BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

	:	
Resource Adequacy	:	
Technical Conference	:	Docket No. M-2024-3051988
	:	

Comments of NRG Energy, Inc.

Date: January 9, 2025

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I. Summary

NRG Energy, Inc. ("NRG") respectfully submits these Comments in response to the Public Utility Commission ("PUC" or "Commission") Secretarial Letters issued on November 15 and 26, 2024, which established a timeline for written comments regarding resource adequacy in Pennsylvania to be submitted. NRG appreciated the opportunity to participate in the Commission's November 25, 2024, Technical Conference, and to contribute to the lively discussion that ensued. Our comments here expand on the themes presented by Travis Kavulla at the in-person conference. As discussed throughout the Technical Conference and reiterated here, the Commonwealth does not have a resource adequacy problem. While reserve margins are shrinking throughout the PJM region, Pennsylvania's combination of dispatchable resources (including the fuel to power such resources), growing renewable resource fleet, and opportunities for direct consumer participation have established the standard by which other states in the region should seek to emulate. NRG focuses its comments on two important items that will further support the needs of customers throughout the Commonwealth.

A. Retail Competition Supports Resource Adequacy

Pennsylvania's retail market, over which the Commission has exclusive jurisdiction, supports resource adequacy by aligning retail customer commitments to take supply service with the revenues that ultimately flow to power generation located in the Commonwealth and elsewhere. While many parties focus on PJM and its wholesale auctions as a source of revenue for the investment in and continued operation of power plants, the first panel of the Technical Conference underscored that these auctions are intended to operate parallel to organic, retail-market activities. NRG explains in these comments how, when a customer chooses to do business with us, we support resource adequacy as a buyer of generation and transmission services to supply our customers. These retail relationships flatten out the volatility to which end-use customers might otherwise be exposed to by offering them the opportunity to contract for energy products that need not reflect the rapid ups and downs of PJM's energy and capacity markets from one day, month, or year to another day, month, or year.

Indeed, at the time the Technical Conference was held, it was possible for residential retail customers to purchase a long-term retail contract that brought them through and past the 2025-26

PJM capacity year, with prices that were lower than utility default service (even though the utility price had yet to reflect the upswing in the PJM capacity market). The Commission should continue to encourage customers to be aware of potential price spikes at wholesale, and to consider their retail purchasing options accordingly. Finally, to the extent the Commission is concerned that Pennsylvania customers, through their retail arrangements, may not have sufficient supply, there may be incremental steps the Commission can take to obtain those assurances which we describe more fully below.

B. Two Actionable Proposals for a More Active Demand Side of the Pennsylvania Electricity Market

In embarking on the project to introduce competition to the energy markets nearly three decades ago, the Commission, PJM, and federal regulators have spent substantial attention to ensuring the supply side of the market is robustly competitive and dynamic—and as noted in the Comments of the Commission's former chairman, Glen Thomas, the supply-side of the market is indeed competitive and dynamic.[1] Yet, over the years, less attention has been given to improvements on the demand side, which should be a co-equal and active force in any market across from the supply side. Demand-side participation has yet to meet its potential in Pennsylvania, despite the lofty promises that were made when the foundational technology investments in advanced metering were made.

For the demand side of Pennsylvania's market, NRG makes two actionable and concrete recommendations that this Commission should pursue in the short term:

- Rate design for utility-offered default products should reflect the peak-demand-related services, such as the provision of capacity; all utility default customers should be on a time-of-use ("TOU") rate; and
- Smart-device programming has become commonplace in most PJM states, and Pennsylvania should establish programs that allow customers and their suppliers to more readily optimize such affordable, customer-side devices in relation to the energy and capacity markets.

[1] Written Comments of Glen R. Thomas, Pennsylvania Public Utility Commission Technical Conference on Resource Adequacy in Pennsylvania, Post-Technical Conference Comments, Docket No. M-2024-3051988.

On rate design, Pennsylvania's residential default service consumers should be paying a rate that reflects the increased costs of serving peak demand in an on-peak period *by default*. Optional TOU rates have failed to achieve any substantial level of enrollment in Pennsylvania. Adopting such rates as *opt-out* would set the table for a reduction in capacity costs by actually conveying a price signal that customers could act around, and provide a more meaningful benchmark for competitive retail products available in the shopping marketplace. A TOU rate for default shopping would both offer opportunities for the customers on it to save money, and would reduce capacity obligations for Pennsylvania as a whole.

Meanwhile, realizing that retail pricing is a fundamental building block to galvanize demand-side actions, the Commission should additionally consider programs to encourage the adoption and automation of distributed energy resources, and smart thermostats especially, that facilitate load-serving entities' reductions of peak load during those hours when capacity costs (and transmission costs, which are also demand-related, and which weigh on consumer affordability) are incurred.

The demand side of this market is exclusively jurisdictional to this Commission. While the Commission should develop opinions and positions on PJM market design, there is no entity other than this Commission to deal with the retail market it is charged to regulate. The issues that NRG identifies in these comments consequently deserve the Commission's particular attention. NRG provides additional guidance on these two specific actions the Commission can take below.

C. About NRG Energy, Inc.

NRG is the leading essential home services company offering a unique whole-home experience to millions of North American customers. As a Fortune 500 company, NRG has provided leadership in competitive energy markets by creating a platform that offers consumers more control over their energy use and home automation and protection, especially with its newly acquired tech-forward smart home solutions. NRG serves 8 million customers across North America, including a significant share of retail energy customers in Pennsylvania. NRG has three offices in the Commonwealth to support its substantial investment in serving our customers, in Philadelphia, Pittsburgh and Wyomissing, staffed with hundreds of employees that support our businesses. NRG's retail energy subsidiaries include Electric Generation Suppliers

(“EGSs”) and Natural Gas Suppliers (“NGSs”), which serve customers of all sizes across the Commonwealth.[2]

Recently, NRG announced a partnership with RenewHome and Google Cloud to expand what will be one of, if not the largest residential smart-thermostat Virtual Power Plant (“VPP”) in the United States. We are targeting the enrollment of nearly half a million customers in that VPP by the end of the decade. While initially focusing on Texas due to the value its energy-only wholesale market conveys to demand-side resources, NRG ultimately hopes to expand these activities to other regions. PJM represents a marketplace where dispatchable smart thermostats, as part of a VPP, can have substantial value in the face of elevated capacity prices, as well as due to other demand-related charges that EGSs are responsible for, including transmission.[3] In this vein, NRG offers comments in this proceeding that focus on ensuring that Pennsylvania’s retail regulation is well-geared toward making the demand side of the energy market a full and co-equal participant across from the supply side, and thus better ensure resource adequacy at those times when it is threatened.

II. The Role of Retail Markets to Support Resource Adequacy in PJM

While recent capacity auction outcomes[4] and anticipated load growth in PJM[5] demonstrate shrinking reserve margins in the region, Pennsylvania is in the enviable position of having robust resources throughout the Commonwealth to serve its customers. As PJM has noted, even in

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[2] NRG’s licensed retail companies include: Direct Energy Business, LLC (Docket No. A-11025 and A-125072); Direct Energy Business Marketing, LLC (Docket No. A-2013-2368464 and A-2013-2365792); Direct Energy Services, LLC (Docket No. A-110164 and A-125135); Energy Plus Holdings LLC (Docket No. A-20092139745); Gateway Energy Services Corporation (Docket No. A-2009-2137275 and A-2009-2138725); Green Mountain Energy Company (Docket No. A-2009-2139745 and A-2017-2583732); Independence Energy Group LLC d/b/a Cirro Energy (Docket No. A-2011-2262337 and A-2013-2396449); Reliant Energy Northeast LLC d/b/a NRG Home/NRG Business/NRG Retail Solutions (Docket No. A-2010-2192350 and A-2015-2478293); Stream Energy Pennsylvania, LLC (Docket No. A-20102181867 and A-2012-2308991); and XOOM Energy Pennsylvania, LLC (Docket No. A-2012-2283821 and A-2012-2283967).

