California North Coast Offshore Wind Studies

Electricity Market Revenue Study

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TABLE OF CONTENTS

1. INTRODUCTION

This report provides an analysis of revenue generated from offshore wind farms for selling electricity through markets regulated by the California Independent System Operator (CAISO).

1.1 Purpose

If offshore wind power is developed in California, the projects will have access to several market revenue opportunities, including the resource adequacy market (RA), the energy market, and the ancillary services (AS) market. Harris et al. (2020) describes the organization of these markets.

The purpose of this report is to make initial estimates of the revenue available given our assumptions about the generation profiles of California-based offshore wind and recent historical prices. This will help shed light on which of these markets could be financially viable for offshore wind to participate in, and to develop a quantitative understanding of the revenue streams and their magnitudes.

In order to provide context, market revenues are compared to four alternative renewable resource types: California solar, California land-based wind, New Mexico land-based wind, and Wyoming land-based wind. New Mexico and Wyoming were chosen because they are candidates for imports of wind energy into California.

1.2 Background

The background section describes how three relevant energy markets function in California: resource adequacy, energy, and ancillary services.

Resource adequacy (RA) is the mechanism in California to ensure adequate generation capacity is available to match peak loads and ramping needs on the system. Load serving entities are responsible for procuring RA in advance through bilateral contracts with qualifying generators. In order to qualify, the generators are required to offer bids in the energy market and to be available for generation. In the context of variable renewable energy like offshore wind, there is a "typical" coincident peak capacity factor for each resource type to define their estimated contribution to meeting these peak conditions on the power system, based on the characteristics of the project. This is called the effective load carrying capacity (ELCC) of that resource.

Energy and AS are dispatched in two integrated markets that are organized by the CAISO: the Day Ahead Market (DAM), and the Real-Time Market (RTM), both of which are available to offshore wind generators (Hundiwali, et al., 2019, P. 12). Energy markets pay generators based on the timing and location of energy generation, with markets that clear up to a day in advance (DAM) and as fast as 5 minutes ahead (RTM).

Participation in regulation up and regulation down AS markets requires the ability to respond to automatic generator control signals on a four second time step, which has been recently proven for land-based wind farms (Delparte, 2020a; Loutan and Gevorgian, 2020).

Bids into the energy and AS markets must be coordinated. Variable energy resources, such as offshore wind, are only able to bid a sum of AS and energy equal to the maximum available power of the generator (Delparte, 2020b, section 4.3). For example, a 2 MW wind farm with a forecast output of 1 MW for one hour could bid 1 MW into the energy market and 100 kW into the AS market, but CAISO would only award a sum total of up to 1 MW in regulation up and energy. For comparison, a conventional (dispatchable) 2 MW generator making the same bid could sell 1 MW into the energy market *and* 100 kW into the regulation up market. For offshore wind, as with any resource in general, participation in the AS market would mean forgoing the opportunity of potential energy revenue for regulation revenue. AS provides two types of revenue: payment is made to generators for holding capacity in reserve, and additional "mileage" payments are made based on a combination of CAISO's dispatch signal and the generator's capability to follow it (Sadeghi-Mobarakeh & Mohsenian-Rad, 201; Departe, 2020a section

4.3.1; Delparte, 2020c). For the purposes of this analysis, mileage payments are ignored, because historical CAISO data have shown their value to be small and actual mileage dispatches are unknown.

This report does not consider certain other revenue opportunities and mechanisms that are in principle available to offshore wind projects. These include financial participation in transactions for Congestion Revenue Rights and Convergence Bidding. Both of which could be entered into independently from offshore wind development. Our analysis also does not consider how offshore wind power could be paired with energy storage to improve the value of the resource (e.g., participation as a hybrid resource).

2. METHODS

In this section we first describe our method for estimating the annual generation profile of offshore wind and other resources. Then we describe how we used these to estimate a value for the available revenue through each mechanism under consideration.

2.1 Annual Generation Profiles

We estimate the typical annual hourly generation of six different resource types with a variety of associated methods. The profiles were created for hypothetical generators with 1 MW nameplate capacity.

For each resource, we develop an 8,760-hour annual load profile and estimate capacity factors using the formula below:

$$\text{Capacity Factor} = \frac{\text{Generation [MWh]}}{\text{Capacity [MW]}} \cdot \frac{\text{1 year}}{\text{8760 hours}}$$

2.1.1 Offshore Wind

The electricity generation profile for a 48 MW development in the BOEM call area was extracted from Severy et al. (2020). An 8,760-hour annual profile for a possible 48 MW project was divided by 48 to create a profile normalized per 1 MW of nameplate capacity, and the capacity factor was extracted from this.

2.1.2 California Solar and Land-based Wind

We estimate the profile for in-state renewables by combining historical data on total energy generated and the timing of generation. We start with the historical quantities of in-state energy generation by fuel type and installed in-state electric generation capacity by fuel type (CEC, 2020) to estimate a typical annual capacity factor for both solar and wind across the entire state. Then, historical hourly profiles of generation and curtailment (CAISO, 2020c) from 2019, the most recent year on record, were scaled to match the estimated annual energy of a 1 MW project, based on the typical capacity factors calculated above.

2.1.3 California, New Mexico, and Wyoming Land-based Wind (Method 2)

A different method was used to generate profiles for New Mexico and Wyoming-based wind farms because rich datasets of historic wind generation were not available. This method was applied to California land-based wind as well, providing a more direct comparison to these results as well as a sensitivity analysis on California land-based wind. These results are referred to as “Method 2” to distinguish the results for California land-based wind.

Again, the first step was to calculate capacity factors by location. These relied on the EIA (2020a)’s data of net generation by state and energy source and existing nameplate by state and energy source and followed the method above.

We then use an hourly estimated wind power dataset (“80-Meter Hub Height (Current Technology)” (NREL, 2020)) which is scaled by the capacity factor to create generation profiles. The locations used for these data are shown in Table 1.

Table 1 Locations of representative wind farms.

State	*Nearby Project[1]*	*Project Hub Height[1]*	*Latitude*	*Longitude*
CA	Alta Wind Energy Center	80m	35.06	-118.40
NM	New Mexico Wind Energy Center	80m	34.73	-104.04
WY	Top of the World Wind Project	80m	43.07	-105.82

[1]Source: USGS (2020)

All of the calculated capacity factors are shown in Table 2. It is notable that offshore wind has a significantly higher capacity factor than other resources. In the context of renewable energy development on the north coast of California, where offshore wind could be developed first, the capacity factor for the offshore wind resource is much higher than solar development along the coast. The typical solar capacity factor in Humboldt County is approximately 15%, while statewide the solar generators have nearly double the capacity factor, reflecting higher irradiance in other regions of California (EIA, 2020b).

Table 2 Calculated capacity factors by development type and location along with their seasonal variation, as measured by the coefficient of variance across the seasonal average capacity factors.

