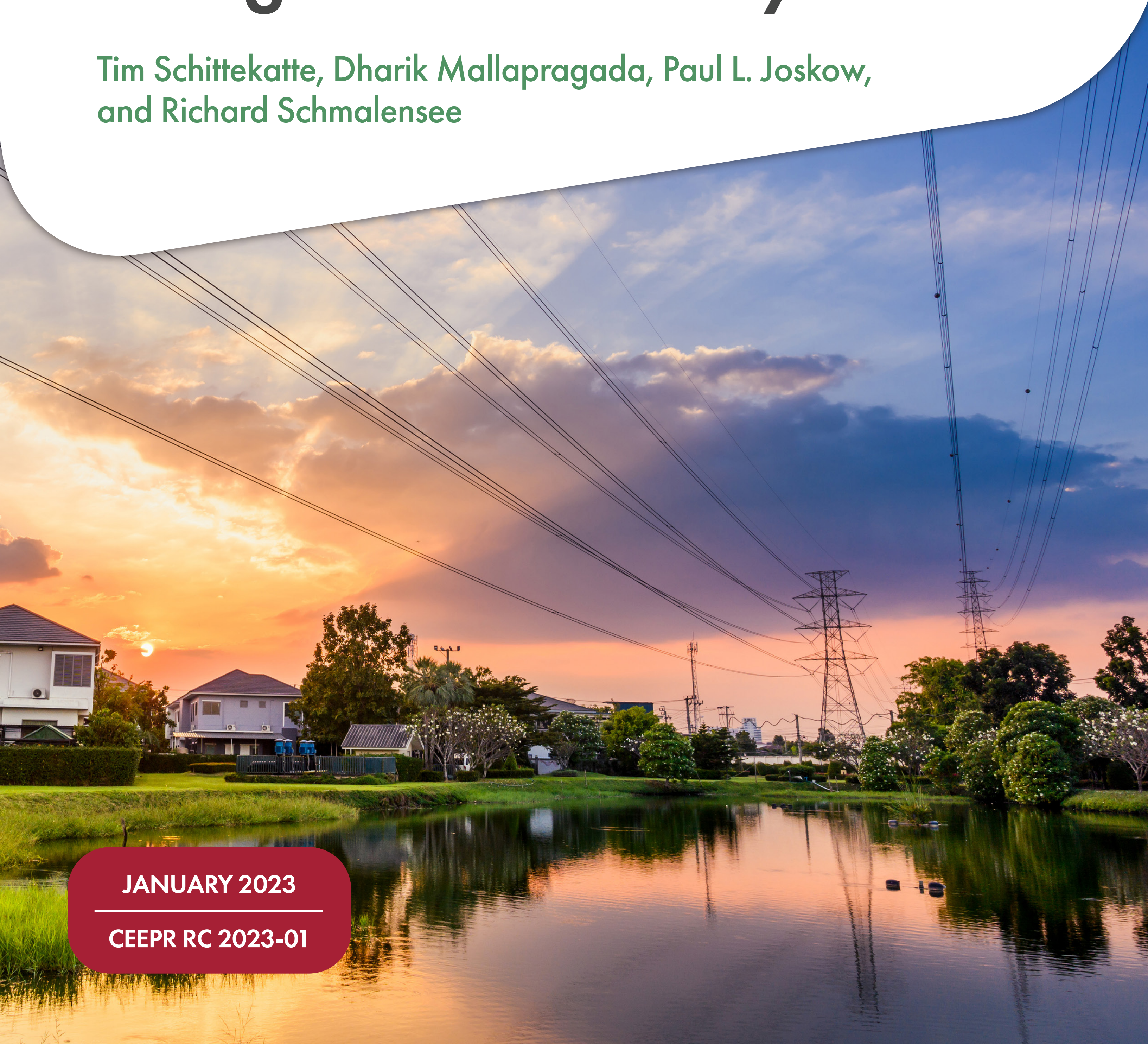
MIT Center for Energy and Environmental Policy Research

