Institute *for* Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

ELECTRICITY POLICY INSIGHTS

Resource Adequacy in a Decarbonized Future

Wholesale Market Design Options and Considerations

March 2021

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Executive Summary

Electricity supply must match electricity demand at each instant to prevent outages. Thus, the reliability of electricity supply depends on there being both an adequate set of generation resources to meet the highest level of demand and a system capable of delivering power from those resources to end-users. This report focuses on the first of those two components: the sufficiency of generation capacity, termed "resource adequacy."

Different jurisdictions employ different approaches to resource adequacy. This report focuses on those jurisdictions that use wholesale market mechanisms to incentivize sufficient generation capacity. Broadly, the approaches taken in those jurisdictions can be divided into two types: energy-only, in which revenues from payments for electric energy must cover the costs of investing in generation as well as operating it; and what we call energy-plus-capacity payments, in which a price cap in the energy market limits prices that could be paid for energy, leaving a deficit that is filled in by payments for capacity. In all jurisdictions, those mechanisms were designed to support investments in conventional, thermal generation resources, most of them reliant on fossil fuels. Consequently, the growing presence of renewables on the grid has raised concerns about whether existing approaches to resource adequacy—energy-only and energy-plus-capacity payments alike—can continue to serve the changing electricity sector efficiently. Similar but differently motivated concerns arise from evidence suggesting that existing approaches to resource adequacy embody biases that favor fossil-fueled generation and tilt the field against renewables.

This report examines these concerns by looking to the relevant economics and policy literature, and to the empirical evidence gathered by regulators and researchers. It finds that both types of approach are flexible enough to be compatible with scenarios in which renewables are pervasive. Indeed, in principle, each approach can arrive at the same outcome. But this report also finds that a region's approach to resource adequacy can bear on the pace of renewables' deployment, and that relying on capacity payments creates more opportunities to favor thermal resources and impede renewables.

Recognizing that the political challenges of adopting and maintaining an energy-only approach to resource adequacy make capacity payments a likely feature of most regions' approach, this report takes a close look at how capacity payments can favor some resources over others and suggests steps to avoid or at least mitigate such discrimination. Those steps, which include improving energy price formation, increasing demand responsiveness, expanding the availability of hedging instruments, refining capacity demand curves and available capacity products, and updating non-performance penalties can make energy-and-capacity market designs friendlier for renewables. Notably, several of the suggested improvements would be applicable in energy-only settings as well as those where energy-plus-capacity payments operate. Individually and in combination, those incremental changes would make markets more capable of efficiently facilitating the transition to renewable resources.

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I. Introduction

If electricity supply does not match demand at each instant, a widespread blackout can occur. Having, at each instant, sufficient generation capacity ready to match electricity supply to demand is called "resource adequacy."[1] It is distinct from reliability, which additionally concerns the ability to deliver power over a stable electric grid in spite of disturbances. This report considers the relationship between resource adequacy and renewable energy. More specifically, it examines whether current approaches to resource adequacy are capable of ensuring that the lights stay on in high-renewables deployment scenarios, and considers how different approaches to resource adequacy can affect the pace and pattern of renewables' deployment. Based on this examination, it concludes that, while certain adjustments are necessary, current approaches to resource adequacy are indeed compatible with maintaining system reliability *and* operating a renewables-heavy grid. It then provides recommendations for market design measures that can support the cost-effective provision of resource adequacy amid continued deployment and integration of renewables into the grid.

The feasibility of an approach to resource adequacy depends most fundamentally on whether the dispatch of electricity in a given region is coordinated through centralized wholesale energy markets or vertically integrated utilities. Because regions with organized wholesale electricity markets contain the majority of generation capacity and load nationwide,[2] this report focuses its attention there. Particularly in regions where generators recover their costs of investing in generation capacity through organized wholesale markets rather than pursuant to state-regulated integrated resource planning (IRP), the structure and operation of those wholesale markets makes ensuring resource adequacy relatively complex.[3] Most importantly, those markets must provide sufficiently strong investment signals to generation owners to build an adequate fleet of resources. By contrast, in regions without organized wholesale markets, resource adequacy mechanisms involve bilateral contracting, with state economic regulators (in coordination with vertically integrated utility companies) deciding what resources to build and maintain through administrative processes and competitive procurements.[4]

Resource Adequacy Basics

Electricity's characteristics complicate the task of constantly matching supply and demand to maintain resource adequacy—for one, it is expensive to store electricity in large quantities. Consequently, maintaining resource adequacy necessitates correctly predicting patterns of both supply and demand. On the supply side, this requires evaluating what amount of electricity diverse available resources—ranging from conventional power plants, to utility-scale renewables, to flexible and distributed resources—will be capable of providing when required. This evaluation cannot simply add up resources' maximum outputs under conditions specified by the manufacturer (termed "nameplate capacity"). Instead, it involves specifying each resource's maximum possible output in the conditions particular to the times and place in which it actually operates. On the demand side predictions can also be challenging because key demand-side inputs, such as the timing, frequency, intensity, and duration of weather events, can never be known in advance, but those events can spark

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1 *See* Planning Resource Adequacy Assessment Reliability Standard, 134 FERC ¶ 61,212, P 6 (2011) ("'Resource Adequacy,' [] is defined as the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses).").

2 *About 60% of the U.S. Electric Power Supply Is Managed by RTOs*, U.S. Energy Info. Admin. (Apr. 4, 2011).

3 In some of the centralized wholesale trading regions, like California, resource adequacy is in the hands of state regulators who employ non-market mechanisms to maintain it.

4 For regulated, vertically integrated utilities, processes like IRP are frequently used to model and plan the optimal set of resources needed to ensure resource adequacy. There also exist hybrid resource adequacy approaches which combine IRP with market-based resource adequacy approaches.

dramatic spikes in electricity consumption to levels well above normal. Further, the adoption rates for technologies like electric vehicles and rooftop solar are hard to predict with precision, but those technologies significantly change load patterns and make them more dynamic, compounding the challenge of forecasting electricity demand.

These inherent uncertainties make it prohibitively expensive to ensure that there is *always* sufficient generating capacity to prevent *any* outage. Even in a situation where capacity significantly exceeds expected demand, a combination of unexpected occurrences could still cause consumption to surge and limit grid operators' ability to meet it with operational resources. So, in practice, approaches to maintaining resource adequacy aim to keep the frequency of outages due to insufficient generation capacity below a certain level, rather than to prevent them completely. On pages 19-23, this report discusses how an August 2020 heatwave and February 2021 cold snap caused events of this sort in California and Texas respectively.

Resource Adequacy Standards

While there is no mandatory, nationwide standard for resource adequacy, most systems use the so-called 1-day-in-10-year standard, or 0.1 Loss of Load Expectation (LOLE). This standard—which is very stringent and, consequently, costly[5]—requires that the system experience no more than one outage every 10 years due to inadequate capacity. A few regions prescribe resource adequacy requirements other than this 1-in-10 standard, such as a minimum capacity surplus margin over the highest monthly forecasted load.[6]

"Market design" is a term used to describe the rules and incentive structures that are meant to translate resource adequacy specifications, such as a planning reserve margin,[7] into investments and operational capabilities. Regions' approaches to market design and compensation are more diverse than their choices of reliability standard. This is not only true from one country to another—even within the United States regions' approaches vary, with the two most important approaches being energy-only and energy-plus-capacity markets.[8] In all regions, however, the imperative to maintain a resource fleet capable of meeting aggregate demand is complicated by features of the electricity marketplace, such as time-invariant retail rates that make demand unresponsive to changes in supply and the imposition of legal obligations to serve consumer demand.[9] Market designs intended to solve the resource adequacy problem need to strike a workable balance between the competing priorities and obligations under which electricity market stakeholders operate.[10]

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[5] Estimates suggest that, in order to justify the stringent 1-in-10 standard, the social damages from 1 MWh of load being curtailed (beyond the 1-in-10) would need to equal approximately $300,000. *See* Astrape Consulting, The Economic Ramifications of Resource Adequacy White Paper (2013), https://perma.cc/GP3K-28D5.

[6] *See* James Bushnell, Michaela Flagg & Erin Mansur, *Capacity Markets at a Crossroads* 32 tbl.3 (Energy Institute at Haas Working Paper No. 278, 2017), https://perma.cc/6UJK-R74K.

[7] The North American Electricity Reliability Corporation (NERC) describes a reserve margin as the "percentage of additional capacity over load," meaning the amount of capacity in excess of the highest annual load peak that should be available "to meet unforeseen increases in demand, unforeseen outages of existing capacity, and trends which will identify whether capacity additions are keeping up with load growth." NERC, Reliability Metrics Specifications Sheet ALR 1-3 Reserve Margin (2009).

[8] *See* Figure 5 (describing available resource adequacy approaches with examples), *infra*, and accompanying text.

[9] Steven Stoft famously dubbed these "demand-side flaws." Steven Stoft, Power System Economics 15–16 (2002). Resource adequacy being a public good, and the fact that markets generally underprovide public goods, also contributes to market design considerations. *See* Paul L. Joskow, *Capacity Payments in Imperfect Electricity Markets: Need and Design*, 16 Util. Pol'y 162, 165 (2008).

[10] For a good introductory discussion of how these constraints bear on regions' market design options, see Peter Cramton & Steven Stoft, The Convergence of Market Designs for Adequate Generating Capacity with Special Attention to the CAISO's Resource Adequacy Problem: A White Paper for the Electricity Oversight Board 8–11 (2006), and see generally Peter Cramton, *Electricity Market Design*, 33 Oxford Rev. Econ. Pol'y 589 (2017).

Key Terms: Resource Adequacy, Reliability, and Resilience

While resource adequacy certainly relates to electricity reliability and resilience, it is also narrower than they are.[11] System reliability, as noted above, measures not only whether generation capacity is sufficient to serve consumers' aggregate demand for electricity, but also how well the transmission and distribution systems that link generation to end-users operate. Resilience in the electricity context measures the ability of a given system, whether an individual building or the electricity grid as a whole, to bounce back from an outage.[12] Resource adequacy is thus an indispensable input into electricity reliability and resilience, both of which rely on a variety of inputs but would fail without the capacity on which resource adequacy is focused.

Renewables' Proliferation and Resource Adequacy

The proliferation of renewables is sure to effectuate changes to important features of electricity markets, and so may require adjustments to legacy approaches to resource adequacy as well. Renewables' operational characteristics modify the short- and long-term supply-side uncertainties at play in wholesale electricity markets. In particular, renewable generation is variable across seasons and days as well as being intermittent, meaning that its output level depends on external conditions such as weather and cannot be fully controlled. These features make it somewhat harder to know how much renewable generation will be available at any given moment, especially when planning years in advance.[13] (Notably, however, renewables' presence also mitigates some supply-side uncertainties, such as fuel supply.) Additionally, prevalent renewables can reduce energy prices because, once they are built and connected to the grid, it costs very little for them to produce an additional unit of energy as they have no fuel input costs. The resulting price changes can affect investment incentives—though, as explained below, concerns about adverse consequences of this effect tend to be overblown.

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[11] *See* Astrape Consulting, *supra* note 5, at 7 (noting that resource adequacy failures are responsible for a small fraction of the outages that impair reliability, the majority being the result of distribution system problems).

[12] *See* Burcin Unel & Avi Zevin, Inst. for Pol'y Integrity, Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System 4–5 (2018), https://policyintegrity.org/files/publications/Toward_Resilience.pdf; *see also* Conn. Pub. Utils. Reg'y Auth., Distributed Energy Resources in Connecticut—Draft (2020) (describing how resilience benefits accrue differently and in overlapping ways to individuals, communities, and the electricity system).

[13] In the past, it was sufficient to know the joint probabilities of generator outages and of the electricity demand being above the normal levels to establish the amount of generation needed to meet resource adequacy standards. Steven Corneli, A PRISM-Based Configuration Market for Rapid, Low Cost and Reliable Electric Sector Decarbonization 21 (2020), https://perma.cc/X5FB-CXKP. With intermittent resources, correlations in the output of various resources at all locations are an additional factor for assessing resource adequacy. Intermittency also induces higher output uncertainty, complicating the analysis.

Renewables on the Rise

The technological and policy developments that drive the proliferation of renewables are expected to continue along their current trends, if not accelerate.[14] First, technological improvements are causing renewables to become increasingly cost-competitive with traditional generators, and to siphon off at least some of the revenues that would otherwise flow to traditional generators.[15] Second, renewable generation, which many policymakers and corporations consider necessary for the achievement of their climate and clean energy goals, receives financial support through subsidies, renewable portfolio requirements, and voluntary corporate procurements. The pursuit of increasingly ambitious clean energy targets by governments and corporations can be expected to yield continued support for renewables' deployment. Indeed, President Joseph Biden, during his election campaign, has promised a non-emitting electricity sector nationwide by 2035, and many states have similarly ambitious goals for their territories, achievement of which will necessarily involve strong decarbonization policies.[16] Whether those policies are implemented in the form of supportive policies for renewables, pollution pricing schemes, or other forms of commitment to clean energy, renewables will continue to enjoy a strong position in the market.[17] Further, corporate clean energy commitments are significant and growing in scale.[18]

The potential need to modify design elements of the electric grid and wholesale markets that were originally crafted with conventional resources in mind will intensify in the coming years, given renewables' growth. Regulators have been investigating whether and how different approaches to resource adequacy are compatible with high levels of renewables deployment,[19] and blackouts in California in August 2020 and in Texas in February 2021—discussed in depth below—have turned public attention to that and related issues as well. By grounding its analysis in the findings of economic research, this report seeks to contribute rigorous conclusions and insights to these debates.

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14 U.S. Energy Infor. Admin., Annual Energy Outlook 2020, at 3 (2020), https://perma.cc/SXP3-77FY ("The electricity generation mix continues to experience a rapid rate of change, with renewables the fastest-growing source of electricity generation through 2050 because of continuing declines in the capital costs . . . .").

15 *Id.*

16 Biden Harris Campaign, *The Biden Plan to Build a Modern, Sustainable Infrastructure and an Equitable Clean Energy Future*, https://perma.cc/E6WG-QSNQ (last visited Dec. 22, 2020).

17 Supportive policies for renewables partly compensate for the fact that emitting generators in the energy sector do not pay for the societal damages they cause by emitting greenhouse gases and local air pollutants like sulfur oxides and particulate matter, which pose health hazards. Those policies thus have similar incentive effects on renewables' deployment as emission pricing. *See* Sylwia Bialek & Burcin Unel, Inst. for Pol'y Integrity, Capacity Markets and Externalities: Avoiding Unnecessary and Problematic Reforms (2018), http://policyintegrity.org/files/publications/Capacity_Markets_and_Externalities_Report.pdf (comparing effects of renewable support programs and emission pricing policies).

18 Rob Hardison et al., Nat'l Renewable Energy Lab'y, Voluntary Renewable Energy Procurement Programs in Regulated Utility Markets 2–5 (2020) (tallying corporate clean energy commitments and purchases); *see also Corporate Clean Energy Buying Grew 18% in 2020, Despite Mountain of Adversity*, Bloomberg New Energy Fin. (Jan. 26, 2021) (describing trend).

19 *See, e.g.*, Mass. Att'y Gen. Off. & Reg'y Ass't Project, Wholesale Electric Design for a Low/No-Carbon Future: Report on the October 2019 Symposium & Proposed Next Steps (2020), https://perma.cc/AMK2-MEZ7; *see also* Sonia Aggarwal et al., Wholesale Market Design for Rapid Decarbonization (2019).

Clean Energy Policies and Resource Adequacy

Renewables can potentially affect the functioning of resource adequacy mechanisms but the reverse is also true: the choice of resource adequacy mechanism can meaningfully influence the scale and pace of investments in renewables.

For instance, in several regions, the rules governing resource adequacy have been applied in ways that significantly undermine states' support for the deployment of renewables and energy storage, and thereby help to protect the share of wholesale capacity market revenues flowing to fossil-fueled resources.[20] The adoption of such rules in three wholesale trading regions—PJM, ISO-New England, and New York ISO[21]—has been criticized for creating market barriers for renewable generation and storage, impairing market efficiency, and raising consumer costs.[22] Similarly, a recent fuel-security proceeding in ISO-New England threatened to reshape the approach to resource adequacy in that region[23] in a way that would boost revenues paid to fossil-fueled and nuclear resources to the detriment of renewables.[24]

The interactions between renewables and resource adequacy in regions with organized wholesale electricity markets will be particularly consequential for climate goals. The success of power sector decarbonization efforts hinges on outcomes in the wholesale trading regions administered by Regional Transmission Operators (RTOs).[25] These regions house the major coastal and midcontinent urban load centers, making them responsible for the majority of U.S. electricity sector carbon emissions.[26] And there is a great deal of overlap between regions with wholesale electricity markets and states that already have explicit clean energy goals in place (see Figure 1). Wholesale markets' approaches to resource adequacy will therefore inevitably interact with state-level clean energy goals.

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[20] Eric Gimon, Energy Innovation, Why the Clean Industry Should Be Interested in Resource Adequacy (2020), https://perma.cc/6RQ3-83ST.

[21] In all three regions, the rules limited access to capacity market revenue by clean resources receiving state subsidies. Kathryne Cleary, *What the Minimum Offer Price Rule (MOPR) Means for Clean Energy in PJM*, Resources Mag., Jan. 21, 2020; Jeff St. John, *FERC Dissents Reveal Continued Political Tension on Clean Energy Policy*, Green Tech. Media, Nov. 20, 2020.

