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Capacity market design and renewable energy: Performance incentives, qualifying capacity, and demand curves

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ABSTRACT

A review of capacity markets in the United States in the context of increasing levels of variable renewable energy finds substantial differences with respect to incentives for operational performance, methods to calculate qualifying capacity for variable renewable energy and energy storage, and demand curves for capacity. The review also reveals large differences in historical capacity market clearing prices. The authors conclude that electricity market design must continue to evolve to achieve cost-effective policies for resource adequacy.

1. Approaches to ensure resource adequacy

A longstanding challenge in electric power systems has been the question of how to ensure long-run resource adequacy and system reliability. In general, resource adequacy paradigms can be categorized as traditional rate-of-return regulation and centralized planning, energy-only markets, and different forms of capacity markets and payments (Bushnell et al., 2017; Hogan, 2005; Cramton and Stoft, 2006). In an ongoing debate over the necessity of specific capacity mechanisms covered extensively in the literature, proponents argue that imperfections in wholesale energy markets fail to achieve a least-cost portfolio of resources that satisfy consumer reliability preferences (Joskow, 2008; Cramton and Stoft, 2006). A number of reviews of capacity markets in the United States exist (e.g., Bushnell et al., 2017; Bhagwat et al., 2016; Porter et al., 2015; FERC, 2013). However, as market rules are complex and constantly evolving, it is worth revisiting these issues regularly. In this paper, we provide an updated review of selected rules and operating procedures for the four formal capacity markets in the United States, with a focus on factors that are of particular relevance to variable renewable energy (VRE) resources.

PJM, ISO-NE, MISO, and NYISO are independent system operators/regional transmission organizations (ISOs/RTOs) that all operate centralized capacity markets. Table 1 summarizes general characteristics of these markets, illustrating differences in capacity procurement methods, auction procedures, and products. Note that ISO-NE bundles capacity obligations with financial call options to supply energy when the energy price rises above a specified strike price (ISO-NE, 2016b). In this sense, the ISO-NE capacity market is similar to a so-called reliability options model, as proposed by Vazquez et al. (2002) and Oren (2005), while PJM, NYISO, and MISO all conduct forward capacity markets. Among the other regional electricity markets in the United States, CAISO and SPP also impose resource adequacy requirements on load-serving utilities but without a centralized capacity market. In contrast, ERCOT relies on an energy-only market with high price caps and a real-time price adder that reflects the marginal value of available operating reserves to provide incentives for investments and resource adequacy.

In this paper, we explore several sources of heterogeneity in current centralized capacity market designs in the United States. Our review includes incentives for firmness of capacity and penalties for non-performance, as recent attention has been given to the importance of performance incentives in capacity markets (FERC, 2013; Mastropietro et al., 2015, 2016). Moreover, we discuss how the capacity markets use different approaches to calculate the qualifying capacity of VRE and energy storage in contributing to system reliability, an issue that is becoming more important as the installed capacity of these resources grows. For instance, Bothwell and Hobbs (2017) illustrate how capacity credit calculations of wind and solar have significant impacts on market efficiency. We also review system requirements for capacity, with a focus on the different methodologies used to determine downward sloping capacity demand curves. Finally, we briefly analyze how historical prices in the four capacity markets evolved over time and relate

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Table 1
Comparison of general capacity market characteristics.

