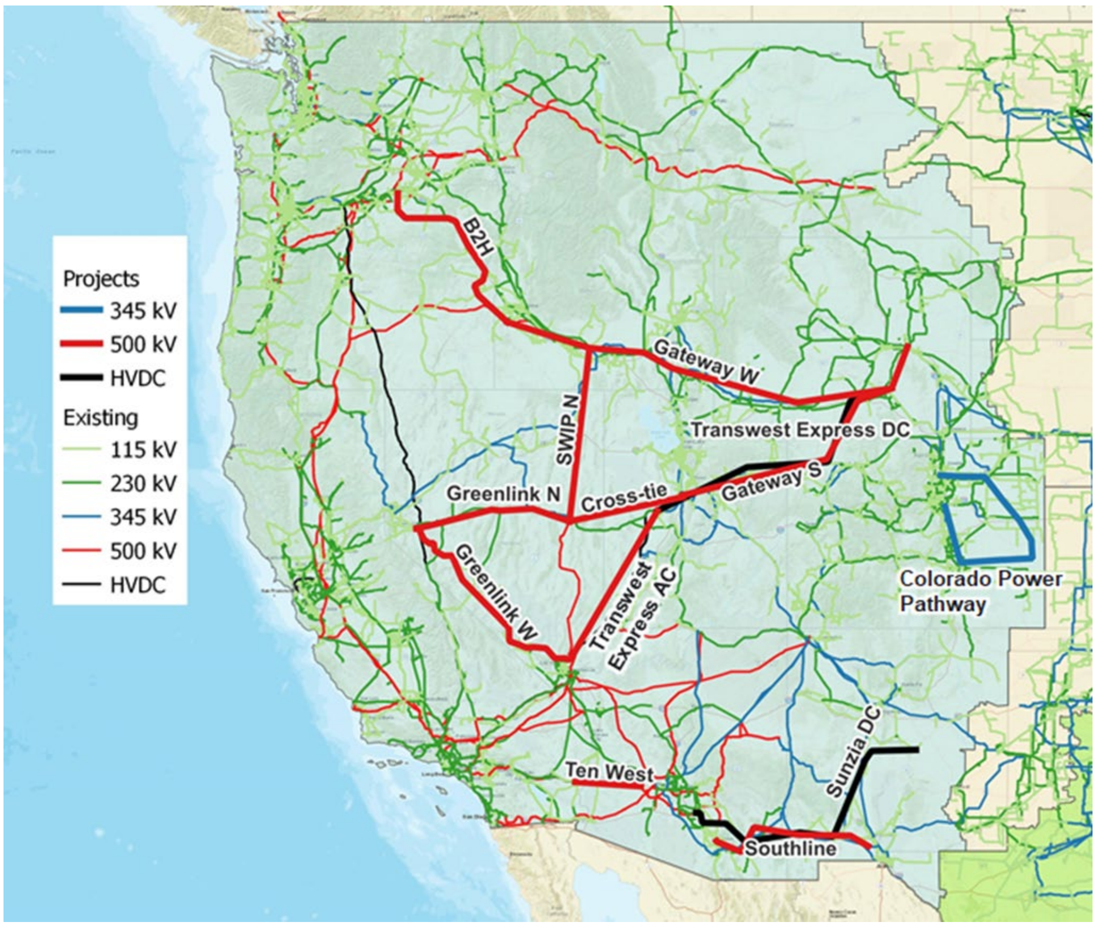


Figure 7. Selected baseline transmission projects.

3.2 Methodology for Adding Renewable Capacity to the Baseline Assessment

This section describes the two-step approach followed to add new renewable resources to the High RE case, also illustrated in Figure 8.

Step 1 identifies potential points of interconnection by looking at the distance of the candidate renewable projects from high-voltage substations. Only renewable projects that are located within 50 miles from high-voltage substations are selected to keep interconnection costs within a reasonable range. In Step 1, potential points of interconnection are locations with historic and planned retirements[5] and development activities for renewable supply based on a review of the interconnection queues for each BA in the Western Interconnection[6]. Step 1 renewable capacity additions associated with the BTPs also depend on the transmission capacities of the lines. Therefore, although many renewable projects may meet the distance criteria, not all are added to the baseline cases. To this end, renewable projects are added up to a point where the cumulative nameplate capacity of these projects exceeds the transmission capacity during peak solar/wind periods by a modest amount of 10%–20% because of capacity factor considerations and engineering judgment. By oversizing the renewables' capacity relative to the BTPs' ratings, their economic value can increase when utilized during the times of the year when renewable projects do not simultaneously operate at their peak capacity. Oversizing renewable capacity relative to the BTPs' ratings allows for greater utilization of transmission during off-peak generation periods. Since peak generation times are relatively infrequent throughout the year, this approach leads to an overall increase in economic value.

In **Step 2**, the optimistic capacity numbers from Step 1 are passed to the production cost model/GridView to further adjust renewable capacity by imposing two additional constraints. The first additional constraint relates to curtailing wind and solar resources, and the second constraint relates to the loading levels of the BTPs and interface paths. Although no standard curtailment thresholds exist, curtailment levels are constrained to an area average below 20% with consideration of the economic constraints on project developers. For the second constraint, the utilization levels of existing interface paths and BTPs are considered to avoid overutilization. WECC's utilization metrics (i.e., U75, U90, U99) and overutilization guidelines (i.e., U75 ≤ 50%, U90 ≤ 20%, U99 ≤ 5%) are soft constraints to add renewable capacity (for more information, see Appendix A), however, without strictly enforcing those limits as long as renewable curtailment remains below 20%. Note that Step 2 requires production cost modeling iterations, where new renewable capacity is adjusted until the 20% curtailment limits are respected.

This two-step method provides a holistic approach by considering and modeling many renewable projects simultaneously and relying on GridView to redispatch the generation portfolio to meet the system demand at a minimum cost. It is important to note that this method can capture spatiotemporal interactions between all renewable projects added in the system, which is an important element in generation capacity planning. For example, adding renewables in one part of the system will impact the curtailment of renewables located in a different part of the system. Knowing these interactions allows more informed decisions about adding new renewable projects in the baseline cases.

However, this two-step approach does not account for interconnection requirements or any local reinforcements needed to support new renewable resources. This methodology can therefore be considered as an optimistic approximation as it does not account for all interconnection procedures and possible constraints that could further limit renewable capacity, including constraints on existing available firm transmission rights.

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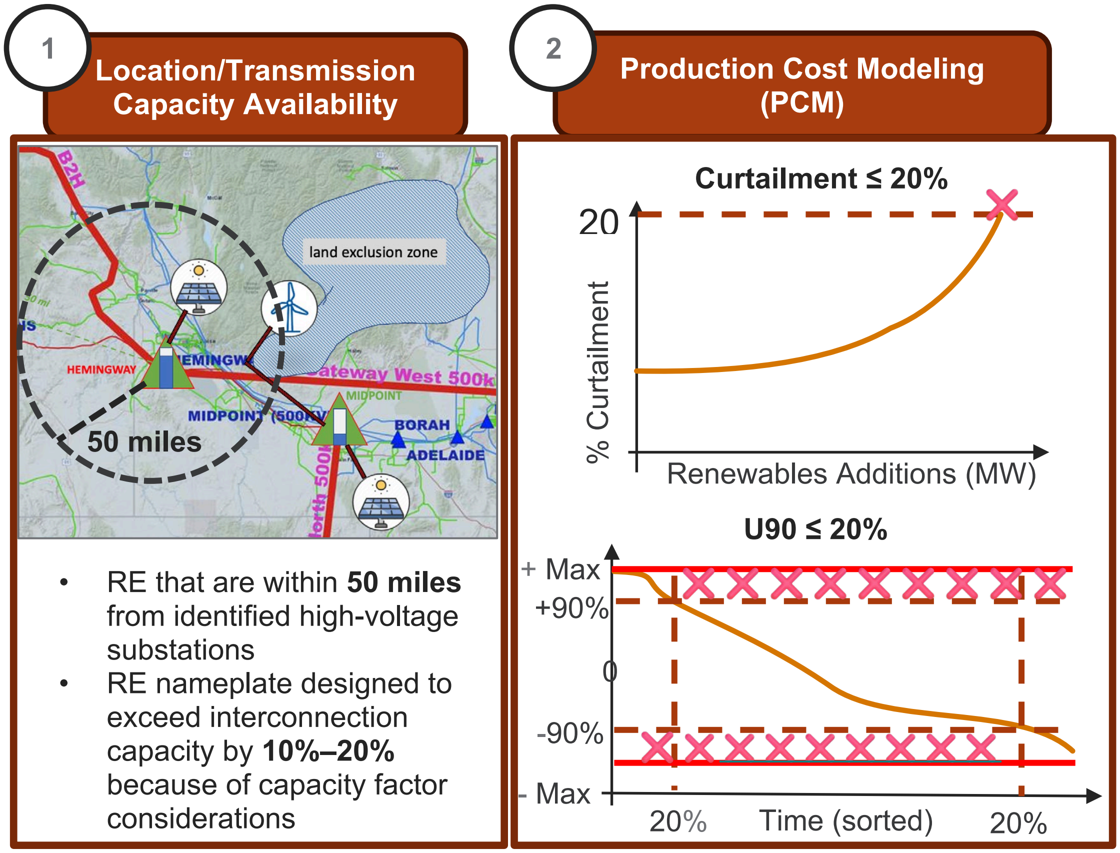
[5] Planned base load retirements (mainly from coal power plants) release existing transmission capacity for use in interconnecting new wind and solar resources. For example, in Wyoming, two of the four Jim Bridger coal units with a total capacity of 2.1 GW are already retired in the Base case (industry planning case), which is replaced by an equal amount of wind and solar in the High RE case.

[6] Most Western Interconnection generation interconnection queues can be found on the Open Access Same-Time Information System (OASIS; https://www.oasis.oati.com/cwo_default.htm). The California Independent System Operator's (CAISO's) queue information is available at https://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx (user account needed).



- RE that are within **50 miles** from identified high-voltage substations
- RE nameplate designed to exceed interconnection capacity by **10%–20%** because of capacity factor considerations

Figure 8. Illustration of the two-step process for adding renewable generation to the High RE case.

Table 3 shows the existing, new, and total installed capacities of solar, wind, and BESS resources. The existing solar and wind capacities refer to the installed capacities found in the Base case, which remained the same in the High RE case. Figure 9 and Table 4 show the new solar, wind, and BESS capacities added by state and load area. Figure 10 displays the new solar, wind, and BESS capacities geographically.

Table 3. Solar, wind, and hybrid energy storage capacities (GW) of the baseline cases.

Capacity (GW)	Base Case	High RE Case
Existing Wind	36	36
Existing Solar	40	40
Existing BESS	11.2	11.2
New Wind	0	29
New Solar	0	29
New BESS	0	14.5
Total Wind	36	65
Total Solar	40	69
Total BESS	11.2	25.7
Total Capacity (all technologies)	307	379.5
Peak Demand	203	203

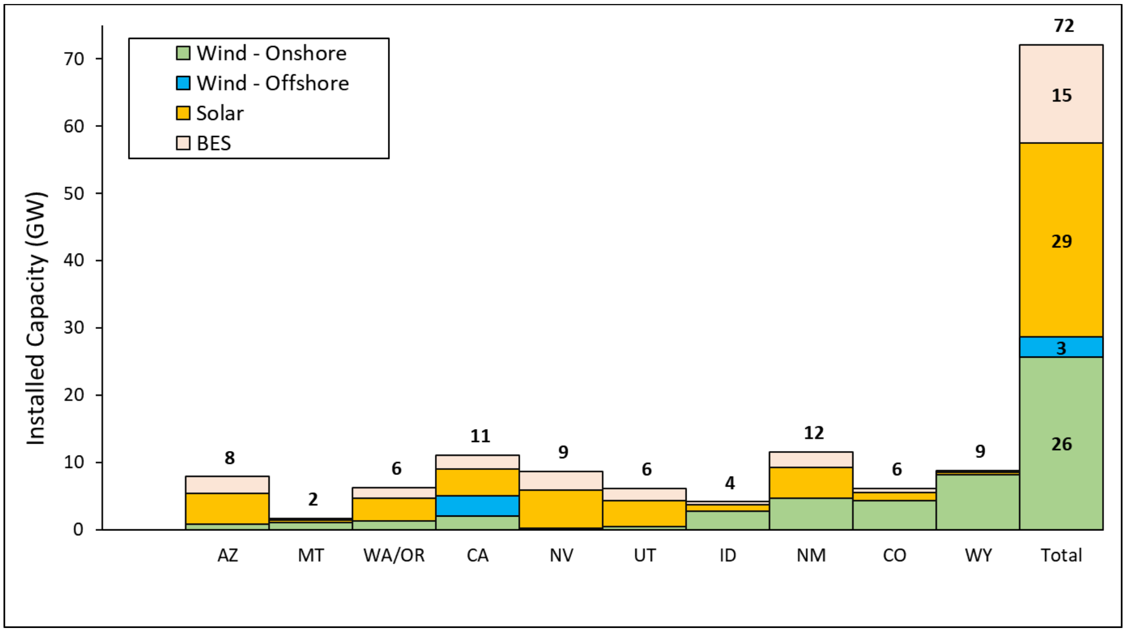


Figure 9. Installed capacities of new wind, solar, and BESS projects by state for the High RE case.

Table 4. Installed capacities of new wind, solar, and BESS projects by load area for the High RE case.

Load Area	Solar (GW)	BESS (GW)	Wind (GW)	Total (GW)
AZPS	5.70	2.85	0.20	8.75
BANC	0.93	0.46	0.20	1.59
BPAT	3.00	1.50	1.30	5.80
CIPV	2.00	1.00	3.60	6.60
CISC	0.20	0.10	0.50	0.80
CISD	0.75	0.38	0.30	1.43
EPE	0.30	0.15	0.00	0.45
IPMV	0.75	0.37	2.67	3.79
IPTV	0.22	0.11	0.00	0.33
LDWP	2.25	1.12	0.87	4.24
NEVP	0.10	0.05	0.00	0.15
NWMT	0.40	0.20	1.05	1.65
PAUT	1.92	0.96	3.65	6.53
PAWY	0.41	0.21	4.45	5.07
PGE	0.15	0.08	0.00	0.23
PNM	0.74	0.37	1.36	2.47
PSCO	1.17	0.59	4.03	5.79
SPPC	5.49	2.74	0.24	8.47
SRP	0.30	0.15	3.60	4.05
TEPC	0.40	0.20	0.30	0.90
TH_Malin	0.15	0.08	0.00	0.23

Load Area	Solar (GW)	BESS (GW)	Wind (GW)	Total (GW)
TIDC	0.08	0.04	0.00	0.11
WACM	0.00	0.00	0.30	0.30
WALC	1.58	0.79	0.00	2.36
Total (GW)	28.98	14.49	28.61	72.07

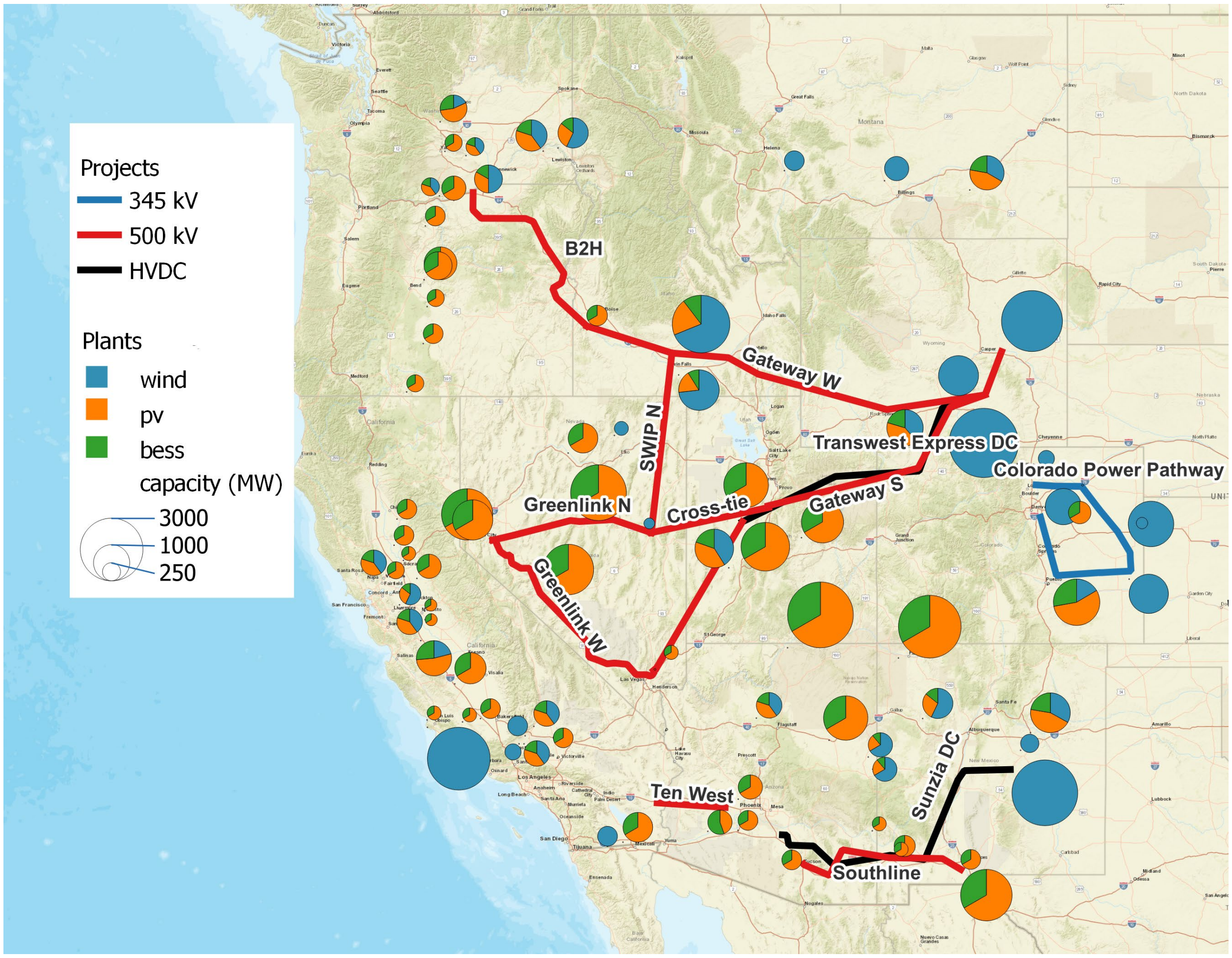


Figure 10. New wind, solar, and hybrid energy storage projects added in the High RE case.

3.3 Production Cost Modeling Assumptions

A set of production cost modeling operating rules, summarized below, help to better mimic the expected operations and flow directions of new transmission projects:

- Based on developer's specifications of TransWest Express (TWE), Wyoming wind generation should not utilize the PacifiCorp Wyoming (PAWY) system. To represent this operational procedure, an economic hurdle rate of 500 $/MWh from TWE Wyoming to PAWY is imposed. As a result, this hurdle rate minimizes the surplus generation flowing through the PacifiCorp alternating current (AC) system.
- The dispatch cost of California hydro resources are adjusted (set to −30 $/MWh from −20 $/MWh) to prevent curtailing hydro prior to wind and solar energy. This adjustment was

made after observing high hydro curtailment values in California due to adding new wind and solar generation outside California.

- A day look-ahead optimization logic is selected that provides BESS commitment/decommitment recommendations based on the day-ahead schedule to better manage the upcoming peak and valley demands (or prices) and interchange schedules. GridView can look ahead from 1 to 7 days (168 hours) to see if any commitment improvement can be applied. This study uses a 7-day look-ahead logic to maximize improvements.
- To allow a BESS to collect financial incentives, including the federal Investment Tax Credit, a hybrid operation of new solar and BESS using a set of penalty functions and linear constraints that align the BESS charging schedule with periods of high solar generation is enforced. In GridView, this combination of penalty functions and linear constraints is set through the base *nomogram* designed to mimic specific operational limitations. Nomograms are expressed as a series of algebraic elements in the following form:

  *If Sum[Items(i) * Coefficient(i)] − (Limit for Commitment) > 0 Then*
  *Penalty Cost * Sum(Items(i) * Coefficient) − (Limit for Commitment)*
  End

  A user-defined cost penalty is assessed whenever the equation becomes false. Complex constraints can be built using multiple nomograms to define the constrained operation.

  The BESSs in the High RE case are modeled as hybrid resources that share the same point of interconnection (POI) with the solar facilities. To hybridize their operation in GridView, two nomogram constraints are applied:

  Constraint 1: BESS charging is only allowed from the colocated solar facility. This is graphically shown in Figure 11, where BESS charging is penalized during the nighttime (hours 20–6), shown in Figure 11-a, forcing the BESS to charge only from the solar resource during the daytime (hours 7–19), shown in Figure 11-b. Mathematically, Constraint 1 is expressed as follows:

  Sum (Solar power output + BESS charge) ≥ 0

  A penalty of 1000 $/MW is applied to discourage the violation of Constraint 1.

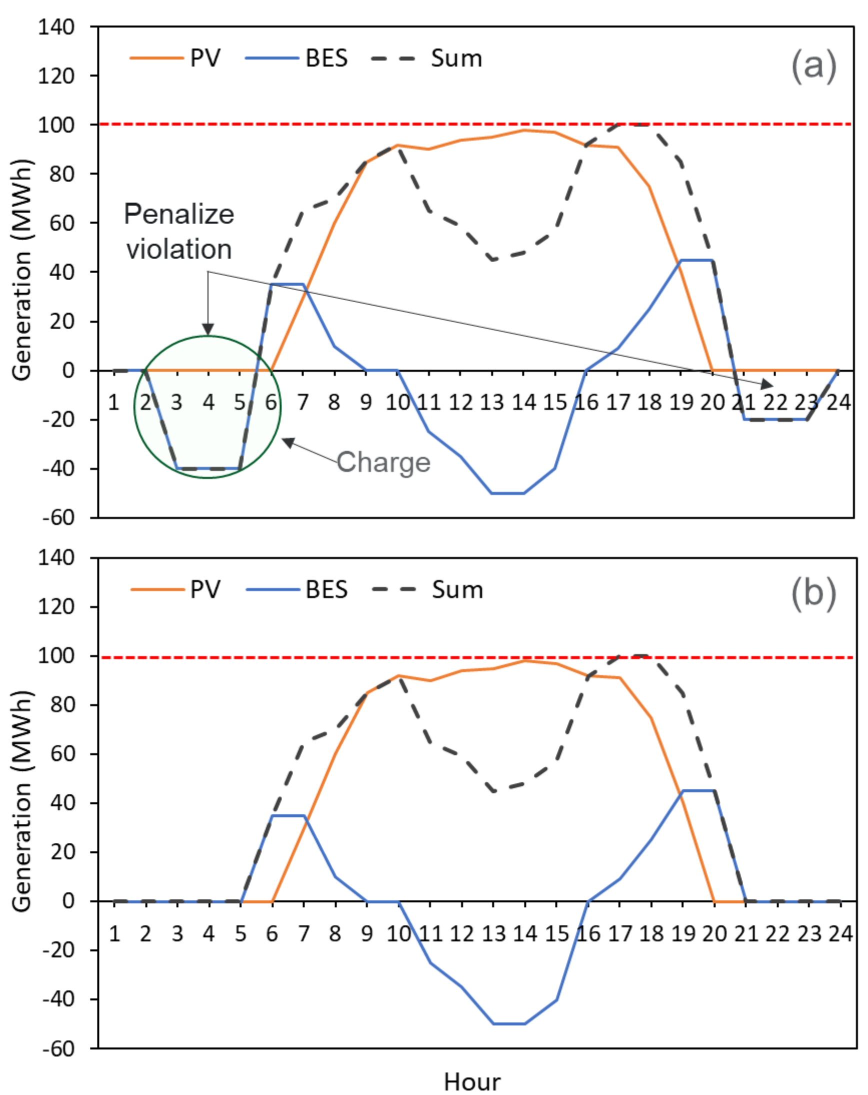


Figure 11. (a) Nonhybrid operation; (b) hybrid operation after applying Constraint 1.

Constraint 2: The total plant output of the hybrid system (battery plus solar) is limited to the solar nameplate capacity. This is graphically shown in Figure 12, where BESS discharging is penalized during the daytime, shown in Figure 12-a, to avoid exceeding the solar nameplate capacity (e.g., 100 MW), shown in Figure 12-b. Mathematically, Constraint 2 is expressed as follows:

Sum (Solar power output + BESS Discharge) ≤ Solar nameplate capacity

A penalty of 1000 $/MW is applied to discourage the violation of Constraint 2.