[22] *See, e.g.*, Sylwia Bialek & Burcin Unel, Inst. for Pol'y Integrity, Capacity Markets and Externalities: Avoiding Unnecessary and Problematic Reforms 6 (2018), http://policyintegrity.org/files/publications/Capacity_Markets_and_Externalities_Report.pdf (noting economic validity of state clean energy policies and criticizing fundamental premise of MOPR's adoption); Michael Goggin & Rob Gramlich, Grid Strategies, A Moving Target: An Update on the Consumer Impacts of FERC Interference with State Policies in the PJM Region 6 tbl.2 (2020) (estimating costs of MOPR to consumers).

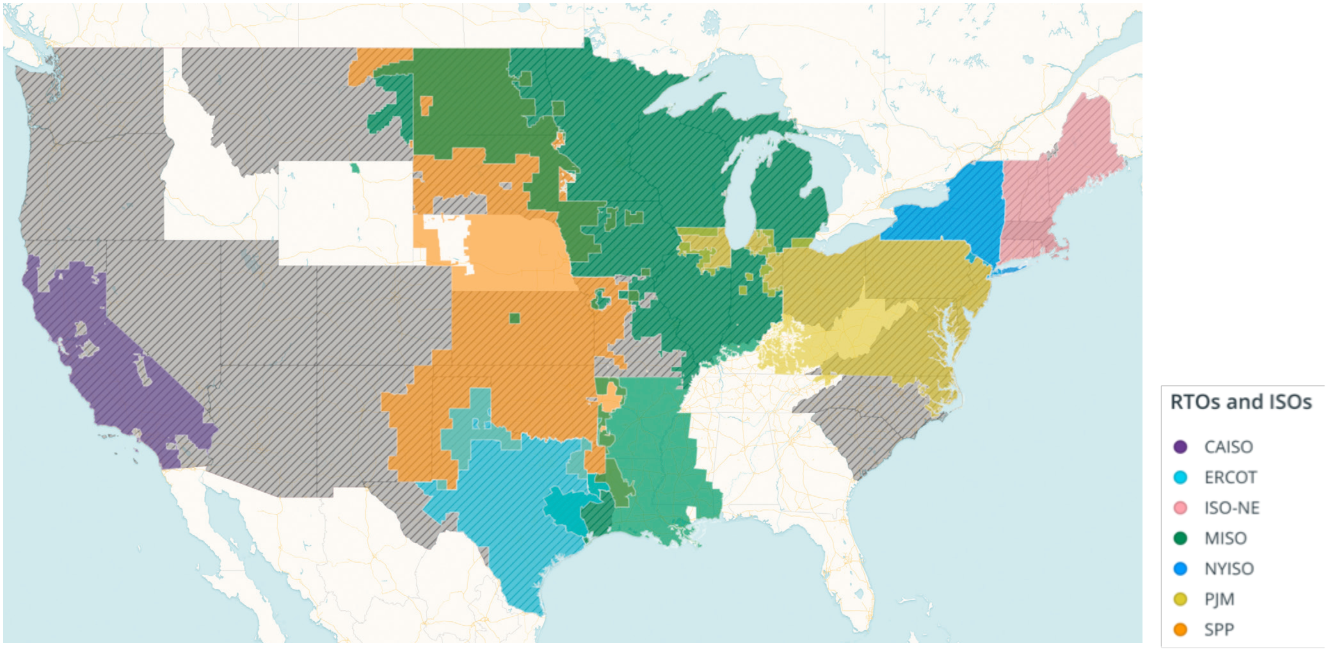
[23] Order Addressing Arguments Raised on Rehearing, 173 FERC ¶ 61,204 (2020); *see also* Gavin Bade, *ISO-NE Files Short-term Fuel Security Plan to Relieve Gas Constraints*, Util. Dive (Mar. 27, 2019) (explaining that renewable resources are not eligible for the Inventoried Energy Program, even though ISO-NE acknowledged that offshore wind can relieve grid stress during cold snaps).

[24] Resource adequacy regulations that obstruct renewables deployment have been considered at the state level as well. For instance, in Indiana, the 21st Century Energy Task Force, formed by Indiana's General Assembly, recommended passing a law that would create a mechanism "to assure generation and transmission resource adequacy throughout Indiana." 21st Century Energy Policy Dev. Task Force, Final Report 11 (2020). Given that in recent years large Indiana utilities have announced plans to close thousands of megawatts of coal-fired generating capacity and the Task Force cautioned against shifting to renewables too quickly, many fear that the recommendations will be used to create a resource adequacy mechanism that would favor fossil-fuel generation. *See* Sarah Bowman, *Indiana's Energy Future: Report Praises Renewables but Doesn't Rule Out Fossil Fuels*, Ind. Star, Nov. 20, 2020, https://perma.cc/4DHC-7F5P.

[25] In the United States, there are seven RTOs: Electric Reliability Council of Texas (ERCOT); Independent System Operator New England (ISO-NE); New York Independent System Operator (NYISO); Pennsylvania, New Jersey, and Maryland Interconnection (PJM); Southwest Power Pool (SPP); California Independent System Operator (CAISO); and Midcontinent Independent System Operator (MISO). *See* Figure 1. Notably, ERCOT is the only one of these that is not subject to federal regulation. *ERCOT*, Federal Energy Reg. Comm'n, https://www.ferc.gov/industries-data/electric/electric-power-markets/ercot (last visited July 13, 2020).

[26] The combined total annual load for ISO-NE, MISO, NYISO, and PJM was 1,756 TWh in 2015, while the total sales to ultimate customers in the United States totaled 3,759 TWh in 2015. *Table 1.2. Summary Statistics for the United States, 2009–2019*, U.S. Energy Info. Admin., https://perma.cc/H5UQ-QN8A (last visited Feb. 3, 2021). ISO-NE serves 14.8 million people, MISO 42 million, NYISO 19.8 million, and PJM 65 million. N. Am. Electric Reliability Corp., 2020 Summer Reliability Assessment 18, 22, 23, 26 (2020). The U.S. population is 330.1 million. *U.S. and World Population Clock*, U.S. Census, https://www.census.gov/popclock/?intcmp=w_200x402 (accessed Mar. 11, 2021).

Figure 1: Map of U.S. states with renewable portfolio standards and goals displayed with the U.S. footprint of all regions with wholesale electricity markets.



Not pictured: Hawaii, which has a renewable portfolio standard in place but no wholesale electricity market, and Alaska, which neither has a renewables target nor a wholesale electricity market. States with a mandatory renewable portfolio standard or a voluntary target in place are striped.[27]

Proposed Novel Approaches to Resource Adequacy

Currently, policymakers and stakeholders are engaged in an active conversation about how best to pursue the interacting objectives of ensuring resource adequacy and enabling the rapid deployment of renewables—all without driving up the costs ultimately paid by consumers.[28] Various proposed approaches have been presented in academic circles, as well as to state governments and RTOs and their stakeholders. For instance, New Jersey is considering new market designs for wresting control over resource adequacy within its borders from PJM.[29] New York is exploring a similar reclamation of authority over resource adequacy from its RTO, NYISO.[30] In ISO-NE there is also a push for capacity market reforms,[31] and innovative market designs with long-term resource adequacy contracts were discussed at a December 2020 academic conference.[32] The proposals are diverse. Table 1 lists three illustrative examples; it is not comprehensive.

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27 For underlying data, see *State Renewable Portfolio Standards and Goals*, Nat'l Conf. of State Legislatures (Jan. 4, 2021), https://perma.cc/5EZ4-NJLM; *Independent System Operators*, U.S. Dep't of Homeland Sec., https://perma.cc/6TGF-LXK5 (last visited Feb. 2, 2021).

28 *See, e.g.*, Frank A. Felder, NEPOOL's Pathways to the Future Grid Process: Project Report 7–8 (2021), https://perma.cc/FU9C-676B (identifying objectives and noting their interactions).

29 *See Investigation of Resource Adequacy Alternatives*, N.J. Bd. Pub. Utils., https://perma.cc/9VHL-GD8Z (last visited Feb. 21, 2021) (listing technical conference and work session presentations on resource adequacy and related proposals).

30 N.Y. Pub. Serv. Comm'n, Order Initiating Proceeding and Soliciting Comments, Case No. 19-E-0530 - Proceeding on Motion of the Commission to Consider Resource Adequacy Matters (Aug. 8, 2019); *see also* Kathleen Spees et al., Brattle Grp., Qualitative Analysis of Resource Adequacy Structures for New York (2020).

31 Jason York, *NE States Considering Different Market Models*, RTO Insider (Feb. 1, 2021) (reporting on resource adequacy proposals presented to states participating in New England Energy Vision workshop series); *see also* Kathleen Spees, The Brattle Grp., The Integrated Clean Capacity Market: A Design Option for New England's Grid Transition (Oct. 1, 2020) (presentation to NEPOOL).

32 *Market Design for the Clean Energy Transition: Advancing Long-Term Approaches*, World Res. Inst., https://www.wri.org/events/2020/12/market-design-clean-energy-transition-advancing-long-term (providing links to agenda and presentations to conference with Resource for the Future).

Table 1. Sample proposals currently discussed for resources adequacy design.

Proposal	Key features
Integrated Clean Capacity Market[33] (similar to Forward Clean Energy Market)[34]	Objective: select lowest-cost suite of clean and emitting resources that can meet specified objectives; • Allows participating states to each specify the total percentage of load they seek to procure from non-carbon emitting resources and, under some designs, the maximum amount of fossil fuel generation capacity they each are willing to rely on. • Establishes a downward sloping demand curve for capacity that is used to co-optimize energy and capacity procurement that conforms to state policy prescriptions. • Allows for voluntary participation by corporate sustainability buyers, retailers, cities, and others.
"Hybrid" market[35]	Objective: establish two compatible market mechanisms: one for long-term (up to 20-year) capacity procurement, the other for short-term (day-ahead and real time) energy procurement; • Subjects long-term capacity contracting opportunities to an extensive list of administratively specified parameters, potentially including technology-neutral or technology-specific criteria for participation and factors for valuation.
Voluntary residual market[36]	Objective: Remove impediments to states and other entities procuring resources that meet decarbonization goals while also securing capacity; • Adds a voluntary residual market mechanism to an RTO's centralized capacity market, and counts capacity acquired through the residual market toward regional resource adequacy requirements; • Allows state agencies and voluntary corporate purchasers, as well as utilities, to participate in the residual market, which can operate through bilateral contracting or centralized auctions.

Like this report, these proposals all consider how ensuring resource adequacy at reasonable cost interacts with ongoing, and accelerating, renewables deployment. But whereas these proposals would add new mechanisms to existing market structures or provide novel combinations of existing mechanisms, this report's recommendations focus on adjustments that could be made to existing market mechanisms in their current configurations. Even though we recognize that our recommendations and these novel proposals are potentially compatible, we do not analyze their merits.

[33] Kathleen Spees et al., The Brattle Grp., How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals through a Forward Market for Clean Energy Attributes (2019).

[34] *Id.*

[35] *See* Paul L. Joskow, Hybrid Electricity Markets to Support Deep Decarbonization Goals (Dec. 16, 2020), https://perma.cc/F8Y5-FA9X.

[36] Casey Roberts, Sierra Club, Voluntary Residual Capacity Markets to Facilitate Implementation of State Clean Energy Policies (Jan. 25, 2021), https://perma.cc/EL3F-NET8 (presentation for New England Energy Vision Wholesale Market Design Technical Forum).

Roadmap of this Report

In this report, we discuss how approaches to maintaining resource adequacy interact with the deployment of renewables. We study whether existing resource adequacy approaches can be effective in a high-renewables future, and we compare how those resource adequacy approaches affect the deployment of renewables.

Although this report identifies various approaches to ensuring resource adequacy, it closely examines just two: an energy-only market that employs scarcity pricing, and an energy-plus-capacity market. As we explain in Section II, these two approaches lie on opposite ends of the spectrum of resource adequacy approaches in wholesale markets. In Section II we also provide background information on how energy-only and energy-plus-capacity markets have functioned to date. In addition, we provide an overview of other resource adequacy approaches used in wholesale markets across the United States and internationally.

An insert between Sections II and III discusses recent blackout events in California and Texas. Resource adequacy is an important part—though not the entirety—of the story of each of those events. The summaries presented highlight the limited roles that regional approaches to resource adequacy played in each instance.

Section III then discusses the relationship between renewables and energy-only markets. It examines critically the misconception that higher renewable penetration will tend to decrease energy market revenues to such a degree that investments in any generation resources, including renewables, will become unsustainable, leading to a lack of resource adequacy. To rebut this argument, Section III shows that energy-only markets are capable of ensuring resource adequacy notwithstanding a large amount of renewable generation and many low-energy-price-hours, in part because maximum energy prices may increase significantly (in contrast to average energy prices, which will very likely decrease) when more intermittent resources are built. It follows that, although energy-only markets are compatible with high penetrations of renewables, stakeholders must be prepared to accept this price effect as renewables' presence grows.

Sections IV and V focus on the relationship between renewables and capacity market design. While capacity markets can ensure resource adequacy with any level of renewable resources, some elements of their current design favor fossil-fueled generators. However, most of the biases against renewables are not inherent to capacity markets, but the result of design choices that can be modified. We list and discuss modifications that could correct for the biases that lead capacity markets to disadvantage renewables. Section VI concludes.

II. Background on Electricity Markets and Resource Adequacy

In most regions of the United States, electricity is first traded in wholesale markets before being sold and distributed to households and most businesses through retail markets. Wholesale markets are run regionally and overseen by RTOs.[37] In all wholesale trading regions except ERCOT, which operates within Texas's borders, resources can receive remuneration not only for the sale of energy they generate but also for their committed capacity, meaning their ability to provide a specified amount of power at a particular time.[38] This is why ERCOT's market design is referred to as "energy-only," while the designs in wholesale trading regions which also compensate resources through a separate market for their capacity—that is, for merely being available to generate electricity—are referred to as "energy-plus-capacity" markets.

Before examining how resource adequacy approaches interact with renewables deployment, it is important to have a good grasp of how existing market designs operate. Therefore, we explain below the functioning of energy-only markets and energy-plus-capacity markets and discuss different options for capacity remuneration. Our discussion only covers mechanisms that have been used as part of existing market designs to ensure resource adequacy.

Energy-Only Markets and Resource Adequacy

To show how energy-only markets attract enough capacity to keep the lights on, we analyze ERCOT. ERCOT is the only RTO in the United States that uses an energy-only design to ensure resource adequacy and serve its customers, which number 26 million and live in an area encompassing about 75% of the land area in Texas.[39]

ERCOT's energy market, like every energy market, takes the form of regularly scheduled auctions. In each auction, resources submit offers consisting of the amount of energy they are willing to provide in a given time interval and the price they require per unit of energy. The RTO then chooses the cheapest set of offers that altogether cover energy demand. ERCOT also monitors how much power plant capacity is available on the grid to act as operating reserves. If the level of operating reserves falls below a certain threshold, ERCOT increases the clearing energy price by a price adder in the amount that reflects the value of the reserves as determined by a mechanism called Operating Reserve

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[37] For simplicity, we refer to all of the regional market operators as RTOs, even though some of them are formally organized as Independent System Operators.

[38] RTOs also feature an ancillary services market that procure services needed to meet technical requirements for the grid, such as regulation, spinning reserve, and others. *See, e.g.*, *Ancillary Services Market*, PJM, https://perma.cc/8CVL-MNC3 (last visited Mar. 14, 2021). However, the revenue from that market constitutes a negligible fraction of the total revenues and thus we ignore it in our analyses.

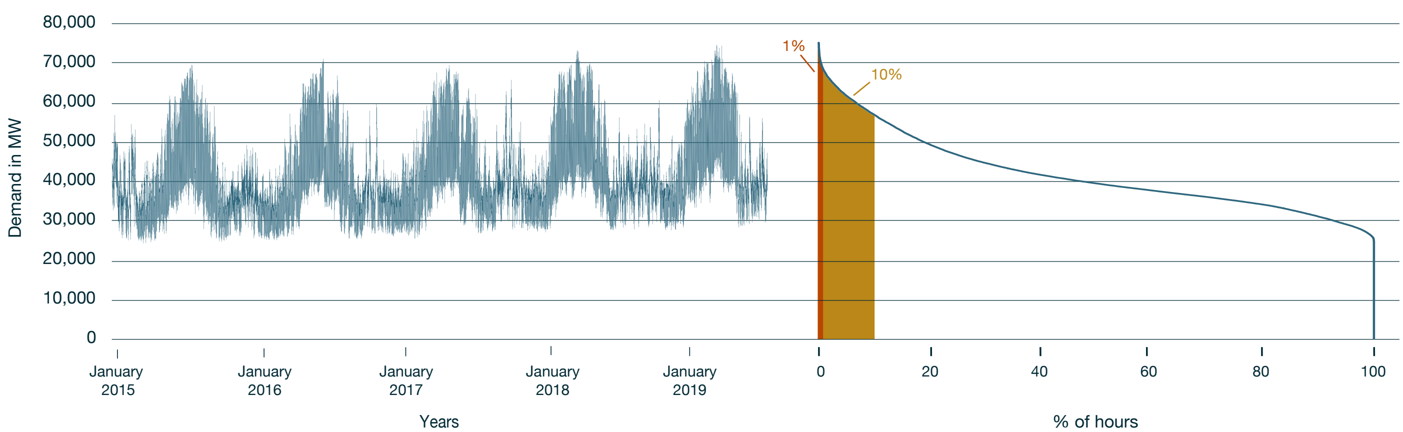
[39] ERCOT does not represent a pure energy-only market. Mechanisms outside energy market, such as Emergency Response Service and the Texas renewable portfolio standard, have helped maintain the resource adequacy in ERCOT over years. ERCOT also uses an energy price cap—referred to as a high system-wide offer cap, or SWOC—which is set at $9,000/MWh, far above the highest allowable prices in other regions. *See Electricity: Regional Wholesale Markets: November 2020*, U.S. Energy Info. Admin. (Jan. 26, 2021) (charting energy prices in other markets). Under a narrow set of conditions, a so-called "low system offer cap" (LCAP) can replace SWOC. The LCAP is currently at $2,000/MWh, or 50 times the daily Houston Ship Channel gas price index of the previous business day. Gürcan Gülen & Michael Soni*, The Impacts of Raising the Energy Price Cap in ERCOT*, 26 Elec. J. 43, 46 (2013). The effect of those mechanisms is relatively small, though, and so we abstract away from them.

