Offshore Wind Industry Responses to Questions from Staff of the California Public Utilities Commission

(Prepared by Offshore Wind California, American Clean Power – California, and Individual Companies)

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Section 1: Global Offshore Wind Data

How much floating offshore wind is coming in the world (and where)? What are the details of any specific projects that are highly likely to move forward?

One hundred and sixty two offshore wind farms are up and running worldwide and 26 more are under construction.[1] The U.K. has the most capacity (10.4 GW[2]), followed by Germany (7.7 GW), and China (7.1 GW).

Of these wind farms, 10 projects are using floating platforms in deep water off the coasts of the U.K. (Scotland), Portugal, Spain, Norway, France, and Japan. This is the offshore wind technology that would be used in California. The National Renewable Energy Laboratory (NREL) reports that globally there are over 7 GW of floating offshore wind projects in planning and permitting phases of development, with the first utility-scale projects expected to be operational in 2024.

Global pipeline of floating offshore wind projects:[3]

- Installed (84 MW)
- Under construction (50 MW)
- Approved (20 MW)
- Permitted (1.549 GW)
- Planned (5.960 GW), including plans for 1 and 2 GW projects

[1] Global Offshore Wind Report 2020, World Forum Offshore Wind.
[2] 1 gigawatt (GW) = 1,000 megawatts (MW), enough to power 750,000 homes.
[3] National Renewable Energy Laboratory Offshore Wind Technology Data Update, 2019.

Floating Offshore Wind Projects (Asia and the Middle East)

Project Name	Country	Status	COD	Project Size (MW)	Substructure Type	Substructure Name	Turbine	Site Water Depth (m)
Shanghai Electric Floating Demonstrator	China	Planning	2023	4	TBD	TBD	TBD	TBD
V-Type Floating Demonstration	China	Planning	2023	12	Spar	TBD	TBD	TBD
Kyushu Wind Lens	**Japan**	**Operational**	**2012**	**0.06**	**Steel semisubmersible**	**Wind Lens Floater**	**3 kilowatts (kW) (RIAMWIND)**	**55**
Fukushima Phase 1	**Japan**	**Operational**	**2013**	**2**	**Steel semisubmersible**	**Fukushima Mirai**	**2 MW (Hitachi)**	**120**
Fukushima Phase 2	**Japan**	**Operational**	**2015**	**7**	**Steel semisubmersible**	**Fukushima Shimpuu**	**7 MW (Mitsubishi)**	**120**
Fukushima Phase 2	**Japan**	**Operational**	**2016**	**5**	**Steel spar**	**Hamakaze Spar**	**5 MW (Hitachi)**	**120**
Goto Sakiyama	**Japan**	**Operational**	**2016**	**2**	**Steel spar**	**Steel Spar**	**2 MW (Hitachi)**	**100**
Hibiki Demo	**Japan**	**Operational**	**2018**	**3**	**Barge**	**Ideol Damping Pool**	**3 MW (Aerodyn)**	**55**
Kitakyushu NEDO	**Japan**	**Operational**	**2019**	**3**	**Barge**	**Ideol Damping Pool**	**3 MW (Aerodyn)**	**100**
Equinor-Hitachi Zosen	Japan	Planning	2022	TBD (Commercial Scale)	TBD	TBD	TBD	TBD
Acacia	Japan	Planning	2023	TBD (Commercial Scale)	Barge	Ideol Dampening Pool	8 MW	TBD
WindFloat Japan	Japan	Planning	TBD	TBD	Steel semisubmersible	PPI WindFloat	TBD	TBD
KFWind	South Korea	Permitting	2025	500	Steel semisubmersible	PPI WindFloat	63 x 8 MW (MHI Vestas)	150
Donghae Gray Whale	South Korea	Permitting	2025	200	TBD	TBD	TBD	150
Donghae TwinWind	South Korea	Permitting	2025	200	Multiturbine steel semisubmersible	Hexicon	20 x 10 MW	150
KNOC/Equinor	South Korea	Permitting	2026	200	TBD	TBD	TBD	150
Ulsan White Heron	South Korea	Permitting	2026	200	TBD	TBD	TBD	150
Donghae - MOTIE	South Korea	Planning	2022	200	Steel semisubmersible	TBD	TBD	TBD
Donghae 1	South Korea	Planning	2023	200	Spar	TBD	TBD	TBD
Ulsan Demos	South Korea	Planning	2021	5.75	Steel semisubmersible	TBD	TBD	TBD
Floating W1N	Taiwan	Planning	2025	500	Steel semisubmersible	TBD	TBD	TBD
EOLFI – W3	Taiwan	Planning	2030	500	TBD	TBD	TBD	TBD
Plambeck Emirates	Saudi Arabia	Planning	2024	500	Steel semisubmersible	Saipem HexaFloat	TBD	TBD

Table 1. Floating Offshore Wind Projects (Asia and The Middle East).

Floating Offshore Wind Projects (Europe)

Project Name	Country	Status	COD	Project Size (MW)	Substructure Type	Substructure Name	Turbine	Site Water Depth (m)
Floatgen Demo	**France**	**Operational**	**2018**	**2**	**Barge**	**Ideol Dampening Pool**	**2 MW (MHI Vestas)**	**33**
EOLMED (Gruissan)	France	Permitting	2021	25	Barge	Ideol Dampening Pool	4 x 6.2 MW (Senvion)	55
Provence Grand Large Wind Farm	France	Permitting	2021	25.2	Steel tension-leg platform	SBM Windfloater	3 x 8.4 MW (Siemens Gamesa)	90
EOLink Demo	France	**Permitting**	2021	6	Steel semisubmersible	EOLink	6 MW	36
EFGL - Les éoliennes flottantes du Golfe du Lion	France	Permitting	2022	30	Steel semisubmersible	PPI WindFloat	3 x 10 MW (MHI Vestas)	70
Groix-Belle-Ile	France	Permitting	2022	28.5	Steel semisubmersible	Naval Sea Reed	3 x 9.5 MW (MHI Vestas)	60
Bretagne Sud	France	Planning	2025	TBD	Steel semisubmersible	Naval Sea Reed	TBD	TBD
EOLMED (Commercial)	France	Planning	2025	250	Barge	Ideol Dampening Pool	TBD	TBD
EOLink Commercial	France	Planning	TBD	TBD	Steel semisubmersible	EOLink	TBD	TBD
Gicon SOF	Germany	Planning	2021	2.3	Steel tension-leg platform	Gicon TLP	2.3 MW (Siemens Gamesa)	TBD
AFLOWT	Ireland	Planning	2022	6	Steel semisubmersible	Saipem HexaFloat	TBD	100
Inis Ealga floating wind farm	Ireland	Planning	2026	700	TBD	TBD	TBD	TBD
Hywind I Demo	**Norway**	**Operational**	**2009**	**2.3**	**Steel spar**	**Equinor Hywind**	**2.3 MW (Siemens Gamesa)**	**220**
TetraSpar Demo	Norway	Permitting	2021	3.6	Steel spar	TetraSpar	3.6 MW (Siemens Gamesa)	200
FLAGSHIP Demonstration	Norway	Permitting	2022	10	Concrete semisubmersible	OO-Star Wind Floater	10 MW+ (TBD)	TBD
Hywind Tampen	Norway	Permitting	2022	88	Concrete spar	Equinor Hywind	11 x 8 MW (Siemens Gamesa)	300
NOAKA	Norway	Planning	TBD	TBD	Steel spar	Equinor Hywind	8 MW (Siemens Gamesa)	200
Test Area Stadt	**Norway**	**Permitting**	**2025**	**10**	**TBD**	**TBD**	**TBD**	**TBD**

Table 2. Floating Offshore Wind Projects (Europe).

Floating Offshore Wind Projects (Europe [Continued])

Project Name	Country	Status	COD	Project Size (MW)	Substructure Type	Substructure Name	Turbine	Site Water Depth (m)
WindFloat Atlantic	**Portugal**	**Operational**	**2020**	**25**	**Steel semisubmersible**	**PPI WindFloat**	**3 x 8.3 MW (MHI Vestas)**	**100**
W2Power	**Spain**	**Operational**	**2019**	**0.02**	**Multiturbine steel semisubmersible**	**W2Power**	**100 kW**	**600**
BlueSATH	**Spain**	**Operational**	**2020**	**0.03**	**Concrete semisubmersible**	**SATH**	**Aeolos-H 30kW**	**80**
DemoSATH	**Spain**	**Operational**	**2020**	**2**	**Concrete semisubmersible**	**SATH**	**2 MW (XEMC Darwind)**	**80**
Floating Power Plant	Spain	Planning	2021	8	Hybrid wind-wave semisubmersible	P80	5 MW+ (TBD)	600
FLOCAN 5	**Spain**	**Planning**	**2024**	**25**	Steel semisubmersible	**TBD**	**TBD**	**TBD**
X1 Wind	Spain	Permitting	2021	2	Steel tension-leg platform	PivotBuoy	2 MW (MHI Vestas)	600
Nautilus/Balea	Spain	Planning	2023	8	Steel semisubmersible	Nautilus Semi-sub	8 MW (TBD)	120
Equinor Floating Project (Juan Grande)	Spain	Planning	2024	200	Steel spar	Equinor Hywind	TBD	TBD
Iberdrola Demo	Spain	Planning	TBD	TBD	TBD	TBD	TBD	TBD
CanArray	Spain	Planning	TBD	TBD	Multiturbine steel semisubmersible	W2Power	6 MW (TBD)	600
SeaTwirl 1	**Sweden**	**Operational**	**2015**	**0.03**	**Steel spar (VAWT*)**	**SeaTwirl**	**30-kW VAWT**	**35**
SeaTwirl 2	Sweden	Permitting	2021	1	Steel spar (VAWT)	SeaTwirl	1-MW VAWT	100
Hywind Scotland	**UK**	**Operational**	**2017**	**30**	**Steel spar**	**Equinor Hywind**	**6 MW (Siemens Gamesa)**	**112**
Kincardine Phase 1	**UK**	**Operational**	**2018**	**2**	**Steel semisubmersible**	**PPI WindFloat**	**2 MW (MHI Vestas)**	**62**
Kincardine Phase 2	UK	Under Construction	2020	50	Steel semisubmersible	PPI WindFloat	5 x 9.5 MW (MHI Vestas)	62
Marine Power Systems	UK	Planning	2023	TBD	Wind-wave hybrid steel semisubmersible	DualSub	TBD	TBD
Dolphyn Phase 1	UK	Planning	2024	2	Steel semisubmersible	PPI WindFloat +Electrolyzer	2 MW (MHI Vestas)	TBD
Erebus	UK	Planning	2025	96	Steel semisubmersible	PPI WindFloat	TBD	70
Dolphyn Phase 2	UK	Planning	2027	400	Steel semisubmersible	PPI WindFloat +Electrolyzer	10 MW	TBD
Dounreay Tri	UK	Planning	TBD	10	Multiturbine steel semisubmersible	Hexicon	5 MW (TBD)	TBD
Katanes Floating Energy Park	UK	Planning	**2022**	**8**	Hybrid wind-wave semisubmersible	P80	5 MW+ (TBD)	TBD
Dyfed Floating Energy Park	UK	Planning	TBD	TBD	Hybrid wind-wave semisubmersible	P80	5 MW+ (TBD)	TBD

Table 3. Floating Offshore Wind Projects (Europe - Continued).

Floating Offshore Wind Projects (North America)

Project Name	Country	Status	COD	Project Size (MW)	Substructure Type	Substructure Name	Turbine	Site Water Depth (m)
Aqua Ventus	United States	Permitting	2023	12	Concrete semisubmersible	VolturnUS	10 MW + (TBD)	100
Castle Wind	United States	Planning	TBD	1,000	Steel semisubmersible	TBD	TBD	900
Magellan Stiesdal	United States	Planning	TBD	TBD	Steel semisubmersible	TetraSpar	TBD	TBD
Oahu North	United States	Planning	TBD	400	Steel semisubmersible	TBD	TBD	850
Oahu South	United States	Planning	TBD	400	Steel semisubmersible	TBD	TBD	650
Progression South	United States	Planning	TBD	400	Steel semisubmersible	TBD	TBD	600
Redwood Coast	United States	Planning	TBD	150	Steel semisubmersible	PPI WindFloat	8 MW+ (TBD)	600

Table 4. Floating Offshore Wind Projects (North America).

