Lawrence Berkeley National Laboratory

LBL Publications

Title

Quantifying the Financial Impacts of Electric Vehicles on Utility Ratepayers and Shareholders

Permalink

https://escholarship.org/uc/item/6dz355d9

Authors

Satchwell, Andrew

Carvallo, Juan Pablo

Cappers, Peter

et al.

Publication Date

2024-01-21

Copyright Information

This work is made available under the terms of a Creative Commons Attribution-NonCommercial-NoDerivatives License, available at https://creativecommons.org/licenses/by-nc-nd/4.0/

Peer reviewed

eScholarship.org

Powered by the California Digital Library
University of California

Quantifying the Financial Impacts of Electric Vehicles on Utility Ratepayers and Shareholders

Andrew Satchwell, Juan Pablo Carvallo, Peter Cappers,
James Milford, and Hadi Eshraghi

February 2023

This work was funded by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy Strategic Analysis Team under Contract No. DE-AC02-05CH11231.

BERKELEY LAB

Lumina Decision Systems

Disclaimer

This document was prepared as an account of work sponsored by the United States Government. While this document is believed to contain correct information, neither the United States Government nor any agency thereof, nor The Regents of the University of California, nor any of their employees, makes any warranty, express or implied, or assumes any legal responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by its trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof, or The Regents of the University of California. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof, or The Regents of the University of California.

Ernest Orlando Lawrence Berkeley National Laboratory is an equal opportunity employer.

Copyright Notice

This manuscript has been authored by an author at Lawrence Berkeley National Laboratory under Contract No. DE-AC02-05CH11231 with the U.S. Department of Energy. The U.S. Government retains, and the publisher, by accepting the article for publication, acknowledges, that the U.S. Government retains a non-exclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this manuscript, or allow others to do so, for U.S. Government purposes.

Executive summary

Electric vehicles (EVs) can increase retail electricity sales and provide new earnings opportunities to electric utilities through increased capital investments. Using a financial model that mimics the electric utility investment planning and ratemaking processes of an investor-owned utility, the study finds average retail electricity rates are virtually unchanged and earnings increase ~2.2%-4.7% over a 20-year period. Importantly, managing EV charging and shifting it away from utility system peak demand reduces average retail rates ~0.8%-1.0% by lowering incremental generation and distribution system investment costs. Compared to a future without EVs, utility shareholders are better off, but reductions in new generation and distribution infrastructure investments erodes some of the incremental earnings.

While utility infrastructure investments that enable greater EV deployment initially cause retail electricity rates to rise ~1.6%, increases in sales from EV load cause rates to decline ~2.9% in the later years of the analysis period. A forward-looking, long-term perspective is therefore necessary to overcome near-term rate increases, particularly in the recent utility environment of declining sales and limited new generation capital investments.

EV deployment characteristics matter, and they present tradeoffs between economic efficiency and promoting EV adoption. For example, increasing deployment of public and workplace chargers may result in more mid-day EV charging, but that may or may not be economically efficient from a utility cost perspective. Further, our modeling of managed charging behavior identified the aggregate EV charging profile that minimizes impacts on utility system peaks. But implementing such an optimization would require dynamic infrastructure planning processes and/or flexible managed charging strategies reflecting how utility load shapes evolve over time, inclusive of EV load.

Finally as this is a scoping study, many opportunities exist for future research to enhance and expand on these results, especially in exploring rate impacts by customer class and non-participant customer bills.

Report Outline

I. Introduction

II. Analytical Approach

III. Results

IV. Conclusions and Discussion

Supplemental information detailing the utility financial and operational characterization, EV deployment assumptions, and modeling approach, including generation capacity expansion and dispatch logic is available at: https://emp.lbl.gov/publications/quantifying-financial-impacts.

I. Introduction

What are the financial impacts of electric vehicles (EVs) on utilities and ratepayers and how do deployment strategies affect them?

EVs can provide financial upside to electric utilities and ratepayers in several ways. For example:

- From the utility perspective, EVs could drive increased electricity sales and new earnings opportunities through increased capital investments.
- From the ratepayer perspective, increased electric loads from EVs could reduce average all-in retail rates.

The degree to which there are net benefits or costs to shareholders and/or ratepayers depends on how EVs are integrated and managed through enabling grid investments and charging strategies.

Utility shareholder and ratepayer financial impacts are driven by changes in both revenues and costs, which involve important linkages and feedback effects. For example, electricity retail sales drive revenue collection but also determine the level of generation capital expenditure and other energy supply costs. The study explores such relationships in more detail.

Prior work has largely focused on EV impacts on specific rate drivers (e.g., incremental distribution system costs to accommodate EVs) or on utility total revenues but not total costs. Further, rate impact analyses have employed simplified models and representations, including using marginal cost estimates instead of average and embedded costs and considering only short (e.g., 1-3 year) time periods (e.g., BCG, 2019; Szinai et al., 2020; Cutter et al., 2021; Fitch et al., 2022).

Analysis overview

The study estimates the utility earnings and customer rate impacts of EVs under “managed” and “mismanaged” charging strategies. A reasonable range of financial impacts is bounded across different EV deployment assumptions. Finally, we assess the sensitivity of results to different assumptions about:

- High average EV miles traveled (VMT) (i.e., higher retail electricity sales)
- Incremental distribution system costs
- EV charging location
- Utility EV enablement costs (i.e., utility costs to invest in EV charging, controls, and communication, and to deliver and administer EV programs)

The study quantifies financial impacts using Berkeley Lab’s Financial Impacts of Distributed Energy Resources (FINDER) model, which mimics the electric utility investment planning and ratemaking processes of an investor-owned utility (IOU). We assume utility financial and operational characteristics representing a generic summer-peaking, vertically integrated IOU. EV impacts on key utility financial drivers (i.e., retail sales, peak demand, and costs) are also characterized across a range of analytical scenarios using bounded but reasonable values. We use publicly available data sources and tools (e.g., EVI-Pro Lite) as the basis for our assumptions.

How do we define “managed” and “mismanaged” charging?

We define “managed” and “mismanaged” charging based on how they perform in meeting a particular objective at every point in time during the analysis period. In this study, the objective relates to system peak impacts: managed charging minimizes impacts on system peaks, while mismanaged charging maximizes these impacts.

Performance-based charging strategies adapt over time to reflect the achievement of an identified objective. One advantage of the performance-based approach is that it enables representation of the hourly EV charging profile that best meets the objective, as well as how this profile changes over time as EV penetration increases (see illustrative figure on page 9).

