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Smooth Operator? Managing Electric Vehicle Integration in Constrained Distribution Networks

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Smooth Operator? Managing Electric Vehicle Integration in Constrained Distribution Networks*

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Abstract

Electricity distribution network constraints may ultimately limit the pace of transportation electrification. This paper examines the underappreciated challenges that electric vehicle (EV) adoption poses for the distribution grid. While prior research has focused on bulk power and private service upgrades, we emphasize how local distribution capacity is strained by reduced load diversity at small aggregations. We highlight two alternatives to costly infrastructure expansion: (1) demand-based tariffs that allocate scarce distribution capacity more efficiently, and (2) managed charging programs that coordinate EV loads within local limits. While managed charging reduces transformer overloads and smooths load profiles, consumer participation remains a barrier. Economists can play a key role by designing rate structures that align user incentives with local network constraints and by evaluating consumer acceptance of these solutions as electrification advances.

JEL Classification: L94, Q40, Q50

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* The views in this paper are those of the authors and do not necessarily reflect the views of the Federal Reserve Bank of Dallas or the Federal Reserve System.

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1 Introduction

Electric vehicle (EV) sales continue to increase around the world, although at different rates. In 2023, worldwide EV market share (defined as the sum of fully electric and plug-in hybrid shares) of new car sales reached 18%, with a 38% share in China and 10% in the United States.[1] This growth raises several challenges for electricity systems and their users to meet the needs of this newly electrified demand.

The first challenge is the private one facing the customer: Do they have sufficient residential service capacity, or do they require a costly upgrade? Many residential customers in North America are not configured to handle high-powered ("Level 2") chargers in addition to their remaining electrical demands, especially when considering the increasing adoption of air conditioners and electrification of other aspects of the home. This often means residential customers require an upgrade in their level of service at a cost which is born by the customer.[2] The second challenge is at the level of the bulk electric system—the collection of generators and high-voltage transmission network within a region. Here, the challenge is two-fold: the bulk system must be able to produce a sufficient quantum of *energy* to satisfy the driving demands of EV owners, and it must also have sufficient *capacity* to deliver the required energy at the times and rates (and locations) demanded by EV chargers.

This paper focuses on a third challenge to EV integration: the distribution system. Here, the challenge is entirely a capacity issue. The distribution system must be sufficiently sized to provide the required power draw at each node in the network. This can be as large as distribution substations or feeders, serving tens of thousands of homes, to as small as neighbourhood transformers, serving fewer than a dozen homes. Unlike the bulk energy system, which benefits from the load-smoothing of millions of heterogeneous customers with at least some diversity in load profiles, at smaller aggregations there is a greater probability of correlated load profiles—even by random chance—where a large share of customers demand power at the same time can lead to capacity violations on parts of the distribution network. This issue of local load correlation is exacerbated by the fact that, at least in the early stage of EV adoption, EV ownership tends to be spatially correlated (Elmallah et al., 2022).

To date, much of the focus has been on the first two problems. For the private problem, solutions have involved education efforts on the sufficiency of level 1 (120V)

[1] https://www.iea.org/reports/global-ev-outlook-2024/trends-in-electric-cars

[2] A common residential service panel is rated at 100 amps, with a protection buffer reducing the usable power capacity to 80 amps. A Level 2 EV charger can draw up to 40 amps, leaving only 40 amps remaining for all other devices in the home when charging.

charging (Fried et al., 2024), where 200A service upgrade is unlikely to be required, or technical solutions, such as smart panels and smart switches that can better optimize device demand within a customer to avoid the need to upgrade from 100A service. For the bulk system, the increasing prevalence of time-of-use rates and other incentives to shift the timing of electricity demand points to the preferred solution of getting more flexibility out of aggregate demand.[3] There has been far less focus—at least in the economics literature—on the issue of the distribution network.

This gap in research focus is particularly concerning given that distribution networks are facing the earliest pressure from increased electrification. NREL estimates that "utilities are experiencing lead times for transformers of up to 2 years, and prices have increased by 400%–900% in the last 3 years" (McKenna et al., 2024). While the cost of generation and transmission capacity has received substantial economic analysis, distribution network constraints may ultimately prove to be the binding constraint on the pace of transportation electrification.