Demand Curve (ORDC).[40] The total price paid to all power plants that clear the market thus consists of the sum of the ORDC's adder and the highest price offer that was accepted. Consequently, at times of high demand, power plants receive remuneration that exceeds their offers, even for the most expensive unit. As offers submitted by units are always equal to or greater than their marginal generation costs, i.e., the costs of producing an additional MWh of electricity, the resulting clearing prices surpass generation costs. An energy pricing scheme that allows prices to surge above generation costs is referred to as "scarcity pricing."

While paying power plants above their marginal generation costs may seem excessive, it is necessary in an energy-only market to ensure a sufficient level of investment. To understand the reason for this, it is useful to think about the days with the highest net electricity demand.[41]

As the generation capability of the system must correspond to the highest ("peak") amount of electricity that consumers consume from the grid, preventing blackouts requires building power plants that actually stand idle for most of the year. These plants switch on only for the few hours of highest annual demand, sometimes called "super-peak" hours. Figure 2 illustrates the differences in demand between the super-peak times and regular hours in ERCOT. In 2019, ERCOT had a peak load of 74,666 MW, but demand only exceeded 67,500 MW about 1% of the time between 2015 and 2019. Furthermore, demand remained below 56,500 MW for 90% of the time, suggesting substantial need in the system for mostly idle plants, which we refer to here as "super-peakers." Similar demand fluctuations happen across all RTOs.

Figure 2: for years 2015 – 2019, ERCOT's (a) daily maximum demand; and (b) load duration curve, i.e., the percentage of hours during which demand exceeds a given level (MW).[42]



Note: these graphs show five years or 43,800 hours of hourly demand intervals.

[40] Josiah Neeley & Chris Villareal, R Street, The New Frontier for Texas Electricity Competition: Enabling Distributed Resources and Avoiding Price Controls (2020), https://perma.cc/H4UF-METK ("Under the ORDC, as demand nears overall available capacity, price increases are triggered to help encourage new generation to come online. By design, the ORDC is meant to reflect both the probability of a "loss of load" and the cost of involuntary demand curtailment.").

[41] "Net" demand refers to aggregate demand for grid power, which, increasingly, is reduced by the presence and operation of distributed generation.

[42] For underlying data, see *Hourly Load Data Archives*, ERCOT, http://www.ercot.com/gridinfo/load/load_hist/ (last visited Mar. 11, 2021).

The importance of scarcity pricing relates to super-peakers' cost recovery. That is, those resources have a lower cost of investment than the power plants that run more often, but they also have high marginal costs—a combination that makes them economically well-suited for operation at low capacity factors.[43] In hours of highest demand, super-peakers have the highest costs of generation among the units needed to cover total demand, and thus the super-peakers set the energy price. But if the market price were set at their marginal operating cost, the super-peakers would cover only the costs of producing electricity and not earn enough to recover their investment costs as well. Thus, setting the price at super-peakers' marginal operating cost would make investments in generation needed to cover peak demand unprofitable, and, over the long-term, result in an insufficient level of capacity on the grid—and outages—at times of high demand. For this reason, in energy-only markets, prices must exceed marginal generation costs at some times; there must be some scarcity pricing.

Scarcity pricing can be based on operating reserves, as is done in ERCOT, or on other mechanisms. For instance, New Zealand's Electricity Authority maintains scarcity pricing that introduces a $10,000/MWh price floor and $20,000/MWh price cap to the spot market when an electricity supply emergency occurs.[44] Conceptually, design details, such as when scarcity pricing is triggered and how much it boosts energy prices, are grounded in the Value of Lost Load (VOLL), a proxy for consumers' preferences, which market structures generally prevent from being fully revealed.[45] Those specifications are important as they directly influence the system's reserve margin: more frequent instances of a scarcity adder and a larger adder will each widen the margin.

The effect of scarcity pricing is visible in ERCOT's energy prices, which we show in Figure 3 and Figure 4. While the hourly day-ahead energy market prices over a five-year period from 2015 through 2019 remained below $35/MWh for 90% of the time, and below $1,000/MWh for almost 99.9% of the time, there were moments of extreme price spikes. For 20 hours over the five-year span, the clearing price was higher than $2,000/MWh. And, on August 13th and 15th, 2019, when temperatures over 110°F strained Texans and their grid, the real-time market prices in specific zones soared to reach the $9,000/MWh price cap. It is during hours of extreme demand like these that peakers recover their investment costs, but scarcity prices help lower-marginal cost resources that clear the market more frequently to recover their investment costs as well.

The unequal distribution of prices is also visible when looking at ERCOT's price duration curves, which show the number of hours for which the per-MWh energy price was above a given value (see Figure 4).

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43 *See* Paul L. Joskow, *Challenges for Wholesale Electricity Markets with Intermittent Renewable Generation at Scale: The US Experience*, 35 Oxford Rev. Econ. Pol'y 291, 302-07 (2019).

44 New Zealand Electricity Industry Participation Code 2010, Schedule 13.3A: Calculation of Interim Prices and Interim Reserve Prices in Scarcity Pricing Situation (Nov. 3, 2020).

45 For an explanation of how VOLL relates to scarcity pricing (and other forms of shortage pricing), see Judy Chang et al., Brattle Grp., Shortage Pricing in North American Wholesale Electricity Markets 2-4 (2018) ("VOLL is an estimate of the cost of a load shed event to customers. This value can be interpreted as a customer's willingness-to-pay for incremental energy supplies to avoid load shed.").

Figure 3: ERCOT RTO hourly day-ahead market price over time, 2015 – 2019.[46]

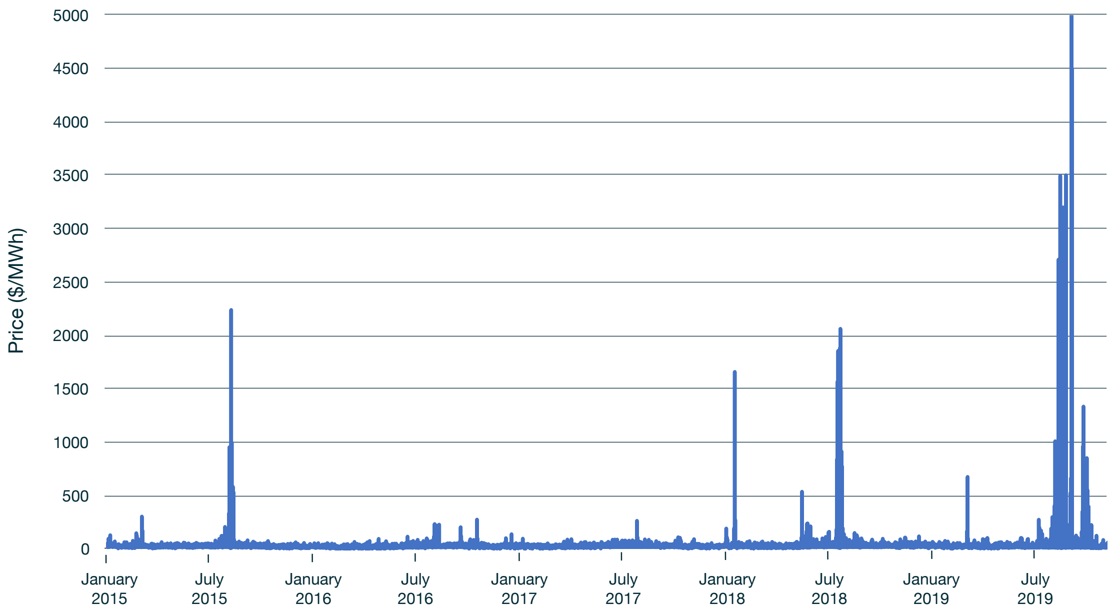
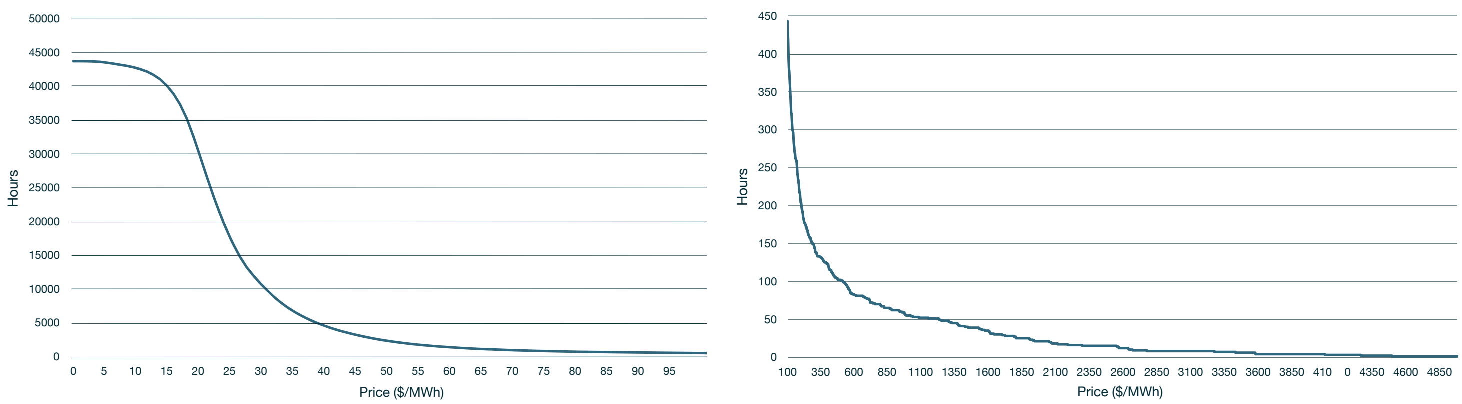


Figure 4: ERCOT RTO hourly day-ahead market price duration, 2015 – 2019.



For readability, the graph is split into two parts: the left panel shows price duration < $100/MWh, and the right panel shows price duration > $100/ MWh.[47]

[46] For underlying data, see *Historical DAM Load Zone and Hub Prices*, ERCOT, http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13060&reportTitle=Historical%20DAM%20Load%20Zone%20and%20Hub%20Prices&showHTMLView=&mimicKey (last visited Mar. 11, 2021).

[47] For underlying data, see *Historical DAM Load Zone and Hub Prices*, ERCOT, http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13060&reportTitle=Historical%20DAM%20Load%20Zone%20and%20Hub%20Prices&showHTMLView=&mimicKey (last visited Mar. 11, 2021).

Figure 3 and Figure 4 make clear that scarcity pricing, by reflecting the value of generation in a given period, reveals the substantial uncertainty that power plants face, as the earnings available from scarcity pricing vary substantially and unpredictably over time.[48] However, despite that uncertainty,[49] electricity prices that reflect scarcity conditions send an important signal for entry and retirement of generation.[50] This is true because energy prices automatically adjust to reflect the need for additional capacity; there cannot be low energy prices when capacity is scarce, and high prices are an incentive to invest in new resources.[51]

In practice, much of the risk involved in recovering costs from energy market revenues is managed through power purchase agreements (PPAs), other forms of long-term bilateral contract, and exchange-based trading, all of which help guide investments and reduce financing costs.[52] These forms of long-term contracting are especially important to renewables,[53] which are relatively capital-intensive and less likely to recover their costs from energy markets in a steady or wholly predictable manner.[54]

Benefits of Paying for Capacity

While an energy-only design can maintain resource adequacy, decisionmakers frequently prefer to avoid scarcity pricing mechanisms for reasons discussed below and in Section III. Without proper scarcity-pricing, however, energy markets generally cannot assure sufficient capacity. Consequently, where policymakers are averse to scarcity pricing and energy-only design outcomes, alternative market mechanisms are needed to incentivize resource adequacy. As we show below, capacity payments can serve as such an alternative.

In addition to the periodically high prices that result from scarcity pricing, one of the main reasons for decisionmakers' reluctance to adopt it is its susceptibility to exertions of market power.[55] At times of energy scarcity, power plant owners can substantially increase prices by bidding fewer MWs of capacity than they could technically apply. And while market rules have been designed to prevent the exertion of market power, research and analyses suggest that price manipulation

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48 In 2019, the ORDC adder contributed $9.76/MWh, which constituted 21% of the average real-time energy price of $47.06/MWh. *See* Potomac Economics, 2019 State of the Market Report for the ERCOT Electricity Markets 16 (2020), https://perma.cc/25ZM-EQ9B. Most of that contribution occurred within one month (August) when the adder soared to ca. $55 (third of the average energy price at that time). *Id.* at 15–16. In 2018, on the other hand, the adder raised prices on average by just $1.97/MWh. *Id.* at 2.

49 Power plants can partly reduce the price risk they face by signing long-term power purchase agreements with retail electricity providers. For a discussion of those contracts, see Rob Gramlich & Michael Goggin, Too much of the wrong thing: The Need for Capacity Market Replacement or Reform 22–23 (2019).

50 Tom Kleckner, *IMM: ERCOT's Shortage Pricing 'Pivotal'*, RTO Insider, June 2, 2020, (quoting market monitor as saying that "[s]hortage pricing is key in ERCOT's energy-only market because it plays a pivotal role in facilitating long-term investment and retirement decisions").

51 This point is well illustrated by Schneider and Goggin, who compare the net revenues of peak generators over time and show that in years with more capacity scarcity, measured as a lower reserve margin, peakers make higher net revenues, which also exceed the cost of new entry for a gas combined cycle generator. This increased profitability in years of scarcity signals new entry. Jesse Schneider & Michael Goggin, *ERCOT 2019: Market Performance Assessment*, Grid Strategies, LLC, Mar. 23, 2020, https://perma.cc/N4FA-LHKL.

52 In Texas, nearly all energy is transacted bilaterally. Potomac Economics, *supra* note 48, at A-12 fig.A10 (indicating that only 11-16% of load is exposed to auction-based market prices in a given month).

53 Eric Gimon, Let's Get Organized! Long-Term Market Design for a High Penetration Grid (2020), https://perma.cc/6PYV-J743.

54 *See* Rob Gramlich & Frank Lacey, Who's the Buyer? Retail Electricity Structure Reforms in Support of Resources Adequacy and Clean Energy Deployment 6–7 (2020) (noting these features of renewables financing as well as others).

55 Cramton, *supra* note 10, at 600; Paul L. Joskow & Jean Tirole, *Reliability and Competitive Electricity Markets*, 38 RAND J. Econ. 60, 70 (2007).

still happens.[56] Scarcity pricing also results in temporary energy price surges, which can result in calls for political intervention and, for some customers on time-variant rates, material increases in energy bills.[57]

For multiple reasons, ranging from the legitimate risk of price manipulation to political preferences, PJM, NYISO, MISO, ISO-NE and CAISO maintain rules that prevent energy prices from rising anywhere close to the levels allowed in ERCOT.[58] These price caps change the energy price distribution, as visible when comparing hourly day-ahead energy prices in ERCOT with prices in PJM and NYISO. While in all three RTOs prices remained below $100/MWh for roughly the same percentage of time over the five-year period from 2015 to 2019, in periods of scarcity, prices in ERCOT sometimes rose to levels that are structurally impossible in PJM and NYISO (see Table 2).[59] Those ERCOT price spikes pulled ERCOT's average prices above $100/MWh up to $464, well above PJM's $145 and NYISO's $140.

Table 2: RTO Hourly Day-Ahead Market Price Duration (Hours), 2015 – 2019

	$100 - 999/MWh	$1,000 - 1,999/MWh	≥ $2,000/MWh
ERCOT	369	34	20
PJM	465	0	0
NYISO	594	0	0

Price caps limit the energy revenue that power plants can earn and thus the possibility of fully recovering investment costs, making it impossible for the peaker power plants that seldom generate electricity to earn sufficient energy revenue to cover their investment costs. Without the possibility of cost recovery, no new plants would be built, and insufficient generation capacity would eventually result.[60] This is known as the "missing money" problem. It is the result of low price caps in energy markets and the reason why an energy-only market with low price caps would result in frequent blackouts. It is possible to calculate the amount of missing money resulting in the short-run from the imposition of a price cap. If ERCOT introduced a cap of $2,000/MWh, for instance, a peaker with a 5% capacity factor (meaning that it runs just 5% of the 8,760 hours in an average year) would lose almost $58,000 per MW of its capacity over the period from 2015 to 2019, which is 19% of its revenue (see Table 3).[61] For a resource that runs constantly at its full capacity, the same cap would result in the loss of just 5% of total revenue. The higher the price cap, the less pronounced the missing money

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56 Matt Butner, *Gone with the Wind: Consumer Surplus from Renewable Generation* (Univ. of Colo. Boulder Econ. Working Paper No. 18-01, 2020); Severin Borenstein, James B. Bushnell & Frank A. Wolak, *Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market*, 92 Am. Econ. Rev. 1376 (2002); Matt Woerman, *Market Size and Market Power: Evidence from the Texas Electricity Market* (Working Paper, 2019).