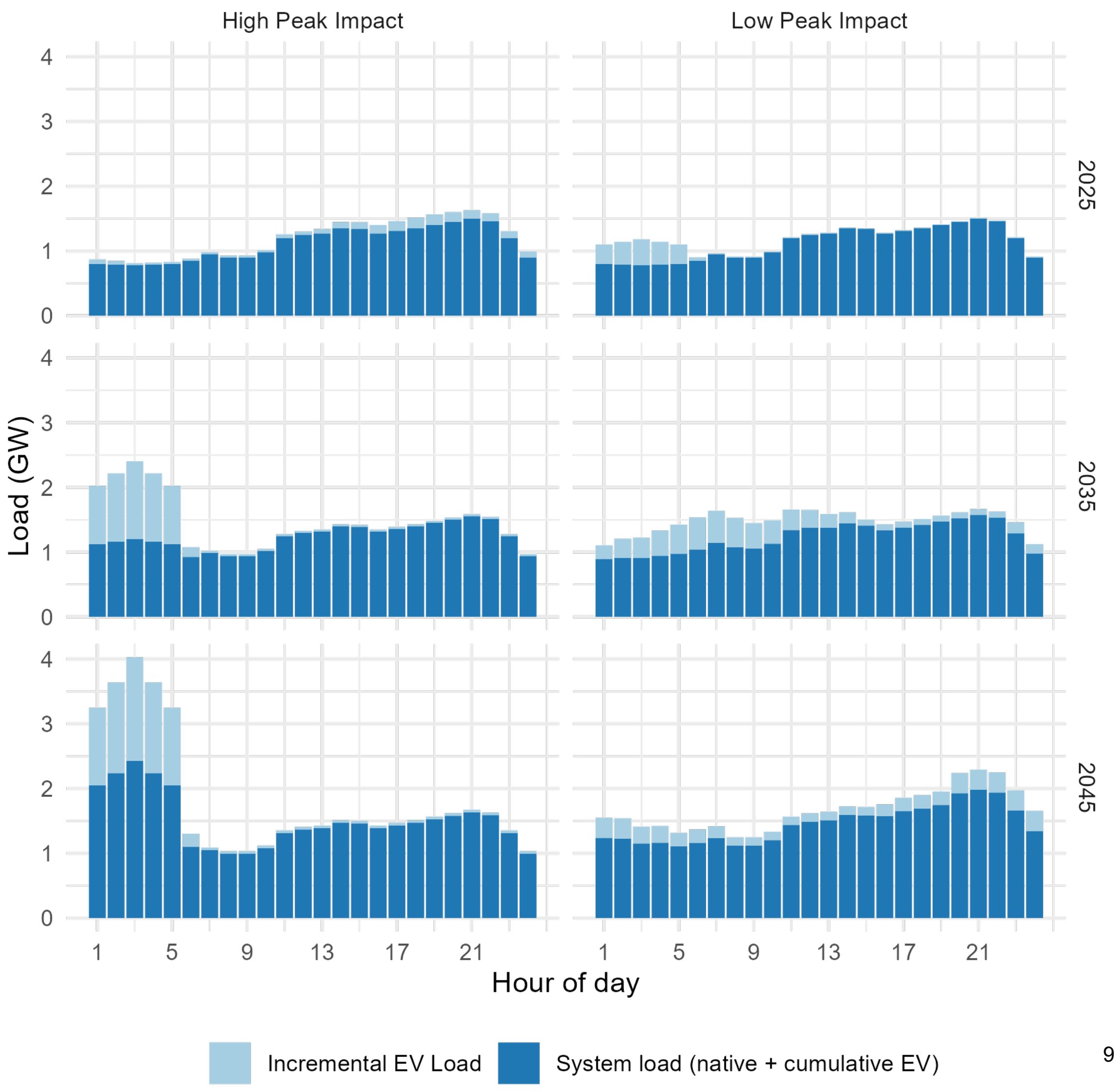
Other possible objectives for performance-based charging strategies include minimizing renewable curtailment, minimizing distribution system loading/costs, and maximizing the load shifting or shedding value of EVs. These were not addressed here but could be addressed in subsequent studies.

In contrast to the performance-based approach, attribute-based charging strategies are based on the attributes associated with charging profiles. Attribute-based charging strategies are rooted in past and current driving behavior and/or vehicle characteristics (e.g., overnight charging), which may become inefficient in the future.

Charging strategies used in this study are characterized by system peak impacts

We characterize two bookend performance-based charging strategies that that minimize or maximize EV charging load during the hour each year when utility demand is the highest. We also consider the magnitude of the incremental EV charging load and whether it sets a new utility annual peak demand. Many utility costs, especially generation capacity and energy costs, are driven by system peak demand. By focusing on these extremes, our analysis can quantify the maximum range of financial impacts, knowing that actual impacts will likely fall somewhere within this range. In this study:

- **Low Peak Impact** is the charging strategy that minimizes EV impacts on peak demand.
- **High Peak Impact** is the charging strategy that maximizes EV impacts on peak demand.



Study boundaries

This analysis does…	*This analysis does NOT…*
Compare outcomes between Low Peak Impact and High Peak Impact charging, across different EV deployment characteristics, and different EV adoption levels.	Model the “optimal” EV adoption or deployment characteristics to minimize utility or customer costs, or to achieve other objectives.
Consider an illustrative utility and generalized light-duty EV charging strategies with a range of reasonable EV deployment characteristics.	Evaluate a broad range of utility physical and financial characteristics, highly specific EV charging strategies and deployments, or medium- and heavy-duty EVs.
Quantify impacts on utility shareholder earnings and customer average rates.	Quantify rate impacts by customer class or participant vs. non-participant customer bills.