Development	*Calculated Capacity Factor*	*COV of Seasonal Average Capacity factor*
Humboldt Call Area Offshore Wind	48.2%	9.3%
CA Solar	26.5%	32.7%
CA Land-based Wind	26.1%	35.2%
CA Land-based Wind (Method 2)	26.3%	27.3%
NM Land-based Wind (Method 2)	38.3%	24.1%
WY Land-based Wind (Method 2)	31.1%	24.3%

Seasonal average generation profiles for the modeled resources are illustrated in Figure 1. This report consistently follows meteorological season definitions in which winter is all of December, January, and February, spring includes all of March, April, and May, and so forth. Offshore wind clearly has the flattest output across the typical day, with land-based wind resources generally displaying a midday dip and solar with an expected diurnal pattern following day and night. The seasonal variation seen in Figure 1 is also summarized at a high level in Table 2 through an estimate of the coefficient of variance (COV, the standard deviation of seasonal capacity factor divided by the annual capacity factor). Offshore wind has by far the least seasonal variation, with a COV of 9%. Other resources have seasonal variability 2.6 to 3.8 times as high, with significant differences in California's land-based wind across the two methods of computation.

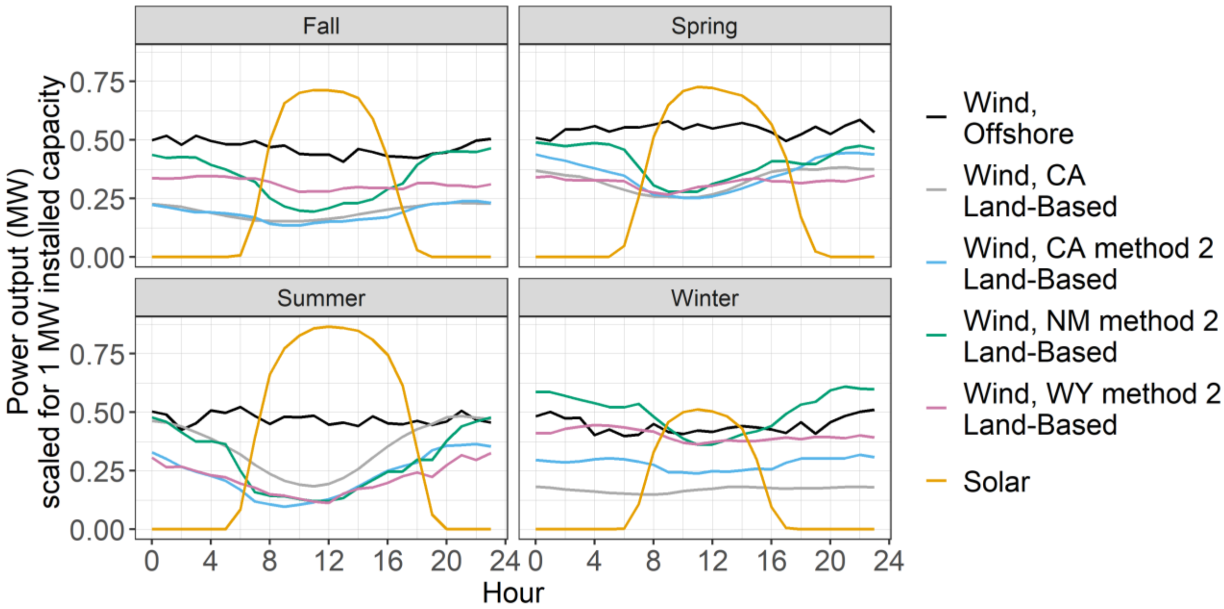

Figure 1 Seasonal average hourly output from a modeled 1 MW facility.

2.2 Revenue Generation Model

We use these capacity factors and generation profiles to estimate revenue across a range of opportunities. First, the Resource Adequacy market is considered, which, as will be explained below, is analyzed entirely independently of the other markets. Second, the methods used to develop hourly annual value of energy and AS in each market are discussed. Third and finally, the generation and value profiles are synthesized into annual revenue and average electricity values.

2.2.1 Resource Adequacy Market

Renewable resources such as solar and wind can sell a fraction of their nameplate capacity in the RA market each month. This fraction is based on the *expected* electricity generation or capacity factor of the resource during peak demand times, determined through CPUC's effective load carrying capability (ELCC) modeling. ELCC values have historically been updated annually. The fraction varies by month and resource type (CPUC 2019), split only into solar and wind, with no discrimination between onshore and offshore wind. The latest available values were found in CPUC (2020) "2020 NQC List for CPUC RA Compliance May 22, 2020 Version." CPUC (2019) includes weighted average price per kWh, projected as far as 2022. As this is the date closest to likely wind farm deployment, 2022 was used. Annual revenue is the product of the monthly RA fraction, the RA price, and the wind farm size, summed across the year. Results in this report are given on a per MW (of development) basis.

2.2.2 Hourly Energy and AS Value Profiles

In order to determine the value of energy in the DAM and RTM and the value of AS in the DAM and RTM, market clearing prices at a number of pricing nodes were extracted from the CAISO OASIS database (CAISO, 2020a; 2020b). In the DAM, both AS and energy are sold on an hourly basis, and thus have a price determined for each hour of the year. In the AS RTM, services are sold every 15 minutes, while in the energy RTM bids clear every five minutes. In order to align with generation profiles, values were averaged across each hour.

Based on the study by the Pacific Gas and Electric Company (2020), there are multiple regions through which electricity could flow or be sold, including Humboldt, the main corridor in the central valley, Vacaville, and the San Francisco Bay Area. To understand variation across space, prices were analyzed at eight nodes across northern California, enumerated in Table 3. Locations are shown on the map in Figure 2.

Table 3. Nodes at which energy prices were analyzed.

Location	*Pricing Node*
Humboldt	HMBUNIT2_7_GN010
San Francisco	BAYSHOR2_1_N001
South SF Bay	OLS-AGNE_7_N001
East SF Bay	RICHMOND_1_N004
Cottonwood	ANDERSON_6_N001
Round Mountain	CEDRCRK_6_N101
Table Mountain	OROVILLE_6_N102
Vacaville	VACAVIL_1_N102

