

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of Consumers Energy)
Company authority to increase its rates for the generation)
and distribution of energy and for other relief)

Case No. U-22070

**DIRECT TESTIMONY
AND EXHIBITS OF
JOHN RICHTER**

On Behalf of

Great Lakes Renewable Energy Association

October 2, 2026

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1 **I. QUALIFICATIONS**

2 **Q. Please state your name and business address.**

3 A. My name is John Richter, and I have no business address, because I am retired.

4 **Q. Who are you representing, and what is your title and role there?**

5 A. I'm representing The Great Lakes Renewable Energy Association (GLREA). I am on the
6 Board of Directors. I am also the Chairman of the Policy Committee.

7 **Q. Please describe the GLREA.**

8 A. The GLREA is a 501(c)(3) (non-profit) corporation based in Michigan. Our Mission
9 Statement is to "Promote the Use of Renewable Energy in Michigan and in the Great
10 Lakes Region, By Empowering Our Members and the Public Through Advocacy,
11 Education and Strategic Collaboration." And our Vision Statement is: "We believe that
12 current and emerging clean, renewable energy solutions can provide 100% of the electrical
13 energy demand in the Great Lakes Region. Furthermore, we believe that increasing
14 development and access to clean, renewable energy that is locally produced, operated and
15 utilized supports economic development, creates new good paying jobs and is essential to
16 supporting healthier, more resilient communities that advance climate justice."

17 **Q. Please describe your educational background.**

18 A. I received a Bachelor of Science degree in Computer Engineering, with a minor in
19 Economics, from Oakland University in 1982. I did some graduate work in software
20 engineering at both Oakland University, and University of Detroit, Mercy. I did some
21 alternative energy coursework at Oakland Community College. I received a Master of
22 Science in Renewable Energy from Murdoch University in Perth, Australia in 2009. I've

1 been through training at Michigan State University's Institute for Public Utilities
2 Regulatory Research and Education's courses on "utility regulation," and "grid school."

3 **Q. Please describe your relevant business experience.**

4 A. At Frontier Communications, I was the Senior Manager of Hardware Integration. In this
5 role, I performed request for proposals (RFPs) and request for quotes, set up the criteria for
6 evaluating the responses, engaged in purchase negotiations, and performed project
7 management for equipment installation, testing, and turn-up. I had a \$25M capital budget
8 for equipment purchases. I also created the Company's capacity forecasting model, and did
9 net present value (NPV) analysis to determine which equipment sites should be closed and
10 consolidated. I was promoted to Director, Product Platform Development, where I again
11 did RFPs and equipment selection. As a Sr. Product Development Manager at Global
12 Crossing, I created new business processes in support of new product launches.

13 During 2002, I consulted on renewable energy policy for the GLREA (among others). In
14 that role, I did a presentation to Michigan legislators and staff on policies to incentivize
15 renewable energy deployments. I was one of three invited presenters to the Northeast and
16 Midwest Caucus meeting on a national RPS at the U.S. Capitol Building. And I was a
17 member of the MPSC Collaborative on Renewable Energy. Under contract with the
18 American Council for an Energy Efficient Economy, I wrote a white paper on energy
19 efficiency policy, which was presented to the Governor of Michigan. I was also featured in
20 the PBS documentary film, *Michigan's Green Energy Economy*.

21 In 2010 and 2011, I was an adjunct instructor at Macomb Community College, teaching a
22 course on solar energy. My resume is provided as **GLREA Exhibit-1, JR(1)**.

Q. Have you previously presented testimony before the Michigan Public Service Commission (“MPSC” or the “Commission”)?

A. Yes, in the following cases:

- U-18091, DTE Electric PURPA case (remand)
- U-18232, DTE REP (reopened)
- U-20165, Consumers Energy IRP case
- U-20359, Indiana Michigan Power rate case
- U-20471, DTE Electric IRP
- U-20561, DTE Electric rate case
- U-20713, DTE Electric REP
- U-20836, DTE Electric rate case
- U-21090, Consumers Energy IRP
- U-21172, DTE VGP
- U-21193, DTE Electric IRP
- U-21375 DTE Electric VGP
- U-21534, DTE Electric rate case
- U-21816, Consumers Energy REP
- U-21972 Consumers Energy VGP
- U-22046 DTE Electric rate case

1 ○ U-22058 DTE Electric special contracts

2 ○ U-22061 DTE Large Load Tariff

3 **Q. What is the purpose of your direct testimony?**

4 A. To provide useful information and recommendations to the Commission on:

5 1. How the influx of data centers has affected capacity adequacy, service reliability, and
6 rates in the PJM and ERCOT regions.

7 2. Why the Commission should direct the Company to shed the load of large load
8 customers prior to shedding the load of other customers, as it did with DTE Electric.

9 3. A new, original option to protect the system from excess load, while enhancing
10 affordability, using a two-tiered DR program.

11 4. The reliability risks of the volatile transient load of large computing load customers,
12 and their lack of UPS ride-through; what to do to protect customers.

13 5. How data centers are different from other customers, which warrants a separate
14 customer rate class.

15 6. How to protect other customers from subsidizing data center customers, as a result of
16 the impact of data center customers on MISO LMP prices, passed on via PSCR.

17 7. How to protect other customers from subsidizing data center customers, as a result of
18 elevated electrical equipment prices resulting from data center demand.

19 **Q. Are you sponsoring any exhibits?**

20 A. Yes:

Exhibit GLREA-1 (JR-1) Resume of John Richter

Exhibit GLREA-2 (JR-2) Consumers Energy responses to discovery

Exhibit GLREA-3 (JR-3) “Processing Power: The Effect of Data Centers on
Wholesale Electricity Markets,” Federal Reserve
Bank of Dallas

Exhibit GLREA-4 (JR-4) Texas NOGRR No. 282 – Large Electronic Load
Ride-Through Requirements

Q. Were these exhibits prepared by you or under your supervision?

A. I prepared my resume, Consumers discovery responses are theirs, and the report from the Federal Reserve Bank of Dallas is from the internet, though I applied electronic highlighter.

II. BACKGROUND – A TSUNAMI OF DATA CENTERS

Q. What is a data center?

A. Amazon Web Services (AWS), one of the largest computing service companies, defines a data center as:

“A data center is a physical location that stores computing machines and their related hardware equipment. It contains the computing infrastructure that IT systems require, such as servers, data storage drives, and network equipment. It is the physical facility that stores any company’s digital data.”¹

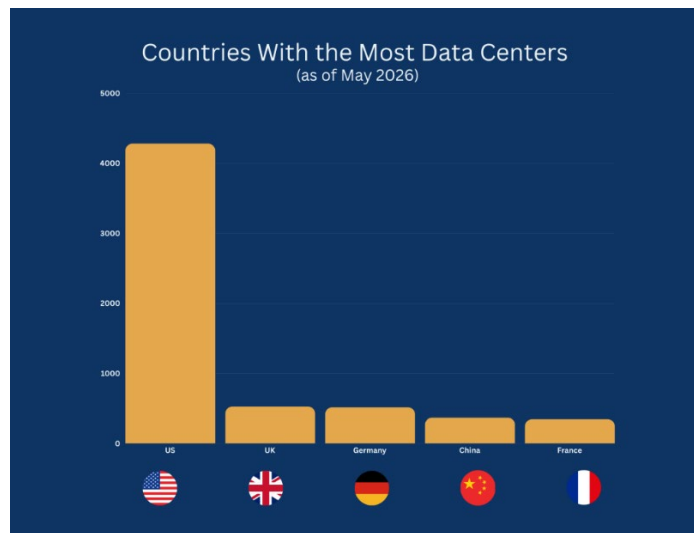
¹ Amazon Web Services, “What is a Data Center?” Accessed on 5/27/26 at: <https://aws.amazon.com/what-is/data-center/>

1 **Q. How many data centers there, and where are they?**

2 A. There are more than 12,000 data centers in the world today, and the US has almost nine
3 times as many as any other country. This year, non-AI workloads are predicted to total 38
4 GW, while AI workloads are expected to hit 44 GW. Nearly \$7 trillion will be spend on
5 data centers by 2030, 40% of it by US companies.²



² “Measuring the Data Center Boom: Facts and Statistics (2026),” *programs.com*, Sept. 12, 2026. Accessed on 9/15/26 at: <https://programs.com/resources/data-center-statistics/> and citing data from: <https://www.datacentermap.com/>



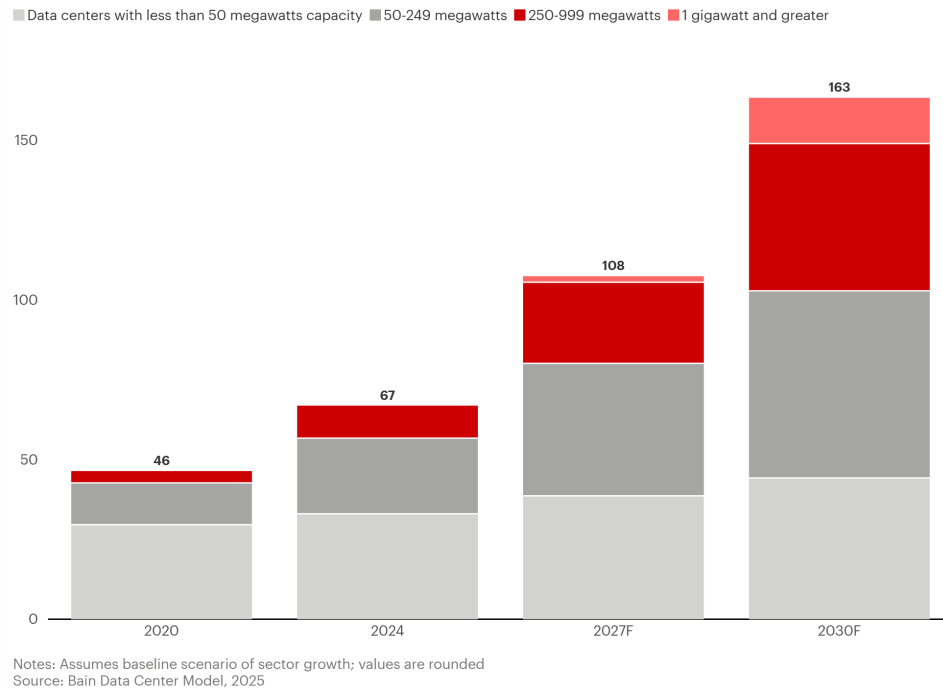
1
2 **Q. Data centers have been around for decades, why have they become an issue for the**
3 **grid only recently?**

4 A. The term “data center” is extremely broad. Many of the older data centers are tiny by
5 today’s standards. In 2024, the average data center had a load of only 4 MW.³ In 2020,
6 there were only 46 data centers in the world larger than 250 MW of load. Today, we’re
7 planning data centers more than 38 times that size:⁴

³ Ibid.

⁴ Padraic Brick, Tatum Quinn, Peter Hanbury, Aaron Denman, and Alessandro Cannarsi, “AI Data Center Forecast: From Scramble to Strategy,” *Bain & Company*, accessed on 5/27/26 at: <https://www.bain.com/insights/ai-data-center-forecast-from-scramble-to-strategy-snap-chart/>; Clearview reports that the Delta Gigasite data center in Millard, UT is expected to draw 9,700 MW. Accessed on 5/28/26 at: <https://cleanview.co/data-centers/us>

Global data center capacity by size (gigawatts)



1

2

As a result, over time, larger data centers will dominate:⁵

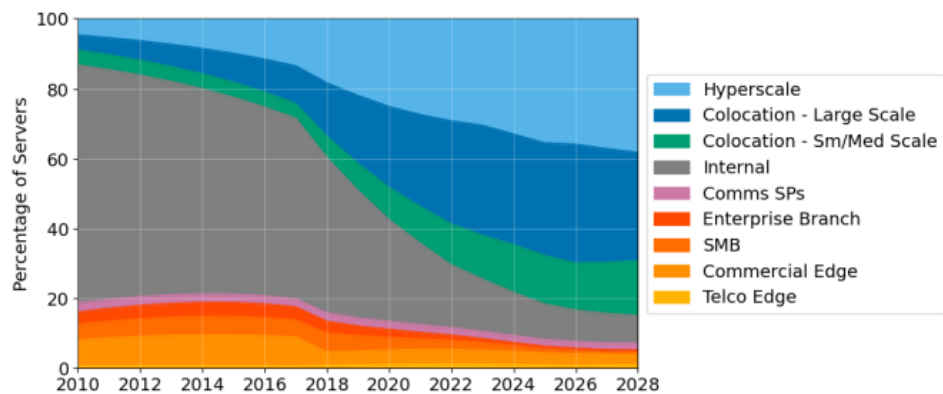


Figure 4.1. Distribution of servers by data center type.

3

⁵Arman Shehabi et al, “2024 United States Data Center Energy Usage Report,” *LBL Publications*, December 2024, p 37. Accessed on 5/27/26 at: <https://escholarship.org/uc/item/32d6m0d1>.

1 **Q. What are these data centers being used for?**

2 A. While many existing data centers are being used for traditional data processing,
3 supporting websites or streaming, most of the new data center proposals are for artificial
4 intelligence (AI). It is estimated that by 2030, 50%⁶ to 70%⁷ of data center computing
5 will be for AI. There are two distinct AI activities: training a new AI model, or answering
6 queries made to the AI, which is called “inference.” The AI industry’s focus is moving
7 from training to inference, as it moves from development to sales.⁸

8 **Q. How much energy can it take to train a new AI model?**

9 A. Each new model is more complex and requires more processing and energy. For
10 example, training the AI model ChatGPT-3 consumed 1,300 MWh.⁹ It’s successor,
11 ChatGPT-4, consumed 50 GWh - 38 times as much energy.¹⁰

⁶ Padraic Brick, Tatum Quinn, Peter Hanbury, Aaron Denman, and Alessandro Cannarsi, “AI Data Center Forecast: From Scramble to Strategy,” *Brain & Company*, accessed on 5/26/26 at: <https://www.bain.com/insights/ai-data-center-forecast-from-scramble-to-strategy-snap-chart/>

⁷ McKinsey Quarterly, slide 3 “The AI effect.” Accessed on 5/26/26 at: <https://www.mckinsey.com/quarterly/the-five-fifty/five-fifty-more-data-more-demand>

⁸ Digital Ocean, “AI Inference vs Training: Key Differences Explained,” February 27, 2026. Accessed on 5/27/26 at: <https://www.digitalocean.com/resources/articles/ai-inference-vs-training>

⁹ James Vincent, “How much electricity does an AI consume?” *The Verge*, February 16, 2024. Accessed on 5/27/26 at: <https://www.theverge.com/24066646/ai-electricity-energy-watts-generative-consumption>

¹⁰ James O’Donnell and Casey Crownhart, “We did the math on AI’s energy footprint. Here’s the story you haven’t heard,” *MIT Technology Review*, May 20, 2025. Accessed on 5/27/26 at: <https://www.technologyreview.com/2025/05/20/1116327/ai-energy-usage-climate-footprint-big-tech/>

1 **Q. How many new data centers are being proposed in the US and in Michigan?**

2 A. In the US, the market intelligence company Clearview is tracking 1,287 operating data
3 centers with a total load of 61 GW, and 2,090 planned data centers, with a planned load
4 of an additional 377 GW. In Michigan, Clearview is tracking 2 operating data centers
5 with a load of 4 MW, and 16 planned data centers with a planned load of 2,940 MW.¹¹
6 Their list did not provide a load estimate for the Flex data center proposed in South Lyon
7 Township. I attended the data center informational meeting in South Lyon Township on
8 January 22, 2026; the representative from developer Verrus stated that the project's load
9 would start at 200 MW and ramp to 525 MW. The Clearview report may be an
10 underestimate.

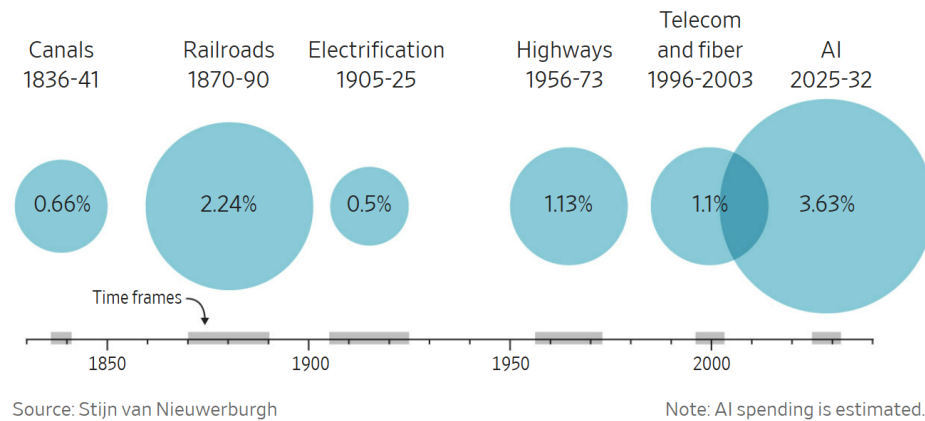
11 **Q. How much money is being invested in data center expansion?**

12 A. It is difficult to comprehend the size of this industry. The Wall Street Journal compared
13 the capital investment of the four largest US tech companies as a percentage of the US
14 Gross Domestic Product (GDP) and found that it exceeded the percentage of GDP spent
15 on the US railway system construction at its peak development, the U.S. interstate
16 highway system, or the dot com boom, stating, "Never before has the U.S. economy been
17 so dependent on the build-out of a single industry."¹²

¹¹ Clearview, "Data Centers in the United States," and "Data Centers in Michigan," last updated September, 2026. Accessed on 9/15/26 at: <https://cleanview.co/data-centers/us> and <https://cleanview.co/data-centers/michigan>, respectively.

¹² Konrad Putzier and Justin Lahart, "The AI Build-Out Is Becoming the Biggest Economic Bet in U.S. History," *The Wall Street Journal*, September 23, 2026. Accessed on 10/1/26 at: <https://www.wsj.com/economy/the-ai-build-out-is-becoming-the-biggest-economic-bet-in-u-s-history-c60716dd> (paywall).

Average annual infrastructure spending as a percentage of GDP



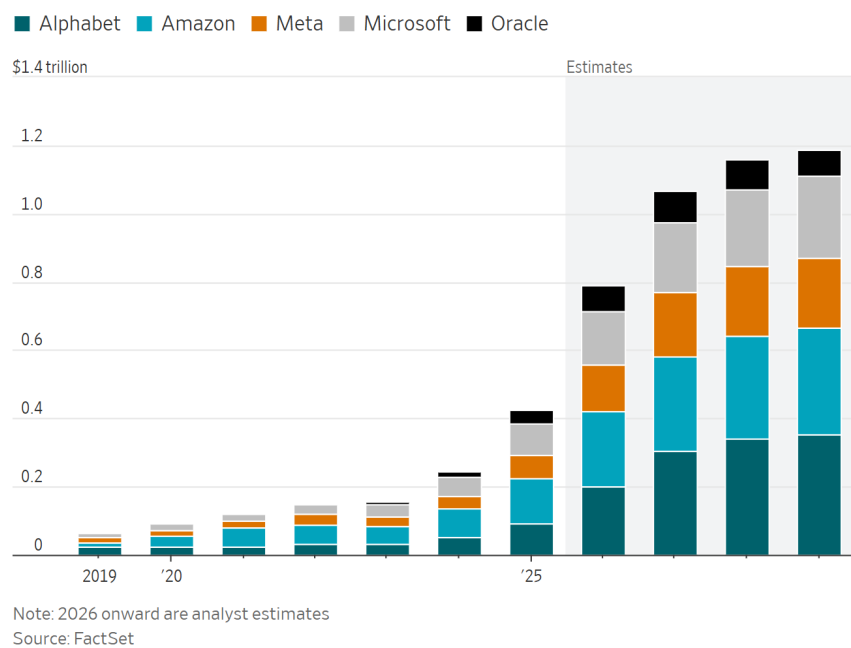
Quick Summary

- Total investment in U.S. data centers and AI infrastructure is projected to reach \$10.3 trillion from 2025 to 2032.

[View more](#)

The same WSJ article also graphed the annual capital spending of the five large US hyperscale data center companies, in *trillions* of dollars:

Capital spending at five large hyperscalers



1 Data center capital investment hit \$770 B in 2025.¹³ For comparison, the
2 aggregate capital investment for 47 US investor-owned energy utilities in 2025 was
3 \$215B.¹⁴ In the first half of 2025, data center development and IT accounted for 92% of
4 the growth in US GDP.¹⁵ It is simply astounding.

¹³ Rystad Energy, “Putting things in perspective: Data center investments now on par with renewables, oil and gas,” March 25, 2026. Accessed on 6/3/26 at: <https://www.rystadenergy.com/insights/putting-things-in-perspective-data-center-investments-now-on-par-with-renewables>

¹⁴ Jason Lehmann, Heike Doerr, and Dan Lowrey, “US utility capex forecast nudges higher on increased generation spending plans,” *S&P Global*, September 23, 2025. Accessed on 5/27/26 at: <https://www.spglobal.com/market-intelligence/en/news-insights/research/2025/10/us-utility-capex-forecast-nudges-higher-on-increased-generation-spending-plans>

¹⁵ Nick Lichtenberg, “Without data centers, GDP growth was 0.1% in the first half of 2025, Harvard economist says,” *Fortune*, October 7, 2025. Accessed on 5/29/26 at: <https://fortune.com/2025/10/07/data-centers-gdp-growth-zero-first-half-2025-jason-furman-harvard-economist/>

1 **Q. What historical technological development had an impact of the scale of data centers**
2 **and the artificial intelligence?**

3 A. The comparison made by multiple experts, including a former CEO of Google and the
4 Pope, is the industrial revolution^{16,17,18} or the invention of the wheel.¹⁹ It is very difficult
5 to predict what our lives will be like in 20 or 30 years.

6 **Q. How much will data centers affect demand for electrical energy in the US?**

7 A. A 2024 study by Lawrence Berkeley National Laboratories (LBNL) estimated that data
8 centers consumed 1.9% of US electrical energy in 2018, and 4.4% in 2023. LBNL
9 projected that by **2028**, data centers will consume between 6.7% and 12.0% of US
10 electrical energy (see graph below).²⁰

¹⁶ Arcelia Martin, “A New Era of Data Center Development Is Like a Second Industrial Revolution,” *Inside Climate News*, 3/14/26. Accessed on 7/26/26 at: <https://insideclimatenews.org/news/14032026/data-center-development-energy/>

¹⁷ Hannah Devlin, “AI could be as transformative as Industrial Revolution,” *The Guardian*, 5/3/23. Accessed on 7/26/26 at: <https://www.theguardian.com/technology/2023/may/03/ai-could-be-as-transformative-as-industrial-revolution-patrick-vallance>

¹⁸ Nathan Schneider, “Pope Leo XIV compares AI to the Industrial Revolution – as new alternatives to big AI firms take shape,” 5/26/26. Accessed on 7/26/26 at: <https://theconversation.com/pope-leo-xiv-compares-ai-to-the-industrial-revolution-as-new-alternatives-to-big-ai-firms-take-shape-283249>

¹⁹ Bob Choat, “Unleash the AI Revolution: How Today’s Tech Compares to Historic Innovations,” *Medium*, 3/26/2023. Accessed on 7/26/26 at: <https://medium.com/@bobchoat/unleash-the-ai-revolution-how-todays-tech-compares-to-historic-innovations-28c1be8d223>

²⁰ Arman Shehabi et al, “2024 United States Data Center Energy Usage Report,” *LBL Publications*, December 2024, p 5. Accessed on 5/27/26 at: <https://escholarship.org/uc/item/32d6m0d1>

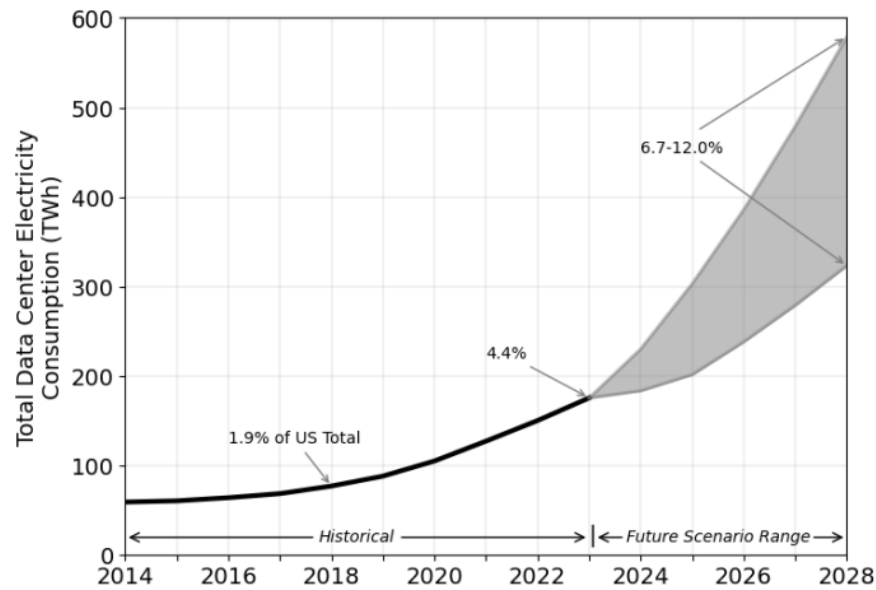
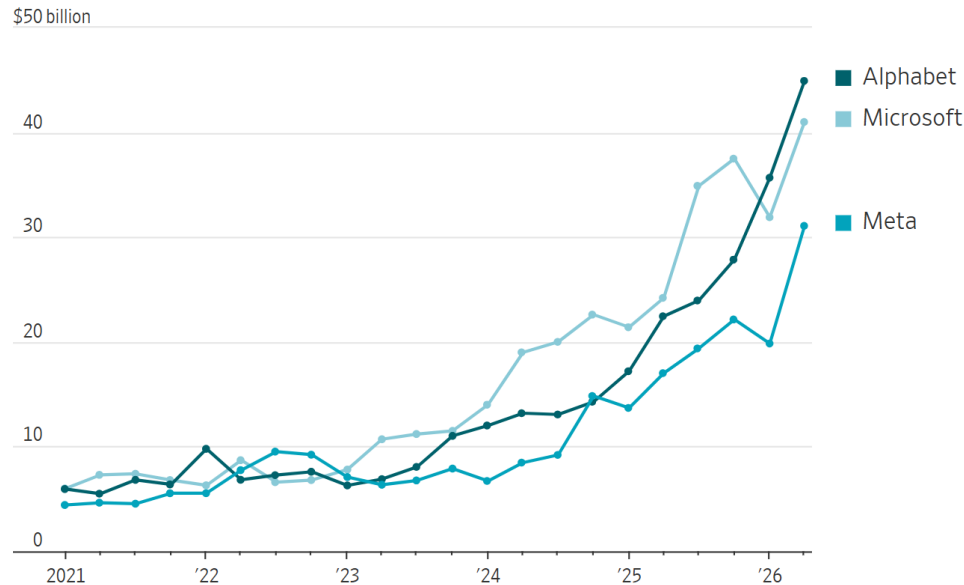


Figure ES-1. Total U.S. data center electricity use from 2014 through 2028.

Since the LBNL study, AI companies have continued to accelerate their build-out of data centers;²¹ the estimates of power demand have since increased with it.

²¹ Meghan Bobrowsky, “Meta Stumbles as Tech Investors Demand Better Answers on AI Spending,” *Wall Street Journal*, July 29, 2026. Accessed on 7/30/26 at: <https://www.wsj.com/tech/ai/meta-stumbles-as-tech-investors-demand-better-answers-on-ai-spending-fc731909>

Capital expenditures, quarterly



Note: Data are for calendar quarters and include finance leases.
Sources: the companies

In December of 2025, Bloomberg NEF forecast that US data center demand would reach 106 GW by 2035, 36% above its projection in April, 2025. In July, 2026, it increased its estimate another 83%, to 194 GW, about 20% of the nation's electricity.²²

Jim Robb, president and CEO of the North American Electric Reliability Corp., told a House subcommittee that the rate of increase in electricity demand is "staggering." Summer peak demand is projected to rise by 200 GW, with winter demand growing faster. "That's 70% higher than what we projected at this time last year," Robb said.²³

²² Luke James, "Data centers forecast to use 20% of US power by 2035 — analysts estimate usage will rocket to 194 gigawatts, 83% more than forecast seven months ago," *tom's Hardware*, July 22, 2026. Accessed on 9/29/26 at: <https://www.tomshardware.com/tech-industry/data-centers/bnef-nearly-doubles-its-us-data-center-power-forecast-to-194gw>

²³ Robert Walton, "January's Winter Storm Fern was 'classic near-miss' for US grid, says NERC's Robb," *Utility Dive*, March 20, 2026. Accessed on 9/15/26 at: <https://www.utilitydive.com/news/januarys-winter-storm-fern-was-classic-near-miss-for-us-grid-says-nerc/815291/>

1 **Q. How much will data centers affect demand for electrical energy in Michigan?**

2 A. That's difficult to say with any precision. Some proposals become operating data centers,
3 and some never get built. The 1.4 GW Oracle data center under construction in Saline
4 Township is projected to ramp to a load of 10,298 GWh/yr. in 2029.²⁴ The proposed
5 Google data center in Van Buren Township will consume an estimated 7,884
6 GWh/year,²⁵ for a total DTE Electric (DTEE) data center load of (10,298 GWh/yr. +
7 7,884 GWh/yr.) 18,182 GWh/yr. For comparison, DTEE's current projection of 2026
8 service area sales is 44,360 GWh.²⁶ Therefore, the combined load of these two data
9 centers will be approximately **41%** (18,182 GW/yr. / 44,360 GWh/yr.) of DTE Electric's
10 2026 retail sales. DTE Electric (DTEE) has said they are in discussions with an
11 additional 6 GW of potential data center projects, over and above the two in Saline
12 Township and Van Buren Township.²⁷

²⁴ U-22046, DTEE exhibit A-15: line 5, column (g).

²⁵ U-22058 Direct testimony of K. L. Bilyeu, 3 Tr 280.

²⁶ U-22046, DTEE exhibit A-15, schedule E1, line 1, column (e).

²⁷ Robert Walton, "DTE sees up to 8.4 GW data center opportunity," *Utility Dive*, May 1, 2026. Accessed on 5/27/26 at: <https://www.utilitydive.com/news/dte-energy-data-center-earnings-reliability/819052/>

1 In U-21589, Consumers Energy testified that they have inquiries from over 30
2 different data center leads that total over 15 GW of load.²⁸ In its contemporaneous
3 Integrated Resource Plan (IRP) filing, the Company states that they have 1.9 GW of large
4 load growth already on the system or with executed contracts.²⁹ For comparison, the
5 Company owns generating capacity of 6,474 MW.³⁰ Intelligence platform Sightline
6 Climate estimates that 30-50% of the US data center pipeline will not be built.³¹ If half of
7 the DTE “potential” projects and half of the Consumers Energy “inquiries” were built, it
8 would represent $(.5 \times 6 \text{ GW}) + (.5 \times 15 \text{ GW}) = 10.5 \text{ GW}$ of additional load.

²⁸ U-21859, Direct testimony of Laura Connolly, 3 Tr 85.

²⁹ U-22127 Consumers IRP application, part 1, p 2.

³⁰ Ibid, p 64.

³¹ Olivia Wang, “Data center outlook: half of 2026 pipeline may not materialize,” *Sightline Climate Outlook*, February 24, 2026. Accessed on 5/28/26 at:
<https://www.sightlineclimate.com/research/data-center-outlook>

1 **A. Capacity Adequacy in the PJM Region**

2 **Q. How has the tsunami of data center proposal affected grid capacity**
3 **forecasting?**

4 A. Historically, utilities could forecast gradual growth in demand from existing
5 customers, and the addition of new customers. Each customer had a demand *much*
6 smaller than the capacity of a new powerplant. The flood of hyperscale data
7 center projects has made forecasting future grid capacity needs much more
8 difficult. A single data center can take the entire output of a new gas power plant.
9 DTE Energy President and CEO Joi Harris made this relationship explicit, stating
10 that, “Any new data center load that we bring on after this 1.4 gigawatts [referring
11 to the Oracle data center in Saline Township will require additional resources. If
12 we bring on something in the gigawatt range, it would require a combined cycle
13 to support it.”³²

14 New hyperscale data centers are being constructed in just 18-24 months.³³

15 According to Electric Power Research Institute Senior Program Manager Bobby
16 Nobel, just getting a new gas turbine takes longer; about 5 years from order to

³² DTE Energy Co. (DTE), “Q3 2025 Earnings Call,” p 10, October 30, 2025. Accessed on 9/17/26 at https://s24.q4cdn.com/970999156/files/doc_financials/2025/q3/DTE-Q3-25-transcript.pdf

³³ Brian Bradsher, “Data Center Construction: How Hyperscale Projects are Built and why Jobsite Visibility Matters,” *True Look*, September 12, 2025. Accessed on 9/17/26 at: <https://www.truelook.com/blog/data-center-construction>

1 delivery.³⁴ To meet the demand of a new data center with a large gas-fired plant,
2 the turbine would need to be ordered years before construction on the data center
3 begins. This is a radical change from historical experience in load planning.

4 **Q. Have other parts of the US already experienced dramatically higher loads as a**
5 **result of new data centers?**

6 A. Yes, Northern Virginia has been called “data center alley” due to the high
7 concentration of new data centers there. In 2025, Virginia had 12GW of data
8 centers, consuming 40% of the state’s electricity.³⁵ The entire PJM region has
9 seen explosive growth in power demand. Monitoring Analytics, the independent
10 market monitor for the Eastern grid operator PJM Interconnection reported that
11 “PJM attributed almost all of this increase in the summer peak load forecast to the
12 anticipated additions in data center demand.”³⁶

³⁴ Bobby Nobel, “5-year waits and rising costs: How demand is redefining the gas turbine market,” *Utility Dive*, March 23, 2026. Accessed on 9/17/26 at: <https://www.utilitydive.com/news/5-year-waits-and-rising-costs-how-demand-is-redefining-the-gas-turbine-mar/813385/>

³⁵ “AI Data Center Statistics in US 2026,” in table: “US Data Center Energy by State 2026,” *Global Statistics*. Accessed on 6/3/26 at: <https://www.theglobalstatistics.com/ai-data-center-statistics-in-us/>

³⁶ “Analysis of the 2026/2027 RPM Base Residual Auction Part A,” *Monitoring Analytics*, October 1, 2025, p 8. Accessed on 5/29/26 at: https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_A_20251001.pdf

1 This Monitoring Analytics report shows that peak-hour demand was fairly
2 constant from 2014 – 2023, varying between 138 GW and 144 GW, but rose to
3 149 GW in 2024 (+3.2%) and 156 GW in 2025 (+4.9%), as shown in the table
4 below. These are substantial increases in load for a huge region. PJM’s forecasts
5 of peak load are getting revised upwards every year, projecting a peak load of 164
6 GW in 2027:³⁷

Table 1 PJM Peak Load between 2009 and 2025^s

		Hour Ending	
	Date	(EPT)	PJM Load (MWh)
2009	Mon, August 10	17	123,900
2010	Tue, July 06	17	133,297
2011	Thu, July 21	17	154,095
2012	Tue, July 17	17	150,879
2013	Thu, July 18	17	153,790
2014	Tue, June 17	18	138,448
2015	Tue, July 28	17	140,266
2016	Thu, August 11	16	148,577
2017	Wed, July 19	18	142,387
2018	Tue, August 28	17	147,042
2019	Fri, July 19	18	148,228
2020	Mon, July 20	17	141,449
2021	Tue, August 24	17	145,563
2022	Wed, July 20	18	144,356
2023	Thu, July 27	18	144,215
2024	Tue, July 16	18	148,890
2025	Mon, June 23	18	156,256

³⁷ Ibid, p 7, Table 1 & 2.

Table 2 Forecasted Summer Peak Load for 2022 through 2026 as reported in the recent load forecast reports⁹

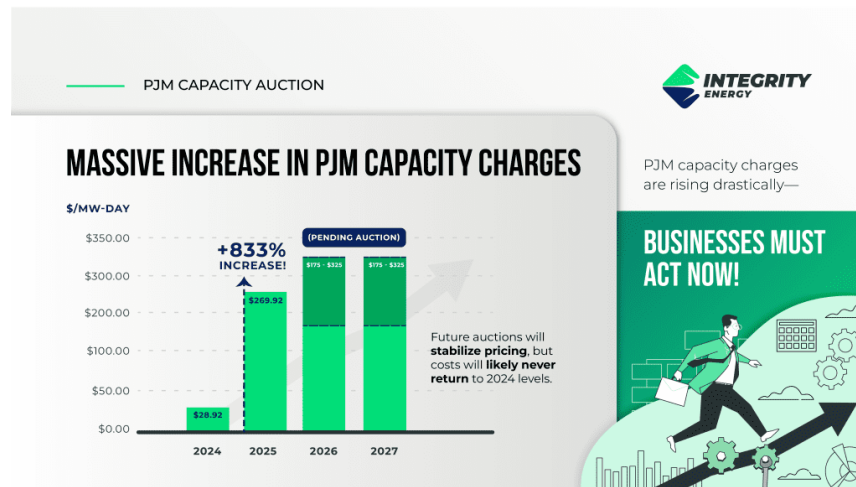
Report	Forecasted Summer Peak Load (MW)					
	2022	2023	2024	2025	2026	2027
2022 Load Forecast	148,938	149,351	150,309	151,165	152,259	152,322
2023 Load Forecast		149,059	149,737	150,924	152,736	154,275
2024 Load Forecast			151,247	153,493	156,803	159,859
2025 Load Forecast				154,144	158,937	164,186

As a result of this explosive growth in data center load, PJM capacity auctions have failed to meet the planning reserve requirements, and PJM has been forced to invoke emergency measures to prevent firm load shedding.

Q. How have PJM capacity auction prices been affected by increasing load?

A. PJM capacity prices have skyrocketed, increasing from \$28.92/MW-day in 2024 to \$269.92/MW-day in 2025, an 833% increase! The capacity price increased an additional 22% in the 2026/27 auction, but would have gone higher if not for an artificial price cap:³⁸

³⁸ Renee Sanders, “How the Latest PJM Auction Impacts 2026–2027 Energy Costs,” *Integrity Energy*, July 24, 2025. Accessed on 5/29/26 at: <https://www.integrityenergy.com/resources/about-us/news-media/pjm-announces-expensive-energy-changes-in-2026/>



A report from Monitoring Analytics put the responsibility for this increased load squarely on data centers:

“There are clear warning signs for the capacity market and for PJM reliability. The capacity market was short of reaching its reliability objective in the most recent capacity auctions... PJ was also short of meeting its reliability target as of June 1, 2025... *Data center load growth is the primary reason* for recent and expected capacity market conditions, including total forecast load growth, the tight supply and demand balance, and high prices. *But for data center growth*, both actual and forecast, the capacity market would not have seen the same tight supply demand conditions, the same high prices observed in the 2025/2026 BRA, the 2026/2027 BRA, and the 2027/2028 BRA, and the currently expected tight supply conditions and high prices for subsequent capacity auctions.”³⁹ (emphasis added)

³⁹“State of the Market Report for PJM, 2025,” *Monitoring Analytics*, March 12, 2026, p 1. Accessed on 9/20/26 at: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025-som-pjm-vol1.pdf

1 **Q. Did the market monitor make any recommendations to address the steep**
2 **increase in data center load’s impact on the PJM capacity market?**

3 A. Yes, Monitoring Analytics recommended that data centers be required to bring
4 their own new generation, or have their load treated as curtailable:

5 *“It is clear that continuing to simply accept the interconnection of*
6 *large data center loads that cannot be served reliably because*
7 *there is not adequate dispatchable capacity, is not a reasonable*
8 *path forward...* There is not enough capacity currently to meet the
9 data center load. The solution is not to create reliability issues and
10 wealth transfer issues by clearing the capacity market at the
11 maximum price and at a quantity less than the reliability
12 requirement by allowing the ongoing interconnection of large data
13 center loads without adequate generation to serve them... The
14 market solution is *to require data centers to bring their own new*
15 *generation.* This would include an expedited fast track load and
16 generation interconnection process for large new data center loads
17 that bring their own new generation with locational and temporal
18 characteristics reasonably matched to their load profile. *The*
19 *preferred solution would include creating a queue* for the addition
20 of large new data center loads, which would not be interconnected
21 until there is adequate capacity to serve them. Another solution
22 would require data centers that do not bring their own new
23 generation to be *curtailable prior to current demand side*
24 *customers but without the pretense that the data centers are*
25 *providing “demand response” for which they should be paid.*
26 Given the level of data center load growth, this curtailability
27 solution would provide a strong incentive to bring new generation,
28 if enforced on a specific data center basis. This broad bring your
29 own new generation solution to the issues created by the addition
30 of unprecedented amounts of large data center load does not
31 require a continued massive wealth transfer.”⁴⁰ (emphasis added)

32 In November, 2025, Monitoring Analytics went so far as to file a
33 complaint with FERC, asking for permission to block new large load
34 interconnections unless those projects come with matching new generation, or can

⁴⁰ Ibid, p 2.

1 be serviced reliably with both transmission and capacity adequacy.⁴¹

2 **Q. Have the high PJM capacity auction prices attracted enough new generation**
3 **to ensure resource adequacy?**

4 A. No. In the 2028/2029 auction, secured capacity (generation + demand response)
5 fell 6.8GW short of the reserve requirement. The prior auction also fell short, by
6 6.5 GW.⁴² This is reflected in Monitoring Analytics declaration (above) that
7 continuing to connect large data center loads that can't be served reliably is
8 *unreasonable*.

9 **Q. What emergency measures have been taken to prevent load shed in the PJM**
10 **region?**

11 A. PJM and the DOE have taken an entire series of measures. In 2025, the US
12 Department of Energy (DOE) issued 202(c) orders deferring the retirement of
13 some dispatchable generation. PJM has also expanded the time window of
14 demand response programs to 24 hours a day.⁴³ The EPA normally limits backup
15 generators to 50 hours of non-emergency use per year, but the EPA modified its
16 rules, stating that hours run under dispatch by NERC or a load balancing authority

⁴¹ Maeve Allsup, "Does PJM have the authority to approve flexible data centers?" *Latitude Media*, November 26, 2026. Accessed on 9/20/26 at: <https://www.latitudemedia.com/news/does-pjm-have-the-authority-to-approve-flexible-data-centers/?nab=1>

⁴² Paul Gerke, "PJM capacity auction easily hits price cap... Again," *Renewable Energy World*, July 16, 2026. Accessed on 7/26/26 at: <https://www.renewableenergyworld.com/news/pjm-capacity-auction-easily-hits-price-cap-again/>

⁴³ PJM Inside Lines, "2025 in Review: Operations Improvements See PJM Through Record Peaks, Growing Demand," September 20, 2026. Accessed on 9/20/26 at: <https://insidelines.pjm.com/209696-2/>

1 do not count against the non-emergency operating limit.⁴⁴

2 In January, 2026, the DOE identified more than 35 GW of backup
3 generation capacity at data centers and industrial sites. The DOE authorized
4 customers with backup generators in the PJM region to run on backup power at
5 the discretion of PJM, through the end of the month.⁴⁵ The order also applied to
6 Duke Energy and ERCOT.⁴⁶ The cost of running on backup generators is borne
7 by the owners of the large load.⁴⁷

8 In May 2026, PJM recalled generation maintenance, to ensure all
9 generation facilities were available for upcoming hot weather, and PJM issued a
10 Maximum Generation Alert and Load Management Alert, implementing demand
11 response.⁴⁸ This was still considered insufficient, so PJM asked the US DOE to
12 grant “transmission owners and electric distribution companies” emergency

⁴⁴ Kirland & Ellis, “New EPA Guidance Clarifies When Data Centers and Other Operators May Utilize Emergency Backup Generators to Support Local Power Supply,” May 12, 2025. <https://www.kirkland.com/publications/kirkland-alert/2025/05/new-epa-guidance-clarifies-when-data-centers-and-other-operators-may-utilize-emergency-backup>

⁴⁵ Charles Paullin, “Data Centers in PJM Grid Can Rely Solely on Generators During the Cold, DOE Rules,” January 29, 2026. Accessed on 9/20/26 at: <https://insideclimatenews.org/news/29012026/data-centers-in-pjm-grid-can-rely-solely-on-generators-during-the-cold-doe-rules/>

⁴⁶ Ethan Howland, “PJM gets emergency approval to curtail data centers, large loads during hot weather,” May 19, 2026. Accessed on 9/20/26 at: <https://www.utilitydive.com/news/pjm-doe-emergency-order-curtail-data-centers/820571/>

⁴⁷ MGrid.org, “DOE Orders SPP to Dispatch Backup Generation Across 17 States, Then Extends It Into August,” August 3, 2026. Accessed on 9/20/26 at: <https://mgrid.org/2026/08/03/doe-orders-spp-to-dispatch-backup-generation-across-17-states-then-extends-it-into-august/>

⁴⁸ PJM Inside Lines, “May 18 Hot Weather Operations Update,” May 18, 2026. Accessed on 9/20/26 at: <https://insidelines.pjm.com/may-18-hot-weather-operations-update/>

1 authority to curtail service to large loads (> 50 MW) on 15 minutes notice.⁴⁹ This
2 request was granted the same day.⁵⁰ Similar emergency authority has been
3 granted multiple times since, but only as a last resort, prior to shedding other
4 customer loads.