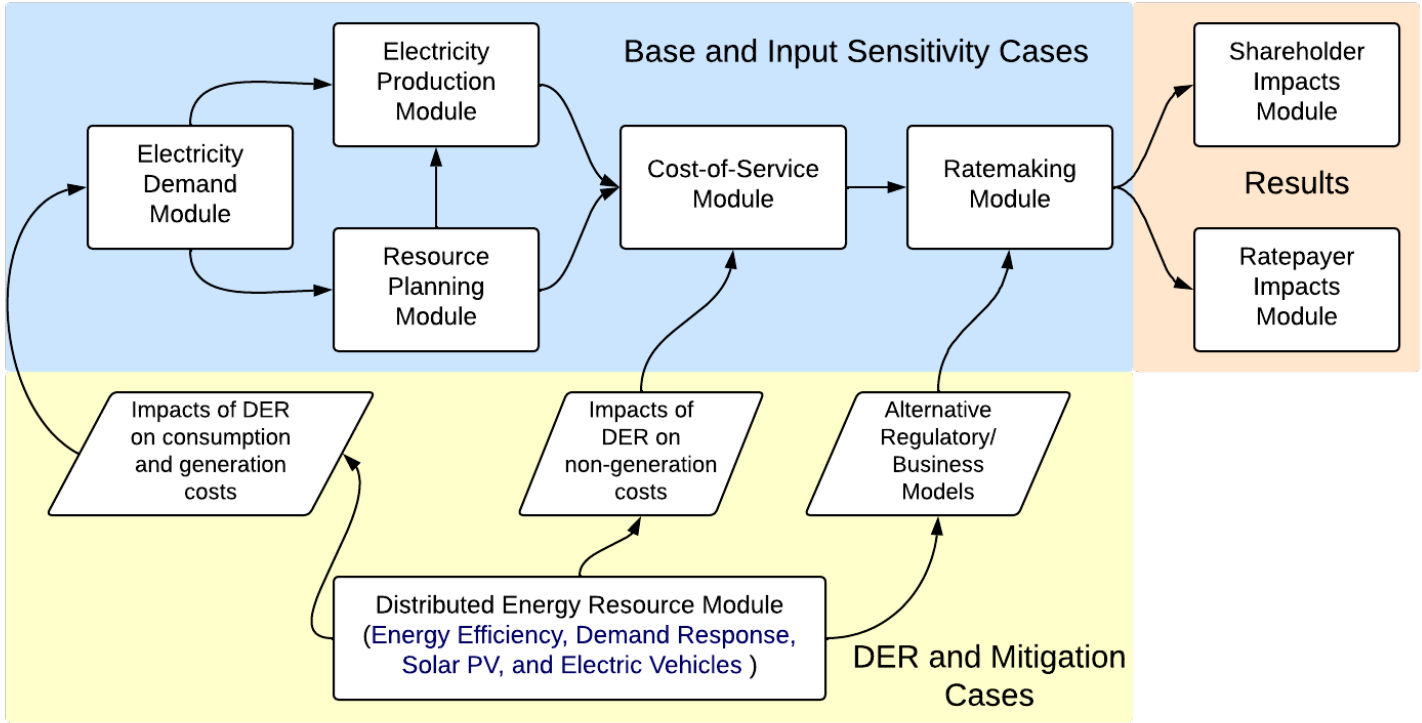
BERKELEY LAB

II. Analytical Approach

Berkeley Lab's FINDER model

The FINDER model is pro-forma financial model of changes in utility costs and revenues with the addition of DERs. The model emphasizes the representation of the utility planning and ratemaking processes, and utility accounting mechanisms. Model outputs include shareholder metrics (achieved return-on-equity (ROE) and earnings) and ratepayer metrics (average retail rates and bills).

The FINDER model has been developed over more than 14 years and used to support foundational research and state technical assistance in seven states and two regions. Throughout these projects, the FINDER model has been publicly reviewed and vetted.



For more information on the FINDER model and related publications, see: https://emp.lbl.gov/projects/finder-model

Analysis structure

Research question	What are the financial impacts of EVs under High Peak Impact charging?	How does a Low Peak Impact charging strategy affect financial impacts, and how robust are results to different deployment assumptions?
EV charging strategy	High Peak Impact charging	Low Peak Impact charging
Comparison point	No incremental EVs	High Peak Impact charging
Sensitivity cases	None	Charging location, average VMT, utility EV enablement costs, and EV-driven distribution CapEx costs

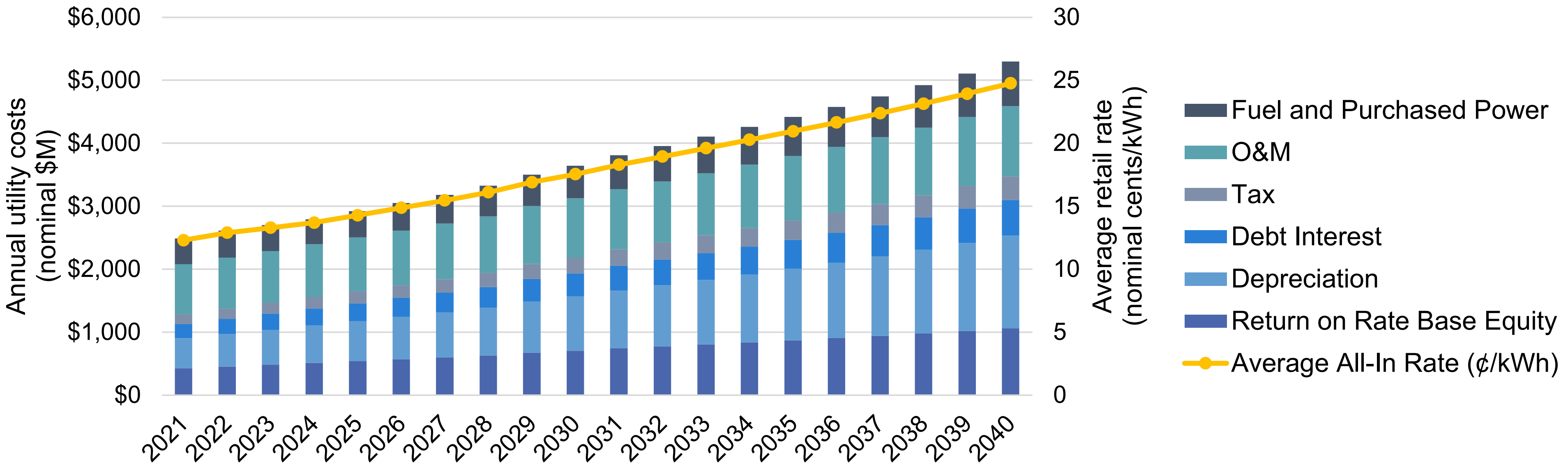
We first establish the financial impacts of EVs under a High Peak Impact charging strategy compared to a future without incremental EVs (see page 9 for definitions of charging strategies). We then identify the effectiveness of a Low Peak Impact charging strategy in mitigating financial impacts. Finally, we explore sensitivity and robustness of results across four sensitivity cases that vary EV deployment characteristics and impacts on utility retail sales, peak demand, and direct costs.

Financial metrics

Metric	Calculation	Representation
Earnings	Revenues - Costs	Quantifies future utility earnings opportunities
All-in Average Retail Rate	Revenues / Sales	Quantifies total rate impacts across all utility ratepayers
Annual Cost per EV	Costs / EVs	Quantifies average incremental annual utility cost impact of integrating EVs (inclusive of utility generation, distribution, EV program, and charging control costs)

We report three financial impact metrics: utility achieved after-tax earnings, ratepayer all-in average retail rates, and incremental costs per EV. All financial metrics are discounted over 20 years assuming a 7% nominal rate for utility earnings (representing average utility weighted average cost of capital) and a 5% nominal rate for average all-in retail rates and costs per EV. Discount rates are consistent with prior studies (e.g., Cappers et al., 2019; Satchwell et al., 2017).

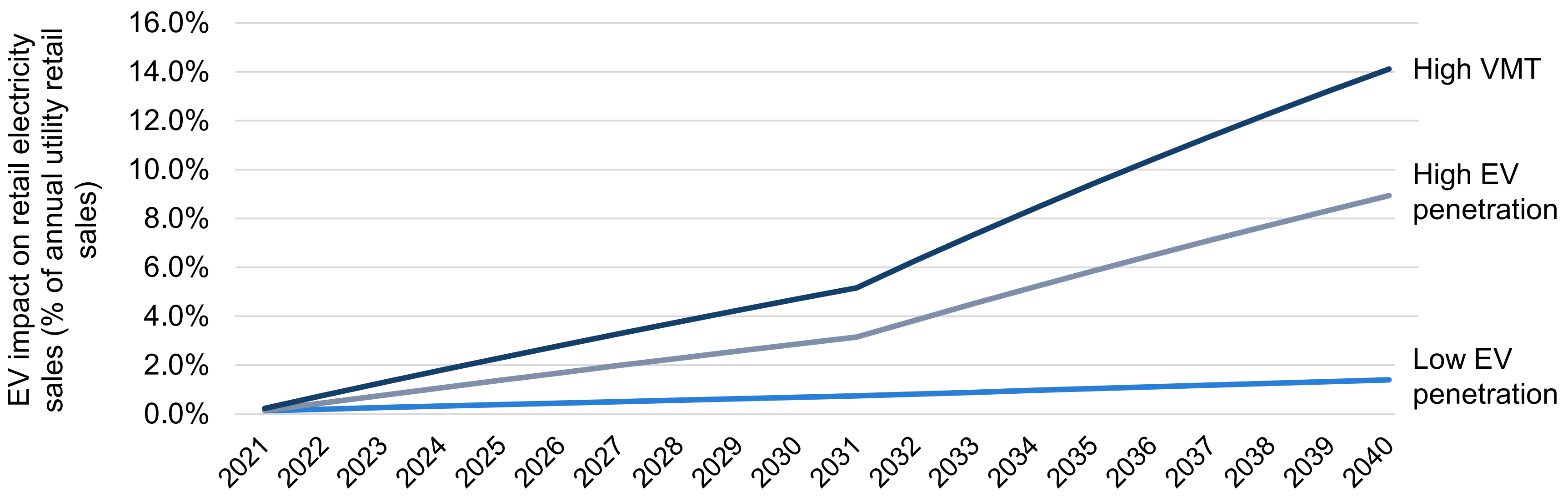
Summer-peaking, vertically integrated utility characterization