[3] Notably, Pennsylvania and most other PJM states require retailers (EGSs) to be charged the cost of and price into their retail offers both capacity and transmission. In some retail markets, such as Texas, transmission is strictly a pass-through cost. This provides for the possibility that EGSs may design retail products that allow customers to avoid transmission peaks and thus reduce the cost to serve them, offering the potential for additional value sourced from the competitive retail market for demand flexibility beyond what the capacity market itself makes available.

[4] https://insidelines.pjm.com/pjm-capacity-auction-procures-sufficient-resources-to-meet-rto-reliability-requirement/ (Retrieved January 2, 2025.)

[5] https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250107/item-07-2025-preliminary-pjm-load-forecast.pdf (Retrieved January 2, 2025.)

scenarios with no new resource additions, the Commonwealth is likely to be resource adequate through 2032.[6] Notably, this expectation does not reflect the anticipated return of the retired Three Mile Island nuclear facility[7] or other potential resources that may return to service in Pennsylvania,[8] nor the addition of any of the 10,500 MWs of new resources in the PJM interconnection queue.[9]

As the Commission considers the impacts to Pennsylvania consumers of tightening reserve margins, it is important to view the matter holistically, inclusive not just of capacity markets but energy market and cost trends for the regulated and often non-competitive transmission and distribution services, as well. For example, analysis provided by the Independent Market Monitor for PJM demonstrates that capacity markets represent less than 7% of total PJM market billings in 2024.[10] Energy and transmission costs (58.3% and 32.2%, respectively) represent the bulk of a PJM bill today. Notably, these figures do not reflect the portion of utility distribution and other state-specific costs or fees customers may pay, meaning that capacity is an even smaller percentage of customers' overall bill.

A. The Energy Markets Remain Liquid and Forward Prices are Declining, Suggesting an Abundance of Energy in the Future without Government Intervention

The supply of energy is not today or at any observable point in the future drying up in Pennsylvania or PJM—if one is to judge by the actual market participants who buy and sell energy. Chart 1 shows what a trader may buy energy for, for the year 2028. As can be seen, the price one were to pay in April 2024 is significantly higher than if the same energy were to be purchased at the very end of 2024. This is hardly indicative of a market that is blaring warning signs about a lack of energy.

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[6] https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2024/20241121-pa-resource-adequacy-analysis.pdf (Retrieved January 2, 2025.)
[7] https://www.constellationenergy.com/newsroom/2024/Constellation-to-Launch-Crane-Clean-Energy-Center-Restoring-Jobs-and-Carbon-Free-Power-to-The-Grid.html (Retrieved January 2, 2025.)
[8] Eg., *see* https://www.powermag.com/largest-pennsylvania-coal-fired-plant-will-convert-to-natural-gas/ (Retrieved January 2, 2025.)
[9] Value represents megawatts of capacity described as Active resources in the PJM Interconnection Queue located in Pennsylvania as of January 2, 2025. https://www.pjm.com/planning/service-requests/serial-service-request-status
[10] Market Monitor Report at 12. December 16, 2024. https://www.monitoringanalytics.com/reports/Presentations/2024/IMM_MC_Webinar_Market_Monitor_Report_20241216.pdf (Retrieved January 2, 2025.)

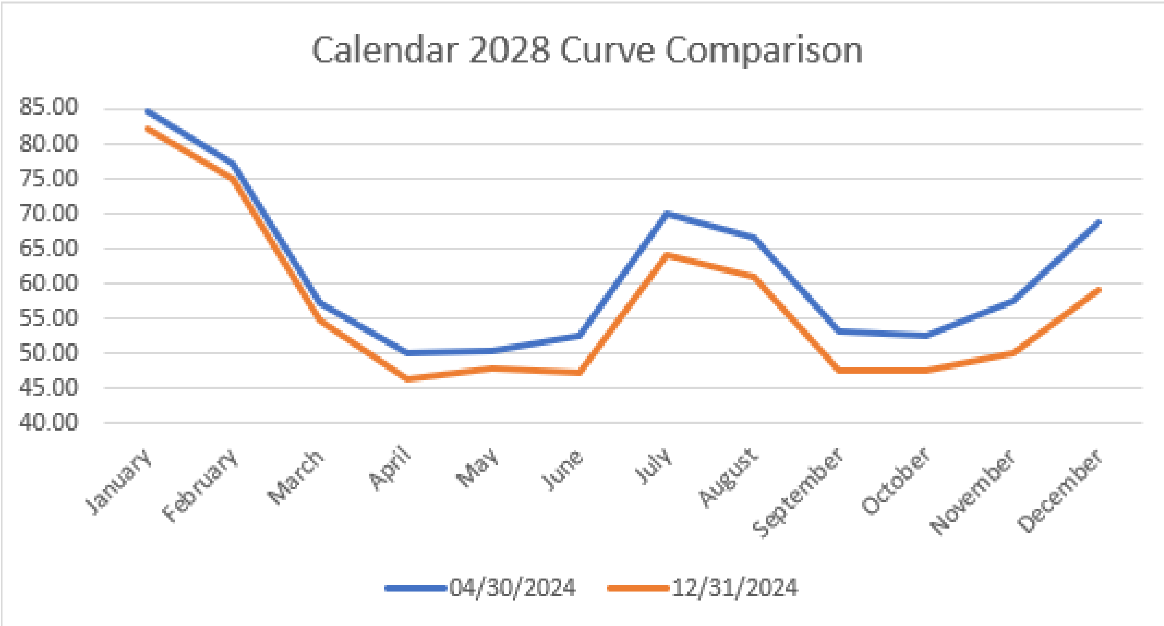


Chart 1: April 2024 vs December 2024 Forward Curve (for 2028)

While NRG understands that investment in generating capacity is needed, and why certain market operators, utilities, policymakers, and many others have their own reasons to stress that narrative, the people actually buying and selling power in this market are apparently satisfied that adequate energy will be available in the later part of this decade based on their willingness to enter into binding financial commitments to sell that energy at a price that is lower than it was a year ago. The Commission should focus on this elemental question of the availability of energy supply in any policymaking in which it engages on the topic of its above-captioned docket.

Second, the Commission should be apprised of the fact that energy supplies—if purchased today—are not significantly higher in 2030 than they would be in 2028, 2026, or even today. Chart 2 demonstrates each annual curve overlaid against one another as of Dec. 31, 2024. These are the prices at which, by month and for each year between 2025 and 2030, one may purchase energy. It is relatively flat, only slightly escalating year-on-year. This signifies a market in with future supply in relative equilibrium in view of load-growth expectations. The following chart specifically shows the "PJM West Hub," the primary liquid trading hub to serve significant portions of PJM, including Pennsylvania for the purpose of bilateral trades that are informed by PJM's own marketplaces generally.