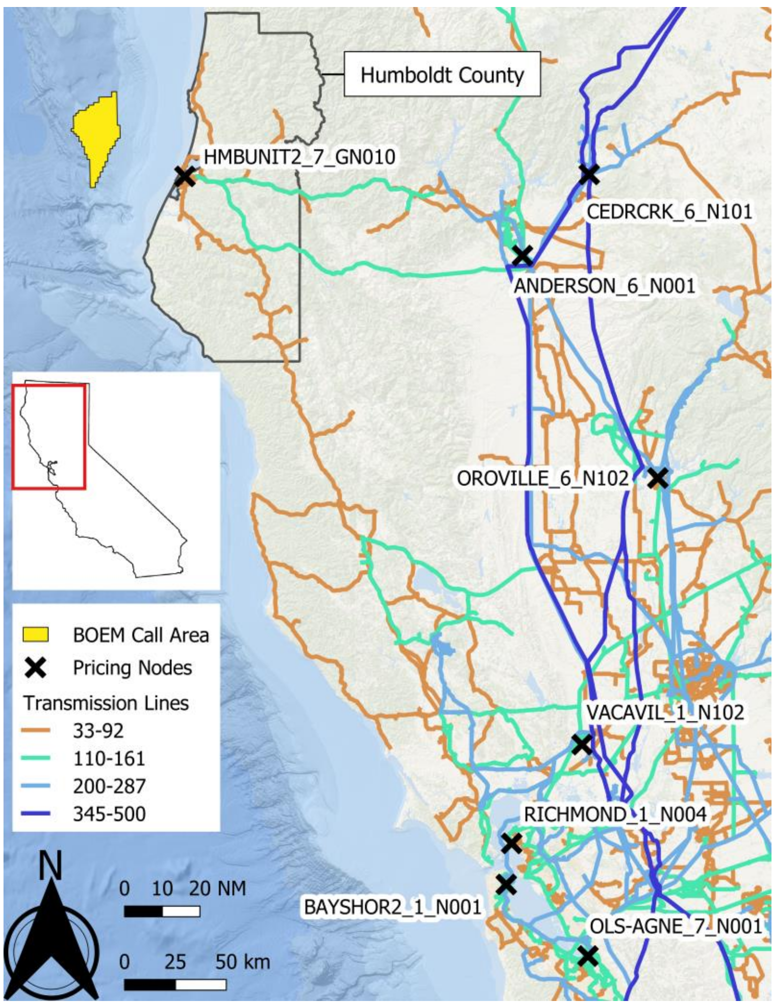

Figure 2. A map of pricing node locations analyzed in this report. Also shown are existing transmission lines in northern California.

Seasonal average hourly energy market clearing prices at four nodes are shown in Figure 3 for the DAM and RTM. Prices in both markets generally fall between $25 and $50 per MWh, but there is significant variation across the hours and seasons. Midday price troughs caused by the significant deployment of solar PV so far in California suggest that additional electricity generated from solar (without storage) will generally be less valuable than electricity generated from wind, particularly land-based wind which tends to have a midday generation trough.

No clear trend is visible between the RTM and the DAM, aside from random variability between them, and trends across nodes are small.

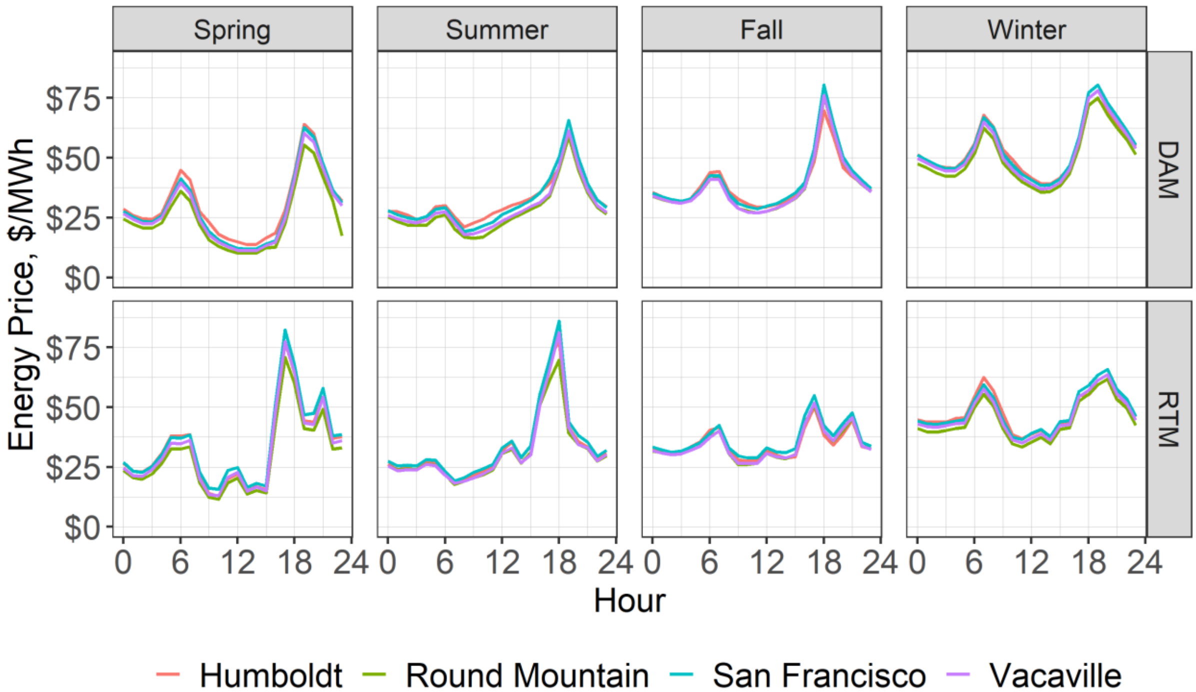

Figure 3 Seasonal average electricity price in the DAM and RTM in 2019 across a representative sample of nodes.

2.2.3 Hourly Ancillary Services Value Profiles

Ancillary Services are not transacted at specific nodes like energy, but in two regions and eight sub-regions (CAISO, 2019, section 8.3.3). AS regional prices are built up from larger to smaller regions: the price in a particular sub-region is equal to sum of the shadow price in that subregion, plus the shadow price in the system region, plus the shadow price in the expanded system region. Per Delparte (2020b) “the Ancillary Service Marginal Price of a reserve in a sub-region will always be higher than or equal to the price of the same reserve in the outer sub-region or Expanded System Region.”

The AS prices for our analysis of offshore wind are estimated using the sum of the Expanded System Region, the System Region, and the NP26 subregion which includes NP15 and ZP26 in Figure 4. Seasonal average hourly ancillary services market clearing prices in the DAM and RTM are shown in Figure 5. As mentioned above, the “total” price is the sum of three nested regions. AS prices are highest in spring and the hours 16:00 to 20:00 but are generally quite low, below $10/MWh. This leads to the hypothesis that the AS market will not be a lucrative market for offshore wind, which will be explored further in the Results section.

Figure 4 CAISO sub-regions. NP26 includes NP15 and ZP26. Source: [*http://oasis.caiso.com/mrioasis/logon.do*](http://oasis.caiso.com/mrioasis/logon.do)

