



**EPIC REPORT NO. 2026-001**

# **Data Centers in Kentucky: Policy Analysis for the General Assembly**

Cost Allocation, Ratepayer Protection, and Economic Development

**Kentucky Energy Planning and Inventory Commission**

June 2026

Prepared pursuant to KRS 164.2807

*This report is provided for informational purposes to assist the Kentucky General Assembly. It does not constitute a formal recommendation or position of any state agency, utility, or regulated entity*

## Overview

Kentucky is well-positioned to compete for data center investment. The state offers among the nation's lowest industrial electricity rates, available land, abundant water resources, a growing fiber infrastructure, and a regulatory environment with a demonstrated record of supporting large economic development projects. Data center development represents a significant opportunity for job creation, capital investment, and long-term tax revenue across multiple regions of the state. The question is not whether data centers should locate in Kentucky, but how to ensure they are integrated into the state's electric system in a way that protects existing ratepayers and maintains reliability.

Experience from other states shows that development can be accommodated successfully when cost allocation rules, tariff structures, and planning processes are established before major infrastructure commitments are made. When those structures are in place, states have attracted substantial investment while maintaining affordability and reliability for existing customers.

The 2024 General Assembly created EPIC before significant hyperscale development arrived. This effort paired a data center tax incentive program with independent supply adequacy oversight, directing the PSC to review proposed retirements against projected load. The PSC used tools granted in its November 2023 order denying LG&E/KU's closure of the Ghent 2 and Brown 3 coal units. Additionally, in its October 2025 order, the PSC approved LG&E/KU's Mill Creek and Brown combined-cycle units, conditioning approval on the utility's commitment not to proceed if the data center load does not materialize. That condition reflects an approach the General Assembly may consider extending. The question before the General Assembly is how to extend that instinct system-wide through tariff standards rather than addressing it one project at a time.<sup>1</sup>

More directly, in October 2025 the PSC approved EKPC's Data Center Power tariff, which was designed to ensure the customer bears the full cost of infrastructure it directly causes.<sup>2</sup>

The tariff applies to loads of 15 megawatts or more, with enhanced requirements for projects exceeding 250 megawatts. It requires application fees with no cap, scaled collateral, and a PSC-approved special contract for each project, a structure designed to ensure serious developers move forward while discouraging speculative or non-committed requests.

The experience of other states shows that the presence or absence of those standards determines whether existing customers are sufficiently protected. Ohio established cost allocation rules before significant development arrived, attracting substantial investment without shifting infrastructure costs to existing customers. Virginia did not have data center focused protections for existing customers. As a result, proceedings proposing residential customer rate increases of \$14 to \$37 per month by 2040 point to data center growth as a significant contributor in several proceedings. The Virginia legislature and regulators have limited options to address the increase because the relevant infrastructure has already

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<sup>1</sup>Kentucky General Assembly, 2023 Regular Session, SB 4 (retirement of fossil fuel-fired electric generating units); 2024 Regular Session, HB 8 (data center tax incentive program); SB 349 (creating the Kentucky Energy Planning and Inventory Commission under KRS 164.2807). Kentucky Public Service Commission Order, Case No. 2025-00045, October 28, 2025 (approving LG&E and KU Mill Creek 6 and Brown 12 combined-cycle units, conditioned on load development).

<sup>2</sup>In the Matter of the Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. to Establish a New Tariff for Data Center Power, Order, Case No. 2025-00140 (Ky. P.S.C. Oct. 30, 2025).

been deemed used and useful, permitting its inclusion in the rate base. Additional drivers of the proposed increase include the Virginia Clean Economy Act, a renewable portfolio standard (RPS) that specifies renewable generation resources, and retail choice for loads greater than 5 MW. An RPS approach to generation is typically more expensive than least cost planning. Under retail choice, certain large customers may procure generation outside the regulated system, which can affect how system costs are allocated among remaining customers depending on how those costs are structured.

Kentucky's regulated, vertically integrated utility system has delivered reliable, low-cost electricity to Kentucky homes and businesses for decades. Its utilities are diverse in their business models and wholesale market participation, with both investor-owned utilities and electric cooperatives (both PSC regulated and PSC exempt TVA cooperatives), RTO-participants and a non-RTO participant, and even differences between the level of market participation for the RTO participants, making utility policy work particularly complex in the Commonwealth. This means that individualized cost allocation rules must be in place before major infrastructure commitments are made to ensure each utility's existing customers are protected. Once a prudently incurred investment qualifies as used and useful and enters the rate base, the PSC's tools for reassigning cost recovery are limited. Ensuring the proper allocation rules are in place protects existing customers while remaining a competitive destination for new investment.

This document provides an analytical foundation for that assessment. It describes Kentucky's current data center pipeline, explains the regulatory model that governs how costs are assigned and recovered, examines the efficacy of existing tariffs, identifies principal policy questions before the General Assembly to consider, and draws on the documented experience of other states to inform Kentucky's approach. The goal throughout is to support development that works for Kentucky: investment that benefits the state's economy, ratepayers, and industries that depend on affordable, reliable electricity.

### **About This Document**

At its January 2026 meeting, EPIC's Executive Committee passed a motion directing the Commission to conduct topical studies on energy policy issues before the Kentucky General Assembly. Data center development is the first topic taken up under that authority. The study reflects EPIC's statutory responsibility to provide independent analysis of supply adequacy, rate design, infrastructure planning, and economic development across multiple utility jurisdictions to the General Assembly.

This document provides in-depth technical background, describing Kentucky's current data center landscape, an overview of principal tariff structures currently in use or under development, analysis of how those tariffs allocate risks and benefits, and assesses Kentucky's readiness to protect affordability and reliability with significant data center development forecasted. The accompanying two-page legislative briefing serves as a high-level summary of this technical background document. The briefing is EPIC's primary public-facing product. This document is available on request for legislators, staff, utilities, regulators, and others who want the full analytical basis behind the briefing's findings.

A note on scope: EPIC is a new agency. The work that will most firmly establish the Commission's credibility is its own primary analysis: the energy inventory, the retirement review function, and the demand forecasting work underway through EPIC's three technical committees. This document draws on public sources, comparative state experience, and established utility regulatory principles. It builds on that foundation as EPIC's own supply adequacy data and primary analysis mature.

## How to Use This Document

Start with the *Overview*, which sets out the report's core argument. Then see the two-page legislative briefing (EPIC 2026-002) for the public-facing summary. This background document provides sourcing and analytical depth for each section of the briefing. Section II on Kentucky's regulated utility model and Sections V and VI on cost allocation and state comparisons are the most substantive portions.

## I. Kentucky's Data Center Landscape

### A. What is a Data Center?

A data center is a facility housing computing equipment, including servers, networking hardware, and storage, along with the infrastructure needed to keep it running continuously, including power distribution, cooling, and physical security. Most data centers fall into one of three categories: enterprise facilities operated by a company for its own computing needs; colocation facilities that rent space and power to multiple tenants; and hyperscale campuses, typically exceeding 100 megawatts of capacity, operated by a single company at a large scale. Amazon Web Services, Microsoft, Google, and Meta account for most new hyperscale construction and a disproportionate share of new electricity demand.