Research Commentary

Economy-Wide Decarbonization Requires Fixing Retail Electricity Rates

Tim Schittekatte, Dharik Mallapragada, Paul L. Joskow, and Richard Schmalensee



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RC-2023-01 Commentary

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Introduction

Reaching ambitious CO_2 emission-reduction targets will require substantially electrifying important energy-intensive sectors, while at the same time decarbonizing the electricity supply mix and thereby raising the cost of electricity. Recent economy-wide decarbonization studies, such as the IEA 'Net Zero by 2050 Scenario' (Figure 1) estimate that about 40% of 2020-2050 emission reductions will come from electrification, leading to more than a doubling of the share of electricity in final energy consumption by mid-century.[1] Absent fundamental reform of retail electricity rates, this massive transformation will be substantially more difficult than necessary.

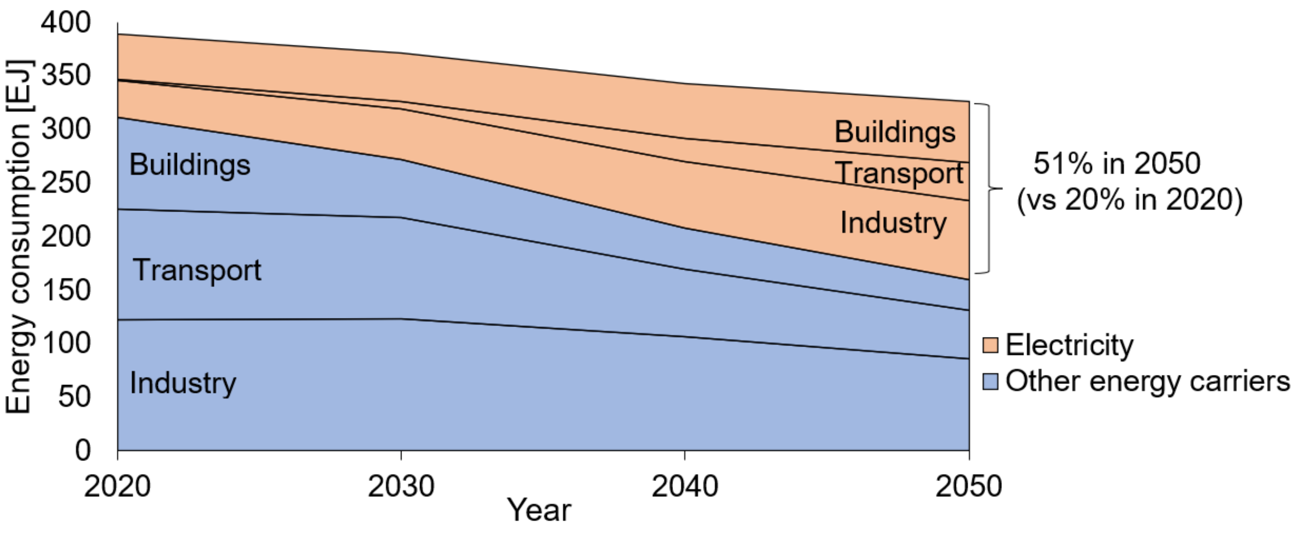


Figure 1. Evolution of the electrification per sector in the EIA's 2021 Net Zero Emissions by 2050 Scenario. Exclusion of "Other sectors" (representing 5.5% of energy consumption in 2020) as no breakdown per energy carrier is provided.

Historically, electric meters of residential and small commercial customers could only record total consumption between readings, which as a practical matter were infrequent (often monthly). Electricity was priced on an almost flat volumetric rate, i.e., a constant price per kWh of electric energy consumed, determining most of the bill, plus a small fixed charge ($/connection). Very roughly, the volumetric price was determined by dividing the total costs the utility had to cover in some period – including fuel for current generation and charges (such as interest on debt) related to past investment in generation, transmission and distribution – by expected kWh demand in that period. Regimes of this basic sort still dominate in the U.S., where only 7.3% of U.S. consumers are enrolled in alternative rate plans.[2] A similar situation prevails in most of the rest of the world.