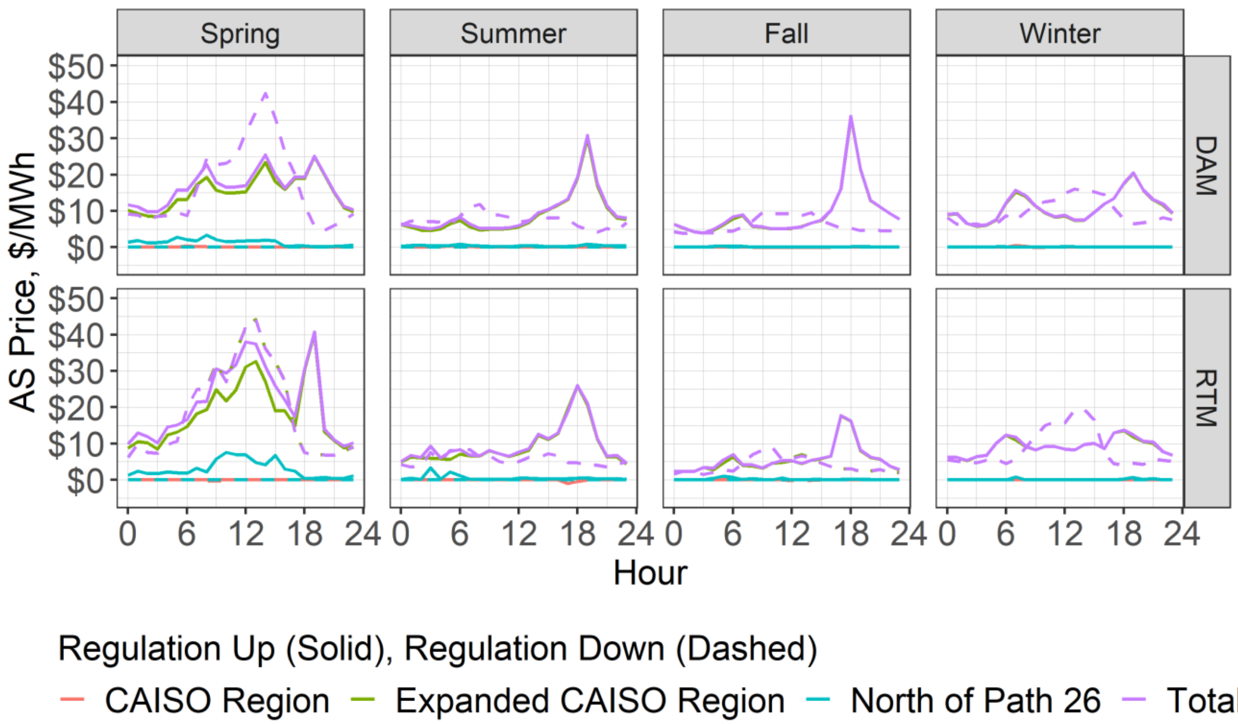

Figure 5 Seasonal average price of ancillary services in 2019 in the RTM and DAM.

2.2.4 Average Electricity Value and Annual Revenue Calculation

Generating energy and AS market revenue requires placing a bid into the market that is at or below the market clearing price, then operating the power plant as dispatched. For zero-marginal-cost energy sources such as wind and solar, which do not incur fuel costs, it is typical to bid $0.00 (i.e., be a “price taker”), since all bidders are awarded the market clearing price, not their bid prices. This allows for a near-maximization of revenue. Renewable energy producers with a production tax credit (PTC) will typically bid the negative of their PTC, as it is profitable to pay up to the PTC value, which depends on the details of projects and the available tax credits when they were developed. For example, a wind project with a PTC of $15/MWh from the federal government, may be willing to pay up to $15/MWh to generate electricity (Huntowski, et al., 2012). Developments which begin construction before December 31, 2020 are currently eligible for a PTC of $15/MWh, but this tax credit has not been extended beyond the end of 2020 (DOE, 2020). Therefore, for this analysis, the influence of production tax credits was not included, and thus all renewable energy producers are assumed to bid $0.00 at every time interval.

The revenue at each node was then calculated as the product of energy produced and price at each hour where the clearing price met or exceeded the bid ($0.00), summed up over the year. The average value of electricity produced was calculated as the revenue divided by the total energy produced by the farm (regardless of whether it was sold in the market).

Revenue and average value of sold electricity have an independent outcome for each of the six possible developments in Table 2 at each of eight nodes in Table 3, 48 in total.

3. RESULTS

Summarizing our overall results, Table 4 illustrates the potential yearly revenue for three hypothetical 1 MW renewable energy facilities. More details on the various revenue pathways are summarized in subsequent sections below.

The estimated total revenue for each project type in Table 5 includes contributions from energy market participation, deploying up to 10% of generation capacity into the AS market with perfect market information, and selling capacity credit with typical values of RA for California. The total revenue per installed MW for offshore wind is approximately a factor of two higher than land-based wind or solar. This is due to its high capacity factor and greater overall energy generation for each installed MW. However, the unit value per kWh of the electricity generated is approximately the same across each resource type.

All of our results are presented with a significant caveat: They depend on historic data for prices and market conditions, which may change significantly in the future. Examples of factors driving change in future outcomes are transmission changes, load shape changes due to electrification, and increased penetration of distributed energy resources like solar, storage, and electric vehicles.

Table 4 Annual revenues and generation, and effective value of electricity generated by offshore wind and two illustrative alternatives, with energy sold at the Humboldt node. Revenues are reflective of a 1-MW facility.

	Development		
	Offshore Wind	*CA Land-Based Wind*	*CA Average Solar*
Energy Revenue ($/yr)	$153,000	$79,000	$71,600
Additional AS Revenue[1] ($/yr)	$1,400	$908	$1,570
RA Revenue ($/yr)	$6,780	$6,780	$5,060
Total Revenue[1] ($/MW•yr)	$161,000	$86,700	$78,200
Electricity Generated (MWh)	4220	2290	2320
Effective Value ($/MWh)	$38.20	$37.90	$33.70

[1]Up to 10% of hourly output is sold into the AS market, following Loutan and Gevorgian (2020).

3.1 Resource Adequacy Revenues

Table 5 shows the fraction of nameplate capacity that can be sold in the RA market, its projected price in 2022, and the resulting revenue. These are based on onshore wind resources since there is no standard assumption available currently for the RA fraction from offshore wind. RA revenue for a California land-based wind farm is 34% greater than revenue for a solar development of equal nameplate capacity. If offshore wind is installed and operated, a higher RA fraction will likely be appropriate based on the actual characteristics of generation and will likely be higher than what is shown in Table 4, given the significantly higher capacity factors for the offshore resource. Thus, our results for offshore wind are indicative of a lower-bound estimate, benchmarked to land-based wind.

Table 5 Resource adequacy revenues for a 1 MW resource. No differentiation is made between onshore and offshore wind (CPOC, 2020).

	RA Fraction		*RA Price, $/MW*	*Period Revenue, $/MW*	
Month	*Wind*	*Solar*	*Both*	*Wind*	*Solar*
Jan	0.14	0.04	$2,960	$414	$118
Feb	0.12	0.03	$2,960	$355	$89
Mar	0.28	0.18	$2,960	$829	$533
Apr	0.25	0.15	$2,960	$740	$444
May	0.25	0.16	$2,960	$740	$474
Jun	0.33	0.31	$2,960	$977	$918
Jul	0.23	0.39	$2,960	$681	$1,154
Aug	0.21	0.27	$2,960	$622	$799
Sep	0.15	0.14	$2,960	$444	$414
Oct	0.08	0.02	$2,960	$237	$59
Nov	0.12	0.02	$2,960	$355	$59
Dec	0.13	0.00	$2,960	$385	$0
Annual	-	-	-	$6,778	$5,062

3.2 Energy Market Revenue and Values

The total revenue from energy market participation is summarized in Figure 6 Projected monthly average energy market revenue from simulated 1 MW facilities, based on 2019 CAISO market clearing prices at the Humboldt node.Figure 6 - Figure 10, showing the seasonality and annual total revenue expected from the various resources we analyzed.

