



A "no data center" sign sits in a field Jan. 4, 2026, near the intersection of West County Road 550 South and State Road 109 near Grant City, Ind., in Henry County. Credit: Jenna Watson/Mirror Indy

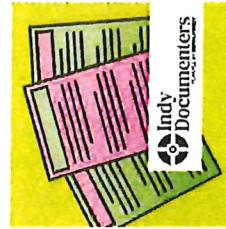
The company has broken ground on a data center campus near Monrovia in Morgan County, about 10 miles southwest of Indianapolis city limits. The 550-acre site will hold several data center buildings and another support building. It's unclear how much energy and water the site would use, but Google has said it will pay for 100% of the power it uses and not use groundwater at the site.

But others being built near Indianapolis might not be so large.

Another company, called RadiusDC, is planning to build two data centers in Plainfield. On Jan. 5, the Plainfield Plan Commission approved the company's proposal to build two 100,000-square-foot data centers.

The company has said the site would use 24 megawatts of electricity and use about 700 gallons of water a day — the equivalent to the average daily water usage of two to three average houses or 14-18 loads of laundry.

East of Indianapolis, Surge Development planned to build a 775-acre Hancock County MegaSite with a large-scale data center and industrial complex, but the company later withdrew its application after residents opposed it.



Indy Documenters track data center proposals affecting your neighborhood. 📄 Read their notes.

UPCOMING EVENT

Chat N Chew with Mirror Indy

Local neighborhoods are speaking out against data centers.
What do you have to say?

📅 Feb. 24, 6-7:30 p.m.

📍 The AMP at 16 Tech, 1220 Waterway Blvd.

🆓 Free, but must register

Mirror Indy, a nonprofit newsroom, is funded through grants and donations from individuals, foundations and organizations.

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First Regular Session of the 124th General Assembly (2025)

PRINTING CODE. Amendments: Whenever an existing statute (or a section of the Indiana Constitution) is being amended, the text of the existing provision will appear in this style type, additions will appear in this style type, and deletions will appear in ~~this style type~~.

Additions: Whenever a new statutory provision is being enacted (or a new constitutional provision adopted), the text of the new provision will appear in this style type. Also, the word NEW will appear in that style type in the introductory clause of each SECTION that adds a new provision to the Indiana Code or the Indiana Constitution.

Conflict reconciliation: Text in a statute in this style type or ~~this style type~~ reconciles conflicts between statutes enacted by the 2024 Regular Session of the General Assembly.

HOUSE ENROLLED ACT No. 1007

AN ACT to amend the Indiana Code concerning utilities.

Be it enacted by the General Assembly of the State of Indiana:

SECTION 1. IC 6-3.1-45 IS ADDED TO THE INDIANA CODE AS A NEW CHAPTER TO READ AS FOLLOWS [EFFECTIVE JANUARY 1, 2025 (RETROACTIVE)]:

Chapter 45. Small Modular Nuclear Reactor Manufacturing Expense Tax Credit

Sec. 1. This chapter applies to a taxable year beginning after December 31, 2024.

Sec. 2. As used in this chapter, "department" refers to the department of state revenue.

Sec. 3. As used in this chapter, "qualified investment" means a taxpayer's expenditures incurred in the manufacture of a small modular nuclear reactor in Indiana.

Sec. 4. As used in this chapter, "small modular nuclear reactor" means a nuclear reactor that:

- (1) has a rated electric generating capacity of not more than four hundred seventy (470) megawatts;
 - (2) is capable of being constructed and operated, either:
 - (A) alone; or
 - (B) in combination with one (1) or more similar reactors if additional reactors are, or become, necessary;
- at a single site; and

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(3) is required to be licensed by the United States Nuclear Regulatory Commission.

The term includes a nuclear reactor that is described in this section and that uses a process to produce hydrogen that can be used for energy storage, as a fuel, or for other uses.

Sec. 5. As used in this chapter, "state tax liability" means a taxpayer's total tax liability that is incurred under:

- (1) IC 6-3-1 through IC 6-3-7 (the adjusted gross income tax);
- (2) IC 6-5.5 (the financial institutions tax); and
- (3) IC 27-1-18-2 (the insurance premiums tax);

as computed after the application of the credits that under IC 6-3.1-1-2 are to be applied before the credit provided by this chapter.

Sec. 6. As used in this chapter, "taxpayer" means a person, corporation, partnership, or other entity that makes a qualified investment.

Sec. 7. A taxpayer is entitled to a credit against the taxpayer's state tax liability in the taxable year in which the taxpayer makes a qualified investment. The amount of the credit provided by this section is equal to twenty percent (20%) of the amount of the taxpayer's qualified investment.

Sec. 8. (a) If the amount determined under section 7 of this chapter for a taxpayer in a taxable year exceeds the taxpayer's state tax liability for that taxable year, the taxpayer may carry the excess over to the following taxable years. The amount of the credit carryover from a taxable year shall be reduced to the extent that the carryover is used by the taxpayer to obtain a credit under this chapter for any subsequent taxable year.

(b) A taxpayer is not entitled to a carryback or refund of any unused credit.

Sec. 9. (a) If a pass through entity is entitled to a credit under section 7 of this chapter but does not have state tax liability against which the tax credit may be applied, an individual who is a shareholder, partner, or member of the pass through entity is entitled to a tax credit equal to:

- (1) the tax credit determined for the pass through entity for the taxable year; multiplied by
- (2) the percentage of the pass through entity's distributive income to which the shareholder, partner, or member is entitled.

(b) The credit provided under subsection (a) is in addition to a tax credit to which a shareholder, partner, or member of a pass



through entity is otherwise entitled under this chapter. However, a pass through entity and an individual who is a shareholder, partner, or member of the pass through entity may not claim more than one (1) credit for the same qualified investment.

Sec. 10. To receive the credit provided by this chapter, a taxpayer must claim the credit on the taxpayer's annual state tax return or returns in the manner prescribed by the department. The taxpayer shall submit to the department:

- (1) information verifying that the taxpayer's qualified investment was made with respect to a small modular nuclear reactor that will be manufactured in Indiana; and
- (2) all information that the department determines is necessary for the calculation of the credit provided by this chapter.

SECTION 2. IC 8-1-7.9 IS ADDED TO THE INDIANA CODE AS A NEW CHAPTER TO READ AS FOLLOWS [EFFECTIVE UPON PASSAGE]:

Chapter 7.9. Expedited Generation Resource Plans and Large Load Customers

Sec. 1. (a) As used in this chapter, "acquisition" means a project or an arrangement that is undertaken:

- (1) by an energy utility to construct, purchase, lease, or otherwise acquire a generation resource; and
- (2) in accordance with an approved EGR plan.

(b) The term includes the purchase of energy or capacity through a power purchase agreement.

Sec. 2. As used in this chapter, "acquisition costs" means the total costs of an acquisition made under an EGR plan, including:

- (1) planning;
- (2) construction; and
- (3) operating;

costs related to the acquisition.

Sec. 3. As used in this chapter, "appropriate regional transmission organization" has the meaning set forth in IC 8-1-8.5-13(b).

Sec. 4. As used in this chapter, "commission" refers to the Indiana utility regulatory commission created by IC 8-1-1-2.

Sec. 5. (a) As used in this chapter, "construction and operating costs" means costs:

- (1) incurred or to be incurred by an energy utility under this chapter after the issuance of an order by the commission under this chapter; and



(2) related to an approved or commission modified acquisition or project.

(b) The term includes procurement, contractual, construction, operating, maintenance, financing, legal, regulatory, and project evaluation, analysis, and development costs incurred after the issuance of an order by the commission under this chapter.

Sec. 6. As used in this chapter, "corporation" refers to the Indiana economic development corporation established by IC 5-28-3-1 or its successor.

Sec. 7. As used in this chapter, "energy utility" means:

- (1) an electric utility listed in 170 IAC 4-7-2(a) and any successor in interest to that utility; or
- (2) a corporation organized under IC 8-1-13.

Sec. 8. As used in this chapter, "expedited generation resource plan", or "EGR plan", means a plan developed by an energy utility for acquiring generation resources to meet load growth that exceeds the lesser of:

- (1) five percent (5%) of the energy utility's average peak demand over the most recent three (3) calendar years; or
- (2) one hundred fifty (150) megawatts.

Sec. 9. As used in this chapter, "generation resource submittal" means a compliance filing made to the commission for approval of the acquisition of a specific generation resource in accordance with the criteria set forth in an approved EGR plan.

Sec. 10. As used in this chapter, "large load customer" means a new or existing customer of an energy utility, or not more than four (4) multiple new or existing customers of an energy utility, that:

- (1) requests new or additional electricity demand that in the aggregate exceeds the lesser of:
 - (A) five percent (5%) of the energy utility's average peak demand over the most recent three (3) calendar years; or
 - (B) one hundred fifty (150) megawatts;
- (2) plans to make a capital investment that exceeds five hundred million dollars (\$500,000,000) in a new or expanded facility in Indiana; and
- (3) plans to employ at the new or expanded facility in Indiana at least fifty (50) full-time employees with wages that on average meet or exceed the most recently published annual national average according to the Bureau of Labor Statistics of the United States Department of Labor.

Sec. 11. As used in this chapter, "office" refers to the Indiana



office of energy development established by IC 4-3-23-3.

Sec. 12. (a) As used in this chapter, "planning costs" means costs:

- (1) incurred or to be incurred by an energy utility before the issuance of an order by the commission under this chapter; and
 - (2) related to an acquisition or project.
- (b) The term includes study, analysis, pre-engineering, engineering, legal, financing, and regulatory costs.

Sec. 13. As used in this chapter, "pre-filing meeting" means a meeting to review and discuss a filing or submittal by an energy utility in accordance with:

- (1) section 18 of this chapter;
 - (2) section 20 of this chapter; or
 - (3) section 22 of this chapter;
- as applicable.

Sec. 14. As used in this chapter, "project" refers to a project relating to energy infrastructure and generation resources that:

- (1) are required primarily to serve a large load customer of an energy utility; and
- (2) may be designed to serve more than one (1) large load customer of the energy utility or to meet other customer demand or energy needs.

