The Persistence of Volumetric Pricing

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Abstract

How to recover the costs of electricity distribution has become a prominent and controversial issue in the wake of California Public Utilities Commission proposals to reform compensation for solar electricity homeowners who sell into the grid, with subsequent proposals to recover more of the distribution costs through fixed charges based on household income. This debate raises questions about the ubiquity of volumetric pricing for fixed-cost recovery in regulated industries. Ideal cost recovery entails marginal cost pricing of kilowatt-hours delivered, per-user connections, and capacity needed to handle coincident peak use. Remaining uncovered costs of distribution should be recovered by fixed charges. Equity and efficiency considerations suggest assigning fixed charges on the basis of willingness to pay or income, although neither is perfect. Nevertheless, volumetric recovery of fixed costs has persisted for several reasons: mistaken analogies to competitive markets, simplicity, network effects, incumbent resistance, and fairness and rights. Getting pricing right matters not just for general efficiency but also to remove pricing barriers to decarbonization. For this reason, electricity regulators should consider recovering more fixed costs through fixed charges.

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1. Introduction

In virtually every regulated sector—water, mail delivery, telephones, and electricity—regulators have most if not all costs covered by volumetric prices; that is, prices are based solely on how much of the regulated service the customer uses. This is still the case even though a large fraction of the costs of these regulated services are independent of volume—and were that not the case, these services could be supplied competitively rather than through regulated monopolies. Following recent proposals by the California Public Utilities Commission to move compensation for sales of solar power into the grid and then make retail prices per kilowatt-hour for electricity purchased closer to marginal cost, this has become a salient issue for electricity distribution.[1] Volumetric pricing can discourage efficient uses of the regulated service, resulting in too little electricity use, counter to efforts to decarbonize the economy through widespread electrification. It can also create political problems when substitutes for the regulated entity (e.g., residential solar panels) reduce demand and create revenue holes that must somehow be filled.[2] A major concern is that these revenue holes would be filled by relatively less well-off electricity customers lacking the income or ability (i.e., do not own homes with rooftops exposed to the sun) to install solar panels.

Understanding why we are in this situation requires consideration of why regulators are averse to having fixed charges to recover costs that do not vary with volume. This in turn requires clarification of the intuitively simple concept of fixed costs, which can be (a) how much it costs to build a local distribution grid apart from costs that vary with use, (b) what the costs of a grid would be if use were to approach zero, (c) how much of the costs that do not vary with volume nonetheless vary with other things, particularly, how many users connect to the grid, or (d) how much of the costs of the grid would not be covered if efficient prices equal to marginal cost were charged. The purpose of this paper is not to propose a particular method for pricing use of the grid and attaching users to it, but to clarify thinking about why efficient pricing is misunderstood, controversial, and resisted.

Section 2 of this paper provides necessary context. With regard to electricity, the focus is on how the costs of distribution are recovered by regulated distribution utilities. Focusing on distribution does not mean that pricing puzzles are solved for the other major stages in the electricity sector, generation and transmission. This section reviews those puzzles as a reminder that serious problems remain at the forefront of policy discussion. It is important at the outset to note that the debate over the role of fixed versus volumetric pricing in distribution is separate from the optimal method for

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[1] On changes to compensation to providers of electricity from residential solar power systems, see CPUC (2022). The proceeding to consider income graduated fixed charges is in process (see CPUC n.d.; Public Advocate's Office 2023). For indicators of the opposition from multiple positions on the political spectrum, see Nikolewski (2023); Faruqui (2023). For responses to these arguments, see Borenstein (2023).

[2] See Shawhan (2016) for a conceptual discussion of optimal pricing principles for electricity.

pricing the electricity that is distributed. In principle, all energy costs could be recovered through real-time volumetric prices based on wholesale energy cost, while distribution costs are recovered primarily through fixed fees with only a small if any volumetric charge. Whether the latter is the case is the primary subject of this paper.

One might observe that most goods are supplied without separate fixed fees. Section 3 delves more deeply into what we mean by fixed costs by presenting several possible definitions. This concept is more slippery than it may initially appear. If fixed costs were defined as the cost of delivering electricity assuming none was delivered, they would be zero, but there would be no reason to build a grid that would not be used. Another, slightly more complex definition is that if costs were computed as a function of output, fixed costs would be the limit of costs as output goes to zero. This construct captures the idea that fixed costs are the minimum amount one has to pay to produce, assuming one is producing something.

Section 4 presents a base case model for recovering the costs of a regulated facility when marginal cost pricing is insufficient to recover those costs. This concern is particularly acute for electricity distribution, where the marginal cost of delivering an additional kilowatt-hour of electricity is, in the short run at least, close to or equal to zero. General results require assuming a correlation between the willingness to pay for electricity delivery at marginal cost and the quantity of electricity delivery one would demand at marginal cost. Two potentially surprising insights follow from the base case. First, if all users are charged a uniform fixed cost for delivery, some users with low demand might be cut off from access to electricity; mitigating this loss of benefit can warrant charging a price above marginal cost for each kilowatt-hour delivered. Second, cutting off low-demand users could be avoided with nonuniform pricing. In particular, if high willingness to pay for electricity is correlated with income, then one could cover fixed delivery costs by charging high-income users higher fixed fees and then letting everyone purchase the quantity delivered at marginal delivery cost. In other words, equity and efficiency may be partners, not opposing policy goals, as they are usually characterized.

In electricity distribution, however, there can be a difference between costs that are independent of how much electricity is consumed and costs that do not vary on any other margin. Some costs of electricity distribution are variable but do not vary directly with electricity delivered. One is the costs associated with being connected to the grid—having a line run to one's residence or business, setting up billing, potential nonpayment risk, and perhaps others. In principle, these costs should be included in the fixed fee. Another is that the local electricity grid needs to be designed large enough to carry the greatest quantity demanded at any given time. To reflect this, many have proposed a "demand charge" based on the amount of electricity demand at the time when demand over the network as a whole is largest ("coincident peak") (Faruqui 2015; NREL 2017). Charges reflecting customer-specific and coincident peak costs still need not cover total costs, thus requiring prices above cost for all of these. Again, to the extent that these costs can be recovered more from users with the highest willingness to pay for electricity delivery, other charges can be brought closer to marginal cost, meaning equity can promote efficiency. However, the larger those costs, the smaller the amount of remaining costs that would need to be covered through fixed fees, if those long-run costs are covered with volumetric premiums (equal to long-run marginal cost, including the cost of adding grid capacity) during periods of peak demand.

