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# Disaggregating growth in future retail electricity rates

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ABSTRACT

The retail rate impacts of a number of emerging trends (e.g., rapid deployment of electric vehicles and storage, transmission build-out for large-scale renewables deployment, and grid modernization) are unknown. Importantly, decision-makers are concerned about the potential future rate impacts on energy affordability and equity. We disaggregate the key drivers of retail electricity rates and assess their impacts on future rate growth considering their interactions and uncertainty. Specifically, we develop ranges of future cost growth for a generic investor-owned and vertically-integrated electric utility representing typical cost and operating characteristics. The rate driver growth rate ranges are applied in isolation and jointly to quantify the uncertainty and variability in future retail electricity rates. The results identify what rate drivers and factors may minimize and/or decrease uncertainty in retail rate growth and their linkages to industry trends.

## 1. Introduction

A number of emerging trends in the electric industry have the potential to impact future retail electricity rates. At present, 36 states are pursuing some form of grid modernization proceeding that promote investment in advanced grid technologies (NCCETC, 2021). System cost declines coupled with state and federal incentive programs are helping to drive increased penetration levels of a number of different distributed energy resources (Barbose et al., 2021), which have affected utility incurred costs to ensure safe and reliable electricity delivery (Cohen et al., 2016; Flinn and Webber, 2017). Electric vehicle production has exponentially increased in recent years and now represents more than 3% of all cars manufactured in the U.S. (EPA, 2021). A number of industry publications are predicting that these trends will continue (EIA, 2021; Cole et al., 2019), which could result in dramatic increases in utility costs as well as net energy sales and peak demand to accommodate transportation electrification.

Decision-makers are concerned about the potential future rate impacts of these and other industry trends on energy affordability and equity. However, prior research efforts to better understand past, present, and future rate impacts have been somewhat limited in their scope. Some researchers have sought to better understand the historical effects of specific policies, like restructuring of the retail commodity market (Fagan, 2006; Fabrizio et al., 2007; Kwoka, 2008; Su, 2015; Zarnikau and Whitworth, 2006; Swadley and Yücel, 2011; Apt, 2005), renewable portfolio standards (Wang, 2016; Upton and Snyder, 2017; Tra, 2016; Heeter et al., 2013), or both (Morey and Kirsch, 2013). Others have chosen to characterize recent trends in specific drivers of retail rates, like utility-incurred operating costs (Fares and King, 2017) or capital investments (EIA, 2014a, 2014b, 214c, 214d). Third, researchers have attempted to forecast specific rate drivers, like capital expenditure (CapEx) needs through scenario-based capacity expansion modeling (EIA, 2021; Cole et al., 2019) or to explore the inter-relationships of competing alternatives (Jayadev et al., 2020). These approaches lack a more robust and nuanced understanding of the key drivers of retail rates, specifically their interactions with and uncertainty of future rate growth.

To fill this gap in the literature, we explored how the variability and contributions of individual rate drivers affect future rate growth. Specifically, we develop forward-looking estimates of the range in growth rates for key cost-related and non-cost-related rate drivers to better understand how they could affect retail rate growth for a generic U.S. investor-owned and vertically integrated utility. This analysis is not tied to any specific policy or technology that might affect these key drivers in the future. Instead, we focus on the likely range in those key rate drivers, without making any assumptions about what may cause them to be at one point or another in that range. To that end, our analysis describes the connections and relationships that exist between the change in these rate drivers and the consequent growth in retail rates.

The remainder of this article is organized as follows. In Section 2, we provide details on the approach and key assumptions made in our analysis. Section 3 presents and compares results. Section 4 concludes

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with our main takeaways from the analysis.