Sec. 15. As used in this chapter, "project costs" means the total costs of a project, including:

- (1) planning costs; and
 - (2) construction and operating costs;
- related to the project.

Sec. 16. As used in this chapter, "reasonable risk premium" means compensation:

- (1) negotiated between an energy utility and a large load customer; and
- (2) paid by the large load customer.

Sec. 17. (a) The commission may expedite, in accordance with this chapter, the review of filings and submittals made by an energy utility to meet the energy infrastructure and generation resource needs of customers. An energy utility may request an expedited review by the commission under either or both of the following:

- (1) Sections 18 through 21 of this chapter (concerning EGR plans).
- (2) Sections 22 through 24 of this chapter (concerning large



load customer projects).

(b) This chapter does not preclude an energy utility from petitioning the commission under other applicable statutes for approval of a generation resource acquisition to meet the needs of its customers.

(c) This chapter does not preclude an energy utility from petitioning the commission under, or in conjunction with, other applicable statutes, including:

- (1) IC 8-1-2-24;
- (2) IC 8-1-2-42;
- (3) IC 8-1-2.5;
- (4) IC 8-1-8.5;
- (5) IC 8-1-8.8; or
- (6) IC 8-1-39;

for approval of a project to meet the needs of large load customers.

Sec. 18. (a) This section applies to an energy utility that petitions the commission for approval of an EGR plan.

(b) An energy utility may file a petition with the commission for approval of an EGR plan to acquire generation resources to meet the extraordinary needs for electricity by the energy utility's customers.

(c) In a petition under this section, an energy utility must do the following:

- (1) Describe the energy utility's EGR plan for acquiring generation resources to meet the anticipated extraordinary growth in the load of its customers.
- (2) Demonstrate a need for generation capacity that exceeds the lesser of:
 - (A) five percent (5%) of the energy utility's average peak demand over the most recent three (3) calendar years; or
 - (B) one hundred fifty (150) megawatts.
- (3) Provide a load growth forecast for a minimum of five (5) years from the date of the petition.
- (4) Describe the status of customer contracts and commitments that support the load growth forecast described in subdivision (3).
- (5) Explain how the EGR plan is consistent with or differs from the energy utility's most recent integrated resource plan.
- (6) Propose the accounting authority needed from the commission to support the EGR plan.
- (7) Propose the manner in which the capital costs and operating and maintenance expenses related to the EGR plan



will be included in the energy utility's revenue requirement.

(8) Identify the type and amount of capacity and energy:

(A) that is included in the EGR plan;

(B) that does not exceed seventy-five percent (75%) of the energy utility's peak capacity over the forecast period described in subdivision (3); and

(C) with respect to which the energy utility may request expedited approval in a subsequent generation resource submittal.

(9) Identify the criteria to be included in a generation resource submittal that must be met for the acquisition to be approved by the commission.

(10) Certify that at least thirty (30) days before the filing of the petition the energy utility held a pre-filing meeting with the commission and the office of utility consumer counselor to review the EGR plan.

(11) Describe how the energy utility considered implementing grid enhancing technologies to defer or minimize the need for additional investment in generation.

(12) Describe how the EGR plan will support the provision of electric utility service with the attributes set forth in IC 8-1-2-0.6, including:

(A) reliability;

(B) affordability;

(C) resiliency;

(D) stability; and

(E) environmental sustainability.

(13) Describe how the EGR plan reasonably protects existing and future customers and is consistent with:

(A) the provision of safe, reliable, and affordable electric utility service; and

(B) economical rates.

(14) Include:

(A) verified testimony; and

(B) exhibits;

supporting the petition and constituting the energy utility's case in chief.

(15) Include a proposed order for the petition.

Sec. 19. (a) This section applies to an energy utility that petitions the commission for approval of an EGR plan.

(b) Notwithstanding IC 8-1-8.5 or any other statute, the commission may approve an energy utility's EGR plan to



construct, purchase, lease, or otherwise acquire generation resources under this chapter for purposes of meeting the needs of the energy utility's customers. The commission shall make its decision based on whether the relief requested is just, reasonable, and in the public interest.

(c) The commission may:

- (1) approve the energy utility's petition in its entirety;
- (2) deny the energy utility's petition in its entirety; or
- (3) modify the petition, subject to the energy utility's acceptance of the modification.

(d) The commission shall issue a final order on the petition not later than ninety (90) days after receiving the energy utility's complete petition. A petition is considered:

- (1) complete unless the commission provides a notice of deficiency to the energy utility not later than five (5) business days after the filing of the petition; and
- (2) approved if the commission does not issue a final order on the petition within the ninety (90) day period set forth in this subsection.

Sec. 20. (a) This section applies to an energy utility that submits to the commission for approval a generation resource submittal in accordance with an approved EGR plan.

(b) An energy utility may submit a generation resource submittal to the commission for approval of an acquisition that the energy utility intends to make in accordance with an approved EGR plan.

(c) In a generation resource submittal under this section, an energy utility must do the following:

- (1) Describe:
 - (A) the type of technology used in the generation resource to be acquired;
 - (B) the amount of capacity and energy to be acquired;
 - (C) key contractual terms for the acquisition; and
 - (D) the estimated acquisition costs.
- (2) Demonstrate that the acquisition meets the criteria set forth in the energy utility's approved EGR plan.
- (3) Explain how the acquisition is consistent with or differs from the energy utility's most recent integrated resource plan.
- (4) Detail the status of customer contracts and commitments that support the acquisition.
- (5) Certify that at least thirty (30) days before the filing of the generation resource submittal the energy utility held a



pre-filing meeting with the commission and the office of utility consumer counselor to review the acquisition.

(6) Describe how the energy utility considered implementing grid enhancing technologies to defer or minimize the need for additional investment in generation.

(7) Describe how the acquisition will support the provision of electric utility service with the attributes set forth in IC 8-1-2-0.6, including:

- (A) reliability;
- (B) affordability;
- (C) resiliency;
- (D) stability; and
- (E) environmental sustainability.

(8) Describe how the acquisition reasonably protects existing and future customers and is consistent with:

- (A) the provision of safe, reliable, and affordable electric utility service; and
- (B) economical rates.

(9) Include supporting affidavits and exhibits.

(10) Include a proposed order for the submittal.

Sec. 21. (a) This section applies to an energy utility that submits to the commission for approval a generation resource submittal in accordance with an approved EGR plan.

(b) Notwithstanding IC 8-1-8.5 or any other statute, the commission may approve an energy utility's generation resource submittal to construct, purchase, lease, or otherwise acquire generation resources under this chapter for purposes of meeting the needs of the energy utility's customers. The commission shall make its decision based solely on whether the submittal meets the criteria and requirements set forth in the energy utility's approved EGR plan.

(c) The commission may:

- (1) approve the energy utility's generation resource submittal in its entirety;
- (2) deny the energy utility's generation resource submittal in its entirety; or
- (3) modify the energy utility's generation resource submittal, subject to the energy utility's acceptance of the modification.

(d) The commission shall issue a final order on the energy utility's generation resource submittal not later than:

- (1) sixty (60) days after receiving the energy utility's complete generation resource submittal, if the acquisition is a clean



energy project (as defined in IC 8-1-8.8-2); or
 (2) one hundred twenty (120) days after receiving the energy utility's complete generation resource submittal, if the acquisition would otherwise require a certificate under IC 8-1-8.5-2.

A generation resource submittal is considered complete unless the commission provides a notice of deficiency to the energy utility not later than five (5) business days after the filing of the generation resource submittal. A generation resource submittal is considered approved if the commission does not issue a final order on the generation resource submittal within the period set forth in subdivision (1) or (2), as applicable.

Sec. 22. (a) This section applies to an energy utility that petitions the commission for approval of a project to serve a large load customer.

(b) An energy utility may submit to the commission a petition for approval of a project to serve a large load customer only if the following are satisfied:

(1) The petition concerns serving the energy needs of a large load customer.

(2) The large load customer commits to significant and meaningful financial assurances that must:

(A) include reimbursement by the large load customer of at least eighty percent (80%) of the project costs reasonably allocable to the large load customer; and

(B) afford protections for the energy utility's existing and future customers from project costs reasonably allocable to the large load customer regardless of whether the large load customer ultimately takes service in the anticipated amount and within the anticipated time frame.

(3) At least thirty (30) days before the energy utility's submission of the petition to the commission, the energy utility held at least one (1) pre-filing meeting with:

(A) the corporation;

(B) the office;

(C) the office of utility consumer counselor;

(D) the appropriate regional transmission organization; and

(E) the large load customer;

to review the project.

(c) An energy utility may petition the commission for approval of a project to serve:



(1) one (1) or more large load customers at one (1) or more locations; or

(2) not more than four (4) customers whose aggregate demand satisfies the amount set forth in section 10(1) of this chapter.

In any case in which more than one (1) large load customer is to be served by a project, a reference in this chapter to one (1) large load customer is a reference to all large load customers to be served by the project, in accordance with IC 1-1-4-1(3).

(d) In submitting a petition to the commission under this section, an energy utility must demonstrate that the large load customer and the associated projects meet the requirements of this chapter.

Sec. 23. (a) This section applies to an energy utility that petitions the commission for approval of a project to serve a large load customer.

(b) In a petition under this section, an energy utility must include, at a minimum, the following:

(1) The energy utility's complete case in chief, which must include, at a minimum, the following:

(A) An agreement from the large load customer that describes the financial assurances:

(i) that afford protections for the energy utility's existing and future customers; and

(ii) to which the large load customer has committed regardless of whether the large load customer ultimately takes service in the anticipated amount and within the anticipated time frame.

(B) A description of:

(i) the demand side management and self-generation options reviewed with the large load customer; and

(ii) the investments the large load customer will undertake to reasonably minimize the amount of incremental and other costs incurred by the energy utility.

(C) A description of how the energy utility considered implementing grid enhancing technologies to defer or minimize the need for additional investment in generation.

(D) A description of how the energy utility may provide for the requisite amount of electricity needed by the large load customer, including the estimated project costs.