Data centers run around the clock at sustained high-power loads. A 100-megawatt facility draws electricity roughly equivalent to the continuous average consumption of approximately 80,000 homes. Their high load factor can improve utilization of transmission and generation assets when rates are designed properly, but they can also accelerate the need for new infrastructure if demand assumptions are speculative or poorly matched to the utility's planning model.<sup>3</sup>

The Uptime Institute's tier classification system is the industry standard for data center design reliability, used by developers, lenders, and utilities worldwide to describe how a facility handles equipment failures and maintenance. The tiers run from I to IV, with each level requiring greater redundancy and on-site backup capability. Tier III is the baseline for commercial colocation and hyperscale construction. It requires N+1 redundancy across all critical power and cooling systems, meaning each system must have at least one backup unit beyond what is needed to run the facility at full capacity. If a facility requires ten cooling units to operate, it must have eleven installed; if one power feed fails, another is ready to carry the load. The facility can sustain continuous operations while any single component is being serviced or has failed. Tier IV requires 2N redundancy, meaning two fully independent systems for every critical function, each capable of carrying the full load alone.<sup>4</sup>

Both tiers require substantial on-site backup generation or large batteries with minimum fuel reserves. Tier III requires 72 hours of on-site fuel; Tier IV requires 96 hours. For a campus of approximately 400 megawatts (in the range of the Louisville project currently in LG&E/KU's pipeline), that means maintaining enough on-site diesel or batteries to power the facility at full load for 3 to 4 days without drawing from the grid. This on-site generation capacity is a relevant consideration for Kentucky's supply adequacy picture. As large data center campuses are built across the state, the backup generation assets they must

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<sup>3</sup>Congressional Research Service, *Data Centers and Their Energy Consumption: Frequently Asked Questions*, R48646, January 23, 2026, pp. 3-4.

<sup>4</sup>Uptime Institute, *Uptime Institute Tier Standard: Topology*, 2022. Available at [uptimeinstitute.com](https://uptimeinstitute.com). The Tier Standard is the globally recognized authority on data center infrastructure design requirements and is referenced by lenders, insurers, developers, and utilities in evaluating facility specifications.

maintain represent a significant share of installed capacity that does not appear in utility resource plans or EPIC’s current energy inventory. On-site backup generation does not substitute for utility capacity but may have implications for emergency operations and load behavior. How that capacity interacts with utility reserve margins and emergency response planning is a question EPIC’s demand forecasting and primary energy supply committees will examine as the Commission’s data develops.

Tier	Availability	Redundancy	On-Site Fuel
Tier III	99.982%	N+1 concurrent maintainable	72 hours
Tier IV	99.995%	2N or 2N+1 fault tolerant	96 hours

Table 1. Uptime Institute tier standards for data centers most relevant to hyperscale development.

**B. Kentucky’s Current Pipeline**

Kentucky hosts 37 data centers across nine markets, with 24 in Jefferson County. LG&E/KU reported to the PSC in March 2026 that it had 29 potential data center projects in its pipeline, with 11 of those projects, representing combined demand of approximately 3.5 gigawatts (GW), assigned a probability of 50 percent or greater of proceeding. The CEO of LG&E/KU’s parent company told investors in May 2026 that total prospective electricity demand from potential data centers in LG&E/KU’s territory could reach approximately 12 GW. Federal data showed Kentucky utilities generated a maximum of 18.4 GW in the summer of 2024, providing context for the scale of these projections.<sup>56</sup> EKPC currently has 11 active data center projects seeking over 10 GW of power.

Kentucky’s first hyperscale facility, announced in January 2025, is a Powerhouse Data Centers and Poe Companies campus in southwest Louisville. LG&E secured an initial power capacity of 335 megawatts, with a near-term expansion to 402 megawatts. The first phase of 130 megawatts is targeted for commercial operation in late 2026, supported by a new LG&E switch station. Projected investment over the project’s lifetime is approximately \$11 billion.<sup>7</sup>

Additional projects are under consideration in Hancock, Mason, Clark, Oldham, Meade, Gallatin, Carroll, Madison, Laurel, Jackson, Marion, Hardin and Simpson counties. Other Kentucky utilities are also fielding significant inquiry activity, including projects proposed at the site of a former western Kentucky aluminum mill and at an eastern Kentucky industrial park. The scale of reported project activity across utility service territories statewide increases the importance of establishing cost-allocation expectations and planning frameworks before major infrastructure commitments are made. Several rural proposals have encountered local opposition over zoning, transparency, and infrastructure concerns. The speculative nature of some inquiries, where developers explore multiple markets simultaneously without binding commitments, is a recurring issue discussed in Section IV.

**C. National Context**

<sup>5</sup>Liam Niemeyer, ‘KU and LG&E have 20 data center projects in the pipeline,’ WUKY, August 14, 2025. Updated figures: LG&E and KU PSC filing, March 2026 (29 total projects; 11 projects with ≥50% probability totaling approximately 3.5 GW); Liam Niemeyer, ‘Utilities report as many as 30 data centers under discussion in Kentucky,’ Kentucky Lantern, May 29, 2026.

<sup>6</sup>John Bevington, PPL Corporation, testimony to Kentucky AI Task Force, November 2025.

<sup>7</sup>Powerhouse Data Centers and Poe Companies, press release, January 16, 2025.

U.S. data centers consumed approximately 176 terawatt-hours in 2023, about 4.4 percent of national electricity use. Projections suggest the figure could reach 8 to 12 percent by 2028.<sup>8</sup>

## II. Kentucky's Regulated Integrated Utility Model

Kentucky did not deregulate its electric utility sector. Every kilowatt-hour sold to a Kentucky retail customer is sold at rates set and approved by the Public Service Commission, except for those sold by a municipal utility, such as the Frankfort Plant Board, or a TVA cooperative. Understanding this regulatory structure is the starting point for every data center policy question, because it determines who bears the financial risk when a utility must serve a large new load.

### A. How the Model Works

In a regulated integrated utility, a single company owns generation, transmission, and distribution assets and serves retail customers at PSC-approved rates. An investor-owned utility earns a regulated return on its infrastructure investment. The PSC reviews the utility's costs, determines which were prudently incurred, and sets rates that allow recovery of those costs plus the approved return, or in the case of a cooperative, the cost of debt. Investments flow into the rate base and are recovered from all customers over the life of the asset, typically 20 to 40 years for generation.

Kentucky never pursued deregulation, which has been a key factor in helping to keep Kentucky's energy rates lower than other nearby states that separated the obligation to generate electricity from the obligation to serve customer load. The PSC's statutory mechanisms under KRS Chapter 278 apply across investor-owned and cooperative utility types, with the exception of TVA-served distribution cooperatives, which fall outside PSC jurisdiction.

