The Potential Impacts of Large Loads on Electricity Prices: Analysis for Alliant Energy Utilities

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Executive Summary

Nationally, energy affordability has become a top priority for policymakers, regulators, utilities, and other industry stakeholders. Many factors can drive increases in retail electricity prices, such as investment to replace aging transmission and distribution (T&D) infrastructure, volatile fuel costs, or rising equipment costs. Recently, the potential impact of load growth has drawn particular attention, particularly the addition of new “large loads” such as data centers.

To better understand how adding large loads to service territories of Wisconsin Power and Light (WPL) and Interstate Power and Light (IPL) could affect prices there, Alliant Energy commissioned The Brattle Group to develop this white paper. The paper provides an economic framework for exploring these potential impacts within the broader context of other rate drivers, as well as Alliant Energy’s market structure, regulatory environment, and ratemaking practices. The paper does not attempt to forecast future prices that involve factors beyond the impact of large loads.

Historical Perspective on Alliant Energy’s Electricity Prices

Historically, changes in the Alliant Energy utilities’ average electricity prices per kilowatt-hour (kwh) have compared favorably with national trends. Between 2010 and 2025, the national average residential electricity price increased by 48% in nominal terms, compared to 49% for WPL and 36% for IPL. In inflation-adjusted terms, the national average residential price increased by 0.7% over that period, compared with an 8.1% *decline* for IPL and a 0.8% increase for WPL.

The nominal increase in Alliant Energy’s electricity prices was driven primarily by network and capacity investments. The cost of transmission, distribution, and generation equipment rose at varying rates over the historical analysis period, and Alliant Energy’s investment needs increased accordingly. For power generation specifically, Alliant Energy’s investment in renewable generation traded higher capital costs for significantly lower variable costs and reduced customer exposure to fluctuations in fuel prices.

Historical Relationship Between Load Growth and Electricity Price Changes

Several studies have shown that, historically, load growth has put downward pressure on electricity prices. For example, a recent analysis by Berkeley Lab and Brattle found that the states experiencing the largest load growth between 2019 and 2025 were also among those with the most significant reductions in inflation-adjusted electricity prices. Over that period, many utilities had available capacity on their systems to accommodate load growth without needing to make proportional infrastructure investments. As a result, the fixed cost of the existing power system could be "shared" across more load, thus reducing the average rate paid by all customers.

Current Questions Regarding Retail Electricity Prices

Given the sudden increase in load forecasts driven by the emergence of large loads, a key question facing the power sector is whether load growth in a given service territory can continue to put downward pressure on electricity prices, or whether reductions in available capacity will lead to the opposite effect.

Large and fast load growth is also contributing to industry-wide effects that extend beyond the service territories where large loads are actually being built; these are not the subject of this paper but form part of the context. The sudden increase in electricity demand nationally has further strained supply chains that were already under pressure and were sized for a slower pace of growth. As a result of this as well as broader inflationary trends, costs have risen across the board—at least temporarily—for turbines, transformers, switchgear, cable, fuel, engineering and construction services, and labor. These cost increases affect every utility, including those with no significant load growth activity, because all utilities must continue replacing aging equipment and meeting organic load growth at whatever prices the market now demands.

These effects are felt especially acutely in jurisdictions where customers lack long-term hedges. In much of PJM, for example, retail customers are exposed to capacity prices that have risen to a negotiated market price cap, which, in turn, has contributed to retail electricity price increases in several states. While utilities in the Midcontinent Independent System Operator (MISO) region—including WPL and IPL—are mostly hedged due to owning their own generation and do not have the same exposure to capacity market price fluctuations as most PJM utilities, the relevance of this issue for further exploration remains.[1]

[1] While this paper does not attempt to quantify these macroeconomic effects or attribute them to individual customers, they represent an additional channel through which large load growth can increase costs for existing ratepayers. Such impacts could be considered in future analyses, along with other macro impacts that may reduce the cost of new resources in the long run.

Alliant Energy’s Positioning on Load Growth and Associated Price Impacts

Based on our review of WPL’s and IPL’s market structure, regulatory environment, and approach to ratemaking, the utilities are well-positioned to mitigate the risk of a cost shift from large loads to other customers for the specific matters within the utilities’ control. Specifically, the utilities’ Individual Customer Rate (ICR) contains a mechanism designed to ensure that new large loads pay at least the incremental costs to serve them.

Because each large customer’s contract must produce enough revenue to cover at least the full incremental cost of generation serving that customer, existing customer rates should not be affected in terms of generation costs. The distribution portion of existing customers’ rates also should remain unaffected by the addition of large loads to the service territory, because large loads typically connect at the transmission level and do not require distribution system investments.

However, transmission investment decisions are made by two transmission companies serving the region (ITC in Iowa and ATC in Wisconsin), not by WPL and IPL. The transmission companies make their own investment decisions and recover the costs through charges that Alliant Energy’s operating utilities pass on to its customers. A portion of those transmission companies’ investments are driven by anticipated load growth. Investments are also being made to maintain the existing system by replacing aging equipment, addressing local reliability needs, and meeting baseline reliability standards, and these investments are needed regardless of whether any new large load customers connect.

The costs of these transmission investments will be recovered from new large load customers and existing customers, and their net effect on rates will depend on the relationship between the cost increase and the load increase. If the transmission costs grow more slowly than the load base expands, then average transmission rates decline, and existing customers benefit. If the opposite is true, then average rates increase. The key question, therefore, is not whether transmission costs will rise, but whether the revenue contribution from new large customers will outpace the incremental transmission investment required to serve them.

Balancing Load Growth, Cost Recovery, and Customer Protection

As jurisdictions across the US continue to confront the challenges of load growth-driven electricity price increases, a range of mechanisms are emerging to unlock the benefits of this load growth without inadvertently increasing costs for existing customers.

Well-designed rate structures and contract terms can address situations in which the incremental cost of serving a new large customer exceeds the revenue collected from that customer. These mechanisms tie revenue from large load customers more closely to the costs they impose on the system, ensuring that incremental revenue at least matches incremental costs. Where uncertainty is high, tariff provisions and accompanying policies may build in additional protection for existing customers (e.g., requiring premiums for accelerated investments or financial contributions to low-income funds).

Additionally, utilities and regulators have developed mitigation tools that align forecast and performance risk with the customers driving those risks (e.g., large loads not materializing at anticipated levels of load required for revenue sufficiency). Contractual protections—such as take-or-pay obligations, collateral requirements, exit fees, up-front contributions, and long-term commitments—help match cost recovery to the timing and durability of the load, and, like Alliant Energy's ICR, are increasingly being incorporated into utility large load tariff proposals across the US.

Ultimately, we consider the most relevant question facing decision-makers not to be whether Alliant Energy should serve additional large load customers, but rather under what terms the company can do so while benefiting existing customers.

The central principle is that incremental costs associated with serving new large load customers should be matched or exceeded by incremental revenues collected from those customers. Achieving that outcome requires tariff design and contractual protections that assign both cost-shift risk and stranded-cost risk to the customers that create them, and potentially new initiatives to more efficiently utilize existing power infrastructure. Under this framework, Alliant Energy can pursue the benefits of load growth and economic development while potentially improving affordability for existing ratepayers.

It is important to acknowledge, however, that Alliant Energy does not have control over transmission investments required to support regional and local reliability. The trajectory of transmission rates will depend on whether load growth outpaces cost growth, and these costs will ultimately be passed through to customers as they materialize in the coming years, consistent with robust cost allocation practices.

I. Introduction

Nationally, energy affordability is among the most pressing current priorities for regulators and policymakers. After decades in which average retail electricity prices grew more slowly than inflation, some states have begun to experience a reversal of this trend.[2] In California and several New England states, for example, average residential electricity prices increased by more than three times the rate of inflation during the five-year period from 2020 to 2025. In New Jersey and Virginia, electricity prices were a defining issue in the most recent gubernatorial elections.

Research has shown that many factors have recently contributed to changes in electricity rates.[3] Those factors include the need to replace aging transmission and distribution (T&D) infrastructure, fluctuations in fuel prices (e.g., natural gas), rising costs of power generation equipment, and the costs of preparing for and recovering from extreme weather and natural disasters, among others. The relative importance of these factors varies significantly over time, and from one state or utility to the next.[4]

A potential driver of electricity rate changes that has begun to attract the attention of the national media, regulators, and policymakers is the impact of load growth, particularly from "large loads" such as data centers.[5] Several research studies indicate that, historically, load growth is correlated with downward rate pressure. For example, a recent study by Berkeley Lab

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2 In this paper, we use the term retail rate to refer to charges seen on customer bills (e.g. $0.04/kWh or $4/kW), a bill as the total amount paid by customers at the end of a billing cycle (rate multiplied by usage), and price of electricity as the total collected revenue divided by total retail electricity sales. For this analysis we focus primarily on the price of electricity.

3 Wiser, Ryan, et al. *Retail Electricity Price Trends and Drivers: Data Update—2026 Edition*. Lawrence Berkeley National Laboratory, April 2026. PDF. https://emp.lbl.gov/sites/default/files/2026-03/Retail%20Price%20Trends_2026%20edition.pdf.

