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Northern California and Southern Oregon Offshore Wind Transmission Study

Volume 1 (Revised)

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The Schatz Energy Research Center at Cal Poly Humboldt advances clean and renewable energy. Our projects aim to reduce climate change and pollution while increasing energy access and resilience.

Our work is collaborative and multidisciplinary, and we are grateful to the many partners who together make our efforts possible.

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Revision Notes

This report was first published in October 2023. Subsequently, minor errors were detected and this revised report was published in January 2024 with corrections and clarifications. The changes in this revised report include the following:

1. In Figure ES-1 and Figure 21 (the same figure), the order in the legend was changed to match the order of the stacked bars. In addition, the colors and fill patterns for the bars in the chart were modified to make them more accessible.
2. In Figure 3, the fill pattern for the Del Norte planning area was corrected and now matches the legend.
3. For Figure 7, a footnote was added to the caption to better explain the meaning of the dashed black lines and the grey arrows in the figure.
4. In Figure 18, the colors and fill patterns for the bars were modified to make them more accessible.

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List of Acronyms

Acronym / Term	Meaning
AB	California Assembly Bill
AC	Alternating current
ADS	Anchor Data Set
BIOS	Biogeographic Information and Observation System
BOEM	Bureau of Ocean Energy Management
BPA	Bonneville Power Administration
CA	California
CAISO	California Independent System Operator
CAPEX	Capital expenditures
CEC	California Energy Commission
CNDDB	California Natural Diversity Database
CO_2	Carbon Dioxide
COD	Commercial Operations Date
CPUC	California Public Utilities Commission
CSG	Core Steering Group
DC	Direct current
DNV	Det Norsk Veritas Group
DOD	Department of Defense
EIR	Environmental Impact Report
ESO	Electricity system operator
GW	Gigawatt
HVAC	High-voltage alternating current
HVDC	High-voltage direct current
IEA	International Energy Agency
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
ISO	Independent System Operator
ITC	Investment Tax Credit
kV	kilovolts
kWh	kilowatt hour
LCOE	Levelized Cost of Energy
LCOE+T	Levelized Cost of Energy plus Transmission
LCOT	Levelized Cost of Transmission
LMP	Local Marginal Price
MPA	Marine Protected Area
MW	Megawatt
MWh	Megawatt hour
N-1	N-1 contingency (any single component loss)
NERC	North American Electric Reliability Corporation
NMS	National Marine Sanctuary
NREL	National Renewable Energy Laboratory
NYSERDA	New York State Energy Research and Development Authority

Acronym / Term	Meaning
O&M	Operation and maintenance
ODOE	Oregon Department of Energy
OPEX	Operational expenses
OR	Oregon
ORBIT	Offshore Renewables Balance-of-System and Installation Tool
OSW	Offshore wind
PAC-PARS	Pacific Coast Port Access Route Study
Path 66	California Oregon Intertie
PCM	Production cost model
PG&E	Pacific Gas and Electric
POI	Point of Interconnection
PPA	Power Purchase Agreement
PTC	Production Tax Credit
RETI	California Renewable Energy Transmission Initiative
RTO	Regional Transmission Operators
Schatz Center	Schatz Energy Research Center
TARA	Transmission Adequacy & Reliability Assessment
TFG	Technical Focus Group
TMY	Typical Meteorological Year
TPP	Transmission Planning Process
TWh	Terawatt hours
U.S.	United States of America
UK	United Kingdom
USCG	United States Coast Guard
VO&M	Variable operation and maintenance
VSC	Voltage Source Converter
WEA	Wind Energy Area
WECC	Western Electricity Coordinating Council

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EXECUTIVE SUMMARY

Offshore wind (OSW) power based on floating technology in the coastal waters of the U.S. Pacific Ocean has great potential to contribute to climate mitigation and renewable energy goals in California, Oregon, and other parts of the western U.S. To achieve development of OSW at scale, investments in transmission infrastructure are needed to deliver this power to major metropolitan areas because these are the primary electricity load centers. Currently the transmission infrastructure serving coastal regions where OSW is most likely to be developed has limited capacity and is designed to bring power from the east to serve modest coastal loads. The development of OSW generation and the interconnection of this resource to the bulk power grid will require major investments in new transmission infrastructure and upgrades to existing infrastructure. This study investigated the development of up to 25.8 GW of OSW energy on the northern coast of California and the southern coast of Oregon. The focus of the study was to assess various transmission alternatives that could deliver OSW power to distant load centers while also providing energy benefits to rural coastal communities near to where OSW power may be developed.

Scope, method and approach

This study explored transmission solutions for regional OSW development ranging from about 7 GW to almost 26 GW of total installed capacity in the OSW study area, which ranged from Coos Bay, Oregon in the north to Cape Mendocino, California in the south. Three development scenarios were considered (Low, Mid and High), and for each scenario multiple transmission alternatives were considered. This included two alternatives in the Low scenario, six alternatives in the Mid scenario, and two alternatives in the High scenario. The scenarios and the transmission alternatives considered were informed by a review of prior research and studies on the topic, as well as by direct input from the project's Technical Focus Group (TFG).

The key goals of the study were to assess the cost and function of each of the transmission alternatives. This involved the specification of proposed new transmission infrastructure, both onshore and offshore, that could accommodate the OSW development, followed by a steady-state power flow analysis to assess the need for additional transmission system network upgrades. We then estimated the cost of the new transmission infrastructure and the required network upgrades using accepted cost guidelines. This was followed by a production cost analysis that allowed us to determine how much wind power could be injected into the system throughout the year, how much would need to be curtailed, what the wholesale value of the power and the systemwide benefits electricity benefits might be. Finally, we determined the levelized cost of energy and the levelized cost of transmission for each of the alternatives, as well as the system-wide benefits. We then compared the results across alternatives and drew conclusions.

Going beyond an electrical assessment of the transmission alternatives, we also conducted preliminary assessments related to potential barriers to onshore and offshore transmission development and routes, including consideration of existing uses and designations (e.g., marine protected areas, fishing grounds, and DOD operational areas), logistics, geo-physical constraints, rights-of-way, environmental impact, and permitting.

Study areas, scenarios and transmission alternatives

Five wind study areas were defined. Three of these were based on areas defined by the Bureau of Ocean Energy Management (BOEM), including the Coos Bay and Brookings Call Areas in Oregon and the Humboldt Wind Energy Area in California. The other two locations were notional (i.e., hypothetical) areas offshore from Del Norte County, California and Cape Mendocino, California. Selection of these notional areas was informed by preliminary sea space analysis led by the California Energy Commission. The assumed OSW development in these five study areas totaled 7.2 GW for the Low development scenario, 12.4 GW for the Mid development scenario, and 25.8 GW for the High development scenario. We then defined two transmission alternatives for the Low development case, six alternatives for the Mid development case, and two more alternatives for the High development case. The transmission alternatives included an assessment of the following technologies and configurations:

- onshore and offshore transmission routes,
- high-voltage AC (HVAC) and high-voltage DC (HVDC) solutions,
- long-distance offshore transmission routes via undersea HVDC cables,
- radial connections from individual wind farms to immediate onshore landing locations,
- offshore meshed networks with shared HVAC buses,
- an HVDC backbone that connects multiple wind farms, and
- the use of phase shifting transformers to allow lower voltage, local transmission systems to receive power from the gigawatt-scale wind farms being studied.

We note that some of the necessary technologies for large-scale development of floating OSW power are neither fully developed nor commercially available at this time. This is also true for many of the offshore transmission technologies we considered (i.e., floating substations, floating HVDC conversion stations, dynamic high-capacity HVAC and HVDC cables). Therefore, we made assumptions regarding technologies that are expected to be available in the coming years, and our assumptions are described and documented in the report. Actual feasible future configurations, especially for the larger configurations involving offshore meshed networks on floating platforms, may differ in some aspects from those described in this report. In particular, the larger-scale scenarios (i.e., 12.4 GW and 25.8 GW) are more likely to feature a mix of HVAC and HVDC export cables in the later phases of development, as this would allow early development with HVAC export cables and later development with HVDC export cables. Table ES-1 summarizes the characteristics of the 10 transmission alternatives investigated.

Table ES-1. Characteristics of the ten transmission alternatives considered in the study

Characteristic	Alt. 7.2a	Alt. 7.2b	Alt. 12.4a	Alt. 12.4b	Alt. 12.4c	Alt. 12.4d	Alt. 12.4e	Alt. 12.4f	Alt. 25.8a	Alt. 25.8b
Total wind farm capacity (GW)	7.2	7.2	12.4	12.4	12.4	12.4	12.4	12.4	25.8	25.8
CA wind farm capacity (GW)	4.1	4.1	9.3	9.3	9.3	9.3	9.3	9.3	16.0	16.0
OR wind farm capacity (GW)	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	9.8	9.8
Offshore HVDC backbone connecting wind farms	No	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes
Offshore HVDC mesh network	No	No	No	No	No	No	Yes	Yes	Yes	Yes
No. of HVAC undersea export cables	9	9	14	14	14	9	3	3	0	0
No. of HVDC undersea cables	0	2	2	5	3	5	8	10	27	22
No. of floating HVAC substations	9	9	14	14	14	9	3	3	0	0
No. of floating HVDC conversion stations	0	0	0	0	5	8	7	8	15	15
No. of new onshore 500 kV HVAC transmission lines	7	7	7	8	7	8	6	8	11	15
No. of new onshore 500 kV HVAC substations	5	5	3	5	5	5	5	5	5	5
No. of new onshore HVDC transmission lines	0	1	1	1	0	1	2	1	1	1
No. of new onshore HVDC conversion stations	0	3	3	4	1	2	5	4	8	7
No. of new phase shifting transformers	5	6	5	8	6	8	7	7	9	8

Subsea cable routing considerations

The study included a high-level assessment of the challenges and opportunities associated with deploying subsea electrical cables that will be necessary to transmit OSW power to shore, as well as overland transmission routes that will be necessary to interconnect the OSW power to the bulk electric system and get it to the major load centers where it can be utilized. Publicly available data for the study region were compiled to inform the assessment, and several key considerations were identified. Offshore cable routing challenges can include:

- Challenging bathymetric and geophysical characteristics, including submarine canyons, turbidity flows, fault lines and seismic displacement, substrate conditions, and steep slopes
- Usage conflicts, including U.S. Department of Defense operational areas, vessel traffic, fairway designations, cable landing locations, existing submarine cable locations, fishing grounds and marine protected areas
- Deeper water depths, which present challenges associated with cable laying, siting, and repair
- Required spacing between cables, which increases with depth
- Cable landfall challenges, including roads and access, shipborne access to deep water (cable lay vessels require approximately 30 feet of water depth), and existence of marine protected areas or national marine sanctuaries

Key findings include the understanding that the depth-limitation for undersea electrical cables is a critical factor in establishing subsea cable routes. It may be preferable for several reasons (e.g., vessel traffic density, MPAs, submarine canyons, seismicity, fault lines and displacement potential, etc.,) to route subsea electrical transmission cables further from shore. Exporting power to major load centers, such as the San Francisco Bay Area, would therefore require routing cables further offshore if subsea transmission were pursued. However, doing so may require laying transmission cable onto the abyssal plain at depths greater than 3,000 meters. At present, transmission cable installation at such depths is not possible due to the technological limitations of existing cables. However, industry is working to relax these depth constraints, but the timeline for development and market readiness for such cables is not yet known.

Additionally, areas for cable landfall are limited, and selecting those areas will need to consider submarine canyons, the slope of the continental shelf, and water depths where cable lay vessels may safely operate while still staying within the typical distance limit for an onshore cable pull-in of 3,280-4,920 ft (1,000-1,500 m). All of these factors were considered at a high level to develop a conceptual map of potential or notional undersea cable corridors for the transmission alternatives examined in this study.

Transmission route feasibility

The study included a preliminary assessment of factors that could influence the feasibility of potential transmission line routes, both undersea and overland. This effort involved identifying potential environmental concerns and permitting or regulatory challenges associated with the transmission routes being studied. Areas of examination included cable landfall locations, subsea cable and overland transmission line corridors, land ownership or designation, sensitive marine and terrestrial habitats, and potential for interaction with special-status plants and wildlife (e.g., Federal and State Endangered Species Acts). Based upon the potential environmental impacts and subsequent permitting complexity, the line segments were screened, compared and differentiated. Each line segment was ranked based on potential barriers to development, ranging from low to very high barriers to development. In addition, we attempted to identify areas where potential transmission routes could overlap with military utilized airspace, and we note that it will be critical to ensure early consultation with the DOD during preliminary planning stages for any potential projects that include overlap with military utilized airspace.

Further analysis is warranted to identify which transmission segments are most feasible to permit. The geographic layout for the transmission line routing would need to be further defined, including whether existing segments would be expanded or new lines and easements would be created altogether. Future analysis would also use additional data, including tower locations, tower height, undergrounding or reconductoring of existing lines, expansion of rights-of-way and easements. Also, the specific locations and footprints of any new substations or HVDC converter stations would need to be further evaluated. Ground truthing of sensitive ecological communities would also be recommended to confirm habitat types and potential presence of plant and/or animal species of regulatory concern. For subsea routes, future analysis would make use of more robust oceanographic surveys, as well as available geophysical datasets regarding seabed characteristics, substrate types, and the presence of specific benthic communities.

Transmission analysis results and cost estimation

For each of the alternatives, we estimated the transmission related cost for new offshore and onshore infrastructure, as well as the need for upgrades to existing transmission infrastructure. The total cost of transmission, both onshore and offshore, across the 10 alternatives ranged from $7.5 billion (7.2 GW scenario) to $41.3 billion (25.8 GW scenario). We assumed an OSW farm CapEx of $3,500/kW to $3,700/kW.[1] The total transmission costs accounted for 23% to 32% of the combined wind farm and transmission system costs across all 10 alternatives. One characteristic that clearly drove transmission costs up was longer undersea cable runs. See Figure ES-1 for a summary of costs for the 10 transmission alternatives.

We structured our analysis so we could assess the tradeoffs between the use of HVAC versus HVDC infrastructure. This included examining alternatives that featured only HVAC infrastructure, and others that relied heavily on HVDC infrastructure. We also examined alternatives that put more emphasis on onshore infrastructure, and others that included substantial offshore infrastructure. In general, we found the alternatives that emphasized the use of HVDC infrastructure were more expensive. However, we note that the cost estimates for much of the HVDC infrastructure involve equipment that is not yet commercially available, so this observation is uncertain and could change as new information about equipment costs becomes available.

[1] These costs are reported in 2022 dollars, assume a wind farm deployment in the year 2032, and assume cost decreases as the nascent floating OSW industry matures.

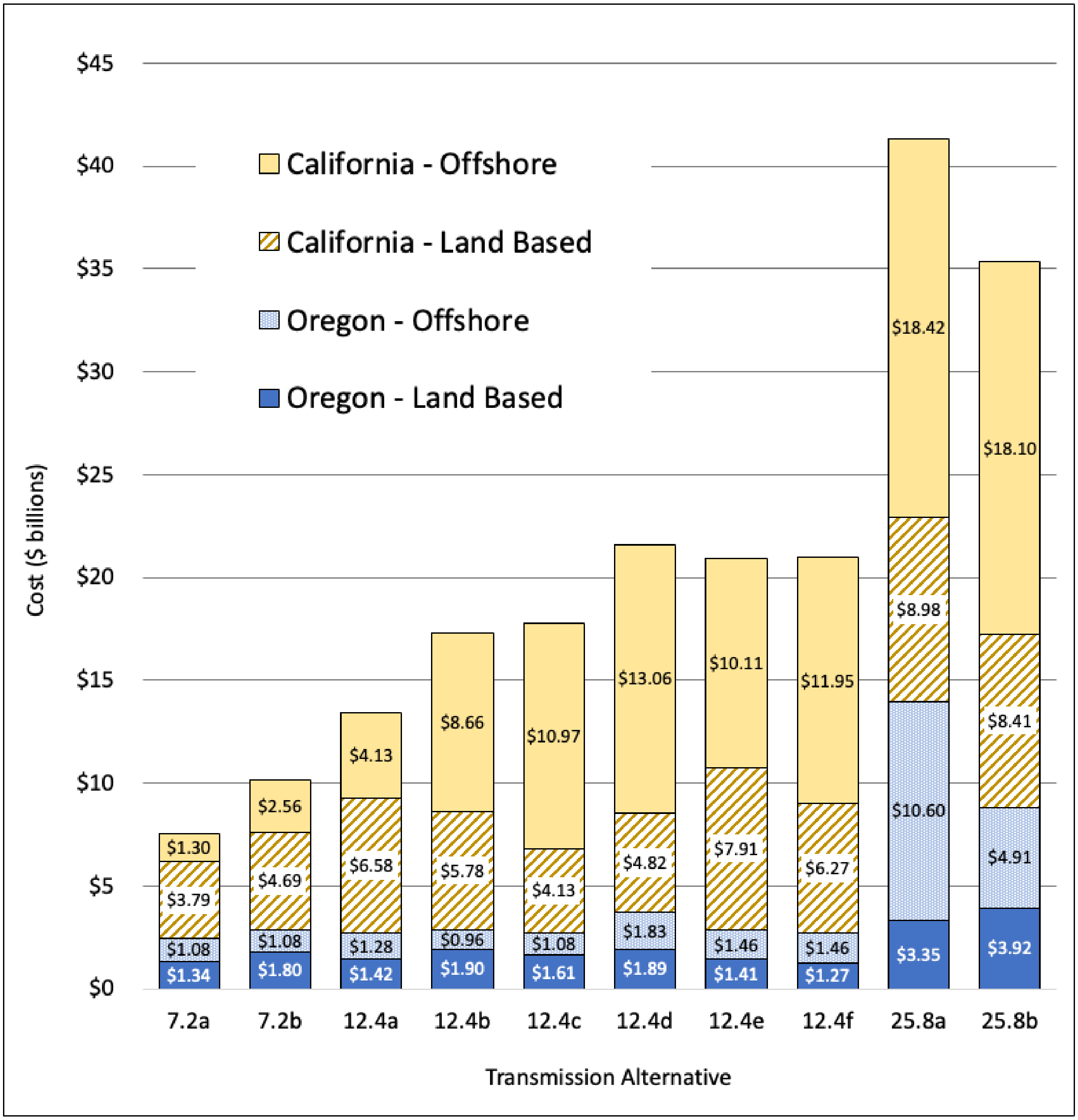

Figure ES-1. Estimated transmission costs for land-based and undersea infrastructure in California and Oregon

Although HVDC infrastructure appears to be more expensive in the alternatives we examined, there are reasons why HVDC infrastructure might be preferred. For example, if there is a desire to utilize a meshed offshore transmission network, which can offer many advantages, then HVDC technology will likely be critical on the West Coast. This is because there are likely to be long distances between adjacent wind farm areas and between the wind farms and the load centers where the power is most needed. Since undersea HVAC cables are limited in terms of the distance that they can efficiently transmit power (i.e., roughly 60 miles maximum), HVDC technology becomes critical for alternatives featuring long-distance undersea transmission.

It is also important to note that the cost to develop necessary transmission infrastructure is only one aspect of OSW power development to be considered. There will be other costs, such as permitting and environmental mitigation costs, that were not considered in this study. Perhaps more importantly, this study only conducted a very preliminary assessment of the environmental and permitting challenges that might be encountered for each of the alternatives examined. Further research in this area will be critical to the transmission planning and decision-making process. In addition, a full assessment of multiple types of costs and benefits that compares systemwide aggregate benefits to costs should be conducted to ensure a holistic cost-benefit approach that can effectively identify the most cost-effective solutions.

We also examined the cost to connect local coastal communities to the new transmission infrastructure installed to support wind power generated off their coasts. Such connections can benefit communities by improving electricity reliability and expanding capacity in these areas. We found that this cost was relatively low, accounting for about 0.4% to 2.4% of estimated total transmission costs. Finally, we examined the geographic distribution of costs and found that the distribution by region varied across the alternatives, but in general a large portion of the costs could be attributed to offshore infrastructure in some alternatives, and more to onshore infrastructure in others. In terms of onshore infrastructure, the results again varied by alternative, but it was common for a large portion of the cost to be attributed to the Central Valley of California, the San Francisco Bay Area, and the Humboldt area in California, and the BPA and PacifiCorp territories in Oregon.

Production cost and levelized cost of energy results

Production cost modeling (PCM) allowed us to simulate the performance of the various transmission alternatives on an hourly basis over a full year. For any given run, the production cost model determined the most cost-effective mix of generation resources that could be dispatched to meet the hourly loads across the entire WECC region while satisfying all of the transmission system constraints. The PCM results provided us with an estimate of the annual curtailment of wind power that would be necessary for any given alternative. Curtailment was very low, ranging from 0.6% to 2.4%. In addition, the PCM results provided us with an estimate of the annual revenues that could be generated in the wholesale market, as well as the system-wide benefits in terms of production cost savings and CO_2 emissions savings. Estimated potential wholesale revenues ranged from $44/MWh to $54/MWh. Systemwide production costs savings ranged from $0.6 billion to $1.7 billion per year, and CO_2 emissions savings were estimated to be worth $0.6 billion to $1.2 billion per year. All dollar values are provided in 2022 dollars and estimated for the study year of 2032.

The PCM results also provide an indication of how well the new transmission infrastructure would be utilized. For example, the model showed us that the proposed new transmission lines in the 12.4 GW alternatives would be utilized at relatively high capacity. Nearly half the new lines would be used at full capacity at least part of the time, and the aggregate of all new lines in each alternative were utilized at an average annual capacity of about 35% to 50%. In addition, we found that new transmission infrastructure built to accommodate OSW development, whether it be onshore or offshore, can also serve other transmission system needs by providing additional routes for power flow. This can lead to lower cost systemwide power flow solutions, potentially resulting in substantial savings to ratepayers.

We estimate that the OSW plant LCOE in 2032 would be between $64/MWh and $66/MWh. By 2050, the LCOE could fall to $46–$47/MWh. The combined cost of OSW and transmission, LCOE+T, is between $77/MWh and $85/MWh for a commercial operations date of 2032. Revenues estimated using the production cost model for the 7.2 GW and 12.4 GW alternatives ranged from $44/MWh to $54/MWh, lower than the 2032 LCOE or LCOE+T. However, this conclusion is limited to the specific year and revenue structure (i.e., market price with $25/MWh production tax credit) that were modeled in this study. Additional work would be required to explore the effects of alternatives such as electricity sales through power purchase agreements (PPAs), utilization of the investment tax credit instead of the production tax credit, and an extension of the revenue analysis to years beyond 2032.

With regard to the cost-effectiveness of various transmission alternatives and a comparison between them, we stress the importance of examining both the costs and the benefits for the alternatives, and the benefits should include the direct OSW transmission related benefits, as well as broader systemwide benefits. Production cost model results indicate that the system-wide production cost savings throughout the Western Electricity Coordinating Council (WECC) region could amount to $0.6 billion to $1.5 billion annually, representing about 4% to 11% savings. In addition, the value of the estimated CO_2 emissions reduction amounts to another $0.5 billion to $1.1 billion annually.

Key findings

The northern Coast of California and the southern coast of Oregon have some of the best wind resources in the United States, and development of these resources can contribute to meeting the clean energy goals of California, Oregon, and other western states. Because the existing transmission grid infrastructure that serves these coastal regions is limited in capacity, major investments in new transmission grid infrastructure will be needed.

Numerous studies, including Pfeifenberger, J., et al. (2023), have demonstrated the importance of and the benefits associated with proactive transmission planning to accommodate the development of renewable energy resources at the gigawatt scale. If the development of OSW projects and their associated transmission upgrades were to occur piecemeal over time, it is likely that the long-term result will be less than optimal. Studies show that proactive, long-term planning can reduce costs, environmental and community impacts, transmission congestion, and OSW curtailment, while increasing reliability and grid services. To accomplish this, policy makers and transmission planner should facilitate a coordinated, integrated planning effort for major transmission upgrades at a regional scale to accommodate many gigawatts of OSW power on the West Coast of the United States.

The development of tens of gigawatts of floating OSW power generation on the West Coast will not occur quickly; a successful effort would take decades, and the associated transmission upgrades would also take place over decades. A proactive and coordinated transmission planning effort with a long-term outlook should be initiated very soon. This planning effort should consider how early investments in transmission infrastructure can set the stage for subsequent phases of investment. It should also identify the most cost-effective pathways over the long term, recognizing that this may involve spending more upfront to make sure that the infrastructure can accommodate future growth and development while meeting the needs of both rural and urban constituencies. In general, we recommend transmission planning efforts that consider a 25-year time horizon and that identify near-term transmission upgrades that are well-positioned to support a future vision. This long-term and proactive transmission planning approach may also include an assessment of regionalization of transmission planning, grid operation, and wholesale power markets. While studies have shown that there are many possible benefits associated with regionalization (Hurlbut et al. 2023), there may also be risks that need to be assessed and mitigated, and various approaches to be considered.

Most OSW projects to date have utilized radial interconnections between the wind generators and the transmission system. This approach connects the generators to the nearest suitable onshore substation via dedicated export cables. In this configuration, the wind farm owner usually owns and maintains the export cables, since they are used solely to connect their wind generators to the grid. This radial approach tends to be the simplest and lowest cost solution when the scale of development is low, the point of interconnection is relatively close by, and the transmission grid is already robust enough to readily accept the new generation.

However, with gigawatt-scale OSW development from multiple wind farms, the radial interconnection approach becomes problematic, with too many undersea cables, too many onshore landings, and a lack of coordinated planning. Therefore, a more regional, meshed network approach may be preferable. The benefits of the meshed network can be many, including fewer cables and lower associated impacts, reduced curtailment, more optimal power flows, and improved reliability and resilience. These benefits have been documented in prior studies done on the East Coast (Pfeifenberger et al. 2021; USDOE and BOEM 2023) and Great Britain (DNV 2020). On the U.S. West Coast there are long distances between the large OSW resources located on California's northern coast and Oregon's southern coast and the major load centers of San Francisco, Sacramento, Los Angeles, Portland and beyond. To deliver power over these long distances, a meshed HVDC network technology may offer the best solution, although multiple technology advances are needed to enable this possibility in the deep waters of the U.S. West Coast. While localized offshore HVAC mesh systems may also play a role, a long-distance offshore mesh system will require HVDC technology.

In addition, the work being done on the East Coast has found that a phased approach for a mesh network design would be preferable. The researchers identified "mesh ready" infrastructure that could be installed in the near-term, and that would allow the addition of cables at a later date that could interconnect the multiple nodes in the network. The researchers estimated no more than a 1% cost increase in the first phase to be mesh-ready, and another 3% to 6% cost increase for full implementation of the meshed system. This approach and these cost increases were for an HVAC meshed system. It may be possible to take a similar approach with an HVDC mesh system, but that would need to be researched and costs would need to be estimated.

With integrated mesh transmission systems, where the infrastructure may be shared amongst multiple wind farm developers, it becomes particularly important to determine who should pay for, own, and operate the transmission infrastructure. The offshore mesh network will likely become part of the overall transmission network, and will therefore also serve to move onshore power from one onshore location to another onshore location via the offshore infrastructure. This suggests that the offshore mesh network is part of the overall grid and should be managed by the transmission operator rather than the OSW generator. The question of who should pay for, own, and operate offshore transmission infrastructure is a policy and regulatory issue that must be resolved to facilitate the necessary planning and future development of the transmission infrastructure needed to support OSW development.

Recommendations

We offer the following recommendations for further research and next steps.

- Build on the work that has been done to conduct a detailed analysis of routes and rights-of-way for promising transmission pathways that are relevant to initial gigawatt-scale OSW development in northwestern California.
- Examine the potential role of energy storage in supporting OSW development.
- Conduct an exhaustive assessment of transmission alternatives for OSW on the northern coast of California and southern coast of Oregon.
- Examine phased approaches to regional transmission development.
- Examine regionalization of the western power market, as well as transmission planning, development and operation.
- Conduct more rigorous transmission cost-benefit analyses that examine multiple types of needs and benefits and compare aggregate, systemwide benefits to costs.
- Engage with industry and installation contractors to better assess floating transmission component development timelines, limitations, supply chain issues and market readiness.
- Develop comprehensive transmission cost-benefit analysis for various offshore topologies considering technological readiness and challenges for initial rounds of OSW plant developments.

1 BACKGROUND

Since 2019, the Schatz Energy Research Center (Schatz Center) at Cal Poly Humboldt has engaged in planning and feasibility studies related to the potential development of floating offshore wind (OSW) energy off the northern California coast. In this study, a project funded by the Department of Defense (DOD) and managed by the California Energy Commission (CEC) in collaboration with the Oregon Department of Energy (ODOE), the Schatz Center has led an analysis, working with partners, to better understand the opportunities and challenges associated with the transmission infrastructure that is needed to support gigawatt-scale OSW energy development off the northern California and southern Oregon coasts. These areas have some of the most abundant OSW resources in the United States, and their development has great potential to contribute to the climate and clean energy goals of California, Oregon, and the nation. However, these coastal areas are distant from the major load centers and the electrical transmission infrastructure is limited. Significant investment would be required to expand the bulk transmission system to develop this gigawatt-scale OSW resource. The expanded infrastructure would likely include the creation of new offshore and subsea infrastructure, new onshore and offshore substations, and new onshore and offshore transmission lines, as well as upgrading the existing onshore infrastructure.

Lacking major population centers or large-scale industrial and manufacturing facilities, the northern California and southern Oregon coastal regions are currently served by limited grid infrastructure that is designed to bring power from large transmission lines east of the coastal mountains to meet the modest loads in the coastal communities. In Humboldt County, California, for example, arterial transmission lines feeding the county consist solely of two 115 kilovolt (kV) lines running east-west, and two 60 kV lines, one running north-south and the other running east-west. Previous Schatz Center studies have looked at the potential for export of electricity from proposed OSW energy generators located offshore of Humboldt County and found that only a small capacity wind farm, on the order of 140 to 170 MW, could be accommodated using existing transmission infrastructure (Jacobson et al. 2022). Southern Oregon's coastal electrical grid is slightly more robust, utilizing 230 kV lines running along the coastline, but the transmission system is still designed to bring power from the east to serve the modest coastal loads. Therefore, exporting gigawatts of OSW power from this region to major load centers will require significant transmission upgrades.

Figure 1 displays the project study area within the larger Western Electricity Coordinating Council (WECC) regional footprint. Figure 2 provides a qualitative look at the relative capacities of the transmission lines serving the coastal areas being considered. The thickness of the lines is indicative of the line voltage, with thickener lines indicating higher voltages and therefore greater transmission capacity. The thickest purple line that runs nearly the length of the north-south map is a high-voltage direct current (DC) line, called the Pacific DC Intertie. It connects large-scale hydroelectric power in the Pacific Northwest to the Los Angeles area. The next thickest lines represent 500 kV alternating current (AC) lines. These run primarily north-south along the Interstate Highway 5 corridor and also connect to large load centers and power plants. The rest of the lines shown are primarily intended to serve regional loads. The next thickest lines represent 230 kV AC lines, after which thinner 115 kV AC lines are represented, and finally the thinnest lines shown represent 60 to 69-kV AC lines.

As visible in Figure 2, coastal communities in southern Oregon are primarily served by 230 kV and 115 kV lines, whereas the northern California coast is primarily served by 115 kV and 69 kV lines. What is less evident from Figure 2 is that these coastal transmission lines pass through rugged, mountainous, and fire prone regions, which can add greater risk for outages. Notably, OSW energy development presents an opportunity to provide a reliable and resilient form of clean energy to these somewhat remote, rural communities. However, the presence of OSW generators alone will not guarantee that the coastal communities hosting these installations will benefit from the energy generated. Indeed, an underlying goal in this study was to explore transmission alternatives that could provide energy benefits to local communities, while also cost-effectively transmitting gigawatts of power to more distant electrical load centers.

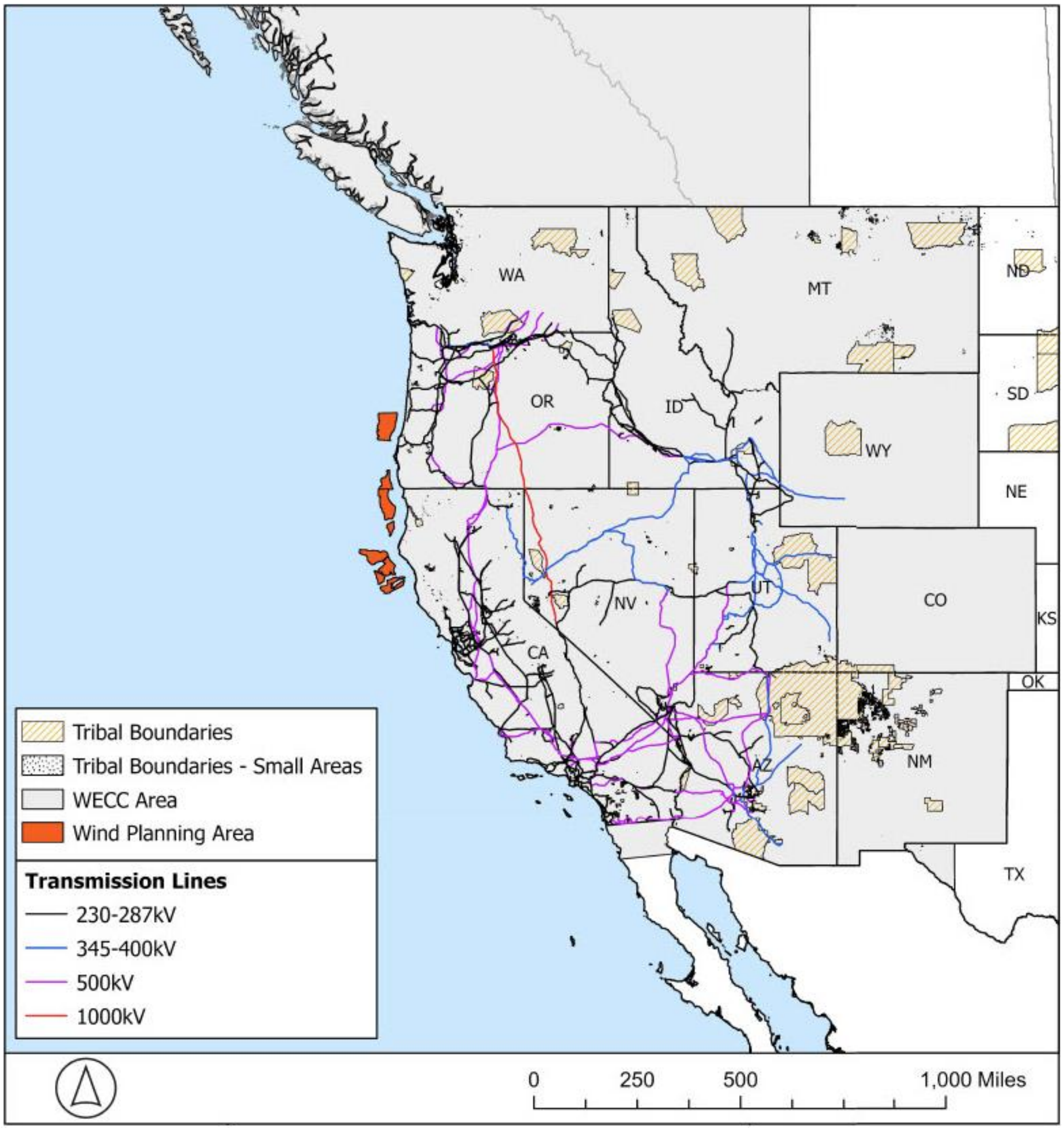

Figure 1. Broad overview of project study area and Western Electricity Coordinating Council (WECC) regional footprint

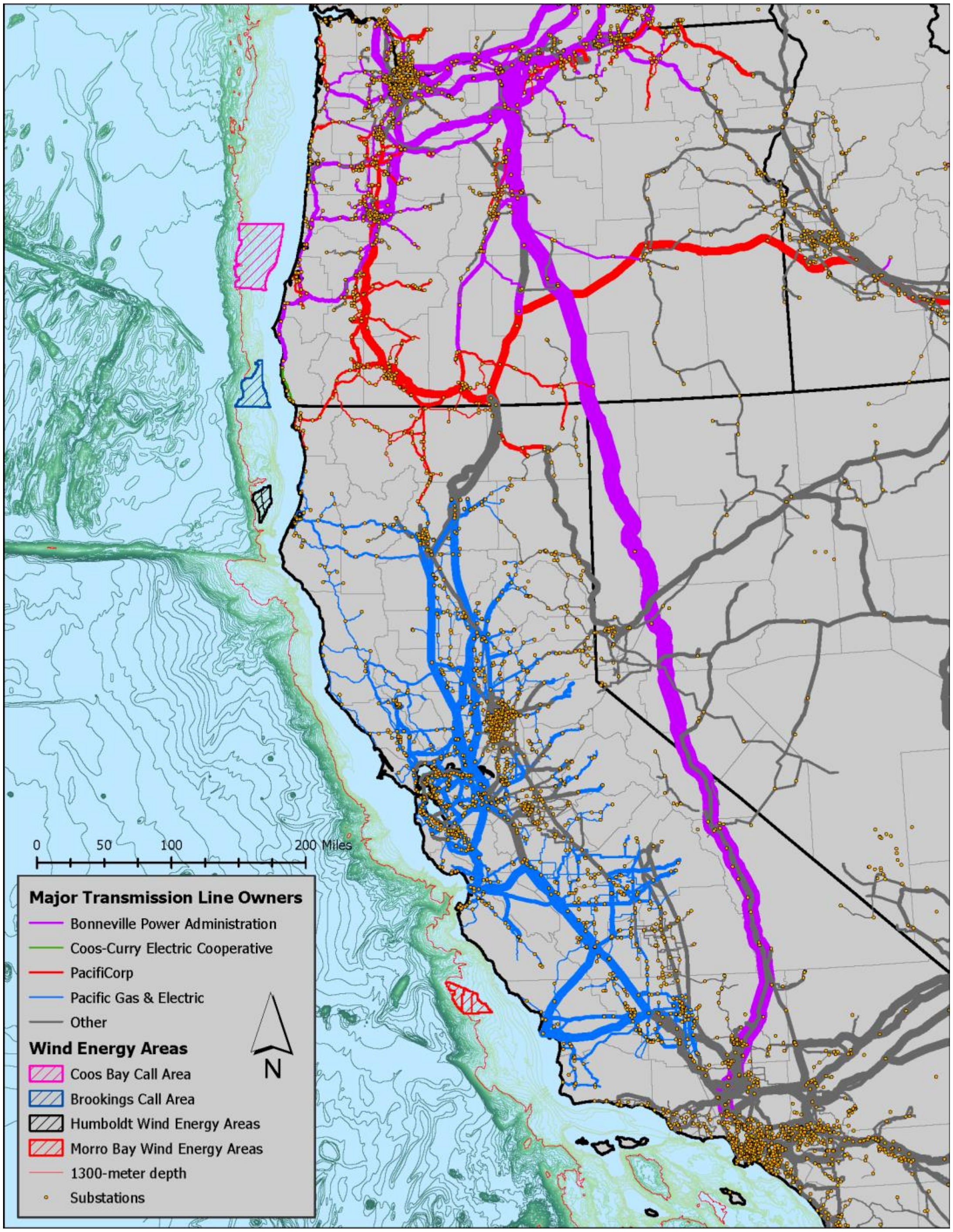

Figure 2. Existing transmission infrastructure and officially delineated BOEM "Call" or "Wind Energy Areas" in California and southern Oregon.[2] Line thickness corresponds to line voltage.

