Two Prices for the Same Kilowatt-Hour: Distortions in Residential and Non-Residential Tariffs in the US

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1 Motivation and research question

Regulated electricity tariffs in the US set widely varying marginal prices for the same kilowatt-hour depending on who buys it. A single utility can have dozens of rate schedules split by customer size, voltage, load factor, and time-of-use option. As a result, two customers connecting at the same voltage on the same distribution system can face marginal prices that differ by more than half. The boundaries between customer classes reflect the history of regulator rate cases more than any difference in the cost of serving those customers.

An accurate characterization of electricity tariffs in the US matters more now than ever. Electrification decisions, from heat pumps and electric vehicles to new large loads, are being made based on these schedules. At the same time, customer-level storage and generation are blurring the historical distinctions between customer classes. If both residential and non-residential prices are far from social marginal cost, a joint redesign will be required to set the correct marginal incentives while ensuring overall cost recovery.

In this paper, we will measure, for US utilities, the wedge between the marginal price of a kWh and social marginal cost within major customer classes, as well as the marginal price wedges between classes. The motivation for this paper is the same as in McRae and Wolak (2021), but expanded beyond the residential sector and applied to utilities in the United States. We focus on three questions:

1. How far apart are residential and non-residential marginal prices for customers served at the same voltage from the same network?
2. How far is each marginal price from social marginal cost, which includes energy, losses and environmental costs?
3. How much of the distortion could be removed by consolidating rate classes and moving fixed-cost recovery out of the per-kWh price?

Most existing work on electricity tariff distortions in the US focuses on the residential sector. Borenstein and Bushnell (2022) show that residential prices exceed social marginal cost across much of the US, but they note that they "have not studied commercial and industrial rates, which are more complex, with greater use of time-varying pricing that determine (and distort) customer incentives." We build on Borenstein and Bushnell (2022) in two directions. First, we measure marginal prices from the tariff sheets themselves rather than from average variable revenue, which hides blocks, seasons, and riders. Second, we extend their analysis to commercial and industrial classes, where the greater tariff complexity makes average revenue an even worse proxy for the marginal price.

This paper will be the first to quantify the tariff distortions across customer classes in the US. While Borenstein (2016) discusses the options for utility fixed cost recovery, most empirical work has concentrated on the residential sector, including both how customers respond to nonlinear prices (Ito, 2014) and the distributional effects of alternative rate designs (Borenstein et al., 2021; Burger et al., 2020). The small empirical literature on the non-residential sector studies how firms respond to time-varying prices (Jessoe and Rapson, 2015; Blonz, 2022) rather than comparing these prices to marginal costs or the prices faced by other customer classes.

Non-residential tariffs have been understudied until now because of cost. Commercial and industrial rates are spread across thousands of utility-specific PDFs with different layouts, rider structures and effective dates, while

revenue by rate schedule sits in FERC Form 1 under inconsistent schedule names. Agentic AI tools make it feasible to collate these data. They can read tariff sheets, extract rate components into a common structure and write the reconstruction code. The revenue match against FERC and EIA data provides a cross-check on the accuracy of the imported data.

2 Methodology

We start with the utilities for which the fewest assumptions are needed: vertically integrated investor-owned utilities in states without retail choice. For these utilities, nearly all customers receive bundled service under a single regulated tariff, and the utility files revenue and sales by rate schedule in FERC Form 1. There are about 60 such utilities with annual sales above 5 TWh, serving roughly 37 percent of US retail electricity sales. Follow-up work will extend this sample to utilities in restructured states (where the delivery tariff is regulated but the energy component is set separately) and to municipal utilities and cooperatives (for which only revenue by customer class is available). For every utility we cover two tariff years, 2019 and 2025, and the standard residential schedule, the small and large general-service schedules, the main industrial schedule and their time-of-use variants.

For each utility, the analysis has four steps:

1. **Collect and structure tariffs.** Gather the tariff sheets in force for each utility and year: base energy and customer charges, seasonal and block structures, time-of-use options, and the riders (fuel, environmental, energy efficiency) and franchise fees layered on top. Tariff sheets are PDFs with inconsistent layouts. We will use AI-assisted extraction with human checks on a validation sample. We start from the NREL Utility Rate Database for those utilities where its coverage is complete.
2. **Reconstruct revenue and validate.** For each schedule, rebuild billed revenue from the tariff components and compare it with revenue, sales and customer counts by rate schedule in FERC Form 1 (Schedule 304) and with monthly sales in EIA-861M. A residual of a few percent (attributable to franchise fees and discounts) is the test that the tariff extraction is correct.
3. **Compute marginal prices.** Derive the price of an additional kWh by class, month and hour, including riders, using load-research or ResStock/ComStock load shapes to weight customers across blocks. Results will be reported with sensitivities to the assumed spread of customer use.
4. **Compare with social marginal cost.** We follow Borenstein and Bushnell (2022) for marginal energy cost (locational marginal prices where the utility is in an ISO, system lambda from FERC Form 714 elsewhere, adjusted for marginal losses) and for marginal emissions damages. The wedge is the marginal price minus this cost.