This sort of retail pricing will discourage efficient electrification in two related ways. First, retail customers generally do not see the often-substantial hour-to-hour variation in the marginal cost of electricity supply, which is reflected in spot wholesale prices.[3] This means they have no incentive to reschedule demand to periods when the cost of electricity is lower than average. The inability to do this will make the total cost of utilizing electric technologies with load-shifting capability inefficiently high. This problem will grow as societies seek to increase the share of electric vehicles (EVs), perhaps the leading example of a technology with load-shifting capability, and HVAC systems based on heat pumps.

The increased penetration of advanced meters has recently made it possible to implement rate plans with time-varying prices by lowering the costs of recording consumption with high frequency (e.g. hourly) and with communications capabilities that would support load control options, so that this problem is in principle soluble economically. As of 2021, there were over 111 million advanced meters with these capabilities installed in residential (97 million) and commercial (13 million) locations in the U.S.[4] Only a small fraction of these meters are presently being used to support more effective retail rates of the type we discuss here.

The second reason that traditional rate designs discourage electrification is the way that investment-related charges (as well as utility costs incurred to support social programs such as subsidies for energy efficiency programs) are reflected in electricity prices. In the short run, capital costs are, by definition, fixed and do not vary with instantaneous variations in consumption. Thus, volumetric electricity prices that include fixed costs are too high to provide good short-run price signals and inefficiently discourage electrification. For example, Borenstein and Bushnell estimate short-run marginal generation costs over 2014–2016 by utility-state in the U.S. and find that these costs average around only one-third of average volumetric rates.[5]

This does not mean that consumers are paying too much for electricity, however. If the average volumetric rates at retail were reduced to around the average marginal cost of supplying power, utilities' revenues would fail to cover the significant fraction of their total cost that reflects historical investments in transmission and distribution capacity. Moreover, in the longer run, additional investments in network capacity will be required to serve growing electricity demand, and the incremental capital costs involved may well be higher than the historical costs reflected in today's retail rates. Electricity consumers need to cover network capacity costs, but in order to maintain incentives for electrification, this should not be done via inefficiently high volumetric rates. Rather, there is a need for substantially higher capacity charges, unrelated to current kWh consumption but linked to impacts on future network investment costs. We discuss below how charges for network investment costs of this sort might be set equitably while encouraging efficient behavior.

Here, we make the case for urgent action to reform retail electricity rates so that they that encourage, rather than work against, cost-efficient electrification while not ignoring considerations related to equity, complexity, consumer acceptability, and the recovery of reasonable costs incurred by utilities. We do not propose a single optimal solution for all situations, but rather we have identified particularly promising directions of reform. We now discuss in turn potential solutions to the two problems identified above.

Problem 1: Most volumetric rates do not mirror hourly variations in marginal cost.

Figure 2 provides data on wholesale prices in Texas (ERCOT) and California (CAISO), two systems with relatively high penetration of intermittent renewable generation. The top panels show hourly wholesale prices for 2012 to 2020, and the bottom panels show and more detailed average wholesale price patterns by hour. The Figure shows that wholesale prices can vary substantially from one hour to another. We can see from the top panels that there are a few hours each year with very high prices, signaling system stress conditions during which demand reductions are extremely valuable. We can see from the bottom panels that within the day, there are fairly consistent price patterns indicating when it is relatively more or less costly to the system as a whole to use electricity.

