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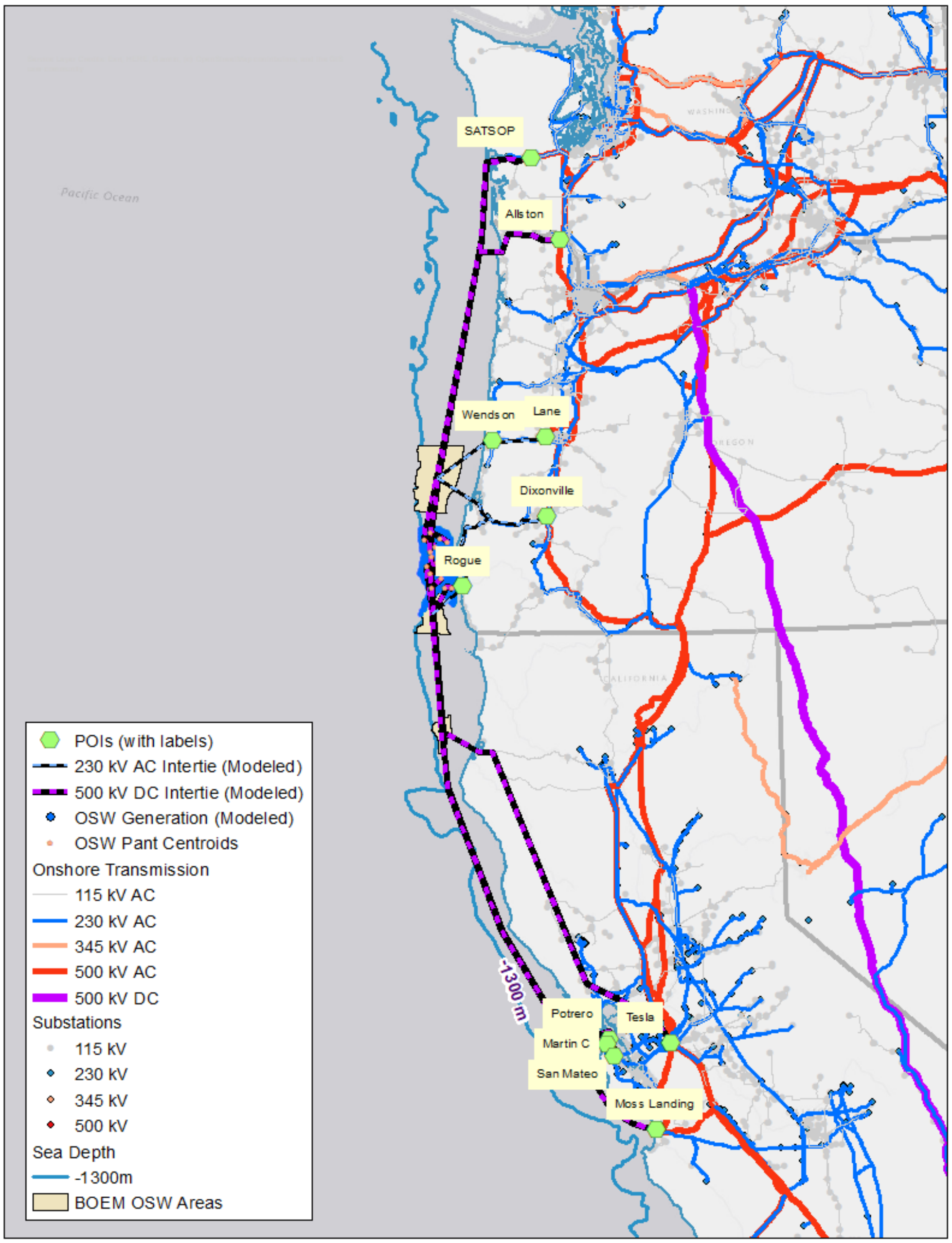
BOEM 2023-067

An Offshore Wind Energy Development Strategy to Maximize Electrical System Benefits in Southern Oregon and Northern California



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BOEM
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OCS Study
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An Offshore Wind Energy Development Strategy to Maximize Electrical System Benefits in Southern Oregon and Northern California

September 2023

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DISCLAIMER

This study was funded, in part, by the U.S. Department of the Interior, Bureau of Ocean Energy Management (BOEM), through Interagency Agreement Number M22PG00006 with the Pacific Northwest National Laboratory (PNNL). This report has been technically reviewed by BOEM, and it has been approved for publication. The views and conclusions contained in this document are those of the authors and should not be interpreted as representing the opinions or policies of BOEM, PNNL or any of their sponsors or affiliated entities. The mention of trade names or commercial products does not constitute endorsement or recommendation for use.

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CITATION

Douville TC, Severy M, Datta S, Siddiqui S, He L, Oikonomou K, Nekkalapu S, Boff D, Maharjan M, Nguyen Q, Harris K, Zhu J, Zhou S, Henry B, Busch J. 2023. An Offshore Wind Energy Development Strategy to Maximize Electrical System Benefits in Southern Oregon and Northern California: National Offshore Wind Research and Development Consortium & U.S. Department of the Interior, Bureau of Ocean Energy Management. Xx p. Report No.: OCS Study BOEM 2023-067. Contract No.: M22PG00006 .

ACKNOWLEDGMENTS

The authors express gratitude to the many reviewers of this work convened by the Pacific Ocean Energy Trust through the Pacific Offshore Transmission Solutions working group. John Fazio, John Ollis, Dor Hirsch Bar Gai, and Daniel Hua from the Northwest Power and Conservation Council advised on the application of, and the research team’s proposed modification to, the Associated System Capacity Credit methodology. The NOWRDC Advisory Board provided review and guidance throughout the project duration. In addition, the following reviewers provided guidance and volunteered their time to ensure coordination of several concurrent studies throughout the project duration:

- Dmitry Kosterev, Jeff Barton, and Anders Johnson, Bonneville Power Administration
- Chelsea Loomis, NorthernGrid
- Song Wang, Portland General Electric
- Fangfang Du and Scott Beyer, PacifiCorp

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List of Abbreviations and Acronyms

AC	Alternating current
ADS	Anchor data set
ASCC	Associated system capacity contribution
BPA	Bonneville Power Administration
BCR	Benefit-cost ratio
BOEM	Bureau of Ocean Energy Management
CAISO	California Independent System Operator
COI	California Oregon Intertie
DC	Direct current
EPA	Environmental Protection Agency
GW	Gigawatts
HVAC	High voltage alternating current
HVDC	High voltage direct current
JEDI	Jobs and Economic Development Impact
kV	Kilovolt
mi	Statute mile
MTDC	Multi-terminal high voltage direct current
MVA	Megavolt-ampere
MW	Megawatt
NOWRDC	National OSW Research and Development Consortium
NW	Northwest
OSW	Offshore wind
PACW	Pacificorp West
PCM	Production cost model
PDCI	Pacific DC Intertie
PGE	Portland General Electric
PG&E	Pacific Gas and Electric
POI	Points of interconnection
PSEI	Puget Sound Energy
SCL	Seattle City Light
SW	Southwest
WEA	Wind Energy Area
WECC	Western Electricity Coordinating Council
WI	Western Interconnection
WPP	Wind Power Plant

Executive Summary

As electricity generation portfolios transition to renewable energy resources, planning to ensure adequate, reliable, and resilient supply of electricity must also adapt to meet system demand. The pursuit of lowest cost of energy at the plant level, though helpful in the initial maturation of bulk-scale renewable energy technologies, has also resulted in plants which require significant compensating reserves, often fossil-fueled, at the system level. Intermittent renewable energy generation poses unique capacity challenges which increasingly depend on weather events at varying timescales, from sub-hourly ramping to decadal droughts. Geographic and technological diversity may provide a solution to many of these challenges, facilitated by transmission planning that considers operational elements such as frequency response, regulation, ramping, and contingency reserves and quantifies other system-wide benefits and costs. This work extends a valuation approach of these elements to the planning of electricity transmission systems within the context of offshore wind (OSW) emergence in Northern California and Southern Oregon.

OSW on the U.S. West Coast is a resource that poses system value today through diversification of a renewable energy resource portfolio, rather than on a leading cost of energy basis. Inherent timing and consistency of power supply underlie this value along with locations of onshore power injection. In this work, OSW energy is sited in the areas off the West Coast between Coos Bay, Oregon and Eureka, California. Three generation and transmission scenarios across two future representations of the Western Interconnection (WI) are modeled, including (i) 3.4 gigawatts (GW) of installed OSW capacity connected through a 2030 high voltage alternating current (HVAC) Radial Topology, (ii) 16.3 GW of installed OSW capacity connected through a 2030+ high voltage direct current (HVDC) Radial Topology, and (iii) 16.3 GW of installed OSW capacity connected through a 2030+ multi-terminal high voltage direct current (MTDC) Backbone Topology (Figure ES.1). The final two scenarios retained the first scenario (3.4 GW of OSW) and optimized the siting of the remaining 12.9 GW, unrestricted to existing planning areas.

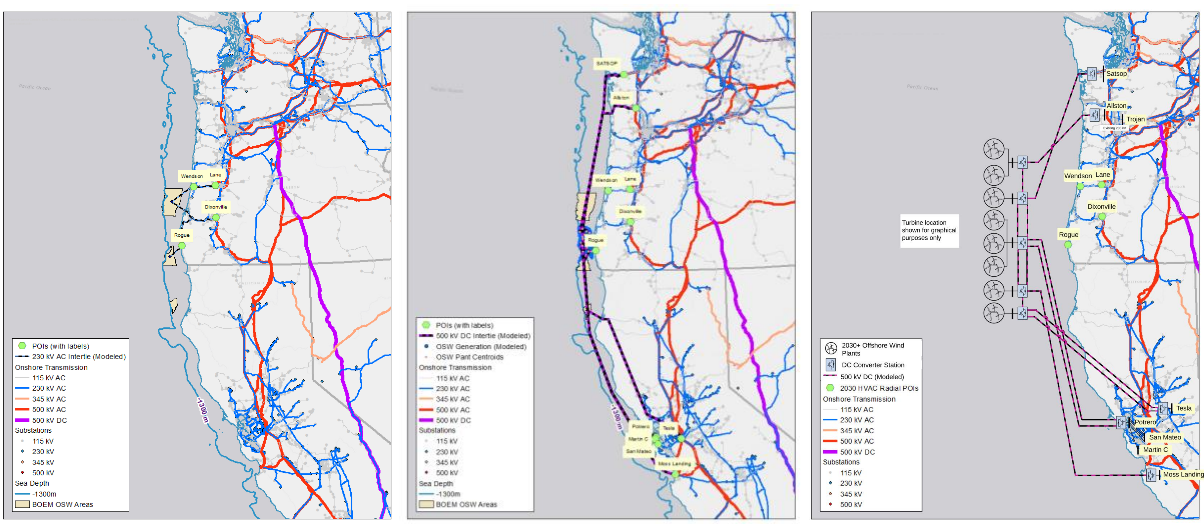

Figure ES.1. Three generation and transmission topologies spanning two representations of the Western Interconnection

From left to right, 2030 HVAC Radial Topology (3.4 GW OSW), 2030+ HVDC Radial Topology (16.3 GW OSW), 2030+ MTDC Backbone Topology (16.3 GW OSW).

Detailed production cost and power systems models of each topology were constructed. Hourly dispatch simulations were run at nodal scale to assess energy, emissions, and transmission infrastructure impacts under standard conditions and resilience events such as heat waves or wildfires. Zonal dispatch over 18 meteorological years of wind, solar, and hydropower production informed capacity value through the Associated System Capacity Contribution (ASCC) metric. Key hours from the dispatch simulations were then carried to alternating current (AC) power flow analysis where N-1 steady state contingency, voltage stability, and transient stability simulations were conducted to identify necessary system reinforcements. A novel MTDC transient stability model was developed and utilized.

Table ES.1. Benefit-cost ratios (BCRs) for each scenario for different combinations of critical assumptions

CO_2 cost ($/tonne)	Annual probability of 3-day heat wave occurring in SW	Floating OSW HVDC Transmission Cost Factor	Benefit-Cost Ratio		
			2030 HVAC Radial	2030+ HVDC Radial	2030+ MTDC Backbone
$105	50%	2.00	1.355	0.835	0.879
$105	400%	2.00	1.703	0.870	0.923
$105	**50%**	**1.25**	**1.355**	**1.017**	**1.088**
$105	400%	1.25	1.703	1.060	1.142
$270	50%	2.00	1.902	1.289	1.355
$270	400%	2.00	2.249	1.325	1.399
$270	50%	1.25	1.902	1.571	1.678
$270	400%	1.25	2.249	1.615	1.731

Baseline assumptions are shown in bold. BCRs above 1 in green, below 1 in red.

Cost associated with construction and operation of OSW generation and new transmission investments were evaluated for each scenario. At system scale, all benefits and costs were discounted and annualized in 2022 dollars, and net value was assessed under the variation of three critical parameters: (i) the cost of carbon, (ii) the annual probability of a 3-day heat wave in the southwest and California, and (iii) a scaling factor of floating OSW HVDC transmission costs over land-based HVDC. Benefit-costs ratios, shown in Table ES.1, and detailed waterfall plots, such as shown in Figure ES.2, were compiled for each scenario.

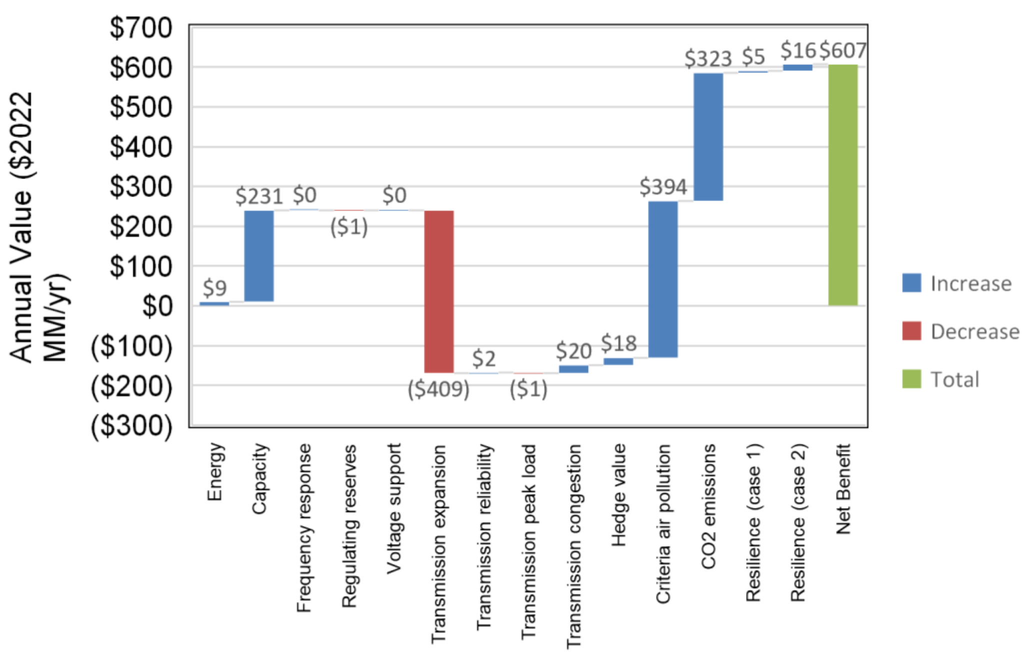

Figure ES.2. Relative valuation of 2030+ MTDC Backbone Topology compared to the 2030+ HVDC Radial Topology under baseline assumptions

Blue bars indicate a positive value for the MTDC Backbone, red indicates negative value, and green shows the cumulative total of all components. Cost of carbon: $105/tonne; heat wave probability: 50%; HVDC cost factor: 1.25.

The following themes were observed in the results:

Annual net benefits of $127M to $6B and net costs of $1.6B to $795M are found for OSW topologies depending on key assumptions for carbon costs, heat wave probabilities and HVDC cost factors.

Net value over the base case is largest for the 2030 HVAC Radial Topology, where system-wide benefits exceed costs in every case, including without a system-wide cost on carbon dioxide emissions. Net value is most negative for 2030+ HVDC Radial Topology with low carbon cost and high HVDC cost factor. All scenarios provide a benefit-cost ratio (BCR) of at least 1.289 under the high carbon costs assumption (Table ES.1). The MTDC Backbone increases annual value over the HVDC radial case in all cases, with improvements ranging from $362M to $1.26B, or BCRs by 0.045 to 0.123. The MTDC Backbone Topology provides the greatest upside potential of all topologies in terms of annual net benefits. Floating HVDC costs are important value drivers. Assuming moderate heat wave probability and high costs of carbon, BCRs of 1.0 were reached for the 2030+ HVDC Radial Topology and MTDC Backbone Topology at HVDC scale factors of 3.22 and 3.41, respectively.

Capacity is a key value of west coast OSW, and it can be significantly enhanced through interregional transmission design.

For all topologies in the baseline assumptions, capacity contributions are the third most valuable offering from OSW, behind the avoided emissions and energy value. As assessed through the ASCC metric, capacity is worth as much as 42%, 43% and 60% of the energy value for the 2030 HVAC Radial Topology, 2030+ HVDC Radial Topology, and 2030+ MTDC Backbone Topology, respectively. As with any intermittent resource, the value of OSW capacity degrades as more OSW is developed, but transmission design can serve as a hedge against the erosion of capacity value. Without changing the OSW generation or POIs, the MTDC Backbone allows for interregional transmission and increases the ASCC by 28% and 9% to the Northwest and WI, respectively, over the 2030+ HVDC Radial topology (Figure ES.3).

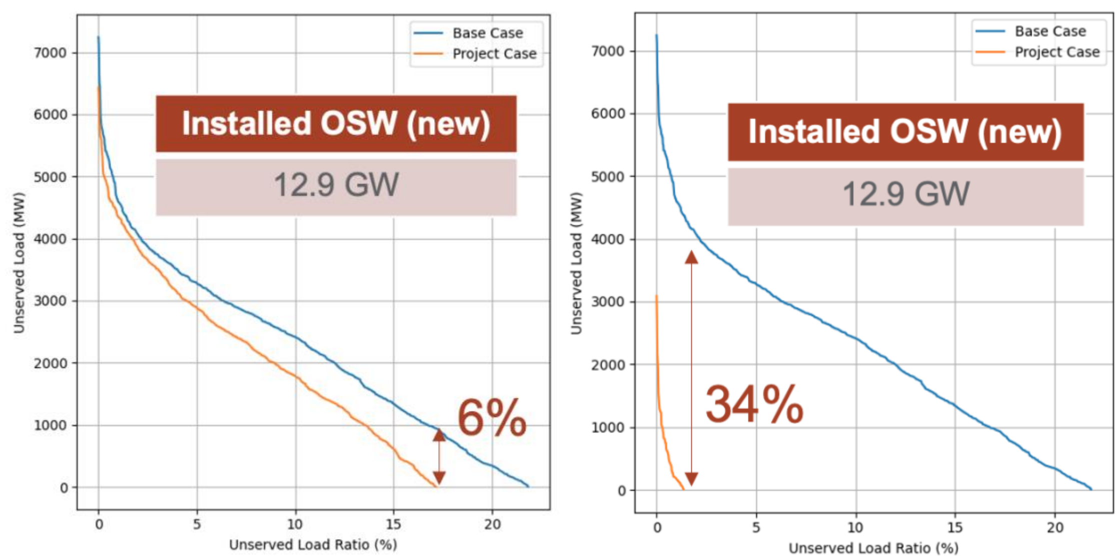

Figure ES.3. Capacity shifts posed by MTDC transmission in the Northwest
2030+ HVDC Radial (left) and 2030+ MTDC Backbone (right). Blue curves correspond to base cases, and orange curves to an additional 12.9 GW of OSW in Southern Oregon and Northern California.

OSW yields diminishing marginal value with installed capacity, but reductions can be mitigated through transmission design.

As installed capacity of OSW increases, the system-wide marginal value (or incremental value of the next megawatt [MW]) decreases between the two radial topologies. However, the marginal value improves when the transmission system is designed as a backbone to share power across a region rather than to individual POIs. This is observed even though transmission expansion costs are the highest for the MTDC backbone, as seen in Figure ES.4. The benefit of the MTDC Backbone over the HVDC Radial topology is provided by increased value in capacity, regulating reserves, energy, hedge value, and transmission congestion.

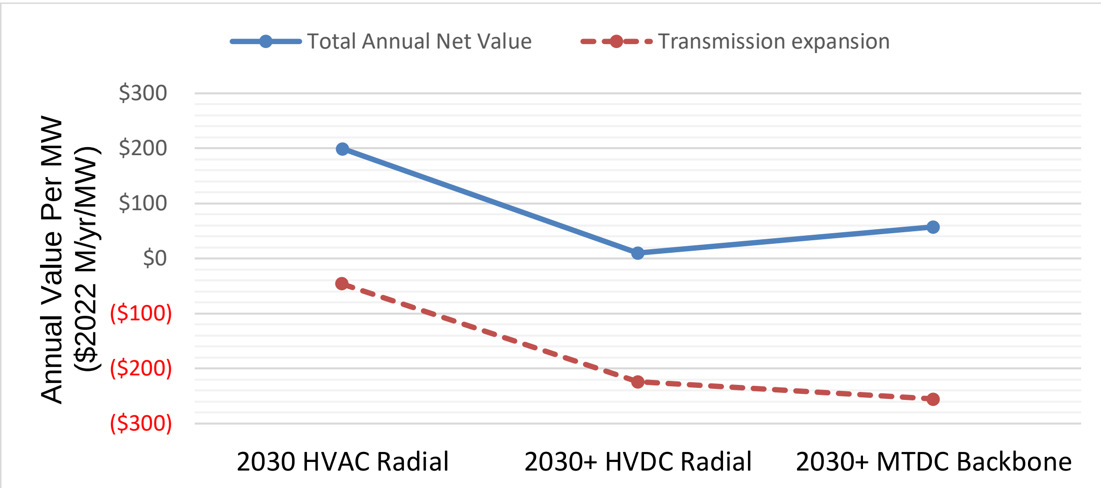

Figure ES.4. Marginal annual total and transmission expansion value for all topologies
Cost of carbon: $270/ton; probability of 3-day heat wave: 50%; HVDC cost factor: 1.25.

These results suggest that the impact of transmission design on the overall system value resulting from a change in generation portfolio should be considered on multiple time horizons by planners and policymakers proactively to identify development pathways to long-term and wide-ranging net benefits.

Application of the valuation approach developed in this study reveals that further understanding of system value is possible through additional resilience scenarios and more accurate cost estimates of floating OSW transmission equipment, as technology matures. The approach could also be applied at greater scale and in other contexts, for OSW or other portfolio changes to the generation mix, to aid policymakers and transmission planners seeking clean electricity and clean energy futures.

1 Overview

As the electricity sector transitions to a generation mix with much more renewable energy, the search for those renewable energy resources and the planning for transmission to support them, must consider broader system impacts than the provision of energy. For example, some of the most energetic land-based wind energy sites in the U.S., though offering a compelling cost of energy based on current technology, may also rely significantly on dispatchable reserves to balance supply when wind speed suddenly drops. Reliance on fossil fuel-fired reserves will be reduced in the future, in accordance with public policy. One way to do so is through siting renewable energy resources with less inherent volatility or greater natural complementarity with load. Geographic and technological diversity of renewable energy generators will also help reduce fluctuations in energy supply, which underscores the reliance of the energy transition on robust transmission. Transmission performance must be assessed under typical but also contingency and fault conditions so that least-cost expansion strategies can be identified accurately. For these reasons, an opportunity arises to bring forward transmission and generation *operational* considerations to better inform the *planning* of new renewable energy resources and the transmission to support them.

Valuation of these operational elements is incomplete within the context of emerging asynchronous grids. Review of the literature indicates avoided costs approaches (ISO-NE, 2016; Collier et al., 2019; Jorgensen et al., 2021, Novacheck & Schwartz, 2021) and market valuations (Beiter et al., 2017; Mills et al., 2018; Beiter et al., 2020; Younes et al., 2020), primarily of energy and capacity provision by OSW. Beiter et al. (2020) quantified impacts to ramping and contingency reserves. Douville & Bhatnagar (2021) and Novacheck & Schwartz (2021) also quantified OSW impacts to transmission congestion in Oregon. Mongird & Barrows (2021) composed a valuation framework for distributed wind resources in various off-grid and interconnected contexts. This work seeks to extend such a valuation approach to transmission scale, focus more deeply on grid support services impacts, and apply it within the context of OSW emergence in Northern California and Southern Oregon.

1.1 Research Questions

In contrast to valuations restricted to project revenue or levelized cost of energy calculations, comprehensive accounting for system value provides a better perspective for evaluating different transmission and generation scenarios that affect the grid beyond the project boundary. A system-wide valuation strategy would enable identification of transmission designs that fully unlock the potential value of new energy resources. Key questions to be addressed through the strategy fall into two major groups:

1. <u>Evaluation of system benefits</u>
   What is the net value of OSW energy to the operation of regional and interregional electricity transmission systems? How do net benefits change with the amount of OSW development? How do net benefits change as the broader generation and transmission portfolios evolve to meet changing public policy, reliability, or economic objectives?
2. <u>System planning</u>
   How can OSW generation and transmission be designed to maximize net benefits? What role can transmission planning coordination play in influencing net benefits? How can an offshore transmission asset serve the system when not being used to transmit OSW?

This report documents the strategy and its implementation through three offshore generation and transmission topologies off the coast of Southern Oregon and Northern California.

1.2 Major Assumptions

To enable the focus on the valuation methodology and the many dispatch and power systems analyses to exercise it, significant assumptions were made in this work. Detailed cable routing, considering sea floor conditions and conflicts with ocean co-use, was neglected. Similarly, the siting of Balance of Plant equipment, including export cables, substations, and converter stations, was not pursued as part of this effort. Future dispatch of generators across the WI assumed a large market construct rather than representing the contracts in place today. Finally, some limitations were placed on the power system analysis. Though contingency analysis was undertaken, it was limited to single contingencies. System reinforcements were considered for transmission lines of kilovolt rating of 230 kV or higher. Remedial action schemes were not considered.

1.3 OSW Resource

Within the approximate geographic boundary offshore of Coos Bay, Oregon, to Eureka, California, the Bureau of Ocean Energy Management (BOEM) has designated the Coos Bay Call Area, Brookings Call Areas and two lease areas, OCS-P0561 and OCS-P0562, in Northern California. These areas have the technical potential for more than 10.5, 3.5, 0.77, and 0.83 GW of OSW generation potential, respectively.[1] These areas may be characterized by dominant North-South wind directions, robust net capacity factors, high average wind speed, and consistent power production potential in the evenings and mornings, as shown in Figure 1.

1.4 Southern Oregon and Northern California Transmission

Transmission networks reaching the coast have some capacity for interconnection of OSW near Coos Bay, but interconnection capacity is significantly lower in the more remote coastal regions such as near the Oregon-California border and further south extending to Eureka. North of San Francisco, the load centers and the HVAC transmission lines are located more than 100 miles inland of the coast. Outside of trans-Coast Range 230 kilovolt (kV) transmission lines into and north of Coos Bay, the major links from the coast to the higher capacity inland transmission corridors are limited to approximately 120 miles of 115 kV transmission from Grants Pass to Crescent City on the PacifiCorp system and approximately 145 miles of 115 kV interties into Humboldt Bay on the Pacific Gas and Electric (PG&E) system. In general, the 115 kV lines have limited capacity to transmit significant quantities of power today. These locations coincide with world-class wind energy resources both in terms of energy and inherent time of production (Figure 1). In the Northwest, major load centers like Seattle and Portland are powered primarily by the region's abundant hydropower and wind, solar, and natural gas resources to the north and to the east. Excess hydropower is also sent to Southern California on the Pacific DC Intertie (PDCI), a 500 kV (per pole) direct current (DC) line running approximately 850 miles from the John Day Dam in The Dalles, Oregon, south to the Nevada-Oregon Border, and then continuing to Los Angeles. The California-Oregon Intertie (COI) is a collection of AC lines which transfer additional hydropower to California and increasingly surplus solar power from California to the Pacific Northwest. San Francisco is powered predominantly by inland wind, solar, nuclear, hydro, and natural gas resources.

[1] Assuming greater than 3 MW per kilometer squared (km^2) (Musial et al., 2019). In this study 5.5 MW/ km^2 was assumed (see Appendix C).

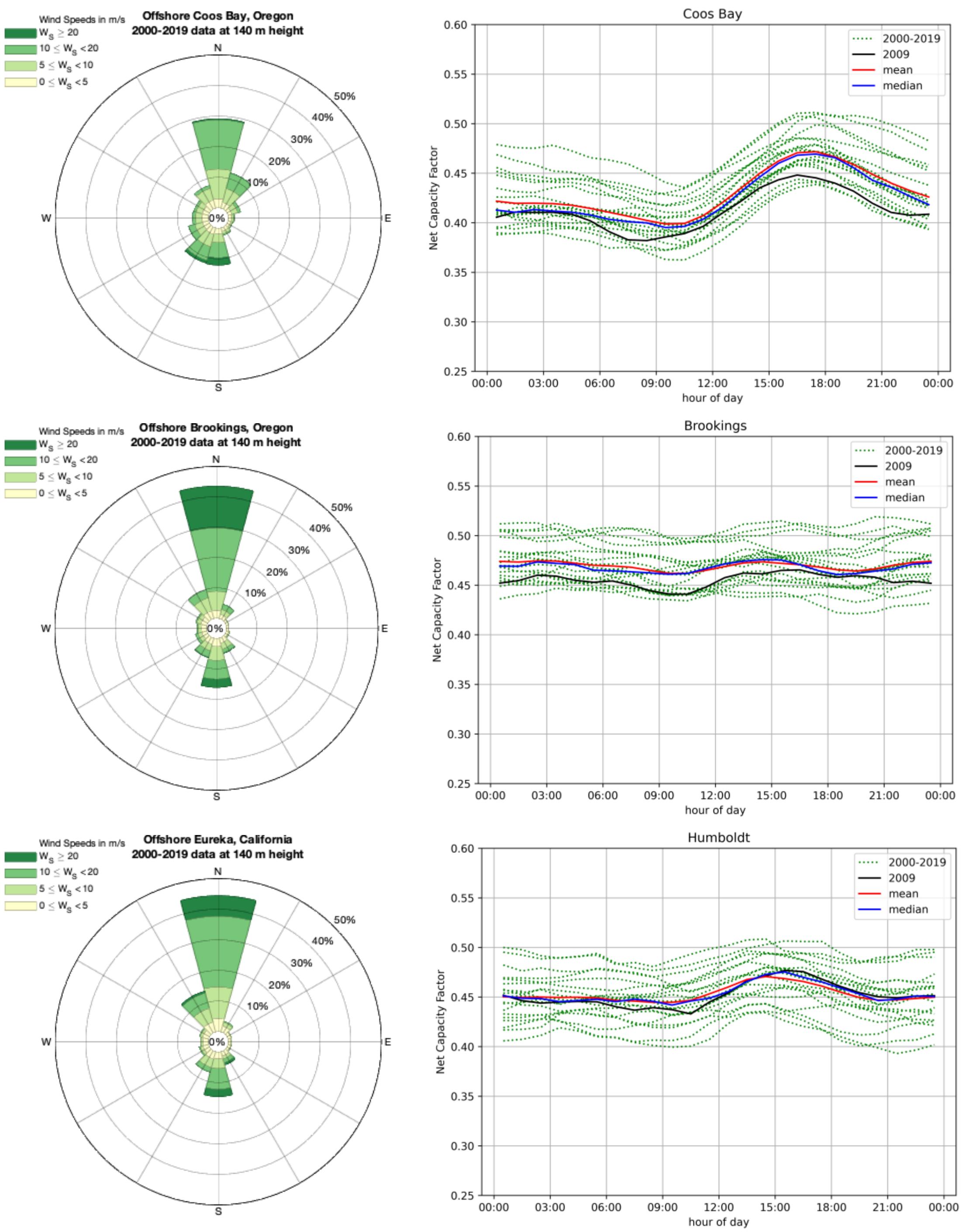

Figure 1. Coos Bay Call Area, Brookings Call Area, and Humboldt Wind Energy Area (WEA) wind rose and potential net capacity factor characteristics

Assumptions used to produce net capacity factors are provided in Appendix C. Time in local (Pacific) time zone.

2 Methods

Given the complexities of reversing power flow at the coast and the accelerating changes to the generation mix, it is imperative that a system-wide development strategy considers OSW generation and transmission concepts that are fully informed by best available data across multiple time horizons.

2.1 Approach

Three future scenarios of generation and transmission systems were designed for OSW development using a series of electric system modeling tools (Figure 2). Importantly, in this strategy, the onshore electrical transmission capacity was consulted *first*, and then offshore generation and transmission concepts were envisioned which would support power flows to the onshore points of interconnection (POIs) where the power could be received. System-wide economic value of each scenario was calculated by comparison to a baseline with less OSW generation or with alternate transmission design.

