



Whitepaper: Survey of State Actions Required to Implement PJM Large Load Tariff Proposals

Prepared for PJM

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Whitepaper Abstract

This whitepaper surveys current state level rate and regulatory structures and activities undertaken to date to respond to the emergence of large loads and indicates potential rule changes needed to support the retail implementation of recent large load proposals of PJM Interconnection, L.L.C. (PJM). This whitepaper is based upon PJM's filed Reliability Backstop Procurement (RBP) and Interim Resource Adequacy Service (IRAS) framework proposals and may be subject to change based upon action by the Federal Energy Regulatory Commission (FERC).¹

This paper focuses its research upon those states with restructured retail electricity markets and a traditionally regulated state with large loads participating within PJM's Reliability Pricing Model (RPM) market. Specifically, these include: Delaware, Illinois, Maryland, New Jersey, Ohio, Pennsylvania, and Virginia. Collectively, these jurisdictions represent those that will need to make associated retail changes to support certain aspects of PJM's large load proposals.

This whitepaper includes appendices that describe in detail:

- (i) State legislative, regulatory, or Relevant Electric Retail Regulatory Authority (RERRA) actions taken to date to respond to emerging large loads;
- (ii) Minimum state-level actions necessary to accommodate PJM's RBP and IRAS proposal frameworks; and,
- (iii) Suggested additional actions that could help protect ratepayers in accordance with the spirit of the Statement of Principles and Ratepayer Protection Pledge.

PJM Critical Issue Fast Path (CIFP) Process Summary

PJM has been pursuing a multi-pronged approach to respond to the unprecedented addition of large loads, most notably data centers, in the PJM Region. PJM's response has been guided by the Statement of Principles Regarding PJM from the 13 PJM state governors and National Energy Dominance Council issued in January 2026.^{2,3} The Statement of Principles focused on procurement of new capacity resources through a backstop auction commencing by September 2026 that provides 15-year price certainty for new capacity resources. Concurrent with the

¹ RBP filed under Docket No. ER26-3380-000, IRAS filed under Docket No. ER26-3515-000

² Statement of Principles Regarding PJM, National Energy Dominance Council, 1 (Jan. 16, 2026), available at: <https://www.energy.gov/documents/statement-principles-regarding-pjm>

³ The PJM states include the 13 states of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia, and the District of Columbia.

Statement of Principles, the PJM Board of Managers issued a Decisional Letter in January 2026 to guide the CIFP proceedings in the spring and summer of 2026. The Board's Decisional Letter laid out a process to develop frameworks for multiple work areas including voluntary "Bring Your Own New Generation", large load reductions referred to as "Connect and Manage", and a RBP auction.⁴

The RBP and "Connect and Manage" subsequently renamed (IRAS), CIFP processes culminated in tariff filings at FERC on July 31st and August 13th, 2026, respectively.⁵

RBP Filing

The July 31st filing defines the RBP as *"a one-time procurement, starting in 2026, to address resource adequacy challenges in the PJM Region arising from insufficient capacity committed through Reliability Pricing Model Auctions starting in the 2027/2028 Delivery Year."*⁶ The final RBP target is a region-wide value based on the initial target of the 2028/2029 Delivery Year Unforced Capacity (UCAP) shortfall in the Base Residual Auction (BRA) (6,831.3 MW UCAP) minus the Qualifying RBP Offset UCAP MW and load that has obtained an opt-out.⁷ Qualifying RBP Offset UCAP MW can be described as new capacity brought voluntarily by new load within the RBP window that meets the proposed evidence criteria.^{8,9} Loads that are eligible to obtain an opt-out are those served by Electric Distributors with rates that are not subject to regulation by the state and thus cannot appropriately assign costs of the procurement (i.e., certain municipal and cooperative utilities) and certain loads that participate as peak load shaving customers.^{10, 11}

PJM will open a procurement window on September 30, 2026, subject to timely FERC acceptance of the proposal by September 29, 2026. The procurement window will allow for both decrementing the RBP procurement target by Qualifying RBP Offset UCAP MW and qualifying opt-outs, and for proposals to be submitted from resources seeking to participate in the RBP. The proposals will be vetted for feasibility and other gating criteria, before being assessed, with offers accepted on a least-cost, pay-as-bid basis that prioritizes earlier in-service

⁴ David E. Mills, PJM Board Chair, Board Decisional Letter on Critical Issue Fast Path - Large Load Additions, PJM Board, Jan. 16, 2026, available at: <https://perma.cc/P57T-ZXYJ>

⁵ RBP filed under Docket No. ER26-3380-000, IRAS filed under Docket No. ER26-3515-000

⁶ Proposed Tariff, Attachment DD, section 18

⁷ Id., Section 18.1

⁸ Transmittal Letter, pp. 31-38

⁹ Proposed Tariff, Attachment DD, section 18.2

¹⁰ Transmittal Letter, pp. 44-46

¹¹ Proposed Tariff, Attachment DD, section 18.1(d).

dates. Once offers are accepted, cost will be allocated to Electric Distributor zone areas based on the pro rata share of the final target. The relevant state and/or RERRAs can determine how RBP costs are to be allocated to Load Serving Entities (LSEs) and then Electric Distributors communicate these RBP LSE allocations to PJM for billing.^{12,13} RBP cost allocated to LSEs within a zone area should realize the cost allocation intent of assigning such costs to the LSEs that serve the large load customers that compose the Final RBP Target. PJM does not have the authority to assign customers directly to end-use customers, therefore in its proposal, PJM relies on the states to create a cost allocation mechanism that appropriately assigns such costs to the right customers.¹⁴ PJM's proposal also provides a backstop cost allocation mechanism should an Electric Distributor not report any state and/or RERRA determinations.

IRAS Filing

The August 13th IRAS filing explains the proposed capacity framework available for large loads that do not obtain their own new capacity or elect to receive an RBP allocation. IRAS *"is a load reduction service, effective starting with the 2027/2028 Delivery Year, through which Eligible New Large Loads may be compensated for providing load reductions requested by the Office of the Interconnection to maintain system reliability for the purpose of supporting the integration of New Large Loads to the PJM Region that are not in arrangements with new capacity additions to the PJM Region"*¹⁵ A New Large Load is end-use customer load that is either a Large Load that goes into service after June 1, 2027 or subsequent incremental load that puts a site over the Large Load threshold that didn't previously meet it.^{16,17} Bring Your Own New Capacity (BYONC) is also defined in this filing as Megawatts (MW) of UCAP that have made arrangements with New Large Loads and meet the proposed tariff criteria to qualify as new resources.^{18,19}

¹² Proposed Tariff, Attachment DD, section 18.3(b)(iii).

¹³ Affidavit of Danielle Croop Behalf of PJM Interconnection, LLC. at 51-55

¹⁴ Absent state action, PJM will allocate costs based on existing capacity market cost allocation, using the Peak Load Contribution of each LSE within a Zone Area for that Zone Areas assigned RBP costs.

¹⁵ Proposed Tariff, Attachment DD-4, section 1(b)

¹⁶ Proposed RAA, Definitions define Large Load as "end-use customer(s) load that has a cumulative peak load of 50 megawatts or greater at a single electrical site behind one or more points of interconnection, where for configurations involving multiple affiliated load facilities or multiple points of interconnection with affiliated load facilities behind them, all affiliated load facilities within a one-mile radius will be considered a single electrical site.

¹⁷ Proposed Tariff, Definitions – New Large Load. If there is no reliability shortfall for three consecutive delivery years, then New Large Load is defined as Large Loads that go into service in a Delivery Year where there is a capacity shortage.

¹⁸ Transmittal Letter, pp. 50-53

¹⁹ Proposed Tariff, Attachment DD-4, section VI

Eligible New Large Loads that can provide IRAS are determined by subtracting the New Large Loads that contracted BYONC MWs or have RBP MW allocation from the New Large Load total.²⁰ This difference between the Large Load's peak and its secured RPM UCAP or RBP capacity is the amount of MWs that the New Large Load will have subject to IRAS.

PJM has proposed that IRAS could be called on in Real-Time prior to Pre-Emergency Load Management Reduction Actions.²¹ IRAS can be activated on a systemwide or zonal basis depending on the reliability need.²² PJM will designate the MW quantity and location of IRAS to be activated, but it is the responsibility of the Electric Distributor to direct Eligible New Large Loads to curtail.^{23,24}

The IRAS proposal also includes a payment mechanism for loads that are subject to IRAS reductions during the relevant delivery year set at 50% of the Non-Performance Charge Rate.^{25,26,27} The proposed tariff allows for a lower rate for load reduction as established by the RERRA.²⁸

High Level Summary of State Implementation Steps

The PJM states and the District of Columbia, with Electric Distributors that participate in the RPM capacity market will need to take state level action to revise state regulations, tariffs, LSE handbooks and related materials, and potentially state statutes in some limited instances. At a minimum, tariffs will need to accommodate the addition of the new RBP capacity product and UCAP with an IRAS performance and crediting mechanism.

Table 1 below provides a high-level summary of actions that each state will be required to take in order to facilitate the proposed RBP and IRAS frameworks.

²⁰ Proposed Tariff, Attachment DD-4, section V

²¹ Affidavit of Christopher Pulong on Behalf of PJM Interconnection, LLC. at 26, Figure 3

²² Transmittal Letter, p. 82

²³ Affidavit of Christopher Pulong on Behalf of PJM Interconnection, LLC at 42, 55

²⁴ Proposed Tariff, Attachment DD-4, section III

²⁵ The Non-Performance Charge Rate is defined in Tariff, Attachment DD, section 10A(e) as "Non-Performance Charge Rate = (Net Cost of New Entry (stated in terms of installed capacity) for the LDA and Delivery Year for which such calculation is performed * (the number of days in the Delivery Year / 30) / (the number of Real-Time Settlement Intervals in an hour).

²⁶ Proposed Tariff, Attachment DD-4, section X(a)

²⁷ Transmittal Letter, pp. 101-102

²⁸ Id. p. 106

Table 1: State Actions Necessary to Implement PJM Frameworks

Action	RBP	IRAS
Modify retail supplier tariffs and handbooks to define RBP capacity and allocation mechanisms to LSE loads	X	
Define procedures to allocate RPM UCAP that has an IRAS performance obligation to LSE loads		X
Provide information resources, such as updated FERC M-2 tariff attachments or LSE informational materials to define RBP capacity and RPM UCAP with an IRAS performance requirement, calculation methods, and allocations to LSE loads	X	X
Update tariff definitions to identify RBP and IRAS eligible customers	X	X
Determine roles and responsibilities for capacity products between Electric Distributor and LSEs in markets with competitive retailers	X	X
Enumerate the process for RBP capacity re-assignment in a default event	X	
Devise interruptible tariffs that reflect IRAS program parameters for dispatch		X
Determine curtailment methods and enforcement mechanisms to ensure delivery of IRAS MW obligation to PJM		X
Identify IRAS payment levels and mechanisms and administration responsibilities		X

State Actions Taken to Date to Respond to Emerging Large Loads

All PJM states with Electric Distributors participating in the RPM have taken some level of action to date at the legislative or regulatory level.

Table 2 below provides a succinct summary of recent state legislation or Governor executive actions to address the growth of large data center loads.

Table 2: State Legislation Regarding Electric Rates for Large Data Center Loads

DE	MD	NJ	PA	OH	IL	VA
HB 233	HB 1035 HB 1532	AB 796	Gov. Shapiro's Executive Order 2026-05 ²⁹		Gov. Pritzker's policy framework & call for legislation ³⁰	HB 1393 / SB 253 HB 284 / SB 371

Some of the legislation listed in Table 2, such as NJ AB 796 and DE HB 233, is wide-ranging and covers multiple aspects of data center development, while others may have provisions that are relevant to large load data centers in the context of a larger bill.

In addition to legislative actions, several PJM states have taken measures at their RERRAs to develop large load data center tariffs. Ohio and Pennsylvania have done the most in this area and their activities are summarized in Table 3.

Table 3: State RERRA Actions to Respond to Emerging Large Loads

DE	PA	OH	VA
Development of a Model Large Load Tariff (paused)	- Development of a Model Large Load Tariff - PPL's active LP-6 rate	- AEP's active DCT rate - FE and Duke large load tariff filings - AES proposed large load tariff - PUCO Order in AEP SSO proceeding to create separate SSO framework for large loads	- Dominion's approved GS-5 rate pending January 2027 availability - VA SCC work to devise model tariff language for emergency load reduction programs³¹

²⁹ Gov Shapiro Executive Order, 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

³⁰ Press Release, Gov. Pritzker Pauses New Data Center Tax Incentives: Governor outlines framework to protect consumers and lower energy costs, calls on General Assembly to act in veto session, June 5, 2026, available at: <https://gov-pritzker-newsroom.prezly.com/gov-pritzker-pauses-new-data-center-tax-incentives>

³¹ Letter of Chair of Virginia State Corporation Commission, Kelsey Bagot and President and CEO of Data Center Coalition, Josh Levi to Ms. Paula Conboy, Chair of PJM Board of Managers, and Mr. David Mills, President and CEO

In addition to the actions shown in Table 3, DE, MD, NJ, and VA will commence additional RERRA proceedings to devise large load tariffs based on the legislative directives included in the bills shown in Table 2.

State Appendix Reports

This whitepaper includes Appendices that describe in detail state actions taken to date to respond to emerging large loads, minimum state level actions necessary to accommodate PJM's RBP and IRAS proposal frameworks, and suggested additional actions that could help protect ratepayers in accordance with the spirit of the Statement of Principles and Ratepayer Protection Pledge.

Each state is unique in terms of its Electric Distributors, RERRA policies, regulations, competition status, and existing tariffs. The state appendices describe the current landscape and provide guidance to state level stakeholder discussions on RBP and IRAS implementation.

The State Appendices included in this Whitepaper are as follows:

- Delaware
- Maryland
- New Jersey
- Pennsylvania
- Ohio
- Illinois
- Virginia

A. Delaware State Appendix

Delaware is a restructured state with an active retail choice market in Delmarva Power & Light (DPL), the sole investor-owned electric utility in the state. Delaware also has the Delaware Electric Cooperative (DEC) and several municipal utilities that are members of the Delaware Municipal Electric Corporation (DEMEC).³² This Appendix is largely focused on DPL.

To date, the state has taken several actions to prepare for the expected increase in Large Load Customers including a Delaware Public Service Commission (DE PSC) docket to develop a large load customer tariff³³ and recent legislation to authorize the DE PSC to update its regulations and subsequently create a large load tariff. The legislation, the Delaware General Assembly's House Substitute 1 for House Bill No. 233 (herein referred to as HB 233)³⁴ was signed by Governor Matt Meyer on August 26, 2026.^{35, 36}

HB 233 includes several provisions to protect consumers while facilitating implementation of PJM's proposed Reliability Backstop Procurement (RBP), Bring Your Own New Capacity (BYONC), and Interim Resource Adequacy Service (IRAS). The DE PSC paused the procedural schedule in the large load tariff docket to await the additional direction that will come from the legislature via HB 233.

In addition to the new large load tariff to be mandated by HB 233, there are several changes to DPL's existing tariffs that will need to occur in order to align them with PJM's proposal.

Minimum Required State Level Actions Needed

Retail Supplier Coordination Tariffs

PJM's RBP and IRAS proposals involve creating a new RBP capacity product type and Reliability Pricing Model (RPM) Unforced Capacity (UCAP) with a mandatory interruptible load obligation and potential crediting system, respectively. At a minimum, the RBP capacity product will need to be defined in the definitions section of the DPL Electric Supplier Agreement contract and

³² DEMEC member municipalities include the Cities of Newark, Dover, Milford, Lewes, New Castle, and Seaford, and the following towns: Middletown; Clayton; and Smyrna.

³³ DE PSC Docket 25-0826.

³⁴ HB 233 (passed July 1, 2026), available at: <https://legis.delaware.gov/BillDetail/143381>

³⁵ Press Release: Governor Matt Meyer Signs Energy Consumer Protection Legislation, August 26, 2026. Available at <https://news.delaware.gov/2026/08/26/governor-matt-meyer-signs-energy-consumer-protection-legislation/>

³⁶ House Bill 445 is another pending Delaware measure signed by Gov. Meyer that requires large energy users to secure sufficient electricity supply to meet their operational needs. HB 445, available at: <https://legis.delaware.gov/BillDetail/143386>

Supplier Operating Manual. Beyond definitions, the methods used to determine capacity obligations (aka “tags”), settlement procedures, and reallocation provisions for unsubscribed RBP capacity in the event of a default of a large load with an RBP capacity obligation will need to be codified in both the Electric Supplier Agreement and Operating Manual. A summary of sections of the Electric Supplier Agreement and the Operating Manual that will require revisions are included in Table 4 below.

Table 4: Supplier Coordination Agreement Sections to be Revised for RBP and IRAS

Section/Source	DPL	
	Electric Supplier Agreement ³⁷	Operating Manual ³⁸
Definitions	pp.9 - 13	N/A
Capacity Obligation and EDC to EGS Data Transfer	Article 9 (pp.34-36) Load Obligation Allocation and Energy Scheduling	Section I (pp. 4-5) Introduction & Section II. (pp. 6-14) Supplier Capacity Peak Load Contribution
RBP Reallocation Procedure	New section required	

In the future, there will be two different types of capacity products in PJM: UCAP acquired through the RPM Base Residual Auction (BRA) and Incremental Auctions (IA) and RBP capacity. Large load capacity subject to IRAS requirements will be treated and settled like existing UCAP obligations, but will have an added requirement to curtail or interrupt load up to the IRAS Eligible New Large Load quantity when the interruption trigger is activated. Both RPM UCAP and RBP capacity will have their own procedures for daily allocation to load and determination of customer capacity obligations or capacity tags.

Currently, RPM capacity obligations are based on contributions to PJM’s five coincident peak (5 CPs) load hours. Large load capacity obligations may be set based on other parameters such as load size, nameplate, or a ramp schedule instead of the historical 5 CPs. The sum of large load customers’ BYONC, RBP, and IRAS capacity must sum to the total large load capacity obligation. It is possible that large loads could have two different capacity types to cover their capacity

³⁷ Delmarva Electric Supplier Coordination Agreement, available at: <https://www.delmarva.com/my-account/my-dashboard/rates-tariffs/delaware-electric/current-tariffs>

³⁸ Pepco Holdings (PHI) Supplier Operating Manual, available at: https://www.pepco.com/cdn/assets/v3/assets/bltbb7c204688a1a6a8/bltd44af5b06b575cc8/651dcb78d19d94000df07cf4/PHI_Supplier_Operating_Manual.pdf

obligation, which would then result in the settlement of two separate capacity products for one load.

Large load customers who enter the market via BYONC will have their capacity entered into the RPM via the BRA or IAs as price takers and be cleared through the RPM with other capacity. These large load customers will then settle any differences in bilateral contract terms or pricing relative to the RPM privately with the capacity provider.

While RPM capacity obligations for customers reset on June 1st each year, it is possible for intra-year adjustments of RBP capacity in the event that a large load RBP capacity subscriber exits the market via default. When this occurs, the remaining RBP customers across all PJM zones will be allocated a pro-rata share of the defaulted RBP capacity obligation. The Electric Supplier Agreement and Operating Manual will need a mechanism to facilitate this process.

FERC M-2 Tariffs

On its website, PJM maintains an inventory of the calculation methods and parameters used to determine Total Hourly Energy Obligation (THEO), Peak Load Contribution (PLC) and Network Service Peak Load (NSPL) for each Distribution Company.³⁹ It is not a FERC or state-mandated requirement for each EDC to maintain a current Attachment M-2 to the PJM Open Access Transmission Tariff (OATT), but most Distribution Companies, including DPL, have an Attachment M-2 on file with their PLC contribution calculation methods as an information resource to stakeholders. This document will need to be updated to reflect RBP capacity and IRAS Eligible New Large Load and the methods used to determine total zonal or EDC capacity obligations and their translation to individual customer capacity obligations.

Interruptible Load and Emergency Curtailment Tariffs

DPL presently does not have an interruptible tariff or rules regarding emergency energy curtailment for large customers in its tariff for retail delivery service.

DPL has customers taking IRAS with Eligible New Large Load, it will have to develop an interruptible tariff that is consistent with the IRAS tariff provisions regarding DPL responsibilities and implementation methods. The DE PSC will also need to determine roles and responsibilities for DPL who would be responsible for dispatch and performance of IRAS curtailments and LSEs who will be assigned the UCAP associated with the New Large Load Customer. The PJM proposed tariff contemplates that DPL will implement any demand response compensation to IRAS resources for their event performance, but the DE PSC could determine if LSEs should play

³⁹ THEO, PLC, and NSPL Methodology Inventory, available at: <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/theo-plc-and-nspl>

a role in this process. The DE PSC may also determine that IRAS customers should not be compensated for their interruptions.⁴⁰

State Level Response to Data Center Growth

Delaware has taken several steps to respond to the challenges posed by load growth from Large Load Customers. The DE PSC initiated a proceeding in 2025 to investigate the creation of a large load tariff for DPL.⁴¹ This proceeding was subsequently paused as HB 233 advanced in the legislature.

HB 233 is a comprehensive bill that requires the DE PSC to finalize regulations for Large Load Customer tariffs. Within 180 days of the regulations being finalized, DPL must file a tariff specific to Large Load Customers that conforms with the regulations developed and statutory guidance.⁴² HB 233 includes directives in the following areas:

- Tariff principles such as prohibition of cross subsidies and direct assignment of capacity and other costs to large loads
- Requirements for Electric Service Agreements and DE PSC evaluation criteria
- Financial assurance requirements
- Load curtailment and interruptible rates
- Retail competition
- Delegation of authority to DE PSC to coordinate tariffs with PJM requirements

HB 445, signed by Governor Meyer on August 26th, 2026 includes provisions for Electric Service Agreements regarding minimum firm capacity levels for interconnection and a requirement that Large Load Customers have a plan to obtain 100% of their capacity requirements within 10 years of commencing operation that is within or proximate to the DPL zone.

RBP and IRAS Status Evaluation in Interconnection Process

HB 233 includes several sections that detail guidance for the DE PSC to use in evaluating Large Load Customer ESAs. It directs the DE PSC to positively view Large Load Customers that BYONC, particularly low carbon resources, that are located with or adjacent and deliverable to Delaware.⁴³ HB 445 has passed both houses of the Delaware legislature and if enacted, would require binding minimum levels of secured generation capacity prior to interconnection and a

⁴⁰ FERC Docket ER26-3515, Proposed Tariff, Attachment DD-4, Section III, Section X, August 13, 2026.

⁴¹ DE PSC Docket 25-0826.

⁴² HB 233 proposed modifications to Subchapter II, Chapter 1, Title 26, § 317G. (a).

⁴³ HB 233 proposed modifications to Subchapter II, Chapter 1, Title 26, § 203G. (d)(4).

ten year runway to procure 100% of the Large Load's capacity needs.⁴⁴ In HB 233 and HB 445 DE Legislature and Governor have provided clear guidance that interconnection requests from Large Loads that have firm BYONC capacity arrangements should get prioritization.

Suggested Optional State Actions for Consideration

Large Load Competitive Retail Electric Supplier Certification

Delaware is a restructured state with an active retail choice market in the DPL service area. The Delaware PSC regulates electric suppliers to establish standards for participation in the competitive retail electricity market and to provide oversight of competitive electric market activity. The existing framework gives the DE PSC visibility into the competitive retail electricity market, and protects other ratepayers by ensuring that competitive electric suppliers are qualified to serve retail load by evaluating the management, operational, and financial integrity of the organizations.

As Large Load Customers enter or expand in Delaware, the scale and characteristics of these customers present risks that differ from those associated with traditional retail load. Specifically, they pose an elevated level of risk in the event of a default due to their scale and also their potential to receive RBP and/or RPM UCAP with an IRAS curtailment obligation. Both of these capacity types could take time to re-allocate to other large load customers in the event of an abrupt unplanned termination of operations.

To respond to these risks, the DE PSC could evaluate whether the existing electric supplier certification framework provides sufficient information and safeguards for electric suppliers serving Large Load Customers. The sections below present options for DE PSC consideration to strengthen the certification and oversight of electric suppliers serving Large Load Customers to ensure that high-quality retail suppliers are serving these customers and providing timely disclosures that provide insight into large load market activity.

Current Certification Framework

Title 26, Chapter 10 of the Delaware Code includes a section entitled *Certification of Electric Suppliers*. This section requires all electric suppliers to obtain a certificate from the DE PSC before offering electric supply service to retail customers in Delaware.^{45, 46} This section also

⁴⁴ HB 445 proposed modifications to Chapter 80, Title 29 of the Delaware Code §8066(b), and §8066(d)(1) - (2).

⁴⁵ 26 Del. C. § 1012 (Certification of electric suppliers, available at: <https://delcode.delaware.gov/>

⁴⁶ "Electric supplier" is defined as a person or entity certified by the DE PSC that sells electricity to retail electric customers utilizing the transmission and/or distribution facilities of a nonaffiliated electric utility. See 26 Del. C. § 1001.

authorizes the DE PSC to develop rules and regulations for supplier certification, which may include customer-protection measures regarding⁴⁷:

- Standardized customer information and billing;
- Service terms and conditions;
- Procedures for handling disputes and changing suppliers, and;
- Standards for suppliers who offer Green Power.

The statute language is broad and delegates rulemaking to the DE PSC.

The DE PSC established its *Rules for Certification and Regulation of Electric Suppliers* in Title 26, Section 3001 of the Delaware Administrative Code (Supplier Rules).⁴⁸ The Supplier Rules provide operational, technical, financial, and consumer protection standards to which electric suppliers must adhere to become certified and participate in Delaware’s retail electricity market.

Delaware’s supplier-certification framework is primarily focused on consumer protection for residential and small commercial customers. Section 2.0 of the Supplier Rules describes the certification requirements for electric suppliers. In summary, this section contemplates that an applicant will provide the following to the DE PSC as part of its application review⁴⁹:

- general information about its business and leadership team;
- marketing plans and materials if the supplier proposes to serve residential and small commercial customers;
- copies of standard contracts and all related contract materials applicable residential and small commercial customers;
- a copy of its performance bond or guarantee to DPL as required by the Electric Supplier Agreement, which may be submitted after the supplier certificate is granted.
- financial information such as certified financial statements and the recent annual report to shareholders and SEC Form 10-K;
- disclosure of bankruptcies and adverse regulatory or legal action related to retail energy services;

⁴⁷ Id., § 1012(b).

⁴⁸ 26 Del. Admin. C. § 3001 § 1.0, et. al., available at:
<https://regulations.delaware.gov/AdminCode/title26/3000/3001.shtml>

⁴⁹ Id., § 2.2.1 through § 2.2.23.

- a description of the applicant’s experience with the regional and wholesale market and other retail electricity markets;

Section 2.3 of the Supplier Rules detail the financial security requirements, but these only apply to electric suppliers serving residential and small commercial customers. The initial security requirement is \$100,000 with annual updates based on the greater of \$100,000 or 5% of the electric supplier’s annual revenues from sales of electric supply service to residential customers and small commercial customers in Delaware in the prior calendar year.⁵⁰ There are several types of financial security accepted by the DE PSC.

Finally, the Supplier Rules provide the DE PSC with ongoing oversight of customer enrollment, billing and metering, electric supplier contracts and summaries, supplier changes, contract transfers, and required reporting.⁵¹ Under existing reporting requirements, an electric supplier must notify the DE PSC and the Delaware Division of the Public Advocate within ten days of the revocation of its authority to sell electricity in any jurisdiction, or if there are changes to an electric supplier’s principal officers or ownership of the electric supplier business. Suppliers must also report changes to their corporate, regulatory, financial, and compliance status within 30 days and provide related information through annual reporting.⁵²

These existing requirements could be adapted to provide additional oversight of suppliers serving Large Load Customers.

HB 233 Provisions Relevant to Electric Suppliers

HB 233 addresses the risks associated with Large Load Customers by establishing requirements for utility service agreements and tariffs. HB 233 does not directly establish requirements for electric supplier certification, but it establishes policy considerations that are relevant to how the DE PSC might alter regulation for electric suppliers serving large loads. HB 233 focuses on ratepayer protection, financial assurance, operational reliability, and transparency. Table 5 below details the sections of HB 233 that are relevant to retail energy suppliers.

⁵⁰ Id., § 2.2.1 through § 2.3

⁵¹ 26 Del. Admin. C. § 3001, §§ 4.0, 10.10, 12.0.

⁵² Id., §§ 12.1-12.3.