[2] We note that the Oregon call areas have been updated and reclassified as wind energy areas by BOEM since this map was generated. Our adjustments that account for restrictions as discussed in Section 4 largely account for the BOEM updates. The updated Oregon Wind Energy Areas can be found here: https://www.boem.gov/renewable-energy/state-activities/Oregon

2 Scope, Methods, and Approach

This study examined 10 alternatives for building new bulk electrical transmission infrastructure that could support gigawatt-scale OSW projects with up to 25.8 GW in installed capacity in a region spanning from Cape Mendocino in northern California to Coos Bay in southern Oregon. The study examined possible OSW development in five OSW study areas and assessed the expected costs and benefits associated with 10 transmission alternatives.

One of the first tasks was to convene a Technical Focus Group (TFG). The purpose of the TFG was to help us make well-informed choices about the input data sets we would use for the transmission analyses and the alternatives we would consider. We engaged a group of stakeholders, including transmission planners, regulators, and policy makers. We drew on their technical expertise and real-world experience to help ensure that our study was well informed and produced outcomes that were relevant and valuable. In addition to the CEC, ODOE, and DOD, individuals from the following organizations participated in our TFG:

- Aspen Environmental Group
- Bonneville Power Administration
- California Independent System Operator
- California Public Utilities Commission
- Coos-Curry Electric Cooperative
- NorthernGrid
- Oregon Public Utilities Commission
- PacifiCorp
- Pacific Northwest National Laboratory
- Pacific Gas & Electric Company
- Portland General Electric
- United States Bureau of Ocean Energy Management

2.1 Key questions to be answered

With input from our TFG, we identified the following key questions to be answered in this study:

- How can we deliver OSW power in a cost-effective manner to where it can be absorbed into regional transmission systems?
- How can we ensure coastal communities receive benefits (energy and other benefits)?
- How can we ensure that OSW development contributes to grid resilience and reliability?

In addition to these key questions, our goals included identifying possible policy and market challenges and opportunities related to OSW development, and identifying key next steps for research and planning efforts that can move the development of OSW power on the West Coast forward. The key questions and issues noted were explored by comparing the 10 transmission alternatives in light of results from the analyses we conducted. This included power flow analyses, production cost modeling, technology readiness and logistical considerations, and high-level permitting assessments.

2.2 Methodology

The methodology we followed is outlined in the list below. In the sections that follow, we briefly describe the methodology and present the results we generated. Finally, we compare the costs and benefits across the various transmission alternatives and discuss key conclusions from our research.

- **Section 3. Review existing studies** - We identify and review relevant literature that examines OSW energy development and transmission infrastructure in the region.
- **Section 4. Define OSW study areas** - We define the OSW areas that we evaluated and discuss the restrictions that were considered.
- **Section 5. Define OSW development scenarios** - We define the scale of OSW energy development that we studied and we describe the process for generating estimates of hourly OSW energy generation annual profiles.
- **Section 6. Develop transmission alternatives** - We describe the process used to develop the 10 transmission alternatives that we studied, and we briefly describe the alternatives. This includes a high-level assessment of permitting and environmental challenges associated with various onshore and offshore transmission routes.
- **Section 7. Transmission analysis methodology and results**
    - **Power flow analysis** - We describe the power flow analysis and results. This analysis was used to determine the transmission system network upgrades needed to accommodate the new OSW energy generation.
    - **Cost estimation -** We describe the estimation process for determining the cost of new transmission infrastructure and upgrades.
    - **Production cost modeling -** We describe the production cost modeling analysis. This analysis allowed us to estimate how much wind power could be injected into the transmission system, how much might need to be curtailed, and what the value of the power could be.
- **Section 8. Transmission alternative cost results** - We present the cost results determined from the analyses discussed in the previous section and we compare and contrast the costs of the 10 transmission alternatives.
- **Section 9. Production cost modeling results** - We present the results of the production cost modeling analysis. This includes estimates of annual OSW energy generation, as well as curtailed energy, estimates of average wholesale market pricing and resulting potential revenues from the generated OSW energy, and estimates of the systemwide production cost benefits associated with each of the alternatives examined.
- **Section 10. Levelized cost of energy and transmission** - We discuss the methodology and present results for the levelized cost of energy (LCOE) and levelized cost of transmission (LCOT) in \$/MWh. This allows the cost of the various alternatives to be further compared with each other.

- **Section 11. Potential revenue sources** - We discuss the assumptions behind the potential revenue estimates generated via the production cost model and present alternate revenue structures that could be examined.
- **Sections 12 and 13. Discussion of results, conclusions and recommendations** - We discuss the overall results of the study, highlight key findings, and suggest further research that could help move the possible development of OSW energy on the West Coast forward.

2.3 Approach

This study explored transmission solutions for regional OSW development ranging from about 7 GW to almost 26 GW of total development in the study area. Three development scenarios were considered (Low, Mid and High), and for each scenario multiple transmission alternatives were considered. This included two alternatives in the Low scenario, six alternatives in the Mid scenario, and two alternatives in the High scenario. The scenarios and the transmission alternatives considered were informed by a review of prior research and studies on the topic, as well as by direct input from the project's TFG.

It is important to note that the aim of this study was not to identify the optimal transmission solution for any particular OSW development scenario. Instead, it was to explore a broad range of possible solutions and consider the opportunities and constraints, as well as the potential costs and benefits associated with each alternative.

3 Review of Existing Studies

The key focus of this project is to evaluate OSW transmission options for the northern California and southern Oregon coasts. We examined existing studies that considered the ability of existing transmission infrastructure to accommodate OSW development and the need for new infrastructure. Special focus was given regarding what infrastructure was required and the cost of the infrastructure upgrades, as well as documentation of the benefits provided. Studies were identified through both independent research and with the guidance of the TFG. A full list of studies considered and reviewed can be found in Appendix A. Below is a brief summary of key findings from our literature review.

3.1 Criteria and methodology of transmission analysis

The Atlantic OSW Transmission Literature Review and Gaps Analysis (USDOE 2021) found that existing OSW energy and transmission planning studies were inadequate to plan for the required infrastructure upgrades necessary to realize the United States' 2030 OSW energy deployment goals. Specific gaps were identified and include the following four themes:

- The first theme found studies to be isolated with respect to geographic and oceanic planning. Nearly all studies considered state-specific Independent System Operators (ISOs) or Regional Transmission Operators (RTOs), assuming an individual state has claim to specific OSW resources. This lack of regional coordination was found to have implications for understanding grid interconnection and coordination across the eastern seaboard.
- The second theme identified was a lack of coordination between OSW generation planning and transmission development. As opposed to regional or more broadly

coordinated approaches, it was more common for RTOs and ISOs to use the generator interconnection queue to analyze project specific deployments and to determine transmission requirements to bring individual new generators online.

- The third theme identified was a limited range of technical analysis. In the studies reviewed, the gaps analysis identified a lack of landfall locations, transmission cable routing, and points of interconnection. Additionally, some of the studies that were reviewed assumed technology availability, though additional technology development is still required. In particular, HVDC breakers are referenced as being critical to a meshed offshore transmission network. Without such technology, the reliability benefits of a meshed network may not be achievable. The study authors point out that few HVDC breakers were in operation globally as of the time of the report's publication.
- Finally, the study found that “reliability” and “resiliency” considerations are broadly defined at best, and rely on metrics which may be hard to define. Some studies were found to lack consistency across temporal scales of wind speeds utilized for modeling, and most of the reviewed studies used one year or less of data. With limited temporal scales, reliability or resiliency analyses cannot be realistically modeled because interdecadal variability, including extreme weather events (hurricanes, etc.,), may not be adequately captured, and may therefore be omitted from long term planning and development considerations.

3.2 Existing infrastructure and need for expansion

Previous studies show that the existing transmission infrastructure on the northern coast of California and southern coast of Oregon does not have the capacity to accommodate gigawatt scale OSW power generation, but rather is designed to transmit modest amounts of power from eastern generators to small coastal communities. The transmission network on the coasts of Oregon and California consists of 60 kV, 115 kV and 230 kV HVAC lines.

Early studies looking at transmission capacity in Oregon found that relatively small amounts (2-3 GW) of utility scale generation from OSW could be interconnected with “minimal” transmission investment (Novacheck & Schwarz 2021) and (Douville et al. 2020). However, as we learned from additional sources, the ability of the existing grid in southern Oregon to absorb between 2-3 GW is optimistic under optimal DC power flow assumptions. Additionally, the initial studies considered injection across the entirety of the Oregon coastline, as opposed to interconnection at a few specific locations. When contingency analyses were conducted for 2-3 GW injected at a few specific locations, the available transmission capacity was shown to decrease (Douville 2023).

Other studies assessing the grid in Oregon found that significant upgrades, including reconductoring and development of new 500-kV lines, would be required to interconnect new OSW generators within the Oregon grid. For example, as part of PacifiCorp’s 2023 Integrated Resource Plan they estimated that incremental transmission for 1 GW of OSW would cost approximately $947 million, with incremental transmission costs for up to 3.5 GW costing $1.115 billion (PacifiCorp 2022). NorthernGrid’s economic study looked at injections of 1,800 MW of OSW via the Fairview Substation, and 1,200 MW through Wendson, which triggered the need for significant upgrades to transmission corridors by developing a 500 kV loop between the Fairview, Wendson, Lane, Alvey and Dixonville substations (NorthernGrid 2023).

BPA's 2022 Cluster Study Report (BPA 2022) looked at 600 MW of power injected at Fairview and 1,600 MW at Rogue and found that new 500 kV reinforcements would be required at Rogue and Fairview, and multiple new 500 kV lines would be required to connect Rogue to Fairview, Fairview to Alvey, and Fairview to Lane substations at a cost of approximately $904 million (Bonneville Power Administration 2022). The same study found that approximately 80 MW could be injected at the Rogue substation without upgrades. It appears the generating resources being studied were floating offshore resources.[3]

PacifiCorp also prepared an Economic Study Request to examine the interconnection of 1 GW of OSW energy on the southern Oregon coast (PacifiCorp 2023). They examined interconnecting to the Del Norte substation and sending the power northeast to the Sams Valley substation and beyond. Per a PacificCorp 2022-2023 local transmission system planning document, the Sams Valley 500 kV to 230 kV substation is planned for a service date of 2025, and it includes upgrade to lines and transformers from Sams Valley to Grants Pass. PacifiCorp evaluated three different transmission options, each building on the previous, with the largest investment including a new 500 kV path between Snow Goose, Corral, and Longhorn substations. For the most modest option, where upgrades essentially terminated at Sams Valley and then relied on existing infrastructure, the total transmission cost was about $670 million.

PacificCorp also ran a production cost model that assessed the impacts of adding 1 GW at Del Norte and they found that the best-case solution resulted in a suboptimal benefit-cost ratio of 0.21; however, this benefit-cost ratio only considered the benefits provided within the PacifiCorp Balancing Authority Area. If benefits to the wider bulk electric system were considered, it appears the benefit-cost ratio would be greater than 1.7, a substantial improvement that emphasizes the importance of considering regional costs and benefits in these transmission planning analyses for OSW development. Because the large amounts of power that are being generated penetrate far into the bulk transmission system, there are substantial systemwide benefits and costs that should be considered when looking for the optimal solutions.

Studies in California found generally that the available transmission capacity is insufficient to interconnect OSW generators to major load centers because of the weakly developed transmission network serving the Humboldt and northern California regions as a whole. In a PG&E study published in 2020 (Pacific Gas and Electric Company 2020), a modeled 48 MW of OSW power injected at Humboldt Bay was enough to trigger thermal overloads, requiring about $550 million worth of upgrades. According to the same study, larger upgrades required more costly investments: injecting 144 MW required a total of $950 million in upgrades, and injection of 1,836 MW examined the use of extensive subsea HVAC or HVDC upgrades, which the study estimated to cost between $1.7 billion and $3 billion. In a follow-on study examining transmission solutions for OSW development in Humboldt County, CA (Daneshpooy & Anilkumar 2022), it was found that the existing transmission infrastructure serving the Humboldt County coast of California could transmit up to 30 MW for a full-deliverability interconnection, and up to 174 MW for an energy only interconnection. For greater than 480 MW of transmission

[3] A presentation titled "Transmission Studies for Large Scale Off-Shore Integration in Southern Oregon" was delivered by Dmitry Kosterev, Transmission Planning, Bonneville Power Administration on January 12, 2023 at the USDOE sponsored West Coast Offshore Wind Transmission Workshop. This presentation identifies a 2022 BPA Transmission Service Request for studying 1,600 MW of OSW being injected at Rogue and 600 MW at Fairview.

capacity, major (500 kV) expansions would be required, as would considerations for interaction across Path 66 (the California Oregon Intertie).

The CAISO 2021-22 Transmission Plan outlines OSW scenarios that include the development of 1.6 GW of OSW in Humboldt Bay and a future outlook of 2.2 GW off the coast of Del Norte County and 6.2 GW off the coast of Cape Mendocino (CAISO 2022). Proposed upgrades include a new Fern Road substation, new 500 kV HVAC lines, delivery to the Bay Area via subsea HVDC cables to a new HVDC converter station in a notional Bay Area hub, and finally LCC HVDC bipole cables to connect the Humboldt OSW energy area to the Collinsville 500/230 kV substation. The most expensive option of the upgrades is the utilization of HVDC subsea cables, estimated at $4.0 billion. In comparison, the overland routes to Fern Road substation are estimated at $2.4 billion, while HVDC injections to Collinsville substation are estimated at $2.1 billion. In CAISO's 20-year transmission outlook the authors explored long-term grid upgrade requirements needed to support 1.6 GW of OSW in Humboldt, and 4 GW total as part of the 20-year outlook considering notional areas. The report specifies the need for two 500 kV AC lines to the Fern Road 500 kV substation and a HVDC line to the Collinsville 500/230 kV substation.

3.3 Literature review influence on the transmission alternatives evaluated

When we began crafting the 10 transmission alternatives that we eventually evaluated, we drew heavily on the literature sources described here, as well as on personal communications with many of the individuals who were involved in preparing the reports we cite. Key literature review influences on our selected transmission alternatives are described below:

- The California transmission infrastructure options were inspired by the CAISO Transmission Planning Process (TPP) and the previous Schatz Center studies in partnership with PG&E (2020) and Quanta Technology (2022). Features inspired by these studies included a point of interconnection (POI) on Humboldt Bay, transmission lines running east and/or south from Humboldt Bay, and an undersea transmission cable to the San Francisco Bay Area.
- The 500 kV line from Fern Road to Tesla and the San Francisco Bay Area POI hub were inspired by the CAISO TPP.
- The 500 kV loop in Oregon and the Rogue and Wendson POIs were inspired by the NorthernGrid Economic Study Request.
- The Del Norte POI for OSW from the Brookings Call Area and the connection to Sams Valley were inspired by the PacifiCorp Economic Study Request.

3.4 Need for broader look at costs and benefits

PNNL prepared a Literature Review and Gap Analysis (Douville et al. 2023) that identified an emergent theme arising from the source materials reviewed and indicated a lack of qualitative benefits that might address stakeholder concerns. The study called for relating any cost-benefit analysis more broadly to social, cultural, environmental, and economic impacts to coastal and ocean reliant communities, as these specific concerns have been absent from many of the studies and analyses to date. The study asserts that intentional design of infrastructure will be a requirement of new developments in order to prevent new inequities which might otherwise be created.

4 Offshore Wind Study Areas

The OSW study areas chosen for this study were based primarily on areas designated by the BOEM for potential OSW development. In addition, we considered areas on the northern coast of California that have been identified as possible sites for future development (Beiter et al. 2020). Figure 3 shows the OSW study areas considered. From north to south, the areas are the Coos Bay and Brookings Call Areas (both off the Oregon coast), and the Del Norte notional area, the Humboldt Wind Energy Area (WEA), and the Cape Mendocino notional area (all in waters offshore from California).

The Humboldt WEA has also been designated by BOEM, and a northern California lease auction was completed in December 2022 that resulted in two leases being issued to potential wind farm developers at a combined value of $331.5 million (BOEM n.d.a). Finally, the Del Norte and Cape Mendocino notional areas are locations of interest that offer substantial wind energy resources and might be candidate areas BOEM could consider for future potential leasing activities.

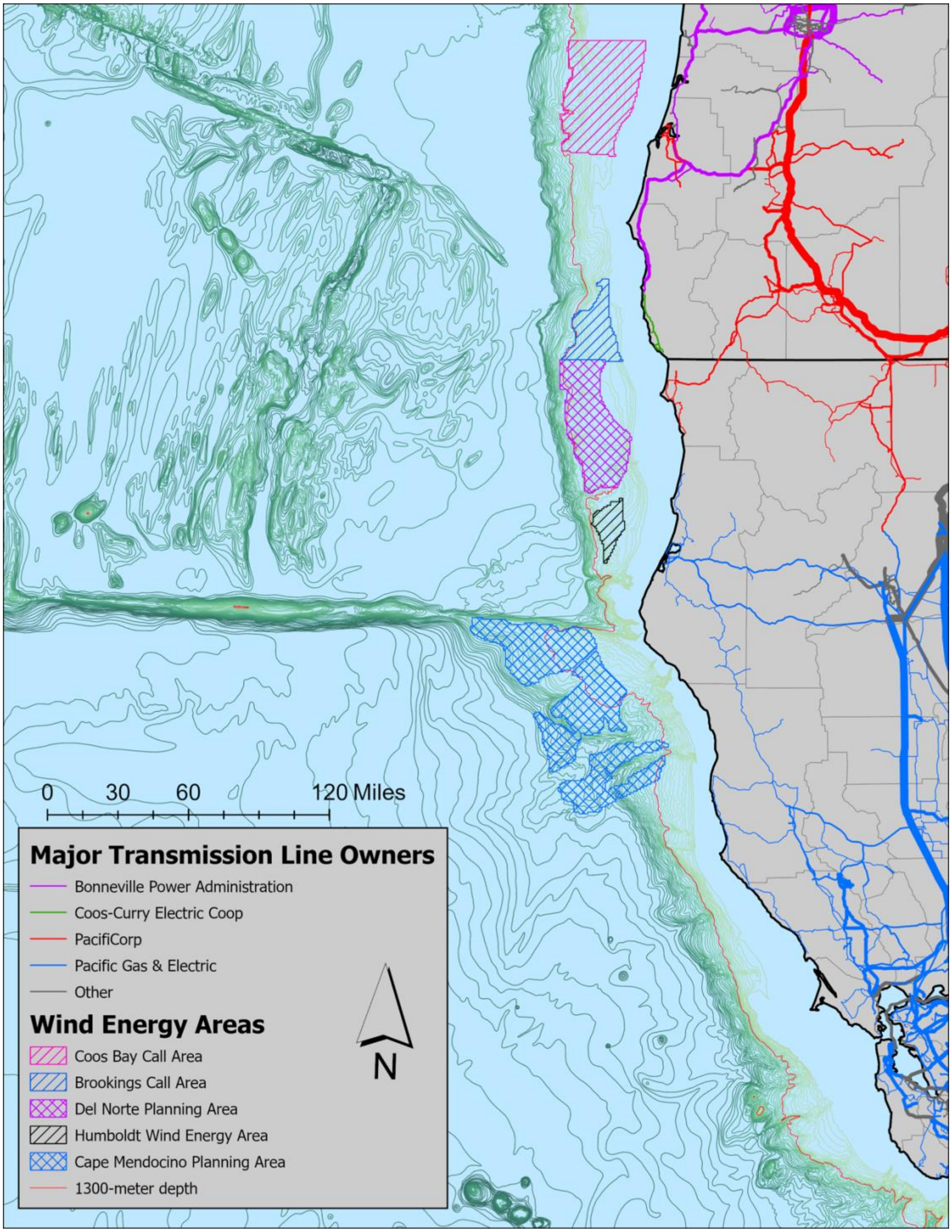

Figure 3. Unmodified offshore wind study areas[4]

[4] Map shows Coos Bay and Brookings Call Areas as initially released by BOEM. Following stakeholder input, Draft Wind Energy Areas with reduced footprints were proposed in August 2023 by BOEM. See BOEM website for further information. https://www.boem.gov/renewable-energy/state-activities/Oregon

These two notional areas, though not the exact geometries specified in this report, have been explored in previous Schatz Center OSW feasibility and economic studies, including Chapman et al. (2021) and Severy et al. (2020). These latter notional areas were also based in part on information provided by the CEC as part of the AB 525 offshore wind strategic planning process. As discussed in a September 2023 workshop, the CEC has begun the process of identifying additional sea space off the northern coast of California to meet the state's OSW development goals (CEC 2022). Information from this process was used to help define the Del Norte and Cape Mendocino notional areas.

4.1 Restrictions applied to wind study areas

In order to increase the probability that the proposed wind farm development scenarios considered in this study are aligned with DOD mission compatibility needs and to avoid other potential conflicts and restrictions, the project team considered multiple factors that might further restrict OSW development.

First, wind farm areas were selected using known geographic boundaries for: 1) Call Areas and WEAs defined by the BOEM, and 2) notional areas, provided by the CEC as part of its sea space analysis, which may be considered for future call areas. The Call and Wind Energy Areas represent the theoretical maximum area that could be developed under current federal leasing guidelines. The notional areas were considered in the same way, though they are hypothetical in nature and do not represent officially delineated areas being considered by BOEM for potential leasing at this time.

Once the maximum potentially developable areas were identified, additional layers of restriction were considered and subsequently subtracted from the total areas previously described. A proposed shipping lane, or fairway realignment Pacific Coast Port Access Route Study (PAC-PARS) drafted by the United States Coast Guard (2023) was incorporated into the study area (see Figure 4). Following the guidelines of the United States Coast Guard (USCG) study, the PAC-PARS fairway areas that intersected the various wind areas were subtracted and considered to be permanently unavailable for development. The wind areas most heavily affected by this were the Coos Bay Call Area, the Del Norte notional area, and the Cape Mendocino notional area.

Additional development restrictions were obtained from a 2023 Wind Energy Siting Analysis for the Oregon Call Areas (Carlton et al. 2023). These data layers were utilized to identify military flight corridors (i.e., low altitude aviator training, see Figure 5), as well as sea space wind exclusion areas which would preclude the development of permanent, floating assets (see Figure 4). After excerpting the areas noted above, and the area proposed by the PAC-PARS fairway, the remaining portion of the Coos Bay Call Area was identified as potentially available for development. The wind exclusion and military flight corridor layers did not affect any other Call, Wind Energy or notional area identified as part of this study. Other areas offshore from the Oregon coast did not appear to have restrictions from the Coast Guard or Department of Defense with respect to possible development, although it is possible that mitigations may be required in some locations.

Information regarding additional potential airspace restrictions associated with military special use airspace was acknowledged and mapped, but it was not utilized to restrict OSW areas or potential routes for transmission line corridors considered in this study. The special use airspace covers most of the area associated with wind call areas off of the Oregon Coast. Nonetheless, we note that areas for transmission upgrades may intersect with known military utilized airspace and could pose an obstruction to low altitude military training or other use of airspace. As such, early and frequent communication between potential developers and the DOD will be critical in order to meet both national security needs and homeland infrastructure developments requirements.

In addition to following the previously stated guidelines, we note that it will be critical to ensure early consultation with the DOD during the preliminary planning stages for any potential projects that include any overlap with military utilized airspace. Additional consultation with the Federal Aviation Administration should also be pursued independent of communications with the DOD.

Communications with CEC staff indicated that sea sponge and coral habitats were present and likely to impact approximately 50% of the developable space in the Del Norte notional area. This further reduced the potentially developable portion of the Del Norte notional area.

For the Cape Mendocino notional area, we only considered the northernmost portion for potential development. This was for several reasons, including the presence of Marine Protected Areas and subsea canyons that are ecologically important and may pose significant barriers to development. PAC-PARS fairway areas prevalent off of Cape Mendocino were also assessed and considered to be significant barriers to development. In addition, there is a lack of existing transmission infrastructure, roads, or significant population centers in the Lost Coast region (the coastal area south of Cape Mendocino and north of Fort Bragg).

After removing the restricted areas and areas considered unlikely for development, we prepared a final series of maps. These maps were shared for review with members of the project's Core Steering Group (CSG), which included representatives from the DOD, the ODOE, and the CEC.

With respect to undersea transmission cable routes, many of the same restrictions identified earlier were considered. With respect to overland transmission line alternatives, the proposed routes followed existing transmission corridors, where rights-of-way and transmission infrastructure are already present. In most cases, existing rights-of-way would need to be expanded to accommodate additional transmission infrastructure. All transmission alternatives and associated routes have been reviewed by DOD representatives to assess DOD mission compatibility as part of CSG review activities. Key takeaways derived from mapping proposed OSW developments, in concert with a DOD mission compatibility assessment, are that development may be possible, but would require early and frequent communication and coordination with DOD leadership to ensure that mission compatibility and national defense are not impacted.

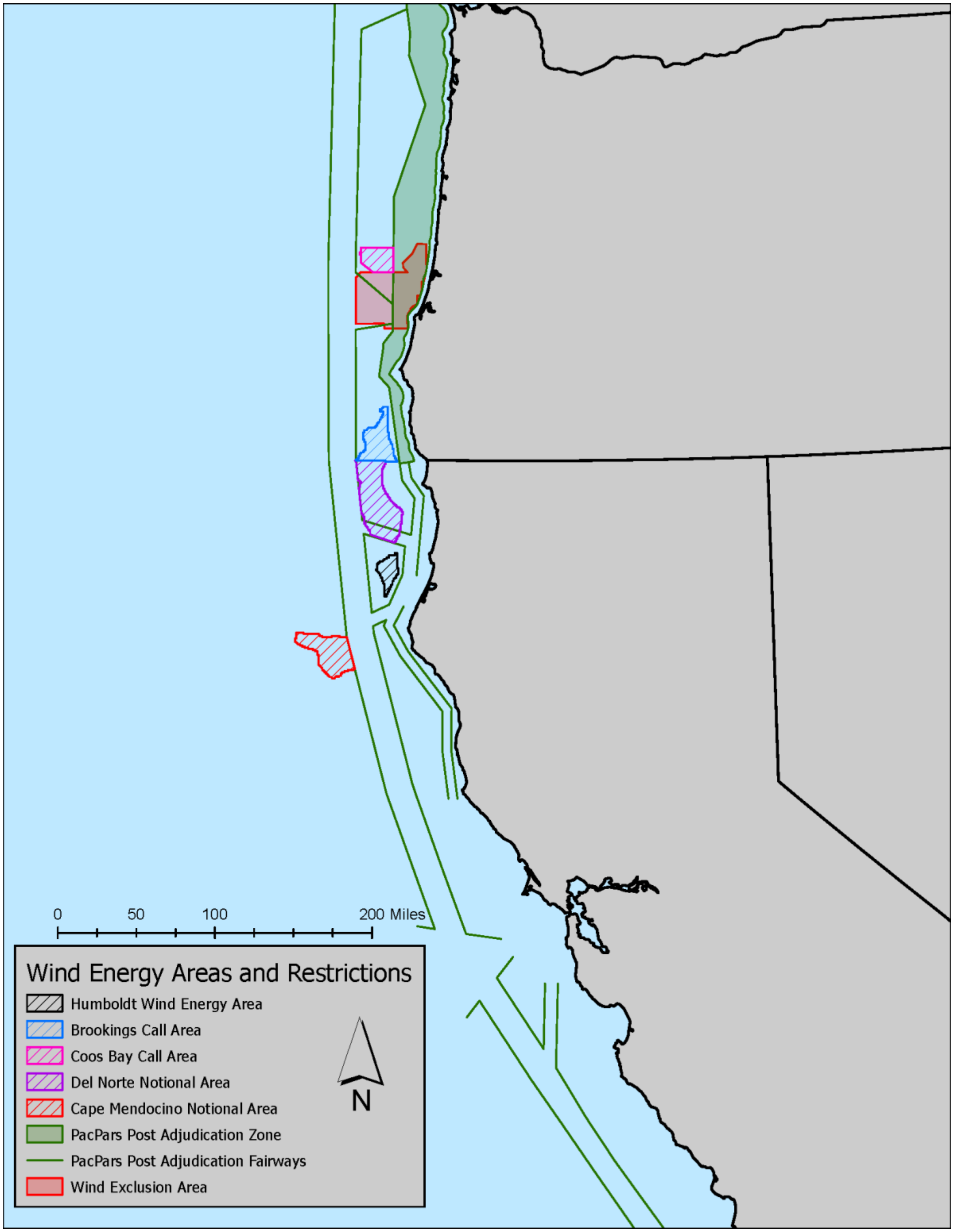

Figure 4. OSW study areas with known PAC-PARS and Wind Exclusion Areas subtracted from areas considered for development as part of the study

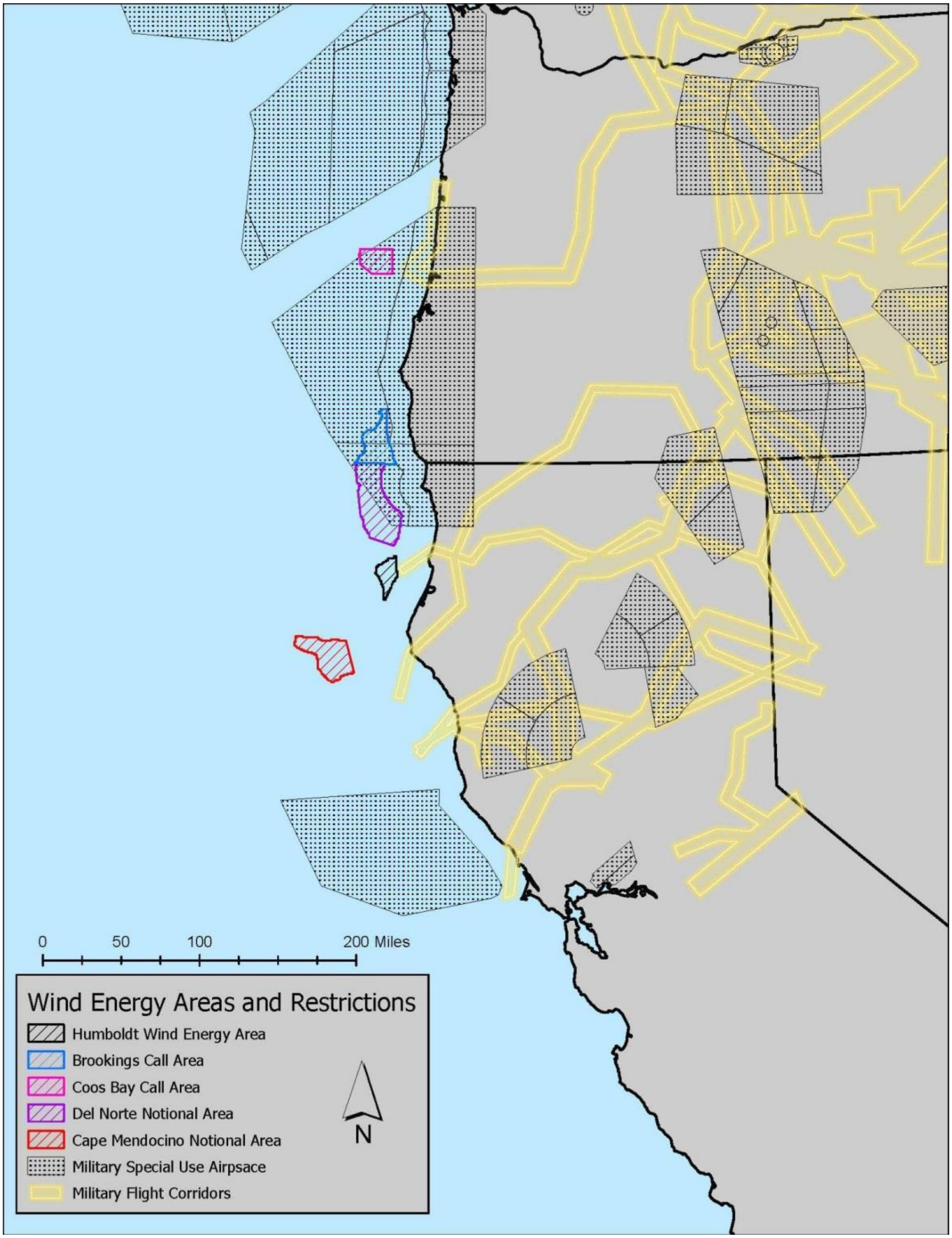

Figure 5. OSW study areas with known Military Special Use Airspace areas and Military Flight Corridors

Table 1 lists each of the wind study areas, identifies the source of the boundaries for each, lists the assumed potentially developable area, and lists some of the known potential restrictions that were adjusted for in each of the areas. The study made use of publicly available data sets, see Appendix B for a complete list.

Table 1. Offshore wind study area characteristics

OSW Study Area	State	Source of Boundaries	Unrestricted Area (sq. mi.)	Assumed Potentially Developable Area (sq. mi.)	Possible Restrictions Considered*
Coos Bay	OR	Coos Bay Call Area (BOEM)	1362	300	Wind Exclusion and PAC-PARS restrictions considered; additional restrictions may apply.
Brookings	OR	Brookings Call Area (BOEM)	447	447	None considered, but restrictions may apply.
Del Norte	CA	Notional Area (AB525 Sea Space Analysis)	1061	531	PAC-PARS, coral and sea sponge restrictions considered; additional restrictions may apply.
Humboldt	CA	Humboldt Wind Energy Area (BOEM)	206	206	None considered, but restrictions may apply.
Cape Mendocino	CA	Notional Area (AB525 Sea Space Analysis)	2399	480	PAC-PARS and undersea canyon restrictions considered; additional restrictions may apply.

*Note that additional restrictions may apply, but further investigation was beyond the scope of this study.

