COMMONWEALTH OF PENNSYLVANIA

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October 2, 2026

Via Electronic Filing
Matthew L. Homsher, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

Re: Pennsylvania Consumer Advocate
v.
PPL Electric Utilities Corporation

Docket No. C-2026-

Dear Secretary Homsher:

Attached for electronic filing, please find the Office of Consumer Advocate's Formal Complaint and Public Statement in this proceeding.

Copies have been served on the parties as indicated on the enclosed Certificate of Service.

Respectfully submitted,

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Certificate of Service

CERTIFICATE OF SERVICE

Pennsylvania Consumer Advocate	:	
	:	
v.	:	Docket No. C-2026-
	:	
PPL Electric Utilities Corporation	:	
	:	

I hereby certify that I have this day filed electronically on the Commission's electronic filing system and served a true copy of the following document, the Office of Consumer Advocate's Formal Complaint and Public Statement, upon parties of record in this proceeding in accordance with the requirements of 52 Pa. Code Section 1.54 (relating to service by a participant), in the manner and upon the persons listed below.

Dated this 2nd day of October 2026.

SERVICE BY E-MAIL ONLY

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Dated: October 2, 2026

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Consumer Advocate	:	
	:	
v.	:	Docket no. C-2026-
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PPL Electric Utilities Corporation	:	
	:	

NOTICE TO PLEAD

You are hereby advised to file a written response within 20 days to the attached Office of Consumer Advocate's (OCA) Complaint and Public Statement in the above-captioned proceeding. If you do not file a written response to OCA's Complaint and Public Statement, the Chief Administrative Law Judge may rule in favor of OCA as to the attached Complaint and Public Statement.

All pleadings, such as answers to complaints, must be filed with the Secretary of the Pennsylvania Public Utility Commission:

Matthew L. Homsher, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

A copy should also be served on the undersigned counsel, the Chief Administrative Law Judge and all other parties.

Respectfully submitted,

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FORMAL COMPLAINT OF THE
PENNSYLVANIA CONSUMER ADVOCATE
REGARDING PPL ELECTRIC UTILITIES CORPORATION'S
EXISTING RATES AND SERVICE
IN RELATION TO ADDITIONS OF DATA CENTERS
TO THE UTILITY'S ELECTRIC DISTRIBUTION SYSTEM AND THE PJM REGION

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Date: October 2, 2026

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II. Reliable Utility Service: The separate rate and service classification should include for the provision of mandatory interruptible service to CLEs during pre-emergency and emergency conditions, as appropriate. The omission of mandatory interruptible rates schedules and implementing tariff operating procedures to prevent existing customers from experiencing emergency forced customer outages results in unjust, unreasonable, and/or unduly discriminatory or preferential rates and unreasonable, inadequate, and/or unreliable service. 47

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VI. Cost Causers Should Pay: The separate rate and service classification should include appropriate provisions to address cost allocation impacts for capacity, RBP and IRAS costs. The omission of specific tariff provisions to ensure that default service and shopping customers are not subsidizing capacity, RBP, IRAS costs caused by data centers results in unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful rates. 63

VII. Cost Shifting and Stranded Costs: The separate rate and service classification should include appropriate provisions to address cost shifting and stranded costs impacts. The omission of a rate schedule applicable to data centers that contains sufficient provisions to prevent cost shifting and the shifting of stranded costs risks from data centers onto other ratepayers results in unjust, unreasonable, or unduly discriminatory or preferential rates. 67

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Appendix D – Ogur Affidavit

Appendix E – Deupree Affidavit

Appendix F – Konidena Affidavit

BEFORE THE
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Pennsylvania Consumer Advocate	:	
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v.	:	Docket No. C-2026-
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FORMAL COMPLAINT OF
THE PENNSYLVANIA CONSUMER ADVOCATE
REGARDING PPL ELECTRIC UTILITIES CORPORATION'S
EXISTING RATES AND SERVICE
IN RELATION TO ADDITIONS OF DATA CENTERS
TO THE UTILITY'S ELECTRIC DISTRIBUTION SYSTEM AND THE PJM REGION

A. INTRODUCTION

Before the Pennsylvania Public Utility Commission (Commission), and pursuant to applicable statutes and regulations at 71 P.S. Section 309-4, 66 Pa. C.S. Sections 102, 501-502, 701, 1301-1304, 1309, 1501-1502, 1505, 2803, 2805(a), and 2807(a), (e); and 52 Pa. Code Sections 5.1(a)(2), 5.21-5.24, 57.19, 57.52, 57.194(d), and by and through the Office of Consumer Advocate (OCA) and the undersigned assistant consumer advocates employed therein, the Pennsylvania Consumer Advocate, Darryl A. Lawrence (Complainant), hereby files this Formal Complaint (Complaint) against PPL Electric Utilities Corporation (PPL Electric or Company), as a public utility and electric distribution company (EDC), generally alleging that PPL Electric's exiting tariff rates, rules, and regulations are unjust, unreasonable, and/or unduly discriminatory or preferential and existing service is unreliable, unreasonable, inadequate, and/or unduly discriminatory or preferential because it causes existing consumers to inappropriately bear the risks and consequences of: (1) paying for new and higher costs that are caused by the additions of data centers to PPL Electric's service territory and the regional grid operated by PJM

Interconnection, L.L.C. (PJM); and (2) receiving service that is frequently interrupted or curtailed due to strains placed on electricity transmission infrastructure and generation supply as a result of the fast-paced interconnections of and service to data centers without PPL Electric taking preventative steps to ensure that either there is sufficient new supply to meet the new data center demand or there is the provision of mandatory interruptible service to data center customers during pre-emergency and emergency conditions, as appropriate.

Accompanying this Complaint are the attached affidavits of the OCA's Expert Witnesses Zachary Teti, M.S. (Teti Affidavit), Frank Felder, Ph.D. (Felder Affidavit), Matthew Hoyt, M.P.A (Hoyt Affidavit), Serhan Ogur, Ph.D. (Ogur Affidavit), Michael Deupree, M.A. Econ, (Deupree Affidavit), and Rao Konidena, M.S. Electrical Engineering, MBA (Konidena Affidavit) (collectively, the Affidavits).

The OCA recognizes the existence of Rate LP-6 in PPL Electric's tariff, which the Commission approved based on a settlement in PPL Electric's 2025 rate case. However, that settlement contained a specific provision allowing the parties to re-open Rate LP-6 after the Commission's issuance of a final model tariff. Given that the Commission has issued a final model tariff, further given that the Commission left it up to the EDC's discretion to voluntarily adopt the model tariff, and further given the rapidly evolving data center load forecasts for PPL Electric's service territory, upon preliminary review, the OCA believes and avers that Rate LP-6 contains inadequate protection for existing customers from the known and foreseeable costs and reliability impacts due to unprecedent, rapid additions of data centers to the PPL Electric system and the PJM grid.

Accordingly, as supported by the attached Affidavits, and as further explained below, Complainant specifically alleges that existing rates are unjust, unreasonable, and/or unduly

discriminatory or preferential, 66 Pa. C.S. Sections 1301-1304, and existing service is inadequate, unreasonable, unreliable, and/or unduly preferential, 66 Pa. C.S. Sections 1501-1502, because:

(Claim 1): PPL Electric's tariff does not establish a new customer classification for rates and service applicable only to data centers to appropriately address the cost impact risks and reliability impacts to service risks presented by the ongoing additions of data centers to PPL Electric's system and the PJM region, 66 Pa. C.S. Sections 1301-1304, 1501-1502;

(Claim 2): PPL Electric's tariff omits mandatory interruptible service rates schedules and implementing tariff operating procedures that are necessary to protect existing customers from experiencing emergency forced customer outages due to the ongoing and foreseeable impacts to reliable service caused by data center additions to PPL Electric's system and the PJM region, 66 Pa. C.S. Sections 1301-1304, 1501-1502, 2803, 52 Pa. Code Section 57.52;

(Claim 3): PPL Electric's tariff omits sufficient and adequate operating rules and interconnection terms and conditions to protect existing customers from experiencing emergency forced customer outages due to the ongoing and foreseeable impacts to reliable service caused by data center additions to PPL Electric's system and the PJM region, 66 Pa. C.S. Sections 1301-1304, 1501-1502, 2803, 2805(a), 2807(a), 52 Pa. Code Section 57.52;

(Claim 4): PPL Electric has failed to take reasonable steps to ensure the continued provision of service without unreasonable interruption or outages to its existing customers, particularly its most vulnerable customers, despite known and impending resource inadequacy and transmission constraints that could compromise service as early as July 1, 2027, 66 Pa. C.S. Sections 1501-1502, 52 Pa. Code Sections 57.19, 57.52, 57.194(d);

(Claim 5): PPL Electric's tariff omits specific provisions to ensure that transmission and distribution incremental investments caused by data center interconnections as well as the data

centers' fair share of embedded costs related to the utility's local transmission system will be paid for by the data centers, 66 Pa. C.S. Sections 1301-1304, 2807(e);

(Claim 6): PPL Electric's tariff omits specific provisions to ensure that default service and shopping customers are not subsidizing PJM capacity, Reliability Backstop Procurement (RBP), Interim Resource Adequacy Service (IRAS) costs caused by data centers, 66 Pa. C.S. Sections 1301-1304, 2807(e);

(Claim 7): PPL Electric's Rate LP-6 omits sufficient rules and regulations to prevent cost shifting and the shifting of stranded costs risks from data centers onto other ratepayers, 66 Pa. C.S. Sections 1301-1304; and

(Claims 8 and 9): PPL Electric's tariff omits sufficient provisions and PPL has failed to take reasonable steps to prevent exacerbating existing affordability challenges for residential customers or to adequately protect eligible low-income customers from the costs and affordability impacts associated with rapid data-center load growth, including through adequate universal service fund contributions, 66 Pa. C.S. Sections 1301-1304.

As explained further below, Complainant intends to prove these allegations through the development of a robust evidentiary record. Also as explained further below, Complainant requests relief commensurate with the claims and allegations herein.

B. FACTUAL BACKGROUND

I. The Necessity of this Complaint to Ensure Protection of Existing Utility Consumers

1. This Complaint is necessary because the rapid onset of the massive amounts of electricity demand from planned and potential data centers onto PPL Electric's utility electric systems is relatively new and impacting existing Pennsylvania utility consumers today and will continue to impact these consumers into the future. Fortunately, a "Public Policy Consensus" that

is positive for existing utility consumers has emerged, with some level of buy-in from the data center industry. That Public Policy Consensus directs public utilities to ensure that: (1) data centers pay for the costs that they cause related to the addition of new utility infrastructure to both interconnect data centers and meet the data centers' electricity demand needs; (2) data centers bear the risks of stranded costs related to new utility infrastructure that is built to interconnect data centers and meet data center demand; and (3) data centers bear the risks and consequences related to any reliability impacts caused by their additions to utility systems operated by EDCs and the regional grid operated by PJM. While the Public Policy Consensus aspires to protect existing consumers from the costs, risks, and reliability impacts of interconnecting data centers to utility systems, the work now for this Complainant, Respondent, Commission, and other interested parties, is to ensure that the goal of protecting existing ratepayers is effectuated through binding utility tariffs governing rates, rules, and regulations of utility service and other binding requirements relating to certain aspects of utility service.

II. The Consumer Advocate's Position Regarding Data Center Additions to Electricity Systems

2. The interconnection of large-scale data centers to electric utility systems in Pennsylvania presents opportunities and challenges. As opportunities, if introduced and implemented in a thoughtful and considered manner that places reliability and affordability at the forefront, utility consumers can potentially benefit from the additions of data centers to electricity systems. As challenges, without sufficient safeguards for utility ratepayers, the interconnection of new data centers could create substantial upward pressure on electricity bills and increase electricity reliability risks for existing consumers. Such an outcome would be untenable because Pennsylvania ratepayers (1) did not cause or contribute to the drivers of these increased costs and reliability risks; and (2) already are experiencing increased electricity rates and affordability

challenges, due to many factors, as well as decreased service reliability due to increased outages due to storms.

3. To protect existing consumers from escalating costs of electricity bills that for some is increasingly unaffordable, data centers should pay for the costs they are causing to serve their electricity needs. Data centers should pay for network upgrade infrastructure costs, both transmission and distribution, that are incurred by utility providers to meet their needs given that data centers are the but-for causers of and receive commensurate benefit from the new infrastructure. Additionally, data centers should pay their fair share of embedded costs of electricity systems. Additionally, to mitigate price increases for existing consumers, data centers should pay for the increased PJM capacity, RBP, and IRAS costs that are incurred by providers in the PJM markets to serve their needs.

4. To protect existing customers, new data centers should bear the costs and consequences of the increased reliability risks caused by their but-for contributions to the growing resource adequacy shortage in the PJM region and Pennsylvania, and the growing transmission constraints, unless and until there exists sufficient capacity and necessary wires infrastructure within the PJM Region to meet their electricity consumption needs. Specifically, this means data centers being subject to mandatory interruptible service and rates during times of pre-emergency and emergency load control events to prevent the escalation of emergency actions that can affect firm customers and critical load. This also means the rules and regulations governing interconnection safeguard existing consumers from outage risks due to resource adequacy shortages and transmission constraints.

5. To protect existing consumers, PPL Electric must adhere to statutory authority and responsibility and effectuate such adherence through binding tariffs. Existing statutory authority

places mandatory obligations upon PPL Electric to act in a manner that respects a cooperative federalism framework controlling electricity service in Pennsylvania and that protects reliable and affordable electricity service for existing ratepayers within PPL Electric's service territory.

6. To protect existing consumers, from ongoing and near-term, anticipated harm, the Commission can and must act soon by order based on a robust formal record on the issues and claims raised in this Complaint and grant such relief as necessary and proper to correct and prevent harm for non-data center utility customers. Regional resource adequacy shortfall begins as early as June 1, 2027, and EDC mandatory interruptible service and rate schedules and rotating firm load shed curtailment procedures need to be updated prior, hence the urgency to act soon.

III. Data Center Electricity Demand – Size and Speed to Power – In Context

7. Data centers demand extraordinary amounts of electricity to power their businesses. To put their usage into context, one American home consumes approximately 11,000 kilowatt-hours (kWh) on average per year. One advanced data center chip (i.e., the specialized microprocessor powering cloud computing, artificial intelligence, and/or enterprise servers) consumes about as much as the average residential household. A one-gigawatt (GW) data center consumes the same amount of power as one million homes[1]— almost half of the Limerick nuclear plant (at 2.3 GW) or half of the Hoover Dam (at 2 GW). *See* Felder Affidavit.

8. The average existing data center operating today is approximately 45 MW, which is the equivalent demand of power of all homes in the Williamsport, Pennsylvania urban area (population of 56,000). In contrast, the average planned data center is 177 megawatts (MW).

[1] 1 GW equals 1,000 megawatts (MW) and 1 MW equals 1,000 kilowatts (kW). GW, MW, and kW are units of power, the instantaneous draw of power. If operated for 1 hour, a 1 GW load consumes 1 gigawatt-hour (GWh) of energy, a 1 MW load consumes 1 megawatt-hour (MWh), and a 1 kW load consumes 1 kilowatt-hour (kWh). There are 8,760 hours in a year so a 1 GW data center consumers 8,760 GWh or 8,760,000 MWh of load if it operates 100% of the time.

Hyperscale data centers, such as the planned 4,400 MW data center campus in Homer City, Pennsylvania, will generate and consume as much power as all the homes in the Philadelphia urban area (population of 5.7 million). *See* Felder Affidavit.

9. Pennsylvania and the PJM region are in the midst of a dramatic increase in electricity demand driven almost exclusively by data centers. *See* Teti Affidavit. By contrast, for more than two decades, electricity load growth in Pennsylvania and throughout the PJM region remained relatively flat. From 2001 through 2024, Pennsylvania's and the PJM region's average aggregate load growth was approximately 0.3% per year. Thus, for more than twenty years, Pennsylvania and the PJM region experienced little average growth in overall electricity demand. *See* Teti Affidavit.

10. In contrast, due to data center activity, in Pennsylvania, the total annual average aggregate five-year energy usage for Pennsylvania utility consumers is expected to increase overall to 7.85% per year. This is primarily driven by an increase in data center demand growth of approximately 18.56% for the five-year period of 2025-2030. Meanwhile, the peak load in Pennsylvania is expected to increase by at least 6,123 MW, or approximately 6.1 GW, by 2030 due to data center activity. This could amount to a 21% increase in statewide electricity peak demand compared to the average peak demand of 29,397 MW over the ten-year period of 2016-2025. An increase of 6,123 MW, or 6.1 GW, of peak load by 2030 is extraordinary, unprecedented, and nearly on par with doubling the entire service territory peak load of one of the biggest electric utilities in Pennsylvania. For the PJM region, PJM's 2026 Long Term Load Forecast (LTLF) confirmed that electricity demand from data center growth is still projected to grow up to approximately 30 GW between 2027 and 2031, during both summer peak and winter peak. *See* Teti Affidavit.

11. For context, 1 GW, which is the equivalent of 1,000 MW, is the size of a very large power plant, like a nuclear generation unit. *See* Felder Affidavit. This means Pennsylvania is anticipating peak load growth of around six very large power plants and the PJM region is expecting peak load growth of around 30 very large power plants.

12. Furthermore, in addition to their massive size in electricity demand, data centers want to interconnect to the electrical grid quickly, which is generally referred to as a need for "speed to power." The rapid pace at which data centers can come online and require electric service presents a distinct challenge for electric-system planning that is distinguishable from traditional large commercial and industrial loads. *See* Felder Affidavit.

13. For example, PJM has observed unprecedented data center-load growth in portions of its footprint and has explained that rapid load growth can require transmission system reinforcements before existing system capacity is exhausted. PJM observed that the extra-high-voltage reinforcements require time to build, creating a risk that local reliability issues can quickly become regional reliability issues. *See* Felder Affidavit.

14. Data centers' need for speed to power is unique because of (1) ongoing, rapid development of information and computational technologies that require capital be deployed as quickly as possible to keep up with competitive market pressures; and (2) the significant amount of capital that data center developers are able to deploy quickly in order to interconnect to the electrical grid, often outpacing the rate at which supporting utility wires and generation supply infrastructure can be constructed and placed into service. *See* Felder Affidavit.

15. PJM also has identified that the timing of data center additions as particularly significant where multiple data centers are proposed in the same geographic area. According to PJM, the pace of forecasted load growth can create timing challenges for completing needed grid

investments, whiles data centers' desired time to market creates a need for alternative approaches for connecting new data centers to the grid. *See* Felder Affidavit.

16. The Commission found that PPL Electric's projected increase in industrial usage and peak load is "almost entirely due to the onboarding of large data centers" and that PPL Electric's data center-driven demand and peak-load growth is by far the largest among Pennsylvania EDCs. Indeed, PPL Electric forecasts demonstrate average annual energy-use growth of 20.51% over the next five years, including a 51.05% annual increase in industrial usage, compared with virtually no growth in residential or commercial usage. *See* Teti Affidavit.

17. PPL Electric recently stated in a filing with the Commission that it expects a substantial increase in the data center forecast underlying its current planning assumptions, stating that the current pipeline of advanced-stage data centers in PPL Electric's service territory, representing projects that have signed agreements and will pay for project-related work even if the projects do not advance, totals approximately 31.8 GW by 2034.[2]

18. This 31.8-GW by 2034 figure is significantly greater than the large-load forecasts relied upon in PPL Electric's most recent 2025 base rate case and as the Commission saw the forecast when it issued its order approving the 2025 rate case settlement on June 4, 2026, resulting in Rate LP-6. In context, this 31.8 GW figure compares almost equally in size with PJM's 2026 LTLF figure of *region-wide* growth in demand of 30 GWs between 2027 and 2031.

19. On September 29, 2026, the PJM Load Analysis Subcommittee (LAS) met to review the annual large load adjustments submitted by EDCs to begin the process to create the 2027 LTLF. The PJM LAS prepares and reviews PJM reports and technical analyses and

[2] *See Petition of PPL Electric Utilities Corporation for Approval of Its Non-Bypassable Customer Protection Transmission Rider, Elimination of Its Transmission Service Charge, Changes to Its Generation Supply Charges, Changes to Its Retail Tariff, and Changes to Its Electric Generation Supplier Coordination Tariff*, Docket No. P-2026-3065185, Petition (filed Sept. 14, 2026).

coordinates information related to electric peak demand and energy forecasts, including large load). While the OCA's witness is still in the middle of reviewing these EDC preliminary submissions in more detail, discussions at this meeting supported the following findings. First, the EDC large-load forecasts remain large. For example, PPL Electric submitted a large load forecast adjustment for 12,764 MW by 2030.[3] In the prior annual submission, PPL Electric requested 13,343 MW by 2030.[4] Second, the large load forecast adjustments continued to change which reflects their inherent uncertainty, even after extensive review by PJM and the Commission. Third, the apparent inconsistencies in methodologies between EDCs in load forecast submissions to PJM justifies the need for discovery in this proceeding to understand exactly how PPL Electric determines their large load forecasts and adjustments over time. *See* Teti Affidavit.

IV. Known and Foreseeable Impacts of Data Center Demand on Electricity Systems—Ongoing and Prospective Harms

a. Service Reliability Impacts

20. PJM has identified the rapid growth of data centers in Pennsylvania and across the PJM region as a resource adequacy concern. In PJM's analysis, forecasted electricity demand is expected to continue to increase faster than new generation resources can be developed and brought online, creating challenges in maintaining an adequate supply of electricity. *See* Felder Affidavit.

21. PJM also has identified timing challenges with the pace of forecasted load growth and has noted that data centers' desired development timelines can create challenges in reliably connecting new large loads to the grid. Accordingly, the issue involves not only whether the transmission system can accommodate new data centers but also whether sufficient generation

[3] https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2026/20260929/20260929-item-5e---ppl.pdf
[4] Act 45 Annual Report, p. 31.

resources will be available when the additional demand comes online to reliably serve that demand. *See* Felder Affidavit.

22. Based on publicly available information, the PJM Base Residual Auctions (BRA) for the 2027/2028 and 2028/2029 delivery years cleared short, 6.5 GW and 6.8 GW, respectively, of PJM's reliability requirement, indicating that insufficient capacity resources were procured to meet projected system needs. In context, this 6.5 GW and 6.8 GW shortage compares almost equally (a bit greater) in size with the Commission's expectation of Pennsylvania's 6.1 GW growth in peak load by 2030. *See* Felder Affidavit.

23. The BRA is how PJM ensures that the PJM grid has sufficient electric generating capability (i.e., capacity) to meet the demands of end-use customers for a future delivery period. By clearing short of the reliability requirement, the 2027/2028 and 2028/2029 BRA results indicate that the auction was not able to secure the level of supply needed to maintain reliability in these two deliver years. PJM's own BRA reports attribute the shortfalls to data center demand grown as the number one reason, followed by supply development barriers. *See* Felder Affidavit.

24. The Commission has recognized that the growing impact of data centers in Pennsylvania and throughout PJM, together with constrained generation resources, presents significant resource-adequacy and reliability challenges that require coordinated action by policymakers, regulators, utilities, and generators to maintain reliable operation of the bulk electric system. The Commission has found the following:

> The impact of data centers and other large load customers in both Pennsylvania and PJM's broader footprint is significant. Among other factors, an insufficient level of construction of electric generation and continued retirement of base load electric generation is resulting in the need for stakeholders such as policy makers,

> regulators, utilities, and generation owners, to work together to ensure the continued reliable operation of the BES.[5]

See Felder Affidavit.

25. A September 14, 2026, independent report commissioned by the Commission makes this point in stark terms:

> Pennsylvania's electricity system is experiencing a tightening of supply and demand. State and regional load is growing, largely due to data center development, and supply is constrained as aging generators retire and new resource deployment is hindered. These two simultaneous trends cause high electricity prices, and also expose other challenges: recent assessments from grid operator PJM and the North American Electric Reliability Corporation (NERC), the national body charged with regulating electric system reliability, have both identified PJM's system as stressed, with looming reliability concerns.

The report continues (emphasis added):

> The team modeled three scenarios and found the following: in both the Reference scenario and the High Load And Low Supply scenario, we find that from 2027 through 2030, the PJM planning criterion for resource adequacy (loss of load expectation or "LOLE" of 0.1) is not met in PJM. Meanwhile, in the No New Data Centers scenario, LOLE is below this 0.1 threshold (see Table 1).
>
> In the Reference scenario, which relies on PJM's 2026 Load Forecast, modeled 2030 LOLE is 0.59 or nearly six times worse than the PJM planning criterion. This result is mainly due to large-load additions stemming from data center additions, which are projected to surge in 2030. In 2030, the High Load and Low Supply scenario, a worst-case future of higher-than- expected load additions and constrained resource deployment, has an LOLE of 13.20. This LOLE value is over 100 times worse than PJM's planning criterion and indicates an expectation of more than 13 days with loss of load events per year. As in the Reference scenario, these reliability issues are largely due to surging data center additions. In the High Load forecast, data centers are projected to contribute over 200 TWh of additional new load between 2029 and 2030 PJM-wide. (For reference, the entire state of Pennsylvania's 2025 electricity demand was about 150 TWh). In this High Load and Low Supply scenario, in-state generators are unable to meet between 2 and 19 percent of PJM-wide electricity between 2031 and 2040. [6]

[5] PAPUC, Electric Power Outlook for Pennsylvania 2025-2030, August 2026, p. 6, https://www.puc.pa.gov/filing-resources/reports/electric-power-outlook-report/.

[6] Synapse Energy Economics, Inc., "Assessing Electricity Resource Adequacy in Pennsylvania and PJM, September 14, 2026, p. ii, https://www.puc.pa.gov/media/4044/2026_assessing_electricity_resource_adequacy_in_pa_and_pjm.pdf.

The key takeaway from the September 14, 2026 independent report is that Pennsylvania and the broader PJM region face a significant and worsening mismatch between growing electricity demand and constrained supply, with data center development identified as a principal driver of the projected load growth. The report's modeling indicates that PJM fails to meet its resource-adequacy criterion from 2027 through 2030 under both the Reference and High Load/Low Supply scenarios. Under the Reference scenario, projected 2030 loss-of-load expectation is 0.59—nearly six times PJM's planning criterion—and rises to 13.20 under the High Load/Low Supply scenario. The report therefore underscores that continued data center growth, absent commensurate new supply and other system investments, could materially increase electricity prices and place substantial additional pressure on the reliability of the regional electric system. *See* Felder Affidavit.

26. NERC has recognized that the rapid integration of emerging data centers or large computational loads can create reliability impacts extending to the bulk power system, which in turn can impact the distribution system. NERC explains that the addition of large computational loads may increase a transmission owner's need to shed load (i.e., curtail customers' usage) during periods of grid strain, including under-frequency load-shedding (UFLS), and could ultimately require the transmission utility to coordinate with the distribution utility to disconnect all residential customers interconnected through EDCs while still failing to satisfy its load shedding requirements. NERC further cautions that the rapid addition of large computational loads creates a risk that "the local distribution system may not contain enough load to cover the UFLS requirements," potentially requiring transmission-level load to be included in UFLS programs. *See* Felder Affidavit.

27. If data centers are added to PPL Electric's utility system without sufficient new supply to serve them or without meaningful ways to curtail their electricity consumption during times of supply shortages, then the reliability of utility service distributed by PPL Electric to all customers will be degraded.[7] *See* Felder Affidavit; *see also* Hoyt Affidavit. This service reliability degradation could result in mandatory load shedding or forced customer outages of existing ratepayers, such as residential customers. As more data center load is added to the PPL Electric system and PJM that is not sufficiently supplied or curtailable, the risk, frequency, magnitude, and duration of potential mandatory load-shedding events increase. *See* Felder Affidavit; *see also* Hoyt Affidavit.

28. PPL Electric is already in the process of interconnecting and serving new data center customers. *See* Ogur Affidavit. However, based on publicly available information and PPL Electric's Retail Tariff, PPL Electric is not ensuring that existing customers are safeguarded from outage risks presented by new data center additions. *See* Hoyt Affidavit. PPL Electric's failure to ensure adequate safeguards are in place against the backdrop of already constrained resource adequacy and increasingly frequent emergency events means the outage risk to PPL Electric's existing customers is both imminent and potentially severe. *Id*.

29. The harms alleged above are ongoing and prospective, necessitating immediate corrective and preventive measures.

[7] See NERC, Large Loads Task Force White Paper, Characteristics and Risks of Emerging Large Loads, July 2025, p. 16, https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf. Large loads also have important implications for operational reliability. Operational reliability is the ability of the electric power grid to withstand the sudden outages of large power plants or transmission facilities by maintaining grid stability without resulting in load curtailments. See NERC, NERC Issues Level 3 Alert, Reliability Guideline Focused on Large Load Challenges, May 4, 2026, https://www.nerc.com/newsroom/nerc-issues-level-3-alert-reliability-guideline-focused-on-large-load-challenges.

b. Cost Causation, Affordability, and Low-Income Customer Impacts

30. In addition to negatively impacting reliability of utility service, the rapid connection of massive amounts of data center loads to PPL Electric's system will cause significant costs to be incurred to interconnect and meet this extraordinary demand for electricity. Specifically, data centers materially influence distribution, transmission and generation planning outcomes by requiring large amounts of new generation and transmission facilities to serve them. *See* Felder Affidavit; *see generally* Ogur Affidavit.

31. The scale of transmission investment driven by customer service needs and increasingly by data center demand is substantial and growing. For example, in 2025, approximately $5.8 billion worth of solutions to supplemental projects, or local transmission projects, were evaluated by PJM in 2025, of which $3.4 billion was driven by customer service. In 2024, approximately $4.5 billion of supplemental projects presented to PJM were driven by customer service. Some subsets of the customer service driven projects identified in 2024 and 2025 are being driven by new data center demand within Pennsylvania. The EDCs of Pennsylvania, and PPL Electric in particular, are propelling a sizeable portion of the reported local transmission buildout. The OCA has been able to confirm that, in 2026, which has not ended yet, so far there are approximately $1.3 billion in supplemental projects driven by data centers in Pennsylvania, which will be constructed in upcoming years if all necessary regulatory approvals are received. *See* Teti Affidavit.

32. The local transmission investment driven by customer service needs, or data center interconnections, are actively being allocated by PPL Electric to other customers. For example, in publicly available documents before the Pennsylvania Public Utility Commission, PPL Electric indicates its plans to construct network upgrades as a Supplemental Project that are necessary to

interconnect and serve a hyperscale data center campus. The first portion of the Supplemental Project involves network upgrades that are estimated to cost a total of $59.9 million, and PPL Electric plans to assign $21.5 million (36%) to the data center and $38.4 million (64%) to remaining utility ratepayers.[8] The second portion of the Supplemental Project involves network upgrades that are estimated to cost a total of $118.5 million, and PPL Electric plans to assign $0 (0%) to the data center and $118.5 million (100%) to existing ratepayers.[9] Of the total $178.4 million in estimated costs that PPL Electric estimates that it will incur to serve the hyperscale data center, PPL Electric plans to recover only $21.5 million (12%) of the total costs from the data center, which is the cost causer and primary beneficiary of the network upgrades, and the remaining $156.9 million (88%) from existing ratepayers, which neither cause nor commensurately benefit from the network upgrades.

33. PJM wholesale markets consist of products for energy, capacity, and selected ancillary services. Pricing for these products is based on the marginal cost of providing one more unit of the product under given supply and demand conditions, subject to any bid, offer, or price caps. Because these prices are based on marginal costs, not average costs, higher demand raises prices as more resources are needed to produce each additional unit and these additional resources are more expensive due to a myriad of development barriers. Data centers increase the demand for energy and capacity and therefore raise prices and wholesale costs, which flow to retail rates and consumers' electricity bills. *See* Felder Affidavit; *see also* Ogur Affidavit.

34. The PJM Independent Market Monitor (IMM), Monitoring Analytics, LLC, has repeatedly been on record tabulating the increased capacity costs due to data centers. In August

[8] See Letter of Notification of PPL Electric Utilities Corporation (filed Dec. 19, 2025), available here: https://www.puc.pa.gov/pcdocs/1907838.pdf.

[9] See Application of PPL Electric Utilities Corporation (filed Apr. 6, 2026), available here: https://www.puc.pa.gov/pcdocs/1921888.pdf.

2026, the IMM reported that the cumulative cost increases due to future data center demand starting with the 2025/2026 Base Residual Auction (BRA) is over $29 billion and will continue to grow. The IMM has also documented increases in wholesale prices for energy, capacity, and ancillary services in the last 12 months, which are presented in Table 1.

Table 1: Rapid Rise in Energy, Capacity, and Ancillary Services Prices from 2025 (Jan-Jun) to 2026 (Jan-Jun)

Category	2025 (Jan-Jun) $/MWh	2026 (Jan-Jun) $/MWh	Percent Change
Energy	$49.21	$72.68	47.7%
Capacity	$6.39	$19.61	207.1%
Transmission	$18.82	$19.88	5.6%
Ancillary Services	$1.06	$1.63	53.7%

See Felder Affidavit; *see also* Ogur Affidavit.

35. Additional wholesale market costs – stemming from PJM's Reliability Backstop Procurement (RBP) and Interim Resource Adequacy Service (IRAS) proposals currently pending before the Federal Energy Regulatory Commission (FERC) – may result from the addition of data centers to the PJM region, affecting costs that all consumers may pay in their retail bills. *See* Felder Affidavit; *see also* Ogur Affidavit.

36. As recognized by the Commission, electric utility customers in Pennsylvania are currently facing growing affordability concerns caused in part by growing rates for electricity. This is also true for customers served by PPL Electric, which has significant bill affordability problems facing its low-income customers. These concerns will only grow to the extent that new data center development results in additional costs related to network interconnection within PPL Electric's service territory that are passed along to PPL Electric customers, including but not limited to low-income residential customers. *See* Deupree Affidavit.

37. If data centers are added to PPL Electric's utility system without sufficient tariff protections in terms of just and reasonable and/or not unduly preferential rates, residential customers, including low-income customers, will see undue bill increases, and low-income customers, in particular, will face acute energy affordability challenges, as they pay for costs that they did not cause but rather are caused by data centers. *See* Deupree Affidavit; *see also* Ogur Affidavit.

38. The harms alleged above are ongoing and prospective, necessitating immediate corrective and preventive measures.

c. Stranded Costs and Cost Shifting Impacts

39. In addition to causing higher costs, planning for the rapid interconnection of immense amounts of potentially speculative data center loads presents a risk of stranded costs that utilities may seek to recover from other customers. Risks of stranded cost and cost-shifting refer to the possibility that stranded costs or cost-shifting may occur in the future. Stranded costs refer to a utility's return of and on asset investments built to serve a particular customer or group of customers that are no longer taking service commensurate with the assets constructed to serve them (i.e., stranded assets), meaning that the utility cannot appropriately earn its return of and on those assets from that customer or group of customers. Generation, transmission, and/or distribution facilities can become stranded assets. For assets built to serve large computational loads, ratepayers may end up paying for stranded costs because large computational loads did not interconnect at the time and amount that were forecasted or halted service prematurely or failed to materialize as expected. When this occurs, EDCs do not receive the expected payment from data centers and then attempt to recover their costs from existing ratepayers. *See* Felder Affidavit.

40. The harm alleged above is ongoing and prospective, necessitating immediate corrective and preventive measures.

V. The Public Policy Consensus Regarding the Corrective and Preventatives Measures Needed to Address Data Center Impacts on Electricity Systems

41. Given data centers' transformative impact on the bulk electric system and local distribution systems, a widespread consensus among the federal government, state governments, and data center industry has emerged. That consensus says that existing residential, commercial, and industrial consumers, i.e., non-data center customers, should not experience reliability problems or pay costs caused by data centers (the Public Policy Consensus). Per the Public Policy Consensus, the Commonwealth of Pennsylvania, the Commission, the federal government, the data center industry, PJM, and FERC all acknowledge the need for and the importance of tariffs and binding requirements, especially at the state levels, to protect existing retail ratepayers from the potential adverse reliability and cost consequences of rapidly interconnecting massive amounts of data center-large loads to power systems. *See* Felder Affidavit.

a. The "Ratepayer Protection Pledge" of the White House, Data Centers, and Public Utilities, including PPL Electric

42. On March 5, 2026, the White House issued the Ratepayer Protection Pledge, which many large owners and users of data centers (some of the most well financed companies in the world), such as Amazon, Google, Meta, Microsoft, OpenAI, Oracle, and xAI, have signed.[10] These prominent owners of data centers have pledged to pay for the costs that they cause within the states and regional markets where they plan to locate their new facilities.[11]

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[10] *See* The White House, Ratepayer Protection Pledge, March 4, 2026, available at https://www.whitehouse.gov/articles/2026/03/ratepayer-protection-pledge/; *see also* The White House, Fact Sheet: President Donald J. Trump Advances Energy Affordability with the Ratepayer Protection Pledge, March 4, 2026, https://www.whitehouse.gov/fact-sheets/2026/03/fact-sheet-president-donald-j-trump-advances-energy-affordability-with-the-ratepayer-protection-pledge/.

[11] Id.

43. On July 23, 2026, the Ratepayer Protection Pledge was updated to bring more than 200 additional utilities, data center developers, cooperatives, and states into this growing national commitment to protect consumers from the reliability and costs impacts from data centers.[12] The utility signatories include Exelon Corp., FirstEnergy Corp., and PPL Corp., the parent companies of PECO Energy Co., FirstEnergy Pennsylvania Electric Co., and PPL Electric Utilities Corp..[13]

44. The Ratepayer Protection Pledge calls on large data center and AI companies to ensure that the costs associated with their growing electricity demand are not shifted to existing residential and business ratepayers. In particular, the Pledge provides that participating companies will build, bring, or buy the new generation needed to serve their data centers; pay for all new power-delivery and network infrastructure required to serve their load; enter into separate rate arrangements and pay for committed power and infrastructure even when the power is not used; invest in local jobs and workforce development; and contribute to grid and community resilience, including by making backup generation available during periods of system scarcity. The Pledge thus expressly contemplates that data center customers, rather than other utility customers, should bear the full incremental costs associated with their electricity demand and related infrastructure needs. *See* Felder Affidavit.

45. The Ratepayer Protection Pledge provides as follows:

> America's continued economic and technological leadership depends on reliable, large-scale data center infrastructure built here at home. Data center infrastructure is the foundation of the internet, cloud computing, and artificial intelligence (AI), and supports our economic and national security. As that infrastructure grows and the related electricity demand increases, the American people should not be footing the bill for the benefit of private

[12] See The White House, President Trump's Ratepayer Protection Pledge Secures American AI Dominance, Protects Consumers, July 23, 2026, available at https://www.whitehouse.gov/releases/2026/07/president-trumps-ratepayer-protection-pledge-secures-american-ai-dominance-protects-consumers/.

[13] See The White House, Ratepayer Protection Pledge, Signatories, (last accessed Sep. 8, 2026) available at: https://www.whitehouse.gov/ratepayer-protection-pledge/#signatories.

companies. Instead, the data center boom should be leveraged to address affordability and benefit all American households and businesses.

President Trump is calling on the leading United States hyperscalers and AI companies to build, bring, or buy all of the energy needed for building and operating data centers, paying the full cost of their energy and infrastructure, no matter what.

As part of the Ratepayer Protection Pledge, companies agree to protect American consumers from price hikes due to data center energy and infrastructure requirements, and lower electricity costs for consumers in the long term, including by:

1. Building, Bringing, or Buying New Power Supply

- **WHAT**: Companies will build, bring, or buy the new generation resources and electricity needed to satisfy their new energy demands, paying the full cost of those resources whether by building, or buying from, new or otherwise additive power plants. Where possible, these companies will also add more capacity that serves the broader public by increasing supply.
- **WHY**: This advances self-sufficiency and protects Americans from higher prices.

2. Paying for New Power Delivery Infrastructure Upgrades

- **WHAT**: Companies will pay for all new power delivery infrastructure upgrades required to service their data centers, including adequate network upgrade costs to ensure that these expenses are not passed on to the ordinary household.
- **WHY**: This way, data centers can benefit all ratepayers and the grid.

3. Paying Whether They Use the Power or Not

- **WHAT:** Companies will voluntarily negotiate new, separate rate structures with their utilities and relevant State governments wherever they build data centers. Importantly, they will pay these rates for the power and related infrastructure that are brought online to service their data centers, whether they use the electricity or not.
- **WHY**: This will protect the American people from increased utility bills as a result of the development of these data centers.

4. Investing in Local Job Creation and Workforce Development

- **WHAT**: Companies will invest in the local communities in which they build data centers. This includes hiring from within the local community and establishing programs to develop relevant skills.
- **WHY:** This allows all American workers to benefit from the oncoming technological boom at every step from construction to operation.

5. Contributing to Electric and Community Resilience

- **WHAT**: Companies will coordinate with grid operators to contribute to a more reliable grid and, whenever possible, make available their backup generation resources at times of scarcity to prevent blackouts and power shortages in their communities.
- **WHY**: Consumers will benefit from enhanced grid resilience from data center power resources in times of emergency.[14]

b. The Commission's Large Load Model Tariff Policy

46. On May 13, 2026, the Commission issued its final order establishing a voluntary large load Model Tariff policy framework (Model Tariff Policy). The Commission left it up to the EDCs' individual discretion to file with the Commission tariffs that conform with the Model Tariff Policy; therefore, the protections included in the Model Tariff Policy are not implemented unless and until the EDC and the Commission take appropriate action.

47. To address the risks of cost shifting and stranded costs, the Model Tariff Policy represents an important first step toward ensuring that the costs and risks associated with rapidly growing large loads, particularly data centers and other computational loads, are not shifted unfairly to existing customers.[15] The Commission has now established a general, broad, statewide policy framework for large-load customers at or above 50 MW individually or 100 MW in the aggregate, including but not limited to providing guidance for minimum contract terms, an 80-

[14] https://www.whitehouse.gov/releases/2026/03/ratepayer-protection-pledge/
[15] Pa. PUC, *Interconnection and Tariffs for Large Load Customers*, Docket No. M-2025-3054271, Final Order at 4–5, 121–128 (Apr. 30, 2026; entered May 12, 2026).

percent minimum billing-demand requirement, collateral requirements, customer-funded interconnection and planning studies, six-month deadlines for interconnection studies, and cost allocation principles designed to make large loads responsible for the distribution and transmission investments necessary to serve them.[16] The Model Tariff Policy also establishes protections against premature load departure through long-term contracts and an exit-fee framework, while allowing limited flexibility for customers to reduce contracted capacity.[17] However, with respect to the risks of cost shifting and stranded costs, the Model Tariff Policy leaves a number of consequential policy questions for future, EDC-specific tariff proceedings and further Commission consideration. In particular, the framework does not comprehensively resolve how existing large-load customers and existing contractual arrangements should be grandfathered or transitioned into updated tariff language; or how the exit-fee provisions should be applied to particular investments, revenues, and remaining contractual obligations in individual cases. *See* Hoyt Affidavit.

48. The Model Tariff Policy leaves it to each EDC, to determine how to revive and implement an interruptible service class for large load customers through individual tariff proceedings.[18] Rather than establishing a uniform statewide interruptible-service structure, the Commission ordered that interruptible service programs be based on each EDC's existing interruptible tariff provisions.[19] This approach gives each EDC flexibility to develop a program suited to its system and customer base, but it also means that an important element of the large-load framework remains to be worked out on a utility-by-utility basis. Yet, this portion of the Model Tariff Policy overlooks that current EDC tariffs do not offer comprehensive interruptible rate schedules. *See* Hoyt Affidavit.

[16] *Id*.
[17] *Id.* at 124–125.
[18] *Id*. at 92.
[19] *Id*.

49. Importantly, the Model Tariff Policy recommends cost responsibility protections that reinforce "cost causation principles to help ensure that large load customers are responsible for infrastructure and interconnection costs associated with serving their projects, reducing the risk of shifting those costs onto existing residential and small business customers" and contract terms and exit provisions that provide "guidance related to load ramping schedules, minimum contract terms, and customer exit provisions to support long-term cost recovery and system stability." However, the Model Tariff Policy leaves the critical question of how upgrade costs will ultimately be allocated to EDC-specific tariff proceedings.[20] In particular, the Model Tariff Policy does not fully answer whether a large-load customer will be required to bear 100% of the cost of necessary system upgrades or instead be responsible only for a defined portion of the costs attributable to the customer's load.[21] Equally important is the methodology the specific EDCs will use to identify and quantify that "customer-caused" amount in individual tariff proceedings.[22] Accordingly, individualized EDC-tariff proceedings are the appropriate venue to determine how, within each service territory and under each EDC's tariff, the costs caused by computational large-load customers should be identified, allocated, and recovered, ensuring that those customers bear their fair share without shifting costs to the EDC's broader customer base.

50. The Model Tariff Policy recognized the impact that the addition of data centers will have on universal service programs and agreed with commenters that the addition of data centers has an impact on the rates all customers pay for electricity, especially in relation to capacity and transmission rates. The Commission recognized that large-load growth raises broader affordability and universal-service concerns. As such, the Commission recommended a requirement that large

[20] Pa. PUC, *Interconnection and Tariffs for Large Load Customers*, Docket No. M-2025-3054271, Final Order at 41-42 (Apr. 30, 2026; entered May 12, 2026).
[21] *Id*.
[22] *Id*.

load customer contribute to the utility's universal service programs annually, with the minimum amount to be contributed based on a flat fee of the large load customer's peak demand rather than a volumetric charge.[23] At the same time, however, the Model Tariff Policy appropriately leaves for EDC-specific proceedings whether and how large loads should contribute more broadly to share in the costs of universal-service programs.[24]

c. Governor Josh Shapiro's Executive Order 2026-05

51. Notably, and most recently, on August 18, 2026, Pennsylvania Governor Josh Shapiro signed Executive Order 2026-05,[25] laying out strict standards to protect Pennsylvania utility consumers from the reliability and affordability impacts of adding data centers to electricity systems (Executive Order).

52. Regarding reliability impacts on the electricity system caused by data centers, the Executive Order directs the Governor's Special Counsel for Energy Affordability to work with the Commission to develop rules and procedures addressing the reliability impacts of data centers. Specifically, it calls for electric utilities to revise their resource adequacy and emergency load-control procedures so that data centers are curtailed before other customers during pre-emergency and emergency events, unless the data center has secured sufficient incremental capacity to serve its full demand. The Executive Order also directs that data centers not be classified as critical loads exempt from curtailment, thereby prioritizing system reliability and protection of other customers during periods of constrained supply. *See* Felder Affidavit. In this regard, the Governor's Executive Order provides as follows:

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[23] *Id.*
[24] *Id*. at 17, 29, 83, 106, and 114-116.
[25] *See* Executive Order, Commonwealth of Pennsylvania, Governor's Office, Executive Order 2026-05 – Protecting Pennsylvania Consumers from Data Center Impacts, Issued August 18, 2026, By Direction of Josh Shaprio, Governor, available at https://www.pa.gov/content/dam/copapwp-pagov/en/governor/documents/eo2026_05_protecting%20pennsylvania%20consumers%20from%20data%20center%20impacts_final_executed.pdf (last visited August 22, 2026).

> a. To limit reliability impacts on the electric system caused by data centers, the Governor's Special Counsel for Energy Affordability ("Special Counsel") shall engage with the Pennsylvania Public Utility Commission ("Commission"), and shall advocate for the rapid development of rules, procedures, and orders that would:
>
> (1) Ensure each electric utility that has received a request to interconnect a data center in its territory files with the Commission revisions to both its pre-emergency interim resource adequacy service (IRAS) and emergency load control procedures so that utilities curtail data centers prior to any other customer during pre-emergency IRAS or emergency events, unless the data center customer has secured incremental electric capacity for the entirety of its demand; and
>
> (2) Ensure that utilities do not classify a data center as critical load exempt from curtailment during pre-emergency or emergency events.[26]

53. Regarding cost impacts on other consumers caused by data centers, the Executive Order also directs the Special Counsel to work with the Commission to develop tariffs that prevent data center-related costs from being shifted to other customers. Specifically, it calls for data centers to bear their allocated PJM reliability backstop auction costs, non-data center customers to be protected from those costs if a data center cannot pay them, and data centers to pay all Commission-jurisdictional interconnection costs incurred by utilities as a result of their development. *See* Felder Affidavit. In this regard, the Executive Order provides as follows:

> b. To limit electric system costs caused by data centers from being imposed on other customers, the Special Counsel shall engage with the Commission, and shall advocate for the rapid development of rules, procedures, and orders that would allow for the timely approval of utility tariffs that accomplish the following:
>
> (1) Charge the appropriate data center customers for any PJM reliability backstop auction costs in accordance with the procedures ultimately approved by the Federal Energy Regulatory Commission in docket ER26-3380-000; and
>
> (2) Prevent an electric utility from charging non-data center customers for backstop auction costs, including in the event that a data center becomes insolvent or is otherwise not able to pay the auction costs assigned to it; and

[26] Executive Order 2026-05, p. 6.

(3) Ensure that data center customers pay all Commission-jurisdictional interconnection costs that the utility incurs due to the development of data centers.[27]

54. Regarding the advancement of PJM's reliability backstop auction, IRAS, and related items, the Executive Order also directs the Special Counsel to work with the Commission to advance PJM's reliability backstop auction and related resource-adequacy measures. Specifically, it calls for rules and procedures requiring utilities to submit appropriate megawatt adjustments for reliability backstop auction targets, register large loads with PJM—including applicable locational requirements for incremental capacity—and implement credits associated with PJM's pre-emergency IRAS program, consistent with the applicable FERC proceedings. *See* Felder Affidavit. In this regard, the Executive Order provides as follows:

> In advance of PJM's reliability backstop auction and related actions, the Special Counsel shall engage with the Commission, and shall advocate for the rapid development of rules, procedures, and orders:
>
> (1) For electric utilities to submit megawatt adjustments for any reliability backstop auction target in accordance with the procedures ultimately approved by the Federal Energy Regulatory Commission in docket ER26-3380-000; and
>
> (2) For electric utilities to register large loads in PJM's large load registry, including any locational requirements for incremental electric capacity; and
>
> (3) For implementation of credits pertaining to PJM's pre-emergency IRAS program following the Federal Energy Regulatory Commission's ultimate disposition of relevant rules and procedures in docket ER26-3515-000.[28]

d. North American Electric Reliability Council's (NERC's) Large Loads Action Plan and Project 2026-02 Computational Loads

55. NERC has identified large, rapidly developing loads—particularly data centers—as a significant and growing threat to electric system reliability. NERC reports that electricity demand is increasing substantially, while actual peak demand in some areas has already approached or exceeded forecasts, and emphasizes that computational loads present unique

[27] Id.
[28] *Id*, pp. 6-7.

reliability concerns because of their scale, rapid development, and operational characteristics. NERC's CEO has described this as a "five alarm fire." *See* Felder Affidavit.

56. In the NERC Reliability*First*-PJM region, NERC identifies this region as "High Risk," its most severe designation, reflecting projected energy shortfalls that exceed established resource-adequacy criteria. For PJM specifically, NERC finds that planned generation additions are not keeping pace with rapidly increasing demand and expected generator retirements, with the region's projected resource margin falling below the Reference Margin Level beginning in 2029. The assessment further notes that recently approved generation projects intended to accelerate new resource development were not sufficiently advanced to be included in NERC's analysis, underscoring the region's growing resource-adequacy and reliability challenges. *See* Felder Affidavit.

57. NERC has initiated an action plan to understand and address the reliability risks of the emerging computational loads.[29] NERC also has initiated Project 2026-02, Computational Loads, to develop reliability standards addressing emerging risks from rapidly growing large loads, including data centers, AI computing facilities, and cryptocurrency operations. NERC's initiative recognizes that these loads are connecting to the Bulk-Power System at unprecedented speed and scale, fundamentally changing demand patterns and creating new reliability challenges for both system operations and long-term planning. *See* Felder Affidavit.

e. Regional Transmission Organization and Federal Energy Regulatory Commission

58. On January 16, 2026, the White House National Energy Dominance Council and the thirteen governors of the states within the PJM footprint signed a Statement of Principles

[29] https://www.nerc.com/initiatives/large-loads-action-plan

Regarding PJM. The Statement of Principles identified concerns regarding the adequacy of electric generation resources to serve growing demand, including demand from large data centers. It called for PJM and the affected states to take measures to address those concerns, including allocating to certain new data center loads the costs of new capacity procured through a proposed Reliability Backstop Auction. *See* Felder Affidavit.

59. On June 18, 2026, the FERC issued show-cause orders to PJM and the other regional transmission organizations under its jurisdiction, directing them to demonstrate how they are interconnecting large load customers, including data centers and manufacturing facilities, in a manner that maintains reliable and affordable electric service as demand for electricity increases from data centers. *See* Felder Affidavit.

60. Additionally, the PJM Board of Managers (PJM Board) has identified concerns regarding both grid reliability and the allocation of costs associated with serving large-load customers. The Board reported that the 2027/2028 Base Residual Auction cleared 5.6% below PJM's target reserve margin—the first time the auction had cleared below the applicable reliability requirement—and stated that the result warranted corrective action. *See* Felder Affidavit.

61. Further, on June 24, 2026, PJM adopted a new capacity advisory emergency procedure in response to projected or actual capacity deficits occurring outside periods of extreme temperatures. PJM stated that it expected such instances to increase as electricity demand grows faster than new generation resources are added and as the share of intermittent generation resources on the grid increases. *See* Felder Affidavit.

62. The PJM Board has also identified concerns regarding the affordability of wholesale electricity costs for consumers within the PJM footprint. The Board stated that PJM should design its markets to provide transparent price signals that encourage desired market

behavior while avoiding undue costs to consumers. The PJM Board has also stated that action by the states is also necessary to address these issues. *See* Felder Affidavit.

63. PJM recently completed its Critical Issues Fast Path (CIFP) stakeholder process that addresses two key aspects of connecting large loads to the PJM system: procuring additional suppliers and curtailing selected large loads when available resources are insufficient. As a result of the CIFP stakeholder processes, PJM made two important filings before FERC. First, on July 31, 2026, PJM filed pursuant to Federal Power Act (FPA) Section 205 revisions to the PJM Open Access Transmission Tariff (OATT) and the Reliability Assurance Agreement Among Load Serving Entities (RAA) to establish the Reliability Backstop Procurement (RBP)[30]—a one-time procurement of new capacity to address resource adequacy challenges in the PJM Region arising from insufficient commitments of capacity in the 2027/2028 and 2028/2029 Reliability Pricing Model (RPM) Auctions, primarily driven by the unprecedented addition of large loads, most notably data centers. *See* Felder Affidavit.

64. Second, on August 13, 3036, PJM filed pursuant to FPA Section 205 revisions to the OATT and RAA to establish Interim Resource Adequacy Service (IRAS)—a service to be implemented by PJM solely during periods when there are insufficient resources to reliably meet demand in real time operations-when triggered by system conditions to prioritize load reduction in zones where new data centers have not brought their own new capacity or had their capacity needs covered through the RBP.[31] *See* Felder Affidavit.

[30] Reliability Backstop Procurement to Address Resource Adequacy and Large Loads, PJM Interconnection, L.L.C., Docket No. ER26-3380 (July 31, 2026) (PJM RBP Filing), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260731-5214.

[31] Proposal to Establish Interim Resource Adequacy Service and a Large Load Registry to Address System Reliability, Docket No. ER26-3515 (August 13, 2026) (PJM IRAS Filing), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260813-5118

65. These actions are relevant to retail customers because PJM's proposed mechanisms address both the availability and allocation of electric-system resources needed to serve rapidly increasing large loads. The RBP would procure additional capacity to address identified resource adequacy shortfalls, while the IRAS would permit PJM to send curtailment signals to EDCs that in turn will reduce certain large loads when available resources are insufficient to meet demand. These actions have the potential to avoid escalation of emergency procedures and reduce the price increases that occur as the demand-supply balance tightens. The need for these measures, and the manner in which their costs and associated risks are allocated, can affect the wholesale costs and reliability of electric service ultimately received and paid for by retail customers. Thus, PJM's actions reflect a direct connection between the growth of large load customers and the costs and reliability obligations borne by the broader customer base. *See* Felder Affidavit.

66. On September 29, 2026, FERC approved portions of PJM's RBP filing, with a multiple-month delay in implementation, including authorizing PJM to conduct the RBP auction and proceed to procure new capacity resources. However, FERC did not approve three portions of the RBP filing: cost allocation, Transmission Owner exit rules, and LSE collateral requirements.[32]

67. When establishing the need for further paper hearing procedures on the issue of cost allocation, the FERC stated the following:

> We recognize that the rapid emergence of large loads presents a shared regulatory challenge that implicates both federal and state authority. Under the FPA, the Commission oversees rates and practices affecting wholesale service, including PJM's procurement of capacity through the RBP. However, states determine how Commission-approved rates are collected among the relevant retail consumers along with the rates for state-jurisdictional matters. Specifically, states have authority over how the wholesale costs of providing electricity, including transmission of such electricity to the retail customers, are recovered through retail rates. We are encouraged by the NEDC/PJM Governors' Principles, in which the governors of all 13 PJM states agreed to use all available authorities to ensure that their state public utility commissions design rate class structures to ensure that their

[32] *PJM Interconnection, L.L.C.*, 196 FERC P61,245 (2026).

> states' LSEs allocate their share of the cost to procure new capacity through the [RBP] to new data center loads that have not otherwise procured capacity or agreed to be curtailable. We are also encouraged by the execution of the President's Ratepayer Protection Pledge, through which data center developers have committed to shield retail ratepayers from increased electricity prices. *Our partners in the states are more than capable of ensuring that these promises reach fruition. While we appreciate and take seriously the issues that PJM's RBP proposal is designed to address, as well as the concerns surrounding the unprecedented influx of large loads more broadly, having only such powers as are given to us by Congress, we will not pretend that all of these issues can be solved exclusively by market design in the federal sphere. The PJM states have their own role to play.*[33]

68. In his concurring Statement accompanying FERC's Order, Commissioner Rosner stated:

> Many of the issues driving this filing extend beyond PJM's jurisdiction to solve alone. States and retail authorities must play an active role – particularly in establishing large-load retail tariffs, enforcing collateral requirements, and establishing clear rules for which customers should be curtailed first when circumstances require it (Hint: homes, hospitals, and schools should never be curtailed before data centers). As the order acknowledges,[1] these are decisions that sit squarely with states and their regulators, and meaningful progress requires their continued leadership.[34]

69. In sum, the FERC stated that now is the time, and – for Pennsylvania EDCs – the Commission is the place, to take all actions necessary to ensure that consumers are protected during this period of price and reliability instability. The Commission is empowered and entrusted to enact safeguards for retail electric customers associated with changes in law at the federal level.

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[33] *Id.* at ¶ 161 (omitting quotations) (*citing PJM Interconnection, L.L.C.*, 195 FERC ¶ 61,211, at P 69 (2026); Transmittal at 106; U.S. Department of Energy, *Statement of Principles Regarding PJM* 2 (Jan. 2026), https://www.energy.gov/documents/statement-principles-regarding-pjm; The White House, *President Trump's Ratepayer Protection Pledge Secures American AI Dominance, Protects Consumers* (July 2026), https://www.whitehouse.gov/releases/2026/07/president-trumps-ratepayer-protection-pledge-secures-american-ai-dominance-protects-consumers/) (emphasis added).

[34] *PJM Interconnection, L.L.C.*, 196 FERC P61,245, ¶ 3 (2026) (Rosner, Commissioner, concurring) (*citing PJM Interconnection, L.L.C.*, 196 FERC P61,245, ¶ 161 (2026)).

f. Commission's Most Recent Actions at M-2026-3064961 Addressing Cost Allocation and Reliability Impacts of Data Centers

70. On September 10, 2026, the Commission voted 5-0 in favor of Vice Chair Barrow's Motion at M-2026-3064961,[35] addressing cost allocation and reliability.

71. On cost allocation impacts, the September 10, 2026 Motion directed the Commission to hold a technical conference this fall to examine cost responsibility associated with large computational loads, including data centers. Vice Chair Barrow stated:

> Time is of the essence as costs for energy, capacity, distribution, and transmission are already increasing for ordinary retail customers, largely driven by new large computational load customers. Ensuring that new costs are allocated to the customers driving the increases is central to the Commission's mission to protect the public interest.[36]

72. On reliability impacts, the September 10, 2026 Motion directed Commission staff to develop proposed updates to utility emergency electric load control regulations, including greater clarity regarding the order, criteria, and circumstances under which customers may be curtailed during pre-emergency and emergency conditions.

73. On reliability impacts, the Commission voted 4-0 to approve the Tentative Order entered at M-2026-3064961. The October 1, 2026 Tentative Order, commendably, advanced proposed safeguards, aimed at protecting utility consumers and preserving electric reliability during periods when electricity supplies may be strained due to data center additions to the grid. In the Tentative Order, the Commission sought public comments on the proposed changes to the Commission's regulations. In the October 1, 2026 Tentative Order, the Commission, for the first time, proposed an appropriate definition of data center—or, Computational Load Entity (CLE)—

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[35] *Motion Directing Staff to Issue Tentative Order Pursuant to the Public Utility Commission's Provisions at 52 Pa. Code Section 57.52 (Emergency load control and energy conservation by electric utilities) and Establish a Technical Conference On Large Computational Load Cost Allocation*, Issued Sept. 10, 2026, available at https://www.puc.pa.gov/pcdocs/1949305.pdf (last visited October 1, 2026).

[36] *Id*.

that relates specifically to data center-large loads and excludes other types of large loads, like manufacturers, that are not currently causing the reliability and costs impacts.

74. More specifically, in the October 1, 2026 Tentative Order, the Commission proposed the following definitions in order to define a data center:

> *Computational Load Entity*- an entity that operates or owns and maintains a Computational Load Site.
>
> *Computational Load Site*- One or more buildings, structures, or installations that:
>
> (i) Is a customer or applicant that has an anticipated maximum peak demand of 25 MW at a single point of interconnection or 50 MW at multiple points of interconnection that are interconnect to a single feeder;
>
> (ii) Primarily contains information technology infrastructure used for:
>
> a. Creating, executing, and delivering software applications and services;
>
> b. Artificial intelligence training, deployment, and delivery;
>
> c. Cryptocurrency mining; or
>
> d. Other computational activities at a data center.
>
> (iii) Is supplied through electrical equipment that is connected to the EDC's system; and
>
> (iv) Is not a facility used for manufacturing or manufacturing operations, as such terms are defined in 61 Pa. Code § 32.1, as of September 8, 2026.

75. Additionally, in the October 1, 2026 Tentative Order proposed new definitions for various types of load control events, including Pre-Emergency Load Control Events, Emergency Load Control Events, and Emergency Forced Outage Events. The Commission further proposed that EDCs establish curtailment procedures, effectuated through separate mandatory interruptible rates schedules and tariff operating procedures, that are applicable to CLE customers as follows: (1) for CLE customers subject to PJM IRAS service, mandatory interruptible rates that get implemented during Pre-Emergency Load Control Events; and (2) for all CLE customers, mandatory interruptible rates that get implemented during Emergency Load Control Events or

when PJM issues certain level of emergency communications. The point of the use of interruptible rates is for the curtailment of interruptible customers "to prevent escalation of emergencies and avoid Emergency Forced Outage Events" affecting firm customers, including customers that the Commission designated for protection from curtailment through identified Critical Load Levels.

VI. Utility Tariffs as Necessary Fasteners for Implementing Statutory Mandates and the Public Policy Consensus

76. The rates, rules, rules, regulations, practices, classifications, contracts, operating procedures in or based in PPL Electric's Retail and Supplier Tariff must implement existing statutory obligations of PPL Electric to provide reasonable, efficient, and reliable utility service to existing consumers at affordable rates as well as relevant Commission regulations, orders, and policies relating to these statutory obligations.

77. The Retail and Supplier Tariffs are the necessary fasteners to effectuating the Public Policy Consensus that promotes requiring data centers to pay for the costs that they cause and to bear the reliability risks to electricity service that they cause.

78. PPL Electric, as a public utility and EDC, is in a unique position to control interconnections to the electric distribution system and PJM grid and enhance system reliability given the myriad of generators and transmission companies that place power in a particular distribution system and the myriad of retail consumers that take power from a particular distribution system. *PP&L Indus. Cust. Alliance v. Pa. PUC*, 780 A.2d 773, 782 (Pa. Cmwlth. 2001).

79. PPL Electric, as a public utility and EDC, is in a unique position to impose tariff rules, regulations, and practices governing either or both of interconnection conditions, mandatory interruptible rates, curtailment schemes during pre-emergency conditions, emergency conditions, and emergency forced outage conditions, including consequences for an interruptible customer's

nonperformance, to preserve the reliability of a jurisdictional utility's distribution system and reliable service to existing consumers.

C. COMPLAINANT INFORMATION, 52 PA. CODE SECTION 5.22(A)(1)-(3)

80. The Complainant is Darryl A. Lawrence, Pennsylvania's Consumer Advocate.

81. The contact information for the Complainant is as follows:

Darryl A. Lawrence
Pennsylvania Consumer Advocate
Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923

82. The Complainant is represented by the Assistant Consumer Advocates who are employed by the OCA. 71 P.S. § 309-3.[37] The contact information for Complainant's attorneys:

Mel El Atieh, Deputy Consumer Advocate
PA Attorney I.D. # 209323

Jake Guthrie, Assistant Consumer Advocate
PA Attorney I.D. # 334367

Katie Kennedy, Assistant Consumer Advocate
PA Attorney I.D. # 317237

Crystal Zook, Assistant Consumer Advocate
PA Attorney I.D. # 334159

Ryan Morden, Assistant Consumer Advocate
PA Attorney I.D. # 335679

Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923
Phone: 717-783-5048
Fax: 717-783-7152
E-mail: OCAPPL1309@paoca.org

[37] The Consumer Advocate with the approval of the Attorney General shall appoint attorneys as assistant consumer advocates and such additional clerical, technical and professional staff as may be appropriate, and may contract for such additional services as shall be necessary for the performance of his function. 71 P.S. § 309-3.

83. The Complainant's interest in this case is to ensure that existing utility consumers are shielded from paying the costs and bearing the reliability risks caused by the unprecedented demand of data centers interconnecting to the electric utility's distribution system and to the regional electric grid.

84. The OCA was established by the General Assembly in 1976 to serve as the legal representative for all utility ratepayers in the Commonwealth. The Consumer Advocate possesses the authority, duty, and discretion to represent the interests of consumers before the Commission. 71 P.S. §§ 309-2, 309-4.

D. RESPONDENT INFORMATION, 52 PA. CODE SECTION 5.22(A)(4)

85. The Respondent is PPL Electric Utilities Corporation (PPL Electric).

86. The contact information for the Respondent is as follows:

PPL Electric Utilities Corporation
Two North Ninth Street
Allentown, PA 18101

87. Respondent is a public utility corporation serving approximately 1.5 million electric distribution and transmission customers with authority to provide electric public utility service in portions of Berks, Bucks, Carbon, Chester, Clinton, Columbia, Cumberland, Dauphin, Forest, Juniata, Lackawanna, Lancaster, Lebanon, Lehigh, Luzerne, Lycoming, Monroe, Montgomery, Montour, Northampton, Northumberland, Perry, Pike, Schuylkill, Snyder, Susquehanna, and Union Counties.

88. Respondent's currently effective distribution and provider of last resort services tariff is Tariff Supplement No. 2 to Electric Pa. P.U.C. No. 202 (Retail Tariff), available on PPL Electric's website at the following link: https://www.pplelectric.com/site/More/About-Us/Electric-Rates-and-Rules/Current-Electric-Tariff/Table-of-Contents

89. Respondent's currently effective supplier tariff is Tariff Supplement No. 2 to Electric Pa. P.U.C. No. 2S (Supplier Tariff), available on PPL Electric's website at the following link: https://www.pplelectric.com/site/Other-Parties/Electricity-Suppliers/Coordination-Tariff.

90. Respondent's utility code number is 110500.

E. STATUTORY AUTHORITY AND REGULATIONS, 52 PA. CODE SECTION 5.22(C)

I. Burden of Proof and General Powers to Act by Order

91. As the proponent of an order setting just and reasonable and not unduly discriminatory rates and reasonable, adequate, and reliable service, Complainant will bear the burden of proof. 66 Pa. C.S. §§ 315(a), 332(a).

92. As a Commonwealth agency, the Commission, upon its own motion or upon complaint, may give reasonable notice and hold hearings as to why the utility's existing rates and service satisfy applicable law given the addition of data centers to the utility's service territory. 66 Pa. C.S. § 1309.

93. The Commission has the full power, authority, and duty to act by order in an adjudication of an adversarial proceeding requiring the development of a formal record to enforce the Public Utility Code and the Commission's regulations. 66 Pa. C.S. § 501(a) (general powers; enforcement of provisions of part); 66 Pa. C.S. § 502 (enforcement proceedings by the Commission); 52 Pa. Code § 1.8 (defining "adversarial proceeding" as "[a] proceeding initiated by a person to seek authority, approvals, tariff changes, enforcement, fines, remedies or other relief from the Commission which is contested by one or more other persons and which will be decided on the basis of a formal record.")

II. Due Consideration of Consumer Interests

94. Given that a utility's rates and service relating to the interconnection of and service to new data centers will substantially affect the interests of existing consumers, the Commission must "consistent with its other statutory responsibilities, take such action with due consideration to the interests of consumers." 71 P.S. § 309-5.

III. Utility Obligation to Serve

95. Certificated public utilities in Pennsylvania are generally under an obligation to serve customers within their certificated service territory. 66 Pa. C.S. § 1501; *Colombo v. Pa. PUC*, 48 A.2d 59, 61 (Pa. Super. 1946) ("The obligation to serve the public is inherent in every certificate of public convenience.").

96. Included in the obligation to serve is a duty to make line extensions in order to connect new customers, subject to reasonable rules and regulations set forth in the utility's tariff. 66 Pa. C.S. § 1501; 52 Pa. Code § 57.19.

97. EDCs are also under an obligation to furnish electric supply service, inclusive of transmission and generation supply service, to customers that do not elect to choose a retail electric supplier. Such obligation is for the EDC to act as a provider of last resort or default service provider. 66 Pa. C.S. § 2807(e).

IV. Utility Rates

98. A utility's "rate" is defined broadly in statute, as follows:

> **"Rate."** Every individual, or joint fare, toll, charge, rental, or other compensation whatsoever of any public utility…made, demanded, or received for any service within this part, offered, rendered, or furnished by such public utility…whether in currency, legal tender, or evidence thereof, in kind, in services or in any other medium or manner whatsoever, and whether received directly or indirectly, and *any rules, regulations, practices, classifications or contracts affecting any such compensation, charge, fare, toll, or rental*.

66 Pa. C.S. § 102 (emphasis added).

99. By definition, a rate includes not just the monetary charge for the service but also any rules, regulations, practices, classifications, or contracts affecting such charge. *Id*.

100. Upon its own motion, or upon complaint, the Commission may find the existing rates of a public utility for any service unjust, unreasonable, or otherwise unlawful. 66 Pa. C.S. § 1309(a). In finding such, the Commission must determine and establish the just and reasonable rates to be thereafter observed and in effect by force of law. *Id*.

101. In a rate complaint brought under Section 1309, the Commission must make a final decision and order within nine months beginning on the date of the filing of the complaint. 66 Pa. C.S. § 1309(b). If a final order has not been made by the expiration of such nine-month period, a final order of the Commission which determines or fixes a rate reduction shall be retroactive to the expiration of such nine-month period and subject to further conditions of statute. *Id*.

102. Rates must adhere to tariffs that are publicly on file with the Commission. 66 Pa. C.S. § 1303.

103. Every rate made, demanded, or received by a public utility shall be just and reasonable, and in conformity with regulations or orders of the commission. 66 Pa. C.S. § 1301.

104. Every rate, made, demanded, or received by a public utility must not be unduly discriminatory or preferential. 66 Pa. C.S. § 1304.

105. Cost of providing service is the "polestar" ratemaking principle in achieving just and reasonable rates. *Lloyd v. Pa. Pub. Util. Comm'n*, 904 A.2d 1010, 1020 (Pa. Cmwlth. 2006)

V. Quality of Utility Service

106. Utility "service" is defined broadly in statute, in pertinent part, as follows:

> **"Service."** Used in its broadest and most inclusive sense, includes any and all acts done, rendered, or performed, and any and all things furnished or supplied, and any

> and all facilities used, furnished, or supplied by public utilities, or contract carriers by motor vehicle, in the performance of their duties under this part to their patrons, employees, other public utilities, and the public, as well as the interchange of facilities between two or more of them…

66 Pa. C.S. § 102; *see also PECO Energy Co. v. Twp. of Upper Dublin*, 922 A.2d 996, 1000 (Pa. Cmwlth. 2007) (citing 66 Pa. C.S. § 102) (service is defined "in its broadest and most inclusive sense").

107. Utility "facilities" is defined broadly in statute, in pertinent part, as follows:

> **"Facilities."** All the plant and equipment of a public utility, including all tangible and intangible real and personal property without limitation, and any and all means and instrumentalities in any manner owned, operated, leased, licensed, used, controlled, furnished, or supplied for, by, or in connection with, the business of any public utility.

66 Pa. C.S. § 102.

108. A public utility must furnish and maintain adequate, efficient, safe, and reasonable service and facilities. 66 Pa. C.S. § 1501.

109. A public utility must make all such repairs, changes, alterations, substitutions, extensions, and improvements in or to such service and facilities as shall be necessary or proper for the accommodation, convenience, and safety of its patrons, employees, and the public. 66 Pa. C. S. § 1501.

110. A public utility's service shall be reasonably continuous and without unreasonable interruptions or delay. Such service and facilities shall be in conformity with the regulations and orders of the commission. 66 Pa. C.S. § 1501.

111. As to service, a public utility cannot make or grant any unreasonable preference or advantage to any person, corporation, or municipal corporation, or subject any person, corporation, or municipal corporation to any unreasonable prejudice or disadvantage. 66 Pa. C.S. § 1502.

112. No public utility shall establish or maintain any unreasonable difference as to service, either as between localities or as between classes of service, but this section does not prohibit the establishment of reasonable classifications of service. 66 Pa. C.S. § 1502.

113. PPL Electric must work with the Federal Government, other states in the region, NERC, Reliability*First*, and PJM "to ensure the continued provision of adequate, safe and *reliable* electric service to the citizens and businesses of this Commonwealth." 66 Pa. C.S. § 2805(a) (emphasis added).

114. For purposes of the Electricity Generation Customer Choice and Competition Act, "reliability" is defined as follows:

> **"Reliability."** Includes adequacy and security. As used in this definition, "adequacy" means the provision of sufficient generation, transmission and distribution capacity so as to supply the aggregate electric power and energy requirements of consumers, taking into account scheduled and unscheduled outages of system facilities; and "security" means designing, maintaining and operating a system so that it can handle emergencies safely while continuing to operate.

66 Pa. C.S. § 2803.

115. PPL Electric maintain the integrity of the distribution system at least in conformity with the National Electric Safety Code and such other standards practiced by the industry in a manner sufficient to provide safe and reliable service to all customers connected to the system consistent with this title and the commission's regulations. 66 Pa. C.S. § 2807(a).

116. In performing its duties to maintain the integrity of the distribution system, PPL Electric must implement procedures to require all electric generation suppliers to deliver energy to the electric distribution company at locations and in amounts which are adequate to meet the energy supplier's obligations to its customers. 66 Pa. C.S. § 2807(a).

117. PPL Electric must include in its electric tariff rules and regulations filed with the Commission addressing emergency load control that conforms with the Commission's regulations.

52 Pa. Code § 57.52(a). PPL Electric must take reasonable steps to bring the demands within the then-available capacity or to otherwise control load. *Id*. The steps must include, but are not limited to, reduction or interruption of service to one or more customers, in accordance with the utility's procedures for controlling load. *Id*.

118. PPL Electric must establish procedures for controlling load during forced customer outage events. 52 Pa. Code § 57.52(b). Such procedures must include schedules of manual load shedding priorities to followed in compliance with Section 57.52(a). *Id*. These procedures may be revised if required by the Commission. *Id*.

119. The Commission may "order customers by whatever scheme to curtail usage during abnormal peaks" in order to preserve the reliability of a jurisdictional utility's distribution system, "as long it provides substantial reasons why there is no reasonable alternative so competition needs to bend to ensure overall system reliability." *PP&L Indus. Cust. Alliance v. Pa. PUC*, 780 A.2d 773, 782 (Pa. Cmwlth. 2001). Indeed, "only the distributor is in position to enhance system reliability because of the myriad of generators and transmission companies that place power in a particular distribution grid." *Id.*

F. CLEAR AND CONCISE STATEMENT OF THE ACT OR OMISSION BEING COMPLAINED OF, 52 PA. CODE SECTION 5.22(A)(5)

120. Specific Claims I through IX, or Claims 1 through 9, are presented below in this Section.

121. Given that PPL Electric's 2025 Rate Case Settlement was entered into by the rate case parties prior to the Commission's adoption of the Model Tariff Policy, the settling parties agreed that any party could bring a filing before the Commission to modify Rate LP-6 without such a filing being construed as breaking the Settlement. 2025 Rate Case Settlement ¶ 97.

122. As set forth in the specific claims below, the OCA believes and avers that Rate LP-6 contains inadequate protection for existing customers from the known and foreseeable costs and reliability impacts due to unprecedent, rapid additions of data centers to the PPL Electric system and the PJM gird.

123. The OCA avers that PPL Electric has acknowledged some of this gap through its filing of the CPTR Petition on September 14, 2026, addressing, to some extent, cost allocation. The OCA filed an Answer and New Matter to the CPTR Petition. Without commenting on the merits of the CPTR Petition here, gaps in customer safeguards exist. The specific Claims below identify all of the existing gaps and areas requiring further investigation.

I. <u>Rate and Service Classification</u>: A new customer classification for rates and service applicable only to data centers is necessary and appropriate. The omission of a separate rate classification for computational load entities (CLEs) in PPL Electric's Retail Tariff results in unjust, unreasonable, or unduly discriminatory or preferential rates, while the omission of a separate service classification for data centers results in inadequate, unreasonable, or unreliable service.

124. Paragraphs 7 through 119 are incorporated by reference and restated in this section.

125. PPL Electric's existing rates are unjust, unreasonable, or unduly discriminatory or preferential because it does not establish a reasonable classification of service for data centers—or, computational load entities (CLEs)—with eligibility defined by appropriate criteria defining the specific rates and rules and regulations of service. 66 Pa. C.S. §§ 1301, 1304. Such criteria should include an appropriate definition for data centers, and the OCA supports the use of the definition of "Computational Load Entity" and "Computational Load Site" proposed in the Commission's October 1, 2026 Tentative Order for purposes of establishing an appropriate rate classification that does not by design over-include other large loads, like traditional manufacturing

loads, which, unlike data centers, are not currently causing the ongoing and foreseeable cost and reliability impacts to electricity systems.

126. While PPL Electric's tariff establishes classifications of service for high-voltage service, LP-5 and LP-6, such existing rate classifications are unjust, unreasonable, and unduly preferential for data centers because the tariff does not establish reasonable classifications of service applicable only to data centers given the unique nature of their loads and the costs risks, cost shifting risks, and reliability degradation risks that they cause the distribution system and other customers to experience. Rather, Rate LP-6 is applicable to new customers of a particular size interconnecting at 69 kV or higher, regardless of the reliability- and cost-related risks associated with the customer's end-use function. Rate LP-5 currently captures all other customers interconnecting at 69 kV or higher. *See* Hoyt Affidavit.

127. Moreover, the landscape regarding forecasted data center demand in PPL Electric's service territory has changed since PPL's 2025 Rate Case, which was the proceeding that established Rate LP-6. In that regard, the OCA incorporates paragraphs 16 through 19 from above as restated herein.

128. The creation of a separate rate classification in PPL Electric's Retail Tariff for computational load entities (CLEs), specifically, would be just and reasonable and not unduly discriminatory or preferential because it will ensure that data centers—or, CLEs—pay their full share of the costs that they are causing and prevent costs from being shifted or imposed on other ratepayers. *See* Felder, Ogur, Deupree, Hoyt Affidavits.

129. The creation of a separate rate classification in PPL Electric's Retail Tariff for CLEs, specifically, would be a reasonable classification of service because the size of CLE demand and the nature of their loads present unique reliability risks that must be addressed by PPL Electric

through adequate tariff provisions, including interconnections terms and conditions, interruptible rates, and tariff operating provisions, that will ensure the continued provision of safe and reliable electricity service to existing consumers. *See* Hoyt Affidavit.

130. The creation of a separate rate classification in PPL Electric's Retail Tariff for computational loads would be a reasonable classification of service because it relates to how PPL Electric has incorporated and will incorporate proposed data center additions into its load forecast and which load forecasts are used for different planning efforts. *See* Felder, Teti Affidavits. Specifically, given the rapid and significant changes in projected CLE growth in PPL Electric's service territory, an independent, record-based examination of the assumptions underlying PPL Electric's claimed 31.8-GW forecast in its CPTR Petition, including the extent to which the projects are under signed Electricity Service Agreements (ESAs) or Construction Services Agreements (CSAs), the terms thereof, and how advanced and likely to materialize projects are, before relying on that forecast in evaluating any related cost recovery mechanisms. *See* Teti, Hoyt Affidavits.

II. <u>Reliable Utility Service</u>: The separate rate and service classification should include for the provision of mandatory interruptible service to CLEs during pre-emergency and emergency conditions, as appropriate. The omission of mandatory interruptible rates schedules and implementing tariff operating procedures to prevent existing customers from experiencing emergency forced customer outages results in unjust, unreasonable, and/or unduly discriminatory or preferential rates and unreasonable, inadequate, and/or unreliable service.

131. Paragraphs 7 through 119 are incorporated by reference and restated in this section.

132. As explained above, the Model Tariff Policy leaves it to each EDC, to determine how to revive and implement an interruptible service class for large load customers through

individual tariff proceedings.[38] Rather than establishing a uniform statewide interruptible-service structure, the Commission ordered that interruptible service programs be based on each EDC's existing interruptible tariff provisions.[39] This approach gives each EDC flexibility to develop a program suited to its system and customer base, but it also means that an important element of the large-load framework remains to be worked out on a utility-by-utility basis. Yet, this portion of the Model Tariff Policy overlooks that current EDC tariffs do not offer comprehensive interruptible rate schedules. *See* Hoyt Affidavit.

133. Additionally, in the Commission's regulations at 52 Pa. Code 57.72(a)(1), utilities are required to take the reasonable steps necessary to bring demands within then-available capacity including through interruption of service to one or more customers. 52 Pa. Code § 57.52(a)(1). In the Commission's October 1, 2026 Tentative Order, the Commission proposed that EDCs establish curtailment procedures, effectuated through separate mandatory interruptible rates schedules and tariff operating procedures, that are applicable to CLE customers as follows: (1) for CLE customers subject to PJM IRAS service, mandatory interruptible rates that get implemented during Pre-Emergency Load Control Events; and (2) for all CLE customers, mandatory interruptible rates that get implemented during Emergency Load Control Events or when PJM issues certain level of emergency communications.

134. Mandatory interruptible rate schedules applicable to CLEs, as appropriate, combined with appropriate tariff operating procedures, can reduce or defer the escalation of emergency actions that need to be taken on the PJM grid or PPL Electric system that can impact firm customers, including residential, small business, and traditional large commercial and industrial consumers. *See* Hoyt Affidavit.

[38] *Id*. at 92.
[39] *Id*.

135. By failing to establish an operationally interruptible class as part of PPL Electric's Retail Tariff, the Commission permits data centers to take service on terms that may require other customers to bear costs and reliability risks that could otherwise be avoided or mitigated through curtailment. *See* Hoyt Affidavit.

136. PPL Electric's tariff fails to provide an effective mechanism to distinguish CLE customers from other customers that require firm service. *See* Hoyt Affidavit.

137. PPL Electric's tariff fails to distinguish interruptible service for CLE customers taking IRAS service during Energy Emergency Alert (EEA) Level 1 calls by PJM from all other CLE customers that should be subject to interruptions during certain EEA Level 2 calls by PJM. *See* Hoyt Affidavit. This IRAS or EEA Level 1 call by PJM is referred to in the Commission's October 1, 2026 Tentative Order as a Pre-Emergency Load Event.

138. PPL Electric's tariff fails to distinguish interruptible service for CLE customers taking service during certain EEA Level 2 calls by PJM. *See* Hoyt Affidavit. This EEA Level 2 call by PJM is referred to in the Commission's October 1, 2026 Tentative Order as an Emergency Load Event.

139. As the Commission's proposal in the October 1, 2026 Tentative Order shows, the purpose of the use of interruptible rates is for the curtailment of interruptible customers "to prevent escalation of emergencies and avoid Emergency Forced Outage Events" affecting firm customers, including customers that the Commission designated for protection from curtailment through identified Critical Load Levels.

140. PPL Electric's tariff fails to establish penalties for non-compliance with PPL Electric's reliability orders to curtail load for CLE customers subject to its interruptible rate options. In the Model Tariff Policy, the Commission specifically adopted penalties for failure to

comply with calls to curtail customer load, finding that such penalties are required to sufficiently encourage large load customers to comply with interruption directives from EDCs. *See* Hoyt Affidavit.

141. IRAS, to date, remains a proposal subject to federal regulatory review and implementation, and its ultimate form, timing, and effect remain uncertain. States therefore cannot assume that the PJM process will resolve these issues on a particular timetable or through a particular mechanism. The uncertainty surrounding IRAS, coupled with the pace of projected large-load additions, provides an independent reason for the Commission to evaluate now whether their existing regulatory and planning frameworks adequately account for the timing, magnitude, and reliability implications of anticipated data-center demand. It does not, however, provide a reason to delay having in place the tariff rate schedules and tariff operating procedures necessary to permit PPL Electric to accommodate IRAS-EEA Level 1- or EEA Level-2 calls from PJM in its retail electric distribution tariff, which are otherwise required to ensure resource adequacy on PPL Electric's system or may otherwise be required to ensure reliable service when there are strains on transmission facilities relating to interconnection of and service to data centers. *See* Felder Affidavit.

142. Likewise, the fact that the October 1, 2026 Tentative Order is not yet final does not provide a reason for PPL Electric to delay having in place the tariff rate schedules and tariff operating procedures necessary to permit PPL Electric to accommodate IRAS-EEA Level 1- or EEA Level-2 calls from PJM in its retail electric distribution tariff, which are otherwise required to ensure resource adequacy on PPL Electric's system or may otherwise be required to ensure reliable service when there are strains on transmission facilities relating to interconnection of and

service to data centers. This is especially so given the amount of forecasted CLE customers in PPL Electric's project pipeline.

143. Without a provision regarding IRAS, PPL Electric's tariff fails to account for the changed system conditions created by data center growth and lacks a mechanism to align the rates and service obligations of data center customers with the costs and reliability impacts their demand imposes on the system, both for data centers customers that are currently in the process of interconnecting to PPL Electric's system or that will interconnect in the future. *See* Hoyt Affidavit.

144. Emergency curtailment requirements are necessary because CLE customers can materially increase the amount of load that must be shed during system emergencies. Additionally, protecting uninterrupted service to new data centers could increase the curtailment burden on residential and small commercial customers. *See* Hoyt Affidavit.

145. PPL Electric's tariff is unjust, unreasonable, and/or unduly discriminatory or preferential because it does not establish mandatory interruptible rates and tariff operating procedures to implement interruptible rates for all CLE customers in times of emergency conditions that connect to the system and cause resource adequacy shortages or degradation of service reliability to the distribution system and existing consumers. This includes establishing interruptible rates with different dispatches of interruption during load control procedures, including differentiating between pre-emergency and emergency service interruptions, as well as material penalties for non-compliance with calls for interruption. *See* Hoyt Affidavit.

146. If CLE customers are added to PPL Electric's utility system without sufficient new supply to serve them or without meaningful tariff provisions to curtail their electricity consumption during times of supply shortages, then the reliability of utility service distributed by PPL Electric

to all customers will be degraded.[40] *See* Felder Affidavit; *see also* Hoyt Affidavit. This service reliability degradation could result in mandatory load shedding or forced customer outages of existing ratepayers, such as residential customers. As more data center load is added to the PPL Electric system and PJM that either is not sufficiently supplied or curtailable, the risk, frequency, magnitude, and duration of potential mandatory load-shedding events increase. *See* Felder Affidavit; *see also* Hoyt Affidavit.

III. Reliable Utility Service: The omission of tariff operating rules, and interconnection terms and conditions, to prevent existing customers from experiencing emergency forced customer outages results in results in unjust, unreasonable, and/or unduly discriminatory or preferential rates and unreasonable, inadequate, and/or unreliable service.

147. Paragraphs 7 through 119 are incorporated by reference and restated in this section.

148. To protect existing consumers, interconnection and retail service should be conditioned on a showing that the load can be served without degrading reliability for existing customers. *See* Felder Affidavit; *see also* Hoyt Affidavit.

149. PPL Electric's tariff results in unlawful rates and service because it permits PPL Electric to interconnect and commence service to new CLE customers without determining that the proposed load can be served reliably from both transmission deliverability and resource adequacy perspectives and without degrading electric utility service to existing customers. *See* Felder, Hoyt Affidavit.

[40] See NERC, Large Loads Task Force White Paper, Characteristics and Risks of Emerging Large Loads, July 2025, p. 16, https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf. Large loads also have important implications for operational reliability. Operational reliability is the ability of the electric power grid to withstand the sudden outages of large power plants or transmission facilities by maintaining grid stability without resulting in load curtailments. See NERC, NERC Issues Level 3 Alert, Reliability Guideline Focused on Large Load Challenges, May 4, 2026, https://www.nerc.com/newsroom/nerc-issues-level-3-alert-reliability-guideline-focused-on-large-load-challenges.

150. PPL Electric's tariff is unjust, unreasonable, and/or unduly discriminatory or preferential because it does not establish an interconnection process that ensures through binding commitments that the CLE customer or electric supplier serving the CLE customer is bringing sufficient self-supply, bilateral supply arrangements, demand response or other PJM-qualifying capacity resources to match the customer's actual load obligations. *See* Felder/Hoyt Affidavit.

151. PPL Electric's tariff further fails to distinguish CLE customers in terms of critical and non-critical load under reasonable and transparent tariff rules and regulations, allowing the possibility for CLE customer load – the potential size of a Pennsylvania city – to be treated as fully firm during times of load emergencies, and thereby exacerbating system reliability problems and costs borne by non-data center customers. *See* Hoyt Affidavit.

152. PPL Electric's tariff fails to distinguish between what load, including CLE customer load, should be classified as "critical" for purposes of protecting essential human needs during emergency load shed events and what load should be classified as non-critical. In the absence of such distinctions, customers may not be adequately advised to inform PPL Electric in the event that critical load exists on site, or mistakenly claim that critical load exists even though such load does not serve essential human needs. *See* Hoyt Affidavit.

153. PPL Electric's tariff further fails to specify how the Company would verify (1) whether and to what extent a data center load would include "critical" load which services essential human needs; and (2) the adequacy of the physical configuration of customer equipment in order to segment critical from non-critical load for purposes of satisfying the requirements of Rate LP-6. Without such specifications, customers may not be placed on sufficient notice as to PPL Electric's requirements to operate its system during emergency load shed events. *See* Konidena Affidavit; *see also* Hoyt Affidavit.

154. A preliminary examination of PPL Electric's tariff shows that it produces unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful rates and service because emergency load procedures do not differentiate service to CLE customers based on critical and non-critical portions of a data center's load, including defining "critical load" for purposes of informing customers as to what types of end-use service required to ensure essential human needs are met will be protected during load control emergencies. *See* Hoyt Affidavit.

155. The data center tariffs should require the physical configuration, telemetry, and behind-the-meter separation needed to ensure that critical and non-critical functions of CLEs can be distinguished. Distinguished loads should then be addressed separately in EDC's operational readiness and emergency load control measures. *See* Hoyt Affidavit.

156. The Commission's October 1, 2026 Order proposes definitions and meanings of Critical and Non-Critical Load protections. It further proposes details of what segmentation should require. The fact that the October 1, 2026 Tentative Order is not yet final does not provide a reason for PPL Electric to delay having in place the necessary tariff rules, regulations, and practices to ensure segmentation of CLE customer load, which are otherwise required to ensure resource adequacy on PPL Electric's system or may otherwise be required to ensure reliable service when there are strains on transmission facilities relating to interconnection of and service to data centers. This is especially so given the amount of forecasted CLE customers in PPL Electric's project pipeline.

IV. <u>Inadequate Protections for Critical Loads and Vulnerable Customers</u>: PPL Electric has failed to take reasonable steps to ensure the provision of safe, reliable and/or not unduly discriminatory service to its existing customers, particularly its most vulnerable customers, despite known and impending resource inadequacy and transmission constraints that could compromise service as early as July 1, 2027.

157. Paragraphs 7 through 119 are incorporated by reference and restated in this section.

158. An EDC shall strive to prevent interruptions of electric service and, when interruptions occur, restore service within the shortest reasonable time. 52 Pa. Code § 57.194(d).

159. Interruptions in electric service can create serious risks to customers who depend upon electricity for essential medical equipment, including respirators. *See Alderwoods (Pa.), Inc. v. Duquesne Light Co*., 106 A.3d 27, 31–32 (Pa. 2014) (*Alderwoods*). This may include residential customers and commercial customers, like hospitals.

160. Certain electrically powered medical equipment cannot safely be without power for an extended period because interruption of the therapy or treatment it provides may cause serious injury, medical deterioration, or, depending upon the customer's condition, a life-threatening emergency. Such equipment may include, but is not limited to, home ventilators and other mechanical-ventilation devices; oxygen concentrators used by customers requiring continuous supplemental oxygen; certain BiPAP and other noninvasive ventilation devices; infusion pumps administering essential medications; insulin pumps; suction equipment necessary to maintain a customer's airway; home dialysis equipment; and certain feeding and monitoring equipment used by medically fragile customers. *See* 52 Pa. Code § 56.111; *Alderwoods*, 106 A.3d at 31–32 (recognizing the dangers associated with prolonged power outages, including the idling of powered essential medical equipment such as respirators).

