Comments of the Natural Resources Defense Council in response to PJM's Powering Reliability Through Market Design Paper

Preface

NRDC appreciates the opportunity to submit these comments in response to PJM's April 2026 paper on its capacity market and broader resource adequacy framework reforms. [1] Before entering the substance of our comments, we take a moment to urge caution. PJM starts its discussion of market reform with the observation that markets can suffer from a 'credibility trap' where decision makers are unwilling to accept market results and indulge in rule changes in the hope of yielding more desirable outcomes. This erodes market participant confidence and ultimately results in what is essentially a regulatory risk premium.

As PJM acknowledges in the paper, it has itself demonstrated a tendency to fall into this trap, frequently making rule changes in response to the crisis *du jour,* or simply because of displeasure with market outcomes. Any old PJM hand can probably rattle off a long list of capacity market rule changes that arguably fall into this category: restricting, then eliminating seasonal resources; several rounds of barriers to external resources; innumerable demand response changes; restrictions on bilateral trading and incremental auction participation; arbitrary increases in the reliability requirement; the 2018 MOPR; the post-Elliott settlement and changes to performance penalty rules, and so on. The point here is not to relitigate old issues, but to urge caution before proceeding with another round of dramatic changes. A major challenge for PJM will be distinguishing the actions genuinely needed to adapt to changing circumstances from those that are mostly changes for the sake of change.

PJM's paper is premised on the idea that current markets are insufficient to attract needed investment. However, this is presented as a conclusory statement, supported mostly by input from third parties with obvious self-interest in more lucrative markets. It is difficult to reconcile that claim with observations that PJM queue Cycle 01 attracted in the neighborhood of $500 billion of new entrants and the RRI attracted around $50 billion in nominally 'firm' new-build commitments in a matter of months.[2] Investment decisions for both Cycle 01 and RRI were made after PJM requested RPM price caps on Feb 20, 2025.

This leads us to suggest a simple null hypothesis that may or may not be true:

---

[1] Powering Reliability Through Market Design, May 6, 2026, https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2026/20260506-powering-reliability-through-market-design.pdf. (the "Market Design Paper").

[2] Based on PJM-published nameplate energy, considering only new builds, and estimating investment at $2.00/W for gas, $1.75/W for storage, and $10.00/W for nuclear.

> PJM's markets are sufficient to attract capital. The issues PJM currently faces are the result of timing mismatches between markets and project development timelines and the lack of coordinated resource adequacy planning.

PJM should disprove this, or at least test it, before committing to major market changes designed to attract investment. As a "quasi-governmental institution," PJM is as vulnerable to regulatory capture as any utility commission. Unless PJM takes a very skeptical approach to demands to make its markets more lucrative, it risks transferring vast amounts of money and risk in ways contrary to the public interest.

Be skeptical of claims resource adequacy can be solved solely by making markets more lucrative

The tendency to make reflexive rule changes isn't helped by the intense political pressure PJM is under. Not all of this is justified: nobody could have foreseen the load surge from data centers with sufficient time to build new resources; the current shortage was inevitable. It is unfair for anyone to have expected PJM to maintain a large surplus generation fleet waiting in the wings just in case a surprise technology change caused a dramatic increase in demand. Indeed, NRDC was one of those calling PJM to account for maintaining unreasonably high reserve margins in the late 2010s, and we support PJM's market outcomes of the time as properly shrinking an overbuilt legacy coal fleet and allowing economic replacement. (Though we would urge PJM to be more candid about the causes of this trend, and rather than blaming environmental and climate policy, acknowledge that the coal fleet was doomed as soon as fracking and modern combined cycle units came on the scene.)

It may also have occurred to PJM that the amount of rancor directed at it as an institution is disproportionate to what appears to be a correct market response to changing circumstances. An old adage says politicians survive crises based on how much political capital they have going in. This applies to institutions as well, and the tone of the current situation reflects a reservoir of ill-will that many external stakeholders, especially states, had built up towards to PJM over time. That is relevant here because any market redesign will only be successful if PJM is able to reset its relationship with the states in this region. This market redesign will fail if it is approached as a separate effort from governance reform.

David Mills' insights that the most essential infrastructure is legitimacy and that the issues confronting PJM are really about what we owe each other and choices that must be made by democratic institutions cut deep. Our comments below give heavy weight to respecting state authority and establishing clear lines of responsibility for decision making between PJM and elected officials. Most fundamentally, these market reforms will only be successful if PJM is able to reach a place where states, and even the general public, see it as a trusted partner enabling their energy policies.