We model a US vertically integrated utility intended to be generally representative of a summer-peaking utility with average costs and cost growth. The model input assumptions are based on recent historical data (i.e., within the previous 2-3 years) and do not incorporate impacts of changes to federal or state policies (e.g., clean energy tax credits) or other trends in future utility costs and loads (e.g., via building electrification). We assume the utility collects revenue via flat, average rates and does not have revenue decoupling.

Based on our input assumptions and prior to adding EVs, the modeled total non-fuel costs grow at a 4.3% compound annual rate while total fuel and purchased power (FPP) costs grow at a 2.9% compound annual rate from 2021 to 2040. The modeled average all-in retail rate is 12.3 ¢/kWh in 2021 and grows at a compound annual rate of 3.7% per year through 2040 (roughly doubling to ~24.8 ¢/kWh).

How do we represent EV impacts on utility sales?

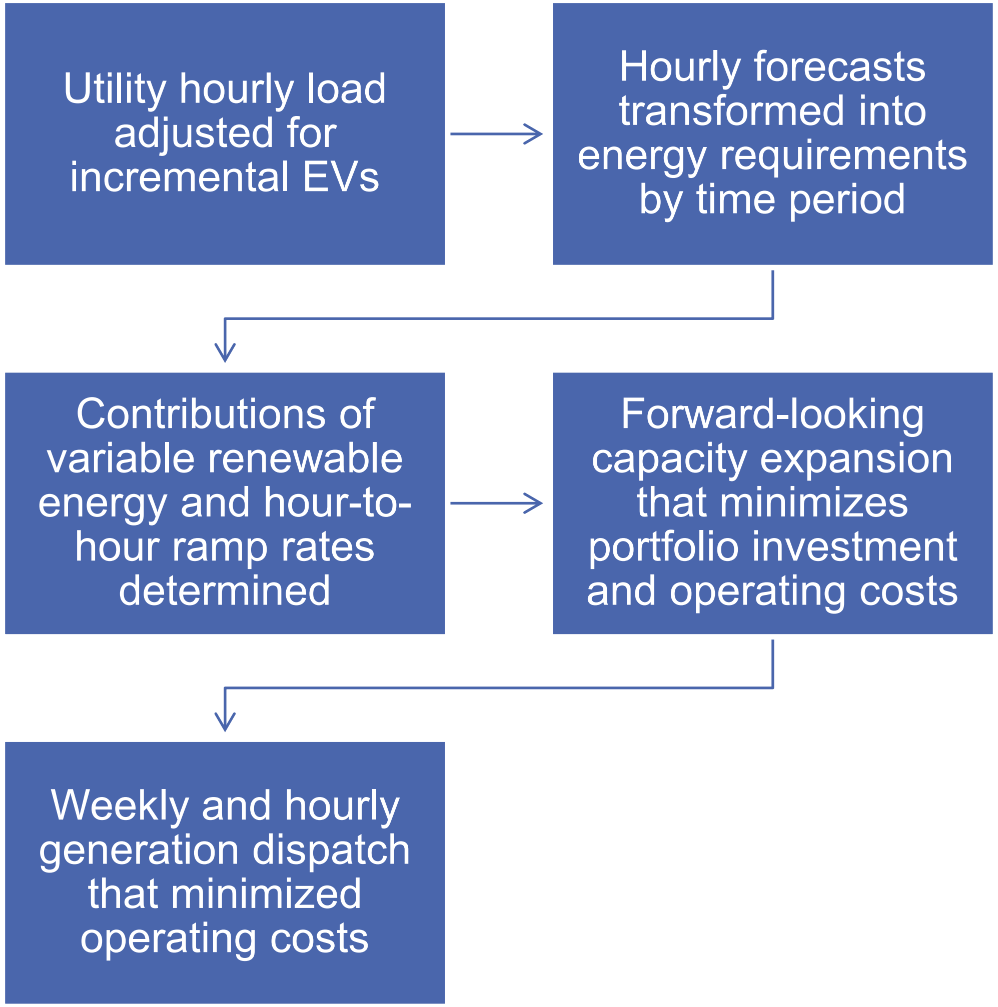


Annual EV impacts on retail electricity sales are based on the share of light-duty vehicle (LDV) stock and average daily VMT. Assumptions are consistent with scenarios in the NREL Electrification Futures Study (Mai et al., 2018) and meant to be representative if not necessarily comprehensive. Compared to 2021:

- The Low EV penetration scenario represents 8% LDV stock and a ~1.5% increase in 2040 retail electricity sales.
- The High EV penetration scenario represents 56% LDV stock and a ~9.0% increase in 2040 retail electricity sales.
- We also develop a sensitivity case assuming High VMT that represents a ~14.0% increase in 2040 retail electricity sales (based on the highest VMT assumption in EVI-Pro Lite).

How do we characterize EV impacts on utility generation and supply costs?

Generation capital, operations and maintenance (O&M), and FPP costs are modeled *endogenously* in FINDER using a built-in capacity expansion and dispatch logic. Endogenous modeling allows new generating plants and supply purchases to meet growth in retail sales and peak demand from EVs. Importantly, the portfolio of utility generation that is built and its hourly dispatch is optimized to be the least cost to ratepayers while meeting important planning and operational constraints (e.g., ramping requirements, renewable portfolio standards). The capacity expansion and dispatch logic starts with utility loads (inclusive of residential, commercial, and industrial customer loads) and EV charging hourly load shapes; bins and transforms them into simplified load representations; determines the future generation portfolio; and then dispatches the generation portfolio to meet hourly load in each year (see figure at right).



How do we characterize EV impacts on utility distribution and program costs?

Utility distribution CapEx and O&M costs are modeled *exogenously* outside of FINDER. EV charging can trigger distribution system upgrades when demand exceeds certain thresholds. Because a utility-specific model was not available for this study, we developed a reasonable proxy based on expert-elicited probabilities of feeder upgrades and costs driven by EV impacts on coincident peak and non-coincident peak demand (see CalETC, 2020). We use non-coincident maximum residential EV charging demand as the power level to inform secondary distribution system upgrade estimates, and coincident peak demand as the power level to inform primary system and substation upgrade estimates.

Utility EV enablement costs are also modeled *exogenously* outside of FINDER. These represent the ratepayer-funded costs of implementing utility EV programs and utility-owned EV charging infrastructure (including direct ownership and customer rebates). We exclude host site investment costs (i.e., EV owner, workplace, or municipal cost contribution). Utility EV enablement costs are based on publicly available utility regulatory filing data, as well as caps on program size intended to represent the utility market share of EV charging infrastructure. Additional charger control and communication costs are assumed to enable implementation of a Low Peak Impact charging strategy (see supplemental information for additional details on sources and range of utility EV enablement costs).