The Coos Bay and Brookings Call Areas were officially winnowed down by BOEM and designated as Draft Wind Energy Areas in August 2023, after our analysis was complete but before we released this report (BOEM 2023). BOEM (n.d.b) indicates that they utilized a "...comprehensive process to identify the potential offshore locations that appear most suitable for floating OSW energy leasing and potential development, taking into consideration possible impacts to local coastal and marine resources and ocean users." The Draft WEAs specified by BOEM for potential development (lease sales) include 95.6 square miles in the Coos Bay area and 247.4 square miles in the Brookings area. This is contrasted with the areas considered in our study, which included 300 square miles in the Coos Bay Call Area and 447 square miles in the Brookings Call Area. Our largest development scenario of 5.9 GW of nameplate capacity in Brookings consisted of a turbine footprint (including mooring line standoffs) of 360 square miles, whereas the Coos Bay wind farm consisted of a fully built out footprint (including standoffs) of 237 square miles. This reduction in lease area footprint across both call areas represents a reduction in the number of turbines possible for installation and may impact the results of our study for the full 25.8 GW buildout scenario. We discuss this in the next section.

5 OFFSHORE WIND DEVELOPMENT SCENARIOS

The OSW development scenarios selected for this study range from “Low” (7.2 GW of installed OSW generation capacity), to “Mid” (12.4 GW), to “High” (25.8 GW), and are tied to the clean energy policy goals for California and Oregon, and more broadly to the larger western states region.

California has ambitious and aggressive climate policies to achieve energy sector decarbonization by 2045. These policies include reducing statewide greenhouse gas emissions to 85% below 1990 levels and reaching a 100% clean electric grid. In addition, as directed by Assembly Bill (AB) 525 (Chiu, 2021), the CEC established preliminary planning goals for the development of OSW energy off the California coast in federal waters of 2 GW to 5 GW by 2030, and 25 GW by 2045. These preliminary planning goals for OSW development will be further evaluated as part of the complete AB 525 strategic planning process.

Oregon has established a statewide goal to achieve 100% clean electricity serving Oregon consumers by 2040, as well as a 50% economy-wide emissions reduction by 2035 and a 90% economy-wide emissions reduction by 2050. In addition, Oregon has adopted a goal of planning for up to 3 GW of OSW development by 2030.

Oregon also has aggressive clean energy and climate policies. Oregon’s 100% clean electricity law requires the state’s largest retail electricity providers to eliminate greenhouse gas emissions associated with electricity serving Oregon consumers by 2040 (Oregon State Legislature 2021a). Oregon’s Climate Protection Program, established by the Oregon Department of Environmental Quality (2021), regulates the state’s economy-wide reduction of greenhouse gases, with an interim target of 50 percent reduction by 2035 and 90 percent reduction by 2050. In addition, Oregon has a state goal to plan for the development of up to 3 GW of floating OSW within federal waters off its coast by 2030 (Oregon State Legislature 2021b). As a result, Oregon policy recognizes the merits of studying and planning for floating OSW, though Oregon has not committed to deployment targets.

In light of these legislative and regulatory goals, the OSW development scenarios chosen for this study were selected to align with the planning targets of both Oregon and California. For the Low and Mid development scenarios, which could be seen to represent near and mid-term buildout scenarios, respectively, Oregon’s stated planning goal of 3 GW was used as a guide. In California, the 2030 preliminary planning goal of 2 GW to 5 GW of OSW energy served as a guideline for the Low development scenario. The Mid development scenario of 7.2 GW on the northern coast of California represents a step toward the larger buildout goals for the state. For the High development scenario, total nameplate capacity in Oregon was stepped up to a total of 9.8 GW, while the total capacity in California was increased to 16 GW.

The 16 GW of OSW development in California for the High development scenario is roughly consistent with California’s 2045 preliminary planning goal of 25 GW, with the understanding that not all OSW development in California will necessarily take place off the North Coast. There is currently a lease on the Central Coast for the Morro Bay Wind Energy Area, and per NREL’s 2022 assessment, it is expected to accommodate 3 to 5 GW of capacity (Cooperman et al. 2022). This would indicate that another 4 to 6 GW of development on the California coast in another location (i.e., beyond the areas considered in this study and the Morro Bay WEA) may be necessary to meet the 25 GW goal by 2045. The following tables show the OSW development capacities that were considered in this study in the Low (Table 2), Mid (Table 3) and High

(Table 4) development scenarios, including how those capacities were broken out by state and by OSW study area.

As noted in the previous section, BOEM's recent identification of Draft Wind Energy Areas has reduced the size of the potentially developable ocean areas adjacent to southern Oregon. Compared to the footprints utilized in our study, which were based on the previously designated call areas, the new lease area footprints will allow for the siting of only about 40% of the turbines we modeled in the Coos Bay call area and approximately 55% of those modeled for the Brookings call area under the High development scenario. We note that the reduced developable area defined by BOEM does not impact the Low or Mid development scenarios we modeled.

Table 2. Wind farm capacities for Low development scenario (7.2 GW total, 3.1 GW in OR and 4.1 GW in CA)

Development Scenario	Wind Area	Nameplate Output Capacity (GW)
Low	Coos Bay	1.3
Low	Brookings	1.8
Low	Del Norte	2.1
Low	Humboldt	2
Low	Cape Mendocino	0

Table 3. Wind farm capacities for Mid development scenario (12.4 GW total, 3.1 GW in OR and 9.3 GW in CA)

Development Scenario*	Wind Area	Nameplate Output Capacity (GW)
Mid[1]	Coos Bay	1.3
Mid[1]	Brookings	1.8
Mid[1]	Del Norte	6.7
Mid[1]	Humboldt	2.6
Mid[1]	Cape Mendocino	0
Mid[2]	Coos Bay	1.3
Mid[2]	Brookings	1.8
Mid[2]	Del Norte	4.6
Mid[2]	Humboldt	2.6
Mid[2]	Cape Mendocino	2.1

*There are two Mid development scenarios. Mid[1] focuses only on the four northern wind areas and does not feature any development in the Cape Mendocino area, whereas Mid2 develops 2.1 GW in Cape Mendocino, with a comparable decrease in capacity in Del Norte.

Table 4. Wind farm capacities for High development scenario (25.8 GW total, 9.8 GW in OR and 16 GW in CA)

Development Scenario	Wind Area	Nameplate Output Capacity (GW)
High	Coos Bay	3.9
High	Brookings	5.9
High	Del Norte	4.6
High	Humboldt	2.7
High	Cape Mendocino	6.3

5.1 Offshore wind power generation estimates

Offshore wind generation profiles for each of the scenarios shown in Table 2, Table 3 and Table 4 were developed using data from the WIND toolkit (Draxl et al. 2015). This dataset contains modeled one hour wind speed and direction data for Central and North America including offshore areas along the coastline, spanning from 2007-2014. A typical meteorological year

(TMY) of hourly wind speed data was assembled from this 8-year data set. In this process, one month of data were selected from the eight years of data available for the TMY dataset for each month of the year such that the month selected most closely matched the average single turbine power generation in that month given the full data set. Each wind area had its TMY data set assembled independent of all other call areas to give the best possible fit for the TMY data.

It was assumed that 15 MW turbines will be utilized, and turbine layouts were assumed to be a hexagonal close packed structure of offset rows. Rows of turbines were assumed to be spaced at 10 rotor diameters while columns were spaced at four rotor diameters. Rows were set perpendicular to the prevailing wind direction. These assumptions follow NREL's site assessment (Cooperman et al. 2022). A Gaussian plume wake model was used to estimate wake losses, and proportional losses, shutdown losses affecting single turbines, and shutdown losses affecting the entire farm were also considered. Resulting estimated capacity factors ranged from 42% to 52% depending on location. Table 5 provides cumulative installed capacity, the annual generation at the wind farm, and the annual capacity factor for each of the scenarios and wind farm configurations that were evaluated. Note that the generation and capacity factor values do not account for the curtailment that was determined via production cost modeling; this is discussed in section 9.

Table 5. Offshore wind farm installed capacities and annual generation

Development Scenario	Transmission Alternatives	Installed Capacity (GW)	Annual Generation (TWh)	Annual Capacity Factor
Low	7.2a, 7.2b	7.2	30.44	48.3%
Mid[1]	12.4a, 12.4b, 12.4c, 12.4d,12.4e	12.4	52.98	48.8%
Mid[2]	12.4f	12.4	53.50	49.2%
High	25.8a, 25.8b	25.8	109.66	48.5%

Peak generation numbers for each wind area were used for the power flow analyses, and hourly wind generation profiles were used for the production cost model analyses. Appendix C includes more detailed information regarding how the wind generation profiles were developed. In addition, we present a set of plots that characterize the power generation curves for each wind farm that was modeled.

6 TRANSMISSION ALTERNATIVES

In this section we provide an overview of the 10 transmission alternatives that were evaluated, and we discuss some of the reasoning regarding how they were developed. Once again, it is important to note that the aim of this study was not to identify the optimal transmission solutions, but instead was to learn from the exploration of a broad range of possible transmission alternatives. Technology options explored in the various transmission alternatives included:

- Onshore and offshore transmission routes,

- High-voltage AC (HVAC) and high-voltage DC (HVDC) solutions,
- Long-distance offshore transmission routes via undersea HVDC cables,
- Radial connections from individual wind farms to immediate onshore landing locations,
- Offshore meshed networks with shared HVAC buses,
- An HVDC backbone that connects multiple wind farms, and
- The use of phase shifting transformers to allow lower voltage, local transmission systems to be served by the gigawatt scale wind farms being deployed off their coasts.

We note that all the necessary technologies for large-scale development of floating OSW energy are not fully developed nor commercially available at this time; this includes floating turbines, floating substations, floating HVDC conversion stations, mesh transmission networks, and dynamic high-capacity HVAC and HVDC cables. Therefore, we made assumptions regarding technologies that are expected to be available in the coming years. Our assumptions regarding floating offshore infrastructure are discussed below.

To confine the breadth of the study, the overland portion of the transmission analysis only considered transmission routes along existing transmission corridors. In addition, regarding all overland routes, following existing corridors, we considered only overhead lines for all new and upgraded lines, as opposed to underground lines. The undergrounding of transmission lines, while substantially more expensive, tends to improve their reliability because they are not subjected to major risks posed by high winds, extreme storms and wildfires. Also, while the development of completely new transmission corridors through previously "undisturbed" lands is likely to be more challenging, there may be some situations where it makes sense to consider new corridors; however, such an analysis was beyond the scope of this study.

For the transmission analyses, we utilized standard electrical transmission system data for the region obtained from the Western Electricity Coordinating Council (WECC) and modified them to meet CAISO planning standards. The study year used for the transmission analysis was 2032. It is important to note that standard transmission planning data are available for a 10-year time horizon, and that is what determined the study year. However, it is not expected that a full-scale buildout of OSW on the West Coast will be completed by 2032. In addition, it is likely that development will occur over time and in a phased approach. Consequently, it is important to consider that early planning decisions will affect later opportunities and a long-term, carefully conceived, phased vision is likely to be most effective.

The main focus of this study was to examine the transmission system upgrades that would be required to support specific levels of OSW development, and to estimate what those upgrades would likely cost. This was accomplished by conducting power flow analyses for all 10 alternatives, and production cost modeling (PCM) for eight of the 10 alternatives[5]. While this study did not include a detailed assessment of the potential issues and challenges associated with each of the alternatives evaluated, we did complete a high-level assessment of the potential

[5] PCM analyses for the 25.8 GW scenario were not conducted as part of this study. We note that due to data limitations, the PCM analyses could only be conducted for the 2032 study year. We expect that the development of OSW on California's North Coast and the southern coast of Oregon at a scale similar to the 25.8 GW scenario is not likely to happen before 2040 or later. By that time, electrical demand profiles and generation mixes are likely to be significantly different from the 2032 estimates. Therefore, running the PCM model for 25.8 GW of OSW in 2032 would not likely produce meaningful results.

challenges, issues, and constraints that might be encountered. This effort included a general assessment of both the offshore infrastructure and cable routes, as well as the onshore transmission corridors that would need to be expanded to accommodate additional transmission line capacity.

6.1 Floating offshore infrastructure

Most OSW farms globally utilize fixed-bottom infrastructure (turbines, substations, etc.). However, for the development of OSW technology in northern California and southern Oregon, fixed bottom infrastructure is largely infeasible due to the extreme water depths and unique terrain challenges, such as steep shelf embankments and submarine canyons. These oceanographic and geologic challenges represent a departure from the conditions found where existing OSW farm developments have occurred or are planned at scale, such as in Northern Europe and off of the East Coast of the United States. In those areas, the relatively shallow water depth (less than 60 meters) does not logistically or economically prevent developers from affixing the turbine platforms directly to the seafloor.

Floating infrastructure brings many new challenges. Equipment like wind turbines and offshore substations need to be supported by floating platforms or other floating structures, and these structures will be constantly in motion. Therefore, the cables that interconnect these moving components will need to be dynamic cables that are designed to withstand motion while in operation.

6.2 HVAC and HVDC cables

It is likely that the transmission solutions for floating OSW off the northern California and southern Oregon coasts will include both AC and DC cables. AC transmission cables are more widely implemented and are a more developed technology. This suggests that the first market-ready transmission solutions for floating OSW will utilize AC cables. However, AC transmission cable efficiency is both voltage and distance-dependent, making them non-ideal for long-distance transmission. While these efficiency and distance constraints do not necessarily preclude widespread use, they increase the cost of transmission due to the mitigation measures required. However, for radial connections bringing the generated power directly to an onshore landing point with cable run distances in the 20- to 40-mile range, little if any mitigation would be required.

When considering using subsea cables to route power to distant major load centers (e.g., Portland or the San Francisco Bay Area), the inefficiencies of HVAC cables become prohibitive because of the hundreds of miles of length that will be required. In these cases, the implementation of HVDC subsea cables becomes appealing because HVDC transmission capacity is not length dependent. When exporting power from OSW farms to the onshore grid, there is a commonly cited breakeven point at between 80-100 km (about 50-60 miles) at which HVDC becomes a more economical choice than HVAC (Huang et al. 2023).

Subsea export cables extend from an offshore substation to a coastal landfall point where there is a transition joint between the subsea and overland cables. Current Industry standards for fixed-bottom OSW farms specify static export cables. Floating OSW plants require “dynamic” cables that are designed to withstand motion while in operation (see Figure 6). Export cables can use a relatively short segment of dynamic cable between the floating substation and the seabed, then transition to a static cable for the remaining distance to the cable landfall. For this study, we assume the availability of dynamic HVAC power export cables with a capacity of 1 GW, which is approximately twice the capacity of current HVAC export cables. For HVDC power cables we assume a capacity of 2 GW, which is comparable to currently available static HVDC cables, and a 525 kV bipole configuration with metallic return, bundled for installation in a single trench. We note that according to Huang et al. (2023), HVAC dynamic export cables are not currently available at high voltages (they are currently available at 33 and 66 kV), and HVDC dynamic export cables do not exist in any form.

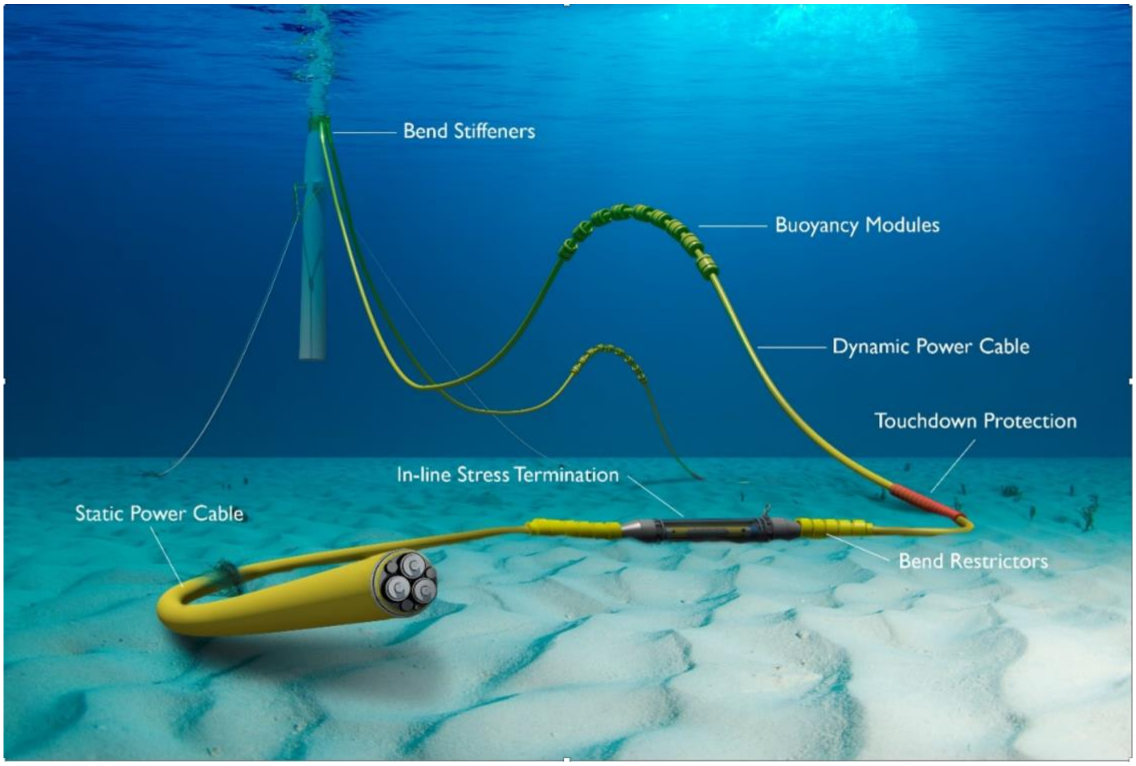

Figure 6. Dynamic subsea cable system components. Illustration by Josh Bauer, NREL.

6.3 Floating HVAC and HVDC substations

Substations are used to boost the voltage of the electrical power generated by wind turbines before transmitting the power over long distances. If there is a desire to use HVDC cables, then the AC power from the turbines must first be converted into DC power, then transmitted via the HVDC cables, and then converted back to AC power in order to be injected into the bulk AC electric power grid.

Current offshore substations are commonly located on fixed platforms. We assumed that floating platforms would support similar substation structures. For HVAC substations we modeled 1 GW floating systems, which are comparable to current fixed-bottom HVAC substation capacities. Each platform holds a transformer to step up from the turbine array system voltage of 132 kV to the export cable voltage of 400 kV. The offshore substation also has switchgear to protect the equipment against electrical faults, and depending on the cable length, has reactive power compensation to maintain voltage at the specified level.

For HVDC conversion stations, we assume the use of voltage source converter (VSC) technology and a modular 2 GW system per platform, which is comparable to fixed-bottom

HVDC substations that are planned to be in service by 2030 (TenneT n.d.). Each platform holds a transformer to step up the wind turbine array system voltage from 132 kV to the export cable voltage of 525 kV. HVDC export systems require an AC/DC converter between the collection system and the export cable. The offshore platform also holds DC circuit breakers, an emerging technology, to protect the equipment from electrical faults. The offshore platform is expected to support 10 stories and cover a footprint roughly the size of a soccer field.

6.4 Offshore mesh networks

To date, OSW farms have commonly utilized radial connections, where wind farms are connected to the nearest onshore location where they can tie into the existing electrical transmission system. However, as the industry scales up there is more attention being paid to networked interconnection schemes. Such schemes include shared substations, meshed grids, and offshore HVDC backbones that tie multiple wind farms together and allow for power to flow in multiple directions at any given time. These types of configurations can potentially increase reliability and decrease congestion issues. Utilizing a meshed, or networked connection can also allow for power sharing across the regional power grid, again improving reliability and allowing power to flow to locations where it is most valued. However, these types of configurations can be more complicated from a technology, regulatory and wholesale energy market perspective.

Meshed grid systems have been studied in New York, New Jersey and Great Britain. In New York, a study found that networked concepts (shared substations, meshed grid, and common backbone) were economically justifiable if they encompassed at least three OSW projects with a minimum aggregate rating of 3 GW (DNV GL et al. 2020). In New Jersey, a state level approach was initiated to examine various transmission solutions, including a meshed offshore grid approach (Pfeifenberger et al. 2022). And in Great Britain, an extensive study examined an array of offshore network transmission solutions that could serve to accommodate approximately 60 GW of OSW generating capacity by 2050 (DNV GL 2020). The UK study examined four HVAC networked technologies and four HVDC networked technologies. The researchers found that the integrated networked designs would likely offer many advantages, including reductions in the number of onshore cable landings, reductions in required onshore transmission upgrades, reductions in costs, reduced impacts to the environment and coastal communities, and improved transmission services.

In our current study, we examined both offshore radial and networked transmission solutions. For the networked solutions we took a mixed approach. In all of the alternatives we assumed that the cumulative AC capacity from each wind farm was connected to a common busbar[6] that could serve any of the floating substations, HVAC or HVDC, that were associated with that wind farm. In Alternatives 7.2a through 12.4b, this is the only “networking” to speak of, and all connections to shore are radial via HVAC export cables. Then, starting with Alternatives 12.4c and 12.4d, we begin to interconnect some of the adjacent OSW farms via long-distance HVDC cables. But there still are no networked connections within the HVDC transmission system. In these two alternatives, all connections within the HVDC transmission system are via individual, two terminal HVDC cables. Finally, in Alternatives 12.4e through 25.8b, we assume networked, multi-terminal connections within the offshore HVDC transmission system. In these mesh

[6] This busbar is assumed to be a set of cables that interconnect the floating offshore substations serving a regional wind farm. The voltage serving these floating substations is assumed to be 132 kV. The actual design and implementation of a common AC busbar system may be different from these assumptions.

configurations, we assume that the offshore transmission assets can be shared between multiple OSW projects.

We note that these offshore transmission technologies are all still very much in development and there are numerous technologies and configurations in the HVDC space that could be used to create meshed networks within the DC system. We assessed these technologies at a conceptual level and did not specify detailed technology choices or cost parameters.

6.5 Serving local coastal community loads

Offshore wind development in northern California and southern Oregon is being considered in rural regions that are characterized by limited transmission infrastructure and frequent and extended power outages. The transmission infrastructure needed to deliver renewable power to major load centers can also provide reliability benefits to OSW "host" communities and communities along transmission routes, provided that the new infrastructure includes connections to the local systems that serve these communities. However, it is also possible for the new infrastructure to bypass rural communities if local connections are not included.

If development of OSW is to be successful, it will need the support from communities in the coastal regions near the wind farms. This support, in turn, will depend, in part, on the delivery of tangible and meaningful benefits to these communities. Increased electricity reliability represents one important form of community benefit that could result from OSW development.

To address this, each of the transmission alternatives considered in this study included some points of interconnection to local systems in coastal regions near the respective wind farms. While quantifying the associated reliability benefits is beyond the scope of the current analysis, we were able to estimate the cost associated with providing these interconnections. The infrastructure needed to serve these local communities included phase shift transformers, autotransformers, and local transmission lines to interconnect new substations to existing nearby substations.

Phase shifting transformers are used at the point of interconnection between the new, high-voltage transmission infrastructure and the lower voltage electrical systems that serve local communities. The phase shifting transformers are needed to control power flow within the AC system. The GW scale wind farms being modeled are located offshore from small communities with minimal electrical loads. If that power is brought onshore and interconnected to the local transmission system, it could overload the lines in the local system. In this case, the phase shifting transformer creates a phase shift between the high-voltage side (e.g., 500 kV) where the wind generators are connected, and the lower voltage side (i.e., 115 kV) that serves local loads. The phase shift allows for control of the power flow to ensure that the local lines do not become overloaded. In addition, auto-transformers were used to connect new 500 kV lines to existing 230 kV substations serving local communities.

Points of interconnection with local systems are noted in single line electrical schematics that are shown below in the description of the transmission alternatives.

6.6 Offshore cable routes

Numerous data sources were used to inform the layouts of the subsea cables, as well as the overall transmission alternatives that were studied. GIS data from project partners Mott MacDonald and H. T. Harvey & Associates were utilized, and primarily consisted of publicly available geospatial and infrastructure level data for five geographic regions (the Oregon coast, the North Coast of California, the Mendocino area in California, the San Francisco Bay Area, and the Central Coast of California. Data included spatial distributions of endangered species and species of special consideration, hydrology, hydrographic and topographic layers, benthic seafloor and sediment characteristics, subsea cables, submarine canyons, Marine Protected Areas, National Marine Wildlife Sanctuaries, ship traffic, and ship density. Several key considerations emerged from this and previous analyses (Porter, A. and Phillips, S. 2020) regarding the development of subsea cable routing for OSW energy transmission.

Bathymetric and geophysical characteristics, which include submarine canyons, turbidity flows, fault lines and seismic displacement, substrate conditions, and steep slopes, can all present significant challenges. Subsea transmission routes were defined at a high level with consideration for logistical and ecological impacts. Geomorphologic and oceanographic constraints related to siting and layouts were compared to technological capabilities of existing and developing equipment. In addition to the aforementioned constraints, factors including DOD operational areas, vessel traffic, fairway designations, cable landing locations, existing submarine cable locations, fishing grounds and marine protected areas (MPAs) were considered for routing purposes.

Additional consideration was given to the presence of submarine canyons, some of which extend up to 100-miles offshore from the coastlines. Along the northern coast of California, particularly from Cape Mendocino and southward to the Monterey Bay area, deeply incised submarine canyons are a prevalent characteristic of the continental slope. Mitigating for these features may require wholesale avoidance, which entails siting the cables deeper than 3,000 meters. Cable routing closer to shore would allow for the siting of subsea transmission cables in water depths for which HVDC cables are currently rated; however, there are significant ocean user conflicts associated with nearshore cable routing. In addition to potential conflicts with commercial fishing operations, updated fairway alignments along the West Coast, for which no permanent developments are permissible, would coincide with the proposed routes along the shallower extents of the continental shelf. Other considerations included Marine Protected Areas, submarine cables, depth contours, slopes, and fault zones or seismic activity centers, as well as vessel traffic.

Deeper water depths also present challenges. At present, the approximate limiting water depth for cables is 6500 ft (2,000m). The technology necessary for cable laying at 9,800ft (3,000 m) or deeper is currently under development. In general, the technology risk increases with depth because additional challenges associated with cable laying, siting, and repair become more expensive and complicated with deeper depths.

The spacing between cables also presents increased challenges with depth. When laying a cable parallel to an existing cable, a new cable typically needs to be placed about 2 to 3 times the water depth from existing cable to allow enough space for repairs to be conducted such that the repaired cable will not overlay an adjacent cable. Cables installed in water depths offshore of the continental shelf would therefore potentially be spaced approximately 3 to 5 miles (4.8-8.0 km) apart to allow for standard repair methodology. This is not necessarily a hard constraint, as repairs may potentially be conducted in a shorter width, though at a higher cost.

In addition to routing considerations, cable landfall considerations were made. Factors including roads and access, shipborne access to deep water, and the existence of marine protected areas or national marine sanctuaries (NMS) were all considered. Cable lay vessels typically require approximately 30 ft (~10 m) of water depth, and therefore the distance to the 30 ft contour was assessed along the shoreline to check the distance to this water depth. This distance is important because the typical limit of a cable pull to shore is 3280 ft to 4920ft (1,000-1,500m).

All of the factors were utilized by the Mott MacDonald team to create a conceptual map of example corridors. The feasibility of these options is not confirmed, and is based on an early review of constraints and hazards; the options are conceptual or notional in nature only. These concept level options formed the basis of our consideration for design and layouts of offshore transmission alternatives. Figure 7 illustrates a conceptual subsea cable layout, with various obstacles or areas of special consideration displayed in conjunction with notional cable routes. Additional information regarding subsea cable and landfall considerations is provided in Appendix D.

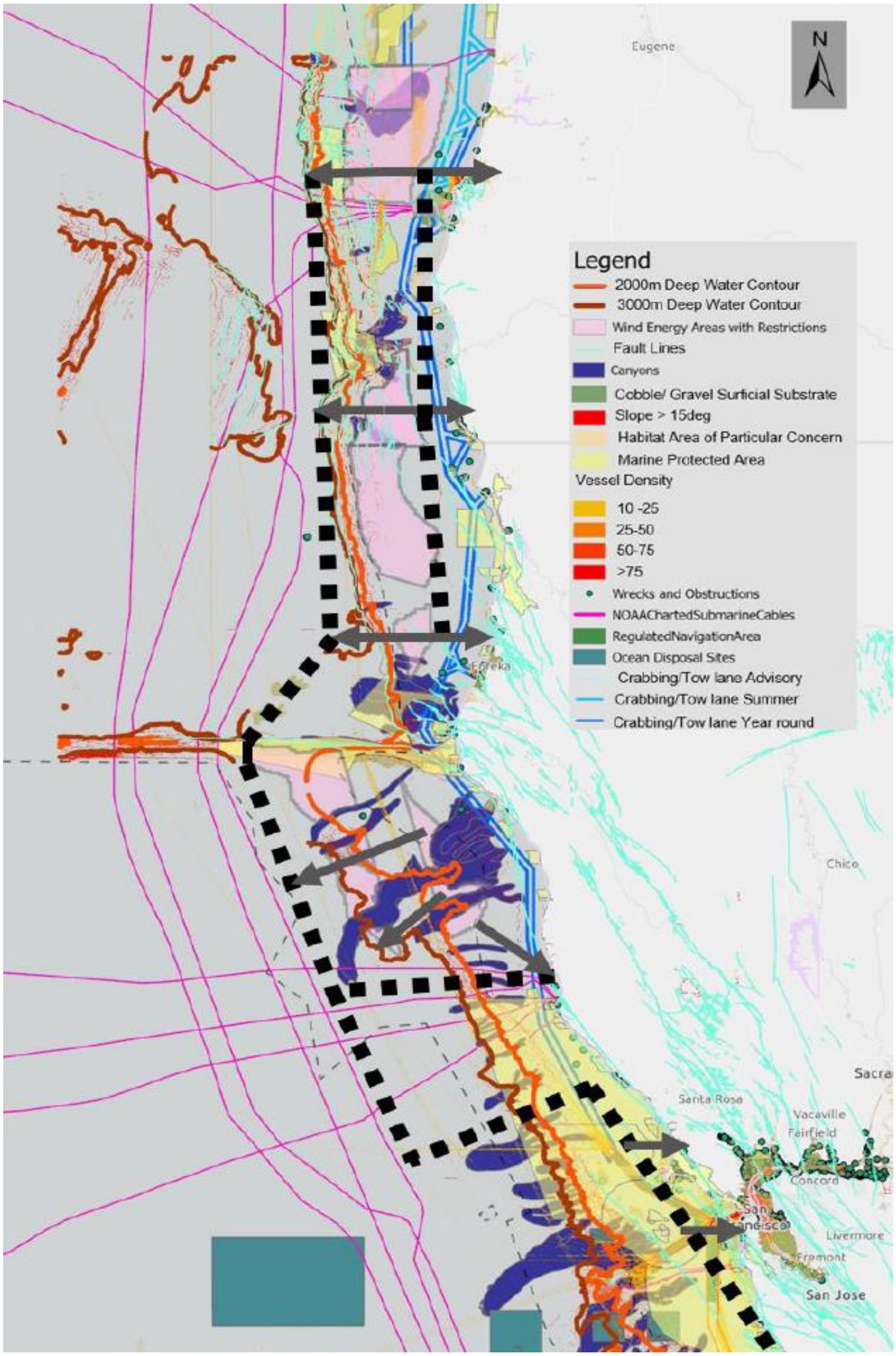

Figure 7. Summary of subsea constraints and example conceptual large-scale transmission corridors[7].

[7] Dotted black lines indicate notional offshore HVDC transmission routes. Solid gray arrows indicate potential export cable routes from wind energy areas to long distance HVDC cables or to landfall locations.

6.7 Development of transmission alternatives

The development of the transmission alternatives was driven primarily by the OSW farm capacities being proposed, the proximity and capacity of existing onshore transmission infrastructure, the proximity of electricity load centers, the assumed capacities of various transmission technologies, and the transmission planning standards enforced by entities such as CAISO and WECC. Table 6 provides a list of the transmission technologies that were considered and the assumed transmission capacities for these technologies. We note that some of these technologies do not currently exist, but all are being discussed and pursued by the OSW industry and are expected to begin to become commercially available in the next decade or so. Dynamic HVDC cables are expected to be available by 2035 (Huang et al. 2023), whereas the first floating substations are expected to be available by 2030 (Skopljak 2023).

Table 6. Assumed capacities for transmission line technologies (per line)

Technology	**Capacity (GW)**	**Notes**
HVAC overhead (500 kV)	3.2	Mature in use technology currently available.
HVAC undersea (400 kV)	1.0	Technology in development; requires dynamic cables and floating substations that do not currently exist. Assumed maximum distance of 60 miles due to higher cable power losses and increased reactive power compensation requirements at greater distances.
HVDC overhead (±500 kV)	3.0	Technology exists today.[8] Assumed voltage source converter (VSC) bi-pole technology.
HVDC undersea (±525 kV)	2.0	Technology in development; requires dynamic cables and floating substations that do not currently exist. Assumed voltage source converter (VSC) bi-pole technology

All of the alternatives we evaluated required floating offshore substations, and many included floating offshore HVDC conversion stations, both of which will require dynamic HVAC and/or HVDC export cables. We note here that the assumptions we used, in addition to the characteristics stated in Table 6, are that the floating offshore HVDC conversion stations will be available in a 2 GW modular format, where each conversion station would have its own floating platform that would be roughly the size of a soccer field (115 yards long by 84 yards wide). This is based on TenneT's 2GW Program (TenneT n.d.), which currently is being developed for fixed bottom HVDC conversion stations, features a 525 kV bipolar cable, and is designed to be multi-terminal ready, which is key for future adoption of an HVDC mesh network.

[8] HVDC technology is common throughout the world, though less so in the United States. One relevant example in the US is the Pacific DC intertie that runs from northern Oregon to Los Angeles, California. It is a ±500 kV line that carries up to 3.1 GW of DC power.

Based on these assumed capacities, we crafted a series of alternatives that were expected to be capable of transmitting the power generated by the OSW developments to onshore transmission infrastructure that could then handle the power flow and convey it to the electricity load centers in the San Francisco, Sacramento, Portland and other metropolitan areas. In addition to the capacities listed in Table 6, we adhered to the CAISO planning standard that dictates that no more than 1.15 GW of generation can be dropped due to the loss of one transmission line. This meant that transmission line redundancies were planned to cover the loss of a single line and make sure this power loss criterion was not exceeded.

Using these guidelines, we developed a set of possible transmission alternatives, starting with the Low development scenario and building toward the Mid and High development scenarios. We based our initial proposed alternatives on information we gained from other recent and related transmission studies, such as the CAISO's 2021-2022 Transmission Plan (CAISO 2022) and NorthernGrid's economic study request to examine OSW in Oregon (NorthernGrid 2023). Once we had a set of potential transmission alternatives, we presented them to our Technical Focus Group, received feedback, and then made adjustments based on that feedback. For example, we expanded our alternatives to include more variety, such as interconnections into the PacifiCorp system, which straddles both northern California and southern Oregon, via the Del Norte and Sams Valley substations. This was informed by PacifiCorp's economic study request analysis that was conducted in response to the Oregon Public Utility Commission's request to study OSW integration (Austin 2023).

Below we briefly describe the transmission alternatives that were evaluated. Table 7 lists the transmission alternatives and the development scenarios that each are associated with, and Table 8 outlines the key characteristics of each alternative.