Section 2: U.S. East Coast Progress

What is the status of East Coast offshore wind goals, commitments, PPAs, etc. – when are projects (of what sizes?) there likely to start generating?

Plans are in development on the U.S. East Coast for 29 GW of offshore wind by 2035 with the following state commitments: New York (9.0 GW), New Jersey (7.5 GW), Massachusetts (3.2 GW), Virginia (5.2 GW), Connecticut (2.3 GW), Maryland (1.6 GW), Rhode Island (0.4 GW), Maine (0.012 GW).[4] Almost all of these East Coast projects will be sited in shallow waters and use fixed-bottom foundations.

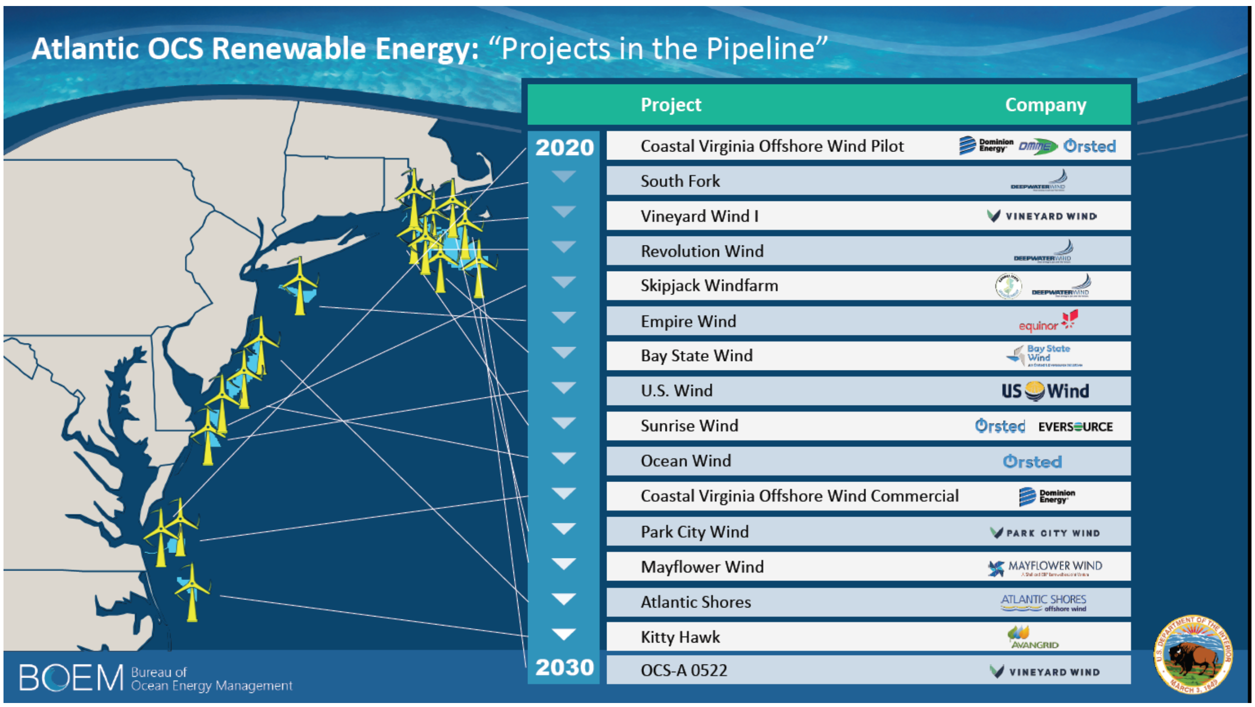

Figure 1. Atlantic OCS Renewable Energy "Projects in the Pipeline".

At the end of 2019, the U.S. had 6.4 GW of offshore wind capacity under federal and state permitting with signed offtake agreements—a threefold increase from the previous year.[5]

[4] Special Initiative on Offshore Wind, University of Delaware, April 2020.
[5] NREL. October 8, 2020. https://www.nrel.gov/news/program/2020/2019-offshore-wind-data.html

Developers have reported the following schedule for U.S. offshore wind projects generating power:

U.S. East Coast Offshore Wind Project Electricity Generation Schedule			
Year	Project (Developer)	Customer	Capacity
2023	Vineyard Wind 1 (Vineyard Wind)	Massachusetts	800 MW
2023	South Fork Wind Farm (Orsted)	New York	132 MW
2023	MarWin (US Wind)	Maryland	248 MW
2023	Revolution Wind (Orsted)	CT/RI	704 MW
2024	Ocean Wind (Orsted)	New Jersey	1,100 MW
2024	Sunrise Wind (Orsted)	New York	880 MW
2025	Park City Wind (Vineyard Wind)	Connecticut	804 MW
Mid-2020s	Empire Wind (Equinor)	New York	816 MW
Mid-2020s	Mayflower Wind (EDPR-Shell)	Massachusetts	804 MW
2026	Skipjack Wind Farm (Orsted)	Maryland	120 MW
2027	Empire 2 (Equinor)	New York	1,260 MW
2028	Beacon 1 (Equinor)	New York	1,230 MW

Table 5. U.S. East Coast Offshore Wind Project Electricity Generation Schedule.

Section 3: 10 GW Goal for California

Is there a write-up on why consider/establish a "10 GW offshore wind goal"?

A draft report prepared by the California Energy Commission (CEC), California Public Utilities Commission (CPUC), and California Air Resources Board (CARB) shows that at least 10 GW of offshore wind will be needed in California's 100% clean energy portfolio by 2045. The report also suggests offshore wind would result in $900 million in total resource cost savings as compared to a portfolio without offshore wind.[6] The report indicates that California will need roughly 140 GW of new renewable energy and storage by 2045 to achieve 100% clean energy. Ten GW of offshore wind would represent roughly 7% of the total capacity needed to meet 2045 requirements.

Furthermore, 10 GW is only a small fraction of the state's full offshore wind technical potential of 112 GW. Industry experience confirms the importance of large state commitments and economies of scale to drive down price and spur market competition in offshore wind. California's energy customers would benefit from a target to bring the industry to scale. Targets and goals have proven effective in East Coast states and other markets. A 10 GW planning target would also position California as an offshore wind leader in the U.S. and Pacific Rim, and a natural hub for the supply chain, jobs and port facilities to deploy this renewable energy technology on the West Coast and beyond.

[6] Draft SB 100 Joint Agency Report: Charting a Path to a 100% Clean Energy Future, December 2020.

Section 4: Cost Projections for Floating Offshore Wind

Costs for floating offshore wind farms have been rapidly declining in recent years and are expected to decline further during the next decade. Industry analysts estimate that Levelized Cost of Energy (LCOE) levels will drop from between $110/MWh and $175/MWH in 2019 to $60/MWh in 2032. NREL reports that the main drivers of these cost reductions are bigger wind turbines and blades, optimization of substructures and logistics, and industrialization of component manufacturing.

Global Floating Offshore Wind Cost Trends, 2014-2032[7]

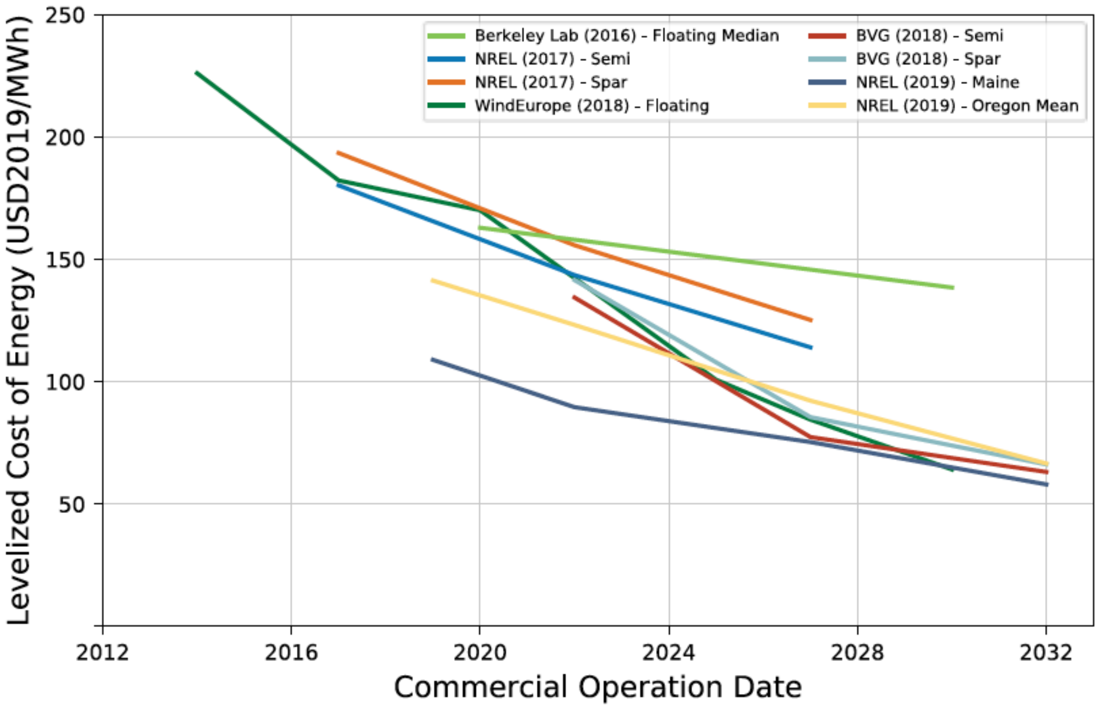

Figure 2. Global Floating Offshore Wind Cost Trends, 2014-2032.

In California, floating offshore wind costs are estimated to drop by an average of 44% between 2019 and 2032 and reach $53–$64/MWh by 2032, according to a November 2020 report by NREL. That same study also estimated high net capacity factors ranging from 49-55 percent for floating offshore wind power generation at five sites off the north and central California coast. The projected cost declines for offshore wind follow reductions already observed for onshore wind (71% decrease from 2009 to 2020) and utility-scale solar (90% decrease from 2009 to 2020).[8]

[7] National Renewable Energy Laboratory 2019 Offshore Wind Technology Data Update, November 2020.
[8] Lazard Levelized Cost of Energy Analysis – Version 14.0, October 2020.

Estimated Levelized Cost of Energy Trajectory Between 2019 and 2032[9]

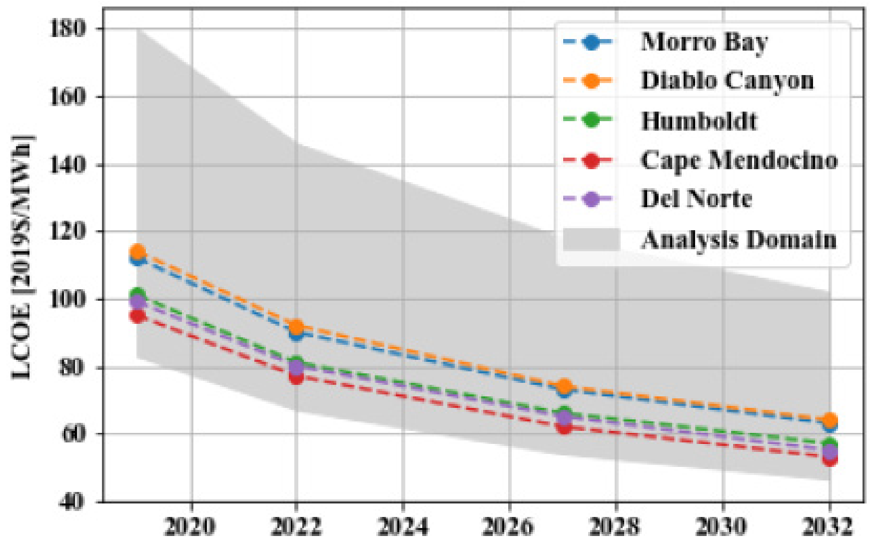

Figure 3. Estimated Levelized Cost of Energy Trajectory Between 2019 and 2032.

