PJM Market Update Webinar
Q&A

Compiled: Feb. 3, 2025

The following are answers to the questions our presenters received from participants during the PJM Market Update webinar on Jan. 28, 2025.

Policy

What impact could the new administration have on energy markets?

While we are still in early days of the new administration, some action related to energy markets has been swift and notable, mainly through executive orders:

Action	Possible impacts/outcomes/consideration
Doubling domestic energy production within five years, with eased permitting requirements for gas and thermal electric facilities.	Making approvals easier to obtain could help to increase energy production. However, it takes time to build new generation and pipelines, due to approvals, reviews, and actual construction. It's important to note that we need the infrastructure to make that energy useful. Constraints on pipelines and the current transmission system are limiting factors to our ability to double production and then be able to use that energy.
Pumped the brakes on further offshore and some onshore wind licenses.	This will impact where licenses are required for construction and operations.
Lifted the LNG export pause.	Approvals for new projects can commence, which would lead to even larger LNG export growth in coming years. This is bullish for pricing in the 10-year-out timeframe when projects come to fruition from this action. *See Q/A on page 2 for more info on impact.*
Provided incentives for U.S. oil drilling/producers.	Since natural gas is often extracted from the same wells, we could see a production increase as a result of more oil wells being drilled. However, producers still have a break-even price so it would have to be a profitable environment for them to increase production.
FERC Commissioner Mark Christie was named Chair of the Commission	Christie is in his fourth year of serving on FERC; he was previously a long-time Commissioner for the Virginia State Corporation Commission. The FERC remains 3 democrats and 2 republicans.

Fundamentals

What are the main drivers of bullish prices in PJM?

Some of the key drivers we discussed during the webinar include:

- Artificial intelligence (AI) data center demand growth is raising grid reliability concerns.
- Insufficient base generation and transmission lines may hinder grid support for rising demand.
- Recent capacity prices for planning year 25/26 and forward prices beyond 2026 reflect the above concern.
- Market/regulatory changes, as we saw with the Reliability Pricing Model (RPM) capacity market, will likely result in higher costs for consumers.

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Fundamentals (con't)

What is the impact of rising LNG exports on pricing in 2025 and beyond?
One effect of increased LNG exports could be higher prices if production levels can't meet the demand. In addition, infrastructure needs to be built out. Without enough pipeline capacity, the growth in production won't be able to get out to the demand centers resulting in even more bullish momentum. With the international prices for LNG exports being so much higher than current domestic prices, there's a lot of incentive to increase exports to capitalize on the higher prices overseas. The U.S. needs to find the balance between capitalizing on higher prices overseas and keeping domestic prices reasonable.

Reliability Pricing Model (RPM) Capacity Market

How does PJM ensure that capacity auction payments ensure reliability as per the rationale of the capacity payments?
PJM relies on its capacity market to send meaningful financial signals to inform decisions by asset owners and demand response providers to build new resources, re-invest in existing facilities, or retire uneconomic generating stations. PJM's capacity market is designed so that prices are lower when supply is plentiful and prices rise as supply becomes more scarce.

Postmortems on the 2025/26 BRA seem to point to at least three factors elevating prices that will be properly planned for in the future, so should we expect 2026/27 BRA to clear much lower?
All else being equal, PJM has taken steps to either decrease volatility or stabilize pricing in the capacity market. These market design changes still require approval by the Federal Energy Regulatory Commissions (FERC). It is important to note that outside of these proposed changes, load in the PJM region is growing at its fastest rate in many years.

Learn more about the July BRA results in our report. Read more about some of the factors contributing to the 25/26 BRA results in our report.

Some customers are not taking the June 1 capacity increases seriously on the theory that it would be so devastating to business that the government will obviously step in to lower those prices. Is this a possibility?
The outstanding tariff changes and various litigation are nearly all focused on changes to the market design impacting *future* auctions.

How would PJM's plan to revise its Surplus Interconnection Service rules impact the upcoming capacity auction if approved?
PJM's proposed tariff changes revise the existing Surplus Interconnection Service option to remove most of the limitations that currently exist on the use of such service.

I recently heard of a capacity ceiling and floor price that PJM is proposing for the 26/27 auction. What impact would this have if implemented.
On Dec. 30, 2024, Pennsylvania Governor, Josh Shapiro, on behalf of the Commonwealth, filed a complaint at FERC against PJM seeking to reduce the administrative price cap used in PJM's demand curve in advance of the 26/27 capacity auction. The complaint focused on the peak capacity prices that can result when available supply falls short of target reserve margins.

PJM and Governor Shapiro met to discuss the concepts of a market cap and floor and have agreed on a path forward for the complaint, which is subject to consultation with PJM Members, the PJM Board of Managers, and approval by FERC. Substantively, the parties agreed in principle on a cap of $325/MW-day and a floor of $175/MW-day for the auction clearing price for the 2026/2027 and 2027/2028 auctions. It's important to note that this is one of several outstanding capacity market-related issues under consideration by FERC at this time.

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RPM Capacity Market (con't)

Potential impact: If approved by FERC, the settlement proposal will establish a lower cap and higher floor for capacity market outcomes for the 2026/27 and 2027/28 delivery years. Under the current market rules, the auction does contain a cap based upon the Cost of New Entry (CONE) and a floor of zero.

Any expectations on where the PJM 2025/26 third Incremental Auction may settle?