A few key trends can be observed in Table 8. First, as expected, the total amount of new transmission infrastructure increases steadily from the Low to the Mid to the High development scenarios. However, what is more notable is that the amount of HVAC infrastructure increases somewhat from the 7.2 GW to the 12.4 GW scenario, but then decreases significantly as a greater reliance on HVDC infrastructure is employed. This can particularly be seen in Alternatives 12.4e, 12.4f, 25.8a and 25.8b. We note that as the alternatives progress from 7.2a through to 25.8b and the amount of HVDC infrastructure steadily increases, this corresponds to a greater reliance on an offshore HVDC transmission network. It is also notable that the total number of floating offshore substations, both HVAC and HVDC, increases through to Alternatives 12.4c and 12.4d, but then decreases when an offshore HVDC mesh network solution is adopted

Table 7. List of ten transmission alternatives by development scenario

OSW Development Scenario	Transmission Alternatives
Low - 7.2 GW	7.2a, 7.2b
Mid - 12.4 GW	12.4a, 12.4b, 12.4c, 12.4d, 12.4e, 12.4f
High - 25.8 GW	25.8a, 25.8b

Table 8. Characteristics of the ten transmission alternatives

Characteristic	Alt. 7.2a	Alt. 7.2b	Alt. 12.4a	Alt. 12.4b	Alt. 12.4c	Alt. 12.4d	Alt. 12.4e	Alt. 12.4f	Alt. 25.8a	Alt. 25.8b
Total wind farm capacity (GW)	7.2	7.2	12.4	12.4	12.4	12.4	12.4	12.4	25.8	25.8
CA wind farm capacity (GW)	4.1	4.1	9.3	9.3	9.3	9.3	9.3	9.3	16.0	16.0
OR wind farm capacity (GW)	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	9.8	9.8
Offshore HVDC backbone connecting wind farms	No	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes
Offshore HVDC mesh network	No	No	No	No	No	No	Yes	Yes	Yes	Yes
No. of HVAC undersea export cables	9	9	14	14	14	9	3	3	0	0
No. of HVDC undersea cables	0	2	2	5	3	5	8	10	27	22
No. of floating HVAC substations	9	9	14	14	14	9	3	3	0	0
No. of floating HVDC conversion stations	0	0	0	0	5	8	7	8	15	15
No. of new onshore 500 kV HVAC transmission lines	7	7	7	8	7	8	6	8	11	15
No. of new onshore 500 kV HVAC substations	5	5	3	5	5	5	5	5	5	5
No. of new onshore HVDC transmission lines	0	1	1	1	0	1	2	1	1	1
No. of new onshore HVDC conversion stations	0	3	3	4	1	2	5	4	8	7
No. of new phase shifting transformers	5	6	5	8	6	8	7	7	9	8

6.8 Description of transmission alternatives

Below we briefly describe the alternatives and make comparisons between those in each development scenario. For one example alternative in each scenario, we also provide a single-line schematic showing the proposed new transmission infrastructure and the existing infrastructure it interconnects with, along with a map that shows the physical routes that were assumed. Further descriptions of the transmission alternatives, single-line schematics, and maps for all the alternatives are included in Appendix E. Importantly, we note that all transmission corridors that were examined are notional, primarily follow existing corridors, and may not match future layouts.

6.8.1 Low development scenario - Alternatives 7.2a and 7.2b (7.2 GW)

Alternative 7.2a was developed to accommodate 7.2 GW of OSW development. It features radial connections via 500 kV AC export cables between the proposed OSW farms and nearby onshore substations. Figure 8 provides a single line electrical schematic and Figure 9 provides a physical geographic map of Alternative 7.2a. Similar figures for Alternative 7.2b are included in Appendix E.

In Oregon, this alternative drew heavily on the NorthernGrid approach, where approximately 3 GW of OSW is connected on the central and southern Oregon coast, with 500 kV substation upgrades and a 500 kV AC transmission line loop created between Wendson, Lane, Alvey, Dixonville and Fairview substations (NorthernGrid 2023). From here forward in this report we refer to this approach as the "NorthernGrid 500 kV loop." This particular approach in Oregon is repeated through a number of the transmission alternatives that were considered.

In California this transmission alternative, and all the transmission alternatives that follow, rely on the establishment of two new 500 kV substations at Del Norte and Humboldt. In Alternative 7.2a, each of these new substations are connected via 500 kV AC lines to the planned Fern Road substation in the Central Valley. This connects the California wind generation into the main 500 kV transmission backbone that runs along the I-5 corridor of California and thereby connects the power to the load centers in Sacramento and San Francisco. In addition, a new 500 kV line is added between the Round Mountain and Tesla substations, which are part of the 500 kV backbone. This additional line is needed to handle the additional power flow and is included in every transmission alternative that follows.

Connections to lower voltage, local transmission grids via phase-shifting transformers were included for the Wendson (230 kV), Fairview (230 kV), Rogue (230 kV), Del Norte (115 kV) and Humboldt (115 kV) substations.

Transmission Alternative 7.2b also featured radial connections from all wind farms to shore. Differences between 7.2a and 7.2b are that we eliminated the 500 kV loop in Oregon (between Wendson, Lane, Alvey, Dixonville and Fairview substations), and instead deployed redundant lines from the coastal substations to the 500 kV transmission backbone to the east. In addition, in California we eliminated the overland transmission lines running from the Del Norte substation to Fern Road, and instead added two HVDC lines running from the Del Norte substation to the Humboldt substation via an offshore cable route. We note that these lines both originate and terminate at onshore HVDC conversion stations, so they do not require floating conversion stations. We chose the offshore route for these cables because it avoids overland transmission lines along the remote, rugged, and environmentally sensitive coast line of far northern

California. This stretch of coastline also hosts national and state parks, as well as multiple Native American Indian Reservations.

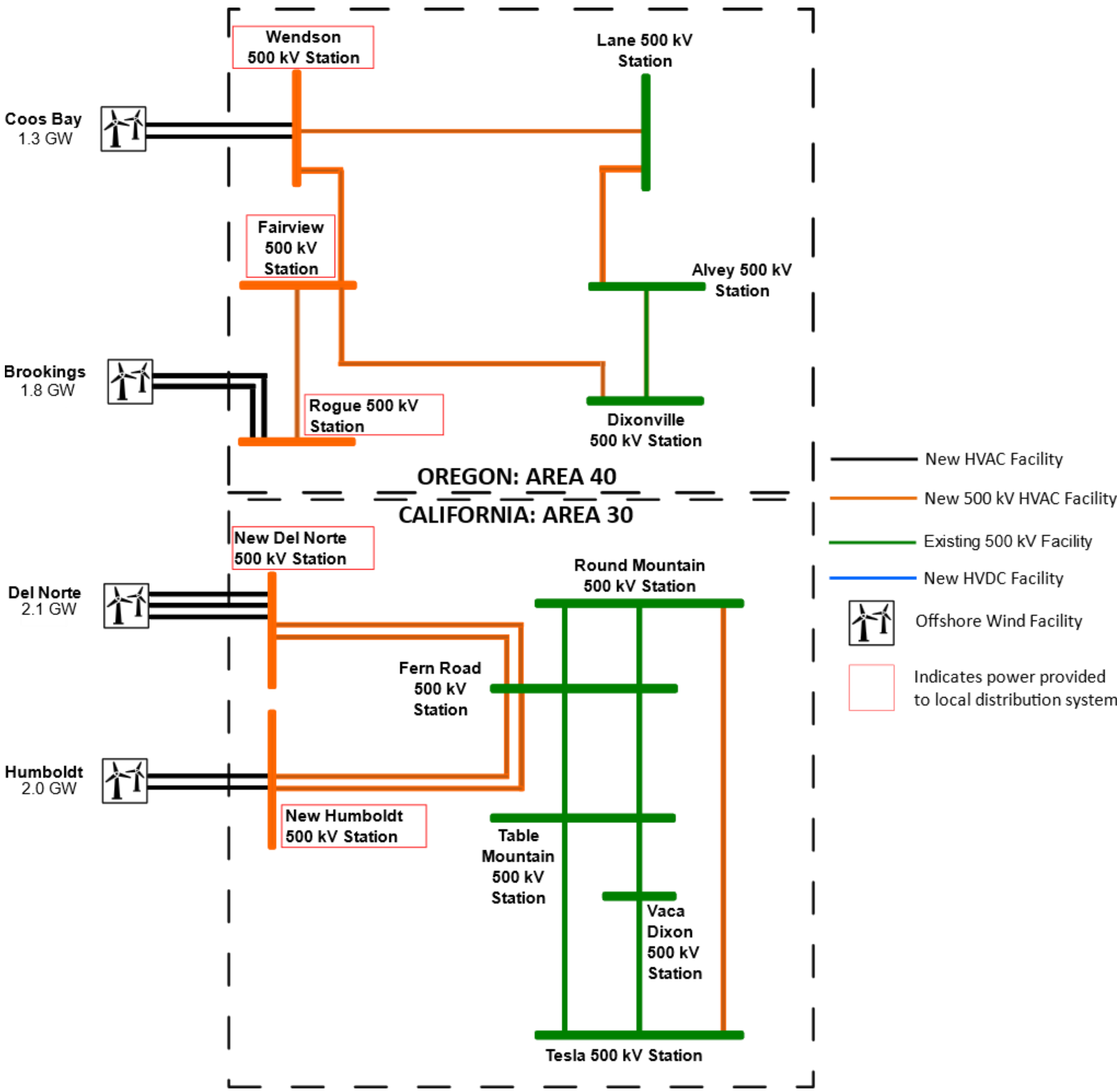

Figure 8. Single line electrical schematic for Alternative 7.2a

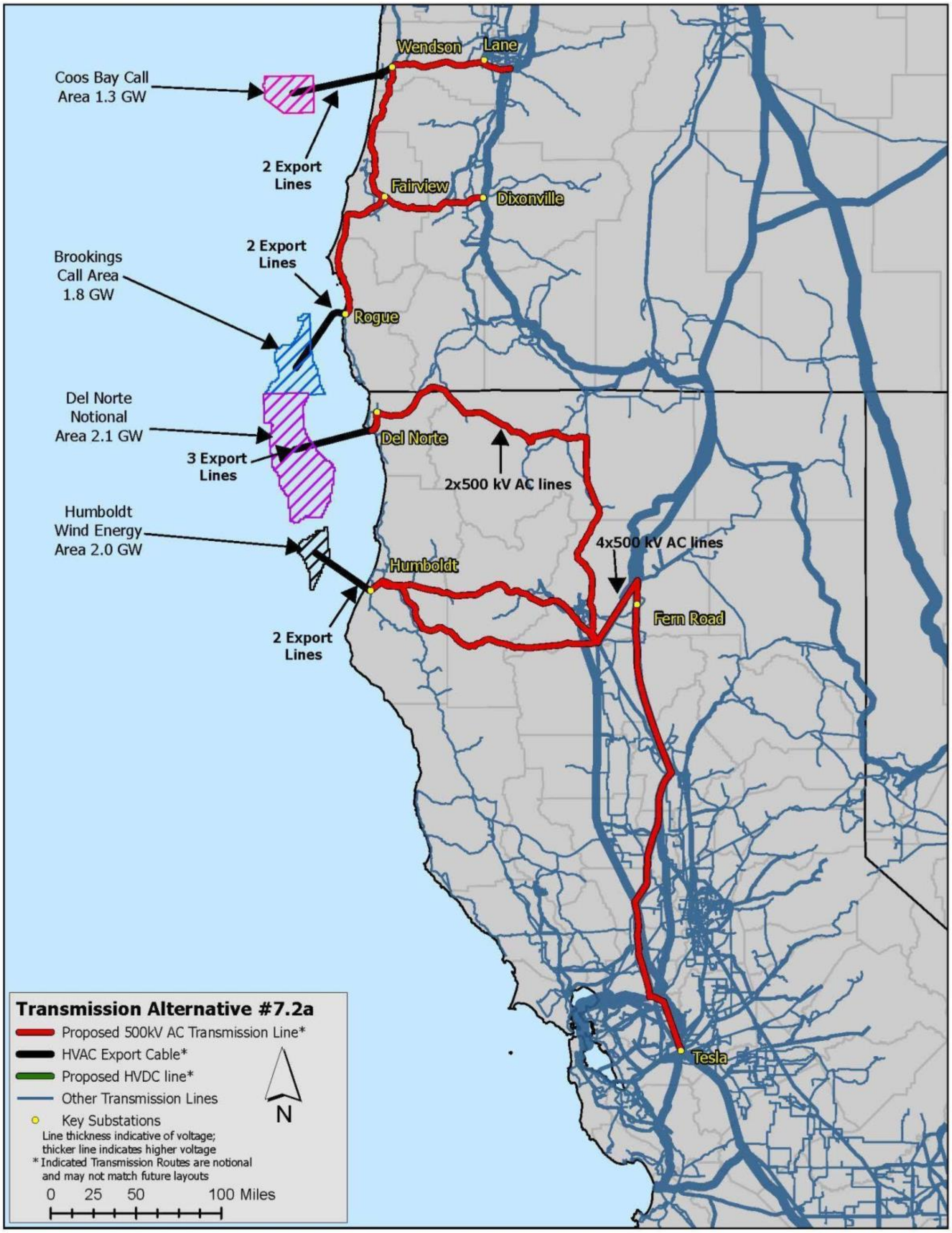

Figure 9. Physical map for Alternative 7.2a

6.8.2 Mid development scenario - Alternatives 12.4a through 12.4f (12.4 GW)

The six transmission alternatives under the Mid development scenario, identified as Alternatives 12.4a through 12.4f, are all configured to accommodate 12.4 GW of OSW power. In this section we highlight Alternative 12.4c and discuss the other alternatives in comparison.

Alternative 12.4c is the first to explore both radial and meshed offshore network connections to bring OSW power to shore via 500 kV AC export cables, as well as interconnecting OSW farms with subsea HVDC cables. This alternative provides OSW power to POIs within the state where the power is generated (i.e., power generated off the Oregon coast is connected to substations located in Oregon).

In Oregon, this alternative connects the Coos Bay and Brookings wind farms radially to Wendson and Rogue substations, respectively. Here, approximately 3 GW of OSW is connected on the central and southern Oregon coast, with 500 kV substation upgrades and a 500 kV AC transmission line added to create a loop between Wendson, Lane, Alvey, Dixonville and Fairview substations (the NorthernGrid 500 kV loop). All of the Mid development scenarios feature the NorthernGrid 500 kV loop, with the exception of Alternative 12.4a.

In California, Alternative 12.4c connects the Del Norte and Humboldt OSW farms via two subsea HVDC cables. This requires the development of dynamic HVDC cables, as well as floating HVDC conversion stations. This contrasts with Alternatives 7.2b, 12.4a and 12.4b, which all utilize onshore HVDC conversion stations and static undersea HVDC cables to connect the Del Norte and Humboldt substations.

In Del Norte, power is brought ashore via seven HVAC export cables, connecting to the new Del Norte substation, and from there it is transmitted via two new 500 kV HVAC lines to the Fern Road substation.

The Humboldt OSW farm is connected to an offshore network via two HVDC subsea cables running north to Del Norte, and a single HVDC subsea cable running south to the Moss Landing substation. Power brought directly onshore from the Humboldt wind farm is accomplished using three 500 kV HVAC export cables connected to the Humboldt substation, and the Humboldt substation is connected via a single new 500 kV AC line running to the Fern Road substation in the Central Valley. This approach ties the California OSW generation into the main 500 kV transmission backbone that runs along the I-5 corridor of California, as well as more directly injecting power into the San Francisco Bay Area via the Moss Landing substation connection.

As in all other transmission alternatives, a new 500 kV HVAC line is added between the Round Mountain and Tesla substations, which are part of the existing 500 kV backbone. This additional HVAC line is needed to handle the expanded power flow along this corridor.

Connections to lower voltage, local transmission grids via phase-shifting transformers were included for the Wendson (230 kV), Fairview (230 kV), Rogue (230 kV), Del Norte (115 kV), Humboldt (115 kV) and Moss Landing (230 kV) substations. Figure 10 provides a single line electrical schematic and Figure 11 provides a physical map showing the proposed transmission routes for Alternative 12.4c. Similar figures for the other Mid development alternatives are included in Appendix E.

In comparing Alternative 12.4c with the other Mid development scenarios, Alternatives 12.4a and 12.4b feature undersea HVDC lines that connect the Del Norte and Humboldt onshore substations. These 12.4a and 12.4b alternatives involve land-based HVDC conversion stations and static HVDC cables that run offshore and undersea to the alternate location where they again come ashore and connect to a land-based HVDC conversion station. As noted above, floating offshore substations and HVDC conversion stations do not currently exist, nor do the dynamic cables that are required to connect to the floating substations. For those reasons, we examined these cases that utilize an undersea HVDC link between the Del Norte and Humboldt OSW areas while utilizing HVDC conversion stations that are located onshore. This eliminates the need for dynamic HVDC cables since the onshore HVDC conversion stations are fixed.

Similarly, Alternatives 12.4a and 12.4b feature an overland HVDC cable running from the Humboldt substation to the Collinsville substation, and in Alternative 12.4b an undersea cable running to the Martin substation in the San Francisco Bay Area that also connects on both ends to a land-based HVDC conversion station. Because these solutions do not require floating offshore HVDC conversion stations and dynamic HVDC cables, they are likely to be deployable in a nearer timeframe than the alternatives that rely on the floating infrastructure.

Another distinction between Alternatives 12.4a and 12.4b when compared to 12.4c is that 12.4a and 12.4b interconnect all or part of the Brookings wind farm to the Del Norte substation in California, rather than to the Rogue substation in Oregon. The Del Norte substation is owned by PacifiCorp, whereas the Rogue substation is owned by Bonneville Power Administration. Therefore, this alternate approach ties the Brookings wind farm into the PacifiCorp transmission system as opposed to the Bonneville Power Administration transmission system. It also feeds the OSW power generated into the southwestern region of Oregon rather than directing the power more toward the central and northwestern regions of Oregon. These alternatives were influenced by the OSW transmission studies that were recently conducted by PacifiCorp (Austin 2023).

In a similar vein, Alternatives 12.4a, 12.4b and 12.4d all feature a connection between the Del Norte substation in northern California and the Sams Valley substation in southern Oregon. These substations are both owned by PacifiCorp. This interconnection would also serve to feed OSW power into the southwestern region of Oregon.

As we move successively from Alternative 12.4a through to Alternative 12.4f, there is an increased utilization of HVDC technology, with Alternatives 12.4c through Alternative 12.4f featuring an increased use of floating offshore HVDC technology. Alternatives 12.4d, 12.4e and 12.4f all feature floating offshore HVDC conversion stations that interconnect multiple OSW farm areas, and Alternatives 12.4e and 12.4f minimize the use of HVAC floating substations and HVAC export cables.

In all Mid development alternatives, a new 500 kV line is added between the Round Mountain and Tesla substations in California to handle the expanded power flow along this corridor.

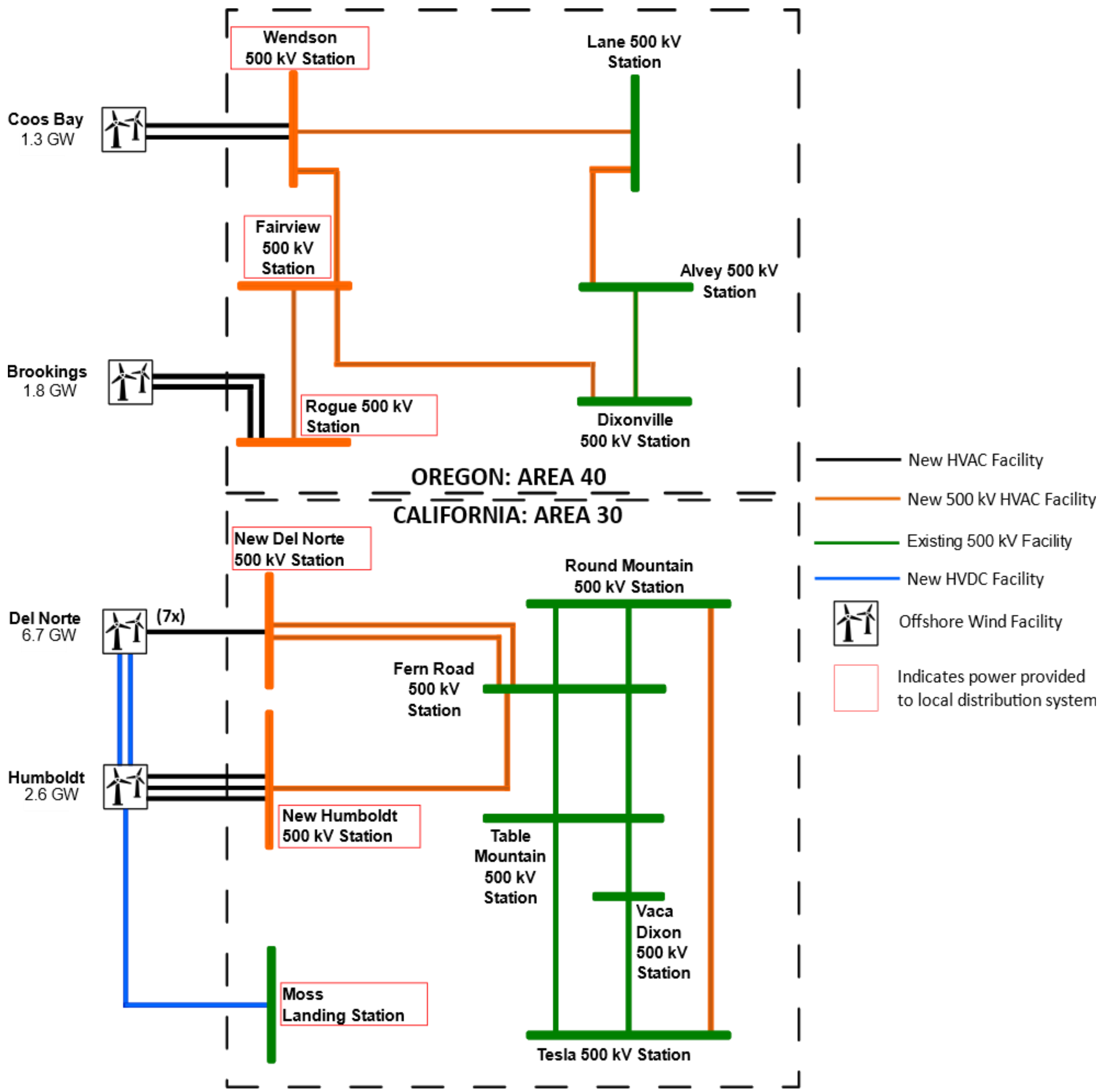

Figure 10. Single line electrical schematic for Alternative 12.4c

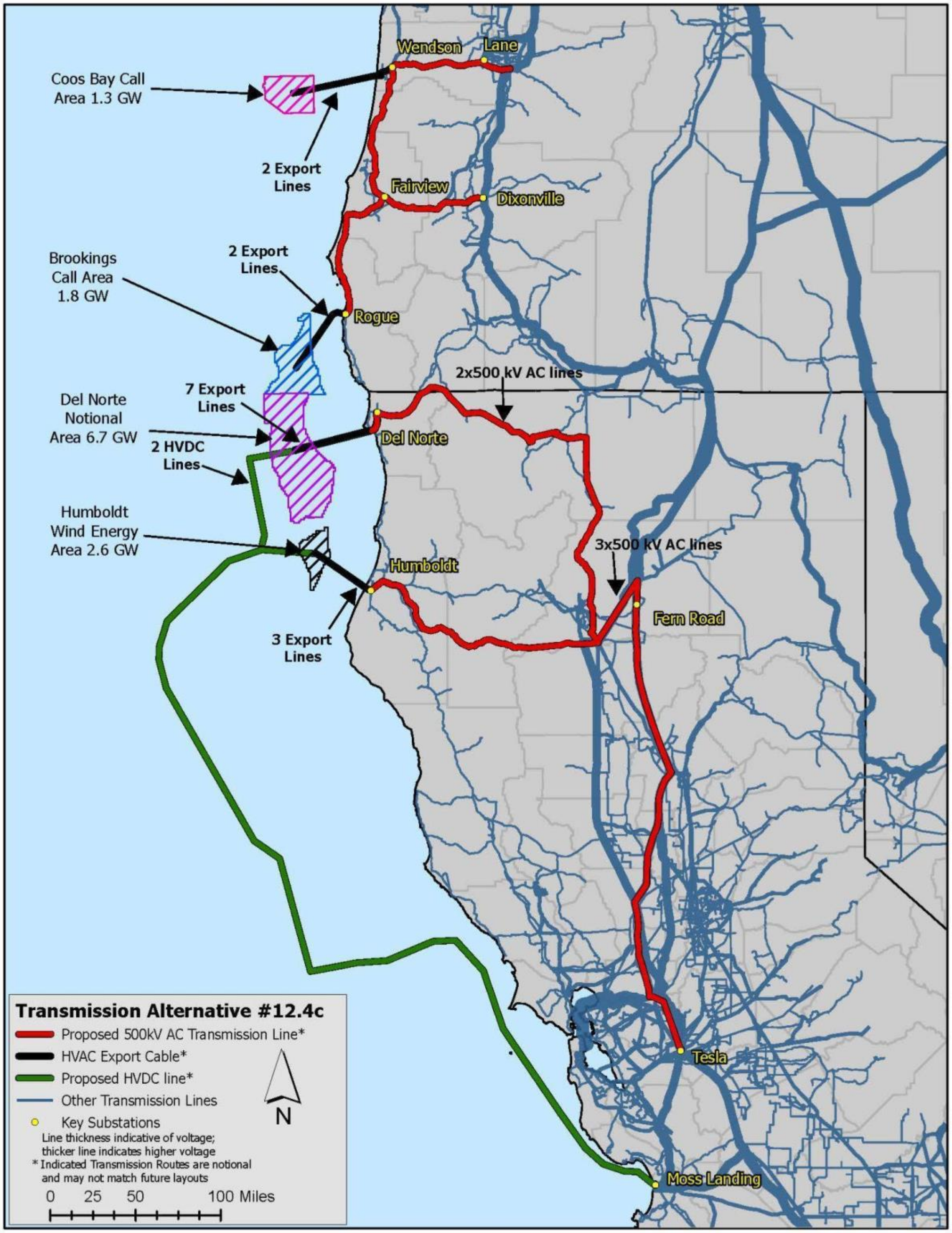

Figure 11. Physical map for Alternative 12.4c

6.8.3 High development scenario - Alternatives 25.8a and 25.8b (25.8 GW)

Alternatives 25.8a and 25.8b were developed to accommodate 25.8 GW of OSW generation capacity. We note that this High development scenario is the most futuristic, and therefore the most uncertain. Cost estimates and other assumptions become less certain the further in the future they are. In addition, this High development scenario will require greater technological advances and significantly more infrastructure development, again adding to the uncertainty.

In this section we highlight Alternative 25.8a, and compare Alternative 25.8b to 25.8a. Alternative 25.8a features the most robustly developed offshore network of all the transmission alternatives examined, making extensive use of floating HVDC infrastructure. Both radial and meshed offshore network connections, all HVDC, transmit OSW power to shore via bipolar 525 kV dynamic HVDC export cables. Radial connections from OSW farms to POIs transmit power primarily along state lines, however an HVDC "backbone" runs offshore as far north as Tillamook and as far south as Moss Landing, thereby transmitting power regionally along the broader West Coast within the project study area.

In Oregon, power is transmitted north of Coos Bay and injected at the Tillamook substation via two new HVDC subsea export cables.[9] Power is injected radially from Coos Bay via two HVDC subsea export cables to Wendson, and from Brookings via three HVDC subsea export cables to Rogue. As with others before, this alternative employs the NorthernGrid 500 kV HVAC loop to interconnect the Rogue, Fairview, Wendson, Lane, Alvey and Dixonville substations. Power can also be exported south from Coos Bay via two HVDC subsea export cables to Brookings. From Brookings, power can flow north to Coos Bay via two subsea HVDC cables and south to Del Norte via three subsea HVDC cables.

In California, Alternative 25.8a continues the offshore HVDC backbone by connecting the Del Norte, Humboldt and Cape Mendocino wind farms via subsea HVDC cables. In addition, from Cape Mendocino two HVDC undersea cables transmit power to the San Francisco Bay Area Martin substation and further south to the Moss Landing substation. Power can also be transmitted radially from Del Norte and Humboldt OSW farms to onshore substations via undersea HVDC export cables.

The onshore transmission infrastructure in California includes two parallel 500 kV HVAC lines connecting the Del Norte and Fern Road substations, as well as two 500 kV HVAC lines connecting Humboldt and Fern Road. In addition, there are two new transmission lines, one bipolar 500 kV HVDC and one 500 kV HVAC, that run from the Humboldt substation to the Collinsville substation, thereby providing OSW power to the greater San Francisco Bay Area.

Connections to lower voltage, local transmission grids via phase-shifting transformers were included for the Tillamook (230 kV), Wendson (230 kV), Fairview (230 kV), Rogue (230 kV), Moss Landing (230 kV), Martin (230 kV), Del Norte (115 kV) and Humboldt (115 kV) substations. Figure 12 provides a single line electrical schematic and Figure 13 provides a

[9] In retrospect, we note that BPA Tillamook is a very weak transmission interconnection point, and will likely need a 500-kV line to the BPA Keeler 500-kV substation. The 500-kV line length is 58 miles and could likely be built in the existing transmission corridor. The line would also provide an additional power source to a rapidly growing load area. This would add an estimated $225 million to the transmission upgrade costs for Alternative 25.8a, less than a 1% increase in total transmission system upgrade costs.

physical map showing the proposed transmission routes for Alternative 25.8a. Similar figures for Alternative 25.8b are included in Appendix E.

As in all other transmission alternatives examined, a new 500 kV line is added between the Round Mountain and Tesla substations in California to handle the additional power flow in this corridor.

Comparing Alternatives 25.8a and 25.8b, the differences are that 25.8b drops one of the 500 kV HVAC transmission lines that runs from the Del Norte substation to Fern Road, and instead the 2nd 500 kV HVAC line runs to the Sams Valley substation in southern Oregon. Additional differences include the fact that there are only two subsea HVDC transmission lines connecting the Del Norte and Brookings OSW farms in Alternative 25.8b (instead of three), there are no subsea HVDC lines connecting the Brookings wind farm with the Coos Bay wind farm, and there are no long-distance subsea HVDC lines running from Coos Bay to Tillamook/Portland, Oregon. Instead of some of this offshore HVDC transmission infrastructure there are additional onshore 500 kV HVAC lines that have been added, doubling up on lines between Wendson and Lane, Fairview and Dixonville, Lane and Alvey, and Alvey and Dixonville.

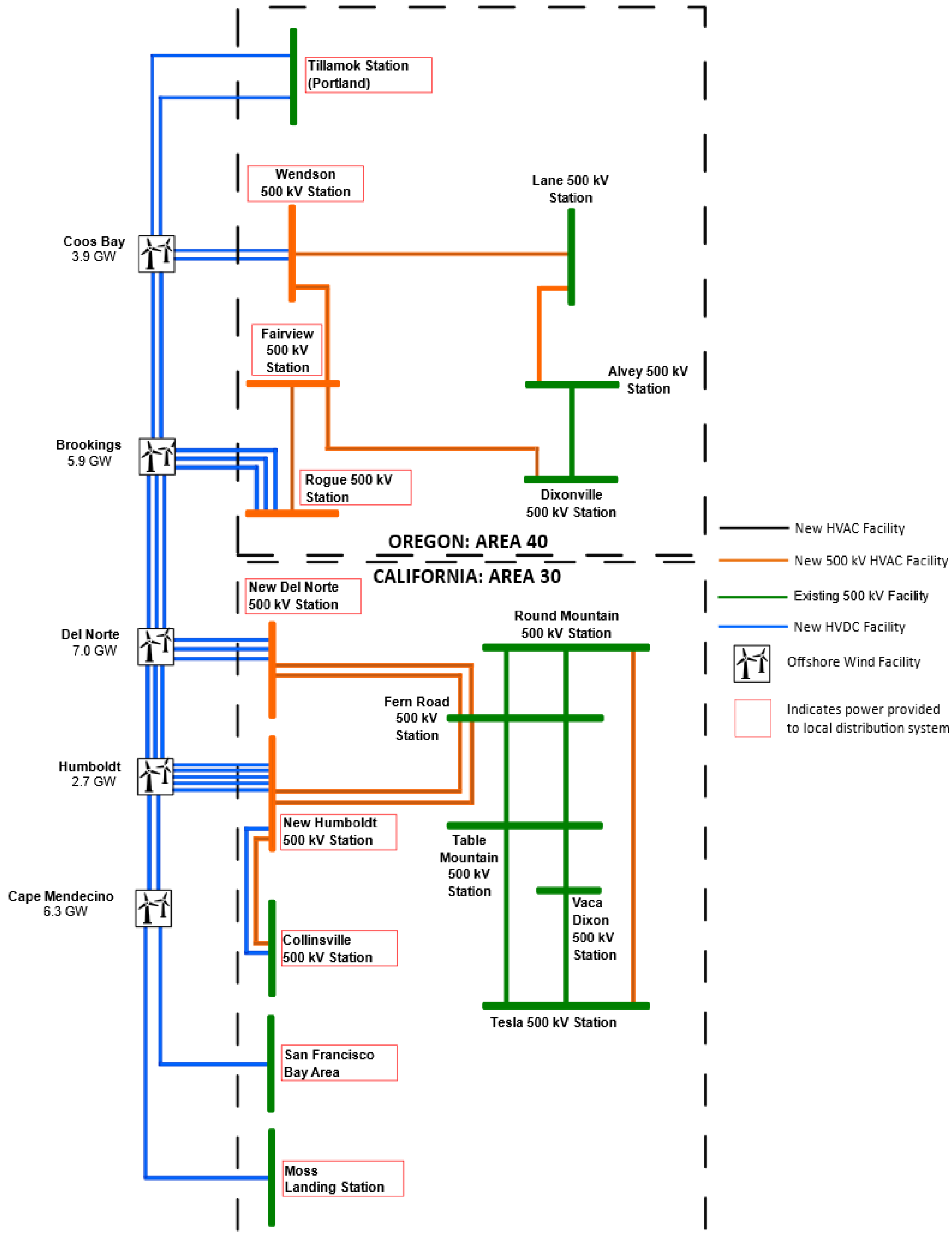

Figure 12. Single line electrical schematic for Alternative 25.8a

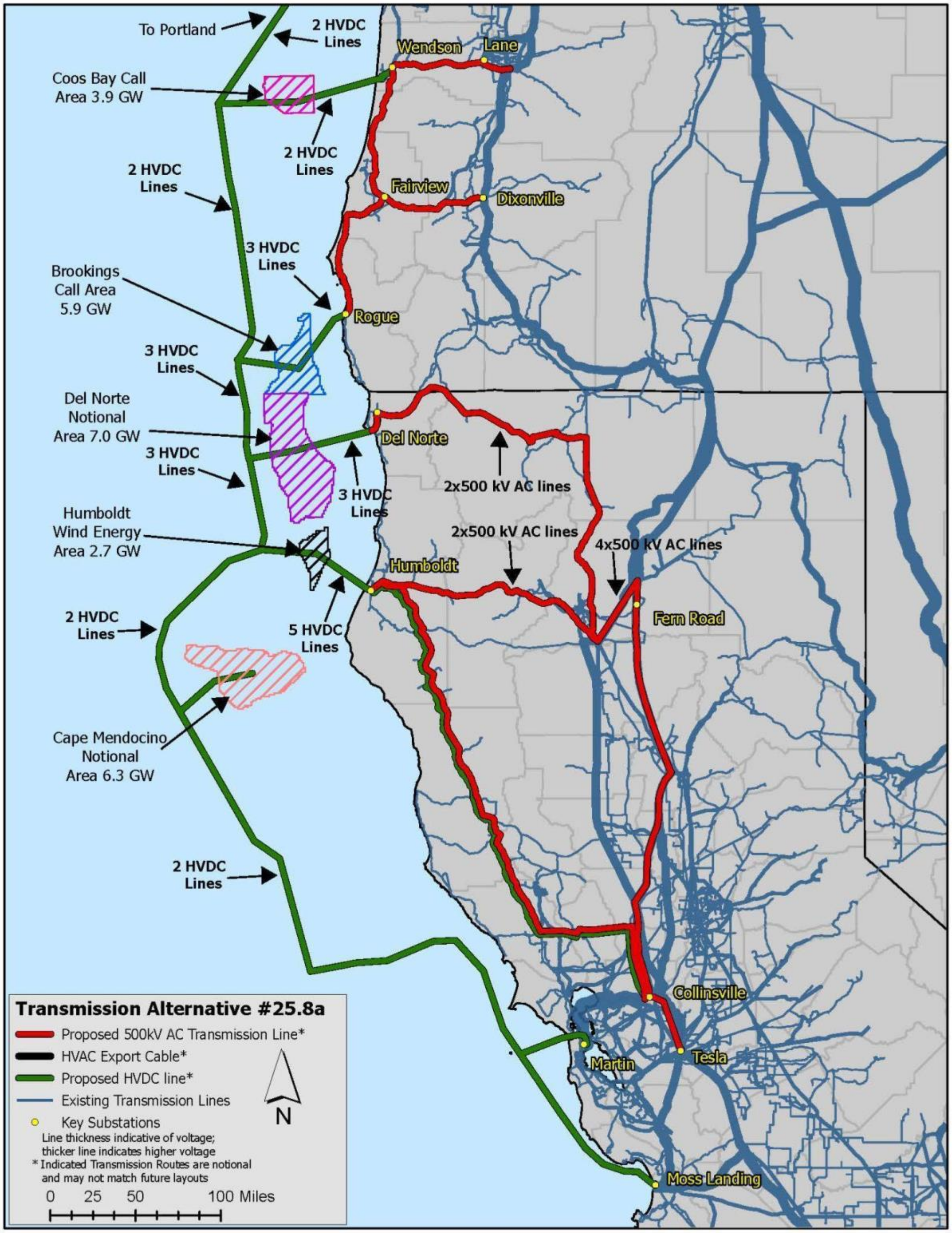

Figure 13. Physical map for Alternative 25.8a

6.8.4 High-level assessment of permitting challenges for transmission routes

H. T. Harvey & Associates utilized California Department of Fish and Wildlife GIS databases (BIOS and CNDDB, in addition to others) to provide a high-level summary and assessment of potential permitting challenges along the proposed overland and subsea transmission corridors. Their experience with permitting and navigating the environmental landscape with respect to endangered species, species of special concern, and areas of biological importance or special significance provided critical insight.