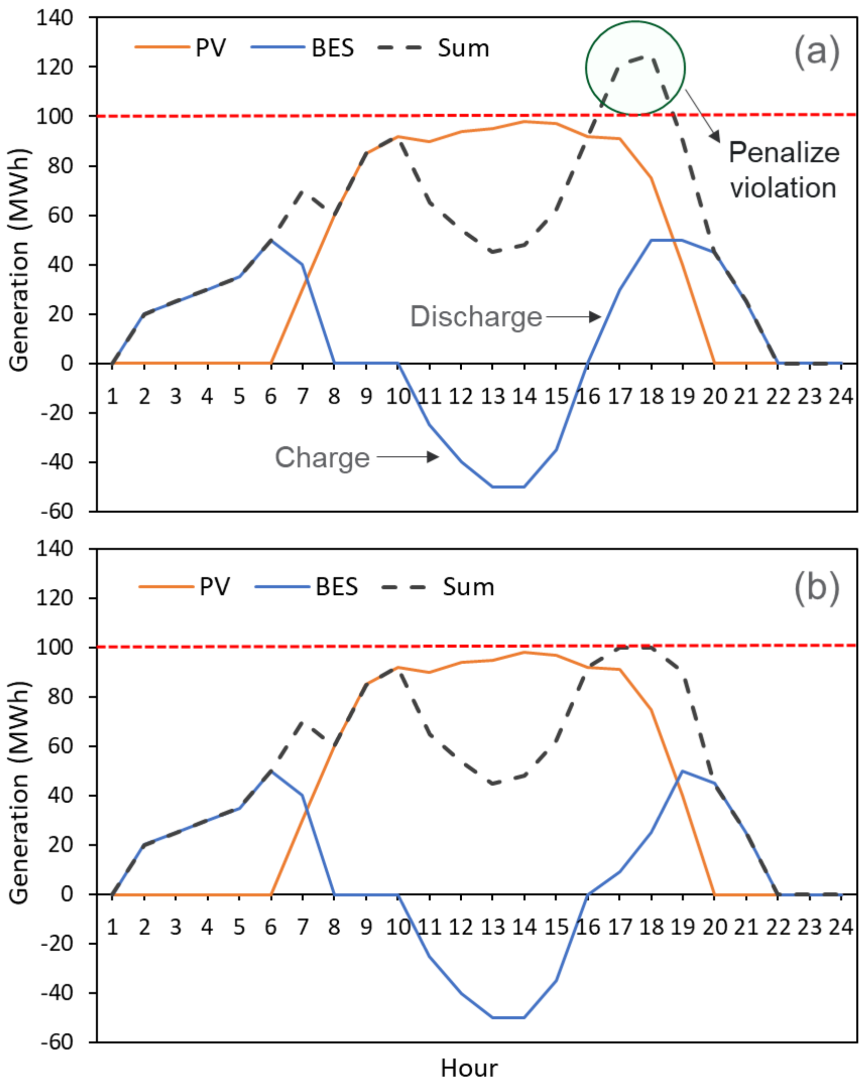


Figure 12. (a) Nonhybrid operation; (b) hybrid operation after applying Constraint 2.

3.4 Automation for the Development of the Production Cost Modeling High Renewables Case

The study team focused on two key considerations for developing the High RE case. These involve ensuring the reproducibility of the process for updating the GridView database and automating the data exchange between the power flow model (e.g., PSLF, PSSE) and GridView. To this end, the study team developed three sets of Python scripts, shown in Figure 13, to automate (1) the incorporation of new transmission projects and related components, (2) the update of interface capacity limits, and (3) the addition of new solar, wind, and hybrid battery energy storage projects and associated hourly generation profiles. For more comprehensive insights into this capability, please refer to Appendix D.

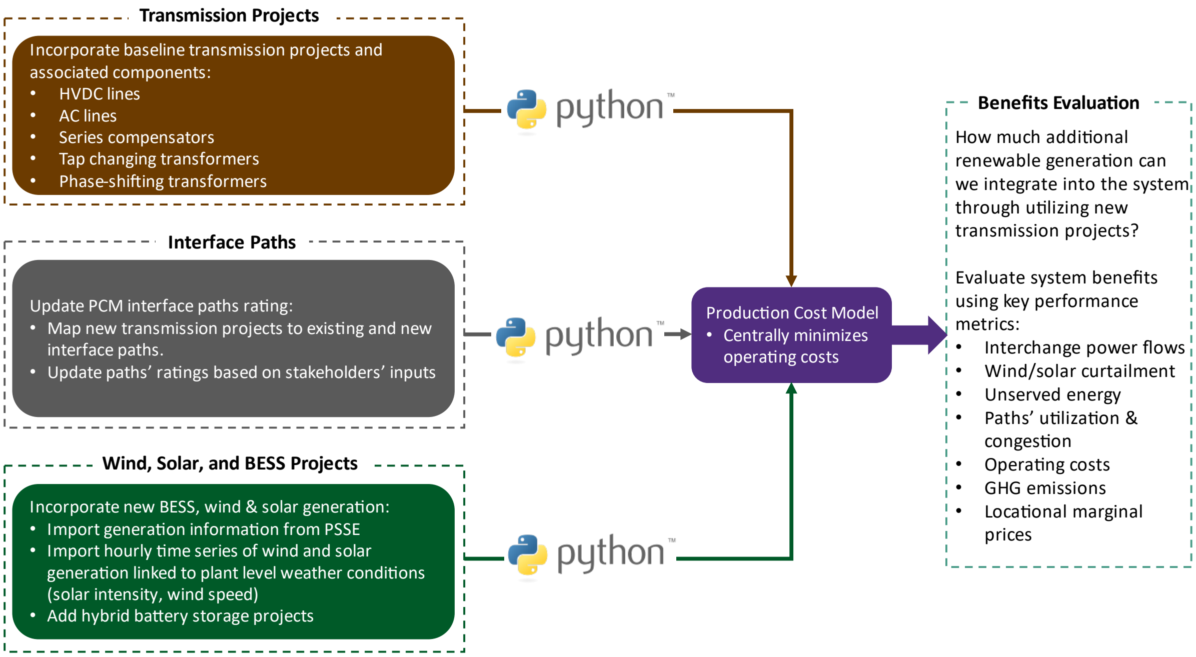


Figure 13. Automation process for updating the GridView Production Cost Model database.

Before presenting the simulation results, the study team first reports the simulation setup assumptions:

- Each hour was simulated for the entire year, Jan 1st through Dec 31st.
- Electricity demand and ancillary service requirements remained the same across all simulations, based on the WECC 2030 ADS.
- No additional thermal generation retirements were forced[7]. Instead, the thermal energy output is economically displaced by low-cost renewable resources as more renewable capacity is added in the Western Interconnection system.
- Wind and solar resources follow 2009 weather conditions for both existing and new renewable plants. Hydro resources follow 2009 water availability budgets. Load profiles follow 2009 electricity consumption shapes.
- No contingency (N-1) analysis was considered as part of the production cost modeling simulations. Contingency analyses are conducted in the AC power flow simulations (see Section 5.0 for more information).
- Bonneville Power Administration (BPA) hydropower plants in the WECC 2030 ADS are modeled without the capability to spill water. Instead, the actual water availability flowing through each plant's turbine is converted to a monthly energy budget (MWh) that is exogenously imported into GridView. Within the production cost model, the monthly energy budget is strategically allocated across weeks, days, and hours using a load-following logic designed to smooth out variations in net electricity demand. In this context, a significant portion of BPA hydropower production is directed to California to support early morning and late evening load ramps.

[7] Retirements from the Base case are respected.

4.0 Production Cost Modeling Results

In this section, the study team presents the production cost modeling results of the Base and High RE cases. The study team conducted production cost simulations for 8,760 dispatch hours (equivalent to one year) to understand the impact of additional transmission capacity and renewable resources on the Western Interconnection operations and decarbonization. The following metrics assess the operation changes:

- Generation output by technology type at different spatial and temporal resolutions.
- Interface paths' utilization using WECC metrics (i.e., U75, U90, U99). For more information about the definitions and mathematical expressions of these metrics, see Appendix A.
- Solar and wind curtailment at different spatial and temporal resolutions.
- CO_2 emissions at different spatial resolutions.
- Generation costs.

4.1 Generation Dispatch

The annual energy produced (in TWh) and percent generation by technology type of the Base and High RE cases are shown in Figure 14 and Figure 15, respectively.

In the High RE case, the energy produced from new wind and solar resources displaces the energy produced by the coal and natural gas supply by an amount of 144 TWh or 15%. In other words, the BTP transmission capacity combined with 72 GW of new wind, solar, and hybrid BESS capacity (Table 3) results in a 15% shift of total energy production to cleaner resources in the High RE case compared to that in the Base case.

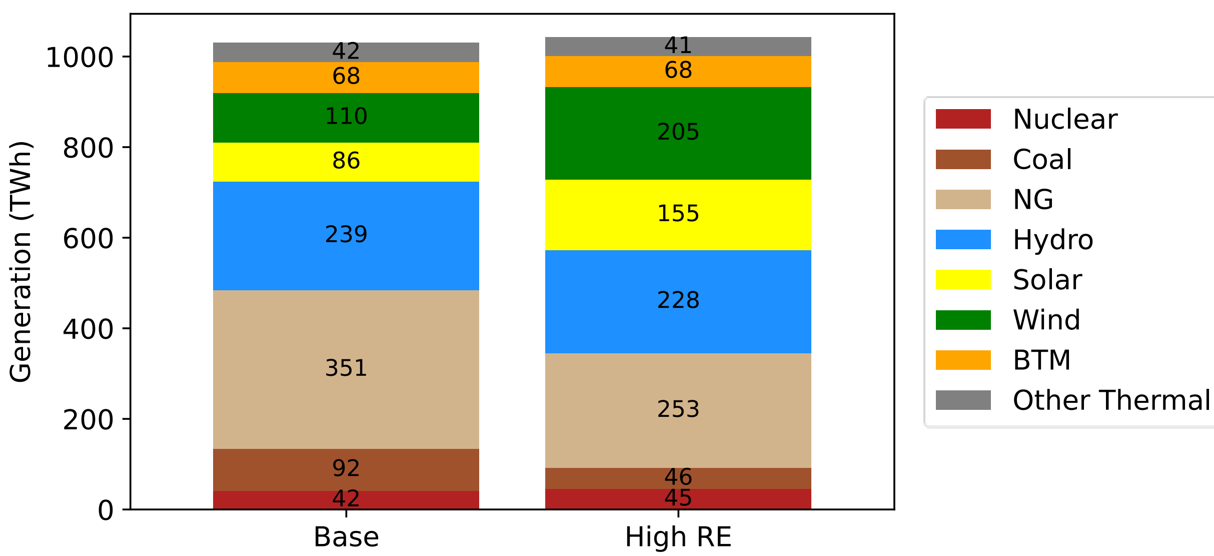


Figure 14. Energy produced (TWh) by technology type – total U.S. Western Interconnection (2030).

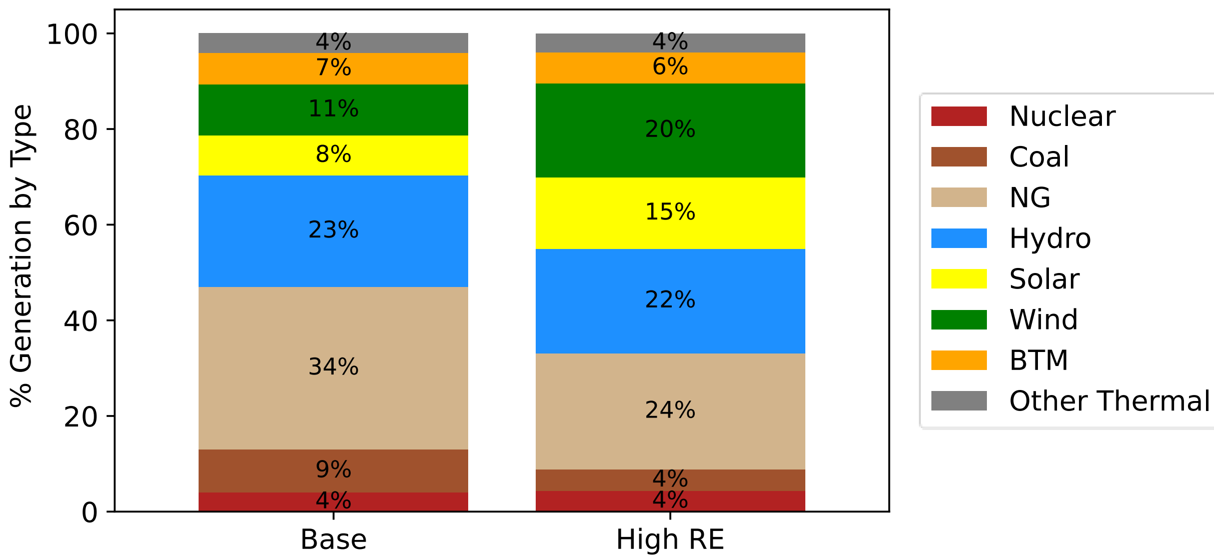


Figure 15. Percent energy produced by technology type – total U.S. Western Interconnection (2030).

Figure 16 and Figure 17 respectively show the seasonal and regional generation output by technology type for the High RE case. As expected, solar generation peaks in summer, while wind generation peaks in winter. The California and Southwest regions produce the highest amounts of solar energy, while the Basin region produces the highest amounts of wind energy.

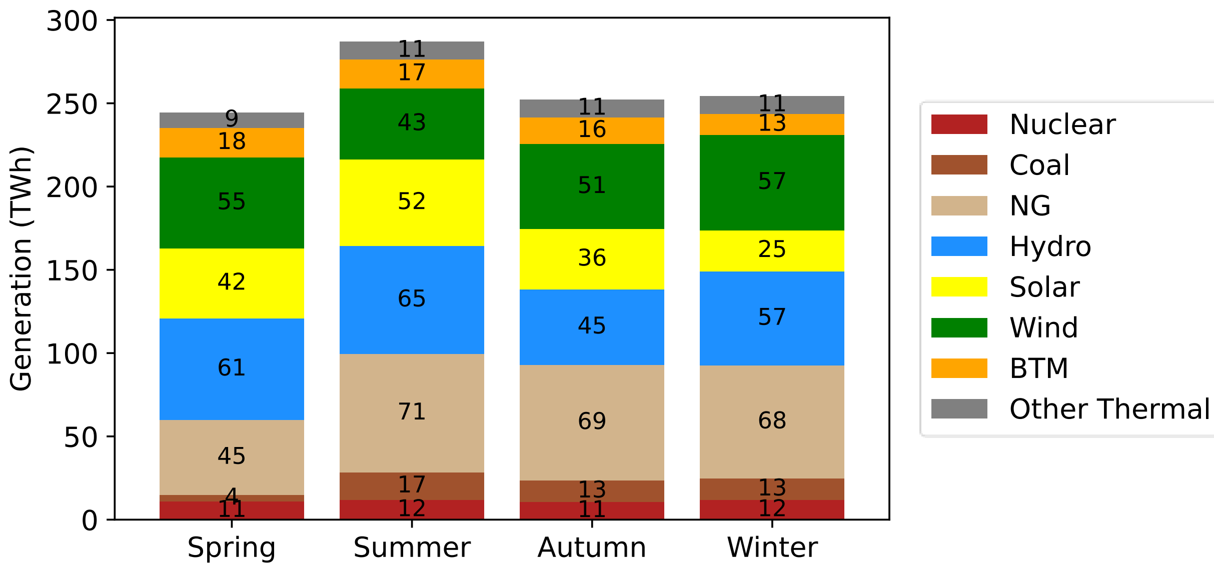


Figure 16. Seasonal energy produced for the High RE case – total U.S. Western Interconnection (2030).

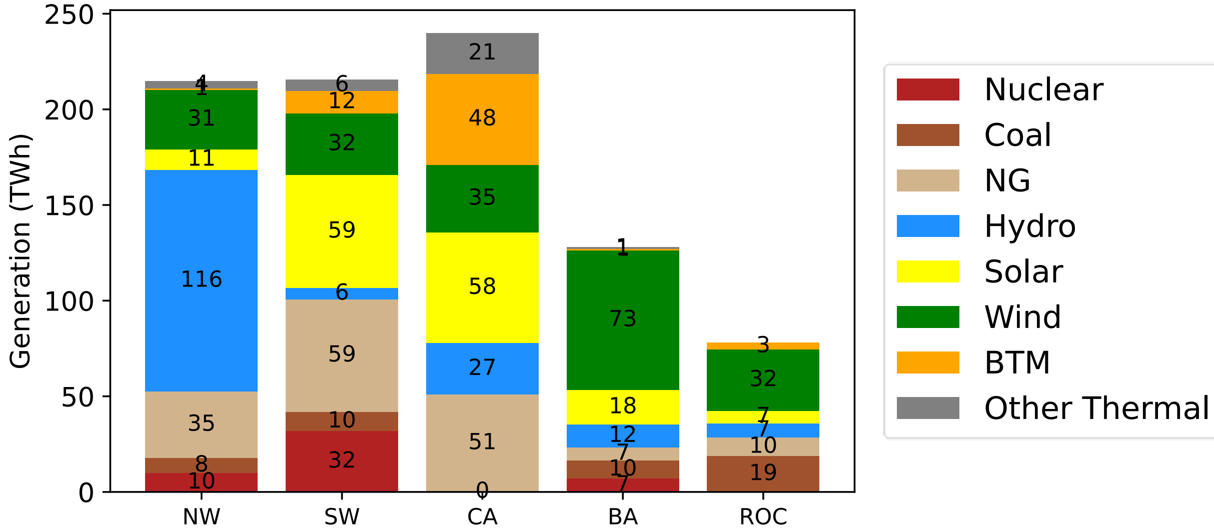


Figure 17. Energy produced by the WECC subregions in the High RE case: NW (Northwest), SW (Southwest), CA (California), BA (Basin), ROC (Rockies).

The impact of adding new renewable generation and additional BTP transmission capacity to the generation mix is also shown in Figure 18, which displays the generation difference between the High RE and Base cases by WECC load area. As expected, low-cost wind and solar resources have displaced the energy produced by coal and natural gas resources. This substitution is observed not only in areas with significant additions of new renewable capacity (e.g., SRP, PSCO, WACM, AZPS, PAUT) but also in areas with no or little new renewable capacity (e.g., PSEI, AVA, NVEP, CIPB, CISC). This result indicates the additional BTP transmission capacity can connect low-cost generation in resource-rich renewable regions (e.g., PAWY, AZPS, NEVP, NWMT) with the rest of the Western Interconnection system, thus reducing the fossil generation even in areas far away from the renewable locations.

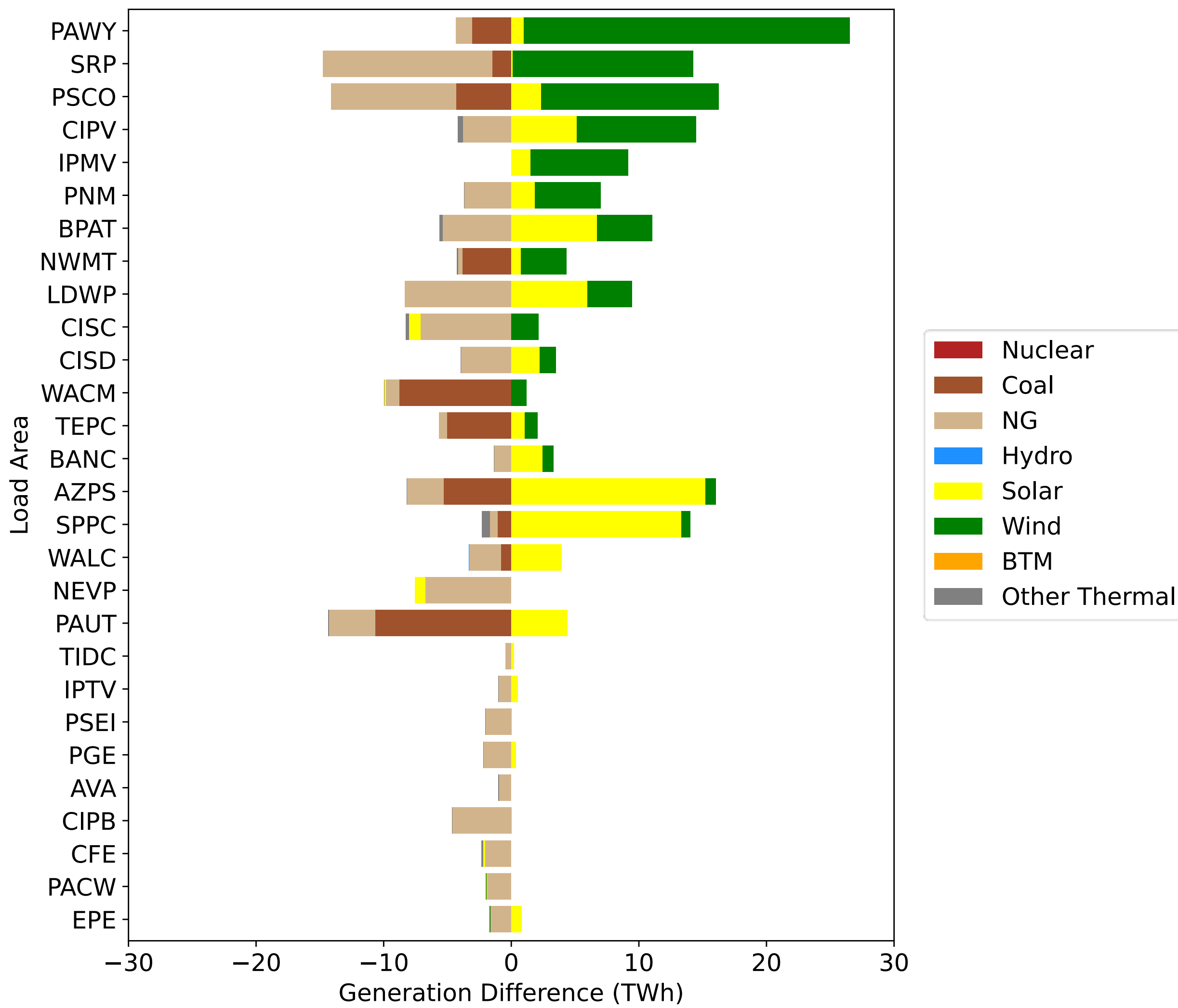


Figure 18. Generation difference between the High RE and Base cases by WECC load area.

4.2 Capacity Factors

Table 5 and Table 6 compare the average capacity factors of coal and natural gas resources between the Base and High RE cases by load area. As expected, the addition of new renewable resources and BTP capacity in the High RE case has greatly decreased the average capacity factors for both coal and natural gas resources compared to those in the Base case. More specifically, the average capacity factor of coal resources was reduced by 47 percent between the Base case (70%) and the High RE case (37%), while the average capacity factor of natural gas resources was reduced by 33 percent between the Base case (36%) and the High RE case (24%). The load areas that experienced the greatest percentage of capacity factor reduction were those with high installed capacities of natural gas and coal resources (e.g., SRP, WALC, WACM, SPPC, AZPS, NEVP, PAUT, PAWY, PSCO, NWMT).

It should be noted that the reduction of coal plant capacity factors below 50% may cause an additional maintenance cost for additional wear due to thermal cycling. The modeling results do not capture the additional operations and maintenance (O&M) costs incurred by thermal cycling; thus, the results may be overly optimistic. Some of the coal plants may no longer be economically viable if dispatched according to the High RE case under the current market constructs. As a result, coal power plants may shift to seasonal operations (e.g., during heavy load summer periods) or shut down completely, leaving natural gas resources as the main thermal dispatchable resource in the system for the rest of the year.

Table 5. Coal average capacity factors by load area.

Load Area	Base Case	High RE Case	% Difference
WALC	64%	10%	−54%
SPPC	71%	17%	−54%
AZPS	62%	22%	−40%
PAUT	71%	32%	−40%
WACM	76%	37%	−38%
TEPC	81%	43%	−38%
PSCO	82%	52%	−30%
PAWY	50%	29%	−21%
SRP	28%	7%	−21%
NWMT	80%	59%	−21%
CISC	44%	43%	−1%
Average	70%	37%	−33%

Table 6. Natural gas average capacity factors by load area.

Load Area	Base Case	High RE Case	% Difference
SRP	51%	28%	−23%
SPPC	28%	7%	−21%
PAWY	46%	26%	−20%
TH_PV	62%	43%	−20%
WALC	40%	21%	−19%
PNM	30%	12%	−18%
PACW	67%	49%	−18%
NEVP	27%	11%	−16%
NWMT	76%	60%	−16%
BPAT	66%	51%	−15%
WACM	24%	9%	−15%
PGE	62%	49%	−13%
AZPS	35%	22%	−13%
IPMV	17%	5%	−13%
PSCO	35%	24%	−11%
IPTV	39%	28%	−11%
PSEI	48%	37%	−11%
PAUT	31%	20%	−10%
CIPB	21%	11%	−10%
TEPC	55%	46%	−10%
LDWP	17%	7%	−9%

Load Area	Base Case	High RE Case	% Difference
AVA	39%	31%	−8%
EPE	46%	39%	−7%
CISD	14%	7%	−6%
CIPV	16%	9%	−6%
TIDC	8%	2%	−6%
CISC	17%	11%	−5%
BANC	21%	19%	−2%
IID	3%	2%	−1%
Average	36%	24%	−12%

Figure 19 shows the CO_2 emissions change for the baseline cases with respect to the year 2005. The High RE case shows a reduction of CO_2 emissions by 73% relative to 2005, reaching to 27% CO_2 emissions in 2030. This is an 18 percentage point decrease from that in the Base case, where no BTPs and new renewable projects are considered. This result indicates that with the additional transmission capacity of the BTPs, along with the renewable capacity in the High RE case, the Western Interconnection has the potential to achieve up to 73% of its decarbonization targets by 2030. Further transmission expansion efforts and renewable capacity, including thermal plant retirements, would be required to reach 100% carbon pollution-free electricity by 2035.