57 Even short periods of scarcity pricing can send bills soaring for consumers participating in a real-time price tariff. Chris Martin & Rachel Adams-Heard, *Blunder Sent Power Prices Surging 24,000% and Texans Pay Up*, Bloomberg, Aug. 3, 2019; Rebecca Hersher, *After Days of Mass Outages, Some Texas Residents Now Face Huge Electricity Bills*, NPR, Feb. 21, 2021.

58 For the maximum prices that energy can reach in each of those markets, see Chang et al., *supra* note 45, at 5 fig.1. Note that those markets often have elements of scarcity pricing but of very limited magnitude.

59 PJM is poised to adopt to a new version of scarcity pricing, implementation of which will allow energy prices to rise to levels over $10,000/MWh. PJM Interconnection, L.L.C., 173 FERC ¶ 61,123, PP 76, 81–85 (2020); *see also* PJM Interconnection, L.L.C., 171 FERC ¶ 61,153 (2020).

60 *See* Joskow, *supra* note 9.

61 Under a theoretical $2,000/MWh price cap, a generator running only 5% of the year (when revenues per MWh are highest) would have received $254,459/MWh over the period of 2015 through 2019, as opposed to $313,236/MWh under the actual, uncapped priced; the difference is equal to $58,777/MWh. Calculations assume no other changes happen as a result of the cap.

problem becomes—evident from a comparison of the $2,000 and $5,000 cap scenarios in Table 3—but also the less effective the cap is at preventing exertions of market power.

Table 3: ERCOT RTO West Hourly Day-Ahead Market, 2015-2019 Impact of Hypothetical Price Caps on Total Revenue for 1 MW.

	Actual Revenue†	$2,000 Cap		$5,000 Cap	
		Theoretical Revenue	% Difference	Theoretical Revenue	% Difference
Power plant with 100% capacity factor	$1,256,301	$1,196,566	-4.75%	$1,251,293	-0.40%
Peaker with 5% capacity factor	$313,236	$254,459	-18.76%	$308,276	-1.58%

For the purposes of these calculations we are assuming that the peaker runs 5% of the time and collects the highest ~438 hourly day-ahead prices each year. We do not include revenue from the ancillary services market.[62]

To deal with the missing money problem, RTOs with energy price caps have to provide an additional source of revenue. They do so by offering remuneration for capacity. If the capacity payments equal the money lost due to energy price caps, the sum of capacity remuneration and energy revenue under a price cap corresponds to the energy revenue that would flow to those resources in a non-capped market. Consequently, a capacity remuneration mechanism combined with capped energy prices could provide the same incentives to invest in generation as an energy-only market without price caps, ensuring sufficient capacity buildout. In other words, capacity remuneration can restore the missing money in energy markets with price caps.[63] Note, however, that incentives might differ substantially under the two systems, resulting in distinct generation mixes and even different outage probabilities.[64]

Capacity Remuneration Mechanisms

Diverse capacity remuneration mechanisms can address the missing money problem. They may vary significantly in several respects, including:

- whether the capacity contracts follow from individual negotiations or centralized market assignment;
- how the price for capacity is set;
- the duration of contracts for capacity;
- the penalties for resources that fail to perform as required by their contracts; and
- the amount of capacity procured relative to predicted demand.

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62 For underlying data, see *Historical DAM Load Zone and Hub Prices*, ERCOT, http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13060&reportTitle=Historical%20DAM%20Load%20Zone%20and%20Hub%20Prices&showHTMLView=&mimicKey (last visited Mar. 11, 2021).

63 Some studies provide additional reasons for introducing resource adequacy mechanisms, such as missing markets, *see, e.g.*, David Newbery, *Missing Money and Missing Markets: Reliability, Capacity Auctions, and Interconnectors*, 94 Energy Pol'y 401 (2016), or resource adequacy externalities, *see, e.g.*, Donna Peng & Rahmatallah Poudineh, *Electricity Market Design under Increasing Renewable Energy Penetration: Misalignments Observed in the European Union*, 61 Utils. Pol'y 100970 (2019). Because those arguments are less well demonstrated than "missing money," both in the economic literature and filings made by RTOs to FERC, we do not address them here.

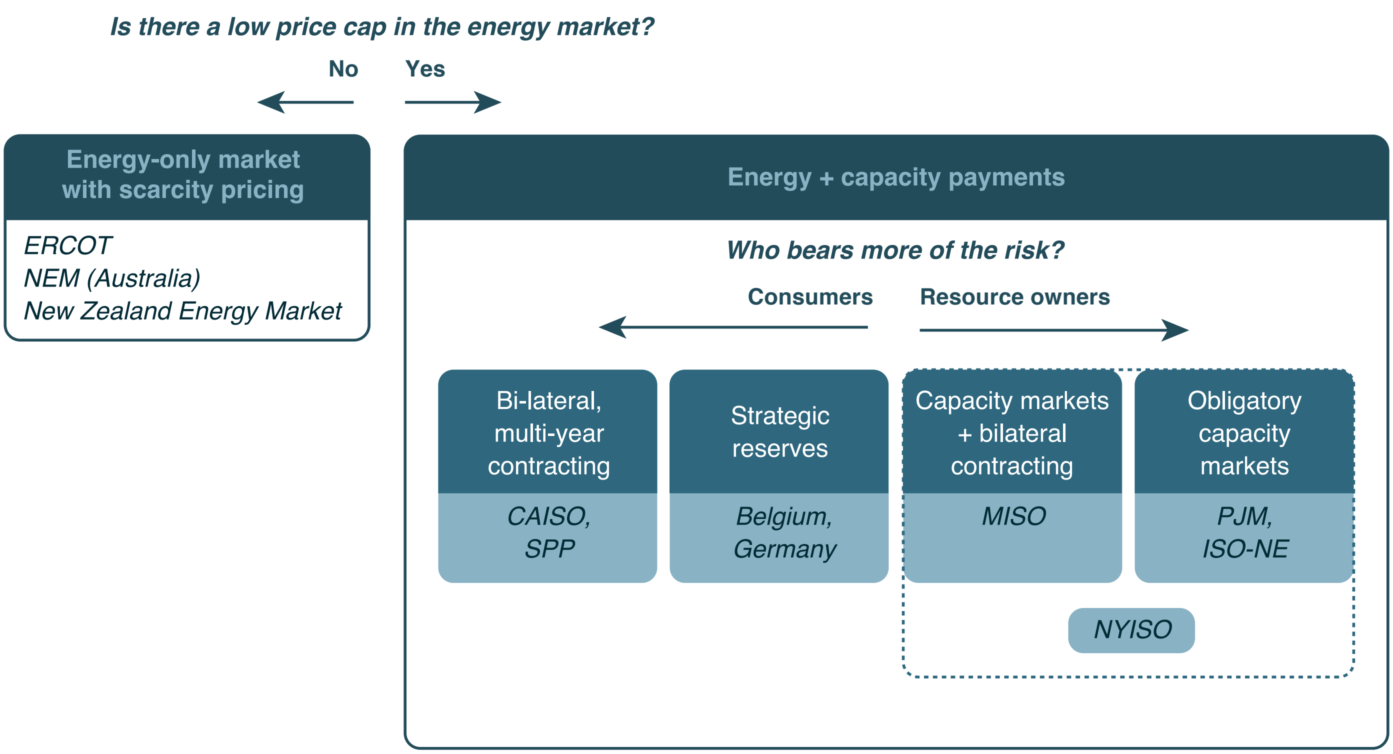
64 The differences in incentives largely depend on the price cap and the penalty for not being able to generate despite receiving capacity remuneration. For instance, the incentive to avoid outages in super-demand periods is much higher under a scarcity pricing scheme than in a market with capped energy prices where a capacity remuneration mechanism imposes low non-performance penalties.

Different combinations of these elements yield allocations of investment risk that fall along a spectrum, with consumers bearing the most risk on one extreme and power plant owners bearing it on the other. One example of the latter is an annual capacity market which assigns capacity payments to power plants based on auctions in which resources clear the market in the order of their offers—i.e., from the cheapest to the most expensive. This sort of approach limits remuneration certainty to just one year and exposes the resources to the risk of not clearing the auction in the next period because their offers might not be competitive. Such capacity markets have been implemented in PJM, ISO-NE, Colombia, Ireland, and elsewhere.

By contrast, consumers are the primary risk-bearers where resources agree to bilateral, multi-year contracts with utilities. Although such contracts yield greater certainty regarding compensation to be paid for capacity, which in turn allows for lower costs of financing, it also means that the risk of retail utilities paying uneconomic power plants for capacity falls on consumers. CAISO and SPP employ this approach; there, utilities use a combination of long-term capacity contracts and "self-supply" to cover all resource adequacy needs. The Belgian and German approach to compensating capacity also places more risk on consumers than resource owners, but the quantity of risk involved is relatively low: capacity contracts are signed only with resources that act as a strategic reserve for use in emergencies.

Approaches that are somewhere between the two extremes might involve both (multi-year) bilateral contracts or self-supply as well as a voluntary capacity market, as is the case in MISO. NYISO operates a seasonal capacity market but also accepts some forms of bilateral capacity contracts. Figure 5 classifies the resource adequacy approaches introduced above, showing that the fundamental division between design choices results from energy market price caps being very high (or absent) versus relatively low, such that capacity must be remunerated separately. Regions where the cap is high or absent use an energy-only market with scarcity pricing. Regions where the cap is relatively low also compensate capacity.

Figure 5: Available resource adequacy approaches, with examples of approaches implemented in the United States and abroad.



The choice of capacity remuneration mechanism affects the efficiency of the electricity sector at large. Below, we discuss capacity market design in more detail, abstracting away from its merits relative to other capacity remuneration mechanisms.

How Capacity Markets Operate

Capacity markets take the form of auctions in which demand for capacity is construed administratively at a level that will satisfy resource adequacy requirements. Those requirements are usually specified as the sum of super-peak demand and a reserve margin. Some regions, like MISO, specify capacity demand as the number of MWs needed (also called a "vertical demand curve"); other regions, like PJM, NYISO, and ISO-NE, use a downward-sloping demand curve.

Individual resources offer the amount of capacity they can provide and the minimum price they require for keeping that capacity ready to generate energy over a specified time period. When aggregated, these offers constitute a capacity supply curve, which intersects with the capacity demand curve and so indicates what price is to be paid to all resources that clear the capacity market. In return for capacity payments, those resources are obligated to keep their capacity ready to generate if called, as might occur if generation proves scarce relative to demand. If they fail to be ready to generate, they may face non-performance penalties.

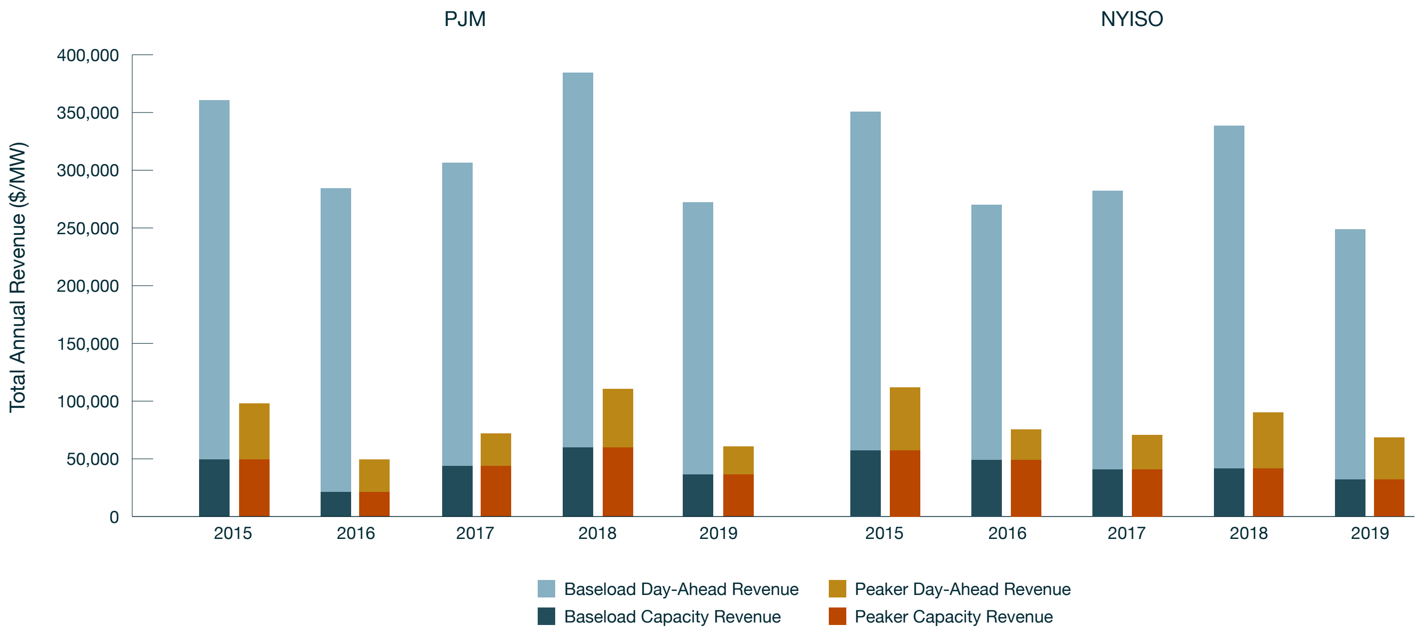
In the absence of market power, we can expect power plant offers to represent the amount needed to allow them to break even. Assuming equilibrium, we would expect the offers of power plants to be proportional to the missing money plus the expected non-performance penalties driven by a resource's outages.[65] As a consequence, under ideal circumstances, such as investor risk neutrality and price caps being binding only in situations when the full fleet of resources is needed, an energy-only market design would yield results very similar to an energy-plus-capacity market design.[66] However, the assumptions needed for the equivalence of the two market designs are very strict. We show below that in practice they do not hold and that the choice between energy-only and energy-plus-capacity markets matters to the energy mix—as does the selection of design features within the chosen market type.

Capacity market payments provide a substantial share of revenue for power plants, especially for peakers. The two panels of Figure 6 present the annual revenue (per 1 MW of capacity) earned in NYISO's and PJM's capacity and day-ahead energy markets by each of two types of power plants: resources that run at their full capacity and a peaker with capacity utilization of 5%. In those markets, a unit that runs year-round derives only about 15% of its combined revenue from the capacity market, but for a peaker well over a half of its combined revenue can be paid for capacity.

[65] In a well-designed, competitive energy-only market, which is in equilibrium, all power plants needed for resource adequacy would at least break even. The missing money would thus define the maximum capacity payments that resources need to stay active in the market. *See* Sylwia Białek & Burcin Unel, *Efficiency in Wholesale Electricity Markets: On the Role of Externalities and Subsidies* (CESifo Working Paper No. 8673, 2020); Joskow & Tirole, *supra* note 55.

[66] For a presentation of the equivalence under the idealized circumstances, see Bialek & Unel, *supra* note 65 and Joskow & Tirole, *supra* note 55.

Figure 6: Annual Revenue in PJM and NYISO for 1 MW from the Capacity Market (Reliability Pricing Model) and Hourly Day-Ahead Market, 2015 to 2019.



For the purposes of these calculations we are assuming that baseload plants are any resources that run at full capacity and peaker plants run 5% of the year, or collect the highest ~438 hourly day-ahead prices each year. We do not include revenue from the ancillary services market.

Blackouts and Resource Adequacy in California and Texas

Over the past six months, big blackouts have focused attention on present approaches to electric system reliability—and resource adequacy in particular.[67] The first event took place in August 2020 in California. The second one, which was far larger, took place in February 2021, mainly in ERCOT but, to an extent, in MISO and SPP as well.[68] These successive instances of systems failing to keep the lights on raise many questions, including:

- Why did market participants and regulators fail to anticipate the potential for climatic extremity and related impacts on energy system components and on the performance of the regional bulk power system as a whole?
- What role did the presence of renewables play in both the planning decisions and the operational performance of the systems that failed?
- What role did market design—especially the presence or absence of capacity remuneration—play? And did the market designs in each region actually perform consistent with their respective resource adequacy standards?

Before discussing the answers suggested by events in California and Texas, it is important to note that bulk power system-level blackouts can result from several factors, of which the region's approach to resource adequacy is just one. For instance, resource adequacy standards in most regions explicitly allow for a "1-in-10" (that is, one event or one day of lost load in a ten-year period) exception to perfect reliability. In addition, even if the overall logic of a resource adequacy approach is sound, aspects of its implementation can still cause problems—examples include mis-specification of scarcity prices (in an energy-only market) or of a capacity demand curve or non-performance penalty (in an energy-plus-capacity market). On top of these design elements, operational factors can also play a role, such as transmission problems or poor planning that fails to avoid congested transmission capacity.

Official investigations have clarified how the August 2020 events unfolded in California,[69] and thus suggested answers to the questions above. There, extreme heat drove demand to exceed the planning targets prescribed by California's state-directed resource adequacy planning process while also straining resources in neighboring regions.[70] On the supply side, while the heat made gas-fired units less efficient,[71] at least one gas unit was unavailable due to untimely scheduled maintenance.[72] And cloud cover and smoke from wildfires, as well as low wind levels, caused renewables to generate at

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67 *See* Resources Radio, *Shedding Light on Electricity Blackouts, with Severin Borenstein* (Feb. 23, 2021), https://perma.cc/7NGT-9B7R (Severin Borenstein stating: "Most power outages that we experience as residential and small commercial consumers are distribution line failures. . . . The kind that we experienced in California in August and has been going on in Texas is extremely rare. These are system shortages or sometimes shortages in local power areas where there just isn't enough electricity available.").