Revenue in the RTM and the DAM across the year for various developments are shown in Figure 6, showing similarity in the average prices between the markets for each resource. High market prices in winter combine with a consistent offshore wind resource to boost its value during that season, while all the resources are similar in terms of revenue per MW in the summer.

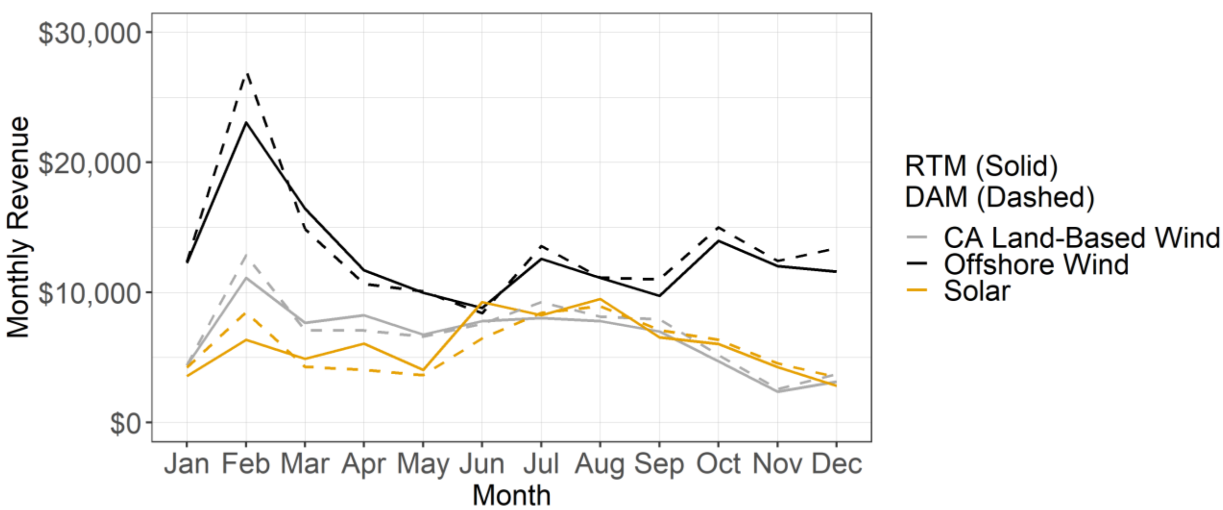

Figure 6 Projected monthly average energy market revenue from simulated 1 MW facilities, based on 2019 CAISO market clearing prices at the Humboldt node.

Figure 7 depicts the annual revenues of the various renewable energy types we considered across the studied nodes for a hypothetical 1 MW project. This figure assumes that all produced electricity is offered into the depicted market (DAM or RTM energy markets) at a bid of $0.00, with no production tax credit. They also assume perfect fidelity in output prediction (this is, naturally, a larger assumption for the DAM). There is some, though not a great divergence, between the DAM and RTM market prices across this period. For a given nameplate capacity, offshore wind would generate the most revenue, by a significant margin. This result is independent of where the energy is sold.

For all development types and market, interconnection at the Humboldt and the San Francisco Bay pricing nodes generate the most revenue, while those in the main corridor in the Central Valley, Table Mountain, Round Mountain, Cottonwood, and Vacaville tend to generate slightly less.

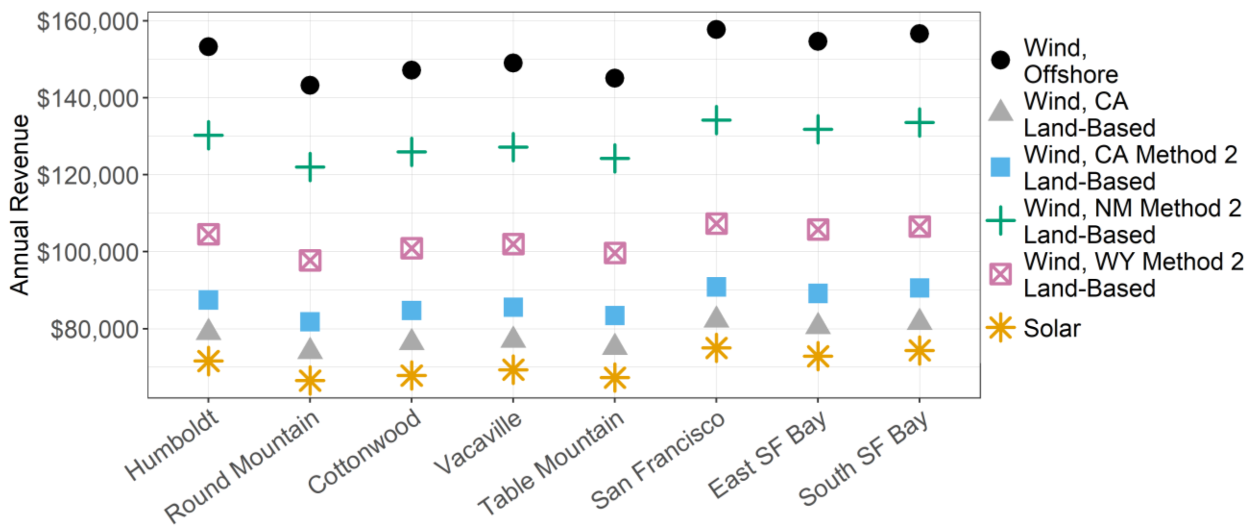

Figure 7 Projected revenues from simulated 1 MW facilities at all considered nodes, based on 2019 CAISO RTM market clearing prices. See Appendix 0 for raw data.

Looking at the unit value of electricity produced (per MWh), shown in Figure 8, land-based wind with profiles generated from method 2 produce the most valuable electricity, while solar produces the least valuable electricity. Offshore wind and California land-based wind calculated via method 1 produce electricity with similar values.