5 In July 2026 emission limits for power plants were waived.⁵¹ In a July
6 heat wave, PJM called on demand response, and notified neighboring regions that
7 it would not export power. Spot wholesale electricity prices surged beyond \$2,500
8 per megawatt compared with about \$40 per MWh when PJM is not in distress.⁵²

9 **Q. How does the PJM process to curtail data centers prior to shedding other**
10 **loads work?**

11 A. PJM updated their emergency procedures to support this new capability.
12 Escalation starts with a “capacity advisory,” usually 3-5 days before the
13 forecasted short-fall. Demand response resources are put in a state of readiness.
14 PJM warns DOE of a potential North American Energy Reliability Corporation
15 (NERC) Energy Emergency Alert (EEA) level-1. PJM issues a public appeal to

⁴⁹ Michael E. Bryson, “Request for Emergency Order Under Federal Power Act, Section 202(c),” DOE, May 17, 2026. Accessed on 9/20/26 at <https://www.energy.gov/documents/pjms-202c-backup-gen-application-202-26-23>

⁵⁰ DOE, “Order 202-26-23,” May 18, 2026. Accessed on 9/20/26 at: <https://www.energy.gov/documents/doe-emergency-order-no-202-26-23pdf>

⁵¹ Electric Choice, “PJM Emergency Orders: Heat Wave Threatens Record Electricity Demand,” June 30, 2026, updated July 2, 2026. Accessed on 9/20/26 at: <https://www.electricchoice.com/blog/pjm-emergency-order-heat-wave-2026/>

⁵² Tim McLaughlin, “Eastern US Power Grid Operator Orders Emergency Curbs as Electricity Use Nears Record,” *US News* (Reuters), July 3, 2026. Accessed on 9/20/26 at: <https://www.usnews.com/news/top-news/articles/2026-07-03/largest-us-power-grid-pjm-escalates-emergency-actions-to-avoid-blackouts>

1 reduce demand, and then goes to NERC EAA level-2. Prior to a manual load
2 dump warning, it issues an emergency use of back-up generators warning. PJM
3 will issue a manual load dump warning (NERC EEA level-3) upon issuance of an
4 emergency use of back-up generators action.⁵³

5 **Q. Were PJM's emergency measures sufficient to avoid shedding of firm data**
6 **center load?**

7 A. Yes. On July 2 and July 3, PJM issued backup generator warnings, but no
8 dispatch order was given. Demand Response of >6 GW, and >5 GW
9 (respectively) were used. "The DOE emergency emissions order covered 51
10 generating plants, 594 generating units, and approximately 20.4 GW of capacity.
11 PJM reported that 17 plants, representing 94 generating units and about 3.25 GW
12 of capacity, operated beyond normal emissions limits for a combined 1,107
13 operating hours."⁵⁴ At least one data center voluntarily switched to backup power.
14 It is unknown how many others may have done so.⁵⁵

⁵³ Paul Dajewski, "Manual 13, Emergency Operations Revision 98 – Annual Review," PJM, June 4, 2026. Accessed on 9/20/26 at: <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2026/20260604/20260604-item-03---1-manual-13---revision-98---presentation.pdf>

⁵⁴ Shane Snider, "PJM Issued First Backup-Generator Warnings During Heat Wave," *Data Center Knowledge*, July 20, 2026. Accessed on 9/20/26 at: <https://www.datacenterknowledge.com/energy-power-supply/pjm-issued-first-backup-generator-warnings-during-heat-wave>

⁵⁵ Jack Newsham, "Dark smoke rose above a Virginia data center as a heat wave pushed the power grid close to its limits," *Business Insider*, July 11, 2026. Accessed 9/20/2026 at: <https://www.businessinsider.com/virginia-data-center-diesel-backup-generator-heat-wave-pjm-2026-7>

1 **Q. Has the DOE granted any other jurisdictions the right to direct large loads to**
2 **run on backup generation to avoid the shedding of other customer loads?**

3 A. Yes. In addition to the 13-State PJM region, the DOE has granted similar
4 authority to Southwest Power Pool (SPP)⁵⁶, Duke Energy, and ERCOT.⁵⁷

5 **Q. Is the capacity crisis in PJM over?**

6 A. No. A report commissioned by the Pennsylvania Public Utility Commission, and
7 conducted by Synapse Energy, Mondre Energy, and Aspen Technologies projects
8 that the Loss of Load Expectation (LOLE) will be between 6 and 100 times worse
9 than the planning criterion. The LOLE goal of 0.1 was maintained in only one
10 modeled scenario – the scenario with no new data centers.⁵⁸

⁵⁶ Mara Hoplamazian, “Power grids can't handle AI boom as summer heat triggers emergency orders,” Spotlight PA, July 31, 2026. <https://www.spotlightpa.org/news/2026/07/data-centers-power-grid-heat-wave-emergency-orders-federal-government/>

⁵⁷ Ethan Howland, “PJM gets emergency approval to curtail data centers, large loads during hot weather,” May 19, 2026. Accessed on 9/20/26 at: <https://www.utilitydive.com/news/pjm-doe-emergency-order-curtail-data-centers/820571/>

⁵⁸ Diana DiGangi, “PJM faces 2030 reliability crisis if data center load growth continues: report,” *Utility Dive*, September 16, 2026. Accessed on 9/20/26 at: <https://www.utilitydive.com/news/pjms-reliability-could-start-failing-by-2030-if-data-center-growth-continues/830405/>

B. Capacity Adequacy in the MISO Region

Q. How do the results of recent MISO capacity auctions compare to the results of the PJM capacity auctions?

A. Most of the lower peninsula is in MISO zone 7, so I have considered the auction results for zone 7. Unlike the PJM capacity auctions I described earlier in this testimony, MISO capacity auctions (Planning Resource Auctions, or PRAs) have been able to meet their reserve requirement. However, the clearing price for summer capacity has shot up dramatically in the last two auctions. In figure 1, shown below, I took the Clearing price in \$/MW-day directly from the cited MISO publications. For comparison to the Cost of New Entry (CONE), I computed the clearing price in \$/MW-year by multiplying the \$/MW-Day by 365.

Figure 1: Historical MISO Zone-7 Summer PRA Pricing and CONE

MISO PRA Auction Period	Clearing Price (\$/MW-day)	Clearing Price (\$/MW-year)	Zone-7 CONE (\$/MW-year)
2023 / 24 ⁵⁹	\$10.00	\$3,650	\$105,910
2024 / 25 ⁶⁰	\$30.00	\$10,950	\$127,135
2025 / 26 ⁶¹	\$660.50	\$241,082	\$130,930
2026 / 27 ⁶²	\$424.30	\$154,870	unknown

⁵⁹ MISO, “Planning Resource Auction Results, for Planning Year 2023-24,” May 19, 2023, slide 4. Accessed on 9/17/26 at: <https://efis.psc.mo.gov/Document/Display/304494>.

⁶⁰ MISO, “Planning Resource Auction Results, for Planning Year 2024-25,” April 25, 2024 , slide 3. Accessed on 9/17/26 at: <https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf>.

⁶¹ MISO, “Planning Resource Auction Results, for Planning Year 2025 – 26,” April 2025, slide 12. Accessed on 12/17/26 at: https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf

⁶² MISO, “Planning Resource Auction, Results for Planning Year 2026 – 27,” April 2026, slide 13. Accessed on 9/17/26 at: <https://cdn.misoenergy.org/2026%20PRA%20Results%20Posting%2020260522%20-%20Corrections754715.pdf>

1

2 **Q. Describe and explain the change in the PRA price that Figure 1 illustrates.**

3 A. The summer capacity price tripled from 2023/24. It then increased more than 22
4 times in the 2024/25 auction, declining by about a third in the 2025/26 auction.

5 **Q. Is the spike in the MISO PRA price the result of scarcity?**

6 A. Yes, much of the jump from 2023/24 to 2024/25 was the result of scarcity, though
7 MISO's shift in the shape of its assumed demand curve was also a factor:

8 “In three of the four pre-seasonal planning years (PY 2019-22), the
9 auction cleared under \$10/MW-day. Summer 2025-26 changed
10 that: \$666.50/MW-day, a 22x increase over the prior year's
11 approximately \$30/MW-day.
12 Two structural changes drove the increase. The system surplus fell
13 60%, from 6.5 GW to 2.6 GW. That removed the cushion that had
14 kept prices low. A new downward-sloping demand curve then
15 replaced the old all-or-nothing pricing. The shrinking cushion now
16 translates directly into higher prices.”⁶³

⁶³ William Rawlings, “A beginner’s guide to the MISO capacity market,” *Modo Energy*, March 24, 2026. Accessed on 9/17/26 at: <https://modoenergy.com/research/en/miso-capacity-market-bess-explainer>

1 **Q. Why is the value of the Cost of New Entry (CONE) relevant to the pricing of**
2 **capacity in the MISO PRA?**

3 A. CONE represents the cost of a new power plant, specifically the cost of the kind
4 of new power plant likely to be built to add capacity. MISO is estimating CONE
5 based on the cost of an “advanced combustion turbine.”⁶⁴ PRA is now a seasonal
6 auction, producing four prices (spring, summer, fall, winter). The annualized PRA
7 price is capped at CONE, however, the seasonal price may be higher than that.
8 Higher capacity prices provide a market signal to attract additional investment in
9 capacity resources.

⁶⁴ MISO, “Cost of new Entry (CONE) and net CONE calculation for Planning Year 2025/26,” September 23, 2024, slide 4. Accessed on 9/17/26 at:
<https://cdn.misoenergy.org/20240923%20RASC%20Item%2003%20CONE%20and%20Net%20CONE%20Update649247.pdf>

1 **Q. Should Michigan follow the PJM model of seeking capacity for whatever data**
2 **centers get built?**

3 A. No, I agree with Monitoring Analytics.⁶⁵ It is unreasonable to connect loads that
4 will compromise resource adequacy and grid reliability. This is especially
5 important in Michigan, because of our very limited power import capability; we
6 cannot assume we can fill a capacity gap with imports. Rolling blackouts are very
7 expensive; Oak Ridge National Laboratories puts the cost of blackouts to
8 customers in the US at \$121B in 2024. We need to *ensure* resource adequacy
9 before connecting new large loads.

10 **C. Options for Addressing Capacity Adequacy**

11 **Q. Has the challenge of meeting the capacity needs of new data center**
12 **development been researched?**

13 A. Volumes of articles and studies have been written on the question of how to meet
14 exploding demand while retaining grid reliability and energy affordability. Most
15 fall into one of three categories, which are not necessarily mutually exclusive:

⁶⁵ “State of the Market Report for PJM, 2025,” *Monitoring Analytics*, March 12, 2026, p 1.
Accessed on 9/20/26 at:
https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025-som-pjm-vol1.pdf

- 1 1. Continue with the current utility and service structure, but use lower cost
2 resources such as grid-enhancing technologies for T&D, and Virtual Power
3 Plants (VPPs) for capacity.⁶⁶ GLREA witness Boehnke will provide
4 compelling testimony on the VPP option.
- 5 2. Require new data centers to bring their own capacity (“BYOC”), either as
6 battery storage or new generation facilities. Many data center developers are
7 pursuing this approach to get up and running sooner (“speed to power”) with
8 the intention of connecting to the grid later. This may take the form of paying
9 for grid-connected capacity assets, or on-site storage and/or generation
10 facilities. Building on-site gas turbine power plants appears to be the most
11 popular BYOC approach. The data centers with special contracts proposed in
12 DTE Electric cases U-21990 and U-22058 are examples of this option.
- 13 3. Curtail service to large loads during periods of severe grid stress, either as first
14 stage of load shedding, or as a demand response program. The Commission’s
15 approval in DTE Electric case U-22059 is an example of this option.

16 **Q. Who is supporting requiring data centers to provide their own capacity?**

17 A. President Trump has been a leading advocate of this approach, announcing it in
18 his State of the Union Address in February:

⁶⁶ For example: Jigar Shah and Arnab Pal, “Governors are promising lower power bills. Here’s the only credible path to deliver,” *Utility Dive*, February 26, 2026. Accessed on 10/1/26 at: <https://www.utilitydive.com/news/governors-are-promising-lower-power-prices-Jigar-Shah-Arnab-Pal/813128/>.

1 “We have an old grid. It could never handle the kind of numbers,
2 the amount of electricity that's needed. So I'm telling them, they
3 can build their own plant. They're going to produce their own
4 electricity. It will ensure the company's ability to get electricity,
5 while at the same time, lowering prices of electricity for you,” he
6 said.⁶⁷

7 The PJM Market monitor has also been an advocate of this approach.⁶⁸ In March
8 of this year, FERC has ordered PJM to pursue both co-location (one version of
9 BYOC) and load flexibility:

10 “Today’s order helps break the logjam. It directs PJM to establish
11 new pathways for *co-location*—directly connecting a large load
12 with the power needed to serve it at the same site—and load
13 *flexibility* that enable large co-located loads to reduce how much
14 they lean on the grid, while ensuring that they pay their fair
15 share... and co-located large loads and generators can get online
16 faster and easier than would otherwise be the case. Grid operators
17 like PJM should allow and encourage large loads and generators to
18 pursue these time- and cost-saving co-location arrangements.”⁶⁹
19 (emphasis added)

⁶⁷ Reuters, “Trump says he has told big tech companies to build their own power plants,” February 24, 2026. Accessed on 9/20/26 at: <https://www.reuters.com/business/energy/trump-says-he-has-told-big-tech-companies-build-their-own-power-plants-2026-02-25/>

⁶⁸ Monitoring Analytics, “State of the Market Report for PJM, 2025,” March 12, 2026, p 1. Accessed on 9/20/26 at: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025-som-pjm-voll.pdf

⁶⁹ FERC, “Docket EL25-49-000,” Appendix, p 3, item 4, December 18, 2025. Accessed on 9/20/26 at: <https://www.ferc.gov/media/e-1-el25-49-000-0>

1 FERC issued an order to RTOs and ISOs to “defend or revise” their large
2 load interconnect tariffs. Part of the order was to “accommodate co-location
3 agreements and behind-the-meter generation.” Another section called for
4 “providing new transmission services for flexible large loads.”⁷⁰ PJM spent
5 months trying to work out agreements on these two directives, but they were
6 opposed by the Data Center Coalition trade group and the discussions ended in a
7 stalemate.⁷¹

8 U.S. Senators Josh Hawley (R-Mo.) and Senator Richard Blumenthal have
9 also supported the BYOC approach. They introduced a bill, the “Guaranteeing
10 Rate Insulation from Data Centers (GRID) Act” that would *require* data centers to
11 provide their own generation (not just capacity, such as battery storage). It would:

12 “Ensure new data centers use energy from power generation
13 sources that are separate from the grid, with a 10-year off-ramp for
14 existing data centers to find an alternative power source.”⁷²

⁷⁰ Paul Gerke, “FERC takes historic action, orders US grid operators to ‘defend or revise’ large load interconnection tariffs,” *Renewable Energy World*, June 18, 2026. Accessed on 9/20/26 at: <https://www.renewableenergyworld.com/news/ferc-takes-historic-action-orders-us-grid-operators-to-defend-or-revise-large-load-interconnection-tariffs/>

⁷¹ Katherine Blunt, “The Fight Over Making Data Centers Power Down to Avoid Blackouts,” *The Wall Street Journal*, January 6, 2026. Accessed on 9/20/26 at: <https://www.wsj.com/business/energy-oil/ai-data-center-blackouts-electric-grid-1fed9803>

⁷² Josh Hawley, “Hawley, Blumenthal Introduce Bill to Prevent Data Centers from Increasing Electricity Costs for Americans,” February 11, 2026. Accessed on 9/20/26 at: <https://www.hawley.senate.gov/hawley-blumenthal-introduce-bill-to-prevent-data-centers-from-increasing-electricity-costs-for-americans/>

1 The Governors of New Jersey⁷³ and Pennsylvania⁷⁴ have asked their legislatures
2 to require new data centers to bring their own generation facilities.

3 **Q. Are data center developers actually designing for 100% island power**
4 **(off-grid)?**

5 **A.**Some are. A data center in West Virginia is being designed with 2 GW of gas
6 generators, potentially scaling to 8 GW, in a huge microgrid. A Meta data center
7 In Louisiana is planning 7+ GW of dedicated onsite generation – a \$200 billion
8 project, with no grid dependency in the design. xAI Colossus complex in
9 Memphis plans 2 GW of onsite capacity. Per Avanza Energy, for all three of these
10 example projects: “These are not backup strategies. They are primary power
11 strategies - a parallel private power infrastructure built from scratch over 18
12 months.”⁷⁵

⁷³ Zach Blackburn, “Sherrill proposes ‘guardrails’ for data centers,” *New Jersey Globe*, May 17, 2026. Accessed on 10/1/26 at: <https://newjerseyglobe.com/governor/sherrill-proposes-guardrails-for-data-centers/>.

⁷⁴ Kyle Bagenstose, “Pennsylvania’s Governor Has a Plan to Make Data Centers Bring Their Own Energy. Now Comes the Hard Part,” *Inside Climate News*, May 28, 2026. Accessed on 10/1/26 at: <https://insideclimatenews.org/news/28052026/pennsylvania-gov-shapiro-ai-data-center-plan/>.

⁷⁵ Christopher Johnson, “The \$150 Billion Private Grid: How Data Centers Built the Largest Private Power Program in US History,” *Avanza Energy*, June 2, 2026. Accessed on 7/27/26 at: <https://avanzaenergy.substack.com/p/the-150-billion-private-grid-how>.

1 **Q. If a data center was constructed in Consumers Energy’s territory and**
2 **operated 100% off-grid, how would that affect the Company?**

3 **A.** It wouldn’t affect the Company, nor its ratepayers. Nothing would change
4 for Consumers Energy. But the Company might view that as a lost
5 opportunity to supply capacity and energy, and earn a profit on the capital
6 invested in equipment necessary to do so. I would not expect the Company
7 to favor data centers providing their own on-site generation.

8 **Q. If a data center was constructed in Consumers Energy territory and**
9 **generated most of its own power, but signed up for standby service,**
10 **how would that affect the Company?**

11 **A.** The Company would gain revenue from the standby power agreement. It
12 would also need to plan capacity to meet the customer load on the
13 occasions when the customer switches to grid power.

14 **Q. Do Data Centers prefer building on-site power plants to getting their**
15 **energy from the grid?**

16 **A.** Generally, no. Data Centers much prefer grid power, *if and only if* the grid
17 can provide capacity quickly. The long delays to install and interconnect
18 new grid generation facilities have forced data centers into building on-site
19 power.⁷⁶ As Clear View put it,

⁷⁶ Shaun Walsh, “Hyperscalers didn’t set out to be power companies. The grid left them no choice.” *Utility Dive*, May 28, 2026. Accessed on 9/29/26 at:
<https://www.utilitydive.com/news/hyperscaler-data-center-power-companies-grid-utilities/820568/>

“Power generation efficiency is out. *Speed to power is all that developers care about.* AI data centers can generate \$10–12 million per MW annually, or \$10–12 billion per GW. Bringing a data center online even a few years early could result in tens of billions in revenue that would otherwise be forgone.”⁷⁷ (emphasis added)

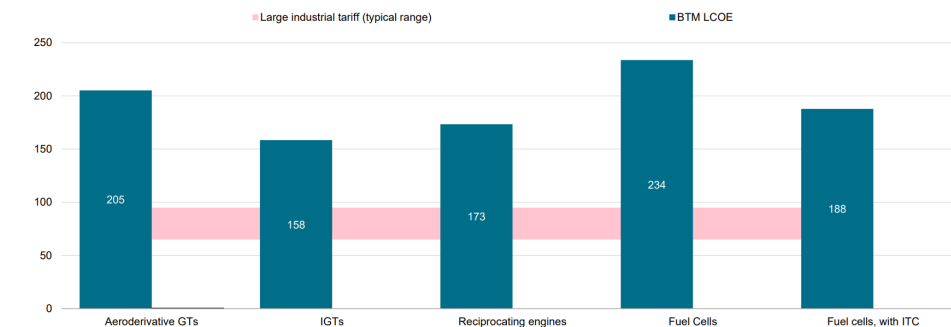
Another report put it this way: “Hyperscalers are increasingly giving up on the grid for AI training capacity.”

Q. Why do data centers prefer grid power?

A. S&P Global did a study showing that the cost of on-site power is more than twice as expensive as utility energy under large load tariffs:

The speed-to-power premium for behind-the-meter bridge solutions now reaches ~\$100/MWh or 130% over typical retail tariffs for large loads

Levelized cost of BTM power supply for a data center, 10 year operating life (2026 \$/MWh)



Data compiled: May 13, 2026
ITC = investment tax credit; BTM = behind the meter; GT = gas turbine; IGT = industrial gas turbine.
Notes: For details on cost and methodology, see LCOE for behind-the-meter generation for data centers in the US available on S&P Global's Core platform.
Source: S&P Global Energy
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S&P Global
Market Intelligence

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⁷⁷ Michael Thomas, “Bypassing the Grid: How Data Center Developers Are Building Their Own Power Plants,” Clearview, 2026. Accessed on 7/27/26 at: <https://cleanview.co/reports/behind-the-meter-data-centers>

1 **Q. What are the benefits of data center on-site generation?**

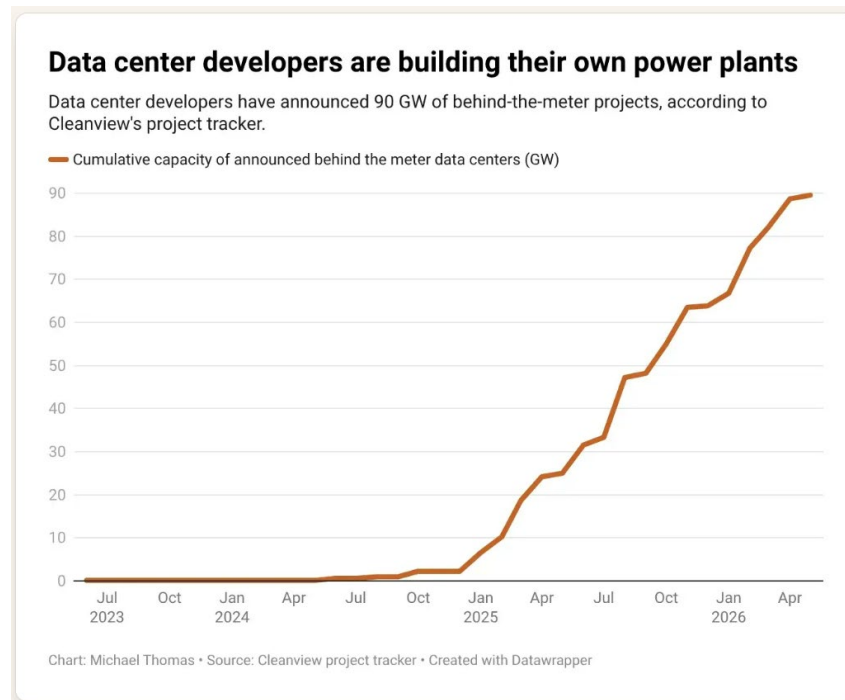
2 **A.** According to The Rocky Mountain Institute, there are benefits for all parties. The
3 customer gets speed-to-power, and a choice of technologies. Other ratepayers are
4 insulated from the costs of new generation and the risk of the customer's load
5 failing to materialize. Utilities get planning certainty and increased resource
6 adequacy.⁷⁸ I would add that the Public Service Commission doesn't need to
7 determine how much generation-related costs the data center imposed on the utility.

8 **Q. Are data centers already building on-site, behind the meter (BTM)**
9 **generation?**

10 **A.** Many are, and the practice is increasing rapidly. Bloom Energy reports that "over
11 one-third of data centers are expected to use 100% onsite power by 2030 and
12 developers increasingly expect permanent onsite generation to emerge as a
13 preferred long-term approach."⁷⁹ A company called Cleanview did a
14 comprehensive study of data centers building on-site generation. It identified 59
15 data centers, totaling 82 GW that are planning onsite power since 2025; about 25%
16 of all planned data center capacity in the US. The trend includes nearly every
17 hyperscaler, and a broad variety of generation equipment including gas turbines of
18 various kinds and reciprocating engines.⁸⁰

⁷⁸ Alyssa Perez, Sarah Wang, and Charles Cannon, "New Ways to Power Data Centers and Other Large Energy Users," *Rocky Mountain Institute*, February 6, 2026. Accessed on 8/1/26, at: <https://rmi.org/resources/new-ways-to-power-data-centers-and-other-large-energy-users/>

⁷⁹ "2026 Data Center Power Report," *Bloom Energy*, January, 2026, p 3. Accessed on 7/27/26 at: <https://www.bloomenergy.com/wp-content/uploads/2026-power-report.pdf>

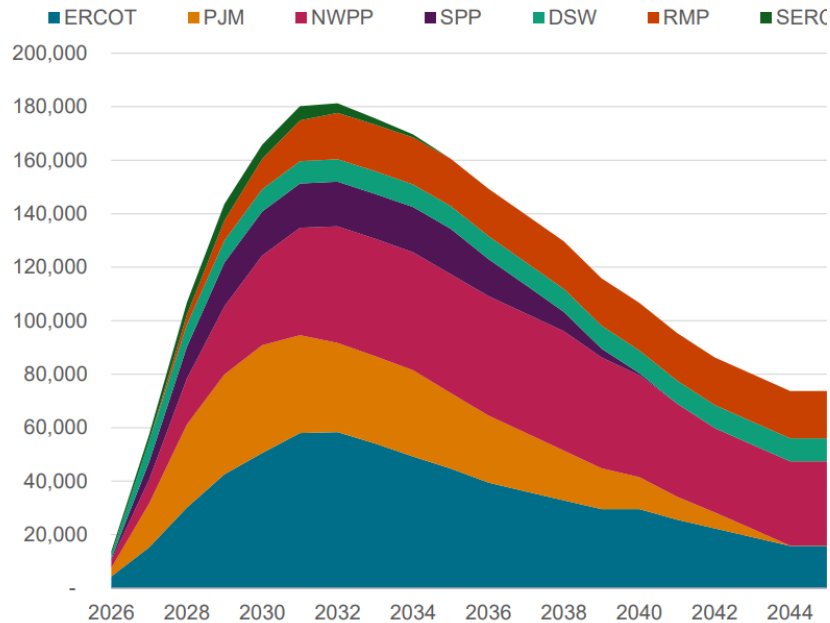


1

⁸⁰ Michael Thomas, “Bypassing the Grid: How Data Center Developers Are Building Their Own Power Plants,” *Cleanview*, 2026. Accessed on 7/27/26 at: <https://cleanview.co/reports/behind-the-meter-data-centers>

1 S&P Global also reported on data center's move to on-site power,
2 projecting rapid increases across the next four to six years:⁸¹

US: Projected datacenter demand served by behind-the-meter gas generation, by US power market. May 2026 IHV (GWh)



3
4 **Q. Does Michigan law allow data centers to generate on-site generation?**

5 **A.** Yes. The law creating tax incentives specifically names on-site generation as an
6 option, see MCL 205.54.(10)e(ix)(A). But Michigan law does not *require* on-site
7 generation, as President Trump and some Governors have suggested.

8 **Q. How has the impact of data centers' huge loads on resource adequacy been**
9 **addressed in Michigan?**

10 **A.** Through two different methods. Firstly, in U-21990, which approved special
11 contracts for a data center in Saline Township, and U-22058, which proposes
12 special contracts for a data center in Van Buren Township, developers have offered
13 to pay for utility owned measures that provide capacity. In U-21990, the developer

1 agreed to pay for battery capacity equal to the load of the new data center. In U-
2 22058, the developer is offering to pay for a mix of batteries, renewable energy
3 generation, and ZRCs, as well as provide temporary participation in a DR program,
4 which combined, provide capacity approximately equal to the load of the proposed
5 data center. In each of these cases, the utility will own and operate the batteries and
6 generation; the developer is just paying for it.

7 Secondly, in U-21990, the Commission ordered DTE Electric to shed the
8 load of its large load customers before shedding the load of other customers, and to
9 make this a part of its operating procedures, or to execute agreements with the
10 customers to reduce load when necessary:

11 “Additionally, in order to ensure that the addition of this
12 significant new load will not adversely impact the grid reliability
13 experienced by other customers, DTE Electric is directed, within
14 90 days of the date of this order, to file an application to update its
15 Emergency Electric Procedures outlined in Section C3 of its Rate
16 Book for Electric Service and any other relevant DTE Electric
17 procedures to indicate that, after the event level step including the
18 issuance of public appeals and after the event level step that
19 implements voluntary load reductions, *the company will shed firm*
20 *load from the Customer prior to shedding firm load of any of DTE*
21 *Electric’s other customers* to the extent that firm load shedding is
22 directed by the regional transmission organization and shedding
23 the load of the Customer can prevent shedding load of other DTE
24 Electric customers. *Alternatively, DTE Electric may develop and*
25 *execute agreements necessary to enable a required load reduction*
26 *from the Customer at the appropriate step within the emergency*
27 *procedures outlined above to effectuate a required load reduction*
28 *in lieu of firm load shedding* and shall reflect the required load

⁸¹ “AI infrastructure growing pains: Ensuring energy resilience amid grid constraints and public demands,” S&P Global, June 11, 2026, slide 22. Accessed on 8/1/2026 at: <https://on24static.akamaized.net/event/53/56/76/9/rt/1/documents/resourceList1781194546520/ai-infrastructuregrowingpainswebinardeckfinalversion1781194546520.pdf>

1 reduction within its Emergency Electric Procedures.”⁸² (emphasis
2 added)
3

4 **Q. Which option did DTE Electric choose?**

5 A. DTEE chose to implement firm load shedding of large load customers before other
6 customers, in case U-22059, which the Commission gave ex parte approval on
7 August 27, 2026.

8 **Q. Does Consumers Energy have procedures to shed large load customers before**
9 **shedding the load of other customers?**

10 A. Not that I’m aware of.

11 **Q. Have other jurisdictions required large load customers to be shed prior to**
12 **other customers, in emergency conditions?**

13 A. Yes. As I discussed earlier in this testimony, the DOE gave authority to PJM, Duke
14 Energy, and SPP to do so during certain peak load periods. SPP has gotten FERC
15 approval for offering non-firm transmission service to large loads, subject to
16 curtailment during grid emergencies.⁸³ Texas has gone much further: Texas Act
17 SB6, signed into law on June 20, 2025.⁸⁴ This law creates a whole series of rules
18 for large loads (defined as > 75 MW). The Texas law will:

⁸² U-21990, Commission order dated December 18, 2025, p 41-2.

⁸³ Molly Glick, “EWS: FERC has greenlit SPP’s proposal to offer data centers (temporary) transmission service,” energy central, Jun 8, 2026. Accessed on 9/21/26 at: <https://www.energycentral.com/energy-management/post/news-ferc-has-greenlit-spp-s-proposal-to-offer-data-centers-temporary-inxpqWQTeA8SqLf>

⁸⁴ Bill Track, “TX SB6,” 2026. Accessed on 9/21/26 at: <https://www.billtrack50.com/billdetail/1830294>

1 “Require large loads with on-site backup generation capable of
2 serving at least 50% of their on-site demand that do not export
3 back to the grid to provide information about the facilities and
4 generation to the interconnecting utility and to ERCOT. *During*
5 *grid emergencies ERCOT may direct such large loads, with*
6 *reasonable notice, to deploy their backup generation or curtail*
7 *load.”*⁸⁵ (emphasis added)

8 This curtailment may occur only after ERCOT has exhausted all market tools
9 (e.g., demand response) and a grid emergency is occurring or imminent.⁸⁶ This
10 procedure appears functionally similar to the first firm load shed defined in
11 DTEE’s emergency procedures, approved in U-22059.

⁸⁵ Julia D. English, Katlyn A Davis Farrell, “Texas Senate Bill 6 Significantly Expands Regulatory Oversight Over Large Loads in ERCOT,” *McGuire Woods*, July 10, 2025. Accessed on 9/21/26 at: <https://www.mcguirewoods.com/client-resources/alerts/2025/7/texas-senate-bill-6-significantly-expands-regulatory-oversight-over-large-loads-in-ercot/>

⁸⁶ Baker Botts, “Texas Senate Bill 6: Understanding the Impacts to Large Loads and Co-located Generation,” July 18, 2025. Accessed on 9/21/26 at: <https://www.bakerbotts.com/thought-leadership/publications/2025/july/texas-senate-bill-6-understanding-the-impacts-to-large-loads-and-co-located-generation>

1 **Q. How is the first firm load shed procedure implemented in U-22059 different**
2 **from a demand response (DR) program?**

3 A. There are at least three differences. Firstly, all possible DR is invoked before the
4 first firm load shed procedures. Secondly, MISO recently changed their demand
5 response resource rules to require an annual test, showing at least an 80% load
6 reduction;⁸⁷ no such annual test applies to the first firm load shed procedure.
7 Thirdly, while the first firm load shed procedure protects grid *reliability* from
8 excess large load demand, it does not help the Company to meet the *resource*
9 *adequacy* requirements of MISO. Demand response (DR) is a resource in the MISO
10 resource adequacy process, while the first firm load shed procedure ordered in U-
11 22059 is not.

12 Putting large loads on a demand response program would directly reduce
13 the amount of capacity resources (battery storage and/or peaker plants) necessary to
14 maintain resource adequacy. This would enhance affordability, either for the data
15 center customer, other customers, or both.

⁸⁷ Ben Duwve and Jill Drum, “FERC Accepts MISO’s Revised Demand Resource Real Power Testing Requirements,” *Troutman Pepper Locke*, December 11, 2025. Accessed on 7/27/26 at: <https://www.troutmanenergyreport.com/2025/12/ferc-accepts-misos-revised-demand-resource-real-power-testing-requirements/>

1 **Q. What is the advantage of the first firm load shed of large load customers**
2 **before other customers, vs. some kind of demand response agreement with the**
3 **customers?**

4 A. The first firm load shed procedure was quick and easy to implement, and applies
5 uniformly to all large load customers. Since DTE Electric already had approval for
6 one customer (U-21990) and was contemporaneously pursuing approval of special
7 contracts for another (U-22058), time was of the essence.

8 **Q. Should the Commission order Consumers Energy to modify its emergency**
9 **procedures to shed the firm large load customers prior to shedding the firm**
10 **load of other customers, similar to the changes the Commission approved for**
11 **DTEE in U-22059?**

12 A. Yes. Just as it was reasonable and prudent for the Commission to direct DTE
13 Electric to implement first firm load shed procedures for large load customers, it is
14 reasonable and prudent to do so for large load customers of Consumers Energy. I
15 see no reason to differentiate large loads in DTE Electric territory from large load
16 customers in Consumers Energy's territory. This measure is necessary because it
17 eliminates the very real risk that new data center demand causes rolling blackouts.
18 However, I believe there is a better alternative, which would significantly improve
19 affordability – a new version of demand response. Because DR is an option for the
20 customer (not mandatory), the first firm load shed procedure is still necessary for
21 large load customers who are *not* enrolled in a DR program.

1 **Q. Has the potential impact of putting large loads on demand response been**
2 **studied?**

3 A. Yes, making data center loads “flexible” has been an area of intense study and
4 discussion. According to an often-cited study from Duke University, if all US data
5 centers cut back their usage by 1-2% during peak hours, NGCC (natural gas
6 combined cycle) construction would be reduced by 10-15%.⁸⁸ The study noted that
7 adding flexibility changes not just the amount of new generation required, but the
8 type of generation:

9 “If there is only limited flexibility, the most significant source of
10 new electricity for data centers over the next five years is likely to
11 be new natural gas combined-cycle (NGCC) units—assuming data
12 center electricity is provided by utilities and is not constrained by
13 factors such as company preferences for renewable or low-carbon
14 generation... all retail customers see price reductions of around
15 0.5% to 2.8% in the modeled scenarios, as data center flexibility
16 reduces stress on the grid during the highest-cost peak hours and
17 lowers capital expenditures.”⁸⁹

⁸⁸ M.T. Ross and Jackson Ewing, “Data Centers and Generation Capacity over the Next Decade: Potential Benefits of Flexibility,” *Nicholas Institute for Energy, Environment & Sustainability*, 2026, p 17. Accessed on 8/1/26 at: <https://nicholasinstitute.duke.edu/sites/default/files/publications/data-centers-generation-capacity-over-next-decade.pdf>

⁸⁹ Ibid, p 3.

1 A study by Boston University reported that AI data centers can be designed
2 with flexibility, and could offer 18-55% flexibility relative to their average power
3 consumption.⁹⁰

4 A study in the PJM region showed that curtailment during just 15 peak days
5 per year could free 6-17% of total system capacity.⁹¹

6 **Q. Have data centers voluntarily signed up for DR programs?**

7 **A.** Yes. Google has declared that their data centers (across the country) are providing
8 one GW of flexible load via DR programs.⁹² Google's proposed data center in Van
9 Buren Township has agreed to provide 650 MW of DR for six years.⁹³ A
10 Department of Energy report identified no grid-aware flexible operation at data
11 centers, other than Google.⁹⁴ Data center enrollment in DR in the PJM region
12 makes up about 5% of the program.⁹⁵

13 **Q. Are data center customers generally willing and able to reduce their load**
14 **during times of grid stress?**

15 **A.** There seems to be considerable disagreement about that. The Electric Research
16 Power Institute (ERPI) has been researching the topic and created a "flexibility
17 framework," which identifies different kinds of flexibility. The study shows that
18 flexibility allows system operators to add large loads while maintaining reliability,
19 while minimizing rate raising infrastructure investments. But problems can come
20 up in the operating parameters of the agreements; traditional bill credits may be
21 insufficient to get data centers to agree to reduce their usage.⁹⁶ Grid Strategies
22 President Rob Gramlich explained it this way:

1 “There’s just not anywhere near enough money in that for a
2 hyperscaler to say, *Oh yeah, I’m gonna not run my Nvidia chips for*
3 *a while to make \$200 a megawatt hour.* That’s peanuts compared
4 to the bazillions [they] just spent.”⁹⁷ (emphasis in the original)

5 Consider that the data center under construction in Saline Township is expected to
6 house \$30-40 billion of electronics.⁹⁸ That’s a huge investment to let stand idle.

⁹⁰ Herman K. Trabish, “Deep Dive: Data centers are ready to negotiate flexibility for speed,” *Utility Dive*, June 26, 2026. Accessed on 10/1/26 at: <https://www.utilitydive.com/news/data-centers-flexibility-utilities-speed-to-power/822588/>

⁹¹ Latitude Media, “The Terms of Power: Inside the New Utility Rates for Data Centers,” March, 2026. Accessed on 9/2/26 at: <https://www.latitudemedia.com/research/the-terms-of-power-inside-the-new-utility-rates-for-data-centers/?nab=1>

⁹² Michael Terrell, “A new milestone for smart, affordable electricity growth,” *Google*, March 19, 2026. Accessed on 7/27/26 at: <https://blog.google/innovation-and-ai/infrastructure-and-cloud/global-network/demand-response-data-center-milestone/>

⁹³ U-22058, direct testimony of N.T. Foley, 3 TR 90

⁹⁴ Jeff St. John, “Google’s new plan to keep its data centers from stressing the grid,” *Canary Media*, August 28, 2025, citing a DOE report from July 30, 2024. Accessed on 7/24/26 at: <https://www.canarymedia.com/articles/utilities/google-ai-data-center-flexibility-help-grid>

⁹⁵ Jack Newsham, “Dark smoke rose above a Virginia data center as a heat wave pushed the power grid close to its limits,” *Business Insider*, July 11, 2026. Accessed on 7/26/27 at: <https://www.businessinsider.com/virginia-data-center-diesel-backup-generator-heat-wave-pjm-2026-7>

⁹⁶ Herman K. Trabish, “Data centers are ready to negotiate flexibility for speed,” *Utility Dive*, June 26, 2026. Accessed on 9/24/26 at: <https://www.utilitydive.com/news/data-centers-flexibility-utilities-speed-to-power/822588/>

⁹⁷ Katie Brigham, “The Software That Could Save the Grid,” *Heatmap*, July 11, 2025. Accessed on 10/1/26 at: <https://heatmap.news/climate-tech/emerald-ai-nvidia-data-centers>

⁹⁸ Dustin Blitchok, “Data center news: Altman visits Saline data center, says it’s ‘huge bet’ on AI,” *Planet Detroit*, June 1, 2026. Accessed on 10/1/26 at: <https://planetdetroit.org/2026/06/michigan-data-center-news-altman-saline/>

1 **Q. Can data centers provide flexible load without reducing their computing**
2 **operations?**

3 A. Yes, either by using on-site batteries or backup generators. There is a pilot
4 underway in the Pacific Northwest, for a data center with a 31 MW/62 MWh
5 battery system to provide flexibility.⁹⁹ Here in Michigan, the “Flex Project” data
6 center project proposed by developer Verras for South Lyon Township is planning
7 to have sufficient battery storage onsite to power the data center for four hours, and
8 plans to participate in DTE’s DR programs.¹⁰⁰ The 100 MW data center proposed
9 in Gibraltar, MI has offered to use its 30-35 diesel generators to support DTE
10 Electric’s grid.¹⁰¹ Jeff Monday, chief growth officer at Fluence, put it this way:

⁹⁹ Julian Spector, “In a first, a data center is using a big battery to get online faster,” *Canary Media*, October 24, 2025. Accessed on 9/4/26 at:
<https://www.canarymedia.com/articles/batteries/aligned-data-center-get-online-faster>.

¹⁰⁰ Verras, “Project Flex Study Meeting,” *Lyon Township*, January 2026, slides 15, 19-20. Accessed on 7/27/26 at:
<https://cms2.revize.com/revize/lyontownship/Project%20Flex%20Presentation%20-%20001-22-26.pdf>

¹⁰¹ Brian Allnutt, “Gibraltar data center could support DTE grid with diesel generators: Developer,” *Planet Detroit*, March 11, 2026. Accessed on 10/1/26 at:
<https://planetdetroit.org/2026/03/gibraltar-data-center-diesel-generators/>.

1 “The most interesting BYOP [Bring Your Own Power]
2 configurations aren’t islanding from the grid — they’re using storage
3 to become a better grid citizen than a conventional load. Storage lets
4 a data center smooth its own ramps, shape its own profile, and show
5 up to the interconnection point as predictable, controllable
6 demand. That’s the opposite of autonomy. That’s partnership at
7 machine speed.”¹⁰²

8 **Q. What is the most likely result, if the Commission does not require data centers**
9 **to bring their own capacity, or to participate in a DR program?**

10 A. Data center demand will require major new capacity additions to Consumers
11 Energy’s grid. This will likely take the expensive form of batteries and/or peaker
12 plants.