Table 5: HB 233 Provisions That May Impact Electric Suppliers

Topic	Bill Provisions Pertinent to Electric Suppliers (edited for brevity)	New or Modified Section of Chapter 1, Title 26 of Delaware Code
Financial Assurance	“Require that each large energy use facility seeking new or modified service shall,..... provide appropriate financial security to ensure that the Commission-regulated electric utility’s existing customers are held harmless for any of the costs in paragraphs (e)(1)a. through (e)(1)e. of this section for the entire term of the ESA.”	§ 203G. (c)(11) § 317.(e)(2)
Direct Assignment of PJM Capacity Obligations	Allocate any financial or other obligation assigned to a Delaware Commission-regulated electric utility associated with PJM’s Reliability Backstop Procurement of new capacity undertaken for large energy use facilities directly to the large energy use facility that gave rise to the financial or other obligation; any costs that cannot be directly assigned must, to the maximum extent possible, be assigned to the class of customers for large energy use facilities	§ 317.(e)(1)(b) § 317.(e)(1)(e)
Interruptibility and Load Curtailment	“The ESA must include provisions to.....Establish enforceable curtailment and interruptibility obligations during emergencies and other circumstances determined by the Commission, Commission-regulated electric utility, or directed by the federal regional transmission system operator.” “All Commission-regulated electric utilities shall develop a load shed protocol to allow large energy use facilities to be curtailed in anticipation of or during emergency conditions, including the installation of any necessary equipment or technology before a customer is interconnected.....(1) The load shed protocol, to the extent feasible.... shall do all of the following: a. Require the pre-emergency curtailment of large energy use facilities subject to directives from PJM to the Commission-regulated electric utility in accordance with applicable PJM requirements.....”	§ 203G. (c)(9) – (10) § 317.(b)

Topic	Bill Provisions Pertinent to Electric Suppliers (edited for brevity)	New or Modified Section of Chapter 1, Title 26 of Delaware Code
Retail Competition	“Nothing in this section, § 317 of this title, or any regulation promulgated hereunder shall be construed to do any of the following: (1) Limit or impair the right of any retail electric customer, including a large energy use facility, to purchase electric supply service from a certified electric supplier. (2) Require a large energy use facility to procure electric supply service from a Commission-regulated electric utility.”	§ 203G. (j)(1)-(3) § 1008.(c)(1)-(2)

HB 233 isn’t prescriptive on how financial assurance, direct assignment of capacity costs, or load shedding and curtailment performance requirements will impact electric suppliers. It delegates significant flexibility to the DE PSC to ensure that Delaware ratepayers will not bear increased costs from large loads⁵³, and as a result the share of responsibility between DPL and the electric suppliers for the items in Table 5 will have to be decided by the DE PSC in the forthcoming large load tariff proceeding.

As the DE PSC works to implement the large load tariffs proscribed by HB 233, it will need to ensure alignment of its interruptible rate and demand response provisions with PJM Manual 13 and Attachment DD-4, section X of PJM’s proposed tariffs assuming they receive FERC approval.^{54, 55}

[Suggested Changes to Certification](#)

The DE PSC should consider creating a new electric supplier license category for Large Load Customers and require new and existing retail suppliers apply for certification to serve this category. This would help ensure that electric suppliers seeking to serve Large Load Customers are qualified and have the financial assurance necessary to support those obligations.

In addition to creating this new category, the DE PSC could consider adoption of the regulatory enhancements for certification and oversight of electric suppliers serving Large Load Customers detailed below. Their purpose is to help ensure that electric suppliers demonstrate that they have the financial, operational, and technical capabilities to provide retail electric service to

⁵³ HB 233 proposed modifications to Subchapter II, Chapter 1, Title 26, § 203G. (f)

⁵⁴ FERC Docket ER26-3515, Proposed Tariff, Attachment DD-4, August 13, 2026

⁵⁵ Affidavit of Christopher Pilog on Behalf of PJM Interconnection, LLC. at 24

Large Load Customers. These requirements could be incorporated into the existing Supplier Rules within the authority delegated to the DE PSC. Specific areas of the application process that the DE PSC may want to modify are summarized in Table 6 below.

Table 6

Application Criteria	Suggested Change	Rationale
Definitions: Large Load Customers.	Define Large Load Customer using a threshold that captures customers subject to PJM’s RBP.	Presently, the Supplier Rules only identify residential and small commercial classes as triggering additional compliance requirements. PJM’s definition of large load customers differs somewhat from HB 233’s definition of “large energy use facility.” PJM’s proposed tariffs offer states significant flexibility in definitions for RBP allocation and IRAS execution, but state level definitions that differ from PJM’s definitions should be appropriately identified. ^{56, 57, 58}
Financial Information ⁵⁹	In addition to the provision of recent financial statements, the DE PSC may want to evaluate credit agency ratings and available credit with PJM and unrelated financial institutions. ⁶⁰	Minimize financial defaults by ensuring that the electric supplier is financially sound. Reduce the risk of unallocated RBP capacity to ratepayers in a default to align with the cost responsibility policies embedded in HB 233.

⁵⁶ PJM Proposed tariffs delegate cost allocation of RBP and IRAS operationalization to the states at Proposed Tariffs Attachment DD, section 18.3(b)(iii); Attachment DD-4, III(c); Attachment DD-4, IX(b)(i); and Attachment DD-4, X

⁵⁷ FERC Docket ER26-3515, Proposed Definitions, August 13, 2026

⁵⁸ HB 233 defines a “Large energy use facility” as one that uses 75 MW of electric demand at a load factor of 85% or greater, has instantaneous demand of 100 MW, or a maximum demand of 30 MW and offers services described by NAICS Code 518210 (e.g., data processing, hosting, computer infrastructure provider). The definition excludes petroleum refining facilities.

⁵⁹ 26 Del. Admin. C. § 3001, §§ 2.2.18, 2.2.19.

⁶⁰ Id. §§ 2.2.16. Note that if the company is not publicly traded, audited accounting statements are required.

Application Criteria	Suggested Change	Rationale
Regional and Wholesale Experience	An electric supplier should demonstrate: that there are multiple key staff with experience serving large load customers in PJM or other markets; and the organization can demonstrate their ability to support customer load shedding for loads with IRAS performance obligations that is compliant with HB 233 requirements.	Minimize defaults or operational issues by requiring a high level of sophistication and organizational capability. Load shedding capability is important to ensure adherence to IRAS load curtailment obligations and specific HB 233 mandated curtailment requirements. ^{61, 62}
Financial Assurance and Bonding Requirements:	Determine if the Credit Amount in the Electric Supplier Agreement is sufficient to protect other ratepayers in the event of a Large Load Customer default and check for alignment in financial amounts and mechanisms with the financial assurance requirements detailed in HB 233. ⁶³	The Supplier Rules do not require financial assurance from suppliers exclusively serving large commercial customers ⁶⁴ , but the Electric Supplier Agreement with DPL requires an electric supplier to demonstrate Credit Resources sufficient to support a Credit Amount of two months of customer payments to the supplier. ⁶⁵ This amount should be stress tested against potential default exposure scenarios to determine adequacy.

Suggested Changes to Reporting Obligations for Large Loads

The existing electric supplier reporting requirements provide the DE PSC and the Division of the Public Advocate with information about current market activity, and changes to an electric supplier's business and retail energy regulatory status in other jurisdictions. Given that an electric supplier's certificate remains valid until revoked by the DE PSC or relinquished by the electric supplier, annual and periodic reporting provide an important window into the status of

⁶¹ HB 233 proposed modifications to Subchapter II, Chapter 1, Title 26, § 203G. (c)(9) and § 203G. (c)(10)

⁶² Amend Subchapter III, Chapter 1, Title 26, § 317.(b)

⁶³ HB 233 proposed modifications to Subchapter II, Chapter 1, Title 26, § 203G. (c)(11)

⁶⁴ 26 Del. Admin. C. § 3001, §§ 2.3.

⁶⁵ Delmarva Electric Supplier Agreement, Filed 1/29/2026, Article I: Definitions, Article 7.1 Creditworthiness.

an electric supplier's business. This is especially true for electric suppliers serving Large Load Customers given their size and scale.

Therefore, the DE PSC may want to consider amending the Supplier Rules to add events that would trigger a prompt reporting obligation for electric suppliers that serve Large Load Customers.⁶⁶ Such events may include:

- A material change in large load usage volumes if outside of the established ramp schedule;
- A request from the large load to switch its electric supplier;
- Voluntary termination of a Large Load Customer contract;
- Involuntary loss of a Large Load Customer; or
- A failure of a large load to perform during an IRAS event.

The DE PSC may also want to consider expanding the existing annual update requirements for an electric supplier that serves Large Load Customers. Expanded reporting could include:

- The number of Large Load Customers served;
- Aggregate Large Load Customer demand;
- Peak demand associated with each Large Load Customer;
- PJM zone location of each Large Load Customer;
- Actual and projected RBP and IRAS capacity obligations;
- Large Load Customer demand forecasts, and;
- Current financial assurance levels applicable to Large Load Customer service.

These recommended reporting requirements are intended to provide the DE PSC with timely information necessary to monitor electric supplier risk profiles, evaluate long-term capacity obligations, and periodically reassess whether financial assurance requirements remain appropriately calibrated.

Prohibition of Supplier Consolidated Billing for Large Load Customers

Although it's unclear if this provision is in common use in Delaware, but sections of the Electric Supplier Agreement include provisions for supplier consolidated billing, where the electric supplier would invoice both DPL's distribution charges and supply charges on one bill.⁶⁷ Given

⁶⁶ 26 Del. Admin. C. § 3001, §§ 12.1-12.3.

⁶⁷ Delmarva Electric Supplier Agreement, Filed 1/29/2026, Articles 12.4, and 13.

the complexity and magnitude of financial guarantees and long-term service commitments for distribution, billing and collections for distribution service should be handled directly by DPL.

DE PSC Authority to Implement

No statutory amendments appear to be necessary to implement these recommendations. Section 1012 of Title 26, Chapter 10 of the Delaware Code appears to authorize the DE PSC to develop regulations for the certification and oversight of electric suppliers. Therefore, the DE PSC appears to possess sufficient authority to establish additional certification and reporting requirements applicable to electric suppliers serving Large Load Customers.

Required Changes to Regulations to Implement Suggested Changes

If the DE PSC elects to impose more detailed and enhanced requirements on electric suppliers that serve Large Load Customers, it would likely need to amend or clarify its regulations and application requirements in several areas summarized in Table 7.

Table 7⁶⁸

Supplier Rules Section or Related Document	Recommended Change
Section 1.0 (Definitions)	Define Large Load Customers, and RBP and IRAS capacity obligations that may be relevant to electric supplier evaluation criteria.
Section 2.2 (Certification) Section 2.2.16 (Financial) Section 2.2.18 (Regional and Wholesale Experience) Section 2.2.19 (Retail Experience) Section 2.4 (Other Information)	Create a new category of supplier license Add additional requirements to determine financial integrity and managerial and technical ability.
Section 2.3 (Financial Security Amount)	Adjust based on the DE PSC review described in Table 6 and interpretation of HB 233.

⁶⁸ Other confirming amendments may be necessary beyond those listed in the table.

Supplier Rules Section or Related Document	Recommended Change
Section 12.3 (Reports)	Expand the annual reporting requirements for an electric supplier that serves Large Load Customers to include reporting that is specific to Large Load Customers.
Section 12.3 (Reports)	Add event-driven reporting triggers for electric supplier serving large load customers
New Provision (Certification Modifications for Serving Large Load Customers)	Add certification requirements before a certified electric supplier begins serving a Large Load Customer.
New Provision (Load Curtailment)	Add provisions on the ability of an electric supplier to facilitate loadshedding when necessary to support reliability and comply with operational requirements of customers with an IRAS performance obligation.
DE PSC Certification Application	Changes to reflect suggested additional financial, operational, and technical evaluation criteria.
DPL Electric Supplier Agreement	Changes incorporated into Supplier Rules will need to be carried over to the Electric Supplier Agreement contract that the retail electric supplier signs with DPL.

Prohibition on Large Loads Taking Standard Offer Service (SOS)

The DE PSC should evaluate whether Large Load Customers should be eligible for SOS and whether appropriate eligibility limitations are warranted to protect other SOS customers and manage the potential risks associated with serving these customers. Recent customer switching reports indicate that very few commercial customers with demands 500 kW take SOS.⁶⁹

⁶⁹ The April 2026 switching report indicates that there were nine customers > 500 kW taking SOS. Monthly switching reports are available at: <https://depsec.delaware.gov/customer-electric-choice/>

Allowing very large loads to take SOS supply could create material credit, procurement, and cost-allocation risks for other SOS customers. The first is the potential spike in uncollectibles should a large load take SOS and become unable to pay due to financial distress. Retail energy suppliers bidding on the right to provide SOS would also be likely to include a greater risk premium on this service for C&I customers. This is true even if it's an unhedged hourly LMP product because the migration of large loads onto SOS adds significant variable load risk which could spike PJM financial assurance requirements for the SOS supplier since they are based on the scale of a market participant's market activity.⁷⁰

HB 233 has language in it that seems to presume that Large Load Customers will take service from competitive electric suppliers, but includes language that allows for them to take SOS. Specifically, the amendments to § 203G. (c)(4) state *"For large energy use facilities that procure electricity from the Commission-regulated electric utility, obligate the large energy use facility to pay a minimum amount or percentage of supply costs, which cannot be less than 90% of contract capacity, based on the large energy use facility's projected electricity usage for the electricity services the Commission-regulated electric utility is contracted to provide for the duration of the contract. This paragraph does not apply to a large energy use facility that procures electric supply service from a certified electric supplier."*

It's unclear how this provision could be implemented for energy costs since the SOS is an hourly index product for large customers.

In addition to the language of HB 233 that presumes availability of SOS to large loads, the DE PSC would also need to review Sections 1003 and 1006 of Title 26 of the Delaware Code that deal with retail competition and SOS. The DE PSC would need to evaluate the statutory requirements regarding obligation to provide SOS to Large Load Customers.⁷¹

The DE PSC should therefore consider both the scope of its existing authority under Sections 1003 and 1006 of the Delaware Code and whether any limitation on SOS eligibility for Large Load Customers would be consistent with the statutory framework established by HB 233.

⁷⁰ A PJM Market Participant's credit requirements are based on Peak Market Activity (PMA) which is calculated based on a formula that uses the highest weekly dollar market activity levels in the past year. The PMA calculation is detailed in the "Credit Overview and Supplement to the PJM Credit Risk Management Policy" document Version 3.8, pp. 18-22.

⁷¹ 26 Del. C. § 1006(a)(1), (b)(2).

Require PJM Subaccounts for Each Large Load

The DE PSC may want to require each Large Load Customer to establish its own PJM subaccount. This action would allow all market activity for the large load to be separate from other retail loads and provide direct visibility between the customer, the electric supplier, and the PJM market.

Revised Switching Rules for Large Accounts

Given the complexity of large loads, the potential for RBP capacity and IRAS obligations, and the potential impact of large loads on an electric supplier financial qualifications and financial assurance, the DE PSC may want to consider modifications to switching procedures set forth in the Supplier Rules. It may be beneficial to require a Large Load Customer or new electric supplier to notify the DE PSC of a request to transfer electric supplier service. The DE PSC may also want to ensure that the new electric supplier is properly certified, has adequate financial assurance for the new load, and that all capacity obligations are transferred from the discontinuing electric supplier. While the DE PSC could give prompt consideration to such applications, additional time to process a switch could be beneficial to all parties to ensure a smooth transition and to give the DE PSC insight into large load market activity.

Conclusions- Delaware

The DE PSC will need to create new regulations that will guide the development of large load tariffs. These regulations and required tariff updates must include the following in order to accommodate the new RBP capacity product type and IRAS performance obligations and crediting mechanisms:

- Electric Supplier Agreements and Operating Manuals
- FERC M-2 tariff attachments
- Interruptible tariffs that can implement EDC responsibilities under IRAS
- Policies that delineate EDC and LSE roles in IRAS implementation

To provide increased oversight and visibility into the Large Load Customer market, the DE PSC could also consider taking the following actions:

- Create a new category of retail electric supplier license with more rigorous application criteria and added reporting requirements.
- Interpret aspects of HB 233 that deal with electric generation supply, assignment of PJM capacity obligations, financial assurance, and IRAS curtailments to determine roles and responsibilities between electric suppliers and the distribution utility.

- A prohibition on Large Load Customers from taking SOS default supply, if permitted by statute.
- A prohibition on supplier consolidated billing and revised electric supplier switching rules.

In summary, the recommendations in this report are aligned with the spirit of HB 233 to give the DE PSC visibility and control over the development of service to Large Load Customers and to prevent any cross subsidization or undue rate impacts to other customers.

B. Maryland State Appendix

Maryland is a restructured state with an active retail choice market. Maryland has recently adopted legislation including the *Next Generation Energy Act* (Next Act) in 2025 and the *Reducing Energy Load Inflation for Every Families Act* (RELIEF Act) in May 2026^{72,73} to address the provision of electric service to data centers and other large load customers. As discussed in this whitepaper appendix, this legislation requires the electric distribution companies (EDCs) to file rate schedules for large loads in September 2026 and establish a large load registry by July 2027. Per the RELIEF Act, the General Assembly's intent is "that residential retail electric customers in the State should not bear the financial risks associated with large load customers interconnecting to the electric system serving the State."⁷⁴

In addition to legislation, the Maryland Public Service Commission (MD PSC) has been active with a Public Conference (PC 72) proceeding addressing load forecasts and PJM's proposed Reliability Backstop Procurement (RBP).⁷⁵ It is also in the process of promulgating regulations on load studies and tariff requirements for large load customers in Rulemaking 93 (RM 93).⁷⁶

The Maryland EDCs will be filing large load tariffs in September 2026 and this will provide an opportunity to create alignment between the new large load tariffs and PJM's RBP, Bring Your Own New Capacity (BYONC), and Interim Resource Adequacy Service (IRAS) frameworks.⁷⁷

State Level Response to Data Center Growth

Next Generation Energy Act (2025) and Reducing Energy Load Inflation for Every Families Act (RELIEF Act)

Maryland adopted the *Next Generation Energy Act* (Next Act) in 2025, which added Section 4-212 to the Maryland Public Utilities Act (PUA) to require the electric companies to file a dedicated rate schedule for large load customers.⁷⁸ The *Reducing Energy Load Inflation for Every*

⁷² The Next Generation Act (HB 1035/SB 937), effective June 1, 2025, available at:

<https://mgaleg.maryland.gov/mgaweb/Legislation/Details/HB1035?ys=2025rs>

⁷³ The *Reducing Energy Load Inflation for Every Families Act* (HB1532), effective May 12, 2026, available at:

<https://mgaleg.maryland.gov/mgaweb/Legislation/Details/hb1532?ys=2026RS>

⁷⁴ PUA § 4-212(b).

⁷⁵ Public Conference Docket materials, available at: <https://webpscxb.pscmaryland.com/DMS/pc/PC72>

⁷⁶ Rulemaking 93 proceeding materials, available at: <https://webpscxb.pscmaryland.com/DMS/administrative-docket>

⁷⁷ RBP filed under Docket No. ER26-3380-000, IRAS filed under Docket No. ER26-3515-000.

⁷⁸ The Next Generation Act (HB 1035/SB 937), effective June 1, 2025, available at:

<https://mgaleg.maryland.gov/mgaweb/Legislation/Details/HB1035?ys=2025rs>

Families Act (RELIEF Act) (§ 7-233), adopted in May 2026, amended the Next Act’s tariff filing requirements and added other non-tariff requirements for large load customers.⁷⁹

Through the RELIEF Act, the General Assembly made clear their intent that residential customers be protected from the financial risks associated with large load customers.⁸⁰ The RELIEF Act also requires the MD PSC to develop a large load customer registry by July 1, 2027 and establish regulations that govern an EDC’s provision of voluntary, large-load interruptible interconnection service.^{81, 82, 83}

Under PUA Section 4-212, the electric distribution companies must file the “large load customer” rate schedules for electric service on September 1, 2026. A large load customer is defined as a commercial or industrial customer that has or is projected to have an aggregate monthly demand of at least 25 megawatts (MW) and a load factor over 60 percent.⁸⁴ This legislation establishes minimum requirements for the rate schedules, and is intended to ensure that costs associated with large new electric loads (including PJM costs) are allocated to those customers.

Public Conference and Rule Making Proceedings

The MD PSC has been actively preparing for increasing amounts of large load customers taking electric service in Maryland. In Public Conference 72 (PC72), the MD PSC recently received stakeholder comments on the Maryland load forecasts impacting the RBP procurement, payment for RBP capacity, and compliance with statutes.⁸⁵ This was in response to a notice to stakeholders issued in July 2026.⁸⁶

The MD PSC is also in the late stages of promulgating regulations on load studies and tariff requirements for large load customers, Rulemaking Session 93 (RM93).⁸⁷

⁷⁹ The *Reducing Energy Load Inflation for Every Families Act* (HB1532), effective May 12, 2026, available at: <https://mgaleg.maryland.gov/mgaweb/Legislation/Details/hb1532?ys=2026RS>

⁸⁰ PUA § 4-212(b).

⁸¹ See § 4-212(G).

⁸² See § 4-212(H).

⁸³ See § 4-212(c) and (d).

⁸⁴ See § 4-212(c).

⁸⁵ Public Conference Docket materials are available here: <https://webpscxb.pscmaryland.com/DMS/pc/PC72>

⁸⁶ The July 13, 2026 Request for Comments issued in PC72, available at:

<https://webpscxb.pscmaryland.com/DMS/pc/PC72>

⁸⁷ This rulemaking process on collateral and load studies began in Docket No. PC 72 in late 2025, with a notice issued in the Maryland Register on June 26, 2026 requesting comments on the proposed regulations through July 20, 2026. See Maryland Register, V. 53, Issue 13, available at: dsd.maryland.gov/MDRIssues/5313/Assembled.aspx

Harmonizing Legislative Directives with PJM's RBP and IRAS Proposals

Large Load Tariff Features

PUA § 4-212, as modified by the Next Act, requires all EDCs to submit a proposal to establish a large load tariff with the MD PSC by September 1, 2026. Data centers and other large industrial consumers with a monthly maximum demand of at least 25 MW and a load factor of more than 60% will be required to take service on a large load tariff.

PUA § 4-212(d) identifies the parameters that the MD PSC must consider when determining whether to approve a large load tariff which include:

- Ensure large load customers pay for the just and reasonable costs associated with any electric transmission or distribution system buildout for interconnecting or serving the customer;
- Protect ratepayers from financial risks associated with large load customers by using several specified mechanisms, including financial assurances;⁸⁸
- Allocate costs to large load customers, including wholesale costs such as transmission and capacity costs, and direct or indirect costs, and fees or obligations caused.⁸⁹

As the MD PSC and the EDCs work to create large load tariffs that are responsive to recent legislation and statutory directives, they will need to pay attention to the following tariff parameters to ensure that they are aligned with PJM's RBP and IRAS proposals to facilitate implementation.

- Definitions – Maryland's large load definitions are different than PJM's. The MD PSC may want to bifurcate large load tariffs by size based on PJM's definition or use state authority to allocate RBP to loads under the 50 MW PJM threshold. All other relevant terms from the PJM RBP and IRAS proposals should be defined in the MD PSC jurisdictional tariffs to promote alignment.^{90,91}
- RBP Versus RPM UCAP Status – the tariffs will need to define these as different types of capacity products and include cost allocation procedures for each option.⁹² This language could be included in the large load tariffs or the Retail Supplier Coordination tariffs so that the LSE serving the large loads can allocate and settle capacity accurately.

⁸⁸ Other mechanisms include: minimum billing for distribution and transmission service, long-term contract commitments and exit fees, financial assurances, penalties, and reimbursement requirements for the delay or cancellation of projects after system construction has started.

⁸⁹ See § 4-212(d).

⁹⁰ FERC Docket ER26-3380, Proposed Tariff, Definitions, July 31, 2026.

⁹¹ FERC Docket ER26-3515, Proposed Tariff, Definitions, August 13, 2026.

⁹² FERC Docket ER26-3515, Proposed Tariff, Attachment DD-4, section IX, August 13, 2026.

The capacity type can also impact customer financial assurance obligations since RBP capacity has a 15-year RBP term.⁹³

- IRAS Status – customers with an IRAS curtailment obligation will need to be subject to priority curtailment based on tariff language that mimics the IRAS curtailment procedures that will be codified in PJM Manual 13.⁹⁴ Additionally, if there will be a payment mechanism for IRAS curtailment performance, it will need to be harmonized with the demand response crediting language in PJM’s proposed IRAS tariff Attachment DD-4, Section X.⁹⁵

Existing Maryland Interruptible Requirements

Under the Code of Maryland Regulations (COMAR 20.50.12.15), all Maryland EDCs must establish and maintain comprehensive resilience plans. The text explicitly defines the required scope of these mandates:

“An electric utility shall have resilience plans to prepare for and recover from various utility-defined credible event threat scenarios such as pandemics, physical attacks, cyber attacks, **electric supply shortages**, weather events, significant infrastructure failures, and other credible disturbances with the potential to lead to large and widespread electric outages or loss of critical facilities essential for public health and safety.”⁹⁶

While electric supply shortages are included in EDC resilience plans, there are no mandatory interruptible or emergency curtailment provisions in the current Maryland EDC tariffs. The RELIEF Act directs the MD PSC to establish, by order or regulation, for each EDC a voluntary large-load interruptible interconnection service.⁹⁷ The MD PSC will need to ensure that the parameters of this program integrate with the requirements of PJM’s IRAS proposal approved by FERC.

⁹³ The MD PSC’s proposed regulations contemplate that the utilities (or electric cooperatives) may require collateral from a large load customer. The MD PSC may also want to consider LSEs bearing some of the RBP commitment risk along with the large load customer in the event of a default or shutdown in operations prior to transfer of RBP obligation to another subscriber or socialization among remaining RBP customers across PJM.

⁹⁴ Affidavit of Christopher Pulong on Behalf of PJM Interconnection, LLC.at 24

⁹⁵ FERC Docket ER26-3515, Proposed Tariff, Attachment DD-4, section X, August 13, 2026

⁹⁶ COMAR 20.50.12.15, available at: <https://regs.maryland.gov/us/md/exec/comar/20.50.12.14#E> (emphasis added)

⁹⁷ See § 4-212(H) as modified by HB1532.

Minimum Required State Level Actions

Retail Supplier Coordination Tariffs

PJM’s RBP and IRAS proposals involve the creation of a new capacity product and RPM UCAP that has an associated interruptible performance obligation, respectively. At a minimum, they will need to be defined in the definitions section of the Electric Supplier Coordination tariffs along with determination of capacity obligations (aka “tags”), settlement procedures, and reallocation provisions for unsubscribed RBP capacity in the event of a default of a large load with an RBP capacity obligation. A summary of sections of the Supplier Coordination Tariffs that will require revisions are included in Table 8 below.

Table 8: Retail Supplier Coordination Tariff Sections to be Revised for New Capacity Product Types

Tariff Section	BGE⁹⁸	Pepco⁹⁹	Delmarva¹⁰⁰	Potomac Edison¹⁰¹
Definitions	pp. 1 - 3	pp. 1- 4	pp.1-4	pp.1 – 4
Capacity Obligation and Utility to Supplier Data Transfer	Sec 9 (pp. 17 – 20) Load Reconciliation, Capacity, and Transmission Accounting Processes	Sec 9 (pp. 20 – 23) Load Reconciliation, Capacity, and Transmission Accounting processes	Sec 9 (pp. 17 – 20) Load Reconciliation, Capacity, and Transmission Accounting processes	Sec 9 (pp. 19 – 24) Load Reconciliation, Capacity, and Transmission Accounting processes
RBP Reallocation Procedure	New section required			

In the future, there will be two different types of capacity products in PJM: Unforced Capacity (UCAP) acquired through the Reliability Pricing Model (RPM) Base Residual Auction (BRA) and Incremental Auctions (IA) and RBP Capacity. Large loads electing IRAS will be settled like existing UCAP obligations, but will have an added requirement to interrupt when the PJM reliability

⁹⁸ BGE Electric Supplier Coordination Tariff, available at: <https://www.bge.com/my-account/my-dashboard/rates-tariffs/electric-service>

⁹⁹ Pepco Electric Supplier Tariff, available at: <https://www.pepco.com/my-account/my-dashboard/rates-tariffs/maryland/current-tariffs>

¹⁰⁰ Delmarva Electric Supplier Coordination Tariff, available at: <https://www.delmarva.com/my-account/my-dashboard/rates-tariffs/maryland/current-tariffs>

¹⁰¹ Potomac Edison Supplier Coordination Tariff, available at: https://www.firstenergycorp.com/customer_choice/maryland/maryland_tariffs.html

trigger is met. Both RPM UCAP and RBP capacity will have their own procedures for daily allocation to load and determination of customer capacity obligations or capacity tags.

Currently, RPM capacity obligations are based on contributions to PJM's five coincident peak (5 CPs) load hours. Large load capacity obligations may be set based on other parameters such as load size, nameplate, or a ramp schedule instead of the historical 5 CPs. A large load customer's total capacity must sum to the total large load capacity obligation, but this could be met through a combination of BYONC, RBP, and IRAS. As a result, it is possible that service to one customer could require the settlement of two separate capacity products. ETE observes that Supplier Coordination tariffs in Maryland are all very similar across EDCs and that it may make sense to coordinate necessary revisions on a joint basis.

Large load customers who enter the market via BYONC will have their capacity entered into the RPM via the BRA or IAs as price takers and be cleared through the RPM with other capacity. These large load customers will then settle any differences in bilateral contract terms or pricing relative to the RPM privately with the capacity provider.

While RPM capacity obligations for customers reset on June 1st each year, it is possible for intra-year adjustments of RBP capacity in the event that a large load RBP capacity subscriber exits the market via default. When this occurs, the remaining RBP customers across all PJM zones will be allocated a pro-rata share of the defaulted RBP capacity obligation. The EGS Coordination tariff will need a mechanism to facilitate this process.

FERC M-2 Tariffs

On its website, PJM maintains an inventory of the calculation methods and parameters used to determine Total Hourly Energy Obligation (THEO), Peak Load Contribution (PLC) and Network Service Peak Load (NSPL) for each EDC.¹⁰² It is not a FERC or state-mandated requirement for each EDC to maintain a current Attachment M-2 to the PJM Open Access Transmission Tariff (OATT), but most EDCs do have an Attachment M-2 on file with their PLC contribution calculation methods as an information resource to stakeholders. A summary of Attachment M-2 documents for each Maryland EDC is shown in Table 9 below.

