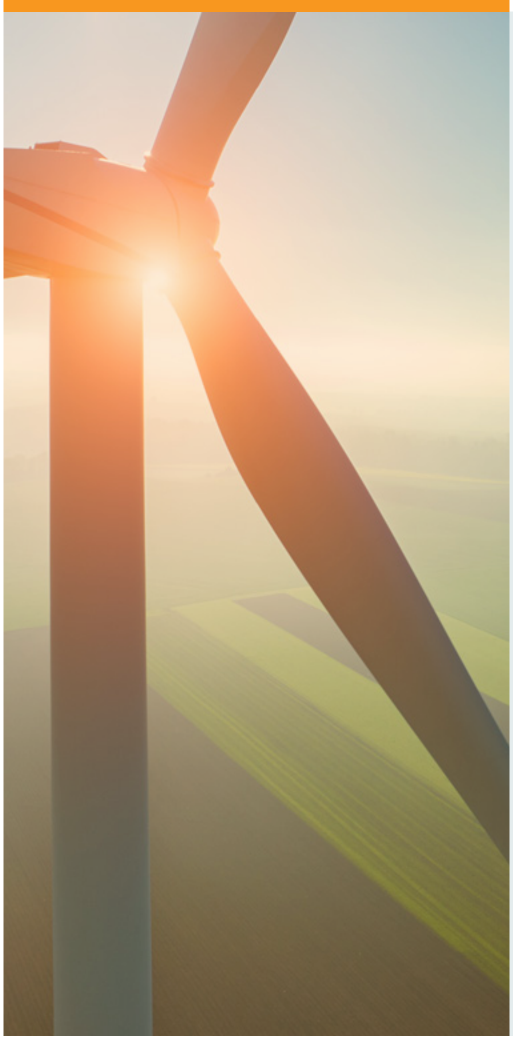
White Paper

Market Considerations for Wind Development in Selected U.S. Markets

By Rachel Green, Himali Parmar, and George Katsigiannakis



Shareables

- Despite strong headwinds from low natural gas prices, investment in wind development continues to be strong
- Strong wind potential and supportive transmission cost allocation, in spite of low PPA pricing, continues to stir wind investment in Texas Panhandle and SPP
- ISO-NE offers the highest revenue potential for wind resources from its stronger energy and REC pricing
- PJM and NYISO offer lower revenue potential than ISO-NE but better transmission availability and encouraging market participation rules

Executive Summary

In addition to existing state and federal regulation and the potential for federal CO_2 regulation, the federal production tax credit (PTC) provides an ongoing incentive for wind development in the United States. The extended tax credit provides a new wind facility that begins construction between 2016 and 2019 with an after-tax credit of up to $23/MWh. When deciding where to build or invest in a new wind facility, one must think well beyond the physical resource potential. Some of the key markets to consider include ERCOT, ISO-NE, NYISO, PJM, and SPP. With potential merchant revenue being more than 50 percent higher in ISO-NE than in SPP, market pricing and wind market participation rules present a significant consideration for the profitability of a new wind facility.

Exhibit 1 outlines and compares some of the key investment considerations affecting returns across markets. ISO-NE, for example, offers the highest wind revenue potential and favorable price lock-ins in the capacity market. However, the significant transmission constraints and curtailment risk in this region may make development in other ISOs more favorable.

EXHIBIT 1. INVESTMENT CONSIDERATIONS

	PJM	ISO-NE	NYISO	SPP	ERCOT
Energy Market	Face penalties and receive LOC payments for deviations	Exempted from some deviation charges	No deviation charges	Deviations face penalties with exceptions; eligible for uplift	Penalty for deviations, but can change commitment
Capacity Market	2 settlements 3-year forward	2 settlements 3-year forward 7-year price lock-in	Single settlement; prompt auctions	Self-supply	Self-supply; scarcity pricing in energy market
Renewable Credits	Yes—REC market; lowest pricing	Yes—REC market; highest pricing	Yes—contracts	No	No
Transmission Cost Allocation	Less favorable	Less favorable	Less favorable	Favorable	Very favorable
Wind Potential (Premium Sites)	Less favorable	Less favorable	Less favorable	Very favorable	Very favorable
Wind Revenue Potential	Moderate—location dependent	Strong—location dependent	Moderate—location dependent	Moderate—location dependent	Moderate—location dependent