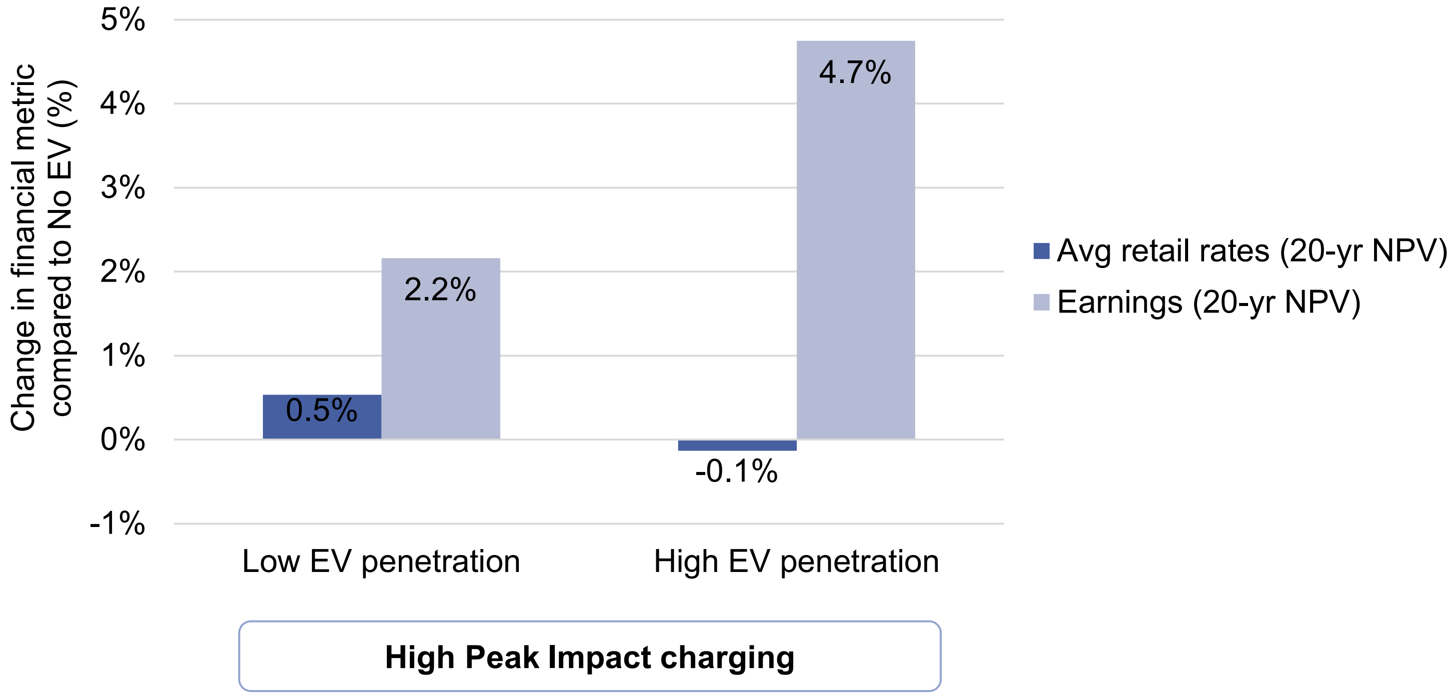
BERKELEY LAB

III. Results

What are the financial impacts of EVs under High Peak Impact charging?

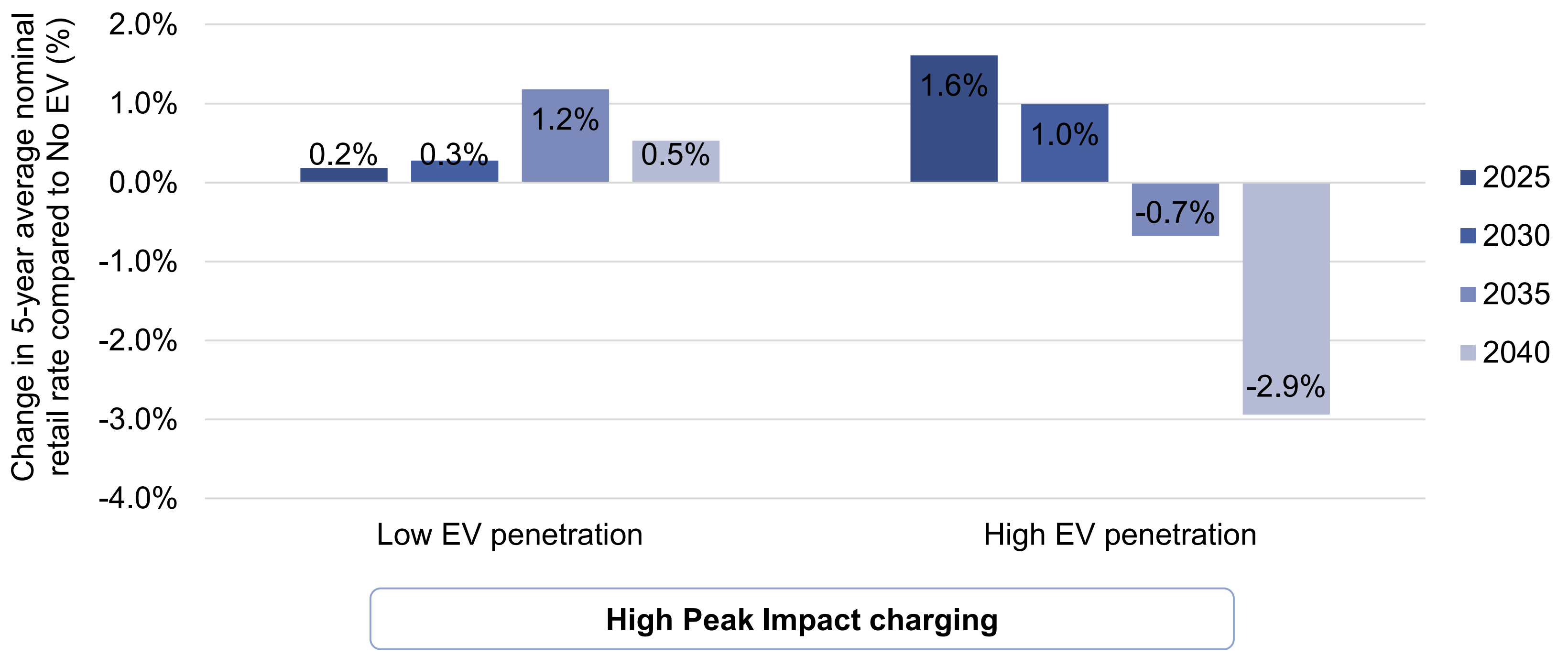
Comparison point: Utility without any incremental EV deployment

EVs generally increase shareholder earnings and retail rates are remain roughly unchanged



Compared to a scenario without incremental EVs and assuming EV charging is highly coincident with utility system peak demand (i.e., under High Peak Impact charging), all-in average retail rates increase modestly (~0.5%) at Low EV penetration and slightly decrease (-0.1%) at High EV penetration levels. Utility shareholder earnings increase ~2.2% to 4.7% as EV penetration level increases.

