Stabilizing Consumer Bills Through State-Driven Long-Term Bilateral Contracting: A Guide for States With Restructured Electric Industries

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"If you don't know where you are going, any road will take you there"

–George Harrison[1], also Alice in Wonderland[2]

"When suppliers do not ensure that their electricity portfolio is sufficiently hedged, changes in wholesale electricity prices can leave them financially at risk and can result in their failure and their passing on costs to consumers and other network users. Hence, suppliers should be appropriately hedged when offering fixed-term, fixed-price electricity supply contracts."

European Union Directive, June 2024[3]

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[1] George Harrison, "Any Road," track 1 on *Brainwashed* (Dark Horse, 2002).

[2] Paraphrase of Lewis Carroll, *Alice's Adventures in Wonderland* (London: Macmillan and Company, 1895), 89-90.

[3] Directive (EU) 2024/1711 of the European Parliament and of the Council of 13 June 2024 amending Directives (EU) 2018/2001 and (EU) 2019/944 as regards improving the Union's electricity market design, OJ L, 2024/1711, 26.6.2024. ELI: https://eur-lex.europa.eu/eli/dir/2024/1711/oj/eng (2024 EU Directive).

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I. Executive Summary

Electric bills have become sharply higher and more volatile in certain restructured states, and voters are increasingly asking who is responsible for controlling the price they pay for power. In healthy commodity markets, long-term forward bilateral trading markets with many buyers and sellers negotiating mutually agreeable terms work alongside the central short-term spot market to insulate consumers from its price swings. Unfortunately, this price insulation (hedging) is largely absent from Northeastern wholesale capacity markets today. This report will attempt to offer both an explanation for a lack of price stabilization, and describe how states can fix it.

This problem is concentrated in capacity markets specifically, including over a dozen restructured U.S. states throughout New England, New York, and much of the Mid-Atlantic where prices have risen sharply over the last couple years. For years, competitive markets served customers well and prices stayed low and stable. In fact prices were clearing below the cost of new entry, to the benefit of consumers. And while competition is still bringing consumer benefits, the instability of prices is difficult for consumers and their elected representatives to manage. As responsibility for different pieces of electricity service has fragmented across state and federal jurisdiction and amongst several parties, it has become genuinely unclear who owns the job of managing price risk and protecting ratepayers.

It is not a problem that is inherent to competitive power markets. Some states like Texas and California, and countries like the United Kingdom (U.K.) and Australia, have successfully restructured and have functioning hedging taking place. It is a design gap specific to states that never gave load-serving entities (LSEs) the incentive or obligation to procure power years in advance. Regions with vertically integrated utilities largely avoid the problem because state-overseen resource planning insulates consumers by design. California solved it after the 2000-2001 electricity crisis—which resulted from exclusive reliance on short-term spot markets—by mandating long-term bilateral contracting by LSEs. Texas avoided the problem from the outset by building bilateral contracting into its retail access program design. Thus, the problem remains at varying levels in the restructured states within PJM, New York, and ISO-New England (ISO-NE), and in particular those where demand growth surged recently—concentrated primarily in the PJM region.

The natural entity to oversee or require bilateral contracting is the state, who has always had and retains responsibility for generation resource planning, generation portfolios, and resource adequacy as well as retail service. By contrast, regional transmission organizations (RTOs[4]) were not originally designed to have any involvement in forward contracts or hedging. They were built to administer short-term reliability, transmission service, and energy spot markets—the "air traffic controller" of the system, not the planner or procurer of planes or fuel.[5]

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[4] Although there are independent system operators (ISOs) that are not RTOs, this report uses RTOs for simplicity, unless specific reference to ISOs is needed.

[5] *See*, Hogan, Hitt, and Schmidt, *Governance Structures for an Independent System Operator* (June 1996), https://whogan.scholars.harvard.edu/sites/g/files/omnuum4216/files/whogan/files/iso0696.pdf; FERC Order No. 888, 75 FERC ¶ 61,080 (April 1996) https://www.ferc.gov/industries-data/electric/industry-activities/open-access-transmission-tariff-oatt-reform/history-oatt-reform/order-no-888; Arizu, Dunn Jr., and Tenenbaum, *Transmission System Operators – Lessons from the Frontlines* (June 2002), https://documents1.worldbank.org/curated/en/622701468781814067/pdf/280870Transmission0systems0EMS0no-04.pdf.

We use “long-term,” “bilateral,” and “forward” contracting as interchangeable terms. A balanced portfolio with a portion of shorter, medium, and longer term would be a prudent strategy to provide consumer price stability. While contracts likely need to be longer now than in the past, generators can be financed without full cost recovery and while retaining “merchant” risk.

Two assumptions stand in the way of state action, and we think both are wrong. It is widely assumed that restructured states have permanently ceded resource procurement responsibility to RTOs, putting it beyond the reach of state policy makers. We disagree. It is also widely assumed that the now is a uniquely bad time to begin state-overseen procurement since contracts signed during a period of high demand and resource scarcity would lock in high prices and create “stranded costs.” We disagree with that view as well.

We do not claim that state-overseen bilateral contracting is the only way to run an efficient, reliable power system that insulates customers and stabilizes bills. But it is an option with real merit that has received little attention. Earlier attempts at examining these issues[6] were largely ignored because capacity prices were well *below* the long-run marginal cost of new generation for many years, so the problem wasn’t yet visible. Now that high prices have caught policy makers’ attention, this is the right moment to revisit market structures built for the long-term health of restructured power markets. With wholesale power markets facing rising political pressure, it matters more than ever that all parties share a common vision for reforms that produce a coherent long-term outcome for consumers and industry participants alike.

This paper offers a vision and practical guide for policymakers who want to establish state-overseen long-term bilateral contracting as a means of stabilizing customer bills.

States should:

- Require all LSEs—including competitive retail suppliers, not just utility default suppliers—to procure a specified a balanced share of supply a predetermined number of years in advance. A balanced portfolio would include shorter, medium, and longer term purchases.
- Establish substantially more stringent creditworthiness standards for all LSEs, to ensure they can financially back the procurement of supply needed to serve the load they have contractually committed to serve.

RTOs and FERC should:

- Enable and facilitate LSEs partially or fully complying with capacity obligations using bilateral contracts.
- Provide analysis and technical support about future capacity supply and demand, and accreditation (i.e. Effective Load Carrying Capability) to facilitate bilateral trading of capacity.
- Shift market design toward more objective, physical products, starting with a more granular capacity market (such as a seasonal) and extending to energy and ancillary services. Physically determined markets are inherently better suited to bilateral

[6] *See*, Gramlich & Lacey, *Who’s the Buyer: Retail Electric Market Structure Reforms in Support of Resource Adequacy and Clean Energy Deployment*, at 20 (Mar. 2020). https://gridstrategiesllc.com/wp-content/uploads/2024/05/whos-the-buyer.pdf. (Concluding that “In the 13 states with retail competition outside of Texas, there is some degree of a market flaw where responsibility for resource procurement has not been clearly assigned to customers or their load-serving entities.”)

contracting because they are less subjective and less exposed to arbitrary "stroke-of-the-pen" interventions.
- Provide more stable, predictable market rules for capacity and energy products.

The paper describes the benefits of bilateral contracting, examines why such contracting has historically been lacking, compares the U.S. experience to power markets abroad, assesses states' legal and practical ability of states to require hedging, and outlines specific actions that can be taken by states and RTOs.

II. Introduction

Consumer utility bills have risen in recent years.[7] Elected officials and political candidates at all levels are hearing from voters and asking tough questions of everyone in the electric industry.[8] Recent increases in central capacity market prices are one of the most visible causes of these utility bill increases, along with increases in energy market prices and utility spending on transmission and distribution. Volatile prices themselves do not necessarily harm consumers or become political problems if structures are in place to insulate consumers from these price swings. Unfortunately, in most restructured states, small consumers (households and small businesses) have been exposed to volatile prices, and recent high capacity market prices have been reflected on their utility bills.

Reliability is also in question. Recent capacity auctions in PJM have cleared with insufficient supply. Yet the market is uncertain for generation investors. Investors do not know how long price collars[9] will remain in place, how long the costs of new generators and associated equipment will remain so high, or who will be their buyer ("off-taker"). There exists a "credibility gap" hindering investment, as articulated in PJM's recent white paper on the future of the capacity market.[10]

Moving forward, risk management tools that can foster investment in new generation and protect customers from price spikes are necessary to drive credibility and stability for investors and consumers. An effective solution would be to have most supply, including capacity, procured through properly managed portfolios that include bilateral contracts, as opposed to solely relying on short-term central spot markets.

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[7] U.S. Bureau of Labor Statistics, "Consumer Price Index for All Urban Consumers: Electricity in U.S. City Average," retrieved from FRED, Federal Reserve Bank of St. Louis, accessed August 2026, https://fred.stlouisfed.org/series/CUSR0000SEHF01.

[8] *See, e.g.*, PJM Governors' Collaborative, Letter to PJM Board of Managers, (Apr. 9, 2026).

[9] PJM proposed and FERC approved a price cap and floor. *See,* Troutman Pepper Locke, "PJM Seeks Extension of Price Collar for Capacity Auctions," Lexology (Mar. 11 2026), https://www.lexology.com/library/detail.aspx?g=0466eaaf-ae87-4660-8b37-9d630fdd9756.

[10] *See,* PJM, Powering Reliability Through Market Design: Addressing Rising Demand and Constrained Supply, and Stimulating Investment to Support Durable Reliability at 5-6 (May 6, 2026) (PJM White Paper). PJM refers to a "credibility trap" caused by government intervention when capacity market prices soar, but it also can be thought of as a "gap" between what the market needs to stimulate investment and the protections that customers need from price volatility during periods of market scarcity.

While often thought of solely as consumer protection, forward contracting is also the best way to attract new generation assets. Investors and developers can build more at lower risk and lower cost of capital when they have bilateral contracts.