161. The consequences of an interruption of electric service may depend upon the customer's underlying medical condition, the nature of the medical equipment or therapy involved, and the duration of the interruption, among other circumstances. *See Jackson v. Pa. Pub. Util. Comm'n,* 522 A.2d 1187, 1118–19 (Pa. Cmwlth. 1987).

162. For customers who depend upon certain equipment continuously or for critical portions of the day, however, an extended interruption of electric service may leave no medically adequate alternative and may place the customer at substantial risk. *See Alderwoods* at 31-32.

163. Accordingly, an anticipated interruption of electric service is not merely an inconvenience for these customers; advance notice may be necessary to permit the customer/patient, caregiver, physician, or emergency personnel to arrange backup power, alternative treatment, or relocation before the interruption occurs. *See* 52 Pa. Code § 56.71(1).

164. There are customers who rely, for example, on electrically powered positive-airway-pressure devices, including CPAP devices, to treat obstructive sleep apnea. *See* Konidena Affidavit.

165. The PUC treats an EDC's communication concerning medical-emergency procedures as a regulated obligation, and that failure to adequately explain those procedures can form the basis of an enforcement proceeding and monetary penalty. *Bureau of Investigation & Enforcement v. FirstEnergy Pennsylvania Electric Co.*, Docket No. C-2024-3052650, Tentative Opinion and Order (Pa. P.U.C. Mar. 26, 2026).

166. Under 52 Pa. Code Section 56.201, an EDC must maintain written public information concerning its customer-service rules, make that information available prominently and on its website, and inform new customers where to find it. That information must include procedures for discontinuance and reconnection and must indicate that additional protections may be available to people with serious illnesses.

167. While Pennsylvania's medical-certificate system is structured as a customer-initiated protection, rather than a system in which an EDC independently identifies medically

dependent customers, PPL Electric nevertheless has an obligation to provide safe, adequate, efficient, and reliable service to its customers.

168. PPL Electric also knows that medically vulnerable customers exist within its service territory and that some customers depend upon uninterrupted electric service to operate essential medical equipment.

169. Where PPL Electric has advance knowledge of potential capacity shortages or anticipated service interruptions, it is believed and therefore averred that those customers have a heightened need for timely notice so that they may obtain backup power, arrange alternative treatment, or otherwise take measures necessary to protect their health and safety.

170. PPL Electric is an active participant before PJM, FERC, and is imposed with state and federal mandates causing it to know or reasonably know that there is a capacity shortfall happening as described above and herein as early as July 1, 2027.

171. It is believed and therefore averred that PPL Electric has failed to take reasonable steps to warn medically vulnerable customers of the forecasted interruption of electric service, including by failing to provide notice or other communications to customers who may be medically vulnerable and whose medical conditions require uninterrupted electric service.

172. The OCA respectfully avers that PPL Electric could provide adequate advance notice without causing unnecessary alarm by using measured, factual, and appropriately qualified communications.

173. PPL Electric should inform customers that it is monitoring a potential resource constraint, explain the period during which service could be affected, describe the circumstances that could result in an interruption, acknowledge the degree of uncertainty, and advise customers,

particularly those who depend upon electrically powered medical equipment, to review and implement their backup plans.

174. As the risk becomes more certain, the OCA would hope that PPL Electric could provide updated information concerning affected areas, expected timing, and anticipated duration as well.

175. Thus, responsible advance notice need not cause panic; a measured warning that accurately communicates the nature and uncertainty of the risk would be sufficient to allow customers who require additional preparation time to take reasonable protective measures.

176. It is believed and therefore averred that as of this filing, PPL Electric has not communicated with its customers, including but not limited to its medically fragile or vulnerable customers, that a shortage is coming.

177. Moreover, it is believed that PPL Electric has not considered establishing a program for grid-serving distributed energy storage—or, distribution system battery storage–that can be used by the EDC to manage peak load of the distribution system and to serve as a load reducer for the distribution system. Such a battery storage program would be different from large utility-scale battery storage that serves as a new capacity resource within the PJM and directly connects to the PJM bulk system. Rather, such a battery storage program would connect directly to the distribution system, be of moderate size, available daily by the EDC for system use, and be a visible and controllable distribution system asset to manage utility system peak load. *See* Konidena Affidavit.

V. <u>Cost Causers Should Pay</u>: The separate rate and service classification should include appropriate provisions to address cost allocation impacts for network upgrades. The omission of specific tariff provisions to ensure that network upgrade costs caused by data centers will be paid for by the data centers, the but-for cost causers, in addition to their fair share of embedded costs, results in unjust, unreasonable, and unduly discriminatory or preferential rates.

178. Paragraphs 7 through 119 are incorporated by reference and restated in this section.

179. As explained above, the Model Tariff Policy leaves the critical question of how upgrade costs will ultimately be allocated to EDC-specific tariff proceedings.[41] In particular, the Model Tariff Policy does not fully answer whether a large-load customer will be required to bear 100% of the cost of necessary system upgrades (i.e., the but-for costs of customer interconnection and service) or instead be responsible only for a defined portion of the costs attributable to the customer's load.[42] Equally important is the methodology the specific EDCs will use to identify and quantify that "customer-caused" amount in individual tariff proceedings.[43] Accordingly, individualized EDC-tariff proceedings are the appropriate venue to determine how, within each service territory and under each EDC's tariff, the costs caused by computational large-load customers should be identified, allocated, and recovered, ensuring that those customers bear their fair share without shifting costs to the EDC's broader customer base.

180. CLE customers more often than not require substantial transmission network upgrades, local transmission upgrades, substations, transformers, breakers, line extensions, feeder upgrades, and other wires facilities. *See* Hoyt Affidavit. The core regulatory question is whether these costs will be assigned to the CLE customers that cause them or socialized across existing

[41] Pa. PUC, *Interconnection and Tariffs for Large Load Customers*, Docket No. M-2025-3054271, Final Order at 41-42 (Apr. 30, 2026; entered May 12, 2026).
[42] *Id*.
[43] *Id*.

customers. The starting point should be a but-for cost causation standard, as recently accepted by the Commission in the Model Tariff Policy. *See* Ogur Affidavit.

181. A preliminary examination of PPL Electric's tariff shows that it produces existing rates and any negotiated rates stemming therefrom that are unjust, unreasonable, and/or unduly discriminatory or preferential because it does not establish with sufficient specificity the requirement for the data center customer to pay the full incremental costs that would not have been incurred but for their load. This includes directly assigned and allocated distribution costs and transmission costs that may otherwise be recovered through Network Integration Transmission Service (NITS) rates or other wholesale charges that flow through to retail customers. *See* Ogur Affidavit.

182. Distribution cost recovery should be addressed in a similar manner. *See* Ogur Affidavit.

183. The OCA submits that PPL Electric's averments in the CPTR Petition are insufficient to indicate that the proposed mechanism will function as described by PPL Electric, including PPL Electric's lack of specificity regarding how PPL Electric is proposing to define "but-for" costs for purposes of the CPTR mechanism and whether and to what extent the CPTR will sufficiently protect consumers. Rather, the CPTR Petition indicates that the proposed mechanism is likely to result in intra-class cost shifting, may under- or over-recover the but-for costs of data center interconnections, and otherwise would not result in just and reasonable and not unduly discriminatory or preferential rates for new and existing customers.

184. Without addressing the averments made in PPL Electric's CPTR Petition, the CPTR Petition is, itself, further evidence of the likelihood of harm to its existing ratepayers, and that its rates are currently unjust, unreasonable, and/or unduly discriminatory or preferential. PPL

Electric's existing retail rate structure is not capable of allocating transmission upgrade costs consistent with existing policy direction from the Commission and Ratepayer Protection Pledge in the absence of a new rate mechanism.

185. With regard to transmission costs, the OCA's investigation intends to also address whether existing retail transmission cost assignment and rate design mechanisms remain just and reasonable, including evaluating jurisdictional questions, M-2 attachments, and other documents governing how transmission owners and EDCs assign and recover NITS and other cost-of-service-based, transmission-related costs. It may also involve developing retail provisions that require EDCs to absorb federally assigned transmission costs in the first instance, to the extent legally permissible. This approach would allow the Commission to preserve consistency with PJM and FERC cost assignment while developing retail mechanisms that prevent inappropriate cost shifting to existing customers. *See* Ogur Affidavit.

186. The OCA alleges that PPL Electric can, at present and consistent with existing FERC precedent and policy, directly assign transmission network upgrade costs to new CLE customers when the new CLE customer is the but-for cause of PPL Electric incurring those costs.[44] As a result, the Commission should ensure that the relief proposed can be effectuated through

[44] *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act*, 69 FERC P61,086, n. 30, 34 (1994) ("Under a line-by-line pricing method, the costs of each transmission line, or segment, are allocated to individual transmission transactions, based on the usage each transaction makes of each line or segment."); *Public Serv. Co.*, 175 F.E.R.C. P61,111, ¶ 64 (2021) ("The Commission has established that embedded and incremental pricing models can be used simultaneously for related projects. Leeward states that it opposes the 'mixing and matching' of incremental and embedded pricing. However, in the Transmission Pricing Policy Statement, the Commission embraced a flexible approach to cost disaggregation and specifically noted that line-by-line 'or' pricing is permissible. The Commission stated such proposals 'would permit the use of embedded costs for some lines when this is the higher of embedded or incremental costs, and the use of incremental cost for other lines when this is the higher of embedded or incremental costs.'") *modified on other grounds Public Serv. Co.*, 177 F.E.R.C. P61,094 (2021); *cf. Gas Transmission Nw. v. FERC*, 157 F.4th 674, 704 (5th Cir. 2025) (affirming FERC's rejection of rolled-in treatment for interstate natural gas expansion facilities that are caused by an incremental customer interconnections and do not accrue additional marginal benefits to existing customers).

establishing a consistent definition of "but-for" costs to be applied through whatever mechanism is approved to be just, reasonable, and not unduly discriminatory or preferential.

187. If PPL Electric constructs dedicated or highly project-specific facilities and then refunds contributions in aid of construction through delivery revenues, existing customers may face stranded cost risk if the CLE customer later reduces load, delays ramp, or exits service. Embedded recovery through volumetric distribution rates is therefore inappropriate where costs are highly site-specific. *See* Ogur Affidavit.

188. While transmission upgrade costs are recovered through federal jurisdiction transmission rates, PPL Electric's retail distribution tariff results in unjust, unreasonable, and unduly discriminatory or preferential rates because it fails to condition retail service on state-jurisdictional protections that prevent the federal allocation from producing retail cost shifting. *See* Ogur Affidavit.

189. The CPTR Petition proposes that PPL Electric would recover the costs of non-market based transmission rates, which includes both NITS and Transmission Enhancement Charges (TECs), where TECs are the mechanism by which transmission owners in the PJM recover costs associated with regional transmission expansion projects constructed as part of PJM's Regional Transmission Expansion Plan (RTEP).[45] Because RTEP projects are regional and allocated between PJM transmission zones, instead of local projects the costs of which are allocated intra-zonally through NITS, it is more difficult to investigate and determine the but-for causer of such projects pursuant to the cost causation principle. Therefore, the OCA does not address the recovery of TECs in this Complaint.

[45] CPTR Petition ¶¶ 35-37.

VI. Cost Causers Should Pay: The separate rate and service classification should include appropriate provisions to address cost allocation impacts for capacity, RBP and IRAS costs. The omission of specific tariff provisions to ensure that default service and shopping customers are not subsidizing capacity, RBP, IRAS costs caused by data centers results in unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful rates.

190. Paragraphs 7 through 119 are incorporated by reference and restated in this section.

191. Existing default service rates may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful because they require default service customers to subsidize the costs of providing service to CLE customers. *See* Ogur Affidavit.

192. Data center tariff provisions should be coordinated with retail choice and default service rules. Shopping status should not allow a CLE customer to avoid capacity, transmission, RBP, public policy, or reliability costs that are attributable to its service requirements. Similarly, costs caused by shopping CLE customers should not be shifted into standard offer or default service charges paid by residential customers. *See* Ogur Affidavit.

193. Pennsylvania consumers are already subject to increased energy, capacity, and ancillary services costs associated with generation supply as a result of the interconnection of current and prospective new data center customers, or the incremental load associated with the expansion of customer operations for current data center customers. As a result, Pennsylvania customers are already experiencing generation supply rate harm from the addition of CLEs to the PJM grid. *See* Ogur Affidavit; *see also* Deupree Affidavit.

194. All PPL Electric retail customers, including both default service and shopping customers, are subject to these increased generation supply and transmission costs. Because such costs are increasing over time and all retail electric customers face exposure to increasing costs,

retail competition would not adequately permit customers to limit or avoid the possibility of facing data center-related cost increases. *See* Ogur Affidavit.

195. With regard to capacity costs, the OCA's investigation intends to address whether existing retail capacity assignment and rate design mechanisms remain just and reasonable, including evaluating jurisdictional questions surrounding transmission-owner-specific M-2 attachments to the PJM tariff, assessing load and capacity obligation data, and developing retail provisions that govern whether and how EDCs or other parties (where legally permissible) absorb, assign, or reassign PJM capacity costs. One approach contemplated by the OCA is direct assignment of all capacity costs to the EDC, irrespective of customer choice status, followed by subsequent reallocation under Commission-jurisdictional retail tariffs. This approach is akin to how many states currently assign all PJM-level transmission costs to EDCs. Developing new retail tariffs for capacity cost allocation would involve cost-of-service analysis and retail rate design that reflects the unique impact of CLEs on PJM planning parameters. *See* Ogur Affidavit.

196. With regard to default service, while the OCA anticipates a data center receiving default service from PPL Electric to be rare, the OCA intends to investigate whether PPL Electric should establish a separate default service rate class for data center customers. Due to the unique risks and costs associated with procurement of energy, capacity, and ancillary services costs for data center customers – including but not limited to Reliability Backstop Procurement (RBP) Obligation and Interim Resource Adequacy Service (IRAS) costs, described *infra* – PPL Electric's current default service rate class structure may result in cost-shifting among large commercial and industrial default service customers. *See* Ogur Affidavit. The Commission must ensure that no default service costs are shifted between customer classes, even if it would be a reasonable amount. *Compare* 66 Pa. C.S. § 2807(e)(7) *with* 66 Pa. C.S. § 1304. The OCA may advocate for the

establishment of a new default service rate for data center customers, or otherwise recommend that the default service rate components for the large commercial and industrial classes are modified to ensure that costs unique to data center customers are not shifted to other customers.

197. While PPL Electric, in the CPTR Petition, avers that the CPTR mechanism, as proposed, could be utilized to assign RBP- and IRAS-related costs directly to new data center customers,[46] it is unclear whether or not the Commission could approve such a mechanism. Specifically, costs incurred under the RBP and IRAS mechanisms, as proposed, would be generation supply costs and not related to the allocation or assignment of transmission rates. The Public Utility Code and Commission's regulations prohibit the use of bundled generation supply and transmission rates.[47] As a result, it is unclear whether and to what inclusion of RBP and IRAS costs in a transmission rate mechanism would result in just, reasonable, and/or unduly discriminatory or preferential rates.

198. However, PPL Electric's attempt to develop a rate mechanism to recover RBP and IRAS-related costs in the CPTR Petition is evidence that PPL Electric's existing tariff is unjust, unreasonable, and/or unduly discriminatory or preferential because PPL Electric admits through this proposal that it lacks adequate tariff mechanisms to currently recover RBP and IRAS-related costs from the data center customers which PJM identified as the causers of those costs.

199. A preliminary examination of PPL Electric's Retail Tariff demonstrates that existing rates are unjust, unreasonable, and/or unduly discriminatory or preferential because the Retail Tariff omits broad cost responsibility, reporting, and change-in-rules provisions that remain durable as PJM and FERC rules evolve so that consumer protections continue to function as PJM

[46] CPTR Petition ¶¶ 76-85.
[47] 66 Pa. C.S. §§ 2804(3), 2807(c)(1); 52 Pa. Code § 54.4(b)(3) (providing that generation and transmission charges should separately appear on customers' bills).

implements RBP, C&M, forecasting reforms, interconnection reforms, or related market changes. *See* Hoyt Affidavit.

200. A preliminary examination of PPL Electric's Retail Tariff demonstrates that existing rates are unjust, unreasonable, and/or unduly discriminatory or preferential because the Retail Tariff does not condition retail service to prevent exposure to PJM's RBP costs. *See* Hoyt Affidavit.

201. PPL Electric's Retail Tariff is unjust, unreasonable, or unduly discriminatory or preferential because it does not establish a RBP obligation, which is a necessary input that PPL Electric, as an electric distributor member of PJM, may be required to provide to PJM so that it can allocate the costs of RBP mechanism. *See* Hoyt Affidavit.

202. It is unclear whether PPL Electric will require data center customers to bear responsibility for all RBP-related charges, how those charges will be identified and how data centers will be required to pay for these costs as a condition of retail service or whether PPL Electric will seek to pass such costs through such costs to default service, transmission riders, or other retail mechanisms. *See* Hoyt and Ogur Affidavits.

203. Recognizing that PJM's proposed RBP cost allocation procedures were not found to be just and reasonable as of the time of the filing of this Complaint[48] does not excuse the unjustness, unreasonableness, and/or unduly discriminatory nature of PPL Electric's existing tariff, which would not permit it to effectively allocate the costs of the RBP mechanism that was approved by FERC. Rather, because the RBP was approved, and the question of cost allocation remains to be addressed, a record must be developed and PPL Electric must modify its tariff in order to be able to accommodate FERC's ultimate decision regarding RBP cost allocation.

[48] *PJM Interconnection, L.L.C.*, 196 FERC ¶ 61,245 (2026).

204. If PJM implements IRAS as proposed, PPL Electric's tariff and operating procedures must require interruptible service to data centers. If a CLE customer is allowed to connect ahead of full system readiness, it should not receive the same rights as existing firm customers while exposing those customers to greater reliability risk. The tariff should make explicit that any accelerated or conditional interconnection requires enforceable operating obligations that are capable of being executed by the PPL Electric and coordinated with PJM emergency operations. *See* Hoyt Affidavit.

205. In sum, PPL Electric's existing tariff provides rates that are unjust, unreasonable, and/or unduly discriminatory or preferential because the tariff results in the allocation of generation supply costs caused by data centers to other customers that did not cause PPL Electric to incur the costs associated with generation supply, including its default service supply rates and the constituent components which determine those rates. These costs are the direct result of PPL Electric's current and ongoing undisciplined interconnection of new data center customers and a lack of adequate tariff measures to address the same.

VII. <u>Cost Shifting and Stranded Costs</u>: The separate rate and service classification should include appropriate provisions to address cost shifting and stranded costs impacts. The omission of a rate schedule applicable to data centers that contains sufficient provisions to prevent cost shifting and the shifting of stranded costs risks from data centers onto other ratepayers results in unjust, unreasonable, or unduly discriminatory or preferential rates.

206. Paragraphs 7 through 119 are incorporated by reference and restated in this section.

207. Under existing rates and tariff provisions, substantial costs caused by data centers are being and will be shifted to and subsidized by existing consumers, including residential consumers and low-income households. *See* Hoyt, Ogur, and Deupree Affidavits.

208. Enforcing adequate and sufficient terms and conditions of retail service before a data center customer is interconnected can help mitigate against such cost-shifting. Under Section 1501 of the Public Utility Code, extensions of service and facilities are conditioned upon reasonable rules and regulations captured in a utility's tariff. 66 Pa. C.S. § 1501; *see also* 52 Pa. Code § 57.19. Where a utility's tariff permits the undisciplined interconnection of new CLE customers, its tariff is unreasonable because it does not contain adequate terms and conditions for extensions of service.

209. As described *supra*, the Commission's Model Tariff Policy established a policy framework for specific terms and conditions of retail service for new data center customers to be captured in a contract for retail service between EDCs and the customers, including: tariff eligibility; service term and load ramping; minimum monthly charges; cost responsibility; financial security; exit procedures and fees; interconnection study processes; interruption and curtailment; self-construction options; universal service funding contributions; and reporting requirements. *See* Hoyt Affidavit.

210. In addition to the Model Tariff Policy provisions, the Commission should also establish minimum contractual terms that every EDC must include when contracting with a CLE customer seeking interconnection. Those terms should address, among other things, the customer's committed load, expected in-service date, required transmission and distribution upgrades, payment and security obligations, milestones and deadlines, cancellation or termination rights, and responsibility for costs if the customer delays, downsizes, or withdraws. *See* Hoyt Affidavit.

211. The existence of an EDC's ability to contract with CLE customers is not sufficient protection for the EDC's customers, because a utility's practices and procedures *must be consistent with its tariff*. 66 Pa. C.S. § 1303. Contracts between an EDC and its customers which do not

conform to a Commission-approved tariff, or contracts that contain terms which are not identified with sufficient specificity in an EDC's tariff, risk being *ultra vires* and exceeding the scope of a utility's authority under the Public Utility Code. *Id.* As a result, a utility's non-tariffed practices cannot constitute sufficient protections for its current customers, and EDCs should be required to have the terms of such contracts captured in their tariffs.

212. Data center customers' contracts for service with EDCs should establish minimum requirements governing the customer's load commitment, interconnection milestones, financial responsibility, construction obligations, and consequences for failure to proceed. Without such contractual protections and Commission visibility into the commitments underlying CLE customer development, the tariff permits EDCs to incur costs based on uncertain or speculative load while shifting the resulting risks and costs to other ratepayers.

213. This framework requires the Commission to have meaningful visibility into the development pipeline for CLE customers, rather than learning about a proposed load only after the EDC has incurred or proposes to incur substantial transmission or distribution costs.

214. The Commission considered a reporting framework in the Model Tariff Policy that would have given it—and, subject to confidentiality protections, the statutory advocates—substantial visibility into large-load development, including executed Energy Service Agreements (ESAs) and transmission Letter of Authorizations (LOAs) and, upon request, copies of those agreements.[49] However, the Commission ultimately declined to impose those reporting requirements in the Final Order, finding that further consideration of their scope, content, timing, and feasibility was necessary.[50] Ultimately, despite the importance of the Model Tariff Policy, it

[49] Pa. PUC, *Interconnection and Tariffs for Large Load Customers*, Docket No. M-2025-3054271, Final Order at 108-109, 113-114 (Apr. 30, 2026; entered May 12, 2026).
[50] *Id*. at 113-114.

did not mandate a procedure through which utility tariffs must be updated in accordance with the Commission's new policy on large load interconnections. As a result, it is left to individual tariff proceedings for each EDC to see necessary updates to its tariff in order to be *consistent with* the Model Tariff Policy, where applicable, or diverge where there is a demonstrated need based on the system characteristics of the EDC and/or more recent factual and policy developments that must be considered. *See* Hoyt Affidavit.

215. At a minimum, EDCs should be required to provide the Commission with executed ESAs and transmission LOAs associated with CLE customer projects and, upon Commission request, copies of those agreements and related interconnection documents.

216. Requiring that these agreements not only exist but are disclosed would give the Commission the information necessary to distinguish non-speculative, actionable load commitments from speculative development, assess whether proposed system investments are actually being driven by CLE customers, and ensure that the appropriate customer bears the costs associated with its commitments. It also creates an adequate record that allows the Commission to monitor whether EDC contracting practices are consistent with Pennsylvania's cost-allocation and reliability policies. *See* Hoyt Affidavit.

217. While PPL Electric's tariff contains the Rate LP-6 rate schedule, it is not specifically applicable to data centers and therefore lacks the protections identified above in this complaint. Any new rate schedules established to apply specifically to data centers must also contain sufficient mechanisms that protect against the risks of cost shifting and the risks of other customers paying stranded costs. *See supra*.

218. Further, PPL Electric, the OCA, and other parties to the Joint Petition for Non-Unanimous Settlement agreed that, following the Commission's adoption of the Model Tariff

Policy, Rate LP-6 could be re-opened to modify Rate LP-6 to be consistent with the Commission's Model Tariff Policy consistent with the terms of the Settlement. *See* Hoyt Affidavit.

219. Rate LP-6 is inconsistent with the Model Tariff Policy and, therefore, is unjust, unreasonable, and/or unduly discriminatory or preferential. The following provisions of LP-6 are inconsistent with the Model Tariff Policy: minimum monthly charges; contribution in aid of construction requirements, including LP-6's lack of but-for cost contributions; contract exit and material modification protections; interconnection study procedures; self-construction options; and peak demand-based contributions to universal services costs. *See* Hoyt Affidavit.

220. Rate LP-6 also does not require that (1) the ESAs be updated by the customer at the time that the customer becomes aware that such an update is required and (2) that PPL Electric provide such an updated ESA to the Commission and statutory advocates. Under this framework, the Commission cannot ensure that rates charged under Rate LP-6 are just and reasonable unless CLE customers are subject to enforceable commitments commensurate with the costs their proposed interconnections impose on the system, and PPL Electric's tariff is, therefore, unjust, unreasonable, and/or unduly discriminatory or preferential. *See* Hoyt Affidavit.

221. A preliminary examination of PPL Electric's tariff shows that it produces existing rates that are unjust, unreasonable, and/or unduly discriminatory or preferential because it does not establish the requirement for the data center customer to enter into negotiated electric service agreement or transmission service agreement that comply with just and reasonable tariff rates, rules, and regulations to protect existing customers from cost shifting and reliability risks, consistent with the policy framework in the Commission's Model Tariff Policy, and in light of the specific cost, reliability, and market risks posed by data centers. *See* Hoyt Affidavit.

222. To the extent that PPL Electric's service territory is sufficiently unique to warrant deviation from the Model Tariff Policy, the Commission has not reached that determination in a proceeding dedicated to investigating the basis for any potential deviation. Unless and until a substantial record is developed to support the uniqueness of PPL Electric's service territory in comparison to Pennsylvania, generally, LP-6's inconsistencies with the Model Tariff Policy should be presumed to be unjust, unreasonable, and/or unduly discriminatory or preferential.

223. PPL Electric's tariff is unjust and unreasonable absent requirements that ensure CLE customers have made sufficiently non-speculative commitments before EDCs undertake substantial investments or incur costs to serve those customers. Accordingly, the Commission should require EDCs to enter into specific, Commission-approved contractual arrangements with CLE customers as a condition of pursuing the construction of interconnection facilities, through the siting and construction of distribution and/or transmission facilities. *See* Hoyt Affidavit.

224. The OCA intends to investigate whether PPL Electric has proposed or intends to propose the construction of transmission and/or distribution facilities to interconnect and serve new data center customers to the Commission and/or PJM when no ESA has been executed and/or when no LOA has been executed with a new data center customer. This investigation will include at what point in discussions with a new data center customer PPL Electric determines to propose and/or site and construct facilities associated with the interconnection and service of a new data center customer.

VIII. <u>Adequate Affordability Protections as Data Centers Interconnect</u>: PPL Electric has failed to take reasonable steps to protect residential customers from growing affordability challenges associated with increasing electricity costs in their bills resulting from data center interconnections and service within the PJM region and within PPL Electric's service area.

225. Paragraphs 7 through 119 are incorporated by reference and restated in this section.

226. As recognized by the Commission, electric utility rates have increased significantly across the State in recent years. The rates charged by PPL Electric are no exception. Rates for electric service from PPL Electric have increased across all major customer classes over the past decade. *See* Deupree Affidavit.

227. Moreover, the magnitude of these increases is particularly pronounced in the most recent years, as nearly all of the increase occurred between 2021 and 2025. During that period alone, the average rate for electric service from PPL Electric increased by 36.9 percent, following a period of relative rate stability in the preceding years. The recent and substantial escalation in rates affects all customer classes. *See* Deupree Affidavit.

228. An increasing number of Pennsylvania's residential customers are struggling to keep up with rising energy costs, many of whom do not meet the income requirements for hardship assistance or other income-based utility relief, yet have limited discretionary income available to absorb increases in electric bills. As a result of rapidly rising costs, even modest increases in residential electricity costs may impose a meaningful financial burden on households that do not qualify for traditional assistance programs but nevertheless have limited capacity to accommodate higher utility expenses. *See* Deupree Affidavit.

229. Data centers are interconnecting to the PPL Electric's electric distribution system at a time when residential customers already face significant affordability concerns due to the level of current electric rates. *See* Deupree Affidavit.

230. Consumers are already facing disconnections for failure to pay at a higher rate, with one out of six American households reportingly behind on paying their utility bills. *See* Deupree Affidavit.

231. The traditional principle of gradualism remains applicable to Pennsylvania's rapidly emerging data-center load, but PPL Electric's current rates do not reflect gradualism because they fail to account for the speed and magnitude at which data-center demand and associated system costs are materializing. It is therefore necessary for PPL Electric's rates to be structured so that the costs and risks associated with that growth are recovered gradually and appropriately to the cost-causers of the costs and risks, the data centers, rather than immediately shifted to existing customers. The failure of the EDC's tariff to provide such protections results in rates that are unjust, unreasonable, or unduly discriminatory or preferential. *See* Deupree Affidavit.

232. Additionally, neither LP-6 nor CPTR directly addresses the immediate affordability crisis confronting a residential customer who cannot afford today's bill, nor does the proposed CPTR provide direct bill relief or additional protections targeted at households with the least ability to absorb electric-cost increases. The Commission should therefore ensure that data centers bear the costs they cause and that PPL Electric's tariff and customer-protection measures, considered holistically in light of the issues presented herein, adequately protect residential customers and preserve the affordability of electric service.

233. The existing tariff's failure to address these issues comprehensively allows the costs and risks associated with rapid data-center load growth to continue to accrue to residential customers and permits issues affecting the affordability and reasonableness of rates to be addressed piecemeal across separate proceedings rather than comprehensively in this proceeding.

234. Absent Commission action, PPL Electric's rates will continue to reflect an inadequate allocation of data-center-related costs and risks, resulting in rates and service that are unaffordable, unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful.

235. Moreover, to protect bill affordability, it is believed that PPL Electric has not considered establishing a program for grid-serving distributed energy storage—or, distribution system battery storage–that can be used by the EDC to manage peak load of the distribution system and to serve as a load reducer for the distribution system. Such a battery storage program would be different from large utility-scale battery storage that serves as a new capacity resource within the PJM and directly connects to the PJM bulk system. Rather, such a battery storage program would connect directly to the distribution system, be of moderate size, available daily by the EDC for system use, and be a visible and controllable distribution system asset to manage utility system peak load. *See* Konidena Affidavit.

IX. <u>Adequate Protections for Low-Income Customers as Data Centers Interconnect</u>: The separate rate and service classification should include appropriate provisions to require data center customers to contribute appropriately to low-income customer payment programming. The omission of sufficient provisions in the existing tariff to protect eligible low-income customers from the costs and affordability impacts associated with rapid data-center load growth, including through adequate Universal Service Fund contributions, results in rates and service that are unjust, unreasonable, and/or unduly discriminatory or preferential.

236. Paragraphs 7 through 119 are incorporated by reference and restated in this section.

237. As explained above, in the Model Tariff Policy, the Commission stated that contributions to universal service costs should be based on data center customers' peak demand, not on a volumetric or fixed-price basis. Such a structure is consistent with the cost causation principle, since increased energy burdens associated with retail electric supply charges, including transmission and capacity, can be correlated with the significant peak demands of new data center customers. *See* Deupree Affidavit.

238. Under Rate LP-6, PPL Electric includes, as part of LP-6 customers' fixed monthly charges, that such customers contribute towards a class-based allocation of $11 million to PPL

Electric's Universal Services Rider (USR), an amount which does not vary with the customer's contracted demand amount. The $11 million contribution is not indexed to inflation or overall universal service cost amounts. The $11 million figure may have been based on 2025 load projections for data centers and is likely now insufficient as data-center demand and associated costs have grown, leaving low-income customers vulnerable and unprotected under the current tariff. *See* Deupree Affidavit.

239. PPL Electric's rate design for data center customers' contribution to universal services costs is unjust, unreasonable, and/or unduly discriminatory or preferential because it reflects a static amount of costs to be recovered over time, whereas universal services costs can vary significantly year-to-year and are likely to increase over time. The Rate LP-6 USR contribution is also inconsistent with the Model Tariff Policy because it is not based on the data center customers' peak demand.

240. Low-income customers are particularly vulnerable to the potential costs associated with rapid data center development because they have less ability to absorb increases in their electric bills and are more likely to depend on customer assistance programs to maintain essential service. *See* Deupree Affidavit. Moreover, the vast majority of low income customers are not enrolled in customer assistance programs and thus do not get the benefit of these program.

241. Large-load interconnections can and do increase wholesale energy, capacity, and transmission costs, and the resulting costs can affect residential customers, including customers participating in PPL Electric's Customer Assistance Program (CAP). *See* Deupree Affidavit.

242. The Commission's own statements recognize a direct connection between rapid data-center growth, rising electric costs, and residential affordability. Vice Chair Kimberly Barrow has called for large-load customers to make contributions commensurate with the supply costs

associated with their increased demand, while noting that residential electricity prices had risen 10.2% year over year and identifying data-center demand, among other factors, as a source of growing supply-price pressure. She also cited PJM's forecast that data-center demand could reach 32 GW by 2030. *See* Deupree Affidavit.

243. The failure of PPL Electric's existing tariff and mechanisms to provide the protections for eligible low-income customers, including but not limited to adequate identification and tracking of confirmed low-income customers, compliance with applicable Commission requirements, and an adequate Universal Service Fund contribution, leaves eligible low-income customers exposed to the costs and affordability impacts associated with rapid data-center load growth. *See* Deupree Affidavit.

244. The failure to include sufficient provisions in the tariff to ensure these protections are maintained and adequately funded results in rates and service that are unjust, unreasonable, or unduly discriminatory or preferential.

G. SUMMARY OF ALLEGATIONS

245. Based on the foregoing, the OCA generally alleges that PPL Electric's exiting tariff rates, rules, and regulations are unjust, unreasonable, and/or unduly discriminatory or preferential and existing service is unreliable, unreasonable, inadequate, and/or unduly discriminatory or preferential because it causes existing consumers to inappropriately bear the risks and consequences of: (1) paying for new and higher costs that are caused by the additions of data centers to PPL Electric's service territory and the PJM regional grid; and (2) receiving service that is frequently interrupted or curtailed due to strains placed on electricity transmission infrastructure and generation supply as a result of the fast-paced interconnections of and service to data centers without PPL Electric taking preventative steps to ensure that either there is sufficient new supply

to meet the new data center demand or there is the provision of mandatory interruptible service to data center customers during pre-emergency and emergency conditions, as appropriate.

246. The OCA makes the specific allegations as laid out above in Section F, Claims I through IX, or Claims 1 through 9, as supported by the attached Affidavits of the OCA's qualified expert witnesses.

247. For summary purposes, based on the foregoing, and as supported by the attached Affidavits, Complainant specifically alleges that existing rates are unjust, unreasonable, and/or unduly discriminatory or preferential, 66 Pa. C.S. Sections 1301-1304, and existing service is inadequate, unreasonable, unreliable, and/or unduly preferential, 66 Pa. C.S. Sections 1501-1502, because:

(Claim 1) PPL Electric's tariff does not establish a new customer classification for rates and service applicable only to data centers to appropriately address the cost impact risks and reliability impacts to service risks presented by the ongoing additions of data centers to PPL Electric's system and the PJM region, 66 Pa. C.S. Sections 1301-1304, 1501-1502;

(Claim 2): PPL Electric's tariff omits mandatory interruptible service rates schedules and implementing tariff operating procedures that are necessary to protect existing customers from experiencing emergency forced customer outages due to the ongoing and foreseeable impacts to reliable service caused by data center additions to PPL Electric's system and the PJM region, 66 Pa. C.S. Sections 1301-1304, 1501-1502, 2803, 52 Pa. Code Section 57.52;

(Claim 3): PPL Electric's tariff omits operating rules and sufficient interconnection terms and conditions to protect existing customers from experiencing emergency forced customer outages due to the ongoing and foreseeable impacts to reliable service caused by data center

additions to PPL Electric's system and the PJM region, 66 Pa. C.S. Sections 1301-1304, 1501-1502, 2803, 2805(a), 2807(a), 52 Pa. Code Section 57.52;

(Claim 4): PPL Electric has failed to take reasonable steps to ensure the continued provision of service without unreasonable interruption or outages to its existing customers, particularly its most vulnerable customers, despite known and impending resource inadequacy and transmission constraints that could compromise service as early as July 1, 2027, 66 Pa. C.S. Sections 1501-1502, 52 Pa. Code Sections 57.19, 57.52, 57.194(d);

(Claim 5): PPL Electric's tariff omits specific provisions to ensure that transmission and distribution incremental investments caused by data center interconnections as well as the data centers' fair share of embedded costs related to the utility's local transmission system will be paid for by the data centers, 66 Pa. C.S. Sections 1301-1304, 2807(e);

(Claim 6): PPL Electric's tariff omits specific provisions to ensure that default service and shopping customers are not subsidizing PJM capacity, Reliability Backstop Procurement, Interim Resource Adequacy Service costs caused by data centers, 66 Pa. C.S. Sections 1301-1304, 2807(e);

(Claim 7): PPL Electric's Rate LP-6 omits sufficient rules and regulations to prevent cost shifting and the shifting of stranded costs risks from data centers onto other ratepayers, 66 Pa. C.S. Sections 1301-1304; and

(Claims 8 and 9): PPL Electric's tariff omits sufficient provisions and PPL has failed to take reasonable steps to prevent exacerbating existing affordability challenges for residential customers or to adequately protect eligible low-income customers from the costs and affordability impacts associated with rapid data-center load growth, including through adequate universal service fund contributions, 66 Pa. C.S. Sections 1301-1304.

H. CLEAR AND CONCISE STATEMENT OF THE RELIEF SOUGHT, 52 PA. CODE SECTION 5.22(A)(6)

248. To protect existing consumers and ensure their continued access to affordable and reliable electricity service, the Consumer Advocate requests relief:

a. To remedy the specific Claims I, V, VI, and VII, or Claims 1, 5, 6, and 7, above, the establishment of rates, rules, regulations, practices, classifications or contracts in or based in PPL Electric's Retail Tariff, for distribution service and default service, and Supplier Tariff, as appropriate, that are just, reasonable, not unduly discriminatory or preferential, and otherwise consistent with the Public Utility Code, 66 Pa. C.S. Sections 102, 1301-1304, by creating a separate customer class for data centers that requires the data centers to pay their full share of their costs for retail electric service and to prevent those costs from being imposed on other ratepayers;

b. To remedy the specific Claim IV, or Claim 4, the observation and provision of reasonable, adequate, reliable, not unduly preferential service and facilities.

c. To remedy the specific Claims I and II, or Claims 1 and 2, above, the establishment of rates, rules, regulations, practices, classifications or contracts in or based in PPL Electric's Retail Tariff for distribution service that are just, reasonable, not unduly discriminatory or preferential, and otherwise consistent with the Public Utility Code, 66 Pa. C.S. Sections 102, 1301-1304, 1309, 1501-1502, 2805(a), and 2807(a), and 52 Pa. Code Section 57.52, by creating a separate customer class for data centers that subjects the data centers to mandatory interruptible rates and implementing tariff operating provisions to ensure overall system reliability for existing customers; and

d. To remedy the specific Claims I and III, Claims 1 and 3, above, the establishment of PPL Electric's load tariff rules and regulations governing interconnection,

reliability, load shed plans and load shed schedules that will result in reliable, adequate, reasonable, and not unreasonably preferential or advantageous service by ensuring protection for existing customers from the growing reliability risks caused by the growing resource inadequacy problem caused by the integration of new data centers to the electric system. 66 Pa. C.S. §§ 102, 1501-1502, 1505, 2805(a), and 2807(a), (e); 52 Pa. Code § 57.52.

e. To remedy the specific Claims VIII and IX, Claims 8 and 9, above, the establishment of adequate affordability protections, including but not limited to the establishment of ongoing contributions of data center customers to PPL Electric's universal service programs to mitigate the higher electricity rates caused by data center interconnections and to benefit consumers who need bill payment assistance.

249. The OCA respectfully requests that the Commission send this Complaint to the Office of Administrative Law Judge (OALJ) for the assignment of a presiding officer(s) for the purposes of investigation and hearings, including public input hearings and evidentiary hearings, with the right of the Complainant, Respondent, intervenors, and other interested parties to investigate, engage in discovery, submit pre-served written direct and responsive testimonies, move for the admission into evidence of pre-served testimonies, and otherwise develop a robust evidentiary record on the issues raised in this Complaint. Given the high level of public interest in data centers and their effects on electric utility bills that consumers pay, the OCA also respectfully requests that the Commission schedule and hold public input hearings in sufficient quantity and formats and adequate notice thereof to encourage consumers and members of the public to attend and participate. Finally, given the high level of public interest in data centers and their effects on electric utility bills that consumers pay, the OCA respectfully requests the Commission begin considering holding oral argument on the litigated issues before the Commission after exceptions

are filed to the presiding officer's Recommended Decision, provided that a party submits a written request for oral argument at the same time that exceptions are due. 52 Pa. Code § 5.538(b).

250. The OCA specifically reserves the right and requests the opportunity to submit written, pre-served direct testimony after the OCA and its experts have had the reasonable opportunity to engage in discovery of relevant information. The OCA and its experts are at an information disadvantage which can only be cured by pursuing and obtaining relevant information through discovery. The OCA reserves the rights to develop the issues identified in the experts' Affidavits, as well as potential solutions to address them, as additional information becomes available based in discovery and to submit final recommendations in written testimony.

251. As identified in the Ogur Affidavit, the OCA's proposed tariff revisions "affect[] more than 5% of the customers and amounts to in excess of 3% of the total gross annual intrastate operating revenues of" PPL Electric. *See* Ogur Affidavit; 66 Pa. C.S. § 1309(b). By statute, therefore, the OCA is entitled to a Commission determination regarding this Complaint within nine months, subject to refund if the Commission issues a final order past the deadline for decision.

252. Given the rate relief sought in this Complaint, the OCA respectfully requests that the Commission direct the OALJ to set a reasonable litigation schedule that follows the nine-month statutory timeframe set forth in Section 1309(b) of the Public Utility Code. 66 Pa. C.S. § 1309(b). Should the litigation schedule be set using a Public Meeting date following the expiration of the nine-month period, any relief afforded will be subject to any refunds, as appropriate. *Id*.

I. VERIFICATION AND SIGNATURE, 52 PA. CODE SECTION 5.22(B)

I, Darryl A. Lawrence, hereby state that the facts set forth in this Complaint are true and correct (or are true and correct to the best of my knowledge, information and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. Section 4904 (relating to unsworn falsification to authorities).

/s/ Darryl A. Lawrence	10/2/2026
Signature	Date

J. PUBLIC STATEMENT OF THE CONSUMER ADVOCATE, 71 P.S. SECTON 709-4(E)

253. The Pennsylvania Office of Consumer Advocate was established by the General Assembly in 1976 to represent the consumers of Pennsylvania in matters involving their utility rates and service, as regulated by the Commission.

254. The OCA's enabling statute is found at 71 P.S. Sections 309-1 – 309-8. In accordance with the requirements of 71 P.S. Section 732-201(b), Consumer Advocate Darryl A. Lawrence[51] was appointed by Attorney General Dave W. Sunday and unanimously confirmed by the Pennsylvania Senate.[52]

255. Pursuant to statute, the Consumer Advocate has the authority and duty to represent the interests of utility consumers as a party before the Commission in any matter properly before

[51] Consumer Advocate Darryl Lawrence possesses over 20 years of dedicated public service as an employee of the OCA, possess the training, experience, and attainment to represent the interest of consumers, and holds no conflict of interests. 71 P.S. § 309-2.

[52] https://www.attorneygeneral.gov/taking-action/darryl-lawrence-confirmed-by-pa-senate-as-pennsylvanias-consumer-advocate/

the Commission. 71 P.S. § 309-4(a). The Consumer Advocate has the statutory authority and duty to initiate proceedings if in the Consumer Advocate's judgment such may be necessary, in connection with any matter involving regulation by the Commission. *Id*.

256. In determining the interests of consumers, the Consumer Advocate must consider the public interest, the resources available, and the substantiality of the effect of the proceeding on the interest of consumers. 71 P.S. § 309-4(b).

257. Pursuant to statute, the Consumer Advocate must issue publicly a written statement whenever he determines to initiate a Commission proceeding stating concisely the specific interest of consumers to be protected. 71 P.S. § 309-4(e).

258. The Consumer Advocate has determined that consumers served by PPL Electric have a direct and substantial interest in paying affordable utility rates that reflect their cost of service. Additionally, consumers served by PPL Electric have a direct and substantial interest in receiving electricity service that is not subjected to the imminent and/or potentially severe risk of recurring and prolonged outages when reasonable steps can be taken by the utility to avoid such an outcome. PPL Electric's decisions to rapidly interconnect and serve the massive amounts of data center electricity demand threaten these interests of existing consumers.

259. To protect these interests of existing consumers of PPL Electric, the Consumer Advocate has determined that it is necessary to file this Formal Complaint against PPL Electric and initiate this proceeding before the Pennsylvania Public Utility Commission to ensure that PPL Electric (1) charges rates for electricity service that are just and reasonable and not unduly discriminatory or preferential to any particular customer class; and (2) observes, furnishes, and enforces reasonable, adequate, sufficient, and reliable service and service that is not unduly preferential as between classes of service.

260. By initiating this proceeding, the Consumer Advocate, by and through the assistant consumer advocates employed at the OCA, will seek to ensure that adequate, reasonable, reliable and not unduly preferential service is provided to all customers at just, reasonable, and not unduly preferential or discriminatory rates and otherwise in accordance with applicable statutes.

Respectfully submitted,

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Date: October 2, 2026

Appendix A – Teti Affidavit

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Office of Consumer Advocate	:	Docket No. C-2026-
v.	:	
PPL Electric Utilities Corporation	:	

AFFIDAVIT OF ZACHARY TETI, M.S.

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I. Witness Information

My name is Zachary "Zach" Teti. My job title is Senior Regulatory Analyst, and I am employed by the Pennsylvania Office of Consumer Advocate (OCA). My office is located at 555 Walnut St, Harrisburg, PA 17101. The OCA is a state agency that represents the interests of Pennsylvania utility consumers before the Pennsylvania Public Utility Commission (PUC), federal regulatory agencies, and state and federal courts.

I am a Pennsylvanian who received a B.A. degree in Economics from Millersville University in 2013 and an M.S. in Energy Economics from Pennsylvania State University in 2021. I have thirteen years of experience in the banking and energy industries, most recently specializing in organized wholesale and retail electricity markets. My background comprises energy market design and analysis; econometric research in an academic setting; and financial planning, analysis, and control in a banking setting. I was employed as a Senior Regulatory Analyst serving as a representative to the NEPOOL Markets Committee between 2021 and 2024, analyzing wholesale electricity market design and transmission planning policy.

I joined the OCA as a Senior Regulatory Analyst in April 2025. My role and responsibilities include monitoring and evaluating various technical issues and trends affecting the Pennsylvania utility industry, such as investor calls, reliability metrics, and return on equity. Additionally, I serve as an expert or support expert witnesses on discrete issues in public utility rate cases and default service plans. These cases are listed in my attached curriculum vitae as Attachment A. Most importantly, I closely monitor and evaluate electricity markets, transmission planning, and general stakeholder processes managed and conducted by PJM Interconnection, L.L.C. (PJM). PJM is the independent system operator/regional transmission organization that manages core electricity service functions across a region that includes fourteen jurisdictions

including Pennsylvania.[1]

Of relevance, as part of my PJM responsibilities, I am responsible for actively monitoring and participating in the PJM Transmission Expansion Advisory Committee (TEAC).[2] I closely observe and evaluate meeting materials and discussions which are focused on the issues, needs, and solutions presented by PJM and the transmission owners within PJM that result in transmission projects. I also monitor and participate in the PJM Load Analysis Subcommittee (LAS) which prepares and reviews PJM reports and technical analyses and coordinates information related to electric peak demand and energy forecasts.[3] Additionally, I actively monitored and participated in the PJM Critical Issues Fast Path (CIFP) processes addressing the integration of data centers into the grid of PJM. Those processes were referred to as CIFP – Large Loads Additions and CIFP – Reliability Backstop Procurement (RBP) and Connect and Manage (C&M). Both of these processes culminated in PJM's separate filings to the Federal Energy Regulatory Commission (FERC) as follows: (1) PJM's Reliability Backstop Procurement (RBP) to Address Resource Adequacy Concerns Stemming from Large Loads, Docket No. ER26-3380; and (2) PJM's Proposal to Establish Interim Resource Adequacy Service (IRAS) and a Large Load Registry to Address System Reliability, Docket No. ER26-3515.[4]

II. Purpose of Affidavit

My affidavit addresses load forecasts for data centers in Pennsylvania and the service territories of the electric distribution companies (EDCs) of Pennsylvania. To address load forecasts, I will review the PUC's June 2026 report, titled *Electricity Load Forecast Accountability*

[1] PJM is an independent system operator / regional transmission organization that manages electricity markets, transmission planning, and other core electricity service functions across a 14-jurisdiction region that includes Pennsylvania. *See also* Felder Affidavit for more information about PJM.
[2] PJM Transmission Expansion Advisory Committee, https://www.pjm.com/committees-and-groups/committees/teac
[3] PJM Load Analysis Subcommittee, https://www.pjm.com/committees-and-groups/subcommittees/las.
[4] Interim Resource Adequacy Service (IRAS) was referred to as Connect and Manage (C&M) during the CIFP.

Annual Report (Act 45 Annual Report)[5] the PUC's 2026 report titled *Electric Power Outlook for Pennsylvania 2025-2030* (2026 EPO Report),[6] the PUC's 2025 report titled *Electric Power Outlook for Pennsylvania 2024-2029* (2025 EPO Report),[7] and the PUC's 2024 report titled *Electric Power Outlook for Pennsylvania 2023-2028* (2024 EPO Report).[8]

My affidavit also addresses the supplemental projects that were identified before PJM for the Pennsylvania EDC service territories as being driven by customer service to data centers. Addressing the load forecast and supplemental transmission projects driven by customer service to data centers, together, provides a comprehensive review of available information related to prospective data centers in Pennsylvania.

My affidavit will show that demand for electricity is expected to increase quickly, dramatically, exponentially – and this is a concern. The potential approaches to address this concern may be further refined and developed as additional information becomes available, including through formal discovery and further legal, regulatory, market, and economic analysis. My affidavit nevertheless establishes why the existing tariff is unjust and unreasonable as applied to this increasing demand for electricity, which reflects the proposed rapid growth of large loads, including data centers and other computational large loads (CLEs). The current framework exposes existing customers to costs, risks, and reliability impacts associated with serving these new loads without adequate protection. Accordingly, the purpose of this affidavit is to identify the principal

[5] Electricity Load Forecast Accountability Annual Report, Pennsylvania Public Utility Commission (June 2026), available at https://www.puc.pa.gov/media/3981/final-act-45-report-2026-6_26_26.pdf (last visited Sept. 7, 2026) (Act 45 Annual Report).
[6] *Electric Power Outlook for Pennsylvania 2025-2030,* Pennsylvania Public Utility Commission (August 2026), available at https://www.puc.pa.gov/media/4014/2026-epo-2025-2030_final_8-25-26.pdf (last visited Sept. 7, 2026) (2026 EPO Report).
[7] *Electric Power Outlook for Pennsylvania 2024-2029,* Pennsylvania Public Utility Commission (August 2025), available at https://www.puc.pa.gov/media/3586/final-draft-2025-epo-2024-2029-8-2025.pdf (last visited Sept. 7, 2026) (2025 EPO Report).
[8] *Electric Power Outlook for Pennsylvania 2023-2028,* Pennsylvania Public Utility Commission (August 2024), available at https://www.puc.pa.gov/media/3124/2024-epo-2023-2028-7-2024_final.pdf (last visited Sept. 7, 2026) (2024 EPO Report).

issues warranting Commission review now, not to present a final evidentiary record or prescribe definitive tariff provisions. Those issues, and the appropriate customer protection should be further developed through PUC proceedings as the record is supplemented. Given the pace of data center load growth and the time required to plan and construct necessary infrastructure, such review is increasingly urgent.

III. Data Center Load Forecasts

A. Explanation of Electricity Demand

Current and forecasted consumer demand for electricity drives the planning and construction of energy infrastructure (i.e., the electric grid) which includes distribution, transmission, and generation facilities as well as battery storage and demand response infrastructure and resources. Based on the Energy Information Administration's (EIA's) Glossary of Terms,[9] electricity demand for residential consumers means the requirement a consumer has for electricity as an input to heat or cool their dwellings and to cook, heat water, and other residential uses. For commercial and industrial customers, electricity demand means the requirement a consumer has for electricity to provide products and/or services or to consume.

The term "load" refers to an end-use device or customer that receives power from the electric system and is an expression used in the electricity industry similar to "demand." The term "peak load" is the maximum load during a specified period of time – when measured electricity demand in a given place is at its highest. Then, "coincident peak load" refers to the combined peak loads of two or more EDCs or customers during the same time interval. In contrast, "noncoincidental peak load" is the peak load of an individual EDC or customer that may or may not occur during the coincident peak. A source of common confusion around peak load is the

[9] Available at https://www.eia.gov/tools/glossary/ (last visited Oct. 1, 2026). Available at https://www.eia.gov/tools/glossary/index.php?id=Residential%20sector (last visited Oct. 1, 2026).

difference between a snapshot of demand and consumption over time. Kilowatt hours (kWh), megawatt hours (MWh), or gigawatt hours (GWh) measures how much electricity consumers use or consume over time. Meanwhile, kilowatt (kW), megawatt (MW), and gigawatt (GW) measure how much electricity consumers are demanding at a given moment.

Coincident peak load is a key concept in distribution, transmission system, and supply-side planning and therefore has a major impact on electricity costs and grid reliability. Coincident peak load is concerned with the hours in a year when system or regional electricity demand reaches its highest level. A widespread heat wave and air-conditioning usage to cool homes and businesses is a common driver of coincident peak load. Similarly, cold snaps lead to heightened electricity usage to heat homes and businesses, causing winter peaks. Coincident peak load is important because high-demand periods put more stress on the electric grid. At the regional level, both adding and planning to add significant load to the coincident peak will ultimately result in the need for significant construction of generation, transmission and distribution facilities. These requirements emerge in response to forward-looking planning and conditions that add stress to real-time operations of the PJM grid during peaks.

Lastly, the term "load forecast" refers to the projected or expected average electricity usage and peak load based on the data and methods used by the EDCs and PJM and as reported by the PUC. Accurate load forecasts are important. Conversely, inaccurate or inflated forecasts influence planning processes and may drive an overbuilding of energy infrastructure.

B. Data Center Load Forecasts for Pennsylvania EDCs based on PUC Reports

1. Data centers are driving significant electricity demand projections over the next five years (through 2030) for Pennsylvania.

a. Average Consumption Projections (GWh)

According to the PUC, the total annual average aggregate five-year energy usage for

Pennsylvania utility consumers is expected to increase significantly, mostly due to the increased demand in electricity from data centers.[10] In 2026, the PUC found that overall electricity consumption is expected to increase by 7.85% per year, driven mainly by an increase in data center demand growth of approximately 18.56% for the five-year period of 2025-2030.[11] In 2025, the PUC found that annual electricity consumption is expected to increase overall to 6.17% per year, driven mainly by an increase in data center demand growth of approximately 14.77% for the five-year period of 2024-2029.[12]

Table 1 (Table 3 from the 2026 EPO Report) shows the average aggregate five-year electrical energy projections in gigawatt hours (GWh). Data center projections are classified under the "Industrial" category.[13]

Table 1: Average Aggregate Five-year Electrical Energy Projection (PUC)

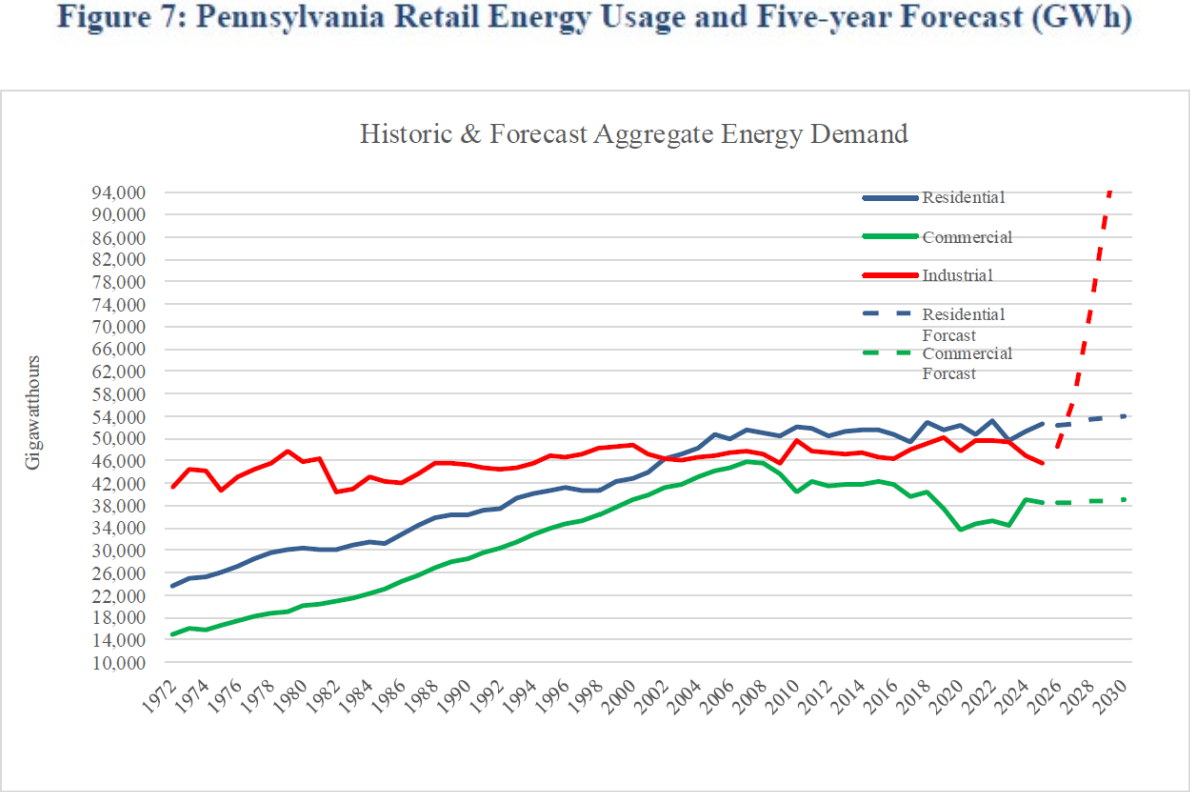
Table 3: Average Aggregate Five-year Electrical Energy Projection

PA Energy Usage Projection (GWh)				
Year	Residential	Commercial	Industrial	Total
2026	51,796	38,195	48,486	138,476
2027	52,180	38,252	57,219	147,652
2028	52,750	38,510	73,006	164,266
2029	53,000	38,485	92,169	183,655
2030	53,516	38,678	106,737	198,930
Average annual growth (%)	0.52%	0.32%	18.56%	7.85%

Additionally, **Figure 1** (Figure 7 from the 2026 EPO Report) shows the Pennsylvania average retail energy usage since 1972 along with five-year forecast, in GWh, again with data center demand classified as industrial demand:[14]

[10] 2026 EPO Report, p. 4, 32; 2025 EPO Report, p. 3.
[11] 2026 EPO Report, p. 4, 32.
[12] 2025 EPO Report, p. 3
[13] 2026 EPO Report, p. 33.
[14] 2026 EPO Report, p. 33.

Figure 1: Pennsylvania Retail Energy Usage and Five-year Forecast (GWh) (PUC)



After a period of commercial and residential load growth in PA throughout the 70s, 80s, and 90s, aggregate load has been flat since the turn of the century per **Figure 1**; that is, from 2001 to 2025, the average aggregate load growth rate in Pennsylvania was 0.3% per year.[15] In this timeframe (2001-2024), load growth has been flat in the thirteen states and the District of Columbia, which are fully or partially served by PJM: an increase of 0.3% per year.[16] As made apparent in **Table 1** and **Figure 1**, forecast aggregate demand for the industrial category is exponential in the immediate future. While the PUC discusses the high forecast load projections for the "industrial sector", I read the report as clearly showing that such industrial forecasts are

[15] The PUC provides Electric Power Outlook (EPO) Reports on their website going back to 2002. Average of Year-over-Year Changes in Total Aggregate Net Consumption (GWh) reported in EPO Reports from 2002-2026.
[16] Average of Year-over-Year Changes in Total Aggregate Net Consumption (GWh) reported in EIA-861 from 2002-2026. Available at https://www.eia.gov/electricity/data/state/ (last visited 9/17/2026).

driven by forecasts for data center loads.[17]

b. Peak Load Projections (MW)

Through Act 45[18] of 2025, the General Assembly of Pennsylvania declared that PUC oversight of electric load forecasts is necessary to provide information on projections for significant growth in electricity demand driven by data centers, vehicle and building electrification, and other large load customer additions.[19] Act 45 requires the PUC to investigate the EDCs' methodologies, data, and assumptions for developing the load forecasts they submit to PJM, and to identify the specific projections driven by electricity demand for data centers.[20] In the PUC's Act 45 Annual Report, the PUC found that the EDCs have collectively projected that **peak load** will increase by approximately 15.6 GWs in Pennsylvania by 2030:

> The additional electric peak load (additional expected peak electric usage at one time during a calendar year) projected by EDCs in Pennsylvania by 2030 is approximately **15,619 megawatts**. [21]

However, the PUC noted that PJM found the 15.6 GWs of data center demand additions to be too speculative, and, therefore, PJM adjusted downward the Pennsylvania EDCs' forecasts for peak load by approximately 9.5 GWs, or 9,469 MWs, to approximately 6 GWs, or 6,123 MWs by 2030:

> PJM discounted the increase to Pennsylvania EDCs' peak load forecasts to approximately **6,123 MW[s] by 2030**. For context, the EDCs' total noncoincidental peak load (i.e., the maximum load that each EDC could experience on one day, but not necessarily all at the same time) in 2024 was 30,323 MW. [22]

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[17] 2026 EPO Report, p. 4, 35, 36

[18] Act 45 of 2025 added Article XVIII-B, "Electricity Load Forecast Accountability," to Pennsylvania's Fiscal Code. 72 Pa. Stat. Ann. § 1804-B. Act 45 gives the PUC a formal oversight role over the electricity-load forecasts that the EDCs submit to PJM. a. Pub. Util. Comm'n, *Electricity Load Forecast Accountability Report*, https://www.puc.pa.gov/filing-resources/reports/electricity-load-forecast-accountability-report/ (last visited Sept. 30, 2026).

[19] Act 45 Annual Report, p. 1.

[20] Act 45 Annual Report, p. 1.

[21] Act 45 Annual Report, p. 2 (emphasis added).

[22] Act 45 Annual Report, p. 2 (emphasis added).

Even with the downward adjustment made by PJM, the PUC concluded that: "The EDCs' and PJM's forecasts by 2030 exhibit a significant increase in expected peak load in Pennsylvania in a short time frame."[23]

In summary, the PUC found that the Pennsylvania EDCs had forecasted data centers will cause growth in peak load for Pennsylvania by approximately 15.6 GW, or 15,619 MW, by 2030. The PUC further found that PJM discounted the Pennsylvania EDCs' peak load forecasts by 9.4 GW, or 9,469 MW, resulting in a PJM-adjusted peak load forecast of approximately 6 GW, or 6,123 MW, by 2030, for the Commonwealth. The PUC concluded, "[t]he impact of data centers and other large load customers in both Pennsylvania and PJM's region on electric load forecasts is significant."[24]

The PUC provides Electric Power Outlook (EPO) Reports on their website going back to 2002.[25] In **Table 2**, I gathered the historical peak load (MW) information reported by the PUC in Table 1 of these EPO Reports to show the historical peak load for all consumers during the ten-year period of 2016-2025. During this period, as **Table 2** illustrates, the annual peak load is either flat or not showing any clear direction or pattern. The average peak load over this ten-year historical period was 29,397 MW.

[23] Act 45 Annual Report, p. 2.
[24] Act 45 Annual Report,, p. 3.
[25] *See* PUC's Website, available at (last visited Sept. 8, 2026).

Table 2: Peak Load of Pennsylvania from 2016-2025

Year	Peak Load	% Difference Compared to Avg.
2025	29,641	0.8%
2024	30,323	3.1%
2023	28,192	-4.1%
2022	29,241	-0.5%
2021	29,730	1.1%
2020	28,755	-2.2%
2019	29,204	-0.7%
2018	30,278	3.0%
2017	29,204	-0.7%
2016	29,403	0.0%
Average:	**29,397**	

If 6,123 MW-worth of data center-drive peak load materializes in Pennsylvania by 2030, this could amount to a 21% increase in statewide electricity peak demand compared to the average peak demand reported in **Table 1** of 29,397 MW. A 21% increase in peak demand is an extraordinary quantity. To put it into context, 6,123 MW is nearly on par with the entire service territory peak load of the biggest electric utilities in Pennsylvania, PECO and PPL Electric. To give greater context of this increase, in **Table 3**, I show the reported peak loads in 2025 by EDC, sorted highest to lowest: [26]

[26] 2026 EPO Report, Table 1, p. 32.

Table 3: Peak Load by EDC (2025) (Highest to Lowest)

EDC	Peak Load (MW)
FE PA	10,705
West Penn	*3,912*
Met-Ed	*3,003*
Penelec	*2,895*
Penn Power	*895*
PECO	8,379
PPL	7,557
Duquesne	2,695
UGI	217
Citizens'	50
Pike County	20
Wellsboro	18
Total	**29,641**

Plainly said, the EDCs' projections of 15.6 GW peak load growth by 2030 due to data centers, and PJM's adjusted 6 GW of peak load growth by 2030 due to data centers, are both extraordinary and unprecedented. OCA Witness Frank Felder will discuss data center's unique need for "speed to power", which partly explains these unprecedented, dramatic increases in load growth over the next five years.

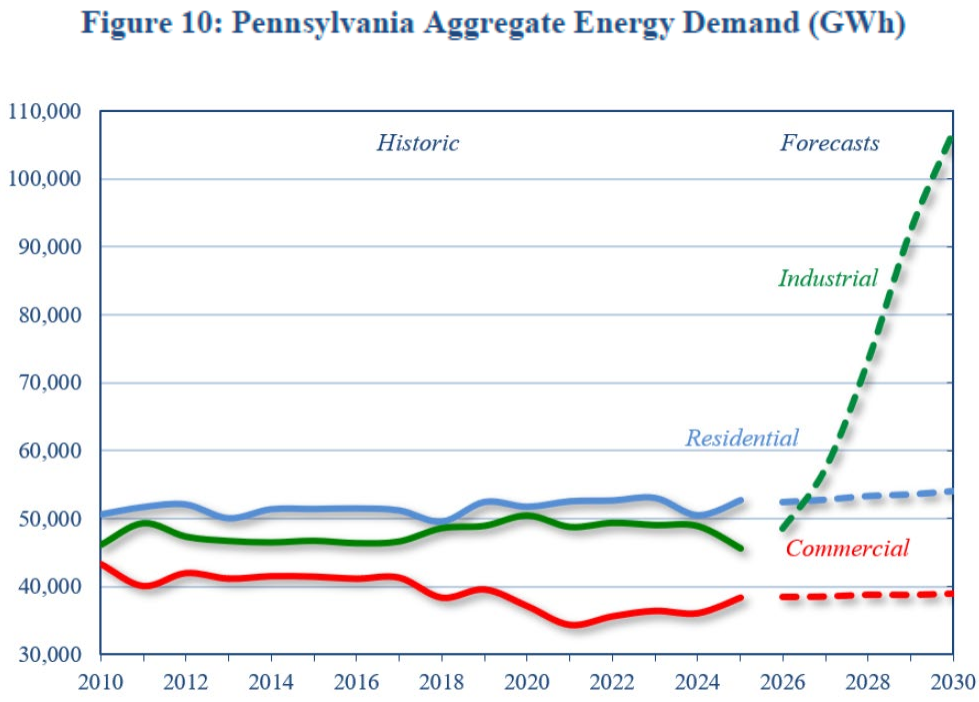
2. Residential, commercial, and manufacturing industrial electricity demand is not projected to increase significantly.

According to the PUC's 2026 and 2025 EPO Reports, the growth in electricity demand is not driven by residential or commercial demand growth rates, which exhibit nearly flat annual demand growth rates of 0.52% and 0.32%, respectively.[27] To show that data center demand is driving the projections for significant increases in electricity demand, **Figure 2** (Figure 10 from the 2026 EPO Report, which focuses on the forecast and historic residential, commercial, and industrial aggregate energy demand since 2010) depicts this growth, again classifying the data center demand

[27] 2026 EPO Report, p. 32-33; *see also* 2025 EPO Report, p. 3, 28-29.

as industrial demand:[28]

Figure 2: Pennsylvania Aggregate Energy Demand (GWh) (PUC)



3. Data center electricity demand came rapidly as the PUC only first began reporting data center demand growth in 2025.

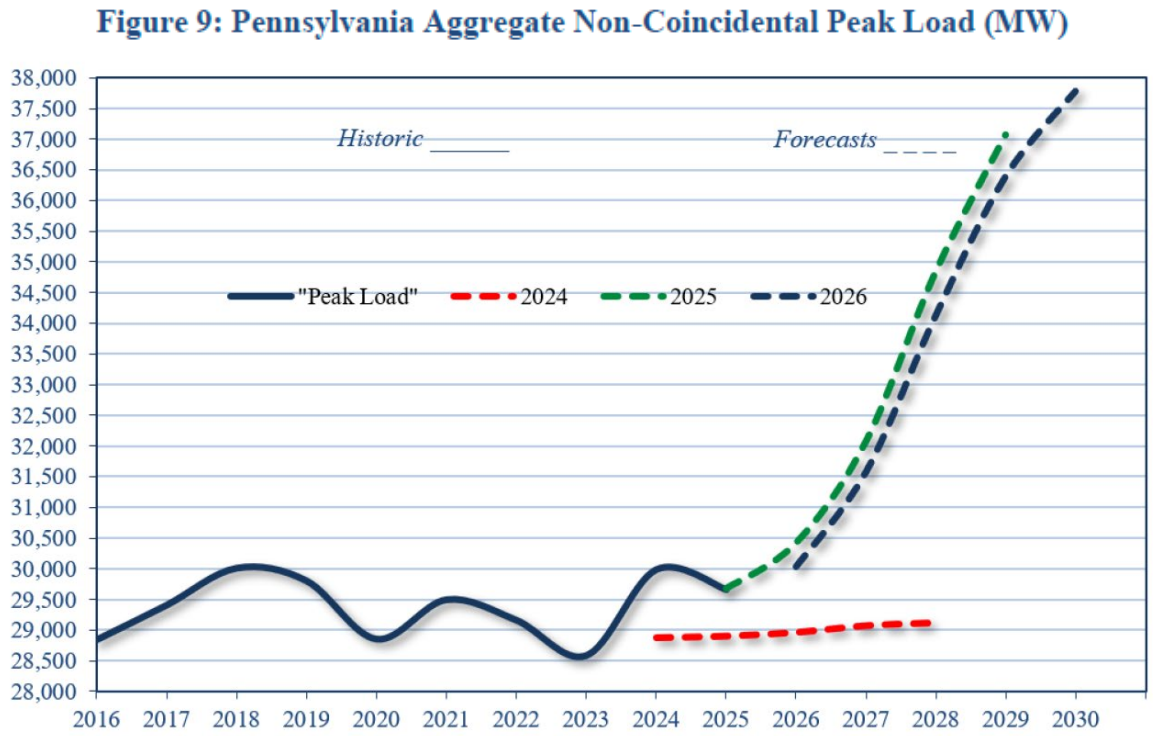
This significant growth in electricity demand due to data center demand was first reported by the PUC in August 2025 in the PUC's 2025 EPO Report. Indeed, in the 2024 EPO Report, the PUC concluded that annual electricity consumption is expected to increase overall by only 0.76% per year, including an industrial demand growth increase of only 0.22% for the five-year period of 2023-2028.[29] Thus, awareness or knowledge of the demand for electricity needed by data centers came suddenly.

Figure 3 (Figure 9 from the 2026 EPO Report) shows that Pennsylvania forecasted aggregate non-coincidental peak load in megawatts (MWs), increased dramatically beginning with the five-

[28] 2026 EPO Report, p. 35.
[29] 2024 EPO Report, p. 3. 30-31.

year period examined in the PUC's 2025 EPO Report, 2024-2029:[30] Again, this knowledge came suddenly and the proposed or anticipated development is rapid.

Figure 3: Pennsylvania Aggregate Non-Coincidental Peak (MW) (PUC)



C. Dependability/Credibility of the Load Forecasts

The PUC noted in its 2026 EPO Report that any load forecast beyond the five-year forecast in the EPO Reports "should be taken with the proverbial grain of salt" and that its "20-year forecasts should be seen as much more speculative than its five-year forecasts." I agree with the PUC's statements about long-term projections beyond the five-year mark, and, as a result, I do not put emphasis on 20-year forecasts in my affidavit.

In June 2026, the PUC released its first Act 45 Annual Report, in which the PUC identified and analyzed forecasted growth in electricity load associated with data centers.[31] The Act 45

[30] 2026 EPO Report, p. 35.
[31] Pa. Pub. Util. Comm'n, Electricity Load Forecast Accountability Annual Report (2026), https://www.puc.pa.gov/media/3981/final-act-45-report-2026-6_26_26.pdf.

Annual Report is distinct from the EPO Report as it reflects the PUC's focused investigation of the EDCs' methodologies, data, and assumptions for developing the load forecasts they submit to PJM, and the PUC identification of specific projections driven by electricity demand for data centers.[32]

A core objective of the PUC's assessment in the Act 45 Annual Report was to ensure that the EDC load forecasts do not contain (1) duplicative or (2) non-firm, or rather "speculative" demand. The Act 45 Annual Report states that "Act 45 is intended to avoid duplicative counting of load and create more accurate and transparent load forecasting."[33]

"Duplicative" means that the same prospective customer is counted two or more times by one EDC or among two or more EDCs or counted two or more times within the PJM region. Double counting is an issue because duplicative requests would result in inflated load forecasts.

"Firm" means customers that are "most likely to come into service due to there being an executed contract with firm commitments," and "'Non-Firm" means customers that are less likely to come into service and are therefore more speculative.[34] I assume non-firm or speculative means customers that do not have an executed contract with certain commitments as defined therein.

As I continue my discussion herein, where the PUC refers to load as "firm" I will refer to the same as "non-speculative" and where the PUC refers to load as "non-firm" I will refer to the same as "speculative." This is because the terms "firm" and "non-firm" have specific meaning as to the type of service that certain customers receive, meaning firm, or non-interruptible, service versus non-firm, or interruptible, service. It is important to keep these concepts separate and distinct.

[32] Act 45 Annual Report, p. 1.
[33] Act 45 Annual Report, p. 1.
[34] Act 45 Annual Report, p. i.

As noted above, the PUC found that with PJM's adjustments, approximately 6,123 MW of incremental peak load is forecasted by 2030 in Pennsylvania. In reviewing the EDCs' load forecasting methods, the PUC "found that the differences in the EDCs' forecast methodologies make it difficult to achieve consensus on what may be the 'correct' methodology to achieve the most accurate forecast."[35] The PUC found that the EDCs' large load adjustment requests in Pennsylvania and other PJM states varied by EDC with no consistent methodologies for key thresholds for inclusion in forecasts such as ramp rates, utilization rates, and inclusion/non-inclusion of large load customers with/without executed construction contracts or electric service obligations.[36]

That said, the PUC made two important findings: (1) the PUC found no evidence of duplication, or double counting, of **non-speculative** data center customers within Pennsylvania by the EDCs in the load forecasts; and (2) PPL Electric and PECO were the only EDCs with non-speculative data center load in their 20-year load forecasts.[37] I take these findings to mean that the PJM-adjusted projection of 6 GW of peak load growth by 2030 due to data centers in Pennsylvania is not only extraordinary and unprecedented, but also, to some extent, verified by the PUC. This is important for the pleading in the above-captioned proceedings initiated by the OCA. For the PUC and interested parties in these proceedings, further topics will be predicated on a somewhat certain load forecast of peak load in Pennsylvania.

However, importantly, I note that the OCA does not necessarily agree with the PUC's determination that certain load forecasts are non-speculative based on the existence of certain contracts. Contracts alone do not predict whether a data center's load – which drives the planning

[35] Act 45 Annual Report, p. i.
[36] Act 45 Annual Report, p. ii.
[37] Act 45 Annual Report, p. ii.

for construction of new electricity infrastructure – will materialize as projected. Contracts can be broken, especially in the absence of enforceable consequences for nonperformance. The rigor and strength of contractual commitments and protections can help in discerning whether load is non-speculative. Contracts can also ensure that load meets its obligations. However, this requires exercises of transparency and detailed review and analysis, exercises that OCA Witness Matthew Hoyt will address.

D. PJM Load Forecasts of Data Centers for the PJM Region

Pennsylvania's extraordinary and unprecedented forecast load growth due to data centers is not unique to Pennsylvania but is something the entire PJM region is experiencing. PJM produces an annual report on load forecasts called the *Long-Term Load Forecast Report* (PJM LTLF or LTLF).

In the 2025 LTLF, PJM's evaluation of large load adjustment requests, a key variable in the annual long-term load forecasts, projected that electricity demand from data center growth would be up to ~30 GW between 2025 and 2030.[38] PJM's 2026 LTLF confirmed that electricity demand from data center growth is still projected to grow up to ~30 GW between 2027 and 2031, during both summer peak (MW) (191,017MW less 160,451 MW = 30,566 MW or 30.5 GW) and winter peak (172,202 MW less 142,536 MW = 29,666 MW or 30 GW).[39] The 2026 LTLF anticipated slightly lower [(though relatively the same)] peak demand in the near term through 2032 due to updates to the electric vehicle and economic forecasts as well as improved vetting of requested adjustments for data centers and large loads.[40]

[38] *See* 2025 Long-Term Load Forecast, p. 9, available at https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf; *see also* PJM Inside Lines (Jan. 8, 2026), available at https://insidelines.pjm.com/2025-year-in-review-planning-prepares-for-burgeoning-electricity-demand/.
[39] *See* 2025 Long-Term Load Forecast, available at https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf; *see also* PJM Inside Lines (Jan. 8, 2026), available at https://insidelines.pjm.com/2025-year-in-review-planning-prepares-for-burgeoning-electricity-demand/.
[40] For example, the updated load forecast for summer 2026 predicted a slight drop in peak electricity use attributed

PJM noted that the 2026 LTLF included growth in data center load in the following PJM Zones: AEP, ATSI, APS, BGE, COMED, Dayton, DQE, JCPL, METED, PECO, PEPCO, PL.[41] PJM considered near-term forecast years evidenced by contractual commitments such as Electric Service Obligation (ESO)/Construction Commitment (CC) as less speculative, while PJM considered longer-term projects as more speculative and derated such projects because of their greater uncertainty. This distinction, which was put in place by PJM for the 2026 LTLF, brought large load adjustments down in the near-term forecast years (i.e., 2026-2028) compared with the 2025 LTLF.[42] **Table 4** below shows the 2026 LTLF and changes from the 2025 LTLF, reflecting how adjustments in PJM's accounting of speculative data center projects affected the forecast. In the 2026 LTLF, PJM chose to release the discounted, non-firm load requests back into the load forecast in 2030 and beyond.[43]

to large loads (-0.7%), economic activity (-0.5%) and EVs (-0.1%) compared to the PJM 2025 LTLF. *See* PJM Inside Lines (Jan. 14, 2026), available at https://insidelines.pjm.com/pjms-updated-20-year-forecast-continues-to-see-significant-long-term-load-growth/.

[41] *See* PJM Inside Lines (Jan. 14, 2026).

[42] *See* PJM Inside Lines (Jan. 14, 2026).

[43] 2026 PJM Long-Term Load Forecast Presentation to the Load Analysis Subcommittee, p. 25, available at https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2026/20260123/20260123-item-03---pjm-2026-long-term-load-forecast---presentation.pdf; *see also* PJM Manual 19, p. 29, "Non-Firm may be considered for load forecast periods not covered by an RPM Auction."

Table 4: PJM's 2026 LTLF and Changes from the 2025 LTLF (PJM)

Year	Summer Peak (MW)	Change From 2025 Long-Term Load Forecast (MW/%)	Year (Winter Season Dec. – Feb.)	Winter Peak (MW)	Change From 2025 Long-Term Load Forecast (MW/%)
2027	160,451	-3,735 (-2.3%)	2026/27	142,536	-4,155 (-2.8%)
2028	165,567	-4,414 (-2.6%)	2027/28	147,807	-5,759 (-3.8%)
2029	171,530	-4,564 (-2.6%)	2028/29	153,434	-6,186 (-3.9%)
2030	183,008	-875 (-0.5%)	2029/30	160,126	-7,111 (-4.3%)
2031	191,017	-1,630 (-0.8%)	2030/31	172,202	-3,994 (-2.3%)
2035	216,872	+6.949 (+3.3%)	2034/35	199,622	+1,477 (+0.1%)

The above peak forecasts incorporate large load adjustment requests. PJM refers to this as Adjustments Above Embedded to Summer Peak Load (MW) in Table B9 of its LTLF dataset. In 2026 LTLF, large load adjustment requests amounted to 33,707 MW in 2030. In 2025 LTLF, large load adjustment requests amounted to 32,795 MW in 2030, a relatively similar quantity across LTLFs.[44] **Figure 4** then presents these large load adjustment requests (denoted Data Center Increase (Table B9)) in blue in a graph alongside the aggregate forecast increases previously discussed (green).[45] The aggregate forecast increase reflects the LTLF Summer Peak difference

[44] 2026 LTLF Data available at https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.

[45] To directly compare large load adjustment requests to the aggregate forecast increases, a diversity factor is applied. The diversity factor reflects the difference between noncoincident peak and peak load. For example, large

between a reference year (e.g., 183,008 MW in 2030) and 2026 (156,373 MW).[46] This shows the inextricable linkage between data center load growth and the aggregate forecasted load growth in PJM. As apparent in **Figure 4**, essentially all projected PJM load growth through 2035 (in aggregate) is due to large load additions (i.e., data centers).

Figure 4: PJM 2026 Load Forecast

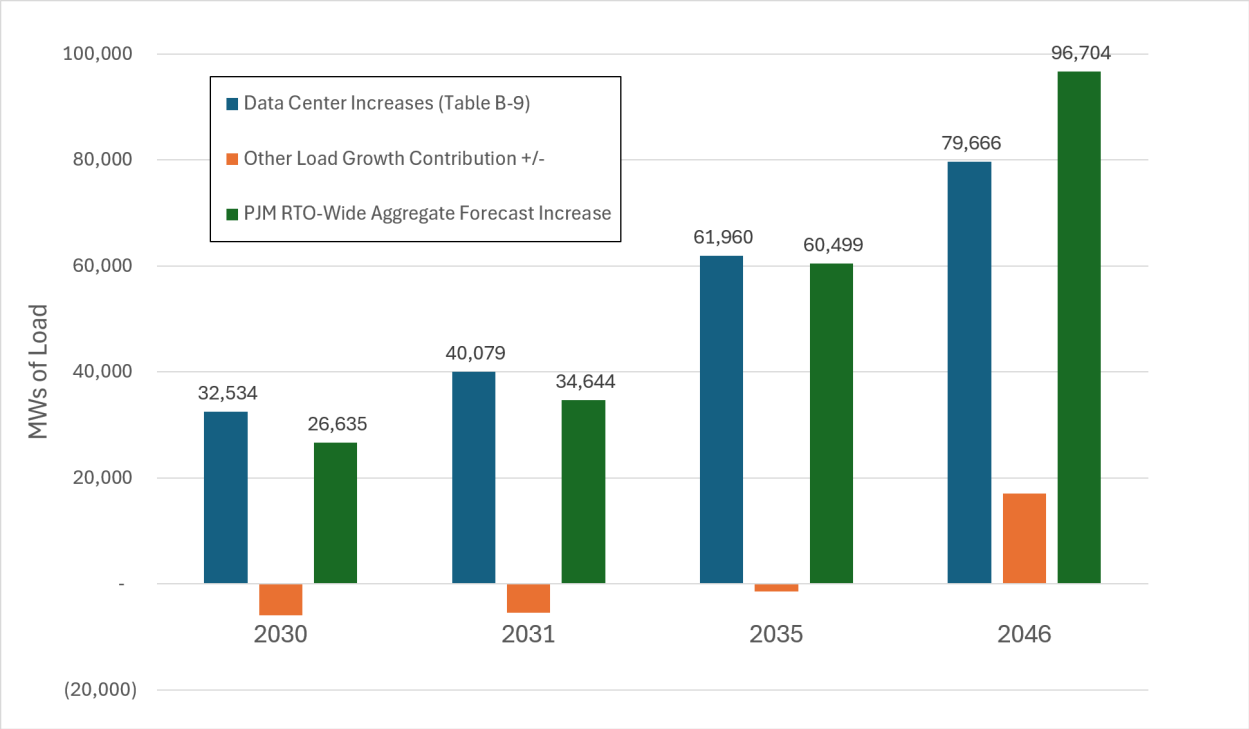


Figure 5 is a graph presented by PJM's Independent Market Monitor (IMM) showing that the peak load of data centers is beginning to drive up the regional peak.[47, 48] The graph has two y-axes: values for the PJM Summer Peak Load (MW) are on the left and corresponds with the orange line and values for the July Peak Data Center Load (MW) are on the right and correspond with the

load adjustment requests of 33,707 MW x 3.5% Diversity Factor = 32,534 MW.

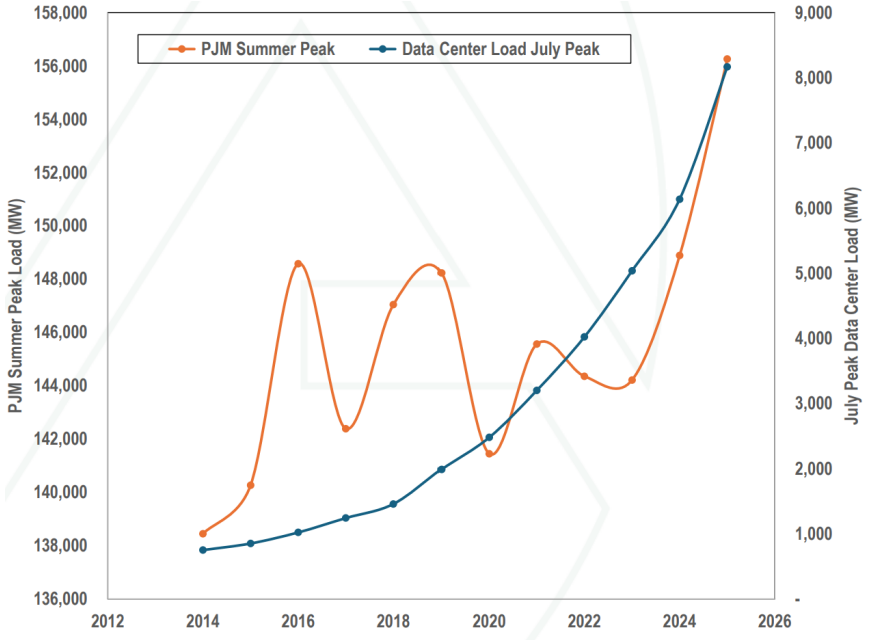
[46] 2026 LTLF Data

[47] "The PJM Market Monitoring Unit [is] responsible for promoting a robust, competitive and nondiscriminatory electric power market in PJM by implementing the PJM Market Monitoring Plan." https://www.monitoringanalytics.com/company/about.shtml

[48] https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2026/20260819/20260819-item-06---rcstf-imm-proposal---presentation.pdf

blue line. Viewed together, it is evident that data center demand has reached a scale at which it is increasingly contributing to, and, in some instances, materially influencing, the region's peak electricity demand.

Figure 5: PJM Summer Peak and Data Center July Peak (IMM)



E. Data Center Demand Projections by EDC

1. PPL Electric Utilities Corporation (PPL Electric)

In the 2026 EPO Report, the PUC found for PPL Electric:

> Over the next five years, **total energy usage is projected to increase at an average annual rate of 20.51%**. This includes a residential usage average annual increase of 0.01%, commercial usage increase of 0.10%, and **industrial usage increase of 51.05%** […] PPL [Electric] has projected a substantial increase in industrial usage and peak load […] Note that this is almost entirely due to the onboarding of large data centers. PPL [Electric]'s demand and peak load growth due to data centers is by far the largest of any of the PA EDCs.[49]

[49] 2026 EPO Report, p. 49 and n. 79 (PPL's projections and additions due to data center load have been documented in the *PJM Load Forecast Report January 2025*, available at https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-loadreport.ashx, and supporting documents, available at: https://www.pjm.com/planning/resource-adequacy-planning/loadforecast-dev-process.aspx.) (emphases added).

Again, while the PUC classified the data center demand growth as industrial usage, the PUC also explained that the industrial usage increase is almost exclusively due to the interconnection of large data centers. **Figure 6** (Figures 23 and 24 from the 2026 EPO Report) are shown below.[50, 51] The 2026 EPO Report specifically notes that the scale of this figure "does not allow for the full growth of the industrial usage (over 94,141 GWh by 2030) to be shown" due to the amount of growth forecast.

[50] 2026 EPO report, p. 50.
[51] https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2026/20260819/20260819-item-06---rcstf-imm-proposal---presentation.pdf

Figure 6: PPL Electric Energy Usage (GWh) and Peak Load (MW) (PUC)

Figure 23: PPL Electric Utilities Corporation energy usage (GWh) (see note above)

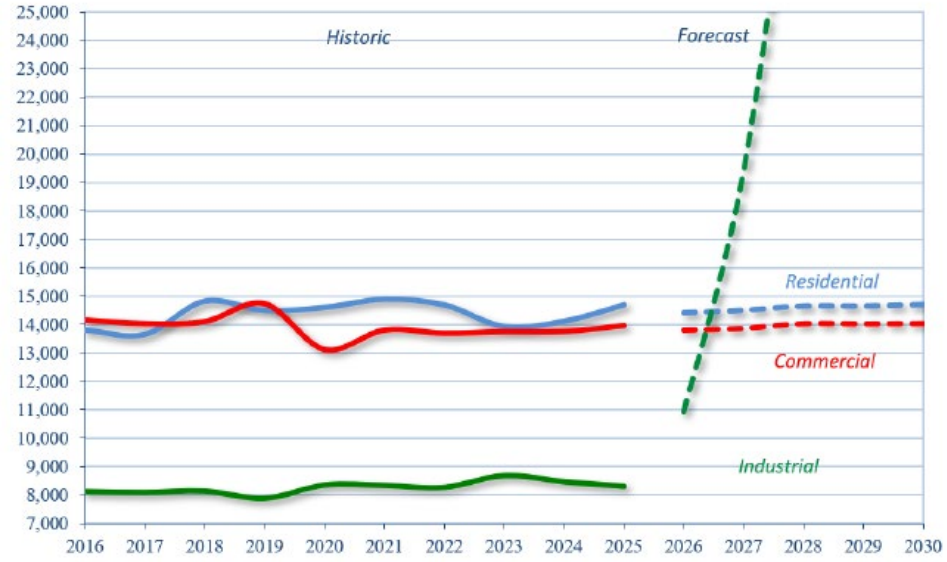
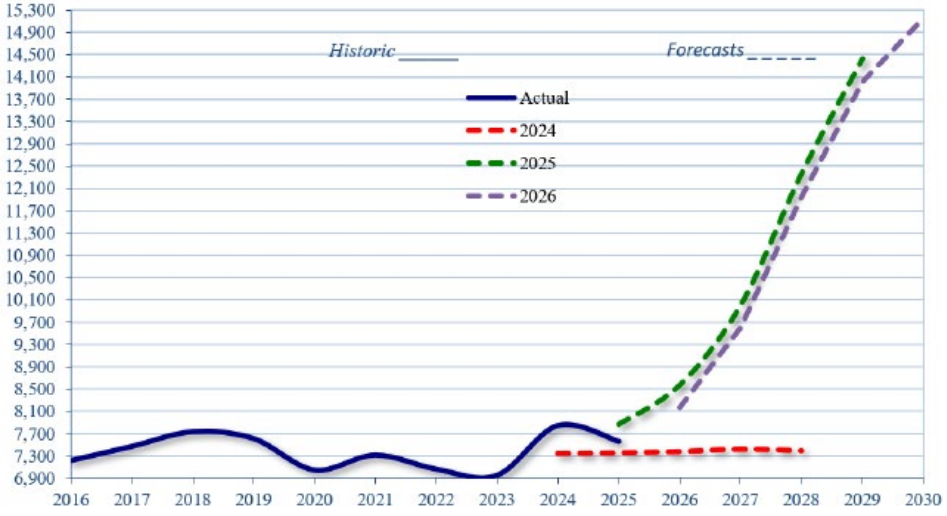


Figure 24: PPL Electric Utilities Corporation peak load (MW)



In the Act 45 Annual Report, the PUC explained regarding PPL Electric:

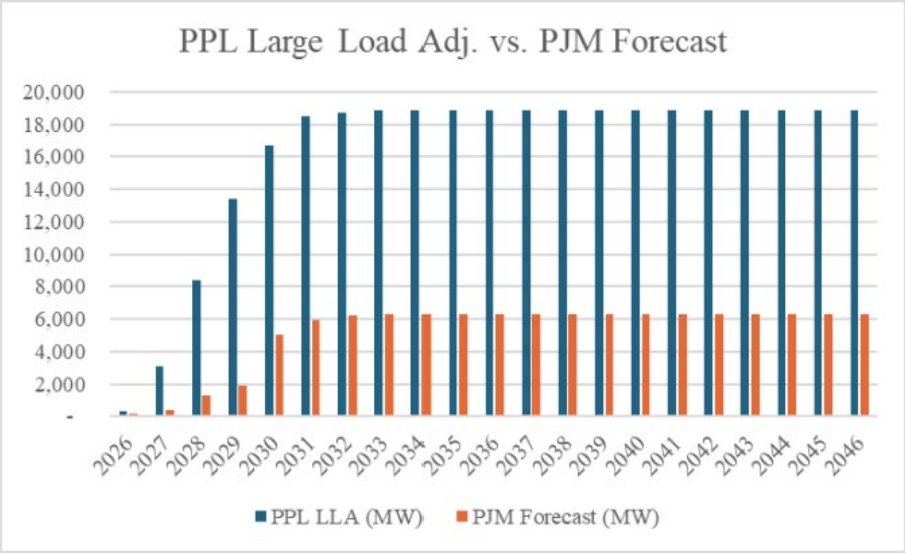
PPL [Electric]'s forecasting methodology is described in its large load adjustment request submitted to PJM. PPL [Electric] indicated that load is included in its forecast after a letter of authorization (LOA) is executed with a retail customer. The LOA includes monetary penalties if the customer cancels the project. PPL [Electric] avers that this approach excludes speculative projects and aligns with PJM's requirements for defensible forecasts. PPL [Electric] then works with the retail customer to finalize the details of an electric services agreement and construction

> service agreement (CC/ESO equivalent). PPL [Electric] assumes an 80% utilization factor consistent with ESA minimum demand payment obligations. In its LTLF, PJM reduced PPL [Electric]'s large load adjustment request by discounting all projects with a signed LOA to 0 MW prior to 2031 and applying a 33% discount factor to load estimated beyond 2031.[52]

The PUC reported that PJM significantly discounted PPL Electric's large load adjustment forecast (by over 8,000 MW in 2030 and 8,800 MW in 2035) in part due to PPL Electric's inclusion of speculative load in its forecast.[53] **Figure 7** (Figure 13 in Appendix B from the Act 45 Annual Report) is shown below.[54]

Figure 7: PPL Electric Large Load Adj. vs. PJM (PUC)

Figure 13: PPL



2. PECO Energy Company (PECO)

In the 2026 EPO Report, the PUC found for PECO:

> Over the next five years, total energy usage is projected to increase at an average annual rate of 2.28%. This includes a residential usage average annual increase of 0.55%, commercial usage average annual decrease of -0.02%, and **an industrial usage increase of 5.26%** as shown in Figure 21 below.[55]

[52] Act 45 Annual Report, p. 14.
[53] Act 45 Annual Report, p. 18.
[54] Act 45 Annual Report, App'x B, Figure 13, p. 37.
[55] 2026 EPO Report, p. 47 (emphasis added).