The H. T. Harvey & Associates team worked to identify potential high-level environmental concerns and key permitting or regulatory challenges associated with each segment of all of the transmission alternatives. Areas of particular focus included cable landfall locations, subsea and overland cable corridors, and transmission line corridors. Land ownership or designation was considered a key factor, including national parks, wild and scenic rivers, and marine protected areas. Sensitive marine and terrestrial habitats, as well as the potential for interaction with special-status plants and wildlife (e.g., Federal and State Endangered Species Acts) were also considered. Based upon the severity or likelihood for environmental impacts and permitting challenges, the line segments were screened, compared and differentiated.

Figure 14 shows the transmission line segments that were evaluated and ranks the various segments according to the barriers to development that were identified, ranging from low to very high barriers to development. As can be seen, line segment 3 is identified as having "very high" barriers to development. This is primarily related to the east-west section of this segment located in northern California. This portion of the segment has many challenges, including potential impacts to Redwood National Park, a state wilderness area, redwood forests, and marbled murrelet and northern spotted owl critical habitat. These challenges make this section of segment 3 very difficult to permit. However, the more north-south portion of segment 3 does not have these same challenges and would likely be easier to permit.

Segments 20 and 21 shown in Figure 14 also are ranked with "very high" barriers to development. These include potential impacts to state and federal threatened or endangered species and impacts to marine protected areas, national marine sanctuaries, and biologically important areas, as well as potential impacts to San Francisco Bay and the Delta. Cable routing into the San Francisco Bay requires coordination with several additional agencies, further complicating the permitting process.

In northern California, segments 13 & 14 run roughly parallel to Highways 299 and 36 and are ranked as having "high" barriers to development. Here, challenges in permitting are associated with Tribal lands, two national forests, the Humboldt Bay National Wildlife Refuge, and the Trinity Wild and Scenic River. Closer to the coast, both routes would require permitting from the Humboldt Bay Harbor, Recreation, and Conservation district.

Similarly, in southern Oregon segments 6 and 7 are ranked as having "high" barriers to development. Key issues here that result in the "high" barrier ranking are the combination of terrestrial and subsea components, as well as the number of special-status species, habitats, land use, and permits that would be required for each segment. If these were only terrestrial in nature, they would be ranked as "medium" barriers to development.

Subsea obstacles were found to be present south of the Humboldt OSW farm area (see segment 15 which is ranked as having "high" barriers to development). Challenges found in the offshore environment consist of sensitive habitats, seismically active regions, steep submarine canyons, and significant depths. Similar challenges to subsea alternatives are also present further south, where sections of the proposed routes intersect with several Marine Protected Areas (segments 15 and 20). These areas cannot be completely avoided, but route adjustments could reduce transit of some protected areas by making landfall further south instead of the proposed onshore landing areas. This presents additional topographical challenges because of the deep underwater canyons in the region, and adds additional costs and maintenance challenges associated with adding significant cable lengths.

In addition to the potential permitting challenges noted above, Figure 15 shows a map of the proposed transmission routes along with an overlay of military utilized airspace. We note that where the transmission routes overlap with military utilized airspace, there may be a need for mitigation. In any event, there should be early and ongoing consultation with DOD to ensure that transmission projects do not adversely impact DOD mission compatibility or national defense.

Appendix F contains more detailed information about the methods and approach used to conduct the high-level permitting and environmental assessment, as well as the results of the assessment.

An in-depth analysis would be needed to further identify which transmission segments are most feasible to permit and could therefore move toward development. The geographic layout for the transmission line routing would need to be further defined, including whether existing segments would be expanded or new lines and easements would be created altogether. Future analysis would also use additional data, including tower locations, tower height, undergrounding or reconductoring of existing lines, expansion of rights-of-way and easements. Ground truthing for sensitive ecological communities would also be recommended to confirm habitat types and potential presence of plant and/or animal species of regulatory concern. For subsea routes, future analysis would make use of more robust oceanographic surveys, as well as available geophysical datasets regarding seabed characteristics, substrate types, and the presence of specific benthic communities.

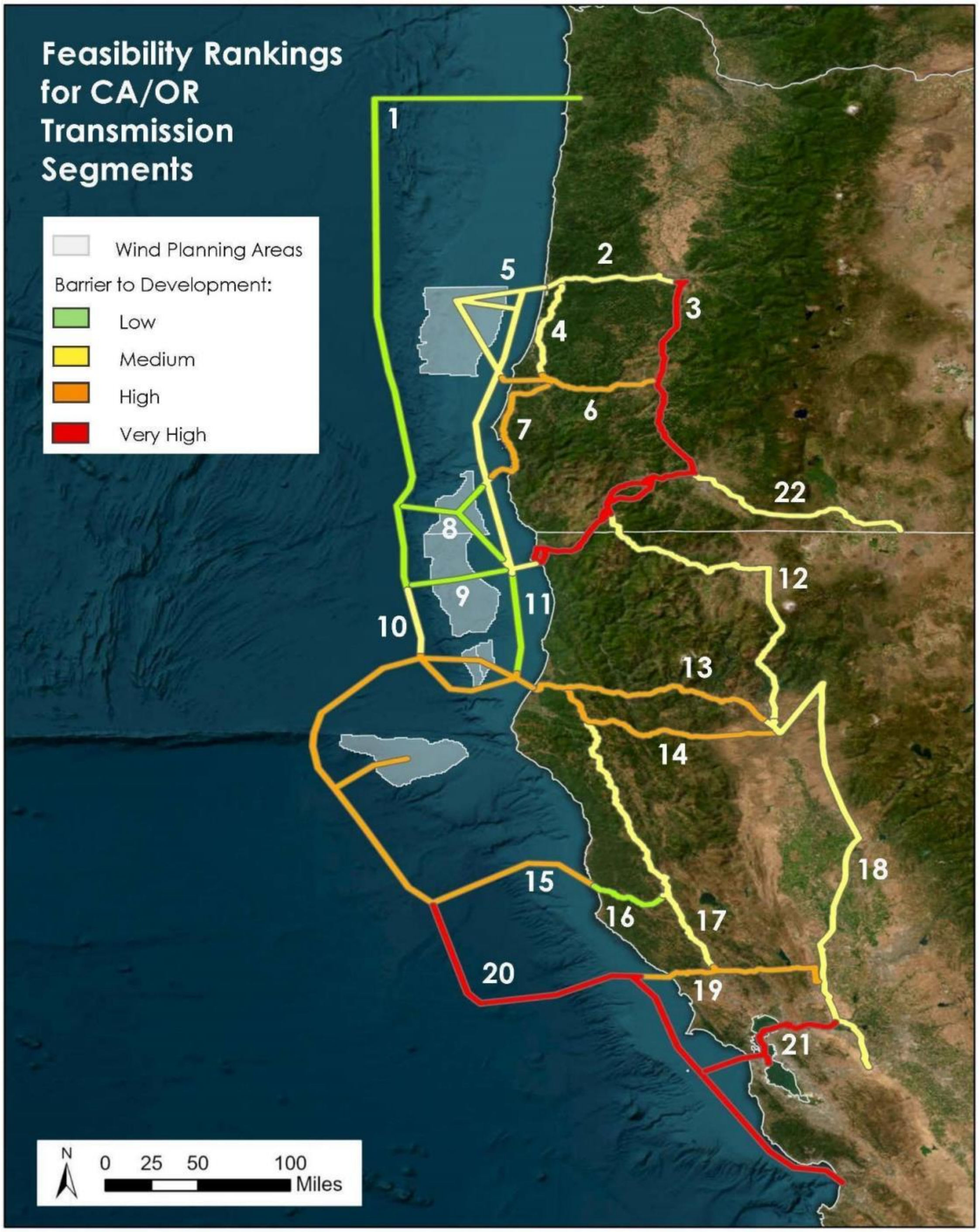

Figure 14. Permitting feasibility map showing individual segments as analyzed by H. T. Harvey & Associates

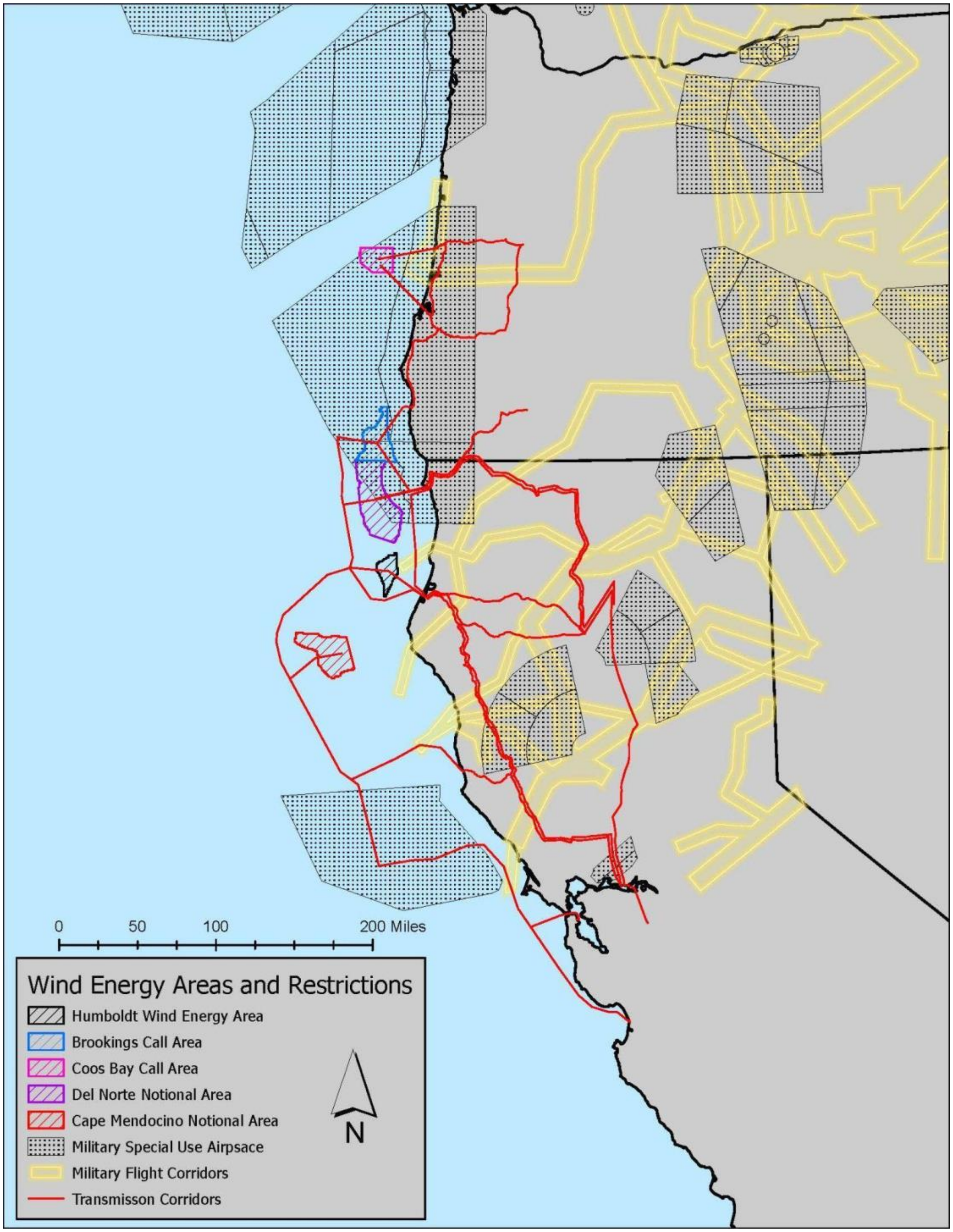

Figure 15. Map showing overlap of transmission corridors with military utilized airspace

6.8.5 Other transmission alternatives considered

The 10 transmission alternatives described above are the alternatives that were evaluated in this study. However, additional transmission alternatives were considered as part of the process of developing the final 10 alternatives that were evaluated. This section briefly describes a few of the key alternatives that were considered, but not evaluated.

In Transmission Alternatives 7.2b, 12.4a, and 12.4b, we consider the possibility of onshore HVDC conversion stations at Del Norte and Humboldt, with static HVDC cables connecting these substations via offshore HVDC cables. This approach was chosen as an alternative to floating offshore HVDC conversion stations for the Del Norte and Humboldt wind farms with dynamic HVDC undersea cables connecting them. Floating offshore HVDC conversion stations and dynamic undersea HVDC cables are two technologies that are still under development, whereas onshore HVDC conversion stations and static undersea HVDC cables already exist.

One other key alternative that was considered but not evaluated was to have an overland transmission line running along the coast between Del Norte and Humboldt. This line could be either HVAC or HVDC (we note that HVDC was required undersea because the distance was too far for an HVAC cable between Del Norte and Humboldt). However, this onshore coastal transmission line was not included in any of the alternatives largely because the coastal onshore route would involve a new transmission corridor that would run through state and national parks, ecologically sensitive areas, and Tribal lands, likely posing serious challenges.

We also considered an alternative that included a parallel 230 kV AC line and a 500 kV AC line between Humboldt and Collinsville substations, as well as alternatives that included 500 kV AC lines running in parallel with HVDC lines between Wendson and Lane substations and between Fairview and Dixonville substations. Due to the limited time and resources available, none of these alternatives were evaluated. Most other revisions that took place as we developed the 10 transmission alternatives that were evaluated were small changes in response to feedback from our Technical Focus Group.

Another alternative which was identified through the environmental and permitting assessment involved an alternate routing of subsea cables from the HVDC backbone to the San Francisco Bay Area and Moss Landing onshore locations. This alternative avoided the Greater Farallones and Cordell Banks National Marine Sanctuaries. This route would still require passing through the Monterey Bay NMS, but reducing the number of sanctuaries crossed from three to one could avoid some ecologically sensitive areas and lessen barriers to permitting. Moreover, the legislation that created the Greater Farallones and Cordell Banks Marine Sanctuaries includes language that is more restrictive with respect to undersea power cables than the corresponding legislative language for the Monterey Bay NMS. The overall route lengths for the two pathways were similar, which indicates that the cost of development, the cost of maintenance, and the implications for power flow would not change appreciably. Ultimately, the routes shown in the maps presented above were the ones studied for this project. Figure 16 below shows the alternative subsea route to deliver power to the San Francisco Bay Area (Martin substation) and to the Moss Landing substation in Monterey Bay. As noted above, the alternative route could help address some of the issues that were identified in the high-level environmental and permitting assessment that found very high barriers to development (Figure 14) for the original cable route. See Appendix D for additional information about this alternative route.

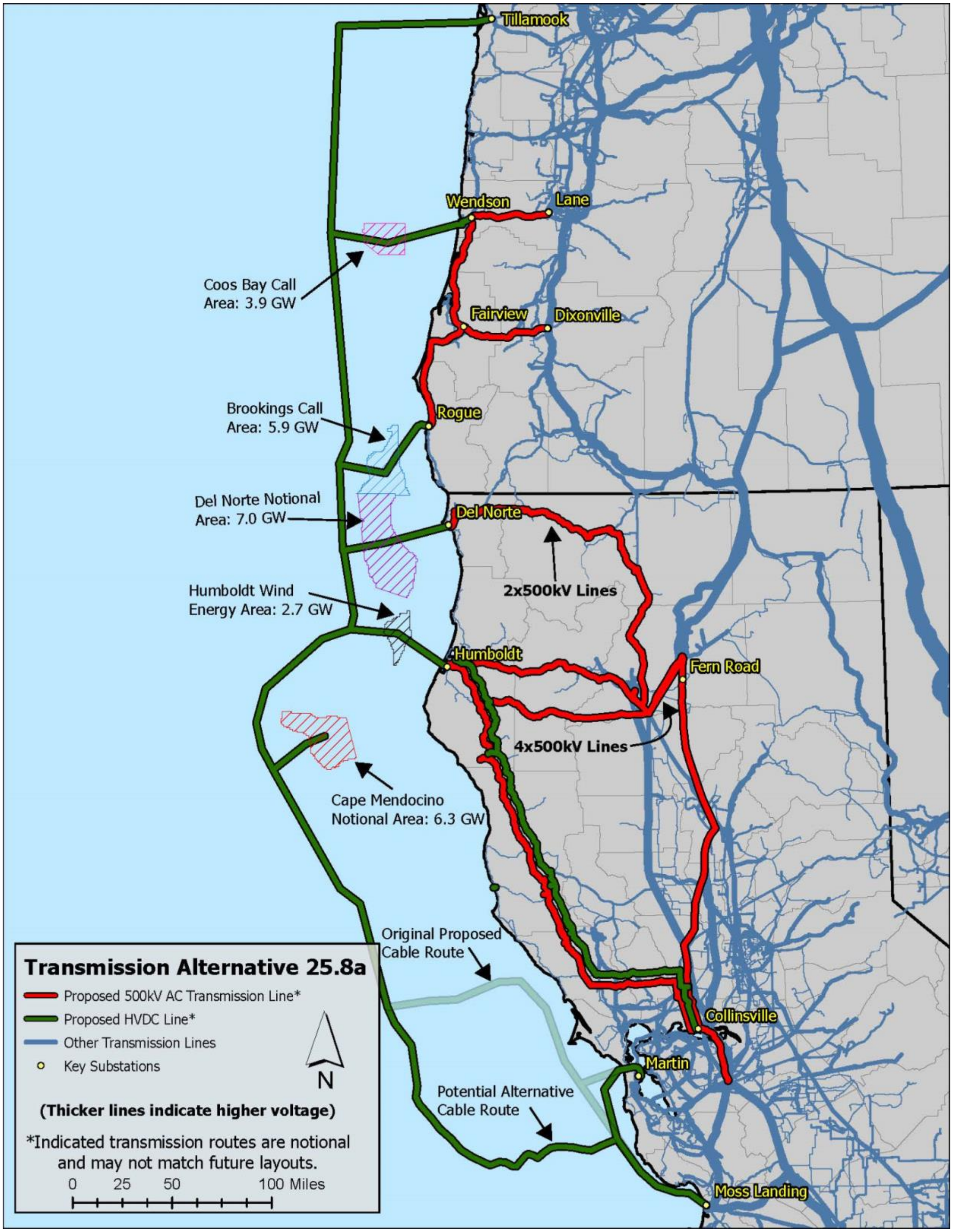

Figure 16. Map of alternative subsea cable layout for Alternative 25.8a

7 TRANSMISSION ANALYSIS METHODOLOGY AND RESULTS

The transmission analysis work for this study was conducted by Quanta Technology and consisted of:

1. Steady state power flow analyses and the determination of required network upgrades to accommodate the proposed OSW generation,
2. Cost estimation for the network upgrades and the proposed new onshore transmission infrastructure, and
3. Production cost modeling to assess the ability to feed the hourly generated wind power into the transmission system over a full year and to estimate the annual wholesale power market value of the wind energy generated.

In parallel, the NREL team on this project developed cost estimates for all of the offshore infrastructure, including the floating OSW farms and the supporting offshore transmission infrastructure (i.e., the floating HVAC and HVDC substations, the HVAC and HVDC export cables bringing the power to shore, and the HVDC cables connecting the wind farms together).

The overall flow of these analyses was as follows. The proposed wind generation and new transmission infrastructure for each alternative, as discussed in Section 6, was modeled in the power flow analyses. The results of the power flow analyses identified network upgrades that would be required in the transmission system. The proposed wind generation along with the proposed new transmission infrastructure and the required network upgrades were then analyzed in the production cost model. In addition, costs were estimated for the proposed new transmission infrastructure (both onshore and offshore), for the required network upgrades, and for the floating OSW farms themselves.

In this section of the report, we describe the methodology employed to conduct these analyses, as well as some of the interim results (such as the results of the power flow analyses). More detailed information about the methodology employed and the results generated can be found in Appendices G and H.

7.1 Power flow analysis methods and results

A steady-state power flow reliability analysis was conducted by Quanta Technology to ensure the CAISO controlled grid would comply with the North American Electric Reliability Corporation (NERC) reliability standards, the WECC regional criteria, and the CAISO planning standards. Quanta Technology then identified the need for transmission network upgrades on the northern California coast and southern Oregon coast, adhering to the guidelines established by NERC for ensuring system reliability. The NERC reliability standards impose specific criteria to be met under diverse operating conditions. In addition, WECC Regional Criteria and CAISO ISO Planning Standards were adhered to. This adherence included contingency analyses, in which the transmission system's performance with the addition of the OSW generation was evaluated under normal conditions and following the loss of single or multiple bulk electric system elements. Details regarding the power flow analysis reliability standards and criteria can be found in Appendix G.

The power flow cases for the 2032 CAISO Transmission Planning Process were used as the baseline power flow models. These cases reflect peak loading conditions for the years studied and were updated to reflect assumptions of this study. To support the evaluation of all OSW transmission alternatives, "2032 Summer Peak" long-term planning models (through the year

2032) were used in the study. The reliability study was performed using PowerGEM's TARA (Transmission Adequacy & Reliability Assessment) Software[10] in order to evaluate the local impact of OSW generation using steady-state power flow analysis (viz., the studies do not consider short circuit analysis). Constraints were examined to determine if they could be mitigated via "congestion management" or system redispatch. If not, the required network upgrades were determined.

Quanta Technology performed the power flow analysis on the 10 transmission alternatives. The results of the steady-state power flow reliability analysis provide crucial insights into the performance of the transmission network on the northern California coast and southern Oregon coast when significant OSW generation is introduced. Using load flow analysis, peak load scenarios were studied in order to gain a comprehensive perspective on the transmission system's reliability across all transmission alternatives. Contingency analysis highlighted critical failure scenarios that could potentially lead to thermal overloads. Table 9 presents an overview of the number of thermal violations across all the transmission alternatives. As expected, the number of violations generally increases as we move from the 7.2 GW scenario to the 25.8 GW scenario. Appendix H presents a more detailed account of the thermal overload violations on specific transmission circuits across all 10 transmission alternatives.

As can be seen in Table 9, the power flow analysis was first conducted for the 2032 base case condition. This was defined as the CAISO 2032 baseline power flow case, without the proposed OSW generation or the proposed new transmission infrastructure. As shown in Table 9, there were some thermal violations even in the base case. Therefore, the following criteria were used to determine when network upgrades were warranted. For each of the more than 200 individual transmission circuits evaluated in the power flow analysis, if the base case condition resulted in a circuit loading of less than 100% of the capacity and the post condition (i.e., after adding the OSW generation and proposed new transmission infrastructure) resulted in a circuit loading of ≥ 103%, then network upgrades were assumed to be required and the associated costs were estimated. Similarly, if violations existed on the circuit in the 2032 base case (≥ 100% loading) and the post-OSW conditions caused a ≥ 10% increase in the overloaded condition, then network upgrades were assumed to be required and the associated costs were estimated.

[10] https://www.power-gem.com/TARA.html

Table 9. Count of resulting thermal violations from power flow analysis for each of the 10 transmission alternatives and the 2032 base case

Transmission component affected	2032 Base Case	Alt. 7.2a	Alt. 7.2b	Alt. 12.4a	Alt. 12.4b	Alt. 12.4c	Alt. 12.4d	Alt. 12.4e	Alt. 12.4f	Alt. 25.8a	Alt. 25.8b
115 kV Transmission Lines	14	17	36	24	12	36	11	27	20	39	43
230 kV Transmission Lines	0	10	19	21	17	22	28	22	23	39	33
500 kV Transmission Lines	0	0	2	5	3	2	4	2	2	5	1
Transformers (500/230 kV)	1	0	0	2	1	1	2	1	1	3	3
Transformers (230/115 kV)	1	2	1	4	4	5	6	6	1	9	8

7.2 Cost estimation methodology

Costs were estimated by Quanta Technologies and by NREL for both new onshore transmission infrastructure and network upgrades, as well as for offshore infrastructure. Onshore infrastructure included:

- New HVAC substations,
- New HVDC conversion stations,
- New transmission lines (both HVAC and HVDC),
- New transformers, and
- Reconductoring of transmission lines.

Offshore infrastructure included:

- Floating OSW farms (including turbines, mooring, floating platforms, and array cables),
- Floating offshore substations and HVDC conversion stations, and
- HVAC and HVDC export cables.

In this section we discuss the methodology used to estimate costs in these various categories. All costs were estimated in 2022 dollars.

7.2.1 Onshore transmission infrastructure costs

Quanta Technology developed the cost estimates for the new onshore transmission infrastructure and network upgrades. Cost estimates developed are non-binding and are not based on a transmission owner's preliminary engineering or design. Cost estimates were derived using publicly available cost estimation resources. These resources included 1) the "2022 PG&E Proposed Generator Interconnection Unit Cost Guide" (PG&E 2022) and 2) the "Oregon Public Utility Commission Request for Offshore Wind Integration - Economic Study Request," prepared by PacifiCorp in March 2023 (Austin 2023). Both resources provide valuable data and insights into the projected costs of OSW developments and new infrastructure in the respective regions. Appendix I provides the cost parameters that were used to estimate the onshore transmission costs, including both new transmission infrastructure and required network upgrades.

7.2.2 Offshore floating wind farm and transmission infrastructure costs

Our project team collaborators from NREL estimated costs for the OSW farm and associated transmission system components. We note that because the floating OSW industry is still in its nascency, most of these components are still in development and therefore the cost estimates have a significant amount of uncertainty associated with them.

NREL used a bottom-up approach to model capital expenditures (CapEx) for the OSW plants and offshore transmission elements in each transmission alternative, building up total cost estimates from the estimated costs of individual components and a step-by-step model of the installation process. They combined these customized CapEx values with previously published estimates of financing and operating costs for floating OSW plants to obtain levelized costs of energy and transmission.

Cost estimates for offshore equipment, including wind energy facilities, floating substations, converter platforms, and subsea transmission cables were obtained from NREL's Offshore Renewables Balance-of-System and Installation Tool (ORBIT) (Nunemaker et al. 2020)[11]. ORBIT uses site-specific parameters to model the costs of procuring and installing OSW projects and the associated electrical infrastructure. Location specific inputs included depth, distance to port, and distance to cable landfall. The site-specific parameters used in ORBIT can be found in Appendix J.

We used the following set of technology assumptions for wind plant components. Each OSW power plant used 15-MW wind turbines with dimensions based on the IEA 15-MW Reference Wind Turbine (Gaertner et al. 2020). Figure 17 identifies the major wind turbine components and indicates dimensions for the IEA 15 MW Reference Turbine on a floating semi-submersible substructure. We assumed a turbine capital cost of $1,500/kW or $22.5-million per turbine.

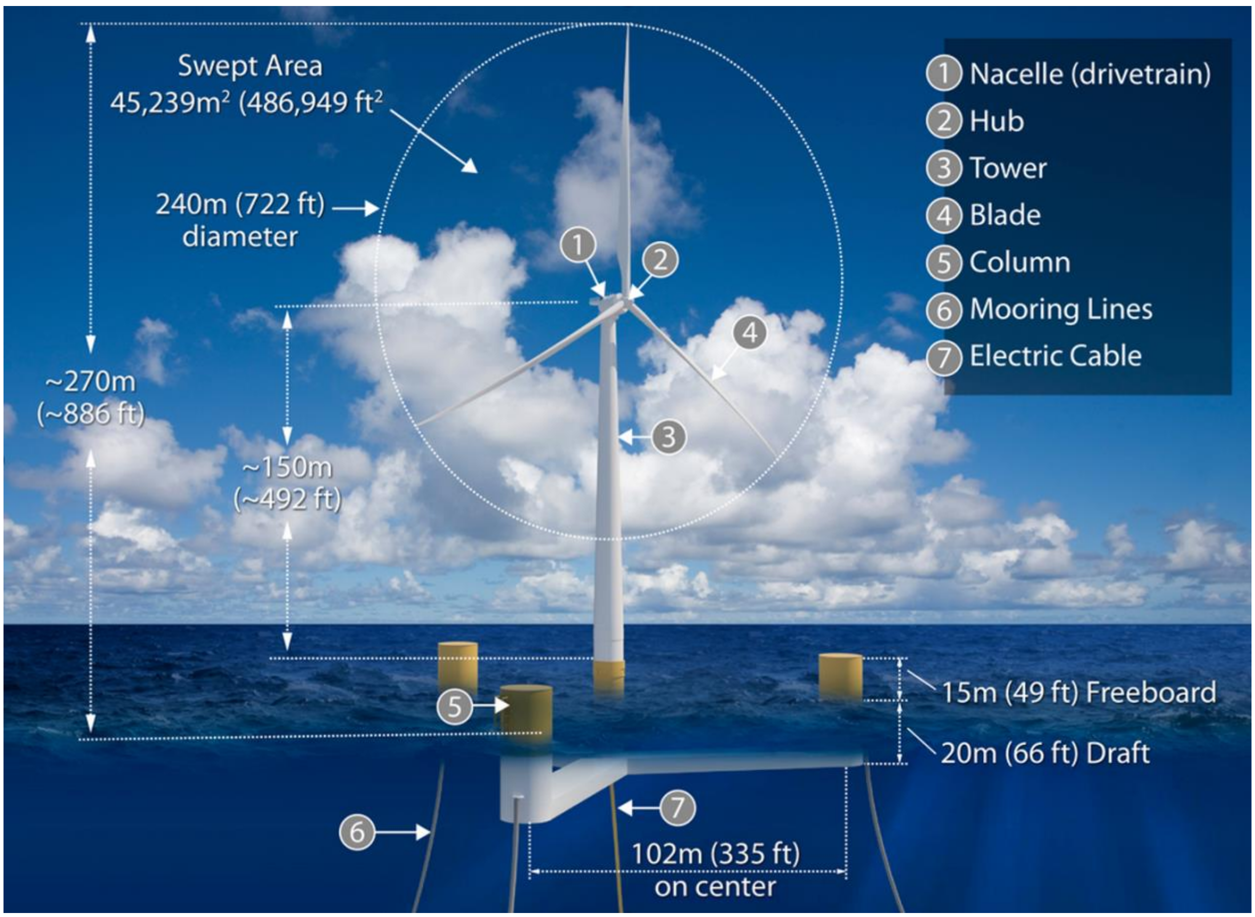

Figure 17. International Energy Agency (IEA) 15-MW Reference Wind Turbine with dimensions on a floating semi-submersible substructure. Illustration by Joshua Bauer, NREL.

The number of wind turbines per proposed wind farm would be between 87 and 467, depending on the prescribed generation capacity for each alternative analyzed. Because the water depths in the study region are too deep for fixed-bottom designs, we modeled only floating wind turbines

[11] https://github.com/WISDEM/ORBIT Version 1.0.8

and substations and developed cost estimates based on semi-submersible platforms with semi-taut mooring lines and drag embedment anchors. We used a wind and wave time series to simulate weather delays affecting the tow-out process and other vessel operations during installation. The intra-array power collection system consisted of dynamic AC cables with a voltage of 132 kV (Carbon Trust 2022).

The offshore export system includes floating offshore substations, export cables, and subsea "backbone" cables that directly connect two wind plants or coastal substations. The technology selection for each of these components varies among the transmission alternatives studied and several alternatives contain a mixture of technology types. Almost all of the technologies that we modeled—including floating substations and dynamic export cables for both HVAC and HVDC technologies—have not yet been proven at commercial scale, which increases the uncertainty of the cost estimates (Huang et al. 2023).

The floating OSW energy industry is in a nascent stage, with only 123 MW of pilot-scale and pre-commercial scale projects operating at the end of 2022 (Musial et al. forthcoming). We expect costs to decline as manufacturers gain experience, supply chains develop, and installation processes become more streamlined. To estimate how OSW plant CapEx is likely to change over time, we apply a learning rate. Learning rates are observed empirically in many industries and are expressed as the percent cost reduction for every doubling of industrial output—in this case, cumulative global OSW energy deployment in megawatts. CapEx costs were estimated out through 2050 based on assumptions of the global floating OSW development trajectory and a learning rate of 11.5%.

Detailed assumptions and model inputs to ORBIT, key technology cost estimates for technologies that are still in development (e.g., floating substations and dynamic cables), and detailed assumptions in terms of learning curve cost reductions are all provided in Appendix J.

7.3 Production cost modeling

The comprehensive production cost analysis for OSW and associated transmission expansion considered capital and fixed costs for the transmission additions and system operating costs, as well as annual electricity costs derived using the Production Cost Modeling (PCM) methodology as discussed below.[12]

The PCM analysis served two main functions: 1) Assessing the estimated value of the OSW generation within the broader wholesale power market based on hourly conditions of load, alternate generating resources and their associated operating costs, system characteristics, congestion, etc., and 2) assessing congestion issues and the possible need for curtailment of OSW generation over the hourly profile for a full year.

While the steady-state power flow analysis was utilized to determine the need for network upgrades, it was based on an assessment of only the 2032 summer peak conditions. The PCM analysis was conducted for the full 8,760 hours of the study year. This allowed assessment of hour-by-hour power flows and congestion on each link in the transmission system over a full year, and subsequently an assessment of when the new wind generation would need to be curtailed.

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[12] We only conducted the PCM analysis for the Low development (7.2 GW) and Mid development (12.4 GW) transmission alternatives.

GridView, a production cost model developed by Hitachi, was used to simulate the Western Interconnection grid in order to minimize total energy production costs while accounting for transmission congestion limitations. Parameters used in the optimization process included fuel costs, variable operating and maintenance costs (VO&M) like generator start-up costs, renewable energy costs, battery storage costs, and the costs of other ancillary services. The simulation determined the committed generation and ancillary services at the generating unit level for each hour of the study year, providing valuable insights into the most cost-effective approach for integrating OSW generation into the grid and for optimizing the overall grid operation.

The transmission grid models used for this study were obtained from CAISO and referenced as "ISO Planning PCM-2032 Base Portfolio," reflective of the 2032 study year conditions. Some of the key assumptions applicable to the study are as follows:

- The ISO Planning PCM-2032 Base Portfolio builds on the WECC Anchor Data Set (WECC 2023) for 2032. The WECC Anchor Data Set (ADS) is intended to be a compilation of load, resource and transmission topology information used by the Regional Planning Groups in the Western Interconnection as part of their regional transmission plans.
- The models reflect generation station additions, retirements, and the overall expected CAISO outlook for the year 2032. The outlook is guided by the current California Public Utilities Commission integrated resource plan and long-term procurements plan processes.
- The models include unit-specific cost data (for emission rates, variable operations and maintenance [O&M], and associated fuel prices). The CAISO models include this information based on plant performance and operating history.
- The CAISO system's hourly values for the study year for loads and renewable resources are considered.
- The grid models include the rest of WECC and interactions between CAISO and neighboring California regions (northwest, southwest, etc.).
- The models simulate the generating unit commitment and dispatch process, considering generator-forced outages and N-1 system security.
- The model calculates key parameters, including local marginal prices (LMPs), production profiles, capacity factors, and curtailments.
- To be consistent with CAISO modeling assumptions, the curtailment price for renewables was set at $25/MWh, based on the assumption that a federal Production Tax Credit (PTC) will be available to support development of the wind farms. No other fixed or variable O&M costs were associated with the renewable projects (including the OSW development).
- The analysis did not consider OSW farm participation in any ancillary service markets, which is consistent with the current CAISO market treatment of other variable energy resources such as land-based wind and solar generation.
- The CAISO models do not include Ancillary Service market prices (primarily due to the confidential nature of the bid data). The prices obtained by the models are proxy representations of the impact of scarcity pricing events.

- The OSW generation profiles for the OSW resources that were considered in each alternative were developed using modeled hourly wind speed data for 2006 through 2014 from the WIND toolkit (Draxl et al. 2015). See Section 5 and Appendix C for further information regarding the OSW generation profiles.