A forgotten element of restructured markets was that there needs to be a sophisticated *buyer* of wholesale power to be the counterparties to sophisticated power producers. As written in the 2020 report, *Who's the Buyer?*[11], when no entity has the incentive, ability, or responsibility to procure power then there is no counterparty for sellers and no contracts are likely to be established. Other restructured markets around the world, such as the U.K., Australia, and California have mandatory forward contracting, or hedging. Texas has a retail design where hedging results naturally. The International Energy Agency (IEA) reports that globally, 95 percent of generation is under some form of forward contract or regulatory regime. Indeed, Northeastern restructured U.S. markets, which lean heavily on short-term spot and capacity market prices to signal new investment, are the exception to how power is transacted and generation is financed almost everywhere else in the world.

In the U.S., some restructured states have made some attempts to implement hedging over the years, focused mainly on incumbent utilities with supplier of last resort obligations. Those efforts need to be improved and expanded to all LSEs, including competitive retail providers, to provide effective risk management for customers and suppliers.

In restructured states, responsibility for insulating consumers from volatile—especially high and rising—prices has never been clearly understood by the relevant parties. Some assume that restructured states gave up the job during restructuring in the early 2000s, while others consider that job to remain with states even after generation was divested from utilities and retail supply became a competitive service. Practically speaking, when scarcity was less an issue, most parties were content to rely on the spot market and shorter-duration capacity markets to address both hedging and resource adequacy. In the current environment, however, responsibility for ensuring that needed hedging happens needs to be clearly assigned to entities equipped to accomplish it.

States can use their existing authority over resource adequacy and customer protection to ensure sufficient contracting occurs. Over the last year, leaders of RTOs have suggested that while their central markets remain critical to resource adequacy, there may be an important remaining role for states.[12] More recently, PJM's Board of Managers and CEO opened an inquiry into the long-term future of the PJM capacity market and PJM staff issued two white papers about the topic.[13] Two of the pathways identified by PJM, 'Path A' and 'Path C', rely significantly on long-term forward contracting. PJM identifies LSEs as the likely counterparties but does not identify who would require them to assume this responsibility.

[11] Gramlich & Lacey.

[12] *See,* Pre-Filed Comments of ISO-NE President and CEO Gordon van Welie and ISO-NE VP of System Operations and Market Administration in Docket No. AD25-7-000, Meeting the Challenge of Resource Adequacy in Regional Transmission Organization and Independent System Operator Regions (May 16, 2025). *See also* Pre-Filed Statement of Manu Asthana on Behalf of PJM Interconnection, L.L.C. (May 202, 2025) in the same docket. All available via FERC's eLibrary: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=D9588CDF-B767-CBBE-9F45-96EF79F00000

[13] *See,* PJM, "Powering Reliability Through Market Design Workshops," accessed August 2026, https://www.pjm.com/committees-and-groups/workshops/prtmdw. *See specifically* PJM White Paper.

One option for driving increased forward contracting to hedge against price volatility and provide market credibility that has received insufficient attention is state PUC-driven procurement of forward power contracts by LSEs. In this paper, we describe this option, evaluate its benefits, and describe ways it can be implemented in restructured states.

III. Long-Term Contracting Is a Critical Risk Management Tool that Provides Many Benefits

Long-term bilateral contracts provide direct benefit to end-use consumers by insulating them against price swings, most notably the upward swings that can disrupt household budgets in a painful manner. An end-use customer who has most or all of their power needs covered under bilateral contracts barely feels the pain (or gain) when the spot prices swing up and down. bilateral contracts are like fixed rate mortgages: a homeowner's monthly payments are unaffected by today's interest rates once they are locked in.

Industrial electricity customers who were the leading political force for competitive markets have frequently emphasized long-term contracts: "In a real competitive market, power prices would be set by negotiated transactions between willing buyers and sellers, not dictated by RTOs or regulators or 'organized markets.' In a real competitive market, suppliers would be seeking out customers, offering longer-term bilateral contracts, and striving to add value through innovation."[14]

Volatile spot prices can still send important market signals, but with long-term contracting, consumers can be shielded from unexpected and large impacts on their monthly bills. What is harmful to consumers is not the volatility per se but the excessive exposure to those prices, both in our regulatory system where end-use consumers generally do not know or care what happens behind the outlet on the wall, or in our political system where there is only so much tolerance for changes in utility bills.

This price insulation or "hedging" phenomenon holds true for both energy and capacity, which are the primary wholesale electricity products. It also applies to other products, such as Renewable Energy Certificates (RECs), for which consumers may be responsible. Most of the recent attention has focused on capacity markets because those costs have been mostly unhedged; in fact, wholesale electric energy prices have risen more than capacity[15] but energy market costs have been more hedged so they have not harmed consumers.

There have been major warnings about the risks of relying only on short-term spot markets since the start of electricity restructuring. The failed initial California restructuring experience is 'Exhibit A', where 100% reliance on spot markets led to the loss of $40 billion in excess payments from consumers to producers and traders. Stanford Economist Dr. Frank Wolak's

[14] Joint Comments, PJM Industrial Users Group, Industrial Energy Users–Ohio, West Virginia Energy Users Group, NEPOOL Industrial Customer Coalition, Southwest Industrial Customer Coalition, and Coalition of the Midwest Transmission Customers, FERC Conference on Competition in Wholesale Power Markets, Docket No. AD07-7-000 (Mar. 13, 2007).

[15] *See,* Monitoring Analytics, LLC, *Quarterly State of the Market Report for PJM: January through March*, at 21 (May 14, 2026), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2026/2026q1-som-pjm.pdf (which shows energy to be roughly 70% of the wholesale cost of power in the first quarters of both 2025 and 2026 while less than 5% of such cost was attributable to capacity cost.)

review of the 2000-2001 California electricity crisis concluded, "[t]he most important lesson is that any re-structuring process should begin with a large fraction of final demand covered by long-term forward contracts."[16] Similarly, MIT economist Dr. Paul Joskow's review of the crisis concluded that "a good retail procurement framework...must assure that a large fraction of retail demand is being met with longer-term fixed price contracts and only a small fraction fully exposed to the spot market."[17]

FERC has long valued the risk-mitigating role of long-term contracting. In 2007, the Commission noted that "[i]t is important that wholesale sellers and buyers have adequate opportunities to sell and buy electric power through long-term power contracts to allow them to manage their exposure to uncertain future spot market prices...The Commission believes that it is important for buyers and sellers in organized markets to be able to choose a portfolio of short-term, intermediate-term, and long-term power supplies."[18] FERC's interest, however, has seldom led to action on long-term contracting, since generation siting, retail service, and resource portfolios are generally reserved for states under the Federal Power Act (FPA).[19]

Long-term contracting also benefits consumers in the longer term by reducing the cost of financing new generation. With a firm power purchase agreement (PPA) in place, a developer can attract more debt financing, which carries a lower cost of capital than equity financing. While investors have some willingness to invest on a pure merchant basis (where there is no contract and no rate base cost recovery), that type of investment relies on very stable and predictable markets, and requires a higher ratio of equity to debt and thus raises the weighted average cost of capital required for investment. Higher financing costs can undermine project viability, delaying projects that could address and improve reliability, and are ultimately passed through to consumers as higher power costs.

Longer-term contracts are likely needed more today than in the past. In previous surges of independent power development, it was relatively easy to forecast profits from new units given their lower marginal cost due to efficiency of operation relative to the older units that tended to set power market prices. Also power demand is notoriously difficult to predict today with very large queues of large loads including data centers that may or may not materialize.

Long-term contracting also can help integrate clean energy, and in particular clean firm power. Financing costs can be high for highly capital-intensive and long lead-time generation projects. New clean firm technologies will be needed to achieve reliability and reduce emissions, which are both important goals for most restructured states. New York's future energy plans rely on the generic category of "Dispatchable Emission-Free Resources" (DEFRs), but it is unknown which resource will become affordable enough to serve that need. It could be nuclear, long-duration storage, next-generation geothermal, or other options. Long-term contracts could help

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[16] Frank Wolak, *Lessons from the California Electricity Crisis*, University of California Energy Institute, Center for the Study of Energy Markets (2003), https://regulationbodyofknowledge.org/wp-content/uploads/2013/03/Wolak_Lessons_from_the.pdf

[17] Paul Joskow, *California's Electricity Crisis*, Oxford Review of Economic Policy, Vol. 13, Iss. 3 (Sept. 1, 2001) https://academic.oup.com/oxrep/article-abstract/17/3/365/438600.

[18] FERC, *Wholesale Competition in Regions with Organized Electric Markets*; Proposed Rules at P 84, 126 *Fed. Reg*. 36,276, 36,288 (July 2, 1987) https://www.govinfo.gov/content/pkg/FR-2007-07-02/html/E7-12550.htm.

[19] FPA section 201(b)(1), 16 U.S.C. § 824(b)(1) ("The Commission...shall not have jurisdiction...over facilities used for the generation of electric energy...")

reduce the risk for these highly capital-intensive technologies to enter the market. The IEA recently recognized the benefits of long-term contracts for the evolving generation technology mix: "The importance of long-term markets is growing as the electricity system shifts toward capital-intensive technologies."[20]

Long-term contracting also solves what investors call the "price cannibalization" problem: new renewable generation entering the market suppresses prices, which can make that same generation unprofitable even when the market needed the investment. A developer who signs a PPA before committing capital is insulated from that future price suppression—a dynamic renewable energy investors know well from the "duck curve", where zero marginal cost resources depress their own value as penetration rises. Because long-term contracts tend to include capital cost recovery, lenders can recover their investments without depending on volatile day-to-day spot prices. Many observers are debating how electricity markets should be designed for a future with high penetrations of zero production cost renewable resources. Long-term contracts are a key solution to this challenge.[21]

Long-term contracts also benefit customers by reducing generation market power. Dr. Frank Wolak explained:

> Fixed-price forward contract commitments sold by generation unit owners reduce their incentive to exercise unilateral market power in the short-term energy market because the generation unit owner only earns the short-term price on any energy it sells in excess of its forward contract commitment and pays the short-term price for any production shortfall relative to these forward contract commitments. This logic argues in favor of the regulator monitoring the forward contract positions of retailers as part of its regulatory oversight process to ensure that there is adequate fixed-price forward contract coverage of final demand.[22]

[20] International Energy Agency, "Electricity Market Design Building on strengths, addressing gaps," at 59, (Nov. 2025) https://iea.blob.core.windows.net/assets/cea07fb2-fb8d-4d95-b939-7ece0d085ae4/EnergyMarketDesign.pdf (IEA Electricity Market Design).