The Problem

We offer an alternative problem statement than the one PJM presented. While PJM argues that supply is lagging due to an investment doldrum compounded by unhelpful political interventions, we see a different narrative. The issues facing PJM today are fundamentally load forecasting and resource adequacy planning problems, compounded by the timing mismatch between RPM and construction timelines for new supply. Over the years, RPM has largely replaced, and in some cases preempted, state resource adequacy planning. However, PJM does not see itself as a planner in this sense, though its stewardship of RPM has from time to time given the impression that it does. For nearly twenty years, essentially nobody was in charge of resource adequacy planning for the region, though many in government appeared to have the impression that it was PJM's responsibility.

Good fortune let this work for quite some time—the region had inherited an overbuilt coal fleet from 20th century vertically integrated utilities, and flat load growth allowed newer resources to comfortably replace that fleet based on economic opportunity, with no reliability urgency. PJM asks the question "Why This Transition is Harder than the Last One." The answer to that lies more in the favorable circumstances of the 2010's. The region enjoyed excess reserve margin, and slow load growth meant that friction in retirement decisions was enough to cushion against short-term capacity price shocks. At the same time, the dominant new technology had a Net CONE that was lower than the going-forward costs of many incumbent units.[3] PJM could rely on adequate reserve margins at politically acceptable prices. Economically motivated developers could bring new supply to market on their own time and displace incumbent units that were more-or-less waiting in line to be replaced. This was essentially an energy transition on "easy mode."

Lack of clear resource adequacy planning responsibility and an inability to procure far enough in advance to avoid problems are root causes.

A pair of developments presented more challenging resource adequacy situations that exposed governance, planning and market shortcomings. First, motivated by the increasing urgency of climate change, some states committed to economy-wide decarbonization. Many of those plans took the approach of electrifying building and transportation sectors and setting a timeline for retirements of carbon emitting generation, while also establishing a range of incentives for the development of new clean energy resources. This implicitly relied on a market response, counting on RPM to attract sufficient carbon-free supply on a schedule dictated by the required fossil retirements. Given that those retirements were legislated with least eight years notice, and sometimes much more, lawmakers appropriately acted in the expectation that PJM's markets, in concert with state incentives, would attract investment without taking any more deliberate planning steps.

[3] Or at least acted as if they did. Market behavior in the late 2010's very strongly suggests a Net CONE somewhere around $150/MW-day.

However, this did not work in practice. In addition to chronic delays in PJM's interconnection queue, and lack of proactive transmission planning, PJM does no long term resource adequacy planning, and RPM does not send price signals far enough in advance for orderly replacement of retiring units. While the market was able to handle a "push" transition when gas displaced legacy coal, it did not work for a "pull" where forced retirements were intended to attract replacements. Market timing and the lack of explicit new entry mechanisms did not work well in this situation. The price signal to attract new entry only occurs as reserve margins drop, but project development times are longer than the three-year BRA lookahead, creating a reliability gap between retirements and replacements. Since clean energy laws almost invariably include reliability backstops, this ends up creating a Catch-22 where pivotal suppliers can block retirement mandates simply by ignoring them. Be that as it may, the result across PJM was planning processes and market dynamics failed to attract meaningful investment in clean energy even with state policy creating an absolutely clear need.

The region's failure to deliver new investment in response to state and federal energy policy is by far the most important issue to address with these market reforms

The second development, of course, is the surge in power demand from data centers which rapidly depleted reserve margins and will soon put the region into resource adequacy shortage. In this case, markets functioned as designed by raising prices. The rapid transition from surplus to shortage exposed several shortcomings in the 'social contract' around resource adequacy—who is guaranteed service, what obligations does existing supply have to existing load, and how are load sheds allocated—that PJM and the stakeholder process have responded to in a surprisingly short time. Contradicting the thesis that PJM markets are unable to attract capital, there does not appear to be any shortage of investors interested in developing new supply to serve the data centers, though other factors delay new entry. However, it raises a challenge for PJM's markets, as tens or hundreds of billions of dollars in windfall payments to existing asset owners may not be a politically sustainable way to attract new entry.