While the PUC classified the data center demand growth as industrial usage, I assume this growth of 5.26% is due almost exclusively due to the interconnection of large data centers. **Figure 8** (Figures 21 and 22 from the 2026 EPO Report) is shown below.[56]

Figure 8: PECO Energy Usage (GWh) and Peak Load (MW) (PUC)

Figure 21: PECO Energy Company energy usage (GWh)

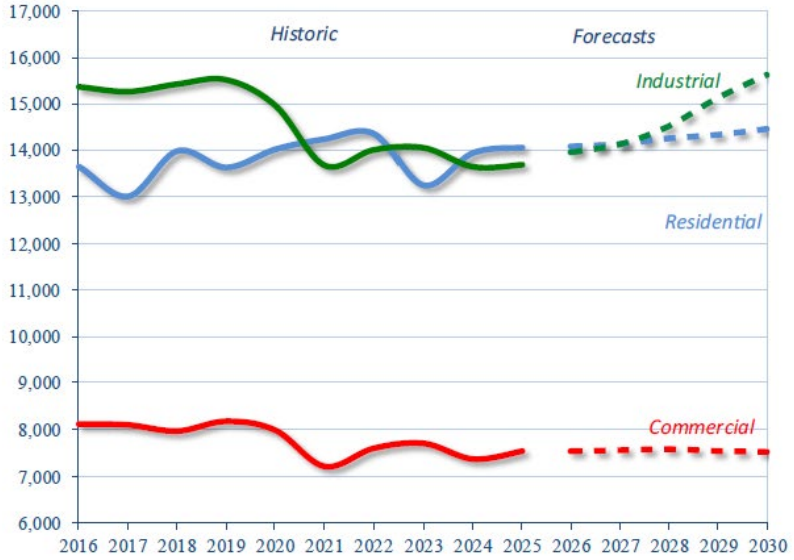
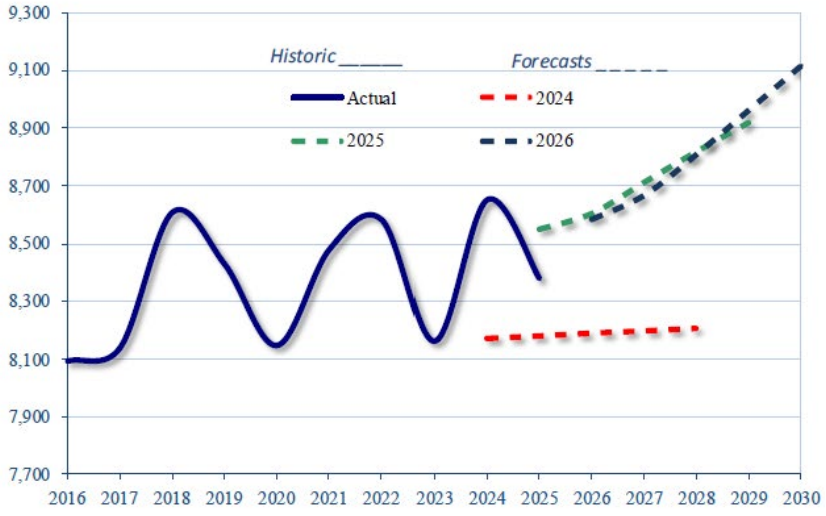


Figure 22: PECO Energy Company peak load (MW)



[56] 2026 EPO Report, p. 48.

In the Act 45 Annual Report, the PUC found as to PECO:

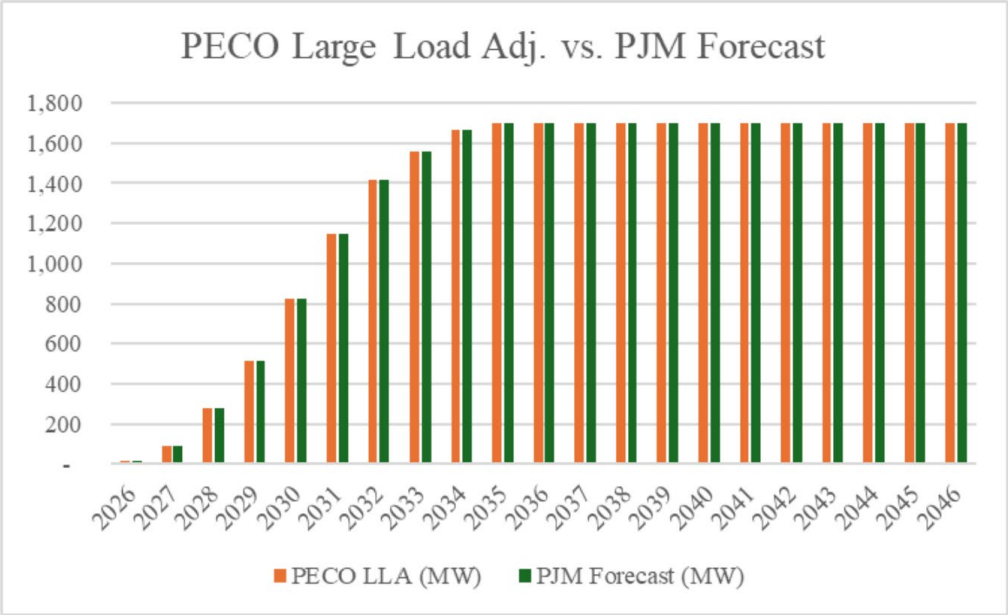
> PECO indicated that its load forecast includes projects that have signed engineering agreements with financial deposits, i.e., equivalent to a CC/ESO. PECO also considers whether the customer project has been submitted, or is expected to be submitted by year-end, to the Transmission Expansion Advisory Committee (TEAC) at PJM through the FERC-approved M-3 procedure.[57] PECO averred that this approach establishes a certainty criterion that "draws a line" and excludes more prospective large load projects, which have expressed interest in coming to its service territories but have not made firm commitments. It was also noted that of roughly 65 GW in total customer-requested capacity across Exelon, PECO's parent company, approximately 45 GW of less-certain project capacity is excluded from the forecast submitted to PJM. To further refine its forecast, PECO applies a linear ramp assumption over a 5-year to 8-year period beginning from each project's estimated in-service date. Final forecasted demand is translated from customer-requested capacity by using an assumed utilization rate of 70% applied to the original capacity request.[58]

The PUC reported that PJM did not significantly adjust PECO's large load adjustment request in its LTLF. **Figure 9** (Figure 12 in Appendix B of the Act 45 Annual Report) depicts PECO's large load adjustment submittal and PJM's resulting adjustments and is shown below.[59]

[57] The next section of this affidavit focuses on the M-3 process at PJM. Transmission Owners present (1) asset management projects, (2) supplemental projects, and (3) any other transmission expansion or enhancement of Transmission Facilities that is not planned by PJM to the Transmission Expansion Advisory Committee (TEAC) and to the Subregional RTEP (SRRTEP) Committees, which are stakeholder groups guided by PJM.
[58] Act 45 Annual Report, pp. 13-14.
[59] Act 45 Annual Report, App'x B, Figure 13, p. 37.

Figure 9: PECO Large Load Adj. vs. PJM (PUC)

Figure 12: PECO



3. FirstEnergy Pennsylvania Electric Company (FE PA)

By the Order entered on Dec. 7, 2023, at Docket Nos. A-2023-3038771, *et al*., the PUC granted certain approvals and certificates of public convenience for the unification of the four FirstEnergy Company EDCs that operate in Pennsylvania (Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company) into one EDC, FirstEnergy Pennsylvania Electric Company (FE PA). In order to avoid confusion, the FE PA rate districts are discussed below separately, similar to how the PUC discusses them separately in the 2026 EPO Report and the Act 45 Annual Report.

a. Metropolitan Edison Company (Met-Ed)

In the 2026 EPO Report, the PUC found for Met-Ed:

> Over the next five years, total energy usage is projected to increase at an average annual rate of 0.50%. This includes a residential usage average annual increase of 0.93%, commercial usage increase of 0.37%, and industrial usage increase of 0.08% as shown in Figure 13 below.
>
> Met-Ed's highest peak load in 2025 was 3,003 MW. This represents a YOY decrease

of 2.28% from the previous year's peak of 3,073 MW. The five-year peak load forecast is projected to increase by 0.13% each year as shown in [the figure] below.[60]

Figure 10: Met-Ed Energy Usage (GWh) and Peak Load (MW) (PUC)

Figure 13: Met-Ed energy usage (GWh)

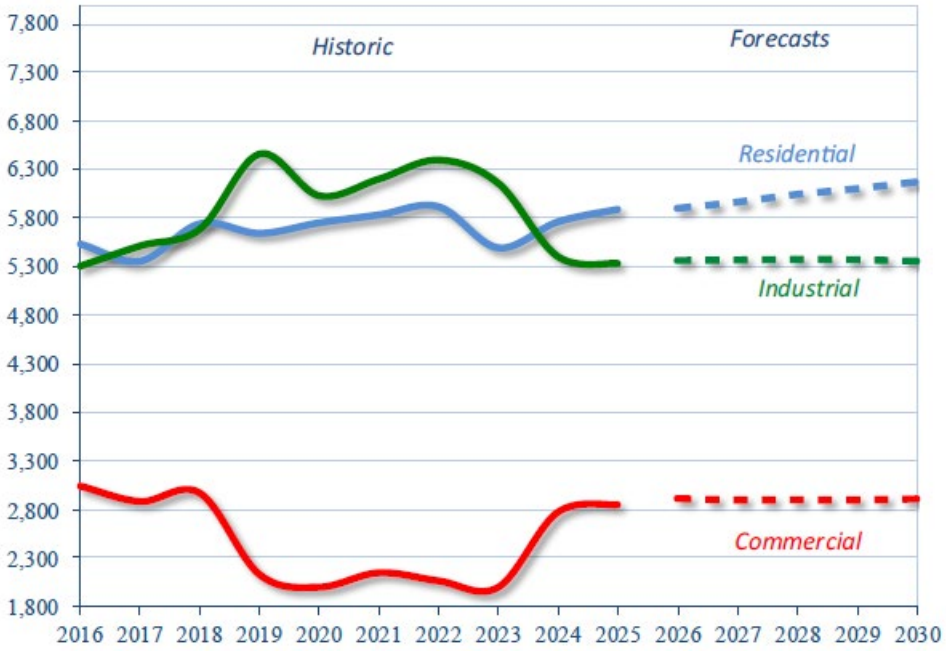
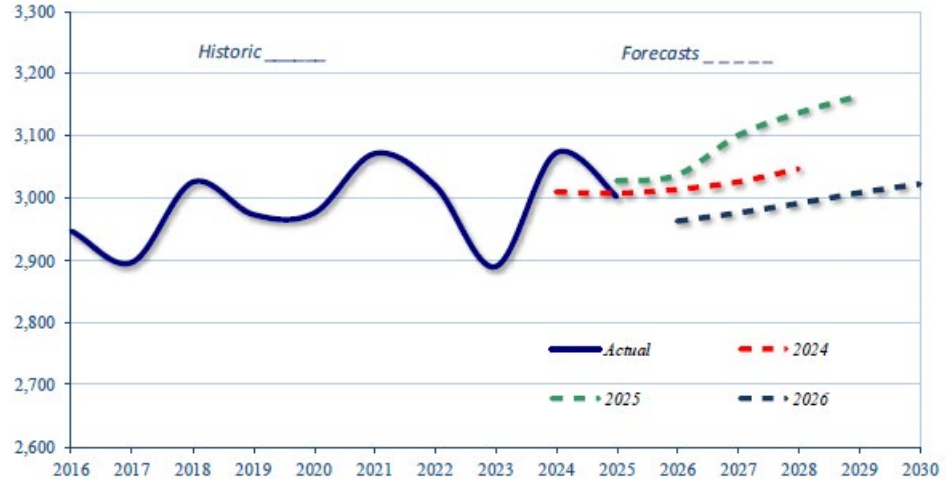


Figure 14: Met-Ed peak load (MW)



In the Act 45 Annual Report, the PUC found for Met-Ed:

Met-Ed is considered PJM's Metropolitan Edison zone (METED). FE PA's large load adjustment submittal to PJM for Met-Ed consisted of 1,000 MW for one project with

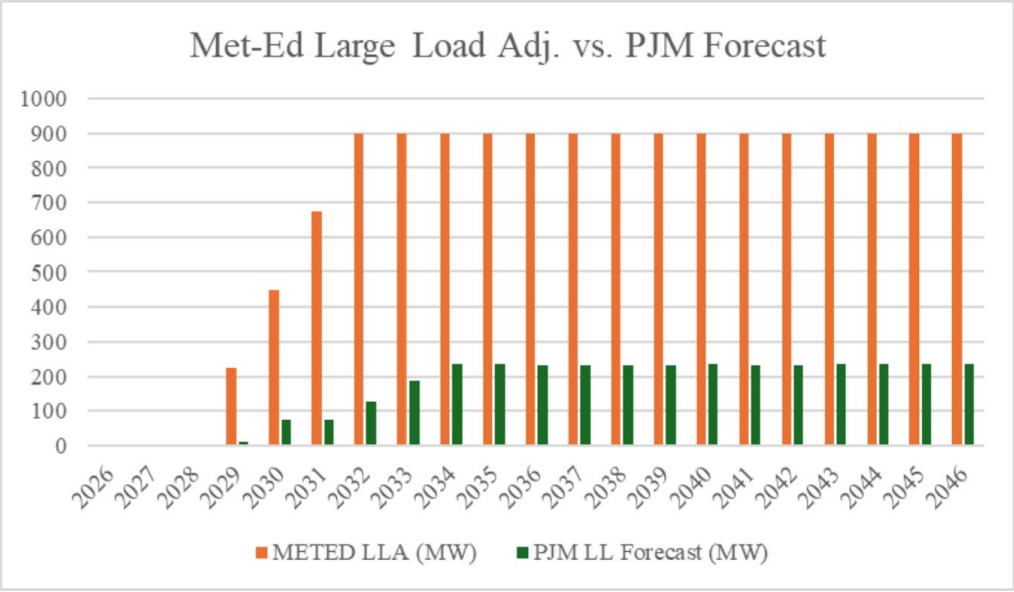
[60] 2026 EPO Report, p. 39-40.

a four-year ramp starting in 2029 at 250 MW. PJM discounted this load to 10 MW in 2029, ramping up to 234 MW over six years. A graph depicting Met-Ed's large load adjustment submittal and PJM's resulting adjustments is provided as Figure 9 in Appendix B of this report.[61]

Figure 11 (Figure 9 in Appendix B of the Act 45 Annual Report) depicts Met-Ed's large load adjustment submittal and PJM's resulting adjustments and is shown below.[62]

Figure 11: Met-Ed Large Load Adj. vs. PJM (PUC)

Figure 9: Met-Ed



b. Pennsylvania Electric Company (Penelec)

In the 2026 EPO Report, the PUC found for Penelec:

Over the next five years, total energy usage is projected to decrease at an average annual rate of -0.12%. This includes a residential usage average annual increase of 0.37%, commercial usage increase of 0.18%, and industrial usage decrease of -1.23%, as shown in Figure 15 below.

Penelec's highest peak load in 2025 was 2,895 MW. This represents a YOY increase of 4.78% from the previous year's peak of 2,953 MW. The five-year peak load forecast is projected to decrease by an average of -0.05% per year as shown in Figure 16 below.[63]

[61] Act 45 Annual Report, p. 14-15 (citations omitted).
[62] Act 45 Annual Report, App'x B, Figure 9, p. 33.
[63] 2026 EPO Report, p. 41.

The PUC did not find forecasted data center demand growth in Penelec.

Figure 12 (Figures 15 and 16 from the PUC's 2026 EPO Report) is shown below.[64]

Figure 12: Penelec Energy Usage (GWh) and Peak Load (MW) (PUC)

Figure 15: Penelec energy usage (GWh)

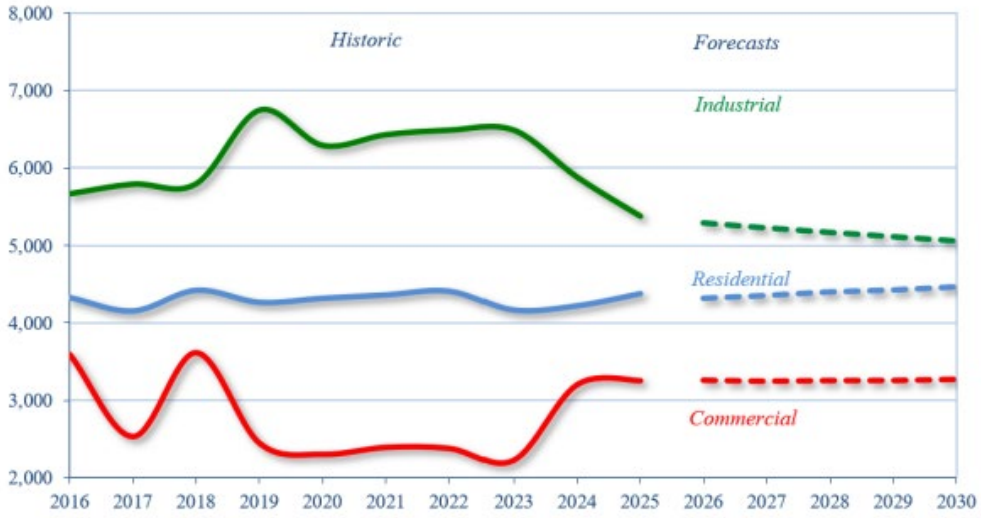
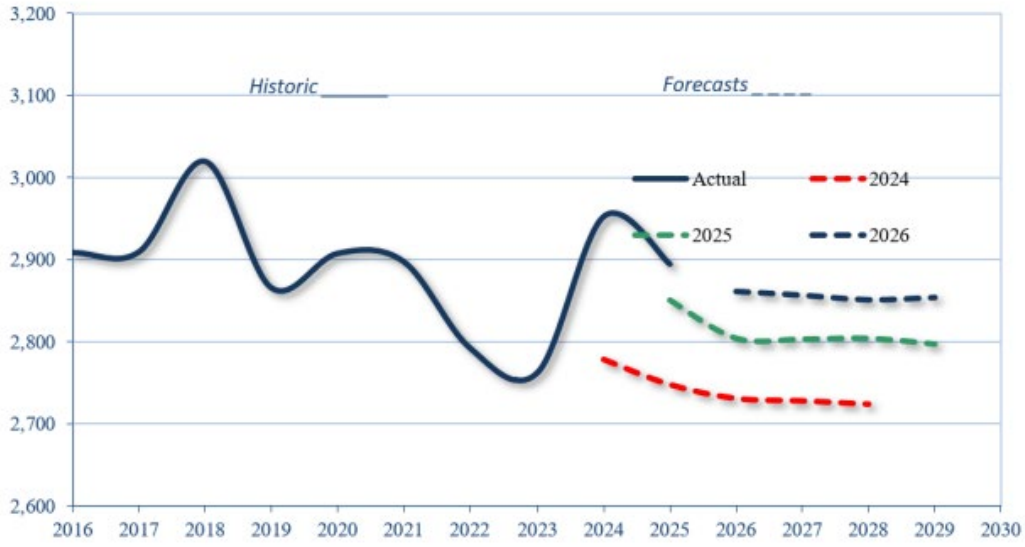


Figure 16: Penelec peak load (MW)



In the Act 45 Annual Report, the PUC found for Penelec:

FE PA did not include a large load adjustment for Penelec in its large load

[64] 2026 EPO Report, p. 42.

adjustment submittal to PJM.[65]

Accordingly, the PUC reported that PJM did not adjust PECO's large load adjustment request in its LTLF.

c. Pennsylvania Power Company (Penn Power)

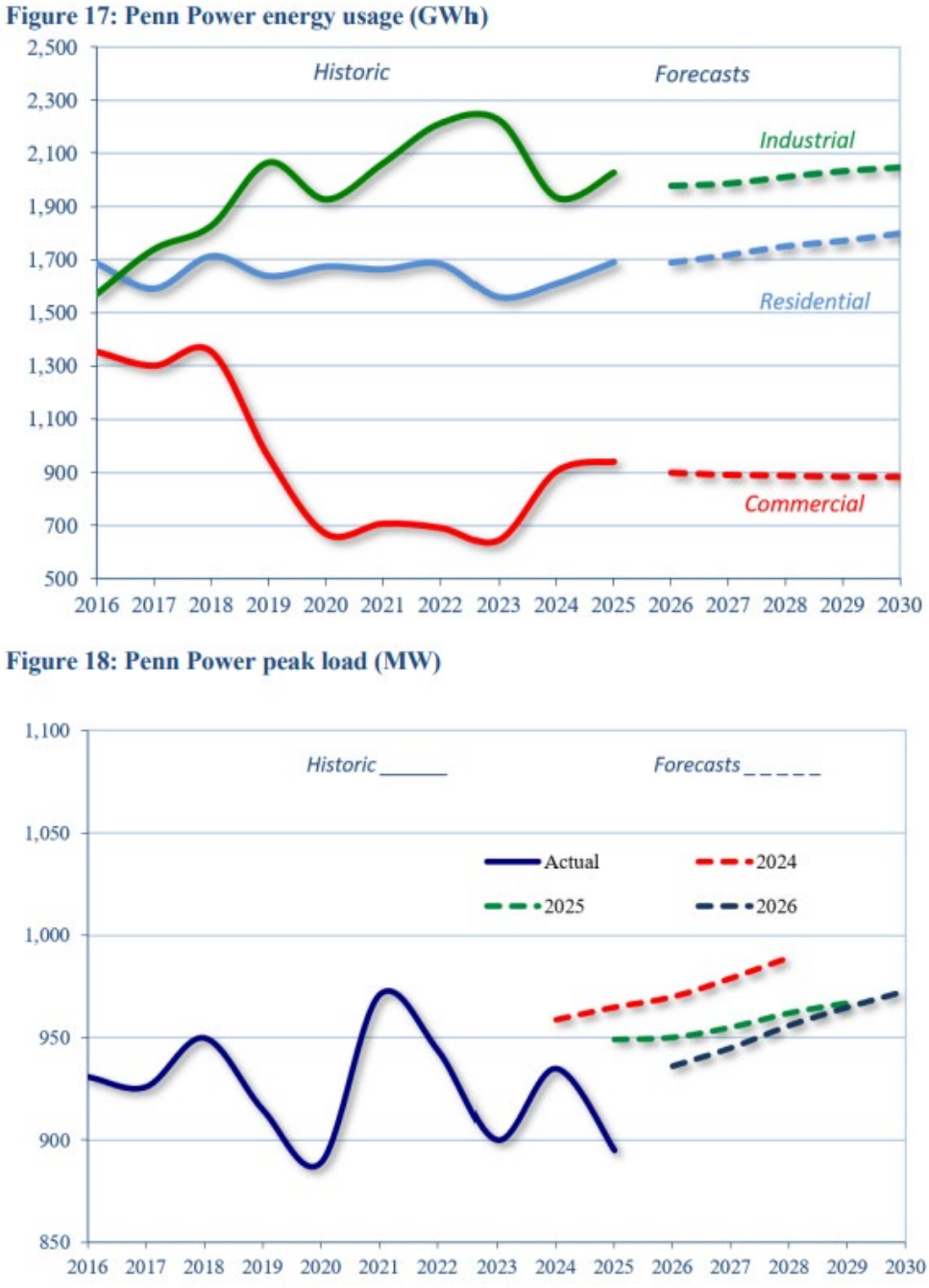
In the 2026 EPO Report, the PUC found for Penn Power:

> Over the next five years, total energy usage is projected to increase at an average annual rate of 0.31%. This includes residential usage increasing at an average annual rate of 1.26%, a commercial average annual usage decrease of -1.21%, and an industrial usage increase of 0.19% as shown in Figure 17 below.
>
> Penn Power's highest peak load in 2025 was 935 MW. This represents a YOY increase of 3.89% from the previous year's peak of 900 MW. The five-year peak load forecast is projected to increase by an average of 0.80% per year as shown in Figure 18 below.[66]

Figure 13 (Figures 17 and 18 from the PUC's 2026 EPO Report) is shown below.[67]

[65] Act 45 Annual Report, p. 15.
[66] 2026 EPO Report, p. 43.
[67] 2026 EPO Report, p. 44.

Figure 13: Penn Power Energy Usage (GWh) and Peak Load (MW) (PUC)



In the Act 45 Annual Report, the PUC found for Penn Power:

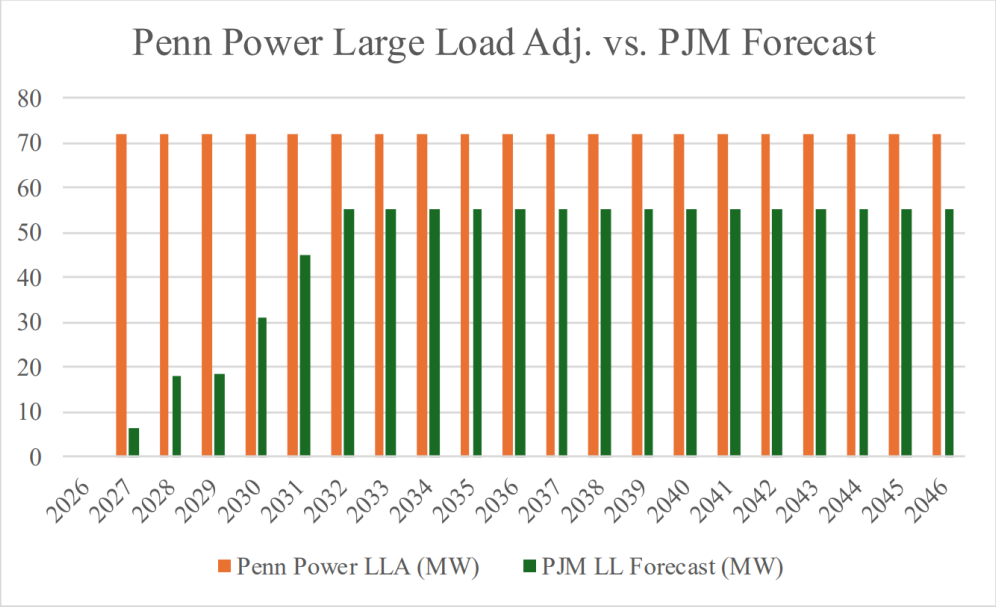
Penn Power is part of PJM's American Transmission Systems, Inc. zone (ATSI). FE PA's large load adjustment submittal to PJM for Penn Power included 80 MW for one project. PJM adjusted this load to 6.3 MW in 2027, ramping up to approximately 55 MW by 2032. A graph depicting Penn Power's large load adjustment submittal and

PJM's resulting adjustments is provided as Figure 10 in Appendix B of this report.[68]

The PUC reported that PJM adjusted Penn Power's large load adjustment request from 80 MW to approximately 6 MW in 2027 and ramping to 55 MW by 2032 in its LTLF. **Figure 14** (Figure 10 in Appendix B of the Act 45 Annual Report) depicts Penn Power's large load adjustment submittal and PJM's resulting adjustments and is shown below.[69]

Figure 14: Penn Power Large Load Adj. vs. PJM (PUC)

Figure 10: Penn Power



d. West Penn Power Company (West Penn)

In the 2026 EPO Report, the PUC found for West Penn:

> Over the next five years, total energy usage is projected to increase at an average annual rate of 0.08%. This includes a residential usage average annual increase of 0.74%, commercial usage decrease of -0.40%, and industrial usage decrease of -0.20%. See Figure 19 below.
>
> West Penn's highest peak load in 2025 was 3,912 MW. This represents a YOY increase of 0.98% from the previous year's peak of 3,874 MW. The five-year peak load forecast is projected to decrease by an average of -0.85% per year as shown in Figure 20

[68] Act 45 Annual Report, p. 15 (citations omitted).
[69] Act 45 Annual Report, App'x B, Figure 9, p. 34.

below.[70]

Figure 15 (Figures 19 and 20 from the PUC's 2026 EPO Report) is shown below.[71]

Figure 15: West Penn Energy Usage (GWh) and Peak Load (MW) (PUC)

Figure 19: West Penn energy usage (GWh)

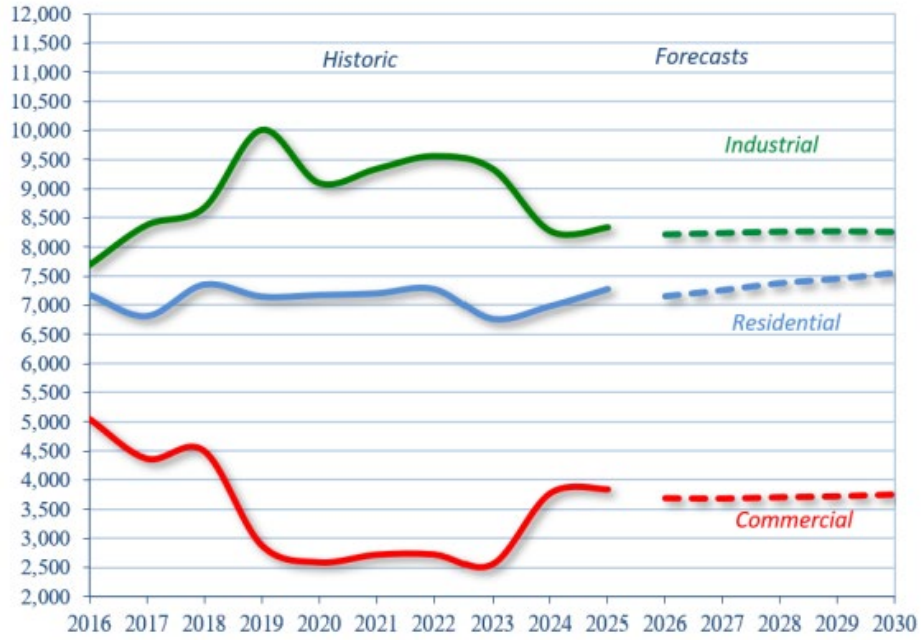
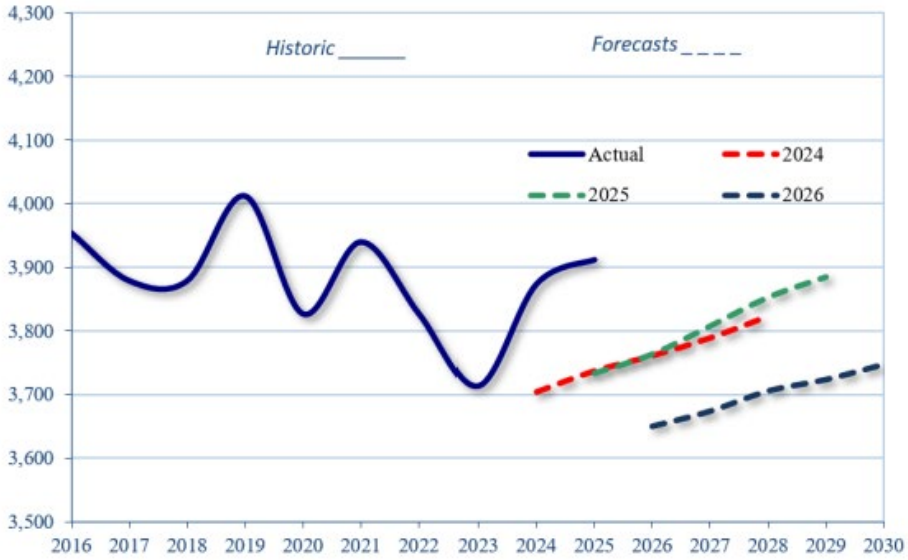


Figure 20: West Penn peak load (MW)



[70] 2026 EPO Report, p. 45.
[71] 2026 EPO Report, p. 46.

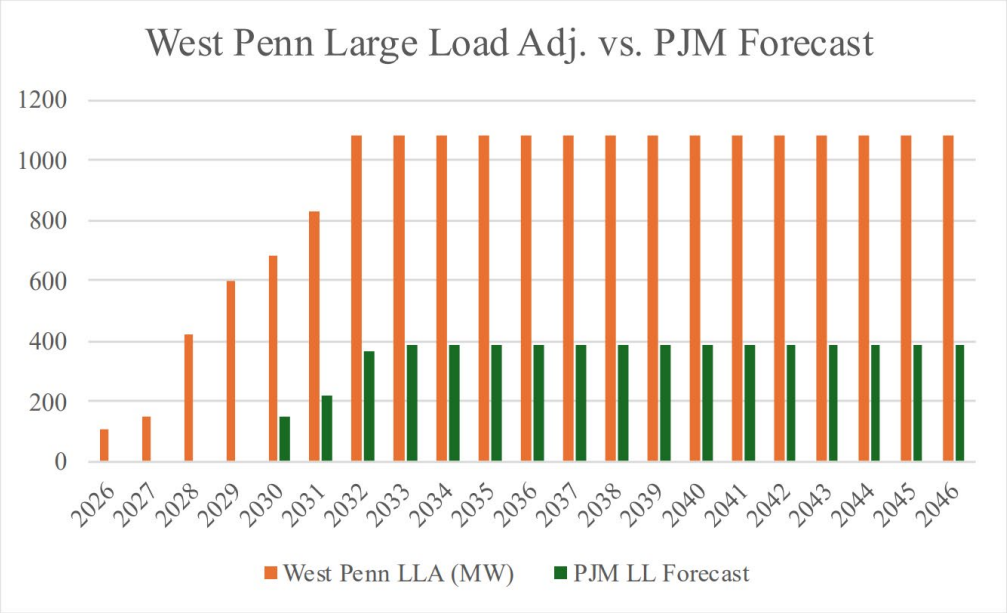
In the Act 45 Annual Report, the PUC found for West Penn:

> FE PA's West Penn is part of PJM's Allegheny Power zone (APS). FE PA's large load adjustment submittal to PJM for West Penn included seven projects totaling 1,240 MW. 47 PJM adjusted this load in its forecast to approximately 150 MW starting in 2030, ramping up to approximately 386 MW by 2033. A graph depicting West Penn's large load adjustment submittal and PJM's resulting adjustments is provided as Figure 11 in Appendix B of this report.[72]

The PUC reported that PJM adjusted West Penn's large load adjustment request from 1,240 MW to approximately 150 MW in 2030 and ramping to 386 MW by 2033 in its LTLF. **Figure 16** (Figure 11 in Appendix B of the Act 45 Annual Report) depicts West Penn's large load adjustment submittal and PJM's resulting adjustments and is shown below.[73]

Figure 16: West Penn Large Load Adj. vs. PJM (PUC)

Figure 11: West Penn



4. Duquesne Light Company (Duquesne)

In the 2026 EPO Report, the PUC found for Duquesne:

[72] Act 45 Annual Report, p. 15 (citations omitted).
[73] Act 45 Annual Report, App'x B, Figure 9, p. 35.

Duquesne notes that its customer base is projected to grow at a compound annual growth rate of 0.3% between 2026 and 2045. However, its total net energy sales are projected to decline at a compound annual growth rate of 0.3% between 2026 and 2045. Over the next five years, total energy usage is projected to increase at an average annual rate of 2.2%. This includes a residential usage average annual increase of 1.19%, commercial usage increase of 2.08%, and an industrial usage increase of 4.15%, as shown in Figure 11 below.[74]

Figure 17 (Figures 11 and 12 as they appear in the PUC's 2026 EPO Report) is shown below.[75]

Figure 17: Duquesne Energy Usage (GWh) and Peak Load (MW) (PUC)

Figure 11: Duquesne energy usage (GWh)

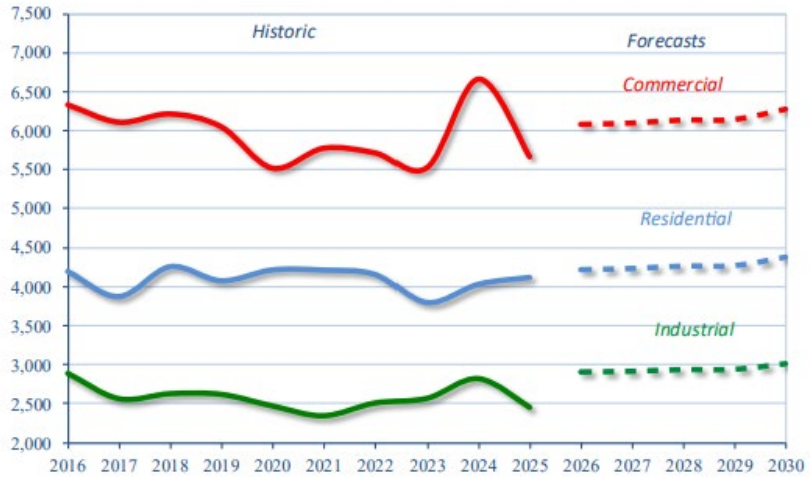
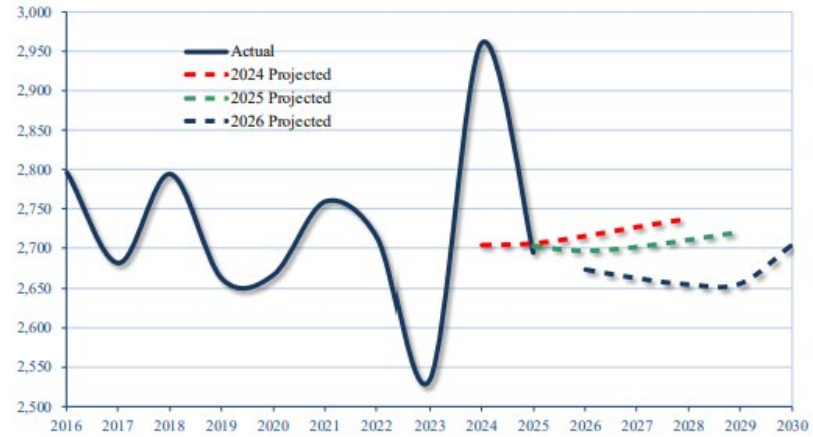


Figure 12: Duquesne peak load (MW)



[74] 2026 EPO Report, p. 36-37.
[75] 2026 EPO report, p. 38.

In the Act 45 Annual Report, the PUC explained regarding Duquesne:

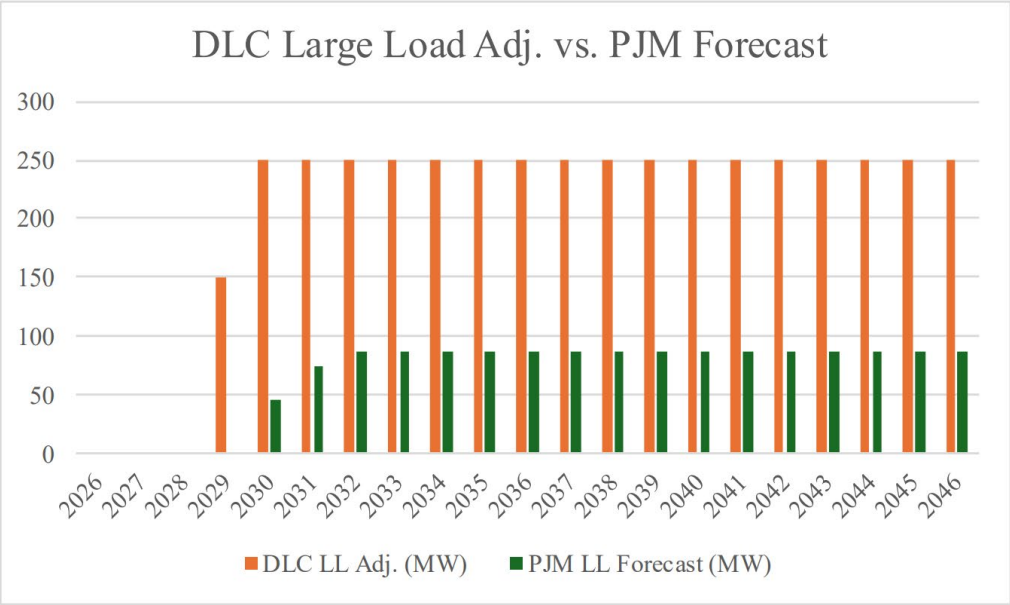
> DLC's Large Load Adjustment Methodology, included in its response to the TUS Data Request, indicated that DLC only includes loads in its large load adjustment for projects that have completed an initial interconnection study and have been presented to PJM stakeholders as part of the M-3 process. Projects that reach this milestone have: 1) funded all interconnection study costs; 2) demonstrated control of the property; 3) provided sufficient technical information about the project; and 4) indicated that the developer has been informed of the costs they would be required to fund to be interconnected. DLC's large load adjustment submitted to PJM in 2025 represents the addition of a single large load within PJM's Duquesne Light Company zone, sized to reflect the most mature request going through its interconnection process. However, DLC noted that it has received eight interconnection applications, which together represent over three (3) gigawatts (GW) of potential load.
>
> DLC's Large Load Adjustment Request Summary identified a load adjustment of 250 MW, consisting of an initial 75 MW at the start of 2029, an additional 75 MW coming online six months later, and the full 250 MW in 2030. PJM accounted for this load in its Total Adjustment to Summer Peak Load as 46 MW in 2030, 75 MW in 2031, and 87 MW in 2032 through 2046. A graph depicting DLC's Large Load Adjustment Request and PJM's resulting adjustments is provided as Figure 8 in Appendix B of this report.[76]

The PUC reported that PJM discounted Duquesne's large load adjustment forecast from 250 MW to 46 MW in 2030. **Figure 18** (Figure 8 in Appendix B of the Act 45 Annual Report) depicts Duquesne's large load adjustments submittal and PJM's resulting adjustments and is shown below.[77]

[76] Act 45 Annual Report, p. 13.
[77] Act 45 Annual Report, App'x B, Figure 8, p. 32.

Figure 18: Duquesne Large Load Adj. vs. PJM (PUC)

Figure 8: Duquesne Light Company



5. UGI Utilities, Inc. – Electric Division (UGI)

In the 2026 EPO Report, the PUC found for UGI:

Over the next five years, total energy usage is projected to decrease at an average annual rate of -0.19%. This includes a residential average annual decrease of 0.19%, commercial usage decrease of 0.33%, and an industrial increase of 0.38%.

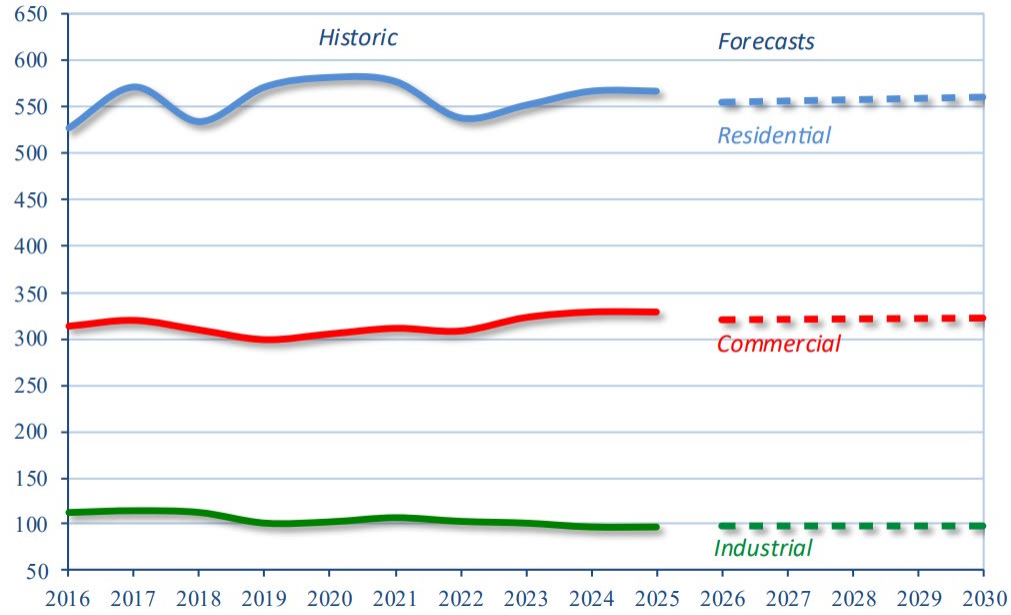
UGI's highest peak load in 2025 was 217 MW, which is unchanged from the previous year's peak of 217 MW. The five-year peak load forecast is projected to decrease by an average of -1.42% per year.[78]

Figure 19 (Figure 27 from the PUC's 2026 EPO Report) is shown below.[79]

[78] 2026 EPO Report, p. 53.
[79] 2026 EPO Report, p. 53.

Figure 19: UGI Energy Usage (GWh) and Peak Load (MW) (PUC)

Figure 27: UGI Utilities Inc. energy usage (GWh)



In the Act 45 Annual Report, the PUC found Pennsylvania's four smaller EDCs (Citizens' Electric Company, Pike County Light and Power, Wellsboro Electric Company, and UGI Utilities Inc. – Electric Division) reported to the PUC that they did not file a large load adjustment forecast with PJM in 2025.[80] The PUC thus did not report specific findings for UGI or the other smaller EDCs in relation to PJM adjustments to large load adjustment requests in its LTLF.

6. 2027 Load Forecast

On September 29, 2026, the PJM Load Analysis Subcommittee (LAS) met to review the annual large load adjustments submitted by EDCs to begin the process to create the 2027 LTLF. Again, the LAS prepares and reviews PJM reports and technical analyses and coordinates information related to electric peak demand and energy forecasts (including large loads). This affidavit is focused on information from prior LTLFs as the information presented on 9/29/2026

[80] Act 45 Annual Report, p. 12.

is quite preliminary. While I am still in the middle of reviewing these EDC preliminary submissions in more detail, discussions at this meeting supported the following findings.

- First, the EDC large-load forecasts remain large. For example, PPL Electric submitted a large load forecast adjustment for 12,764 MW by 2030.[81] In the prior annual submission, PPL Electric requested 13,343 MW by 2030.[82] With this submission, PJM will be relied on once more to vet the request and adjust it to a level that more accurately reflects certain, non-speculative demand.
- Second, the large load forecast adjustments continued to change which reflects their inherent uncertainty, even after extensive review by PJM, the PUC, and PJM stakeholders in previous load forecasts. For example, PECO submitted a large load forecast adjustment for 1,084 MW in 2030 on 9/29/2026 versus the submission of 1.7 GW in the previous load forecast.[83, 84]
- Third, although the EDC presentations were informative, details regarding methodologies are varied, which indicates an optimized standard approach has not been developed. For example, the methodologies presented by PECO (Exelon), Duquesne, PPL Electric and FirstEnergy differ in terminology and approach.[85] If these methodologies are consistent or comparable across Pennsylvania, it is not clear. This inconsistency justifies the need for discovery to understand exactly how the EDCs determine their large load forecasts and adjustments over time.

[81] https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2026/20260929/20260929-item-5e---ppl.pdf
[82] Act 45 Annual Report, p. 31.
[83] https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2026/20260929/20260929-item-5i---exelon.pdf
[84] https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2025/20250916/20250916-item-04d---exelon-large-load-request.pdf
[85] For example, see p. 3 at https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2026/20260929/20260929-item-5g---duquesne.pdf or p. 3 at https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2026/20260929/20260929-item-5i---exelon.pdf

- Finally, Relevant Electric Retail Regulatory Authority (RERRA) review (in Pennsylvania, the PUC) was vague and not highly transparent. This suggests a need for a uniform EDC large load forecasting process as discussed by OCA Witness Matthew Hoyt in his affidavit.

F. Summary of the Data Center Load Forecasting Issues

Pennsylvania & PJM

- Consumer demand for electricity and the forecast of "coincident peak load" drives the planning and construction of energy infrastructure, including distribution, transmission, battery storage, generation supply, and demand response infrastructure and resources.
- Accurate load forecasts are important because inaccurate or inflated forecasts can lead to an overbuilding of energy infrastructure with associated costs.
- Based on load forecasts, the total annual average aggregate five-year energy usage for Pennsylvania utility consumers is expected to increase significantly, mostly due to the increased demand in electricity from data centers.[86] In 2026, the PUC found that annual electricity consumption is expected to increase overall to 7.85% per year, driven mainly by an increase in data center demand growth of approximately 18.56% for the five-year period of 2025-2030.[87]
- Based on load forecasts, the peak load in Pennsylvania is expected to increase by at least 6,123 MW by 2030 due to data center activity. This could amount to a 21% increase in statewide electricity peak demand compared to the average peak demand of 29,397 MW over the ten-year period of 2016-2025. An increase of 6,123 MW peak load by 2030 is extraordinary and unprecedented and nearly equal to the entire service territory peak load of the biggest electric utilities in Pennsylvania, PECO and PPL Electric.
- While Pennsylvania is expecting a significant increase in peak load growth by 2030 due to data

[86] 2026 EPO Report, p. 4, 32; 2025 EPO Report, p. 3.
[87] 2026 EPO Report, p. 4, 32.

centers, this extraordinary and unprecedented load growth due to data centers is not unique to Pennsylvania but is something the entire PJM region is experiencing. PJM's 2026 LTLF confirmed that electricity demand from data center growth is still projected to grow up to ~30 GW between 2027 and 2031, during both summer peak (MW) and winter peak.

EDCs of Pennsylvania

- There is a high degree of uncertainty for most EDCs in Pennsylvania as evidenced by the discounting/adjustments made by PJM. The magnitude of the submissions by the EDCs and the discounted/adjusted amounts projected by PJM both reflect substantial load growth and warrant a response from the PUC. OCA Witness Matthew Hoyt addresses how uncertainty calls for specific types of tariff provisions (e.g., security requirements).
- PPL Electric's forecasted load growth that is attributed to data centers is the most substantial in Pennsylvania. The PUC reported that PJM significantly discounted PPL Electric's large load adjustment forecast (a reduction of over 8 GW in 2030 to arrive at approximately 5 GW of incremental peak load in PPL Electric) in its LTLF. With this forecasted load growth from data centers, over the next five years, total energy usage in PPL Electric is projected to increase at an average annual rate of 20.51% per the 2026 EPO Report.[88]
- PECO's forecasted load growth that is attributed to data centers is also substantial. The PUC reported that PJM did not significantly adjust PECO's large load adjustment request in its LTLF. In 2030, the peak load of data centers is forecasted to be approximately 800 MW. With this forecast load growth from data centers, over the next five years, total energy usage is projected to increase at an average annual rate of 2.28% (with industrial usage increase of 5.26%) per the 2026 EPO Report.[89]

[88] 2026 EPO Report, p. 49.
[89] 2026 EPO Report, p. 47.

- FE PA forecasted load growth that is attributed to data centers for three of its four subsidiary companies. FE PA's large load adjustment submittal to PJM for:
    - Met-Ed consisted of 1,000 MW for one project with a four-year ramp starting in 2029 at 250 MW. PJM discounted this load to 10 MW in 2029, ramping up to 234 MW over six years.[90]
    - Penn Power included 80 MW for one project. PJM adjusted this load to 6.3 MW in 2027, ramping up to approximately 55 MW by 2032.[91]
    - West Penn included seven projects totaling 1,240 MW. PJM adjusted this load in its forecast to approximately 150 MW starting in 2030, ramping up to approximately 386 MW by 2033.[92]
- Duquesne also forecasted load growth that is attributed to data centers. The PUC reported that PJM discounted Duquesne's large load adjustment forecast from 250 MW to 46 MW in 2030. Per the 2026 EPO Report, over the next five years, total energy usage is projected to increase at an average annual rate of 2.2% (with industrial usage increase of 4.15%).[93]
- Pennsylvania's four smaller EDCs (Citizens' Electric Company, Pike County Light and Power, Wellsboro Electric Company, and UGI Utilities Inc. – Electric Division) reported to the PUC that they did not file a large load adjustment forecast with PJM in 2025.[94]

IV. Supplemental Transmission Projects at PJM

Transmission Owners present (1) asset management projects, (2) supplemental projects, and (3) any other transmission expansion or enhancement of Transmission Facilities that is not

[90] Act 45 Annual Report, p. 14-15 (citations omitted).
[91] Act 45 Annual Report, p. 14-15 (citations omitted).
[92] Act 45 Annual Report, p. 15 (citations omitted).
[93] 2026 EPO Report, p. 36-37.
[94] Act 45 Annual Report, p. 12.

planned by PJM to the Transmission Expansion Advisory Committee (TEAC) and to the Subregional RTEP (SRRTEP) Committees, which are stakeholder groups guided by PJM.[95] Supplemental projects that are categorized as being driven by "customer service" can be an early indication of a potential or prospective data center. That is, supplemental projects cover transmission level voltage "customer service" where a customer requests interconnection and it is uncommon for any customer other than a large load customer to require transmission upgrades as a condition of service.

In many instances, to my knowledge, the broader electricity community is first made aware of large load additions during a supplemental project presentation given by a Transmission Owner to either a SRRTEP Committee or the TEAC. So, tracking and consolidating these supplemental projects driven by "customer service" then serves as a cross-reference to the load forecast discussed in the previous section. This is a challenging standalone task and the additional task of directly linking supplemental projects associated with data centers to the load forecast is more challenging. This suggests or emphasizes the need for this accounting in the registry proposed in Docket No. ER26-3515.

Pursuant to the Attachment M-3 Process, supplemental projects are presented through the TEAC (230 kV and above facilities) or the SRRTEP Committees (below 230 kV facilities) for review and comment in a three-part meeting process that includes at a minimum (i) an Assumptions Meeting, (ii) a Needs Meeting and (iii) a Solutions Meeting.[96] The Solutions Meetings are followed by a round of comments before the Transmission Owners finalize the Supplemental Projects. The OCA monitors the TEAC and the SRRTEP, including the SRRTEP –

[95] Attachment M-3 https://www.pjm.com/-/media/DotCom/committees-groups/committees/toa-ac/2024/20240613-special/oatt-attachment-m-3-clean-5-31-2024.pdf.
[96] PJM Manual 14b, https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf.

Mid-Atlantic Subcommittee where Pennsylvania EDC transmission projects are in scope.

PJM compiles information presented before TEAC and SRRTEP and maintains a database entitled *Informational Only - M3 Process Needs Status*.[97] The fields in this dataset include:

- Need Number
- Transmission Owner
- PJM Sub-Region
- Need Meeting Date
- Solution Meeting Date
- Local Plan Posting Date
- Local Plan Year
- PJM Upgrade ID
- Withdrawn or Cancellation Date
- Notes
- Project Name
- Problem Statement
- Driver
- Solution Description
- Total Expected Load (MW)

At the start of 2026, I began supplementing this data with the following fields where possible based upon presentations made by transmission owners to the SRRTEP-Mid Atlantic or TEAC:

- **SRRTEP/TEAC** – indicates the committee in which the need is being presented.
- **Data Center** – "Y/N" if the supplemental project relates to a data center.
- **Initial Load (MW)** – reflects the initial load if the supplemental project relates to a data center and if the ramp of the demand is understood.
- **Final Load** – reflects the final load if the supplemental project relates to a data center and if the ramp of the demand is understood.
- **In-Service Date of Load** – the in-service date of the data center if the supplemental project relates to a data center.
- **Solution Cost ($MM) –** estimated cost of the solution associated with the need.
- **PA PUC Docket Number** – if there is an associated proceeding at the PUC.

From this exercise, the new activity presented thus far in 2026 is reflected in **Table 5**.

[97] Most recently: https://www.pjm.com/forms/registration/Meeting%20Registration.aspx?ID={D5A13C0D-3754-4653-9A5A-812E99396339}

Table 5: Supplemental Projects Related to Data Centers in Pennsylvania

Transmission Owner	Data Center Count	Initial Load (MW)	Final Load	Solution Cost ($MM)
APS	1	80	80	$22.8
ATSI	0	0	0	$0.0
DLC	0	0	0	$0.0
MetEd	1	0	1,000	$0.0
PECO	0	0	0	$0.0
Penelec	0	0	0	$0.0
PPL	14	2,515	8,214	$1,072.0
UGI	2	350	700	$201.2
Total	**18**	**2,945**	**9,994**	**$1,296.0**

So, thus far in 2026 alone, $1.3 billion-worth of solutions for needs driven by customer service for data centers in Pennsylvania have been put forth to the TEAC or SRRTEP – Mid-Atlantic.

I reviewed the supplemental projects compiled by PJM in the database entitled *Informational Only - M3 Process Needs Status* which were driven by customer service presented as far back as 2024. **Table 6** indicates that there are 39 supplemental projects amounting to $4.3 billion in transmission solutions that may pertain to data centers in Pennsylvania. This reflects a substantial increase in capital expenditure given the transmission rate base owned by Transmission Owners operating across Pennsylvania was $14.8 billion in 2024.[98] In Table 6, supplemental project data is broken out by the year in which the need was presented.

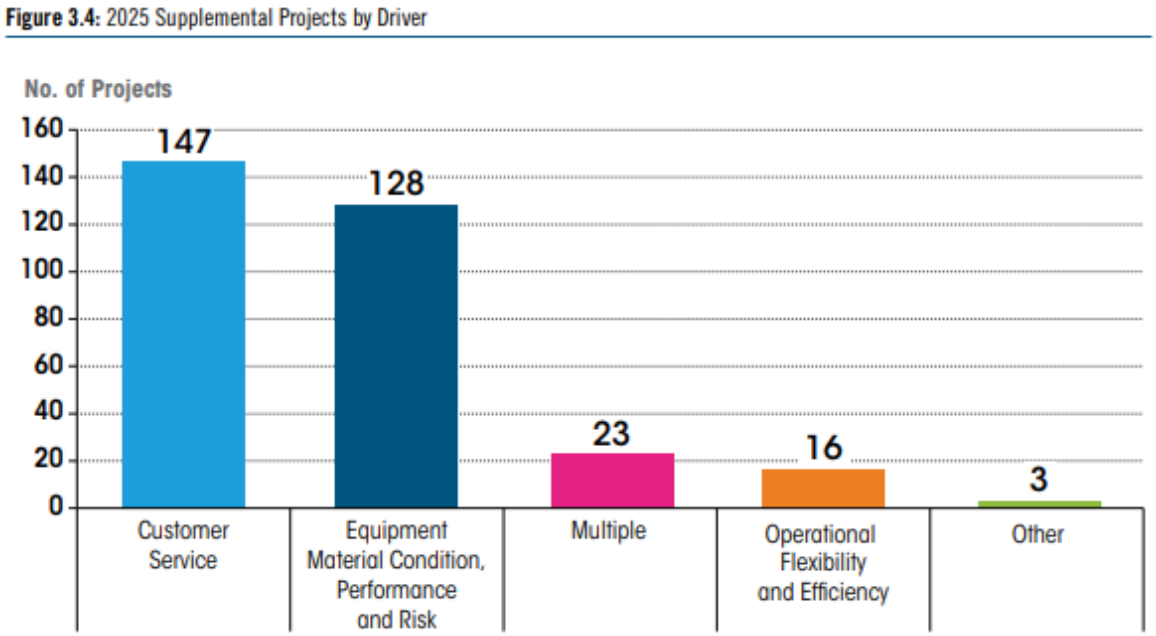
[98] Duquesne Light Co., PECO Energy Co., American Transmission Systems Inc., Mid-Atlantic Interstate Transmission LLC, and PPL Electric Utilities Corp. own the transmission in Pennsylvania. https://www.spglobal.com/market-intelligence/en/news-insights/research/pjm-transmission-growth-rebounds-datacenters-boost-outlook-for-future-expansion

Table 6: Supplemental Projects Driven by "Customer Service" Since 2024 in Pennsylvania

Transmission Zone	Need Number	Final Load In-Service	Solution Cost ($MM)	Load In-Service (MW) 2028	2030	2032	2034
		2026					
APS	APS-2026-004	2028	$ 22.8	80	80	80	80
PPL	UGI-2026-0001	2029	$ 94.0	100	200	200	200
PPL	UGI-2026-0003	2030	$ 107.2		500	500	500
PPL	PPL-2026-0013	2028	$ 28.8	290	290	290	290
PPL	PPL-2026-0001	2032	$ 109.2	200	550	1,500	1,500
PPL	PPL-2026-0002	2033	$ 76.5	100	380	900	1,200
PPL	PPL-2026-0003	2033	$ 81.2	75	300	750	1,500
PPL	PPL-2026-0004	2032	$ 130.6	60	450	1,350	1,350
PPL	PPL-2026-0016	2027	$ 3.3	60	60	60	60
PPL	PPL-2026-0029	2031	$ 408.0	290	500	1,250	1,250
PPL	PPL-2026-0015	2028	$ 65.4	100	100	100	100
PPL	PPL-2026-0037	2031	$ 169.0		225	900	900
			$ 1,296				
		2025					
PECO	PE-2025-001	2029	$ 27.0		50	50	50
PECO	PE-2025-004	2028	$ 180.5	600	600	600	600
PECO	PE-2025-008	2034	$ 174.5		140	140	500
PPL	PPL-2025-0002	2028	$ 141.0	300	350	350	350
PPL	PPL-2025-0003	2033	$ 197.6	960	1,440	1,440	1,980
PPL	PPL-2025-0005	2029	$ 73.5	430	500	500	500
PPL	PPL-2025-0006	2031	$ 159.0	450	920	1,000	1,000
PPL	PPL-2025-0007	2030	$ 89.0	155	450	450	450
PPL	PPL-2025-0008	2029	$ 231.7	300	600	600	600
PPL	PPL-2025-0009	2029	$ 13.5	375	500	500	500
PPL	PPL-2025-0010	2030	$ 88.5	700	1,000	1,000	1,000
PPL	PPL-2025-0012	2030	$ 186.9	700	1,500	1,500	1,500
PPL	PPL-2025-0013	2030	$ 74.9	200	1,200	1,200	1,200
PPL	PPL-2025-0014	2031	$ 220.0	500	900	1,000	1,000
			$ 1,857				
		2024					
DUQ	DLC-2024-003	2029	$ 46.3		250	250	250
PECO	PE-2024-008	2028	$ 7.0	290	290	290	290
PPL	PPL-2024-0001	2032	$ 244.0	540	1,040	1,275	1,275
PPL	PPL-2024-0003	2031	$ 196.6	720	720	1,440	1,440
PPL	PPL-2024-0004	2030	$ 81.0		1,000	1,000	1,000
PPL	PPL-2024-0005	2025	$ 17.8	40	40	40	40
PPL	PPL-2024-0006	2026	$ 9.0	100	100	100	100
PPL	PPL-2024-0010	2028	$ 117.8	350	350	350	350
PPL	PPL-2024-0011	2029	$ 67.5		350	350	350
PPL	PPL-2024-0012	2030	$ 73.3	500	1,000	1,000	1,000
PPL	PPL-2024-0017	2028	$ 242.0	400	400	1,000	1,000
PPL	PPL-2024-0018	2026	$ 2.5	45	45	45	45
PPL	PPL-2024-0019	2026	$ 1.5	50	50	50	50
			$ 1,106				
			$ 4,260	**10,060**	**19,420**	**25,400**	**27,350**

In 2025, $5.8 billion of regionwide solutions to supplemental projects were evaluated by PJM. Customer service – likely data centers – was the main driver per **Figure 20**.[99] Per PJM, the transmission solutions related to customer service totaled $3.4 billion.[100]

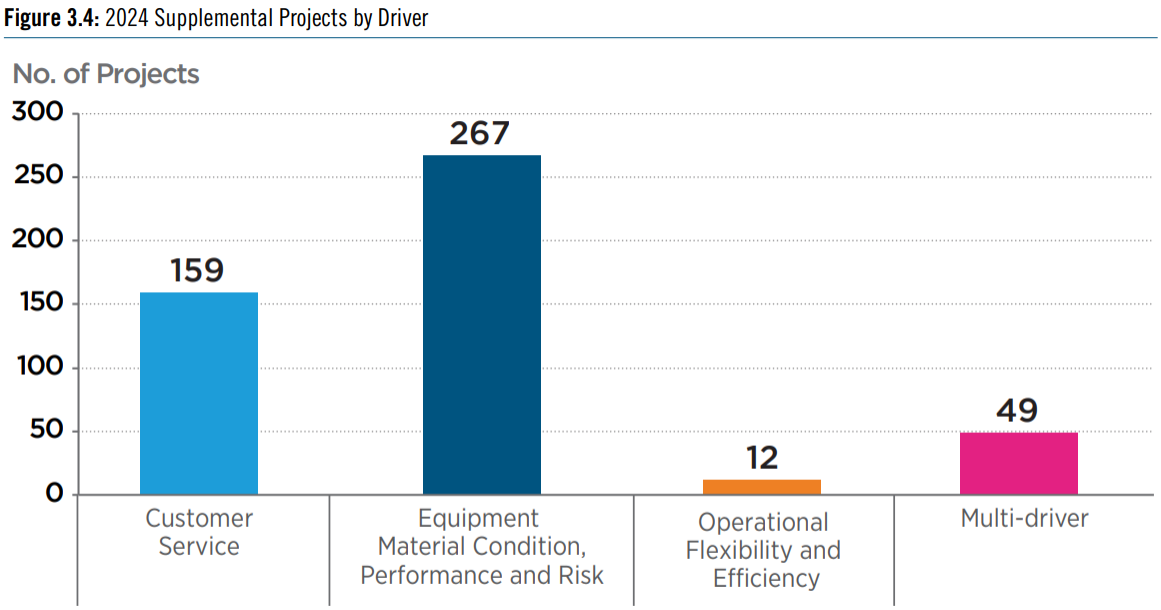
Figure 20: 2025 Supplemental Projects by Driver (RTEP 2025) (PJM)



In 2024, there was a greater number of supplemental projects in total and a greater number of supplemental projects driven by customer service. Again, the largest driver in terms of project cost was customer service, which totaled approximately $4.5 billion.[101] **Figure 21** shows the supplemental projects by drivers in 2024 as reported in the RTEP 2024.[102]

[99] *See* RTEP 2025 Regional Transmission Expansion Plan, p. 73. Available at https://www.pjm.com/-/media/DotCom/library/reports-notices/2025-rtep/2025-rtep-report.pdf (last visited Sept. 11, 2026)
[100] RTEP 2025 Regional Transmission Expansion Plan, p. 73.
[101] RTEP 2024 Regional Transmission Expansion Plan, p. 76. Available at https://www.pjm.com/-/media/DotCom/library/reports-notices/2024-rtep/2024-rtep-report.pdf?_sp=9cdbedbe-1b27-4d90-884a-cca36145c5db (last visited Sept. 21, 2026)
[102] RTEP 2024 Regional Transmission Expansion Plan, p. 76.

Figure 21: 2024 Supplemental Projects by Driver (RTEP 2024) (PJM)



In summary, $5.8 billion-worth of solutions to supplemental projects were evaluated by PJM in 2025 ($3.4 billion driven by "customer service") and $4.5 billion driven by customer service in 2024. Comparing this to the information I compiled in Table 6, the EDCs of Pennsylvania are seemingly propelling a sizeable portion of the reported local transmission buildout. As shown in **Table 5**, there are approximately $1.3 billion in supplemental projects driven by data centers in Pennsylvania that have been presented thus far in 2026 which will be constructed in upcoming years if approved. This grand, upcoming buildout is seemingly continuing to enlarge.

V. Conclusion

This section concludes my affidavit.

ATTACHMENT A
CURRICULUM VITAE OF ZACHARY TETI
PROFESSIONAL EXPERIENCE

Pennsylvania Office of Consumer Advocate • Harrisburg, PA • April 2025-Present • Senior Regulatory Analyst
Customized Energy Solutions • Philadelphia, PA • April 2024-September 2024 (Contract) • Compliance Analyst
Avangrid • Orange, CT • May 2021-April 2024 • Regulatory Analyst – FERC, ISO New England & New York ISO
Penn State University • University Park, PA • August 2019-May 2021 • Research Assistant – Energy Economics
TD Bank • Mount Laurel, NJ • February 2018-July 2019 • Assistant Vice President – Retail Lending Financial Analysis
JP Morgan Chase • Newark, DE • July 2013-February 2018
Budgeting, Forecasting and Analysis - Associate – Consumer Banking Technology • July 2017-February 2018
Financial Control – Associate & Analyst – International Trade Finance • July 2013-July 2017
Lancaster County Workforce Investment Board • Lancaster, PA • December 2012-May 2013 • Research Intern

EDUCATION & OTHER UNDERTAKINGS

Penn State University • University Park, PA • May 2021 • MS in Energy Economics
Millersville University • Millersville, PA • May 2013 • BA in Quantitative Economics, minor in Statistics
Curator for the Global Shapers Philadelphia Hub – World Economic Forum Initiative • September 2017-May 2021

PUBLICATIONS & TESTIMONY

Zachary Teti & Seth Blumsack, "By A Show of (Which) Hands: Empirical Analysis of Regional Transmission Owner Stakeholder Voting," Journal of Political Institutions and Political Economy, now publishers, vol. 5(4), pages 487-522, December 2024.

Direct & Rebuttal Testimony on behalf of the Office of Consumer Advocate, Docket No. R-2025-3054394, Pennsylvania Public Utility Commission v. Citizens' Electric Company of Lewisburg, PA, 2025

Direct, Rebuttal & Surrebuttal Testimony on behalf of the Office of Consumer Advocate, Docket No. R-2025-3057164, Pennsylvania Public Utility Commission v. PPL Electric Utilities Corporation, 2025

Direct Testimony on behalf of the Office of Consumer Advocate, Docket No. R- 2025-3059523, Pennsylvania Public Utility Commission v. UGI Utilities, Inc. – Gas Division, 2026

Direct Testimony on behalf of the Office of Consumer Advocate, Docket No. R- 2025-3059430, Pennsylvania Public Utility Commission v. UGI Utilities, Inc. – Electric Division, 2026

Direct Testimony on behalf of the Office of Consumer Advocate, Docket No.: A-2025-3059443, Letter of Notification of PPL Electric Utilities Corporation Filed Pursuant to 52 Pa. Code Chapter 57 Subchapter G, for Approval to Build Approximately 1.1 Miles of New Parallel Double Circuit 230 kV Transmission Taps that are Needed to Connect the Existing Susquehanna-Harwood #1 & #2 Transmission Lines on the New Tomhicken 230 kV Switchyard that are Respectively Located in Luzerne County, Pennsylvania, 2026

Affidavit of Zachary Teti, M.S.

I, Zachary Teti, (Affiant) being duly sworn (affirmed) according to law, depose and say that I am authorized to make this affidavit on behalf of the Pennsylvania Consumer Advocate and Office of Consumer Advocate (OCA), being an employee of the OCA, and have been authorized to make this affidavit on the Consumer Advocate's and OCA's behalf, and that the facts above set forth are true and correct to the best of my knowledge, information and belief, and I expect to be able to prove the same at any hearing hereof.

Zachary Teti

Signature of Affiant

9/30/26

Date

Sworn and subscribed before me the date below:

Signature of Official Administering Oath

9/30/26

Date

(My Commission Expires)

Commonwealth Of Pennsylvania - Notary Seal
Gabriel-Andres Sanchez, Notary Public
Dauphin County
My Commission Expires Feb. 06, 2027
Commission # 1432279

Appendix B – Felder Affidavit

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Office of Consumer Advocate	:	
	:	
	:	
	:	Docket No. C-2026-
v.	:	
	:	
	:	
	:	
PPL Electric Utilities Corporation	:	

FORMAL COMPLAINT OF THE
PENNSYLVANIA CONSUMER ADVOCATE
REGARDING PPL ELECTRIC UTILITIES CORPORATION'S
EXISTING RATES AND SERVICE
IN RELATION TO ADDITIONS OF DATA CENTERS
TO THE UTILITY'S ELECTRIC DISTRIBUTION SYSTEM
AND THE PJM REGION

AFFIDAVIT TESTIMONY

OF

Frank A. Felder, Ph.D.

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

Date Served: October 2, 2026

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I. Witness Information

My name is Frank A. Felder, and my business address is 1855 Saint Francis Street, #1612, Reston, VA, 20190. I am a Principal at Independent Electricity Consultants LLC.[1]

I am a long-standing consultant and former professor whose research, teaching, and consulting have centered on the engineering, economics, and public policy of electricity markets in the U.S. and internationally. From 2004 to 2020, I was an Assistant, Associate, and Research Professor at the Bloustein School of Planning and Public Policy at Rutgers University, New Jersey. I also directed the Center for Energy, Economic and Public Policy and the Rutgers Energy Institute. In both capacities, I led research and teaching initiatives on the power sector, including numerous studies for the New Jersey Board of Public Utilities.

As a consultant, I have advised every sector of the power industry – utility generation, independent power producers, regional transmission organizations/independent system operators (RTOs/ISOs), transmission utilities, non-utility transmission developers, distribution utilities, retail load aggregators/electric generation suppliers, public utility commissions, and federal and state government agencies on the topics of reliability, electricity markets and regulation, electricity policy, and economic development. I also have extensive international experience in electricity markets and have trained over 3,000 industry professionals on electricity markets and resource adequacy.

Since April 2024, the Pennsylvania Office of Consumer Advocate (OCA) has engaged me to assist it with its filings for the Commission's Distributed Energy Resource and Large Load Model Tariff proceedings.[2] Since August 2025, I have also been engaged by the OCA on matters

[1] https://www.independentelectricityconsultants.com/.
[2] Pennsylvania Public Utility Commission, Distributed Energy Resources Participation in Wholesale Markets, Docket No. L-2023-3044115, and Pennsylvania Public Utility Commission, Interconnection and Tariffs for Large Load Customers, Docket No. M-2025-3054271.

relating to large loads and the PJM Interconnection (PJM), the power system operator, wholesale market administrator, and transmission planner for the Mid-Atlantic region, which includes Pennsylvania.[3] Since September 2025, I have been involved in PJM's extensive stakeholder processes aimed at addressing the challenges large loads pose to the bulk power system (generation and transmission) and wholesale electricity markets. I have provided testimony before the Pennsylvania Public Utility Commission (PUC or PA Commission).[4]

I hold a Ph.D. in technology, management, and policy and a Master of Science in technology and policy from the Massachusetts Institute of Technology, and a Bachelor of Science in applied mathematics and a Bachelor of Arts in mathematics from Columbia University. Please see Exhibit 1, Frank A. Felder, curriculum vitae, for additional information.

II. Purpose of Affidavit

The purpose of my affidavit is to identify and describe the applicable public policy issues of reliability and affordability in this matter and how they can be addressed in the context of the interconnection of data centers to the electric power system. The rapid, massive growth of data centers in the Mid-Atlantic region is threatening reliability and driving up wholesale market and transmission costs. Without the concerted action of federal and state policymakers and regulators, ordinary ratepayers will continue to pay more for a less reliable service. I am providing this affidavit at the request of the Pennsylvania Office of Consumer Advocate (OCA).

[3] https://www.pjm.com/about-pjm.
[4] Pennsylvania Public Utility Commission, Letter of Notification of PPL Electric Utilities Corporation Filed Pursuant to 52 Pa. Code Chapter 57 Subchapter G, for Approval to Build Approximately 1.1 Miles of New Parallel Double Circuit 230 kV Transmission Taps that are Needed to Connect the Existing Susquehanna-Harwood #1 & #2 Transmission Lines on the New Tomhicken 230 kV Switchyard that are Respectively Located in Luzerne County, Pennsylvania, Docket No.: A-2025-3059443, July 8, 2026.

III. Summary of Findings and Recommendations

I preliminarily find the following:

1. The massive and rapid build-out of data centers and artificial intelligence (AI) facilities is resulting in substantial ongoing and expected increases in electricity demand in Pennsylvania and the PJM region.
2. This ongoing and expected increase in electricity demand risks undermining the reliability of the electric power system.
3. One major reliability concern is resource adequacy, that is, the inadequate amount of supply available to serve the region's electricity demand as data centers interconnect to the power system faster than new supplies.
4. This anticipated reduction in resource adequacy increases the likelihood that PJM will require Electric Distribution Companies (EDCs) to implement mandatory load shedding of electricity customers by curtailing their ability to consume electricity.
5. Curtailment of non-data center load, especially residential, threatens safety, public health, and economic activity.
6. This ongoing and expected increase in electricity demand is shifting the electricity-related costs and stranded cost risks caused by data centers to ordinary ratepayers.
7. Federal and Pennsylvania policies affirm that large loads should not reduce the reliability of the electric power system.
8. Federal and Pennsylvania policies state that large loads should pay for their costs, not ordinary ratepayers.

The issues identified in this Affidavit, as well as potential approaches to address them, may be further developed as additional information becomes available. Such information may include responses to formal discovery from PPL Electric, as well as supplemental legal, regulatory, market,

and economic research. This Affidavit provides an overarching assessment of the rapidly changing circumstances facing PPL Electric and the broader PJM region, particularly the unprecedented growth in requests to interconnect large new customers, including data centers and other computational large-load customers. The magnitude and pace of this growth create emerging risks that warrant timely consideration and further investigation by the PA Commission because the existing tariff framework does not adequately protect PPL Electric's customers from potential cost increases, risks to system reliability, or other adverse impacts associated with serving these new loads.

Accordingly, this Affidavit explains why the PA Commission must review the status quo and why appropriate customer protections must be established in the near term as PPL Electric and other utilities within PJM prepare to and are preparing to accommodate rapidly growing large-load interconnection requests. This Affidavit is not intended to prescribe a single set of specific tariff provisions or to prejudge the outcome of any PA Commission proceeding. Rather, it is intended to demonstrate the need for PA Commission review and action and to identify the principal issues that should be addressed. The Pennsylvania Commission must develop and evaluate the specific issues presented by PPL Electric through a formal proceeding informed by a complete evidentiary record.

Given the pace of large-load growth and the time required to plan and construct the transmission and distribution infrastructure necessary to serve such customers, the need for that review is increasingly immediate. Establishing appropriate protections while infrastructure is being built and before the resulting costs and risks are shifted to PPL Electric's broader customer base is the only way for the PA Commission to preserve the reliability and affordability of electric service for both new and legacy customers.

IV. The Public Policy Consensus Regarding Data Centers and Their Adverse Reliability and Cost Impacts for Ordinary Ratepayers

Federal and state regulators and market participants interact in ways that affect electric-system reliability, wholesale and retail market costs, and transmission and distribution charges across customer classes, including data centers and ordinary ratepayers. These regulatory bodies, market administrators, and electricity consumers are defined and described further below, but it is worth briefly identifying them upfront and noting their abbreviations.

The Federal Energy Regulatory Commission (FERC) regulates wholesale electricity markets, transmission, and the reliability of the bulk power system (generation, transmission, and a limited set of distribution facilities).[5] The Pennsylvania Public Utility Commission (PUC) regulates retail electricity markets and electric distribution companies' (EDCs) tariffs and charges. Wholesale markets refer to electricity generation sold to wholesale buyers, called load serving entities (LSEs), which then resell electricity to retail customers, the final users of electricity. The North American Electric Reliability Corporation (NERC), under FERC's supervision, writes and enforces the electric power system's reliability rules. PJM is the system operator, wholesale market administrator, and regional transmission planner. Data centers are large electricity consumers, and their forecasted demand is growing rapidly and massively. FERC, the PUC, and others operate under a federal-state policy and legal framework of cooperative federalism, which means they need to work together and coordinate their policies and activities to provide reliable, affordable electricity.[6]

This section of my affidavit (1) summarizes the existing policy frameworks related to data centers (e.g., principles, pledges, executive orders, PUC model tariffs, and NERC guidance on

[5] FERC, Reliability Explainer, August 16, 2023, https://www.ferc.gov/reliability-explainer.
[6] Federal Power Act, 16 U.S.C. §791a-828c and 66 Pa. C.S. §2805.

computational loads) and assesses how these policies address the reliability risks and increased costs; and (2) reviews PJM's Reliability-Based Planning (RBP) and PJM's Interim Resource Adequacy Service (IRAS) initiatives, and the associated PJM filings at FERC. For ease of explanation, I use the term 'data centers' generically to refer to all types of data centers, AI facilities, and computational large-load customers. Different organizations use specific terms and definitions, which I will review and discuss throughout my affidavit. Where appropriate, I capitalize those specific terms.

A. PJM's Role in Shaping Pennsylvania's Electricity Reliability, Costs, and Policies

The PJM regional transmission organization (RTO) is the electricity grid operator, market administrator, and transmission planner for the Mid-Atlantic region.[7] Pennsylvania is one of 13 states, plus the District of Columbia, within the PJM footprint. PJM is a non-profit utility regulated by FERC. PJM does not own generation or transmission assets. Instead, it administers wholesale electricity markets that determine power plant operations and investments, demand response, and transmission operations and planning.

PJM's wholesale electricity markets comprise energy, capacity, and selected ancillary services. The energy market accounts for the largest share of buyers' wholesale electricity costs. Energy, measured in megawatt-hours (MWh), refers to the electricity that powers electrical devices such as lighting, air conditioning, and computers. Capacity is the second-largest product, measured in megawatts (MW). Capacity ensures resource adequacy; that is, the PJM region has enough supply to meet demand except for one day in 10 years. PJM's capacity market is called the Reliability Pricing Model (RPM) and consists of auctions, called base residual auctions (BRAs), that PJM conducts to procure sufficient supplies. Ancillary services, the smallest contributor to

[7] PJM, About PJM, https://www.pjm.com/about-pjm.

wholesale market costs, refer to the numerous services that help ensure reliable operations, some of which PJM procures through a market mechanism. For this affidavit, PJM's capacity market, or RPM, is the most relevant. As discussed further below, because of the rapid and massive increase in the expected electricity demand from data centers, PJM has proposed a Reliability Backstop Procurement (RBP) to FERC to supplement PJM's existing RPM.

PJM also conducts regional transmission planning in coordination with the region's electric utilities. PJM's planning process assesses the need for additional regional transmission to meet future changes in electricity demand. Local or individual utility transmission planning, referred to as supplemental projects, is driven by utilities but coordinated with PJM.

B. Overall Context of Data Centers

The race to plan, build, and connect large data centers, many of which consume as much power as a large plant produces, is motivated by national security, national and regional economic development, and AI expansion. Data centers originated with the development of mainframe computers and provide multiple computational and data services central to modern life. They expanded with the invention of the transistor, the shift from mainframes to minicomputers and microcomputers, and the development of cloud services. Around 2022, data centers entered a new phase of rapid, massive deployment, driven by the development of large-scale AI models.[8] Data centers vary substantially by size, business model and ownership, function, type of backup power supply, level of reliability, location, and other attributes.[9]

[8] Enconnex, The History of Data Centers: An Exponential Evolution, March 2024, https://www.enconnex.com/data-center-history-and-evolution/ and Christopher Tozzi and James Walker, Data Center Knowledge, Data Center Milestones: From ENAIC to Generative AI, January 26, 2026, https://www.datacenterknowledge.com/data-center-construction/8-milestones-in-data-center-history-1946-to-today.

[9] CoreSite, The Role of Data Centers in Powering Digital Everything", https://www.coresite.com/blog/the-role-of-data-centers-in-powering-digital-everything.

Data centers use extraordinary amounts of electricity to power their businesses. To put their usage into context, one American home consumes approximately 11,000 kilowatt-hours (kWh) on average per year.[10] One advanced data center chip (i.e., the specialized microprocessor powering cloud computing, artificial intelligence, and/or enterprise servers) consumes about as much as the average residential household.[11] A one-gigawatt (GW) data center consumes the same amount of power as one million homes[12]— almost half of the Limerick nuclear plant (at 2.3 GW)[13] or half of the Hoover Dam (at 2 GW).[14]

The size of the average existing data center today is 45 MW,[15] and the average planned data center size is 177 MW.[16] Hyperdata centers, such as the planned 4,400 MW data center campus in Homer City, Pennsylvania, will generate and consume almost as much power as all the homes in the Philadelphia urban area (population of 5.7 million).[17]

In addition to their electricity demand, data centers want to connect to the electrical grid quickly, a need often referred to as "speed to power."[18] Data centers' desire for speed to power is

[10] U.S. Energy Information Agency, Frequently Asked Questions (FAQs), https://www.eia.gov/tools/faqs/faq.php?id=97&t=3. The average residential consumption of electricity in 2022 was 10,791 kWh.

[11] Hanwha Data Centers, What Are the Power Requirements for AI Data Centers? November 12, 2025, https://www.hanwhadatacenters.com/blog/what-are-the-power-requirements-for-ai-data-centers/. The average annual consumption of a data center computer chip depends on several factors, including the chip and the number of hours the chip is consuming electricity.

[12] 1 GW equals 1,000 MW (megawatts) and 1 MW equals 1,000 kW. GW, MW, and kW are units of power, the instantaneous draw of power. If operated for 1 hour, a 1 GW load consumers 1 GWh (gigawatt-hours) of energy, a 1 MW load, 1 MWh, and a 1 kW load, 1 kWh. There are 8,760 hours in a year so a 1 GW data center consumers 8,760 GWh or 8,760,000 MWh of load if it operates 100% of the time.

[13] Montgomery County Pennsylvania, Limerick Clean Energy Centers, https://www.montgomerycountypa.gov/departments/department-public-safety/division-emergency-management/limerick-clean-energy-center.

[14] Bureau of Reclamation, Hover Dam, March 12, 2015, https://www.usbr.gov/lc/hooverdam/history/essays/biggest.html.

[15] Cleanview, Data Centers in the United States, September 2026, https://cleanview.co/data-centers/us.

[16] Cleanview, Data Centers in the United States, September 2026, https://cleanview.co/data-centers/us.

[17] "Supersized data centers are coming. See how they will transform America." Washington Post (December 15, 2025), available at https://www.washingtonpost.com/climate-environment/interactive/2025/giant-data-centers-energy-pollution/ (last visited January 14, 2026).

[18] Ascend Analytics, Data Centers and US Energy Markets: The Need for Speed, February 13, 2025, https://www.ascendanalytics.com/blog/data-centers-and-us-energy-markets-the-need-for-speed.

unique because of (1) the ongoing, rapid development of information and computational technologies that require capital to be deployed as quickly as possible to keep up with competitive market pressures, and (2) the significant amount of capital that data center developers can deploy quickly to interconnect to the electrical grid, often outpacing the rate at which supporting infrastructure can be constructed and placed into service.

C. The Expansion of Data Centers in Pennsylvania and the Region

Pennsylvania, the state that includes PJM, and the United States at large are experiencing a dramatic increase in electricity demand driven primarily by new, large loads that are almost exclusively data centers.[19] These large loads are physically connected to an electric distribution company (EDC), which is connected to the transmission system that PJM operates. They consume large amounts of electricity and are growing in both size and number.[20] PJM forecasts summer peak load growth of 3.6% per year for the next 10 years and 2.4% for the next 20 years, resulting in a 10-year increase of 65,733 MW or 65.7 GW and a 20-year increase of 96,704 MW or 96.7 GW, driven almost exclusively by data centers.[21] PJM forecasts approximately 30 gigawatts (GW) of new load from data centers between 2025 and 2030.[22] For instance, in May 2026, PPL

[19] NERC, Large Loads Task Force White Paper, Characteristics and Risks of Emerging Large Loads, July 2025, p. 2, https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf, "Emerging large loads have grown substantially in recent history, and forecasts that data centers alone may account for as much as 12% of all U.S. electricity consumption by 2028 (up from 4.4% in 2023)."

[20] McKinsey & Company, Scaling bigger, faster, cheaper data centers with smart designs, August 1, 2025, https://www.mckinsey.com/industries/private-capital/our-insights/scaling-bigger-faster-cheaper-data-centers-with-smarter-designs.

[21] PJM, 2026 PJM Load Forecast Report, January 14, 2026, p. 6, https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2026-load-report.pdf. See also Modo Energy, Data centers define PJM's 2046 load forecast, undated, https://modoenergy.com/research/en/pjm-load-forecast-data-centers-2046.

[22] PJM Inside Lines, 2025 Year in Review: Planning Prepares for Burgeoning Electricity Demand, January 8, 2026, https://insidelines.pjm.com/2025-year-in-review-planning-prepares-for-burgeoning-electricity-demand/. Also see Modo Energy, Data centers define PJM's 2046 load forecast, undated, https://modoenergy.com/research/en/pjm-load-forecast-data-centers-2046, which, using PJM data, finds "The large load component, principally data center additions, accounts for more than 100% of peak demand growth over the next five years as base demand contracts. PJM's large load adjustments grow by 35.1 GW between 2026 and 2031, against total demand growth of 34.6 GW. Beyond 2031, the balance shifts slightly. The base layer begins to contribute and data center additions decelerate, but remain dominant."

announced that its data center pipeline to 2034 had increased to 28.3 GW, up from 25.2 GW three months earlier.[23] For comparison, 1 GW (1,000 MW) is the size of a very large power plant, and PJM's peak demand in 2025 was 161 GW.[24]

PJM has also observed "unprecedented" data-center load growth in portions of its footprint and has explained that rapid load growth can require transmission-system reinforcements before existing system capacity is exhausted.[25] PJM further notes that reinforcements, particularly at the extra-high-voltage level, "require time to build," creating a risk that local reliability issues can quickly become regional reliability issues.[26] The timing of data center additions is also particularly significant when data centers are proposed in the same geographic area. PJM has identified the "pace of forecasted load growth" as presenting "timing challenges for needed investment," explaining that data centers' desired time to market creates a need for alternative mechanisms to connect new large loads to the grid.[27]

Chairman Steve DeFrank of the PUC summarizes the implications of new large loads[28]:

> "Pennsylvania's electricity needs have been relatively stable for years, but large new loads have the potential to fundamentally change that picture… That makes accurate forecasting and careful planning more important than ever. We need a clear picture of what demand is actually coming and sufficient generation and transmission to reliably serve that growth, while continuing to protect existing consumers from unreasonable costs."

[23] Ethan Howland, Utility Dive, PPL 'advanced' data center pipeline grows to 28.3 GW in Pennsylvania, May 11, 2026, https://www.utilitydive.com/news/ppl-data-center-pipeline-pjm-blackstone-earnings/819804/.
[24] PJM, Summer 2025 Weather Normalized RTO Coincident Peaks (MW), November 4, 2025, https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/summer-2025-peaks-and-5cps.pdf?ref=blog.gridstatus.io.
[25] PJM Interconnection, Impact of Forecasted Large Load Adjustments in RTEP, June 26, 2023, p. 5, https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2023/20230626/20230626-item-04---impact-of-forecasted-large-load-adjustments-in-rtep.pdf.
[26] PJM Interconnection, Impact of Forecasted Large Load Adjustments in RTEP, June 26, 2023, p. 5, https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2023/20230626/20230626-item-04---impact-of-forecasted-large-load-adjustments-in-rtep.pdf.
[27] PJM Interconnection, *The Challenges with Reliably Connecting Large Loads*, May 9, 2025, p. 7, https://www.pjm.com/-/media/DotCom/committees-groups/workshops/llaw/2025/20250509/20250509-item-02---large-load-additions-workshop---presentation.pdf.
[28] NorthcentralPA.com, Pa. Utility Commission report anticipates demand spike from data centers, September 4, 2026, https://www.northcentralpa.com/news/pa-utility-commission-report-anticipates-demand-spike-from-data-centers/article_986f44c4-35fb-409e-95a0-e902dfe991aa.html.

Mr. Teti's affidavit reviews the PJM large load forecasts and the Commission's review of those forecasts overall for Pennsylvania and by utility.