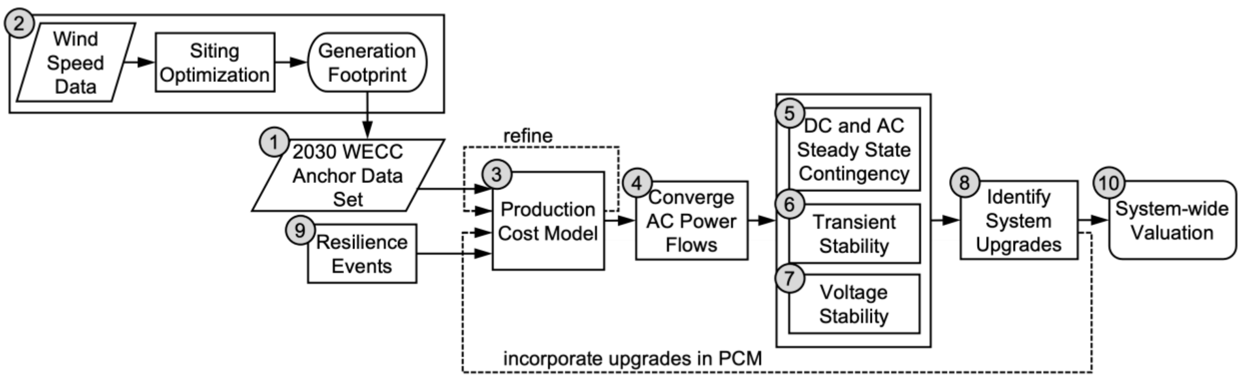

Figure 2. Abbreviated flow diagram of modeling approach for generation optimization, transmission design, and valuation

The development strategy was implemented using the following steps:

1. <u>Base case production cost modeling</u> – Build the base case production cost model (PCM) in GridView[2] for the WI using the Western Electricity Coordinating Council (WECC) 2030 Anchor Data Set (ADS) and identify buses for potential interconnection. When applied to years beyond 2030, adjust the ADS for future generation portfolios based on energy policy.
2. <u>Generation and transmission footprint</u> – Collect modeled wind speed data at hub height for 20 years for the entire Northern California and Southern Oregon region from Optis et al. (2020). Convert wind speeds into a power generation profile using a reference turbine power curve and applying loss factors. For near-term scenarios, locate generation within existing BOEM Lease Areas, Wind Energy Areas, and Call Areas. For long-term future scenarios, select the optimal OSW footprint for each development scenario based on the timing of OSW energy and capacity delivery (see Appendix C). Then, considering time horizon and quantity of the resource, develop a viable transmission sub-system for each OSW generation footprint. Minimize the overall transmission cost per MW, using distance as a first-order proxy for transmission cost.

[2] GridView is a security-constrained, economic dispatch simulation software supported by Hitachi Energy.

3. Production cost modeling – Run the PCM for the base case and each OSW scenario with the optimized generation footprint and power profile. Refine PCM and re-run as needed to address major line overloads, issues, or looping.
4. AC power flow – Converge the AC power flow using representative hours from the PCM output, matching the dispatch from the PCM in the power flow model.
5. Steady-state contingency – Run DC and AC steady-state contingency (N-1) analysis.
6. Transient stability – Run transient stability analysis.
7. Voltage stability – Run voltage stability analysis.
8. Identify upgrades – Identify necessary upgrades to the transmission system based on contingency and stability analysis then build the upgrades in the PCM and re-run.
9. Resilience – Define the set of extreme events that will be used to test the resilience of the future scenarios. Resilience test events included (i) a 3-day heat wave[3] in Southern California and the Southwest U.S. with variable annual probability of occurrence that increases system-wide load (using data from the Environmental Protection Agency (EPA) 2023b), (ii) a wildfire occurring along the path of the California-Oregon Intertie (Path 66) with an 8% annual probability of occurrence that shuts down Path 66 (using data from Cal-Adapt, 2023), and (iii) a long-term drought that limits hydropower generation in the Pacific Northwest based on the hydropower dispatch from 2001 with a 14% annual probability of occurrence (Turner et al., 2022).
10. System valuation – Apply a system-wide valuation for each scenario with OSW compared to the base case without OSW (see Appendix A).

2.2 Scenario Definitions

Three OSW generation scenarios and associated transmission topologies were analyzed using the modeling approach described above. To expand the transmission system, the following technology capacities, based upon current and pending technology maturity, are assumed across all scenarios:

- Overland 230 kV HVAC transmits 400 megavolt-ampere (MVA) per circuit
- Overland 500 kV HVAC transmits 1,500 MVA per circuit
- Subsea 230 kV HVDC transmits 375 MVA per circuit
- Subsea 500 kV HVDC bipolar circuits transmit 2,600 MVA[4]

The scenarios include one near-term scenario with OSW development in 2030 using existing interconnection capacity and two longer term OSW development scenarios using radial HVDC and multi-terminal HVDC (MTDC) offshore transmission topologies (Table 1). The results from each of the three OSW scenarios are compared to a relevant base case.

Table 1. Overview of study scenarios

Scenario	Base Case	Base Case OSW Installations (GW)	New OSW Installations (GW)
2030 HVAC Radial	2030 ADS + BC Hydro dispatch updates	0	3.4
2030+ HVDC Radial	2030 ADS + 32 GW land-based wind and solar energy, 7.2 GW OSW, CAISO transmission changes	7.2	12.9
2030+ MTDC Backbone		7.2	12.9

[3] Average heat wave durations across the West averaged 2.5 days from 1961-2021. Accounting for decadal rates of change of heatwave duration (Habeeb et al., 2015), the average heat wave duration became 3.0 at project midpoint.

[4] See Prysmian, NKT, or ABB press releases regarding emerging 500 kV HVDC cable capacities.

2.2.1 2030 Base Case

The base case is built from WECC's 2030 ADS, which includes existing transmission paths, load profiles, and generation dispatch schedules. The 2030 ADS is modified to account for a refined monthly dispatch schedule of British Columbia hydropower to serve load within the province.

2.2.2 2030 HVAC Radial Topology

The 2030 OSW case uses radial HVAC interconnections between the offshore generation resource and Southern Oregon onshore POIs. Existing capacity at these POIs is readily extended through 230 kV upgrades. For this scenario, 3.4 GW of OSW capacity are installed off the coast of Southern Oregon. The OSW power generation profile is based on the average profile of either the BOEM Coos Bay (for Dixonville, Lane, and Wendson POIs) or Brookings (for the Rogue POI) Call Areas. Generation is sited at the centroid of each area. After modeling the electrical losses inherent to OSW generation system and export cables, the peak power flow injection into the onshore POIs is 2.7 GW combined across all four POIs. Appendix C provides further information regarding power production and loss assessments.

In this topology, power from the Oregon Call Areas is delivered to four POIs: Wendson, Lane, Dixonville, and Rogue substations at injection limits enabled by 230 kV onshore upgrades (Figure 3, Table 2**Error! Reference source not found.**). Radial HVAC interconnections are modeled in a hypothetical straight line between the centroid of the Coos Bay and Brookings Call Areas to an onshore cable landing point without considering any marine cable routing conflicts (Figure 4**Error! Reference source not found.**). Onshore routes are mapped to existing cable corridors. Lane and Dixonville POIs require double circuit 230 kV runs to land 800 MWs of power each. Additional double circuit 230 kV lines between Rogue and Fairview are assumed.

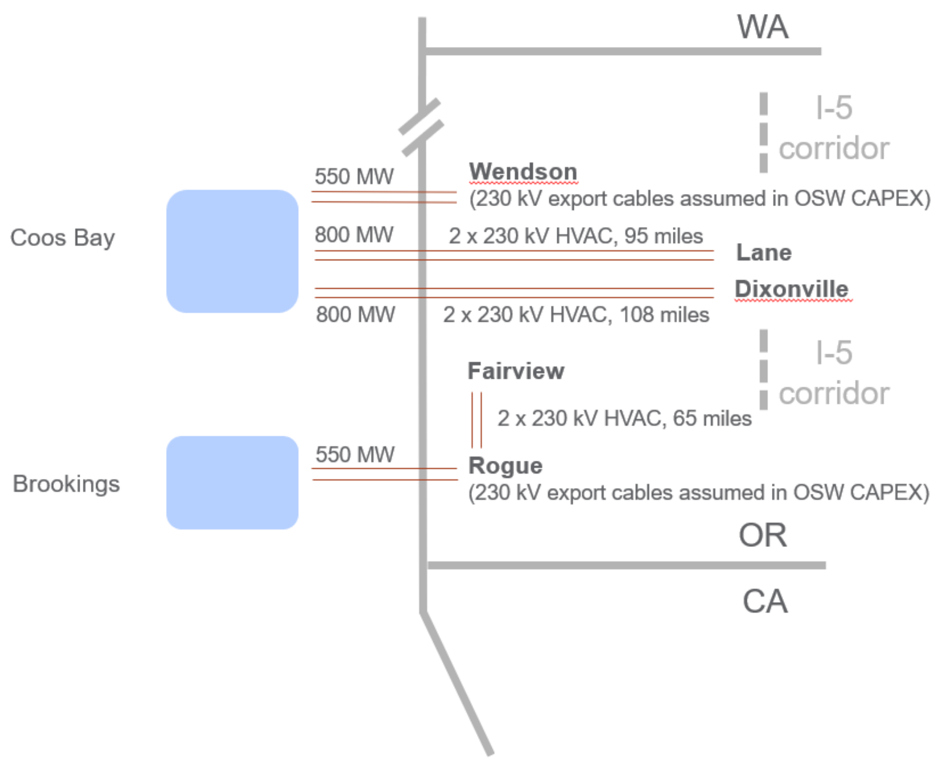

Figure 3. Transmission expansion to support interconnections of 2030 HVAC Radial Topology
Graphic not to scale.

Table 2. 2030 HVAC Radial Topology OSW generation and interconnection detail

Point of Interconnection	Installed Capacity (MW)	Power Injection (MW)	Number of Plants	Plant Area (km²)
Wendson	700	550	1	127
Lane	1,000	800	1	182
Rogue	700	550	1	127
Dixonville	1,000	800	1	182
Total	*3,400*	*2,700*	*4*	*618*

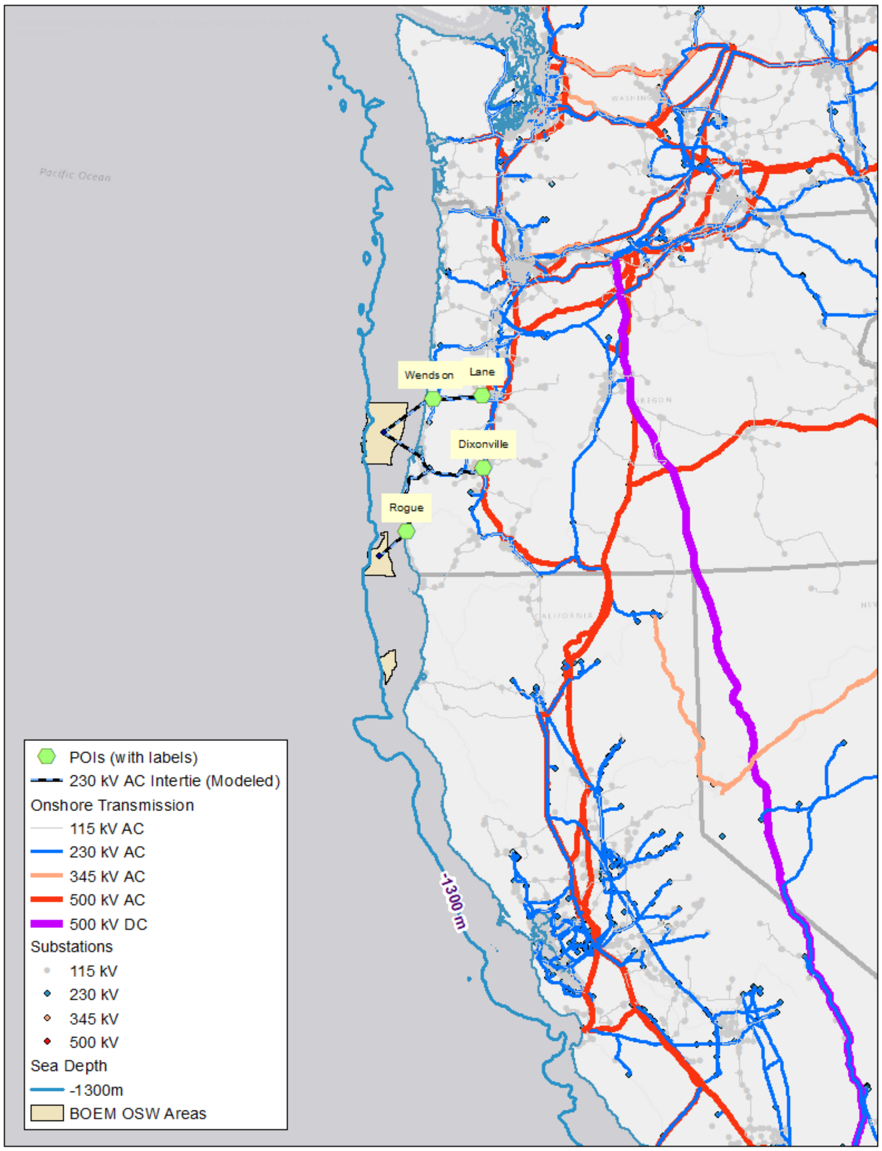

Figure 4. 2030 HVAC Radial Topology injecting 2,700 MW at four POIs through 230 kV transmission

230 kV interconnections to POI substations and new 230 kV circuits onshore into Rogue substation indicated. Additional onshore upgrades not shown.

Onshore transmission system upgrades required to allow for interconnection of 3.4 GW of installed OSW capacity are detailed in Table 3. As indicated in Figure 2, these onshore upgrades were identified based on DC contingency analysis, DC production cost modeling, AC contingency analysis, and through consultation with regional balancing authorities. By either fixing impairments on the existing system or expanding the system at 230 kV or lower to enable four POIs, the upgrades identified in this topology yield an upper limit of 230 kV interconnection capacity (2.7 GW).

Table 3. Onshore transmission upgrade buildup for 2030 HVAC Radial Topology

Onshore Infrastructure	Description	Cumulative power flow capacity by POI (GW)	Cumulative Total Power Flow Capacity (GW)
Existing	Existing system capacity at POIs using WECC 2030 ADS heavy summer case	0.37 at Wendson 0.48 at Fairview	0.85
Fairview-Alvey	Fix impairments	0.55 at Wendson 0.55 at Fairview	1.1
Wendson-Toledo	Fix impairments		
Fairview-Reedsport	Fix impairments		
Reedsport-Tahkenitch	Fix impairments		
Coos Bay Call Area to Dixonville	New 230 kV line from Sam's Valley to Whetstone New 230 kV line Canyonville to Days Creek	0.55 at Wendson 0.55 at Fairview 0.80 at Dixonville	1.9
Coos Bay Call Area to Lane	Fix transformer from Lane S1 to Lane Fix Alvey N to Lane S1 line Fix impairments Lane to Willow	0.55 at Wendson 0.55 at Fairview 0.80 at Dixonville 0.80 at Lane	2.7
Rogue to Fairview	New 230 kV line Rogue to Fairview	0.55 at Wendson 0.55 at Rogue 0.80 at Dixonville 0.80 at Lane	2.7

Approximate cumulative power flow capacity (two far right columns) indicates the capacity that can be accommodated at the POIs after implementing the upgrades.

2.2.3 2030+ Base Case

For higher capacities of OSW to be installed, a time horizon beyond 2030 will need to be considered due to the lengthy siting, permitting, and construction processes for large OSW plants and the required transmission enhancements. Thus, a base case beyond 2030 was created to account for realistic changes to the generation portfolio in WECC that would happen simultaneously with further OSW plant development. New capacity additions were modeled based on existing interconnection queues in WECC, primarily composed of new land-based wind and solar energy projects. However, capacity growth was targeted within the bounds of the existing transmission system, such that individual plants do not see uneconomic curtailment (i.e., curtailment greater than approximately 15%). In the 2030+ base case, 35 GW of new solar and wind generators were installed on top of the 270 GW of existing capacity in WECC, including 3 GW of OSW installed capacity connected at Diablo Canyon, in proximity to the existing BOEM Morro Bay Lease Areas (Figure 5).

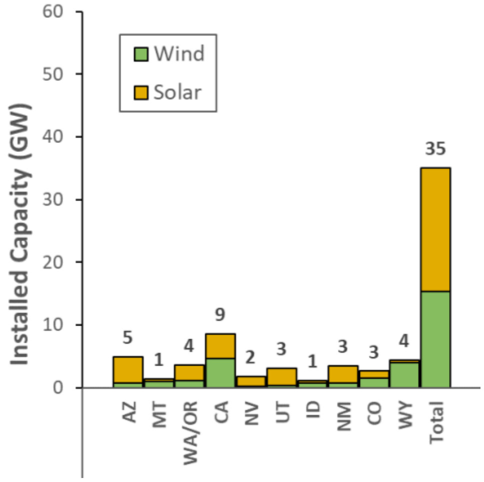

Figure 5. Wind and solar installed capacity by state added to the 2030 ADS to create the 2030+ base case

In addition, and in accordance with California Independent System Operator (CAISO) transmission studies in California, a new Collinsville substation and 230 kV link to the existing Pittsburg substation were added to CAISO's transmission system (Figure 6) for the 2030+ base case. Finally, OSW generation from the 2030 HVAC Radial Topology is also included in the 2030+ future base case. In total, 38.4 GW of new wind and solar generation is added to the ADS 2030 for this base case, 7.2 GW corresponding to OSW.

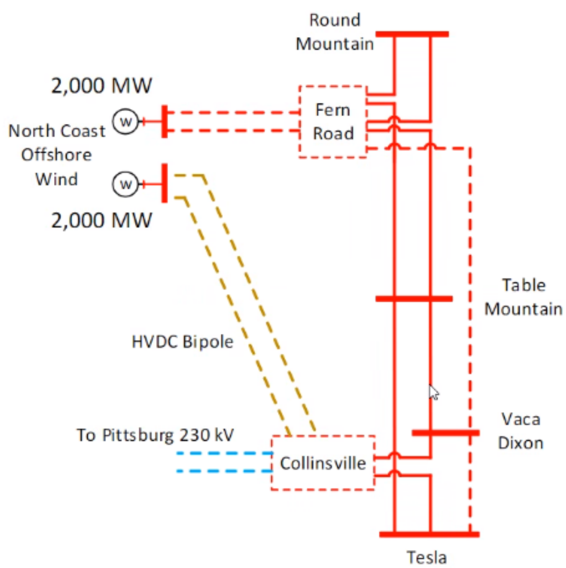

Figure 6. Collinsville substation and 230 kV link to Pittsburg incorporated into 2030+ base case (CAISO, 2022)

2.2.4 2030+ HVDC Radial Topology

For the first 2030+ scenario, a radial HVDC topology is used to interconnect OSW to onshore in California, Oregon, and Washington. In addition to the base case that includes 7.2 GW of OSW, an additional OSW installed capacity of 12.9 GW is added in this scenario, which is equivalent to 10.1 GW peak power flow at the POI after applying loss factors. Total OSW installed capacity for this scenario comes to 20.1 GW. The OSW power generation profile is modeled using the optimized OSW siting based on delivery of energy and capacity (see Appendix C). This optimal location of OSW development, herein referred to as "Opt20," is located near the border between California and Oregon. This area provides superior average net capacity factor (NCF, 47.4%) to the Coos Bay Call Area (43.0%), Brookings Call Area (47.0%), and two Humboldt Lease Areas (45.3%), and has peak average daily generation at 5:00 pm based on 20 years of modeled wind speeds (Figure 7). The Opt20 footprint was developed for the purposes of this study and is not tied to development plans of any existing or future call area.

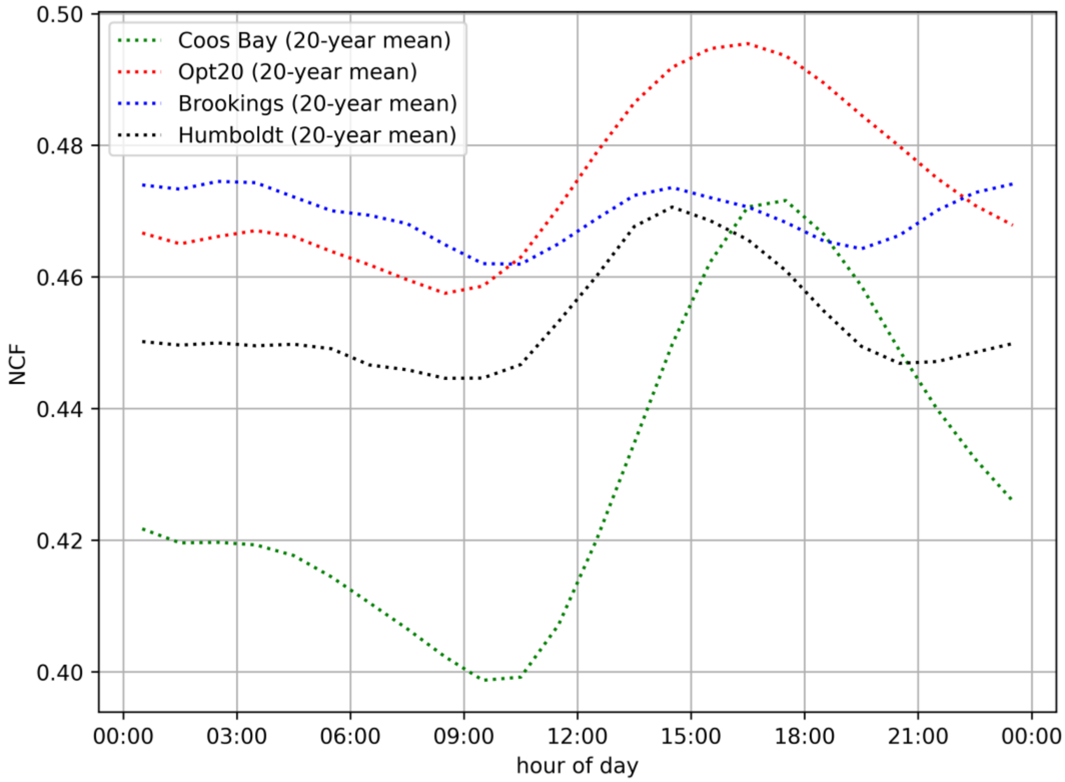

Figure 7. 20-year means of daily hourly net capacity factors

Optimized footprint (red line) compared to existing OSW areas in California (black line) and Oregon (green and blue lines). Time in local (Pacific) time zone.

The new OSW generation capacity is distributed to seven POIs (Figure 8, Table 4) that were selected based on their potential to absorb OSW without forcing curtailment above approximately 15%. This potential was assessed through hourly dispatch simulations of the WECC throughout the year, indicating demand and capacity of onshore POIs to absorb OSW power. With a focus on significant OSW power supply and interregional power system needs, a wide geographic range of POIs emerges from Satsop (near Grays Harbor, Washington), to Moss Landing, California. Radial interconnections are made through 500 kV HVDC cables to the POIs, sized to the power flows (rather than installed capacities) from the new OSW plants within Opt20 (Figure 9). Similar to the 2030 HVAC Radial Topology, hypothetical cables are routed in a straight line from the centroid of the wind plants to the POI without taking cable routing into account.

Table 4. 2030+ HVDC topologies OSW generation and interconnection detail

Point of Interconnection	Installed Capacity (MW)	Power Injection (MW)	Number of Plants	Plant Area (km^2)
Satsop	1,900	1,500	2	173
Allston	3,000	2,350	4	230
Tesla	2,300	1,800	2	209
Potrero	600	480	1	109
Martin C	1,700	1,330	2	155
San Mateo	1,400	1,110	2	127
Moss Landing	2,000	1,530	2	182
Total	*12,900*	*10,100*	*15*	*618*

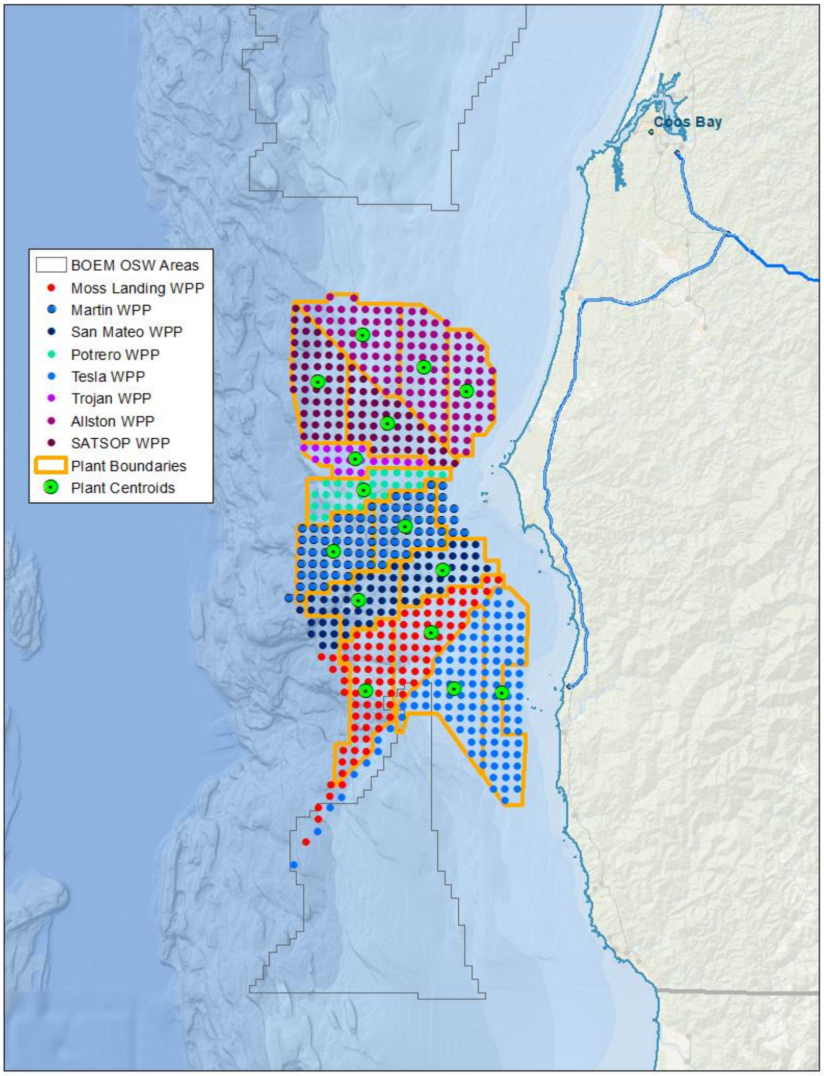

Figure 8. Wind power plants associated with seven POIs between Coos Bay and Brookings Call Areas

Approximate plant sizes from the Opt20 footprint with centroids marked in green at right. The Trojan Wind Power Plant (WPP) combines output with Allston WPP and delivers all power through the Allston 230 kV substation.

A simplified diagram of transmission expansion and cable ratings for this topology is shown in Figure 9 and a scaled diagram is included in Figure 10. To develop this topology, long-distance radial runs to the large load centers of San Francisco and Portland were envisioned, and then shorter route extensions considered to substations within those areas. This resulted in the savings of three HVDC converter stations which would otherwise be required by individual radial lines from OSW plants to their destination POIs at Trojan in Portland, and Martin and San Mateo in San Francisco. Further, in the Portland load center, the topology lands the power for both Allston and the Trojan substations first at Allston and then leverages existing 230 kV AC transmission to provide power to Trojan. This was possible because the OSW injection intended for Trojan totaled only 300 MW. OSW generation intended for Trojan is combined under the Allston POI in Table 4.

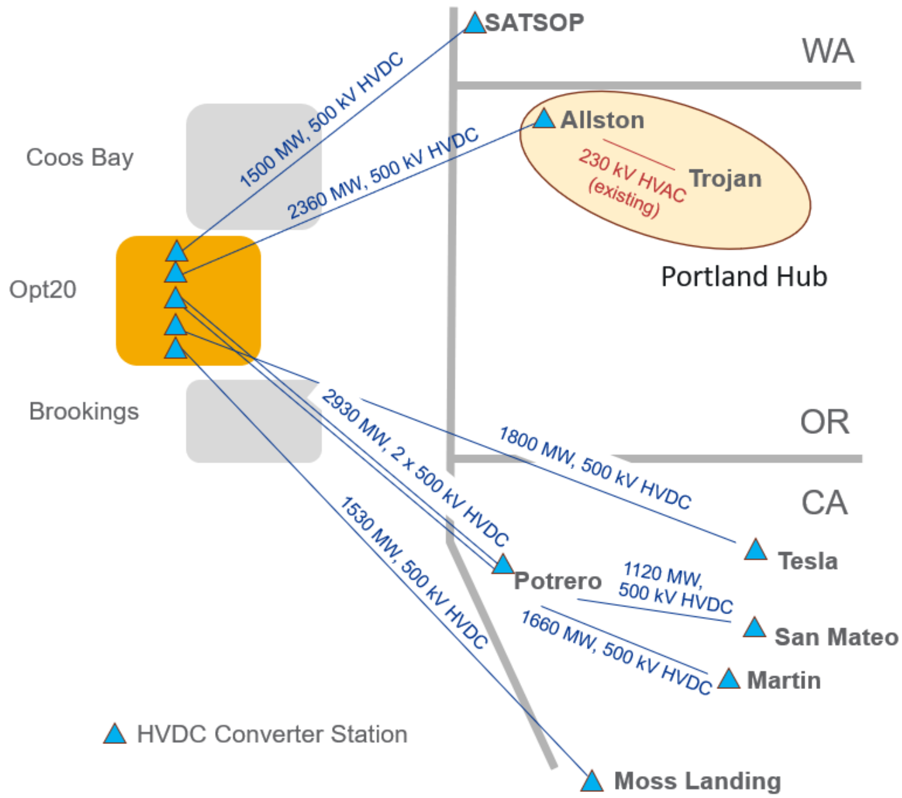

Figure 9. Transmission expansion as part of 2030+ HVDC Radial Topology
Graphic not to scale. Cable carrying capacities corresponding to maximum output from OSW plants.

In San Francisco where more power is delivered across three substations, the existing AC transmission could not be similarly leveraged without significantly departing from the radial HVDC design concept and the point-to-point HVDC strategy of this topology. In San Francisco, the main feed from offshore was planned into the Potrero substation at 2,930 MW, with extensions into Martin and San Mateo substations on the San Francisco Peninsula to deliver an additional 1,660 MW and 1,120 MW, respectively. This DC hub concept yielded bi-directional flows between the San Francisco POIs, which meant less power flowing into Potrero and more power flowing south to Martin than was originally assumed in the initial radial design. However, curtailment of power flows at the individual POIs and into the DC hub was checked to ensure potential economic viability of OSW projects supporting the power flows, and curtailment did not exceed 10%. As 500 kV HVDC infrastructure is typically not economically justified at distances less than 50 miles (Timmers et al., 2023), further economic refinement of this topology would likely entail the design of an AC hub in this area. Nevertheless, the HVDC radial topology presents a useful scenario for purposes of evaluating the power system tradeoffs of interest in this study.

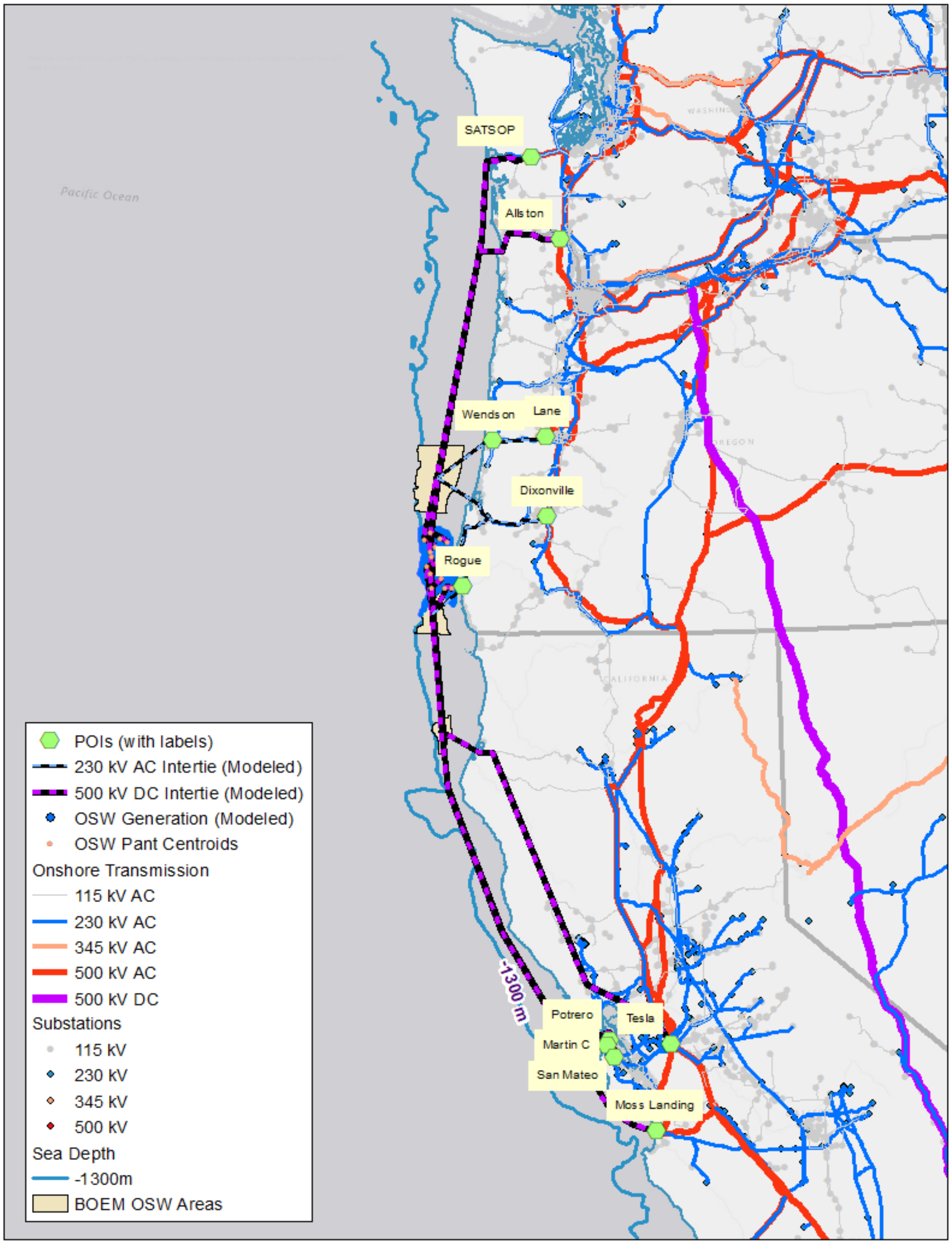

Figure 10. 2030+ HVDC Radial Topology injecting 10,100 MW at seven points of interconnection through 500 kV transmission

Generation and 230 kV interties from the 2030 HVAC Radial Topology, injecting 2,700 MW in Southern Oregon, are included in the 2030+ base case Generation and POIs are identical to the 2030+ MTDC Backbone Topology. The eighth POI at Trojan is not highlighted on this graphic because it is connected to Allston with existing 230 kV HVAC.