[9] The Cost of Floating Offshore Wind Energy in California Between 2019 and 2032, National Renewable Energy Laboratory, November 2020

Section 5: Timeline and Permitting

What would a timeline look like for offshore wind to get built in California? What are some key milestones?

Permitting offshore wind in California will require compliance with the federal permitting process and the State of California permitting process. Each process is governed by a multitude of laws, regulations and agency guidance. While it is not likely that the state and federal permitting processes can be joined, a large portion of these processes can be conducted concurrently. A number of steps can occur prior to the start of the formal federal permitting process, which includes the issuance of a lease and the in-depth analyses and studies that must be conducted by the lessee as part of the preparation of a Construction and Operation Plan (COP).

The following is a summary covering initial planning efforts through issuance of a permit to contract and operate an offshore wind farm.

California Offshore Wind Development Permitting Framework

BOEM OCS Lease	COP Surveys, Reports and Studies	Project-Level Federal and State Permits

BOEM OCS Lease

Federal Permits/Consultations

- BOEM NEPA EA/Finding of No Significant Impact
- USFWS/NMFS Endangered Species Act (ESA) Section 7 Consultation
- NMFS Magnuson-Stevens Fishery Conservation and Management Act (MSFCMA) Section 305(b) EFH Consultation
- National Historic Preservation Act (NHPA) Section 106 Consultation
- CCC Federal Consistency Determination

COP Surveys, Reports and Studies

Surveys, Reports and Studies

- Site Assessment Plan
- COP Survey Plan
- Geophysical and Geotechnical (G&G) Survey Reports and Site Characterization Report
- Sediment Profile Imaging and Benthic Survey Report
- Benthic Assessment Report and Post-Construction Monitoring
- Offshore and Onshore Electromagnetic Frequency (EMF) Assessment
- Air Emissions Inventory
- Fisheries Technical Report and Communication and Outreach Plan
- Essential Fish Habitat (EFH) Assessment
- Avian and Bat Risk Assessment
- Biological Resources Reports: Marine Mammals, Sea Turtles Gish, Habitat, Wetlands, Rare/Protected Species, Invasive Species
- Animal Exposure Modeling/Assessment
- Navigational Risk Assessment Waste/Spill Prevention Plans
- Hydrodynamic and Sediment Transport Modeling Report
- Acoustic Assessment Reports – Underwater, In Air, and onshore
- Munitions and Explosives of Concern Desktop Study
- Marine and Onshore Archaeological Resources Assessment
- Historic Architectural Resources Survey and Historic Resources Visual Impact Assessment
- Visual Resource and Visual Impact Assessments
- MetOcean Report
- Commercial and Recreational Fisheries Technical Report
- Economic Development Analysis
- Coastal Zone Management (CZM) Consistency Certification
- Safety Management Systems – Construction and Operations

Project-Level Federal and State Permits

Federal Permits/Consultations

- BOEM NEPA EIS Record of Decision
- Federal Aviation Administration (FAA) Obstruction Evaluation / Airport Airspace Analysis
- Individual Clean Water Act (CWA) Section 404 Permit
- Individual Permit pursuant to Section 10 of the Rivers and Harbors Act of 1899
- US Coast Guard Private Aids to Navigation Application
- Clean Air Act (CAA) Outer Continental Shelf Air Permit
- Endangered Species Act (ESA) Section 7 Consultation
- NMFS Magnuson-Stevens Fishery Conservation and Management Act (MSFCMA) Section 305(b) EFH Consultation
- Bald and Golden Eagle Protection Act (BGEPA) Incidental Take Permit, Migratory Bird Treaty Act (MBTA) Compliance
- Marine Mammal Protection Act (MMPA) Authorization
- USFWS Incidental Take Authorization (IHA) or Letter of Authorization
- National Historic Preservation Act (NHPA) Section 106 Consultation

State Permits/Consultations

- State Lands Commission State Tidelands Lease
- California Environmental Quality Act (CEQA) EIR Notice of Determination
- CPUC Permit to Construct (possibly needed by IOU)
- CDFW Section 1600 Streambed Alteration Agreement
- CA Department of Transportation (CalTrans) Encroachment Permit (if needed)
- CCC Federal Consistency Review and Coastal Development Permit
- Assembly Bill (AB) 52 Tribal Consultation
- CDFW California Endangered Species Act (CESA) Consultation and Incidental Take Permit
- National Pollutant Discharge and Elimination System (NPDES) Construction General Permit
- Regional Water Quality Control Board CWA Section 401 Water Quality Certification

Regional/Local Permits

- Local Review and Approvals including Conditional Use, Zoning, Building Permit, etc.

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Figure 4. California Offshore Wind Development Permitting Framework.

Initial Planning Process

Development of wind energy areas on the Outer Continental Shelf (OCS) typically begins with the federal Bureau of Ocean Energy Management (BOEM) identifying potential offshore wind planning areas or wind energy areas (WEAs), and then identifying and reaching out to stakeholders that may be affected in the vicinity of the potential WEA. This includes the state(s) with adjacent coastal zones, local municipalities, affected parties, NGOs, etc. BOEM creates a Task Force made up of these stakeholders to help identify potential issues and constraints that may be encountered within a planning area (this process began in 2016 in California). The Task Force and stakeholder outreach process is used to refine the potential lease areas prior to issuance of the Call for Nominations and Information (Call) that is published in the Federal Register. The Call allows developers to document interest in obtaining wind energy lease areas and for the public to comment on the areas and their potential concerns. The Call for the California planning areas was issued in October 2018 and multiple developers, local and state agencies, concerned industries and NGOs responded and provided their interest or concerns. Since that time, BOEM has continued its stakeholder outreach efforts and has conducted environmental analyses that will be used to support the next step, the preparation of a National Environmental Policy Act (NEPA) Environmental Assessment (EA) that has to be completed prior to a lease auction and before the formal federal permitting process can begin.

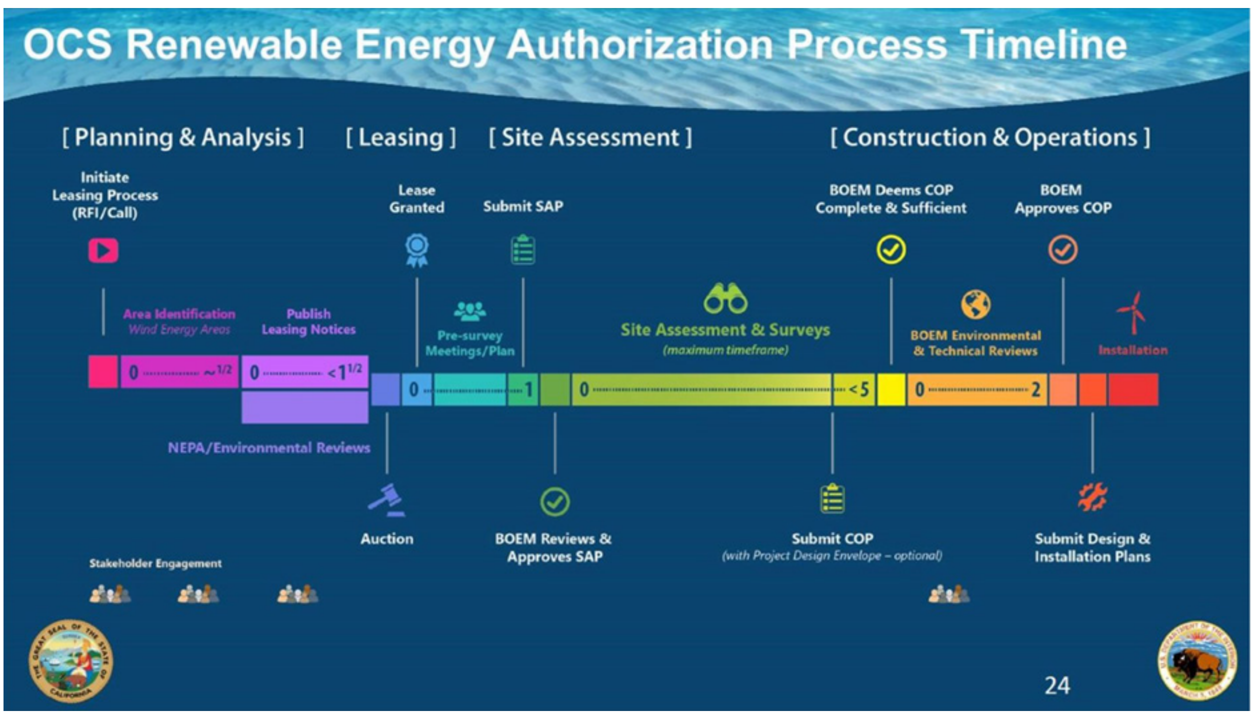


Figure 5. OCS Renewable Energy Timeline.

Leasing Process

Prior to a lease auction of identified WEAs, BOEM must complete a NEPA EA that analyzes the issuance of the lease or leases as well as reasonably foreseeable activities related to site assessment and site characterization (meteorological and environmental studies, geophysical and geotechnical (G&G) studies, etc.) that a lessee is required to complete along with a Site

Assessment Plan (SAP) submitted to BOEM for approval (30 CFR 585). Through the EA process, much of the SAP associated activities are analyzed and typically permitted or have completed consultations. However, additional permits such as an Incidental Harassment Authorization (IHA) for marine mammals may be required for buoy deployment and geophysical and geotechnical (G&G) surveys. This process can take 6-18 months, but may run concurrently with the analyses and studies required by BOEM for submission of a COP. It should be noted that at the leasing stage BOEM will need to prepare a Coastal Zone Management Act (CZMA) Consistency Determination for the leasing and associated site assessment activities and must receive concurrence of the consistency determination from the California Coastal Commission (CCC).

BOEM will initiate the NEPA EA process with issuance of a Notice of Intent (NOI) to prepare an EA. Under current BOEM NEPA guidance (Secretarial Order 3355), they have 6 months between issuance of the NOI and completion of the EA, which concludes with the issuance of a Finding of No Significant Impact (FONSI). A lease auction cannot commence until after this process is completed. BOEM will announce a Proposed Sale Notice in the Federal Register to notify interested parties and provide an opportunity for the interested parties and stakeholders to comment (usually 60 days). Developers wishing to participate in the lease auction are required to submit comments in order to be eligible to bid (unless they have been determined eligible in a past auction). BOEM will review all comments and issue a Final Sale Notice (FSN) in the Federal Register and the auction is anticipated to commence approximately 45 days after the FSN is issued. It typically takes a 2-3 months for BOEM to execute a lease with the successful bidder.

Construction and Operation Plan

The COP is prepared by the lessee and provides a description of all proposed activities and planned facilities for a project under a commercial lease. Pursuant to 30 CFR 585.626, the COP must include a description of all planned facilities, including onshore and support facilities, as well as anticipated project easement needs for the project. It must also describe the activities related to the project including construction, commercial operations, maintenance, decommissioning, and site clearance procedures. The COP will provide the basis for the analysis of the environmental and socioeconomic effects and operational integrity of construction, operation, and decommissioning activities. The resource areas covered by the COP include marine, aquatic and coastal species and habitats, recreation, visual, socioeconomics, commercial fishing, cultural and historic resources, among others. Many resources analyzed in the COP are dependent on the data gathered during the G&G surveys. As noted above, a developer also needs to prepare and submit a SAP for approval and permits such as an IHA for marine mammals and a U.S. Army Corps of Engineers (USACE) Nationwide Permit for buoy deployment may be required for that effort. Similarly, separate permits including a USACE permit for the geotechnical borings, a US Environmental Protection Agency (EPA) OCS air permit and an IHA for marine mammals may be required during the data gathering phase of the COP preparation. The data gathering process and development of a COP can take 18 months or longer. Once a COP is submitted to BOEM, it is reviewed for completeness and sufficiency. This process can take 3-6 months. During this time, BOEM may ask for additional or updated information which could extend the sufficiency review timeframe.