D. The Public Policy Consensus Regarding the Reliability and Cost Impacts on Ordinary Ratepayers

1. The Potential Reliability and Cost Impacts of Data Centers

The public's acceptance of data centers depends, in part, on the ability of regulators to address two key public policy issues: reliability and affordability.[29] If large loads are added to the electric power system without sufficient new supply to serve them or without meaningful policies to curtail their electricity consumption during times of supply shortages, then the reliability of the system, specifically its resource adequacy, will deteriorate.[30] This deterioration could result in mandatory load shedding of ordinary ratepayers, such as residential customers.[31] As more load is added to PJM that is not sufficiently supplied or curtailable, the frequency, magnitude, and duration of potential mandatory load-shedding events increase. The head of Exelon, the largest U.S. utility by customer count, has warned that the country could face blackouts starting in 2027 due to AI load, and that electricity bill increases are needed to fund new infrastructure.[32]

[29] Rachel Mural, Dipesh Pherwani, Chaitanya Gupta, Yiqi Yu, Ai Takahashi, Dongjoo Kim, Subir Majumder, Henry Lee, Minlan Yu, and Le Xie, AI, Data Centers, and the U.S. Electric Grid: A Watershed Moment, February 2026, p. 2, https://www.belfercenter.org/sites/default/files/2026-02/Mural%20et%20al_AI%20Data%20Centers%20Grid_20260206.pdf, "While overregulation could hinder AI development, insufficient regulation risks grid instability, rising consumer costs, reliance on high-emission energy sources, public backlash, and setbacks to state and corporate climate goals."

[30] NERC, Large Loads Task Force White Paper, Characteristics and Risks of Emerging Large Loads, July 2025, p. 16, https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf. Large loads also have important implications for operational reliability. Operational reliability is the ability of the electric power grid to withstand the sudden outages of large power plants or transmission facilities by maintaining grid stability without resulting in load curtailments. See NERC, NERC Issues Level 3 Alert, Reliability Guideline Focused on Large Load Challenges, May 4, 2026, https://www.nerc.com/newsroom/nerc-issues-level-3-alert-reliability-guideline-focused-on-large-load-challenges.

[31] PJM IRAS FERC Filing, pp. 16-17, "[i]n light of the deteriorating resource adequacy outlook…." Citing PJM Board July 27, 2026 Decisional Letter, p. 1.

[32] Martha Muir, Financial Times, Utility boss warns US faces blackouts due to power supply shortfall, June 27, 2026, https://www.ft.com/content/14d2e591-7cd5-4456-904f-1b7fdc5cbc1a?syn-25a6b1a6=1.

The second public policy challenge is affordability. Rapidly connecting massive amounts of large loads could increase wholesale market prices for energy, capacity, and ancillary services,[33] and raise transmission and distribution rates. However, with proper transmission and distribution rate design, it is possible to protect non-large load customers from transmission and distribution rate increases, and perhaps even lower them – but this is not guaranteed. In addition to protecting ratepayers from higher costs due to large loads, they should also be protected from stranded costs, that is, the costs ratepayers end up paying because large loads did not interconnect at the time and amount forecasted, or they halted service prematurely. The result is stranded assets – generation, transmission, and distribution facilities – the costs of which data centers would not contribute, or sufficiently contribute, towards. When this occurs, EDCs, such as PPL, attempt to recover their costs from ordinary ratepayers. Increasing electricity rates through cost shifting from large loads to ordinary ratepayers, whether directly due to large loads or due to the risk of stranded costs, is an affordability issue, particularly given the challenges that almost 20% of Pennsylvanian families have in paying their utility bills.[34]

[33] Monitoring Analytics (the PJM Independent Market Monitor), 2026 Quarterly State of the Market Report for PJM: January through March, p. 20, May 14, 2026, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2026/2026q1-som-pjm.pdf, finds that comparing the first quarter of 2025 to the first quarter of 2026, energy prices have increased 78.5%, capacity prices 398.1%, ancillary service prices 69.0%, and transmission 5.3%. The report further states on p. 2, "Data center load growth is the primary reason for recent and expected capacity market conditions, including total forecast load growth, the tight supply and demand balance, and high prices." Monitoring Analytics, 2025 State of the Market Report, Volume 1: Introduction, March 12, 2026, p. 18, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025-som-pjm-vol1.pdf, finds that energy prices have increased 47.3%, capacity prices 252.0%, ancillary service prices 16.8%, and transmission 1.8%

[34] The Pennsylvania Independent, Pennsylvania lawmakers introduce legislation to lower energy costs, May 1, 2026, https://pennsylvaniaindependent.com/economy/pennsylvania-lawmakers-introduce-legislation-to-lower-energy-costs/, reports that electricity shutoffs in the Commonwealth increased by about 21% between October 2024 and October 2025, and one in five households has difficulty paying their utility bills. See also, CAUSE-PA, Distributed Energy Resources Participation in Wholesale Markets, Chapter 57 Docket No., L-2023-3044115, June 9, 2026, p. 3, https://www.puc.pa.gov/pcdocs/1934550.pdf, "Pennsylvania is experiencing these same trends. Energy insecurity impacts roughly 1 in 4 Pennsylvania households. According to the latest United States Census Bureau Household Pulse Survey, around 24.4 percent of Pennsylvania households could not afford their home energy bills in 2024, compared to 23 percent nationwide. And costs are only going up. Over the past year, electric generation prices have skyrocketed across the Commonwealth, driving up residential rates as much as 40 percent in some service areas. Hundreds of thousands of Pennsylvania families pay more than 10 percent of their household income on home energy

I discuss reliability and affordability in more detail below.

2. The Public Policy Consensus to Protect Ordinary Consumers from the Reliability and Cost Impacts of Data Centers

a. Federal Policy

Federal and state policies on large loads and the electric power system are solidifying. Both federal and state governments play important roles in ensuring that large loads do not adversely affect the reliability of the electric power system or shift costs to ordinary ratepayers. The federal government, the Federal Energy Regulatory Commission (FERC), PJM, the Commonwealth of Pennsylvania, the Pennsylvania Commission, and the data center community all acknowledge the need for and the importance of policies to protect ordinary ratepayers from the potential adverse reliability and cost consequences of rapidly interconnecting massive amounts of large loads to the power system.

On March 5, 2026, the White House issued the Ratepayer Protection Pledge (Pledge), which many large data center owners and users (some of the most well-financed companies in the world), such as Amazon, Google, Meta, Microsoft, OpenAI, Oracle, and xAI, have signed.[35] The Pledge states:[36]

> Today, pursuant to the Ratepayer Protection Pledge, leading United States hyperscalers and AI companies guarantee that data centers' energy needs will not increase household electricity costs for American citizens. Instead, **these companies will build, bring, or buy the new generation resources and electricity needed to satisfy their energy demands, and pay for all new power delivery infrastructure upgrades to service their data centers**. They will voluntarily negotiate new, separate rate structures with their utilities and relevant State governments, and pay those rates, and for their infrastructure, whether they use the electricity or not. They will also invest in local

costs, with many facing energy burdens of 30 percent or higher. In 2025, nearly 390,000 Pennsylvania households faced involuntary termination of electric or gas service—a 10 percent increase from 2024."

[35] The White House, President Trump Secures Historic Commitment to Keep Electricity Costs Down Amid Data Center Boom, March 5, 2026, emphasis added, https://www.whitehouse.gov/releases/2026/03/president-trump-secures-historic-commitment-to-keep-electricity-costs-down-amid-data-center-boom/.

[36] The White House, Ratepayer Protection Pledge Proclamation, March 4, 2026, https://www.whitehouse.gov/presidential-actions/2026/03/ratepayer-protection-pledge-proclamation/, emphasis added.

> communities and coordinate with grid operators to **contribute to a more reliable grid**. These measures will ensure that Americans are protected from higher energy prices, benefit from grid upgrades and increased grid resilience, and benefit from this technological boom while the United States continues its global leadership in innovation and advanced technology.

On July 23, 2026, the White House expanded the signatories to the Ratepayer Protection Pledge. It now includes over 300 organizations representing every stakeholder in the U.S. power system, including Exelon, which owns PECO; PPL; and FirstEnergy, which owns Met-Ed, Penelec, Penn Power, and West Penn Power.[37]

On January 16, 2026, the White House National Energy Dominance Council and the 13 governors of the states within the PJM footprint signed the Statement of Principles Regarding PJM. These principles recognized the resource adequacy risk posed by data centers because of their size, the need to assign the costs of new capacity to these data centers, and the need for PJM and states to act.[38]

The Data Center Coalition, the membership association of the data center industry,[39] stated "We agree that reliability must be maintained and that new capacity should accompany significant new load additions."[40]

[37] The White House, Data centers pay their way. Ratepayers pay theirs., https://www.whitehouse.gov/ratepayer-protection-pledge/.
[38] National Energy Dominance Council and PJM Governors, Statement of Principles Regarding PJM, January 16, 2026, https://www.energy.gov/documents/statement-principles-regarding-pjm.
[39] Data Center Coalition, The Voice of the Data Center Industry, https://www.datacentercoalition.org/cpages/home.
[40] Data Center Coalition, DCC Connect & Manage Alternative: State-Led Implementation with Immediate Residential Consumer Protection, June 23, 2026, https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260630/20260630-item-02i---data-center-coalition---cm---executive-summary.pdf.

On June 18, 2026, the FERC ordered PJM, along with other system operators, to demonstrate to FERC how they are interconnecting large load customers reliably and affordably.[41] Specifically,[42]

> FERC today issues tailored show cause orders under Section 206 of the Federal Power Act to each of the six regional grid operators under its jurisdiction. These groundbreaking proceedings represent historic action by the Commission to push our country's electric markets and economy into the future by speeding the integration of large energy users, like data centers and manufacturing operations, onto the electric grid. **These actions are designed to ensure that consumers nationwide continue to enjoy reliable, affordable power, as demand soars and technology leaps forward**.

The FERC also finds that urgent action is needed "to assure that computational loads are reliably integrated into the operation of the Bulk-Power System."[43]

b. Pennsylvania Governor's Policy on Data Centers

Pennsylvania's data center policy focuses on reliability and affordability. On August 19, 2026, the Governor issued Executive Order 2026-05 – Protecting Pennsylvania Consumers from Data Center Impacts (PA Executive Order).[44] The PA Executive Order makes clear that ordinary ratepayers need protection from the reliability and cost impacts of data centers, and that, to achieve this, the Commission needs to act. In Section 3, Protecting Pennsylvania Consumers, the PA Executive Order states:

[41] Docket No. EL24-118, *PJM Interconnection, L.L.C.*, 195 FERC ¶ 61,211, June 18, 2026, https://www.ferc.gov/media/e-7-el26-67-000.

[42] FERC, Fact Sheet: FERC Takes Action to Supercharge America's Grid for Efficiency, Reliability, and a Bold Energy Future, June 18, 2026, https://www.ferc.gov/news-events/news/fact-sheet-ferc-takes-action-supercharge-americas-grid-efficiency-reliability-and, emphasis added.

[43] 196 FERC ¶ 61,031 United States of America Federal Energy Regulatory Commission, Order Directing the North American Electric Reliability Corporation to File Reliability Standard(S) Pertaining to Computational Load Integration, July 16, 2026, p. 5, para. 9.

[44] Commonwealth of Pennsylvania Governor's Office, Executive Order 2026-05 – Protecting Pennsylvania Consumers from Data Center Impacts, August 18, 2026, https://www.pa.gov/content/dam/copapwp-pagov/en/governor/documents/eo2026_05_protecting%20pennsylvania%20consumers%20from%20data%20center%20impacts_final_executed.pdf. The Pennsylvania Governor is also a member of the PJM Governors' Collaborative that calls for PJM to protect consumers from adverse reliability and costs due to data centers. PJM Governors' Collaborative, Letter to David Mills, Interim President, CEO, and Chair, PJM Board of Managers, April 9, 2026, https://governor.maryland.gov/media/783.

a. To limit reliability impacts on the electric system caused by data centers, the Governor's Special Counsel for Energy Affordability ("Special Counsel") shall engage with the Pennsylvania Public Utility Commission ("Commission"), and shall advocate for the rapid development of rules, procedures, and orders that would:

(1) Ensure each electric utility that has received a request to interconnect a data center in its territory files with the Commission revisions to both its pre-emergency interim resource adequacy service (IRAS) and emergency load control procedures so that utilities curtail data centers prior to any other customer during pre-emergency IRAS or emergency events, unless the data center customer has secured incremental electric capacity for the entirety of its demand; and

(2) Ensure that utilities do not classify a data center as critical load exempt from curtailment during pre-emergency or emergency events.

b. To limit electric system costs caused by data centers from being imposed on other customers, the Special Counsel shall engage with the Commission, and shall advocate for the rapid development of rules, procedures, and orders that would allow for the timely approval of utility tariffs that accomplish the following:

(1) Charge the appropriate data center customers for any PJM reliability backstop auction costs in accordance with the procedures ultimately approved by the Federal Energy Regulatory Commission in docket ER26-3380-000; and

(2) Prevent an electric utility from charging non-data center customers for backstop auction costs, including in the event that a data center becomes insolvent or is otherwise not able to pay the auction costs assigned to it; and

(3) Ensure that data center customers pay all Commission-jurisdictional interconnection costs that the utility incurs due to the development of data centers.

c. In advance of PJM's reliability backstop auction and related actions, the Special Counsel shall engage with the Commission, and shall advocate for the rapid development of rules, procedures, and orders:

(1) For electric utilities to submit megawatt adjustments for any reliability backstop auction target in accordance with the procedures ultimately approved by the Federal Energy Regulatory Commission in docket ER26-3380-000; and

(2) For electric utilities to register large loads in PJM's large load registry, including any locational requirements for incremental electric capacity; and

(3) For implementation of credits pertaining to PJM's pre-emergency IRAS program following the Federal Energy Regulatory Commission's ultimate disposition of relevant rules and procedures in docket ER26-3515-000.

Thus, the Executive Order seeks to ensure that the rapid growth of data center electricity demand does not undermine grid reliability or shift the resulting costs and risks onto other electricity customers. It directs state regulators and utilities to develop mechanisms that hold data centers responsible for the incremental generation, transmission, interconnection, and reliability costs associated with their load; protect non-data center customers from those costs; require data

centers to bear appropriate reliability and capacity obligations; and allow data centers to be curtailed during system emergencies before other customers unless they have secured sufficient incremental capacity. More broadly, the Order seeks to align the development of large new data center loads with the availability of adequate electric capacity and the principle that customers causing incremental system costs should bear those costs.

The PA Executive Order also references the Governor's Responsible Infrastructure Development (GRID) policy. "Governor Shapiro's 'all-of-the-above' energy strategy is focused on diversifying Pennsylvania's power grid to secure the Commonwealth's energy future while building more reliable, affordable, and sustainable energy."[45] The policy further states:

> In its initial application for GRID certification, a project developer must provide DOR and OTO with an energy plan detailing how it will provide for its energy needs without imposing costs on Pennsylvanians and other utility ratepayers. Developers must agree to build, bring online, or buy incremental electric capacity needed to meet new energy demand while paying the full cost of the capacity. That capacity must generally come from resources located within the same deliverability area as the proposed GRID project, and must also include increasing percentages of energy coming from dispatchable clean firm energy resources located within the Commonwealth, up to 32 percent in 2035. Developers must also pay all costs associated with interconnection, transmission, distribution, network upgrades, ancillary services, or dedicated facilities caused in whole or in part by the project's electricity demand.[46]

Taken together, federal and Pennsylvania policies make clear that ordinary consumers should be protected from the adverse reliability and cost impacts of data centers.

[45] Commonwealth of Pennsylvania, Governor Shapiro Releases Full Governor's Responsible Infrastructure Development (GRID) Standards to Protect Pennsylvanians and Establish Strict Guardrails to Hold Data Center Developers Accountable, May 27, 2026, https://www.pa.gov/governor/newsroom/2026-press-releases/gov-shapiro-releases-full-grid-standards-to-protect-pennsylvania.

[46] Commonwealth of Pennsylvania, Governor Shapiro Releases Full Governor's Responsible Infrastructure Development (GRID) Standards to Protect Pennsylvanians and Establish Strict Guardrails to Hold Data Center Developers Accountable, May 27, 2026, https://www.pa.gov/governor/newsroom/2026-press-releases/gov-shapiro-releases-full-grid-standards-to-protect-pennsylvania. Also, see PAPUC, Interconnection and Tariffs for Large Load Customers, Docket No. M-2025-3054271, Final Order, May 12, 2026, https://www.puc.pa.gov/pcdocs/1929842.pdf.

c. Pennsylvania Public Utilities Commission Policy on Large Loads

On May 13, 2026, the Commission issued its final order establishing its Large Load Model Tariff Framework ("Model Tariff"). The Model Tariff recommends cost responsibility protections that reinforce "cost causation principles to help ensure that large load customers are responsible for infrastructure and interconnection costs associated with serving their projects, reducing the risk of shifting those costs onto existing residential and small business customers."[47] It also recommends contract terms and exit provisions that provide "guidance related to load ramping schedules, minimum contract terms, and customer exit provisions to support long-term cost recovery and system stability."[48]

As stated from the start of the Commission docket on Interconnection Tariffs for Large Load Customers, protecting customers from stranded costs is the Commission's primary concern: "First and foremost, the Commission must protect the Commonwealth's ratepayers. In this case, that means ensuring that if any upgrades are undertaken to enable the interconnection of large loads, they are made with a high degree of ratepayer protection against the risk of utility investment for projects that may not materialize. In such cases, questions may arise about who will ultimately bear these stranded costs."[49] The Commission's work on large loads is not done. In June 2026, the PUC issued requests for comments for Potential Regulations for Interconnecting Electric Loads.[50]

[47] PAPUC, PUC Releases Final Order Establishing First-of-Its-Kind Large Load Model Tariff Framework, May 13, 2026, https://www.puc.pa.gov/press-release/2026/puc-releases-final-order-establishing-first-of-its-kind-large-load-model-tariff-framework-05132026.
[48] PAPUC, PUC Releases Final Order Establishing First-of-Its-Kind Large Load Model Tariff Framework, May 13, 2026, https://www.puc.pa.gov/press-release/2026/puc-releases-final-order-establishing-first-of-its-kind-large-load-model-tariff-framework-05132026.
[49] PA PUC, En Banc Hearing Concerning Interconnection and Tariffs for Large Load Customers, Public Meeting of March 27, Agenda No. 3054271-CMR, Motion of Chairman Stephen M. DeFrank, https://www.puc.pa.gov/pcdocs/1871997.pdf.
[50] PAPUC, Potential Regulations for Interconnecting Electric Loads Docket No. L-2025-3059032, June 22, 2026.

On August 6, 2026, Chairman DeFrank issued the following statement regarding a PPL request to build transmission facilities, which is worth reading in full (emphasis added):[51]

> Before the Commission is the Letter of Notification filed by PPL Electric Utilities Corporation (PPL or the Company) on May 1, 2026. PPL seeks approval to build approximately 0.25 miles of new double circuit 138 kV transmission taps, connect existing transmission lines to the new Pitney 138 kV Switchyard, and build two 0.1-mile-long double circuit transmission lines to a new customer-owned substation located in East Lampeter Township, Lancaster County. As explained in PPL's filing, this LON Project is needed to meet the electric needs and demands of an existing customer requesting upgrades to its transmission-level service. The customer is requesting an upgrade to receive an initial load of 130 MW in 2027. The customer then plans to increase its load to approximately 350 MW by 2028. Consequently, upon energization this customer will fall within the category of a "large load" interconnection pursuant to the Commission's Large Load Model Tariff, defined as individual customers exceeding 50 MW of demand.
>
> **I find it appropriate to use this proceeding to note the work that lies ahead for this Commission in the large load interconnection arena, particularly regarding cost allocation.** Herein, PPL estimates a total cost for the project of $36.4 million. The Company proposes to recover $21.3 million from the customer seeking interconnection while placing the responsibility for the remaining $14.9 million on the Company itself, and therefore ultimately its existing ratepayers.
>
> The Commission has taken a significant step in addressing large load interconnection issues through our aforementioned Large Load Model Tariff. Furthermore, PPL is to be commended for being the first utility in the Commonwealth with a large load tariff approved by this Commission that addresses a number of key issues, including universal service cost recovery, load ramping, MW size, security obligations, exit fees, and interruptibility options. **However, as I noted in my statement approving PPL's Tariff, the Company has not adopted the Commission supported "but for" test when allocating network upgrade costs for large load interconnection.**
>
> We must strive to navigate this energy transition toward an affordable and reliable outcome. **It is evident from review of this LON Project that more work is needed here at the Commission, in coordination with our regulated utilities, customers, and stakeholders, to craft policies that fairly allocate costs of large load interconnection in a way that encourages economic development while maintaining affordability and reliability. With that said, I encourage our electric distribution companies to consider operational and tariff modifications that can support these endeavors.**

[51] Statement of Chairman Stephen M. DeFrank, Letter of Notification of PPL Electric Utilities Corporation for Approval to Construct 138 kV Transmission Lines, Public Meeting of August 6, 2026, Agenda No. 3062201-TUS, Docket No. A-2026-3062201.

Chairman DeFrank's statement made it clear that "work lies ahead" to protect consumers from data center costs while maintaining reliability, including "operational and tariff modifications."

On September 10, 2026, the PUC unanimously adopted a motion directing its Law Bureau and Bureau of Technical Utility Services to 1) draft a tentative order outlining proposed amendments and modifications that EDCs must make to their tariffs to incorporate a pre-emergency provision for large load customers that have secured capacity, as PJM proposed, implementing curtailment protocols within the EDC's emergency load control procedures, and 2) have the PUC host a technical conference this fall to address who should pay the costs that data centers impose on the grid.[52,53]

d. PJM Board of Managers Statements

The PJM Board of Managers (PJM Board) is concerned with both the reliability and cost allocation issues associated with large loads. Regarding reliability, it stated:

> The Board analyzed the various proposals through a particular frame that we thought would be helpful to explain. That frame begins with the organization's mandate to maintain grid **reliability**. As the results of the 2027/2028 Base Residual Auction (BRA) display, the RTO has cleared short of its reliability requirement for the first time in history. The 2027/2028 BRA cleared 5.6% short of our target reserve margin indicating that the system is at higher risk than previous years. The Board views this outcome as a clear signal that current trends are not acceptable and warrant corrective action.[54]

[52] Pennsylvania Public Utility Commission, Commissioner's Motion of Vice Chair Kimberly Barrow, September 10, 2026, https://www.puc.pa.gov/pcdocs/1949305.pdf.

[53] On October 1, 2026, the Commission approved the Tentative Order in M-2026-3064961, which proposes safeguards to protect utility customers and maintain electric reliability as data centers increase grid demand. The T.O. seeks public comment on proposed regulatory changes, including a definition of a data center, or Computational Load Entity (CLE), focused specifically on data center-related large loads and excluding other large loads, such as manufacturing facilities, that are not currently creating the same reliability and cost impacts. The T.O. also proposes definitions for Pre-Emergency Load Control Events, Emergency Load Control Events, and Emergency Forced Outage Events. Among other things, the T.O. would also require EDCs to establish CLE curtailment procedures through mandatory interruptible rate schedules and tariff operating procedures.

[54] PJM, Board Decisional Letter on Critical Issue Fast Path – Large Load Additions, January 16, 2026, p. 1, https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260116-pjm-board-letter-re-results-of-the-cifp-process-large-load-additions.pdf. Emphasis in the original. Also see PJM Independent Market Monitor, CIFP-LLA [Critical Issues Fast Path – Large Load Additions], October 9, 2025, p. 1, https://www.pjm.com/-/media/DotCom/committees-groups/cifp-lla/2025/20251024/20251024-item-04g---imm-memo.pdf, "The current tight/short conditions in the PJM Capacity Market are almost entirely the result of large data center load additions,

To underscore the urgency of the situation, on June 24, 2026, PJM adopted a new capacity advisory emergency procedure because "PJM is now seeing forecasted or actual capacity deficits outside of extreme hot or cold periods and expects these instances to increase as demand growth outpaces the addition of new power resources and the percentage of intermittent generation resources on the grid continues to increase."[55]

Regarding cost allocation, the PJM Board of Managers stated:

> Further, as a mission-driven organization that fundamentally exists as part of a larger system serving consumers, PJM must be conscious of the **affordability** challenges facing the 67 million consumers in our footprint today. There is much that our states can be doing to contend with higher wholesale costs at the retail level. At the same time, as the market administrator, PJM should seek to balance the design of its markets to simultaneously set transparent prices that incent the desired behavior from market participants while not being punitive to consumers.[56]

Note that the PJM Board states that it is important for states to act as well.

As previously mentioned, PJM has also explained that data centers' desired time to market creates additional challenges in reliably connecting those loads to the grid.[57] The concern, therefore, extends beyond whether the transmission system can physically accommodate new data

both actual historical and forecast. The current supply of capacity in PJM is not adequate to meet the demand from large data center loads and will not be adequate in the foreseeable future."

[55] PJM Inside Lines, PJM Adds Emergency Procedures to Maintain Reliability, June 24, 2026, https://insidelines.pjm.com/pjm-adds-emergency-procedures-to-maintain-reliability/?utm_source=news.energycentral.com&utm_medium=newsletter&utm_campaign=daily-template-june-2026-26th-fri.

[56] PJM, Board Decisional Letter on Critical Issue Fast Path – Large Load Additions, January 16, 2026, p. 2, https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260116-pjm-board-letter-re-results-of-the-cifp-process-large-load-additions.pdf. Emphasis in the original. Also see, PJM Inside Lines, PJM Files Price Collar, Expedited Interconnection as Part of Large Load Plan, March 2, 2026, https://insidelines.pjm.com/pjm-files-price-collar-expedited-interconnection-as-part-of-large-load-plan/, "Further efforts directed by the Board remain the focus of intensive deliberation among PJM Members and stakeholders as they address longer-term solutions to issues of insufficient power supplies, affordability and grid reliability in the face of extraordinary demand."

[57] *See* PJM Interconnection, The Challenges with Reliably Connecting Large Loads, May 9, 2025, p. 7, https://www.pjm.com/-/media/DotCom/committees-groups/workshops/llaw/2025/20250509/20250509-item-02---large-load-additions-workshop---presentation.pdf.

centers. The system must also have sufficient supply resources available, at the time the new demand materializes, to serve that demand reliably.[58]

As a result of this rapid and massive demand for electricity in Pennsylvania and the PJM region due to data centers, and the unprecedented speed to power desired by data centers, PJM has identified the rapid growth of data centers as a resource adequacy concern because forecasted electricity demand may increase faster than new generation resources can be brought online.[59] PJM has explained that "forecasted supply may not be sufficient to meet the forecasted load" and that the pace of forecasted load growth creates "timing challenges for needed investment," such that transition mechanisms may be necessary to maintain resource adequacy.[60]

e. Independent Market Monitor (IMM)

The Independent Market Monitor (IMM), operated by Monitoring Analytics, LLC, is an independent organization that monitors PJM's electricity markets and evaluates whether those markets are operating competitively and efficiently. The IMM analyzes how that growth affects electricity demand, capacity-market prices, grid reliability, and the costs borne by other electricity customers. Its findings therefore provide an important market-based perspective for regulators, utilities, policymakers, and the public when assessing the potential effects of continued data-center development. Per the IMM, "[t]he current tight/short conditions in the PJM Capacity Market are almost entirely the result of large data center load additions, both actual historical and forecast.

[58] *See* PJM Interconnection, The Challenges with Reliably Connecting Large Loads, May 9, 2025, p. 7, https://www.pjm.com/-/media/DotCom/committees-groups/workshops/llaw/2025/20250509/20250509-item-02---large-load-additions-workshop---presentation.pdf.

[59] PJM Interconnection, LLC, Large Load Additions Workshop, May 9, 2025, p. 7, https://www.pjm.com/-/media/DotCom/committees-groups/workshops/llaw/2025/20250509/20250509-item-02---large-load-additions-workshop---presentation.pdf.

[60] PJM Interconnection, LLC, Large Load Additions Workshop, May 9, 2025, p. 7, https://www.pjm.com/-/media/DotCom/committees-groups/workshops/llaw/2025/20250509/20250509-item-02---large-load-additions-workshop---presentation.pdf.

The current supply of capacity in PJM is not adequate to meet the demand from large data center loads and will not be adequate in the foreseeable future."[61]

f. PJM Reliability Backstop Procurement and Interim Resource Adequacy Service and Large Load Registry FERC Filings

PJM recently completed its Critical Issues Fast Path (CIFP) stakeholder process that addresses two key aspects of connecting large loads to the PJM system: procuring additional suppliers and curtailing selected large loads when suppliers are short. As a result of the CIFP stakeholder processes, PJM has made two important filings before FERC: (1) on July 31, 2026, PJM filed pursuant to Federal Power Act (FPA) Section 205 revisions to the PJM Open Access Transmission Tariff (OATT) and the Reliability Assurance Agreement Among Load Serving Entities (RAA) to establish the Reliability Backstop Procurement (RBP)[62]—a one-time procurement of new capacity to address resource adequacy challenges in the PJM Region arising from insufficient commitments of capacity in the 2027/2028 and 2028/2029 Reliability Pricing Model (RPM) Auctions, primarily driven by the unprecedented addition of large loads, most notably data centers.

On September 29, 2026, the FERC issued its Order Accepting Reliability Backstop Procurement and Establishing Further Procedures.[63] Relevant to this affidavit, the FERC found that PJM's RBP proposal may be just and reasonable if modified, specifically PJM's RBP cost

[61] PJM Independent Market Monitor, CIFP-LLA (Critical Issues Fast Path – Large Load Additions), Oct. 9, 2025, https://www.pjm.com/-/media/DotCom/committees-groups/cifp-lla/2025/20251024/20251024-item-04g---imm-memo.pdf.

[62] Reliability Backstop Procurement to Address Resource Adequacy and Large Loads, PJM Interconnection, L.L.C., Docket No. ER26-3380, July 31, 2026, (PJM RBP Filing), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260731-5214.

[63] FERC, Order Accepting Reliability Backstop Procurement and Establishing further Procedures, Docket Nos. ER26-3380-000 and ER26-108-000, September 29, 2026 (FERC RBP Order).

allocation method[64] and the RPB collateral for LSEs.[65] Resolution of these issues will delay PJM's proposed RBP schedule.[66]

In this order, the FERC made an important statement, affirming my prior discussion regarding the Public Policy Consensus and the need for states to act.

> We recognize that the rapid emergence of large loads presents a shared regulatory challenge that implicates both federal and state authority. Under the FPA, the Commission oversees rates and practices affecting wholesale service, including PJM's procurement of capacity through the RBP. However, "states determine how Commission-approved rates are collected among the relevant retail consumers along with the rates for state-jurisdictional matters."[67] Specifically, states have authority over how the wholesale costs of providing electricity, including transmission of such electricity to the retail customers, are recovered through retail rates. We are encouraged by the NEDC/PJM Governors' Principles, in which the governors of all 13 PJM states agreed to "[u]se all available authorities to ensure that their state public utility commissions design rate class structures to ensure that their states' LSEs allocate their share of the cost to procure new capacity through the [RBP] to new data center loads that have not otherwise procured capacity or agreed to be curtailable."[68] We are also encouraged by the execution of the President's Ratepayer Protection Pledge, through which data center developers have committed to shield retail ratepayers from increased electricity prices.[69] Our partners in the states are more than capable of ensuring that these promises reach fruition. While we appreciate and take seriously the issues that PJM's RBP proposal is designed to address, as well as the concerns surrounding the unprecedented influx of large loads more broadly, having only such powers as are given to us by Congress, we will not pretend that all of these issues can be solved exclusively by market design in the federal sphere. The PJM states have their own role to play.[70]

Secondly, on August 13, 3036, PJM filed pursuant to Federal Power Act (FPA) Section 205 revisions to the OATT and RAA to establish Interim Resource Adequacy Service (IRAS)—a service to be implemented by PJM solely during periods when there are insufficient resources to

[64] FERC RBP Order, p. 64.
[65] FERC RBP Order, p. 81.
[66] FERC RBP Order, p. 83.
[67] *PJM Interconnection, L.L.C.*, 195 FERC ¶ 61,211, at P 69 (2026); *see also* Transmittal at 106 (quoting the same).
[68] U.S. Department of Energy, Statement of Principles Regarding PJM, January 2026, https://www.energy.gov/documents/statement-principles-regarding-pjm.
[69] The White House, President Trump's Ratepayer Protection Pledge Secures American AI Dominance, Protects Consumers, July 2026, https://www.whitehouse.gov/releases/2026/07/president-trumps-ratepayer-protection-pledge-secures-american-ai-dominance-protects-consumers/.
[70] FERC RBP Order, pp. 64-65, ¶161.

reliably meet demand in real time operations-when triggered by system conditions to prioritize load reduction in zones where new data centers have not brought their own new capacity or had their capacity needs covered through the RBP.[71]

Together, these PJM filings aim to address the region's fundamental resource adequacy problem: supply does not meet demand. The rapid, massive addition of new data centers faster than additional supply that can serve them reduces the resource adequacy of PJM. Resource adequacy is a technical engineering term that quantifies the frequency, duration, and magnitude of supply shortages, i.e., when demand exceeds supply. When these situations occur, PJM must direct EDCs to load shed manually, i.e., involuntarily curtail customers' electricity consumption so supply and demand are in balance. Otherwise, if the supply-demand imbalance persists even for relatively short periods, widespread and prolonged blackouts may occur. Customers who are curtailed to prevent a widespread blackout are, in effect, experiencing a blackout as they do not have access to electricity.

PJM's RBP and IRAS filings attempt to address the forecasted shortages in two ways: the RBP procures additional supply, and IRAS requires new data centers that do not bring sufficient new supply to serve their load to be curtailed first. This reduces the risk that PJM and the EDCs will have to involuntarily curtail ordinary ratepayers. The IRAS filing also removes forecasted data center load that does not bring its own new capacity from the PJM BRA.

Relevant to the purposes of this filing, the RBP proposal has the following elements:

- Establishes a final RBP target based on the observed MW UCAP shortfall (the amount of resource capacity, measured in units of unforced capacity [UCAP] by which PJM falls short of

[71] Proposal to Establish Interim Resource Adequacy Service and a Large Load Registry to Address System Reliability, Docket No. ER26-3515, August 13, 2026, (PJM IRAS Filing), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260813-5118

its resource adequacy standard) in the Base Residual Auction (BRA) for the delivery year 2028/2029[72] and any qualifying RBP offset UCAP MW;[73]

- For one time only,[74] procures RBP UCAP from RBP resources for a fixed term of up to 15 years, starting with the 2028/2029 delivery year and ending with the 2042/2043 delivery year;[75]
- PJM serves as the counterparty that directly procures the RBP resources on behalf of buyers, similar to the role that PJM plays in the traditional capacity market;[76]
- PJM charges the cost of RBP UCAP to buyers[77] and those buyers must post credit associated with the obligation;[78]
- RBP charges are allocated to electric distributor zones/areas and further allocated to load serving entities (LSE) within the relevant zone/area.[79] As noted previously, LSEs are the entities that purchase wholesale electricity on behalf of their retail customers from PJM. LSEs are registered with PJM and must meet a variety of requirements, including paying for purchases made through PJM on behalf of their customers.
- It requires states to assign the RBP costs to retail loads[80] via the RBP obligation (RBO), which is the state and/or RERRA (relevant electric retail regulatory authority)-determined allocation of RBP UCAP MW to LSEs within each zone/area;[81]
- If RBOs are not reported to PJM, PJM will allocate the RBO to all load in the zone/area base on its peak load contribution;[82]

[72] PJM RBP FERC Filing, p. 8
[73] PJM RBP FERC Filing, p. 32
[74] PJM RBP FERC Filing, p. 25.
[75] PJM RBP FERC Filing, p. 8.
[76] PJM RBP FERC Filing, p. 47.
[77] PJM RBP FERC Filing, p. 82.
[78] PJM RBP FERC Filing, p. 114.
[79] PJM RBP FERC Filing, pp. 96-97.
[80] PJM RBP FERC Filing, p. 11.
[81] PJM RBP FERC Filing, p. 98
[82] PJM RBP FERC Filing, p. 99.

Relevant to the purposes of this filing, PJM's IRAS and Large Load Registry proposal has the following elements:

- Establishes the Large Load Registry that PJM maintains[83] to improve the accuracy and transparency of load forecasts and to administer the RBP and IRAS;[84]
- Proposes IRAS, a new capacity product for large loads that, after May 31, 2027,[85] neither brings new capacity (BYONC)[86] nor purchases capacity from the RBP; such loads are to be curtailed before pre-emergency load management response[87] by electric distributors based on state-sanctioned load reduction plans;[88]
- Encourages states to re-evaluate their load reduction plans;[89]
- Proposes that curtailed IRAS load is compensated[90] and the costs assigned by electric distribution tariffs;[91] and
- Excludes new large loads that do not bring their own new capacity from the Variable Resource Requirement (VRR) Curve in the BRA to protect ordinary ratepayers from further capacity price increases.[92]

[83] PJM IRAS FERC Filing, p. 5.
[84] PJM IRAS FERC Filing, p. 17 and pp. 45-46, "In addition, PJM proposes to obtain information from Electric Distributors, to coordinate with applicable Transmission Owners and Electric Distributors, as needed, to validate the information provided in the Large Load Registry, and/or to consult with relevant Large Loads."
[85] PJM IRAS FERC Filing, p. 52: "Given that PJM is currently short of capacity and looking to reestablish a healthy capacity reserve margin, PJM is proposing that any capacity added to the system starting with the 2027/2028 BRA will qualify as new–subject to the gating criteria discussed below, while capacity already on the system would not fall within the definition of BYONC."
[86] PJM RBP FERC Filing, p. 23.
[87] PJM IRAS FERC Filing, p. 21.
[88] PJM IRAS FERC Filing, p. 6 and p. 76, "Interim Resource Adequacy Service may be called on, as necessary, to maintain required RTO/Zonal Reserves, IROLs [Interconnection Reliability Operating Limits] within limits, and/or prevent cascading outages if available economic generation is not sufficient."
[89] PJM IRAS FERC Filing, p. 3.
[90] PJM IRAS FERC Filing, p. 17.
[91] PJM IRAS FERC Filing, p. 104: "The IRAS rate is compensation for a wholesale load reduction service, but the entities to be paid the rate and the loads to be charged to support such compensation must be determined at the state level consistent with the Electric Distributor's state-approved load reduction plans and other state-approved programs, ratees, and rules."
[92] PJM IRAS FERC Filing, pp. 5-6.

All these provisions, except for the last one, require state action by the Commission and electric distribution utilities. Given the ongoing and dynamic nature of the RBP and IRAS filings at FERC, the key takeaway is that Pennsylvania needs to act now to protect ordinary ratepayers from reduced reliability and shifting costs, regardless of what FERC approves.[93]

V. NERC Large Load Action Plan and Definition of Computational Load

As noted previously, NERC is the North American Electric Reliability Corporation. It develops and enforces reliability standards that are approved by FERC under the Federal Power Act,[94] monitors the bulk power system, assesses resource adequacy, audits owners, operators, and users for preparedness, and educates and trains industry personnel.[95]

NERC has initiated its Large Loads Action Plan to address the unique reliability challenges of data centers.[96] As part of this effort, NERC is requesting comments on the following definition:[97]

> Computational Load Site: One or more buildings, structures, or installations at a single location that:
> 1. primarily contains information technology infrastructure used for:
> - creating, executing, and delivering software applications and services;
> - artificial intelligences (sic) training, deployment, and delivery;
> - cryptocurrency mining; or

[93] Both the RBP and IRAS filings are replete with calls for both states and EDCs to act. See, for example, PJM RBP FERC Filing, p. 10: "The PJM states will each play a central role in protecting their respective residential customers from cost shifts. Indeed, as a product of cooperative federalism, the RBP specifically contemplates a framework in which both PJM and the PJM states have distinct roles, within the boundaries of their respective jurisdictional authorities." Also see PJM IRAS FERC Filing, p. 3: "It [IRAS] is an example of a federal regime encouraging (but not mandating) states to re-evaluate load reduction plans, which are traditionally in the state jurisdictional bailiwick, while providing PJM the necessary tools to address situations where regional resource adequacy shortfalls would jeopardize reliability. In this regard, it is an example of the federal regime helping to effectuate state decisions associated with the rates, terms, and conditions of retail service."

[94] FERC, Grid Reliability and the Role of the Federal Energy Regulatory Commission, August 28, 2026, https://www.ferc.gov/grid-reliability-and-role-federal-energy-regulatory-commission.

[95] NERC, Who We Are, https://www.nerc.com/who-we-are. See also FERC, Reliability Explainer, https://www.ferc.gov/reliability-explainer.

[96] NERC, Large Load Action Plan, https://www.nerc.com/initiatives/large-loads-action-plan and Project 2026-02 Computational Loads, https://www.nerc.com/standards/reliability-standards-under-development/2026-02-computational-loads.

[97] NERC, Draft 1 of CLO-002-1 Computational Load Operational Data and Communication, August 2026, 2, https://www.nerc.com/globalassets/standards/projects/2026-02/formal-posting-1/formal-posting-1/project-2026-02-clo-002-1-draft-1-clean.pdf.

• other computational activities at a data center; and

2. is supplied through electrical equipment that is connected to the Bulk-Power System.

Because FERC, PJM, the PA PUC, and NERC use different terms and definitions for large loads, it is not necessary to pick one; the relevant definition should be used in context. PJM's definition of large load should be used for PJM's RBP and IRAS and large load initiatives, and NERC's definition should be used for reliability requirements and tariff provisions. However, a definition of large load is needed for retail electricity cost allocation to ensure that existing industrial customers that are not computational loads are not allocated costs they did not cause.

VI. Reliability Impacts and Risks Due to Large Loads

Previously, I observed that data centers are the predominant driver of new large-load interconnection requests and differ materially from legacy large-load customers in scale, their pace of development, and operational characteristics.[98] As customers, data centers present unique risks to reliable electric utility service due to their large peak demands, high load factors, and development uncertainty.[99]

In this section, I explain the risks specific to PJM resource adequacy that computational large loads pose to the grid and to Pennsylvania EDC distribution systems. I also describe the role of PJM's Attachment O to Manual 13 (emergency operations affecting data centers) and the need

[98] Rachel Mural, Dipesh Pherwani, Chaitanya Gupta, Yiqi Yu, Ai Takahashi, Dongjoo Kim, Subir Majumder, Henry Lee, Minlan Yu, and Le Xie, AI, Data Centers, and the U.S. Electric Grid: A Watershed Moment, February 2026, p.2, https://www.belfercenter.org/research-analysis/ai-data-centers-us-electric-grid, "In July 2024, a voltage fluctuation in northern Virginia triggered the simultaneous disconnection of 60 data centers, prompting a 1,500-megawatt (MW) power surplus, which forced emergency adjustments to prevent cascading outages." The report states, on page 5, "Data centers use large, steady electricity loads with limited ability to reduce (or ramp down) their power usage; simultaneously, their energy demand can fluctuate according to equipment usage and job complexity."

[99] NERC, Large Load Action Plan, https://www.nerc.com/initiatives/large-loads-action-plan, "An increasing number of large commercial and industrial loads are rapidly connecting to the bulk power system (BPS). Emerging large loads—such as data centers (including cryptocurrency and artificial intelligence applications), hydrogen fuel plants, and others—present unique challenges in BPS planning and operations. In addition to the rapid growth of emerging large loads, their electrical behavior can be distinctive and often less predictable than that of conventional loads. These unique characteristics pose risks to the BPS that need to be understood and managed."

for state-level protections to be linked to PJM policies to protect residential and small commercial customers.

A. Power System Reliability: Operational Security and Resource Adequacy

Data centers can adversely affect power system reliability. NERC is concerned with the reliability impacts of large loads. Its Chief Executive Officer has said, "I've called this a hyper-complex risk environment for the sector. I've been quoted as describing the situation as a five-alarm fire."[100] According to NERC, "Projected annual energy demand rose to nearly 4.95 million GWh in 2025, while actual summer peak demand in several areas approached or exceeded the normal forecast. Data center and computational loads continued emerging as a major reliability consideration due to their scale, speed of development, and unique operational characteristics."[101]

Power system reliability consists of resource adequacy and operational security.[102] Resource adequacy is "The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."[103] Operational reliability is the ability of the electric power grid to withstand sudden outages of large power plants or transmission facilities while maintaining grid stability without load curtailments.[104]

Data centers affect operational security if a sufficiently large number of them trip offline, i.e., intentionally disconnect electrically from the grid, in response to fluctuations in voltage or current. Data centers disconnect from the grid and rely on their backup power to ensure continued operations during power system blackouts. In Virginia alone, several such events on

[100] Jennifer Hiller, The Wall Street Journal, The 'Five Alarm' Risks Facing the Power Grid This Summer, July 2, 2026, https://www.wsj.com/business/energy-oil/the-five-alarm-risks-facing-the-power-grid-this-summer-3404b031.
[101] NERC, 2026 State of Reliability: Assessment Overview of 2025 Bulk Power System Performance, June 24, 2026, p. vii, https://www.nerc.com/globalassets/programs/rapa/pa/nerc_sor_2026_overview.pdf.
[102] FERC, Reliability Explainer, August 16, 2023, https://www.ferc.gov/reliability-explainer.
[103] NERC, Glossary of Terms, https://www.nerc.com/glossary-of-terms?q=resource+adequacy.
[104] NERC, NERC Issues Level 3 Alert, Reliability Guideline Focused on Large Load Challenges, May 4, 2026.

July 22, 2026, February 17, 2025, and July 10, 2024, almost resulted in blackouts.[105] If enough data centers disconnect in a short enough period, the power system may not be able to withstand this large reduction in load, resulting in power outages or even blackouts. A power outage occurs when one or more customers do not have electricity, whereas a blackout refers to large-scale power outages across a city or region.

Data centers also affect resource adequacy. Their rapid, massive deployment without accompanying supplies reduces resource adequacy. NERC's long-term reliability assessment of its Reliability First region, which includes parts of the PJM, is that it is "high risk," its highest risk designation.[106] According to NERC, "In high-risk areas, planned resources as of July 2025 would result in energy shortfalls that exceed resource adequacy targets or baseline criteria for unserved energy or loss of load."[107] Specifically for PJM, NERC states:

> Current projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements. The anticipated resource margin falls below the Reference Margin Level starting in 2029. Recently approved new generation projects for expedited interconnection under the PJM Reliability Resource Initiative were not far enough to include in the LTRA [Long-Term Reliability Assessment] risk analysis.[108]

When the power system is short-supplied (i.e., resources are inadequate), PJM may have to, as a last resort, require EDCs to disconnect some load to return the system to load-supply equilibrium and avoid cascading outages that could lead to a blackout. PJM refers to this situation

[105] PJM Inside Lines, PJM, Dominion Review Large Load Transfer Event, August 11, 2026, https://insidelines.pjm.com/pjm-dominion-review-large-load-transfer-event/. Also see Shane Snider, Data Center Knowledge, Fault in Data Center Alley Triggered 3 GW Load Drop, July 23, 2026, https://www.datacenterknowledge.com/outages/fault-in-data-center-alley-triggered-3-gw-load-drop-on-pjm.

[106] NERC, Long-Term Reliability Assessment, January 2026, p. 7, https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[107] NERC, Long-Term Reliability Assessment, January 2026, p. 6. NERC states in footnote 8, "The criteria used for risk determination in the LTRA include resource adequacy targets established by regulatory authorities."
traditional 1-day-in-10 years load-loss criteria, and probabilistic loss-of-load-hour and expected unserved energy metrics.

[108] NERC, Long-Term Reliability Assessment, January 2026, p. 8.

as "manual load dump" or "load shed,"[109] but the term "rolling blackout" is also used. Because the EDC can choose which loads to curtail (PJM does not make that determination), resource adequacy and curtailment plans are linked (unlike cascading load outages due to operational security, which PJM and the EDCs do not control).[110] NERC, PJM, and the EDCs have a coordinated set of procedures that are invoked as anticipated supply shortages emerge to prevent such shortages and mitigate their size and duration. NERC has a series of Energy Emergency Alerts (EEAs) PJM progressively issues as required,[111] PJM has more specific and detailed emergency operations procedures that it follows beyond NERC's EEAs,[112] and EDCs have emergency load control and energy conservation plans that are implemented, in part, based upon PJM instructions.[113] In addition, the Department of Energy can issue 202(c) orders to PJM under the Federal Power Act to dispatch generation units and direct their operations as needed to maintain reliability.[114]

NERC has found that the rapid integration of data centers can create reliability impacts extending to the distribution system.[115] The addition of large loads may increase a transmission owner's need to shed load, including under-frequency load-shedding (UFLS), and may require the transmission utility to coordinate with EDCs to disconnect all of its residential customers while still failing to satisfy its load shedding requirements.[116] NERC further warns that the hasty addition

[109] PJM Manual 13, Emergency Operations, Revision 98, June 24, 2026, https://www.pjm.com/-/media/DotCom/documents/manuals/m13.pdf.
[110] PJM Manual 13, Emergency Operations, Revision 98, June 24, 2026, p. 13, https://www.pjm.com/-/media/DotCom/documents/manuals/m13.pdf.
[111] NERC, EOP011-4, Emergency Operations, https://www.nerc.com/globalassets/standards/reliability-standards/eop/eop-011-4.pdf.
[112] PJM Manual 13, Emergency Operations, Revision 98, June 24, 2026, https://www.pjm.com/-/media/DotCom/documents/manuals/m13.pdf.
[113] 52 Pa. Code § 57.52, https://www.law.cornell.edu/regulations/pennsylvania/52-Pa-Code-SS-57-52.
[114] U.S. Department of Energy, 2026 202(c) Orders, https://www.energy.gov/ceser/2026-doe-202c-orders.
[115] NERC, Characterization and Risks of Emerging Large Loads, July 2025, p. 36, https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf.
[116] NERC, Characterization and Risks of Emerging Large Loads, July 2025, p. 36, https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf.

of large loads creates a risk that "the local distribution system may not contain enough load to cover the UFLS requirements," potentially requiring transmission-level load to be included in UFLS programs.[117]

B. Data Centers are Challenging PJM's Resource Adequacy

The Reliability First Corporation is the NERC regional organization responsible for ensuring the reliability and security of the PJM region.[118] Its resource adequacy criterion is "one day in ten years," meaning that the PJM region should have sufficient resources to avoid mandatory load curtailment no more than one day in 10 years.[119] As documented by Mr. Teti, the PJM wholesale market has cleared short twice in a row, below the one-in-ten-year criterion,[120] or the PJM Regional Reliability Requirement.[121] Furthermore, Mr. Teti finds that large computational loads are forecasted to be substantial, even with the downward adjustments that PJM and the Commission have implemented.[122] PJM also has acknowledged the problem: "Insufficient commitments of capacity in the 2027/2028 and 2028/2029 Reliability Pricing Model (RPM) Auctions, primarily driven by the unprecedented addition of large loads, most notably data centers,

[117] NERC, Characterization and Risks of Emerging Large Loads, July 2025, p. 36, https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf.
[118] Reliability First, Forward Together, https://www.rfirst.org.
[119] Tim Fryfogle, ReliabilityFirst, ReliabilityFirst Long-term Reliability Assessment highlights resource adequacy risk in MISO, PJM over next 10 years, January 13, 2025, https://www.rfirst.org/resource-center/reliabilityfirst-long-term-reliability-assessment/.
[120] See Mr. Zachary Teti's affidavit.
[121] PJM IRAS FERC Filing, p. 53 and PJM Inside Lines, PJM Capacity Auction Procures 138,318 MW of Generation Resource as Work Continues To Address Growing Electricity Demand, July 14, 2026, https://insidelines.pjm.com/pjm-capacity-auction-procures-138318-mw-of-generation-resources-as-work-continues-to-address-growing-electricity-demand/: "The capacity of the resources procured in the auction, plus FRR resources, is short of PJM's reliability requirement by 6,831 MW, meaning that the committed supply is less than what would be required to meet the one-event-in-10-year reliability standard."
[122] See Zachary Teti's affidavit. See also PJM Interconnection, L.L.C., Reliability Backstop Procurement to Address Resource Adequacy Concerns Stemming From Large Loads, Docket No. ER26-3380-000 (F.E.R.C. filed July 31, 2026), p. 8: "Last year, PJM's BRA [Base Residual Auction] for the 2027/2028 Delivery Year, which ran from December 4, 2025, through December 10, 2025, likewise cleared 6,623 MW short of the PJM Region Reliability Requirement, at the market cap of $333.44/MW-day (UCAP)."

have given rise to resource adequacy shortfalls—and associated real-time operational issues that IRAS is intended to address."[123] The PUC has found the following:[124]

> The impact of data centers and other large load customers in both Pennsylvania and PJM's broader footprint is significant. Among other factors, an insufficient level of construction of electric generation and continued retirement of base load electric generation is resulting in the need for stakeholders such as policy makers, regulators, utilities, and generation owners, to work together to ensure the continued reliable operation of the BES. PJM in particular must manage a significant impact from data centers. It continues to be essential that stakeholders address resource adequacy to ensure ERS are maintained and the BES functions reliably.

A September 14, 2026, independent report commissioned by the PUC makes this point in stark terms:[125]

> Pennsylvania's electricity system is experiencing a tightening of supply and demand. State and regional load is growing, largely due to data center development, and supply is constrained as aging generators retire and new resource deployment is hindered. These two simultaneous trends cause high electricity prices, and also expose other challenges: recent assessments from grid operator PJM and the North American Electric Reliability Corporation (NERC), the national body charged with regulating electric system reliability, have both identified PJM's system as stressed, with looming reliability concerns.

The report continues (emphasis added):

> The team modeled three scenarios and found the following: in both the Reference scenario and the High Load And Low Supply scenario, we find that from 2027 through 2030, the PJM planning criterion for resource adequacy (loss of load expectation or "LOLE" of 0.1) is not met in PJM. Meanwhile, in the No New Data Centers scenario, LOLE is below this 0.1 threshold (see Table 1).
>
> In the Reference scenario, which relies on PJM's 2026 Load Forecast, modeled 2030 LOLE is 0.59 or nearly six times worse than the PJM planning criterion. This result is mainly due to large-load additions stemming from data center additions, which are projected to surge in 2030. In 2030, the High Load and Low Supply scenario, a worst-case future of higher-

[123] PJM IRAS FERC Filing, p. 6. See also Patricio Rocha Garrido, PJM, *Estimated Preliminary Resource Adequacy Metrics for 2028/2029 Under Different Shortage Levels*, CIFP-LLA, Oct. 21, 2025. https://www.pjm.com/-/media/DotCom/committees-groups/cifp-lla/2025/20251021/20251021-item-03---estimated-preliminary-resource-adequacy-metrics-for-2028-2029-under-different-shortage-levels---pjm-presentation.pdf and https://www.pjm.com/-/media/DotCom/committees-groups/cifp-lla/2025/20251021/20251021-agenda---updated.pdf.

[124] PAPUC, Electric Power Outlook for Pennsylvania 2025-2030, August 2026, p. 6, https://www.puc.pa.gov/filing-resources/reports/electric-power-outlook-report/.

[125] Synapse Energy Economics, Inc., "Assessing Electricity Resource Adequacy in Pennsylvania and PJM, September 14, 2026, p. ii, https://www.puc.pa.gov/media/4044/2026_assessing_electricity_resource_adequacy_in_pa_and_pjm.pdf.

> than- expected load additions and constrained resource deployment, has an LOLE of 13.20. This LOLE value is over 100 times worse than PJM's planning criterion and indicates an expectation of more than 13 days with loss of load events per year. As in the Reference scenario, these reliability issues are largely due to surging data center additions. In the High Load forecast, data centers are projected to contribute over 200 TWh of additional new load between 2029 and 2030 PJM-wide. (For reference, the entire state of Pennsylvania's 2025 electricity demand was about 150 TWh). In this High Load and Low Supply scenario, in-state generators are unable to meet between 2 and 19 percent of PJM-wide electricity between 2031 and 2040.

The ongoing and forecasted reduction in PJM's resource adequacy requires protecting ordinary ratepayers from being curtailed due to the rapid, massive deployment of data centers. First, the Commission must take appropriate regulatory action to ensure that EDCs prepare for the implementation of PJM's IRAS proposal and the possibility that IRAS is not adopted or put on hold due to litigation. The Commission must also ensure that, during resource shortages beyond any IRAS load reductions, EDCs curtail non-IRAS data centers before ordinary ratepayers.

Curtailing non-large computational loads, especially residential, threatens safety, public health, and economic activity. For example, without electricity, street and traffic lights do not work, hospitals and other medical facilities must reduce or shut down their operations, pharmacies close and cannot process prescriptions, residents may not have access to heat or cooling, at-home medical devices such as dialysis and oxygen equipment may not be able to function, and economic activity comes to a standstill as many business shut down and may lose inventory that requires refrigeration or support from electrical equipment. These are only a few examples of the critical services that require electricity. Government reports, scholarly research, and observations extensively document these safety, health, and economic consequences of blackouts.[126]

[126] For example, see Oak Ridge National Laboratory, Analysis shows power outages of US electricity customers billions, March 4, 2026, https://www.ornl.gov/news/analysis-shows-power-outages-cost-us-electricity-customers-billions, Casey, Joan A., et al. "Power outages and community health: a narrative review." *Current environmental health reports* 7.4 (2020): 371-383, https://pmc.ncbi.nlm.nih.gov/articles/PMC7749027/pdf/nihms-1646047.pdf, and Andresen, Adam X., et al. "Understanding the social impacts of power outages in North America: a systematic review." *Environmental Research Letters* 18.5 (2023): 053004.

Data centers, however, have multiple options and the financial resources to avoid being curtailed (BYONC, co-location, demand response [DR]), have backup generation, and have stated their willingness to do so.

- Even if there were not resource adequacy concerns, it is prudent for EDCs to update their tariffs, curtailment plans, and procedures in response to a new type of load.
- Given the looming resource adequacy concerns, it is even more important for EDUs to update their curtailment plans.
- PJM expects EDCs to curtail large computational load, as laid out in its IRAS filing.

Pennsylvania EDCs should ensure that all large loads are curtailed before residential consumers and are subject to substantial, timely state penalties, in addition to any penalties imposed by the FERC or NERC, for non-compliance[127] to ensure this requirement is met. An exception to this large load curtailment-first policy could be warranted for the certified portion of a large load deemed critical or vital by the federal government or Pennsylvania, so long as the large load can curtail all its remaining non-critical load. To ensure this, discovery as part of a formal proceeding involving EDCs is necessary. Mr. Matthew T. Hoytt's affidavit further discusses this topic.

VII. Increasing Wholesale Market Cost Increases Due to Large Loads

PJM wholesale markets consist of products for energy, capacity, and selected ancillary services. Pricing for these products is based on the marginal cost of providing one more unit of the product under given supply and demand conditions, subject to any bid, offer, or price caps. Because these prices are based on marginal costs, not average costs, higher demand raises prices

[127] NERC is the North American Electric Reliability Corporation, which has authority via FERC to enforce NERC and regional reliability standards, including issuing monetary penalties and/or non-monetary sanctions, https://www.nerc.com/programs/enforcement.

as more expensive resources are needed to produce each additional unit. Data centers increase the demand for energy and capacity and therefore raise prices and wholesale costs, which flow to retail rates and consumers' electricity bills.[128]

The PJM Independent Market Monitor (IMM), Monitoring Analytics, LLC, has repeatedly been on record tabulating the increased capacity costs due to data centers. In August 2026, the IMM reported that the cumulative cost increases due to future data center demand starting with the 2025/2026 Base Residual Auction (BRA), amount to over $29 billion and will continue to grow.[129] The IMM has also documented increases in wholesale prices for energy, capacity, and ancillary services in the last 12 months, which are presented in Table 1.

Table 1: Rapid Rise in Energy, Capacity, and Ancillary Services Prices from 2025 (Jan-Jun) to 2026 (Jan-Jun) [130]

Category	2025 (Jan-Jun) $/MWh	2026 (Jan-Jun) $/MWh	Percent Change
Energy	$49.21	$72.68	47.7%
Capacity	$6.39	$19.61	207.1%
Transmission	$18.82	$19.88	5.6%
Ancillary Services	$1.06	$1.63	53.7%

VIII. Reliability Backstop Procurement, Transmission and Distribution Stranded Cost Risks

Data centers increase costs for bulk grid services and present unique cost-shifting risks to existing customers if interconnection and service proceed without adequate customer protection

[128] Meeks, R., Pless, J., Qi, Z., & Wang, Z. (2026). Who Pays for Growth? Evidence from Data Centers and the Grid, MIT CEEPR Working Paper Series, https://ceepr.mit.edu/workingpaper/who-pays-for-growth-evidence-from-datacenters-and-the-grid/.
[129] Monitoring Analytics, 2026 Quarterly State of the Market Report for PJM: January through June, August 13, 2026, pp. 1-2, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2026/2026q2-som-pjm.pdf.
[130] Monitoring Analytics, LLC, Independent Market Monitor for PJM, 2026 Quarterly State of the Market Report for PJM: January through June, August 13, 2026, p. 20, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2026/2026q2-som-pjm.pdf.

mechanisms.[131] Data centers also materially influence distribution, transmission and generation planning outcomes by requiring large amounts of new generation and transmission facilities to serve them.[132] This creates the risks of future stranded costs and cost-shifting.

Stranded costs are the costs of utility assets built to serve a particular customer or group of customers that no longer use enough service to justify them (i.e., stranded assets). As a result, the utility cannot appropriately recover these costs, including its return on those assets from that customer or group of customers. Generation (e.g., via the RBP), transmission, and/or distribution facilities can become stranded assets. Ratepayers may end up paying for the stranded costs of assets built to serve large loads because they did not interconnect at the time and amount forecasted, or they halted service prematurely. When this occurs, EDCs do not receive the expected payment from data centers and attempt to recover their costs from ordinary ratepayers. Increasing electricity rates through cost shifting from large loads to ordinary ratepayers, whether directly due to the impact of data centers or due to the risk of stranded costs, is an affordability issue. The size of data centers, fluctuations and revisions in their forecasted demand by PJM and utilities, and the general uncertainty surrounding AI all underscore the real and large risk of stranded costs.

[131] Rachel Mural, Dipesh Pherwani, Chaitanya Gupta, Yiqi Yu, Ai Takahashi, Dongjoo Kim, Subir Majumder, Henry Lee, Minlan Yu, and Le Xie, AI, Data Centers, and the U.S. Electric Grid: A Watershed Moment, February 2026, p. 2, https://www.belfercenter.org/sites/default/files/2026-02/Mural%20et%20al_AI%20Data%20Centers%20Grid_20260206.pdf, "While overregulation could hinder AI development, insufficient regulation risks grid instability, rising consumer costs, reliance on high-emission energy sources, public backlash, and setbacks to state and corporate climate goals."

[132] See, for example, State of Maryland Office of People's Counsel, PJM Transmission Cost Impacts on Electricity Customers in Maryland An Overview of PJM Transmission Planning and Costs, March 2026, p. 1, https://opc.maryland.gov/Portals/0/Files/Publications/Rising%20Transmission%20Costs%202026-03-25%20CORRECTED%20FINAL.pdf, which finds that PJM may assign Maryland ratepayers an additional $5.4 billion in new capacity costs between 2031 and 2035. See also, Union of Concerned Scientists, New UCS Analysis Reveals Billions of Dollars in Unreported Data Center Costs Passed onto PJM Customers, September 29, 2025, https://www.ucs.org/about/news/billions-dollars-unreported-data-center-costs-pjm, which states "A new analysis by the Union of Concerned Scientists (UCS) reveals how millions of people across Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia are footing the bill for an additional $4.3 billion in electricity infrastructure projects approved in 2024 solely to connect wealthy private companies' data centers."

EDCs should demonstrate that their distribution and transmission cost assignment policies and tariff provisions ensure that non-large loads do not pay any of the costs or bear any of the risk of stranded investment due to large loads. Where they cannot, they could or propose tariff modifications to mitigate that risk, as I discussed above regarding the Ratepayer Protection Pledge. This recommendation is also consistent with the Commission's Large Load Model Tariff, which requires all but-for costs of interconnection and service to be directly assigned to the large load and recovered through a customer contribution.[133] The EDCs should also demonstrate that their tariffs require sufficient credit and collateral from large loads to cover all costs attributable to them, including potential stranded investment, or propose modifications to their contracts with the interconnecting customers to achieve this. As noted above in describing PJM's RBP proposal, PJM explicitly acknowledges that it may shift RBP costs to non-large load customers unless states act. To ensure cost shifting will not occur, discovery as part of a formal proceeding involving EDCs is necessary. Mr. Matthew T. Hoytt and Dr. Serhan Ogur's affidavits discuss these topics further.

IX. Summary and Conclusion

I reserve the right to update any portion of my affidavit as needed if additional relevant information is made available.

[133] PAPUC, PUC Releases Final Order Establishing First-of-Its-Kind Large Load Model Tariff Framework, May 13, 2026, p. 42, https://www.puc.pa.gov/press-release/2026/puc-releases-final-order-establishing-first-of-its-kind-large-load-model-tariff-framework-05132026.

Appendix B – Felder Affidavit – Attachment A

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SUMMARY

Internationally recognized inter-disciplinary researcher, advisor, and educator in the electricity sector

- Author/co-author of 53 peer-reviewed publications and numerous research reports, book chapters, discussion papers, policy briefs, and presentations (Google Scholar profile)
- Rank in top 1.2% of researchers worldwide and 0.51% in energy by ScholarGPS
- Advised national and state governments on clean energy policy, electricity markets, renewables and energy efficiency in China, India, Gulf Cooperation Council, and elsewhere
- Awarded over $23 million in research grants and contracts
- Presented in 15 countries and trained 3,000+ professionals from 40+ countries in electricity markets
- Directed large research and advisory teams at major research university and international think tank
- Consulted with all parts of the electric power industry domestically and internationally

PROFESSIONAL AND ACADEMIC EXPERIENCE

Principal, Independent Electricity Consultants, LLC, 1998 to present, expert witness, consulting, and training services to the electric power industry on wholesale and retail electricity markets throughout North America, Canada, Africa, Asia, and Europe. Clients included RTOs/ISOs, USAID, EPA, EIA, NARUC, NASEO, generators, transmission companies, energy service companies, rate payer advocates, and law firms.

Senior Visiting Researcher, Oxford Institute for Energy Studies, Jun. 2023 to present

Program Director, Renewables and Utilities (formerly Energy Transitions and Electric Power), KAPSARC, International Energy Think Tank, Riyadh, Saudi Arabia, Dec. 2020 to Dec. 2022

- Led program of 10 engineers and economists with a budget of $3.2 million conducting research and providing advisory services involving power system modeling, renewable integration, demand management, smart meters, rate design, cost of service, industrial development, electric vehicles, electricity innovation, and green hydrogen
- Also*, Acting Program Director, Markets and Industrial Development*, Jun. 2021 to Oct. 2021
  Led program of 12 economists, MBAs, and analysts on oil, natural gas, and petrochemicals with a budget of $5.5 million conducting research and providing advisory services on oil supply-demand modeling, hydrocarbon markets and policies, storage, and blue hydrogen
- Visiting Researcher, March 1, 2023 to February 28, 2025

Research Professor, Edward Bloustein School of Planning and Public Policy, Rutgers University, New Jersey, Jul. 2018 to Nov. 2020*, Associate Research Professor*, Sep. 2007 to Jun. 2018, *Assistant Research Professor*, Sep. 2004 to Aug. 2007

- *Director,* Rutgers Energy Institute, July 2018 to September 2020, led 70+ interdisciplinary faculty and staff institute on research, education and outreach initiatives sponsored by the Deans of Arts and Sciences, Business, Engineering, Environmental and Biological Sciences, and Planning and Policy
- *Director*, Center for Energy, Economics & Environmental Policy, October 2006 to November 2020, *Acting Director*, Feb. 2006 to Sep. 2006, conducted policy and economic analyses for the New Jersey Board of Public Utilities
- *Program Director*, Public Informatics, Bloustein School of Planning and Public Policy, Jul. 2018 to Nov. 2020, developed new master's program in data science and analytics for planning and policy students

Public

Assistant Professor of Management, Manhattan College, School of Business, NYC, 2002-2004

Senior Consultant, The Economics Resource Group, Inc., Cambridge, MA, 1994-1998

Nuclear Engineer and Officer, U.S. Navy, 1987-1992

EDUCATION

Massachusetts Institute of Technology, Cambridge, MA
- Ph.D. in Technology, Management and Policy (Engineering Systems Division), September 2001, Probabilistic Risk Analysis of Restructured Electric Power Systems: Implications for Reliability Analysis and Policies
- M.S. in Technology and Policy, 1994

Columbia University, New York, NY, B.S. Applied Mathematics, 1987; B.A. Mathematics, 1987

PUBLICATIONS AND RESEARCH (*indicates student or post-doctoral advisee)

Peer-Reviewed Publications

Boukadoum, N., Zerouti, M., Zouaghi, I., Felder, F.A., & Benhassine, W. (2026). Regulating electricity distribution concessions after reform: Benchmarking efficiency, productivity, and scale in Algeria. *Utilities Policy*, https://doi.org/10.1016/j.jup.2026.102321.

Albalawi, A., Nezamuddin, N., Muhsen, A., Gertin, T., Felder, F. A., Almansour, A., & Elshurafa, A. M. (2026). A spatial and technical assessment of floating offshore wind energy in the red sea using a GIS–AHP framework. *Scientific Reports*, https://doi.org/10.1038/s41598-026-49570-4.

Alhadhrami, K., Petitet, M., Abouof, S., Darandary, A., Laing, T., Felder, F., and Elshurafa, A. (2026). Achieving Net-Zero in Saudi Arabia's Power Sector by 2060 considering land and mineral availability, Energy, 140067, https://doi.org/10.1016/j.energy.2026.140067.

Kumar,* P., Caggiano, H., Shwom, R., Felder, F., and Andrews C., (2025). "Reflections on Energy Efficiency Policies in Sustainable Transition: Bedrock, Gramechanger, or More of the Same?" Environmental Policy and Governance, https://doi.org/10.1002/eet.70022.

Petitet, M., Felder, F., and Elshurafa, A. (2025). "Cross-Border Electricity Trading in the GCC Countries, Egypt, Jordan and Iraq: Hourly Market Coupling or Bilateral Agreements?" Energy, 136320, https://doi.org/10.1016/j.energy.2025.136320.

Petitet, M., Felder, F., and Elshurafa, A. (2024). "Finding Opportunity in Economic Power Dispatch: Saving Fuels Without Impacting Retail Electricity Prices in Fuel-Producing Countries," Energy Economics, 138, 107841, https://doi.org/10.1016/j.eneco.2024.107841.

Petitet, M., Ünel, B. and Felder, F. (2023). "Making Electricity Capacity Markets Resilient to Extreme Weather Events." Economics of Energy & Environmental Policy, 12(2), https://doi.org/10.5547/2160-5890.12.2.mpet

Fuentes, R. and Felder, F. (2023). "Systematically Mapping Innovations in Electricity Using Startups: A Comprehensive Database Analysis," Technology in Society, 74, 102282, https://doi.org/10.1016/j.techsoc.2023.102282.

Zhou,* J., Coit, D., Felder, F., and Tsianikas, S. (2023). "Combined Optimization of System Reliability Improvement and Resilience with Mixed Cascading Failures in Dependent Network Systems," Reliability Engineering & System Safety, 237, 109376, https://doi.org/10.1016/j.ress.2023.109376.

Soummane, S., Elshurafa, A., Alatawi, H., and Felder, F., (2003). "Modeling cross-seasonal fuel savings from load shifting in the Saudi industrial sector and interlinkages to export revenues," Energy Strategy Reviews, 47, 101093, https://doi.org/10.1016/j.esr.2023.101093.

Kumar,* P., Caggiano, H., Shwom, R., Felder, F., and Andrews C., (2023). "Saving from home! How income, efficiency, and curtailment behaviors shape energy consumption dynamics in US households?" Energy, 271, 126988, https://doi.org/10.1016/j.energy.2023.126988.

Athawale, R. and Felder, F., (2023). "Overbuilding Transmission: A Case Study and Policy Analysis of the Indian Power Sector," Energy Policy, 174, 113437. https://doi.org/10.1016/j.enpol.2023.113437.

Kumar*, P., Caggiano, H., Cuite, C., Felder, F. and Shwom, R., (2023). "Analyzing spillovers from food, energy, and water conservation behaviors using insights from systems perspective," Behavioural Public Policy, 1-35. https://doi.org/10.1017/bpp.2022.41.

Selcuklu, S, Coit, D., and Felder, F., (2023). "Electricity generation portfolio planning and policy implications of Turkish power system considering cost, emission, and uncertainty," Energy Policy, 173, 113393. https://doi.org/10.1016/j.enpol.2022.113393.

Kumar*, P., Caggiano, H., Cuite, C., Andrews, C., Felder, F., Shwom, R., Floress, K., Ahamed, S., and Schelly, C. (2022). "Behaving or Not? Explaining Energy Conservation via Identity, Values, and Awareness in Suburban American Homes," Energy Research & Social Science, 92, 102805. https://doi.org/10.1016/j.tej.2022.107186.

Elshurafa, A., Muhsen, A. and Felder, F. (2022). "Cost, footprint, and reliability implications of deploying hydrogen in off-grid electric vehicle charging stations: A GIS-assisted study for Riyadh, Saudi Arabia, *International Journal of Hydrogen Energy*, August 2022, 32641-32654. https://doi.org/10.1016/j.ijhydene.2022.07.160.

Elshurafa, A., Al Atawi, H., Hasanov, F. Felder, F., (2022). "Cost, Emission, and Macroeconomic Implications of Diesel Displacement in the Saudi Agricultural Sector: Options and Policy Insights", *Energy Policy,*168, 113090. https://doi.org/10.1016/j.enpol.2022.113090.

Felder, F., & Kumar*, P. (2021). A review of existing deep decarbonization models and their potential in policymaking. *Renewable and Sustainable Energy Reviews*, *152*, 111655. https://doi.org/10.1016/j.rser.2021.111655.

Zhou*, J., Coit, D. W., Felder, F., & Wang, D. (2021). Resiliency-based restoration optimization for dependent network systems against cascading failures. *Reliability Engineering & System Safety*, *207*, 107383, https://doi.org/10.1016/j.ress.2020.107383.

Nguyen*, H., and Felder, F. (2020). Generation Expansion Planning with Renewable Energy Credit Markets: A Bilevel Programming Approach, *Applied Energy*, 276(15), https://doi.org/10.1016/j.apenergy.2020.115472.

Hochman, G., Goldman, A., Felder, F., Mayer, J., Miller, A., Holland, P., Goldman, L., Manocha, P., Ze, S., Aleti, S. (2020). The potential economic feasibility of direct electrochemical nitrogen reduction as a route to ammonia, *ACS Sustainable Chemistry & Engineering*, 8(24), 8938-8948, https://doi.org/10.1021/acssuschemeng.0c01206.

Froio*, Z., Kumar*, P. and Felder, F. (2020), Not Adding Up: Free Ridership and Spillover Calculations in *Energy Efficiency Evaluations*, *Energy Efficiency*, 13, 991-1005. https://doi.org/10.1007/s12053-020-09872-6.

Selcuklu*, S., Coit D., Felder, F. (2020). Pareto Uncertainty Index for Evaluating and Comparing Solutions for Stochastic Multiple Objective Problems, *European Journal of Operational Research*, 284(2), 644-659. https://doi.org/10.1016/j.ejor.2020.01.004.

Rodgers*, M., Coit, D., and Felder, F. (2019). A Metamodeling Framework for Quantifying Health Damages of Power Grid Expansion Plans, *International Journal of Environmental Research and Public Health*, 16, 1857. https://doi.org/10.3390/ijerph16101857.

Rodgers*, M., Coit, D., and Felder, F. (2019). Assessing the Effects of Power Grid Expansion on Human Health Externalities, *Socio-Economic Planning Sciences*, 66, 92-104. https://doi.org/10.1016/j.seps.2018.07.011.

Rodgers*, M., Coit, D., Felder, F., Carlton, A. (2018), Generation Expansion Planning Considering Health and Societal Damages - A Simulation-Based Optimization Approach, *Energy*, 164, 951-963. https://doi.org/10.1016/j.energy.2018.09.004.

Song*, S., Qing, L., Felder, F., Wang, H., and Coit, D. (2018). Integrated optimization of offshore wind farm layout design and turbine opportunistic condition-based maintenance, *Computers & Industrial Engineering*, 120, 288-297.

Figueroa-Candia*, M., Felder, F. and Coit, D. (2018). Resiliency-Based Optimization of Restoration Policies for Electric Power Distribution Systems, *Electric Power Systems Research*, 161, 188-198. https://doi.org/10.1016/j.epsr.2018.04.007.

Zhou*, J., Huang, N., Coit, D. W., & Felder, F. A. (2018). Combined effects of load dynamics and dependence clusters on cascading failures in network systems. *Reliability Engineering & System Safety*, 170, 116-126. https://doi.org/10.1016/j.cie.2018.04.051.

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Shan*, X., Felder, F., & Coit, D. (2017). Game-theoretic Models for Electric Distribution Resiliency/Reliability from a Multiple Stakeholder Perspective. *IISE Transactions*, 49(2), 159-177.

Felder, F., & R. Athawale. (2016). Optimizing New York's Reforming the Energy Vision. *Utilities Policy*, 41C, 160-162.

Farkas*, C. M., Moeller*, M. D., Felder, F. A., Henderson, B. H., Carlton, A. G. (2016). High Electricity Demand in the Northeast U.S.: PJM Reliability Network and Peaking Unit Impacts on Air Quality. *Environmental Science & Technology*, 50 (15), 8375-8384.

Athawale, R., Felder, F., & Goldman*, L. (2016). Do CHPs Perform? Case Study of NYSERDA Funded Projects. *Energy Policy*, 97, 618-627.

Felder, F. (2016). Why Can't We All Get Along? A Conceptual Analysis Combined with a Case Study. *Energy Policy*, 96, 711-716.

Li*, S., Coit, D., & Felder, F. (2016). Stochastic optimization of electric power generation expansion planning with discrete climate change scenarios. *Electric Power Systems Research*. 140, 401-412.

Chandramowli*, S., Felder, F., Mantell, N., Irving, W., & Seneca, J. (2016). LP-CEM: A modeling tool for power systems planning incorporating climate change effects and macro-economic trends. *Energy Strategy Review*, 11, 1-18.

Tekiner-Mogulkoc*, H., Coit, D., & Felder, F. (2015). Mean-Risk Stochastic Electricity Generation Expansion Planning Problems with Demand Uncertainties Considering Conditional-Value-at-Risk and Maximum Regret as Risk Measures. *International Journal of Electrical Power and Energy Systems*, 73, 309-317.

Farkas*, C., Moeller*, M., Felder, F., Baker, K.R., Rodgers, M., & Carlton, A. G. (2015). Temporalization of Peak Electric Generation PM Emissions during High Energy Demand Days. *Environmental Science & Technology*, 49(7), 4696-4704.

Bridges*, A., Felder, F., McKelvey*, K. & Niyogi*, I. (2015). Screening for Health Effects in Energy Planning. *Energy Research and Social Science*, 6, 74-77.

Athawale, R., & Felder, F. (2014). Incentives for Combined Heat and Power Plants: How to increase society benefits. *Utilities Policy*, 31, 121-132.

Chandramowli*, S., & Felder, F. (2014). Impact of Climate Change on Electricity Systems - A Review of Models and Forecasts. *Sustainable Energy Technologies and Assessments*, 5, 62-74.

Tekiner-Mogulkoc*, H., Coit, D., & Felder, F. (2012). Electric Power System Generation Expansion Plans Considering the Impact of Smart Grid Technologies. *International Journal of Electrical Power and Energy Systems*, 42(1), 229–239.

Chandramowli*, S., Transue*, M., & Felder, F. (2011). Analysis of Barriers to Development in Landfill Communities Using Interpretive Structural Modeling. *Habitat International*, 35, 246-253.

Tekiner*, H., Coit, D., & Felder, F. (2010). Multi-period Multi-objective Electricity Generation Expansion Planning Problem with Monte-Carlo Simulation. *Electric Power Systems Research*, 80(12), 1394-1405.

Transue*, M., & Felder, F. (2010). Comparison of Energy Efficiency Incentive Programs: Rebates and White Certificates. *Utilities Policy*, 18(2), 103-111.

Felder, F. (2009). A Critical Assessment of Energy Accident Studies. *Energy Policy*, 37, 5744-5751.

Felder, F., & Haut, R*. (2008). Balancing Alternatives and Avoiding False Dichotomies to Make Informed U.S. Electricity Policy. *Policy Sciences*, 41, 165-180.

Greenberg, M., Mantell, N., Lahr, M., Felder, F., & Zimmerman, R. (2007). Short and Intermediate Economic Impacts of a Terrorist-Initiated Loss of Electric Power: Case Study of New Jersey. *Energy Policy*, 35, 722-733.

Felder, F., & Hajos*, A. (2006). Using Restructured Electricity Markets in the Hydrogen Transition: The PJM Case. *Proceedings of the IEEE* (special issue), 94(10), 1864-1879.

Guirguis, H., & Felder, F. (2005). Accounting for Extreme Values in GARCH Forecasts of Day-Ahead Electricity Prices. *KIEE International Transactions on Power Engineering*, 5-A(3), 300-302.

Felder, F. (2005). Top-Down Composite Modeling of Bulk Power Systems. *IEEE Transactions on Power Systems*, 20(3), 1655-1656.

Guirguis, H., & Felder, F. (2004). Further Advances in Forecasting Day-Ahead Electricity Prices Using Time Series Models. *KIEE International Transactions on Power Engineering*, 4A(3), 159-166.

Felder, F. (2004). Incorporating Resource Dynamics to Determine Generation Adequacy Levels in Restructured Bulk Power Systems. *KIEE International Transactions on Power Engineering*, 4A(2), 100-105.

Yoon, Y., & Felder, F. (2003). A Critique of Designing Resource Adequacy Markets to Meet Loss of Load Probability Criterion. *KIEE International Transactions on Power Engineering*, 3A(1), 35-41.

Farr, J., & Felder, F. (2003). An Introduction to Electricity Market Auctions Using a Spreadsheet. *INFORMS Transactions on Education*, 4(1), 11-22.

Felder, F. (1996). Integrating Financial Theory and Methods in Electricity Resource Planning. *Energy Policy*, 24(2), 149-154.

U.S. National Science Foundation Grants (Peer Reviewed)

RAPID: COVID-19, Consumption, and Multi-dimensional Analysis of Risk (C-CAR), CBET 2031677, $190,764, Senior Investigator, June 1, 2020 through May 31, 2021.

Collaborative Research: CAS: Electrochemical Approaches to Sustainable Dinitrogen Fixation, CHE/CAS 1955014, $295,216, Senior Investigator, August 1, 2020 through July 31, 2023.

Collaborative Research Modeling Strategic Regulators in Network Infrastructure Planning, $399,002, (Rutgers University grant of $85,890), Principal Investigator, CMMI 1825225, September 1, 2018 through August 31, 2021.

Electrochemical Approaches to Sustainable Dinitrogen Fixation, $300,000, Senior Investigator, CHE 1665146, September 1, 2017 through August 31, 2020.

EAGER: Smart & Connected Communities, National Science Foundation, $250,000, Senior Investigator, AGS1645786, August 1, 2016 through July 31, 2018.

EaSM-3: Regional decadal predictions of coupled climate-human systems, National Science Foundation, OCE1419584, $1,200,000, co-PI, June 1, 2014 through August 31, 2017. Designated Bloustein PI for $414,615.

Green Energy Technology for Undergraduates Program (GET UP!), National Science Foundation, EEC1263250, $367,890, Senior Personnel, March 15, 2013 through February 29, 2016. Presented to high school teachers and undergraduate students on July 9, 2014.

Climate to Humans: A Study of Urbanized Coastal Environments, Their Economics and Vulnerability to Climate Change, National Science Foundation, OCE1049088, $3,853,332, co-PI, March 1, 2010 through February 28, 2016. Designated Bloustein PI for $525,448. Additional $225,000 assigned Bloustein.

IGERT: Solutions for Renewable and Sustainable Fuels in the 21st Century, National Science Foundation OCE1049088, $3,197,329, co-PI and Lead on Policy and Infrastructure Logistics for Efficient Fuel Technology Deployment, September 1, 2009 through August 30, 2014. Funded 24 doctoral students (including 2 Bloustein students) and 4 master students. Served on Leadership, Committee and Admission Committee. Developed and taught two new graduate seminars.

Public

Nanotechnology for Clean Energy, National Science Foundation, 0903661, Faculty, $1,218,737, 2008-2013. Developed graduate course given to Rutgers and Princeton Universities.

The Electricity Journal

Felder, F. A. and Petitet, M. (2022). Extending the reliability framework for electric power systems to include resiliency and adaptability, *The Electricity Journal*, 35(8), 107186. https://doi.org/10.1016/j.tej.2022.107186

Fuentes, R., Hasan, S. and Felder, F. A. (2022). How can Energy Storage catalyze GCC Electricity policy? Issues and Options. *The Electricity Journal*, 35(4), 107110.

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Felder, F., Unel, B., & Dvorkin, Y. (2021). Modeling strategic objectives and behavior in the transition of the energy sector to inform policymaking. *The Electricity Journal*, *34*(8), 107009.

Elshurafa, A. M., Alatawi, H., Soummane, S., & Felder, F. A. (2021). Assessing effects of renewable deployment on emissions in the Saudi power sector until 2040 using integer optimization. *The Electricity Journal*, *34*(6), 106973.

Baldwin, S. and Felder, F. (2019). Residential Energy Supply Market: Unmet Promises And Needed Reforms. *The Electricity Journal,* 32(3), 31-38.

Freed, M. and Felder, F. (2017). Non-energy benefits: Workhorse or unicorn of energy efficiency programs? *The Electricity Journal*, 30(1), 43-46.

Felder, F. (2015). Should Relief be Granted from the Clean Power Plan for Reliability Reasons? *The Electricity Journal,* 28(6), 5-11.

Felder, F., and Athawale, R. (2014). The Life and Death of the Utility Death Spiral. *The Electricity Journal*, 27(6), 9-16.

Chandramowli*, S., & Felder, F. (2014). Climate Change and Power Systems Planning – Opportunities and Challenges. *The Electricity Journal*, 27(4), 40-50.

Felder, F. (2013). Nuclear Power in the Second Obama Administration. *The Electricity Journal*, 26(2), 25-31.

Felder, F. (2012). Watching the ISO Watchman? *The Electricity Journal*, 25(10), 24-37.

Felder, F. (2011). Examining Electricity Price Suppression Due to Renewable Resources and Other Grid Investments. *The Electricity Journal*, 24(4), 34-46.

Felder, F. (2010). The Practical Equity Implications of Advanced Metering Infrastructure. *The Electricity Journal*, 23(6), 56-64.
Farr, J. and Felder, F. (2005). Competitive Electricity Markets and System Reliability: The Case for New England's Proposed Locational Capacity Market. *The Electricity Journal*, 18(8), 22-33.

Felder, F. (2004). Shining Light, Not Shedding Light. *The Electricity Journal*, 17(7), 51-54.

Farr, J., & Felder, F. (2002). A Critique of Existing Market-based Market Performance Monitoring and

Mitigation Policies. *The Electricity Journal*, 15(6), 10-18.

Felder, F. (2002). The Need for Governance of Restructured Electric Power Systems and Some Policy Implications. *The Electricity Journal*, 15(1), 36-43.

Rotger, J., & Felder, F. (2001). Reconciling Market-Based Transmission and Transmission Planning. *The Electricity Journal*, 14(9), 31-43.

Felder, F. (2001). An Island of Technicality in a Sea of Discretion': A Critique of Existing Electric Power Systems Reliability Analysis and Policy. *The Electricity Journal,* 14(3), 21-31.
Felder, F., Hopper, G., & Lukens, J. (1998). The Benefits of Retail Electricity Competition in Low-Cost States: Expectations for an Evolving Industry, *The Electricity Journal*, 11(7), 75-81.

Felder, F., & Peterson, S. (1997). Market Power Analysis in a Dynamic Electric Power Industry. *The Electricity Journal*, Volume # needed, 10(3), 12-19.

Jaffe, A., & Felder, F. (1996). Should Electricity Markets Have A Capacity Requirement: If So, How Should It Be Priced? *The Electricity Journal*, 9(10), 52-60.

Felder, F. (1996). Integrating Financial Thinking with Strategic Planning to Achieve Competitive Success. *The Electricity Journal*, 9(4), 62-67.

Felder, F. (1995) Modeling Natural Gas Prices as a Random Walk: The Advantages for Generation Planning. *The Electricity Journal*, 8(9), 61-67.

Law Review Journals

Tortta, J., Dressel, A., Agbre, S., Benevento, D., Butrus, G., Chambers, T., …Spina, S. (2014). Report of the System Reliability & Planning Committee. *Energy Law Journal*, 35(2), 1-21.

Felder, F. (2014). Climate Change Mitigation and the Global Energy System**.** *Villanova Environmental Law Journal*, 25(1), 89-106.

Book Chapters

Hochman, G., Goldman, A. and Felder, F. (2022). "Alternative ammonia production processes and the use of renewables." In Murthy, G. *Biomass, Biofuels, Biochemicals- Green-Economy: Systems analysis for sustainability.* Elsevier pre-publication.

Felder, F. (2020) "Market Versus Planning Approaches to Transmission and Distribution Investment." In M. R. Hesamzadeh, J. Rosellon, & I. Vogelsang. *Transmission Network Investment in Liberalized Power Markets*. Springer, pre-publication.

Athawale, R., & Felder, F. (2016). Residential Rate Design and Death Spiral for Electric Utilities: Efficiency and Equity Considerations. In F. Sioshansi (Ed.), *Future of Utilities - Utilities of the Future: How technological innovations in distributed energy resources will reshape the electric power system* (pp. 193-209). Amsterdam: Elsevier Press, 2016.

Felder, F. & Chandramowli*, S (2016). Impact of Extreme Events on the Electric Power Sector: Challenges, Vulnerabilities, Institutional Responses, and Planning Implications from Hurricane Sandy. In K. M. O'Neill, & D. J. Van Abs, (Eds.), *Taking Chances on the Coast After Hurricane Sandy* (pp. 242-257). New Brunswick, NJ: Rutgers University Press.

Felder, F. (2014). What Future for the Grid Operator? In F. Sioshansi (Ed.), *Distributed Generation and its Implications for the Utility Industry* (pp. 399-415). Amsterdam: Elsevier Press.

Felder, F. (2013). The evolution of demand side management in the United States. In F. Sioshansi (Ed.), *End of Electricity Demand Growth: How energy efficiently can put an end to the need for more power plants (*pp. 179-200). Amsterdam: Elsevier Press.

Felder, F. (2012). The Equity Implications of Smart Grid: Questioning the Size and Distribution of Smart Grid Costs and Benefits. In F. Sioshansi (Ed.). *Smart Grid: Integrating Renewable, Distributed & Efficient Energy* (pp. 85-100). Amsterdam: Elsevier Press.

Felder, F., Andrews, C., & Hulkower, S. (2011). Which Energy Future. In F. Sioshansi (Ed.), *Energy Sustainability and the Environment: Technology, incentives, behavior* (pp. 30-61). Amsterdam: Elsevier Press.

Felder, F., Mantell, N., Lovrien, N., Buehler, & Cottrell, A. (2009). Energy Master Planning: The Case of New Jersey. In E. Kahraman & A. Baig (Eds), *Environmentalism: Environmental Strategies and Environmental Sustainability* (pp. 41-72). Hauppauge, New York: Nova Science Publishers.

Reports

Felder, F., A Net Zero Energy System with Liberalized Markets and Regulated Transportation and Delivery, Oxford Institute of Energy Studies, Paper EL59, May 2025.

Alhadhrami, K., Petitet, M., Abuouf, S., Darandary, A., Laing, T, Felder, F., and Elshurafa, A, Are There Adequate Materials and Land Resources for the Saudi Power Sector to Achieve Net Zero by 2060?, April 2025.

Felder, F., The Importance and Implications of FERC Order 1920 for State Energy Offices, September 2024.

Felder, F. and Petitet, M., *An Emerging Framework for the Probabilistic Cost-Benefit Analysis of the Reliability, Resiliency and Adaptability of Electric Power Systems*, KAPSARC Discussion Paper, July 2024.

Petitet, M., Ricuad, B., Felder, F., and Elshurafa, A., *How Can Bilateral Contracts Support Electricity Trade? A Regional Electricity Model Perspective for the GCC Plus Egypt, Jordan, and Iraq*, KAPSARC Discussion Paper, June 2024.

Felder, F., *The Challenges of Incorporating Consumer Reliability Preferences into Electricity Markets with a Capacity Requirement*, Oxford Institute of Energy Studies, Paper EL54, May 2024.

Al-Balawi, A., Nezamuddin, N., Felder, F., Muhsen, Abdelrahman, and Elshurafa, A., *Assessment of the Potential of Floating Offshore Wind Turbines in the Red Sea*, KAPSARC Discussion Paper, May 5, 2024.

Petitet, M., Felder, F., and Elshurafa, A., *Finding Opportunity in Economic Dispatch: Saving Fuels Without Impacting Retail Electricity Prices*, KAPSARC Discussion Paper, March 17, 2024.

Al-balawi, A., Felder, F., and Khan, M. (2023). *Recent Developments and Trends of Cybersecurity in the Power Sector*, KAPSARC Commentary, October 26, 2023.

Petitet, M., Elshurafa, A., and Felder, F. (2023). *From Europe to the Middle East: How the European Energy Crisis Can Reshape the Power Sector Reform Endeavors?* Discussion Paper, Oct. 24, 2023.

Felder, F., Petitet, M., Hasan, S., and Elshurafa, A. (2023). *Modeling of the Interconnected Middle East and North Africa Electricity System: Including Uncertainties to Better Inform Policymakers*, KAPSARC Commentary, September 26, 2023.

