Resources for the Future

Reducing Risk in Merchant Wind and Solar Projects through Financial Hedges

Jay Bartlett

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About the Authors

Jay Bartlett is a Senior Research Associate at Resources for the Future, where he works on financial, economic, and policy analysis for the Future of Power Initiative. His current focus is clean energy project finance.

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Abstract

US wind energy projects have increasingly opted to sell directly into wholesale electricity markets rather than under long-term power purchase agreements (PPAs). Although PPAs offer low risk to projects' revenue, a limited pool of potential customers and strong competition among project developers have depressed prices. Selling into wholesale markets may increase returns, but such "merchant" projects generally need financial hedges so that future revenues will predictably cover financing costs. In this paper, I provide an overview of the five general designs for hedging risk in merchant wind projects, with a focus on the specific risks that are, and are not, hedged under each design. From project data, I find that merchant wind has both increased, accounting for almost half of new capacity in 2017 and 2018, and diversified, with at least three hedging designs used in each of the past three years. I then assess the more restrained growth of merchant solar energy and propose that differences in costs, subsidies, project sizes, and generation profiles may explain the disparities between merchant wind and merchant solar. Evaluating the revenue risks to wind and solar projects yields insights to future financing challenges, including the near-term declines in federal subsidies and, more significantly, the long-term erosion in prices due to increasing penetrations of wind and solar.

Contents

1. Introduction

To achieve the emissions reductions limiting the atmospheric concentration of carbon dioxide (CO_2) to 450 parts per million, the International Energy Agency (IEA) estimates that global investment in renewables, other low-CO_2 technologies, electricity networks, and energy efficiency must average $2.3 trillion annually, three times current annual investment (Reicher et al. 2017). Such an investment would constitute a large proportion of global inflows of investible capital. An even more challenging problem is that only a very small percentage of capital is available for high-risk assets,[1] and many zero-carbon energy investments (e.g., nuclear power plants) are subject to significant technology and market risks. Over the past decade, wind and solar energy has reached technological maturity and has often experienced the policy stability that together have enabled such installations to obtain lower-risk financing. Additionally, the reduced costs and risks of wind and solar have allowed financial hedges to emerge, expanding projects' opportunities beyond traditional contracted arrangements to direct participation in wholesale electricity markets. The combination of a large pool of lower-cost capital and broad market prospects has positioned wind and solar, alone among clean energy sources, to provide an outsized contribution to a low-carbon future.

In selecting the contracted or hedged project structure that will maximize their return with acceptable risk, developers of wind and solar projects assess three main areas of revenues and costs. First is the expected energy revenue, as well as the risk, under the various contracting and hedging options discussed in this paper. The second area is project value other than that from energy revenue. Projects operating in certain wholesale markets may receive revenue for providing capacity to the market.[2] In addition, state and federal policy incentives provide project value. Wind and solar plants generate renewable energy certificates (RECs) that recognize the environmental attributes of the electricity. Projects receive revenue from selling RECs, whether in compliance markets used to meet state renewables' obligations or in voluntary markets. The federal production tax credit (PTC) for wind and the investment tax credit (ITC) for solar, as well as accelerated depreciation, provide valuable tax credits and deductions. The greater amount of value and the lower the risk from non-energy revenue, the less critical is energy revenue to project viability.

[1] For example, only 1 percent (or $89 billion) of the $7.3 trillion US bond market is for new high-yield investments.

[2] The amount of credit that wind and solar projects receive in capacity auctions, given their intermittent nature, is a key consideration to the importance of capacity revenues to overall wind and solar project values.

The third area to determine project structure is the cost of financing. The project developer generally contributes a minority of the capital, so it needs to provide a market rate of return to the other capital providers. In a wind or solar project, capital comes in three forms: debt, tax equity, and sponsor equity.[3] Debt is the cheapest form of financing, but in return, lenders require that there be very little risk to interest and principal payments. The next cheapest source, tax equity, is a type of equity where returns come from such tax benefits as the ITC or PTC, depreciation and interest deductions, as well as from cash due to electricity and REC sales. Finally, sponsor equity (a.k.a. cash equity) ranks highest in risk and return, with its value from electricity and REC sales after the lender and tax equity investor have achieved their returns.[4] The cost and availability of these forms of capital will depend on the level and risk of energy and non-energy revenue.

For wind and solar projects not owned by utilities or the final electricity customer, project developers must decide to whom they will sell their electricity. Either they can sell electricity under a long-term contract known as a power purchase agreement (PPA), or they can sell into wholesale markets. Projects selling into wholesale markets—often referred to as "merchant" generators[5]—face the uncertainty of wholesale electricity prices over a 20- to 30-year project life. To secure financing from debt and tax equity investors, who have low tolerances for risk, projects generally seek a hedge against energy price fluctuations. These hedges may take one of several forms, each of which has particular risk characteristics. Note that the distinction between contracted (PPA) and merchant structures refers only to the physical sale of electricity, whether sold directly to a utility or customer (jointly referred to as an electricity "offtaker") or, instead, sold into the wholesale market. Depending on the hedge, a merchant structure may be financially similar or even less risky than a contracted one. The choice of contracted versus merchant sales and, if merchant, of the type and extent of the hedge will depend on numerous factors, including wholesale electricity prices, PPA and hedge fixed ("strike") prices, non-energy revenue

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[3] For an example of solar project finance structures and required costs of capital, see Feldman and Schwabe (2017).

[4] The project developer is not the only entity that may contribute sponsor equity; infrastructure funds, for example, are common providers of sponsor equity.

[5] Electricity projects may be owned and operated under several arrangements, the most common of which are (i) utility-owned with electricity sold to customers, (ii) customer-owned, (iii) owned by a third party with electricity sold to either a utility or customer under a long-term contract (PPA), and (iv) owned by a third party with electricity sold in the wholesale market. It is this last "merchant" arrangement (iv) that we focus on here.

(such as capacity payments, REC sales, and tax incentives), and financing costs.[6] As these factors change, so too will the relative attractiveness of merchant hedging and contracted options.

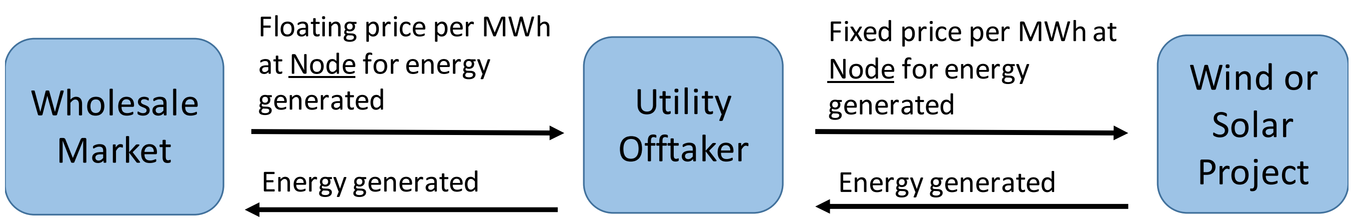
The layout of this paper is as follows. Section 2 provides a review of physical PPAs, which historically have been the predominant method of structuring wind and utility-scale solar projects. Furthermore, physical PPAs are a basis of comparison for merchant structures and their resultant risk profiles. In Section 3, I discuss the five general hedging designs for merchant wind projects, with particular attention to the risks that projects are, and are not, exposed to under each design. Section 3 concludes with a risk-based comparison of the structures, first from the perspective of the project and then from the perspective of the counterparty. Section 4 reviews the limited progress to date on installing solar under merchant arrangements, and Section 5 offers possible explanations for the differences in financing merchant wind versus merchant solar. In Section 6, I conclude with thoughts on how merchant wind and solar might evolve and be challenged, given the significant changes in policies and electricity markets that are under way.