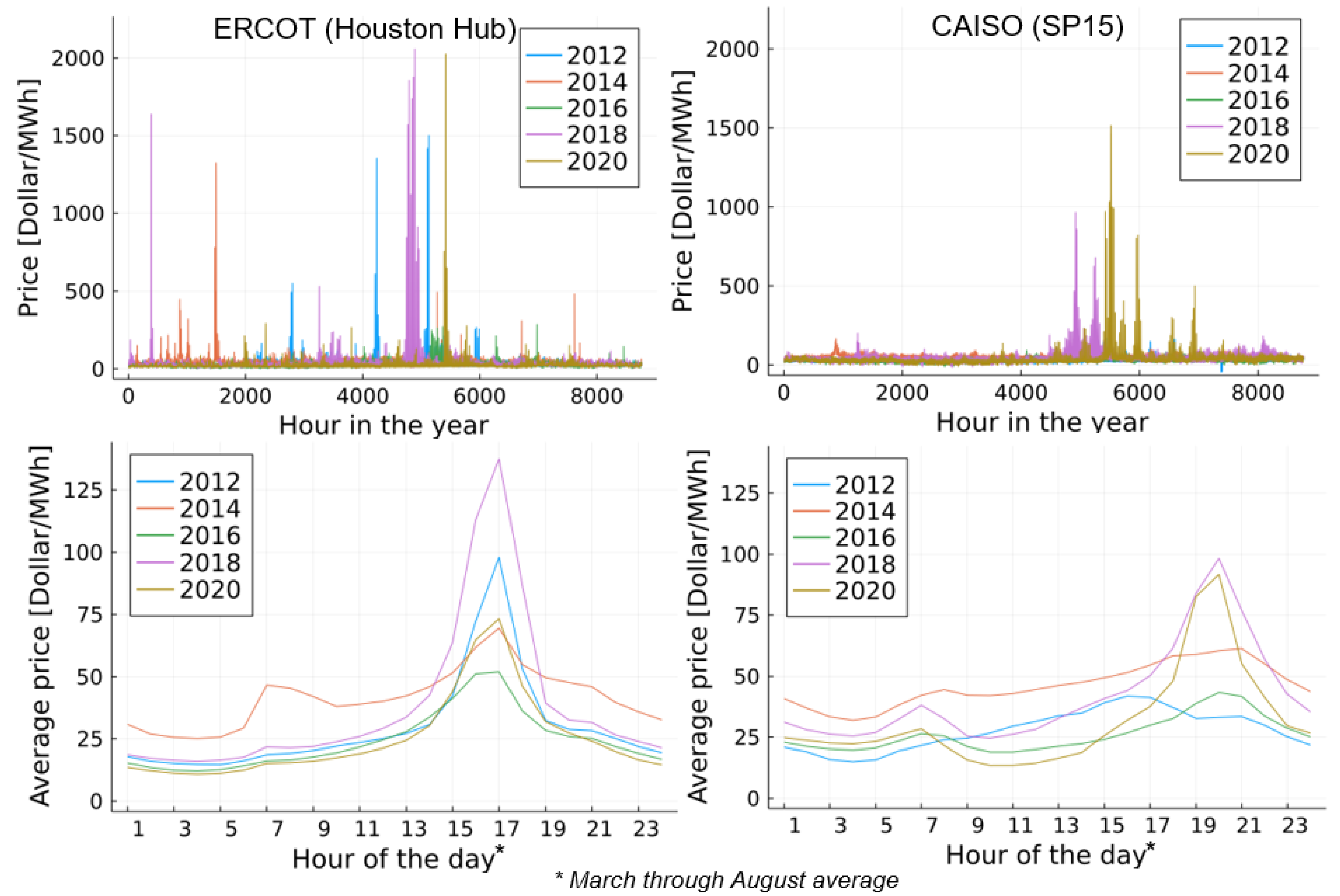


Figure 2. Top- Day-ahead price series for the Houston Hub in ERCOT (left) and SP15 in CAISO (right) for selected years, down-averaged daily day-ahead prices in CAISO from March through August for the same systems and years.

As power systems decarbonize, relying heavily on wind and solar generation that have zero marginal cost, wholesale spot prices are expected to become more volatile, with more hours of very high prices and many more hours of very low prices.[3] The efficiency cost of time-invariant volumetric rates, which provide no incentives for shifting demand to periods when marginal cost is low, will accordingly increase – and increase substantially as the importance of demand from EV charging and other sources of shiftable demand increases. The Econ 101 reform would be to charge consumers wholesale spot prices, adjusted if necessary for transmission and distribution losses. While advanced meters have made such real-time pricing (RTP) widely feasible today, however, RTP is not popular.