The third PJM Incremental Auction (IA), which is an opportunity for PJM to meet any additional load growth and for resources to balance any long or short positions, is scheduled for the end of February. PJM published the Third IA Planning Period Parameters at the end of January. Once the results are final, final rates by locational delivery area (LDA) will be available. It's important to keep in mind however that the final capacity rates for any given delivery year typically follow the BRA settlement rates by LDA closely. This means that the IA results have very little impact on the final rates.

Can you provide an anticipated increase/impact to a business customer's monthly invoice for the capacity increases going into effect on June 1, 2025?

Since capacity costs are based on unique customer attributes, specifically a customer's peak load contribution (PLC), the impact will be different and unique in terms of monthly capacity costs post June 1, 2025. As a reminder, your PLC is your highest usage during the five highest-demand days in the summer, as determined by PJM. In this case, your PLC from summer 2024 will impact your costs on June 1, 2025.

The other half of the equation in determining your monthly capacity costs is the final rate for your transmission zone. As a loose example, since the PJM BRA settled approximately 9x higher than the current rates, which run through May 31, you could look at your monthly capacity costs (if this cost is passed through on your invoice) and multiple that line item by nine.

Here's an example of what that impact could look like for a customer with a 1 MW/1,000 kW PLC:

Capacity tag = 1,000 kW	June 1, 2024 -May 31, 2025	June 1, 2025 -May 31, 2026
Auction clearing prices	$28.92/MW-day	$269.92/MW-day
Annual capacity costs	$10,556	$98,521
Estimated annual increase	**$87,965**	
Estimated monthly increase	**$7,330**	
Percent increase YoY	**833.33%**	

Source: NRG's PJM BRA webinar – November 2024. The example above is for illustrative purposes only. Results/costs may vary based on a customer's load profile, PLC, and location.

Strategy

PJM index prices have remained very low through this recent cold snap. Do you have any comments about that trend and about the risk of participating in index markets?

While index pricing has not remained "very low" through this cold snap, historically speaking—and considering that Mid-Atlantic daily gas pricing was trading at $100/DTh in Transco and $40/DTh in Tetco—the power market avoided a pricing catastrophe like we saw with Winter Storms Uri and Elliott. Since the spot gas market does have a major impact on spot electricity prices, in the past, day-ahead pricing has reached over $700/MWh when daily gas pricing has been as high as we saw during the cold snap. The fact that daily average power pricing never exceeded $300/MWh *was a win* for the index market.

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Strategy (con't)

Some additional insights on pricing trends

- January 2025 index pricing settled nearly $20/MWh below where the January forwards were trading at the end of December when the significant below-normal forecasts began creeping into the market. Even with the extreme cold that materialized, index pricing still could not exceed the forward pricing that resulted from the below-normal forecasts.
- Traders always bake a below-normal winter into pricing. If we get a mild winter, you can almost guarantee that index pricing will settle substantially below where the forwards were trading.
- Any amount of exposure to index pricing in the winter months is a weather bet. While there have been materially lower prices more often than not in the index market, the risk for strong index pricing during the winter will always be present.
- Over the past 10 years, January/February West Hub index, on average, has settled at $38.33/MWh, with the highest pricing happening in February 2015 ($75.79/MWh) and the lowest happening in February 2020 ($19.89/MWh).

Strategy considerations
In terms of buying preferences and whether fixing all costs, floating all costs, or a combination of both is "better," it all comes down to a specific customer's risk tolerance.

- Locking in everything at a fixed price for the term will come with a premium, so your final price over the term may net higher than being on an index product where all costs are settled at market rates for the same term.
- Index prices could net lower than a fixed price for certain terms but your business would have to have some level of risk tolerance for fluctuations in monthly costs based on how the market may move—especially during the winter months.
- A hybrid product allows you to execute a customized blend of fixed and index purchases over term and align purchases and decisions with market conditions and risk tolerance. This is a flexible, fully customizable option that also allows you to incorporate energy services like load management/demand response.

If someone has an agreement currently in place that will terminate in the next month or two, would it be a good strategy to wait six months or so, until some of the new administration's energy actions/directives are implemented/take effect?
It's important to keep in mind that there is no certainty that the new administration is going to be able to significantly impact energy markets in a favorable way in the short-term/six months from now. That said, if you were considering a short-term fixed price contract to see where the market goes in six months, you could be putting your business at risk for increases in cost components that are part of your overall fixed price. There are about 25 cost components that comprise a PJM retail price, some of which are not connected to the incoming administration's federal policies but rather state- and ISO-level actions and policy. And, some of these costs have been historically trending upward.

Implementing a more strategic buying approach that addresses and manages each cost component according to your location, risk tolerance, usage patterns, and current market fundamentals, is a thoughtful way to position your business to achieve lower costs.

Consider: A popular option among larger buyers is to enter into a long-term contract that fixes renewable portfolio standard (RPS) and ancillary services, while allowing for layered purchases of the energy component. There are many bullish fundamentals that are keeping forward energy pricing very much elevated compared to what we've seen over the past couple of years. Of all cost components, the price of energy would be most impacted by the policies of the new administration and implementing a layering approach helps customers gradually reduce their risk exposure.

Strategy example: a customer locks in RPS and ancillaries for several years and at the same time starts with a 25% energy hedge for the term to start reducing risk. As they move through the contract term, with NRG's assistance, they wait for opportune times to make additional energy purchases, with the intent to lock in 100% of their load at a fixed rate through multiple layers over time.