Electric Rate Impacts of Medium- and Heavy-Duty Vehicle Electrification Investments

May 2026

Energy+Environmental Economics

E3 Authors

Emily Rogers, Senior Managing Consultant

Christa Heavey, Director

Paul Picciano, Managing Consultant

Caitlin McMahon, Senior Consultant

Eric Cutter, Partner

Energy and Environmental Economics, Inc. (E3)
44 Montgomery Street, Suite 1250
San Francisco, CA 94104

Acknowledgments

This report was funded by Powering America’s Commercial Transportation (PACT), with support from the Edison Electric Institute (EEI). E3 is an independent economic consulting firm, and all report conclusions and analysis are our own.

Table of Contents

Table of Figures

Table of Tables

Acronym Definitions

Acronym	Definition
ACC	Avoided Cost Calculator
BEV	Battery Electric Vehicle
CA	California
CPUC	California Public Utilities Commission
EIS	Electrification Impact Study
GA	Georgia
IEPR	Integrated Energy Policy Report
MHD	Medium- and Heavy-Duty
MHDV	Medium- and Heavy-Duty Vehicles
O&M	Operations and Maintenance
PG&E	Pacific Gas & Electric
TOU	Time-of-use rates
VMT	Vehicle miles traveled

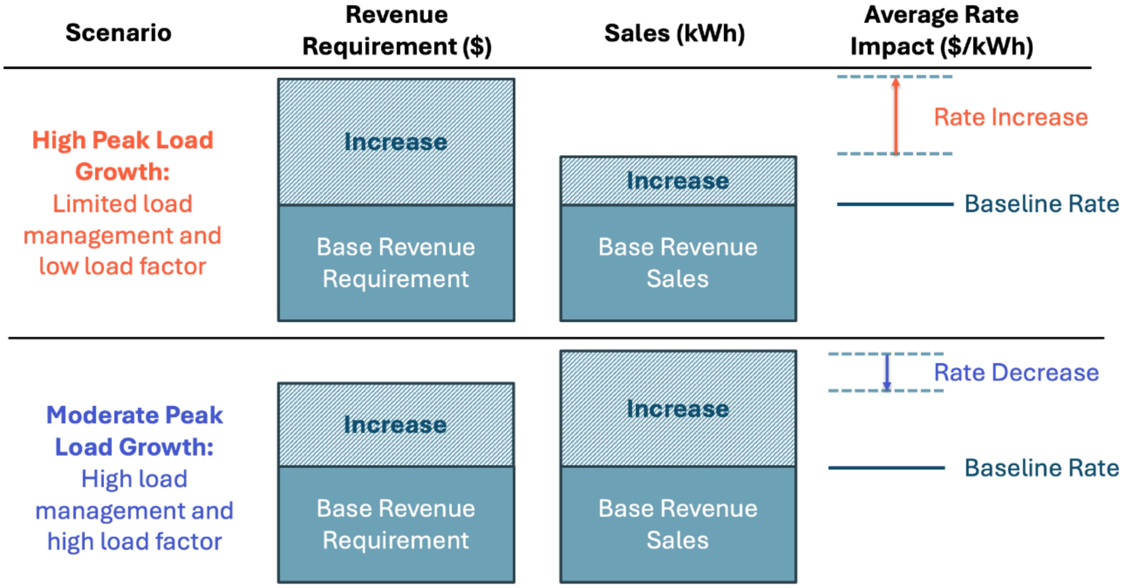
Executive Summary

Utilities are weighing investments to integrate medium- and heavy-duty (MHD) vehicle electrification while facing rate affordability challenges in many parts of the country. As electricity demand rises nationally, including demand from transportation electrification, understanding how MHD vehicle load affects customer rates is critical for policymakers, utilities, and fleet operators.

This study evaluates how MHD vehicle electrification will affect average residential electricity rates in California (PG&E) and Georgia (Georgia Power) in 2028 and 2035, isolating the impact from all other drivers of rate change by holding system conditions constant to 2024 levels. The analysis examines multiple scenarios, including an unmanaged charging scenario and a conservative managed charging scenario, and incorporates a range of distribution infrastructure cost assumptions using regulator-recognized marginal cost and cost allocation frameworks. Publicly available data informs all system cost, marginal cost, and load forecasts; however, limited available public data in Georgia required reliance on select California data sources for certain cost categories.

Using a three-step cost allocation and ratemaking framework, as shown in Executive Summary Figure 1 below, the study quantifies incremental utility system costs for added MHDV load, allocates those costs across customer classes using standard cost-of-service principles, and estimates the resulting change in average residential rates. New MHDV load increases both energy sales and certain categories of system costs (generation, transmission, distribution). Whether rates experience upwards or downward pressure depends on the relative magnitude of these effects.

Executive Summary Figure 1. Illustrative Rate Impact Dynamics

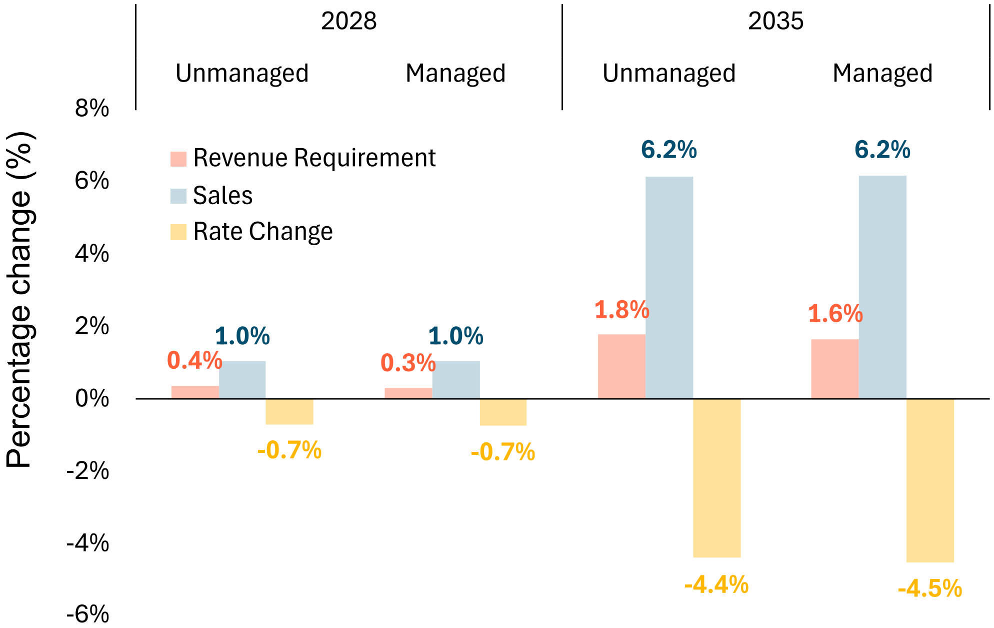


Results show that MHD vehicle electrification applies neutral to downward pressure on residential rates in both California and Georgia in the core scenarios.

1. **California** (PG&E): In the main scenario using ACC-based marginal costs, MHDV electrification applies downward pressure on average residential rates in both 2028 and 2035, as increased sales outweigh incremental costs. However, when higher distribution costs derived from PG&E's Electrification Impact Study (EIS Part 2) are applied, electrification produces upward rate pressure in 2028 and in 2035 under unmanaged charging, while managed charging returns downward pressure by 2035.
2. **Georgia** (Georgia Power): Due to significantly smaller MHDV adoption levels and lower incremental costs, the impact on residential rates is neutral to slightly downward in 2028 and 2035 across all scenarios.

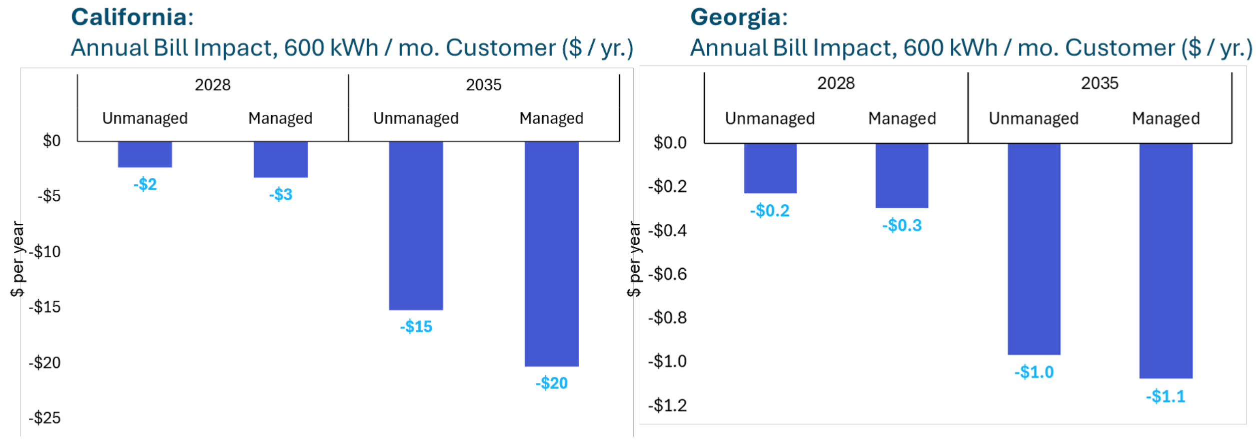
Executive Figure 2 illustrates how MHD vehicle electrification applies pressure on rates by increasing both electricity sales, shown in blue, and the utility revenue requirement, shown in red. At the system-wide level, average rate impacts depend on the relative growth of these two components: if system sales grow faster than the revenue requirement, average rates experience downward pressure. The California ACC-based marginal costs scenario is shown in this figure.