We frame PJM's market reform efforts against the response to those two events.[4] Of the two, the inability to respond to state and federal policies is the more important. This is partially because of the grave danger of climate change, which is certainly a national security issue[5] and is likely to become a threat to services as basic as food security.[6] PJM is not an environmental regulator, but sits on the critical path of any feasible plan to decarbonize the United States' economy. It is unacceptable for PJM structures to inhibit or block government responses to climate change. Identifying and correcting the market and

[4] We are reluctant to call the response to data centers a market failure.
[5] See, e.g., National Intelligence Estimate: Climate Change and International Responses Increasing Challenges to US National Security Through 2040 (2021). See also Department of Defense, Climate Change and Global Security (2024).
[6] See, e.g., IPCC, Climate change and land (2019).

planning shortfalls that have left PJM behind nearly every other region in attracting investment in low carbon supply and adjacent technologies[7] must be a centerpiece of the current market reform effort.

Reforming how PJM interacts with state policy is also necessary for any solution to be politically sustainable. When states joined PJM, they did not do so under any understanding that they were ceding their authority to set electricity policy. Nonetheless, that is what happened, culminating in the 2018 MOPR which *by design* nullified the ability of state policy to influence the region's resource adequacy mix. While the expanded MOPR has been trimmed back, widespread sentiment remains in many statehouses that PJM's processes are something their energy policies need to fight through and overcome to be successful.

PJM's reform paper correctly highlights issues of political economy as central to the success of this reform effort. To the list of political items PJM discusses we would add **respect for state authority**. It's vital for PJM decision makers to realize that states are not questioning PJM's legitimacy solely because of the price shock from data centers. The ever-increasing friction between state goals and PJM's markets and processes has been eroding elected officials' views towards PJM for many years; the data center issue became a focus of this discontent, but is by no means the cause. Blame falls on PJM for data center related shortfalls not because anyone expected PJM to have a crystal ball, but because PJM has left state decision makers feeling powerless over their own energy policy, which they now see as restricted or undermined by PJM's planning and market structures. Remedying this must be the center of reforms; without that, no system of product definitions, price hedges and risk allocation can be enough to provide a "foundation on which a durable market design can rest."

The challenges and outcomes of the state policy and data center issues lead us to recommend 5 broad principles for these reforms:

1. Planning and procurement must extend far enough into the future to bring new generation online *before* resource adequacy drops.
2. States must be able to influence this forward planning, including anticipating growth and setting constraints on what types of supply will serve load under their jurisdiction.
3. There must be paths to new entry that do not require raising prices to Net CONE for everyone.
4. There should be few, if any, limits on states', utilities', or private parties' ability to procure supply.
5. Greater authority over planning must be matched with operational and financial structures that ensure the consequences of decisions fall on those who made them.

PJM presented three distinct paths for market design, but recognized that "These paths are not fully mutually exclusive." NRDC agrees and presents a hybrid approach that incorporates elements from all three paths with the primary goal of enabling states to achieve better policy outcomes, preserving

[7] For many years, the standard answer to this question was that the PJM region is not as suitable to renewables as other parts of that country. That is no longer convincing: solar has become the lowest cost source of energy in PJM (Lazard, Levelized Source of Energy Analysis v 16.0), and PJM has lagged RTOs as diverse as CAISO and ERCOT in storage deployment.

reliability, and building resilience for any future shocks to the electricity system. The section below discusses design elements in greater detail.

Market Design

Following from these principles, we suggest market reforms that focus on addressing the state agency and timing problems discussed above. The reforms feature laddered procurements with explicit allowances for new entry that we believe would have led to better outcomes for both state energy policies and surprise load growth. These suggestions mix portions of PJM's three proposed paths: the laddered procurement follows PJM's path A. We supplement path A with much greater allowances for states or possibly private parties to procure capacity outside PJM markets or to decline capacity service altogether. Those greater freedoms necessitate including elements of Path B and C to prevent free ridership.

NRDC proposes that a capacity market or something like it should be maintained, but with options to obtain supply outside of centralized auctions liberalized. Under this proposal, capacity would be procured in a series of tranches, ranging from perhaps as far as 15 years in the future through a prompt auction. Purchases in the longest-term auctions will be primarily driven by state regulators and LSEs. As the delivery year approaches, PJM would take a progressively greater role in procurement, culminating in a prompt auction where PJM buys needed residual capacity to maintain resource adequacy.