Energy Market Participation Rules and Pricing

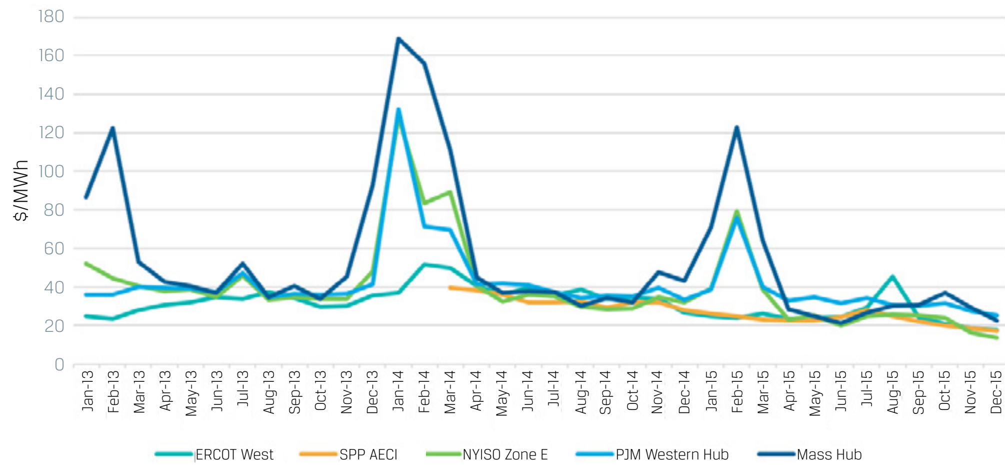
Wind facilities tend to derive much of their revenue from energy markets. RTOs that also operate centralized capacity markets tend to impose restrictive energy market participation rules on generating resources, including wind. For example, in ISO-NE, NYISO, and PJM, resources with capacity commitments are required to participate in the energy market. Of the three, PJM has the most stringent rules for participation: Resources must bid into both the day-ahead and real-time energy markets, whereas in ERCOT and SPP—which do not have centralized capacity markets—resources can, but are not required to, participate in the day-ahead and real-time energy markets.

Participation requirements matter because, in most markets, resources face penalties if they do not meet their energy market commitments. Wind resource is a function of weather, and weather can deviate from any forecast, presenting a significant risk for wind facilities. When it comes to penalties, NYISO offers the most flexible market for wind resources, as they do not face any deviation charges. ERCOT also presents a lax penalty system; wind resources face penalties for deviations from commitments, but resources may alter their commitment just 10 minutes in advance. ISO-NE generally imposes penalties for resource deviations, although wind units are exempted from some charges. SPP has deviation penalties for wind; however, since market participation is voluntary, resources could opt not to participate when wind availability is uncertain. PJM is the most rigid market of the bunch because capacity resources must commit in the day-ahead market and they face penalties for real-time deviations. However, PJM is not all bad for generators. While resources are beholden to their commitments, PJM is also beholden to theirs. If wind resources in PJM experience reduced dispatch for reliability reasons, they are eligible to receive a Lost Opportunity Cost (LOC) Credit[1] for the energy revenue the generators would have received had they been dispatched. The resulting reduction in curtailment risk makes PJM's rather draconian approach to penalty risk somewhat more palatable for investors and owners alike.

Energy market prices (Exhibit 2) have historically been the highest in the Northeast (ISO-NE, NYISO, and PJM). This has largely been driven by higher natural gas prices there, particularly in ISO-NE. Strong seasonality in natural gas prices has led to price spikes in the winter months, presenting additional upside potential for wind generators, considering they tend to produce more during these months.

[1] LOC compensation is equal to the (LMP price—cost at actual operating output) *(forecasted operation—actual operation).