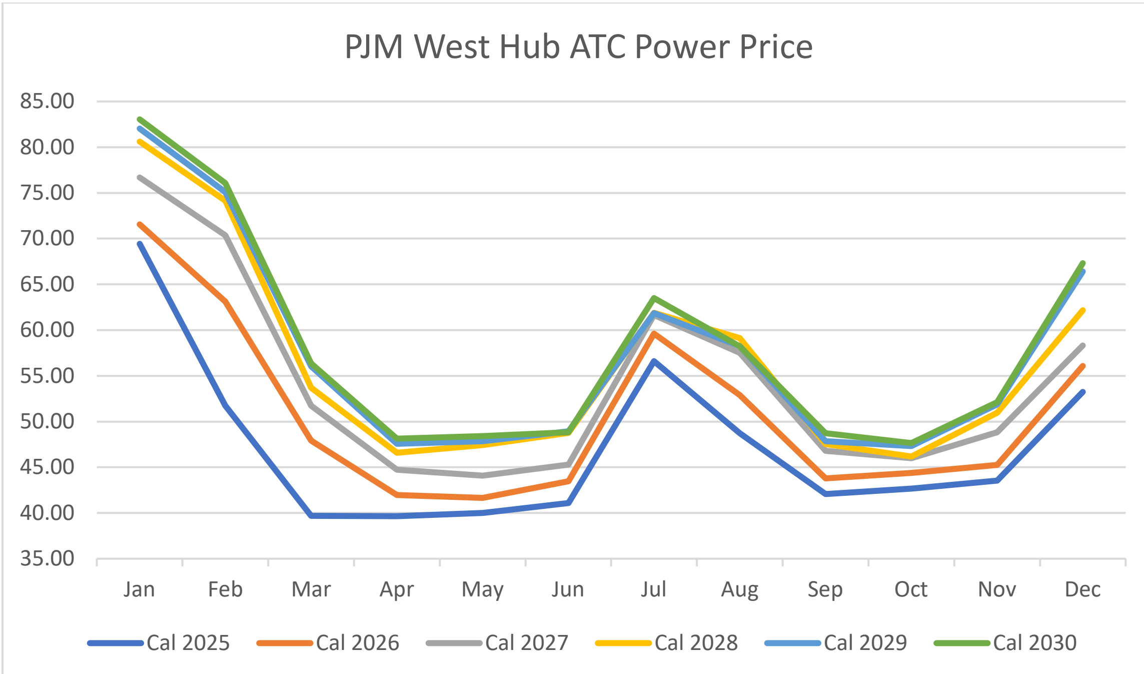


Chart 2: PJM Energy Market Forward Prices 2025-30 (West Hub, inc. PA)

This empirical evidence of trading leads to this primary conclusion: Whatever the load growth that market participants contemplate, it appears that this load growth is met by the addition of resources producing additional energy to meet those needs, with relatively little inflation in prices.

Those buying energy—and thus energy consumers, through retail product purchases—can take advantage of the above trends *now*, at least in Pennsylvania, thanks to the competitive retail market that allows a customer to enter into a month-long, year-long, or five-year-long retail contract. If the Commission believes longer-term price stability is a good in and of itself for customers or a certain class of customers, it should consider relying on the wholesale energy trading trends now available for purchase to encourage customers to take advantage of that stability. Such deals do not require the action of any regulated utility or any investment it may (want to) make.

B. The PJM Capacity Market is Less Liquid than Energy Markets, but Utility-Sponsored Generation is Not a Workable Solution

There are two important caveats to the above data concerning the energy market, which co-exists alongside the capacity market, which is sometimes thought of as producing revenue necessary to obtain and retain “steel in the ground” net of any energy-market revenues that power plants need to operate. One caveat is that one may surmise that the traders involved in the activity visually depicted above may be reckoning that the forward curves assume an equilibrium that is achieved by any data centers or new large loads bringing online their own incremental generation. In NRG’s view, that may be the one view of such trading that assumes a regulatory treatment that, so far, does not exist formally. It may be a wise protection for the Commission to consider how best to create the right conditions for that to occur, as we discuss below.

The second important caveat is that, while energy markets are widely traded and the result of thousands of hourly auctions and the forward estimations of those auctions’ cleared results that unfold over any given year, capacity markets are a more momentous event (an annual auction, with subsequent residual or incremental auctions) and these are indeed tightening. This has left capacity buyers more dependent on the centralized auctions that PJM runs, or alternatively to take matters into their own hands by self-arranging new capacity (both generation and demand resources). In its own reaction to high capacity prices, PJM itself has proposed a multitude of capacity market and interconnection rule changes, and these are likely to facilitate a moderation in pricing over time and expedite new entry.[11] Given the panoply of market and administrative reactions to a single year’s capacity clearing price, this Commission should not panic by adopting hasty and poorly conceived solutions to force generation into the mix via contracts backed by promises of ratepayer or taxpayer money. Notably, in those places where regulated utilities themselves bear the responsibility for capacity in PJM, pricing has consistently been

[11] *See* FERC Docket Nos. ER25-682 (which proposes various capacity market updates regarding the treatment of qualifying resources that are retained under a "reliability must run" agreement as capacity, retention of a dual-fuel fired combustion turbine plant as the reference resource, updates to the Non-Performance Charge based on the RTO net CONE, and the Base Residual Auction schedule); ER25-712 (enabling a one-time reliability-based expansion of the eligibility criteria for PJM’s interconnection process Transition Cycle #2); ER25-778 (intended to facilitate the rapid expansion of existing and planned generating facilities on PJM’s system through the expedited Surplus Interconnection Service process); and ER25-785 (which would require all Existing Generation Capacity Resources to offer into the capacity auctions beginning with the 2026/2027 Delivery Year).

higher than the competitive market's clearing price.[12] On this last point, it is of vital importance that the Commission recognize that any interceding action it may take to commandeer regulated utilities to produce capacity investment will have a chilling effect on market-based investments.

Efforts to re-insert the local distribution utilities in the generation business not only flout existing Pennsylvania law,[13] but also fail to extract any advantage the utility may claim to have. Simply put, the utilities cannot enter the market any faster or cheaper than the independent investment that has given Pennsylvania so many advantages in the electricity sector over the last 25 years. Utilities would be subject to the same interconnection queue and would have to manage the same supply-chain issues that any developer does. There is no "easy" button that would allow a utility to take such actions faster or cheaper than other market participants. In fact, under the classic cost-of-service model, consumers would be on the hook for such utility investments for 20-30 years at full freight instead of investors being responsible for gains or losses. However, there are additional things the Commission can do to ensure a security of supply.

