ENERGY INNOVATION POLICY & TECHNOLOGY LLC®

www.energyinnovation.org

98 Battery Street, Suite 202
San Francisco, CA 94111

ELECTRIC RATE DESIGN AND REGULATION TO PROMOTE INDUSTRIAL ELECTRIFICATION

Sonali Deshpande and Jeffrey Rissman, September 2026

Promoting industrial electrification requires comprehensive policy support across multiple jurisdictions. This brief covers the policy levers utilities and their regulators can use.

A complementary brief explores policy levers available to state legislators.

Electrification can eliminate industrial emissions but faces obstacles

The industrial sector is a pillar of the United States' economy, manufacturing everything from steel to food products. It also emits 30 percent of the country's greenhouse gases (GHG),[1] mainly from burning fossil fuels to create heat for industrial processes. Besides reducing heat demand through efficiency improvements, electrification powered by clean energy is the best option to eliminate GHGs and other industrial pollution. Compared to clean electricity, green hydrogen uses much more energy, sustainable bioenergy is in short supply, and carbon capture fails to address upstream methane leakage or capture all on-site carbon dioxide (CO_2).[2] No technical barriers exist to electrified heating, as electricity can deliver heat at any temperature demanded by industry.

However, most U.S. industrial firms need economic incentives to electrify, as they pay roughly 4.7 times more for electricity than for the same amount of energy from natural gas, on average.[3] While the superior efficiency of electrical heating compared to fossil fuel combustion (thanks to heat pumps at low temperatures, and by avoiding energy losses in exhaust gases at high temperatures) makes up some of this "spark gap," electricity is still the more expensive option in most cases today. Closing the spark gap will be the single most impactful step in decarbonizing U.S. industry, since energy costs dominate the lifetime expense of owning and operating industrial heating equipment.

Fortunately, utility regulators have several tools at their disposal to lower the cost to serve industrial customers, lowering industry's prices without necessarily increasing expenses for others: namely, adopting electricity rates that better reflect the cost of service and regulations that accelerate clean energy buildout and grid modernization. Regulatory action will be crucial in creating an environment where clean, electrified industry can thrive, boosting U.S. competitiveness for decades to come.

---

[1] U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2022*. 2024. https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks. Note that this figure allocates emissions from the electricity sector to the end-use sectors purchasing electricity; the industry sector is responsible for 23% of U.S. GHGs if electric power is considered a separate sector.

[2] Rissman and Sawe. *The Industrial Zero Emissions Calculator*. 2024. Energy Innovation. https://energyinnovation.org/report/industrial-zero-emissions-calculator/

[3] U.S. Energy Information Administration. State Energy Data System (2025 updates). Table E5. Industrial sector energy price estimates, 2024. https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_sum/html/sum_pr_ind.html&sid=US

Rate design options to promote industrial electrification

Utility regulators or Public Utilities Commissions (PUCs) have authority over the prices monopoly utilities charge customers, including large industrial users. They allow utilities to allocate electricity rates across customer classes in ways that balance different objectives, such as cost causation, incentives to conserve, and the ability to understand the rate. Most rates attempt to approximate the cost of electricity service to each customer class, including the cost of the energy itself, the costs of delivering energy to the customer, and the costs of grid infrastructure.

Because industrial firms tend to be sophisticated customers with large power system demands; industrial electric bills can be complex, including demand charges (fees based on peak power draw), energy charges (based on the quantity and value of electricity consumed), transmission charges (covering costs of moving electricity from power plants to the distribution system), distribution charges (for local electricity delivery to the industrial facility), and fixed charges to cover services such as meter reading, billing, and customer service.

In aggregate, these fees can be appropriate for an entire customer class (i.e., all industrial electricity users), but they can be poorly aligned with the cost to serve specific industrial customers. For example, most industrial rates do not adequately reflect the lower cost of serving flexible energy users—those who can shift consumption away from peak periods (when meeting high demand requires extra grid infrastructure and running expensive "peaker" power plants) to periods where there is extra power supply (like the middle of the day, when solar output is highest) or there is spare capacity on the wires that deliver power to customers.

For example, utilities in some states levy demand charges based on the customers' highest electricity consumption in the billing period irrespective of whether that power is demanded during peak periods. These "non-coincident" demand charges are sometimes the highest charge on an industrial customer's bill and can disincentivize firms from using energy storage or flexible operations to shift energy consumption away from the system peak.