13 **Q. Is the Company contemplating the addition of peaker plants?**

14 A. Yes. In the Company’s contemporaneous Integrated Resource Plan (IRP) case
15 U-22127, the Company is requesting Certificate of Needs (CONs) for two gas
16 peaker plants, a 456 MW simple gas turbine at its existing D.E. Karn site, and a
17 919 MW simple gas turbine at its existing Thetford site, for a total of 1,375 MW.
18 These resources are “primarily address reliability needs by providing dependable
19 capacity and dispatchable energy.”¹⁰³

¹⁰² Jeremiah Karpowicz, “Battery energy storage is foundational to the AI economy,” *Renewable Energy World*, May 20, 2026. Accessed on 10/1/26 at: <https://www.renewableenergyworld.com/energy-storage/battery/battery-energy-storage-is-foundational-to-the-ai-economy/>

¹⁰³ U-22127, Company application initial filing, part 1, p 4 & p 84, lines 19-20.

1 **Q. How much is the Company projecting these two new peaker plants to cost**
2 **ratepayers?**

3 A. In the IRP, the Company is asking for Commission approval to recover in rates,
4 capital costs of \$1.2B and \$2.4B for Karn and Thetford, respectively.¹⁰⁴ That's a
5 total of \$3.6B for 1,375 MW (1.375 GW) of capacity, or \$2.6B/GW of capacity.
6 Note that this would be more expensive if the Company was not re-using sites
7 already equipped for power generation, so these costs should be considered the
8 minimum that new simple cycle power plants will cost. Presumably these costs will
9 be recovered over the lifetime of these new turbines, with return *on* capital added to
10 the return *of* capital. Various taxes on these new assets will also be recovered from
11 ratepayers, if the Commission approves the CONs. Therefore, the total cost to
12 ratepayers will be considerably higher than the total capital cost of \$3.6B.

13 **Q. Will data centers pay for this added capacity?**

14 A. Consumers Energy has a standard tariff for large loads, approved by the
15 Commission in U-21859. As far as I know, the Company is under no obligation to
16 seek compensation over and above that tariff, or to seek Commission approval for
17 the interconnection of new large load customers. The Company may apply for
18 approval of special contracts in the future.

¹⁰⁴ Ibid, p 106.

1 **Q. Does Consumers Energy have any large loads in operation, or contracted for**
2 **service?**

3 A. Yes, according to their filing in their concurrent IRP, case U-22127. In their
4 application, the Company states that:

5 “Since the 2021 IRP, the electric supply industry has changed in
6 material ways. Consumers Energy has seen substantial economic
7 development in its service territory, resulting in *approximately 1.5*
8 *GW of contracted new large load growth, above the approximately*
9 *400 MW of large load growth that is already online* or otherwise
10 reflected in the Company’s near-term load outlook. The Company
11 is also talking with existing and prospective new customers who
12 are considering the Company’s electric service territory for
13 expanded or new business opportunities, which could add even
14 more load in the future.”¹⁰⁵ (emphasis added)

15
16 **Q. What advantage would be gained if the large load customers were enrolled in**
17 **a demand response program instead of being subject to a first firm load shed**
18 **policy, such as the one the Commission approved in U-21059?**

19 A. Load enrolled in a utility demand response program gets a significant capacity
20 credit in the MISO capacity adequacy process. An emergency shut-off program
21 accomplishes much of the same thing in terms of *actual* resource adequacy, but is
22 not reflected in the MISO PRA or resource adequacy procedures. With large loads
23 on demand response, Consumers Energy would need to build less peaking capacity
24 than with large loads receiving firm service, whether or not they are subject to “first
25 load to shed” procedures.

¹⁰⁵ U-22127, CECO IRP application initial filing, part 1, p 4.

1 **Q. How would the enrollment of data center customers in DR reduce costs?**

2 A. Because of the capacity credit for the DR program, the Company would not need to
3 acquire capacity resources to meet the demand of the data center customer. The
4 savings for a 1 GW data center would be *billions* of dollars.

5 **Q. What action should the Commission take, which would eliminate the risk that**
6 **large load demand causes rolling blackouts, while improving affordability?**

7 A. The Commission should direct the Company to create an option in its large load
8 tariff, to specify that the service is not firm; putting the large load customer into a
9 two-tiered demand response (DR) program. Large loads in this second tier (which I
10 will call “tier-2”) would only be called upon after existing DR customers (tier-1)
11 have been called upon, but would not receive any reduction in their electric rates.
12 To the large load customer, this would function much like the current first firm load
13 shed procedure in U-22059; the large load customer would have their service
14 curtailed only when necessary to prevent the firm load shed of other customers. But
15 it would have the huge advantage that Consumers Energy could register the
16 customer’s load flexibility as demand response in the MISO resource adequacy
17 process. Therefore, Consumers Energy would not have to acquire nearly as much
18 additional capacity to meet the large customer’s load. This would reduce the
19 Company’s cost of service, putting downward pressure on customer rates.

1 Q. **Is there any downside for the large load customer in “last demand response”**
2 **option vs the first firm load shed procedure?**

3 A. There is only one that I can think of. MISO recently changed their demand
4 response rules to require an annual test, showing at least an 80% load reduction.
5 Under the tier-2 DR option, the large load customer would be required to switch to
6 backup power once a year. With sufficient advanced notice, this should not be a
7 major burden to the customer; they are likely doing occasional tests of their backup
8 power systems already.

9 Q. **How would offering large load customers in a two-tiered demand response**
10 **program affect Consumers Energy?**

11 A. Because the Company would not (necessarily) need to sign PPAs or acquire
12 generation or storage assets to supply the customer’s load under the MISO resource
13 adequacy process, the Company’s opportunity to earn a profit may be reduced. I
14 would not expect the Company to favor this option.

15 Q. **Can you summarize your proposed options to ensure resource adequacy as**
16 **new large load customers are interconnected?**

17 A. Yes. I propose that new large load customers be presented with four options (which
18 are not mutually exclusive) to provide the capacity needed to support their load:

- 19 1. A special contracts approach in which the customer provides funding for
20 sufficient capacity to support their load, for the duration of the primary
21 supply agreement (PSA). They will still be subject to a “first firm load
22 shed” provision.

- 1 2. The customer can build their own on-site power generation system. The
2 customer may either be entirely off-grid, with no utility interconnect, or
3 interconnected on standby power. Because standby power still imposes a
4 major load on the grid (on occasion), the customer, when pulling power
5 from the grid, would still be subject to the “first firm load shed” provision.
- 6 3. The customer can sign up for a traditional demand response program.
7 Unless the customer agrees to 100% load reduction during declared events,
8 the customer would still be subject to the “first load shed” provision.
- 9 4. The customer can sign up for a new program, as a tier-2 demand response
10 participant, at 100% of their load. The customer would only be called upon
11 to drop their load off the grid after all standard (tier-1) DR customers had
12 been called upon, and if there was still a shortfall of capacity. The customer
13 would need to participate in a DR test once per year so that their
14 participation in DR will get capacity consideration in the MISO resource
15 adequacy process. The “first load to shed” provision would have no impact
16 on this customer, since their load will already be off-grid before any firm
17 load shedding occurs. Compared to the special contracts or on-site power
18 options, this option allows the data center customer to interconnect without
19 the delays of power plant or battery construction. Compared to the
20 traditional DR program, this option will call upon the customer to reduce
21 their load less frequently.

III. LARGE COMPUTING LOADS CAN BE A RISK TO GRID RELIABILITY

Q. How do data centers pose a risk to grid reliability?

A. I will talk about two different ways in which data centers have been shown to affect grid reliability: dramatic load volatility (ramp up and ramp down), and simultaneous UPS trips due to voltage transients.

A. Data Center Load Volatility

Q. Is data center load volatility a recognized issue?

A. Yes. Former US Secretary of Energy (and former Governor of Michigan) Jennifer Granholm explained the issue on LinkedIn:

“One of the least understood aspects of the AI-data-center boom is not the size of the load ... it’s the *volatility of the load*.

Utilities have historically treated data centers as large but relatively flat demand sources — closer to steady industrial load than to highly dynamic systems.

AI changes that. Why?

Because frontier AI clusters may involve tens of thousands of GPUs operating in synchronized computational cycles. Instead of millions of independent computing tasks smoothing each other out, you increasingly get giant clusters behaving almost like a single machine.

That means power demand can ramp sharply — and quickly. And the volatility doesn’t stop with the chips.

When GPU utilization spikes, heat spikes, cooling systems ramp, pumps and chillers respond, and power electronics react.

At very large scale, those coupled swings can become significant grid events.

A 1 GW AI campus experiencing a rapid 10% load swing means a 100 MW change in demand.

That is utility-scale generation territory.

And unlike traditional utility planning assumptions, these changes

1 may occur in seconds — or sub seconds — rather than over hours.

2 This matters because the grid was largely designed around gradual
3 load ramps, predictable industrial demand and hourly planning
4 models.

5 AI infrastructure may require a different architecture: 1) *onsite*
6 *batteries for power smoothing*; 2) *advanced inverter systems*; 3)
7 sophisticated reactive power management; 4) grid-aware workload
8 scheduling and 5) *new interconnection standards*.

9 Ironically, the future AI campus may look less like a passive
10 customer and more like a miniature grid operator.

11 The next era of grid planning may not just be about adding more
12 power.

13 It may be about *managing a fundamentally different kind of*
14 *load.*¹⁰⁶ (emphasis added)

15 Granholm identifies several critical points, and I will return to the issues in
16 her post at multiple points further in my testimony.

17 **Q. What does this load volatility look like to the grid?**

18 A. A transmission company in Wisconsin described it this way:

19 “This ‘new breed’ of data centers often have extreme operating
20 variability and need to ramp load up and down by hundreds of
21 megawatts on a second-to-second basis. ‘This is equivalent to
22 turning Wisconsin’s capital city of Madison on and off,
23 repeatedly,’ the firm said, *requiring specialty power electronic*
24 *devices at mega-scale* to safely integrate the variable load.”¹⁰⁷
25 (emphasis added)

¹⁰⁶ Jennifer Granholm, *LinkedIn*, 2026. Accessed on 7/26/26 at:
https://www.linkedin.com/posts/jennifergranholm_one-of-the-least-understood-aspects-of-the-activity-7458242574542327808-bZoX/

¹⁰⁷ Mary B. Powers and Debra K. Rubin, “Energy Sector Debates New US Rules to Power Up More 'Large Load' Data Centers,” *Energy News-Record*, December 15, 2025. Accessed on 7/26/26 at: <https://www.enr.com/articles/62219-energy-sector-debates-new-us-rules-to-power-up-more-large-load-data-centers>

1 **Q. Can you provide a more technical view of data center load volatility?**

2 A. Yes. When training a new AI model, data center load may vary wildly in
3 milliseconds or even *microseconds*:

4 “A.I.-related data centers, though, operate differently, with demand
5 profiles that can shift dramatically from second to second. This is
6 especially true for training operations when tasks might be spread
7 across many graphics processing unit servers at a time. These
8 power-hungry devices can ramp up in unison in seconds or even
9 microseconds, driving demand spikes. Operations can then power
10 down just as rapidly, which can create a surge on the connected
11 grid. As a result, these facilities can affect grid reliability across a
12 utility’s network.”¹⁰⁸

13 Uptime Institute explains this common AI training phenomenon in more detail:

14 “Uptime Intelligence estimates that in worst-case scenarios, the
15 difference between the low and high points of power draw during
16 training program execution can exceed 100% on a system level
17 (the load doubles almost instantaneously, within milliseconds) for
18 some configurations.

19 *These extremes occur every few seconds*, whenever a batch of
20 weights and biases is loaded on GPUs and the training begins. This
21 is often accompanied by a massive spike in current, produced by
22 power excursion events as GPUs overshoot their thermal design
23 power rating (TDP) to opportunistically exploit any extra thermal
24 and power delivery budget following a phase of lower transistor
25 activity. In short, power spikes are made possible by intermittent
26 lulls.

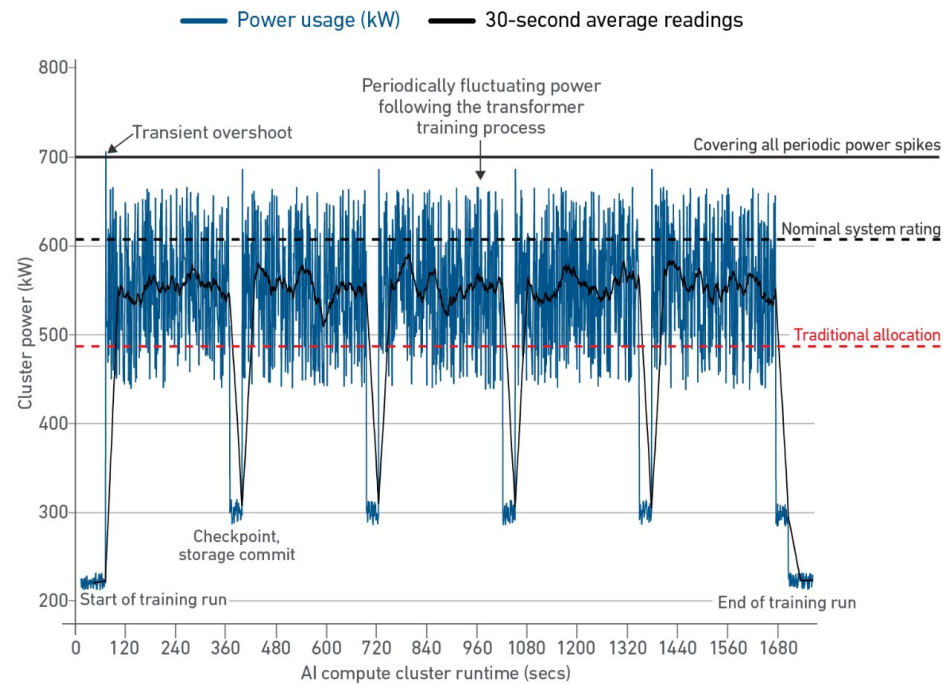
27 This behavior is common in modern compute silicon, including in
28 personal devices and generic servers. Still, it is only with large AI
29 compute clusters that these fluctuations across dozens or hundreds
30 of servers move almost synchronously.”¹⁰⁹ (emphasis added)

¹⁰⁸ Chuck Ross, “It’s not just the load: A.I. data center grid impacts,” *Electrical Contractor*, January 15, 2026. Accessed on 6/2/26 at: <https://www.ecmag.com/magazine/articles/article-detail/it-s-not-just-the-load--a.i.-data-center-grid-impacts>

¹⁰⁹ Daniel Bizo, “Electrical considerations with large AI compute,” *Uptime Institute*, November 19, 2025. Accessed on 6/2/26 at: <https://journal.uptimeinstitute.com/electrical-considerations-with-large-ai-compute/>

Uptime Institute goes on to explain that a server cluster can spike *over its rated load*, and provides a graph of a training cluster's load over time, illustrating the spikes over rated load:¹¹⁰ (emphasis added)

Figure 1 Power profile of a GPU-based training cluster (algorithmic not real-world data)



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In electrical terms, no multi-rack workload is perfectly synchronous, while the presence of other loads will help smooth out the edges of fluctuations further. When including non-compute ancillary loads in the cluster — such as storage systems, networks and CDUs (which also require UPS power) — a lower safety margin above the nominal rating (e.g., 10% to 15%) appears sufficient to cover any regular peaks over the nominal system power specifications, even with the latest AI hardware.

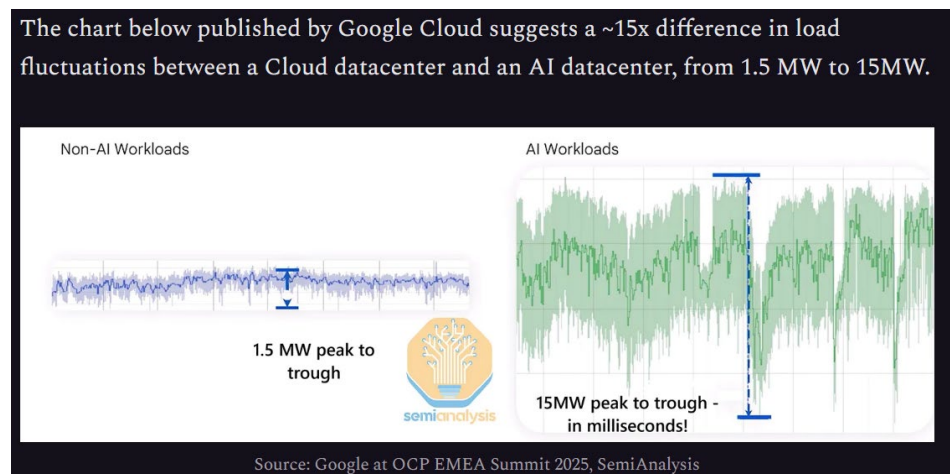
Q. How do these wild swings in power consumption by AI computing clusters affect the grid?

A. Semi Analysis opens with a bleak warning of the consequences of these load swings, before turning to a more technical description:

¹¹⁰ Ibid.

1 “Not only is the scale massive, but AI training workloads have a
2 *very unique load profile*, unexpectedly rising and falling from full
3 load to nearly idle in fractions of a second. Our power grids were
4 never designed to handle this pattern. At Gigawatt-scale, the worst-
5 case scenario is *a blackout for millions of Americans*.”¹¹¹
6 (emphasis added)

7 Semi Analysis provides a graph, showing how AI systems load swings wildly, but
8 non-AI computing has much smaller changes in power draw:¹¹²



9
10
11 Semi Analysis goes on to discuss simulations, showing that AI data centers in
12 Texas could trigger cascading power losses resulting in a blackout. It draws a
13 parallel to the massive blackout in Spain and Portugal that started on April 28, 2005
14 with 2.2 GW of generation tripping off-line, resulting in cascading breaker trips
15 and total collapse within 27 seconds.¹¹³

¹¹¹ Jeremie Elliahou Ontiveros, Dylan Patel, and Ajey Pandey, “AI Training Load Fluctuations at the Gigawatt-scale – Risk of Power Grid Blackout?” *Semi Analysis*, June 25, 2025. Accessed on 6/2/26 at: <https://newsletter.semianalysis.com/p/ai-training-load-fluctuations-at-gigawatt-scale-risk-of-power-grid-blackout>

¹¹² Ibid

¹¹³ Ibid

1 **Q Does data center load volatility have impacts beyond grid reliability?**

2 A. Yes. It's been recently reported that data center load volatility shortens the lifespan
3 of gas-fired turbines, and has even caused the main generator shaft to snap, in at
4 least one example.¹¹⁴ *Fortune* reported that data center load volatility causes
5 “batteries, generators, and colling systems to malfunction of wear out far sooner
6 than expected.” The article also reported that on-site gas-fired engines and turbines
7 have developed cracks, with batteries later installed to remediate the swings in
8 load.¹¹⁵

9 **Q Load fluctuations are nothing new, why do data centers represent a new risk?**

10 A. The load volatility of data centers is different in both scale and speed. The grid
11 adapts to changing load via two different mechanisms over two different time
12 periods. In the short term (seconds) the grid relies on the kinetic energy stored in its
13 spinning turbine and generator mass to adjust to sudden changes in load, with some
14 assistance from the energy stored in spinning industrial motors. This rotational
15 energy is only sufficient for 5-10 seconds of load variation.¹¹⁶ The move to

¹¹⁴ Harriet Weber, “AI Data Center Turbines, Backlogged for Years, Are Suffering Early Deaths. Here's Why.” *Investor's Business Daily*, July 29, 2026. Accessed on 8/4/26 at: <https://www.investors.com/news/turbine-generator-ai-data-center-power-threat/#:~:text=8%2F1%2F2026-.AI%20Data%20Center%20Turbines%2C%20Backlogged%20For%20Years%2C%20Are%20Suffering%20Early,Here's%20Why.&text=AI%20data%20centers'%20thirst%20for,intelligence%20boom%20%E2%80%94thermal%20turbine%20generators.>

¹¹⁵ Bloomberg and Naureen S. Malik, “AI’s volatile power demand is damaging its own data centers,” *Fortune*, August 6, 2026. Accessed on 10/126 at: <https://fortune.com/2026/08/06/ais-volatile-power-demand-is-damaging-its-own-data-centers/>

¹¹⁶ “Inertial Response”, *Groklopedia*. Accessed on 7/26/26 at: https://groklopedia.com/page/inertial_response

1 inverter-based generation (wind and solar) is reducing the total amount of energy
2 stored in spinning parts. As Jennifer Granholm noted in her LinkedIn post (quoted
3 earlier), this calls for advanced inverter systems.

4 Over longer periods of time, utilities adjust the production of their
5 generators. Simple gas-fired turbine generators (“peaker plants”) can ramp up to
6 peak output in five minutes.¹¹⁷ Combined cycle gas-fired plants rely on the
7 production of steam for about a third of their output and can take over 30 minutes
8 to ramp to full power.¹¹⁸

9 Semi Analysis explains that the problem that data centers pose is the ability
10 to ramp generation up or down by hundreds of MW in *seconds*, compared with the
11 ability of fossil-fueled generators ramp rates of 5-50 MW/*minute*.¹¹⁹ The mismatch
12 in timing is severe.

13 **Q. What solution is there to data center load volatility causing power outages?**

14 A. Both Semi Analysis and Jennifer Granholm recommend battery storage, which can
15 adjust output at the sub-second speeds necessary.

¹¹⁷ Rob Rapier, “The load following power plant: the new peaker,” *GE Vernova*, (c) 2026. Accessed on 7/26/26 at: <https://www.gevernova.com/gas-power/resources/articles/2017/load-following-power-plant>

¹¹⁸ Michael Welch and Andrew Pyn, “Improving the Flexibility and Efficiency of Gas Turbine-Based Distributed Power Plants,” September 14, 2015. Accessed on 7/26/26 at: <https://www.power-eng.com/gas/turbines/improving-the-flexibility-and-efficiency-of-gas-turbine-based-distributed-power-plants/>

¹¹⁹ Jeremie Elliahou Ontiveros, Dylan Patel, and Ajey Pandey, “AI Training Load Fluctuations at the Gigawatt-scale – Risk of Power Grid Blackout?” *Semi Analysis*, June 25, 2025. Accessed on 7/26/26 at: <https://newsletter.semianalysis.com/p/ai-training-load-fluctuations-at-gigawatt-scale-risk-of-power-grid-blackout>

B. Fault Ride Through

Q. What is Fault Ride Through (FRT)?

A. When a UPS detects utility power outages, or utility power that has varied in voltage or frequency outside of specified parameters, it disconnects the facility from the grid and switches to backup power. The UPS can be configured to be more sensitive, or less sensitive to brief variations in utility voltage and/or frequency. This is commonly called either Voltage Ride Through, or VRT, or more generally Fault Ride-Through (FRT). I will be using the term FRT.

Q. Is the risk of simultaneous UPS trips (non-ride through) a recognized issue?

A. Yes. As a result of a very brief voltage variation, sixty data centers in Virginia, using 1,500 MW power, dropped off the grid simultaneously, and did not return to the grid for hours on July 10, 2024. According to the National Energy Reliability Council (NERC) incident report:

“ ‘A lightning arrestor failed on a 230 kV transmission line in the eastern interconnection, resulting in a permanent fault that eventually ‘locked out’ the transmission line,’ the NERC report said. A lightning arrestor is a piece of equipment designed to protect against power surges. This led to a series of short supply disturbances, *lasting a matter of milliseconds before the system corrected itself*, but it was enough to cause data centers in the area to automatically switch to their backup UPS systems as a precautionary measure because ‘data center loads are sensitive to voltage disturbances,’ the report said.” (emphasis added) ¹²⁰

More recently, a second, similar incident occurred in Virginia. This time a

¹²⁰ Matthew Gooding, “Virginia narrowly avoided power cuts when 60 data centers dropped off the grid at once,” *Data Center Dynamics*, March 20, 2025. Accessed on 8/1/26 at: <https://www.datacenterdynamics.com/en/news/virginia-narrowly-avoided-power-cuts-when-60-data-centers-dropped-off-the-grid-at-once/>

1 voltage disturbance caused 3 GW of load to drop off-line, about 3% of PJM's entire
2 load at the time. It took the grid more than 10 minutes to stabilize, and Ting electric
3 monitors measured the disturbance all the way to Chicago.¹²¹

4 **Q. Are these kinds of events limited to Virginia?**

5 A. No. Reuters reviewed disclosure filings in Texas (ERCOT) and identified "more
6 than 30 near-miss incidents since 2020, triggered by big energy users like data
7 centers and crypto miners switching offline."¹²²

8 **Q. Could this kind of event really cause a major power outage?**

9 A. Yes, according to Alison Silverstein, a former senior adviser to the chairman of the
10 US Federal Energy Regulatory Commission, who said: "What it tells us is that the
11 behavior of data centers has the potential to cause cascading power outages for an
12 entire region."¹²³

13 **Q. Why would data centers configure their uninterruptable power System (UPS)**
14 **to trip due to a voltage fluctuation that lasted only milliseconds, and how could**
15 **the data centers prevent this behavior?**

16 A. Reuters explains that the settings on the UPSs could be changed, but data centers

¹²¹ Tim McLaughlin, "Massive disconnect of power roils largest US electric grid," Reuters, July 22, 2026. Accessed on 10/1/26 at: <https://www.reuters.com/business/energy/massive-disconnect-power-roiled-largest-us-electric-grid-2026-07-22/>.

¹²² Tim McLaughlin, "Big Tech's data center boom poses new risk to US grid operators," Reuters, March 19, 2025. Accessed on 6/2/26 at: <https://www.reuters.com/technology/big-techs-data-center-boom-poses-new-risk-us-grid-operators-2025-03-19/>

¹²³ Ibid

1 are concerned with protecting their equipment from voltage variations:

2 “Many data centers are engineered by their operators to switch to
3 local generators at the smallest hint of a problem on the grid to
4 minimize the risk of an interruption to services like Google search
5 or crypto mining, according to NERC.

6 Some grid operators have proposed requiring data centers to ‘ride
7 through’ routine voltage dips without disconnecting. But data
8 center operators are opposed because of the risk of damaging
9 electronic equipment and cooling systems.

10 ERCOT last year withdrew a proposal that would have imposed
11 ride-through restrictions on data centers and crypto miners after
12 facing pushback from an industry group, the Data Center
13 Coalition.

14 The group, whose members include Amazon, Google, and Meta,
15 cited costs and the risk of damaging computer chips and cooling
16 systems exposed to fluctuating voltage levels.”¹²⁴

17 **Q. Isn’t it better to risk damage to some equipment than to risk a blackout?**

18 A. It is easy to understand the data center operator’s concern if you understand the cost
19 of the equipment at risk. Oracle’s co-CEO Clay Magouyrk recently visited the
20 construction site for the Oracle data center in Saline Twp., where he announced that
21 the electronics they will install in that data center will cost \$30-40 *billion*.¹²⁵
22 Obviously, they want to protect that huge investment.

¹²⁴ Ibid.

¹²⁵ Dustin Blitchok, “Data center news: Altman visits Saline data center, says it’s ‘huge bet’ on AI,” *Planet Detroit*, June 1, 2026. Accessed on 10/1/26 at:
<https://planetdetroit.org/2026/06/michigan-data-center-news-altman-saline/>

1 **Q. Are rules being put in place to prevent grid problems from the sensitivity of**
2 **data center UPSs?**

3 A. Grid operators are beginning to put rules in place. A recent scholarly article
4 published by arXiv explained it this way:

5 “With data centers becoming increasingly large and critical
6 electrical loads, their impact on the stable operation of the power
7 grid is becoming a major concern. Unlike traditional loads, data
8 center operations are highly sensitive to fluctuations in voltage and
9 frequency. To protect their equipment, uninterruptible power
10 supply (UPS) systems often disconnect data centers from the grid
11 at the first sign of a disturbance, switching instead to local backup
12 energy. While this ensures service continuity for the data center
13 itself, it poses a serious challenge for the grid: when such massive
14 loads disconnect simultaneously during a fault, they amplify the
15 stress on the system rather than alleviating it. The sudden reduction
16 in power demand can worsen instability and, in extreme cases,
17 contribute to cascading failures. The July 2024 event in the Eastern
18 Interconnection was a stark reminder of the dangers posed by the
19 abrupt disconnection of large data center loads during grid
20 disturbances.

21 To address this issue, power system operators are increasingly
22 requiring data centers to provide fault ride-through (FRT)
23 capabilities, which refers to the ability of grid-connected devices to
24 remain connected and continue operating during a grid
25 disturbance, commonly in the form of voltage or frequency
26 deviations from nominal values. Specifically, voltage ride-through
27 (VRT) refers to a device’s ability to remain connected during a
28 deviation in voltage magnitude for a short period of time without
29 tripping offline. Requiring data centers to remain connected will
30 ensure that the post-fault load conditions is similar to pre-fault
31 conditions. Traditionally, VRT is required for bulk generators.
32 However, due to the growing scale of data center loads, more
33 stringent VRT requirements are being proposed for data centers
34 recently.”¹²⁶

¹²⁶ Yiheng Xie, Wenqi Cui, Adam Wierman, “Enhancing Data Center Low-Voltage Ride-Through,” *arXiv*, 2026. Accessed on 8/19/26 at: <https://arxiv.org/html/2510.03867v1>.

1 **Q. Is the problem of simultaneous UPS trips similar to the problem of data center**
2 **load volatility?**

3 A. While the causes are different, the impact on the grid is similar to a rapid load
4 ramp-down; a large amount of load suddenly drops off the grid. But it is different
5 in two ways: data center load volatility goes both directions – increases as well as
6 decreases in load, and simultaneous UPS trips can be far more massive than
7 volatility in the load of a single data center, because it can involve many data
8 centers dropping off the grid simultaneously. In the Virginia example cited earlier,
9 60 data centers went off-grid simultaneously. In that case, it involved 1,500 MW of
10 load. A handful of hyperscale data centers today drop several times that much load
11 due to UPS trips.

12 **Q. Does Consumers Energy have an FRT standard for large loads?**

13 A. Apparently not yet. When asked about it in discovery, the Company seems to be
14 waiting for MISO to establish rules:

15 **Question:**

16 67. In both Texas and Virginia, data centers have simultaneously tripped off-
17 grid (switched to backup generation) in response to very brief transients on
18 the power grid, causing a sudden and dramatic drop in load. Texas as [sic,
19 “has”] recently instituted mandatory “ride-through” rules for data centers
20 (see: [https://www.utilitydive.com/news/texas-puc-approves-ride-through-](https://www.utilitydive.com/news/texas-puc-approves-ride-through-rulesdata-centers/825051/)
21 [rulesdata-centers/825051/](https://www.utilitydive.com/news/texas-puc-approves-ride-through-rulesdata-centers/825051/)).

22 a. What service requirements or interconnect standards that will apply to
23 future large load customers address UPS ride-through rules?

1 **Response:**

2 “The Company is actively engaged in the MISO Large Load Working
3 Group. Company personnel routinely participate in LLWG meetings,
4 technical discussions, stakeholder feedback efforts, and internal reviews of
5 proposed MISO tariff and process changes related to large-load
6 interconnections and reliability requirements.”¹²⁷

7 **Q. Does Consumers Energy have ramp rate standard for large loads?**

8 A. Apparently not yet. When asked about it in discovery, the Company cited tariff
9 provisions MISO proposed on August 28, 2026 for computational large loads, and
10 that the Company will require future large loads to comply with the MISO
11 requirements, NERC requirements, “or other applicable regulatory or reliability
12 authorities.” The Company also mentions that the MISO proposal sets both up-
13 ramp and down-ramp limits at 30 MW per minute.¹²⁸

14 **Q. How has DTE Electric addressed FRT and ramp rates for large loads?**

15 A. Yes, DTE Electric reports that they have set specific operating parameters,
16 including FRT and ramp rates, with both large load customers for which they have
17 executed agreements,¹²⁹ though they are not publicly available.

¹²⁷ GLREA Exhibit 2 (JR2), Company response GLREA-CE-0919, by Kurt K. LaFrance.

¹²⁸ Ibid, GLREA-CE-0921, by Kurt K. LaFrance.

¹²⁹ U-22061, GLREA exhibit 2, DTE Electric responses GLREADE-1.2a, 1.3a, and 1.4a

1 **Q. Is Consumers Energy’s monitoring of large loads suitable to data center**
2 **customers?**

3 A. It doesn’t sound like the Company’s monitoring systems are sufficiently fast at this
4 time to detect the kinds of ramp rates that large computing loads are capable of. In
5 response to discovery, the Company states that,

6 “Because the billing meter data is recorded in 15-minute intervals,
7 changes in power factor that occur for only a very brief duration,
8 such as milliseconds, are not separately identified or measured as
9 individual events for billing purposes. Instead, any such changes
10 would be reflected only to the extent that they are incorporated into
11 the interval data used to determine the customer's average power
12 factor.”¹³⁰

13 But also:

14 “The Company is actively participating in MISO's Large Load Working
15 Group and related stakeholder processes addressing ramp rates, ride-
16 through requirements, telemetry, forecasting, PMU monitoring, and
17 modeling requirements for Computational Loads. The Company will
18 continue to support development of reliability requirements necessary to
19 maintain reliable system operations as large computational loads are added
20 to the system.”¹³¹

21 **Q. Have any other jurisdictions adopted an FRT standard?**

22 A. Yes. Texas has adopted a UPS ride-through standard called NOGRR 292, “Large
23 Electronic Load Ride-Through Requirements”¹³² which addresses UPS ride
24 through of both voltage and frequency transients.

¹³⁰ Ibid, GLREA-CE-0920d, by Kurt K. LaFrance.

¹³¹ Ibid, GLREA-CE-0921ci, by Kurt K. LaFrance.

¹³² Exhibit GLREA-4.

1 **Q. What justification does ERCOT provide for implementing its FRT standard?**

2 A. The document has a section titled “Justification of Reason for Revision and Market
3 Impacts, which reads:

4 The frequency and voltage *ride-through requirements in this NOGRR are*
5 *necessary to ensure Large Electronic Loads do not present a reliability risk*
6 *to the system* by tripping when frequency and voltage excursions within a
7 specified range occur. *ERCOT has identified many events* since October
8 2022 that included Load loss from one or more LELs during a typical
9 voltage disturbance in which system protection operated as designed. As
10 LELs increase on the ERCOT System, similar events would be expected to
11 increase in magnitude and frequency, leading to frequency instability and
12 other reliability problems absent frequency and voltage ride-through
13 requirements. ERCOT has also identified ride-through risks associated with
14 other Large Loads and intends to submit a NOGRR to address those risks.
15 ERCOT anticipates that the requirements for those Large Loads could differ
16 from those proposed in this NOGRR based on differences in the technology
17 of the loads, just as ERCOT’s ride-through requirements for different
18 generating technologies differ from one technology to another.”¹³³
19 (emphasis added)

20 Note that these requirements apply only to large *electronic* loads (LELs),

21 but not other kinds of industrial customers.

¹³³ Ibid, p 1-2.

1 **Q. Does the NOGRR 292 standard, adopted in Texas, provide general guidelines,**
2 **or does it provide specific, testable standards of performance and establish**
3 **penalties for non-compliance?**

4 A. NOGRR 292 is very specific about when the customer must ride-through for both
5 frequency (section 2.6.4) and voltage (section 2.14) transients. It provides tables
6 showing how long (in seconds) the UPS must ride-through (remain on grid power)
7 depending on how severe the variation in voltage or frequency in the grid power.¹³⁴
8 The standard imposes the ultimate penalty for non-compliance: it allows ERCOT to
9 disconnect the customer:

10 “...if ERCOT determines that the operation of an LEL [Large
11 Electric Load] following a failure to comply with the requirements
12 of this Section 2.14 poses an imminent risk to local or system
13 reliability, ERCOT may require the LEL to disconnect from the
14 ERCOT System and remain disconnected until the Customer
15 representing the LEL has demonstrated to ERCOT’s satisfaction
16 that the LEL can comply with the ride-through performance
17 requirements of this Section.”¹³⁵

18 **Q. Should the Commission delay setting rules for FRT until NERC, FERC, or**
19 **MISO, or some other governing body establishes FRT standards?**

20 A. No. NERC specifically recommends that “Regulators should work with utilities to
21 address the risks posed by emerging large loads.”¹³⁶

¹³⁴ Ibid, p 3 and p 5, respectively.

¹³⁵ Ibid, p 7.

¹³⁶ NERC, “2026 State of Reliability,” June 24, 2026, p 8. Accessed on 10/1/26 at:
https://www.nerc.com/globalassets/programs/rapa/pa/nerc_sor_2026_overview.pdf

1 **Q. What has MISO proposed regarding large loads, FRT, and ramp rates?**

2 A. On August 28, 2026, MISO proposed new “Interconnection Reliability
3 Requirements for Large Loads (the “IRR Proposal”) to FERC. MISO is proposing
4 new rules that will address FTR, and ramp rates, among other issues.¹³⁷ MISO
5 distinguishes large *computational* loads from other large loads, and incremental
6 requirements of ramp rates, Phasor Measurement Unit requirements (PMU), and
7 ride-through requirements apply only to computational loads.¹³⁸ This is similar to
8 the ERCOT requirement, which applies only to large *electronic* loads.

9 **Q. How does the MISO proposal define a large computational load in its**
10 **proposal?**

11 A. MISO makes this definition in two stages, defining a large load, and then a large
12 computational load:

13 **“Large Load:** Load with Demand of 50 MW or more associated
14 with any facility or aggregation of facilities located at a single
15 substation behind one or more Point(s) of Withdrawal from the
16 Transmission System that is owned, operated, or controlled by: (a)
17 a single entity or (b) a group of entities that will coordinate with
18 respect to the profile of the Load. Large Load does not include
19 Load used exclusively for charging an Electric Storage Resource.”

20 **“Computational Load:** Large Load comprised of 25 MW or more
21 of Demand from information technology equipment, such as
22 servers, storage, and networking hardware.”¹³⁹

¹³⁷ FERC, “Filing Description for Accession Number 20260828-5278,” Transmittal Letter, p 1.
Accessed on 10/1/26 at: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260828-5278&optimized=false

¹³⁸ Ibid, p 11.

¹³⁹ Ibid.

1 **Q. What large computational load monitoring is MISO proposing?**

2 A. MISO is proposing high-resolution sampling (e.g., PMU-level > 60 samples per
3 second) to capture fast voltage, frequency, and real/reactive power changes. PMUs
4 should maintain GPS-quality tie synchronization to support system-wide
5 correlation of events and dynamic monitoring.¹⁴⁰

6 **Q. Is sampling at a rate of > 60 samples per second unreasonably fast?**

7 A. No, it sounds unreasonably *slow* to me, given that data center loads can vary wildly
8 in *milliseconds*. In contemporaneous case U-22061, DTE Electric responded to our
9 discovery on the subject, testifying that: “The meters DTE currently utilizes for
10 primary service customers samples at a rate of 1024 samples per cycle or roughly
11 61,440 samples per second.”¹⁴¹ (emphasis added) Clearly PMUs with much higher
12 sample rates than MISO’s proposed minimum sample rate are available.

13 **Q. When will the MISO proposals for large computational loads take effect?**

14 A. MISO has requested an effective date of December 4, 2026, but we don’t know if
15 FERC will grant that implementation date.

¹⁴⁰ Ibid, p 18.

¹⁴¹ U-22061, GLREA Exhibit 2, p 12 of 43, GLREADE-1.3f by M. Witkowski.

1 **Q. What should the Commission order with regard to fault ride-through (FRT),**
2 **ramp rates and PMU?**

3 A. Prior to energizing a large computational load, having FRT rules, ramp rate limits,
4 and *PMU & telemetry* in place are essential for reliability of the grid. The
5 Commission should order the Company, in the event that it is going to energize a
6 large computational load customer before the MISO proposals (or similar rules) are
7 in effect, to have Company FRT policies and ramp rate limits in place, with
8 sufficiently high-speed and highly synchronized PMU in place to ensure
9 compliance. It would be imprudent to turn up a large computational load without
10 these steps in place, just because MISO rules were not yet in enacted.

11
12 **IV. DATA CENTERS ARE UNIQUE CUSTOMERS**

13 **Q. In what way are data centers a unique load?**

14 A. Multiple aspects of data centers make them a unique load, including:

- 15 1. The risk that a data center's load will not materialize – potentially causing stranded
16 assets.
- 17 2. Their 24-hour/day and 365 day per year (24x365) load profile.
- 18 3. The rate at which new data centers are being proposed greatly exceeds any historical
19 load increase, which strains electric utilities' ability to grow capacity fast enough.
- 20 4. Data center developers are not like other customers. They have declared a willingness
21 to pay their full impact to the grid, and demonstrated this willingness by the special
22 contracts they have signed with DTE Electric (see U-21990 and U-22058).

1 5. Data center UPS systems may simultaneously trip the data center off-grid in response
2 to transient grid fluctuations, resulting in grid voltage and frequency instability,
3 possibly even resulting in cascading blackouts.

4 6. Data centers doing AI training have loads that vary wildly in less than a second, which
5 can cause frequency deviations.¹⁴²

6 7. Data centers have unique legal obligations under State law.

7 I will address each of these differentiators in order.

8 **Q. Why do data centers present a greater risk of stranded grid assets than typical large**
9 **industrial loads?**

10 **A. According to the Company:**

11 “...data center hardware needs to be refreshed more often than other
12 typical manufacturing equipment, and data centers have the ability to
13 easily transfer their functions to locations outside of Michigan. She states
14 that other differences from typical large industrial customers are that data
15 centers do not develop local supply chains and do not create significant
16 local commercial activity or employment. Ms. Connolly opines that these
17 differences present a greater risk for stranded assets.”¹⁴³

¹⁴² Chuck Ross, “It’s Not Just the Load: A.I. data center grid impacts,” *Electrical Contractor*, January 15, 2026. Accessed on 5/27/26 at: <https://www.ecmag.com/magazine/articles/article-detail/it-s-not-just-the-load--a.i.-data-center-grid-impacts>

¹⁴³ U-21859, Commission order dated November 6 2025, p 13.

1 ABATE has made similar observations:

2 “[b]eyond their size, it is the relatively new and immediate scale of their
3 proliferation, their specific operating characteristics, and their limited
4 operational ties to their localities that make them unique. As such they
5 present specific stranded cost concerns which are not present with other
6 types of large customers, such as industrial or manufacturing entities....
7 While a sizable manufacturing facility entails a local workforce and
8 supply chain commitments which ground it in its location, data center
9 customers have none of these locational attachments.”¹⁴⁴

10 I agree with their assessments. These characteristics, along with the huge
11 size of their loads, are why tariff terms such as long contract duration, minimum
12 payments, and exit fees are essential. But these are not the only characteristics
13 that make data center loads unique.

14 **Q. How do the planning and forecasting of large computing loads differ from typical**
15 **large industrial loads?**

16 A. New data centers differ in both scale and speed from new industrial facilities. Load can
17 materialize in 18-36 months, which is faster than new industrial facilities and faster than an
18 electric utility can get a new gas-fired plant approved, permitted, built, and
19 interconnected.¹⁴⁵ Load planning for data centers requires a different process.¹⁴⁶ This has
20 led to data center developers’ willingness to work with electric utilities in ways large
21 industrial customers have not. Recently, Microsoft filed a protest with FERC that the
22 transmission company’s Large Load Project Commitment Agreements and Minimum

¹⁴⁴ Ibid, p 60.

¹⁴⁵ “How Should Utilities Prepare for Rapid Data Center Load Growth?” *Ascend Analytics*, March 16, 2026. Accessed on 8/3/26 at: <https://www.ascendanalytics.com/blog/best-practices-utilities-managing-data-center-demand>

¹⁴⁶ Emeka Obikwelu, “The New Large-Load Compact,” *Power Magazine*, July 14, 2026. Accessed on 8/3/26 at: <https://www.powermag.com/the-new-large-load-compact/>

1 Transmission charge agreements are deficient and provide insufficient customer protection,
2 citing its status as a signatory to the White House's Ratepayer Protection Pledge.¹⁴⁷ The
3 customer is asking for tougher terms and conditions!

4 **Q. How do Data Center developers work with electric utilities differently from typical**
5 **large industrial customers?**

6 A. Data center developers have repeatedly declared that they are willing to pay the full costs
7 of their impact to the grid.^{148,149} In U-21990 and U-22058, Oracle and Google each
8 provided substantial funding for network assets to be owned and operated by the utility
9 (DTE Electric). This is not behavior we normally see in other customers. One analyst put it
10 this way:

¹⁴⁷ Ethan Howland, "Microsoft, PowerHouse Hillwood dispute data center service agreements." *Utility Dive*, August 24, 2026. Accessed on 8/25/26 at: <https://www.utilitydive.com/news/microsoft-powerhouse-hillwood-data-center-service-ferc/828566/> and also "Microsoft Protest ATC Transmission 205 Filing (ER26-3265)," posted 8/21/26, p 2, accessed at:

https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260821-5282&optimized=false.

