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# Factors influencing recent trends in retail electricity prices in the United States

Ryan Wiser *, Eric O'Shaughnessy, Galen Barbose, Peter Cappers, Will Gorman

*Lawrence Berkeley National Laboratory, 1 Cyclotron Rd., MS 90-4000, Berkeley, CA 94720, USA*

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ABSTRACT

This study analyzes the primary drivers of recent state-level trends in U.S. retail electricity prices. We summarize pricing trends, explore descriptive relationships, and employ regression models to quantify the influence of various factors. Although the recent national rise in retail prices has largely tracked inflation, state-level trends vary widely. We identify a number of factors that explain trends in subsets of states. States with the greatest price increases typically exhibited shrinking customer loads—partially linked to growth in net metered behind-the-meter solar—and had renewables portfolio standards (RPS) in concert with relatively costly incremental renewable energy supplies. By contrast, recent utility-scale wind and solar deployment that occurred outside RPS programs (but that benefited from tax incentives) had no discernible impact on increased retail prices. Hurricanes, storms and wildfires also contributed to sizable price increases in some states, most notably in California, where wildfire risk mitigation and liability insurance were major cost drivers. Fluctuations in natural gas prices—particularly following the onset of the Ukraine-Russia war—further contributed to sharp price increases through 2022–2023 in many states, with moderation in 2024. The relative influence of these factors varies across states and over time, and relationships may change in the future. Nonetheless, the findings underscore the diverse set of price determinants and highlight the need for continued research to inform effective policy and ensure customer affordability.

## 1. Introduction

Low-cost electricity has long afforded the United States with a competitive economic advantage over many other advanced economies. In recent years, however, retail electricity prices have risen rapidly in nominal terms. Though this increase in national-average retail electricity prices has largely tracked inflation, some states experienced steep price increases exceeding inflation, whereas many others saw reductions in inflation-adjusted prices. Price escalation can strain household budgets (Hua, 2025), undermine economic competitiveness (Huntington and Liddle, 2022), and hinder the electrification of energy systems (Huntington, 2025).

There is a long history of research exploring factors shaping retail electricity prices (Basheda et al. 2006). Much of this literature has analyzed individual influences, such as fossil fuel prices (Ohler et al. 2020; Alexopoulos, 2017); renewable electricity generation (Oosthuizen et al. 2022) and renewables portfolio standards (RPS) (Morey and Kirsch, 2013; Barbose, 2024; Tra, 2016); electricity market restructuring (Joskow, 2006; Morey and Kirsch, 2013; Zarnikau et al. 2023; Amenta et al. 2022; Dormady, Welch, et al. 2025; Dormady et al. 2019; Ros, 2017); and regulatory mechanisms including revenue decoupling (Kahn-Lang, 2016; Brucal and Tarui, 2021; Cappers et al. 2020) and auctions for default service in retail choice markets (Dormady, Roa-Henriquez, et al. 2025). Recent price trends have renewed focus on multi-factor analyses, as illustrated by state-level assessments (e.g., California studies by Sieren-Smith et al. 2024; Rule, 2025; Singh, Ong, and Sud, 2025) and contributions from the gray literature (Pierpont, 2024; EIA 2024b; ETE, 2025). Other recent research has leveraged detailed utility cost data. Forrester et al. (2024), for example, find widespread increases in utility costs from 2019 to 2023, most notably in distribution-related capital expenditures—which rose by roughly 50 %, far outpacing inflation. Fuel and purchased power costs also surged, spiking in 2022 after the onset of the Ukraine-Russia war, before moderating as natural gas and wholesale electricity prices declined.

This study extends existing literature by assessing multiple potential drivers behind recent trends in state-level retail electricity prices in the United States. We document pricing trends, explore descriptive relationships, and employ reduced-form regression models to evaluate the

* Corresponding author.
*E-mail address:* rhwiser@lbl.gov (R. Wiser).

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relative influence of various grid, market, and policy factors. We reach ten key findings, drawing on the descriptive and regression analysis. Given the limitations of the present study, we conclude by briefly highlighting areas that would benefit from further study.

## 2. Methods and data

Beyond highlighting some trends descriptively, our central analytic approach consists of a series of state-level reduced-form regressions. In each, the dependent variable is the change in average retail electricity prices for a given state over a specified period ("price delta") (EIA 2025b). Our core results are based on 5-year timeframes, with an emphasis on the period from 2019 to 2024, though we explore results for alternate 5-year periods in the main text, and we provide results for longer and shorter timeframes in the Supplemental Information (SI: see SI-1). State-level annual average prices are based on data reported to the U.S. Energy Information Administration (EIA) on Form EIA-861 and represent the all-in average price, inclusive of volumetric, demand, and fixed customer charges collected by all retail service providers in each state, including delivery-only, energy-only, and bundled (energy + delivery) service providers.

Each regression is based on a cross section of price changes across 48 observations (contiguous U.S.) using the following functional form:

$$\Delta p_{Y-y} = \alpha + X\beta + \Delta p_{y-\underline{y}}\gamma + \varepsilon$$

Where $\Delta p_{Y-y}$ is the change in price from year $y$ to year $Y$, $X$ is a vector of independent regressors, $\Delta p_{y-\underline{y}}$ is the change in price from a prior timeframe beginning in year $\underline{y}$, $\alpha$ is a constant, $\beta$ and $\gamma$ are regression coefficients, and $\varepsilon$ is an error term. The vector $X$ includes independent variables that could drive price changes. The objective is to measure the contemporaneous effects of $X$ on prices over the period $Y-y$ (e.g., 2019–2024). The model includes a lagged price change $\Delta p_{y-\underline{y}}$ to account for trends in prices and the regressors prior to the timeframe of interest that could have lagged impacts on prices. Including $\Delta p_{y-\underline{y}}$ ensures that the coefficient $\beta$ measures the contemporaneous impacts of $X$ on prices in the timeframe of interest ($Y - y$). However, it is possible that the pre-trend variable could bias our coefficients of interest in states where unobserved factors explain price changes over multiple timeframes, in which case the pre-trend variable would correlate with the error term in our model. Consequently, we include results from alternative specifications without the pre-trend variable in SI-2.