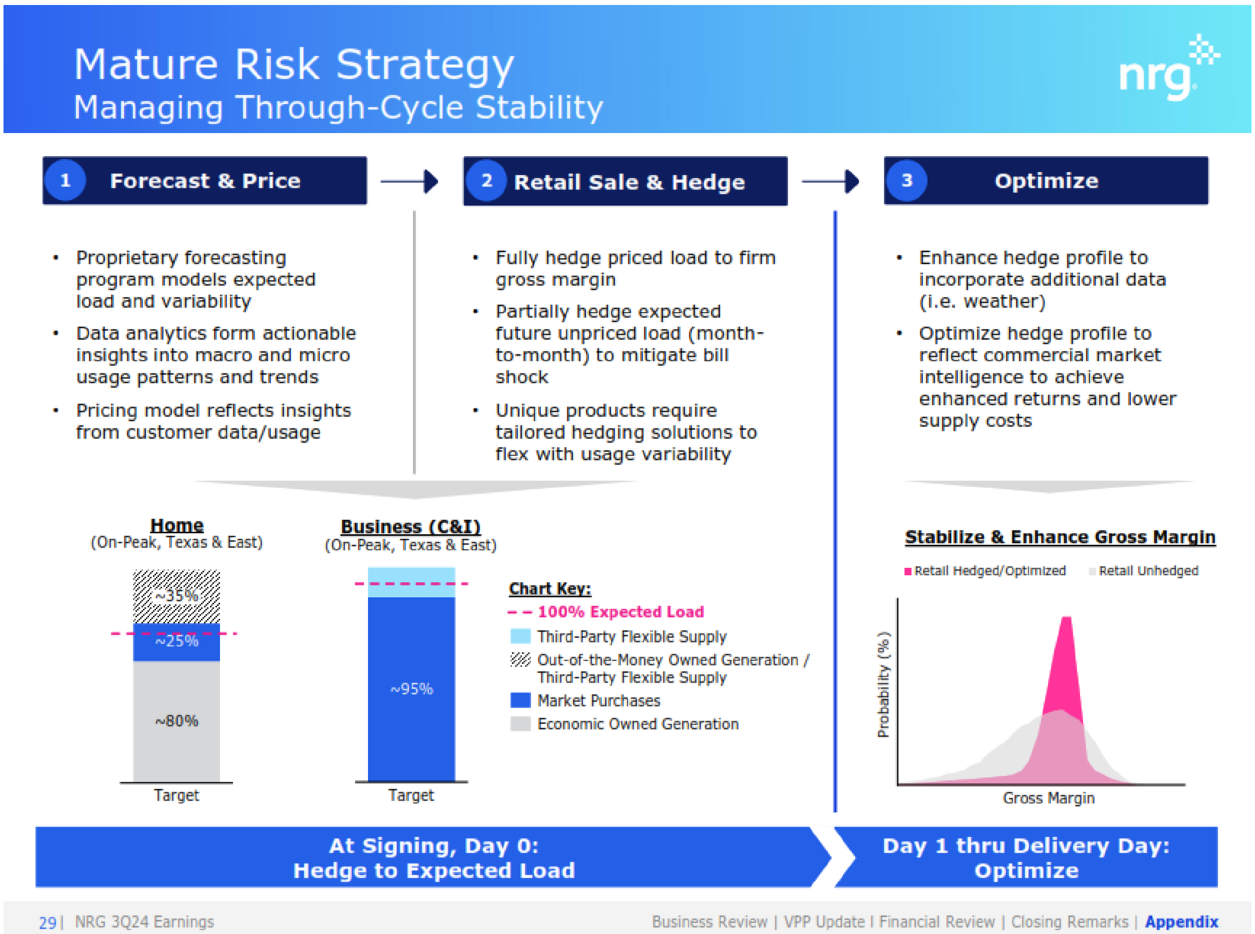
C. Retail Competition, through Load Serving Entities ("LSEs") Contracting Activities, Advances Resource Adequacy

Perhaps most important in considering how shrinking—but still reliable—reserve margins impact customers across the Commonwealth is to consider how Load Serving Entities, and specifically competitive retailers or as Pennsylvania terms them "Electric Generation Suppliers" (EGSs) like NRG, use the energy markets to provide the most efficient, affordable prices to their customers. NRG does many things in the eastern restructured markets. We are a generation owner, a demand response provider, and a shipper of about two bcf/day of natural gas across the country via the interstate pipeline system. We also are an EGS or the equivalent in most PJM states, serving about 10% of all demand in the eastern restructured markets. Because the retail market structure is the exclusive jurisdiction of state public utility commissions, unlike wholesale markets, it is important to recognize the vital role retail markets have in ensuring resource adequacy.

[12] *See* Appalachian Power Company Fixed Resource Requirement rates for Delivery Years 2020/2021 ($480.98/MW-Day), 2021/2022 ($465.33/MW-Day), 2022/2023 ($503.29/MW-Day), 2023/2024 ($450.17/MW-Day), and 2024/2025 ($464.74/MW-Day). https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/frr-lse-capacity-rates (Retrieved January 2, 2025.)

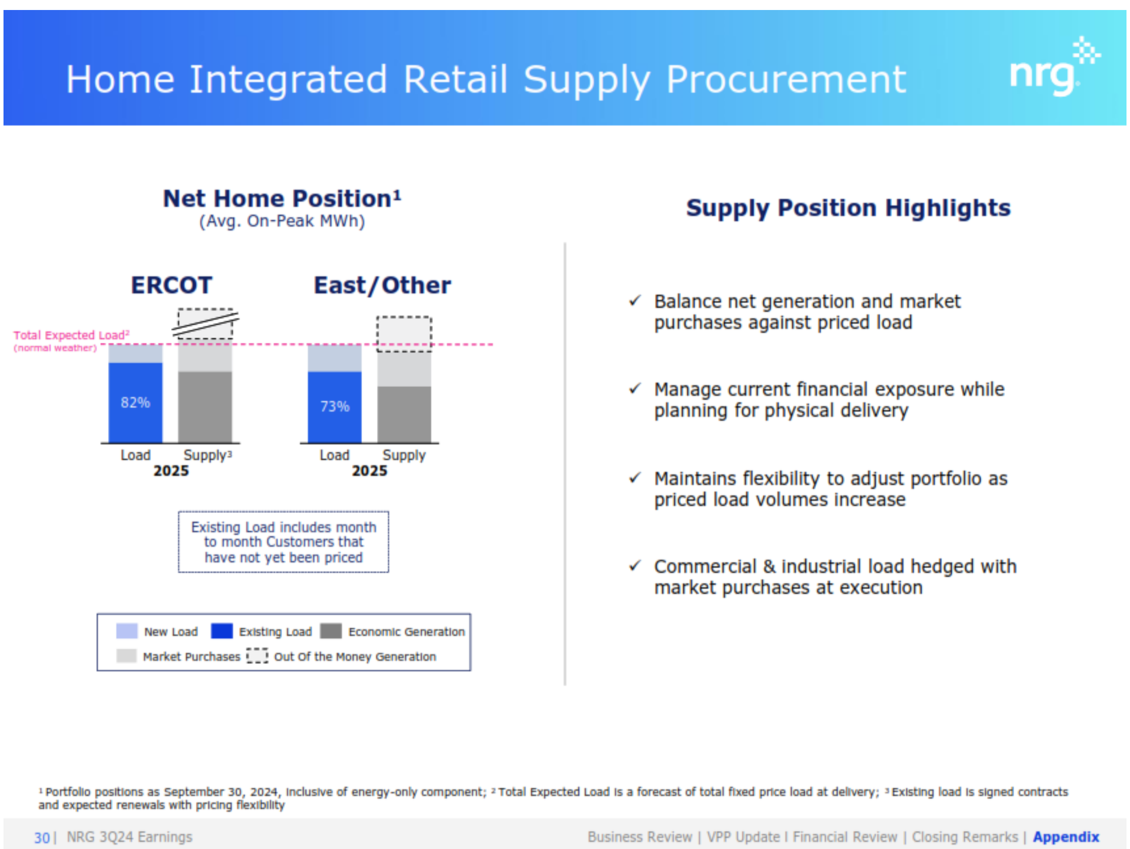
[13] See 66 Pa C.S. Sec 2802(14), 66 Pa C.S. Sec 2804(5), 66 Pa C.S. Sec 2806(a), and 66 Pa C.S. Sec 2806(d).

Below is an illustration, which NRG routinely shares with its investors as a public company, on how we satisfy our obligations to our customers while managing our own risk within the PJM markets and other wholesale markets that are full of risk.



NRG, when it signs up a new retail customer, engages in a policy of “back-to-back hedging.” On day one of service with a retail customer, we estimate the customer’s load, make adjustments for extreme weather, and then bilaterally purchase the supply that is necessary to cover that estimated load. These bilateral contracts provide us the certainty that the rates that our customers have agreed to pay are adequate to cover the obligations we have made to upstream parties who have agreed to furnish us energy (or are adequate to cover the cost of operating our own power plants). In turn, those upstream contracts that we, as a “load-side” party sign, are a major source of revenue to our counterparties, namely the power plants in PJM. As this Commission’s Technical Conference highlighted in Panel 1, those revenues are sometimes more important, if less visible, than PJM’s own energy and capacity markets. The rechristened Three Mile Island, the Crane Energy Center, is an excellent example of how that occurs at scale, but this activity happens day-in, day-out on a more mundane basis as well, with retailers like ours using our trading floor to execute “buys” to hedge our supply costs from power plant owners who wish to “sell” and thus lock in a certain amount of revenue associated with their production of (or their opportunity to produce on demand) energy.