¹⁴⁸ Sonal Patel, "White House Expands Data Center Ratepayer Pledge as Congress Moves to Codify Protections," *Power Magazine*, July 23, 2026. Accessed on 8/3/26 at: <https://www.powermag.com/white-house-expands-data-center-ratepayer-pledge-as-congress-moves-to-codify-protections/>.

¹⁴⁹ Kinsey Grant Baker, "Anthropic to cover 100% of grid upgrade costs, demand-driven price hikes from data centers," *Energy Central*, February 12, 2026. Accessed on 8/3/26 at: <https://www.energycentral.com/customer-engagement-experience/post/news-anthropic-to-cover-100-of-grid-upgrade-costs-demand-driven-price-qbmOHOLAdave6KO>.

1 “...data centers have more strategic options than many earlier industrial
2 loads. They can sign long-term power purchase agreements, co-locate with
3 generation, install backup generation and batteries, build private
4 substations, participate in demand response pilots, or shift some workloads
5 across time and geography. These options do not eliminate the need for
6 reliable grid service, but they change the bargaining relationship between
7 customer and utility.”¹⁵⁰

8 **Q. How does the response of large computational loads to brief grid disturbances differ**
9 **from typical industrial loads?**

10 A. As I discussed earlier in this testimony, large computational loads are concerned with
11 protecting their extremely expensive electronic equipment from power quality issues; their
12 UPS settings can cause their load to trip off the grid (to run on backup power) during
13 minor grid disturbances. There have been numerous documented cases of this behavior,
14 some involving dozens of data centers dropping off-grid simultaneously. National Energy
15 Reliability Corporation’s (NERC’s) Large Load Working Group report went into extensive
16 discussion of the negative impacts that data center’s tendency to trip off can have on the
17 grid. UPS trips can negatively affect frequency stability, rotor angle stability, and voltage
18 stability.¹⁵¹

19 **Q. How does the load profile of data centers differ from typical industrial loads?**

20 A. The load profile of a data center is unusual because these facilities typically run
21 24x7x365. Most industrial facilities have downtime at night, and/or weekends, and/or

¹⁵⁰ Morgan Bazilioan, “How Artificial Intelligence Data Centers Are Reshaping the Regulatory Architecture of U.S. Electricity,” *AI Energy*, 2026. Accessed on 8/3/26 at: <https://www.aixenergy.io/how-artificial-intelligence-data-centers-are-reshaping-the-regulatory-architecture-of-u-s-electricity/>.

¹⁵¹ “Characteristics and Risks of Emerging Large Loads: Large Load Task Force White Paper,” *NERC*, July 2025, p 22-8. Accessed on 8/3/26 at: <https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf>.

1 holidays.

2 As I discussed earlier in this testimony, the load profile of data centers is unique
3 because their load can rise to contracted capacity (or even above it) and plunge to a small
4 fraction of contracted capacity in sub-second time intervals, repeatedly, over minutes and
5 hours. Quoting former Secretary of Energy Granholm again:

6 “One of the least understood aspects of the AI-data-center boom is not the size of
7 the load ... it’s the *volatility of the load*.

8 Utilities have historically treated data centers as large but relatively flat
9 demand sources — closer to steady industrial load than to highly dynamic
10 systems... And unlike traditional utility planning assumptions, these
11 changes may occur in seconds — or subseconds — rather than over hours.

12 This matters because the grid was largely designed around gradual load
13 ramps, predictable industrial demand and hourly planning models...

14 AI infrastructure may require a different architecture...”

15 AI changes that.”¹⁵² (emphasis added)

16 In addition to the contract conditions needed to prevent stranded assets, a tariff for
17 data centers needs to include limitations about ramp rates, for both ramp-up and ramp-
18 down speeds (MW/minute). Computational load does not behave like industrial load. On
19 May 4 of this year, the National Energy Reliability Corporation (NERC), issued a level 3
20 alert, escalating its prior level 2 alert because it

21 “...found that entities generally did not have sufficient processes,
22 procedures, or methods to address risks associated with computational
23 loads. This contrasts with the robust historical experience with traditional
24 non-power electronic non-computational load. As seen in the public
25 report, NERC found specific deficiencies with the treatment of
26 computational loads.”¹⁵³

¹⁵² Jennifer Granholm, *LinkedIn*, 2026. Accessed on 9/29/26 at:
https://www.linkedin.com/posts/jennifergranholm_one-of-the-least-understood-aspects-of-the-activity-7458242574542327808-bZoX/

¹⁵³ “Essential Action to Industry Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control,” *NERC*, May 4, 2026. Accessed on 8/3/26 at: <https://www.nerc.com/globalassets/programs/bpsa/alerts/level-3-computational-load-alert.pdf>

1 The alert requires transmission entities to acknowledge the alert by August 3, 2026.
2 The alert requires transmission entities to collect a variety of data about data centers,
3 including “electrical size and power factor,” “dynamic characteristics” (UPS ride-through),
4 “expected ramp rate (MW/min) in down-ramp and up-ramp,” “protective devices,” “on-site
5 generation,” and other information.¹⁵⁴ NERC has also modified its organization
6 registration manual to require every “Computational Load Entity (CLE)” to register with
7 NERC.¹⁵⁵ NERC had previously issued a white paper on large loads, which described how
8 AI training can create rapid load ramps, both up and down. Using a “high-speed recorder”
9 on a 50 MW block of a Google data center, ramp speed was measured and recorded, with
10 approximately 40% of load ramping up or down in 250 milliseconds.¹⁵⁶

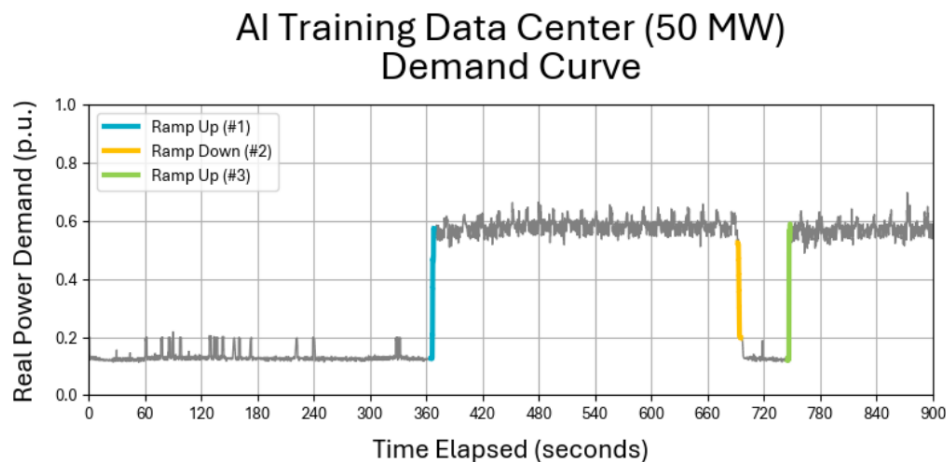


Figure 2.2: An AI Training Data Center Begins a Training Run (EdgeTunePower)

¹⁵⁴ Ibid, “Essential Action #1,” p 3-5.

¹⁵⁵ “Appendix 5A Organization Registration and Certification Manual,” NERC, p 1. Accessed on 8/3/26 at: <https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/proposed/appendix-5a-redline-to-last-approved---april-2026-posting.pdf>.

¹⁵⁶ “Characteristics and Risks of Emerging Large Loads: Large Load Task Force White Paper,” NERC, July 2025, p 6-7. Accessed on 8/3/26 at: <https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf>.

Chapter 2: Characterization of Large Loads

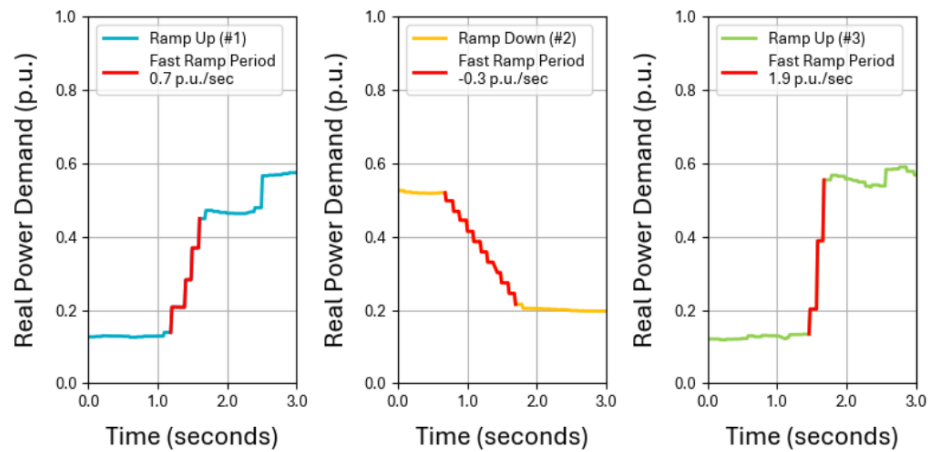


Figure 2.3: Zoomed-In Views of AI Training Data Center Ramping Up and Down Due to Transitioning Between Training and Saving Checkpoint Progress

NERC's large load working group recommended that:

“Several other factors, such as *load ramp rates*, real-time behavior and flexibility, protection systems, and backup power schemes, *should be considered if a large load definition is developed for regulatory procedures or policies*. Some of the additional factors for consideration are described below.”¹⁵⁷ (emphasis added)

¹⁵⁷ Ibid, p 11.

1 **Q. What risks to the reliable operation of the grid has NERC attributed to high load**
2 **ramp-rates?**

3 **A. NERC says that these rapid swings in load can cause issues with frequency regulation, and**
4 **trigger outages:**

5 “Large load ramp rates may cause issues with frequency regulation by
6 outstripping the reserves held to regulate frequency. These reserves are
7 provided by on-line spinning resources with headroom to manage a
8 decrease in frequency and units that can further lower their output to
9 manage an increase in frequency. With larger ramp rates, more regulation
10 services will be needed to handle larger swings... If the system operator
11 fails to procure adequate regulation to manage frequency, then load shed
12 or rapid generation curtailment may take place and result in unplanned
13 outages, reducing system security/reliability. In addition to the loss of
14 load, the sudden restoration of a large load could exhaust available
15 balancing reserves, ultimately leading to decreased system frequency and
16 potential frequency instability. Large rapid changes in demand will also
17 rapidly alter the flow of reactive power in the system, potentially
18 exceeding the ability of existing voltage controls to respond and lead to
19 over- and undervoltage conditions. This could lead to the unplanned
20 outages of generation plants initiated by voltage-ride through protection,
21 load loss related to undervoltage load shedding, or even more widespread
22 outages caused by voltage instability and collapse.”¹⁵⁸

¹⁵⁸ Ibid, p 20.

Q Have other jurisdictions recognized that data centers require special regulatory treatment?

A. Yes. Oregon enacted a law that has special rules for data centers. It defines data centers using code 518210 of the 2022 North American Industry Classification System (“Computing Infrastructure Providers and Web Hosting.”)¹⁵⁹ It requires the PUC to create a separate tariff for these customers, with specific terms and conditions. Also, the Georgia PSC has issued a series of orders on data centers, including a provision to ensure that data center revenue *reduces* residential bills.¹⁶⁰

Q Has the MISO recognized that data centers are a unique kind of load?

A. Yes. On August 28, 2026, MISO proposed new “Interconnection Reliability Requirements for Large Loads (the “IRR Proposal”) to FERC. In the IRR proposal, MISO distinguishes large *computational* loads from other large loads, and incremental requirements of ramp rates, Phasor Measurement Unit requirements (PMU), and ride-through requirements apply only to computational loads.¹⁶¹ The proposal provide the following definition and justification:

“This filing also proposes a new definition of Computational Load in order to further support the consistent interpretation of the proposed reliability framework described in this filing, as follows:

¹⁵⁹ Kevin Hardy, “With electricity bills rising, some states consider new data center laws,” *Stateline*, February 5, 2026. At: <https://stateline.org/2026/02/05/with-electricity-bills-rising-some-states-consider-new-data-center-laws/> linked to: “House Bill 3546”, *Oregon Legislative Assembly*, 2025. Accessed on 8/3/26 at:

<https://olis.oregonlegislature.gov/liz/2025R1/Downloads/MeasureDocument/HB3546/Enrolled>

¹⁶⁰ “Data Center Fact Sheet,” *Georgia Public Service Commission*, March, 2026. Accessed on 8/3/26 at: <https://psc.ga.gov/site/downloads/datacenterfactsheet.pdf>

1 **Computational Load:** Large Load comprised of 25 MW or
2 more of Demand from information technology equipment,
3 such as servers, storage, and networking hardware.

4 As explained by Ms. Li, the Computational Load definition distinguishes a
5 subset of Large Loads that may exhibit operational characteristics
6 different from more traditional loads, including rapid changes in demand,
7 highly coordinated control behavior, and power-electronic responses
8 during system disturbances. This distinction allows MISO to apply certain
9 incremental requirements - such as Ramp, PMU, and Ride-Through
10 requirements—only where those characteristics warrant additional
11 reliability consideration. *The Computational Load definition is necessary*
12 *as certain proposed requirements are intended to apply only to Large*
13 *Loads with operating characteristics that warrant additional reliability*
14 *consideration.* Computational Loads may exhibit rapid and coordinated
15 changes in demand, significant power-electronic behavior, and distinct
16 responses to Transmission System disturbances. Defining Computational
17 Load supports a more targeted and risk-informed approach, rather than
18 applying the same requirements to all Large Loads regardless of facility
19 type or operating behavior.”¹⁶² (emphasis added)

20 **Q Has the Commission recognized that data centers are a unique industry?**

21 A. Yes. In U-21859, the Commission stated, “As Consumers makes clear in its application,
22 data centers are a unique industry with characteristics that differ significantly from other
23 commercial and industrial enterprises.”¹⁶³

24 **Q. What characteristics of data centers has the Commission recognized as unique?**

25 A. The Commission has recognized several characteristics that make data centers unique:

- 26 1. The load “presents unique and significant cost implications.”¹⁶⁴

¹⁶¹ FERC, “Filing Description for Accession Number 20260828-5278,” Transmittal Letter, p 11. Accessed on 10/1/26 at: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260828-5278&optimized=false.

¹⁶² Ibid, p 11.

¹⁶³ U-21859, Commission order dated November 6, 2025, p 10 and p 103.

¹⁶⁴ U-21859, Commission order dated March 13, 2025, p 3.

2. The magnitude of the potential stranded costs.¹⁶⁵

3. The risk of cross-subsidization.¹⁶⁶

4. "... unprecedented character, including the high load factor, 24/7/365 demand profile, and the fact that the vast majority of new generation and transmission investments will be driven by such a small number of discrete loads."¹⁶⁷

Q. What has the Commission said about the data center and the large load tariff?

A. In U-21859, the Commission ordered that the large load tariff should be end-use neutral, explaining:

"...eligibility should be end-use neutral, rather than applied only to data center customers. The Commission agrees with the Staff that the end-use at issue here does not involve a unique type of *service such as that required for metal melting* or electric vehicle charging, but that the size itself is the unique feature that must be addressed."¹⁶⁸ (emphasis added)

Q. Do you agree with that Commission finding that the large load tariff should be end-use neutral?

A. No. Firstly, in the NERC Large Load report, under the section on "Power Quality" and the sub-section "Voltage Fluctuations," the report discussed how electric arc furnaces (metal melting) induce voltage fluctuations into the bulk power system. The next two sentences are: "Some new large electric loads, such as cryptocurrency miners and *AI data centers*, also have the potential to introduce significant voltage fluctuations to the supply system.

¹⁶⁵ ¹⁶⁵ U-21859, Commission order dated November 6, 2025, p 10.

¹⁶⁶ Ibid, p 103-4.

¹⁶⁷ Ibid, p 116.

¹⁶⁸ Ibid, p 106.

1 This can be attributed to the significant variation in the load profile of these loads”¹⁶⁹
2 (emphasis added). Contrary to the statement in the Commission order, data centers as an
3 end-use **do** involve issues similar to metal melting.

4 For all of the reasons described above, and perhaps additional reasons that other
5 intervenors in the instant case will identify, data centers require different tariff terms and
6 conditions, different power quality monitoring equipment, and different operational
7 methods and procedures than other end-uses. The State Legislature has given the MPSC
8 legal obligations specific to data centers.

9 **Q. What determines if a group of customers constitute a separate customer rate class?**

10 A. According to the National Associations of Regulatory Commissioners (NARUC):

11 “... the customers served by the utility are separated into several groups
12 based on the nature of service provided and *load characteristics*. The three
13 principal customer classes are residential, commercial, and industrial. It
14 may be reasonable to subdivide the three classes based on characteristics
15 such as *size of load*, the voltage level at which the customer is served, and
16 other service characteristics such as whether a residential customer is all-
17 electric or not.”¹⁷⁰ (emphasis added)

18 Both the MISO proposal and the MPSC currently define large load customers
19 based on the size of the load. However, the MISO proposal classifies large *computing*
20 loads based on their end-use, because that end-use has different load and service
21 characteristics.

¹⁶⁹ “Characteristics and Risks of Emerging Large Loads: Large Load Task Force White Paper,” NERC, July 2025, p 32-6. Accessed on 8/3/26 at: <https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf>

¹⁷⁰ NARUC, “Electric Utility Cost Allocation Manual,” January 1992, p 22. Accessed on 9/27/26 at: <https://www.scribd.com/document/579704094/NARUC-Electric-Utility-Cost-Alloc-Manual-Jan-1992>

1 **Q Does the MPSC have statutory obligations regarding data centers, which it does not**
2 **have for other industrial customers?**

3 A. Yes. Michigan statute restricts data centers from using tariffs available to some other
4 industrial customers, and requires that data centers **not** use “A rate that causes residential
5 customers to subsidize the costs incurred to provide electric service to the facility.”¹⁷¹
6 Although the ratemaking process normally assigns costs to the customer *class* that causes
7 them, the legislature has given the Commission a specific legal obligation to ensure that
8 residential customers do not subsidize *any particular data center facility*. This regulatory
9 treatment of data centers is mandated by Michigan law.

10 **Q Do the statutory requirements in MCL 205.54ee(10) apply to all large computational**
11 **loads based in Michigan?**

12 A. Not necessarily, but we can’t tell immediately. The rules apply to an “enterprise data
13 center,” which is defined by meeting about nine different qualifications spelled out in the
14 statute. Some qualifications will clearly be met by any computational large load. Others
15 may not. One of the qualifications is a certification that the building meets green building
16 standards by The Michigan Strategic fund, within 3 years of being placed in service.¹⁷²
17 Therefore, at the time a new computational large load is placed into service, we cannot
18 know if it is subject to the requirement that it is not provided on “a rate that would result in
19 a subsidy from residential customers.”

¹⁷¹ MCL 205.54ee(10)(e)(x)(C).

¹⁷² MCL 205.54ee(10)(e)(vii).

1 **Q. What action should the Commission take, due to the unique qualities of large**
2 **computational loads, and the unique legal requirement regarding their rates?**

3 A. It would be reasonable and prudent to put large computational loads in their own customer
4 rate class. This would be consistent with NARUC guidelines and would not blend the
5 allocation of costs of large industrial customers with varying load profiles and large
6 computing customers with 24x365 load profiles into one rate class bucket. However, due
7 to the legislative directive, the Commission should consider putting each large computing
8 load customer into a separate customer rate class; that way each rate case will
9 automatically provide usage and revenue figures for each large computing load, allowing a
10 demonstration that costs did not exceed revenues. Such a demonstration would be much
11 more difficult if the usage and revenue of all large loads were lumped together.

12 **V. ALLOCATIONS AND RATES FOR DATA CENTERS**

13 **Q. What direction did the Commission give Consumers Energy as to how it should**
14 **illuminate the effect of the new data centers on rates in the future?**

15 A. In U-21859, the Commission directed the Company to provide six specific cost-of-service
16 (COS) studies, five of which include the data centers, and one which (study 4) excludes
17 them, in its next rate case (which is the instant case). The Company has provided those
18 COS studies for the first five in exhibits A-80 through A-84, and states that the sixth was
19 identical to the fifth.

1 **Q. What assumptions did the Company make in preparing the COS studies requested by**
2 **the Commission?**

3 A. The Company assumed the addition of a 1 GW large load customer, with a 90% load
4 factor. The Company assumed the additional load would be served with a PPA, and used
5 cost data from a PPA they executed in 2025. The Company assumed the customer would
6 pay for any upgrades to the distribution system that their service required, and that
7 transmission costs would increase in proportion to their existing load/transmission
8 expenses.

9 **Q. What were the results of the five COS studies Consumers Energy provided?**

10 A. Company exhibit A-64 shows the rates approved in U-21859 (study 4) and compares them
11 to rates under the four other study assumptions, which include a new 1 GW data center.
12 The exhibits show that residential, primary class, and secondary class customers would
13 have lower rates under any of the four studies with a data center included, than those in
14 study 4. In other words, the major customer classes would all benefit from the addition of
15 a large load customer

16 **Q. Do you agree with the results of the Company's COS studies?**

17 A. The study appears thorough, but I cannot opine on the reasonableness of the assumptions
18 on which it is based.

19 **Q. Have there been studies that show that traditional ratemaking results in cost-shifting**
20 **from large computing load customers to other customers?**

21 A. Yes, there have been several:

1. “Extracting Profit from the Public: How Utility Ratepayers Are Paying for Big Tech’s Power,” by Harvard Law School
2. “Retail Electricity Price Trends and Drivers: Data Update-2026 Edition” by Lawrence Berkeley National Laboratory and the Brattle Group
3. “AI Data Centers Are Sending Power Bills Soaring,” by Bloomberg News
4. “What Happens When Data Centers Come to Town,” by The University of Michigan
5. “Processing Power: The Effect of Data Centers on Wholesale Electricity Markets,” by The Federal Reserve Bank of Dallas

I will discuss each of these studies in turn.

Q. What did the Study by Harvard Law School say about data centers and electric rates?

A. The executive summary summarizes the problem of utility incentives and the power of the utilities to control the relevant data:

“Regulated utility rates reimburse utilities for their costs of providing service and provide an opportunity to profit on their investments in new infrastructure. This age-old formula was designed to motivate utility expansion so it would meet society’s growing energy demands. The sudden surge in electricity use by data centers - warehouses filled with power-hungry computer chips - is shifting utilities’ attention away from societal needs and to the wishes of a few energy-intensive consumers.

Utilities’ narrow focus on expanding to serve a handful of Big Tech companies, and to a lesser extent cryptocurrency speculators, breaks the mold of traditional utility rates that are premised on spreading the costs of beneficial system expansion to all ratepayers. The very same rate structures that have socialized the costs of reliable power delivery are now forcing the public to pay for infrastructure designed to supply a handful of exceedingly wealthy corporations. To provide data centers with power, utilities must offer rates that attract Big Tech customers and are approved by the state’s public utility commission (PUC). Utilities tell PUCs what

1 they want to hear: that the deals for Big Tech isolate data center energy
2 costs from other ratepayers' bills and won't increase consumers' power
3 prices. But verifying this claim is all but impossible. Attributing utility
4 costs to a specific consumer is an imprecise exercise premised on
5 debatable claims about utility accounting records. The subjectivity and
6 complexity of ratemaking conceal utility attempts to funnel revenue to
7 their competitive lines of business by overcharging captive ratepayers.
8 While PUCs are supposed to prevent utilities from extracting such undue
9 profits from ratepayers, utilities' control over rate-setting processes
10 provides them with opportunities to obscure their self-interested
11 strategies.”¹⁷³

12 The report goes on to explain the socialization of costs problem:

13 “For many utilities, their expectations about growth are now dominated by
14 new data centers. Rather than being dispersed across a utility's service
15 territory like homes and businesses, these new data center consumers that
16 are benefitting from utility expansion are identifiable and capable of
17 paying for infrastructure that will directly serve their facilities. If PUCs
18 allow utilities to follow the conventional approach of socializing system
19 expansion, utilities will impose data centers' energy costs on the public.
20 *The easiest way for utilities to shift data centers' energy costs to the public*
21 *is to simply follow long-standing practices in rate cases.”*¹⁷⁴ (emphasis
22 added)

23 The study then explains how data centers drive up the wholesale market

24 price of energy; this is a theme that is repeated in numerous studies and articles:

¹⁷³ Eliza Martin, Ari Peskoe, “Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech's Power,” *Harvard Law School, Environmental & Energy Law Program*, March 2025, p 1-2. Accessed on 8/25/26 at: <https://eelp.law.harvard.edu/wp-content/uploads/2025/03/Harvard-ELI-Extracting-Profits-from-the-Public.pdf>.

¹⁷⁴ Ibid, p 10.

1 “In much of the country, utilities procure power through markets
2 administered by non-profit corporations called Regional Transmission
3 Organizations (RTOs). Market prices are influenced by a host of factors,
4 such as fuel and technology costs, and ultimately reflect generation supply
5 and consumer demand. If supply is constrained by a data center demand
6 surge, market prices would likely increase, at least in the short term.
7 Consumers’ utility bills will include these higher power market prices.
8 PUCs can protect ratepayers from market price increases by allocating the
9 costs of higher prices to data centers. But PUCs rarely order utilities to
10 adjust the formulae that spread FERC-regulated market and transmission
11 costs to ratepayers.”¹⁷⁵

12 The report also explains how data centers can manipulate demand charges:

13 “Data centers, and many non-residential ratepayers, also face utility-
14 imposed demand charges that are tied to their peak consumption during a
15 specified month, year, or other time period. These charges are intended to
16 reflect the costs of building power systems that have sufficient capacity to
17 generate and deliver energy when consumer demand is unusually high. In
18 RTO regions, PUC-regulated data center special contracts and tariffs
19 likely reflect FERC-approved demand charges that incorporate regional
20 transmission costs and may also include costs of procuring sufficient
21 power plant capacity to meet peak demand. By reducing their energy use
22 during just a few hours of the year, data centers may be able to reduce
23 their share of regional costs that are allocated to demand charges and
24 effectively force other ratepayers to pick up the tab... Data centers and
25 other large energy users have significant incentives to forecast when this
26 peak hour will occur and reduce their consumption of utility-delivered
27 power during that hour.”¹⁷⁶

¹⁷⁵ Ibid, p 14.

¹⁷⁶ Ibid, p 18.

1 **Q. What did the Study by Lawrence Berkeley National Laboratory and the Brattle**
2 **Group say about data centers and electric rates?**

3 A. This was a broad study of the trends in electric rates (higher) and their drivers. The study
4 showed that the first and third largest drivers were “Fuel / wholesale supply, and
5 Generation CapEx.”¹⁷⁷ As I’ll discuss later in this testimony, data center demand has been
6 partly responsible for wholesale energy costs (MISO LMP). Generation CapEx is driven
7 by increasing load and supply-chain constraints (which I will discuss as data center-driven
8 later in this testimony).¹⁷⁸

9 **Q. What did the study by Bloomberg say about data centers and electric rates?**

10 A. Like other studies, it points to the impact on wholesale electric prices:

11 “The power needs of the massive complexes are rapidly driving up
12 electricity bills... A Bloomberg News analysis of wholesale electricity
13 prices for tens of thousands of locations across the country reveals the
14 effects of the AI bloom on the power market with unprecedented
15 granularity... electricity now costs as much as 267% more for a single
16 month than it did five years ago in areas located near significant data
17 center activity.”¹⁷⁹

¹⁷⁷ Ryan Wiser et al, “Retail Electricity Price Trends and Drivers: Data Update–2026 Edition,” *Lawrence Berkeley National Laboratory and the Brattle Group*, April 2026, slide 18. Accessed on 8/25/26 at: https://eta-publications.lbl.gov/sites/default/files/2026-03/retail_price_trends_2026_edition.pdf

¹⁷⁸ Ibid, slide 22.

¹⁷⁹ Josh Sual et al, “AI Data Centers Are Sending Power Bills Soaring,” September, 29, 2025. Accessed on 8/25/26 at: <https://www.bloomberg.com/graphics/2025-ai-data-centers-electricity-prices/>

1 **Q. What did the study by the University of Michigan say about data centers and electric**
2 **rates?**

3 A. One of the study's key findings is straightforward on the relationship:

4 "Increased Utility Rates: Data centers increase local electric utility rates
5 by driving up overall energy demand, which can strain grid capacity and
6 force utilities to invest in costly infrastructure upgrades. These costs are
7 passed on to residents through higher rates."¹⁸⁰

8 The report goes on to highlight the lack of accountability:

9 "When data centers are built, they raise utility rates for nearby
10 communities. As demand surges, utility companies often pass the costs of
11 infrastructure upgrades and increased energy procurement onto residents
12 and small businesses through higher rates. Many communities, especially
13 in rural or suburban areas, do not realize the connection until their
14 monthly bills spike. Companies and legislatures also withhold information
15 about the electricity and water use of data centers, preventing consumers
16 from realizing that increased utility costs are often associated with the
17 arrival of energy-intensive facilities. By keeping usage data confidential or
18 vaguely reported, corporations and policymakers avoid public scrutiny,
19 even as these facilities strain local resources... This lack of accountability
20 allows data center operators to expand rapidly while shifting the financial
21 and environmental burdens onto utility customers. As a result, many
22 residents must pay higher bills without understanding the cause, leaving
23 them unable to advocate for better regulations or compensation. The
24 financial strain caused by data centers most severely impacts lower
25 income households, whose utility bills represent a disproportionate share
26 of their income, exacerbating economic inequality in the region."¹⁸¹

¹⁸⁰ Terry Nguyen and Ben Green, "What Happens When Data Centers Come to Town?" July, 2025, p 3. Accessed on 8/25/26 at: <https://stpp.fordschool.umich.edu/sites/stpp/files/2025-07/stpp-data-centers-2025.pdf>

¹⁸¹ Ibid, p 8-9.

1 **Q. What did the Study by the Federal Reserve Bank of Dallas say about data centers and**
2 **wholesale electric rates?**

3 A. This major study was focused on the impact of data center load on wholesale energy
4 prices. It constructed hourly supply curves for generators across the US and solved for a
5 least-cost dispatch model that clears regional markets hour by hour. Simulation runs were
6 done with and without data center load. I have included this study, with the addition of
7 yellow highlighter markings, as **exhibit GLREA-3 (JR-3)**. The original report is also
8 available on the internet.¹⁸²

9 The report found that existing data centers have *already* increased wholesale
10 electricity prices by 2-6% on average, nationwide. It also finds that by 2028, data centers
11 will increase wholesale prices by 20-50%.¹⁸³ The model was able to recover historical
12 market outcomes accurately.¹⁸⁴ Three cases were run with varying amounts of announced
13 data center construction getting completed. Even in the low-end case, generation costs
14 grew 10-15%.¹⁸⁵ The report has three main findings:

- 15 1. “First, data center expansion has already increased generation costs,
16 competitive wholesale benchmark prices, and emissions in several regions. We
17 find that generation costs have increased by 5–15% from 2021-2025, depending
18 on data center utilization assumptions.”
- 19 2. “Second, the impacts of data center load are nonlinear. Because of highly
20 convex short-run supply curves, even moderate increases in load can generate
21 disproportionately large increases in marginal generation costs when the system
22 is operating near scarcity.”

¹⁸² Owen Kay, Robert Reaser, and Reid Taylor, “Processing Power: The Effect of Data Centers on Wholesale Electricity Markets,” *Federal Reserve Bank of Dallas*, March 2026. Accessed on 8/25/26 at: <https://www.dallasfed.org/research/papers/2026/wp2606>

¹⁸³ Ibid, Abstract (before page 1).

¹⁸⁴ Ibid, p 12.

¹⁸⁵ Ibid, p 23.

1 3. “Third, the forward-looking results show that the data center build-out will
2 have increasing effects on wholesale markets. Unclear forecasts on how much
3 proposed data center capacity will actually be built is a main source of
4 uncertainty, but in all scenarios tested, the model implies meaningful increases
5 in wholesale market pressure.”¹⁸⁶

6 **Q. Have other parts of the US already experienced dramatically higher loads as a result**
7 **of new data centers?**

8 A. Yes, Northern Virginia has been called “data center alley” due to the high concentration of
9 new data centers there. In 2025, Virginia had 12GW of data centers, consuming 40% of the
10 State’s electricity.¹⁸⁷ The entire PJM region has seen explosive growth in power demand.
11 Monitoring Analytics, the independent market monitor for the Eastern grid operator PJM
12 Interconnection reported that “PJM attributed almost all of this increase in the summer
13 peak load forecast to the anticipated additions in data center demand.”¹⁸⁸
14 Monitoring Analytics report shows that peak-hour demand was fairly constant from 2014 –
15 2023, varying between 138GW and 144 GW, but rose to 149 GW in 2024 (+3.2%) and 156
16 GW in 2025 (+4.9%), as shown in the table below. These are substantial increases in load
17 for a huge region. PJM’s forecasts of peak load are getting revised upwards every year,
18 projecting a peak load of 164 GW in 2027:¹⁸⁹

¹⁸⁶ Ibid, p 35.

¹⁸⁷ Global Statistics, “AI Data Center Statistics in US 2026,” in table: “US Data Center Energy by State 2026.” Accessed on 6/3/26 at: <https://www.theglobalstatistics.com/ai-data-center-statistics-in-us/>

¹⁸⁸ Monitoring Analytics, “Analysis of the 2026/2027 RPM Base Residual Auction Part A” October 1, 2025, p 8. Accessed on 5/29/26 at: https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_A_20251001.pdf

¹⁸⁹ Ibid, p 7, Table 1 & 2.

Table 1 PJM Peak Load between 2009 and 2025⁸

	Date	Hour Ending (EPT)	PJM Load (MWh)
2009	Mon, August 10	17	123,900
2010	Tue, July 06	17	133,297
2011	Thu, July 21	17	154,095
2012	Tue, July 17	17	150,879
2013	Thu, July 18	17	153,790
2014	Tue, June 17	18	138,448
2015	Tue, July 28	17	140,266
2016	Thu, August 11	16	148,577
2017	Wed, July 19	18	142,387
2018	Tue, August 28	17	147,042
2019	Fri, July 19	18	148,228
2020	Mon, July 20	17	141,449
2021	Tue, August 24	17	145,563
2022	Wed, July 20	18	144,356
2023	Thu, July 27	18	144,215
2024	Tue, July 16	18	148,890
2025	Mon, June 23	18	156,256

Table 2 Forecasted Summer Peak Load for 2022 through 2026 as reported in the recent load forecast reports⁹

Report	Forecasted Summer Peak Load (MW)					
	2022	2023	2024	2025	2026	2027
2022 Load Forecast	148,938	149,351	150,309	151,165	152,259	152,322
2023 Load Forecast		149,059	149,737	150,924	152,736	154,275
2024 Load Forecast			151,247	153,493	156,803	159,859
2025 Load Forecast				154,144	158,937	164,186

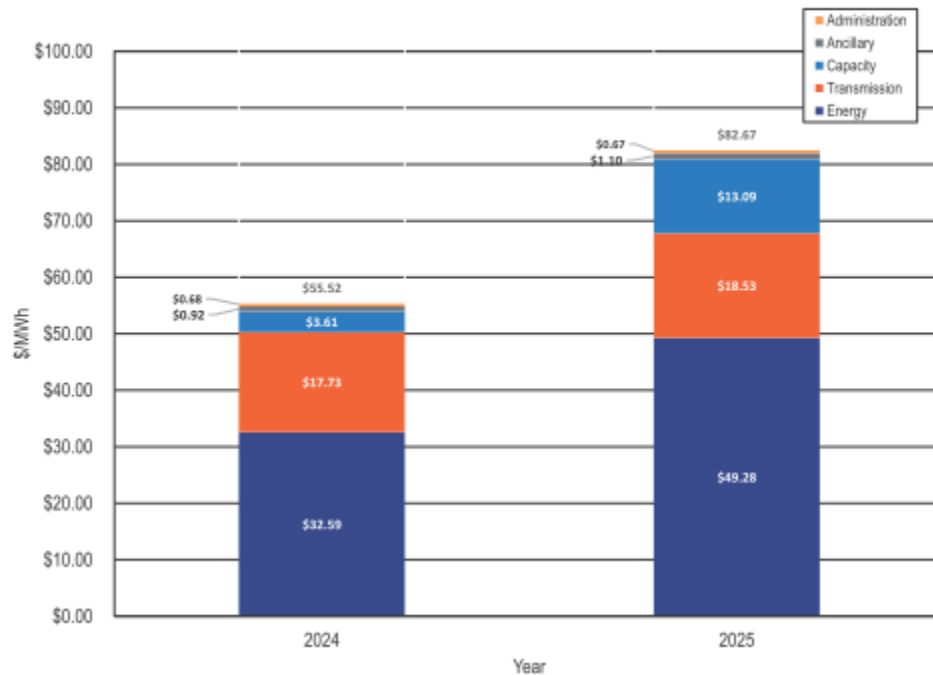
Q. Did PJM wholesale auction energy prices also increase significantly as the studies cited earlier in your testimony predicted?

A. Yes, from 2024 to 2025 the cost of wholesale energy in the PJM auctions increased from \$32.59/MWh in 2024 to \$49.28/MWh in 2025, an increase of 51.2%.¹⁹⁰ Monitoring

¹⁹⁰ Ibid, p 17, table 9, the first row labeled “Energy.”

Analytics tracks the total cost of wholesale power, which includes the cost of capacity, transmission, and ancillary services. The total cost per MWh increased by 54%. A graphic shows the contribution of each of the components to the price increase; both energy and capacity prices contributed to the overall increase:¹⁹¹

Figure 3 Total cost per MWh by category: 2024 and 2025



¹⁹¹ Ibid, p 17.

1 **Q. Is there newer data available from PJM?**

2 A. Yes. The PJM Market monitor released results for the first half of 2026 on August 13th.
3 Compared to the first half of 2025, wholesale energy prices increased 50.3%, from
4 \$76.16/MWh to \$114.50/MWh.¹⁹² The trend of higher energy prices has continued in the
5 PJM region.

6 **Q. Did the PJM State of the Market report address the cause of the increase in the**
7 **market price of energy?**

8 A. Yes, the report mentions data centers 203 times. For example:

- 9 • “Data centers are already raising energy market costs to all customers by increasing
10 load, specifically increasing the frequency of emergency high load alert events...”
- 11 • “The MMU recommends that PJM establish a load queue for large new data center
12 loads to ensure that such loads are not added until there is adequate generation capacity
13 to serve them...”
- 14 • “The growth in data center load and the expected future growth in data center load are
15 unique and unprecedented and uncertain and require a different approach than simply
16 asserting that it is just supply and demand...”
- 17 • “A significant flaw in PJM’s benefit/cost analysis is that projected benefits are based
18 on load forecasts which are currently dominated by projected large data center loads
19 that are not verified by PJM and cannot be verified by PJM. That creates a bias towards
20 finding transmission projects beneficial despite the fact that data center loads are
21 imposing transmission costs on other customers as a result...”
- 22 • “The Virginia case illustrates the imposition of transmission costs by data centers on
23 other PJM customers. These additional transmission costs are in addition to the
24 significant capacity market costs imposed on other customers by the actual and forecast
25 addition of large data centers...”

¹⁹² “State of the Market Report for PJM, January through June,” *Monitoring Analytics*, LLC, August 13, 2026, p 20. Accessed on 8/25/26 at:
https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2026/2026q2-som-pjm.pdf

- “Data center load growth affects energy market prices. Increased demand without matching energy supply puts upward pressure on prices, all else equal. It is difficult to shield customers from the costs caused by data center load growth in the energy market. The impact on the energy market is greater when data centers are added without adding corresponding generating capacity and its associated energy output, what has been termed connect and manage.”¹⁹³

Q. Is the MPSC aware of the rapid increases in the wholesale electric rates in PJM?

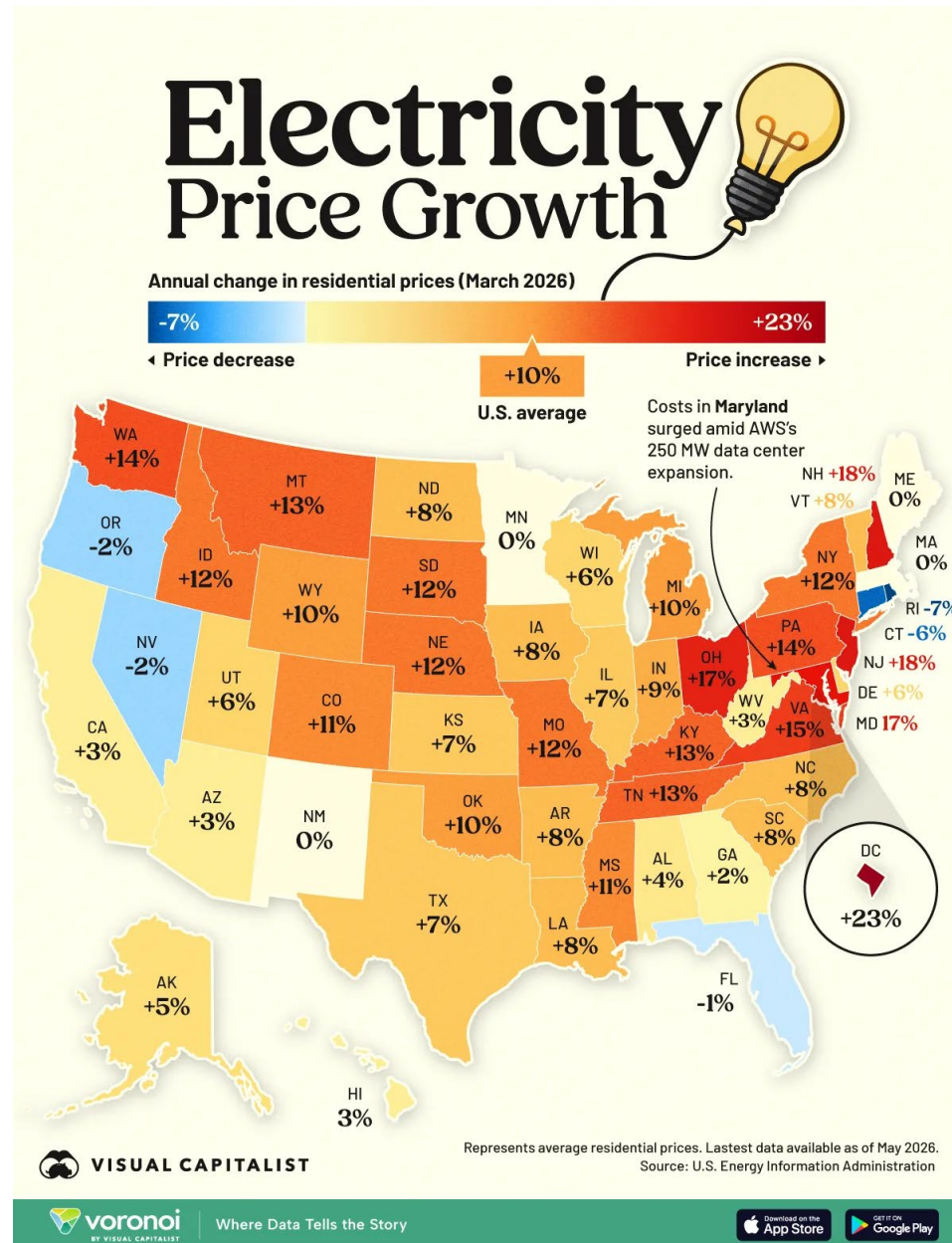
A. Someone at the MPSC is aware of the PJM *capacity* market; the MPSC website on affordability includes a graph of PJM capacity market prices over time.¹⁹⁴

¹⁹³ Ibid, p 37, 47, 52, 99, 101, 188, respectively

¹⁹⁴ “Why Utility Rates are Rising,” MPSC, undated. Accessed on 8/25/26 at:
<https://www.michigan.gov/mpsc/commission/energy-affordability-in-michigan>.