4 California offers a striking illustration of the combined effects of all these different drivers: the state has experienced the largest energy price increases in the nation, driven by aging infrastructure requiring replacement, severe wildfire risk, and high behind-the-meter (BTM) solar deployment that has reduced electricity sales. As a result, California experienced the highest price increase despite having only average statewide data center deployment. According to data center load growth forecasts from EPRI and total sales volumes from EIA, data center load deployment in California is 3.9% of total load, compared to 3.93% nationally. *See (https://powering-intelligence.epri.com/).*

5 In this paper, large customers refer to customers whose power requirements are in the range of tens of megawatt (MW) or more. Growing electricity demand also comes from manufacturing facilities, electric vehicles, and building electrification.

and Brattle found that the three states experiencing the highest rate of load growth between 2019 and 2025 (North Dakota, New Mexico, and Nebraska) were among the states that also experienced the most significant declines in inflation-adjusted average electricity prices.[6] This outcome was possible because the fixed cost of the power system was able to be "shared" across more load. The question now being asked by electricity industry decision-makers is whether conditions can be created to enable that historical trend to persist, or whether the sudden emergence of large load customers could instead lead to rate increases.

The potential impact of large load customers on retail electricity rates is relevant in Alliant Energy's service territories. In Wisconsin, for example, planned data center growth is expected to materially increase electricity demand, and state regulators and policymakers continue to debate how the associated infrastructure costs of serving that load growth should be allocated and recovered from customers.[7] Similarly, policymakers are considering legislation that would require a separate tariff for data centers, along with a method to allocate costs to data centers proportionally.[8]

Given the complexity of this topic, Alliant Energy commissioned The Brattle Group to write a white paper that provides an economic framework for exploring the impact that data centers and other large customers could have on retail electricity rates in Alliant Energy's Iowa and Wisconsin jurisdictions. We consider that impact within the broader context of other rate drivers, as well as Alliant Energy's market structure, regulatory environment, and ratemaking practices. The paper focuses exclusively on the potential rate impacts of large load growth and the tools available to utilities and regulators to address those impacts. Other factors that may independently drive rate changes are acknowledged where relevant but are not the focus of this paper.[9]

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6 Wiser et al., 2026

7 Wisconsin Policy Forum. "Data Centers May Change Wisconsin's Utility Landscape." January 2026. https://wispolicyforum.org/research/data-centers-may-change-wisconsins-utility-landscape/.

8 Iowa Legislature. *House File 2690: A Bill for an Act Relating to Water and Energy Use for Data Centers, Including Reporting and Tariff Requirements, and Including Effective Date Provisions*. 91st General Assembly, 2026. https://www.legis.iowa.gov/legislation/BillBook?ga=91&ba=HF%202690.

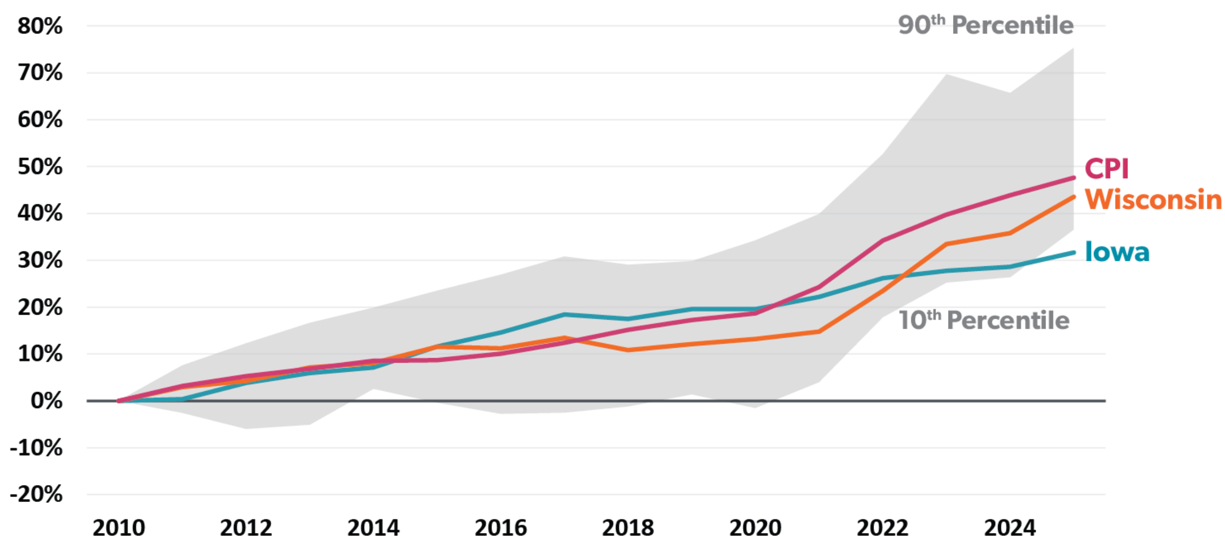
9 For example, an unanticipated increase in electricity demand, driven by data centers or other loads in the U.S. and across the world, can also put temporary upward pressure on the prices of electrical equipment, fuel, and other supply chain inputs. These cost increases are not specific to any one utility or customer; they reflect broader market conditions. While in this paper we do not attempt to quantify these macroeconomic effects or attribute them to individual customers, they represent an additional channel through which large load growth can increase costs for existing ratepayers. Such impacts could be considered in future analyses, along with other macro impacts that may reduce the cost of new resources in the long run.

In the remainder of the paper, we first review recent electricity price trends in Wisconsin and Iowa and identify key drivers of price changes in those jurisdictions. Next, we describe an economic framework for evaluating how adding new large customers may increase or decrease prices for existing customers. We then apply that framework specifically to Alliant Energy's conditions to examine how prices for existing Iowa and Wisconsin customers may be affected by load growth, and how tariff and contractual protections can be deployed to protect existing customers from cost-shift risks.

II. Electricity Price Trends in the US

Between 2010 and 2025, US electricity prices across states, on average, largely tracked inflation. Fifteen states experienced retail electricity price growth that outpaced inflation over this period. However, electricity prices in Iowa and Wisconsin grew more slowly than inflation, with the Consumer Price Index (CPI) increasing by 48%, compared to electricity price increases in Iowa and Wisconsin of 31% and 44%, respectively. Figure 1 below compares residential nominal electric price changes from 2010 through 2025 with the overall rate of inflation.

FIGURE 1: NOMINAL RESIDENTIAL ELECTRICITY PRICE CHANGES SINCE 2010



Note: Data from EIA. Prices are determined by total residential revenue divided by total MWh residential sales. Consumer Price Index (CPI) data from Bureau of Labor Statistics. 90th and 10th percentile values determined to be the 5th and 45th highest state increases, respectively.

As a share of household expenditures, electricity costs have generally declined between 2010 and 2025.[10] Yet, electricity prices have become a flashpoint for public concern, driven by a combination of factors that, taken together, have caused recent increases to be perceived as a more acute problem than the long-run inflation-adjusted trend would suggest.

First, electricity prices have risen in nominal terms. Even where inflation-adjusted prices have held steady or fallen, average residential electricity prices have climbed by over 45% in nominal

10 Wiser et al., 2026

terms since 2010. Electricity demand is relatively inelastic, and customers absorb these increases accordingly, with customers on fixed incomes or incomes that have not kept up with inflation being most affected. Broader economic pressures, including widening wealth inequality and negative consumer sentiment in a high-inflation environment, likely amplify that frustration.

Second, regional disparities have compounded this dynamic. California and parts of New England have experienced particularly steep price increases. California, which accounts for 12% of the US population, experienced an average nominal retail electricity price increase of 120% between 2010 and 2025, compared to an average increase of 50% in other states over that same period. Even where local price trajectories are more moderate, high-profile examples of dramatic increases elsewhere can fuel a general sense that electricity is becoming unaffordable.

