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Electricity demand from commercial and industrial (C&I) customers is rising in the United States, with projections for future demand growth from datacenters [1]. Increasing C&I demand has been linked to rising electricity prices [2, 3], and several analyses project datacenter demand growth to fuel future price increases [4, 5]. The notion that demand growth increases electricity prices is often framed as a foregone conclusion, especially in mass media coverage of the issue. However, the cost structure of the electricity industry implies that demand growth can reduce prices under certain conditions, a relationship that continues to be supported by empirical evidence [6, 7].

In this Commentary, we aim to clarify the relationship between electricity demand and prices in the short- and longer-term. We outline three dimensions that shape this relationship: system capacity utilization, system expansion costs, and cost allocation in the rate design process. We explain why demand growth has historically been largely associated with falling electricity prices and explore arguments that future C&I demand growth may increase prices.

Background

At the dawn of the electric grid in the early 20th century, Samuel Insull intuited that demand growth could reduce electricity prices [8]. He observed that a large share of electric system costs accrue from capital investments in generation, transmission, and distribution system infrastructure, as opposed to ongoing costs such as fuel purchases and system maintenance. In economic parlance, these capital costs are "sunk," meaning that costs are incurred before system-operational decisions and do not vary with the level of system output. Insull observed that average (per-unit) system costs, and therefore retail electricity prices, could be reduced by spreading sunk capital costs over more sales. Insull's vision was implemented by treating electricity service as a natural monopoly, where a single utility could provide the service at lower average cost than multiple competing firms. In exchange for exclusive franchise rights to sell electricity, monopoly utilities were subject to regulation, which replaced competition as the force that minimized costs and prices.

The U.S. grid and regulated monopoly model have evolved substantially since Insull's time. Competition was introduced into the retail electricity service and generation sectors to varying degrees across regions of the United States over the past 50 years. Much of the system now operates under competitive wholesale electricity markets with various rules and mechanisms that add further nuance to the relationship between demand and retail electricity prices. Still, across the myriad grid system structures today—from competitive wholesale markets to vertically-integrated regulated utilities—the foundational principle remains the same: average costs and therefore prices tend to decline when sunk capital costs are spread over more sales. Yet demand growth also increases variable costs (e.g., fuel) and can create the need to incur capital costs to expand or enhance the network. The impact of demand growth on prices ultimately depends on the net effects of economies of scale, impacts on variable costs, and the need to incur additional capital costs. The remainder of this paper explores three concepts that elucidate the nuanced relationship between demand and prices.

Demand and system capacity utilization

Utilities must procure enough generation, transmission, and distribution system capacity to reliably meet electricity demand at all times. Electric system capacity is incompletely utilized, given that capacity needed to meet peak demand (e.g., hot summer days) sits idle during times of low demand (e.g., temperate spring nights). Further, the grid has relatively little storage capacity to shift generated electricity across time. The implication of low grid capacity utilization is that the system has spare capacity to absorb demand growth, to a degree. The grid's ability to do so is affected by the alignment of demand growth with where and when the system is underutilized, and especially the degree to which new demand affects peak system capacity requirements.

Demand growth that can be met with existing system capacity drives the economies of scale envisioned by Insull [9]. That theoretical relationship has empirical support, with recent analyses demonstrating that historical demand growth (or contraction) has been associated with retail electricity price reductions (or increases) [6, 7] (Figure 1). Further, the impacts of new demand on capacity utilization can be mitigated through load flexibility measures, such as curtailing demand during system peaks [10, 11].

However, recent U.S. C&I demand growth projections are dramatic, indicating the need to undertake substantial capital investments [1]. Hence, while future C&I demand growth will spread sunk capital costs over more units, that demand growth will require capital investment costs that complicate the expected net effect on price.