Freedom to procure capacity directly allows LSEs and regulators to make their own decisions regarding hedging strategies. Hedging is a means to manage price volatility and risk but is not a substitute for resource adequacy planning. Resource adequacy would remain a shared service for most, with the ability to opt out limited to entities that can take on load shed obligations: either retail regulators on behalf of the customers they represent, or wholesale end use customers on their own behalf. This follows the IRAS model currently before FERC.

The energy and ancillary services (E&AS) markets are the primary mechanisms to avoid the incentives to free ride on shared reliability that PJM discusses.[8] We support the E&AS reforms PJM proposes. Beyond the operational benefits those reforms bring, E&AS prices must be allowed to rise high enough to answer complaints from well-prepared customers that they are being taken advantage of by those with insufficient capacity positions. Price hedging, possibly in the form of an energy strike price included in the standard capacity product, would protect most customers from potentially highly volatile spot markets and lead to payments from loads that are short capacity to loads that are long capacity during stress periods.[9] Ideally, the combination of energy prices and hedging would be sufficient to reduce the need for administrative penalties for not meeting operational capacity obligations.

[8] Markets Reform paper, p14.
[9] See Markets Reform Paper, Appendix C.

A. The transition to any new market design is critical and extremely dangerous.

Before describing the details of NRDC's market reform proposal, we urge caution through the transition period. PJM's first rule in any market reform should be "do no harm." We mean this in two senses. First, load that is currently served by PJM should not lose firm service through inaction, at least not without giving state regulators more than sufficient time to adjust to these reforms. Transitions of the scope PJM is contemplating may require significant revision of retail structures and place new responsibilities on state regulators and utilities. Institutions will take varying amounts of time to adapt to new rules, unwind existing arrangements, and enter into new ones. Very simply, customers of a state regulator that takes several years to reorganize its approach to resource adequacy should not be at risk of decreased reliability or face cost shifts due to actions by faster-moving parties.

Second, mistakes in the transition process could easily lead to opportunities for exercise of market power or large unintended wealth transfers, and so the transition must be carefully managed to ensure that protections that currently exist are not circumvented. We see four immediate risk areas:

1. **New approaches may allow defection of existing supply**. If the system creates new forward commitments beyond those in RPM without limits or priority on who can contract with existing supply, new loads will be able to contract with supply that is currently serving native load. The transition should not undermine PJM's nascent bring-your-own-capacity rules or enable poaching of resources that are already serving native load.
2. **State power imbalances create winners and losers**. Some PJM states have remained vertically integrated or otherwise committed to development of in-state supply. Others have chosen to rely on PJM markets for much of their needs. This is a desirable outcome–a major benefit of markets is capturing flexibility in siting and advantages of one location over another. But, under some new market structures that could be introduced, states with a surplus of generation would have considerable power (literally and figuratively) over states that are short. For example, many eastern states have relied on, and paid for, external generation and associated transmission rather than in-state supply. Without appropriate safeguards, this supply could be yanked from serving those states to support load growth elsewhere, or put those states in a bidding war against deep-pocketed large loads. This threat must be mitigated; states that made their decisions to trust wholesale power markets cannot be exploited for having made that decision. Such an outcome would likely cause great damage to PJM's credibility in the states that relied on wholesale markets most.
3. **Mismatches between capacity and E&AS designs lead to overpayment**. Current capacity prices were set under a particular set of assumptions for energy and ancillary services revenue. As the changes contemplated to the E&AS markets will generally serve to increase revenue, revising those markets without corresponding changes to the capacity market Net CONE calculations and offer rules risks double payment. Increased E&AS revenue reduces the missing money problem, so capacity revenues based on greater amounts of missing money become

excessive. FERC has previously recognized that prospective changes to E&AS market designs must be accounted for in capacity market design.[10]

4. **Shifts in market designs undermine state-led procurement efforts**. Transitioning the RTO level resource adequacy regime must not disrupt state efforts to spur new entry of fast-to-market generation. For instance, New Jersey via the Garden State Energy Storage Program, Maryland via the Next Generation Energy Act, and Illinois via the Clean and Reliable Grid Act are all at various stages of tendering for new energy storage to meet respective state targets. Given that developers bidding into these tenders are tailoring their bids based on projected market revenues, shifts in market-based revenues could dissuade developer participation in ongoing tenders and affect the viability of projects already tendered at bid prices based on structurally different assumptions about market revenues.