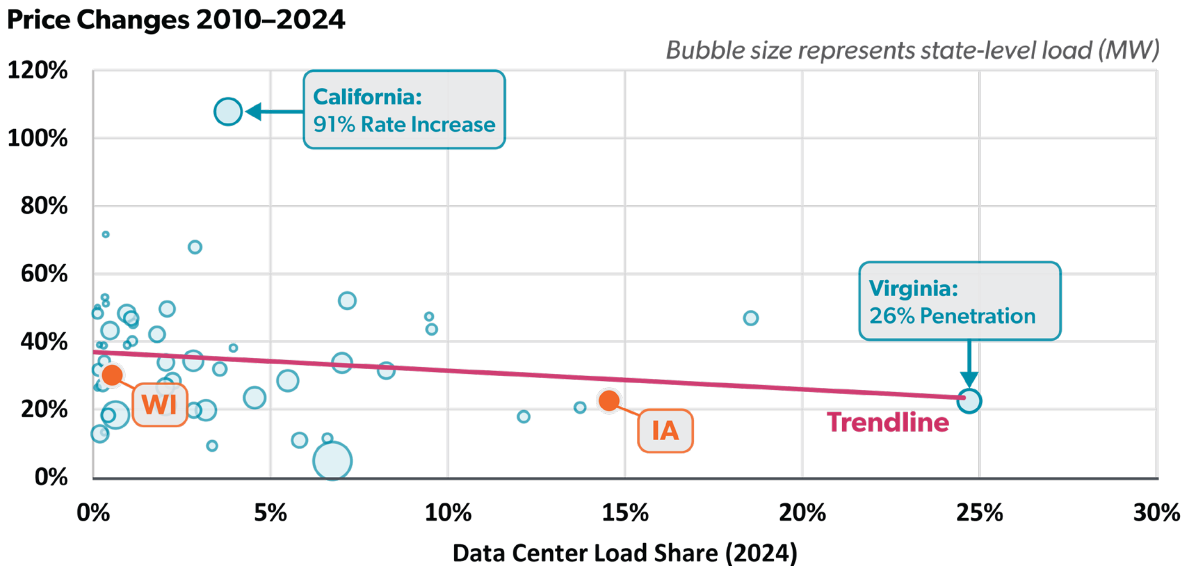
The pace of electricity price increases has also accelerated in recent years. While recent electricity price increases coincide with broadly elevated prices across the economy, more than half of states experienced electricity price increases at a rate faster than already higher-than-normal general inflation between 2022 and 2025, making the increases more pronounced for customers and adding to public frustration.

Recent electricity price increases coincide with a period of substantial projected growth in electricity demand from large customers, particularly data centers. This timing adds a new dimension to affordability concerns. According to an EPRI study, data centers are projected to consume between 9% and 17% of US electricity by 2030, up from 4–5% today.[11] The sheer scale and speed of this anticipated growth have given data centers an outsized presence in public discourse about electricity costs, fueling worry that further price increases may follow.

However, electricity prices for existing customers need not increase when new large customers are connected to the power system. Historically, data center growth has not been correlated with price increases (see Figure 2 below).

[11] EPRI. *Powering Intelligence 2026: Updated Scenarios of U.S. Data Center Electricity Use and Power Strategies.* February 2026. https://www.epri.com/research/products/000000003002034687.

FIGURE 2: STATE-LEVEL DATA CENTER PENETRATION VS ELECTRIC PRICE CHANGES SINCE 2010



Notes: Data from EPRI Powering Intelligence 2026 Updated Scenarios of US Data Center Electricity Use and Power Strategies and EIA. Negative relationship still holds when excluding California and/or Virginia and focusing on more recent years. Trendline equation is y = -0.55x + 0.37 with an R-squared of 0.02.

As noted in a recent study by Berkeley Lab and Brattle, across the US, nationwide increases in electricity price are driven by a confluence of different cost drivers. These include:

- **Network maintenance and upgrades**: The cost to build and maintain the physical infrastructure of the electric system has become more expensive in recent years. Between 2019 and 2023, transmission capital investment, transmission maintenance, and distribution maintenance costs each increased by about 20%, while distribution capital investment costs rose by 50%.[12]
- **Power plant investments:** Generation costs have also increased, driven by higher demand and higher underlying equipment costs for all energy technologies.[13] Further, state policy that requires utilities to add renewable generation beyond market-based levels can contribute to higher retail prices (though where renewable resources are cost-competitive, they do not result in this upward price pressure).[14]
- **Fuel costs**: Because natural gas often sets the marginal price of electricity in wholesale markets, swings in gas prices can affect the prices customers ultimately pay for power. The

[12] Wiser et al., 2026

[13] GridLab. *The New Reality of Power Generation.* September 2025. https://gridlab.org/wp-content/uploads/2025/09/GridLab_Gas-Turbine-Costs-Report-1.pdf.

[14] Roughly 75% of renewable capacity in the US is built through competitive market channels, where developers generally select the least-cost resources, reducing rate pressure for customers. See footnote 5.

Ukraine-Russia war has been a major contributor to sharp price movements in the last five years, with gas prices spiking in 2022 before falling back materially by 2025.

- **Extreme weather and wildfires:** Extreme weather events increase utilities' capital expenditures through short-term recovery efforts, rebuilding, increased liability insurance, and infrastructure hardening. These costs are especially pronounced in high-risk areas. For example, California has been negatively impacted by wildfire risks, with wildfire-related costs increasing from 1.7% of the revenue requirement to 17% for the three large IOUs between 2019 and 2024.[15]
- **Behind-the-meter solar programs**: Many rooftop solar compensation programs reduce bills for solar owners. However, the power system's fixed costs must be recovered from other customers, resulting in a higher average retail electric price.[16] The impact can be significant for states such as California, where net-metering programs have reduced electricity load by over 5%.[17]

While historical data indicates that data center growth has not led to increases in electricity prices, it is unclear whether this trend will persist. As we show in the next section, the impact of new large customers on electricity prices will depend on a variety of factors, as well as on how those factors interact with market and regulatory structures and with the design of tariffs and contracts for the large customers.

III. The Economic Framework of Price Impacts from Load Entry

Whether and how existing customers are ultimately impacted by new large load customers depends on the difference between the additional revenue collected from large load customers and the additional investment costs required to serve them.

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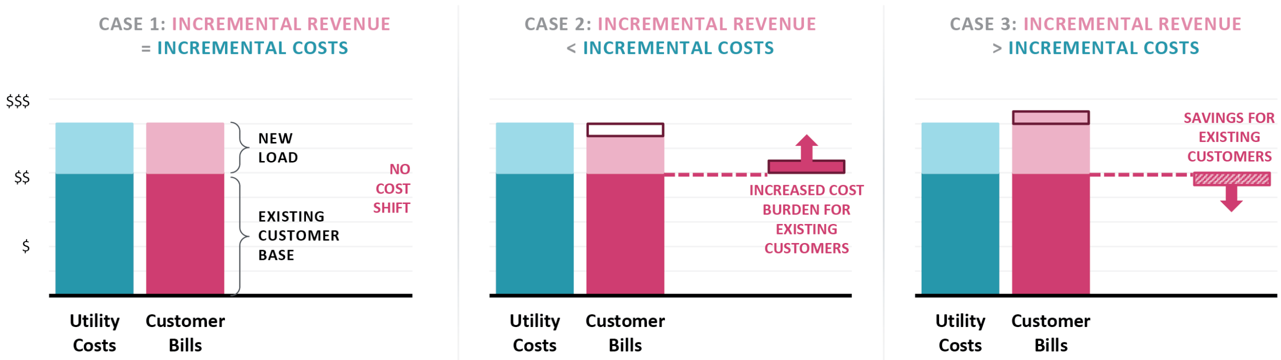
[15] Wiser et al., 2026

[16] Conceptually, retail rates are designed such that system costs are directly recovered from customers who incurred those costs. But in practice fixed system costs are recovered through volumetric rate components which can result in a cost shift onto other customers when a customer reduces their volumetric consumption. (See https://docs.nlr.gov/docs/fy25osti/91888.pdf).

[17] Wiser et al., 2026

If the incremental revenue recovered from new large load customers is insufficient to cover the incremental costs of serving them, the difference in net costs must be recovered from the existing customer base. Retail electricity costs for existing customers will increase as a result. Conversely, if revenue recovered from new large load customers exceeds the costs of serving them, retail electricity costs for existing customers will decrease. Figure 3 below illustrates three alternative cost shift outcomes, in which any difference between costs and revenue associated with large load customers—whether positive or negative—is passed on to existing customers.

FIGURE 3: ILLUSTRATION OF LARGE LOAD CUSTOMER COST RECOVERY SCENARIOS



Below, we discuss three factors that will drive large load customer cost recovery outcomes: mechanisms to collect revenue from the large load customer, factors that impact the size of the system upgrade needed to serve the new load, and factors that impact the marginal cost of system upgrades.

A. Incremental Revenue from Large Load Customers

Utilities and regulators have several broad options for pricing electricity service to large load customers, each with implications for revenue sufficiency and who bears the risk if actual costs or usage differ from expectations.

One option is to serve large load customers under the **utility's standard large commercial and industrial tariff**. Those tariffs are typically built around two components: a demand charge, which reflects various measures of maximum usage, and a volumetric energy charge, which reflects total electricity consumption. Designed well, these rate components generally reflect the different types of costs that the utility incurs when serving customers.

In practice, policy objectives as well as customer bill stability and simplicity considerations commonly result in a mismatch between how revenue is collected from each customer and how utility costs are incurred. For example, the demand-based billing determinant used to charge the customer (e.g., maximum billing demand) may not align with the system's actual peaks. Similar mismatches can arise when the costs of major system upgrades are not recovered from the customers who benefit from them.

A second option is to create a **new tariff** specifically for large customers. These tariffs often include features not typically found in general service rates, such as minimum bills, demand ratchets, term commitments, and capacity reservation or subscription charges.[18] Those provisions can provide stronger protection against under-recovery.[19]

For example, minimum billing demand can ensure that fixed costs are recovered even if the customer's load does not materialize as expected, while longer contract terms can reduce the risk that a large customer exits the system before the utility has recovered the costs incurred to serve it. These tariffs tend to rely more heavily on demand-based charges, which better align cost recovery with the fixed costs that large customers impose on the system.