[6] Financing costs will have both independent and dependent determinants (e.g., interest rates and project risks).

2. Physical Power Purchase Agreement

A physical PPA (sometimes referred to as a traditional PPA) for wind projects was developed in the early 2000s from similar contracts between utilities and fossil-fuel power projects owned by independent power producers (Davies et al. 2018). Although ownership and contracting options have broadened in recent years, physical PPAs remain the most common structure for wind and solar projects (Caplan 2018). A physical PPA may be with a utility or the end user of electricity, such as a large commercial customer, but in either case the electricity generated by the project is delivered to the offtaker (the purchaser of electricity). Figure 1 illustrates a physical PPA with a utility offtaker in a region with deregulated wholesale power markets. In contrast to the merchant structures shown later, the utility offtaker, rather than the project itself, interacts with the wholesale markets under a physical PPA.

Figure 1. Energy and financial flows for project with physical PPA



Note: In this hypothetical physical PPA, the utility is operating within the area of a regional transmission organization (RTO) or an independent system operator (ISO), which manage wholesale electricity markets.

The typical structure of a physical PPA has several features that minimize project risk. First, the project receives a fixed payment for each MWh it generates, the price of which is specified in the contract.[7] Historically, utility offtakers have purchased energy from the project at its point of interconnection to the grid (the node), with the utility bearing responsibility for the transmission of electricity (Goggin et al. 2018). Additionally, most physical PPAs for wind have had durations of 15 to 25 years (Wiser and Bolinger 2018), roughly the expected life of wind projects.[8] Lastly, if the offtaker is

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[7] If a project combines wind or solar with energy storage, a variation on a physical PPA, known as a tolling agreement, is also feasible. A tolling agreement, common in fossil-fuel power projects, allows the offtaker to decide when the project will dispatch electricity. For more information on tolling agreements for solar-plus-storage projects, see Sinaiko (2018).

[8] In its assumptions for levelized costs of energy, Lazard assumes a 20-year facility life for wind projects (Lazard 2017).

a utility that serves a retail load, there is a relatively low risk of default on the contract (known as counterparty risk). However, the low risk profile of physical PPAs and limited pool of potential offtakers—90% of physical PPA offtakers for wind have been utilities or utility cooperatives (Vavrik 2017)—have led to strong competition among projects and low PPA prices. As a result, wind projects have expanded beyond physical PPAs to various merchant structures in order to obtain higher revenues.

3. Merchant Wind

This section describes the five general hedging structures that could be used by merchant wind projects to mitigate risk, categorized by the risk that is hedged.[9] The first three structures—bank hedge, synthetic PPA, and electricity forward contract—are swap contracts that trade actual (or floating) wholesale electricity prices for a predetermined fixed price.[10] In each case, the wind project pays a premium for the counterparty to bear the risk of electricity price volatility. The counterparty expects to profit given that the strike (fixed) price it pays to the wind project is less than the expected (forecast average) floating price. In exchange, the wind project receives a fixed price that will allow it to secure lower-cost financing than would be possible if electricity prices were unhedged. The next structure, proxy revenue swap, hedges against both electricity price and weather (wind speed) risks. The final structure, natural gas forward contract, exploits the correlation between electricity and natural gas prices to use natural gas forwards to hedge against electricity price risk.

The counterparties in these merchant structures are not load-serving utilities, and they will likely have higher counterparty credit risks, which would need to be mitigated through guarantees, letters of credit, or some other mechanism. The structures are discussed here in their general forms; as merchant projects have become more prevalent, structures have increased in complexity and customization.

3.1. Electricity-Based Wind Hedges

Bank Hedge (a.k.a. Fixed-Volume Price Swap)

A bank hedge is the most tested hedge structure and is particularly common in ERCOT.[11] The counterparty is a financial institution, often the same institution that provides tax equity to the project. The term of the hedge runs 12 to 13 years, which aligns with the term required by wind tax equity investors.[12] Figure 2 shows the

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[9] The risks discussed are limited to electricity price, generation, curtailment, and congestion risks, which are affected by the choice of PPA or hedging structure. Other risks exist for wind and solar projects, such as permitting and regulatory risks, which are less dependent on project structure.

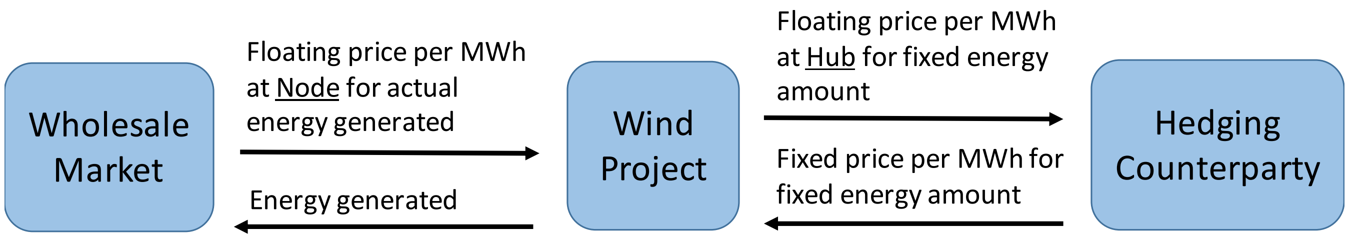
[10] A swap contract is the general name for a financial derivative in which two parties exchange cash flows from different financial instruments.

[11] The Electric Reliability Council of Texas (ERCOT) manages the wholesale market for most of Texas.

[12] The PTC is a tax credit for the first 10 years of electricity generation. The wind tax equity investor may not achieve its required return after 10 years, so 2 to 3 more years of electricity and REC sales may provide the necessary supplement. If the hedge lasts for 12 or 13 years, the electricity price will have greater stability over the entire tax equity investment period.

structure of a bank hedge, which may be either financial (as shown) or physical (where the project purchases fixed volumes of electricity in the wholesale market to sell to the counterparty), but the hedging effects are equivalent.

Figure 2. Energy and financial flows for project with bank hedge (financial)



Bank hedges remove some of the project's risks of wholesale price fluctuations, but several areas of risk remain. The project receives the electricity price at the node, where the power plant connects to the grid, but the counterparty usually requires that the contract settle at a larger trading hub, which often has a different price.[13] This difference, known as basis risk, is the result of transmission congestion that constrains prices from equalizing across the grid. Although the project could potentially hedge basis risk by purchasing transmission rights, it is difficult to predict the amount of transmission rights that would be needed, and transmission rights have a typical term of only one or two years (Goggin et al. 2018). As a result, transmission rights (or similar insurance products) have not supported wind project financing (Eberhardt and Brozynski 2017).