¹⁰² THEO, PLC, and NSPL Methodology Inventory, available at <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/theo-plc-and-nspl>

Table 9: Procedures for PLC Definitions in PJM OATT Attachment M-2

BGE	Pepco	Delmarva	Potomac Edison
Attachment M-2 pp. 2-4 (Revised 9/01/2014)	No M-2 filed w/ PJM.	Attachment M-2, pp. 1-2 (revised 7/14/2011)	Attachment M-2, pp. 2-5 (revised 9/27/2013)

The Maryland utilities should consider updating their M-2 Tariffs or other informational materials available to LSEs to reflect the new RBP capacity product type and the operational procedures associated with UCAP that is subject to IRAS. The methods used to determine total zonal or EDC capacity obligations and individual customer capacity obligations will also need to be updated since it is expected that large load customer capacity obligations will be based on a load size determination and not contribution to 5 CP hours.

For the EDCs that maintain PJM OATT Attachment M-2 tariffs or other informational materials for LSEs on their websites, they will most likely have to update them to reflect the new RBP capacity product and UCAP that has an IRAS curtailment obligation associated with it. The methods used to determine total zonal or EDC capacity obligations and individual customer capacity obligations will need to be updated since they will be determined based on load size and not contribution to 5 CP hours. This update should also include a description of the procedures for allocation of unassigned RBP capacity, should a default occur. PJM's pending RBP and IRAS frameworks assign the total capacity or curtailment obligations to the EDC, respectively, and leave the responsibility to assign RBP capacity and IRAS operating procedures to the EDCs and state regulators.¹⁰³ As a result, RBP and IRAS rules and regulations will have to be clearly documented in state jurisdictional tariffs.

RBP and IRAS Status Evaluation in Interconnection Process

In the interconnection process, Large Demand Project Applicants or Customers should be required to disclose their planned status as BYONC, IRAS, RBP, or hybrid during the load study stage. Currently, the MD PSC is in the process of establishing regulations for load studies in RM93¹⁰⁴, and this disclosure could be a requirement of the load study request made by the large load customer. This information may be helpful in understanding the coordinated analysis of transmission and distribution system impacts of multiple projects in the interconnection and

¹⁰³ FERC Docket ER26-3515, Proposed Tariff, Attachment DD-4, sections IX, III(a), August 13, 2026

¹⁰⁴ Under the proposed regulation, load study means an initial analysis of the feasibility and timing of providing the requested retail services to the large load customer, which shall include the effects of interconnection on the utilities transmission and distribution systems over the contract period; and consideration of other interconnection requests. See Maryland Register, V. 53, Issue 13, available at: dsd.maryland.gov/MDRIssues/5313/Assembled.aspx

cluster study process and is valuable for the EDC to know before expending resources conducting studies.

Suggested Optional State Actions for Consideration

Large Load Competitive Retail Electric Supplier Licensing

MD PSC regulates electric power suppliers to establish standards for participation in the competitive retail electricity market and to provide the MD PSC with oversight of electric suppliers serving retail customers. The existing framework gives the MD PSC visibility and control over the competitive retail electricity market and protects other ratepayers by ensuring that electric suppliers are qualified to serve retail load by evaluating the management, operational and financial integrity of the organizations.

New large load customers represent a different scale and risk profile compared to traditional retail customers. Due to their scale, a default event of a large load customer poses complexity due to the potential to receive RBP and/or RBP UCAP with an IRAS curtailment obligation. Both of these capacity types may take some time to re-allocate to other large load customers in the event of an abrupt unplanned termination of operations.

To respond to this risk, the MD PSC could consider creating a new large load licensing category and require that an electric supplier interested in serving large loads petition the MD PSC to obtain a new license or modify an existing license to serve large loads. The MD PSC could also require enhanced financial assurance and bonding, managerial and technical staff qualifications, and reporting requirements as a condition of approval to provide service to large loads. The purpose of these more stringent requirements would be to ensure that high-quality electric suppliers are serving large loads and to provide the regulator with disclosures that provide timely insight into large load market activity.

Current Licensing Framework

Maryland requires retail energy suppliers to obtain a license from the MD PSC.¹⁰⁵ Applicants must provide proof of the following: technical and managerial competence; compliance with the requirements of the FERC and PJM; organizational financial integrity, and financial assurance. Under the statute, a residential electricity supplier license is valid for three years, and a license may not be transferred without approval.

¹⁰⁵ Md. Code, Pub. Util. § 7-507(a), available at:

<https://mgaleg.maryland.gov/mgaweb/Laws/StatuteText?article=gpu§ion=7-507&enactments=false>

The MD PSC has established regulations implementing these statutory licensing requirements in the Code of Maryland Regulations (COMAR) Title 20, Subtitle 51 (Supplier Rules).¹⁰⁶ In addition to the statutory requirements detailed above, the regulations require an applicant to provide¹⁰⁷:

- Financial documents such as balance sheets and income statements, a current long-term bond or other senior debt rating (if available), credit reports or ratings, and proof of having met the credit requirements of PJM (if applicable);
- A statement on the terms of competitive billing, if the applicant provides this service, and;
- Financial assurance in the form of a performance bond with amounts that vary depending on the circumstances, as summarized in Table 10 .¹⁰⁸

Table 10: Summary of MD PSC Bonding Requirement Triggers

Criteria Requiring a Bond	Bond Amount
If supplier collects deposits or prepayments	\$50K
If supplier cannot satisfy the financial integrity requirements	\$250K
If providing consolidated supplier billing	\$500K

The MD PSC considers an applicant to have “acceptable financial integrity” if it either receives an unsecured credit allowance greater than \$2,000,000 from PJM or demonstrates financial integrity through a list of financial indicators.¹⁰⁹

In addition to MD PSC Bonding requirements, each EDC maintains creditworthiness provisions enumerated in their retail energy supplier coordination tariffs. These provisions are largely uniform and the EDC creditworthiness evaluation is based on the EDCs financial exposure to the retail energy supplier. The criteria for evaluation are not listed, but each supplier coordination tariff states that “*The Company will apply, on a non-discriminatory basis, reasonable financial evaluation standards to assess and examine the Electricity Supplier’s financial condition.*” All supplier tariffs except for BGE have a section dealing with “Failure to Maintain Creditworthy

¹⁰⁶ COMAR 20.51.02.01 et seq., available at: <https://regs.maryland.gov/us/md/exec/comar/20.51>

¹⁰⁷ This list is non-exhaustive.

¹⁰⁸ COMAR., 20.51.02.02, 20.51.02.08(F-H), and 20.51.03.02.

¹⁰⁹ COMAR., 20.51.02.08.

Status” and give the EDC recourse to require additional credit resources such as a parental guarantee, surety bond, letter of credit, or deposit in the required credit amount.^{110, 111, 112, 113}

An electricity supplier license remains valid unless suspended by the MD PSC. Licensed electricity suppliers are subject to ongoing reporting requirements including disclosing material changes to a list of financial indicators within 10 business days¹¹⁴ and annual updates of business metrics

Suggested Changes to Licensing

The MD PSC should consider enhancements to its Supplier Rules to establish a Large Load Supplier definition and licensing category. Like other states, the existing criteria were not designed for electric suppliers that serve large load data center customers and enhancements are necessary to ensure that electric suppliers that serve “Large Load Customers” are technically and financially qualified to minimize the risks to other customers in the event of a default.

Specific areas of the licensing process that the MD PSC may want to modify are summarized in Table 11 below.

Table 11

Application Criteria (Current requirements listed if relevant)	Suggested Change	Rationale
Definitions:	Define Large Load Customer and related terms as necessary to ensure alignment with PJM language ¹¹⁵	New terminology is necessary to establish requirements for electric suppliers that serve Large Load Customers

¹¹⁰ BG&E Electric Supplier Coordination Tariff, PSC MD E-6, Section 5: Creditworthiness, Effective June 1, 2000

¹¹¹ Potomac Edison Company, Electric Supplier Coordination Tariff, PSC MD No. 54, Section 5: Creditworthiness, Effective July 1, 2000.

¹¹² Delmarva Power – Maryland, Electric Supplier Coordination Tariff, PSC MD No. 10, Section 5: Creditworthiness, Effective January 9, 2001.

¹¹³ PEPCO, Electric Supplier Coordination Tariff, PSC MD No. 2, Section 5: Creditworthiness, Effective June 16, 2000

¹¹⁴ COMAR., 20.51.03.01(B) and (C).

¹¹⁵ FERC Docket ER26-3515, Proposed Definitions, August 13, 2026.

Application Criteria (Current requirements listed if relevant)	Suggested Change	Rationale
Financial Integrity/Bonding:	Add additional rigor to the financial integrity analysis for electric suppliers serving large loads. Add a bonding requirement based on financial exposure for large load customers administered by either the MD PSC or the EDCs.	The current ambiguity and EDC discretion in the creditworthiness provisions of the supplier coordination tariff and the MD PSC bonding criteria that are only triggered by select circumstances are not suitable customer protections from the risks associated with large loads. HB 1532 requires direct assignment of RBP capacity and prohibits other customers from subsidizing large load customers. ¹¹⁶
Managerial and Technical Ability: While the regulation requires the applicant provide technical and managerial competency, the application contains the details. ¹¹⁷	Electric power supplier should demonstrate that the organization and key staff have experience with large loads in PJM or other markets and should demonstrate that they can help customers shed load, either as a Curtailment Service Provider (CSP) or through other load management program.	Minimize defaults or operational issues by requiring a high level of sophistication and organizational capability. Load shedding capability is important to ensure adherence to IRAS load curtailment obligations.

¹¹⁶ See Sections 4-212(d)(3)(II) and 4-212(e) as modified by HB1532.

¹¹⁷ Per the application, the applicant must provide a description of itself and its current operations, as well as its “intended operations in Maryland, past work experience, business plans, and other items or information that demonstrate technical and managerial competency.” See Applications to Supply Electricity or Electric Generation Service, available here: <https://psc.maryland.gov/regulated-utilities/electricity/application-for-licenses-to-supply-electricity/>

Application Criteria (Current requirements listed if relevant)	Suggested Change	Rationale
Supplier Consolidated Billing¹¹⁸	Supplier consolidated billing should not be permitted for suppliers serving Large Load Customers.	Supplier billing for large load customers is potentially complex, results in financial exposure of the EDC to the retail energy supplier, and limits the ability of the EDC to address credit issues with the large load customer directly.

Suggested Changes to Reporting Obligations for Large Loads

The MD PSC requires licensed electricity suppliers to report information about current market activity and the status of the supplier's business. Given the scale and importance of managing Large Load Customers, the MD PSC may want to consider specifying events involving Large Load Customers that would trigger a prompt reporting obligation such as the following:

- A material change in large load usage volumes if outside of the established ramp schedule;
- A request from the large load to switch its electric power supplier;
- Voluntary termination of a Large Load Customer contract;
- Involuntary loss of a Large Load Customer; or
- A failure of a large load to perform during an IRAS event.

The MD PSC could also consider expanding the existing annual reporting requirements for an electric supplier who serves Large Load Customers to:

- The number of Large Load Customers served;
- Aggregate Large Load Customer demand;
- Peak demand associated with each Large Load Customer;
- PJM zone location of each Large Load Customer;
- Actual and projected RBP and IRAS capacity obligations;
- Large Load Customer demand forecasts, and;
- Current financial assurance levels applicable to Large Load Customer service.

¹¹⁸ Although provisions for supplier consolidated billing are present in the COMAR regulations at Md. Code Regs. 20.53.05.07, but ETE understands that this is not a currently active program in MD.

These reporting requirements would provide the MD PSC with information necessary to monitor supplier risk profiles, evaluate long-term capacity obligations, and periodically reassess whether financial assurance requirements remain appropriately calibrated.

MD PSC Authority to Implement

No statutory amendments appear necessary to implement these recommendations.

The MD PSC appears to possess sufficient authority to establish additional licensing, bonding or financial assurance, and reporting requirements applicable to suppliers serving “Large Load Customers”.

Required Changes to Regulations to Implement Suggested Changes

If the MD PSC elects to impose more detailed requirements on electric power suppliers serving Large Load Customers, it would need to amend or clarify its regulations and the application requirements in several areas summarized in Table 12.

Table 12¹¹⁹

Regulation Section	Recommended Change
Section 20.51.01.02 (Definitions)	Define Large Load Customers or data center customers, as appropriate. Identify RBP and IRAS obligations and other relevant terms from the PJM RBP and IRAS filings.
Section 20.51.01.02 (Application Requirements)	Add requirements for the provision of information needed to evaluate a license to serve Large Load Customers, including managerial and technical ability.
Sections 20.51.02.08(F) (Financial Integrity) and 20.51.03.02 (Collection of Prepayment or Deposit)	Modify financial assurance and bonding requirements applicable to Large Load Customers so that they are a standalone requirement, and amounts scale immediately when a new Large Load Customer is added.

¹¹⁹ Other confirming amendments may be necessary beyond those listed in the table.

Regulation Section	Recommended Change
Sections 20.51.02.04 (Material Change in Application) and 20.51.03.01(B) and (C) (Describing Material Change and Annual Reporting)	Expand the existing material change and annual reporting requirements to include mandatory reporting of information that is specific to Large Load Customers.
Section 20.51.03.01A(1) (Defining Material Change) or establish a new provision	Add event-driven reporting triggers for electric power supplier serving Large Load Customers.
MD PSC License Application and Reporting Materials	Changes to reflect suggested changes detailed above.

Prohibition on Large Loads Taking Standard Offer Service (SOS)

To ensure that SOS remains stable and affordable for Maryland customers, the MD PSC should consider whether Large Load Customers should be able to receive SOS in the future. Large Load Customers may have multiple capacity types and their entry onto SOS could spike the PJM financial assurance requirements for the SOS provider.¹²⁰ These risks are in addition to the uncollectible risk.

C&I customers with demands over 600 kW have received hourly-priced service (HPS) as the default since approximately 2005 if they do not select a competitive supplier.¹²¹ The EDCs provide HPS as part of the SOS categories.¹²²

Maryland law defines SOS as electric service that an electric company must offer under § 7-510(c) of the Public Utilities Article,¹²³ and § 7-510(c)(2) provides that a customer is deemed to have chosen SOS if, among other circumstances, the customer cannot arrange for electricity

¹²⁰ A PJM Market Participant's credit requirements are based on Peak Market Activity (PMA) which is calculated based on a formula that uses the highest weekly dollar market activity levels in the past year. The PMA calculation is detailed in the "Credit Overview and Supplement to the PJM Credit Risk Management Policy" document Version 3.8, pp. 18-22.

¹²¹ Although COMAR 20.52.01.02 retains a definition of "Type III" service for large customers that are ineligible for Type I or Type II SOS, the operative Type III service provisions in COMAR 20.52.02.03 applied only during specified transition periods that expired in 2005. COMAR 20.52.02.03(B), available at: <https://regs.maryland.gov/us/md/exec/comar/20.52.02.03#B>

¹²² COMAR 20.52.03.04, available at: [https://regs.maryland.gov/us/md/exec/comar/20.52.02.03#B\(4\)](https://regs.maryland.gov/us/md/exec/comar/20.52.02.03#B(4))

¹²³ Md. Code Ann., Pub. Util. § 7-501(n), available at: <https://mgaleg.maryland.gov/mgaweb/website/laws/StatuteText?article=gpu§ion=7-501&enactments=False&archived=False>

from a supplier or does not choose a supplier.¹²⁴ The MD PSC’s SOS regulations echo the obligation to serve, stating that, “[a] utility or any other Commission-authorized entity shall provide SOS to any eligible customer choosing SOS, whose electric service has not been denied or terminated . . .”.¹²⁵

This whitepaper recommends that Large Load Customers be excluded from SOS which would require the statute governing SOS to be amended to expressly establish this policy.

Prohibition on Supplier Consolidated Billing

Presently, there are regulations that detail provisions for supplier consolidated billing, where the retail energy supplier bills for distribution service on behalf of the EDC and then remits payment to the EDC.¹²⁶ Due to the scale of large customer loads, the potential credit exposure to the EDC, and the potential complexity of “Large Load Customer” rates, this whitepaper recommends that supplier consolidated billing not be available to large load customers.

Require PJM Subaccounts for Each Large Load

The MD PSC may want to require each large load to set up its own PJM subaccount. This action would ensure that all market activity for the large load is separate from other retail loads and ensures direct line of sight between the customer, the EGS, and the PJM market.

Revised Switching Rules for Large Accounts

Given the complexity of large loads, the potential for RBP capacity and IRAS obligations, and the potential impact of large loads on supplier financial assurance requirements, the MD PSC may want to consider modification of electric supplier switching rules for large loads. It may be beneficial to require the large load customer or a new retail electric supplier to submit a notification to the MD PSC indicating a request to transfer electric supplier service. The MD PSC may want to ensure that the new supplier is properly licensed, has adequate financial assurance, and that all capacity obligations are transferred from the discontinuing electric supplier. While the MD PSC could give prompt consideration to such applications, additional time to process a switch could be beneficial to all parties to ensure a smooth transition and to give the MD PSC insight into large load market activity.

¹²⁴ Md. Code Ann., Pub. Util. § 7-510(c)(2), available at:

<https://mgaleg.maryland.gov/mgaweb/Laws/StatuteText?article=gpu§ion=7-510&enactments=false>

¹²⁵ COMAR 20.52.01.03(A), available at: <https://regs.maryland.gov/us/md/exec/comar/20.52.01.03#A>

¹²⁶ COMAR 20.59.05.05.

Conclusions- Maryland

The MD PSC will be actively considering new large load tariffs from the MD EDCs with filings expected in September 2026. These tariffs will need to address the following:

- Harmonization of definitions with PJM's RBP and IRAS proposals
- Identification of customers with RBP capacity allocations and the procedures to assign this capacity to LSEs
- Development of interruptible tariffs that facilitate operationalization of IRAS including IRAS dispatch triggers and performance measurement and enforcement.
- Payments for IRAS performance, if applicable, will need to be formalized in the tariffs using a mechanism that is compatible with the PJM IRAS tariffs accepted by FERC

Additionally, implementation of the RBP and IRAS proposals will require updates to the retail supplier coordination tariffs, FERC M-2 attachments (if filed) or EDC informational materials for LSEs regarding capacity calculation and allocation methods.

This whitepaper also suggests the following changes that may be helpful to oversight and management of large load customers in Maryland:

- Creation of a new electric supplier licensing category to serve large load customers with revised managerial, technical, and financial capabilities requirements;
- Revisions to financial assurance levels for retail suppliers serving large load customers. This should also include a determination as to whether the MD PSC through bonding or the EDCs through their creditworthiness supplier tariff provisions should be the one to require and monitor retail supplier financial assurance based on large loads served;
- Added MD PSC oversight to retail suppliers serving large load customers through additional annual reporting fields and events that trigger prompt MD PSC notification;
- Restrictions on large load customer ability to take SOS;
- A requirement for Large Load Customers to establish PJM subaccounts;
- Prohibition of supplier consolidated billing for retail suppliers serving large load customers.
- Modification in electric supplier switching rules to ensure that large load customer switches involving transfer of non-standard capacity products are executed properly.

C. New Jersey State Appendix

New Jersey is a restructured state with an active retail choice market. The New Jersey Legislature just passed the Data Center Fair Share Act (Assembly Bill No. 796 or AB 796) which was signed by Governor Mikie Sherrill in July 2026.¹²⁷ The enactment of AB 796 provides clear direction to the New Jersey Board of Public Utilities (NJ BPU) to create a statewide framework for large load and data center regulations and tariffs. The legislative direction in AB 796 is largely aligned with the state level actions that will be necessary in order to implement PJM's Reliability Backstop Procurement (RBP), Bring Your Own New Capacity (BYONC), and Interim Resource Adequacy Service (IRAS) framework.

The New Jersey investor-owned utilities Public Service Gas & Electric (PSEG), Jersey Central Power & Light (JCPL), Atlantic City Electric (ACE), and Rockland Electric (Rockland) all have large commercial rates, but each one will be required to submit a new large load tariff per the directives in AB 796. As a result, the existing large commercial rates are not necessarily indicative of the rates that will ultimately be applicable to large load customers.

AB 796 delegates significant authority to the NJ BPU and requires that by July 2027 the BPU shall establish standards for the provision of electricity to large data center customers which can form the basis of large load customer tariffs and performance obligations.¹²⁸

In addition to the NJ BPU proceedings necessary to implement AB 796, there are several other required and suggested changes that must be made to facilitate the implementation of PJM's proposed RBP, BYONC, and IRAS frameworks. These include updates to the retail energy supplier tariff provisions, operating manuals, and any other documentation regarding allocation of capacity charges to retail load. Suggested changes include creation of a separate large load category for retail energy supplier licensing, changes to the NJ Basic Generation Service (BGS) to preclude service to large loads, and modified switching rules for large load changing retail energy suppliers. These suggested changes are to help implement the objectives of AB 796 to ensure that there is no cross subsidization of data centers by other customers or stranded costs in the event of an unplanned data center shutdown.¹²⁹

¹²⁷ Assembly Bill No. 796 (Senate Reprint dated June 18, 2026), available at: <https://nileg.state.nj.us/bill-search/2026/A796>

¹²⁸ AB 796 1(b).

¹²⁹ Id, 1(b)(2), 1(b)(3).

Summary of AB 796 by Topic Area

AB 796 provides clear direction to the NJ BPU to create a regulatory and tariff framework for Large Load Customers. Table 13 below provides a summary of key provisions and implications for RBP, BYONC, and IRAS implementation.

Table 13: AB 796 Provisions by Category

Topic	Summary Description of Provisions	Location in Bill Text	Implications for Coordination w/ PJM Proposal
New Capacity	Incentivize new clean generation, align new BYONC against actual large load capacity, and devise a tariff framework for sites with on-site generation to ensure data centers bear full costs of service.	1(b)(5-7) 1(d)(9)	Required for Implementation of BYONC and use of Effective Load Carrying Capability (ELCC) to match new capacity resources with large load capacity requirements.
Demand Response/ Load Shed	Create an intra-utility market for demand response (DR) where data centers can buy DR capacity from participants who can achieve negative peak load contribution (PLC) values through export. Require priority curtailment from large load customers w/ demand flexibility commitments that have measurable and enforceable performance standards.	1(b)(9) 1(b)(11) 1(d)(4-5)	DR mechanism must be coordinated w/ PJM capacity ratings. Negative PLC values may require engagement w/ PJM to implement. Demand response standards and penalty mechanisms should align with IRAS rules.
Deemed Capacity Values and "Tags"	Assess ELCC against load size and ensure that assigned capacity costs, inclusive of RBP capacity, are right sized to the scale of the load and frequently reviewed to assess changes.	1(b)(7-8) 1(d)(3) 1(d)(9)	Matching of accredited resource capacity to load size requires state assessments conform to PJM ELCC and UCAP and RBP allocation methodologies.
Financial Guarantees	Ensure that data center customer provides financial guarantees for 85 percent of its requested electric service requirements for 10 years or other metrics as decided by the BPU. Also creates an intra-class stranded cost recovery mechanism.	1(d)(1-2)	Need to determine who RBP and Unforced Capacity requirements are valued in the financial assurance assessment.

Topic	Summary Description of Provisions	Location in Bill Text	Implications for Coordination w/ PJM Proposal
Inter-connection	Provide an evaluation framework to prioritize data center interconnection requests	1(b)(10)	
Timelines	The BPU has one year from bill enactment to create standards for the provision of electricity to large data center customers and each distribution utility has 180 days from a BPU order setting standards to file a tariff for a large load rate class.	1(b) 1(c)	This presumes that RBP and IRAS proposals receive timely action at FERC to provide regulatory certainty for state level implementation.

As the BPU works to implement Large Load Tariffs, it will need to ensure alignment with the following tariff sections presuming they are approved by the Federal Energy Regulatory Commission (FERC):¹³⁰

- BYONC for new generation (Attachment DD-4, section VII)
- BYONC for demand response (Attachment DD-4, sections VI(b)(ii), section VII(i)(ii))
- Large load demand response implementation (PJM Manual 13¹³¹)
- Intra-utility demand response payment mechanisms (Attachment DD-4, section X)

Minimum Required State Level Actions Needed

In addition to the known action items resulting from AB 796, the sections below list the known tariff changes that will be required in order to align state level tariffs with PJM's new frameworks.

Tariffs Related to Retail Energy Supplier Coordination

PJM's RBP and IRAS proposals involve creating a new RBP capacity product and Reliability Pricing Model (RPM) Unforced Capacity (UCAP) with a mandatory interruptible load obligation and potential crediting system, respectively. At a minimum, the RBP capacity product will need to be defined in the definitions section of the Third Party Supplier Agreement.¹³² In NJ, the Third Party

¹³⁰ FERC Docket ER26-3515, Proposed Tariff, Attachment DD-4, August 13, 2026.

¹³¹ Affidavit of Christopher Pulong on Behalf of PJM Interconnection, LLC. at 24

¹³² RBP Capacity is defined in the Definitions section of the proposed tariffs and the EDC allocation procedure is detailed in Attachment DD-4, section IX.

Supplier Agreement is the contract that retail energy suppliers sign prior to offering service in an electric distribution company (EDC) territory.

In addition to definitions, these agreements will also need to be modified to accommodate determination of RBP capacity obligations (aka “tags”), settlement procedures, and reallocation provisions for unsubscribed RBP capacity in the event of a default of a large load with an RBP capacity obligation. The capacity obligation framework and allocation methodology is further detailed in the distribution company operating manuals and related procedural documents.

A summary of the sections of the Third Party Supplier Agreement that will require revisions are included in below in Table 14, while Table 15 identifies the operating manuals and specific sections expected to require corresponding revisions.

Table 14: Third Party Supplier Agreement Sections to be Revised for New Capacity Product Types

Section	PSEG¹³³	JCPL¹³⁴	O&R¹³⁵	ACE¹³⁶
Definitions	Article I (pp. 3 - 8)	Article I (pp.3 - 8)	Article I (pp. 6 - 10)	Article I (pp. 4 - 8)
Capacity Obligation and Utility to Supplier Data Transfer	Article 9: (pp. 30 – 33) Procedures for Energy Scheduling, Capacity Resource Submission and Transmission Procurement; Appendix C (pp. 65 – 68) Customer Capacity and Transmission Obligations	Article 9: (pp.30 – 33) Procedures for Energy Scheduling, Capacity Resource Submission and Transmission Procurement;	Article 9: (pp. 27 – 29) Procedures for Energy Scheduling, Capacity Resource Submission and Transmission Procurement; Appendix D (pp.57 – 62) Load profiling Methodology and Customer Capacity and	Article 9: (pp. 30 – 34) Procedures for Energy Scheduling, Capacity Resource Submission and Transmission Procurement;

¹³³ PSEG Third Party Supplier Agreement, available at:

<https://nj.myaccount.pseg.com/myservicepublic/energychoiceandthirdpartysuppliers/thirdpartysuppliers>

¹³⁴ JCPL Third Part Supplier Agreement, available at:

https://www.firstenergycorp.com/supplierservices/nj/supplier_registration.html

¹³⁵ Rockland Electric Co Third Party Supplier Agreement, available at: <https://www.oru.com/en/business-partners/become-an-energy-service-company-partner/how-to-become-an-electric-supply-company-for-orange-rockland>

¹³⁶ ACE Supplier Coordination Agreement, available at: <https://www.atlanticcityelectric.com/doing-business-with-us/energy-suppliers/retail-energy-suppliers/register-with-us>

Section	PSEG ¹³³	JCPL ¹³⁴	O&R ¹³⁵	ACE ¹³⁶
			Transmission Obligations	
RBP Reallocation Procedure	New section required			

Table 15: Operating Manuals and Respective Sections to be Revised for New Capacity Product Types

	PSEG	JCPL	O&R	ACE
Operating Manual	Capacity & Transmission Obligation Information ¹³⁷	Supplier Capacity Manual ¹³⁸	No Supplier Operating Manual available	Pepco Holdings Supplier Operating Manual ¹³⁹
Capacity Obligation and Utility to Supplier Data Transfer – Sections for Revisions	pp. 1 – 2	pp. 2 – 8	N/A	Section I Introduction & Section II. Supplier Capacity Peak Load Contribution (pp. 4- 14)

In the future, there will be two different types of capacity products in PJM: UCAP acquired through the RPM Base Residual Auction (BRA) and Incremental Auctions (IA) and RBP capacity. Large load capacity subject to IRAS requirements will be treated and settled like existing UCAP obligations, but will have an added requirement to curtail or interrupt load up to the IRAS Eligible New Large Load quantity when the interruption trigger is activated. Both RPM UCAP and RBP capacity will have their own procedures for daily allocation to load and determination of customer capacity obligations or capacity tags.

Currently, RPM capacity obligations are based on contributions to PJM’s five coincident peak (5 CPs) load hours. Large load capacity obligations may be set based on other parameters such as load size, nameplate, or a ramp schedule instead of the historical 5 CPs. The sum of a large load customer’s BYONC, RBP, and IRAS capacity must sum to the total large load capacity obligation.

¹³⁷ PSEG Capacity & Transmission Obligation Information, available at:

<https://nj.myaccount.pseg.com/myservicepublic/energychoiceandthirdpartysuppliers/energychoicedocuments?>

¹³⁸ JCPL Supplier Capacity Manual, available at:

https://www.firstenergycorp.com/supplierservices/nj/supplier_registration.html

¹³⁹ Pepco Holdings (PHI) Supplier Operating Manual, available at:

https://www.pepco.com/cdn/assets/v3/assets/bltbb7c204688a1a6a8/bltd44af5b06b575cc8/651dcb78d19d94000df07cf4/PHI_Supplier_Operating_Manual.pdf

It is possible that large loads could have two different capacity types to cover their capacity obligation, which would then result in the settlement of two separate capacity products for one load.