Executive Figure 2. PG&E Change in Revenue Requirement, Sales, and Rate Impacts from MHD Electrification



Illustrative bill impacts for a representative residential customer indicate savings in the core scenarios (up to ~$20/year in California by 2035, ~$1/year in Georgia). These results are shown below in Executive Figure 3.

Executive Figure 3. Annual Bill Impact for Average Residential Customers


California: Annual Bill Impact, 600 kWh / mo. Customer ($ / yr.)

Georgia: Annual Bill Impact, 600 kWh / mo. Customer ($ / yr.)

The timing and certainty of load materialization plays a role in rate pressure. Since utilities make large upfront infrastructure investments to prepare for new load, delayed or lower load materialization force these upfront investments to be recovered over a smaller number of kilowatt-hours and thus could apply upward pressure on rates. In practice, MHD vehicle electrification and associated rate impacts will occur differently on a utility-by-utility basis but least regrets strategies can help ensure favorable outcomes.

Several key factors can support MHD vehicle electrification driving neutral to downward pressure on electric rates:

1. Transmission and distribution system upgrade costs: Strategically siting MHD electric vehicle charging, enabling flexible interconnection strategies, and actively managing load can minimize or defer costly grid infrastructure upgrades, which strongly influence overall rate impacts.
2. Ratemaking: Timely updates to cost allocation and rate design ensure new MHD vehicle loads and associated costs are properly incorporated into rates, reducing the risk of cost shifts to other customers.
3. Tariff design and cost responsibility: Smart tariff design and cost responsibility rules can support utilities in right-sizing investments for future loads to minimize risks of lower or delayed load materialization. Rate structures that can support electrification load materialization include time-of-use rates, which encourage usage during low marginal supply cost hours, and subscription charges or grid access charges, which give fleets higher predictability on their electric bills while recovering costs for the utility based on available site capacity.
4. Proactive planning and communication: Early coordination between fleets and utilities, supported by integrated system planning, can lower system costs, prioritize cost-effective investments, and mitigate risks associated with uncertain load growth.

Introduction

Utilities are weighing investments to integrate medium- and heavy-duty (MHD) vehicle electrification while facing rate affordability challenges in many parts of the country. Providing a clear narrative on how MHD vehicle electrification affects rates and rate affordability is extremely important as more fleets consider their future electrification and utilities plan to integrate large electrification loads.

Electrification is generally beneficial to utilities and their customers: with new electric load, a utility's fixed costs can be spread among more kilowatt-hours, thus putting downward pressure on customer rates over time. However, electrification also drives additional fixed costs, as electric utilities will need to invest in grid infrastructure to ensure new load from electrification can be supported. E3 evaluated these two competing trends – new investment costs that may apply upward pressure on rates versus increased load to recover those fixed costs and reduce average rates – to determine the impacts of MHD vehicle electrification to average residential rates in California and Georgia in the short and long terms. E3 evaluated residential rates specifically due to the importance of affordability and ensuring that changes in the commercial and industrial sectors do not impact residential customers.

E3 evaluated the impact of new MHD vehicle electrification loads on revenues and the following cost categories: energy, generation capacity, transmission, and distribution. If revenues and costs are equal, there is no impact on rates. If costs exceed revenues, new load may lead to upward pressure on rates and cause cross subsidization. If revenues exceed costs, new load drives downward pressure on rates.

Vehicle electrification, and MHD vehicle electrification in particular, is expected to trigger upgrades to the transmission and distribution systems due to high-powered DC fast charging stations and load hot spots along transit and shipping corridors. Because utility transmission and distribution upgrades are shared infrastructure, and costs are therefore socialized amongst utility ratepayers, it is important to analyze how these investments affect residential rates. Socialization of infrastructure costs across utility ratepayers is a feature of traditional utility ratemaking and applies to infrastructure costs generally, not only for MHD vehicle electrification. E3 evaluated a high distribution cost sensitivity because the size and cost of transmission and distribution upgrades triggered by new MHD vehicle load are uncertain.

There are many factors that impact rate changes over time. This study isolates the impact of MHD vehicle electrification on rates by keeping all other factors equal to 2024 levels. The conclusion of this study provides a directional impact of MHD vehicle electrification on rates and does not conclude that rates will increase or decrease in absolute terms, since many other factors (i.e. replacement of aging infrastructure, grid hardening investments) impact rates.

Effective policies and tariff design can help ensure that new MHD vehicle electrification loads apply neutral to downward pressure on rates. E3 examined rules regarding cost responsibility for transmission and distribution infrastructure investments and tariff design for electric vehicle customers.

Rate Impact Analysis

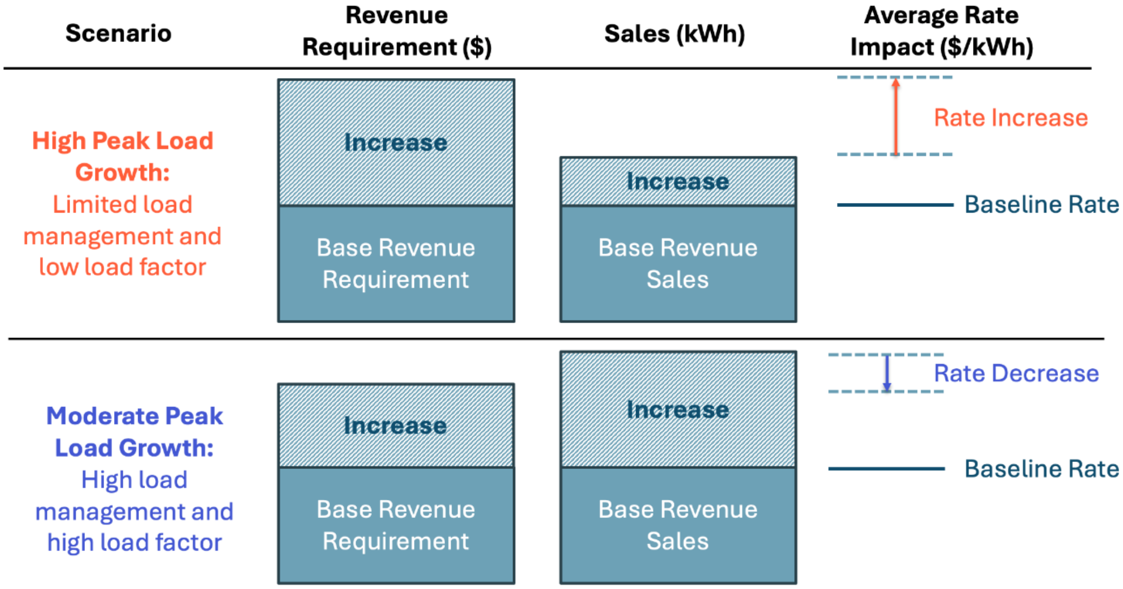
Methodology

Utility Ratemaking Background

Rate design is the process through which the utility revenue requirement is collected from customers using various charges. Utilities make capital investments in generation, transmission, and distribution infrastructure based on forecasts of future electric demand and system needs. Under cost-of-service regulation, these investments are incorporated into the utility revenue requirement via rate base and recovered over time through depreciation and a rate of return. Because investments are made in advance of load realization, differences in forecasted and realized load growth can affect the timing and distribution of cost recovery. E3 evaluated rates in the short-term in 2028 and long-term in 2035 to capture these effects.