One reason for their unpopularity is that optimization takes consumer effort, and electricity typically only represents a small percentage of household spending in wealthy nations. Thus, the benefits from frequently reacting to price information might rarely be worth the effort involved. On the other hand, failure to pay attention can occasionally be very costly. The business model of Griddy, a Texas retailer, was based on RTP, leading, most of the time, to low bills even if consumers didn't react to price changes. In February, 2021, however, wholesale spot prices in ERCOT were at their maximum for four straight days. When the crisis hit, Griddy urged its 29,000 customers to switch to alternative suppliers with fixed, lower rates, but only 9,000 did so. In May, the Texas legislature outlawed RTP.[6] Not only will increased spot price volatility mean that the efficiency costs of time-invariant rates will grow, but after Griddy, RTP will be even less attractive than before because of higher perceived bill risk.

Popular "second-best" rate designs that embody some of the time-varying nature of spot prices are time of use (TOU) rates and critical peak pricing (CPP). TOU rates are predefined, e.g., at least a year ahead, and calibrated on historical price data. Typically, TOU rates differ by season, type of day (workdays or weekends), and/or time of the day (e.g., peak, shoulder, or off-peak). CPP provides extra incentives to reduce consumption during a handful of hours with the highest wholesale prices. An alternative to CPP is for consumers to agree for an ex-ante bill credit to allow for remote load control (that they can override at a cost) during CPP events, giving the load-serving entity the ability to cut customer utilization when system capacity is heavily stressed. These programs, when in place, are generally well-subscribed in U.S. jurisdictions. For example, many U.S. utilities offer air conditioning (AC) cycling options that give the utility to ability to cycle the customers AC for a maximum number of days and hours per day during the summer when demand peaks on very hot days in most of the U.S.

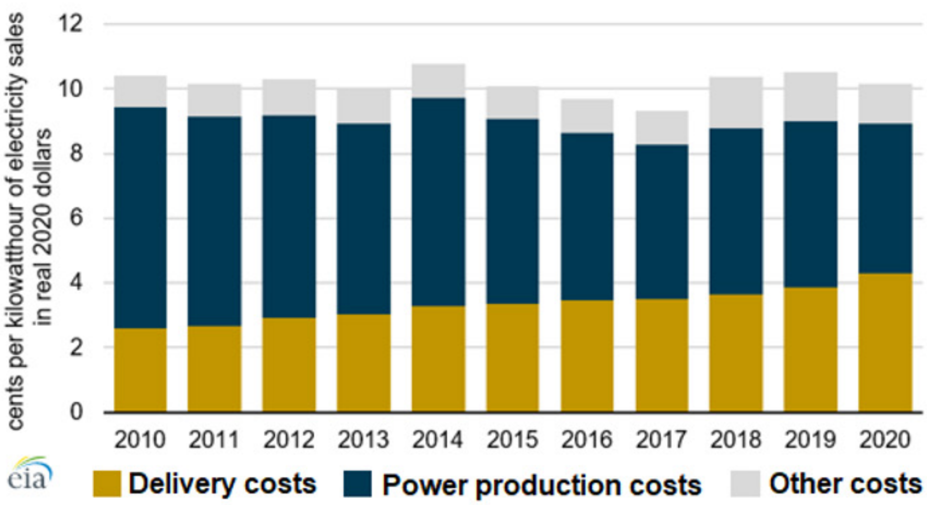
Most of the existing academic literature has been skeptical about TOU rates, typically finding that they capture only about one-fifth of the efficiency gains that would be produced by RTP on an hourly basis with alert consumers.[7] This literature mostly focused on demand characterized by independent hourly demand functions and thermal-dominated generation. In recent work, we introduce alternative assessment criteria that are tailored to a context with high volumes of intra-day shiftable loads.[8] Using historical data from three U.S. markets, we find that while TOU rates are obviously not good at predicting scarcity events or absolute spot price levels, they are reasonably good at predicting within-day relative price differences. If TOU rates are adjusted relatively infrequently, consumers should be able to develop efficient usage habits, especially taking advantage of intra-day load shifting opportunities based on relative price differences.