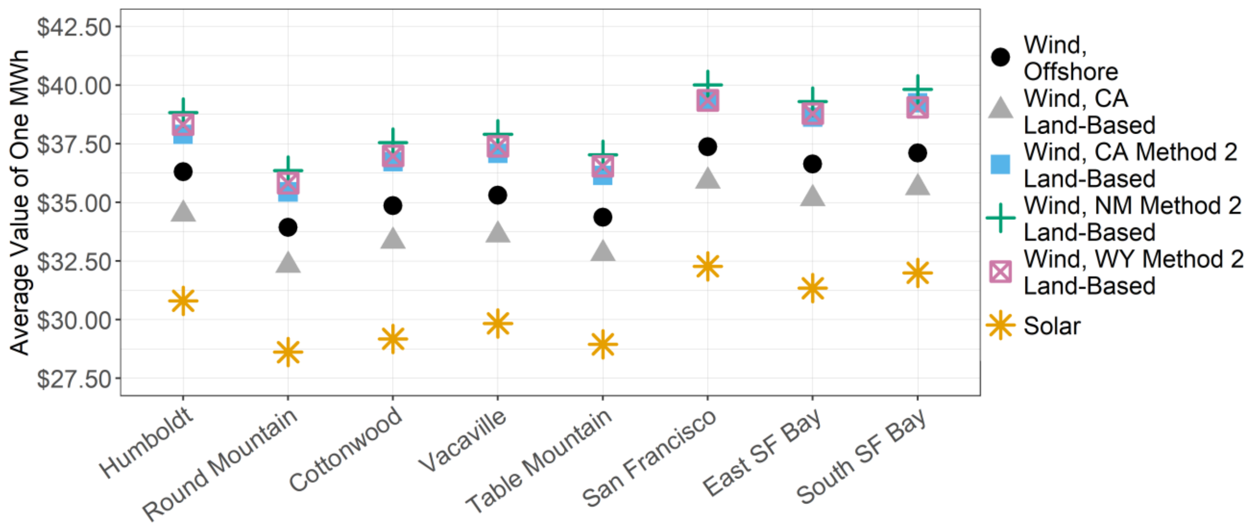

Figure 8 Average electricity selling price from simulated 1 MW facilities at all considered nodes based on 2019 CAISO RTM market clearing prices. See Appendix 0 for raw data. Note that zero is not included in the y-axis to enable emphasis on the differences between various resources and between nodes.

Figure 9 and Figure 10 show the price trend over time in the RTM and DAM, respectively. These show a subset of previously studied technologies to allow for a clear visualization of the broad trend in energy prices. For all nodes except San Francisco, prices have trended slightly downwards for the past three years from around $40/MWh to $30/MWh (Figure 9). Prices at the San Francisco node have increased over this period, driven by a price spike relative to other nodes in early 2019, and relatively high prices during the second half of 2019. Prices at the San Francisco node have returned to normal relative to the other nodes during the first half of 2020.

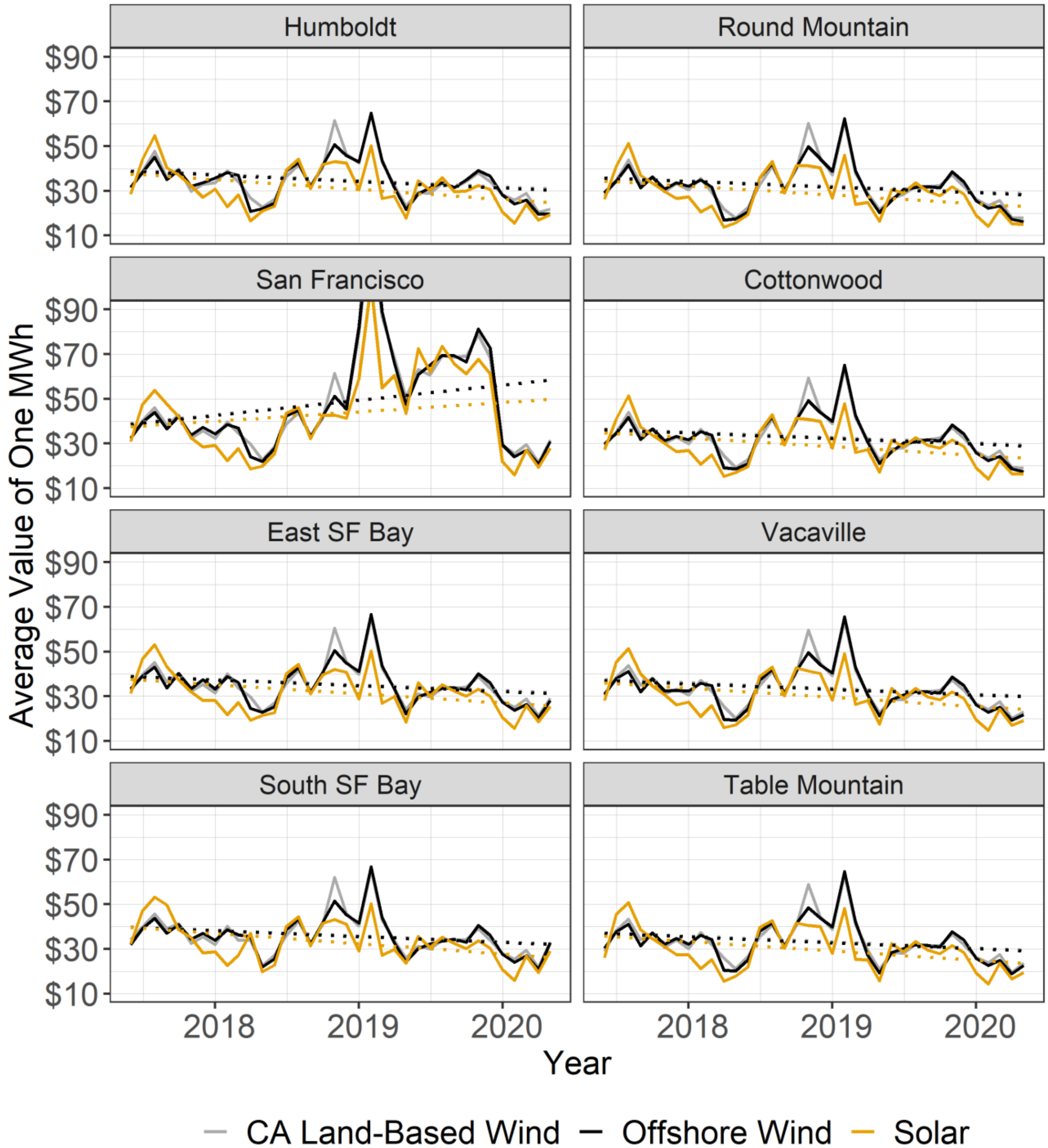

Figure 9 Average monthly value of electricity for various renewable energy developments across studied CAISO nodes (see Table 3) from July 2017 to July 2020 in the Real-Time Market. A simple linear trend for each is shown with a dashed line. Note that the land-based and offshore wind trend lines are nearly coincident. The year tick marks the beginning of the associated year. In February 2019, values in San Francisco exceed the chart range, at $131.4, $134.6, and $101.5 per MWh of land-based wind, offshore wind, and solar, respectively.