## 2. Approach and key assumptions

In this analysis, we characterized a generic U.S. investor-owned and vertically-integrated electric utility representing industry-average costs using historic FERC Form 1 data. We collected data for each of the cost-related (i.e., utilities' capital expenditures, non-fuel operations and maintenance (O&M) expenses, and fuel and purchased power costs) and non-cost-related (i.e., retail sales, peak demand, and customers) retail rate drivers from all U.S. electric utilities that reported FERC Form 1 for the historical period of 2008–2019. Where applicable, we segmented the FERC Form 1 utility CapEx and non-fuel O&M cost data by generation, transmission, distribution, and (all) other services. From this initial set of data, we used various quality assurance filters to down-select to a final sample of utility data.

We established starting year values from each utility's average 2019 retail sales, total customers, and total average fuel and purchased power cost values ($/MWh) (see Table 1). We derived the utility's starting year peak demand level based on a 56% annual load factor, which is the average among U.S. utility system load shapes based on EIA Form 930 data. Average CapEx and non-fuel O&M costs were normalized by customer counts (within their respective FERC Form 1 samples). The per-customer values were then multiplied by the starting year number of customers to derive starting year total budgets for these categories.

We also made several assumptions about the utility's financial characteristics. Specifically, we assumed a 56%:44% debt-to-equity ratio with a 4% debt service cost based on average values observed in the EEI 2019 Financial Review (EEI, 2020) and an authorized return on equity (ROE) of 9.65% based on the amount the typical U.S. electric utility received in 2019 as reported by S&P Global Market Intelligence (Fontanella, 2020). We assumed an accumulated deferred income tax (ADIT) value of 95% and average asset useful lifetime of 34 years, based on previous rate analyses using similar methods (see, e.g., (Cappers et al., 2019)).

In order to estimate future retail rates, we assumed compound annual growth rates (CAGRs) for each of the rate drivers and bounded them with a range of Low, Medium, and High values to characterize the potential variability (see Table 1). We first calculated three samples for each rate driver that corresponded to the respective Low, Medium, and High categories. Specifically, the average of the 2nd quintile (i.e., 20–40th percentile of utilities) represented the Low value, the average across all utilities in the sample was used to derive the Medium value (i.e., 50th percentile), and the average of the 4th quintile (i.e., 60–80th percentile) represented the High value. For each sample, we developed an annual 10-year sample-weighted moving average of the aggregate annual value and then developed annual growth rates for each year in the sample.[1] The 2019 10-year moving average growth rate for each sample was then assigned as the Low, Medium, and High CAGR. We then compared the Low, Medium, and High CAGRs to publicly available literature describing historical and future trends in each rate driver to inform whether the use of historical data for future projections was reasonable.[2]

**Table 1**
Starting year values and CAGR assumptions for rate drivers.

| Rate driver | 2019 Rev. Req. Value | Low CAGR | Medium CAGR | High CAGR |
|---|---|---|---|---|
| Generation (Gen) CapEx | $563 M | -5.3% | 4.7% | 8.4% |
| Transmission (Tx) CapEx | $298 M | 7.1% | 7.9% | 8.3% |
| Distribution (Dx) CapEx | $258 M | 6.1% | 7.1% | 7.9% |
| Other (Oth) CapEx | $79 M | 3.3% | 7.0% | 10.3% |
| Gen Non-Fuel O&M | $311 M | 0.0% | 0.9% | 3.1% |
| Tx O&M | $202 M | 3.4% | 5.1% | 7.5% |
| Dx O&M | $120 M | 1.8% | 3.5% | 4.4% |
| Oth O&M | $298 M | 0.5% | 1.5% | 3.7% |
| Fuel and Purchased Power | $36/MWh | -5.8% | -3.0% | 1.7% |
| Retail Sales* | 20,092 GW h | -0.2% | 0.3% | 1.7% |
| Customers* | 962,851 | -0.2% | 0.3% | 1.7% |
| Peak Demand* | 4072 MW | -0.2% | 0.3% | 1.7% |

* Retail sales and customers were strongly correlated (ρ = 0.94) in the FERC Form 1 dataset. Consequently, a constant use-per-customer was assumed over the entire analysis period. Since we also assumed a constant system load shape with a load factor of 56% that simply adjusted uniformly in all hours with changes in annual retail sales, all three non-cost-related rate drivers (i.e., retail sales, system peak, customers) were assigned identical CAGRs.