Large load customers who enter the market via BYONC will have their capacity entered into the RPM via the BRA or IAs as price takers and be cleared through the RPM with other capacity. These large load customers will then settle any differences in bilateral contract terms or pricing relative to the RPM privately with the capacity provider.

While RPM capacity obligations for customers reset on June 1st each year, it is possible for intra-year adjustments of RBP capacity in the event that a large load RBP capacity subscriber exits the market via default. When this occurs, the remaining RBP customers across all PJM zones will be allocated a pro-rata share of the defaulted RBP capacity obligation. The Retail Tariff or RES Handbook will need a mechanism to facilitate this process.

FERC M-2 Tariffs

On its website, PJM maintains an inventory of the calculation methods and parameters used to determine Total Hourly Energy Obligation (THEO), Peak Load Contribution (PLC) and Network Service Peak Load (NSPL) for each EDC.¹⁴⁰ It is not a FERC or state-mandated requirement for each EDC to maintain a current Attachment M-2 to the PJM Open Access Transmission Tariff (OATT), but most distribution utilities do have an Attachment M-2 on file with their PLC contribution calculation methods as an information resource to stakeholders. A summary of Attachment M-2 documents for each New Jersey EDC is shown in Table 16.

Table 16: Procedures for PLC Definitions in PJM OATT Attachment M-2

PSEG	JCPL	O&R	ACE
Attachment M-2 pp. 1-2 (Revised 6/21/2017)	Attachment M-2 pp. 2-5 (Revised 9/27/2013)	No M-2 filed w/ PJM.	Attachment M-2 pp. 1-2 (Revised 7/14/2011)

For the EDCs that maintain PJM OATT Attachment M-2 tariffs, they will most likely need to update them to reflect RBP capacity and IRAS Eligible New Large Load and the methods used to determine total zonal or EDC capacity obligations and their translation to individual customer

¹⁴⁰ THEO, PLC, and NSPL Methodology Inventory, available at <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/theo-plc-and-nspl>

capacity obligations. This update may also need to include a description of the procedures for allocation of unassigned RBP capacity, should a default occur.

Interruptible Load and Emergency Curtailment Tariffs

The New Jersey EDCs do not presently have consistent tariff provisions for emergency curtailment or interruptible loads. New Jersey Administrative Code (NJAC) has limited provisions for curtailment of service due to safety related emergencies.¹⁴¹ JCPL and PSEG have provisions in their general rules that allow for interruption of service due to emergencies affecting the integrity of the system or insufficient fuel supplies.^{142,143} The ACE Third Party Supplier agreement states that ACE has the right to curtail or interrupt service due to directives from PJM.¹⁴⁴

All of these existing tariff provisions will be superseded by the demand response rules that the NJ BPU is required to promulgate per the guidance from AB 796. In addition to devising an interruptible load program that is consistent with the PJM IRAS proposal, the BPU will also need to determine roles and responsibilities for the EDCs, who are responsible for dispatch and performance of IRAS curtailments¹⁴⁵ and LSEs who will be assigned the UCAP associated with the New Large Load Customer. The PJM proposed tariff contemplates that the EDC will implement any demand response compensation to IRAS resources, but the NJ BPU could determine if LSEs should play a role in this process.

RBP and IRAS Status Evaluation in Interconnection Process

AB 796 provides legislative direction for the NJ EDCs to evaluate a large load data center's capacity procurement status and portfolio of capacity resources as part of its assessment process.¹⁴⁶

¹⁴¹ N.J.A.C. 14:3-3A.1

¹⁴² Public Service Electric and Gas Company, Tariff for Electric Service, Standard Terms and Conditions, 13.2 (Emergencies), Original Sheet No. 35.

¹⁴³ Jersey Central Power & Light Company, Tariff for Service, Section 4 (Supply and Use of Service), 4.04 (Emergency Curtailment of Service), Original Sheet No. 17.

¹⁴⁴ Atlantic City Electric, New Jersey Third Party Supplier Agreement, Article 15 (System Operation), 15.1 (Disconnection and Curtailment), p. 41.

¹⁴⁵ FERC Docket ER26-3515, Proposed Tariff, Attachment DD-4, Section III, August 13, 2026

¹⁴⁶ AB 796, 1(b)(10).

Suggested Optional State Actions for Consideration

Large Load Competitive Retail Electric Supplier Licensing

NJ BPU regulates electric power suppliers to establish standards and provide oversight to participants in the competitive retail electricity market. The existing framework gives the NJ BPU visibility and control over the competitive retail electricity market and protects other ratepayers by ensuring that electric suppliers are qualified to serve retail load by evaluating the management, operational, and financial integrity of the organizations.

New large load customers represent a different scale and risk profile compared to traditional customers. Due to their scale, a default event of a large load customer poses complexity due to the potential to receive RBP and/or RBP UCAP with an IRAS curtailment obligation. Both of these capacity types may take some time to re-allocate to other large load customers in the event of an abrupt unplanned termination of operations.

To respond to this risk, the NJ BPU could consider creating a new large load licensing category and require that an electric supplier interested in serving large loads petition the NJ BPU to obtain a new license or modify an existing license to serve large loads. The NJ BPU could also require added financial assurance, staff qualifications, firm experience, and additional reporting requirements as a condition of approval to provide service to large loads. The purpose of these more stringent requirements would be to ensure that high-quality electric suppliers are serving large loads and providing the regulator with disclosures that provide timely insight into large load market activity.

Current Licensing Framework

Currently, electric power suppliers must obtain a license from the NJ BPU before providing retail electric service to customers.¹⁴⁷ To apply for a license, the electric supplier must fill an application with the NJ BPU per the governing requirements within the New Jersey Statutes, Title 48, Chapter 3 (N.J.S.A. § 48:3-78(a)) and the BPU's regulations (N.J.A.C. 14:4-5) (Supplier Rules).

Under the statutory provisions, the NJ BPU is charged with promulgating standards for evaluating and issuing licenses to electric power suppliers and for monitoring licensees after a license has been issued. The existing framework is designed to provide the NJ BPU with

¹⁴⁷ Electric power supplier" is statutorily defined as a person that is licensed by the NJ BPU to offer, and to assume the contractual and legal responsibility to provide, electric generation service for use by retail customers. N.J.A.C. 14:4-1.2, available at: <https://regulations.justia.com/states/new-jersey/title-14/chapter-4/subchapter-1/section-14-4-1-2/>

information and safeguards regarding the financial condition, qualifications, and ongoing activities of electric power suppliers. Among other things, the framework requires suppliers to:

- Register with the NJ BPU;
- Post a surety bond;
- Provide evidence of financial integrity;
- Disclose disciplinary proceedings or actions in which the supplier is involved in;
- Quantify retail sales, if any;
- Describe the products and service to be provided;
- Agree to comply with reliability standards and the NJ BPU's standards of conduct for suppliers;
- Provide information regarding in-state employees and investigate events that may disqualify an electric power supplier from maintaining or receiving a license;
- Maintain an office within the state.¹⁴⁸

In addition, the statute provides for the continuation of a license provided that the licensee pays an annual license renewal fee and provides an annual information update. Minimum reporting requirements include sales and tax information, such as the electric power suppliers' sales volume for the most recent 12-month and calendar year by customer class. These ongoing reporting requirements provide the NJ BPU with a mechanism to monitor supplier activity after licensing and to identify changes in a supplier's business or customer base.

The NJ BPU's Supplier Rules elaborate on the statutory licensing standards applicable to electric power suppliers.^{149, 150} The regulations establish a broader framework governing initial applications, annual application updates, fees, bonding, ongoing compliance, utility responsibilities, license terms, and enforcement. Key aspects of the Supplier rules are summarized in the sections below in the context of recommended considerations for the NJ BPU.

Considerations with AB 796 and Retail Energy Suppliers

AB 796 primarily addresses the provision of service to large data center customers by EDCs and does not directly address the licensing requirements applicable to electric power suppliers under N.J.S.A. § 48:3-78(a). Nevertheless, AB 796 contains several elements that provide useful

¹⁴⁸ N.J.S.A. 48:3-78(c). In addition, Subsection (b)(3) contains annual information update requirements, and Subsection (d) includes the electric public utility obligations with respect to electric power suppliers.

¹⁴⁹ N.J.A.C. 14:4-1.2, available at: <https://regulations.justia.com/states/new-jersey/title-14/chapter-4/subchapter-5/>

¹⁵⁰ See e.g., the New Jersey Shop for Energy Suppliers Webpage, available at: <https://www.nj.gov/bpu/commercial/shopping.html>

policy and regulatory context for developing policies for licensing suppliers that serve Large Load Customers. These include:¹⁵¹

- Defining the characteristics of “large data center loads” and “large data center load customers”;¹⁵²
- Protecting against large data center customers being subsidized by other electric public utility customers, and;¹⁵³
- Requiring priority curtailment of large data center customers under system emergencies.¹⁵⁴

The New Jersey Legislature also recognizes the importance of financial guarantees in the context of providing utility service to large data centers in Assembly Bill No. 796. The legislation directs the NJ BPU to establish standards requiring each electric public utility to establish rates, terms and conditions that ensure that a large data center customer provides “adequate financial guarantees that it will pay for at least 85 percent of the electric supply it requests for a period of 10 years. . . .”^{155, 156} Although these requirements do not directly apply to electric power supplier licensing, they provide a relevant policy consideration for the NJ BPU when evaluating whether additional financial assurance requirements should apply to electric power suppliers serving Large Load Customers.

Suggested Changes to Licensing

The NJ BPU should consider enhancements to its Supplier Rules to establish a Large Load Supplier definition and licensing category. The existing criteria are generally focused on protection of residential and small commercial customers and were not designed for electric suppliers that serve large data center customers. Enhancements are necessary to ensure that electric suppliers that serve Large Load Customers are qualified and to minimize the supply-related risks associated with providing retail service to Large Load Customers.

¹⁵¹ Assembly Bill No. 796, Subsection 1(c), available at: <https://njleg.state.nj.us/bill-search/2026/A796>

¹⁵² Id., 1(b)(1).

¹⁵³ Id., 1(b)(2).

¹⁵⁴ Id., 1(b)(11).

¹⁵⁵ Id., (c).

¹⁵⁶ See e.g., id., Section 1(d)(2) (requiring “posting of deposits, financial security, or, for large data centers with sufficiently high credit ratings, financial commitments, in respective forms approved by the board, sufficient to protect ratepayers against material increase in rates” if the data center ceases operations or takes less service than anticipated).

Specific areas of the application process that the NJ BPU may want to modify are summarized in Table 17 below.

Table 17

Application Criteria (Current requirements listed if relevant)	Suggested Change	Rationale
Definitions	Define Large Load Customer and related terms as necessary to ensure coordination with PJM language ¹⁵⁷ and terminology used in AB 796.	New terminology is necessary to establish requirements for electric suppliers that serve Large Load Customers. States have a lot of flexibility to use their own definitions to allocate RBP capacity and for IRAS execution, but any state definitions that are different from PJM definitions must be documented. ¹⁵⁸
Financial Integrity: Must disclose records and information about past financial dealings and conditions, and references from financial institutions. ¹⁵⁹	Add additional rigor to the financial review which may include minimum credit agency ratings or other financial health indicators based on financial statements.	Minimize financial defaults by ensuring that the electric power supplier is financially sound. Helps to reduce the potential for ratepayer subsidies of RBP costs upon a default, consistent with New Jersey's state policy.

¹⁵⁷ FERC Docket ER26-3515, Proposed Definitions, August 13, 2026.

¹⁵⁸ PJM Proposed tariffs delegate cost allocation of RBP and IRAS operationalization to the states at Proposed Tariffs Attachment DD, section 18.3(b)(iii); Attachment DD-4, III(c); Attachment DD-4, IX(b)(i); and Attachment DD-4, X.

¹⁵⁹ N.J.A.C. 14:4-5.3 available at: <https://regulations.justia.com/states/new-jersey/title-14/chapter-4/subchapter-5/section-14-4-5-3/>

Application Criteria (Current requirements listed if relevant)	Suggested Change	Rationale
Managerial and Technical Ability: Must have a membership in PJM, be a signatory to the PJM Reliability Assurance Agreement, and comply with FERC and other regulatory standards. ^{160, 161}	Electric power supplier should demonstrate that the organization and key staff have experience with large loads in PJM or other markets and should demonstrate that they can help customers shed load, either as a Curtailment Service Provider (CSP) or through other load management program.	Minimize defaults or operational issues by requiring a high level of sophistication and organizational capability. Load shedding capability is important to ensure adherence to IRAS load curtailment obligations.
Bonding: Submit a surety bond for the amount of \$250,000. ¹⁶²	An electric power supplier serving Large Load Customers with RBP obligations should have a higher level of mandatory bonding than other providers.	The long-term nature of RBP creates potentially significant financial obligations for Large Load Customers and AB 796 includes multiple provisions to reduce the risk of cross subsidization of data centers by other customers through financial guarantees. Electric supplier bonding should be evaluated by BPU as part of implementation of AB 796 financial guarantee provisions.

Broadly, the suggested changes highlighted in Table 17 align with the policy goals and directives in AB 796. Despite this, it is possible that a change in electric supplier bonding requirements could require a change in the statutes governing energy competition. Presently, the existing

¹⁶⁰ There may be other additional technical requirements generally applicable to all electric power suppliers. This list is most pertinent to Large Load Customers.

¹⁶¹ N.J.A.C. 14:4-5.2 available at: <https://regulations.justia.com/states/new-jersey/title-14/chapter-4/subchapter-5/section-14-4-5-2/>.

¹⁶² N.J.A.C. 14:4-5.4 (f), (g) available at: <https://regulations.justia.com/states/new-jersey/title-14/chapter-4/subchapter-5/section-14-4-5-4/>.

fixed \$250,000 bonding requirement does not vary based on the size of the electric supplier customer base or financial exposure associated with Large Load Customers.

Suggested Changes to Supplier Reporting Obligations for Large Loads

Electric power supplier reporting to the NJ BPU provides regulators with information about current market activity. Given the scale and importance of managing Large Load Customers, the BPU may want to consider specifying events involving Large Load Customers that would trigger a prompt reporting obligation. These reporting requirements would be in addition to the annual reporting contemplated in N.J.A.C. 14:4-5.7. The NJ BPU may want to consider amending its regulations to require timely notification whenever an electric power supplier serving Large Load Customers experiences any of the following:

- A material change in large load usage volumes if outside of the established ramp schedule
- A request from the large load to switch its electric power supplier;
- Voluntary termination of a Large Load Customer contract;
- Involuntary loss of a Large Load Customer; or
- A failure of a large load to perform during an IRAS event.

The BPU could also consider expanding the existing annual update requirements for an electric power supplier who serves Large Load Customers to include the following information regarding Large Load Customer service:

- The number of Large Load Customers served;
- Aggregate Large Load Customer demand;
- Peak demand associated with each Large Load Customer;
- PJM zone location of each Large Load Customer;
- Actual and projected RBP and IRAS capacity obligations;
- Large Load Customer demand forecasts, and;
- Current financial assurance levels applicable to Large Load Customer service.

These reporting requirements would provide the BPU with information necessary to monitor supplier risk profiles, evaluate long-term capacity obligations, and periodically reassess whether financial assurance requirements remain appropriately calibrated.

NJ BPU Authority to Implement

With the exception of electric supplier bonding levels described earlier, no statutory amendments appear necessary to implement the rest of these recommendations, The NJ BPU

appears to possess sufficient authority to establish additional licensing requirements applicable to suppliers serving Large Load Customers, and to increase the applicable bonding requirements. As noted above, N.J.S.A. § 48:3-78(a) sets out the minimum obligation of the NJ BPU to promulgate standards for evaluating, issuing, and monitoring a license to electric power suppliers. The NJ BPU may add to the minimum statutory standards.

Required Changes to Regulations to Implement Suggested Changes

If the NJ BPU elects to impose more detailed and enhanced requirements on electric power suppliers serving Large Load Customers, it would need to amend or clarify its regulations and the application requirements in several areas summarized in Table 18. Table 18¹⁶³

Regulation Section	Recommended Change
Section 14:4-1.2 (Definitions)	Define Large Load Customers or data center customers, as appropriate, and RBP and IRAS capacity obligations that may influence electric power supplier evaluation criteria.
Section 14:4-5.3 (Application Form)	Add requirements for the provision of information needed to evaluate a license to serve Large Load Customers, including financial integrity, and managerial and technical ability.
Section 14:4-5.4 (f), (g) and (h) (Board Review Procedure and Annual Information Update)	Modify financial assurance requirements so that they scale immediately when a new large load customer is added.
Section 14:4-5.7 (Required Contents of the Annual Information Update)	Expand the existing annual update and notification requirements to include the information specific to Large Load Customers.
New Provision (Periodic Change Reporting for Large Load Customers)	Add event-driven reporting triggers for electric power supplier serving Large Load customers.

¹⁶³ Other confirming amendments may be necessary beyond those listed in the table.

Regulation Section	Recommended Change
New Provision (Load Curtailment)	Add provisions on the ability to facilitate load shedding, as necessary to ensure reliability.
NJ BPU License Application	Changes to reflect suggested changes detailed above

Prohibition on Large Loads Taking Basic Generation Service – Commercial and Industrial Energy Pricing (BGS-CIEP)

To ensure that BGS remains stable and affordable in New Jersey, the NJ BPU should consider whether Large Load Customers should receive BGS in the future. The current statutory and regulatory framework broadly contemplates BGS as a source of generation service for customers that have not selected, or cannot obtain service from, an alternative electric power supplier.

The Electric Discount and Energy Competition Act of 1999 (Act) requires “each electric public utility shall provide basic generation service.”¹⁶⁴ The Act defines BGS as electric generation service provided to “any customer that has not chosen an alternative electric power supplier” and further includes customers that cannot obtain service from an electric power supplier for any reason, including non-payment. The NJ BPU’s regulations reflect this framework.

This suggests that Large Load Customers are currently contemplated within the BGS framework. Accordingly, if the policy objective is to establish different eligibility requirements for Large Load Customers, the BPU may want to consider whether changes to the existing statutory or regulatory framework are appropriate.

Require PJM Subaccounts for Each Large Load

The NJ BPU may want to require each large load to set up its own PJM subaccount. This action would ensure that all market activity for the large load is separate from other retail loads and ensures direct line of sight between the customer, the electric power supplier, and the PJM market.

¹⁶⁴ N.J. Stat. § 48:3-57 (Electric public utility to provide basic generation service; Retail Margin Fund, use; report), available at: <https://lis.njleg.state.nj.us/nxt/gateway.dll?f=templates&fn=default.htm&vid=Publish:10.1048/Enu>

Revised Switching Rules for Large Accounts

Given the complexity of large loads, the potential for RBP capacity and IRAS obligations, and the potential impact of large loads on an electric power supplier's bonding requirement, the NJ BPU may want to consider modification of electric power supplier switching rules for large loads. It may be beneficial to require the large load customer or new electric power suppliers to submit a notification to the BPU indicating a request to transfer service. The BPU may want to ensure that the new electric power supplier is properly licensed, has adequate bonding for the new load, and that all capacity obligations are transferred from the discontinuing electric power supplier service. While the BPU could give prompt consideration to such applications, additional time to process a switch could be beneficial to all parties to ensure a smooth transition and to give BPU insight into large load market activity.

Conclusions – New Jersey

The NJ BPU will spend the next 12 months working through a process to translate AB 796 into rules and regulations for large loads. Once the regulations are finalized, the EDCs will be required to submit large load tariffs. This process at the NJ BPU will require close coordination with PJM to ensure that New Jersey's rules align with the final RBP and IRAS rules that are ultimately approved by FERC. In addition to the NJ BPU process to implement AB 796, the following EDC tariffs or agreements will require updates or new sections to reflect procedures for assignment and settlement of RBP capacity and UCAP that has a corresponding IRAS obligation:

- Third party supplier agreements
- Electric supplier operating manuals
- FERC M-2 Attachments
- Interruptible tariffs that can implement EDC responsibilities under IRAS
- Policies that delineate EDC and LSE roles in IRAS implementation

This whitepaper also suggests the following changes that may be helpful to oversight and management of large load customers in New Jersey:

- Creation of a new electric supplier licensing category to serve Large Load Customers with revised managerial, technical, and financial capabilities requirements;
- Additional bonding requirements, if authorized by a change in statute or BPU determines that it has sufficient authority to alter them;
- Added NJ BPU oversight to electric suppliers serving Large Load Customers through additional annual reporting fields and events that trigger prompt BPU notification;

- Limitations on Large Load Customer eligibility to take BGS-CIEP service;
- A requirement for Large Load Customers to establish PJM subaccounts;
- Modification in electric supplier switching rules to ensure that large load customer switches involving transfer of non-standard capacity products are executed properly.

D. Pennsylvania State Appendix

Pennsylvania is a restructured state with an active retail choice market in all major electric distribution companies (EDCs). Throughout the last year, the Pennsylvania Public Utility Commission (PA PUC) has actively worked with a broad range of stakeholders to devise a large load retail distribution tariff framework which culminated in May 2026 with an Order and model large load tariff.¹⁶⁵ In addition, Pennsylvania Power and Light (PPL) recently concluded a base distribution rate case with a settlement agreement that resulted in the creation of a new large load customer distribution rate, LP-6.^{166, 167}

In August 2026, Governor Josh Shapiro issued an Executive Order regarding data center development that includes several directives to the EDCs and PA PUC to implement state level tariffs necessary to implement PJM's proposed Reliability Backstop Procurement (RBP) and Interim Resource Adequacy Service (IRAS).¹⁶⁸ The Governor stated that the motivation behind the Executive Order is ratepayer protection and that his office will interact with the PA PUC via the Governor's Special Counsel for Energy Affordability.

Although the PA PUC has expended significant effort already developing large load tariffs, they will likely require some additional modifications to facilitate implementation of PJM's RBP, Bring Your Own New Capacity (BYONC), and IRAS frameworks.

Minimum Required State Level Actions Needed

Retail Supplier Coordination Tariffs

PJM's proposed RBP and IRAS frameworks involve creating a new RBP capacity type and an interruptible load obligation and potential payment mechanism, respectively. At a minimum, the RBP capacity product will need to be defined in the definitions section of the Electric Generation Supplier (EGS) Coordination tariffs along with determination of capacity obligations (aka "tags"), settlement procedures, and reallocation provisions for unsubscribed RBP capacity in the event of a default of a large load with an RBP capacity obligation. A summary of sections of the EGS Coordination Tariffs that will require revisions are included in Table 19 below.

¹⁶⁵ PA PUC Docket M-2025-3054271, Interconnection and Tariffs for Large Load Customers, Order, 5/12/2026, Appendix.

¹⁶⁶ PA PUC Docket R-2025-3057164, Opinion and Order, 6/11/2026, pp. 31-36.

¹⁶⁷ PPL Electric Pa. P.U.C. No. 202, Original Page No. 35C, Effective July 1, 2026.

¹⁶⁸ Gov Shapiro Executive Order, 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

Table 19: Retail Supplier Coordination Tariff Sections to be Revised for New Capacity Types and Operational Procedures

Tariff Section	PPL¹⁶⁹	FirstEnergy EDCs^{170,171}	PECO¹⁷²	Duquesne¹⁷³
Definitions	Sheet 4-4C	Sheet 5 - 10	Sheet 4-7	Sheet 4-6B
Capacity Obligation and EDC to EGS Data Transfer	Rule 4 (Sheet 8 - 8C) Coordination Obligation	Rule 4 (Sheet 16 - 19) Coordination Obligations	Rule 4 (Sheet 13- 15) Coordination Obligations	Rule 4 (Sheet 11-13) Coordination Obligations
RBP Reallocation Procedure	New section required			

In the future, there will be two different types of capacity products in PJM: Unforced Capacity (UCAP) acquired through the Reliability Pricing Model (RPM) Base Residual Auction (BRA) and Incremental Auctions (IA) and RBP Capacity. Large loads electing IRAS will be settled like existing UCAP obligations, but will have an added requirement to interrupt when the PJM reliability trigger is met. Both RPM UCAP and RBP capacity will have their own procedures for daily allocation to load and determination of customer capacity obligations or capacity tags.

Currently, RPM capacity obligations are based on contributions to PJM's five coincident peak (5 CPs) load hours. Large load capacity obligations may be set based on other parameters such as load size, nameplate, or a ramp schedule instead of the historical 5 CPs. A large load customer's total capacity must sum to the total large load capacity obligation, but this could be met through a combination of BYONC, RBP, and IRAS. As a result, it is possible that service to one customer could require the settlement of two separate capacity products. ETE observes that EGS Coordination tariffs in Pennsylvania are all very similar across EDCs and that it may make sense to coordinate necessary revisions on a joint basis.

Large load customers who enter the market via BYONC will have their capacity entered into the RPM via the BRA or IAs as price takers and be cleared through the RPM with other capacity.

¹⁶⁹ PPL Electric Supplier Coordination Tariff available at: <https://www.pplelectric.com/site/Other-Parties/Electricity-Suppliers/Coordination-Tariff>

¹⁷⁰ FirstEnergy Pennsylvania EDCs include Metropolitan Edison, Penelec, Penn Power, and West Penn Power.

¹⁷¹ FirstEnergy PA EDC Supplier Tariffs, available at:

https://www.firstenergycorp.com/customer_choice/pennsylvania/pennsylvania_tariffs.html

¹⁷² PECO Electric Generation Supplier Tariff, available at: <https://www.peco.com/my-account/my-dashboard/rates-tariffs/electric-service/current-electric>

¹⁷³ Duquesne Supplier Tariff, available at: <https://duquesnelight.com/service-reliability/service-map/rates/tariff-resources>

These large load customers will then settle any differences in bilateral contract terms or pricing relative to the RPM privately with the capacity provider.

While RPM capacity obligations for customers reset on June 1st each year, it is possible for intra-year adjustments of RBP capacity in the event that a large load RBP capacity subscriber exits the market via default. When this occurs, the remaining RBP customers across all PJM zones will be allocated a pro-rata share of the defaulted RBP capacity obligation. The EGS Coordination tariff will need a mechanism to facilitate this process.

FERC M-2 Tariffs

On its website, PJM maintains an inventory of the calculation methods and parameters used to determine Total Hourly Energy Obligation (THEO), Peak Load Contribution (PLC) and Network Service Peak Load (NSPL) for each EDC.¹⁷⁴ It is not a FERC or state-mandated requirement for each EDC to maintain a current Attachment M-2 to the PJM Open Access Transmission Tariff (OATT), but most EDCs do have an Attachment M-2 on file with their PLC contribution calculation methods as an information resource to stakeholders. A summary of Attachment M-2 documents for each Pennsylvania EDC is shown in Table 20 below.

Table 20: Procedures for PLC Definitions in PJM OATT Attachment M-2

PPL	FirstEnergy EDC¹⁷⁵s	PECO	Duquesne
No M-2 filed w/ PJM, but refers to state jurisdictional supplier tariff	Attachment M-2 pp. 2-5 (Revised 9/27/2013)	Attachment M-2, pp. 1-3 (revised 9/1/2014)	No M-2 filed w/ PJM, but refers to state jurisdictional supplier tariff

For the EDCs that maintain PJM OATT Attachment M-2 tariffs, they will most likely need to update them to reflect the new RBP capacity product and UCAP that has an IRAS curtailment obligation associated with it. The methods used to determine total zonal or EDC capacity obligations and individual customer capacity obligations will need to be updated since they will be determined based on load size and not contribution to 5 CP hours. This update should also include a description of the procedures for allocation of unassigned RBP capacity, should a default occur. PJM's pending RBP and IRAS frameworks assign the total capacity or curtailment obligations to the EDC, respectively, and leave the responsibility to assign RBP capacity and IRAS

¹⁷⁴ THEO, PLC, and NSPL Methodology Inventory, available at <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/theo-plc-and-nspl>

¹⁷⁵ Despite separate Attachment M-2s filed for Metropolitan Edison, Penelec, West Penn Power (legacy Allegheny) and Penn Power (located in the ATSI transmission zone), all four Attachment M-2 documents appear to be identical.

operating procedures to the EDCs and state regulators.¹⁷⁶ As a result, RBP and IRAS rules and regulations will have to be clearly documented in state jurisdictional tariffs.

State Level Response to Data Center Growth

Governor's Executive Order

In August 2026, Governor Shapiro issued Executive Order 2026-05 that addresses multiple aspects of data center development including: environmental permitting; pathways for expedited permit review for data centers that agree to abide by the Governor's Responsible Infrastructure Development (GRID) Requirements¹⁷⁷; annual reporting requirements on energy, water, and other metrics; and directives for the PA PUC to issue rules, procedures, and orders to limit reliability and affordability impacts on the electric grid for PA consumers.¹⁷⁸

Several aspects of the Executive Order require development of new tariffs or modifications to existing tariffs. The relevant parts of the Executive Order that will require PA PUC action on RBP or IRAS related matters are detailed below (summarized for brevity):

3(a)(1) EDCs that have received a request to interconnect a data center must file with the Commission revisions to both its pre-emergency IRAS and emergency load control procedures so that utilities curtail data centers prior to any other customer, unless the data center customer has secured incremental electric capacity for the entirety of its demand;

3(b)(1) Charge data center customers for any RBP auction costs in accordance with the procedures ultimately approved by the FERC;

3(b)(2) Prevent an EDC 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;

3(c)(1) For EDCs to submit megawatt adjustments for any reliability backstop auction target in accordance with the procedures ultimately approved by the FERC in docket ER26-3380-000;

¹⁷⁶ FERC Docket ER26-3515, Proposed Tariff, Attachment DD-4, sections IX, III(a), August 13, 2026.