[21] *See,* Gramlich & Hogan, *Wholesale Electricity Market Design for Rapid Decarbonization: A Decentralized Markets Approach* (June 2019), https://powermarkets.org/project/3079/.

[22] Frank Wolak, *Wholesale Electricity Market Design*, at 35 (Nov. 20, 2019), https://fsi-live.s3.us-west-1.amazonaws.com/s3fs-public/wolak_november_2019.pdf.

IV. Long-Term Bilateral Contracting is an Important Complement to Organized Central Power Markets

The IEA's comparison of power markets around the world noted, "Together, short- and long-term markets form the backbone of a well-functioning electricity market design: the former reveal efficient price signals, while the latter convert those signals into investable certainty. Long-term markets can therefore play a stabilising role in systems characterised by growing price variability, capital-intensive assets and rising demand for predictable returns."[23]

Recently RTO leadership have publicly considered long-term contracting. ISO-NE and PJM executives suggested increasing the focus on long-term contracting at last year's FERC resource adequacy conference.[24] In PJM's recent white paper on the future of PJM's capacity market, long-term capacity procurement was emphasized in Paths A and C. Path A focused on a capacity market with better hedging, Path B on differentiated customer reliability, and Path C towards more granular energy and ancillary services markets.[25] In general, all three paths are very compatible with state-overseen long-term hedging.

Bilateral contracting and central spot markets are often discussed as either-or propositions, but they are not. Private bilateral long-term contracts and the central capacity market go hand-in-hand. The ERCOT market monitor noted, "Only a small share of the power produced in ERCOT is settled in the real-time market."[26]

Even where there is more bilateral contracting, the benefits of the central capacity market remain in place. The central spot market would continue to provide transparency and efficiency for consumers and equal access to capacity for competitive retailers. The central market also would continue to provide market power monitoring and mitigation.

Long-term contracting has become a best practice for restructured markets around the world. As described in Appendix A, other markets where supply is provided by independent power producers and retail service is provided by competitive retail suppliers, such as the U.K. and Australia, rely significantly on long-term contracting to insulate consumers and attract investment. Increasingly the contracting is mandatory and overseen by the government market regulatory agency.

Contracting is generally *allowed* in the current RTO capacity markets and always has been. The residual aspect of PJM's Base Residual Auction (BRA) capacity market is intended for final trading of entities' excess or surplus and was not designed to serve as the sole place for procuring or selling the product. The relevant PJM market rule manual states that "[t]he bilateral market provides resource providers an opportunity to cover any auction commitment

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[23] IEA Electricity Market Design, at 58.

[24] *See* Pre-Filed Comments of ISO-NE President and CEO Gordon van Welie and ISO-NE VP of System Operations and Market Administration in Docket No. AD25-7-000, Meeting the Challenge of Resource Adequacy in Regional Transmission Organization and Independent System Operator Regions (May 16, 2025). *See also* Pre-Filed Statement of Manu Asthana on Behalf of PJM Interconnection, L.L.C. (May 202, 2025) in the same docket. All available via FERC's eLibrary: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=D9588CDF-B767-CBBE-9F45-96EF79F00000

[25] PJM White Paper.

[26] Potomac Econ., Indep. Mkt. Monitor for the Electric Reliability Council of Texas (ERCOT), 2025 State of the Market Report for the ERCOT Electricity Markets 1 (2026).

shortages."[27] It is treated as self-supply in the capacity exchange tool such that both the supplier and buyer are insulated from the clearing price. The PJM White Paper notes, "[t]he capacity market was designed assuming most load would be protected from spot price spikes through long-term supply contracts. That protection was never consistently put in place."[28]

Private bilateral long-term contracting for energy complements the core energy market design. The energy market model, which is generally used in the nine North American power markets (PJM, ISO-NE, New York, MISO, SPP, Texas, California, Ontario, and Alberta) is a bid-based security-constrained economic dispatch with locational marginal prices and financial transmission rights that has become established as the standard market design across the country. The original theories developed in the 1980s and implemented first by PJM and then others in the 1990s remain applicable today. Hedging was always intended to be performed in such markets, though by private parties and not within the central market itself. To facilitate trading, RTOs created hubs such as "PJM Western Hub," which are the weighted average prices of many nodes. Whether or not there are capacity markets, LSEs and independent power producers (IPPs) can transact forward energy contracts that ultimately settle on the day-ahead and real-time spot prices posted in the Locational Marginal Pricing (LMP) system.

Long-term contracting was originally envisioned and anticipated by FERC and the industry participants designing these markets when RTOs were created. The original IPPs expected that their business would rely on long-term contracting with LSEs. The industry evolved out of Public Utility Regulatory Policies Act (PURPA) Qualifying Facility contracts, which were long-term contracts. The general consensus in the 1990s was that RTOs would serve as the "air traffic controller" while sophisticated and creditworthy LSEs, IPPs, and marketers would trade wholesale power with each other. There was always an expectation that bilateral agreements would naturally develop as hedging instruments, as they have in most commodity markets.

In most of the control areas to the west of PJM, MISO and SPP, the topic of hedging is not relevant to the RTO capacity market discourse because the utilities are vertically integrated. In those states and utility service territories, the retail customers are hedged via the utilities' obligation to serve and integrated resource planning, in which those utilities build and own the generation needed to serve load. Pros and cons of restructured competitive markets and integrated regulated systems are beyond the scope of this document but are well documented elsewhere.[29] However, as discussed at length both above and below, long-term contracting and similar risk management tools can be utilized in a restructured market. To summarize: long-term contracting is deeply compatible, if properly done, with harnessing the benefits of competition through restructured markets.

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[27] PJM, *PJM Manual 18: PJM Capacity Market, Rev. 62* (effective Dec. 17, 2025), https://www.pjm.com/-/media/DotCom/documents/manuals/m18.pdf.

[28] Walter Graf, *Powering Reliability Through Market Design: Addressing Rising Demand and Constrained Supply, and Stimulating Investment to Support Durable Reliability*, at 6, (PJM, May 20, 2026), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2026/20260520/20260520-powering-reliability-through-market-design.pdf.

[29] *See for example*, Paul L. Joskow, *Lessons Learned from Electricity Market Liberalization*, 29 Energy J. (Special Issue) 9 (2008); Severin Borenstein & James Bushnell, *The U.S. Electricity Industry After 20 Years of Restructuring*, 7 Ann. Rev. Econ. 437–463 (Aug. 2015). DOI: 10.1146/annurev-economics-080614-115630; Steve Cicala, *Restructuring the Rate Base*, 115 AEA Papers & Proc. 363–368 (May 2025). DOI: 10.1257/pandp.20251112.

V. Now is a Difficult Time to Procure Power, but the Root Cause of Price Risk Cannot Be Ignored Either

While many may agree that long-term contracting would have shielded consumers from the recent increase in prices, they may disagree about starting now to pursue them. Going "long" at a time when the market is short of supply has risks as well, as California also learned in 2001 with its Department of Water Resources contracts.[30] There is some legitimacy to this concern, and there is a possibility of swinging the pendulum too far in the procurement direction.

There is a balance to be struck between the extremes of full hedging and no hedging, and market conditions can affect the timing and quantity of prudent hedging. Some of the risk of buying at the top of the market can be avoided by procurements that purchase a mix of spot, short-term, medium-term, and long-term contracts. That is likely the most prudent strategy.

The concern may also be over-stated because prices available for long-term contracts may be attractive due to the interest of power sellers to also lock in prices in such contracts. IPP sellers shoulder great risk presently at all stages of development, but the major risk is capacity market prices, which are impossible to predict as they rely on many subjective forces and market developments well outside of their control. Locking in a contract provides great benefit to such suppliers. Power suppliers might be willing to accept lower prices if provided more certainty under long-term contracts. Anecdotally, it appears forward prices are discounted at the time of this writing. While prices change all the time, there could be first-mover advantages for states or LSEs to procure power soon. The structure could be put in place now, and at least some contracting should occur now, but not necessarily full hedging if the prices are too high.

VI. Despite its Benefits, Long-Term Contracting for Capacity in Restructured and Competitive Markets Has Been Limited

When utilities divested generation as part of restructuring, retail service was assigned either to competitive suppliers or some form of utility default providers (nearly always the incumbent utility), and 1-3 year resource adequacy responsibility shifted to RTOs. There was a general reduction in the amount of power that was committed under long-term contracts as these arrangements took hold.

As Morey and Kirsch observed, "[i]n principle, producers and retail choice consumers could mitigate electricity price risks through long-term contracts. In practice, however, such long-term contracts are a rarity."[31] They noted that "long-term contracting in retail choice states has been hindered by customers' ability to switch suppliers, by customers' ability to switch from alternative retail providers to the incumbent utility's standard offer or Provider of Last Resort (POLR) service whenever the competitive market price rises above the regulated rate, by public policies that protect buyers from service curtailments when there is a power shortage and their

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[30] California State Auditor, *California Energy Markets: Pressures Have Eased, but Cost Risks Remain*, (Dec. 2001), https://information.auditor.ca.gov/pdfs/reports/2001-009.pdf.