2.2.5 2030+ MTDC Backbone Topology

A second topology using the same Opt20 generation footprint is evaluated using an MTDC backbone to link all the offshore substations into a single network (Figure 11) instead of using individual radial interconnections between one offshore substation and one POI. The backbone allows power from OSW generators to flow to multiple POIs and provides an alternative offshore interregional transmission pathway (Figure 14). The same POIs are considered, based on system needs and capabilities as dictated by hourly production cost simulations described in 2.2.4.

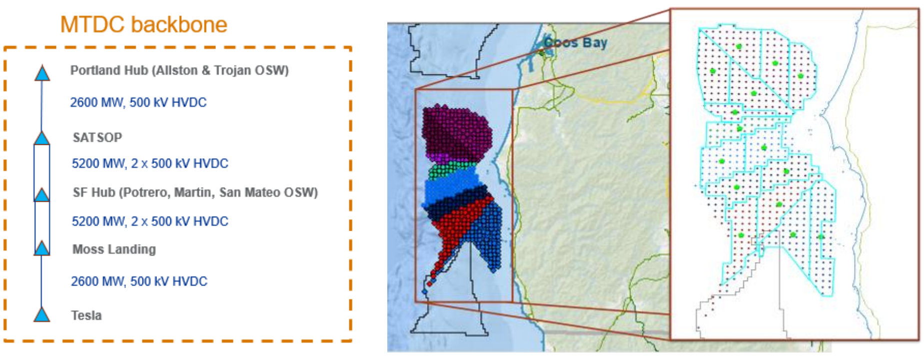

Figure 11. 2030+ MTDC Backbone Topology injecting 10,100 MW at seven points of interconnection through 500 kV transmission
The base case includes the 2030 HVAC Radial Topology.

The approach to designing the backbone is indicated in Figure 12. Starting with the 2030+ HVDC Radial Topology, connections were made between the ocean-side converters and a dispatch simulation was conducted without constraining power flows on the backbone.

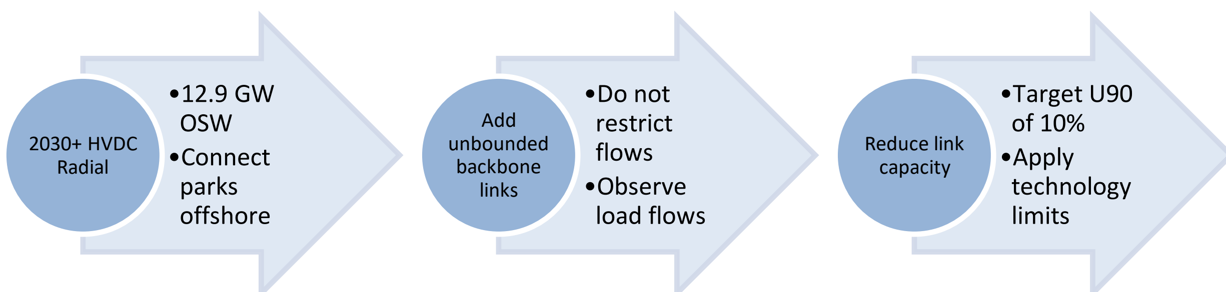

Figure 12. Approach to MTDC sizing

Once the system use of the backbone was characterized from this run (Figure 13), the absolute value of load duration curves was plotted and then technology limitations were considered such that approximately 10% of the hours would be limited by cable power transfer capacity. This limitation mitigates the potential for oversizing components and corresponds with utilization statistics for the PDCI (WECC, n.d.).

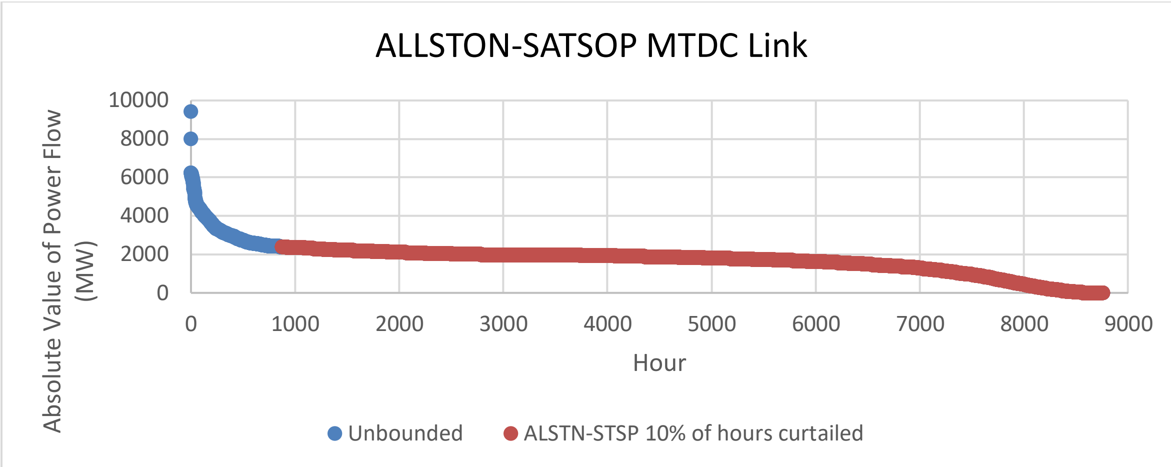

Figure 13. Example of the unbounded load duration curve on the MTDC backbone and how the system was designed without oversizing with respect to system need

The final result of the sizing effort, detailed in Figure 14 and shown completely in Figure 15, resulted in reinforcement of the N-S links south of Satsop on the backbone. With the introduction of bi-directional flows, looping was observed among the San Francisco links. For this reason, sub-sea AC extensions from Potrero to Martin and to San Mateo were selected in the San Francisco Bay. Flows to Tesla were also particularly utilized in the dispatch simulations, and the links from the backbone to the Tesla POI were accordingly reinforced.

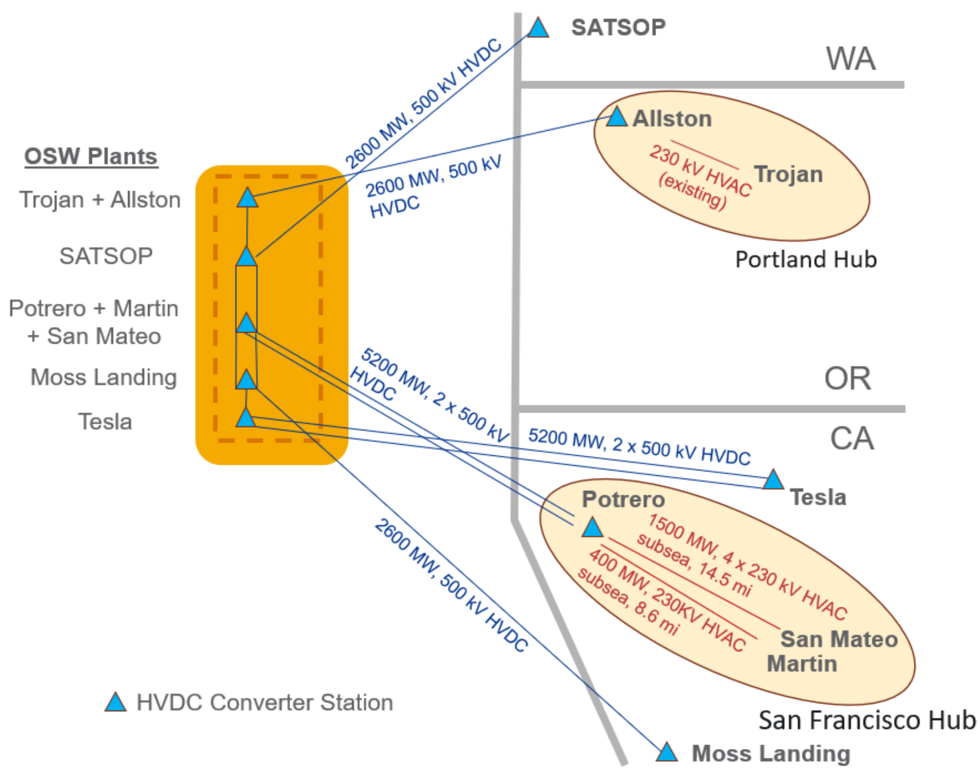

Figure 14. Transmission expansion incurred by 2030+ MTDC Backbone Topology
Graphic not to scale. Cable carrying capacities corresponding to maximum assumed technology limits.

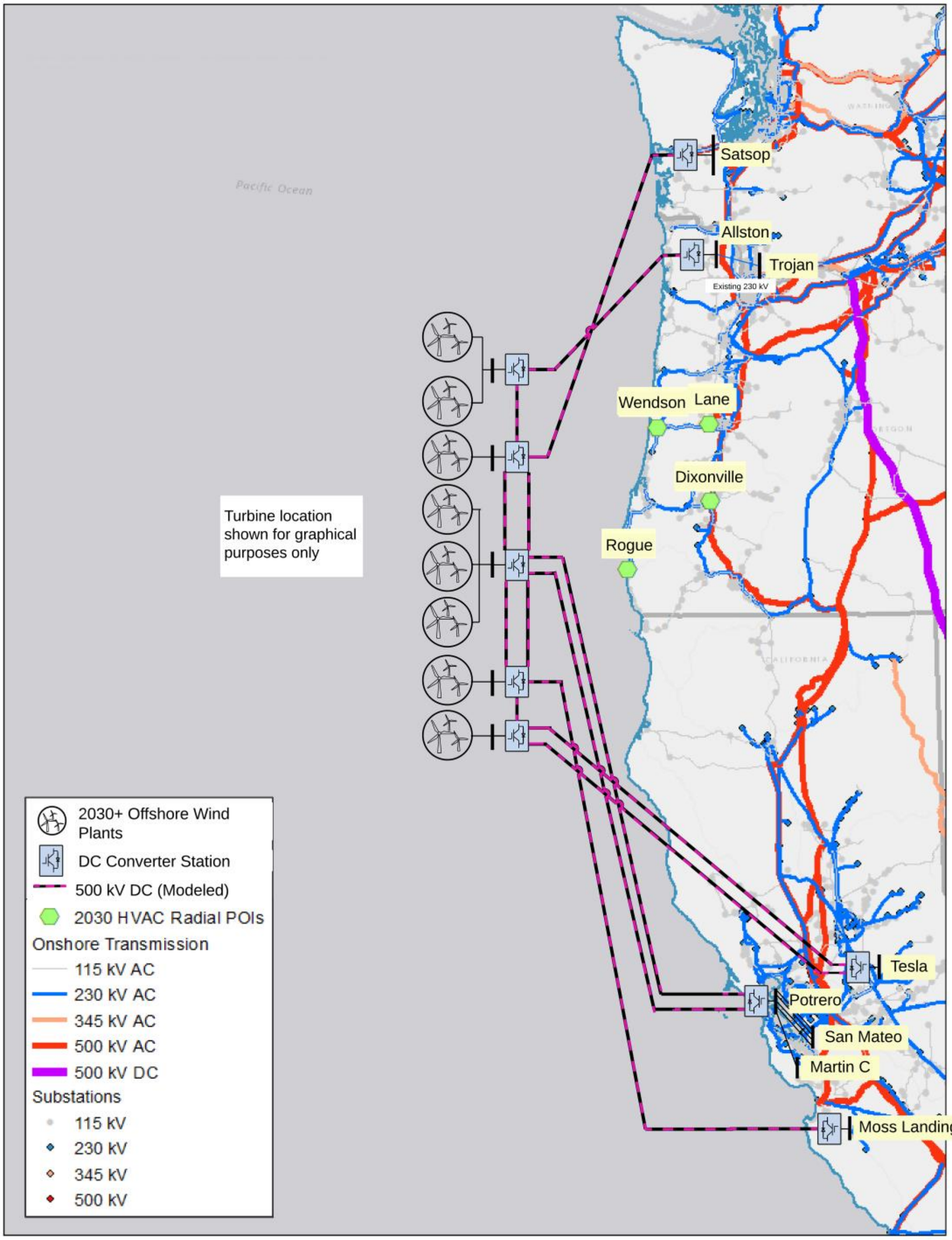

Figure 15. 2030+ MTDC Backbone Topology injecting 10,100 MW at seven points of interconnection through 500 kV transmission

Generation and 230 kV interties from the 2030 HVAC Radial Topology, injecting 2,700 MW in Southern Oregon, are included in the 2030+ base case and their POIs are indicated in green. Generation is identical to the 2030+ HVDC Radial Topology, but an AC hub is introduced in San Francisco. Detailed view of the MTDC backbone, shown through a single line diagram over the ocean, is not to geographic scale.

2.3 Valuation Assumptions

The following assumptions were of critical importance to the valuation exercise:

- A financial discount rate of 7.25%
- Operating lifetimes of a wind power plant (30 years) and transmission assets (40 years)
- Capacity value was associated with the avoided cost of combustion turbines, which would only deliver capacity and not energy, and only in either CA or the NW, where capacity credit is highest.
- Transmission costs were taken from the Jobs and Economic Development Impact (JEDI) model with conservative build assumptions (Goldberg & Keyser, 2013). Subsea transmission costs were not explicitly modeled. Instead, offshore HVDC costs were scaled from overland costs to account for additional technological components needed in the offshore environment and the potential for additional routing incurred by marine spatial conflicts, which were not directly modeled.
- Constant revenues, generation, and emission reductions through project lifetime
- Social cost of carbon was $105/tonne from Biden Administration (White House, 2021) or $270/tonne from the EPA (2022), see Appendix B.2.
- Criteria air pollution cost was NO_x: $160,000/tonne, SO_2: $830,000/tonne, data from EPA BenMAP (EPA 2023a), weighted average for electricity generation in WECC, see Appendix B.2
- Carbon and criterial air pollutant emissions rates for thermal generation are retained at the values specified in the 2030 ADS.
- Extreme event probabilities for resilience cases:
    - Heat wave: 100% annual reoccurrence, data from EPA Climate Indicators (EPA 2023b)
    - Wildfire: 6% annual probability of wildfire along Path 66 (COI), data from Cal-Adapt (2023)
    - Drought: 3-in-21-year occurrence using 2001 hydropower generation conditions (Turner et al., 2022)
- Value of lost load during resilience events was calculated from the Interruption Cost Estimator Calculator (LBNL, 2023), which provides the cost per unserved MWh of load by state and by sector (residential, commercial, and industrial). The unserved load calculated during resilience events by the PCM was split between sectors based on the total sector load in each utility (see Table 10 from EIA, 2022), then multiplied by the appropriate cost of unserved load for the state and sector combination.

3 Valuation Results

Quantification of system benefits and costs over project lifetimes were annualized then discounted and adjusted to 2022 dollars. The BCR for each scenario compared to the base case is shown in Table 5. A sensitivity analysis is presented in Table 5 to show how results change as a function of different assumptions. The benefit cost ratio for each scenario is shown for a range of cost of carbon, annual probability of 3-day heatwaves, and floating OSW HVDC transmission cost factors. In the subsections below, the valuation results are detailed for each scenario using the parameter assumptions highlighted in grey, which are \$105/tonne CO_2, 50% annual probability of 3-day heat wave, 1.25 HVDC cost factor. The HVDC cost factor is applied in attempt to capture higher costs associated with offshore transmission that may be incurred through designing viable cables routes, mitigations around subsea canyons, and other technical and engineering challenges. Designing feasible cable routes is outside the scope of this study. Ranges of annual value under all assumptions are also provided.

Table 5. Benefit-cost ratios for each scenario across a range of assumptions

CO_2 cost (\$/tonne)	Annual probability of 3-day heat wave occurring in SW*	HVDC Transmission Cost Factor	Benefit-Cost Ratio		
			2030 HVAC Radial	2030+ HVDC Radial	2030+ MTDC Backbone
\$105	50%	2.00	1.355	0.835	0.879
\$105	400%	2.00	1.703	0.870	0.923
\$105	***50%***	***1.25***	***1.355***	***1.017***	***1.088***
\$105	400%	1.25	1.703	1.060	1.142
\$270	50%	2.00	1.902	1.289	1.355
\$270	400%	2.00	2.249	1.325	1.399
\$270	50%	1.25	1.902	1.571	1.678
\$270	400%	1.25	2.249	1.615	1.731

The bold, italicized row is used as the standard case for the graphics in the following subsections.
*Annual probability of 50% indicates one occurrence every other year and 400% indicates 4 heat waves per year.

3.1 2030 HVAC Radial Topology vs. 2030 Base Case

Using HVAC radial interconnections, 3.4 GW of OSW generation are connected to POIs in Southern Oregon. Valuation for this scenario is performed by comparing system-wide metrics in the 2030 HVAC Radial scenario compared to the 2030 base case (Figure 16) using the baseline assumptions of \$105/tonne CO_2, 50% annual probability of 3-day heat wave occurrence, and 1.25 escalating cost factor for HVDC components, as highlighted in Table 5.

Benefits accrue from a reduction in system-wide production cost (energy value), which are equivalent to an annual \$504 million reduction from the 2030 HVAC Radial Topology to the base case. With this transmission topology and generation profile, OSW provides 33% capacity credit to the system, which is valued as \$210 million per year using the avoided cost of a new combustion turbine of 1119 MW capacity. The largest portion of valuation benefits accrue due to reductions in criteria air pollution and CO_2 emission, which provide a societal value due to reduced impacts to public health (criteria air pollutants, see EPA, 2023c) and climate change (CO_2, see White House, 2021). Since less natural gas is used across the WECC if OSW is developed, plant operators will have to hedge \$98 million less per year to account for future volatility of fuel costs (the methodology for calculating hedge value is described in Severy et al., 2022). The last significant benefit is from an improvement in resilience, where there is a reduction in unserved load in Northern Oregon, California, Arizona, and New Mexico during the modeled extreme event in the OSW scenario. Lastly, frequency response, regulating reserves, transmission peak load, and transmission congestion all provide a small benefit to the electrical system.

Amortized capital expenses (CapEx), annual operating expenses (OpEx) for the OSW plant make up most of the costs in this scenario. Other costs are due to transmission expansion to allow for OSW interconnection and transmission reliability upgrades to address faults on the system that appear after installation of OSW (see cost details in

Table 6).

If all valuation components are summed together, the 2030 HVAC Radial Topology shows an annual net benefit between $708 million per year to $2.4 billion per year with a value of $708 million per year using the baseline assumptions.

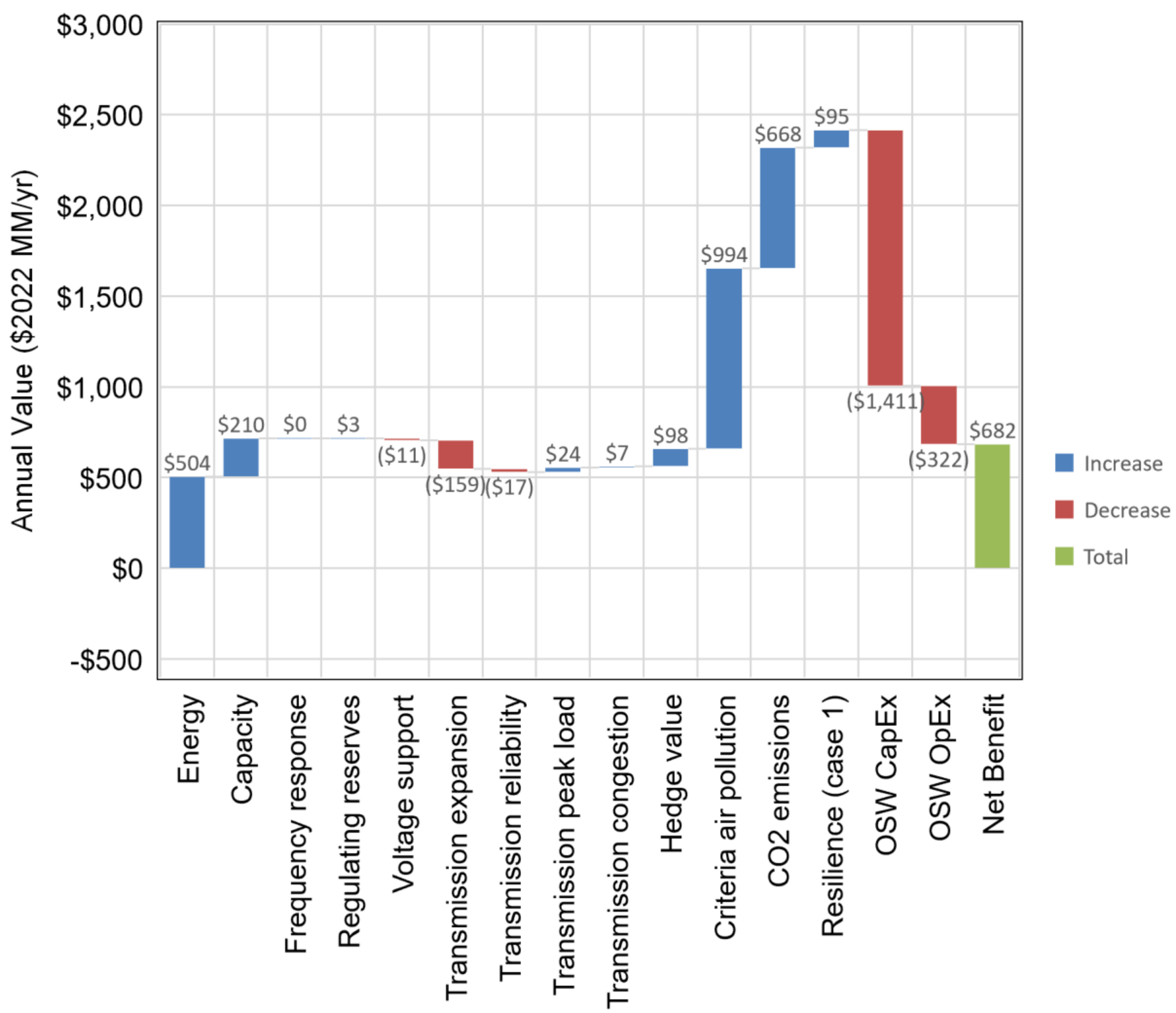

Figure 16. Waterfall plot showing cumulative valuation in million dollars per year of the 2030 HVAC Radial Topology compared to the base case

Blue bars indicate a positive value, red indicates negative value, and green shows the cumulative total of all components. Numbers in parentheses correspond to negative values.

Table 6. Transmission expansion and reliability costs for 2030 HVAC Radial Topology

Location	Description	Distance	Capital Cost	Operating Cost
Interconnection Links				
Fairview to Alvey	Fix 230 kV overload	95 mi	$80M	
Wendson to Toledo	Fix 230 kV overload	60 mi	$50M	
Fairview to Reedsport	Rebuild 115 kV	39 mi	$18M	
Reedsport to Tahkenitch	Rebuild 115 kV	4.4 mi	$4M	
Coos Bay Call Area to Dixonville	New 230 kV line	95 mi	$276M	$36M/yr
Coos Bay Call Area to Lane	New 230 kV line	108 mi	$311M	$41M/yr
Rogue to Fairview	New 230 kV line	65 mi	$121M	$16M/yr

Location	Description	Distance	Capital Cost	Operating Cost
		Transmission Expansion Total	$860M	$93M/yr
		Annualized Total*	$177M/yr	
Reliability / Contingency Upgrades				
Whetstone to Meridian	Upgrade conductors to fix 230 kV overload	12 mi	$41M	
Ponderosa GIS-Ponderosa AIS	Upgrade conductors to fix 230 kV overload	0.2 mi	$19M	
La Paloma to Tex_Sun	Upgrade conductors to fix 230 kV overload	1.0 mi	$10M	
La Paloma to Tex_Sun	Upgrade conductors to fix 230 kV overload	1.0 mi	$10M	
Bid Eddy to Quenett Creek	Upgrade conductors to fix 230 kV overload	6.4 mi	$24M	
Midway to La Paloma	Upgrade conductors to fix 230 kV overload	11 mi	$28M	
Midway to La Paloma	Upgrade conductors to fix 230 kV overload	11 mi	$28M	
SKA 287 to Min 287	Upgrade conductors to fix 230 kV overload	59 mi	$60M	
		Transmission Reliability Total	$222M	
		Annualized Total*	$17M/yr	

* 40-year lifetime for transmission with 7.25% discount rate. Includes 1.25 cost factor for HVDC converters.

3.2 2030+ HVDC Radial Topology vs. 2030+ Base Case

The 2030+ HVDC Radial Topology includes 12.9 GW more OSW generation than the 2030+ base case. This amount of generation provides a $1.4B reduction in annual production costs across the WECC (Figure 17). Using the 2030+ HVDC Radial Topology, the OSW generation provides 3.2 GW of capacity credit (evaluated using ASCC), which is a 25% capacity credit valued at $594 million per year. Significant societal benefits are seen from reductions in CO_2 and criteria air pollutants. The HVDC radial topology provides less resilience benefit than the HVAC topology, because the 2030+ base case used in the HVDC topologies has more generation capacity than the 2030 base case to meet demand during emergency events. To isolate the resilience value of OSW transmission, a new case (Case 2) was created which removed drought conditions and increased probability of occurrence. Reduction in lost load is seen in California and the desert southwest (SW), as summed in Appendix B.1.

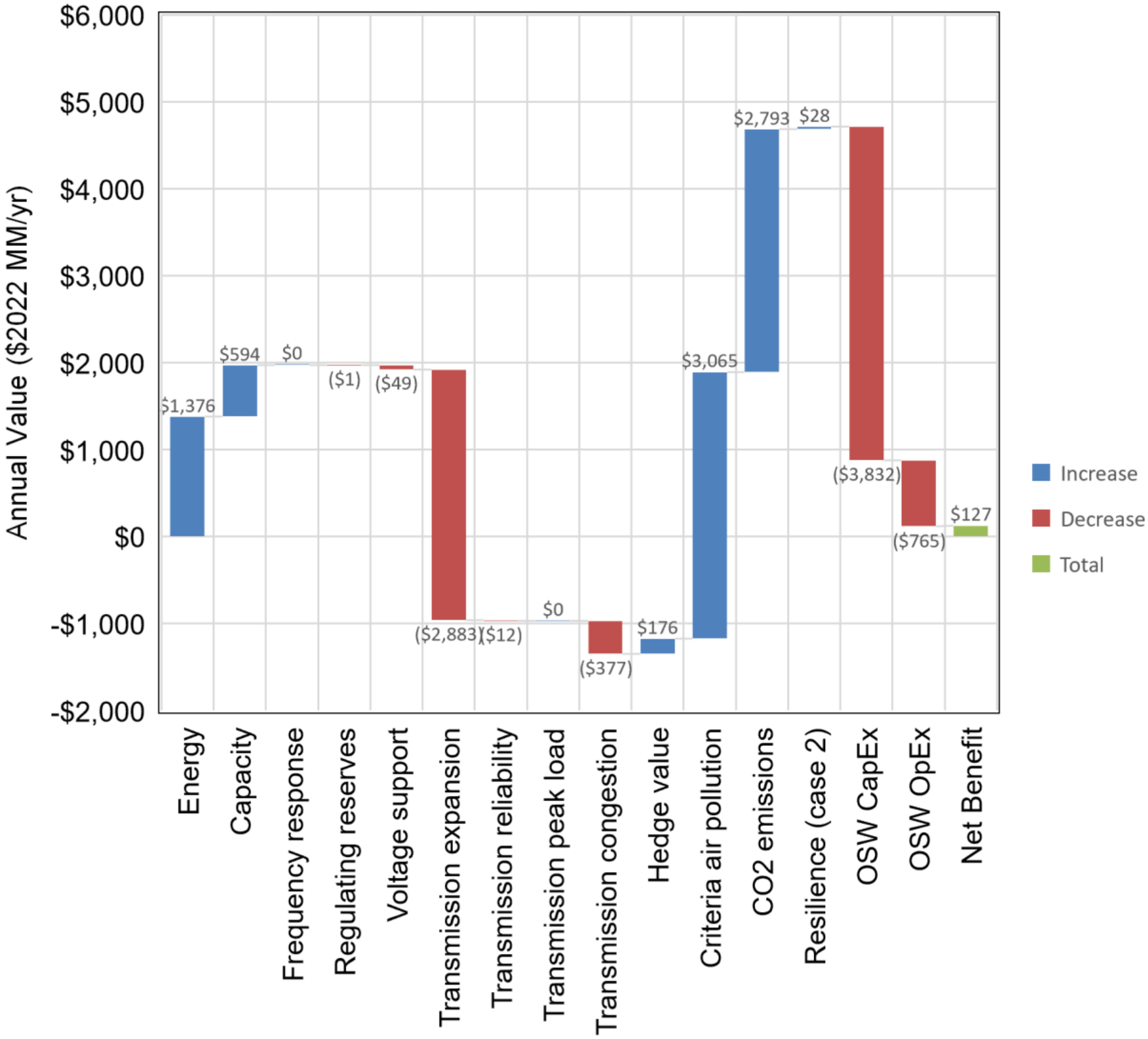

Figure 17. Waterfall plot showing cumulative valuation in million dollar per year of the 2030+ HVDC Radial Topology compared to the base case
Blue bars indicate a positive value, red indicates negative value, and green shows the cumulative total of all components. Numbers in parentheses correspond to negative values.

Building transmission to support the 2030+ HVDC Radial interconnections is amortized to $2.9B per year, which is significantly more costly than the 2030 HVAC Radial Topology on an absolute and per MW basis. Additional transmission expansion costs stem from new 500 kV transmission lines needed to interconnect OSW to capable substations (Table 7). In addition, several transmission reliability upgrades were made to fix impairments on the existing transmission system.

Table 7. Transmission expansion and reliability costs for 2030+ HVDC Radial Topology

Location	Description	Distance	Capital Cost	Operating Cost
HVDC Interconnection Links and Converter Stations[*]				
Satsop	500kV DC interconnect	310 mi	$2.2B	$175M/yr
Allston	500kV DC interconnect	274 mi	$2.1B	$166M/yr
Trojan	500kV DC interconnect	16 mi	Use existing 230 kV	
Potrero	500kV DC interconnect	402 mi	$3.8B	$198M/yr
Martin	500kV DC interconnect	8 mi	$0.9B	$101M/yr
San Mateo	500kV DC interconnect	26 mi	$0.9B	$105M/yr
Moss Landing	500kV DC interconnect	444 mi	$2.6B	$209M/yr
Tesla	500kV DC interconnect	405 mi	$2.5B	$199M/yr
		Transmission Expansion Total	$15B	$1.2B/yr
		Transmission Expansion Total after applying 1.25 HVDC Cost Factor	$19B	$1.4B/yr
		Annualized Total[**]	$2.9B/yr	
Reliability / Contingency Upgrades				
Storey to Borden (PG&E)	Upgrade conductors to fix 230 kV overload	5 mi	$16M	
Warnerville to Wilson (PG&E)	Upgrade conductors to fix 230 kV overload	50 mi	$50M	
Storey to Borden (PG&E)	Upgrade conductors to fix 230 kV overload	10 mi	$21M	
Embarcadero to Potrero (PG&E)	Upgrade conductors to fix 230 kV overload	15 mi	$16M	
Embarcadero to Potrero (PG&E)	Upgrade conductors to fix 230 kV overload	15 mi	$16M	
Embarcadero to Potrero (PG&E)	Upgrade conductors to fix 230 kV overload	15 mi	$16M	
Big Eddy to Quenett Creek (BPA)	Upgrade conductors to fix 230 kV overload	6 mi	$25M	
		Transmission Reliability Total	$160M	
		Annualized Total[**]	$12M/yr	

[*] HVDC costs including converters from JEDI (Goldberg & Keyser, 2013)
[**] 40-year lifetime for transmission with 7.25% discount rate. Includes 1.25 cost factor for HVDC converters.