### B. The Obligation to Serve

Under KRS Chapter 278, Kentucky utilities are obligated to provide service to any customer within their service territory who requests it. Utilities are generally required to serve customers within their service territory, subject to interconnection requirements and PSC-approved terms. If the customer is within the service territory and meets the interconnection requirements, the utility must serve the customer.

An electric utility can establish a tariff or special contract to ensure that a prospective customer meets certain obligations to receive service. A tariff is typically used when there are likely to be multiple customers sharing the same characteristics and protections can be applied uniformly. A special contract is a better fit when a customer needs individualized terms to protect existing customers and the company.

In a competitive or partially deregulated market, a supplier can price the risk of serving a load into a negotiated contract and walk away from a deal that does not work. Kentucky utilities do not have that option. The rules governing what a data center must pay, what financial assurances it must provide, and what happens if it fails to materialize are established through PSC-approved tariffs or special contracts. Without those rules, the utility may build the necessary infrastructure and collect rates under a different tariff that may not ensure the data center customer is paying a sufficient share of the costs to protect other customers from subsidizing them.

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<sup>8</sup>A. Shehabi et al., 2024 United States Data Center Energy Usage Report, Lawrence Berkeley National Laboratory, LBNL-2001637, December 2024, pp. 5-6.

### C. Rate Base and Ratepayer Risk

Kentucky retains a regulated retail utility model under KRS Chapter 278. Rates remain subject to PSC approval, and major infrastructure additions and cost recovery are reviewed through ratemaking, CPCN proceedings, IRPs, or special-contract proceedings, depending on the utility and the assets at issue. That framework matters because it determines not only how utilities recover costs, but also how risks are filtered before those costs reach existing customers. Unlike in fully deregulated states, utilities cannot rely solely on bilateral private contracts to allocate all large-load risk. Instead, Kentucky relies on a combination of tariffs, PSC review, and a utility-specific planning process. The PSC serves as a meaningful buffer, granting CPCNs as an initial review as to the prudence of utility investment decisions, a subsequent review to ensure investments are prudent, verification that the assets resulting from the investment are used and useful, and finally, in addressing cost allocations in the rate base to ensure the cost causer incurs the expense to the extent possible.

In fact, the used-and-useful standard became a permanent part of the review process in Kentucky because forecasted load growth did not materialize as expected. In 1978, LG&E was granted a CPCN to construct Trimble County Unit 1 (PSC Case 8924). The assets were projected to come online in 1983 and 1985, respectively. Construction was delayed, and Trimble County 1 did not enter service until 1990. When the PSC conducted a prudence review on the investment, it was discovered that the load growth forecast had not materialized. While rarely applied in practice, the PSC disallowed recovery of 25 percent of the asset, deeming it not to be used and useful, to protect customers from those costs entering the rate base (PSC Case 9934). In each rate case from the early 1990s through the early 2000s, LG&E was required to demonstrate that 25 percent portion of the cost of that plant and the return on investment was not included in the rate base.

In its October 2025 order approving LG&E/KU's two new 645-megawatt combined-cycle plants, the approval was conditioned on the utility's commitment not to proceed if the load does not develop as anticipated.<sup>9</sup>

In an investor-owned utility setting, prudence review, the used-and-useful concept, and cost-causation principles can prevent speculative or poorly supported costs from being incurred or shifted directly to existing customers. It can be more difficult in a cooperative model where the member and customer are the same party.

This distinction is especially important in evaluating risk allocation. For shareholder-owned utilities, when a plant or tariff-supported investment is not deemed prudent or sufficiently used and useful, the initial financial consequence can remain with shareholders through reduced earnings, delayed recovery, or disallowance rather than flowing immediately into customer rates. For member-owned cooperatives, PSC review protects rates but does not create an external shareholder buffer. If costs are disallowed or market outcomes weaken cooperative financial metrics, the residual risk remains within the cooperative system and is ultimately borne by member-owners, who are also the end-use customers served by that system. The practical implication is that tariff design and financial security requirements may need to be calibrated differently across utility types to achieve equivalent levels of customer protection.

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<sup>9</sup>Kentucky Public Service Commission Order, Case No. 2025-00045, October 28, 2025.

The practical effect is that the same regulatory concept does not produce the same economic result across all utilities. A PSC disallowance at an investor-owned utility can leave the shortfall with outside equity investors. A comparable disallowance at a member-owned cooperative may protect current billing treatment while still weakening the cooperative's margins, debt metrics, and borrowing costs, which ultimately affect the same member base that owns and buys power from the system.

#### **D. Why This Differs from Virginia**

In Virginia, much of the used-and-useful prudence review is conducted as part of the CPCN process, determining whether a project is necessary or duplicative at the front end. When paired with rate adjustment clauses in Virginia, there is a very strong assurance of recovering the investment and achieving a return on equity before an asset is put into service. Virginia's projected residential rate increases of \$14 to \$37 per month per household by 2040 are not primarily due to data centers paying too little per kilowatt-hour. They are the result of statutory assurance of recovery of transmission and generation infrastructure built into the rate base in anticipation of large loads that, in some cases, did not perform as projected or were not required to prepay their share of infrastructure costs. Once that infrastructure is in rate base, the PSC's options for reassigning cost recovery are limited. The lesson for Kentucky is simple: establish cost allocation rules before infrastructure commitments are made, not after, and ensure a prudence review is conducted before the investment is made to prevent recovery of an investment that is not beneficial to the customer base.

Virginia remained a major data center market throughout this period. The issue was never development itself but the absence of rules that assigned costs appropriately and limited assurance of recovery until after the investment was made and reviewed. Kentucky's PSC again demonstrated in its October 2025 KU/LG&E CPCN order that it has both the authority and the willingness to condition recovery and returns on load materialization.

#### **E. IRP in a Regulated State**

In competitive electricity markets, generation investment decisions are largely made by independent developers responding to market price signals. In Kentucky's regulated model, those decisions are made by utilities and reviewed by the PSC, the Attorney General's Office of Rate Intervention, and other stakeholders through integrated resource planning. At a basic level, an IRP shows projected demand, planned resource additions and retirements, and how the utility intends to maintain reliability at least cost. The PSC reviews whether demand assumptions are supported, and stakeholders join in the IRP process, challenging the utility's assumptions. This all occurs before a utility files a CPCN to seek approval for making an initial investment.

If data center demand projections in IRP filings are optimistic, utilities may seek approval for generation additions before demand is contractually firm. An IRP process that tracks data center demand separately from general load growth and requires evidence of project probability is the first of multiple steps in Kentucky's review process, positioning the Commonwealth well to protect existing customers.

#### **The Central Point**

In Kentucky, cost allocation rules must be in place before infrastructure is built. States that put these rules in place before major development arrives attract investment on terms that work for developers and existing customers alike.