EV charging has certain features that warrant more focus on the distribution network, as well as caution regarding the aforementioned solution of time-of-use pricing. First is the size, or magnitude, of their power demand relative to typical residential devices. A Level 2 charger draws power at a rate of 5kW to as much as 20kW (with the most common power draw being roughly 7kW), far larger than most other large electrical devices in the home (e.g. air conditioners, dryers, ovens). As such, when a homeowner chooses to charge their vehicle it often becomes the home's new peak regardless of hour of day. When several households with electric vehicles in a local neighbourhood choose to charge at the same time, this can quickly become the new local transformer peak. The second feature is the significant flexibility of charge timing. Bailey et al. (2025a) find even a small financial incentive can result in a large shift in charging times from defined peak to off-peak periods. La Nauze et al. (2024) similarly find EV charging very responsive to time-of-use pricing to shift to middle-of-the-day solar hours. The observed intertemporal elasticities are an order of magnitude larger than typical price elasticity of residential electricity demand. This flexibility suggests shifting EV charge timing to periods of spare capacity may be both technically and economically feasible. However, this blessing of flexibility risks becoming a curse when consumers face common pricing resulting in a collective shift to the same period – even if it does not coincide with the bulk system peak – resulting in problematic so-called "shadow peaks" on the local distribution network (Muratori,

[3]According to U.S. Energy Information Administration data, the number of electric utility customers enrolled in some form of time-varying rate in the United States grew from 4.6 million in 2013 to 15.6 million in 2023 (EIA, 2024).

2018; Turk et al., 2024; Bailey et al., 2025b).

While economists may not have been as focused on the distribution challenge, this issue has occupied the attention of engineers and utility planners. Two particularly helpful recent examples are Elmallah et al. (2022) and Li and Jenn (2024), which each combine data from real world distribution circuits with assumptions from the EV load profile to estimate the infrastructure costs of full electrification of transportation in California. Elmallah et al. (2022) show that evening home charging overlaps with winter heating peaks, imposing particular stress on feeders in colder regions. Li and Jenn (2024), using empirical EV adoption and travel models mapped to 5,000 real feeders, estimate that two-thirds of California's circuits will need upgrades by 2045, with statewide costs ranging from \$6–20 billion.[4] Notably, residential feeders bear the brunt of these upgrades, raising the question of what can be done to minimize these costs and how the cost burden should be shared.

In this paper, we bring attention to the challenge of integrating EVs in the distribution network and discuss potential solutions. Broadly speaking, there are three pathways to accommodating high levels of residential EV charging. The first is to rapidly expand the capacity of each local network to allow for an influx of new high-powered demand. However, supply chain constraints and global demand for distribution equipment make this a costly and potentially lengthy pathway, and one with potentially undesirable distributional consequences. The second route is to pursue tariff reforms that not only encourage consumers to shift the timing of their consumption but also discourage large power draws on the distribution network. Turk et al. (2024) propose subscription tariffs, a form of demand charge, to reduce the magnitude of power draws. Ovaere and Vergouwen (2025) demonstrate substantial coincident peak reduction on distribution transformers from the introduction of demand charges on residential customers in Belgium. Third is a technological solution to better coordinate charging at a local level by sequencing EV charging to avoid the situation of too much coincident load. This "managed charging" solution is explored by Bailey et al. (2025b) in a field experiment and shown to be effective in reducing shadow peaks. The outstanding question remains: are consumers willing to offer flexibility in this way? Early evidence suggests that enrollment may be a significant barrier to these programs' success (Burlig et al. (2025)).

Our analysis makes three primary contributions. First, we synthesize the engineering and economic literatures on distribution network constraints to provide a

[4] These cost estimates preceded a period of steep inflation for distribution network equipment and thus likely underestimate future costs.

comprehensive view of the challenge. Second, we present new data on load diversity factors at various levels of aggregation to illustrate why distribution networks face unique constraints compared to the bulk power system. Finally, we evaluate the economic efficiency and practical feasibility of potential solutions by describing the tradeoffs between pricing mechanisms and direct load management. We discuss how incentives to adopt or promote various solutions differ between electricity "resellers" who rent the use of distribution system infrastructure and "integrated retailers" that own distribution system infrastructure. Although our paper focuses on, and uses examples from, the private passenger vehicle market in North America, the insights raised throughout generalized beyond this region.

The rest of this paper proceeds as follows. Section 2 offers a background on local distribution networks—their taxonomy, the roles of various components, and highlights recent trends. Section 3 presents the economic challenge of EV charging and coincident loads, with an illustration of load diversity factors at various aggregations. Section 4 explores various solutions to the EV charging and distribution network challenge, from technological to economic. Section 5 concludes with a discussion of future directions needed for research in this area.

2 Background on local distribution networks

The electricity distribution system (EDS) is the final link in the power delivery chain, transporting electricity from transmission substations to homes, businesses, and distributed energy resources. As shown in Figure 1, EDS circuits begin at substations that can serve serve up to (roughly) 50,000 customers. There, "primary" transformers step down high-voltage transmission power (e.g., 115–230 kV) to medium-voltage (typically 4–35 kV) and distribute it along feeders (also referred to as "circuits"). At the other end of circuits, distribution (or "secondary") transformers further reduce this to service voltages (e.g., 120/240V), and deliver electricity to end-users via service drops to individual meters.