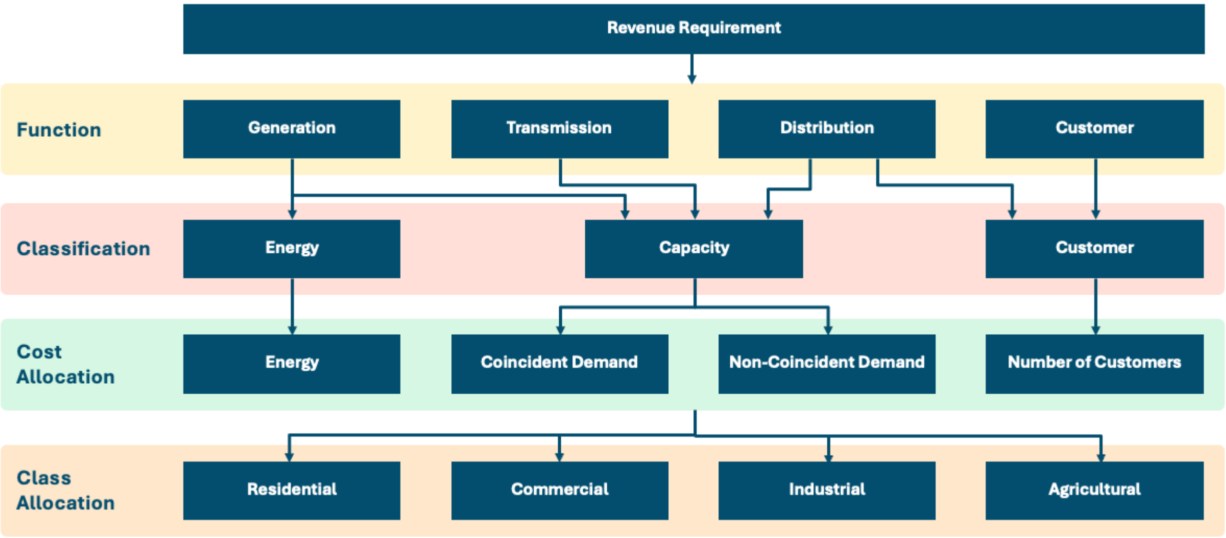
The balance between a new load's impact on utility revenue requirement vs. sales determines whether a new load will cause an average rate increase or decrease. This dynamic is illustrated in Figure 1 below.

Figure 1. Illustrative Rate Impact Dynamics



Utility rate design processes use function, classification, cost allocation, and class allocation to recover revenue requirement from customers classes, as shown in Figure 2 below. First, the revenue requirement is established, representing the total amount of revenue the utility must collect to recover costs from generation, transmission, distribution, and billing and customer service. Second, costs are allocated across customer classes to determine how much revenue should be collected from each group, based on drivers such as energy consumption, coincident peak (CP) demand, and noncoincident peak (NCP) demand. Third, rates are designed by structuring tariffs to collect the allocated revenue while balancing competing objectives such as cost reflectiveness, affordability, and support for electrification. To assess residential rate impacts in this analysis, we apply simplified assumptions regarding how the existing allocation of costs to the residential class evolves in response to growth in MHD vehicle electric loads.

Figure 2. Traditional cost of service study flowchart



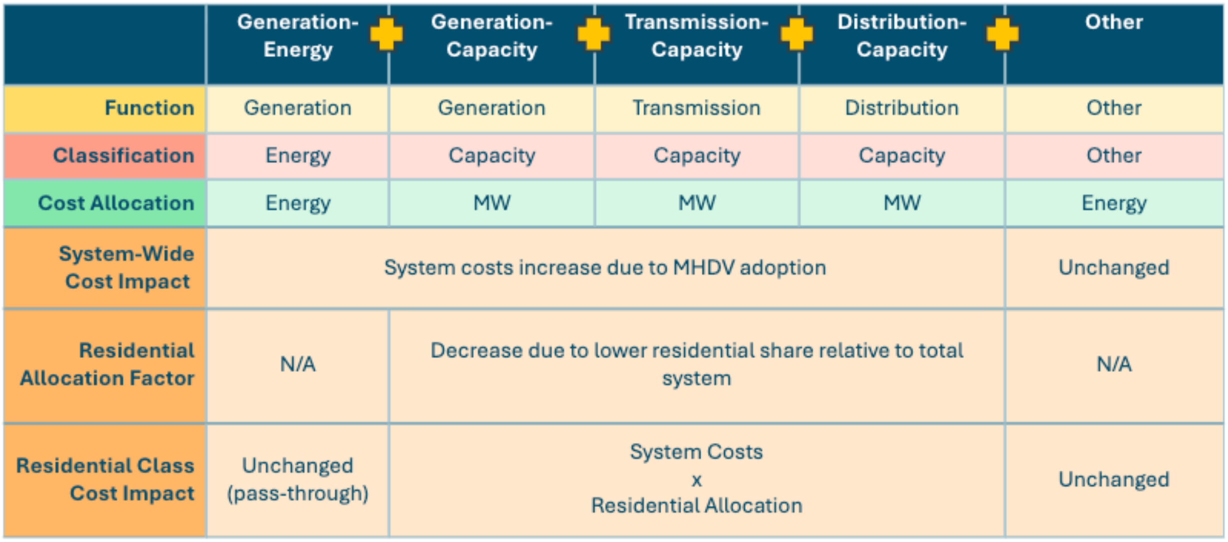
Analysis Approach

The analysis estimates residential electricity rate impacts from medium- and heavy-duty vehicle (MHDV) electrification using a three-step framework that mirrors traditional ratemaking processes. First, incremental impacts on electric system costs are estimated by assessing changes in generation energy, generation capacity, transmission capacity, and distribution capacity attributable to additional MHDV electric load. These incremental costs are added to baseline system cost levels to reflect post-electrification conditions.

Second, system costs are divided among customer groups based on measures such as electricity use and contribution to peak demand, reflecting standard cost allocation principles. In this analysis, overall system costs rise due to increased electricity use and required infrastructure upgrades from MHDV electrification, while residential electricity use is assumed to remain unchanged. As a result, the residential share of total system costs declines as MHDV adoption increases, all else equal. Note that these cost-sharing assumptions involve uncertainty and are litigated between utilities and regulators.

Finally, the total residential share of system costs is divided by residential electricity demand to estimate the average residential electricity rate impact in each analysis year, relative to 2024 average rates. This approach, outlined in Figure 3, provides a high-level estimate of rate impacts.

Figure 3. Rate Impact Calculation



	Generation-Energy	Generation-Capacity	Transmission-Capacity	Distribution-Capacity	Other
Function	Generation	Generation	Transmission	Distribution	Other
Classification	Energy	Capacity	Capacity	Capacity	Other
Cost Allocation	Energy	MW	MW	MW	Energy
System-Wide Cost Impact	System costs increase due to MHDV adoption				Unchanged
Residential Allocation Factor	N/A	Decrease due to lower residential share relative to total system			N/A
Residential Class Cost Impact	Unchanged (pass-through)	System Costs x Residential Allocation			Unchanged

Cost Categories

E3 evaluated how MHD vehicle electrification loads may affect electricity system costs by examining several key cost categories: generation energy, generation capacity, transmission capacity, and distribution capacity. These categories reflect the primary components of the electric system that may require additional investment as new MHDV load is added.

Generation energy costs reflect the cost of generating additional electricity to serve new MHDV charging demand. These costs are driven by which power plants operate on the margin to meet incremental energy needs and vary based on factors such as generator efficiency and fuel prices. Generation capacity costs reflect the cost of ensuring the electric system has sufficient power plant capacity to meet peak system demand and maintain reliability.

Transmission capacity costs represent the cost of upgrading transmission power lines and equipment to move electricity from supply to loads. Similarly, distribution capacity costs represent investments in lower voltage infrastructure, such as local distribution lines and substations, that deliver electricity from the transmission system to lower voltage customers. The hourly timing of load and location can have a large impact on associated transmission and distribution costs.

Distribution infrastructure plays a critical role in enabling EV charging and is a key bottleneck and cost driver for interconnection. Unlike generation and transmission systems, which are planned around aggregate system needs, distribution systems are highly localized and must accommodate load growth at specific substations, feeders, and service transformers. Primary distribution systems are generally planned to serve diversified coincident peak loads, assuming that not all connected equipment operates simultaneously. In contrast, secondary systems are sized based on connected load with much lower diversity factors, making them especially vulnerable to concentrated EV charging.

Deferring or avoiding distribution upgrades therefore depends on the availability of highly reliable mechanisms to shift or limit EV charging loads. Strategies such as managed charging, load controls, and time-based or capacity-based rates can reduce coincident peak impacts, allowing utilities to more fully utilize existing infrastructure. Without such measures, distribution upgrades could represent a significant share of the incremental capital costs for infrastructure needed to accommodate vehicle electrification – and therefore a material driver of residential rate impacts – although distribution cost estimates in particular have a wide range.

Scenarios

The analysis evaluates two planning horizons, a short-term outlook in 2028 and a long-term outlook in 2035. Two regions are examined: California (using inputs for Pacific Gas & Electric) and Georgia (using inputs for Georgia Power). California is selected as the primary target region for the revenue requirement model due to its strong electric vehicle (EV) adoption, relatively high retail electricity rates, and the availability of high-quality public data. The California Public Utilities Commission's (CPUC) Integrated Resource Plan (IRP) proceeding provides detailed information on utility costs, revenue requirements, and key modeling inputs for the state's investor-owned utilities. The California Energy Commission's (CEC) 2024 Integrated Energy Policy Report (IEPR) for California provides EV stock forecasts. Georgia is included as a contrasting region, offering a different policy and regulatory environment, lower electricity rates, and a more modest EV adoption forecast, based on E3's PATHWAYS model, allowing for comparative insights across market conditions. For each region and year, there is a scenario for both unmanaged and managed charging. These charging load shapes are discussed below, in Section MHD Electric Vehicle Stock and Load Shapes. All scenarios studied in this analysis are described in Table 1.