Project NEPA Environmental Impact Statement (EIS)

Once the COP is deemed sufficient, BOEM regulations require an additional NEPA analysis specific to the proposed offshore wind farm and associated activities. The EIS is prepared by a third-party NEPA contractor. The contractor works for BOEM and supports them in every aspect related to development of the EIS (document preparation, scoping meetings, public hearings, additional analyses as required, etc.), but is paid by the lessee. The contractor and the lessee are barred from interacting with one another on anything other than budget and scope changes. There are a number of other agencies that are typically involved at the EIS stage. Federal agencies include USACE, U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS), the EPA and the U.S. Coast Guard (USCG). These agencies may be cooperating agencies to the NEPA EIS which means there could be one decision document, a Record of Decision (ROD) that authorized the project to proceed and includes the conditions of approval. In addition, there are a multitude of state agencies that have jurisdiction and authority over permitting of an offshore wind farm.

Table 6. Federal, State, and Local Approvals for Offshore Wind Development Project.

AGENCY	LEGAL AUTHORITY	PERMIT/APPROVAL	TIMELINE*
FEDERAL			
Bureau of Ocean Energy Management (BOEM)	Outer Continent Shelf Lands Act (43 United States Code (U.S.C.), Chapter 29)	Finding of No Significant Impact (FONSI) for Lease Issuance	6 months from Notice of Intent (NOI) to FONSI per SO 3355
BOEM	Outer Continent Shelf Lands Act (43 United States Code (U.S.C.), Chapter 29)	COP Approval	3-6 months
BOEM	National Environmental Policy Act (42 U.S.C. Section 4321 et. seq.)	Record of Decision (ROD)	2 years for Project EIS per CEQ NEPA Guidelines may include all cooperating agencies and a single ROD (applicants may opt to be a FAST-41 project)
California Office of Historic Preservation	National Historic Preservation Act (16 U.S.C. Section 470 et. seq.)	Section 106 Consultation and Programmatic Agreement	Concurrent with NEPA Process, BOEM using NEPA Substitution
Native American Tribes	Native American Graves Protection and Repatriation Act (25 U.S.C. Section 3001 et. seq.) Required by BOEM as lease stipulation	Tribal consultation	Concurrent with NEPA Process
Federal Aviation Administration (FAA)	Title 14 of the Code of Federal Regulations (CFR) Part 77	Obstruction Evaluation/Airport Airspace Analysis	Concurrent with NEPA Process (may be separate permit/authorization or may be included in single ROD)

AGENCY	LEGAL AUTHORITY	PERMIT/APPROVAL	TIMELINE*
Department of Defense (DOD)	32 CFR Part 211; 49 U.S.C. Section 44718; Required by BOEM during the NEPA review and in leases	DOD Consultation	Concurrent with NEPA Process
U.S. Army Corps of Engineers	Section 404 of the Clean Water Act Section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. 403)	Individual permit	Concurrent with NEPA Process (may be separate permit/authorization or may be included in single ROD)
U.S. Coast Guard	Title 33 of the CFR Part 66	Private Aids to Navigation Application	Concurrent with NEPA Process (may be separate permit/authorization or may be included in single ROD)
U.S. Environmental Protection Agency	Clean Air Act Section 328 (40 CFR Part 55)	Outer Continental Shelf Air Permit	Concurrent with NEPA Process (may be separate permit/authorization or may be included in single ROD)
U.S. Fish and Wildlife Service	Endangered Species Act (16 U.S.C. Section 1531 et. seq.) Bald and Golden Eagle Protection Act (16 U.S.C. 668-668c) Migratory Bird Treaty Act (16 U.S.C. 703-712) Marine Mammal Protection Act (16 U.S.C. 1361-1407)	Section 7 Consultation Incidental Take Permit(s)	Concurrent with NEPA Process (may be separate permit/authorization or may be included in single ROD)
National Marine Fisheries Service	Magnuson-Stevens Fisheries Conservation and Management Act (16 U.S.C. Chapter 38 Section 1801 et. seq.) Marine Mammal Protection Act (16 U.S.C. 1361-1407)	Essential Fish Habitat Consultation Incidental Take Authorization	Concurrent with NEPA Process (may be separate permit/authorization or may be included in single ROD)
CALIFORNIA			
State Lands Commission	California Public Resources Code 6301-6314 California Environmental Quality Act (California Public Resources Code 21000-21189)	State Tidelands Lease Notice of Determination (NOD)	2-3 years for Environmental Impact Report (this table assumes separate NEPA EIS and CEQA EIR process)

AGENCY	LEGAL AUTHORITY	PERMIT/APPROVAL	TIMELINE*
California Department of Fish and Wildlife	• California Department of Fish and Game Code Section 1600 • California Endangered Species Act	Lake and Streambed Alteration Agreement Incidental Take Permit	Concurrent with CEQA Process, issued after NOD
California Office of Historic Preservation	Public Resources Code Sections 5024 and 5024.5	SHPO Consultation	Concurrent with CEQA Process
Native American Tribes	Assembly Bill 52 (Public Resources Code Section 5097.94)	AB 52 Tribal Consultation	Concurrent with CEQA Process
California Coastal Commission	California Coastal Act (Title 14 Natural Resources Division 5.5) Coastal Zone Management Act (16 U.S.C. Section 1451 et.seq.)	Coastal Development Permit Consistency Determination	Concurrent with CEQA Process, issued after NOD
Central Coast Regional Water Quality Control Board	Clean Water Act Section 401 (33 U.S.C. Section 1341) Clean Water Act Section 402(p)	Water Quality Certification Construction General Permit	Concurrent with CEQA Process, issued after NOD
California Public Utilities Commission (CPUC)	CPUC General Order 131-D (Public Utilities Code)	Permit to Construct (if needed)	2-3 years; Dependent on role of CPUC in CEQA Process and whether Proponent's Environmental Assessment is required.
California Department of Transportation (CalTrans)	California Street and Highways Code Section 660	Encroachment Permit (if needed)	2-4 months
LOCAL			
Jurisdiction with Approval Authority (e.g., City of Morro Bay, County of San Luis Obispo)	California Constitution, Article XI, Section 7	Conditional Use Permit, Zoning Permit, Building Permit, etc.	6-9 months for Local Permitting

* = Assumes no appeals or project applicant or agency delays.

Federal and state permit approvals may occur after the BOEM EIS and SLC EIR decisions.

The formal NEPA process is initiated when BOEM issues a NOI in the Federal Register. The NOI is also published in local newspapers and should include date(s) and location(s) of scoping meetings. BOEM develops the EIS based on the COP data, scoping comments and inter-agency consultations with cooperating and other agencies. A draft EIS is issued for public comment (at least 45 days) and public hearing(s) are then conducted. BOEM prepares a final EIS based on the input from the public and issues a final EIS for public comment (at least 30 days). After the close of the comment period on the final EIS, they issue the ROD, which if feasible per the Council on

Environmental Quality (CEQ) NEPA regulations, will include decisions from cooperating agencies (e.g. NMFS, USFWS, EPA and USACE). Under current CEQ NEPA regulations, although not required, the EIS process should be completed within two years.

State Permitting and the California Environmental Quality Act (CEQA)

In California, there are many state and local agencies from which an offshore wind farm must seek approval. In addition, the project must be reviewed under CEQA and the anticipated level of impacts associated with a project of this magnitude, an Environmental Impact Report (EIR) will be necessary. It is worth noting that it is possible for a joint EIR/EIS to be prepared that complies with CEQA and NEPA, whether that is likely for an offshore wind project is unclear. This summary and the associated permitting schedule and table assume these processes would be conducted separately.

The EIR requires a Lead Agency, and at this time, it is believed that the State Lands Commission (SLC) would act as that lead agency given their permitting authority to issue a State Tideland Lease. The Lead Agency is the public agency with the greatest responsibility for supervising or approving the project as a whole or which will act first on the project (CEQA Guidelines Section 15051). In addition to the SLC, the following agencies have jurisdiction or permitting authority over an offshore wind farm:

- California Coastal Commission
- California Department of Fish and Wildlife
- California Regional Water Quality Control Board
- California Department of Transportation
- California Historic Preservation Office
- California Public Utilities Commission (CPUC), if an investor operated utility must develop or upgrade transmission or substation infrastructure
- Local county, municipality where onshore activities would occur.

CEQA requires state and local government agencies to inform decision makers and the public about the potential environmental impacts of proposed projects, and to reduce those environmental impacts to the extent feasible. An EIR contains in-depth studies of potential impacts, measures to reduce or avoid those impacts, and an analysis of alternatives to the project. A key feature of the CEQA process is the opportunity for the public to review and provide input on proposed projects. The CEQA process is likely to take a minimum of 2 to 2.5 years and begins with a posting of a Notice of Preparation (NOP) on the Governor's Office of Environmental Planning (OPR) CEQAnet Web Portal that is also posted locally with the County Clerk and other public locations and in newspapers in the vicinity of the proposed project.

There are a number of steps needed to complete the CEQA process including the need for responsible and/or trustee agencies as identified by the OPR to respond to the NOP, at least one scoping meeting for projects of statewide importance (offshore wind is assumed to be that), issuance of a draft EIR for public comment, public hearing(s), preparation of a final EIR and response to comments and issuance of a Notice of Determination (NOD). Typically, it takes several months after the NOD for the pertinent State agencies to issue their permits, which can add another 3-6 months to the 2-to-2.5-year timeframe for CEQA and State permitting completion.

From NOI for the EA to issuance of a ROD for the federal permitting, an NOD for CEQA and the subsequent state agency permits discussed above is an approximately 5.5-year process. That 5.5-year process will not begin until the NOI for the NEPA EA for the lease issuance is issued. While there may be opportunities to speed up this timeframe at the margins (e.g., the COP may be prepared in less than 18 months), it is unlikely that would occur. It should be noted that this timeline does not take into account potential for time to be added to this process due to unforeseen issues such as project design changes, inter-agency disagreements, extended agency review timeframes, etc. which could add some number of months to the process depending on the specifics and the resolution of the delay.