Q. Have utilities in the PJM region increased residential electric rates significantly in the past two years?

A. Yes. Here is a map showing 12-month electric rate increases in the US, as of May, 2026:¹⁹⁵



The accompanying chart shows that six of the eight states with the largest increases in electric rates are in the PJM region (at least partly); New Hampshire and Washington are not in the PJM region.¹⁹⁶

Electricity Price Growth by State

The following table shows the annual change in average residential electricity prices by state in March 2026.

10 ▾ entries per page

Search:

Rank	State	Annual Change in Residential Electricity Prices Mar 2026
1	District of Columbia	22.5%
2	New Jersey	18.2%
3	New Hampshire	18.0%
4	Maryland	17.2%
5	Ohio	16.6%
6	Virginia	14.5%
7	Washington	14.1%
8	Pennsylvania	13.6%
9	Montana	13.0%
10	Tennessee	12.8%
--	us U.S. Average	10.2%

¹⁹⁵ Dorothy Neufeld, “Mapped: Where Electricity Prices Jumped the Most in America,” *Visual Capitalist*, June 1, 2026. Accessed on 8/25/26 at: <https://www.visualcapitalist.com/mapped-where-electricity-prices-jumped-the-most-in-america/>.

¹⁹⁶ Ibid.

1 **Q. Has the MISO region seen the kind of load growth and wholesale price pressure seen**
2 **in the PJM region?**

3 A. The data center tsunami is just starting here. MISO reported that the average load in 2025
4 was 3% greater in 2025 than in 2024. However, the all-in wholesale energy price in MISO
5 went up 67% during that period to an average of \$53/MWh. This was attributed to a 58%
6 increase in the price of natural gas, and issues with transmission congestion.¹⁹⁷ But the
7 report points to a different future: “MISO projects load additions of over 16 GW by the
8 end of 2027 and an additional 11.5 GW by the end of 2030.”¹⁹⁸

9 **Q. How does the MISO wholesale energy price affect Consumers Energy electric rates?**

10 A. The impact depends on whether the Company is a net buyer or a net seller of energy. In
11 2025, Consumers Energy was a net seller of energy, so higher a MISO LMP would have
12 put downward pressure on Consumers PSCR.¹⁹⁹ However, that position could change
13 dramatically when the data centers’ load ramps up. If Consumers Energy becomes a net
14 *buyer* of energy as the MISO LMP goes up due to regional data center demand, the MISO
15 wholesale price could put upward pressure on Consumers Energy’s PSCR. This would be
16 passed on to residential customer electric bills.

¹⁹⁷ “2025 State of the Market Report for the MISO Electricity Markets,” *Potomac Economics*, June 2026, p ii. Accessed on 8/25/26 at:
<https://cdn.misoenergy.org/20260701%20Markets%20Committee%20of%20the%20BOD%20Item%202004%20State%20of%20the%20Market%20Report765607.pdf>

¹⁹⁸ Ibid, p 22.

¹⁹⁹ Exhibit GLREA-xxx (JR-2), Company response GLREA-CE-0923.

1 **Q. How does the MPSC’s historical ratemaking treat wholesale electric energy prices?**

2 A. Wholesale energy rates, and fuel costs, are treated as entirely external to the ratepayers,
3 utilities. There is no assumed causation of wholesale energy prices from a set of customers.

4 **Q. Based on the studies you quoted, and the PJM market monitor, it seems that data**
5 **center customers are causing wholesale energy rates to go up in that region; how is**
6 **that reflected in ratemaking?**

7 A. So far, ratemaking has not been altered to reflect the effect of data centers on wholesale
8 rates. Data center customer load driving up wholesale market prices is exactly what the
9 studies I cited earlier warned about, and is exactly what has happened in the PJM region. It
10 is not mere coincidence that residential rates in the PJM region have been increasing faster
11 than in most other areas.

12 **Q. What is the MPSC’s obligation regarding data centers and other customer rates?**

13 A. A relevant statute requires that an enterprise data center “facility will not take electric
14 service under any of the following rates... A rate that causes residential customers to
15 subsidize the costs incurred to provide electric service to the facility.”²⁰⁰

²⁰⁰ MCL 205.54ee(10)(e)(x)(C).

1 **Q. Would a cost-of-service (COS) study, like those in the instant case, determine the**
2 **extent to which residential customers are subsidizing data center facilities?**

3 A. I don't think so. The COS studies assume that the load of the new large load customer is
4 met with a new PPA. It does not appear to assume any change in wholesale energy costs.
5 How could it? A determination of the impact of new load on wholesale energy rates would
6 require a detailed simulation, such as the one performed for the Federal Reserve Bank of
7 Dallas, which I quoted earlier in this testimony.

8 **Q. How can the MPSC ensure that residential customers don't subsidize data center**
9 **facilities, through the wholesale energy auction mechanism?**

10 A. The study from Harvard Law explained it this way:

11 "Market prices are influenced by a host of factors, such as fuel and
12 technology costs, and ultimately reflect generation supply and consumer
13 demand. If supply is constrained by a data center demand surge, market
14 prices would likely increase, at least in the short term. Consumers' utility
15 bills will include these higher power market prices. PUCs can protect
16 ratepayers from market price increases by allocating the costs of higher
17 prices to data centers."²⁰¹

18 Protecting residential customers from the impact of data centers on MISO LMP
19 will require two steps which are not currently considered in the ratemaking process:

20 1. Noting how much net energy the electric utility buys or sells on the MISO market.

21 This is already established in PSCR cases.

²⁰¹ Eliza Martin, Ari Peskoe, "Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech's Power," *Harvard Law School, Environmental & Energy Law Program*, March 2025, p 14. Accessed on 8/25/26 at: <https://eelp.law.harvard.edu/wp-content/uploads/2025/03/Harvard-ELI-Extracting-Profits-from-the-Public.pdf>

2. Determining how much upward influence that data center customers have had on the MISO LMP. As variety of factors influences the LMP clearing price, making this determination complicated.

Q. How can the MPSC accurately determine the influence of data center load on MISO LMP?

A. That would be very challenging; the Harvard study admitted the difficulty stating: “Attributing utility costs to a specific consumer is an imprecise exercise premised on debatable claims about utility accounting records.”²⁰² The only study I’ve seen that attempted to do so was the detailed study by the Federal Reserve Bank of Dallas. That study included the whole country. Surely it could be reproduced for just the MISO region, on an annual basis.

Q. Is there an alternative to imprecise and debatable analysis of the impact of data centers on MISO LMP?

A. Yes, I can think of two. The MPSC could just ignore the issue, and let residential customers subsidize data centers, through the PSCR process. Or, the MPSC, or some higher authority, could require data centers to supply their own on-site power generation.

As I discussed earlier in this testimony, other jurisdictions are considering that approach.²⁰³

²⁰² Ibid, p 1-2.

²⁰³ There are numerous reports:

RMI: <https://rmi.org/new-ways-to-power-data-centers-and-other-large-energy-users/>

PJM: <https://www.utilitydive.com/news/pjm-ferc-behind-the-meter-data-center-colocation/812939/>

US Energy Secretary: <https://www.axios.com/2025/09/26/data-centers-energy-cost-chris-wright>

Gov of NJ: : <https://newjerseyglobe.com/governor/sherrill-proposes-guardrails-for-data-centers/>

Gov of PA: : <https://newjerseyglobe.com/governor/sherrill-proposes-guardrails-for-data-centers/>

1 **Q. What should the Commission order to protect residential ratepayers from subsidizing**
2 **data centers via the MISO LMP auctions?**

3 A. These costs are normally recovered via the PSCR process. The Commission should order a
4 new study that measures the degree to which data centers' load has increased the MISO
5 LMP rates be included in Consumers Energy's next PSCR case. The Commission should
6 then order changes to the PSCR process to apply a higher PSCR cost to data centers,
7 reflective of their impact on the MISO LMP rates.

8 **VI. DATA CENTERS ARE DRIVING UP THE COST OF EQUIPMENT**

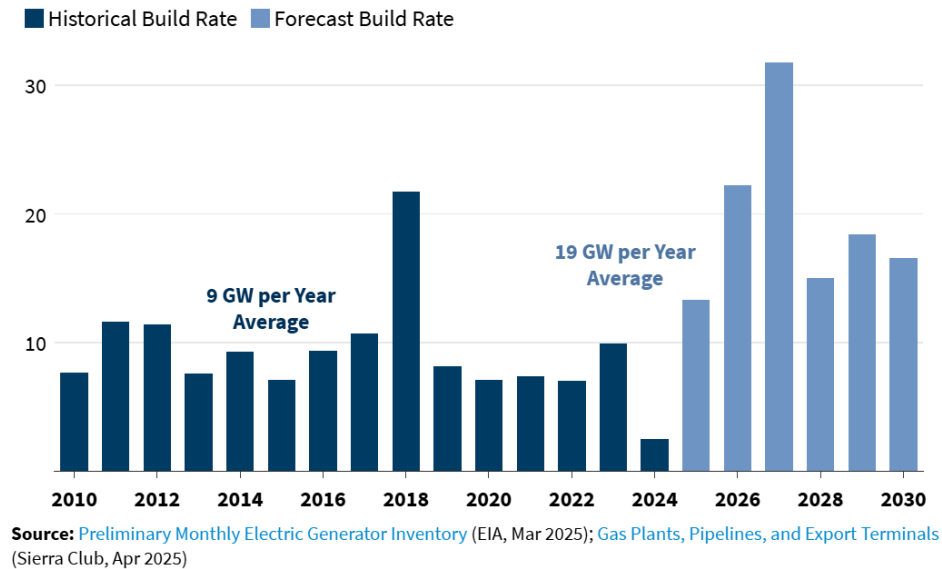
9 **Q. How do data centers impact the cost of electrical equipment?**

10 A. As I discussed earlier in this testimony, the rapid load growth driven by data centers is
11 causing the construction of huge amounts of additional generating capacity. Orders for gas-
12 fired generation tripled in 2025.²⁰⁴ Demand is expected to increase dramatically this year
13 and in 2027:²⁰⁵

²⁰⁴ Brandon Vigliarolo, "AI datacenter boom triples US gas power builds, filling the air with more CO2," *The Register*, January 29, 2026. Accessed on 6/4/26 at: <https://www.theregister.com/software/2026/01/29/us-gas-power-projects-tripled-in-2025-on-ai-demand/4388904>

²⁰⁵ Jesse Cohen, Tyler Fitch, Lauren Shwisberg, "Gas Turbine Supply Constraints Threaten Grid Reliability; More Affordable Near-Term Solutions Can Help," Rocky Mountain Institute, June 18, 2025. Accessed on 6/4/26 at: <https://rmi.org/gas-turbine-supply-constraints-threaten-grid-reliability-more-affordable-near-term-solutions-can-help/>

US gas-fired generation capacity additions (GW)



This demand surge has caused order backlogs and price increases in critical power system components, especially gas turbines:

“There are effectively only three relevant manufacturers that can produce large-scale gas turbines: GE Vernova (\$162B market cap), Siemens Energy (\$91B), and Mitsubishi Heavy Industries (\$84B). These machines sit at the center of the modern power plant. They are the hardware that converts fuel into motion and motion into electrons. Today, they are booked solid for years. GE, Siemens, and Mitsubishi are each reporting order backlogs that stretch roughly five years, with many delivery slots already sold into the next decade.”²⁰⁶

²⁰⁶ Zach Fredericks, “The gas turbine bottleneck reshaping energy infrastructure Electricity costs are rising fast, and the hardware to generate more power is suddenly scarce,” February 10, 2026. Accessed on 6/4/26 at: <https://www.primary.vc/articles/the-gas-turbine-bottleneck-reshaping-energy-infrastructure-ex8qe>

1 High demand and limited manufacturing capacity have driven up the cost of
2 building CCGT plants. According to the CEO of Next Era, from 2022 to 2025, the price to
3 build a CCGT price tripled, from \$785/kW to 2,400/kW.²⁰⁷ That's not a hypothetical
4 number or the results of a study; it's *history*. In January, GE Vernova, one of the world's
5 largest manufacturers of gas turbines, reported that they're booking orders for gas-fired
6 plants at \$2,500/kW, with prices "still rising."²⁰⁸ In 2025, utilities reported that GE
7 Vernova was charging them a \$25M reservation fee to accept orders.²⁰⁹

²⁰⁷ Nicholas Cunningham, Costs to build gas plants triple, says CEO of NextEra Energy," *Gas Outlook*, March 3, 2025. Accessed on 6/2/26 at: <https://gasoutlook.com/analysis/costs-to-build-gas-plants-triple-says-ceo-of-nextera-energy/>

²⁰⁸ Brian Martucci, "GE Vernova Q4 gas turbine orders surge 74%," *Utility Dive*, January 20, 2026. Accessed on 6/4/26 at: <https://www.utilitydive.com/news/ge-vernova-gas-turbine-orders-offshore-wind-earnings/810974/>

²⁰⁹ Grid Lab, "The new reality of power generation," September 2025, p 2. Accessed on 6/4/25 at: <https://www.utilitydive.com/news/ge-vernova-gas-turbine-orders-offshore-wind-earnings/810974/>

1 **Q. Will the price of gas turbines affect Consumers Energy’s customers?**

2 **A.** Yes. As I discussed earlier in this testimony, in its contemporaneous Integrated Resource
3 Plan (IRP) case, Consumers is proposing the addition of two new simple-cycle gas plants,
4 adding a total of 1,375 MW of capacity at a capital cost of \$3.6B.²¹⁰ This works out to
5 (\$3.6B / 1,375,000 kW) = 2,618/kW, which is even a little higher than the quote from the
6 CEO of NextEra Energy in my testimony above.

7 **Q. Are order backlogs and surging prices limited to gas turbines?**

8 **A.** No, electrical transformers also exhibit order backlogs and rapid price increases:

9 “The U.S. is grappling with a severe transformer shortage, disrupting
10 infrastructure projects and driving up costs. Lead times for power
11 transformers have surged from 30–60 weeks pre-pandemic to as long as 4
12 years, with prices increasing 60%–80% since 2020.”²¹¹

²¹⁰ U-22127, Company application initial filing, part 1, p 4, p 84, & 106.

²¹¹ Electrical Trader, “Transformer Shortages: Supply Chain Impact on Pricing,” February 2, 2026. Accessed on 6/4/26 at: <https://electricaltrader.com/blogs/news/transformer-shortages-supply-chain-impact-pricing>

This table provides a nice summary of the electrical equipment supply chain problem:²¹²

Power Transformer Lead Time Data: Current Benchmarks

Equipment Type	Average Lead Time	Price Change Since 2019	Demand Growth Since 2019
Power transformers	128 weeks	+77%	+119%
Generator step-up transformers	144 weeks	+45%	+274%
Distribution transformers	Extended but shorter	+78% to +95%	+34%
Medium-voltage switchgear	Extended	+50%	Significant

As you can see, price changes vary by type of equipment, but all of them exceed inflation. Data centers have *caused* equipment prices to go up.

Q. Doesn't the rate-making process, and the protections in the data center special contracts, protect other ratepayers from data-center induced costs?

A. No, at least not fully. Wood MacKenzie studied 20 large power users. "In almost all of those cases, the firm found, the money that large energy users paid to electric utilities would not be enough to cover the cost of the equipment needed to serve them. The rest of the costs would be borne by other utility customers or the utility itself."²¹³ Ben Hertz-Shargel, the global head of grid edge research for Wood MacKenzie explained it this way:

²¹² Wes Garrett, "Power Transformer Lead Times Hit Record Highs as U.S. Grid Equipment Shortage Deepens," *Industrial Sage*, May 6, 2026. Accessed on 6/4/26 at: <https://www.industrialsage.com/power-transformer-lead-times-us-grid-shortage/>

²¹³ Ivan Penn, "Data Centers' Hunger for Energy Could Raise All Electric Bills," *The New York Times*, May 16, 2025. Accessed on 6/4/26 at: <https://www.nytimes.com/2025/05/16/business/energy-environment/data-centers-utilities-electricity-bills.html>

1 “The policies that states and utilities have put in place will significantly
2 reduce risks of spreading the costs of improvements for the large-load
3 customers, but ‘they do not provide complete protection,’ Mr. Hertz-
4 Shargel said. ‘*Only by removing data-center-caused infrastructure from*
5 *utilities books*, such as by allowing large loads to contract with third
6 parties for generation via clean transition tariffs, are both ratepayers and
7 utility shareholders fully protected.’ ”²¹⁴ (emphasis added)

8 **Q. How will these equipment price increases affect Consumers Energy’s ratepayers?**

9 A. I’ve already discussed the Company’s proposal to add simple-cycle gas turbines. In their
10 contemporaneous IRP, the Company is also proposing to acquire over 17,000 MW of solar
11 and wind capacity by 2040.²¹⁵ Building that much solar and wind capacity is going to
12 require a lot of transformers and switchgear, the price of which has been driven up by data
13 centers. Unless ratemaking is changed significantly from its historical assumptions, these
14 added costs will be allocated across customer classes.

15 **Q. Would it be fair for data center companies in Michigan pay costs caused by data**
16 **centers built outside of Michigan?**

17 A. There are only a handful of companies responsible for the commissioning of most of the
18 data center capacity being built in the US. The list of parent-company customers in a
19 hypothetical large computing load customer class is very short. Just as rapid increases in
20 data center load have driven up PJM wholesale electric rates for the entire region, data
21 centers across the country have driven up the cost of electrical equipment for every utility
22 building new generation facilities. Consider the only alternative: would it be fair that
23 Michigan’s non-data center customers pay for costs caused by a handful of wealthy tech

²¹⁴ Ibid.

²¹⁵ U-22127, Company application initial filing, part 1, Direct Testimony of Steven Q. McClean, p 84.

1 companies? I don't think that would be fair. I don't think it's fair that residential customers
2 in PJM are paying for higher wholesale energy costs caused by data center customers
3 today; it violates the fundamental principle of cost causation. *Someone* is going to pay for
4 the cost impacts of the data centers on wholesale energy rates and on electrical equipment
5 prices. The Commission's decisions will determine *who* will pay. The costs should be paid
6 by the companies causing the costs, regardless of geography.

7 **Q. How could the Commission protect residential ratepayers from the cost of data**
8 **center-driven equipment price increases?**

9 A. Thus far, the Commission's orders on data centers have focused on preventing the costs of
10 stranded resources being passed on to other customers. This was an essential first step.
11 However, cost-of-service studies and standard cost allocations will not protect other
12 ratepayers from the *indirect* costs caused by data center demand driving up the prices of
13 MISO energy and capacity, nor the increased prices of electrical equipment and gas
14 turbines. If the Commission allocates a pro-rated percentage of the cost of new generation
15 facilities to data centers, that would protect residential ratepayers from the increase in the
16 equipment costs. The Company says that they have "1.9 GW of large load growth already
17 on the system or with executed contracts."²¹⁶ The data center customer should pay for the
18 portion of the new generating facilities required to serve it; a sufficient amount to cover
19 their demand.

²¹⁶ Ibid, application p 2.

1 **Q. What should the Commission do to protect residential ratepayers from subsidizing**
2 **the increased cost of new generation facilities required to serve the new data center**
3 **customers?**

4 A. The actual cost impact of the data center's load cannot be established based on Consumers
5 Energy's COS studies, but may be somewhat further revealed based on review of the
6 Company's contemporaneous IRP case. But the Commission's order should establish how
7 it intends to protect other customers from the increase in equipment costs and LMP, caused
8 by data center development, pending more specific data from the IRP.

9 **VII. RECOMMENDATIONS**

10 **Q. What actions should the Commission take in this case?**

- 11 1. The Commission could direct the Company to propose amendments to its emergency
12 procedures to shed the firm load of large load customers prior to shedding the firm load of
13 other customers, as it did for DTE Energy in U-21990 and changes which the Commission
14 approved in U-22059.
- 15 2. The Commission could direct the Company to propose, in its next rate case, an option in its
16 large load tariff, that specifies that the service to a large load is not firm; putting the large
17 load customer into a new two-tiered demand response (DR) program. Large loads in this
18 second tier would only be called upon after existing DR customers (tier-1) have been
19 called upon, but would not receive any reduction in their electric rates.

- 1 3. The Commission should order that Terms and Conditions added to GPD for large loads in
2 U-22061 should apply only to large *computing* loads as defined in the MISO proposal to
3 FERC discussed in this testimony. Operating parameters such as fault ride-through and
4 ramp rates would likewise apply only to large computing loads.
- 5 4. The Commission should order the Company to have Fault Ride-Through (FRT) policies
6 and ramp rate limits in place before Company energizes a large computational load
7 customer, if it plans to do so before the MISO proposals (or similar rules) are in effect. The
8 Commission should require that these policies should be backed up with sufficiently high-
9 speed and highly synchronized PMUs in place to ensure customer compliance.
- 10 5. The Commission should order the Company, in its next rate case, to implement a new
11 customer rate class for large computational loads. Alternatively, the Commission could
12 order the Company to implement a new customer rate class for each large computational
13 load customer.
- 14 6. The Commission should order a new study that measures the degree to which data centers'
15 aggregated load has increased MISO LMP prices, to be included in Consumers Energy's
16 next PSCR case. The Commission should order changes to the PSCR process to apply
17 PSCR cost to data center customers that is reflective of their impact on the MISO LMP
18 rates, whenever the Company is a net importer of energy.
- 19 7. The Commission's order should establish how it intends to protect other customers from
20 the increase in equipment costs and LMP/PSCR costs caused by data center development,
21 pending more specific data from the IRP.

1 **Q.** **Does that conclude your testimony?**

2 **A.** **Yes.**

John Richter
1529 Landings Ln
Milford, MI 48381

C: (248) 508-7051
johnrichter@pm.me

EDUCATION

Michigan State University, Institute of Public Utilities

“Accounting & Ratemaking” and “Power Grid School” courses

Murdoch University, Perth, Australia

M.S. in Renewable Energy

Oakland Community College, Rochester Hills, Michigan

Alternative Energy Technologies (Solar, Wind, Biomass)

Oakland University, Rochester, Michigan

B.S. Engineering, minor in Economics

SAT composite 1260 (98th percentile); Student Life Scholarship

Graduate studies in Software Engineering

RE EXPERIENCE

Policy Analyst, Great Lakes Renewable Energy Association (GLREA) (2020-1)

Provide expert testimony in electric utility cases before the MPSC, and represent GLREA in case settlement meetings and MPSC stakeholder groups.

Case	Utility	Case Type
U-18091	DTE Energy	PURPA (remand)
U-18232	DTE Energy	REP (reopened)
U-20165	Consumers Energy	IRP
U-20359	Indiana Michigan Power	Rate
U-20471	DTE Energy	IRP
U-20561	DTE Energy	Rate
U-20713 & U20851	DTE Energy	REP & VGP
U-21090	Consumers Energy	IRP
U-20836	DTE Energy	Rate
U-21172	DTE Energy	VGP
U-21193	DTE Energy	IRP

Adjunct Instructor, Macomb Community College (2009 – 2011)

Grant-funded curriculum development. Classroom instruction in solar energy. Online/classroom hybrid course including labs.

President and Policy Analyst GLREA (2002 – 2003)

Non-profit administration focused on financial planning, fundraising & recruitment. Staffing, budget, and strategic planning. Developed position papers on policy initiatives. Conducted a briefing entitled *Wind Power and Distributed Generation* to U.S. Congressional Staffers at the U.S. Capitol Building. Member of the MPSC collaborative on renewable energy and the Michigan Wind Working Group of the DOE’s *Wind Powering America* program.

Renewable Energy Consultant (2002-2009)

American Green Careers

Project management and meeting facilitation for a team of independent contractors for the start-up of a private school green jobs training program. Created a documented, repeatable process.

Great Lakes Renewable Energy Association

Researched, developed, and presented policy recommendations: *Opportunities for Renewable Energy Deployment* to Michigan legislators and staff.

Midwest Education Connection Network (MECNet)/Urban Options

Developed K-12 educational materials: *Michigan's Renewable Energy and Efficiency Success Stories*. This complemented materials from NEED.

American Council for an Energy Efficient Economy (ACEEE)

Researched and authored *Michigan's Current Energy Situation* section of an energy efficiency white paper for Governor Jennifer Granholm.

Speaker

Scores of speaking engagements at conferences, community colleges, and community groups for three decades, including:

- American Solar Energy Society; *Making the Benefits of RE Real* and *World Oil Depletion and Its Implications for U.S. Energy Policy*
- Pierce Cedar Creek RE Conference - Keynote speaker: *RE Cornucopia*
- PBS Documentary: *Michigan's Green Energy Economy* – extensive interview

Contributing Writer

Home Power Magazine, The Rock River Times, ReNews, Energy Paths, Energy Times

CORPORATE

Century Link Communications (formerly *Level 3*, *Global Crossing*, *Frontier*, and *EXPERIENCE Allnet Communications*), Southeastern Michigan – September 1987 to March 2002, December 2002 – May 2018

Senior Software Architect

Designed the modifications to dozens of integrated custom applications required for new product releases – quote, order, provision, bill, operational support, and customer portal.

Senior Product Development Manager

Planned, directed, and coordinated all work activities to build new services on-time and within budget. Created cross-functional project teams with members from various departments; build team commitment to project objectives. Wrote software specifications.

Director, Product Platform Development

Responsible for the selection, purchase, project management, installation, integration, and operation of multi-million dollar real-time call processing systems. Performed vendor/product evaluation, purchase negotiations and installation project management.

Managed staff of 23 Software Engineers developing real-time call processing software and integrating purchased systems.

Senior Manager of Hardware Integration

Responsible for evaluation, selection, engineering, purchase, and installation of all switching equipment and Digital Cross-connect Systems (DCS). Planned and managed annual capital budget in excess of \$25M. Negotiated pricing and payment terms, installation schedules, and acceptance testing procedures with vendors. Created network traffic forecasting model for budgetary and capacity planning.



September 21, 2026

Via Electronic Mail

Don L. Keskey
Public Law Resource Center PLLC
University Office Place
333 Albert Avenue, Suite 425
East Lansing, MI 48823

RE: MPSC Case No. U-22070 – In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief.

Dear Mr. Keskey:

Attached to this letter are copies of the following documents:

- A copy of your September 9, 2026 interrogatories with our internal numbering system annotated in the margins; and
- Consumers Energy Company's responses to 22070-GLREA-CE-0918 through 0928.

A Proof of service has been electronically filed in this docket. Please contact me if you have any questions regarding this matter.

Sincerely,

 Digitally signed by Gary
A. Gensch, Jr.
Date: 2026.09.21
09:54:04 -04'00'

Gary A. Gensch Jr.
Phone: 517-788-0698
Email: gary.genschjr@cmsenergy.com

CC Parties Per Attachment 1 to the Proof of Service

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
CONSUMERS ENERGY COMPANY
for authority to increase its rates for the generation
and distribution of electricity and for other relief.

Case No. **U-22070**

**SECOND DISCOVERY REQUEST OF GREAT LAKES RENEWABLE
ENERGY ASSOCIATION TO CONSUMERS ENERGY COMPANY**

TO: mpsc.filings@cmsenergy.com
gary.genschjr@cmsenergy.com
anne.uitvlugt@cmsenergy.com
bret.totoraitis@cmsenergy.com
evan.keimach@cmsenergy.com
Michael.rampe@cmsenergy.com
spencer.sattler@cmsenergy.com

The Great Lakes Renewable Energy Association (GLREA) serves this Second Discovery Request upon Consumers Energy Company, comprising Interrogatories and Requests for Documents. Please serve copies of all responses, attachments, and documents to GLREA counsel Don L. Keskey at **donkeskey@publiclawresourcecenter.com** and also to GLREA Experts John Richter at **johnarichter@pm.me** and Richard Boehnke at **rick.boehnke@gmail.com**.

22070-GLREA-CE-0918

66. If Consumers Energy Company (CECo) is currently in discussions with any developers of data centers (large loads), what is the approximate aggregated capacity (GW) of data center proposals under discussion?

22070-GLREA-CE-0919

67. In both Texas and Virginia, data centers have simultaneously tripped off-grid (switched to backup generation) in response to very brief transients on the power grid, causing a sudden and dramatic drop in load. Texas has recently instituted mandatory “ride-through” rules for data centers (see: <https://www.utilitydive.com/news/texas-puc-approves-ride-through-rules-data-centers/825051/>).

- a. What service requirements or interconnect standards that will apply to future large load customers address UPS ride-through rules?
- b. To what degree is CECo engaged with the MISO Large Load Working Group?
- c. Does CECo believe that the existing rules are adequate to protect grid reliability and power quality from large load customers simultaneously tripping off-grid?
 - i. If not, what actions is the Company taking to expand, strengthen, or deepen these requirements?

22070-GLREA-CE-0920

68. Some data centers have been sources of power quality problems (see: <https://flex.com/resources/power-quality-the-unseen-phenomenon-behind-some-of-the-biggest-data-center-challenges>). These power quality issues may be quite different than harmonics caused by industrial loads.

- a. Do any contractual agreements future large load customers must sign to get electric service provide CECo and its customers protection from data center induced power quality issues (including harmonics)?
- b. How does CECo measure the power factor an industrial customer causes?
- c. How does CECo conduct on-going monitoring of the power factor of industrial customers, to ensure that equipment changes the customer makes do not change their power factor below the limit?
- d. Is CECo’s measurement of customer power factor able to detect power factor changes that occur repeatedly, but for very brief durations (milliseconds)?

22070-GLREA-CE-0921

69. Data centers have demonstrated an ability to ramp load up and down very rapidly (micro-seconds). What ramp rate limits will apply to future large load customers?

- a. In what rule, contract, or agreement are these ramp rate rules defined and specified.
- b. Are there limits to how fast a large load customer may reduce load (vs. increase load)?
 - i. Is so, what are they?
- c. Is CECo confident that the existing ramp rate rules are adequate to protect the grid and other customers from large load customer's rapid ramp rates causing grid instability?
 - i. If not, what actions is the Company taking to expand, strengthen, or deepen these requirements?

22070-GLREA-CE-0922

70. In the most recent 12-months of MISO capacity auctions, was CECo a net buyer or a net seller of capacity?

- a. How much net capacity did the Company buy or sell?
- b. What was the net amount of money paid to or received from MISO?
- c. If the seasonal PRA prices had all been substantially higher during the period, would that have produced upward or downward pressure CECo customer rates?

22070-GLREA-CE-0923

71. Over any recent 12-month period, was CECo a net buyer or seller in the daily MISO energy auctions.

- a. How much net energy did the Company buy or sell over the 12-month period?
- b. What was the net amount of money paid to or received from MISO?
- c. If LMP had been substantially higher during all hours of the 12-month period, would that have produced upward or downward pressure on CECo customer rates?

22070-GLREA-CE-0924

72. What is the most recent MISO value for Cost of New Entry (CONE)?

22070-GLREA-CE-0925

73. If a customer that met the criteria for the large load tariff built on-site generation to meet part or all of their load, but still wanted to interconnect to CECo's grid, what tariff, rate sheet, or other rules would apply?

- a. Under what circumstances would such a customer be subject to standby charges, and what stand-by charges would apply?

22070-GLREA-CE-0926

74. How will the Company ensure that it has sufficient capacity to service a new large load customer before providing them service?

22070-GLREA-CE-0927

75. What steps has the Company taken to determine the likely load profile of data center customers?

- a. Has Edison Electric Institute (EEI) provided any studies or information on the load profile of data center customers?
- b. Some electric utilities service numerous data center customers. Have any of them published data-center aggregated load figures that would reveal the general load profile of this new technology (that the Company is aware of)?

22070-GLREA-CE-0928

76. Is CECo free to report a customer's energy use, load profile, and total payments, or are those figures considered confidential information?

Respectfully submitted,

Don L. Keskey

Don L. Keskey (P23003)
Brian W. Coyer (P40809)
Public Law Resource Center PLLC
University Office Place
333 Albert Avenue, Suite 425
East Lansing, MI 48823
Telephone: (517) 999-7572
E-mail: donkeskey@publiclawresourcecenter.com
bwcoyer@publiclawresourcecenter.com

Dated: September 9, 2026

U22070-GLREA-CE-0918
Page 1 of 1

Question:

66. If Consumers Energy Company (CECo) is currently in discussions with any developers of data centers (large loads), what is the approximate aggregated capacity (GW) of data center proposals under discussion?

Response:

The Company's 2026 Second Quarter Earnings Call referenced an economic development pipeline around 9 GW. This is inclusive of data centers and manufacturing.

Witness: LAURA M CONNOLLY

Date: September 17, 2026

U22070-GLREA-CE-0919

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Question:

67. In both Texas and Virginia, data centers have simultaneously tripped off-grid (switched to backup generation) in response to very brief transients on the power grid, causing a sudden and dramatic drop in load. Texas has recently instituted mandatory “ride-through” rules for data centers (see: <https://www.utilitydive.com/news/texas-puc-approves-ride-through-rulesdata-centers/825051/>).

- a. What service requirements or interconnect standards that will apply to future large load customers address UPS ride-through rules?
- b. To what degree is CECO engaged with the MISO Large Load Working Group?
- c. Does CECO believe that the existing rules are adequate to protect grid reliability and power quality from large load customers simultaneously tripping off-grid?
 - i. If not, what actions is the Company taking to expand, strengthen, or deepen these requirements?

Response:

a. The Company evaluates large-load interconnections through applicable tariff provisions, interconnection agreements, planning criteria, and reliability requirements established by NERC, MISO, and other applicable regulatory authorities. MISO and industry stakeholders are actively evaluating additional large-load reliability requirements through MISO’s Large Load Working Group (LLWG), including ride-through requirements for Computational Loads. The Company anticipates that future MISO tariff and business practice manuals will include additional requirements addressing ride-through performance and other operational characteristics of large loads.

b. The Company is actively engaged in the MISO Large Load Working Group. Company personnel routinely participate in LLWG meetings, technical discussions, stakeholder feedback efforts, and internal reviews of proposed MISO tariff and process changes related to large-load interconnections and reliability requirements.

c. The Company recognizes that the rapid growth of large data centers and other emerging loads presents new reliability considerations for transmission operators, load-serving entities, and regulators. The Company supports continued evaluation of large-load operational requirements and reliability standards through MISO stakeholder processes to ensure that planning assumptions, operating requirements, modeling standards, and interconnection requirements appropriately address the characteristics of these facilities. The Company is also monitoring NERC’s efforts to maintain system reliability and the proposed standards related to Computational Loads. The Company believes NERC efforts can complement MISO’s efforts in protecting the grid.

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c.i. The Company is actively participating in MISO stakeholder initiatives addressing large-load interconnections and reliability requirements. Through those forums, the Company is evaluating potential enhancements related to load modeling, EMT data requirements, operating agreements, interconnection readiness criteria, and operational performance expectations for large-load customers. The Company will continue to support the development of reasonable and technically justified requirements designed to maintain reliability as large-load interconnections increase across the MISO footprint.

Witness: KURT K LAFRANCE

Date: September 18, 2026

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Question:

68. Some data centers have been sources of power quality problems (see:

<https://flex.com/resources/power-quality-the-unseen-phenomenon-behind-some-of-the-biggest-data-center-challenges>).

These power quality issues may be quite different than harmonics caused by industrial loads.

- a. Do any contractual agreements future large load customers must sign to get electric service provide CEC and its customers protection from data center induced power quality issues (including harmonics)?
- b. How does CEC measure the power factor an industrial customer causes?
- c. How does CEC conduct on-going monitoring of the power factor of industrial customers, to ensure that equipment changes the customer makes do not change their power factor below the limit?
- d. Is CEC's measurement of customer power factor able to detect power factor changes that occur repeatedly, but for very brief durations (milliseconds)?

Response:

- a. Yes. Consumers Energy has both contractual and tariff-based protections to address customer-induced power quality concerns. The Facilities Agreement expressly provides that the project is subject to the Company's Rate Book and applicable electric service tariffs, including power factor requirements. In addition, agreements with large load customers require the Company to design, construct, operate, and maintain its facilities in compliance with applicable laws, regulations, tariffs, and good utility practice.

Prior to interconnection, Consumers Energy evaluates each proposed load in accordance with applicable tariff provisions, planning criteria, and reliability standards established by NERC, MISO, and other regulatory authorities. These evaluations determine the system upgrades and facility requirements necessary to ensure the proposed load can be served without adversely affecting the safety, reliability, or power quality experienced by other customers. The customer's projected demand and power factor assumptions, along with any required distribution facilities, are documented in the Facilities Agreement.

- b. The Company measures an industrial customer's average power factor during the billing period by metering the customer's kilowatt-hours (kWh) and lagging kilovar-hours (kVARh). These measurements allow the Company to determine both the amount of real power used by the customer and the amount of lagging reactive power associated with the customer's load.

The metered lagging kVARh and kWh values are used to determine the customer's average power factor for the billing period. The Company also uses the measured lagging reactive power to determine whether the customer's power factor is above or below the currently approved tariff

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standard of 0.875 for purposes of applying the power factor adjustment in the applicable rate schedule.

- c. Consumers Energy does not conduct ongoing monitoring of customer power factor for the purpose of ensuring compliance with a specific power factor threshold outside of meeting the Company's tariff language. Power factor requirements are established through the Company's tariffs and administered through billing metering. Changes to a customer's power factor resulting from equipment modifications are reflected in metered usage and addressed through the applicable tariff provisions. For customers served from dedicated substations, power quality monitoring equipment may also provide power factor information; however, it is not used as a continuous compliance monitoring program.
- d. For large customers served from dedicated substations, power quality monitoring is available in addition to the billing metering. This monitoring has the capability to provide power factor information. This information is continuously monitored, but stored in minimum, maximum and average values every 10 minutes.

For billing purposes, the Company determines a customer's average power factor using metered energy and reactive energy values recorded over billing meter intervals. These measurements are used to calculate the customer's average power factor over the billing period.

Because the billing meter data is recorded in 15-minute intervals, changes in power factor that occur for only a very brief duration, such as milliseconds, are not separately identified or measured as individual events for billing purposes. Instead, any such changes would be reflected only to the extent that they are incorporated into the interval data used to determine the customer's average power factor.

Witness: KURT K LAFRANCE

Date: September 21, 2026

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Page 1 of 2

Question:

69. Data centers have demonstrated an ability to ramp load up and down very rapidly (micro-seconds). What ramp rate limits will apply to future large load customers?

- a. In what rule, contract, or agreement are these ramp rate rules defined and specified.
- b. Are there limits to how fast a large load customer may reduce load (vs. increase load)?
 - i. Is so, what are they?
- c. Is CECo confident that the existing ramp rate rules are adequate to protect the grid and other customers from large load customer's rapid ramp rates causing grid instability?
 - i. If not, what actions is the Company taking to expand, strengthen, or deepen these requirements?

Response:

- a. MISO filed proposed tariff provisions on August 28, 2026, establishing Large Load Ramp Requirements in proposed Tariff Section 37A.7. The tariff provides that Computational Loads are subject to ramp requirements and that up-ramp and down-ramp limits will be established by MISO consistent with the process set forth in the MISO Business Practices Manual for Large Load. The tariff further provides that Computational Loads must maintain effective up-ramp and down-ramp rates that do not exceed the limits specified in the BPM unless otherwise directed by the Balancing Authority, Reliability Coordinator, or Transmission Operator.

The Company will require future large load customers to comply with applicable ramp-rate requirements established by MISO, the applicable Transmission Owner, NERC, or other applicable regulatory or reliability authorities, to the extent such requirements are necessary to maintain reliable system operations.

- b. MISO's proposal includes both up-ramp and down-ramp limits for Computational Loads.
 - b.i. MISO states in its Interconnection Reliability Requirements filing that it is proposing initial up-ramp and down-ramp limits of 30 MW per minute. The tariff does not specify the numerical values directly and instead provides that the specific limits will be established through the MISO Business Practices Manual for Large Load. However, the filing testimony explains that MISO is proposing initial up-ramp and down-ramp limits of 30 MW per minute and that ramp limits will be measured in aggregate across the applicable Point(s) of Withdrawal. MISO also proposes to allow eligible generation or other resources to provide ramp smoothing when evaluating compliance with those limits.
- c. The Company supports MISO's efforts to establish enforceable ramp-rate requirements and other Large Load reliability requirements, including telemetry, forecasting, PMU, modeling, and ride-through requirements. The Company continues to participate in the MISO stakeholder process as these requirements are finalized.

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c.i. The Company is actively participating in MISO's Large Load Working Group and related stakeholder processes addressing ramp rates, ride-through requirements, telemetry, forecasting, PMU monitoring, and modeling requirements for Computational Loads. The Company will continue to support development of reliability requirements necessary to maintain reliable system operations as large computational loads are added to the system.

Witness: KURT K LAFRANCE

Date: September 21, 2026

U22070-GLREA-CE-0922

Page 1 of 1

Question:

70. In the most recent 12-months of MISO capacity auctions, was CECo a net buyer or a net seller of capacity?

- a. How much net capacity did the Company buy or sell?
- b. What was the net amount of money paid to or received from MISO?
- c. If the seasonal PRA prices had all been substantially higher during the period, would that have produced upward or downward pressure CECo customer rates?

Response:

In 2025 CECo was a net buyer of capacity in the MISO planning resource auction.

- a. The monthly net capacity position for calendar year 2025 is shown in the table below.

2025 Capacity Position by Month	
Month	Net Capacity Position (ZRC)
January	1,311
February	1,311
March	164
April	165
May	165
June	(307)
July	(307)
August	(307)
September	(903)
October	(903)
November	(903)
December	86

- b. As shown on Exhibit A-26 (RTS-1) Revised from Case No. U-21593, the net capacity charges in 2025 was \$13,550,832.
- c. As CECo was a net buyer in the capacity market for the calendar year 2025, it is reasonable to assume a uniform increase in each season of the PRA for the year would have produced upward pressure on CECo customer rates.

Witness: JOSHUA W HAHN

Date: September 18, 2026

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Question:

71. Over any recent 12-month period, was CECo a net buyer or seller in the daily MISO energy auctions.

- a. How much net energy did the Company buy or sell over the 12-month period?
- b. What was the net amount of money paid to or received from MISO?
- c. If LMP had been substantially higher during all hours of the 12-month period, would that have produced upward or downward pressure on CECo customer rates?

Response:

As can be seen on Exhibit A-32 (SKS-1) from Case No. U-21593, the Company's 2025 PSCR reconciliation filing, CECo was a net energy seller for the year 2025.

- a. CECo was a net seller of 496,257 MWh in calendar year 2025, which is calculated by adding column (c) from lines 10 and 11 in Exhibit A-32 (SKS-1) from Case No. U-21593.
- b. The charges for net interchange to MISO was \$93,791,000 for calendar year 2025. This is calculated by adding column (c) from lines 14 and 18 in Exhibit A-32 (SKS-1) from Case No. U-21593.
- c. As CECo was a net seller in the energy market for the calendar year 2025, it is reasonable to assume a uniform increase in LMPs for all hours of the year would have produced downward pressure on CECo customer rates.

Witness: JOSHUA W HAHN

Date: September 17, 2026

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Question:

72. What is the most recent MISO value for Cost of New Entry (CONE)?

Response:

At the time of this filing the most recent MISO CONE value for the 2026/2027 planning year was \$137,510/ZRC year.

Witness: JOSHUA W HAHN
Date: September 17, 2026

U22070-GLREA-CE-0925

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Question:

73. If a customer that met the criteria for the large load tariff built on-site generation to meet part or all of their load, but still wanted to interconnect to CECO's grid, what tariff, rate sheet, or other rules would apply?

a. Under what circumstances would such a customer be subject to standby charges, and what stand-by charges would apply?

Response:

a. Any full service customer with a generating installation with a combined onsite nameplate capacity greater than 550 kW is subject to the Company's General Service Self Generation Rate GSG-2. The terms of the rate are outlined in the Company's tariff book, starting with Sheet D-81.00.

Witness: LAURA M CONNOLLY

Date: September 17, 2026

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Page 1 of 1

Question:

74. How will the Company ensure that it has sufficient capacity to service a new large load customer before providing them service?

Response:

This will be addressed through the Company's Integrated Resource Planning process.

Witness: LAURA M CONNOLLY
Date: September 17, 2026

U22070-GLREA-CE-0927

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Question:

75. What steps has the Company taken to determine the likely load profile of data center customers?

- a. Has Edison Electric Institute (EEI) provided any studies or information on the load profile of data center customers?
- b. Some electric utilities service numerous data center customers. Have any of them published data-center aggregated load figures that would reveal the general load profile of this new technology (that the Company is aware of)?