A typical distribution circuit serves 500 to 3,000 customers, depending on regional density and configuration (*U.S. Department of Energy Electricity Distribution System Modernization Report*, 2023). However, secondary transformers serve a much smaller number of customers – often as few as five or ten households – and this paper focuses on issues relating to serving EVs at the ends of these nodes. While components such as transformers, conductors, and breakers have traditionally followed a 25–40 year replacement cycle (National Renewable Energy Laboratory, 2021), electrification at these low levels of aggregation may necessitate an accelerated timeline.

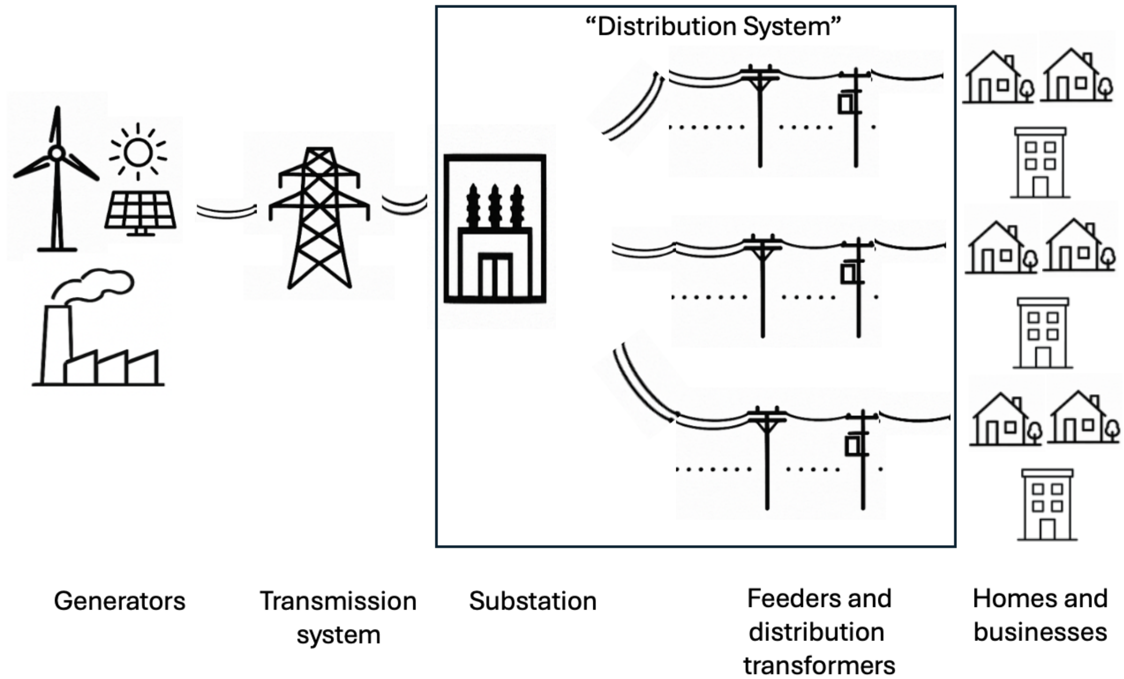


Figure 1: Electricity Distribution System Diagram

Since 2020, severe supply chain disruptions have driven steep price increases and delivery delays that persist as of this writing (fall 2025). These delays and price pressures coincide with rapid load growth at the grid edge driven by electrification of vehicles, heating, and industrial processes. Such localized load increases require upsizing transformers, reconductoring feeders, and investing in voltage regulation and monitoring infrastructure. Additionally, bidirectional power flows from rooftop solar and batteries introduce voltage volatility and protection challenges, necessitating advanced inverters and adaptive control systems (U.S. Department of Energy, 2022; MIT Center for Energy and Environmental Policy Research, 2024).

3 The EV charging challenge

The economic problem facing a distribution planner is one of cost-minimization subject to the requirement to maintain system reliability at a socially acceptable level. To do so, the system planner must size the capacity at each node in the network, i.e. substations, feeders, and primary and secondary transformers, to meet instantaneous demand in nearly all situations.

One feasible, albeit extremely conservative, solution to this problem would be to size the capacity at each node according to its aggregate maximum *potential* demand. For example, consider a secondary transformer serving 10 homes, each with 200A service and thus a maximum possible draw of 38.4kVA (200A x 240V x 80% breaker safety restriction). In this example, the conservative planner would size the transformer at 10 x 38.4 = 384kVa. In turn, the feeder serving 100 such transformers would be sized at 100 x 384 = 38,400kVa, and so on.

Clearly such a solution, though feasible, would have exceedingly high costs and leave the system with significant excess capacity. It ignores the reality that customers rarely draw power at their absolute maximum potential and that all customers in an aggregation node do not all hit their peak at the exact same time. Diversity in load profiles is a key reason distribution planners do not follow the above-described extreme sizing solution. With growing shares of EVs, it is not clear ex-ante in which direction load diversity should go. In what follows, we discuss load diversity factors, and factors that could lead to increases or decreases in this critical planning metric.