In our core model, we define the dependent variable as the change in price in real 2024 dollars. We explore alternative specifications with price deltas defined as percentage changes; see SI-3. These alternative specifications do not substantially affect our core results, and the models generally perform better when price changes are defined in absolute terms. We present five core models, each corresponding to a different 5-year period. The primary model explains the change in state-level prices from 2019 to 2024. This 5-year timeframe is selected because it bounds the recent, sharp increase in nominal electricity prices (and the attention that has drawn), and it avoids complications that may arise from the COVID-19 pandemic. As robustness checks over time, we also include models for 2018–2023, 2017–2022, 2016–2021, and 2015–2020—though we acknowledge that model performance for some of these may be impacted by COVID-19. Some effects may accrue over longer (or shorter) timeframes. As additional robustness checks, we provide results in SI-1 for models with timeframes each ending in 2024 and starting years running from 2015 to 2023. All analysis is restricted to the contiguous United States (i.e., excludes Alaska, Hawaii, Washington, DC).

State-level average retail electricity prices are adjusted for regional consumer price inflation (via the consumer price index) and expressed in real 2024 dollars. We convert nominal price data into real prices using regional Consumer Price Indices from the U.S. Bureau of Labor Statistics (https://www.bls.gov/cpi/regional-resources.htm). We provide regression results in nominal price terms in SI-3. While retail prices faced by individual customers can vary—depending on the utility, customer type, and specific rate plan—we aggregate to the state-level average. Using state-level averages more readily facilitates the construction of explanatory variables from publicly available sources that compile data at geographic levels that cannot be easily mapped to utility service territories and aligns with the fact that many price drivers operate at the state or regional level. A disadvantage of this approach is the small number of available observations; data come solely from the 48 contiguous states, limiting the statistical power of the models and requiring a focus on a limited number of explanatory variables.

Each core regression includes eight explanatory variables, chosen based on prior literature, prevailing discourse, and analyst judgement (see Table 1). These variables capture a range of grid, market, and policy characteristics hypothesized to influence price trajectories.

Several caveats accompany these variables and their definitions. Some variables, such as "gas exposure" and "wind+solar delta" may be more precisely specified at the utility- or regional-level, but data limitations largely preclude alternative resolutions. Other measures are necessarily blunt. The "BTM delta" (BTM = behind-the-meter solar) variable, for example, reflects growth in net metered BTM solar, but does not adjust for variations in precise compensation structures across states.

More broadly, there is considerable diversity in how electric-sector costs are recovered in prices. In some cases, costs are recovered contemporaneously. In others, costs are recovered over multi-decadal timeframes or are held in balancing accounts and only embedded in prices some years later, after a utility rate case. Contracting and hedging practices also vary regionally and by utility and are impacted by the presence and design of retail choice—influencing when and how costs are recovered in retail prices. In many retail choice markets, customers who choose to remain with their incumbent utility are served with "standard offer" supply service, the costs of which are often determined one to multiple years in advance via auction (Dormady, Roa-Henriquez, et al. 2025). Our simplified, 48-state regression model is unable to capture these nuances of how costs translate to prices; more detailed, single-issue or smaller-geography models are likely required, and are recommended. Nonetheless, our core model performs reasonably well and has the benefit of describing broad, generalized trends at a national level—even if imprecise or inaccurate for individual states.

The model is reduced-form in that we do not attempt to specify detailed structural mechanisms between the drivers and prices. The coefficients should be interpreted as the total estimated effect of each driver on price changes in each 5-year timeframe. For instance, increases in customer load can affect prices in numerous ways, such as spreading fixed costs over more sales, increasing demand for costlier peaking power generation, and increasing the need for investments in grid infrastructure upgrades. Our reduced-form model consolidates the aggregate impacts of all these mechanisms into a single estimated net effect in each timeframe. Additionally, several of the variables are correlated. Variance inflation factor tests (see SI-4) indicate that the RPS growth and BTM delta variables are particularly collinear though mostly not to a degree that is considered problematic, except for the BTM delta variable in the 2018–2023 timeframe. Nonetheless, the strong correlation between RPS and BTM solar could bias the results on those coefficients and should be considered in the interpretation of results. We provide results of robustness checks excluding the BTM delta variable in SI-5.

With the exception of "BTM delta", all variables are defensibly exogenous in models of electricity price trends over 5-year timeframes and therefore have plausibly causal interpretations. For instance, "gas exposure" may have a broader structural relationship with electricity prices in the long term because gas infrastructure investments may respond to signals from retail electricity prices. However, within a 5-year timeframe, state-level gas exposure is primarily determined by

**Table 1**
Independent variables included in core regression models.

| Variable and name | Definition | Hypothesized Impact | Data Source |
|---|---|---|---|
| End-use-customer load delta [load delta] | Percentage change in state retail sales between starting year and ending year | Unclear: may reduce prices due to fixed costs being spread over more load, though current discussions about growing load often center on concerns about potential price increases by driving up variable costs and imposing new fixed costs | (EIA 2025b) |
| Behind-the-meter solar delta [BTM delta] | Change in the amount of net metered behind-the-meter solar, as a percentage of state retail sales, between starting year and ending year | Likely to increase prices based on the presence of fixed costs that are recovered through volumetric retail prices, net metering, and other state-level support programs with costs recovered through electricity prices | (EIA 2025c; 2025d) |
| Utility-scale wind & solar share delta [wind+solar delta] | Change in the share of total in-state generation coming from utility-scale wind and solar between starting and ending year | Unclear: some believe that utility-scale wind and solar increases retail prices; others believe that they decrease prices | (EIA 2025b) |
| RPS growth requirement [RPS growth] | Required growth in utility-scale renewable energy from starting year to ending year, beyond already-available RPS supply, as a percentage of state retail sales; multiplied by a regional estimate of the marginal incremental cost of renewable energy based on recent prices for renewable energy credits | Likely to increase prices if RPS requires more renewable energy than would otherwise be delivered by market alone; no such effect if market would have delivered supply without RPS | (Barbose, 2024) |
| Natural-gas price exposure [gas exposure] | Average share of total in-state generation from natural gas from the starting year to ending year multiplied by the average price of gas over that same period at hubs from which gas may be purchased | Likely to increase retail electricity prices when natural gas prices rise, with the opposite effect when gas prices fall; may be challenging to estimate given unobserved hedging practices and regulations that impact how costs pass through to retail prices | (EIA 2025b; Abb. 2025) |
| Customer electric reliability change [reliability delta] | Change in System Average Interruption Frequency Index (SAIFI) from starting year (and prior, assuming possible lagged effects) to ending year (and prior), focused solely on major events; SAIFI measures the average number of times customers experience a power outage | Likely to increase prices if it is a reasonable proxy for the costs of rebuilding infrastructure after major power outages impacted by natural disasters | (EIA 2025a) |
| California dummy [California] | Binary variable for California, to reflect unique impact of wildfire risk on retail prices and any other unique aspects of the state | This variable will carry a positive coefficient in years that California prices exhibit above-average increases due to factors unique to the state, such as recent price increases associated with wildfire mitigation | N/A |
| Prior price trend [prior trend] | Change in average retail price in the state in the 5-year period prior to the analysis period | Serves as a control variable for correlation between the variables of interest and longer-term electricity price trends | (EIA 2025b) |