Principles for efficient pricing in general, and the inefficiency of recovering fixed costs by any definition through volumetric pricing, reflect familiar textbook economics. Section 5 discusses reasons why volumetric cost recovery persists, not just in electricity distribution but also in most other regulated sectors, including postal delivery, water service, and formerly telephone service, before the mobile cellular and internet-based innovations. One reason could be aversion based on the lack of fixed charges in conventional competitive markets: if we pay for apples on a volumetric basis, why not electricity? Reasons for volumetric pricing may include avoiding perceived complexity of billing separate fixed fees and, in some cases, social and economic justifications for maximizing penetration of a regulated service by not charging customers just to be connected. Policy-related reasons include equity and fairness: those who use a service relatively little should not have to pay the same fee as those who use it more, whereas those who use the service more (and likely have higher income) should pay more.

Section 6 concludes with observations on the policy costs of retaining volumetric pricing. In some regulated sectors, volumetric pricing means that when demand falls, prices rise to cover non-volume-related costs, creating a conservation penalty. With respect to electricity, one concern is that high volumetric pricing fosters inefficient substitution away from grid-delivered electricity.[3] Most important, where the use of electricity generated by non-carbon-emitting sources is the primary method for attenuating climate change in several energy end uses, high per-kilowatt-hour electricity prices impede electrification.

[3] The idea for this paper arose from the debate over the CPUC's order to change how residential solar panel owners would be compensated for electricity they supply into the grid and pay for their connections to it, as well as more recent proposals before the CPUC to recover higher fixed charges based on income. See CPUC (n.d., 2022); Public Advocate's Office (2023).

2. Context

With regard to the electricity sector, the focus here is on recovery of costs of the distribution grid. Percentages can vary considerably given variation in average cost of generation, resulting from changes in the price of natural gas and the mix of different technologies used to generate electricity, but a 2021 estimate from the Department of Energy attributed 31 percent of the retail price of electricity to distribution (EIA 2022). Distribution is not the only portion of the electricity sector for which pricing is an issue; generation—the electricity itself—and transmission, moving that electricity over long distances, face pricing challenges as well. Those challenges will not be resolved here, but reviewing them is useful to provide some context for assessing the role of volumetric cost recovery of distribution.

2.1. Generation

The pricing of generation may initially seem relatively unproblematic. Generators make bids to supply energy at different times (moderated by transmission costs, discussed in Section 2.2). In several respects, however, it is not that simple.

Perhaps the longest-standing issue in pricing electricity at wholesale is that much of the time, generation capacity exceeds demand. At those times, to oversimplify, the wholesale price of electricity will be the short-run marginal cost, determined largely by the cost of the fuel used to generate that electricity. Recovery of the costs of constructing the generator requires "scarcity pricing"—that is, charging high prices when the demand for electricity approaches or exceeds the capacity of generators to produce it. This is especially so for generators that come online only when demand is at its highest (e.g., on hot summer afternoons when air conditioners are in heavy use).

This is fine in theory, and it works pretty well for hotel rooms at resorts during vacation season. But in practice, it can result in very high prices for electricity during very short intervals, as much as 50–100 times the normal price (Brennan 2004). Moreover, when the system is most stressed, individual generation companies might be tempted to hold electricity off the market to raise the price even more (Friedman 2009). For this reason, electricity prices are generally capped at levels that may not allow recovery of the costs of building generators, particularly those used only at peak demand times. Price caps create what has been called "missing money" that generators would otherwise need to make building units profitable. In many areas, this missing money is recovered through "capacity markets," where the grid manager takes bids from generators to be available to supply electricity at or under the price cap (Joskow 2008).

Further complicating the situation is that capacity markets are created not just to provide for generation cost recovery but also to ensure that generators or load-serving entities (LSEs; retail providers or, for residential users, the distribution utilities) have more than enough capacity to meet expected demand in case of unforeseen spikes in demand or outages in generation or transmission. If effective, instituting capacity markets to meet reserve requirements would ensure that except for rare emergency contingencies, there would be excess generation capacity relative to the amount of electricity users consume. Having this level of capacity available would preclude the availability of scarcity rents to cover the fixed costs of providing generation (Lueken 2017). Inability to capture scarcity rents vastly increases the missing money necessary to give generators a return on investment—especially when the marginal costs of supplying electricity from renewable resources needed to facilitate decarbonization of the grid and the economy at large are essentially zero, and their costs are almost entirely for capacity.

Other issues with the pricing of electricity show up at the retail level. One longtime problem is that retail prices do not match fluctuations in wholesale prices, providing no incentive to cut back on electricity use at peak periods, when the electricity is most expensive. The cause used to be a combination of retail price regulation and the lack of technology to trace when electricity is used to allow time-based billing. In many places, retail rates are less regulated, and smart meters that allow tracking of when electricity is consumed are widely deployed, but real-time pricing is still not widespread. Users, especially residential users, and the regulators and legislators who represent them, do not want to be exposed to the risk of highly varying prices. Limiting exposure to this risk is understandable, but it also limits the degree to which wholesale prices are transmitted to consumers. Risk-averse consumers could mitigate risk by selecting retail price contracts with limits on price exposure, in principle compensating their retail supplier for taking on that risk.