[31] Matthew J. Morey & Laurence D. Kirsch, Christiansen Associates Energy Consulting LLC, *Retail Choice in Electricity: What Have We Learned in 20 Years?*, Electric Markets Research Foundation at 52-53 (Feb. 11, 2016), https://hepg.hks.harvard.edu/sites/g/files/omnuum10586/files/hepg/files/retail_choice_in_electricity_for_emrf_final.pdf.

own contracted supplies are insufficient to meet their load obligations, and by asymmetries in the positions held by buyers and sellers in retail choice markets."[32] PJM studied generation investment in 2016 and found that "evidence suggests that buyers and sellers are hedging their respective capacity price risks through bilateral contract in reasonably small volumes…Several factors may explain the reluctance to fix prices bilaterally…retail choice regimes in several PJM states deter competitive retail providers from long-term wholesale contracting because end-use customers under such regimes typically are committed to six-month or one-year contracts with their suppliers."[33]

Some restructured markets do have significant long-term contracting, at least for energy. Texas restructured differently from all other U.S. states by avoiding significant reliance on default service. While Texas' market design is often labeled "energy-only," that only refers to what ERCOT operates and ignores the significant amount of bilateral long-term contracting that occurs between and among LSEs, IPPs, and marketers. The Texas market has consistently had much more long-term contracting by competitive retailers, and active forward markets for power that look to real-time markets for price discovery, not for transaction of substantial amounts of power.[34] Although ERCOT has no capacity market, the value of energy hedging has been shown to benefit consumers and the integrity of the market.

Generation developers in Texas are able to sign long-term PPAs prior to committing significant capital into projects and thereby hedge their risks and pass on lower financing costs to their LSE buyer, who can then offer customers a lower rate. Texas experienced a massive spot price shock with Winter Storm Uri, but most consumers were hedged under long-term contracts. A variety of factors led to the power outages, but neither reliance on markets nor the ERCOT market design were among them.[35] The spot-price-only service offered by companies like "Griddy" was banned by the legislature after the event—an example of a state regulating the content of a competitive retail supply product to better protect customers from exposure to short-term price risk.

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[32] Morey & Kirsch, at 55.

[33] PJM, *Resource Investment in Competitive Markets*, at 28 (May 5, 2016).

[34] *See,* Gramlich & Lacey; Potomac Economics, *2025 State of the Market Report for the ERCOT Electricity Markets,* at 1 (May 2026), https://www.potomaceconomics.com/wp-content/uploads/2026/06/2025-State-of-the-Market-Report-for-ERCOT.pdf ("Only a small share of the power produced in ERCOT is settled in the real-time market.").

[35] Carey W. King, et al., *The Timeline and Events of the February 2021 Texas Electrical Grid Blackouts*, University of Texas at Austin (July 2021), https://energy.utexas.edu/sites/default/files/UTAustin%20%282021%29%20EventsFebruary2021TexasBlackout%2020210714.pdf.

VII. In Recent Years, Capacity Hedging Has Declined in Restructured States

The amount of hedging has been decreasing over time with more active long-term bilateral contracting in previous years in RTO regions than there is today. The problem is much more acute with capacity than with energy, where significant hedging does occur. Over a decade ago, many of the retail electricity providers would procure capacity in a portfolio of contracts and pass along these price guarantees to their retail electric customers. This process was disrupted in part due to changes and interruptions in wholesale capacity markets. Uncertainty in capacity market design led states to replace actual hedges with estimates of capacity prices. When that happened, the actual prices began to flow through to customers automatically such that no entity was actually performing the hedging function.

PJM's shift in 2014 to "capacity performance" significantly changed suppliers and other market participants' assessment of individual and aggregate supply in the market, opening them up to price risk and physical risk of over- or under-procuring. At that time, New Jersey introduced a partial capacity price pass-through mechanism specifically because PJM repriced its capacity auctions for delivery years that had already cleared, after suppliers had already submitted fixed-price bids into the state's default-service auction based on the original cleared prices. It was decided that suppliers could not reasonably be expected to bear a risk that arose after their bids were locked in which stemmed from a discretionary PJM rule change rather than a market outcome.

The second significant area of subjective capacity market policy change was RTO application of the Minimum Offer Price Rule (MOPR) to state policies and the subsequent inability of PJM to conduct Base Residual Auctions on their normal three-year-forward schedule: the 2022/2023 BRA, originally scheduled for May 2019, was postponed by FERC order pending resolution of an expanded MOPR and was not held until May 2021, and every subsequent BRA remained delayed relative to the normal cadence for several years thereafter.[36]

A third significant policy change to capacity markets, a rather abrupt shift to using Effective Load Carrying Capability (ELCC) for accrediting capacity, changed individual and aggregate supply in ways that would have been difficult for market participants to predict. A major PJM hedging counterparty describing forward market liquidity as "at an all-time low" and reporting reduced capacity to support prior levels of generator and load-serving entity hedging.[37]

Counter-intuitively, the lack of wholesale market stability has resulted in states reducing hedging requirements. In 2020 in New Jersey, where fixed-price Standard Offer Service (SOS)

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[36] FERC Order, Docket Nos. EL16-49-000 and EL18-178-000 (Dec. 19, 2019) (directing PJM to expand the Minimum Offer Price Rule); *see also*, FERC Order (July 2019) (directing postponement of the 2022/2023 Base Residual Auction pending resolution of the MOPR proceeding); FERC Order (Nov. 12, 2020) (permitting PJM to reestablish its capacity auction schedule); PJM Inside Lines, "PJM Reestablishes Capacity Auction Schedule," (Nov. 19, 2020), https://insidelines.pjm.com/pjm-reestablishes-capacity-auction-schedule/. The 2022/2023 BRA was ultimately held May 19–25, 2021, with subsequent Delivery Year auctions (2023/2024, 2024/2025, 2025/2026) each remaining delayed relative to PJM's normal three-year-forward cadence.

[37] Letter from Matthew J. Picardi and Sean Chang, Shell Energy North America (US), L.P., to PJM Board of Managers, "Re: Critical Issue Fast Path ('CIFP') Capacity Market Reforms and Looking Beyond" (Sept. 18, 2023), https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/20230918-shell-letter-regarding-cifp-capacity-market-reforms-and-looking-beyond.ashx.

had prevailed, it set the first proxy price because it was the first state to face a Provider of Last Resort (POLR) auction without a known scheduled date for a PJM capacity auction. New Jersey's retail load service auction procures approximately one-third of residential and small commercial load for a 36-month period each year, producing a three-year rolling ladder, so at any given time roughly two-thirds of Basic Generation Service Residential and Small Commercial Pricing (BGS-RSCP) requirements are already under contract for one or two more delivery years from prior auctions.[38] This hedging covered capacity and energy use for three years.

Maryland followed suit in 2020, and subsequent states adopted proxy prices as their POLR retail service auction schedules progressed.[39]

Not every state had a three-year forward auction—about half had a three-year forward for part of the load, and all of it was fixed price. Maryland had a two-year hedge, but the auction was conducted in a way that at least a portion of it was fixed price versus a realized actual price.

By 2023, fixed-price bilateral contracting elsewhere in PJM was becoming harder to sustain. Auction clearing prices became unreliable: the 2024/2025 BRA result for the Delmarva Power & Light South zone (DPL South) was revised after the auction closed but before results were published. It was then challenged in litigation, then reverted to its original, substantially higher result by order of the U.S. Court of Appeals for the Third Circuit in March 2024, which held that PJM's post-auction revision constituted impermissible retroactive ratemaking in violation of the filed-rate doctrine. The result was challenged again in a further complaint that reached the D.C. Circuit as recently as January 2026. A supplier that had priced a fixed-term bilateral contract for DPL South load based on either the original or the revised 2024/2025 auction result would have watched its underlying capacity cost basis change multiple times over more than three years of litigation. Auction delays, an unresolved re-pricing dispute working its way through the federal courts, and a changing accreditation methodology together left market participants with no stable reference point against which to hedge.[40]

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[38] The current all-requirements procurement framework was restated and re-approved in early 2026. *See,* Order by the New Jersey Board Of Public Utilities (BPU) "In The Matter of the Provision of Basic Generation Service (BGS) for the Period Beginning June 1, 2026" (Feb. 12, 2026). In the Order, "to mitigate risk to ratepayers, the Board directed the EDCs to procure, through the auction, approximately one-third of their BGS Residential and Small Commercial Pricing ('BGS-RSCP') customers' load for a thirty-six (36)-month period via a single clearing price for each EDC's BGS supply requirements."

[39] Paul Ring, "Another State To Use Capacity Proxy Price For SOS Auctions Due To Lack Of PJM Forward Capacity Price," EnergyChoiceMatters.com (Mar. 4, 2020), https://www.energychoicematters.com/stories/20200304aza.html (reporting Maryland PSC Staff's proposal, modeled on New Jersey's BGS proxy price methodology, to use a positive capacity proxy price – calculated as the average of the Preliminary Zonal Net Load Price from the last two Base Residual Auctions, multiplied by 0.9 – for the April 2020 SOS auction).

[40] PJM Power Providers Group v. FERC, 96 F.4th 390 (3d Cir. 2024) (holding that PJM's post-auction revision of the LDA Reliability Requirement for the Delmarva Power & Light South zone constituted impermissible retroactive ratemaking under the filed-rate doctrine); D.C. Circuit Confirms FERC's Section 206 Authority to Reprice PJM Capacity Auctions Despite Third Circuit Section 205 Ruling, Washington Energy Report (Jan. 28, 2026), https://www.troutmanenergyreport.com/2026/01/d-c-circuit-confirms-fercs-section-206-authority-to-reprice-pjm-capacity-auctions-despite-third-circuit-section-205-ruling/; *see also*, PJM Inside Lines, "PJM Capacity Auction Procures Adequate Resources," (Feb. 27, 2023) https://insidelines.pjm.com/pjm-capacity-auction-procures-adequate-resources/ (describing FERC's initial approval of PJM's revised DPL South auction parameters).