The Financial Impacts of Distributed Energy Resources (FINDER) pro forma financial model was used to quantify the utility's annual costs and revenues over the 10-year analysis period. For this analysis, the FINDER model calculated all costs and revenues at the total utility level and without allocation to individual rate classes. One of the first, and most important, steps in utility ratemaking is to determine the utility's annual revenue requirement. The revenue requirement is comprised of all the capitalized and expensed costs incurred by a utility in a given year. We mapped our rate drivers to the utility revenue requirement in two ways. First, expensed cost-related rate drivers (i.e., FPP and non-fuel O&M) mapped directly to corresponding revenue requirement elements each year. To derive values for 2020–2030, we applied the 2019 starting year value for FPP and each category of non-fuel O&M to the respective CAGR value. Second, capitalized cost-related rate drivers (i.e., CapEx) are associated with the utility's rate base that is inclusive of depreciation, equity return, debt service, and taxes. We allocated the utility's start of year rate base, based on normalized FERC Form 1 start-of-year plant-in-service data, to the four CapEx categories (i.e., generation, transmission, distribution, and other) based on each categories' share of starting year total CapEx budget. To derive annual rate base values for 2020–2030, we applied the 2019 starting year value for each category of rate base to the respective CAGR value. For each CapEx category, we derived the revenue requirement elements each year based on assumptions of typical utility depreciation schedules, capital structure, and federal and state tax rates, described above.

The utility's annual revenue requirement in this analysis, therefore, is the sum of all rate drivers and is divided by annual utility-level retail sales to derive an annual all-in average retail rate. Implicit in this calculation is the assumption that the utility files an annual general rate case using current test year data and implements this rate with no regulatory lag (i.e., perfect cost recovery). Although actual rate levels are impacted by infrequent rate cases, use of historic test years, and regulatory lag, these simplifying ratemaking assumptions should have little to no effect on the relative contribution of individual rate drivers in our analytical results. In contrast, our simplifying assumptions around capital expenditures (i.e., no optimization of least cost revenue requirement or minimum system costs), inclusion of all utility costs in the revenue requirement (i.e., no cost disallowances through regulatory decision), and development of rate driver growth ranges based on long-run historical trends for a large sample of utilities (i.e., regional or local historic or current cost trends can vary considerably), may over- or under-estimate the relative contributions of individual rate drivers depending on regional- or utility-specific conditions.

[1] Specifically, the sum of that particular driver across all utilities in the sample over a 10-year period ending at time *t* was divided by 10 to produce a sample-weighted 10-year average value at time *t*.

[2] Adjustments were made to the High CAGR for retail sales and customers to reflect national forecasts with load growth CAGRs that ranged from 1.5% to 2.0% (see, e.g., (Mai et al., 2018; Weiss et al., 2017)). High CAGR for FPP was adjusted to allow possible positive growth consistent with higher end EIA Annual Energy Outlook's 2019–2030 fuel cost forecasts in the 1.5–2.2% range (EIA, 2019).

## 3. Analytical results

### 3.1. Which rate drivers contribute the most to future retail rate growth?

Assuming all cost-related rate drivers continue to grow at their medium CAGR, the retail rate components with the highest CAGRs are associated with CapEx. Specifically, the rate component for transmission CapEx grows by 9.1%/year, for distribution CapEx by 8.7%/year, for other CapEx by 8.7%/year, and for generation CapEx by 7.7%/year (see Fig. 1).[3] O&M rate component growth is considerably smaller, ranging from 0.6%/year (generation) to 4.8% (transmission). However, these rate component increases are offset, in part, by modest FPP cost reductions (− 3.0%/year) (see Fig. 1).