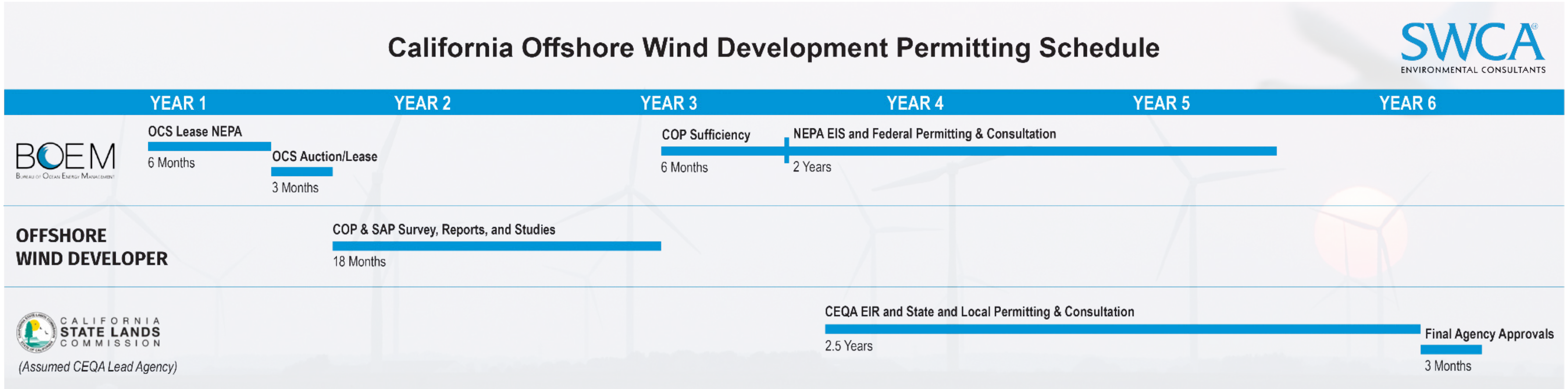
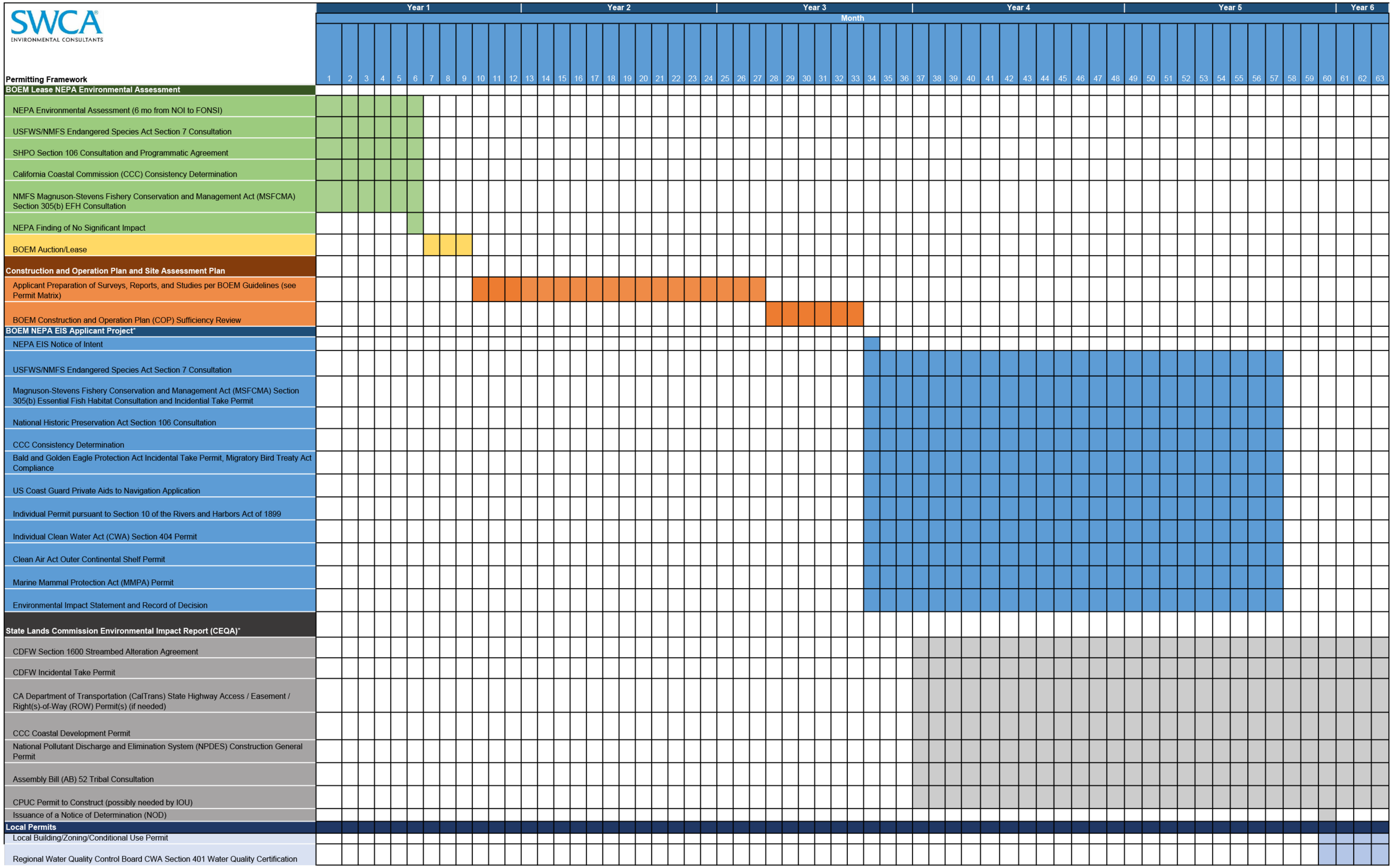


Figure 6. California Offshore Wind Development Permitting Schedule.



* = federal and state permit approvals may occur after the BOEM EIS and SLC EIR decisions.

Table 7. Linear Permitting Timetable.

Section 6: Transmission

Introduction

There is no question that California will need to invest in new transmission to achieve its SB 100 goals. There simply isn't capacity to deliver 140 GW of new renewables and storage to load centers through today's system. Considerations about transmission upgrades needed to facilitate offshore wind should be made within this context.

The California Independent System Operator (CAISO) sensitivity analysis in the upcoming Transmission Planning Process (TPP) will provide much needed information on both the available capacity for offshore wind as well as potential upgrades needed and associated costs of those upgrades. This information will feed into a future Integrated Resource Plan (IRP) cycle (e.g., the 2022-2024 cycle) and inform offshore wind resource cost assumptions. It could also, at the CPUC's direction, lead to additional planning for offshore wind as part of a base reliability/policy case in the next TPP cycle (2022-2023). If this and other adjustments result in offshore wind being selected as part of a Reference System Plan (RSP), which is then transferred as part of the reliability and policy base case for a future TPP, then new transmission or system upgrades could be authorized by the CAISO. Once authorized, it could take 10 years or longer[10] for a new transmission line to be constructed. Thus, it is essential to begin planning for offshore wind transmission upgrades as soon as possible.

The CPUC has a duty to assess the most cost effective near-term and long-term solutions to achieve reliability and climate objectives. The offshore wind industry recommends that the CPUC take the following steps, starting as soon as possible, in support of these goals, and to properly assess and plan for a future with offshore wind:

Near term

1) Recommend a Preferred System Plan in this IRP cycle built around a 38 million metric ton (MMT) greenhouse gas (GHG) target. GHG target assumptions are critical to planning for the right portfolio. The IRP is not currently planning to meet SB 100 requirements.
2) Related to procurement of capacity to replace the Diablo Canyon Nuclear Power Plant facility, differentiate between mid-term (by 2025) and longer-term (by 2030) capacity needs. Offshore wind will not be able to show up in time to meet the scale of procurement contemplated in the CPUC's recent mid-term ruling. But if a portion of this capacity will be needed later, closer to 2030, then the CPUC should order exploration of longer-term resources like offshore wind that may ultimately provide the greatest capacity value and system diversity, while also making the greatest use of existing transmission capacity. The CPUC should not leave offshore wind left behind simply because planning for Diablo Canyon replacement has come so late.
3) Manage the TPP sensitivity analysis to be performed by the CAISO to maximize the value of this review. Consider requesting scenarios with different assumptions about

[10] https://www.tanc.us/news-article/how-long-does-it-take-to-permit-and-build-transmission-to-meet-californias-policy-goals/

retention of PG&E transmission deliverability. Consider requesting scenarios where fewer gas resources are retained in the Los Angeles (LA) Basin.

Medium Term

4) Make larger improvements to the IRP process which will better account for the value of offshore wind, and thus how much offshore wind is picked up as part of Preferred System Portfolios (PSP). Key changes include differentiating the Effective Load Carrying Capability (ELCC) in the Resource Adequacy proceeding by geography to account for the tremendous time-of-day benefits of offshore wind; adjusting assumptions about gas retirement in key load centers; and properly accounting for the costs of keeping gas facilities online in development of new portfolios.

Longer Term

5) Work with the CAISO and the CEC to create a special process for evaluation and potential approval of transmission solutions for offshore wind. Start by acknowledging SB 100 results which call for diverse renewables and new transmission. Transmission planning for new or majorly upgraded long-distance lines that will optimize renewable resource build will be an intensive process that we need to get ahead of now. Standard processes (IRP portfolios, interconnection requests, and cluster studies) are not likely to address the questions we need to be answering and the transmission system we need to plan for. A special planning process for offshore wind may be warranted. Alternatively, this planning could be part of a Renewable Energy Transmission Initiative (RETI) 3.0 process that looks at multiple renewable resources and resource zones, with the intent of identifying least-regrets solutions in the 2035-2045 timeframe.

What are the most viable routes from Central Coast and North Coast projects?

On the Central Coast, utilizing existing capacity with projects interconnecting at Morro Bay or Diablo Canyon would be the first most viable option. However, additional transmission capacity may be needed to maximize development of the Morro Bay offshore wind resource, which could support up to 7 GW total, given the limited capacity to interconnect at Diablo Canyon and Morro Bay currently, as well as limits to deliverability in the transmission system (Path 26) to the LA Basin. See map of Central to Southern California CAISO system below. Deliverability to the LA Basin would allow offshore wind to supply local resource adequacy, enabling reduced reliance on local fossil resources.

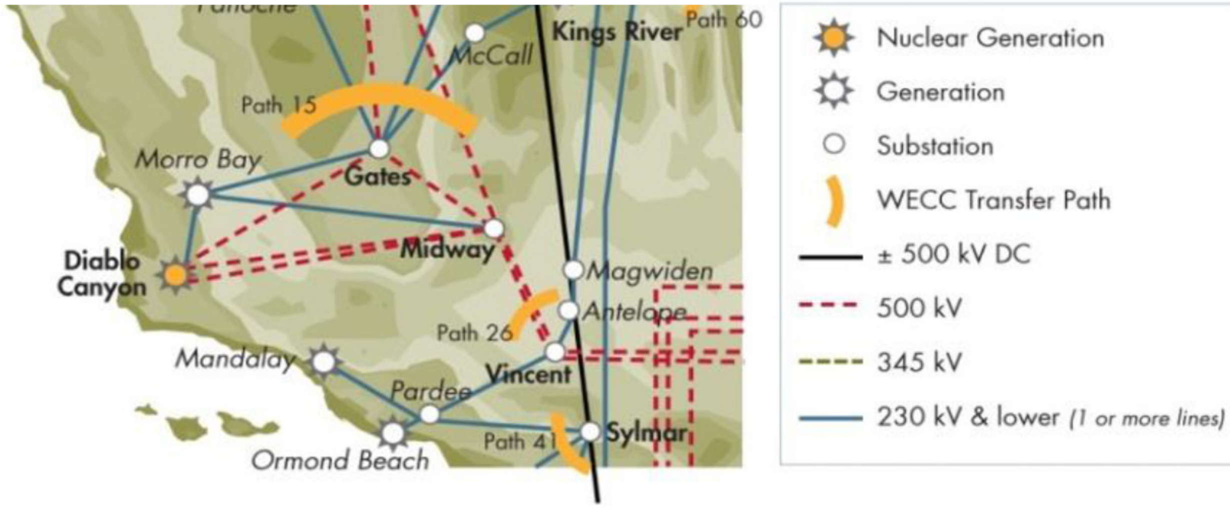


Figure 7. Central to Southern California CAISO system

To add transmission capacity to the LA Basin, a subsea transmission line from the central coast to the LA basin may be a viable option. However, assumptions about the quantity of natural gas generation resources retained in basin will affect the cost-benefit analysis associated with this, or other options to connect to the LA Basin. See record in Rulemaking 16-02-007 and 20-05-003, including ACP-CA comments[11], CalWEA[12], and CEERT[13] comments.