Considering these recent results and the simplicity and low bill risk that makes TOU rate designs more attractive than RTP to risk averse consumers, we recommend the acceleration of the wider adoption of TOU rates, especially when accompanied by a CPP program built around load control options. While TOU rates are currently not widely adopted in the U.S., they are increasingly available as an option, and the Public Utility Commission of Hawaii recently announced the first-in-the-nation state-wide plan to introduce mandatory TOU rates for most customers.[9]

In the longer run, barriers to the widespread adoption of RTP may not be insurmountable: the lack of predictability can be mitigated as consumers acquire appliances that include communications and control capabilities that facilitate a high degree of automation in electricity consumption, and bill stability can be guaranteed by complementing spot pricing with hedging or insurance products.

Problem 2: On average, volumetric rates substantially exceed short-run marginal costs.

The left panel in Figure 3 shows the evolution of spending categories of major U.S. utilities between 2010 and 2020. The right panel displays an anonymized bill of a residential consumer in Cambridge, Massachusetts for October, 2022. Nearly all the costs incurred by the utility are passed through via volumetric rates in the bill. The total volumetric rate amounts to 0.32 \$/kWh. This is nearly twice the charge for generation (0.18 \$/kWh), which in turn is higher than typical prices in the relevant wholesale spot market (Boston Hub within ISO New England).



Service from 10/11/22 - 10/24/22			13 Days	
Meter Number	Current Read	Previous Read	Current Usage	Reading Type
X	75964	75891	73	Actual

Total Charges for Electricity		
Supplier (Eversource) (Basic Svc Fixed)		
Generation Service Charge	73 kWh X .17871	\$13.05
Subtotal Supplier Services		\$13.05
Delivery		
(Rate 01 R1 RESIDENTIAL)		
Customer Charge (Prorated)		\$3.03
Distribution Charge	73 kWh X .07147	\$5.22
Transition Charge	73 kWh X -.00177	-\$0.13
Transmission Charge	73 kWh X .04437	\$3.24
Revenue Decoupling Charge	73 kWh X .00267	\$0.19
Distributed Solar Charge	73 kWh X .00341	\$0.25
Renewable Energy Charge	73 kWh X .00050	\$0.04
Energy Efficiency	73 kWh X .02254	\$1.65
Subtotal Delivery Services		\$13.49
Total Cost of Electricity		**\$26.54**

Figure 3. Left: Breakdown of major U.S. utilities annual spending by category.[10]
Right: Anonymized bill of residential consumer supplied between 10/11/2022 and 10/24/2022 by Eversource in Cambridge, MA.

Short-run marginal cost is typically below average total cost because the need for transmission, distribution, and generation capacity is not driven by short-run changes in energy consumption (kWh) but by sustained increases in instantaneous customer demand for power (kW) that in the longer run by lead to additional investments in network capacity. In this case, the necessary reform is to lower the average volumetric rate closer to average marginal cost and to increase fixed charges so that the utility's total costs are covered. This sort of reform raises two new issues, however, one related to fairness and another related to long-run efficiency.

In the interest of fairness, Borenstein and co-authors propose to recover system costs that are fixed in the short run via fixed charges that differ among consumers and are tightly linked to ability to pay.[11] Individuals with similar incomes may derive very different benefits from being connected to the electric power system, however; compare a small luxury condo with a large remote villa. Fairness arguments are, as so often, not simple.

However, fixed charges of this sort that are independent of all aspects of electricity consumption cannot provide any incentives for consumers to reduce the need for future investment in network capacity – by, for instance, smoothing usage so their peak demand is reduced. The left panel in Figure 3 shows that network costs have been rising, and we expect this trend to continue due to increases in demand resulting from electrification. To provide incentives to reduce the need for investment, the authors of the *MIT Utility of the Future Study* propose to rely heavily on individualized capacity charges (in \$/kW).[12] In theory, each individual customer's capacity charge would reflect the impact of increases in her peak kW demand on the need for future investment in system capacity. Besides the technical challenges involved in computing theoretically correct consumer-specific capacity charges, serious issues of fairness would arise and would conflict with the long-standing regulatory principle of charging the same prices to all consumers in a rate class on a particular transmission and distribution network.