Rate impacts are driven by timing of infrastructure investments and increase in sales

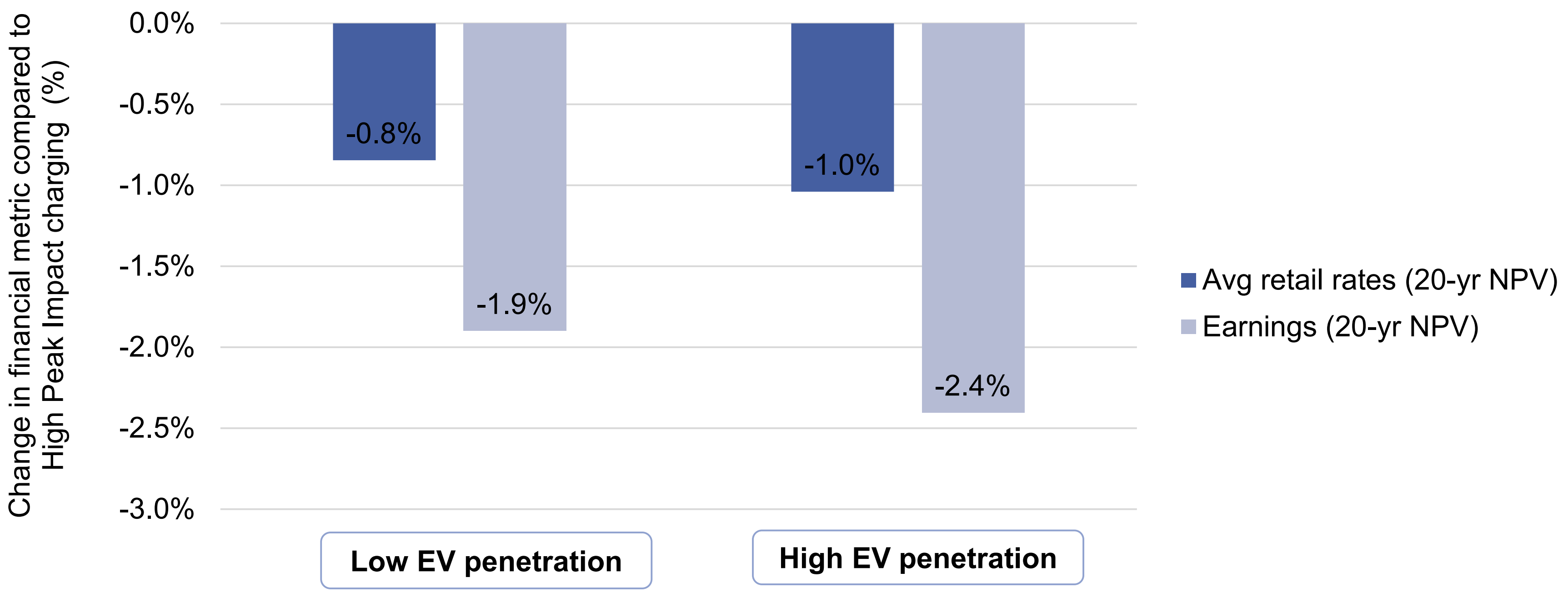


Although large early infrastructure investments cause rates to initially rise, sales increases from EV load at High EV penetration cause average rates to drop substantially over time (e.g., ~2.9% reduction between 2035 and 2040). At Low EV penetration, investments in generation and distribution infrastructure are not sufficiently offset by sales growth to cause rates to decline, though the increase in retail rates slows in later years of the analysis period. Rate increases (e.g., ~1.2% between 2030 and 2035 at low EV penetration) are particularly sensitive to large, lumpy investment costs (e.g., from the addition of new generating plants, which account for ~48-61% of total incremental capital investment).

How does a Low Peak Impact charging strategy affect financial impacts, and how robust are results to different deployment assumptions?

<u>Comparison point</u>: Utility with incremental EVs deployed with High Peak Impact charging

Low Peak Impact charging reduces rates and earnings



EVs deployed under Low Peak Impact charging reduce average retail rates (~0.8-1.0%) by lowering incremental generation and distribution system investment costs. The Low Peak Impact charging reduces coincident peak demand relative to the High Peak Impact charging strategy but maintains the same level of annual energy, which results in fewer demand-driven costs spread over the same level of retail sales. Shareholder earnings are also reduced under the Low Peak Impact charging strategy (~1.9%-2.4%), because reductions in new generation and distribution infrastructure investments erode some of the incremental earnings. It’s important to note, however, that utility shareholders are better off compared to a future without EVs even under Low Peak Impact charging.

Shareholder earnings impacts are primarily driven by incremental investment costs that are typically much higher in High Peak Impact EV charging deployment scenarios

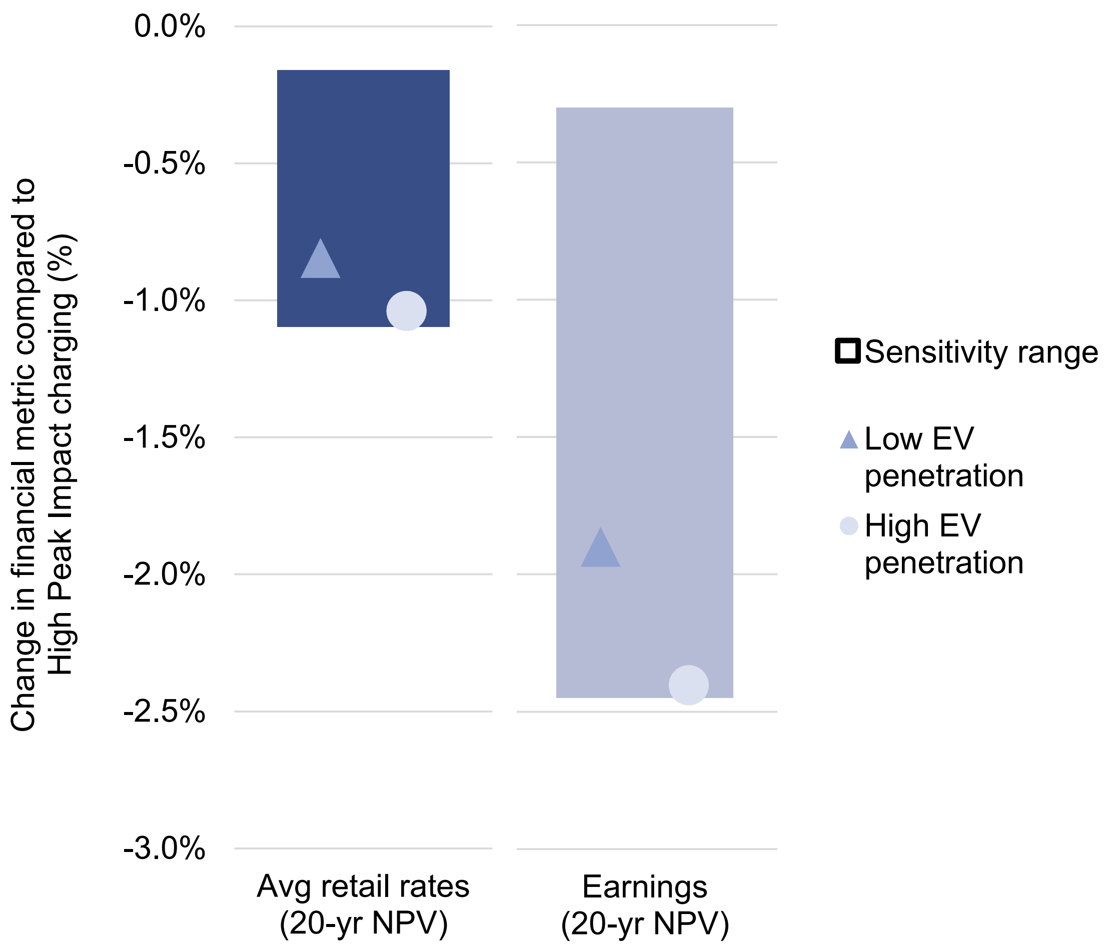
EV Penetration and Charging Strategy	Incremental Generation Costs ($M; 20-yr NPV)	Incremental Distribution Costs ($M; 20-yr NPV)	Incremental Capitalized EV Program Costs ($M; 20-yr NPV)	Total Incremental CapEx Costs ($M; 20-yr NPV)	
Low EV High Peak Impact	$362	$175	$53	$589	
Low EV Low Peak Impact	$12	$11	$62	$85	-86%
High EV High Peak Impact	$602	$357	$283	$1,242	
High EV Low Peak Impact	$342	$213	$331	$886	-29%