In a bank hedge, the prices (floating and fixed) and fixed volume are contracted hourly at the hub. The fixed-volume feature requires that the project balance the risk of generating insufficient electricity (volume risk) against the risk of significant unhedged generation (price risk). The hourly nature of the contract creates the additional risk of mismatch in the timing of wind generation versus contracted hourly power sales (shape risk). To limit the extent of volume and shape risks, fixed hourly volume is typically determined by the project's hourly generation in a "P99" scenario (Eberhardt and Brozynski 2017), the amount forecasted to be exceeded 99 percent of the time. Separately, there is the risk of wind curtailment, the result of insufficient transmission capacity and/or inflexible generation on the grid. To cover temporary

[13] A node is the point of interconnection to the electricity grid. Trading activity in electricity markets takes place at a hub, which covers a larger area and thus provides greater liquidity. Hub prices reflect average nodal prices in the region.

shortfalls from these risks, the financial institution counterparty may provide the project a "tracking account," a loan that is repaid when project revenue exceeds contract requirements.

Synthetic PPA (a.k.a. Corporate PPA or Virtual PPA)

A synthetic PPA replicates much of the structure of a traditional PPA without the physical transfer of electricity to the counterparty, a nonutility corporation (hence corporate PPA). The corporation is often interested in the transaction as a hedge against electricity price fluctuations as well as for its environmental attributes. The corporate counterparty is generally more interested in voluntary renewable energy certificates (RECs) and corporate renewable energy goals than in compliance RECs. Compliance RECs, if relevant, may be sold separately to load-serving entities that typically need them to comply with state renewable portfolio standards (RPSs).

Figure 3. Energy and financial flows for project with synthetic PPA

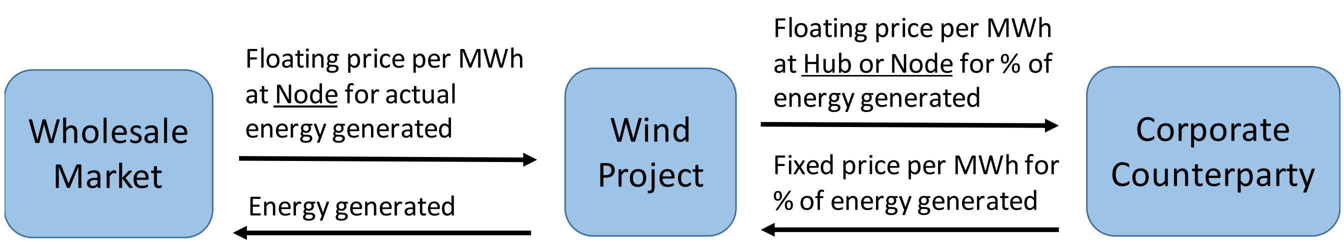


Figure 3 shows the basic design of a synthetic PPA, which resembles that of a bank hedge, with some important differences.[14] Synthetic PPAs have greater flexibility in settlement location than do bank hedges, and basis risk for the project will not exist if the contract settles at the node instead of the hub.[15] In addition, the quantity of electricity in a synthetic PPA is a percentage of the actual electricity generation, removing the project's volume, shape, and curtailment risks that exist in bank hedges. If the contract percentage is less than 100 percent, there will be price risk for the remaining electricity generated. If the synthetic PPA is for 100 percent of the electricity

[14] Synthetic PPAs are often structured as contracts for differences (CfDs) (Marks and Rasel 2014). Rather than have the project pay the floating price and the counterparty pay the fixed price (as shown), only the price difference is paid in CfDs.

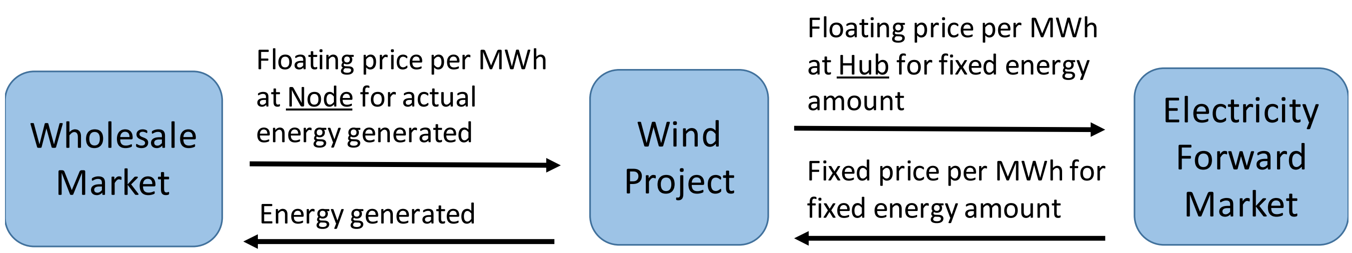
[15] A majority of wind synthetic PPAs settle at the hub (Davies et al. 2018), leaving the project with basis risk.

generated and the contract settles at the node, a synthetic PPA would replicate the financial characteristics of a traditional PPA, albeit for a generally shorter duration (12 to 13 years for a synthetic PPA versus 15 to 25 years for a traditional PPA).

Electricity Forward Contract

Projects could also participate in electricity forward markets (e.g., in ERCOT), which would involve trading contracts to secure more stable pricing for their electricity generation.[16] Figure 4 shows a project with electricity forward contracts, which swap floating electricity prices for a fixed price. Although the general structure is the same as that of a bank hedge, electricity forward contracts are done on a monthly rather than an hourly basis (although there are separate monthly prices for peak and off-peak) and there are additional complexities that the wind project developer would need to assess. For example, the developer would need to estimate expected peak and off-peak generation, the correlation between its generation and spot prices, as well as its capacity factor during scarcity hours, to sell the correct number of forward contracts (Aydin et al. 2017).[17]

Figure 4. Energy and financial flows for project with electricity forward contract



Another major difference with bank hedges is that the counterparty could be any participant in the electricity forward markets. Because the market has numerous participants, these contracts may be more competitively priced than bank hedges, which are offered by a comparatively small group of financial institutions. However, electricity forward contracts are traded liquidly for only one to two years into the future (Aydin et al. 2017). Low-cost project financing, in the form of tax equity and

[16] Trading of monthly futures contracts occurs on various exchanges for electricity at hubs in the wholesale markets (ERCOT, PJM, MISO, SPP, CAISO, NYISO, and ISO-NE). Although we discuss forward contracts, which are negotiable and traded over the counter, futures contracts are similar in design but have standardized terms and are traded on an exchange.

[17] For example, a 100 MW wind project with an estimated capacity factor of 40 percent and wind generation-forward price correlation of –25 percent during on-peak hours would sell 100 MW * 40% * (100% – 25%) = 30 MW of electricity forward contracts per on-peak hour. As the party receiving the fixed price, the wind project is considered the seller of this contract.