Most generally, there is an implied social contract in RPM as it is now, where PJM handles resource adequacy at least in the short-term and existing supply is dedicated to serving existing load. Furthermore, the capacity market was designed with keen awareness for the potential exercise of market power and is heavily mitigated. Those features need to be maintained through the transition: states must not suffer any increased price or reliability risks compared to today simply because they act methodically in response to PJM's changes.

That leads to a recommendation: The transition out of current RPM structures for existing load and supply must be load-driven**.** That is, existing supply can only be allowed to leave RPM for any future construct as matching amounts of load leave. This framework will avoid the poaching by new large loads of supply committed to native load, and ensure fairness among states and zones that have different resource adequacy positions and energy policies. States should set the pace at which they shift their load to future constructs; as they do that, matching generation also exits RPM, most likely through contracts with the exiting load.

Load should set the pace of transition to a new market structure

B. Strong real-time operations and markets are necessary.

NRDC's proposal is centered on states and private actors having greater freedom to decide their own resource adequacy and hedging paths. That only works if all market participants can be confident that this will not result in risk shifting to well-hedged market participants from those who made different choices. Here, we will describe the changes to real-time operations and energy markets that are necessary to avoid bad outcomes. As a starting point, this resembles the "full strength" energy markets described in PJM's paper and includes the Reserve Certainty Senior Task Force (RCSTF) recommendations, but with some caveats and modifications:

[10] *PJM Interconnection, LLC*, 171 FERC ¶ 61,153, PP 308-15 (2020).

- If reserve markets include a high-priced ORDC, curtailable or non-capacity backed load must be routinely included as supply of reserves in market clearing. There has never been any need to establish the nature of the pool's obligations to non-firm load before the last year, but those discussions must happen before recalibrating ORDCs. It does not immediately appear reasonable to allow reserve prices to rise to the thousands of dollars without first considering that the system has non-firm load that could be curtailed to meet a reserve deployment.
- The RUR and Energy Gap Reserves products should be carefully designed to work well with storage resources. RUR should allow charging storage to provide ramp up by committing to reduce its rate of charge. To allow storage participation and better reflect constraints on the gas system and dual fuel capabilities, PJM should consider denominating the Energy Gap Reserves in MWh rather than MW, as ISO-NE has done with their newly developed Energy Imbalance Reserves product.

In addition to the transition issues discussed above, the potential for much higher energy and ancillary services prices also must be paired with a mechanism to protect capacity-backed load from the full impact of this price volatility. While capacity price surges grab more headlines because they are dramatically revealed, we echo the Market Monitor's concern that rising energy prices are actually the more significant issue.

This could be accomplished in several ways. By default, LSEs and suppliers could enter into simple bilateral energy hedging contracts. It would also be possible to build this into the capacity product, along the lines of the options PJM discusses in Appendix C of the markets reform paper. For example, the capacity product can include an energy call option.[11] Load that purchases capacity is guaranteed their cost of energy will go no higher than some strike price; generation that sells capacity will receive no higher than the strike. This can be administered as a two-settlement system which allows dispatch and LMP formation to proceed as normal, then implementing the call option through financial settlement.

C. Private hedging can reduce price volatility but is not a substitute for resource adequacy planning.

Much discussion has centered on the idea that with the proper incentives, LSEs can be relied on to take on much of the resource adequacy planning burden.[12] We disagree. We are unaware of any study that has shown, even in theory, that outside of vertically integrated areas competitive LSE's private

[11] This is one of the areas where the disconnect between marginal ELCC and real-time energy creates problems, since there's no particular relationship between a MW of UCAP and the amount of energy a resource is expected to deliver in a given hour. NRDC's position remains that under marginal ELCC, a capacity supplier's energy obligations should reflect the assumptions behind their accreditation, not their ELCC-adjusted UCAP.

[12] For example, PJM's Option 1 (Market Reform Paper p32) would require 90% of resource adequacy needs be met by LSE capacity hedges. In Appendix C, PJM presents voluntary LSE hedging as the default approach if the region takes Path C and transitions to energy markets to "reduce the region's reliance on the capacity market over time." Appendix C goes on to note that some of the more sophisticated hedging schemes could potentially replace capacity markets.

hedging strategies would sum up to meet regional resource adequacy needs. Indeed, there are compelling reasons to believe private hedging would not lead to acceptable resource adequacy outcomes:

- The incentives for an LSE are different than those for the system as a whole. In the discussion of hedging, PJM notes that "The level…of the required hedge would be up for debate…" This statement glosses over a serious incentive mismatch. A competitive LSE will be under great pressure to only hedge load that it is nearly certain it will serve. Providing retail service is a competitive, low margin business—paying for 1MW of excess hedge can easily offset the revenue on many MW of served load. So, while a resource adequacy planner aiming to hit the 90/10 load forecast would plan for the last MW of capacity they purchase to only have a 10% chance of being needed, a profit-maximizing LSE would plan for the last MW of capacity they purchase to have a much greater chance of being sold. It is tempting to believe that this can be overcome by properly setting the cost of being underhedged, except that…
- Retail LSEs choose who they serve. A retail LSE that is at risk of being underhedged has a simple remedy: stop signing up new customers. Greater penalties for failing to adequately hedge only strengthen this incentive.
- Market incentives can punish hedges. Hedging is expensive, which creates competitive advantage for suppliers that take on more risk exposure. Since obligations for a failed supplier's load will be transferred to the public via provider of last resort provisions, this both creates a race to the bottom and transfers some portion of the ensuing risk to the public.

PJM's market reform paper provides an example of LSE hedging, reproduced below, that illustrates our concern. The example shows how a well-hedged LSE, LSE A, can protect its customers from high capacity prices compared to LSE B that relies on the spot market. However, PJM's discussion neglects an important detail: By the time the virtues of LSE A's hedging strategy manifest in year 7, it would have been offering higher-priced service than LSE B for six years and probably have gone out of business. Even in the best-case scenario, the outcome of this is to limit LSE A's customer base to those that appreciate and can pay for the benefits of hedging.

Table 1. Illustrative Capacity Costs ($/MW-day) by Year for LSE A and B

Year:	1	2	3	4	5	6	7	8	9	10	Avg.
BRA Price	$220	$180	$160	$100	$60	$30	$300	$450	$500	$500	$250
Load Obligation	100	100	100	100	100	100	100	100	100	100	100
BRA Costs	$22,000	$18,000	$16,000	$10,000	$6,000	$3,000	$30,000	$45,000	$50,000	$50,000	$25,000
LSE A:											
Contracted MW	70	70	70	70	70	70	70	70	70	70	70
Contracted Costs	$17,500	$17,500	$17,500	$17,500	$17,500	$17,500	$17,500	$17,500	$17,500	$17,500	$17,500
BRA Revenues	$15,400	$12,600	$11,200	$7,000	$4,200	$2,100	$21,000	$31,500	$35,000	$35,000	$17,500
Total Net Costs	$24,100	$22,900	$22,300	$20,500	$19,300	$18,400	$26,500	$31,000	$32,500	$32,500	$25,000
LSE B:											
Total Costs	$22,000	$18,000	$16,000	$10,000	$6,000	$3,000	$30,000	$45,000	$50,000	$50,000	$25,000

The result of these dynamics is that in a competitive retail environment, attempting to address resource adequacy through hedging requirements amplifies load forecast risk and transfers it to the provider of last resort. As discussed above, load forecast risk is amplified because of the incentives to competitive LSEs to forecast conservatively and underhedge in low-priced years. This increased risk is then concentrated on POLR customers rather than spread across all load.

Since the most sophisticated customers are the ones most likely to shop LSEs, this has the effect of increasing costs for residential ratepayers, who are less flexible even if technically provided with retail choices. In the worst case, when the provider of last resort is unable to find firm capacity for its load, this structure would result in concentrating curtailment risk due to load growth on the system's least sophisticated customers. Some may simply respond *caveat emptor*, but it is unclear if PJM states are as willing to do this as Texas. In any event, no discussion of the role of LSE hedging strategies can be considered complete unless it incorporates the option value of bankruptcy, consumer behavior, and the equity impacts between more and less sophisticated customers.

A regulator might mitigate these risks by encouraging their incumbent utility to aggressively hedge, but the basic asymmetry between an LSE with an obligation to serve and LSEs that can choose their customer will remain. Relying on LSEs to self-hedge, retail competition, and maintaining standard offer service is a classic trilemma. You can only have two of the three.

Unless PJM states agree to give up retail competition with standard offer service, we can only conclude that a resource adequacy construction that relies primarily on LSE self-hedging is untenable. PJM's current approach, with centralized load forecasting, central procurement, and cost allocation to LSEs, was chosen for good reason. We propose updating this model with greater state and private involvement in load forecasting, more options for LSEs to procure capacity for themselves, and options for load to opt out entirely, all of which are discussed in the next section. Despite those modifications, we do not believe the region can do without the core features of a single load forecast and some entity as the backstop capacity purchaser.