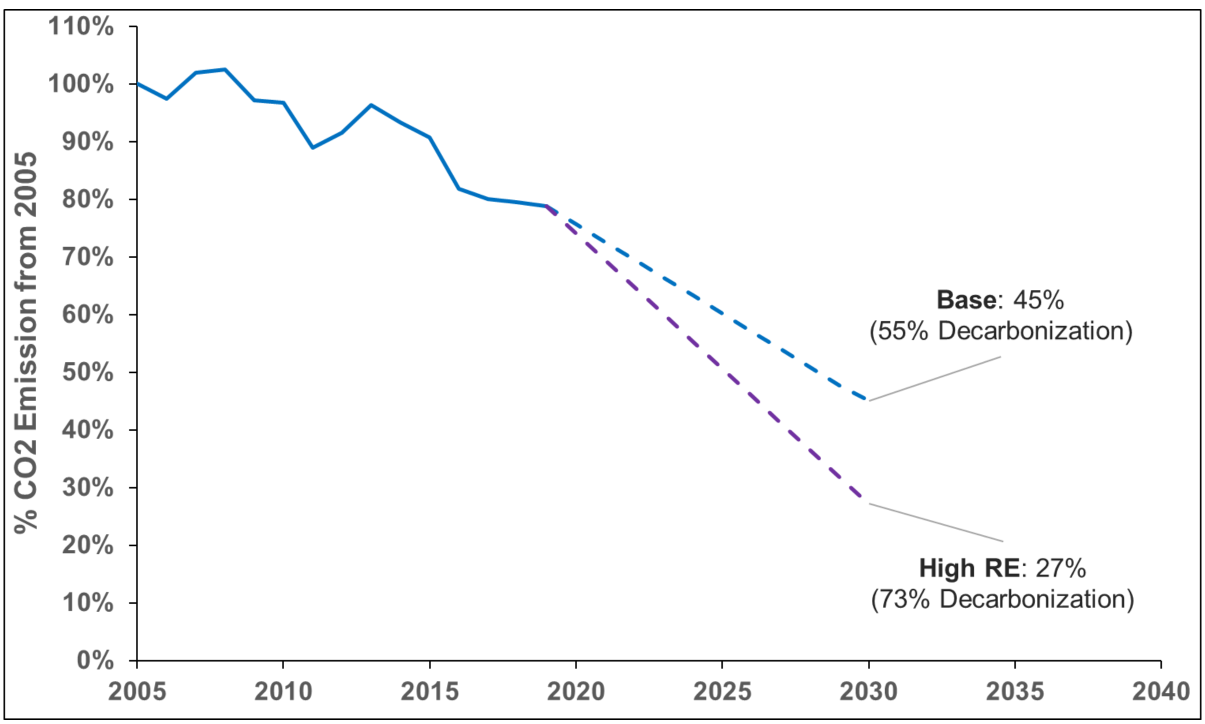


Figure 19. CO_2 emissions change for the baseline cases with respect to the year 2005 – total U.S. Western Interconnection.

Figure 20 disaggregates the total U.S. Western Interconnection CO_2 emissions by technology type. Natural gas resources emit the highest amounts of total CO_2 emissions followed by coal resources. Figure 21 visualizes the percent CO_2 emissions difference between the High RE and Base cases by state. The largest percent reduction is observed in the central-west Western

Interconnection states (i.e., Utah, Nevada, Wyoming, Colorado, Arizona, New Mexico), where large amounts of thermal capacity are replaced by renewable energy.

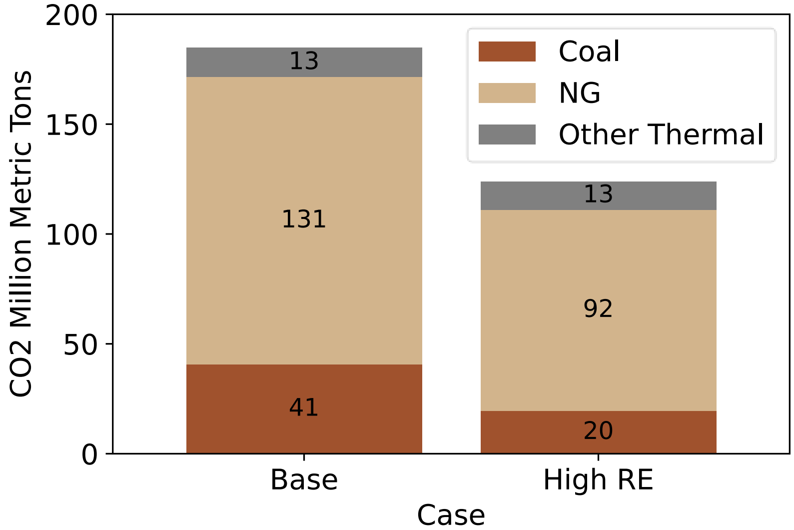


Figure 20. CO_2 emissions by technology type – total U.S. Western Interconnection (2030).

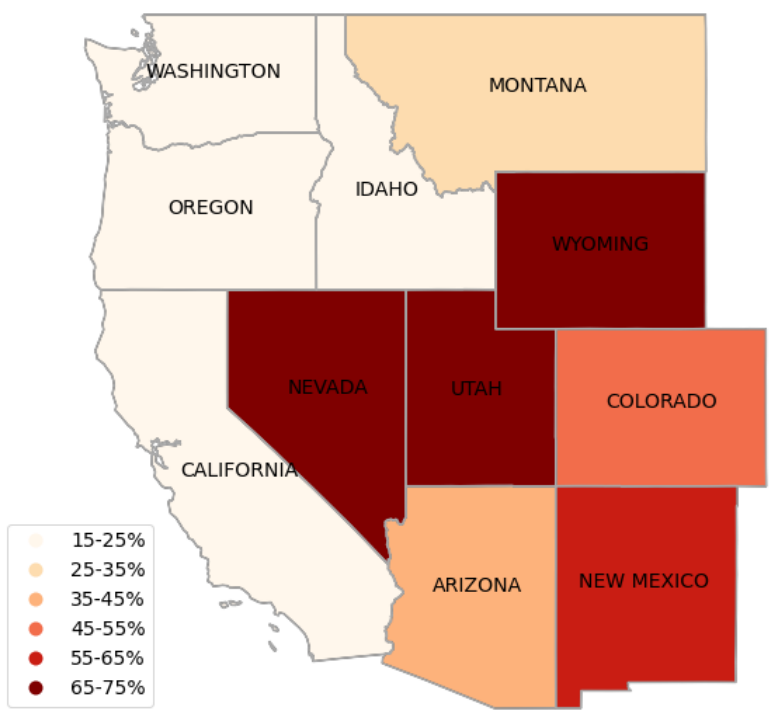


Figure 21. CO_2 emissions reductions for the High RE case relative to the Base case.

4.3 Wind and Solar Curtailment

Figure 22 and Figure 23 depict the annual curtailment (in TWh) and the percent curtailment, respectively, of wind and solar resources for the baseline cases. The curtailment levels for wind and solar resources increase as renewable integration levels rise in the High RE case. Specifically, the percent curtailment of wind increases from 1.8% in the Base case to 7.6% in the High RE case, while the percent curtailment of solar increases from 3.7% in the Base case to 6.1% in the High RE case[8]. Overall, as more renewables are added in the Western Interconnection, transmission saturation and overgeneration increase curtailment. Unless the transfer capability of the transmission network is further enhanced or new energy storage resources are added, any new variable renewable additions above the levels in the High RE case will drastically increase curtailment.

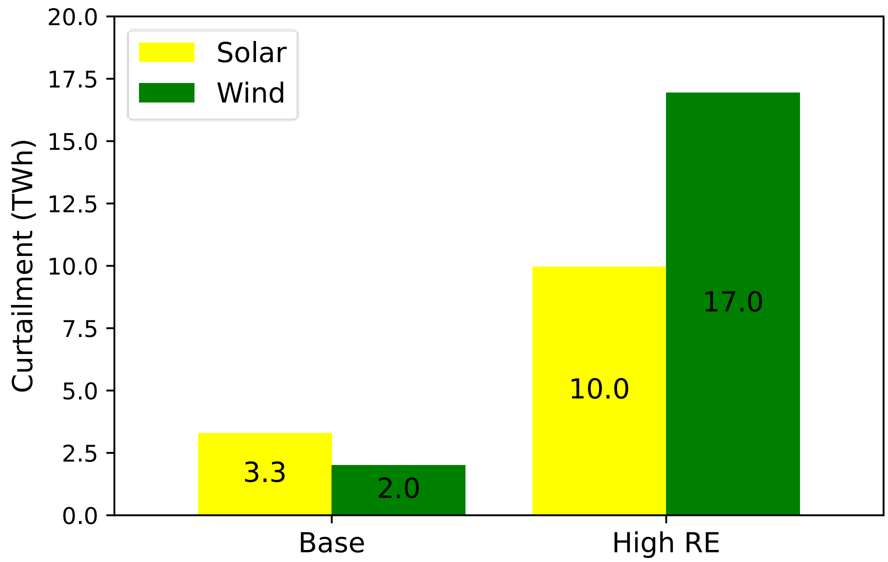


Figure 22. Wind and solar curtailment (TWh) – total U.S. Western Interconnection (2030).

[8] Please note that the figures in this section show only wind and solar curtailment. Hydro spillage is not allowed for the majority of hydropower facilities and is therefore zero, as outlined in the modeling assumptions covered in Section 3.4.

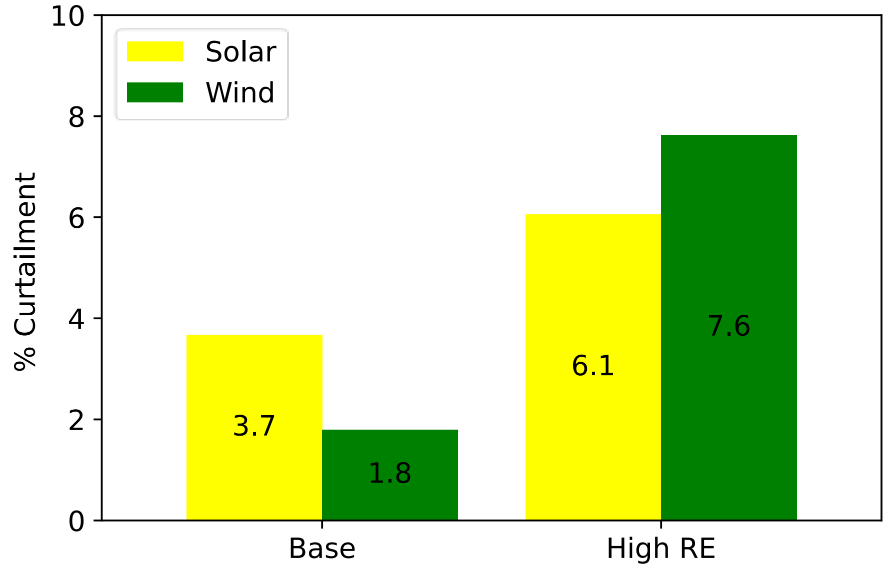


Figure 23. Percent wind and solar curtailment – total U.S. Western Interconnection (2030).

Figure 24 shows the percent wind and solar curtailment in the High RE case for select load areas[9]. As expected, the highest percent curtailment is observed in areas that experienced large additions of renewable capacity (Table 4), such as PAWY, NWMT, PSCO, and SRP. It is important to note that none of the load areas exceeded the 20% curtailment limit imposed to protect the economic feasibility of the renewable project (see Section 3.2).

[9] The geographical boundaries of the U.S. Western Interconnection load areas are shown in Figure 3.

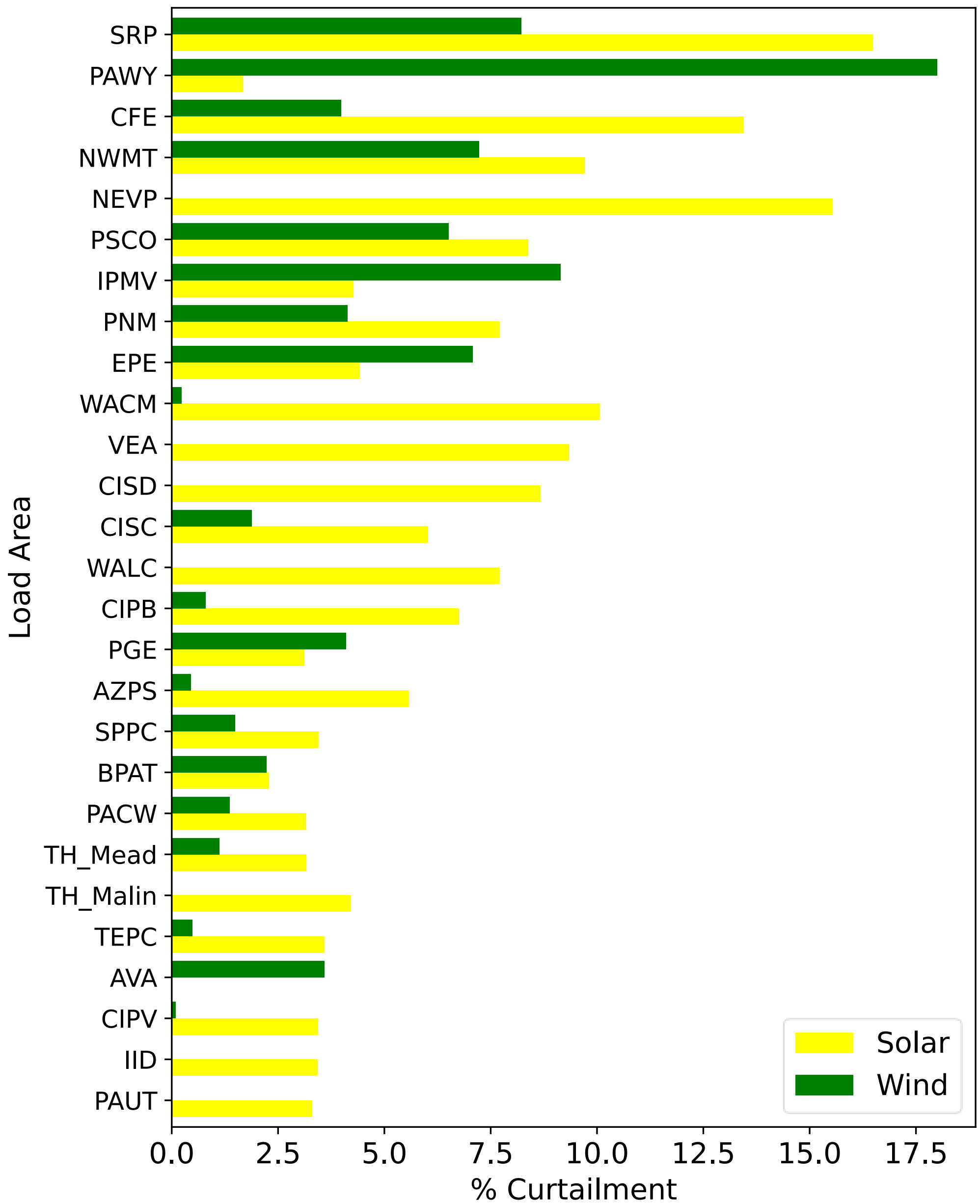


Figure 24. Percent wind and solar curtailment for select load areas for the High RE case.

Figure 25 shows the hourly average of renewable curtailment (combined wind and solar) for each month of the year to better understand the seasonal characteristics of curtailment. For both baseline cases, renewable curtailment peaks during springtime (i.e., March, April, May) because of several coincidental factors: (1) hydropower overgeneration due to increased runoff flows (precipitation and snowmelt), which are typical in the Western Interconnection system; (2) low-load conditions due to lower heating and/or air-conditioning electricity demands; and (3) solar overgeneration due to favorable weather conditions.

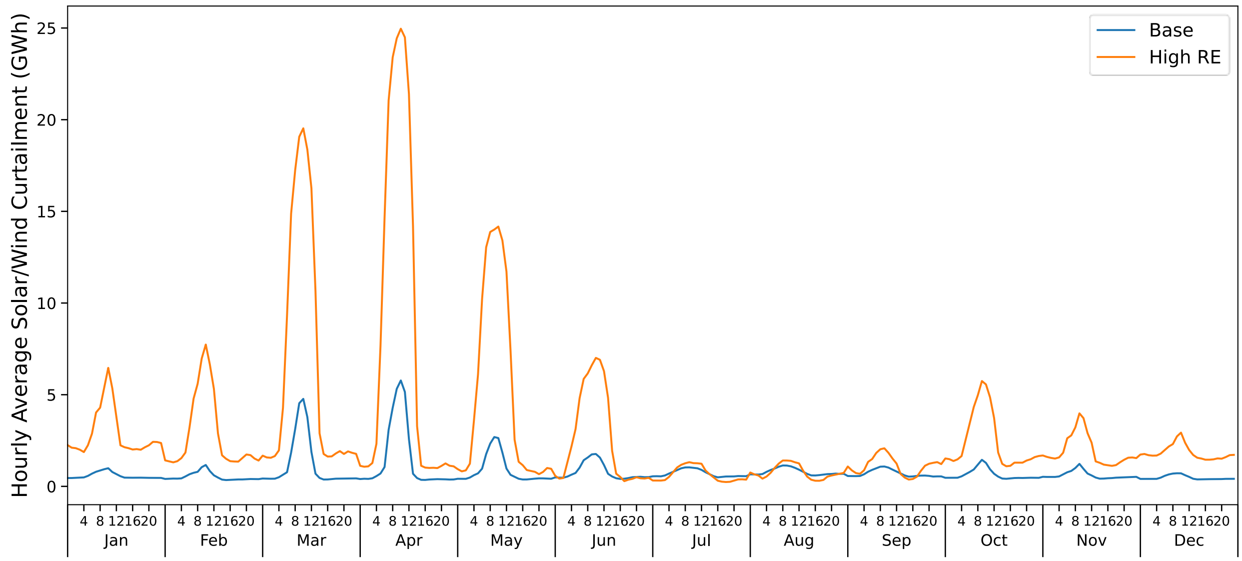


Figure 25. Hourly average of aggregated wind and solar curtailment (GWh) by month.

4.4 Interregional Net Energy Transfers

Figure 26 shows the interregional net energy transfers for the Base case (top) and High RE case (bottom) over a period of one year. In the Base case, power transfers adhere to a business-as-usual convention, with transfers from the Northwest (primarily from hydro resources) and Southwest (mainly from coal, natural gas, and other thermal plants) meeting the high demand in California, which is the highest among all regions (Figure 5). In the High RE case, the additional renewable and BTP capacities have reduced the net energy transfers from the Northwest to California by about 26%. This result indicates that the additional BTP capacity provides congestion relief to critical transmission corridors connecting these two regions, such as Paths 65 and 66. On the contrary, energy transfers are considerably increased (about 74%) from Basin to California utilizing the additional BTP capacity to move abundant wind and solar energy to California. These operational changes are further explored next.

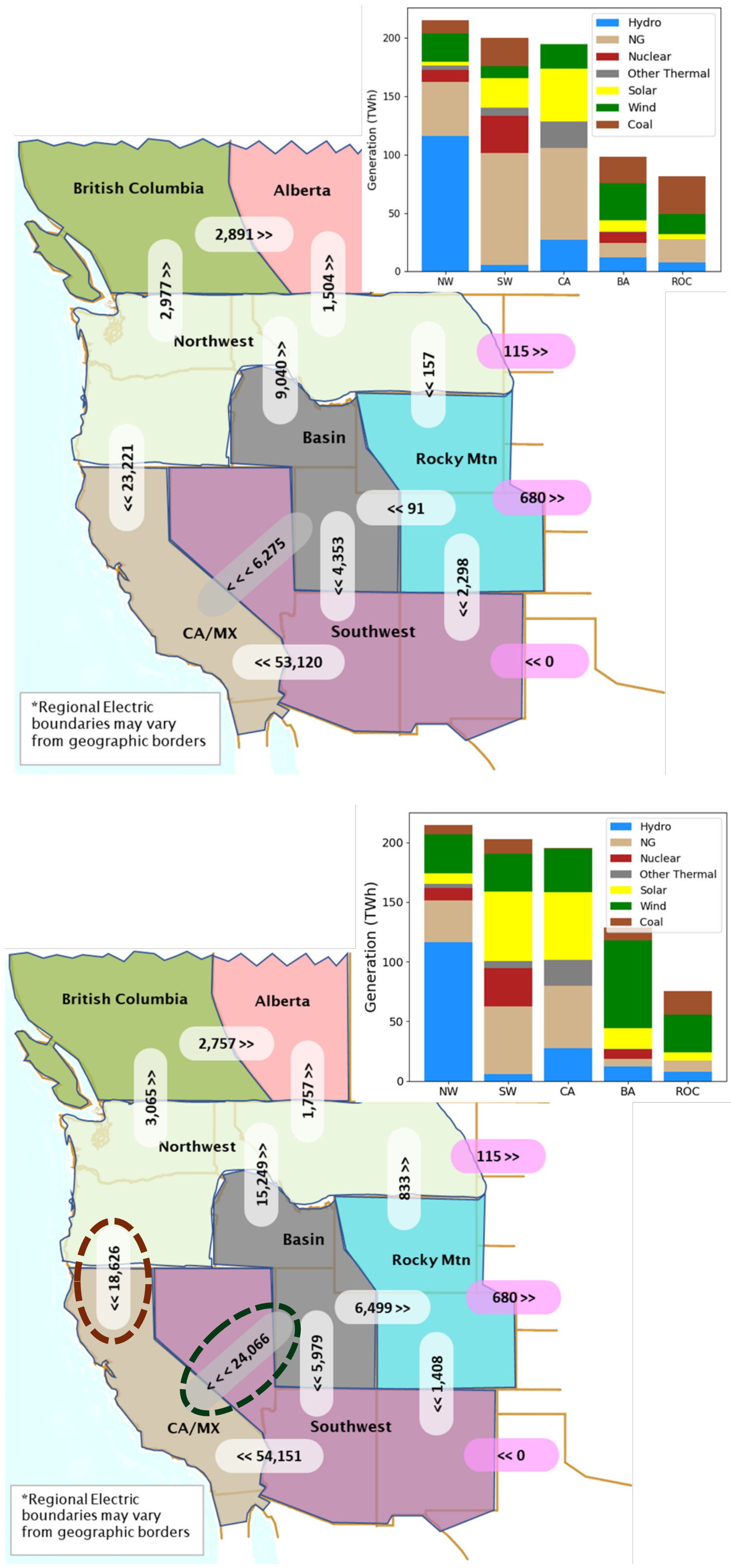


Figure 26. Net interregional energy transfers (GWh) for the Base case (top) and High RE case (bottom).

4.5 Utilization of Interface Paths

This section investigates the operational changes in path utilization due to the new renewable resources and BTP capacity in the High RE case. To understand these changes, the study team presents the flow duration curves and utilization metrics of existing interface paths for the Base and High RE cases. The study team also presents historical/actual flows (referred to as “Act” in the plots) of existing interface paths whenever data are available.

To better understand the interactions among existing paths, new BTPs, and new renewable projects, the study team grouped our analysis based on the geographical footprint of interface paths as follows:

- Group 1 – Interactions between Pacific Northwest (PNW) and California: Path 65[10] (Pacific DC Intertie), Path 66[11] (California–Oregon Intertie).
- Group 2 – Interactions between Southwest and California: Path 46[12] (West of Colorado River), Path 27[13] (Intermountain Power Project DC Line).
- Group 3 – Interactions between Idaho and PNW: Path 14[14] (with B2H)

Figure C.1 in Appendix C shows the WECC interface paths.

4.5.1 Group 1 Analysis

In Figure 27-a, the flow duration curve of Path 65 shows less energy exports from the PNW to Southern California (positive values) in the High RE case compared to those in the Base case. This is because (1) the utilization of new renewable energy and energy storage supply in California (about 11 GW; see Figure 8), which displaces a portion of energy imports from the PNW to California, and (2) the increase in energy imports from the Desert Southwest, Basin, Rocky Mountain, and Northeast regions (Utah, Arizona, Colorado, Nevada, Wyoming, Montana, New Mexico) due to the additional BTP capacity and new renewable energy added in these areas.