Nonetheless, we believe it is possible to link capacity charges approximately to pressures on investment in system capacity without raising intractable equity issues. Policies of this sort might resemble systems in Spain and some other nations,[13] where consumers in specific geographic areas pay for maximum kW usage in particular time slots. Capacity might be free during the night for the whole year, for instance, while the price per kW might be very high during peak hour periods in the high demand season. Consumers' maximum kW usage is surely positively related to their ability to pay and to the benefits they derive from the power system. This basic approach, tailored to system-specific conditions, seems to us a reasonable compromise between the provision of economic incentives, simplicity, and equity.

Conclusions and a call for action

Getting electricity retail rates right is crucial to affordable and cost-effective economy-wide electrification, which in turn is essential to reaching declared climate goals. As we have shown, current almost entirely time-invariant, volumetrically based electricity rates will make electrification slower and more expensive than it should be. We have shown the general directions reform must take to mitigate this problem, recognizing that the optimal details are likely to differ regionally. This Commentary is a call for action to accelerate research on retail electricity rate design and on deployment of systems that will facilitate rather than hinder economy-wide decarbonization.

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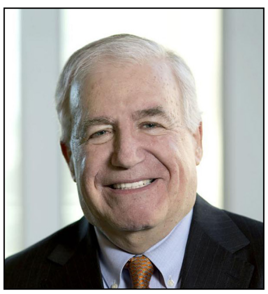
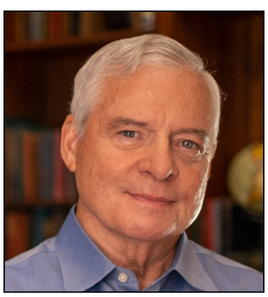
About the Authors

Tim Schittekatte is a Research Scientist at MIT and joined the MIT Energy Initiative (MITEI) in October 2021. At MIT, he conducts research and teaches about power market design and regulation. Prior to joining MIT, he was a research fellow at the Florence School of Regulation (FSR) at the European University Institute (EUI) where he is now also a part-time Assistant Professor. He graduated as an engineer from Ghent University, Belgium and completed the EMIN program, an international master in economics. He holds a Ph.D. in energy economics from University Paris-Sud XI.

Dharik Mallapragada is a Principal Research Scientist at MIT and joined the MIT Energy Initiative in May 2018. Through his Ph.D. and nearly five years of research experience in the chemicals and energy industry, Dharik has worked on a range of sustainability-focused research topics, as well as developing novel tools for energy systems analysis. At MIT, Dharik is working on advancing power systems modeling tools to study questions around renewables integration and economy-wide electrification. Dharik holds a M.S. and Ph.D. in Chemical Engineering from Purdue University. He received a B.Sc. in Chemical Engineering from the Indian Institute of Technology, Madras.



Paul L. Joskow is the Elizabeth and James Killian Professor of Economics, Emeritus, at the Massachusetts Institute of Technology (MIT) where he joined the faculty in 1972. He has served as the Chairman of the Department of Economics and as the Director of the Center for Energy and Environmental Policy Research. From 2008 to 2017, he was the President of the Alfred P. Sloan Foundation. He is a Fellow of the American Academy of Arts and Sciences and the Econometric Society, and a Distinguished Fellow of the American Economic Association and of the Industrial Organization Society. He has published widely on topics in industrial organization, energy economics, electricity markets, and government regulation.



Richard Schmalensee is Professor of Economics, Emeritus and the Howard W. Johnson Professor of Management, Emeritus at the Massachusetts Institute of Technology (MIT) and served for nine years as the Dean of the MIT Sloan School of Management. He was a member of the President's Council of Economic Advisers from 1989 through 1991 and served for 12 years as Director of the MIT Center for Energy and Environmental Policy Research. He is a Fellow of the Econometric Society, a Member of the American Academy of Arts and Sciences, and Member of the Executive Committee of the National Bureau of Economic Research.

Contact.

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