To be clear, the incentives facing sellers and buyers already align, and encourage the hedging of loads. NRG’s energy traders would rather be “long and wrong”—buying expensive insurance to cover our retail contractual obligations, throughout the year and especially during spot-market price spikes—than “short and fired,” with its potential for insolvency. NRG simply has no desire to financially expose itself to very high energy prices when customer load is higher than we might expect. This is how the retail market is supposed to work in support resource adequacy. At least for our company, NRG believes the market meets that expectation. Indeed, our company carries what is essentially a reserve margin cushion on our own simply to support the economics of our retail sales activity.



Notably, it is the fact that our company is *not* a cost-of-service regulated utility that motivates NRG to do all the things related above. As a competitive retailer, if we fail to raise adequate revenue from our customer contracts to cover our costs, we have no recourse to retroactively effective adjustments clauses or other tariffs. A return to that kind of energy economy would actually mean an elimination of the positive incentives that today exist, and which are related above, for licensed EGSs to align supply with demand within the Pennsylvania retail market. Understood properly, eliminating customer choice and binding customers to a marketplace dominated by the incentive structure extant during the era of "cost of service" regulation is in fact detrimental to resource adequacy.

D. The Commission Can Further Encourage Retail Forward Contracting Through Its Competitive Retail Market

Given these dynamics, whereby retailers like EGSs have an ingrained incentive to forward contract for the supply that their customers by contract will require, state regulators have options to nudge the retail market to ensure it is living up to its obligations. By the same token, to the extent that regulators are especially worried about resource adequacy because of new large loads potentially entering the system, the Commission could require such loads to demonstrate the adequacy of their forward contracting arrangements.

1. Residential customers have affordable options that mitigate capacity price spikes available to them, and the Commission and policymakers should nudge customers toward those options

First, the Commission can and should encourage the formation of longer-term contracts between willing buyers and sellers in the retail market.[14] Customers have the ability to avoid the impending price volatility resulting from the latest round of capacity auctions by signing longer term contracts with retail suppliers that lock in pricing for an extended period of time. As of January 2, 2025, a PECO customer has the ability to sign up for a 3-year electricity supply

[14] To be clear, our recommendation here is for the PUC to encourage longer term contracting between willing buyers and willing sellers in the competitive market in order to retain the economic benefits of the competitive market. Our recommendation is not meant to suggest that the regulated utilities should be mandated to enter into long term power-purchase agreements that create nonbypassable costs for *all* customers, regardless of their choice. If utilities are permitted or required to enter into PPAs, choice effectively ends, as every customer on default service will be prevented from leaving that service because they must pay the cost of those PPAs or pay a potentially exorbitant "exit fee" to cover their share of those costs. Long term PPAs force customers to bear the investment risk and drive up the price for electricity. The Commonwealth abandoned this approach 25 years ago and it should not return to it.

contract priced between $0.09500 per kilowatt hour (for system power without renewable attributes), to $0.13490 per kilowatt hour (for renewable energy).[15] Similar offers are available in the Duquesne Light, PPL and MetEd. These products offer price stability and serve as an insurance product against future price increases that are sure to come with increased capacity costs.

The Commission has been instrumental in educating Pennsylvania consumers about the benefits of retail choice and the options and opportunities it offers for more than a decade.[16] As a result of its Retail Market Investigation, the PUC undertook a Statewide Consumer Education Campaign that resulted in mailings to consumers that increased awareness about the opportunity to shop for retail energy supply, and ultimately in consumers taking heed and exercising their right to choose.[17] NRG urges the Commission to revisit those very successful past efforts and encourage consumers to engage the retail market to protect themselves against future price fluctuations by signing up for longer term electricity supply contracts that can be found on PAPowerSwitch.com. It has been over a decade since the PUC's customer education campaign, when: 1) postcards signed by all 5 PUC commissioners that encouraged consumers to shop and promoted the PAPowerSwitch website were mailed; 2) PAPowerSwitch.com tri-fold flyers with detailed explanation of steps to choosing suppliers/shopping were created; and 3) the regulated utilities sent customers letters encouraging them to shop. Now is the perfect time for the Commission to proactively reengage consumers by reminding them of their options and encouraging them to shop for longer term insurance products.

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[15] www.papowerswitch.com. Notably, even as late as the third quarter of 2024, after the PJM 2025-26 auction results posted, offers available on the government website were substantially below utility default service provider offers even when long-term offers. Customers and the Government of Pennsylvania that did not choose or advertise those offers likely will pay more through either a competitive or utility selection now.

[16] In fact, in a 2016 PUC press release, the Commission unveiled the results of a survey showing that almost all respondents (94%) were aware that they had the ability to shop. See PUC Marks 20th Anniversary of Electric Competition in PA; New Survey Shows High Levels of Customer Awareness and Satisfaction with Electric Choice, Touts 14 Consecutive Months of Growth, Announces Upgrades to Electric Shopping Website PAPowerSwitch, 12/8/16. https://www.puc.pa.gov/press-release/2016/puc-marks-20th-anniversary-of-electric-competition-in-pa-new-survey-shows-high-levels-of-customer-awareness-and-satisfaction-with-electric-choice-touts-14-consecutive-months-of-growth-announces-upgrades-to-electric-shopping-website-papowers.

[17] *Investigation of Pennsylvania's Retail Electricity Market: End State of Default Service*, Final Order, Docket I-2011-2237952, February 14, 2013.

2. *The Commission could require that data centers 'bring their own' generation*

The concern raised by the PJM Independent Market Monitor and by FERC Commissioner Mark Christie in recent proceedings involving a Pennsylvania data center is that new large loads may sap the system of the existing resources that hitherto been expected to supply other customers in a relatively low-load-growth environment.[18]

Before the Commission does anything based on this largely speculative fear, the Commission should ask itself, based on the evidence it gathers and not mere speculation, if it is so profoundly concerned that data center load growth will disrupt the system's resource adequacy in a way that the wholesale market is incapable of solving it. If the answer is "yes," and that the Commission feels that it is forced to do something, then there is a fairly obvious answer: requiring data centers to bring their own new capacity to the table before interconnecting to the system.

Certain utilities have argued that the era of data centers requires them to get back into the power-generation game through Commission-approved power plants that would be charged to all customers. It would be a profound irony, and a huge mistake, for the Commission—in trying to avoid a perceived cost shift associated with the growth of data centers—to end up perpetuating one by requiring utilities to sign long-term power purchase agreements (or utility-owned generation) that all residential or other commercial and industrial customers, not just data centers, were obliged to pay for. This "solution" would actually *ensure* the outcome that regulators are ostensibly trying to avoid by entertaining the concept. It is ludicrous and should be discarded by the Commission out of hand.

3. *The Commission could require EGSs to demonstrate adequate forward contracting to cover their contractual supply obligations*

Certain regulators in different sectors and internationally engage in prudential regulation to ensure that customer-facing suppliers have adequately contracted upstream for the service they, through retail contract, are obliged to provide. Pennsylvania undertakes periodic checks on

[18] *See* Concurrence of Commissioner Christie. PJM Interconnection, L.L.C.. 189 FERC ¶ 61,078, November 1, 2024 at P 2: "Co-location arrangements of the type presented here present an array of complicated, nuanced and multifaceted issues, which collectively could have huge ramifications for both grid reliability and consumer costs." *See also* FERC Docket No. ER24-2172. Answer and Motion For Leave to Answer of the Independent Market Monitor for PJM. July 10, 2024 at 6-7: "While the proposed amendment to the ISA is creative, its benefits to the co-located load come at the expense of other customers in the PJM markets. If this approach were extended to all the nuclear plants in PJM, the impact on the PJM grid and markets would be extreme."

retailers' financial health, but does not engage in this style of regulation. While NRG currently views this style of regulation as needless in this market, given the potential that already exists for significant and negative financial consequences to EGSs that do not adequately hedge their retail books, it may provide additional comfort to the Commission to know that the retail market is suffuse with credible retailers who do, in fact, have a risk-mitigation strategy that aligns forward contracting with their retail load obligations.