Table 1. Rate Impact Analysis Scenarios

Scenario	C1	C2	C3	C4	G1	G2	G3	G4
Region	California (PG&E)				Georgia (Georgia Power)			
Year	2028		2035		2028		2035	
EV Load	Unmanaged Charging	Managed Charging	Unmanaged Charging	Managed Charging	Unmanaged Charging	Managed Charging	Unmanaged Charging	Managed Charging

Key Inputs

The analysis relies on a set of publicly available data inputs to estimate system cost impacts, cost allocation, and resulting residential rate effects. The key inputs are listed below in Table 2 and subsequently described in detail.

Table 2. Key Inputs and Sources

Input	Region	Source
Utility energy sales	Both regions	EIA 861[1]
Existing allocations	California	CPUC cost and track tracking tool for PG&E[2]
	Georgia	GA Power 2022 Rate Case Filing[3]
Marginal costs	California	CPUC Avoided Cost Calculator (ACC)[4]
	California sensitivity	PG&E EIS Part 2 Draft Study[5]
	Georgia	NREL Cambium[6], CPUC ACC
MHD EV stock	California	CEC's IEPR 2024[11]
	Georgia	E3's PATHWAYS[12]
MHD load shapes	Both regions	E3's EV Grid[7]

Utility baseline energy sales for 2024 are sourced from the U.S. Energy Information Administration's Form EIA-861, which provides standardized utility-level data on electricity sales by customer class. Existing cost allocation factors are based on jurisdiction-specific cost-of-service information. For California, allocation assumptions are informed by the CPUC's Cost and Revenue Tracking Tool for PG&E, which provides detailed, publicly reported information on revenue requirements and cost allocation across customer classes. For Georgia, allocation assumptions are based on Georgia Power's most recent cost-of-service study.

Table 3 below summarizes the costs used in this analysis. Marginal cost assumptions vary by region and cost component. In California, marginal generation, transmission, and distribution costs are based on the Avoided Cost Calculator (ACC), which reflects state-approved marginal cost methodologies. In Georgia, marginal energy costs are sourced from NREL's Cambium dataset, while transmission and distribution marginal costs are drawn from ACC-based estimates given a GA-specific source was not available. The marginal costs in Table 3 below are weighted by hourly EV load to represent costs based on time of day that medium- and heavy-duty EVs are charging.

---

[1] Annual Electric Power Industry Report, Form EIA-861 detailed data files - U.S. Energy Information Administration (EIA)
[2] Itemized List of Revenue Requests & Cost and Rate Trackers (CRT)
[3] DKT 44280 Georgia Power Company's 2022 Rate Case Filing
[4] https://www.cpuc.ca.gov/dercosteffectiveness
[5] https://www.ethree.com/wp-content/uploads/2025/11/PGE_EIS.pdf
[6] Cambium | Energy Systems Analysis | NLR
[7] E3's EV Grid model: EVGrid - E3

Table 3. Summary of approximate marginal costs in $/MWh, weighted by EV load shapes

Region	Year	Generation-Energy	Generation-Capacity	Transmission-Capacity	Distribution-Capacity	Distribution-Capacity Sensitivity
CA	**2028**	$54.1	$18.1	$6.0	$0.2	$272.0
	2035	$56.7	$4.8	$6.2	$6.5	$40.8
GA	**2028**	$37.0	$12.0	$6.0	$0.2	NA
	2035	$34.9	$9.5	$6.2	$6.5	NA

Because marginal costs based on historical data may understate the scale of required upgrades and distribution cost assumptions are a key point of uncertainty, E3 developed a California sensitivity using higher distribution costs from PG&E's Electrification Impact Study Part 2.[8] The study includes estimates of primary and secondary distribution costs from multiple different electrification technologies and distributed energy resources, including vehicle electrification, building electrification, distributed solar and storage, and energy efficiency, for 2025-2030, 2031-2035, and 2036-2040. The study represents the deepest dive yet into secondary distribution costs, using a new modeling approach combined with recent historical data, which results in a significantly larger estimate for secondary distribution costs as a proportion of total distribution costs relative to prior studies.

To develop an estimate of distribution costs attributable to MHDV electrification in the study years 2028 and 2035, E3 first interpolated annual distribution cost projections within each period reported in the draft EIS. E3 then allocated a share of those projected costs to MHDV charging based on MHDV load growth as a proportion of total load growth in the same year. This approach assumes that distribution upgrade costs scale proportionally with incremental load. Under this proportional allocation, MHDV electrification accounts for approximately 12 percent of total electrification-driven distribution costs in 2028 and 14 percent in 2035.The load forecasts used in the PG&E study were from the California Energy Commission's 2023 Integrated Energy Policy Report (IEPR).[9]

Distribution upgrade costs are highly project-specific and have a wide range. The California Grid Needs Assessment and Distribution Deferral Opportunity Report[10] provides data for distribution upgrade costs across the three CA investor-owned utilities, as shown below for 2023. The average distribution upgrade cost across about 500 projects was $95/kW-yr, where the highest project cost was about $9,500/kW-yr and lowest cost was about $0.14/kW-yr, demonstrating a huge range of

---

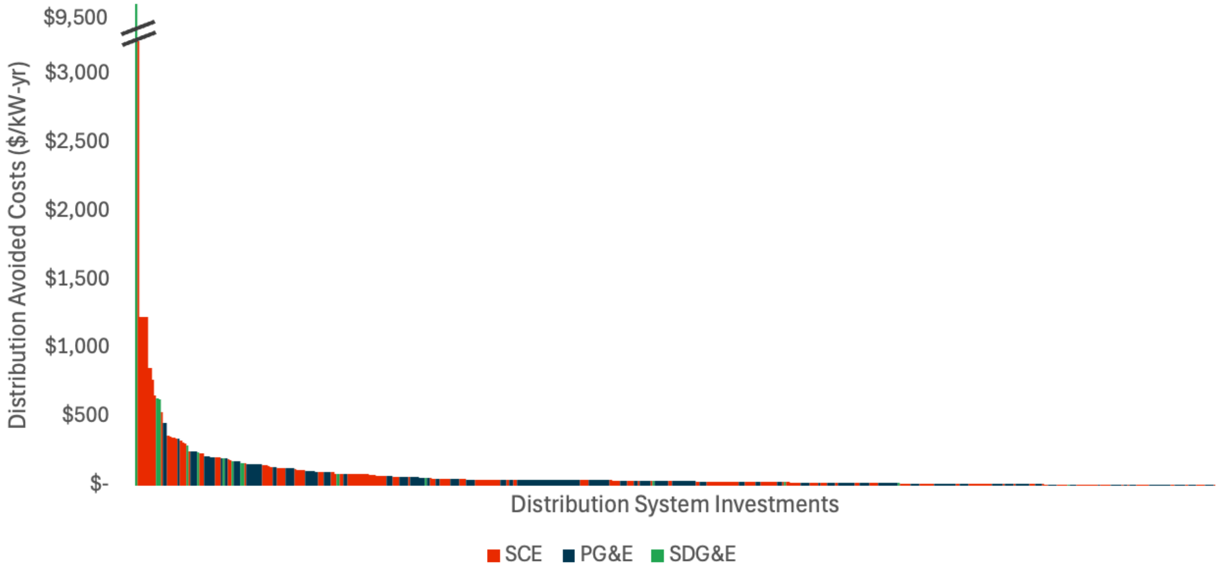
[8] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M596/K907/596907812.PDF

[9] 2023 Integrated Energy Policy Report

[10] 2023 Distribution Deferral Opportunity Report and Grid Needs Assessment, Pacific Gas and Electric Company, CPUC Rulemaking R.21-06-017.

costs. In this study, we evaluated an average distribution cost of $0.20/MWh and $272/MWh based on publicly available data to bookend the potential impact of this uncertain cost component.

Figure 4. CA Distribution System Investments by Utility ($/kW-yr)



MHD Electric Vehicle Stock and Load Shapes

E3 utilized electric MHD vehicle stock forecasts from the California Energy Commission's (CEC) 2024 Integrated Energy Policy Report (IEPR) for California[11] and E3's PATHWAYS[12] 2025 model results for Georgia. E3 selected the lower EV adoption scenario for each stock forecast, "Baseline" for California and "One Big Beautiful Bill (OBBB) Act Low"[13] for Georgia, to ensure that estimated cost and rate impacts reflect a cautious view of near- and medium-term electrification outcomes rather than high-growth scenarios. Both are econometrically driven forecasts and are the latest available. The IEPR "Baseline" forecast incorporates some federal and state policies, programs, and regulations, but not all. The "OBBB Low" forecasts ZEV adoption based on the EPA's estimate of adoption with no new federal standards. The stock forecasts are shown below in Figure 5.