68 Roughly 500 MW of load was shed for two periods—two hours on one day and about twenty minutes on the next day—in California. Mark Specht, *Power Outages in Texas and California Have Less in Common than You Think*, Union of Concerned Scientists, Feb. 18, 2021, https://perma.cc/FM2H-GCS4. In Texas alone (i.e., excluding other Midwest and Southeastern states, which also saw load shedding), utilities were ordered to shed between 10,000 and over 16,000 MW of load for several hours at a time every day for about four days. *Id.*

69 Cal. Indep. Sys. Operator, Cal. Pub. Utils. Comm'n & Cal. Energy Comm'n, Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave (2021) [hereinafter California Root Cause Analysis].

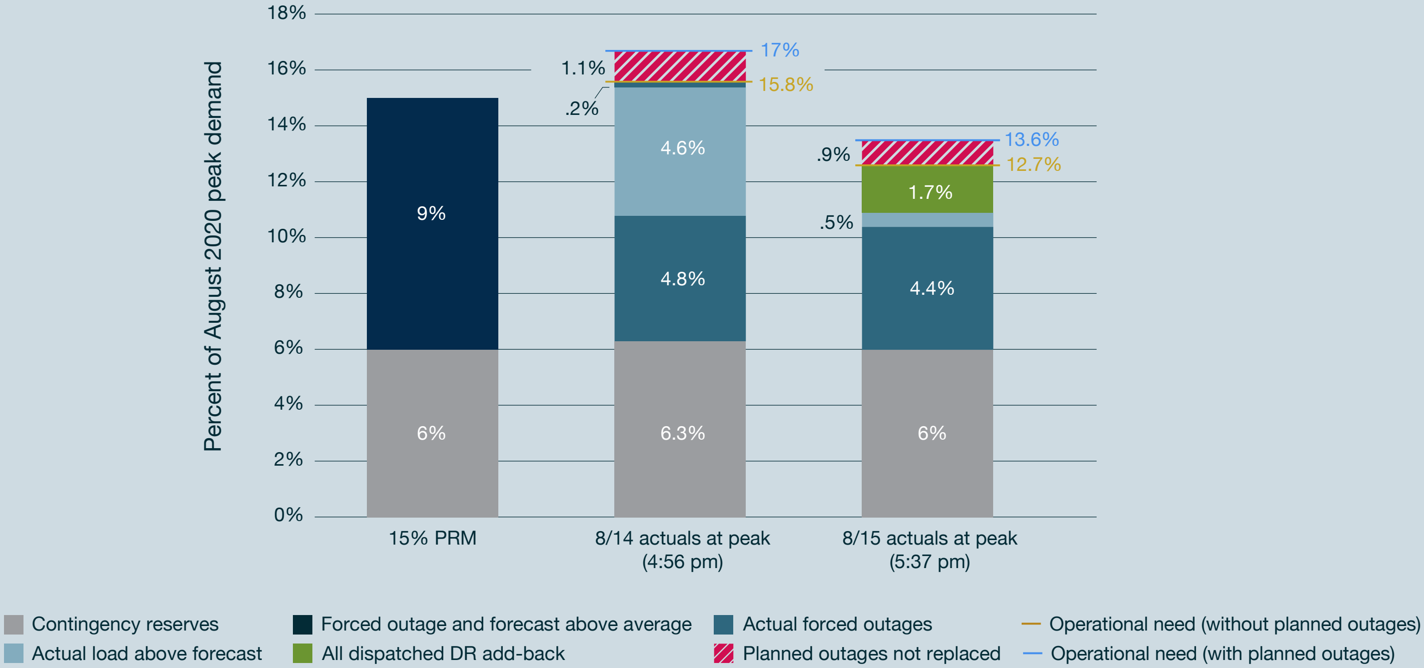
70 *Id.* at 19–21.

71 *Id.* at 48, 58 ("Under very high temperatures, ambient derates are not uncommon for the natural gas fleet, and high temperatures reduce the efficiency of these resources.").

72 *Id.*

levels below what they had bid into the day-ahead market.[73] Neighboring regions were of little help: they had limited excess capacity to export,[74] and a major transmission line at the north end of the state, which might have brought some relief, was still being repaired after damage from a storm in May.[75] In addition to these physical factors, California's retail utilities bid for less power in the day-ahead energy market than they would actually need, which in turn led to CAISO scheduling the export of energy that California customers would sorely miss.[76] Demand response also underperformed, potentially because bidders exploited loopholes that allowed them to excuse non-performance.[77] Apart from these factors, the blackout investigation also found that resource adequacy specifications contained small errors that created a risk of overestimating the resources available to meet demand at key points of the day, especially the evening when customer-owned solar stops generating, causing the grid demand to rise abruptly.[78]

Figure 7. August 2020 CAISO Planning Reserve Margin Compared to Actual Net Generation and Operational Need at Peak on August 14 and 15, 2020.[79]



Overall, the August 2020 blackouts in California do not appear to be the result of a fundamental error or failure, but rather of an accumulation of small errors and misestimations combined with extraordinary weather conditions. Some of those errors seem to have arisen from resource adequacy implementation, indicating that better specification (but not a

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[73] *Id.* at 49–50.

[74] *Id.* at 40 ("The energy markets can help fill the gap between planning and real-time conditions, but the West-wide nature of this extreme heat wave limited the energy markets' ability to do so.").

[75] *Id.* at 88.

[76] CAISO and the CPUC's investigation ascribed this error at least in part to "convergence bidding" practices that are normally relied upon to reduce the discrepancies between day-ahead and real-time bids. *Id.* at 61–63.

[77] CAISO, Demand Response Issues and Performance 30 (2021) (reiterating recommendation that CAISO establish performance incentives and penalties for demand response).

[78] California Root Cause Analysis, *supra* note 69, at 40–43, 58–59; *see also* Hudson Sangree, *New CAISO CEO Vows Urgency on Resource Adequacy*, RTO Insider, Dec. 1, 2020 (quoting CAISO's CEO: "We know that the resource base is changing dramatically. . . . And as the resource base has changed, we need to make sure that our planning and procurement and our operations adapt sufficiently rapidly to stay ahead of the reliability curve.").

[79] *Id.* at 43 fig.4.2.

complete overhaul) of the way California thinks about available capacity is needed. This conclusion pertains to renewables' presence and operations—solar capacity seems to have been slightly overestimated, for instance—but also to the efficiency of gas resources under extreme heat conditions and to the precision of bids received from demand response program participants. For these reasons, the authors of the *Final Root Cause Analysis* recommended a variety of tweaks—rather than basic reforms—to planning and operational measures.[80]

As for the February 2021 cold snap and its dire impacts on Texas in particular, several factors are clearly relevant, even if it remains to be determined how exactly they relate to the outages:

- Texas's buildings are poorly insulated and three-fifths of residents rely on electric heaters;[81] the severe cold thus drove load up to 74GW—above the *summer* peak and far above the expected winter peak;[82]
- generation—including gas, coal, nuclear, and wind—was not winterized and succumbed to operational and mechanical failures;[83]
- several gas-fired generation facilities were unavailable due to maintenance, which had been scheduled on the assumption that those facilities would not be needed;[84]
- ERCOT's lack of meaningful transmission linkages to other regions, which allows Texas to avoid federal regulation of its electricity sector, meant that imports could not ameliorate supply issues even after SPP and MISO had taken measures to deal with their own outages;[85]
- equipment failures at gas extraction wells and compressor stations severely limited gas supplies;[86]
- hospitals and residential end-users were given priority over electricity sector participants for those scarce natural gas supplies resulting in lacking fuel for gas power plants.[87]

Figure 8 captures the consequences of these combined factors for the enormous gap between electricity supply and demand from February 15th to 19th.

80 *Id.* at 70–75.

81 *Texas: State Profile and Energy Estimates*, U.S. Energy Info. Admin. (Mar. 19, 2020).

82 Veronica Penney, *How Texas' Power Generation Failed During the Storm, in Charts*, N.Y. Times, Feb. 19, 2021 (indicating expected load and generation).

83 Generation failures included frozen, immovable coal piles; equipment failures at gas plants built without walls or roofs to facilitate heat venting; a sensor failure that caused a nuclear plant to trip offline for almost two days; and frozen, inoperable wind turbine blades. Keith Everhart & Gergely Molnar, *Severe Power Cuts in Texas Highlight Energy Security Risks Related to Extreme Weather Events*, Int'l Energy Agency, Feb. 18, 2021.

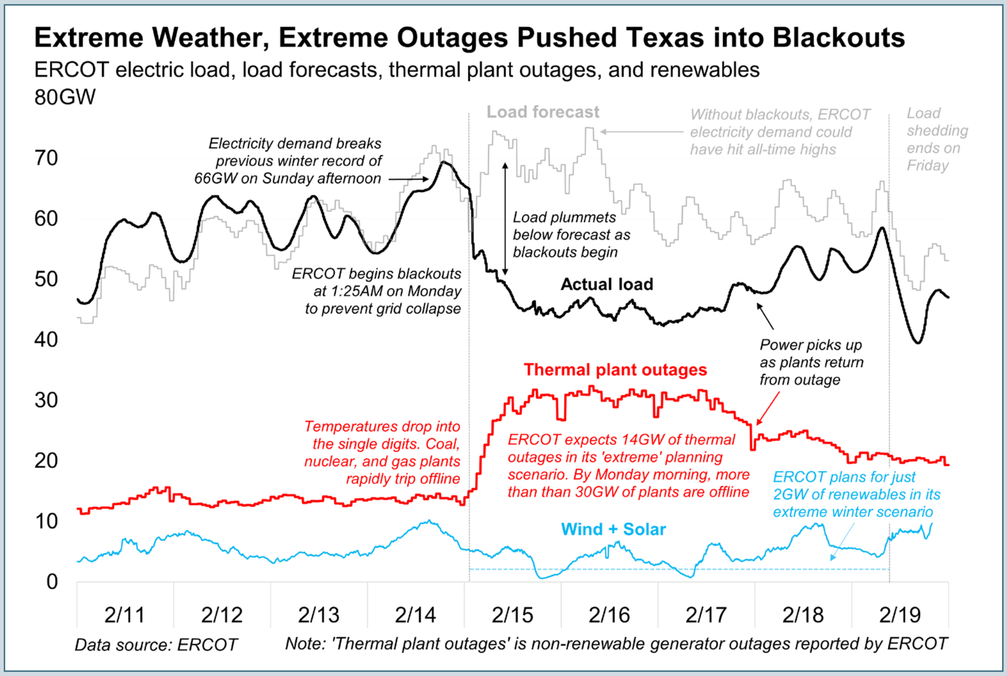
84 *Id.*

85 ERCOT maintains one 820 MW intertie with the neighboring Southwest Power Pool (SPP), and a 400 MW intertie with Mexico. Kevin Carden & Alex Krasny Dombrowsky, Astrape Consulting, Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region for 2024 (DRAFT) 62 (2020). Even if SPP had been able to send maximal exports to ERCOT, it would have offset just a small fraction of the deficiency, which ranged from 10,000 to 16,500 MW of unserved load. ERCOT, Press Release: Grid Operator Has Restored Power to 500,000 Households (Feb. 15, 2021).

86 *Texas Gas Well Freeze-offs, Power Cuts Persist*, Argus (Feb. 17, 2021), https://perma.cc/8UJ7-F2CS.

87 Joe Carroll, *Freeze Spurs Texas to Give Energy Priority to Homes, Hospitals*, Bloomberg, Feb. 12, 2021.

Figure 8. Load, Forecast Load, and Thermal and Renewable Generation Performance in ERCOT, February 11 to 19, 2021.[88]



A nascent consensus seems to hold that at least some of the risks of severe cold to the Texas energy system, of which the electric grid is a part, were known[89] but ignored.[90] A critical question, however, is whether those risks were ignored because they were known but thought to be exceedingly rare, or despite being both known and thought to be frequent enough to present a material risk.[91] A related question is whether the facts of climate change should prompt planners

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[88] Reproduced with permission. Brian Bartholomew (@BPBartholomew), Twitter (Feb. 24, 2021, 12:24 AM), https://twitter.com/BPBartholomew/status/1364446059028750337/photo/1.

[89] *See, e.g.*, FERC/NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (2019); Texas Dep't of Pub. Safety & Emergency Mgmt., State of Texas Hazard Mitigation Plan 44 (2018) ("Extreme cold can affect all regions of Texas; however, it has not been the cause of any major Disaster Declaration in the last five years."); Quanta Tech., Report on Extreme Weather Preparedness Best Practices 15 (2012) (prepared for the Pub. Util. Comm'n of Tex.) ("As presently structured, the [compulsory facility] plans often lacked weatherization plans related to extreme cold or hot weather."); Fed. Energy Reg'y Comm'n & N. Amer. Elec. Reliability Corp., Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1–5, 2011—Causes and Recommendations (2011) (discussing outages caused by both 2011 and 1989 cold weather events); Pub. Util. Comm'n of Tex., Electric Utility Response to the Winter Freeze of December 21 to December 23, 1989—Evaluation of the Actions Taken by Texas Utilities to Correct Technical Plant Equipment Problems 1, 7 (1990) ("The combination of heavy demand and loss of generating units caused near loss of the entire ERCOT electric grid. . . . All utilities should ensure that they incorporate the lessons learned during December of 1989 into the design of new facilities in order to ensure their reliability in extreme weather conditions.").

[90] *See, e.g.*, FERC Open Commission Meeting, 46:30-48:30 (Feb. 18, 2021), https://www.ferc.gov/news-events/events/february-18-2021-virtual-open-meeting-02182021 (Opening remarks of Comm'r Clements) (referring to winterization and planning recommendations in FERC/NERC 2011 report and stating agreement with Texas legislator who said in 2011 that any critical assessment of the event should not "sit on the shelf for twenty years"); Jeremy Schwartz, Kiah Collier & Vianna Davila, *"Power Companies Get Exactly What They Want": How Texas Repeatedly Failed to Protect Its Power Grid Against Extreme Weather*, Tex. Trib. & ProPublica, Feb. 22, 2021 (tracking legislative and regulatory debates over potential winterization requirements).

[91] *See* Peter Behr, *'Impossible to Avoid.' Years of Grid Warnings Haunt Texas*, E&E News, Feb. 18, 2021 ("Mike Ross, SPP senior vice president of government affairs and public relations, said . . . . 'You've heard of hundred-year floods. I mean, this is an 85-year event.'").

and regulators to revise their understanding of and approach to "exceedingly rare" weather events.[92] The answers to these questions will resonate in particular in conclusions about how ERCOT and the Public Utility Commission of Texas employed scarcity pricing during the crisis and what rules ought to govern scarcity pricing in future scenarios.[93]

Answering questions about causes will help assess what exactly the February 2021 cold snap means for approaches to resource adequacy in ERCOT and neighboring RTOs, MISO and SPP. A thorough investigation is needed to identify the factors actually responsible for the outages. However, it appears even now that neither the presence of renewables nor a given region's choice of wholesale market design is a root cause of the energy system's blind spot for how extreme cold could translate into a supply shortage severe enough to spur prolonged outages.[94]

Taken together, the August and February events (1) indicate that extreme weather and climate change are increasingly relevant factors that should inform any approach to resource adequacy, whether by being reflected in participation requirements or prompting adjustments, for instance, to the amount of capacity procured for energy-and-capacity approaches and changes to scarcity pricing schemes for energy-only markets; (2) do not cast doubt on whether resource adequacy approaches can handle renewables' growing presence but suggest that attention should be paid to estimating particular resources' capacity contributions and identifying when times of scarcity can be expected to occur; and (3) show that the effectiveness of various market designs in supporting adequate investments depends on the institutions and processes that develop and interpret information about foreseeable scenarios like those faced over the past six months.

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[92] Elec. Power Res. Inst., Exploring the Impacts of Extreme Events, Natural Gas Fuel and Other Contingencies on Resource Adequacy, at vii (2021) ("KEY FINDINGS: 1. The electric industry systematically understates the probability and depth of many high impact common mode events: Extreme weather events are rising in frequency, intensity, geographic scope, and duration; the impact of weather is non-linear and rising much faster than frequency . . . ."); *see also* John Schwartz, *Climate Change May Explain Frigid Weather So Far South, Experts Say*, N.Y. Times (Feb. 17, 2021).

[93] Letter from Carrie Bivens, Vice Pres., Potomac Econ., and Dir., ERCOT Indep. Market Monitor, to Arthur C. D'Andrea, Chairman, Pub. Util. Comm'n of Tex. (Mar. 4, 2021), https://perma.cc/27X4-HRX2 (describing deviation from protocol and noting that the action imposed $16 billion of costs on ERCOT's market); Pub. Util. Comm'n Tex., Second Order Directing ERCOT to Take Action and Granting Exception to Commission Rules (Feb. 16, 2021), https://perma.cc/P28J-F5RN; *see also* Rutgers University, *The Texas Power Freeze: First Impressions* (transcript) 22:40–22:55, 37:00-40:00 (Mar. 9, 2021), https://www.linkedin.com/feed/update/urn:li:activity:6775842254906109953/ (remarks of Alison Silverstein and Eric Gimon).

[94] Notably, although wind and solar generation underperformed relative to their day-ahead bids, for the duration of the cold snap wind performance mostly exceeded the "low output" threshold that ERCOT uses for resource adequacy planning. *Compare* Figure 8, *supra*, *with* ERCOT, *Final Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Winter 2020/2021*, at 2 (Nov. 5, 2020), https://perma.cc/L89A-RZ3E.