Incremental distribution and generation investments, as well as capitalized EV charging infrastructure, increases equity ratebase and provides a financial upside to shareholders. Low Peak Impact EV charging strategies reduce incremental generation and distribution CapEx costs relative to the High Peak Impact charging strategy by lowering peak demand impacts, though incremental capitalized EV program costs are slightly higher under Low Peak Impact EV charging to accommodate additional charging controls and communication costs. Low Peak Impact charging reduces total incremental CapEx costs between 29% and 86% depending on the EV penetration level.

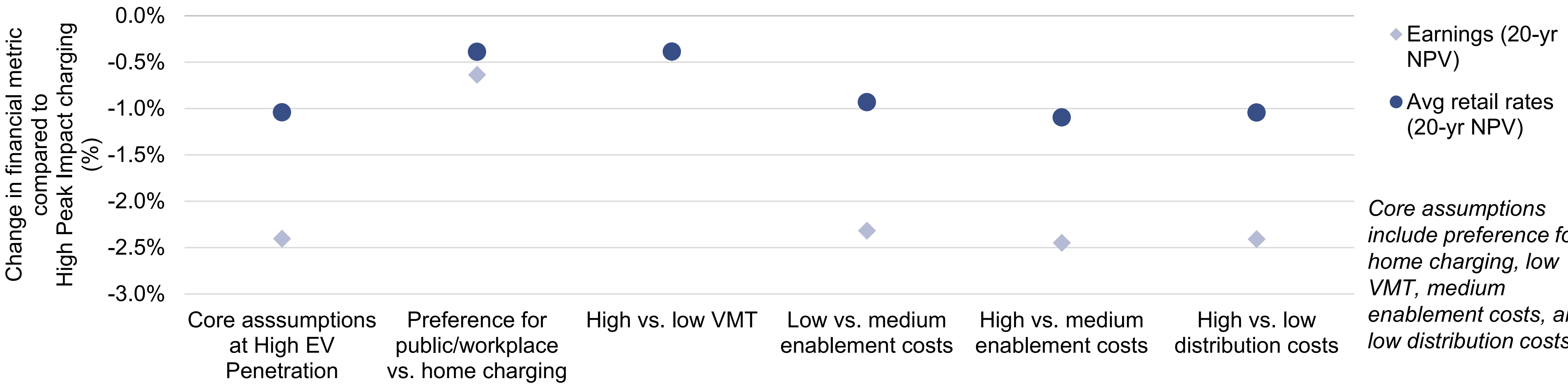
Financial impacts of Low Peak Impact charging are directionally consistent across sensitivities

The results across the sensitivity cases are all directionally consistent with core case results (i.e., all cases reduce average retail rates).

The range of impacts to shareholders is larger than to ratepayers due to differences in what types of costs change (i.e., average retail rates are affected by *all* costs, whereas shareholder earnings are affected primarily by CapEx costs).



Shifting EV charging to midday or increasing EV impacts on retail electricity sales minimizes differences between charging strategies



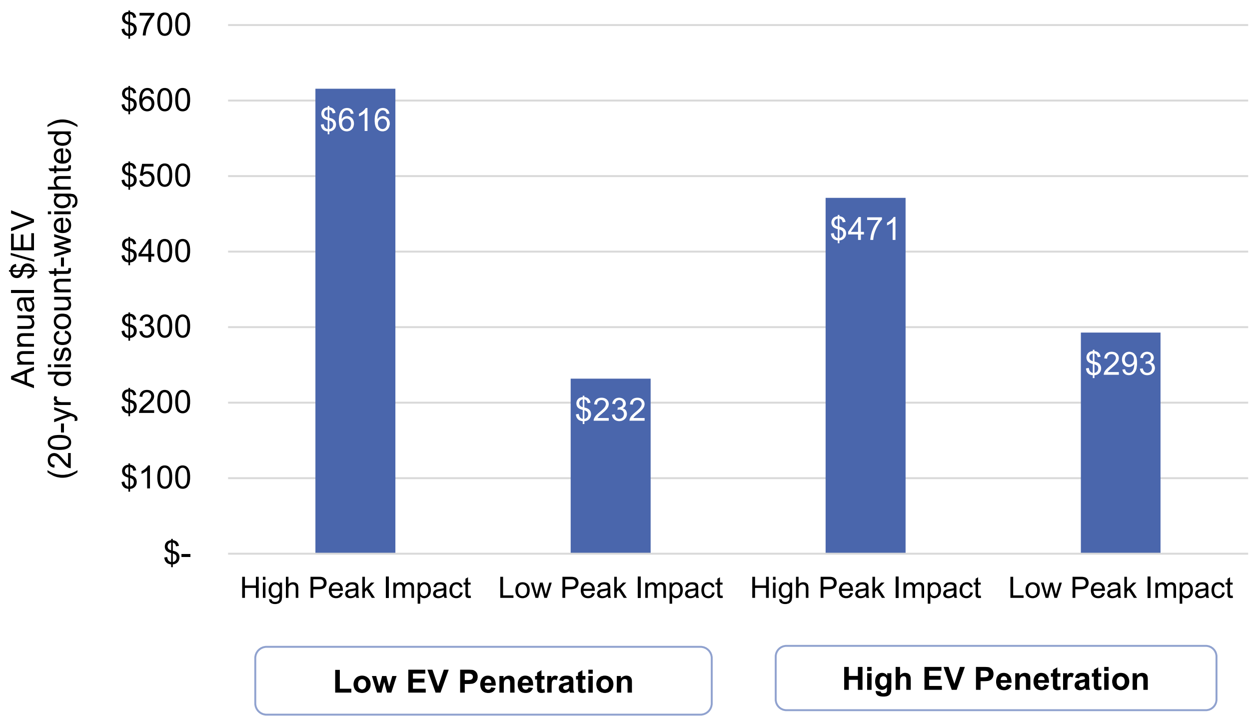
Core assumptions include preference for home charging, low VMT, medium enablement costs, and low distribution costs.