3.1 The role of load diversity in network planning

A core determinant of distribution costs is the diversity in load profiles downstream of a potential constraint. Boiteux and Stasi (1964) define a *diversity factor* as "the ratio of the sum of individual maximum loads on a circuit divided by the peak aggregate load". To illustrate with a simple numerical example, consider 24 households, each with 2kW peak instantaneous loads and nothing otherwise. If these 24 household's peak loads all occurred in different hours of the day, the diversity factor would be $(24 \times 2)/2 = 24$. However, if the maximum load of all households occurs at the same time, the diversity factor would be $(24 \times 2)/48 = 1$. A lower diversity factor indicates a less diverse set of load profiles, 1 being the extreme of fully coincident peaks.

The diversity factor is affected by the size of the aggregation of underlying loads. As the size of the aggregation decreases, so too do the diversification benefits of aggregating different charging profiles. Rather than averaging across thousands and eventually millions of diverse EV charging patterns across the entire bulk energy system, the collective load profile of EVs on a single distribution transformer serving ten homes is more prone to extreme patterns. This is likely to be exacerbated by the spatial connectedness of the distribution system. Consider, for example, a suburban community with similar commuting habits leading to correlated charging patterns.

3.2 Empirical evidence of load diversity patterns

Figure 2 illustrates the benefits of averaging across many vehicles, as compared to the wide range of outcomes for smaller aggregations. The figure uses actual charging data collected from electric vehicles over the course of 5 weekdays in June 2023 (Bailey et al., 2025b). Averages are computed by summing the aggregate load and dividing by the number of EVs in the group to calculate "per-vehicle" average profiles for comparability across different group sizings.

The leftmost panel averages daily diurnal load profiles over the full set of 100 vehicles. Each line represents a single day's average load profile. Although there is hourly variation and day-to-day variation, the patterns share fairly similar characteristics. Here, we see the benefits of larger aggregations: flatter average load profile across the day and more consistency across days. The middle panel averages over smaller groups of 10 EVs, i.e. to represent the equivalent of a secondary transformer in a distribution network. Here we clearly see the effect of small-number aggregation, with load profiles varying significantly across groups and days. The rightmost panel demonstrates even more erratic behavior, with individual lines representing single vehicle load profiles for each day.

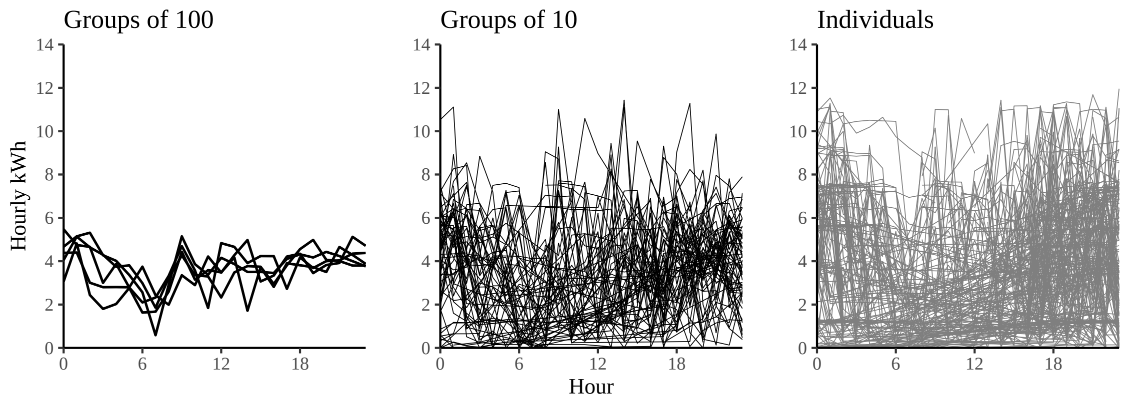
The benefit of larger groups, with smoother load profiles, is that the likelihood of extreme peaks is lessened due to diversity across a larger set of consumers. As observed in this data snapshot, even at groups of 10, coincident peaks within a group can lead to extreme peaks more frequently—an issue for distribution systems facing nodal capacity constraints.

This empirical evidence suggests that the traditional approach to distribution planning, which relies heavily on assumed diversity factors, may need significant revision as EV adoption increases. The potential for highly correlated charging behavior, especially in neighbourhoods with similar household characteristics and travel patterns, could substantially reduce the diversity benefit that planners have historically counted on.

4 Solutions and constraints

The load aggregation issues described above arise from physical (engineering) constraints. One way these constraints could be relaxed is by adding sufficient capacity to the distribution system to accommodate all patterns of end-use load; however, this would be costly and inefficient. It may be more cost-effective to provide incentives for electricity end-users to adjust their behavior in ways that minimize system investment

Figure 2: Average load profiles at various aggregations



Notes: Data from actual EV charging over the course of one workweek (data from Bailey et al. (2025b)). Each line represents a diurnal load profile for the respective grouping and day. The values shown are average per-vehicle values, i.e. they reflect actual values for the individual panel and they are the sum of hourly demand divided by the number of charging vehicles for the other two panels.

costs conditional on a certain level of end-user access.