After taking into account the capital and operating expenses of the new OSW plant, the net valuation for the 2030+ HVDC radial topology is $134 million per year using the baseline assumptions of $105/tonne CO_2, 50% annual probability of 3-day heat wave occurrence, and 1.25 escalating cost factor for HVDC components. Using the range of assumptions, the net value varies from a cost of $1.6 billion per year to value of $4.9 billion per year.

3.3 2030+ MTDC Backbone vs. 2030+ Base Case

The 2030+ MTDC Backbone Topology shows an annual net value ranging from a cost of $1.2 billion per year to a benefit of $6.1 billion per year and a value of $734 million per year (Figure 18) using the baseline assumptions. As with the other two topologies, energy, capacity, hedge value, resilience, and emissions reductions provide the main benefits; while transmission expansion, transmission congestion, OSW plant capital and operating expenses are the primary system-wide costs. Transmission expansions costs for the MTDC backbone topology are shown in Table 8. Resilience benefits from case 2 are enhanced by the ability of the backbone to send Northwest (NW) hydropower to reduced unserved load in California and the desert southwest (SW).

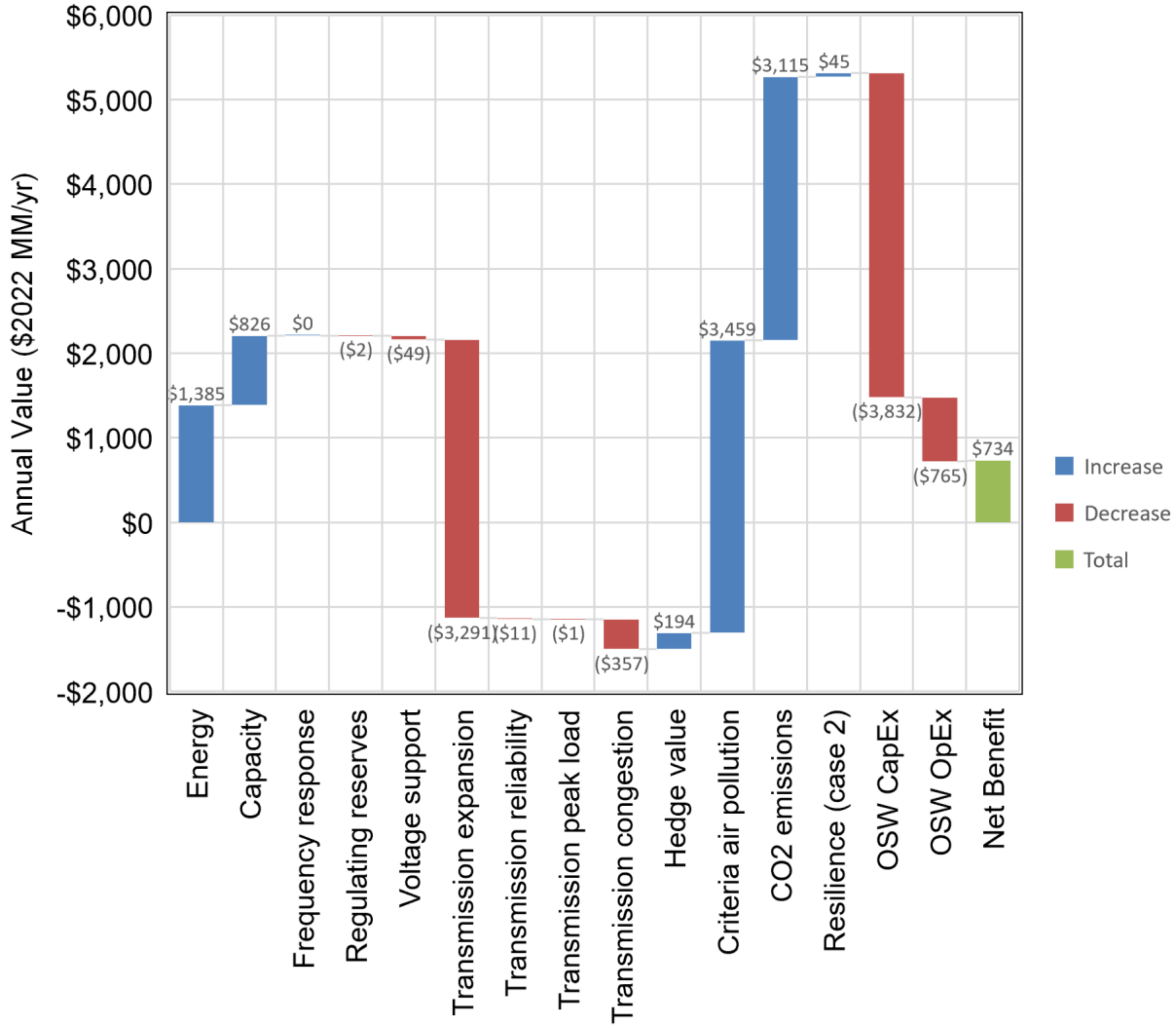

Figure 18. Waterfall plot showing cumulative valuation in million dollar per year of the 2030+ MTDC Backbone Topology compared to the base case

Blue bars indicate a positive value, red indicates negative value, and green shows the cumulative total of all components. Numbers in parentheses correspond to negative values.

Table 8. Transmission expansion and reliability costs for 2030+ MTDC Backbone Topology

Location	Description	Distance	Capital Cost	Operating Cost
HVDC Interconnection Links to Shore and Converter Stations[*]				
Satsop	500 kV bipole	310 mi	$2.2B	$175M/yr
Allston	500 kV bipole	274 mi	$2.1B	$166M/yr
Trojan	500 kV bipole	16 mi	Use existing	Use existing
Potrero	2x 500 kV bipole	402 mi	$3.8B	$198M/yr
Martin	230 kV AC connection	9 mi	$0.05B	$4M/yr
San Mateo	230 kV AC connection	15 mi	$0.3B	$21M/yr
Moss Landing	500 kV bipole	444 mi	$2.6B	$209M/yr
Tesla	2x 500 kV bipole	405 mi	$2.5B	$199M/yr
HVDC Links along Backbone, where 'Location' indicates the offshore substations to be connected[*]				
Allston to Satsop	500 kV bipole	7 mi	$15M	$100M/yr
Satsop to Potrero	2x 500 kV bipole	14 mi	$50M	$203M/yr
Potrero to Moss Landing	500 kV bipole	24 mi	$66M	$206M/yr

Location	Description	Distance	Capital Cost	Operating Cost
Moss Landing to Tesla	500 kV bipole	10 mi	$20M	$101M/yr
Transmission Expansion Total			$14B	$1.6B/yr
Transmission Expansion Total after applying 1.25 HVDC Cost Factor			$17B	$2.0B/yr
Annualized Total**			$3.3B/yr	
Reliability / Contingency Upgrades				
Storey to Borden (PG&E)	Upgrade conductors to fix 230 kV overload	5 mi	$16M	
Snow Goose to Klamath Falls (PacifiCorp)	Upgrade conductors to fix 230 kV overload	50 mi	$50M	
Storey to Borden (PG&E)	Upgrade conductors to fix 230 kV overload	10 mi	$21M	
Embarcadero to Potrero (PG&E)	Upgrade conductors to fix 230 kV overload	15 mi	$16M	
EmbarcaderoTR11 to TR12 (PG&E)	Upgrade conductors to fix 230 kV overload	15 mi	$16M	
Embarcadero to Embarcadero TR11 (PG&E)	Upgrade conductors to fix 230 kV overload	15 mi	$16M	
Big Eddy to Quenett Creek (BPA)	Upgrade conductors to fix 230 kV overload	6 mi	$25M	
Transmission Reliability Total			$137M	
Annualized Total**			$11M/yr	

[*] HVDC costs including converters from JEDI (Goldberg & Keyser, 2013)
[**] 40-year lifetime for transmission with 7.25% discount rate. Includes 1.25 cost factor for HVDC converters.

3.4 2030+ MTDC Backbone Topology vs. 2030+ HVDC Radial Topology

Comparing the valuation between the 2030+ MTDC Backbone Topology and HVDC Radial Topology shows that the MTDC backbone provides benefits to the system despite having larger interconnection costs to build the backbone (Figure 19).

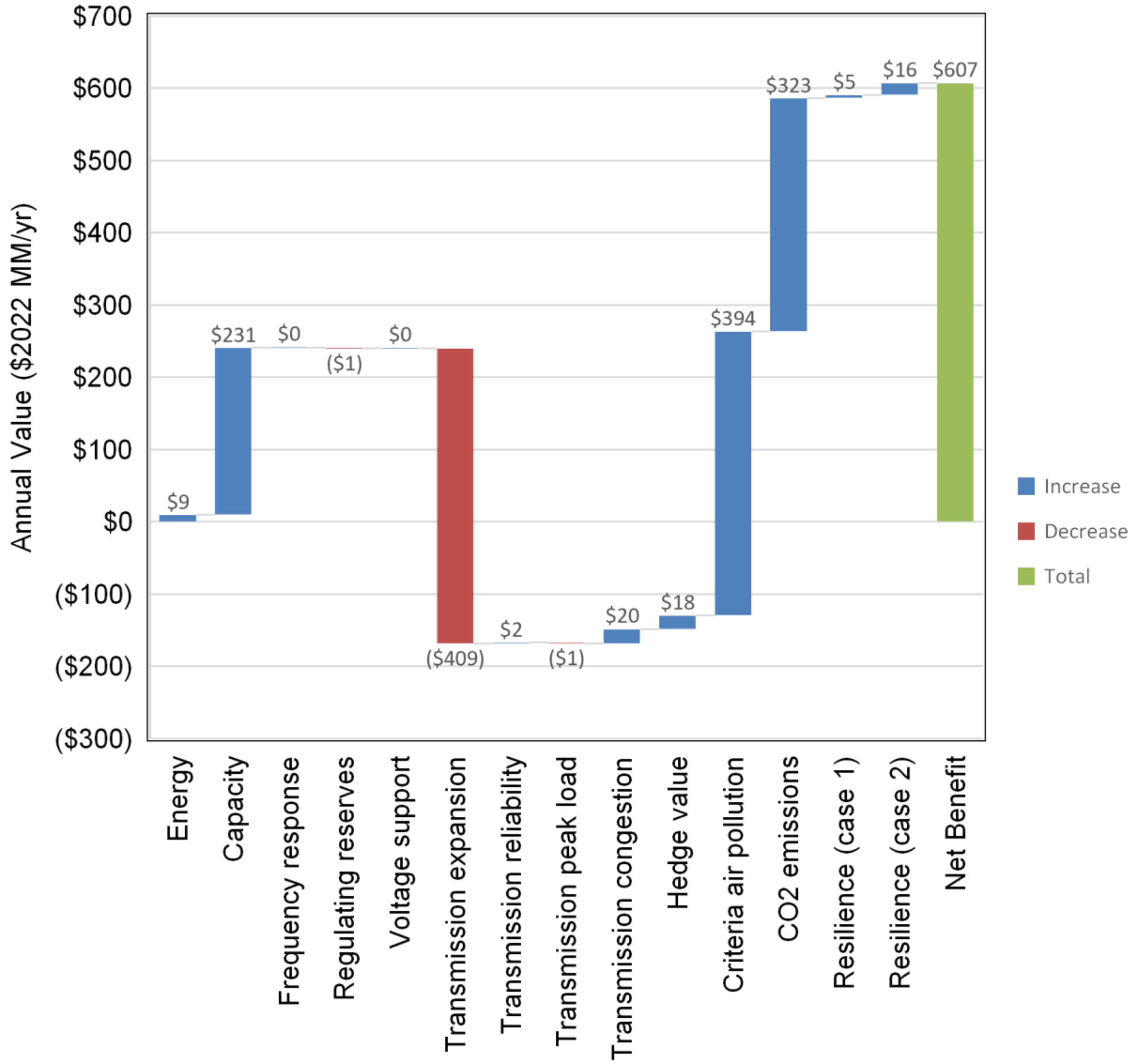

Figure 19. Waterfall plot showing valuation of 2030+ MTDC Backbone Topology compared to the 2030+ HVDC Radial Topology

Blue bars indicate a positive value for 2030+ MTDC backbone, red indicates negative value, and green shows the cumulative total of all components. Numbers in parentheses correspond to negative values.

In particular, the backbone has greater capacity credit to the system in the northwest (Figure 20). Based on the ASCC calculations, the capacity credit increases from 6% with HVDC radial to 24% with MTDC Backbone in the northwest because the backbone provides a pathway for excess solar generation from California to serve load in the northwest during critical hours of the year, thereby reducing the unserved load in the northwest.

System-wide emissions are also reduced because the backbone opens a new path for interregional transmission flows and allows a cleaner generation dispatch by delivering OSW and other variable renewables to loads across a wider geographic area based on load and renewable generation with less reliance on thermal generation.

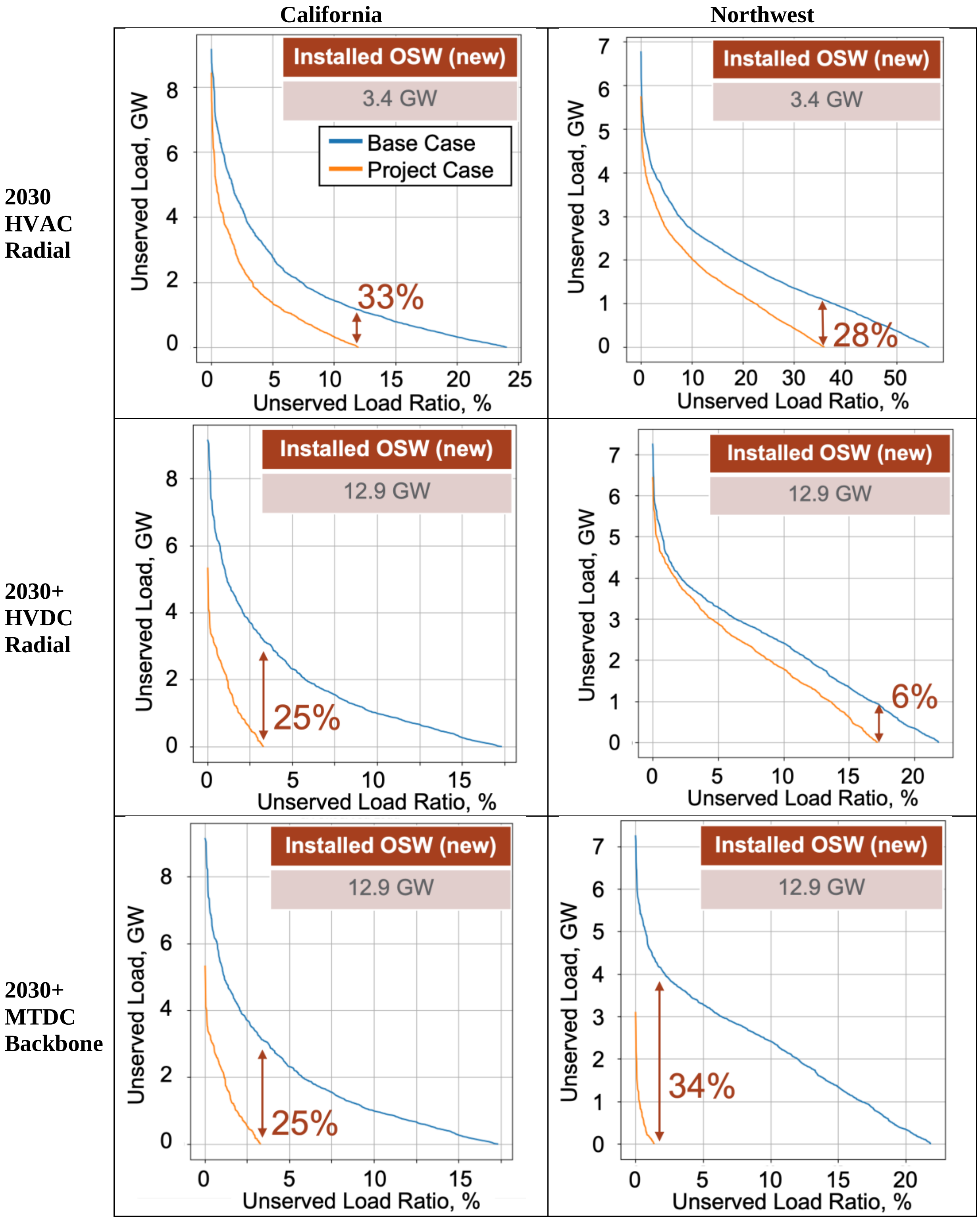

Figure 20. Associated System Capacity Contribution (ASCC) calculation for all three topologies for both California and Northwest region

4 Discussion

Following the valuation, additional sensitivity analysis with the technoeconomic model reveals the following themes:

Annual net benefits of $127M to $6B and net costs of $1.6B to $795M are found for OSW topologies depending on key assumptions for carbon costs, heat wave probabilities, and HVDC cost factors.

Net value over the base case is largest for the 2030 HVAC Radial Topology, where system-wide benefits exceed costs in every case, including without a system cost of carbon. All scenarios provide a BCR exceeding 1.289 under the high carbon costs assumption. For the beyond-2030 scenarios, net value is positive for the baseline set of assumptions but negative for low carbon costs combined with high HVDC cost factors. The MTDC backbone is more cost-effective and increases annual value over the HVDC case in all cases. Improvements range from an increase in net benefit of $362M to $1.26B, and thus improvements of BCRs by 0.045 to 0.123. This is true despite the higher dependence of the backbone on floating OSW HVDC transmission expansion ($2.6B for the MTDC backbone vs. $2.3B for the HVDC radials, unscaled). The MTDC Backbone Topology also provides the greatest upside potential of all topologies in terms of annual net benefits ($6B/year). Further maturation of the HVDC Radial Topology would likely result in an AC hub, eliminating converter stations at Martin and San Mateo and implementing AC instead of DC line expansions, thus yielding an additional annual cost savings of $370M, unscaled. Even in this case, assuming similar dispatch and system reinforcements for reliability for the HVDC radial case, the MTDC Backbone would improve the net annual value.

Capacity is a key value of west coast OSW, and in can be significantly enhanced through interregional transmission design.

For all topologies in the baseline assumptions, capacity contributions are the third most valuable offering from OSW, behind the avoided emissions and energy value. Only for the 2030 HVAC Radial Topology, more frequent heatwaves (400% probability) grow the resilience value enough to surpass capacity. Capacity value was considered for the Northwest and California, separately, and the maximum contribution was valued. As assessed through the ASCC metric, capacity is worth as much as 42%, 43% and 60% of the energy value (including the avoided costs of energy production, spinning reserves, and ramping reserves) for the 2030 HVAC Radial Topology, 2030+ HVDC Radial Topology, and 2030+ MTDC Backbone Topology, respectively. As with any intermittent resource, the value of OSW capacity degrades as more OSW is developed, but transmission design can serve as a hedge against the erosion of capacity value. Without changing the OSW generation or POIs, the MTDC backbone increases the ASCC by 28% and 9% to the Northwest and WI, respectively, over the 2030+ HVDC Radial Topology. Also, the generation-then-transmission optimization showed that generation footprints can be shaped for capacity value without significantly sacrificing energy potential.

OSW yields diminishing marginal value with installed capacity, but reductions can be mitigated through transmission design.

As is well understood for non-dispatchable generation, as installed capacity of OSW increases, the value of the next MW decreases for the two radial topologies. However, once the transmission system benefits from topologies outside of the ability to interconnect OSW, the marginal value improves. This is observed even though transmission expansion costs continue to climb as seen in Figure 21.

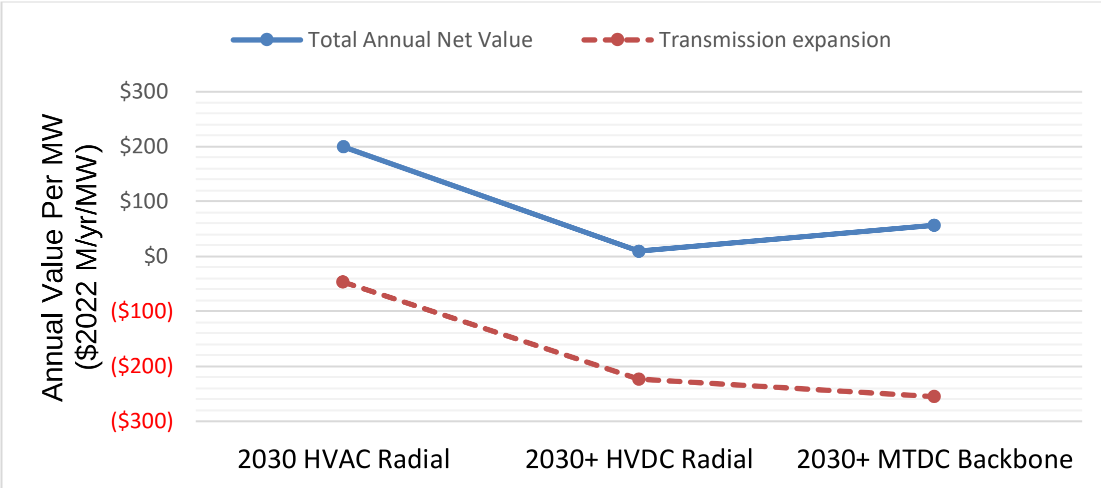

Figure 21. Marginal annual total and transmission expansion value for all topologies

The source of this effect can be inferred from Figure 22. Only the marginal value of emissions continues to increase through all topologies. Energy, hedge, and capacity marginal value decrease by 27%, 48%, and 50%, respectively between the 2030 HVAC Radial Topology and the 2030+ HVDC Radial Topology. Key reversals in the degradation, which are enabled through the MTDC backbone, correspond to capacity, regulating reserves, energy, hedge value, and transmission congestion. The MTDC backbone plays a key role in restoring each of these value elements.

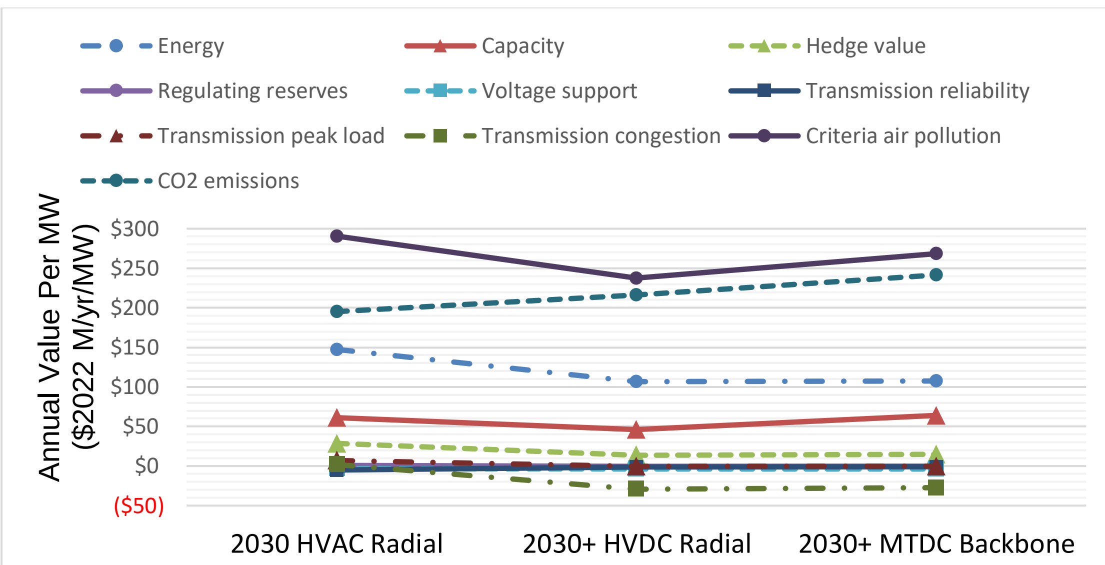

Figure 22. Marginal annual value detail for all topologies

Even though the MTDC backbone can mitigate diminishing returns, outside of emissions reductions, the highest marginal value of OSW is found in the 2030 HVAC Radial Topology. This effect is largely due to the ability to use pre-existing system transmission capacity. These early gains could be targeted in a strategy that delivers value to those communities most impacted by project development first while securing the long-term opportunity to provide interregional benefits through complex transmission concepts such as the MTDC backbone.

Annualized resilience value of OSW is a function of the deterministic scenarios considered and their likely probabilities of occurrence.

Multiple resilience events were considered in this analysis, spanning heat wave and corresponding thermal generation de-rates due to reduced cooling capacity, wildfires resulting in de-energization of major transmission corridors, and droughts reducing hydropower availability. These events were inspired by recent occurrences in the West. Some events indicated the value of OSW capacity while others occurred in a time when OSW net capacity factors were low. Other events, such as a prolonged heat wave, showed large resilience value but were highly unlikely to occur. Care was also taken not to double-count probabilities of certain probability types when combining events. Positive correlations of resilience events, for example heat waves and wildfires, informed annual probabilities. Resilience benefit arose from two sources, First, generator diversity provided a direct capacity benefit when needed, even though heatwaves were chosen at times of low OSW capacity factor. 2030 HVAC Radial Topology indicated that 23% of the total benefits were associated with resilience during the heatwave, wildfire, and drought event, assuming a 400% probability of 3-day heat wave and low carbon cost. Secondly, resilience benefits were associated with additional transmission capacity. The MTDC backbone enhanced resilience if additional generation capacity was available to utilize it, as seen when the drought conditions were removed from the simulated event and more north-south flow was observed on the backbone. In general, the additional capacity added to the 2030+ base cases resulted in less unserved load during the resilience events and thus limited relative value of the OSW increments. These observations underscore the importance of many resilience events with accurate probabilities to assess resilience value comprehensively.

Floating OSW HVDC transmission costs could significantly impact net value.

Technical maturity of key HVDC transmission components to support floating OSW energy conversion and transmission is low and the costs are largely unknown at the present time. To consider this potential variability in costs, sensitivity studies scaled overland HVDC transmission costs for siting, land control, materials, construction activities, and operational costs by 125-200%. However, costs could be even higher, due to future technological, environmental, or permitting challenges. Assuming moderate heat wave probability (100%) and high costs of carbon ($270/tonne), BCRs of 1.0 were reached for the 2030+ HVDC Radial Topology and MTDC Backbone Topology at OSW HVDC scale factors of 3.22 and 3.41, respectively. Beyond these HVDC cost factors and at the high heat wave probability and high costs of carbon, these topologies are no longer cost effective (BCRs are less than 1.0).

5 Summary

Robust system dispatch and power systems simulations have been conducted to identify the incurred or avoided system costs posed by three OSW generation and transmission topology increments to the WI on near- (2030) and mid-term (2030+) time horizons. Value elements within focus span energy, capacity, grid support services (frequency response, regulation, contingency reserves, ramping reserves), voltage support, transmission expansion and reliability upgrades, emissions, and natural gas price hedges. Study scenarios included 3,400MW of OSW under a 2030 HVAC Radial Topology, 12,900 MW of OSW under a 2030+ HVDC Radial Topology, and 12,900 MW of OSW under a 2030+ MTDC Backbone Topology. New production cost and power flow steady-state and dynamic models were constructed, and simulations conducted. The outputs of these simulations were relayed to the technoeconomic valuation approach, and finally cost effectiveness was assessed at the scale of the WI while varying key parameters of the cost of carbon, probability of heat waves, and a floating OSW HVDC transmission cost multiplier.

Under all parameters and when compared to a base case with no OSW, benefits exceeded costs for the 2030 HVAC Radial Topology. It was the only topology where a cost of carbon was not necessary to show economic viability over the base case. Two topologies based on a more heavily decarbonized WI also showed BCRs greater than 1, though not for the more conservative parameter values. This was primarily due to the significant amount of renewable energy in the base case and the degree of expense incurred to expand the system and land much more power than the 2030 topology. However, erosion of marginal value, though still positive for most parameter values, was observed in terms of capacity but also resilience, hedge value, and even energy for the 2030+ HVDC Radial Topology. The introduction of a MTDC Backbone topology improved BCRs and restored marginal value by enabling significant benefits outside of the flow of OSW power. These results suggest that the impact of transmission design on the overall system value of a generation portfolio change should be considered on multiple time horizons by planners and policymakers in advance to yield development pathways to long-term and wide-ranging net benefits.

5.1 Future Work

The valuation approach developed in this study and its implementation has resolved an approach which could be utilized more broadly to further optimize the value of OSW in the region of interest, across the West Coast, and in other contexts. Some suggested next steps to further refine and exercise the method are as follows:

- Establish robust, geographically-specific, credible scenarios that indicate the resulting effects and probabilities of occurrence for extreme events to include in the resilience valuation. In particular, probabilistic scenarios should be developed for heat waves, earthquakes, wildfires, ice storms, droughts, hurricanes, and other events that impact system generation capacity, transmission operation, and system load
- Compare ASCC trends shown against other capacity metrics such as Equivalent Firm Capacity or Effective Load Carrying Capacity and investigate the hydropower modeling assumptions and their alternatives
- Sharpen estimates of floating OSW transmission costs, including floating AC substations or AC/DC converter stations and dynamic export cables, and update costs as technology matures
- Expand the regions of consideration beyond Coos Bay and Eureka, and then conduct a robust generation and transmission co-optimization
- Consider alternate plant and transmission design, including overland HVDC instead of subsea HVDC infrastructure, and conduct detailed electrical loss modeling
- Develop dynamic models representing future heavily asynchronous generation portfolios for MTDC stability evaluation, with the goal of simulating full Palo Verde 2 generation trips and faults on the DC systems of the MTDC topology
- Complete detailed N-1-1 studies with contingency lists informed by system operators
- Mature the MTDC concept of this study by designing a Remedial Action Schemes, with fully redundant and independent high-speed communications between multiple points in the WI

5.2 Areas of Replicability

Though the valuation approach was developed with OSW in mind and calibrated for the West Coast context, the bottom-up and system-wide strategy should be employed in other contexts such as west coast wide, Gulf Coast, the Atlantic Coast, and the Great Lakes. The valuation could be employed at regional scales as well and for other types of generation or for portfolio changes under consideration by planners and policymakers. In this way, policies may be drafted that are more targeted to the strengths and weaknesses of existing infrastructure and the potential of new generation assets.

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A Appendix A: Valuation Application

In this appendix, analysis informing the valuation is compiled and extractions from the valuation tool are included for each topology. A format key for the tool extracts may be seen in Table 9. Valuation components are presented according to the structure of the methodology presented in Appendix B: Valuation Methodology.

Table 9. Format key of the valuation tool

Type	Example	Units	Description
Comment	This is a comment field.	--	All units should be specified with comments.
Calibration Input	781	$/kW	Avoided costs of dispatchable resource.
Input from PCM	Production Costs	$	Cost of energy production for the WECC system.
Input from Power Flow	Reactive power compensation	kVA	Reactive power needed to stabilize voltage at POI.
Assumptions	30	years	Operational life of OSW plant
Base Case Header	**WECC ADS 2030**	--	Details of the base case specified in comments.
OSW Scenario Header	**2030 Radial HVAC Topology**	--	Details of OSW case specified in comments.
Monetary Value	($1,000,000)	$	Negative numbers in red, positive in black.
Percentage	5.00%	%	Discount rate.
Number	1,000	--	Tonnes of CO_2
Units	$/kW	$/kW	Units specified for every quantity. "--" indicates N/A.

Assumptions implemented in the valuation are detailed in Table 10. The last three assumptions correspond to parameters which were varied to produce ranges of system values for each topology.

Table 10. Valuation assumptions

Assumptions	Value	Notes
Discount rate	7.25%	Utility discount rate (PG&E)
Operating life of wind plant	30	Years
Operating life of transmission	40	Years
Operating life of battery system for avoided FRR	30	Years
Annual cost of shunt capacitor	$5	$/kVAr/yr
Cost of new combustion turbine	$152	$/kW-yr, 2021, CAISO (2021)
CO_2 cost (Biden)	$105	$/tonne, White House (2021)
CO_2 cost (EPA)	$270	$/tonne, EPA (2022)
NO_x unit cost	$158,297	$/tonne, EPA (2023a)
SO_2 unit cost	$828,631	$/tonne, EPA (2023a)
Avoided cost of battery storage	$580	$/MW, CAPEX (NREL, 2022)
HVDC subsea bipole 500 kV capacity (MVA)	2600	Various industry press releases[4]
Annual probability along COI (maximum value over 40 years of transmission service along the COI in Northern CA/Southern OR)	6%	Cal-Adapt (2023)

Assumptions	Value	Notes
Annual probability of drought occurring	14%	3 in every 21 years drought, Turner (2022)
Cost of Unserved Load		Varies by state, utility, and sector (residential, commercial, and industrial) with data from LBNL, (2023) and EIA, (2022).
CO_2 cost	\$105	Vary \$105 or \$270/tonne (White House, 2021; EPA, 2022)
Cost factor on subsea HVDC transmission	1.25	Vary: 1.25 or 2.0.
Annual probability of heat wave occurring	50.00%	Vary: 50% or 400% EPA (2023b)

A.1 2030 HVAC Radial Topology

A.1.1 Energy, Contingency, and Ramping Reserves

Energy value, including impacts to contingency and ramping reserves, was extracted from GridView dispatch simulations as shown in Table 11.