(E) A description of how the expected project solution will support the provision of electric utility service with the attributes set forth in IC 8-1-2-0.6, including:



- (i) reliability;
- (ii) affordability;
- (iii) resiliency;
- (iv) stability; and
- (v) environmental sustainability.

(F) A description of how the expected project solution and its implementation, if approved by the commission, reasonably protects existing and future customers and is consistent with:

- (i) the provision of safe, reliable, and affordable electric utility service; and
- (ii) economical rates.

(G) A description of the changes that the energy utility will make to the energy utility's:

- (i) submissions under IC 8-1-8.5; or
- (ii) filings under IC 8-1-39;

or both, that are necessary to update the energy utility's plans under those statutes to incorporate the project.

(H) Information concerning each:

- (i) large load customer; and
- (ii) economic development project;

included in the petition.

(I) A letter to the energy utility from the corporation supporting the petition's request.

(J) A letter to the energy utility from the office certifying that a pre-filing meeting took place and that at the meeting:

- (i) the large load customer's proposed project; and
- (ii) the expected project solution proposed by the energy utility;

were adequately discussed.

(K) A description of the communications and information sharing that:

- (i) took place with the appropriate regional transmission organization before the pre-filing meeting described in clause (J); and
- (ii) concerned the capacity and energy needs of each large load customer included in the petition.

(L) A proposed order for the petition.

(2) A copy of a notice of filing with:

- (A) the corporation;
- (B) the office;



(C) the office of utility consumer counselor; and

(D) the appropriate regional transmission organization.

A notice that is delivered electronically to the parties set forth in this subdivision satisfies the notice requirement under this subdivision.

Sec. 24. (a) This section applies to an energy utility that petitions the commission for approval of a project to serve a large load customer.

(b) The commission may approve a petition in whole or in part. The commission shall make its decision based on whether the relief requested is just, reasonable, and in the public interest. The commission shall issue its final order on the petition not later than one hundred fifty (150) days after receiving the energy utility's complete petition and case in chief. A petition is considered:

(1) complete unless the commission provides a notice of deficiency to the energy utility not later than seven (7) business days after the filing of the petition; and

(2) approved if the commission does not issue a final order on the petition within the one hundred fifty (150) day period set forth in this subsection.

(c) If an energy utility files a petition that includes one (1) or more large load customers and one (1) or more proposed projects, the commission may:

(1) approve the energy utility's petition in its entirety;

(2) deny the energy utility's petition in its entirety; or

(3) modify the petition, subject to the energy utility's acceptance of the modification.

(d) The commission may approve a reasonable risk premium for a project if requested in an energy utility's petition and if the commission finds that the reasonable risk premium is appropriate.

If the commission approves a reasonable risk premium:

(1) the large load customer is responsible for the amount of the reasonable risk premium; and

(2) the reasonable risk premium may not be:

(A) included in the energy utility's:

(i) revenue requirement;

(ii) authorized net operating income; or

(iii) calculations under IC 8-1-2-42(d)(3) or IC 8-1-2-42(g)(3)(C); or

(B) otherwise considered for purposes of setting the authorized return in any future general rate case or other regulatory proceeding involving the energy utility.



(e) The commission may approve an energy utility's request to construct, purchase, lease, or otherwise acquire an energy generation resource under this chapter (notwithstanding and instead of under IC 8-1-2.5, IC 8-1-8.5, or IC 8-1-8.8) for the purpose of serving one (1) or more large load customers. In approving an energy utility's request under this chapter to acquire an energy generation resource to serve one (1) or more large load customers, the commission must find that:

- (1) the information provided by the energy utility under section 23 of this chapter is complete;
- (2) reasonable and demonstrable consideration was given to nongeneration alternatives by the parties involved;
- (3) existing and future customers of the energy utility will be adequately protected if the request is granted; and
- (4) the energy utility has considered the impact of the request on the energy utility's preferred resource portfolio in the energy utility's most recent integrated resource plan.

(f) An energy utility shall promptly notify the commission if, after the commission has approved a petition under subsection (e), one (1) or more of the large load customers with respect to whom the petition was approved:

- (1) no longer requires service from the energy utility or materially alters or terminates the large load customer's service requirements; and
- (2) the project is incomplete.

(g) The commission may, not later than sixty (60) days after receiving a notice under subsection (f), conduct an investigation under IC 8-1-2-58 through IC 8-1-2-60 to determine whether the public interest would still be served by completion of the project. An investigation under this subsection does not preclude the energy utility from continuing construction of the project to serve the large load customer or from continuing to serve the large load customer. If the commission finds that completion of the project is no longer in the public interest, the commission may modify or revoke the order approving the petition.

Sec. 25. (a) The commission shall review an energy utility's:

- (1) estimated acquisition costs submitted under section 20(c)(1)(D) of this chapter; or
- (2) estimated project costs filed under section 23(b)(1)(D) of this chapter;

as applicable.

(b) If the commission approves, with or without modification, an



energy utility's generation resource submittal or petition for approval of a project, the energy utility may recover:

- (1) acquisition costs; or
- (2) project costs;

as applicable, that have been reviewed and found reasonable by the commission, with a return at the energy utility's weighted average cost of capital.

(c) If the commission denies an energy utility's generation resource submittal or petition for approval of a project, the energy utility may recover planning costs that have been reviewed and found reasonable by the commission, without a return.

(d) Absent fraud, concealment, or gross mismanagement, an energy utility may recover:

- (1) acquisition costs; or
- (2) project costs;

as applicable, with a return at the energy utility's weighted average cost of capital, that the energy utility has incurred or contractually will incur in reliance on a commission order issued under this chapter.

Sec. 26. (a) Upon request by an energy utility, the commission shall determine whether the information and related materials filed or submitted, or to be filed or submitted, by an energy utility under this chapter:

- (1) are confidential under IC 5-14-3-4 or are trade secrets under IC 24-2-3;
- (2) are exempt from public access and disclosure by Indiana law; and
- (3) must be treated as confidential and protected from public access and disclosure by the commission.

(b) The parties to a pre-filing meeting under this chapter shall execute a nondisclosure agreement to review or discuss information or materials considered confidential under IC 5-14-3-4 or to be trade secrets under IC 24-2-3.

(c) If the corporation is in negotiations with an industrial, research, or commercial prospect about a potential economic development project and, based on communications related to those negotiations, determines that the potential economic development project for a new or expanded facility in Indiana may result in the economic development project requiring new or increased energy demand of at least twenty (20) megawatts, the corporation shall notify the affected energy utility not later than fifteen (15) days after making the determination. All



communications of the corporation, including notice under this section to an affected energy utility, regarding a potential economic development project are considered confidential and exempt from disclosure under IC 5-14-3-4(b)(5). Upon the corporation's provision of the notice required by this subsection, any subsequent:

- (1) meeting;
- (2) pre-filing meeting;
- (3) communications; or
- (4) information sharing;

involving the corporation, the affected energy utility, or the industrial, research, or commercial prospect about a potential economic development project may be subject to a nondisclosure agreement with respect to information or materials considered confidential under IC 5-14-3-4 or to be trade secrets under IC 24-2-3.

(d) An energy utility may request, and the commission may approve, financial incentives under IC 8-1-8.8-11(a) for:

- (1) an acquisition; or
- (2) a project;

that qualifies as a clean energy project (as defined in IC 8-1-8.8-2).

(e) An energy utility may request that review of an arrangement under IC 8-1-2-24 and any related rates and charges under IC 8-1-2-25 that are:

- (1) submitted with a generation resource submittal; or
- (2) filed with a petition for a project;

under this chapter be reviewed and approved or denied by the commission not later than ninety (90) days after the date of submittal or filing, as applicable.

(f) Notwithstanding IC 8-1-8.5 or any other applicable statute, an energy utility may begin construction of an acquisition or a project before filing a petition or submittal under this chapter.

(g) The commission may require an energy utility to file with the commission progress reports and updates with respect to an acquisition or project under this chapter. Any required progress reports or updates under this subsection shall be made in a form and at a frequency that the commission determines to be reasonable.

SECTION 3. IC 8-1-8.5-2.1, AS AMENDED BY THE TECHNICAL CORRECTIONS BILL OF THE 2025 GENERAL ASSEMBLY, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2025]: Sec. 2.1. (a) This section does not apply to the retirement, sale, or transfer of:

HEA 1007 — Concur



- (1) a public utility's electric generation facility if the retirement, sale, or transfer is necessary in order for the public utility to comply with a federal consent decree; or
 - (2) an electric generation facility that generates electricity for sale exclusively to the wholesale market.
- (b) A public utility shall notify the commission if:
- (1) the public utility intends or decides to retire, sell, or transfer an electric generation facility with a capacity of at least eighty (80) megawatts; and
 - (2) the retirement, sale, or transfer:
 - (A) was not set forth in; or
 - (B) is to take place on a date earlier than the date specified in; the public utility's short term action plan in the public utility's most recently filed integrated resource plan.
- (c) Upon receiving notice from a public utility under subsection (b), the commission shall consider and may investigate, under IC 8-1-2-58 through IC 8-1-2-60, the public utility's intention or decision to retire, sell, or transfer the electric generation facility. In considering the public utility's intention or decision under this subsection, the commission shall examine the impact the retirement, sale, or transfer would have on the public utility's ability to meet:
- (1) the public utility's planning reserve margin requirements or other federal reliability requirements that the public utility is obligated to meet, as described in section ~~13(i)(4)~~ **13(n)(6)** of this chapter; and
 - (2) the reliability adequacy metrics set forth in section ~~13(e)~~ **13(h)** of this chapter.
- (d) Before July 1, 2026, if:
- (1) a public utility intends or decides to retire, sell, or transfer an electric generation facility with a capacity of at least eighty (80) megawatts; and
 - (2) the retirement, sale, or transfer:
 - (A) was not set forth in; or
 - (B) is to take place on a date earlier than the date specified in; the public utility's short term action plan in the public utility's most recently filed integrated resource plan;
- the commission shall not permit the public utility's depreciation rates, as established under IC 8-1-2-19, to be amended to reflect the accelerated date for the retirement, sale, or transfer of the electric generation asset unless the commission finds that such an adjustment is necessary to ensure the ability of the public utility to provide reliable service to its customers, and that the unamended depreciation rates



would cause an unjust and unreasonable impact on the public utility and its ratepayers.