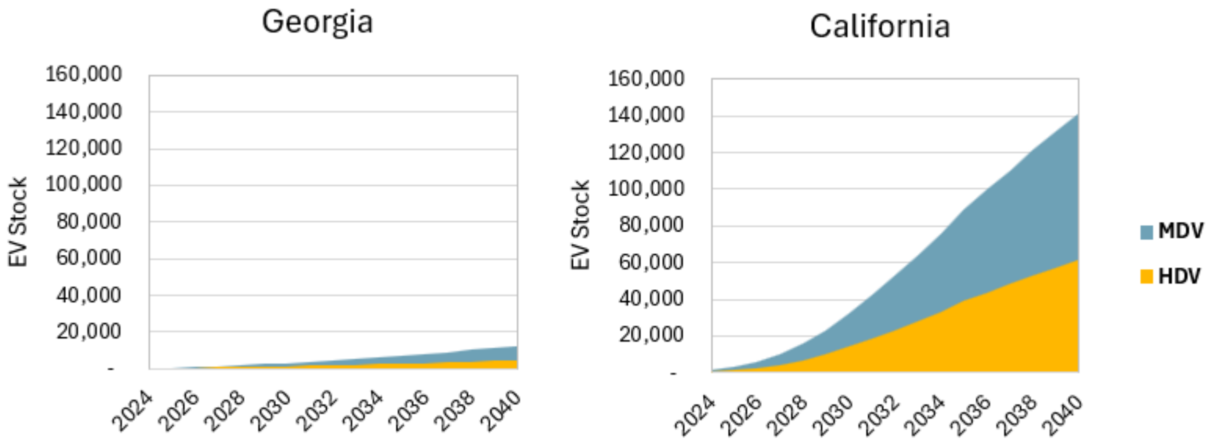
---

[11] CA_Planning_Library_2024_IEPR_Plug-in_Electric_Vehicle_Stock_Forecast.xlsx

[12] PATHWAYS - E3

[13] OBBB is referring to the "One Big Beautiful Bill Act" formally cited as: United States Congress, Public Law 119-21. 119th Congress, 2025.

Figure 5. Electric MHDV Stock Forecasts



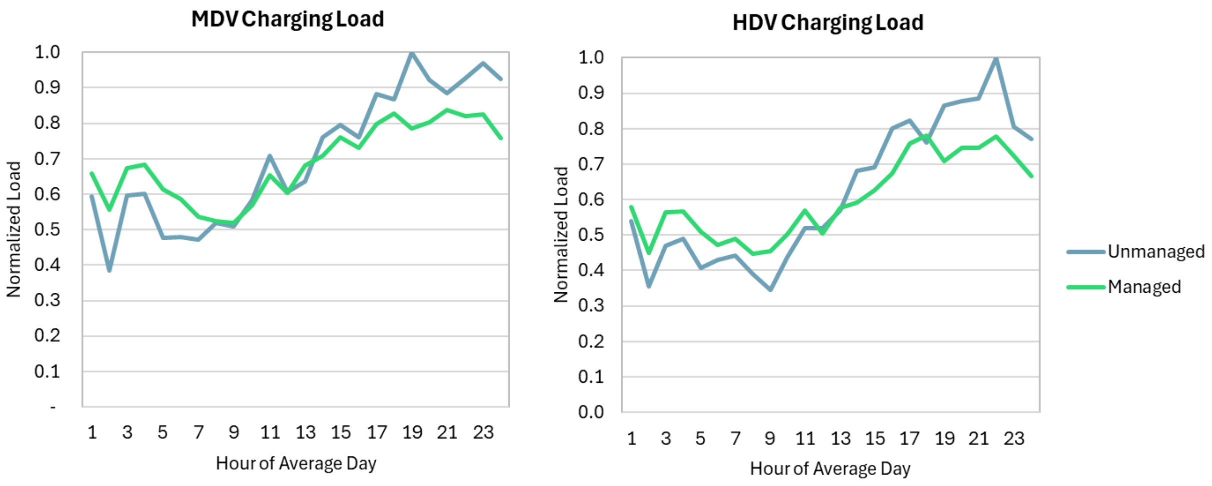
The electric MHD charging load shapes in this analysis are from E3's EV Grid model. The tool is used to generate MDV and HDV diversified, population average EV charging load shapes based on the driving patterns of thousands of drivers and characteristics of the driver population. These include charger access, vehicle types, and cost to charge vehicles in various locations. The tool simulates how customer types make charging decisions based on their charging access and vehicle type, then weights them based on how representative each customer type is of the population of drivers. All charging types allow drivers to meet their travel needs based on the constraints in the optimization, including their driving patterns and charger availability.

The shapes vary slightly by year due to efficiency improvements over time, but don't vary by location. E3 made a simplifying assumption that charging patterns for MHD fleets would be consistent between states. In the analysis, two types of load management were modeled:

1. **Fully Unmanaged Charging** is based on a driver's travel patterns, convenience of and access to different charging locations, and relative price differences between charging locations. A driver will charge their vehicle as needed at different sites to meet their driving needs. A driver sees and responds to the relative prices for different charging locations but does not respond to price differences that change within a given location. For example, drivers see that charging at their depot is generally cheaper than public locations and therefore prefer depot charging when possible. However, they do not see that charging at their depot can have different prices throughout the day, such as through time-of-use (TOU) rates.
2. **Partially Managed Charging** blends the unmanaged charging described above with managed charging. Managed charging includes driver response to price changes at given locations. Unlike unmanaged charging, the driver sees TOU rates when available at each location and responds accordingly. For example, drivers with depot charging are assumed to program their charging to start when the off-peak period begins for the commercial TOU rate. This charging type is called "managed" throughout the rest of the paper.

The load shapes used in the model for 2028 are shown below in Figure 6. The load shapes for 2035 have the same pattern but slightly less annual energy due to assumed efficiency improvements. The managed shapes (green) have lower charging at the end of the day than the unmanaged shapes (blue) during the common system peak hours. There is a decrease in load during evening hours, but only by about 15%, since the "managed" shapes are conservative and include some unmanaged charging. Both the MDV and HDV shapes are depot charging with 150 kW DCFC chargers.

Figure 6. Average Day EV Charging Load Shapes



As described above, E3's EV Grid tool generates diversified, population average shapes that represent thousands of drivers. Since thousands of drivers are represented in these load shapes, not all vehicles are charging at the same time. The model considers existing driving patterns as a constraint in the optimization to create the shapes. This makes the population average shape smoother than an individual load shape would be. Therefore, the peak load per vehicle is lower than the charger power modeled, 150 kW, since not all vehicles are charging at the same time.

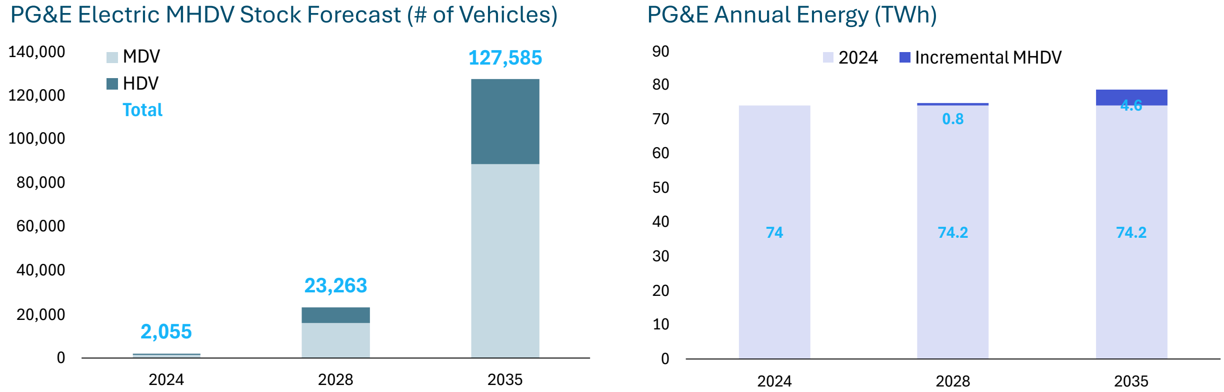
Results

Results of the rate impact analysis are presented first for California (PG&E) and then Georgia (Georgia Power). For each jurisdiction, we show the assumed forecast of electric MHDVs and the corresponding impact on annual energy sales in 2028 and 2035. Next, we show the resulting estimated impact on the total revenue requirement based on incremental system costs associated with the MHDV growth. We then show the average system rate impact, comparing the average rate (revenue requirement divided by energy sales) before and after vehicle growth. Lastly, we show the allocation of costs to the residential class, the average residential class rate impact, and an illustrative monthly bill impact.