A third option is a **negotiated contract** for an individual large load customer. These arrangements are less transparent than generally applicable tariffs, but they give utilities more flexibility to tailor rate design and assign costs directly related to the customer's characteristics. For example, a utility could require the customer to pay for transmission upgrades undertaken on its behalf, thereby protecting existing customers from those costs.

At the same time, accurately establishing cost causation is not always straightforward. Some deeper system investments may create spillover effects, both positive and negative, that are harder to isolate. A new large load customer, for instance, might fund generation capacity that improves reliability for other customers, while also increasing regional natural gas demand and, at the margin, fuel costs. For that reason, transparency in how costs are identified and allocated remains important even under a contract-based approach.

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18 EPRI. *Tariff Design at an Inflection Point.* February 2026. https://www.epri.com/research/products/000000003002034687.

19 These provisions can be included directly within the tariff or within individual Energy Service Agreements (ESAs), which are often confidential. How these provisions are incorporated can impact the transparency of the tariff. More generally, a new tariff treats all customers on the rate as a class and does not consider customers' unique circumstances. Utilities with new tariffs for large load customers address this tension by using the tariff to establish baseline requirements and using ESAs for customer-specific requirements.

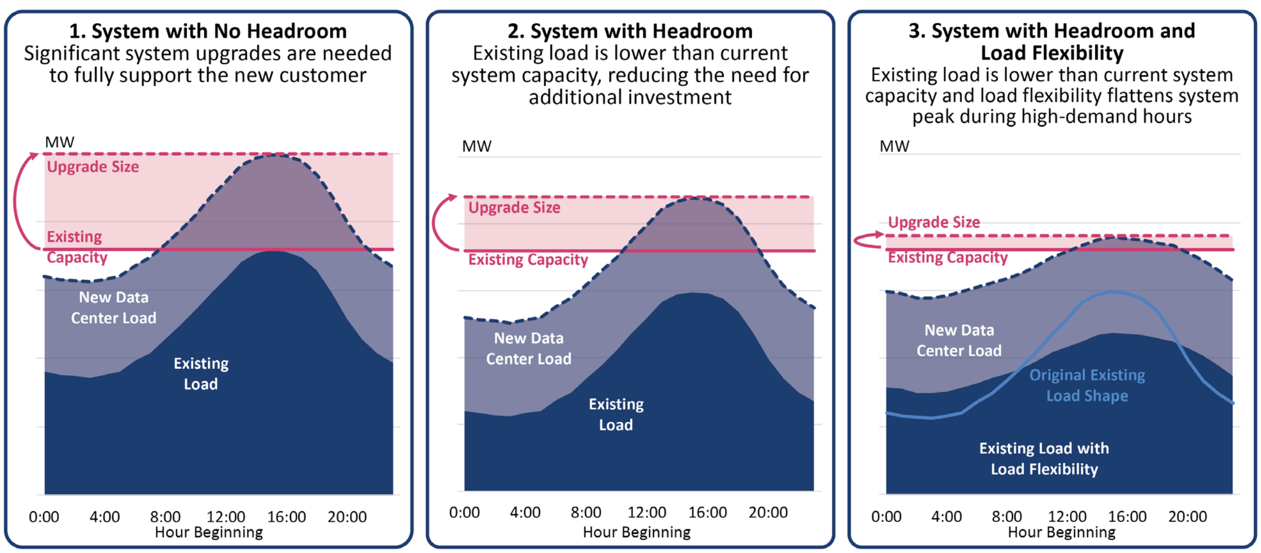
Regardless of the tariff option used to serve large load customers, if a utility can design rates that reflect the cost of service and include guardrails to ensure revenue recovery, the incremental revenue collected from new large load customers should be sufficient to cover the incremental costs they impose on the system. If that condition is met, existing customers should not be adversely impacted by the addition of new customers.

B. Upgrade Size

Another important determinant of the incremental system cost of serving a new customer is the amount of additional transmission and generation capacity required to accommodate that load. Available system capacity and load flexibility are both key factors influencing the size of required upgrades.

Figure 4 below illustrates these concepts by showing the same amount of new customer load added on the peak day under three different system conditions: (1) a base case, (2) a case in which the load is added in a location with available capacity, and (3) a case in which the load is flexible and can be added where capacity is available.

FIGURE 4: UPGRADE SIZE SCENARIOS – DAILY LOAD SHAPE ON PEAK DAY



In Case 1, **there is no available capacity to accommodate the new customer**. Adding a new customer without any accompanying flexibility, therefore, requires significant investment to expand the system and serve the additional load.

In Case 2, by contrast, **the system has some headroom**. That available capacity may exist for several reasons, including recent system investments, the loss of other large load customers, or lower-than-expected demand due to energy efficiency, demand response, or shifting system peaks. For example, a utility may have invested in a large generation asset and then experienced slower-than-expected load growth because energy efficiency measures reduced demand. In that situation, some of that unused capacity can be used to serve a large load customer with only modest additional upgrades.

Case 3 shows the role of **load flexibility**. In this system, there is some capacity available, but that capacity alone may be insufficient to meet the full demand of a large load customer. That capacity can be coupled with additional headroom created by demand flexibility from the new customer or existing customers. Programs such as mandatory curtailment during reliability events or the use of on-site generation can keep peak demand flat while still allowing additional large customers to connect.

Other factors can also affect the size of the required upgrade, including the accuracy of load forecasts. If utilities overestimate the amount of new demand that will materialize, they may procure more generation or transmission capacity than is ultimately needed, resulting in larger-than-necessary system upgrades and higher system costs.

Even when rates are perfectly cost-reflective and if there is no risk of shifting costs to existing customers, properly sizing system upgrades needed still offers important benefits. First, it helps keep the incremental cost of serving new customers as low as possible, allowing utilities to offer more competitive rates. Second, when new large load customers make better use of existing infrastructure and improve overall system utilization, they can place downward pressure on rates by spreading fixed costs of the existing system across a larger base of customers.

C. Marginal System Upgrade Costs

The final major component of incremental system cost is the cost of the required upgrades themselves. Utility resource planning processes seek the least-cost options to serve new load, but the least-cost solution can vary significantly across jurisdictions. We discuss those differences in greater detail in Section IV below, focusing on how each system cost element affects Alliant Energy's overall cost framework. Primarily, these costs are capital expenditures and operational and maintenance costs directly associated with system infrastructure. However, there are also indirect cost effects that can arise when new large load customers are added to the system. These include:

- **Fuel costs**: In wholesale organized markets, meeting additional demand for electricity may require dispatching higher marginal cost resources, which results in higher market-clearing prices for all customers. There may be some indirect cost effects as well: additional loads drive up demand for fuel, placing greater strain on fuel supply and infrastructure, and indirectly increasing prices for all customers.
- **Transmission congestion**: Even if an electric grid can reliably interconnect and serve large load customers, additional demand on the transmission system can increase line congestion and increase energy prices, particularly during peak hours.[20] On the other hand, a new load sited in a location with abundant renewable generation can absorb that generation, reducing transmission congestion and costs.
- **Greater market exposure:** Increased demand can put pressure on planning reserve margins (PRM); utilities short on capacity may need to rely on the short-term capacity market to meet PRM requirements, and therefore be exposed to fluctuations in capacity market pricing. Cost-effective, flexible capacity resources like demand response can serve as effective hedging instruments.

These effects can be harder to isolate and attribute to specific large load customers than direct generation or transmission cost impacts. In many cases, they tend to surface only when system demand grows materially, and they are shaped by broader market conditions.

In some regional markets, cost allocation rules can amplify this effect: a utility that is not itself experiencing load growth may still face higher costs because regional transmission or capacity investments driven by load growth at a neighboring utility are allocated across all participants in the market. In that sense, cost shifts can cross utility boundaries, depending on how regional costs are shared.