Once a prudently incurred investment enters rate base, the PSC has limited tools to reassign its recovery to the customers who caused it.

### III. Kentucky’s Utility Structure

Kentucky’s electric utility structure is more complex than most states. It includes utilities participating in two different regional transmission organizations and one major utility that operates independently of any RTO and five distribution cooperatives that receive power from TVA. The PSC’s statutory mechanisms under KRS Chapter 278 apply across investor-owned and cooperative utility types, with the exception of TVA-served distribution cooperatives, which fall outside PSC jurisdiction. One benefit of RTO membership is that utilities can pool generation resources, lowering the reserve margin any single utility must carry independently. As a result, a non-RTO utility’s resource planning obligations reflect a higher reserve margin requirement than comparably sized RTO-participating utilities.

#### A. PJM-Participating Utilities

Kentucky Power Company (AEP) has participated in PJM Interconnection since 2004 and serves eastern Kentucky. Duke Energy Kentucky joined PJM in 2011 and serves northern Kentucky counties. East Kentucky Power Cooperative joined PJM in June 2013, serving 89 counties through 16 member cooperatives. The member cooperatives collectively serve an estimated 520,000 retail customer accounts across those counties.<sup>1011</sup>

Customers of these three utilities pay PJM’s regional capacity market costs through their electric rates. PJM capacity prices have risen from \$28.92 per megawatt-day in the 2024/2025 delivery year auction to \$333.44 per megawatt-day in the 2027/2028 delivery year auction, a nearly twelvefold increase over three auction cycles.<sup>12</sup>

The 2027/2028 delivery year auction, conducted in December 2025, was the first in which PJM’s cleared capacity fell short of the reliability requirement across the entire RTO.

Delivery Year	Clearing Price	Change	Note
2024/2025	\$28.92/MW-day	-	Prior baseline
2025/2026	\$269.92/MW-day	+833%	Data center load growth identified as contributing factor in PJM capacity market analyses

<sup>10</sup>East Kentucky Power Cooperative, Owner-Member Cooperatives, ekpc.coop: EKPC “generates and transmits power to 16 owner-member cooperatives serving 89 Kentucky counties” and describes powering “the lives of 1.1 million people.” EKPC is a generation and transmission cooperative and does not publish a retail customer account count. The 520,000 figure in the body text is an approximation based on household and account data published by EKPC’s 16 member cooperatives in their individual annual reports and PSC filings.

<sup>11</sup>Kentucky Power Company customer count: Kentucky Power Company, Form SF-1 (Securitization Financing Order), filed with the U.S. Securities and Exchange Commission, September 2024: “As of September 30, 2024, Kentucky Power Company provided transmission and distribution service of electric power to approximately 162,500 retail customers.” Duke Energy Kentucky customer count: U.S. Energy Information Administration, Form EIA-861 Annual Electric Power Industry Report, 2023 data; see also findenergy.com/providers/duke-energy-kentucky (approximately 154,700 customers).

<sup>12</sup>Kentucky utilities participating in PJM maintain generation sufficient to earn capacity auction revenues, which partially offset regional capacity market costs recovered in customer rates. This offset applies to existing capacity positions. It does not reduce the cost allocation risk associated with new generation built to serve large loads that have not yet made binding financial commitments to the utility.

2026/2027	\$329.17/MW-day	+22%	At FERC-approved price cap
2027/2028	\$333.44/MW-day	+1.3%	First auction PJM cleared capacity below reliability requirement

Table 2. PJM capacity market clearing prices. Source: PJM Interconnection Base Residual Auction Reports.

### B. MISO-Participating Utilities

Big Rivers Electric Corporation joined MISO in December 2010 and serves western Kentucky through three member cooperatives covering 22 counties and approximately 116,000 customers. Big Rivers customers are subject to MISO’s regional capacity market and transmission cost allocation rules.<sup>13</sup>

### C. LG&E/KU – The Non-RTO Utility

LG&E/KU exited MISO in 2006 after the PSC determined that RTO membership did not provide sufficient net benefits to Kentucky customers.<sup>14</sup> The utility remains vertically integrated and serves approximately 981,000 electric customers across Louisville and 77 Kentucky counties, with total customer accounts exceeding 1.3 million when natural gas service is included. It is the only major Kentucky utility outside an RTO.<sup>15</sup>

Because LG&E/KU does not participate in regional wholesale markets, all generation commitment and dispatch decisions are made internally under PSC oversight. Cost allocation for new generation can be assigned directly by the PSC without navigating RTO market rules. This is also the utility with the largest prospective data center pipeline, 29 projects representing prospective demand that could reach approximately 12 gigawatts, and the one for which the PSC recently approved \$2.798 billion in new generation capacity.<sup>16</sup>

Utility	RTO	Service Area	Status
Kentucky Power (AEP)	PJM	Eastern Kentucky	Member since 2004
Duke Energy Kentucky	PJM	Northern Kentucky	Member since 2011
East Kentucky Power Coop	PJM	89 counties, 16 member cooperatives	Member since 2013
Big Rivers Electric Corp	MISO	Western Kentucky, 22 counties	Member since 2010
LG&E/KU	Non-RTO	Louisville and central Kentucky	Exited MISO 2006

Table 3. Kentucky electric utilities and RTO status.

<sup>13</sup>Big Rivers Electric Corporation, 2024 Annual Report, bigrivers.com: “We provide wholesale electric power and shared services to three distribution cooperative Member-Owners across 22 counties in western Kentucky. Together, they distribute retail electric power and provide other services to more than 116,000 homes, farms, businesses and industries.” Big Rivers is a generation and transmission cooperative; retail customer accounts are held by its three distribution member cooperatives: Jackson Purchase Energy Corporation, Kenergy Corp., and Meade County Rural Electric Cooperative Corporation.

<sup>14</sup>Kentucky Public Service Commission Order, Case No. 2006-00172, May 31, 2006.

<sup>15</sup>Louisville Gas and Electric Company and Kentucky Utilities Company, About LG&E and KU, lge-ku.com/about: “LG&E serves 335,000 natural gas and 436,000 electric customers in Louisville and 16 surrounding counties. KU serves 545,000 customers in 77 Kentucky counties and 28,000 customers in five counties in Virginia.” Electric-only customer total: approximately 436,000 (LG&E) + 545,000 (KU Kentucky) = 981,000. The commonly cited figure of 1.3 million includes LG&E natural gas customers.

<sup>16</sup>Kentucky Public Service Commission Order, Case No. 2025-00045, approving LG&E and KU construction of Mill Creek 6 and Brown 12 combined-cycle generating units, October 28, 2025.

## IV. The Policy Issues

Good policy addresses a predictable set of questions that arise when large loads enter a regulated utility system. The following describes those questions in the Kentucky context. States that put tariff structures, cost-assignment rules, and financial security requirements in place before major development arrived have attracted substantial investment without shifting costs onto existing customers. In some cases, they have helped mitigate rate impacts on existing customers from other rate increases associated with non-data center investments in the grid. EPIC presents this as factual context, not recommendations on specific legislation.