(e) The commission may issue a general administrative order to implement this section.

(f) This section expires July 1, 2026.

SECTION 4. IC 8-1-8.5-13, AS AMENDED BY P.L.93-2024, SECTION 68, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2025]: Sec. 13. (a) The general assembly finds that it is in the public interest to support the reliability, availability, and diversity of electric generating capacity in Indiana for the purpose of providing reliable and stable electric service to customers of public utilities.

(b) As used in this section, "appropriate regional transmission organization", with respect to a public utility, refers to the regional transmission organization approved by the Federal Energy Regulatory Commission for the control area that includes the public utility's assigned service area (as defined in IC 8-1-2.3-2).

(c) As used in this section, "capacity market" means an auction conducted by an appropriate regional transmission organization to determine a market clearing price for capacity based on the planning reserve margin requirements established by the appropriate regional transmission organization for a planning year with respect to which an auction has not yet been conducted.

(d) As used in this section, "fall unforced capacity", or "fall UCAP", with respect to an electric generating facility, means:

(1) the capacity value of the electric generating facility's installed capacity rate adjusted for the electric generating facility's average forced outage rate for the fall period, calculated as required by the appropriate regional transmission organization or by the Federal Energy Regulatory Commission;

(2) a metric that is similar to the metric described in subdivision (1) and that is required by the appropriate regional transmission organization; or

(3) if the appropriate regional transmission organization does not require a metric described in subdivision (1) or (2), a metric that:

(A) can be used to demonstrate that a public utility has sufficient capacity to:

(i) provide reliable electric service to Indiana customers for the fall period; and

(ii) meet its planning reserve margin requirement and other federal reliability requirements described in subsection

~~(1)(4)~~; **(n)(6)**; and

(B) is acceptable to the commission.



(e) As used in this section, "MISO" refers to the regional transmission organization known as the Midcontinent Independent System Operator that operates the bulk power transmission system serving most of the geographic territory in Indiana.

(f) As used in this section, "planning reserve margin requirement", with respect to a public utility for a particular resource planning year, means the planning reserve margin requirement for that planning year that the public utility is obligated to meet in accordance with the public utility's membership in the appropriate regional transmission organization.

(g) As used in this section, "refuel" or "refueling" means a planned fuel conversion from one fuel source to another fuel source with respect to an electric generation resource with a nameplate capacity of at least one hundred twenty-five (125) megawatts by a public utility.

~~(g)~~ (h) As used in this section, "reliability adequacy metrics", with respect to a public utility, means calculations used to demonstrate all of the following:

(1) Subject to subsection ~~(q)(2)(B)~~; **(u)(2)**, that the public utility:

(A) has in place sufficient summer UCAP; or

(B) can reasonably acquire not more than:

(i) thirty percent (30%) of its total summer UCAP from capacity markets, with respect to a report filed with the commission under subsection ~~(t)(n)~~ before July 1, 2023; or

(ii) fifteen percent (15%) of its total summer UCAP from capacity markets, with respect to a report filed with the commission under subsection ~~(t)(n)~~ after June 30, 2023;

such that it will have sufficient summer UCAP;

to provide reliable electric service to Indiana customers, and to meet its planning reserve margin requirement and other federal reliability requirements described in subsection ~~(t)(4)~~; **(n)(6)**.

(2) Subject to subsection ~~(q)(2)(B)~~; **(u)(2)**, that the public utility:

(A) has in place sufficient winter UCAP; or

(B) can reasonably acquire not more than:

(i) thirty percent (30%) of its total winter UCAP from capacity markets, with respect to a report filed with the commission under subsection ~~(t)(n)~~ before July 1, 2023; or

(ii) fifteen percent (15%) of its total winter UCAP from capacity markets, with respect to a report filed with the commission under subsection ~~(t)(n)~~ after June 30, 2023;

such that it will have sufficient winter UCAP;

to provide reliable electric service to Indiana customers, and to



meet its planning reserve margin requirement and other federal reliability requirements described in subsection ~~(t)(4)~~: **(n)(6)**.

(3) Subject to subsection ~~(q)(2)(B)~~; **(u)(2)**, with respect to a report filed with the commission under subsection ~~(t)~~ **(n)** after June 30, 2026, that the public utility:

(A) has in place sufficient spring UCAP; or

(B) can reasonably acquire not more than fifteen percent (15%) of its total spring UCAP from capacity markets, such that it will have sufficient spring UCAP;

to provide reliable electric service to Indiana customers, and to meet its planning reserve margin requirement and other federal reliability requirements described in subsection ~~(t)(4)~~: **(n)(6)**.

(4) Subject to subsection ~~(q)(2)(B)~~; **(u)(2)**, with respect to a report filed with the commission under subsection ~~(t)~~ **(n)** after June 30, 2026, that the public utility:

(A) has in place sufficient fall UCAP; or

(B) can reasonably acquire not more than fifteen percent (15%) of its total fall UCAP from capacity markets, such that it will have sufficient fall UCAP;

to provide reliable electric service to Indiana customers, and to meet its planning reserve margin requirement and other federal reliability requirements described in subsection ~~(t)(4)~~: **(n)(6)**.

(i) As used in this section, "retire" or retirement" means a planned permanent ceasing of electric generation operations with respect to an electric generation resource with a nameplate capacity of at least one hundred twenty-five (125) megawatts by a public utility.

~~(t)~~ **(j)** As used in this section, "spring unforced capacity", or "spring UCAP", with respect to an electric generating facility, means:

(1) the capacity value of the electric generating facility's installed capacity rate adjusted for the electric generating facility's average forced outage rate for the spring period, calculated as required by the appropriate regional transmission organization or by the Federal Energy Regulatory Commission;

(2) a metric that is similar to the metric described in subdivision (1) and that is required by the appropriate regional transmission organization; or

(3) if the appropriate regional transmission organization does not require a metric described in subdivision (1) or (2), a metric that:

(A) can be used to demonstrate that a public utility has sufficient capacity to:

(i) provide reliable electric service to Indiana customers for



the spring period; and

(ii) meet its planning reserve margin requirement and other federal reliability requirements described in subsection ~~(t)(4)~~; **(n)(6)**; and

(B) is acceptable to the commission.

~~(j)~~ **(k)** As used in this section, "summer unforced capacity", or "summer UCAP", with respect to an electric generating facility, means:

- (1) the capacity value of the electric generating facility's installed capacity rate adjusted for the electric generating facility's average forced outage rate for the summer period, calculated as required by the appropriate regional transmission organization or by the Federal Energy Regulatory Commission; or
- (2) a metric that is similar to the metric described in subdivision (1) and that is required by the appropriate regional transmission organization.

~~(j)~~ **(l)** As used in this section, "winter unforced capacity", or "winter UCAP", with respect to an electric generating facility, means:

- (1) the capacity value of the electric generating facility's installed capacity rate adjusted for the electric generating facility's average forced outage rate for the winter period, calculated as required by the appropriate regional transmission organization or by the Federal Energy Regulatory Commission;
- (2) a metric that is similar to the metric described in subdivision (1) and that is required by the appropriate regional transmission organization; or
- (3) if the appropriate regional transmission organization does not require a metric described in subdivision (1) or (2), a metric that:
 - (A) can be used to demonstrate that a public utility has sufficient capacity to:
 - (i) provide reliable electric service to Indiana customers for the winter period; and
 - (ii) meet its planning reserve margin requirement and other federal reliability requirements described in subsection ~~(t)(4)~~; **(n)(6)**; and

(B) is acceptable to the commission.

~~(k)~~ **(m)** A public utility that owns and operates an electric generating facility serving customers in Indiana shall operate and maintain the facility using good utility practices and in a manner:

- (1) reasonably intended to support the provision of reliable and economic electric service to customers of the public utility; ~~and~~
- (2) reasonably consistent with the resource reliability requirements of MISO or any other appropriate regional



transmission organization; and

(3) reasonably maximizes the economic value of the electric generating facility.

† (n) Not later than thirty (30) days after the deadline for submitting an annual planning reserve margin report to MISO, each public utility providing electric service to Indiana customers shall, regardless of whether the public utility is required to submit an annual planning reserve margin report to MISO, file with the commission a report, in a form specified by the commission, that provides the following information for each of the next three (3) resource planning years, beginning with the planning year covered by the planning reserve margin report to MISO described in this subsection:

(1) The:

- (A) capacity;
- (B) location; and
- (C) fuel source;

for each electric generating facility that is owned and operated by the electric utility and that will be used to provide electric service to Indiana customers.

(2) With respect to a report submitted to the commission after December 31, 2025, the amount of generating resource capacity or energy, or both, that the public utility plans to retire and that is owned and operated by the public utility and used to provide retail electric service in Indiana, including the:

- (A) capacity;
- (B) location;
- (C) fuel source; and
- (D) planned retirement date;

for each electric generating facility. The public utility must include information as to whether the planned retirement is required in order to comply with environmental laws, regulations, or court orders, including consent decrees, that are or will be in effect at the time of the planned retirement. In addition, the public utility must provide its economic rationale for the planned retirement, including anticipated ratepayer impacts, and information concerning the public utility's plan or plans with respect to the amount of replacement capacity identified to provide approximately the same accredited capacity within the appropriate regional transmission organization as the amount of capacity of the facility to be retired.



(3) With respect to a report submitted to the commission after December 31, 2025, the amount of generating resource capacity or energy, or both, that the public utility plans to refuel, including the:

- (A) capacity;
- (B) location;
- (C) existing fuel source;
- (D) proposed fuel source; and
- (E) planned completion date of the refueling;

with respect to each electric generating facility that the public utility plans to refuel. The public utility must provide its economic rationale for the planned refueling, including anticipated ratepayer impacts, and information concerning the public utility's plan or plans with respect to the extent to which the refueling will maintain or increase the current generating resource accredited capacity or energy, or both, that the electric generating facility provides, so as to provide approximately the same accredited capacity within the appropriate regional transmission organization.