Aljamed, F., Felder, and Elshurafa, A. (2023). *An Overview of Integration Costs of Variable Renewables in the Power Sector*, KAPSARC Commentary, June 19.

Fuentes, R., Chen, D., and Felder, F. (2023). *What Innovations Are Chinese Startups Pursuing*, KAPSARC Commentary, June 13.

Elshurafa, A., Petitet, M. and Felder, F. (2023). *How Firm Capacity and Forced Outage Rate Assumptions of Renewables Impact Capacity Expansion Model Results*, KAPSARC Discussion Paper, March 9.

Fuentes, R. and Felder, F. (2023). *Innovation by Gulf Cooperation Council Electricity Startups: A Global Comparison*, KAPSARC Commentary, February 28.
Petitet, M. and Felder, F. (2023). *Lessons from the European Electricity Crisis,* KAPSARC Instant Insight, February 20.

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Felder, F. (2014). Review of the book *Transforming the Grid: Electricity System Governance and Network Integration of Distributed Generation*, by D. Bauknecht. *The Energy Journal*, 35(3), 184 186.

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Felder, F. (1998). Review of the book *International Comparisons of Electricity Regulation*, R. J. Gilbert & E. P. Kahn. *The Energy Journal*, 19(1).

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Felder, F. (1994). Review of the book *Electric Utility Mergers: Principles of Antitrust Analysis*, by M. W. Frankena & B.M. Owen. *The Energy Journal*, 15(4), 233-234.

Sponsored Research

Study of Public Procurement, Financial, and Legal Authorities Necessary to Facilitate the Development of Town Center Distributed Energy Resources (Microgrids), $60,000, New Jersey Board of Public Utilities, Senior Investigator, March 1, 2019 through February 28, 2021.

Rutgers Energy Institute, Rutgers University, $900,000, Director, July 2018 through June 2021.

Clean Energy Evaluation and Market Assessments, New Jersey Board of Public Utilities, $926,284, Principal Investigator, July 2016 through October 2017.

Clean Energy Evaluation and Market Assessments, New Jersey Board of Public Utilities, $926,284, Principal Investigator, September 2015 through June 2016.

Clean Energy Evaluation and Market Assessments, New Jersey Board of Public Utilities, $908,231, Principal Investigator, June 24, 2014 through November 6, 2015.

New Jersey Energy Resilience Bank, New Jersey Board of Public Utilities (funded by U.S. Department of Housing and Urban Development), $230,000, Principal Investigator, October 17, 2014 to March 31, 2017.

Solar Utility Networks: Replicable Innovations in Solar Energy (SUNRISE), U.S. Department of Energy (Subcontractor to PHI Services Company), $30,000, Principal Investigator, September 1, 2014 to August 31, 2016.

Clean Energy Evaluation and Market Assessments, New Jersey Board of Public Utilities, $1,356,553, Principal Investigator, June 2013 through November 2014.

Review of Impact Evaluation Contractors and Work Product, PSE&G, $113,479, Principal Investigator, January 15, 2012 to December 30, 2015.

Electricity Demand and the Impacts on Air Quality, Rutgers University Faculty Grant Proposal, $10,261, Principal Investigator, December 6, 2011 to December 30, 2012.

Evaluation of Reports re: Proposed Atlantic Wind Connection Backbone Transmission Project, Atlantic Wind Connection, $13,860, co-Principal Investigator, September 1, 2011 to October 31, 2011.

Review of Connecticut Renewable Portfolio Standards, Connecticut Energy Advisory Board, $58,963, Principal Investigator, February 18, 2011 to December 31, 2011.

Collection of Wind Resource Data, New Jersey Board of Public Utilities, $4,889, Principal Investigator, January 1, 2011 to September 30, 2011.

Economic Impacts of Water Main Infrastructure Investments, Winning Strategies, $40,782, Principal Investigator, December 20, 2010 to June 1, 2011.

Economic Impact of Accelerated Infrastructure Improvement Projects, New Jersey Natural Gas Company, $13,436, Principal Investigator, November 8, 2010 to January 14, 2011.

Economic Impacts of Water Main Infrastructure Investments, Aqua America, Inc., $17,702, Principal Investigator, November 15, 2010 to March 31, 2011.

Energy Technology Grants, PSEG Services Corporation, $236,000, Principal Investigator, December 1, 2009 to December 31, 2011.

Impacts of Energy Infrastructure, New Jersey Natural Gas, $13,587, June 17, 2010 to August 3, 2010.

Describe and Quantify the Economic Benefits of the NJ DEP Action Plan for the NJ Global Warming Response Act, New Jersey Department of Environmental Protection, $15,630, Principal Investigator,
July 14, 2009 to October 14, 2009.

MOA between Rutgers' Center for Energy, Economic and Environmental Policy (CEEEP) and the New Jersey BPU/Clean Energy Program, New Jersey Board of Public Utilities, $1,830,281, Principal Investigator, June 1, 2009 through May 31, 2013 (covering four contracts).

Innovative Partnership Institute, New Jersey Department of Environmental Protection, $6,000, co-Principal Investigator, April 2009.

New Jersey Department of Environmental Protection: Assessing the Potential for New Jersey Forests to Sequester Carbon and Contribute to Greenhouse Gas Emission Avoidance, $7,000, co-Principal Investigator, May 2009.

New Jersey Office of Clean Energy Program: Research and Related Activities Regarding the Energy Efficiency Program, Principal Investigator, $244,367, September 1, 2008, to April 30, 2009.

Comprehensive Assessment of the PA Technical Reference Manual, Clean Power Markets, $187,950, Principal Investigator, October 1, 2008 to December 31, 2012.

New Jersey Hydrogen Learning Center, New Jersey Board of Public Utilities, Principal Investigator, $73,928, May 1, 2008 to June 20, 2009.

New Jersey State Energy Master Plan (Part 3), New Jersey Board of Public Utilities, Principal Investigator, $200,127, November 1, 2007 to October 31, 2008.

New Jersey State Energy Data Center (Part 2), New Jersey Board of Public Utilities, $175,989, Principal Investigator, Nov. 14, 2006 through December 31, 2007.

New Jersey State Energy Master Plan (Part 2), $216,570, New Jersey Board of Public Utilities, Principal Investigator, October 1, 2006 to June 30, 2008.

Diesel Generator and Performance Standard Abstract, Clean Energy Group, $10,000, Principal Investigator, April 30, 2007 to December 31, 2007.

Rutgers Energy Institute, The Future Electric Power System in a Carbon Constrained World, $30,000, co-Principal Investigator, 2007-2008.

New Jersey Meadowlands Renewable Energy Task Force, New Jersey Meadowlands, $100, 000, Principal Investigator, May 15, 2006 to October 31, 2008.

Natural Resources Defense Council, Energy Efficiency, $15,000, Principal Investigator as of Oct. 30, 2006 (co-Principal Investigator prior), July 26, 2005 through Dec. 31, 2006.

New Jersey Board of Public Utilities, New Jersey State Energy Data Center, $99,965, Principal Investigator as of Oct. 30, 2006 (co-Principal Investigator prior), Dec. 1, 2005 through Dec. 31, 2006.

New Jersey Board of Public Utilities, New Jersey State Energy Master Plan, $140,747, co-Principal Investigator, Feb. 1, 2005 through May 24, 2006.

New Jersey Board of Public Utilities, New Jersey Hydrogen Learning Center, $200,000, Principal Investigator as of Oct. 30, 2006, Feb. 1, 2005 through Aug. 31, 2007.

New Jersey Board of Public Utilities, New Jersey Energy Efficiency Evaluation, $523,837, Principal Investigator as of Oct. 30, 2006, (investigator prior), Jan. 1, 2005 through Dec. 31, 2006.

New Jersey Board of Public Utilities, State Technologies Advancement Collaborative, $43,881, co-Principal Investigator, May 11, 2005 through August 31, 2006.

New Jersey Board of Public Utilities, Evaluation of CO_2 Emission Allocation as part of the Regional Greenhouse Gas Initiative, $15,000, co-Principal Investigator, April 15, 2005 through June 30, 2005.

Retail Electricity Supply Association, Assessment of Customer Response to Real Time Pricing, $41,000, co-Principal Investigator, Jan. 1, 2005 through Oct. 31, 2005.

New Jersey Board of Public Utilities, Economic Impact Analysis of a 20% New Jersey Renewable Portfolio Standard, *2004,* $204,247, Senior Investigator*,* Nov 1, 2003 through Jan. 31, 2005.

New Jersey Board of Public Utilities, New Jersey Electric Distribution Reliability Standards, $33,999, Investigator, Feb. 1, 2004 through Dec. 31, 2004.

Rutgers University Teaching

Data Analytics: Using Big Data (graduate)
Climate Change, Public Health and Policy (undergraduate)
Sustainable Energy Policy and Planning (graduate)
Introduction to Statistics (undergraduate and graduate)
The Science, Technology and Policy of Global Climate Change (undergraduate Byrne seminar, honors undergraduate seminar, undergraduate seminar at University of Konstanz)
Energy Engineering, Economics and Policy (graduate seminar; joint course with Princeton University)
Integrated Energy Challenges and Opportunities I and II (year-long graduate seminar)
Energy Planning for Communities Living in Landfills (Planning Studio)
Directed Studies: Victoria Nielsen (Fall 2013); Allison Bridges, Kathryn McKelvey, and Ishanie Niyogi (Spring 2013); Shankar Chandramowli (Summer 2012, Fall 2012, Fall, 2013), Zachary Froio (Fall 2017), Pratyusha Kiran (Fall 2017), Pranay Kumar (Fall 2017), Ashley Scull (Fall 2017)
In-depth Introduction to Electricity Markets (two-day professional short course)
Cost Benefit Analysis of Energy Efficiency and Renewable Energy Projects (one-day professional short course)
Environmental Management (four-day professional short course)

Rutgers University Student Advising and Service

Post-doctoral, Dissertation, Master Thesis, and Undergraduate Advisor/Committees:

- Jose Espiritu Nolasco, System Reliability Estimation and Component Replacement Analysis for Electricity Transmission and Distribution Systems, Oct. 2007 (external department doctoral committee member)
- Hatice Tekiner, Multi-Objective Power Generation Expansion Planning Considering Environmental Impacts and Smart Grid Technologies, Jan. 2008 to May 2010 (external department doctoral committee member)

- Ariel Martin, Development of a Decision Support System to Operate the Supplemental Lighting System in a Tomato Greenhouse Equipped with an On-site Power Generator, October 2013 (external department doctoral committee member)
- Bernhard Brauß, The Issue-Attention Cycle in Energy Policy, Bachelor Thesis, University of Konstanz, Department of Politics & Public Administration, March 2012 (Appraiser)
- Shuya Li, Robust Optimization of Generation Expansion Planning Problems Considering Climate Change's Uncertain Impact, September 2012 to May 2014 (external department masters committee member)
- Caroline Farkas, Impact and Sensitivity Analyses of Energy Sector Emissions: Air Quality Modeling of the PJM Region, Dec. 21, 2015, (external department doctoral committee member)
- Saltuk Bugra Selcuklu, Multi-objective Generation Expansion Planning Considering Uncertainty and Modeling with the Pareto Uncertainty Index, October 2015 (external department doctoral committee member)
- Shankar Chandramowli, Impact of Climate Change on Electricity Systems and Markets, January 2015 (doctoral committee chair)
- Xiaojun (Gene) Shan, Ph.D., Improving the Modeling of Offshore Wind and Electric Distribution Reliability for Public Policy Formulation, post-doc advisor, Jan. 2014-Dec. 2014
- Rebeca Meier, "Feed-in Tariff or Renewable Portfolio Standard – A Quantitative Analysis of the Impact of current Energy Policies on the Provision of Renewable Energy," Joint Masters Thesis with University of Konstanz and Rutgers University, Spring 2016
- Shane Patel, Fall 2014, "Characteristic Problems of Government-Supported Demonstration Scale Energy Innovation: Establishing A Framework for the Evaluation of Energy Innovation Government Programs, undergraduate research paper
- Chhayang Patel, 2014-2015 academic year, undergraduate Arresty Research Program Adviser
- Rutgers Energy Institute Summer Intern co-Adviser (Kaila Roffman, Summer 2015; Christopher Cohane, Summer 2014)
- Allison Bridges, Leveraging Amenity-Led Growth and Collective Action For Sustainable Development In Florianópolis, 1965-2016, April 2016, (doctoral committee member)
- Eric Zimmermann, Internship Supervisor, Summer 2016
- Brian Kemp, Internship Supervisor, Summer 2016
- Mark Rodgers, Simulation-based Optimization Models for Electricity Generation Expansion Planning Problems Considering Human Health Externalities, August 2016 (co-chair, doctoral committee)
- Sanling Song, Improving the Modeling of Offshore Wind and Electric Distribution Reliability for Public Policy Formulation, Feb. 2016 to Mar. 2017
- Carla Corona, Understanding Transitions to Sustainability in Developing Countries: The Chilean Energy Transition, May 2016
- Jacob Yu, Solar Market Analysis, Rutgers Energy Institute Summer Internship, 2017
- Ioanna Tsoulou, A Social-ecological Approach for Heat Adaptation of Senior Low-income Housing, March 2020, (doctoral committee member)
- Jian Zhou, Joint Optimization of System Hardening and Restoration for Resilience Enhancement against Cascading Failures, August 2020 (doctoral committee member)
- Hieu Nguyen, Collaborative Research Modeling Strategic Regulators in Network Infrastructure Planning, post-doctoral supervisor, August 2019 to August 2020
- Jip Kim, Strategic Planning for Low-Carbon Power Systems, May 2021, NYU (doctoral committee member)
- Pranay Kumar, Energy Conservation Behaviors in U.S. Households: Combining Top-Down and Bottom-up Approaches, May 2023 (doctoral committee member)

Rutgers University Senate (July 1, 2019 to September 30, 2020)
Bloustein Search Committee, Research Analyst in Urban Informatics (January to February 2019)

Bloustein Faculty Search Committee (Fall 2018 to Spring 2019)
Bloustein Teaching and Advising Committee (Spring 2018)
Bloustein School Non-tenure Track Appointment and Promotion Committee (April 2018 to present)
Bloustein School Strategic Planning Committee for Research, Practice and Service (March-April 2018)
Hult Prize Challenge, Judge (December 2017)
Bloustein School Search Committee, Research Professor/Director of Research and Evaluation, Heldrich Center for Workforce Development (2017 to 2018)
School of Graduate Studies, Graduate Faculty in Energy Systems (Spring 2015 to present)
Bloustein School Liaison with School of Engineering regarding Masters of Energy Systems (Spring 2015)
Board of Advisors, Rutgers EcoComplex Advisory Board, Member, May 6, 2014 to present
Bloustein Faculty Council: Non-tenure Track Committee, May 2014
Lead Instructor for a class on "Sustainable Energy" for New Jersey Governor's School in Engineering & Technology (Summer 2012); Lecturer Summer 2018
Steering Committee, Edward J. Bloustein School of Planning and Public Policy, September 2006 to August 2008
Associate Director, Rutgers Energy Institute, May 2007 to April 2009
New Jersey State Sustainability Institute, Expert Advisory Board (July 2006 to Dec. 2007)

Other Academic Activities

Editorial Boards
Member of Editorial Board, *Energy Efficiency* (January 2020 to present)
Member of Editorial Board, *Utilities Policy* (September 2016 to present)
Member of Editorial Board, *The Electricity Journal* (January 2013 to date)
Book Review Editor, *The Energy Journal* (January 2012 to July 2019)
Member of Editorial Board, *KIEE International Transactions on Power Engineering* (2005 to 2006)
Member of Editorial Board, *SAM Advanced Management Journal*, (December 2002 to August 2004)

Reviewer
Utilities Policy (February 2025; July 2025), *Journal of Critical Infrastructure Policy* (August 2024), *Reliability Engineering & System* Safety (March 2022), *Energy Policy* (October 2020), *Applied Energy (*June 2018*), WIREs Energy and Environment* (December 2017), *Journal of Planning Education and Research* (June 2017; July 2018), *Energy Research and Social Science* (January 2017), *Energy Efficiency Journal* (November 2020, October 2020, October 2019, February 2018, October 2016), The *Energy Journal* (May, 2025; April, 2025; August 2019, August 2016; March 2017), *Netherlands Foundation for Fundamental Research on Matter, FOM* (May 2016); *International Political Science Review* (April 2016), *MIT Press* (January 2016), *CSEE Journal of Power and Energy* Systems (November 2015), *Sustainable Cities and* Society (August 2015), *IBM Journal of Research and* Development (May 2015), *Nature Climate Change* (April 2015), *Utilities Policy* (December 2018, June 2018, March 2018, Jan. 2017, Oct. 2016, Jan. 2015, June 2015, July 2015, August 2015, Oct. 2015, April 2016; July 2016), PNAS (Dec. 2014), *Environmental Science & Technology* (Nov. 2014, March 2016; April 2018), *European Journal of Transport and Infrastructure Research* (Sept. 2014, Nov. 2017), *Climatic Change* (June 2018, Sept. 2014)*, Transportation Research Part D: Transport and Environment* (June 2014, March 2018), *Electric Power Systems Research* (Mar. 2014), *International Journal of Management Science and Engineering Management* (August 2013), *Policy Sciences* (June 2013), *Environmental Science and Technology* (August 2013), Academy of Finland (April 2013), Nazarbayev University (Winter 2013; Fall 2013; Winter 2017), *Journal of Regulatory Economics* (January 2013), New Jersey Department of Environmental Protection (May 2013)

Invited Academic Activities

Peer Reviewer, U.S. Environmental Protection Agency, Integrated Planning Model, Fall 2020.

International Conference of Applied Energy, "Applied Energy Symposium: MIT A+B," Session co-Chair, May 22-23, 2019.
Geographical Sciences Committee, National Academies of Sciences, Engineering and Medicine, "Climate Change, Coastal Flooding, and the Electric Power Grid," December 6, 2018.
China-US 2018 Joint Eco-environmental Symposium: Advances in Critical Needs for the Nexus of Food, Energy, and Water Systems, Invited Keynote Speaker, October 24-28, 2018
Symposium on Realizing the Value of Nuclear Engineering – A Celebration of Michael Golay's Career, Cambridge, MA, March 26-27, 2018
Peer Reviewer, US Department of Energy, International Electricity Market Model (Nov. 2016)
University of Texas Interdisciplinary Electricity Conference, "The Nexus of Markets and the Environment," Austin, TX, April 21-22, 2016
Initiative for Sustainable Electric Power Systems Workshop, Penn State University, November 19-20, 2015, invited speaker
INFORMS 2015, organized session on Optimizing Reliability and Resiliency of Electric Power Systems, November 2015
University of Texas Interdisciplinary Electricity Conference, "The Nexus of Markets and the Environment," Austin, TX, April 9-10, 2015
Organizing Committee, Center for Research in Regulated Industries, Rutgers Business School, 34th Annual Eastern Conference
Session Chair, FERC Workshop/Trans-Atlantic Infraday, Electricity Markets Restructuring, Nov. 7, 2014
Invited Lecturer, Center for Sustainable Electric Power Systems Seminar, Penn State University, October 14, 2014
Rutgers Energy Institute, 9th Annual Symposium, "Will the Potential for a Death Spiral in Electricity Rates Hinder Transformation of the Electric Power System?", May 6, 2014
Invited Panelist, 2014 Biennial Workshop in Service Engineering (BeWiSE), Penn State University, September 16-17, 2014
Technical Program Committee, Council of Engineering Systems Universities (June 8-11, 2014)
Invited Participant, KAPSRC, Workshop on Energy Systems Modeling (October 3, 2013)
Invited Participant, MIT Conference on Modeling Social, Technical and Natural Systems for Policy (September 25-27, 2013)
Discussant, Center for Research in Regulated Industries (May 16 & 17, 2013)
Expert participant in *Gathering Global Intelligence to Accelerate Development—Foreign Experts Traveling in Anhui Specialized in New Energy*, (September 24-27, 2012)
Participant, Council of Engineering Systems Universities Conference, Delft, (June 18-20, 2012)

OTHER PROFESSIONAL ACTIVITIES

International Activities

- Peer Review of Multilateral Cross-Border Power Trade, U.S. Department of State and National Association of Regulatory Utility Commissioners, Kuching Malaysia, August 28-29, 2024
- Peer Review of Competitive Wholesale Electricity Market Establishment Strategies, U.S. Department of State and National Association of Regulatory Utility Commissioners, Ulaanbaatar, Mongolia, May 27-29, 2024
- Sustainable Development of Power Sector and Enhancement of Electricity Trade in the South Asian Region: Policy, Regulatory Issues and Challenges, USAID, January 15, 2016, New Delhi, India
- Capacity Building Program for Designing, Managing and Operating a Power Trading Entity in Nepal, USAID, September 14-18, 2015
- Workshop on Efficient and Effective Electricity Market Design, Operation and Management, Kenya, USAID, Feb. 1-5, 2010
- Regional Electricity Markets Workshop, Libreville, Gabon, USAID, January 25-30, 2009
- Electricity Market Development Program, Bentota, Sri Lanka USAID, August 18-20, 2008
- Electricity Market Development Program, Dhaka, Bangladesh, USAID, August 13-15, 2008

Senior Advisor, Digital Wind, January 1, 2025 to present

Consumer Advisory Council, New York Independent System Operator, March 18, 2011 to December 1, 2013, Co-Chair.

Energy Services Providers, Troy, NY, Director, March 2005 to July 2006
Member of the Board of Directors of a retail electricity supplier.

Validigm Corporation, New York, NY, *Director*, June 2000 to December 2000
Member of the Board of Directors of a high-tech, computer network evaluation and applications company.

HONORS AND AWARDS

Associate Member, Sigma Xi, Scientific Research Honor Society of North America
Member, Tau Beta Pi, National Engineering Honor Society
Member, Alpha Sigma Nu, American Nuclear Society Honor Society
Twice awarded the Navy Achievement Medal

I, Frank Felder, (Affiant) being duly sworn (affirmed) according to law, depose and say that I am authorized to make this affidavit on behalf of the Pennsylvania Consumer Advocate and Office of Consumer Advocate (OCA), being the holder of a contract with the OCA that engaged my subject matter expertise, and have been authorized to make this affidavit on the Consumer Advocate's and OCA's behalf, and that the facts above set forth are true and correct to the best of my knowledge, information and belief, and I expect to be able to prove the same at any hearing hereof.

Frank A. Felder

Frank A Felder

Signature of Affiant Date: October 1, 2026

Sworn and subscribed before me the date below:

10/1/2026

Signature of Official Administering Oath Date: 10-1-26

8 31 2026

(My Commission Expires)

ANDREW DANIEL LUCKABAUGH
Notary Public
Commonwealth of Virginia
Registration No. 00339997
My Commission Expires Aug 31, 2028

Appendix C – Hoyt Affidavit

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Office of Consumer Advocate	:	
	:	
v.	:	Docket No.
	:	C-2026-
PPL Electric Utilities Corporation	:	
	:	

FORMAL COMPLAINT OF THE
PENNSYLVANIA CONSUMER ADVOCATE
REGARDING PPL ELECTRIC UTILITIES CORPORATION'S
EXISTING RATES AND SERVICE
IN RELATION TO ADDITIONS OF DATA CENTERS
TO THE UTILITY'S ELECTRIC DISTRIBUTION SYSTEM AND THE PJM REGION

AFFIDAVIT

of

Matthew T. Hoyt

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

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I. Witness Name, Contact Information, and Professional and Educational Background

My name is Matthew T. Hoyt. I am employed by Exeter Associates, Inc. ("Exeter") as a Senior Analyst and Principal. My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia MD 21044.

I have been employed at Exeter since 2016 in various roles, most recently as a Principal of the firm, beginning in 2023. At Exeter, my work is primarily related to retail and wholesale electricity markets; energy procurement; electrification; reliability; transmission planning; rate design assessment; and state electricity policy design, implementation, and evaluation. Recent projects that I have led include technical audits of several electric utility programs and their accompanying riders, assessments of energy procurement strategies related to default electric service, and comprehensive evaluations of rules, regulations, and policies related to electric vehicles ("EVs"), electric storage, renewable portfolio standards, transmission planning, large load additions, and resource adequacy constructs. I primarily support state utility commission, state energy office, office of consumer advocate, and non-profit association clients with this work.

Prior to joining Exeter, I worked as a Data Scientist at AEP Energy, a competitive retail electric generation service supplier, and as a Senior Analyst at TargetPoint Consulting, a market research and energy consulting firm. I hold separate Bachelor of Arts degrees in English and Government from Georgetown University's College of Arts and Sciences. I also hold a Master of Public Administration from the John Glenn College of Public Affairs at The Ohio State University. Please see Exhibit A for my complete resume.

Of specific relevance to this petition, I have previous and ongoing engagements with multiple clients that require monitoring and evaluating changes in PJM Interconnection's

("PJM's") capacity market rules, load forecasts, transmission expansion processes, wholesale market pricing conditions, large load interconnection requests, capacity entry and retirement, interconnection queue processes, changes in the costs of new resource costs within the PJM region, and more. For example, I recently supported the Consumer Advocates of PJM States ("CAPS") during the 2021 and 2025 PJM Quadrennial Reviews,[1] CAPS and the Maryland Office of People's Counsel ("OPC") during PJM's Critical Issue Fast Path – Large Load Addition ("CIFP – LLA") and CIFP – Reliability Backstop Procurement and Connect and Manage ("CIFP – RBP and C&M") processes, and the Maryland OPC during PJM's Powering Reliability Through Market Design ("PRTMD") process.[2] Work in several of these proceedings is still ongoing. I also support the Maryland Department of Natural Resources' Power Plant Research Program in assessing the need and alternatives for transmission projects proposed in the state that are subject to a Certificate of Public Convenience and Necessity ("CPCN"), and have assisted the Maryland OPC, the Pennsylvania Office of Consumer Advocate ("OCA"), and the Delaware Division of the Public Advocate with various matters related to large load additions, including tariff provisions, cost-allocation protections, and reliability requirements. Finally, I presented testimony in PPL Electric Utilities Corporation's ("PPL's" or "Company's") most recent base rate case addressing large load additions, reliability, and EV program issues on behalf of OCA.

Collectively, these engagements have required me to evaluate how changes in load, resource supply, wholesale market rules, transmission planning, and utility tariff provisions affect system reliability, utility costs, and the allocation of those costs among customers.

[1] The Quadrennial Review encompasses PJM's periodic evaluation of capacity market parameters, including the assumed Cost of New Entry ("CONE") and the shape of the Variable Resource Requirement ("VRR") (i.e., capacity market demand curve).

[2] PJM's PRTMD process is a recent initiative intended to evaluate PJM's approach to regional resource adequacy and initiate efforts to overhaul PJM electricity market rules.

II. Purpose of Affidavit

I have been retained by the OCA to assist in the evaluation of PPL's treatment of computational large load customers and to assess whether PPL's existing tariffs, service requirements, and emergency operating procedures adequately protect existing customers from the costs and reliability risks associated with the anticipated addition of these loads.

My affidavit addresses three principal topics. First, I explain why the magnitude, pace, and uncertainty of prospective computational large load additions create an immediate need to evaluate the terms under which PPL provides service to these customers. Second, I identify the tariff protections that I believe are necessary to ensure that computational large loads bear the costs and risks they cause and that existing customers are not exposed to unreasonable cost-shifting or reliability consequences. I then evaluate PPL's existing large load tariff provisions against those protections and identify areas in which additional requirements are warranted.

Finally, I address emergency load-control requirements applicable to computational large loads, including the designation of critical and non-critical load, curtailment priority, and the need for physical and operational capabilities necessary to implement curtailment. I then evaluate PPL's public emergency load-control procedures against those requirements and identify additional protections necessary to ensure that computational large loads can take service without degrading the reliability of service to existing customers or receiving preferential treatment at the expense of other customers during emergency conditions.

My evaluation necessarily relies on publicly available tariff and operating information. As discussed below, material aspects of PPL's actual treatment of computational large loads are implemented through customer-specific agreements, engineering and interconnection studies,

cost-allocation determinations, and non-public operating procedures. Accordingly, additional discovery in this proceeding is necessary to determine how PPL is applying its existing requirements in practice and to develop a complete record.

III. Summary of Findings and Recommendations

I preliminarily find and recommend the following:

- The magnitude, pace, concentration, and uncertainty of prospective computational large load additions create an immediate need for Commission review of the terms under which PPL provides service to these customers.
- Commission review should occur now, before additional costs and service arrangements become difficult to unwind.
- Computational large loads should be subject to differentiated tariff and service requirements commensurate with the costs and reliability risks they create.
- PPL's tariff should establish enforceable minimum requirements that apply to customer-specific arrangements and preserve Commission oversight.
- The Commission should require computational large loads to enter Commission-jurisdictional agreements that memorialize material customer-specific service obligations and remain subject to Commission oversight.
- Computational large loads should bear all directly assignable and "but-for" costs caused by their requests for service.
- New computational large loads should be required to satisfy applicable resource adequacy obligations as a condition of firm service.
- Computational large loads should be subject to mandatory and enforceable curtailment requirements.
- PPL's existing LP-6 tariff contains useful protections but is not sufficient to address the costs and reliability risks identified in this Affidavit.
- The Commission should establish a uniform framework governing the treatment of computational large loads during system emergencies.
- PPL's tariff and emergency operating procedures should establish a defined sequence for computational large load reductions during pre-emergency and emergency conditions.
- PPL should require the physical and operational infrastructure necessary to make these emergency protections effective and enforceable.

- Additional discovery and continuing Commission oversight are necessary.

IV. There Is an Immediate Need to Evaluate Utility Treatment of Computational Large Load Customers

A. Recent Trends Mark a Decided Shift in Utility Conditions

Between the mid-2000s and early 2020s, the U.S. experienced relatively flat electricity demand growth.[3] Under those conditions, utilities could plan around gradual load growth dispersed across many customers and physical locations, and could add infrastructure incrementally as that growth materialized. Growth-related investments could also be made and recovered over time with comparatively limited risk of stranded investment, i.e., development of infrastructure for demand that never appears.

Gradual investment helped control the level of transmission and distribution ("T&D") costs passed on to consumers. Capital assets are most expensive for ratepayers early in their service lives because utilities have an opportunity to earn a regulated rate of return on the undepreciated value of these assets. Additionally, gradual, dispersed load growth allows utilities and system operators more time to identify and address emerging reliability needs. Put another way, because changes in demand generally occurred with some degree of predictability during those twenty years, system operations and infrastructure could be adapted over time at reasonable cost and reduce operational impact.

Recent developments represent a material departure from those conditions.[4] As explained in the Affidavit of Mr. Zachary Teti, Pennsylvania now faces an extraordinary level of proposed

[3] Schipper, M. & Hodge, T. (May 13, 2025). "After More Than a Decade of Little Change, U.S. Electricity Consumption Is Rising Again." U.S. Energy Information Administration. https://www.eia.gov/todayinenergy/detail.php?id=65264.

[4] The 2023 PJM load forecast was the first to reflect a material change in expected summer peak demand. Specifically, after several years of a projected annual growth rate of under 0.5%, the 2023 forecast rises to 0.8% per

computational large load additions relative to the Commonwealth's recent historical electricity load growth. Mr. Teti also explains the significant differences among utility-submitted, PJM-adjusted, and firm-only large load forecasts, demonstrating the uncertainty associated with how much of that proposed demand will ultimately materialize. The Affidavit of Dr. Frank Felder likewise describes the rapid expansion of computational large loads in Pennsylvania and PJM. A defining characteristic of these computational large loads is their emphasis on "speed to power" (i.e., minimizing the time between a request for electric service and the date on which the customer can begin taking its requested load).[5]

Planning for the uncertainty surrounding prospective computational large load growth is fundamentally different from historical, ordinary incremental growth. Traditional sources of load forecast uncertainty, such as weather or economic growth, or changes in customer usage, arise from dispersed and independent factors, allowing forecasting errors to offset each other across customers and locations. By contrast, a computational large load can cause a discrete change of hundreds of megawatts ("MW") or more in a single location, or not materialize at all. As a result, substantial and long-lived utility investments may be triggered by individual customer projects whose timing, magnitude, and persistence remain uncertain.

The magnitude and pace of forecast computational large load additions can also create significant cost impacts for other customers. As discussed in the Affidavits of Dr. Felder and Dr. Serhan Ogur, rapid projected load growth can increase capacity and transmission costs, including

year, followed by 1.6% in 2024. See https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2024-load-report.pdf, p. 2. Additionally, in February 2023, PJM published its *Resource Retirements, Replacements & Risks* report that identified "high demand data centers" as a driver of system risk. See: https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx, p. 1.

[5] Kahrl, F. & Frick, N. M. (June 2026). *Speed to power: Solutions for accelerating large load connections*. Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/speed-power-solutions-accelerating.

by causing investments to be made before the corresponding large load revenues materialize. Dr. Felder further explains that large load growth can affect reliability by reducing resource adequacy (i.e., demand grows faster than sufficient generation can be added) and introducing new operational security concerns (i.e., large loads can cause abrupt changes in power flows, voltage, frequency, and other reliability requirements).

These considerations raise an immediate question: whether existing utility tariffs, service requirements, and emergency load-shed procedures adequately assign the costs and risks created by computational large loads while continuing to ensure safe, reliable, and adequate service at just and reasonable rates. As discussed below, I do not believe PPL's existing tariff provisions, service arrangements, and emergency procedures are sufficient to implement the Pennsylvania Public Utility Commission's ("PUC's" or "Commission's") large load policies or to protect other customers. I also identify a need for immediate action to address these deficits.

B. Computational Large Loads Introduce Unique Reliability Risks

Regarding reliability, large load interconnections can materially affect electric system reliability through resource adequacy, transmission deliverability, and system operation impacts. First, large increases in load raise peak demand and, in turn, the amount of planning reserves that must be procured to maintain reliability. If new generation and other capacity resources are not developed and placed into service on a timeline that keeps pace with the load increase, system reliability is degraded.

Second, reliability is determined by the ability to deliver power to specific load pockets where large loads, such as data centers, are interconnected. Rapid concentration of computational large loads in a given area can stress the transmission system and give rise to localized reliability

concerns. Either inadequate generation supply or insufficient transmission deliverability can reduce reliability. These concerns are especially acute at the bulk power system level, where the scale and concentration of large load interconnections can quickly exceed the assumptions embedded in prior planning studies and infrastructure configurations.

Third, the unique operating characteristics of data centers can cause reliability issues to emerge. Data centers are often highly sensitive to power quality and install protections such as breakers and switches to avoid damaging equipment.[6] Where a data center is unable to ride through an event and instantly reconnect to the grid, the result can be a grid-wide disturbance.[7] Rapid changes in power consumption in response to variable operations can also trigger unwanted power oscillations that damage grid equipment.[8] See the Affidavit of Dr. Felder for additional discussion of the recent Northern Virginia grid disturbance caused by data centers.

C. Computational Large Loads Introduce Unique Market Risks

As introduced above, a central risk associated with large load interconnections is uncertain demand. Data center developers frequently submit multiple interconnection requests across regions to preserve optionality, with only a subset of projects ultimately constructed.[9] As a result, requests for service may include speculative or duplicative inquiries that do not translate into realized load.

[6] Energy Systems Integration Group ("ESIG"), Large Loads Task Force. (March 2026). *Large Load Disturbance Events.* https://www.esig.energy/reports-briefs/large-load-disturbance-events/.
[7] *Id*., at 2–3.
[8] *Id*., at 11.
[9] Martucci, B. (May 15, 2025). "A fraction of proposed data centers will get built. Utilities are wising up." *Utility Dive*. https://www.utilitydive.com/news/a-fraction-of-proposed-data-centers-will-get-built-utilities-are-wising-up/748214/.

Data center demand is also highly heterogenous. There are numerous types of data centers, and each differs substantially in its power profile, reliability requirements, and sensitivity to price and latency. [10] Certain workloads, such as AI training loads, are more flexible and location-independent, making them more likely to relocate in response to market or system conditions. Other loads tied to critical services require zero latency and near perfect reliability, and may not materialize where system conditions compromise those requirements. The intended application of a data center may also change during development, altering its load characteristics and grid requirements after system planning assumptions have been finalized. [11]

Outside of demand uncertainty, the time requirements and complexity of data center development and operations come with inherent risk. Data center developments involve complex coordination among multiple parties including data providers, developers, utilities, and investors. The involvement of many interdependent actors creates sequencing and execution risk, particularly when progress by one party serves as a bottleneck for the entire project. Even if the load does ultimately materialize, the delays caused by such bottlenecks can delay when the large load begins paying for the infrastructure required to serve the customer.

In the longer term, there is mismatch between the long-lived nature of electric grid investments and the uncertainty surrounding AI-driven data center growth. Short-term contracts, preliminary agreements, or authorization letters provide limited assurance that either the load will

[10] Data Center Frontier. (May 18, 2022). "Understanding the Differences Between 5 Common Types of Data Centers." https://www.datacenterfrontier.com/sponsored/article/11427373/belden-understanding-the-differences-between-5-common-types-of-data-centers; Delp, A. & Tairych, D. (Oct. 14, 2025). "What Is a Neocloud?" Equinix. https://blog.equinix.com/blog/2025/10/14/what-is-a-neocloud/; Direct Testimony of Stan Blackwell. Virginia SCC Docket No. 2025-00058. March 31, 2025, at 8. https://www.scc.virginia.gov/docketsearch/DOCS/84sc01!.PDF.
[11] ESIG, Large Loads Task Force. (Dec. 2025). *Forecasting for Large Loads: Current Practices and Recommendations.* https://www.esig.energy/wp-content/uploads/2026/02/ESIG-Large-Loads-Forecasting-report-2025.pdf, p. 11.

materialize or that it will persist over the full life of associated utility assets. This asymmetry creates significant risk that utility investments may be stranded (i.e., the utility can no longer earn a return on and of the investment from the customer that caused the investment), with costs ultimately borne by parties other than the data center.

D. Computational Large Load Outage and Cost-Shifting Risks Are Immediate and Urgent

The magnitude and immediacy of anticipated computational large load growth make it unreasonable to defer review of how PPL or other Pennsylvania utilities propose to serve these customers. PPL is already making consequential decisions in response to computational large load customers' requests for service. This includes developing construction plans, entering service arrangements, and/or beginning construction for some of PPL's pipeline of nearly 31.8 gigawatts ("GW") of new load in the Company's pipeline as of August 2026.[12] If realized, this represents a more than quadruple increase from PPL's historical peak demand of 7.8 GW.[13] PPL Corporation's "2nd Quarter 2026 Investor Update" presents a plan to invest over $8.35 billion in T&D in Pennsylvania between 2026 and 2029, at least a portion of which will serve prospective data center customers.[14]

PPL also must determine how these customers will be treated during system stress and emergency conditions that are not merely hypothetical. For example, in December 2025, PJM issued a Post Contingency Local Load Relief Warning specifically for the PPL zone to address a

[12] PPL Corp. (Aug. 7, 2026). "PPL Corporation delivers solid second-quarter 2026 earnings; reaffirms guidance and long-term growth outlook." https://investors.pplweb.com/2026-08-07-PPL-Corporation-Delivers-Solid-Second-Quarter-2026-Earnings-Reaffirms-Guidance-and-Long-Term-Growth-Outlook.
[13] PJM Interconnection. (Jan. 14, 2026). *2026 PJM Load Forecast Report*. https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2026-load-report.pdf.
[14] PPL Corp. (Aug. 7, 2026). *2nd Quarter 2026 Investor Update*. https://filecache.investorroom.com/mr5ir_pplweb2/1337/PPL_2026_Q2_Investor_Update_vFINAL.pdf, slides 26-27.

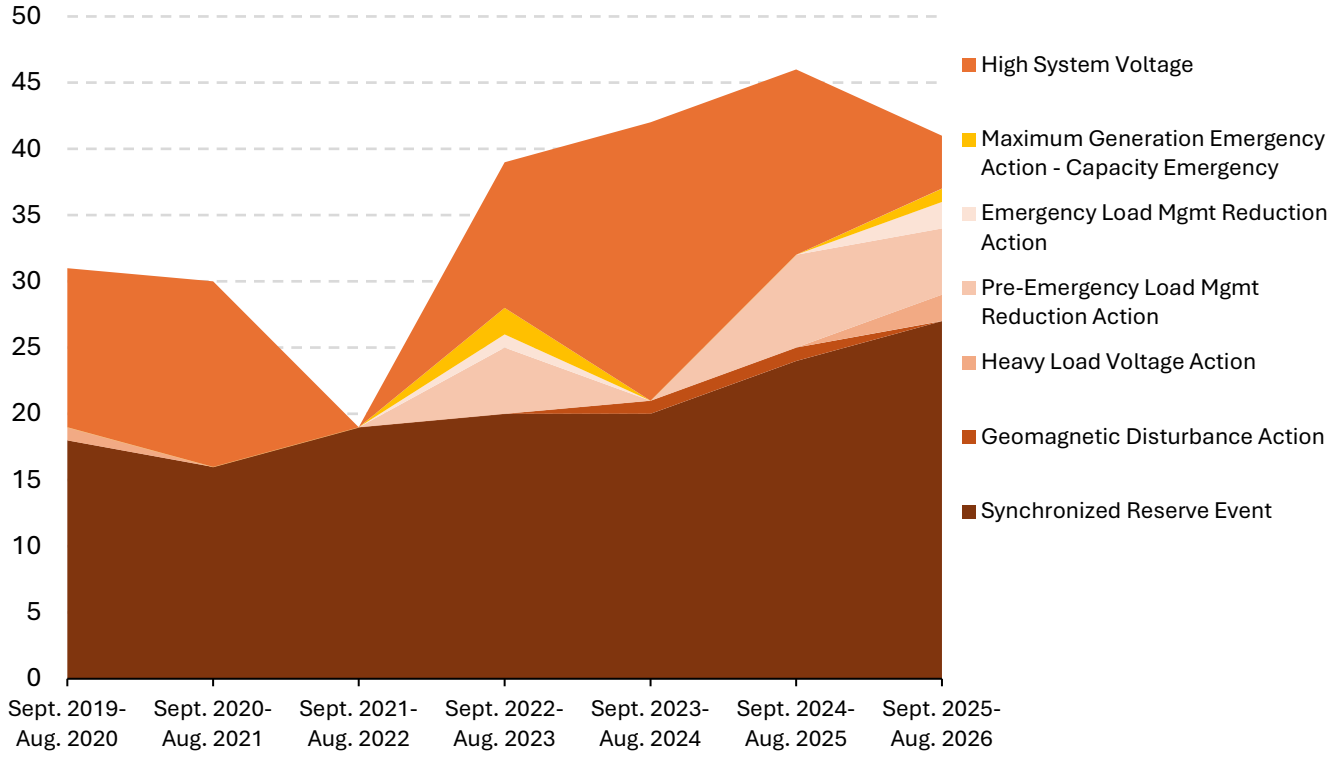
transmission contingency constraint.[15] That is, PPL was one contingency (i.e., equipment outage) away from requiring load shed.

PPL has also been subject to multiple recent PJM-wide emergency actions during periods of extreme system stress. For example, on July 2 of this year, PJM issued a Maximum Generation Emergency Action – Capacity Emergency Reduction Action to address Regional Transmission Organization ("RTO")-wide capacity shortfalls.[16] This was followed by additional Emergency Load Management Reduction Action on July 3.[17]

Figure 1 visualizes a notable increase in emergency actions over the last seven years affecting PPL, particularly synchronized reserve events.[18] This increase coincides with a variety of changes on the grid, including resource retirements, increased penetration of variable generation resources (e.g., solar and wind power), and additional large load connections throughout PJM. Regardless of the causes of these emergency actions, their increasing frequency demonstrates that the system is already experiencing periods of heightened stress, even before accounting for potentially massive additional load growth in the PPL service territory.

[15] PJM Interconnection. (Dec. 8, 2025). Post Contingency Local Load Relief Warning. https://emergencyprocedures.pjm.com/ep/pages/viewposting.jsf?id=104924.
[16] PJM Interconnection. (July 2, 2026). Maximum Generation Emergency Action—Capacity Emergency. https://emergencyprocedures.pjm.com/ep/pages/viewposting.jsf?id=105314.
[17] PJM Interconnection. (July 3, 2026). Emergency Load Mgmt Reduction Action. https://emergencyprocedures.pjm.com/ep/pages/viewposting.jsf?id=105340.
[18] A synchronized reserve event is an emergency procedure under which PJM directs generating resources to rapidly increase output, or demand resources to reduce load, within 10 minutes to restore the balance between supply and demand. These events can be triggered by conditions including unexpected generation outages, transmission outages, or increases in load.

Figure 1. Number of PJM Emergency Actions by Type, Excluding Drills and Tests (September 2019 – August 2026)



Source: Derived using postings from PJM's Emergency Procedures dashboard, available at: https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf

Some of the decisions PPL is currently making are difficult or impossible to unwind after the fact. Costs may sometimes be reallocated retrospectively, but infrastructure that has already been constructed cannot be "unbuilt," contractual arrangements may extend for years, and service conditions established today may determine future operational capabilities. Therefore, waiting to address these issues allows important cost and reliability consequences to become embedded before the Commission has determined whether existing protections are adequate.

The urgency of these issues is also reflected in the actions underway outside individual utility service territories. As Dr. Felder explains, the Federal Energy Regulatory Commission ("FERC"), North American Electric Reliability Corporation ("NERC"), PJM, federal policymakers, and Pennsylvania policymakers are actively addressing the reliability, cost-

allocation, forecasting, and operational implications of computational large loads. NERC's CEO recently described the situation and its impacts as a "five-alarm fire."[19] PJM, in particular, continues to address resource adequacy, emergency procedures, wholesale market impacts, transmission planning, and cost allocation through a multitude of active stakeholder processes and pending tariff revisions filed before FERC.

Many of the requirements proposed by the above entities depend upon state-jurisdictional utility tariffs, curtailment plans, emergency procedures, and retail service requirements. Accordingly, broader federal and regional action does not eliminate the need for Commission review; rather, it makes timely Commission and utility action more important. Those actions will not, by themselves, ensure adequate protections for PPL customers unless they result in corresponding changes to PPL's own tariffs, service requirements, contracts, or operating procedures. Moreover, the short- and long-term risks associated with additional computational large loads are already material and consequential. The Commission therefore should not defer review of PPL's existing practices while awaiting further regional or federal action.

E. The Commission Has Already Recognized the Need to Evaluate Utility Treatment of Computational Large Loads

Given the unprecedented nature of large load customers, the Pennsylvania Public Utility Commission has already recognized the need for each utility to adopt a large load tariff that works to mitigate the novel risks associated with these large customers. In 2025, the Commission initiated Docket No. M-2025-3054271, Interconnection and Tariffs for Large Load Customers, to consider how Pennsylvania's jurisdictional utilities should interconnect and provide service to large loads,

[19] Hiller, J. (July 2, 2026). "The 'Five Alarm' Risks Facing the Power Grid This Summer." *The Wall Street Journal*. https://www.wsj.com/business/energy-oil/the-five-alarm-risks-facing-the-power-grid-this-summer-3404b031.

particularly data centers and other energy-intensive computational facilities. That process culminated in a model tariff adopted by Final Order on May 12, 2026.

Additionally, the Commission recently commissioned an independent resource-adequacy analysis by Synapse Energy Economics to evaluate the reliability implications of projected load growth in Pennsylvania and PJM.[20] The study, as described in further detail in the Affidavit of Dr. Felder, found that PJM would fail to satisfy its resource-adequacy planning criterion from 2027 through 2030 with modeled loss-of-load expectation in 2030 reaching 0.59, or "nearly six times worse than the PJM planning criterion."[21] Importantly, the study attributed the 2030 result as "mainly due to large-load additions stemming from data center additions."[22] PUC Chairman DeFrank succinctly captured the implication of this analysis, stating that it "sends a clear warning: electricity demand and supply are moving out of balance, and the status quo is not sustainable."[23]

The present question is therefore not whether computational large loads warrant differentiated treatment, but whether each utility's actual tariffs, service arrangements, cost-responsibility provisions, and emergency procedures adequately implement the Commission's established policies and protect other customers from the particular costs and risks these loads create. Answering that question requires evaluation not only of PPL's tariff language, but also of how PPL is applying those requirements to actual and prospective computational large load

[20] Knight, P., Sharaf, S. & Chavin, S., et al. (Sep. 14, 2026). *Assessing Electricity Resource Adequacy in Pennsylvania and PJM*. Synapse Energy Economics, Inc. https://www.puc.pa.gov/media/4044/2026_assessing_electricity_resource_adequacy_in_pa_and_pjm.pdf.
[21] *Id.*, at 25. Results applicable under Synapse's Reference scenario using PJM's 2026 Load Forecast. PJM's planning criterion identifies the target amount of regionwide generation capacity needed to reliably serve regionwide peak load while meeting the industry standard of limiting power loss events to one occurrence every 10 years.
[22] *Id.*
[23] DiGangi, D. (Sep. 16, 2026). "PJM faces 2030 reliability crisis if data center load growth continues: report." *Utility Dive*. https://www.utilitydive.com/news/pjms-reliability-could-start-failing-by-2030-if-data-center-growth-continu/830405/.

customers. Where existing practices do not provide adequate protection, the Commission should establish corrective requirements before additional long-term commitments are made or ordinary customers bear the brunt of outages.

Importantly, publicly available information does not disclose the status of prospective computational large load additions in the PPL service territory; the service dates and load ramps PPL relies upon for planning purposes; the infrastructure PPL has committed or proposes to construct; the costs already incurred or committed; the financial security supporting those commitments; or the contractual protections applicable if individual projects are delayed, reduced, or abandoned. It also does not address the full scope of operating requirements during emergencies. Those are details that must be understood through discovery in a Commission proceeding.

For the reasons discussed below, I recommend that the Commission require PPL to serve computational large loads under updated service terms and conditions commensurate with the costs and risks they create. I also address the basis for Commission action and recommend specific protections that the Commission should require PPL to incorporate into large load tariffs and utility emergency operating procedures. These recommendations follow my review of information presently available. Additional discovery would allow further development of a PPL-specific record necessary to determine the precise tariff, contractual, and operating modifications that should be required.

V. Statutory Requirements Governing Service to Computational Large Loads

I am not an attorney; however, I am advised by counsel that the Commission has unique regulatory, adjudicatory, and enforcement responsibilities that bear directly on the immediate and urgent needs identified above. Additionally, each public utility in Pennsylvania has statutory

obligations with respect to furnishing electricity service. Because a shared understanding of these responsibilities is foundational to the recommendations that follow, I summarize below the principal statutory provisions informing my understanding. These observations reflect my lay understanding of Pennsylvania Consolidated Statutes, most especially Title 66, the Public Utility Code. The OCA will address additional legal considerations in the formal complaint accompanying this affidavit.

A. Statutory Requirements

The Public Utility Code establishes overlapping responsibilities relevant to the issues discussed above. These include obligations concerning the adequacy and reliability of electric service, requirements governing the treatment of customers, and the Commission's authority to supervise public utilities and require corrective action. In my understanding, the following provisions are particularly relevant:

Reliability and Adequacy of Electric Service

- 66 Pa. C.S. § 1501 requires that every public utility "shall furnish and maintain adequate, efficient, safe, and reasonable service and facilities," and undertake action as required to ensure these standards are met in conformity with Commission orders and regulations. Further, § 1501 provides that "every public utility may have reasonable rules and regulations governing the conditions under which it shall be required to render service."
- 66 Pa. C.S. § 2805(a) requires that the Commission work with the Pennsylvania utilities, PJM, NERC, and other relevant market participants to "ensure the continued provision of adequate, safe and reliable electric service to the citizens and businesses of this Commonwealth."
- 66 Pa. C.S. § 2807(a) establishes as a duty of electric distribution companies ("EDCs") to maintain the distribution system in conformity with national and industry standards "in a manner sufficient to provide safe and reliable service to all customers connected to the system consistent with this title and the commission's regulations." Additionally, 66 Pa. C.S. §2807(a) allows EDCs to put into place procedures that require generation suppliers to supply power to the EDC "at locations and in amounts which are adequate to meet the energy supplier's obligations to its customers."

Taken together, these provisions establish responsibilities directed not merely toward connecting individual customers, but toward maintaining adequate and reliable electric service for customers generally. That distinction is particularly important where the addition of computational large loads may affect the facilities, resources, or planning necessary to continue providing reliable service to other customers.

Treatment of Customers

- 66 Pa. C.S. § 1502 states that public utilities shall not "as to service, make or grant any unreasonable preference or advantage to any person, corporation, or municipal corporation," or subject these same parties "to any unreasonable prejudice or disadvantage." The statute also limits the establishment of differentiated service to only "reasonable classifications of service."

This provision is relevant not only to whether service provided to a particular customer is adequate, but also to whether the terms or consequences of providing that service create unreasonable preferences, disadvantages, or deficiencies in service affecting other customers. In other words, the statute provides for nondiscrimination.

Commission Supervisory and Contractual Authority

- 66 Pa. C.S. § 501 addresses the general powers of the Commission, including the "general administrative power and authority to supervise and regulate all public utilities doing business within this Commonwealth," and requires public utilities to "observe, obey, and comply" with Commission regulations or orders.
- 66 Pa. C.S. § 504 provides the Commission with authority to "require any public utility to file periodical reports, at such times, and in such form, and of such content, as the commission may prescribe, and special reports concerning any matter whatsoever about which the commission is authorized to inquire, or to keep itself informed, or which it is required to enforce," which would include contracts between a public utility and retail customer, as specified by the Commission.
- 66 Pa. C.S. § 508 gives the Commission "power and authority to vary, reform, or revise, upon a fair, reasonable, and equitable basis, any obligations, terms, or conditions of any contract heretofore or hereafter entered into between any public utility and any person, corporation, or municipal corporation" concerning the public interest.

- 66 Pa. C.S. § 1505 allows the Commission, upon finding that "service or facilities of any public utility are unreasonable, unsafe, inadequate, insufficient, or unreasonably discriminatory," to act in various ways to require "reasonable, safe, adequate, sufficient, service or facilities to be observed, furnished, enforced, or employed, including all such repairs, changes, alterations, extensions, substitutions, or improvements in facilities as shall be reasonably necessary and proper for the safety, accommodation, and convenience of the public."

These provisions provide the broader regulatory context for the more specific service obligations described above. In my understanding, they reinforce that the Commission's role is not limited to reviewing utility conduct after a reliability or service problem has occurred; the Public Utility Code also gives the Commission supervisory authority relevant to utility practices, contractual arrangements, and conditions of service that implicate the public interest.

B. State Versus Federal Jurisdiction

Questions exist regarding the extent to which a commission may require retail customer protections affecting customers that are part of interstate wholesale markets, as is the case for Pennsylvania. These questions arise because interstate transmission rates and revenue requirements in regional transmission systems like PJM are subject to federal jurisdiction, while state-level tariffs govern the terms of and costs of retail service. In general, wholesale service concerns the sale or transmission of electricity for resale, while retail service concerns the delivery and sale of electricity to the end-use customer that ultimately consumes it.

From a public policy perspective, I view the Commission's responsibilities as distinguishable from FERC's. Except in limited circumstances where a customer takes direct access wholesale service (i.e., the end-use customer takes wholesale electric service directly from the transmission system), new loads, including computational large load customers, interconnect to the broader bulk power system through EDCs. The Commission has responsibility over the terms of retail service provided by state-jurisdictional EDCs, as discussed above. That

responsibility encompasses the conditions under which a utility agrees to serve a computational large load customer and the allocation among retail customers of costs incurred in providing that service. Additionally, while FERC has clear jurisdiction over the allocation of regional transmission upgrade costs through its formula rate process, the Commission retains authority over whether transmission investments are placed into FERC-regulated transmission rate base; conditions of retail service; the terms of revenue guarantees imposed on large load customers; and, given the FERC-determined transmission revenue requirement, other issues of transmission cost allocation and rate design within Pennsylvania.

This perspective is consistent with FERC Order 888, which confirmed that "even where there are no identifiable local distribution facilities, states nevertheless have jurisdiction in all circumstances over the service of delivering energy to end users."[24] FERC has also recently emphasized state jurisdiction over terms of retail service in the context of large load additions. In its June 18, 2026 order instituting a show cause proceeding regarding large load customer treatment in PJM's Open Access Transmission Tariff, FERC stated that its authority is limited to jurisdictional transmission rates, and that states determine how those FERC-approved costs are recovered from retail customers.[25]

These respective federal and state roles involve two distinct steps. FERC sets the transmission revenue requirement and allocates it to the zone. How that zonal total is divided among retail customers is then addressed in accordance with state law and regulation. FERC discussion of large load cost shifting reinforces these distinct steps. FERC stated in the show cause

[24] FERC. *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*. Order 888, 75 F.E.R.C. P 61,080. April 24, 1996.
[25] FERC Docket No. EL26-67-000. Order Instituting Proceeding Under Section 206 of the Federal Power Act, 195 FERC ¶ 61,211. (June 18, 2026), at 69.

order that it was "encouraged by efforts taken by states to reform retail tariffs" to address "the potential for retail cost shifting as large loads come online."[26] FERC further explained that greater transparency regarding the costs of network upgrades serves the purpose of allowing state regulators to "protect residential and small commercial customers by incorporating those costs into retail rates" given their authority to set rates for different classes of retail customers.[27]

VI. Necessary Protections of a Large Load Tariff

While increases in costs or the probability or severity of emergency operating actions are not categorically limited to new computational large loads, computational large load customers, as compared to organic load growth and traditional customers, are a prevalent and consequential category of customer warranting differentiated service conditions given their atypical size, accelerated need to interconnect, and potential atypical system impacts. Put another way, the unique sizes and reliability requirements of computational large loads, as described above, can and do drive unique costs and risks, and therefore should face service terms and conditions that are commensurate with those impacts.

The Commission reached a similar conclusion in developing its Large Load Model Tariff. It found that, "[o]verall, there was broad consensus regarding the fundamental principle of cost causation and the need to protect ratepayers from unreasonable cost shifting. There was general agreement that large load customer guidance is needed in the areas of interconnection costs, interconnection studies, minimum contract terms, exit fees, and collateral, among other areas."[28] What follows is further discussion of the specific tariff provisions intended to accomplish those

[26] *Id.*
[27] *Id.*, at 69–70.
[28] PA PUC Docket No. M-2025-3054271. *Interconnection and Tariffs for Large Load Customers.* Pennsylvania Bulletin, 56 Pa.B. 3271. (May 30, 2026). https://www.pacodeandbulletin.gov/secure/pabulletin/data/vol56/56-22/790.html.

objectives. I first discuss which customers should be subject to the large load tariff. I then address the regulatory and contractual framework necessary to preserve Commission oversight and assign large load costs consistent with cost causation. Finally, I identify the principal tariff provisions needed to protect other customers from the financial and reliability risks associated with large load interconnection and service.

In addressing these recommended protections, I recommend that the Commission pursue consistent minimum standards across all EDCs, not just PPL. Such an approach is necessary to avoid a "race to the bottom" in which computational large loads seek service from EDCs that impose the least stringent requirements. This form of regulatory arbitrage undermines Commission efforts to establish just and reasonable requirements and protect existing customers.

A. The Definition of Large Load Customers Should Capture the Customers That Create Material Cost and Reliability Risks

The way the tariff defines large load should encompass all of the customers creating the cost and reliability risks addressed above. As a general matter, it is reasonable for a large load tariff to apply based principally on the magnitude and system impacts of the load rather than the particular business conducted by the customer.

The Commission adopted that general approach in its Large Load Model Tariff. The model tariff applies to new customers, or incremental new load, of at least 50 MW individually or 100 MW in the aggregate. The Commission also preserved EDC discretion to apply the tariff to customers below the 50-MW threshold.

Consistent with that discretion, I initially recommend that PPL set the computational large load tariff threshold at no greater than 25 MW of individual peak demand, with an appropriate

aggregation requirement for affiliated, commonly controlled, or otherwise related loads located within the same service area or geographic vicinity. Determination of the specific size thresholds should account for the actual customers applying to receive service, as supported by discovery. In general, a lower threshold and aggregation requirement reduces opportunities for prospective large loads to structure projects or divide load among related facilities in a manner that avoids tariff requirements.

A 25-MW threshold is also reasonable when compared with emerging large-load tariff practice. According to an August 2026 survey of large load tariffs by Lawrence Berkeley National Laboratory ("LBL"), almost all evaluated tariffs feature a minimum-demand thresholds, with 5 MW, 25 MW, 50 MW, and 100 MW among the most commonly used thresholds.[29] I calculate the weighted-average across the 55 tariffs LBL reviewed as approximately 38 MW. A 25 MW threshold is somewhat more protective but still within the range of thresholds already used by utilities and regulators.

Although large load protections may reasonably apply to customers across multiple industries, the relief requested in this proceeding is narrower. The concerns addressed in this affidavit arise principally from the distinctive characteristics of computational large loads, as detailed above and in the Affidavit of Dr. Felder. Likewise, OCA's complaint specifically challenges PPL's treatment of computational large loads and the cost and reliability risks associated with those customers.

[29] Frick, N. M., Cappers, P. & Kavlak, G., et al. (Aug. 2026). *Electricity Rate Designs for Large Loads: Evolving Practices and Opportunities 2026 Update*. Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/electricity-rate-designs-large-0.

Accordingly, my recommendation here is to specifically define "Computational Load Sites." I recommend the following definition:

> Computational Load Site—One or more buildings, structures, or installations that:
> (i) is a customer or applicant that has an anticipated maximum peak demand of 25 MW at a single point of interconnection or 50 MW at multiple points of interconnection that are interconnected to a single feeder;
> (ii) primarily contains information technology infrastructure used for:
> (A) creating, executing, and delivering software applications and services;
> (B) artificial intelligence training, deployment, and delivery;
> (C) cryptocurrency mining; or
> (D) other computational activities at a data center;
> (iii) is supplied through electrical equipment that is connected to the EDC's system; and
> (iv) is not a facility used for manufacturing or manufacturing operations.

This definition is intended to capture computational facilities whose size and operating characteristics create the types of material cost and reliability risks addressed in this affidavit, while preserving the Commission's ability to apply separate large load requirements to other customer types where appropriate.

In applying this definition (and subsequent large load tariff protections), I recommend that the Commission permit grandfathering only for customers already receiving retail electricity service. Importantly, I distinguish "receiving retail electricity service" from "receiving utility services in preparation for taking service," such as engineering, interconnection, or construction related services. Accordingly, grandfathering should not apply to customers that remain in the development or interconnection pipeline unless their load is already energized and is receiving retail electric service.

B. Large Load Tariffs Should Establish Minimum Requirements for Customer-Specific Agreements and Preserve Commission Oversight

Each Pennsylvania utility currently follows its own standard practice when undertaking studies and entering necessary agreements in advance of a customer taking service. These studies

and agreements are necessary to determine customer-specific facilities, costs, and operating requirements, and to implement any identified requirements for an individual customer. Examples of such arrangements include, but are not limited to:

- Engineering studies, which identify the facility and system upgrades required to reliably serve all existing customers and the proposed load;
- Interconnection agreements, which establish the facilities, upgrades, costs, and technical requirements associated with the utility's physical connection to the customer's facilities, usually based on the findings of the applicable engineering study;
- Transmission Security Agreements ("TSAs") which, as proposed in certain other retail choice jurisdictions in PJM and thus far adopted by PECO in Pennsylvania, are customer agreements filed with FERC that provide transmission-revenue guarantees to the transmission owner based on the customer's stated load ramp and applicable transmission rates. The Commission would lack jurisdiction over the terms of a TSA to the extent the EDC is not a party to the agreement; and
- Electric Service Agreements ("ESAs") which, as distinct from TSAs, are Commission-jurisdictional agreements that memorialize relevant terms and conditions of retail service to a large load customer, including, but not limited to, contract demand, load-ramp schedules, and contract-termination procedures.

The nomenclature often differs by state and even utility. PPL, for instance, requires an ESA that governs "the customer's interconnection to the transmission system at voltages equal to or greater than 69 kV, including the constructing, maintaining, and operating of transmission facilities," but does not make a reference to a TSA or interconnection/engineering study in its tariff.[30]

These arrangements can serve important functions in implementing the conditions under which an individual large load customer takes service. They are not, however, substitutes for tariff-level requirements. Standing alone, a customer-specific study or agreement may address only a

[30] PPL Corp. *General Tariff: Rate Schedule LP-6*. Issued June 30, 2026.

subset of the costs, reliability requirements, or operating obligations associated with service, and the scope and terms of those arrangements may vary by utility or customer.

A large load tariff should establish the minimum requirements that apply to customer specific agreements. The tariff should also identify the studies, agreements, and other customer-specific contracts necessary to implement those requirements. Addressing these protections at the tariff level provides the baseline requirements that customer-specific agreements can then implement based on the particulars of each individual customer.

Additionally, because material terms of service may ultimately be implemented through customer-specific agreements, the tariff should also preserve appropriate Commission oversight over how those agreements apply the tariff's requirements. That oversight should include a requirement that EDCs file with the Commission all customer-specific agreements associated with computational large loads. These filings would provide the Commission with the information necessary to determine whether the agreements implement applicable tariff requirements and adequately protect other customers. To make that review meaningful, both Commission Staff and statutory advocates should have access to unredacted agreements when necessary to perform their statutory responsibilities, subject to applicable confidentiality protections.

For the same reasons, review of PPL's existing agreements is necessary in this proceeding. Without those materials, it is not possible to determine whether PPL is consistently implementing the protections described in this affidavit or whether customer-specific terms create additional cost or reliability risk exposure for non-large load customers.

C. It Is Essential That the Large Load Tariff Require Commission-Jurisdictional Agreements

The tariff should obligate a large load customer to enter a Commission-jurisdictional ESA or equivalent agreement in order for service to commence. Such an agreement is necessary because many material aspects of service must ultimately be specified and implemented on a customer-by-customer basis. Without a Commission-jurisdictional agreement memorializing those terms, important conditions of retail service could be established outside the Commission's direct review and oversight. Commission review should include, to the extent permitted by law, authority to review and require modification of customer-specific arrangements to address apparent computational large load risks and ensure compliance with applicable tariff requirements, statutory obligations, and ratemaking principles over time.

Although a FERC-jurisdictional TSA may offer certain customer protections, it provides no foundation for retail service to large load customers and cannot function on its own as a comprehensive service agreement for two primary reasons. First, the Commission is not a party to the TSA, does not approve the complete agreement, and does not directly control its subsequent amendment or enforcement. Further, FERC has shown reluctance to disturb voluntary bilateral agreements between large loads and utilities. In accepting a TSA between Commonwealth Edison and Equinix over the protest of the Illinois Attorney General, FERC observed that the Illinois Commerce Commission retains authority to establish terms of retail service including retail consumer protection provisions, and declined to defer its ruling pending a state decision: "We also note that the Illinois Commission retains authority to establish terms of retail service between ComEd and Equinix, including retail consumer protection provisions. As such, it is unnecessary to defer ruling on the instant filing, as Illinois Attorney General suggests, pending an Illinois

Commission decision on the appropriate state retail rules for large load interconnection."[31] FERC further stated that questions regarding the total cost and appropriate allocation of costs for transmission facilities were not before it. These findings illustrate the limited ability of a TSA to carry out state policy or respond to evolving Commission requirements.

A more recent ComEd TSA dispute further illustrates this limitation. In September 2026, FERC rejected ComEd's attempt to cancel a TSA supporting a proposed 1.8 GW data center following a dispute with the data center developer. The dispute revolved around whether the customer had satisfied the TSA's initial credit-support requirement through a $1.00 letter of credit. FERC declined to exercise primary jurisdiction over interpretation of the disputed credit-support terms, leaving that contractual dispute to the courts.[32] This dispute again suggests that FERC approval of a TSA does not itself establish that the agreement contains adequate financial security. The TSA also does not appear to provide FERC or the Commission with an effective mechanism to revise deficient contractual protections after the agreement has been accepted.

Second, the TSA does not act as a substitute for retail tariff protections from non-transmission-related costs and risks. Vital conditions under which service should be permitted to commence, including curtailment requirements under emergency conditions, billing obligations, and other retail service terms and conditions, must be identified at the retail tariff level. Further, federal jurisdictional agreements are not the correct venue to define or secure obligations arising from the utility's provision of retail service. For example, a minimum billing demand establishes the quantity against which the customer's transmission-related retail charges will be assessed. The

[31] FERC Docket No. ER26-989-000. Order Accepting Transmission Security Agreement, at 38. (March 10, 2026); see also FERC Docket No. ER25-3492-000. Order Accepting Transmission Security Agreement. (Nov. 21, 2025).
[32] Howland, E. (Sep. 23, 2026). "FERC rejects ComEd's cancellation of PowerHouse Hillwood data center contract." *Utility Dive*. https://www.utilitydive.com/news/ferc-exelon-comed-powerhouse-hillwood-data-center/831127/.

minimum contract term and exit fee govern the customer's ability to terminate or reduce that service and allocate the resulting stranded-cost risk. Collateral secures the customer's payment obligations associated with taking service. Each of these are essential retail rate and service requirements even where the dollar amounts ultimately reflect FERC-approved transmission charges.

The two limitations described above reinforce the need for a Commission-jurisdictional agreement. Such an agreement should establish certain protections as a condition of retail service and limit individual customer agreements strictly to addressing customer-specific details necessary to implement those protections.

Several other jurisdictions have reached similar conclusions regarding the need for state-jurisdictional agreements to implement retail consumer protections irrespective of the availability of a TSA. For example, Ohio requires a state-jurisdictional agreement between the utility and data center customers containing minimum demand, term, collateral, and exit provisions applicable to transmission costs.[33] Virginia utilities likewise require large load customers to execute state-jurisdictional ESAs establishing customer-specific capacity and retail service obligations under Commission-regulated tariffs.[34,35]

[33] Public Utilities Commission of Ohio Case No. 24-508-EL-ATA. *In the Matter of the Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers*. Opinion and Order. (July 9, 2025).
[34] Virginia Electric and Power Company. (Jan. 1, 2026). Agreement for Electric Service. https://www.dominionenergy.com/-/media/content/rates-and-tariffs/pdfs/virginia/terms-conditions/agreement-service.pdf.
[35] Virginia State Corporation Commission Case No. PUR-2025-00058. Final order: Application of Virginia Electric and Power Company for a 2025 biennial review. (Nov. 25, 2025). https://www.scc.virginia.gov/docketsearch/DOCS/89g601!.PDF.

D. A Just and Reasonable Large Load Tariff Assigns All But-For Costs to Computational Large Loads Consistent with Cost Causation

Cost causation is central to any consideration of large load interconnection. New large load customers should bear the costs they cause for the electric system, rather than shifting those costs onto existing customers. Likewise, when a new large load drives the need for incremental infrastructure, that entrant should bear the associated financial burden.

As discussed above, the unique size, ramp rate, and reliability requirements of computational large loads, among other distinguishing features, drive unique infrastructure costs and reliability risks. Tariffs that allow new large loads to impose these costs or risks onto existing customers without offsetting benefits are neither just nor reasonable. The PUC, in particular, has the responsibility to identify and enforce reasonable means of calculating the financial burden caused by new computational large load customers and to implement tariff structures that obligate those customers to pay the associated costs.

A direct means of implementing cost causation is to identify and assign "but-for" costs. "But-for" costs reflect the financial investments required by PPL or other utilities to upgrade T&D systems to support a large load customer that would not have been required in the absence of that large load customer's request to interconnect and receive utility service. But-for costs may be attributable to an individual large load customer, a group of new large load customers requiring simultaneous network upgrades, or the large load/data center class.

The Commission expressly adopted this same cost-causation principle in its Large Load Model Tariff. Specifically, the Commission determined that, where a Network Improvement would not have been needed "but for" the interconnection of a Large Load Customer, "the costs of the upgrade should be allocated to that customer irrespective of whether other customers would benefit

from it."[36] The use of incremental cost or "but-for" cost tests is also consistent with emerging practices in other jurisdictions.[37] According to LBL's August 2026 survey of large load tariffs, 45 tariffs, or 82% of the tariffs reviewed, contained a provision regarding direct cost assignment, for either capacity, interconnection, generation, network transmission, or a combination thereof. The prevalence of such provisions is on the rise.[38] PPL itself has recently proposed a retail transmission rider intended to more directly assign certain transmission network upgrade costs associated with LP-6 customers.[39]

Moving from identification of "but-for" tests to ensuring those costs are actually recovered from the customers that caused them requires additional tariff provisions. These may include customer contribution in aid of construction ("CIAC") that provides for upfront contributions; a combination of tariff terms that ensure over-time contributions, including minimum billing demand, contract term, and financial security; and/or exit procedures that recover remaining obligations when service is reduced or terminated. These types of provisions can collectively create a comprehensive revenue guarantee for large load interconnection upgrade costs that are driven by a specific load.

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[36] PA PUC Docket No. M-2025-3054271. *Interconnection and Tariffs for Large Load Customers*. Final Order, at 42.
[37] For example, the Incremental Cost Test proposed by Xcel Energy in Minnesota: "If the Incremental Cost Test shows that revenues are projected to be lower than incremental costs, then the customer and the Company will develop a proposal in the ESA to bring additional revenues such that incremental costs are paid for and a benefit is shown for system customers." RTO-imposed transmission charges are a part of the calculation. For additional information, see: Minnesota Public Utilities Commission Docket No. M-25-289. *In the Matter of Northern States Power Co.'s, d/b/a Xcel Energy's, Petition for Approval of Large General Time of Day Service Customers and Large Peak Controlled Time of Day Service Tariff.* Petition of Xcel Energy, at 18. (July 15, 2025.) https://efiling.web.commerce.state.mn.us/documents?doSearch=true&dockets=25-289.
[38] Frick, N. M. (Berkeley Lab) et al. (Aug. 2026.) *Electricity Rate Designs for Large Loads: Evolving Practices and Opportunities 2026 Update*.
[39] Specifically, on September 14, 2026, PPL filed a petition seeking approval of a new Customer Protection Transmission Rider intended to support direct allocation of certain transmission network upgrade costs associated with large load customers. In its proposal, PPL acknowledged that its existing transmission cost recovery approach "limits the ability for the company to directly assign certain transmission network costs associated with large-load growth to a specific customer class." See: https://news.pplweb.com/2026-09-14-PPL-Electric-Proposes-New-Customer-Protection-Transmission-Rider,-Building-on-its-Existing-Customer-Protection-Framework.

In addition to recovering identified but-for costs, enforceable guarantees should be required to protect existing customers from the risk of delayed, reduced, or abandoned load. In the alternative, an emerging approach to "but-for" cost assignment is the inclusion of "hold harmless" provisions in tariffs, as identified by LBL, which implement mechanisms for utilities to recover shortfalls in revenue from the large load customer if revenue from the large load customer is shown to be deficient compared to the costs incurred to serve the customer. Such provisions may be implemented in the form of periodic incremental cost tests, formulaic backstops that automatically adjust charges, or ratepayer impact analyses that prevent cost shifting. As of August 2026, twenty-five, or 46%, of tariffs reviewed by LBL had at least one version of a hold harmless provision.[40]

Costs attributable to large load development but not directly assignable to one specific large load customer should be addressed by ensuring that the applicable costs are recovered from the large load customer class rather than shifted to other customer classes. Dr. Ogur further addresses how PPL's existing transmission and capacity cost allocation mechanisms can result in cost shifting and identifies potential mechanisms for preventing those costs from being imposed on existing customers.

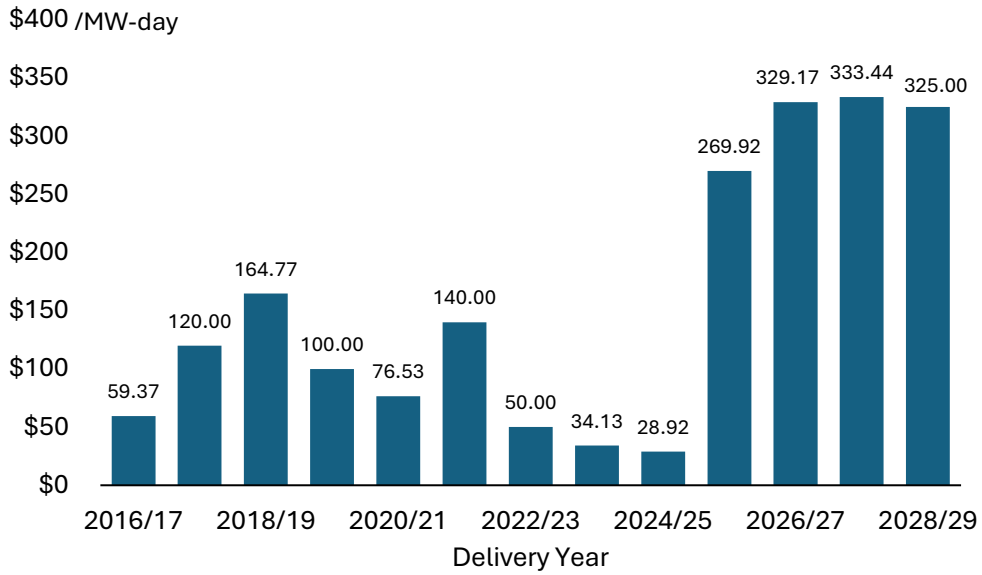
E. Computational Large Loads Should Be Subject to BYONC Requirements to Ensure They Bring Supply Necessary to Reduce or Offset Adverse Cost and Reliability Impacts on Other Customers

Under flat or steady growth, PJM was able to procure sufficient capacity for its entire customer base through its capacity market, the Reliability Pricing Model ("RPM"), with comparatively limited price volatility. This changed in the last several years, with PJM clearing less capacity than its reliability requirement in the two most recent capacity auctions for Delivery

[40] *Id.*

Years ("DY") 2027/2028 and 2028/2029. Concurrently, clearing prices jumped from $28.92/MW-day for DY 2024/2025 to $296.92 MW-day for DY 2025/2026, and have remained over $300/MW-day for the three subsequent auctions.[41,42] Figure 2 depicts the magnitude of this shift in capacity market conditions, as also described above.[43]

Figure 2. PJM Capacity Auction Clearing Prices (RTO)



At a time when PJM is managing generator retirements and delayed interconnection queues, data centers add an additional source of demand that places further pressure on the capacity market. According to PJM's Independent Market Monitor ("IMM"), the costs of the 2027/2028 base residual auction were approximately $6.5 billion higher than they would have been in the absence of data center load.[44] In response to these conditions, on August 13, PJM filed with FERC

[41] Howland, E. (Dec. 18, 2025). "PJM capacity prices hit record high as grid operator falls short of reliability target." *Utility Dive*. https://www.utilitydive.com/news/pjm-interconnection-capacity-auction-data-center/808264/.
[42] PJM delivery years run from June 1 through May 31.
[43] Beginning with the DY 2026/2027 auction, the clearing prices shown in Figure 2 reflect a price "collar" (i.e., a predetermined minimum and maximum price that constrains the auction clearing price). Absent the collar's maximum, clearing prices would have been higher, reaching as high as $555/MW-day in DY 2028/2029.
[44] PJM Interconnection. (Jan. 5, 2026). *Analysis of the 2027/2028 RPM Base Residual Auction Part A*. Monitoring Analytics.

several proposed reforms developed through its most recent Critical Issue Fast Path.[45] Under one portion of PJM's proposal, for large loads above the amount reflected in the DY 2028/2029 auction forecast, a Load-Serving Entity ("LSE") must bring new capacity in a quantity that meets or exceeds its large customers' peak load or the load will be subject to curtailment requirements. PJM describes the self-supply requirement as "Bring Your Own New Capacity" ("BYONC"). As proposed by PJM, BYONC is specifically defined as megawatts of Unforced Capacity equivalent to a large load's peak demand. BYONC resources must join the PJM system no earlier than May 31, 2027. These new resources must function as price takers for the next 10 consecutive DYs, bidding into the RPM at $0/MW.

If an LSE does not bring such capacity online under PJM's Interim Resource Adequacy Service ("IRAS") proposal, its large customers will be subject to load reduction requests during PJM emergencies before Pre-Emergency Load Management Response. Beginning with the 2029/30 DY base residual auction, large load customers that do not satisfy the applicable BYONC requirement will also be excluded from RPM demand. PJM's BYONC and IRAS requirements are described further in the Affidavit of Dr. Felder.

PJM's proposal addresses resource adequacy issues through wholesale-market rules. At the retail level, the PUC should require that all new computational large loads satisfy comparable BYONC obligations as a condition of commencing service through a Pennsylvania EDC. This requirement should cover all computational large loads that have not yet interconnected to the

https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20272028_RPM_Base_Residual_Auction_Part_A_20260105.pdf.

[45] FERC Docket No. ER26-3515-00. *Proposal of PJM Interconnection, L.L.C. to Establish Interim Resource Adequacy Service and a Large Load Registry to Address System Reliability*. (Aug. 13, 2026).

system. PJM's currently proposed BYONC requirements should serve as a minimum standard for what qualifies as "new" in terms of BYONC.

I recommend a mandatory BYONC requirement. However, should the Commission proceed with less than a mandatory BYONC requirement, I recommend that meeting the BYONC standard confer benefit to eligible computational large loads. This may include preferential treatment during emergency procedures compared to other computational large loads, akin to PJM's proposed treatment of IRAS and non-IRAS large loads. This recommendation is addressed in further detail in Sections IX and X below.

In implementing this requirement, EDCs should verify, subject to PUC inspection, that the BYONC will deliver energy to the EDC at locations and in amounts which are adequate to meet the electricity needs of the Computational Load Entity. At a minimum, the amount of qualifying capacity should be sufficient to cover the customer's peak demand together with the applicable PJM reserve requirement. These arrangements can be addressed by customer attestation, but should be subject to EDC verification and inspection on at least a quarterly basis. Periodic verification is necessary to determine whether the customer's electric generation supplier or self-supply arrangements remain sufficient as the customer ramps-up its load and continues to take service.

Quantity alone, however, is not sufficient. To ensure that qualifying capacity can actually support the load where it interconnects without creating avoidable transmission needs, I also recommend a complementary, Pennsylvania-specific BYONC requirement that the new generation capacity be within the same Locational Deliverability Area ("LDA") as the large load. The PUC has recently recognized the system benefits that can stem from building load near generation

through a recent Complaint filed with FERC, stating that "siting a large load near or at the same point of interconnection as a new generating facility could reduce the network upgrades needed to interconnect only the load or only the generating facility."[46] This locational requirement is critical because capacity located elsewhere in PJM may satisfy a regional capacity obligation while providing limited relief to the transmission constraints, deliverability risks, or infrastructure needs created by a large load in a particular area.

F. Computational Large Loads Should Be Subject to Curtailment Requirements to Provide Critical Reliability Protection

Curtailment requirements should be a central condition of service under a large load tariff. Computational large loads can add hundreds or even thousands of megawatts of demand at a single location and, as discussed above, can materially contribute to resource-adequacy and operational reliability risks. A tariff governing service to these customers should therefore ensure that, when system conditions require load reductions, PPL has a clear and enforceable ability to obtain relief from computational large loads rather than relying disproportionately on involuntary interruption of residential, small commercial, and other non-data center customers.

The Commission should require mandatory curtailment of the non-critical portion of computational large load during specified PJM- or utility-directed pre-emergency and emergency conditions. This obligation should apply as a condition of interconnection and continued service and should not depend on whether the customer voluntarily elects an interruptible rate option. The tariff should establish the customer's underlying obligation to curtail and authorize PPL to implement that obligation through Commission-approved emergency operating procedures. Where

[46] FERC Docket No. EL26-98-000. *Complaint of the Pennsylvania Public Utility Commission*, p. 11. This position refers the Secretary of Energy's advanced notice of proposed rulemaking ("ANOPR") on large loads.

a computational large load seeks protection for a portion of its demand as critical load, only the specifically identified and verified critical portion should receive such treatment; the balance of the customer's demand should remain available for curtailment.

The tariff should also condition commencement and continuation of service on the customer maintaining the physical, operational, metering, communication, and backup capabilities necessary to carry out required curtailments within the applicable emergency timeframe. At a minimum, PPL should be able to verify that non-critical load can be separately reduced, measure actual performance, communicate curtailment instructions, and confirm compliance. Failure to perform when directed should carry meaningful tariff consequences, including, where appropriate, modification of the customer's service conditions. The specific requirements for identifying critical load, segregating load, verifying customer capabilities, sequencing curtailments, and restoring load following an emergency are addressed in greater detail in Section IX below.

These protections should apply regardless of the ultimate disposition or scope of PJM's proposed IRAS. IRAS may establish an additional regional mechanism requiring certain large loads that do not bring qualifying new capacity to reduce demand before PJM reaches broader emergency actions. PJM, however, does not determine the retail order in which individual Pennsylvania customers are curtailed, and IRAS would not necessarily encompass every computational large load that may affect system reliability. PPL's retail tariff and Commission-approved emergency procedures therefore must independently establish the obligations necessary to protect customers within PPL's service territory. The relationship between PJM emergency requirements, Pennsylvania load-shed priorities, and PPL's implementation procedures is addressed in Sections VIII through X below.

Accordingly, at the tariff level, the Commission should require that the PPL tariff: (1) make non-critical computational large load subject to mandatory curtailment during defined pre-emergency and emergency conditions; (2) condition interconnection and continued service on demonstrated capability to perform that curtailment; (3) provide for verification, testing, and enforceable consequences for nonperformance; and (4) expressly coordinate those tariff obligations with PPL's Commission-approved emergency operating procedures. Sections IX and X address the necessary emergency-procedure protections and deficiencies in PPL's existing procedures in greater detail.

G. A Just and Reasonable Large Load Tariff Includes Other Well-Understood Features That Mitigate Cost and Risk Transference

The following section briefly identifies various other mechanisms that can be used with the intent of ensuring that large load customers do not impose risk or costs on other customers. Notably, LBL's recent review of 55 large load utility tariffs identifies many of these same mechanisms as provisions that have been or are being implemented to mitigate cost and operational risks caused by new large, predominantly data center, loads. Table 1 summaries key large load tariffs based on prevalence and recency, and categorizes them as being either established, stable, emerging, or declining practices.

Table 1. Organized Large Load Tariff Elements			
Established Practice	**Stable Practice**	**Emerging Practice**	**Declining Practice**
Minimum demand threshold (aggregation below)	Load factor threshold	Study requirements	Customer type
Minimum contract duration	Aggregation rules	Load-ramp period	
Minimum bill (monthly billing demand & monthly demand charge)	Load forecast requirements (reporting and frequency of reports)	Hold harmless (formulaic backstop, incremental cost coverage, no harm analysis)	
Collateral requirements	Price premium	Resizing or reassigning of contract capacity	
Direct assignment		Exit fees	
Customer-specific resource procurement (Behind-the-meter generation, customer-led procurement, load flexibility)			

Source: Mims Frick (Berkeley Lab) et al., *Electricity Rate Designs for Large Loads: Evolving Practices and Opportunities 2026 Update,* August 2026. See the full report for additional description of large load tariff elements not otherwise addressed below.

These various provisions interact towards meeting the Commission statutory and regulatory objectives. For example, binding exit fees reduce need for long contract terms as a means of ensuring cost causation. The provisions the Commission ultimately adopts for each utility should be designed to function collectively to avoid cost and risk absorption by non-large load customers.

Ramp Limits Ensure That Cost Obligations Begin in a Timely Manner

A large load customer's ramp period reflects the amount of time required for the customer's demand to reach its full contract capacity. Long ramp periods for large load customers compound uncertainty regarding whether and when projected load will materialize and permits delayed or

insufficient contributions by large load customers toward the "but-for" costs they impose on the system.

To address these concerns, the tariff should limit the load-ramp period. The PUC's Large Load Model Tariff sets the load ramp to a maximum of five years and requires that the minimum contract term commence only after completion of the load ramp. This tariff feature aligns customer commitments with the long-lived nature of utility investments in T&D infrastructure while ensuring timely and predictable recovery of investments.[47] Load-ramp requirements should be explicitly incorporated into both the tariff and a Commission-jurisdictional ESA.

CIAC Requirements Ensure That Large Load Customers Directly Fund the Incremental Facilities Required to Serve Them

A tariff should require large load customers to bear 100% of the costs of direct interconnection and distribution facilities and all directly assignable "but-for" transmission network upgrades. CIAC is one mechanism to ensure adequate customer contributions are made towards this end, although other customer-specific cost recovery mechanisms may be appropriate for certain wholesale costs as discussed in the Affidavit of Dr. Ogur.

In the case of distribution costs, direct payment via CIAC has an advantage over embedded recovery of distribution costs through volumetric rates insofar as the costs of required distribution upgrades will vary significantly across projects based on location, distance from existing infrastructure, facility size, and customer-specific equipment needs. Applying an embedded cost recovery approach risks diluting cost causation principles by spreading highly site-specific costs

[47] Consider, for example, a customer with an anticipated peak load requirement of 1,000 MW that establishes a ramp requirement of 100 MW for the first nine years of the TSA and 1,000 MW for Year 10. Due to the expiration of the TSA, this customer would not have any obligation to continue contributing revenue towards the investments made by the EDC to enable 1 GW of service in Year 10.

across a broader customer base. Additionally, recovering these costs over time through usage-based charges introduces an acute risk of under-recovery if the customer's actual load deviates from projections or if the customer exits service prematurely. The Commission reached a similar conclusion in the Large Load Model Tariff, where it directed EDCs to assess CIAC to recover all distribution and transmission costs necessary to interconnect new large load customers.[48]

The PUC should exercise careful review of the refundability of CIAC to large customers. To the extent that the Commission prefers to retain a refundable CIAC structure, at a minimum, refunds should be explicitly capped at the amount contributed. Minimum billing demands and exit fees should also apply alongside a refundable CIAC structure to ensure adequate contribution.

Minimum Demand Provisions Guarantee Cost Responsibilities Proportionate to the Projected Demand Driving Investment

Minimum demand charges guarantee a certain monthly responsibility for costs associated with projected demand. A minimum demand charge of 90%, for example, would require that a customer pay the higher of their actual demand and 90% of their contracted demand (i.e., maximum anticipated demand). The nature of the cost recovery certainty provided by these charges depends upon other aspects of a large load tariff. Under a tariff that requires large load customers to directly pay for their "but-for" distribution and directly assignable transmission costs, a minimum demand charge provides certainty that the large load customer will contribute the level of revenues assumed when rates for the customer were set via a cost of service study ("COSS") or otherwise.

[48] PA PUC Docket No. M-2025-3054271. *Interconnection and Tariffs for Large Load Customers*. Final Order, at 42–43.

In the absence of a requirement for large customers to pay their "but-for" costs, the incremental costs caused by large load customers will be embedded in the utility's overall revenue requirement and be recovered in the same manner as other embedded costs. While the minimum demand charge will provide greater assurance that the large load class produces the revenues assumed in designing its rates, the minimum demand provision does not itself ensure that all incremental costs caused by large load customers have been assigned to that class through the COSS. Moreover, a minimum monthly billing demand does not necessarily establish the quantity of load used to allocate transmission and capacity costs. Separate requirements may therefore be necessary to prevent cost shifting in those categories.

Minimum charges should persist throughout the contract term and be enforceable regardless of customer operational decisions. Minimum monthly charges should also protect against the risk of under-utilization before and after ramp periods. The absence of minimum demand provisions tied to a percentage of contracted capacity would allow large load customers to take substantially less service than contemplated at the point in time when the utility planned and incurred fixed costs, while correspondingly reducing the large load customer's contribution toward recovery of those fixed costs. I propose 90% as insurance against the uncertainty surrounding the timing and magnitude of usage-based contributions from computational large loads. Ninety percent also reflects practice in other jurisdictions. For example, in August, the Michigan Public Service Commission approved a proposed Indiana Michigan Power Large Power tariff that includes a minimum monthly billing demand of no less than 90% of the greater of (a) the customer's established contract capacity; or (b) the customer's highest previously established monthly billing demand during the past 11 months.[49] See also the Affidavit of Dr. Ogur for

[49] Michigan PSC Docket No. U-21986. Notice of Proposal for Decision. (May 19, 2026).

additional discussion of minimum-demand and peak-load-contribution requirements as mechanisms for preventing transmission and capacity cost shifting to existing customers.

Minimum Contract Terms Ensure That Large Loads Contribute to Cost Recovery over a Reasonable Period

The minimum contract term is a common large load tariff component, and one for which best practices are emerging. A contract term adds an additional layer of certainty that the revenues as assumed in the COSS will be recovered as planned by ensuring that the minimum demand obligations remain in effect over an appropriately long period. The PUC's Large Load Model Tariff sets a minimum initial contract term of five years after the load-ramp period, which cannot exceed five years. A 5-year term is at the lower end of acceptable. Instead, a minimum contract term of at least 15 years is consistent with tariffs in several other jurisdictions.[50] For example, in Michigan, the Public Service Commission recently established a 15-year minimum term for large load customers of Consumers Energy.[51] 15 years is also the modal requirement per LBL's recent evaluation of large load tariffs.[52] I likewise suggest a minimum 15-year retail tariff contract term to increase the probability that the customer adequately contributes to the embedded costs of its service and does not strand investments. This contract term should also be reflected in an ESA.

Study Deposits Assign Certain Pre-Interconnection Costs Directly to the Customer Causing the Study

The provision of electric service to large load customers requires significant planning prior to interconnection to ensure T&D systems will be able to continue to reliably serve existing customers after the entry of the large load into those systems, and to determine necessary facilities

[50] Smart Electric Power Alliance ("SEPA"). Database of Emerging Large-Load Tariffs. Last accessed March 31, 2026. https://sepapower.org/large-load-tariffs-database/.
[51] Michigan PSC Case No. U-21859. Order, at 107. (Nov. 6, 2025).
[52] Kahrl, F. & Frick, N. M. (June 2026). *Speed to power: Solutions for accelerating large load connections*. Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/speed-power-solutions-accelerating.

and upgrades for interconnection. A large load tariff should require customers to pay for all costs associated with this research, including the costs of any required load and engineering studies. Where large load additions are evaluated on a cluster basis, costs should only be apportioned among the large loads included within the study. These costs should be paid up front or backed by financial security.