D. Responsibility for planning should be shared between PJM and states

For a market to work, there needs to be some elasticity of supply. At least in theory, RPM was designed with an assumption that there would be a pool of planned CTs waiting in the wings and offering at prices that would tell them to begin construction. While that may be idealized, it does point out that price signals need to be sent far enough in advance to be met by new entrants; unactionable price signals amount to little more than rents for incumbents.

However, longer term procurement raises political concerns. The further in the future one looks, the more the forecast becomes about policy decisions that it is inappropriate for PJM to make. Long-term load forecasts include simple greater uncertainty, larger impacts from policy interventions, and decisions regarding allowance for economic growth or other load-side surprises that belong to elected officials.[13]

---

[13] The last concern is relevant to the data center load growth issue. Simply by being solely responsible for load forecasts, PJM inevitably was the one blamed when those forecasts fell short. Explicitly involving

These concerns pull in opposite directions. To reconcile the need for procurement that matches new build timelines with the challenges of long-term load forecasting, we propose a structure that shares load forecasting responsibility between PJM and states and has a laddered procurement with PJM taking increasing responsibility for capacity procurement as the delivery years approach.

In this model, PJM would develop an econometric load forecast, as is done today. States would then overlay this with additions or subtractions, reflecting things such as electrification programs, economic growth opportunities not captured by PJM, energy efficiency efforts, or simply a different view than PJM on the trajectory of native load. Functionally, states reducing their load forecast would work identically to them simply opting load out of RPM, discussed in the next section. The final load forecast for each state must be approved by both PJM and that state's retail regulator (or other entity, as provided by state law.) Such a structure, we believe, better reflects the cooperative federalism envisioned in the Federal Power Act. It is enabled by the full-strength energy pricing and energy call options described above, and by states' knowledge that risk of curtailments will reflect their capacity position.

E. PJM should run a residual procurement over an extended time horizon

These load forecasts would feed into a laddered procurement, where PJM holds separate auctions buying capacity for delivery years ranging from prompt to far out in the future. These auctions are intended to serve as a default procurement approach. The design of these auctions should be such that if states or LSEs are comfortable with the default, they need do nothing and PJM will handle resource adequacy. The auctions also allow for states to modify the quantities and timing of forward purchases, say to implement a different hedging schedule, support clean energy goals, or in anticipation of additional load growth. Finally, states and LSEs need not use the auctions at all: bilaterally contracted capacity counts towards auction requirements, or they can simply opt out and take on responsibility for their own resource adequacy.

Exactly how far out in the future is a matter for discussion: there is an appeal in going out as far as 15 years to support technologies with extended construction times and match the timing of states' large-scale decarbonization efforts, but we acknowledge risk that sellers may demand unreasonably high risk premiums that far out. Closer examination of the performance of other countries' long-term procurements[14] may help guide this discussion.

Under this proposal, PJM would procure sufficient capacity to cover 100% of the load forecast in the prompt auction, declining to zero in the furthest forward auctions. As a straw proposal, simply procuring 10% per year is a reasonable starting point. This means PJM would by default ensure that 10% of capacity needs are met in the nine-year forward auction, 20% in the eight-year forward auction, and so on up to full coverage in the prompt auction. Procurements for the far future (say, 10+ years) will largely be driven by states. In addition to quantity and timing, we propose two major enhancements over RPM:

---

state regulators in determining if the system should hold (and pay for) excess capacity for unplanned load growth would go a long way towards avoiding similar situations in the future.

[14] Market Reform paper, p33.

1. First, some auctions may include a requirement for procuring new build capacity. This requirement may bind, resulting in separate clearing prices for existing and new build capacity. The requirement will be set auction-by-auction, either by request of states[15] or by PJM when it determines there is a need. This takes the new build auction mechanism contemplated for the Reliably Backstop Auction and allows it to be used in anticipation of a resource adequacy shortfall rather than in response to one.
2. Second, states may set additional binding constraints on the types of supply that may be procured to serve their load.

Together, these two provisions give states direct tools to implement their energy policies through PJM auctions if they choose, and gives PJM the ability to take direct action to stimulate new build when it foresees tightening reserve margins.

F. Flexibility to not participate in the centralized capacity structure provides additional options for states and wholesale customers.