California

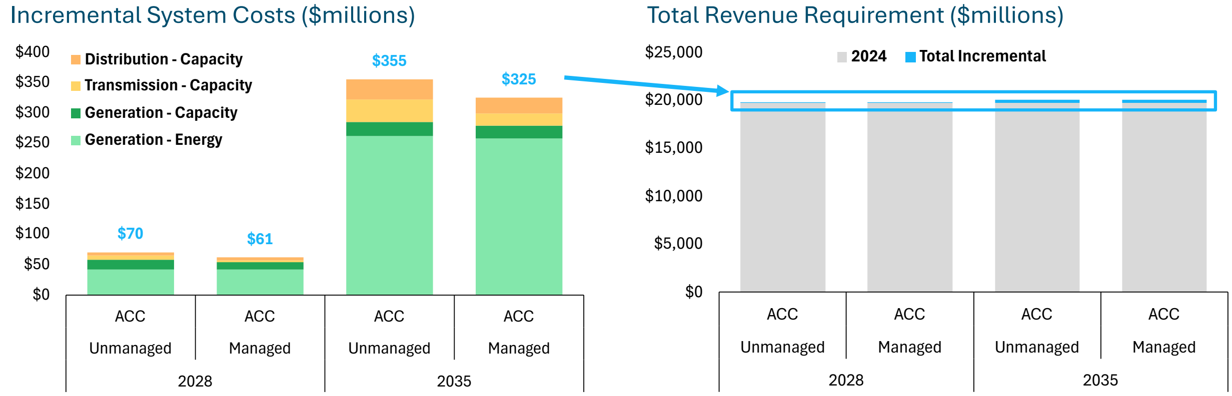
The assumed MHDV forecast for PG&E, based on the CEC's California Energy Demand baseline forecast, shows significant growth in MHDV stock from 2024 levels. In particular, we see a dramatic increase between 2028 and 2035: by 2028, MDHV electric stock here are 11x that of 2024 levels but 62x by 2035. Nevertheless, MHDV energy consumption remains a relatively small share of total load by 2035 (~5%).

Figure 7. PG&E Electric MHDV Stock Forecast and Energy Impact



The total utility revenue requirement increases due to the incremental costs associated with the incremental MHDVs. Annual incremental system costs are evaluated using hourly EV load and hourly marginal costs from the CA ACC for energy, generation capacity, transmission capacity, and distribution capacity. As shown in Figure 8, incremental costs are dominated by generation-related costs, but transmission and distribution costs grow by 2035 due to greater impacts in peak load hours. Total incremental costs, which reach $325 to $355 million annually by 2035, remain a very small share of the total revenue requirement (0.3% - 1.8%) of around $20 billion. Managed charging partially mitigates incremental costs.

Figure 8. PG&E Incremental System Costs and Impact on Revenue Requirement



Growth in MHD electric load applies downward pressure on system-wide average rates, with the percentage change in increased sales exceeding the percentage change in additional revenue requirement, as shown in Figure 9 below for system-wide. Depending on how costs are allocated to different customer classes will indicate whether there is any shift of costs between customer classes. For the residential class, electric sales do not change since MHD vehicle customers are not in the residential class, resulting in rate impacts that are directly proportional to changes in revenue requirement.

Figure 9. PG&E Change in Revenue Requirement, Sales, and Rate Impacts from MHD Electrification

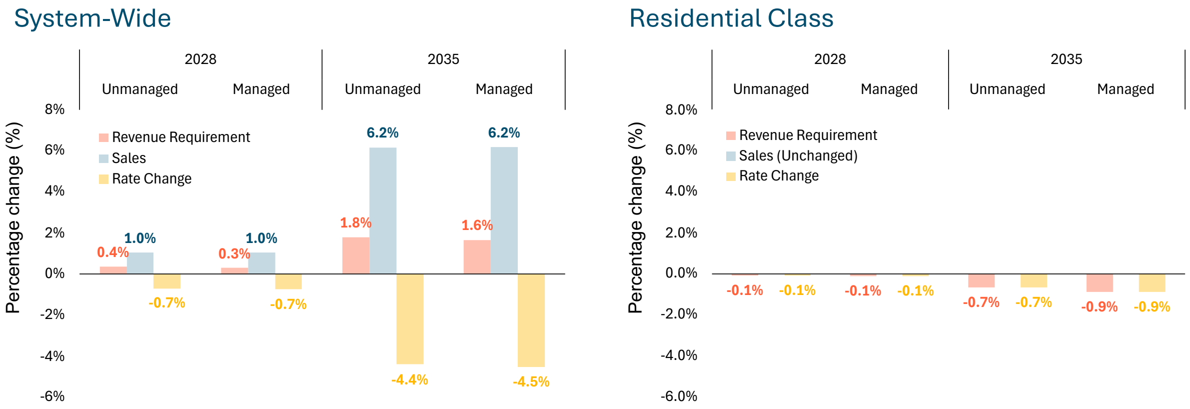


Figure 9 shows the resulting impact on the average electricity rate (left) and on the average residential classes rates (right). The average rate impact is assessed by calculating the average rate (total revenue requirement divided by total sales) with and without the incremental MHDV adoption and taking the difference.

Figure 10. PG&E Average System Rate Impact (left) and Residential Rate Impact (right)

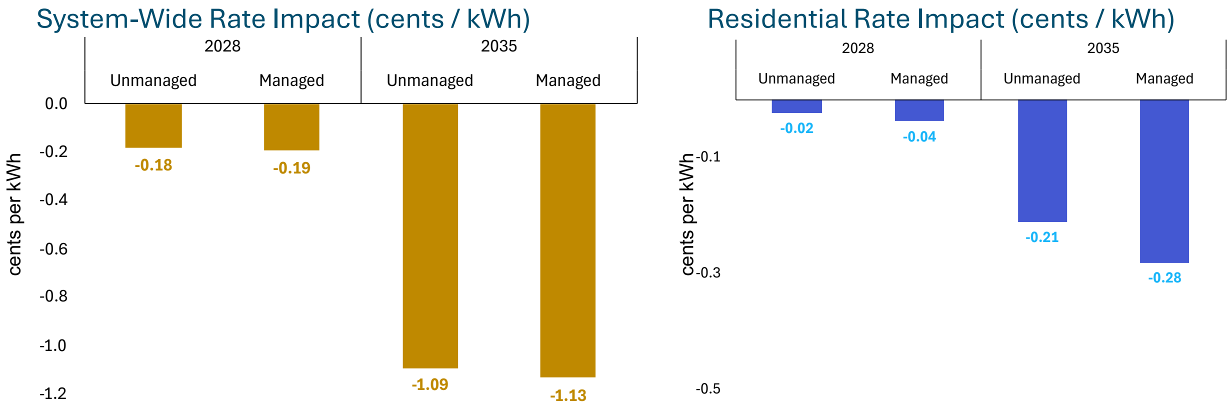
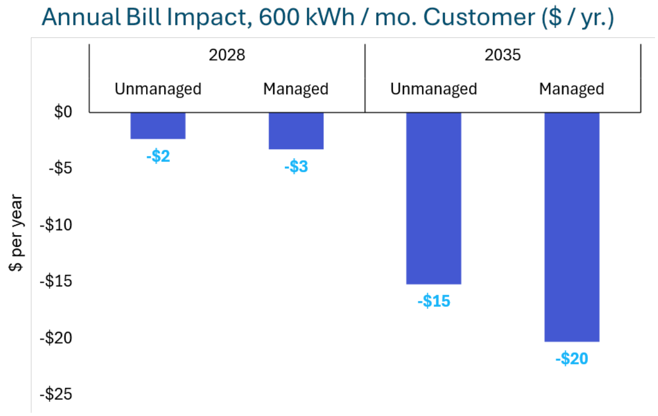


Figure 11 shows the resulting impact on illustrative bills for an example customer consuming 600 kWh per month. Importantly, these results assume that customer class cost allocations are updated to reflect changes in loads and therefore cost responsibility. Note that if cost allocation shares remain unchanged from current levels, incremental costs will increase residential rates; while that is an unrealistic scenario, there can be lags in updating cost allocations. After reflecting changes to cost allocations, capturing lower cost shares from the residential class results in reduced rates and bill savings, upwards of ~$20/year for an example customer in 2035.

Figure 11. PG&E Bill Impact



For the California higher distribution cost sensitivity, results show upward pressure on rates in 2028 but downward pressure by 2035 when MHD EV growth is significantly higher. This trend aligns directionally with PG&E's EIS findings on rate pressure. Average rates for the residential class therefore also increase in 2028. They also increase in 2035 when charging is unmanaged, but managed charging is able to drive a reduction. These results are summarized in Figure 12 below. On the left, the change in revenue requirement outpaces the increase in system-wide sales in 2028, resulting in small upward pressure on rates. This changes by 2035, when the increase in sales is proportionally larger than the increase in revenue requirement, resulting in a downward pressure on rates. On the right, residential electric sales are unchanged since MHD load is in the commercial class. Therefore, rate pressure is directly proportional to the change in revenue requirement.