VIII. Healthy Long-Term Bilateral Markets are Needed to Create and Support Effective Risk Management

The following characteristics are important for healthy bilateral contracting markets. The table below provides the characteristic, the commercial function, and the general status in restructured power markets:

Table 1: Characteristics, functions, and status of healthy bilateral markets

Characteristic	Commercial Function	Status in Restructured Power Markets
Transparent benchmark prices	Common valuation reference for all parties	Established – day-ahead and real-time LMPs are widely accepted references
Standardized products	Reduce transaction costs, enable secondary trading	Partially established – energy and capacity products are standardized; long-dated PPAs remain bespoke
Forward liquidity	Enable price discovery and hedging over the relevant planning horizon	Reasonably deep in the short term; comparatively thin beyond one to three years
Financial intermediaries	Warehouse risk neither buyer nor seller wants to hold alone	Structurally reduced since the 2008 financial crisis and Dodd-Frank era bank retrenchment
Stable market structure	Give participants confidence that prices and rules will not shift under them	Undermined at times by "stroke of the pen" risk, e.g. MOPR and ELCC rule changes
Creditworthy counterparties	Enable durable performance over the life of a contract	Uneven – varies widely by load-serving entity and supplier

These characteristics are mutually reinforcing, and weaknesses in any one of them can limit the market as a whole. Measured against this framework, restructured electricity markets have made genuine progress on price transparency but comparatively little progress on forward liquidity and financial intermediation—precisely the characteristics most relevant to the revenue certainty new generation requires. This helps explain both why voluntary long-term contracting has remained limited and why several of the remedies described later in this paper—creditworthiness standards, standardized contract terms, and state-backed procurement—are best understood as ways of supplying missing maturity characteristics rather than overriding market design.

IX. Policy is Required to Assign and Enforce Long-Term Contracting

One might be tempted to "let the market work," because, after all, these are markets. In any normal commodity market, when there is value in hedging for both buyer and seller, there will be "room for a deal," and the two parties will voluntarily sign a contract that binds them to share the risk in some way. Markets can accomplish great things when the standard features of markets are present: many buyers and sellers, homogeneous products, free entry and exit, available information, little market power, and low transactions costs. However, they do not work well when market failures exist and are not mitigated.

We argue there is a market failure in many restructured power markets, requiring policy intervention. As stated in the 2020 report, *Who's the Buyer?,* "[w]e identify two key flaws in retail market structures that hinder resource procurement: rules around default service provision that undermine retail suppliers' incentive to sign long-term contracts, and insufficient creditworthiness of retail suppliers."[41] Essentially, default providers have no incentive to hedge on behalf of the retail customers they serve, as they are simply pass-through entities. And competitive retailers, for their part, have no incentive because they are not held responsible for procuring capacity.

US restructured states are not alone in having this market failure. Appendix A describes a number of international experiences. The IEA notes, "the European Union introduced a new regulation requiring retail suppliers to have in place or implement appropriate hedging strategies to limit exposure to changes in wholesale electricity prices."[42] That EU Directive states, "[w]hen suppliers do not ensure that their electricity portfolio is sufficiently hedged, changes in wholesale electricity prices can leave them financially at risk and can result in their failure and their passing on costs to consumers and other network users. Hence, suppliers should be appropriately hedged when offering fixed-term, fixed-price electricity supply contracts."[43]

[41] Gramlich & Lacey.

[42] IEA Electricity Market Design, at 61.

[43] 2024 EU Directive.

X. States Commissions Likely Have Sufficient Authority to Require Long-Term Contracting but Legislation May Be Needed in Some Instances

States have a great deal of flexibility under existing legal and regulatory structures to assign hedging responsibilities, as evidenced by the wide variety of retail service policies around the country. They can decide, for example, how much to rely on utilities vs IPPs for power supply. Neither FERC-jurisdictional RTOs nor FERC itself have the power to over-rule states' choices in such industry structure matters.

States have vested substantial authority in their regulatory commissions (public utility commissions, PUCs for short) and have the ability to add to or clarify those powers through legislation.

Across restructured states, the PUCs have significant authority over the default service providers, who are nearly universally the incumbent utilities that are the primary subject of PUC regulation. However, competitive retail providers were not subject to regulation as public utilities under many state laws, so authority over competitive retailers is less clear and varies from state to state.

The easiest mechanism for mandating hedging would be within default (standard offer/POLR) service to customers who have not selected a competitive supplier of electricity. In essentially every restructured state the utility commission already possesses—and routinely exercises—the authority to dictate hedging. There are ample precedents and examples of both targeted legislative and commission action to ensure that default/standard offer service is implemented in a manner that protects customers through hedging mechanisms. Some states (like Pennsylvania) have very explicit statutes on this topic (for example, 66 Pa. Cons. Stat. § 2807(e)(3.2)) that require default service plans to include a "prudent mix" of spot purchases, and, as discussed above, some restructured jurisdictions like Ohio, New Jersey, and Washington D.C. embrace laddering and similar hedging strategies in their default/standard offer mechanisms.

A challenge in restructured states is that under their restructuring laws competitive retail suppliers were declared to not be public utilities and not be subject to standard rate and service regulatory tools. The PUCs were generally tasked with only lightly managing the competitive suppliers who were envisioned as replacing the PUC-regulated integrated utilities.

All PUCs do, however, have some form of licensing authority over competitive suppliers and the responsibility to determine that competitive retailers are financially sound. This power is based on a consumer protection mandate to ensure that these suppliers are honest and accurate in their dealings with customers. A PUC can use this authority to prevent the operation of competitive retailers who do not provide sufficient price certainty for retail customers by failing to procure the capacity and energy needed to serve those customers.

There have been limited applications of these authorities by PUCs over competitive retailers. In 2014, the Pennsylvania PUC, in the wake of a wave of consumer complaints about polar vortex price spikes, found some supplier offerings to be improper. However, this finding relied on theories of failure to disclose risks and suppliers adhering to contract terms—not openly asserting jurisdiction over the substance of the contracts. Similarly, after the same 2014 events, the New York Public Service Commission made a broad finding that competitive suppliers had overcharged and were overcharging customers, including finding some of the products that had been sold to customers to be imprudent, arguably making an implicit finding that there had not been sufficient hedging. The legal justification for the decision to require suppliers to use the regulated distribution system has not been broadly applied suggesting this may have been a unique case motivated by the trauma of the 2014 winter price hikes.

The PUC of Texas (PUCT) has adopted relatively sophisticated financial standards that ensure that competitive suppliers have "the financial and technical resources to provide continuous and reliable service" with the PUCT having real enforcement authority to back it up. However, the farthest this has gone, relying on the PUCT's basic authority was requiring that suppliers have substantial letters of credit backing up their contracts and provisions of services.

Appendix A provides greater detail on eight specific state restructuring laws. As detailed in that appendix, nearly all the restructured states have laws that explicitly exclude competitive retailers from the category of "public utility" and therefore the specific regulations regarding such utilities. However, those same state laws give the PUCs broad licensing authority and financial integrity oversight regarding these competitive retailers, and states can build requirements for hedging on this solid foundation of licensing and consumer protection laws.

State commissions can certainly require more hedging by default utility providers (and have previously done so) by exercising their core authority over utilities. Surely there will be winners and losers of any policy change and this change could be disruptive to certain business models. State regulators and possibly legislators will need to consider various interests as well as the broad long-term public interest of efficient, reliable electricity service for their constituents.

XI. States Have the Legal Authority to Oversee Capacity Procurements, But Must Respect FERC's Jurisdiction Over Wholesale Markets

States legally can direct LSEs to procure sufficient capacity to meet load via long-term contracts. This is grounded in their authority, as reserved to them under the FPA, to ensure that sufficient generation is built to serve load and extends to their ability to make determinations about the adequacy and composition of this load.[44] Consistent with this authority, PUCs are given authority, by state law, to oversee the safety and adequacy of retail electricity service to customers. FERC's limited authority over resource adequacy is relevant and described in Appendix C.

If states choose to require long-term contracting, overseen by their PUCs, they can align economic hedging with other state responsibilities, such as their price risk tolerance, energy policy, demand side engagement, resource mix, and economic development objectives. States also can align the procurement with their resource preferences and energy policy.[45] These are

[44] FPA section 201(b)(1), 16 U.S.C. § 824(b)(1)("The Commission...shall not have jurisdiction...over facilities used for the generation of electric energy..."); *see also Pacific Gas & Elec. Co. v. State Energy Resources Conservation and Development Comm'n*, 461 U.S. 190, 205 (1983) ("[n]eed for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the States.").

[45] The environmental attributes of electric generating resource sold on an unbundled basis are outside FERC jurisdiction. FERC may have ancillary authority over these attributes if they are bundled with electric sales undertaken under FERC's jurisdiction, but they are largely in the domain of states. *See WSPP, Inc.*, 139 FERC ¶ 61,061

benefits of state-overseen long-term contracting that many states may find attractive, in addition to the customer protection benefits explained above.

State-directed procurement authority, however, is not without two important legal limits. To understand these limits, it is important first to understand that the wholesale markets that are the focus of this paper use mandatory capacity markets, meaning that even those generators who have long-term contracts for their capacity must offer it via the capacity auction.[46] The long-term contracts do not serve to remove this generation from the market but instead function more as a contract for differences. That is, these resources bid into the capacity markets and receive the market clearing price, which is charged to the appropriate load-serving entity. If the market price is higher than the contract price, the generator "refunds" that difference to the contractual counterparty. If the contract price is lower than the market clearing price, the generator keeps the difference. Regardless of the market price, retail customers only pay the contractual price—hence the price certainty and stability benefits to retail customers.