Although FPP costs, generation CapEx, and generation O&M account for over half of the retail rate in 2020, rates in 2030 are predominantly comprised of generation, transmission, and distribution CapEx-related costs (see Fig. 2). The largest component of rates goes from fuel and purchased power (27% of total) in 2020 to generation CapEx (25% of total) in 2030. Interestingly, the second largest rate component is approximately 10% points smaller in both cases (i.e., generation CapEx (18%) in 2020 and transmission CapEx (16%) in 2030). Though the transmission CapEx rate driver grows on a compound annual basis by 9.1%/year, which is the highest CAGR of all rate drivers, its starting year value is considerably lower than generation CapEx, which represents only 10% of the total retail rate in 2020. This results in a modest increase (6% points) to its share of the total retail rate between 2020 and 2030. In contrast, the share of the FPP rate component drops by 13% points from 2020 to 2030 to become the fourth largest rate component. The other rate drivers produce relatively modest changes (i.e., 3% points or less) in their relative share.

### 3.2. How sensitive is future retail rate growth to variability in the growth of each rate driver, in isolation?

Future retail rate growth is highly uncertain and depends on variability of each rate driver. To better understand the uncertainty associated with each rate driver's potential effects on retail rate growth, we first explore variability in isolation. We ran the model iteratively with 100 random draws of an independent triangular distribution at the assumed Low, Medium, and High CAGR (see Fig. 1) for one rate driver at a time while holding all other rate drivers' CAGR constant at their Medium value. This produced a distribution of outcomes that represented the uncertainty associated with that single rate driver in isolation and, when normalized by the relative change in the growth in retail rates, quantified an elasticity for each rate driver (i.e., the percentage change in CAGR of rates between 2020 and 2030 per 1% change in the CAGR of the rate driver between 2020 and 2030).

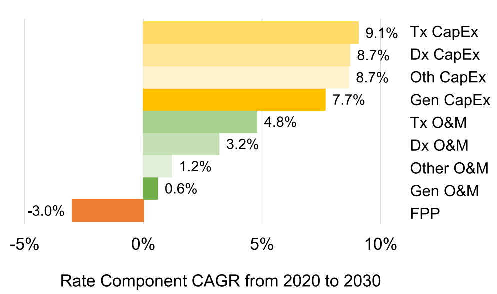


**Fig. 1.** Rate component CAGR from 2020 to 2030.

The rate driver with the largest elasticity (in absolute value) is sales, coincident peak demand, and customers (Sales-CP-Cust) (see Fig. 3). A one percent increase in the growth of this rate driver resulted in a 0.88–0.93% decrease in the growth of retail rates, holding all other rate drivers constant. Other than an increase in total FPP costs, which are driven by aggregate sales multiplied by the average FPP cost, there were no changes in the annual budgets for CapEx or non-fuel O&M. So any increase in sales growth, ceteris paribus, lowered average retail rates by spreading the utility's fixed costs over the larger sales base, almost on an equi-proporational basis.

On the cost side, a one percent reduction in the growth of either generation CapEx budgets ($) or fuel & purchased power costs ($/MWh) resulted in a 0.07–0.14% or 0.10–0.14% decrease in rate growth, respectively. This represents an order of magnitude difference in the absolute value of elasticities when compared to retail sales. Both of these cost drivers have fairly wide ranges in their elasticity values, while the rest of the cost-related rate drivers have considerably smaller and thus less variable elasticity values.

### 3.3. How sensitive is future retail rate growth to variability in the growth of all rate drivers, jointly?

In reality, there are feedback loops between the different cost-related and non-cost-related rate drivers that determine retail rate growth. For example, increases in sales and peak demand growth will likely create the need for additional CapEx by requiring new generation, transmission, and distribution infrastructure to serve new and growing load. In turn, additional utility investment will likely result in higher O&M expenses over time to support new capital projects. Therefore, the joint uncertainty in all rate drivers must be considered for a more complete picture of future rate growth.