Regarding North Coast transmission, the Schatz Energy Research Center[14] has examined multiple transmission pathways to the south, south east, and south from the Humboldt call area: 1) Interconnection into the Round Mountain Substation and upgrades to the 500 kV lines south to the Bay Area; 2) Interconnection at the Vaca-Dixon Substation; and 3) Interconnection at a new Bay Area substation via a new subsea line (two routes). See map below:

[11] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M350/K325/350325204.PDF
[12] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M350/K792/350792115.PDF
[13] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M329/K382/329382132.PDF
[14] http://schatzcenter.org/pubs/2020-OSW-R4.pdf

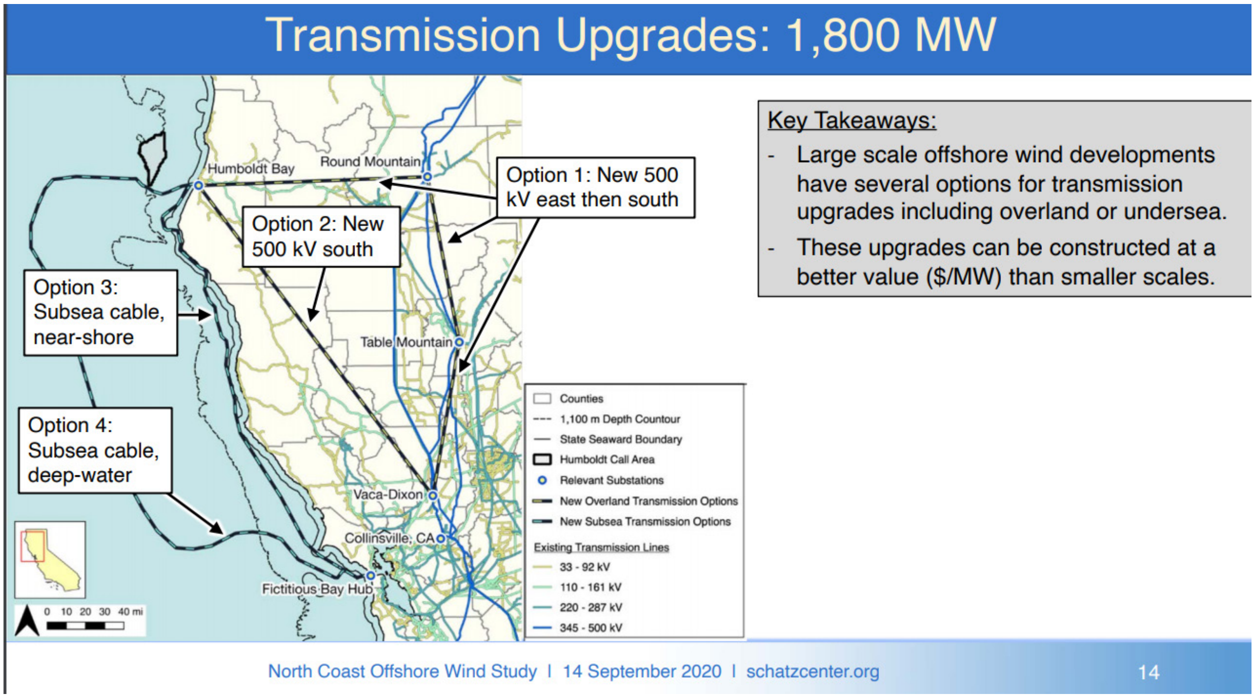


Figure 8. Transmission Upgrades: 1,800 MW.

In addition to these options, there may be opportunities to upgrade transmission to utilize existing rights-of-way or to repurpose pipeline rights of way. Finally, there may be options to route transmission east and then feed into the southern intertie system via substations at the California-Oregon border. All of these transmission options may work. Without further study of the transmission network capabilities and benefits, costs and system benefits, as well as environmental and cultural resource assessments, it would be premature to conclude one pathway is more viable than another.

The planned 22 GW offshore wind outlook assessment in the next TPP cycle may provide further information on the viability of different transmission options. As indicated by the findings of the Schatz Energy Research Center, it is likely that the most optimal transmission solution from the North Coast will be larger than the capacity of the Humboldt call area alone, and instead will serve multiple offshore wind project areas. The transmission planning for offshore wind contemplated in AB 525 (Chiu) would also further this assessment.

The Energy Division has an important role in directing the CAISO's studies on transmission options for offshore wind through the resources selected in the base case IRP portfolio, GHG targets driving selected portfolios, decisions about gas fleet retention assumptions, and in proposed policy-based resource sensitivities.

What is the existing capacity per CAISO?

On the North Coast, studies from the Schatz Energy Research Center and CAISO analysis have indicated there is limited capacity to connect offshore wind. A small project of 100-200 MW would require some level of upgrades. Larger projects would require new transmission. The Schatz report also emphasized the importance of scale in determining the cost-effectiveness of a future project. The 22 GW outlook scenario in the 2021-2022 TPP cycle will help determine the optimal transmission solution from the North Coast.

On the Central Coast, CAISO has indicated that 3-4 GW of offshore wind could interconnect to the CAISO grid.[15] In other conversations with industry, CAISO staff has indicated 5-7 GW of offshore wind could be interconnected. In a presentation during a Modeling Advisory Group webinar of the IRP (August 2020), CPUC staff, examining CAISO's white paper for the 2019-2020 IRP cycle assumptions, estimated 5 GW of deliverable capacity is available in the central coast for offshore wind.

The factors that affect how much transmission is known to be available in the central coast are as follows:

1) The CAISO hasn't done a full assessment of offshore wind interconnection and deliverability, including power-flow analysis to fully assess capacity for offshore wind resources interconnecting at Morro Bay or Diablo Canyon in the Central Coast. This is a primary reason for the more thorough 8 GW offshore wind sensitivity analysis that will be part of the 2021-2022 TPP. With the completion of this assessment, the CAISO, CPUC, and industry will have a much better understanding of the transmission capability for offshore wind in the central coast.
2) The range is affected by assumptions about whether PG&E will retain its deliverability rights associating with Diablo Canyon for three years (to 2028), or whether the CPUC could compel PG&E to relinquish those rights. Without this 2 GW of deliverability capacity, the lower end of the range (3 GW) is more likely, according to CAISO staff.
3) There are projects in the interconnection queue for Diablo Canyon and Morro Bay interconnection today that may be able to come online sooner and could use up some of the transmission capacity that would otherwise be available to offshore wind.

[15] CAISO Presentation at 2019 IEPR Workshop: https://efiling.energy.ca.gov/GetDocument.aspx?tn=229915&DocumentContentId=61375

Transmission capability estimates to support CPUC's IRP process

	Estimated FCDS Capability (MW)				Incremental Upgrade Cost Estimate ($million)				Estimated EODS Capability** (MW)
	A		B					C	D
Transmission zones and sub-zones	Existing System	Minor Upgrades	Major Upgrade #1	Major Upgrade #2	Existing System	Minor Upgrades	Major Upgrade #1	Major Upgrade #2	Existing System
Northern CA	**2,000**		**2,000**				**$ 285**		**3,900**
- Round mountain	500								2,100
- Humboldt	-								100
- Sacramento River	2,000								4,600
- Solano	600		2,000				$ 322		1,300
Southern PG&E	**1,100**		**1,000**				**$ 55**		**TBD**
- Westlands	1,100		1,000				$ 55		TBD
- Kern and Greater Carrizo	1,000		1,500				$ 241		TBD
- Carrizo	400		700				$ 53		400
- Central Valley North & Los Banos	1,000		1,000				$ 274		TBD
Tehachapi	**4,300**	**1,000**				**$ 100**			**5,100**
Greater Kramer (North of Lugo)	**600**		**400**				**$ 146**		**600**
- North of Victor	300		400				$ 485		300
- Inyokern and North of Kramer	100		400				$ 485		100
- Pisgah	400		400				$ 261		400
Southern CA Desert and Southern NV	**3,000**		**2,800**				**$ 2,156**		**9,600**
- Eldorado/Mtn Pass (230 kV)	250		1,400				$ 76		2,400
- Southern NV (GLW-VEA)	700		1,400				$ 150		700
- Greater Imperial*	1,200		1,400				$ 2,334		3,100
- Riverside East & Palm Springs	2,950		1,500				$ 2,156		5,500

* Subject to mitigation of the S-line constraint.

** Estimate EODS capability numbers are inclusive of the FCDS estimates. So the incremental EODS capability = Estimated EODS capability - Estimated FCDS capability

NOTE:
(i) The transmission areas indented in the table are subsets of the overarching transmission areas listed immediately above the indented areas.
(ii) The transmission capability estimates rely on the latest generation interconnection studies as one of the inputs. Estimated available transmission has been reduced by the amount of renewable resources that have come online by December 31, 2018 assuming that all these resources have a contract with an entity within CAISO BA.
(ii) The estimated capability added due to major upgrades and corresponding costs are ballpark numbers and are conceptual in nature.

Figure 9. Transmission Capability Estimates to Support CPUC's IRP Process.

Who is expected to provide transmission from the projects to onshore?

It is expected that developers would plan for and build the export cable that connects an offshore wind facility to an onshore substation. This would be a capital cost of the project.

Is the cost of sub-sea transmission included in the NREL-forecasted $53-64/MWh cost?

The cost of bulk transmission is not included in this cost. The NREL report included costs of interconnecting a wind farm from an offshore substation to an onshore substation or transmission line, including the export cable, offshore substation, spur line, and cable landfall. Costs of onshore substation upgrades and bulk transmission system upgrades were not included.[16]

We note that transmission expansions such as those contemplated for offshore wind would not be approved solely for the benefit of offshore wind. These would be system investments that, if

[16] 8/27/20 IRP MAG Webinar on Offshore Wind Costs: https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442466870

approved, would provide reliability value across the system. Thus, these costs should not be attributed to the resource cost assumptions for offshore wind.

Pacific Transmission Expansion Project (PTEP) **-** *The call referenced the PTEP project as a submarine cable project that could be considered for Resource Adequacy (RA) purposes and not even necessarily offshore wind purposes. Is this really a single project being pushed by an entity or is it a project concept being endorsed by a variety of entities?*

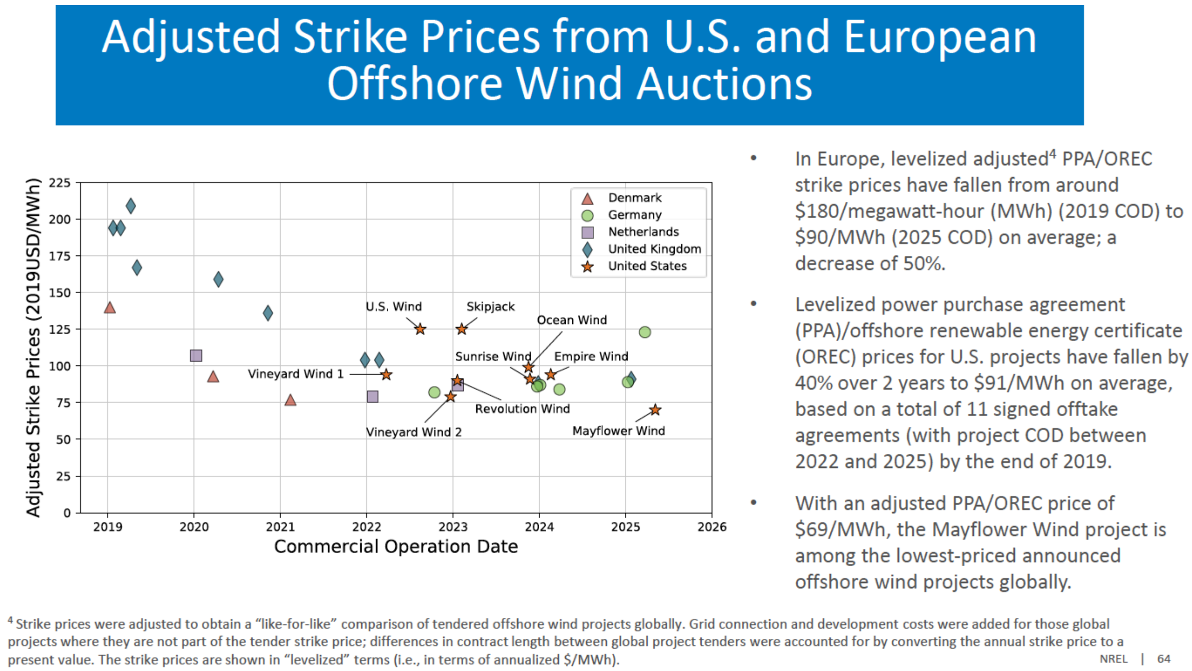
The Pacific Transmission Expansion project is proposed by Three Rivers Energy Development LLC. Multiple offshore wind developers are interested in a subsea central coast to LA basin transmission option as a way to supply local capacity to the LA Basin, or to more broadly enhance the deliverability of central coast offshore wind given system congestion in Path 26. ACP-California, CalWEA, and CEERT, all referenced this concept in filings in the recent IRP process. While the project has been proposed by a single developer, if approved, the project would of course be put out for a competitive solicitation. In addition, this project isn't conceived as an offshore wind specific project. It could also support delivery of other central valley and central coast resources to the LA Basin.