Another issue in this nonexhaustive list is that even if consumers might be exposed to real-time prices to encourage electricity use when it is cheap and conserve it when it is expensive, the price mechanism may not always work as needed. As renewable-sourced generation plays a bigger role, electricity supply can become more intermittent—clouds may temporarily block the sun, or the wind may die down for a moment before resuming. This may happen more quickly than prices could react to balance supply and demand during these minute-by-minute fluctuations. Until battery storage becomes more widespread to allow generators, LSEs, or users to smooth out these fluctuations, some method for technological control of electricity use to match demand to supply might be necessary (Brennan 2021).

2.2. Transmission

In important respects, some debates regarding the pricing of transmission have been settled. Pricing based on distance and zones, where transmission costs increase simply because of the distance between generation and load, have lost the argument to "postage stamp" prices that are the same regardless of distance, with congestion surcharges at every node (Hogan 1992). These charges essentially cover the opportunity costs of trying to inject energy at a particular location when portions of transmission that would be used to move that energy are at capacity. Such charges encourage generation where lines have space and discourage generation where lines are full. Because demand to use a network can vary rapidly, these nodal prices can change quickly (e.g., 15 minutes for each of thousands of nodes in a transmission system as in the PJM energy market).

Although instituting nodal pricing to efficiently allocate space on transmission lines is no small achievement, it does not settle longer-term issues. To allow those affected by nodal prices—generators directly, LSEs indirectly—to hedge their price volatility, they may be able to obtain "financial transmission rights," essentially, claims on the rents created by congestion prices. This gives entities a claim on those rents and thus an incentive to perpetuate them by opposing adding capacity that would alleviate congestion (Joskow and Tirole 2000).

A related set of issues is perhaps more pressing. Mitigating climate change by reducing fossil fuel emissions is likely to require a vast increase in renewable-powered generation, wind and solar. This increase is not just to substitute for fossil fuel–powered generation, coal and natural gas, in the current electricity system but also to provide energy to replace fossil fuel use in transportation and heating. Increasing the degree of electrification in turn will require vast increases in transmission capacity, both because of the added generation and because the best places to produce wind and solar power are not near either current generator or user locations (ESIG 2021).

Providing incentives for any regulated entity to expand to meet growing demand, be it an electricity transmission grid, water system, or postal service, is a long-standing problem. In transmission, it shows up in allegations that grids are too slow to respond to requests for interconnection and calls for expansion; these are planned over decades and not in response to individual requests for expansion.[4] One solution is to allow a transmission grid, in this case, to charge fees exceeding the average cost of expansion, giving it an incentive to do so. Whether such prices could be designed in such a way as to prevent inefficient expansion or excessive transmission prices is outside the scope of this study, although calls for planning suggest that a price-based solution may not be available.

[4] Brennan (2022b) discusses whether this planning independent of specific connection requests is consistent with efforts to bring competition to wholesale generation.

3. Defining Fixed Costs

A common understanding of fixed costs is necessary for policy discussions regarding how much to use volumetric prices to recover all or part of these costs. Even beyond the electricity context, the idea of fixed costs is more ambiguous than it might first appear. It turns out that the appropriate target for optimal cost recovery, volumetric or otherwise, is associated only indirectly with fixed costs.

It is commonplace in basic economic textbooks to characterize costs as the sum of two things—fixed costs and variable costs—where only the latter vary with output. If *Q* is output, this is usually written as

$$C(Q) = F + VC(Q),$$

where *C* is the total cost, *F* is the fixed cost, and *VC* is variable cost. With this formulation,

$$F = C(0),$$

since by definition variable costs of no output are zero. This invites the first definition of fixed cost: the cost of producing no output. However, if one is producing no output, one would not incur the fixed costs either. This suggests there are no fixed costs—or that we need a better definition.

We can think of fixed costs in a second way, which more carefully corresponds to the intuition that these are the costs one must incur to produce anything. To make automobiles, for example, one has to build a factory to produce any amount, be it one car or the maximum capacity of the factory. Expressing fixed costs in a way that conforms to this intuition is that they are the measure of cost as the quantity is positive but becomes decreasingly small.[5] This idea is captured in the simple textbook formulation above, but without the potential confusion created by having the cost of producing nothing be positive.

This formulation of fixed costs leaves out two important considerations particularly pertinent to electricity distribution. One is that the costs necessary to deliver electricity may include costs that vary on other dimensions and thus should not be treated as fixed, even if they do not vary by the amount of electricity delivered. One obvious example is that costs can vary with the number of users connected to the distribution grid. The previous section included that as a variable cost but not one associated with volume delivered.[6] Fixed costs should be restricted to those that

[5] Mathematically, it is the limit of costs *C*(*Q*) as quantity *Q* gets arbitrarily close to 0.
[6] In practice, the marginal cost of connecting an additional customer to the grid will vary across customers, depending on, for example, how far they are from local transformers and from each other (e.g., whether they live in single-family homes or apartment buildings).

would remain as all variables approach zero—the quantity of electricity delivered, the number of customers, and anything else.[7]

Another important consideration is that costs fixed by these measures in the short term may vary over longer periods. The most relevant example for electricity distribution is capacity. Some distribution facilities have more or larger transformers and substations to handle the maximum amount of electricity that all or parts of the grid would have to distribute at any time. The price of electricity demanded at times when the grid is most stressed—or when the grid would have to be expanded to meet reliability requirements—should reflect this cost. This price is known in the electricity sector as a demand charge.[8]

An illustration of a demand charge in a more familiar context would be in the prices of summer resort hotels. During nine months of the year, the cost of the hotel building is essentially fixed, in that a hotel does not need more rooms to handle the small number of visitors. In that case, the variable cost associated with additional visitors is relatively small, leading to low off-season rates. In the summer, however, the variable cost of housing additional visitors includes the cost of adding more hotel rooms. Thus, during the tourist season, the price of hotels is higher—often much higher—to cover the capital cost associated with expanding hotel capacity. That premium of summer rates over off-season rates is essentially the demand charge for using an additional hotel room at high demand times.