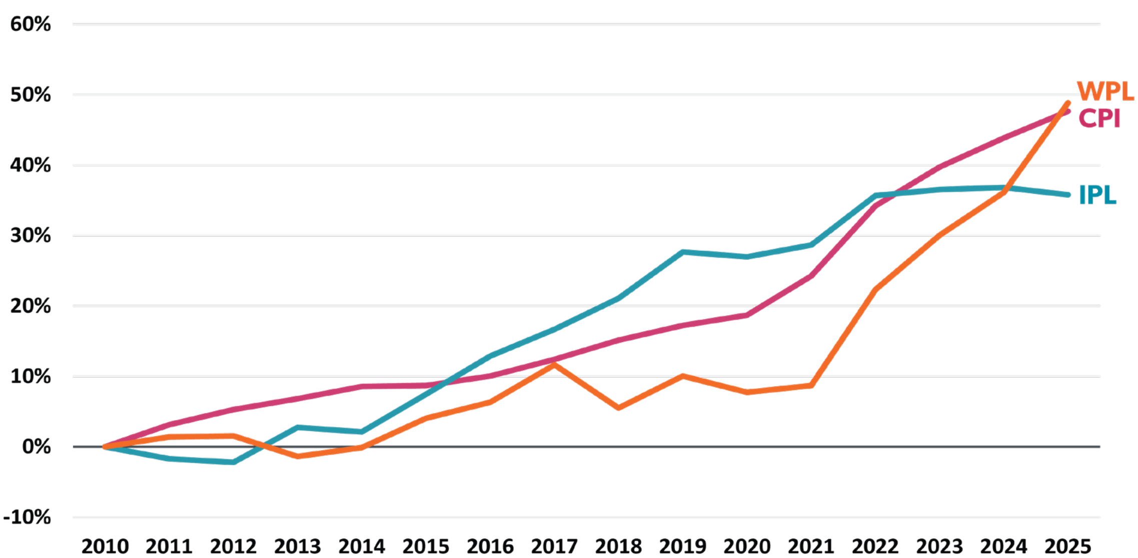
[20] Mamkhezri, Jamal, Xiaochen Sun, and Yuting Yang. *The Hidden Cost of the Cloud: Data Centers and Electricity Market Inefficiency*. USAEE Working Paper No. 25-660. November 9, 2025. SSRN. https://doi.org/10.2139/ssrn.5736562.

IV. Historical Price Trends and System Cost Drivers for Alliant Energy Utilities

Price trends in Iowa and Wisconsin—where Alliant Energy's companies, IPL and WPL, operate—have generally compared favorably with national trends. Between 2010 and 2025, electricity prices in both jurisdictions increased at a rate similar to or slower than inflation. In real terms, average prices decreased by 1.5 cents/kWh for IPL and increased by 0.15 cents/kWh for WPL. However, in nominal terms, prices increased by 4.68 cents/kWh for IPL and 6.06 cents/kWh for WPL over the same period.

As a result, Alliant Energy is not immune to broader concerns about affordability, and new large customers are evaluated within this context. Figure 5 below summarizes the historical trend in average electricity prices for IPL and WPL.

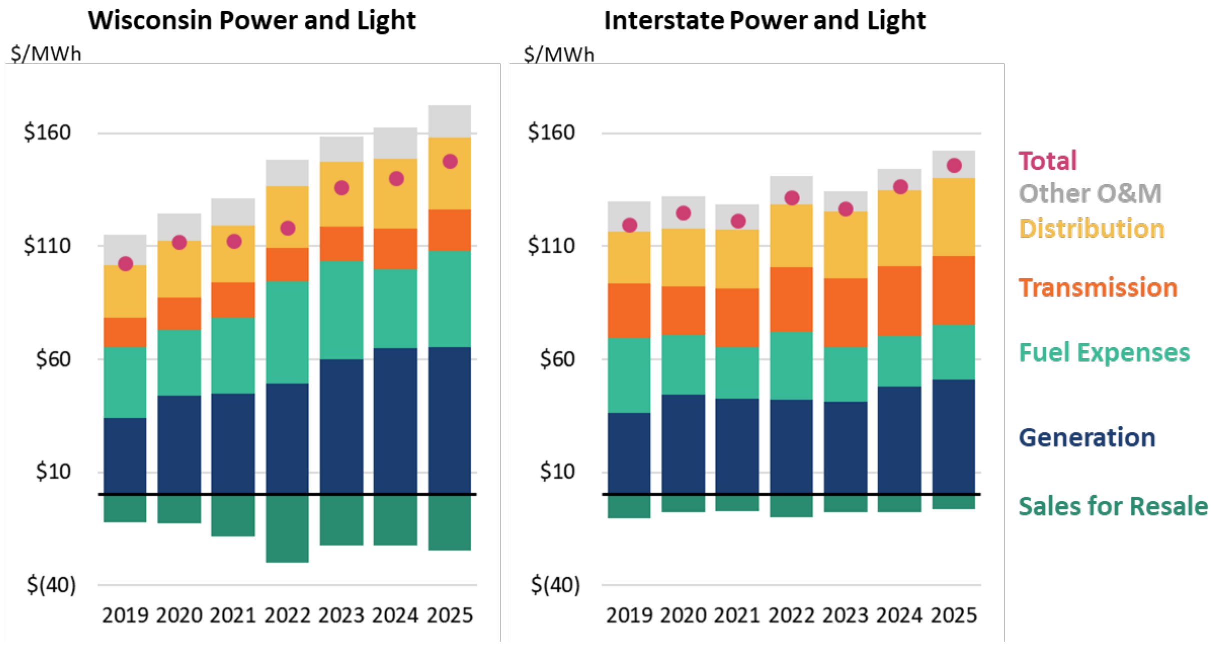
FIGURE 5: NOMINAL RESIDENTIAL ELECTRICITY PRICE CHANGES FOR IPL AND WPL (2010–2025)



Note: Data from EIA-861. 2025 EIA-861 data not yet available; used FERC Form 1 utility data to calculate residential prices as residential revenue divided by MWh sales. Inflation data from BLS.

Much of the recent price increases in Alliant Energy's jurisdictions have been driven by the replacement of aging T&D infrastructure and increasing equipment costs. Figure 6 below shows capital expenditures (CapEx) and operating and maintenance (O&M) costs between 2019 and 2025. Generation capacity investment and related costs represent the largest share of total costs, followed by distribution, transmission, and fuel.[21] We examine these factors in greater detail below.

FIGURE 6: CAPEX AND O&M COSTS FOR WPL AND IPL



Notes: Data from FERC Form 1 financial data. Rate base calculated using gross plant net of accumulated depreciation, and an assumed 7% WACC and 26% federal tax rate. Income tax credits are not included. Generation includes rate base, O&M, and depreciation. Fuel expenses include non-fuel O&M, fuel, and purchased power. Distribution includes rate base and depreciation.

TRANSMISSION

Transmission is a meaningful component of Alliant Energy utilities' cost structure (see Figure 6 above), comprising 11% of 2025 costs for WPL and 22% of 2025 costs for IPL. These costs have increased by nearly 41% and 26% respectively for WPL and IPL over the past seven years, though the share of overall costs has remained roughly constant.

Cost increases are driven by continued investment into transmission infrastructure from reliability investments and multi-value projects that, at least in part, are needed regardless of additional load interconnections, as well as by overall equipment cost increases that are not unique to Alliant Energy's territory. IPL's higher transmission costs likely also reflect greater regional transmission investment over time, especially projects tied to reliability and renewable

[21] Fuel costs are partially offset by sales for resale, or revenue that Alliant Energy earns by selling energy into the MISO market.

generation development. That broader buildout helps explain why IPL's transmission cost baseline has remained higher than WPL's.[22]

However, neither IPL nor WPL directly owns the transmission system serving its customers. IPL receives transmission service from ITC Midwest (ITC) and WPL from American Transmission Company (ATC).[23] These transmission owners charge Alliant Energy for access to transmission facilities, load dispatch, and regional market operations under MISO- and FERC-approved cost allocation and cost recovery structures. IPL and WPL then allocate those transmission costs among customer classes based on each class's relative share of transmission-related demand and recover costs through a Regional Transmission Service (RTS) rider in IPL and through base rates in WPL.

Notably, ITC and ATC plan, build, operate, and maintain their transmission systems largely independently of Alliant Energy. As stakeholders, IPL and WPL have some limited influence over what these companies invest in and when, but ITC and ATC are ultimately responsible for transmission investment decisions.[24] And, as members of a larger regional network, IPL and WPL may share in the costs and benefits that extend well beyond their service territories.

For example, MISO's Multi-Value Projects (MVPs) are allocated broadly across load in the relevant MISO footprint, meaning IPL or WPL customers may bear a share of MVP costs even when the underlying facilities are located elsewhere on the regional grid. It is important to note that MISO proceeded with the MVP projects because of the positive net benefits that they bring to the region, and the initiative began before load was expected to grow.

DISTRIBUTION

Distribution costs have remained relatively stable as a share of total costs for WPL, holding at approximately 18% between 2019 and 2025. In IPL, the share of distribution costs has grown from 18% to 23% over the same period, driven by rising equipment costs and ongoing capital investment to maintain local reliability. Part of this investment reflects improvements in the single-phase distribution system to reduce long-term operating and maintenance costs and improve service reliability.

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22 See https://www.itc-holdings.com/projects/multi-value-project-mvp-4.

23 WPL transferred ownership of its transmission assets to ATC in 2001 (see https://www.sec.gov/Archives/edgar/data/107832/000095012001000006/0000950120-01-000006-0001.txt). and IPL sold its transmission assets to ITC in 2007 (see https://www.sec.gov/Archives/edgar/data/52485/000089706907002172/cmw3169.htm).

24 Through its subsidiary, Wisconsin Power & Light, Alliant Energy owns about 16% of ATC.

Alliant Energy's distribution cost profile is also shaped by the nature of its service territory. Both IPL and WPL serve large, rural geographies with relatively few customers per mile of line, and more infrastructure is needed per customer than in a comparably sized urban utility. This geographic factor contributes to higher per-customer distribution costs and will remain a structural factor as the system grows.