RPM is currently a "must buy/must sell" construct, with limited exceptions for generators exporting from the region and a deliberately inflexible FRR option. Our final recommendation is that PJM largely abandon this path for load, preserving only must offer requirements for supply. In particular:

1. No requirement for states or wholesale customers to take capacity service for their entire load. Provided that they demonstrate ability to curtail as needed, states should be free to remove any or all of their load from RPM. This approach serves the purpose of putting public interest questions of who is guaranteed firm service and what exactly the "shared reliability compact" squarely in the hands of democratically accountable regulators. Similarly, wholesale end-use customers that want to go "full ERCOT" can opt to take energy-only service, backed by PJM's right to curtail. Such a customer might still face transmission charges, essentially making permanent the Interim NITS and non-firm Contract Demand Service from PJM's co-location filing.
2. States are explicitly free to contract with capacity supply under any terms they wish and have that capacity credited against the load in their state. This would eliminate the type of pre-emption conflict that led to the *Hughes v. Talen* ruling, as well as foreclose any return to a 2018-style MOPR.

To give states assurance that their policies will not be perpetually under the risk of having these protections taken away, PJM and the states should also examine governance approaches to "tying PJM's hands." Ideally, this could be as simple as reserving filing rights over the relevant sections of the tariff to the states, as is done now on behalf of transmission owners and EDCs. If this proves impossible,[16] more

[15] For clarity, we are envisioning states requesting individually, not collectively.
[16] See, e.g., Kelliher, Joseph, *States cannot be granted filing rights under Section 205 of the Federal Power Act*, Utility Dive, July 27, 2026.

complex means might be necessary. Regardless of the method, states cannot be left knowing that they are always a 205 filing away from having their energy policies invalidated.

G. PJM should encourage aftermarket liquidity.

PJM has a long history of restricting bilateral trades in capacity, generally incorporating a preference for "physical delivery" or "steel (lithium?) in the ground" over suppliers trading in obligations. Most recently, for example, the Reliability Backstop Procurement and IRAS BYONC filings both propose that new supply take on resource-specific obligations that cannot be met in any other way. Restrictions are certainly necessary to ensure like-for-like substitution. For example, it would defeat the point of a procurement for new supply if winning bidders could turn around and meet their commitment by buying from existing resources; transmission system constraints must be respected, and so on. But PJM's antipathy to aftermarket transactions often appears to go beyond that and be based in some not-fully-articulated belief that trading in obligations is somehow tawdry and represents a second-rate way of meeting obligations.

We believe PJM should reconsider that position. Whether PJM adopts the NRDC reforms or some other proposal, the outcome of these market reforms is very likely to involve expanded types of forward commitments. Subject only to rules that ensure replacements are true substitutes, PJM should allow, and even encourage, bilateral trading in all types of obligation.

The economic benefits of liquid markets are well known, and include easier entry and exit, price discovery, quicker convergence on equilibrium pricing, and lower transaction costs, among others. For the purposes of these market reforms, however, the most import is risk reduction and management. Building power plants is a risky business. The Market Reform Paper highlights today's challenging project development environment, which includes risks that might not be resolved until years after a supplier has an interconnection agreement and financing in hand.

The most fundamental thesis of NRDC's proposal is that PJM needs structures that will create a long-term pipeline of new-build generation in anticipation of tomorrow's needs rather than in response to today's crisis. That requires suppliers to take on significant risk many years in advance. Some of that risk may not be avoidable by the developer. For example, there is little a project developer can do in the face of, say, delays siting a backbone transmission upgrade their project depends on or the caprices of a hostile administration. Risk that cannot be avoided must be managed, and the ability to meet commitments through bilateral transactions is a critical tool for this.

The success of any forward contracting scheme in attracting new entry will hinge on developers knowing they are not entering potentially ruinous arrangements. The prices resulting from these forward arrangements will heavily depend on developers' assessments of how much risk they are taking on and their ability to hedge it. Absent pressing and concrete reasons to limit aftermarket trading, there should be no restrictions on bilateral trades other than those necessary to ensure the replacement supply is a true substitute for that being replaced.

Conclusion

NRDC appreciates this opportunity to comment on PJM's market reform efforts. We believe that reforms focused on addressing the governance, planning, and timing of resource adequacy in the region are the best approach to resolving the region's new entry and political issues, and emphasize our caution against reforms that transfer risk from any private party to the general public without substantial, ongoing retail regulator involvement.