III. Energy-Only Markets Are Viable, Even with a High Share of Renewables

An energy-only approach has ensured resource adequacy in regions like Texas, New Zealand, and Australia for decades.[95] However, some electricity sector stakeholders have argued that, while energy-only markets performed well in the past, their ability to maintain resource adequacy may fade as renewable generation increases.[96] That view usually extrapolates from the idea that the low generation costs of renewables will cause low energy market prices, and will, in turn, make energy-only markets unviable This section analyses that argument and refutes it. Our analysis shows that the argument is incorrect because it disregards the intermediating effects of the following factors: long-term market responses; daily patterns of availability of renewables, and variability; and the role of prices in signaling scarcity. Overlooking these factors will tend to provide misguided conclusions about energy-only markets' ability to provide for resource adequacy in a high-renewables scenario.

Energy-only skeptics' argument generally goes as follows. To begin, carbon-free resources like solar panels and wind turbines have low or zero marginal costs,[97] so an increasing share of these resources on the grid is likely to decrease electricity prices,[98] reducing the revenue available from energy markets to all participating resources as a result.[99] This, they say, could make it impossible to recover the costs of building new power plants through energy-only markets, even with scarcity pricing, thereby making new investment unprofitable and risking resource inadequacy.[100] Some even envision that the drop in electricity prices due to low marginal cost resources could lead to excessive generation retirements and acute supply shortages, should there be no additional mechanisms to counteract it.[101]

The ultimate conclusion of this argument is that energy-only markets will fail to provide for resource adequacy. From this conclusion it follows that capacity payments will become necessary to make generation investments—in renewables, just like other resources—profitable enough to ensure resource adequacy, such that capacity markets may eventually become necessary even in regions that historically have not had them. A further implication of this argument is that remunerating capacity in addition to energy is necessary not only to ensure resource adequacy but also to achieve clean energy deployment goals, which require significant investments in new generation capacity.

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95 *See* Eric S. Schubert et al., *The Texas Energy-Only Resource Adequacy Mechanism*, 19 Electricity J. 39, 40 n.1 (2006).

96 *See, e.g.*, Gavin Bade, *The Great Capacity Market Debate: Which Model Can Best Handle the Energy Transition?*, Utility Dive, Apr. 18, 2017 (quoting Gordon van Welie, CEO of ISO-NE: "the Texas model, in the long-run, is very vulnerable. It'll work for a while; it'll work as long as you've got demand growth in Texas."); *see also generally* Int'l Renewable Energy Agency, Innovation Landscape Brief: Redesigning Capacity Markets (2019).

97 Andreas Bublitz et al., *A Survey on Electricity Market Design: Insights from Theory and Real-world Implementations of Capacity Remuneration Mechanisms*, 80 Energy Econ. 1059, 1061 (2019).

98 Thomas Jenkin, Philipp Beiter & Robert Margolis, Nat'l Renewable Energy Lab'y, Capacity Payments in Restructured Markets under Low and High Penetration Levels of Renewable Energy 28 (2016).

99 Bublitz et al., *supra* note 97, at 1061; Jorge Blazquez et al., *The Renewable Energy Policy Paradox*, 82 Renewable & Sustainable Energy Rev. 1, 3 (2018).

100 *See, e.g.*, Peeter Pikk & Marko Viiding, *The Dangers of Marginal Cost Based Electricity Pricing*, 13 Baltic J. Econ. 49, 59 (2013); Bade, *supra* note 96 (quoting Gordon van Welie, CEO of ISO-NE, on ERCOT's energy-only market: "What that investor has to do is look out into the future over 30 years and say, 'How much money can I earn to cover my costs from the energy market?' The picture then is going to look grim. You're going to just see low prices as far out as the eye can see with them actually declining going forward.").

101 U.S. Dep't of Energy, Office of Energy Efficiency & Renewable Energy, *Wind's Near-Zero Cost of Generation Impacting Wholesale Electricity Markets* (May 8, 2018), https://perma.cc/CK7K-YQVC ("While market signals may prompt unprofitable resources to exit the market, excessive retirements may cause supply shortages.").

Such implications would be particularly relevant for the United States, where energy-only markets are frequently touted as the superior market design for encouraging investments in renewable resources and thus as the superior resource adequacy approach for a decarbonized electricity sector.[102]

Skeptics of energy-only markets are not wrong to suggest that renewables with near-zero generation costs will have meaningful effects on energy prices, but those effects are not simply downward pressure at all times and locations. In the very short term, low-marginal-cost renewables can indeed drive some energy prices to zero (or even to negative values), when they are the marginal resources and capacity is not scarce.[103] And even when renewables are not the resource on the margin, they can affect the profitability of other power plants. This is because renewables' entry, just as any new resource entry, shifts the energy supply curve out, lowering energy prices when the new resources are providing meaningful amounts of electricity.[104]

But the entry of renewables has more complex effects. The decrease in price levels driven by a supply curve shift is a short- to medium-term effect that signals the need for retirements to some capacity owners. Unless the new entry coincides with demand growth or decommissioning of another resource, it increases the amount of capacity on the grid, possibly beyond what is needed. The ensuing drop in some energy prices shrinks all resources' profits indicating the presence of excess capacity, and prompting retirement of unprofitable units. As resources compete mostly with the units that are adjacent to them in the merit order, meaning those resources in the supply curve that have similar marginal costs,[105] renewables' entry can be expected to drive the retirement of medium-cost units and to leave high-cost gas and oil-fired power plants' revenues largely unaffected in the long-term. Finally, in the long-run, retirements can mitigate some of the price effects stemming from the supply curve shift by reducing supply and thereby pushing prices higher.

Crucially, the presence of renewables also changes the *pattern* of energy prices, not just the level of those prices. That is, renewable generators' daily and seasonal variability means that the presence of more renewables might cause energy prices to rise substantially when renewable generation flags, even if it also causes average annual prices to sink. Thus, in systems reliant on solar generation, evening prices may go up significantly.[106] Renewables' variability, combined with their

[102] *See, e.g.*, William Hogan & Philip Baker, *Energy Markets Will Deliver the Flexible, Decarbonised Power System Needed, Not Capacity Markets*, Euractiv, Dec. 17, 2018, https://perma.cc/L84R-QBVW.

[103] Some research suggests, though, that the number of low-price hours will be limited in the future if electricity consumers, especially the cross-sectoral consumers, such as users of heat pump technologies, see real-time prices. Such consumers would use the lowest-price periods to satisfy their electricity demand, effectively driving up the energy prices. *See* Philipp Härtel, Magnus Korpås, *Demystifying Market Clearing and Price Setting Effects in Low-Carbon Energy Systems*, 93 Energy Econ. 105051 (2021).

[104] This type of effect is called a merit-order effect. For an overview of empirical estimates of that effect. *See* Audun Botterud & Hans Auer, *Resource Adequacy with Increasing Shares of Wind and Solar Power: A Comparison of European and U.S. Electricity Market Designs*, 9 Econ. of Energy & Env't Pol'y 71, 80 (2020).

[105] For an explanation of the different effects across the merit order, see Bialek & Unel (2020), *supra* note 65, at 15. The competition among resources adjacent to each other in the merit order owes not only to their adjacency but also to their properties. Mid-merit resources, such as coal, have high investment and maintenance costs, and ramp slowly, such that they must operate for long durations to be profitable. Peaking resources, such as gas and oil, are characterized by relatively low investment and maintenance costs and the ability to ramp quickly, allowing them to be profitable even when operating for very short periods of time, as long as the price at that time is relatively high. Given currently operated generation technologies, a mid-merit resource like coal is not a substitute for a peaking technology.

[106] MISO expects low midday prices but July evening hours' prices are forecasted to be as high as $300/MWh. Amanda Durish Cook, *MISO Anticipates High Energy Prices at 50% Renewables*, RTO Insider, July 26, 2020; *see also* Hamid Aghaie, *The Impact of Intermittent Renewables on the Resource Adequacy in Electricity Markets*, IEEE 25th International Symposium on Industrial Electronics (ISIE), at 598, 602 (2016); James Bushnell & Kevin Novan, *Setting with the Sun: The Impacts of Renewable Energy on Wholesale Power Markets* 30 fig.2 & 32 fig.4 (NBER Working Paper 24980, 2018) (showing substantial long-term decrease in mid-day prices combined with an increase in shoulder hour prices in CAISO).

partial unpredictability, is likely to result in both more frequent scarcity situations[107] and a surge in the maximum prices that energy markets reach. On windless, cloudy days, a lower amount of useful capacity will be available than would be the case with traditional dispatchable resources, creating higher scarcity prices. As a consequence, studies indicate that peak prices will generally increase in line with the growing presence of renewable generation.[108] However, average electricity prices can rise or fall as renewables' presence grows, depending on those renewables' degree of intermittency and the design of scarcity pricing (see box on page 27). With correctly designed scarcity pricing, then, regardless of the effect on average prices, a higher share of renewables can boost profits for capacity that is able to produce in times of scarcity.[109]

Finally, the argument that under energy-only markets high renewable penetration will lead to insufficient revenues which in turn will threaten resource adequacy overlooks the signaling role of prices: in the long term, it is impossible to have consistently low energy prices as well as insufficient generation resources because that insufficiency will push prices higher. With a functioning scarcity pricing mechanism, capacity scarcity will boost energy prices, counteracting any revenue insufficiency problems.

The features of energy-only markets noted above also suggest that they are better suited than energy-plus-capacity markets for attracting investment in battery storage, demand response resources, and other flexible technologies. This is because the business models that make flexible technologies valuable draw on energy price dispersion and volatility, both of which are more pronounced in energy-only market designs than energy-plus-capacity ones. Batteries' profits, for instance, increase with increases in the difference between prices at which they buy energy and those at which they can sell it. For demand response resources, profitability rises with the difference between the wholesale energy price and retail rates paid by end-users. For both of those resource types, well-designed scarcity pricing can send strong investment signals.[110]

Multiple engineering and economic studies have confirmed the viability of the energy-only approach in a high renewables future, showing through modeling and simulations that scarcity pricing can attract sufficient investment even with zero-cost resources.[111]

Admittedly, taking an energy-only approach to resource adequacy as renewables' portion of the generation mix grows will involve challenges. In particular, implementing an energy-only approach is likely to face political opposition because optimal market rules, applied to a rising share of renewables, will *by design* result in significant price volatility and increasing maximum price levels.[112] (See the box on the next page) For instance, a study conducted in Australia predicts that

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[107] Aghaie, *supra* note 106, at 598, 601.

[108] Jenny Riesz, Joel Gilmore & Iain MacGill, *Assessing the Viability of Energy-Only Markets with 100% Renewables: An Australian National Electricity Market Case Study*, 5 Econ. of Energy & Env't Pol'y 105, 109–11 (2016).

[109] Aghaie, *supra* note 106, at 601 figs.2 &3.

[110] Jacob Mays. *Missing Incentives for Flexibility in Wholesale Electricity Markets*, 149 Energy Pol'y 112010, at 8 (2021); Cramton, *supra* note 10, at 607.

[111] *See, e.g.*, Audun Botterud & Hans Auer, *Resource Adequacy with Increasing Shares of Wind and Solar Power: A Comparison of European and U.S. Electricity Market Designs*, 9 Econ. of Energy & Env't Pol'y 71 (2020); Todd Levin & Audun Botterud, *Electricity Market Design for Generator Revenue Sufficiency with Increased Variable Generation*, 87 Energy Pol'y 392 (2015); Anthony Papavasiliou & Yves Smeers, *Remuneration of Flexibility Using Operating Reserve Demand Curves: A Case Study of Belgium*, 38 Energy J. 105 (2017); Riesz, Gilmore & MacGill, *supra* note 108. *But see also* Oscar Kraan et al., *Why Fully Liberalised Electricity Markets Will Fail to Meet Deep Decarbonisation Targets Even with Strong Carbon Pricing*, 131 Energy Pol'y 99 (2019); Arne van Stiphout, Kristof De Vos & Geert Deconinck, T*he Impact of Operating Reserves on Investment Planning of Renewable Power Systems*, 32 IEEE Transactions on Power Systems 378 (2017).

[112] Frank A. Wolak, *The Role of Efficient Pricing in Enabling a Low-Carbon Electricity Sector*, 8 Econ. of Energy & Env't Pol'y 29, 37–38 (2019); Carsten Helm & Mathias Mier*, On the Efficient Market Diffusion of Intermittent Renewable Energies*, 80 Energy Econ. 812, 813 (2019).

maximum prices will need to reach as high as $80,000/MWh there to maintain the current levels of resource adequacy in a 100% renewables scenario.[113] Given that policymakers usually shun even short-lived surges in energy prices, it is not obvious that the levels of energy prices required to send accurate signals about resource investment needs will be tolerated. Additionally, if consumers are allowed to sign real-time pricing contracts for their energy usage but are not fully informed about price spikes' occurrence or their impacts on energy bills or if reduced consumption might be difficult or dangerous for them, disastrously high energy bills can result—something that occurred for numerous retail customers in ERCOT during the February 2021 cold snap. Because an energy-only market with artificially low scarcity prices will not yield adequate revenue, it is not clear that energy-only markets will be able to retain their current form in a high-renewables future.[114]

Even as they reduce average energy prices, renewables can also drive maximum price peaks higher

Assume that two energy systems, A and B, face identical electricity demand. Most of the time, the demand is represented by a low demand curve but for ten hours a year the demand surges, i.e., the demand curve is shifted out. The two systems are also almost identical in terms of their resource mix: system A reached an equilibrium with 100 MW of nuclear generation which is just sufficient to cover the regular demand. Additionally, 15 MW of gas generation are on the system, which is switched on only during the high demand time. System B has the same resources but a quarter of the nuclear generators (25MW) are replaced by wind turbines of equal effective capacity. The wind intensity fluctuates over time.

Gas generators have the highest marginal generation costs and thus act as peakers. In System A, the peakers run during the ten hours of high demand each year. Those hours are characterized by a scarcity price necessary for the peakers to recover their investment cost while collecting energy revenue for only a short time. In System B, the utilization of gas generation is very different. The gas resources may not be dispatched at all during peak demand times if those peak hours happen to experience strong winds. On the other hand, gas resources are sometimes dispatched even on regular demand days if there is no wind. On those no-wind days, though, energy prices tend to equal the marginal generation costs of gas power plants, so the energy revenue from regular demand times does not help recover these peakers' fixed costs. The main source of revenue is thus peak net demand periods when the wind does not blow. In those hours, capacity scarcity is higher than the scarcity System A ever experiences, resulting in system B's prices surging above System A's peak prices.

Despite strong similarities between them, Systems A and B end up with very different price distributions. Depending on wind availability, System B's prices will sometimes be above and sometimes below those of System A. As the unavailability of the electricity generation source exacerbates capacity scarcity, we should expect the maximum price in a given year to be higher in the system with more intermittent resources.

[113] Riesz, Gilmore & MacGill, *supra* note 108, at 105.

[114] Even though we refer to ERCOT and Australian markets as energy-only, in their current form they have price caps, albeit set at very high levels—ERCOT maintains a $9,000/MWh cap on energy prices and the cap in Australia's energy market is set at $13,500/MWh.

IV. How Capacity Markets Can Encumber Renewables Deployment

In principle, both energy-only markets with scarcity pricing and capped energy-plus-capacity markets can yield very similar outcomes with respect to investment in generation generally and in renewable generation in particular. But, as noted in Section III, leading analysts have argued that energy-only market design is superior to relying on capacity markets for the purpose of encouraging investments in renewable resources and new energy technologies.[115] Their argument marries economic theory and growing practical concerns over the negative impacts that recently-adopted capacity market rules are expected to have on the addition of renewable resources to the generation resource mix. It aligns with observations made by policymakers, researchers, and members of the environmental community that capacity markets' rigid, and arguably arbitrary, requirements for market participation often disadvantage new technologies like energy storage or solar generation.[116] Evidence suggests that existing capacity market rules do often overstate the capacity contributions of conventional resources,[117] inflate prices,[118] and over-procure capacity.[119] Taken together, such effects could slow down retirements of fossil-fueled generators and increase the costs of investments in renewables.[120] Indeed, the apparent conflict between some capacity market rules and the deployment of renewables has been quite thoroughly articulated by a member of the Federal Energy Regulatory Commission,[121] and has inspired calls to re-examine the entire concept of capacity markets.[122]

If capacity markets do negatively affect the deployment of renewables, their presence in key regions bodes ill for decarbonization of the electricity sector. Capacity markets operate in four wholesale electricity trading regions in the Northeast and Midwest: ISO-NE, MISO, NYISO, and PJM, which together serve about 40% of the United States' population and administer nearly half of the total annual electricity load of the United States.[123] Particularly in the Northeast and Mid-Atlantic, the potential threat posed by capacity markets to state-level clean energy policies has prompted several

115 *See, e.g.*, William W. Hogan, *Electricity Market Design: Energy and Capacity Markets and Resource Adequacy* 9 (EUCI Conference, Capacity Markets: Gauging Their Real Impact on Resource Development and Reliability, 2015), https://perma.cc/7J3N-QNSB ("Better scarcity pricing would reduce the size and importance of capacity payments and improve incentives for renewable energy.").

116 Michael Hogan & David Littell, Reg'y Assist. Project, Get What You Need: Reclaiming Consumer-Centric Resource Adequacy 1–2 (2020).

117 Gramlich & Goggin, *supra* note 49, at 15. As noted in the description of the August 2020 rolling blackouts in California above, it is also possible to overstate the capacity contribution of renewables, as seems to have occurred there. *See* California Root Cause Analysis, *supra* note 69, at 41–42, 49–50 (noting that behind-the-meter solar received credits in the day-ahead market that its contributions did not match, and that utility-scale wind and solar underperformed relative to their day-ahead bids as well).