Figure 12. PG&E Higher Distribution Costs Sensitivity - Change in Revenue Requirement, Sales, and Rate Impacts from MHD Electrification

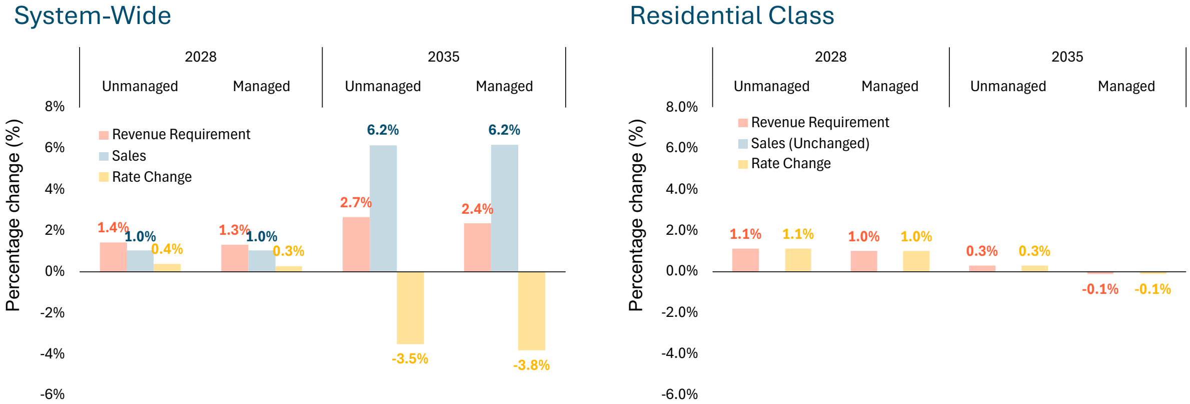
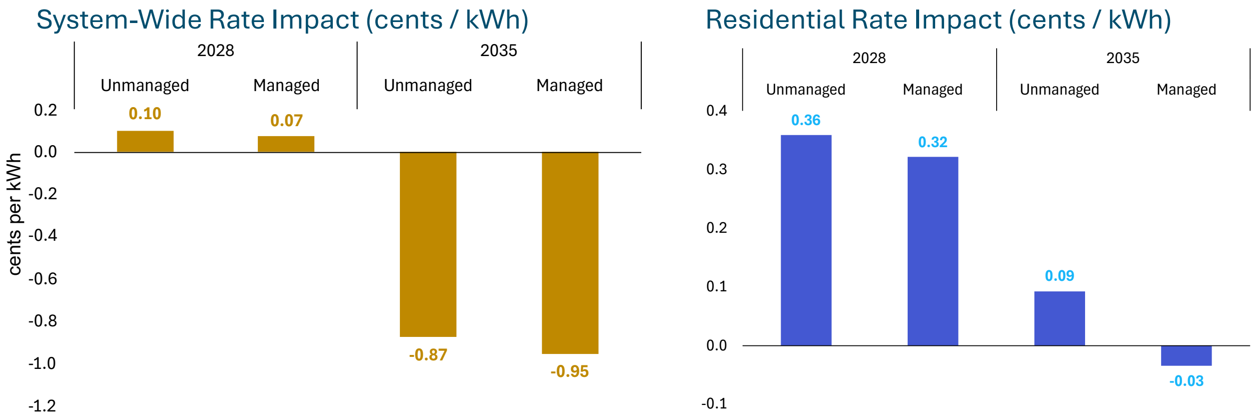


Figure 13 illustrates the rate impacts in cents per kWh for the system-wide average (left) and residential average (right). For average residential customer, this translates to bill impacts between +$26 (2028, unmanaged) to -$2 (2035, Managed) per year.

Figure 13. PG&E Rate Impact Sensitivity – Higher Distribution Costs



Georgia

The assumed MHDV forecast for Georgia Power shows modest growth in MHDV stock from 2024 levels, based on E3 modeling. MHDV electricity consumption remains a small share of total load by 2035 (~0.3%). Note that this case reflects a much smaller magnitude of adoption than in CA.

Figure 14. Georgia Power Electric MHDV Stock Forecast and Energy Impact

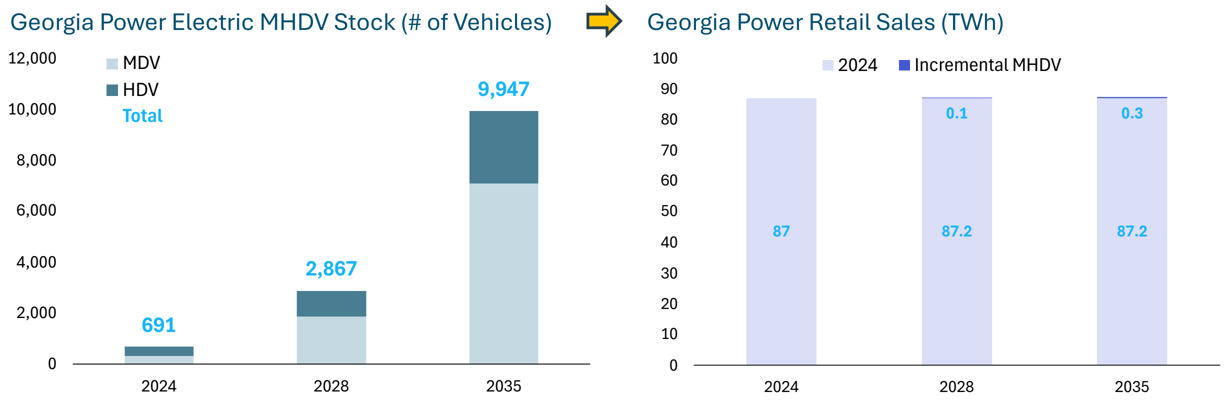
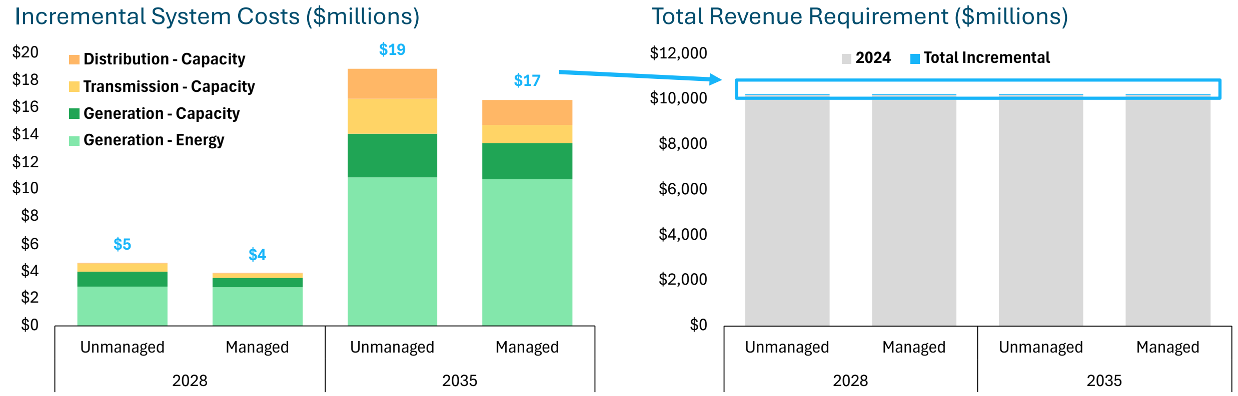


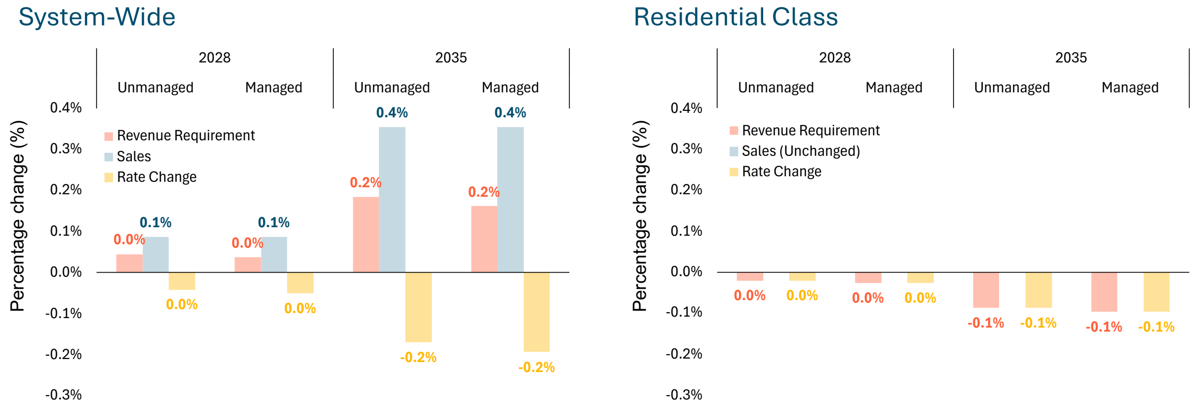
Figure 15 shows the estimated impact on incremental system costs and Georgia Power's revenue requirement. Again, annual incremental system costs were evaluated using hourly EV load and hourly marginal costs. While generation-related marginal costs are derived from NREL Cambium modeling for GA territory, costs for transmission and distribution were kept the same as the CA analysis due to public data availability in GA. Again, incremental costs are dominated by generation-related costs, but transmission and distribution costs grow by 2035 due to impacts on greater impacts in peak load hours. Total incremental costs remain a very small share of the total revenue requirement (0.0% - 0.2%), while managed charging partially mitigates incremental costs.