In this section, we describe several potential solutions. We discuss how electricity tariffs designed to improve the operation of the bulk power system (e.g. time-varying electricity prices) present both opportunities and drawbacks in the context of the electricity distribution system. We then discuss recent pricing proposals that are specifically designed to address electricity distribution system costs and constraints. Managed EV charging programs offer a technical alternative to price-based incentives. These require consumers to relinquish a degree of control over their EV charging behavior. A small number of recent randomized experiments explore the early promise of this technology. Finally, we describe incentives facing electricity distribution system operators and retailers and discuss how industrial organization will likely affect the perceived attractiveness of alternatives by market participants.

4.1 The promise (and potential peril) of time-varying pricing

Economists have long advocated for time-varying prices as an efficient way to reduce the overall costs of the bulk power system (e.g. Bohn et al. (1984); Hogan (1985); Borenstein (2005); Allcott (2011); Jessoe and Rapson (2014)). However, until recently, most electricity consumers faced time-invariant prices regardless of conditions in the wholesale electricity market. Notably, fixed costs of grid infrastructure and operations were (and are) often recovered via these volumetric charges. Under such a pricing regime, grid operators are faced with the choice of either building sufficient generating capacity to meet demand at all times, including even the rarest peak hours, or risk occasional power shortages. Allowing retail prices to rise to reflect scarcity in the wholesale market, as recommended by most economists, creates an incentive for consumers to conserve during peak hours and can reduce overall system costs.

The proliferation of smart metering infrastructure in recent decades allows electricity usage to be measured frequently (e.g. hourly) at the household level, and it is becoming common for customers to be charged prices based on their time-of-use (TOU).[5] However, these time-varying price structures were designed with the bulk power system in mind and may inadvertently create new challenges for distribution networks. For example, if a large number of EV owners facing common price signals pursue a simple decision rule to commence charging when the price drops after the TOU peak period ends, this can induce localized "shadow peaks", exhausting capacity at distribution system bottlenecks even during periods of ample spare capacity on the bulk system.

This potential for common pricing signals leading to correlated behavior was highlighted by Turk et al. (2024) in a simulation study using representative customer behavior in the Northeast United States. Bailey et al. (2025b) confirm the development of TOU-rate-induced "shadow peaks" in a randomized control trial involving roughly 200 electric vehicle owners in Alberta, Canada.

We illustrate the effect of time-of-use pricing using load duration curves. A load duration curve calculates the aggregate hourly load on a distribution transformer—in this case serving 10 homes—and plots these values in descending order. Figure 3 shows two load duration curves: one for transformers whose customers face standard flat pricing, and the other for those facing randomly assigned time-of-use pricing. Under TOU, the load duration curve reaches a considerably higher maximum value—roughly 25% higher than flat pricing—illustrating a greater coincidence of charging activity. Given the randomized allocation of TOU vs flat pricing in their experiment, Bailey et al. (2025b) attribute this increase in coincident behavior as an unintended consequence of time-of-use pricing.

The dramatic spike in coincident load revealed in this experiment raises important questions about the potential unintended consequences of commonly-faced time-varying price signals in the presence of large and flexible loads, such as EV charging. In short, any tariff rate that jumps discontinuously at a given time risks creating

[5]The literature on time-varying pricing is extensive. Harding and Sexton (2017) provide a review as of 2017, though many papers have been written since then.

high correlation in household EV charging behaviour, and will fail to provide an incentive to smooth load at the end of distribution nodes. Although such pricing mechanisms may efficiently balance system-wide supply and demand, they appear to create problematic local congestion that could exacerbate the need for substantial upgrades to distribution networks. This tension between system-level optimization and local constraints requires new approaches to rate design.