¹⁷⁷ PA Governor's Responsible Infrastructure Development (GRID) information page, available at <https://dced.pa.gov/business-assistance/data-center-resources/grid-requirements/>

¹⁷⁸ Gov Shapiro Executive Order, 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

3(c)(2) For EDCs to register large loads in PJM’s large load registry; and

3(c)(3) For implementation of credits pertaining to PJM’s pre-emergency IRAS program following the FERC’s ultimate disposition.

The Governor’s Executive Order is aligned with PJM’s proposed tariff frameworks which delegate authority for RBP capacity allocation to individual customers to the EDC.¹⁷⁹ Similarly with IRAS, the PJM proposal includes dispatch triggers that will be codified in PJM 13¹⁸⁰ and operationalized by the EDC who will be responsible for a total IRAS curtailment target that must be met by individual EDC large load customers responding to EDC curtailment procedures.¹⁸¹ The IRAS proposal also contemplates a payment mechanism for IRAS performance between zero and 50% of the Non-Performance Charge Rate.¹⁸² Any payments to large load customers curtailing Eligible New Large Loads would have to be codified in EDC tariffs somewhere.

Large Load Tariffs

On May 13, 2026, the PA PUC released its final Order establishing a model tariff framework for large load customers, defined as a customer connected to the electric distribution system with maximum contract capacity of over 50 MW individually or multiple closely located customers with maximum Contract Capacity of 100 MW in the aggregate (Model Tariff).¹⁸³ The terms of the Model Tariff span many topics relevant to Large Load Customers including deposits and financial security, minimum contract term lengths, notice periods and rules for modifications, interconnection and planning queue, contributions in aid of construction (CIAC), and interruptible service.

The PA PUC will need to consider modifications to the Model Tariff in order to be responsive to the Governor’s Executive Order and to incorporate the operational requirements of RBP, BYONC, and IRAS proposals.

¹⁷⁹ FERC Docket ER26-3515, Proposed Tariff, Attachment DD-4, section IX(b), August 13, 2026.

¹⁸⁰ Affidavit of Christopher Pulong on Behalf of PJM Interconnection, LLC. at 24

¹⁸¹ FERC Docket ER26-3515, Proposed Tariff, Attachment DD-4, section III(a), August 13, 2026.

¹⁸² Id., Section X.

¹⁸³ See Final Order, PA PUC Docket A-2025-3054271, p. 11 (May 12, 2026); See also id., Appendix A - Model Tariff (defining “Large Load Customer”). Per the Model Tariff, “Contract Capacity” refers to the amount of monthly peak load requirements for each month during a ramping period, as set by contract.

Table 21: Suggested Modifications to Model Tariff to Accommodate RBP and IRAS Proposals

Tariff Section/Topic	Required Change	Rationale
Definitions	Need to acknowledge PJM definitions for Large Loads, RBP, BYONC, and IRAS programs. ¹⁸⁴	To write tariffs that operationalize PJM responsibilities that are delegated to the states, ¹⁸⁵ alignment of terminology is important so that states can utilize their own large load definitions for RBP allocation and IRAS execution
Service by Capacity Category Types	The tariff will need to define the following four possible capacity option scenarios and how they impact delivery service terms like financial assurance, exit provisions, and interruptibility: • BYONC • IRAS • RBP; or • Hybrids	The service types will dictate the requirements for interruptions or financial assurance. Customers with RBP capacity will have different financial assurance or exit obligations due to the 15-year RBP term. ¹⁸⁶ Structures can change if shortage conditions are absent for three years.
Interruption Triggers and Program Rules for IRAS	IRAS Eligible New Large Loads need to be identified in accordance with PJM Tariff Attachment DD-4, section IV and EDCs must provide tariffs that conform to PJM interruption triggers codified in PJM Manual 13. Payment of credits, if any, for IRAS curtailments will have to be included in retail tariff rules.	Implementation of IRAS at the customer level is delegated to EDCs in PJM's proposed tariffs. The EDCs will have to create rules for individual customers regarding curtailment and payment of credits for performance, if any.

¹⁸⁴ For example, the PPL LP-6 criteria for large loads is "a peak electric demand of 50 MW or greater at a single facility or at least equal to 75 MW in the aggregate among facilities taking service from PPL Electric at or above 69 kV within a 10-mile radius." Whereas the Model Tariff defines them as "customers at or over 50 MW individually or 100 MW in the aggregate." Both of these are different from the PJM definitions. The PJM proposal gives states a lot of flexibility, but state definitions should be identified separately from PJM definitions.

¹⁸⁵ PJM Proposed tariffs delegate cost allocation of RBP and IRAS operationalization to the states at Proposed Tariffs Attachment DD, section 18.3(b)(iii); Attachment DD-4, III(c); Attachment DD-4, IX(b)(i); and Attachment DD-4, X.

¹⁸⁶ The PA PUC may also want to consider LSEs bearing some of the RBP commitment risk along with the customer in the event of a default or shutdown in operations prior to transfer of RBP obligation to another subscriber or socialization among remaining RBP customers across PJM.

Although Table 21 references the Model Tariff, the suggested changes are also applicable to the new PPL LP-6 tariff.

Pennsylvania currently has a statutory obligation for EDCs to maintain emergency load control and energy conservation plans.¹⁸⁷ The statute requires utilities to “establish procedures for controlling load and emergency conservation” that include schedules of load shedding priorities and that these procedures be on file at PA PUC. It appears that the statute gives the EDC and the PA PUC the authority to revise the load shedding procedures.

A summary of current PA EDC tariff provisions for load interruptions is provided in Table 22.

Table 22: EDC Tariff References to Load Shedding and Interruption Procedures

Tariff Section	PPL¹⁸⁸	FirstEnergy EDCs¹⁸⁹	PECO¹⁹⁰	Duquesne¹⁹¹
Rules	Rule 4.G – Emergency Load Control; Rule 4.H – Emergency Energy Conservation	Rule 18: Load Control; Rule 19 Energy Conservation	Rule 12.3 – Emergency Load Control; Rule 12.4 – Emergency Energy Conservation	Rule 39 – Curtailment w/o Notice Rule 39.1 – Emergency Load Control Rule 39.2 – Emergency Energy Conservation
Riders	N/A	Emergency Energy Conservation Rider	Emergency Energy Conservation	Rider 17 – Emergency Energy Conservation

The PA PUC may include IRAS rules in the tariff sections detailed in Table 22 above or elsewhere in the retail tariff or the EGS Coordination tariffs. Since most large load customers will be served by competitive retailers, the PA PUC may want to consider roles and responsibilities for the EDCs, who are responsible for dispatch and performance of IRAS curtailments¹⁹² and

¹⁸⁷ 52 Pa. Code § 57.52.

¹⁸⁸ PPL Electric, Electric Pa. P.U.C. No. 202, First Revised Pages 9D and 9E.

¹⁸⁹ First Energy Pennsylvania, Electric Pa P.U.C. No. 1, First Revised Page 57, Original Pages 58, 192, and 193

¹⁹⁰ PECO Electric Company, Tariff Electric Pa. P.U.C. No. 8, Original Pages 22-23, and 89.

¹⁹¹ Duquesne Light Company, ELECTRIC – PA. P.U.C. NO. 25, Original Pages 32, 125-126, Second Revised Page 33

¹⁹² FERC Docket ER26-3515, Proposed Tariff, Attachment DD-4, section III, August 13, 2026.

LSEs who will be assigned the UCAP associated with the New Large Load Customer. Another consideration is the methods of curtailment for IRAS as some EDCs may opt for physical interruption of supply while others may rely on a penalty mechanism. This will need to be documented in retail tariffs somewhere.

A review of the applicable emergency load control retail tariff rules and riders indicates that they are similar across EDCs in Pennsylvania. The PA PUC may want to consider a coordinated revision process.

RBP and IRAS Status Evaluation in Interconnection Process

The Governor's Executive Order promotes a clear periodization plan for large load data centers that are willing to sign a Consent Order and Agreement to the GRID requirements. The GRID requirements include BYONC for 100% of the new large load. At the present time, the Executive Order supersedes the guidance in the Model Tariff for the conduct of Full Planning Studies and Interconnection Studies.

Tariff Clean-up

Some PA EDCs such as PPL use PJM Generation PLC's to bill distribution related riders.¹⁹³ Where this is the case, the EDCs and PA PUC will need to determine how to handle customers with RBP and IRAS capacity obligations.

Suggested Optional State Actions for Consideration

Large Load Competitive Retail Electric Supplier Licensing

Pennsylvania regulates EGS in order to have visibility and control over the competitive market. PA PUC's regulation of EGS also protects other ratepayers by ensuring that EGS are qualified to serve retail load by evaluating management and financial integrity of the organizations.

The PA PUC could consider creating a new large load category and require that EGS interested in serving large loads petition to modify their PA PUC EGS licenses. The PA PUC could also require added financial assurance, staff qualifications, firm experience, and additional reporting requirements as a condition of approval to service large loads. The purpose of these more stringent requirements would be to ensure that high-quality EGS are serving large loads and providing the regulator with disclosures that provide timely insight into large load market activity.

¹⁹³ PPL Electric, Electric Pa. P.U.C. No. 202, First Revised Page 26A.

Current Licensing Framework

The Pennsylvania Electricity Generation Customer Choice and Competition Act (the “Competition Act”), 66 Pa.C.S. § 2809 requires PA PUC to promulgate regulations to establish licensing requirements for electricity suppliers designated as EGS.¹⁹⁴ An EGS cannot sell, broker, or market electricity or related services to end use customers unless it is licensed by the PA PUC.¹⁹⁵ Before issuing a license, the PA PUC must make the following findings:

- the applicant is fit to perform the retail service that it seeks to provide end use customers,¹⁹⁶
- the applicant has met financial and tax commitments,¹⁹⁷ and;
- the applicant’s application is in the public interest and is consistent with state law and policy.

In order to receive and maintain a license, an applicant must provide “a bond or other security approved by the commission in form and amount.” This requirement, which is further delineated within the PA PUC’s regulations, is intended to help ensure “the financial responsibility of the electric generation supplier” and the provision of retail electricity supply in accordance with a supplier’s contracts, agreements or arrangements.

To implement its statutory obligation to issue and oversee EGS licensing, the PA PUC established its *Electricity Generation Supplier Licensing Regulation*. This regulation sets out the PA PUC’s licensing requirements, application procedures, reporting obligations, financial security requirements, transfer procedures, and grounds for suspension or revocation of an EGS license.¹⁹⁸

¹⁹⁴ See 66 Pa. C.S. § 2809 (Pennsylvania Public Utility Code, Title 66, Chapter 28), available at: <https://www.palegis.us/statutes/consolidated/view-statute?txtType=HTM&ttl=66&chpt=28&sctn=>

¹⁹⁵ See 66 Pa. C.S. § 2803 (definitions) and § 2809 (license requirement).

¹⁹⁶ See § 2809(b) (License application and issuance). The PA PUC may grant an EGS license to an applicant if the PA PUC determines that the “applicant is fit, willing and able to perform properly the service proposed”, able to follow other applicable statutes and regulations, and rules, and that the proposed service is consistent with the public interest.

¹⁹⁷ See § 2809(c) (Financial responsibility).

¹⁹⁸ 54 Pa. Code §§ 54.31, 54.43 (Sections 54.33 and 54.40 focus on financial fitness and assurances, competency and experience, and identification of service parameters), available at: <https://www.pacodeandbulletin.gov/Display/pacode?file=/secure/pacode/data/052/chapter54/chap54toc.html&d=reduce>

Under Section 54.40, an applicant must provide an initial bond or other approved financial security in the amount of \$250,000 as a condition of licensure. Section 54.40 contemplates the modification of this initial security amount “commensurate with the nature and scope of business” within Pennsylvania when “substantial evidence is submitted in support of the modification.” After an applicant completes its first year as a licensed EGS, the PA PUC will annually review the security requirement for the EGS and may modify the security amount based on the licensee’s reported annual gross receipts information. Section 54.40 states that after the first year, “[t]he security level will be 10% of the licensee’s reported gross receipts.” Suppliers are required to maintain continuous security throughout the duration of their license and must renew or continue security instruments annually when necessary. Section 54.40 indicates that acceptable forms of financial assurance include bonds, letters of credit, and other PA PUC-approved financial instruments.

Suggested Changes to Licensing

The PA PUC could amend its *Electricity Generation Supplier Licensing* regulation and corresponding EGS applications to establish a Large Load definition and specific requirements for EGS applicants seeking to serve these loads. These additional requirements would supplement the PA PUC’s existing licensing framework without requiring creation of an entirely separate licensing program. Specific areas of the application process that PA PUC may want to alter are summarized in Table 23.

Table 23

EGS Application Criteria	Suggested Change	Rationale
Managerial and Technical Ability	EGS should demonstrate that the organization and key staff have experience with large loads in PJM or other markets.	Minimize defaults or operational issues by requiring a high level of sophistication and organizational capability.
Ability to Facilitate Load Shedding	EGS should demonstrate that they can help customers shed load, either as a Curtailment Service Provider (CSP) or other load management program.	Successful implementation of IRAS will require active EGS engagement to ensure that IRAS load is properly scheduled and that EGS staff work with customers to ensure load shedding is accomplished if no physical interruption

EGS Application Criteria	Suggested Change	Rationale
Financial Assurance (FA)	EGS should have a higher level of FA than a typical EGS if serving customers with RBP obligations.	The long-term nature of RBP results in a higher financial obligation for the customer and the current 10% of gross receipts criteria to set FA levels may be insufficient. In the event of a customer default, the RBP capacity re-allocation process may take several months to implement, especially the first time. States may want to consider EGS FA to cover RBP capacity during a gap between customer default and RBP capacity re-allocation.

The PA PUC may find that the current method to determine FA, namely a \$250,000 initial bond and subsequent annual levels based on a percentage of gross receipts, may be inadequate for an EGS serving large load with long-term RBP commitments. This annual approach would not account for the financial exposure associated with a Large Load Customer in the first year of service, prior to the FA reset resulting from the gross receipts analysis. The current process could also result in inadequate FA on an intra-year basis if the EGS adds a new large load customer since the addition of these loads represents a large step-wise change and is different from typical C&I retail energy market activity.

Suggested Changes to EGS Reporting Obligations for Large Loads

EGS reporting to the PA PUC provides regulators information about current market activity. Given the scale and importance of managing large loads, the PA PUC may want to consider specifying large load events that trigger a prompt reporting obligation. Section 54.34 currently requires reporting of changes in organizational structure or operational status but does not specifically require notification following material changes in large customer load. The PA PUC may want to consider amending Section 54.34 to require timely notification whenever an EGS serving large loads experiences any of the following:

- A material change in large load usage volumes if outside of the established ramp schedule
- A request from the large load to switch EGS
- Voluntary termination of a Large Load Customer contract;
- Involuntary loss of a Large Load Customer; or
- A failure of a large load to perform during an IRAS event

Section 54.39 currently requires an EGS to submit quarterly reports of gross receipts and annual reports containing tax information, gross receipts, and electricity sales by energy source. The PA PUC could consider expanding these reporting requirements for EGS serving large load customers to include:

- the number of Large Load Customers served;
- aggregate Large Load Customer demand;
- peak demand associated with each Large Load Customer;
- PJM zone location of each Large Load Customer;
- Actual and projected RBP and IRAS capacity obligations;
- Large load customer demand forecasts; and
- current financial assurance levels applicable to Large Load Customer service.

Some of this reporting may be duplicative of the reporting metrics included in Section 2 of Governor Shapiro's Executive Order, but the PA PUC may want to confer with DEP as to the most efficient reporting structures for data centers, EDCs, and EGS.

PA PUC Authority to Implement

No statutory amendments appear necessary to implement these recommendations. The PA PUC appears to possess sufficient authority to establish additional licensing requirements applicable to suppliers serving Large Load Customers. Section 2809 contemplates that the PA PUC will establish licensing requirements and determine the information required in license applications. Section 2809(b) authorizes the PA PUC to prescribe the form and contents of license applications by regulation, while Section 2809(c) authorizes the PA PUC to establish the form and amount of financial security required as a condition of licensure.

Required Changes to Regulations to Implement Suggested Changes

If the PA PUC does elect to impose greater financial assurance requirements on EGSs serving large loads, it would need to clarify Section 54.40 to provide that financial assurances may be used to satisfy obligations associated with supplier defaults involving long-term RBP capacity

commitments. Clarifying the permissible uses of financial security would reduce uncertainty regarding the PA PUC’s authority to utilize financial assurance to mitigate costs that might otherwise be shifted to other customers. The regulations could also be clarified to state that the PA PUC should be named as the beneficiary of the bond or security instrument to codify the language in the EGS application, Appendix D.¹⁹⁹

Table 24

Regulation Section	Recommended Change
Section 54.31 (Definitions)	Define large load customers and RBP and IRAS capacity options that may influence EGS evaluation criteria.
Section 54.33 (Application Form)	Add additional information for evaluation of a license to serve large load customers
Section 54.34 (Change Reporting)	Add event driven reporting triggers for EGS serving large load customers
Section 54.39 (Annual Reporting)	Add additional annual reporting metrics for EGS serving Large Load Customers.
Section 54.40 (Bonds or Other Security)	Modification of FA requirements to EGS serving large load customers so that they scale immediately when a new large load customer is added.
PA PUC EGS License Application	Changes to reflect suggested additional financial, operational, and technical evaluation criteria.

Prohibition on Large Loads Taking Default Service

In order to ensure that default service remains stable and affordable, it is suggested that Large Load Customers get excluded from default generation service in the future. Section 2807(e)(2) of the Competition Act requires the PA PUC to promulgate regulations governing an electric distribution company’s obligation to serve retail customers.²⁰⁰ The PA PUC has stated that the

¹⁹⁹ The EGS Application, available here: https://www.puc.pa.gov/media/3631/egs_lic_app-092325.pdf

²⁰⁰ 66 Pa.C.S. § 2807(e) (obligation to serve), available at: <https://www.palegis.us/statutes/consolidated/view-statute?txtType=HTM&ttl=66&chpt=28&sctn=>

Competition Act makes clear that the purpose of this statutory obligation is to address the scope of retail electric service that an EDC acting as a “provider of last resort” must provide customers who either have not chosen an EGS or who contracted for electric energy that was not delivered.²⁰¹ Neither the Competition Act nor the PA PUC’s regulations implementing the Competition Act expressly permit the exclusion of the Large Load Customer group from default service. The Competition Act does include a discretionary provision giving a default service provider the option to provide a large customer defined as customers with a peak demand of 15 megawatts or greater with a negotiated rate.²⁰²

The potential for large loads to take service on default supply introduces two significant risks onto EDC commercial customers. The first is the potential spike in uncollectibles should a large load take default service and become unable to pay due to financial distress. Retail energy suppliers bidding on the right to provide default service would also be likely to include a greater risk premium on C&I default service, even if it’s an unhedged hourly LMP product, because the migration of large loads onto default service adds significant variable load risk. A migration of a large load to default service could also spike PJM financial assurance requirements for the default service supplier since they are based on the scale of a market participant’s market activity.²⁰³

Determining the PA PUC’s authority to exclude Large Load Customers from default service requires a close inspection of the statutory language and frameworks.²⁰⁴ The PA PUC should address this recommendation and its statutory authority to implement the regulation under the Competition Act in a future proceeding.

²⁰¹ PA PUC Proposed Rulemaking Order on the Obligation to Serve Retail Customers, Docket No. L-00040169, p. 2 (December 16, 2024).

²⁰² 66 Pa.C.S. § 2807(e)(5)(1); see also *id.*, § 2807(e)(5)(ii) (referring to an EDC’s option to acquire or build generation for customers with loads in excess of 20 megawatts).

²⁰³ A PJM Market Participant’s credit requirements are based on Peak Market Activity (PMA) which is calculated based a formula that uses the highest weekly dollar market activity levels in the past year. The PMA calculation is detailed in the “Credit Overview and Supplement to the PJM Credit Risk Management Policy” document Version 3.8, pp. 18-22.

²⁰⁴ Title 52, Chapter 54, Subchapter G: Default Service, available at: <https://www.pacodeandbulletin.gov/Display/pacode?file=/secure/pacode/data/052/chapter54/subchapGtoc.html&d=reduce>

Require PJM Subaccounts for Each Large Load

The PA PUC may want to require each large load to set up its own PJM subaccount. This action would ensure that all market activity for the large load is separate from other retail loads and ensures direct line of sight between the customer, the EGS, and the PJM market.

Revised Switching Rules for Large Accounts

Given the complexity of large loads, the potential for RBP capacity and IRAS obligations, and the potential impact of large loads on EGS financial assurance requirements, the PA PUC may want to consider modification of EGS switching rules for large loads. It may be beneficial to require the large load customer or new EGS to submit a notification to the PA PUC indicating a request to transfer EGS service. The PA PUC may want to ensure that the new EGS is properly licensed, has adequate FA for the new load, and that all capacity obligations are transferred from the discontinuing EGS. While the PA PUC could give prompt consideration to such applications, additional time to process a switch could be beneficial to all parties to ensure a smooth transition and to give PA PUC insight into large load market activity.

Conclusions- Pennsylvania

The PA PUC will need to modify the following documents to implement the new RBP capacity product and operationalize IRAS tracking, curtailments, and payments if applicable:

- Retail supplier coordination tariffs
- FERC M-2 attachments
- IRAS interruption triggers and procedures which can be located in the Terms and Conditions or within the large load tariffs themselves
- IRAS payment crediting mechanisms which can be detailed within the retail tariff or potentially retail supplier coordination tariffs if EGS are to have a role

Governor Shapiro's Executive Order will spur PA PUC action on these items and may result in revisions to the Model large load tariff, or creation of a new large load tariff.

This whitepaper also suggests the following changes that may be helpful to oversight and management of large load customers in Pennsylvania:

- Creation of a new electric supplier licensing category to serve Large Load Customers with revised managerial, technical, and financial capabilities requirements;
- Additional FA requirements for EGS serving large load customers with RBP capacity assignments;

- Added PA PUC oversight to EGS serving Large Load Customers through additional annual reporting fields and events that trigger prompt PA PUC notification;
- Limitations on Large Load Customer eligibility to take default supply service;
- A requirement for Large Load Customers to establish PJM subaccounts;
- Modification in electric supplier switching rules to ensure that large load customer switches involving transfer of non-standard capacity products are executed properly.

E. Ohio State Appendix

Ohio is a restructured state with an active retail choice market in all major electric distribution companies (EDCs). The Public Utility Commission of Ohio (PUCO) has approved one Data Center Tariff (DCT) with AEP Ohio and the other major EDCs all have DCT proposals in proceedings before the PUCO.

Ohio is somewhat advanced in comparison to other PJM states in terms of large load data center tariff development, but these existing and pending tariffs will require some changes to conform with PJM's proposed Reliability Backstop Procurement (RBP), Bring Your Own New Capacity (BYONC), and Interim Resource Adequacy Service (IRAS) frameworks.²⁰⁵ In addition to the DCT rates, changes will also be required in the Competitive Retail Electric Service (CRES) provider handbooks and related materials so that retail energy suppliers can support the new RBP capacity product type and customers with IRAS curtailment obligations.

Minimum Required State Level Actions Needed

Retail Supplier Coordination Tariffs

PJM's proposed RBP and IRAS frameworks involve creating a new RBP capacity type and an interruptible load obligation and potential payment mechanism, respectively. At a minimum, the RBP capacity product will need to be defined in the definitions section of the CRES provider Coordination tariffs along with determination of capacity obligations (aka "tags"), settlement procedures, and reallocation provisions for unsubscribed RBP capacity in the event of a default of a large load with an RBP capacity obligation. A summary of sections of the CRES Coordination Tariffs that will require revisions are included in Table 25.

²⁰⁵ Gov Shapiro Executive Order, 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

Table 25: Summary of Required Changes to Supplier Coordination Tariffs to Accommodate RBP and IRAS

Section	Duke ²⁰⁶	AES ²⁰⁷	First Energy EDCs ^{208,209}	AEP ²¹⁰
Definitions	Sheet 20.4 PP. 1– 5	PP. 1 - 5	PP. 3 - 6	Sheet No.103-56 – 103-58
Capacity Obligation and Utility to Supplier Data Transfer	Rule 4 (Sheet No.33.2 PP. 1 – 3) Company and Certified Supplier Obligations (General Terms)	Rule 3 (PP. 8 – 10) Coordination Obligations	Rule 3 (PP.9) Coordination Obligations; Section 4 (PP.10 – 11) Company and Certified Supplier Obligations (General Terms)	Paragraph 31.4 (Sheet No.103-28 – 103-29) RTO Settlements and Reliability Requirements
RBP Reallocation Procedure	New section required			

Table 26: Summary of Required Changes to Supplier Operating Manuals

	Duke	AES	First Energy EDCs	AEP
Operating Manual	Certified Supplier Guidebook ²¹¹	Peak Load Contribution Methodology ²¹²	Supplier Capacity Manual ²¹³	CRES Provider Handbook ²¹⁴

²⁰⁶ Duke Energy Ohio Certified Supplier Tariff, available at: <https://www.duke-energy.com/home/billing/rates/certified-supplier-tariff>

²⁰⁷ AES Alternative Generation Supplier Coordination Tariff (G08), available at: <https://www.aes-ohio.com/rates-tariffs>

²⁰⁸ FirstEnergy Ohio EDCs include Ohio Edison, Cleveland Electric Illuminating Co, and Toledo Edison.

²⁰⁹ FirstEnergy Ohio EDCs each have their own Supplier Tariff linked on the FirstEnergy webpage. The supplier tariffs are identical across EDCs and are available at: https://www.firstenergycorp.com/customer_choice/ohio_.html

²¹⁰ AEP Ohio Supplier Tariff information is included in the Supplier Terms and Conditions section of the Retail Electric Tariff (Sheet 103-28 to 103-55), available at: <https://www.aepohio.com/company/about/rates/>

²¹¹ Duke Ohio Certified Supplier Guidebook, available at: <https://www.duke-energy.com/partner-with-us/retail-electric-and-gas-sup/electric/guidebook>

²¹² AES Ohio Capacity and Transmission Information and Methodology, available for download at: https://cres.aes-ohio.com/Home/LevelOne/Capacity_and_Transmission

²¹³ FirstEnergy Ohio's Supplier Capacity Manual, available at: https://www.firstenergycorp.com/supplierservices/oh/supplier_registration.html

²¹⁴ AEP Ohio Choice Operation CRES Provider Handbook, available at: <https://www.aepohio.com/company/about/choice/cres/provider-handbook>

	Duke	AES	First Energy EDCs	AEP
Capacity Obligation Allocation Methodology	Chapter 4: Obtaining End-Use Customer Historical Usage	pp. 1 - 5	PP. 2 - 8	Chapter 7.5 (PP. 16) Peak Load Contribution Tags

In the future, there will be two different types of capacity products in PJM: Unforced Capacity (UCAP) acquired through the Reliability Pricing Model (RPM) Base Residual Auction (BRA) and Incremental Auctions (IA) and RBP Capacity. Large loads electing IRAS will be settled like existing UCAP obligations, but will have an added requirement to interrupt when the PJM reliability trigger is met. Both RPM UCAP and RBP capacity will have their own procedures for daily allocation to load and determination of customer capacity obligations or capacity tags.

Currently, RPM capacity obligations are based on contributions to PJM's five coincident peak (5 CPs) load hours. Large load capacity obligations may be set based on other parameters such as load size, nameplate, or a ramp schedule instead of the historical 5 CPs. A large load customer's total capacity must sum to the total large load capacity obligation, but this could be met through a combination of BYONC, RBP, and IRAS. As a result, it is possible that service to one customer could require the settlement of two separate capacity products.

Large load customers who enter the market via BYONC will have their capacity entered into the RPM via the BRA or IAs as price takers and be cleared through the RPM with other capacity. These large load customers will then settle any differences in bilateral contract terms or pricing relative to the RPM privately with the capacity provider.

While RPM capacity obligations for customers reset on June 1st each year, it is possible for intra-year adjustments of RBP capacity in the event that a large load RBP capacity subscriber exits the market via default. When this occurs, the remaining RBP customers across all PJM zones will be allocated a pro-rata share of the defaulted RBP capacity obligation. The retail supplier coordination tariffs will need a mechanism to facilitate this process.

FERC M-2 Tariffs

On its website, PJM maintains an inventory of the calculation methods and parameters used to determine Total Hourly Energy Obligation (THEO), Peak Load Contribution (PLC) and Network Service Peak Load (NSPL) for each EDC.²¹⁵ It is not a FERC or state-mandated requirement for each EDC to maintain a current Attachment M-2 to the PJM Open Access Transmission Tariff

²¹⁵ THEO, PLC, and NSPL Methodology Inventory, available at <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/theo-plc-and-nspl>

(OATT), but many EDCs in PJM have an Attachment M-2 on file with their PLC contribution calculation methods as an information resource to stakeholders. Ohio is somewhat unique in that only the First Energy EDCs maintain M-2 attachments. The other EDCs either post this information on their websites for retail energy suppliers or default service auction data rooms. A summary of Attachment M-2 documents for each Ohio EDC is shown in Table 27 below.