Figure 15. Georgia Power Incremental System Costs and Impact on Revenue Requirement



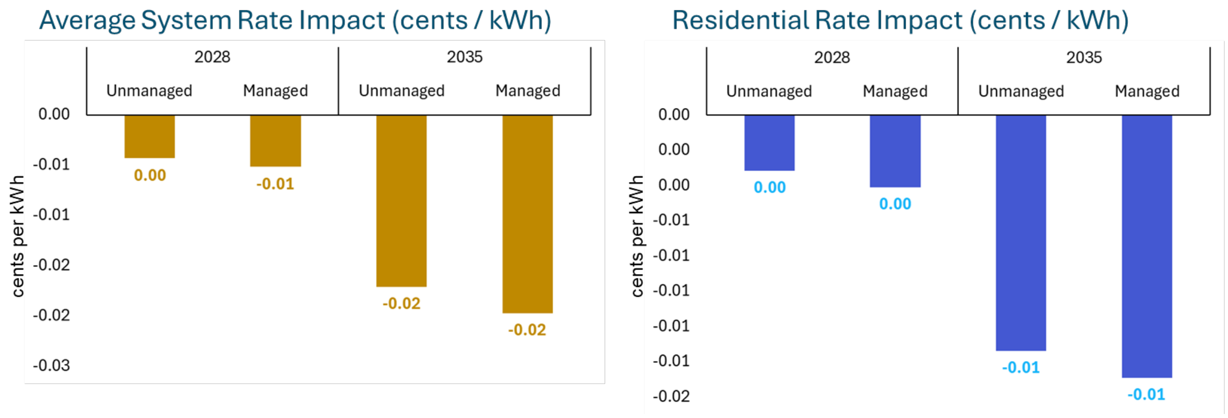
System wide, on average, the growth in MHDV EV adoption here has minor impacts on average and residential rates but still reflects downward pressure with the load growth occurring slightly outweighing the incremental costs. Figure 16 summarizes Georgia Power results, showing that MHD vehicle electrification has smaller system impacts because both load growth and incremental costs are small. In this case, increases in electricity sales slightly exceed growth in the revenue requirement, resulting in a mild downward pressure on average system and residential rates in both 2028 and 2035. Managed charging further reduces cost growth, but overall rate impacts remain small due to the limited scale of MHD EV adoption in Georgia relative to the existing system.

Figure 16. Georgia Power Change in Revenue Requirement, Sales, and Rate Impacts from MHD Electrification



The downward pressure on rates is shown in cents per kWh below. Note that there is a change in y-axis scale in Figure 16 compared to Figure 9. Again, depending on how costs are allocated to different customer classes will indicate whether there is any shifting of costs between customer classes.

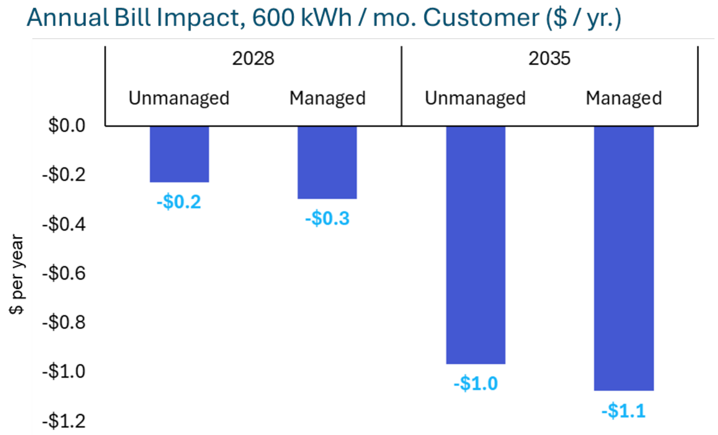
Figure 17. Georgia Power Average System Rate Impact (left) and Residential Rate Impact (right)


Average System Rate Impact (cents / kWh)

Residential Rate Impact (cents / kWh)

Figure 18 shows the average residential rate and bill impact for Georgia Power, assuming a customer who consumes 600 kWh per month. Again, it is important to note that cost allocation shares are updated for this analysis. Capturing lower cost shares from the residential class results in slightly reduced rates and bill savings, ~$1/year for an example customer in 2035.

Figure 18. Georgia Power Residential Rate and Bill Impact


Annual Bill Impact, 600 kWh / mo. Customer ($ / yr.)

Discussion

In this analysis, E3 quantified the average residential rate impact from MHD vehicle electrification in California and Georgia in the near-term (2028) and long-term (2035). In California, MHD vehicle electrification applied light downward pressure near-term that increased long-term to 0.21-0.28 cents per kWh. In Georgia, MHD vehicle electrification applied neutral to very light downward pressure (0-0.01 cents per kWh) to rates near-term and long-term. In the core distribution cost scenarios, MHD vehicle electrification did not apply upward pressure on rates in both the unmanaged and managed charging scenarios.

In the high distribution cost scenario, California MHD vehicle electrification applied upward pressure to rates near-term due to distribution costs outweighing the associated MHD electric load and long-term recovered to more neutral pressure with managed charging. Actual distribution upgrade costs are hard to predict and will vary widely within one state as well as across the country. If distribution costs are higher or lower than forecasted, it will impact results accordingly. Managing load is a least regrets strategy to help lower or defer distribution upgrade costs and apply downward pressure on rates. Utilities are not a monolith and MHD vehicle electrification with associated rate impacts will occur differently in practice on a utility-by-utility basis.

The main factors that support MHD vehicle electrification driving downward pressure on rates are:

1. Transmission and distribution system upgrade costs: Siting MHD electric vehicle charging near substations with headroom can avoid costly upgrades to the transmission and distribution systems. Flexible interconnection strategies, such as phased interconnection, load limit schedules, or curtailment agreements, in addition to charging load management can minimize or defer required upgrades and associated costs. Phased upgrades timed with load growth and customer distributed energy resources (DER) and load management can reduce grid costs and avoid initial upwards pressure caused on rates by upfront investment.

   Future utility investment decisions may require firmer software communication and controls, such as distributed energy resource management systems (DERMS), for fleet load management to justify avoidance of infrastructure upgrade investments. The portion of grid needs assumed to be driven by MHDV charging and associated investment costs will have a large influence on rate impact.
2. Ratemaking: Timely updates of cost allocation processes will ensure that new costs and loads from MHD vehicle electrification are incorporated into updated rates. These updates will ensure rates reflect the increasing shares of MHD vehicle contribution to system costs, thus helping mitigate cost shifts to other customers. Minimizing the magnitude of incremental costs such as distribution system investments will also help mitigate adverse rate impacts across all classes.
3. Tariff design and cost responsibility: Tariff design impacts both potential charging load management of MHDVs and associated utility revenues and costs from MHDV customers. Smart tariff design and cost responsibility rules can support utilities in right-sizing investments for future loads to minimize risks of lower or delayed load materialization. One of the major risks utilities face in upgrading infrastructure for any major new load point source is upfront capital expenditure without firm guarantees of the expected load materializing once these initial investments have taken place. Without the load materializing, these upfront investments are not spread over an increased amount of electricity sales and therefore can apply upward pressure on rates. Expected load could be delayed due to external factors such as site construction timelines and supply chains or the project could be abandoned due to market conditions, for example.

This dynamic has been of particular concern for utilities with potential large data center customers, where data center customers may be pursuing interconnection at multiple sites without the intention or ability to fully develop all sites. Compared to data centers, MHD vehicle electrification loads are expected to be much smaller and more flexible, contributing to lower risk of abandoned upfront utility investments. MHD vehicle electrification load has a potential different set of risks including dependency on shipping economics so it is still important to implement rate structures for these customers that can support downward pressure on all rates.

Due to the nature of these upfront infrastructure investments, upgrades will often initially cause upward pressure on rates until load materializes. The following rate structures can support electrification load materialization:

   a. Time-of-use rates with high differential between peak and off-peak periods and dynamic hourly rates encourage usage during low marginal supply cost hours, which typically align with low electric demand and high renewable supply periods.
   b. Subscription charges or grid access charges, instead of traditional demand charges, give fleets higher predictability on their electric bills while recovering distribution costs for the utility based on available site capacity. Examples of the subscription charge tariff structure include PG&E BEV rates[14], which replace the traditional kW demand charge with a monthly subscription kW level based on expected maximum EV charging load.

4. Proactive planning and communication:
   a. Effective and early communication between fleets and utilities can aid the interconnection and planning process.
   b. Improved utility integrated system planning (ISP) can reduce system costs, identify prioritized cost-effective investments, and mitigate risk of load materialization. In contrast to traditional utility integrated resource planning (IRP) which focuses on resource builds with more siloed planning, ISP aims to explicitly integrate generation, transmission, distribution, and distributed energy resources into a unified electricity planning process for future years.

---

[14] PG&E Electric Schedule BEV, https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_BEV.pdf