Response:

The Company has conversations with each customer about their expected load factor and usage. We use that information to model a load shape for each customer.

- a. The Company is not aware of any studies from EEI.
- b. The Company is not aware of any published load data.

Witness: LAURA M CONNOLLY

Date: September 17, 2026

U22070-GLREA-CE-0928
Page 1 of 1

Question:

76. Is CECo free to report a customer's energy use, load profile, and total payments, or are those figures considered confidential information?

Response:

Individual customer data is confidential as governed by the Customer Data Privacy rules in the Company's Rate Book.

Witness: LAURA M CONNOLLY
Date: September 17, 2026



Federal Reserve
Bank of Dallas

Processing Power: The Effect of Data Centers on Wholesale Electricity Markets

Owen Kay, Robert Reaser and Reid Taylor

Working Paper 2606

March 2026

Research Department

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Processing Power: The Effect of Data Centers on Wholesale Electricity Markets^{*}

Owen Kay[†], Robert Reaser[‡] and Reid Taylor[§]

March 17, 2026

Abstract

Artificial-intelligence-driven data centers are reversing two decades of flat U.S. electricity demand and have generated questions about how this growth will impact electricity prices. We quantify this effect using an hourly, unit-level least-cost dispatch model covering wholesale electricity markets in the continental United States. We find that existing data centers have already increased wholesale prices by 2 to 6% on average nationwide, with substantially larger effects in regions hosting major data center corridors. Extending the model through 2028, we show that if proposed construction proceeds under high-utilization scenarios, wholesale prices could rise dramatically (50%), while more moderate build-out yields smaller (20%) but still meaningful effects. Impacts vary due to utilization and build-out assumptions. Finally, we use the model to address several policy discussions including optimal data center siting decisions and renewable build-out uncertainty.

JEL code: L94, P18, Q41, Q42, Q48

Keywords: electricity prices, energy, data centers, artificial intelligence

^{*} The views expressed in this presentation are those of the authors and do not necessarily reflect the views of the Federal Reserve Bank of Dallas or the Federal Reserve System.

[†] Owen Kay, Federal Reserve Bank of Dallas, owen.a.kay@gmail.com.

[‡] Robert Reaser, Department of Economics, University of California, Davis, rreaser@ucdavis.edu.

[§] Corresponding Author: Reid Taylor, Federal Reserve Bank of Dallas, reidbtaylor@gmail.com.

1 Introduction

After nearly two decades of flat electricity consumption in the United States, load growth has re-emerged as a defining feature of power markets. A central driver of this reversal is the rapid expansion of data centers, fueled by recent advances in artificial intelligence (AI). Unlike traditional sources of demand growth, such as households, commercial buildings, or gradual electrification, data centers arrive in large, discrete increments, cluster geographically, and operate at high utilization rates. Their expansion therefore represents a qualitatively different form of load growth: concentrated rather than diffuse, persistent rather than transitory, and fast relative to the pace of generation and transmission investment.

These features matter because electricity markets are characterized by non-linear and steep short-run supply curves (Borenstein 2002). Generator outages, transmission constraints, fuel availability, and limited interconnection capacity imply that incremental demand is often met on sharply rising portions of the merit order. When supply is elastic, new load primarily increases production with modest price effects. When supply is tight, even moderate demand increases can produce large changes in generation costs, prices, and emissions. While these mechanisms are well documented in the context of weather shocks and outages, far less is known about how they operate in response to persistent, geographically concentrated demand growth such as that generated by data centers.

This paper quantifies the incremental effect of data center expansion on wholesale electricity market outcomes in the United States. We focus on three main equilibrium objects: generation costs, competitive wholesale prices, and carbon emissions. Our approach is structural. We construct hourly supply curves for conventional generators using unit-level data and estimates of capacity, outages, fuel costs, operating costs, and emissions. We then solve a least-cost dispatch model that clears regional electricity markets hour by hour. We combine this framework with detailed data on the location, timing, and power capacity of data centers to compare market outcomes to various counterfactual data center utilization scenarios.

The first part of the paper is retrospective and isolates the marginal contribution of data centers to market outcomes over the recent period of rapid expansion from 2021-2025. For each hour and region, we compute equilibrium dispatched quantities and prices under observed conditions and under alternative “no data center” counterfactuals. This comparison yields estimates of the additional generation costs, price impacts, and emissions attributable to data center demand, holding fixed contemporaneous supply conditions and inter-regional power flows. Because data center utilization is not directly observed, we evaluate a range of capacity and utilization scenarios, allowing impacts to vary with both the scale and temporal profile of computing load.

In the second part of the paper we analyze how a number of different scenarios for the data center build-out would impact wholesale electricity markets in the future. Using pre-AI-boom demand projections together with announced generation additions and retirements, we construct hourly demand and supply paths under alternative potential data center growth scenarios. These simulations characterize how future prices and emissions depend on the interaction between data center deployment, utilization patterns, and the pace of supply expansion. Importantly, these forward looking exercises are disciplined by the same dispatch framework used in the retrospective analysis, linking projected impacts directly to short-run market responses. We find that in our high-capacity demand scenario, monthly average wholesale prices increase by \$10–\$40, nationwide. Mid- and low-use demand scenarios still see sizable effects from \$5 to \$20.

Our results highlight three main findings. First, realized data center growth has already increased generation costs and wholesale prices in regions facing tight supply constraints, with effects that are nonlinear in system load. Price impacts are largest when data center demand coincides with periods of scarcity or congestion, reflecting the convexity of short-run supply. Second, these price effects are accompanied by shifts in dispatch toward higher-cost and, in many cases, higher-emissions generation, implying that data center expansion has environmental consequences even absent changes in average emissions rates. Third, counterfactual scenarios indicate that future impacts are highly uncertain and effects could be substantially larger if projected data center capacity comes online faster than new generation or transmission, particularly renewable energy

sources which currently constitute the majority of proposed capacity additions.

We use our results to discuss a number of contemporary policy issues. First, we discuss how the wholesale price effects can pass-through to end-use retail customers. Our empirical approach simulates the effects of variable costs due to data centers, but the data center expansion likely will require large investments in transmission and distribution upgrades to the grid. The effect of data centers on fixed costs is ambiguous as the large increase in demand can offset portions of the additional fixed costs, resulting in a lower average fixed cost per unit. Using some simplifying assumptions, we calculate the rate of wholesale price pass-through and the effect of data centers on the electricity component of inflation. We next explore how market integration through increased transmission is able to lower the effect of data centers by allowing cheaper, idle generation to serve demand that was previously in a separate market. Lastly, as an alternative, we explore how the spatial reallocation of data center compute can act as virtual transmission by comparing simulated outcomes to an optimal spatial allocation of compute that minimizes hourly costs of generation.

We contribute to a growing literature on the economic and environmental consequences of electricity-intensive computing infrastructure. As projections for data centers have ballooned, a number of technical reports have estimated the energy demands associated with this construction boom (Shehabi et al. 2024; Green et al. 2024). However, there have been relatively few academic studies on the economic impacts of these changes. Bogmans et al. (2025) provide quantitative projections of the effect of AI-driven data center growth on electricity prices and carbon emissions at economy-wide scale using a multi-country computational general equilibrium model. Similarly, recent work has begun to document localized wholesale price effects of data center expansion in major corridors (Mamkhezri et al. 2025; Feher et al. 2025), while related research on cryptocurrency mining, an extreme form of high-utilization computing load, finds increases in retail electricity prices with only partial fiscal offsets (Benetton et al. 2023). Other work by Gargano and Giacoletti (2025) studies the political economy of attracting data centers showing that state incentives meaningfully shift data center siting and investment, without commensurate increases in local tech employment.

In contrast to much of this earlier work, our approach constructs a detailed model of electricity supply at a precise geographic and temporal scale. This approach allows us to appropriately capture the non-linear price response to changes in demand that occurs when particular markets or times are constrained. In the most closely related work to our own, [Wade et al. \(2025\)](#) use a capacity expansions model to forecast long run effect of rising demand from data centers and crypto mining in U.S. power markets. However, they lack detailed geographic and temporal data on data centers and instead assume fixed growth rates in compute from demand. In contrast, we use detailed site-specific data on existing and proposed data centers to model the wholesale electricity market impacts at a detailed geographic and temporal level through 2028.

More broadly, our analysis underscores that the consequences of demand growth depend not only on how much electricity is consumed, but on where and when that consumption occurs and on the availability of marginal supply. Recognizing this point, a growing literature has emphasized that if demand is able to flexibly avoid congested hours and locations, impacts on wholesale markets can be mitigated ([Norris et al. 2025](#)). This literature has mostly focused on temporal flexibility and how this flexibility maybe impact which generation comes online and emissions profiles ([Knittel et al. 2025](#); [Ross and Ewing 2026](#)). In contrast, our analysis of siting decision documents how geographic flexibility in where compute occurs can provide system benefits. As data centers continue to expand, understanding these interactions will be essential for infrastructure planning, market design, and climate policy. By quantifying both realized impacts and plausible future trajectories, this paper provides an empirical foundation for those discussions.

2 Data

2.1 Electricity Supply Data

Our primary data source for electricity supply is the Environmental Protection Agency's (EPA) Continuous Emission Monitoring System (CEMS), which reports hourly electricity pro-

duction and fuel use at nearly every conventional generator in the U.S.¹ CEMS reports generator *gross* electricity production, which we convert into net production using EIA-923 data to calculate observed plant-level ratios. For each generation unit, we observe characteristics including the technology and fuel type, precise geographic location, emissions of regulated air pollutants, and coverage by environmental regulations. We calculate maximum generator capacity as the 99th percentile of observed generation. Generators are grouped into regions based on the EPA's eGRID subregions.

We closely follow Hausman (2025) and Ham et al. (2025) to construct hourly market supply curves. Generator-specific marginal costs are calculated as the sum of fuel costs, variable operations and maintenance costs, and pollution permit prices. Specifically, for generator i in hour t , the marginal cost is given by

$$MC_{it} = HeatRate_i * FuelCost_{it} + VOM_i + Permit_{it}. \quad (1)$$

The heat rate for generator i , $HeatRate_i$, is calculated from the observed data as the ratio of total fuel consumption to annual net generation.² For coal- and coke-fired generators, we use data from the EIA on state specific monthly fuel costs paid by power plants. For natural gas and oil-fired generators, we use daily fuel spot prices (Henry Hub and West Texas Intermediate) and apply a state-by-month specific markup, computed from EIA data on average fuel prices paid by power plants. We observe environmental trading program permit prices from the EPA and the Regional Greenhouse Gas Initiative (RGGI). Technology-specific O&M costs are calibrated from the EIA based on Hausman (2025). Furthermore, power plants are often offline for either routine maintenance or unexpected outages. We follow Hausman (2025); Ham et al. (2025) and uniformly derate generator capacity by the planned outage rate and stochastically apply unplanned outages to individual hours. All dollar values are inflation adjusted using the total CPI index to 2024 values.

¹CEMS comprises the universe of coal, natural gas, oil, and other combustible fuel generators with capacity over 25 MW, but not nuclear or renewable generators. Following Ham et al. (2025), we drop commercial, industrial, and cogeneration units whose main function is not selling into electricity markets.

²We censor anomalous heat rates below 4 mmBtu per MWh and above 50 mmBtu per MWh.

Table 1 provides summary statistics for the thermal generator fleet in 2025. Coal- and natural gas-fired power plants make up the vast majority of the thermal generation fleet. The range of marginal costs for natural gas units is much larger than for coal-fired units, reflecting both the volatility in gas prices and the large variance in heat rates (efficiency) coming from different technology types (combined cycle vs simple cycle). There is also a significant amount of oil-fired generation capacity but these units tend to be much higher marginal cost and are often among the last generators to be dispatched.

Table 1: Thermal Generator Characteristics Statistics

Fuel	N Units	Avg Capacity	Min Capacity	Max Capacity	Mean MC	Min MC	Max MC
Coal	368	456.6	24.6	1338.6	31.3	13.4	82.3
Coke	5	156.5	19.4	288.9	38.2	35.6	42.5
NG	2761	159.0	2.6	955.2	47.2	14.3	557.8
Oil	234	53.2	1.9	551.9	356.4	115.0	856.5

Notes: This table summarizes the capacity and marginal costs of the 3368 thermal generation units active in the lower 48 states in 2025. The unit of observation is the generator unit and the columns report the average, minimum and maximum capacity and marginal cost for unit of each primary fuel type in 2025.

2.2 Data Centers

We obtain data on the characteristics of existing and planned data centers including the precise geographic location, peak power demand (MW), operational dates, capital cost, square footage, and site acreage from the Cleanview data center tracker. The data set covers all categories of data centers.

For our model of electricity markets, we require a measure of hourly data center power demand. There are, however, three sources of uncertainty in the power demand for data centers. First, not all data centers release public information on the size of their infrastructure. Approximately 67% of data centers in our data have a reported power capacity. For those with missing power data, we impute capacity using the year of first operation and site characteristics. Second, while the maximum power demand may be known, actual utilization is unknown for all data centers. Although many data centers publicly state their intent for 100% utilization, industry reports show

real-world utilization is much lower and varies by data center type. This motivates our analysis to test the sensitivity of our results to various utilization assumptions. Lastly, some data centers have installed on-site “behind-the-meter” backup power generation and can produce their own electricity. Information on the size and utilization of “behind-the-meter” sources is not publicly reported. In our various utilization scenarios, we are agnostic as to whether the reduced utilization is due to lack of computing needs or a switch to on-site generation as they have the same impact on the electricity grid.

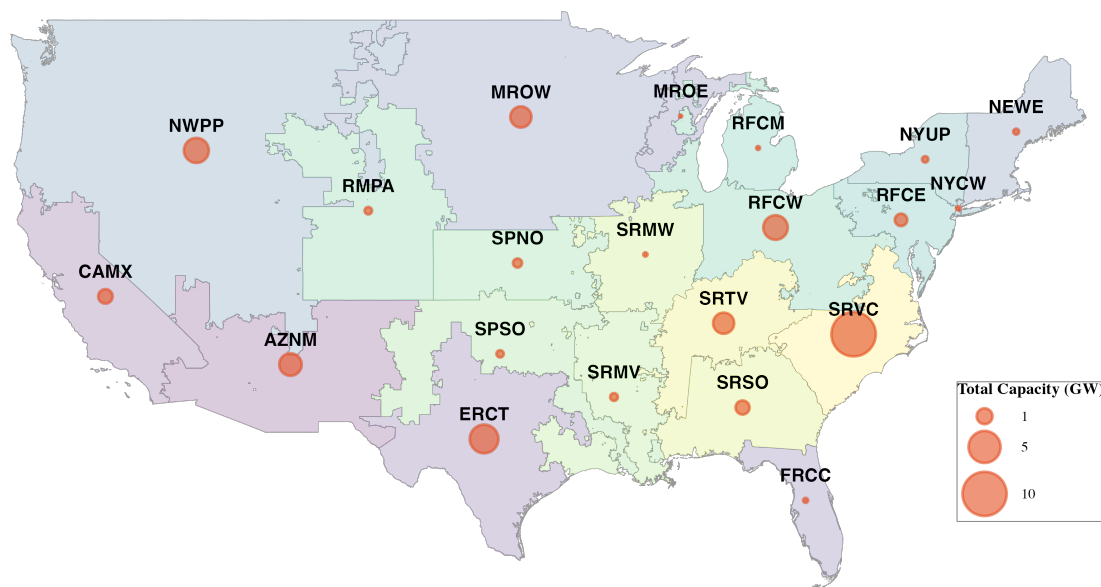
We capture this uncertainty by constructing four data center demand profiles that allow us to analyze the effect on prices across a variety of potential scenarios. We vary both the power capacity (the maximum power draw at a point in time) and the utilization rate (the percentage of maximum used in a given hour). In the Full-Capacity scenario, we assume 100% of installed power capacity is used 100% of the time. For the reasons noted above, this scenario is highly unlikely, but provides a useful upper bound. We leverage data from Bloomberg/DC Byte, which reports average annual utilization rates and market share by data center type as reported by industry participants. We scale data center capacity and utilization by these rates to construct two plausible scenarios. First, we allocate a percentage of power equal to the market share for training data centers to every hour as these have a 100% utilization rate. Next, we allocate the remaining portion according to the weighted average utilization rate across all other data center types. In our Mid-Range scenario, we assign this power equally across all hours of the day. In our Mid-Range-Peak scenario, data centers only operate during business hours, operating at full capacity the required number of hours to meet the observed utilization rate every day, centered around 1PM. Lastly, our Low-Capacity scenario reduces the capacity of data centers, assuming 50% less power in each hour than in the Mid-Range scenario.

While data centers are siting across the country, Figure 1 shows the geographic distribution and concentration of operational data center capacity in 2025, and Figure 2 shows operational and proposed data center capacity as of 2030. To date, Virginia has led the way with the most operational data center capacity in the country. However, by 2030, Texas (and thus the ERCOT

grid) is slated to be the leader in data center power demand.

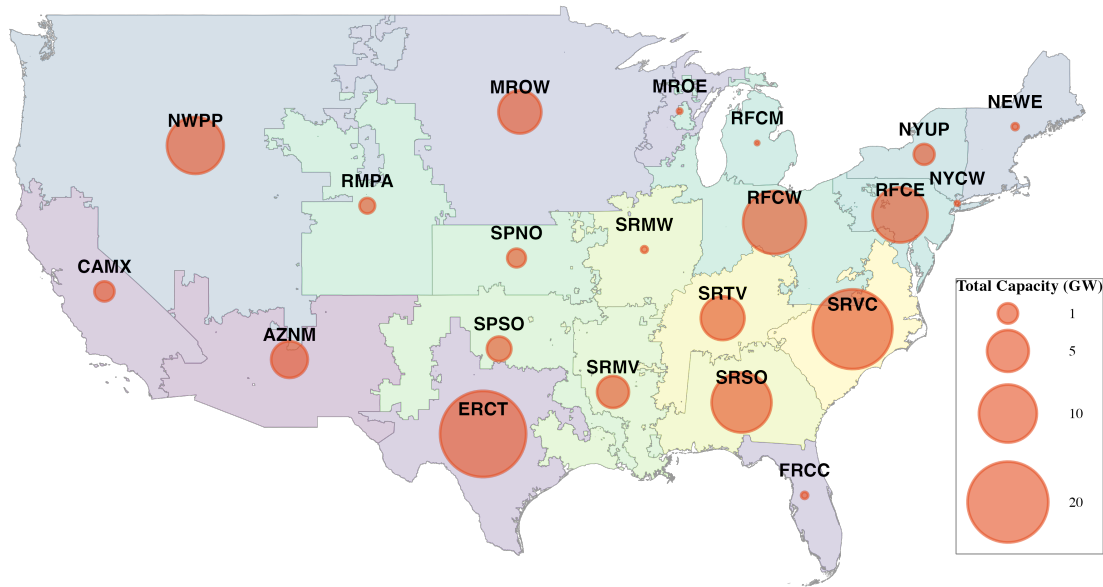
Data centers consider a combination of factors when deciding where to locate. Electricity access is a primary consideration. Grid interconnection queues can often require projects to wait years for access to connect, driving data centers to areas that will allow them to connect quickly. While cheaper electricity rates can lower costs for data centers, they do not exclusively locate in grids with the lowest prices. Using data from the Census Bureau American Community Survey and the EIA, we report demographic variables for the counties where data center siting occurs in Appendix Table A1. Data centers locate along major fiber optic cable corridors and often near major urban areas to reduce latency and benefit from skilled labor markets. This pattern is evident when comparing differences between counties with and without data centers. As noted before, counties with data centers have marginally higher electricity rates than areas without.

Figure 1: Installed Data Center Capacity: 2025



Notes: Map plots the operational data center power capacity as of the end of 2025 by eGRID subregion. Data are sourced from Cleanview. Larger circles represent more cumulative capacity in the subregion.

Figure 2: Installed and Planned Data Center Capacity: 2030



Notes: Map plots the operational data center power capacity as of the end of 2030 by eGRID subregion. Data are sourced from Cleanview. Larger circles represent more cumulative capacity in the subregion.

3 Structural Dispatch Model

To analyze both the ex post period and the forward looking scenarios, we construct a short-run competitive dispatch benchmark for each subregion. In each hour, conditional on residual demand to be served by inframarginal generators, available unit-level capacity, and unit-level marginal costs, we solve a linear program that minimizes the total cost of meeting load within the subregion. Formally, for each region r and hour t , we solve

$$\min_{q_{it}} \sum_{i \in I_r} mc_{it} q_{it} \quad (2)$$

$$\text{s.t.} \quad \sum_{i \in I_r} q_{it} = d_{rt} \quad \forall r, t \quad (3)$$

$$0 \leq q_{it} \leq K_{it} \quad \forall i \in I_r, t. \quad (4)$$

Here, I_r denotes the set of conventional generating units in region r , q_{it} is output from unit i in hour t , mc_{it} is the marginal cost of unit i in hour t , and d_{rt} is residual demand in region r and hour t after accounting for non-thermal generation. Generation from each unit is bounded above by available derated capacity K_{it} . Available capacity varies at the hourly level in the model. We first apply monthly derating factors to account for expected outages and then incorporate a stochastic hourly outage component to capture unexpected outages, so that in some hours a unit may be unavailable and $K_{it} = 0$.

Solving this problem yields two objects of interest: optimal dispatch quantities, q_{it}^* , and the shadow value on the power-balance constraint, λ_{rt}^* . We interpret λ_{rt}^* as the marginal cost of serving an additional MWh of residual demand in region r at hour t . Because the model is based on unit-level marginal costs rather than strategic offers and abstracts from non-convex operating constraints such as start-up costs and ramping constraints, λ_{rt}^* should be interpreted as a competitive marginal-cost benchmark.

This interpretation is also relevant outside organized wholesale markets. In regions served primarily by vertically integrated utilities, there is often no directly observed wholesale market price analogous to that in RTOs and ISOs. In those regions, λ_{rt}^* remains economically meaningful as the model-implied marginal cost of serving an additional MWh of load. For expositional simplicity, we refer to λ_{rt}^* throughout as the regional price.

Our counterfactual is best viewed as a short-run partial-equilibrium exercise that isolates how the marginal cost of serving load changes when data center demand is added or removed, condi-

tional on realized non-thermal generation, generator availability, and estimated marginal costs. The framework does not recover a full market equilibrium for the interconnected U.S. power system, as it abstracts from endogenous interregional trade, strategic bidding, and non-convex operating constraints. Accordingly, the resulting regional price should be interpreted as a model-based benchmark under observed system conditions rather than as a literal prediction of the realized hourly market-clearing price.

4 Ex Post Analysis

In this section, we use the dispatch framework from Section 3 to quantify the contribution of data center load to generation costs, model-implied regional prices, and emissions for 2021-2025. Throughout, these estimates should be interpreted as short-run partial-equilibrium counterfactuals: they measure how market outcomes change when data center demand is added or removed, holding fixed contemporaneous supply conditions, non-thermal generation, and inter-regional power flows.

Each of our alternatives is compared to the reference case where we set net load for conventional generation equal to observed thermal generation in each region. For the data center utilization scenarios, we subtract implied data center demand from observed net generation in each hour, to produce a no-data-center residual demand scenario for each counterfactual. We then re-solve the dispatch model for q_{it} and λ_{rt} without data center demand.

By setting our baseline residual demand for thermal generation equal to observed thermal generation in each region, we allow thermal generation to be re-optimized but hold other source of supply and demand fixed. Embedded in this modeling decision is an assumption that other sources of supply such as nuclear, wind, solar, and hydro are always inframarginal. This is consistent with very low marginal costs for these sources of supply.

In addition, we are implicitly fixing the net interchange between regions to their historic levels. Observed generation in each region is equal to regional electricity consumption plus net exports. For the counterfactual scenario that includes data center demand, this simply ensures

that net exports between the various regions match observed net exports. In our no-data-center counterfactuals, we subtract the hourly assumed data center load from observed generation. Thus, we also fix transmission flows between regions to their observed levels, even in the counterfactual without data center demand. This implies that the marginal data center electron is always generated within the same region. In reality, if a neighboring region had cheaper generation available and transmission lines between regions were not at capacity, we would expect incremental data center load to be partially met by the neighboring region.

These considerations motivate our use of eGRID subregions to define our geographic markets. EPA's methodology for assigning plants to eGRID regions is intended to limit imports and exports within an aggregated area in order to produce regional emissions rates that reflect the electricity consumption within that geographic area. To the extent that the eGRID subregion boundaries successfully limit bias introduced by imports and exports, our main results can be interpreted as the additional costs, emissions, and price impacts of data center load. Because we fix historic trade flows, our model does not capture inter-regional re-dispatch that would occur in a no-data-center counterfactual. In that respect, our cost estimates will understate the true impacts of data center load. The direction of the bias on emissions and local price impacts is ambiguous. Changes to emissions depend on the regional generation mix. Local price impacts would be biased up in cases where a region is a net-importer and biased down for net-exporters.

We then compute counterfactual dispatch under "no-data-center" counterfactual demand scenarios. To do so, we subtract data center electricity demand from the measure of total conventional generator electricity demand used in the base case. We only observe capacities for existing data centers, not utilization rates, so we calculate total data center electricity demand under a number of alternative assumptions of utilization rates described in Section 2. For each "no-data-center" demand scenario, we solve the dispatch model for generator production levels, q_{it}^{-DC} , and wholesale prices, λ_{it}^{-DC} , at each hour had there been no data center demand.

The model is able to recover market outcomes accurately. In Appendix Figure A5, we show a plot of observed vs. simulated dispatch at the plant-hour level for a random subset of the sample.

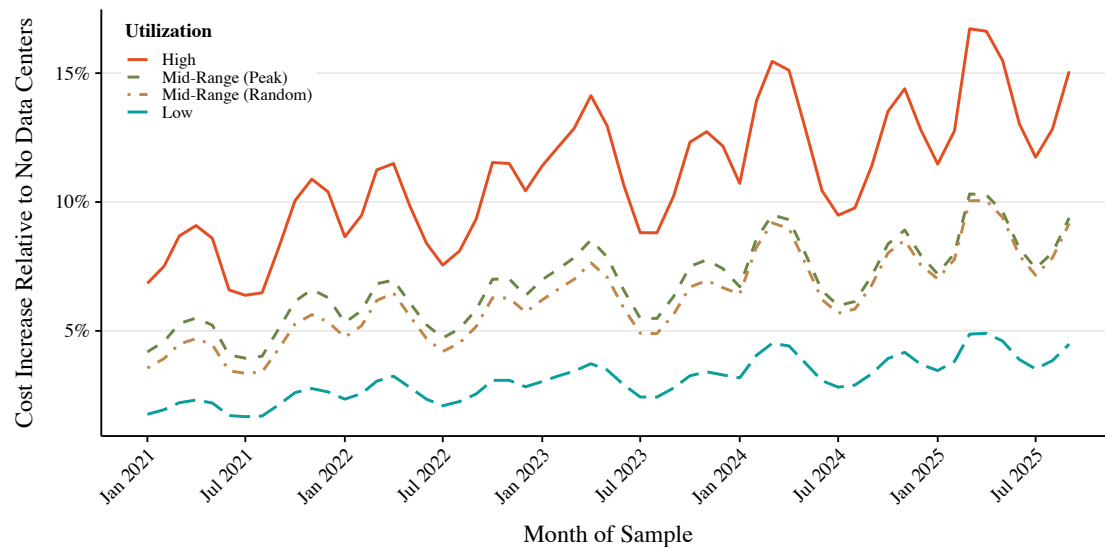
There is a mass of observations along the 45-degree line, indicating that our simulated hourly dispatch instructions closely match actual market outcomes. In Appendix Table A3, we calculate correlations between the simulated and observed generation. For hourly generation, there is a correlation coefficient of .631, suggesting a strong positive relationship. Due to our application of stochastic outages and abstraction from transmission congestion, this number is expected to be less than 1, and is in line with similar applications in the literature (Hausman 2025; Ham et al. 2025). When we aggregate to month and yearly levels of generation, we see even stronger correlations between observed and simulated, reaching .863 for the unit-by-year level. This is further evidence that stochastic outages play a role in the hourly-level correlations.

4.1 Additional Generation Costs

We begin by calculating the difference in total generation costs between the simulated baseline and each no-data-center counterfactual, $\sum_i mc_{it} q_{it} - \sum_i mc_{it} q_{it}^{-DC}$. We compare the simulated no-data-center counterfactuals to the simulated baseline, rather than to observed generation, so that the resulting differences reflect only changes in dispatch induced by removing data center load.³

³Generator-specific production in the simulated baseline may differ from observed production for several reasons, including mismatch between simulated and realized outages, the omission of ramping constraints, and imperfect representation of the underlying transmission network.

Figure 3: Percentage Increase in Monthly Generation Costs
Attributed to Data Center Load, 2021–2025Q3



Notes: Graph shows the load-weighted average monthly incremental thermal generation costs as a percentage of no-data-center generation costs by various data center utilization scenario.

Figure 3 reports the percentage increase in simulated monthly generation costs in the baseline relative to each no-data-center counterfactual. In the high-utilization scenario, in which all operational data centers are assumed to run at full power in every hour, we estimate that by 2025 data center load increased generation costs by roughly 10 to 15% nationwide, depending on the season. At the other end of the scenario range, the low-utilization case implies cost increases of at most about 5%. These estimates should be interpreted as a range across utilization assumptions rather than as formal bounds. More generally, except in hours with negative marginal prices, additional load mechanically increases variable generation costs even if its effect on the model-implied price is smaller or more heterogeneous.

Focusing on the mid-range scenarios, which are calibrated to observed utilization rates, we estimate additional costs of 5% at the beginning of our sample, increasing to a peak of 10% in spring of 2025. The scenario which concentrates data center demand in peak business hours yields generation costs that are, at times, an additional 1% higher than the scenario in which usage is spread evenly throughout the day.

The estimates also reveal a notable seasonal pattern. Cost increases in the summer and winter

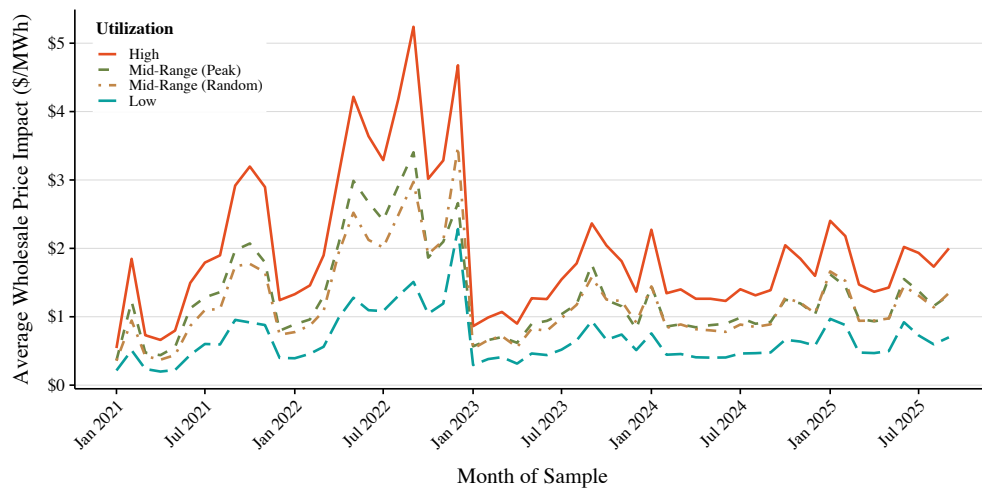
tend to be several percentage points lower than in the shoulder seasons. A likely explanation is that generators commonly schedule maintenance outages in the spring and fall, when demand is typically lower because of milder weather. As a result, available thermal capacity is reduced in those months, and the relevant portion of the thermal supply curve becomes steeper. As data center load expands over the sample, the market therefore clears on a steeper portion of the supply curve in the shoulder seasons than it would in the absence of that load raising costs by more for a similar shift in demand.

4.2 Competitive Wholesale Price Effects

We next turn to the competitive benchmark price in the wholesale market. While cost of generation is a relevant measure for the areas of the country covered by vertically integrated utilities, for the majority of the country covered by competitive wholesale electricity markets, the market price is relevant both for generator profits and the price paid by utilities to procure electricity for retail customers.

Figure 4 contains our estimates of the nationwide load-weighted average monthly price effects of data centers under the same four data center demand scenarios. Similar to our characterization of additional costs, we use the difference between the baseline competitive wholesale price using observed net load and our counterfactual scenarios. By late 2025Q3, the marginal generator dispatched to meet electricity demand was approximately \$0.50 to \$2.00 more expensive, on average, than what would have been dispatched in a the counterfactual world without data center load.

Figure 4: Average Monthly Competitive Wholesale Price Impact, 2021–2025Q3



Notes: Graph shows the load-weighted average monthly simulated market price impact of data centers by data center utilization scenario.

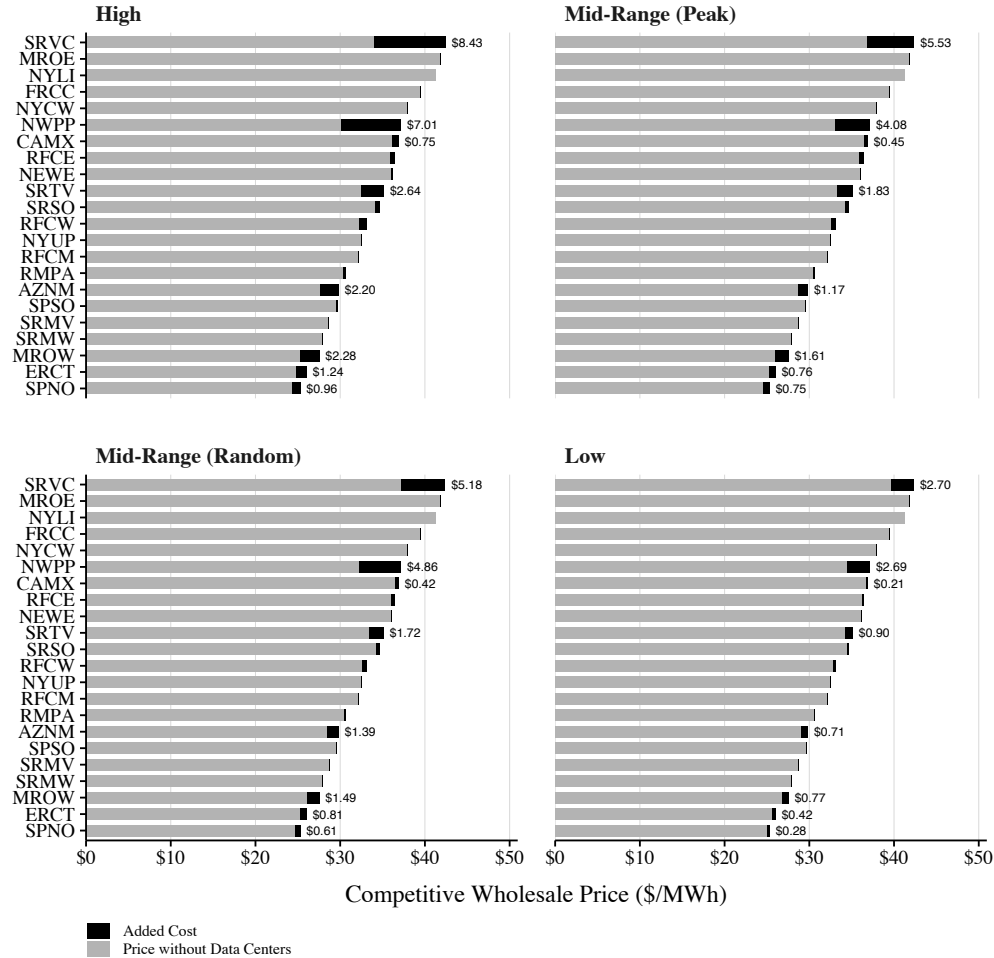
The highest estimated price effects occurred during the summer of 2022. Large spikes to natural gas prices caused by the Russian invasion of Ukraine increased wholesale electricity prices as natural gas generators are often the marginal generator, and set the market price. Our estimates show that during this period, data center demand added an additional \$1 to \$5 to the nationwide wholesale price, depending on the utilization assumption of data centers.

The distribution of data center load across the U.S. and the heterogeneity in regional power plant fuel composition means that there is substantial variation in results by region. In Figure 5 we show the average price impacts by eGRID subregion from 2023 to 2025Q3. The largest effects are seen in SRVC which is home to “Data Center Alley” in northern Virginia, the densest collection of data centers in the country. Northwest Power Pool (NWPP), which cover the majority of the pacific northwest also has significant effects from data centers. Our mid-range scenarios indicate data centers were responsible for a \$5 increase in competitive wholesale prices in SRVC, a greater than 10% increase, and a \$4 increase in NWPP.

ERCOT (ERCT), which is the grid covering the vast majority of Texas, has very little price effect despite containing the second highest amount of data centers behind SRVC. Data centers have added less than \$1 to wholesale prices, likely driven by nation-leading supply build out. We

also find that data centers had little impact in the subregion covering most of California, CAMX. While Californians face the highest average retail electricity prices in the nation during this period, even our upper-bound estimates yield an impact of less than \$0.75.

Figure 5: Average Regional Competitive Wholesale Price Impact, 2024-2025Q3



Notes: Graph shows the load-weighted average simulated market price impact of data centers by data center utilization scenario and eGRID subregion.

Our model allows us to decompose the welfare impacts of data centers associated with our modeled generation. We calculate the total competitive wholesale payments made to dispatchable generators, their total production costs, and the competitive, inframarginal rents earned. Total payments are $\sum_{rt} \lambda_{rt} Q_{rt}$, where λ_{rt} is the competitive wholesale price of subregion r in hour of sample t , and $Q_{rt} = \sum_i q_{it}$ is total thermal net generation in hour t . Production costs are total variable costs (fuel, variable O&M, emissions permits) summed across all dispatched generators and

hours. Competitive rents equal the difference between wholesale payments and production costs. Computing these three objects in our baseline simulations and our no-data-center counterfactuals allows us to identify the changes driven by data center demand.

Table 2: Data Center Impact on Payments, Production Costs, and Competitive Rents, Mid-Range (Peak) Utilization Scenario (Millions of 2024 Dollars), 2021-2025Q3

	Year					Cumulative
	2021	2022	2023	2024	2025	
<i>United States</i>						
Δ Payments	5,836	10,048	6,241	6,096	6,182	34,404
Δ Production Costs	3,723	5,737	4,242	4,057	4,037	21,796
Δ Rents	2,113	4,311	1,999	2,039	2,145	12,607
<i>Restructured Markets</i>						
Δ Payments	2,718	4,159	2,745	2,571	2,817	15,010
Δ Production Costs	1,775	2,461	1,866	1,635	1,701	9,437
Δ Rents	943	1,698	879	936	1,116	5,573
<i>Non-Restructured Markets</i>						
Δ Payments	3,118	5,889	3,495	3,523	3,365	19,390
Δ Production Costs	1,948	3,276	2,376	2,420	2,336	12,356
Δ Rents	1,170	2,613	1,120	1,102	1,029	7,034

Notes: All values in millions of 2024 dollars. Δ rows report the difference between observed (with data centers) and the no-data-centers counterfactual under the Mid-Range (Peak) utilization scenario. Restructured Markets aggregates all ISO/RTO-affiliated facilities; Non-Restructured Markets covers facilities outside organized wholesale markets.

Table 2 presents these three objects computed from our observed dispatch and our no-data-center scenarios.⁴ Notably, we find a cumulative welfare transfer from wholesale consumers to suppliers in our mid-peak scenario of \$12.6 billion from 2021 to 2025 that was driven by data center demand. The cumulative impact of data centers on production costs totaled over \$21 billion. We decompose these results by “Wholesale Markets,” regions in the U.S. that have restructured and have a competitive wholesale electricity market, and those that are areas that are still under the traditional, “Vertically Integrated” format, since the interpretations differ with respect to the “Payments” row. In restructured markets, our system price represents the competitive wholesale benchmark. Thus, the values reflect the interpretation above. We find total transfers from wholesale

⁴Past work, such as [Borenstein et al. \(2002\)](#), similarly decompose these welfare objects. Because we only compute a competitive equilibrium in our setting, we make no claims about the market power effects of data centers.

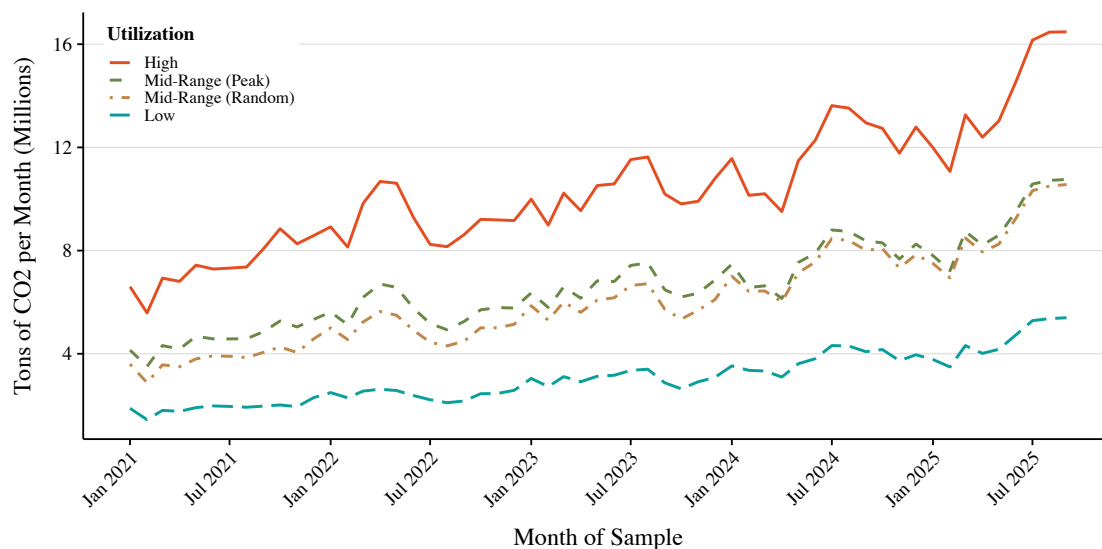
buyers to suppliers of approximately \$5.5 billion during our sample period.

In non-restructured, vertically integrated markets, the system price in our model still represents the shadow price of supplying an additional MWh, but this object does not have an explicit mapping to a system price. Thus, we should think of the change in rents in these markets as the gap between the marginal cost of generation and the average cost of all dispatched generation. Under cost-of-service regulation, we would expect these savings to eventually flow back to ratepayers and would not be the persistent windfall that they are in their wholesale counterpart.

4.3 Emissions

From our model results, we observe the additional output required to meet data center load. Using plant specific emissions rates, we can estimate the incremental emissions, measured as tons of CO_2 , directly related to data center load growth. Our results, shown in Figure 6, suggest that incremental emissions have been steadily increasing over our sample period as data center load continues to increase, suggesting that data center demand growth has generally outpaced the rate at which new renewable generating capacity has connected to the grid.