Our joint uncertainty analysis used 100 random draws from all rate drivers' triangular distributions, while imposing correlations among the distributions. Spearman correlation coefficients were derived from a natural log transform for every FERC Form 1 data point, by rate driver, in our full sample (see Fig. 4).[4] We found that retail sales were highly positively correlated with distribution CapEx, distribution O&M, and other O&M, while retail sales were more modestly correlated with transmission CapEx, transmission O&M, and generation CapEx. Generally, there tended to be strong positive correlation across rate drivers of the same category (e.g., generation CapEx with generation O&M) and weaker correlation across categories of the same rate driver (e.g., generation CapEx vs. transmission CapEx). Finally, FPP costs ($/MWh) were poorly correlated with any other rate driver.

When variability was applied jointly to all rate drivers, generation CapEx remained the largest rate component but was also the most uncertain rate component (20–25% of total retail rate) (see Fig. 5).

[3] There are two factors that will alter the CAGR of the rate component relative to the CAGR for its associated cost-related rate driver. First, incurred capital expenditures are recovered via depreciation, debt service cost, return on equity, and any applicable taxes. However, each year's rate component includes not just the new CapEx but also all of the undepreciated CapEx associated with previous investments. Second, the costs eligible for recovery are divided by retail sales, which itself is changing over time. The combined growth effects of costs (numerator in the rate component calculation) and sales (denominator in the rate component calculation) results in a CAGR for each rate components that will differ from the CAGR for its associated cost-related rate driver.

[4] Both Spearman and Pearson methods for deriving correlation coefficients were applied first to untransformed data points, which resulted in different results. This suggests that the assumptions embodied in the Pearson method, that one is evaluating a linear relationship between two normally distributed variables, is rather weak. When the log transform of the data points was undertaken, the correlation coefficients produced were much more consistent. This supports the assumptions embodied in the Spearman method that the data elements have a non-linear relationship that are not normally distributed. As such, we elected to report and use the Spearman method applied to a natural log transformed dataset.