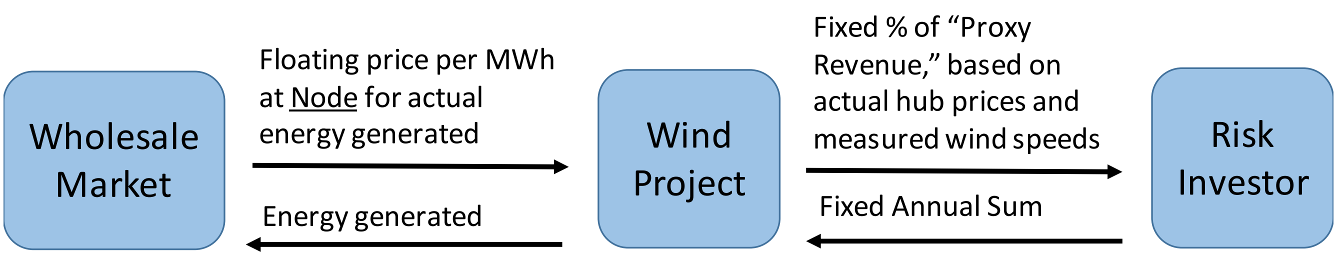
particularly in the form of debt, may be very difficult or impossible to obtain with electricity prices unhedged beyond a couple of years. Projects without long-term hedges may use these contracts, but such projects are rare.

3.2. Electricity and Weather-Based Wind Hedge

Proxy Revenue Swap

Introduced in 2016, proxy revenue swaps are a method of hedging both price and generation (wind speed) risks to wind projects. One counterparty in the transaction (there may be multiple counterparties)[18] is a weather risk investor—typically an insurance company—seeking risk that is uncorrelated with its other investments. Figure 5 illustrates the basic design, in which the counterparties provide the project with a fixed annual payment and receive a fixed percentage of annual "proxy revenue." Proxy revenue is based on actual hub prices, actual wind speeds, and agreed-upon inefficiencies, such as availability, performance, and electrical losses (Eberhardt and Brozynski 2017).

Figure 5. Energy and financial flows for project with proxy revenue swap



Since proxy revenue swaps settle at liquid trading hubs, they expose wind projects to basis risk. Additionally, although a proxy revenue swap insures against wind speed risk, it results in greater project exposure to operational risks compared with a physical or synthetic PPA, since the contract is based on proxy generation rather than actual generation. Operational risks include equipment performance, non-availability (e.g., maintenance downtime), and curtailment risks. To date, proxy revenue swaps have been limited to 10 years, which is somewhat short for wind tax equity investors, who prefer a secure cushion beyond the 10-year PTC. Nonetheless, wind projects using proxy revenue swaps have secured both tax equity and debt financing (Eberhardt and Brozynski 2017).

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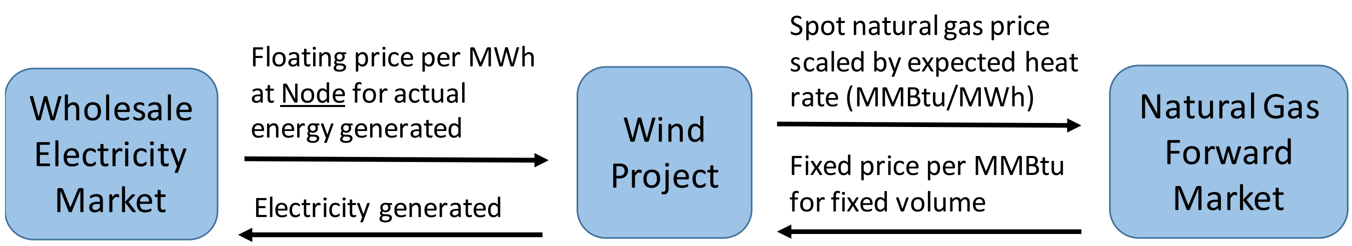
[18] In a proxy revenue swap, one counterparty (the insurance company) may seek the wind speed risk while another counterparty may seek to hedge the price risk of an electricity liability.

3.3. Natural Gas-Based Wind Hedge

Natural Gas Forward Contract

Unlike electricity forward markets, natural gas contracts at Henry Hub are traded out for 10 to 12 years, so natural gas hedges have the potential to combine competitive market pricing with a hedge of sufficient duration for project financiers. Similar to electricity forwards, natural gas forward contracts are on monthly basis, but without electricity's peak/off-peak distinction. To hedge against electricity price risk, the wind developer would sell a certain number of natural gas forward contracts based on the amount of electricity generation it wishes to hedge as well as the expected market heat rate (the ratio of electricity to natural gas prices).[19, 20]

Figure 6. Energy and financial flows for project with natural gas forward contract



The structure shown in Figure 6 illustrates how the wind project is long (has positive exposure to) electricity prices and short (has negative exposure to) natural gas prices. This hedging design thus requires a very strong correlation between natural gas and electricity prices and for that correlation to hold for the duration of the contract. Although historically, natural gas and electricity prices have been highly correlated (see Aydin et al. 2017 for a comparison of ERCOT and Henry Hub prices), the risk of electricity and gas prices' decoupling in the future presents a threat to this structure.[21] In addition to electricity basis risk caused by transmission congestion, a natural gas–

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[19] The expected market heat rate allows the conversion of a natural gas price, in $/MMBtu, to an electricity price, in $/MWh. $/MMBtu * ($/MWh) / ($/MMBtu) = $/MWh.

[20] From our example in electricity forward contracts, a 100 MW wind project would sell 30 MW of on-peak hour electricity forward contracts. If the expected on-peak electricity price were $60/MWh and natural gas forwards were $3/MMBtu, the implied on-peak heat rate would be 20 MMBtu/MWh, and the wind project would sell 30 * 20 = 600MMBtu/on-peak hour of natural gas forward contracts. The wind project would repeat this calculation for off-peak hours to determine the total number of natural gas forward contracts to sell for each month.

[21] For example, with enough wind and solar capacity, wholesale electricity prices would fall to zero or below when solar and wind generation exceeds load. However, the spot gas price would still be positive, resulting in a loss for wind projects using natural gas forward contracts.

based hedge introduces gas basis risk, the difference between the price of gas at the trading hub (e.g., Henry Hub) and the price of gas for natural gas power plants at the wind project's node, which could also be substantial in pipeline-constrained locations like the Northeast (Aydin et al. 2017).[22]

3.4. Summary of Wind Hedging Structures

Table 1 summarizes the risks of wind projects using each of the hedging structures discussed as well as of a wind project with a physical PPA for comparison. The proxy revenue swap stands out as the only option that hedges against weather risk. The next three structures (the physical and synthetic PPA options) share similar profiles, with risk increasing going down the column, first because of a shorter time period and second because of the addition of basis risk. A bank hedge and an electricity forward contract are broadly similar in structure but divergent in contract duration. Finally, natural gas forwards and unhedged merchant arrangements are unique in their risk profiles.