EXHIBIT 2. HISTORICAL POWER PRICES IN ILLUSTRATIVE REGIONS (2012–2015)



Source: SNL Financial

Capacity Market Participation Rules and Pricing

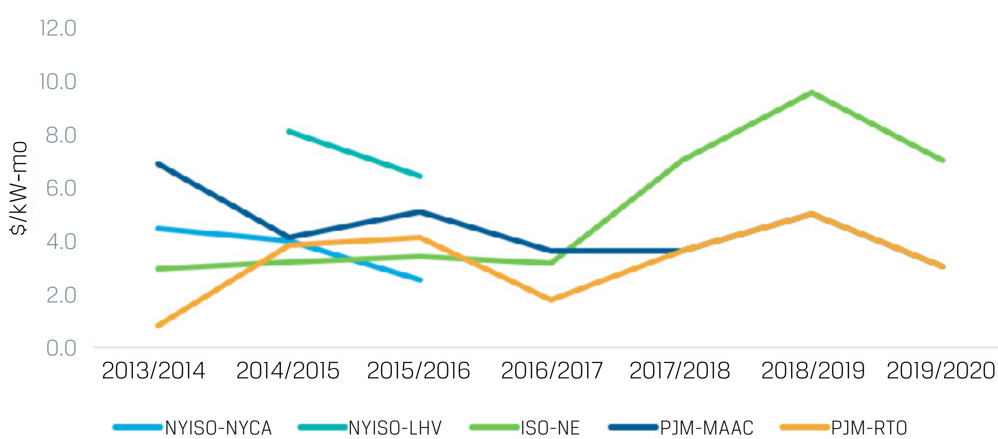
With caps on energy market prices, resources that are mainly used under peak conditions but are nonetheless necessary to achieve traditional levels of reliability are usually not fully valued by energy markets alone. The goal of the capacity market is therefore to ensure that demand can be reliably met even during the summer peak by providing the additional revenue that units may require to justify entry to (or remaining in) the market. This "lost revenue" cannot be obtained in the energy markets alone due to price caps and other ISO/RTO market power policing activities on the part of the market monitoring unit.

ERCOT and SPP have fundamentally different approaches to capacity markets compared to ISO-NE, NYISO, and PJM. The former rely on bilateral transactions and scarcity pricing in the energy market to adequately compensate resources, while the latter operate centralized auctions to procure capacity. While, theoretically speaking, both market systems will lead to the same overall revenue for a plant—that is, enough to compensate the going-forward cost of the marginal resource—the centralized capacity market has the additional benefit of allowing for future resource planning. Specifically in PJM and ISO-NE, whose capacity auctions are conducted three years in advance of the commitment period, developers for new wind facilities who participate in the auctions would have at least one year of guaranteed revenue if their facility clears the auction and comes online. ISO-NE is particularly friendly for development because of its seven-year price lock-in, allowing resources to lock in the capacity price they will receive for up to seven years.

However, due to the variable nature of wind resources' output, they receive capacity market payments for a significantly de-rated portion of their installed capacity. The default capacity de-rates in PJM and NYISO for on-shore wind are 13 percent and 10 percent, respectively. ISO-NE's capacity market bases a wind resource's de-rated capacity value on its historical average performance. Because of these de-rates, capacity payments represent a small portion of a wind resource's revenue.

In regions with centralized capacity markets, price volatility has historically been driven primarily by supply/demand balance and changes to market constructs. Exhibit 3 illustrates some of the cleared capacity prices in ISO-NE, NYSIO, and PJM. For the 2014/2015 and 2015/2016 delivery periods, the highest capacity prices were seen in the NYISO Lower Hudson Valley zone, while the lowest were in the NYISO NYCA region and ISO-NE. However, looking ahead to the forward auctions that have already cleared, capacity prices move significantly higher in ISO-NE post 2017 as a result of tight supply and a new market structure. With such large shifts seen in pricing dynamics, it is important to consider potential changes in regions' supply/demand balances and market rules when making wind investment decisions.