118 Robert McCullough et al., *Why Have PJM Capacity Markets Decoupled from Actual Capacity Bids?*, 32 Electricity J. 106640, at 11 (2019).

119 Newbery, *supra* note 63, at 401, 408.

120 William Driscoll, *Biased Capacity Markets Accelerating Gas over Solar, Storage*, PV Mag., Nov. 26, 2019.

121 Order Rejecting Tariff Revisions, 172 FERC ¶ 61,206 (2020) (Glick, Comm'r, dissenting) ("Today's order is just the latest in the Commission's ever-growing compendium of attempts to block the effects of state resource decisionmaking.").

122 *See* Jasmin Melvin, *FERC's Glick Questions Continued Necessity of Mandatory Capacity Markets*, S&P Global, July 15, 2020 (quoting Rob Gramlich at American Public Power Association conference as an example of calls to reconsider role of capacity markets).

123 The combined total annual load for ISO-NE, MISO, NYISO, and PJM was 1,756 TWh in 2015, while the total sales to ultimate customers in the United States totaled 3,759 TWh in 2015. U.S. Energy Info. Admin, *Annual Energy Outlook: Table 1.2. Summary Statistics for the United States, 2009-2019*, https://perma.cc/S52A-A89A (accessed Mar. 10, 2021). The population (in millions) served by ISO-NE, MISO, NYISO, and PJM is 14.8, 42, 19.8, and 65, respectively, while the entire U.S. population is 328.2 million.

states to vocally consider alternatives.[124] For example, Connecticut has argued that participation in ISO-NE's capacity market forces the state to invest in natural gas-fired plants, contrary to the state's public policy goals.[125] Furthermore, Illinois, Maryland, and New Jersey, all in PJM, have publicly indicated their exploration of leaving the PJM capacity market because of the disadvantage it creates for low carbon resources.[126] Finally, New York began studying alternatives to NYISO's capacity market due to concerns about the potential future impacts of the existing market design on the state's clean energy ambitions.[127]

The rest of this Section examines six elements of market design that tend to cause capacity market outcomes to diverge from the outcomes of energy-only markets with respect to renewables deployment.

Asymmetric Risk Effects

As investors typically are risk-averse, higher investment risks deter investment and raise the cost of financing.[128] Capacity markets decrease risks related to investment cost recovery compared to an energy-only market design that includes scarcity pricing.[129] They do so by replacing highly volatile and unpredictable scarcity prices with energy and capacity payments that are more consistently and predictably distributed over time. In other words, capacity mechanisms represent a financial hedge for generation resources.[130]

That risk reduction effect from capacity remuneration is stronger for resources with lower fixed costs and higher operating costs, such as gas power plants, as capacity payments allow them to recover, risk-free, a substantial share of their fixed costs.[131] For sufficiently low per-MW investment costs, capacity payments could completely cover annualized investment costs, completely eliminating the risk for the resource.[132] However, for high fixed cost, low operating cost resources like

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[124] Catherine Morehouse, *11 Attorneys General Urge FERC to Respect State Energy Rights*, Utility Dive, Oct. 29, 2019 ("[S]tates with more aggressive clean energy goals have protested CASPR, saying it continues to promote incumbent fossil fuel generators."); Jasmin Melvin & Valarie Jackson, *Capacity Market Turmoil Has States Eyeing the Exit as Grid Operators Seek Solutions*, S&P Global, Feb. 13, 2020 ("[N]ew market rules in [PJM and ISO-NE] have drawn criticism for purportedly disadvantaging renewable energy resources and frustrating state clean energy policies. As such, several states have put leaving the capacity market, or even the entire regional transmission organization, as an option on the table to ensure their decarbonization goals can be achieved.")

[125] Catherine Morehouse, *Connecticut 100% Carbon-free Plan Is Change to Move Beyond ISO-NE Gas Focus: DEEP Chief*, Utility Dive, Sept. 9, 2019.

[126] Arianna Skibell, *Md. Weighs Existing U.S. Grid Market over FERC Order*, E&E News, Apr. 24, 2020; Jeff St. John, *Why Illinois May Need to Ditch PJM's Capacity Market to Reach 100% Clean Energy*, GTM, Mar. 17, 2020; Frustrations from PJM states with decarbonization goals are likely exacerbated by the fact that PJM states have the least authority over resource adequacy compared to other RTOs. *See* Ann McCabe, David A. Svanda & Betty Ann Kane, Org. PJM States, Making Markets Work for PJM States 8–9 (2019).

[127] *See* Kathleen Spees et al., The Brattle Grp., Quantitative Analysis of Resource Adequacy Structures (2020) (estimating economic benefits of exiting NYISO's capacity market construct).

[128] Investors could, with access to complete futures and contract markets, hedge against revenue fluctuations with minimal transaction costs, reducing or removing the impact of investment risks on investment decisions. However, the financial products needed to do so have not been developed. *See* Newbery, *supra* note 63, at 402; Fabio Genoese & Christian Egenhofer, CEPS Task Force Report: Reforming the Market Design of EU Electricity Markets: Addressing the Challenges of a Low-Carbon Power Sector 2 (2015).

[129] Marie Petitet, Dominique Finon & Tanguy Janssen, *Capacity Adequacy in Power Markets Facing Energy Transition: A Comparison of Scarcity Pricing and Capacity Mechanism*, 103 Energy Pol'y 30, 31 (2017).

[130] Jacob Mays, David P. Morton & Richard P. O'Neill, *Asymmetric Risk and Fuel Neutrality in Electricity Capacity Markets*, 4 Nature Energy 948, 948–49 (2019).

[131] *Id.* at 952.

[132] Note that there is no risk for resources associated with recovering generation costs as, because of auction design of the energy markets, resources produce electricity only in situations when the price they receive exceeds their generation costs.

renewables or nuclear generators, capacity payments cover only a small share of their investment costs, and energy prices will therefore determine whether they recover most of those costs.[133]

As a result, in a fundamental way, capacity markets favor resources with relatively low investment costs, decreasing the risks associated with them and thus also financing costs. As fossil-fueled resources happen to have such cost characteristics,[134] capacity markets will tend to favor emitting resources, slow renewables deployment, and thus slow decarbonization.

Measuring Renewables' Capacity Contributions Poorly

Opting for an energy-plus-capacity approach to resource adequacy means needing to specify design elements for a capacity market as well as an energy market. For instance, it is necessary to define capacity products, specify when trading will occur, identify who is allowed to bid into the market, determine any limits on the bids that can be submitted, and so on. Capacity markets implemented across the United States, despite relying on the same basic idea, differ in their design details. An important difference in their implementation relates to the way those markets account for the intermittency of renewables and limitations of storage resources.

Both energy and capacity markets rely on forecasts to establish the prices at which resources clear and to allocate those resources. Solar and wind are more dependent on weather conditions than fossil-fueled resources and cannot adjust their power output according to an order from the grid operator—in industry jargon, they are not "dispatchable"—so non-hydro renewable supply forecasts are inherently uncertain. Batteries are dispatchable, and so can offset renewables intermittency to some extent, but batteries are also limited in their energy injections to the amount of energy they have stored at a given moment. Renewables and batteries thus present a greater challenge to RTOs' forecasting of how much generation capacity available resources will be able to contribute under capacity scarcity conditions. In practice, RTOs tend to assign a capacity value ("capacity credits") to each resource type, which defines how much of a given resource's nameplate capacity can be considered firm enough to be saleable in a capacity auction.[135] RTOs have chosen very different approaches to assigning capacity credits and a number of recent RTO proceedings have focused on how capacity markets should account for renewables' capacity.[136] While overestimating the capacity value of renewables can result in insufficient capacity, undercounting it means allocating less capacity revenue to wind and solar resources than would be economically optimal, suppressing the build-out of renewables. Undercounting renewables' capacity contributions will also cause excess capacity—specifically, non-renewable capacity—to be built.

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[133] For a review of price hedging instruments used currently by renewable developers, see Jay Bartlett, *Reducing Risk in Merchant Wind and Solar Projects through Financial Hedges* (RFF Working Paper 19-06, 2019).

[134] While 40% of the levelized cost of a new gas power plant may be capital investment, that percentage can be as high as 80-90% for new wind and solar generation. Brendan Pierpont, *A Market Mechanism for Long-Term Energy Contracts to Support Electricity* 6 (Resources for the Future, 2020), https://perma.cc/EAL4-FCJL.

[135] *See, e.g.*, Lennart Söder et al., *Review of Wind Generation Within Adequacy Calculations and Capacity Markets for Different Power Systems*, 119 Renewable & Sustainable Energy Rev. 109540, at 2–3 (2020); Eduardo Ibanez & Michael Milligan, Nat'l Renewable Energy Lab'y, "Comparing Resource Adequacy Metrics and Their Influence on Capacity Value," Int'l Conf. on Probabilistic Methods Applied to Power Systems (PMAPS), Durham, UK (2014).

[136] *See, e.g.*, PJM Interconnection L.L.C., FERC Docket No. ER21-278-000 (Oct. 30, 2020) (proposing use of Effective Load Carrying Capability construct "for determining the relative amount of capacity that variable, limited duration, and combination resources may offer" in PJM's capacity market); ISO New England, *ISO New England's Draft 2021 Annual Work Plan* 10 (Sept. 17, 2020) (indicating that preliminary study of ELCC would "analyze the capacity value of adding renewable generation and energy storage resources.").

Energy-only markets are better able to properly account for the value of intermittent resources because those markets rely on forecasts over a much shorter time-horizon—minutes and days rather than months and years. This means that the forecasts informing energy-only markets are starkly more accurate than those needed to inform capacity markets, and that energy market operators can know and better compensate the contributions of wind and solar resources to reliability.

Favoritism Through Operational Requirements

Defining operational requirements can amount to picking the winners and losers of capacity market auctions. For instance, if an RTO knows that it needs fast ramping capability, must such capability be available for a full hour, or are smaller intervals sufficient? And is it sufficient for resources to be available just during peak demand, during shoulder ramping periods, or must they be available all the time?[137] Answers to questions like these determine whether and how resources may participate in a capacity market. Thus, capacity markets' tendency to impose operational requirements that are effectively if not always expressly technology-specific makes for another potential bias.

A clear example of where operational requirements have tilted a capacity market against some technologies and in favor of others comes from PJM, where, since 2019, the market operator has imposed strict participation rules on storage technologies.[138] Batteries have had to be capable of a 10-hour discharge to participate in the capacity market, and their compensable capacity capped based on whatever level of capacity they could sustain for the full 10-hour duration.[139] Applications of currently available commercial batteries can entail a wide variety of rates and levels of discharge, but most of those entail discharge durations of between 15 minutes and four hours. Thus, PJM's "10-hour rule" (which PJM has proposed to replace but, as of this writing, remains in force) effectively excluded many ways that batteries might participate in capacity markets and perform a valuable service. This, of course, keeps batteries' revenues below what fuller utilization would yield and causes capacity payments to flow to other resources that might not have cleared the market had PJM's requirement been less incompatible with batteries' operational profiles. Notably, other RTOs, recognizing that batteries can add significant value over short spans of time, authorize batteries to bid their capacity for shorter durations.

Understanding the contributions of energy-limited resources, especially batteries, to resource adequacy can be challenging.[140] In the context of capacity markets, it might require construing batteries' patterns of charge and discharge to assign capacity credit to those resources, a task that entails making speculative assumptions about how battery owners form expectations about energy prices. Those assumptions mean that the market operator may misrepresent the battery owners' decisions in its modeling, for example by assuming the wrong price threshold below which the batteries start charging in a given the weather situation. As a consequence, capacity markets may systematically mis-value storage for resource adequacy purposes. By contrast, in an energy-only market, the market operator can allow storage resources to participate in auctions without knowing or construing their charge and discharge patterns in advance. And, further, the

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137 *See* James Bushnell, Michaela Flagg & Erin Mansur, *Capacity Markets at a Crossroads* 29 (Energy Institute at Haas Working Paper No. 278, 2017).

138 *PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,049 P 101 (2019) (describing PJM's energy storage resource compliance filing as "setting an Energy Storage Resource's capacity value based on the level of continuous output that can be sustained for 10 hours ensures that PJM dispatchers can call upon such resources to manage loads in a typical summer peak day in a manner comparable to any other dispatchable resource."); *but see* PJM Interconnection, L.L.C.: Effective Load Carrying Capability Construct, FERC Docket No. ER21-278, at 2 (Oct. 30, 2020) (proposing to "replace the current 10-hour rule for storage resources" in 2021).

139 Iulia Gheorghiu, *Tesla, Others Question Storage Hourly Requirements, Charges in FERC Order 841 Compliance Plans*, Utility Dive, Feb. 13, 2019 (listing capacity market participation rules in effect in 2019 for batteries across RTOs).

140 Bushnell, Flagg & Mansur, *supra* note 137, at 29; Herman K. Trabish, *Battery Energy Storage Is Getting Cheaper, but How Much Deployment Is Too Much?*, Utility Dive, June 30, 2020.

market operator need not specify operational requirements to minimize the chances that administrative decisions will distort market outcomes. Instead, storage resources with diverse durations of discharge capacity can participate freely in auctions, optimizing their bids with respect to the expected energy prices and their discharge abilities.

Favoritism Through Obligation Periods

Capacity markets can also encumber renewables' participation by only allowing sales of products that are partly or wholly incompatible with renewables' patterns of generation. Capacity contracts with long, seasonally uniform obligation periods are the clearest example of this. They tend to substantially exclude renewable resources whose generation capability varies seasonally and diurnally. Wind farms, for instance tend to generate less energy in mid to late summer and more in winter and spring. They also tend to generate more at night than during the day.[141] Such changes in generation ability are well understood. Adopting a uniform, long-duration capacity commitment nonetheless ensures that at least some of wind's generation potential goes unvalued and unused by capacity markets.[142] Notably, RTOs differ in this respect: while PJM's annual obligation periods generally disfavor renewables,[143] NYISO's use of two obligation periods (summer and winter) and monthly auctions facilitates renewables' participation by accommodating cyclical changes in their pattern of generation.

Energy-only markets do not confront renewables with such hurdles to participation. For reasons similar to those discussed above in relation to measuring capacity contributions, renewables' participation in energy-only markets does not require as many carefully crafted—and potentially mis-specified—administrative rules as is the case in capacity markets.[144] Nor do energy-only markets create as many opportunities for RTOs' decisions to shape or intervene in market operation.

Mis-specifying Penalties for Non-Performance

In capacity markets, resources that fail to perform consistent with the capacity obligations they undertake when clearing the market often face non-performance penalties.

Whereas energy-only markets' prices adjust constantly, sending granular signals about what resource availability patterns are of greatest value, energy-plus-capacity markets lack this dynamism and granularity. Capping energy prices causes resources to be exposed to the same price—the price cap—under different levels of energy scarcity. Therefore, energy-plus-capacity market designs have to rely on administrative approaches—such as penalties for nonperformance—to signal the social value of providing electricity in times of scarcity.

Penalties for nonperformance should be calibrated to enhance resources' incentives to be available when their generation would be most valuable to society. As energy prices under an energy-only market by design reflect the social value

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[141] Sylwia Bialek & Burcin Unel, *Will You Be There for Me the Whole Time? On the Importance of Obligation Periods in Design of Capacity Markets*, 32 Electricity J. 21, 22 (2019) (citing Katie Coughlin & Joseph H. Eto, Lawrence Berkeley Nat'l Lab'y, Analysis of Wind Power and Load Data at Multiple Time Scales (2010)).
[142] *Id.*
[143] *See* PJM Manual 18: PJM Capacity Market, Section 4.10 Seasonal Capacity Performance Resources 112–13 (2021).
[144] The obligation period of the energy product traded can bear upon intermittent renewables.

of generation, a non-performance penalty should approximate the revenue loss that the resource would experience for failing to perform in an energy-only market. In addition to being efficient, this would, in principle, be neutral towards all types of resources.

Because renewables have more uncertain generation capabilities than conventional resources, they are more likely to miss their capacity market performance commitments. As renewables are affected by penalties to a greater degree than conventional resources, mis-specifying penalties is especially consequential for them: set too high, non-performance penalties will discourage renewables' capacity market participation and decrease their share in the resource mix.[145] By implication, penalties set too low will inefficiently favor renewables. Although the scale of the outsized effects of penalty misspecification is difficult to estimate, the growing presence of renewables means that those effects will grow.

Minimum Offer Price Rules that Target Renewables

Capacity markets can impose still other rules that encumber renewables' deployment for reasons unrelated to renewables' variability or intermittency. The Minimum Offer Price Rule (MOPR) in PJM is perhaps the clearest example of this.[146] MOPR was originally devised to limit buyers' ability to use market power to inefficiently suppress prices. But it has lately been applied in a way that encumbers renewable and storage deployment, impeding some PJM member states' pursuit of clean energy deployment goals. Specifically, in its current form, MOPR requires that any resource in receipt of a "state subsidy" (which includes direct subsidies or payments from participation in Renewable Energy Credit markets) must offer its capacity at a price equal to or above specified offer floors. The floors are meant to reflect what PJM believes the resource would bid in the absence of state support. Rules with a similar underlying logic have been introduced in ISO-NE and NYISO as well.[147] Analyses like Bialek and Unel (2018) and Bialek and Unel (2020) indicate that MOPR and its counterparts in other RTOs detract from efficiency and bias the resource mix toward fossil fuels.[148] The magnitude of those effects, as well as adverse impacts on consumers, is significant.[149] Currently, there are no rules similar to MOPR in energy markets.