Figure 6: Incremental Monthly CO_2 Emissions, 2021–2025Q3

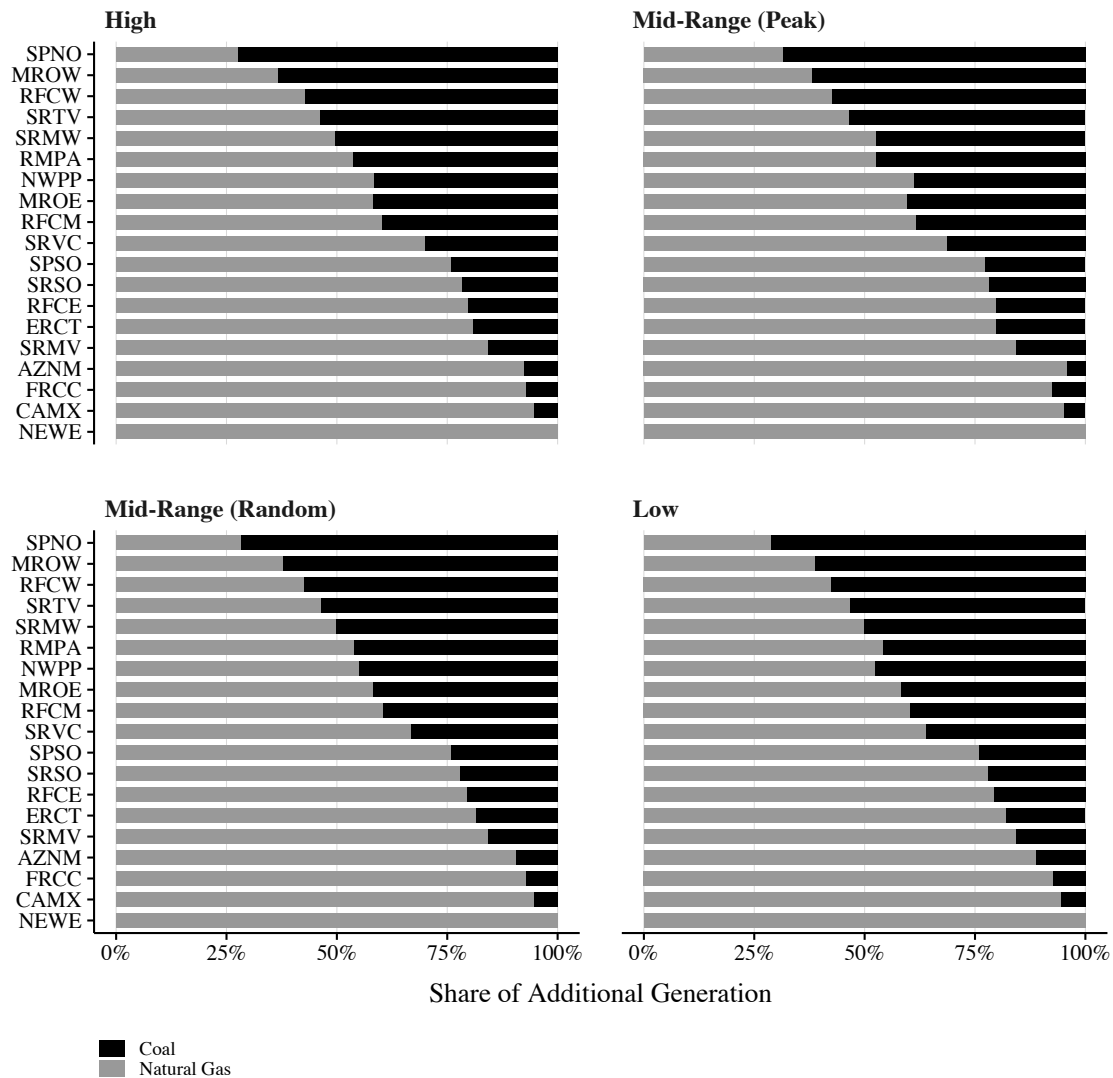


Notes: Graph shows the monthly simulated emissions impact of data centers by data center utilization scenario.

By 2025, data centers were generating between 5 and 16 million additional tons of CO_2 per month. For reference, a moderate social cost of carbon (SCC) estimate of \$51, results in external damages ranging from \$3 billion to \$9.7 billion annually depending on the data center demand assumption. As with the welfare transfer implied by the increase in wholesale prices, this increase in damages must necessarily be weighed against the positive externalities and productivity gains created by data centers to calculate a total effect of data centers, an exercise which is a promising avenue for future research.

It is important to note that not all data centers will have the same emissions impacts. Importantly, the different generation mix across regions and time means that incremental demand is met by generation units of varying efficiencies and technologies. Figure 7 shows the fuels used by the marginal thermal generators to meet data center demand across regions. In New England and California, this is almost entirely natural-gas-fired generation, while in much of the upper Midwest, coal plays an important role.

Figure 7: Share of Incremental Load Met by Coal vs. Natural Gas
By Region, 2024–2025Q3



Notes: Graph shows the generation type breakdown for the incremental generators by data center utilization scenario and eGRID subregion.

5 Forward Looking Analysis

Next we present a forward-looking analysis that quantifies how projected data center expansion changes wholesale market outcomes through 2028. This exercise is complicated by various dimensions of uncertainty. Where and when data centers will be constructed is constrained by regulatory processes and slow-moving electricity interconnections. On the supply side, the timing and

size of power plant additions and retirements are uncertain. Additionally, we must create a credible no-data-center electricity consumption counterfactual to quantify the incremental effect of data centers. Our model is able to handle the wide range of uncertainty and we address each of these in turn by constructing various counterfactual scenarios to test. As such, the exercise should be interpreted as simulating the effects *if* a particular scenario arises, and not assigning a probability to any such outcome.

In general, two results emerge. **First, effects are highly state-dependent: under the high-end power usage assumption, data center load drastically raises generation costs and wholesale prices relative to the no-new-data-center benchmark.** In fact, demand is so large that in a significant number of hours, there is insufficient available generation to meet the need. The middle and low scenarios result in more moderate, but still economically significant wholesale market effects. Second, the distributional consequences of the build-out are geographically uneven, with larger price effects in regions that are both most exposed to new data center construction and that face supply constraints.

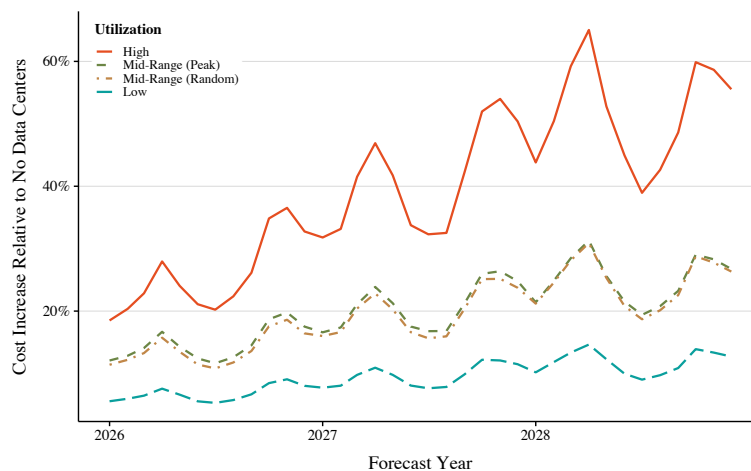
Unlike the ex-post exercise, the forecast requires constructing hourly net load from total forecast demand and non-thermal supply. For each subregion-hour, forecast net load equals projected total demand minus projected output from wind, solar, hydro, storage, and other non-fossil baseload resources as these resources are inframarginal. We then solve the same hourly least-cost thermal dispatch problem outlined in Section 3 to determine the dispatch instructions for thermal generators and market price. Our supply forecast is exogenous and incorporates announced and expected additions, retirements, derates/uprates, outages, and fuel-cost paths from EIA-based inputs. Given the relatively short time frame of our forecast window and interconnection queues for new supply that are greater than 5 years, we believe this assumption is justified. The demand forecast for non-data-center load is derived from the EIA Annual Energy Outlook and data center load for planned locations is reported by Cleanview.⁵

We evaluate the same four demand scenarios (high, mid_peak, mid_rand, low) that differ

⁵Full details on demand and supply forecasts are provided in Appendix D

in effective utilization and intraday load shape. However, to reflect the additional uncertainty from data centers not completing construction or being ‘behind the meter’, we scale down new data center capacity by 40% of announced for the mid-scenarios. This in turn lowers the low-end case, which is a further 50% reduction. The mid-peak scenario is our preferred central case with high and low scenarios bounding the effects. All effects are reported relative to a no-data-center counterfactual in the same time period.

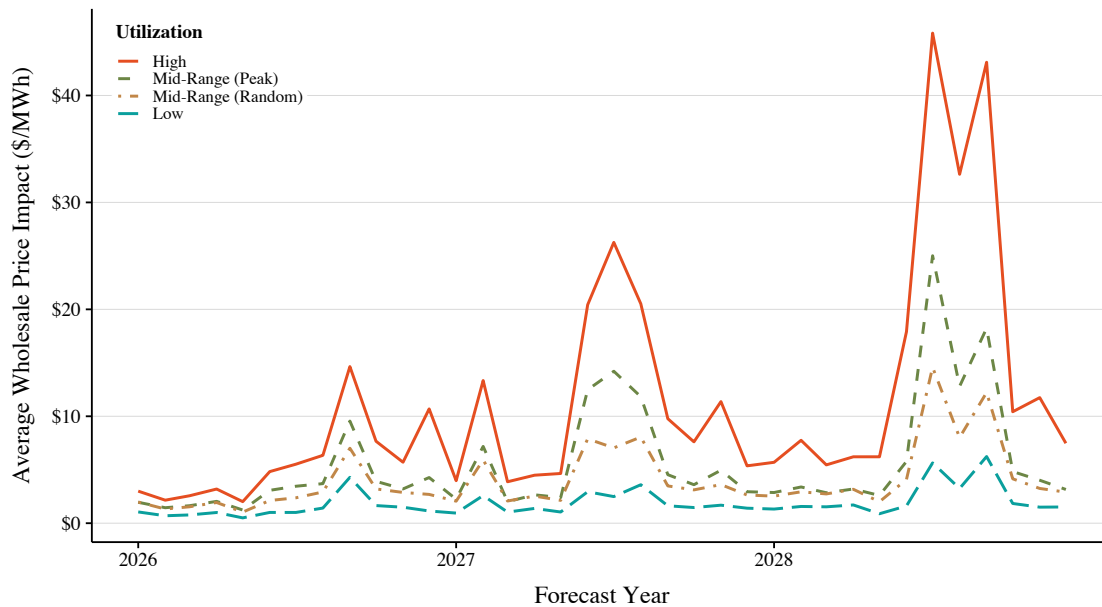
Figure 8: Projected Percentage Increase in Generation Costs, 2026–2028



Notes: Graph shows the simulated load-weighted average monthly percentage increase in thermal generation costs by data center utilization scenario.

Figure 8 reports monthly percentage changes in generation cost, and Figure 9 reports monthly wholesale price effects in levels. The very large estimated effects in the high-end case reflect the dramatic announced growth in data centers. If all data centers arrive as planned, and run continuously, generation costs are set to increase by 60% and prices more than \$40 higher than a no-data-center counterfactual. While this scenario is highly improbable, it reflects the tail upside risk data centers pose to electricity prices. The mid-scenarios imply more modest, yet still significant, 20–30% increases in generation costs by 2028 with substantial month-to-month variation. Interestingly, the scenario where utilization is concentrated in the peak hours leads to significantly higher market prices when compared to the smoother mid-scenario. Even in the low-end case, generation costs are estimated to grow by 10–15%, with prices rising by close to \$10 on average in some months.

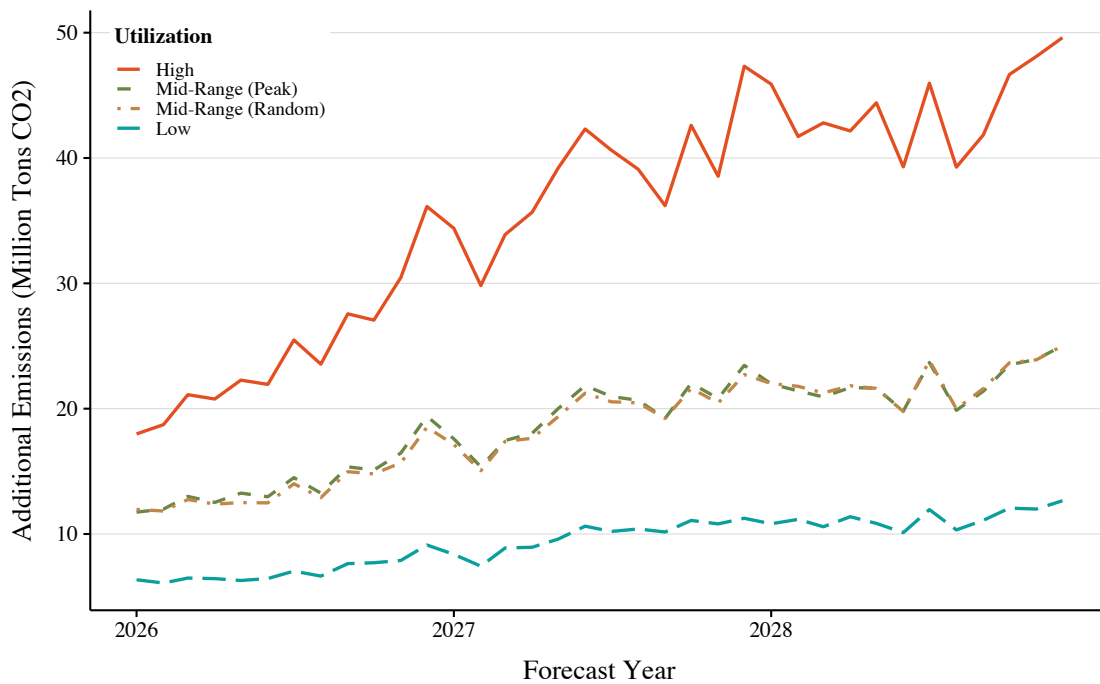
Figure 9: Projected Average Monthly Competitive Wholesale Price Impacts, 2026–2028



Notes: Graph shows the simulated load-weighted average monthly wholesale market price increase by data center utilization scenario.

Figure 10 reports incremental monthly CO_2 emissions from the required additional generation. In the high-demand scenario, data center growth greatly increases emissions, resulting in 45 to 50 million tons of CO_2 per month. In the mid-scenario, emissions increases are still high, reaching over 20 million tons of CO_2 per month by 2028. It is important to note we are measuring grid-generated emissions. Part of the reason we lower proposed capacity is that some data centers may create their own on-site generation ‘behind-the-meter’. These sources of energy are often more heavily polluting than on-grid assets, and would be additional to what is shown in Figure 10. The mid-scenario results in around \$12 billion annually in additional damages using a SCC of \$51.

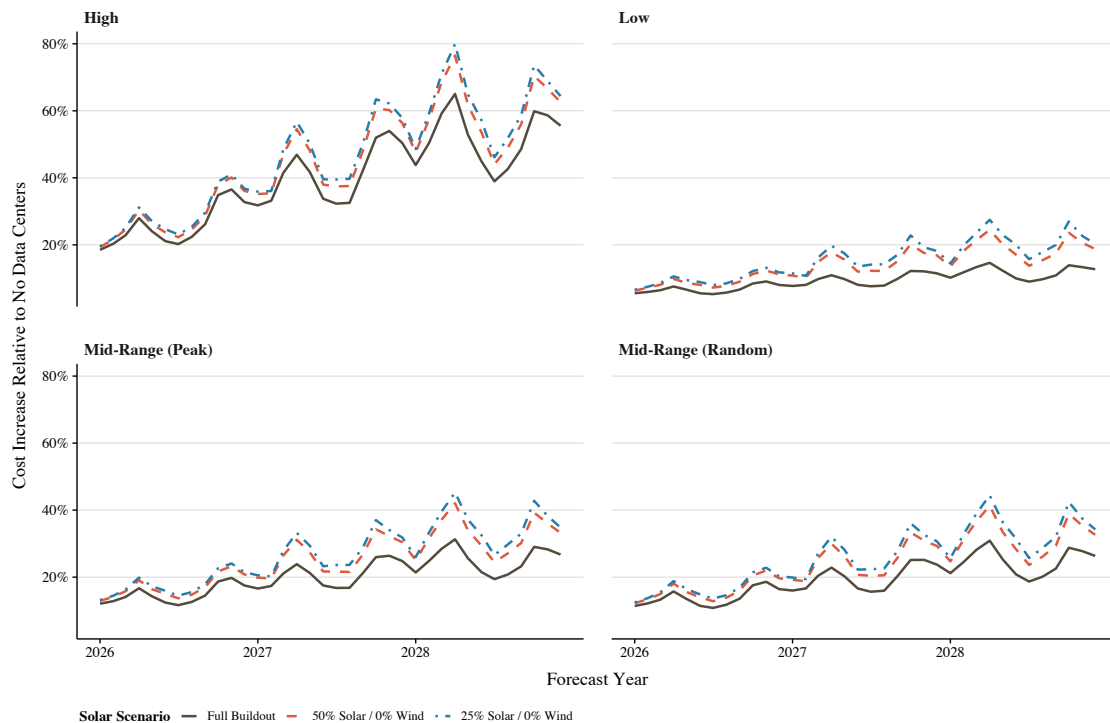
Figure 10: Projected Incremental Monthly CO₂ Emissions, 2026–2028



Notes: Graph shows the simulated monthly incremental grid emissions by data center utilization scenario.

Finally, we discuss how alternative assumptions about the build-out of supply would impact our results. Specifically, we estimate the increases in thermal generation costs attributed to data centers if the increase in solar and wind generation is smaller than expected. Figure 11 shows effects under two counterfactual supply scenarios. The black lines reproduce the baseline results shown in Figure 8. The dashed lines show the case where no additional wind generation is built and only 50% (red dashed) or 25% (blue dashed) of planned solar generation is built and available.

Figure 11: Projected Percentage Increase in Generation Costs
Under Alternative Renewable Build-Out, 2026–2028



Notes: Graph shows the simulated load-weighted average monthly incremental thermal generation costs by data center utilization scenario and renewable build-out scenario.

These alternative counterfactuals show that slower build-out of wind and solar capacity would substantially amplify the market effects of data center expansion, even though data center demand is held fixed across scenarios. With fewer additional low-marginal-cost renewable resources available, incremental load is more likely to be served by higher-marginal-cost thermal generation. Given the convexity of the short-run electricity supply curve, this shift pushes dispatch further into the steeper portion of the supply stack. Consequently, the same increment to demand generates larger increases in generation costs and wholesale prices when renewable build-out falls short of expectations.

6 Discussion

We use our model to speak to several active policy conversations surrounding the rapid expansion of data centers. These concerns have emerged in a period characterized by elevated inflation, an aging grid, and substantial uncertainty about the pace and location of new investment. We first discuss the total effect of data centers on retail rates and how the price increases relate to inflation. Data center connections will require large investments in transmission and distribution upgrades, however an outsized increase in demand could lead average fixed costs to decrease, leaving the effect on rates ambiguous. We next use our model to consider how market integration and data center flexibility can mitigate some of the increases in wholesale market prices.

6.1 Fixed Cost Allocation

Our empirical analysis focused on the impacts to variable generation costs, but the electricity sector also requires large fixed expenditures to build, maintain, and expand generation, transmission, and distribution infrastructure. How these fixed costs are allocated across customers can differ across market designs. In vertically integrated systems, utilities generally recover both fixed and variable costs through retail rates, subject to regulatory review. In restructured markets, wholesale energy costs are determined in the market, while transmission and distribution costs are recovered through regulated charges that are allocated across customer classes.

The effect of new data center load on the fixed-cost component of customer bills is theoretically ambiguous. Under simple average-cost allocation, total fixed costs are divided by the total kWh of electricity sold and recovered through retail rates. An increase in electricity consumption with no corresponding increase in fixed expenditures reduces the average fixed cost per unit of electricity sold. In this sense, additional load can lower the burden borne by each existing customer.⁶ This outcome is especially relevant if data centers locate where there is pre-existing spare

⁶Related concerns arise in the opposite direction when utilities face a shrinking customer base or declining sales, which can increase fixed cost recovery per customer; see, for example, [Davis and Hausman \(2022\)](#).

transmission and distribution capacity and thereby raise utilization of underused assets.

At the same time, the scale, concentration, and clustering of proposed data center projects is likely to require substantial new expenditures on interconnection, transmission, substations, and local distribution networks. In that case, the numerator in the average-cost calculation rises as well, and potentially by more than the increase in energy sales. Whether data center growth lowers or raises the fixed-cost component of retail bills therefore depends on how strongly new load increases capital utilization relative to how much new infrastructure it necessitates.

This ambiguity is central to current policy debates. In some jurisdictions, legislators and regulators have proposed mechanisms to shield existing customers from network upgrade costs associated with large-load interconnections. At the same time, several data center developers have indicated a willingness, at least in principle, to fund portions of network upgrades required to serve their facilities or to build incremental generation. How such commitments are translated into regulated cost recovery, and whether they meaningfully prevent cost socialization onto existing customers, remains uncertain. We view the incidence of fixed costs under large-load growth as an important direction for future research.

6.2 Wholesale Price Pass-Through and Inflation

Our model can be used for a back-of-the-envelope calculation of how data-center-driven wholesale price increases may ultimately affect residential electricity prices and, through that channel, headline inflation. In practice, retail rates adjust only imperfectly and with a lag, as utilities and retail suppliers must seek approval from state regulators or otherwise recover higher procurement costs through regulated or contractual mechanisms. Rather than modeling this institutional process directly, we assume that increases in average wholesale electricity prices pass through fully to retail prices within one year. This assumption primarily affects timing rather than the long-run cumulative price effect.

To translate wholesale price changes into retail electricity prices, we use data from the EIA

that shows energy costs account for roughly one-half of the total retail electricity price.⁷ This means a given percentage increase in wholesale prices implies an approximately one-half-as-large percentage increase in retail electricity prices, holding other retail cost components fixed. We then map these retail electricity price changes into headline PCE inflation by allowing the electricity expenditure share to evolve endogenously with the model-implied retail price path, beginning from the current baseline expenditure share of 1.27 percent. This is a partial-equilibrium exercise: it holds constant the prices and expenditure shares of all other goods, abstracts from regulatory or fiscal offset policies, and does not incorporate any income or general-equilibrium effects associated with higher electricity expenditures.

The inflationary impacts depend importantly on the assumptions about both data center build-out and utilization. Using the wholesale price effects shown in Figure 9, when utilization is concentrated in peak hours, the implied contribution to inflation is approximately 0.05 percentage points in 2026 and 0.12 percentage points in 2028 through the retail electricity channel. When utilization is distributed more evenly over the day, the effects are modestly smaller. Under the low-capacity scenario, the implied contribution falls to roughly 0.02 percentage points in 2026 and 0.04 percentage points by 2028.

At the upper bound, if all proposed data center capacity were to operate continuously at maximum utilization, annual PCE inflation could rise by approximately 0.6 percentage points in 2028. While this full-capacity scenario is highly implausible, it illustrates the extent to which the inflationary consequences of large-load growth are highly nonlinear.

6.3 Transmission Constraints and the Value of Market Integration

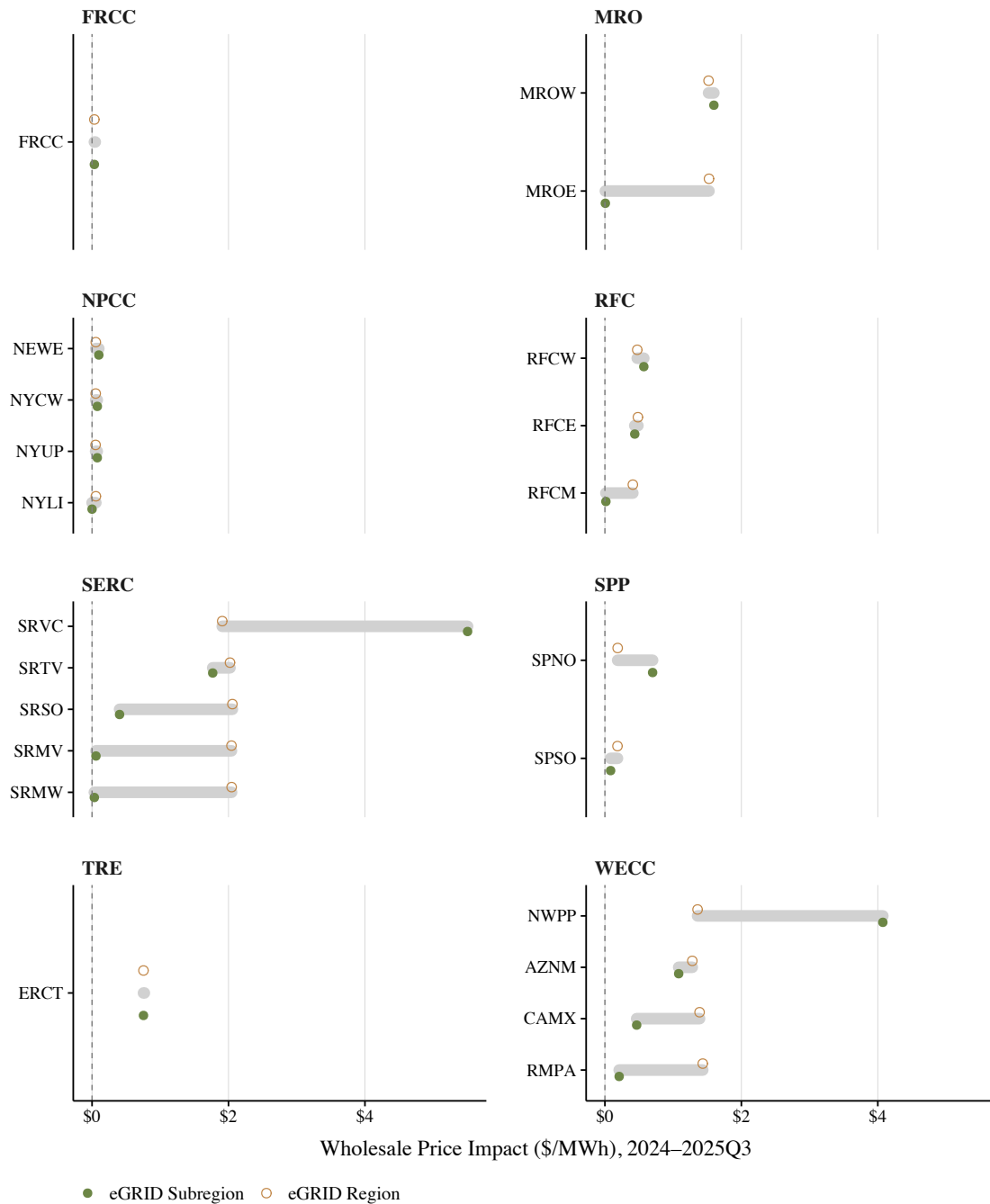
We can also use our results to speak to the role of transmission and market integration in mitigating localized price pressure. A main outcome of our model is that load growth is highly uneven across regions with low-cost generation and spare capacity often located elsewhere. This creates a natural role for transmission: moving relatively cheap electricity from lower-demand

⁷See EIA (2023) for a breakdown of electricity prices.

areas into the most constrained locations. Achieving this in practice, however, requires substantial interstate and sometimes interregional transmission expansion, which is costly, slow to permit, and subject to regulatory and political constraints.

To quantify the potential importance of these frictions, Figure 12 presents a counterfactual in which markets are seamlessly integrated and transmission congestion is eliminated. Operationally, this means that the hourly least-cost dispatch problem is solved at the level of the aggregated eGRID region instead of subregion, allowing the model to dispatch the lowest-cost available generation across a wider geographic footprint. In the regions that are most exposed to data-center-driven scarcity in the baseline, such as SRVC, this integration substantially attenuates the local price effects of data center demand. At the same time, the gains are not uniform. Despite a decrease in the nationwide average price, some regions experience higher prices under aggregation because previously idle, out-of-merit units are now called upon more frequently to serve demand elsewhere in the larger integrated market. In that sense, market integration does not eliminate scarcity; rather, it redistributes it across space and reduces the extent to which scarcity is concentrated in a small number of constrained subregions.

Figure 12: Change in Price Effects with Market Aggregation



Notes: Graph shows the change in the simulated load-weighted average wholesale market price impact by market aggregation level and subregion. Effects for the mid-peak scenario are shown.

We do not attempt to quantify the capital costs, siting barriers, or political economy constraints associated with the transmission build-out needed to support this level of integration. Nonetheless, the exercise highlights that transmission constraints are first-order for the incidence of data-center-

driven price increases.

6.4 Geographic Compute Flexibility as Virtual Transmission

Physical transmission is not the only potential margin of adjustment. A conceptually related alternative is greater flexibility in where compute is performed. If computational workloads can be curtailed, deferred, or spatially reallocated across geographically dispersed data centers, then compute flexibility can act, at the margin, like a form of virtual transmission. This shifts effective electricity demand away from stressed regions and toward regions with lower prices and more spare capacity.

In principle, increased flexibility can improve grid reliability and lower wholesale prices, but it requires sufficient excess and geographically diverse compute capacity, network capability, and tolerance for latency and other operational constraints. **In practice, many data center operators market their services on the basis of extremely high reliability, making frequent and unplanned curtailment costly.** In this sense, spatial compute flexibility may substitute for transmission only if firms are willing to maintain some level of costly overbuild of data center capacity across multiple regions or institute some prioritization of tasks.

To illustrate the potential magnitude of this margin, we compare observed data center siting against the geographic allocation of compute chosen by a social planner minimizing short-run electricity operating costs.⁸ This counterfactual abstracts from latency, construction costs, labor availability, interconnection constraints, and other factors that shape actual siting decisions. We solve a national dispatch problem without regional transmission constraints using excess thermal capacity that remains idle in the no-data-center counterfactual and allocate total hourly data center demand to the lowest-cost available generation nationwide. The resulting hourly generation pattern identifies where compute would be served if short-run electricity operating cost were the sole objective.

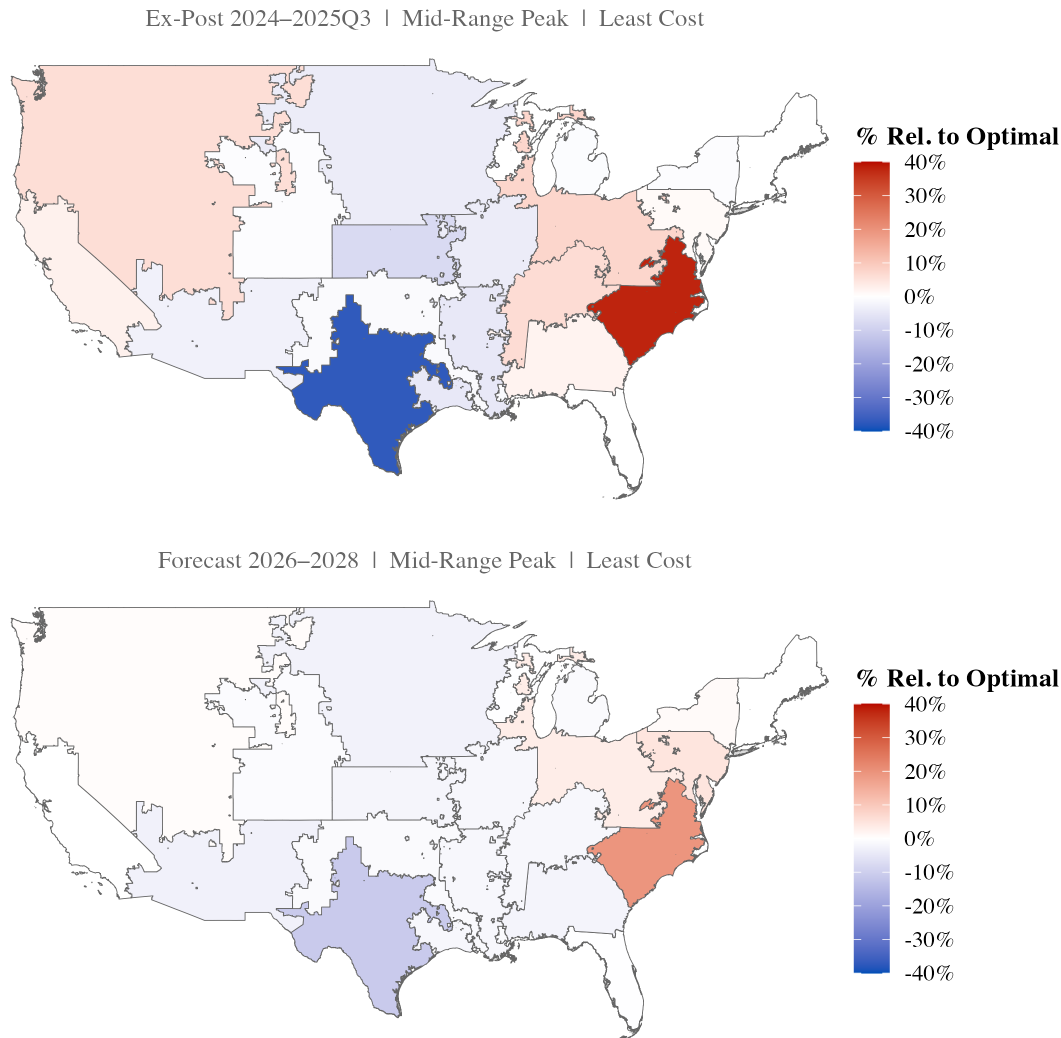
Figure 13 shows that the difference in geographic allocation between observed and the opti-

⁸For full details on how we solve the social planner's problem, see Appendix E.

mal allocation in our mid-peak demand scenario is large.. Over 2024–2025Q3, ERCOT accounts for 11.7 percent of realized data center compute in the data, whereas the social planner would allocate approximately 49 percent there—a gap of roughly 37 percentage points. By contrast, SRVC supplies 38.8 percent of realized compute over this period, while the cost-minimizing allocation assigns it only 0.78 percent due to the high pre-existing wholesale prices. Under the planner allocation, just four regions—ERCT, MROW, AZNM, and SPNO—would serve more than 75 percent of compute demand. These wedges imply that non-energy siting constraints are first-order determinants of realized data center geography and, in turn, of the regional distribution of wholesale price pressure.

The same qualitative pattern persists in the forecast period, although the allocation becomes somewhat less concentrated. For example, SRVC accounts for 19.36 percent of installed compute in the forecast but only 3.4 percent under the least-cost allocation, while ERCOT rises from 21.8 percent installed to 30.7 percent under the benchmark. Under the forecasted system, 75 percent of compute is served by eight regions—ERCT, RFCW, SRTV, AZNM, NWPP, MROW, SRSO, and SRVC—rather than four. This change suggests that future capacity expansion and evolving system conditions may reduce, but do not eliminate, the degree to which realized data center geography diverges from a short-run cost-minimizing allocation.

Figure 13: Distribution of Observed Compute Compared to the Optimal Allocation



Notes: Maps show the percentage point difference in the compute market share by subregions between the optimal spatial allocation and the observed distribution.

7 Conclusion

This paper provides one of the first empirical assessments of how expanding data center load affects wholesale electricity market outcomes in the United States. Using an hourly least-cost dispatch model built from unit-level data covering the continental U.S., we estimate how data center load changes generation costs, competitive benchmark wholesale prices, and carbon emissions in both the recent historical period and a set of forward-looking counterfactuals.

Three main findings emerge. First, data center expansion has already increased generation costs, competitive wholesale benchmark prices, and emissions in several regions. We find that generation costs have increased by 5–15% from 2021-2025, depending on data center utilization assumptions. These effects are not uniform across markets and are largest in subregions where data center growth coincides with relatively tight thermal capacity, such as Virginia and the Carolinas. Second, the impacts of data center load are nonlinear. Because of highly convex short-run supply curves, even moderate increases in load can generate disproportionately large increases in marginal generation costs when the system is operating near scarcity. These effects are most pronounced in seasons when outages or maintenance reduce available capacity. Third, the forward-looking results show that the data center build-out will have increasing effects on wholesale markets. Uncertainty in how much proposed data center capacity will actually be built is a main source of uncertainty, but in all scenarios tested, the model implies meaningful increases in wholesale market pressure.

The broader policy implication of our model is that the economic consequences of data center expansion depend not only on the size of the increase in demand, but also on where it is located, when it operates, and how quickly new supply can be built. We contribute to active policy discussions by using our model to show how transmission expansion and interconnection policy, resulting in broader market integration, can lead to lower nationwide effects, albeit at the expense of consumers in previously shielded subregions. We also highlight that data center flexibility can play a role in reducing the effects by comparing the observed build-out to a optimal spatial allocation of compute that prioritizes least-cost computing.

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A Appendix: Tables

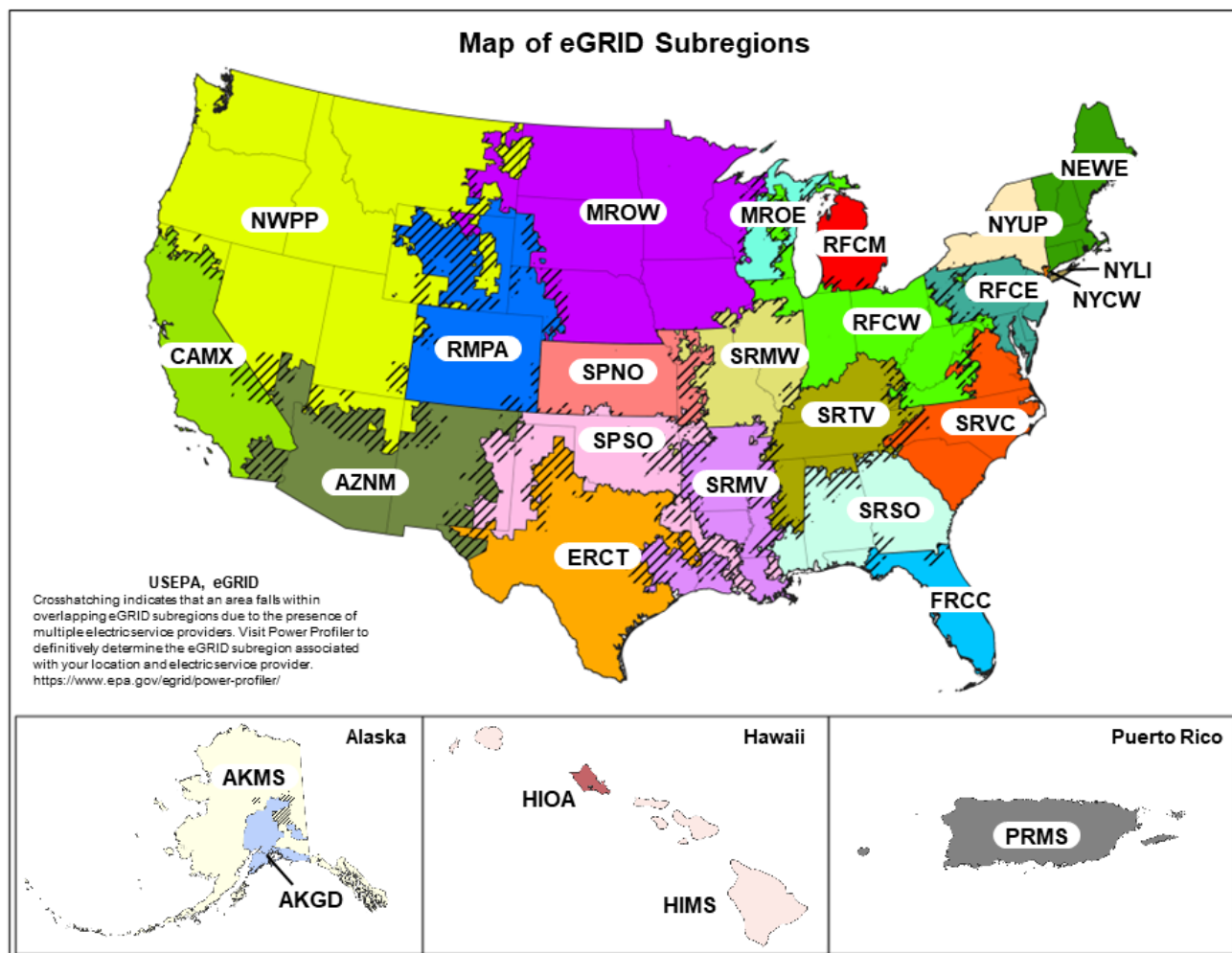
Appendix Table A1: County Characteristics: Data Center vs. Non-Data-Center Counties

	DC counties	Non-DC counties	Difference
Population	508,698	68,056	440,642***
Median household income (USD)	81,069	64,439	16,630***
Poverty rate (%)	12.06	14.48	-2.42***
Unemployment rate (%)	4.70	4.69	0.01
Bachelor's degree or more (%)	33.88	23.01	10.86***
Non-Hispanic White share (%)	62.41	75.26	-12.85***
Median age	38.38	42.01	-3.63***
Industrial electricity price (cents/kWh)	8.07	7.70	0.37*
N counties	271	2751	

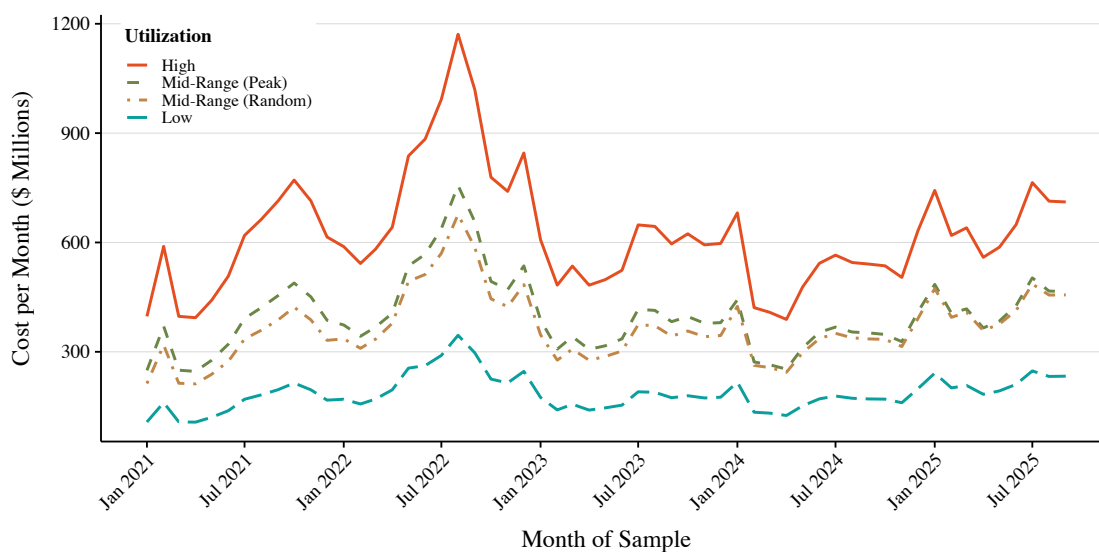
Notes: DC counties are counties with at least one non-cancelled data center in the Cleanview sample. Demographics are from ACS 2019–2023 5-year estimates. Industrial electricity price is from EIA-861 and is constructed at the county level using utility-state industrial revenue and sales mapped to counties via service territories, then averaged over 2019–2023. Difference reports mean(DC) - mean(Non-DC). * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

B Appendix: Figures

Appendix Figure A1

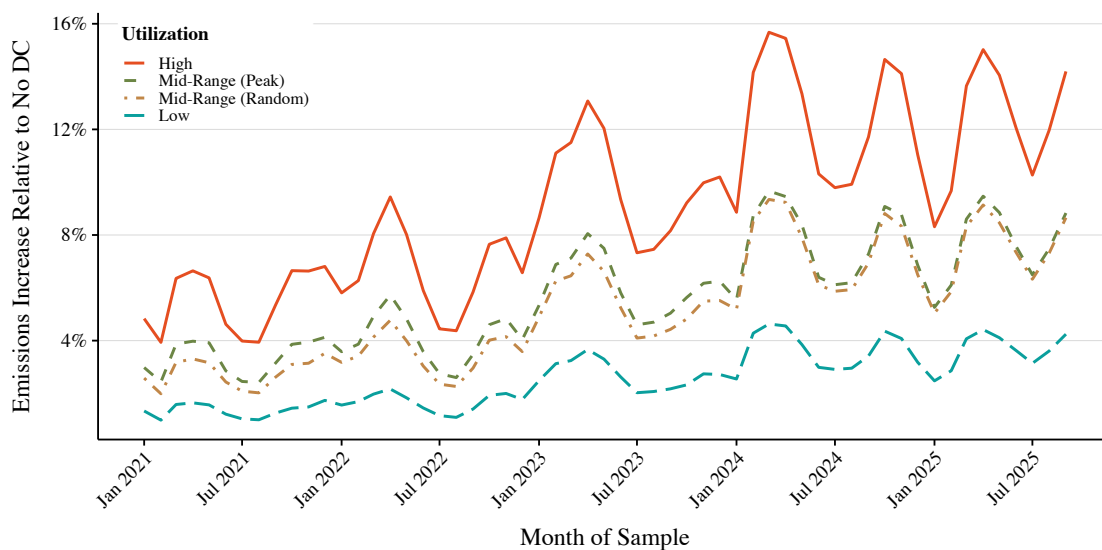


Appendix Figure A2: Monthly Incremental Costs, 2021–2025Q3

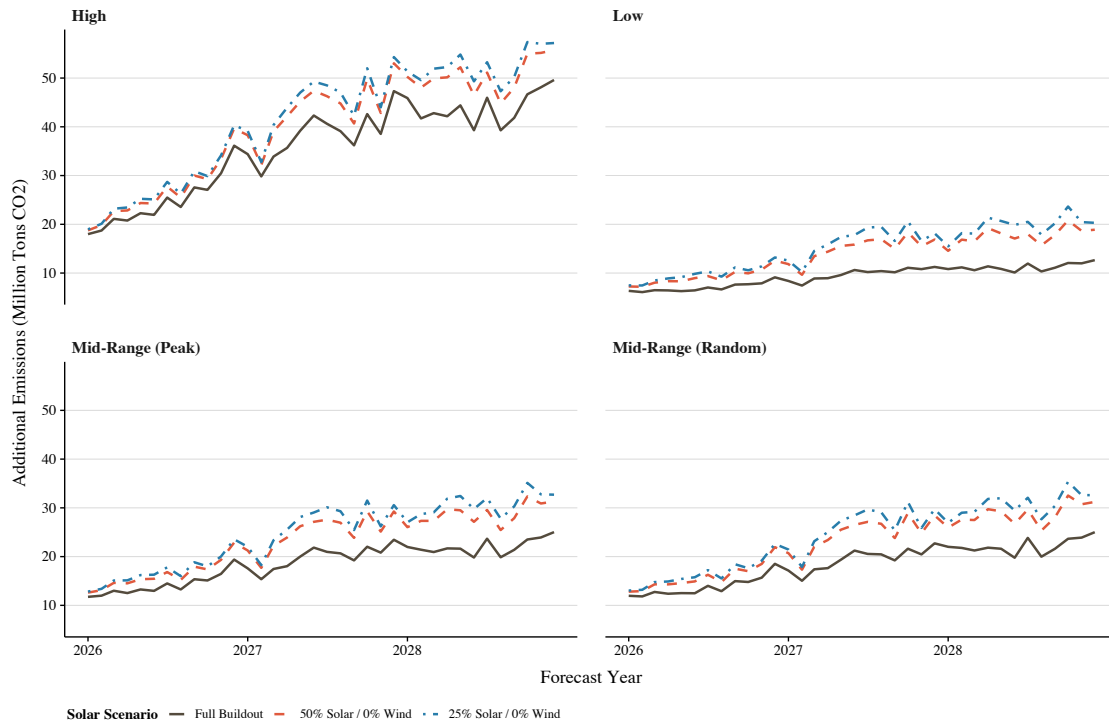


Notes: Graph shows the average

Appendix Figure A3: Monthly Percentage Increase in CO₂ Emissions, 2021–2025Q3



Appendix Figure A4: Forecasted Incremental Carbon Emissions under
Alternative Renewables Buildout, 2026–2028



C Appendix: Ex Post Model Fit

Here, we discuss the goodness of fit of our baseline model, simulated on observed outcomes from 2021–2025.⁹ We compare the results from our eGRID subregion model to those from the model using the aggregated regional definitions and show that, in general, the subregion model appears to match the observed data better.