These mechanics here are important because these generators remain market participants selling power in federally regulated markets. As a result, states that choose to direct and oversee long-term contracting must ensure that the programs are designed not to run afoul of matters that are within the jurisdiction of FERC. First, states may not exercise their authority with the aim of affecting FERC-regulated wholesale market prices. According to the Supreme Court, this was Maryland's goal when creating a program assuring participating generators revenue at a guaranteed level, so long as they participated in PJM's FERC-jurisdictional capacity market.[47] This should not be a daunting prohibition for states considering long-term contracting as a way to protect customers and incent new capacity to enter the market. The *Allco* case provides a roadmap: the goals of the program need to be focused on state objectives such as price stabilization (as opposed to aiming at federally regulated markets); it cannot require any particular action in federally regulated markets, and the load-serving entity should be directed to meet the objectives with some flexibility to execute specific contracts, and those contracts should be subject to FERC review.[48]

Second, while states can direct investments in designated generating resources, such as via long-term contracting, FERC's rules governing the eligibility of these resources to participate in mandatory capacity markets, and any penalties associated with the failure to do so, still control. In some instances, this has triggered concern that states will be required effectively to pay twice for generating capacity, once through the state mandate and another time though FERC-administered penalties. But, well designed state-overseen long-term capacity procurement programs along with RTO market rules that accommodate the contracts, can easily avoid this

(2012)(finding that unbundled REC transactions are outside of the Commission's FPA authority and do not affect the wholesale sales in a way that would trigger the Commission's FPA authorities).

[46] The mandatory nature of participation is important so that the grid operates can accurately balance supply and demand, establish fair market clearing prices, prevent power shortages, and maintain overall grid reliability. Broad participation ensures accurate price signals and equitable sharing of reliability costs.

[47] *Hughes v. Talen Energy Marketing, LLC,* 136 S.Ct. 1288 (2016). The Court expressly withheld judgment with respect to state-based measures "untethered to a generator's wholesale market participation, such as tax incentives, land grants, direct subsidies, construction of state-owned generation facilities, or re-regulation of the energy sector."

[48] *See Allco Finance Ltd. v Klee, et al*., Nos. 3:15-cv-608 and 3:16-cv-508, *Omnibus Ruling in Related Cases on Motions to Dismiss Complaints and for Preliminary Injunctive Relief*, U.S. District Court, D.Conn (Aug. 18, 2016). Under the current RTO tariffs, there already is a ban on bidding behavior that suppresses prices for anti-competitive reasons through imposition of a "focused MOPR."

potential pitfall by not providing incentives outside of the contractual arrangement.[49] What a state cannot do, however, is argue that FERC's market participation rules impair its ability to exercise authority over generating facilities.[50]

The open legal question, requiring a state-by-state analysis, is whether existing state law is sufficient to authorize PUCs to mandate that all LSEs engage in some amount of long-term hedging to protect customers or whether legislation is needed to fill in any authority gaps.

XII. State Requirements for Long-Term Contracting

First and foremost, responsibility for procurement needs to be assigned. Power sellers and investors need to know who is responsible, so they know who their customer or counterparty will be. That entity is nearly always going to be designated and/or regulated by a state. Market participants are accustomed to doing business with a variety of counterparties ("off-takers") such as:

- A state entity: Government agencies like NYSERDA and the Illinois Power Agency have been procuring electricity products for a number of years and have experience with Requests for Proposals and competitive procurement.
- New large loads: Hyperscalers, for example, are significant purchasers of power in PPAs and other contract types from IPPs.
- Munis and coops: These smaller non-profit utilities often buy power from IPPs. They might also choose to build and own their own power, but they have always had the option of buying power under PPAs from IPPs.
- Competitive retailers.
- Default retail suppliers/LSEs.

States policies would include certain key components. This section describes in greater detail an approach to long term power procurement in which states mandate procurement of power.

A. Long-Term Contracting Requirement

The basic requirement would be to require any entity providing retail electric service to end-use retail customers to demonstrate that they have contracted or own a sufficient percentage of the power required to serve those customers some number of years ahead of time.

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[49] States could still choose to require contracting with more expensive resources that satisfy other policy goals—like emerging dispatchable carbon-free technologies—but that is not the same as paying twice or paying a FERC penalty.

[50] In *N.J. Bd. of Pub. Utils. v. FERC*, the court rejected the argument made by state authorities that market participation requirements, including penalties for failure to participate, interfered with FPA section 201(b)(1)'s commitment of authority over generating facilities to states.

B. Creditworthiness standard

An important secondary requirement is to make sure competitive retailers are sufficiently creditworthy. This is important to ensure they can actually do their most important job which is procurement of power and that can cost a lot of money. Such policies might reduce the number of competitive retailers capable of operating in the state, but in general there are many more suppliers than are needed to provide sufficient competition. Whereas Texas generally has significant creditworthiness standards, and that feature has likely contributed to the greater degree of long-term contracting there, most restructured states have relatively weak requirements.

C. Load Migration Policy

A key third feature of state policy would address the challenge of load migration. A real challenge in regulating hedging of competitive retail suppliers, whether default or competitive suppliers, is the risk of their customers migrating to other suppliers or back to the default provider. With poorly designed default service, customers may have an incentive to leave retail choice altogether, undermining the competitive retailers' business plans. If they purchase power and capacity to supply their load under long-term contracts with resource owners while they are unable to enter long-term contracts with retail customers, they face the risk that retail customers may switch to default service providers, leaving them unable to recover the costs of their long-term contracts with resource owners. Similarly, utilities that provide default service (and their regulators) can have the same disincentive to enter into long-term contracts for the same reason. If market alternatives become more attractive to consumers, the utilities could be burdened with what might be considered another stranded asset for which they will seek recovery from ratepayers. In contrast to the Texas market, there is not a robust market of intermediaries in the thirteen hybrid states because the customers may move freely back to default service, leaving the market altogether such that the intermediary would be stuck with excess power and no customer to whom it can sell. As stated by Morey and Kirsch, "merchant generators operating in the reformed wholesale markets consequently are unable to readily find either retail providers on the buy side of the market or power marketers on the sell side of the market interested in long-term deals."[51]

As an example of the concerns about load migration, in Illinois, where default service is procured for the utilities by the Illinois Power Agency (the IPA), the IPA recently stated:

> Customer switching behavior impacts volume risk and, in turn, variability in utility customer volumes impacts price risks. The IPA's historical procurement strategy involves buying power in a "laddered" approach with a large fraction of the power to serve retail customers in the Delivery Year procured through forward purchases over a three-year procurement horizon. In a period of rising prices, those forward purchases are likely to be priced below market. Therefore, the blended price of utility supply may be less than the current price of an ARES offer, even an offer through municipal aggregation. This price difference can result in increased customer migration back to the utility. The reverse can occur as well; higher utility supply costs relative

[51] Morey & Kirsch, at 53-54.

to alternatives through ARES suppliers or municipal aggregation can result in eligible retail customers migrating away from the utilities.[52]

The clearest general solution to load migration is to have consistent requirements across all retail suppliers and have contracting obligations follow load as it may migrate. Some states may rely more on default service and other states may prefer more of a Texas model without any default supplier, so there is no single approach that applies to all states. But if it follows the general approach where contracting applies to all LSEs and follows the load, it should generally work. A consistent requirement would eliminate the incentive for load to migrate between suppliers based on whatever the hedging policy is.

D. Summary of state requirements

State risk management requirements for mandatory contracting include:

1. Any LSE serving retail customers in the state is required to procure power to serve a certain percentage of the load they have committed to serve. This includes both default and competitive providers.
2. Capacity hedging by any LSE would be credited in RTO capacity market rules.
3. The amount of hedging could vary depending on market prices at a given time, risk tolerance, and other factors.
4. A forward period of 5 or more years in the future, striking a balance to achieve sufficient price insulation while avoiding too much risk of stranded costs that could result if forecasts are too high.
5. A rolling procurement process where each year or some other periodicity, procurement is required. The rolling approach avoids too much reliance on market prices at any given point in time.
6. Arrangements for competitive procurement. Competitive procurement strategies, described by others,[53] are important and beneficial but are beyond the scope of this paper.
7. Arrangements between LSEs and potentially other states to procure power together. There could be joint procurements or coordinated efforts.[54]
8. Robust qualifications and creditworthiness requirements on the LSEs. These requirements should be consistent to avoid an artificial incentive for load to migrate.

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[52] Illinois Power Agency, *2026 Electricity Procurement Plan*, at 71 (Mar. 20, 2026) https://icc.illinois.gov/docket/P2025-0893/documents/378106/files/662959.pdf.

[53] *See*, John Wilson, et al, *Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement* (April 2020) https://energyinnovation.org/wp-content/uploads/All-Source-Utility-Electricity-Generation-Procurement-Best-Practices.pdf.

[54] One example is New England's attempts to jointly procure offshore wind energy, prior to the current permitting challenges in that industry. *See*, States of Connecticut, Rhode Island, and the Commonwealth of Massachusetts, *Offshore Wind Multi-State Coordination Memorandum of Understanding,* (signed October 3, 2023) https://www.mass.gov/doc/ma-ri-ct-offshore-wind-procurement-collaboration-memorandum-of-understanding/download.

9. Creditworthiness verification. A state commission can utilize independent third-party organizations or governmental entities to administer accreditation that work closely with existing financial institutions, regulators, and credit rating organizations where appropriate.
10. A state commission can allow multiple standardized methods for establishing and maintaining credit support, including:
    a. Parent guarantees
    b. Independent credit ratings
    c. Revolving credit facilities
    d. Letters of credit
    e. Posted collateral
    f. Other comparable financial instruments
11. Provisions to enable and ensure equal treatment of demand-side as well as supply-side resources.
12. Penalties and arrangements for default and non-delivery.
13. Grandfathering of existing arrangements, to avoid disruption to existing commercial contracts.
14. Develop a robust risk transfer ecosystem that bridges the mismatch between long-lived generation assets and short-duration retail customer obligations. Ensure that the risk transfer market is supported by transparent, predictable, and stable underlying market rules
15. Sufficient state commission staff expertise and resources to be able to perform the functions above.