investment decisions that preceded the timeframe and exogenous gas prices. The “load delta” variable may not be strictly exogenous because customers will adjust demand in response to changes in electricity prices. However, electricity demand is widely considered to be reasonably price-inelastic in the near to medium term (Burke and Abayasekara, 2018; Labandeira et al. 2017; Csereklyei, 2020), suggesting that the impacts of endogenous load responses are limited within 5-year timeframes. We therefore assert that the “load delta” variable is defensibly exogenous. The “BTM delta” variable likely responds to trends in retail electricity prices within a 5-year timeframe. For instance, high rates of net metered BTM solar adoption in California are at least partly a response to electricity price increases in the state. The coefficients on this variable therefore lack a perfectly causal interpretation. Still, we include the variable in our core models given interest in the effects of BTM on prices and the broad literature that has asserted causal effects (NASEM, 2023; NARUC, 2016). The “BTM delta” variable correlates with the “gas exposure,” “RPS growth,” and “California” variables and therefore affects the estimated effects of those variables. We provide results of various robustness checks in the SI, including models excluding the “BTM delta” (SI-5) and “California” (SI-6) variables.

Beyond these core variables, we investigated a broader universe of potential price drivers: coal plant retirements, wildfire risk, natural hazard risk, utility-ownership of generation, publicly (vs. privately) owned utilities, retail electric competition, presence of a competitive wholesale market, energy efficiency savings, electric vehicle penetration, advanced metering infrastructure, and demand response. Regression results with these variables are included in SI-7, and findings are briefly summarized in the main text. These candidate price drivers were omitted from the core models either due to data constraints (resulting in potentially weak proxies) or because they were less likely to significantly impact state-level price changes over the study window. Wildfires and storms are examples of the former. Clearly these have impacted retail prices (see discussion later, and related figures in SI-9), but the impacts are highly variable and costs are recovered in prices very differently across states and utilities; other than a California dummy we were incapable of developing a strong proxy that effectively captures these variations. Many of the other possibilities seemed unlikely to have uniquely large impacts specifically over the most recent 5-year study window. Electric vehicle penetration, for example, is modest in the vast majority of states, and advanced metering build out largely preceded the most recent 5-year period. Relatedly, though retail and wholesale competition have been studied extensively, these variables seemed less likely to significantly impact national trends over the last 5 year period. Results shown in the SI and described later generally confirm our intuition. Nonetheless, we recommend additional analysis on these and other possible price drivers, though such analyses would likely require different techniques, in some cases focused on different timeframes or subsets of states.

## 3. Summary of regression results

Results for the five core regressions are summarized in Table 2. All results are based on standardized variables. In the case of “California,” the variable is standardized by dividing the binary values by the standard deviation. The models explain around one-third of the variation in price changes in the first three timeframes and explain well over half of the variation in the two most recent timeframes. This despite the simplicity of the models, the small number of observations, the limited number of explanatory variables, and imperfections in the design of some of those variables. The primary model, focused on the most recent 5-year period, has an adjusted $R^2$ of 0.86. The increasing explanatory power of the model in recent timeframes is partly due to the growing influence of the “BTM delta” and “California” variables (Fig. 1). California is an outlier in terms of price changes in the latter timeframes (Fig. 2). From 2019–2024, the average California retail price increased by 6.2 cents/kWh—more than twice the increase of any other state—due largely to wildfire-related costs (discussed in a subsequent section). The unique nature of California price changes was our motivation for including a dummy variable in the model, the inclusion of which significantly increases the $R^2$ in later time periods. However, the model still explains over 60 % of the variation in price changes when excluding the California variable.

Fig. 2 illustrates predicted state-level price changes for the 2019–2024 period from the regression model and compares those to actual price changes. The model predicts recent price changes within 0.5 cents/kWh of the actual price change in 38 of the 48 states.

## 4. Ten key findings

Ten key findings derive from our descriptive analysis and regression models.

**Table 2**
Core regression model results. Region-clustered robust standard errors in parentheses.

| | 2015-2020 | 2016-2021 | 2017-2022 | 2018-2023 | 2019-2024 |
|---|---|---|---|---|---|
| wind+solar delta | 0.11 | 0.15* | −0.07 | −0.19 | **−0.16** |
| | (0.1) | (0.05) | (0.09) | (0.13) | **(0.1)** |
| RPS growth | 0.21 | −0.07 | 0.69 | 0.53* | **0.31*** |
| | (0.13) | (0.3) | (0.18) | (0.06) | **(0.1)** |
| BTM delta | −0.17 | 0.04 | −0.35 | 0.41* | **0.46*** |
| | (0.37) | (0.31) | (0.18) | (0.09) | **(0.14)** |
| load delta | −0.33 | −0.3* | −0.23 | −0.36* | **−0.47*** |
| | (0.13) | (0.06) | (0.23) | (0.1) | **(0.09)** |
| gas exposure | −0.17 | 0.13 | 0.29 | 0.19 | **0.05** |
| | (0.09) | (0.08) | (0.26) | (0.13) | **(0.11)** |
| reliability delta | 0.01 | 0.19 | 0.01 | 0.16 | **−0.11** |
| | (0.1) | (0.27) | (0.14) | (0.21) | **(0.09)** |
| California | 0.24 | 0.32 | 0.62* | 0.47* | **0.72*** |
| | (0.25) | (0.19) | (0.09) | (0.05) | **(0.03)** |
| prior trend | 0.36* | 0.1 | −0.08 | −0.18* | **−0.23*** |
| | (0.1) | (0.09) | (0.2) | (0.05) | **(0.02)** |
| Adj. $R^2$ | 0.38 | 0.32 | 0.44 | 0.63 | **0.86** |

* $p < 0.1$

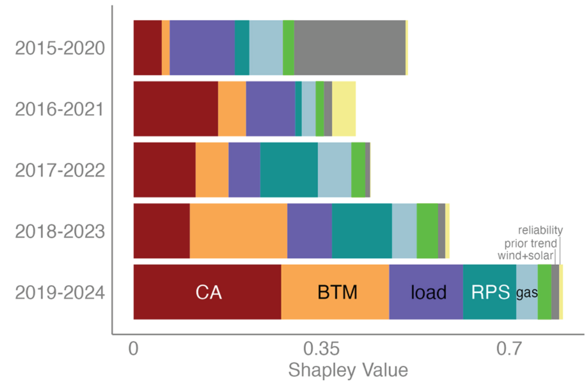


**Fig. 1.** Shapley values of independent variables by timeframe. Note that Shapley values reflect the relative contribution of each independent variable to model unadjusted $R^2$.