Conclusion

As described above, the CPUC can facilitate determination of the best offshore wind transmission solutions through its role in setting assumptions and targets for the IRP, its direction to the CAISO in the Transmission Planning Process, and by leading and engaging in broader, more holistic assessments of long-term transmission solutions needed to achieve SB 100 goals and for large-scale offshore wind.

Section 7: Procurement

What are costs of existing offshore wind contracts on a $/MWh basis?



[17]

Figure 10. Adjusted Strike Prices from U.S. and European Offshore Wind Auctions.

When will you begin to discuss PPAs with CCAs, IOUs and POUs?

Offshore wind developers have had and continue to have discussions with California's load-serving entities (LSEs) about offtake possibilities. In particular, the recent announcement by a group of Community Choice Aggregators (CCAs) to form a Joint Powers Authority (JPA) may enhance the buying-power of CCAs and enable offshore wind developers to secure financing of their projects. Market certainty – in the form of clear procurement obligations and financially viable off takers – is necessary to facilitate procurement of large projects and long lead-time renewable resources.[18]

What has the Los Angeles Department of Water and Power (LADWP) publicly stated about its interest in offshore wind?

LADWP has not publicly stated a position about offshore wind but they do have a plan to clean their grid and get to 100% clean energy by 2045. The recent NREL study completed for LADWP on their LA 100 plan is comprehensive. There may be opportunities for LADWP to consider new energy resources to meet the 100% goal. As they look to replace the once-through cooling plants

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[17] NREL 2019 Offshore Wind Technology Data Update.

[18] American Clean Power – California is a party to relevant CPUC proceedings that address procurement certainty and highlight the need for resource diversity and clean capacity, such as IRP, RA, RPS, and PCIA.

to help clean their grid, they will need to back that up with reliable clean energy sources. Offshore wind has the potential to do that if they are able to connect at their coastal plants.

A utility plan that is reliant on green-hydrogen, which is the direction LADWP has been heading, will require large quantities of high-capacity renewable energy to manage hydrogen production costs, which would be another benefit to LADWP of investing in offshore wind. Since LADWP does its own integrated resource planning and they have their own balancing authority, developers will be exploring these solutions directly with LADWP. However, on transmission planning, it would make sense for the CAISO and LADWP to coordinate, especially in assessing a sub-sea transmission solution that could deliver offshore wind to both the CAISO and LADWP balancing areas.

Section 8: Offshore Wind Investment Tax Credit

We heard "if a project can demonstrate a commitment of 5% of total project costs by 2025, and be online by 2035, it is eligible for the 30% ITC." Per which particular piece of legislation? Are there new ITC revisions on the table that we need to keep an eye on as California? I heard the Covid relief bill passed in December 2020 included the 30% ITC for offshore wind (see CohnReznick article). Is there news (or pending news) other than that?

The Consolidated Appropriations Act, 2021

In December 2020, Congress passed and President Trump signed the Consolidated Appropriations Act, 2021 (including Coronavirus Stimulus and Relief).[19] In Section 204, "Extension of energy credit for offshore wind facilities," a 30% investment tax credit (ITC) was created for offshore wind.[20] That extension expires at the end of 2025.[21] However, IRS guidance discussed below enables a safe harbor for projects placed into service within 10 years of the start of construction.

IRS Guidance on the Offshore Wind ITC, Notice 2021-05

The Internal Revenue Service (IRS) issued guidance[22] that an offshore wind developer can meet the agency's "Safe Harbor" construction continuity requirement so long as the qualified project is placed in service "within 10 calendar years after the calendar year during which construction of the project began." The Safe Harbor provision requires a firm investment commitment by the developer of 5% of the CapEx of the project at the time the developer seeks to qualify for the tax credit, i.e., at the commencement of construction.[23]

LCOE Analysis

The Investment Tax Credit will reduce the Levelized Cost of Energy (LCOE) for 3 to 4 GW of offshore wind off the central coast of California by 15—20%. This LCOE reduction will save California ratepayers $3.6 to $7.8 billion over the life of the wind farm(s). Inputs for the model, including an LCOE benefit analysis using NREL data, are provided in the following graphics prepared by Xodus Group, Inc..

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[19] https://www.govtrack.us/congress/bills/116/hr133/text

[20] US Congress Passes Five-Year Offshore Wind Tax Credit, by Nadja Skoplijak, *offshoreWIND.biz*, December 23, 2020

[21] Offshore wind, renewable energy figures prominently in US coronavirus stimulus package, Renewables Consulting Group, January 4, 2021

[22] Beginning of Construction for Sections 45 and 48; Extension of Continuity Safe Harbor for Offshore Projects and Federal Land Projects, Internal Revenue Service, Notice 2021-05, December 31, 2021. https://www.irs.gov/pub/irs-drop/n-21-05.pdf

[23] IRS Gives Offshore Wind and Federal Land Projects More Time to Qualify for Tax Credits, Latham & Watkins, January 7, 2021

LCOE Benefit Analysis –Xodus High Level Model

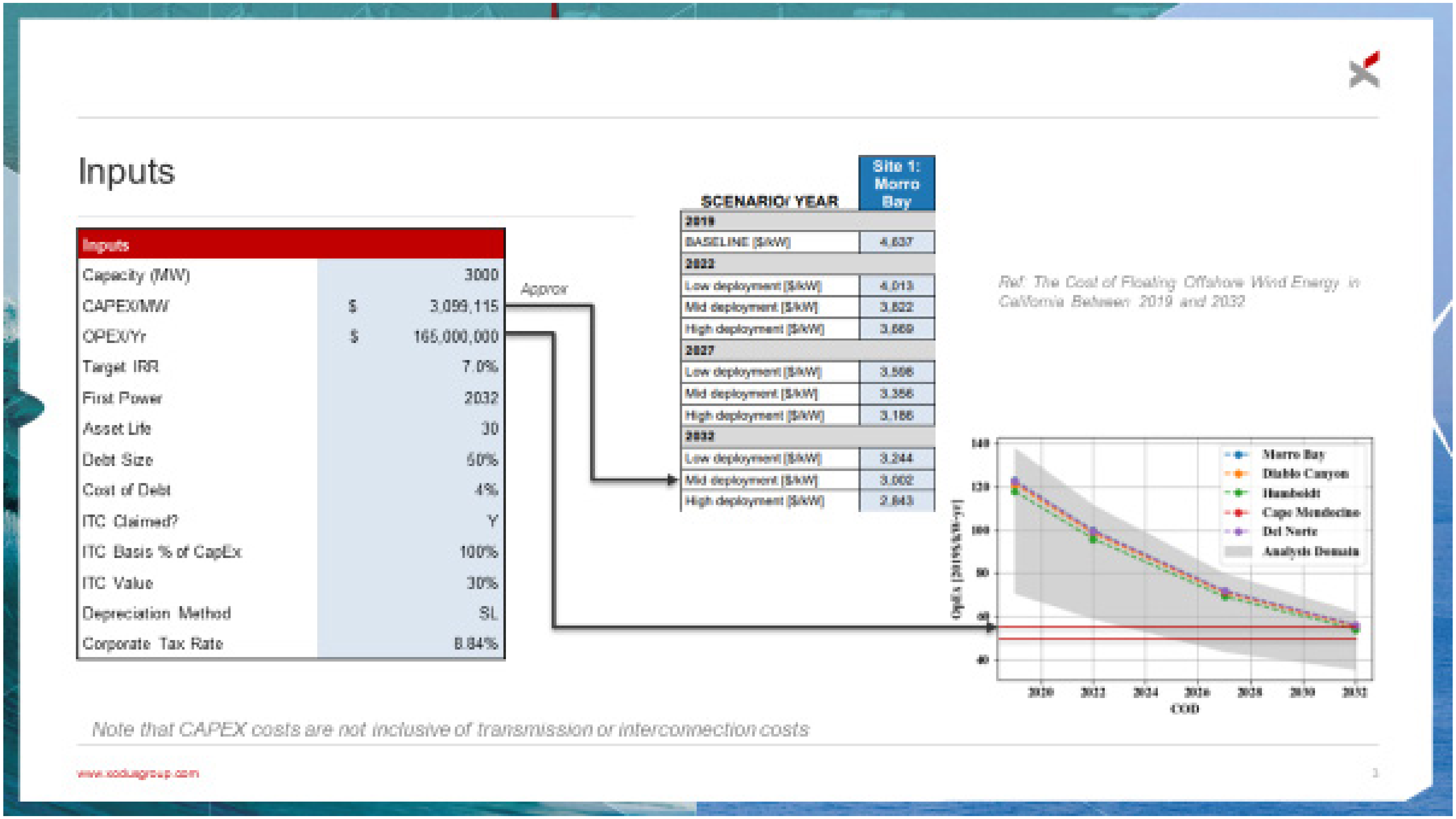

Figure 11. Inputs

Results

Total Revenues		
With ITC	$	34,732,526,000
Without ITC	$	42,611,738,000
Savings to Rate Payers	$	7,879,212,000

LCOE ($/MWhr)		
With ITC	$	87
Without ITC	$	107
Difference	$	20
% Reduction		(18.7%)

- Approx. $8 billion savings to California ratepayers
- Approx. 20% reduction on Levelized Cost of Energy (LCOE)
- Certain simplifications were made to incorporate the benefits from tax equity partners into the model.

www.xodusgroup.com 4

Figure 12. Results

LCOE Benefit Analysis –Xodus NREL Data

4 GW Wind Farm Revenue – NREL Data (No ITC)

Item	Site 1: Morro Bay
2019 COD	
GCF [%]	55.5
Total losses [% of gross production]	15.0
NCF [%]	46.5
2022 COD	
GCF [%]	56.2
Total losses [% of gross production]	14.7
NCF [%]	47.2
2027 COD	
GCF [%]	57.7
Total losses [% of gross production]	14.4
NCF [%]	48.7
2032 COD	
GCF [%]	58.3
Total losses [% of gross production]	14.2
NCF [%]	49.4

4GW - 14MW turbine Generates
Net P50 = Approx. 18,000,000 [MWh/a]

Revenue [Per/Yr] = Net Yield x LCOE

Revenue [Per/Yr] = $1,206,000,000

Revenue [30 Yrs] = $36,180,000,000

SCENARIO/ YEAR	Site 1: Morro Bay
2019	
Baseline [$/MWh]	112
2022	
Low deployment [$/MWh]	94
Mid deployment [$/MWh]	90
High deployment [$/MWh]	88
2027	
Low deployment [$/MWh]	77
Mid deployment [$/MWh]	73
High deployment [$/MWh]	70
2032	
Low deployment [$/MWh]	67
Mid deployment [$/MWh]	63
High deployment [$/MWh]	60

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Figure 13. 4 GW Wind Farm Revenue – NREL Data (No ITC)