In Figure 27-b, the PNW monthly average energy exports to California peak in May, June, and July for both cases because of the increased hydropower energy production in the PNW during these months. However, a reverse flow (negative values) is observed for the remaining months, indicating California exports to the PNW. This is more evident in the High RE case because of the increased energy imports to California (specifically from Paths 27 and 46), which have entirely shifted operations during daytime compared to the Base case, as shown for the month

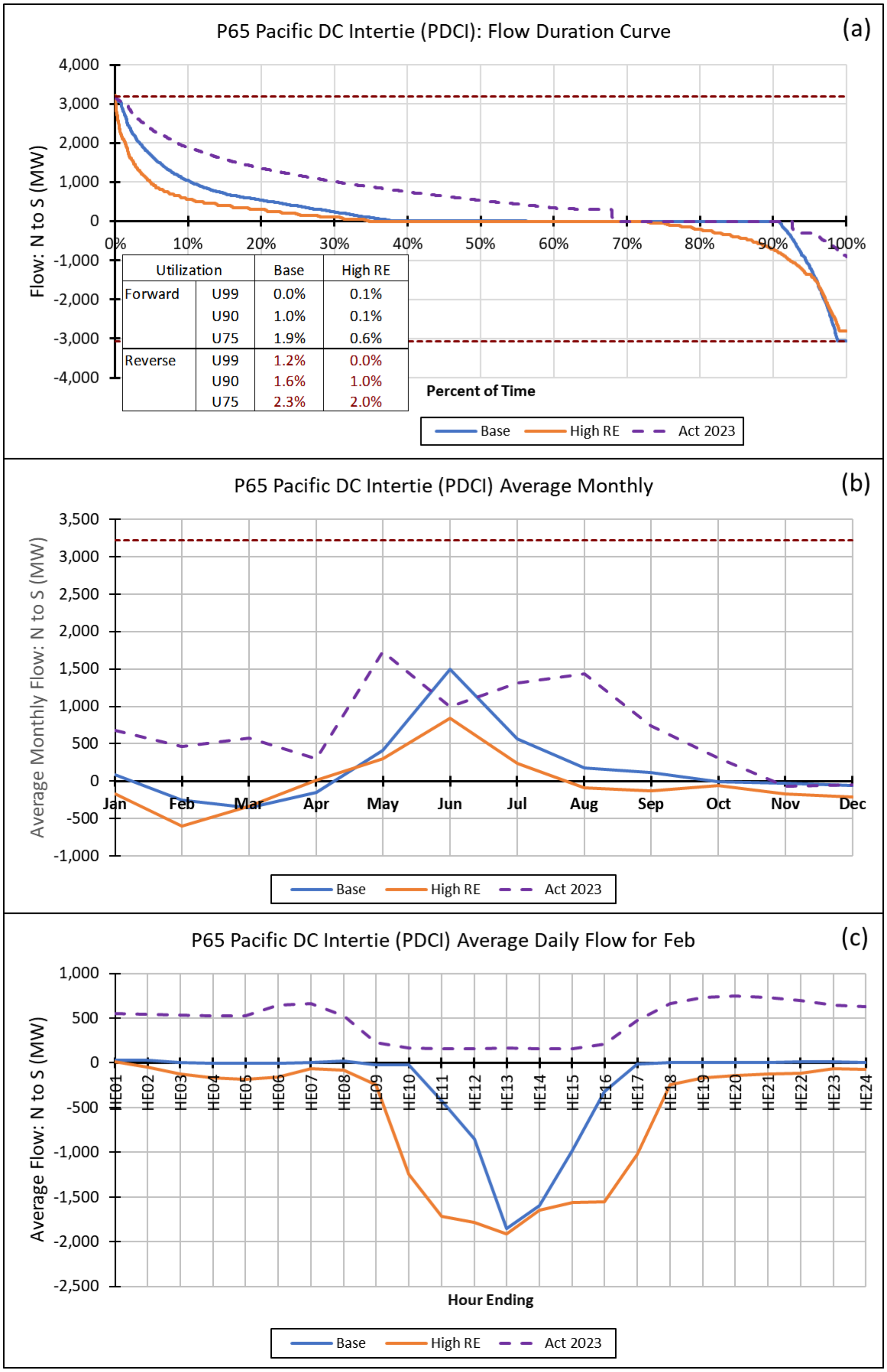
[10] Path 65 (Pacific DC Intertie) transfers electricity from Northwest (Celio substation) to Southern California (Sylmar substation). The PDCI line is a ±500 kV direct current (DC) multiterminal system. This system is divided into the northern and southern systems; the demarcation point is the Nevada–Oregon border (NOB). The North to South limit is 3,220 MW, while the South to North limit is 3,100 MW.
[11] 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, while the South to North limit is 3,675 MW.
[12] Path 46 (West of 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 11,200 MW transfer limit.
[13] Path 27 (Intermountain Power Project DC Line) consists of one DC line from Intermountain station in central Utah to Adelanto station in Southern California (IPPDC). The Northeast to Southwest limit is 2,400 MW, while the Southwest to Northeast limit is 1,400 MW.
[14] Path 14, which includes the B2H project, runs across eastern Oregon and southwestern Idaho.

of February in Figure 27-c. This solar energy production surplus gradually changes the flow direction on Path 65 during the daytime (Figure 27-c), sending more electricity to the PNW in the High RE case (about 23% of 8760 h) than in the Base case (about 9% of 8760 h).

In Figure 28-a, the flow duration curve of Path 66 shows less PNW energy exports in the High RE case compared to those in the Base case. Specifically, the U75 and U90 metrics respectively decreased to 20.6% and 9.4% in the High RE case from 32.7% and 18.5% in the Base case. This is observed for almost all months of the year, as shown in Figure 28-b. However, it is important to note that the U99 values for the forward North to South direction (PNW to California) are 0% and 2.9% for the Base and High RE cases, respectively. This result indicates that although the overall North to South flows of Path 66 were reduced in the High RE scenario, the flows became more prone to sharp peaks, suggesting that the path is utilized to provide firm power support to California when solar energy generation starts decreasing.

Like Path 65, Path 66 sends more electricity to the PNW (negative values) in the High RE case (about 13% of 8760 h) than in the Base case (about 4% of 8760 h), as shown in Figure 28-a. This is because of the higher amount of solar capacity installed in Northern California (BANC, CIPV, CIPB) in the High RE case.

Interestingly, there is a notable surge in PNW power exports via Path 66 in both scenarios compared to the actual 2023 flows (Figure 28-a). This can be attributed to the retirement of coal and nuclear plants in California, which is factored into the baseline cases but not represented in the 2023 flows. Consequently, PNW power exports increase significantly in the Base case and to a lesser extent in the High RE case, serving to compensate for California’s thermal retirements.



Utilization		Base	High RE
Forward	U99	0.0%	0.1%
	U90	1.0%	0.1%
	U75	1.9%	0.6%
Reverse	U99	1.2%	0.0%
	U90	1.6%	1.0%
	U75	2.3%	2.0%

Figure 27. (a) Path 65 flow duration curve and utilization metrics for the whole year; (b) Path 65 monthly average power flow; (c) Path 65 hourly average power flow for February.

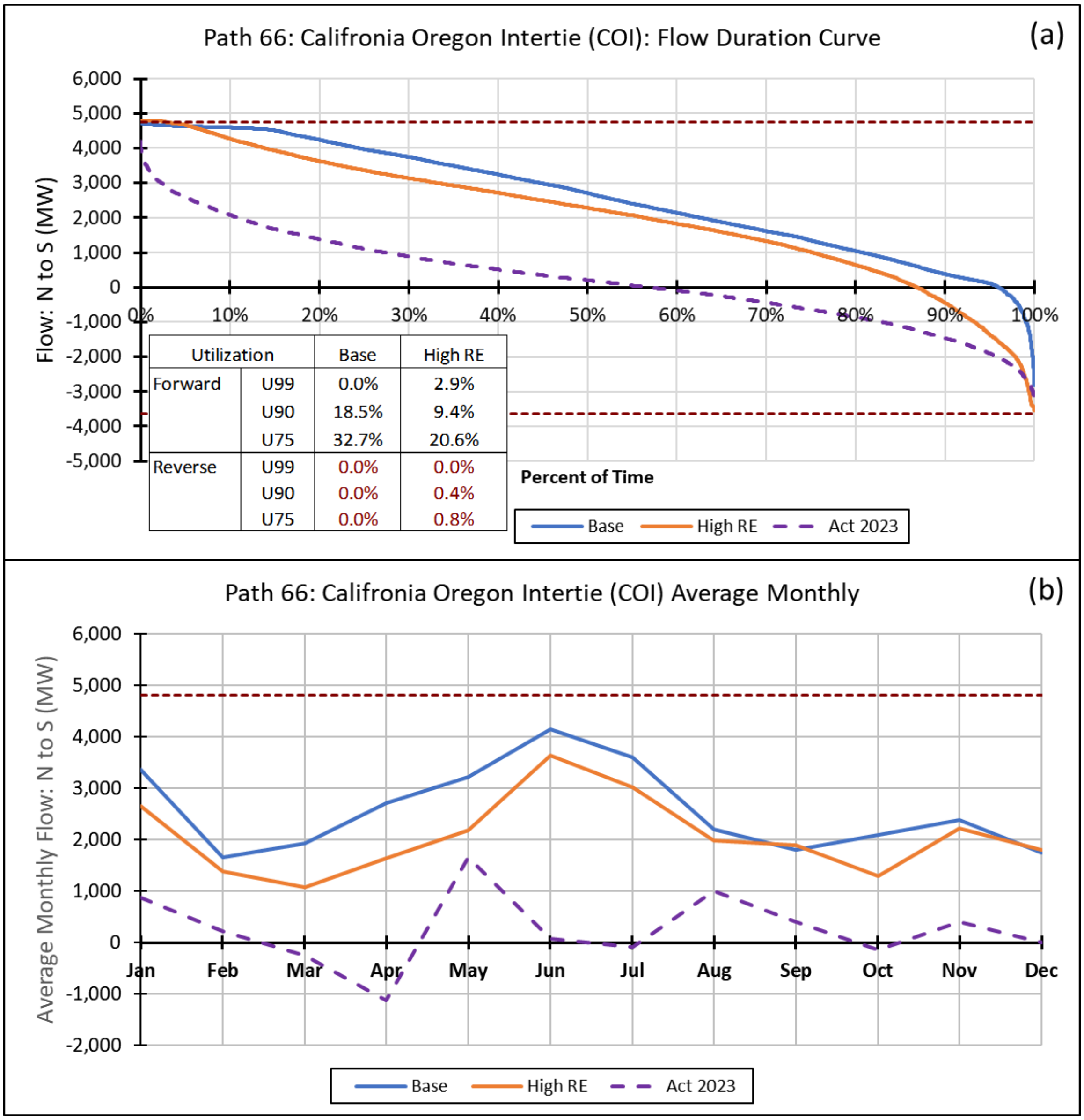


Figure 28. (a) Path 66 flow duration curve and utilization metrics for the whole year; (b) Path 66 monthly average power flow.

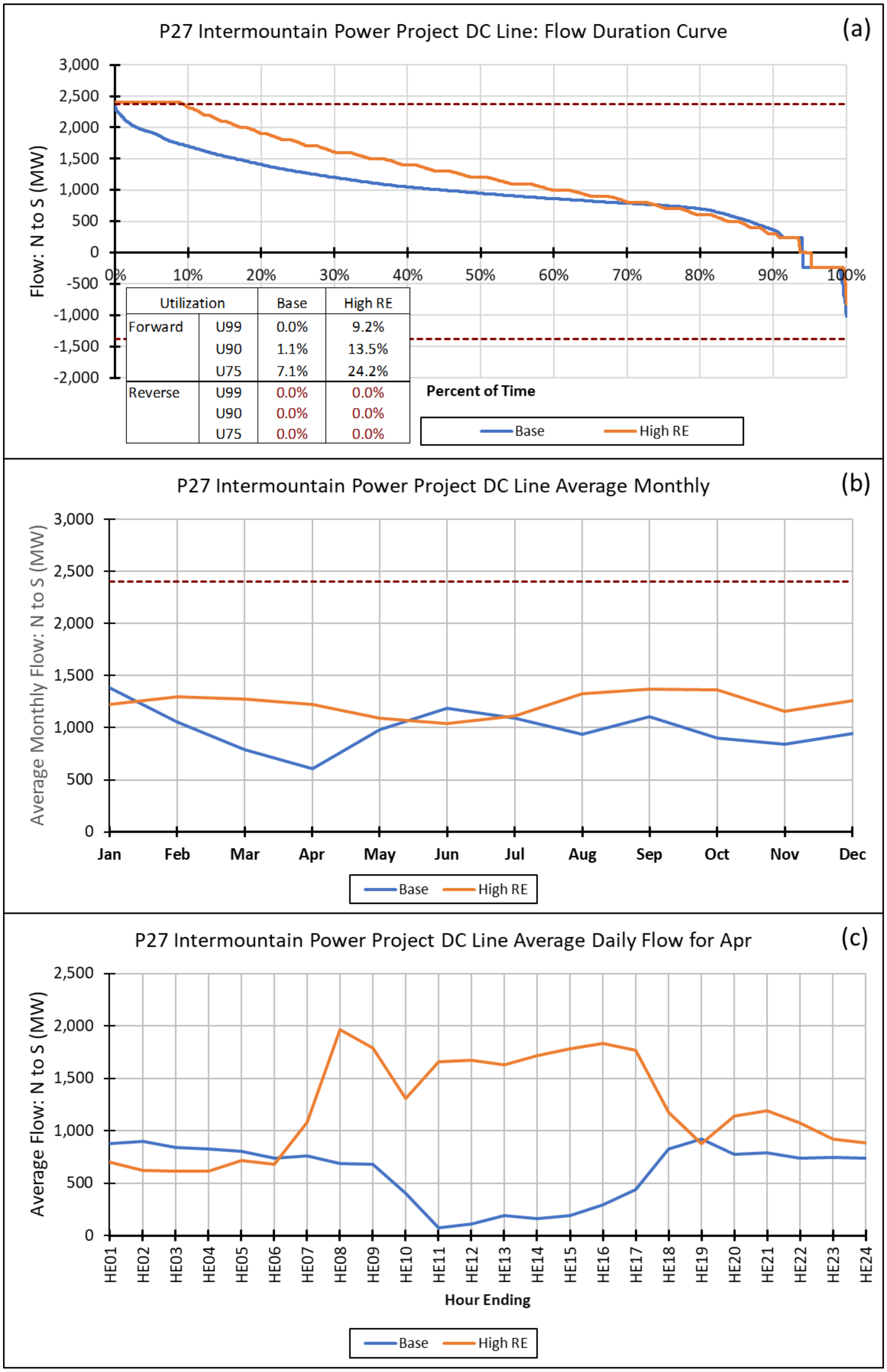
4.5.2 Group 2 Analysis

Figure 29 and Figure 30 respectively display the flow duration curves of Paths 27 and 46. There is a modest increase in power flowing into Southern California from these paths in the High RE case compared to that in the Base case. As previously mentioned, Paths 27 and 46 utilize new renewable supply from the Desert Southwest and Basin regions together with BTP capacity to boost Southern California imports.

On Path 27, increased imports to Southern California are evident for almost all months except for June and January, when PNW hydropower production (see Appendix E) displaces wind and solar imports to California (refer to Figure 29-b). This displacement of renewables—wind, solar, and hydro—and, more specifically, the prioritization of renewable curtailment are influenced by exogenously defined curtailment values found in the WECC 2030 ADS. These values reflect policy decisions (e.g., production cost credit) and other hydro-environmental factors (e.g., nonpower-related applications). For the month of April, energy imports to Southern California via Path 27 show an increase during the morning (hours 8–11) to support the morning load ramp[15], as depicted in Figure 29-c. Meanwhile, in July, energy imports to Southern California via Path 46 peak in the evening hours to support the evening peak demand.

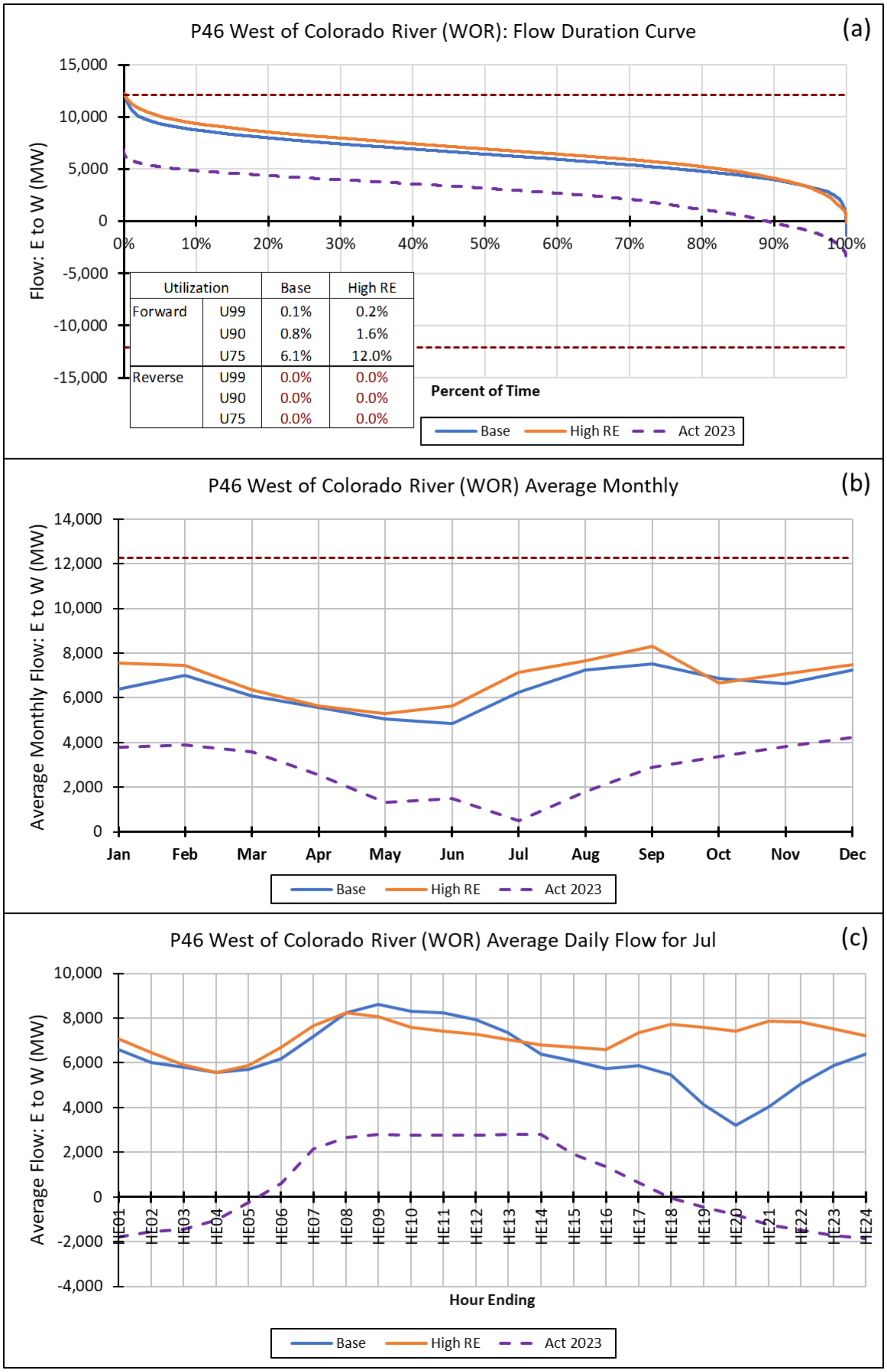
An interesting observation regarding Path 46 is that historic flows in 2023 recorded negative values for approximately 10% of the year, indicating energy flowing from Southern California to the Desert Southwest. These hours coincide with the early morning and nighttime hours (see Figure 30-c), during which solar generation in both Southern California and the Desert Southwest is low or zero. During these hours, Southern California utilizes wind, hydropower, and pumped hydro storage resources to support the Desert Southwest demand. In contrast, in the 2030 baseline cases, the wind development in New Mexico and the solar and energy storage additions in the Desert Southwest help to serve the Desert Southwest load, thereby diminishing the need for energy exports from California.

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



Utilization		Base	High RE
Forward	U99	0.0%	9.2%
	U90	1.1%	13.5%
	U75	7.1%	24.2%
Reverse	U99	0.0%	0.0%
	U90	0.0%	0.0%
	U75	0.0%	0.0%

Figure 29. (a) Path 27 flow duration curve and utilization metrics for the whole year; (b) Path 27 monthly average power flow; (c) Path 27 hourly average power flow for April.



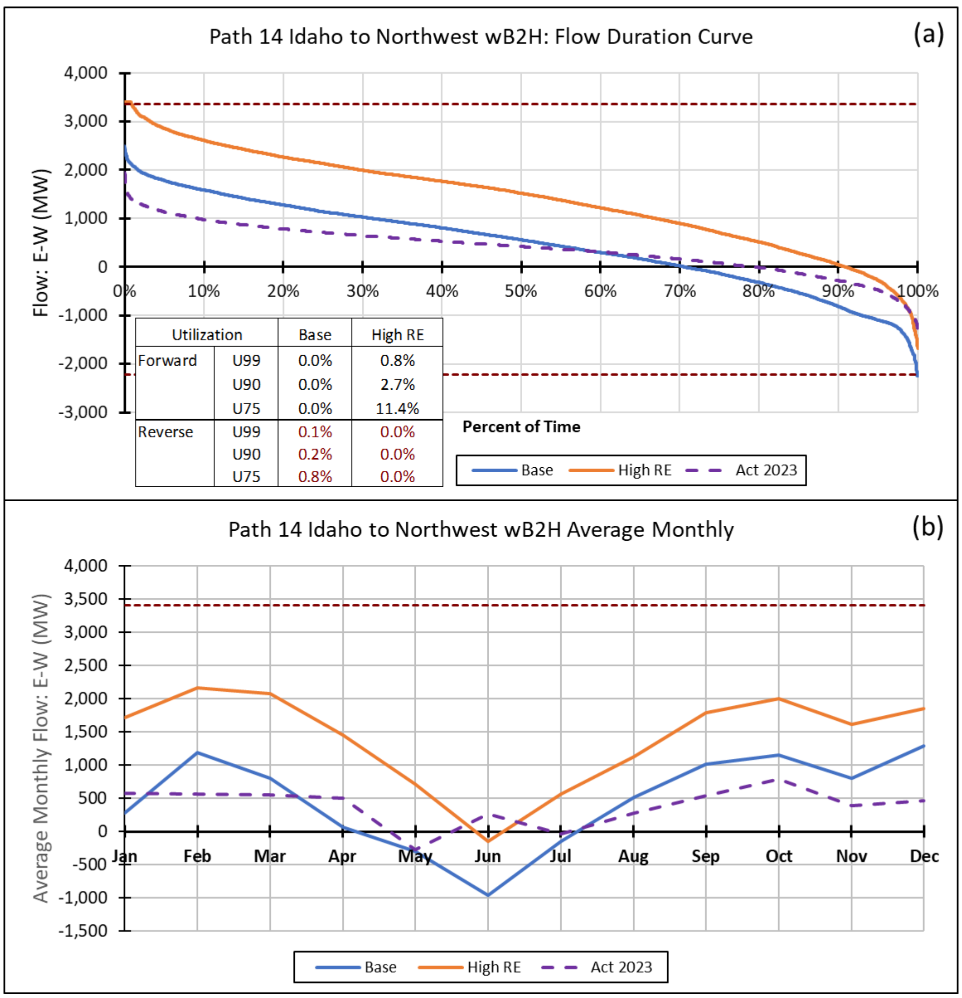
Utilization		Base	High RE
Forward	U99	0.1%	0.2%
	U90	0.8%	1.6%
	U75	6.1%	12.0%
Reverse	U99	0.0%	0.0%
	U90	0.0%	0.0%
	U75	0.0%	0.0%

Figure 30. (a) Path 46 flow duration curve and utilization metrics for the whole year; (b) Path 46 monthly average power flow; (c) Path 46 hourly average power flow for July.

4.5.3 Group 3 Analysis

Figure 31-a shows the flow duration curve of Path 14 (with B2H connection), connecting eastern Oregon (Northwest) with southwestern Idaho. Comparing the two baseline scenarios, it's evident that power exports from southwestern Idaho have increased in the High RE case compared to those in the Base case, thanks to both the additional transmission capacity provided by the B2H project and the introduction of new renewable supply in the region.

In Figure 31-b, the monthly average flows exhibit a seasonal pattern, with southwestern Idaho exports diminishing (zero or negative values) during the summer because of the high reliance of the Northwest on hydro resources during these months. On the other hand, southwestern Idaho exports (positive values) to the Northwest mainly occur during the winter months to support the high Northwest winter demand. These exports are intensified in the High RE case because of the introduction of new renewable resources in eastern Idaho and the greater region (e.g., Wyoming and Utah).



Utilization		Base	High RE
Forward	U99	0.0%	0.8%
	U90	0.0%	2.7%
	U75	0.0%	11.4%
Reverse	U99	0.1%	0.0%
	U90	0.2%	0.0%
	U75	0.8%	0.0%

Figure 31. (a) Path 14 flow duration curve and utilization metrics for the whole year; (b) Path 14 monthly average power flow.

4.6 Generation Cost

Table 7 shows the total generation cost by load area for both cases, including the fuel cost, the minimum up and down costs, the startup costs, and the O&M costs of generating units. Evidently, the addition of low-cost renewable resources in the High RE case has reduced the total annual generation cost WECC-wide by 32% compared to the Base case.

Table 7. Total generation cost (M$) by load area.

Load Area	Base Case	High RE Case	% Difference
AVA	181.8	152.2	−16%
AZPS	513.3	378.8	−26%
BANC	355.3	288.9	−19%
BCHA	96.6	88.4	−9%
SPAT	499.0	419.1	−16%
CFE	491.3	442.8	−10%
CIPB	860.9	601.9	−30%
CIPV	1,033.3	789.4	−24%
CISC	1,604.2	1,214.7	−24%
CISD	561.9	357.0	−36%
EPE	238.1	216.9	−9%
IID	58.0	51.0	−12%
IPFE	4.1	1.9	−55%
IPMV	5.0	2.4	−52%
IPTV	104.1	75.4	−28%
LDWP	723.0	274.0	−62%
NEVP	415.3	186.2	−55%
NWMT	94.8	70.7	−25%
PACW	225.6	166.5	−26%
PAID	60.6	48.0	−21%
PAUT	534.0	255.3	−52%
PAWY	135.7	78.3	−42%
PGE	283.2	239.3	−15%
PNM	284.0	158.8	−44%
PSCO	706.9	405.5	−43%
PSEI	344.9	282.5	−18%
SCL	1.5	0.0	−100%
SPPC	89.7	50.2	−44%
SRP	953.0	587.1	−38%
TEPC	171.1	117.4	−31%
TH_PV	437.4	316.4	−28%
TIDC	47.3	16.0	−66%
VEA	0.7	0.7	−9%
WACM	311.5	182.6	−41%
WALC	205.3	129.8	−37%
WECC Total	**12,632.3**	**8,646.1**	**−32%**

5.0 AC Power Flow Modeling

This section provides a brief description of the methods that were used to create AC power flow cases from the production cost model. It conveys the evolution of the power flow from the production cost model, why it is necessary to advance the state-of-the-art in power flow analytics, and the benefits that industry can gain from this analysis to replicate the process for detailed transmission planning studies.