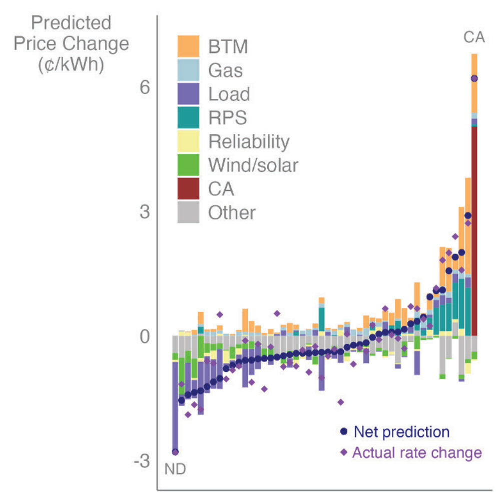


**Fig. 2.** Model predictions and actual price deltas for 2019–2024 timeframe.

### 4.1. National-average retail electricity prices have tracked inflation in recent years

Over the last five years, national-average retail electricity prices increased sharply in nominal terms—rising by 23 % from 2019 to 2024 (Fig. 3, left panel). However, after adjusting for inflation, prices have been trending downwards for decades and largely remained flat over the last five years outside a bump upwards in 2022 corresponding to the onset of the Ukraine-Russia war. Electricity bills are, of course, impacted by prices and consumption—and so prices, alone, do not fully describe the impact of electricity expenditures on households or the economy more broadly. Yet total electricity costs as a fraction of GDP and residential electricity costs as a fraction of overall household expenditures have also generally been on a downward trajectory (Fig. 3, right panel).

### 4.2. State-level retail electricity price trends vary widely

National averages mask substantial state-level differences in both overall average retail prices and recent price changes (Fig. 4). In 2024, average state-level retail prices varied by more than a factor of three, from less than 8 cents/kWh in North Dakota to more than 27 cents/kWh in California. Examining recent trends in inflation-adjusted prices, 31 states saw real price declines from 2019 to 2024, while 17 states experienced increases. States on the West Coast and in the Northeast were most affected by rising prices—especially California, where average retail prices increased by 6.2 cents/kWh in real 2024 dollars.

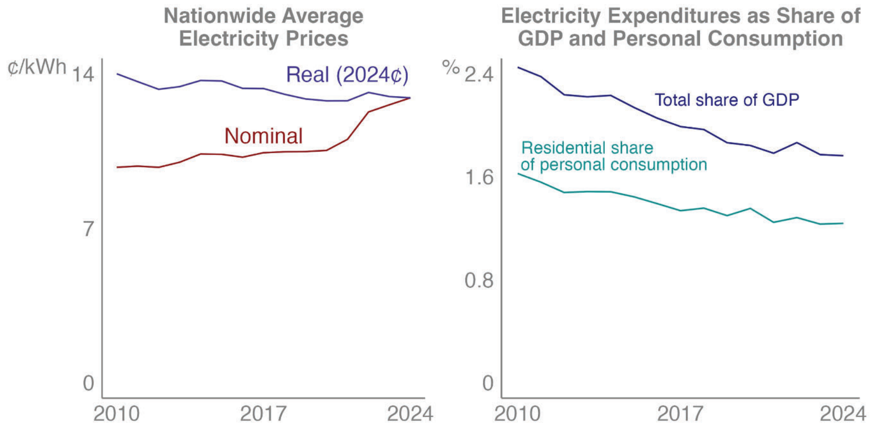


**Fig. 3.** National-average retail electricity prices (left) and electricity costs as a fraction of GDP and personal expenditure (right).

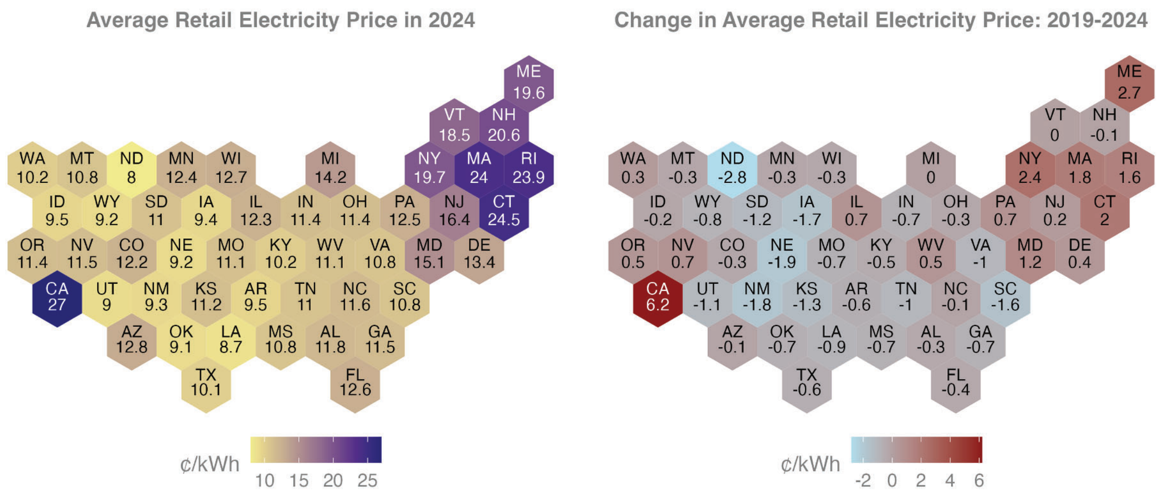


**Fig. 4.** State-level average retail electricity prices in 2024 (left) and inflation-adjusted price changes from 2019 to 2024 (right).