ISO/RTO	Capacity Procurement	Auctions	Planning Horizon	Zonal Requirements	Must Offer and Bidding Provisions
PJM	Centralized market Forward Contract	Base Residual Auction Incremental Auction	3 years prior to annual delivery 20,10, and 3 months prior to annual delivery	System-wide price zone plus 12 Locational Delivery Areas (subzones). No direct mapping to PJM load zones	Must offer into day-ahead market (DAM)
ISO-NE	Centralized market Capacity contract with financial call option for energy	Forward Capacity Auction Annual Reconfiguration Auctions (ARA1, ARA2, ARA3) Monthly Reconfiguration Auction	3 years prior to annual delivery 24, 8, and 3 months prior to annual delivery 2 months prior to monthly delivery	System-wide price zone and 2 subzones 1. South East New England 2. Northern New England	Must offer into DAM and real-time market (RTM), must schedule maintenance with ISO
MISO	RA Requirement: Bilateral contracts or voluntary centralized market Forward Contract	Planning Resource Auction	1 year prior to annual delivery	10 Local Resource Zones, each with separate requirement	Must offer full cleared unforced capacity into DAM, with exception for scheduled maintenance. Also applies to VREs and participating external resources
NYISO	Centralized market Forward Contract	Capability Period Auction/Strip Auction (6 months) Monthly Auction Spot Market Auction	At least 30 days prior to each 6 month delivery period For any remaining month in 6 month capability period For upcoming month only	System-wide New York Control Area zone and three subzones	Resources must offer their unforced capacity into the DAM.

to the reported capacity margins in the respective systems, before concluding with a brief discussion on the outlook for capacity markets in the United States.

2. Selected capacity mechanism design features

2.1. Incentives for operational performance

While performance incentives were part of some early capacity market design recommendations (e.g. Cramton and Stoft, 2006; Batlle and Pérez-Arriaga, 2008), it is only in recent years that U.S. markets have begun to implement direct penalties for non-performance of capacity supply obligations. Financial penalties for under-delivery of capacity have been shown in conceptual and empirical work to positively impact market outcomes (Mastropietro et al., 2015, 2016). In this section, we discuss the implementation of explicit performance incentives in U.S. capacity markets.

2.1.1. Overview of U.S. markets

At the outset, we note that the energy-only market approach, as in ERCOT, implicitly provides a strong performance incentive: if a resource is not available to produce when prices are high, it loses scarcity revenues and may not achieve cost recovery. A capacity mechanism based on reliability options, as in ISO-NE, could lead to the same short-term incentives, as resources must pay the difference between energy market clearing prices and the strike price during non-performance (ISO-NE 2016b). Another important consideration is that allowable capacity market bids are usually based on unforced capacity (UCAP), i.e. the installed capacity (ICAP) of a resource derated for the expected level of outages. Since updates to the calculated UCAP values are based on prior-period availability, this also serves as an indirect performance incentive.

PJM is transitioning to a more stringent performance requirement in its capacity market by requiring 100% Capacity Performance Resources beginning with the 2020/2021 delivery year. These resources must be available throughout the entire delivery year whenever PJM determines emergency conditions exist (PJM, 2017a). Eligible resources that clear the auction are subject to PJM's Non-Performance Assessment during the delivery year. Resources that overperform receive a Bonus Performance Credit and resources that underperform must pay a Non-Performance Charge. PJM compares actual metered output against expected performance to determine a Performance Shortfall in each performance assessment hour, which are the hours when PJM declares emergency conditions (including certain warnings and pre-emergency actions).

The expected performance of a generation resource is equal to its committed UCAP multiplied by an adjustment factor, capped at 1. The adjustment factor is the sum of the total amount of actual performance for all generation resources, net energy imports (only included for PJM-wide emergency events), and the total demand response bonus performance, all divided by the total amount of committed UCAP of all generation capacity resources. The shortfall is calculated net of exempt MWs unavailable due to approved reasons, including planned maintenance outage MWs for which the resource was online but scheduled down by PJM. The actual performance may not exceed the MW level at which the resource was scheduled and dispatched. The hourly Non-Performance Charge for underperforming resources is calculated as the product of the shortfall and the Non-Performance Charge Rate.

The Non-Performance Charge Rate for Capacity Performance Commitments is calculated as the net cost of new entry (CONE) (in $/MW-day) in ICAP terms for the local delivery area in which the resource resides multiplied by 365 days and divided by 30, the anticipated number of hours per year PJM expects emergency actions to be in effect. A resource performing above expectations will receive a share of the total revenues collected from underperforming resources, as a fraction of the total bonus performances of all resources.