Table 1. Risk exposure of hedging structures and physical PPA

<table>
<tr><th rowspan="3">Offtaker or Hedging Structure</th><th colspan="7">Risk Category</th><th rowspan="3">Typical Duration (Years)</th></tr>
<tr><th colspan="3">Quantity Risks</th><th colspan="2">Electricity Price Risks</th><th colspan="2">Gas Price Risks</th></tr>
<tr><th>Weather (Wind Speeds)</th><th>Operational and Curtailment</th><th>Contracted Volume / Shape</th><th>Electricity Hub Price</th><th>Node-vs-Hub (Basis)</th><th>Electricity-Gas Price Correlation</th><th>Node-vs-Gas Hub (Gas Basis)</th></tr>
<tr><td>Proxy Revenue Swap</td><td></td><td>●</td><td></td><td></td><td>●</td><td></td><td></td><td>10</td></tr>
<tr><td>Physical PPA</td><td>◖</td><td>◖</td><td></td><td></td><td></td><td></td><td></td><td>15 - 25</td></tr>
<tr><td>Synthetic PPA (Node)</td><td>◖</td><td>◖</td><td></td><td rowspan="4">● For any portion of the generation that is not hedged</td><td></td><td></td><td></td><td>Up to 12-13</td></tr>
<tr><td>Synthetic PPA (Hub)</td><td>◖</td><td>◖</td><td></td><td>●</td><td></td><td></td><td>Up to 12-13</td></tr>
<tr><td>Bank Hedge</td><td>●</td><td>●</td><td>●</td><td>●</td><td></td><td></td><td>Up to 12-13</td></tr>
<tr><td>Natural Gas Forwards</td><td>●</td><td>●</td><td>●</td><td>●</td><td>●</td><td>●</td><td>Up to 10-12</td></tr>
<tr><td>Electricity Forwards</td><td>●</td><td>●</td><td>●</td><td>● (after 2 yrs)</td><td>●</td><td></td><td></td><td>1-2</td></tr>
<tr><td>Merchant - Unhedged</td><td>◖</td><td>◖</td><td></td><td>●</td><td>●</td><td></td><td></td><td>N/A</td></tr>
</table>

Notes: A full circle indicates that the risk is entirely borne by the project; a half circle indicates that the risk is either shared between the project and the counterparty or that the only the project's revenue is affected. For example, under a physical PPA, a project's revenue would decrease with lower wind speeds, but the project is not contractually obligated to generate a fixed quantity of electricity. Not all of these risks are independent; for instance, volume and shape depend on wind speed and operational factors.

Sources: Adkins 2016, Aydin et al. 2017, Davies et al. 2018, Wiser and Bolinger 2018.

[22] A gas-based hedge assumes that local gas-fired power plants will generally set the electricity price for the area; gas basis risk describes the potential discrepancy between the gas price at the trading hub and the local gas price. Although gas basis swaps could be used hedge this risk, they are traded for only a few years into the future (Aydin et al. 2017).

A retrospective analysis of 60 operating wind farms in ERCOT, using hourly node and hub electricity prices and generation data to simulate revenues and returns under five arrangements, confirms the qualitative risk assessment of Table 1. The structures, in order of the lowest to highest standard deviation in returns, were proxy revenue swap, node PPA, hub PPA, bank hedge, and unhedged merchant (Vavrik 2017). The cost of financing is similarly ranked, because of both a lower cost of debt, tax equity, and sponsor equity with less revenue risk and a lower-cost capital mix (e.g., a project can be financed with a greater percentage of debt if revenue risk is minimized). The average returns to the project owner, calculated on a levered (after debt payments) after-tax basis, were in reverse order, with the exception of the proxy revenue swap, which placed in the middle. We would expect this typical trade-off between risk and return. However, other determinants of offtaker and counterparty demand can affect the PPA and hedge strike prices offered. For example, utility demand for traditional PPAs and corporate demand for synthetic PPAs would be also affected by RPS requirements and corporate renewable energy goals.

Table 2 lists all the wind projects installed in 2017 in the United States under a merchant or part-merchant basis. First, note that merchant installations of 3,381 MW represented 48 percent of total 2017 wind installations (42 percent excluding the two Amazon projects).[23] With low prices for physical PPAs and the urgency to construct wind projects before the phase-out of the PTC, the proportion of merchant projects rose slightly further in 2018.[24] In 2017, synthetic PPAs and bank hedges were the most common structures used, accounting for 83 percent of merchant MW installed. Two projects using proxy revenue swaps were completed, and the Falvez Astra project is believed to be the first wind project without a hedge to have secured tax equity financing (Metcalf 2016). The structures in Table 2 refer only to long-term hedges; wind capacity listed as “True Merchant—Unhedged” may use electricity forward contracts to hedge price risk over a timeframe of less than two years. Finally, although projects have reportedly used hedges based on natural gas in prior years (Wiser and Bolinger 2018), no project installed in 2017 could be found with a gas-based hedge.

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[23] It is also noteworthy that 15 of the 18 merchant wind projects in 2017 were in ERCOT or SPP, neither of which has capacity markets, so capacity revenue may not be a significant factor in the viability of merchant wind.

[24] In 2018, 7,588 MW of wind was installed, of which 3,709 MW (49 percent) was under merchant structures, based on preliminary data. Bank hedges and synthetic PPAs accounted for 1,508 MW and 1,588 MW, respectively (American Wind Energy Association 2019).