C.1 Quantities

Table A2 shows that our model using eGRID subregions closely matches first and second moments of observed generation quantities. In addition, our model matches the reality that the majority of capacity is offline at any given moment, reflected in our median quantity being zero. Our model using the aggregate eGRID regions also performs well in this respect.

Appendix Table A2: Observed Versus Simulated Generation, Summary Statistics

	Count	First and Second Moments		Percentiles		
		Mean	SD	25th	Median	75th
Observed generation	120,076,459	73.78	141.35	0	0	88.49
Subregion simulation	120,076,459	73.76	154.84	0	0	31.88
Aggregate simulation	120,076,459	73.77	155.73	0	0	35.54

This table summarizes observed versus simulated generation at the unit $\times$ hour level. Sample covers 2021–2025.

Table A3 presents the correlations between observed and simulated generation at the unit $\times$ hour, unit $\times$ month, and unit $\times$ year levels. Despite the fact that we apply uniform derates and stochastic outages across all units, simulated output is still highly correlated with observed generation. Figure A5 provides a useful visualization for the mechanisms that cause our simulated generation to deviate from observed, by construction. The density of observations along the x-axis represent observations where we stochastically removed units from the supply curve while they

⁹Given the similarity of our model to those of Hausman (2025) and Ham et al. (2025), much of the discussion that follows closely mirrors the discussion of model fit in those papers.

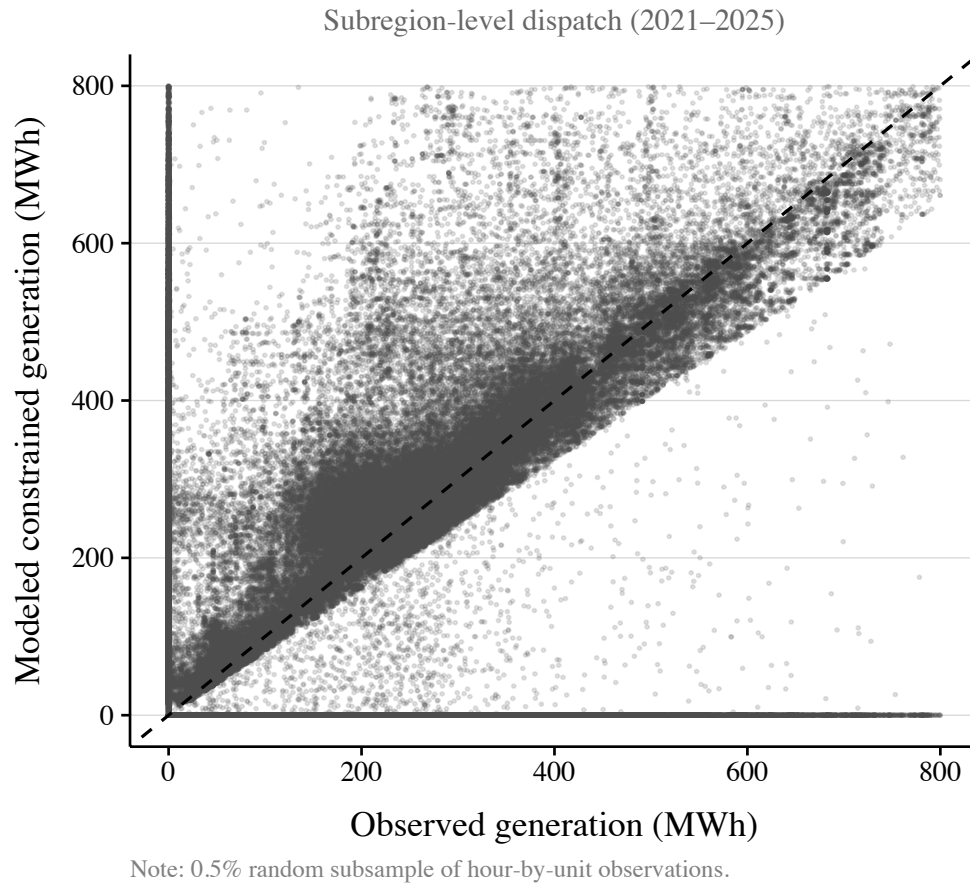
were actually on in reality. Similarly, the points along the supply curve are those observations where the unit was offline in reality, and our model left them available for dispatch. The set of off-diagonal points below the 45-degree line reflect the uniform derates we apply to each unit by fuel type. When we smooth over these structural mismatches by aggregating to the monthly and yearly levels, unit-level correlations rise substantially. These values are reported in the middle and right-most columns of Table A3. Unit-level correlations in our subregion model are slightly higher than the aggregated model, which suggests that the boundaries of the eGRID subregions delineate more electrically-consistent areas.

Appendix Table A3: Correlation Between Observed and Simulated Generation: Aggregate vs. Subregion

Version	Correlation with Observed Generation		
	Hourly	Monthly (unit $\times$ month)	Yearly (unit $\times$ year)
Subregion	0.631	0.787	0.863
Aggregate	0.617	0.772	0.848

Hourly correlations are computed at the unit $\times$ hour level. Monthly and yearly correlations average over hours within unit $\times$ month and unit $\times$ year, respectively. Sample covers 2021–2025.

Appendix Figure A5: Model Fit: Hourly Observed Versus Simulated Output



C.2 Competitive Wholesale Prices

We are also able to compare our competitive wholesale price to the set of restructured markets in our setting: CAISO, ERCOT, ISONE, MISO, NYISO, PJM, and SPP. All of these markets report some version of an unconstrained price of energy —the component of each node’s locational price that excludes congestion costs and line losses. Thus, it represents the shadow price of the system-wide power balance constraint, just as the competitive wholesale price in our simulations.¹⁰ The actual system energy price is derived from generator bids, so in some hours, especially when local constraints bind, our model may diverge from the observed prices. However, in the majority of hours, when there are limited constraints on the system, we should expect system prices to reflect

¹⁰Because the optimization problem that each market solves is more complex than our simple LP, how they calculate this value tends to vary in practice.

the marginal cost of the generator on the margin.

In Table A4 we compare how our simulated prices match observed moments. Panels A and B pool all markets together while Panel C compares the moments of individual wholesale markets. We compute average prices for each wholesale market using the hourly simulated price of each subregion that overlaps the wholesale market, weighted by its share of that market's load.¹¹ We weight observed prices by total load in that market. Our choice to simulate a static model with constant marginal cost up to each unit's capacity with no transmission constraints within an eGRID subregion means we do not capture the intertemporal and spatial dynamics that can cause system prices to vary substantially. Panels B and C exclude observations from hours when prices fall in the top and bottom 1% of the observed distribution.

Panel B shows that for the vast majority of hours the simulated prices replicate observed moments well, at a national level. While the average simulated price lies just \$1.33 below the observed price, just a 3% deviation. At the market level, the simulated moments largely track the observed moments, particularly in regions featured prominently in this paper. Namely, CAISO, ERCOT, MISO, PJM, and SPP all closely match the observed moments after filtering out extreme observations. While the mean prices in ISONE and NYISO diverge, the median prices, particularly in ISONE, are still close. Given the simulated in both markets falls below the observed mean, our results should tend to understate the effect of data centers on wholesale prices in these regions, given the convex nature of the market supply curve.

Hourly price correlations follow a similar pattern to the quantity discussion, but highlight additional modelling assumptions. With no intra-regional transmission capacity constraints or generator constraints such as start-up costs, ramp rates, or minimum uptimes, the simulated prices will follow a much flatter pattern than is observed in reality. Aggregating to the monthly-of-sample and annual levels leads to much higher correlations between simulated and observed prices. The analysis in this paper primarily concerns itself with the monthly and annual levels of analysis—levels, at which, simulated prices are highly correlated with observed prices.

¹¹This approach is similar in spirit to how many ISOs/RTOs compute their system-level energy price. It is often a load weighted average of several load zones.

Appendix Table A4: Observed Versus Modeled Wholesale Electricity Prices

	N	Mean	SD	25th pct.	Median	75th pct.
<i>A: All Observations</i>						
Observed price	269,536	45.43	87.35	22.04	32.36	51.53
Modeled price	269,536	39.99	19.39	28.93	34.88	44.58
<i>B: Excl. Top/Bottom 1%</i>						
Observed price	259,712	40.31	30.45	22.32	32.40	50.70
Modeled price	259,712	38.98	14.87	29.08	34.90	44.23
<i>C: By ISO/RTO, Excl. Top/Bottom 1%</i>						
CAISO — observed	36,754	48.17	32.77	29.66	43.28	59.49
CAISO — modeled	36,754	48.77	14.50	36.55	45.88	55.17
ERCOT — observed	39,044	36.09	30.17	18.87	26.30	40.81
ERCOT — modeled	39,044	35.81	17.22	24.88	29.10	40.63
ISONE — observed	39,584	52.05	38.81	25.93	38.05	59.80
ISONE — modeled	39,584	43.50	12.70	34.76	38.91	47.51
MISO — observed	25,363	32.75	18.99	21.48	26.44	35.26
MISO — modeled	25,363	31.78	6.83	27.75	30.03	33.08
NYISO — observed	39,569	58.86	50.18	27.30	39.42	64.82
NYISO — modeled	39,569	43.16	18.50	30.42	36.26	47.38
PJM — observed	39,713	42.25	26.45	23.24	32.66	49.55
PJM — modeled	39,713	38.81	10.66	32.40	35.27	39.86
SPP — observed	39,685	31.02	26.83	15.68	24.35	37.87
SPP — modeled	39,685	33.02	13.09	24.77	27.95	34.78

This table reports moments of observed market prices and modeled competitive wholesale prices, weighted by observed hourly load (MWh). Observed prices use the energy component of each ISO/RTO's LMPs from their real-time price data for 2021–2025Q3. Modeled prices are the shadow price of the power-balance constraint from the least-cost dispatch model. All prices in \$/MWh. Panel A includes all hours for which at least one price is available. Panel B removes prices above and below the 99th and 1st percentiles, respectively. Panel C disaggregates Panel B by ISO/RTO. No data for 2021 MISO prices.

D Appendix: Forward Looking Model

In order to solve for market prices in future pieces, we must construct hourly demand and supply forecasts out through 2028. We detail their construction below.

Appendix Table A5: Correlations Between Hourly Observed
And Modeled Wholesale Prices

	Hourly	Monthly	Annual
<i>A: All Observations</i>			
ISO/RTO Price $\times$ hour	0.305	0.517	0.677
<i>B: Excl. Top/Bottom 1%</i>			
ISO/RTO Price $\times$ hour	0.504	0.629	0.773
<i>C: By ISO/RTO, Excl. Top/Bottom 1%</i>			
CAISO	0.478	0.496	0.717
ERCOT	0.470	0.693	0.710
ISONE	0.393	0.446	0.688
MISO	0.481	0.738	0.881
NYISO	0.425	0.574	0.861
PJM	0.684	0.854	0.898
SPP	0.531	0.783	0.761

This table reports the Pearson correlation between the observed energy component of the LMP and the modeled competitive wholesale price at the hourly level. Hourly correlations use the full panel of ISO/RTO $\times$ hour observations. Monthly and annual correlations first average prices within ISO/RTO $\times$ hour $\times$ month-of-sample and ISO/RTO $\times$ hour $\times$ year, weighted by observed load. Panel A uses all available observations. Panel B removes prices above and below the 99th and 1st percentiles, respectively. Panel C disaggregates Panel B by ISO/RTO. No data for 2021 MISO prices.

D.1 Forward Looking Demand Scenarios

To calculate a demand forecast through 2028, we combine data on current hourly production from EPA eGRID and EIA-930, and annual electricity consumption from the EIA Annual Energy Outlook (AEO).

Our goal is to forecast electricity demand from all sources except data centers. We start with the 2021 observed annual net generation (TWh) by eGRID region as reported in the 2021 EPA eGRID model. We then subtract off annual data center demand in 2021 using the observed 2021 data center capacity from cleanview and market wide utilization rates reported from Bloomberg NEF/DC Byte. We use annual forecasts of electricity demand by electricity market module (EMM)

region from the 2021 EIA AEO to calculate year-over-year growth rates from 2021 through 2028. As these forecasts were made prior to the massive performance improvements in AI and subsequent build out of data centers, we use the 2021 numbers as representing expected electricity growth absent modern large-scale data centers but including expectations of growth in demand from electrification and the energy transition.¹² Year-over-year growth rates are calculated for the EMM regions reported in the AEO and then mapped to EPA eGRID regions.¹³ We then apply these growth rates to the 2021 net generation without data center demand calculated above to estimate annual demand for years 2026-2028 *net* of data center demand.

To apportion this annual demand number across hours within a year we use data from the EIA-930 form which reports hourly net generation by balancing authority for January 2021 through 2025. For each balancing authority, we generate a share for each hour of the year which is the percent of annual net generation consumed in that specific hour. Using these observed shapes, we then construct a panel of forecast load shapes for our forward-looking years by performing a block bootstrap at the month level to allow for temporal correlation in demand. This results in a 3-year panel (2026-2028) where the load shape for each calendar month is a random selection from the corresponding donor months. The selected month from the bootstrap draw is consistent across balancing authorities to account for common shocks. We assign the load shape to our eGRID geography by using the shape of the most represented balancing authority within the eGRID region.¹⁴ Lastly, each hourly load factor is then multiplied by the annual electricity demand number to yield the hourly load.

For each of our demand scenarios, we use reported power and operational dates for all operational and proposed data centers from CleanView, the same source we use for our ex-post analysis. We use 100% of reported data centers operating at 100% capacity as our highest case. For the two mid-range cases, we allocate compute across hours as before using estimated market shares and

¹²Note that this methodology does not account for data center demand crowding out other sources of electricity demand growth.

¹³For the eGRID regions that span multiple EMM regions, we use the sum of demand over the underlying regions for the growth rate.

¹⁴The majority of eGRID regions are largely or entirely comprised of one balancing authority.

utilization rates from Bloomberg/DC Byte. Unlike before, there is an additional source of uncertainty in data center demand. There is significant uncertainty in which data centers will actually be constructed. There have been a number of reports of data center developers submitting duplicate or speculative bids and many operators have constructed (or plan to) on-site primary and back-up generation. To represent this uncertainty, we first scale down the data center power capacity by 40% for all planned projects before constructing our mid-range scenarios. The low-end utilization case is a 50% reduction from the mid-range scenario. Hourly data center demand is added to the hourly demand without data centers constructed above when calculating the appropriate counterfactuals.

D.2 Forward Looking Supply Scenarios

Constructing forecasted thermal supply is straight forward. We use the EIA's Form 860m to gather the most up-to-date information on planned retirements, uprates, and derates to apply to our existing thermal panel at the monthly-level. We use the last available heat rate, capacity, and permit prices for each existing generating unit.¹⁵ Form 860m also contains information on new planned thermal generation by month. We apply average heat rates from existing plants of the same generator type and of newer construction vintage (since 2017) to capture technological innovation. We apply the permit prices from units of the same subregion to planned units. Plants are derated and have stochastic outages as in our baseline approach.

In order to construct unit-level marginal costs, we require data on fuel costs. We retrieve the Henry Hub and WTI prices corresponding to the months drawn in our bootstrap, and for each day, we compute the deviation in observed price from the donor month's average annual natural gas or oil price. We multiply these coefficients by the annual natural gas and petroleum prices for electric power projected in the 2025 AEO. We apply the state-specific markups to these daily natural gas and oil prices to capture the time-invariant spacial differences in prices faced by our panel of thermal units. Coal and coke plants receive the same treatment, utilizing the fuel cost data

¹⁵We ignore unit degradation over time. Given our forward looking scenarios is over only a three-year period, we don't expect unit heat rates to change much over this time. To the extent that they do, our results will tend to under-estimate costs and emissions across thermals.

from the EIA Form 923 that corresponds to each donor month and projected coal prices from the 2025 AEO.¹⁶

For renewables, we use data from the EIA-930 to estimate regional month-by-hour capacity factors for installed solar and wind. We apply these hourly capacity factors for the forward looking years using the same bootstrap draw used for estimating the demand profile. We then apply these capacity factors to the total amount of installed wind and solar from existing units and planned units in EIA-860m.

We perform a similar exercise for hydroelectric units. We create average hourly generation profiles for each month by using hourly data from the EIA-930. For each subregion-hour within a donor month, we compute the average share of that month's total hydro generation that is utilized. We then apply those shares to the total monthly output of each hydroelectric facility, as reported in the EIA-930, for that donor month.¹⁷ We use average hourly capacity factors by subregion for planned hydro units. We take this approach in order to preserve some of the complex seasonality and environmental constraints inherent to hydro operations without explicitly modeling reservoir shadow prices as in [Bushnell \(2003\)](#).

For nuclear, cogeneration plants, and other, less common generation technologies, such as geothermal plants, receive the same treatment we use the EIA-923 to compute average monthly capacity factors. We then assume all of these units generate at that fraction of their nameplate capacity for the given month.¹⁸ While output from nuclear plants does show some variation across months due to factors such as maintenance outages/derates, their hourly production tends not to fluctuate, as it can be quite costly for these units to ramp up and down. Cogeneration plants are typically used in industrial processes, and thus typically do not respond to wholesale market signals. Other generation types, such as geothermal, tend to operate similarly to nuclear plants,

¹⁶The AEO does not include projected coke prices for delivered power. Because coal and coke are substitutes, the price of coke is highly correlated with coke. We observe that over our sample, the cost for coke is, on average, \$0.40 per MMBTU higher than coal. Thus, we use the price of coal with a \$0.40 markup for the small number of coke units in our panel.

¹⁷If the shares work out such that a facility ever produces above its nameplate capacity, we instead force that facility to have uniform output for all hours within a month.

¹⁸For cogeneration units, we first compute a monthly capacity factor, and multiply this by the average fraction of their reported net generation that is sold to the grid—a number that is reported annually in the EIA-923 data.

or are so uncommon (e.g. wood-burning generators), that the benefit to directly modeling their supply decision in a more detailed manner would provide little-to-no benefit to our analysis.

Along with solar, grid-scale storage capacity is expanding at a rapid pace. However, storage is unique in its role as an electricity arbitrageur. Batteries are constrained by their state-of-charge, round-trip efficiency, and rated power capacity (their upper limit on charging and discharging), rather than by fuel costs or daily weather patterns. Thus, we cannot treat it similarly to the technologies described above.¹⁹ We treat the battery fleet in each subregion as a single price-taking agent who seeks to smooth the daily net load profile by charging in low net load periods and discharging during periods of high net load.

We construct the aggregate battery fleet in each subregion by combining data on the existing fleet with planned additions from EIA Form 860m. Planned additions report the rated power capacity but not the energy capacity, or duration of time the battery can continuously discharge at their maximum power capacity before having to recharge. To handle this, we probabilistically assign a duration of two or four hours.

We assume the objective of this subregional battery operator is to flatten the daily net load curve rather than to arbitrage prices across time. However, because we have no intra-regional transmission constraints, our wholesale prices will be convex with respect to net load. Thus, this objective function mirrors that of a profit maximizing agent. In addition, we assume this battery operator has perfect foresight over the net load within a 24-hour period.²⁰ The battery operator's "peak-shaving problem" is described as follows:

For each day, d , the operator observes hourly net load, d_t and chooses x_t and y_t , charge and discharge, to minimize the peak net load and maximize the net load trough. Formally, for each

¹⁹Hydroelectric resources also act as arbitrageurs, shifting energy delivery to periods of highest value. However, unlike battery storage which typically operates on a short-term, typically daily, cycle, Hydro scheduling is governed by additional intertemporal constraints spanning seasons (e.g., reservoir management and environmental flows). Modeling these constraints are beyond the scope of this paper. See [Bushnell \(2003\)](#) for further discussion.

²⁰At the time of solving for battery charge and discharge, net load is equal to our forecasts for regional demand minus solar, wind, hydro, nuclear, cogeneration, and other thermal plants.

hour, t :

$$x_t = \min(K, \max(0, \underline{d} - d_t)), \quad (5)$$

$$y_t = \min(K, \max(0, d_t - \bar{d})), \quad (6)$$

where we use binary search to numerically solve our peak and trough thresholds, $\underline{d}$ and $\bar{d}$, subject to a daily energy balance constraint:

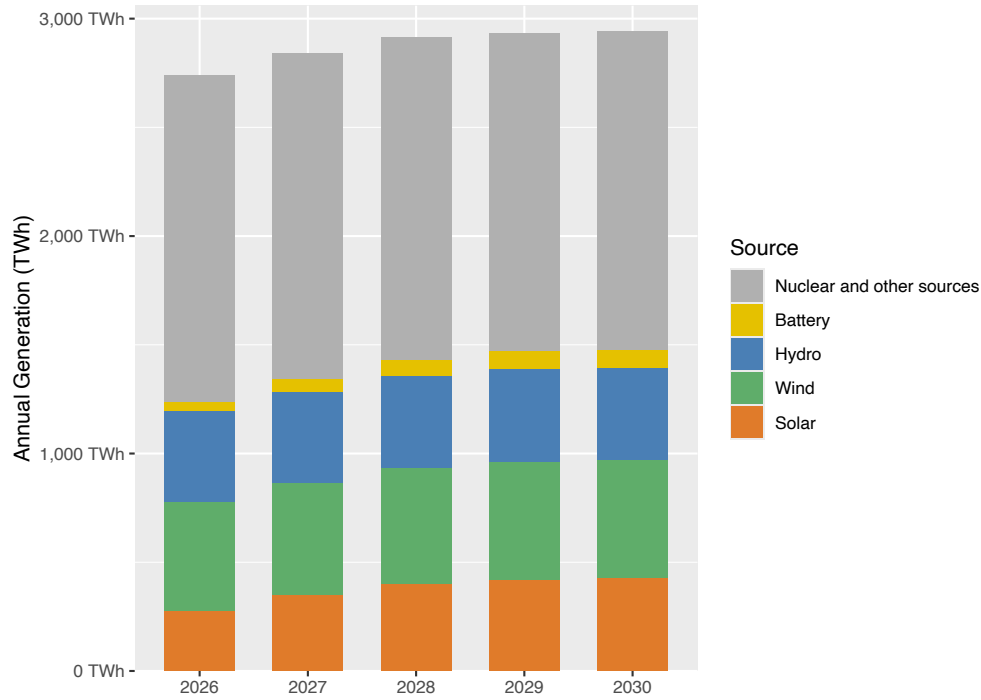
$$\begin{aligned} \sum_{t=0}^{24} y_t &= \eta \sum_{t=0}^{24} x_t, \text{ where} \\ \sum_{t=0}^{24} y_t &\leq E \\ \eta \sum_{t=0}^{24} x_t &\leq E \end{aligned} \quad (7)$$

Equation 7 ensures that the battery operator charge and discharge is exactly equal and does not exceed its total energy capacity (in MWh), E . The parameter η represents the round-trip efficiency of batteries, which we set at 0.85.²¹

Figure A6 shows the supply from non-thermal generators in each year used in our forecast. The majority of this generation comes from nuclear and other sources (predominately nuclear) though solar, wind, and hydro all contribute meaningfully. The majority of the growth comes from increased solar generation.

²¹Batteries lose some energy when charging and discharging. This value is typically 0.8 to 0.9 for grid-scale storage.

Appendix Figure A6: Non-thermal supply forecast



E Appendix: The Social Planner's Problem

For each hour t , we solve a national dispatch with no regional constraints:

$$\begin{aligned}
\min_{q_{it}} \quad & \sum_{i \in I} mc_{it} q_{it} \\
\text{s.t.} \quad & \sum_{i \in I} q_{it} = \text{DC Load}_t^{\text{national}} \\
& 0 \leq q_{it} \leq K_{it}^{\text{idle}} \quad \forall i \in I.
\end{aligned}$$

That is, we minimize the total cost of generation required to meet total data center demand, $\text{DC Load}_t^{\text{national}}$, subject to a generator capacity constraint, K_{it}^{idle} —the capacity of generator i not dispatched in the no-DC counterfactual. For the ex-post period, this means we are solving over one of the counterfactuals which originally subtracted assumed data center demand from the observed net generation of our thermal panel. In the forecast period, since we build net load from the ground

up, this means solving the planner's problem from the dispatch solution that does not include data center demand.

NOGRR Number	<u>282</u>	NOGRR Title	Large Electronic Load Ride-Through Requirements
Date Posted	November 14, 2025		

Requested Resolution	Normal
Nodal Operating Guide Sections Requiring Revision	2.6.4, Frequency Ride-Through Requirements for Large Electronic Loads (new) 2.14, Voltage Ride-Through Requirements for Large Electronic Loads (new)
Related Documents Requiring Revision/Related Revision Requests	Nodal Protocol Revision Request (NPRR) 1308, Related to NOGRR282, Large Electronic Load Ride-Through Requirements
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) establishes frequency and voltage ride-through requirements for Large Electronic Loads.
Reason for Revision	☒ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☐ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive <i>(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)</i>
Justification of Reason for Revision and Market Impacts	The frequency and voltage ride-through requirements in this NOGRR are necessary to ensure Large Electronic Loads do not present a reliability risk to the system by tripping when frequency and voltage excursions within a specified range occur. ERCOT has identified many events since October 2022 that included Load loss from one or more LELs during a typical voltage disturbance in which system

	protection operated as designed. As LELs increase on the ERCOT System, similar events would be expected to increase in magnitude and frequency, leading to frequency instability and other reliability problems absent frequency and voltage ride-through requirements. ERCOT has also identified ride-through risks associated with other Large Loads and intends to submit a NOGRR to address those risks. ERCOT anticipates that the requirements for those Large Loads could differ from those proposed in this NOGRR based on differences in the technology of the loads, just as ERCOT's ride-through requirements for different generating technologies differ from one technology to another.
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Sponsor	
Name	Patrick Gravois
E-mail Address	patrick.gravois@ercot.com
Company	ERCOT
Phone Number	512-248-4695
Cell Number	
Market Segment	Not applicable

Market Rules Staff Contact	
Name	Cory Phillips
E-Mail Address	cory.phillips@ercot.com
Phone Number	512-248-6464

Proposed Guide Language Revision

2.6.4 Frequency Ride-Through Requirements for Large Electronic Loads

- (1) A Customer that proposes to interconnect or maintains an interconnection of a Large Electronic Load (LEL) with the ERCOT System shall ensure the LEL complies with the frequency ride-through requirements of this section, unless:
 - (a) The LEL received approval to energize from ERCOT on or before November 14, 2025; or
 - (b) The LEL satisfied the following requirements on or before November 14, 2025:

- (i) Its Large Load Interconnection Study (LLIS) has been completed and results communicated in the manner contemplated by paragraph (6) of Planning Guide Section 9.4, LLIS Report and Follow-up; and
 - (ii) The interconnecting TDSP for the LEL has provided the confirmation or letter contemplated in Planning Guide Section 9.5, Interconnection Agreements and Responsibilities.
- (2) An LEL shall ride through frequency disturbances of the magnitude and duration specified in Table A below, as measured at the LEL's Service Delivery Point, or if the LEL is co-located with a Generation Resource or Energy Storage Resource, at the Point of Interconnection Bus (POIB) of that Resource. An LEL is not required to ride-through if it is either performing in accordance with its interconnecting TDSP's Under-Frequency Load Shed (UFLS) program or providing an Ancillary Service that would require the LEL to trip or reduce consumption due to a frequency disturbance.

Table A

Frequency (f) in (Hz)	Minimum Ride-Through Time (seconds)
$f > 61.8$	May ride-through or trip
$61.2 < f \leq 61.8$	299
$58.8 \leq f \leq 61.2$	continuous
$57.0 \leq f < 58.8$	299
$f < 57.0$	May ride-through or trip

- (3) Nothing in paragraph (2) above shall be interpreted to require an LEL to trip or transfer load to backup generation for frequency conditions beyond those for which ride-through is required.
- (4) If an LEL is consuming electric current from the grid at the time of the frequency disturbance, the LEL shall continue to consume electric current from the grid during frequency deviations requiring ride-through. In addition, an LEL should continue to consume active power within 10% of the pre-disturbance level during frequency deviations requiring ride-through.
- (5) If protection systems are installed and activated to trip the LEL, they shall enable the LEL to ride-through frequency conditions beyond those defined in paragraph (2) above to the maximum level the equipment allows, unless the protection systems are set to respond to an UFLS event or Ancillary Service obligation.
- (6) If frequency protection schemes are installed and activated to trip an LEL, they shall use filtered quantities or add sufficient time delays to prevent misoperations while providing

the desired equipment protection. Protection schemes shall not trip an LEL based on an instantaneous frequency measurement.

- (7) If ERCOT determines that an LEL has failed to ride through a frequency disturbance in accordance with any requirement in this Section 2.6.4:
- (a) The interconnecting TDSP shall provide available information to ERCOT to assist with ERCOT's event analysis;
 - (b) The Customer representing the LEL shall:
 - (i) Investigate and determine the root cause of the frequency ride-through failure and report the results of the investigation to ERCOT within 90 days of ERCOT's request;
 - (ii) Develop a plan to ensure the LEL can meet the applicable ride-through performance requirements and submit the plan to ERCOT within 90 days of completion of (i) above; and
 - (iii) Implement the plan upon ERCOT approval within 180 days of (ii) above unless ERCOT approves a longer timeline.
 - (c) Notwithstanding the requirements of paragraph (b) above, if ERCOT determines that the operation of an LEL following a failure to comply with the requirements of this Section 2.6.4 poses an imminent risk to local or system reliability, ERCOT may require the LEL to disconnect from the ERCOT System and remain disconnected until the Customer representing the LEL has demonstrated to ERCOT's satisfaction that the LEL can comply with the ride-through performance requirements of this Section.

2.14 Voltage Ride-Through Requirements for Large Electronic Loads

- (1) A Customer that proposes to interconnect or maintains an interconnection of a Large Electronic Load (LEL) with the ERCOT System shall ensure the LEL complies with the voltage ride-through requirements of this section, unless:
- (a) The LEL received approval to energize from ERCOT on or before November 14, 2025; or
 - (b) The LEL satisfied the following requirements on or before November 14, 2025:
 - (i) Its Large Load Interconnection Study (LLIS) has been completed and results communicated in the manner contemplated by paragraph (6) of Planning Guide Section 9.4, LLIS Report and Follow-up; and
 - (ii) The interconnecting TDSP for the LEL has provided the confirmation or letter contemplated in Planning Guide Section 9.5, Interconnection Agreements and Responsibilities.

- (2) An LEL interconnecting with the ERCOT System shall ride through the root-mean-square positive sequence voltage conditions of the magnitude and duration specified in Table A below, as measured at the LEL's Service Delivery Point, or if the LEL is co-located with a Generation Resource or Energy Storage Resource, at the Point of Interconnection Bus (POIB) of that Resource. An LEL shall remain connected to the Transmission Grid during voltage conditions requiring ride-through. Additional LEL performance requirements for voltage conditions requiring ride-through are listed below.

Table A

Root-Mean-Square Positive Sequence Voltage (p.u. of nominal)	Minimum Ride-Through Time (seconds)
$V > 1.20$	May ride-through or trip
$1.10 < V \leq 1.20$	2.0
$0.90 \leq V \leq 1.10$	Continuous
$0.80 \leq V < 0.90$	2.0
$0.50 \leq V < 0.80$	0.5
$0.20 \leq V < 0.50$	0.25
$V < 0.20$	0.15

- (a) When voltage at the Service Delivery Point or, if the LEL co-located with a Generation Resource or Energy Storage Resource, at the POIB, remains within the continuous operating range in Table A during a disturbance or exceeds 1.1 per unit and remains below 1.2 per unit for less than 2 seconds for an overvoltage condition, the LEL shall continue consuming active power from the grid at the pre-disturbance level during the disturbance.
- (b) When voltage at the Service Delivery Point or POIB falls below 0.9 per unit but remains above 0.8 per unit and then returns to above 0.9 per unit within 2 seconds, the LEL shall continue consuming active power from the grid during the low voltage condition. In such cases, the LEL may reduce its active power consumption proportional to the voltage drop but shall return to 90% of its pre-disturbance consumption level from the grid within one second of voltage at the Service Delivery Point or POIB returning to above 0.9 per unit.
- (c) For any voltage condition at the Service Delivery Point or POIB that an LEL is required to ride-through and involves a voltage condition below 0.8 per unit, the LEL may decrease active power consumption from the grid but shall return to at least 90% of its pre-disturbance consumption level from the grid within one second of voltage at the Service Delivery Point or POIB returning to above 0.90 per unit. Additional performance requirements for the allowable reduction of consumption in active power when voltage drops below 0.8 per unit are defined as follows:

- (i) For any LEL that satisfies the requirements in paragraph (1)(b) above after November 14, 2025 but on or before January 1, 2028, if the LEL needs to temporarily reduce active power consumption from the grid to allow the facility to ride through the voltage disturbance in accordance with the performance requirements defined in paragraph (c) above, that reduction in active power shall be proportional to the voltage drop for any voltage between 0.8 and 0.5 per unit at the Service Delivery Point or POIB, if capable. The LEL may reduce active power consumption as much as needed for voltage drops below 0.5 per unit. If the LEL equipment is not capable of the performance described above, then the LEL may reduce active power consumption as much as necessary to remain connected to the grid but shall return to pre-disturbance consumption as defined in paragraph (c) above.
 - (ii) For any LEL that satisfies the requirements in paragraph (1)(b) above after January 1, 2028, the LEL shall continue consuming active power from the grid when the voltage at the Service Delivery Point or POIB is between 0.8 and 0.5 per unit but may temporarily reduce active power consumption from the grid proportional to the voltage drop. When the voltage at the Service Delivery Point or POIB is below 0.5 per unit, the LEL may reduce active power consumption as needed to allow the facility to ride through the voltage disturbance in accordance with the performance requirements defined in paragraph (c) above.
- (d) When a voltage disturbance causes the voltage at the Service Delivery Point or POIB to drop outside the continuous operating range in Table A of paragraph (2) above, an LEL shall not consume electric current during the disturbance at a level that exceeds 125% of its maximum electric current consumption during normal operations.
- (3) Nothing in paragraph (2) above shall be interpreted to require an LEL to trip or transfer load to backup generation for voltage conditions beyond those for which ride-through is required.
- (4) If installed and activated to trip or transfer the LEL, all protection systems (including but not limited to protection for over-/under-voltage) shall enable the LEL to ride-through voltage conditions beyond those defined in paragraph (2) above to the maximum level the equipment allows.
- (5) If instantaneous over-current or over-voltage protection systems are installed and activated to trip or transfer the LEL, they shall use filtered quantities or time delays to prevent misoperation while providing the desired equipment protection. Any alternating current instantaneous over-voltage protection that could disrupt the LEL power

consumption shall use a measurement window of at least one cycle of fundamental frequency.

- (6) An LEL shall not implement a load trip or transfer scheme that disconnects or transfers load to backup generation due solely to a certain number of voltage sags or swells within a certain period of time if the LEL is required under paragraph (2) above to ride through each such condition.
- (7) If ERCOT determines that an LEL has failed to ride through a voltage disturbance in accordance with any requirement in this Section 2.14:
 - (a) The interconnecting TDSP shall provide available information to ERCOT to assist with ERCOT's event analysis;
 - (b) The Customer representing the LEL shall:
 - (i) Investigate and determine the root cause of the voltage ride-through failure and report the results of the investigation to ERCOT within 90 days of ERCOT's request;
 - (ii) Develop a plan to ensure the LEL can meet the applicable ride-through performance requirements and submit the plan to ERCOT within 90 days of completion of (i) above; and
 - (iii) Implement the plan upon ERCOT approval within 180 days of (ii) above unless ERCOT approves a longer timeline.
 - (c) Notwithstanding the requirements of paragraph (b) above, if ERCOT determines that the operation of an LEL following a failure to comply with the requirements of this Section 2.14 poses an imminent risk to local or system reliability, ERCOT may require the LEL to disconnect from the ERCOT System and remain disconnected until the Customer representing the LEL has demonstrated to ERCOT's satisfaction that the LEL can comply with the ride-through performance requirements of this Section.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
CONSUMERS ENERGY COMPANY for
authority to increase its rates for the generation
and distribution of electricity and for other relief

Case No. **U-22070**

PROOF OF SERVICE

Carol Dane says that on **October 2, 2026**, she served a copy of the **Testimony and Exhibits of John Richter** on behalf of the **Great Lakes Renewable Energy Association** to **Consumers Energy Company** upon the following parties via email:

Name/Party	E-mail Address
ADMINISTRATIVE LAW JUDGE Christopher S. Saunders	saundersc4@michigan.gov
CONSUMERS ENERGY COMPANY Gary A. Gensch, Jr. Anne M. Uitvlugt Bret A. Totoraitis Evan B. Keimach Michael C. Rampe Spencer A. Sattler	mpsc.filings@cmsenergy.com gary.genschjr@cmsenergy.com anne.uitvlugt@cmsenergy.com bret.totoraitis@cmsenergy.com evan.keimach@cmsenergy.com Michael.rampe@cmsenergy.com spencer.sattler@cmsenergy.com
MICHIGAN PUBLIC SERVICE COMMISSION STAFF Nicholas Q. Taylor Alena M. Clark Amit T. Singh Michael J. Orris Lori Mayabb	taylorn10@michigan.gov clarka55@michigan.gov singha9@michigan.gov orrism@michigan.gov mayabbl@michigan.gov
ATTORNEY GENERAL DANA NESSEL Celeste R. Gill Lucas Wollenzien	Ag-enra-spec-lit@michigan.gov gillc1@michigan.gov wollenzienl@michigan.gov
MICHIGAN ENVIRONMENTAL COUNCIL, CITIZENS UTILITY BOARD OF MICHIGAN; NATURAL RESOURCES DEFENSE COUNCIL; SIERRA CLUB Christopher M. Bzdok Tracy Jane Andrews	chris@tropospherelegal.com tjandrews@tropospherelegal.com

Holly L. Hillyer Natasha Fowles Sean Clark Sue Fruchey Aiden Glaser Schoff Kayla Cherry Ben Havumaki Shannon Fisk Helen Li Joshua Denzler	holly@tropospherelegal.com natasha@tropospherelegal.com sean@tropospherelegal.com sue@tropospherelegal.com aglaserschoff@synapse-energy.com kcherry@synapse-energy.com bhavumaki@synapse-energy.com sfisk@earthjustice.org hli@earthjustice.org jdenzler@5lakesenergy.com
WALMART, INC. Melissa M. Horne	mhorne@hcc-law.com
THE KROGER COMPANY Kurt J. Boehm Jody Kyler Cohn Michael L. Kurtz	KBoehm@BKLawfirm.com JKylerCohn@BKLawfirm.com mkurtz@BKLawfirm.com
MICHIGAN CABLE TELECOMMUNICATIONS ASSOCIATION Sean P. Gallagher Joann Schofield	sgallagher@fraserlawfirm.com jschofield@fraserlawfirm.com
MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL; FOUNDRY ASSOCIATION OF MICHIGAN; ENERGY MICHIGAN; INSTITUTE FOR ENERGY INNOVATION; ADVANCED ENERGY UNITED Laura A. Chappelle Timothy J. Lundgren Justin K. Ooms Haylee N. Skank	lachappelle@varnumlaw.com tjlundgren@varnumlaw.com jkooms@varnumlaw.com hnskank@varnumlaw.com
SOLAR TECHNOLOGY LLC; HEMLOCK SEMI CONDUCTOR Jennifer U. Heston	jheston@potomaclaw.com
MICHIGAN MUNICIPAL ASSOCIATION FOR UTILITY ISSUES (MI-MAUI) AND THE MICHIGAN COALITION TO PROTECT PUBLIC RIGHTS-OF-WAY (PROTEC) Nathan D. Inks Michael J. Watza	nathan@bloomsluggett.com mike@bloomsluggett.com

URBAN CORE COLLECTIVE Amanda Urban Mark Templeton	aurbanlaw@gmail.com templeton@uchicago.edu
MICHIGAN STATE UTILITY WORKERS COUNCIL Benjamin L. King	bking@michworkerlaw.com
HOME BUILDERS ASSOCIATION OF MICHIGAN Cole V. Lussier Sharon M. Sanders	clussier@dickinsonwright.com ssanders@dickinsonwright.com
ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY (ABATE) Stephen A. Campbell Michael J. Pattwell Benjamin J. Holwerda	scampbell@ClarkHill.com mpattwell@ClarkHill.com bholwerda@ClarkHill.com
THE ECOLOGY CENTER, ENVIRONMENTAL LAW & POLICY CENTER, UNION OF CONCERNED SCIENTISTS AND VOTE SOLAR Daniel Abrams Katie S. Duckworth Nicholas Wallace Alondra Estrada	mpscdockets@elpc.org dabrams@elpc.org kduckworth@elpc.org nwallace@elpc.org aestrada@elpc.org

PUBLIC LAW RESOURCE CENTER PLLC

Carol Dane

Carol A. Dane
Public Law Resource Center PLLC
University Office Place
333 Albert Avenue, Suite 425
East Lansing, MI 48823
Telephone: (517) 999-3782
E-mail: adminasst@publiclawresourcecenter.com

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