EXHIBIT 3. HISTORICAL CLEARED CAPACITY PRICES (2013–2019)



Source: ISO-NE, NYISO and PJM Auction Results

Renewable Resource Compensation

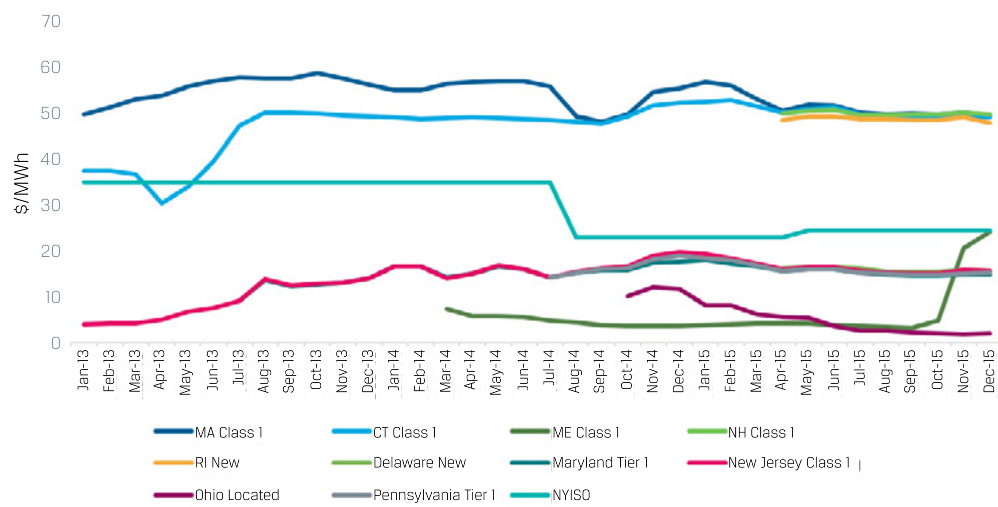
In order to meet state renewable portfolio standard (RPS) targets, ISO-NE, NYISO, and PJM all have additional compensation markets for renewable resources. In contrast, the wind development boom of the past six to eight years in SPP and ERCOT has created a long-term oversupply of renewables compared to any binding renewable targets, rendering additional compensation markets unnecessary.

State RPS policies in ISO-NE and PJM create markets where utilities can compensate renewables either through long-term Power Purchase Agreements (PPAs) or through the Renewable Energy Credit (REC) market. Even so, not all renewable resources are treated equally, as most state RPS policies have specific sub-targets for different technology classes that create multiple, distinct markets. New wind resources in these markets qualify as Tier (or Class) 1 resources and are generally compensated at a rate that is noticeably higher than the wholesale power rate. However, it is important to keep in mind that all of these REC markets are dictated by the structure and design of each state's RPS standards. As a result, although the risk is low, there is always the possibility that a state RPS policy could be altered or eliminated, which would affect both the opportunity and revenue available to renewable developers and existing sources of renewable generation.

Compared to ISO-NE and PJM, NYISO has an altogether different structure to both its RPS policy and in how the state compensates renewable generators. Rather than operating a REC market, NYSERDA solicits bids from qualifying renewable sources and provides long-term contracts to the lowest cost resources. NYSERDA has conducted eleven renewable solicitations since 2005 (including one in progress). To-date, these solicitations have resulted in 10-20 year contracts with 70 renewable assets totaling an aggregate capacity of 2.2 GW. However, change may be coming to New York's renewable markets. The state is currently in the process of significantly increasing its renewable energy goals and is also considering changes to the structure of its renewable markets that would incorporate elements seen in PJM and ISO-NE, including a REC market.

Exhibit 4 provides the historical renewable premium in the ISO-NE, NYISO, and PJM states. Tier 1 REC prices in ISO-NE have been more than double PJM REC prices and NYISO contract prices. However, despite ISO-NE's attractive pricing, developers looking to minimize risk may prefer the stability of the NYSIO contract market.

EXHIBIT 4. AVERAGE HISTORICAL REC PRICES (2013–2015)