Not all customers are subject to these broad rate design practices. The largest users have enough market power to shop around, allowing them to negotiate bespoke rates outside of default rates in exchange for offering regional economic development benefits and spreading fixed system costs over more load. "Hyperscale" data centers, for example, sometimes attempt to reach rate agreements for similar projects with multiple utilities—agreements that are reviewed by regulators but could still increase other customers rates' as their terms are often hidden from public view.

Certain smart rate reforms, pursued via transparent and fair regulatory processes, can encourage flexible electricity use in the industrial sector, facilitating industrial electrification without raising utility costs and facilitating faster interconnection when the grid is otherwise constrained. Some plants can load-shift with operational changes, while others can do so with energy storage (e.g., electric batteries, thermal batteries) charged using grid electricity and/or on-site renewables. However, it should be noted that not all plants can consume power flexibly (e.g., plants with high load factors, 24/7 operations, and process temperatures that exceed what today's thermal batteries can provide).

Time-differentiated rates use price signaling to encourage shifts in electricity consumption to reflect the value of electricity delivered.

- **Real-time energy pricing:** The energy component of rates fluctuates every hour or 15 minutes, in line with varying power generation costs. Rates are based on wholesale electricity prices in deregulated markets and marginal generation costs for that period in regulated markets.

- **Time of use (TOU) rates:** Rates are differentiated by two or three periods (peak, off-peak, and sometimes mid-peak). Peak rates are highest, off-peak rates are lowest, and mid-peak rates fall in between. Residential TOU rates are now available in most states. However, industrial TOU rates will likely not be granular enough to meaningfully reduce costs through flexible electricity use.
- **Critical peak pricing:** Rates are higher for a few hours out of the year when the grid is particularly strained (e.g., extreme weather, plant outages).
- **Time-varying delivery charges:** TOU and critical peak pricing can be applied exclusively to transmission and distribution costs, which are driven by grid congestion and do not necessarily peak at the same times as generation costs.
- **Seasonally differentiated rates** offer lower pricing during times of year where electricity use is relatively low (historically winter, though as electric heating for buildings becomes more common, spring and fall may become the lowest-use seasons).

Lower demand charges can encourage flexible electricity use or on-site renewables.

- **Shift to coincident demand charges:** "Non-coincident" demand charges apply regardless of when the demand occurs, meaning firms cannot avoid them by load shifting. Utilities can instead offer "coincident" demand charges, which apply only to demand during peak electricity use periods across the whole grid, so firms with some flexibility can shift consumption away from peak periods in exchange for lower demand charges. However, coincident demand charges should not necessarily replace all noncoincident demand charges, which are sometimes a fair way to recover a system's fixed costs.
- **Shift to TOU demand charges:** Another common (but less effective) alternative to non-coincident demand charges are TOU demand charges, where high consumption during off-peak periods incurs a lower demand charge than high consumption during peak periods.
- **Increase the role of volumetric charges:** To recover their costs, utilities could rely less on demand charges and more on "volumetric charges," which are based on overall electricity consumption. This provides an incentive for on-site renewable energy and energy efficiency, but it could disincentivize electrification using grid electricity.

Demand management strategies use methods other than price signals to encourage load shifting, and sometimes the use of on-site clean energy and storage. Today, most utilities only use demand response as an emergency backstop, but regulators can instead require their integration in utility planning to achieve more meaningful cost reductions.

- **Interruptible rates:** Most utilities offer customers an optional, discounted electricity rate in exchange for the ability to stop their service when the grid is strained, but it is typically treated as a last resort option. Interruptible rates should instead be a standard offering that utilities count on during planning.
- **Demand-response programs:** Customers can receive incentive payments, such as bill credits, in exchange for lowering their electricity consumption when the grid is strained.
- **Virtual power plants (VPPs):** VPPs are digital networks of energy generation, storage, and flexible loads that can respond to signals from utilities, acting collectively as a flexible resource for the grid. Industrial firms with energy storage or flexible consumption patterns could be large participants in future VPP networks.

Special rates and incentives typically aim to attract new customers to a utility or help spread fixed system costs over more electricity sales. They can be designed to promote industrial electrification.