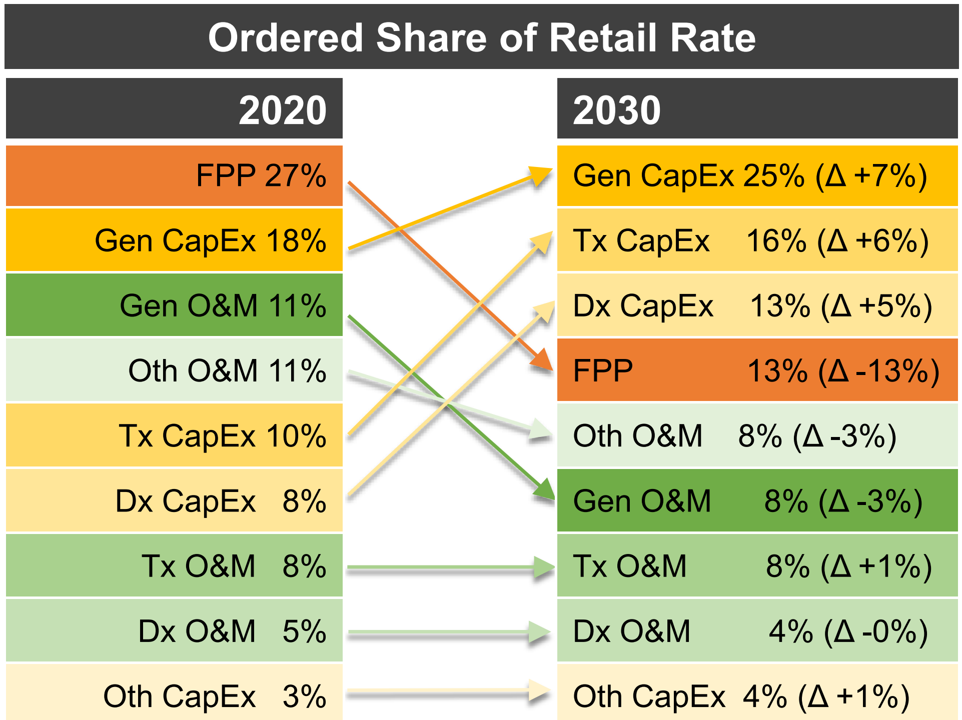


**Fig. 2.** Ordered share of retail rate in 2020 and 2030.

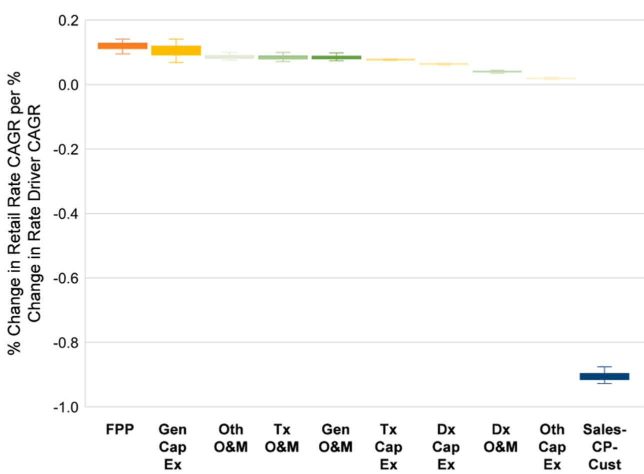


**Fig. 3.** Rate driver elasticity.

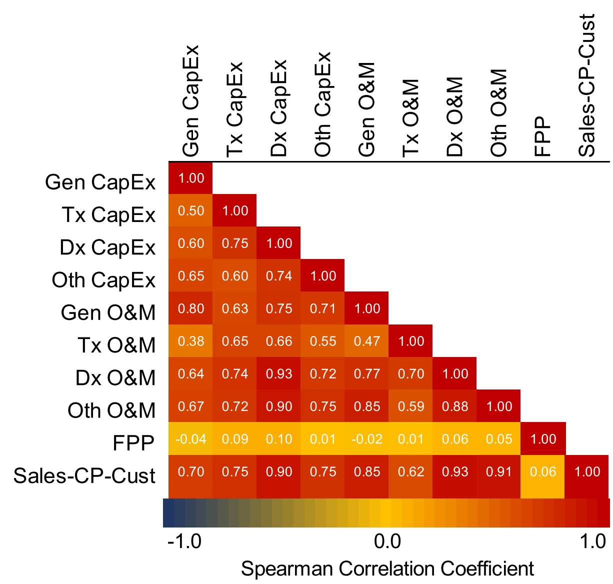


**Fig. 4.** Spearman correlation coefficients amongst rate driver growth.

Transmission CapEx comprised between 14% and 17% of the total retail rate, while distribution CapEx as well as FPP costs were between 11% and 15%.

## 4. Discussion and conclusions

We disaggregated retail rates into cost- and non-cost-related drivers and found through deterministic and stochastic analysis that generation CapEx costs, FPP costs, and retail sales are the most significant drivers that impact future retail electricity rate growth. Our analytical results suggest a number of factors that could minimize future retail rate growth and/or decrease its uncertainty.

First, higher growth in retail sales likely has the biggest potential to mitigate retail rate growth. This rate driver had nearly a unitary elasticity (0.88–0.93), whereby the percentage change in retail sales growth produces a very similarly sized percentage change of the opposite direction in retail rate growth, assuming there is no feedback effect. Since a number of utility costs are positively and strongly correlated with sales, peak demand, or customer growth ($r = \sim 0.6$–$0.9$), expanding the growth in these non-cost-related rate drivers will also likely increase the growth in certain types of utility incurred costs. Industry experience suggests managing the peak demand impacts associated with load expansion is key to mitigating the cost implications. So, policies that promote increased electricity consumption that incorporates demand management strategies, like electrification of space heating and transportation that promote improvements in system load factor, could be a driving force in slowing the growth in retail rates and reducing its future uncertainty.