5.1 Importance of the Linkage between the Production Cost Model and Power Flow Model

Grid planners need enhanced power grid reliability studies to prepare the transmission network for the increasing penetration of variable generation and the growing variability and volume of electric demand. Grid planning at the interconnection level currently requires only a small number of system snapshots to manage today's grid. As transmission expands, however, planners will need greater numbers of system snapshots for reliable grid planning, especially interregional transmission, as intricate transactions among BAs become more common and as variable renewable energy (VRE) penetration increases. Grid planners will need datasets, tools, and models that provide the ability to examine solutions across thousands of chronological power flow cases to understand the operational impacts of increased penetration of VRE and changing load patterns (Hitachi Energy n.d.; WECC 2021a). A chronological power flow is valuable in transmission planning to calculate performance indices for systems with a high penetration of renewables, such as the optimal combination of network reinforcements to reduce energy spillage and the cost-effectiveness of equipment investments (WECC 2020c).

The process to create a single, operable AC power flow model takes a substantial amount of time, as it involves production cost modeling, the convergence of the AC power flow, and reactive power planning (da Silva et al. 2012; Hitachi Energy n.d.; ISO New England 2019; WECC 2021a, 2021c). To address these challenges, PNNL developed a chronological AC power flow automated generation (C-PAGE) tool (Vyakaranam et al. 2021) to bring system dispatch time series from the production cost model into time-sequenced power flow runs for reliability analysis. The study team used C-PAGE to convert nodal production cost model outputs to AC power flow cases for the selected Base and High RE cases in this section.

5.2 Chronological AC Power Flow Automated Generation (C-PAGE)

The analysis in this report used the C-PAGE tool (Vyakaranam et al. 2021) to convert system dispatch time series from a production cost model into time-sequenced power flow runs for a reliability study. C-PAGE includes procedures for translating datasets between production cost models and power flow models, creating chronological AC power flow instances, and automating the process with choices for delivering results in a variety of formats. The study team used C-PAGE to generate AC power flow cases.

Figure 32 depicts the three-stage C-PAGE procedure for preparing AC power flow cases. Each step is described in more detail below.

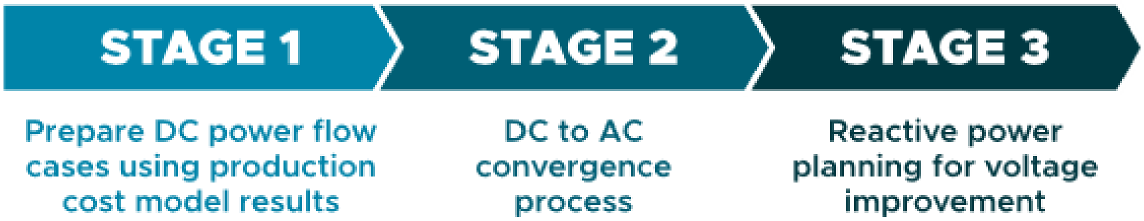


Figure 32. C-PAGE AC power flow three-stage convergence process.

Stage 1 – Prepare the direct current (DC) power flow cases using production cost model results:

For C-PAGE to successfully prepare the DC power flow case using the production cost model generation dispatch, the system topologies of the production cost model and power flow model must match. The production cost model outputs consist of the load at the BA level, along with load distribution factors to distribute loads at each node and generation aggregated at the power plant level. Figure 33 shows the process of disaggregating generation and load from the power plant and BA levels, respectively, to the nodal level for use in a power flow model. Appendix D presents detailed data mappings and validation of the production cost model and power flow model.

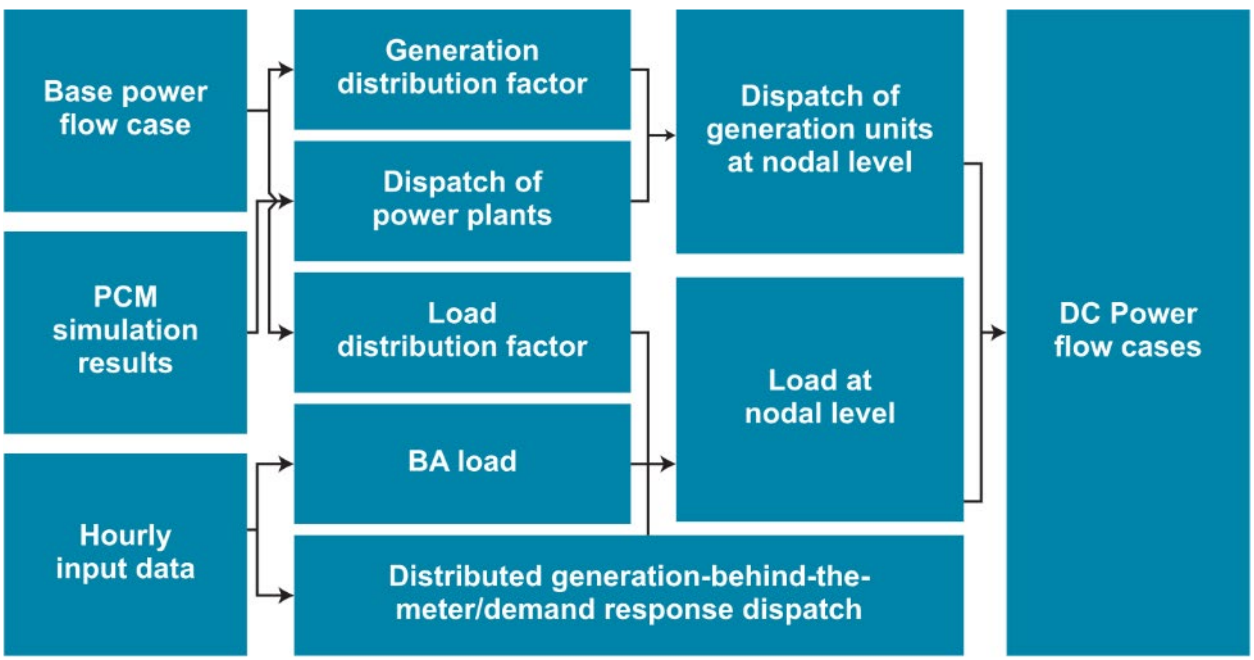


Figure 33. Process of disaggregating generation and load from production cost model simulation results to power flow cases.

Stage 2 – DC-to-AC convergence process:

A production cost model uses a DC power flow, where transmission line losses are zero. Thus, the total generation in the resulting DC power flow case is equal to the total load, which is reflective of the forecasted substation load plus the estimated transmission line losses. However, the transmission line losses are inherently calculated in the AC power flow solution. Therefore, when converting the DC power flow case to an AC power flow case to ensure generation, load, and losses are equal, either nodal load reduction or increases in total generation are required to compensate for the transmission losses. In this chapter, the study team lowered the loads in C-PAGE to compensate for the losses to ensure that the production cost model generation outputs remain unchanged. Accordingly, in Step 2 of the procedure, the nodal loads must be iteratively reduced before an AC power flow solution is found. A detailed procedure for converting a converged DC power flow case from the production cost model results to a converged AC power flow case is presented in Appendix D.

Stage 3 – Reactive power planning for voltage improvement:

After achieving a converged AC power flow case, the priority shifts to improving the bus voltage profile. This is a crucial step because a good voltage profile at one time step directly affects the possibility of achieving a converged AC power flow solution in subsequent time steps. In this stage, C-PAGE scans all bus voltages to identify voltage violations and adjusts or adds local reactive devices to mitigate bus voltage violations. Appendix D presents a detailed reactive power planning procedure to improve the voltage profile. The final converged AC power flow case for the current time step is the resulting power flow case after improving the voltage profile using existing and additional shunts.

5.2.1 The Linkage between the Production Cost Model and the Power Flow Model Is Critical for Investigating the Reliability of Future Scenarios

The linkage between the production cost model and the power flow model is critical for investigating the reliability of nodal scenarios with high penetrations of wind, solar, and battery storage—that is, the future decarbonized grid. On the one hand, the production cost model deals with the resource adequacy, reserve requirement, and flexibility requirement and provides inputs (load, generation dispatch, high-voltage direct current [HVDC] schedule, phase shifter setting) to build the power flow cases. On the other hand, the power flow model deals with a detailed analysis of the power flow, the voltage stability, and the contingency analysis and provides feedback to improve the transmission network in the production cost model. Both models are needed for power system planning studies. Normally, this entire process may take a few weeks to months to create a base AC converged power flow case from the production cost model output, as it involves production cost modeling simulation, AC convergence, and reactive power planning. C-PAGE enables power planners to generate many power flow cases in a matter of minutes per production cost model. Linking power flow samples from one hour to the next is necessary in order to adequately evaluate the effects of shared ramping/variability hours across all scenarios. Thus, the linkage between the production cost model and the power flow model is critical for investigating the reliability of future scenarios.

The study team successfully created the power flow scenario described in this report using the 2030 high renewable production cost model. Moreover, the study team selected 17 hourly snapshots (for more information see Appendix D) during a summer peak day (4 p.m. MST, July 29, 2030) to create power flow cases for the High RE case. While the contingency analysis below is only conducted for the starting reference case (peak hour, July 29, 2030, 4 p.m. MST) in the Base and High RE datasets, the creation of additional hours could be used for future power flow analyses.

5.3 Contingency Analysis

The purpose of the contingency analysis is to test the nodal transmission expansion scenarios' overall robustness and demonstrate the power flow case development method, which can also enhance more detailed reliability analyses. This contingency analysis is limited to the most critical and impactful contingencies recognized by the transmission planning community and does not begin to approach a full reliability planning study. For the purposes of this study, the criteria for the selected contingencies are as follows:

- Select large power plants 500 MW or above to understand the availability of the pseudo-governor response. A subset of these contingencies was considered, and an example of one such contingency is provided in this report below.
- Highly loaded pre-contingency lines are high-impact; they significantly change the flow pattern of the post-contingency system. A subset of these lines was considered for the study's individual outages, and a demonstrative example of one such contingency is summarized in this report below.

The analysis in this section evaluated two contingencies. Contingency #1 is the outage of 2600 MW of generation from a power plant in the Southwest. Contingency #2 is the outage of a double-circuit transmission line in the Northwest. Table 8 lists the contingency limit monitoring settings for buses and lines with a nominal voltage greater than or equal to 230 kV. Only buses and branches above 230 kV are monitored in this study.

Table 8. Contingency limit monitoring settings.

	Voltage Levels (kV)	Low (kV) (0.9 pu)	High (kV) (1.1 pu)
Voltage Limits	230	207	253
	345	310.5	379.5
	500	450	550

	Normal	Contingency
Line Flow Limits	100% of normal rating	Minimum of 130% of normal rating or 100% of emergency rating (if available)

5.3.1 The Loss of Two Generators at a Single Power Plant with a Total Output of Approximately 2600 MW

In highly interconnected transmission grids with high penetrations of VRE, large utility-scale BESSs can play a key role in maintaining frequency response reserves. After the loss of a large generator, a BESS can quickly either cease charging or increase generation (if there is sufficient headroom) faster than other types of generators to provide the necessary power to recover grid frequency.

As part of the contingency analysis, the analysis in this study evaluated the pseudo-governor response following the loss of generators in a large power plant in the Base and High RE cases. In this pseudo-governor response simulation, the generation redispatch compensates for an imbalance between generation and load at a predefined set of generators in the system in which the contribution of each generator[16] is proportional to its capacity while respecting headroom limitations. For this analysis, the study team evaluated the hour of 4 p.m. MST on July 29, 2030. The reason for considering this instance is that it is the peak load hour of the year.

[16] Redispatch is not based on dynamics data or any actual governor parameters. There is a predefined set of generators in the system in which the contribution of each generator is proportional to its capacity while respecting headroom limitations.

Figure 34 shows the generation mix of the Base and High RE cases pre-contingency. Note that all BESSs are charging in the Base case, and the analysis considers them as loads at the chosen hour in this scenario. Therefore, they do not contribute to the generation mix in the chart in this figure.

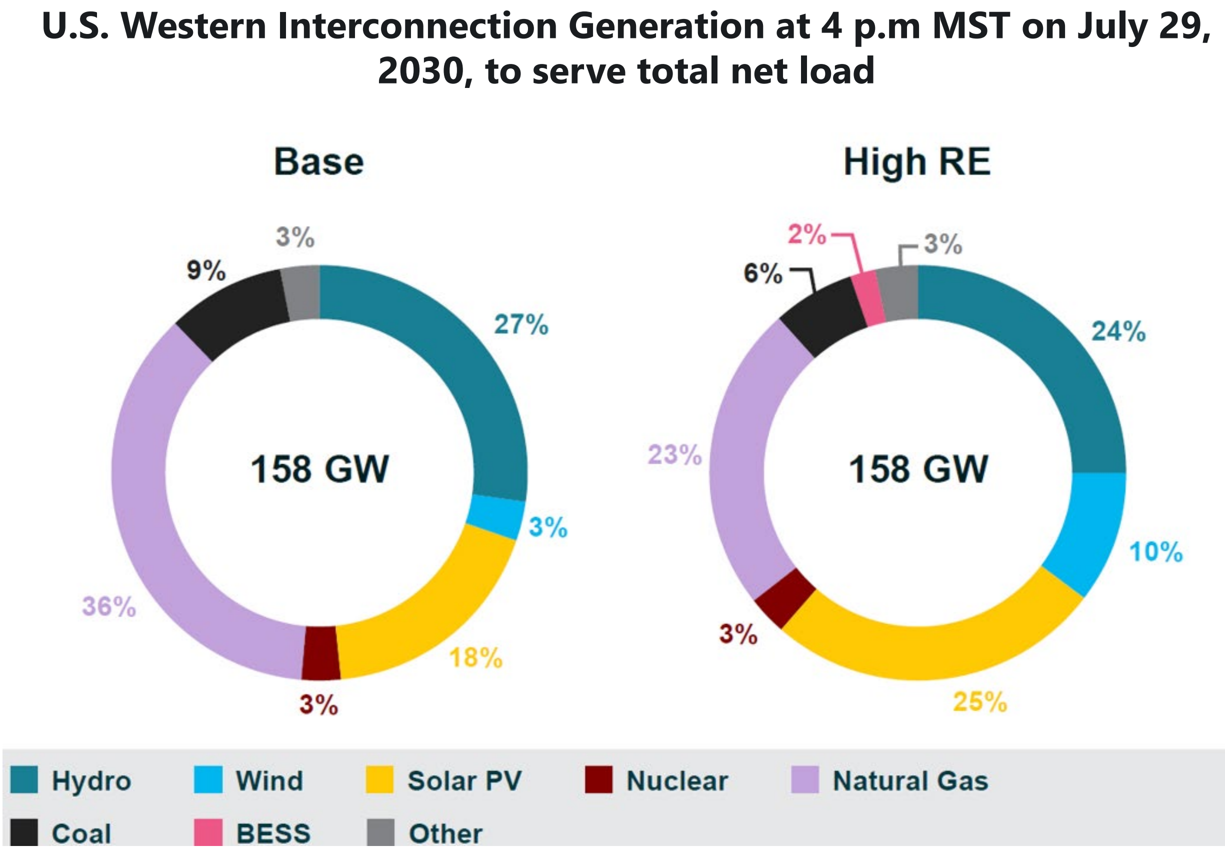


Figure 34. Pre-contingency generation mix for the Base and High RE cases.

Figure 35 shows the generation redispatch by type to make up for the loss of 2600 MW of generation. Notice that solar and wind do not participate in the redispatch because they have no headroom, nor coal because its governors are typically slow to react or are disabled. At the time of generator loss, the BESS devices in the system are charging in the Base case and have enough reserved energy to cease charging and ramp up their generation to participate in the pseudo-governor response process. BESS devices are also dispatchable at any stage of operation. A positive BESS redispatch after the contingency means that it either charges at a lower level to decrease its consumption or discharges at higher level to increase its generation.

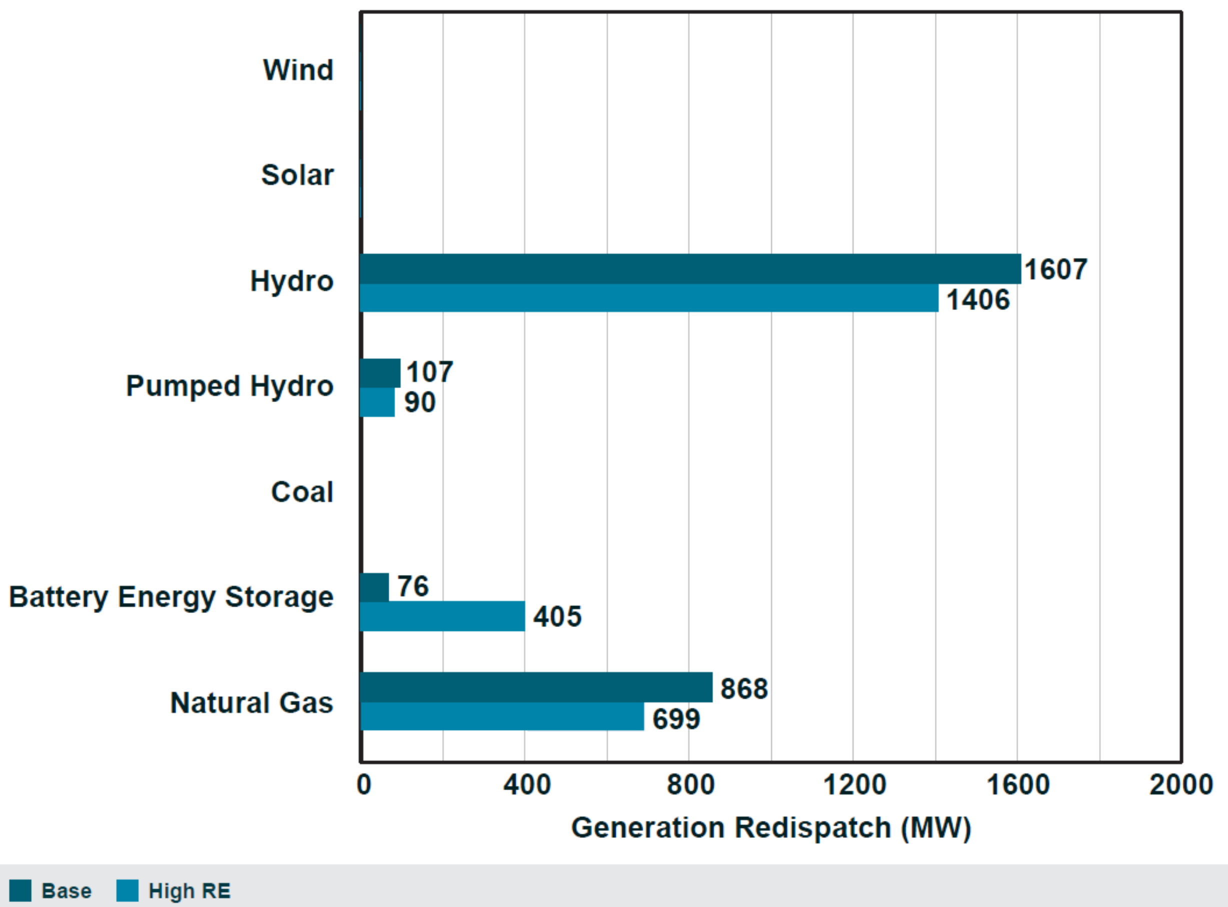


Figure 35. Generation redispatch after the loss of 2600 MW of generation; hydro accounts for the greatest contribution in both the Base and the High RE redispatch; BESS has higher contributions in the High RE case.

Figure 36 and Figure 37 show the pre- and post-contingency voltage heatmaps and transmission line power flows for the Base and High RE cases, respectively. In both cases, the loss of the two generation units in the Southwest will require more generation from other areas to offset the current system load. As a result, the power flow from Arizona to the San Diego area is reduced, the power flow from the Northwest to California is increased, the power flow from Utah to Las Vegas and then to the Los Angeles area is increased, the power flow from Utah to Arizona is increased, and the flow from Arizona to Las Vegas is reversed. There is no significant change in the voltage profiles pre- and post-contingency.

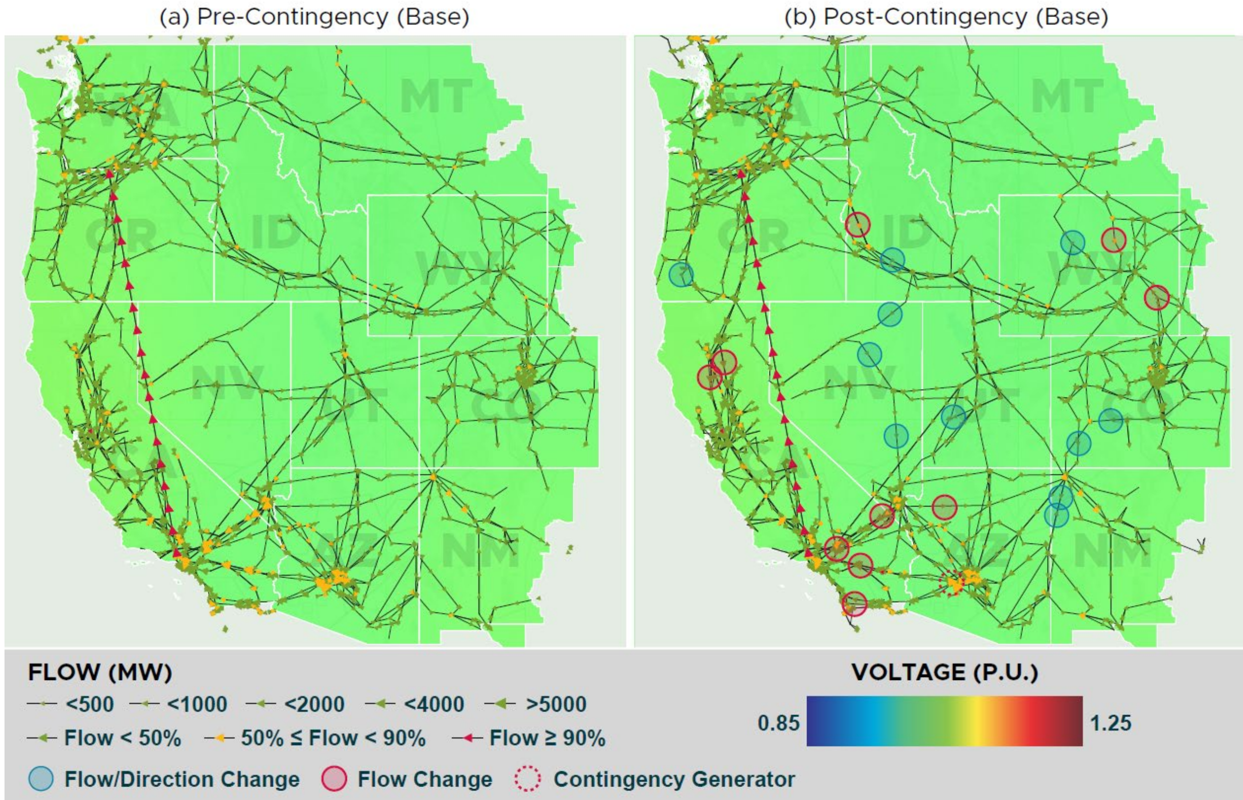


Figure 36. Base case voltage heatmaps (a) pre- and (b) post-contingency for the loss of 2600 MW of generation: no significant voltage changes following the contingency.

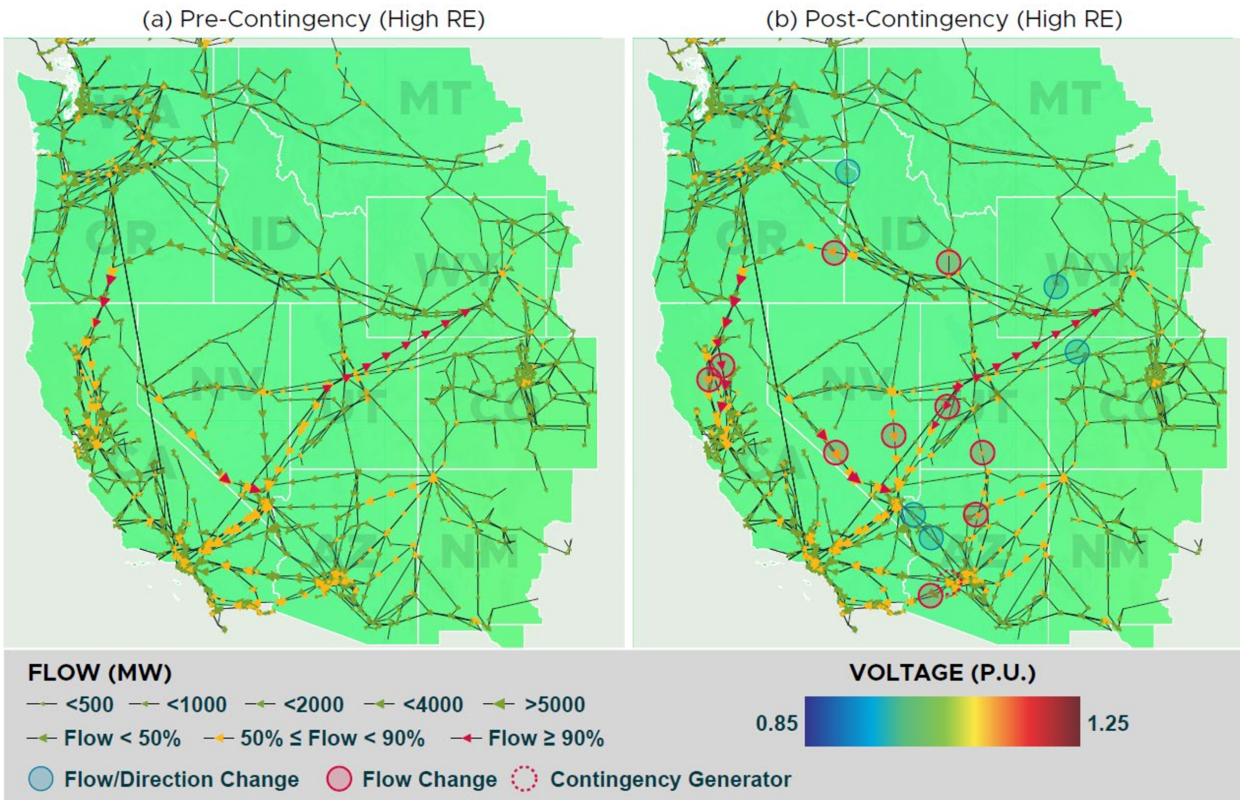


Figure 37. High RE case voltage heatmaps (a) pre- and (b) post-contingency for the loss of 2600 MW of generation: no significant voltage changes following the contingency.