Table 27: Procedures for PLC Definitions in PJM OATT Attachment M-2 or Company Websites

Duke²¹⁶	AES²¹⁷	First Energy EDCs	AEP
No M-2 filed w/ PJM. Information available upon request.	No M-2 filed w/ PJM. Information available on AES website.	Attachment M-2 pp. 2-5 (Revised 9/27/2013)	No M-2 filed w/ PJM, but refers to AEP Ohio webpage ²¹⁸

For the EDCs that maintain PJM OATT Attachment M-2 tariffs, they will most likely need to update them to reflect the new RBP capacity product and UCAP that has an IRAS curtailment obligation associated with it. This whitepaper recommends that the Ohio EDCs that do not currently maintain Attachment M-2 tariffs create one. This would greatly aid transparency to the marketplace and serve as a central location for stakeholders and market participants to find applicable methodologies for RBP and RPM UCAP that has an IRAS performance obligation.

The methods used to determine total zonal or EDC capacity obligations and individual customer capacity obligations will need to be updated since they will be determined based on load size and not contribution to 5 CP hours. This update should also include a description of the procedures for allocation of unassigned RBP capacity, should a default occur. PJM's pending RBP and IRAS frameworks assign the total capacity or curtailment obligations to the EDC, respectively, and leave the responsibility to assign RBP capacity and IRAS operating procedures to the EDCs.²¹⁹ As a result, RBP and IRAS rules and regulations will have to be clearly documented in state jurisdictional tariffs.

²¹⁶ Some Duke PLC tag calculation methodologies are posted on their Competitive Bidding Process RFP webpage available at <https://www.duke-energyohiocbp.com/Home.aspx>

²¹⁷ AES Ohio PLC Tag calculation methodologies, available at https://cres.aes-ohio.com/Home/LevelOne/Capacity_and_Transmission

²¹⁸ AEP Ohio PLC Definitions and processes, available at: <https://www.aepohio.com/company/about/choice/cres/calculations>

²¹⁹ FERC Docket ER26-3515, Proposed Tariff, Attachment DD-4, sections IX, III(a), August 13, 2026.

Large Load Tariff Development

The PUCO has moved relatively quickly toward establishing EDC-specific tariffs for large load data centers. These tariffs have focused on ensuring that the costs and risks associated with large, rapidly developing loads are not shifted to other customers.

The first major development was AEP Ohio's Data center Tariff (AEP Schedule DCT). AEP proposed the tariff in May 2024²²⁰ in response to extraordinary growth in data center service requests in central Ohio, which created uncertainty regarding how much of the proposed load was firm versus speculative.²²¹ On July 9, 2025, PUCO approved AEP Schedule DCT as a mechanism for requiring greater financial and contractual commitments from data centers while protecting other customers from the costs of underutilized or stranded infrastructure.²²² The tariff, effective as of July, 2025 has become a model for other Ohio EDCs.²²³ Key characteristics of the tariff include a separate data center customer class, long-term contractual commitments, minimum-demand billing, collateral requirements, and exit obligations intended to align infrastructure investment with credible load commitments.

In June 2026, the FirstEnergy Ohio utilities (Ohio Edison, The Cleveland Electric Illuminating Company, and The Toledo Edison Company) filed a proposed Schedule DCT in response to PUCO's Entry on Rehearing, which directed the Companies to file an application for tariff approval that creates a separate class for data centers.²²⁴ The proposal, currently under PUCO review²²⁵, follows many of the principles established by AEP but is not identical.²²⁶

AES Ohio is moving toward a similar structure through its pending rate proceeding for its proposed Data Center Tariff (Tariff Sheet D23) as of July 2026.²²⁷ Like AEP's tariff, it would require data center customers to enter into specific service agreements and assume responsibility for infrastructure required to serve their projects.

²²⁰ PUCO Case No. 24-508-ET-ATA.

²²¹ Select Committee on Data Centers, Jennifer French, Chair, May 27, 2026.

²²² PUCO Case No. 24-508-ET-ATA, Opinion & Order adopting the joint stipulation and recommendation filed by various parties on October 23, 2024, as modified herein, July 9, 2025.

²²³ PUCO Case No. 24-508-ET-ATA, Finding & Order approving the final tariffs filed by Ohio Power Company pursuant to the Opinion and Order in this proceeding, July 23, 2025.

²²⁴ PUCO Case No. 26-35-EL-RDR, Entry on Rehearing, May 31, 2026.

²²⁵ PUCO Case No. 26-697-EL-ATA.

²²⁶ PUCO Case No. 26-697-EL-ATA, Schedule DCT, June 12, 2026.

²²⁷ PUCO Case No. 25-958-EL-AIR, Stipulation and Recommendation, July 21, 2026, Exhibit 2, Original Sheet No. D23.

Duke Energy Ohio is the most recent EDC to move toward a dedicated data center tariff. In July 2026, Duke filed a proposed data center tariff (Rate DC)²²⁸ in, explaining that it had already incorporated protections into individual data center contracts but was proposing a standardized tariff to provide greater assurance that new data centers pay the costs of directly serving their load and an appropriate share of overall delivery-system costs.²²⁹

While Ohio is developing a relatively consistent regulatory framework for large data center loads across its four major IOUs, there are certain details that differ. These data center tariff filings for each Ohio EDCs are detailed in Table 28.

²²⁸ PUCO Case No. 26-755-EL-ATA.

²²⁹ PUCO Case No. 26-755-EL-ATA, Application of Duke Energy Ohio, Inc. for Approval of a New Service and Tariffs For Serving Data Center Load, July 27, 2026.

Table 28: Comparison of Ohio EDC Data Center Tariffs

Topic	AEP – Schedule DCT	FirstEnergy – Schedule DCT	AES – Tariff D23	Duke – Rate DC
<i>Tariff status</i>	Effective	Proposed	Proposed; effective date of 1/1/2027 pending PUCO approval	Proposed
<i>Applicability</i>	Data center customers with >25 MW monthly maximum demand at a Single Location or an aggregated Total Customer Contract Capacity in Service Territory >25 MW ²³⁰	No minimum MW threshold; applies based on being a Data Center Customer ²³¹	Data center customers with an aggregate monthly maximum demand > 25 MW ²³²	Data center customers with a monthly maximum demand ≥25 MW, an aggregated Total Customer Contract Capacity in Service Territory ≥25 MW, or where required T&D investment is ≥\$10 million ²³³
<i>Generation / supply service</i>	Option to take AEP Standard Offer Service or CRES supply ²³⁴	CRES required as the SSO does not separately procure supply for data centers; the Companies are preparing another application for SSO supply in the event of CRES default ²³⁵	Competitive supply preferred, but SSO backstop permitted if customer certifies that it is unable to secure generation service from an AGS ²³⁶ ; stipulation requires AES to	CRES required initially; Duke proposes a separate default SSO available to data center customers once approved by the PUCO ²³⁸

²³⁰ AEP tariff book, Schedule DCT, Original Sheet Nos. 223-2 and 223-4, Effective April 10, 2026.

²³¹ PUCO Case No. 26-697-EL-ATA, FirstEnergy Application for Approval of Tariff Amendments, Schedule DCT, Exhibit B, pp. 1-2, June 12, 2026.

²³² PUCO Case No. 25-958-EL-AIR, Stipulation and Recommendation, Exhibit 2, AES Data Center Tariff, Original Sheet No. D23, p. 1.

²³³ PUCO Case No. 26-755-EL-ATA, Duke Energy Ohio Application for Approval of a new Service and Tariffs for Serving Data Center Load, Exhibit B, Rate DC, pp.1-2.

²³⁴ AEP Schedule DCT, Original Sheet No. 223-1.

²³⁵ FirstEnergy Schedule DCT, Exhibit B, p. 3 and Exhibit C-2.

²³⁶ AES Tariff D23, p. 2.

²³⁸ Duke Energy Ohio Rate DC, p. 2 and p. 6.

Topic	AEP – Schedule DCT	FirstEnergy – Schedule DCT	AES – Tariff D23	Duke – Rate DC
			adopt an SSO generation product for data centers ²³⁷	
<i>Interruptible service and curtailment for large loads</i>	Does not establish a dedicated interruptible program ²³⁹	Does not establish a dedicated interruptible program	Does not establish a dedicated interruptible program ²⁴⁰	Company curtailment requirements may be informed by PJM requirements for large loads; For SSO customers, Duke coordinates curtailment capability with PJM; CRES customers coordinate PJM participation through their supplier or selected CSP ²⁴¹
<i>Mandatory emergency curtailment</i> ²⁴²	Preserves right to disconnect or curtail load under its Terms and Conditions and OAC 4901:1-10-16 ²⁴³	Preserves right to disconnect or curtail pursuant to its Electric Service Regulations ²⁴⁴ and OAC 4901:1-10-16 ²⁴⁵	Preserves right to disconnect or curtail under Emergency Electrical Procedures Sheet D11 ²⁴⁶ and OAC 4901:1-10-16 ²⁴⁷	Preserves right to disconnect or curtail in accordance with Emergency Electric Procedures, Sheet No. 75, of the Company's Tariff ²⁴⁸ and

²³⁷ AES Stipulation and Recommendation, p. 20.

²³⁹ AEP's broader tariff book includes options for interruptible service via riders IRP-L and IRP-E, as well as a Pilot Demand Response Rider; IRP-E allows for customer participation in other PJM DR programs through a CSP (see Rider IRP-E on Original Sheet No. 471-1).

²⁴⁰ AES' Stipulation includes a Curtailable Use Reliability Benefit (Rider D32), but it aims to exclude data centers (see AES Tariff D32, p. 1).

²⁴¹ Duke Energy Ohio Rate DC, p. 5.

²⁴² OAC 4901:1-10-16 (Notice of disconnection of nonresidential service, applies to all Ohio IOUs), available at: [Rule 4901:1-10-16 - Ohio Administrative Code | Ohio Laws](#)

²⁴³ AEP Schedule DCT, Original Sheet No. 223-7.

²⁴⁴ FirstEnergy tariff books, Electric Service Regulations, section RE Long Term Capacity Shortages.

²⁴⁵ FirstEnergy Schedule DCT, Exhibit B, p. 7.

²⁴⁶ AES Ohio Rates and tariffs, Emergency Electrical Procedures, Third Revised Sheet No. D11.

²⁴⁷ AES Tariff D23, pp. 7-8.

²⁴⁸ Duke Energy Ohio Electric Tariff, Rider EEP, Emergency Electric procedures, Sheet No. 75.2.

Topic	AEP – Schedule DCT	FirstEnergy – Schedule DCT	AES – Tariff D23	Duke – Rate DC
				OAC 4901:1-10-16; Duke has sole discretion over customer curtailment in response to any emergency condition ²⁴⁹
<i>Minimum Billing Relative to Contract Capacity</i> ²⁵⁰	Contract Capacity is the mutually agreed monthly peak load requirement after the Load Ramp Period; For New Load, the DCT minimum billing structure is tied to Contract Capacity and applies across applicable riders ²⁵¹	Contract Capacity is the mutually agreed monthly peak load requirement for each month following the Load Ramp Period; monthly billing demand is the greater of 85% of applicable Contract Capacity or actual usage, both during and after the ramp period ²⁵²	Contract Capacity reflects the Customer’s load agreed to by the Company and Customer; Minimum Billing Demand must be at least 85% of Contract Capacity, including the Contract Capacity specified in the Ramp Period ²⁵³	Contract Capacity is the mutually agreed monthly peak load requirements for each month during the contract term, including the Load Ramp Period; the ESA establishes a Minimum Billing Percentage between 60% and 85% ²⁵⁴
<i>Financial guarantee / collateral</i>	New Load without specified investment-grade ratings and liquidity >10X collateral requirement must provide collateral equal to 50% of total minimum charges over full contract term;	New Load collateral is tied to the estimated cost to construct at Construction Agreement execution and final cost to construct incremental transmission and distribution facilities at ESA execution; investment-grade customers	Collateral equals Ramp Period Minimum Charges + 3 years of Service-Term Minimum Charges + Exit Fee; acceptable security includes qualifying parent/affiliate guarantee, irrevocable LOC, or cash; parent/affiliate guarantor	Requirements are largely ESA-specific; acceptable forms of credit support include cash, LOC, or parent guaranty; amount is tiered based on credit rating and can range from 0–100% of project cost, reflecting actual project risk ²⁵⁸

²⁴⁹ Duke Energy Ohio Rate DC, p. 5.

²⁵⁰ With PUCO approval, all four IOUs have the right to suspend service if a customer’s usage exceeds Contract Capacity by more than 1,000 kW.

²⁵¹ AEP Schedule DCT, Original Sheet Nos. 223-1, 223-3, and 223-4.

²⁵² FirstEnergy Schedule DCT, Exhibit B, pp. 1 and 4.

²⁵³ AES Tariff D23, p. 6.

²⁵⁴ Duke Energy Ohio Rate DC, p. 1.

²⁵⁸ Duke Energy Ohio Rate DC, p. 5.

Topic	AEP – Schedule DCT	FirstEnergy – Schedule DCT	AES – Tariff D23	Duke – Rate DC
	acceptable forms include qualifying parent/affiliate guarantee, irrevocable LOC, or cash ²⁵⁵	can use parental guarantee/similar security; others must generally use third-party LOC/surety ²⁵⁶	must generally have ≥A-/A3 ratings and liquidity >10× collateral ²⁵⁷	

²⁵⁵ AEP Schedule DCT, Original Sheet No. 223-6.

²⁵⁶ FirstEnergy Schedule DCT, Exhibit B, pp. 5-6.

²⁵⁷ AES Tariff D23, pp. 6-7.

Items in the RBP and IRAS That Will Need to be Incorporated into Ohio's Data Center Tariffs

The EDCs and the PUCO will need to revise the existing and proposed data center tariffs to align with PJM's proposed RBP and IRAS frameworks. Future iterations of the data center tariffs shown in Table 28 should address the following items.

- Definitions – most of the Ohio data center tariffs apply to data center customers with a monthly maximum demand of at least 25 MW, while PJM uses a 50 MW threshold. The Ohio IOUs should consider filing two data center tariff options, one for customers under 50 MW that are not subject to PJM rules, and one for customers over that 50 MW threshold that will need to align with the new PJM rules. All other relevant terms from the PJM RBP and IRAS proposals should be defined in the PUCO jurisdictional tariffs to promote alignment.^{259,260}
- IRAS Status – customers with an IRAS curtailment obligation will need to be subject to priority curtailment based on tariff language that mimics the IRAS curtailment procedures that will be codified in PJM Manual 13.²⁶¹ Additionally, if there will be a payment mechanism for IRAS curtailment performance, it will need to be harmonized with the demand response crediting language in PJM's proposed IRAS tariff Attachment DD-4, Section X.²⁶²
- RBP Versus RPM UCAP Status – the tariffs will need to define these as different types of capacity products and include cost allocation procedures for each option. The tariff cost allocation methods should align with PJM's RBP cost allocation tariff proposal.²⁶³ This language could be included in the data center tariffs, but as described above it will be needed in the Retail Supplier Coordination tariffs so that the LSE serving the large loads can allocate and settle capacity accurately.

RBP and IRAS Status Evaluation in Interconnection Process

All four data center tariffs require data center customers to enter into an interconnection agreement between the EDC and the Customer in advance of connecting any source of power to the Company's system, consistent with Ohio Administrative Code (OAC) 4901:1-22.²⁶⁴

²⁵⁹ FERC Docket ER26-3380, Proposed Tariff, Definitions, July 31, 2026.

²⁶⁰ FERC Docket ER26-3515, Proposed Tariff, Definitions, August 13, 2026.

²⁶¹ Affidavit of Christopher Pilog on Behalf of PJM Interconnection, LLC at 24

²⁶² FERC Docket ER26-3515, Proposed Tariff, Attachment DD-4, section X, August 13, 2026.

²⁶³ FERC Docket ER26-3515, Proposed Tariff, Attachment DD-4, section IX, August 13, 2026.

²⁶⁴ OAC Chapter 4901:1-22, Interconnection Services, available at: <https://codes.ohio.gov/ohio-administrative-code/chapter-4901:1-22>

Requirements concerning contract capacity, minimum billing demand, term commitments, financial guarantees, and ramp schedules are governed through the EDCs' respective data center tariffs and ESAs. This whitepaper recommends that the PUCO should require potential data center customers to disclose their planned status as BYONC, IRAS, RBP, or hybrid in their ESA.

State Level Response to Data Center Growth

Ohio's response to rapid data center growth has focused primarily on EDC-specific data center tariffs designed to protect existing customers from the financial risks associated with large new loads. These tariffs are summarized in Table 28.

In addition to tariffs, House Bill 15, effective August 14, 2025, made broad changes to Ohio energy policy and expressly authorized PUCO to approve nondiscriminatory programs for energy-intensive customers, including interruptible rates that enhance distribution and transmission grid reliability.²⁶⁵ However, HB 15 does not itself establish an interruptible-service requirement for data centers, define a mandatory level of load curtailment, or create the customer-specific curtailment framework that would be necessary to implement PJM's proposed IRAS requirements. Thus, while HB 15 provides statutory authority for interruptible rates, additional tariff provisions or other regulatory action would be needed to translate IRAS status into an enforceable obligation for a data center to curtail to a specified level when directed.

Suggested Optional State Actions for Consideration

Large Load Competitive Retail Electric Supplier Licensing

PUCO regulates Competitive Retail Electric Service (CRES) providers to establish standards for participation in the competitive retail electricity market and to provide oversight of electric suppliers serving retail customers. The existing framework gives the PUCO visibility and control over the competitive retail electricity market and protects other ratepayers by ensuring that electric suppliers are qualified to serve retail load by evaluating the management, operational and financial integrity of the organizations.

New large load customers represent a different scale and risk profile compared to traditional retail customers due to their size and also their potential to receive RBP and/or RPM UCAP with

²⁶⁵ House Bill 15, p. 35, see HB 15 Summary, available at: [House Bill 15 | 136th General Assembly | Ohio House of Representatives](#); see also Section 4909.192 of Ohio Revised Code, available at: [Section 4909.192 - Ohio Revised Code | Ohio Laws](#)

an IRAS curtailment obligation. Both of these capacity types could take some time to re-allocate to other large load customers in the event of an abrupt unplanned termination of operations.

To respond to this risk, the PUCO could consider creating a new large load licensing category and require that a CRES providers interested in serving large loads petition the PUCO to obtain a new license or modify an existing license. The PUCO could also require added financial assurance, managerial and technical staff qualifications, and reporting requirements as a condition of license approval to provide service to large loads. The purpose of these more stringent requirements would be to ensure that high-quality electric suppliers are serving large loads and to provide the regulator with disclosures that provide timely insight into large load market activity.

Current Licensing Framework

Ohio requires all CRES providers to obtain a certificate from the PUCO before offering competitive retail electric service. The statutory framework is established in Chapter 4928 of the Ohio Revised Code.²⁶⁶ Section 4928.08 contemplates the PUCO's establishment of a certification process and adoption of rules governing the financial, technical, and managerial capability of CRES providers, as well as the provision of financial assurance to electric distribution companies.

The PUCO implemented this authority through Ohio Administrative Code Chapter 4901:1-24, which establishes certification requirements applicable to retail electric generation providers, power marketers, governmental aggregators, and power brokers (Supplier Rules).^{267, 268} The Supplier Rules list the required application contents for a retail electric generation provider that seeks CRES certification.²⁶⁹ The application must include evidence of ownership, managerial experience and capabilities, credit ratings, and relevant financial information (including financial statements, financial arrangements, and forecasted financial statements), technical ability and experience in scheduling and providing power under contract agreements, and information about the applicant's status as a supplier in other states.²⁷⁰

²⁶⁶ Ohio Rev. Code §§ 4928.06 and 4928.08., available at: <https://codes.ohio.gov/ohio-revised-code/chapter-4928>

²⁶⁷ Ohio Rev. Code § 4901:1-24-14.

²⁶⁸ Relatedly, PUCO established rules for CRES to abide by in Ohio Administrative Code Chapter 4901:1-21, available at: <https://codes.ohio.gov/ohio-administrative-code/rule-4901:1-21-07>

²⁶⁹ Retail electric generation provider means a person who is certified to provide retail electric generation in the state. Id.

²⁷⁰ Application materials available on the PUCO website, available at: <https://puc.ohio.gov/utilities/electricity/resources/competitive-retail-electric-service-certification>

Under the Supplier Rules, an EDC may require a retail electric generation provider to provide and maintain financial security to protect it in the event that the retail electric generation provider fails to deliver generation service to its customers.²⁷¹ The current framework relies on EDC-administered security evaluations. Each company has a method for establishing creditworthiness and financial assurance, as summarized in Table 29 below.

²⁷¹ Ohio Rev. Code § 4901: 1-24-14.

Table 29: Financial Assurance Summary

Topic	AES Ohio	AEP Ohio	Duke Ohio	FirstEnergy Ohio
<i>Creditworthy/Unsecured Credit Determination</i>	Unsecured credit limits generally increase as the investment grade of a CRES business increases, and the maximum unsecured credit limit is 100% of an entity's net worth for a AAA rating.	Reviews credit ratings to determine if at least two ratings meet the following: BBB- for Standard & Poor's, Baa3 for Moody's Investors' Services, or BBB- for Fitch Ratings. Reserves right to limit unsecured credit.	CRES presumed creditworthy if it has bond rating of at least BBB- for Standard & Poor's or Baa3 for Moody's Investors' Services. Reserves right to limit unsecured credit.	EGS presumed creditworthy and can receive an unsecured credit limit which will be a maximum of 5% of a Supplier's Tangible Net Worth if at least two investment grade senior unsecured debt ratings (or if unavailable, corporate issuer credit ratings) meet the following: BBB- for Standard and Poor's and Fitch; Baa3 for Moody's Investors' Services.
<i>Financial Assurance Determination</i>	Must make reasonable alternative credit arrangements with a CRES that is unable to meet the creditworthiness criteria or who causes their credit risk to rise above the CRES's unsecured credit limit.	Must make reasonable alternative credit arrangements with a CRES Provider that is unable to meet the minimum investment grade rating requirements or whose security requirements exceed their allowed unsecured credit limit.	Must make reasonable alternative credit arrangements for a CRES that is unable to meet the creditworthiness criteria or that has credit requirements that exceed its allowed unsecured credit limit.	Must make reasonable alternative credit arrangements with an EGS that is unable to meet the creditworthiness criteria or has credit requirements that exceed its allowed unsecured limit.
<i>Acceptable Financial Assurance Instruments</i>	Guarantee of payment, irrevocable letter of credit, prepayment account, surety bond or other mutually agreeable arrangement.	Financial guarantee from related entities	Irrevocable letter of credit, a cash deposit, parental guarantee of payment, other mutually agreeable arrangement.	A guarantee of payment from a parent company that meets the credit requirements for unsecured credit limit, an irrevocable Letter of Credit, a cash deposit, or other mutually agreeable security or arrangement.

Topic	AES Ohio	AEP Ohio	Duke Ohio	FirstEnergy Ohio
<i>Calculation of Financial Assurance</i>	30 days estimated CRES summer energy usage x highest monthly average PJM Day Ahead energy price from prior summer + 30 days estimated CRES capacity obligation x final Dayton zonal capacity price for the upcoming delivery year	Utility to determine, and then provide an initial estimate of the CRES Provider's security requirements.	30 days estimated CRES summer energy usage x next July forward index price - allowed unsecured credit limit	Initial credit amount of \$250,000; if the customer load responsibility served by the supplier requires additional credit, the Companies will use its EGS Credit Exposure Formula to assess: Weighted Average Monthly Peak kW x Max 12-month LMP x 3 x 5 days ²⁷²
<i>Citation</i>	AES Ohio Alternate Generation Supplier Handbook, pp. 41-43 (Feb. 24, 2021)	Ohio Power Company, P.U.C.O. No. 22, Terms and Conditions of Service, 2nd Revised Sheet Nos. 103-31 through 103-35	Duke Energy Ohio Retail Electric Tariff, P.U.C.O. Electric No. 20, Sheet No. 35.5, pp. 1-2	Ohio Edison Supplier Tariff, Rules and Regulations, Credit Requirements, Sheet 1, 2nd Revised Page 14 of 49; Cleveland Illuminating and Toledo Edison Supplier Tariffs, Rules and Regulations, Credit Requirements, Sheet 1, 3rd Revised Page 14 of 49

²⁷² Supplier Exposure Formula Slide posted to FirstEnergy Ohio's Supplier Registration Creditworthiness webpage, available at: https://www.firstenergycorp.com/supplierservices/oh/supplier_registration/creditworthiness.html

PUCO is responsible for deciding whether to grant certification applications and it will approve an application if it finds that the applicant can provide reasonable financial assurances sufficient to protect EDCs and customers from default.²⁷³ It also must find that an applicant is managerially, financially, and technically fit and capable of: (a) performing the service that it intends to provide, and; (b) complying with all applicable PUCO rules and orders.

A certified CRES providers must report annually on several metrics,²⁷⁴ and it must also report managerial changes to its business operations within 30 days of a material change. A material change includes significant changes in ownership, affiliation, retirement or changes to generation resources relied upon, license status in other jurisdictions, bond rating reductions below BBB, bankruptcy, or relevant court rulings.²⁷⁵ Reporting a material change reporting could result in a license status change (e.g., revocation) at the discretion of PUCO.

Suggested Changes to Licensing

The PUCO should consider enhancements to its Supplier Rules for CRES providers serving large load customers. This could include establishment of a Large Load Supplier definition and licensing category. The existing criteria may not be fully responsive to the risks associated with large load customers and enhancements to the Supplier Rules could ensure that CRES providers serving Large Load Customers are qualified and minimize risks related to defaults.

Specific areas of the application process that the PUCO may want to modify are summarized in Table 30 below.

Table 30: Suggested Modifications to PUCO's Application Process

Application Criteria	Suggested Change	Rationale
Definitions	Define Large Load Customer and related terms from PJM's RBP and IRAS filings.	CRES providers need to be able to support RBP capacity and IRAS curtailment procedures so harmonization with PJM terminology will support state level implementation

²⁷³ Ohio Rev. Code § 4901: 1-24-10.

²⁷⁴ Ohio Rev. Code § 4901: 1-24-06.

²⁷⁵ Ohio Rev. Code § 4901: 1-24-11.

Application Criteria	Suggested Change	Rationale
Managerial and Technical Ability	CRES providers should be able to demonstrate key staff have experience with large loads in PJM or other markets	Minimize defaults or operational issues by requiring a high level of sophistication, organizational capability, and demonstrated experience serving large loads.
Financial Integrity/Assurance	PUCO to determine a standardized level of financial assurance to be maintained by CRES providers serving Large Loads based on the scale of the default risk.	Currently the EDCs maintain the creditworthiness mechanisms for CRES providers, which PUCO could maintain or consolidate under PUCO supervision. Current requirements vary by EDC and consistency would help ensure that Ohio's policy goals for consumer protections are uniformly applied.
Ability to Support Load Shedding	CRES providers should demonstrate that they can help customers shed load, either as a Curtailment Service Provider (CSP) or through other load management program.	Although the proposed PJM IRAS tariff places the responsibility for directing curtailment on the EDCs, the CRES providers serving the customer should be able to support and facilitate load shedding that IRAS curtailment obligations are met.

Suggested Changes to Reporting Obligations for Large Loads

The PUCO requires licensed CRES providers to report information regarding current market activity and the status of the supplier's business. The PUCO may want to augment its reporting requires for CRES providers serving large load customers to include:

- A material changes in large load usage volumes if outside of the established ramp schedule;
- Voluntary termination of a Large Load Customer contract;
- Involuntary loss of a Large Load Customer; or
- A failure of a large load to perform during an IRAS event.

The PUCO could also consider expanding the existing annual update requirements for an electric power supplier who serves Large Load Customers. The expanded reporting elements could include:

- The number of Large Load Customers served;
- Aggregate Large Load Customer demand;
- Peak demand associated with each Large Load Customer;
- PJM zone location of each Large Load Customer;
- Actual and projected RBP and IRAS capacity obligations;
- Large Load Customer demand forecasts, and;
- Current financial assurance levels applicable to Large Load Customer service.

These reporting requirements would provide the PUCO with information necessary to monitor supplier risk profiles, evaluate long-term capacity obligations, and periodically reassess whether financial assurance requirements remain appropriately calibrated.

PUCO Authority to Implement

No statutory amendments appear necessary to implement these recommendations. The PUCO appears to possess sufficient authority to establish additional licensing, financial assurance, and reporting requirements applicable to CRES providers serving Large Load Customers, as outlined in Sections 4928.06 and 4928.08 of Chapter 4928 of the Ohio Revised Code.²⁷⁶

Required Changes to Regulations to Implement Suggested Changes

If the PUCO elects to impose more detailed requirements on CRES providers serving Large Load Customers, it would need to amend or clarify its regulations and application requirements in several areas summarized in Table 31.

Table 31: Recommended Changes to Ohio Regulations

Regulation Section	Recommended Change
Section 4901:1-24-01 (Definitions)	Define Large Load Customers or data center customers, as appropriate, and RBP and IRAS terminology to ensure consistency with the PJM tariffs.

²⁷⁶ Ohio Rev. Code §§ 4928.06 and 4928.08., available at: <https://codes.ohio.gov/ohio-revised-code/chapter-4928>

Regulation Section	Recommended Change
Sections 4901:1-24-05 (Application Content) and 4901:24-15(B) (Annual Reporting)	Add detailed requirements for the provision of information needed to evaluate a license to serve Large Load Customers, including managerial and technical ability.
Section 4901:1-24-14 (Financial Integrity)	Modify financial assurance and bonding requirements applicable to Large Load Customers so that they are a standalone requirement, and amounts scale immediately when a new Large Load Customer is added or reduced.
Sections 4901:1-24-11 (Material Change in Application)	Expand the existing material change and annual reporting requirements to include mandatory reporting of information that is specific to Large Load Customers.
Sections 4901:1-24-11 (Material Change in Application)	Add event-driven reporting triggers for electric power supplier serving Large Load Customers.
PUCO License Application and Reporting Materials	Changes to reflect suggested changes detailed above.