Second, managing growth in generation CapEx could also be

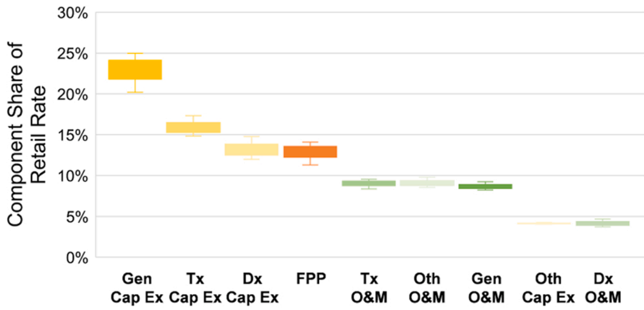


**Fig. 5.** Share of the full retail rate by component * Ordering based on the magnitude of the median component share of retail rate.

impactful. Generation CapEx is expected to be the biggest and the most uncertain share (20–25%) of retail rates by 2030. Although the rate elasticity for generation CapEx is only 0.10–0.14, it is still is one of the three most effective ways to manage the growth in rates. System planning experience as well as our correlation analysis results indicate by slowing the growth in peak demand, the growth in utility-incurred generation CapEx can also be reduced. This feedback effect can help mitigate and manage the level and uncertainty in the growth of average retail rates.

Third, FPP costs have the highest level of elasticity. As such, decreasing levels of FPP costs would decrease volatility of future retail rates. Since the majority of utility-scale renewable energy resources have no fuel costs to speak of, increased deployment could continue to drive down future impacts of FPP costs on retail rates. Generation costs for fossil plants, on the other hand, are subject to global market fluctuations in fuel prices. Most utilities pass these volatile costs directly onto their customers. Thus, rate components associated with fuel and purchased power costs should become more stable through policies and practices that result in the replacement of non-zero marginal cost generation resources with those having zero marginal costs.

Together, these observations suggest that reducing levels and volatility of future retail rates could be achieved via increased retail sales, decreased generation CapEx, and smaller FPP costs. Various interactions may come into play when trying to implement these changes. For example, increased electrification of heating and transportation will increase retail sales. However, to ensure that this does not increase peak demand at the same level, efforts to improve load factor will be necessary. This may involve various strategies that could include changes in retail rate design to manage peak demand, incentive-based programs targeting peak demand reduction, resource planning to ensure a portfolio of flexible resources, and/or others. Further, electrification while maintaining the same generation mix will likely result in higher FPP costs alone due to higher utilization. As such, increasing retail sales while maintaining low FPP costs will likely entail pairing electrification with decarbonization- both increasing built renewable capacity as well as increasing renewable utilization via wires or storage strategies. With any strategy, it will be important to understand the consequent impacts on ratepayers, with special attention paid to vulnerable populations.

The results have implications for decision makers engaged in assessing retail rate impacts. Deterministic methods are the most commonly employed among utilities, regulators, and other stakeholders for rate impact calculations, including to determine the rate impacts in a general rate case proceeding (e.g., a percentage increase or decrease in a typical customer bill) and impacts from distributed energy resources (e.g., an increase or decrease in the average all-in retail rate). But, stochastic analysis that factors in the relationships of and uncertainty in rate drivers can help prioritize actions. For example, one possible conclusion from our deterministic analysis is that FPP costs are not a significant driver of future retail rates (i.e., a 13% reduction in FPP cost's share of retail rates). The stochastic analysis assessing variability of rate drivers in isolation, however, concluded that FPP costs were one of the more uncertain rate drivers and warrant attention.

Therefore, absolute rate or bill impacts may be less important than the ordering of rate drivers and relationships to one another in the context of identifying actions to address future rate growth. Whether or not retail rate impacts manifest will come down to policies and decisions, largely at the state-level given their purview of retail electricity markets, that mitigate or exacerbate these relationships.

## Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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