In this same vein, it is also worth considering whether the retail structure is properly designed to facilitate the entry and performance using advanced metering infrastructure of devices like smart meters and other distributed energy resources. For example, in Texas, NRG intends to sign up half a million of our residential customers to direct load control smart thermostat programs by the end of the decade. That will furnish a private source of capacity in that market for us of about 650 MW exclusively dedicated to our residential customer portfolio. This is another source of hedging that NRG is engaging in—a physical hedge similar to power plants, but arising from customers themselves and thus even more closely matched to their resource adequacy needs, which does not need to be sourced from bilateral contracts. To the extent that this kind of innovation requires a boost on the regulatory and policymaking front, we examine it below.

4. *The Commission could choose to create a long-term default service product as a backstop 'insurance policy' against wholesale market volatility*

NRG opposes and consumers themselves would resent the Commission's obliging them to take a particular service from a monopoly service provider when they previously had a choice in the energy supply they bought. This includes activities that eat away at their choice, such as the inclusion of utility-owned supply costs in nonbypassable charges that all customers must pay, even if they procured through retail contract with an EGS their own supply.

However, if the Commission did wish to create an ironclad backstop product, which nevertheless ensured customer choice, it could create utilities' Default Service Provider offerings into long-term default product. Namely, it could require utilities to bid a 7- or 10-year "all-in priced" product—including energy, capacity, and transmission costs—and have the wholesale suppliers to these default auctions offer a full-requirements product for any residential customer within the utility service territory who elected to take service under it. This would come at a premium, certainly, but it would represent a move to make the default product available in the retail market into a genuine "provider of last resort" product. It would thus encourage other, more organic retail offers to do the lifting on resource adequacy and customer attraction described in the above subsections, even while providing a genuine insurance against enduring, escalatory capacity and energy prices that the Commission is concerned about.

III. Creating a More Active Demand Side in Pennsylvania's Retail Electricity Market

So far in these comments, NRG has attempted to describe the *status quo* of the wholesale and retail competitive markets, and how these are working already to achieve resource adequacy. As noted, there are certain avenues the Commission may undertake to ensure the purchase of supply by those who have obligation to serve it under either a retail contract or because of their role as a default supplier, but the most-advertised approaches in this proceeding (e.g., utiltiy-sponsored generation through nonbypassable charges) would be extremely damaging to the positive activites in the competitive market that currently *support* resource adeqaucy.

In this section, then, NRG proposes two actionable recommendations that involve the Commission's exclusive role in regulating the demand side of the marketplace. In particular, many states, including Pennsyvlania, have not followed through with the promise of restructuring—which was not just about how to competitively source generation, but about how to empower consumers, that is the demand side of the electricity industry, to exist as a co-equal participant across from the supply side, especially when the latter has features of scarcity.

A. The Commission should take steps to implement opt-out time-of-use ("TOU") rates for all customers who take utility default service

One of the often-promised benefits of smart meters is their ability to create an enhanced retail experience, including time-varying rates that better reflect the cost of energy at wholesale and the opportunity for demand to participate in response to a more dynamic price signal. As then-Commissioner Robert Powelson opined in his characteristically forward style when the Commission first implemented Act 129 providing for smart-meter technology, "To be frank, it is pointless to have smart meters if you are still going to have 'dumb' rates."[19] And yet, even as

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[19] Statement of Commissioner Robert F. Powelson, Implementation of Act 129 of 2008 – Relating to Smart Meter Procurement and Installation, Docket No. M-2009-2092655, June 18, 2009.

the utility companies' customers have paid handsomely for this investment, several years later they have little to show for it—at least as regards "smart" rates.

Notably, Pennsylvania's regulated utilities who serve as Default Service Providers ("DSPs), have a legal obligation to offer such a rate to essentially all customers with smart meter technology.[20] And according to filings made by all of the investor-owned utilities, smart meters have been fully deployed across all service territories. The roll-out has resulted in smart-meter technology being nearly ubiquitous for Pennsylvania ratepayers.[21] As such, most of the PA utilities have approved TOU rates available for customers who voluntarily choose to sign up.[22] These plans are all "opt-in" and are available to residential and small commercial default service customers who may elect to be served under those rates.[23] The TOU rates generally include two or three pricing periods (depending on the utility)—Peak, Off-Peak, and Super Off-Peak—that remain constant year-round or are seasonal, and are subject to the adjustments made to the utilities' standard non-time varying default service rates (quarterly or semi-annually as applicable).[24] These rates are derived via price multipliers applied to the default service rates calculated for each rate class.

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[20] 66 Pa. C.S. § 2807(f)(5); DCIDA v. PUC, 123 A.3d 1124 (Pa.Cmwlth. 2015), rehearing denied, 2015 Pa. Commw. LEXIS 472 (Oct. 30, 2015), appeal denied, 2016 Pa. LEXIS 1131 (Pa., June 1, 2016).

[21] PECO has deployed approx. 1.7M smart meters serving ~98-99% of its customers; PPL has deployed approx. 1.5M smart meters; the First Energy Companies have deployed approx. 2.1M smart meters; Duquesne Light has deployed approx. 621,000 smart meters. See: *PPL Electric's Annual Smart Meter Progress Report 2021*, Docket No. M-2014-2430781, August 31, 2021. *2023 Annual Progress Report Smart Meter Technology Procurement and Installation Plan*, First Energy Companies, Docket No. M-2013-2341990, M-2013-2341991, M-2013-2341993 and Docket No. M-2013-2341994, August 1, 2023. Duquesne Light Company Annual Smart Meter Deployment Update for 2014, Docket No. M-2009-2123948. PECO Act 129 Smart Meter Plan, Stakeholder Collaborative #24, October 28, 2015.

[22] See: *Petition of PECO Energy Company for Approval of its Default Service Program for the Period from June 1, 2021 through May 31, 2025 Final Opinion and Order*, Docket No. P-2020-3019290, December 3, 2020; *Petition of PPL Electric Utilities Corporation for Approval of its Default Service Plan for the Period Jun 1, 2021 through May 31, 2025 Final Order*, Docket No. P-2020-3019356; *Petition of [First Energy Utilities] for Approval of Its Default Service Plan for the Period From June 1, 2023 through May 31, 2027 Final Order*, August 2, 2022; The Commission approved a pilot EV-TOU rate for Duquesne Light in 2020 as part of the Company's default service program for June 1, 2021 through May 31, 2025 (Docket No. P-2020-3019522). Their EV-TOU whole home rate was extended for the June 1, 2025 through May 31, 2029 Default Service Plan in Docket No. P-2024-3048592 (Final Order not yet posted). And on the Motion of Chairman DeFrank, Duquesne Light has been directed to prepare a supplemental filing to establish a TOU rate available to all residential and small commercial default service customers with smart meters to become effective on 6/1/25.

[23] Notably, Pennsylvania's commercial and industrial default service customers with PLCs of 100 kW (PPL, PECO, First Energy) or 200 kW (Duquesne Light) and larger are already served on TOU rates – they receive hourly priced default service rates.