GENERATION CAPACITY

Alliant Energy has invested in renewable energy in recent years, adding 1,500 MW of solar power since 2022 and operating nearly 1,800 MW of wind power.[25] These investments were supported by abundant wind and solar resources in Iowa and Wisconsin and benefited from federal tax credits and accelerated tax depreciation. While building these facilities required up-front capital, they generate electricity with no fuel costs, helping keep customer bills more stable and less vulnerable to swings in fuel prices.[26]

Alliant Energy's generation investments were intended to replace coal units slated for retirement in 2025 and 2026, but these retirements were delayed due to market conditions. Generation investment has been largely additive, which contributed to increases in Alliant Energy's generation capacity costs.[27] (Some of this additional cost is netted out in sales for resale where excess generation is sold to other utilities.) Generation capacity costs for WPL increased from 29% of total costs in 2019 to 38% in 2025. On a level basis, generation capacity costs increased by 93% over the same period. Generation capacity costs for IPL increased at a more moderate pace, increasing from 28% of total costs in 2019 to 38% of total costs in 2025. On a level basis, generation capacity costs increased by 40% over the same period.

As electricity demand grows across the country, the cost of building new power plants and buying electrical equipment is rising. As an indicator of this tightening market, the price that generators receive for making their capacity available during peak summer months in MISO rose from $30/MW-day to $666.50/MW-day in just one year. This dramatic increase in price was driven in part by shrinking surplus capacity across the region.[28]

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[25] See https://www.alliantenergy.com/our-energy/solar and https://www.alliantenergy.com/our-energy/wind

[26] See https://eta.lbl.gov/news/wind-energy-benefits-outweigh-costs.
Last December, Iowa produced 63% of its total electricity from wind (See https://www.chooseenergy.com/data-center/wind-generation-by-state/)

[27] See https://www.utilitydive.com/news/wisconsin-utilities-coal-retirement-miso-delay/626005/.

[28] Part of this reduction in capacity was driven by retirements and changes in resource accreditation—i.e., how much capacity can be bid into the market—but rising load also tightened reserve margins. *See* MISO, *Planning*

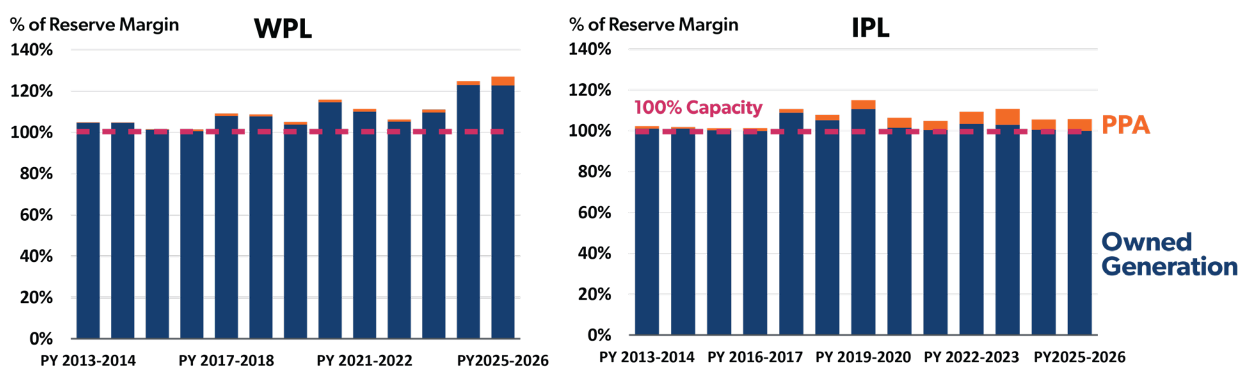
Continued on next page

IPL and WPL are better positioned to manage rising generation capacity prices than utilities in other parts of the country. In the PJM region, utilities must buy most of their capacity through centralized auctions, with all customers paying the auction clearing price, including when prices spike.

The dynamic is different for IPL and WPL. Like many other MISO utilities, IPL and WPL own or contract for the power needed to serve their customers (see Figure 7 below). They only need to procure *additional* capacity from the market or from contracts when their existing capacity is insufficient to cover the increased demand. In other words, only their residual demand not met by existing capacity is subject to market prices, instead of all demand as in the case of PJM utilities.

Moreover, to the extent that IPL and WPL can procure capacity below MISO capacity market prices through demand response, bilateral contracts with generators, or extensions of existing units' operating lives, customers would benefit from those arrangements.

FIGURE 7: WPL AND IPL CAPACITY PROCURED FROM PPAS AND OWNED GENERATION, RELATIVE TO RESERVE MARGIN



Note: Capacity value data from Alliant Energy accounts for capacity accreditation methods. In some cases, values exceed 100% because the utilities are long on capacity (which can be sold to other entities or into the MISO capacity market). PY = Planning Year

FUEL PRICES

Alliant Energy's changing generation mix toward greater renewable penetration has been the main driver of lower fuel costs in recent years, though both utilities remain exposed to movements in natural gas and other fuel markets. As renewables make up a larger share of supply, fuel costs become a smaller piece of overall costs, and customer prices become less sensitive to swings in fossil fuel prices.

Resource Auction Results for Planning Year 2025–26. April 2025. https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

WPL, for example, is relying much less on fuel-burning generation, with its renewable share of retail sales rising from 21% in 2020 to 36% in 2025. IPL's renewable share also increased, rising from 44% to 50% over the same period.[29] Reflecting this shift, fuel costs in WPL fell from 27% of total costs in 2019 to 25% in 2025, while IPL's fuel costs fell from 25% to 16%. On a level basis, fuel costs decreased 34% for WPL and 26% for IPL.

Even so, fuel market volatility still affects retail prices. The extent of that exposure varies by utility and region, depending on factors such as pipeline constraints, hedging practices, and market design. Alliant Energy's location in the central United States provides some insulation from the tighter link between natural gas and electricity prices seen in other regions. The Midwest remains more reliant on coal and is less dependent on natural gas than regions such as New England, where gas plays a major role in both electricity generation and home heating.[30]

Still, utilities have only limited ability to shield customers from sustained increases in fossil fuel prices, so fuel market volatility has continued to contribute, at least in part, to changes in Alliant Energy's retail prices.

V. Impacts of Future Load Growth on Electricity Price

Electricity demand across the Midwest is expected to grow significantly in the coming years, including in the areas served by Alliant Energy in Iowa and Wisconsin (see Figure 8 below). For example, according to MISO, demand for electricity between 2025 and 2030 in MISO's Load Zone 3 (which includes Iowa) and MISO's Load Zone 2 (which includes most of Wisconsin) is expected to increase by 41% and 46%, respectively. Notably, MISO has revised its load forecasts sharply upward in recent years, largely due to a surge in requests from data centers and other large facilities seeking to connect to the grid.[31]

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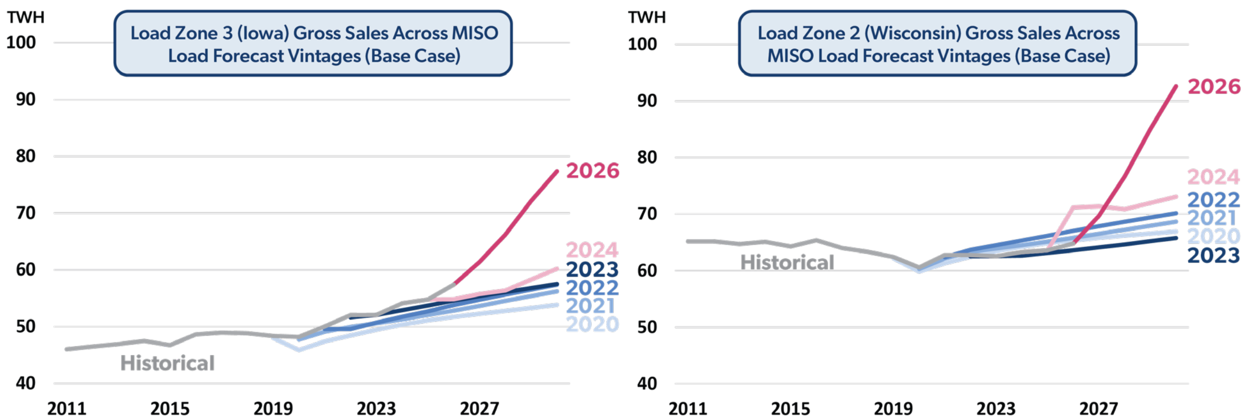
29 See IPL and WPL Electric Utility Retail Customer Data Renewable Energy, Energy Mix, and Greenhouse Gas Emission Rates, June 2025.

30 See https://www.eia.gov/electricity/monthly/update/print-version.php.

31 MISO. *Long-Term Load Forecasting Results Summary*. April 2026. https://cdn.misoenergy.org/20260413%20LTLF%20Workshop%202026%20Long%20Term%20Load%20Forecast%20Summary_UPDATED750524.pdf.