A demand charge serves the same purpose in the electricity context. It is important to note that the cost warranting a demand charge for any individual user is based not on that individual user's maximum demand, but on the amount the customer demands when the system is most stressed overall, known as "coincident peak demand."[9] Suppose that for a particular distribution system, peak demand occurs on summer afternoons. A household that has a programmable thermostat and no one home during the afternoon may not use much electricity at that time; its peak demand may be at night. The demand charge for that household should be based only on its lower use during the afternoons, when each additional kilowatt demanded requires an additional kilowatt of capacity in the grid. Uses at night, even if peak for that household, do not incur that cost.

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[7] Regulators may elect to cover these marginal but nonvolumetric costs through volumetric prices. If so, those who use a lot of electricity will in effect subsidize the connections of those who do not use very much.

[8] To the extent that the grid is not sized to deliver peak demands, demand charges could be thought of as congestion charges on the distribution grid. I thank Darryl Biggar for that observation.

[9] These costs, like connection charges, can vary across customers on the grid, as different aspects of the grid, from neighborhood transformers to regional substations, may require expansion at different times depending on when different areas manifest peak demands. Moreover, while ideally a demand charge would be based on the power used at the exact coincident peak, in practice it will likely be a surcharge on energy delivered at times expected to be at or near coincident peak, such as on very hot summer afternoons.

Basing demand charges on coincident peak demand provides the appropriate incentive to move discretionary electricity use from times when the distribution grid is under stress to times when capacity is relatively available. In practice, since the specific high-volume time need not be known in advance and may vary across a distribution grid, the most effective way to cover these marginal capacity charges could be through a higher cost per kilowatt-hour during predictably high-demand periods, akin to the higher summer prices for hotel rooms at beach resorts.

This is a matter of more than theoretical consequence. Much of the equipment in a distribution grid is related in some way to the volume of electricity delivered. This does not include considerable portions of the wires, particularly as the wires get closer to end users. But it may include much of the cost of substations and transformers installed to deliver the expected peak amount of electricity to those users. It may well be that if demand charges or, more likely, peak period pricing of distribution to reflect these long-run costs were more widely implemented, the costs that would need to be covered through other modifications to distribution pricing might be considerably less.[10]

Returning to the theoretical baseline, fixed costs are those not covered by volumetric and connection costs equal to marginal costs. We should add revenue from demand charges to efficient cost recovery, where the efficient demand charge is the marginal cost of expanding the relevant capacity of the distribution grid to handle the maximum amount of electricity customers demand. Taking all these variable costs into account, not just those associated with electricity volumes, reduces the amount of fixed distribution costs that need to be imposed on customers for cost recovery purposes, as well as the need for equity and potential efficiency mandates of basing such charges on willingness to pay or income.

[10] A utility engineer at a conference once told me that only 25 percent of distribution costs were fixed. I initially found this surprising, but after considering both peak volume costs and marginal individual connection costs, it seems increasingly plausible. However, I do not know what the range of estimates for this percentage might be.

4. A Theoretical Baseline and Policy Insight

4.1. Baseline Results

Some basic results can help in understanding the proper role and limits of volumetric pricing of electricity distribution. (Many of these are derived in the appendixes.) A useful baseline is to consider how one would set prices for a service where marginal costs are associated with both the volume of service delivered and the number of users who get that service, with a standard assumption to come up with the baseline.[11] The results first show, unsurprisingly, that the optimal price for each unit delivered equals the marginal cost of delivering that volume, and the optimal price of connecting any user equals the marginal cost of connecting that user.[12]

This conventional economic principle applies in practice if the revenues obtained by marginal cost pricing suffice to cover cost. However, in regulated industries such as electricity distribution, characterized by high fixed costs and low marginal costs per unit volume and for connecting any individual customer, marginal cost pricing is unlikely to cover costs.[13] How to adjust prices to cover costs is a long-standing central question of regulatory economics. The basic principle, known as Ramsey pricing after Frank Ramsey's (1927) qualitatively identical theory of optimal taxation to cover a government budget, is that the price of each service provided by the regulator should be marked up over marginal cost in proportion to the inverse of the elasticity of demand (Baumol and Bradford 1970). That is, services customers would mostly keep buying in the face of a price increase should get a higher markup, and those for which their demand is sensitive to price should get a low markup.

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[11] The assumption is that we rank users by how much volume (of electricity in this case) they would choose to have delivered at a given price per unit. If one user would demand more electricity than a second at some delivery price, that first user would demand more than the second at any delivery price. Visually, the demand curves for electricity for any pair of users do not cross.

[12] The model neglects time-varying prices, as those arise more from the wholesale side than the distribution side. The model also neglects demand charges or peak period distribution charges, which reflect time-sensitive variation in distribution costs. Some have asked whether electricity distribution should be subsidized to promote electrification, specifically substituting electricity use for the use of fossil fuels in other sectors, such as automobile transportation or home heating. Such a subsidy in general does not necessarily reduce greenhouse gas emissions, since fossil fuel–generated electricity is also delivered through distribution grids. If fossil fuel–generated electricity becomes a relatively insignificant portion of the total electricity supply, such subsidies can be a "second best" approach to promoting electrification in the absence of explicit prices on greenhouse gas emissions through either taxes or cap-and-trade permit programs.

[13] Borenstein (2022) notes that in California, these fixed costs include not just costs of distribution but also costs of programs to fund electricity efficiency, reduce electricity costs for low-income customers, and control wildfires.

Ramsey pricing does not directly apply in this case, however. It applies when the demand for each service offered by the regulator is independent of the others' prices. This does not hold for electricity distribution with regard to demand for connection and demand for delivery, because the willingness to pay for connection depends on the price per unit delivered. The optimal volumetric charge when extra is needed to cover distribution costs will exceed marginal cost (see also Brennan 2010). However, there is no similarly general result that the per-customer charge will exceed the marginal cost of connection; it could be less. We might expect positive markups on the connection charge, especially if demand for connection is highly or perfectly inelastic. In this case, though, because connection to the distribution grid and delivery of electricity through it are complements, the theory of the second best (Lipsey and Lancaster 1957) works in the other direction. That theory implies that if delivery prices are above marginal cost, charges for connection, as a complement, should be below them to promote efficiency.