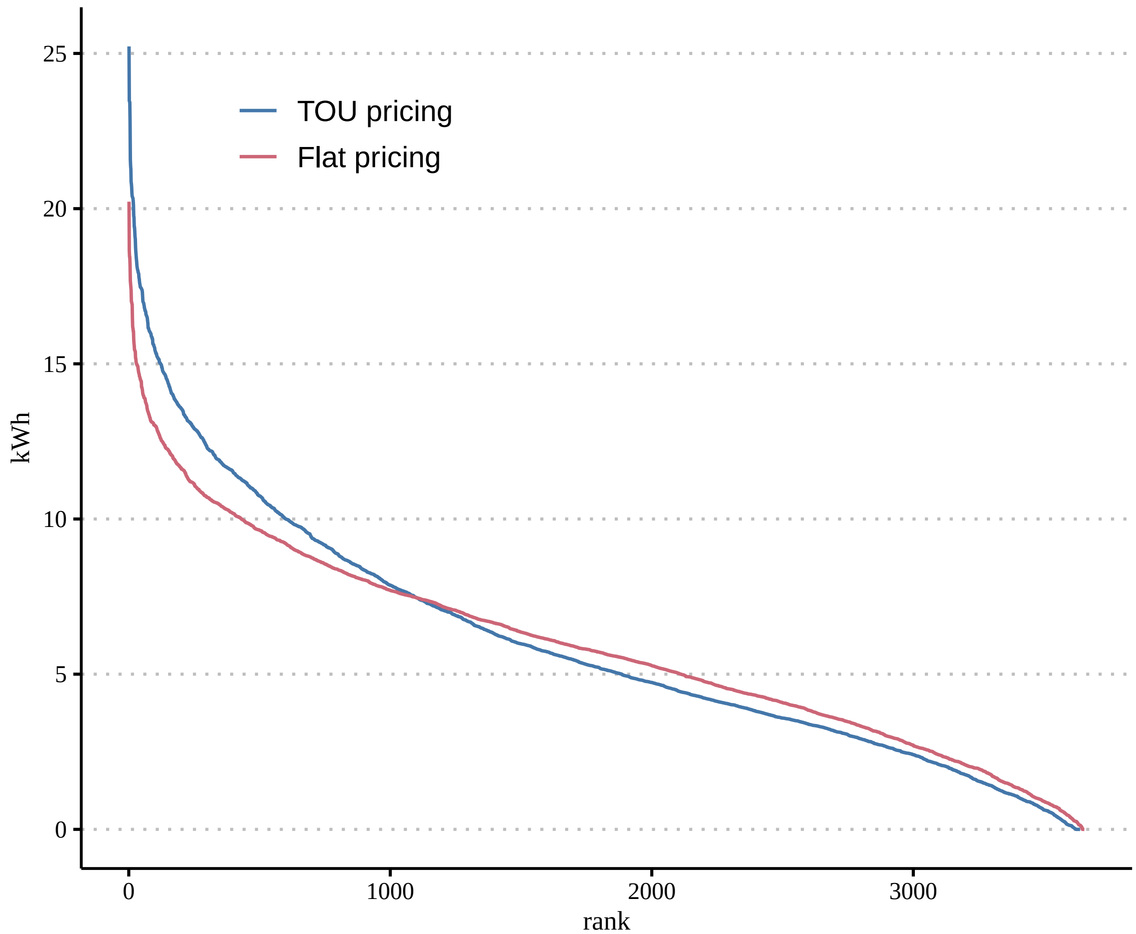
4.2 Tariff-based solutions

A complete measure of a customer's electricity cost must include their contribution to congestion (capacity constraints) on the distribution system. Turk et al. (2024) recommend adapting network tariffs to specifically reflect these costs. They argue that traditional volumetric pricing described above does not align incentives for efficient use of the distribution system. Instead, they propose tariff designs that reflect local costs, such as capacity-based (so-called "demand") charges or time-varying network access fees. These reforms aim to encourage consumers to shift usage away from system peak periods and avoid exacerbating local congestion, particularly as electric vehicles add substantial load to residential circuits. Under such a model, tariffs would vary not just by time of day, but also by the physical constraints of the feeder or substation a customer is connected to. The authors point to European models – particularly in the Netherlands and the United Kingdom – that have implemented such targeted network charges to mitigate congestion and defer capital-intensive upgrades. This approach allows for more efficient integration of distributed energy resources, and aligns customer behavior with grid needs without relying entirely on centralized control or real-time communication systems.

The economic rationale for distribution-specific tariffs stems from the localized nature of congestion costs. Unlike generation capacity, which can generally serve any customer in the system, distribution capacity benefits only those customers downstream of the relevant equipment. By implementing tariffs that reflect these localized costs, utilities can send more precise signals about the true marginal cost of service at each point in the network.

There is promising empirical evidence that consumers do respond to demand charges (i.e. per kW) by reducing their peak hour consumption. In a study of Belgian electricity consumers, Ovaere and Vergouwen (2025) find households reduce their maximum demand by roughly 1 to 3% after the introduction of demand charges based on a consumer's monthly 15-minute peak demand (in kW). Moreover, they find that transformers with large penetration of EVs reduce their peak hour consumption

Figure 3: Transformer load duration curves under time-of-use versus flat pricing



Notes: Data from actual EV charging over the course of 5 months (Bailey et al., 2025b). Each point in the figure represents the average hourly aggregate load on a transformer whose downstream customers. The two lines separate these averages by customers facing either a time-of-use tariff or flat pricing.

even more—roughly 6 to 7%—reflecting the greater magnitude of EV charge timing flexibility.