8 TRANSMISSION INFRASTRUCTURE COSTS ESTIMATES

For each of the transmission alternatives, we estimated the transmission related cost for both new offshore and onshore infrastructure, as well as the need for network upgrades to existing onshore transmission infrastructure. New offshore infrastructure included floating HVAC substations, floating HVDC conversion stations, and undersea HVAC and HVDC cables. New onshore infrastructure included new substations, new HVDC conversion stations, new autotransformers, new phase shifting transformers, and new HVAC and HVDC transmission lines. Onshore network upgrades included new transformers and reconductoring of existing transmission lines. In this section we summarize and discuss the costs results, with an emphasis on the comparison of costs across alternatives that will support the same level of OSW development (i.e., 7.2 GW, 12.4 GW or 25.8 GW). Additional detailed cost results for both the onshore and offshore transmission infrastructure are provided in Appendix K. All costs are in 2022 dollars.

8.1 Comparison of costs across the transmission alternatives

Figure 18 shows the total cost by alternative, as well as the breakdown between the three cost categories (new offshore infrastructure, new onshore infrastructure, and network upgrades). As expected, the total cost increases as we progress from Alternative 7.2a (7.2 GW of total capacity) through to Alternative 25.8b (25.8 GW of capacity). Figure 18 also shows that the majority of the cost is accounted for by the new onshore and offshore transmission infrastructure, with a relatively small portion being allocated to network upgrades. Also, the cost of offshore infrastructure represents a higher portion of the total costs in many of the higher capacity scenarios, where a greater reliance was placed on offshore transmission infrastructure, particularly on floating HVDC conversion stations and an HVDC transmission backbone that interconnects numerous OSW farms in the region. This is particularly noteworthy in the 25.8-GW scenario.

Not surprisingly, when the total transmission-related cost is normalized according to the total OSW generation capacity being interconnected ($ billions/GW), the normalized costs are more uniform, ranging from a high of $1.74 billion/GW to a low of $1.04 billion/GW (see Figure 19). The lowest normalized costs are clearly demonstrated for Alternatives 7.2a and 12.4a, with Alternative 25.8b being the next lowest normalized cost. The highest normalized costs are for Alternatives 12.4d, 12.4e, 12.4f, and 25.8a. These are the alternatives with the most floating offshore HVDC conversion stations and dynamic HVDC undersea cables, indicating that these technologies may be comparatively more expensive. However, Alternative 25.8b also utilizes a lot of offshore HVDC infrastructure, and the normalized cost in that alternative is the third lowest of the alternatives examined.

The costs in Figure 18 and Figure 19 are based largely on current cost guide data from PG&E and PacifiCorp, as well as on estimates for the cost of offshore transmission technologies that are still under development and do not yet commercially exist. We note that there is substantial uncertainty in these cost estimates. As a result, in Figure 20 we present an estimated range of transmission-related costs. The low values in the ranges are the costs shown in Figure 18, and the high values in the ranges are simply those initial estimates increased by a factor of two. The estimated transmission cost range for the Low development scenario (7.2 GW) is $7.5 billion to $20.2 billion, for the Mid development scenario (12.4 GW) it ranges from $13.4 billion to $43.2 billion, and for the high development scenario (25.8 GW) it ranges from $35.3 billion to $82.7 billion.

Figure 21 shows a rough breakdown of the estimated costs of infrastructure located in California versus the cost of infrastructure located in Oregon. For transmission lines that cross state lines, the cost was split evenly between the two states. For offshore infrastructure, the costs were split based on the proximity to state coastal boundaries. As shown in Figure 18, Figure 21 also demonstrates that for the larger capacity scenarios, especially the 25.8 GW scenario, there is a greater portion of the cost associated with the offshore infrastructure, namely the floating HVDC conversion stations and HVDC undersea cables.

When comparing costs between the various alternatives, there are some interesting things to note. The lowest cost alternatives examined at each scale were consistent with the alternatives exhibiting the lowest normalized cost. These were Alternative 7.2a at the Low development scale, 12.4a at the Mid development scale, and 25.8b at the High development scale. We note here, and discuss further in Section 10, that there is a correlation between longer subsea cable lengths and higher offshore transmission costs, and this appears to be part of the reason why the transmission alternatives just noted are the lowest cost within their respective development scenarios. Each of them has the shortest undersea cable runs when compared to the other alternatives in their scenario. The difference in cost between Alternative 25.8a and 25.8b is mainly because Alternative 25.8a has more undersea cables that traverse significantly greater cumulative distance. In Alternative 25.8a, HVDC cables cover almost 50% greater distance than in Alternative 25.8b.

Another interesting comparison is between Alternatives 12.4b and 12.4d. They are fairly similar in their onshore transmission configuration, and both use offshore HVDC cables. The key difference is that 12.4b does not require any floating offshore HVDC conversion stations or any dynamic HVDC cables, because it uses onshore HVDC conversion with static offshore HVDC cables running between the onshore conversion stations. We note that while these two alternatives present similar transmission line interconnections and capacities, the cost for 12.4b is about $4.3 billion less than for 12.4d, a 20% reduction. This amounts to a cost decrease of about $0.35 billion per gigawatt in terms of the normalized cost. This is likely due to the high expected cost of floating offshore HVDC conversion stations and dynamic HVDC cables. We also note that Alternative 12.4a has the least HVDC infrastructure, and it is the cheapest alternative in the Mid development scenario.

Figure 22 examines the relationship between the normalized cost of transmission infrastructure ($B/GW) and the portion of the total transmission cost that is associated with HVDC infrastructure. It appears from the Mid development scenario alternatives (12.4a-12.4f) that there is a linear relationship (coefficient of variation = 0.92) and that the normalized cost increases as the cost burden shifts toward more HVDC infrastructure. The Low development (7.2a and 7.2b) and High development (25.8a and 25.8b) alternatives also show an increase in normalized cost as the HVDC cost portion increases. However, it is important to note that the cost estimates for floating infrastructure (substations and HVDC conversion stations), dynamic cables, and much of the HVDC technologies are for equipment that is not yet commercially available. As a result, the inference that HVDC alternatives are more expensive is uncertain and merits further consideration as additional information becomes available.

Alternatives 12.4c through 25.8b all feature an offshore HVDC backbone, and Alternatives 12.4e through 25.8b feature an offshore HVDC mesh network. Many of these alternatives exhibit higher normalized costs. However, it is hard to imagine developing OSW at scale on the West Coast with up to 25 GW or more of capacity, and not utilizing HVDC technology, both onshore and offshore. In that regard, Alternative 25.8b indicates that transmission solutions utilizing onshore and offshore HVDC technology might be cost competitive. It is also important to note that the comparisons being made here are based on costs only, and do not consider the different benefits that each of these transmission alternatives may provide. We will examine that question somewhat in the next section when we discuss the production cost model results.

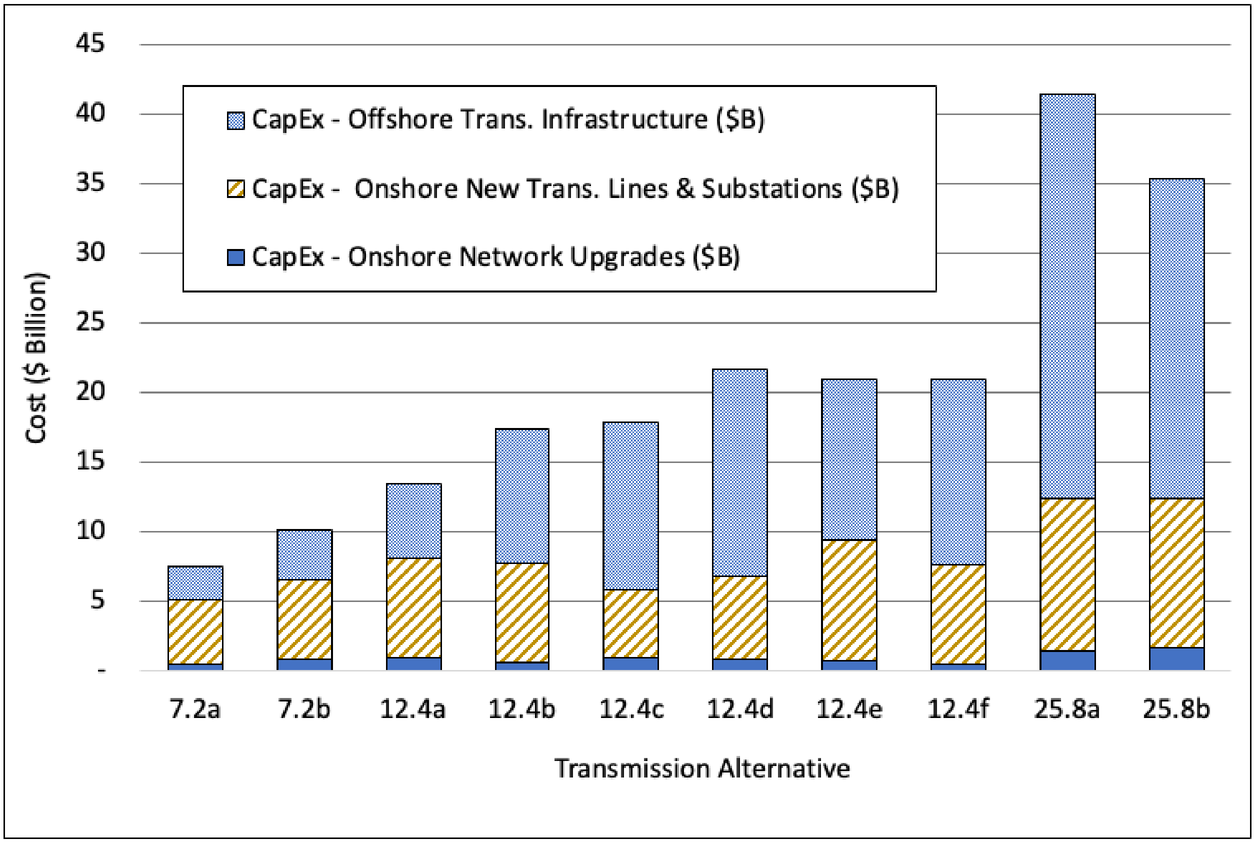

Figure 18. Total transmission system cost broken out by offshore transmission infrastructure, new onshore transmission lines and substations, and network upgrades for existing transmission infrastructure

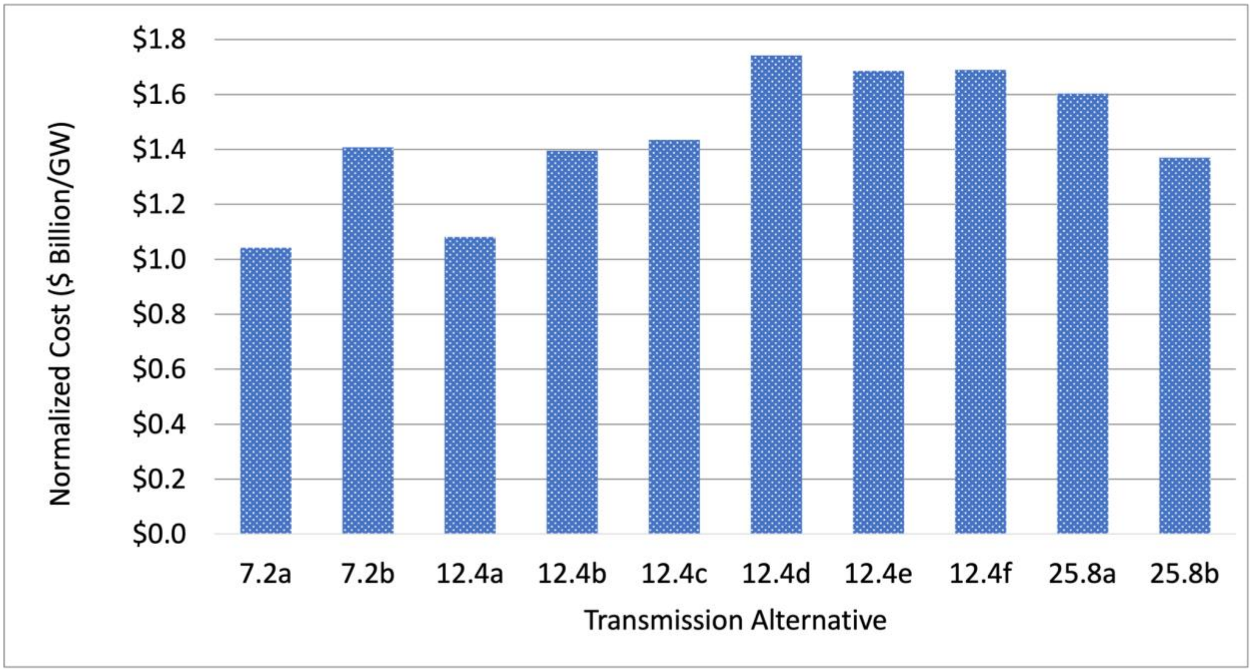

Figure 19. Total transmission system costs normalized based on the total installed OSW generation capacity

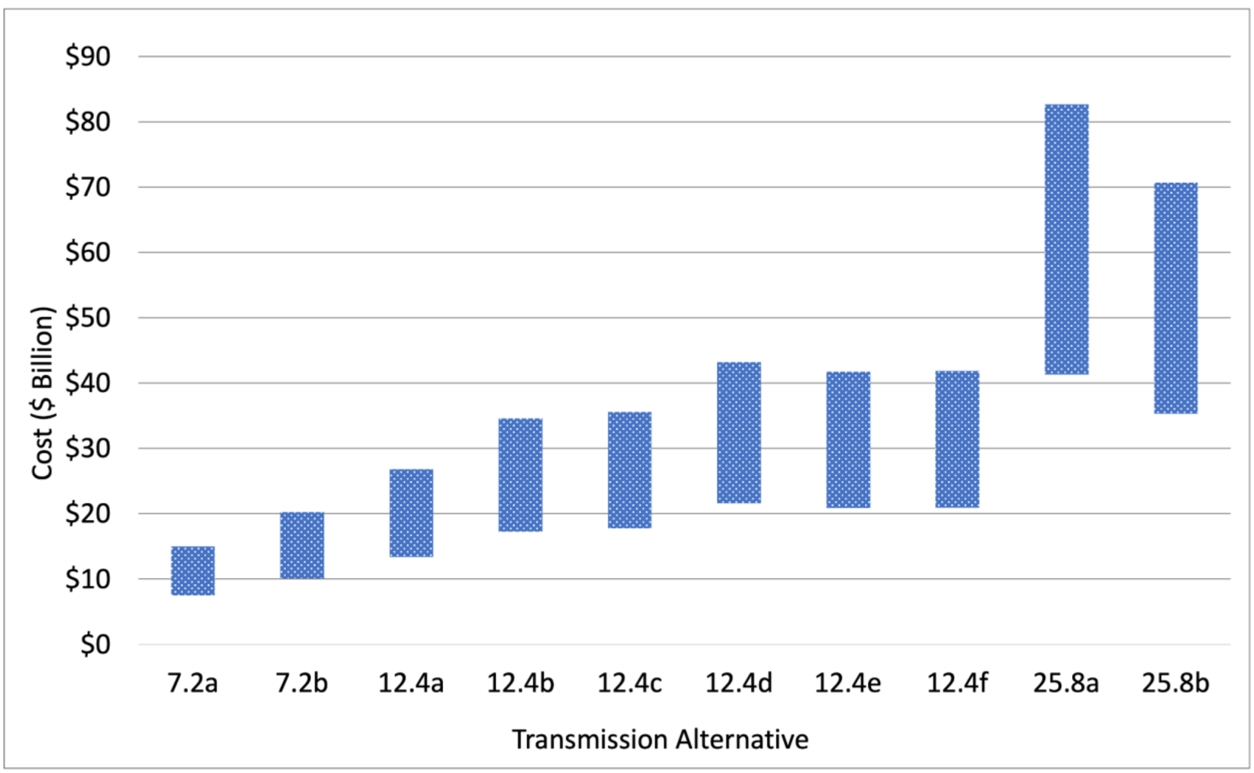

Figure 20. Estimated range of possible total transmission related costs

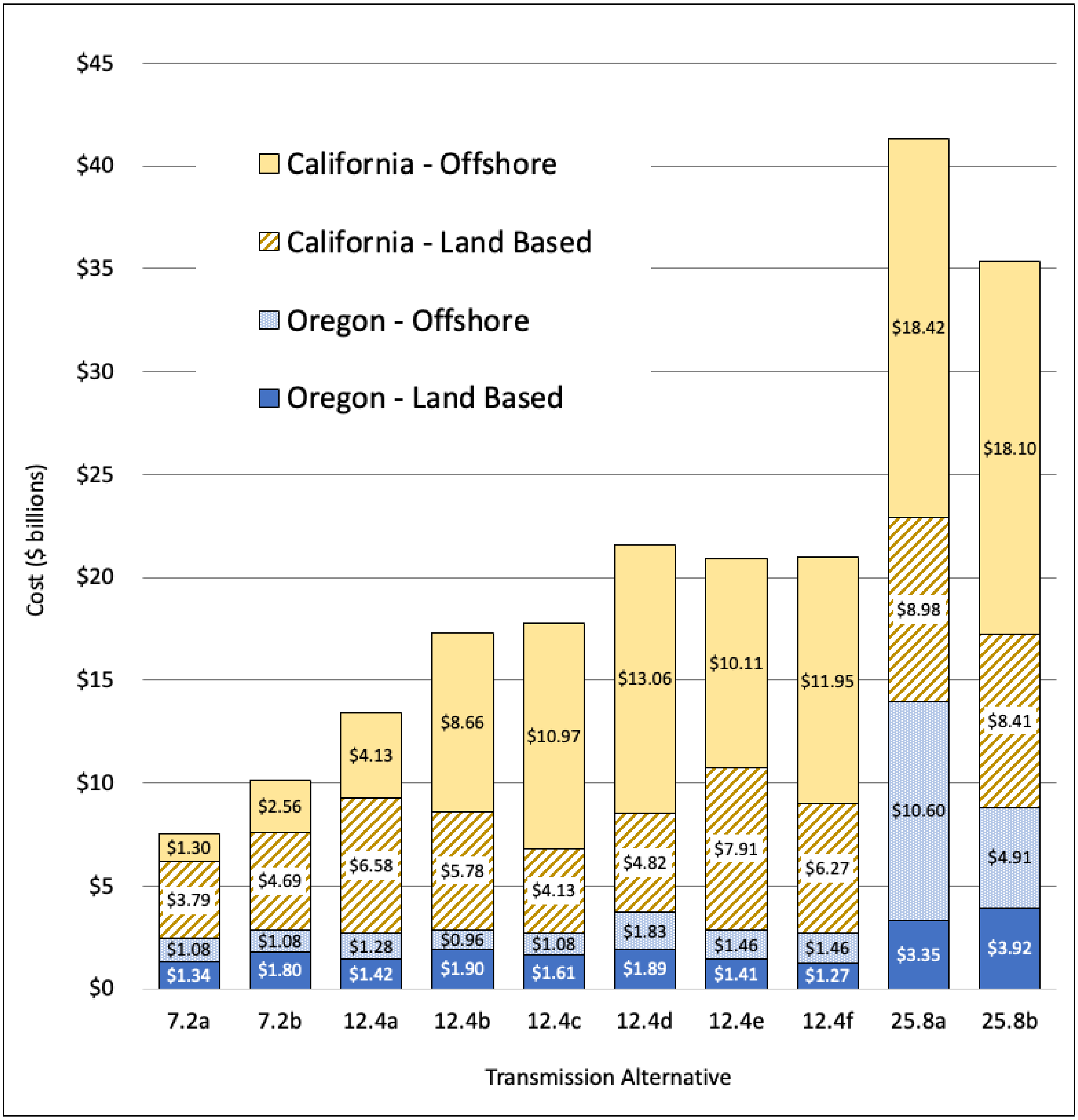

Figure 21. Estimated transmission costs for land-based and undersea infrastructure in California and Oregon

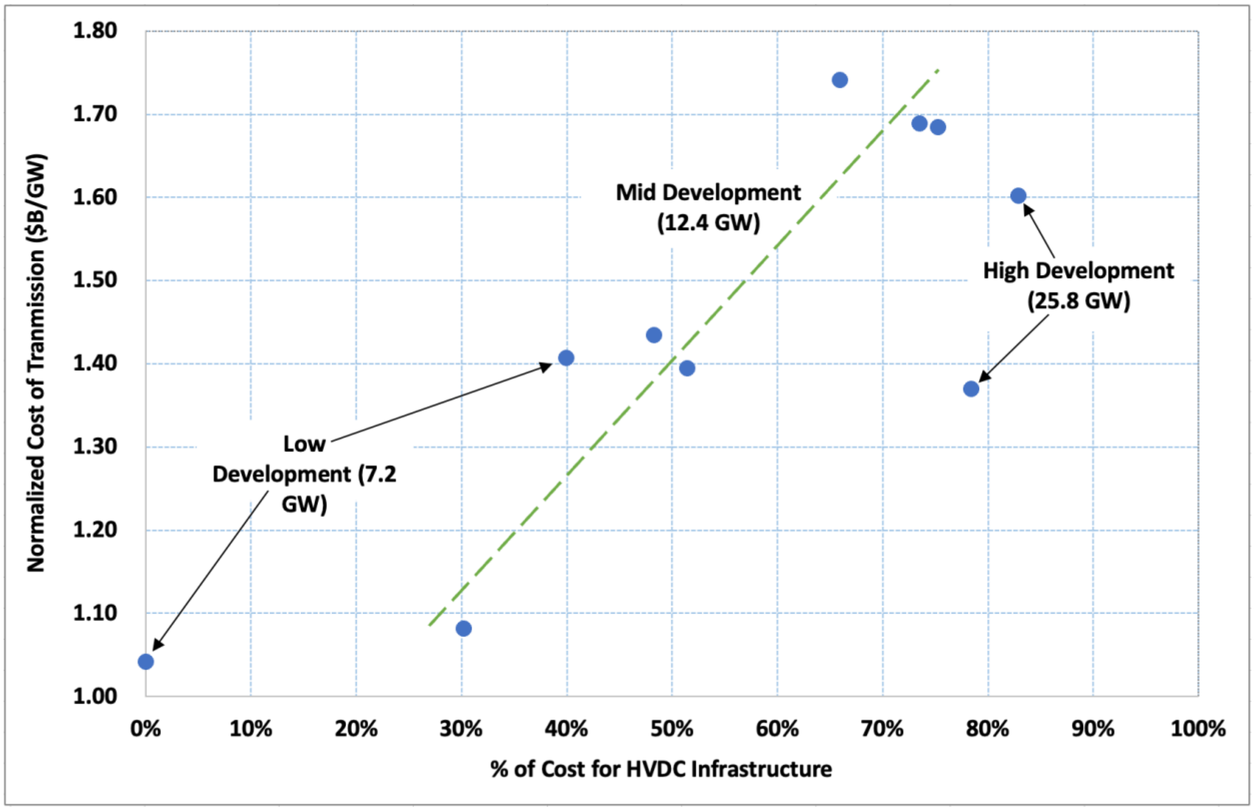

Figure 22. Relationship between normalized cost of transmission and portion of cost attributable to HVDC infrastructure

8.2 Cost to serve local communities

As described in Section 6, specific transmission infrastructure was installed across all of the transmission alternatives to ensure that the wind power generated can serve the local coastal communities that will be impacted by these projects. We estimated the costs for the required infrastructure, including phase shift transformers, auto-transformers, and new transmission lines. Table 10 presents the costs for this infrastructure in each alternative. The cost of adding these local connections ranged from 0.4% to 2.4% of the overall cost of the respective transmission alternatives. While this analysis is not exhaustive and there may be additional costs or additional locations where power should serve local communities, this analysis does provide an idea of the magnitude of the cost associated with providing power to local communities.

Table 10. Cost to provide OSW power to local communities

Transmission Alternative	Transmission Infrastructure Needed	Cost ($M)	% of Total Transmission Cost
7.2a	(3) auto-transformers, (2) phase shifting transformers, (1) 115 kV transmission line	181.50	2.4%
7.2b	(3) auto-transformers, (2) phase shifting transformers, (1) 115 kV transmission line	181.50	1.8%
12.4a	(1) auto-transformers, (2) phase shifting transformers, (1) 115 kV transmission line	102.10	0.8%
12.4b	(3) auto-transformers, (2) phase shifting transformers, (1) 115 kV transmission line	181.50	1.0%
12.4c	(3) auto-transformers, (2) phase shifting transformers, (1) 115 kV transmission line	181.50	1.0%
12.4d	(3) auto-transformers, (2) phase shifting transformers, (1) 115 kV transmission line	181.50	0.8%
12.4e	(3) auto-transformers, (2) phase shifting transformers, (1) 115 kV transmission line	181.50	0.9%
12.4f	(3) auto-transformers, (2) phase shifting transformers, (1) 115 kV transmission line	181.50	0.9%
25.8a	(3) auto-transformers, (2) phase shifting transformers, (1) 115 kV transmission line	181.50	0.4%
25.8b	(3) auto-transformers, (2) phase shifting transformers, (1) 115 kV transmission line	181.50	0.5%

8.3 Geographic distribution of costs

In terms of the geographic distribution of onshore transmission related costs, Table 11 shows the total onshore transmission costs by geographic region. These include required investments in new substations and HVDC conversion stations, new HVAC and HVDC transmission lines, and required network upgrades. It is nearly uniform across all alternatives that the majority of the investments occur in the following geographic regions: California Central Valley, Humboldt, San Francisco Bay Area, BPA service territory (Oregon), and PacifiCorp service territory (northern California and southern Oregon). Figure 23, Figure 24, and Figure 25 show the geographic distribution of onshore and offshore transmission costs throughout the study region for transmission Alternative 7.2a, Alternative 12.4c and Alternative 25.8a, respectively. Regional transmission infrastructure investment maps for all 10 transmission alternatives are included in Appendix L. We note that in these figures the size of the box that holds the transmission system investment for a given region is indicative of the magnitude of the investment required (i.e., a larger box indicates a higher cost). Note that regional costs are not borne by ratepayers within a specific region, but rather are covered on a system-wide basis (Severy, M. et al. 2021).

Table 11. Total land-based transmission infrastructure investment ($M) required for each alternative by geographic region

Geographic Region	Alt. 7.2a	Alt. 7.2b	Alt. 12.4a	Alt. 12.4b	Alt. 12.4c	Alt. 12.4d	Alt. 12.4e	Alt. 12.4f	Alt. 25.8a	Alt. 25.8b
Central Valley Area	2,216	1,244	2,061	1,472	2,061	1,774	2,850	2,061	2,344	1,993
Humboldt Area	595	1,558	1,574	1,764	420	420	1,558	883	2,811	2,875
San Francisco Bay Area	50	1,215	1,294	1,748	166	1,955	1,307	1,922	1,940	1,950
Central Coast Area	-	-	-	-	479	-	479	-	479	479
BPA Territory	1,210	1,259	473	1,245	1,254	1,195	1,323	1,146	3,088	2,974
PacifiCorp Territory	1,051	1,143	2,520	1,430	1,341	1,332	1,768	1,490	1,504	1,805
Avista Corp. Territory	-	-	-	-	-	-	-	-	96	96
Portland General Electric Territory	-	-	-	-	-	-	-	-	29	124
Los Angeles Area	4	70	80	19	24	32	35	35	33	33
Total	**5,125**	**6,490**	**8,000**	**7,679**	**5,744**	**6,709**	**9,320**	**7,537**	**12,324**	**12,328**

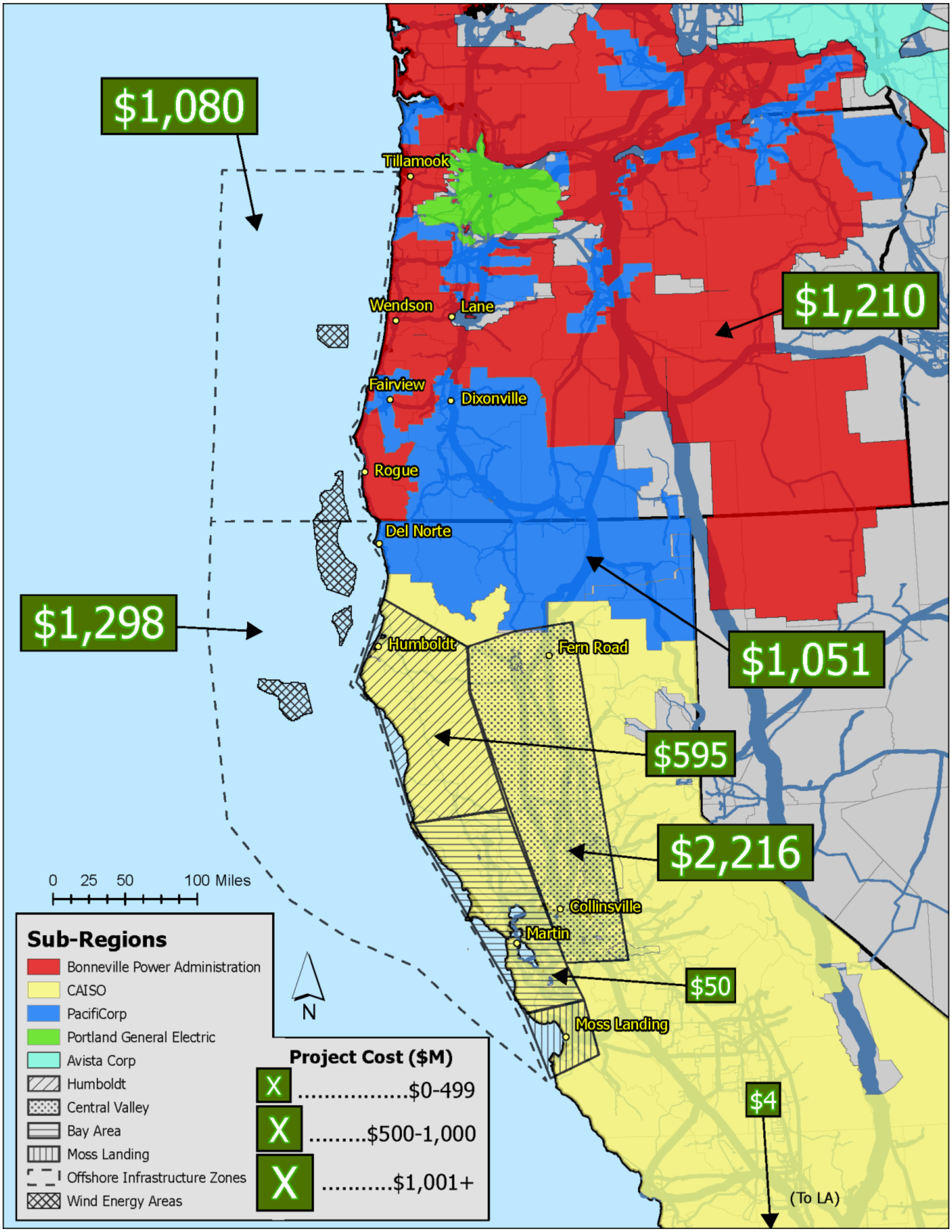

Figure 23. Regional transmission infrastructure investment map for Alternative 7.2a

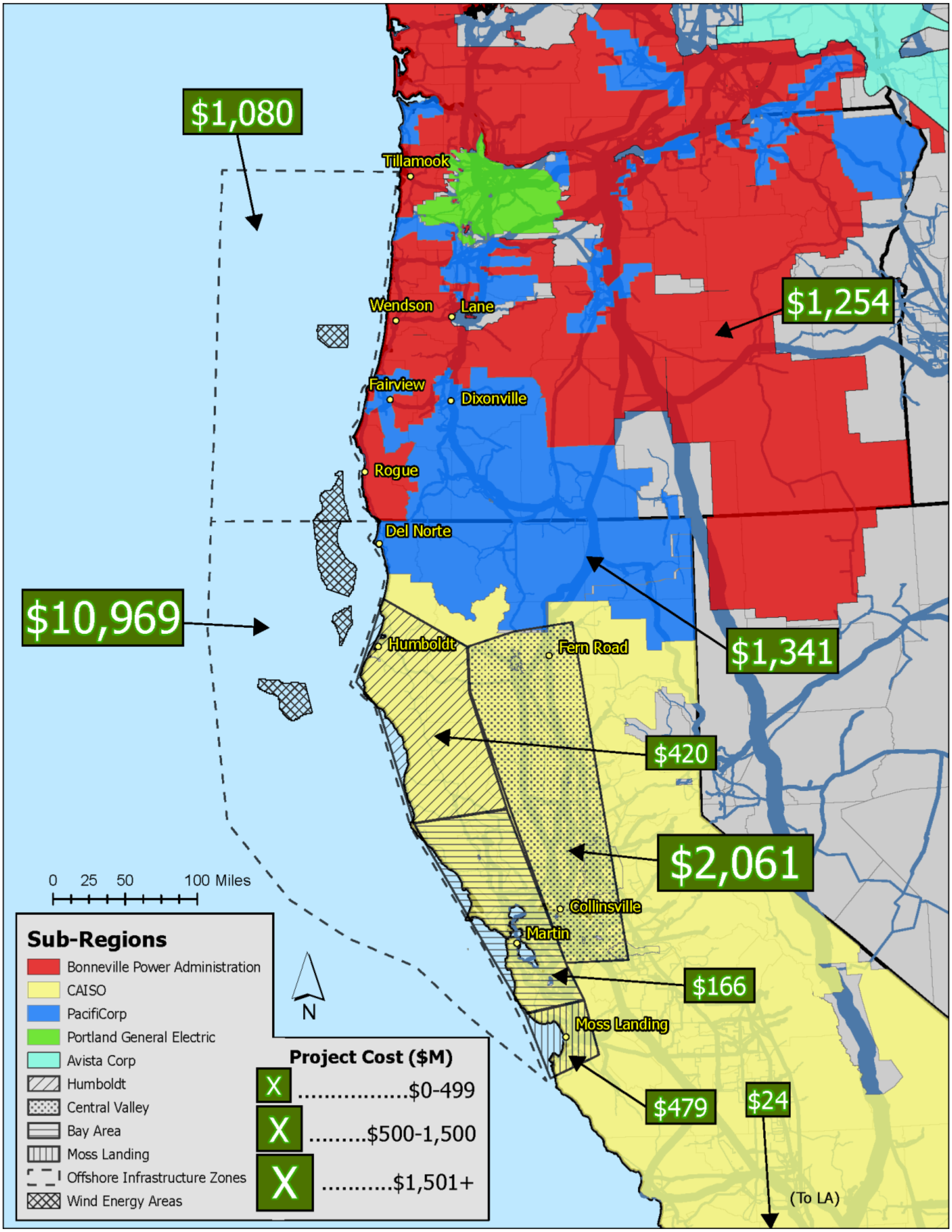

Figure 24. Regional transmission infrastructure investment map for Alternative 12.4c

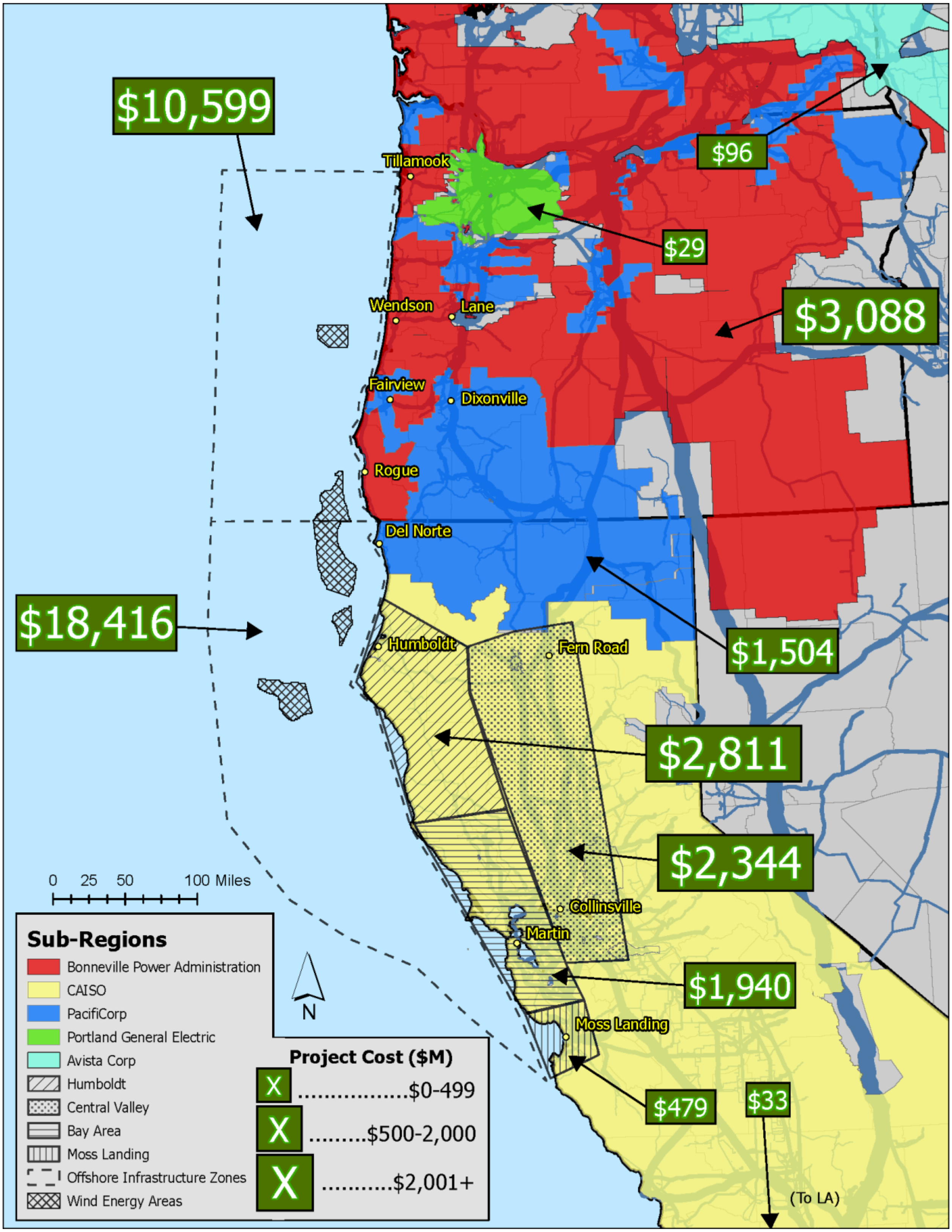

Figure 25. Regional transmission infrastructure investment map Alternative 25.8a

9 PRODUCTION COST MODELING RESULTS

The production cost model (PCM) analysis was conducted for the Low (7.2-GW) and Mid development (12.4-GW) alternatives. In the following content we present summary results for the PCM runs. Table 12 and Table 13 show the results for the 7.2-GW and 12.4-GW alternatives, respectively. We note that the Locational Marginal Prices (LMPs) shown in the tables refer to the cost to buy and sell power at different locations within the wholesale electricity market. LMPs are made up of three components that account for the cost of energy, the cost associated with congestion in the transmission system at different locations, and energy losses in the system. More detailed production cost results for each alternative are provided in Appendix M.