A positive markup on use extracts more from those who use electricity more but will not stop using electricity just because of a per-unit markup on delivery. Such a positive markup creates a trade-off between charging a higher fixed fee on top of it to cover cost and reducing the fixed fee below marginal connection cost to have more users paying the markup for each unit delivered. An example of the former would be where all customers have identical demands and the efficient way to cover cost is to increase the fixed fee paid by all and keep the volumetric price equal to marginal cost of delivering an additional unit of electricity. An example of the latter in a different context is charging low prices for personal computer printers (the fixed-connection analogue) but a higher price for ink used in them (the volumetric analogue). My guess is that the former usually dominates the latter, but the derivation does not indicate this one way or the other.

4.2. Policy Options for Fixed-Cost Recovery

The setting of inefficient markups, up for use and possibly in either direction for the fixed fee to connect to the distribution grid, invites analysis of ways to restore efficient pricing. Here, that would entail spreading the costs of distribution not covered by volumetric pricing of delivery in such a way as to keep volumetric pricing at marginal cost, while keeping fixed fees low enough to avoid disconnection by those willing to cover the marginal cost of staying connected. One method for doing this, in principle, would be to charge markups over marginal connection costs based on the willingness to pay to be connected. Willingness to pay cannot be directly observed, which encourages the use of something observable and arguably associated with willingness to pay—income. Income-based markups also operate in the direction of reducing wealth inequality. This is perhaps a rare instance where equity and efficiency complement each other.[14]

[14] Income-graduated fixed charges would also respond to concerns that uniform fixed fees across all users would create equity issues, as lower-income households that do not use much electricity could see higher electricity bills with these fixed fees (see Borenstein *2023)*.

However appealing income-based fixed charges may be on efficiency and equity grounds, implementing them is problematic. On the operational side, distribution utilities typically lack access to user income data, and it may not be legal or desirable for them to obtain it.[15] Income may not be correlated with willingness to pay for connection to the grid.[16] Higher-income households could choose to install solar power systems and storage to allow them to disconnect from the grid. Higher income may be correlated with a demand not to be subject to outages from distribution or the rest of the centralized electricity production system, as well as with owning homes in sunny locations that enable the use of solar power systems. Thus, an income-based surcharge on the fixed fee could serve as an incentive for such homes to detach from the distribution grid, even if they would remain at fixed fees equal to the marginal cost of keeping them connected.

This suggests reconsidering the idea of basing fees on willingness to pay. Apart from the operational concern of the inability to observe willingness to pay, there is a problem in principle. Willingness to pay for connection to the distribution grid is not independent of the price to connect to the grid. Prices based on willingness to pay to connect to the grid create an incentive to reduce willingness to pay to do so, such as by installing solar generation or adopting greater energy efficiency beyond the point where the benefits otherwise justify the expense. Inefficient disconnection from or use of the distribution grid is exactly the problem that basing fees on income or willingness to pay is imagined to solve. Perhaps the lesson is not to let the perfect be the enemy of the good and to accept some income differentiation of fixed fees to minimize the divergence of volumetric charges from their marginal cost.

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[15] Borenstein et al. (2021), 36–40, assess potential methods for basing fixed charges on income in California. These include integrating fixed charges with the state tax system, having distribution utilities collect verifiable data on user income or obtain income data from in-state tax returns, or basing charges on the average income in a user's location.

[16] I thank Amparo Nieto for bringing this possibility to my attention.

5. The Persistence of Volumetric Pricing

We have seen that efficient pricing of electricity distribution would entail marginal cost pricing of use and capacity and fixed fees to cover customers' specific costs and costs not recovered by marginal cost pricing overall. This result holds for most price-regulated industries—water, postal service, and formerly telephone service—where high fixed costs relative to variable costs preclude sustainable competition. In light of the inefficiency of recovering most or all costs through volumetric pricing, this section reviews some possible explanations for its persistence.

5.1. Fixed-Cost Recovery in Competitive Markets

One possible explanation is that most goods and services are purchased volumetrically. We buy everything from apples to plane tickets by the unit, without paying a fixed up-front fee for the ability to obtain these items. Superficially, this appears to contradict the argument in favor of fixed-cost recovery.

However, the theoretical model supports both the arguments for fixed fees for regulated services and volumetric pricing in competitive markets. Support for fixed fees for electricity distribution and other regulated services rests on two assumptions in the baseline model: that there are customer-specific fixed costs apart from the cost of supplying the good being purchased and that marginal cost prices fail to cover all the costs of supplying the good. Neither of those assumptions, particularly the latter, holds for goods supplied competitively. For such goods, competitive supply typically implies that marginal costs eventually rise; otherwise, we would be likely to see significantly noncompetitive market conditions. Prices equal to that rising marginal cost will be enough to cover the costs of firms in the market; otherwise, they would leave.

Exceptions to this rule abound, leading to market alternatives to simple volumetric pricing. Some services may be purchased on a subscription basis, where consumers pay for the ability to consume varying quantities of the delivered service; video programming networks and online media publications are good examples. Sometimes volumetric prices may be used to cover customer-specific costs. An interesting example is using the markups on wine to cover rent of the table in a restaurant, because diners who are drinking are more likely to linger (Lott and Roberts 1991).

5.2. Simplicity

When there are customer-specific costs, why are those not covered through fixed fees? For example, we could imagine that going out to dinner would include a price for the food and a separate price per hour for how long someone used the table. One answer may be to avoid complexity. Adding a fixed fee, especially to a volumetric price, increases the calculations behind the prices and the marketing needed to attract customers. Buyers may have a harder time determining how much purchasing a good actually costs them. Such up-front fees are not unheard of; the membership fee to use a discount store can be considered as a way to cover per-buyer costs associated with maintaining accounts.

Regulators can face similar problems. Customer confusion would likely reduce public support for their decisions regarding approving rates and how they are structured. They may find it easier to simply say that water, postage, or electricity distribution costs so much per unit, rather than attempt to explain how rates are divided between volumetric charges and fixed fees.