One margin of adjustment that is consistent with a shift to demand charges is encouraging EV owners to use lower kW chargers, i.e. Level 1 or lower kW Level 2 chargers. While EV early adopters tend to use higher powered level 2 charging for home charging, Fried et al. (2024) show that for most EV owners, lower powered charging is sufficient to meet the bulk of their driving needs. A policy of educating consumers on the potential sufficiency of Level 1 charging could be coupled with a greater build-out of neighbourhood Level 3 chargers to meet occasional shortfalls. This offers an alternative path to widespread Level 2 home charger use that would reduce the strain of higher power draws on the distribution network.

4.3 Technological solutions

Technological solutions that enable centralized control are also promising. In the field trial by Bailey et al. (2025b), EV owners were randomly enrolled in a managed charging program where they specified personal preferences—such as "charge to 80% by 7 a.m."—and the utility scheduled charging times to coordinate across vehicles on the same transformer. The program reduced coincident peak charging by 17% compared to an unmanaged group, and by 33% relative to a time-of-use group. As a result, transformer capacity violations fell by about 80% compared to unmanaged charging.

While the effectiveness of managed charging to deal with capacity constraints appears strong, questions remain as to the willingness of EV owners to participate in such programs. Bailey et al. (2025b) explore this in a follow up to their study, inviting control group participants to opt-in to a subsequent managed charging program with offers of $0, CAD$75, and CAD$150 to join, and find 34 out of 35 survey respondents elect to join, with 29 of those 34 remaining after 6 months in the program.[6]

Burlig et al. (2025) further investigate the willingness of EV owners to accept automated charge scheduling in a large-scale field trial. They randomize the population of electric vehicle (EV) owners in an EV-dense region of California into an EV managed charging program that controls the timing of EV load on the electric distribution system. The key contribution of their work is to randomize the entire eligible population, thereby retrieving the population-wide take-up rate of the managed charging program. At low, moderate, and high levels of financial incentives, uptake is low. They find that less than 7% of eligible EV owners opted into a managed

[6] At the time of the experiment, CAD$1 ≈ USD$0.74.

charging program even with financial incentives of USD$40 per month. This take-up rate is well below what would be required to reliably avoid capacity violations on secondary distribution transformers, and suggests the existence of significant barriers to the voluntary adoption of managed charging programs.

The contrasting findings on consumer acceptance of managed charging emphasize the difference in take-up estimates taken from the general population (Burlig et al., 2025), versus those estimated from a population who have already expressed willingness to be part of a study and thus may not generalize as readily (Bailey et al., 2025b). They also highlight the importance of program design and implementation. Factors such as transparency, reliability of charging outcomes, and the degree of control relinquished appear to significantly influence willingness to participate. This tension between technological effectiveness and consumer acceptance represents a key challenge for policymakers and utilities seeking to implement these solutions at scale.

More broadly, managed EV charging fits into the wider development of "virtual power plants" (VPPs) that aim to control a multitude of distributed energy resources, including solar panels, flexible devices, and batteries (Razdan et al., 2025). The latter, batteries, are particularly promising in that, unlike altering demand for EV charging or other electricity consumption, charging and discharging a battery occurs independently from a household's consumption profile. Furthermore, locating batteries at downstream points in the distribution network can relieve congestion at granular nodes, as well as allowing battery dispatch to benefit the broader bulk energy system.

4.4 Incentives and constraints

How distribution system costs are recovered informs which pathways are likely for EV integration into the distribution network. Most distribution utilities in the U.S. operate under rate-of-return (RoR) regulation, allowing them to recover operating expenses and earn an outsized regulated return on capital investments. This creates a well-documented incentive to overcapitalize, known as the Averch-Johnson effect, which encourages expansion of the physical grid even when more efficient alternatives exist (Averch and Johnson (1962)). In the context of distribution systems, this incentive leads distribution utilities to prefer increasing network capacity through capital investments rather than pursuing strategies to smooth load. It also highlights an important distinction between electricity resellers, who rent access to the distribution system, and integrated retailers that own parts of the electric grid in addition to interfacing with end-use customers.

Recent work has confirmed the persistence of the Averch-Johnson incentive problem in modern electricity markets. Cicala (2025) finds that, following the deregulation of generation in the 1990s, integrated retailers increased their transmission and distribution capital stock by roughly 9.5 percent above counterfactual levels. Despite falling generation costs, utilities captured savings through expanded investment in the rate base, suggesting that RoR regulation distorted utility decisions. These results imply that electrification-driven upgrades, such as transformer or feeder expansion to accommodate EV loads, could systematically overshoot cost-minimizing levels in the absence of regulatory directives. Dunkle Werner and Jarvis (2022) reaffirm that RoR regulation continues to bias energy utilities toward capital-heavy solutions, costing U.S. consumers an estimated excess $7 billion per year over the past three decades.