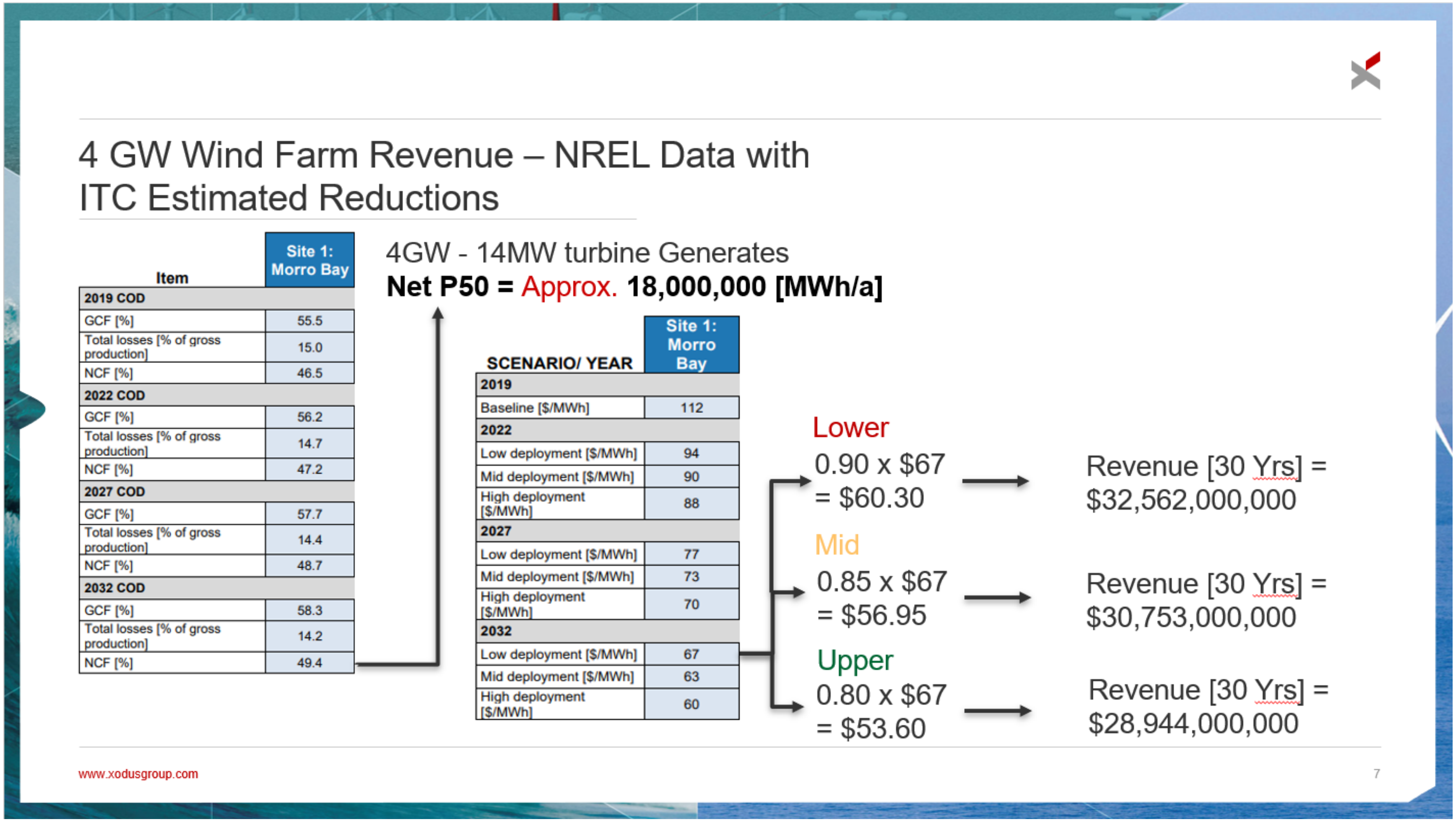

Figure 14. *4 GW Wind Farm Revenue – NREL Data with ITC Estimated Reductions.*

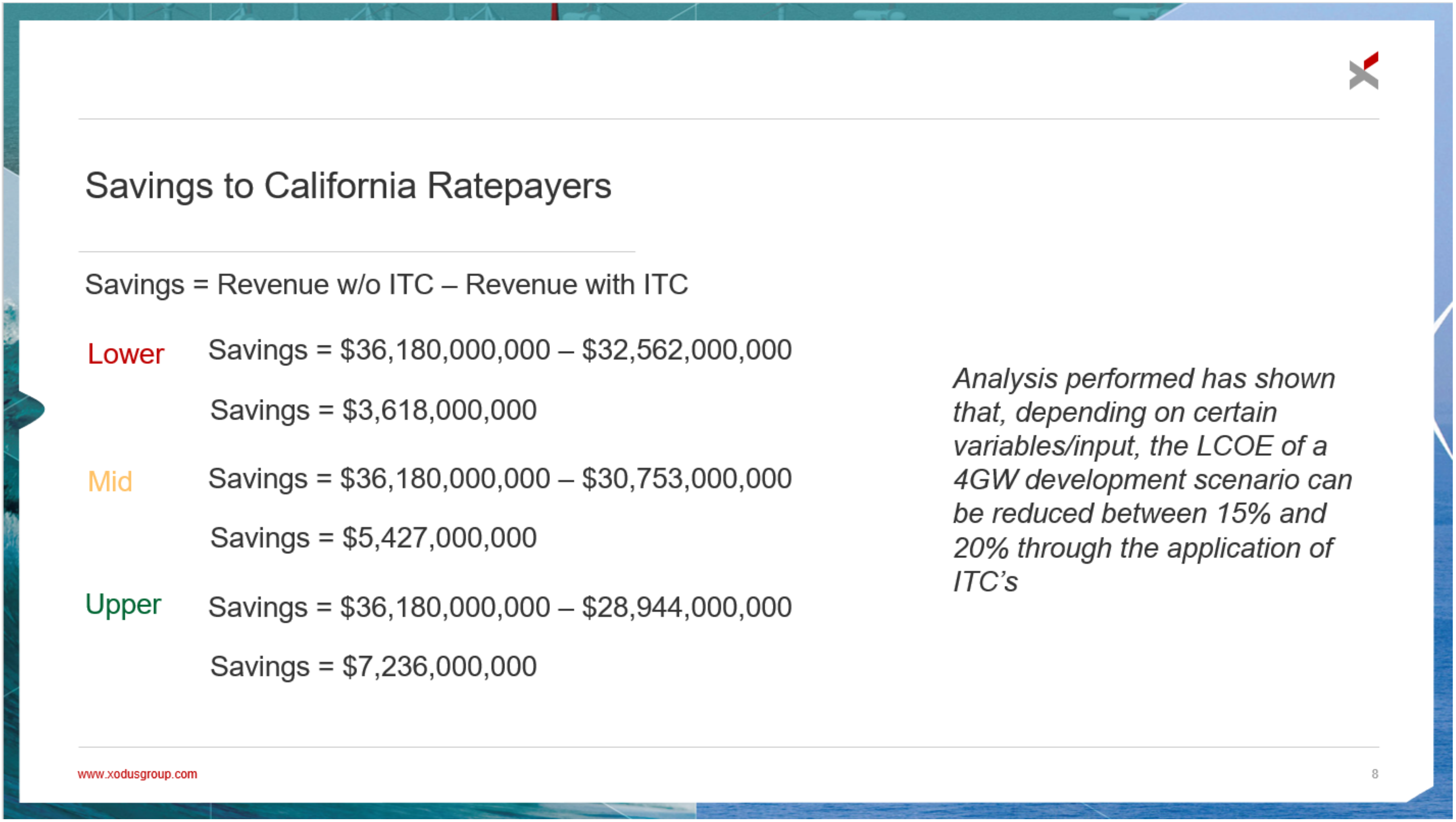

Figure 15. Savings to California Ratepayers

Section 9: Technology and Research

***Turbine Size** – The NREL report (and studies around the port needs) expect these offshore wind turbines to be massive. Should California be expecting to use 5 MW, 10 MW, or even 15 MW turbines? Is there a 'if built by x date, the turbines will likely be x MW" type rule. What are the area implications for the larger turbines (larger turbines need larger distance between turbines, right?)*

By the time California projects will be built, the standard turbine size will be at least 15 MW. Turbine spacing is a factor of turbine size, so larger distances between turbines will be required to optimize operations. Due to the larger turbine generator size, fewer turbines will be installed to reach the intended project capacity.

Subsea cables and floating substations - Information on subsea cable technology development and floating substation. What are the other floating wind projects around the world looking at in terms of sea cabling?

Dynamic cables - LV dynamic cables

All of the first prototypes and proof of concept floating wind projects are small enough and close enough to shore to use 22-66kV dynamic cables for which there is existing technology available on the market.

MV dynamic cables

Large-scale commercial floating wind farms in areas such as Humboldt and Morro Bay will require power to be transmitted using higher voltage cables (130-250kV). The UK Carbon Trust Joint Industry Partnership has identified a gap in the market for suitable HV dynamic cables. State-of-the-art work on dynamic cabling is a current focus for the industry. More information is available in the Phase II delivery report from the UK Carbon Trust Joint Industry Partnership (JIP).[24]

In recent years, we have seen major interest from various entities that are funding the advancement of power systems for offshore wind farms. These include dynamic HV power cable qualifications as part of the Carbon Trust awards that is bringing in expertise from the oil and gas industry to support the design, testing an qualification of 130kV to 250kV power cables to optimize the power transmission system and power to shore solutions, companies that are working on developing floating substations and subsea substations to harness deep-water far from coast offshore sites with good high wind resource potential, and also other technology development opportunities with companies that are looking to advance the subsea wet-mate connector technology to 66kV which enables subsea substations and some exciting field optimizations that minimize impacts to the fishing industry by place more equipment underwater.

The US Department of Energy (DOE) has issued various funding opportunities and requests for information regarding the advancement of offshore wind technologies (DE-FOA-0002236, DE-

[24] https://www.carbontrust.com/resources/floating-wind-joint-industry-project-phase-2-summary-report

FOA-0002389). The European Commission initiated the Horizon 2020 – Research and Innovation Framework Programme, which issued a funding opportunity to demonstrate innovation technologies for floating wind farms and to develop the next generation of renewable energy technologies. With these recent funding opportunities to advance the technologies for offshore wind and other funding opportunities like the Carbon Trust award for qualifying dynamic HV power cables, we see benefits to offshore wind farm developments with cables to shore and also for other potential opportunities evaluating long distance transmission opportunities with HVDC power systems like the Trans Bay Cable which consists of a 53-mile submarine HVDC cable that brings power to the San Francisco area.

Research Centers - *What is the Catapult Offshore Wind Technology Centre and how might their work intersect with CA planning needs?*

The Offshore Renewable Energy (ORE) Catapult Centre is instrumental to the growth of the UK's offshore wind sector and is also increasingly influential globally. The center undertakes R&D and innovation projects to further the work of the sector. They publish in-depth reports and also educational materials about offshore wind. For example, they published a study in January 2021 looking at the costs of developing floating offshore wind.[25] They also work extensively with the offshore wind supply chain.

Are the Electric Program Investment Charge (EPIC) projects related to offshore wind examples in CA going to be important for investors to see success or are they more likely to look at installation experience in other parts of the world?

Offshore wind developers have indicated that investors are confident in installation experience elsewhere and aren't going to require further demonstration and testing. While technology improvement, learning and innovation will be ongoing, as with any technology, there is no reason to delay planning and implementation for offshore wind in order to wait for research questions to be completed or answered. Indeed, this delay in progress would slow the pathway to large-scale projects, which are essential to achieving competitive prices. What industry needs most is not research funding, but comprehensive statewide planning toward a long-term deployment goal.[26]

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[25] https://ore.catapult.org.uk/press-releases/uk-floating-offshore-wind-subsidy-free-2030/

[26] American Clean Power – California submitted comments to the CEC on the EPIC research proposal and report in 2020 (available upon request).