### A. Supply Adequacy

Supply adequacy is the question of whether a utility's generation and transmission resources are sufficient to reliably serve its load. For instance, LG&E/KU's 2025 PSC filing projected a 29 percent increase in seasonal peak demand by 2032, almost entirely from large economic development projects. Ensuring that the companies are prepared to serve this load growth without shifting costs to existing customers is the legislative and regulatory policy goal. Recognizing that a generation fleet adequate for one demand scenario may not be adequate for another is crucial in approaching policy. With cooperatives, investor-owned utilities, market participants and non-participants, a one-size-fits-all approach will not adequately address the needs of each utility jurisdiction.

EPIC's statutory mandate is to provide an independent assessment of supply adequacy across Kentucky's generating fleet. As data center projects move from speculative to committed, EPIC's energy inventory and adequacy assessments track whether generation and transmission utilization and additions keep pace with load growth and whether reserve margins, higher for utilities not in an RTO than for utilities within an RTO are maintained across all utility service territories.

### B. Cost Responsibility

When a utility builds a power plant, substation, or transmission line to serve a data center, the cost is paid either by the data center through a contract or by all existing customers through rates. Cost causation is the foundational principle: costs should be assigned to the customer whose service requirements produce them. This principle is well established in utility regulatory practice. When an upgrade benefits all customers, much like when a road is widened to the benefit of an entire community, it is appropriate for all customers to contribute to that upgrade.

Applying cost causation to data centers requires tariff structures and contract terms that identify and allocate costs when infrastructure commitments are made. The alternative is that costs flow into the rate base and are recovered from all customers, which is the default in the absence of specific rules. States that have adopted cost causation rules, with Ohio as the most developed example in the region, have done so through prepayment or contractual requirements, minimum billing floors, and financial security obligations. Each tool addresses a different aspect of the problem. EKPC has addressed these issues through its Data Center Power tariff, which was designed to ensure the customer bears the full cost of infrastructure it directly causes the cooperative to incur.

Several Kentucky utilities have PSC-approved large load tariffs that establish interconnection requirements and cost protections for existing customers, providing a regulatory foundation that many other states are still working to build.

### C. Speculative Load

Not every project in a utility's interconnection queue will be built. Much like generation in RTO queues, developers exploring multiple markets simultaneously may file interconnection requests without binding financial commitments, signed service agreements, or local approvals. Utilities must conduct engineering and feasibility studies on projects that may never materialize, distorting demand forecasts, requiring additional engineering and planning work, and suggesting the need for additional generation investments.

LG&E/KU's interconnection queue drew attention to this issue during its CPCN proceedings. The PSC found it troubling that the utility had not provided evidence supporting the probability estimates it assigned to individual projects. An application fee structure requiring prospective customers to pay the full cost of interconnection studies before those studies begin, as stipulated in LG&E/KU's EHLF tariff and EKPC's DCP tariff, reduces the incentive to file speculative requests.

### D. Regional Cost Spillover

For Kentucky utilities in PJM and MISO, regional cost allocation is a direct concern. When data center development in northern Virginia was a significant factor in large transmission expansion projects, PJM allocated those costs across all member utilities based on load ratio share. Kentucky customers in PJM contributed to infrastructure costs primarily driven by data center growth in another state, though Kentucky utilities' small load ratio share within PJM limits the magnitude of that exposure. The inverse is equally true: when Kentucky utilities add transmission infrastructure, the regional cost allocation framework distributes a portion of those costs across other PJM members. Supplemental state-jurisdictional cost allocation requirements can direct data centers served by Kentucky utilities to bear a direct share of Kentucky-specific infrastructure costs, but regional transmission costs set through FERC-jurisdictional processes fall outside the scope of what the PSC can address through retail tariff design alone.

### E. Federal Policy

Two federal actions are underway with direct implications for Kentucky. In October 2025, DOE directed FERC to initiate rulemaking on interconnection of large loads above 20 megawatts to the interstate transmission grid (Docket No. RM26-4-000). FERC received nearly 200 stakeholder comments. DOE's proposal explicitly preserves state PSC authority over retail rate design and cost allocation. The original DOE directive set an April 30, 2026, deadline for final action. FERC did not issue a final rule by that date; instead, on April 16, 2026, FERC issued an Order Regarding Intent to Act, committing to take action by the end of June 2026. FERC stated it will address the issues raised in the ANOPR "in a manner that is quick, efficient, and legally durable." As of the date of this report, FERC has not yet issued its final order.

In January 2026, the National Energy Dominance Council and 13 PJM state governors, including Kentucky's Governor, issued a Statement of Principles calling on PJM to hold a Reliability Backstop Procurement (RBP), a one-time centralized capacity procurement with data centers required to pay for generation built on their behalf. PJM released its formal RBP proposal on April 10, 2026, targeting procurement of approximately 15 gigawatts of new capacity deliverable by June 2031, and announced plans to file the proposal with FERC in June 2026. On May 19, 2026, PJM's board announced it intends to accelerate the auction to September 2026 rather than waiting until 2027, citing heightened near-term reliability risk from data center load growth. FERC approval of the tariff filing will be required before the

auction can proceed. The Statement carries political weight but no binding legal force on PJM's operations independent of FERC approval.

Both federal actions preserve state PSC authority over retail rates. EPIC is monitoring both and will report to the General Assembly as the federal framework develops.

#### **F. Time-to-Market Mismatch**

One of the most fundamental tensions in data center energy policy is the mismatch between how quickly a data center can be built and how long it takes to build the energy infrastructure required to serve it. A large data center can be designed, permitted, and placed into commercial operation in as little as 12 to 18 months. A new substation takes two to three years. A significant transmission upgrade takes three to five years. A new combined-cycle natural gas generating unit takes four to six years from approval to commercial operation. Nuclear and other large baseload resources take more than a decade.

This creates a structural problem for all parties. A data center developer wants to know that power will be available before committing to a site and beginning construction. A utility operating under a regulated integrated model cannot commit to providing a specific block of power at a future date without first obtaining PSC approval to build the necessary generation and transmission. This, in turn, requires demonstrating that the demand justifying those investments is reasonably certain to materialize. The PSC will likely not issue a CPCN to a utility to begin construction on new generation until the data center customer has proper zoning in place, any special use permits required are attained, and environmental permitting requirements are addressed. Each party is waiting for the other before making a binding commitment.