The effect of Low Peak Impact charging on the financial impacts of High Peak Impact charging is most sensitive to **where EV charging occurs** and **increases in electricity load from charging**. Increasing the amount of charging at public and/or workplace locations shifts charging from mostly nighttime (when residential charging tends to occur) to mid-day hours. A shift to more public/workplace charging results in a charging profile similar to the High Peak Impact charging strategy, thus reducing the difference between them. One implication of this finding is that workplace charging may encourage mid-day load building, which may or may not be economically efficient from the utility cost perspective. Higher VMT increases peak demand impacts of EVs which in turn accelerates generation and distribution infrastructure investments, particularly for Low Peak Impact charging (even when these incremental investments are smaller than in the High Peak Impact case). The remaining sensitivity cases change cost assumptions for both the High Peak Impact and Low Peak Impact charging strategies by approximately the same amount and result in little difference compared to results based on core assumptions.

Managed charging strategies reduce the incremental annual cost of integrating EVs by ~38-62%

Improvements in EV charging management strategies have a bigger impact on the annual cost of integrating EVs under low penetration (~$380 per EV) than under high penetration (~$180 per EV). The managed charging costs per EV are inclusive of the benefits of lower total CapEx and operational costs (see page 25) plus the ratepayer-funded portion of incremental control and communication costs to enable Low Peak Impact charging.

The cost per EV results can be used to inform customer and/or shareholder incentive design to promote Low Peak Impact charging strategies, though incentives would be a new and incremental cost that would increase average all-in retail rates. The results can also inform utility planners and power system analysis about range of costs to integrate EVs as a "rule of thumb."



IV. Conclusions and Discussion

Key findings and discussion

The study finds that ratepayers are always better off if EVs are deployed with Low Peak Impact (i.e., “managed”) charging strategies because of lower cost impacts. This suggests that pricing and programs to encourage non-coincident peak charging are highly beneficial from the ratepayer perspective. Compared to a future without EVs, shareholders are also better off, but managed charging reduces new generation and distribution infrastructure investments and erodes some of the incremental earnings.

Large initial utility infrastructure investments enable both greater EV deployments and greater long-term decreases in retail electricity rates. These investments also lead to near-term rate increases, representing a shift from the recent utility environment of declining sales and limited new generation capital investments. A forward-looking, long-term perspective can overcome near-term rate increases and enable long-term decreases.

The rate impacts in this study are overall quite small on a total utility basis but could be more significant for certain customer classes depending on cost allocation and cost recovery, which this study does not explore. Furthermore, even under High Peak Impact charging and pronounced increases in system costs, we find that ratepayer impacts are not too severe, likely giving decision-makers adequate time to address related concerns.

Finally, the “managed” charging behavior we modeled was based on the aggregate EV charging profile that minimized utility system peak impacts. Implementing this optimal strategy would require dynamic infrastructure planning processes and/or flexible managed charging strategies to reflect how the utility load shape evolves inclusive of EV load (e.g., EV TOU periods will change from overnight to mid-day as coincident peak EV load impacts increase).

Future research opportunities

We identify several future opportunities to build on this study by enhancing the precision and expanding the scope of the results:

- Assume higher and lower EV penetration levels than were modeled in this study to provide additional data points and reveal linearity or non-linearity in financial impacts (e.g., does doubling the EV penetration double the financial impacts?).
- Model a different pace of EV adoption to assess sensitivity of timing of rate increases and decreases.
- Model medium-duty and heavy-duty EVs (MDVs and HDVs) and impacts on charging requirements and utility generation and distribution system expansion costs.
- Incorporate a more detailed distribution cost model for more nuanced differences between scenarios and to allow for distribution system expansion beyond upgrading the existing feeders.
- Explore additional charging strategies and profiles, utility characterizations, and customer-class impacts for a more comprehensive picture of the utility and ratepayer impacts.
- Model EV-specific rate designs and quantify cost shifts between EV owners and non-EV owners.
- Perform a benefit-cost analysis based on the National Standard Practice Manual for DERs using utility revenue requirement values from FINDER and other modeling to assess EVs from additional perspectives (e.g., societal, non-participating customer).

BERKELEY LAB

Contacts

Andrew Satchwell | ASatchwell@lbl.gov
Juan Pablo Carvallo | JPCarvallo@lbl.gov
Peter Cappers | PACappers@lbl.gov

For more information

Download publications from the Electricity Markets & Policy: https://emp.lbl.gov/publications
Sign up for our email list: https://emp.lbl.gov/mailing-list
Follow the Electricity Markets & Policy on Twitter: @BerkeleyLabEMP

Acknowledgements

This work was funded by the U.S. Department of Energy (DOE) Office of Energy Efficiency and Renewable Energy (EERE) Strategic Analysis Team (SA) under Contract No. DE-AC02-05CH11231. We would like to especially thank Ookie Ma and Kara Podkaminer (DOE) for their support of this work. For reviewing the study and providing valuable feedback, we thank Michelle Levinson (World Resources Institute), Galen Barbose (Berkeley Lab), and Kara Podkaminer, Noel Crisostomo, and Paul Spitsen (DOE).

The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof, or The Regents of the University of California.

References

Boston Consulting Group. 2019. The Costs of Revving Up the Grid for Electric Vehicles. December 20. Available at: https://www.bcg.com/publications/2019/costs-revving-up-the-grid-for-electric-vehicles

California Electric Transportation Coalition [CalETC]. 2020. The Infrastructure Needs and Costs for 5 Million Light-Duty Electric Vehicles in California by 2030. Available at: https://caletc.com/assets/files/EV-infrastructure-study-white-paper-FINAL.pdf

Cutter, E., E. Rogers, A. Nieto, J. Leana, J. Kersey, N. Abhyankar, and T. McNair. 2021. Distribution Grid Cost Impacts Driven by Transportation Electrification. Available at: https://www.ethree.com/wp-content/uploads/2021/06/GridLab_2035-Transportation-Dist-Cost.pdf

Fitch, T., J. Frost, and M. Whited. 2022. Electric Vehicles are Driving Electric Rates Down. Synapse Energy Economics: October 2022 Update. Available at: https://www.nrdc.org/sites/default/files/media-uploads/evs_are_driving_rates_down_dec_2022_update_0.pdf

Mai, T., P. Jadun, J. Logan, C. McMillan, M. Muratori, D. Steinberg, L. Vimmerstedt, R. Jones, B., and B. Nelson. 2018. Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71500. Available at: https://www.nrel.gov/docs/fy18osti/71500.pdf

Cappers, P., A. Satchwell, W. Gorman, and J. Reneses. 2019. "Financial Impacts of Net-Metered Distributed PV on a Prototypical Western Utility's Shareholders and Ratepayers" *Energies* 12, no. 24: 4794. Available at: https://doi.org/10.3390/en12244794

Satchwell, A., P. Cappers, and C. Goldman. 2017. Financial Impacts of a Combined Energy Efficiency and Net-Metered PV Portfolio on a Prototypical Northeast Utility. Available at: https://emp.lbl.gov/publications/financial-impacts-combined-energy

Szinai, J.K., C.J.R. Sheppard, N. Abhyankar, and A. R. Gopal. 2020. "Reduced Grid Operating Costs and Renewable Energy Curtailment with Electric Vehicle Charge Management" *Energy Policy* 136 (101). Available at: https://doi.org/10.1016/j.enpol.2019.111051