### 4.3. *Residential customers and investor-owned utilities experienced greater increases*

Although this study focuses on average state-level retail electricity prices, notable differences also exist across customer classes and individual electric utilities. Based on data from the Energy Information Administration, residential electricity prices, for example, are not only higher than commercial and industrial prices, but have also risen more rapidly in recent years in nominal terms (see SI-9)—a reflection of cost allocation decisions by utilities and their regulators. The prices charged by investor-owned utilities (IOUs) are also higher and have risen faster than those of publicly owned utilities (POUs) (see SI-9); in California, these disparities are partly due to differences in wildfire risk and related costs (Singh et al. 2025). We leave the fundamental drivers for these differences for future work, as this analysis centers on overall state-level trends.

### 4.4. *Load growth has tended to depress retail electricity prices in recent years*

After decades of stagnant demand, U.S. electricity load is poised to rise, driven by the expansion of data centers, domestic manufacturing, and broader electrification (NERC, 2024). This has raised concerns that increasing load might place upward pressure on wholesale and retail electricity prices. Chandramowli, et al. (2024), for example, forecast a rise in wholesale prices, and EIA, (2025e) projects that retail prices will outpace inflation in the near term. In supply-constrained situations in which marginal generation and delivery costs rise steeply, load growth could lead to higher retail prices. Others, such as Martin and Peskoe (2025), warn of a different concern: that cost allocation practices might disproportionately benefit larger commercial or industrial customers over smaller residential customers.

Contrary to these concerns, our analysis finds that state-level load

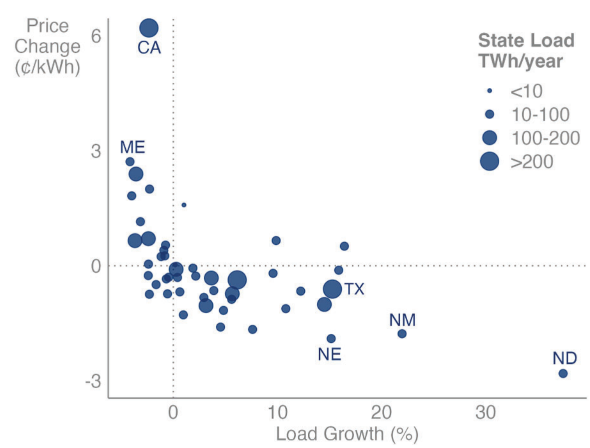


**Fig. 5.** Relationship between load growth and changes in retail electricity prices from 2019 to 2024.

growth in recent years (through 2024) has tended to reduce average retail electricity prices. Fig. 5 depicts this relationship for 2019–2024: states with the highest load growth experienced reductions in real prices, whereas states with contracting loads generally saw prices rise. Regression results confirm this relationship: the load-growth coefficient is among the most stable and statistically significant across model variants. In the 2019–2024 timeframe, the regression suggests that a 10 % increase in load was associated with a 0.6 (±0.1) cent/kWh reduction in prices, on average (note here and in all future references the ± refers to the cluster-robust standard error).

This finding aligns with the understanding that a primary driver of increased electricity-sector costs in recent years has been distribution and transmission expenditures—often devoted to refurbishment or replacement of existing infrastructure rather than to serve new loads (ETE, 2025; Pierpont, 2024; EIA 2024a; Forrester et al. 2024). Spreading these fixed costs over more demand naturally exerts downward pressure on retail prices. It is also notable, however, that this negative load-price relationship was pronounced when considering overall average retail prices but was smaller and lost statistical significance when analyzing residential prices alone (see SI-8). Load growth over this historical period was led by commercial customers, and cost allocation practices have tended to benefit those large, non-residential customers.

Whether these historical relationships extend to a future of significant, nationwide load growth is unclear and is a point to which we return in the conclusion.

### 4.5. Behind-the-meter solar was associated with higher prices

Related to net-load contraction, considerable attention has been given to the potential impact of net metered BTM solar on retail electricity prices. Much of the discourse centers on the disconnect between utility rate structures and underlying cost structures. Because utilities must allocate costs (both variable and fixed) over broad customer classes, the revenues that utilities collect from individual customers never precisely match the total underlying costs of electricity supply. Net metered BTM solar can exacerbate this challenge, especially when fixed costs are recovered through volumetric rates, by causing utilities to collect less revenues from BTM solar adopters than utilities planned to collect from those adopters, a situation that can lead to higher retail prices (NASEM, 2023; NARUC, 2016). Additional factors may contribute to price increases, including higher distribution system costs to accommodate BTM solar, surcharges to support BTM solar rebates, and solar carve-outs within RPS programs. Numerous studies have examined these effects for net metered BTM solar, often focusing on individual states or utilities and reaching divergent conclusions depending on scope and methods (Sieren-Smith et al. 2024; ICF, 2018; E3 2023; Johnson et al. 2017; Sergici et al. 2019; Picciariello et al. 2015).

From 2019 to 2024, growth in net metered BTM solar substantially reduced net electricity load in some states—by over 5 % in California, Maine and Rhode Island, and by more than 2 % in another seven states. These reductions provide direct bill savings for participating customers. However, given the disconnect between rate structures and cost structures under many net metering programs, and the financial cost of policy support, our regression results indicate that these load reductions were associated with increased retail prices for the broader customer base. Specifically, the two most recent 5-year periods show that a 5 percentage-point increase in net metered BTM solar as a share of total sales was associated with an average price increase of 1.1 (±0.3) cent/kWh; in contrast, the effects are much smaller and not statistically significant in earlier 5-year windows. The magnitude of this estimated effect is consistent with a scenario in which, in an average state with growing net metered BTM solar, the grid-system cost savings is less than 50 % the utility-bill savings earned by adopters—which generally follows at least some of the past literature (O'Shaughnessy et al. 2025). This provides some assurance that the regression model is reflecting effects of the correct general magnitude, notwithstanding potential concerns about the endogeneity of the variable (see SI-5). In California, larger recent price impacts from net metered BTM solar have been estimated due to the presence of sizable fixed costs recovered through especially-high volumetric retail rates (Sieren-Smith et al. 2024); any such unique effects should be captured by the California variable discussed later.