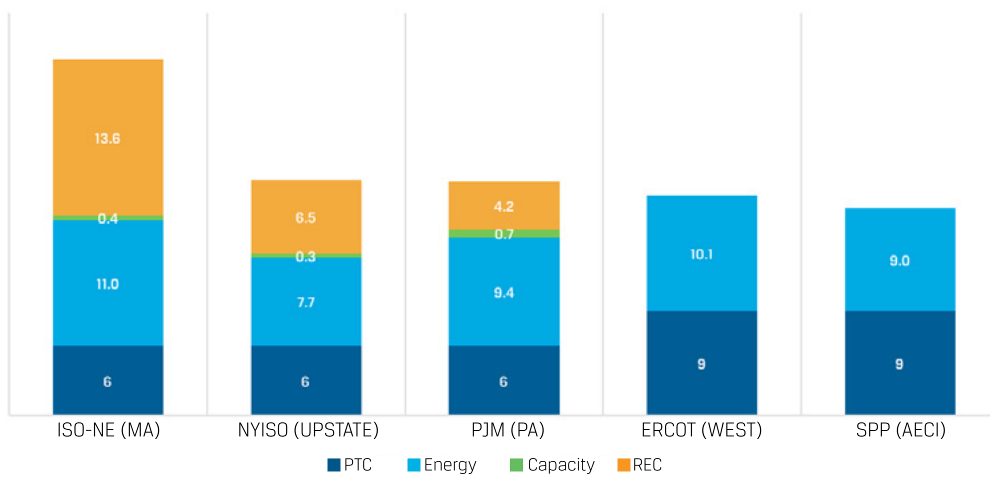


Source: SNL Financial

Wind Revenue Potential Across Regions

To underline the potential revenue across regions, Exhibit 5 illustrates the energy, capacity, REC, and PTC revenue of a hypothetical 100 MW wind facility in each region. Both market prices and expected capacity factors impact a facilities' revenue potential. To capture illustrative differences in wind potential across markets, the hypothetical plant is assumed to have a 30 percent capacity factor in ISO-NE, NYISO, and PJM. While in SPP and ERCOT, because there is better wind resource potential in these regions, the plant is assumed to have a 45 percent capacity factor. For capacity market payments, the facility is assumed to have the default reserve margin contribution of on-shore wind for each region.[2] In this simplistic comparison, excluding any considerations for curtailment or energy market penalties, the highest potential revenue is seen in ISO-NE. While there is variation in all three markets (and even within a given ISO) ISO-NE has seen the highest market prices, followed by PJM, NYISO, ERCOT, and SPP. Even though ERCOT and SPP have historically had lower market energy prices, and do not offer capacity payments or renewable credits, the higher expected wind generation in these areas, leads to the potential revenue being comparable to that of PJM and NYISO. The high potential revenue in ISO-NE provides an attractive incentive for wind development; however, one must also consider the relative interconnection and other costs at a given site, which can be high in ISO-NE.

EXHIBIT 5. ILLUSTRATIVE REVENUE OF A 100 MW WIND FACILITY IN 2015 ACROSS REGIONS ($MM)[3]



Source: ICF

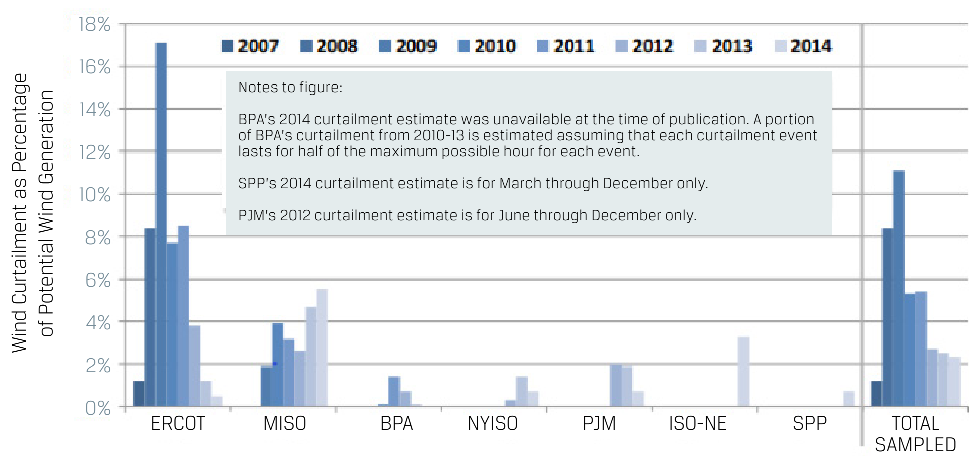
[2] PJM default capacity de-rate is 13%. NYISO default for on-shore wind is 10%. ISO-NE assumed de-rate is 10%.