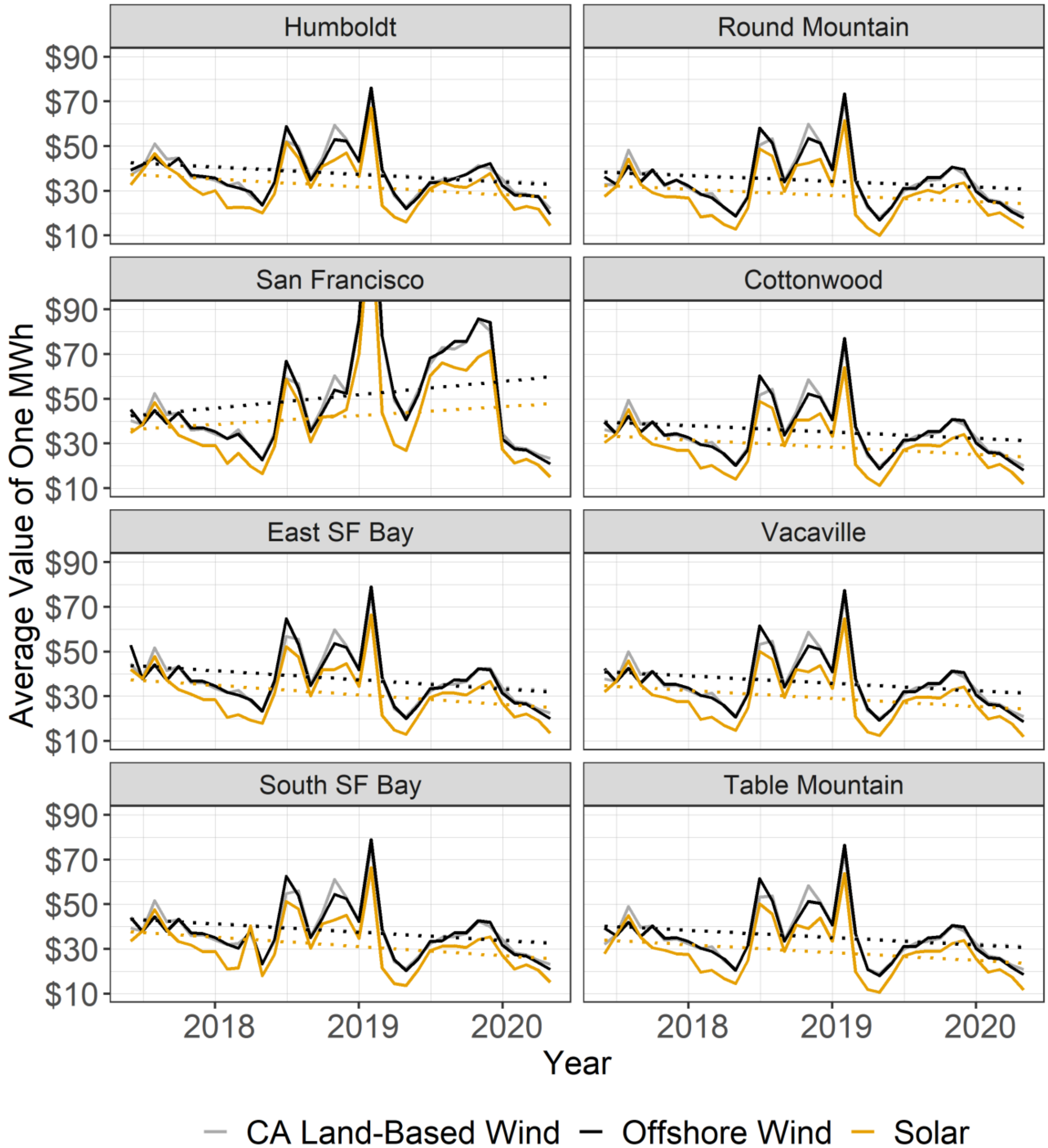

Figure 10 Average monthly value of electricity for various renewable energy developments across the studied CAISO nodes (see Table 3) from July 2017 to July 2020 in the Day-Ahead Market. A simple linear trend for each is shown with a dashed line. Note that the land-based and offshore wind trend lines are nearly coincident. The year tick marks the beginning of the associated year. In February 2019, values in San Francisco exceed the chart range, at $153.2, $158.9, and $133.9 per MWh of land-based wind, offshore wind, and solar, respectively.

3.3 Integrated AS-Energy Market Revenues

In order to develop a best-case assessment of the value which the AS market provides to offshore wind, hourly AS prices were combined with hourly energy prices. Figure 11 compares the monthly revenue in the energy market only (in teal) with the revenue if the generator had perfectly bid the entirety of its capacity into the market (among energy, regulation up, and regulation down) which ended up clearing at the highest price in that hour (in red). This comparison was performed at the Humboldt pricing node (HMBUNIT2_7_GN010) using 2019 data. It should also be noted that the proof of concept tests showing that wind farms can provide frequency regulation services occurred with the turbines operating with 10% headroom, meaning that they could only sell 10% of their hourly production potential on the AS market (Loutan and Gevorgian, 2020). Thus, the potential increases in value shown in Figure 11 would only be available to 10% of the energy produced by the facility.

Revenues for several months (March, April, and May) are noticeably higher with integrated market participation, reflecting a number of hours in these months in which AS were more valuable than the equivalent energy. However, fully capturing these differences would require an unrealistic level of accuracy in predicting market prices, since bids must be made before clearing prices can be established. In this omniscient case, annual revenue is 8% higher, at $171,000 compared to $158,000 with participation only in the energy market. Thus, AS market participation has the potential to provide additional revenue for offshore wind development but would require a sophisticated bidding strategy.

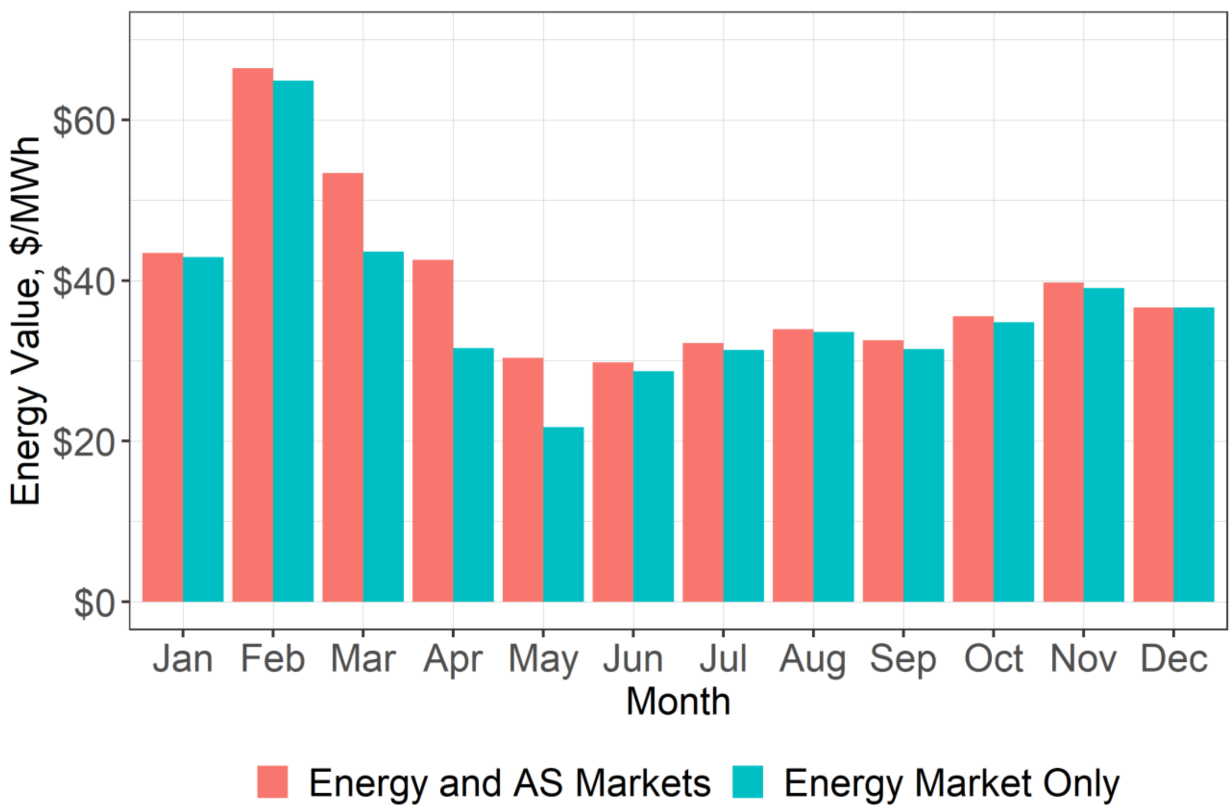

Figure 11 Monthly revenues derived from 2019 CAISO data from the RTM at the Humboldt node, showing energy market only compared to a prescient bidding strategy combining AS and energy markets.