Treatment of Large Loads Taking Default Service

Ohio's existing statutory framework does not exclude Large Load Customers from Standard Service Offer (SSO). However, the PUCO recently recognized the need for a separate SSO procurement framework for Large Load Customers to protect other customers from the SSO cost impacts that Large Load Customers may cause.²⁷⁷

Ohio law requires each EDC to provide consumers within its service territory, on a comparable and nondiscriminatory basis, an SSO that includes the generation services necessary to maintain essential electric service for customers that do not select a CRES provider.²⁷⁸ The statute does not establish a separate default-service framework for exceptionally large customers or otherwise exclude them from eligibility for the SSO.

²⁷⁷ Finding and Order, In the Matter of the Application of Ohio Power Company for New Tariffs related to the Standard Offer for Data Center Load, Case No., 26-113-EL-ATA, p. 12 (August 5, 2026).

²⁷⁸ Ohio Rev. Code § 4928.141(A)(1), available at: <https://codes.ohio.gov/ohio-revised-code/section-4928.141>

Recently, the PUCO approved an interim SSO framework applicable to data center customers on AEP Ohio's DCT in order to minimize SSO disruptions and cost impacts that can occur when a data center takes SSO. The framework permits AEP Ohio to hold a separate SSO procurement process for data center customers that return to the SSO. These customers are subject to a 180-day advance notice requirement prior to their return, and must pay the full cost of the procurement conducted by AEP Ohio on their behalf, including administrative costs.²⁷⁹ This framework recognizes that the return of an exceptionally large customer to default service can create procurement and cost-allocation issues that may not be appropriately addressed through the ordinary SSO procurement process.

This Whitepaper recommends that PUCO standardize its policies for large load customers taking SSO across all EDCs.

Require PJM Subaccounts for Each Large Load

The PUCO may want to require each large load to set up its own PJM subaccount. This action would ensure that all market activity for the large load is separate from other retail loads and ensures direct line of sight between the customer, the CRES provider, and the PJM market.

Revised Switching Rules for Large Accounts

Given the complexity of large loads, the potential for RBP capacity and IRAS obligations, and the potential impact of large loads on CRES provider financial assurance requirements, the PUCO may want to consider modification of electric supplier switching rules for large loads. It may be beneficial to require the Large Load Customer or new CRES to submit a notification to the PUCO indicating a request to transfer service. The PUCO may want to ensure that the new CRES is properly licensed, has adequate financial assurance for the new load, and that all capacity obligations are transferred from the discontinuing electric supplier service. While the PUCO could give prompt consideration to such applications, additional time to process a switch could be beneficial to all parties to ensure a smooth transition and to give PUCO insight into large load market activity.

Conclusions- Ohio

The PUCO will need to modify the existing and pending DCT rates to implement the new RBP capacity product and operationalize IRAS tracking, curtailments, and payments if applicable.

²⁷⁹ Finding and Order, In the Matter of the Application of Ohio Power Company for New Tariffs related to the Standard Offer for Data Center Load, Case No., 26-113-EL-ATA, p. 12 (August 5, 2026).

CRES providers will also need to be able to receive allocations of RBP capacity and assist with IRAS performance. As a result, the following tariffs and documents will need to be modified:

- Retail supplier coordination tariffs
- FERC M-2 attachments or Company information webpages for CRES Providers
 - This whitepaper recommends that each EDC make an Attachment M-2 filing to aid transparency.
- IRAS interruption triggers and procedures which can be located in the Terms and Conditions, within the DCT rates themselves, or in a rider
- IRAS payment crediting mechanisms which can be detailed within the retail tariff or potentially retail supplier coordination tariffs if CRES providers are to have a role

In addition to the required items detailed above, this whitepaper also suggests the following changes that may be helpful to the PUCO's oversight and management of large load customers:

- Creation of a new electric supplier licensing category to serve Large Load Customers with revised managerial, technical, and financial capabilities requirements;
- FA requirements for CRES providers serving large load customers with RBP capacity assignments that are consistent across EDCs;
- Added PUCO oversight to CRES providers serving Large Load Customers through additional annual reporting fields and events that trigger prompt PUCO notification;
- A requirement for Large Load Customers to establish PJM subaccounts;
- Modification in electric supplier switching rules to ensure that large load customer switches involving transfer of non-standard capacity products are executed properly.

PUCO is already in the process of assessing the rules and requirements for large load customers to take SSO and therefore this whitepaper does not offer a recommendation as PUCO is already taking action to determine the best path forward on this issue.

F. Illinois State Appendix

Illinois is a restructured state with an active retail choice market. Commonwealth Edison Company (ComEd) serves the northern portion of the state which is located within PJM. To help prepare for the expected increase in Large Load Customers, the Illinois Commerce Commission (ICC) conducted a proceeding that resulted in updates to ComEd’s General Terms and Conditions (GT&Cs). These updates include supplemental language defining a “Large Demand Project Applicant or Customer” and revised its Rider DE – Distribution System Extensions to address cost allocation matters for large load customers.²⁸⁰

ComEd does not currently have a dedicated tariff for data centers, but has existing rates for large and high voltage commercial customers that may be suitable for use with data centers with additional modifications.²⁸¹ In June 2026, Illinois Governor Pritzker outlined a policy framework for data centers that includes creation of special data center electricity rates; full assignment of all costs including those for generation, transmission, and distribution; and interruptible service obligations that are related to the percentage of clean energy supply to the data centers. Gov. Pritzker has called on the legislature to work with his office during the Fall 2026 veto session to pass legislation that accomplishes his stated objectives.²⁸²

Whether the IL legislature is able to pass legislation or not, ComEd’s existing tariffs will require some modifications to align with PJM’s proposed Reliability Backstop Procurement (RBP), Bring Your Own New Capacity (BYONC), and Interim Resource Adequacy Service (IRAS) framework.

Minimum Required State Level Actions Needed

Tariffs Related to Alternative Retail Energy Supplier (ARES) Coordination

PJM’s RBP and IRAS proposals involve creating a new RBP capacity product type and Reliability Pricing Model (RPM) Unforced Capacity (UCAP) with a mandatory interruptible load obligation and potential crediting system, respectively. At a minimum, the RBP capacity product will need to be defined in the definitions section of the Retail Electric Supplier Resource Handbook (RES Handbook) and ComEd’s Schedule of Rates for Electric Service, IL ICC No. 10 (Retail Tariff). This will need to include the determination of RBP capacity obligations (aka “tags”), settlement

²⁸⁰ Compliance Filing for ICC Docket Nos. 25-0677/25-0679 (Cosol.), p. 2, March 30, 2026.

²⁸¹ ComEd’s Extra Large Load delivery class applies to customers with demand greater than 10 MW and delivery voltages below 69 kV. The High Voltage Delivery Class applies to customers taking service at voltages of 69 kV or higher. See IL ICC No. 10 Original Sheet 137.

²⁸² Press Release, Gov. Pritzker Pauses New Data Center Tax Incentives: Governor outlines framework to protect consumers and lower energy costs, calls on General Assembly to act in veto session, June 5, 2026, available at: <https://gov-pritzker-newsroom.prezly.com/gov-pritzker-pauses-new-data-center-tax-incentives>

procedures, and reallocation provisions for unsubscribed RBP capacity in the event of a default of a large load with an RBP capacity obligation. IRAS operational procedures will also need to be codified in the Retail Tariff, where applicable. A summary of RES Handbook and Retail Tariff sections that will require revisions are included in Table 32 below.

Table 32: RES Handbook and Retail Tariff Sections to be Revised for New Capacity Types and Operational Procedures

Tariff Section	RES Handbook²⁸³	Retail Tariff²⁸⁴
Definitions	Chapter 1	General Terms & Conditions, Sheets 127-133
Capacity Obligation and EDC to ARES Data Transfer	Chapter 2	
RBP Reallocation Procedure	To be added	

In the future, there will be two different types of capacity products in PJM: UCAP acquired through the RPM Base Residual Auction (BRA) and Incremental Auctions (IA) and RBP capacity. Large load capacity subject to IRAS requirements will be treated and settled like existing UCAP obligations, but will have an added requirement to curtail or interrupt load up to the IRAS Eligible New Large Load quantity when the interruption trigger is activated. Both RPM UCAP and RBP capacity will have their own procedures for daily allocation to load and determination of customer capacity obligations or capacity tags.

Currently, RPM capacity obligations are based on contributions to PJM's five coincident peak (5 CPs) load hours. Large load capacity obligations may be set based on other parameters such as load size, nameplate, or a ramp schedule instead of the historical 5 CPs. The sum of a large load customer's BYONC, RBP, and IRAS capacity must sum to the total large load capacity obligation. It is possible that large loads could have two different capacity types to cover their capacity obligation, which would then result in the settlement of two separate capacity products for one load.

Large load customers who enter the market via BYONC will have their capacity entered into the RPM via the BRA or IAs as price takers and be cleared through the RPM with other capacity.

²⁸³ ComEd RES Handbook, available at: <https://www.comed.com/doing-business-with-us/energy-suppliers/res-resources>

²⁸⁴ ComEd Retail Tariff, ICC No. 10, available at <https://www.comed.com/current-rates-tariffs>

These large load customers will then settle any differences in bilateral contract terms or pricing relative to the RPM privately with the capacity provider.

While RPM capacity obligations for customers reset on June 1st each year, it is possible for intra-year adjustments of RBP capacity in the event that a large load RBP capacity subscriber exits the market via default. When this occurs, the remaining RBP customers across all PJM zones will be allocated a pro-rata share of the defaulted RBP capacity obligation. The Retail Tariff or RES Handbook will need a mechanism to facilitate this process.

FERC M-2 Tariffs

On its website, PJM maintains an inventory of the calculation methods and parameters used to determine Total Hourly Energy Obligation (THEO), Peak Load Contribution (PLC) and Network Service Peak Load (NSPL) for each EDC.²⁸⁵ It is not a FERC or state-mandated requirement for each EDC to maintain a current Attachment M-2 to the PJM Open Access Transmission Tariff (OATT), but most EDCs do have an Attachment M-2 on file with their PLC contribution calculation methods as an information resource to stakeholders. ComEd's M-2 tariff discusses PLC calculations in detail and will need to be updated to reflect RBP capacity and IRAS Eligible New Large Load and the methods used to determine total zonal or EDC capacity obligations and their translation to individual customer capacity obligations.

Interruptible Load and Emergency Curtailment Tariffs

ComEd's Retail Delivery Service tariff (Rate RDS) contains a general emergency/shortage curtailment provision requiring customers to comply with ComEd directives and potentially reimburse ComEd for costs resulting from failure to curtail²⁸⁶, and its Electric Energy Contingency Plan (EECP) establishes a system-wide emergency curtailment hierarchy to be used during an electric-energy shortage.²⁸⁷ The EECP allows for mandatory curtailment in extreme scenarios and can lead to disconnection for customers that do not comply.²⁸⁸

In addition, ComEd offers voluntary and mandatory load-response programs (Riders VLR²⁸⁹ and MLR²⁹⁰) that can be used for distribution and transmission reliability events. While ComEd does

²⁸⁵ THEO, PLC, and NSPL Methodology Inventory, available at <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/theo-plc-and-nspl>

²⁸⁶ ComEd Schedule of Rates for Electric Service, Rate RDS, 3rd Revised Sheet No. 78, December 2, 2016.

²⁸⁷ ComEd Schedule of Rates for Electric Service, General Terms and Conditions, Electric Energy Contingency Plan, Original Sheet Nos. 212, 213 and 214.

²⁸⁸ Id., Original Sheet No. 213.

²⁸⁹ ComEd Schedule of Rates for Electric Service, Voluntary Load Response and System Reliability Program (Rider VLR), Sheet Nos. 360, 361, and 362.

²⁹⁰ ComEd Schedule of Rates for Electric Service, Mandatory Load Reduction Program (Rider MLR), Sheet Nos. 467, 468, 469, and 470.

have general emergency-curtailement language and voluntary/mandatory demand-response riders, the curtailment provisions and triggers are not specific to IRAS.

Presuming the Federal Energy Regulatory Commission (FERC) approves PJM's proposed tariffs, ComEd will need to file an interruptible rate that incorporates the IRAS dispatch triggers from PJM Manual 13²⁹¹ and establish a payment mechanism for IRAS curtailments between zero and 50% of the Non-Performance Charge Rate.²⁹² In addition to devising an interruptible load program that is consistent with the PJM IRAS proposal, the ICC will also need to determine roles and responsibilities for ComEd, who is responsible for dispatch and performance of IRAS curtailments²⁹³ and LSEs who will be assigned the UCAP associated with the New Large Load Customer. The PJM proposed tariff contemplates that the EDC will implement any demand response compensation to IRAS resources, but the ICC could determine if LSEs should play a role in this process.

State Level Response to Data Center Growth

The ICC action on Large-Load Customers has focused on strengthening ComEd's existing interconnection and cost-recovery framework rather than creating a new data center rate schedule. The ICC approved revisions to ComEd's GT&C and Rider DE to define the term "Large Demand Project Applicants or Customers" and require additional financial security from Large Demand Projects expected to reach 50 MW or more.²⁹⁴ The Rider DE revisions expand customer responsibility for certain distribution facilities, require letters of credit for larger deposits, and are intended to ensure that the costs of distribution infrastructure built for large-load projects are borne by the requesting customer and not shifted to existing ratepayers.²⁹⁵

In addition to the ICC, the IL Legislature has had several bills introduced with various provisions that would address data center development and utility costs.²⁹⁶ In June 2026, Governor Pritzker's office issued a press release that outlined a policy framework to address data center development. The components of this proposed framework that impact electric utility service include the following.²⁹⁷

- Create a rate class for data centers and establish data center electricity rates.

²⁹¹ Affidavit of Christopher Pulong on Behalf of PJM Interconnection, LLC.at 24

²⁹² FERC Docket ER26-3515, Proposed Tariff, Attachment DD-4, section X, August 13, 2026

²⁹³ Id, Attachment DD-4, Section III.

²⁹⁴ ICC Order RE Docket Nos. 25-0677 and 25-0679, pp. 162-163, March 19, 2026.

²⁹⁵ Compliance Filing for ICC Docket Nos. 25-0677/25-0679 (Cosol.), Rider DE, March 30, 2026.

²⁹⁶ In the 2026 session, these bills include, but are not limited to, SB 3761, SB 4016/HB5513, and SB 2181.

²⁹⁷ Press Release, Gov. Pritzker Pauses New Data Center Tax Incentives: Governor outlines framework to protect consumers and lower energy costs, calls on General Assembly to act in veto session, June 5, 2026, available at: <https://gov-pritzker-newsroom.prezly.com/gov-pritzker-pauses-new-data-center-tax-incentives>

- Assign the costs that data centers impose on the electric grid to the new data center rate class, including distribution, generation, and transmission, where possible; assign to data centers the costs that they impose on water systems.
- Ensure all utilities in the state are equipped to fairly manage and allocate the cost of data centers' demand.
- Data centers should temporarily go dark when the grid is strained to ensure reliable electric service for Illinoisans. Legislation should direct utilities to assign data centers interruptible electric service based on how much of their own clean energy they self-supply. Data centers that don't supply their own clean energy could have their electric service interrupted when the grid is strained so Illinoisans' lights stay on.
- Establish a framework for data centers to generate or pay for their own new clean energy resources that allows participants to receive timely service and financial consideration for their contributions to Illinois' clean energy goals.

Gov. Pritzker's proposed data center framework addresses many of the state jurisdictional tariff changes that will be required in order to implement RBP and IRAS. In particular, the creation of rate classes or sub-rate variants that acknowledge RBP capacity assignment and IRAS interruptible obligations will need to be created through a proceeding at the ICC which may be guided by legislative direction.

Customers subject to IRAS requirements will be interruptible and interruptible rates, including curtailment triggers, are subject to state jurisdiction. ComEd does not presently have a standalone mandatory interruptible rate for large demand customers.

The clean energy self-supply referenced in Gov. Pritzker's framework can likely be procured through the BYONC mechanism.

RBP and IRAS Status Evaluation in Interconnection Process

In the interconnection process, during the initial engineering analysis and/or Cluster Study process, Large Demand Project Applicants or Customers should be required to disclose their planned status as BYONC, IRAS, RBP, or hybrid. This information may be helpful in understanding the coordinated analysis of transmission and distribution system impacts of multiple projects under the Company's Cluster Study process.²⁹⁸ It is recommended that prospective Large Demand Project Applicants make a showing of their plans for generation capacity before the EDC expends resources conducting studies.

²⁹⁸ Compliance Filing for ICC Docket Nos. 25-0677/25-0679 (Consol.), p. 2 and Sheet No. 149.3, March 30, 2026.

Suggested Optional State Actions for Consideration

Large Load Competitive Retail Electric Supplier Licensing

Illinois regulates ARES in order to establish minimum standards for participation in the competitive retail electricity market and to provide the ICC with oversight of suppliers serving retail customers. The existing framework gives the ICC visibility and control over the competitive electricity market and protects other ratepayers by ensuring that ARES are qualified to serve retail load by evaluating management and financial integrity of the organizations.

New Large load customers pose an elevated level of risk in the event of a default due to their scale and also their potential to receive RBP and/or UCAP with an IRAS curtailment obligation, both of which may take some time to re-allocate to other large load customers in the event of an abrupt unplanned termination of operations. To respond to this risk, the ICC could consider creating a new large load licensing category and require that an ARES interested in serving large loads petition the ICC to obtain a new license or modify an existing license. The ICC could also require added financial assurance, staff qualifications, firm experience, and additional reporting requirements as a condition of approval to provide service to large loads. The purpose of these more stringent requirements would be to ensure that high-quality ARES are serving large loads and providing the regulator with disclosures that provide timely insight into large load market activity.

Current Licensing Framework

In the state of Illinois, an ARES must obtain a certificate of service authority from the ICC prior to supplying retail customers with electric generation service. To apply for a certificate of service authority, an ARES must file an application with the ICC per the governing requirements within Illinois Public Utilities Act (220 ILCS 5/16-115) and the ICC's regulations (83 Ill. Adm. Code 451).^{299, 300}

Under the statutory provisions, the ICC is required to issue the certificate of service authority after making statutory findings that the applicant has met certain criteria. In summary, an applicant for an ARES license must:

- Possess sufficient technical, financial and managerial resources, and ability to provide the service it seeks to provide;

²⁹⁹ See Section 16-115(d) of the Illinois Public Utilities Act (220 ILCS 5/16-115(d)), available at: <https://www.ilga.gov/Documents/legislation/ilcs/documents/022000050K16-115.htm>

³⁰⁰ See 83 Ill. Adm. Code 451, available at: <https://www.ilga.gov/agencies/JCAR/EntirePart?titlepart=08300451>

- Maintain a license or permit bond, from a responsible surety or financial institution, of the requisite size provided for in statute;
- Comply with applicable laws, regulations and procedures, only provide service to eligible customers, and adhere to reporting requirements;
- Procure the required renewable energy as required by law, and;
- Disclose lawsuits and regulatory complaints against it regarding the provision of retail supply to customers.³⁰¹

The ICC established regulations in the Illinois Administrative Code to implement these statutory requirements for ARES.³⁰² These regulations include license categories based on the proposed customer population that an ARES intends to serve, as summarized in Table 33 below.

Table 33

Criteria Applicable to Customer Population Served		Non-Residential Customers with Maximum Demands Greater than One MW	Non-Residential Customers with Annual Usage Greater Than 15,000 kWh	All Retail Customers
Relevant Section of IL Code		IL Code 451.100 Subpart B	IL Code 451.200 Subpart C	IL Code 451.200 Subpart D
License Bond Requirements ³⁰³		\$30,000	\$150,000	\$300,000 ³⁰⁴
Financial Qualification Criteria (Must Satisfy One of the following Five criteria) ³⁰⁵				
1) Credit Agency Ratings – (Commercial Paper/Long-Term) S&P Moody's Fitch		A-2 / BBB- P-2 / Baa3 F-2 / BBB-		

³⁰¹ See Subsection (d) 1 through 11 of Section 16-115 of the Illinois Public Utilities Act (220 ILCS 5/16-115), available at: <https://www.ilga.gov/Documents/legislation/ilcs/documents/022000050K16-115.htm>

³⁰² 83 Ill. Adm. Code Part 451, available at: <https://www.ilga.gov/documents/legislation/ilcs/documents/022000050K16-128.htm>
<https://www.ilga.gov/agencies/JCAR/EntirePart?titlepart=08300451>

³⁰³ 83 Ill. Adm. Code Part 451.50(a).

³⁰⁴ Notably, the IL Public Utilities Act (220 ILCS 5/16-115 (d)(10)) indicates, “[t]he amount of the bond shall equal . . . \$500,000 if the applicant seeks to serve all eligible customers. An additional \$500,000 is required if using in-person solicitations.

³⁰⁵ 83 Ill. Adm. Code Part 451.110(a), 451.210(a), 451.310(a)

Criteria Applicable to Customer Population Served		Non-Residential Customers with Maximum Demands Greater than One MW	Non-Residential Customers with Annual Usage Greater Than 15,000 kWh	All Retail Customers
2) Line of Credit Requirement w/ RTO or unaffiliated wholesale supplier		Greater of <u>\$500,000 or 5%</u> of IL Revenue for last 12 months	Greater of <u>\$750,000 or 7.5%</u> of IL Revenue for last 12 months	Greater of <u>\$1,000,000 or 10%</u> of IL Revenue for last 12 months
3) RTO membership with 100% physical delivery		ARES is an RTO member and purchases 100% of its physical electric energy for delivery to the IL service area		
4) Maintain an unconditional guarantee, payment bond, or letter of credit per an exposure formula ³⁰⁶ that can be drawn upon in a default or failure to supply energy to its customers.		Unconditional corporate guarantee allowed if corporation can meet credit ratings outlined in Step 1; Payment bond from a qualifying surety provider meeting minimum Best's ratings criteria, or; Letter of Credit from financial institution meeting minimum ratings criteria		
5) Have a line of credit or revolving credit agreement with financial institutions meeting minimum ratings criteria.		Greater of <u>\$500,000 or 5%</u> of IL Revenue for last 12 months	Greater of <u>\$750,000 or 7.5%</u> of IL Revenue for last 12 months	Greater of <u>\$1,000,000 or 10%</u> of IL Revenue for last 12 months

For Subparts B through D, the ICC's regulations also include an alternative pathway to demonstrate financial capabilities that involve extensive financial disclosures if the ARES is unable to qualify via the five criteria detailed in Sections 451.120(a), 451.220(a), and 451.320(a).³⁰⁷

The Illinois Administrative Code also includes a Subpart E that applies to an ARES that intends to *"provide electric power and energy exclusively to itself (i.e., the applicant), or to subsidiaries or*

³⁰⁶ Exposure formula that determines the required amount of guarantee, payment bond, or letter of credit is 1,080 multiplied by the peak MWs of load served multiplied by the average the 45 highest daily market prices of electric energy traded during the previous year.

³⁰⁷ Alternative criteria are detailed in 83 Ill. Adm. Code Part 451.120(b), 451.220(b), and 451.320(b)

*other corporate affiliates of the applicant that are at separate locations.*³⁰⁸ This would be applicable in the case where a large load customer sets up a captive internal entity to serve as an ARES to itself or corporate affiliate entities. An ARES licensed under Subpart E does not have bond or credit requirements.

The different supplier categories also have separate evaluation criteria for management experience and technical qualifications which, like the financial qualifications, also increase in stringency with declining customer category size. These requirements are summarized in Table 34 below.

³⁰⁸ 83 Ill. Adm. Code Part 451.400.

Table 34

Criteria	ARES Type	Non-Residential Customers with Maximum Demands Greater than One MW (Subpart B)	Non Residential Customers with Annual Usage Greater Than 15,000 kWh (Subpart C)	All Retail Customers (Subpart D)
Technical Qualifications	Non-Generation Owning	Must have one individual on staff with at least <u>two years</u> experience buying or selling power and energy in wholesale markets.	Must have one individual on staff with at least <u>two years</u> experience buying or selling power and energy in wholesale markets as well as <u>six months</u> of scheduling experience working for an entity that is either a member of PJM, a market participant in the Midwest ISO, or has a system operator certificate from NERC, or has earned Certified Energy Procurement Professional status by the Association of Energy Engineers or equivalent certification.	Must have one individual on staff with at least <u>four years</u> experience buying or selling power and energy in wholesale markets as well as <u>one year</u> of scheduling experience working for an entity that is either a member of PJM, a market participant in the Midwest ISO, or has a system operator certificate from NERC, or has earned Certified Energy Procurement Professional status by the Association of Energy Engineers or equivalent certification.
	Generation Owning	All requirements for non-generation owning ARES and Maintain technical staff on-call 24x7 and have at least two individuals with at least two years experience with generation facilities		
Managerial Qualifications	All ARES	At least one individual in a management position has <u>three or more years</u> of experience with a business enterprise.	At least one person in a management position with <u>four or more years</u> experience with enterprise financial and administration responsibilities including profit and loss responsibilities.	At least <u>three or more individuals</u> in management positions with <u>four or more years</u> experience with enterprise financial and administration responsibilities including profit and loss responsibilities, <u>four years</u> experience buying and selling power and energy in wholesale markets, and <u>four years</u> electric system operational experience

The current licensing framework shows that the financial, technical, and managerial competency standards applicable to ARES become more stringent as the size of the customers served decreases. This framework—under which requirements are less stringent for ARES serving larger customers—is consistent with the broader policy objective in restructured states of protecting residential and small commercial customers from potentially bad actors. In comparison, this policy framework holds that large commercial customers in excess of one MW are generally thought to be sophisticated, and able to evaluate and respond to the business risks of poor execution or default by an ARES.

In light of the new customer protection challenges posed by Large Load Customers, the ICC could consider the need to review its approach to ARES that only serve large customers.

Suggested Changes to Licensing

The ICC should consider enhancements to 83 Ill. Adm. Code Part 451 to establish a Large Load Supplier definition and licensing category. The existing criteria in Adm. Code Part 451 Subparts B and E for large load customers were not designed for ARES serving large data center loads. Enhancements are necessary to ensure that those ARES serving Large Load Customers are qualified and to minimize the supply-related risks associated with providing retail service to Large Load Customers.

Specific areas of the application process and licensing criteria that ICC should review and evaluate for changes are summarized in Table 35.

Table 35

EGS Application Criteria	Suggested Change	Rationale
Managerial and Technical Qualifications	ARES should demonstrate that the organization and multiple key staff have experience with large customers with a minimum demand of 50 MW in PJM or other markets.	Minimize defaults or operational issues by requiring a high level of sophistication and organizational capability.

EGS Application Criteria	Suggested Change	Rationale
Financial Assurance and Bonding Requirements	License bond amounts are set in statute at static levels that are too low. They should be amended and increased for ARES that service Large Load Customers. This would require a change in law. ³⁰⁹	The flat bonding requirements do not take the additional long-term obligations that ARES take on through the RBP. In the event of a customer default, the RBP capacity re-allocation process may take several months to implement, especially the first time. States may want to consider financial assurance in an amount that will cover RBP capacity during a gap between customer default and RBP capacity re-allocation.
Demonstration of Financial Qualification	The current five pathways for demonstration of financial qualification may need to be more targeted with added rigor for ARES serving large loads.	The ICC may want to eliminate the physical delivery option and revise the current options where the dollar value of financial instruments decreases for ARES serving large loads. Aside from parent company credit ratings, a formulaic option based on credit exposure may be more appropriate for concentrated large load risk.
Supplier Single Billing	Presently, ARES can invoice ComEd charges, collect payment, and remit to ComEd. Supplier single billing should be prohibited for complex and bespoke large load invoicing.	Given the complexity and magnitude of financial guarantees and long-term service commitments for distribution billing and collections should be handled directly by ComEd.

³⁰⁹ Although the ICC included a bonding option as one of the pathways to demonstrate financial qualifications in Subparts B, C, and D, it is not mandatory since ARES can use other methods to demonstrate financial qualifications. As a result, the mandatory bonding levels in statute limit the authority of the ICC to require higher levels of bonding as a condition of licensure.

Suggested Changes to EGS Reporting Obligations for Large Loads

The periodic reporting by an ARES to the ICC provides regulators information about current market activity. Given the scale and importance of managing large loads, the ICC may want to consider specifying large load events that trigger a prompt reporting obligation. The reporting in Subpart H of the regulation focuses on annual reporting to ensure compliance with the financial, technical and managerial qualifications within the ICC regulations.³¹⁰ It also includes kilowatt-hour reporting on amounts sold and delivered to retail customers. The ICC could consider amending Subpart H to add requirements around timely notification whenever an ARES serving large loads experiences any of the following:

Change Reporting: Applicable when the customer experiences a significant change in level of service to a Large Load Customer.

- A material change in large load usage volumes if outside of the established ramp schedule;
- A request from the large load to switch ARES providers;
- Voluntary termination of a Large Load Customer contract and;
- Involuntary loss of a Large Load Customer.

Customer Service Reporting: Applicable annually to provide the ICC with detailed information regarding the Large Customer Load obligations of each ARES.

- the number of Large Load Customers served;
- aggregate Large Load Customer demand;
- peak demand associated with each Large Load Customer;
- PJM zone location of each Large Load Customer;
- Actual and projected RBP and IRAS capacity obligations;
- Large load customer demand forecasts; and
- current financial assurance levels applicable to Large Load Customer service.

These reports would provide the ICC with information necessary to monitor ARES risk profiles, and evaluate long-term capacity obligations.

³¹⁰ See e.g., § 451.740, § 451.750, § 451.760.