~~(2)~~ (4) The amount of generating resource capacity or energy, or both, that the public utility has procured under contract and that will be used to provide electric service to Indiana customers, including the:

- (A) capacity;
- (B) location; and
- (C) fuel source;

for each electric generating facility that will supply capacity or energy under the contract, to the extent known by the public utility.

~~(3)~~ (5) The amount of demand response resources available to the public utility under contracts and tariffs.

~~(4)~~ (6) The following:

- (A) The planning reserve margin requirements established by MISO for the planning years covered by the report, to the extent known by the public utility with respect to any particular planning year covered by the report.
- (B) If applicable, any other planning reserve margin requirement that:
 - (i) applies to the planning years covered by the report; and
 - (ii) the public utility is obligated to meet in accordance with the public utility's membership in an appropriate regional transmission organization;



to the extent known by the public utility with respect to any particular planning year covered by the report.

(C) Other federal reliability requirements that the public utility is obligated to meet in accordance with its membership in an appropriate regional transmission organization with respect to the planning years covered by the report, to the extent known by the public utility with respect to any particular planning year covered by the report.

For each planning reserve margin requirement reported under clause (A) or (B), the public utility shall include a comparison of that planning reserve margin requirement to the planning reserve margin requirement established by the same regional transmission organization for the 2021-2022 planning year.

~~(5)~~ (7) The reliability adequacy metrics of the public utility, as forecasted for the three (3) planning years covered by the report.

~~(m)~~ (o) Upon request by a public utility, the commission shall determine whether information provided in a report filed by the public utility under subsection ~~(f)~~ (n):

(1) is confidential under IC 5-14-3-4 or is a trade secret under IC 24-2-3;

(2) is exempt from public access and disclosure by Indiana law; and

(3) shall be treated as confidential and protected from public access and disclosure by the commission.

~~(n)~~ (p) A joint agency created under IC 8-1-2.2 may file the report required under subsection ~~(f)~~ (n) as a consolidated report on behalf of any or all of the municipally owned utilities that make up its membership.

~~(o)~~ (q) A:

(1) corporation organized under IC 23-17 that is an electric cooperative and that has at least one (1) member that is a corporation organized under IC 8-1-13; or

(2) general district corporation within the meaning of IC 8-1-13-23;

may file the report required under subsection ~~(f)~~ (n) as a consolidated report on behalf of any or all of the cooperatively owned electric utilities that it serves.

~~(p)~~ (r) In reviewing a report filed by a public utility under subsection ~~(f)~~ (n), the commission may request technical assistance from MISO or any other appropriate regional transmission organization in determining:

(1) the planning reserve margin requirements or other federal



reliability requirements that the public utility is obligated to meet, as described in subsection ~~(f)(4)~~; **(n)(6)**; and

(2) whether the resources available to the public utility under subsections ~~(f)(1)~~ **(n)(1)** through ~~(f)(3)~~ **(n)(5)** will be adequate to support the provision of reliable electric service to the public utility's Indiana customers.

(s) With respect to a report submitted under subsection **(n)** after December 31, 2025, commission staff shall review the reports submitted by public utilities and shall, not later than ninety (90) days after the date of submission of the reports, submit to the commission a staff report concerning any planned retirements included in the reports under subsection **(n)(2)**. The report must make recommendations to the commission based on whether each planned retirement:

(1) is consistent with the standards set forth in subsection **(m)**;

(2) will be replaced with an amount of replacement capacity that will provide approximately the same accredited capacity within the appropriate regional transmission organization as the amount of capacity of the facility to be retired;

(3) will not adversely and unreasonably impact a public utility's ability to provide safe, reliable, and economical electric utility service to the public utility's customers;

(4) will result in the provision to Indiana customers of electric utility service with the attributes of:

(A) reliability;

(B) affordability;

(C) resiliency;

(D) stability; and

(E) environmental sustainability;

as set forth in IC 8-1-2-0.6; and

(5) is required in order to comply with environmental laws, regulations, or court orders, including consent decrees, that are or will be in effect at the time of the planned retirement.

(t) The commission shall make the staff reports prepared under subsection **(s)** publicly available by posting the staff reports on the commission's website. Upon the posting of a staff report on the commission's website, the commission shall accept public comments on the report for a period not to exceed thirty (30) days after the date of posting.

~~(q)~~ **(u)** If, after reviewing a report filed by a public utility under subsection ~~(f)~~; **(n)** and any staff report prepared with respect to the public utility under subsection **(s)**, the commission is not satisfied



that the public utility can either:

(1) provide reliable electric service to the public utility's Indiana customers; or

(2) either:

(A) (1) satisfy both:

- (i) (A) its planning reserve margin requirement or other federal reliability requirements that the public utility is obligated to meet, as described in subsection ~~(1)(4)~~; **(n)(6)**; and
- (ii) **(B)** the reliability adequacy metrics set forth in subsection ~~(g)~~; **(h)**; or

~~(B)~~ (2) provide sufficient reason as to why the public utility is unable to satisfy both:

- (i) (A) its planning reserve margin requirement or other federal reliability requirements that the public utility is obligated to meet, as described in subsection ~~(1)(4)~~; **(n)(6)**; and
- (ii) **(B)** the reliability adequacy metrics set forth in subsection ~~(g)~~; **(h)**;

during one (1) more of the planning years covered by the report, the commission ~~may~~ **shall** conduct an investigation under IC 8-1-2-58 through IC 8-1-2-60 as to the reasons for the public utility's potential inability to meet the requirements described in subdivision (1) or (2); ~~or both; provide sufficient reason as to that inability, as described in subdivision (2).~~ In addition, if the public utility has indicated in its report under subsection (n)(2) that it plans to retire an electric generating facility within one (1) year of the date of the report, the commission must conduct an investigation under IC 8-1-2-58 through IC 8-1-2-60 as to the reasons for the public utility's potential inability to meet the requirements described in subdivision (1) or provide sufficient reason as to that inability, as described in subdivision (2). However, a public utility may request, not earlier than three (3) years before the planned retirement date of an electric generation facility, that the commission conduct an investigation under IC 8-1-2-58 through IC 8-1-2-60, for the purposes described in this subsection, with respect to the planned retirement. If the commission conducts an investigation at the request of a public utility within the three (3) year period before the planned retirement date of an electric generation facility, the commission may not conduct a subsequent investigation that would otherwise be required under this subsection with respect to the retirement of that same electric generation facility unless the commission is not satisfied, as of the time that an investigation would otherwise be required under this subsection, that the public



utility can meet the requirements described in subdivision (1) or provide sufficient reason as to that inability, as described in subdivision (2). If a certificate is granted by the commission under this chapter for a facility intended to repower or replace a generation unit that is planned for retirement, and the certificate includes findings that the project will result in at least equivalent accredited capacity and will provide economic benefit to ratepayers as compared to the continued operation of the generating unit to be retired, the certificate under this chapter constitutes approval by the commission for purposes of an investigation required by this subsection. However, if the commission finds that facts and circumstances regarding the planned retirement have changed significantly since the certificate was granted and that those changes concern the public utility's ability to meet the requirements described in subdivision (1), the commission may conduct an investigation into the planned retirement of the unit.

(v) If, upon investigation under IC 8-1-2-58 through IC 8-1-2-60, and after notice and hearing, as required by IC 8-1-2-59, the commission determines that the capacity resources available to the public utility under subsections ~~(1)(1)~~ (n)(1) through ~~(1)(3)~~ (n)(5) will not be adequate to support the provision of reliable electric service to the public utility's Indiana customers; or to allow the public utility to satisfy both its planning reserve margin requirements or other federal reliability requirements that the public utility is obligated to meet (as described in subsection ~~(1)(4)~~ (n)(6)) and the reliability adequacy metrics set forth in subsection ~~(g)~~; (h), the commission shall issue an order:

- (1) directing the public utility to acquire or construct; or
- (2) prohibiting the retirement or refueling of;

such capacity resources that are reasonable and necessary to enable the public utility to provide reliable electric service to its Indiana customers, and to satisfy both its planning reserve margin requirements or other federal reliability requirements described in subsection ~~(1)(4)~~ (n)(6) and the reliability adequacy metrics set forth in subsection ~~(g)~~; (h). The commission shall issue an order under this subsection not later than one hundred twenty (120) days after the initiation of the investigation under subsection (u). If the commission does not issue an order within the one hundred twenty (120) day period prescribed by this subsection, the public utility is considered to be able to meet the requirements described in subsection (u)(1) with respect to the retirement of the electric generation facility under



investigation. Not later than ninety (90) days after the date of the ~~commission's~~ an order by the commission under this subsection, the public utility shall file for approval with the commission a plan to comply with the commission's order. **Notwithstanding IC 8-1-3 or any other law, any appeal of an order by the commission under this subsection is entitled to priority review and shall be given expedited consideration in accordance with Rule 21 of the Indiana Rules of Appellate Procedure.**

(w) With respect to a report submitted under subsection (n) after December 31, 2025, if the commission issues an order under subsection (v) to prohibit the retirement or refueling of an electric generation resource, the commission shall create a sub-docket to authorize the public utility to recover in rates the costs of the continued operation of the electric generation resource that was proposed to be retired or refueled. The commission must find that the continued costs of operation are just and reasonable before authorizing their recovery in the public utility's rates. The creation of a sub-docket under this subsection is not subject to the one hundred twenty (120) day time frame for the commission to issue an order under subsection (v).

The (x) A public utility's plan under subsection (v) may include:

- (1) a request for a certificate of public convenience and necessity under this chapter; or
- (2) an application under IC 8-1-8.8;

or both.

~~(s)~~ (y) Beginning in 2022, the commission shall include in its annual report under IC 8-1-1-14 the following information:

- (1) The commission's analysis regarding the ability of public utilities to:

- (A) provide reliable electric service to Indiana customers; and
- (B) satisfy both:

- (i) their planning reserve margin requirements or other federal reliability requirements; and
- (ii) the reliability adequacy metrics set forth in subsection ~~(g)~~; (h);

for the next three (3) utility resource planning years, based on the most recent reports filed by public utilities under subsection ~~(f)~~; (n).