5.3. Network Effects

For some services, the value any user places on it depends on how many other users also use it. This "network externality" creates an incentive for private suppliers or regulators of such services to reduce or eliminate fixed fees to increase the number of people who use the service.[17] On the private side, this partly explains why social networks such as Facebook or LinkedIn often do not charge users to join their services, at least at a basic level.

The networks effect argument is not necessarily present in all regulated sectors, leading many of them to be mislabeled as networks (Brennan 2009). An example of a regulated service with network effects is postal service, which around the world entails universal service rates to maximize its availability within countries. Electricity distribution, however, does not have specific network externalities, in the sense that the value of electricity distribution to any given user depends at the margin on the number of others on the same distribution grid.[18]

[17] If network externalities depend not on how many others are on the same service but on how much the others that are on it use it, incorporating them would argue for higher fixed fees and lower volumetric (use-based) charges.

[18] Electricity is the power source for communications technologies that have network externalities, but that does not imply a benefit to one user from other users being on the same electricity grid. In theory, each user of a communications technology could generate their own electricity but still be on a common communications network. I thank Ephram Glass for noting this possibility.

5.4. Incumbent Resistance

As noted in Section 1, a major impetus behind increased interest in electricity pricing has been the California regulators' proposal to impose fixed charges and reduce volumetric charges associated with electricity distribution, particularly having the fixed charges increase with income. Invariably, a proposal to change a pricing structure, even if it leaves the distribution utilities' profits unchanged, will reduce electricity spending for those who use a lot of electricity and increase it for those who may not take much electricity off the grid. Income-based fixed charges will inflate both effects for low-income households that use a lot of electricity and high-income households that do not use much. This will be especially true for households that take less electricity from the distribution network because they have installed solar power, and these are likely to be relatively well-off users who own homes on which solar panels can be mounted and storage batteries installed. Such households, and the solar industry that depends on them, are likely to be among the strongest opponents of fixed charges, particularly when income-based.

The proposal to recover more distribution costs through fixed charges arose from a slightly less recent proposal in California to change the amount households with solar power receive for sending electricity they do not need into the distribution and larger transmission system. The amount given to those households changed from the retail price of electricity to a price equal to the social benefits of that power and does not include the distribution and transmission networks used to deliver it, which at least in the short run are fixed. In perhaps oversimplified terms, we can view this social benefit as the avoided cost of generating electricity in central power plants plus the value of reduced carbon emissions and other pollutants associated with that central generation.

Proposals to recover distribution through fixed fees can be regarded as a move toward making the volumetric price for purchase equal to that social benefit. Eliminating this asymmetry between the price paid to purchase electricity and the price received when a household has electricity from its solar power system to sell might further solidify decreasing the revenues from home systems, reducing the benefit to owners of existing systems and to potential buyers of new ones, and thus the demand for new residential solar installations.[19]

[19] If distributed solar is unprofitable at efficient volumetric prices, including the value of mitigating emissions of CO_2 and other pollutants, then installing it is economically wasteful (Borenstein 2022). Distributed electricity generation should not be an end in itself. A potentially interesting policy question is whether incumbent solar installation owners would have "stranded costs" meriting recovery when reform of electricity distribution rates makes current solar installations less valuable. Brennan and Boyd (1997) assess the merits of stranded cost recovery arguments when regulators opened generation markets to competition and potentially reduced the value of incumbent generators.

5.5. Fairness and Rights

This last category may be the most compelling argument for volumetric pricing facing regulators and policymakers. Moving from largely volumetric pricing to significant fixed fees, especially without income-based adjustments, means that those who use less electricity will pay the same amount as those who use more. Many may see this as unfair, from the premise that those who use a facility more, in this case electricity distribution, should pay more for it.[20] To that extent that households with more income use more electricity, contributing to fixed costs through volumetric rates provides additional support for this argument on equity grounds.[21] These arguments may be more compelling for services that many believe should be widely available at low prices as a matter of ethical right.[22]

Volumetric cost recovery, with charges above the marginal cost of delivery, will be appealing on equity grounds. To the extent that higher-income users take more electricity from the distribution system, the margin above marginal cost will imply that higher-income users contribute more to covering the electricity distribution system's cost. This will be less true if those higher-income users purchase less electricity from the grid because they generate electricity on their premises with solar power systems. It may be that the increased use of such systems in California, spurred by its very high volumetric prices, weakened this equity argument enough to make distribution cost recovery through fixed charges more appealing.

[20] Similar arguments were used to support volumetric subsidies on long-distance use to cover the fixed costs of providing a landline telephone to homes.
[21] Although wealthier people would pay more to cover fixed costs when volumetric rates include a markup over marginal cost, this implicit tax may be regressive, if the amount of electricity used does not increase proportionally with income.
[22] This complements but is different from the network effects argument in Section 5.3.

6. Summary and Conclusions: Why Does High Volumetric Pricing Matter?

After summarizing pricing issues in generation and transmission, this paper considered multiple definitions of fixed costs, settling on the residual cost not covered by marginal cost pricing as the most relevant for regulatory policy. It has explained why the ideal method for cost recovery of distribution should entail marginal cost pricing of kilowatt-hours delivered, per-user connections, and capacity needed to handle coincident peak use. Remaining uncovered costs of distribution should be recovered by supplemental fixed charges. It is important to keep in mind that these remaining unrecovered costs could be relatively small if volumetric peak period distribution prices were implemented to cover the marginal cost of adding capacity to meet high demand with appropriate reliability.

For efficiency and equity reasons, these fixed charges should be assigned on the basis of willingness to pay or income, but neither is perfect even if legally possible and relevant data are available. Assigning costs based on willingness to pay provides an incentive to reduce it by generating electricity at the household, presumably with solar power, unrelated to the avoided costs of connection and delivery of electricity from central generators. Assigning costs based on income may induce high-income users to install solar power systems to avoid high fixed costs, again unrelated to the actual cost of connection and delivery. The paper then reviewed five reasons why volumetric-based recovery of fixed costs (and individual connection charges) persists: flawed analogies to competitive markets, simplicity, network effects, incumbent resistance, and fairness and rights.