Table 11. 2030 HVAC Radial Topology energy valuation

Component	units	WECC 2030 ADS	2030 HVAC Radial Topology
Energy (including contingency and ramping reserves)			
System Wide Generation	MWh	1,014,071,579	1,015,621,299
System Wide Generation Cost	**\$/yr**	\$14,122,284,360	\$13,618,158,237

For the PCM power flow, we used two-sided violin plot to show the monthly/hourly distribution of power flow on different paths, including maximum, 3rd quartile, median, 1st quartile, minimum value (from top to bottom). The left side (green, median as black dot) is the benchmark base case, and the right side (blue, median as white dot) is our proposed case.

In the 2030 HVAC Radial Topology, 3.4 GW installed capacity (maximum injection 2.7 GW) OSW is interconnected in Southern Oregon.

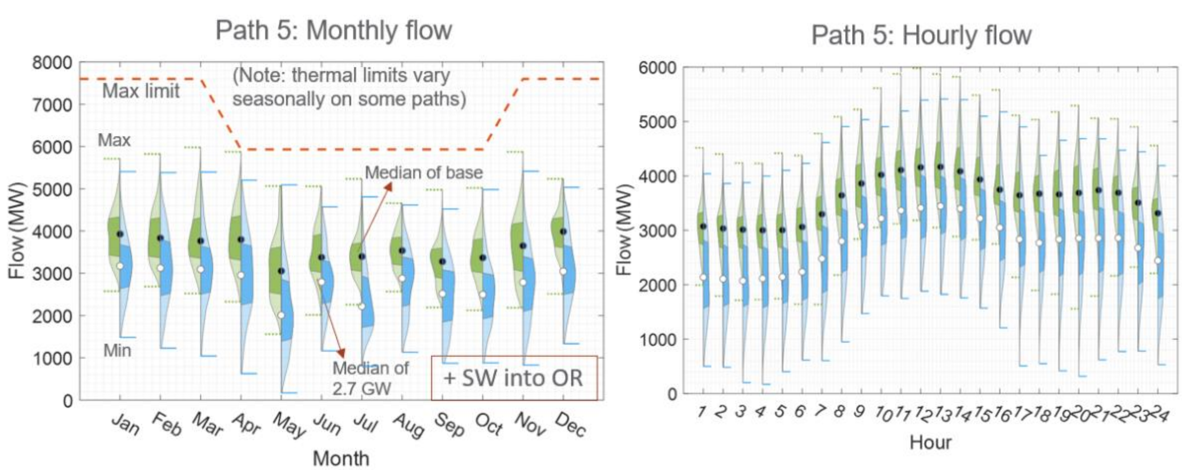


Figure 23. Monthly flow and hourly flow on Path 5 (Southwestern Washington to Northwestern Oregon)

As shown in Figure 23, on Path 5, there is an obvious reduction on power flow from Washington to Oregon, in terms of both metrics. As a conclusion, OSW generation in Oregon footprint reduces imports from Southwestern Washington to Oregon.

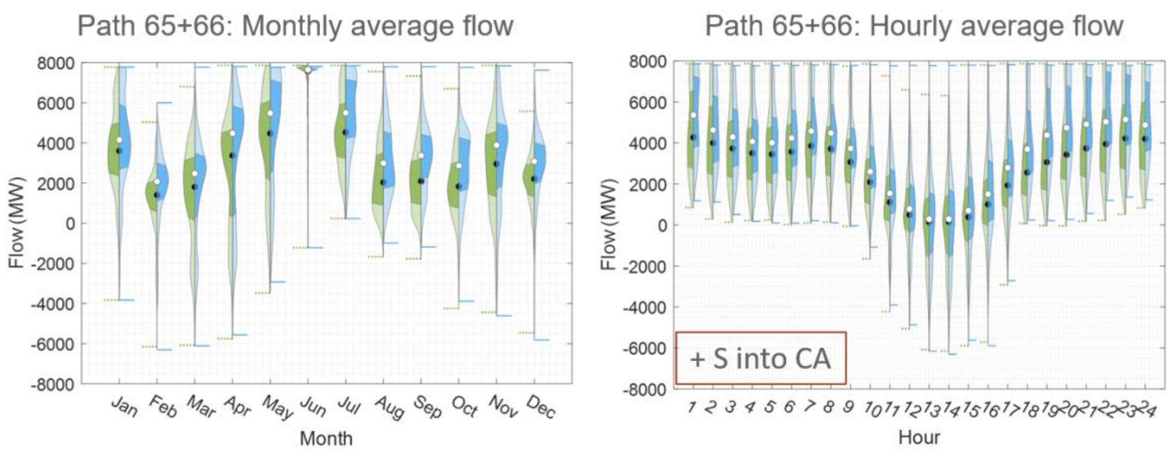


Figure 24. Monthly flow and hourly flow on Path 65+66 (Pacific DC Intertie (PDCI) and California Oregon Intertie (COI) connect Northwest with California)

As shown in Figure 24, on Paths 65 and 66, there is an obvious reduction on power flow from Northwest to California, indicating more OSW availability in OR footprint increases California's energy imports from PDCI/COI.

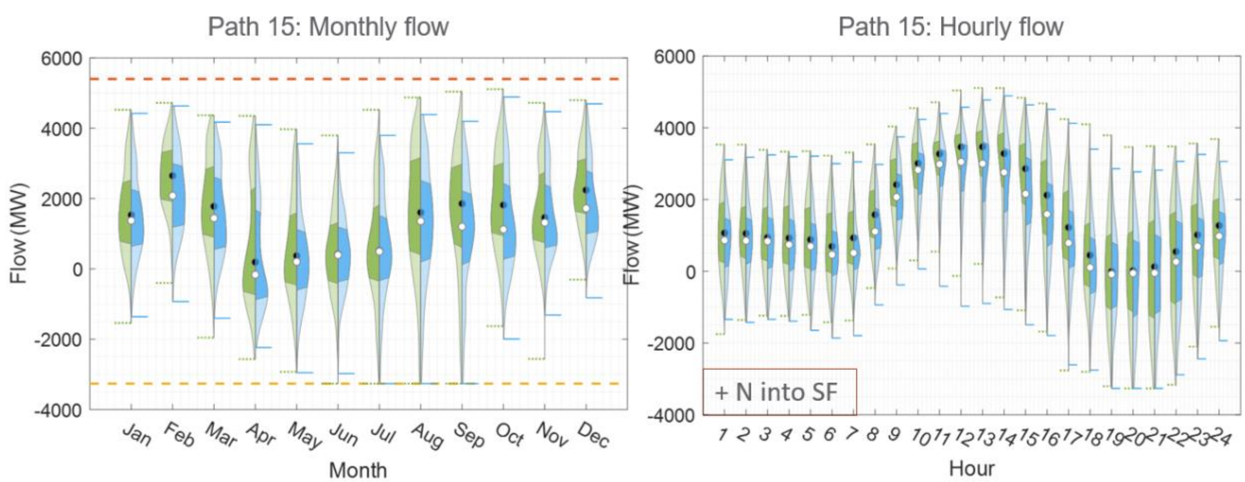


Figure 25. Monthly flow and hourly flow on Path 15 (Southern to Northern California)

As shown in Figure 25, on Path 15, there is a reduction of power exports from Southern to Northern CA due to increased power imports from the Northwest (via Path 65).

A.1.2 Capacity

Capacity value was assessed through the Associated System Capacity Contribution detailed in Appendix B: Valuation Methodology. Avoided costs of combustion turbine procurements and operation were discounted to 2022 dollars and annualized, as shown in Table 12.

Table 12. 2030 HVAC Radial Topology capacity valuation.

Component	units	WECC 2030 ADS	2030 HVAC Radial Topology
Capacity			
New installed OSW capacity	MW	-	3,400
ASCC, CAISO	MW	-	1,119
ASCC, Northwest	MW	-	964
Capacity Credit			33%
Annualized Capacity Value	$/yr, 2022		$210,368,565

A.1.3 Regulating Reserves

Regulating reserves were extracted directly from the GridView dispatch simulation (Table 13).

Table 13. 2030 HVAC Radial Topology regulating reserves valuation

Component	units	WECC 2030 ADS	2030 HVAC Radial Topology
Regulating Reserves			
Regulation up revenue (all generators and regions)	$/yr, 2022	$26,551,168	$22,875,838
Regulation down revenue (all generators and regions)	$/yr, 2022	$25,611,198	$26,605,699
Regulation revenue (up and down, total)	$/yr, 2022	$52,162,366	$49,481,537

A.1.4 Transmission Expansion

Expansion of the transmission system was informed by power flow and dispatch modeling and costs were approximated through the JEDI model (Table 14).

Table 14. 2030 HVAC Radial Topology transmission expansion costs

Component	units	WECC 2030 ADS	2030 HVAC Radial Topology
Transmission Expansion Upgrades			
Transmission expansion, CAPEX	$, 2022	$0	($860,045,636)
Transmission expansion, Annualized CAPEX	$/yr, 2022	$0	($57,072,761)
Transmission expansion, Annual O&M	$/yr, 2022	$0	($93,079,308)

A.1.5 Air Pollution

CO_2 and criteria air pollutants were extracted from GridView dispatch simulations (Table 15). Costs were approximated using the cost of carbon assumptions detailed in Appendix B: Valuation Methodology.

Table 15. 2030 HVAC Radial Topology air pollution costs

Component	units	WECC 2030 ADS	2030 HVAC Radial Topology
Air Pollution			
CO_2 emissions	lb/yr	404,342,064,400	395,616,184,760
NO_x emissions	lb/yr	254,997,466	247,642,055
SO_2 emissions	lb/yr	6,085,268	5,996,698

Component	units	WECC 2030 ADS	2030 HVAC Radial Topology
NOx annual cost	$, 2022	$32,423,572,686	$31,488,313,566
SO_2 annual cost	$, 2022	$4,050,355,308	$3,991,402,931
CO_2 Emission Cost (Biden)	$/yr, 2022	$30,932,258,393	$30,264,726,648
CO_2 Emission Cost (EPA)	$/yr, 2022	$79,540,093,010	$77,823,582,809
Criteria Air Pollutant Cost	$/yr, 2022	$36,473,927,994	$35,479,716,497

A.1.6 Hedge Value

Based on the natural gas system wide fuel use from the GridView dispatch simulation, hedge value was calculated in accordance with Severy et al. (2022), as shown in Table 16.

Table 16. 2030 HVAC Radial Topology hedge value calculations

Component	units	WECC 2030 ADS	2030 HVAC Radial Topology
Hedge Value			
System wide fuel use (primary) natural gas only	MMBtu/year	1,893,248,875	1,801,419,839
Fuel price uncertainty for OSW life	$, 2022	$60,651,376,160	$57,709,577,288
Fuel price uncertainty for OSW life	$/year, 2022	$2,021,712,539	$1,923,652,576

A.1.7 Transmission Reinforcement (Reliability and Resilience)

To consider the impacts of significant OSW power being added to the system, collector systems of floating OSW power plants had to be modeled for the purposes of power flow studies. Large wind plants would contain hundreds of wind turbines, and equivalent representation of the system elements (turbines, transformers, and collector cables) was essential (Muljadi et al. 2006).

In this study, the 66 kV collector system depicted in Figure 26 was designed. Each 66kV cable string has 15 MVA wind turbines. Further, fifteen such wind turbines are lumped together to give an equivalent 225 MVA wind turbines, with the equivalent pad mounted transformer and cable impedances, which are used as inputs for the power flow models.

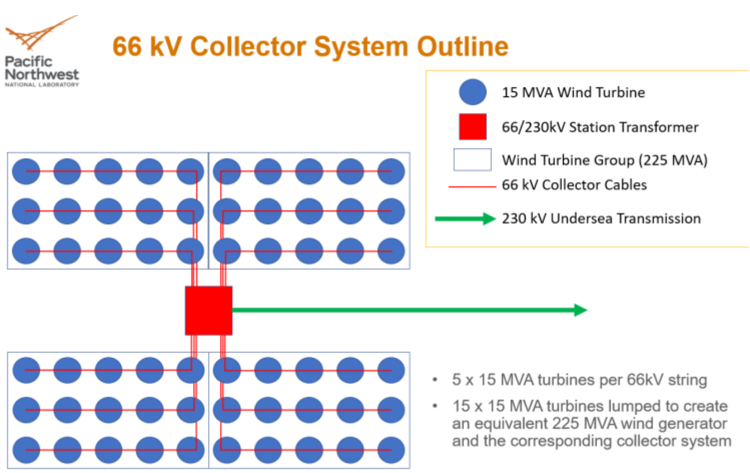


Figure 26. 66kV collector system design

In the next step, converged power flow cases were obtained for different hours of interest. From the PCM results, three key cases were identified (Figure 27):

1. High Load, High Wind Case
2. High Load, Low Wind Case
3. Medium Load, Medium Wind Case

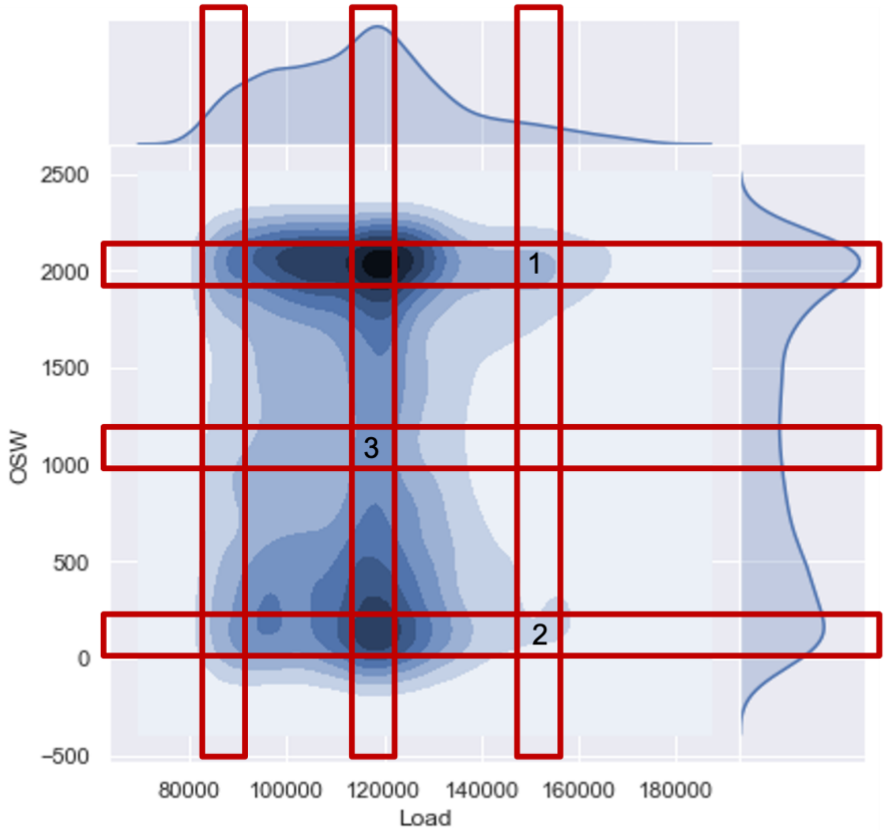


Figure 27. 2030 HVAC Radial Topology, hours targeted for AC power systems analysis

Finally, steady-state reliability was assessed. Since the OSW power was added to Southern Oregon (Northwest), a total of 7134 n-1 contingencies in the Northwest and Northern California (PG&E) were considered, above the 99kV level. Out of these, there were 8 230kV level violations exceeding 125% of the line ratings, which were fixed to re-run the PCMs. The costs for those upgrades are shown in Table 17. As only existing corridors were reinforced, incremental operational costs of the upgrades were considered negligible.

Table 17. 2030 HVAC Radial Topology, transmission reliability upgrades

Component	units	WECC 2030 ADS	2030 HVAC Radial Topology
Transmission Reliability Conductor Upgrades			
Steady state reliability transmission upgrades, CAPEX	$, 2022	$0.00	($221,692,639)
Steady state reliability transmission upgrades, Annualized CAPEX	$/year, 2022	$0.00	($17,113,720)

Component	units	WECC 2030 ADS	2030 HVAC Radial Topology
Steady state reliability transmission upgrades, Annual O&M	$/year, 2022	$0.00	$0
Total transmission reliability	$/year, 2022	$0.00	($17,113,720)

A.1.8 Frequency Response Reserves

Dynamic simulations were run of a double unit failure at Palo Verde nuclear power station for the base case and the OSW case. A significant impact on system frequency was not observed. The frequency nadir (i.e., measured at the lowest point in the response) moved from 59.753 Hz to 59.814 Hz and system frequency recovered to 60 Hz. Thus, no costs were incurred for system frequency response reserves.

A.1.9 Voltage Support

Voltage support costs were equated to incurred shunt capacitor costs, as informed by power flow modeling. Valuation results are shown in Table 18.

Table 18. 2030 HVAC Radial Topology, voltage support costs

Component	units	WECC 2030 ADS	2030 HVAC Radial Topology
Voltage Support			
Total compensation required	MVAr	0	1,525
Cost of voltage support compensation	$/yr, 2022	$0.00	($10,774,469)

A.1.10 Resilience

For resilience, in this scenario we considered three different events to make a resilience case (Case 1), including:

1. 3-day heatwave Jul 28 – Jul 31, load increase by 20% (ratio from historical Cooling Degree Days) in CA+SW. Accordingly, thermal generators in CA and SW are derated by 20% due to loss of cooling capability given high temperatures.
2. Paths 65/66 (PDCI/COI) outage due to wildfire.
3. Drought (from year 2001). The hydro generation reduces by about 30% during the event.

Based on the dispatch simulations of the base case and the OSW case, there is a reduction on the unserved load during the resilience event with 3.4GW OSW installation. Based on the unserved load cost, production cost, and probability of occurrence of different extreme events, Table 19 indicates the annual resilience benefit of OSW.

Table 19. 2030 HVAC Radial Topology resilience valuation.

Component	units	WECC 2030 ADS	2030 HVAC Radial Topology
Resilience			
Unserved load from resilience Case 1: heatwave+thermal derate+wildfire+drought	MWh	832,868	646,209
Unserved load cost from resilience Case 1: heatwave+thermal derate+wildfire+drought	$2022	$93,281,891,048	$69,250,676,607
Unserved load cost in any given year Case 1 *given probability of occurrence*	$2022	$369,039,319	$273,967,672
Production cost during resilience event-- Case 1	$2022	$2,639,873,100	$2,572,177,440
Production costs after probability of occurrence - Case 1	$/yr, 2022	$10,443,795	$10,175,979

A.1.11 OSW Costs

2030 HVAC Radial Topology OSW technology capital and operational costs were scaled from Musial et al. (2019) and are shown in Table 20.

Table 20. 2030 HVAC Radial Topology OSW costs

Component	units	WECC 2030 ADS	2030 HVAC Radial Topology
OSW Costs			
Installed OSW Capacity	MW	0	3,420
CapEx	$, 2018	0	$11,209,196,000
Annualized CapEx	$/year, 2022	0	$1,411,475,866
OpEx	$/year, 2022	0	$321,562,449

A.2 2030+ HVDC Radial Topology

A.2.1 Energy, Contingency, and Ramping Reserves

Energy value, including impacts to contingency and ramping reserves, was extracted from GridView dispatch simulations as shown in Table 21.

Table 21. 2030+ HVDC Radial Topology energy valuation

Component	units	2030 ADS + 38.4 GW VRE	2030+ HVDC Radial Topology
Energy (including contingency and ramping reserves)			
System Wide Generation	MWh	1,014,041,265	1,014,076,305
System Wide Generation Cost	$/yr	$10,827,320,048	$9,451,503,985

In the 2030+ HVDC Radial Topology, 16.3 GW installed capacity (maximum injection 12.8 GW) of OSW is interconnection to Southern Oregon and Northern California.

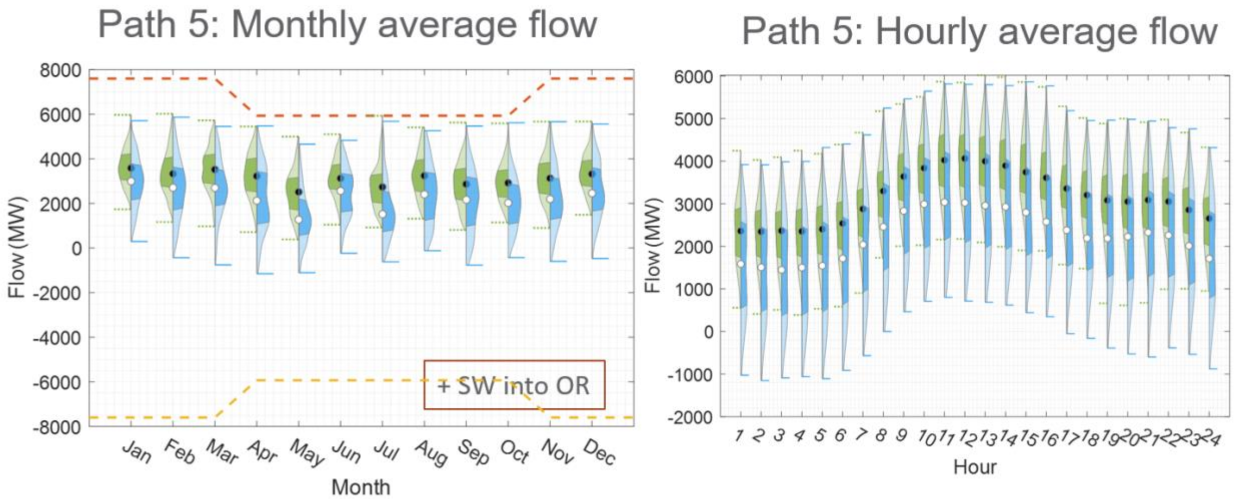


Figure 28. Monthly flow and hourly flow on Path 5 (Southwestern Washington to Northwestern Oregon)

As shown in Figure 28, on Path 5 there is a further reduction on power flow from Washington to Oregon compared with the 2030 HVAC Radial Topology. There are also some reverse power flows in the 2030+ HVDC Radial Topology, indicating OSW generation sends power from Oregon to Washington. OSW generation in Oregon footprint reduces imports from Southwestern Washington to Oregon.

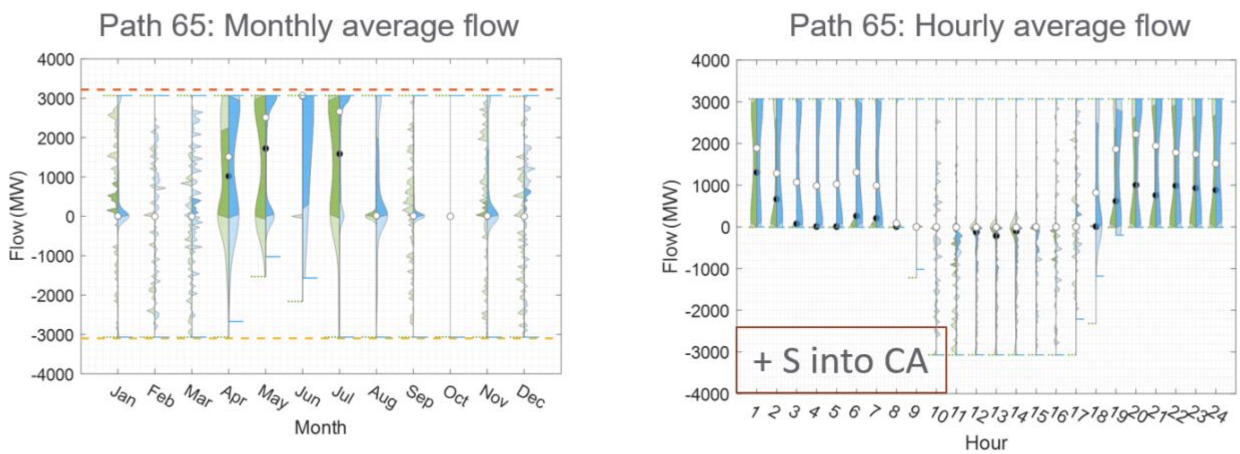


Figure 29. Monthly and hourly flow on Path 65 (PDCI)

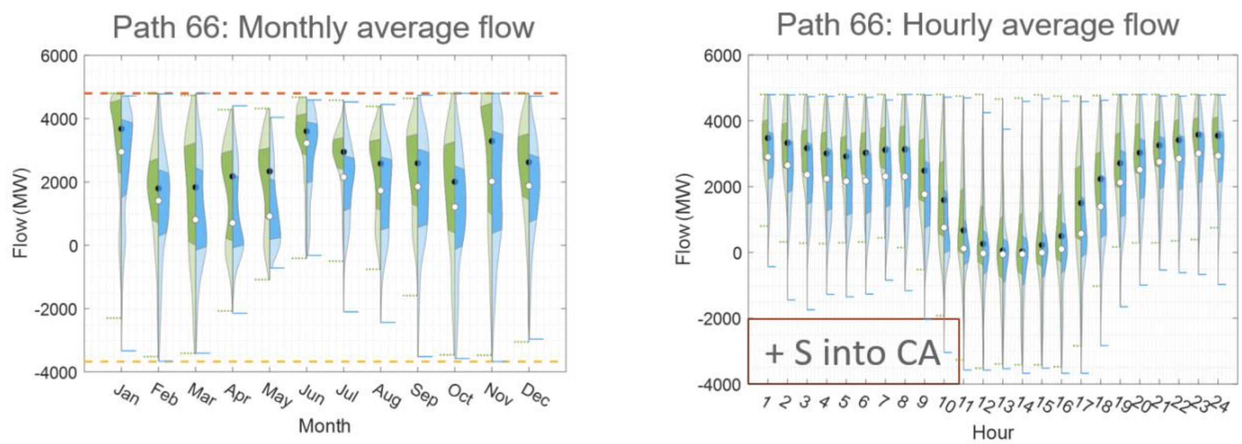


Figure 30. Monthly flow and hourly flow on Path 66 (COI)

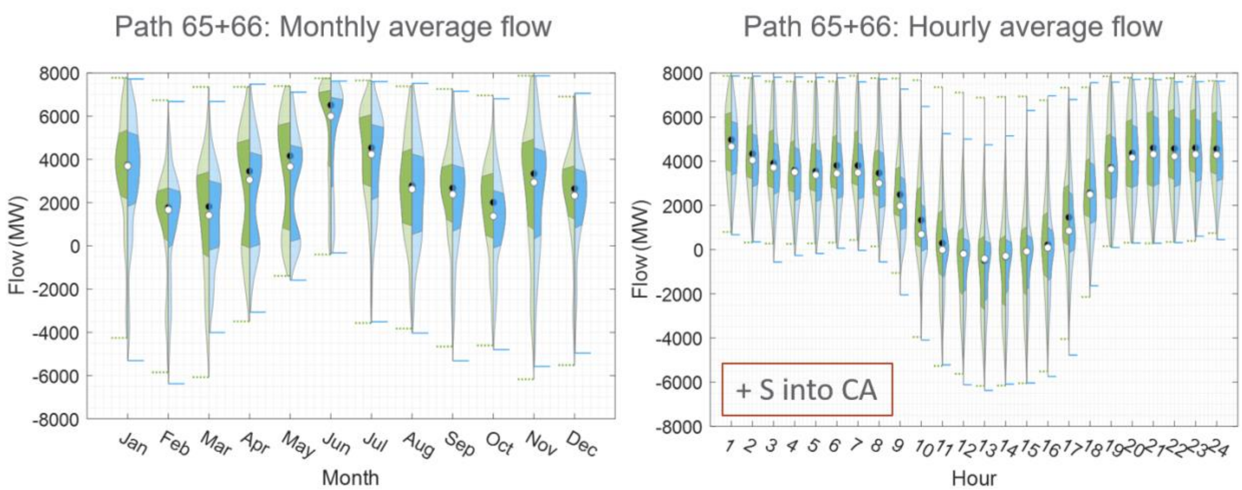


Figure 31. Monthly flow and hourly flow on Path 65+66 (Pacific DC Intertie (PDCI) and California Oregon Intertie (COI) connect Northwest with California)

More OSW increases imports from PDCI during spring off-peak hours (Figure 29), while reduces imports from COI (Figure 30). As a conclusion, with more OSW availability in CA, there is a slight reduction in energy imports from Northwest via combined paths PDCI and COI (Figure 31).

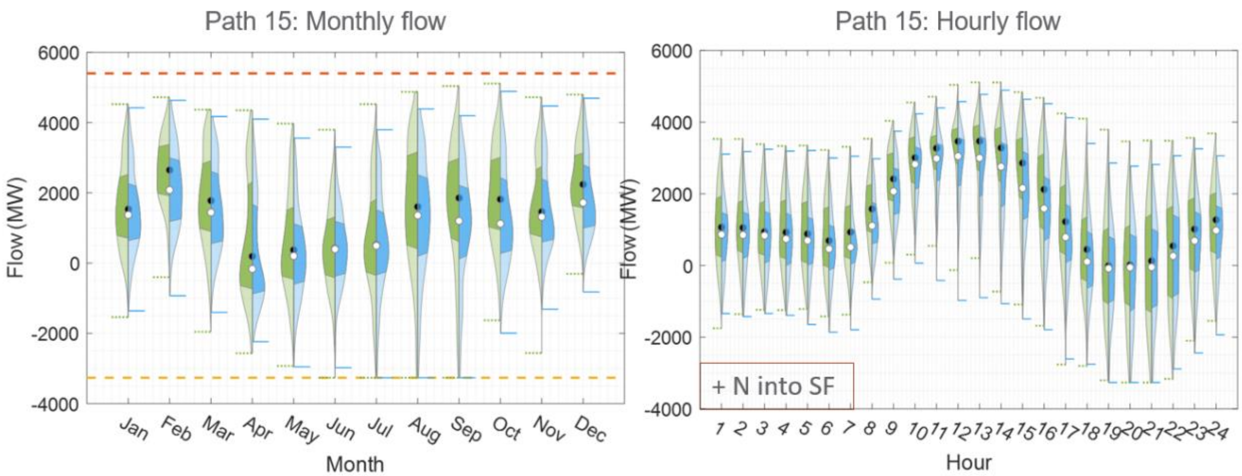


Figure 32. Monthly flow and hourly flow on Path 15 (connecting Southern with Northern California)

As shown in Figure 32, on Path 15, there is a reduction of power exports from Southern to Northern CA due to increased power imports from the Northwest (via Path 65).

A.2.2 Capacity

Capacity value was assessed through the Associated System Capacity Contribution detailed in Appendix B: Valuation Methodology. Avoided costs of combustion turbine procurements and operation were discounted to 2022 dollars and annualized, as shown in Table 22.

Table 22. 2030+ HVDC Radial Topology capacity valuation

Component	units	2030 ADS + 38.4 GW VRE	2030+ HVDC Radial Topology
Capacity			
New installed OSW capacity	MW	-	12,900
ASCC, CAISO	MW	-	3,162
ASCC, Northwest	MW	-	751
Capacity Credit			25%
Annualized Capacity Value	$/yr, 2022		$594,446,294

A.2.3 Regulating Reserves

Regulating reserves were extracted directly from the GridView dispatch simulation (Table 23).

Table 23. 2030+ HVDC Radial Topology regulating reserves valuation

Component	units	2030 ADS + 38.4 GW VRE	2030+ HVDC Radial Topology
Regulating reserves			
Regulation up revenue (all generators and regions)	$/yr, 2022	$46,243,556	$45,256,010
Regulation down revenue (all generators and regions)	$/yr, 2022	$9,142,540	$10,644,738
Regulation revenue (up and down, total)	$/yr, 2022	$55,386,096	$55,900,748

A.2.4 Transmission Expansion

Expansion of the transmission system was informed by power flow and dispatch modeling and costs were approximated through the JEDI model (Table 24).

Table 24. 2030+ HVDC Radial Topology transmission expansion costs

Component	units	2030 ADS + 38.4 GW VRE	2030+ HVDC Radial Topology
Transmission expansion upgrades			
Transmission expansion, CAPEX	$, 2022	$0	($14,920,518,084)
Transmission expansion, Annualized CAPEX	$/yr, 2022	$0	($1,151,799,964)
Transmission expansion, Annual O&M	$/yr, 2022	$0	($1,154,301,861)

A.2.5 Air Pollution

CO_2 and criteria air pollutants were extracted from GridView dispatch simulations (Table 25). Costs were approximated using the cost of carbon assumptions detailed in Appendix B: Valuation Methodology.

Table 25. 2030+ HVDC Radial Topology air pollution costs

Component	units	2030 ADS + 38.4 GW VRE	2030+ HVDC Radial Topology
Air pollution			
CO_2 emissions	lb/yr	305,996,535,368	269,493,070,922
NO_x emissions	lb/yr	204,096,190	181,756,471
SO_2 emissions	lb/yr	5,507,741	5,170,164
NO_x annual cost	$, 2022	$25,951,346,727	$23,110,794,981
SO_2 annual cost	$, 2022	$3,665,953,039	$3,441,261,544
CO_2 Emission Cost (Biden)	$/yr, 2022	$23,408,803,418	$20,616,280,221
CO_2 Emission Cost (EPA)	$/yr, 2022	$60,194,065,932	$53,013,291,997
Criteria Air Pollutant Cost	$/yr, 2022	$29,617,299,766	$26,552,056,525

A.2.6 Hedge Value

Based on the natural gas system wide fuel use from the GridView dispatch simulation, hedge value was calculated in accordance with Severy et al. (2022), as shown in Table 26.