5.3.2 The Loss of a Double-Circuit 500 kV Transmission Line in the Northwest

For the Base case, this double-circuit line is delivering 450 MW (17% capacity) of power in the North–South direction in the Northwest area. Figure 38 shows the pre- and post-contingency voltage heatmaps and transmission line power flows for this Base case. The flow changes in the system are minimal because the contingency line is very lightly loaded before the contingency. There is no noticeable change in the voltage profile after the contingency, as seen in Figure 38.

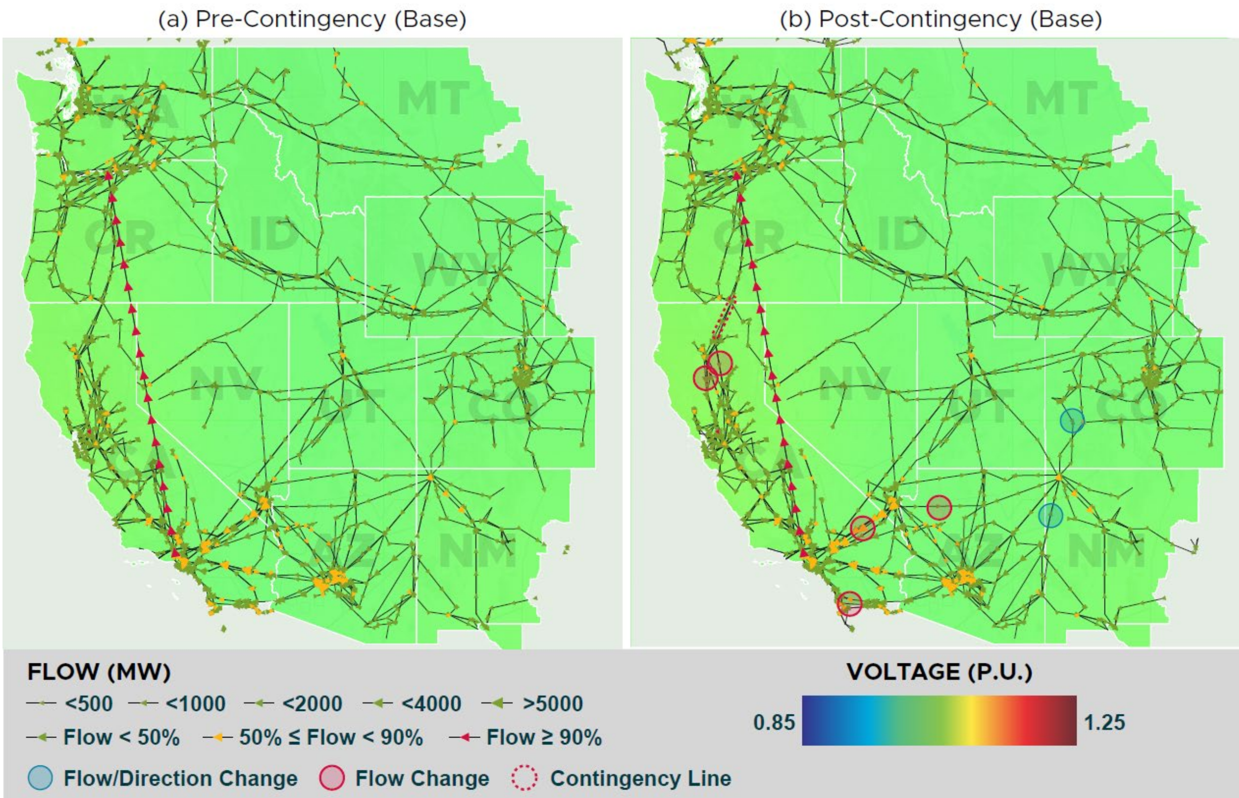


Figure 38. Base case voltage heatmaps (a) pre- and (b) post-contingency for the loss of a double-circuit 500 kV line in the Northwest: no significant voltage changes following the contingency.

For the High RE case pre-contingency, this double-circuit line is delivering 3100 MW (68% capacity) of power in the North–South direction in the Northwest area. Figure 39 shows the pre- and post-contingency voltage heatmaps and transmission line power flows for the High RE case. This contingency causes the power flows in the North–South direction to reroute before the power reaches its intended destination in California. As a result, the North–South flows cause overloads on other North–South lines that are parallel to the contingency line; the power flows from Nevada to Oregon and from Utah to Wyoming are reversed; and power is rerouted east to Idaho, Wyoming, and then to Utah and Las Vegas before flowing to Southern California. There is no significant change in the voltage profile pre- and post-contingency.

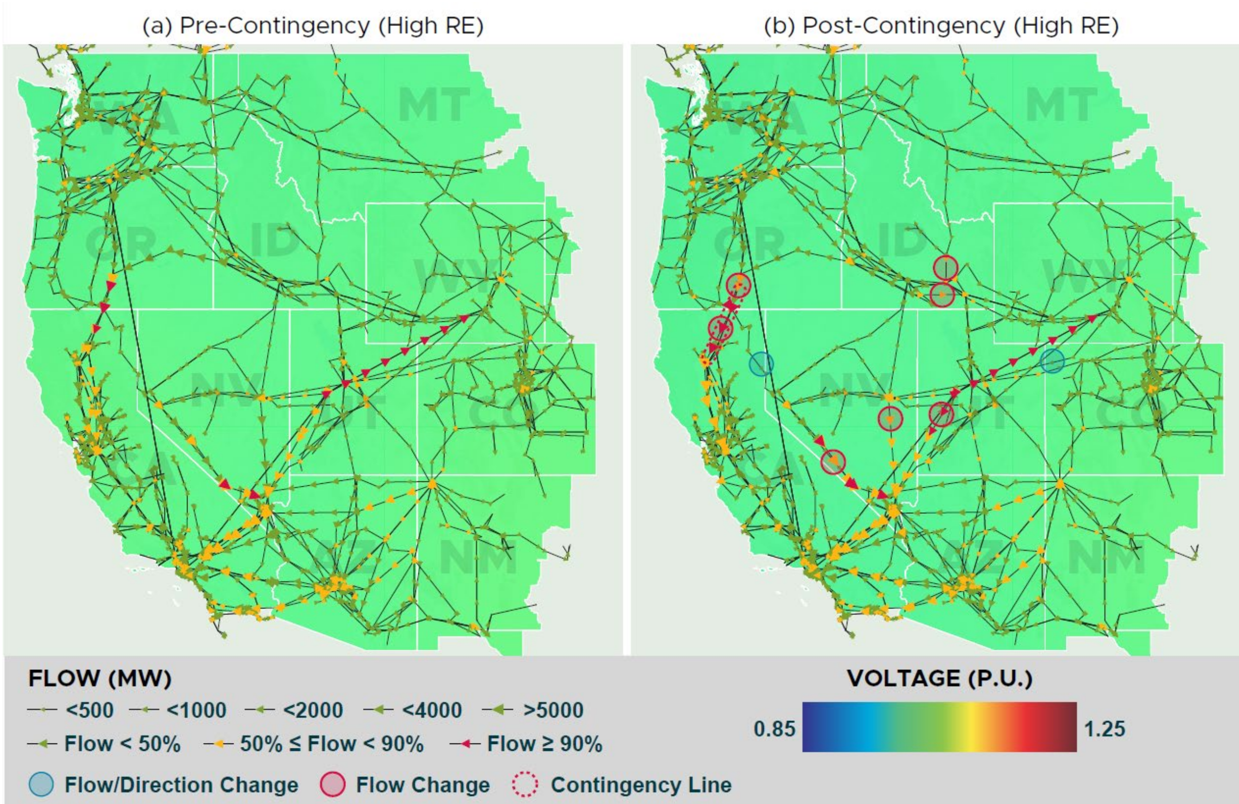


Figure 39. High RE case voltage heatmaps (a) pre- and (b) post-contingency for the loss of a double-circuit 500 kV line in the Northwest: no significant voltage changes following the contingency.

5.3.3 Comparison between the Post-contingency Base Case and Post-contingency High RE Case

The High RE case has new transmission lines compared to the transmission system of the Base case. These new transmission lines are introduced to ensure the effective delivery of new renewable energy introduced in the High RE case. Because of the different topologies between the two cases, the system response to the same contingency is also different.

For the loss of 2600 MW of generation, Figure 40 shows the post-contingency voltage heat maps and flows in both cases. The voltage profiles in the two cases are good with no voltage violations, but the flows are significantly different. The change in flows between the two cases is expected because of a different generation mix and the strengthened transmission system in the High RE case.

For the outage of the double-circuit transmission line, Figure 41 shows the post-contingency voltage heat maps and flows in both cases. Similar to the observations for the previous contingency, the flows are significantly different between the two cases because of the different generation mix and the strengthened transmission system in the High RE case.

In both contingencies, there is no flow on PDCI in the High RE case, while it is fully utilized in the Base case to deliver power in the South–North direction. Moreover, for the peak load time frame selected in this study, the new lines in the High RE case are almost fully loaded post-contingency. This shows that the new lines are effectively utilized as the result of careful planning by utilities, developers, and reliability working groups.

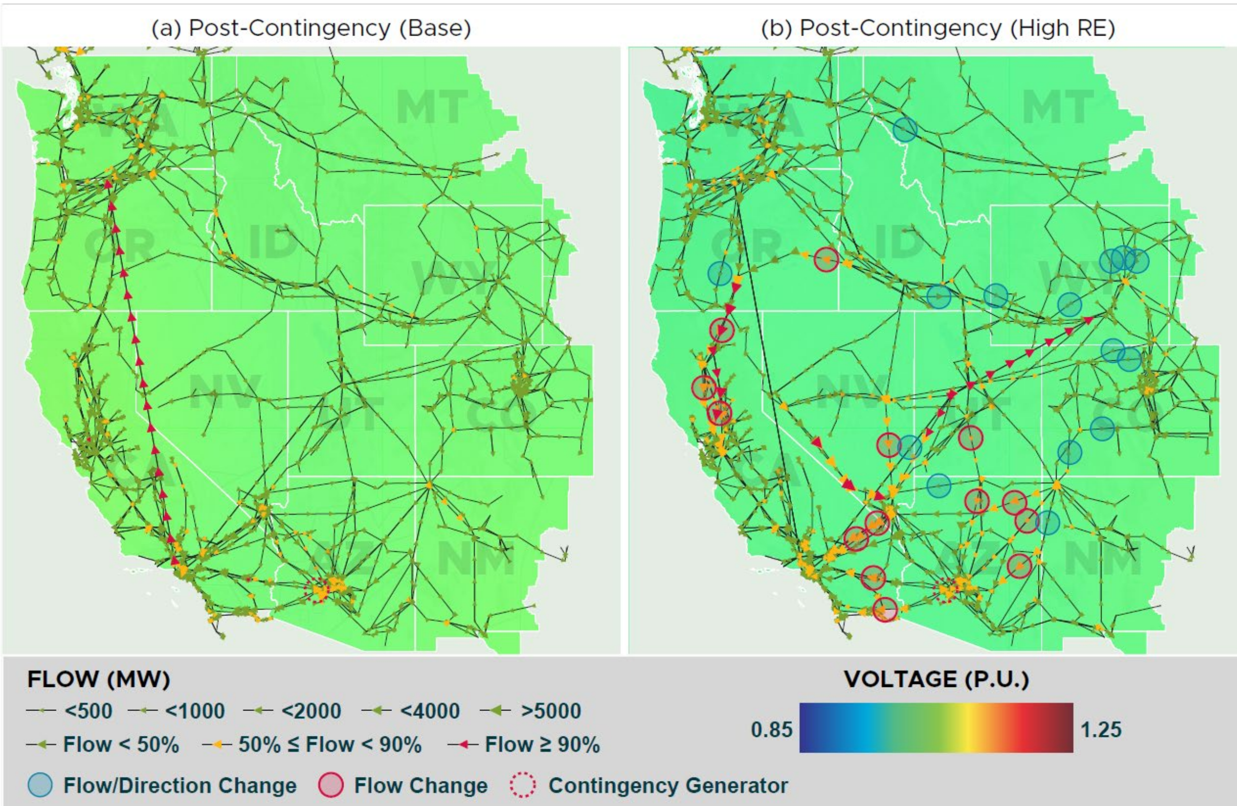


Figure 40. Comparison of voltage heatmaps and flows post-contingency between the (a) Base and (b) High RE cases for the same contingency of 2600 MW of generation loss.

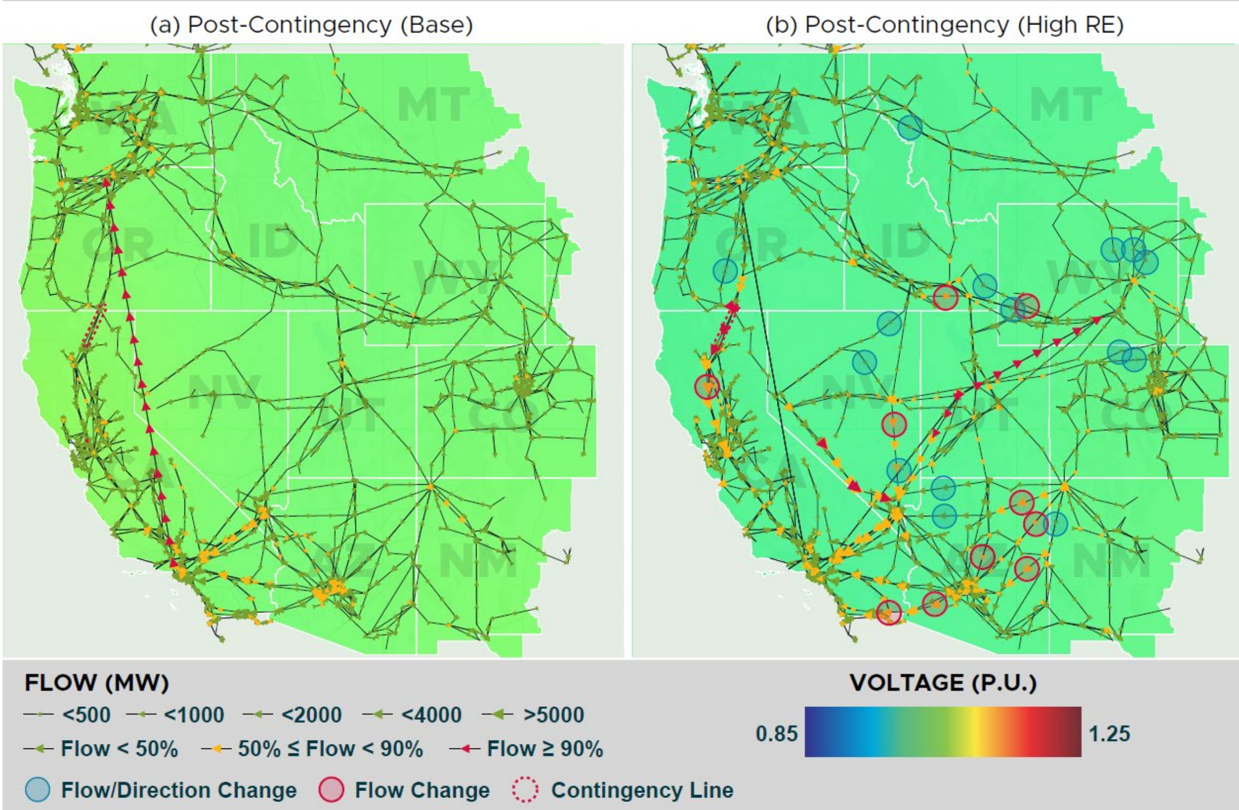


Figure 41. Comparison of voltage heatmaps and flows post-contingency between the (a) Base and (b) High RE cases for the same contingency of a double-circuit line outage.

Power flow analyses within the Western Interconnection demonstrate that the system can withstand selected contingencies on new-build transmission lines even when lines are highly loaded. Energy storage provides a substantial portion of the primary frequency response for the modeled large power plant contingency in the High RE case with approximately 35% instantaneous VRE penetration, though hydro and natural gas still provide the vast majority of the frequency response. The analysis verifies the robustness of certain transmission expansion cases and production cost model portions of this study report. The methods outlined in this chapter will enable planning engineers to perform detailed transmission planning studies on large interregional systems with higher penetrations of VRE and BESSs. The AC power flow study shows that large, interregional systems can maintain voltages within acceptable ranges, given careful reactive power planning.

Future areas of recommended study include additional contingency analyses for combined Eastern and Western Interconnection scenarios under many single and multiple contingencies and several different operating conditions. Additionally, future research should include contingency analyses using dynamic simulation to examine the developed grid models for characteristics such as the frequency response and voltage ride through during grid disturbances.

6.0 Summary and Conclusions

This report established a baseline assessment for how potential investments in transmission and renewable generation projects could contribute to achieving future decarbonization goals across the Western Interconnection. It forms a comparative baseline for the scenario analysis conducted in the NTP Study. It utilizes industry's most reliable data to account for future transmission projects across various stages of development, with a particular focus on those in the permitting stage. Additionally, it incorporates projections for changes in generation capacity (both additions and retirements). This baseline analysis outlines a probable trajectory for the future of the bulk power system, with a horizon extending to 2030.

The key findings of the baseline analysis are listed below:

- **Shift in generation mix:** The High RE case displaces 15% of the fossil thermal generation energy with wind and solar. Thermal generation is replaced not only in areas with significant additions of new renewable capacity but also in areas with no or little new renewable capacity enabled by the augmented transmission system.
- **Carbon reduction potential:** The High RE case reduces CO_2 emissions by 73% from 2005 values. The highest percentage of emissions reduction occurs in the central western states (i.e., Utah, Nevada, Wyoming, Colorado, Arizona, New Mexico), where renewable energy replaces large thermal fossil generation.
- **Capacity factor impacts of existing fossil units:** The High RE case decreases the capacity factors of coal and natural gas resources by 33% and 12%, respectively. The low capacity factor may yield early retirements of fossil units because of low utilization and frequent cycling (startups and shutdowns), increasing O&M cost.
- **Renewable curtailments:** Wind and solar curtailment increases in the High RE case by 5.8% and 2.4%, respectively, compared to those in the Base case. Renewable curtailment peaks during springtime (i.e., March, April, May) as a result of Northwest hydropower runoffs combined with low-load conditions (due to lower heating and/or air-conditioning electricity demands) and solar overgeneration (due to favorable weather conditions). As more renewables are integrated into the Western Interconnection system, transmission saturation and overgeneration will lead to increased curtailments. Without further enhancements to the transfer capability of the transmission network or the addition of energy storage resources, any new renewable additions will significantly exacerbate curtailment issues.
- **Reduction in generation costs:** Generation costs decrease by 32% in the High RE case compared to those in the Base case. Note, however, that capital costs for generation and transmission are not considered as part of this analysis and would be needed for a complete economic evaluation. Most of the infrastructure upgrades selected are either in interconnection queues or the transmission planning pipeline, increasing the likelihood that they will be realized. In other words, the projects selected in this analysis rely implicitly on some economic analysis conducted by those proposing the projects.
- **Shift in energy transfers across regions:** California's annual net energy imports from the Northwest (mainly from Paths 65 and 66) are reduced by ~26% and increased from the Southwest (Basin and Southwest) by ~74% in the High RE case. The BTPs, combined with existing transmission capacity, facilitate increased power transfers to California by accessing newly integrated wind resources from areas with abundant wind, such as Wyoming and New Mexico. This is evidenced by increased power flows on Paths 27 and 46. The increase in

power transfers from the Basin region results in California relying less on power imports from the PNW, thus providing congestion relief on Paths 65 and 66.

- **Primary frequency response participation:** The increased contribution from BESSs in the primary frequency response in the High RE case compared that in the Base indicates the potentially significant role of the technology for reliability in a high renewables power system.
- **System resiliency:** The High RE case is resilient enough to withstand selected high-impact contingencies for the power flow hour modeled in this analysis. This finding suggests that the Western Interconnection can be operated reliably and affordably with a high penetration of renewables.

Future areas of recommended study include additional contingency analyses for combined Eastern and Western Interconnection scenarios under many single and multiple contingencies and several different operating conditions. Additionally, future research should include contingency analyses using dynamic simulation to examine the developed grid models for characteristics such as the frequency response and voltage ride through during grid disturbances.

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Appendix A – WECC Utilization Metrics

The following metrics were used to identify transmission paths that are “highly utilized” according to Western Electricity Coordinating Council (WECC 2006):

1. **U75** designates paths that are utilized at 75% or more of their rated capacities for 50% or more of the hours for the duration of the simulation. The metric is computed separately for the hours for which the flow is positive, the hours for which the flow is negative, and all hours (positive and negative).

$$\mathrm{U75}^{+} = \frac{\sum_{t=1}^{t=h} \mathrm{count}\,(f_t^{+} \geq 0.75 \times \bar{F}^{+})}{h}\,\%$$

$$\mathrm{U75}^{-} = \frac{\sum_{t=1}^{t=h} \mathrm{count}\,(f_t^{-} \leq 0.75 \times \bar{F}^{-})}{h}\,\%$$

$$\mathrm{U75} = \frac{\sum_{t=1}^{t=h} \mathrm{count}\,(f_t^{+} \geq 0.75 \times \bar{F}^{+}) + \sum_{t=1}^{t=h} \mathrm{count}\,(f_t^{-} \leq 0.75 \times \bar{F}^{-})}{h}\,\%$$

f_t^{+}, f_t^{-} are the positive and negative actual flows in a line or at an interface at hour t; $\bar{F}^{+}$, $\bar{F}^{-}$ are the maximum positive and negative rated capacities of a line or interface; and h is the total number of simulation hours.

2. **U90** designates paths that are utilized at 90% or more of their rated capacities for 20% or more of the hours for the duration of the simulation.

$$\mathrm{U90}^{+} = \frac{\sum_{t=1}^{t=h} \mathrm{count}\,(f_t^{+} \geq 0.90 \times \bar{F}^{+})}{h}\,\%$$

$$\mathrm{U90}^{-} = \frac{\sum_{t=1}^{t=h} \mathrm{count}\,(f_t^{-} \leq 0.90 \times \bar{F}^{-})}{h}\,\%$$

$$\mathrm{U90} = \frac{\sum_{t=1}^{t=h} \mathrm{count}\,(f_t^{+} \geq 0.90 \times \bar{F}^{+}) + \sum_{t=1}^{t=h} \mathrm{count}\,(f_t^{-} \leq 0.90 \times \bar{F}^{-})}{h}\,\%$$

f_t^{+}, f_t^{-} are the positive and negative actual flows in a line or at an interface at hour t; $\bar{F}^{+}$, $\bar{F}^{-}$ are the maximum positive and negative rated capacities of a line or interface; and h is the total number of simulation hours.

3. **U99** designates paths that are utilized at 99% or more of their rated capacities for 5% or more of the hours for the duration of simulation.

$$\mathrm{U99}^{+} = \frac{\sum_{t=1}^{t=h} \mathrm{count}\,(f_t^{+} \geq 0.99 \times \bar{F}^{+})}{h}\,\%$$

$$\mathrm{U99}^{-} = \frac{\sum_{t=1}^{t=h} \mathrm{count}\,(f_t^{-} \leq 0.99 \times \bar{F}^{-})}{h}\,\%$$

$$\mathrm{U99} = \frac{\sum_{t=1}^{t=h} \mathrm{count}\,(f_t^{+} \geq 0.99 \times \bar{F}^{+}) + \sum_{t=1}^{t=h} \mathrm{count}\,(f_t^{-} \leq 0.99 \times \bar{F}^{-})}{h}\,\%$$

f_t^+, f_t^- are the positive and negative actual flows in a line or at an interface at hour t; $\bar{F}^+$, $\bar{F}^-$ are the maximum positive and negative rated capacities of a line or interface; and h is the total number of simulation hours (8760 hours).

Any line or interface that exceeds the U75, U90, and/or U99 criteria is identified as **"highly utilized."**

4. **Absolute average flow:**

$$f_{\text{avg}} = \frac{1}{h \times \bar{F}} \sum_{t=1}^{t=h} |f_t|$$

f_t is the actual flow in a line or at an interface at hour t, and $\bar{F}$ is the maximum flow in a line or path (rate A for normal operations)

5. **Congested hours** designate the total number of hours the path has reached its maximum rated capacity for the duration of a simulation.

$$h = \sum_{t=1}^{t=8760} \text{count}\,(f_t = \bar{F})$$

f_t is the flow along a path at hour t, and $\bar{F}$ is the maximum rated capacity of the path.