The mismatch produces several consequences that are visible in Kentucky's current policy discussions. It explains why interconnection queues fill with speculative requests: data center developers file early to preserve their position in a queue, even without firm commitments, because the alternative is waiting years longer for power access. In many cases, they will file multiple applications in multiple states to see where they can get the best deal. It explains why utilities incorporate assumptions about the probability of large loads when filing IRPs and CPCN applications, even when individual projects remain uncertain. It also explains why, in its October 2025 order, the PSC found that LG&E/KU could not provide clear evidence supporting the probability estimates it had assigned to specific data center projects in its interconnection queue. The utility was being asked to justify a multi-billion-dollar generation commitment based on demand forecasts that the market structure makes inherently difficult to pin down.

The mismatch also directly affects Kentucky's competitive position. Data center developers making site selection decisions want a clear, fast answer about power availability. States and utilities that have developed standardized large-load tariff structures, defined interconnection study timelines, and established transparent application processes can provide that answer more quickly and credibly than those that negotiate each project on an ad hoc basis. Speed and predictability in the interconnection process are genuine competitive factors, alongside electricity price and availability.

Addressing the time-to-market mismatch requires mechanisms that can provide both parties with enough certainty to proceed before all uncertainty is resolved. On the utility side, that means tariff structures and contract frameworks that allow a utility to begin planning and committing resources once a data center clears defined milestones, such as payment of application and study fees, demonstration of site control,

and execution of a preliminary service agreement. On the data center side, it means transparency regarding the utility's interconnection timeline, study process, and cost recovery structure, so that developers can plan their own financing and construction schedules around a realistic power availability date. The FERC large-load interconnection rulemaking (Docket No. RM26-4-000) continues to address the federal transmission interconnection dimension of this problem. Kentucky's PSC and General Assembly are addressing the state retail dimension. Both are necessary because the mismatch exists at every level of the infrastructure stack.

## V. Cost Allocation Approaches

The following describes the principal cost allocation mechanisms available in a regulated integrated utility state and the circumstances where each applies.

### A. Direct Assignment

Under direct assignment, a data center that causes a utility to construct new generation is structured so the customer is responsible for the full capital and operating costs associated with the capacity built on its behalf. The utility recovers those costs either through an up-front contribution in aid of construction payment (the EKPC approach) or a long-term service agreement with a monthly capacity charge (the LG&E/KU approach). This approach is appropriate when generation is built for an identified project and would not otherwise be added to the system. It provides the strongest protection for existing customers but may require contract terms long enough to recover the utility's investment, typically 15 years or more for combined-cycle generation.

### B. Tranche Assignment

Where a single plant serves multiple data center customers or a combination of large-load and general system growth, tranche assignment allocates specific capacity blocks to each identified customer. Each customer pays costs for its allocated tranche regardless of actual consumption, with remaining capacity assigned to the general system. This allows efficient use of large plants while maintaining cost assignment.<sup>17</sup>

### C. Minimum Billing for Existing System Capacity

Where a data center is served by existing system generation and no new capacity is built specifically for it, a minimum billing floor requires the customer to pay a set percentage of the contracted capacity regardless of actual use. Ohio's large-load tariff requires 85 percent. According to AEP Ohio's regulatory filings, this requirement reduced speculative interconnection requests by approximately 50 percent without deterring well-capitalized development.<sup>18</sup>

### D. Transmission Cost Assignment

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<sup>17</sup>Tranche assignment agreements must address how outage risk is allocated between the utility and the customer. During scheduled maintenance outages and forced outages, the utility remains obligated to serve the customer through other system resources. The contract terms governing outage periods, including whether the minimum billing obligation is suspended or remains in effect, are a material element of tranche assignment design and are typically addressed through the special contract or tariff governing the arrangement.

<sup>18</sup>American Electric Power Ohio, Large Load Customer Tariff, Public Utilities Commission of Ohio, 2025. The full tariff requirements including application fees, financial security, and contract terms are set out in AEP Ohio Schedule 14 (Large Power Service) and associated riders on file with PUCO; see also footnote 22 for detailed tariff provisions.

Transmission cost assignment is governed by a layered jurisdictional framework that varies significantly across Kentucky's utilities. The applicable rules depend on whether the utility participates in an RTO, the character of the infrastructure at issue, and the cost allocation methodology on file with FERC or approved by the PSC.

Dedicated interconnection facilities, meaning the substation, switching equipment, and physical connection constructed specifically for an individual project—are generally assigned directly to the requesting customer, either through a contribution in aid of construction paid upfront or a recurring facilities charge. This category of cost is the most straightforward to assign at the state level, regardless of RTO membership.

Beyond dedicated facilities, transmission cost allocation becomes more complex and depends critically on the applicable jurisdictional framework. Kentucky utilities that participate in PJM or MISO, Kentucky Power Company, Duke Energy Kentucky, East Kentucky Power Cooperative, and Big Rivers Electric Corporation must operate under the FERC-approved Open Access Transmission Tariff (OATT) applicable to their respective RTOs. Under those OATTs, interconnection-related network upgrades and regional transmission projects are subject to cost allocation methodologies filed with and approved by FERC. FERC Order 1000 (2011) established foundational regional transmission planning and cost allocation requirements for transmission providers subject to FERC jurisdiction. FERC Order 1920 (2024) significantly expanded long-range transmission planning obligations and cost allocation requirements for regional facilities. The cost allocation rules established under those orders, and under each RTO's applicable OATT, govern how network upgrade costs are distributed among utilities and, ultimately, their customers. Retail tariff structures approved by the PSC cannot override these FERC-jurisdictional regional cost allocation rules. Kentucky's state-level cost allocation tools are most effective for generation infrastructure, local distribution facilities, and dedicated interconnection assets within the PSC's direct ratemaking jurisdiction.

Within those jurisdictional constraints, the costs attributable to a specific data center customer from network upgrades triggered by its interconnection should be identified through engineering analysis—including power flow studies, rather than socialized across all customers without attribution. How much of a given network upgrade can be assigned to a specific customer varies by utility, by tariff, and by the applicable FERC-approved framework.

EKPC participates in PJM and serves load under its own PSC-approved tariff structure. Network upgrade costs arising from a data center interconnection must be evaluated under the PJM OATT as well as EKPC's applicable tariff provisions; EKPC may require contribution-in-aid-of-construction treatment for customer-attributable network upgrade costs under its tariff structure. Duke Energy Kentucky and Kentucky Power Company also participate in PJM and are subject to PJM's OATT; cost allocation for their interconnection-related network upgrades must comply with the tariff on file at FERC. Kentucky Power's existing tariff structure may not expressly address all large-load cost allocation scenarios that could arise from significant data center development, which may warrant tariff development in advance of substantial new interconnection activity. It would be imprecise to assume these utilities have identical cost assignment authority or identical tariff tools.

LG&E/KU, as the only major Kentucky utility operating outside an RTO, retains the broadest state-level discretion to assign network upgrade costs through PSC-approved tariffs and special contracts for local

infrastructure. Because LG&E/KU does not participate in PJM or MISO, its local transmission infrastructure investments are not subject to RTO-wide cost allocation through load ratio share or similar FERC-jurisdictional regional mechanisms. The PSC can directly address how those costs are allocated among LG&E/KU’s customers through tariff design and special contract terms, subject to its own engineering and prudence requirements.