Table 26. 2030+ HVDC Radial Topology hedge value calculations

Component	units	2030 ADS + 38.4 GW VRE	2030+ HVDC Radial Topology
Hedge value			
System Wide Fuel Use (primary) natural gas only	MMBtu/year	1,459,326,334	1,294,946,447
Fuel price uncertainty for OSW life	$, 2022	$46,750,404,332	$41,484,394,958
Fuel price uncertainty for OSW life	$/year, 2022	$1,558,346,811	$1,382,813,165

A.2.7 Transmission Reinforcement (Reliability and Resilience)

For the 2030+ HVDC Radial Topology, new hours from the dispatch were selected for power flow study as shown in Figure 33. Like A.1.7., the following three key cases were identified:

1. High Load, High Wind Case
2. High Load, Low Wind Case
3. Medium Load, Medium Wind Case

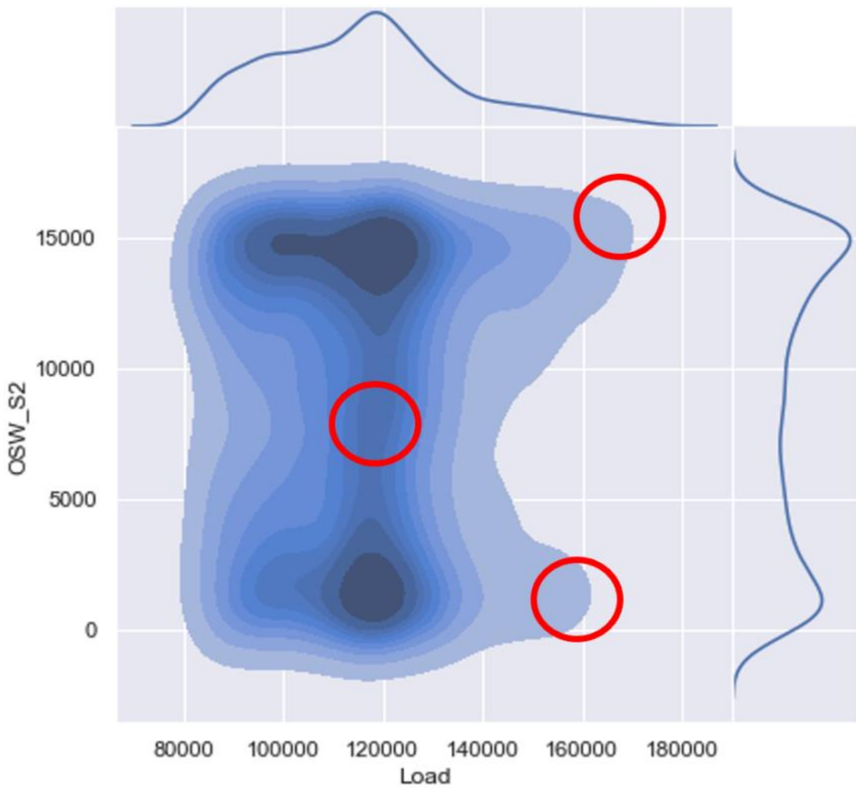


Figure 33. 2030+ HVDC Radial Topology, hours for power systems analysis

Steady state reliability was assessed. The costs for the upgrade to maintain reliable performance are shown in Table 27. As only existing corridors were reinforced, incremental operational costs of the upgrades were considered negligible.

Table 27. 2030+ HVDC Radial Topology, transmission reliability upgrades

Component	units	2030 ADS + 38.4 GW VRE	2030+ HVDC Radial Topology
Transmission reliability conductor upgrades			
Steady state reliability transmission upgrades, CAPEX	$, 2022	$0.00	($159,906,609)
Steady state reliability transmission upgrades, Annualized CAPEX	$/year, 2022	$0.00	($12,344,104)
Steady state reliability transmission upgrades, Annual O&M	$/year, 2022	$0.00	$0
Total transmission reliability	$/year, 2022	$0.00	($12,344,104)

A.2.8 Frequency Response Reserves

Dynamic simulations were run of a double unit failure at Palo Verde nuclear power station for the base case and the OSW case. A significant impact on system frequency was not observed. The frequency nadir (i.e., measured at the lowest point in the response) was 59.93 Hz and system frequency recovered to 60 Hz. Thus, no costs were incurred for system frequency response reserves.

A.2.9 Voltage Support

Voltage support costs were equated to incurred shunt capacitor costs, as informed by power flow modeling. Valuation results are shown in Table 28.

Table 28. 2030+ HVDC Radial Topology, voltage support costs

Component	units	2030 ADS + 38.4 GW VRE	2030+ HVDC Radial Topology
Voltage support			
Total compensation required	MVAr	0	6,900
Cost of voltage support compensation	$/yr, 2022	$0.00	($48,750,056)

A.2.10 Resilience

For the 2030+ HVDC Radial Topology, the resilience case used in the previous scenario (Case 1) was applied. The OSW output is below 20% during the 3-day heatwave, as indicated in Figure 34, which limits resilience value. In addition to Case 1, a new resilience case (Case 2) with a higher probability of occurrence was considered in which the drought conditions were removed. Though OSW production is still low during this event, the case was created to isolate the value of the MTDC scenario. Based on the unserved load cost, production cost, and probability of occurrence of different extreme events, Table 29 categorizes the valuation of the annual resilience benefit of the 2030+ HVDC OSW topology.

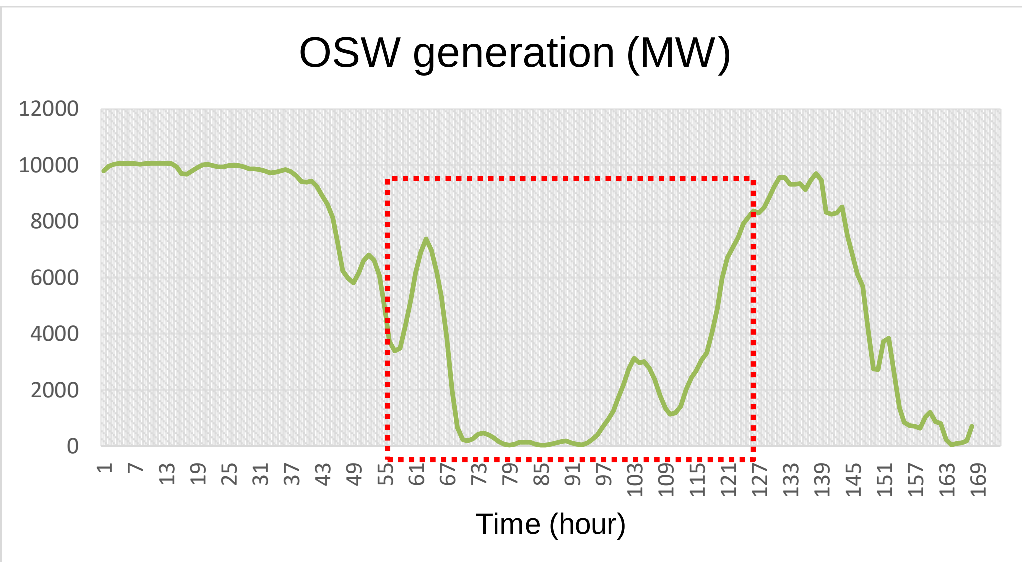


Figure 34. OSW production during Case 1 resilience event

Table 29. 2030+ HVDC Radial Topology resilience valuation

Component	units	2030 ADS + 38.4 GW VRE	2030+ HVDC Radial Topology
Resilience			
Unserved load from resilience Case 1: heatwave+thermal derate+wildfire+drought	MWh	123,148	85,513

Component	units	2030 ADS + 38.4 GW VRE	2030+ HVDC Radial Topology
Unserved load cost from resilience Case 1: heatwave+thermal derate+wildfire+drought	$, 2022	$11,495,668,787	$8,188,854,193
Unserved load cost in any given year Case 1 *given probability of occurrence*	$, 2022	$45,478,857	$32,396,526
Production cost during resilience event--Case 1	$, 2022	$2,145,522,460.82	$1,884,956,247.13
Production costs after probability of occurrence - Case 1	$, 2022	$8,488,058	$7,457,213
Unserved load from resilience Case 2: heatwave+wildfire+thermal derate	MWh	4,854,326,424	4,079,178,195
Unserved load cost in any given year Case 2 *given probability of occurrence*	$, 2022	$134,431,893	$112,965,549
Production costs during resilience event - Case 2	$, 2022	$1,922,484,141	$1,670,920,891
Production costs after probability of occurrence- Case 2	$, 2022	$53,239,762	$46,273,167

A.2.11 OSW Costs

2030+ HVDC Radial Topology OSW technology capital and operational costs were scaled from Musial et al. (2019) and are shown in Table 30.

Table 30. 2030+ HVDC Radial Topology OSW costs

Component	units	2030 ADS + 38.4 GW VRE	2030+ HVDC Radial Topology
OSW Costs			
Installed OSW Capacity	MW	0	12,900
CapEx	$, 2018	0	$30,434,970,000
Annualized CapEx	$/year, 2022	0	$2,514,525,626
OpEx	$/year, 2022	0	$3,832,409,178

A.3 2030+ MTDC Backbone

A.3.1 Energy, Contingency, and Ramping Reserves

Energy value, including impacts to contingency and ramping reserves, was extracted from GridView dispatch simulations as shown in Table 31.

Table 31. 2030+ HVDC Radial Topology energy valuation

Component	units	2030 ADS + 38.4 GW VRE	2030+ MTDC Backbone Topology
Energy (including contingency and ramping reserves)			
System Wide Generation	MWh	1,014,041,265	1,014,395,476
System Wide Generation Cost	$/yr	$10,827,320,048	$9,442,202,687

In the 2030+ MTDC Backbone Topology, generation and POIs are the same as the 2030+ HVDC Radial Topology (i.e., 16.3 GW installed OSW capacity with maximum injection of 12.8 GW interconnected in Southern Oregon and Northern California). In the two-sided violin plots below, the left side is the 2030+ HVDC Radial Topology OSW case, and the right side is the 2030+ MTDC Backbone Topology.

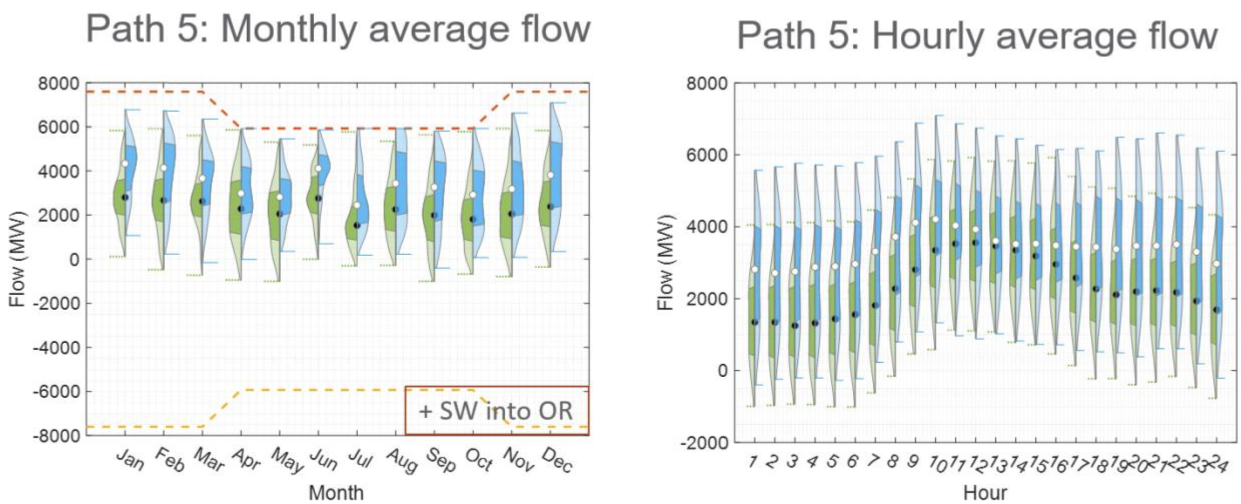


Figure 35. Monthly flow and hourly flow on Path 5 (Southwestern Washington to Northwestern Oregon)

As shown in Figure 35, with MTDC configuration there is an increase in power flow from Washington to Oregon, indicating the system is trying to push energy from Washington to Oregon.

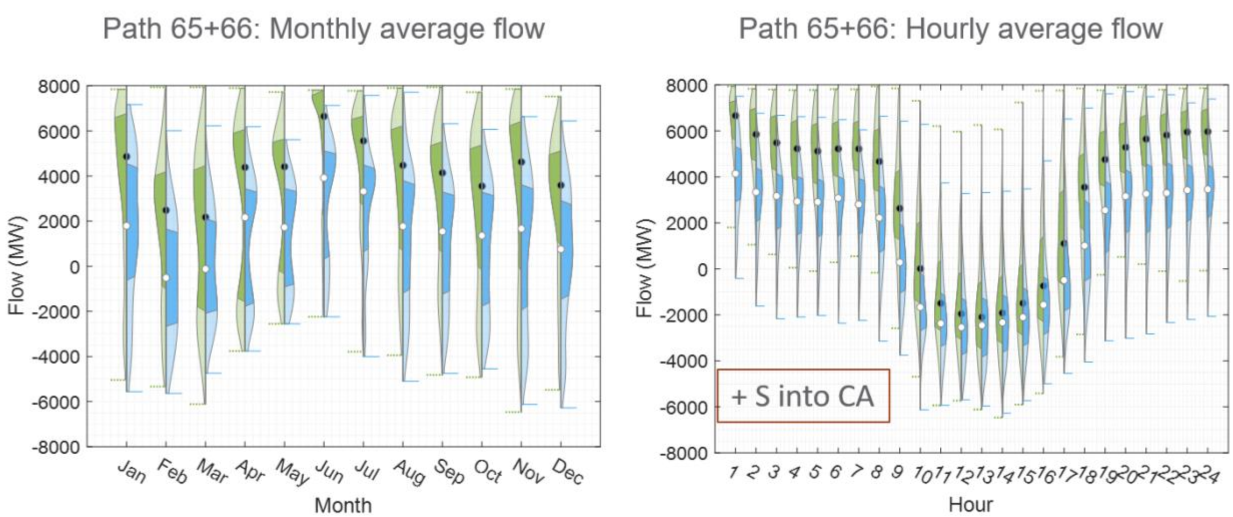
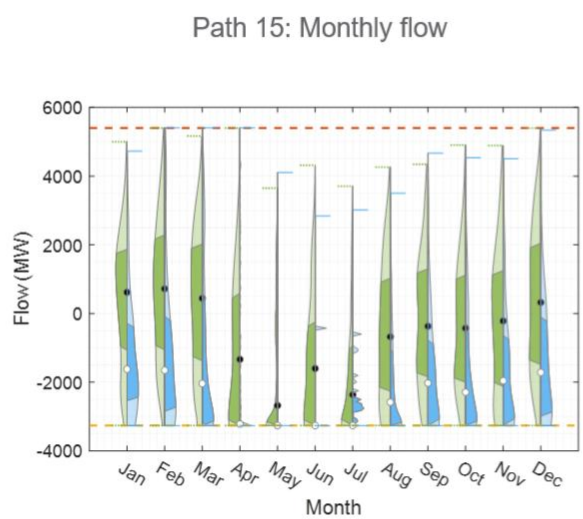


Figure 36. Monthly flow and hourly flow on Path 65+66 (Pacific DC Intertie (PDCI) and California Oregon Intertie (COI) connecting the Northwest with California)

There is also a reduction in the southbound power flow on Paths 65+66 (Figure 36), indicating that the MTDC backbone reduces California's energy imports from Oregon from PDCI/COI.



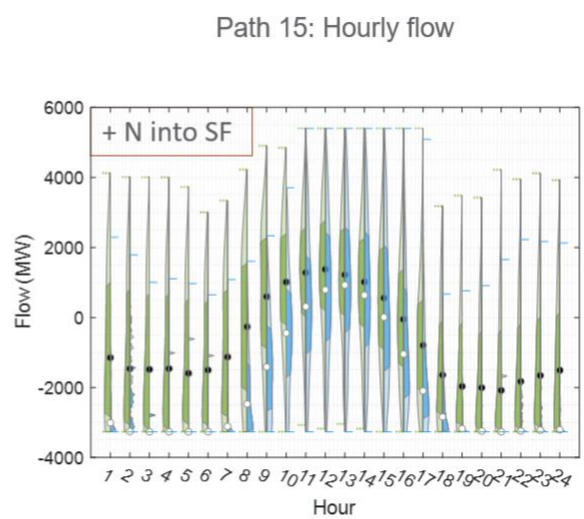


Figure 37. Monthly flow and hourly flow on Path 15 (connecting Southern and Northern California)

As shown in Figure 37, southbound congestion is observed on Path 15, which means there are significant power imports from Northern to Southern California due to increased power imports from OSW and the Northwest via the MTDC backbone.

A.3.2 Capacity

Capacity value was assessed through the Associated System Capacity Contribution detailed in Appendix B: Valuation Methodology. Avoided costs of combustion turbine procurements and operation were discounted to 2022 dollars and annualized, as shown in Table 32.

Table 32. 2030+ MTDC Backbone Topology capacity valuation

Component	units	2030 ADS + 38.4 GW VRE	2030+ MTDC Backbone Topology
Capacity			
New installed OSW capacity	MW	-	12,900
ASCC, CAISO	MW	-	3,162
ASCC, Northwest	MW	-	4,393
Capacity Credit			34%
Annualized Capacity Value	$/yr, 2022		$825,870,515

A.3.3 Regulating Reserves

Regulating reserves were extracted directly from the GridView dispatch simulation (Table 33).

Table 33. 2030+ MTDC Backbone Topology regulating reserves valuation

Component	units	2030 ADS + 38.4 GW VRE	2030+ MTDC Backbone Topology
Regulating reserves			
Regulation up revenue (all generators and regions)	$/yr, 2022	$46,243,556	$46,710,582
Regulation down revenue (all generators and regions)	$/yr, 2022	$9,142,540	$10,238,809
Regulation revenue (up and down, total)	$/yr, 2022	$55,386,096	$56,949,390

A.3.4 Transmission Expansion

Expansion of the transmission system was informed by power flow and dispatch modeling and costs were approximated through the JEDI model (Table 34).

Table 34. 2030+ MTDC Backbone Topology transmission expansion costs

Component	units	2030 ADS + 38.4 GW VRE	2030+ MTDC Backbone Topology
Transmission expansion upgrades			
Transmission expansion, CAPEX	$, 2022	$0	($13,592,410,923)
Transmission expansion, Annualized CAPEX	$/yr, 2022	$0	($1,049,275,791)
Transmission expansion, Annual O&M	$/yr, 2022	$0	($1,583,906,225)

A.3.5 Air Pollution

CO_2 and criteria air pollutants were extracted from GridView dispatch simulations (Table 35). Costs were approximated using the cost of carbon assumptions detailed in Appendix B: Valuation Methodology.

Table 35. 2030+ MTDC Backbone Topology air pollution costs

Component	units	2030 ADS + 38.4 GW VRE	2030+ MTDC Backbone Topology
Air pollution			
CO_2 emissions	lb/yr	305,996,535,368	265,276,171,857
NO_x emissions	lb/yr	204,096,190	178,668,738
SO_2 emissions	lb/yr	5,507,741	5,168,724
NO_x annual cost	$, 2022	$25,951,346,727	$22,718,181,898
SO_2 annual cost	$, 2022	$3,665,953,039	$3,440,303,197
CO_2 Emission Cost (Biden)	$/yr, 2022	$23,408,803,418	$20,293,686,499
CO_2 Emission Cost (EPA)	$/yr, 2022	$60,194,065,932	$52,183,765,283
Criteria Air Pollutant Cost	$/yr, 2022	$29,617,299,766	$26,158,485,095

A.3.6 Hedge Value

Based on the natural gas system wide fuel use from the GridView dispatch simulation, hedge value was calculated in accordance with Severy et al. (2022), as shown in Table 36.

Table 36. 2030+ MTDC Backbone Topology hedge value calculations

Component	units	2030 ADS + 38.4 GW VRE	2030+ MTDC Backbone Topology
Hedge value			
System Wide Fuel Use (primary) natural gas only	MMBtu/year	1,459,326,334	1,277,726,022
Fuel price uncertainty for OSW life	$, 2022	$46,750,404,332	$40,932,728,196
Fuel price uncertainty for OSW life	$/year, 2022	$1,558,346,811	$1,364,424,273

A.3.7 Transmission Reinforcement (Reliability and Resilience)

For the 2030+ MTDC Backbone Topology, the same hours as selected for the 2030+ HVDC Radial Topology were selected for power flow study.

Steady state reliability was assessed. The costs for the upgrade to maintain reliable performance are shown in Table 37. As only existing corridors were reinforced, incremental operational costs of the upgrades were considered negligible.

Table 37. 2030+ MTDC Backbone Topology, transmission reliability upgrades

Component	units	2030 ADS + 38.4 GW VRE	2030+ MTDC Backbone Topology
Transmission reliability conductor upgrades			
Steady state reliability transmission upgrades, CAPEX	$, 2022	$0.00	($136,733,230)
Steady state reliability transmission upgrades, Annualized CAPEX	$/year, 2022	$0.00	($10,555,219)
Steady state reliability transmission upgrades, Annual O&M	$/year, 2022	$0.00	$0
Total transmission reliability	$/year, 2022	$0.00	($10,555,219)

A.3.8 Frequency Response Reserves

Dynamic simulations were run of a Jim Bridger 214 MW generator trip for the OSW case (Figure 39). A significant impact on system frequency was not observed. The frequency nadir (i.e., measured at the lowest point in the response), as shown in Figure 40, has been observed to be 59.96 Hz. Thus, no costs were incurred for system frequency response reserves. Additionally, two other different system responses have been studied for events at Palo Verde station through the dynamic simulations with the MTDC model whose details are presented below. Numerical divergence of the MTDC dynamic model prevented definitive conclusions as to the system stability impact of the MTDC due to the full Palo Verde 2 fault.

MTDC Model

The MTDC model utilized for the transient stability simulations conducted in this work is built upon the formulation of Renedo et al. (2017). It should be noted that a simplified version of WECC, the MiniWECC model (Undrill & Trudnowski, 2008), has been used in these simulations to represent the WI. The MTDC model has been integrated to the MiniWECC model at the locations of interest, as shown in Figure 38, by importing a total power of 10200 MW from the OSW generation. Additionally, the offshore generation has been represented at a single aggregated bus because the MTDC model do not have the capability to provide frequency support from the OSW generations onto the grid and just provides the P (active power), Q (reactive power) injections.

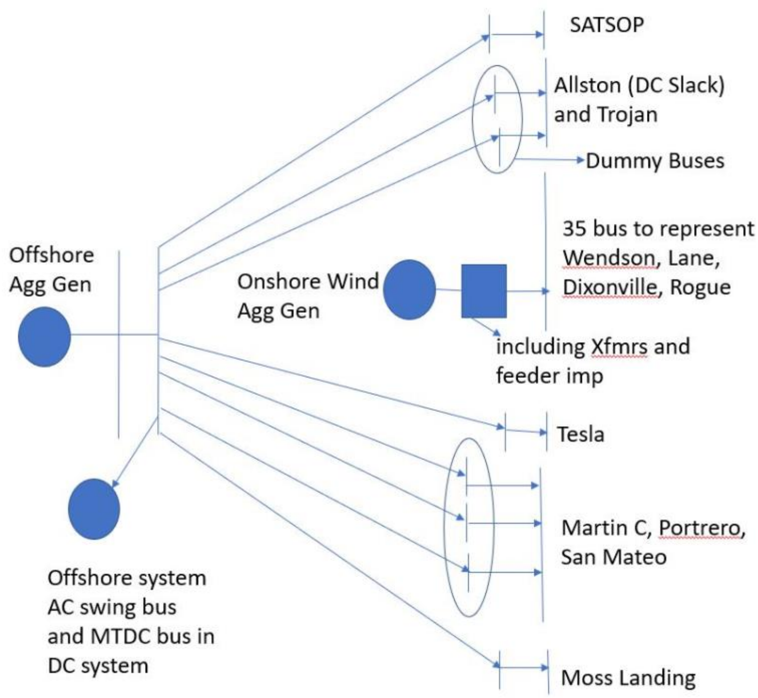


Figure 38. System configuration used in this work after integrating the custom built MTDC model to the MiniWECC

One of the events at Palo Verde considered is when one of its generators have been tripped (214 MW) same as the Jim Bridger tripped generation. The Frequency response observed for this event has been presented in Figure 41. The frequency nadir is close to 59.98 Hz which clearly indicates that the impact on the frequency response reserves for this scenario is also very minimal. Another point to be noted here is that a typical Palo Verde generation trip (around 1400 MW) is conducted to benchmark the system performance. However, the reason why a lesser 214 MW Palo Verde generation trip event has been simulated here is because the custom built MTDC model considered in this work, along with the considered MiniWECC system with a very high penetration of renewables in the system, starts to produce numerical solution divergence issues. This limitation in simulating the 1400 MW Palo Verde generation trip event clearly points to the modeling challenges involved with utilizing the complex system model considered in this work (first of its kind in the literature) and therefore these modeling challenges would need to be investigated further as part of future work.

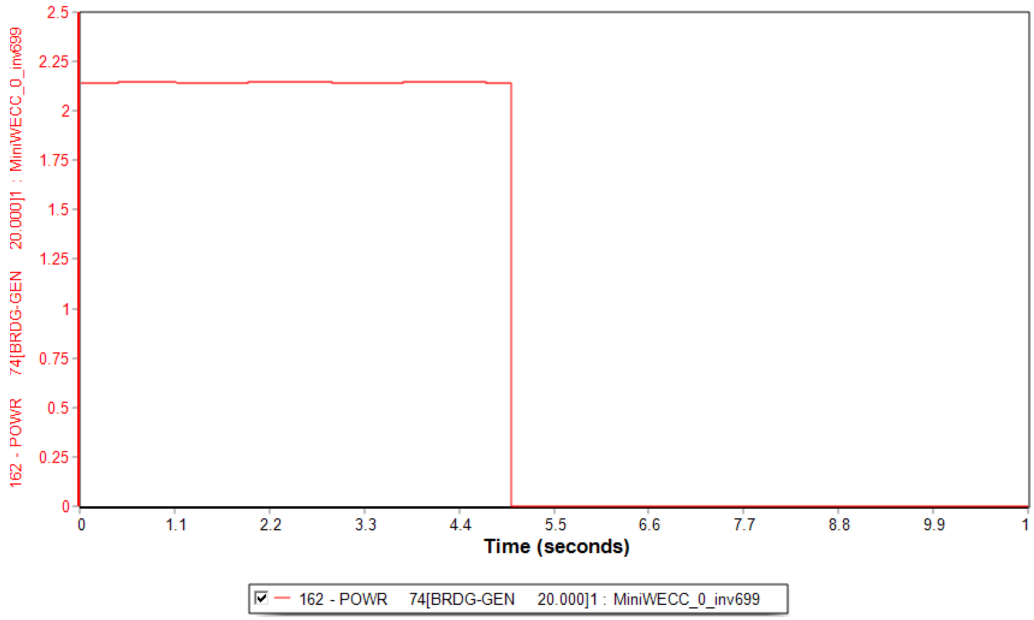


Figure 39. Power generation value (in per unit) of the Bridger generator when it is tripped at 5 secs simulation time

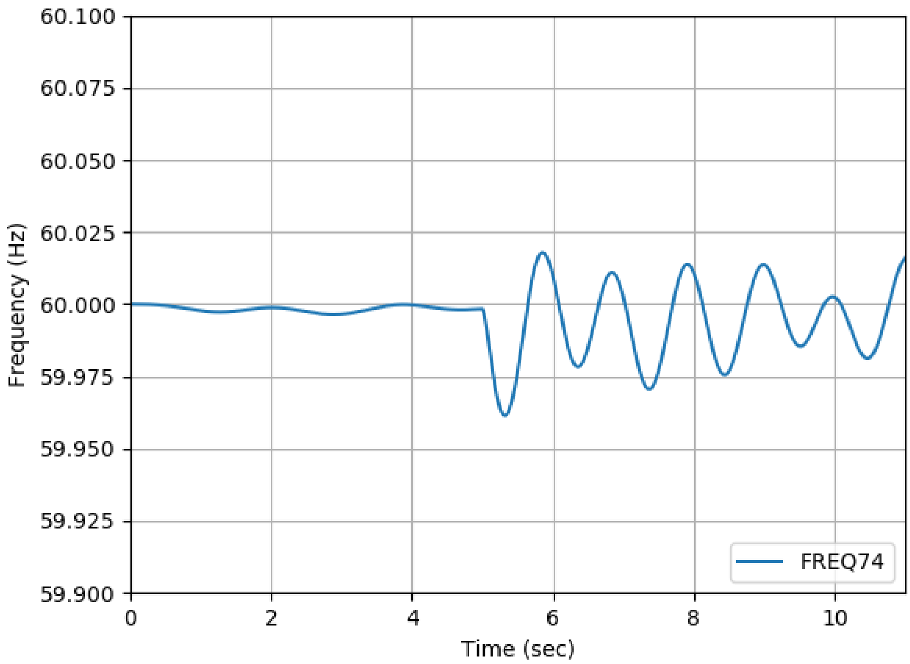


Figure 40. Frequency at Bridger (Bus 74) for the generator trip event at Bridger

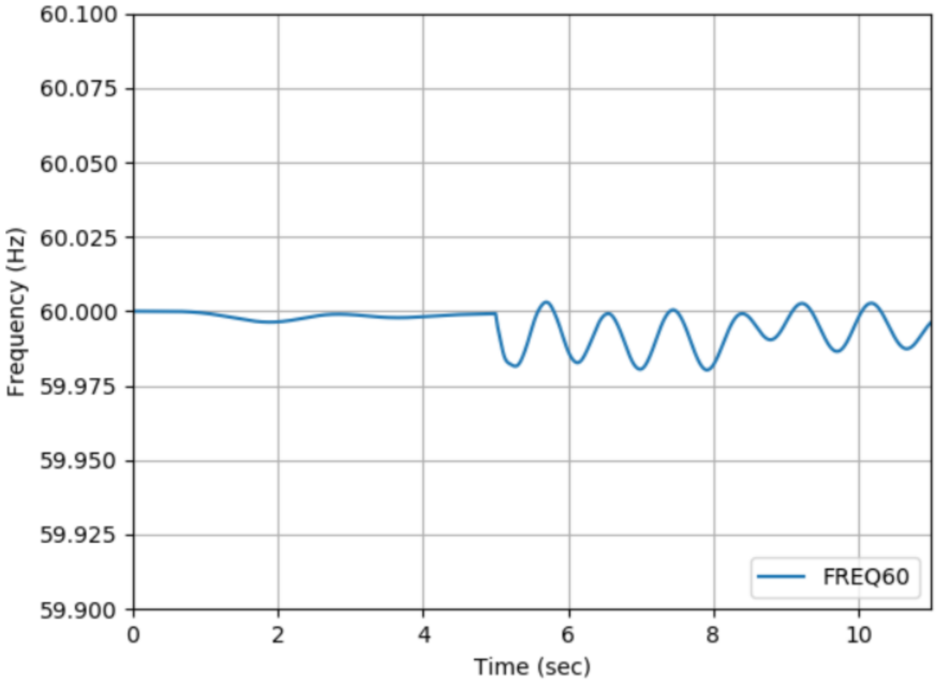


Figure 41. Frequency at Palo Verde (Bus 60) for the generator trip event at Palo Verde

In addition to the earlier described frequency trip events, another fault event at Palo Verde has been tested in this work and the results are presented in Figure 42 and Figure 43 below. Figure 42 shows that the system voltage response is stable (recovers to a non-oscillatory smooth response in the pre-fault steady state value) for the considered three-phase fault at Palo Verde and the corresponding responses of the field winding voltages of the Palo Verde generators has been presented in Figure 43. The presented responses of the field winding are to be expected as the rise in the field winding voltages in the generators correspond to the synchronous power compensation provided by these generators when the fault is applied at their terminals at Palo Verde.