Table 2. 2017 US merchant wind projects, by hedging structure

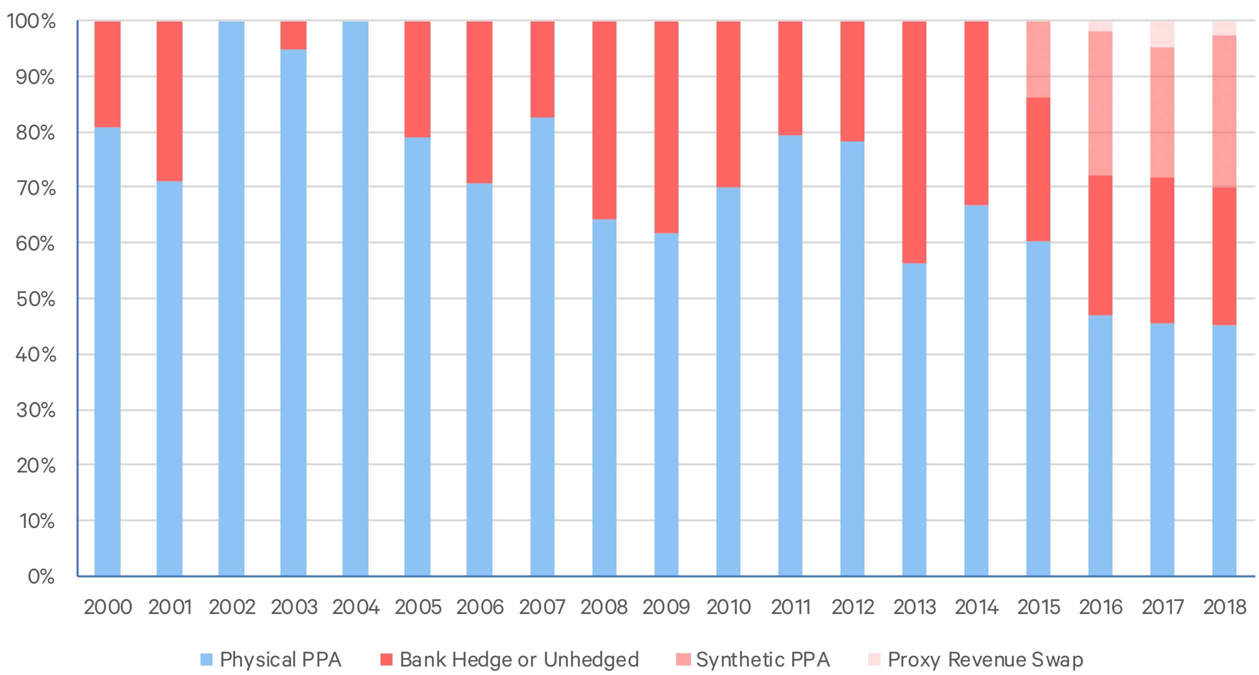
	State	Project Name	Purchasers	Total Project Size (MW)	PPA (non-merchant)	Bank Hedge	Synthetic (Virtual) PPA	True Merchant - Unhedged	Proxy Revenue Swap	Total Merchant Size (MW)
1	IL	Radford's Run	Merchant Hedge	305.8		305.8				305.8
2	KS	Bloom	Microsoft	178.2					178.2	178.2
3	MN	Red Pine	Merchant Hedge	200.0		200.0				200.0
4	NC	Amazon Wind East	Amazon	208.0			208.0			208.0
5	OK	Red Dirt	GRDA PPA / T Mobile	299.3	139.8		159.5			159.5
6	OK	Rock Falls	Kimberly-Clark / Merchant	154.6			120.0	34.6		154.6
7	OK	Thunder Ranch	Undisclosed PPA / Anheuser-Busch	297.8	145.3		152.5			152.5
8	TX	Bethel	Google / Merchant	276.0			225.0	51.0		276.0
9	TX	Amazon Wind Farm Texas	Amazon / Iron Mountain	253.0			253.0			253.0
10	TX	Bearkat 1	Merchant Hedge	196.7		196.7				196.7
11	TX	Bruenning's Breeze	Merchant Hedge	228.0		228.0				228.0
12	TX	Buckthorn	JP Morgan PPA / Merchant Hedge	100.1	50.0	50.0				50.0
13	TX	Chapman Ranch	Merchant Hedge	249.1		249.1				249.1
14	TX	Falvez Astra	Merchant	163.2				163.2		163.2
15	TX	Fluvanna 1	Merchant Hedge	155.4		155.4				155.4
16	TX	Old Setter Wind	Allianz	151.2					151.2	151.2
17	TX	Rocksprings	Undisclosed PPA / Walmart	149.3	99.3		50.0			50.0
18	TX	Willow Springs	Merchant Hedge	250.0		250.0				250.0
		Total (MW)		3,815.6	434.4	1,635.0	1,168.0	248.8	329.4	3,381.1
		% of Total Merchant				48.4%	34.5%	7.4%	9.7%	100.0%

Notes: Only long-term hedges that are used by the projects themselves are shown; projects may also use short-term hedges, and counterparties may use separate hedges. It is uncertain whether the two Amazon wind projects have physical or synthetic PPAs. Excluding those projects would result in total wind merchant installations of 2,920 MW rather than 3,381 MW in 2017.

Sources: American Wind Energy Association 2018, Caplan 2018; company press releases and media reports.

Figure 7 shows how the prevalence of merchant structures has increased since 2000 when they were first employed for wind energy. The percentage of merchant or part-merchant projects has fluctuated, but it generally remained below 30% until the past five years. Moreover, hedging options were limited to bank hedges (although electricity or natural gas forward contracts may have been used), until synthetic PPAs and proxy revenue swaps were introduced in 2015 and 2016, respectively. Although proxy revenue swaps remain infrequently used, capacity installed under a synthetic PPA has roughly equaled capacity installed with a bank hedge over the past three years. Aggregating all merchant structures, approximately half of all US wind capacity since 2016 has come online without a physical PPA. This trend appears likely to continue, at least until wind projects no longer qualify for the PTC.

Figure 7. Percentage of US wind capacity installations, by physical PPA or merchant structure



Notes: For consistency with early years (in which project data contains less detail), projects with bank hedges and those with no long-term hedges are combined, and projects with both physical PPA and merchant portions are allocated as merchant projects. This methodology overestimates the share of merchant capacity, but the difference does not appear to be very large. In 2017 and 2018, stricly merchant capacity represented 48% and 49% of annual installations, whereas projects with at least some merchant portion represented 54% and 55% of respective annual installations. Projects with sythetic PPA and unhedged portions are allocated based on whichever portion is larger. Unhedged capacity could include electricity or natural gas forward contracts.

Sources: American Wind Energy Association 2019, company press releases and media reports.

In addition to choosing the particular hedging structure, wind project developers must decide how much generation to hedge. One strategy (potentially used in the Bethel and Rock Falls projects) is to hedge only the amount needed to satisfy the more risk-averse tax equity investors and/or lenders and to keep the remainder unhedged to increase expected returns (Marks and Rasel 2014). The cost of these long-term (10- to 13-year) electricity market hedges is that counterparties may charge a significant premium due to future electricity market uncertainties. Such uncertainties include the price of natural gas, the amount of zero-marginal cost wind and solar installed in future years, and the extent to which wind generation will benefit from the limited hours of high energy prices. As a result, one project developer noted that bank hedge strike prices offered were 30 to 40 percent lower than forecasted spot electricity prices (Bailey 2015).[25]

3.5. Wind Hedging Structures: Risks to Counterparties

Although this paper focuses on the risks to wind and solar projects, assessing risks to the counterparties under the various structures helps explain their desirability and thus market supply. In a basic sense, this is a simple matter: a structure that hedges a particular risk for the project will generally expose the counterparty to that risk. However, different parties may have different risk tolerances, and some may be able to pass on certain risks to others. Under a physical PPA with a utility, the wind project typically does not bear basis risk, the risk of price fluctuations at the relevant hub or the requirement to produce a fixed volume of energy. The utility offtaker has a large portfolio of energy projects of various technologies, so the basis, price, and volume risks from an individual wind project may have little effect on the overall risk to the utility. Moreover, many states allow the utility to pass price risk onto its consumers. A bank hedge, in contrast, is a relatively risky structure for the project, with only electricity price risk hedged at the respective hub. Still, the bank counterparty will not retain exposure to hub power price risk over the 12- to 13-year contract period; rather, it will enter into natural gas hedging contracts to mitigate this risk. As discussed previously, the strategy of hedging electricity prices with natural gas contracts is imperfect, but for a large financial institution, the residual risks are far less significant than they would be for an individual wind project.

[25] The determinants of hedging strike prices will vary between structures. Banks offering hedges will offset their electricity price risk with natural gas contracts, whereas synthetic PPA counterparties generally have future electricity liabilities. The greater the residual risks that counterparties assume, the greater the discount they will likely apply to wind hedging prices.