Excessive volumetric pricing matters for both efficiency and policy reasons. For any regulated enterprise, including electricity distribution, excessive volumetric pricing would lead to too little use of the service, in the sense that customers would forgo uses that are worth more to them than the cost of providing them. For electricity distribution, this implies that users do too much to become energy efficient—that is, investing in time and equipment to reduce electricity use—rather than too little.[23] It also may induce high-volume users to install solar power systems when the cost of doing so is less than the cost of delivering and purchasing electricity from central generators.

A related problem is what might be called the paradox of conservation. The volume of consumption of a regulated service can fall. In the postal sector, this has occurred as people switch from paper to electronic forms of communications. For water, this can happen when drought reduces supplies and people are either encouraged or required to use less. When volumetric pricing is used to cover fixed as well as marginal cost,

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[23] High volumetric prices may induce electricity theft by bypassing the meter. As of 2013, about 1–2 percent of electricity was stolen (Kelly-Detwiler 2013). High volumetric rates would exacerbate this form of theft.

volumetric prices have to go up to keep the regulated provider solvent.[24] This creates the appearance that users are being punished by higher rates for conserving, sometimes in the case of water at the request of regulators.

These assessments are based on prices relative to accurate marginal costs of electricity, importantly including costs associated with environmental externalities, particularly greenhouse gas emissions from fossil fuel generation. Before about 10 years ago, a widespread belief was that the market price of electricity was too low because it failed to incorporate the costs from the ubiquitous burning of fossil fuels, natural gas, and coal, to generate electricity. In this case, people would use too much electricity if it were made available at prices not reflecting this environmental cost. This view of unincorporated environmental harms also supported policies to promote energy efficiency.[25]

In recent years, however, the electricity policy discussion has flipped. Declining costs of generation from nonemitting sources powered by solar and wind, and policies to promote their use, have reduced greenhouse gas emissions from using electricity, especially at times of the day or year when sunlight and wind are abundant. Electricity from such generators in turn could substitute for the use of fossil fuels in cooking, heating, and most notably, automobile travel as important steps in decarbonizing not only the electricity system but the economy at large. High volumetric prices for electricity impede that decarbonization. Whereas once such high prices might have alleviated policy failure to impose the cost of fossil fuel use (e.g., through a carbon tax), they now may stand in the way of reducing fossil fuel use outside what had typically been powered by electricity.

[24] Brennan and Crew (2016) discussed the problem of high volumetric fees with declining demand in the context of postal services. Brennan (2022a) described how charging a fixed fee to each household to get mail would enable marginal-cost postage and reduce the solvency threat created when demand falls.
[25] Complementing the view that people use too much electricity was a belief that people fail to act in their own self-interest by investing in energy efficiency and that regulation would make them better off despite their choices not to make such investments. For a debate on the merits of whether benefits that people reject in their decisions should nonetheless be counted in assessments of energy efficiency programs, see Allcott and Sunstein (2015a, 2015b), in favor of counting, and Mannix and Dudley (2015a, 2015b), against doing so.

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Appendixes: The Baseline and Cost Recovery Models

Appendix A: Preliminaries

A relatively simple model of how to price a distribution system efficiently can provide some insight into the complexities and policy debates associated with combining fixed charges to users with cost recovery on a volumetric basis.[26] In full generality, the problem is intractable because of the variety of relationships that could exist between the volumetric price charged for distribution and the willingness of users to pay a fixed charge to connect to the grid.

To make the problem tractable and establish a theoretical baseline, a routine assumption is that users can be ranked in order of how much electricity they would purchase at any given price for distribution (net of the price of the electricity itself). Using descending order, and letting $q(p, j)$ be the quantity of electricity user *j* would purchase at price *p*, this assumption states that

$$\text{if } j < k,\ q(p, j) > q(p, k).$$

This assumption ensures that the ranking of users by willingness to pay to be connected to a distribution grid is independent of the volumetric price of electricity distribution, allowing the number of users and the volume of use to be considered as separate in the model.

With that assumption, we can structure the model fairly generally. Let N be the number of users of the grid. The total amount demanded by those N users at price p, $Q(p, N)$ is

$$Q(p, N) = \int_0^N q(p, i)\,di. \tag{1}$$

Because of the descending, nonintersecting demand curve assumption, N is determined by the fixed-connection fee F, which equals the consumer surplus of the *Nth* user at price p:

$$F = \int_p^\infty q(x, N)\,dx. \tag{2}$$

The total welfare of providing electricity at price p to N users will be the sum of the consumer surplus over all N users. For any individual user k, the consumer surplus $cs(p, k)$ will be

$$cs(p, k) = \int_p^\infty q(x, k)\,dx.$$

[26] Some of this derivation is in Brennan (2010).

The total consumer surplus over all N users at price p, $CS(p, N)$, will thus be

$$CS(p, N) = \int_0^N \int_p^\infty q(x, i) dx\, di. \tag{3}$$

This consumer surplus is net of the fixed fees these consumers have to pay to connect to the grid. In the aggregate, those fixed payments will be NF.