PCM analyses for the 25.8-GW OSW energy development scenario were not conducted as part of this study. We note that the PCM analyses could only be conducted for the 2032 study year, because that is the farthest out that the WECC ADS is available for modeling the WECC region. We expect that the development of OSW energy on the northern coast of California and the southern coast of Oregon at a scale similar to the 25.8-GW scenario is not likely to happen by 2032, and it is more likely to occur after 2040. By the time this much OSW farm capacity is installed in the study region, the electrical demand profile and generation mix are likely to differ from the conditions assumed in the 2032 WECC ADS. Therefore, PCM modeling of 25.8 GW of OSW using the 2032 WECC ADS is not likely to produce meaningful results.

The estimated net annual revenues for wind generation for the 7.2-GW alternatives range from \$49/MWh to \$54/MWh, and for the 12.4-GW alternatives they range from \$44/MWh to \$50/MWh.[13] According to the PCM results shown in Table 12, Alternative 7.2a may be preferred over Alternative 7.2b, because greater net revenue is possible in 7.2a. This appears to be due to two factors. First, there is less curtailment in Alternative 7.2a, and therefore greater net generation and a higher capacity factor. Second, the average weighted LMP is greater in 7.2a, so not only is there greater net generation, the power generated is also more valuable. These metrics may be related, because both greater curtailment and lower LMPs can be due to increased congestion in the transmission system and the inability to effectively get power to where it most needs to go. That would indicate that the transmission configuration outlined in Alternative 7.2a is superior, in terms of performance, to the configuration in 7.2b, at least under the circumstances for which it was modeled.

If we look at the single-line schematics for Alternatives 7.2a and 7.2b (Appendix E), we see that Alternative 7.2a features the 500-kV AC transmission line loop in Oregon that connects the Fairview, Wendson, Lane, Alvey, and Dixonville substations, whereas Alternative 7.2b relies on parallel lines between Wendson and Lane and between Fairview and Dixonville. The fact that 7.2a provides an alternate path for power flow may reduce congestion under some circumstances. In California, Alternative 7.2a utilizes four 500-kV AC lines running from the coast (Del Norte and Humboldt) to the Fern Road substation in the Central Valley. The cumulative capacity of these four lines is 12.8 GW. In comparison, the transmission lines available to transmit power in Alternative 7.2b include only one 500-kV AC line running from Humboldt to Fern Road and one overland HVDC line running from Humboldt to Collinsville. The cumulative capacity of these two lines is only 6.2 GW. The lower cumulative capacity in Alternative 7.2b is a likely cause of congestion in some situations.

[13] These net revenues include the assumed \$25/MWh Production Tax Credit.

Table 12. Production cost model results for Alternatives 7.2a and 7.2b (2032 study year, 2022 dollars)

Transmission Alternative	Max. Capacity (GW)	Avg. LMP Weighted by Generation ($/MWh)	Simple Avg. LMP ($/MWh)	Total Annual Gen. (GWh)	Capacity Factor (%)	Annual Curtailed Gen. (GWh)	Curtailment (%)	Annual Revenue ($M)	Net Annual Revenue* ($M)
Alternative 7.2a	7.2	29.4	30.3	30,232	48%	172	0.57%	889	1,645
Alternative 7.2b	7.2	23.8	26.9	29,758	47%	627	2.11%	708	1,452

*Net revenue includes the Production Tax Credit revenue assumed to be $25/MWh.

Table 13. Production cost model results for Alternatives 12.4a through 12.4f (2032 study year, 2022 dollars)

Transmission Alternative	Max. Capacity (GW)	Avg. LMP Weighted by Generation ($/MWh)	Simple Avg. LMP ($/MWh)	Total Annual Gen. (GWh)	Capacity Factor (%)	Annual Curtailed Gen. (GWh)	Curtailment (%)	Annual Revenue ($M)	Net Annual Revenue* ($M)
Alternative 12.4a	12.4	19.2	23.4	51,522	47%	1,215	2.36%	989	2,277
Alternative 12.4b	12.4	23.5	25.5	52,153	48%	611	1.17%	1,226	2,529
Alternative 12.4c	12.4	19.0	23.3	51,791	48%	1,058	2.04%	984	2,279
Alternative 12.4d	12.4	21.1	24.4	52,067	48%	792	1.52%	1,099	2,400
Alternative 12.4e	12.4	23.0	25.8	52,138	48%	727	1.39%	1,199	2,503
Alternative 12.4f	12.4	25.3	27.6	53,061	49%	621	1.17%	1,342	2,669

*Net revenue includes the Production Tax Credit revenue assumed to be $25/MWh.

When examining the utilization of the newly proposed transmission lines in Alternative 7.2b we see that both transmission lines noted earlier, the HVAC line to Fern Road and the HVDC line to Collinsville, are utilized at their maximum capacity at some times; on average the line to Fern Road is used at 81% of its capacity. In comparison, the four HVAC lines running to Fern Road in Alternative 7.2a are never utilized at more than 30% of their capacity.

Conducting a similar comparison for the transmission alternatives shown in Table 13, we see that Alternatives 12.4f and 12.4b demonstrate the highest net revenues, the lowest curtailed energy, and the highest weighted LMPs. The general trend that can be seen in Table 13 is that across all of the alternatives, as the curtailment goes up, the LMPs go down, and the net revenue goes up. Comparing all six alternatives for the 12.4-GW scenario we see that they are ranked in the following order in terms of net revenue from high to low: 12.4f, 12.4b, 12.4e, 12.4d, 12.4c, and 12.4a. We also note that the range in net revenue across these six alternatives is narrow, with the highest value being only 17% greater than the lowest value.

With regard to the utilization of the newly proposed transmission lines in the 12.4-GW alternatives, in every alternative the new lines tend to be utilized at high capacity. Nearly half the new lines are used at full capacity at least part of the time, and all of the lines cumulatively are utilized at an average capacity of about 35% to 50%. When comparing the percent utilization of the new transmission lines across each of the 12.4-GW alternatives with the curtailment and net revenues, there does not seem to be any particular trend or correlation between them.

One interesting thing that was identified via the production cost model analyses is that while the premise of this study implies that the impetus for installing the new transmission infrastructure is to accommodate newly developed OSW generation, once the infrastructure is in place it will provide additional benefits by providing general transmission services to the overall transmission system. The infrastructure will provide new transmission pathways that, at times, might serve to reduce congestion and reduce the average cost of power on the overall system. For example, we observed times when power flowed from onshore substations to offshore substations, then through the offshore transmission infrastructure, and then back on shore at a different location to a different onshore substation. The PCM model chose these power flow solutions because they resulted in a lower overall system cost than alternative solutions.

Table 14 presents the WECC systemwide production costs results for the 7.2 GW and 12.4 GW development scenarios, with a comparison to the base case 2032 production cost run with no OSW development or transmission upgrades. All of the proposed alternatives result in substantial systemwide production cost savings, as well as substantial reductions is CO_2 emissions. Assuming a $72/MT cost for CO_2 in the year 2032 (in 2022 dollars), we have estimated the monetary savings associated with the CO_2 emissions savings. In the last column on the right, we present the total system-wide savings, which includes both production cost savings, as well as CO_2 emissions savings. The production cost savings range from 4.3% to 10.9%, and the CO_2 emissions savings account for another 3.8% to 8.0% savings, for a combined savings ranging from 8.2% to 18.9%. Note we have not estimated the savings associated with a reduction in criteria pollutants, which could be substantial. In addition, the USEPA is currently considering significantly increasing the social cost of carbon, which would increase the system-cost savings substantially.

Table 14. Production cost model systemwide costs and savings (2032 study year, 2022 dollars)

Transmission Alternative	System-wide Production cost ($M)	System-wide Production cost savings ($M)	System-wide CO_2 Emissions (Metric Tons)	System-wide CO_2 Emissions Reduction (Metric Tons)	System-wide CO_2 Cost Savings Valued at $72/MT ($M)	System-wide Total Cost Savings ($M)
Base case	14,147		151,321,561			
Alternative 7.2a	13,543	604	143,574,243	7,747,318	554	1,158
Alternative 7.2b	13,492	655	143,850,543	7,471,018	535	1,189
Alternative 12.4a	12,673	1,474	135,789,895	15,531,666	1,111	2,585
Alternative 12.4b	12,605	1,542	135,590,551	15,731,010	1,126	2,668
Alternative 12.4c	12,667	1,480	136,082,426	15,239,135	1,091	2,570
Alternative 12.4d	12,626	1,521	135,782,000	15,539,561	1,112	2,633
Alternative 12.4e	12,630	1,517	135,585,911	15,735,650	1,126	2,643
Alternative 12.4f	12,804	1,343	138,173,853	13,147,708	941	2,284

10 Levelized Cost of Energy and Transmission

The NREL team developed levelized cost of energy (LCOE) and levelized cost of transmission (LCOT) metrics for each of the transmission alternatives. The LCOE expresses the total cost to build, finance, and operate a power plant, per megawatt-hour (MWh) of electricity generation. Similarly, the LCOT represents the total cost to build, finance, and operate the transmission infrastructure per MWh of generation. The equations used to calculate LCOE and LCOT, as well as the associated financing assumptions, are included in Appendix N. The OSW generation assumed in each alternative was determined as discussed in Section 5 and further explained in Appendix C.

Both LCOE and LCOT are calculated relative to the average annual energy output from OSW in each alternative, which provides a common basis for comparison. We present transmission and generation costs separately because these two types of assets may have different financing sources and terms and different useful lifetimes. The boundary between transmission and generation components could conceptually be drawn at various points between the individual wind turbines and the existing electric grid in California and Oregon. In this study, we draw the boundary at the connection between the intra-array cables and the offshore substation. This choice of boundaries allows us to group all of the elements that vary between transmission alternatives (HVAC or HVDC offshore substations, subsea backbone segments, subsea export cables, new overland transmission lines, and onshore substations) into the LCOT. However, this grouping may not reflect how financial responsibility and ownership are ultimately divided between parties in California and Oregon.

We rely on the Annual Technology Baseline (NREL 2023) for OpEx estimates for floating OSW plants between 2030 and 2050. We use OpEx for Offshore Wind Class 8 (based on annual average wind speed) to represent Brookings, Del Norte, and Cape Mendocino, and Offshore Wind Class 12 to represent Humboldt and Coos Bay.

Table 15 presents total capital expenditures for each alternative, assuming commercial operations starting in 2032. Subtotals are provided for three categories: offshore wind plants (wind turbines, floating platforms, moorings, anchors, and array cables), offshore transmission (floating substations, converter stations, export cables, and interlink cables), and onshore transmission (upgrades, new lines, and substations).

Table 15. 2032 Offshore wind plant and transmission system costs

Transmission Alternative	Offshore Wind Plant CapEx* ($B)	Offshore Trans. CapEx ($B)	Onshore Trans. CapEx ($B)	Total CapEx ($B)	Trans. CapEx ($/kW)	Total CapEx ($/kW)
7.2a	$25.5	$2.4	$5.1	$33.0	$1,042	$4,583
7.2b	$25.5	$3.6	$6.5	$35.6	$1,407	$4,948
12.4a	$44.8	$5.4	$8.0	$58.3	$1,081	$4,698
12.4b	$44.8	$9.6	$7.7	$62.1	$1,395	$5,012
12.4c	$44.9	$12.0	$5.7	$62.7	$1,435	$5,054
12.4d	$44.9	$14.9	$6.7	$66.5	$1,741	$5,364
12.4e	$44.9	$11.6	$9.3	$65.8	$1,685	$5,303
12.4f	$45.0	$13.4	$7.5	$66.0	$1,689	$5,322
25.8a	$95.5	$29.0	$12.3	$136.9	$1,602	$5,305
25.8b	$95.5	$23.0	$12.3	$130.8	$1,370	$5,069

The OSW plant CapEx does not vary significantly between alternatives at a given deployment level (7.2 GW, 12.4 GW, or 25.8 GW). The main factor influencing wind plant CapEx variations between the transmission alternatives, on a dollar per kW basis, is the distribution of wind farm capacity between OSW sites. For example, the alternatives that include turbines sited at Cape Mendocino, Alternatives 12.4f, 25.8a and 25.8b, have higher average CapEx because the deep water in that location increases modeled mooring system costs by approximately $300/kW relative to the other sites. A second factor that influences CapEx in the higher deployment scenarios is that ORBIT does not optimize array cable layouts. Instead, it places all substations at the center of the wind plant. For the largest wind plants (>6 GW), this results in longer cable segments and an approximately $80/kW higher array system CapEx than for the smallest plants (~1 GW).

Offshore and onshore transmission costs exhibit a much greater degree of variation between alternatives, which is consistent with the alternatives' focus on exploring different transmission configurations. The alternatives with the lowest transmission cost per kilowatt of OSW capacity are 7.2a ($1,042/kW) and 12.4a ($1,081/kW). Alternative 12.4d has the highest transmission cost relative to OSW capacity ($1,741/kW), nearly 70% higher than the least-cost alternatives. Much of the difference in transmission cost between alternatives is attributable to the total length of new subsea cable that is installed in each alternative. Figure 26 shows the correlation between longer subsea cable length and higher offshore transmission costs.

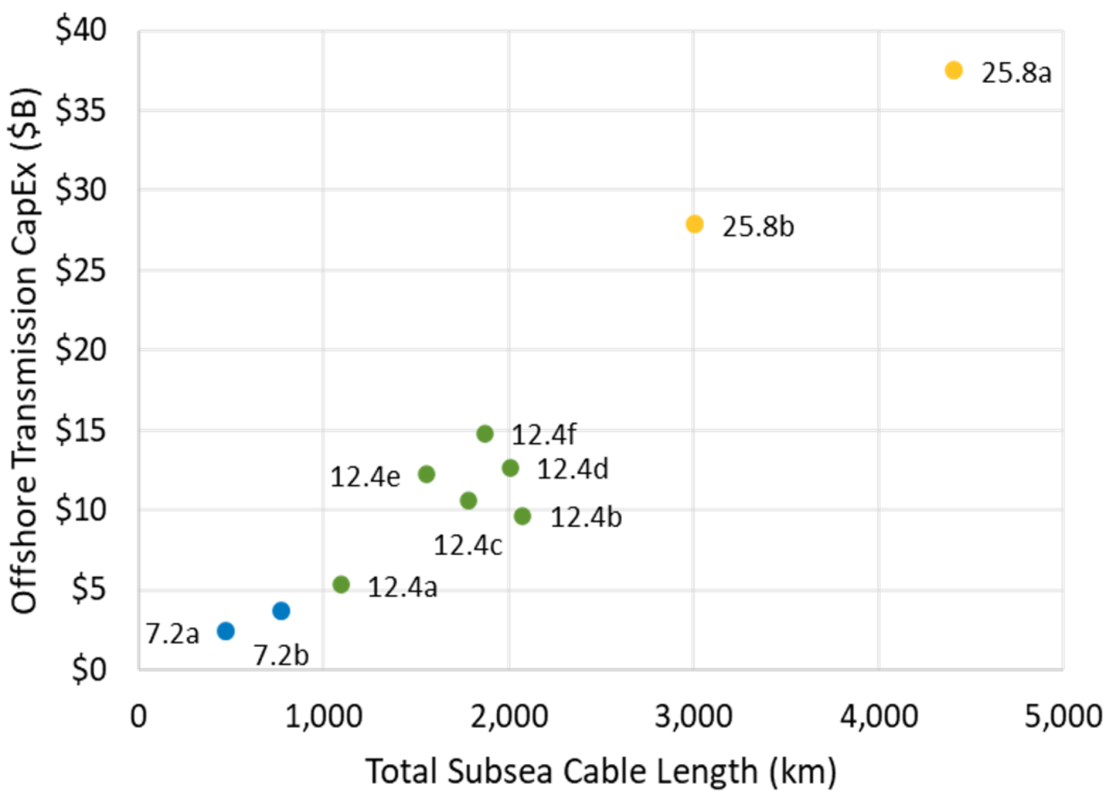

Figure 26. Offshore transmission CapEx versus subsea cable length for each alternative

Building OSW capacity takes time, especially at the scale of the larger deployment scenarios. Although this study focuses on 2032 (due to grid model availability), any realistic large-scale OSW deployment would take place across multiple years, with individual wind plants beginning operations on different dates. Because floating OSW turbines are a relatively new technology, we anticipate that costs will come down as OSW equipment manufacturers, installers, and operators gain experience and build mature supply chains. Figure 27 presents projections of plant CapEx, plant OpEx, LCOE, and LCOE + T for commercial operations dates (CODs) from 2030 to 2050. Offshore wind plant costs do not vary significantly between alternatives at the same total deployment (see Table 15), so we include only three representative alternatives in Figure 27. Alternatives 7.2a and 25.8a have the lowest and highest costs respectively, with cost metrics for the other alternatives following similar trends between those bounds.

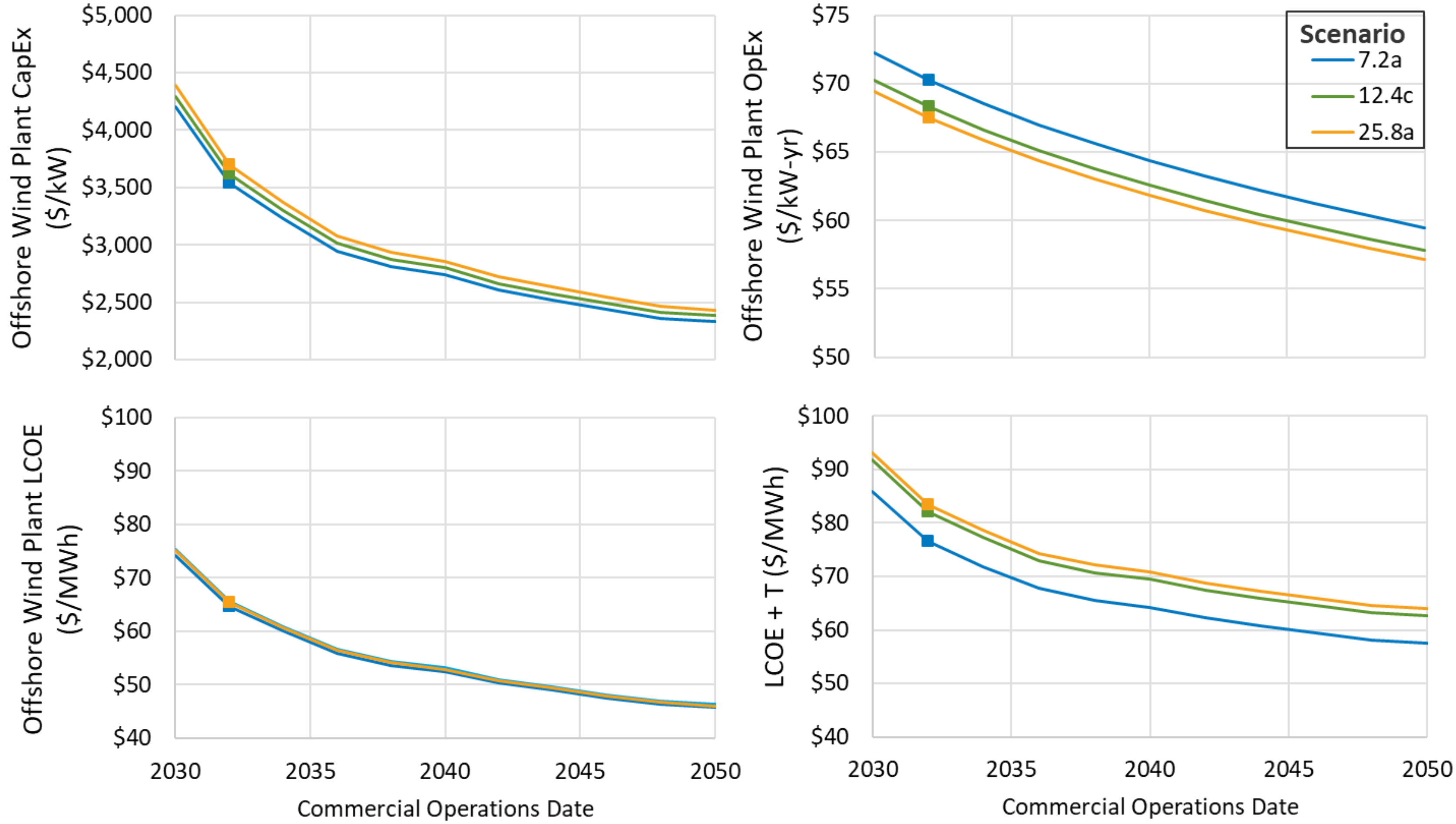

Figure 27. Cost component trajectories for offshore wind power plants beginning operation between 2030 and 2050

(Top left) Offshore wind plant capital expenditures, (top right) offshore wind plant operational expenditures, (lower left) offshore wind plant levelized cost of energy, (lower right) levelized cost of energy.

In 2030, we expect OSW plant CapEx to range from approximately $4,200/kW for Alternative 7.2a to just under $4,400/kW for Alternative 25.8a. By 2050, this range lowers to $2,300/kW for Alternative 7.2a and $2,400/kW for 25.8a. This represents a total CapEx reduction of approximately 45% between 2030 and 2050.

Offshore wind plant OpEx ranges from nearly $69/kW per year for Alternative 25.8a to $72/kW per year for Alternative 7.2a with the COD in 2030. With the COD extended to 2050, the OpEx range decreases to between $57/kW per year to less than $60/kW per year. Over that period OpEx costs are projected to fall by nearly 18%.

Offshore wind plant LCOE values (excluding offshore substations and export cables) are approximately $74-$75/MWh in 2030 and reduce to $46-$47/MWh by 2050 (Figure 27). With the addition of transmission costs, LCOE+T ranges from $86/MWh to $93/MWh for a COD of 2030 and decreases to $58/MWh to $64/MWh for a COD of 2050. The LCOE estimates for earlier CODs are higher than the net revenues of $44/MWh to $54/MWh that were modeled for 2032 (as noted in Section 9), but after about 2038 LCOE estimates for all alternatives are within that range. LCOE+T for all alternatives remains above the estimated 2032 net revenue all the way out to 2050.

Table 16 presents 2032 LCOE and LCOT for all 10 alternatives. Within each deployment level (7.2 GW, 12.4 GW, or 25.8 GW), there is more variation in LCOE than in plant CapEx (Table 15). With similar CapEx and OpEx for all alternatives at a given deployment, the variation in LCOE is primarily caused by differences in the annual energy production of each OSW plant. Energy production depends on the wind resource at each site as well as on estimates of curtailment based on production cost modeling. The analysis of energy production for the 25.8-GW alternatives did not account for curtailment but assumed higher loss factors, so the AEP and LCOE values are not directly comparable for these alternatives. Alternatives 7.2a and 12.4a have the lowest LCOT and LCOE+T values. These alternatives represent the smallest transmission build-outs (in terms of total new line length) within their respective deployment levels. At the 12.4-GW level, Alternative 12.4d has the highest LCOT and LCOE+T.

Table 16. 2032 offshore wind plant AEP, LCOE and LCOT

Transmission Alternative	Annual Energy Production (AEP) [kWh/kW]	Offshore Wind Plant Levelized Cost of Energy* (LCOE) [$/MWh]	Levelized Cost of Transmission (LCOT) [$/MWh]	LCOE + T [$/MWh]
7.2a	4,199	$64.71	$11.81	$76.53
7.2b	4,133	$65.74	$16.20	$81.95
12.4a	4,155	$65.98	$12.39	$78.37
12.4b	4,206	$65.17	$15.78	$80.96
12.4c	4,177	$65.67	$16.35	$82.01
12.4d	4,199	$65.37	$19.74	$85.11
12.4e	4,205	$65.22	$19.06	$84.29
12.4f	4,279	$64.15	$18.78	$82.94
25.8a	4,250	$65.45	$17.94	$83.39
25.8b	4,250	$65.41	$15.34	$80.75

*Offshore wind plant LCOE excludes offshore substation and export cable costs, which are included in LCOT

11 Potential Revenue Sources for Offshore Wind Projects in California and Oregon

The production cost modeling results discussed previously are based on specific revenue assumptions—namely, that OSW producers receive the wholesale market price for electricity and a Production Tax Credit of $25/MWh (See Sections 7 and 9). Other revenue structures may be available for OSW projects that could lead to different results. Offshore wind project revenues depend on the support regime, market structures, and the performance of the plant (Beiter et al. 2020a). Components contributing to OSW revenues may include some combination of the following:

- The market price (if a project operates as a merchant plant, it sells power on the wholesale electricity market and is subject to price fluctuations). These factors are included in the production cost modeling mentioned earlier.
- Capacity credits are payments to generators that have the ability to dispatch an agreed amount of capacity when needed to ensure system adequacy and reliability (Jenkin, Beiter, and Margolis 2016; Glenk and Reichelstein 2022). There are also compensation mechanisms for ancillary services.

- Power purchase agreements (PPAs) are long-term contracts for purchasing a fixed quantity of energy at a fixed rate, which is usually determined through a competitive bidding process (Beiter et al. 2020a). Some states, like Massachusetts, have required utilities to sign PPAs after solicitations to procure certain quantities of electricity generated from OSW.
- Renewable Energy Certificates, which can be sold separately from electricity and represent, according to Beiter et al. (2020a), "the environmental attributes of one megawatt-hour of electric generation from a renewable energy project."
- The Inflation Reduction Act (IRA) made multiple tax incentives available to OSW energy and electrical transmission projects including:
    - Offshore wind energy projects can opt to claim either the Production Tax Credit or the Investment Tax Credit, but not both. To date, most OSW projects in the United States have opted to claim the ITC. See Table 17 for a summary of the available incentives for OSW energy projects from the IRA (Sherlock et al. 2022).
    - The IRA allows for OSW energy projects that meet domestic content requirements to receive tax credit amounts as payments (Comay, Sherlock, and Clark 2022).
    - Based on their point of interconnection, OSW projects may be able to qualify for the "Energy Communities" bonus credit.
    - The IRA makes nearly $2.9 billion available for incentivizing electrical transmission infrastructure including direct loans ($2 billion from Section 50151 Transmission Facility Financing) and grants aimed at facilitating the siting of certain onshore and offshore transmission lines ($760 million from Section 50152 - Grants to Facilitate the Siting of Interstate Electricity Transmission Lines) (Lawson 2022).

Table 17. Available incentives for offshore wind from the Inflation Reduction Act (IRA). Table based on Sherlock et al. (2022).

Incentives	Investment Tax Credit Parameters	Production Tax Credit Parameters
Base Credit Amount	6%	0.5 cents**/kWh ($5/MWh)
Base Credit for Meeting Prevailing Wage and Apprenticeship Requirements[14]	30%	2.5 cents**/kWh ($25/MWh)
Bonus Credit for Meeting Domestic Content Requirements[15]	+10*%	+10%
Bonus Credit for Projects in Energy Communities[16]	+10*%	+10%
Potential Range for Total Credit	6% - 50%	3 cents**/kWh ($30/MWh$

Note: Incentive amounts apply for projects starting construction after 2026. *Projects not meeting prevailing wage and apprenticeship requirements are eligible for domestic content and energy community bonus credits of 2% each. **2021 USD.

12 Discussion of Results

This study did not seek to identify optimal transmission solutions, but instead sought to examine a broad range of alternatives and to draw conclusions and lessons learned from the analyses. In this section we identify and discuss the key findings. We follow that discussion with recommendations for further research that can help lead to the identification of the optimal and/or preferred transmission solutions.

12.1 Transmission infrastructure costs estimates

This study examined numerous alternatives for building transmission infrastructure that can support gigawatt-scale development of OSW on the northern coast of California and southern

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[14] According to the IRS, "to qualify for increased credit or deduction amounts of certain clean energy tax incentives, taxpayers generally need to pay laborers and mechanics employed in construction, alteration or repair no less than applicable prevailing wage rates and employ apprentices from registered apprenticeship programs for a certain number of hours" (Internal Revenue Service (IRS) 2023c).

[15] The IRS indicates "domestic content is generally defined as steel, iron or manufactured products that are manufactured or produced in the United States" in its initial guidance on the domestic content bonus credit (Internal Revenue Service (IRS) 2023b).

[16] The Congressional Research Service also indicates that energy communities are defined "as being a brownfield site; an area which has or had certain amounts of direct employment or local tax revenue related to oil, gas, or coal activities and has an unemployment rate at or above the national average; or a census tract or any adjoining tract in which a coal mine closed after December 31, 1999, or in which a coal-fired electric power plant was retired after December 31, 2009" (Sherlock et al. 2022; Internal Revenue Service (IRS) 2023a).

coast of Oregon. It is clear that the requirement for new infrastructure will largely determine the cost magnitude of these projects. The total cost includes the cost to develop the OSW farms themselves, the cost to build the transmission infrastructure, and the cost to develop the necessary port infrastructure. This study examined the cost of the first two, with a special focus on transmission costs.

The transmission infrastructure needed will likely include both onshore and offshore infrastructure, as well as both HVAC and HVDC infrastructure. However, how much of each of these should be built is debatable. We examined alternatives that featured only HVAC infrastructure, and other alternatives that relied heavily on HVDC infrastructure. We also examined alternatives that put more emphasis on onshore infrastructure, and others that included substantial offshore infrastructure. In general, we found the alternatives that emphasized the use of HVDC infrastructure were more expensive. However, we note that the cost estimates for much of the HVDC infrastructure involve equipment that is not yet commercially available, so this observation is uncertain and could change as new information about equipment costs becomes available. In addition, there may be other reasons why HVDC infrastructure might be preferred. For example, if there are reasons why offshore transmission infrastructure is preferred, then HVDC technology will likely be critical, because undersea HVAC cables are limited in terms of the distance that they can efficiently transmit power (i.e., roughly 60 miles maximum).

As we discuss more in material that follows, the cost to develop transmission is only one aspect to be considered. There will be other costs, such as permitting and mitigation costs that were not considered in this study. Perhaps more importantly, this study only conducted a very preliminary assessment of the environmental and permitting challenges that might be encountered for each of the alternatives examined. Further research in this area will be critical to the transmission planning and decision-making process.

Finally, it will be important to consider the long-term play. OSW development will occur over a period of decades, starting with projects that total a few gigawatts and perhaps expanding to tens of gigawatts. Therefore, it will be wise to take a phased approach to transmission development, and to consider what will be needed in the long run, while still making the best decisions possible for the short term. Ideally the infrastructure built in the early phases will be suitable for expansion, and it will be possible to avoid installing infrastructure today that later becomes a stranded asset. We note that this may mean investing somewhat more in the near term, with a goal of securing long term savings. It will also be important to build flexibility into the system so that it can be adapted and changed as needed in the future.

12.2 Production cost results

Production cost modeling allowed us to simulate the performance of the various transmission alternatives on an hourly basis over a full year. For any given run, the production cost model determined the most cost-effective mix of generation resources that could be dispatched to meet the hourly loads while satisfying all of the transmission system constraints. The PCM results provided us with an estimate of the annual curtailment of wind power that would be necessary for any given alternative. Curtailment was very low, ranging from 0.6% to 2.4%. In addition, the PCM results provided us with an estimate of the annual revenues that could be generated in the wholesale market. These varied from $44/MWh to $54/MWh, and some alternatives examined fared better in terms of the market value of the wind power generated.

The PCM results also provide an indication of how well the new transmission infrastructure would be utilized. For example, the model showed us that the newly proposed transmission lines in the 12.4 GW alternatives were utilized at relatively high capacity. Nearly half the new lines were used at full capacity at least part of the time, and all of the lines cumulatively were utilized at an average capacity of about 35% to 50%. This is a metric that could be useful as part of an optimization analysis, because lines that are not well utilized might be oversized or not needed at all. However, it is important to also remember that the transmission system must be robust, and therefore must be built to handle contingencies where portions of the system are unavailable for use because of outages. These redundancies in the infrastructure sometimes mean that parts of the system will be underutilized during normal operation, but will be critical during a contingency.

One thing learned from the PCM results is that new transmission infrastructure that is built to accommodate OSW development will also be used to serve other transmission system needs. For example, in the alternatives where we modeled an offshore transmission backbone that interconnected multiple regions wind areas (see Alternatives 12.4c through 25.8b), we saw numerous situations where power flowed from existing onshore substations to offshore substations, then through the offshore transmission network to another offshore hub, and then back onshore to a different onshore substation. These power flows were dictated by the PCM optimization model in order to achieve the least cost solution. That means that the new transmission infrastructure, whether it be located onshore or offshore, will provide transmission services beyond accommodating the newly installed OSW generation. These added benefits should be considered when selecting a preferred transmission alternative.

These circumstances also have ramifications for ownership of the offshore transmission infrastructure – should it be owned by a neutral transmission operator, or should it be financed and owned by the OSW developers as part of their OSW farm? This question is discussed more in the ensuing text.

12.3 Levelized cost of energy results and cost-benefit assessment

We modeled capital expenditures, levelized cost of energy, and levelized cost of transmission for 10 OSW transmission configurations from 7.2 GW to 25.8 GW. Offshore wind plant CapEx (excluding offshore substations and export cables) for commercial operations beginning in 2032 is between $3,540/kW and $3,695/kW. We expect these costs to decrease as the level of floating OSW deployment increases, reaching approximately $2,400/kW by 2050. Offshore and onshore transmission CapEx is between $1,042/kW and $1,741/kW. The total length of new transmission lines in each alternative is closely correlated with the transmission CapEx. Offshore wind plant LCOE in 2032 is between $60/MWh and $65/MWh. By 2050, the LCOE could reach $42–$46/MWh. The combined cost of OSW and transmission, LCOE+T, is between $71/MWh and $83/MWh for a COD of 2032. Revenues estimated using a production cost model are lower than the 2032 LCOE or LCOE+T; however, this conclusion is limited to the specific year and revenue structure (market price with $25/MWh production tax credit) that were modeled in this study. Additional work would be required to explore the effects of alternatives such as electricity sales through PPAs, utilization of the investment tax credit instead of the production tax credit, and an extension of the revenue analysis to future years beyond 2032.

With regard to the cost-effectiveness of various transmission alternatives and a comparison between them, we reiterate the importance of examining both the costs for the alternatives, as well as the benefits, where the benefits should include the direct OSW transmission related benefits, and broader systemwide benefits. This study focused more on the direct OSW transmission related benefits, and we recommend further study to assess the systemwide benefits.