FIGURE 8: FORECASTED ELECTRIC LOAD CHANGES IN IOWA AND WISCONSIN



Notes: Data from MISO load forecasts. Load Zone 2 includes Eastern Wisconsin and the Upper Panhandle, including WPL's territory. Load Zone 3 includes Iowa and a portion of southwest Minnesota, including IPL's territory. MISO did not release a 2025 Long Term Load Forecast.

Meeting rapid load growth will require substantial investment in new power plants. Whether existing customers will pay more for investments in generation capacity to serve large load customers depends on how the costs of serving these new large customers are recovered. Alliant Energy's Individual Customer Rate (ICR) includes a mechanism designed to ensure that new large customers pay at least the incremental costs of serving them.[32] Because each large customer's contract must generate enough revenue to cover at least the full incremental cost of serving that customer, existing customer rates would not be affected.

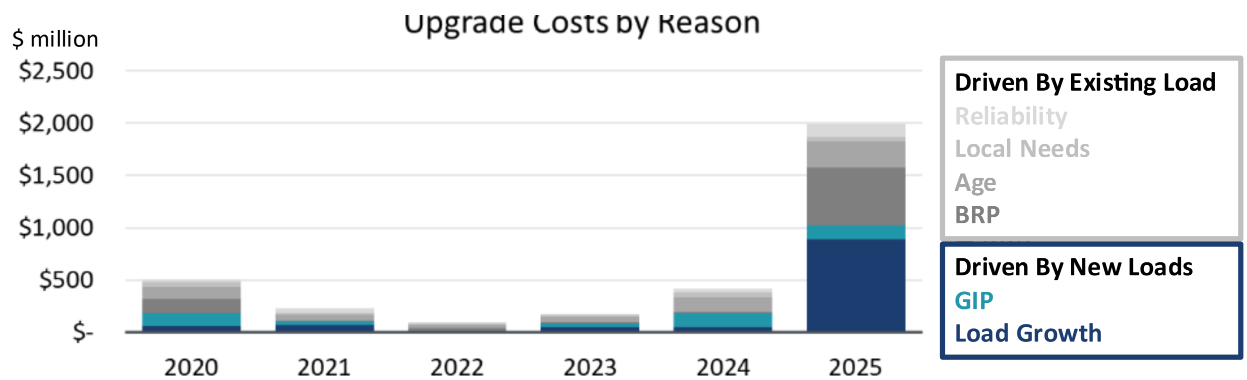
Additional transmission investments may be needed to serve new large customers as well, but their effect on rates depends on the type of investment and the balance between the investment required to connect new large customers and the additional revenue they bring onto the system. Some of these investments are directly attributable to large load customers, and they can be directly assigned those costs. Other investments, including some of the larger network investments, are triggered by large load customers, but effectively will be used by all customers, so the recovery of those costs is typically socialized across the full customer base.

[32] "The ICR Rates will be designed to recover no less than the marginal costs to serve the Customer over the term of the Service Agreement. Non-ICR customers shall be held harmless from any deficiency in revenue provided by any customer served under this tariff or from any stranded investment or cost(s) associated with serving customers under this rate schedule remaining after any Board determined and approved adjustment for specific quantifiable benefits or costs. The Company will make provisions to separately identify the costs and revenue for each respective Rider ICR customer within its books and records." IPL, Rider ICR – Individual Customer Rate, 2024.

Even without data center growth, substantial transmission investment would be needed to maintain reliability and replace aging infrastructure. For example, of the transmission projects identified in the MISO Transmission Plan (MTEP)—the system operator's regional planning process—over the past six years, roughly half of the investments are associated with reliability and the existing system (see Figure 9 below). Those investments would need to be recovered from today's customer base regardless of load growth, putting upward pressure on transmission rates.

The MTEP 2025 plan was particularly large, identifying more than $12 billion in investment, with nearly two-thirds associated with new large load customers. That suggests a growing share of transmission investment is being driven by interconnection-related needs, but it also means a larger customer base over which those costs can be spread.

FIGURE 9: MTEP TRANSMISSION PROJECT COSTS IN ATC AND ITC



Note: MTEP 2020 – MTEP 2025. BRP refers to baseline reliability projects, and GIP refers to generator interconnection projects. GIP and "Load Growth" projects serve additional load. Remaining projects are intended to support existing load by addressing reliability, local needs, aging infrastructure, and baseline reliability needs.

To assess expected trends in the transmission component of Alliant Energy's retail rates, we use data from ATC (the transmission owner for WPL), ITC (the transmission owner for IPL), and MISO to examine impacts on transmission rate for both ITC and ATC customers under two scenarios. These scenarios are intended to capture a range of possible transmission cost outcomes under different large load penetration levels:

- **Lower Data Center Load Scenario:** Under this scenario, all investments currently identified in transmission planning documents are completed, and peak load growth increases reflect historical growth rate and lower data center growth. In Wisconsin, 2018-2024 transmission customer load growth was 0.05%; we estimate total annual growth of 2.5% through 2030, including identified data center projects under construction.[33] In Iowa, historical transmission customer load growth was 2.1%; we estimate total annual growth of 5% through 2030, consistent with EPRI's Iowa state-level "low growth" scenario.[34]

- **Higher Data Center Load Scenario:** Under this scenario, all transmission investments are completed. Peak load growth increases reflect historical growth and higher data center growth. For Wisconsin, we estimate total annual growth of 7% through 2030, which includes identified data center projects under construction *and* planned projects. For Iowa, we estimate total annual growth of 10.4% through 2030 in line with EPRI's Iowa state-level "high growth" scenario.[35]

These two cases reflect different degrees of system utilization, with the same level of investment being recovered from different amounts of new large load demand. In the Higher Data Center Load Scenario, more data center customers interconnect, leading to more efficient use of the system and, ultimately, lower average costs for all customers. In the Lower Data Center Load Scenario, fewer data center customers still enter the system, resulting in higher average transmission costs. However, the speed of new developments and the scale of investment mean there is still uncertainty about the magnitude of large load customer deployment.

Figure 10 below shows the expected range of transmission rate outcomes in WPL and IPL zones. In both zones, increased utilization and large load addition can defray identified transmission project costs across a larger customer base. In WPL, more transmission reliability project costs are expected to increase rates regardless of large load entrance, but to the extent that more large load customers interconnect, reliability project costs can be spread across a larger number of customers. In contrast, Iowa's current transmission rates are higher, but transmission planning documents identify fewer transmission project needs. This means that new large load customer interconnection could lower transmission rates below 2025 levels.

Importantly, even when average transmission costs increase, this does not necessarily translate into a cost shift to existing customers. If Alliant Energy's large load contracts are designed to

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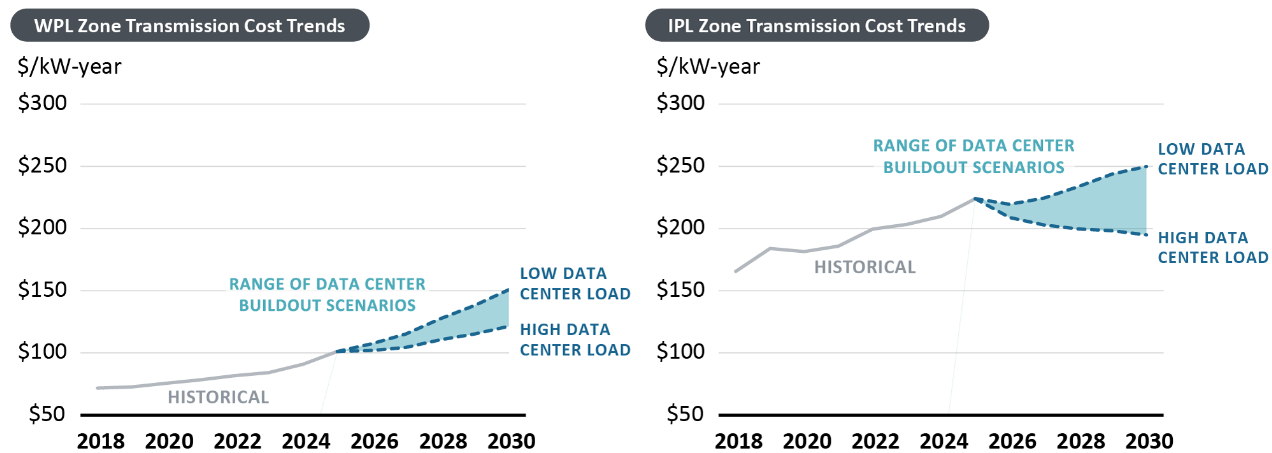
[33] Our estimate includes projects for Microsoft at Mt Pleasant, Vantage in Port Washington, Meta at Beaver Dam, and a data center in Wisconsin Rapids for a total increase in peak load of 1.2 GW using an estimated load factor of 80% during peak load hours.