Let $C(N, Q(p, N))$ be the cost of distributing a total amount of $Q(p, N)$ electricity to N users. The profit $\Pi(p, N)$ from selling electricity at price p to N users, each of whom pays the fixed fee F, will be

$$\Pi(p, N) = p[Q(p, N)] + NF - C(N, Q(p, N)). \tag{4}$$

From equations (1) and (2), this becomes

$$p\int_0^N q(p, i) di + N\int_p^\infty q(x, N) dx - C(N, Q(p, N)). \tag{5}$$

The total welfare $W(p, N)$ from distributing electricity at price p to N users is thus total consumer surplus, less fixed fee payments, plus profits, less distribution cost (with NF subtracted from both consumer surplus and profits):

$$W(p, N) = \int_0^N \int_p^\infty q(x, k) dx\, di + \mathrm{p}\int_0^N q(p, i) di - C(N, Q(p, N)). \tag{6}$$

Appendix B: Optimal p and N: Marginal Cost Pricing

Necessary conditions for maximizing welfare from electricity distribution, $W(p, N)$, will be given by the first-order conditions $W_p = 0$ and $W_N = 0$. From equation (6), these conditions give

$$W_p = 0 => \int_0^N -q(p, i) di + \mathrm{p}\int_0^N q_p(p, i) di + \int_0^N q(p, i) di - C_Q Q_p(p, N).$$

The first and third terms cancel. From equation (1),

$$Q_p(p, N) = \int_0^N q_p(p, i) di.$$

This allows us to combine the second and fourth terms to get

$$W_p = 0 => pQ_p(p, N) - C_Q Qp(p, N) = 0 => p = C_Q.$$

The price of electricity delivered should equal the marginal cost of delivery. If time were explicitly included in this model, which it is not, this relationship would hold over time, thus justifying demand charges equal to the marginal cost of expanding distribution capacity to cover peak demands.

To get the optimal number of connections, set the derivative of equation (6) with respect to N equal to zero:

$$W_N = 0 => \int_p^\infty q(x, N) dx + pq(p, N) - C_N - C_Q Q_N.$$

From equation (1), Q_N equals $q(p, N)$. Because p also equals C_Q at the optimum, $pq(p, N)$ equals $C_Q Q_N$, so the second and fourth terms cancel out. From equation (2), the first term is just the fixed fee, F. Consequently,

$$W_N = 0 \Rightarrow F = C_N.$$

We also have marginal cost pricing for connection. We have the unsurprising results that the price per kilowatt-hour distributed should equal the marginal cost of distributing it, and the distribution connection should be available to everyone willing to cover the marginal cost of connection, with volumetric delivery priced at marginal cost.

Appendix C. Covering Costs

Optimally priced delivery and connection may not cover all the costs of the distribution grid. If not, and assuming a constant connection cost per customer, we now have a constrained optimization, where we maximize total welfare in equation (6) subject to the constraint that revenues to the distribution grid cover costs, which from equation (3) implies that

$$p[Q(p, N)] + NF - C(N, Q(p, N)) = 0.$$

In Lagrangian form, we maximize

$$L(p, N, \lambda) = \int_0^N \int_p^\infty q(x, i)dx\, di + \mathrm{p}\int_0^N q(p, i)di - C(N, Q(p, N))$$
$$- \lambda[p[Q(p, N)] + NF - C(N, Q(p, N))].$$

Because *F*, the fixed fee, is now part of the optimization and endogenous, we use equation (2) to rewrite this as

$$L(p, N, \lambda) = \int_0^N \int_p^\infty q(x, i)dx\, di + p[Q(p, N)] - C(N, Q(p, N))$$
$$- \lambda[p[Q(p, N)] + N\int_p^\infty q(x, N)dx - C(N, Q(p, N))].$$

To find the constrained optimal p and N, set the first-order conditions for this expression equal to zero. After consolidating terms and using relationships between the expressions,

$$Lp = 0 \Rightarrow pQp - CqQ_{\mathrm{p}} - \lambda[Q + pQp - Nq(p, N) - C_q Q_p] = 0.$$

From this,

$$p - C_q = \frac{\lambda}{1-\lambda}\left[\frac{Q - Nq(p,N)}{Q_p}\right].$$

As λ measures the effect on welfare of increasing the level of cost that revenues have to cover, λ is negative. Q_p, the effect of price on demand, is also negative. Because demand falls as N rises, $q(p, N)$, the quantity demanded by buyer N, is less than $1/N$

of the total amount delivered to all buyers, Q, so the numerator is positive. These together imply that

$$p - C_q > 0.$$

To optimally meet the constraint that revenue covers cost, the volumetric price should exceed the marginal cost of delivery. Putting this into price-cost margin terms and defining e_Q as the elasticity of demand for electricity delivery gives

$$\frac{P-C_q}{p} = \frac{\lambda}{1-\lambda}\left[\frac{1}{e_Q}\right]\left[\frac{Q-Nq(p,N)}{Q}\right].$$

This is similar to the familiar price-cost margin from Ramsey pricing, except multiplied by a fraction less than 1 equal to the percentage of deliveries exceeding, over all buyers, what the "last" buyer has delivered.

The optimal number of users would be given by setting the first-order condition for N equal to zero. Using relationships between the variables, this gives

$$L_N = 0 => F + pQ_N - C_N - C_QQ_N - \lambda[pQ_N + F + N\int_p^\infty q_N(x,N)dx - C_N - C_QQ_N].$$

Rearranging and collecting terms give

$$F - C_N = \frac{\lambda}{1-\lambda}\left[N\int_p^\infty q_N(x,N)dx\right] - [p - C_Q]Q_N,$$

since

$$\int_p^\infty q_N(x,N)dx = F_N.$$

We can rewrite this in terms of price-cost margins, with e_N defined as the elasticity of connections *N* with respect to their price *F*, as

$$\frac{F-C_N}{F} = \frac{\lambda}{1-\lambda}\left[\frac{1}{e_N}\right] - \left[p - C_Q\right]\left[\frac{Q_N}{F}\right]. \quad (7)$$

The first term is the familiar inverse elasticity rule for the price-cost margin, pointing to the fixed fee being above marginal cost. However, we have

$$-\left[p - C_Q\right]\left[\frac{Q_N}{F}\right] < 0.$$

The first bracketed term, $p - C_Q$, was found positive above. Q_N is also positive, as the more users connected to a distribution grid, the more electricity will be demanded at a given price. Hence, we cannot show with certainty that the fixed fee exceeds connection cost, although we can expect that if the demand for connection is highly inelastic, as we might expect,[27] the positive term in equation (7) will dominate. The second bracketed term represents the complementarity effect described in the text.

[27] Anne-Marie Cuneo has pointed out that in Nevada, a grid connection is legally necessary to obtain a permit for occupancy of a residence.