The output is a panel of wedges by utility, class, month and hour, together with a decomposition of each marginal price into energy, fixed-cost recovery and rider components.

3 Illustrative example: Georgia Power, residential versus small business, 2025

In an AI-assisted extraction pilot, we rebuilt 2025 revenue for Georgia Power's standard residential tariff (R) and standard small-business tariff (GS) from the tariff sheets and checked it against FERC Form 1 revenue by rate schedule. The reconstruction leaves a residual of 2.6% of the pre-fee bill for GS and 1.6% for R, within the 1.2–3.1% range of municipal franchise fees.

Average revenue per kWh was 26.8 cents for GS and 17.0 cents for R. Both pay the same fuel charge, 4.3 cents in winter and 4.6 cents in summer, so the 9.8-cent gap is all non-fuel cost recovery. Of that gap, 4.3 cents is GS's larger fixed charge ($38 a month with riders, against $16) spread over 634 kWh a month instead of 946. Fixed charges do not distort consumption at the margin. The other 5.5 cents is a gap in the marginal price. At most one of the two prices can equal marginal cost.

Three findings stand out (Table 1). First, the cross-class wedge is a winter one. For eight months of the year, covering 61% of residential kWh, a small business pays 6.9 cents (51%) more than a household for the same secondary-voltage kWh. In summer the usage-weighted residential price is close to the GS price. Both customers are served at secondary voltage from the same network, so only load timing and losses could justify a cost difference. Average residential use in January equals use in July, so household winter load is not obviously less peak-coincident than a shop's.

	GS		R			
	Oct–May	Jun–Sep	Oct–May	Jun–Sep, monthly use (kWh)		
Cents per kWh				0–650	651–1,000	>1,000
Marginal price	20.7	21.0	13.7	14.7	21.3	21.9
of which non-fuel	16.3	16.3	9.4	10.0	16.6	17.2

Table 1: Marginal price of a kWh at Georgia Power, 2025. Prices include the fuel rider (4.29 cents in October–May, 4.59 in June–September), environmental and energy-efficiency riders and an estimated franchise fee. Sources: FERC Form 1 Schedule 304; Georgia Power tariff sheets; Georgia PSC bill calculator; our calculations.

Second, prices follow quantity and season, not the hour. The residential summer blocks raise the marginal price by 6.6 cents at the 651st kWh of the month, whatever hour it is used. A kWh at 3 a.m. in August costs a large household 21.9 cents and a small one 14.7 cents.

Third, most fixed costs are recovered per kWh. GS's basic charge covers only 22% of the average bill, and there is no demand charge, so all other non-fuel costs are recovered through the 13.84-cent base energy rate and the percentage riders on it. Of the 20.7-cent marginal price, 16.3 cents is non-fuel. The fuel rider is the only component tied to energy cost, and it is a seasonal average, not an hourly marginal cost. Whether the non-fuel markup is a distortion depends on hourly marginal energy cost and emissions damages, which is step 4 of Section 2.

4 Policy relevance

Residential tariff distortions are well documented and the remedies are well known: marginal prices close to hourly social marginal cost and fixed costs recovered through fixed charges (Borenstein and Bushnell, 2022; Burger et al., 2020). The non-residential classes have had no such treatment in the literature, despite buying the same product from the same wires.

Understanding how far each class's marginal price is from cost, and how far the classes are from each other, matters for reform. If a small business pays 51% more than a household for the same winter kWh, with no obvious cost difference, the split between classes is hard to defend. Consolidating classes, pricing the marginal kWh at hourly social marginal cost, and recovering fixed costs through fixed charges would address the problem. The counterfactual tariffs we build will show who gains and loses under each design. Electrification is being priced through these same schedules now, and rate cases are deciding which class pays for new load without systematic evidence on what each class pays today. This paper will provide that evidence.

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