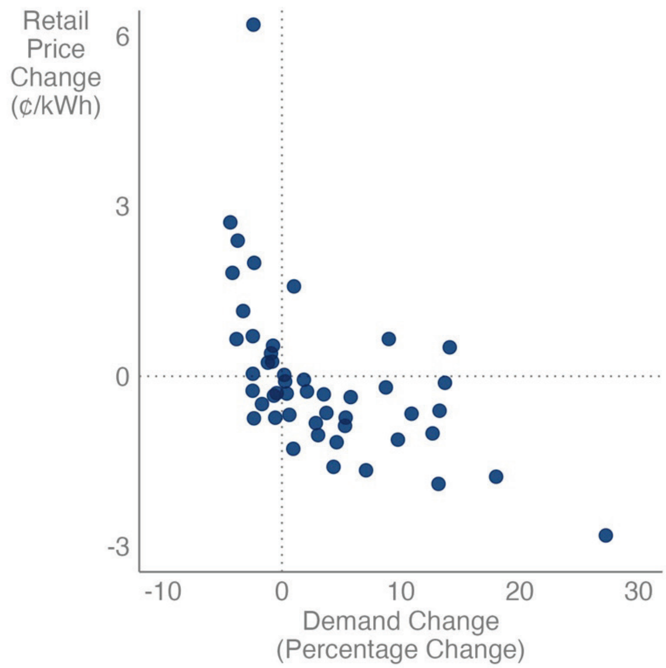

Figure 1. Correlation between load growth and retail price changes from 2019-2024. Each point represents one state in the contiguous United States. The y-axis depicts the change in cents per kWh of state-level average retail electricity prices from 2019 to 2024. The x-axis depicts the percentage change in statewide electricity demand over the same timeframe. Based on data from Wiser et al. [6]. Prices are in real 2024 U.S. dollars. See Wiser et al. [6] for further methodological details and analysis of this correlation.

Demand and system costs

Demand growth in the short term (i.e., before any system expansion in reaction to that growth) requires increased output from existing dispatchable generation sources. As a result, demand growth tends to increase average systemwide production costs in the near term as increasingly higher-cost generators are dispatched to meet growing demand [3]. However, given the capital-intensive nature of the grid, increased production costs may be small relative to the effects of demand on system capacity utilization and the possible need for capital investments.

Projected C&I demand growth will require system infrastructure upgrades that will be recovered through utility bills. Whether those costs translate to price increases depends on the costs of system upgrades relative to existing system costs (as well as how costs are allocated to customers, as explored in the following section). A simple way to explore these relative costs is to explore expected changes in long-term average costs. While prices may deviate substantially from long-term average costs in the near term, retail electricity prices will tend toward average costs under cost-of-service regulation in the long run. Therefore, average costs serve as a useful conceptual guide for the relationship between demand, system costs, and prices.

The average-cost effects of system upgrades depend on the net effect of changes in the numerator (costs) and the denominator (sales) of the average cost equation. The common emphasis on cost increases in media coverage of this topic focuses on the increasing numerator while ignoring the offsetting changes in the denominator. Focusing on both elements of the equation clarifies that the effects of system upgrades on prices depend on the cost of the existing system per unit of existing demand and the cost of the upgraded system per unit of demand in the upgraded system (Figure 2).

Analyzing price impacts in terms of average costs also illuminates the role of the timing of investments and demand growth. If, for example, costs are incurred in advance of future C&I demand growth, the numerator increases today without an accompanying change in the denominator, meaning that average costs will temporarily rise. In such cases, C&I demand growth may temporarily increase prices, even if the longer-term effect is to maintain or possibly reduce prices.