- (2) A summary of:

- (A) the projected demand for retail electricity in Indiana over the next calendar year; and
- (B) the amount and type of capacity resources committed to



meeting the projected demand;

(C) beginning with the commission's annual report due before October 1, 2026, and in each subsequent annual report, the planned retirements or refuelings of electric generation resources and the plans to replace or retain the capacity or energy, or both, of the electric generation resources planned to be retired or refueled; and

(D) beginning with the commission's annual report due before October 1, 2026, and in each subsequent annual report, the reports of commission staff under subsection (s).

In preparing the summary required under this subdivision, the commission may consult with the forecasting group established under section 3.5 of this chapter.

(3) Beginning with the commission's annual report filed under IC 8-1-1-14 in 2025, the commission's analysis regarding the appropriate percentage or portion of:

(A) total spring UCAP that public utilities should be authorized to acquire from capacity markets under subsection ~~(g)(3)(B)~~; ~~(h)(3)(B)~~; and

(B) total fall UCAP that public utilities should be authorized to acquire from capacity markets under subsection ~~(g)(4)(B)~~; ~~(h)(4)(B)~~.

~~(t)~~ (z) The commission may adopt rules under IC 4-22-2 to implement this section.

SECTION 5. An emergency is declared for this act.





DIVE BRIEF

Data center growth has helped PG&E cut rates 11% since 2024, CEO says

But California's "regressive" wildfire policies have become a burden for ratepayers, CEO Patti Poppe said.

Published Feb. 17, 2026

By Emma Penrod

Aerial view of a data center being constructed inside "Data Center Alley" in Ashburn, Va., in 2024. Large load growth from developments like data centers has helped PG&E cut electric rates for the fourth time in two years, CEO Patti Poppe said during a fourth-quarter earnings call. Gerville via Getty Images

Accelerated large load growth has helped PG&E cut electric rates for the fourth time in two years, but wildfire costs continue to drag down affordability measures, PG&E Corporation CEO Patti Poppe said Thursday during a fourth-quarter earnings call.

The company's total large load pipeline declined from 9.6 GW in September 2025 to 7.3 GW at the end of the year, but more projects are entering final engineering phases. PG&E maintains that it can reduce customers' electric bills by about 1% for each gigawatt of new load on the system.

Beyond data centers, Poppe said rapid EV adoption is driving demand for electricity in the PG&E service territory, and that the company also expects to see some growth from California's manufacturing sector.

“You do not think about California when you think about manufacturing, but let me remind everyone on this call that California manufactures more products than any other state in the nation,” she said. “I expect that those companies intend to grow, and so we are working to make sure that we can supply their growth as well, whether it is robotics or silicon manufacturing equipment and chip manufacturing equipment. That all lives here.”

BY THE NUMBERS: PG&E CORP. 2025 FULL-YEAR RESULTS

3.6 GW

Large-load projects that have entered final engineering phases.

43%

Decline in wildfire ignitions tied to PG&E equipment.

\$73 billion

Five-year capital plan.

Carolyn Burke, PG&E Corporation’s executive vice president and chief financial officer, said the company did not plan to update its \$73 billion capital plan at this time despite its view that there could be an additional \$5 billion in growth opportunities on the horizon. The company’s current valuation would not support expanding the plan, she said, so the company plans to focus on affordability and prioritizing capital associated with new load growth that would help lower electric rates.

The company does not plan to issue any new equity under its current five-year plan, but will issue up to \$4.6 billion in debt in 2026 as it focuses on achieving investment-grade credit ratings, Burke said. Although Fitch Ratings upgraded PG&E's credit ratings last September, other credit rating agencies have declined to do so pending California wildfire policy reforms, Poppe said.

The California Earthquake Authority, which oversees the state's Wildfire Fund that reimburses utilities for wildfire-related legal claims, is expected to issue a report with recommendations for reforms on April 1. That report is expected to trigger a legislative process to reform the fund that Poppe said she hopes will result in new legislation before the end of the session.

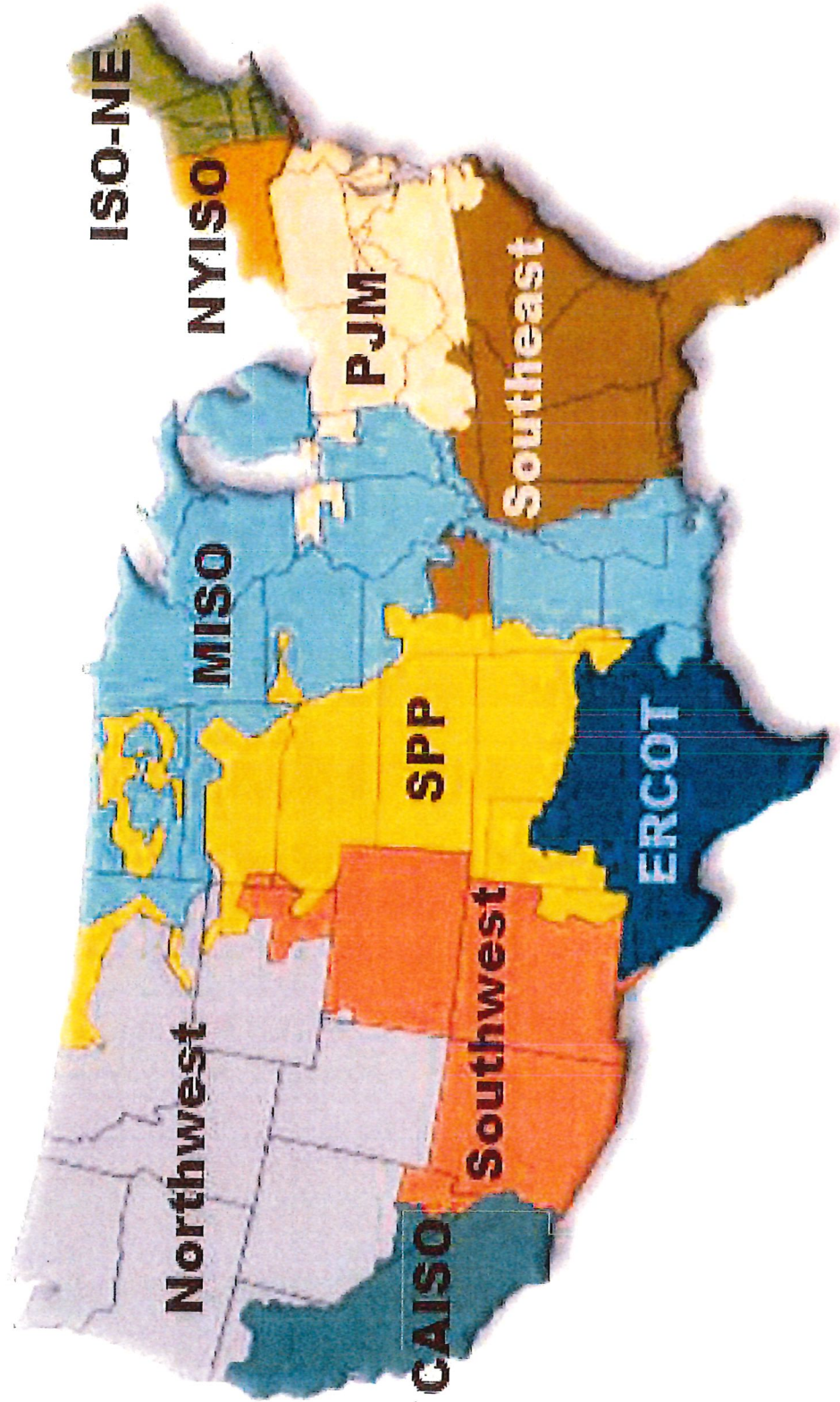
While Poppe said she wasn't ready to take a position on specific reforms, she said she agreed with a Jan. 30 report by the California Public Utilities Commission that the current structure of the fund is "regressive" and unfairly burdens ratepayers.

"It is hard for people to believe and see that you can raise profits and lower rates all at the same time. That is why our performance is so important and why our mantra that performance is power really holds true at this time as we work to educate all of the legislators...that we can, in fact, invest in long-term infrastructure, make the system safe, make the system resilient and lower costs," Poppe said.

If the legislative process does not yield effective reforms, Poppe said all aspects of the company's current plans would be subject to re-evaluation to ensure progress toward investment-grade credit ratings.

"The current valuation is absolutely not sustainable," she said "And we are ringing that bell in every corner of California that we can find and in every conversation to make sure that people

understand the value of the investor-owned utility model and how important attracting low-cost, high quality investment is.”



NEWS RELEASES

FERC Launches Aggressive Targeted Action to Speed Large Load Integration

June 18, 2026

Commission orders all six regional grid operators to justify or reform tariffs for data centers and other large energy users, delivering speed-to-power that is critical to supporting the innovation economy and national security while protecting ratepayers.

[Fact Sheet](#) | [Presentation](#) | [Infographic](#) | [Items E-7](#), [E-8](#), [E-9](#), [E-10](#), [E-11](#), [E-12](#)

The Federal Energy Regulatory Commission (FERC) today issued tailored show cause orders under section 206 of the Federal Power Act to each of the six regional grid operators under its jurisdiction, directing them to justify or reform the rules that govern how data centers, manufacturing facilities, and other large energy users connect to the electric grid.

The orders mark one of the most significant actions the Commission has taken to modernize the nation's electric markets and push the economy into the future by speeding integration of large energy users onto the grid with additional rigorous consumer safeguards. By requiring Regional Transmission Organizations (RTOs)/Independent System Operators (ISOs) and their transmission operators to either defend or revise their tariffs, FERC is moving to ensure that Americans have reliable, affordable power—even as electricity demand and technology accelerates.

Today's orders advance the Secretary of Energy's Advance Notice of Proposed Rulemaking directives, delivering the speed to power that is critical to supporting the innovation economy, leading the global race on artificial intelligence, and reshoring manufacturing jobs back to the United States.

“We are setting the stage for a resilient, reliable, and forward-thinking grid that empowers communities and safeguards consumers by transforming the way large energy users access the grid. It also is critical that FERC provide certainty for investors by directing the markets to protect existing deals and unlock opportunities for technological advancement and economic expansion. We can



facilitate both, which is exactly what we did today,” said FERC Chairman Laura V. Swett.