[3] ISO-NE energy revenue reflects Mass Hub and REC pricing reflects Massachusetts Tier 1. NYSIO energy pricing reflects Zone E and capacity pricing reflects NYCA. PJM energy pricing reflects Western Hub, capacity pricing reflects PJM – MAAC, and REC pricing reflects Pennsylvania Tier 1. ERCOT energy pricing reflects ERCOT West. SPP energy pricing reflects AECI. PTC assumes $23/MWh credit.

Transmission Considerations

Sites with the most favorable geographic conditions for wind tend to be in rural areas, located far from load centers. Wind development in these remote areas can strain the existing transmission system, leading to negative pricing and curtailment risk for generators. When considering where to site a new wind facility, transmission considerations are at the heart of the issue. Markets with greater socialized transmission costs are more favorable for wind development. ERCOT has been far ahead of the curve in this aspect. ERCOT conducts a system-wide assessment, and costs for both reliability and economic projects are allocated across the entire load. In 2005, the Texas legislature passed the multi-billion dollar Competitive Renewable Energy Zone initiative in anticipation of wind development, primarily in the western regions of the state. CREZ transmission lines were energized in 2013/2014 and helped reduce wind curtailment in the state from a high of 17 percent in 2009 to 0.5 percent in 2014 (Exhibit 6).[1] SPP's Highway/Byway cost allocation approach is also favorable for wind development. All transmission projects greater than 300 kV—reliability and economic—identified as Base Plan Upgrades (BPU) are allocated regionally. PJM, NYISO and ISO-NE markets have a less favorable load ratio share cost allocation approach.

EXHIBIT 6. HISTORICAL WIND CURTAILMENT LEVELS



Source: Department of Energy, *Wind Technologies Market Report 2014*.

Next Steps

Developers must consider market participation rules, market pricing, and transmission considerations across regions when considering where to build a new wind facility. The northeastern regions, particularly ISO-NE, offer the markets and prices to incentivize wind development. However, the risk of real-time deviation penalties and transmission congestion present risks there that require careful consideration. Even within a given ISO, differences in pricing and transmission availability can drastically change the outlook on a given wind facility.

[1] Department of Energy, *Wind Technologies Market Report 2014*.

ICF is well positioned to help stakeholders navigate and analyze wind investment opportunities. ICF has expertise in a broad range of offerings essential to wind investment, including renewable power market supply and demand analysis, transmission and wind integration analysis, project strategy development and support, power purchase agreement development, renewable energy request for proposal process design and development, renewable asset valuation, and hedge and risk management strategy analysis.

About the Authors

George Katsigiannakis, Principal, George Katsigiannakis is an expert in U.S. electricity markets and has a deep understanding of all factors affecting U.S. wholesale electric markets, including market design, environmental regulations, fuel markets, transmission, renewables, energy efficiency, and demand-side management. Mr. Katsigiannakis joined ICF in 1997 and has been involved in a large number of projects, including several forward price curve assessments, development support, and financial performance of generation assets. He works in the areas of energy modeling, wholesale market assessments, asset valuations, restructuring, and litigation support as well as contract evaluation and risk assessments. Mr. Katsigiannakis earned a B.S. in Industrial Engineering from Technical University of Crete, Greece, an M.Sc. in Operations Research from The George Washington University and completed the doctoral course work on stochastic modeling and optimization.

Himali Parmar performs analysis in generation, transmission, and ancillary services valuation; transmission studies; and utility restructuring. Her expertise includes forecasting transmission congestion and losses and their effect on locational power prices and plant dispatch in the U.S. power markets.

After earning a master's degree in Electrical Engineering from University of Wisconsin, she was an intern with the American Transmission Company. She did load flow and contingency analysis to develop short-and long-term transmission system plans for the transmission planning group. While a student at University of Wisconsin, Ms. Parmar was a teaching assistant for undergraduate courses in the Electrical Engineering Department.

Rachel Green, Analyst, Rachel Green specializes in modeling and analysis of the U.S. wholesale power markets. She has experience in the areas of market assessment, asset valuation, and development support for private sector clients.

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For more information, contact:

George Katsigiannakis
george.katsigiannakis@icf.com +1.703.934.3223

Rachel Green
rachel.green@icf.com +1.703.225.2401

Himali Parmar
himali.parmar@icf.com +1.703.934.3497