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Energy-only markets with scarcity prices is a relatively simple design,[150] which largely relies on market forces to reach the optimal solution.[151] In contrast, energy-plus-capacity market designs require including multiple, complex features and specifications, such as a non-performance penalty system whose parameters can be misspecified easily. Additional rules for those markets, such as MOPR, compound the distortions, such that energy-plus-capacity markets incentivize entry and exit and generation patterns that are markedly different than those that would occur in energy-only markets.

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145 *See* Gramlich & Goggin, *supra* note 49, at 14.

146 *See* Calpine Corp. v. PJM Interconnection, L.L.C., 169 FERC ¶ 61,239 (2019) (imposing MOPR on resources benefiting from "state subsidies").

147 *See ISO New England Inc.*, 162 FERC ¶ 61,205 (2018) (adopting Competitive Actions with Sponsored Policy Resources program and imposing MOPR on resources receiving state support); *N.Y. Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,121 (2020) (rejecting in part NYISO's 2016 proposed exemptions from application of Buyer Side Mitigation rules).

148 *See* Bialek & Unel (2020), *supra* note 65; *and* Sylwia Białek & Burcin Unel, Capacity Markets and Externalities 6 (2018), http://policyintegrity.org/files/publications/Capacity_Markets_and_Externalities_Report.pdf.

149 Michael Goggin & Rob Gramlich, Grid Strategies, A Moving Target: An Update on the Consumer Impacts of FERC Interference with State Policies in the PJM Region 5 (2020).

150 Ideally, this design would be implemented using a standard financial contract, such as an option with a strike price on the offer cap.

151 Currently, scarcity pricing is administratively determined but, in principle, it could be determined using a more market-based approach.

Those differences result partly from the logic of capacity markets in general, but are mostly driven by particular design choices. If one agrees with the premise that energy-only markets can incent the optimal resource and generation mix, then capacity markets' apparent departures from the results that energy-only markets would deliver suggest that capacity markets' designs are slowing renewables' deployment unnecessarily.

Capacity markets also tend to over-procure capacity,[152] giving rise to a sub-optimally large equilibrium resource fleet and the suppression of energy revenues—an especially important source of revenue for renewable resources.[153] Further, this over-procurement implies that even more fossil-fueled capacity remains online, ready to generate. Without carbon pricing in the energy market, those resources are dispatched too frequently compared to the optimum, further undermining decarbonization efforts.

Capacity markets and over-procurement

RTOs with centralized capacity markets have historically acquired capacity beyond their target reserve margin, and the amount of generation capacity on their system is well beyond what is required to meet demand.[154] For example, PJM's 2020 target reserve margin is 15.9% while the actual 2020 anticipated reserve margin is more than twice that at 35.5%.[155] This over-procurement contributes to climate change and increases costs to consumers. One study found that customers in PJM alone pay an extra $4.4 billion per year for that capacity procured in excess of the target reserve margin.[156]

152 *See* Newbery, *supra* note 63, at 401.

153 *See* James E. Wilson, Over-Procurement of Generating Capacity in PJM: Causes and Consequences 10 (2020).

154 Christina Simeone & John Hanger, Kleinman Ctr. for Energy Pol'y, A Case Study of Electricity Competition Results in Pennsylvania 2 (2016).

155 N. Am. Electric Reliability Corp., 2018 Long-Term Reliability Assessment 10 (2018).

156 Wilson, *supra* note 153, at 10.

V. Ways to Make Capacity Markets More Renewables-Friendly

As we have shown above, both energy-only and energy-plus-capacity market designs present challenges for a high-renewables future. For instance, even if policymakers were persuaded that an energy-only design was better for the purpose of supporting renewables deployment and grid decarbonization, they might still balk at adopting such a design because it would yield significant price volatility and occasionally very high prices. Some have also voiced concerns about how well an energy-only design would support the rapid deployment of renewables because, even if long-term contracts can mitigate the financial risks involved, such a design could still allocate significant risk to investors and elevate financing costs. If these features dissuade policymakers from adopting an energy-only approach to maintaining resource adequacy, then existing capacity market designs must be improved, lest they make decarbonization unnecessarily costly or hinder it outright.

Such improvement is possible. With few exceptions, the capacity market design elements that cause unfavorable treatment of renewables are not inherent or indispensable, and can be modified. Further, existing capacity markets' asymmetric impact on risk profiles of fossil-fueled and renewable resources can be neutralized by providing better hedging opportunities or by developments in green finance. Notably, some measures would improve outcomes in both energy-and-capacity and energy-only markets.

The suggestions below can also be read as evaluation criteria to be added the list of standard economic efficiency criteria for market design, such as keeping transaction costs law and limiting market power. Note, however, that because of the significant design differences across existing capacity markets, some of these design choices may not be possible for a particular wholesale market to implement without additional reforms.

Improve Energy Price Formation

Improving energy price formation by making prices more granular and, when appropriate, allowing them to rise higher, is crucial to pave the way for a renewable future. With the growing presence of renewables, flexibility will play an increasingly important role in grid balancing. Sustaining resources and business models capable of providing that flexibility requires more granular price formation than has been provided for historically.

For energy-plus-capacity market design, raising energy price caps and expanding existing scarcity pricing elements (with emphasis on reserve procurement) is particularly relevant, facilitating investment without imposing capacity markets' bias in favor of gas-fired peaker plants. The higher the price caps, the more the system will resemble an energy-only design, meaning that it will avoid to a greater degree capacity markets' tendency to mis-specify capacity credit and apply coarse capacity product definitions. PJM, for one, has already embraced some improvements to price formation: its new reserve pricing, which uses nested zones, will allow prices in the most congested parts of PJM to soar up to levels previously seen only in ERCOT.[157]

[157] Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C., FERC Docket No. EL19-58-000 (Mar. 29, 2019), https://perma.cc/2MX7-XQHP.

Notably, energy prices are more compatible than capacity prices with emissions pricing. This is because emissions relate to *actual* electricity generation and not to capacity, which is just the *potential* to deliver energy. As such, a market design that seeks to incorporate the social cost of emissions into wholesale market prices, directly or otherwise, should do so by adding an emissions price to each increment of emissions, which track increments of energy closely. A second-best approach might compensate resources through the energy market for each megawatt hour generated without emitting.[158] Constructs that link emissions to capacity, such as the Forward Clean Energy Market design mentioned above, need to first predict the injection profile of a given resource, which is a highly complex task that runs the risk of mis-specifying the resource's (avoided) carbon content. As we explained in Section II, some resources may run just few hours a year, and so have a low environmental impact despite being emissions-intensive. Additionally, the linkage of capacity to emissions, once established, removes incentives for resources to actually avoid emissions.

Establish Appropriately Downward-Sloping Capacity Demand Curves

A properly downward-sloping demand curve serves several important purposes. Existing energy-plus-capacity designs often result in over-procurements of capacity. This disproportionate allocation of wholesale revenues to capacity (and away from energy) combines with capacity markets' bias towards fossil-fueled resources to reduce opportunities for renewables. Proper demand curve design can serve as a countermeasure to the over-procurement problem. Getting the capacity demand curve right involves both selecting an appropriate reference technology[159] and ensuring that the shape of the demand curve is sloped to reflect the social marginal value of each increment of capacity—that is, the amount that each additional unit of capacity contributes to reliability.[160] (The alternative to a downward-sloping demand curve is a fixed level of capacity procurement or vertical demand curve, such as MISO currently employs.)

By signaling a range of energy generation levels that the system can tolerate without outages occurring, a downward-sloping demand curve calibrated to reflect social marginal value safeguards against problems of under- or over-procurement. A properly sloping curve also decreases opportunities to exert market power in energy markets.[161]

Encourage Flexibility of Electricity Demand

Flexible and responsive electricity demand is especially important for integrating renewables.[162] It will also tend to lower the amount of capacity required to serve load while improving system price efficiency.[163] Price volatility encourages investments in the technologies, business models, and practices that will provide the grid with the flexibility required to integrate large volumes of renewables.

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158 Bialek & Unel (2018), *supra* note 148, at 7.

159 *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,040, P 2 (2020) (Glick, Comm'r, dissenting) (criticizing designation of combustion turbines as reference resource).

160 Benjamin F. Hobbs et al., *A Dynamic Analysis of a Demand Curve-Based Capacity Market Proposal: The PJM Reliability Pricing Model*, 22 IEEE Transactions on Power Systems 1–2 (2007).

161 *Id.*

162 Int'l Renewable Energy Agency (IRENA), Solutions to Integrate High Shares of Variable Renewable Energy 7 (2019).

163 Severin Borenstein & James B. Bushnell, *Do Two Electricity Pricing Wrongs Make a Right? Cost Recovery, Externalities, and Efficiency* (NBER Working Papers 24756, 2018).

Thoughtful retail rate design and demand response programs are valuable for increasing demand flexibility,[164] while also conferring other benefits.[165] However, energy-plus-capacity markets will tend to deliver lower variation in energy prices than energy-only markets and thus provide less stimulus for techniques and technologies that enable flexible, responsive demand. Overcoming this tendency in an energy-plus-capacity market context requires, first and foremost, allowing wholesale energy prices to sometimes climb fairly high, as there will be little incentive for demand to respond if prices are kept low. Importantly, however, price-responsive demand can only avert over-procurement of capacity if capacity market demand curves are formulated properly. For instance, the predictions of peak demand that are used to construct the capacity demand curve must account for the impact of energy prices on energy demand levels.

Update Capacity Products and Crediting

With an increasing share of new technologies on the grid, a thorough review of the rules for how resources are accounted for in capacity auctions is needed.[166] For one, the intermittency and seasonality of renewables, combined with their low marginal costs, mean that the probability of outages may increase outside the traditional demand peak times. Capacity credits for renewables need to account for how renewables change the probability of capacity scarcity and how reliable they are in preventing outages. Second, flexible resources like batteries and demand response are energy-limited, such that they are constrained in the number of hours in which they can serve without interruptions. That feature strains against capacity credits that were specified based on conventional resources' operational profiles—especially their continuous dispatchability. Requirements that push energy-limited resources to perform like conventional ones, such as the 10-hour battery discharge requirement in PJM, might align those resources with the logic of existing capacity credits, but they also result in the systematic underestimation of renewable and flexible resources' potential contributions to capacity, resulting in an inefficient use of resources.

Many RTOs have already started reviewing how they credit capacity; however, they should ensure that the rules do not discriminate against renewables. For instance, PJM is working toward adoption of an Effective Load Carrying Capability (ELCC) approach to determining capacity credit for renewables and storage.[167] This approach uses probabilistic modeling of how a resource would respond to expected reliability problems or outage events considering resource availability and use limitations. However, for traditional generation technologies, PJM plans to keep its current approach of assigning capacity credit based on how much generation capacity a resource can contribute during summer peak demand. If the probability of outages increases outside of historical summer peak demand times and if the fossil-fueled resources have different outage and maintenance patterns in the summer than in the rest of the year, then their capacity contributions will be overstated, resulting in overcompensation relative to resources valued using the ELCC methodology. Applying a uniform capacity credit methodology across all resources would eliminate such issues.

The various challenges arising from new technologies' presence on the grid may warrant a complete redesign of capacity market products. For instance, the seasonality of resources, the outage risks showing up outside of traditional peak demand times, and the fact that some resources are energy-constrained all suggest that capacity obligations should be

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[164] Wolak, *supra* note 112, at 43–44.

[165] *See generally* Richard L. Revesz & Burcin Unel, *Managing the Future of the Electricity Grid: Modernizing Rate Design*, 44 Harv. Env't L. Rev. 43 (2020).

[166] Cynthia Bothwell & Benjamin F. Hobbs, *Crediting Wind and Solar Renewables in Electricity Capacity Markets: The Effects of Alternative Definitions upon Market Efficiency*, 38 Energy J. 173 (2017).

[167] PJM, *Issue Charge: Effective Load Carrying Capability for Limited Duration Resources and Intermittent Resource* (Mar. 2020), https://perma.cc/7346-EGGW.

defined for shorter time intervals. Such a change would send more granular signals about when capacity is needed and also provide certainty to market operators that resources like batteries are ready to discharge when they are needed. Consequently, one could envision a capacity market that is split into seasons or months, as well as times of day. The clearing of the individual capacity products, such as a capacity obligation for winter nights or spring late afternoons, would be co-optimized to ensure that the capacity procurement is cost-effective while meeting reliability standards.

Update Performance Penalties and Rewards

A review of pay-for-performance systems could also help integrate renewables efficiently into capacity markets. With a properly designed system of penalties and rewards for the resources that clear capacity markets, resources would have incentives to predict their own future availability accurately and to offer the correct fraction of their nameplate capacity at auction. In such a situation, capacity credits for resources could be given by RTOs as ranges instead of point estimates, allowing for the highest feasible capacity values.[168] The resources, knowing their individual technical parameters and capabilities, would then pick the exact amount of capacity they want to offer, making it less crucial that RTOs compute the correct capacity credit for renewables. RTOs could further facilitate bidders' decisions by releasing granular data on output correlations between resources of various types throughout their footprint. Such information would help resources to better assess their generation capability when scarcity occurs.

Cease Applying Minimum Offer Price Rules to State-Subsidized Resources

MOPR and similar policies that mitigate state clean energy policies should be rescinded. State support for clean energy, and renewables especially, may continue to be necessary to level the playing field between polluting and non-polluting resources, and rescinding MOPR and similar rules will remove an important impediment to the deployment of renewables in PJM, NYISO, and ISO-NE—regions with disproportionate importance to the emissions footprint of the power sector.

Expand Available Hedging Tools in Financial Markets

As noted above, PPAs and other forms of long-term contracts and clean energy procurements already play a meaningful role in quieting financial risk for investments in renewables especially. Introducing further possibilities for resource owners to hedge their risk, for example through novel financial instruments, will mitigate the disparate effects of energy-only and energy-plus-capacity markets on different resources' risk profiles. While new hedging products, such as quantity-related weather contracts, will need to be developed outside of electricity markets, market operators and regulators can still encourage their development, examination, and use. Highlighting the availability of "off-the shelf products" with standardized terms and conditions can help to decrease transaction costs for bilateral hedging between less financially sophisticated parties.[169]

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168 Currently, even if such ranges are available, their upper limits tend to be conservative. For instance, new wind and solar projects in PJM can receive credit up to a class-average capacity value, notwithstanding their actual abilities or location.

169 *See* Int'l Renewable Energy Agency (IRENA), Unlocking Renewable Energy Investment: The Role of Risk Mitigation and Structured Finance 75–76 (2016); European Parliament Directorate General for Internal Policies, *Research for REGI Committee – Financial Instruments for Energy Efficiency and Renewable Energy* (Aug. 2017); Martin Hain et al., *Managing Renewable Energy Production Risk*, 97 J. Banking & Fin. 1 (2018) (discussing financial instruments available to address risks facing renewables).

VI. Conclusion

Wholesale electricity market design cannot ignore the burgeoning transition to a clean electric grid—a transition driven primarily by the deployment of variable renewable resources. To ensure that wholesale markets continue to provide for resource adequacy, while minimizing the total cost of providing electricity as this transition accelerates, policymakers responsible for market design decisions should undertake a critical examination and updating of existing market mechanisms. Notably, the oldest capacity markets in the United States are about 20 years old[170] and the modern energy markets are not much older. Those markets have continued to evolve since they were first established; they are flexible structures that can be adapted to new circumstances.

While recognizing that a growing share of renewables will surely change market outcomes, this report is grounded in the premise that more prevalent renewables will not change the fundamental principles that inform efficient market design—for instance, that market participants should face efficient price signals.[171] Implementing these principles will never be simple or easy, however.

This report does not identify one best way to ensure resource adequacy, and instead recognizes that different resource adequacy approaches can, in principle, achieve similar outcomes. However, even small differences in market design can cause the outcomes of individual resource adequacy approaches to diverge. While this report leaves open the question of which design a given region should adopt, it does highlight important considerations for ensuring that a given energy-plus-capacity design does not tilt the competitive field against renewables. It also indicates possible improvements for energy-only systems. This report's findings take two forms.

The first set of findings identifies design elements in existing capacity markets that put renewables at a competitive disadvantage and thus deserve, at minimum, critical attention, and, ideally, correction.

- Asymmetric risk treatment
- Measurement of renewables' capacity contributions
- Non-neutral operational requirements
- Non-neutral obligation periods
- Minimum Offer Price Rules that target renewables.

In addition to identifying evident pitfalls, this report also points to several measures that can make way for a rising tide of renewables while yet ensuring that resource adequacy is maintained at reasonable cost:

- Improve energy price formation
- Establish appropriately downward-sloping capacity demand curves for energy-plus-capacity markets
- Encourage flexibility of electricity demand
- Update capacity products and capacity crediting for energy-plus-capacity markets
- Update performance penalties and rewards for energy-plus-capacity markets

[170] PJM established its annual capacity market in 2007, New York ISO started procuring capacity in 1999, ISO-New England in 1998, and Midcontinent ISO in 2009.

[171] *See* Gordon W. Leslie et al., *Designing Electricity Markets for High Penetrations of Zero or Low Marginal Cost Intermittent Energy Sources*, 33 Electricity J. 106847, at 2 (2020).

- Cease applying Minimum Offer Price Rules to neutralize state clean energy policies in capacity markets
- Expand the set of hedging tools available in financial markets.

In the long term, market designs for resource adequacy may undergo an overhaul of the sort suggested by proposals like those listed in Table 1.[172] Should that come to pass, the measures listed above could serve not only as steps to take but as criteria by which to evaluate the merits of a given proposal.

[172] *See* Gimon, *supra* note 53; Corneli, *supra* note 13.

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