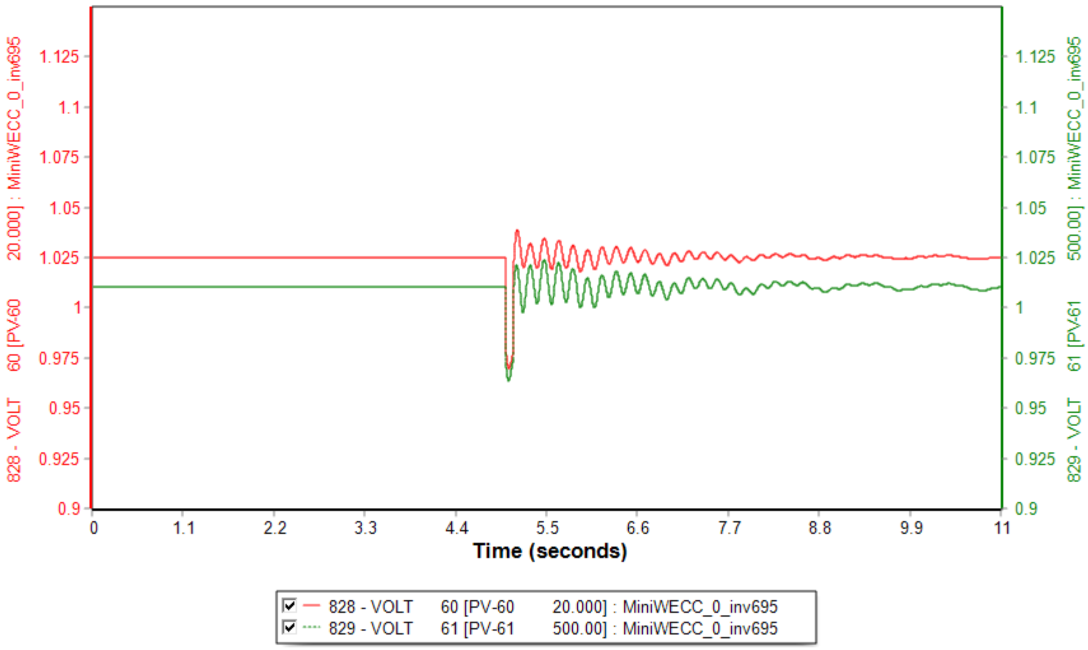


Figure 42. Voltages at Palo Verde locations for a three-phase fault at Bus 60

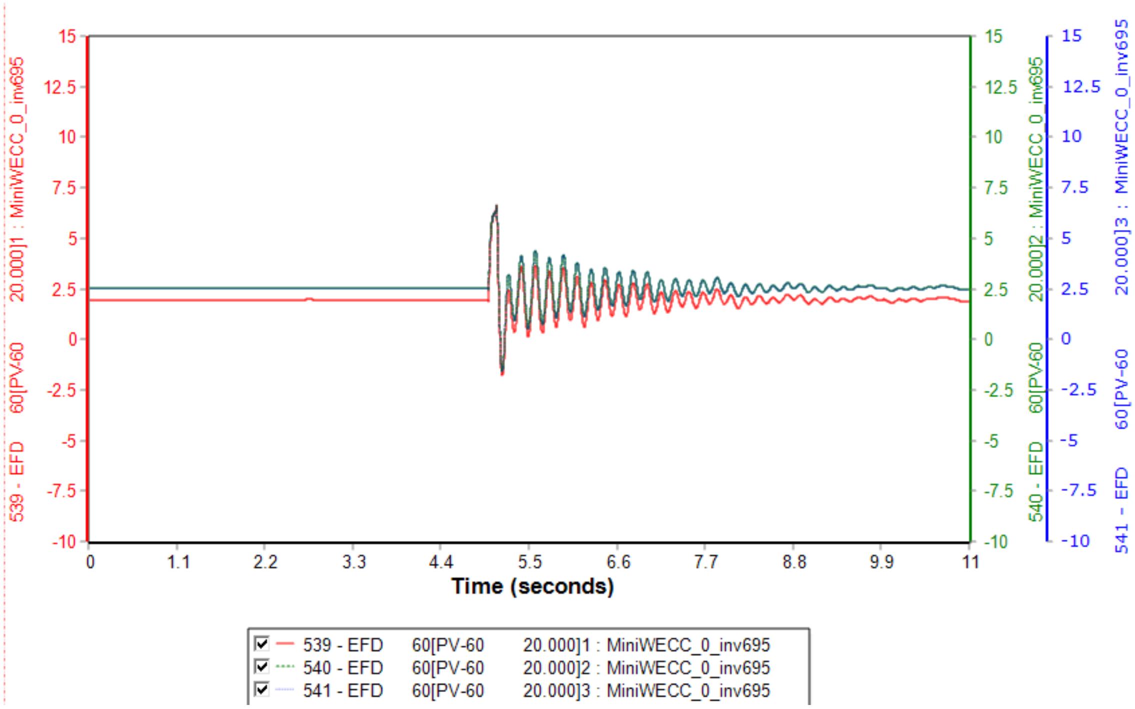


Figure 43. Field winding voltages of generators at Palo Verde for a three-phase fault at Bus 60

A.3.9 Voltage Support

Voltage support costs were equated to incurred shunt capacitor costs, as informed by power flow modeling. Voltage support costs were identical for the 2030+ HVDC Radial Topology and the 2030+ MTDC Backbone Topology.

A.3.10 Resilience

For the resilience assessment of 2030+ MTDC Backbone Topology, resilience Cases 1 and 2 were applied. Based on the unserved load cost, production cost, and probability of occurrence of different extreme events, Table 38 categorizes the valuation of the annual resilience benefit of OSW.

Table 38. 2030+ MTDC Backbone Topology resilience valuation

Component	units	2030 ADS + 38.4 GW VRE	2030+ MTDC Backbone Topology
Resilience			
Unserved load from resilience Case 1: heatwave+thermal derate+wildfire+drought	MWh	123,148	72,254
Unserved load cost from resilience Case 1: heatwave+thermal derate+wildfire+drought	$, 2022	$11,495,668,787	$7,021,088,347
Unserved load cost in any given year Case 1 *given probability of occurrence*	$, 2022	$45,478,857	$27,776,642
Production cost during resilience event--Case 1	$, 2022	$2,145,522,460.82	$1,878,608,820.68
Production costs after probability of occurrence - Case 1	$, 2022	$8,488,058	$7,432,102
Unserved load from resilience Case 2: heatwave+wildfire+thermal derate	MWh	4,854,326,424	3,489,977,611
Unserved load cost in any given year Case 2 *given probability of occurrence*	$, 2022	$134,431,893	$96,648,692
Production costs during resilience event - Case 2	$, 2022	$1,922,484,141	$1,665,999,008
Production costs after probability of occurrence- Case 2	$, 2022	$53,239,762	$46,136,865

In contrast to the 2030+ HVDC Radial Topology with a relatively low resilience value, the 2030+ MTDC Backbone Topology yields greater benefits during the 3-day heatwave even the wind generation is low due to the MTDC backbone's capability of transmitting energy between the Northwest and California.

In Case 2 without drought, the extra benefit of MTDC backbone is observed on the Satsop-Potrero link, as shown in Figure 44 below. The Satsop-Potrero link on the MTDC backbone connects Southern Oregon and Northern California. Under drought conditions and during the 3-day resilience event, there is less positive (southbound) energy flow on the Satsop-Potrero link due to hydropower reduction. Negative (northbound) energy flow is also observed in some hours. Simulating the same 3-day heat wave event in a normal hydropower year without drought, there is more southbound energy flow despite limited OSW generation.

This demonstrates the benefit of MTDC backbone is not only for delivering OSW to onshore buses, but also for delivering other types of energy resources to the areas in need.

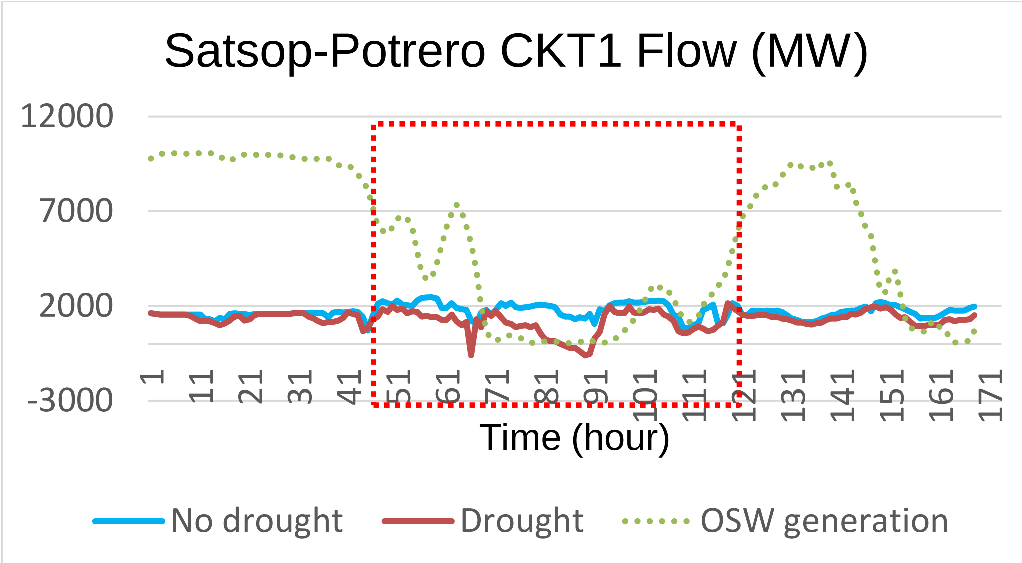


Figure 44. Flow on the MTDC and OSW generation during resilience cases 1 and 2

During a heatwave coinciding with a wildfire and in a drought year (resilience Case 1), both the 2030+ HVDC Radial and MTDC Backbone Topologies show limited benefit due to low OSW generation (green dotted curve) during the resilience event (hours 45 through 120). Limited flow along the backbone is seen particularly in hours of near zero OSW production for this Case 1 (red curve). In resilience Case 2, the drought is removed and flows along the backbone are near 2000 MWs (blue curve) precisely in the hours when OSW production is low, indicating the system use of the 2030+ MTDC Backbone Topology outside of OSW transmission.

A.3.11 OSW Costs

2030+ MTDC Backbone Topology OSW technology capital and operational costs were scaled from Musial et al. (2019), are the same as those of the 2030+ HVDC Radial Topology and are shown in Table 30.

B Appendix B: Valuation Methodology

A novel system-wide electricity generation valuation strategy was composed for this study (Severy et al., 2022). There are many different value streams that a new generator interconnection may provide to the electrical grid. Renewable energy generators such as OSW power plants have the potential to impact the grid through incurred or avoided costs for energy, capacity, operating reserves, reliability, resilience, and emissions reductions. The methodology shown in Figure 45 may be used to quantify the value of a generation or transmission modification on a system-wide scale. In this study, the methods were applied to the OSW generation and transmission scenarios and, for each, a corresponding base case. The resulting values were then compared against incurred capital and operational costs between scenarios.

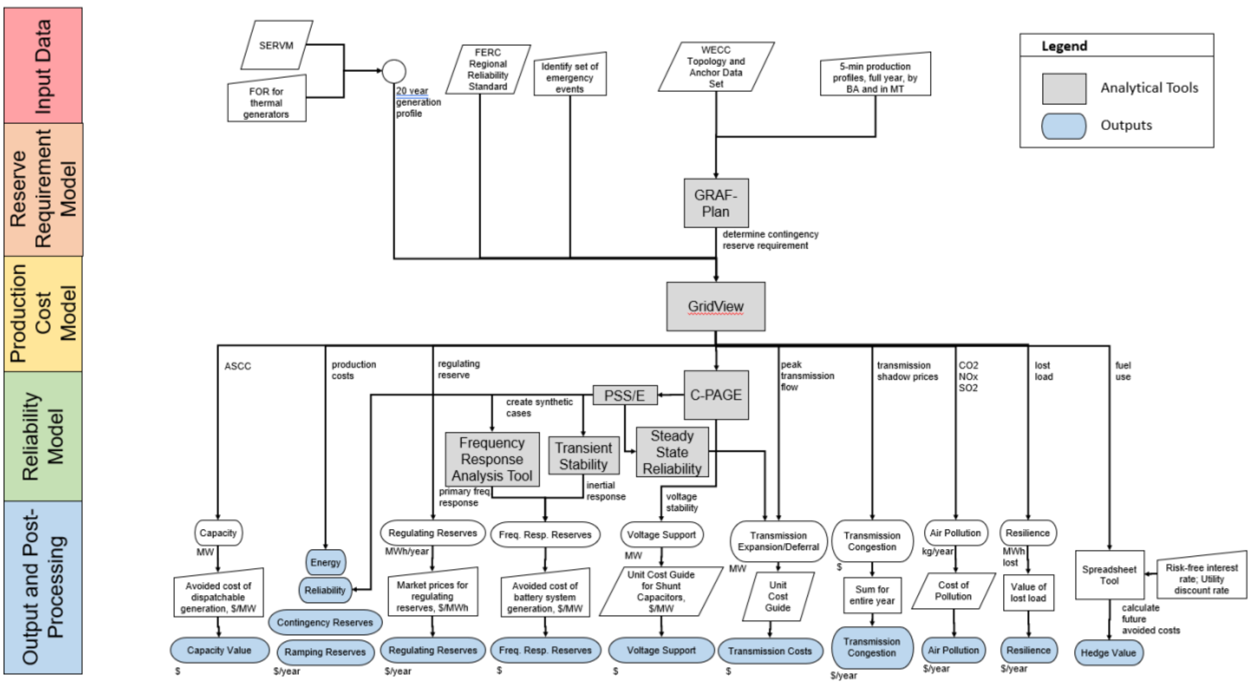


Figure 45. System-wide electricity valuation methodology

In this section, detail beyond the valuation strategy report is provided for capacity and emissions valuation.

B.1 Associated System Capacity Contribution Approach

Capacity credit was assessed through the Associated System Capacity Contribution (ASCC) metric, which quantifies the contributions of a generation portfolio change to hours of potential unserved load. To apply the method, numerous dispatch simulations are run while allowing some variability of generation, transmission capacity, and/or demand, and the hour of greatest unserved load is selected from each. The set of these hours is combined to create a peak-hour curtailment curve for each generation mix. The difference in curtailment between these curves, taken at the point of zero unserved load of the project case, is the ASCC, as shown in Figure 46.

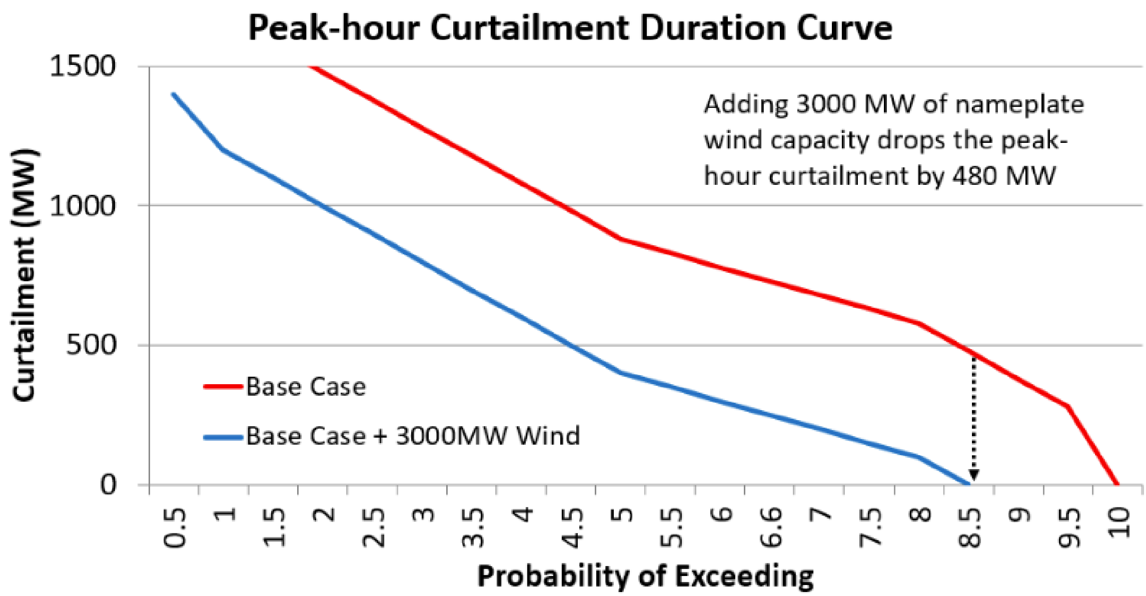


Figure 46. Indication of ASCC calculation (NPWCC, 2023)

To fully apply this method, a new version of GridView was produced which permitted more weather years of input data. Modifications also allowed these data to drive:

1. Temperature-dependent Forced Outage Rates (FORs) for natural gas, steam turbine, nuclear, and hydropower generators (Murphy et al., 2019). Equivalent FOR curves were assumed for wind turbine generators.
2. Temperature de-rates for wind, and solar energy resources under the following assumptions:

Wind Turbine Generators
Wind turbines operate between -20°C to 40°C.
Outside this range, they operate at 0% capacity
Between -20°C to 30°C, they operate at 100% capacity
Between 30°C and 40°C, the power output decreases by 1% per °C
To calculate the rated power output, use equation $P_{out} = DF * P_{rated}$, where DF is defined in Table 39.

Table 39. Definitions of derating factors for wind turbines

Temperature Range	De-rating Factor (DF)
T_{amb} < -20°C	$DF = 0$
-20°C <= T_{amb} < 30°C	$DF = 1$
30°C <= T_{amb} < 40°C	$DF = 1.30 + \frac{-0.01}{°C} * T_{amb}$
T_{amb} >= 40°C	$DF = 0$

Solar Photovoltaic Generators
Solar output decreases linearly with module temperature.
The generic formula is,

$$P_{output} = P_{rated} * \left(1 + T_{coeff}(T_{module} - 25°C)\right),$$

where the general temperature coefficient is -0.4%/°C.

Module temperature can be estimated as 28°C higher than ambient temperature in normal operating conditions (1 m/s wind and 800 W/m^2 solar irradiance).

The resulting derating function is,

$$P_{output}=P_{rated}*\left(1-\frac{0.004}{°C}\left(T_{ambient}+3°C\right)\right)$$

Leveraging these modifications, Monte Carlo dispatch simulations were conducted at zonal spatial resolution while allowing for variance of FOR and energy de-rates. Multiple weather years captured ranges of wind, solar, and hydropower variable renewable energy production. Loads were scaled to show unserved load probabilities in the base and OSW (i.e., "project") cases. Eighteen meteorological years (2000-2017) were used. For each of these years, 30 different trials were run, and the top *N* hours of peak net load (i.e., load minus generation, positive values corresponding to unserved load) were extracted from each trial and plotted on aggregate net load duration curves for CA and the NW. Figure 47 provides an example of this standard approach, with *N* set to 1.

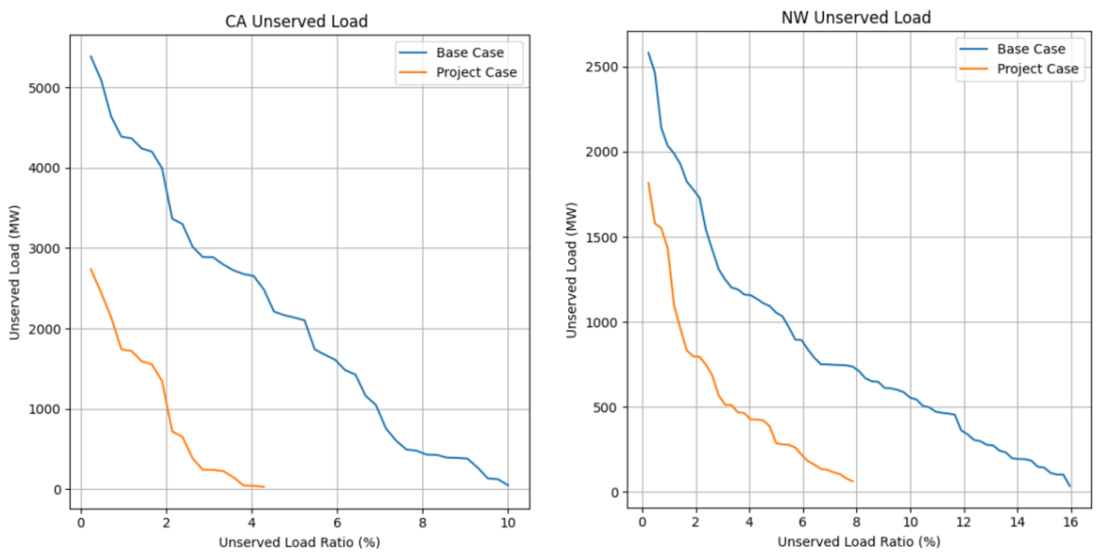


Figure 47. Standard ASCC method (N=1), 2030 HVAC Radial Topology, CA (left) and the NW (right)

At this point, two important modifications were made to the ASCC method, both with the goal of leveraging the variability in the underlying meteorological data. First, though the standard method uses an *N* of 1, convergence of the curves was seen by taking the top 10 hours of unserved load (Figure 50). Efforts were taken to limit N to represent critical system conditions while ensuring consistent shapes of base and project (OSW) curves.

The effect of increasing *N* was in smoothing the load duration curves as more hours are added. This eliminates the potential for relatively few hours to skew the results. Figure 48 indicates the smoothing of the curves as *N* is increased.

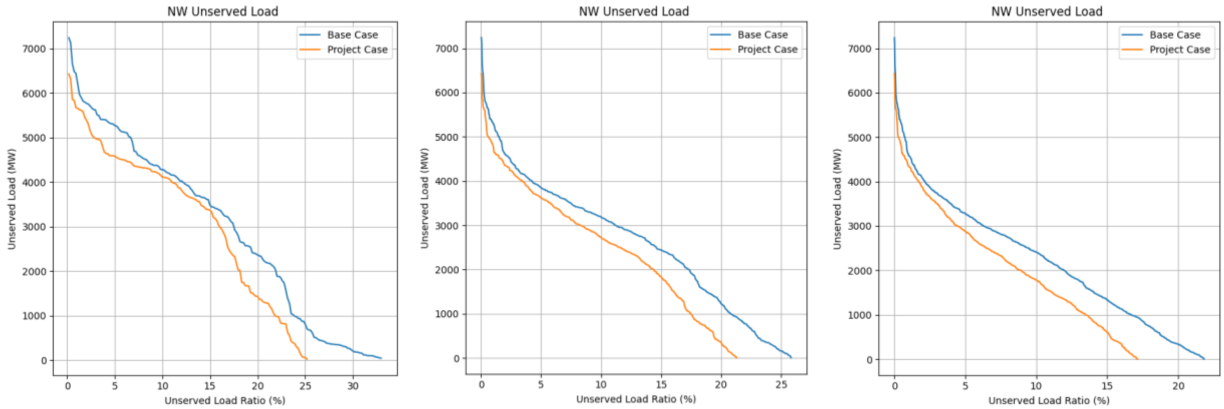


Figure 48. NW net load curves, 2030+ HVDC Radial Topology
N=1 (left), N=5 (middle), and N=10 (right)

Though this approach was effective in smoothing the curves and eliminating a "nose dive" effect that was occasionally observed near the zero crossing of the project case and thus would inflate ASCC, care needed to be taken to ensure the certain years or hours were not oversampled. This effect was observed in the 2030 HVAC Radial Topology ASCC sweeps and loads were scaled up to ensure unserved load arose across multiple weather years (Figure 49).

After ensuring that the variation in weather years was properly sampled, convergence was considered as the value of *N* was varied. In general, given the 30 trials per weather year chosen in the process, convergence was seen at a value of *N* equal to 10. As the number of trials per weather year varies, this convergence may be seen at a different number of top net load hours. Care should be taken to ensure statistical diversity in the net load curve for any value of *N* chosen. This diversity is shown for N=10 in Figure 49. ASCC convergence with N is shown in Figure 50.

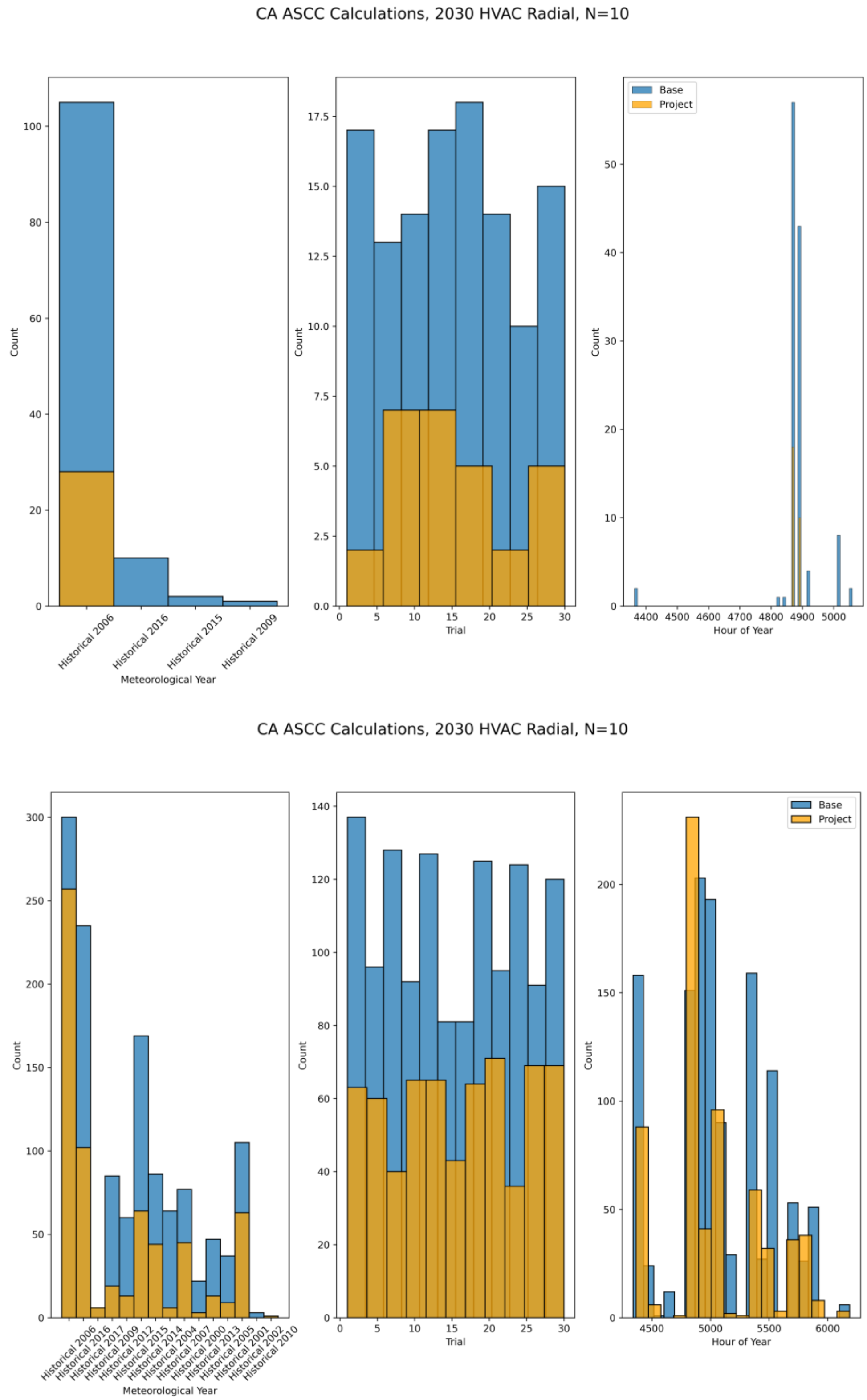


Figure 49. Net load curve compositions by weather years, trials, and hours of year, 2030 HVAC Radial Topology; initial load scaling (top) and final load scaling (bottom)
Initial scaling led to oversampling of the 2006 weather year and very few summer hours for the project case. Increased load scaling improved diversity of years and hours informing the ASCC calculation.

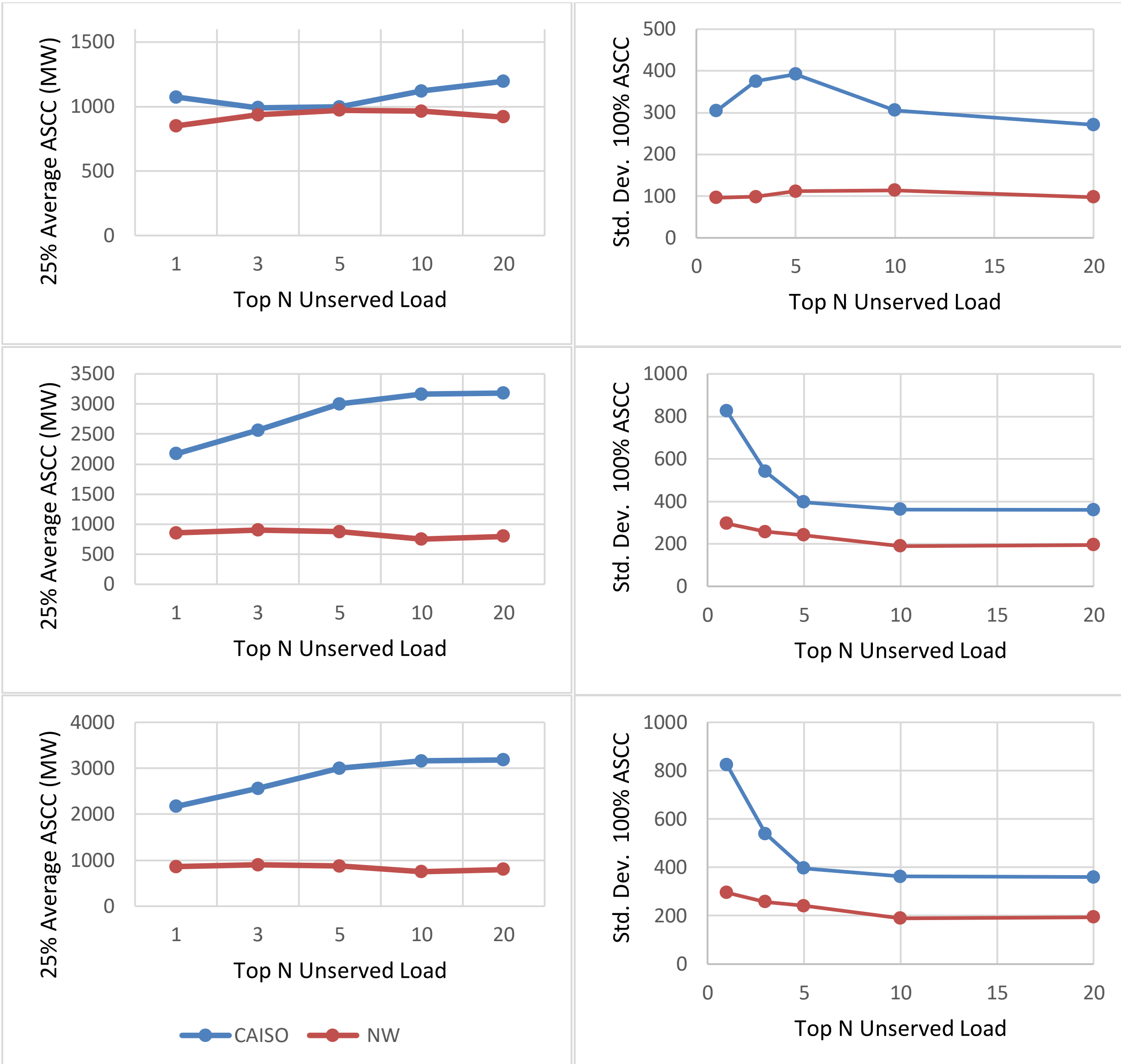


Figure 50. ASCC Convergence using top N unserved load hours.
25% Average ASCC values (left column), 100% ASCC standard deviation (right column). Top row: 2030 HVAC Radial Topology; middle row: 2030+ HVDC Radial Topology; bottom row: 2030+ MTDC Backbone Topology. California ASCC values in blue, Northwest ASCC values in red. Convergence generally seen at for the top 10 net load hours given 30 trials per weather year.

The second major modification to the standard ASCC approach concerned the point of offset chosen between the base and project curves. Capacity contribution was also observed to vary as a function of where the offset between the two curves was taken, as seen in Table 40, Table 41, and Table 42. ASCC was assessed as an average of the final 25%, 50%, and 100% of overlapping hours of unserved load (between base and project cases) rather than the final hour (or zero crossing). After reviewing these results along with the net load curves, the Average ASCC of the final 25% of hours was chosen to capture a more statistically robust measure of capacity and to also align with voluntary load shedding capabilities which exist on the systems today.

Capacity contributions were tracked separately in California (CA) and the Northwest (NW) regions as capacity plans are made separately for these regions. Though the same OSW generation was shown to provide a capacity value to CA and the NW (based on transmission capacity and differences in hours of net load peaks between the two regions, CA net load peaks in summer evenings, NW net load peaks in winter mornings and evenings), only the maximum value was used in the valuation. This decision was based on the valuation through avoided costs of combustion turbine procurement and operation, assuming such a turbine would be used for capacity only. Given that this turbine could also provide capacity value to both regions, it was assumed that the avoided cost was only the maximum capacity value between CA and the NW. Also, it was assumed that this capacity resource could serve whichever regional need was higher. Both assumptions differ from how capacity is procured within regions today. However, the assumptions were consistent with the system-wide valuation approach.