Financial Security Protects Existing Customers from Bearing Costs If Large Load Additions Are Delayed, Reduced, or Abandoned.

Financial security provisions must reflect the scale and duration of investments required to serve large load customers. I recommend requiring deposits, guarantees, letters of credit, bonding, or similar instruments to protect the EDC and other ratepayers from stranded cost risk if a customer fails to meet its take-or-pay obligations or otherwise discontinues service. These protections should remain in place until the associated investment risk is retired, with the ability to "draw down" security requirements over time as obligations are met. "Draw down" mechanisms may include annual or incremental adjustments over time based on compliance with minimum billing obligations, or adjustment mechanisms that are dependent on the credit-worthiness of each customer.[53]

Contract Termination and Exit Fees Protect Existing Customers from Stranded Costs

Exit procedures should restrict a large load customer from terminating their service contract without proper notice. These procedures should also ensure the customer's contribution to revenues is sufficient to offset the entirety of its cost responsibility, particularly in the case of early termination and underutilization.

[53] Frick, N. M. (Berkeley Lab) et al. (Aug. 2026). *Electricity Rate Designs for Large Loads: Evolving Practices and Opportunities 2026 Update,* pp. 6–7.

Short notice periods for contract capacity modifications or terminations are incompatible with multi-decade grid investments. Alignment of the tariff with these significant investments should be reflected in at least a five-year advanced notice of intent to terminate service or change contract capacity. Assuming a customer provides sufficient notice, their responsibility should be limited to the costs attributable to the customer that the utility cannot reasonably avoid, mitigate, or reassign to other customers during the notice period, including any remaining unrecovered customer-specific facilities costs. If a customer fails to provide sufficient notice, penalties should be assessed up to the full remaining value of the contract, consistent with the exit fee formula, in addition to any applicable exit fee.

A tariff should include a formal exit fee provision that would be transparently structured to fully recover the costs of any investments made by the EDC on a large load customer's behalf and assigned to that customer, including both transmission and distribution plant. Such an exit fee should reflect the "but-for" costs caused by the customer. While the exit fee need not apply indefinitely if the customer ultimately provides sufficient rate revenue to pay off the cost of interconnection and service to the customer, it must be coordinated with other tariff provisions—including load-ramp requirements, minimum contract terms, and minimum billing guarantees—to ensure that, in combination, these provisions provide adequate and durable recovery of all costs associated with serving the large load.

If a large load customer is able to find another customer that wishes to take over a portion of the original load's interconnection, exit-fee requirements should be proportionally adjusted in reflection of that replacement load. For example, AEP Ohio's Data Center Tariff ("DCT") allows

a customer to request the assignment of 25% of its contract capacity to another Schedule DCT customer in lieu of paying an exit fee associated with the reallocated power.[54]

Data Reporting Provides Regulators and System Planners with the Information Needed to Verify Large Load Commitments

The Commission should require that PPL's load forecasts and all information used in deriving forecasts be made available to the Commission as part of a regulatory proceeding, during which time stakeholders and the Commission have an opportunity to scrutinize large load requests and provide feedback. This process should occur during the preliminary stages of PJM load forecast development to enable PJM to receive state-level feedback before finalizing its forecasts. The Commission should also establish uniform requirements for EDC treatment of computational large loads in load forecasts, including common standards for customer readiness, duplicate requests, forecast updates, and the information supporting large load adjustments submitted to PJM.

In July 2026, PJM announced its proposed Large Load Registry, a database that will be made available to states, T&D utilities, and other LSEs with operational information on loads 50 MW or higher. Required information would include items such as in-service dates, load sizes and ramp schedules, delivery points, backup generation details, and BYONC information. Registration would occur through the customer's EDC.[55] Thus, the transparent communication of information between PPL and PJM regarding large loads will require tariff-level provisions that ensure information sharing between the large load customer and its utility.

[54] Public Utilities Commission of Ohio Docket No. 24-508-EL-ATA. *Joint Stipulation and Recommendation,* (Oct. 23, 2024).
[55] PJM Interconnection. (July 2026). "CIFP Framework for Service During Periods of Insufficient Resource Adequacy – PJM Proposal."

EDC tariffs should require the computational large load to provide the information to the EDC to satisfy the PJM Large Load Registry criteria as set forth in PJM's tariff, and whatever additional data requirements established by the state. Additional information that may be obtained by PPL and communicated to PJM through forecast updates includes disclosures of known duplicative interconnection requests, detailed customer cost commitments, and confirmation that non-disclosure agreements permit full information sharing with PJM, and that all relevant information has been shared. Additionally, the tariff should set forth the requirements for confidential treatment of any proprietary information, including the EDC's steps to ensure that any proprietary information required to satisfy the PJM Large Load Registry requirements is adequately protected.

It is necessary to address data sharing in the tariff in order to inform prospective customers of their obligations and requirements. A tariff should require large load customers to share all relevant information an EDC may require to make informed projections and reports. This includes, but is not limited to, the status of or changes to construction schedules, load-ramp forecasts, total projected demand, self-supply availability, and designation of critical and non-critical load. As explained in the Affidavit of Mr. Teti, inaccurate or speculative load forecasting generates uncertainty regarding the T&D and generation investments required to support large load interconnection. A similar concern also applies to inconsistent load forecast processes and assumptions across utilities.

Service Conditions Protect Customers from Financial and Reliability Risk by Requiring That Minimum Standards Are Met Prior to Interconnection.

EDC tariffs should establish clear conditions that a computational large load customer must satisfy before interconnecting or commencing service. These conditions should ensure that

projects advance based on demonstrated readiness and that new load does not impose avoidable financial or reliability risks on existing customers.

At a minimum, computational large load customers should be required to satisfy all applicable tariff and regulatory requirements; provide adequate financial security, credit support, or collateral for costs not paid up front; demonstrate site control, necessary permits and approvals, and an ability to construct customer facilities on a schedule consistent with the EDC's construction; and complete all applicable registration, reporting, and certification requirements imposed by the EDC, the Commission, PJM, and other relevant governmental authorities. Consistent with Executive Order 2026-05, service should also be conditioned on completion of applicable state and local approvals, including those associated with Pennsylvania's Governor's Responsible Infrastructure Development ("GRID") requirements.

Service should likewise be conditioned on satisfaction of applicable reliability obligations. Before receiving firm service, a computational large load customer should demonstrate that it has satisfied any applicable capacity-related requirement and possesses the physical and operational capability necessary to comply with curtailment, interruptibility, emergency-load-shed, or similar obligations. Where constrained regional resource adequacy conditions apply, including in current conditions as discussed in the Affidavit of Dr. Felder, the EDC should retain authority to delay or condition service. A customer that materially increases or modifies its load should also be required to complete any additional interconnection review required by the tariff before receiving that incremental service.

These requirements should support a first-ready, first-served approach. Projects that have satisfied all applicable requirements should advance ahead of earlier filed projects that have not

achieved those milestones. Conversely, tariffs should not permit a computational large load customer to obtain accelerated interconnection through the size of its proposed load, larger deposits or fees, or reduced service requirements relative to similarly situated customers.

In any case, the tariff should expressly authorize the EDC to withhold or delay service when a customer has not satisfied reasonable conditions. This framework would allow viable projects to advance while ensuring that interconnection does not occur before the customer has demonstrated both its readiness to take service and its ability to bear the financial and reliability obligations associated with its load.

Additional Requirements of Large Load Tariffs

A large load tariff should also include change-in-rules provisions that remain effective as PJM and FERC requirements evolve. Such provisions are necessary to ensure that consumer protections continue to function as PJM implements capacity, curtailment, forecasting, interconnection, and related reforms, including, but not limited to, RBP and IRAS.

As discussed by Dr. Felder and Dr. Ogur, PJM's RBP proposal does not specifically allocate RBP costs to EDC customer classes. The allocation of those costs among retail customer classes therefore must be addressed through state-jurisdictional utility rates and tariffs. Accordingly, PPL's large load tariff should include a mechanism that assigns RBP costs attributable to computational large loads to those customers, rather than permitting such costs to be shifted to other customer classes. It is also appropriate to treat customers receiving an RBP allocation as having met their BYONC obligations up to the quantity of unforced capacity they fund. Dr. Ogur addresses potential retail cost allocation mechanisms for accomplishing this objective in greater detail.

Additionally, I recommend that a large load tariff require computational large loads to contribute to universal service and other applicable public-purpose programs through explicit, non-bypassable obligations that scale appropriately with load size. These requirements ensure that computational large load customers contribute to programs that support the broader customer base rather than avoiding such obligations because of the structure of their service arrangements. The need for these provisions is addressed further in the Affidavit of Mr. Michael Deupree.

VII. Insufficiency of PPL's Existing Tariff Structures

A. PPL's Current Large Load Tariff Was Approved with the Express Understanding That It Would Be Revised

PPL initiated its most recent distribution base rate case, Docket No. R-2025-3057164, on September 30, 2025. The case sought, among other things, changes to the rates, terms, and conditions applicable to rapidly growing large loads, including data centers.

During the proceeding, PPL and intervening parties, including the OCA, litigated issues concerning the appropriate eligibility threshold for a separate large load rate class, minimum service commitments, financial security, allocation of interconnection and transmission upgrade costs, load forecasting, and protections against stranded costs. The parties reached a non-unanimous settlement in March 2026, which the Commission voted to approve, with a minor modification unrelated to the large load provisions, on June 4, 2026; the Commission entered its final order on June 11, 2026, and the new rates became effective July 1, 2026.

As part of the settlement, PPL established a new Rate Schedule LP-6. LP-6 requires customers with peak demand of 50 MW individually or 75 MW in aggregate to comply with a 10-year initial contract term, 5-year load-ramp period, and an 80% minimum billing demand relative to a provided load-ramp schedule. The settlement also requires security for certain transmission

upgrades placed into rate base, provides for Commission and statutory-advocate notice and disclosure of ESAs and associated cost allocations, and permits customers electing a voluntary interruptible option to receive reduced minimum-load guarantees. Beginning January 1, 2027, LP-6 customers also are responsible for $11 million annually of PPL's universal service costs through a non-bypassable charge.

The PPL proceeding occurred in parallel with the Commission's statewide Large Load Model Tariff proceeding at Docket No. M-2025-3054271. It also occurred in parallel with PJM's CIFP – LLA and CIFP – RBP and C&M processes and preceded various other state and federal actions to address Computational Large Loads, as discussed in the Affidavit of Dr. Felder. The PPL settlement expressly recognized that the LP-6 tariff did not resolve every issue raised regarding large-load service and preserved the parties' ability to seek modifications to LP-6 following the Commission's final determination in the statewide proceeding. These provisions left open the possibility that PPL's tariff would later be conformed to the Commission's broader large-load framework. PPL Corporation shares in this understanding, having told investors as recently as the 1st Quarter 2026 Investor Update that "PPL Electric awaits further Commission action on finalizing a model tariff."[56]

B. PPL's Existing Tariff Does Not Conform with the PUC'S Large Load Model Tariff

Table 2 below compares PPL's LP-6 tariff with the Large Load Model Tariff put forth by the PUC. The table also includes a third column containing my recommended tariff components.

[56] PPL Corp. (May 8, 2026). *1st Quarter 2026 Investor Update*. https://filecache.investorroom.com/mr5ir_pplweb2/1319/PPL_2026_Q1_Investor%20Update_FINAL.pdf.

Table 2. Comparison of PUC Model Tariff, LP-6, and Hoyt Recommendation			
	PUC Large Load Model Tariff, Final Order – April 30, 2026[1]	**2025 PPL Rate Case Settlement (LP-6 Rate)**[2]	**Hoyt Recommendation**
Eligibility	New customers (or new incremental load) at or over 50 MW individually or 100 MW in aggregate. EDCs retain authority/discretion to apply the model tariff to customers below 50 MW. Behind-the-meter generation is excluded from the threshold calculation. (pp. 11-12)	Customers at 50 MW of peak demand individually or 75 MW in aggregate. If an individual customer has a peak demand of between 50-75 MW and requires no transmission network upgrade costs, PPL can petition to serve the customer under the LP-5 rate. (p. 22)	Peak demand in excess of 25 MW individually or 50 MW in aggregate based on service voltage >69 kV, with the customer furnishing and maintaining all equipment necessary to transform the energy from the line voltage. Applicable to Computational Large Loads.
Service Term and Load Ramping	5-year minimum initial contract term with the Commission recommendation that the actual contract length reflects the time until the cost of utility investment to serve the customer can be repaid. (pp. 47-48) The minimum initial term of the contract should begin after the ramp-up period concludes. (p. 18) Load-ramp periods of 3-5 years with EDC-determined interim milestones.	Minimum 10-year initial term with a ramp schedule up to 5 years. (p. 20)*	No less than 10 years following completion of load ramping, with load-ramp schedules capped at 4-5 years. Contract obligations commence only after the ramp is complete.
Minimum Monthly Charges	Monthly billing demand set at greater of 80% of contract capacity or 80% of the highest previously established monthly billing demand from the past 11 months. Minimum demand charge equal to 80% of contracted demand. (p. 70, Appendix)	The greater of actual peak demand values or 80% of the load provided in the ramp schedule until the Rate Base Security Obligation is satisfied.[3] Subsequently, the greater of peak demand values or 80% of the load-ramp schedule for the first 5 years of the initial term and 50% for the second 5 years. (pp. 20-21)*	Minimum demand of at least 90% of contracted capacity for full contract term.

Cost Responsibility	A CIAC will be assessed to a large load customer for all distribution and transmission costs that would not have been needed "but for" the interconnection of the customer except for EDC upgrades or additions that were already planned pursuant to a Commission-approved plan. (p. 42)	A CIAC established through the ESA will require up-front milestone payments ahead of work performed for the cost of directly assignable T&D upgrades. (p. 23)*	Assign 100% of direct and "but-for" network upgrade costs to large load customers to be recovered through CIAC, minimum demand charges, exit fees, or a combination thereof. Where minimum demand charges and/or existing fees are applicable, PPL will credit the payments against the utility's transmission rate base balance for the benefit of other customers. Voluntary CIAC may be appropriate as an option tied to expedited interconnection, but cost responsibility must remain with the large load customer.
Financial Security	Financial security is graduated based upon proposed size of load and partially refunded as load ramps up and facility costs are paid. Security should be sufficient to cover the cost of network upgrades for which the large load customer is the "majority beneficiary" (pp. 19, 28). The identification of a "majority beneficiary" will be resolved in a rate case or formal tariff filing. (p. 28)	Revenue guarantee in the amount of the line extension costs not directly charged to the customer and the customer's Rate Base Security Obligation. Once transmission revenue received equals Rate Base Security Obligation, revenue guarantee is satisfied.*	Require collateral sufficient to cover large load's entire cost responsibility. Security should scale with ramp progress and remain in place until investment risk is retired.
Exit Procedure/Fee	48-month prior notice period applied to both the terms of the contract after initial contract term and the exit fee provisions. (p. 18) A capacity reduction of no more than 20% after the initial contract term is not subject to an exit fee if required notice is provided. Exit fee is the greater of the remaining facilities and network cost obligations or the remaining minimum capacity charge for remaining contract years. (Appendix) Costs not covered by collateral, CIAC, or an exit fee in the event of the exit of a Large Load Customer cannot be allocated to other customers. (pp. 83-84)	Exit fee is equal to the greater of the remaining minimum load guarantee obligation or the remaining Rate Base Security Obligation. (p. 23)* Exit fee will be first applied to the Company's transmission rate base as a reduction of the Rate Base Security Obligation and then subsequently applied to the Company's FERC Transmission Formula Rate revenue requirement. (p. 24)	Require a 5-year or greater notice for exit or material reduction. Exit fees equal to the greater of remaining minimum demand charges or unrecovered facility and network costs, with proceeds credited against transmission rate base.

Interconnection Study Process	6-month maximum time frame to complete interconnection studies absent exigent circumstances. Customer entitled to a 50% refund of the application fee for each 90- day period beyond the 6-month maximum if studies are not completed. EDC's "may be" solely responsible for the costs associated with refunds which should not be allocated to other customers. Option for a customer to contract an independent analysis removed due to privacy / security concerns. (pp. 62-64) Order adopts a biannual Network Open Season for cluster studies at the large load customer's expense. (p. 64)	Not addressed.	Interconnection contingent on a positive Commission finding that the proposed load can be served without degrading the reliability of service to existing customers (including transmission deliverability and resource adequacy).
Interruption/ Curtailment	Interruptible service programs will be based on existing EDC interruptible tariff provisions. Customers that refuse to curtail as directed may be subject to a penalty. EDCs will provide customers with their emergency-response requirements including large load customer actions should a load-shed event be called. (pp. 91-93)	A voluntary interruptible option would reduce minimum load guarantee to 60% (from 80%) for the first 5 years and to 30% (from 50%) for the next 5 years. (p. 21) A large load customer will be required to engineer the ability to separate any critical and non-critical load in order to curtail non-critical load during a load-shedding event. (p. 23)*	Require enforceable curtailment obligations during emergency load-shedding. Large load customers subject to priority curtailment (i.e., before residential or small commercial customers), with no limit on the number or duration of curtailment events and penalties for non-compliance.
Self-Construction	The construction of network-integrated infrastructure by large load customers is allowed if in accordance with all safety and reliability standards of the EDC and Public Utility Code, and all FERC and NERC regulations. (pp. 97-98)	Not addressed.	Allowed, subject to all applicable safety and reliability standards. Customer-installed equipment must be sufficient to carry out all curtailment requirements imposed as a condition of service.
Miscellaneous Required Contributions	Large load customers will contribute to utility universal service programs at a flat fee based on peak demand. (p. 107)	$11 million of Universal Service Rider costs will be allocated to the LP-6 class annually through a customer charge. (p. 24)	Require Commission filing and approval of ESAs. Require explicit, non-bypassable universal service contributions.

Reporting Requirements	No reporting requirements were adopted. Further discussion is pending. (p. 114)	Company will submit ESAs and the allocation of upgrade costs to the Commission. Company will submit annual load forecasts along with associated ESAs, Letters of Authorization, and inquiries about LP-6 service. (p. 24)	Customer will be required to submit intermittent updates on construction and load-ramp progress. Annual load forecasts of large load customers, associated ESAs, and related contracts will be provided to the Commission for review. All large loads required to register and update relevant operations information in an established Large Load Registry.

[1] PA PUC Docket No. M-2025-3054271. *Interconnection and Tariffs for Large Load Customers, Final Order.* April 30, 2026.

[2] PA PUC Docket No. R-2025-3057164. *Notice of Proposed Joint Petition for Approval of Non-Unanimous Settlement of All Issues.* March 13, 2026.

[3] Rate Base Security Obligation is defined as the costs the Company (i.e., PPL) would not have incurred but for the interconnection of the customer, that are placed into rate base and recovered through transmission rates.

C. The Large Load Model Tariff Identifies Additional Issues that Must Also Be Addressed

The Commission's Large Load Model Tariff establishes an important statewide framework for the provision of service to large load customers. As described above, it addresses several fundamental protections, including minimum contract and billing requirements, financial security, interconnection costs, exit obligations, and other measures intended to limit cost shifting to existing customers. The Model Tariff does not, however, resolve every issue necessary to govern service to computational large loads, nor does it operate as a substitute for utility-specific tariff provisions implementing those protections.

One important example is interruptible service and emergency curtailment. Rather than establishing a uniform statewide interruptible-service structure, the Commission directed that large-load interruptible programs be developed based on each EDC's existing tariff provisions. The resulting obligations therefore necessarily depend on utility-specific tariff and operating requirements. As discussed above and in Sections VIII through X below, PPL's existing tariff and emergency procedures must establish enforceable curtailment obligations, identify the treatment

of critical and non-critical load, and ensure that computational large loads possess the physical and operational capability to respond when curtailment is required. The Model Tariff itself does not establish those PPL-specific requirements.

The Model Tariff similarly does not fully establish the regulatory framework for customer-specific agreements and ongoing Commission oversight. The Commission considered, but ultimately did not adopt, comprehensive reporting requirements concerning large-load development and customer agreements, leaving further consideration of the scope, timing, and feasibility of such reporting for later action.

As I explained above, significant terms of large-load service will necessarily be implemented through customer-specific agreements. PPL's tariff should therefore specify the minimum terms those agreements must contain and require that Commission-jurisdictional agreements be filed with the Commission so that the Commission and statutory advocates can determine whether tariff requirements and customer protections are actually being implemented.

More broadly, the Model Tariff did not establish an automatic process by which each EDC's existing tariff would be conformed to the Commission's statewide framework. Implementation therefore requires review of the tariff actually governing service in each utility's territory and, where necessary, utility-specific revisions that both implement the Model Tariff and address issues that the statewide proceeding left unresolved. That is the purpose of the recommendations that follow: to identify where PPL's existing tariff remains insufficient notwithstanding the Commission's Model Tariff and the additional provisions necessary to protect PPL's existing customers.

D. The Commission Should Require Certain Improvements to PPL's Tariff

PPL's LP-6 tariff approved in its 2025 rate case (Docket No. R-2025-3057164, et al.) takes steps towards addressing the costs and risks of new computational large load customers, and my recommendations are consistent with many of the provisions in LP-6, including its use of a defined load-ramp period, minimum contractual commitments, customer financial security, and customer-specific cost responsibility. However, based on the available public record, I have identified notable gaps in the PPL tariff's cost and reliability protections as compared to the Commission's Large Load Model Tariff and my recommended tariff requirements.

First, eligible customers under LP-6 would have loads of 50 MW individually or 75 MW in aggregate. I recommend a lower minimum peak demand to ensure all new data center facilities that may create significant cost impacts or reliability risks are obligated to be responsible for those costs, and responsive to those risks. Subject to additional discovery, I am concerned that a 50-MW threshold may not comprehensively include all new loads with the unique characteristics described earlier. It may also be appropriate to specifically assign tariff requirements to computational large loads to address the relief requested in this proceeding.

Second, LP-6 sets forth a customer cost obligation referred to as the "Rate Base Security Obligation," defined as an amount equal to the cost of upgrades needed to serve the customer, including, but not limited to, the costs that the Company would not have incurred but for the interconnection of the customer, that are placed into rate base and recovered through transmission rates.[57] I agree with the need to obligate the customer to pay for these costs. The obligation, however, should be broadened so that the customer is expressly responsible for all directly

[57] PA PUC Docket Nos. R-2025-3057164, et al. Notice of Proposed Joint Settlement for Approval of Non-Unanimous Settlement of all Issues, at 23.

assignable and "but-for" costs caused by its request for service, including applicable distribution, transmission, interconnection, and engineering-study costs, rather than only those costs ultimately placed into transmission rate base. Any such costs not paid up front should be supported by financial security sufficient to cover the customer's remaining obligation for as long as the associated investment risk remains. Exit and termination provisions should likewise ensure that a customer that reduces or terminates service remains responsible for unrecovered costs that cannot reasonably be avoided, mitigated, or reassigned. These protections collectively implement the cost causation principles discussed above.[58]

Third, LP-6 should more clearly establish the tariff-level requirements that must be implemented through a Commission-jurisdictional ESA or equivalent agreement. As discussed above, material customer-specific terms should not be left solely to individually negotiated agreements without defined tariff standards. The tariff should require an ESA as a condition of service; specify minimum terms addressing committed load, ramp schedules, construction and interconnection milestones, financial responsibility, cancellation and termination, and consequences of delay or downsizing; and require that relevant customer-specific agreements be provided to the Commission, with appropriate access for statutory advocates subject to confidentiality protections.

Fourth, although LP-6 appropriately recognizes the need to identify and segregate critical and non-critical load, its voluntary interruptible option is not a substitute for mandatory emergency curtailment requirements. As discussed above and in Sections VIII through X below, non-critical

[58] Dr. Ogur separately evaluates PPL's existing mechanisms for allocating Network Integration Transmission Service ("NITS") and RPM capacity costs and identifies additional mechanisms that may be necessary to prevent costs attributable to computational large loads from being shifted to other PPL customers.

computational large loads should be subject to enforceable curtailment during defined emergency conditions regardless of whether the customer voluntarily selects an interruptible rate. The tariff should condition service on PPL's verification that the customer can physically segregate, meter, communicate, and curtail its non-critical load and should coordinate those requirements with PPL's Commission-approved emergency operating procedures.

Fifth, LP-6 does not include any BYONC or self-supply provisions. As discussed in the BYONC section above, self-supply requirements are a critical element in protecting other customers from the cost and reliability risks presented by large load customers' generation requirements. PPL's tariff should require new computational large loads to satisfy applicable BYONC requirements as a condition of firm service, including demonstration of sufficient qualifying new capacity to serve the customer's demand and applicable reserve requirement. PPL should verify those arrangements as the customer ramps and continues taking service, and qualifying resources should satisfy the locational requirements discussed above so that the capacity can meaningfully address the deliverability and infrastructure impacts created by the load. Customers that do not satisfy those requirements should be subject to the applicable curtailment treatment rather than shifting the resulting resource adequacy risk to existing customers.

Finally, LP-6's existing reporting requirements should be supplemented by ongoing customer obligations to provide material updates concerning project development and load-ramp progress and to satisfy applicable PPL, Commission, and PJM registration and reporting requirements, including the Large Load Registry discussed above. The tariff should also contain change-in-rules provisions sufficient to preserve these protections as PJM and FERC requirements evolve, including mechanisms to assign any RBP or successor costs attributable to computational

large loads to those customers rather than other retail classes. Existing non-bypassable universal-service obligations should likewise remain applicable to the computational large load class.

The above list should be understood as reflecting only my initial assessment, and I reserve the right to recommend additional modifications.

VIII. Statutory and Regulatory Requirements Governing Emergency Load Control of Computational Large Loads

The reliability concerns described above have direct implications for how utilities must prepare for and respond to emergency system conditions. This section therefore examines the respective responsibilities of the Commission, PJM, and PPL for emergency load control, including how the amount and priority of load curtailment are determined. I then assess whether PPL's existing procedures adequately account for computational large loads and identify additional protections necessary to preserve reliable service and protect other customers during system emergencies.

A. Utility Statutory Requirements

Pennsylvania electric utility emergency load control requirements are principally established in 52 Pa. C.S. § 57.52. More specifically, 52 Pa. C.S. § 57.52 requires each Commission-jurisdictional public utility to "include in its electric tariff rules and regulations filed with the Commission" provisions governing emergency load control, including the following:

i. A load emergency situation exists whenever:

   A. The demands for power on all or part of the utility's system exceed or threaten to exceed the capacity then actually and lawfully available to supply the demands.

   B. System instability or cascading outages could result from actual or expected transmission overloads or other contingencies.

C. The conditions exist in the system or another public utility or power pool with which the utility's system is interconnected and cause a reduction in the capacity available to the utility from that source or threaten the integrity of the utility's system.

ii. In this case, the utility shall take the reasonable steps as the time available permits to bring the demands within the then-available capacity or to otherwise control load. The steps shall include, but are not limited to, reduction or interruption of service to one or more customers, in accordance with the utility's procedures for controlling load.

The statute also includes Emergency Energy Conservation provisions applicable to events that result in (or threaten to result in) conditions that adversely affect "the amount of electric energy which the utility is able to supply." Specifically, utilities must establish procedures for "controlling load and emergency conservation" that include load-shedding priorities consistent with the emergency load control provisions above. Those procedures "shall be revised if required by the Commission." 52 Pa. C.S. § 57.52 also establishes notification requirements applicable during emergency conditions.

Counsel advises me that these requirements operate together with the Commission's broader authority discussed above. In particular, the Commission may require revisions to a utility's emergency procedures where necessary to ensure the provision of adequate, safe, and reliable service consistent with the Public Utility Code, including 66 Pa. C.S. § 1501.

B. PJM Load-Shed Procedures

PJM's emergency load-control authority is principally established in the PJM Operating Agreement, Schedule 1, Section 1.7.11 and the parallel provisions of the PJM Tariff, Attachment K-Appendix.[59] The implementing procedures are set out primarily in PJM Manual 13, Emergency

[59] PJM Interconnection. Operating Agreement, Rate Schedule FERC No. 24. https://agreements.pjm.com/oa/4541; PJM. Open Access Transmission Tariff ("OATT"). https://agreements.pjm.com/oatt/3897.

Operations, Section 2 (Capacity Emergencies) and Section 5 (Transmission Security Emergencies).[60]

The Operating Agreement places affirmative emergency-response responsibilities on two parties: electric distributors and PJM's Office of the Interconnection. Under Section 11.3 (Member Responsibilities), Electric Distributors are required to "(e) Shed connected load, share Generation Capacity Resources and take such other coordination actions as may be necessary in accordance with the directions of the Office of the Interconnection in Emergencies."[61] The Office of the Interconnection, meanwhile, is "responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for direction of the operations of Market Participants as necessary to manage, alleviate or end an Emergency."[62] Those actions must be "carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Entity reliability principles and standards, Good Utility Practice, and the PJM Manuals."[63] Once PJM declares an emergency, its direction remains in effect until the actual or threatened emergency is resolved.

Taken together, these provisions establish that PJM identifies the emergency condition and directs the amount and location of necessary system relief. PJM's authority over what facilities are subject to manual load shedding is limited to excluding critical natural gas infrastructure and is

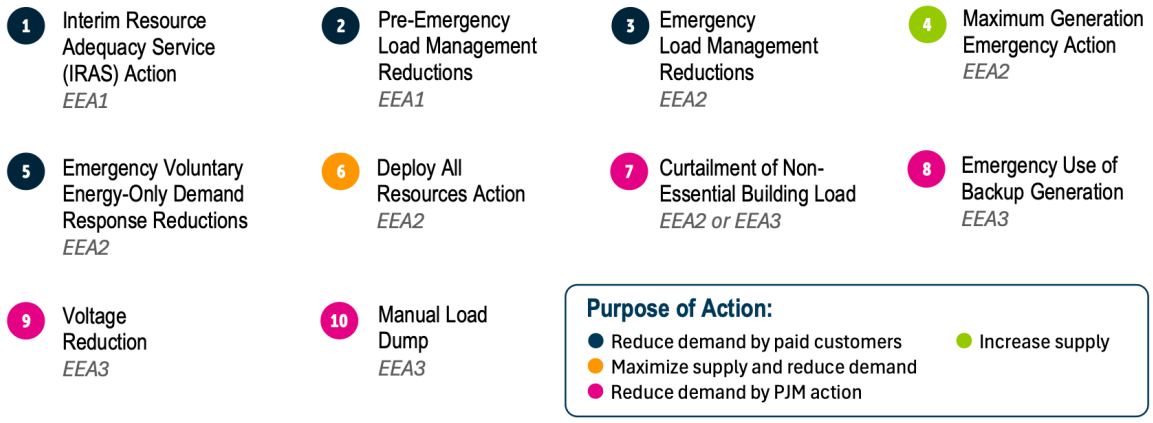
[60] PJM Interconnection. (June 24, 2026). *Manual 13: Emergency Operations Revision 98*. https://www.pjm.com/-/media/DotCom/documents/manuals/m13.pdf.
[61] PJM Interconnection. (July 14, 2011). *Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.* https://www.pjm.com/pjmfiles/directory/merged-tariffs/oa.pdf, PDF p. 135. See: Intra-PJM Tariffs --> OPERATING AGREEMENT --> OA 11. MEMBERS --> OA 11.3 Member Responsibilities -->, p. 4.
[62] *Id.* See: Intra-PJM Tariffs --> OPERATING AGREEMENT --> OA SCHEDULE 1 - PJM INTERCHANGE ENERGY MARKET --> OA SCHEDULE 1 SECTION 1 - MARKET OPERATIONS --> OA Schedule 1 Sec 1.7 General. -->, p. 8.
[63] *Id.*, at PDF p. 259.

based in NERC compliance.[64] Electric distributors, meanwhile, are responsible for implementing the required load reductions consistent with applicable reliability standards, utility obligations, and PJM procedures.

PJM Manual 13 operationalizes the above division by establishing the sequence of emergency actions PJM may direct and the procedures utilities must follow in carrying them out. For a capacity emergency, Manual 13 establishes an escalating sequence intended to exhaust less disruptive measures before involuntary firm-load shedding. The real-time sequence includes Pre-Emergency and Emergency Load Management reductions, Maximum Generation Emergency measures, curtailment of non-essential building load, deployment of all available resources, a Voltage Reduction Action, and finally, a Manual Load Dump Action, with additional warnings and steps in between. These steps are visualized in Figure 3. Each step is assigned an Energy Emergency Alert ("EEA") level with higher numbers indicating greater severity. PJM's emergency action procedure culminates at EEA3, at which stage PJM initiates manual load shed and other forms of emergency forced outage to maintain grid reliability.

[64] NERC EOP-11-4.

Figure 3. Chain of Emergency Action Inclusive of Proposed IRAS Action



Source: PJM. (2026). IRAS Proposal: A Reliability Framework for Rapid Large Load Growth. https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/interim-resource-adequacy-service-proposal.pdf.

PJM may vary the sequence where system conditions require. In any case, manual load dump is a last-resort measure. When applying these procedures, PJM determines the deficient areas, calculates the amount of relief required and from where, and orders the affected transmission/distribution operators to shed that amount. All instructions must be carried out within a 5-minute interval. It is therefore essential that utilities have plans and procedures in place in advance of a PJM instruction.

Manual 13 assigns implementation to the affected Transmission Owners/distribution providers: they must "shed an amount of load equal to or in excess of the amount requested by PJM dispatcher," using their own load-shed plans, which must "consider/recognize priority/critical load," including hospitals, police and fire facilities, 911 facilities, wastewater facilities, critical electric and natural-gas infrastructure, and telecommunications.[65] Thus, the retail priority among

[65] PJM Interconnection. (June 24, 2026). Manual 13: Emergency Operations Revision 98. https://www.pjm.com/-/media/DotCom/documents/manuals/m13.pdf.

customers within the utility's assigned MW obligation remains principally a utility/state-jurisdictional matter.

In directing development of the framework ultimately proposed to be implemented through IRAS, the PJM Board stated that "Ultimately, the determination of which loads are curtailed during emergency conditions rests with TOs, and with LSEs that have direct relationships with their customers. PJM does not have authority to direct individual retail loads to curtail demand."[66] In other words, the PJM Board believes it lacks authority over retail curtailment priority, and defers to states to establish related rules at a retail level.

C. PPL Load-Shed Procedures

PPL is responsible for implementing PJM-directed load management within its service territory. PPL's principal documented procedures are contained in its Emergency Load Control Procedures ("ELCP"), which I reviewed as attached to PPL's 2025 Annual Reliability Report filed April 30, 2026.[67] Technical elements of load shed are also addressed in the Affidavit of Mr. Konidena.

PPL describes the purpose of the ELCP as documenting its "process for addressing the various types of emergencies which may be encountered on the Bulk Electric System," including guidance for coordination with PJM.[68] The ELCP accordingly defines responsibilities principally as between PPL and PJM. It provides that PJM "has authority to direct PPL EU to take actions to preserve the integrity" of the bulk power system, and that PPL, as a PJM member and Transmission

[66] PJM Interconnection. (Jan. 20, 2026). *Informational report* (FERC Docket Nos. EL25-49-000 and EL25-49-001.) https://www.pjm.com/-/media/DotCom/documents/ferc/filings/2026/20260120-el25-49-000.pdf.
[67] PA PUC Docket No. M-2023-3039027. *Reliability Reports (Annual & Quarterly), PPL – 2025 Annual Reliability Report.*
[68] PPL, Emergency Load Control Procedures, at 1.

Owner, is "expected to comply with PJM directives" unless doing so would "violate safety, equipment, regulatory or statutory requirements, or would otherwise jeopardize the safe, stable operation" of the bulk power system.[69] These provisions make clear that PPL's implementation of PJM instructions remains subject to applicable regulatory and statutory requirements.

The ELCP references specific "steps for load shedding."[70] Those steps begin with less severe measures including "Curtailment of Non-Essential Building Load"[71] and voltage reduction.[72] If those and other preceding actions are insufficient, the ELCP identifies load dump as "a last-resort action used to preserve the reliability of the [bulk electricity system] when system conditions threaten stability and all other corrective actions have been exhausted."[73] PPL maintains the capability to implement manual load shedding within the five-minute time frame required by PJM.[74]

It is my understanding that PPL implements manual load shed by opening distribution circuit breakers through its Supervisory Control and Data Acquisition ("SCADA") systems. More specifically, Section 5.8.1.3 indicates that PPL "sheds the directed amount of load by opening distribution circuit breakers ("CBs") via SCADA. The application will then rotate the amount of load shed by opening additional CBs and restoring the initial set of CBs."[75] PPL explains that "Rotating load shedding distributes the impact of service interruptions across different customer

[69] *Id.*
[70] *Id.*, at 3.
[71] The ELCP specifically states that "[t]he purpose of the Curtailment of Non-Essential Building Load is to provide additional load relief. PPL EU will respond to this request by switching off all nonessential light and power load in the various business offices and administrative offices of the company." (4).
[72] The ELCP specifically states that "[a] voltage reduction on the BES is a controlled decrease in system voltage, typically 5% or less, used to reduce electricity demand during emergency conditions. This action helps preserve system reliability by lowering load without disconnecting customers." (5).
[73] PPL, Emergency Load Control Procedures, at 6.
[74] *Id.*, at 3.
[75] *Id.*, at 6.

groups for short durations, minimizing prolonged outages for any single area. Another advantage to rotating shed load this way is that it reduces the adverse impacts of cold load pickup. PPL EU rotates its shed load at a rotation period set by Transmission Operations per collaboration with Distribution Operations and other key internal stakeholders."

PPL attempts to account for certain critical or vital facilities. The ELCP states that "PPL EU has provisions to minimize the overlap of circuits that are designated for manual Load shed, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES." PPL's tariff also separately addresses prioritization of critical natural gas infrastructure.

Additional prioritization is addressed through PPL's Vital Facilities procedures. The ELCP describes "Vital Facilities (VF) PPL EU Operating Instruction (OI) 2180" as addressing facilities requiring "special consideration during load shedding situations." That operating instruction identifies who conducts the reviews, provides examples of vital facilities, and explains how those facilities are removed from PPL's load-shed tables. The underlying operating instruction, however, is not publicly available.

The ELCP also incorporates additional, non-public operational materials. For example, it references "PPL EU TCC Action Guide 2 – Implementing Manual Load Dump," which is marked confidential and is not publicly available. As a result, the publicly available ELCP describes the overall process and certain key implementation steps, but does not itself disclose all of the criteria, instructions, or decision rules governing which specific circuits or customers would be interrupted during a manual load-shed event.

The ELCP has been revised numerous times over its history, including twice during 2025. Based on the materials I reviewed, however, it is not apparent whether PPL has revised its emergency load-control framework specifically to account for the recent and anticipated influx of computational large loads. That issue is significant because, as discussed below, the emergence of very large, potentially curtailable loads may materially affect how emergency load-shed priorities should be structured and implemented. Discovery of additional materials related to PPL load-shed procedures is necessary for the Commission and statutory advocates to evaluate whether PPL's actual implementation procedures treat computational large loads consistently with the reliability, nondiscrimination, and curtailment principles discussed above.

IX. Necessary Protections for Utility Emergency Procedures with Respect to Computational Large Loads

A. Computational Large Loads Are Capable of Managing Their Load in Ways That Do Not Jeopardize Broader Grid Reliability

Computational large loads are not inherently passive consumers of electricity. Many data centers are designed with substantial on-site resilience capabilities because interruption of electric service can jeopardize valuable computing operations.[76] A 2026 Pacific Northwest National Laboratory ("PNNL") technical report describes data-center designs with alternate feeds, automatic transfer schemes, Uninterrupted Power Supply ("UPS"), and on-site generation that can support facility load in the event of disconnection from the grid.[77] The report further notes an

[76] Schaeffer, A. (June 16, 2026). "Powering the Digital Age: Data Centers, AI Growth, and the Role of Backup Power." Engine Technology Forum. https://enginetechforum.org/policy-insider-blog/posts/powering-the-digital-age-data-centers-ai-growth-and-the-role-of-backup-power.

[77] Ross, B. A. & Follum, J. D. (Jan. 16, 2026). *Electromagnetic Transient Modeling of Large Data Centers for Grid-Level Studies*. (PNNL-38817). Pacific Northwest National Laboratory ("PNNL"). https://www.pnnl.gov/publications/electromagnetic-transient-modeling-large-data-centers-grid-level-studies. See the Affidavit of Mr. Rao Konidena for further definition and description of each of these system features.

emerging trend toward using on-site generation not only for backup purposes, but also to support the grid during generation shortages or transmission congestion.[78]

Computational loads also can possess operational flexibility. The Energy Systems Integration Group ("ESIG"), a non-profit educational association focused on power system operations, reports that many modern large load facilities have advanced control systems, and some have associated generation or storage, that can enable them to shift demand, self-supply, or otherwise provide reliability services during stressed system conditions.[79] ESIG separately identifies workload scheduling as a means of more predictable and less disruptive load behavior. The degree of flexibility varies by customer and workload. Nevertheless, this and similar studies suggest that conventional data centers have demonstrated load shifting or load reduction during high-price and emergency conditions. The Affidavit of Mr. Rao Konidena further discusses the technical capabilities of computational large loads to segregate critical and non-critical portions of large loads, disconnect designated load, and transfer critical load to backup supply.

Not every computational large load is currently being designed to support interruptibility. These customers, however, can be required to identify and make available the flexibility they possess. The means may vary by customer; computational large loads can segregate critical from non-critical load, employ UPS or storage for ride-through, transfer some demand to on-site generation, reduce or defer selected computing workloads, and use facility-level controls to ramp demand downward in response to emergency conditions. Several demonstration projects are

[78] *Electromagnetic Transient Modeling of Large Data Centers for Grid-Level Studies*. PNNL.
[79] ESIG. (July 2026). *Large Loads: Behaviors, Capabilities, and Limitations*. https://www.esig.energy/wp-content/uploads/2026/07/ESIG-Large-Loads-Behaviors-Capabilities-Limitations-report-2026.pdf.

already testing techniques including AI workload modulation, demand response, backup power integration, and dynamic load management.[80]

These capabilities are particularly relevant when determining which customers should bear curtailment obligations during emergency conditions. A computational large load that chooses to interconnect during a period of constrained resource adequacy should not be treated as incapable of contributing to emergency relief merely because uninterrupted service is commercially valuable to the customer. Additionally, these customers should not receive priority service at the expense of existing customers, especially those that rely on electricity to meet essential human needs or serve critical loads. Rather, the applicable tariff, service agreement, and emergency procedures should require the physical and operational capability to manage electricity consumption.

B. The Commission Should Establish What Loads Are Considered Critical

The distinction between critical and non-critical load is central to any workable emergency load-control framework. As discussed above, PJM requires utilities to maintain load-shed plans that recognize priority or critical loads, while Pennsylvania regulations require utilities to establish load-shedding priorities that govern the reduction or interruption of service during emergency conditions. 52 Pa. Code § 57.52 specifically requires each utility to establish procedures for controlling load and emergency conservation, and requires those procedures to include "schedules of load shedding priorities." Those procedures may be revised by the utility and "shall be revised if required by the Commission."

[80] Electric Power Research Institute. DCFlex Demonstrations. https://dcflex.epri.com/demonstrations; Frank, A. S. (Oct. 29, 2025). "Mainstreaming AI data center flexibility." *Utility Dive*. https://www.utilitydive.com/news/mainstreaming-ai-data-center-flexibility/804103/.

The classification of load as critical has important consequences, as also discussed in the Affidavit of Mr. Konidena. Load that is removed from, or given lower priority within, a utility's load-shed procedures reduces the amount of demand available to satisfy an emergency curtailment instruction. If a very large customer is treated as critical in its entirety, the practical consequence may be that a greater amount of load must instead be shed from other customers to achieve the same required megawatt reduction. In the case of a computational large load measured in tens or hundreds of megawatts, an overly broad critical-load designation could therefore materially increase the amount or duration of outages imposed on residential customers, small businesses, and other customers that have little or no ability to avoid an interruption. For that reason, a determination that load is "critical" should not rest solely with the customer or utility and should not turn on the commercial value of uninterrupted service.

Pennsylvania law and policy already distinguish genuinely critical infrastructure from ordinary commercial load. For example, Pennsylvania regulations concerning distributed generation identify examples of "critical infrastructure" that include homeland security assignments, emergency services facilities, hospitals, traffic signals, wastewater treatment plants, and telecommunications facilities.[81] The Affidavit of Mr. Konidena further discusses the distinction between critical and non-critical load. More recently, EO 2026-05 directed the Governor's Special Counsel for Energy Affordability to engage with the PUC to advocate for rules, procedures, and orders that would ensure utilities "do not classify a data center as critical load exempt from curtailment during pre-emergency or emergency events."[82] The same EO calls for

[81] 52 Pa. Code § 75.1.
[82] Commonwealth of Pennsylvania. Executive Order 2026-05, Protecting Pennsylvania Consumers from Data Center Impacts. (Aug. 18, 2026). https://www.pa.gov/content/dam/copapwp-pagov/en/governor/documents/eo2026_05_protecting%20pennsylvania%20consumers%20from%20data%20center%20impacts_final_executed.pdf.

data centers generally to be curtailed before other customers during such events unless the data center has secured incremental electric capacity sufficient for its entire demand.[83]

I recommend that the Commission build upon these principles by establishing a uniform definition of critical load for purposes of utility emergency procedures. This definition should be defined to only include the minimum amount of electric demand necessary to prevent an imminent and material threat to human life, public health or safety, the operation of essential public services or critical infrastructure, or the safe shutdown of equipment where interruption itself would create such a threat. Critical-load status should not extend to load merely because interruption would cause economic loss, disrupt ordinary business operations, reduce computational output, breach a private service-level agreement, or impair the commercial value of the customer's service.

This distinction is particularly important for computational large loads. A hospital, emergency communications facility, wastewater treatment plant, or similar critical facility generally exists primarily to perform a function whose interruption can itself threaten public health or safety. By contrast, a data center may contain a limited subset of computing or support functions that arguably serve critical public purposes while simultaneously serving much larger quantities of commercial, deferrable, duplicative, or otherwise non-critical workloads. The fact that some servers within a data center support a critical application should therefore not transform the entire facility, campus, or contracted demand into critical load.

A computational large load seeking critical-load treatment should bear the burden of identifying the specific load for which that designation is sought and demonstrating why interruption of that load meets the Commission's definition. Consistent with the engineering

[83] *Id.*

requirements discussed in the Affidavit of Mr. Konidena, the customer should be required to physically and operationally segregate critical from non-critical demand. I further recommend that the customer or utility install metering and controls sufficient for the utility to verify and independently curtail the non-critical portion, and periodically update its designation as workloads and facility configurations change. Any load that cannot be specifically identified and verified as critical should remain subject to otherwise applicable curtailment requirements.

C. Critical Load Designations Should Reflect Different Levels of Priority and Preserve Flexibility During Emergency Conditions

A critical load designation should not necessarily confer the same treatment to computational large loads as other critical loads during emergency conditions. To the contrary, different critical loads can warrant different degrees of protection depending on the consequences of interruption and the nature and severity of the emergency. NERC recognizes this principle in the technical rationale supporting EOP-011-4: "Critical Loads should not all receive the same level of priority, and the characteristics of a Load shed event (depth/duration/season) will impact the treatment of certain critical Loads. Transmission Operators should consider establishing priorities for different types of critical Loads."[84]

This perspective is bolstered by NERC's review of the February 2021 Texas cold-weather event.[85] In the aftermath, NERC found that utilities experienced difficulty implementing rotational load shed while maintaining service to critical loads and under-frequency load-shed feeders. NERC concluded that some critical loads may withstand outages for several hours without adverse

[84] NERC. (Sep. 2023). *Extreme cold weather preparedness: Technical rationale and justification for EOP-001-4*. https://www.nerc.com/globalassets/standards/projects/2021-07/2021-07-final-ballot_phase-2_technical-rationale-for-eop-011-4_clean_sep2023.pdf.

[85] NERC. (Mar. 10, 2022). "Lessons Learned: Managing Underfrequency Load Shed Obligations and Service to Critical Loads During an Emergency." https://www.nerc.com/globalassets/programs/event-analysis/lessons-learned/ll20220301_managing_ufls_obligations_service_critical_loads_during_energy_emergency.pdf.

consequences and that, if system conditions continue to deteriorate, even some critical loads may ultimately need to be shed to preserve the broader system. These findings demonstrate the importance of retaining flexibility to distinguish among critical loads rather than treating all such loads identically.

Accordingly, the Commission should establish different levels of priority among critical loads and require PPL's emergency procedures to preserve flexibility to adjust treatment of critical loads as system conditions evolve. Loads whose interruption poses immediate risks to public health, safety, or essential public services should receive greater protection than computational loads. Even where a portion of a computational large load qualifies as critical, that designation should not prevent PPL from curtailing the load if conditions deteriorate sufficiently and alternative sources of load shed have been exhausted.

D. The Commission Should Require Emergency Procedures That Do Not Unjustly and Unreasonably Prefer Computational Large Loads

The Commission should ensure that utility emergency procedures do not provide computational large loads with a *de facto* preference in continuity of service at the expense of other customers. As discussed above, PJM determines the amount and general location of load relief required during an emergency, but the affected utility is responsible for determining how that obligation is implemented among its customers. As I understand it, PPL's existing procedures accomplish manual load shed principally by opening and rotating distribution circuit breakers. Accordingly, decisions regarding which loads are included in or excluded from PPL's load-shed tables directly determine which customers bear the consequences of a PJM-directed emergency.

This allocation is particularly consequential as individual computational large loads reach hundreds of megawatts. If substantial computational load is protected from interruption, whether

through exclusion from load-shed tables, customer-specific service arrangements, system design, or operational practice, PPL must obtain the required megawatts of relief elsewhere. In an extreme case, preserving service to a single very large computational customer could require interruption of a much larger number of residential, small commercial, or other customers to obtain an equivalent quantity of load relief.

Such an outcome implicates the nondiscrimination principles described earlier in my affidavit. Section 1502 of the Public Utility Code prohibits utilities from granting an "unreasonable preference or advantage" in service or subjecting other customers to an "unreasonable prejudice or disadvantage." From my public policy perspective, providing a computational large load with even equal protection during an emergency interruption creates undue reliability consequences for customers that did not cause the incremental system need driving the decreased reliability, and may have far fewer means of mitigating an outage.

The Commission should therefore establish a uniform emergency-priority framework applicable to computational large loads. Except for portions of load that satisfy the Commission's definition of critical load, computational large loads should remain available for curtailment and should not receive priority over ordinary firm customers merely by virtue of customer-specific contractual arrangements or utility operating practices. Where a computational large load contributes materially to the system condition necessitating emergency action, or where curtailing that load provides an efficient means of obtaining relief from the emergency, the utility's procedures should permit and, where appropriate, require computational large load curtailment prior to the utility imposing widespread involuntary outages on customers with substantially less ability to manage interruption.

E. The Commission Should Establish Requirements Pertaining to the Emergency Capabilities of Computational Large Loads

Establishing a curtailment priority is insufficient unless computational large loads possess the physical, operational, and communications capabilities necessary to carry out that priority when called upon. PJM requires emergency load-shed instructions to be implemented within minutes, and PPL's existing procedures are designed around that short response period.

At a minimum, the Commission should require computational large load customers to demonstrate the ability to reduce non-critical demand in discrete, verifiable increments sufficient to satisfy utility-directed curtailment instructions. This should include physical segregation of critical and non-critical load; metering and telemetry sufficient for PPL to determine the amount of load available for curtailment and verify actual performance; switching, controls, or other equipment capable of implementing the required reduction within the applicable emergency time frame; and communications protocols that allow PPL to issue and confirm receipt of curtailment instructions. Where backup generation or other customer resources form part of the customer's emergency-response plan, their availability and operating limitations should likewise be identified and verified. The capabilities of PPL's existing and prospective computational large load customers are not apparent from public information.

These capabilities should be demonstrated. Before allowing service to commence, PPL should test the customer's ability to execute required load reductions and certify to the Commission that the necessary facilities and procedures are operational. Periodic testing should continue after interconnection, particularly following material changes to the facility, its load, or its designated critical and non-critical demand. The tariff and associated Commission-jurisdictional service

agreement should also require customers to promptly disclose changes that reduce their available curtailment capability.

Emergency requirements should address restoration as well. Simultaneous or rapid restoration of very large quantities of computational load following an emergency could itself impose material stress on the system.[86] PPL should therefore have authority to sequence or limit restoration and require computational large loads to comply with prescribed ramp rates or other operating instructions when returning curtailed demand to service. Customer-specific restoration requirements should be established in advance to the maximum extent possible and reflected in Commission-jurisdictional service agreements. The sequencing of these processes should also be incorporated into the EDC's emergency operating procedures.

Finally, these obligations must be enforceable. Failure to curtail when directed can force PPL to obtain additional relief from other customers and can frustrate the emergency plan on which system operators are relying. Tariffs and service agreements should therefore establish meaningful consequences for nonperformance, including financial penalties and, for repeated or material failures, modification of the customer's service conditions or maximum firm demand. A customer should not be permitted to receive the benefits associated with firm service while lacking, or declining to maintain, emergency-response capabilities that the Commission has determined are necessary to protect reliable service to the broader system.

[86] NERC. (Jan. 8, 2025). "Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions." https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_large_load_loss.pdf.

X. Insufficiency of PPL's Existing Operating Procedures

As discussed in Section VIII, material aspects of PPL's load-control framework are contained in non-public materials. Access to this information is essential to evaluate PPL's actual treatment of computational large loads. Nevertheless, based on the information that is publicly available, PPL's existing framework does not appear to establish several protections that I believe are necessary. Accordingly, I recommend that the Commission require PPL to revise its tariff and emergency operating procedures to address the following requirements: (1) when computational large loads must reduce demand during pre-emergency and emergency conditions; (2) how computational large loads are prioritized relative to other customers during manual load shedding; (3) the criteria and verification process by which any portion of a computational large load may receive critical-load protection; and (4) the reliability-focused capabilities that each computational large load must meet and maintain as a condition of service.

It is imperative that these tariff and operating procedure revisions are put into effect as quickly as possible. The findings in Section IV demonstrate that PPL is already making infrastructure and service decisions that may be difficult or impossible to unwind once computational large loads initiate service under PPL's existing tariff schedules and operating procedures. For example, a computational large load customer may not install adequately designed customer-owned facilities to appropriately segment non-critical load or support emergency operations with back-up power. Without these safeguards, PPL would lack an effective means of obtaining needed load reductions from these very large customers during system emergencies. This, in turn, increases the likelihood that outages or other emergency actions must instead fall on non-large load customers. Against the backdrop of already constrained resource adequacy and

increasingly frequent emergency events discussed above, the outage risk to PPL's existing customers is both imminent and potentially severe unless and until PPL and the Commission act.

Some of these protections may ultimately be implemented through Commission regulations applicable to all EDCs, while others will require utility-specific tariff provisions, operating procedures, and customer-specific agreements. Ultimately, I recommend a coordinated framework under which PPL knows in advance which computational loads are available for reduction, the sequence in which those reductions will occur, and the physical means by which the required reductions will be obtained.

A. The Commission Should Require PPL to Establish a Defined Sequence for Computational Large Load Curtailment During Pre-Emergency and Emergency Conditions

As discussed above, computational large loads may possess backup generation, UPS systems, workload-management capabilities, and other means of reducing their dependence on the grid. Those capabilities should be incorporated into emergency procedures before PPL is required to impose widespread outages on customers that have substantially less ability to respond. I therefore recommend a staged approach. First, during PJM pre-emergency conditions, PPL should implement any applicable PJM-directed large load reductions, including reductions required under IRAS or a successor program. Customers that have not satisfied the applicable PJM resource adequacy requirement should reduce their net grid demand as required by PJM. This obligation should apply through a mandatory tariff requirement rather than depend on voluntary enrollment in an interruptible-service option.

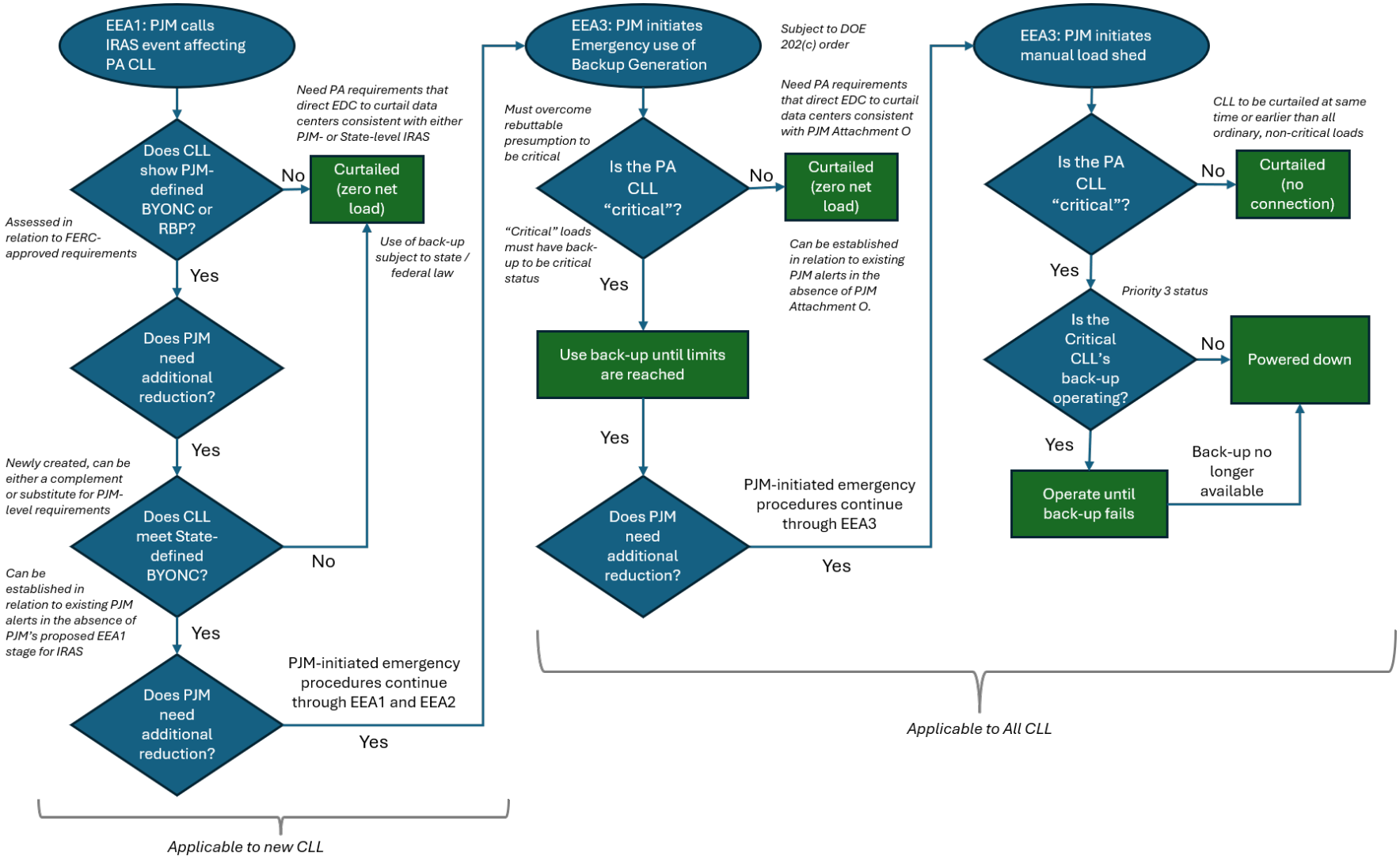
PJM's requirements should not, however, define the outer limit of Pennsylvania's protections. As described in Section VI, a Pennsylvania-specific BYONC requirement may apply

to additional new computational large loads or impose more protective conditions than the minimum PJM standard. Where a new computational large load has not satisfied that state-jurisdictional requirement, PPL's procedures should provide for its curtailment when additional load reduction is required to prevent further deterioration of system conditions. This protection is particularly important before PJM's proposed IRAS framework becomes effective and for computational large loads that may fall outside the scope of the final PJM requirements.

Second, as emergency conditions progress, computational large loads should be required to make available qualifying UPS, backup generation, storage, or other verified customer resources necessary to reduce their net demand from the grid, subject to applicable environmental, operational, and federal or state requirements. A computational large load that receives electric service during a period of constrained resource adequacy should not be permitted to preserve ordinary commercial operations while PPL is approaching involuntary interruption of other firm customers.

Third, if emergency conditions progress to manual load shedding, PPL should apply predetermined priority classifications that distinguish genuinely critical load from non-critical computational demand. Non-critical computational load should be available for interruption no later than ordinary non-critical firm load. Additionally, as discussed below, qualifying critical computational load should receive only the limited protection warranted by the essential services it supports. Figure 4 depicts these recommended stages in sequence as they align with existing and proposed PJM emergency procedures.

Figure 4. Recommended Sequence for Computational Large Load Curtailment During PJM Pre-Emergency and Emergency Conditions



BYONC = Bring Your Own New Generation; CLL = Computational Large Load; EDC = Electric Distribution Company; EEA = Energy Emergency Alert; IRAS = Interim Resource Adequacy Service; RBP = Reliability Backstop Procurement

Figure 4 depicts the interaction among PJM resource adequacy requirements, supplemental Pennsylvania requirements, use of customer backup resources, and eventual manual load shedding. At a high level, the process begins with PJM-directed reductions during a pre-emergency condition; provides an additional mechanism for Pennsylvania to obtain reductions from computational large loads that have not satisfied applicable state resource adequacy requirements; requires use of available backup resources as emergency conditions intensify; and ultimately applies defined critical-load priorities during manual load shedding. The purpose of this sequence is to use available computational large load flexibility before PPL is forced to obtain equivalent relief through broader involuntary interruption of non-large load customers.

As noted in previous sections, this framework should remain durable as PJM rules evolve. The Commission should not make Pennsylvania emergency protections contingent upon the continued existence of IRAS, its precise eligibility criteria, or any other particular PJM construct. PPL's procedures instead should identify the PJM event or operating condition that triggers each required customer action and provide for corresponding state-level procedures if PJM does not establish or maintain an equivalent mechanism. PPL should be required to revise its ELCP, load-shed instructions, and applicable customer agreements to reflect this sequence.

B. Computational Large Loads Should Be Presumed Non-Critical Unless a Limited Portion of Their Demand Is Demonstrated to Serve an Essential Function

As explained in Section IX, treating an entire computational large load as critical can substantially reduce the amount of demand available for emergency relief and thereby shift outages to other customers. To implement the critical-load framework recommended in that section, PPL's tariff should specify a rebuttable presumption that computational large load is non-critical. The

burden should rest with the customer to demonstrate that a specifically identifiable portion of its demand warrants a higher priority.

The resulting PPL priority structure should also recognize that not all critical load is equally situated. Consistent with Section IX, computational load that indirectly supports an essential function should not necessarily receive the same priority as the facility performing that function. I recommend that this distinction be implemented by defining multiple classes of computational load that are separately addressed in PPL's emergency load shed priority.

To overcome the rebuttable presumption, the customer should make the showing described in Section IX. PPL should also require the customer to identify the contractual or operational relationship supporting that designation and periodically reaffirm that the relationship remains in effect. PPL's procedures should establish a documented process for reviewing and verifying this showing and assigning the corresponding level of emergency priority.

Importantly, elevated priority should also be conditioned on PPL's verification of the customer having appropriate UPS and backup power capability. A computational large load that elects not to invest in sufficient UPS and backup capability should not obtain a higher claim on grid power during emergencies as a consequence of that decision.

PPL should verify these classifications on an ongoing basis. Customer certifications should be periodically updated; PPL should have authority to inspect and verify UPS and backup power capability; and customers should promptly report material changes in the services provided, customer relationships, facility configuration, or quantity of load claimed to be critical. Customer-specific critical and non-critical demand quantities should also be memorialized in a Commission-

jurisdictional agreement available for Commission review and reflected, as appropriate, in PPL's load-shed schedules and operating instructions.

C. PPL Should Require Physical Segregation, Metering, and Other Capabilities Necessary to Implement the Required Curtailment Priority

To implement the requirements identified in Section IX, PPL's tariff and service requirements should make the necessary physical configuration a condition of interconnection and continued service. Where a computational large load contains both critical and non-critical demand, the customer should be required to configure its facilities so those loads can be electrically and operationally separated. PPL should be able to curtail non-critical demand without unnecessarily disconnecting the limited portion that has been verified as critical. Where backup power is relied upon, the facility should likewise be capable of routing that resource to the specifically identified critical functions rather than using backup capability to preserve non-essential operations while relying on the grid for critical service.

Appropriate metering, telemetry, switching, controls, and communications should also be required so PPL can determine the quantity of load available, direct a reduction, verify customer performance, and determine whether backup resources are actually supplying the load represented by the customer. PPL should establish objective commissioning and periodic-testing requirements for these capabilities, including re-testing following material facility modifications or changes in critical-load designation. The applicable requirements should be incorporated into PPL's tariff, operating procedures, and/or customer-specific service agreements.

D. PPL's Procedures Should Address Compliance, Restoration, and Continuing Commission Oversight

PPL should revise its tariff and operating procedures to establish how compliance with computational large load curtailment instructions will be measured, documented, and enforced. Consistent with Section IX, the applicable tariff and service agreement should provide consequences for nonperformance, including financial penalties and, where warranted, modification of the customer's firm-service entitlement or other service conditions.

PPL's emergency procedures should likewise specify restoration protocols for computational large loads, including PPL's authority to establish the timing, sequence, and ramp rate for returning curtailed demand to service and to coordinate those actions with PJM.

Finally, the Commission should require PPL to submit the complete emergency operating materials necessary to evaluate implementation of these requirements. The publicly available ELCP does not disclose all of PPL's load-shed tables, critical-facilities procedures, action guides, and other implementation materials. Without those documents, it is not possible to determine whether computational large loads have been excluded from load-shed schedules, how PPL currently designates critical facilities, or whether existing and prospective computational large loads can actually perform the reductions contemplated above. The Commission and statutory advocates should have access to those materials, subject to appropriate confidentiality protections, and PPL should be required to revise them as necessary to implement the Commission's determination in this proceeding.

XI. Conclusion

The anticipated addition of computational large loads represents a material departure from the conditions under which PPL's existing tariffs, service requirements, and emergency operating

procedures were developed. Specifically, the magnitude, pace, concentration, and uncertainty of these loads create substantial financial and reliability risks that warrant differentiated service requirements. Although PPL's existing emergency operating procedures and LP-6 tariff incorporate several important protections, the publicly available record demonstrates that additional tariff, contractual, and emergency operating requirements are necessary to ensure that computational large loads do not receive unreasonable preferential treatment at the expense of existing customers.

Accordingly, I recommend that the Commission establish a proceeding and develop a complete evidentiary record concerning PPL's treatment of existing and prospective computational large loads. That process should result in revisions to PPL's tariff, Commission-jurisdictional customer agreements, and emergency operating procedures sufficient to implement the protections described in this Affidavit. Because PPL is already making investment and operational decisions concerning computational large loads, these protections should be established before additional costs and reliability risks become embedded in the system.

I reserve the right to supplement or revise the findings and recommendations in this Affidavit if additional relevant information becomes available in subsequent proceedings.

EXHIBIT A

Matthew Hoyt Resume

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

MATTHEW T. HOYT

Mr. Hoyt is a Vice President and Principal with Exeter Associates, Inc., with over a decade of experience in the energy industry. At Exeter, Mr. Hoyt develops utility service assessments, provides bill and tariff analysis, audits utility programs, and conducts economic and feasibility assessments of renewable energy, retail supply, electrification, and demand response opportunities. Additionally, Mr. Hoyt evaluates utility sector policy and regulation for private, federal, and state clients, as well as supports clients in complex utility service and rate negotiations.

Mr. Hoyt's graduate coursework focused on electricity policy, applied economics, and utility regulation. He wrote two capstone papers: an econometric assessment of community aggregation policy in retail electric markets and a theoretical assessment of the economic theory of regulatory capture.

Education

M.P.A. (Public Administration), 2016
The Ohio State University

B.A. (Government and English), 2012
Georgetown University

Exeter Associates Employment

2023-current	Principal and Vice President
2022	Managing Consultant
2019-2021	Senior Analyst
2016-2018	Economic Analyst

Previous Employment

2015-2016	Market Research Analyst, Customer Data Science AEP Energy Columbus, OH
2011-2014	Senior Analyst and Project Manager TargetPoint Consulting Alexandria, VA

Professional Experience

Mr. Hoyt's work at Exeter is primarily related to retail and wholesale electricity markets; energy procurement; reliability; transmission planning; rate design assessment; electrification; and policy or program design, implementation, and evaluation. Recent projects that Mr. Hoyt has led include: multiple assessments of resource adequacy constructs in organized wholesale markets for the Consumer Advocates of the PJM States; a comprehensive evaluation of residential time-of-

use rate design and implementation on behalf of the Maine Public Utility Commission staff; a review of energy storage research, development, and deployment strategies on behalf of the National Association of State Energy Officials; a wide-ranging assessment of utility-scale battery energy storage safety, siting, and economic considerations on behalf of the Indiana Office of Energy Development; multiple assessments of energy storage, transmission, solar, electric school bus, nuclear energy, and renewable portfolio standard policies for the state of Maryland; multiple utility management and performance audits on behalf of the Public Utility Commission of Ohio Staff, including evaluations of statutory compliance, economic impacts, budget, and utility rate-setting approach; comprehensive reviews of default electric service procurement practices on behalf of consumer advocate and state department of energy entities in several New England-area states; and support developing tariffs, rules, and regulations addressing the cost and reliability impacts of large load customer additions on behalf of consumer advocates in Maryland, Pennsylvania, and Delaware. In addition to these projects, Mr. Hoyt works with the U.S. Corps of Engineers Commercial Utilities Program, Department of Energy Federal Energy Management Program, and U.S. Air Force Utilities Rate Management Team to support utility service reviews at Army, Department of Energy, and Air Force sites, respectively.

Prior to joining Exeter Associates, Mr. Hoyt worked in a variety of analytical roles managing and analyzing large-scale utility data as well as conducting econometric assessment. As a data scientist at AEP Energy, Mr. Hoyt assessed electricity and gas customer data to address research questions regarding consumer behavior and preferences. At TargetPoint Consulting, Mr. Hoyt supervised stratified surveys, built and maintained large-scale relational databases, and developed predictive models for a variety of corporate clients, including electric utilities and energy-sector trade associations.

Journal Publications

- Dormady, N., **Hoyt, M.**, Cao, C., Koenig, G., & Welch, W.. "An Evaluation of Accuracy of EIA Electricity Price Data: Evidence from Ohio." (In progress)
- Kuykendall, O., **Hoyt, M.**, & Dormady, N. "Default Electric Service in Restructured Jurisdictions." (In progress)
- Dormady, N., Kahn-Lang, J., Choi, Y., Ji, Y. Fox, S., Lamadrid, A., & **Hoyt, M**. (2026). Public Management of Deregulated Systems: Challenges and Opportunities in the Public Management of Retail Energy Markets. Public Administration Review, Forthcoming.
- Ji, Y., Dormady, N., Shafieezadeh, A., Diana, K., **Hoyt., M.**, Lamadrid, A., & Fox, S. (2026) "An Explainable Machine Learning Analysis of Supplier's Margin on Retail Renewables." Energy Economics., 162: 109554. https://doi.org/10.1016/j.eneco.2026.109554.).
- Dormady, N., Welch, W., Ji, Y., Pedron, S., Shafieezadeh, A., Lamadrid, A., **Hoyt, M.,** & Fox, S. (2025). "Efficiency and Consumer Welfare Under Retail Electricity Deregulation: Analysis of Ohio's Retail Choice Markets." Journal of Critical Infrastructure Policy, 6(1), e12031. https://onlinelibrary.wiley.com/doi/10.1002/jci3.12031.
- Dormady, N., Roa-Henriquez, A., **Hoyt, M.,** Pesavento, M., Koenig, G., Welch, W., & Li, Z. (2025). "How are Retail Electricity Prices Formed in Restructured Electricity Markets?" Energy Economics, 143: 108243. https://www.sciencedirect.com/science/article/pii/S0140988325000660?via%3Dihub.

- Dormady, N., **Hoyt, M.,** Roa-Henriquez, A., & Welch, W. (2019). "Who Pays for Retail Electric Deregulation? Evidence of Cross-Subsidization from Complete Bill Data." The Energy Journal, 40(2): 161-194. https://journals.sagepub.com/doi/10.5547/01956574.40.2.ndor.

- Dormady, N., Jiang, Z., & **Hoyt, M.** (2018). "Do Markets Make Good Commissioners?: A Quasi-Experimental Analysis of Retail Electric Restructuring in Ohio." Journal of Public Policy, 1-33. https://doi.org/10.1017/S0143814X18000168

Academic Conference Paper Presentations

- Association for Public Policy Analysis & Management (2024)
- International Association for Energy Economics (IAEE)/USAEE (2026, 2023, 2022, 2018, & 2017)
- Midwest Public Affairs Association (MPAC) (2016)

Grants

- Sloan Foundation. 2026-2027. Choice with No Options: An Evaluation of the Economic Efficiency and Equity Impacts of Submetering Under Retail Electric Deregulation. $150K. (Collaborator) (PIs: Dormady, N., Lamadrid, A., Fox, S., & Shafieezadeh, A.)

- Sloan Foundation. 2022-2026. *Who Pays for Electrification & Resilience?: An Evaluation of the Equity, Justice & Efficiency Impacts of Retail Electric Deregulation*. $0.5M. (Collaborator) (PIs: Dormady, N., Lamadrid, A., Shafieezadeh, A.)

Select Public Consulting Reports

- *Maryland Power Plants and the Environment: A Review of the Impacts of Power Plants and Transmission Lines on Maryland's Natural Resources, Maryland Power Plant Research Program, PPRP-CEIR-23* (with various Exeter Associates staff and contributing authors from Versar, Inc. and Gannett Fleming). (In progress.)

- *A Management Audit of the WarmChoice Program of Columbia Gas of Ohio*, prepared for the Public Utilities Commission of Ohio in response to Case No. 25-688-GA-RDR (with Jared Geiger, Grace Koenig, Abby Huebler, Jeremie Amsallam, and Cali Clark of Exeter Associates).

- *Utility-Scale Battery Energy Storage System Applications and Impacts in Indiana*. (2025). Prepared for the Indiana Office of Energy Development (with Olivia Kuykendall, Will Cotton, Mason Vliet, Jeremie Amsallem, Alex Dominguez, and Cali Clark of Exeter Associates). Indiana-Utility-Scale-Battery-Energy-Storage-Study-July-2025.pdf

- *Considerations for the Design and Implementation of Time of Use Rates for Residential Electric Customers in Maine*. (2025). Prepared for the Maine Public Utilities Commission in response to Docket No. 2024-00231 (with Grace Koenig, Abby Huebler, Makayla Bowen-Longino, and Cali Clark of Exeter Associates). https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2024-00231

- *Review of the Basic Transmission Cost Rider and Associated Pilot Program Established by the Ohio Power Company*. (2025). Prepared for the Public Utilities Commission of Ohio in response to Case No. 24-493-EL-RDR (with Bola Ajanaku, Riya Bhargava, and Cali Clark of Exeter Associates).
  https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A25B24B44847E01737

- *A Management/Performance and Financial Audit of Demand Side Management and Energy Efficiency Rider (Rider DSE) of FirstEnergy Ohio*. (2024). Prepared for the Public Utilities Commission of Ohio in response to Case Nos. 18-1646-EL-RDR, 19-1904-EL-RDR, 20-1673-EL-RDR, 21-1131-EL-RDR, and 22-1044-EL-RDR (with Grace Koenig, Jared Geiger, Makayla Bowen-Longino, and Cali Clark of Exeter Associates).
  https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A24L18B41624D00895

- *Maryland 100% Renewable Portfolio Standard (RPS) and 100% Clean Energy Standard (CES) by 2040 Study*. (2024). Prepared for the Maryland Department of Natural Resources, Power Plant Research Program (with Riya Bhargava, Cali Clark, William Cotton, and Kevin Porter of Exeter Associates and Christopher Clack of Vibrant Clean Energy, among other contributors).
  https://dnr.maryland.gov/pprp/Pages/maryland-100percent-study.aspx

- *Accelerating Energy Storage Research Development and Demonstration: Policy, Programmatic, and Planning Considerations for States*. (2024). Prepared for the National Association of State Energy Officials (with Jeremie Amsallem and Cali Clark of Exeter Associates).
  naseo.org/data/sites/1/documents/publications/NASEO_Energy Storage_v2.pdf

- *Solicitation and Procurement of Default Energy Service in New Hampshire*, prepared for the New Hampshire Department of Energy, March 2024 (with Serhan Ogur, Olivia Kuykendall, Grace Koenig, and Cali Clark of Exeter Associates).
  https://www.energy.nh.gov/sites/g/files/ehbemt551/files/inline-documents/sonh/inv-2023-001-doe-final-report.pdf

- *Review of the Non-Market-Based Services Riders Established by Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company and Associated Pilot Program*, prepared for the Public Utilities Commission of Ohio in response to Case No. 22-391-EL-RDR, July 2023 (with Serhan Ogur, Ari Weissfeld, and Cali Clark of Exeter Associates).
  https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A23G17B23458I01165

- *Retail Supply and Standard Offer Service Reform for Maine*, prepared for Maine Office of the Public Advocate, February 2023 (with Steven Estomin, Serhan Ogur, Olivia Kuykendall, Afton Hauer, and Cali Clark of Exeter Associates).
  https://www.maine.gov/meopa/sites/maine.gov.meopa/files/inline-files/2023-02-01_OPA%20Full%20Retail%20Electricity%20Supply%20Report.pdf

- *Resource Adequacy Constructs in Organized Wholesale Markets*, prepared for the Consumer Advocates of the PJM States, April 2021 (with Christopher Parent and Cali Clark of Exeter Associates).
  https://www.pjm.com/-/media/committees-groups/user-groups/pieoug/2021/20210505/20210505-resource-adequacy-constructs-in-organized-wholesale-markets-report.ashx

- *Nuclear Power in Maryland: Status and Prospects,* prepared for the Maryland Department of Natural Resources, Power Plant Research Program, January 2020 (with Kevin Porter of Exeter Associates and Diane Mountain of Environmental Resources Management, among other contributors).
  https://dnr.maryland.gov/pprp/Documents/NuclearPowerinMaryland_Status-and-Prospects.pdf

- *Final Report Concerning the Maryland Renewable Portfolio Standard As Required by Chapter 393 of the Acts of the Maryland General Assembly of 2017,* prepared for the Maryland Department of Natural Resources, Power Plant Research Program, December 2019 (with Kevin Porter and Rebecca Widiss of Exeter Associates, among other contributors).
  https://dnr.maryland.gov/pprp/Documents/FinalRPSReportDecember2019.pdf

- *Energy Storage in Maryland: Policy and regulatory options for promoting energy storage and its benefits*, prepared for the Maryland Department of Natural Resources, Power Plant Research Program, 2018 (with Rebecca Widiss, Kevin Porter, Stacy Sherwood, and Cali Clark of Exeter Associates and Steven Miller and Aditya Saxena of Mondre Energy).
  https://dnr.maryland.gov/pprp/Documents/Energy-Storage-In-Maryland.pdf

Expert Testimony

- Before the Pennsylvania Public Utility Commission Docket No. R-2025-3057164, Pennsylvania Public Utility Commission v. PPL Electric Utilities Corporation, September 2025, on behalf of the Pennsylvania Office of Consumer Advocate. Testified regarding large load additions, reliability, and electric vehicle programs. Subject to Cross.

- Before the Maryland Public Service Commission, Case No. 9744, Hagerstown Light Department's Application for Change in Electric Rates, June 2024, on behalf of the Maryland Office of People's Counsel. Testified on class cost of service, rate design, and customer fees. Subject to ALJ Questioning.

- Before the Maryland Public Service Commission, Case No. 9741, Potomac Edison's Application for an Electric School Bus Pilot Program, January 2024, on behalf of the Maryland Public Service Commission Staff. Testified on statutory compliance, estimated economic impacts, proposed Pilot criteria, budget, and utility rate-setting approach. Subject to Cross.

- Before the Maryland Public Service Commission, Case No. 9696, Baltimore Gas and Electric Company's Application for an Electric School Bus Pilot Program, July 2023, on behalf of the Maryland Public Service Commission Staff. Testified on statutory compliance, estimated economic impacts, proposed Pilot criteria, budget, and utility rate-setting approach. Subject to Cross.

Select Additional Engagements

- Before the Maryland Public Service Commission PC 82, Reliability Backstop Procurement, September 2026, for the Maryland Office of People's Counsel. Prepared comments.

- Before the New Jersey Board of Public Utilities, Docket No. GA22030141, Audit of the Affiliated Transactions Between Elizabethtown Gas Company and South Jersey Industries and its Affiliates, December 2025, on behalf of the New Jersey Division of the Rate Counsel. Prepared comments.

- Before the Delaware Public Service Commission Docket No. 25-0826, Petition of the Staff of the Delaware PSC Regarding a Large Load Tariff to be Promulgated by Delmarva Power & light Company, August 2025, for the Delaware Division of the Public Advocate, Delaware PSC Staff, and Delaware Department of Natural Resources and Environmental Control. Prepared comments and supported development of regulation.
- Before the Maine Public Utilities Commission, Case No. 2025-00176, Commission Initiated Investigation of Time of Use Rates for Delivery and Standard Offer Service for Investor-owned Transmission and Distribution Utilities, June 2025, for Maine Public Utilities Commission Staff. Prepared comments and supported discovery.
- Before the Maryland Public Service Commission PC 72, Large Load Customer Regulations and Tariffs Interconnecting to the Electric System Servicing Maryland, June 2025, for the Maryland Office of People's Counsel. Supported workgroup engagement and prepared multiple rounds of comments.
- Before the Maryland Public Service Commission PC 66, Resource Adequacy, October 2024, for the Power Plant Research Program and Maryland Office of People's Counsel. Prepared multiple rounds of comments.
- Before the Maine Public Utility Commission, Docket No. 2023-00258, Commission Initiated Inquiry Regarding Standard Offer Service Procurement Strategy, November 2023, for the Maine Office of the Public Advocate. Prepared initial comments and reply comments.
- Before the Massachusetts Department of Public Utilities, Docket No. 23-50, Investigation by the Department of Public on its own Motion into the Provision of Basic Service, February 2023, for the Massachusetts Office of the Attorney General. Prepared reply comments.
- Strategy memos and guidance documents for the U.S. Army, including:
  - *U.S. Army Utility Procurement Assessment: Current and Ideal Practices, Gaps, and Opportunities* (2020), prepared for the U.S. Army Commercial Utilities Program (with Christina Mudd of Exeter Associates).
  - *GOCO Contracts and Energy Conservation Measures*, prepared for the U.S. Army Materiel Command, September 2018 (with Christina Mudd of Exeter Associates).
  - *Army Demand Response Implementing Guidance* (2018), prepared for the Office of the Assistant Chief of Staff for Installation Management (with Christina Mudd and Shawn Kelly of Exeter Associates).
  - *USAR and ARNG: Guidance for Participation in Demand Response Programs*, prepared for the Office of the Assistant Chief of Staff for Installation Management, United States Army Reserve, and the Army National Guard, August 2018 (with Christina Mudd, Felipe Salcedo, and Katherine Fisher of Exeter Associates).
  - *Army Demand Response Program: Data and Reporting*, prepared for the Office of the Assistant Chief of Staff for Installation Management, June 2018 (with Christina Mudd of Exeter Associates).

- *USAR: Utility Provider Assessment – Summary of Opportunities*, prepared for the United States Army Reserve, April 2017 (with Christina Mudd and Felipe Salcedo of Exeter Associates).

- Utility assessments, negotiations, supply option studies, and audit reports, including electric, natural gas, water, and wastewater services, for U.S. Army installations, U.S. Department of Energy laboratories, and U.S. Air Force bases, including:

Fort Detrick	Anniston Army Depot	Kirtland AFB
Fort Meade	Fort Bragg	Holloman AFB
Fort Belvoir	Pantex Plant	Joint Base Charleston
Fort Rucker	Lake City Army Ammo. Plant	Princeton Plasma Physics Laboratory
Fort Greely	Radford Army Ammo. Plant	Sanford Underground Research Facility
Fort Leonard Wood	Holston Army Ammo. Plant	Aberdeen Proving Ground
Devens RFTA	JSMC (Lima Army Tank Plant)	
Rock Island Arsenal	MacDill AFB	
Wright-Patterson AFB		

- Demand response assessment reports for U.S. Army installations, including:

Fort Bliss	Fort Knox	Aberdeen Proving Ground
Detroit Arsenal	White Sands Missile Range	United States Military Academy
Fort Belvoir	Tobyhanna Army Depot	

Select Consulting Support

- *PJM Powering Reliability Through Market Design* (2026), on behalf of the Maryland Office of People's Counsel (with Dr. Serhan Ogur). Provided technical support.

- *PJM Critical Issue Fast Path – Reliability Backstop Procurement & Connect and Manage* (2026), on behalf of the Maryland Office of People's Counsel (with Dr. Serhan Ogur). Provided technical support.

- *PJM Critical Issue Fast Path – Large Load Addition Stakeholder Process* (2025), on behalf of Consumer Advocates of the PJM States and the Maryland Off (with Riya Bhargava, Taylor Carretta, William Cotton, Alex Dominguez, and Dr. Serhan Ogur). Provided technical support.

- *PJM Reliability Pricing Model Price Forecasts* (2025), prepared for Consumer Advocates of the PJM States (with Riya Bhargava, Taylor Carretta, William Cotton, Alex Dominguez, and Dr. Serhan Ogur). Prepared analysis and recommendations (non-public).

- *Assessment of PJM Cost of New Entry (CONE) and Net CONE* (2024-2025), prepared for Consumer Advocates of the PJM States (with Taylor Carretta and Dr. Serhan Ogur). Prepared analysis and recommendations (non-public).

- Testimony support and analysis for the Maryland Department of Natural Resources Power Plant Research Program as part of Certificate of Public Convenience and Necessity cases before the Maryland Public Service Commission:

  - The Potomac Edison Company 's Application for a Certificate of Public Convenience and Necessary to Rebuild Potomac Edison's Messick Road-Ridgeley 138 Kilovolt Transmission Line in Allegany County, Maryland. Case No. 9818, October 2025

- Application of the Potomac Edison Company for a Certificate of Public Convenience and Necessary for the Caroll-Hunterstown Improvements Project. Case No. 9803, July 2025
- Application for a Certificate of Public Convenience and Necessity to Construct a New 500 kV Transmission Line in Portions of Baltimore, Carroll, and Frederick counties. Case No. 9773, December 2024.
- Application for a Certificate of Public Convenience and Necessity for the Brandon Shores Retirement Mitigation Project. Case No. 9748, July 2024.

- Ongoing monitoring, preparation of comments, and other ongoing technical support on behalf of the Maryland Department of Natural Resources Power Plant Research Program and Maryland Office Maryland Office of People's Counsel as part of PJM stakeholder processes:
  - PJM Load Analysis Subcommittee (2025-present)
  - PJM Transmission Expansion Advisory Committee (2025-present)

Affidavit of Matthew T. Hoyt, M.P.A.

I, Matthew T. Hoyt, (Affiant) being duly sworn (affirmed) according to law, depose and say that I am authorized to make this affidavit on behalf of the Pennsylvania Consumer Advocate and Office of Consumer Advocate (OCA), being the holder of a contract with the OCA that engaged my subject matter expertise, and have been authorized to make this affidavit on the Consumer Advocate's and OCA's behalf, and that the facts above set forth are true and correct to the best of my knowledge, information and belief, and I expect to be able to prove the same at any hearing hereof.

Matthew Hoyt

Signature of Affiant

October 1, 2026

Date

Sworn and subscribed before me the date below:

Holly J Finberg

Signature of Official Administering Oath

October 1, 2026

Date

November 25, 2027

(My Commission Expires)

HOLLY J FINBERG
Notary Public - State of Maryland
Anne Arundel County
My Commission Expires Nov 25, 2027

Appendix D – Ogur Affidavit

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Office of Consumer Advocate	:	Docket No. C-2026-
v.	:	
PPL Electric Utilities Corporation	:	

AFFIDAVIT OF SERHAN OGUR, PH.D.

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I. Witness Information

My name is Serhan Ogur. I am employed by Exeter Associates, Inc. ("Exeter") as a Senior Analyst and Principal. My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia MD 21044.

I have been employed at Exeter since 2015 in various roles, most recently as a Principal of the firm, beginning in 2020. At Exeter, my work is primarily related to structuring and analysis of electricity supply contracts; utility rates and tariffs; energy markets and prices; power procurement; default electric service design; project evaluation; demand response opportunities; congestion hedging strategies; and price forecasting. I lead wholesale power portfolio design, energy and capacity procurement, market analysis and forecasting, and risk management functions for some federal agencies that have wholesale status. I am a long-time electricity procurement consultant to federal procurement agencies, advising and supporting their retail and wholesale, short-term and long-term, electricity supply procurement and contracting efforts for federal government sites across the country. I support state consumer advocate offices on design, procurement, and ratemaking issues in utility default service proceedings, and on consumer protection issues in public utility merger cases, by providing expert witness services.

Prior to joining Exeter, my responsibilities at Fellon-McCord & Associates, LLC encompassed overseeing and performing the daily tasks of the "24/7" wholesale electricity desk, including all aspects of scheduling, managing, and monitoring direct market participant load and generation assets (mostly in ISO/RTO markets) as well as their settlements and custom reporting. I was also in charge of developing strategies and making recommendations, through analytical, financial, and market research, for longer-term management of clients' load obligations and generation assets such as Auction Revenue Rights nominations; participation in energy, ancillary services, and capacity markets; load forecasting; energy, basis, and capacity price forecasting; hedging; and peak load management. I also served as the company's lead analyst in various special consulting projects.

In PJM Interconnection, LLC's ("PJM's") Market Strategy and Market Analysis departments, I was responsible for analyzing and reporting on all PJM-administered electricity market products, including day-ahead and real-time energy, operating reserve, regulation, synchronized reserve, virtual transactions, financial transmission rights, capacity, demand response, energy efficiency, and renewables. I was part of the team that developed protocols and business rules for participation of energy efficiency in PJM markets as well as

a lead reviewer for energy efficiency plans and post-installation measurement and verification reports for PJM's capacity market auctions. I also have training and experience in PJM's stakeholder management process.

My responsibilities at the Illinois Commerce Commission ("ICC") included monitoring all Illinois-related developments under federal jurisdiction, mostly Federal Energy Regulatory Commission ("FERC") filings and rulings concerning major Illinois electric public utilities. In addition, I reviewed all actions concerning Illinois public utilities at the FERC level (applications to join RTOs, market-based rate authority filings, merger applications, transmission rate cases, etc.), and developed positions and official comments for the consideration of the ICC to file in the related FERC dockets. I also filed written testimony and served as staff witness in the ICC dockets establishing auction-based competitive wholesale energy procurement mechanisms for major Illinois electric public utilities.

I hold a bachelor's degree in economics from Bogazici University (Istanbul, Turkey) and a Ph.D. in Economics from Northwestern University (Evanston, IL). Please see Exhibit A for my complete resume.

II. Purpose of Affidavit

I have been retained by the Pennsylvania Office of Consumer Advocate ("OCA") to assist in the evaluation of PPL Electric Utilities Corporation ("PPL Electric") with respect to four topics.

My affidavit addresses:

i. The need for a tariff structure (including associated rate schedules and other contractual arrangements) specific to new data centers and artificial intelligence infrastructure, or large computational load entities ("CLEs"), which are also referred to as "large loads" in the respective Affidavits of Mr. Matthew T. Hoyt, Dr. Frank A. Felder, and Mr. Zachary Teti; as well as in various Pennsylvania Public Utility Commission (the "Commission"), FERC, and PJM documents.

ii. The shortcomings of PPL Electric's current PJM Network Integration Transmission Service ("NITS") cost responsibility allocation method in preventing unjust and unreasonable PJM NITS cost shifts from new CLE customers to legacy customers, as acknowledged by PPL Electric in its petition to establish a non-bypassable Customer Protection Transmission Rider,[1] and some alternative PJM NITS cost responsibility allocation methods that would cure such shortcomings.

[1] Petition of PPL Electric Utilities Corporation for Approval of Its Non-Bypassable Customer Protection Transmission Rider, Elimination of Its Transmission Service Charge, Changes to Its Generation Supply

iii. The shortcomings of PPL Electric's current PJM reliability Pricing Model ("RPM") capacity cost responsibility allocation method in preventing unjust and unreasonable RPM capacity cost shifts from new CLE customers to legacy customers and some alternative RPM capacity cost responsibility allocation methods that would cure such shortcomings.

iv. The absence of PPL Electric's PJM Reliability Backstop Procurement ("RBP") cost responsibility allocation mechanism and some RBP cost responsibility allocation mechanisms that would prevent PPL Electric from unjustly and unreasonably allocating any RBP cost responsibility to legacy customers (i.e., any customer other than new CLEs).

Some of the issues and inadequacies that I identify with regard to PPL Electric's PJM NITS, capacity, and RBP cost responsibility assignment mechanisms, as well as potential solutions to them, can be refined and further explored with additional information. Such additional information can come from PPL Electric in response to formal discovery as well as supplemental legal, regulatory, market, and economic research. To that end, my Affidavit is intended to demonstrate that the status quo is unjust and unreasonable in light of the rapidly growing magnitude of new CLE interconnection requests, both in PPL Electric's service territory and across PJM, and that customer protections need to be strengthened to prevent new CLE customers from adversely impacting the reliability and affordability of electric service for PPL Electric's legacy customers. My Affidavit is not intended to prescribe specific solutions to the issues and inadequacies that I identify with regard to PPL Electric's PJM NITS, capacity, and RBP cost responsibility assignment mechanisms. I believe the Commission should initiate a proceeding, and specific solutions should be proposed and arrived at as part of that proceeding.