Synthetic PPAs present complexities and risks to their corporate counterparties. First, synthetic PPAs may settle at the node or the hub, and node-settled contracts shift basis risk from the project to the counterparty. Second, since the contracted volume is a percentage of as-produced generation, the counterparty bears the risk that the amount and timing of wind generation revenue will not align with its needs. Although the counterparty may be purchasing electricity within the wholesale market of the project, which would mitigate its price risk, the quantity and timing of electricity purchases versus contracted wind revenue may not be well matched (volume and shape risks). For example, a corporation may consume more electricity during daytime hours but the wind project may generate more electricity at night, likely a period of different pricing. Third, there may be divergent production incentives between the project (which seeks to maximize generation) and the corporate counterparty (which seeks to maximize electricity revenue) under a synthetic PPA. The project would wish to generate even when wholesale prices are negative, to the detriment of the counterparty. As another illustration, the project would prefer to perform maintenance when wind speeds are low, even if electricity prices are high, which could conflict with the preferences of the counterparty (Davies et al. 2018). Although these concerns also exist under a physical PPA, a utility offtaker has a large portfolio of energy projects and potential risk protection, whereas a corporate counterparty has neither.

The development of proxy revenue swaps has been motivated, in part, to avoid the divergent production incentives of a synthetic PPA and to allocate operational risk back to the project (Davies et al. 2018). Rather than attempt to address these concerns with contractual obligations, the structure of a proxy revenue swap incentivizes the project to maximize its electricity revenue (to be aligned with the incentives of the counterparties) rather than to maximize its generation. As with a synthetic PPA, the counterparties bear the volume and shape risks of electricity revenue, and unique among the hedging structures, the counterparties in a proxy revenue swap also take on the weather (wind speed) risk. However, since one of these counterparties is typically an insurance company, wind speed risk—being uncorrelated with its other investment risks—is a beneficial addition to its portfolio.

Lastly, counterparties for electricity and natural gas forward contracts are long (have positive exposure to) electricity and natural gas prices, respectively. These counterparties may be speculators, having no corresponding short position. However, it is more likely that they are hedging a short position in electricity or natural gas. If so, their position is similar to that of a counterparty in one of the other hedging structures, with a future electricity (or natural gas) liability that they are hedging with a fixed-for-floating swap contract.

4. Merchant Solar

In contrast to wind, solar installed on a merchant basis accounts for a small fraction of the total market. It has emerged only in particular locations and has been subject to significant wholesale power price risk. Of the 15 largest merchant solar plants operating as of May 2018, 11 were in Chile, 3 were in Mexico and 1 was in the United States (Dorothal 2018).[26] In Chile, interest in new merchant solar has stalled over the past two years, in part because the large volume of solar generation in northern Chile, where most solar plants are located, has reduced wholesale power prices (Critchley 2017).

The exception to those general observations for merchant solar is that synthetic PPAs have been used for US solar projects since 2015.[27] An estimated 64 percent of roughly 2.5 GW of offsite corporate procurement of solar between 2015 and 2017 has come from physical or synthetic PPAs, though the split between physical and synthetic PPAs is unclear (Davis and Smith 2018).[28] Bank hedges have been limited so far to wind projects, but solar project developers in ERCOT have been requesting hedging quotes from commodities traders since 2017, reflecting the increasing competitiveness of solar in the wholesale markets (Metcalf 2018).

In the United States, interest in merchant solar beyond synthetic PPAs has generally been as a complement to PPA arrangements. For example, the 315 MW_{DC} Phoebe solar project in Texas, to be completed in 2019, has a PPA with Shell Energy for 89 percent of the power, with the remaining 11 percent to be sold into the wholesale market (Weaver 2018). Additionally, US financiers are growing more comfortable in placing some value on the "merchant tail," electricity generated after a project's PPA ends and sold into the wholesale market. However, lenders have indicated that they would be very cautious in assigning value to such revenues, making the assumption of lower-than-expected wholesale prices, and would require much higher debt service coverage ratios than with contracted revenue (Bhat 2018).

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[26] The lone US project was the 18 MW Barilla Solar project in Texas, completed by First Solar in 2014 and written down in value in 2017 because of lower wholesale power prices in ERCOT.

[27] Additionally, two projects currently under construction in Australia, the 98 MW Susan River Solar farm and 78 MW Childers Solar farm, have proxy revenue swaps in place to hedge their upcoming generation.

[28] However, as noted previously, the financial differences between physical and synthetic PPAs may be minor if the hedge settles at the project's node.

5. Comparison of Wind and Solar

The differences between financing merchant wind and merchant solar may be due to several factors, both historical and persistent. Historically, wind has had lower unsubsidized levelized costs than solar. However, cost differences have been offset to some degree by timing: solar displaces electricity predominantly during midday hours, which historically have received above-average prices (discussed in greater detail below). Furthermore, the gap in levelized costs has narrowed significantly, with utility-scale solar at $43 to $53 per MWh versus wind at $30 to $60 per MWh (Lazard 2017), so differences in unsubsidized levelized costs may not explain much of the recent difference between merchant wind and merchant solar installations. Subsidized costs are a different matter, and the PTC has been a more generous incentive than the ITC,[29] which has required wind projects to obtain less of their value from electricity sales, compared with solar projects. With the PTC incentive of $23 per MWh over 10 years plus the accelerated depreciation benefits, more than half of a wind project's levelized costs may have been covered by subsidies. The PTC began phasing out for projects commencing construction after 2016, declining by 20 percent in 2017, 40 percent in 2018, and 60 percent in 2019 before being phased out entirely thereafter.[30] The urgent subsidy deadline for wind (the solar ITC does not begin to phase down until 2020) may also have favored merchant wind over merchant solar installations recently, as developers, financiers and hedging counterparties have rushed to complete wind deals and commence construction to obtain the greatest possible value of the PTC. If this is the case, there may be substantial development of merchant solar that will be installed over the next few years as the PTC declines and before the ITC deadlines come into effect.

A separate factor that may explain the inability of solar to have secured bank hedges is scale. The significant transaction costs of structuring and financing a bank hedge could make this design unpractical for all but very large projects. For the first few solar bank hedges, the transaction costs could be even greater because the structure would be, to some extent, novel. In Table 2, note that all 18 merchant wind projects in 2017 were in excess of 100 MW. In contrast, in 2017, there were only 3 solar projects of 100 MW or greater (Bolinger and Seel 2018). Whether more numerous solar projects of

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[29] This is true for wind projects with average capital costs and capacity factors. See Bolinger et al. (2009) for a sensitivity analysis of the PTC versus the ITC under ranges of capital costs and capacity factors.

[30] Projects are eligible for the respective year's value of the PTC if they can meet one of two criteria for commencing construction—either a "physical work" test or incurring at least 5% of total project costs (a "safe harbor" provision).

such scale will be developed in the future is unclear, as there may be permitting, transmission, and other advantages of installing smaller solar projects.