Appendix B – Automation for the Development of the Production Cost Modeling High Renewables Case

In this appendix, the study team discusses in more detail the automation developed to update the Production Cost Model (GridView) database of the High Renewables (High RE) case, including new transmission projects, interface paths, wind and solar projects, and battery energy storage projects.

New transmission projects: The study team developed Python scripts to incorporate all 12 baseline transmission projects (BTPs) and associated branch elements (i.e., tap changing transformers, phase-shifting transformers, alternating current [AC] lines, high-voltage direct current [HVDC] lines, and series compensators) into the Production Cost Model database for the High RE case. In total, these 12 BTPs resulted in adding 260 new branch and 184 bus elements into the Production Cost Model database.

Interface paths: The study team developed Python scripts to update the ratings of existing interface paths and create additional paths for monitoring BTPs for the baseline cases. This process included mapping the branches of BTPs to existing and new interface paths. Considering that each BTP consists of multiple line segments, 38 new paths were created (in addition to the existing 83 Western Electricity Coordinating Council [WECC] paths) to monitor the flows of key line segments. It's important to note that no contingency analysis was conducted to determine the rating of the new paths. Instead, the ratings of the new paths were determined using information from the WECC 2020 path catalog and by examining the capacity limits of key branches associated with each new transmission project.

Wind and solar projects: The study team developed Python scripts to incorporate new wind and solar projects and supportive grid elements (e.g., step-up transformers, collector system) into the GridView Production Cost Model database for the baseline cases. The installed capacity of new wind and solar projects and point of interconnection (POI) information were passed to the production cost model through the power flow tool, PSSE, which employs a renewable library module (see Section 6.0 for more information) to provide Regional Energy Deployment System (ReEDS)-sited projects with the necessary modeling realism, including features like step-up transformers and collector systems required to connect new resources to high-voltage substations. Consequently, both the GridView and PSSE baseline cases have the same number of branch and bus elements, thereby facilitating linkages and mapping between the two models. New hourly time series of solar and wind generation profiles (unit-normalized) associated with the new solar and wind projects were created using geographic information system (GIS) plant-level information for the year 2009 and imported into GridView to capture meteorological information and capacity factors at the sited locations.

Battery energy storage systems: The study team developed Python scripts to incorporate hybrid battery energy storage system (BESS) and solar resources into the Production Cost Model database, assuming that every new single solar project is accompanied by a hybrid BESS. The installed power capacity of each BESS resource was set at 50% of the solar nameplate capacity (i.e., the storage to solar power capacity ratio is 0.5) with 4 hours of charge/discharge duration capability. These sizing decisions align with current power industry trends observed in recent interconnection queues.

Appendix C – WECC Interface Paths

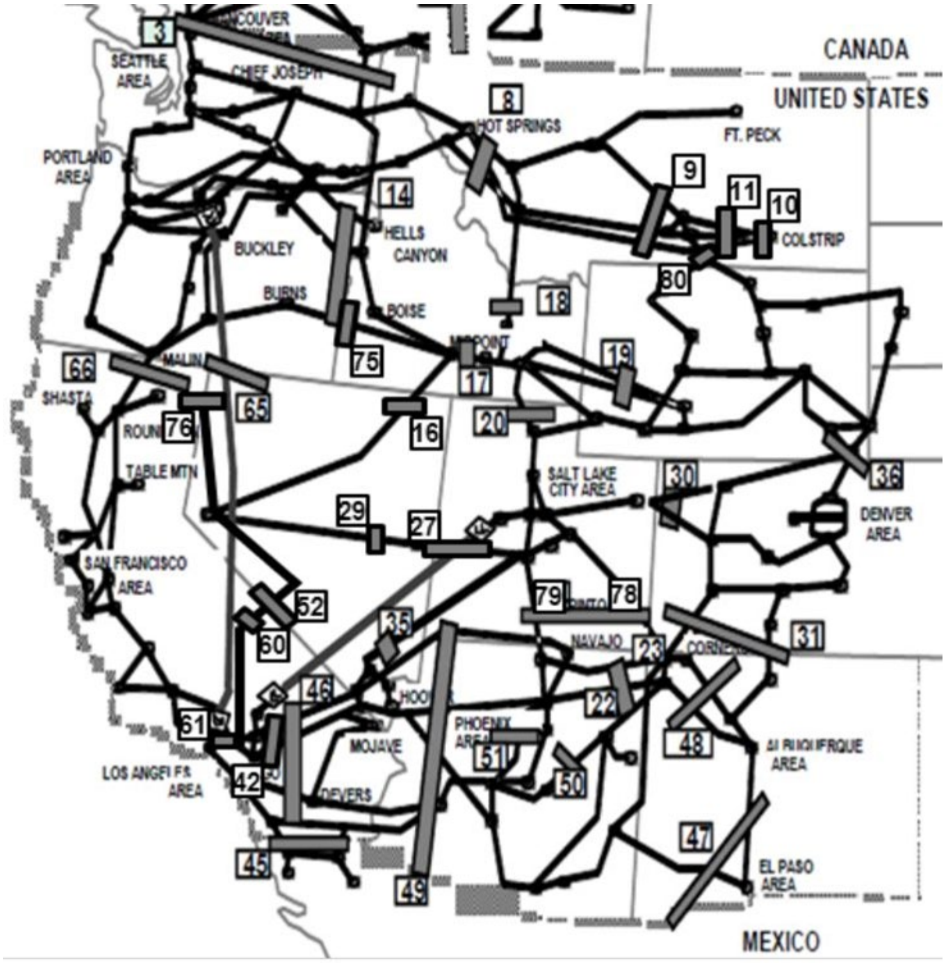


Figure C.1. WECC interface paths. Source: (WECC 2007).

Appendix D – Procedure for Preparing AC Power Flows Based on Production Cost Model Data for Power Flow Case Creation

There are some differences between direct current (DC) and alternating current (AC) power flow modeling. Because the production cost model employs a DC model and linear solver, the study team did not consider the bus voltages in the initial stage of the optimization procedure. The system loss is another element that has an impact on the solution. Unlike AC power flows, where the loss is calculated as part of the power flow solution, a production cost model estimates the loss and adds it to the load. Additionally, solving the chronological power flow models requires assumptions regarding the reactive power load and generation since the production cost model neglects them but the AC power flow does not. The research team used a reference power flow case to determine load distribution factors once; then, they applied those factors to all hours. While this is acceptable in a production cost model because bus voltages are not considered, it is typically not the case in an AC power flow model because of the significant seasonal differences in the bus load distribution and voltage profiles.

Another significant distinction is that the production cost model data do not include information concerning the reactive power dispatch of generators. In a power system, the solution for the power flow traditionally determines the actual reactive power dispatch of generators. The starting point for power flow algorithms like the Newton–Raphson method is either a flat start or the operational point of a converged power flow case. Obtaining convergence for the power flow in a large-scale power system, such as the Western Interconnection, is difficult. It is challenging from the perspective of the power system to develop a dispatch for each generator that offers adequate reactive power while preserving a stable voltage profile for all buses in the system. Mathematically, the power flow in a system of this size is typically unconditioned, meaning that a small change in demand can result in a big change in the system's state or voltage profile. Therefore, if the solution of the prior converged power flow case is far from the solution of the present power flow case, using a flat start or the solution of that case may be inefficient. Furthermore, if voltage violations occur on multiple buses, the algorithm is likely to converge to an unstable solution. This makes it difficult to import production cost model data and solve the chronological AC power flow problem.

Creating a basic converged AC power flow case normally takes a few hours to days because it involves production cost modeling, convergence of the AC power flow, and reactive power planning. With the use of the chronological AC power flow automated generation (C-PAGE) tool created in the National Transmission Planning (NTP) Study, any large, interconnected system, including the Western Interconnection, Eastern Interconnection, and Electric Reliability Council of Texas (ERCOT), may produce a converged AC power flow automatically and in a matter of minutes.

This modeling activity evaluated the engineering feasibility of a future system scenario. Although the study team used the same tools that transmission planners use to test safe and reliable operations for future grid expansions, the full and large scope of contingency analyses that transmission planners customarily perform was not applied. Given the significant numbers of power flow models available for analysis, the study team focused on smaller sets of contingencies that represent the most critical and impactful issues recognized by the transmission planning community. This is due to the large number of power flow scenarios that need to be examined. The Technical Review Committee (TRC) discussed the prioritization of contingency cases for exploration.

The Pacific Northwest National Laboratory (PNNL)-developed C-PAGE tool translated the production cost model outputs of selected operating conditional cases to AC power flow models. C-PAGE uses a three-stage process to translate datasets between the production cost and power flow models.

D.1 Stage 1: Data Mapping and Validation of the Production Cost Model and Power Flow Cases

D.1.1 System Topologies of the Production Cost and Power Flow Models

A seamless transition from production cost model simulation findings to power flow instances is necessary for transmission design studies. Therefore, it is important to understand how the production cost model results are exported to a power flow case, how to validate the process of updating the production cost model results to the power flow case, and the similarities and differences between the production cost model and power flow model. Consistency between production cost and power flow model system topologies is required to correctly feed the production cost model dispatch to power flow models, necessitating rectifying any differences. For example, any transmission lines in the two models must have a one-to-one match for transmission line identification (ID), status, and rating.

D.1.2 Exporting Production Cost Model Simulation Results to the Power Flow Case

The C-PAGE tool produces nodal-level updates to the power flow model after receiving the results of the production cost model simulation. The unit commitment and economic dispatch for generation units, high-voltage direct current (HVDC) dispatch, transformer phase angles, and transmission line status are all provided to all equipment. A power plant in a production cost model is comparable to one or more distinct units in the power flow situation, as mentioned in Appendix A. The state of each of these units is comparable to that of the power plant in the production cost model result when the results are exported to a power flow case. Figure D.1 depicts the process of disaggregating generation and load from the power plant and balancing authority (BA) levels to the nodal level.

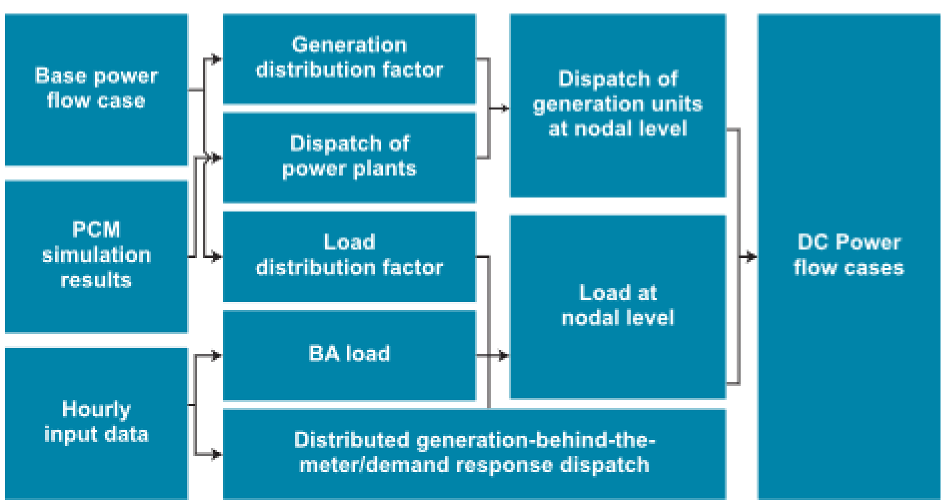


Figure D.1. Process of disaggregating generation and load from the production cost model simulation results to power flow cases.

- Production cost modeling post-processing redispatch procedure

  The results generated from the production cost model require additional analysis and data processing to prepare for power flow and contingency analysis. The production cost modeling post-processing procedure comprises three main phases: a) redispatch hydro power plants, b) redispatch renewable energy resources, and c) system-specific modifications. The mentioned phases are described as follows.

1. **Redispatch hydro power plants:** In GridView, the hydro generation at a given hydro plant is modeled as several units. The hydro generation dispatch is conducted globally on the plant scale. Then, the amount of generation from each unit within a hydro plant is computed based on the unit rating. In other words, the total hydro plant generation is split on all hydro units in proportion to their rating. For example, a total hydro dispatch amount of 10 MW is split equally across 10 hydro units—assuming all units have the same rating. If the capacity rating of each hydro unit is 2 MW, then all units will be 50% loaded. In this way, all hydro units will have the same participation (loading) factor. However, in real systems, not all hydro units will be running simultaneously. The number of active (running) hydro units can be determined based on two criteria: the ratio between the amount of generation dispatch and the total power capacity, and a given priority list. For the previously mentioned example, assuming hydro units have the same priority, the number of active units will be 5 units (50% of the number of plant units). This is calculated by dividing the dispatch amount (10 MW) by total power plant capacity (20 MW). These 5 units will be fully loaded, but the rest of the hydro power plant will be unloaded.

   On the other hand, the capacity limit of each hydro unit varies seasonally and is not fixed across the whole year. This variation will impact the number of hydro units to be dispatched at a particular time instant. If the summer limit for the previous example is reduced to 1.5 MW per unit, then for the same scenario, only 7 hydro units will be dispatched (10/(1.5 × 10) = 0.67% → 70% of number of units). In this case, 6 units will be fully loaded with a total generation of 9 MW, 1 unit will generate 1 MW, and 3 units will be unloaded. It is worth noting that seasonal changes are considered in the GridView model and should be preserved in the power flow cases. The following tables illustrate the difference in hydro dispatch accounting for prioritization, loading distribution, and seasonal limits.

Table D.1. Redispatched hydro units considering the loading distribution and modified capacity limits.

Unit number	1	2	3	4	5	6	7	8	9	10
Power generation profile from GridView	1	1	1	1	1	1	1	1	1	1
Redispatched power considering loading distribution	2	2	2	2	2	0	0	0	0	0
Redispatched power considering reduced unit limits to 1.5 MW	1.5	1.5	1.5	1.5	1.5	1.5	1	0	0	0

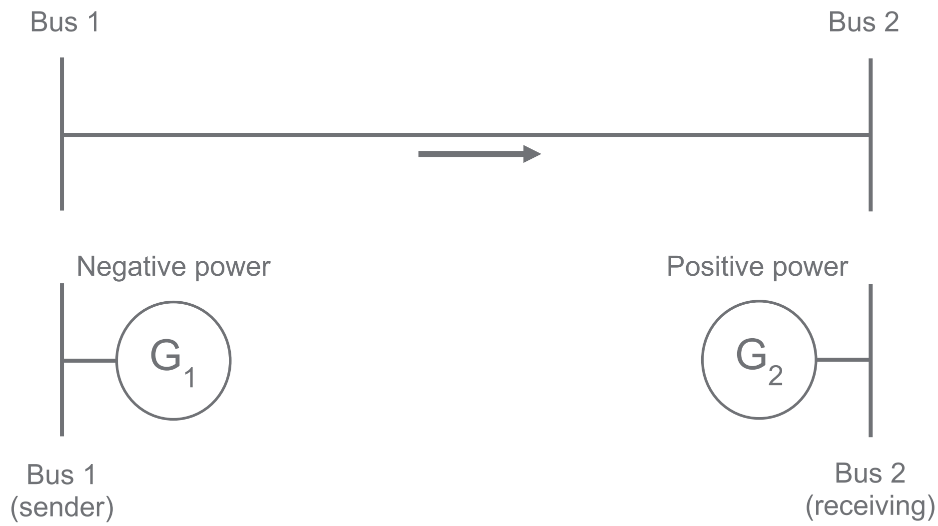
Table D.2. Redispatched hydro considering prioritization and different unit capacity limits.

Unit number	1	2	3	4	5	6	7	8	9	10
Capacity limit (MW)	1	2	1	2	0.5	0.5	2.5	2.5	1	1
Priority	3	2	7	6	4	10	1	5	8	9
Power generation profile from GridView	1	1	1	1	1	1	1	1	1	1
Redispatched power considering prioritization	1	2	0	1.5	0.5	0	2.5	2.5	0	0

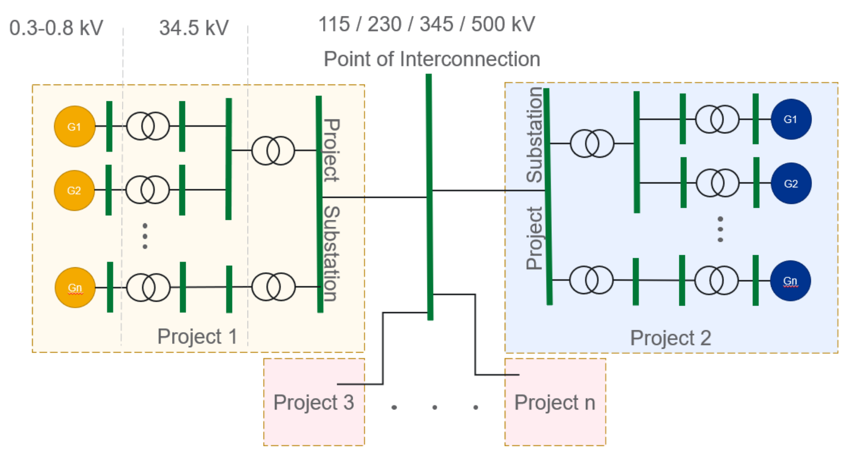
To address the aforementioned challenges, a Python-based script is prepared to redispatch hydro power generation. In this script, two main steps are applied. First, the results from GridView are extracted. The total generation of each hydro power plant is computed by aggregating the power generated by each unit within the power plant. Then, a priority list of each power plant is used to commit individual units. Redispatching hydro units is conducted sequentially until the total amount dispatched equals the precalculated aggregation generation plus the required reserve generation. In this step, the capacity limit of each unit is adopted from the GridView results. Unloaded units will be assumed to be in a turn off status and should not contribute to power flow cases.

2. **Redispatch renewable energy resources:** The renewable energy generation is conducted globally in GridView on the plant-scale level. This results in distributing the total plant dispatch value equally across all the connected units. However, for a particular renewable power plant (solar, wind, and battery storage), the number of units in GridView is usually different than the number of installed units in power flow cases. Generally, a lower number of units is observed in GridView because very small scale units at nearby geographical locations are aggregated into a single point of interconnection (POI) in the GridView model. Accordingly, the amount of unit dispatch will change according to the ratio between the amount of plant dispatch and the corresponding number of units in power flow cases. Moreover, it is important to enforce the status of the battery storage units to ON, even with zero power contribution. This ensures that such devices can contribute to reactive power stability during the solution of power flow cases. In renewable redispatch, no priority is preserved across units of the same power plant.

   To address these challenges, a Python-based script is prepared to redispatch renewable energy resources including solar, wind, and battery storage. The script applies the same procedure adopted in the hydro redispatch with slight modifications. The renewable energy resources between GridView and the power flow cases shall be properly mapped prior to redispatching. For each renewable power plant, the total generation is computed by aggregating the generated power of all units from the GridView results. The computed total generation is split equally across all corresponding units for the corresponding renewable power plant in the power flow case.

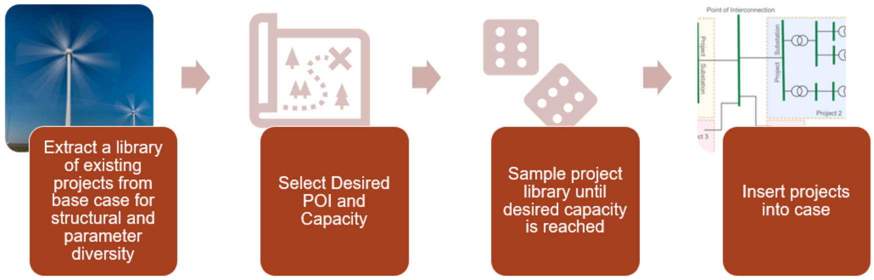


3. **Extract wind and solar samples:** The study team developed scripts to pull wind and solar photovoltaic (PV) samples from the Base case and created a model library.



- The modeled library can be sampled to create new projects with capacity at levels similar to the Regional Energy Deployment System (ReEDS)/Renewable Energy Potential Exchange Model (reVX).

4. **Build new solar and wind projects:** The study team developed procedures to build new solar and wind projects:



- Extract a library of existing projects from the Base case for structural and parameter diversity (see previous point).
- Select the desired POI and capacity.
- Sample project library until the desired capacity is reached.
- Insert projects into case.

In this project, two sets of production cost modeling with various representations of the transmission topology are carried out. The first set of production cost modeling runs is a zonal transmission topology representation that is the same as the topology representation of ReEDS. The second set of production cost modeling runs is a nodal transmission topology with the subsequent power flow modeling representing it at the same level of detail. The selected nodal production cost modeling cases are translated to AC power flow cases using C-PAGE.

D.1.3 Linkage between the Production Cost and Power Flow Models (Test and Validation)

To ensure consistency between the production cost and power flow models, the study team conducted a component-wise (bus, generator, bus load, and transmission line/transformer, HVDC, interface) comparison between the two models' databases. Please note that each component in one model needs to have the same or an equivalent component in the other model. If one specific component exists in one model but not in the other, the study team normalized the models by either adding the component or removing it from a model to maintain equivalency. Appendix B includes examples of how compatibility issues between the two models for specific network components were handled.

The analysis in this chapter used Python scripts to modify all models. To verify the validity of the model, the study team gradually carried out test runs for the modified production cost model along with the model modifications.

1. **Buses:** A comparison of the buses from the power flow and production cost models revealed that the study team identified 27 buses in the production cost model that were absent from the power flow model and 8 buses in the power flow model that were absent from the production cost model. The study team added those buses to the corresponding model to make sure that they match.
2. **Loads:** A comparison identified nine bus loads in the power flow model but not in the production cost model. The study team added them to the production cost model to match those in the power flow model.

3. **Transmission lines/transformers:** An initial comparison of the lines/transformers in the two models resulted in a large number of mismatches. A detailed investigation of the mismatches identified that each mismatch is due to one or more of the following reasons:
    - The 3-winding transformers in the power flow and production cost models are modeled differently.
    - The lines/transformers have same from bus and to bus but different circuit IDs.
    - Several lines/transformers exist in one model but not in the other.

    After addressing these mismatches, the study team identified 18 lines/transformers that still exist in the power flow model but not in the production cost model and 42 lines that exist in the production cost model but not in the power flow model. The study team added those lines/transformers to the corresponding models.
4. **Generators:** A comparison of the generators in the production cost and power flow models identified a large number of differences. Several hundred generators exist in one model but not in the other. There are several reasons for these differences:
    - One model added new variable renewable energy generators but not the other.
    - One model removed some retired generators but not the other.
    - The same generator is present but connected to the system at different voltage levels in the two models.
    - The same generator is present with different IDs in each model.
    - The same generator is present but connected to different buses in each model (the bus was renumbered).
    - One model modeled the power plant at the plant level (“lumped” unit) versus several generators at the bus level in the other model.
    - There were duplicated generators at the same bus (several generators with the same ID connected at the same bus).
    - The production cost model contained generators that were connected at buses that do not exist in the system.
    - The power flow model modeled generators as a synchronous condenser, and these generators do not exist in the production cost model.

Figure D.2 and Figure D.3 show some examples of generator mismatches between the two models.

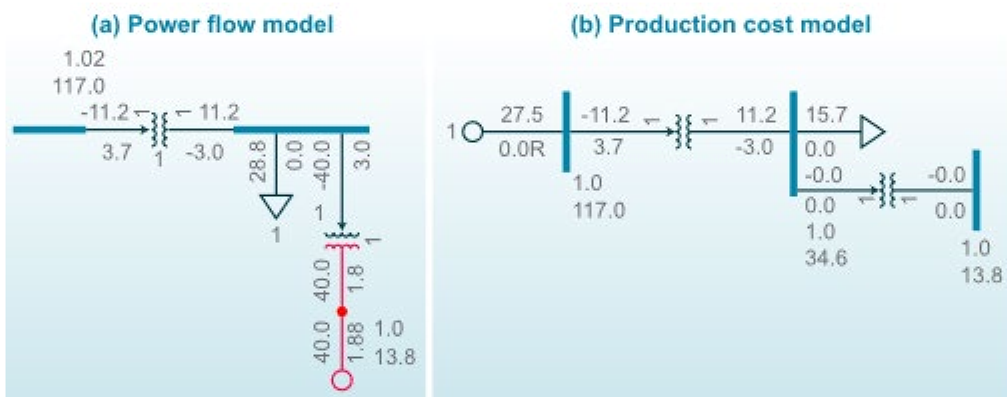


Figure D.2. Same generators modeled at different buses in the (a) power flow and (b) production cost models.

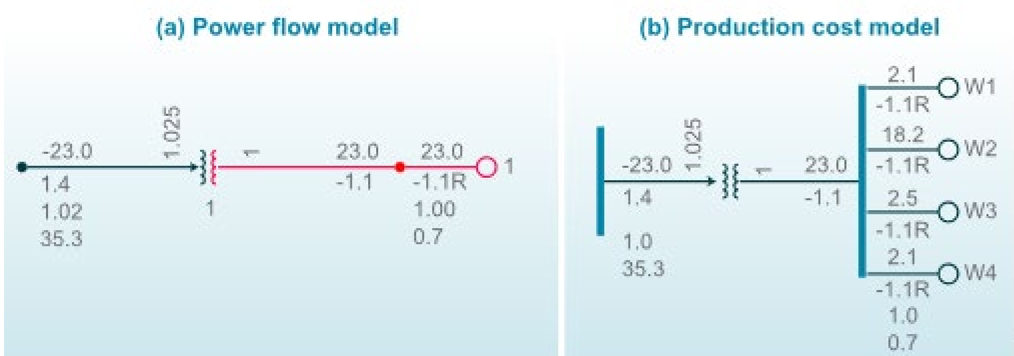


Figure D.3. Generators modeled as one lumped unit vs. several distributed units at the same bus.