[24] PPL's TOU rates are seasonal with summer and winter periods and include Peak/Off-Peak periods, with no Super Off-Peak period.

Unfortunately, though predictably, opt-in TOU adoption in Pennsylvania remains exceedingly low. According to PECO's 2022-2023 Default Service Plan TOU Annual Report, as of May 31, 2023, the cumulative total participation in its TOU Program Years 1 and 2 was just 1,914 customers, of which 1,902 were residential customers, or 0.12% of its customers.[25] Similarly, PPL reports that participation in its program has been very low, with just 0.06% of its customers billed on the TOU rate.[26]

It does not have to be this way. There are strong reasons founded on the traditional principles of utility regulation to employ TOU rates as the default supply option, because they more closely align to the cost-of-service accounting that governs utilities. In addition, time-of-use pricing is empirically demonstrated for its effects of shifting usage away from peak periods and toward off-peak periods. However, for this rate structure to be effective, experience shows that it needs to be *opt-out*, as opt-in programs as demonstrated by the Pennsylvania utilities' programs—consistently show low levels of enrollment.

One of the most significant levels of enrollment in TOU in the United States is Southern California Edison, where 83% of the utility's supply customers are enrolled in time-of-use rates.[27] What is the reason for the high levels of enrollment in SCE? It is simple: The utility has an *opt-out* rate design for time-of-use. Simply put, there is little reason to expect an opt-in model of time-of-use rates to produce substantial customer enrollments, and empirically they have not in Pennsylvania. A default rate that is a flat rate does not respect the basic conventions of cost-of-service ratemaking and it does not reflect the realities of the electric grid — specifically, the fact that periods of high demand impose costs that are related to demand.[28] The recent capacity market outcome in PJM puts a dollar sign and an exclamation point on this observation. The Commission should expeditiously move to make both the default service rate and electric distribution companies' delivery charges to be time-of-use by default.

[25] *PECO Energy Company's 2022-2023 Default Service Program Time-of-Use Annual Report,* Docket No. P-2020-3019290.

[26] Direct Testimony of Andrew Castanaro, Petition of PPL Electric Utilities Corporation for Approval of a Default Service Program and Procurement Plan for the Period June 1, 2025 through May 31, 2029, Docket No. P-2024-3047290, p. 51.

[27] Based on EIA Form 861 data (2023).

[28] Travis Kavulla, *Why is the Smart Grid So Dumb? Missing Incentives in Regulatory Policy for an Active Demand Side in the Electricity Sector* (2023), Energy Systems Integration Group. https://www.esig.energy/wp-content/uploads/2023/01/Why-Is-the-Smart-Grid-So-Dumb-Missing-Incentives-in-Regulatory-Policy-for-an-Active-Demand-Side-in-the-Electricity-Sector.pdf

Making default service and utility distribution rates time-of-use would continue to afford customers the choice to select another product, including a flat-rate product, from the competitive retail market, but it would establish time-of-use rates as the standard. Today, in 2024, five state regulatory commissions, including California, Colorado, Hawaii, Michigan, and Missouri, have ordered the adoption of opt-out time-of-use rates for their electric utilities, and numerous public power utilities have also adopted such rate structures, including utilities like Long Island Power Authority that are in restructured markets. There are few better candidates for rate design focused on eliciting demand-side responsiveness than Pennsylvania.

In contrast, other jurisdictions have wallowed in pilot mode or adopted time-of-use rates only as an opt-in even when results of opt-out pilot programs have been clear successes. One example is Maryland, which in January 2017 convened a stakeholder process to explore a pilot. The pilot ran from June 2019 through May 2021. After years of effort, the three participating utilities have enrolled a total of 2,660 customers out of a base of nearly 2 million residential customers.[29] This 1.4% rate of enrollment is small, and sadly the rate of new enrollments seem to be slowing with BG&E enrolling only 448 new customers, Pepco only 34 new customers, and Delmarva Power only 5 new customers in a one-year period spanning May 2023 to May 2024. The rate was designed to load distribution costs, transmission costs, and costs of the PJM capacity auction into the peak period. In Maryland, this meant a substantial differential between on- and off-peak between 4:1 at the lowest and 6:1 at the highest, depending on the utility. Demand reductions were impressive. Reductions of 9.3 to 13.7 percent were seen during the summer months, when the PJM system peaks, and 4.9 to 5.4 percent during the winter months.[30] After these blockbuster results, however, the Maryland Public Service Commission ruled that the program should remain opt-in. The utilities expect to spend only a small amount of money to market the rate's availability and it cannot reasonably be expected that the rate will become the standard on its own. From the beginning of the stakeholder process to deciding to make the rate permanent, more than five years elapsed— a period of time as long as, if not longer than, the time spent to roll out the actual infrastructure of smart meters in the utilities' service territories.

[29] Report of PC44 Time-of-Use Rate Design Workgroup (Sept. 6, 2024) at 5. Total residential customers figure sourced from EIA Form 861 (2023).

[30] Letter from Work Group of the Maryland Public Service Commission, "In re PC44 Rate Design Work Group Leader's Report and Recommendations on Full-Scale Time of Use Rate Offerings" (June 3, 2022), Project No. PC 44.

One argument sometimes proffered against time-of-use rates is that social and equity concerns counsel against their widespread adoption. Yet in Maryland's pilot, which specifically recruited a sample of low-to-moderate income customers in order to evaluate these claims, the peak load reductions achieved through the pilot's time-of-use rate were "not statistically different" than reductions achieved by customers outside the low-to-moderate income sample. Across the entire pilot population, an impressive 9.3 percent demand reduction in weekday peak loads for Baltimore Gas & Electric was recorded (Sergici et al., 2021). These findings of tiered time-of-use rates are consistent with a Lawrence Berkeley National Laboratory study of critical peak pricing offered by two other utilities, Sacramento Municipal Utility District and Green Mountain Power, which found that vulnerable customers were just as likely as the residential customer class as a whole to be responsive to time-varying rates and consequently obtained proportional benefits (Cappers et al., 2016). As a collection of consumer advocates has concluded, "[r]esearch in most jurisdictions has shown that on average lower-income customers use less electricity, and use proportionately less electricity during peak periods. Such lower usage customers would thus benefit from a change in rate design from a flat rate to either an inverted tier rate or a time-of-use rate" (Colgan et al., 2017).

Notwithstanding the fact that the Commission has recently concluded default service proceedings for PPL, PECO, and Duquesne Light, NRG urges the Commission to consider initiating a statewide docket to consider the adoption of TOU as the default service rate across Pennsylvania for all residential and small commercial customers. Doing so would position Pennsylvania consumers to leverage their investment in the smart meters measuring their energy consumption and to take a more active role in contributing to resource adequacy in the region.

B. Require the Utilities to Include a Smart Thermostat Program in their Act 129 Energy Efficiency and Conservation Plans.

In PJM, most states now have adopted smart thermostat programs that allow for the direct load control of the devices that control the single largest contributor to the PJM summertime peak load by the residential customer class. In NRG's experience, such programs can result in demand reductions of approximately 20% of the capacity needs of the residential customer class. These programs, moreover, often involve enrollment of existing devices or deployment of new devices that, unlike utilty-scale generation solutions, do not require permitting, siting, and interconnection. Smart thermostat programs can achieve positive effects on resource adequacy outcomes in a timely way, and in a way that empowers customers.