FERC's action focuses on the unique operational profiles of large energy users, including those co-located with their own generation, and on the distinct challenges each regional grid operator faces in meeting soaring demand from the proliferation of large loads. Because the six grid operators are unique in their individual advancement toward large load innovation and structure, market design, stakeholder composition and geography, the Commission's orders recognize that a one-size-fits-all solution is not the current most efficient solution for integrating large, energy-intensive loads onto the nation's electric grid.

Tailored Orders, Five Categories of Reform

Under the orders, each RTO/ISO, and its transmission owners have 60 days to either justify why their current tariffs remain just and reasonable without provisions tailored to large loads, or to file tariff changes that address the issues the Commission identified. Each tailored order tees up five categories of reform for the grid operators to address:

- Developing efficient transmission service application and study processes, including consideration of alternative transmission technologies
- Preventing cost shifting and requiring transparency into transmission costs
- Accommodating co-location agreements and behind-the-meter generation
- Providing new transmission services for flexible large loads
- Developing a process to study generating facilities that serve electrically proximate large loads and co-located loads

Additionally, within 30 days, each grid operator and its transmission owners must submit a detailed informational report describing how the grid operator intends to ensure that adequate generation will be available to serve existing and new large loads.

Building on a Track Record of Action

Today's orders build on a series of Commission actions over the past year to address large load growth, including a December 2025 order directing PJM to adopt transparent tariff rules for loads co-located with generation, and the Commission's approval of SPP's High Impact Large Load initiative establishing new study processes for large loads and electrically proximate generation. Commission staff reviewed more than 3,500 pages of public comments submitted in the large load interconnection docket and engaged extensively with stakeholders and federal partners, in developing today's action.

The Six Grid Operators

The RTOs and ISOs include PJM, Interconnection, LLC (PJM); Midcontinent Independent System Operator, Inc. (MISO); Southwest Power Pool, Inc. (SPP); California Independent System Operator Corporation (CAISO); ISO New England Inc. (ISO-NE); and New York Independent System Operator, Inc. (NYISO).

The Federal Energy Regulatory Commission regulates the interstate transmission of electricity, natural gas, and oil, and reviews proposals to build interstate natural gas pipelines, natural gas storage projects, and liquefied natural gas terminals, in addition to licensing hydropower projects. More information is available at www.ferc.gov.

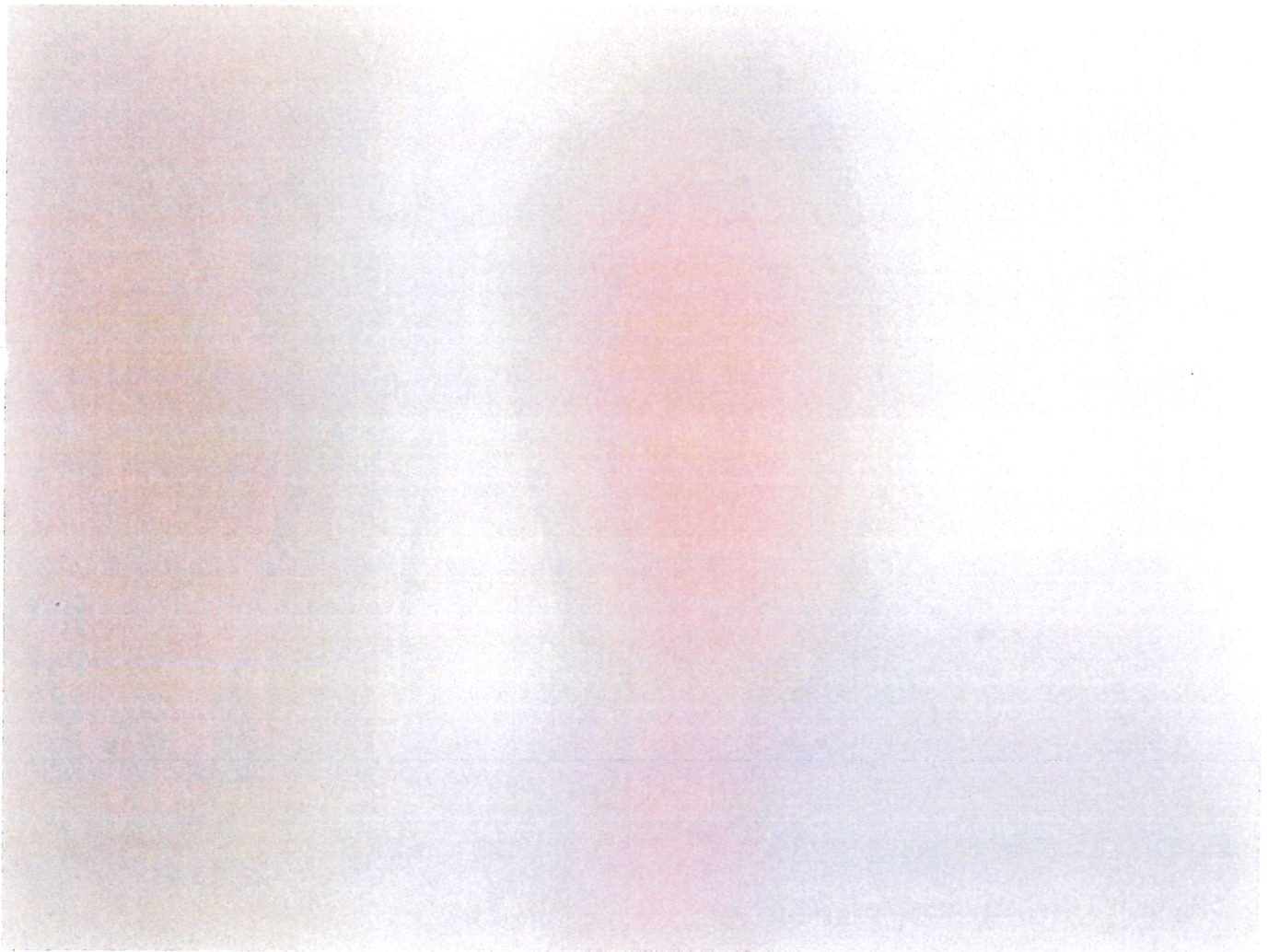
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https://www.journalgazette.net/local/andy-zay-indiana-utility-regulatory-commission-chairman-is-all-in-on-data-centers/article_bce782ff-15f1-4ab6-b707-287001d4470a.html

Andy Zay, Indiana Utility Regulatory Commission chairman, is all in on data centers

Sherry Slater | The Journal Gazette

Jun 16, 2026



Zay



Andy Zay's stance on data centers was crystal clear Tuesday. He's all for them.

"If you're a naysayer on data centers, put your (cell)phones away, cancel your Netflix," the chairman of the Indiana Utility Regulatory Commission said during a speech to members of the Regional Chamber of Northeast Indiana.

Zay was making the point that data centers – such as the ones on Google's 892-acre campus on Fort Wayne's east side – process the online requests residents make every day along with those made by businesses.

Data centers are a hot topic for the five-member IURC board, which is charged with overseeing utilities' infrastructure investments. Zay, who is from Huntington, said the state commission plays "a judiciary role," allowing utilities in the state to have regional monopolies but limiting how much they may charge customers.

“We advocate neither for the public nor the utilities,” Zay said during the chamber’s annual meeting at Grand Wayne Convention Center. More than 300 people attended, according to chamber President and CEO Bill Konyha.

The chamber’s membership is comprised primarily of business and community leaders in 11 counties: Adams, Allen, DeKalb, Huntington, Kosciusko, LaGrange, Noble, Steuben, Wabash, Wells and Whitley.

The IURC oversees more than 600 carriers, including those providing electricity and natural gas. The independent board’s five priorities are making sure those utility providers’ power is reliable, affordable, resilient, stable and environmentally sustainable, Zay said.

The former state senator focused his remarks on the need to meet energy demands, which have spiked in the last few years. Zay said experts who estimate nationwide summertime energy needs have rapidly accelerated their forecasts over the past five years from 24 gigawatts to 166 gigawatts.

Indiana “has got to stay on the cutting edge” of meeting that demand, which is driven by artificial intelligence, Zay said. “How do we assist this growth?”

Zay added that the IURC wants to do so without the cost falling on ratepayers, which include commercial and residential energy customers.

Despite some data center opponents’ concerns, that hasn’t happened in Indiana, according to Zay.

“What we have seen is not only are (data centers) paying their way, they’re more than paying their way,” he said.

In August 2025, Indiana Michigan Power and Google announced an agreement they said will allow the utility to continue to meet residential and business customers’ energy needs in times of high energy demand.

In the joint contract with I&M, Google committed to carrying out nonurgent tasks during hours when the electric grid is under less stress. The “custom demand response structure” represents a new capability by Google, officials said in that release.

“As a large load customer, Google’s participation in this program boosts Indiana Michigan Power’s ability to manage electricity demand during peak times,” the release said. “This helps lower overall energy costs, delivering savings to all I&M customers.”

Zay said Tuesday that a technological revolution is underway and that in 10 years, “it’s going to be a whole different world. It’s going to be a whole different workplace.”

Indiana is prepared to take advantage of the opportunities that revolution offers, he said, “for our children and grandchildren.”

Local data center critics also cite children and grandchildren in their arguments. But their concerns are about the potential effects of air and water pollution on vulnerable populations, which also include the elderly and immunity compromised.

Daniel Elliott, Indiana’s treasurer, preceded Zay’s remarks. Although Elliott didn’t focus on data centers, he said the state has abundant economic development opportunities thanks to his careful management of its financial resources.

“Indiana is positioned to take advantage of these opportunities like no other state is,” he said.

Zay was in full agreement in his presentation.

“Not on my watch is Indiana going to pass this opportunity by,” he said, “and let Indiana become a flyover state again.”