Perhaps the most important difference between the two technologies is also one that will persist.[31] Solar and wind have different generation profiles, and the midday-concentrated profile of solar presents more wholesale power price risk as the amount of solar capacity increases. Between 2011 and 2017, the value of solar electricity in the WECC region (power markets in the West, where most solar has been installed) declined from $34 to $24 per MWh. As a percentage of around-the-clock (ATC) prices, this reflects a change from a 12 percent premium in 2011 to a 27 percent discount in 2017 (Danial 2018b). Whereas solar initially captured high prices during the afternoon, increasing amounts of solar depressed midday prices to the point where such prices are now at a significant discount compared with 24-hour averages. Although solar electricity still commands an average premium of 8 percent over ATC prices outside the WECC, this premium could rapidly become a discount with increased solar capacity (Danial 2018b). Without significant amounts of storage or flexibility, higher penetration of solar will unavoidably erode its own prices.[32] Wind has a less concentrated generation profile, and although wind may generate more at times when prices are lower, the effect is far less pronounced—a discount to ATC prices of 10 percent (Danial 2018a). Models of high penetration of solar and wind also find such a divergence; a study found that in California, 20 percent penetration of solar leads to a 50 percent decrease in its marginal economic value, whereas 20 percent penetration of wind leads to a decrease in its marginal economic value of just 15 percent (Mills and Wiser 2012). Even counterparties that provide wind hedges may be wary of hedging electricity prices for solar projects, given how rapidly and significantly midday prices can fall.[33]

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[31] Solar does possess two advantages with respect to project economics. First, solar electricity production is more predictable than that of wind (lower generation risk). Second, solar has a longer expected project life (a 30-year estimated facility life for utility-scale solar versus 20 years for wind; Lazard 2017). With a longer life, there is more time after a 10- to 13-year hedge for a project to earn additional returns, thus requiring less value (lower prices) from the hedge contract.

[32] The price effect from solar installations is due to utility-scale additions as well as residential and commercial solar. See Bushnell and Novan (2018) for further analysis of the effect of solar on wholesale electricity prices in California.

[33] An exception would be if the counterparty also has a midday electricity liability that would similarly decline over time. Commercial electricity users may have a midday-heavy load profile, which could further explain the ability of solar projects to secure synthetic ("corporate") PPA contracts.

6. Conclusions

Taking into account the differences between wind and solar, as well as the tax credit reductions and the longer-term market changes, it is worth considering how wind and solar hedging structures might evolve. Solar has a limited window for merchant structures (other than synthetic PPAs) to emerge before the ITC begins phasing down in 2020.[34] With a greater proportion of project value needing to come from electricity sales following the phase-down, we would expect project financiers to become more risk averse afterward. If merchant solar deals do not emerge by then, it may take several more years before the decline in project costs can offset the reduced incentive. Another effect of the declining ITC may be increased ownership by regulated utilities, which historically have had less interest in owning solar projects because of "normalization" rules that diminish their benefit from the ITC.[35] For wind, the phase-out is already under way, so projects currently planned are assuming either a reduced or an eliminated PTC. With a lower amount of value from subsidies,[36] project financiers will likely require revenue structures with less risk, such as proxy revenue swaps and PPAs (traditional and synthetic), rather than bank hedges or fully merchant deals.

In the longer term, increased generation capacity of wind and solar present uniquely challenging risks to wind and solar value. Unlike low natural gas prices, which may rise, the effects of increasing wind and solar generation on electricity prices are asymmetric: respective electricity prices will decline.[37] Unlike the reduction or removal of a subsidy, which is known in advance to offtakers or hedging counterparties, the degree of price erosion over time due to increased wind and solar can only be estimated. As observed already with solar in the West, the magnitude of price declines may be substantial. In addition to the regional challenge of falling wholesale prices,

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[34] The ITC phases down from the current 30 percent level to 26 percent in 2020, 22 percent in 2021, and 10 percent thereafter. As with the PTC for wind, ITC eligibility for solar is based on when the project commences construction.

[35] The Internal Revenue Code requires "normalization" of the ITC if claimed by regulated utilities, which spreads out the tax credit over the useful life of the project and thus reduces its present value. For more information, see Burton (2016).

[36] This includes value from RECs as well as tax credits. REC prices have declined in recent years as wind and solar installations have outpaced RPS requirements, a trend that will likely continue as 20 of the 30 RPS states (including Washington, DC) reach their final RPS year by 2026. However, an increase in state RPS mandates could add significant value to eligible wind and solar projects. For an analysis of current RPS markets, see Barbose (2018).

[37] Electricity prices in this section refer particularly to the energy component of wholesale electricity. The components of ancillary services and capacity (in RTOs where capacity receives value) may not have the same price effects.

increased solar and wind will also cause local impairments—increased transmission congestion leading to low nodal prices and/or curtailment. These problems are characterized by their uncertainty. Distinct from risk, which may be quantified and assigned a specific cost, uncertainty adds a potential cost of unknown value to developers and financiers.

A general feature of electricity grids with increasing penetration of wind and solar is that median electricity prices fall but electricity prices during scarcity events rise, resulting in an increasing amount of project value coming from fewer number of hours (Vithayasrichareon et al. 2015). Since scarcity events would most likely occur during shortfalls in wind and solar generation, it is doubtful that wind and solar projects would expect to benefit much from scarcity prices. Consequently, wind and solar hedge prices would drop to reflect both low average prices and the mismatch during scarcity events. Whereas wind and solar have been effective hedges for electricity prices determined by natural gas, a hedge that is effectively against natural gas prices is of diminishing usefulness as renewables predominate.[38] Although such a transformation of the entire US electricity sector may be decades away, in certain states and regions, changes will occur more rapidly. Hedging counterparties and other electricity market participants must already anticipate some of these changes as they consider contracts lasting a decade or more.

Without sufficient storage (including long-term storage) and flexible demand to even out prices over time and without transmission to even out prices over space, the value of wind and solar electricity will decline, and project revenue risks and uncertainties will escalate.[39] Either those risks will be borne by counterparties in exchange for low (perhaps very low) strike prices or the projects themselves may take on the risks.[40] If the strike prices are too low and projects choose to bear the risks, project financing would be both expensive and constrained. An important feature of finance, especially of debt, is that pools of capital are discontinuous with respect to risk (Reicher et al.

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[38] Indeed, with a predominance of wind and solar, a desirable electricity hedge would be one against a shortfall of wind and solar generation. Energy storage, as well as demand response and flexibility, could function as such a hedge.

[39] Flexible demand refers to sources of electricity load that may be shifted to align with generation (typically solar) and includes commercial and residential electric water heaters, space heat, and cooling, as well as residential plug loads and electric vehicle charging. Goldenberg et al. (2018) estimate that under scenarios in 2050 with 42 percent wind and 18 percent solar in ERCOT, flexible demand would increase the average value per MWh of wind and solar by 36 percent and decrease annual curtailment of wind and solar by 40 percent.

[40] This scenario could favor ownership by regulated utilities, which receive a fixed rate of return on their investments. However, ratepayers would reasonably object to bearing the cost of assets that are overvalued.

2017).[41] Adding more asset risk not only raises the required rate of return, it also renders certain lower-cost financing options unavailable. Since lower-cost (higher-grade) debt accounts for the vast majority of debt investments, excessive risk would constrain merchant wind and solar projects to a small segment of available capital. In turn, the constrained capital would limit the possible additions of wind and solar and their role in a low-carbon pathway.

[41] There are regulatory and market reasons for this. For example, insurance, pension, and mutual fund managers may be constrained by state regulators, federal laws, and their own prospectuses, respectively.

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