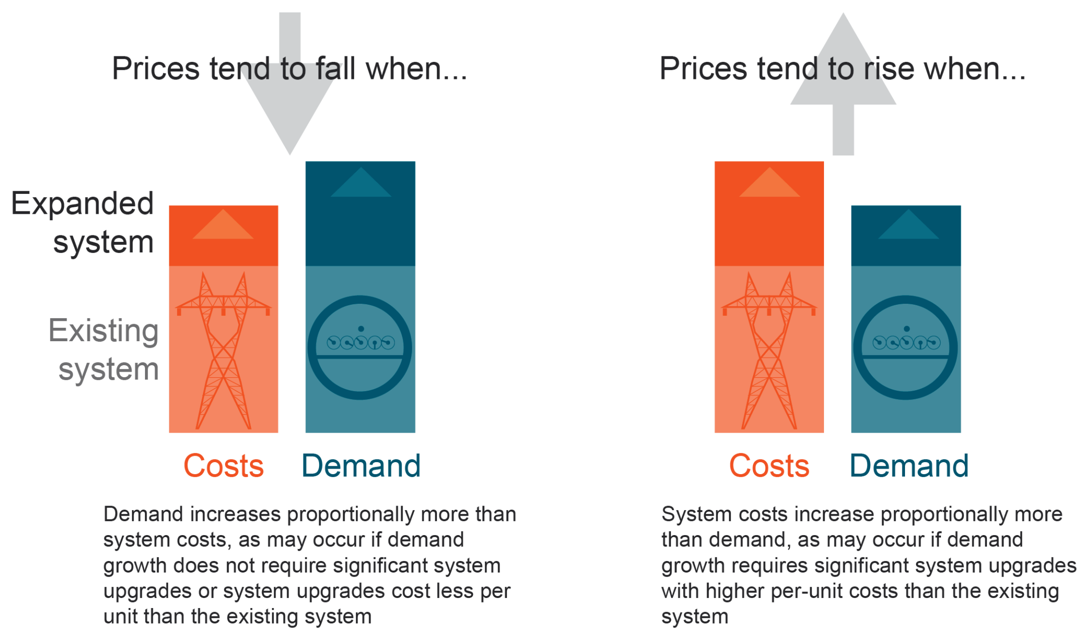

Figure 2. Potential impacts of system expansions on average system costs

Some analysts have argued that demand growth has or will increase retail electricity prices because supply and regulatory constraints, such as mounting interconnection backlogs [4], will increase relative costs. The attribution of recent price increases to C&I demand growth in the PJM wholesale capacity market provides early empirical support for these claims [2]. Others have made the opposite case, arguing that C&I demand growth can reduce average system costs by spreading sunk costs over more sales or through flexibly operating new load in ways that reduce average costs (e.g., datacenters could reduce computing during system demand peaks) [1, 9-11]. Alternatively, even if new demand is inflexible, new large loads could invest in programs to manage costs through leveraging load flexibility among other customers [12]. For example, public utility regulators and/or utilities in California, Georgia, Michigan, and North Dakota have asserted that datacenter-driven demand growth could reduce system costs. Arguments that demand growth could increase or reduce system costs could both turn out to be correct in distinct contexts.

Cost allocation and recovery

The prior two sections explored how demand can affect electricity system costs. How those cost impacts translate to retail electricity prices depends on how rate design converts costs to retail electricity rates.

Electric utilities employ cost-of-service ratemaking when designing retail rates. In principle, regulation should ensure that the costs of investments caused by or benefitting new C&I customers are allocated to individual C&I customers that cause those costs or enjoy these benefits. However, fairly and efficiently allocating shared system costs across new and existing customers is a perpetual challenge [5], described in one seminal guide on rate design as the "nightmare of utility cost analysis" [13]. Ensuring equitable cost-allocation outcomes may require the creation of a separate rate class for these unique large load customers coupled with frequent updates of the metrics used to allocate costs to specific customer classes. These challenges may be exacerbated by state energy policies, economic development objectives, and regulatory models that encourage utilities to offer competitive pricing to new large loads [5].

Utilities and regulators are emphasizing the need to mitigate cost impacts on existing ratepayers in the design of new large-load tariffs to respond to C&I demand growth [1, 14, 15]. New large loads such as datacenters could create stranded energy generation and delivery assets if electric utilities make sizable grid investments but the new demand doesn't ramp up as quickly as expected, new demand does not materialize or fully achieve its projected levels, or new demand exits the system before the utility's investments are fully repaid. For these and other reasons, new large-load tariffs include measures to protect other ratepayers from adverse price impacts. Common large-load tariff measures include varying combinations and designs of up-front payments, collateral requirements, long-term contractual commitments, bring-your-own generation allowances, contribution in aid of construction requirements, and exit fees [15]. System costs could also be managed, such as through proposed requirements for load flexibility commitments during grid interconnection [11], proposals to incentivize new large loads to invest in programs to leverage load flexibility from other customers [12], or requirements or incentives for new large loads to directly support their own new generation.

Synthesis

Electricity demand growth has always had nuanced effects on prices. The regulated monopoly model was based on the notion of economies of scale in electricity service. Those economies of scale are likely to dictate the impacts of demand growth on prices when new demand can be met through underutilized system capacity, when required system upgrades reduce per-unit costs, and when any incremental costs are sufficiently allocated to cost causers. However, projected C&I demand growth will require system upgrades that may encounter supply and regulatory constraints that increase average system costs. Given the magnitude of the expected C&I demand growth, the resulting utility costs to safely and reliably integrate that demand, and the perpetual challenges of allocating costs to ratepayers, projected C&I demand growth poses risks of increasing retail electricity prices for all ratepayers. Still, such an outcome is not predetermined. Utilities and regulators are already implementing measures to mitigate price risks from demand growth, such as new large-load tariffs and load-flexibility commitments. Further, large C&I customers have publicly expressed desires to actively mitigate price risks, such as by participating in demand flexibility and bring-your-own-generation schemes. Identifying the most effective solutions for mitigating the price-increase risks and maximizing the price-reduction opportunities of C&I demand growth is an area for further research.

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