4. DISCUSSION AND CONCLUSION

Overall, the expected revenue available per MW of offshore wind is significantly higher than land-based wind or solar. This is due to the higher overall energy generated (expressed as a higher capacity factor). Each megawatt of installed offshore wind generates more megawatt-hours. However, the value per MWh of offshore wind is approximately the same. Based on our analysis, approximately 4% of the annual revenue is through RA capacity payments, 1% through participation in ancillary services markets, and 95% through generation of energy and participation in energy markets.

Significantly higher winter month resource adequacy (RA) and energy payments for offshore wind compared to solar and persistently high revenue through other seasons lead to far higher revenues on a per MW basis. Offshore wind energy is 20% more valuable than solar on average, due to solar's low generation in the evening and during winter months, the most expensive time of day and season, respectively.

When compared to out-of-state, land-based wind resources, offshore wind loses some of its edge. RA payments are equal for the two resources[1], and the value of Humboldt's offshore wind energy is on par with California land-based wind and lower than the studied sites in California, New Mexico, and Wyoming. New Mexico and Wyoming wind are more valuable because their generation is higher in the winter and evening hours – when electricity is most expensive – compared to the relatively flat offshore wind generation. Where Humboldt Bay's offshore wind has an advantage is in its capacity factor of 48% compared to 26-38% for the studied land-based resources. This higher capacity factor drives significantly higher annual revenues for the same scale generator. Cape Mendocino offshore wind (following from the analysis in Severy et al. (2020)) has a higher capacity factor, 57%, which would drive 20% to 21% higher energy revenue across the eight studied nodes.

Differences in nodal energy prices are relatively significant based on historical trends. Prices in Humboldt and the San Francisco Bay are 10% higher than those in the Central Valley, creating up to 10% more energy revenue in these regions for offshore wind. This implies that the choice of transmission infrastructure – whether subsea cables connecting the wind directly to the San Francisco Bay, or a line through the Central Valley – may influence the value to the energy in the market.

Energy prices and attendant market revenues have fallen over the past three years in both the day-ahead and the real-time markets, except in the San Francisco region. The DAM and RTM are approximately the same across technologies, except that the implied value for solar generation has seen greater declines in the RTM over this period. However, it is important to note that there is significant variability and the trend is not monotonically decreasing. There was a significant increase in price during late 2018 and early 2019 compared to other years, and there is a seasonal cycle of prices that is larger than the year to year trend of the decline.

Participation in regulation up and regulation down ancillary services could drive additional revenue to an offshore wind development, but accurately estimating the possible revenue for a real-world project would require modeling that is beyond the scope of this analysis. If perfect foresight were possible, the potential revenues are 9% higher for a resource that perfectly bids into AS vs. energy in each time step. Current evaluations have shown that wind can sell 10% of its output capability in the RA market, shrinking this potential opportunity to a 0.9% increase in revenue.

These estimates for revenues potential from offshore wind are intended to be a starting point for identifying pathways to value for projects and identifying where additional work is needed to better understand the opportunity. Since the majority of revenue is from the energy market, understanding possible trends in future energy prices could be important, particularly given the trend towards lower

[1] RA payments are independent of a specific development's capacity factor and are defined based on typical performance of a resource. In our analysis we used established values for land-based wind to estimate the RA value of offshore wind, which could be higher in practice.

prices over time. The capability of land-based wind to provide AS has been demonstrated, but the overall potential value is likely ~1% of energy market revenue, indicating a niche role. For RA value, our analysis used existing land-based wind as a benchmark and likely lower bound for the capacity value around 5% of the revenue in the energy market. Additional work to establish the typical expected contribution to peak capacity by offshore wind could result in higher real value. If the RA value factor were approximately scaled with capacity value, the RA value of offshore wind could be about double what we assumed.

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APPENDIX A - REAL-TIME MARKET REVENUES AND ENERGY VALUES

This appendix summarizes the annual revenues and average energy market value per MWh of electricity for each studied resource type at each assessed location.

A.1 RTM Revenue Table

Table 6 shows the annual revenue in the real-time market for each of the development types discussed in this report.

Table 6 Real-Time Market annual revenues for modeled resource types at a scale of 1 MW

Location	*Offshore Wind*	*Solar*	*CA Land-based Wind*	*CA Land-based Wind, Method 2*	*NM Land-based Wind, Method 2*	*NM Land-based Wind, Method 2*
Cottonwood	$147,158	$67,823	$76,361	$84,743	$125,985	$100,902
San Francisco	$157,772	$75,011	$82,232	$90,850	$134,238	$107,341
Round Mountain	$143,269	$66,508	$74,018	$81,785	$121,994	$97,723
Humboldt	$153,250	$71,595	$79,017	$87,451	$130,296	$104,510
South SF Bay	$156,646	$74,362	$81,584	$90,545	$133,624	$106,523
Table Mountain	$145,059	$67,283	$75,148	$83,400	$124,263	$99,666
East SF Bay	$154,661	$72,850	$80,505	$89,150	$131,849	$105,806
Vacaville	$149,056	$69,353	$76,971	$85,568	$127,200	$101,987

A.2 RTM Energy Value Table

Table 7 shows the mean value of electricity produced and sold in the real-time market for each of the development types discussed in this report. Total revenue is divided by total generation, not by the quantity of energy that is sold into the market (i.e. unsold energy decreases the average value).

Table 7 Real-Time Market average value of one MWh of electricity for modeled resource types.

Location	*Offshore Wind*	*Solar*	*CA Land-based Wind*	*CA Land-based Wind, Method 2*	*NM Land-based Wind, Method 2*	*NM Land-based Wind, Method 2*
Cottonwood	$34.86	$29.18	$33.34	$36.73	$37.55	$36.99
San Francisco	$37.38	$32.28	$35.90	$39.37	$40.01	$39.35
Round Mountain	$33.94	$28.62	$32.32	$35.44	$36.36	$35.82
Humboldt	$36.30	$30.81	$34.50	$37.90	$38.83	$38.31
South SF Bay	$37.11	$32.00	$35.62	$39.24	$39.82	$39.05
Table Mountain	$34.36	$28.95	$32.81	$36.14	$37.03	$36.54
East SF Bay	$36.64	$31.35	$35.15	$38.64	$39.29	$38.79
Vacaville	$35.31	$29.84	$33.61	$37.08	$37.91	$37.39