In all cases, the portion of a network upgrade that primarily serves regional system reliability, as distinct from customer-specific interconnection requirements, is subject to the cost allocation rules applicable to the relevant OATT and cannot be unilaterally redirected through state retail tariff design alone.

Approach	When It Applies	Customer Protection	Primary Limitation
Direct Assignment	New generation built for an identified project	Maximum: 100% of dedicated costs assigned	Requires long contract terms (15+ years)
Tranche Assignment	Single plant serving multiple large loads	Strong: each customer pays its assigned block	Requires coordination across multiple agreements
Minimum Billing Floor	Existing system capacity serving new load	Moderate: prevents revenue shortfall if load underperforms	Does not address exposure from future plant retirement
Direct Transmission Assignment	Dedicated interconnection facilities; customer-attributable network upgrades where permitted under applicable tariff	Maximum: no socialization of customer-specific costs	Engineering study required to attribute network upgrade costs; regional transmission costs subject to FERC-approved OATT allocation

Table 4. Cost allocation approaches in a regulated integrated utility state.

## VI. What Other States Show

### A. Virginia

Virginia hosts approximately one-third of global data center capacity, concentrated in Loudoun County. Dominion Energy serves more than 450 data center facilities with aggregate demand exceeding 5.8 gigawatts. Development accelerated from 2015 through 2025 under standard industrial rate structures not designed for sustained hyperscale baseload operation.<sup>19</sup>

The comparison with Virginia is instructive but requires context. Dominion Energy Virginia operates inside PJM, serves a market roughly ten times the scale of LG&E/KU’s current pipeline, and was managing hyperscale development a decade before Kentucky’s first hyperscale project broke ground. The structural differences between the two states are real. While the underlying regulatory mechanism may appear similar in Virginia and Kentucky, there are significant differences in the approach. Virginia considers prudence as part of the CPCN process with limited ability to review the investment for need and prudence after the assets are built. In Kentucky, the CPCN ensures the investment is needed and not duplicative. Upon completion of construction, the investment is reviewed to ensure it is used and useful. If the load did not come online, the PSC can deny the utility recovery, ensuring the investment does not enter the rate base.

<sup>19</sup>Dominion Energy Virginia, 2024 Integrated Resource Plan, filed with the Virginia State Corporation Commission, Case No. PUR-2024-00145: Dominion reported serving more than 450 data center customers with aggregate demand exceeding 5.8 gigawatts as of 2024. Virginia’s share of global data center capacity is widely cited in industry and regulatory sources; see also CBRE, Data Center Trends 2024, citing Northern Virginia as the largest data center market in the world.

Data center development in northern Virginia was associated with approximately \$2 billion in PJM regional transmission expansion projects, with costs distributed across all PJM members based on load ratio share. Analysis in Virginia utility proceedings projected residential rate increases of \$14 to \$37 per household per month by 2040, with data center load growth serving as a significant contributing factor in several proceedings.<sup>20</sup>

The 2025 Virginia General Assembly session saw approximately 30 bills introduced to address cost impacts. Only seven survived and Governor Youngkin vetoed two of those. The Virginia State Corporation Commission (SCC) subsequently acted on its own authority: in November 2025 it approved a new GS-5 rate class, requiring data center customers over 25 megawatts to sign 14-year contracts with minimum billing demand charges of 85 percent for transmission and distribution and 60 percent for generation. In February 2026, under Governor Spanberger, the General Assembly passed SB 253, allowing the SCC to allocate PJM capacity auction costs to data center customers rather than residential accounts, with the SCC projecting average residential bills would fall approximately \$0.52 per month if the reallocation is approved. Virginia remains a cautionary example, but it also now provides reform models Kentucky can study. The GS-5 contract structure and minimum billing demand percentages align closely with several of the cost-causation and financial commitment principles discussed throughout this paper as analytical reference points for evaluating Kentucky's policy options.<sup>21</sup>

## B. Ohio

AEP Ohio adopted a large-load tariff in July 2025, more than two years after imposing a moratorium on new data center connections in March 2023. The moratorium was triggered because the load queue had grown to more than 30,000 megawatts across 50-plus customers at 90-plus sites. Requirements under the July 2025 tariff include a formal load study fee of \$10,000 to \$100,000 depending on project size, full recovery of actual study costs, an 85 percent minimum billing floor on contracted capacity, collateral requirements scaled to customer credit ratings, and 12-year contracts with a four-year ramp-up period and exit fees equal to three years of minimum charges. The tariff was reactive, not proactive, but it effectively filtered speculative demand: when developers were required to pay for a formal load study, projects representing roughly half the prior queue were reported to have declined to proceed, according to utility filings.<sup>22</sup>

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<sup>20</sup>The \$2 billion PJM transmission cost figure and the \$14 to \$37 per month residential rate increase projection are drawn from testimony and exhibits filed in Virginia State Corporation Commission proceedings, including Case No. PUR-2022-00146 (Dominion Energy Virginia 2022 IRP) and subsequent rate case proceedings. See also Virginia Mercury reporting on SCC proceedings, 2024–2025; and Virginia Joint Legislative Audit and Review Commission, Data Center Growth in Virginia: Costs and Policy Considerations, House Document No. 17 (2024).

<sup>21</sup>Virginia General Assembly, 2025 Regular Session. The approximately 30 bills figure reflects legislation tracked by the Virginia Capitol Square database and reporting by the Richmond Times-Dispatch and Virginia Mercury during the 2025 session. Bills that cleared both chambers were primarily limited to transparency and reporting requirements; major cost allocation restructuring bills did not advance.

<sup>22</sup>American Electric Power Ohio, Large Load Customer Tariff, Public Utilities Commission of Ohio, 2025. Tariff requirements including the \$75,000 application fee, 85 percent minimum billing floor, and financial security provisions are set out in AEP Ohio Schedule 14 (Large Power Service) and associated riders on file with PUCO.

According to AEP Ohio’s regulatory filings, speculative interconnection requests dropped approximately 50 percent after the tariff was implemented. No material infrastructure cost socialization to existing customers from non-materializing projects was identified in the covered period.<sup>23</sup>

AEP Ohio operates inside PJM, which adds a layer of FERC-jurisdictional regional transmission cost allocation that state regulators cannot directly control. Kentucky’s LG&E/KU, as the only major Kentucky utility outside an RTO, does not face that regional overlay for local infrastructure investments. When the PSC approves a tariff requiring a data center to pay for generation or distribution infrastructure built on its behalf, that cost assignment does not have to account for PJM’s load ratio share mechanisms. That is a meaningful advantage in the specific context of local infrastructure cost allocation. At the same time, as its own balancing authority, LG&E/KU must maintain a higher reserve margin than comparably sized RTO-participating utilities, a requirement that carries its own resource planning obligations and ultimately affects customers’ rates.