Table 40. CA and NW ASCC statistics, 2030 HVAC Radial Topology (selected values italicized)

Top N Unserved Load	Base Case Unserved Load Ratio	Project Unserved Load Ratio	ASCC	Average ASCC 25%	Average ASCC 50%	Average ASCC 100%
			CA			
1	56.1%	34.4%	1074	1072	1046	1137
3	44.3%	25.2%	1054	990	942	1159
5	35.8%	19.2%	1062	997	946	1238
10	24.0%	11.9%	1152	***1119***	1132	1391
20	13.5%	6.2%	1213	1196	1200	1426
			NW			
1	79.6%	63.7%	954	850	819	865
3	72.7%	54.4%	1061	936	913	865
5	66.6%	48.1%	1096	971	924	841
10	56.3%	35.8%	1081	***964***	886	801
20	40.2%	23.0%	999	918	844	776

Table 41. CA and NW ASCC statistics, 2030+ HVDC Radial Topology (selected values italicized)

Top N Unserved Load	Base Case Unserved Load Ratio	Project Unserved Load Ratio	ASCC	Average ASCC 25%	Average ASCC 50%	Average ASCC 100%
			CA			
1	48.0%	16.9%	2251	2169	2153	2711
3	36.4%	10.4%	2576	2560	2604	2915
5	27.9%	6.5%	3063	3001	3039	3227
10	17.3%	3.3%	3180	***3162***	3171	3303
20	8.9%	1.6%	3203	3181	3181	3308
			NW			
1	33.0%	25.2%	676	856	640	527
3	27.8%	22.9%	870	902	733	535
5	25.8%	21.3%	915	875	709	525
10	21.8%	17.1%	938	***751***	694	540
20	16.0%	11.7%	891	797	768	613

Table 42. CA and NW ASCC statistics, 2030+ MTDC Backbone Topology (selected values italicized)

Top N Unserved Load	Base Case Unserved Load Ratio	Project Unserved Load Ratio	ASCC	Average ASCC 25%	Average ASCC 50%	Average ASCC 100%
			CA			
1	48.0%	16.9%	2251	2169	2153	2711
3	36.4%	10.4%	2576	2560	2604	2915
5	27.9%	6.5%	3063	3001	3039	3227
10	17.3%	3.3%	3180	***3162***	3171	3303
20	8.9%	1.6%	3203	3181	3181	3308

Top N Unserved Load	Base Case Unserved Load Ratio	Project Unserved Load Ratio	ASCC	Average ASCC 25%	Average ASCC 50%	Average ASCC 100%
			NW			
1	33.0%	10.6%	4190	4238	4385	4469
3	27.8%	4.5%	4306	4361	4448	4509
5	25.8%	2.7%	4373	4392	4473	4521
10	21.8%	1.4%	4373	***4393***	4474	4521
20	16.0%	0.7%	4373	4393	4474	4521

B.2 Emissions Valuation

The value of emissions reductions is determined by calculating the quantity of emissions reduced and assigning a system-wide value to those reductions. Direct emissions of CO_2, NO_x, and SO_2 from all electrical generating units in WECC are output from the PCM. Emissions in the base case and each respective scenario were compared to quantify the change in emissions for each scenario.

The value of emissions reductions is more difficult to quantify because the benefit accrues to society in the form of reduced public health impacts (criteria pollutants) and effects of climate change (greenhouse gases). The PCM outputs the cost for carbon dioxide emissions paid by generators into state or provincial carbon markets, but this value is not representative of the system because (i) carbon pricing is not implemented across the entire WECC, (ii) carbon markets do not reflect the entire societal cost of carbon, and (iii) it does not include a value of reduced criteria pollution. Thus, emissions values are derived from public analyses conducted by the EPA and the Biden Administration that reflect the public value of emissions reductions to the nation, as described below.

Two recent estimates for the social cost of carbon have been provided by the White House and EPA (Table 43). The White House (2021) provides a cost of carbon based on the emissions in decadal increments from 2020 through 200 for three different discount rates: 5%, 3%, and 2.5%. The EPA (2022) provides a social cost of carbon at 5-year increments from 2020 through 2050 for discount rates of 2.5%, 2.0%, and 1.5%. The discount rates for future emissions are low because future emissions cause larger incremental impact. To estimate the social cost of carbon for this OSW project, we picked a low estimate as the baseline value from the White House (2021) using the 2.5% discount rate and second estimate from EPA (2022) using the 2.0% discount rate for comparison. A simple average was taken across 2030 to 2059, which is the range of dates when the OSW plants would be operational. This averaging allows the valuation analysis to be relevant to any year while the OSW plant is operating and assumes that the emissions reductions are constant throughout the operating life. Since the EPA data provided values in 5-year increments up to 2050, but the OSW scenario operates through 2059, we used the 2050 value and applied it without variation for all years through 2059. Ultimately, the values are $105 per tonne (metric ton) from White House (2021) and $270 per tonne from EPA (2022).

Table 43. Social cost of carbon calculations

White House (2021)				EPA (2022)			
Discount Rate				Discount Rate			
Year	**5%**	**3%**	**2.5%**	**Year**	**2.5%**	**2.0%**	**1.5%**
2020	$14	$51	$76	2020	$120	$190	$340
2025	$17	$56	$83	2030	$140	$230	$380
2030	$19	$62	$89	2040	$170	$270	$430
2035	$22	$67	$96	2050	$200	$310	$480
2040	$25	$73	$103	2060	$230	$350	$530
2045	$8	$9	$110	2070	$260	$380	$570
2050	$32	$85	$116	2080	$280	$410	$600
Average for years 2030-2059*	$26	$75	**$105**	Average for years 2030-2059	$170	**$270**	$430

Costs from White House (2021) used as baseline value, and EPA (2022) used as high estimate. Cells highlighted in grey indicate the values that were averaged for this analysis, with the final value shown in bold text.

*To calculate the average through 2059, the value from 2050 was applied through 2059.

Emissions of NO_x and SO_2 are PM2.5 precursors and NO_x is also an ozone precursor that has public health impacts, which are quantified by EPA (2023a, 2023c). The public health impacts vary by state due to differences in population density and other demographic factors. EPA (2023c) provides values for the benefit per tonne of emissions reductions by sector and state for criteria air pollutants for the years between 2025 and 2040. Values are taken from this data source for the benefit per tonne of emissions reductions of NO_x and SO_2 from electricity generating units for all states in the WECC. For years between 2040 and 2059 when the OSW plant is operating but there is no available data, the emission value is used from 2040 rather than extrapolating the values into future years as a conservative approach. Since NO_x is a precursor to ozone and PM2.5, values are calculated separately for each then summed as a total benefit value. A weighted average of the benefit per tonne values are taken across all states based on the fraction of electricity generation in each state with generation attributes from 2021 taken from EPA's eGRID (EPA, 2021d). Thus, the benefit per tonne across the WECC is calculated as shown in Table 44.

Table 44. Values for emissions reductions of criteria pollutants

Pollutant	Value	Note
NO_x	$151,229/tonne	Benefit per tonne NO_x reduced as an ozone precursor
NO_x	$7,069/tonne	Benefit per tonne NO_x reduced as a PM2.5 precursor
NO_x total	$158,297/tonne	Benefit per tonne NO_x reduced, total
SO_2	$828,631/tonne	Benefit per tonne SO_2 reduced as a PM2.5 precursor

C Appendix C: Generation Footprint Optimization

To develop generation and transmission designs for the 2030+ profiles, the OSW resource potential was evaluated in federal waters extending from Coos Bay, Oregon to the north, Eureka, CA to the south, and the 1,300-meter bathymetry contour to the west. After consulting the PCM for onshore interconnection capacity, a co-optimization of the annual energy potential and the capacity value was conducted to define an optimal generation footprint. A subsequent optimization of this footprint minimized the overall transmission cost and indicated where individual wind power plants would be located to provide power to the onshore POIs of interest.

The mixed-integer, linear programming optimization problems was formulated as follows:

- Given,
  - A range of hourly hub height wind speed profiles over an entire year (for 20 years)
  - A power curve
  - Various loss factors assigned to power production of each turbine
  - Floating OSW power density (MW/km^2)
- Maximize (step 1),
  - Value as a function of (normalized) energy + capacity
- Minimize (step 2),
  - Transmission penalty*distance from POIs
- Subject to,
  - Installed capacity limits at targeted POIs
  - Geographic limits: south of Florence, OR, and north of Eureka, CA
  - Federal-state water boundary
  - 1300m bathymetry contour
- Define,
  - Optimal Ocean Footprint

C.1 Wind Resource

Hourly wind speeds were extracted at 140 meter hub heights from the Offshore CA and Offshore NW Pacific datasets for the years 2000-2019 at 2 km x 2 km spatial resolution the region indicated in Figure 51 (Optis, 2020). This region was expanded to include the full Coos Bay Call Area, after it was announced. In total, hourly wind speeds of 4,198 locations over 20 years were input to the optimization algorithm.

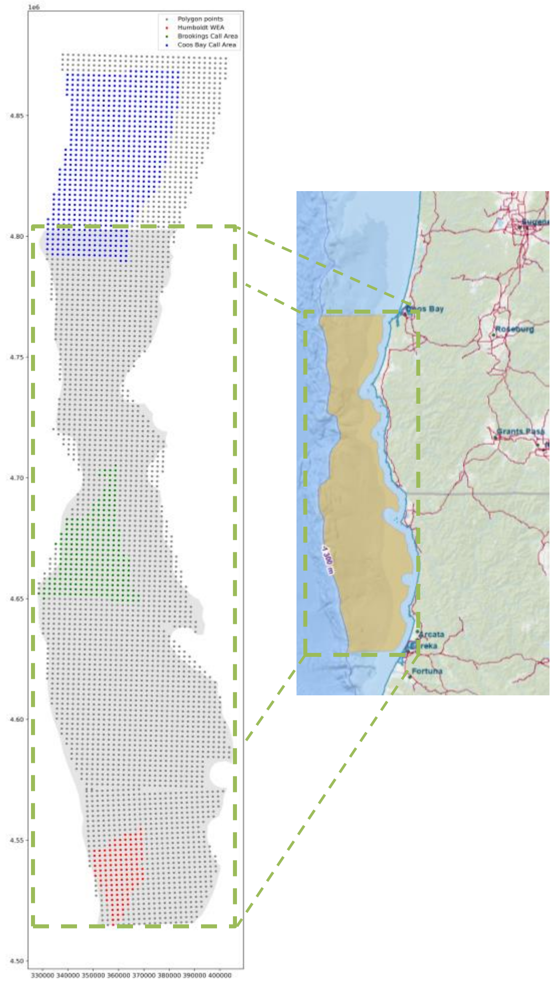


Figure 51. Geographic bounds of generation and transmission optimization

C.2 Power Conversion

Hub height wind speeds were then converted to power by applying a power curve adapted from the NREL 15 MW turbine (Musial et al., 2019). Important updates were made to this power curve, as indicated in Figure 52 and Table 45, notably the addition of a high wind de-rate instead of a sudden cut-out. This addition reduces hysteresis losses and improves energy production in very energetic sites such as those seen in the region of interest.

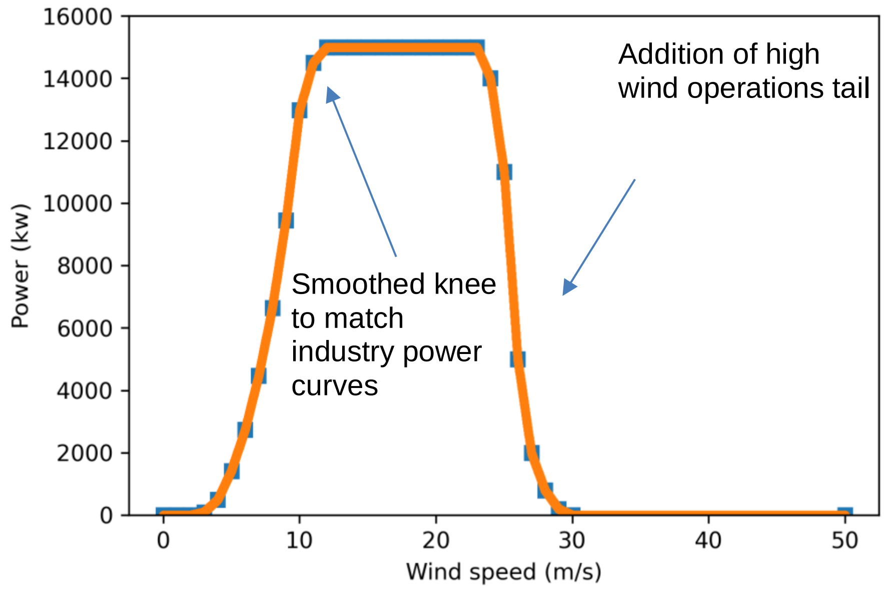


Figure 52. PNNL 15 MW reference power curve

After gross power conversion, losses of 22% were assumed based on consultation with industry. Loss factors were composed of approximately 7% wake losses and 15% additional losses corresponding to turbine availability, hysteresis, blade degradation, electrical losses, curtailments, etc. As these losses would typically be assessed on a site specific basis, constant loss factors are an assumption of this work.

Table 45. PNNL 15 MW reference power curve

Wind Speed (m/s)	P (kw)
0	0
1	0
2	0
3	100
4	499
5	1424
6	2732
7	4469
8	6643
9	9459
10	12975
11	14500
12	15000
13	15000
14	15000
15	15000
16	15000
17	15000
18	15000
19	15000
20	15000
21	15000
22	15000
23	15000
24	14000
25	11000
26	5000

Wind Speed (m/s)	P (kw)
27	2000
28	800
29	200
30	0

C.3 Capacity Proxy

Prior work (Douville & Bhatnagar, 2021; Novaceck & Schwartz, 2021; Jorgensen, et al., 2021), highlighted the capacity value of the west coast OSW resource. For this reason, and noting the importance of capacity in the future with limited dispatchable reserves, potential OSW energy production during net load peak hours was considered in the optimization. The net load duration curves for Pacificorp West (PACW), Bonneville Power Administration (BPA), CAISO, Portland General Electric (PGE), Puget Sound Energy (PSEI), and Seattle City Light (SCL) balancing authorities, as extracted from the 2030 ADS, were consulted. A slope break after the top 175 hours (approximately 2% of the hours per year) was chosen to represent the hours of greatest capacity need (Figure 53).

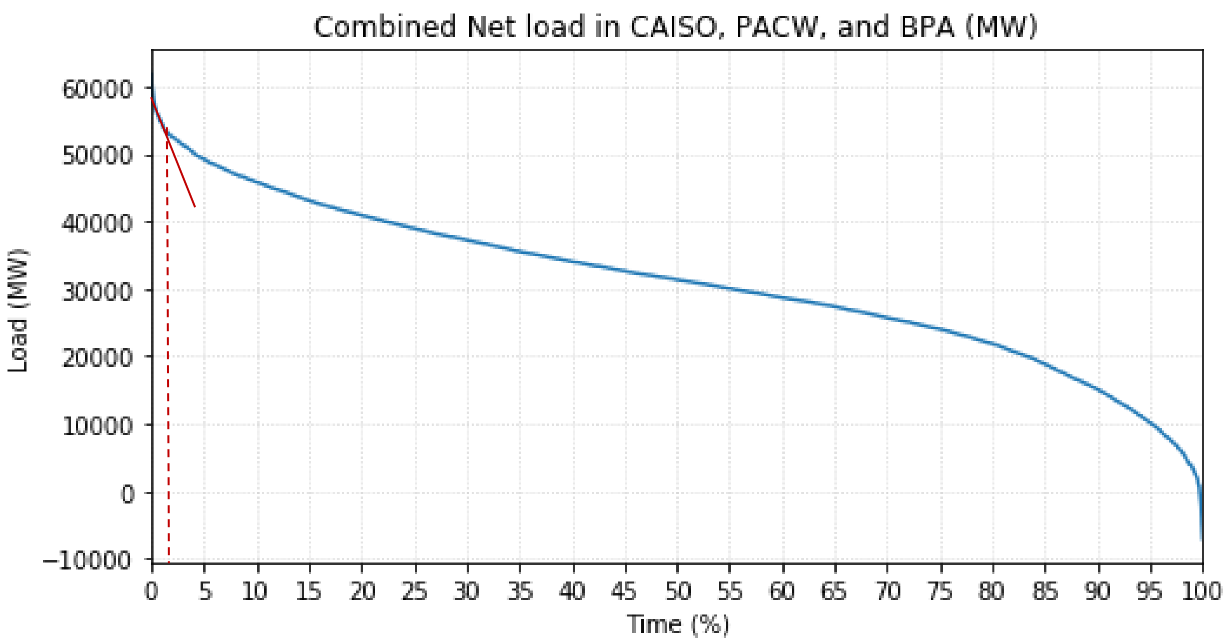


Figure 53. Top 175 hours from an aggregate west coast load duration curve were targeted in the optimization

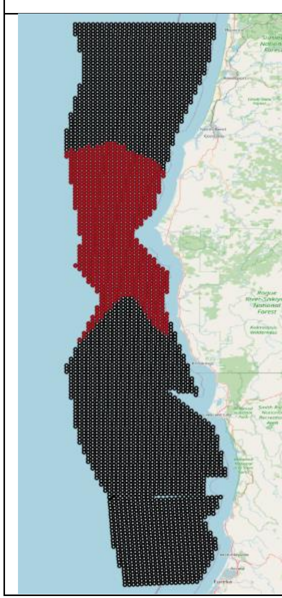
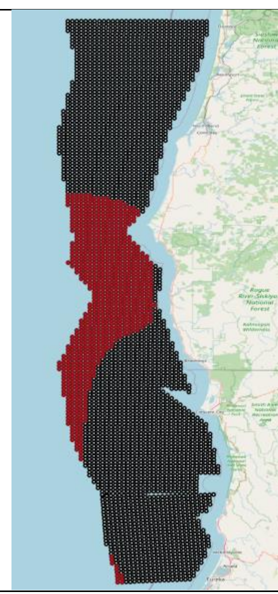
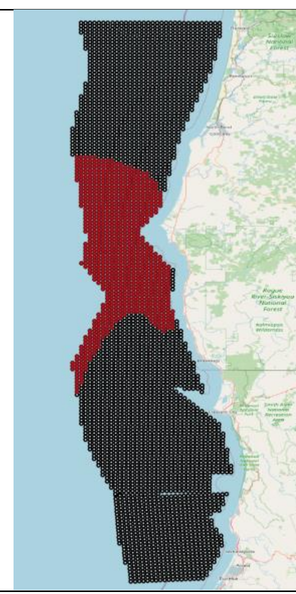
C.4 Footprint Calculations

Finally, to resolve an ocean footprint and equate individual wind plants to specific locations of wind resource from the datasets, a power density of 5.5 MW/km^2 was assumed based on an approximate seven rotor diameter spacing streamwise and spanwise. These assumptions were validated based on consultation with industry of spacing relevant to a 15 MW turbine with rotor diameter on the order of 230 meters. Then the net power production (after losses had been applied) was scaled to give power production per 2 km x 2 km cell in water. Care was taken to average power results over a geographic area rather than wind speeds first, to avoid the effect of washing out the volatility of extreme high and low wind speeds and their critical power sector implications.

C.5 Results

The optimization was performed under a 20 GW capacity limit, and the resulting footprint was labeled "Opt20." Various objective functions were considered and three specifically came into focus: (i) optimized capacity value by minimizing unserved load during the top 175 hours of system load less land-based wind and solar energy production, as represented in ADS 2030, (ii) maximization of energy over all 8760 hours in the year, and (iii) an equal weighting of capacity and energy value. This third objective was informed by previous work which showed approximately equal system value of energy production and capacity (Novaceck & Schwartz, 2021). As a check of the optimization, the objective function was evaluated over two forced footprints, one to the extreme northern end and one to the extreme southern end of the region of interest, each also capable of 20 GW of OSW production. All three optima were found in the middle of the region, centered off the coast of Bandon, which is not the region of highest mean wind speed. This is because wind speeds which are too high to capture with current technology present further south and pull the average wind speeds higher. The optima showed improvements over the next highest forced region of 5.9%, 13.1%, and 12.1% for the objectives of capacity, energy, and combined capacity and energy value, as shown in Table 46.

Table 46. Generation optimization results

	Capacity: min(unserved_load) (GWh)	Energy: max(energy) (GWh)	Combined: 0.5*max(energy) + 0.5*min(unserved_load) (GWh)
Forced North 20 GW	34,677	1,478,719	756,698
Forced South 20 GW	31,095	1,477,103	754,099
Optimal 20 GW	36,718 (+5.9%)	1,673,222 (+13.1%)	848,547 (+12.1%)
			

C.5.1 Multi-Year Averaging

These results above were derived from optimizing the averages of wind production at each hour at each location over the full 20-year dataset. A slightly different result was revealed if the optimization was run 20 separate times, one for each year, and then the most commonly occurring locations over the full 20-year set were selected. Resulting locations and a histogram of selected nodes for the capacity objective function is shown in Figure 54. This latter approach allows for more selected locations and several dispersed clusters. However, most locations were the same and engineering judgement was used to conclude that project development economics would not result in dispersed clusters as seen.

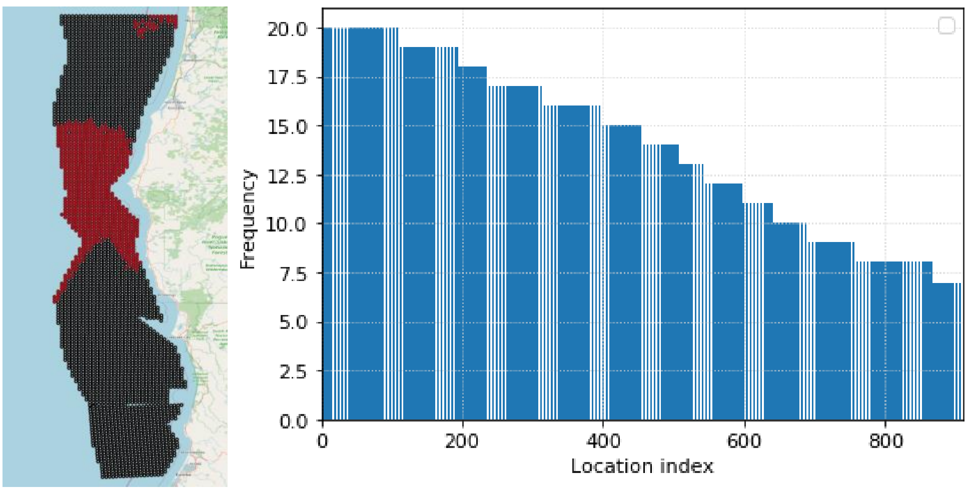


Figure 54. Capacity optimum based on 20 discrete yearly optimizations

C.5.2 Wind Production Trends

Net capacity factors of the Opt20 shape by hour of day resemble the combination of Coos Bay and Brookings characteristics (Figure 55). Average net capacity factors for the year are 47%.

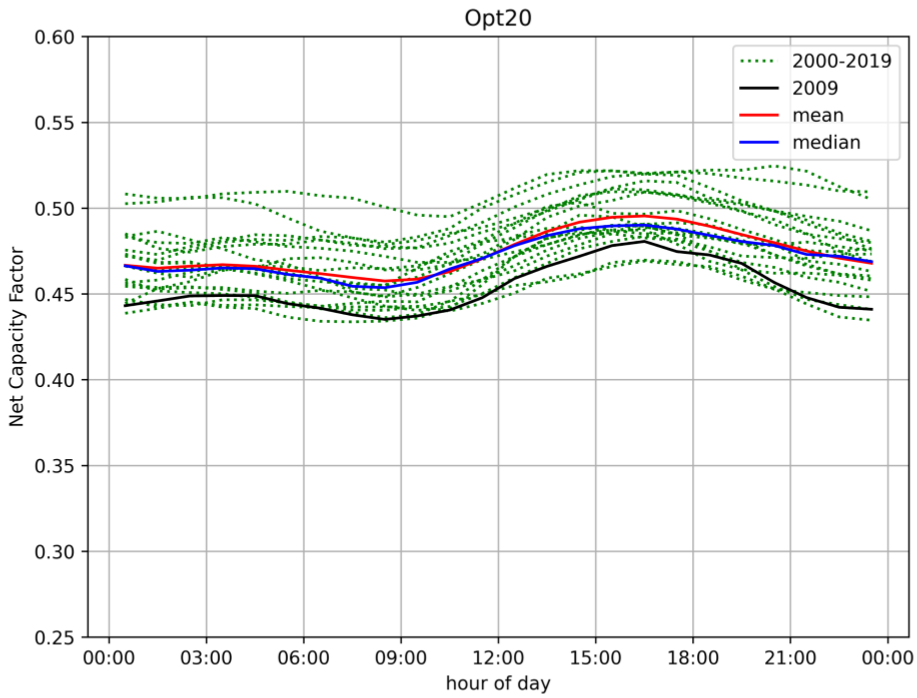


Figure 55. Net capacity factors by hour of day averaged over the year and over the Opt20 footprint based on 20-years of hourly speed data
Time in local (Pacific) time zone.

Seasonal production indicates particularly robust summer production that is fairly consistent across all hours of day (Figure 56). Lowest production is found in winter months, though net capacity factors remain above 40% in most hours and for most years. Interannual spread is tightest in fall.

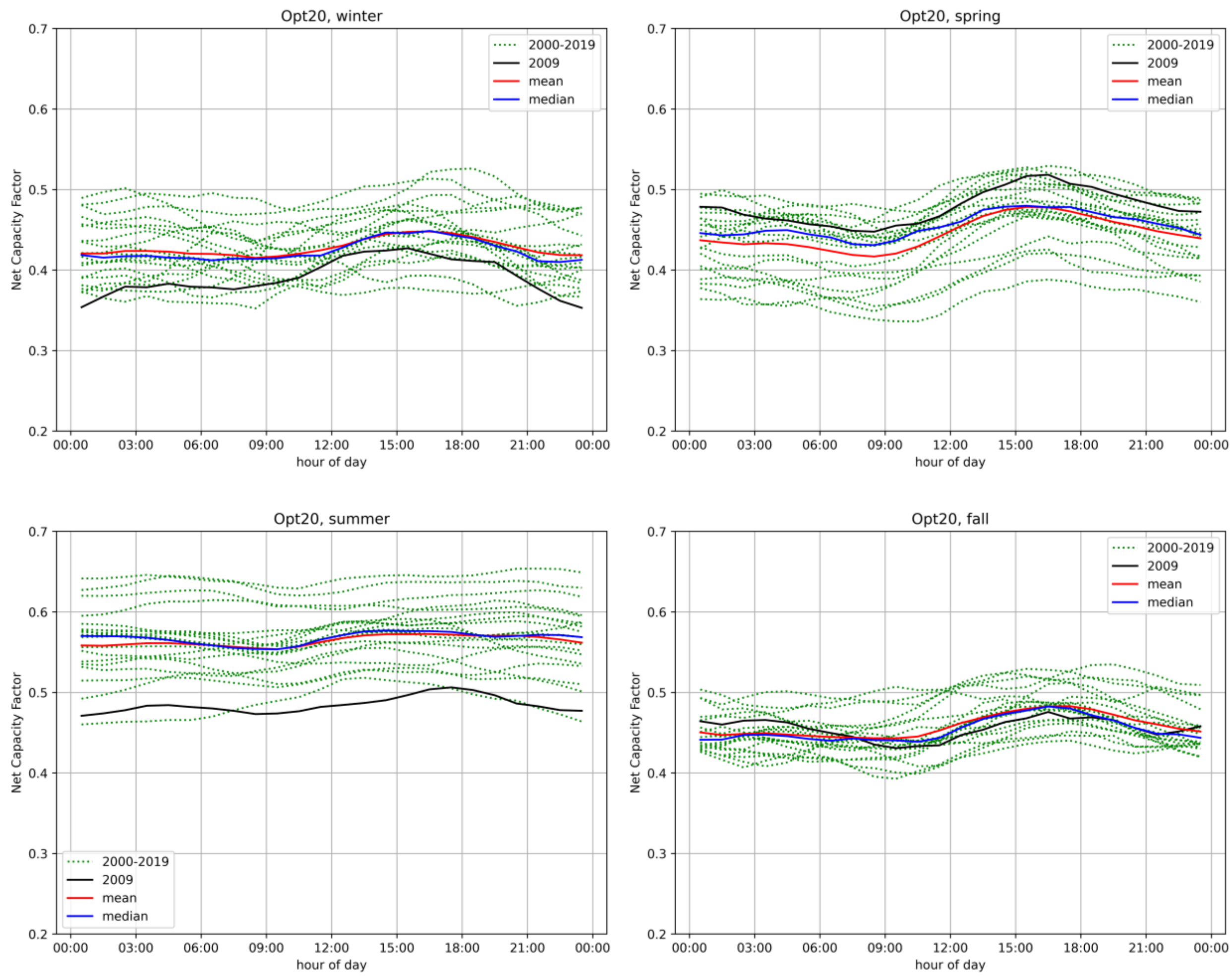


Figure 56. Net capacity factors by hour of day averaged over the four seasons and over the Opt20 footprint based on 20 years of hourly wind speed data
Time in local (Pacific) time zone.

C.5.3 Application of Transmission Limits

Finally, second optimization of the Opt20 footprint selected the locations of highest value to meet the interconnection capacity as revealed through the PCM at eight POIs of interest and then minimized the overall transmission cost, indicating where individual wind power plants would be located to provide power to the onshore POIs of interest. Composition of the optima by intended POI are shown in Figure 57. Wind Power Plants (WPPs) were manually sized to the approximate range of 800-1200 MWs per plant, meaning several POIs were receiving power from multiple WPPs. AC collector systems were linked through park centroids and converters located at the closest centroid to the POI to define Scenario 2 and 3 transmission concepts.

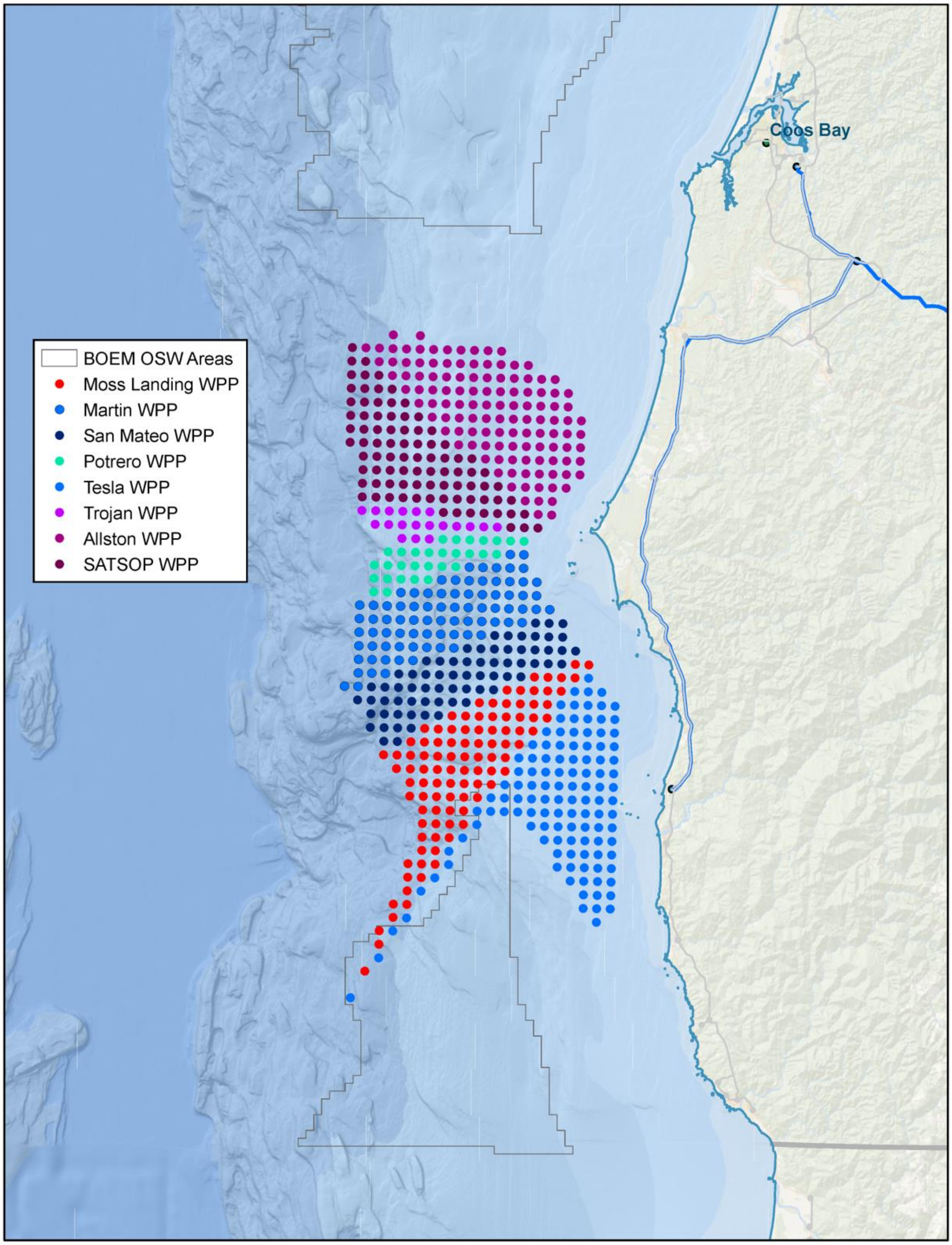


Figure 57. Points of interconnection targets for minimal transmission cost of optimized generation footprint, Opt20

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U.S. Department of the Interior (DOI)
DOI protects and manages the Nation's natural resources and cultural heritage; provides scientific and other information about those resources; and honors the Nation’s trust responsibilities or special commitments to American Indians, Alaska Natives, and affiliated island communities.

Bureau of Ocean Energy Management (BOEM)
BOEM’s mission is to manage development of U.S. Outer Continental Shelf energy and mineral resources in an environmentally and economically responsible way.