### 4.6. Utility-scale wind and solar are not—alone—broadly related to recent price increases

Debates persist in the media, policy, and academic communities regarding the impact of utility-scale wind and solar on retail electricity prices. The research literature from the U.S. and Europe is varied. Some studies report context-dependent price increases (Oosthuizen et al. 2022; Trujillo-Baute et al. 2018), while others suggest that wind and solar—supported by tax incentives in the United States—may have placed downward pressure on prices, at least in some regions and especially for recently built projects (Wiser et al. 2024; Pierpont, 2024). Still others emphasize the price stabilizing or "hedge" benefits of renewable energy relative to other generation sources (Navia Simon and Diaz Anadon, 2025).

Our analysis indicates that, outside of RPS-driven deployment, utility-scale wind and solar did not generally exert upward pressure on state-level retail prices in the most recent periods. Fig. 6 illustrates the lack of an obvious relationship between changes in wind and solar shares and retail electricity prices from 2019 to 2024. The regression models confirm that, over recent 5-year periods and in the absence of state RPS policies, changes in wind and solar shares did not generally drive retail prices higher. In fact, in the most-recent 5-year blocks (2017–2022, 2018–2023, 2019–2024), wind and solar growth may have placed some downward pressure on prices, though these relationships are not statistically significant. Historical reductions in the cost of wind and solar in concert with available tax incentives presumably contribute to these findings. In contrast, in earlier periods there is some suggestive (weak) evidence that wind and solar may have increased prices.

### 4.7. State renewables portfolio standards are associated with recent price increases

While approximately 75 % of utility-scale wind and solar growth in the U.S. from 2019 through 2024 was not mandated by state RPS programs, the remaining 25 % was at least notionally attributable to such policies. State RPS programs intend to deliver societal benefits by requiring renewable energy deployment at specified levels, in some cases with carve-outs for specific technologies. In some states, the required deployment levels (overall, or of particular technologies)

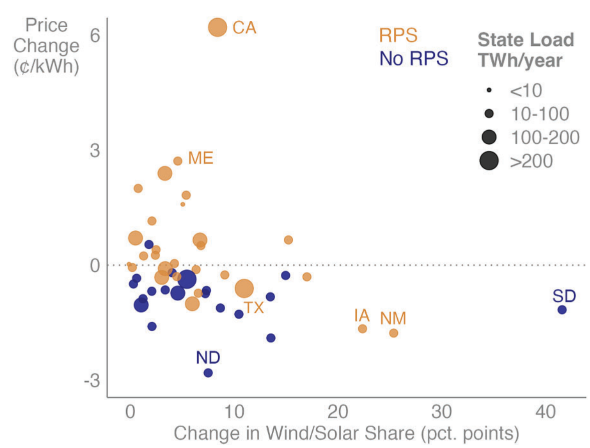


**Fig. 6.** Relationship between growth in utility-scale wind and solar and changes in retail prices from 2019 to 2024.

exceed what the competitive market would supply, compelling electricity suppliers to incur higher costs than would have otherwise occurred. It is therefore expected that RPS policies will often raise retail prices, especially in states with more-costly renewable energy supplies, a relationship confirmed by prior research (Morey and Kirsch, 2013; Barbose, 2024; Tra, 2016).

Our analysis generally supports this expectation. As depicted in Fig. 1, the estimated impacts of RPS are limited in the earlier timeframes but increase substantially in the most recent timeframes. As shown in Fig. 6, most states that experienced retail price increases from 2019 to 2024 have RPS policies. Regression results indicate that, on average, RPS requirements for additional utility-scale renewable energy were associated with increased retail prices of approximately 0.4 (±0.1) cents/kWh over the 2019–2024 period in the states with incremental RPS needs, with similar results for 2018–2023. The apparent impacts for earlier timeframes were considerably smaller and not statistically significant. The change in the RPS impacts from earlier to later timeframes could correspond to changes in RPS policies and the renewable energy market. Alternatively, the changing significance of the RPS result could reflect interactions between RPS policies and other factors that arose in more recent timeframes, or else model performance for the earlier periods may be impacted by the COVID-19 pandemic. The average impact in the latter timeframes aligns with other literature (Barbose, 2024), although impacts in individual states will vary based on policy design and market characteristics. Those states—especially in the Northeast and Mid-Atlantic regions—with relatively lower-quality wind and solar resources have often tended to experience larger price impacts.

### 4.8. Exposure to natural gas price risk increases electricity prices when gas prices rise

Natural gas accounts for a substantial share of U.S. electricity generation, reflecting its economic competitiveness. Natural gas prices are variable, however, and fluctuations have long been known to flow through to both wholesale and retail electricity prices (Ohler et al. 2020; Alexopoulos, 2017); in some markets, the implied volatility of natural gas (and wholesale power) prices may be more important than the actual price (Dormady, Roa-Henriquez, et al. 2025). The extent to which natural gas price changes affect retail electricity prices in a given state depends on several factors: the state's (or larger region's) reliance on natural gas in its resource mix, the presence of pipeline constraints, implied volatility and the extent to which generators or utilities can and do successfully hedge fuel purchases, participation in wholesale power markets, the degree of utility ownership of gas plants, any lag in passing through costs to consumers, and any contracting practices that require suppliers to predict future fuel or wholesale price swings when setting retail electricity prices in advance.

Over the past five years, natural gas prices experienced dramatic swings: increasing sharply in 2022 following the onset of the Ukraine-Russia war and subsequently falling steeply through 2024. Forrester et al. (2024) report a significant increase in fuel and purchased power costs for IOUs in 2022, consistent with the spike in natural gas prices. Data from the EIA show that the states most dependent on natural gas experienced some of the greatest increases in retail electricity prices through 2022–2023 (see SI-9), followed by some of the largest price decreases. The relationship between state-level natural gas share and retail electricity price variability is illustrated in Fig. 7.