III. Summary of Findings and Recommendations

A. <u>NITS Cost Allocation to CLEs</u>

- PPL Electric has at least 24,880 MW in its CLE interconnection queue with an estimated transmission upgrade cost of at least $3.6 billion.
- Under PPL Electric's existing NITS cost allocation process, a prospective or new CLE can raise NITS costs for legacy customers in a number of ways, including, but not limited to:
  i. If the CLE's but-for transmission network upgrade costs are larger than the NITS payments it could be expected to make;

Charges, Changes to Its Retail Tariff, and Changes to Its Electric Generation Supplier Coordination Tariff, Docket No. P-2026-3065185. ("CPTR Petition")

ii. If the prospective CLE never comes online after the transmission owner incurs network upgrade costs to interconnect that CLE;
iii. If the CLE does not come online for multiple years after its network upgrade costs are included in the zonal NITS revenue requirement;
iv. If the CLE comes online but never reaches the load level for which the transmission owner has incurred network upgrade costs;
v. If the CLE shuts down its load center before its NITS payments cover its but-for transmission network upgrade costs; and
vi. If the CLE manages its annual transmission peak load contributions (i.e., network service peak load) to significantly reduce its share of the zonal NITS revenue requirement.

- PPL Electric's NITS cost allocation process can be revised to reduce or eliminate the opportunities for a prospective or new CLE to shift its but-for transmission network upgrade costs to legacy customers in a number of ways, including, but not limited to:
  i. Assignment of a NITS make-whole surcharge, with or without an accompanying minimum network service peak load, to the CLE;
  ii. Assumption of PJM NITS charges by PPL Electric for all retail customers, institution of a non-bypassable NITS charge applicable to all customers, and the Commission setting PPL Electric's NITS cost allocation procedures such that CLEs pay their respective but-for transmission network upgrade (NITS) costs; and
  iii. An "expansion rate" framework, under which a new CLE would pay both its pro-rata share of the existing zonal transmission rate and an expansion rate specifically designed to recover its but-for transmission network upgrade costs.
- Failing to revise PPL Electric's NITS cost allocation process would enable shifting of NITS costs from prospective and new CLEs to legacy customers. The Commission should take action to minimize or eliminate opportunities for such unjust and unreasonable shifting of NITS costs.

B. <u>RPM Capacity Cost Allocation to CLEs</u>

- The load adjustments submitted by PPL Electric to PJM specifically for prospective CLEs for the two-year period from 6/1/2027 through 5/31/2029 resulted in additional RPM capacity cost assignment from PJM to the PPL Electric Zone of $300 million for those two years. If PPL Electric continues to submit similarly large or even larger prospective CLE-specific adjustments to PJM, CLEs' but-for RPM capacity costs will remain elevated or even rise further.

- Under PPL Electric's existing RPM capacity cost allocation process, a prospective or new CLE can raise capacity costs for legacy customers in a number of ways, including, but not limited to:
  i. If the CLE, for which PJM purchased capacity due to PPL Electric's inclusion of that CLE in its load forecast adjustment to PJM, never comes online;
  ii. If the CLE comes online but never reaches its corresponding capacity requirement included in PPL Electric's load forecast adjustment submitted to PJM;
  iii. If the CLE shuts down its load center before the relevant capacity delivery year ends, or even starts; and
  iv. If the CLE manages its annual capacity peak load contributions to significantly reduce its share of the zonal RPM capacity requirements and costs.
- PPL Electric's RPM capacity cost allocation process can be revised to reduce or eliminate the opportunities for a prospective or new CLE to shift its but-for PJM RPM capacity costs to legacy customers in a number of ways, including, but not limited to:
  i. Assignment of a minimum capacity peak load contribution to the CLE;
  ii. Assignment of a capacity make-whole surcharge to the CLE; and
  iii. Assumption of PJM RPM capacity charges by PPL Electric for all retail customers, institution of a non-bypassable capacity charge applicable to all customers, and the Commission setting PPL Electric's capacity cost allocation procedures such that CLEs pay their respective but-for RPM capacity costs.

Failing to revise PPL Electric's capacity cost allocation process would enable shifting of RPM capacity costs from prospective and new CLEs to legacy customers. The Commission should take action to minimize or eliminate opportunities for such unjust and unreasonable shifting of RPM capacity costs.

C. <u>RBP Cost Assignment to CLEs</u>

- PJM assigned an initial RBP Target of 820.5 MW to the PPL Zone. If PJM procures the full 820.5 MW target for the PPL Zone at the procurement ceiling price of $555/MW-day, the resulting cost responsibility for the PPL Zone on average will be $166.3 million per year, or $2.5 billion over the 15-year term of the RBP contracts.
- PJM's RBP proposal places the responsibility of establishing cost responsibility allocation rules for the PPL Zone's RBP costs on the Commission. Neither the Commission nor PPL Electric currently have protections in place to ensure that legacy customers do not get allocated any PJM RBP costs.

- The Commission can ensure that no shifting of PJM RBP costs ever occurs from prospective or new CLEs to legacy customers in the PPL Zone in a number of ways.
  i. Assumption of PJM RBP charges by PPL Electric for all retail customers and a non-bypassable PJM RBP charge applicable only to CLE customers.
  ii. Retail tariff changes that prevent PJM RBP cost assignment to legacy customers.
- The Commission should act expeditiously to establish a retail cost assignment framework to allocate PJM RBP costs exclusively to CLEs for the 15-year duration of these costs.
- The Commission should ensure that any RBP-related credit/collateral costs incurred by PPL Electric are also assigned exclusively to CLEs.

D. Provision of Default Service to CLEs

- The Commission should establish a default service framework exclusively for CLEs. The framework should prevent the shifting of costs or risks from CLEs to legacy customers, including PPL Electric's administrative and credit/collateral-related costs to offer or provide default service to CLEs.

IV. Public Policy Framework

The public policy framework and consensus surrounding the reliability and affordability impacts of new CLE customers on legacy customers, such as residential and small business customers, is presented in detail in the respective Affidavits of Dr. Felder and Mr. Hoyt. This public policy framework and consensus include, but are not limited to, the following:

- White House Ratepayer Protection Pledge (issued on March 5, 2026; supplemented and expanded on July 23, 2026)
- Statement of Principles Regarding PJM by The National Energy Dominance Council and PJM Governors (issued on January 16, 2026)
- FERC's "Show Cause" Order in Docket No. EL24-118 (issued on June 18, 2026)
- PJM Board's Decisional Letter on Critical Issue Fast Path – Large Load Additions ("CIFP-LLA") (issued on January 16, 2026)
- Memorandum of the Independent Market Monitor for PJM ("IMM") in CIFP-LLA (issued on October 9, 2025)
- PJM's RBP Filing with the FERC (filed on July 31, 2026)
- FERC's "Order Accepting Reliability Backstop Procurement and Establishing Further Procedures" in response to PJM's RBP Filing
- PJM's Interim Resource Adequacy Service and Large Load Registry filing with the FERC (filed on August 13, 2026)

- Commonwealth of Pennsylvania Governor's Office, Executive Order 2026-05 – Protecting Pennsylvania Consumers from Data Center Impacts (issued on August 18, 2026)
- The Commission's final order establishing its Large Load Model Tariff Framework in Docket No. M-2025-3054271 (issued on April 30, 2026)
- Commission Chairman Stephen M. DeFrank's Statement in Docket No. A-2026-3062201 regarding cost allocation for large load interconnections (issued on August 6, 2026)
- PPL Electric's CPTR Petition
- The North American Electric Reliability Corporation's ("NERC's") Large Loads Action Plan and Project 2026-02 Computational Loads initiatives

V. The Need for a Tariff Structure Specific to New Computational Large Loads

The need for a tariff structure specific to prospective and new CLEs due to their unique requirements, characteristics, and risks is presented in great detail and specificity in Mr. Hoyt's Affidavit. Those factors include, but are not limited to, the following:

- Drastically changed landscape for utility investments and cost causation due to the influx of new CLEs.
- Unique reliability risks introduced by new CLEs.
- Unique market, investment, and stranded cost risks introduced by CLEs.
- The immediacy and urgency of concerns associated with new CLEs.
- The Commission's recognition of the need to evaluate utility treatment of new CLEs.
- Necessary protections that need to be included in a new CLE-specific tariff structure.
- The need for Commission jurisdictional agreements to accompany the new CLE-specific tariff structure (e.g., Electric Service Agreement ["ESA"]).
- The need to assign all but-for costs to prospective and new CLEs consistent with cost causation.
- The need for Bring-Your-Own-New-Capacity ("BYONC") requirements for prospective and new CLEs at least until the PJM Control Area and the PPL Zone reach a satisfactory level of resource adequacy.
- The need for interruptible rates and/or curtailability requirements for prospective and new CLE customers in the absence of, or in addition to, BYONC requirements.
- Insufficiency of PPL's existing tariff structures for the above stated needs and purposes.

In addition to the list of needs and purposes that are summarized above and discussed in Mr. Hoyt's Affidavit, in direct relevance to my Affidavit, a prospective and new CLE-specific tariff structure (e.g., rate schedule(s), ESAs) is necessary for PPL Electric to be able to segregate CLE-specific costs (e.g., distribution, direct-assign interconnection, NITS, RPM capacity, RBP) and assign them exclusively to prospective and new CLE customers.

VI. Network Integration Transmission Service Costs

E. PPL Electric's Current Method of Determining Customer NITS Costs

The daily NITS charge billed by PJM to a load-serving entity ("LSE") serving load in PJM's PPL Zone is the product of (i) the daily NITS rate for the PPL Zone; and (ii) the daily Network Service Peak Load ("NSPL") assigned by PPL Electric to that LSE as established in PPL Electric's transmission Attachment M-2 to PJM's tariff. NITS rates are typically published in dollars per megawatt per year ($/MW-year) of NSPL.[2] A NITS rate expressed in $/MW-year is converted to dollars per megawatt per day ($/MW-day) by dividing the $/MW-year figure by the number of days in the year (i.e., by 366 for leap years, by 365 for non-leap years). NITS revenues are reconcilable year-to-year, meaning that PPL Electric's inability to earn its full NITS revenue requirement in one year results in an increase to the NITS revenue requirement and to the NITS rate in the subsequent year to ensure that PPL Electric is able to collect its full NITS revenue requirement. Similarly, if PPL Electric's NITS revenues are more than its NITS revenue requirement in one year, this results in a reduction to the NITS revenue requirement and to the NITS rate in the subsequent year to ensure that PPL Electric does not collect more than its NITS revenue requirement.

PPL Electric's NITS rate is established through annual formula rate filings submitted by PPL Electric to FERC. PPL Electric is currently on a January 1 – December 31 NITS rate cycle. The NITS rate for a rate year is determined by dividing the PPL Zone's Net Zonal Annual Transmission Revenue Requirement ("NZATRR") for that rate year by the PPL Zone's coincident peak load ("Zonal 1CP") in the November 1 – October 31 period of the previous year.[3] Table 1 below shows summary statistics for the PPL Zone's NITS rate in the last four years.

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[2] In various PPL Electric and PJM documents, NSPL is also referred to as "Transmission Peak Load Contribution" and "NITS PLC."

[3] For a comprehensive explanation of the determination of PPL Electric's NZATRR, see PJM Open Access Transmission Tariff ("OATT"), Attachment H-8 (Annual Transmission Rates -- PPL Group for Network Integration Transmission Service); and https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates (postings under "PPL Electric Utilities Corporation" for each calendar year).

Table 1. PPL Zone Summary NITS Formula Rate Statistics for the Last Four Years

Rate Year	TRB ($Million) *(A)*	NZATRR ($Million) *(B)*	Zonal 1CP (MW) *(C)*	NITS Rate ($/MW-year) *(D)=(B)/(C)*	ΔTRB ($Million) *(E)*	ΔNZATRR ($Million) *(F)*	NZATRR/TRB *(G)=(B)/(A)*	ΔNZATRR/ΔTRB *(H)=(F)/(E)*
2023	5,852	698	7,501	93,113			11.9%	
2024	6,137	725	7,083	102,296	285	26	11.8%	9.1%
2025	6,573	797	7,460	106,855	435	73	12.1%	16.7%
2026	7,164	890	8,057	110,450	591	93	12.4%	15.7%

TRB: Transmission Rate Base; NZATRR: Net Zonal Annual Transmission Revenue Requirement; CP: Coincident Peak; ΔTRB: Year-over-year change in the TRB; ΔNZATRR: Year-over-year change in the NZATRR.
Source: https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates

PPL Electric is responsible for calculating the NSPL values for all customers in the PPL Zone. PPL Electric's customer NSPL values are based on the PPL Zone peaks between November 1st and October 31st (excluding holidays and weekends) of the prior year. PPL Electric calculates customer NSPL values by averaging each individual customer's interval usage data during each of the five PPL Zone peaks from the prior year ("Zonal 5CP"), as identified by PJM. Each customer's peak-load contribution value is then adjusted based on distribution line loss allocation and reconciliation factors. Distribution line loss allocations are based on the customer service level associated with their rate class. Reconciliation factor allocations are determined such that the sum of customer NSPL values equals the target load for NITS. PPL Electric aggregates the resulting NSPL values by LSE and submits those values to PJM on a daily basis.[4]

Figure 1, which consists of excerpts from postings on PPL Electric's website, demonstrates the procedure outlined in PPL M-2 for the two most recent years.[5] It is notable that PPL Electric's Zonal 5CP hours include both summer and winter days. Furthermore, PPL Electric's Zonal 1CP occurs in the summer in some years (e.g., 2024) while it occurs in the winter in other years (e.g., 2025).

[4] PJM OATT, Attachment M-2 (PPL Electric Utilities Corp.) - Determination of Capacity Peak Load Contributions, Network Service Peak Load and Hourly Load Obligations ("PPL M-2").
[5] Attachment M-2 is a section of PJM's Open Access Transmission Tariff that is accepted by FERC. Attachment M-2 outlines the process by which PPL Electric determines peak-load contributions for transmission and capacity customers.

Figure 1. PPL Electric Summary NSPL Statistics for the Last Two Years[6]

PPL Zone 2025 Metered Peaks
Used in development of the 1/1/26 to 12/31/26 Transmission Peak Load Contributions

	Peak Date	Peak Time (Hour Beginning)	Peak Time (Hour Ending)	Peak Load Value (MW)
TX	1/22/2025	800	900	7839.7
TX	1/23/2025	700	800	7481.4
TX	1/21/2025	800	900	7468.3
TX	6/24/2025	1700	1800	7365.5
TX	6/23/2025	1700	1800	7293.5
TX Target	1/22/2025	800	900	7839.7

Based on the PPL Zone Metered Peaks
Five PPL Zone Peaks from 11/1/24 to 10/31/25

Updated 2/2/26

PPL Zone 2024 Metered Peaks
Used in development of the 1/1/25 to 12/31/25 Transmission Peak Load Contributions

	Peak Date	Peak Time (Hour Beginning)	Peak Time (Hour Ending)	Peak Load Value (MW)
TX	7/16/2024	1500	1600	7255.5
TX	7/10/2024	1600	1700	7216.8
TX	7/9/2024	1400	1500	7137.0
TX	7/15/2024	1700	1800	7118.8
TX	1/17/2024	800	900	6953.4
TX Target	7/15/2024	1500	1600	7255.5

Based on the PPL Zone Metered Peaks
Five PPL Zone Peaks from 11/1/23 to 10/31/24

Updated 12/31/2024

Table 2 shows total annual NSPL values for PPL Electric's retail customers in the last 10 years. Since NSPL is an annual coincident peak load metric, changes in total NSPL are driven primarily by two factors: (i) weather; and (ii) structural load growth (positive or negative). A very cold winter day or a very hot summer day in the PPL Zone can increase the Zonal 1 CP (i.e., zonal peak load). Increase or decrease in baseline loads (e.g., more widespread adoption of air conditioning, electrification of heating, increasing adoption of electric vehicles) and/or energization of new load centers (e.g., data centers, industrial facilities) can also account for changes in Zonal 1CP.

[6] https://www.pplelectric.com/site/-/media/PPLElectric/At-Your-Service/Docs/General-Supplier-Reference-Information/2026/Attachment-2---2025-PJM-and-PPL-Zone-Peak-Load-Dates-for-PLC-Calcs.pdf
https://www.pplelectric.com/site/-/media/PPLElectric/At-Your-Service/Docs/General-Supplier-Reference-Information/2025/2024-PJM-and-PPL-Zone-Peak-Load-Dates-for-PLC-Calcs.pdf

Table 2. PPL Electric Retail NSPLs in the Last 10 Years

NSPL Effective Period	Total NSPL of PPL Electric's Retail Customers (MW)
1/1/2017-12/31/2017	6,664.5
1/1/2018-12/31/2018	7,016.0
1/1/2019-12/31/2019	7,270.0
1/1/2020-12/31/2020	7,520.1
1/1/2021-12/31/2021	6,858.1
1/1/2022-12/31/2022	7,120.0
1/1/2023-12/31/2023	7,110.1
1/1/2024-12/31/2024	6,727.3
1/1/2025-12/31/2025	7,097.8
1/1/2026-12/31/2026	7,666.6
Source: https://www.ppldsp.com/data	

It is important to recognize that the annual levels or changes in 1CP or 5CP do not change the NITS revenues to be collected by the transmission owners in the PPL Zone from transmission customers in the Zone. As shown in Table 1, Column D, the lower the Zonal 1CP, the higher the NITS rate, and vice versa. In other words, Zonal 1CP is a ratemaking construct that determines the NITS rate as an input to PPL Electric's FERC formula rate, while Zonal 5CP is a mechanism to allocate PJM NITS costs among customers and LSEs.

Interconnection of new CLEs typically requires transmission network upgrades. The transmission owner that is responsible for constructing these network upgrades includes the costs associated with constructing, operating, and maintaining these network upgrades in the PPL Zone's transmission rate base and NZATRR. Therefore, a prospective or new CLE increases the NZATRR, i.e., the "numerator" for the formula that determines the PPL Zone's NITS rate, which is paid by all (legacy and new) customers in the PPL Zone as an embedded cost rate. Once it is in service, a new CLE also increases the Zonal 1CP (i.e., the "denominator" for the formula that determines the PPL Zone's NITS rate) and the Zonal 5CP (which determines the share of NZATRR that will be allocated to each customer and/or LSE). The net effect of the integration of a new CLE on the NITS costs incurred by legacy customers depends on the difference between (i) the costs incurred by the transmission owner associated with constructing, operating, and maintaining network upgrades to interconnect a new CLE (i.e., the incremental NZATRR associated with interconnecting a new CLE); and (ii) NITS charges paid by the new CLE (or its LSE).

Table 3 shows the supplemental transmission network upgrade projects submitted by PPL Electric to PJM since 2024 that appear to be associated with interconnecting new CLE customers and for which PPL Electric provided solution cost estimates. The total final load-in-service associated with these 31 supplemental projects is 24,880 MW. This load growth from new CLEs is nearly three times the PPL Zone's most recent annual peak load

(approximately 7,800 MW in 2025). The general magnitude of these figures is confirmed in PPL Electric's CPTR Petition. In the CPTR petition, PPL Electric states that "[t]he current pipeline of advanced stage data centers in PPL Electric's service territory, which have signed agreements and will pay for project-related work even if the projects do not advance, totals approximately 31.8 GW by 2034."[7] In the same filing, PPL Electric also states that [t]he amount of load from those projects well-exceeds the Company's current peak demand of 7.8 GW, meaning that PPL Electric is preparing to more than triple its system demand in approximately 8 years—growth that took over a century to reach."[8]

The total solution cost identified by PPL Electric for these 31 supplemental projects is $3.6 billion. To put this cost magnitude in context, PPL Zone's 2025 transmission rate base is approximately $7.2 billion. As a generalized guiding principle, if the incremental NZATRR associated with interconnecting a new CLE is greater than the NITS charges assigned to that new CLE (or its LSE) in a given rate year, then that new CLE would be shifting NITS costs to legacy customers in that rate year. I note that a more detailed and comprehensive analysis of NITS ratemaking treatment of interconnection costs of new CLEs would need to be conducted to reach more definitive conclusions.

[7] CPTR Petition, paragraph 41.
[8] CPTR Petition, paragraph 42.

Table 3. PPL Electric's New CLE-Related Supplemental Projects in the Last Three Years

Need Number	2028 Load-in-Service (LIS) (MW)	Final LIS (MW)	Final LIS Year	Solution Cost ($Million)	Estimated NZATRR per 2028 LIS MW ($)*	Estimated NZATRR per Final LIS MW ($)*
PPL-2024-0001	540	1,275	2032	244.0	58,741	24,878
PPL-2024-0003	720	1,440	2031	196.6	35,488	17,744
PPL-2024-0004	0	1,000	2030	81.0	N/A	10,530
PPL-2024-0005	40	40	2025	17.8	57,688	57,688
PPL-2024-0006	100	100	2026	9.0	11,700	11,700
PPL-2024-0010	350	350	2028	117.8	43,754	43,754
PPL-2024-0011	0	350	2029	67.5	N/A	25,071
PPL-2024-0012	500	1,000	2030	73.3	19,058	9,529
PPL-2024-0017	400	1,000	2028	242.0	78,650	31,460
PPL-2024-0018	45	45	2026	2.5	7,222	7,222
PPL-2024-0019	50	50	2026	1.5	3,900	3,900
PPL-2025-0002	300	350	2028	141.0	61,100	52,371
PPL-2025-0003	960	1,980	2033	197.6	26,752	12,970
PPL-2025-0005	430	500	2029	73.5	22,221	19,110
PPL-2025-0006	450	1,000	2031	159.0	45,933	20,670
PPL-2025-0007	155	450	2030	89.0	74,645	25,711
PPL-2025-0008	300	600	2029	231.7	100,382	50,191
PPL-2025-0009	375	500	2029	13.5	4,680	3,510
PPL-2025-0010	700	1,000	2030	88.5	16,436	11,505
PPL-2025-0012	700	1,500	2030	186.9	34,705	16,196
PPL-2025-0013	200	1,200	2030	74.9	48,685	8,114
PPL-2025-0014	500	1,000	2031	220.0	57,200	28,600
PPL-2026-0001	200	1,500	2032	109.2	70,980	9,464
PPL-2026-0002	100	1,200	2033	76.5	99,450	8,288
PPL-2026-0003	75	1,500	2033	81.2	140,747	7,037
PPL-2026-0004	60	1,350	2032	130.6	282,967	12,576
PPL-2026-0013	290	290	2028	28.8	12,910	12,910
PPL-2026-0015	100	100	2028	65.4	85,020	85,020
PPL-2026-0016	60	60	2027	3.3	7,042	7,042
PPL-2026-0029	290	1,250	2031	408.0	182,897	42,432
PPL-2026-0037	0	900	2031	169.0	N/A	24,411

*Estimated assuming (i) 13% NZATRR-to-Solution Cost ratio; and (ii) customer's NSPL=LIS.
Source: Affidavit of Mr. Teti, Table 6.

An important consideration in assessing the cost effectiveness of interconnecting new CLEs on the legacy customers in the Zone is by how much a dollar of transmission plant investment (or addition to the transmission rate base) increases the NZATRR. In the last three years, the ratio of NZATRR to the transmission rate base in the PPL Zone averaged 12.1 percent while the ratio of the increase in the NZATRR to the increase in the transmission rate base averaged 13.8 percent.[9] I assumed this value to be 13 percent in my

[9] Source: Table 1.

calculations in Table 3. A more accurate estimate of incremental NZATRR, by year, for each supplemental project could be provided by PPL Electric in the course of a formal proceeding.

Another key assumption in Table 3 is that a new CLE customer's NSPL will equal its load-in-service target. As the NSPL falls below the load-in-service target, the benefit of adding a new CLE for legacy customers declines, turning negative below a threshold NSPL value for that new CLE customer. As I explain below, this is one of the issues that need to be addressed in PPL Electric's NITS cost allocation mechanism to prevent NITS cost shifts from new CLE customers to legacy customers.

F. Inadequacy of PPL Electric's Current NITS Cost Allocation Mechanisms in Preventing Cost Shifts

Under PPL Electric's existing NITS cost allocation mechanism (i.e., determination of customer NSPLs based on the Zonal 5CP construct), interconnection of a new CLE customer can raise NITS costs for legacy customers in a number of ways. First, the costs incurred by the transmission owner associated with constructing, operating, and maintaining network upgrades to interconnect a new CLE (i.e., but-for costs of integrating the new CLE) could be larger than the NITS charges that are projected to be paid by the new CLE (or its LSE) even under the assumption that the new CLE's contribution to the Zonal 1CP and to the Zonal 5CP (i.e., NSPL) would be at least as high as the final load-in-service request of (or the transmission and/or distribution service level requested by) the new CLE. This can happen due to very costly network upgrade requirements to interconnect a new CLE, a relatively low existing NITS rate, or a combination of these factors. However, cost shift from a new CLE to legacy customers could still happen even if the but-for cost of integrating the new CLE would be less than the NITS charges that would be projected to be paid by the new CLE (or its LSE) under the assumption that the new CLE's NSPL would be at least as high as the final load-in-service request of (or transmission and/or distribution service level requested by) the new CLE.

Second, if a new CLE customer were to never come online after the transmission owner incurs network upgrade costs to interconnect that new CLE, legacy customers would be left to pay for the increase in the NZATRR associated with such stranded investment indefinitely.

Third, if a new CLE were not to come online for multiple years after its network upgrade costs are included in the NZATRR, this incremental NZATRR would be borne by all other customers in the PPL Zone until the new CLE comes online or until the new CLE ramps up to its final load-in-service target. For example, the prospective CLE associated with the

supplemental project numbered PPL-2026-0003 in Table 3 is projected to reach 75 MW in 2028 and 1,500 MW in 2033. Assuming all network upgrade costs are included in the PPL Zone's transmission rate base and NZATRR for or before 2028, the project's incremental NZATRR would be larger than its NITS payments in 2028. As a result, there would be NITS cost shifts from this new CLE to legacy customers in 2028. This can create net financial harm to legacy customers due to the time value of money even if that new CLE starts generating benefits for legacy customers after 2033.

Fourth, if a new CLE were to come online but never reach its final load-in-service target, it would contribute less to the NZATRR than it was initially projected to do. In this circumstance, legacy customers would be saddled with the difference between the new CLE's but-for network upgrade costs and that new CLE's NITS payments year after year.

Fifth, a new CLE may come online and ramp up as projected, but it may go out of business and shut down its load center before the net present value of its NITS payments exceed its but-for interconnection costs. In that instance, that new CLE would contribute to the NZATRR for a period of time, but afterwards legacy customers would be left to pay for the increase in the NZATRR associated with such stranded investment indefinitely.

Sixth, and finally, a new CLE customer may come online and reach its load ramp targets on schedule but "manage" its NSPL to minimize its (or its LSE's) NITS charges by significantly reducing its load during Zonal 5CP hours. If a new CLE were to engage in NSPL management practices and successfully reduce its usage during Zonal 5CP hours to very low levels, this would have the effect of minimizing that new CLE's NITS payments and shifting most of its but-for network upgrade costs to legacy customers.

While Zonal 5CP hours are determined after the fact (after the reference year ends) and therefore cannot be perfectly forecasted, large and sophisticated customers (such as large CLEs) have resources at their disposal (e.g., in-house forecasting models, commercial services) to forecast many, if not all, of the Zonal 5CP days and hours in a given year. It is common practice among large and sophisticated customers to manage NITS costs through NSPL management. For example, in a blog post on its website, Constellation NewEnergy, Inc. states:[10]

> ***Strategies for Managing Peak Load Contributions***
>
> *Since annual capacity and transmission rates are based on consumption during peak-setting events, many businesses actively curtail (reduce) their demand at*

[10] Constellation NewEnergy Inc. is a retail electricity supplier affiliate of Constellation and an EGS registered with the Commission. See Retail Electricity Report, Activity Report 2024, p. 40. Available here: https://www.puc.pa.gov/media/3747/retail-elec-choice-report-2024-final.pdf. Published: December 2025. Accessed September 26, 2026.

those times to reduce costs. At Constellation, our Peak Load Management program notifies end users on a day-ahead and/or day-of basis of a potential capacity peak setting event. Consumers who choose to reduce their consumption may lower their capacity obligation for the following year.[11]

In its CPTR Petition, PPL Electric acknowledges the inadequacy of its existing tariffs and procedures in preventing NITS cost shifts from prospective and new CLEs to legacy customers:

> *PPL Electric recovers the costs of owning, operating, and maintaining its transmission system through its FERC-approved Transmission Formula Rate. Transmission upgrades constructed by PPL Electric and placed into transmission rate base increase the Formula Rate revenue requirement recovered from Load Serving Entities ("LSEs") taking transmission service in the PPL Zone. Under the existing allocation process, each LSE's share of these transmission costs is determined based on its customers' contribution to the PPL Electric system peak during the five coincident peak hours from the prior year. Although that process allocates transmission costs among LSEs based on peak load contribution, it does not provide PPL Electric with a mechanism to separately identify and assign to a particular retail rate class the transmission rate base investments required to serve that class. The proposed CPTR would provide that capability by allowing PPL Electric to segregate transmission rate base investments that the Company would not have made but for the interconnection of large load customers and directly assign the associated costs to the Rate LP-6 class, rather than recovering those costs from LSEs and their customers through the FERC-regulated allocation process.*

G. Alternative mechanisms to eliminate NITS cost shifting

As explained in the previous section, the existing NITS cost allocation mechanisms allow shifting of NITS costs from new CLE customers to legacy customers in the PPL Zone. Current rules and procedures associated with assigning NSPLs to customers/LSEs and/or allocating NITS costs should be modified to ensure that NITS costs are never unjustly and unreasonably shifted from new CLEs to legacy customers. This can be accomplished in a number of ways. Below I discuss some of the ways in which this objective can be achieved. The methods I discuss are not intended to be a comprehensive list of the ways in which such unjust and unreasonable cost shifts could be prevented.

[11] https://blogs.constellation.com/energy-management/guide-to-understanding-capacity-and-transmission-costs/. Published: March 27, 2025. Accessed September 26, 2026.

1. *Option 1: Minimum billing demand provisions that include a minimum NSPL + a NITS make-whole surcharge for the new CLE*

Option 1 has two components. As the first component, the CLE's minimum billing demand – as supported in the PUC's Large Load Model Tariff – would be further defined so that a new CLE would be assigned a minimum NSPL based on the contract demand stipulated in the ESA governing the establishment and provision of the new CLE's retail service. For example, the new CLE associated with PPL-2024-0010 in Table 3 has a final load-in-service target of 350 MW. Under Option 1, for each year, this new CLE's NSPL would be determined as the higher of 350 MW and the new CLE's average metered load during the Zonal 5CP hours. This would ensure that the new CLE would contribute at least 350 MW to the Zonal 5CP for a predetermined number of years (e.g., 20 years) starting with the year in which its but-for network upgrade costs are included in PPL Zone's transmission rate base, and thus in the NZATRR. This would effectively prevent cost shifting to legacy customers in the situation where new CLE customer that comes online and reaches its load ramp targets on schedule and "manages" its NSPL to minimize its (or its LSE's) NITS charges by significantly reducing its load during Zonal 5CP hours.

It is important to recognize that a minimum NSPL is not necessarily sufficient to eliminate the possibility of NITS cost shifting because but-for costs of integrating the new CLE could be larger than the NITS charges that would be paid by the new CLE (or its LSE) even with a minimum NSPL. In such circumstances, a second component as described below is needed to ensure that new CLEs do not shift NITS costs to legacy customers.

The second component of Option 1 is that if the new CLE is projected to shift NITS cost to existing customers even when it is assigned a minimum NSPL, then a level of NITS make-whole surcharge (either as an up-front payment or an annual payment) would be determined such that the combination of the NITS make-whole surcharge and the minimum NSPL would prevent shifting of NITS costs from the new CLE to legacy customers. The NITS make-whole surcharge can be part of the FERC jurisdictional PJM NITS rate determination (e.g., the surcharge would be a credit that would be included in the determination of the PPL Zone's NZATRR), or part of the Commission jurisdictional retail tariff (e.g., an ESA-mandated new CLE-specific non-bypassable charge). If the NITS make-whole surcharge is part of the Commission jurisdictional retail tariff, the electric distribution company ("EDC") (in this instance, PPL Electric) collecting such surcharge would return the collected amount to other retail customers via a revenue-neutral rate mechanism for the EDC. Under Option 1, the costs and risks associated with the cost shift scenarios described above would remain with the causer of those costs and risk; i.e., the new CLE.

2. *Option 2: A NITS make-whole surcharge for the new CLE*

The difference between Option 1 and Option 2 is that, rather than combining a minimum NSPL provision with a surcharge as in Option 1, Option 2 would entail only a NITS make-whole surcharge, without applying a minimum NSPL to the new CLE. The surcharge under Option 2 would typically be larger than the surcharge under Option 1, but both options would accomplish the same desired outcome: preventing the shifting of NITS costs and associated risks from new CLEs to legacy customers.

3. *Option 3: Assumption of PJM NITS charges by PPL Electric for all retail customers and a non-bypassable NITS charge*

Under PJM's settlement and billing procedures, each billing line item (e.g., energy, capacity, NITS) is assigned to a PJM member entity representing load (i.e., LSE). It is under the Commission's jurisdiction and authority to determine which PJM billing line items are to be assigned to which PJM member entities for retail electricity customers. For shopping customers, PJM billing line items are assigned either to PPL Electric (which recovers such PJM charges from retail customers via non-bypassable charges) or to the customers' Electric Generation Suppliers ("EGSs"). For default service customers, i.e., load not being served by an EGS, PJM billing line items are assigned either to PPL Electric or to the wholesale default service suppliers. Wholesale default service suppliers in the PPL Electric service territory are determined through default service auctions.

Under Option 3, PPL Electric would assume responsibility for NITS charges for all of its retail customers, and it would collect PJM NITS costs from retail customers via non-bypassable charges. Non-Commission-jurisdictional (wholesale) customers in the PPL Zone would continue to be allocated NITS cost responsibility assignments the same way as it is done today (i.e., through NSPLs based on the Zonal 5CP construct). The Commission would have exclusive jurisdiction over the determination of the rates for PPL Electric to recover its PJM NITS costs. In this scenario, EGSs (for shopping customers) and wholesale default service suppliers (for default service customers) would no longer be responsible for assuming PJM NITS charges on behalf of their corresponding retail customers/loads. This approach is currently being utilized in Ohio. Ohio Power Company's Basic Transmission Cost Rider; and Ohio Edison Company's, The Cleveland Electric Illuminating Company's, and The Toledo Edison Company's Non-Market-Based Services Riders are the retail tariff mechanisms through which these Ohio EDCs recover PJM NITS costs (and certain other non-market-based transmission and other costs) from all retail customers on a non-bypassable basis.

The advantage of Option 3 would be that the Commission could unilaterally determine the embedded and but-for NITS costs that should be assigned to new CLE customers and

effectuate that cost assignment through class cost of service and rate design proceedings that would fall under the Commission's exclusive authority and jurisdiction.

Creation of a retail tariff rate classification specifically for new CLE customers would facilitate more precise assignment of all NITS costs intended for new CLEs only to new CLE customers under Option 3. Furthermore, if the Commission adopts Option 3 or a variant of it, the Commission should also consider making new CLEs that are above a certain load threshold their own respective rate classifications to also prevent cost shifts between new CLEs. This is an approach currently in use in Idaho by Idaho Power Company, with an aggregate power requirements threshold of 20 MW for requiring special contract arrangements.[12]

I note that Option 3 is similar to the approach proposed in PPL Electric's CPTR Petition. The CPTR Petition needs to be studied and explored in greater detail, including its implementation details, through discovery and other means, to determine whether it will adequately prevent PJM NITS cost shifts from prospective and new CLEs to legacy customers under all circumstances. Critical topics that need to be addressed under a solution that entails a construct similar to Option 3, including PPL Electric's CPTR Petition, include, but are not limited to, determination of CLEs' but-for costs; whether CLEs would pay both their but-for costs and embedded costs (i.e., their share of existing NITS costs); state-jurisdictional NITS cost allocation mechanisms (to individual customers and/or customer classes); and transition mechanisms to prevent customers from paying duplicative NITS charges.

4. *Option 4: Expansion rate framework*

Option 4 entails the implementation of "expansion rate" policy, which is described in detail in the supplemental comments of FirstEnergy Service Company ("FirstEnergy Whitepaper"),[13] which were filed in FERC Docket No. RM26-4-000.[14] In summary, under an electric transmission expansion rate framework, a new CLE seeking transmission-voltage interconnection would enter into a long-term agreement with the host transmission owner.

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[12] Idaho Public Utilities Commission Tariff No. 30, General Rules, Regulations and Rates Applicable to Electric Service in the Territory Served from the Company's Interconnected System in Idaho, Rule C, Section 5. Available here (accessed on September 9, 2026): https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/General/0tariff/Idaho%20Power%20Company.pdf

[13] FirstEnergy Supplemental Comments, RM26-4 (Jun. 6, 2026), available here: https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20260605-5169&sid=247f6232-2ae0-44dd-a821-7ac2070e1660.

[14] Interconnection of Large Loads to the Interstate Transmission System, Notice Inviting Comments, Docket No. RM26-4-000 (Oct. 27, 2025) (the Commission issued the ANOPR following a directive from the Secretary of Energy pursuant to section 203 of the Department of Energy Organization Act); see also the full text of the proposed ANOPR, Ensuring the Timely and Orderly Interconnection of Large Loads, Advance Notice of Proposed Rulemaking, Docket No. RM26-4-000 (Oct. 23, 2025).

That agreement would be filed with and reviewed by FERC under the same just-and-reasonable standard applicable to other jurisdictional transmission arrangements. The agreement would obligate the new CLE to pay two distinct rate components: (i) the customer's standard pro-rata share of the existing zonal transmission rate, applying the same tariff structure applicable to all transmission customers within the zone; and (ii) an expansion rate specifically designed to recover the costs of the network upgrades required to support the interconnection, i.e., the but-for costs.[15]

In the OCA's Supplemental Comments in the same FERC docket,[16] the OCA agreed that the FERC need not change its transmission pricing policy to allow the use of an expansion rate policy by transmission owners in the context of new CLEs and supplemental projects.[17]

For legacy customers, Option 4 would represent the best alternative in terms of avoiding the NITS costs and risks associated with integrating new CLEs. Under Option 4, new CLEs would not only be directly assigned the but-for costs for their own interconnection to the transmission system, but they would also pay their fair share of embedded costs. This would be a fair and logical outcome because a new CLE would need to use both the existing transmission system and the new transmission expansion facilities that would not have been needed but for to integrate that new CLE to ensure safe and reliable delivery of capacity and energy from the entire interconnected grid. On the other hand, legacy customers would continue to receive safe and reliable delivery of capacity and energy from the entire interconnected grid in the absence of the new CLEs and the transmission expansion facilities that would not have been needed but for the new CLEs. Therefore, it would be unjust and unreasonable to assign any cost or risk associated with new CLEs' but-for transmission expansion facilities to legacy customers.

Creation of a retail tariff rate classification specifically for new CLEs would facilitate the fulfillment of the goal of preventing NITS cost shifts from new CLEs to legacy customers. It would also greatly enhance the process of assigning all NITS costs intended for new CLEs only to new CLEs under Option 4. Furthermore, if the Commission adopts Option 4 or a variant of the expansion rate framework, the Commission should also consider making new CLEs that are above a certain load threshold their own respective rate classifications to also prevent cost shifts between new CLEs.

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[15] FirstEnergy Whitepaper, p. 5.

[16] Joint Consumer Advocates Supplemental Comments, RM26-4 (Jun. 15, 2026), available here: https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20260615-5141&sid=247f6232-2ae0-44dd-a821-7ac2070e1660

[17] Joint Consumer Advocates Supplemental Comments, RM26-4 (Jun. 15, 2026) at 11-14.

VII. PJM Reliability Pricing Model Capacity Costs

A. PPL Electric's Current Method of Determining Customer Capacity Costs

The daily capacity (i.e., Locational Reliability) charge under PJM's RPM billed by PJM to an LSE serving load in PJM's PPL zone is the product of (i) the Final Zonal Capacity Price for the applicable Delivery Year; and (ii) the Daily Unforced Capacity ("UCAP") Obligation assigned by PPL Electric to that LSE. Capacity prices are typically published in dollars per megawatt per day ($/MW-day) of UCAP Obligation.[18] [19] Final Zonal Capacity Prices are determined and published by PJM after the Third Incremental Auction (typically in March, or 2-3 months before the start of the Delivery Year ["DY"]).[20] Final Zonal Capacity Prices are fixed for each DY, which runs from June 1st of a calendar year through May 31st of the subsequent calendar year.

Obligation Peak Load, or Capacity Peak-Load Contribution ("PLC") as it is more commonly referred to in the industry, is the peak load value on which LSEs' UCAP Obligations are based. Each PJM EDC (e.g., PPL Electric) is responsible for allocating its normalized previous summer's peak to each customer in the zone (both retail and wholesale). An LSE's PLC represents the summation of PLCs for each of an LSE's customers.[21]

PPL Electric is responsible for calculating PLC values for all customers in the PPL Zone.[22] PPL Electric's customer PLC values are based on the PJM Zone peak allocated to the PPL Zone between June 1st and September 30th of the prior year. PJM Peaks are measured between June 1st and September 30th (excluding holidays and weekends). PPL Electric calculates customer PLC values by averaging each individual customer's interval usage data during each of the five PJM Zone peaks ("PJM 5CP") from the prior year, as identified by PJM. Each customer's PLC value is then adjusted based on loss allocation and reconciliation factors. Loss allocations are based on the customer service level associated with their rate class. Reconciliation factor allocations are determined such that the sum of

[18] PJM Manual 18: PJM Capacity Market, Revision 62, Section 9.2.1, pages 211-212.
[19] Installed capacity, or ICAP, is the net capability of a generating unit. It is also the capability of the generating unit at the expected time of the PJM summer peak. (PJM Manual 21B, p. 26). Unforced capacity, or UCAP, is installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating. In summary, UCAP is a generation resource capability metric that results from the lower adjustment of the same generation resource's ICAP value by taking into account the rate of forced outages experienced by that generation resource.
[20] PJM Manual 18: PJM Capacity Market, Revision 62, page 249.
[21] PJM Manual 18: PJM Capacity Market, Revision 62, Section 7.4, pages 169-170.
[22] In various PPL Electric and PJM documents, PLC is also referred to as "Installed Capacity," "ICAP," and "ICAP PLC."

customer PLC values equals the target load for capacity. PPL Electric aggregates the resulting PLC values by LSE and submits those values to PJM on a daily basis.[23]

Figure 2, which consists of excerpts from postings on PPL Electric's website, demonstrates the customer and LSE PLC determination procedure outlined in PPL M-2 for the two most recent years. It is notable that nine of the ten PJM 5CP hours in the last two years occurred at hour ending 18 (5 pm to 6 pm) Eastern Time.

Figure 2. PPL Electric Summary PLC Statistics for the Last Two Years[24]

PJM 2025 Coincident Peaks
Used in development of the 6/1/26 to 5/31/27 Capacity Peak Load Contributions

	Peak Date	Peak Time (Hour Beginning)	Peak Time (Hour Ending)	Peak Load Value[2] (MW)
ICAP	6/23/2025	1700	1800	7454.3
ICAP	6/24/2025	1700	1800	7507.9
ICAP	7/29/2025	1700	1800	7294.3
ICAP	6/25/2025	1400	1500	7316.3
ICAP	7/28/2025	1700	1800	7061.8
ICAP Target[1]				7030.0

[1] Interruptioned Load Added Back and Weather Normalized
[2] Metered Load with Interruptions Added Back
Five Coincident PJM Peaks from 6/1/25 to 9/30/25 excluding Holidays and Weekends
Based on the PJM Summer 2025 Weather Normalized Coincident Peaks

Updated 2/2/26

PJM 2024 Coincident Peaks
Used in development of the 6/1/25 to 5/31/26 Capacity Peak Load Contributions

	Peak Date	Peak Time (Hour Beginning)	Peak Time (Hour Ending)	Peak Load Value[2] (MW)
ICAP	6/21/2024	1700	1800	6870.1
ICAP	7/15/2024	1700	1800	7126.7
ICAP	7/16/2024	1700	1800	7100.1
ICAP	8/1/2024	1700	1800	6785.4
ICAP	8/28/2024	1700	1800	6862.4
ICAP Target[1]	7/15/2024	1700	1800	6910.0

[1] Interruptioned Load Added Back and Weather Normalized
[2] Metered Load with Interruptions Added Back
Five Coincident PJM Peaks from 6/1/24 to 9/30/24 excluding Holidays and Weekends
Based on the PJM Summer 2024 Weather Normalized Coincident Peaks

Updated 12/31/2024

[23] PJM OATT, Attachment M-2 (PPL Electric Utilities Corp.) - Determination of Capacity Peak Load Contributions, Network Service Peak Load and Hourly Load Obligations ("PPL M-2").
[24] https://www.pplelectric.com/site/-/media/PPLElectric/At-Your-Service/Docs/General-Supplier-Reference-Information/2026/Attachment-2---2025-PJM-and-PPL-Zone-Peak-Load-Dates-for-PLC-Calcs.pdf

B. Effects of Prospective and New CLEs on Legacy Customers' Capacity Costs

The IMM reported that in the last four Base Residual Auctions ("BRAs") conducted by PJM (i.e., BRAs for the 2025/2026 DY, 2026/2027 DY, 2027/2028 DY, and 2028/2029 DY), capacity market revenues to capacity sellers (and therefore capacity market costs to load) for the PJM footprint totaled $63.6 billion. The IMM also reported that capacity market revenues would have been $34.3 billion, or 46 percent lower, in the same four BRAs if data center loads were excluded from those BRAs.[25] In other words, the inclusion of existing and planned data centers in PJM's forward capacity procurement target raised capacity costs to non-CLE legacy customers by 86 percent. The data center impacts described by the IMM are also apparent in the load forecast adjustments submitted by PPL Electric to PJM, as demonstrated in Table 4.

Table 4. PPL Zone Legacy Load and Large Load Adjustments in the Last Four BRAs

Delivery Year	Legacy Load* (MW) (A)	Load Adjustments** (MW) (B)	Zonal UCAP*** Obligation (MW) (C) = (A) + (B)
2025/2026	6,816	89	6,905
2026/2027	6,557	175	6,732
2027/2028	6,345	1,349	7,694
2028/2029	6,337	1,141	7,479

*Previous Year's Weather Normalized Coincident Peak Load is scaled by Zonal RPM Scaling Factor and Forecast Pool Requirement ("FPR") to arrive at the UCAP value.
**RPM Load Adjustment submitted to PJM by PPL Electric is scaled by Obligation Peak Load Scaling Factor and FPR to arrive at the UCAP value.
***UCAP: Unforced Capacity
Source: https://www.pjm.com/markets-and-operations/rpm (3rd Incremental Auction Results for 2025/2026 and 2026/2027; Base Residual Auction Results for 2027/2028 and 2028/2029).

Table 4 demonstrates that PPL Electric has been submitting large quantities of load forecast adjustments in the last two BRAs (for DY 2027/2028 and DY 2028/2029). Without these load adjustments, PPL Zone's UCAP requirements would have declined year-over-year in each DY from 2025/2026 through 2028/2029. However, PPL Electric's load forecast adjustment raised the PPL Zone's UCAP requirement by 1,359 MW (or 21 percent) for the 2028/2028 DY, and by 1,141 MW (or 18 percent) for the 2028/2028 DY above the UCAP requirement of the Zone's legacy load. As explained above, larger capacity procurement targets result in higher capacity prices for all customers.

https://www.pplelectric.com/site/-/media/PPLElectric/At-Your-Service/Docs/General-Supplier-Reference-Information/2025/2024-PJM-and-PPL-Zone-Peak-Load-Dates-for-PLC-Calcs.pdf

[25] Market Monitor Report, Members Committee Information Webinar, July 27, 2026, pages 4-5. Available here: https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2026/20260727-web/item-02---marketing-monitoring-report---presentation.pdf

If the new CLEs for which PPL Electric submitted these load adjustments do not contribute at least in the Load Adjustment amounts in Table 4 to the PPL Zone's total PLC in DY 2027/2028 or in DY 2028/2029, then legacy customers will be saddled with larger UCAP requirements and thus higher capacity costs, which in turn will amount to a cost shift from those new CLEs included in PPL Electric's Load Adjustment to legacy customers. PPL Electric also submitted load adjustments for the 2025/2026 and 2026/2027 DYs, but those load adjustments were more modest relative to the legacy load of the PPL Zone. Table 5 presents total PLC of PPL Electric's retail customers in the last 10 years.

Table 5. PPL Electric Retail PLCs in the Last 10 Years

PLC Effective Period	Total PLC of PPL Electric's Retail Customers (MW)
6/1/2017-5/31/2018	6,664.5
6/1/2018-5/31/2019	7,016.0
6/1/2019-5/31/2020	7,270.0
6/1/2020-5/31/2021	7,520.1
6/1/2021-5/31/2022	6,858.1
6/1/2022-5/31/2023	7,120.0
6/1/2023-5/31/2024	7,110.1
6/1/2024-5/31/2025	6,727.3
6/1/2025-5/31/2026	7,097.8
6/1/2026-5/31/2027	7,666.6
Source: https://www.ppldsp.com/data	

C. Background on PJM's Load Adjustment Process

PJM describes its load adjustment process as follows:

> ***Load Adjustments***
>
> *In cases where a zone has experienced or is anticipated to experience a significant load change that may not be captured in the load forecast, PJM may elect to apply a load forecast adjustment by either adjusting model inputs or by an explicit adjustment to the modeled forecast.*
>
> *In cases where the load change has not yet occurred, PJM will base any adjustment on information received from EDC load forecasters in response to PJM's annual request for details on large load changes that are known to the EDC. PJM will handle these requests on a case-by-case basis and perform (or have performed) whatever analysis is required to establish the degree of certainty and magnitude of the load change. Attachment B provides load forecast adjustment guidelines. PJM and the requesting EDC/LSE will produce documentation on and discuss load adjustments at the Load Analysis Subcommittee upon presentation of the annual load forecast.*[26]

[26] PJM Manual 19: Load Forecasting and Analysis, revision 39, page 14.

PJM's governing documents provide the following rights and roles for the Commission as the Relevant Electric Retail Regulatory Authority ("RERRA") for PPL Electric:

> ***Relevant Electric Retail Regulatory Authority Review***
>
> ◦ *The submitter must provide an opportunity to the Relevant Electric Retail Regulatory Authority (RERRA) to review and provide feedback before the load forecast adjustment is submitted to PJM in September. Time for review may vary, and the submitter should engage with the RERRA early in the process to agree upon what is sufficient time for review. In the event that the EDC/LSE covers multiple states, then this process should be engaged with each state.*
>
> ◦ *The RERRA's participation in the review is voluntary, and the submission, via the PJM-provided template, should indicate if the RERRA waived the opportunity (nonresponse from RERRA would could as waiving the opportunity). For instance, the RERRA may choose to point to overlapping regulatory processes that satisfy their review.*
>
> ◦ *The submission must indicate the date that the submitter provided the load forecast adjustment to the RERRA. The submission must indicate whether a meeting occurred and what feedback, if any, was offered by the RERRA. Submission must include verification from RERRA that the representation of their feedback is accurate. If the RERRA does not waive the opportunity, failure to provide RERRA feedback shall constitute an incomplete submission and may result in rejection or discounting.*
>
> ◦ *The submission is not required to conform to the RERRA's feedback, though the submission must provide both perspectives.*
>
> ◦ *PJM will disclose whether or not a RERRA review was conducted at the time of the Load Analysis Subcommittee where such submissions are presented, though PJM will not disclose the content of any feedback from the RERRA. The RERRA will have the opportunity to provide feedback at LAS.*[27]

D. Inadequacy of PPL Electric's Current Capacity Cost Allocation Mechanisms in Preventing Cost Shifts

Under PPL Electric's current capacity cost allocation mechanism (i.e., determination of customer PLCs based on the PJM 5CP construct), interconnection of a new CLE can raise capacity costs for legacy customers in a number of ways. First, if a new CLE that was included in the BRA load forecast as a load forecast adjustment from PPL Electric never comes online, legacy customers will be left to pay for the larger capacity requirement associated with the inclusion of such new CLE in the PPL Zone's capacity auction procurement target. Table 6 shows the PPL Zone capacity costs incurred exclusively for new CLEs (as indicated by PPL Electric to PJM in the form of a load forecast adjustment in the last four BRAs). If these prospective CLEs do not come online in time for PPL Electric to assign PLCs to them for the relevant DY, PPL Electric will scale up PLCs of legacy

[27] PJM Manual 19: Load Forecasting and Analysis, revision 39, page 28.

customers so that capacity procurement costs incurred for legacy customers *and* capacity procurement costs incurred for new CLEs are recovered from legacy customers.

Capacity procurement costs incurred exclusively for new CLEs amount to $8.7 million for the 2025/2026 DY; $21.0 million for the 2026/2027 DY; $164.7 million for the 2027/2028 DY; and $135.4 million for the 2028/2029 DY. It is notable that the vast majority ($300 million) of these costs belong to future DYs. The same issue is likely to continue arising in BRAs that will be conducted by PJM for the 2029/2030 DY and beyond. Therefore, if the Commission acts expeditiously, the Commission has an opportunity to significantly mitigate or completely eliminate potential capacity cost shifts from new CLE customers to legacy customers.

Table 6. PPL Zone Capacity Costs Attributable to New CLEs by PJM Delivery Year

Delivery Year	PPL Electric's Load Adjustments* (MW) (A)	PPL Zone Capacity Price ($/MW-Day) (B)	Capacity Cost Attributable to New CLEs ($Million) (C) = (A) * (B) * (365 or 366)
2025/2026	89	270.40	8.7
2026/2027	175	329.08	21.0
2027/2028	1,349	333.69	164.7
2028/2029	1,141	325.00	135.4

*From Table 4.
Source: https://www.pjm.com/markets-and-operations/rpm (3rd Incremental Auction Results for 2025/2026 and 2026/2027; Base Residual Auction Results for 2027/2028 and 2028/2029).

Second, if a new CLE were to come online but never reach its corresponding capacity requirement included in PPL Electric's load forecast adjustment for the applicable DY, then it would contribute less to the Zone's PLC than it was initially projected to do. In this circumstance, legacy customers would be saddled with the difference between the new CLE's but-for capacity costs and that new CLE's capacity payments for the relevant DY.

Third, a new CLE may come online and ramp up as projected, but it may go out of business and shut down its load center in the middle of the DY. In that instance, that new CLE would contribute to PPL Zone's capacity costs for a period of time, but afterwards legacy customers would be left to pay for that new CLE's share of capacity costs.

Fourth, and finally, a new CLE may come online and reach its load ramp targets on schedule but "manage" its PLC to minimize its (or its LSE's) capacity charges by significantly reducing its load during PJM 5CP hours. If a new CLE were to engage in PLC management practices and successfully reduce its usage during PJM 5CP hours to very low levels, this would have the effect of minimizing that new CLE's capacity payments and shifting most of its but-for capacity procurement costs to legacy customers.

While PJM 5CP hours are determined after the fact (after the applicable summer season ends) and therefore cannot be perfectly forecasted, large and sophisticated customers (such as large CLEs) have resources at their disposal (e.g., in-house forecasting models, commercial services) to forecast many, if not all, of the PJM 5CP days and hours in a given summer season. It is common practice among large and sophisticated customers to manage capacity costs through PLC management. For example, in a blog post on its website, Constellation NewEnergy, Inc. states:

> ***Strategies for Managing Peak Load Contributions***
>
> *Since annual capacity and transmission rates are based on consumption during peak-setting events, many businesses actively curtail (reduce) their demand at those times to reduce costs. At Constellation, our Peak Load Management program notifies end users on a day-ahead and/or day-of basis of a potential capacity peak setting event. Consumers who choose to reduce their consumption may lower their capacity obligation for the following year.*[28]

The actions of new CLEs that fall in any of the four scenarios identified above should be considered to have caused stranded generation investments. Therefore, the CLEs causing such stranded generation investments should pay the entire costs associated with such stranded generation investments. I note that the ways described above in which new CLEs would increase capacity costs for legacy customers do not include the fact that, as identified by the IMM, inclusion of existing and planned data center loads in BRAs have raised, and likely will continue to do so in future BRAs), capacity prices paid by all loads, including legacy loads.

E. Alternative mechanisms to eliminate capacity cost shifting

As explained in the previous section, the existing capacity cost allocation mechanisms allow the shifting of capacity costs from new CLEs to legacy customers in the PPL Zone. Current rules and procedures associated with assigning PLCs to customers and/or allocating capacity costs should be modified to ensure that capacity costs are never unjustly and unreasonably shifted from new CLEs to legacy customers. This can be accomplished in a number of ways. Below I discuss some of the ways in which this objective can be achieved. The methods I discuss are not intended to be a comprehensive list of the ways in which such unjust and unreasonable cost shifts could be prevented.

[28] https://blogs.constellation.com/energy-management/guide-to-understanding-capacity-and-transmission-costs/. Published: March 27, 2025. Accessed September 9, 2026.

1. *Option 1: A minimum PLC*

Under Option 1, a new CLE would be assigned a minimum PLC based on the contract demand stipulated in the ESA governing the establishment and provision of the new CLE's retail service. For example, if a new CLE was responsible for 100 MW of PPL Electric's load forecast adjustment for the 2027/2028 DY, this new CLE's PLC would be determined as the higher of 100 MW and the new CLE's average metered load during PJM 5CP hours (both adjusted by loss and reconciliation factors as necessary). This would ensure that the new CLE would contribute at least 100 MW to the PJM 5CP for the 2027/2028 DY.

2. *Option 2: A capacity make-whole surcharge for the new CLE*

Option 2 entails an annually determined capacity make-whole surcharge for each new CLE such that the capacity make-whole surcharge would prevent the shifting of the new CLE's but-for capacity costs to legacy customers. The capacity make-whole surcharge would be part of the Commission jurisdictional retail tariff (e.g., an ESA-mandated new CLE-specific non-bypassable charge). The EDC (in this instance, PPL Electric) collecting such surcharge would return the collected amount to other retail customers via a revenue-neutral rate mechanism for the EDC. Under Option 2, the costs and risks associated with the capacity cost shift scenarios described above would remain with the causer of those costs and risk; i.e., the new CLE.

3. *Option 3: Assumption of PJM capacity charges by PPL Electric for all retail customers and a non-bypassable capacity charge*

Under PJM's settlement and billing procedures, each billing line item (e.g., energy, capacity, NITS) is assigned to a PJM member entity representing load (i.e., LSE). It is under the Commission's jurisdiction and authority to determine which PJM billing line items are to be assigned to which PJM member entities for retail electricity customers. For shopping customers, PJM billing line items are assigned either to PPL Electric (which recovers such PJM charges from retail customers via non-bypassable charges) or to the customers' EGSs. For default service customers, i.e., load not being served by an EGS, PJM billing line items are assigned either to PPL Electric or to the wholesale default service suppliers. Wholesale default service suppliers in the PPL Electric service territory are determined through default service auctions.

Under Option 3, PPL Electric would assume responsibility for capacity charges for all of its retail customers, and it would collect the incurred capacity costs from retail customers via non-bypassable charges. Non-Commission-jurisdictional (wholesale) customers in the PPL Zone would continue to be allocated capacity cost responsibility assignments the same way as it is done today (i.e., through PLCs based on the PJM 5CP construct). The Commission would have exclusive jurisdiction over the determination of the rates through

which PPL Electric would recover its PJM capacity costs. In this scenario, EGSs (for shopping customers) and wholesale default service suppliers (for default service customers) would no longer be responsible for assuming PJM capacity charges on behalf of their corresponding retail customers/loads.

While a similar approach to Option 3 is currently being utilized in Ohio (e.g., Ohio Power Company's Basic Transmission Cost Rider; and Ohio Edison Company's, The Cleveland Electric Illuminating Company's, and The Toledo Edison Company's Non-Market-Based Services Riders) for PJM NITS costs, I am not aware of any electric retail choice jurisdiction in PJM that utilizes this approach to allocate capacity costs. Furthermore, while NITS is a non-market-based cost, capacity is a market-based cost. Therefore, Option 3 is less desirable for capacity costs than it would be for NITS (and other non-market-based) costs. Nevertheless, it is a mechanically viable alternative that would allow the Commission to ensure that new CLEs' but-for capacity costs are never shifted to legacy customers.

VIII. PJM Reliability Backstop Procurement Costs

A. Background

On July 31, 2026, PJM made a FERC filing proposing an RBP.[29] PJM's RBP proposal establishes a final RBP target based on the observed MW UCAP shortfall in the BRA for the 2028/2029 DY,[30] and any qualifying RBP offset UCAP MW.[31] For one time only,[32] it will procure RBP UCAP from RBP resources for a fixed term of up to 15 years, starting with the 2028/2029 DY and ending with the 2042/2043 DY.[33] PJM will serve as the counterparty that directly procures the RBP resources on behalf of buyers.[34] Load will be allocated responsibility in the form of RBP UCAP,[35] and it must post credit associated with the obligation.[36] RBP charges will be allocated to electric distributor zones/areas and further allocated to LSEs within the relevant zone/area.[37] PJM's RBP proposal requires states to assign the RBP costs to retail loads via the RBP obligation ("RBO"),[38] which is the state and/or RERRA-determined allocation of RBP UCAP MW to LSEs within each zone/area.[39] If

[29] PJM Interconnection, L.L.C., Reliability Backstop Procurement to Address Resource Adequacy Concerns Stemming From Large Loads, Docket No. ER26-3380-000 (F.E.R.C. filed July 31, 2026) ("PJM RBP FERC Filing").
[30] PJM RBP FERC Filing, p. 8.
[31] PJM RBP FERC Filing, p. 32.
[32] PJM RBP FERC Filing, p. 25.
[33] PJM RBP FERC Filing, p. 8.
[34] PJM RBP FERC Filing, p. 47.
[35] PJM RBP FERC Filing, p. 82.
[36] PJM RBP FERC Filing, p. 114.
[37] PJM RBP FERC Filing, pp. 96-97.
[38] PJM RBP FERC Filing, p. 11.
[39] PJM RBP FERC Filing, p. 98.

RBOs are not reported to PJM, PJM will allocate the RBO to all load in the zone/area base on LSE PLCs.[40]

PPL Zone's Initial RBP Target is 820.5 MW, or 12 percent of the overall PJM Initial RBP Target.[41] PJM proposes that the cost to load being allocated for RBP Charges not exceed $555/MW-day, on average, over the 15-year term.[42] If PJM procures 820.5 MW for the PPL Zone at $555/MW-day, the resulting cost responsibility for the PPL Zone on average will be $166.3 million per year,[43] or $2.5 billion over 15 years.[44]

PJM's RBP proposal places the responsibility of establishing RBO allocation rules on the Commission. To eliminate the possibility of shifting these costs from new CLEs to legacy customers in the PPL Zone, the Commission needs to act expeditiously and establish RBO assignment or cost allocation rules and procedures. What is at stake is the allocation of up to $2.5 billion in RBP capacity costs over 15 years, and the possibility that these costs will fall on PPL Zone's legacy customers, including households and small businesses, if the Commission fails to act and/or if the Commission does not get it right. I note that these RBP costs would be in addition to RPM capacity and other (e.g., energy, transmission, distribution) costs that have already been rising precipitously. Dr. Felder's Affidavit discusses rising PJM costs in greater detail and specificity.

On September 29, 2026, FERC issued an "Order Accepting Reliability Backstop Procurement and Establishing Further Procedures" in response to PJM's RBP Filing. In that order, FERC rejected the cost allocation proposed in PJM's RBP Filing and ordered modifications to it. Therefore, PPL Zone's Initial RBP Target is 820.5 MW, or 12 percent of the overall PJM Initial RBP Target, will be modified (higher or lower).

B. Mechanisms to eliminate PJM RBP cost shifting

Neither the Commission nor PPL Electric currently have protections in place to ensure that legacy customers do not get allocated any PJM RBP costs. This is due to the fact that RBO or RBP does not currently exist in PJM's markets and settlement systems. The Commission can ensure that no shifting of PJM RBP costs ever occurs from new CLEs to legacy customers in the PPL Zone in a number of ways.

Under PJM's settlement and billing procedures, each billing line item (e.g., energy, capacity, NITS, RBP) is assigned to a PJM member entity representing load (i.e., LSE). RBO will be a

[40] PJM RBP FERC Filing, p. 99.
[41] PJM RBP FERC Filing, Attachment C, paragraph 46.
[42] PJM RBP FERC Filing, Attachment C, paragraph 29.
[43] 820.5 MW x 555 $/MW-day x 365.25 days/year = $166,326,631.88
[44] $166,326,631.88/year x 15 years = $2,494,899.13

separate billing line item under PJM settlements, distinct from regular capacity charges. It is under the Commission's jurisdiction and authority to determine which PJM billing line items are to be assigned to which PJM member entities for retail electricity customers. For shopping customers, PJM billing line items are assigned either to PPL Electric (which recovers such PJM charges from retail customers via non-bypassable charges) or to the customers' EGSs. For default service customers, i.e., load not being served by an EGS, PJM billing line items are assigned either to PPL Electric or to the wholesale default service suppliers. Wholesale default service suppliers in the PPL Electric service territory are determined through default service auctions.

1. *Option 1: Assumption of PJM RBP charges by PPL Electric for all retail customers and a non-bypassable PJM RBP charge only for new CLE customers*

Under Option 1, PPL Electric would assume responsibility for PJM RBP charges for all of its retail customers, and it would collect the incurred PJM RBP costs only from new CLE customers via non-bypassable charges. The Commission would have exclusive jurisdiction over the determination of the rates through which PPL Electric would recover its PJM RBP costs. In this scenario, EGSs (for shopping customers) and wholesale default service suppliers (for default service customers) would not be responsible for assuming PJM RBP charges on behalf of their corresponding retail customers/loads. While Option 1 generally is not desirable for capacity cost allocation, it would be desirable in this instance (i.e., for PJM RBP costs) because PJM is proposing the RBP as a one-time procurement and RBP costs will cease to be market-based once the RBP is completed by PJM.

Creation of a retail tariff rate classification specifically for new CLEs would facilitate more precise assignment of all PJM RBP costs intended for new CLEs only to new CLEs under Option 1. Furthermore, if the Commission adopts Option 1 or a variant of it, the Commission should also consider making new CLEs that are above a certain load threshold their own respective rate classifications to also prevent PJM RBP cost shifts between new CLEs.

2. *Option 2: Retail tariff changes that prevent PJM RBP cost assignment to legacy customers*

Alternatively, the Commission could establish RBO assignment or PJM RBP cost allocation rules and procedures in related PPL Electric governing documents (e.g., tariff, rate schedules, ESAs, Supplier Coordination Tariff) that prohibit PPL Electric from assigning any PJM RBP costs to legacy customers, including residential and small commercial customers, under any circumstance. Dr. Frank A. Felder's Affidavit discusses this approach in greater detail and specificity.

Regardless of how the Commission resolves to protect legacy customers from unjustly and unreasonably incurring even a small share of PJM RBP costs, the Commission should also ensure that any RBP-related credit/collateral costs incurred by the EDC are also assigned exclusively to new CLEs. Additionally, the Commission should put in place PJM RBP cost allocation rules and procedures that ensure that RBP costs are never paid by legacy customers, including residential and small commercial customers, even if some original new CLE assignees of PJM RBP costs default on their obligations.

On September 29, 2026, FERC issued an "Order Accepting Reliability Backstop Procurement and Establishing Further Procedures" in response to PJM's RBP Filing. In that Order, FERC addressed jurisdictional matters and stated that "states have authority over how the wholesale costs of providing electricity, including transmission of such electricity to the retail customers, are recovered through retail rates," and that "[t]he PJM states have their own role to play [in allocation of RBP costs]." FERC's acceptance of PJM's RBP Proposal (conditioned on a revised cost allocation mechanism), and FERC's deference to states for allocating RBP costs assigned to each EDC to that EDC's retail customers, increases the urgency for the Commission to act in the matter of ensuring that PPL Electric's PJM-assigned RBP costs are allocated exclusively to CLEs, the exclusive causers of these costs.

IX. Default Service for New CLEs

It is my understanding that PPL Electric's obligation to provide electric generation supply service (i.e., default service) as the Default Service Provider in its service territory is governed by 66 Pa.C.S. § 2807(e)(3.1):

> *[I]f a customer contracts for electric generation supply service and the chosen electric generation supplier does not provide the service or if a customer does not choose an alternative electric generation supplier, the default service provider shall provide electric generation supply service to that customer pursuant to a commission-approved competitive procurement plan.*

PPL Electric also has the following legislatively-provided option to provide default service to large customers under 66 Pa.C.S. § 2807(e)(5)(i):

> *Notwithstanding paragraph (3.1), the electric distribution company or commission-approved alternative supplier may, in its sole discretion, offer large customers with a peak demand of 15 megawatts or greater at one meter at a location in its service territory any negotiated rate for service at all of the customers' locations within the service territory for any duration agreed upon by the electric distribution company or commission-approved alternative supplier and the large customer. The commission shall permit, but shall not require, an electric distribution company or commission-approved alternative supplier to provide service to large customers under this*

paragraph. Contract rates entered into under this paragraph shall be subject to review by the commission in order to ensure that all costs related to the rates are borne by the parties to the contract and that no costs related to the rates are borne by other customers or customer classes.

As described in the respective Affidavits of Dr. Felder and Mr. Hoyt, large CLEs have unique characteristics and introduce unique risks. In recognition of this fact, the Commission needs to establish rules governing PPL Electric's provision of default service to new CLEs that insulate legacy customers from the costs and risks of PPL Electric's provision of default service to new CLEs. The rules governing PPL Electric's provision of default service to new CLEs should address, at a minimum, the following:

- There should be minimum notice provisions (e.g., 12 months) for large CLE customers to voluntarily switch to default service.
- There should be minimum notice provisions (e.g., 12 months) for large CLE customers to exit default service.
- The socialization of costs between large CLE customers on default service and other default service customers, including legacy industrial customers on default service, should be prohibited.
- New CLE customers that opt to take default service should be served directly from the PJM spot market on a full pass-through basis.
- Loads of new CLE customers that opt to take default service should be settled by PPL Electric in (a) dedicated PJM settlement subaccount(s) segregated from all other PJM settlements of PPL Electric.
- PPL Electric should not be allowed to use its credit rating or utility-specific collateral to back dedicated subaccounts for new CLE customers on default service.
- If for some reason PPL Electric uses its credit rating or utility-specific collateral to back dedicated subaccounts for new CLE customers on default service, then such large CLE customers should pay the full value and cost of PPL Electric putting up its credit rating or collateral for the benefit of large CLE customers taking default service.
- If PPL Electric's credit/collateral requirements associated with being the LSE for the new CLE at PJM as the default service provider lead to higher borrowing requirements, higher borrowing costs, and/or credit rating downgrades for PPL Electric, the cost impacts of such outcomes should be borne directly by the new CLEs taking default service.
- RBP costs should not be included as a default service rate component that would be applicable to all customers within the large commercial and industrial default

service customer classification and should be limited in application to CLEs taking default service.

X. Cost Increases to Legacy Customers Due to Interconnection of Prospective and New CLEs

PPL Electric's legacy customers are already paying higher costs for electricity supply than they would have in the absence of recent influx of prospective and new CLEs across the PJM footprint. If regulatory action is not taken, legacy customers' electricity supply costs are likely to increase even more rapidly in the near future. In this section of my Affidavit, I discuss both existing and prospective cost increases to legacy customers in turn.

A. Ongoing harm to PPL's legacy customers from influx of CLEs

The sudden influx of CLEs in the PPL Zone and across the PJM footprint is putting upward pressure on legacy customers' electricity supply costs by raising PJM capacity, energy, and ancillary services prices as well as wholesale transmission rates.

To estimate the impact of CLEs (to which the IMM refers as data centers) on capacity revenues received by capacity sellers, which are by design equal to capacity charges paid by LSEs on behalf of customer loads, the IMM conducted scenario analyses and auction simulations that estimated total capacity costs that would have been incurred if CLEs were excluded from the BRAs conducted by PJM to date. The IMM publishes the results of its analyses in reports and presentations in PJM's stakeholder process. The IMM's analysis revealed that total PJM-wide capacity costs would have been lower by 63.5 percent for the 2025/2026 DY; by 45.1 percent for the 2026/2027 DY; by 39.6 percent for the 2027/2028 DY; and by 38.2 percent for the 2028/2029 DY if CLE loads were excluded from the BRAs conducted by PJM for these DYs.[45] Assuming that CLEs increased capacity costs to legacy customers by the same percentage for the PPL Zone as they did PJM-wide, PPL Zone capacity costs would have been lower by $432.8 million for the 2025/2026 DY; by $364.7 million for the 2026/2027 DY; by $372.1 million for the 2027/2028 DY; and by 338.9 million for the 2028/2029 DY if CLE loads were excluded from the BRAs conducted by PJM for these DYs. Summarily, the inclusion of prospective CLEs in the PPL Zone and across the PJM footprint in the capacity auctions (i.e., BRAs) already conducted by PJM increased RPM capacity costs to legacy customers in the PPL Zone by $1.5 billion in the four years between June 2025 and May 2029. Table 7 demonstrates the detailed calculations associated with this estimate.

[45] Source: Market Monitor Report, Members Committee Information Webinar, July 27, 2026, pages 4-5. Available here: https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2026/20260727-web/item-02---marketing-monitoring-report---presentation.pdf

Table 7. Impacts of CLEs on Capacity Costs for PPL Zone Legacy Load in the Last Four BRAs

Delivery Year	Zonal UCAP* Obligation (MW) (A)	PPL Zone Capacity Price ($/MW-Day) (B)	PPL Zone Capacity Costs ($Million) (C)=(A)*(B)*(365 or 366)	Without CLE, PJM-wide Capacity Costs Would Have Been Lower by (%)**: (D)	Without CLE, PPL Zone Capacity Costs Would Have Been Lower by ($Million): (E)=(D)*(C)
2025/2026	6,905	270.40	681.6	63.5%	432.8
2026/2027	6,732	329.08	808.6	45.1%	364.7
2027/2028	7,694	333.69	939.7	39.6%	372.1
2028/2029	7,479	325.00	887.1	38.2%	338.9

* UCAP: Unforced Capacity
** Source: Market Monitor Report, Members Committee Information Webinar, July 27, 2026, pages 4-5. Available here: https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2026/20260727-web/item-02---marketing-monitoring-report---presentation.pdf

The impacts of the upward pressure put on legacy customers' electricity supply costs by the sudden influx of CLEs by raising PJM capacity, energy, and ancillary services prices are also evident in the rising residential and small commercial fixed-price, full-requirements wholesale default service auction prices paid by PPL Electric (in its role as the default service provider for the PPL Electric service territory) in the last three years.[46] For the residential class, the average price for 12-month and 24-month full-requirements default service contracts increased from $63/MWh for the three auctions conducted between October 2023 and October 2024 (for delivery between December 2023 and November 2025) to $92/MWh for the four auctions conducted between February 2025 and July 2026 (for delivery between June 2025 and November 2028). The increase in residential default service auction prices between those two periods was $29/MWh (or 2.9 cents per kilowatt-hour), or 45 percent. For the small commercial class, the average price for 12-month and 24-month full-requirements default service contracts increased from $60/MWh for the three auctions conducted between October 2023 and October 2024 (for delivery between December 2023 and November 2025) to $83/MWh for the four auctions conducted between February 2025 and July 2026 (for delivery between June 2025 and November 2028). The increase in small commercial default service auction prices between those two periods was $23/MWh (or 2.3 cents per kilowatt-hour), or 40 percent. Table 8 presents the

[46] PPL Electric divides each customer class's (i.e., residential, commercial, industrial) default service load into a fixed number of slices, or "tranches." For example, residential default service load is divided into 40 tranches. Each tranche is a "slice" of load, meaning that each tranche incorporates the same residential load "shape," i.e., the hourly residential default service load profile over the course of the year. In other words, each tranche represents 2.5 percent of the residential load (possibly after it is offset by other purchases made by PPL Electric) in each hour. Each winning bid price for the fixed-price, full-requirements contracts, specified in dollars per megawatt-hour, is fixed for the duration of the contract term (either 12 or 24 months) and includes all generation products (with a few exceptions) required to serve load (e.g., energy, capacity, Alternative Energy Credits, and ancillary services).

details regarding PPL Electric's residential and small commercial fixed-price, full-requirements default service auction prices. The sharp increase in default service auction prices for serving residential and small commercial customers reflects rising PJM capacity, energy, ancillary services prices.

Table 8. PPL Electric Default Service Auction Prices for Residential and Small Commercial Classes

Customer Class:			Residential		Small Commercial	
Contract/Product Term:			12 Months	24 Months	12 Months	24 Months
Solicitation	Auction Date	Delivery Period Start Date	Average Auction Price ($/MWh)			
DSP V, Solicitation #6	10/10/2023	12/1/2023	63.27	N/A	58.74	N/A
DSP V, Solicitation #7	4/9/2024	6/1/2024	61.66	N/A	57.93	N/A
DSP V, Solicitation #8	10/1/2024	12/1/2024	65.10	N/A	61.84	N/A
DSP VI, Solicitation #1	2/25/2025	6/1/2025	90.77	87.04	83.81	80.60
DSP VI, Solicitation #2	7/29/2025	12/1/2025	89.54	91.53	81.72	82.70
DSP VI, Solicitation #3	2/24/2026	6/1/2026	92.78	94.33	81.91	83.93
DSP VI, Solicitation #4	7/28/2026	12/1/2026	93.71	95.86	84.43	86.03
Source: https://www.ppldsp.com/default-service-rfp						

While the default service auction prices presented in Table 8 determine (with some PPL Electric-specific adjustments) the generation service prices for default service customers (i.e., the Price-to-Compare, or PTC), and not shopping (i.e., EGS) customers, the increase in default service prices are also indicative of generation service price trends for shopping customers because EGSs rely on the same PJM capacity, energy, and ancillary services markets as PPL Electric's default service suppliers (i.e., default service auction bidders) for determination of their costs to serve residential and small commercial (as well as industrial) customers in the PPL Electric service territory.

It is likely that prospective and new CLEs are also already increasing NITS costs to legacy customers in the PPL Zone. Table 3 identifies 31 PPL Electric supplemental projects with respective final load in service dates between 2025 and 2033 and a total estimated network upgrade cost of $3.6 billion. To the extent that PPL Electric started construction for some of these supplemental projects and included such costs in its NITS rate base and revenue requirement, but the loads have not yet come online or started paying NITS charges, legacy customers are already paying higher NITS rates than they would have in the absence of these prospective or new CLEs. PPL Electric can provide further data and information to determine whether and/or the extent to which prospective and new CLEs have already begun raising NITS costs for legacy customers.

B. Prospective cost increases to legacy customers that would result from Commission inaction

In this Affidavit I have identified three categories in which costs to legacy customers would be higher due to but-for costs of interconnecting and serving prospective and new CLEs if action is not taken to protect legacy customers, including residential and small business customers: PJM NITS costs (Section VI); PJM RPM capacity costs (Section VII); and PJM RBP costs (Section VIII). In this section, I summarize potential cost implications for legacy customers from Commission inaction to prevent unjust and unreasonable cost shifts from prospective and new CLEs to legacy customers.

In Section VI, I demonstrated that PPL Electric has at least 24,880 MW in its CLE interconnection queue with an estimated transmission upgrade cost of at least $3.6 billion. I note that PPL Electric, in its CPTR Petition, estimates total peak load of prospective CLEs as 31,800 MW. In other words, $3.6 billion is a conservative estimate and it would be higher if PPL Electric provided solution cost estimates for all CLEs included in the 31,800 MW estimate. Assuming that one dollar transmission plant addition to the NITS rate base would raise NITS annual revenue requirement (NZATRR) by 13 cents, $3.6 billion in transmission network upgrades would increase the NZATRR by $468 million. These costs will be borne by legacy customers if they are not properly allocated or assigned to CLEs.

In Section VII, I demonstrated that PJM RPM capacity procurement costs incurred exclusively for new CLEs amount to $164.7 million for the 2027/2028 DY; and $135.4 million for the 2028/2029 DY, for an average annual cost of $150 million. These costs will be borne by legacy customers if they are not properly allocated or assigned to CLEs

In Section VIII, I demonstrated that If PJM procures the full 820.5 MW target for the PPL Zone at the procurement ceiling price, the resulting cost responsibility for the PPL Zone will be approximately $166 million per year. These costs will be borne by legacy customers if they are not properly allocated or assigned to CLEs.

The combined potential cost shift from prospective and new CLEs to legacy customers from NITS, RPM capacity, and RBP costs alone is $797 million annually. I note that this estimate of potential cost increases to legacy customers excludes cost increases in other categories, such as, but not limited to, higher energy costs as a result of interconnecting new CLEs without corresponding generation resource additions and higher capacity prices resulting from including prospective CLEs in PJM's load forecast and procurement target for BRAs (centralized RPM capacity auctions) as documented by the IMM.

I prepared Table 9 to put the $797 million per year in potential cost increases to legacy customers in perspective. In Calendar Year 2025, PPL Electric's operating revenues,

including, but not limited to, all billed revenues from the sale of electricity, i.e., distribution, transmission, default service charges, including state tax adjustment surcharge, and all other retail rider revenues, amounted to approximately $3.4 billion.[47] Since some of the NITS, RPM capacity, and RBP related cost increases will be passed through to PPL Electric's retail customers by way of EGSs in their role as LSEs for PPL Electric's retail customers in PJM, I also estimated annual operating revenues of EGSs from sales of generation service in the PPL Electric service territory and added it to PPL Electric's reported operating revenues to provide an apples-to-apples comparison. Adding estimated EGS operating revenues of $3 billion results in total estimated PPL Electric service territory operating revenues of $6.4 billion.

Table 9. 2025 Operating Revenues from Sales of Electricity to PPL Electric Retail Customers

Default Service Generation Sales to:	**Revenues ($)**	**Quantity Sold (kWh)**	**Average Rate ($/kWh)**
Residential	1,043,114,779	8,834,163,000	0.118
Commercial	229,820,958	2,049,183,000	0.112
Industrial	14,613,450	125,752,000	0.116
Public Street and Highway Lighting	1,311,043	11,333,000	0.116
Public Authorities	-	-	-
Total Default Service Generation Sales	1,288,860,230	11,020,431,000	0.117
Imputed EGS Generation Sales to:*	**Revenues ($)**	**Quantity Sold (kWh)**	**Average Rate ($/kWh)**
Residential	707,104,472	5,988,484,000	0.118
Commercial	1,344,955,771	11,992,207,000	0.112
Industrial	944,844,514	8,130,598,000	0.116
Public Street and Highway Lighting	6,152,057	53,180,000	0.116
Public Authorities	76,954	658,000	0.117
Imputed Total EGS Generation Sales	3,003,133,769	26,165,127,000	0.117
Imputed EGS Operating Revenues		$3,003,133,769	
PPL Electric Operating Revenues[48]		$3,410,113,414	
PPL Electric + EGS Operating Revenues		**$6,413,247,183**	
*Assumes class average EGS generation rate equals class average default service rate.			

A $797 million increase in total NITS, RPM capacity, and RBP costs alone would correspond to a 12.4 percent increase in total electric service costs to legacy customers. If other effects, such as higher energy and capacity costs attributable exclusively to prospective and new CLEs, were estimated and included, the percentage increase in costs for legacy customers due to Commission inaction would be even higher.

[47] Source: Electric Annual Report of PPL Electric Utilities Corporation for the Year Ended December 31, 2025 to the Commonwealth of Pennsylvania Public Utility Commission, Schedule 400 – Income Statement, p. 26, line 25.
[48] *Id*.

XI. Summary and Conclusions

PPL Electric's current tariffs and procedures, as they relate to allocation of PJM NITS, PJM RPM capacity, PJM RBP, and default service costs to customers, LSEs of customers, and/or rate classes, are deficient in preventing prospective and new CLEs from raising costs to legacy customers and the shifting of costs and risks from prospective and new CLEs to legacy customers. There are tools and authorities available to the Commission to mitigate or eliminate such unjust and unreasonable cost shifting possibilities. The Commission should initiate a proceeding to explore these deficiencies and best solutions to address them to ensure prospective and new CLEs do not further erode affordability for legacy customers.

Appendix D – Ogur Affidavit – Attachment A

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

SERHAN OGUR, Ph.D.

Dr. Ogur is a Principal of Exeter Associates, Inc. with 25 years of experience in the energy industry specializing in organized wholesale (Regional Transmission Organization / Independent System Operator) and retail electricity markets. Dr. Ogur's diverse background comprises energy management and consulting; analysis, design, and reporting of RTO electricity markets and products; and state and federal regulation of electric utilities.

Dr. Ogur's coursework in graduate school focused on Microeconomic Theory, Game Theory, and Industrial Organization. His doctoral dissertation investigates imperfect competition in deregulated wholesale electricity markets and oligopolistic competition between private and public generators.

Education

Ph.D. (Economics), 2007
Northwestern University

B.A. (Economics), 1996
Bogazici University, Turkey

Exeter Employment

2020-current	Principal and Vice President
2015-2020	Senior Economist

Previous Employment

2014-2015	Senior System Operator Fellon-McCord & Associates, LLC Louisville, KY
2005-2014	Senior Economist PJM Interconnection, LLC Audubon, PA
2001-2005	Economic Analyst Illinois Commerce Commission Springfield, IL

Professional Experience

Dr. Ogur's work at Exeter includes structuring and analysis of electricity supply contracts; utility rates and tariffs; energy markets and prices; power procurement; default electric service design; project evaluation; demand response opportunities; congestion hedging strategies; and price forecasting. He serves as the lead in wholesale power portfolio design, energy and capacity procurement, market analysis and forecasting, and risk management for the Northern California U.S. Department of Energy Labs' power consortium. He is a long-time electricity procurement consultant to the Defense Logistics Agency (DLA) Energy, advising and supporting DLA Energy's retail and wholesale, short-term and long-term, electricity supply procurement and contracting efforts for federal government sites across the country. Dr. Ogur supports state consumer advocate offices on design, procurement, and ratemaking issues in utility default service proceedings, and on consumer protection issues in public utility merger cases, by providing expert witness services.

Prior to joining Exeter, Dr. Ogur's responsibilities at Fellon-McCord encompassed overseeing and performing the daily tasks of the "24/7" wholesale electricity desk, including all aspects of scheduling, managing, and monitoring direct market participant load and generation assets (mostly in ISO/RTO markets) as well as their settlements and custom reporting. He was also in charge of developing strategies and making recommendations, through analytical, financial, and market research, for longer-term management of clients' load obligations and generation assets such as Auction Revenue Rights nominations; participation in energy, ancillary services, and capacity markets; load forecasting; energy, basis, and capacity price forecasting; hedging; and peak load management. Dr. Ogur also served as the company's lead analyst in various special consulting projects.

In PJM Interconnection's Market Strategy and Market Analysis departments, Dr. Ogur was responsible for analyzing and reporting on all PJM-administered electricity market products, including day-ahead and real-time energy, operating reserve, regulation, synchronized reserve, virtual transactions, financial transmission rights, capacity, demand response, energy efficiency, and renewables. He was part of the team that developed the protocols and business rules for participation of energy efficiency in PJM markets as well as a lead reviewer for energy efficiency plans and post-installation measurement and verification (M&V) reports for PJM's capacity market auctions. He also has training and experience in PJM's stakeholder management process.

Dr. Ogur's responsibilities at the Illinois Commerce Commission (ICC) included monitoring all Illinois-related developments under federal jurisdiction, mostly Federal Energy Regulatory Commission (FERC) filings and rulings concerning major Illinois electric public utilities. In addition, Dr. Ogur reviewed all actions concerning Illinois public utilities at the FERC level (applications to join RTOs, market-based rate authority filings, merger applications, transmission rate cases, etc.), and developed positions and official comments for the consideration of the ICC to file in the related FERC dockets. Dr. Ogur also filed written testimony and served as staff witness (including standing cross-examination) in the ICC dockets establishing auction-based competitive wholesale energy procurement mechanisms for major Illinois electric public utilities.

Sample Major Publications and Reports

- *New Hampshire Solicitation and Procurement of Default Energy Service*, prepared for the New Hampshire Department of Energy, March 2024 (with Matthew Hoyt, Olivia Kuykendall, Grace Koenig, and Cali Clark of Exeter Associates)

- *Review of the Non-Market-Based Services Riders Established by Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company and Associated Pilot Program*, prepared for the Public Utilities Commission of Ohio in response to Case No. 22-391-EL-RDR, July 2023 (with Matthew Hoyt, Ari Weissfeld, and Cali Clark of Exeter Associates)

- *Retail Supply and Standard Offer Service Reform for Maine*, prepared for Maine Office of the Public Advocate, February 2023 (with Steven Estomin, Matthew Hoyt, Olivia Kuykendall, Afton Hauer, and Cali Clark of Exeter Associates)

Expert Testimony

- Before the Pennsylvania Public Utility Commission, Docket No. P-2026-3062915, Pike County Light & Power Company, 2026, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

- Before the Pennsylvania Public Utility Commission, Docket No. P-2026-3060298, FirstEnergy Pennsylvania Electric Company, 2026, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

- Before the Federal Energy Regulatory Commission, Docket No. EC25-43, Constellation Energy Corporation, Constellation Energy Generation, and Calpine Corporation, 2025, on behalf of the Pennsylvania Office of Consumer Advocate. Affidavit addressed public utility merger and acquisition issues related to market concentration and horizontal market power.

- Before the Pennsylvania Public Utility Commission, Docket Nos. P-2024-3049357 and P-2024-3049357, Citizens' Electric Company of Lewisburg, PA and Wellsboro Electric Company, 2024, on behalf of the Pennsylvania Office of Consumer Advocate. Affidavit addressed default service issues.

- Before the Pennsylvania Public Utility Commission, Docket No. P-2024-3049343, UGI Utilities, Inc. – Electric Division, 2024, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

- Before the Pennsylvania Public Utility Commission, Docket No. P-2024-3048592, Duquesne Light Company, 2024, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

- Before the Pennsylvania Public Utility Commission, Docket No. P-2024-3047290, PPL Electric Utilities Corporation, 2024, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

- Before the Pennsylvania Public Utility Commission, Docket No. P-2024-3046008, PECO Energy Company, 2024, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

- Before the Pennsylvania Public Utility Commission, Docket No. P-2023-3039927, Pike County Light & Power Company, 2023, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

- Before the Pennsylvania Public Utility Commission, Docket Nos. A-2023-3038771 *et al*, Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company, 2023, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed public utility merger and acquisition issues.

- Before the Pennsylvania Public Utility Commission, Docket Nos. P-2021-3030012, P-2021-3030013, P-2021-3030014 and P-2021-3030021, Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company, 2022, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

- Before the Ontario Superior Court of Justice, In the Matter of Just Energy Group Inc. et al, Court File No. CV-21-00658423-00CL, 2021, on behalf of the *Donin and Jordet* Plaintiffs. Testified on overcharges by a retail electric supplier in a class action suit with plaintiffs in 11 states in the U.S.

- Before the Pennsylvania Public Utility Commission, Docket Nos. A-2021-3025659 and A-2021-3025662, Pike County Light & Power Company and Leatherstocking Gas Company, LLC, 2020, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed public utility merger and acquisition issues.

- Before the U.S. District Court for the District of New Jersey, Civil Action No. 3:17-cv-02680-MAS- LHG, 2021, on behalf of Janet Rolland, et al. Testified on systematic overcharges by a retail electric supplier in a class action suit with plaintiffs in eight states.

- Before the Pennsylvania Public Utility Commission, Docket No. P-2020-3022988, Pike County Light & Power Company, 2020, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

- Before the Pennsylvania Public Utility Commission, Docket No. P-2020-3019907, UGI Utilities, Inc. – Electric Division, 2020, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

- Before the Pennsylvania Public Utility Commission, Docket No. P-2020-3019522, Duquesne Light Company, 2020, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

- Before the Pennsylvania Public Utility Commission, Docket Nos. P-2020-3019383 and P-2020-3019384, Citizens' Electric Company of Lewisburg, PA and Wellsboro Electric Company, 2020, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

- Before the Pennsylvania Public Utility Commission, Docket No. P-2016-2534980, PECO Energy Company, 2016, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

- Before the Illinois Commerce Commission, Docket No. 05-0159, Commonwealth Edison Company, 2005, on behalf of the Staff of Illinois Commerce Commission. Testimony addressed default service design and competitive procurement issues.

- Before the Illinois Commerce Commission, Docket Nos. 05-0160, 05-0161, and 05-0162 (Consolidated), Central Illinois Light Company d/b/a AmerenCILCO, 2005, on behalf of the Staff of Illinois Commerce Commission. Testimony addressed default service design and competitive procurement issues.
- Before the Illinois Commerce Commission, Docket No. 02-0428, Central Illinois Light Company and Ameren Corporation, 2002, on behalf of the Staff of Illinois Commerce Commission. Testimony addressed competition issues in a utility merger case.

Affidavit of Serhan Ogur, Ph.D.

I, Serhan Ogur, (Affiant) being duly sworn (affirmed) according to law, depose and say that I am authorized to make this affidavit on behalf of the Pennsylvania Consumer Advocate and Office of Consumer Advocate (OCA), being the holder of a contract with the OCA that engaged my subject matter expertise, and have been authorized to make this affidavit on the Consumer Advocate's and OCA's behalf, and that the facts above set forth are true and correct to the best of my knowledge, information and belief, and I expect to be able to prove the same at any hearing hereof.