By contrast, electricity resellers have little to no influence over local grid infrastructure. For example, Community Choice Aggregators in California buy power on the wholesale market and deliver it to customers on wires that are rented from a distribution utility, typically at a time-invariant regulated price. Their incentives are to maximize sales margin between wholesale and retail prices, regardless of congestion on the distribution system. Because they lack exposure to the costs of local distribution overloads, they have little incentive to pursue strategies to mitigate local demand spikes.[7] Moreover, while resellers may benefit from controlling EV charging directly through, say, a managed EV charging program, their preferred design of such a program may not address distribution congestion issues.

Given that neither integrated retailers nor resellers face strong market incentives to internalize distribution-level constraints, regulatory intervention is likely necessary to contain costs in settings with high EV adoption. Efficiency requires aligning retail incentives with social costs on the distribution system, and since the latter vary continuously, solutions may need to as well. Whether these take the form of demand charges enabled by advanced metering, subscriptions for demand capacity, managed EV charging protocols, or another solution entirely, regulators will face the challenging task of wrangling support of entities that have very different, and sometimes conflicting, incentives. In the U.K., distribution network operators have begun procuring "demand flexibility services" from retailers and aggregators who can deliver demand reductions from the customers at specific constrained nodes in the network. Such a scheme holds promise for aligning the incentives of the retailer, and ultimately the customer, with the constraints of the distribution network.

[7] A transformer overload typically does not lead to immediate reductions in the ability to delivery power, but rather it degrades the equipment through higher thermal loading, leading to accelerated replacement costs for the distribution network operator.

5 Conclusion

This paper builds on a body of work that seeks to identify and solve challenges related to deep electrification (e.g. Rapson and Muehlegger (2023); Rapson and Bushnell (2024)). We draw attention to the often-overlooked electricity distribution system and the potential bottlenecks that are likely to arise with increased EV adoption. We raise awareness about the potential unintended consequences of traditional load-shifting solutions, such as time-of-use pricing, which use common price signals that may result in new—and larger—shadow peaks.

We identify two main paths forward to resolving the distribution capacity challenge beyond the traditional and costly solution of expanding network capacity. First, managed charging, where EV charging and potentially other large home loads are collectively managed to stay within the aggregate load limit of their upstream distribution equipment. This technological solution has shown promise in trials, though the challenge remains of enrolling sufficient participants in such programs to meaningfully impact the network. One potential outcome may be mandatory enrollment into managed charging programs for all homes installing Level 2 charging, if incentives alone do not elicit sufficient participation.

The second path forward is to institute more demand charges (i.e., per kW charges, rather than per kWh) in residential tariffs, something far more common for commercial and industrial customers. Such charges can more directly allocate scarce capacity to customers in ways that volumetric rates may not. A rates solution can also be deployed without the enrollment challenges of the technical managed charging solution.

Our analysis suggests several important policy implications. First, regulators and utilities should carefully consider the distribution system impacts when designing EV incentive programs and rate structures, including greater consideration of peak demand charges. Second, distribution system planning should incorporate realistic models of charging behavior that account for potential correlation in response to price signals. Third, policymakers may need to consider mandatory managed charging requirements for new Level 2 installations in areas with high EV adoption and constrained distribution capacity if voluntary programs fail to achieve sufficient enrollment.

The appropriate policy solution will likely vary by jurisdiction based on the pace of electrification, existing infrastructure, consumer preferences, and regulatory structures. In areas with constrained distribution capacity, a combination of both pricing reforms and managed charging may be necessary to avoid costly network upgrades while maintaining reliable service. Which potential solutions are supported by electricity retailers will, at least in part, be influenced by whether the retailers are responsible for bearing the costs (and, in the case of RoR regulated utilities, benefits) of distribution system upgrades.

As transportation electrification continues and EV adoption rates grow, integrating EV charging into the distribution network will become increasingly important. Doing so affordably will be challenging. Economists can join engineers and utility planners in contributing solutions to this issue by promoting efficient rate structures and accurately identifying consumers' willingness to accept technological solutions to this challenge.

Several promising research directions emerge from our analysis. First, there is a need for more empirical work on consumer preferences regarding managed charging, particularly studies that isolate which program features drive acceptance or rejection. Second, economists should develop and test distribution-specific pricing mechanisms that balance system-wide efficiency with local constraints. Addressing scarcity at different levels of the grid simultaneously may require multiple price incentives, and it will be valuable to understand how much technology and automation will be required to support consumer decisions in this complex setting. Third, more research is needed on the distributional impacts of different cost allocation approaches for network upgrades necessitated by EV adoption.

Finally, as vehicle-to-grid (V2G) technology matures, new research questions arise about how EVs might not only avoid exacerbating distribution constraints but potentially help to alleviate them. The economic value of such services, and the market mechanisms to appropriately compensate them, are fertile ground for future economic research in this rapidly evolving area.

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