Despite the complexity and variability of the relationship between fuel prices and retail electricity prices, regression results generally confirm these descriptive trends. The coefficients for the gas exposure variable are positive, though insignificant, in every timeframe ending in 2021 or later. Table SI-1.2 in SI-1 provides regression results for the timeframe 2021–2023, chosen to isolate the period in which Ukraine-Russia war disruptions likely had the greatest impact on gas prices and thus on electricity prices in states exposed to gas market volatility. The coefficient in that regression suggests that gas exposure increased

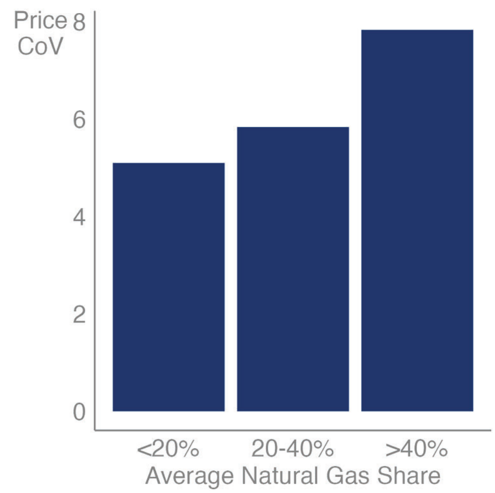


**Fig. 7.** Relationship between natural gas share and retail electricity price variability from 2010 to 2024. Price variability is defined as the coefficient of variation (COV) of state-level retail prices from 2010 through 2024. Average natural gas share is the state-average over the same time period.

electricity prices by 0.9 (±0.2) cents/kWh, on average, from 2021 to 2023 in the 10 states with the most gas exposure (as defined in Table 1).

### 4.9. Hurricanes, storms, and wildfires have increased retail prices

Hurricanes, storms, and wildfires can raise retail electricity prices through both short-term recovery and rebuilding, and longer-term costs such as infrastructure hardening, operational expenditures, and liability insurance coverage to protect utilities against future risks.

In Florida, for example, hurricane damage in 2024 resulted in approved residential price increases across three utilities, ranging from 1.2 to 3.2 cents/kWh for one to one-and-a-half years (Florida PSC 2025a; 2025b; 2024). In Maine, the state's largest utility funds storm recovery costs via a rate rider, which grew from about 0.1 cents/kWh in late 2020 to 1.8 cents/kWh in late 2024 (Maine PUC, 2025) (see SI-9 for additional examples). Regarding longer-term impacts, investments to protect against wildfires have been especially prominent in California. Between 2019 and 2023, California's three large IOUs were authorized to include $27 billion in wildfire-related costs in retail prices (Sieren-Smith et al. 2024; Singh et al. 2025). By June 2024, wildfire-related costs constituted an average of 17 % of total IOU revenue requirements (The Public Advocates Office, 2025)—up from 1.7 % in 2019 and, if directly translated into one-year cost impacts, equivalent to a 4 cent/kWh increase. Other Western states are also confronting wildfire mitigation costs, although to a lesser extent (see SI-9). In 2024, one Oregon utility recovered wildfire-related expenses through a 0.6 cent/kWh surcharge (PGE, 2023) while another includes a 0.7 cent/kWh surcharge on its residential rates (Pacific Power, 2025). A Colorado utility has proposed a wildfire-mitigation program that could increase residential prices by about 1.4 cents/kWh by 2028 (Xcel, 2025).

Developing robust proxy variables for these varied effects is challenging, as disasters and weather events are highly state-specific, infrequent, and unpredictable. As well, cost recovery is highly variable—sometimes nearly contemporaneous, but in other cases delayed by years or recovered over multi-decadal timeframes. Nonetheless, the effect of wildfire risks in California is clear: the coefficient for the California variable increases over successive 5-year periods, corresponding to an additional 5.0 cent/kWh increase in retail prices from 2019 to 2024—somewhat higher than the aforementioned 4 cent/kWh cost estimate for the three major IOUs, which collectively serve 70 % of the state's load. Beyond that state-specific variable, supplementary regressions that independently test "wildfire risk" and a broader "natural hazards risk" variable did not produce statistically significant results for recent 5-year periods (see SI-7). When excluding the California variable, the "wildfire risk" variable is positive in later timeframes. The coefficient in that case implies that retail prices increased by around 1.1 cents/kWh, on average, in the five states with the greatest wildfire risk. Finally, a customer reliability ("reliability delta") metric focused on major power outages is included as an imperfect surrogate for more-immediate natural-disaster recovery costs (Larsen et al. 2020). The coefficient is mostly positive, as expected, but is never statistically significant—perhaps due to the sporadic and unpredictable nature of such natural disasters and the fact that costs are recovered in rates through varied approaches that often include delays and multi-year repayment.

### *4.10. Several other variables appear to have limited statistical explanatory power*

We investigated a range of additional variables through supplementary regressions (see SI-7). Given the limited number of observations and the blunt nature of some of these proxies, these results should be interpreted cautiously as smaller or more nuanced effects are difficult to detect.

Overall, we do not observe a consistent, statistically significant relationship between recent retail price changes and either participation in a competitive wholesale market administered by an independent system operator or the degree of retail market competition. States with greater proportions of utility generation ownership or POU service tend to have seen smaller price increases in the most recent 5-year periods, but these associations are neither generally statistically significant nor robust across earlier periods. Other variables tested—including electric vehicle penetration, demand response program size, energy efficiency savings, and advanced metering infrastructure penetration—show no broad, consistent correlation with recent retail price increases. Finally, regarding coal-plant retirements, we find weak evidence of a downward price effect: the "coal retirements" coefficients are consistently negative but not statistically significant.

For all these variables, additional research employing alternative techniques or richer datasets may be needed to uncover relationships that our limited, state-level approach cannot fully detect.

## 5. Conclusions

This analysis shows that, while the recent increase in average U.S. retail electricity prices has largely tracked inflation, some states experienced steep price increases exceeding inflation, whereas many others saw reductions in inflation-adjusted prices. Our regression models explain a substantial share of this state-level variation, despite the limited number of observations, various complexities with variable specification, and the many factors that impact retail electricity prices.

States with the largest price increases in recent years typically featured shrinking customer loads—partially linked to growth in net metered behind-the-meter solar—and had RPS programs in concert with relatively costly incremental renewable energy supplies. By contrast, the 75 percent of recent utility-scale wind and solar deployment that occurred outside RPS programs (but that benefited from tax incentives) had no broadly discernible impact on increasing retail prices and instead had some (weak) evidence of reducing prices over the most recent time periods. Hurricanes, storms and wildfires contributed to sizable price increases in some states, most notably in California, where wildfire risk mitigation and liability insurance were major cost drivers. Fluctuations in natural gas prices—acutely felt after the onset of the Ukraine-Russia war—further contributed to sharp price increases through 2022–2023 in many states, with moderation observed in 2024. The relative influence of these factors varies across states and over time, and relationships may change in the future.