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MORE INFORMATION





Indiana Michigan Power announces lower rates on electric bills

Indiana Michigan Power seeks permission to buy West Virginia natural gas plant

Indiana Michigan Power is asking for state approval to buy a natural gas operation

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I&M takes ownership of Ohio natural gas-producing facility; terms undisclosed

Indiana Michigan Power announced it will ask for state permission to reduce base rates

I&M asks for shortcut in getting state regulator approval for buying power plants

I&M receives permission to buy an Ohio natural gas plant

Sherry Slater

Assistant Desk Editor

A new era of load growth: How data centers are becoming part of our communities and energy system

Publication April 11, 2025

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The demand is here. How will you serve it?

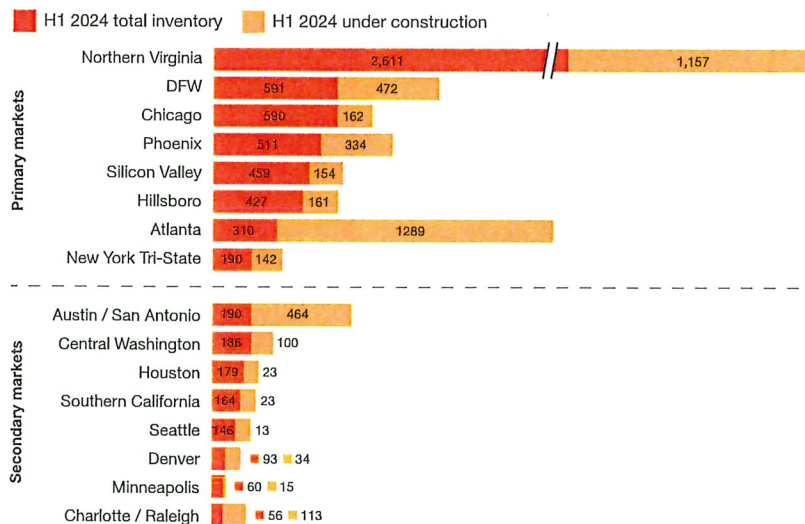
What was once thought to be stagnating to decreasing load growth has begun to shift. Onshoring of manufacturing capacity, building and vehicle electrification, and the expansion of computational needs are creating a new era of load growth. Data centers may encompass future US electricity demand as high as 12% by 2028¹.

Society continues to demand more cloud computing power, be it smoother video streaming, wider-reaching cloud enterprise services, and forward-looking applications such as autonomous vehicles. These trends were already driving data center growth before the AI boom of recent years. Power is an essential, if not critical path, to this growth.

Not all grid participants will be impacted the same. Connection requests of 15 GW in AEP Ohio by 2030² (>40% increase from peak 2023 load) and 80 GW in Oncor (59 GW for data centers³, >90% increase from peak 2023 load), indicate duplicative requests in the queue. Knowing whether “real” annual demand growth

is 4% or 15%⁴ is a grid planning team's constant struggle. Looking across known builds highlights the primary markets where data center demand is growing most as well as robust activity in secondary markets.

Total inventory vs. under construction by market, H1 2024, megawatts (MW)



Source: CBRE North America Data Center Trends H1

This trend of data centers being closer to local customer demand will only increase as cloud computing and AI inference expand due to real-time response needs. Conversely, AI training has greater optionality for site location. While much attention remains focused on energy for AI training needs, at PwC we have seen increased energy needs for AI model inferencing, like many corporate customers that rely on pretrained models⁵.

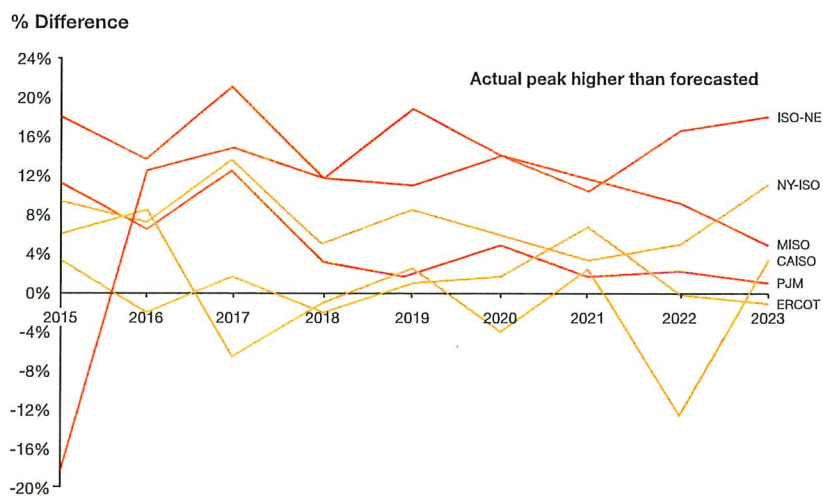
As power providers seek to serve this load, the ability to supply reliable, cost effective, and preferably sustainable energy continues to be differentiators to attract data center demand.

The rules of the game work but aren't enough for near-term growth

Centralized, integrated planning over a set timeframe has been successful in managing infrastructure risks and customer impacts with utility regulators – but this model is being challenged with more dynamic market needs. The PJM capacity auction closing at a total cost increase to consumers from \$2.2 billion to \$14.7 billion⁶ (nearly a seven-fold increase) this summer was just one example of what the future may hold. Utilities and system operators are now quickly updating demand forecasts to account for the increase in resource requirements to service new loads.

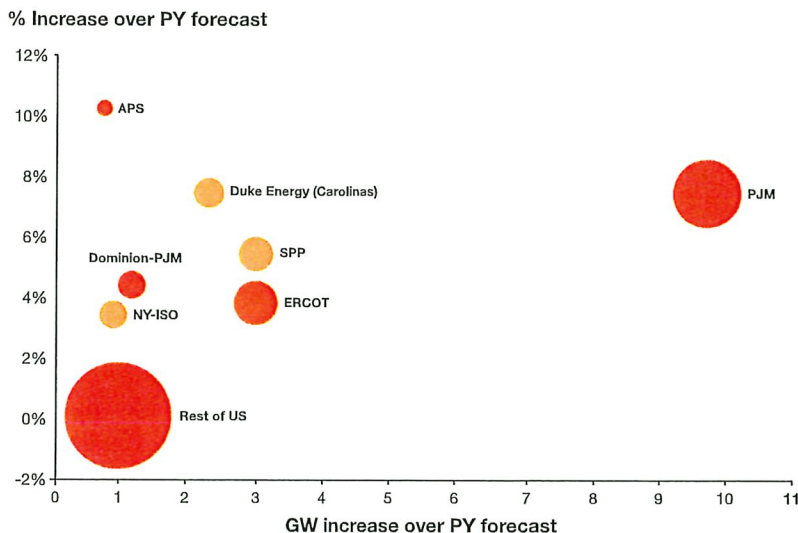
When a single data center can use as much power as 80,000 houses⁷, utilities may have to find a way to accelerate their development timelines, which are traditionally measured in years, not months.

Actual summer peak MW to forecast from 3 years prior



Percent difference calculated as the actual summer peak in MW in the stated year less the forecasted summer peak in MW for the stated year (forecasted from three years ago). For example, if 2019 is the stated year, the 2019 forecast reported in 2016 is used as basis for comparison. A three year window is used as a standard interval for utility integrated resource plans. Sources: S&P Capital IQ Pro; NERC ES&D, EIA-411, FERC 714, NERC 2023 LTRA. See below for additional sources.

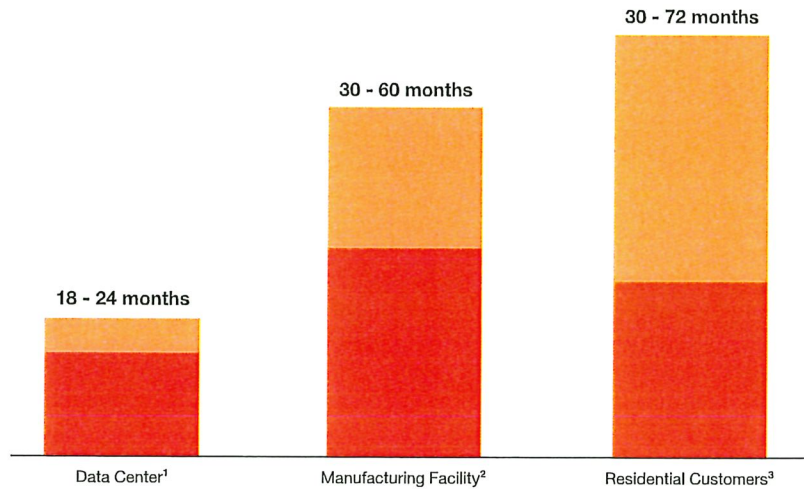
2028 Summer peak MW demand load forecast increase



Source: S&P Capital IQ Pro, Individual Planning Area Resource Plans, NERC ES&D, EIA-411, FERC 714
See below for additional sources

Companies are not waiting on utilities to solve the supply-side challenges and are now finding their own demand-side solutions, including developing on-site generation or other grid solutions, or relocating to markets with power availability. Solutions leveraging gas capacity, battery storage, geothermal generation, and fuel cells are creating a bridge to long-term electricity grid solutions. This may be the start of a trend where modular demand needs are matched to distributed generation.

Full load ramp timeframe for 100 MW of load



Sources:

1) JLL Global Data Centre Outlook 2023

2) Data Center Dynamics, TSMC

3) S&P Capital IQ Pro, 3rd and 7th decile. Calculated as years it took for a utility to gain 80,000 customers leading into 2023. Sample size of 63 with utilities ranging from 200,000 to 8,000,000 electric residential customers from - 60 electric utilities

Benefits beyond power alone

A PwC study found that data centers provide a 6x multiplier of indirect or induced jobs, across the US, for every direct job they provide. Coupling data centers with a larger industrial base could help address siting needs and enable robust economic hubs.

In addition to contributing taxes and jobs, data centers can also become part of the grid by helping alleviate congestion and, over time, becoming a load-balancing asset. While there may be pushback from DC customers reticent to flex IT capacity, the ask may be achievable. For example, data center load flexibility would be most needed for two to three hours during high peak season to trim demand as solar ramps up and down⁸.

To achieve this objective, data centers will require a mix of engineering, operational, and commercial solutions. Engineering solutions might include data center virtualization, shifting AI training loads or leveraging multiple data centers,