To date, Pennsylvania has not pursued a smart thermostat program as part of the Act 129 Energy Efficiency and Conservation programs (EE&C).[31] Such a program, therefore, offers the Commission a unique opportunity to tap into this untouched resource to enable demand response. The current Phase IV program period that began in June 2021 will conclude in 2026. Per the requirements of the Act, the Commission must assess the cost-effectiveness of the EE&C Programs and set additional incremental reductions in electric consumption every five years. Now is the perfect time to consider including Smart Thermostat Programs as part of the Commonwealth's EE&C Program to further reduce energy consumption and peak electric demand. As noted above, NRG's partnership with RenewHome and Google Cloud will create one of the largest residential smart-thermostat Virtual Power Plant ("VPP") projects in the United States. PJM represents a marketplace where dispatchable smart thermostats, as part of a VPP, potentially have substantial value due to elevated capacity prices.

Through these programs, a customer's utility or chosen retail supplier is permitted by its customer to remotely adjust enrolled smart thermostats during a peak load event. Customers may opt-out or manually adjust the thermostat, overriding the utility/supplier control. Customers are typically solicited to enroll in the program in exchange for a bill credit, payable on either a one-time or ongoing basis. The cost of the bill credits is socialized through utility rates or riders. Some programs provide free or subsidized smart thermostats, sometimes including installation, but more often customers are encouraged to "bring your own thermostat."

Typically, these programs have parameters around maximum duration, frequency and amount of cycling reduced. Based on NRG's review of the landscape of such programs in the Eastern United States, utilities have found capacity reductions between 0.65 to 1.15 kW per thermostat when called. Notably, most of the smart thermostats enrolled in utility programs operate on a very limited use case and it is not clear how frequently these devices, once subsidized and installed, are activated. They are typically not used to reduce adopting customers'

[31] Previously, certain Pennsylvania utilities had a program that installed a limiting device on the air conditioning compressor external to consumers' homes. This device, while still used in certain areas, has fallen out of favor with the advent of smart thermostats that can achieve a more granular and customer-centric level of control of air-conditioning systems.

exposure to capacity costs, although they reduce the overall capacity needs of all customers by participation in the PJM market. It would improve both the efficiency and adoption rate of these smart-thermostat programs if the load-serving entities responsible for capacity costs (and energy and transmission costs) also had dispatch rights to the devices subsidized by utility programming. At least one state regulator has recently found a way to make that happen. Earlier this year, the Public Utilities Commission of Ohio ("PUCO") ordered that AEP's smart thermostat programs be co-optimized with a customer's competitive retailer.[32] The PUCO's order requires that EGSs be allowed to:

- market smart thermostats devices and the $75 per-device subsidy as part of retail offerings;
- exercise dispatch rights to obtain energy and capacity cost reductions; and
- sell aggregations of these devices into the PJM capacity market as Demand Response.

The Ohio regulatory model for these smart thermostats thus leverages money that ratepayers are already paying to provide additional capacity to the system and increase cost reductions for individual customers who opt into the program. NRG urges the Pennsylvania Commission to follow Ohio's lead and create smart thermostat program that will allow Pennsylvania customers to play a more active role in ensuring resource adequacy in the Commonwealth. The electric distribution utilities ("EDCs") should be directed to implement a smart thermostat demand response program with the following characteristics:

- Program Mechanics:
  - Residential customers enrolled in the demand response program agree to permit the EDC to call events on their thermostat to reduce (winter)/increase (summer) the temperature of their home by no more than three degrees for no more than four hours during times of peak usage determined by the EDC (Demand Response Event).

[32] *In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143, in the Form of an Electric Security Plan*, Case No. 23-23-EL-SSO; *In the Matter of the Application of Ohio Power Company for Approval of Certain Accounting Authority*, Case No. 23-245-EL-AAM, April 3, 2024.

- EDCs have the ability to call Demand Response Events to implement a PJM directive, to protect its distribution system, to limit or avoid distribution outages, and to reduce load on localized constrained distribution circuits.
- EDCs will not bid the associated demand response into the PJM market. Customers reserve the ability, on their own or through their agent on their behalf (e.g., retail supplier) to engage in energy efficiency and peak demand reduction activities and/or participate in PJM demand response programs.
- EDCs may not subject a customer to more than 16 Demand Response Events in a calendar year, excluding any retail supplier events being noticed through the EDCs' systems.
- EDCs will notify customers of Demand Response Events via app, text message and/or email. Any costs and/or fees associated with marketing and/or administering this program (including but not limited to smart thermostat API costs) will come out of approved EE&C funding.
- Incentive levels and other details of the program (e.g., change in degrees, number of Demand Response Events, etc.) can be adjusted by the EDC as necessary based upon demand in order to optimize participation.
- A Distributed Energy Resources Management System ("DERMS") shall be selected by the EDC through a competitive and transparent process, and its operations shall be compatible with the optimization model that includes both EDC and EGS dispatch instructions, consistent with customer preferences in the competitive retail market.
- EDCs are required to ensure that any participating customer has the customer load settled on the basis of actual advanced meter interval readings so as to align to and the capture the value of the demand-related "tags" associated with capacity and transmission service derived from PJM and the local transmission utility.

- Customer Participation:
  - As part of the initial enrollment process, residential customers must provide affirmative consent to EDCs and EGSs (EDCs/EGSs must maintain consent records for 3 years).

- Residential customers receive an initial $75 incentive toward the purchase of a new qualifying smart thermostat or an initial $50 incentive for an existing qualifying smart thermostat acquired outside of the demand response program (qualified smart thermostats means those that have the required capabilities to administer the program and have reasonably/competitively sourced access costs) through the EDC or an EGS.
- Residential customers receive an annual $25 incentive following each program year (September 1 through August 31) as long as the customer participates (does not override) in at least 75 percent of the Demand Response Events.
- Customers are enrolled in the program for a 12-month term.
- Enrolled customers automatically renew for the next program year unless they expressly opt out of the program.
- Customers will only be permitted to redeem the initial incentive for one thermostat per account number.

- EGS Participation:
  - To enroll customers in the program, an EGS must: (1) provide an account number enabling the EDC to verify a customer's identity as a customer with an active retail supply account that is not previously associated with a $75 smart thermostat rebate under the program, and (2) provide make, model and serial number of the installed smart thermostat.
  - An EGS is allowed to issue dispatch directives to the DERMS, consistent with its contract with its customers.
  - The $75/$50 rebate can be paid directly to the EGS from the EDC as part of an EDC retail offer that includes the installation of a new smart thermostat, or automation or expansion of the use case of an existing smart thermostat in a customer's home or business.

- Stakeholder Engagement:
  - EDCs must work with stakeholders (including thermostat vendors and EGSs) to develop a list of qualifying thermostats to ensure maximum flexibility while maintaining thermostat functionality.
  - EDCs host semi-annual working group meetings where they and other interested stakeholders (including smart thermostat vendors and EGSs) can collaborate on ways to maximize the benefits of the program. The working group will address and form a recommendation as to whether the demand response program should incorporate other in-home demand-response-capable devices. The collaborative will also discuss and implement any reasonable and cost-effective changes necessary to preserve EGS communication channels with their customers relative to programming initiated pursuant to market-based activities, and will further explore a reasonable and cost-effective solution for any potential limitations to EGS provider offered programs that could be impacted or limited due to physical or technology capabilities with smart thermostats and the vendors running the smart thermostat demand response operations.

IV. **Conclusion**

As discussed in the preceding comments, Pennsylvania's competitive retail energy market has served and is serving customers well and should be relied upon to assure resource adequacy in the Commonwealth. There is no upside to a return to a regulated-utility paradigm. The Commission has the ability to exercise its authorities in a way that support the competitive paradigm that already exists.

Meanwhile, the Commission should focus its attention on demand-side solutions. These are not the only or even the largest solution to the region's resource adequacy challenges. But they do represent solutions with a shorter runway to achievement and a return on advanced metering investments that are presently being under-utilized. NRG thanks the Commission for its attention to these matters and looks forward to participating in any future proceedings initiated to consider these issues.

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