ICC Authority to Implement

Legislative amendment would be required to modify the specific bond amounts and expand the acceptable financial instruments beyond bonds, as established in Section 16-115(d)(10) of the statute.

No statutory amendment appears necessary to create a Large Load Customer certification category as long as it is consistent with the prescriptive bonding requirements within the statute. Section 16-115(f) of the statute specifically gives the ICC authority to promulgate rules implementing the ARES certification requirements and specifically directs the ICC to establish criteria applicable to suppliers serving nonresidential customers with maximum electrical demand of one megawatt or more. This authority appears to be sufficient to permit the ICC to establish separate certification requirements applicable to suppliers serving a subset of the higher-demand nonresidential customers, such as Large Load Customers.

Required Changes to Regulations to Implement Suggested Changes

The Illinois legislature would need to amend Section 16-115(d)(10) of the statute to change the license bond amounts for a new license category, but otherwise it appears that the ICC has the authority to create a large load license category with separate requirements.

If the ICC were to create a separate large load category for ARES licensure, it would need to modify 83 Ill. Adm. Code Part 451 in several sections which are detailed in Table 36 below.

Table 36

Regulation Section	Recommended Change
Subpart A, Section 451.10 (Definitions)	Define large load customers and RBP and IRAS capacity options that may influence ARES evaluation criteria.
Subpart A, Section 451.50 (License Bond)	Add new license bond for large load customer category (requires change in statute)
New Subpart	Large load specific financial qualification demonstration, managerial and technical capabilities for RBP and IRAS. This could be structured as a new subpart similar to current subparts B, C, D, etc.

Regulation Section	Recommended Change
Subpart F, Section 451.500	Clarify that ARES serving large load customers cannot offer single billing service.
Subpart H, Section 451.700-770 (Annual Reporting)	Add event driven reporting triggers and additional annual report criteria for ARES serving large load customers.
IL ICC ARES License Application	Changes to reflect suggested changes detailed above

Prohibition on Large Loads Taking Default Service

In order to ensure that Basic Electricity Supply Hourly (BESH) (default generation service) remains stable and affordable in Illinois, the ICC should consider whether Large Load Customers, can be excluded from eligibility to take service. This may require amendments to the existing statutes before the ICC can amend the eligibility for the BESH tariffs to exclude Large Load Customers.³¹¹

The existing framework distinguishes between residential and small commercial customers and other customer classes, providing a basis for the ICC to consider whether Large Load Customers warrant separate treatment within the current default service framework.³¹² For instance, while the Public Utility Act (220 ILCS 5) has provisions recognizing the role of the electric utility to provide supply service to nonresidential customers, it does not include the clear obligation to serve or not to serve Large Load Customers. In contrast, there is a clear statement on the electric utilities' obligation to serve residential and small commercial customers in Section 16-103.³¹³ The ICC should review the relevant statutory frameworks to determine whether they

³¹¹ Commonwealth Edison Company, ICC No. 10, 3rd Revised Sheet No. 29, available at <https://www.comed.com/current-rates-tariffs>

³¹² Public Utility Act (220 ILCS 5), available at: <https://www.ilga.gov/Legislation/ILCS/Acts?ChapterID=23&ChapterNumber=220&Chapter=UTILITIES&MajorTopic=REGULATION>

³¹³ Section 16-103 states, each electric utility shall continue offering to all residential customers and to all small commercial retail customers in its service area, as a tariffed service, bundled electric power and energy delivered to the customer's premises . . . ". 220 ILCS 5/16-103 (b), available at: <https://www.ilga.gov/legislation/ILCS/details?MajorTopic=&Chapter=&ActName=Public%20Utilities%20Act.&ActID=1277&ChapterID=23&SeqStart=&&ChapAct=FullText>

provide sufficient authority to establish different default service eligibility requirements for Large Load Customers and, if not, whether legislative changes would be necessary.

There are several reasons why the ICC should consider taking this step. The potential for large loads to purchase default generation supply from the BESH option introduces two significant risks for other commercial customers. The first is the potential spike in uncollectibles should a large load take default service and become unable to pay due to financial distress. ARES bidding on the right to provide default service would also be likely to include a greater risk premium on this service for C&I customers. This is true even if it's an unhedged hourly LMP product because the migration of large loads onto BESH adds significant variable load risk. A migration of a large load to BESH could also spike PJM Financial Assurance requirements for the default generation supplier since they are based on the scale of a market participant's market activity.³¹⁴

Taken together, these considerations suggest that the ICC should evaluate whether Large Load Customers present sufficiently different financial and market risks to warrant separate treatment under the default service framework.

Require PJM Subaccounts for Each Large Load

The ICC may want to require each large load to set up its own PJM subaccount. This action would ensure that all market activity for the large load is separate from other retail loads and ensures direct line of sight between the customer, the ARES, and the PJM market.

Revised Switching Rules for Large Accounts

Given the complexity of large loads, the potential for RBP capacity and IRAS curtailment obligations, and the potential impact of large loads on ARES financial assurance requirements, the ICC may want to consider modification of ARES switching rules for large loads. It may be beneficial to require the large load customer or new ARES to submit a notification to the ICC indicating a request to transfer ARES service. The ICC may want to ensure that the new ARES is properly licensed, has adequate FA for the new load, and that all capacity obligations are transferred from the discontinuing ARES. While the ICC could give prompt consideration to such

³¹⁴ A PJM Market Participant's credit requirements are based on Peak Market Activity (PMA) which is calculated based on a formula that uses the highest weekly dollar market activity levels in the past year. The PMA calculation is detailed in the "Credit Overview and Supplement to the PJM Credit Risk Management Policy" document Version 3.8, pp. 18-22.

applications, additional time to process a switch could be beneficial to all parties to ensure a smooth transition and to give the ICC insight into large load market activity.

Conclusions - Illinois

There are several changes to ComEd's retail tariffs and related materials that will need to occur in order to align state jurisdictional tariffs and operating procedures with PJM's RBP capacity product and IRAS curtailment requirements. Gov. Pritzker's proposed data center policy framework will likely result in legislation that calls for the creation of Large Load Customer rates. At a minimum, the following additions to ComEd's rate tariffs will be required in order to accommodate procedures for assignment and settlement of RBP capacity and UCAP that has a corresponding IRAS obligation:

- ComEd's retail tariff and supplier handbook
- FERC M-2 Attachment
- Interruptible tariffs that can implement EDC responsibilities under IRAS
- Policies that delineate EDC and LSE roles in IRAS implementation

In regards to ARES licensing and oversight, the ICC should consider reviewing the following:

- Creation of a new ARES licensing category to serve Large Load Customers with revised managerial, technical, and financial capabilities requirements;
- Additional bonding requirements, if authorized by a change in statute;
- Added ICC oversight to ARES serving Large Load Customers through additional annual reporting fields and events that trigger prompt ICC notification; and
- A prohibition on ARES single billing of ComEd charges and Large Load Customer ability to take default BESH generation service.

While the creation of Large Demand Customer tariffs may be subject to the outcome of legislation requested by Gov. Pritzker, the ICC currently has the authority to adjust ComEd's retail delivery service tariff, retail supplier tariff documents, and most of the suggested changes to ARES licensing regulations and oversight.

G. Virginia State Appendix

Virginia has two major investor-owned utilities: Virginia Electric and Power Company d/b/a Dominion and Appalachian Power d/b/a AEP. Dominion participates in PJM's Reliability Pricing Model (RPM) while AEP is a Fixed Resource Requirement (FRR) entity. In addition to Dominion and AEP, there are several cooperatives and municipal utilities in Virginia. This whitepaper focuses largely on Dominion since it participates in the RPM and will need to adjust its retail tariffs for large load customers in order to implement PJM's Reliability Backstop Procurement (RBP), Bring Your Own New Capacity (BYONC), and Interim Resource Adequacy Service (IRAS) frameworks.³¹⁵

Virginia has made significant efforts to respond to the emergence of large load data center customers in the state. This includes a State Corporation Commission (SCC) proceeding in 2025 with Dominion to develop Schedule GS-5 for large load customers greater than 25 megawatts (MW). In 2026 Virginia General Assembly passed two laws that Governor Spanberger subsequently signed into law. HB 1393/SB 253 prohibits other customers from subsidizing the cost to serve GS-5 High-Load Customers, including RBP costs. HB 284/SB371 requires Dominion to file a proposal for establishing a voluntary demand flexibility program.

Implementation of PJM's RBP and IRAS proposals will require additional changes to Schedule GS-5 and potentially the creation of rate variants to facilitate accurate customer cost allocation and the ability to accommodate customers who may have both RBP and RPM UCAP.

Interruptible versions of Schedule GS-5 or an IRAS program rider will be needed to codify the rules for curtailments and potential payments, if applicable, for customers that have an IRAS performance obligation.

The SCC and Data Center Coalition (DCC) have already announced an effort to create model state tariffs. While there is a limited market for competitive generation supply in the Dominion service area, it is unclear if large load customers will opt for competitive supply over Dominion's GS-5 rate or its Large General Service Market-Based Rate (Schedule MBR) which allows large customers to access PJM's wholesale prices for energy and capacity. If any new large loads elect competitive supply, then tariffs and rules pertaining to competitive electric suppliers will need to be updated to ensure that RBP and UCAP with an IRAS performance obligation can be accurately administered by the CSP.

³¹⁵ RBP filed under Docket No. ER26-3380-000, IRAS filed under Docket No. ER26-3515-000.

State Actions Taken to Date

SCC 2025 Dominion Biannual Review and Development of GS-5 Rate

In the 2025 Biennial Review of Dominion's rates, the SCC issued an Order on November 25, 2025 approving a separate rate class for large customers called GS-5. It will become effective on January 1, 2027.³¹⁶ Customers eligible for service on the GS-5 rate have a demand of 25 megawatts (MW) or greater and a load factor of 75% or higher.

Service on the GS-5 rate requires:

- A 14-year contract term with limited ability to reduce contract demand;³¹⁷
- Minimum transmission and distribution demand charges.
- Minimum generation charges applicable to all GS-5 customers except those taking service from a Competitive Service Provider (CSP) or Dominion Schedule 10 prior to January 1, 2026.^{318, 319}
- An exit fee to cover outstanding minimum charges over the duration of the remaining contract term if service terminates; and,³²⁰
- Collateral of \$1.5 million/MW that can be reduced based on the applicant's credit with provisions for third-party guarantees and letters of credit. One fourteenth of the collateral requirement is released each year throughout the contract term.³²¹

The SCC also recognized the need to address in future proceedings the effects of data center-driven load growth on Dominion's cost allocation methodologies, including the allocation of plant and transmission costs.³²² Cost allocation will be taken up in Dominion's 2027 Biennial Review.

³¹⁶ Final Order, Application of Virginia Electric and Power Company d/b/a Dominion Energy Virginia for approval of its 2025 biennial review, PUR-2025-00058, (Nov. 25, 2025), p. 24 (Biennial Review Order).

³¹⁷ Id., pp. 24, 27.

³¹⁸ Id., pp. 7, 25-26 (citations omitted). See also Rebuttal Testimony of J. Scott Gaskill, Case No. PUR-2025-00058, pp. 9-10 (September 10, 2025).

³¹⁹ Witness Gaskill's proposal established the capacity component of base rates as a separate billing determinant and excluded capacity costs from the minimum generation demand obligation for CSP customers. See Gaskill Rebuttal, p. 10.

³²⁰ Id., p. 23.

³²¹ Id., p. 25.

³²² Id., p. 16 (noting the need to transition away from full Average & Excess methodology for allocation of plant costs).

Data Center Coalition (DCC) and SCC Working Group

In the June 30th, 2026 Critical Issue Fast Path (CIFP) RBP meeting, the DCC and SCC issued a joint letter announcing that they will convene a joint working group with other interested states to develop model state regulatory frameworks to better integrate large loads. The first project announced in this letter includes an initiative to develop model state interruptible tariffs and emergency load reduction programs with a target completion date for this work of February 1, 2027. The second is the development of a model state tariff to address the retail allocation of costs associated with PJM's RBP with a target completion date for this work of January 1, 2028.³²³ To date, there are no public materials regarding this new initiative.

Enactment of HB 1393/SB 253

The 2026 Virginia General Assembly passed companion bills HB 1393 and SB 253, which Governor Spanberger subsequently signed into law. The effect of this law is to prohibit other customers from having to subsidize the cost to serve GS-5 High-Load Customers, including RBP costs. The relevant portion of the law states that:

“the Commission shall ... take all measures to reasonably ensure that costs associated with customers taking service under the terms and conditions for customers with a contracted or measured electric demand of 25 megawatts or greater and an anticipated or measured average annual electric load factor of 75 percent or greater (high load customers) are not being subsidized by other customers of the utility, and that such other customers' approved rates are not being adversely impacted by such customers taking service under the terms and conditions for high load customers”.³²⁴

HB 1393/SB 253 reinforces and expands upon the SCC's underlying rationale for establishing Schedule GS-5. While the SCC approved a framework designed to ensure that GS-5 large load customers bear the cost to serve them, the General Assembly has now expressly directed the SCC to ensure that other customers do not subsidize those costs or experience adverse rate impacts as a result of service to GS-5 customers. As a result, the SCC will need to address the legislative directive, presumably in Dominion's 2027 Biennial review, along with its decision to review cost allocation methodologies.

³²³ Joint Letter of Kelsey Bagot (Chair, VA SCC) and Josh Levi (CEO – Data Center Coalition), Letter to the CIFP-RBP Stakeholder Group, June 30th, 2026, available at <https://www.pjm.com/committees-and-groups/cifp-rbp>

³²⁴ Va. Code § 56-585.1:2 (as enacted by 2026 Va. Acts, HB 1393/SB 253).

Enactment of HB 284/SB 371

HB 284/SB 371 (codified at Section 56-596.7 of the Code of Virginia) was passed in April 2026 and requires Dominion to file petitions with the SCC by January 15, 2027 proposing voluntary demand flexibility programs for “high energy demand customers,” which are defined generally as those with demand of at least 25 MW and an annual load factor of at least 75%. The programs must be designed to maximize grid savings and improve reliability and must consider mechanisms including direct load interruption or curtailment and demand response.³²⁵ It gives the SCC a statutory vehicle for creating a program that could help implement PJM’s proposed IRAS framework.

Current Status of Retail Choice in Dominion’s Service Territory

Statutory Background and Recent Legislation

Virginia has historically maintained a limited retail choice market with opportunities to purchase competitive generation supply available to customers with peak demands over 5 MW. There have also been historical periodic openings to customers who can use aggregation of multiple sites to reach 5 MW or those purchasing a 100% green energy supply product.³²⁶

Recently enacted HB 921/SB 818 expands the potential competitive supply market for large-load customers. Previously, nonresidential customers generally could exercise retail choice only if their demand exceeded 5 MW but remained below 1% of Dominion's system peak.³²⁷ The 2026 legislation eliminates that upper limit, meaning that any individual nonresidential Dominion customer with a prior-year noncoincident peak demand above 5 MW may now elect competitive generation supply. The legislation also reduces the notice required for a shopping customer to return to Dominion supply from five years to 18 months, although returning customers are subject to a 12-month minimum stay³²⁸. At the same time, the legislation allows Dominion to seek rate adjustments when movements between utility and competitive supply result in a net load gain or loss of at least 100 MW, providing a mechanism to address stranded costs or other cost-allocation impacts.³²⁹ While HB 921/SB 818 seemingly increases access to competitive generation supply for Virginia's rapidly growing large-load sector, it also provides protections against shifting costs associated with large customers.

³²⁵ HB 284/SB371, as approved, available at: <https://lis.blob.core.windows.net/files/1217713.PDF>

³²⁶ Code of Virginia, § 56-577(3), § 56-577(4), § 56-577(5).

³²⁷ HB 921/SB 818, as approved, p. 1, available at: <https://lis.virginia.gov/bill-details/20261/SB818?>

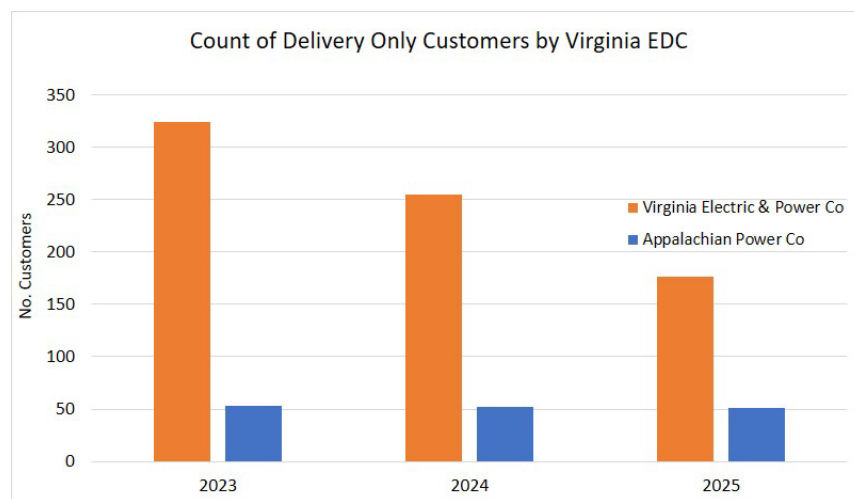
³²⁸ Id.

³²⁹ Id., p. 2.

Current Competitive Supply Provider (CSP) Market Activity

Data obtained from the Energy Information Administration's (EIA) Sales to Ultimate Customers Report provides a window into the competitive generation supply market in Virginia.³³⁰ As of 2025, there were four active power marketers serving customers in either Dominion or AEP's Appalachian Power utility down from seven in 2023.³³¹ The number of customers taking service from CSPs and associated MWh sales have been declined in 2025 relative to 2023 as shown in Figure 1 and Figure 2.³³²

Figure 1

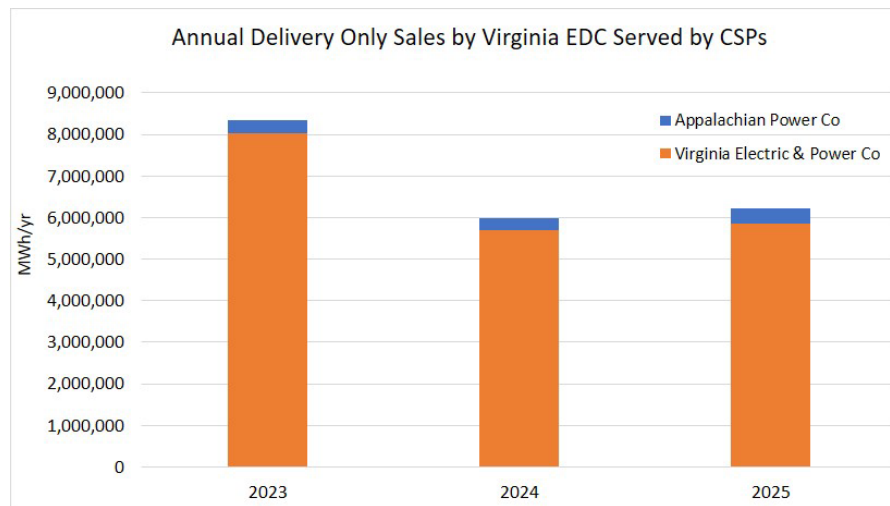


³³⁰ EIA Annual Electric Power Industry Report, Form EIA-861 detailed data files, Sales to Ultimate Customers Report, available at <https://www.eia.gov/electricity/data/eia861/>

³³¹ The remaining active power marketers in 2025 include: Direct Energy Business; Texas Retail Energy, LLC; MP2 Energy LLC; BP Energy Retail LLC.

³³² Customer counts are those reported by the EDCs as taking Delivery Service only due to a mismatch between the numbers reported by CSPs.

Figure 2



Due to the added base rate generation demand charge that will be applicable to new customers on rate GS-5, it is unclear if taking service from a CSP will be economically attractive to new large loads relative to Dominion’s standard GS-5 tariff or Large General Service Market-Based Rate (Schedule MBR) tariff offerings. ETE’s understanding is that a version of Schedule MBR will be available to GS-5 customers in 2027 when the GS-5 rate debuts.

Discussion of Retail Choice in Dominion’s 2025 Biennial Review

In rebuttal testimony regarding Dominion’s proposed minimum generation demand charge for high-load customers, Dominion witness J. Schott Gaskill explained that the Company’s current embedded-cost rates can be more attractive than service with a CSP. He states:

“While PJM capacity and energy prices are at historic highs, we have observed few customers interested in going to choice. On the other hand, we have seen a number of customers return from choice as a result of the high PJM capacity prices because they would rather be on the Company’s embedded cost rates, which are lower.”³³³

³³³ Rebuttal Testimony of J. Schott Gaskill, PUR-2025-00059, p. 6 (August 13, 2025), available at: <https://www.scc.virginia.gov/docketsearch#caseDocs/146026>

Dominion Witness Gaskill's testimony corresponds to the EIA data regarding power marketer sales in Virginia indicating customers returning from choice. As a result, it does not appear that new large loads will prefer serve from CSPs relative to Dominion's tariff offerings.

Cross Subsidy Risk Within Dominion's Tariffed Generation Price Offerings

Fuel Adjustment and Deferrals

In recent years, Dominion has accrued significant deferred fuel costs, reaching approximately \$1.27 billion as of June 30, 2023.³³⁴ This deferral was subsequently addressed through securitization. As of June 30th, 2025 Dominion projected an additional unrecovered fuel deferral balance of \$204.5 million.³³⁵

If new large loads are able to take service on the Fuel Adjustment rider at times when it is set below actual fuel costs, the magnitude and high load factors of large loads could exacerbate Dominion's fuel deferral balances on a going-forward basis. Such under-recoveries would be carried forward for future recovery through a deferral rider or securitization, increasing the potential for cost shifts to other customers, especially if these large loads go out of business or switch to CSP service.

Dominion Identified Risk of Cross Subsidies Under Rider MBR

Dominion Schedule MBR is an optional rate that allows customers to receive generation supply based on the PJM wholesale locational marginal price (LMP) plus adders and generation capacity based on the customer's unique capacity tag set via contribution to PJM's five coincident peaks (5 CP) during the prior summer. This rate allows large loads to have direct exposure to the price fluctuations in the PJM wholesale market for both energy and capacity.³³⁶

In its 2025 Biennial Order, the SCC recognized that generation rates charged to Schedule MBR and SCR customers reflect the wholesale market rates - and not retail rates based on the Company's generation cost of service. It further recognized that MBR and SCR costs can differ from Dominion's standard cost-of-service rates and if the market-based rate remains below the standard tariff rate for an extended period. If this were to occur customers taking service under MBR or SCR could contribute less than their proportional share of revenues, resulting in costs

³³⁴ Financing Order, Case No. PUR-2023-00112, p. 4 (November 3, 2023).

³³⁵ See Application of Virginia Electric and Power Company, to revise its fuel factor pursuant to Va. Code § 56-249.6, Case No, PUR-2025-00059, p. 2 (March 31, 2025), available at: https://www.scc.virginia.gov/docketsearch/DOCS/84ql01%21.PDF?utm_source

³³⁶ Dominion Retail Tariff, Schedule MBR.

being shifted to other customers.³³⁷ The SCC further noted the agreement of Staff and Dominion that cost shifting could occur if (1) MBR load exceeds Dominion's percentage of market purchases and (2) the MBR rate is lower than the standard tariff rate.³³⁸

At the same time, the SCC recognized that MBR and SCR provide a natural hedge against Dominion's short capacity and energy positions, but that the benefit of the hedge exists only up to the amount of the Company's short position.³³⁹ In approving the schedules, the SCC therefore directed Dominion to manage participation so that MBR and SCR load does not exceed the Dominion's short capacity or energy positions and required Dominion to report annually to Staff the total customer load taking service under each schedule.³⁴⁰

Dominion's Existing Interruptible and Demand Response Rates

Section XVIII of the Dominion Retail Tariff details the terms for "Interruptions of Electric Service".³⁴¹ It states that the Company has the right to initiate a *"reduction or interruption of Electric Service to some customers or areas in order to compensate for a power shortage on the Company's system or to limit the extent or duration of the adverse condition or disturbance on the Company's system or to prevent damage."*

In addition to the emergency procedures detailed above, the Company also maintains voluntary demand response programs for commercial customers. These include a Non-Residential Curtailment Program^{342,343} and a Distributed Generation Program whereby participating customers receive an incentive payment for reducing energy usage during a curtailment event.³⁴⁴

Recommended Changes to Dominion's Tariffs

In addition to the changes to the GS-5 rate framework that will be required by the SCC's Order to revisit cost allocations and the directives from HB 1393/SB 253, Dominion will also have to

³³⁷ See Final Order, *Application of Virginia Electric and Power Company*, Case No. PUR-2025-00058, pp. 19 (Nov. 25, 2025) (citing Ex. 3, Filing Schedule 41; Ex. 25 (Miller Direct) pp. 32, 35–38; Ex. 26 (Givens Direct) pp. 37–41; Ex. 97 (Ellis Direct) pp. 5–7).

³³⁸ *Id.*, p. 19 and FN 74 (citing Tr. 742–43 (Gaskill); Tr. 1815 (Ellis); Tr. 2214–15 (Gaskill)).

³³⁹ *Id.*, p. 19 and FN 75–76 (citing Ex. 27 (Stuller Direct) p. 11; Tr. 742–44 (Gaskill)).

³⁴⁰ *Id.*, p. 20.

³⁴¹ Dominion Tariff, Terms and Conditions Section XVIII Interruptions of Electric Service, Available at [Business Rates | Virginia | Dominion Energy](#)

³⁴² Program details are here: <https://www.dominionenergy.com/virginia/save-energy/targeted-sector-programs>

³⁴³ Non-Residential Curtailment Program Terms and Conditions (Rev. 4/16/2026), available at: <https://cdn-dominionenergy-prd-001.azureedge.net/-/media/content/save-energy/targeted-sector-programs/pdfs/virginia/non-residential-curtailment-program-terms-and-conditions.pdf?rev=bcb6fa53ae4448f4baaec8aed26df0e5>

³⁴⁴ <https://www.dominionenergy.com/virginia/save-energy/targeted-sector-programs>

make several tariff changes to implement PJM’s proposed RBP and IRAS frameworks. A high-level summary of these required changes by tariff section are detailed in Table 37.

Table 37: Suggested Modifications to Schedule GS-5 to Accommodate the RBP and IRAS Proposals

Tariff Section/Topic	Required Change	Rationale
Definitions	Need to acknowledge PJM definitions for Large Load Customers, RBP, BYONC, and IRAS programs.	The tariff must be able to operationalize RBP and IRAS and distinguish customer applicability as these responsibilities are under state jurisdiction. ³⁴⁵
Service by Capacity Category Types	Schedule GS-5 will need to be able to accommodate four possible capacity option scenarios to ensure accurate cost allocations. These potential scenarios include: • BYONC RPM UCAP • RPM UCAP w/ IRAS • RBP; or • Hybrids	Customers with RBP capacity or IRAS performance obligations will have different requirements in terms of financial assurance or IRAS performance compared with those who have RPM UCAP. Structures can change if shortage conditions are absent for three years.
Interruption Triggers and Program Rules for IRAS	IRAS Eligible New Large Loads need to be identified in accordance with PJM Tariff Attachment DD-4, section IV and EDCs must file public tariffs that conform to PJM interruption triggers codified in PJM Manual 13. Payment of credits, if any, for IRAS curtailments will have to be included in retail tariff rules.	Implementation of IRAS at the customer level is delegated to EDCs in PJM’s proposed tariffs. The EDCs will have to create rules for individual customers regarding curtailment and payment of credits for performance, if any.

Conclusion- Virginia

The state of Virginia has taken robust action to date to respond to the challenge of emerging large data center loads. These actions have included legislation, a Dominion rate proceeding to

³⁴⁵ PJM Proposed tariffs delegate cost allocation of RBP and IRAS operationalization to the states at Proposed Tariffs Attachment DD, section 18.3(b)(iii); Attachment DD-4, III(c); Attachment DD-4, IX(b)(i); and Attachment DD-4, X.

develop Schedule GS-5, and an upcoming SCC and DCC coordinated working group to develop model state tariffs.

In the coming year, the SCC will need to revisit cost allocations for large load costs in follow-up to the Order from Dominion's 2025 Biennial review and the legislative directives of HB 921/SB 818. In addition to this, the SCC will need to oversee the following changes to Dominion's tariffs to facilitate operationalization of PJM's RBP and IRAS proposals:

- Incorporation of all relevant PJM definitions into the Dominion retail tariff
- Schedules GS-5 and MBR
 - Develop a methodology for RBP cost allocation to large loads and design rate variants to allow for direct assignment of RBP capacity to responsible customers.
 - Create rate variants to accommodate both RBP and RMP UCAP as well as UCAP that may have a corresponding IRAS performance obligation
- Devise an interruptible version of Schedules GS-5 and MBR or an IRAS Program Rider to detail the IRAS curtailment requirements including dispatch, performance measurement, interruption methods (measured curtailment or physical), and payment and crediting mechanism if the SCC and Dominion elect to offer compensation to large loads for their curtailment performance.

At the present time, it's unclear if the SCC needs to impose any additional requirements on CSPs, since the economic proposition for competitive supply for new large loads is unclear given Dominion's proposed base generation demand charge for new customers and the ability to adjust rates for every 100 MW of customer load switching. Existing customers served by CSPs have RPM UCAP, but if new large loads do migrate to CSPs, then SCC and Dominion will need to revise retail supplier tariffs and related cost allocation documentation so that RBP and RPM UCAP with an IRAS performance obligation can move with the customer to a CSP.

Authors

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