XIII. RTO Capacity Market Design Must be Properly Configured to Enable State-Overseen Power Procurement

First and foremost, capacity market rules need to be stabilized. There has been too much regulatory risk for parties to be able to commit to long-term bilateral contracts. There have been dozens of changes to each capacity market, and some of them have had dramatic impacts on market outcomes. Most of these changes are unhedgeable for market participants because they are subjective and difficult to predict. MOPR, capacity performance, and the use of Effective Load Carrying Capability (ELCC) for accreditation have generally been resolved at a high level, but additional clarity and consistency would help market participants confidently execute long-term contracts.

Generally central capacity markets do at least try to allow bilateral contracting, but it does not always work well. Any contract or program avoids potential sanctions through a self-certification. RTO rules need to be able to register procurement contracts such that the right entity who shows up short on its capacity obligation is charged for capacity from the central capacity market. If an LSE procures no capacity ahead of time, it should be charged for its full capacity obligation in the central market. Presently RTO obligations are not always precisely allocated to the LSE. In PJM, costs are first allocated to zones (usually utility footprints or electric distribution company areas), then each zone allocates the obligation to individual LSEs in different ways. Also, capacity costs are allocated in final pre-delivery year billing determinants, not at the year of the auction, which is three years ahead of the delivery year.

RTOs can provide important but non-binding information to market participants that may be very relevant for 5-year or longer-term power procurement. For example, the capacity credit (as measured by ELCC) of a certain resource may be x today and might become 0.5x in the future based on estimated future portfolios and market saturation that can occur, and that would be very important for contracting parties to know. RTOs can provide scenarios and estimates on a non-binding basis to assist market participants in estimating such factors. RTOs can provide power demand forecasting by location to help LSEs and investors estimate the size of the market.

XIV. Certain Products and Contract Types Should Be Enabled

The actual contracts between LSEs and IPPs may take many forms. In the 1980s and 90s, there were "full requirements," "slice of system," "firm," and "non-firm" and other simple types of contracts. Contracts under PURPA were very long-term, covered most costs and risks, and were appealing from an investor perspective. There are now a wide variety of contracts including physical PPAs for energy, virtual PPAs, forwards, futures, and swaps.[55] As long-term utility PPAs, which take most risks off of the developer, are becoming scarce, other forms of contracts are being pursued.[56] The essential twin features of contracts, for the purposes of this paper, are that they commit a revenue stream to the developer to reduce some of the developer's financial risk before committing capital and commit a firm fixed price to the load-serving entity, who is then able to provide stable pricing to their retail customers.

Power purchase agreements to support hedging obligations could, and should, be flexible and accommodate a range of options. To address reliability, contracts could be for capacity alone, capacity plus energy, or capacity plus a call on energy (the terms of the call would need to anticipate fuel purchase obligations if applicable). There could be a range of tenors, perhaps at least 5 years. A prudent approach would include hedges with multiple contracts over a range of tenors to diversify exposure to individual counterparties. Contracts should incorporate assignment provisions to allow all or part of the supply to be reassigned to another party (credit provisions will apply). The purchaser could also separately contract to sell a portion of the purchase and become a supplier themselves, assuming they can meet the security requirements. Contracts would not necessarily need to cover the entire output of a project if there are multiple potential buyers in a relevant transmission region. Contracts will need to incorporate performance obligations and loss provisions; contracting parties will need to have sufficient credit to support their obligations and cover any damages from non-performance. Suppliers will likely need insurance to cover mechanical non-availability. Buyers will likely want

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[55] IEA Electricity Market Design, at 138; *see also*, Australian Energy Regulator, *State of the Energy Market 2019*, at 90 (Nov. 27, 2019), https://www.aer.gov.au/publications/reports/performance/state-energy-market-2019.

[56] Jay Bartlett, *Reducing Risk in Merchant Wind and Solar Projects through Financial Hedges, Resources for the Future*, Working Paper 19-06 (Feb. 2019), https://media.rff.org/documents/WP_19-06_Bartlett.pdf.

to anticipate that there is some small probability of non-performance inherent in any individual generator and structure their hedging program accordingly.

Risk transfer mechanisms need to be available. While a retail customer may choose to go with a different retail entity for their power requirements, their demand for power remains in the same market, with the exceptions of complete shutdowns and/or reduction in their needs. This problem has been solved in other industries through risk transfer mechanisms. There are financially strong entities that step in to take on temporal risks that enable smooth functioning of the overall market. As an illustration, when the end-use-customer signs a 5-year contract and a developer might need a 20+ year contract, a credit worthy intermediary can step in to provide the 20-year or longer contract to the generator and resell 5-year contracts to multiple retail entities over multiple timeframes with a markup to cover for the risks and the costs incurred by the intermediary. While this illustrates a simple situation, a robust risk transfer market can create multiple valuable risk transfer products/contracts with different durations, swaps, indexed pricing, insurance products, reserve funds, futures, contracts for differences, etc. The key concept here is to create a credit worthy contract situation in the market, even when an individual retail entity faces customer churn and structural limitations to meet the obligations of credit worthiness.

XV. RTO Recommendations

If the RTO chooses to enable this path, it should, along with support from FERC:

- Allow LSEs to partially or fully comply with capacity obligations using bilateral contracts.
- Provide analysis and technical support about future capacity supply and demand as well as accreditation (i.e. ELCC) to facilitate the bilateral trading of capacity.
- Shift emphasis in the markets towards objective physical products beginning with a more granular capacity market, such as a seasonal market, and then through the energy and ancillary services markets. These physically determined markets are inherently more conducive to bilateral contracting because they are less subjective and susceptible to arbitrary and unpredictable intervention.
- Provide more stable market rules for capacity and energy products.

XVI. Conclusion

The foregoing evidence supports the hypothesis that states can utilize their authorities over generation to require long-term contracting, and thereby largely shield retail customers from volatile and high prices. There is no magic bullet for quickly bringing down retail rates to our knowledge. Yet this structure would provide a better long-term framework for electricity consumers in regions with restructured electric industries and afford states more control over how their resource adequacy obligations are met.

Appendix A: Long-term contracting is prevalent and increasingly mandatory in other jurisdictions around the world

Australia and the U.K. have competitive retail markets, but, in both nations, the competitive electricity suppliers routinely engage in multi-year forward/hedge contracting. In Australia, retailers routinely manage wholesale price risk by entering forward hedging contracts with generators.[57]

As with the Winter Storm Uri example in the body of the report, it is worth noting explicitly that this U.K. requirement is an energy-hedging obligation—Ofgem's own language refers specifically to purchasing "energy for delivery on future dates." It is cited here for the same reason as the Uri example: as evidence that mandatory hedging requirements are a recognized, functioning regulatory tool for protecting consumers from price volatility, consistent with PJM's own experience in its energy market, and not as a capacity-market-specific precedent.

In the U.K., forward hedging is standard supplier practice as part of the risk management requirement on all companies that hold licenses to sell electricity. As the British national market regulator noted in guidance to suppliers: "Price risk can be considerably reduced by hedging, where licensees purchase energy for delivery on future dates on pre-agreed pricing terms, protecting the licensee from the volatility of price fluctuations...."[58]

California also has a restructured retail market, but most power provided to retail customers is covered by long-term contracts. The California PUC has established requirements for long-term contracts for resource adequacy and price stabilization that apply to retail suppliers, while CAISO serves as a technical advisor but does not operate a capacity market.[59]

For many years, the Australian National Energy Market (NEM) Retailer Reliability Obligation (RRO) imposed a mandatory hedging instrument. The requirement is triggered by the Australia Energy Market Operator (AEMO, like an RTO) and validated by the Australian Energy Regulator (AER, like FERC) if a material shortfall in generation is predicted by the Annual Electricity Statement of Opportunities (ESO) in the coming 5 years. RRO was triggered for New South Wales for summer (Q1) 2024, and the South Australia Minister has triggered it for Q1 in both 2022 & 2023.

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[57] Austl. Competition & Consumer Comm'n, *Inquiry into the National Electricity Market,* at 17 (June 3, 2024). https://www.accc.gov.au/system/files/accc-inquiry-national-electricity-market-report-june-2024.pdf

[58] Ofgem, *Guidance on the Operational Capability and Financial Principles*, at 10 (July 17, 2024), https://www.ofgem.gov.uk/sites/default/files/2024-07/Guidance_on_the_Operational_Capability_and_Financial_Responsibility_Principles_%28marked_up%29.pdf (Ofgem Guidance).

[59] Cal. Pub. Util. Code § 380(b) (West 2025) (CPUC sets RA "in consultation with" CAISO); Cal. Indep. Sys. Operator Corp., FERC Electric Tariff § 40 (Resource Adequacy) (resource adequacy obligations are imposed by the CPUC or other Local Regulatory Authority and demonstrated to the CAISO, which performs the technical Local Capacity Technical Study and net-qualifying-capacity determinations) https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=380.&lawCode=PUC

Australia recently undertook a review of its mandatory hedging and produced a number of recommendations.[60] Notably, a co-author of the paper is now the Chair of the PJM Board of Managers, Paula Conboy. The paper notes (referring to "derivatives," which are a form of long-term contract in use there), "[w]hile the spot market governs the operation of the power system, it is the derivatives market that provides the scaffolding necessary to manage financial risk. Effective derivatives markets allow participants to transfer risk to those best equipped to manage it, enabling retailers to offer predictable prices to consumers and generators to manage the risk of uncertain spot prices. These markets perform a crucial function in maintaining confidence, enabling competition and supporting the long-term health of the NEM."[61]

The British model under which the national energy regulator (Ofgem) manages and oversees the electricity suppliers who provide electricity to customers is an interesting and sophisticated model for a mandated risk management regime that includes hedging. Those suppliers, who hold licenses granted by Ofgem, are roughly equivalent to the competitive suppliers in the restructured states.[62] Ofgem is focused on suppliers meeting a minimal capitalization requirement that includes a "Capital Target" and a "Capital Floor." The Capital Target is a set per-customer requirement that Ofgem believes to be "the reasonable minimum we expect a financially responsible, well hedged, supplier would need to have as a buffer for resilience in the event of a severe but plausible shock."[63] Suppliers meet this Capital Target through approval of a "Capitalisation Plan" that is overwhelmingly a balance-sheet measure, which can include "Alternative Sources of Capital," but the approval process requires suppliers to include details of existing financial arrangements that reduce risk, including hedging.[64] This is motivated by a fundamental belief by Ofgem that "price risk can be considerably reduced by hedging, where licensees purchase energy for delivery on future dates on pre-agreed pricing terms, protecting the licensee from the volatility of price fluctuations"[65] and that prudent and well-capitalized suppliers will have hedges in place. Suppliers who fall below the Capital Target are effectively placed on a probationary status and are subject to "default Transition Controls until they agree an acceptable Capitalisation Plan with [Ofgem] . . . which set[s] out how they will build up their capital to meet the Capital Target." Suppliers that fall below the Capital Floor in breach of their License Conditions are subject to enforcement action.[66]

As discussed above, the PUC of Texas has adopted relatively sophisticated financial standards that ensure that competitive suppliers have "the financial and technical resources to provide continuous and reliable service" with the PUCT having real enforcement authority to back it up.