After considering all the factors mentioned earlier, the comparison identified 112 generators that exist in the power flow model but not in the production cost model and 650 generators that exist in the production cost model but not in the power flow model. Because the generator datasets in the power flow model do not provide enough information (fuel price, heat rate, startup/shutdown cost for thermal units, hourly profile for renewable units, etc.) to implement in the production cost model, the study team removed generators that exist in the power flow model but not in the production cost model. For generators that exist in the production cost model but not in the power flow model, the study team added them to the power flow model. To reduce the complexity of the dynamics model later, the study team removed the units with a capacity less than 20 MW from the production cost model instead of adding them to the power flow model. With this simplification, the power flow model now includes only 320 generators.

1. **HVDC:** The HVDC is modeled to allow power flow in only one direction in the power flow model, while in the production cost model, power is allowed to flow in either direction. Hence, when importing the scheduled power for an HVDC with the flow direction reversed, users need to reverse the converters' functionality (rectifier vs. inverter) at both ends.
2. **Interface definition checks and modifications:** The two models have different definitions of several interfaces. The reasons for the differences are as follows:
    - The interfaces comprise different numbers of transmission lines in both models.

- The interfaces comprise the same number of transmission lines but are defined in opposite directions in the two models.

The study team identified and corrected all differences along with their corresponding flow limits in one or both models to match them.

After the study team addressed all inconsistencies between the component datasets of the two models, components in the two models were added or removed via the steps below.

Steps to add/remove components in the power flow model:

- Add new generators.
  - After the new buses are added, then add the required number of new generators.
- Add new buses.
- Add new lines/transformers.
- Remove generators in the power flow model but not in the production cost model.

The study team developed several EPCL scripts to add components to the power flow model. To maintain the converged power flow case, the study team solved the power flow model after each modification.

Steps to add/remove components to/from the production cost model database:

- Add new buses.
- Add new lines.
- Add new loads.
- Remove generators that do not exist in the power flow model and with a capacity less than 20 MW.

D.1.4 Model Validation

The study team imported the dispatch results from the production cost model into the power flow and obtained a solution for the DC power flow. A comparison of the line/interface flows validated the mapping between the two models. Temporal snapshots showed the closeness of the power flow pattern between power flow cases and the production cost model. In addition, the study team carried out a statistical analysis to measure the goodness-of-fit of the modeling transformation.

D.1.5 Production Cost Model vs. DC Flow Comparison for the High Renewables Case

For the High Renewables (High RE) case, the study team created 24-hour cases on the peak load day (July 29th) and compared them with the production cost model, as shown in the figures below.

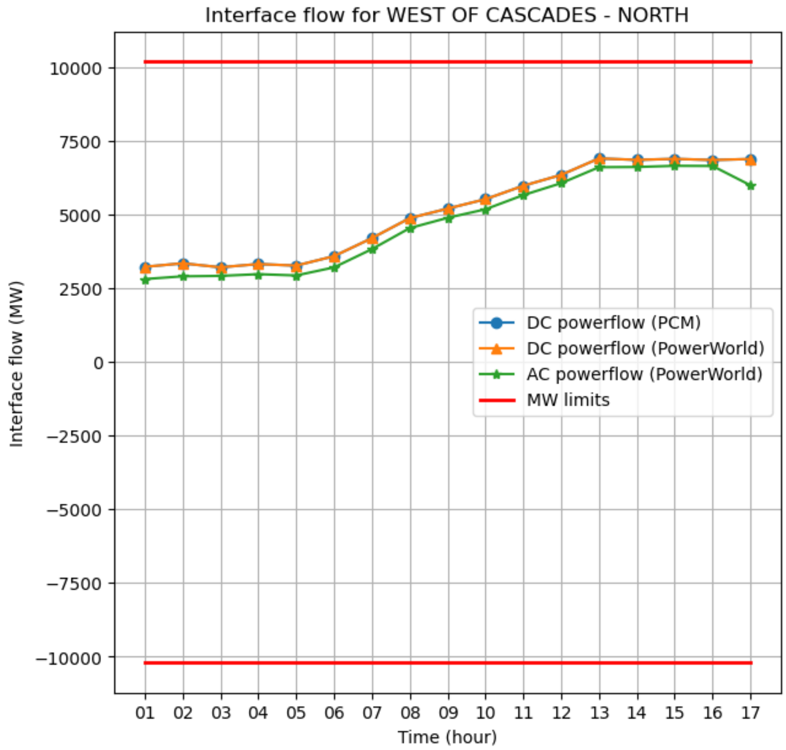


Figure D.4. DC power flow comparison between the production cost and power flow models for Path 4.

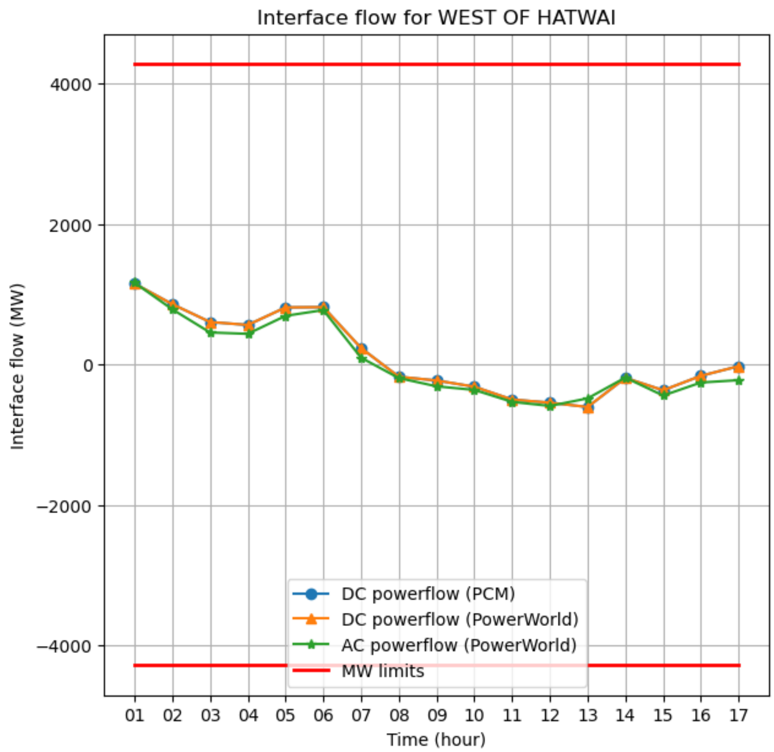


Figure D.5. DC power flow comparison between the production cost and power flow models for Path 6.

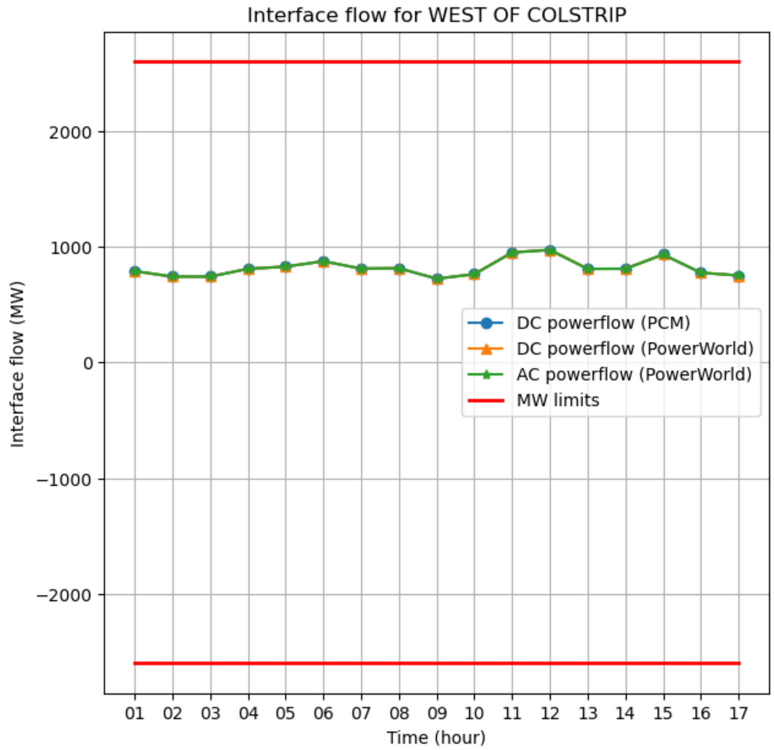


Figure D.6. DC power flow comparison between the production cost and power flow models for Path 10.

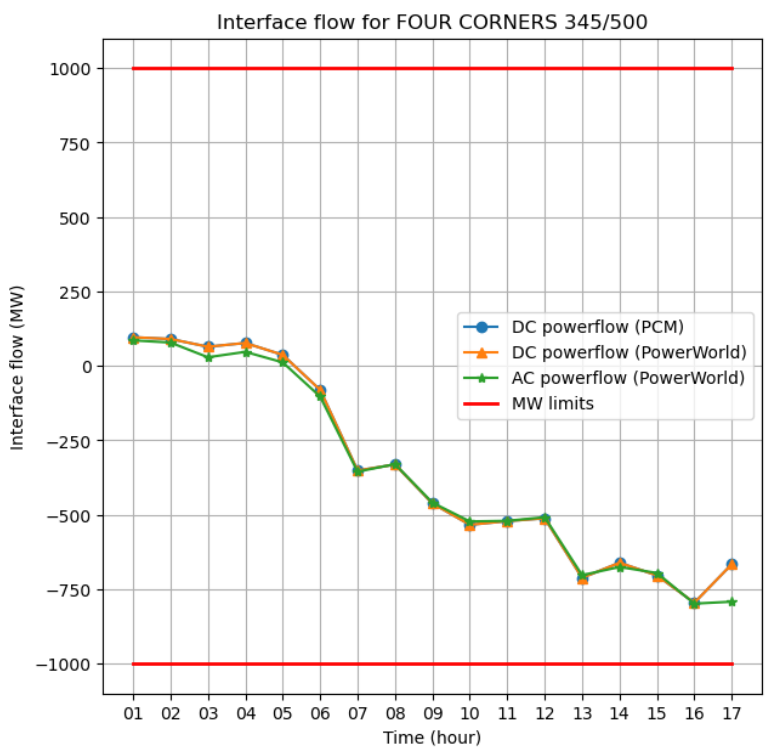


Figure D.7. DC power flow comparison between the production cost and power flow models for Path 23.

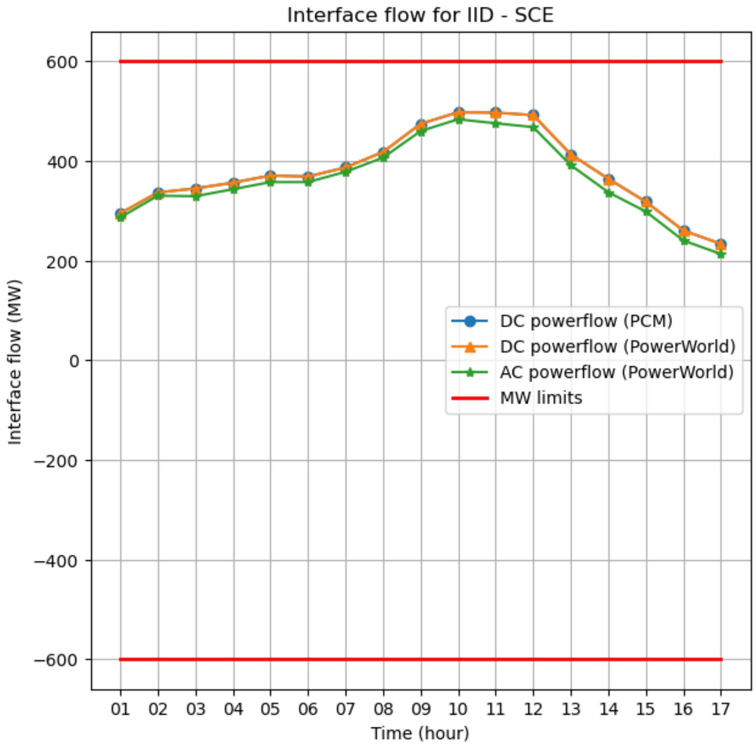


Figure D.8. DC power flow comparison between the production cost and power flow models for Path 42.

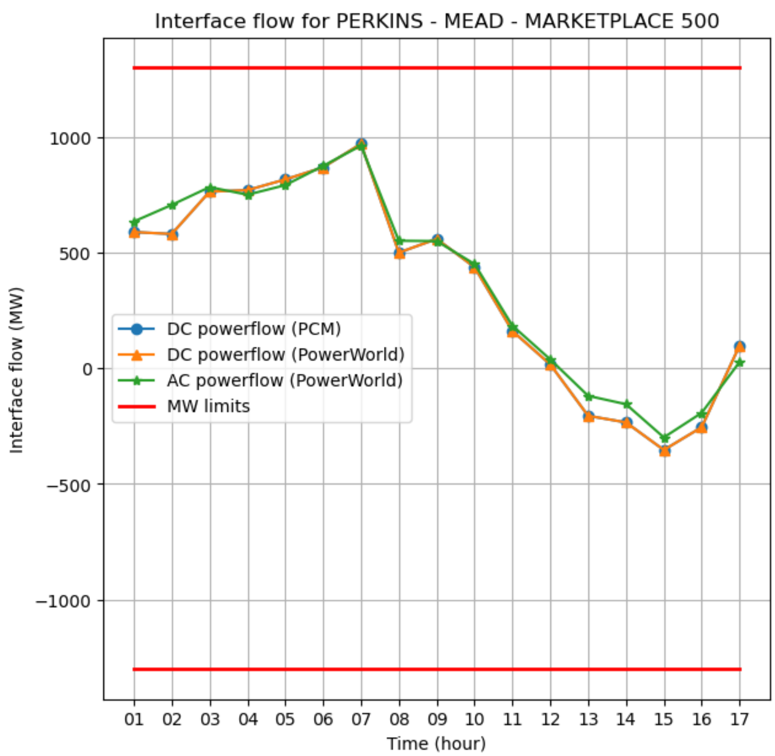


Figure D.9. DC power flow comparison between the production cost and power flow models for Path 63.

In general, the results show acceptable consistency in the interface and branch flows for the production cost model and the exported power flow case.

D.2 Stage 2: DC-to-AC Convergence Process

The approach begins with Step 1 in Figure D.10, which updates the new production cost model result to a converged AC power flow case derived from the preceding time step. The reasoning is that the loading conditions for two consecutive power flow instances are frequently near each other; therefore, the voltage of the prior time step in the converged AC power flow case is a useful starting point for solving for the power flow in the new power flow case.

Because the production cost model employs a DC power flow, the total generation equals the total load in the new power flow condition. In this approach, it is assumed that the dispatch of all generation units, including the unit at the slack bus, is fixed, as in the production cost model results. Therefore, when converting from a DC power flow scenario to an AC power flow scenario, decreasing the nodal loads accounts for transmission losses.

As a result, Step 2 of the process progressively reduces the nodal loads prior to solving for the AC power flow. This step reduces the load further if the power flow does not converge. If the power flow converges, this step compares the resulting real power generation P_{slack} at the slack bus to P_{slack}^0 in the production cost model result. This step reduces the load further if the difference at iteration *k* exceeds a certain tolerance δ; otherwise, the load-reducing process is done. It is worth noting that this step utilizes an adaptive step size μ^{k+1} at iteration (*k* + 1) based on the slack generation difference Δ^k at time *k* to iteratively lower the load as follows:

$$\mu^{k+1} = \Delta^k \sigma = | P_{slack}^k - P_{slack}^0 | \sigma , \quad (1)$$

where σ is a constant coefficient.

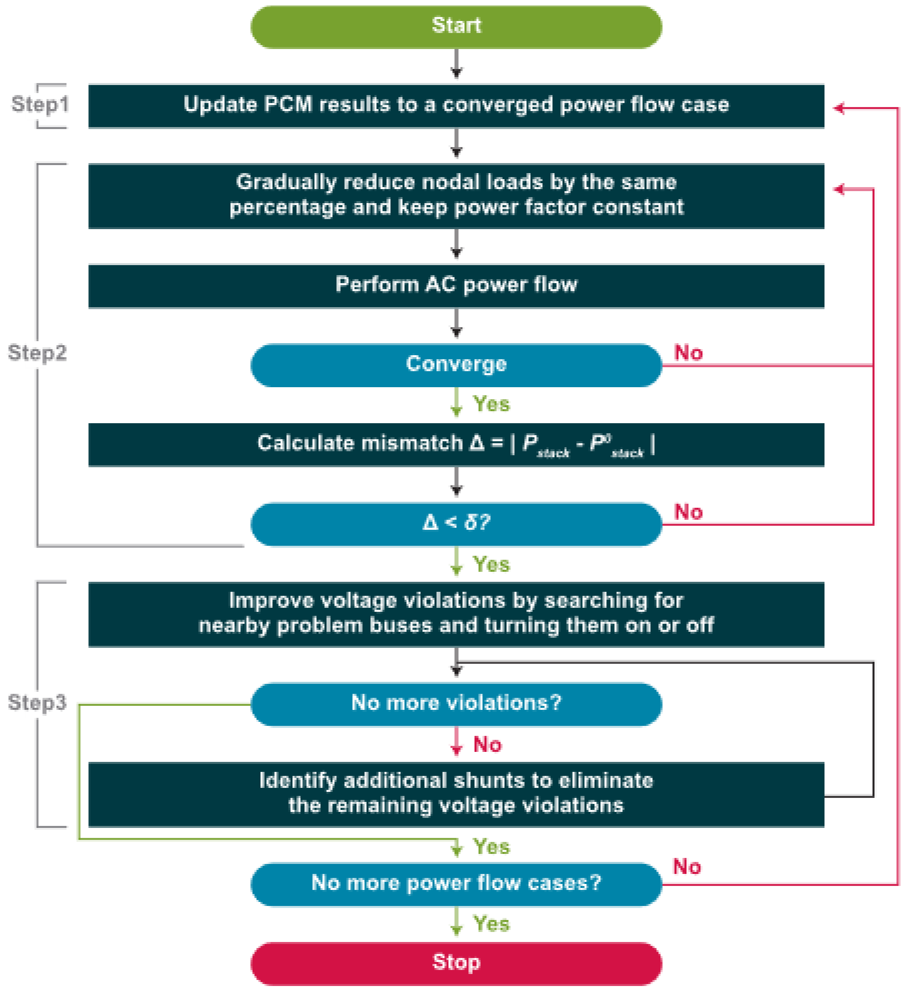


Figure D.10. Procedure to convert a converged DC power flow case from the production cost model results to a converged AC power flow case.

D.3 Stage 3: Reactive Power Planning for Voltage Improvement

After attaining a converged AC power flow situation, the focus moves to improving the bus voltage profile. Improving the voltage after attaining convergence of the AC power flow is critical because a good voltage profile at one time step has a direct impact on the potential of achieving convergence of the AC power flow in succeeding time steps. As a result, Step 3 in Figure D.10 examines all bus voltages to look for voltage violations. The next step is to process each bus that has a voltage violation and identify any current shunts on that bus or any surrounding buses. The level of voltage violation and the shunt step sizes determine whether to turn on, turn off, or change the dispatch of these shunt devices.

After a bus voltage violation is mitigated using the system's existing shunts, Step 3 checks for voltage violations again to discover any remaining violations. If a voltage violation is not completely rectified, this step performs another voltage improvement process based on a *Q-V* analysis to identify the locations and sizes of shunts to add to the system. The resulting power flow scenario is regarded as the final converged AC power flow case for the current time step after enhancing the voltage profile using existing and additional shunts. This step repeats the conversion of the DC power flow from the production cost model findings to a converged AC power flow case (Figure D.10) until all time steps are processed.

Transition planning should include ample reactive power resources to meet reliability requirements under a wide variety of feasible contingencies. The reactive power is a critical reliability service for bulk power systems. Generators, capacitors, transmission lines, and loads all contribute to its supply. Transformers, loads, and transmission lines all use it. The reactive power and voltage magnitude are closely related. Ensuring that the voltage remains within a reasonable range is achievable with careful reactive power planning.

At Stage 2, the voltage profiles of each converged AC power flow case require mitigation to address any voltage breaches. C-PAGE has the ability to improve voltage profiles by performing a *Q*-*V* analysis, which displays the sensitivity and volatility of the bus voltages with respect to reactive power injections or absorptions. As depicted in Figure D.11, the strategy is to gradually improve a voltage profile while using suitable reactive power support devices.

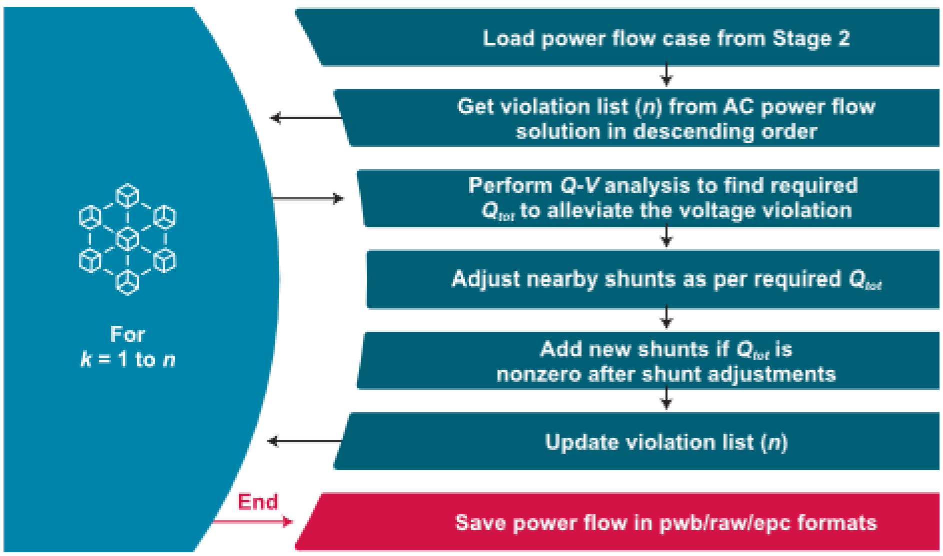


Figure D.11. Reactive power planning to improve voltage profiles.

The reactive power planning algorithm starts by loading the power flow case from Stage 2 and extracting voltage-out-of-range violations for higher voltages. In this work, the focus is on base voltages of more than 230 kV, but the concept is applicable to any voltage level. The algorithm carries out a *Q*-*V* analysis of the bus with the highest voltage violation in the first stage to determine the necessary reactive power support (Q_{tot}) to reduce the voltage violation. This stage also involves sorting the violation list in descending order of voltage. If any shunts, such as capacitors or reactors, are found close to the bus that is being violated the most, the simulator adjusts them to the needed Q_{tot} value and updates Q_{tot}. The simulator inserts a new shunt if Q_{tot} is still nonzero after the shunt changes. Then, it resolves the power flow and derives a list of violations. When the simulator cannot converge at a specific transfer level throughout this process, that bus is skipped. If not, this procedure is repeated until there are no violations left on the list. With reasonable reactive power support devices, this algorithm incrementally improves a voltage profile, which can partially correct flow violations. Performing generation redispatch reduces power flow violations, but this was not done because the study team did not want to change the production cost model generation dispatch at any time. Finally, the algorithm saves the power flow case with the better voltage profile in formats like PowerWorld’s pwb, PSS/E’s raw, and PSLF’s epc.

Appendix E – Aggregated Monthly Energy Targets of Hydropower Resources

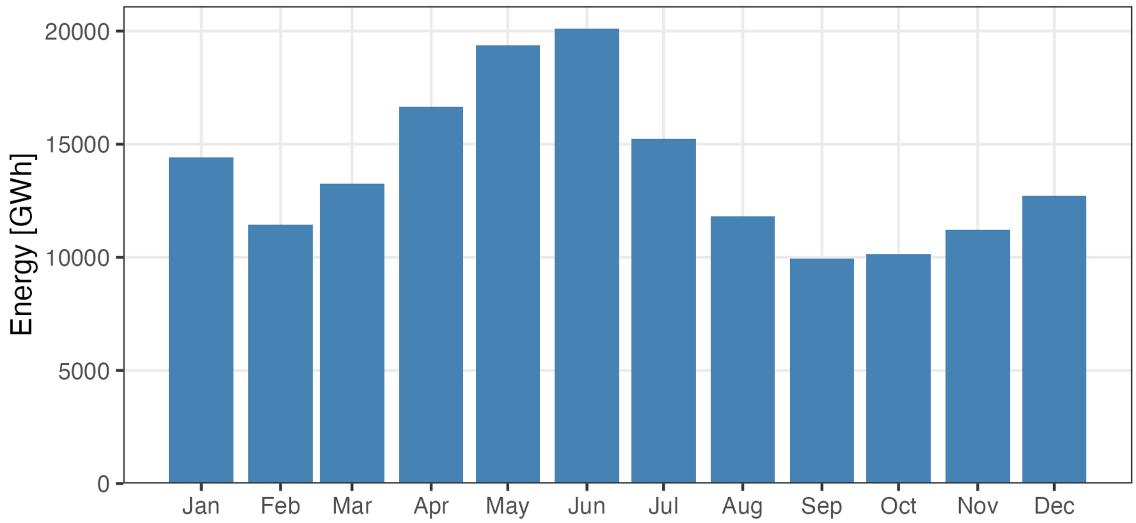


Figure E.1. Aggregated monthly energy targets of hydropower resources across the U.S. Western Interconnection.

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