Signature of Affiant

10/1/2026
Date

Sworn and subscribed before me the date below:

Holly J. Finberg
Signature of Official Administering Oath

10/1/2026
Date

(My Commission Expires)

November 25, 2027

HOLLY J FINBERG
Notary Public - State of Maryland
Anne Arundel County
My Commission Expires Nov 25, 2027

Appendix E – Deupree Affidavit

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Office of Consumer Advocate	:	Docket No. C-2026-
v.	:	
PPL Electric Utilities Corporation	:	

AFFIDAVIT OF MICHAEL DEUPREE

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I. Witness Information

My name is Michael W. Deupree. I am employed by Acadian Consulting Group ("ACG") as a Senior Research Consultant. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

I began my professional career with the Staff of the Kansas Corporation Commission in 2008 while in graduate school conducting analyses of topics related to energy and the economy as a Research Assistant, eventually being promoted to a Research Analyst and later Senior Research Economist after graduation. I left the Kansas Corporation Commission to take a position with ACG in late 2011, where I have been promoted to positions of increasing responsibility since, including my current position which I started in Spring of 2025. While at ACG, my work has focused on supporting state consumer advocates and related retail ratepayers on issues involving utility class cost of service, revenue allocation, rate design, alternative regulation, and consumer protections within mergers and acquisitions by providing expert witness services.

I hold a Bachelor of Arts degree in Business Economics from Buena Vista University in Storm Lake, Iowa, and a Master of Arts degree in Economics from the University of Kansas in Lawrence, Kansas. Exhibit A provides my complete professional resume, including a listing of my publications, presentations, pre-filed expert witness testimony, expert reports, and expert legislative testimony.

II. Purpose of Affidavit

I have been retained by the Pennsylvania Office of Consumer Advocate ("OCA") to review the impact of PPL Electric Utilities Corporation ("PPL Electric") rates on low-income customers.

My affidavit addresses the overall affordability of PPL Electric's rates for electric service, since the assignment of interconnection costs related to new data center, artificial intelligence (hereafter, computational load entities or "CLEs") to all utility costs will increase the current unaffordable burden that is placed on low-income PPL electric customers.

The issues I identify with regard to PPL Electric's rates, and the impact of CLEs on these rates, can be refined and further explored with additional information. Such additional information can come from PPL Electric in response to formal discovery as well as supplemental legal, regulatory, market, and economic research. To that end, my Affidavit is intended to demonstrate that the status quo is unjust and unreasonable in light of the rapidly growing magnitude of new CLE interconnection requests in PPL Electric's service territory. My Affidavit is not intended to prescribe specific solutions to the issues and inadequacies that I identify, but rather to support a finding that the Commission should initiate a proceeding, with specific solutions proposed and arrived at as part of that proceeding.

III. Summary of Findings and Recommendations

As recognized by the Commission, electric utility customers in Pennsylvania are currently facing growing affordability concerns caused in part by growing rates for electricity. This is also true for PPL Electric, which has significant bill affordability problems facing its low-income customers. These concerns will only grow to the extent that new CLE development results in additional costs related to network interconnection within PPL Electric's service territory that are passed along to PPL Electric customers, including low-income residential customers. I therefore recommend that the Commission establish a process to ensure that network interconnection costs, and related costs associated with the provision of reliable service, are appropriately assigned to CLE customers going forward.

IV. Affordability of PPL Electric's Rates

The Commission recently created a Ratemaking Working Group ("RWG") to examine potential improvements to longstanding ratemaking processes, such as Return on Equity ("ROE"), transparency in rate case settlements and the methodology used to establish returns associated with Distribution System Improvement Charges ("DSIC").[1] In creating the RWG, the Commission recognized that utilities and consumers in both Pennsylvania and the country at large are currently confronting a rapidly changing landscape that has placed pressure on utility costs and contributed to a significant number of recently proposed rate increases.[2] As identified by the Commission itself, contributing factors include: persistent inflationary pressures, increased customer arrearages, supply chain constraints, infrastructure needs, electric reliability concerns, and CLE development.[3] The Commission premised the establishment of the RWG in part on the recognized growing affordability concerns among Pennsylvania utilities.[4]

A. Current Unaffordability of Utility Bills/Electric Bills

Even before accounting for the substantial additional electric demand and infrastructure costs associated with proposed CLE customers, electricity costs are already imposing a significant affordability burden on American households. Consumer Reports reported in July 2026 that residential electricity prices had increased steadily and had outpaced inflation since 2022, with federal data indicating a 7.3 percent increase in residential electricity rates between April 2025 and April 2026.[5] Consumer Reports further reported that, entering 2026, approximately one in six U.S. households was behind on its utility bills and that Americans could collectively owe approximately $25 billion in utility debt by the end of 2026.[6] The report also noted that 94.9 million electric utility customers received

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[1] PUC Press Release (September 10, 2026), "PUC Launches Review of Utility Ratemaking to Address Affordability, Transparency and Changing Economic Conditions."
[2] *Id.*
[3] *Id.*
[4] *Id.*
[5] Nicole Greenfield, *Inside the Energy Affordability Crisis: "We Will All Be Affected By This,"* Consumer Reports (July 23, 2026).
[6] *Id*.

final disconnection notices in 2024, with utilities ultimately disconnecting service to approximately 13.4 million households.[7]

The recent surge in CLE has exacerbated these concerns for ordinary ratepayers, as recognized by politicians both within and outside of Pennsylvania. In Executive Order 2026-05, Governor Shapiro argued that PJM capacity-market prices had "surged to record highs" and that CLE customers accounted for $29.4 billion, or 46 percent, of the capacity charges in the four most recent base-residual auctions. The Governor further recognized that new CLE development will require substantial investment in new generation, transmission, and distribution infrastructure, the cost of which may be borne by non-CLE customers without reforms. The Executive Order directs state agencies to take action to "prevent excessive energy cost increases from being passed on to residents of the Commonwealth" and to ensure that CLE customers bear an appropriate share of the costs associated with their extraordinary electric demand.[8] Likewise, the White House issued a "Ratepayer Protection Pledge" on March 4, 2026, calling on CLE customers to "build, bring, or buy all of the energy needed for building and operating data centers, paying the full cost of their energy and infrastructure, no matter what."[9]

The Commission's Vice Chair has also recognized the relationship between CLE growth and affordability concerns facing residential customers. In the Commission's proceeding addressing Large Load Customers, Vice Chair Kimberly Barrow supported requiring large-load customers to contribute to universal-service programs and stated that she would encourage electric distribution companies "to work toward a point where Large Load Customers are making volumetric contributions commensurate with the electric supply cost increases caused by their outsize demand."[10] The Vice Chair has also found that average residential electricity price in Pennsylvania rose 10.2%, from $0.171 to $0.188 per kWh, over the period March 2025 to March 2026.[11] The Vice Chair has attributed this price increase mainly to increases in the supply portion of customer's bills driven by many factors, including: interconnection delays, baseload generation retirements, and the increased need for high-voltage transmission infrastructure, all driven by new CLE demand requirements that are expected to place an additional 32 GW of demand requirements by 2030.[12] In connection with PPL's subsequent proposal to require large-load customers to contribute approximately $11 million toward residential low-income assistance programs, Vice Chair Barrow further recognized that "due to the rising costs associated with the growth of data centers, more customers are in need of assistance."[13]

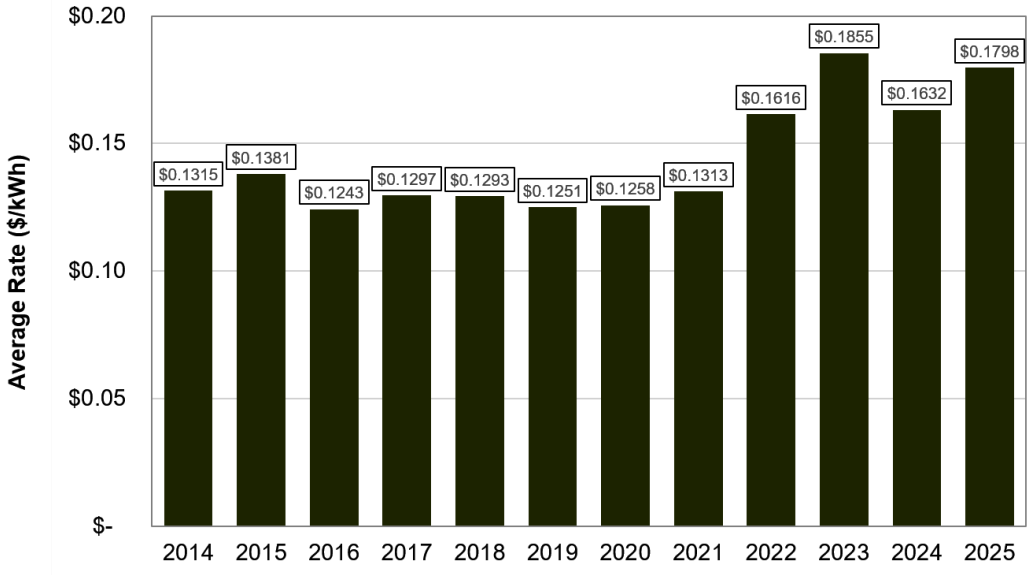
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[7] *Id*.
[8] Protecting Pennsylvania Consumers from Data Center Impacts, Exec. Order No. 2026-05, 56 Pa. Bull. 5898 (Sept. 5, 2026).
[9] "*Ratepayer Protection Pledge,"* White House Press Release dated March 4, 2026.
[10] *Interconnection and Tariffs for Large Load Customers*, Docket No. M-2025-3054271, Final Order, 56 Pa. Bull. 3271 (May 30, 2026) (statement of Vice Chair Kimberly Barrow).
[11] Vice Chair Kimberly Barrow, Pa. Pub. Util. Comm'n, *Prepared Testimony Before the Senate Democratic Policy Committee*, at 2 (June 23, 2026).
[12] *Id*.
[13] Statement of Vice Chair Kimberly Barrow, *Pa. Pub. Util. Comm'n v. PPL Electric Utilities Corp.*, Docket No. R-2025-3057164, at 2 (Oct. 23, 2025).

B. PPL Electric's Rates Over Time

As recognized by the Commission, electric utility rates have increased significantly across the State in recent years. This includes rates for electric service from PPL Electric, which have increased for all major customer classes over the past decade.[14] As shown in Figure 1, the average rate for PPL Electric service in 2025 was $0.1798 per kWh, representing a 36.7 percent increase since 2014, when the average rate for PPL Electric service was $0.1315 per kWh. Worse, nearly all of this increase has occurred in the last few years, 2021-2025. Specifically, rates for PPL Electric service have increased 36.9 percent since 2021, despite being stable for many years preceding these recent rate increases.[15]

Figure 1: PPL Electric Average Rate per kWh, 2014-2025



Source: EIA Form 861, Energy Information Administration

These rate increases have impacted all customer classes. As shown in Table 1, the average rate per kWh for PPL Electric's commercial customers in 2025 was $0.1557 per kWh.[16] This compared to an average rate for commercial service of $0.1318 per kWh in 2014, representing an 18.1 percent increase over 11 years.[17] Likewise, the average rate per kWh for PPL Electric's industrial customers in 2025 was $0.1370 per kWh, representing a 36.3 percent increase from the average rate of $0.1006 per kWh in 2014.[18]

[14] EIA Form 861, Energy Information Administration.
[15] *Id.*
[16] *Id.*
[17] *Id.*
[18] *Id.*

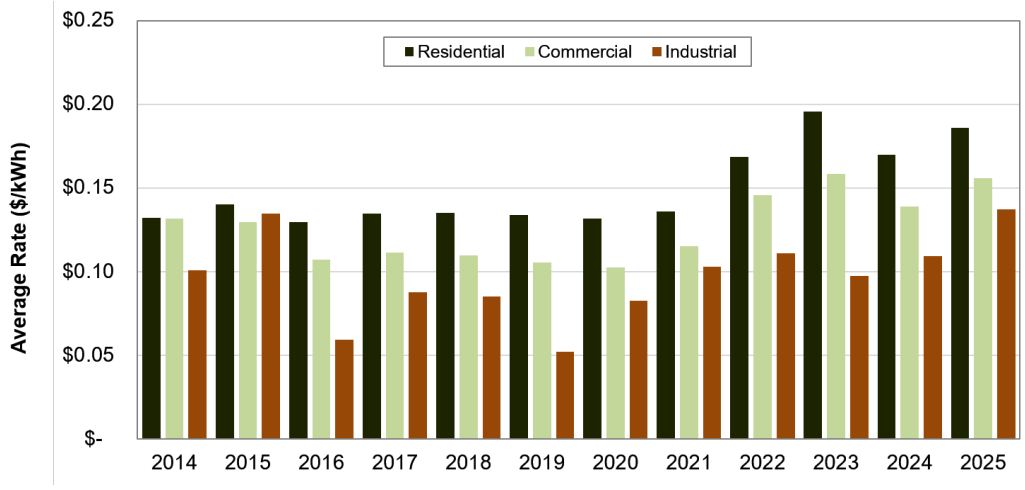
Table 1: PPL Electric Average Rate per kWh by Customer Class, 2014-2025

Year	Residential			Commercial			Industrial		
	Average Monthly Revenue ($000)	Average Monthly Sales (MWh)	Average Rate ($/kWh)	Average Monthly Revenue ($000)	Average Monthly Sales (MWh)	Average Rate ($/kWh)	Average Monthly Revenue ($000)	Average Monthly Sales (MWh)	Average Rate ($/kWh)
2014	$ 77,991	590,814	$ 0.1320	$ 17,291	131,231	$ 0.1318	$ 1,066	10,599	$ 0.1006
2015	82,327	587,718	0.1401	17,134	132,139	0.1297	1,020	7,583	0.1345
2016	78,001	602,744	0.1294	14,318	133,862	0.1070	712	12,012	0.0593
2017	80,796	599,665	0.1347	15,494	139,466	0.1111	884	10,114	0.0874
2018	88,705	657,099	0.1350	17,144	156,589	0.1095	1,233	14,473	0.0852
2019	91,267	682,910	0.1336	16,991	161,407	0.1053	1,901	36,490	0.0521
2020	93,598	710,337	0.1318	16,171	157,937	0.1024	962	11,647	0.0826
2021	101,068	743,710	0.1359	20,878	181,601	0.1150	1,731	16,823	0.1029
2022	132,101	783,546	0.1686	31,939	219,399	0.1456	4,390	39,527	0.1111
2023	129,068	660,329	0.1955	26,719	168,886	0.1582	2,151	22,137	0.0972
2024	115,083	677,351	0.1699	21,850	157,210	0.1390	1,412	12,911	0.1093
2025	136,923	736,188	0.1860	26,620	171,000	0.1557	1,436	10,480	0.1370

Source: EIA Form 861, Energy Information Administration

Rates for PPL Electric residential customers have likewise increased over the past decade. Specifically, the average electric rate for a residential electric customer of PPL Electric in 2025 was $0.1860 per kWh.[19] This is an increase of 40.9 percent over the similar average rate reported in 2014 of $0.1320 per kWh.[20] Worse, the vast majority of this increase has occurred in the last four years, with PPL residential customers seeing average rates increase 36.9 percent since 2021 alone ($0.1359 to $0.1860 per kWh).[21] This average increase of nearly 9.2 percent per year is unsustainable.

Figure 2: PPL Electric Average Rate per kWh by Customer Class, 2014-2025

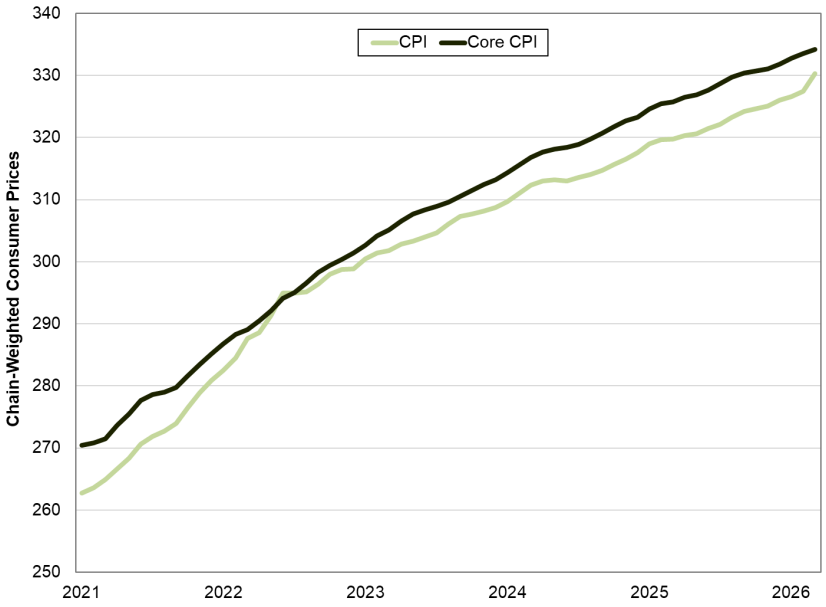


Source: EIA Form 861, Energy Information Administration

[19] *Id.*
[20] *Id.*
[21] *Id.*

The growth in electricity prices comes as costs for consumer goods and services in general have been increasing. The Consumer Price Index ("CPI"), a commonly used measure of changes in the prices of goods and services published by the U.S. Bureau of Labor Statistics ("BLS"), has continually increased since at least 2021. Over the period from January 2021 to January 2026, overall consumer prices increased 24.3 percent, while "core" consumer prices – which remove volatile energy and food prices – increased nearly 23.1 percent.[22]

Figure 3: Consumer Price Index



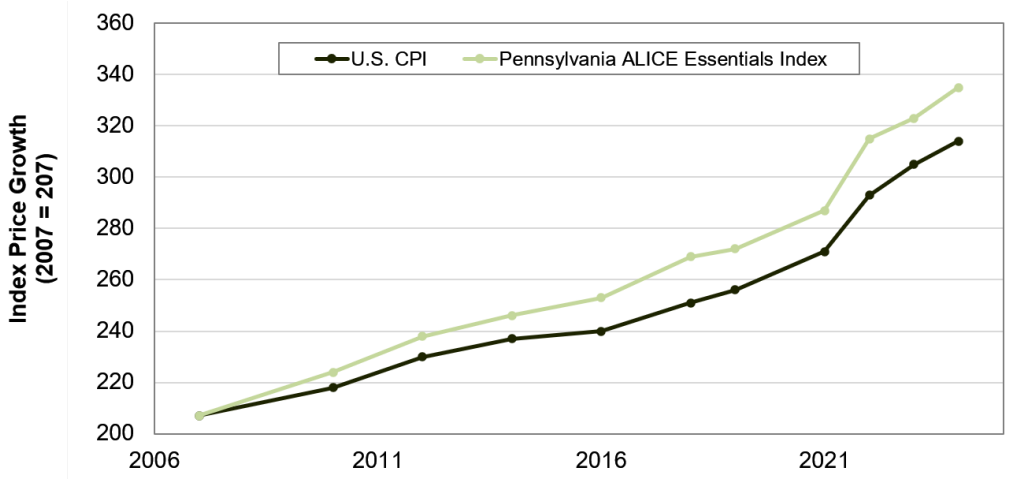
Source: Bureau of Labor Statistics

However, it should be recognized that CPI does not necessarily represent cost inflation for low-income households. Indeed, United For ALICE publishes an Asset Limited, Income Constrained, Employed ("ALICE") Essentials Index to reflect changes over time in the costs of household essentials.[23] Specifically, the ALICE index uses the same information measured by the BLS in its CPI, but reflects only costs associated with housing, childcare, food, transportation, health care, and basic technology.[24] By limiting the index to only these essentials, the ALICE index eliminates items included in the broader CPI that financially insecure low-income households can't afford on a regular basis like full-service meals at restaurants, major appliances, travel, and jewelry.[25] As shown in Figure 4, the ALICE index for Pennsylvania has grown faster than CPI over the last two decades. Specifically, the ALICE index has grown at an average annual growth rate of 5.3 percent over the period 2021-2024, which is faster than the already significant

[22] Bureau of Labor Statistics, CPI-U.
[23] United for ALICE, "The ALICE Essentials Index: Tracking Changes Over Time in the Cost of Basics."
[24] *Id.*
[25] *Id.*

5.0 percent average annual growth rate shown in CPI.[26] This indicates that costs for low-income Pennsylvanians have increased faster than costs for higher earning households.

Figure 4: Growth in Pennsylvania ALICE Essentials Index Compared to CPI



Source: United For ALICE, "The State of ALICE in Pennsylvania: Costs Over Time – The ALICE Essential Index," 2026.

Further, the affordability concerns facing Pennsylvania electric customers extend well beyond households officially classified as living in poverty. United Way's *State of ALICE in Pennsylvania: 2026 Update on Financial Hardship* reports that 27 percent of Pennsylvania households are ALICE (Asset Limited, Income Constrained, Employed), meaning that they earn above the federal poverty level but do not earn enough to afford the basic costs of living in their communities. When combined with households below the federal poverty level, approximately 39 percent of Pennsylvania households fall below the ALICE Threshold.[27] United Way's Pennsylvania ALICE research further recognizes that households below that threshold are forced, today, to make "impossible choices—like deciding whether to pay for utilities or a car repair, whether to buy food or fill a prescription."[28] These findings demonstrate that a substantial share of Pennsylvania households already lack sufficient financial capacity to absorb increases in basic household expenses, including utility costs, without sacrificing other necessities. That existing affordability constraint is directly relevant to the allocation of any additional costs associated with extraordinary new electric loads: even modest increases in residential electricity bills may impose material hardship on customers who already have little or no discretionary income. In light of these already existing concerns and the significant increase in projected load, the Commission should further investigate affordability for all customers, including whether the existing allocation of costs are reasonable and in the public interest.

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[26] United for ALICE, "The State of ALICE in Pennsylvania: Costs Over Time – The ALICE Essential Index," 2026.

[27] *The State of ALICE in Pennsylvania.*

[28] *The State of ALICE in Pennsylvania: 2025 Update on Financial Hardship*, at 1 (United Way of Pennsylvania 2025).

C. Unaffordability of PPL Electric Bills to Low-Income Customers

The Pennsylvania Utility Law Project ("PULP") claims that residential customers across all income levels face on average face a combined energy burden equal to approximately three to four percent of household income, with low-income households facing dramatically higher burdens, from seven to 33 percent, depending on income level.[29] These concerns are particularly relevant in the PPL Electric service territory, where PPL Electric itself acknowledges that rising energy-supply prices are "putting added pressure on household budgets and communities" and that energy supply constitutes nearly half of a residential customer's electric bill.[30] PPL Electric has also reported that more than 18,800 of its customers received over $6.5 million in LIHEAP assistance during the 2025-2026 assistance season, demonstrating the continuing need for bill assistance among customers in its service territory.[31]

Growth in PPL Electric rates is particularly problematic considering the persistent levels of poverty in Pennsylvania. The U.S. Department of Health and Human Services ("HHS") has established 2026 Federal Poverty Income Guideline ("FPIG") that result in an estimated threshold of $24,222 per year for an average household in PPL Electric's service territory.[32] As shown in Table 2, 327,875 people or 160,860 households in PPL Electric's service territory are estimated to be currently living at or below established FPIG thresholds. This estimate of poverty is expanded to 795,877 people or 373,547 households if the poverty threshold is expanded to include persons living in a household making less than 200 percent of the FPIG ($48,445 per year for an average household).[33] This expanded definition of poverty is important since many households with annual incomes greater than FPIG still experience recognized financial hardship. For example, Pennsylvania's Low Income Home Energy Assistance Program ("LIHEAP") is available for households making up to 150 percent of the FPIG.[34] Likewise, the state-wide ALICE Household Survival Budget associated with household essentials discussed earlier is is itself equal to approximately 200 percent of the FPIG.[35]

[29] Elizabeth R. Marx, Testimony Before the Pennsylvania House Consumer Protection, Technology, and Utilities Committee Regarding H.B. 1077, at 2 (Jan. 17, 2023).
[30] PPL Electric Utilities, Understanding Energy Supply Prices & Resource Adequacy.
[31] PPL Electric Utilities, *Application Window for Energy Bill Assistance Through LIHEAP Extended* (Apr. 8, 2026).
[32] Commonwealth of Pennsylvania, Federal Poverty Income Guidelines.
[33] American Community Survey, U.S. Census Bureau.
[34] *Id.*
[35] *Id.*

Table 2: Estimated Population Living in Poverty in PPL Electric Service Territory

Poverty-Level Range	Estimated Population
Below 50 percent	155,532
50 percent - 74 percent	76,801
75 percent - 99 percent	95,542
100 percent - 124 percent	105,132
125 percent - 149 percent	115,676
150 percent - 199 percent	247,194
Below 100 percent	**327,875**
Below 150 percent	**548,683**
Below 200 percent	**795,877**

Source: American Community Survey, U.S. Census Bureau.

Energy affordability reflects a fundamental household proposition in that it defines how expensive energy is relative to a household's income. Affordability, more generally, can be utilized as an index number to measure, among other things, the ability of a household to pay for essential utility services such as natural gas and electricity. Table 3 estimates the current electric bill burden for PPL Electric customers living at 50, 100, and 200 percent of the FPIG established earlier. I estimate that PPL Electric customers living at the FPIG currently have an electric bill burden equal to 5.7 percent.[36]

Table 3: PPL Electric Residential Bill Burden by Poverty Household Income Level

HHS Poverty Level	HHS Income Threshold	Estimated Households Below Threshold	Percent of Included Households	Estimated Annual Bill	Bill Burden at Threshold
50 percent	$ 12,111	66,513	5.3%	$ 1,289	10.6%
75 percent	18,167	111,727	8.8%	1,289	7.1%
100 percent	24,222	160,860	12.7%	1,383	5.7%
125 percent	30,278	212,040	16.8%	1,383	4.6%
150 percent	36,334	263,927	20.9%	1,383	3.8%
200 percent	48,445	373,547	29.6%	1,482	3.1%

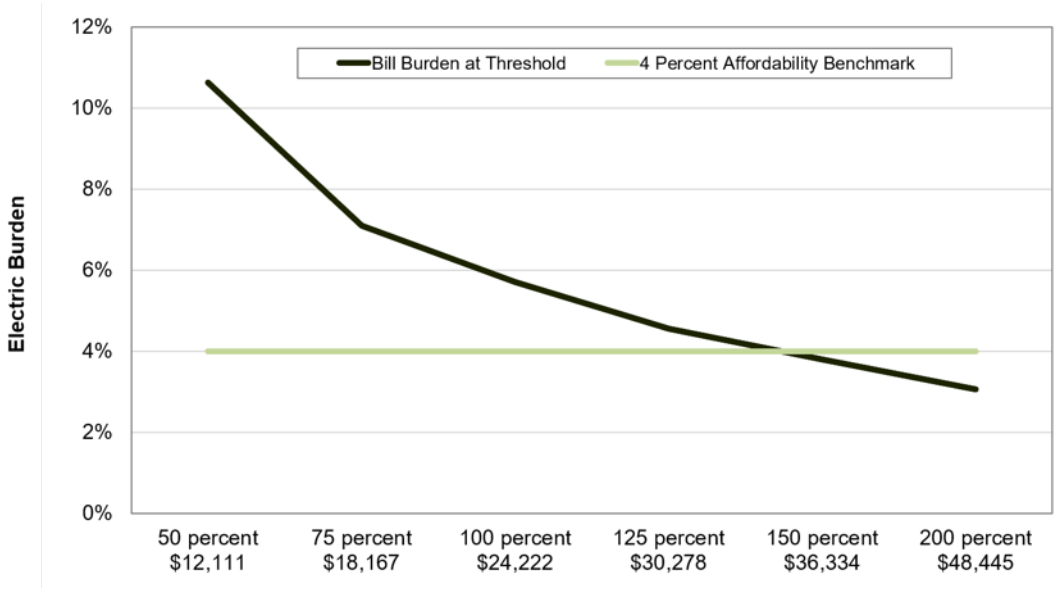
Source: Author's Analysis based on PPL Electric Tariffs and data from U.S. Census Bureau.

While there is no universal definition of "unaffordability," the most accepted and utilized threshold at which a customer's utility bills reach a level of significant burden is when the percentage of income spent on these services exceeds six percent.[37] This threshold comes from the Fisher, Sheehan, and Colton *Home Energy Affordability Gap Study* of

[36] Author's Analysis based on PPL Tariffs and data from U.S. Census Bureau.
[37] *See, Understanding Energy Affordability,* ACEEE (2015), page 2.

2011, which assumed that total shelter costs (including rent/mortgage expenses and all utilities) should not exceed 30 percent of income, and that 20 percent of shelter costs should be allocated to paying for natural gas and electric utility bills.[38] The Commission itself has established a threshold level for affordability in electric utility bills equal to four percent for non-heating households with incomes greater than 50 percent of the FPIG.[39] This is concerning because my estimates show that nearly 13 percent of all households in PPL Electric's service territory are estimated as having an electric burden of greater than five percent, which is above the Commission's established threshold level of unaffordability. Indeed, I find that more than 160,860 households in PPL Electric's service territory have an electric burden that is greater than the Commission's established threshold level of unaffordability.[40]

Figure 5: Estimated Residential Electric Burden by Income Level



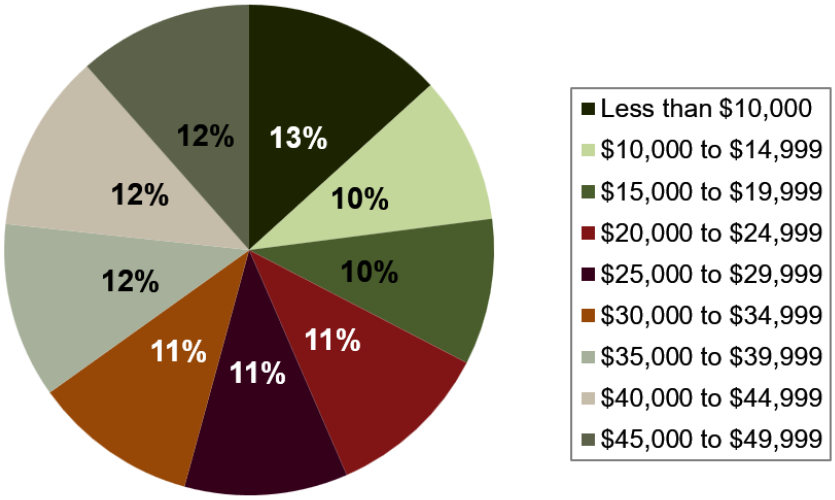
Source: Author's Analysis based on PPL Tariffs and data from U.S. Census Bureau.

Perhaps even more concerning is the distribution of low-income households in PPL Electric's service territory. Figure 6 shows the distribution of households making less than $50,000 a year in PPL Electric's service territory – which roughly equates to all households earning less than 200 percent of the FPIG and living in some level of poverty. Approximately 23 percent of these households make less than $15,000 a year, approximately half the FPIG for an average family in PPL Electric's service territory.[41] A

[38] Fisher, Sheehan, and Colton. *Home Energy Affordability in New York: The Affordability Gap 2008-2010,* June 2011, page 2.
[39] 52 Pa. Code Ch. 69.
[40] Author's Analysis based on PPL Electric Tariffs and data from U.S. Census Bureau.
[41] American Community Survey, U.S. Census Bureau.

full 43 percent of households in this income category make less than $25,000 a year, approximately the FPIG for an average family in PPL Electric's service territory.[42]

Figure 6: Distribution of PPL Electric Households Making Less Than $50,000 a Year



Source: American Community Survey, U.S. Census Bureau.

It should also be recognized that unaffordability concerns are distributed throughout PPL Electric's service territory. Table 4 compares household incomes for the bottom quintile (or bottom 20 percent of all customers) for each county in which PPL Electric operates, to the bill amount that would be required to represent an affordable burden of four percent of total household income. I find that the annual electric bill affordability deficit for these customers ranges from $109 per year in Bucks County, to $1,102 per year in Columbia County.[43]

[42] *Id.*
[43] *Id.*

Table 4: Excess Bill Over Affordable Bill for First Quintile Households

County	Estimated 20th Percentile Household Income	Estimated Annual Electric Bill	Affordable Annual Bill	Excess Bill Over Affordable Bill
Berks	$ 33,441	$ 2,140	$ 1,338	$ 803
Bucks	50,777	2,140	2,031	109
Carbon	29,766	2,140	1,191	950
Chester	56,172	2,140	2,247	-
Clinton	26,432	2,140	1,057	1,083
Columbia	25,952	2,140	1,038	1,102
Cumberland	42,408	2,140	1,696	444
Dauphin	32,362	2,140	1,294	846
Juniata	34,368	2,140	1,375	766
Lackawanna	26,249	2,140	1,050	1,090
Lancaster	41,351	2,140	1,654	486
Lebanon	34,488	2,140	1,380	761
Lehigh	34,544	2,140	1,382	758
Luzerne	26,644	2,140	1,066	1,074
Lycoming	28,037	2,140	1,121	1,019
Monroe	34,606	2,140	1,384	756
Montgomery	48,989	2,140	1,960	181
Montour	32,607	2,140	1,304	836
Northampton	39,581	2,140	1,583	557
Northumberland	27,001	2,140	1,080	1,060
Perry	37,594	2,140	1,504	636
Pike	37,823	2,140	1,513	627
Schuylkill	28,904	2,140	1,156	984
Snyder	31,800	2,140	1,272	868
Susquehanna	29,134	2,140	1,165	975
Union	34,281	2,140	1,371	769
Wayne	28,341	2,140	1,134	1,007
Wyoming	32,234	2,140	1,289	851
York	38,693	2,140	1,548	593

Source: American Community Survey, U.S. Census Bureau.

V. Role of Transmission Rates in Rates for Low Income Customers

Each load-serving entity ("LSE") in PJM Interconnection, LLC ("PJM") is billed charges for transmission-related costs within its region, or zone, based on rates for various services, the most notable of which is Network Integration Transmission Service ("NITS").[44] The NITS rate for each LSE, including PPL Electric, is established through

[44] Manual 27: Open Access Transmission Tariff Accounting, Section 5: Network Integration Transmission Service Accounting, PJM.

annual formula rate filings.[45] Therefore, costs associated with transmission network upgrades that are allocated to PPL Electric's zone for purposes of establishing NITS rates will be assessed to PPL Electric through the annual formula rate process.

As discussed in greater detail in Mr. Hoyt's Affidavit, interconnection of new CLEs typically requires additional transmission network upgrades. The costs associated with constructing, operating, and maintaining these network upgrades are included in PPL Electric's zonal transmission rate base for purposes of NITS, to the extent the network upgrades are allocated to PPL Electric's zone through this process. Importantly, development of zonal transmission rate base is a comprehensive process since the transmission system itself is an integrated system. This means that transmission upgrades need not be physically present within PPL Electric's zone for costs to be partially assigned to PPL Electric's zone – since transmission upgrades elsewhere in PJM may reduce transmission congestion in PPL Electric's zone and thus benefit PPL Electric's customers.[46] Likewise, the locating of a new CLE outside of PPL Electric's zone may require additional transmission network upgrades in PPL Electric's zone as upstream support for the CLE. In short, new CLEs requiring additional transmission network upgrades may place additional rate burdens on PPL Electric's retail customers, including low-income residential customers, even if the CLE in question is physically located elsewhere in Pennsylvania far from PPL Electric's service territory, or even elsewhere in PJM completely outside of Pennsylvania.

In its 2025 State of the Market Report, PJM's Market Monitor found that existing and forecast data center load is already having "a significant and irreversible impact" on energy and capacity markets in PJM.[47] Indeed PJM's Market Monitor describe its capacity market as currently displaying "clear warning signs for the capacity market and for PJM reliability."[48] PJM's Market Monitor found that these strains will continue to grow until the issues associated with the additions of large data center loads are addressed.[49] While PJM energy and capacity markets are separate from costs charged through NITS, it is clear that PJM's Market Monitor itself is indicating that the current rapid growth of CLEs is placing strains on its processes that are unsustainable and will result in escalated prices and increased reliability issues.

> Large data center load additions have already had a significant and irreversible impact that will be paid through May of 2028 **and will have additional significant impacts on other customers as a result of higher transmission costs, higher energy market prices and higher capacity market prices.**
>
> …

[45] *Id.*
[46] *See,* Regional Transmission Expansion Plan (RTEP), PJM.
[47] 2025 State of the Market Report for PJM (March 12, 2026), Independent Market Monitor for PJM, page 1.
[48] *Id.*
[49] *Id.*

> It is clear that continuing to simply accept the interconnection of large data center loads that cannot be served reliably because there is not adequate dispatchable capacity, **is not a reasonable path forward and is not an efficient or competitive market solution and is not a solution of any kind.** That path leads to continued shortfalls, increased reliability issues, continued maximum prices, and continued calls to abandon markets.[50]

In addition to impacting PPL Electric retail customer rates, including residential rates, transmission network upgrades assessed to PPL Electric through NITS will increase universal service program costs for PPL Electric in two additional ways. PPL Electric is currently required to provide bill credits through the Customer Assistance Program ("CAP") to the extent that rates for service meet the Commission's definition of unaffordability discussed earlier.[51] Increased rates for residential electric service will push more customers onto CAP assistance who previously did not qualify for such assistance. Likewise, existing customers receiving CAP assistance will see these credits increase to pay for the increased rates for service. The increased costs associated with the CAP program will be recovered from other residential customers through the Universal Service Rider ("USR"),[52] resulting in still further increased rates for electrical service.

The Commission itself in its Tentative Order regarding a model tariff for large load customers recognized the impact that the addition of CLEs will potentially have on universal service programs, and further sought comments "on whether there should be a required contribution to a utility's low-income program and whether the utility's hardship fund is the appropriate program and whether the amounts proposed are appropriate."[53]

> [W]e agree with CAUSE-PA and TURN that the addition of Large Load Customers has an impact on the rates all customers pay for electricity, especially in relation to capacity and transmission rates. As such, we proposed a requirement that Large Load Customers contribute to the utility's hardship fund annually, with the minimum amount to be contributed based on the Large Load Customer's peak demand.[54]

The Commission has also recognized that there is a strong need to protect ratepayers from unreasonable cost shifting that comes from the cost causation associated with CLE growth.[55] The Commission recognized that growth in CLE use raises broader affordability and universal-service concerns, requiring additional annual contributions to utility universal-service programs based on peak demand to offset these concerns.[56] This

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[50] 2025 State of the Market Report for PJM (March 12, 2026), Independent Market Monitor for PJM, pages 1-2, *emphasis added.*
[51] 52 Pa. Code Ch. 69.
[52] PPL Electric Utilities Corporation Tariff, "Universal Service Rider," Page No. 18.
[53] Interconnection and Tariffs for Large Load Customers, Docket M-2025-3054271, Order issued April 30, 2026 at 98.
[54] *Id.*
[55] *Interconnection and Tariffs for Large Load Customers*, Docket No. M-2025-3054271, Final Order, 56 Pa. Bull. 3271 (May 30, 2026), https://www.pacodeandbulletin.gov/secure/pabulletin/data/vol56/56-22/790.html.
[56] *Id*. at 128.

recognizes that larger CLE customers with greater peak demand requirements on the electrical system place greater rate hardships on low-income customers. However, at the same time, the Model Tariff appropriately leaves a number of consequential policy questions for future, including utility-specific tariff proceedings and further Commission consideration. In particular, the framework does not comprehensively resolve how computational large loads should contribute more broadly to hardship funds and/or share in the costs of universal-service programs.[57]

As part of the Settlement Agreement resolving issues included in the Company's last base rate case, PPL Electric established Rate Schedule LP-6, Large Load Interconnections. Rate Schedule LP-6 is applicable to all "large load (data center) customers" commencing service on or after October 1, 2025, with a peak electric demand of 50 MW or greater at a single facility, or 75 MW in aggregate among multiple facilities taking service within a 10-mile radius.[58]

Rate Schedule LP-6 recognizes the unique concerns CLE customers place on the utility system, and requires that all CLE taking service under the tariff to execute an Electric Service Agreement ("ESA") with PPL Electric governing the customer's interconnection and providing some protections for ratepayers,[59] including mitigation of risks associated with stranded costs.[60] $11 million of USR costs are also assigned to Rate Schedule LP-6 customers annually to help address the increase in customer costs from CLE customers.[61] Importantly, however, this $11 million in allocation of USR costs was based on an assessment of potential customer costs resulting from the influx of CLE customers in 2025, and likely has increased in the year since and will likely continue to increase in the future. The Commission has also acknowledged that the $11 million contribution is small relative to the forecasted short- and long-term rate impacts associated with data-center interconnections and that "due to the rising costs associated with the growth of data centers, more customers are in need of assistance."[62] As a result, the existing tariff is unjust and unreasonable, and it is important to establish an effective mechanism to address and prevent the imposition of additional USR funding requirements as computational needs continue to increase.

This USR Contribution should also be recognized as merely a stop-gap measure. First, access to hardship fund assistance requires that a customer already be in arrears for non-payment,[63] in other words the customer has already demonstrated an inability to pay for electric service. Prior to receiving assistance, the customer will be charged late payment fees while the utility will be required to finance non-payment of service. Secondly, as

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[57] *Id*. at 17, 29, 83, 106, and 114-116.
[58] PPL Electric Utilities Corporation Tariff, "Rate Schedule LP-6; Large Load Interconnections," at page no. 35C.
[59] *Id.* at page no. 35D.
[60] *Pennsylvania Public Utility Commission et al v. PPL Electric Utilities Corporation,* Docket Nos. R-2025-3057164, *et seq.*, Order dated June 4, 2026 at 102-103.
[61] *Id.,* at 221.
[62] Statement of Vice Chair Kimberly Barrow, *Pa. Pub. Util. Comm'n v. PPL Electric Utilities Corp.*, Docket No. R-2025-3057164, at 2 (Oct. 23, 2025).
[63] Utility Assistance Programs - Hardship Funds, Pennsylvania Public Utilities Commission.

stated earlier, new CLEs requiring additional transmission network upgrades may place additional rate burdens on PPL Electric's retail customers even if the CLE in question is physically located elsewhere in Pennsylvania far from PPL Electric's service territory, or even elsewhere in PJM completely outside of Pennsylvania. It is therefore important to ensure that ratepayers do not experience undue hardship from increased transmission investments required to support CLE interconnection rather than solely managing the effects of increasing unaffordable rates for electric service through hardship fund assistance.

> While the increasing cost of electric supply is not the subject of this proceeding, it nevertheless comprises a large percentage of customer bills and is therefore top of mind for electric distribution companies, PJM, this Commission, consumers and politicians. **We owe it to consumers to be hawkish on distribution rates.**[64]

It is also important to recognize that Rate Schedule LP-6 only addresses direct costs associated with interconnection with the transmission system. Transmission network upgrades are not charged directly to CLE customers through Rate Schedule LP-6 provisions. While PPL Electric recently filed a proposal with the Commission to implement a Customer Protection Transmission Rider ("CPTR"), the Company's proposal does not provide enough detail to show how the proposed mechanism would work as described.[65] In particular, PPL Electric has not clearly explained how it would define "but-for" costs under the CPTR mechanism or whether, and to what extent, the mechanism would adequately protect consumers.[66]

PPL Electric's CPTR Petition reflects a substantial increase in the large-load forecast underlying its current planning assumptions. The Petition states that the current pipeline of advanced-stage data centers in PPL Electric's service territory, representing projects that have signed agreements and will pay for project-related work even if the projects do not advance, totals approximately 31.8 GW by 2034. This 31.8-GW figure is significantly greater than the large-load forecasts relied upon in PPL Electric's most recent base rate case and as the Commission saw the forecast when it issued its order on June 4, 2026.

From an affordability perspective, PPL Electric's existing rate structure raises significant concerns regarding whether the costs and risks associated with large computational loads are being appropriately assigned to the customers that cause them. Specifically, the Company's existing rate schedules do not include a reasonably tailored classification of CLE customers, which creates the risk that costs reasonably allocated to these customers based on their unique cost of service – including unique load requirements, interconnection requirements, or impacts on the Company's ability to provide reliable

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[64] PA Public Utility Commission, et al. vs. PPL Electric Utilities Corporation, Docket Nos. R-2025-3057164, et al., Statement of Vice Chair Kimberly Barrow at 2, *emphasis added.*

[65] *Petition of PPL Electric Utilities Corporation for Approval of Its Non-Bypassable Customer Protection Transmission Rider, Elimination of Its Transmission Service Charge, Changes to Its Generation Supply Charges, Changes to Its Retail Tariff, and Changes to Its Electric Generation Supplier Coordination Tariff*, Docket No. P-2026-3065185, Petition (filed Sept. 14, 2026).

[66] *Id.*

service – will be assigned to other customers, resulting in other rate classes subsidizing CLE customers. This includes low-income and other financially vulnerable residential customers such as those on fixed incomes. This potential cost shifting warrants careful examination because many customers are already struggling to afford their electric bills, and imposing additional distribution costs on these customers could further erode affordability over time, placing an increasingly severe burden on all customers.

In my experience and review of affordability in the utility ratemaking context, I intend to conduct discovery and I anticipate finding that moderate and low-income households are unable to absorb any further increases and that both moderate and low-income customers in PPL's service territory do not have enough liquid assets to adjust to a landscape where data center costs are socialized to them by and through proposed mechanisms like CPTR, or without more of a USF offset or assistance.

VI. Summary and Conclusions

As recognized by the Commission, electric utility customers in Pennsylvania are currently facing growing affordability concerns caused in part of growing rates for electricity. This is also true for PPL Electric, which has significant bill affordability problems facing its low-income customers. These concerns will only grow to the extent that new CLE development results in additional costs related to network interconnection within PPL Electric's service territory that are passed along to PPL Electric customers, including low-income residential customers. I therefore recommend that the Commission establish a process to ensure that network interconnection costs, and related costs associated with the provision of reliable service, are appropriately assigned to CLE customers going forward.

Appendix E – Deupree Affidavit – Attachment A

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Spring 2025 – Present	Senior Research Consultant
Summer 2021 – Spring 2025	Research Consultant
Summer 2016 – Summer 2021	Research Associate
Winter 2011 – Summer 2016	Senior Research Analyst

Kansas Corporation Commission, Topeka, Kansas

Utilities Division

Summer 2011 – Winter 2011	Senior Research Economist

Research Division

Spring 2009 – Summer 2011	Research Analyst

Kansas Energy Council

Summer 2008 – Spring 2009	Research Assistant

PUBLICATIONS AND REPORTS

1. The challenges of the regulatory review of diversification mergers. With Dr. David E. Dismukes. *The Electricity Journal* 29 (2016) 8-14. (May 2016)

PROFESSIONAL AND CIVIC PRESENTATIONS

1. "Status and Future of Natural Gas Supply and Infrastructure" (2026). Prepared for the Michigan State University, Institute of Public Utilities (IPU) Grid School. April 14, 2026.

2. "Natural Gas Distribution" (2025). Prepared for the Louisiana State University, Center for Energy Studies, Energy Fundamentals 2025. June 24 and July 8, 2025.

3. "Development Trends, Issues, and Challenges with Clean Hydrogen Production" (2025). Prepared for the Michigan State University, Institute of Public Utilities, Annual Regulatory Studies Program. April 15, 2025.

4. "Status and Future of Natural Gas Supply and Infrastructure" (2025). Prepared for the Michigan State University, Institute of Public Utilities, Annual Regulatory Studies Program. April 8, 2025.

5. "Observed Impact of Formula Rate Plans Across the United States" (2024). Prepared for Arizona Corporation Commission Formula Rate Plan Workshop. October 3, 2024.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. Docket No. UE-260208. (2026). Before the Washington Utilities & Transportation Commission. *Washington Utilities and Transportation Commission v. Portland General Electric Company, GEM Sub LLC and PacifiCorp d/b/a Pacific Power & Light Company.* On Behalf of the Washington State Office for the Attorney General – Public Counsel Unit. Issues: Acquisition Evaluation.

2. Expert Testimony. Docket No. 26-001-U. (2026). Before the Arkansas Public Service Commission. *In the Matter of the Application of Entergy Arkansas, LLC for Approval of Changes in Rates for Retail Electric Service.* On Behalf of the Office of Arkansas Attorney General. Issues: Alternative Regulation, Cost of Service, Rate Design.

3. Expert Report. (2026) *Santee Cooper 2026 Electric System Cost of Service and Rate Design Review.* On Behalf of the South Carolina Department of Consumer Affairs. Issues: Cost of Service, Rate Design.

4. Expert Testimony. Docket No. 2026-61-G. (2026). Before the Public Service Commission of South Carolina. *In the Matter of Application of Piedmont Natural Gas Company, Inc. for an Authority of Rates and Charges.* On Behalf of the South Carolina Department of Consumer Affairs. Issues: Cost of Service, Rate Design.

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6. Expert Testimony. Docket No. R-2026-3060855. (2026). Before the Pennsylvania Public Utilities Commission. *Pennsylvania Public Utilities Commission v. Peoples Natural Gas Company.* On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Macroeconomy, Alternative Regulation, Regulatory Lag, Cost of Service, Rate Design.

7. Expert Testimony. Docket No. R-2025-3059430 (2026). Before the Pennsylvania Public Utility Commission. *Pennsylvania Public Utilities Commission v. UGI*

Utilities, Inc. – Electric Division. On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Macroeconomy, Cost of Service, Rate Design.

8. Expert Testimony. Docket No. 25-064-U (2026). Before the Arkansas Public Service Commission. *In the Matter of the Application of Black Hills Energy Arkansas, Inc. for Approval of a General Change in Rates and Tariffs.* On Behalf of the Office of Arkansas Attorney General. Issues: Cost of Service, Rate Design.

9. Expert Testimony. D.P.U. 26-50 (2026). Before the Commonwealth of Massachusetts Department of Public Utilities. *Petition of Boston Gas Company, doing business as National Grid, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Gas Service and Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General. Issues: Alternative Regulation, Cost of Service, Rate Design.

10. Expert Testimony. Docket No. R-2025-3059428. (2026). Before the Pennsylvania Public Utilities Commission. *Pennsylvania Public Utilities Commission v. National Fuel Gas Distribution Company.* On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Macroeconomy, Alternative Regulation, Regulatory Lag, Cost of Service, Rate Design.

11. Expert Testimony. Docket No. R-2025-3059523. (2026). Before the Pennsylvania Public Utilities Commission. *Pennsylvania Public Utilities Commission v. UGI Utilities, Inc. – Gas Division.* On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Macroeconomy, Alternative Regulation, Regulatory Lag, Cost of Service, Rate Design.

12. Expert Testimony. Docket No. 2025-325-E. (2026). Before the Public Service Commission of South Carolina. *In the Matter of the Application of Dominion Energy South Carolina, Inc. for Authority to Adjust and Increase its Retail Electric Rates and Charges.* On Behalf of the South Carolina Department of Consumer Affairs. Issues: Cost of Service, Rate Design, Alternative Regulation.

13. Expert Testimony. Docket No. 2025.09.072. (2026). Before the Public Service Commission of the State of Montana. *In the Matter of the Application of Montana-Dakota Utilities Co. for Authority to Establish Increased Rates for Electric Service.* Of Behalf of the Montana Consumer Counsel. Issues: Cost Trackers, Cost of Service, Rate Design.

14. Expert Testimony. Case Nos. 25-0594-WW-AIR and 25-0595-WW-ATA. (2026). Before the Public Utilities Commission of Ohio. *In the Matter of the Application of Aqua Ohio, Inc. to Increase its Rates and Charges for its Waterworks Service.* On Behalf of the Staff of the Public Utilities Commission of Ohio Rates and Analysis Department, Regulatory Service Division. Issues: Cost of Service, Rate Design.

15. Expert Testimony. Case No. 25-0593-ST-AIR. (2026). Before the Public Utilities Commission of Ohio. *In the Matter of the Application of Aqua Ohio Wastewater,*

Inc. to Increase Rates for Sewer Service. On Behalf of the Staff of the Public Utilities Commission of Ohio Rates and Analysis Department, Regulatory Service Division. Issues: Cost of Service, Rate Design.

16. Expert Testimony. Docket No. UG-250610. (2026). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission v. Northwest Natural Gas Company.* On Behalf of the Washington State Office of the Attorney General Public Counsel Unit. Issues: Cost of Service, Rate Design.

17. Expert Testimony. D.P.U. 25-85. (2025). Before the Commonwealth of Massachusetts Department of Public Utilities. *Petition of Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00 for Approval of a General Increase in Base Distribution Rates for Gas Service and a Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General. Issues: Cost Benchmarking.

18. Expert Testimony. Docket No. 2025-172-E. (2025). Before the Public Service Commission of South Carolina. *In the Matter of: Application of Duke Energy Carolinas, LLC for Authority to Adjust and Increase its Electric Rates and Charges.* On Behalf of the South Carolina Department of Consumer Affairs. Issues: Cost of Service, Rate Design, Alternative Regulation.

19. Expert Testimony. Docket No. 2025-154-E. (2025). Before the Public Service Commission of South Carolina. *In the Matter of: Application of Duke Energy Progress, LLC for Authority to Adjust and Increase its Electric Rates and Charges.* On Behalf of the South Carolina Department of Consumer Affairs. Issues: Cost of Service, Rate Design, Alternative Regulation.

20. Expert Testimony. Cause No. 46258. (2025). Before the Indiana Utility Regulatory Commission. *Petition of Indianapolis Power & Light Company D/B/A AES Indiana ("AES Indiana") for Authority to Increase Rates and Charges for Electric Utility Service Through a Phase-In Rate Adjustment; and For Approval of Related Relief, Including (1) Revised Depreciation Rates, Including Cost of Removal Less Salvage and Updated Depreciation Expense; (2) Accounting Relief, Including Deferrals and Amortizations, (3) Inclusion of Capital Investment, (4) Rate Adjustment Mechanism Proposal, Including a New Propoerty Tax Rider, and (5) New Schedules of Rates, Rules and Regulations for Service.* On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Cost of Service, Rate Design.

21. Expert Testimony. Docket Nos. R-2025-3055010, R-2025-3055011, and R-2025-3055012. (2025). Before the Pennsylvania Public Utilities Commission. *Pennsylvania Public Utility Commission v. The Pittsburgh Water and Sewer Authority d/b/a Pittsburgh Water.* On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Alternative Regulation, Regulatory Lag.

22. Expert Testimony. Docket No. G-04204A-24-0237. (2025). Before the Arizona Corporation Commission. *In the Matter of the Application of UNS Gas, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of UNS Gas, Inc. Devoted to its Operations Throughout the State of Arizona and for Related Approvals.* On Behalf of the Staff of the Arizona Corporation Commission. Issues: Cost of Service, Rate Design.

23. Expert Testimony. Docket No. R-2025-3054394. (2025). Before the Pennsylvania Public Utilities Commission. *Pennsylvania Public Utility Commission v. Citizens' Electric Company of Lewisburg.* On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Cost of Service, Rate Design.

24. Expert Testimony. Docket No. R-2025-3054393. (2025). Before the Pennsylvania Public Utilities Commission. *Pennsylvania Public Utility Commission v. Valley Energy, Inc.* On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Cost of Service, Rate Design.

25. Expert Testimony. Docket No. R-2025-3054392. (2025). Before the Pennsylvania Public Utilities Commission. *Pennsylvania Public Utility Commission v. Wellsboro Electric Company.* On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Cost of Service, Rate Design.

26. Expert Testimony. Docket No. R-2025-3053499. (2025). Before the Pennsylvania Public Utilities Commission. *Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc.* On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Decoupling, Regulatory Lag.

27. Expert Testimony. Cause No. 46120. (2025). Before the Indiana Utility Regulatory Commission. *Verified Petition of NIPSCO Generation LLC for Certain Determinations by the Commission with Respect to its Jurisdiction Over Petitioner's Activities as a Non-Retail Generator of Electric Power.* On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Rate Design, Large Data Center Loads.

28. Expert Testimony. Case No. U-21859. (2025). Before the Michigan Public Service Commission. *In the matter of the application of Consumers Energy Company for Ex Parte Approval of Certain Amendments to Rate GPD.* On Behalf of the Michigan Attorney General. Issues: Rate Design, Large Data Center Loads.

29. Expert Testimony. Docket No. R-2025-3053112. (2025). Before the Pennsylvania Public Utilities Commission. *Pennsylvania Public Utility Commission v. Philadelphia Gas Works.* On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Decoupling, Regulatory Lag.

30. Expert Testimony. Docket No. E-01773A-24-0220. (2025). Before the Arizona Corporation Commission. *In the Matter of the Application of Arizona Electric Power Cooperative, In. for a Hearing to Determine the Fair Value of its Property*

for Ratemaking Purposes, to Fix a Just and Reasonable Return Thereon and To Approve Rates Designed to Develop Such Return. On Behalf of Arizona Corporation Commission Staff. Issues: Cost of Service, Qualifying Facilities.

31. Expert Testimony. Case No. U-21816. (2025). Before the Michigan Public Service Commission. *In the matter of Consumer Energy Company's application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023.* On Behalf of the Attorney General. Issues: Capital Expense, Cost Recovery

32. Expert Testimony. Cause No. 46120. (2024). Before the Indiana Utility Regulatory Commission. *Petition of Northern Indiana Public Service Company LLC Pursuant to Ind. Code §§ 8-1-2-42.4, 8-1-2-61 and 8-1-2.5-6 for (1) Authority to Modify its Retail Rates and Charges for Electric Utility Service Through a Phase in of Rates; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders (both Existing and New); (3) Approval of Revised Common and Electric Depreciation Rates Applicable to its Electric Plant in Service; (4) Approval of Necessary and Appropriate Accounting Relief, Including, but Limited to, Authority to Capitalize as Rate Base All Expenditures for Improvements to Petitioner's Information Technology Systems through the Design, Development, and Implementation of a Work and Asset Management ("WAM") Program, to the Extent Necessary; and (5) Approval of Alternative Regulatory Plans for the Partial Waiver of 170 IAC 4-1-16(f) and Proposed Remote Disconnection and Reconnection Process and, to the Extent Necessary, Implementation of a Low Income Program.* On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Cost of Service, Rate Design.

33. Expert Testimony. Cause No. 46097. (2024). Before the Indiana Utility Regulatory Commission. *In the Matter of the Verified Petition of Indiana Michigan Power Company for Approval of Modifications to its Industrial Power Tariff – Tariff I.P.* On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Rate Design, Large Data Center Loads.

34. Expert Report. Docket No. AHD-00000J-23-0273. (2024). Before the Arizona Corporation Commission. *In the Matter of the Application of the Arizona Corporation Commission's Exploration of Changes to the Up to 10% Annual Reduction in the Export Rate and the 10-Year Export Rate Effective Period Under the Resource Comparison Proxy Methodology Approved in the Value and Cost of Distributed Generation Docket (E-00000J-14-0023).* On Behalf of the Arizona Corporation Commission Staff. Issues: Value of Solar.

35. Expert Testimony. Case No. U-21585. (2024). Before the Michigan Public Service Commission. *In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and Other Relief.* On Behalf of the Attorney General. Issues: Capital Expenses.

36. Expert Report. *Review of LPSC Rules Regarding Distributed Generation: Report on Phase II of Rule-Making.* Docket No. R-33929. (2019). *In Re: Review of Policies Related to Customer-owned Solar Generation and Possible Modification of the Commission's Current Net Metering Rules.* On behalf of Louisiana Public Service Commission. Issues: Solar Net Metering.

37. Expert Report. *2011 Kansas Generation Planning Survey*. (2011). On behalf of the Kansas Corporation Commission Staff.

38. Expert Testimony. Docket No. 11-KCPE-581-PRE. (2011). Before the Kansas Corporation Commission. *In the Matter of the Petition of Kansas City Power & Light Company ("KCP&L") for Determination of the Ratemaking Principles and Treatment That Will Apply to the Recovery in Rates of the Costs to be Incurred by KCP&L for Certain Electric Generation Facilities Under K.S.A. 66-1239.* On Behalf of the Kansas Corporation Commission Staff. Issues: System Planning, Predetermination.

39. Expert Testimony. Docket No. 10-KCPE-795-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Kansas City Power & Light Company for Approval to Implement a Portfolio of Demand Side Management Programs Including Affordability, Energy Efficiency, Demand Response and Educational Programs, and to Implement a Rider for Recovery of Program Costs and Incentives Associated with this Portfolio.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

40. Expert Testimony. Docket No. 10-WSEE-775-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company for an Order Authorizing them to participate in Efficiency Kansas, Approve the SimpleSavings Program Rider, and related cost recovery.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

41. Expert Testimony. Docket No. 10-BHCG-639-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Black Hills/Kansas Gas Utility Company, LLC, d/b/a Black Hills Energy for Approval to Implement Black Hills Energy's Five-Year Energy Efficiency Plan Consisting of Natural Gas Energy Efficiency Programs to Improve Building and Equipment Efficiency and to Educate About Efficient Energy Usage, to Provide for Program Cost Recovery Through a Rider Mechanism, Permit the Implementation of a Revenue Normalization Mechanism to Replace the Weather Normalization Adjustment, a Performance Incentive Mechanism, and Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

42. Expert Testimony. Docket No. 10-EPDE-497-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of the Empire District Electric Company for Approval to Implement its Portfolio of Energy Efficiency and Demand Response Programs for its Kansas Customers, to Provide for Program*

Cost Recovery and Lost Revenue Through a Rider Mechanism, to Obtain any Necessary Waivers for the Commission, and for Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing. On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

43. Expert Testimony. Docket No. 10-KGSG-421-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Kansas Gas Service, a Division of ONEOK, Inc., for Approval to Implement the Efficiency Kansas Energy Efficiency Program, to Implement Natural Gas Energy Efficiency Programs to Improve Building and Equipment Efficiency and to Educate about Efficient Energy Usage, To Provide for Program Cost Recovery Through a Rider Mechanism, to Establish Administrative Charges and a Program Initiation Fee, Permit the Implementation of a Revenue Decoupling Mechanism, and Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

Affidavit of Michael Deupree, M.A.

I, Michael Deupree, (Affiant) being duly sworn (affirmed) according to law, depose and say that I am authorized to make this affidavit on behalf of the Pennsylvania Consumer Advocate and Office of Consumer Advocate (OCA), being the holder of a contract with the OCA that engaged my subject matter expertise, and have been authorized to make this affidavit on the Consumer Advocate's and OCA's behalf, and that the facts above set forth are true and correct to the best of my knowledge, information and belief, and I expect to be able to prove the same at any hearing hereof.

Michael Deupree — 09/30/2026

Signature of Affiant — Date

Sworn and subscribed before me the date below:

Signature of Official Administering Oath — September 30, 2026

Date

(My Commission Expires)

MELISSA MCMANUS
NOTARY PUBLIC ID #157216
STATE OF LOUISIANA
MY COMMISSION IS FOR LIFE

Appendix F – Konidena Affidavit

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Office of Consumer Advocate	:	
	:	Docket No. C-2026-
v.	:	
PPL Electric Utilities Corporation	:	

AFFIDAVIT OF RAO KONIDENA

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I. Witness Information

My name is Rao Konidena. My business address is Rakon Energy LLC, Roseville, MN 55113. I am the President of Rakon Energy LLC. Rakon Energy is owned and operated by me.

I have been an independent energy consultant for almost a decade, primarily focusing on transmission and distribution reliability studies and policy. I worked in Transmission Asset Management at Midcontinent Independent System Operator ("MISO"), similar to PJM, from September 2003 to May 2018.

Before MISO, I worked as a consultant in Texas. My first job after graduating from college was at a manufacturing facility in India. As a graduate engineer trainee, I was responsible for quality assurance on the shop floor. The company was making diesel generator sets for commercial and industrial customers.

At MISO, I started as an Applications Engineer for Planning, where I ran transmission reliability studies, transmission capacity calculations, and analysis for the MISO Transmission Expansion Plan ("MTEP"). At this initial stage, I had a brief stint in the MISO Control Room in Carmel, Indiana ensuring that the energy management system (EMS) model was an accurate representation of the transmission system.

I was later promoted to Lead, Resource Forecasting in 2006, responsible for a team of engineers running the capacity forecasting software. That forecasting work is incorporated in the MTEP non-transmission alternatives section. After a promotion to Manager of Resource Forecasting in 2009, I led Demand Response and Energy Efficiency forecasting for MTEP.

I worked in compliance, process, and project management for the Transmission Asset Management ("TAM") division as Senior Manager of TAM Operations from 2013 to 2015. In this role, my team

and I were responsible for division-wide financial and strategic planning, supporting corporate planning and compliance efforts. I came back to the Policy Studies department in the Principal Policy Advisor role for MISO in 2015, leading the long-term load forecasting project with Purdue University's State Utility Forecasting Group and Applied Energy Group demand response ("DR"), energy efficiency ("EE") and distributed generation ("DG") potential study at MISO.

Before leaving MISO in 2018, I led policy efforts on energy storage and distributed energy resources within economic transmission planning.

As an independent consultant, I have submitted direct testimonies on behalf of my clients at the Public Service Commission of Wisconsin (Transmission Line Certificate of Public Convenience & Need docket), Minnesota Public Utilities Commission (Aggregator of Retail Customer docket), Kansas Corporation Commission (Demand Response Aggregator docket), California Public Utilities Commission (Diablo Canyon Power Plant extension docket), North Carolina Utilities Commission (Duke Energy Carolinas General Rate Case and Duke Energy Consolidated Carbon Plan and Integrated Resource Plans), Maryland Public Service Commission (Transmission Line Certification of Public Convenience And Necessity docket) and Illinois Commerce Commission (Transmission Line Certificate of Public Convenience and Necessity).

I have also provided energy storage expertise to the OCA in the Pennsylvania Public Utilities Commission energy storage Docket No. M-2020-3022877. I provide generic electrical engineering expertise for OCA in the transmission, distribution services and miscellaneous electric issues.

Additionally, I have submitted testimony and affidavits at the Federal Energy Regulatory Commission (FERC) on behalf of my clients, including an affidavit for Voltus, Inc. on SPP's multi-nodal aggregation (Docket No. ER22-1697); expert testimony via Engleman Fallon, PLLC on

behalf of the Kentucky Public Service Commission in a transmission cost allocation complaint (Docket No. EL25-67-000); an affidavit for the Office of the People's Counsel of D.C. on PJM's Reserves Pricing Proposal; an affidavit for municipal utilities in Wisconsin and Missouri on MISO's Resource Adequacy construct; and an affidavit for the Missouri Joint Municipal Electric Utilities Commission, Missouri River Energy Services, and WPPI Energy on MISO's External Resource Zone proposal (Docket No. ER18-1173-001).

I also have certifications from Stem and Sonnen – battery energy storage manufacturers.

I received a Bachelor of Engineering in Electrical & Electronics Engineering from Bangalore University, a Master of Science in Electrical Engineering from the University of Texas at Arlington, and a Master of Business Administration from the University of Minnesota.

II. Purpose of the Affidavit

The purpose of my Affidavit is to provide information on data center load segmentation and the appropriate separation of critical versus noncritical loads.

I have been engaged by the Pennsylvania Office of Consumer Advocate (OCA) to assess the adequacy of the proposed load classification, substation configuration, distribution topology, protection and controls, redundancy, reliability, and operational considerations to ensure critical loads are appropriately segregated and supported.

III. Summary of Findings and Recommendations

The Electric Distribution Company (EDC) knows where critical customer load is located on its distribution system when the customer load is interconnected. The initial customer intake form helps the EDC know the characteristics of the load, including whether the customer has backup

power. This allows the EDC to segregate critical and non-critical load among its customers before large load interconnections.

With computational load entity[1] (CLE) customer interconnection, it is expected that the EDC would shed critical load only as a matter of last resort.

IV. Overview of Interconnection Facilities

An EDC's distribution system consists of interconnected equipment and control systems, including substations, feeders, transformers, breakers, switches, reclosers, protective relays, communications systems, supervisory control and data acquisition (SCADA) systems, and other monitoring and control equipment. Modern distribution systems can incorporate remotely controlled or automated devices that permit utility personnel and utility control systems to open or close designated switching devices and thereby interrupt or restore service to specified portions of the distribution system.

The transmission system consists of similar components and control systems as the distribution system, and is largely automated and operated both by the EDC (in its capacity as a transmission owner) and by PJM, the independent system operator for the vast majority of Pennsylvania EDCs. There are several different types of points where the transmission system – which operates at a higher voltage (i.e., 69 kV and above) – transitions to the distribution system. One of these points of transition is where customers take service at a higher voltage that needs to be served by the transmission system but the customer still has to take service through discrete distribution system

[1] See "Computational Load Entity means the end-user or the entity that hosts end-users that receives electric power for Computational Load." "Computational Load means Load comprised of electric power demand from information technology equipment, such as servers, storage, and networking hardware." Computational Load Entity Proposed Rules of Procedure Revisions Summary April 1, 2026 NERC https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/proposed/computational-load-entity-summary-of-changes-april-2026-posting.pdf.

components, such as distribution substations and step down transformers (to step down the power from higher voltage to lower voltage), utility electric meters (to measure usage), and service drops[2]. Importantly, whether the EDC or the customer owns the substations and transformers does not change the nature of these components as distribution system components.

The particular equipment and control architecture used for this purpose will depend on the EDC's system design, operating practices, applicable reliability requirements, customer characteristics, and the nature of the emergency condition.

From an engineering standpoint, an EDC can design transmission and distribution infrastructure so that designated loads or groups of loads can be physically disconnected from the distribution system when necessary to address an emergency involving system loading, equipment limitations, or other operating conditions. There is most likely a system disconnect switch to protect the safety of the utility personnel. Physical curtailment can be accomplished through appropriately configured distribution equipment, which may include substation breakers, feeder breakers, sectionalizing switches, remotely operated switches, reclosers, or other devices. The purpose of such curtailment is to reduce electrical demand on the affected portion of the system and thereby assist the EDC in maintaining equipment within applicable operating limits and preserving system reliability.

V. What are critical loads?

An EDC, in general, has customer load divided into critical and non-critical load. Critical load refers to the types of loads that are deemed vital for the health, safety, and general welfare of the

[2] "The service drop is the collection of overhead wires coming from the utility pole (often at the street) to the point of connection to the house. People call these the overhead wires or overhead service. Electricians and utilities use the words service drop." American Society of Home Inspectors, Inc https://www.homeinspector.org/reporter-articles/service-drop/.

public during grid or distribution system emergencies and, therefore, these loads receive priority protection from the EDC during emergency forced customer outage events. In other words, while individual customers may deem certain portions of their own households or business operations as vital to their daily lives or daily operations[3], that is not the same thing as defining the types of loads that receive critical designation from an EDC.

Within that context, typical examples of critical load could be hospitals, fire stations, police stations, and critical energy infrastructure. Examples of critical loads within hospitals could be emergency room services, surgery suites, blood banks, pharmacies that contain medicines requiring refrigeration, and other services that are dependent on uninterruptible power supply (UPS)[4]. For CLE customers like data centers, UPSs "are used to ensure continuous delivery of high-quality power …, supporting transitions between the grid and backup power sources or short interruptions."[5] Additionally, some residential customers within an EDC's load could be considered critical if they are dependent on life-saving equipment such as a continuous positive airway pressure (CPAP) machine.

There are different definitions for critical loads. Texas defines critical loads as "[l]oads for which electric service is considered crucial for the protection or maintenance of public safety; including but not limited to hospitals, police stations, fire stations, critical water and wastewater facilities,

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[3] For example, depending upon the residential owner's preference, some homeowners have backup power supplies such as a small diesel generator set (e.g. Generac set) or a battery (e.g. Tesla Powerwall) to power their refrigerators or other portions of their own demand that they deem "critical" during times when EDC power is shut off. Additionally, most large commercial and industrial loads have backup power supply, but again, that backup power would only be for what they would consider as "critical" on their own premises.

[4] "UPS which stands for Uninterruptible Power Supply is a device that provides backup power to electrical systems during power outages or fluctuations. It helps to ensure uninterrupted operation and protect sensitive equipment from potential damage." https://www.se.com/us/en/product-category/8000-uninterruptible-power-supply-ups/.

[5] Page 7, Navigating Integration: Key Challenges for Data Centers, Nuclear Stakeholders, And Utility Operators Center for Securing Digital Energy Technology, Talbot *et al*, Idaho National Laboratory, August 2025 report available at https://csdet.inl.gov/content/uploads/45/2025/10/Navigating-Integration-report.pdf.

and customers with special in-house life-sustaining equipment"[6]. The North American Electric Reliability Corporation (NERC) does not define critical load but states that critical load circuits "are essential to the reliability of the [Bulk Electric System]" in its Emergency Operating Procedures standard[7]. PJM grid operator also mentions critical load components such as electric compressors in natural gas infrastructure in its Manual 36 that deals with power system restoration after a load shed event[8]. All these different definitions points to a need for a consistent critical load definition. Mr. Hoyt's Affidavit has a recommendation for the critical load definition.

Because critical loads require UPS, most of the EDC's critical customers have some form of backup power. Typical backup power sources are diesel generator sets on the customer premises. If there is an outage, the diesel generator kicks in and runs until the power is back on from the EDC. This switchover from EDC power supply to the diesel generator and from the diesel generator back to EDC power supply happens almost immediately in a matter of seconds or minutes.

Some critical load customers, depending upon their needs, also have battery energy storage systems (BESS) as backup power. Like the diesel generator set up, the battery kicks in almost immediately and switches back to EDC power supply once the power is back on. Based on the battery configuration, it will replenish its charge at an off-peak time[9] when there is no more stress on the electrical grid.

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[6] Source: https://www.law.cornell.edu/regulations/texas/16-Tex-Admin-Code-SS-25-52.
[7] Source: https://www.nerc.com/globalassets/standards/reliability-standards/eop/eop-011-4.pdf.
[8] Page 72, PJM Manual 36: System Restoration Attachment A: Minimum Critical Black Start Requirement. Revision: 36, Effective Date: 06/15/2026 PJM © 2026 https://www.pjm.com/-/media/DotCom/documents/manuals/m36.pdf.
[9] Typical off-peak times are weekdays 9 pm – 6 am, weekends and holidays.

In addition to its role as a backup power resource, a battery provides many grid reliability functions. Specifically, for the distribution grid, a battery energy storage located at a frequently constrained distribution feeder or substation can reduce the loading on the distribution system and allow more energy to flow while the EDC is preparing for constructing the new infrastructure. This would be called a Non-Wires Alternative in distribution system planning. More broadly, by reducing peak demand, batteries provide a system-wide reliability benefit called resource adequacy benefit, in addition to potentially lowering costs, as discussed below.

Another battery solution which also allows EDCs to include in the rate base is providing an incentive to the utility customer to install a battery, but the EDC dispatches it. It is the responsibility of the utility customer to keep a pre-determined amount of charge for the EDC to discharge on a weekday at a certain time window and for a certain duration. In return, the utility customer realizes utility bill savings because the customer's battery functions as a grid resource. Both these solutions work in a complementary way to the primary responsibility of a battery as a back up resource. Battery energy storage systems have sophisticated electronics on board that not only communicate their "state of the charge" with the distribution energy management system when providing grid reliability services but also toggle to the backup mode when needed.

Beyond distribution reliability, batteries can also provide significant savings in PJM peak demand charges that drive transmission and capacity costs. For instance, since one coincident peak (1CP) sets the PJM network integration transmission service (NITS) charges, which are allocated to the EDC's zone, batteries can reduce peak demand during that 1CP hour and reduce the NITS transmission costs. Additionally, since PJM allocates capacity costs based on 5 coincident peaks (5CP), when batteries are dispatched during those 5CP hours, they can directly reduce the capacity

costs allocated to the EDC's zone. By reducing capacity and transmission costs, batteries can benefit customers when EDC's savings are passed on to them.

It is important to realize that backup power is not configured or sized for the entire load at the customer's entire premise – it is configured or sized only for the load that is critical on site. In the example above, for a hospital, the emergency room, surgery, blood bank and pharmacy where refrigerated medicine is stored are most likely on EDC power due to receiving priority protection or their backup power source. Other "loads" at the hospital would not be connected to the backup power source because they are not critical such as hallway lighting, and cafeteria functions.

VI. What are non-critical loads?

In addition to the critical loads, the EDC system serves loads that are non-critical, meaning loads that are deemed not vital for the health, safety, and general welfare of the public during grid or distribution system emergencies. These non-critical loads can typically be segmented from critical loads on the EDC system.

VII. How does a typical EDC segregate critical and non-critical loads?

There is an information gathering phase and resultant engineering phase.

A. Information Gathering:

When a new customer connects to the EDC, there is a "customer intake form" that tells the EDC several customer characteristics such as customer type (residential, commercial or industrial), the customer's peak load, and energy profile (continuous or varying with time of the day). This is also the initial stage at which it is determined whether the customer has critical load and whether the customer intends to have backup power on the premises.

Based on the customer type, and the customer peak load, the EDC has typical requirements for connecting the new load. Those requirements could include the size of the breaker panel, the slots available in the panel, or the physical location of the panel (e.g., it must be situated at a certain height, it must be easily available for utility inspection, etc.). In the case of commercial and industrial load, depending on the state law, a utility inspector must sign off on the electrical wiring once installed by a certified electrician before the new customer is "energized" to the grid.

B. Engineering Phase:

The critical load segregation in the wiring diagram of the circuit breaker panel is relevant here. As mentioned earlier, not all loads within a critical load customer are critical. The certified electrician, when connecting the circuit breakers according to the single line diagram, ensures that the critical load part of the customer load is connected to backup power supply, and installs switches that automate the function of switching over from EDC power supply to backup power when power is interrupted and from backup power to EDC power supply when the power is back.

The switches that alternate between EDC power supply and backup power supply are typically automated. All these switches are housed in "switchgear" equipment. A switchgear equipment commonly consists of circuit breakers, fuses, disconnect switches, relays and control panels.[10] Most likely, depending on the customer type and customer load, this switchgear equipment along with the automatic controls to the backup power supply are housed on the customer premises.

The important point here is this switching equipment or the most used term – switchgear equipment – knows which load is critical on the customer premises and accordingly switches to backup power supply if available. This switchgear equipment also communicates with the EDC using an energy

[10] Schneider Electric, https://www.se.com/us/en/work/featured-articles/what-is-switchgear/.

management system. That energy management system, based on the customer type and load, automatically[11] handles the switching functions and any power surge or power quality issues.

Based on the customer type and load, there is typically a circuit breaker or a disconnect switch, on either the utility side of the meter, the customer side of the meter, or the meter itself, that allows the utility to disconnect the designated load if needed. If the disconnection happens to critical loads or critical load components of non-critical load, the automatic transfer switch, if installed, transfers the power supply from the EDC to the backup power supply. The Affidavit of Mr. Matthew Hoyt discusses the tariff and regulatory requirements that should apply to ensure these physical curtailment capabilities are established, verified, and maintained as a condition of service. The maintenance of adequate switching equipment to transition between grid power and backup power on the customer's side of the interconnection facilities is the responsibility of the customer to maintain, not the EDC, though the EDC may play a role in ensuring that it is configured correctly and consistent with emergency operating procedures.

During a distribution system outage, in some instances, this switching function will switch EDC power supply from one distribution feeder to another, based on how the distribution feeders are configured. All of this is automated. Manual intervention is required only when the automated function fails or equipment like a circuit breaker is stuck in one position. In those situations, the utility sends personnel to remedy the situation.

[11] "A transfer switch is a device that connects equipment to backup power when a primary power source fails. The function of an automatic transfer switch (ATS) is to ensure machines continue operating during power outages or failures. An ATS is an essential part of all functional power systems." What Is an Automatic Transfer Switch, https://thompsonpowersystems.com/resources/blog/what-is-an-automatic-transfer-switch/.

With CLE customers, the EDC also gathers information such as "load ramp" – when does the large load expect to reach its peak load and how. For example, 100 MW by 12/31/2026, 250 MW by 06/30/2027 and 500 MW by 06/30/2028.

VIII. CLE customers are connected to the distribution system

Typically, CLE customers can interconnect to the distribution system through distribution facilities that interconnect to the high-voltage transmission system. As explained above, even if a large load bypasses the main distribution system by interconnecting to the high voltage transmission system at a discrete location, for the interconnection to exist, the customer still has to take service through discrete distribution system components located within the EDC's service territory, such as substations and transformers (to step down the power), electric utility meters (to measure usage) and service drop. Importantly, whether the EDC or the customer owns the substations and transformers does not change the nature of these components as distribution facilities.

The EDC's segregation of critical and non-critical loads for CLE customers from an engineering standpoint, as I discussed above, does not change for CLE customers, meaning it is still possible to segregate critical and non-critical components of large load similar to the example of the hospital that has a critical component (e.g. operating room) and a non-critical component (e.g. cafeteria) of its load. However, ideally this segregation should be done at the outset during the interconnection process and engineering phase of related facilities. As discussed further in the Affidavit of Mr. Hoyt, this technical ability to segregate critical and non-critical demand supports requiring CLE customers to make their non-critical demand independently available for emergency curtailment.

But, in situations where the large load is designated as critical load after interconnection has already occurred and the large load is already taking service, from an engineering standpoint, the

EDC should take steps to a) isolate the critical component of the large load customer by ensuring that the critical load is on a separate circuit[12] with its own protection and communication equipment, b) ensure that the EDC switchgear equipment drops only the non-critical component of the large load during load shed events, and c) ensure that backup power is configured accurately for the critical component of the customer load.

An EDC implementing such a capability would ordinarily establish appropriate operating procedures identifying, among other things: the circumstances under which large load curtailment may be initiated; the equipment and load blocks subject to curtailment; personnel responsible for initiating and supervising the action; communications and control requirements; protection and safety considerations; criteria for determining when restoration may begin; and the sequence and rate at which curtailed load may be restored. Mr. Hoyt's Affidavit addresses how these engineering and operational elements should be reflected in Commission requirements, PPL's tariff, and PPL's emergency operating procedures for CLE customers.

IX. Summary and Conclusions

In summary, segregation of critical and non-critical customer loads on the EDC system is possible from an engineering standpoint. How the EDC plans to keep power delivery towards critical loads must be understood so that there are no surprises during emergency load control events and manual load shed events.

[12] "Therefore, we adopt the Energy Division recommendation, and order respondent utilities to study reconfiguring circuits to narrow exempted load to more nearly match only the load of essential customers. We recognize objections from respondent utilities that it will be far too costly to **rewire circuits to isolate only essential customers**." California PUC decision https://docs.cpuc.ca.gov/published/Final_decision/6143-05.htm.

Appendix F – Konidena Affidavit – Attachment A

RAO KONIDENA

Energy Market Expert • Transmission Planning, Wholesale Markets & Distributed Energy Resources

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Professional Summary

Independent energy regulatory consultant and expert witness with 20+ years of experience spanning transmission planning, wholesale electricity market design, and distributed energy resource integration. Has filed testimony and affidavits before **state commissions in 10+ jurisdictions and the Federal Energy Regulatory Commission**, primarily on behalf of consumer advocates, environmental intervenors, and market participants. Former MISO Principal Advisor who led demand-side potential and grid-scale energy storage studies. Co-author of a Wiley graduate textbook on modern electricity systems.

Areas of Expertise

- Transmission Planning & CPCN Review
- Distributed Energy Resources (DER)
- Demand Response & FERC Order 2222
- Non-Wires Alternatives & Grid-Enhancing Tech
- Cost Allocation & Cost Causation
- Energy Storage Tariffs & Deployment
- Resource Adequacy & Capacity Markets
- Generator Interconnection (MISO/PJM)

Analytical Capabilities: Builds Python-based analytical tools for multi-ISO LMP analysis, benefit-cost modeling, and RTO market-data extraction across PJM, MISO, NYISO, SPP, CAISO, and ISO-NE.

Expert Testimony & Regulatory Engagements

Testimony, affidavits, and regulatory analysis filed through Rakon Energy LLC (2018–present), organized by jurisdiction.

Federal Energy Regulatory Commission (FERC)

- **Voltus, Inc** — Affidavit on SPP's multi-nodal aggregation. Docket No. ER22-1697.
- **Kentucky Public Service Commission (via Engleman Fallon, PLLC)** — Expert testimony in a transmission cost allocation complaint. Docket No. EL25-67-000. [eLibrary]
- **Office of the People's Counsel of D.C. (OPC-DC)** — Affidavit on PJM's Reserves Pricing Proposal. [filing]
- **Municipal utilities (Wisconsin & Missouri)** — Affidavit on MISO's Resource Adequacy construct.
- **Missouri Joint Municipal Electric Utilities Commission, Missouri River Energy Services & WPPI Energy** — Affidavit on MISO's External Resource Zone proposal. Docket No. ER18-1173-001. [eLibrary]

Pennsylvania Public Utility Commission

- **PA Office of Consumer Advocate** — PPL Electric Utilities – Sugarloaf 500/230 kV Transmission Line Project. Docket Nos. A-2026-3061547, P-2026-3061609, and A-2026-3061549 et al.
- **PA Office of Consumer Advocate** — PPL Electric Utilities – LON Susquehanna-Harwood. Docket No. A-2025-3059443.
- **PA Office of Consumer Advocate** — Utility rate case. Docket No. R-2024-3047068. [filing]
- **PA Office of Consumer Advocate** — Transmission line rebuild CPCN. Docket No. A-2022-3037374 (begins p. 198). [filing]
- **PA Office of Consumer Advocate** — Policy proceeding — Utilization of Storage Resources as Electric Distribution Assets. Docket No. M-2020-3022877 (begins p. 18). [filing]

- **PA Office of Consumer Advocate** — Ongoing generic electrical engineering support on transmission, distribution, and miscellaneous electric issues.

Maryland Public Service Commission

- **MD Office of People's Counsel** — NextEra Energy Transmission MidAtlantic — CPCN for 500 kV line, MidAtlantic Resiliency Link Project (Allegany & Garrett Counties). PSC Case No. 9857.
- **MD Office of People's Counsel** — Carroll-Germantown 230 kV line and Potomac Edison Messick Road-Ridgeley 138 kV rebuild CPCNs. PSC Case Nos. 9803 & 9818.
- **MD Office of People's Counsel** — Transmission line rebuild CPCN. PSC Case No. 9698 (filed Sept. 13, 2023). [case]

Massachusetts Department of Public Utilities

- **MA Attorney General's Office, Office of Ratepayer Advocacy (via Center for Renewables Integration)** — Energy storage tariffs — Eversource (DPU 23-126), National Grid (DPU 23-115), Unitil (DPU 23-117). [dockets]

Illinois Commerce Commission

- **Citizens Utility Board & Environmental Defense Fund** — Ameren Transmission Co. of Illinois / Ameren Illinois — transmission line CPCN. Docket No. 24-0088. [docket]
- **Environmental Law & Policy Center & Citizens Utility Board** — Ameren Illinois / Ameren Transmission Co. — transmission line CPCN. Docket No. P2023-0658. [docket]

California Public Utilities Commission

- **San Luis Obispo Mothers for Peace** — PG&E recovery of Diablo Canyon extended-operation costs (Sept. 2023–Dec. 2025) and 2025 Volumetric Performance Fees. Proceeding A.24-03-018. [filing]
- **San Luis Obispo Mothers for Peace** — Proposed extension of Diablo Canyon Power Plant. Proceeding R.23-01-007. [filing]

North Carolina Utilities Commission

- **NC WARN** — Duke Energy Carolinas Biennial Consolidated Carbon Plan & IRP. Docket No. E-100, SUB 190. [filing]
- **NC WARN** — Duke Energy Carolinas rate case. Docket No. E-7, SUB 1276. [filing]

Colorado Public Utilities Commission

- **CO Office of the Utility Consumer Advocate** — Expert testimony on a utility distribution system plan. Proceeding No. 24A-0547E.

Minnesota PUC & Kansas Corporation Commission

- **Voltus, Inc (demand response aggregator)** — Aggregator of Retail Customers — MN PUC Docket No. E999/CI-22-600; Demand Response Aggregator — KS Docket No. 23-EKCE-588-TAR. [KS filing]
- **Vote Solar** — Xcel/IOU IRP filing. MN PUC Docket No. E002/RP-19-368. [filing]

Public Utilities Commission of Nevada

- **Vote Solar** — IOU IRP filings. Docket Nos. 21-06001 and 21-06002. [filing]

Public Service Commission of Wisconsin

- **Environmental Law & Policy Center** — MISO Multi-Value Project (MVP) transmission line CPCN. Docket No. 5-CE-146. [filing]

Consulting & Advisory Engagements

Litigation, Agency & Policy Support

- Earthjustice — Technical analysis on anticipated DOE action regarding the Campbell plant (MI) and Schahfer and Culley plants (IN).
- Earthjustice, Sierra Club, NRDC & EDF — Opinion on DOE/Energy Secretary Chris Wright's August 20, 2025 order to MISO and Consumers Energy.
- Earthjustice — Technical analysis of the NYISO reliability planning process.
- Georgia Public Service Commission — Engaged as Battery Energy Storage System (BESS) consultant.
- Environmental Defense Center (for Mothers for Peace) — Report on the need for Diablo Canyon, submitted to the California Coastal Commission.
- Advanced Energy United (via Center for Renewables Integration) — Report on opportunities for DERs in organized markets.
- Advanced Energy Economy & NRDC Sustainable FERC Project — Monitoring of MISO's FERC Order 2222 implementation.
- Voltus, Inc — Representation at RTO stakeholder committees on FERC Order 2222.
- Energy Storage Association — Advocacy support at MISO on FERC Order 841 compliance.

Developer & Market-Participant Advisory

- Commercial real estate firm's renewable division — Impact of RTO market reforms on existing PPAs and interconnection agreements.
- Spanish renewable developer (via CRI) — MISO/PJM interconnection queue evaluation for solar/storage sites.
- Minnesota solar developer — DER and BESS development opportunities in MISO.
- Community Solar Garden developer — MISO DER Affected Systems Study process.
- Independent Power Producer — MISO seasonal resource adequacy construct and its PPA impacts.
- Renewable developer — MISO Generator Interconnection Queue and seasonal capacity-credit impacts across study cycles.
- Technology companies — Representation at PJM and navigation of MISO market rules for data center interconnection.

Training & International

- USEA workshop — US energy, capacity, and retail markets for the Independent Electricity Market Operator Philippines (IEMOP).
- NARUC International Peer Review — DER and Demand Side Management plan review for Central American regulators.
- USEA / USAID / Power Africa — Ancillary services best practices, Eastern Africa regional workshop.
- Tuatara team — DER training for Colombia's grid operator XM; ESTA International — energy storage benefits for Mexican regulator CRE.

Professional Experience

Rakon Energy LLC • Roseville, MN 2018 – Present
Founder & Principal

- Founded an independent consultancy providing expert testimony, affidavits, and technical analysis on transmission planning, wholesale markets, resource adequacy, and distributed energy resources.
- Filed testimony and affidavits before FERC and 11 state commissions on behalf of consumer advocates, environmental intervenors, municipal utilities, and market participants (detailed above).

- Advise developers, independent power producers, and technology companies on MISO/PJM interconnection, capacity accreditation, and market rules; deliver regulator training with USEA, NARUC, and USAID.

Midcontinent Independent System Operator (MISO) • Eagan, MN Aug 2015 – May 2018

Principal Advisor, Policy Studies

- Recognized as an expert on energy storage and DERs from an economic transmission planning perspective.
- Project manager for the long-term independent load forecast and demand response / energy efficiency / distributed generation potential study.
- MISO representative on the DOE US DRIVE Grid Interaction Technical Team.

Senior Manager, Transmission Asset Management Operations Feb 2013 – July 2015

- Partnered with the division lead on strategic initiatives and operating plans.
- Chaired the Economic Modeling Framework Working Group of international grid operators (GO-15).

Manager, Resource Forecasting (started as Engineer II) Sep 2003 – Jan 2013

- Directed MISO's Demand Response & Energy Efficiency potential study (with Global Energy Partners).
- Directed the MISO Energy Storage Study identifying economic potential for grid-scale storage, advising utilities, asset owners, and investors.
- Owned analytical assessments meeting MISO's FERC compliance obligations (e.g., market-based rates).
- Supported state regulators and the MISO Board with technical analysis of policy drivers.

PwrSolutions, Inc. • Dallas, TX May 2001 – Aug 2003

Student Intern & Electrical Engineer (Consulting)

- Executed generator interconnection studies for Independent Power Producer clients.
- Analyzed future generator and transmission needs in the Eastern Interconnection.

Education

MBA, Global Executive Program — University of Minnesota, Carlson School of Management 2011
Emphases: Strategic Management, International Business. Capstone: marketing mobile EV charging services in the Singapore market.

M.S., Electrical Engineering — University of Texas at Arlington, Energy Systems Research Center 2002
Thesis: Economic Analysis of Distributed Generation (Photovoltaics and Fuel Cells).

B.E., Electrical & Electronics Engineering — Bangalore University 1998

Publications, Boards & Recognition

- Co-author, *Modern Electricity Systems: Engineering, Operations, and Policy to Address Human and Environmental Needs* (Wiley, 2022) — graduate-level textbook.
- Author of multiple publications in The Electricity Journal, Renewable Energy World, and other industry journals; regular Substack contributor for commissioners and regulatory staff.
- President, Board of Directors, Center for Renewables Integration (Dec 2023 – present).
- Board of Directors, Ever Green Energy (Sep 2019 – present).

Appendix F

Affidavit of Rao Konidena

I, Rao Konidena, (Affiant) being duly sworn (affirmed) according to law, depose and say that I am authorized to make this affidavit on behalf of the Pennsylvania Consumer Advocate and Office of Consumer Advocate (OCA), being the holder of a contract with the OCA that engaged my subject matter expertise, and have been authorized to make this affidavit on the Consumer Advocate's behalf, and that the facts above set forth are true and correct to the best of my knowledge, information and belief, and I expect to be able to prove the same at any hearing hereof.

K V Nagaraja Rao — 10/1/26

Signature of Affiant — Date

Sworn and subscribed before me the date below:

10/01/2026

Signature of Official Administering Oath — Date

(My Commission Expires) 01/31/2029

ENRIQUE C VASQUEZ
Notary Public
Minnesota
My Commission Expires 01/31/2029