We also note that the literature indicates that demonstrating the economic advantage of complex offshore topologies, like multi-terminal HVDC meshed grids, can be challenging. An examination of available studies on offshore meshed HVDC grids found that complex offshore topologies, like meshed grids, appear to be cost-efficient only for scenarios considering both high OSW generating capacity and numerous offshore hubs that are geographically spread out (Tractebel Engineering 2016). Otherwise, purely radial topologies tend to be the most cost-effective approaches. In addition, the economic advantage of multi-terminal HVDC meshed grids can only be demonstrated when the overall grid structure is optimized. Therefore, to truly evaluate the benefits of a meshed HVDC grid and adequately compare its costs and benefits to other transmission solutions, a systemwide, multi-value approach that addresses all categories of needs and benefits is needed.

12.4 Overview of key potential environmental issues and/or other permitting conflicts

We conducted a high-level assessment of environmental concerns and key permitting or regulatory challenges associated with the various segments of all of the transmission alternatives. Areas of particular focus included cable landfall locations, subsea and overland cable corridors, and transmission line corridors. Land ownership or designation was considered a key factor, as were sensitive marine and terrestrial habitats and the potential for interaction with special-status plants and wildlife. Based upon the severity or likelihood for environmental impacts and permitting challenges, the line segments were ranked in terms of barriers to development from “low” to “very high.”

In addition to the potential permitting challenges noted above, we identified where the proposed transmission routes overlap with military utilized airspace, and we noted that there may be a need for mitigation. In any event, there should be early and ongoing consultation with DOD to ensure that transmission projects do not adversely impact DOD mission compatibility or national defense.

An in-depth analysis should be conducted to further identify which transmission segments are most feasible to permit and could therefore move toward development. This analysis would include a more detailed look at various alternatives, use of additional and more robust data sets, and ground truthing of databases for sensitive ecological communities.

12.5 Key concerns with regard to undersea cable routing

Key findings from the high-level undersea cable routing assessment include the understanding that the depth-limitation for undersea electrical cables is a critical factor in establishing subsea cable routes. It may be preferable for several reasons (e.g., vessel traffic density, MPAs, submarine canyons, seismicity, fault lines and displacement potential, etc.,) to route subsea electrical transmission cables further from shore. Some hazards, such as the Cape Mendocino Fault Line, may not be avoidable, so mitigating steps or other engineering interventions may be required. South of Cape Mendocino, extensive submarine canyons extend from beyond the toe of the continental slope nearly all the way to shore. This likely precludes nearshore cable routing. Exporting power to major load centers, such as the San Francisco Bay Area, would therefore require routing cables further offshore if subsea transmission were pursued. However, doing so may require laying transmission cable onto the abyssal plain at depths greater than 3,000 meters. At present, transmission cable installation at such depths is not possible due to the technological limitations of existing cables. However, industry is working to relax these depth constraints, but the timeline for development and market readiness for such cables is not yet known.

Additionally, areas for cable landfall are limited, and selecting those areas will need to consider submarine canyons, the slope of the continental shelf, and water depths where cable lay vessels may safely operate while still staying within the typical distance limit for an onshore cable pull-in of 3,280-4,920 ft (1,000-1,500 m). All of these factors were considered at a high level to develop a conceptual map of potential or notional undersea cable corridors for the transmission alternatives examined in this study.

12.6 Transmission planning and development challenges

As noted earlier, the existing transmission grid in the coastal regions of northern California and southern Oregon is significantly undersized to accommodate large, gigawatt scale OSW development on the U.S. West Coast. Significant amounts of new transmission infrastructure, both onshore and offshore, along with significant upgrades to existing transmission systems, will be required to receive and transmit the power generated to major load centers.

The California Renewable Energy Transmission Initiative (RETI)[17] was a high-level examination of renewable energy development and transmission alternatives in California and the West. This process took place before the state was considering OSW development and therefore before development of the OSW goals per AB 525. The RETI Final Plenary Report (California Natural Resources Agency 2017) found that "because transmission often involves high capital costs, environmental and economic implications, and long planning time frames, a long-term strategic approach is warranted. Without proactive decision-making, important options for reaching California's goals at the lowest cost may simply be lost due to inadequate lead time. It is for these reasons that meeting the SB 350 RPS and SB 32 GHG targets requires a focus on electric transmission – making the best use of existing transmission and identifying where new transmission is necessary."

Currently in the West, transmission planning, development, and operation is conducted by many different transmission providers across many different states. In California, transmission planning is centralized under the CAISO, a state-wide transmission provider that conducts transmission planning to meet state-wide needs with input from the CPUC and CEC. In Oregon and the other western states, transmission planning is fragmented under many different transmission providers that conduct local transmission planning to meet the needs of their individual transmission territories. CAISO's transmission planning meets FERC regional planning requirements for the California region. Outside California, regional planning entities such as NorthernGrid produce regional transmission plans that account for the local transmission plans from the many different transmission providers in the NorthernGrid region. The difference in these planning paradigms is that the CAISO's regional transmission plans are the result of centralized, top-down transmission planning, whereas the other regional transmission plans across the West are the result of de-centralized, bottom-up transmission planning.

[17] https://reti.databasin.org/

Transmission siting, permitting, planning and development is a long process that typically takes many years. Getting new transmission infrastructure sited, approved, financed and installed is complex, and the larger the project, the longer it is likely to take. The Transmission Agency of Northern California estimates, based on recently planned and completed bulk transmission projects, that it takes on average 13 years from the start of planning to the fully constructed new transmission system (TANC n.d.), and this time frame has OSW developers concerned. This concern is true even for the initial lease holders in the northern and central California lease areas, where total developed capacities are likely to be no more than about 2 to 5 GW.

When we look out to 2045 with California's goal to develop 25 GW of OSW, the challenges are greatly increased. At these scales of development, it is likely that a regional approach will be desired or even necessary, which poses additional challenges and opportunities. California, Oregon, and other western states need to explore ways to streamline the development of new transmission, ideally through regionalized approaches. This could involve efforts like RETI, programmatic EIRs or EISs, and identification and approval for development of key transmission corridors. This type of work is also taking place on the East Coast of the United States as that region too grapples with the need for large-scale development of transmission infrastructure to support OSW. Lessons from the East Coast can be learned and built upon as efforts move forward in the West.

12.7 Regionalization of the power market and transmission planning and development

Large-scale OSW development on the West Coast is likely to benefit greatly from a regionalized approach to transmission planning and development. In addition, a regionalization of the western power market is likely to bring cost and resource utilization efficiencies to the west, thereby benefiting the long-term operation and utilization of OSW resources. As noted previously, transmission planning and development are currently conducted largely on a state-by-state basis, though there is some broad coordination and regulation. In addition, energy markets in the West are optimized based on balancing areas. Across the West there are currently more than 35 balancing areas within the WECC. The WECC is approved by the Federal Energy Regulatory Commission to be the Regional Entity for the Western Interconnection, which is a regional electric grid that serves two Canadian provinces, 14 western states, and Northern Baja Mexico.

It is likely that a regionalized power market and a regionalized approach to transmission planning and development could lead to a more optimal use of resources across the West and provide significant cost savings to ratepayers. There is currently an active discussion in the west about an examination of the potential benefits and challenges associated with greater regional cooperation. A 2023 report by NREL examined the impacts on California of expanded regional cooperation in operating the Western Grid and found that California's goals for renewable energy and greenhouse gas reduction can be achieved more quickly and with less cost to Californians through expanded regional cooperation (Hurlbut et al. 2023).

One option is to have the CAISO become a multistate regional transmission organization, or RTO. However, such a change would require an alteration to CAISO's governance structure. This alteration would likely be the adoption of an independent governing board rather than the politically appointed leadership structure it currently utilizes. Recent proposed legislation in the California legislature, AB 538 (Holden 2023), would have enabled such a change as a move toward allowing CAISO to become an RTO. Not only can a regionalized approach provide for a more optimal use of resources and lower costs for ratepayers, it may be necessary to allow the

CAISO to maintain its relevance. That is because if CAISO does not adapt and move toward regionalization, many other western states may still do so and very well may choose to join another RTO, such as the Southwest Power Pool. Such a change could isolate CAISO, with a resulting increase in energy costs and decrease in reliability and resilience.

However, while there are likely to be benefits associated with regionalization, there are likely to be challenges as well. For example, one set of concerns relates to the politics of grid management and decarbonization in the Western United States. California is strongly committed to decarbonization and utilization of renewable energy, but some Western states do not share these goals. Some have raised concerns that regionalization could affect California's renewable portfolio standard and undermine its decarbonization efforts. These risks and benefits must be weighed, and if regionalization is pursued, efforts to mitigate the perceived risks will be an important part of the path forward.

In terms of OSW development, regionalization could bring substantial benefits. In addition to enabling a more optimal use of renewable power resources and a decrease in the cost of power, greater regional cooperation could help lead the way to coordinated regional transmission development. As we have outlined in this study, it is likely that regional transmission infrastructure will be needed, especially offshore. In many of the alternatives examined, there are transmission solutions that involve new connections between Oregon and California, and in six of the larger-scale scenarios (Alternatives 12.4c through 12.4f, 25.8a and 25.8b) we include an offshore HVDC backbone that connects multiple wind farm areas, including wind farms in both California and Oregon coastal waters.

A recent study by the Brattle Group found that proactive regional transmission planning for OSW will likely save U.S. consumers at least $20 billion and will reduce environmental and community impacts by 50% (Pfeifenberger et al. 2023). In addition, it will support the timely achievement of energy policy goals, as well as increased reliability, lower risks, increased energy independence and improved climate resilience.

An offshore HVDC network like the ones shown in Alternatives 12.4c through 25.8b poses many challenges and questions that will need to be solved. Questions might include:

- Who should own and operate these shared HVDC transmission networks?
- Who should be responsible for developing and financing them, and how shall they be compensated?
- How will power flows through these networks be managed and who will control them?
- How will these networks impact energy markets and regulatory processes, like California's Renewables Portfolio Standard?

A regionalized effort to plan and develop transmission infrastructure could help resolve some of these questions and move transmission development efforts forward.

California and the West can learn from the efforts that have recently been unfolding on the East Coast of the United States. Due to the relatively shallow coastal waters on the East Coast, OSW development is much further along, with turbines already in the water offshore of both Rhode Island and Virginia, and many other projects under development. While the existing transmission infrastructure layout and the transmission needs are substantially different on the East Coast, there is still much that can be learned. Many states on the East Coast (Connecticut, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, Rhode Island and Vermont) have called for regional cooperation to develop multi-state transmission infrastructure (Silverman 2023).

In addition, the federal government has launched a series of efforts to support transmission development, with OSW being a key focus area. The Biden-Harris Administration has made funding available for clean energy investments and has initiated efforts to accelerate federal permitting processes, including permitting of electric transmission infrastructure. In support of President Biden's agenda, the U.S. Department of Energy (2023) recently initiated a process to designate National Interest Electric Transmission Corridors. This designation can help focus commercial investments, facilitate efforts by transmission planning entities, and unlock siting and permitting tools for transmission projects in identified areas.

12.8 Benefits and challenges of a planned, offshore mesh network

As noted above, there are numerous potential benefits associated with a planned, regionalized approach to developing the transmission infrastructure that will be needed to support 25 GW or more of OSW generation on the northern coast of California and the southern coast of Oregon. Numerous studies have compared conventional radial transmission configurations with integrated mesh systems and identified the benefits associated with mesh networks. Benefits can include:

- Reduced curtailment of OSW
- Lower transmission losses
- Fewer undersea cables and lower associated impacts
- Lower transmission system costs
- Improved utilization of landing points and lease areas
- Lower systemwide generation costs
- Outage mitigation
- Congestion relief
- Improved onshore grid reliability and resilience
- Ancillary services and capacity value
- Cost savings with interregional energy and capacity transfers

The Brattle Group's study for NYSERDA (Pfeifenberger, et al. 2021) and another for New England (Pfeifenberger, et al. 2020) both examined the benefits of a meshed offshore network. In the NYSERDA study the investigators assumed HVDC connections to shore, and examined mesh network configurations on both the HVAC and the HVDC side. While they found the HVAC mesh network was preferred, they also noted that a key disadvantage with the HVAC mesh network was the limited distance that AC power can be transmitted. While the required transmission distances were relatively short in the New York study, that will not be the case on the West Coast. Due to the longer distances that power will need to be transmitted, the HVDC network will be the only option. Additional advantages cited for the HVDC mesh system are the ability to optimize power flows and the ability to provide ancillary services, like primary frequency control, fault ride through capability and black-start capability. Disadvantages identified for the HVDC system include a higher cost than the HVAC mesh system, and the need for HVDC breakers, which are a nascent technology.

NREL and Pacific Northwest National Laboratory also recently collaborated on the Atlantic Offshore Wind Transmission Study. This was a comprehensive look at OSW development and transmission solutions on the East Coast, with the involvement of a Technical Review Committee of more than 150 subject matter experts. While the final report has not yet been published, early information released as part of the Action Plan for Offshore Wind Transmission Development in the U.S. Atlantic Region (USDOE and BOEM 2023) indicates that there are substantial production cost benefits from mesh topologies with interregional components, with benefits outweighing costs when compared to a radial-only reference case.

A study performed by DNV (2020) for National Grid ESO in Great Britain also examined a number of offshore transmission network topologies, including radial connections, and various integrated HVAC and HVDC configurations. The study found substantial benefits with the integrated designs, noting that they could be key to realizing the full potential of OSW and meeting development goals. DNV noted that coordinated development has the potential to reduce impacts on the environment, communities and overall project costs compared to cumulative radial transmission options. They also noted a number of technology barriers that would need to be overcome.

12.9 Transmission planning decisions - a long-term, phased approach

The development of floating OSW at scale on the West Coast will likely take decades, and therefore requires a long-term forecasting horizon and a long-term planning approach. While it is important to make decisions today that serve ratepayers and the electrical system well in the short-term, it is also advantageous to plan for the future. This could be termed a “no-regrets” (or at least “low-regrets”) planning approach, and it may mean that some near-term choices are not the lowest cost solutions, but instead serve well now and also lay a foundation for the future. The investments necessary to develop OSW and the transmission infrastructure that will support it will be substantial. It will be important to avoid spending hundreds of millions of dollars on infrastructure, only to realize 10 years later that it is necessary to replace it because a different approach or technology (e.g., HVDC instead of HVAC) is needed. This situation will require a nuanced approach to cost-benefit analysis and optimization.

With regard to the transmission alternatives that we have examined in this study, we did not directly take a long-term, phased approach. As noted at the start of this document, our goal was not to identify optimal transmission solutions for particular OSW development scenarios, but instead to explore a broad range of possibilities and to learn from that exploration. Therefore, we did not develop phased alternatives as the scale of development increased from the initial scenario of 7.2 GW to the final scenario of 25.8 GW. That said, we can go back and look at the alternatives we developed, examine their ability to follow a phased approach and minimize stranded assets, and identify ways they could be adapted to meet the goals of a phased approach.

One possible phased progression pathway from the Low to Mid to High development scenario could involve a progression from Alternative 7.2a to Alternative 12.4c and then to Alternative 25.8a. This would mainly require a minor change in Alternative 25.8a, where the HVDC line shown going from Cape Mendocino to Moss Landing would instead be an HVDC line going from Humboldt to Moss Landing. Similarly, a progression from Alternative 7.2a to Alternative

12.4d, and then a progression to 25.8a could also be accomplished with only minor changes. This could involve adding one HVAC line from Del Norte to Sams Valley in Alternatives 7.2a and 25.8a instead of two HVAC lines from Del Norte to Fern Road. Similar changes could also be made to progress from Alternative 7.2a to 12.4b and then to 25.8a. In most of these cases it would also be necessary to end up with a mix of HVAC and HVDC export cables in the later phases, because this would allow early development with HVAC export cables and later development with HVDC export cables as needed to increase capacity. However, retaining the existing HVAC export cables from the early phase would eliminate the problem of stranded assets.

Finally, if Alternatives 12.4a or 12.4b were pursued, then in a subsequent phase the long-distance HVDC lines that are proposed in these alternatives and that originate and terminate at onshore HVDC conversion stations could be maintained, and new floating HVDC conversion stations with dynamic HVDC cables could be added as needed. This would mean that a High development scenario like Alternative 25.8a would end up with a mix of long-distance HVDC cables that originate and terminate at both onshore and offshore HVDC conversion stations.

The Brattle Group's NYSERDA study (Pfeifenberger, J., et al. 2021) found that a phased approach for the HVAC mesh network design would be preferable. The researchers identified "mesh ready" infrastructure that could be installed in the near-term, and that would allow the addition of cables at a later date that could interconnect the multiple nodes in the network. The mesh-ready infrastructure included extra cable bays, shunt reactors, additional transformers, additional steel and additional electronics, and additional studies and engineering. The follow-on phase that is necessary to complete the mesh-network required installation of additional cables, as well as additional studies and commissioning. The researchers estimated no more than a 1% cost increase in the first phase to be mesh-ready, and another 3% to 6% cost increase for full implementation of the meshed system. This approach and these cost increases were for an HVAC meshed system. It may be possible to take a similar approach with an HVDC mesh system, but that would need to be researched and costs would need to be estimated.

12.10 Transmission planning decisions - equitable distribution of benefits

Another set of trade-offs that must be negotiated when aiming to develop the optimal transmission solutions include making sure that costs and benefits are equitably distributed and that all communities are treated fairly in the process. For example, if the aim were to solely minimize the capital investment costs, then an "optimal" solution may be arrived at that appears to minimize costs (at least those costs that can be accurately monetized and are explicitly included in the analysis), but is clearly not an equitable solution because it leaves some communities behind. A case in point could be if long-distance transmission is needed to deliver large quantities of bulk power from the wind areas where it is generated to the metropolitan load centers where it can be utilized. A least-cost solution may appear to involve only HVAC lines or HVDC lines that by-pass coastal communities located near off-shore wind farms (i.e., OSW "host" communities) and other small communities along long-distance transmission routes. While this approach might minimize the upfront costs, it clearly leaves these communities without access to the wind power being generated and without the electricity reliability benefits associated with connection to a larger and more robust transmission system.

As noted previously, these coastal communities are served by small transmission lines and already suffer from adequacy and reliability issues. If major new transmission infrastructure is going to be developed that bypasses these communities, solutions that allow power to be "peeled off" from the massive high-voltage lines and delivered to these smaller communities must be considered. This delivery can be accomplished by installing phase-shifting transformers, auto-transformers, and other supporting infrastructure. While this option does add cost, it is expected that the added cost will be small relative to the total cost of required transmission infrastructure for any given alternative. In the transmission alternatives that we examined, these additional costs account for only 0.4% to 2.4% of total transmission costs. We note that there may be a desire to add additional transformers to serve smaller communities along the proposed HVAC transmission corridors, and the added cost is still expected to be relatively small.

In addition, technologies that can benefit local host communities, like energy storage, microgrids, and local transmission and distribution system upgrades, technologies that are not directly associated with OSW development, can also be considered as a means of equitably distributing costs and benefits.

12.11 Technology development implications

The technologies necessary for the full development of floating OSW on the West Coast do not fully exist at this time. Existing OSW developments have primarily utilized HVAC technology, although HVDC options are beginning to be explored and implemented in greater frequency. Due to the distances to shore, and the significant depths associated with California wind energy areas, both HVAC and HVDC systems will likely be utilized. HVAC technologies are mature, but suffer from inefficiencies when they are used to transmit power over long distances and require reactive power compensation. HVDC technologies may be able to overcome some of those challenges, but for undersea applications involving floating infrastructure and deep water, they lack mature, market-ready solutions that can be readily implemented. General industry consensus indicates a breakpoint of between 80-100 km (50-60 miles), after which HVDC transmission lines are more economically viable than HVAC cables for offshore transmission.

In addition, while most OSW farms to date have connected radially, highly interconnected or meshed networks are now being explored and considered for adoption. Both HVAC and HVDC systems can be integrated into meshed networks, which can increase reliability and redundancy, and allow for interconnection between different regions and markets. However, the following technology gaps exist for offshore meshed networks. Floating HVAC substations need to be developed, and perhaps more important and a greater challenge will be the development of floating offshore HVDC conversion stations, which are substantially larger and more massive than their HVAC cousins.

Also needed will be dynamic cables, both HVAC and HVDC. When offshore infrastructure is fixed, like it is on fixed platforms, then transmission systems can utilize static cables because they will not be subject to much movement. However, with floating infrastructure, like substation and conversion stations, the infrastructure will be constantly moving, as will the connection point for the cables. This means that dynamic cables will be needed that can handle the constant movement and stresses they will be subjected to.

In addition to the development and commercialization of these technologies, markets and supply chains will also need to be developed that can supply these technologies at the scale and on the timelines at which they will be needed. This will be no small feat.

Long-distance undersea HVDC cables that can transmit gigawatts of electricity are expected to be important for full scale OSW development in the West, and are included in all but one of the alternatives considered in this study. These cables will be an important technology when interconnecting OSW farms that require cables to be routed through subsea topography that includes deep subsea canyons. These topographic features are common on the West Coast. To avoid these canyons, cable routes have essentially two options. Option 1, where possible, would require routing very close to shore, resulting in implications for vessel traffic and environmental impact considerations related to MPAs and other sensitive, commercially important habitats. Option 2 avoids canyons altogether, which necessitates layouts descending the continental shelf to the abyssal plain, where depths quickly reach more than 3,000 meters.

At present, there are no commercially available high capacity HVDC subsea cables that are rated to this depth. The expected timelines for the adequate development of subsea HVAC and HVDC dynamic cables vary, but it is expected that suitable HVAC technologies will be available sooner than the anticipated timeline for suitable HVDC cables. Because OSW generators produce AC power, HVDC export cables and subsea transmission lines will likely require use of large-scale floating HVDC conversion stations, which at present do not exist. The alternative to floating HVDC conversion stations would be near-shore, fixed bottom HVDC conversion stations, but these would introduce their own challenges in terms of potential use conflicts, environmental issues, and aesthetic concerns.

13 CONCLUSIONS AND RECOMMENDATIONS

13.1 Key conclusions

1. **Transmission infrastructure costs**

   The northern coast of California and the southern coast of Oregon have some of the best wind resources in the United States, and development of these resources has great potential to contribute to the clean energy goals of California, Oregon, and other western states. Because the existing transmission grid infrastructure that serves these coastal regions is very limited in capacity, major new transmission grid infrastructure will be needed to realize this potential. Our study estimates that the cost for new transmission infrastructure to accommodate roughly 25 GW of offshore generation capacity, including new offshore infrastructure, new onshore infrastructure and necessary onshore transmission network upgrades, is on the order of $35 billion to $40 billion. As a point of reference, the expected cost of the OSW farms themselves is approximately $90 billion, though the OSW farm costs should decrease as the sector progresses along the OSW development learning curve.

2. **Proactive transmission planning**

   Numerous studies have demonstrated the importance of and the benefits associated with proactive transmission planning to accommodate the development of renewable energy resources at the gigawatt scale. If the development of OSW projects and their associated transmission upgrades are allowed to occur piecemeal over time, with each new project interconnecting independently, it is likely that the long-term result will be less than optimal. Studies show that proactive, long-term planning can reduce costs, environmental impacts, community impacts, transmission congestion, and OSW curtailment, while increasing reliability and grid services. To accomplish these benefits, policy makers must facilitate a coordinated, integrated planning effort for major transmission upgrades at a regional scale that can accommodate many gigawatts of OSW power on the West Coast of the United States.

3. **Long-term, phased approach to transmission development**

   The development of tens of gigawatts of floating OSW power on the West Coast will not occur quickly; a successful effort would take decades, and the associated transmission upgrades would take place over time as well. A proactive and coordinated transmission planning effort with a long-term outlook should be initiated very soon. This planning effort should consider how early investments in transmission infrastructure can set the stage for subsequent phases of investment. The effort should identify the most cost-effective and inclusive pathways over the long term, recognizing that this may involve spending a little more upfront in order to make sure that the infrastructure can accommodate future growth and development, all while meeting the needs of both rural and urban constituencies.

   The most cost-effective pathways could include technologies such as HVDC meshed networks. While the infrastructure being deployed in the next 5 to 10 years may not utilize an HVDC meshed network configuration, it is possible that the early deployments could be mesh-network ready. This would allow the system to be upgraded to a mesh network at a future date in a cost-effective manner without having to remove and replace outdated infrastructure. In general, we recommend transmission planning efforts that consider a 25-year time horizon and identify near-term transmission upgrades that are well-positioned to support a smartly crafted long-term vision. We note that the transmission infrastructure configurations that are implemented to achieve 25 GW of OSW power development will likely look different than those we evaluated in the High development scenario, and will likely utilize a combination of HVAC and HVDC technologies. While the technologies that are deployed at each stage of development should be compatible with what is planned for the future, they should also be effective for meeting near-term needs.

4. **Regionalization**

   The development of OSW on the West Coast is likely to serve and impact the region as a whole, and not be limited to small, independent projects. In terms of OSW development, grid regionalization could bring substantial benefits. In addition to enabling a more optimal use of renewable power resources and a decrease in the cost of power, greater regional cooperation could also help lead the way to coordinated regional transmission development. It is likely that regional transmission infrastructure will be needed, including offshore infrastructure. Studies have found that proactive regional transmission planning for OSW will likely save U.S. ratepayers substantial amounts of money and significantly reduce environmental and community impacts. However, regionalization of the power market will require regulatory and market changes, and those changes involve risks.

5. **Determining the preferred alternatives**

When trying to determine the preferred transmission alternatives for a large-scale buildout of OSW, it is important to assess all costs and benefits. The costs are largely straightforward to quantify, though there can be a fair amount of uncertainty when forecasting costs for technologies that are still in the early stages of development. Benefits, on the other hand, tend to be more varied and can be more challenging to define and quantify. It is important to employ a proactive regional planning approach that assesses multiple types of needs and benefits and compares aggregate, systemwide benefits to costs in order to ensure a holistic approach that identifies cost-effective solutions. In addition, a transmission alternative assessment must include an evaluation of environmental and permitting challenges, potential use conflicts, and constituent concerns.

6. **Technology status and development**

Many of the technologies required to achieve OSW development at scale are still in development. These include floating AC substations, floating HVDC conversion stations, dynamic HVAC and HVDC cables, and DC circuit breakers. In addition, studies are needed to better understand the challenges and opportunities presented by these new technologies and the new configurations they will enable. These unknowns add risk and uncertainty to the planning, analysis and development process. That said, much work has already been done in this realm, especially in Europe, and to a lesser degree on the East Coast of the United States. The OSW industry expects to be able to meet the challenges ahead as they build on current technologies and knowledge in the wind energy, transmission, and marine industries. This effort will require coordination between planners, technology developers, and policymakers. One key area that will need to be navigated as this industry develops is the supply chain; potential supply chain issues could have significant detrimental impacts on the development process.

7. **Offshore meshed transmission network**

Most OSW projects to date have utilized a radial approach to interconnect wind generators to the transmission system. This approach connects the generators to the nearest suitable onshore substation via dedicated export cables. In this configuration, the wind farm owner usually owns and maintains the export cables, because they are used solely to connect their wind energy generators to the grid. This radial approach tends to be the simplest and lowest cost solution when the scale of development is low, the point of interconnection is relatively close by, and the transmission grid is robust enough to readily accept the new generation. However, with large gigawatt-scale OSW development from multiple wind farms, the radial interconnection approach quickly becomes problematic, and a more regional, meshed network approach may be preferrable. The benefits of the meshed network are many, and can include:

- Reduced curtailment,
- Lower transmission losses,
- Fewer undersea cables with lower associated impacts,

- Improved utilization of landing points and lease areas,
- Lower transmission system costs,
- Lower systemwide generation costs,
- Congestion relief,
- Outage mitigation and improved onshore grid reliability and resilience
- Ancillary services and capacity value.

These benefits have been demonstrated in many recent transmission studies, including studies for New York State, New England, and Great Britain. On the West Coast of the United States there are long distances between the large OSW resources located on California's North Coast and Oregon's southern coast and the major load centers of San Francisco, Sacramento, Los Angeles, Portland and beyond. To deliver power over these long distances, a meshed HVDC network may offer the most cost-effective, reliable, robust, and optimally functioning system.

8. **Ownership of offshore transmission network**

When radial transmission connections are used to connect wind farms to onshore grid infrastructure, the wind farm developer typically owns and maintains the export cables. However, if integrated mesh systems are used, whether they are HVAC or HVDC, the offshore transmission infrastructure typically serves multiple wind farms, and the question of who should own and operate the offshore transmission infrastructure becomes more complicated. Moreover, once installed, the offshore mesh network becomes part of the overall transmission network, and it therefore also can move power from one onshore location to another via an offshore route. This suggests that the offshore mesh network is essentially part of the overall grid, and it could be argued that it should be managed by the grid operator. The question of who should own and operate offshore transmission infrastructure must be addressed from a policy and regulatory perspective to facilitate the necessary planning and future development of the transmission infrastructure needed to support OSW development.

9. **HVAC versus HVDC technology solutions**

The availability of floating and undersea HVDC technology will be critical to achieve OSW development at scale on the West Coast. Although these technologies are mostly still in development, they are expected to be available in the next decade or so to meet the needs of this developing industry. A meshed HVDC network may be needed to reduce the number of floating HVDC conversion stations and keep costs down. Overland HVDC may also play an important role for long-distance transmission, and this technology is available today, though more advances may be needed to fully utilize multi-terminal technology that can serve local systems along the way. HVAC is likely to play an important role in the nearer term for radial connections, because it tends to be cheaper for shorter distances. Further technology development is still needed for dynamic undersea HVAC cables, but this technology is likely to be available sooner than dynamic undersea HVDC cables.

10. **Serving local communities**

To enable successful and equitable development of OSW at scale, it will be important to make sure that local communities receive significant, tangible benefits. Improved electricity reliability provides an important opportunity to bring value to OSW “host” communities and other rural communities along transmission routes. We examined the cost to connect the local electrical systems that serve coastal communities to the new transmission infrastructure that is built to support the delivery of OSW power to major load centers. We found that the phase shifting transformers, autotransformers and other supporting infrastructure needed to safely and reliably connect local communities to the OSW transmission system can be provided at relatively low cost. In the transmission alternatives that we examined, these additional costs account for only 0.4% to 2.4% of total transmission costs. In addition, investment in independent technologies that can provide electricity reliability and resilience benefits to local host communities may also be desirable. Such technologies can include energy storage, microgrids and local transmission and distribution system upgrades that are not directly associated with OSW development. Deployment of these technologies can help to equitably distribute overall project costs and benefits.

11. **Offshore cable routes**

We examined subsea transmission routes at a high level with consideration for logistical, physical and ecological impacts. Factors considered included DOD operational areas, vessel traffic, fairway designations, cable landing locations, existing submarine cable locations, fishing grounds and marine protected areas, depth contours, slopes, submarine canyons and fault zones or seismic activity centers. We used numerous data sources to provide information about these factors, and thereby to inform our development of very preliminary subsea cable layout routes. Much more detailed analyses will be required for any of the proposed cable routes to move forward.

12. **Environmental permitting for onshore and offshore transmission routes**

We conducted a high-level assessment of environmental concerns and key permitting and regulatory challenges associated with the various onshore and offshore transmission routes. Areas of particular focus included cable landfall locations, subsea cable corridors, and overland transmission line corridors. Land ownership or designation and military utilized airspace were considered, as were sensitive marine and terrestrial habitats and the potential for interaction with special-status plants and wildlife. Our assessment was preliminary, and an in-depth analysis should be conducted to further identify which transmission segments are most feasible to permit. This analysis would include a more detailed look at various alternatives, use of additional and more robust data sets, and ground truthing of databases for sensitive ecological communities. Such scrutiny could be part of a proactive planning process, and should include a simultaneous examination of both onshore and offshore transmission alternatives.

13.2 Recommendations for further research

What follows are recommendations for further research related to the transmission needs for OSW development in the West.

1. **Analyze routes and rights-of-way for promising transmission pathways that are relevant to initial gigawatt-scale OSW development in northwestern California.**

   These pathways could include land-based and undersea alternatives, and the analysis would include detailed routing studies, environmental permitting analysis, community engagement, and cost assessment for selected transmission pathways. In some land-based cases, creative possibilities such as underground HVDC lines in existing rights-of-way (e.g., road or railroad rights-of-way) could be considered. The analysis should also assess the potential to provide electricity reliability benefits to OSW host communities and other rural communities along transmission routes. Outreach activities should include engagement with regional communities and associated local governments, Native American Tribes, private sector stakeholders, environmental organizations, and others. Such studies could play an important role in establishing the feasibility of specific transmission pathways that are critical for initial development of gigawatt-scale OSW power in northern California and southern Oregon.

2. **Examine the potential role of energy storage in supporting OSW.**

   Energy storage can be used to complement the development of new transmission. It can be used to relieve congestion, minimize curtailment and optimize the use of OSW power when it is most valuable. In addition, energy storage can provide resiliency and reliability benefits, as well as provide ancillary services to the grid. These added benefits can all provide added revenue potential. In addition, the resilience and reliability benefits can be designed to serve communities in regions hosting OSW power development, and in that way can help address equity issues. However, energy storage comes at a cost. Transmission studies that are performed for OSW energy should also include energy storage components to see how they compare to solutions that solely feature new transmission infrastructure. When the costs and benefits of new transmission infrastructure are assessed, the added costs and benefits of energy storage can easily be added into the analysis. We recommend that a study of regional transmission options that also includes energy storage be conducted.

3. **Conduct an exhaustive assessment of transmission alternatives for OSW.**

   California needs an exhaustive assessment of transmission alternatives that can support its long-term goals for OSW development, reaching 25 GW by 2045. Such an assessment should examine environmental, permitting, land ownership, routes and rights-of-way, military mission compatibility, and other issues related to transmission development. A potential model for this process was the California Renewable Energy Transmission Initiative (RETI) process. RETI was a high-level, non-regulatory planning process that involved the CEC, CPUC, and CAISO. A plenary report for this initiative was published in February 2017.

   The RETI process provided a review of utility-scale renewable energy potential in California and the West and provided an overview of environmental issues and an assessment of transmission implications associated with renewable energy development. This review provided input to California planning and regulatory processes, especially with regard to transmission planning. The RETI process was conducted before floating OSW development was being seriously considered on the West Coast, and therefore it did not address this significant renewable resource. It is likely that an updated RETI type process, along with a detailed study into the transmission options that can support large-scale OSW development, would be tremendously valuable. Information generated through such a process could help inform transmission planning decisions that will need to be made in the next few years and that could impact OSW development on the West Coast for decades to come.

Oregon would also benefit from additional assessment of transmission alternatives, although identifying solutions to meet the state's current planning goal of 3 GW does not require as much additional analysis as is needed in California. This issue should be revisited if Oregon updates its goals for OSW.

4. **Examine optimal phased approaches to regional transmission development.**

   As mentioned above, it will be important to adopt a phased approach to OSW transmission planning and development. An approach that examines near-term and long-term needs, costs, and benefits, and balances these to achieve optimal results would be very beneficial. In most cases it will be desirable to avoid stranded assets, where infrastructure that is deployed in the near term needs to be removed and replaced in later stages of development. We suggest that approaches to achieve the optimal phased development of OSW transmission be explored and documented, and that a preferred approach be identified for planning purposes.

5. **Further examine regionalization of the western power market, as well as transmission planning, development, and operation.**

   A regional approach to OSW transmission development and a regional power market has potential to bring many benefits to the West. This topic needs to be researched and the benefits, risks, and impacts of regionalization need to be assessed. In addition, the role that regionalization can play to help to fully realize the benefits of OSW development at scale on the West Coast should be assessed.

6. **Conduct additional transmission cost-benefit analyses.**

   A more rigorous cost-benefit assessment that examines multiple types of needs and benefits and compares aggregate, systemwide benefits to costs is needed to adequately evaluate transmission options and to identify preferred solutions. In addition, a systematic set of transmission options must be evaluated, and this analysis should be coupled and integrated with the research themes described previously.

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15 APPENDICES

Appendix A – List of Existing Studies Reviewed

Appendix B – List of GIS Data Layers

Appendix C – Wind Generation Profile Memo

Appendix D – Subsea Cable and Landfall Considerations

Appendix E – Transmission Alternative Single-Line Schematics, Maps and Offshore Transmission Configuration Diagrams

Appendix F – Transmission Infrastructure Environmental Concerns and Permitting Analysis

Appendix G – Power Flow Analysis Reliability Standards and Criteria

Appendix H – Power Flow Analysis Thermal Overload Violations

Appendix I – Onshore Transmission Unit Cost Parameters

Appendix J – ORBIT Cost Model Inputs and Learning Curve Assumptions

Appendix K – Transmission Infrastructure Cost Results

Appendix L – Regional Transmission Cost Maps for All Transmission Alternatives

Appendix M – Production Cost Model Results

Appendix N – LCOE and LCOT Equations and Financing Assumptions

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