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[60] *See*, Tim Nelson, et al., *National Electricity Market wholesale market settings review: Final Report,* (Dec. 2025), https://www.energy.gov.au/sites/default/files/2025-12/national-electricity-market-wholesale-market-settings-review-final-report.pdf

[61] Tim Nelson, et al., at 13.

[62] See Ofgem*, Powering Trust: Protecting Customers Through Financial Resilience* (May 1, 2025), https://www.ofgem.gov.uk/sites/default/files/2025-04/FRC_transparency_report.pdf (Powering Trust).

[63] Powering Trust, at 11.

[64] Ofgem Guidance, at 22.

[65] Ofgem Guidance, at 10.

[66] Powering Trust, at 11.

Appendix B: State Restructuring Laws Provide Licensing and Financial Oversight Authorities to State Commissions, which can be used to Require Long-Term Contracting

These laws generally exclude competitive retailers from the category of "public utilities" but do provide licensing and financial oversight responsibilities and authorities.

Maryland law states, "[t]he Commission shall, by regulation or order (1) required proof of financial integrity; (2) require a licensee to post a bond or other similar instrument if, in the Commission's judgment, the bond or similar instrument is necessary to insure an electricity supplier's financial integrity . . . and (4) adopt any other requirements the Commission finds to be in the public interest, which may include different requirements for: (i) electricity suppliers that serve only large customers; and (ii) the different categories of electricity suppliers."[67] Maryland statute requires licensure, separately, of electricity suppliers: "A person, other than an electric company providing standard offer service . . . may not engage in the business of an electricity supplier in the State unless the person holds a license issued by the Commission."[68]

In New Hampshire, the utility commission has full jurisdiction and authority to regulate competitive suppliers: "Competitive energy suppliers are not public utilities pursuant to RSA 362:2 . . . Notwithstanding a competitive energy supplier's non-utility status, the department is authorized to establish requirements, excluding price regulation, for competitive electricity suppliers, including registration, registration fees, customer information, disclosure, standards of conduct, and consumer protection and assistance requirements."[69]

Michigan law defines 'alternative electric supplier,' delineating them as not public utilities subject to the full jurisdiction of the utility commission: "'Alternative electric supplier' means a person selling electric generation service to retail customers in this state . . . An alternative electric supplier is not a public utility." However, this law clearly empowers the commission to regulate those alternative electric suppliers: "The commission shall issue orders establishing the rates, terms, and conditions of service that allow retail customers to take service from an alternative electric supplier."[70]

Pennsylvania law excludes electric generation supplier companies from the category of public authority over which the commission has full jurisdiction but gives the commission authority to regulate competitive suppliers: "The term [public utility] does not include . . .Electric generation supplier companies,"[71] and "[n]o person or corporation, including municipal corporations which choose to provide service outside their municipal limits except to the extent provided prior to the effective date of this chapter, brokers and marketers, aggregators and other entities, shall engage in the business of an electric generation supplier in this Commonwealth unless the person or corporation holds a license issued by the commission."[72]

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[67] Md. Code Ann., Pub. Util. § 7-507(c).

[68] Md. Code Ann., Pub. Util. § 7-507(a).

[69] N.H. Rev. Stat. Ann. § 374-F:7, I.

[70] Mich. Comp. Laws § 460.10a(1).

[71] 66 Pa. Cons. Stat. § 102(2)

[72] 66 Pa. Cons. Stat. § 2809(a).

Illinois' statute expressly excludes alternative retail suppliers (ARES), the Illinois term for competitive retailers, from the definition of a utility subject to the full jurisdiction of the utility commission: "Public utility does not include . . . alternative retail electric suppliers."[73] The law requiring that ARES be certified by the Commission lays out extensive requirements: "(a) Any alternative retail electric supplier must obtain a certificate of service authority from the Commission in accordance with this Section before serving any retail customer or other user located in this State . . . (d) The Commission shall grant the application for a certificate of service authority if it makes the findings set forth in this subsection based on the verified application and such other information as the applicant may submit . . ."[74]

Similarly, Delaware law excludes retailers from primary commission jurisdiction but gives authority to regulate competitive suppliers: "Except insofar as may be necessary to implement Chapter 10 of this title regarding the establishment of Retail Competition, the Commission shall have no supervision or regulation over any Electric Supplier."[75]

Ohio law states that competitive retail suppliers are not public utilities subject to the full jurisdiction of the commission but clearly provides licensing authority to the Commission: "A competitive retail electric service supplied by an electric services company... shall not be subject to supervision and regulation by . . . the public utilities commission,"[76] and "[n]o electric utility, electric services company, electric cooperative, or governmental aggregator shall provide a competitive retail electric service to a consumer in this state on and after the starting date of competitive retail electric service without first being certified by the public utilities commission regarding its managerial, technical, and financial capability to provide that service and providing a financial guarantee sufficient to protect customers and electric distribution utilities from default."[77]

New Jersey statute defines a utility fully subject to commission/board (the New Jersey Board of Public Utilities) jurisdiction: "The term 'public utility' shall include every individual . . . corporation or joint stock company . . . that now or hereafter may own, operate, manage or control within this State any . . . pipeline, gas, electricity distribution . . . system, plant or equipment for public use, under privileges granted or hereafter to be granted by this State or by any political subdivision thereof."[78] The law requires licensure of competitive suppliers and giving the board regulatory authority over them: "A person shall not offer to provide or provide electric generation service to retail customers in this State unless that person has applied for, on an application form prescribed by the board, and obtained from the board, pursuant to standards adopted by the board, an electric power supplier license" and mandating the adoption of "standards [that] include, but need not be limited to . . . Evidence of financial integrity . . .,"[79] which runs in parallel

[73] 220 Ill. Comp. Stat. 5/3-105(b)(9).

[74] 220 Ill. Comp. Stat. 5/16-115.

[75] Del. Code Ann. tit. 26, § 202(f).

[76] Ohio Rev. Code Ann. § 4928.05(A)(1)

[77] Ohio Rev. Code Ann. § 4928.08(B)(1).

[78] N.J. Stat. Ann. § 48:2-13.

[79] N.J. Stat. Ann. § 48:3-78

with the law stating that the "Board shall not regulate, fix, prescribe" the price and certain other aspects of competitive services.[80]

[80] N.J. Stat. Ann. § 48:3-56

Appendix C: FERC's Limited Authority Over Resource Adequacy

Generally, generation portfolios, planning and siting are reserved for states under the FPA: "The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this Part and the Part next following, over facilities used for the generation of electric energy..."[81] FERC's reliability authority under Section 215 does not provide FERC authority over resource adequacy to enforce capacity obligations or otherwise expand supply to meet demand. FPA section 215(i)(2) specifies that FPA section 215 "does not authorize the ERO [NERC] or the Commission to order the construction of additional generation…or to set and enforce compliance with standards for adequacy or safety of electric facilities or services."[82] FPA § 215 does require the ERO [NERC] conduct periodic assessments of the reliability and adequacy of the bulk-power system in North America.[83] Under this authority, NERC issues annual assessments of the adequacy of electricity supplies for the upcoming summer and winter peak demand periods, as well as the long-term (10-year) period, but those are only assessments and not requirements.

These statutory limitations, however, do not preclude RTOs from imposing capacity obligations or mandatory capacity markets. FERC's authority to approve financial penalties designed to incentivize the procurement of capacity in order to meet a resource adequacy requirement by LSEs participating in an organized market was upheld in *Ct. Dep't of Public Utility Control v. FERC*.[84] There, the Commission's approval of ISO-NE's Installed Capacity Requirement (IRC) was challenged by the Connecticut DPUC on the ground that it impinged on state authority over generating facilities reserved to the states under section 201(b) of the FPA. The court rejected Petitioners' argument, holding that the FPA's prohibition against FERC regulation of generating facilities "says nothing about its power to review the capacity requirements that an entity like ISO-NE imposes on member LSE's."[85] The court relied on its 1978 decision in *Municipalities of Groton v. FERC*[86] for the proposition that a capacity deficiency charge aimed at eliciting sufficient generation in the wholesale market involves a "practice affecting rates" under sections 205 and 206 of the FPA.

It might be possible for the FERC-jurisdictional RTO tariff to provide support and a mechanism for state contracting requirements. An RTO could offer an optional hedging requirement where the utility would file in the RTO tariff with the approval of its Relevant Electric Retail Regulatory Authority. With that in a federal tariff, a PUC would have the authority to hedge, or not, in whatever manner they choose.

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[81] FPA section 201(b)(1), 16 U.S.C.§ 824(b)(1).

[82] 16 U.S.C.§ 824o(i)(2).

[83] 16 U.S.C.§ 824o(g).

[84] Connecticut DPUC v. FERC, 569 F.3d 477 (D.C. Cir. 2009)

[85] Connecticut DPUC v. FERC, at 487.

[86] 587 F.2d 1296 (D.C. Cir. 1978).