[34] EPRI's projection includes assumes 90% of data center projects currently under construction and 25% of data center projects in advanced planning stages will be fully operational by 2030. See EPRI. *Powering Intelligence 2026.*

[35] EPRI's projection includes 100% of data center projects currently under construction and in advanced planning stages, as well as 30% of those in early planning stages. See EPRI. *Powering Intelligence 2026.*

pass through the incremental transmission costs attributable to large customers—rather than socializing the costs across the broader rate base—existing customers can be insulated from those increases regardless of how much new investment is required.

FIGURE 10: HISTORICAL AND FORECASTED TRANSMISSION COST TRENDS FOR WPL ZONE AND IPL ZONE



Note: Data from MTEP, ATC OASIS, and ITC OASIS. Data center load growth scenarios are based on EPRI's state-level data center estimates and additional identified data center projects in each state. Data center loads are added on top of transmission customer load growth rates observed annually between 2018 and 2024.

Against that backdrop, Alliant Energy has developed a contract-based approach that combines features of a special large load tariff and an individualized agreement to better align revenue with the costs imposed by new large load customers. These contract rates are designed to directly recover costs incurred on behalf of the customer, hold existing customers harmless, and utilize excess capacity on the system. The contracts include several guardrails, including a minimum 10-year term, contract demand thresholds above which Alliant Energy is not required to provide service, and minimum billing demand requirements that support cost recovery regardless of the customer's actual usage pattern or level.

The rate itself includes both an energy charge and a demand charge designed to recover the costs associated with serving the customer. Energy-related costs are intended to be recovered through a mechanism that reflects the MISO energy costs specific to the customer's location. Generation capacity costs are recovered through a demand charge that increases over time, along with a generation capacity reservation charge, which becomes effective when usage falls below contracted levels. All transmission costs are allocated to the customer based on its contribution to annual consumption and annual coincident peak demand.

As system conditions evolve, our understanding is that Alliant Energy will monitor and refine its rate mechanisms to ensure that large loads continue to be responsible for the full transmission costs that they incur. The rate also includes additional components to recover administrative costs, energy efficiency riders, and taxes.[36]

VI. Emerging Practices for Mitigating Risks Associated with Serving Large Energy Users

Utilities and regulators across the country are evaluating a range of mechanisms to capture the benefits of large load customers without inadvertently increasing costs for existing customers. Large load customers can provide meaningful benefits to a utility system through increased revenue, more opportunities to improve system utilization, and a larger state tax base. However, realizing those benefits depends on appropriately defined rate design and contract terms.

Well-designed rate structures and contract terms can address scenarios in which the incremental cost of serving a new large customer exceeds embedded system costs and a customer's load profile increases capacity or transmission requirements in ways not fully reflected in their rates. Similarly, incentives such as economic development riders and accelerated investment timelines create a gap between the cost of service and the revenue collected.

Table 1 below summarizes several common sources of cost shift risk and the tools that can be used to mitigate them. These mechanisms tie revenue from large load customers more closely to the costs they impose on the system, ensuring that incremental revenue at least matches incremental costs and, where uncertainty is high, building in additional protections for existing customers.

[36] Wisconsin Power and Light Company (WPL), *Application for Approval of an Individual Contract Rate Service Agreement for a Large Load Customer in Beaver Dam, Wisconsin*, Docket No. 6680-TE-115, PSC Ref. #581409 (Apr. 29, 2025) (Public Version).

TABLE 1: STRATEGIES TO MITIGATE COST SHIFT RISKS ASSOCIATED WITH LARGE LOADS

Strategy	Description	Implemented by Alliant Energy
Include Hold-Harmless Provision	These provisions are designed to prevent cost shifts onto existing customers by ensuring that incremental revenue meets or exceeds incremental costs.	✓
Introduce Price Premium	Develop a mechanism that explicitly recovers costs beyond those directly imposed by large load customers (e.g., costs associated with accelerating infrastructure investments needed to serve large load customers, funding for customer assistance programs).	✓
Contribution in Aid of Construction (CIAC)	Some customer-specific facilities may be needed to serve a new large customer. Instead of including the facility costs in the rate base and recovering them from all customers, utilities use CIAC to require the new large customer to pay for those direct costs.	✓ [1]
Frequent Cost of Service Updates	Frequent updates to cost of service ensure that costs are properly identified and allocated in a fast-moving environment impacted by individual large load customers.	✓
Develop New Large Load Class	A new large load class can be designed to align with large load customer load profiles to ensure adequate revenue recovery. Tariff mechanisms specific to the large load class can include guardrails against cost shifting and stranded cost risks.	✓ [2]

Notes:
[1] Alliant Energy customers fund some customer-specific equipment (e.g., distribution level, transformers, and on-premises). Transmission owners do not allow CIAC or self-funding, and Alliant Energy has not used CIAC for generation.
[2] Alliant Energy is evaluating alternative approaches to a large load tariff in both states. The PSCW recently directed WPL to file a large load tariff to replace its ICR tariff.

When serving large load customers, utilities make long-lived investments guided by load forecasts, expected development schedules, and contractual terms. In practice, projects may be delayed, resized, or evolve differently than anticipated, with significant implications for investment recovery. If, for example, a large customer terminates service before the end of its contract term, infrastructure built to serve that customer may become stranded, leaving the utility unable to fully recover its costs.

To address stranded asset risk exposure, utilities and regulators have developed mitigation tools that align forecast and performance risk with the customer driving it. Contractual protections—such as take-or-pay obligations, collateral requirements, exit fees, up-front contributions, and long-term commitments—help match cost recovery to the timing and durability of the load. Table 2 below summarizes the main drivers of stranded-cost risk and several approaches utilities are using to manage this risk.

TABLE 2: STRATEGIES TO MITIGATE STRANDED COSTS RISKS

Strategy	Description	Implemented by Alliant Energy
Take-or-Pay Requirement	Large load customers pay for a committed level of capacity or energy, whether or not they ultimately take that volume, contributing to the recovery of fixed costs associated with infrastructure built to serve the large customers' forecast load.	✓
Collateral Requirement	Collateral provides immediate financial protection if a customer delays, downsizes, defaults, or exits before the utility has recovered the costs of serving it.	✓
Exit Fee	If new large customers terminate service before the contract term is over, they are required to pay a fee to cover stranded investments caused by the departure.	✓
Up-front Payment	New large customers pay for grid infrastructure up front, accelerating service while reducing the risk of existing customers funding upgrades triggered by the new customers.	[1]
Long-term Contractual Commitment	Aligns the customer's financial obligation with the long-lived assets the utility may build to serve it, making it less likely that costs will be stranded if the customer's business plans change.	✓
Bring-your-own Generation Allowances	Allowing large load customers to self-supply some or all of their incremental load with dedicated generation can reduce the amount of utility system expansion needed in the first place, which lowers stranded-cost exposure; customers are still required to pay for any backup, standby, or network capacity the utility must reserve for them.	✓

Note: [1] Large load customers, under current practice, can pay for their preferred generation resource, though transmission owner policy does not allow customers to make an upfront payment for transmission investments at this time.

VII. Conclusions

Energy affordability is a central policy concern. Although average retail electricity prices have increased over the last decade, those increases have generally tracked broader inflationary pressures rather than reflecting a singular effect from large load customer development. In many parts of the country, recent price increases have been driven more by the replacement of aging infrastructure, load reductions that spread fixed costs over a smaller sales base, and growing exposure to extreme weather risk than by investments made to accommodate new large load customers.

State-level evidence likewise does not suggest that data center growth necessarily results in higher electricity prices for existing customers. States with greater data center load penetration have not, on average, experienced disproportionate increases in retail prices through 2025. Historical trends do not mean that new large load customers are always price-neutral, or that this will continue to hold in the future. However, historical trends do suggest that outcomes depend on the balance of available headroom in the system, the need for incremental upgrades, and the extent to which additional demand improves utilization of existing infrastructure.

Where available capacity exists or fixed costs can be spread across a broader customer base, additional load can place downward pressure on average prices. Alliant Energy may be comparatively well-positioned in this respect, given its relative insulation from capacity price spikes and its access to wind-rich resources, both of which could reduce the cost of serving new large load customers compared to other utilities elsewhere.

However, Alliant Energy has little control over regional transmission investments and will be allocated its share of these expenditures as large load customers continue to accelerate timelines for these large investments in Iowa, Wisconsin, and other parts of the Midwest. While these developments will increase transmission rates for all customer classes, Alliant Energy can mitigate the extent of increases for its smaller customers through its cost allocation process.

Ultimately, we consider the most relevant question facing decision-makers not to be whether Alliant Energy should serve additional large load customers, but rather under what terms the company can do so while benefiting existing customers.

The central principle in this regard is that incremental costs associated with serving new large load customers are matched or exceeded by incremental revenue collected from those customers. Achieving that outcome requires tariff design and contractual protections that assign both cost-shift risk and stranded-cost risk to the customers that create them, and potentially new initiatives to more efficiently utilize existing power infrastructure. Under that framework, Alliant Energy can pursue the benefits of load growth and economic development while potentially improving affordability for existing ratepayers.

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