A notable finding relates to customer load. Recent industry discussion has centered on concerns that load growth has or will push electricity prices upwards (Pfeifenberger et al. 2025). Load growth could increase the short-run marginal costs of grid service (e.g., higher fuel costs, or capacity costs) and increase the longer-run average cost by requiring costly upgrades to grid infrastructure. Put simply, assertions that load growth will increase retail prices imply that the infrastructure needed to serve new load will cost more on a normalized basis than the infrastructure to serve existing load. Contrary to these concerns, we find that rising state-level load in recent years (through 2024) has generally been associated with overall price reductions over 5-year timeframes—though that is less true when focused on residential (rather than all-sector average) prices. This suggests that recent state-level growth has generally not had the effects described above, at least when considering effects over 5 years. Instead, given the presence of significant fixed costs not tied to load growth, increased load over our period of study tended to reduce average prices.

It remains unclear whether broader, sustained load growth will increase long-run average costs and prices. In some cases, spikes in load growth can result in significant, near-term retail price increases. Results from recent capacity auctions in the mid-Atlantic region prove this point, with sizable impacts on retail pricing beginning in 2025 (e.g., Howland, 2025). The duration of such impacts remains unclear, however, and will depend on the ability to build new cost-effective infrastructure to serve new loads. In other cases, utilities have argued that load growth will reduce average retail prices, consistent with our analysis of recent impacts (e.g., PG&E, 2025). Overall, our results cast doubt on the simple view that load growth will <u>necessarily</u> increase prices over the medium- to longer-term. Emerging evidence from 2025 suggests near-term impacts that can be either positive or negative; medium- to longer-term effects are uncertain.

In a similar vein, it remains unclear how BTM solar and other load modifiers will impact long-run average costs and prices. While our results suggest that BTM solar led to meaningful price increases in a number of states during our historical analysis period, the same may not hold true in a future with much higher underlying levels of load growth occurring throughout the country. Just as rapid load growth might raise prices in such a context, so too might load reducers, such as BTM solar, help to dampen those price increases, particularly if accompanied by greater co-adoption with storage and continuing advancements in rate designs that better align with utility cost structures.

Most broadly, our findings highlight the complex and evolving mix of factors influencing retail electricity prices. Our analysis was constrained by data volume and the use of blunt or imperfect proxies, pointing to the value of richer datasets and more-refined variables in future research. Analyses focused on different time horizons, absolute price levels, utility- rather than state-level prices, customer-class distinctions, and the effects of individual drivers could yield additional insights. Finally, while statistical models can help clarify broad patterns, state-specific idiosyncrasies reinforce the importance of detailed case studies examining individual utilities, states, and drivers.

## Author contributions

R.W. conceived the work, acquired funding, collected some of the data, oversaw the analysis, and wrote much of the paper. E.O conducted most of the analysis, wrote sections of the paper, and provided edits. G. B. provided feedback on scope, collected some of the data, and provided edits. P.C. provided feedback on scope and provided edits. W.G. contributed to the analysis and provided edits.

## CRediT authorship contribution statement

**Ryan Wiser:** Writing – review & editing, Writing – original draft, Supervision, Project administration, Methodology, Funding acquisition, Formal analysis, Data curation, Conceptualization. **Eric O'Shaughnessy:** Writing – review & editing, Writing – original draft, Visualization, Validation, Methodology, Formal analysis, Data curation. **Will**

**Gorman:** Writing – review & editing, Data curation. **Galen Barbose:** Writing – review & editing, Methodology, Data curation. **Peter Cappers:** Writing – review & editing, Methodology, Data curation.

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## Declaration of Competing Interest

Ryan Wiser: Given their role as an Editorial Board Member with The Electricity Journal, Ryan Wiser had no involvement in the peer-review of this article and had no access to information regarding its peer-review. Full responsibility for the editorial process for this article was delegated to another journal editor.

Eric O'Shaughnessy is an independent consultant; a list of his clients is available at www.cleankws.com

Galen Barbose: I have nothing to declare

Peter Cappers: I have nothing to declare

Will Gorman: I have nothing to declare

## Appendix A. Supporting information

Supplementary data and analysis associated with this article can be found in the online version at doi:10.1016/j.tej.2025.107516.

## Data availability

Data and code are available at: https://emp.lbl.gov/publications

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**Ryan Wiser** is a Senior Scientist and Senior Advisor in the Energy Markets and Policy Department at Lawrence Berkeley National Laboratory. He holds a B.S. in Civil Engineering from Stanford University and an M.S. and Ph.D. in Energy and Resources from the University of California, Berkeley. His research focuses on the U.S. power sector, with an aim to inform public and private decision-making related to electricity system planning, regulation, and renewable energy supply.

**Eric O'Shaughnessy** is an independent renewable energy research consultant and research affiliate at the Lawrence Berkeley National Laboratory. His research focuses on econometric analysis of distributed energy resource and voluntary green power markets. Dr. O'Shaughnessy received his Ph.D. in Environment and Resources from the Nelson Institute for Environmental Studies at the University of Wisconsin-Madison. He also has an M.P.A. from the LaFollette School of Public Affairs at the University of Wisconsin-Madison and a B.S. in Environmental Economics and Policy from Michigan State University.

**Galen Barbose** is a Staff Scientist in the Energy Markets and Policy Department at Lawrence Berkeley National Laboratory, where his research focuses on issues in the electricity industry relating to renewable energy, energy efficiency, and electric system planning. He holds Bachelor's degrees in Philosophy and Mechanical Engineering, and a Master's degree in Energy and Resources from the University of California at Berkeley.

**Peter Cappers** is a Staff Scientist and Strategic Advisor to the Energy Markets and Policy Department at Berkeley Lab. He conducts research and provides technical assistance to territorial, state, federal, and international regulators and policymakers on electric utility regulatory and business models, pricing and rate design, demand response, renewable energy, and energy efficiency market and policy issues. He holds B.A. from Syracuse University in Mathematics and Economics, and a M.S. from Cornell University in Applied Economics.

**Will Gorman** is a Research Scientist in the Energy Markets and Policy Department at Lawrence Berkeley National Laboratory. He received his PhD in Energy and Resources from the University of California, Berkeley and holds a BS in Chemical Engineering and a BA in Plan II Honors from the University of Texas at Austin. His research focuses on the integration of renewable generation into the electric power system, the economics and application of distributed energy resources, and issues of reliability within electricity networks.