- **Special industrial rates:** In many places, large industrial loads can negotiate a bespoke electricity rate with the utility (e.g., flat percentage discount, reduced or avoided non-coincident demand charges, generation rates linked to wholesale market prices). Utilities could make favorable rates conditional on a commitment to flexible electricity use in response to grid needs.
- **Targeted incentives:** PUCs could authorize the creation of a structured utility program to offer targeted incentives for flexible, high-load factor industrial firms to deploy electric heating equipment. Incentive levels should reflect the cost savings from the associated grid-balancing effects.
- **Clean energy transition tariffs** offer large industrial loads that are in vertically integrated markets and lack sufficient land for on-site renewables a way to access new clean energy resources indirectly. Utilities act as an intermediary under this arrangement, contracting with a third-party developer and passing the clean power through to the customer at a fixed rate. Those fixed charges replace the portion of the customer's standard energy and capacity charges that the clean resource covers, insulating the customer from fossil fuel price volatility and—in some cases—lowering their net electricity costs.
- **Gas exit fee reform:** Some natural gas utilities charge an "exit fee" to customers who stop purchasing gas, which disincentivizes a transition to electrified heat. Regulators can prohibit these exit fees in the context of beneficial electrification or introduce exit fee reforms (e.g., require exit fees to reflect only actual unrecovered costs; mandate accelerated depreciation of gas infrastructure), managing cost recovery to protect remaining customers from stranded costs.

Clean energy buildout and grid modernization strategies to lower average electricity costs

Difficulties getting renewable energy built, connected to the grid, and transmitted to industrial buyers in a timeframe that matches factory development or upgrades is another contributor to high electricity prices. Renewables produce electricity at near-zero marginal cost, so they can drive down electricity prices in many hours of the day, lowering average costs and presenting special opportunities for firms that can be flexible with their energy use. They also reduce industry exposure to fossil fuel volatility.

Unfortunately, clean energy resources and new technology face severe roadblocks to development compared to conventional fossil fuels and infrastructure. PUCs can require utilities to allow renewables to compete on a fair playing field and ensure that utilities' investments are aligned with a competitive, market-driven, technologically optimized electricity system (and FERC can do so with grid operators, though federal electricity regulation is out of the scope of this brief).

- **Expand clean energy contract solicitations:** Utilities or regulators can issue more frequent and larger requests for proposals (RFPs) for renewable energy projects like wind, solar, and battery storage. This creates a more competitive bidding environment, driving down renewable costs and increasing renewable volumes, which then drives down overall electricity prices.
- **Require all-source procurement RFPs:** Instead of specifically requesting a new gas plant, all-source procurement allows any technology to bid to fulfill future energy needs. This forces traditional generators to compete with renewables, storage, and demand response on a level playing field. Since wind and solar combined with storage and demand flexibility often comprise the lowest cost portfolio to meet future needs, this technology-neutral approach typically results in renewable deployment and lowers wholesale electricity costs.

- **Require consideration of clean energy resources including demand-side flexibility in IRPs:** Integrated resource plans (IRPs) are long-term roadmaps utilities develop to inform future RFPs, outlining the mix of generation, transmission, and demand-side resources that will cost-effectively and reliably meet projected electricity needs. PUCs can require the consideration of clean energy, storage, and demand response in IRPs and can approve cost-effective projects of these types.
- **Compensate distributed energy resources:** Utilities can compensate customers of all types for electricity generated by behind-the-meter renewables and storage and delivered to the grid. While traditional "net-metering" approaches have typically anchored the compensation rate to fixed retail electricity prices, utilities can instead vary compensation depending on the alignment of the delivered electricity's timing and volume with grid needs, while still ensuring that overall compensation is generous enough to incentivize electrification.
- **Streamline interconnection:** Interconnection queue delays can keep low-cost energy offline for years, forcing the grid to rely on expensive, older plants. PUCs and utilities can streamline connections to the distribution system by adopting standardized interconnection agreements, proactively publishing "hosting capacity maps" that tell developers where the grid is ready to support new resources, and providing fast-track reviews of clean energy projects. Similarly, on the demand side, PUCs can expedite review for industrial facilities seeking to electrify in exchange for commitments to flexibly consume power.
- **Deploy advanced conductors and grid-enhancing technologies:** Using our existing grid assets more efficiently can quickly get more electricity to industrial facilities. For example, instead of building costly new transmission, utilities can upgrade existing corridors where they already own towers and rights-of-way with advanced conductors that can handle more power, and they can use dynamic line ratings to adjust electricity delivery based on real-time transmission capacity, as measured by sensors and weather data, rather than fixed limits.

Thoughtful rate design and regulation can meaningfully reduce the spark gap

Smart rate design and utility regulation are crucial enablers of industrial electrification. Accelerating renewable energy deployment, rewarding flexibility, cutting interconnection delays, and co-optimizing the power and industrial sectors can meaningfully lower electricity costs.

While PUC and utility actions are powerful, they are not sufficient by themselves. State lawmakers can employ complementary incentives, standards, permitting reform, worker training, and other enabling policies to ensure industry is best positioned to reap the benefits of electrification while strengthening economic competitiveness.

To learn more about regulatory and policy options, please contact Energy Innovation's industry team at industry@energyinnovation.org.