**C. Texas**

Texas’s Chapter 313 program provided property tax limitations for qualifying investments, including data centers. The program carried no annual cost ceiling and no automatic sunset provision. Program costs grew from approximately \$130 million in 2021 to over \$1 billion annually by 2023. In 2023, the legislature allowed Chapter 313 to expire and replaced it with a modified program including an annual cap, reduced incentive percentages for data centers relative to manufacturing, and local school district approval authority.

While Texas’s deregulated electric market structure differs fundamentally from Kentucky’s regulated integrated utility model, the Chapter 313 experience illustrates that incentive programs without fiscal controls can grow well beyond their originally intended scope. Kentucky’s data center sales and use tax exemption, enacted through HB 8 in 2024, operates under a different legal and regulatory framework. However, as qualifying projects enter commercial operation, the fiscal cost of that program warrants the periodic monitoring discussed in Section VII.B.

State	What Happened	The Outcome
Virginia	Rapid development under standard rates. Cost allocation frameworks were not tailored to large, sustained loads. Reform legislation in 2025 mostly failed once infrastructure was in rate base.	Projected residential increases of \$14–\$37/month by 2040. Approximately 30 bills introduced in 2025; nearly all failed. The SCC subsequently adopted the GS-5 rate class and capacity cost reallocation on its own authority.
Ohio	AEP Ohio tariff adopted July 2025, after a 2-year moratorium: 85% minimum billing, \$10K–\$100K load study fee, 12-year contracts, exit fees. Reactive, not proactive, but effectively filtered speculative load.	~50% reduction in speculative interconnection requests, according to utility filings. No infrastructure cost socialization to existing customers from non-materializing projects.
Texas	Tax incentive program with no annual cap and no sunset grew from ~\$130M to over \$1B in costs in roughly two years.	Legislature restructured the program in 2023 to include caps, reduced data center incentives, and local approval requirements.

<sup>23</sup>American Electric Power Ohio, Large Load Customer Tariff, Public Utilities Commission of Ohio, 2025. The approximately 50 percent reduction in speculative interconnection requests is drawn from AEP Ohio testimony and exhibits filed with the Public Utilities Commission of Ohio in proceedings related to the large-load tariff. See also AEP Ohio regulatory filings, PUCO Case No. 22-1630-EL-ATA and related dockets.

*Table 5. Comparative state experience with data center development and cost allocation. Virginia did not have cost allocation rules in place when development accelerated and has since adopted corrective measures. Ohio adopted its large-load tariff reactively in July 2025 after a two-year moratorium, and the tariff effectively filtered speculative demand. With respect to local infrastructure cost allocation within its direct ratemaking jurisdiction, Kentucky's PSC, particularly as applied to LG&E/KU as a non-RTO utility, has broader direct authority over cost assignment than either the Virginia State Corporation Commission or Ohio's Public Utilities Commission of Ohio had in the relevant periods. That authority is Kentucky's structural advantage if it is exercised before major infrastructure commitments are finalized; it does not extend to FERC-jurisdictional regional transmission costs applicable to PJM- and MISO-participating Kentucky utilities.*

## VII. EPIC's Work Plan and Ongoing Analysis

### A. Why EPIC Is Examining This

Data center development is a supply adequacy question. Whether Kentucky's generation and transmission fleet can reliably serve the proposed loads is EPIC's core statutory question under KRS 164.2807. LG&E/KU's prospective data center pipeline, with approximately 3.5 gigawatts assigned 50 percent or higher probability of proceeding and total demand that may approach 12 gigawatts, and EKPC's more than 10 gigawatts of active requests, together representing a substantial share of Kentucky's existing installed generating capacity across their combined service territories, are sufficient individually and collectively to warrant a systematic statewide assessment.

Three aspects of EPIC's statutory mandate are directly engaged. First, the retirement review function requires EPIC to assess whether proposed retirements of generation leave Kentucky with adequate reserves to serve anticipated load, which depends directly on how much large-load demand materializes. Second, EPIC's energy inventory needs to be interpreted in light of demand projections to be useful for analysis. A fleet adequate for one scenario may not be adequate for another. Third, the General Assembly created EPIC to provide independent energy analysis to inform state policy, and the legislative deliberations around data center development are precisely that.

### B. Where Further Analysis Is Needed

This document acknowledges five areas where additional work would strengthen the analytical foundation. A statewide large-load demand forecast across all utility service territories, not just LG&E/KU's publicly disclosed queue, would give a more complete picture of supply adequacy risk. EPIC intends to pursue this through coordination with utilities and its information-gathering authority.

A standardized grid impact assessment methodology would support more consistent and defensible cost allocation outcomes. Kentucky utilities in PJM, MISO, and outside any RTO currently use different approaches to determine how much of a network upgrade is attributable to a specific large-load customer.

Given the unique circumstances and business model for each of Kentucky's electric utilities, researching other states with one or more utilities similarly situated as compared to a utility or utilities in Kentucky would give better insights into how best legislative or regulatory strategies can protect existing customers in Kentucky. Rather than taking a wholistic view of another state as a model, seeking out one or more specific utilities that share characteristics like those utilities in Kentucky would be a better method for gathering best practices or cautionary examples from which policies can be modeled.

Demand flexibility analysis specific to Kentucky's prospective data center base, rather than relying on national demonstration data, would allow a more precise estimate of the grid benefit that tariff structures could capture.

The fiscal cost of the sales tax exemption program for data center equipment warrants periodic monitoring by an appropriate state agency as qualifying projects enter commercial operation. EPIC does not administer the program but will track how incentive-qualifying projects translate into actual interconnection commitments over time.

### **C. EPIC's Ongoing Work**

EPIC's three technical committees, covering demand forecasting, primary energy supply, and transmission infrastructure, are each working on aspects of this analysis. The demand forecasting committee is developing a methodology for incorporating large-load interconnection requests into statewide projections. The primary energy supply committee is examining how resources needed to serve prospective large loads interact with existing utility resource plans. The transmission infrastructure committee is reviewing capacity and upgrade requirements across service territories.

EPIC's energy inventory, covering 61 facilities and more than 21,000 megawatts, will be updated annually. The Commission intends to add large-load interconnection queue data as a standard component, so legislators, utilities, developers, and regulators can track the pipeline and its supply-adequacy implications in one place.

EPIC is monitoring the FERC large-load interconnection rulemaking (Docket No. RM26-4-000) for which FERC has committed to action by the end of June 2026, and the PJM Reliability Backstop Procurement process and will report to the General Assembly as the federal framework develops.

EPIC is available to brief members and legislative staff on any topic in this document.

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*Prepared by the Kentucky Energy Planning and Inventory Commission pursuant to KRS 164.2807. This document is provided for informational purposes and does not constitute legal advice, a formal agency order, or a position on pending proceedings before the Kentucky Public Service Commission.*