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**Can Distribution Grid Infrastructure Accommodate
Residential Electrification and Electric Vehicle
Adoption in Northern California?**

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Abstract

In this paper we ask: in what ways will utilities need to upgrade the electric distribution grid to accommodate electrified loads, and what will those upgrades cost? Our study focuses on the PG & E service area in Northern California, which serves 4.8 million electricity customers and is subject to aggressive targets for both EV adoption and electrification of residential space and water heating. We create spatio-temporally detailed electricity demand forecasts, and compare that demand to distribution infrastructure limits across a range of technology adoption scenarios. We find that electrification of residential space and water heating will lead to fewer impacts on distribution feeder capacity than EV charging, but that both transitions will require an acceleration of the current pace of upgrades. We also find that timing and location have a strong influence on total capacity additions in important ways: for example, scenarios that favor daytime EV charging have similar impacts to those with managed nighttime residential charging, but uncontrolled nighttime residential charging could have significantly larger impacts. We project that these upgrades will add at least \$1 billion and potentially over \$10 billion to PG & E's rate base. We conclude that measures that enable the completion of a high number of upcoming upgrade projects—including addressing workforce and supply chain constraints, and pursuing non-wires alternatives like energy storage and demand response—are critical to successful electrification.

1. Introduction

Transitioning from direct fossil fuel combustion to using electricity to meet energy needs is a pillar of many climate change mitigation strategies. Two of those energy needs, residential space and water heating and light-duty vehicles, make up about 10% and 20% of greenhouse gas (GHG) emissions from the US energy sector, respectively (EIA 2022a, EIA 2022b, supplementary section 1). In California, passenger vehicles contributed 28.5% of the state's emissions in 2019 (CARB 2021a). With state and municipal investments in electric heating and aggressive targets for EV adoption, both of these technologies are increasingly prevalent in California. Already, electric heating adoption has doubled over the last 10 years in cooler regions of the state (Kema, Inc. 2010, DNV GL 2020), and EVs constituted over 11% of California's light duty vehicle sales in 2021 (California Energy Commission 2021). A recent nation-wide assessment showed that meeting climate goals would be impossible without investment in residential heating electrification as well electric vehicle (EV) adoption (NASEM 2021).

Both residential electrification (replacing gas-burning appliances with electric space and water heating appliances) and electric vehicle adoption necessitate multiple infrastructure transitions. These transitions

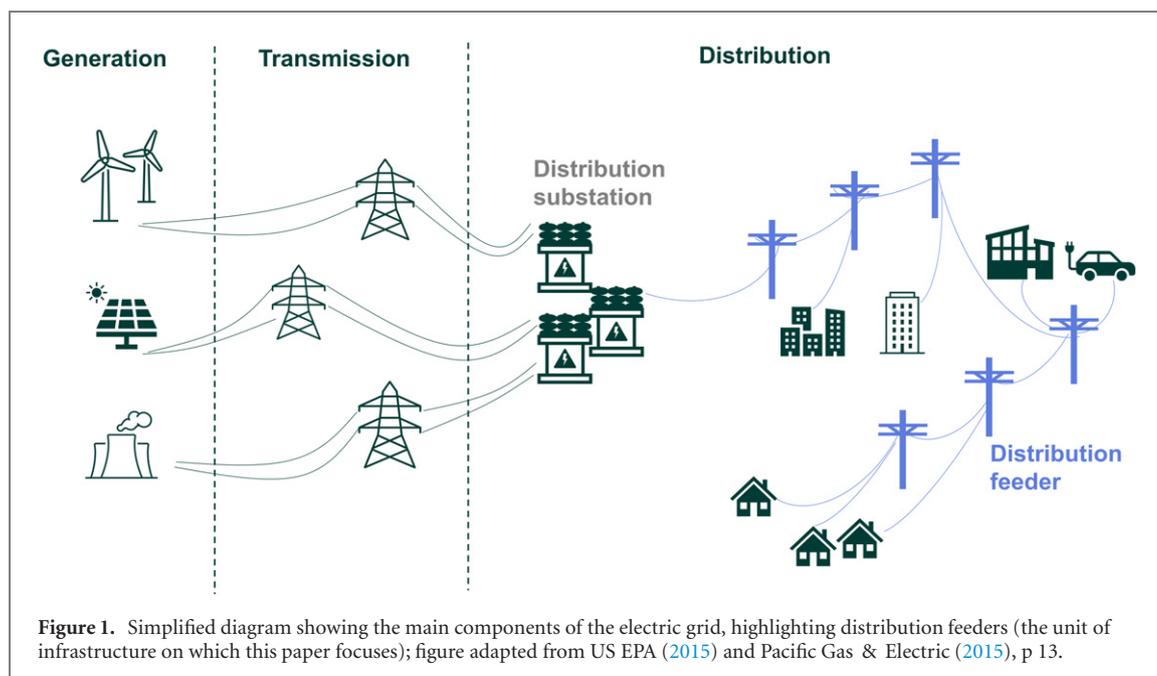


Figure 1. Simplified diagram showing the main components of the electric grid, highlighting distribution feeders (the unit of infrastructure on which this paper focuses); figure adapted from US EPA (2015) and Pacific Gas & Electric (2015), p 13.

include preparing electric infrastructure for increased demand while phasing out gas infrastructure and combustion engine vehicles, and are shaped by workforce transition and supply chain dynamics; concerns about financing, affordability and access to technologies; and questions of how quickly infrastructure can be deployed (Levinson and West 2018, Metais *et al* 2022, Egbue *et al* 2017, Bauer *et al* 2021, Das *et al* 2020, Emerald Cities Collaborative 2020, Greenlining Institute 2019, Building Decarbonization Coalition 2019, Aas *et al* 2020, National Renewable Energy Lab 2021).

Because electrification may change the timing or geography of electricity use, its impact on the electricity grid is particularly important to understand. As figure 1 shows, the electricity grid can be partitioned into generation, transmission and distribution components. Electrification has implications for each: for instance, investments in electricity generation and the expansion of long-distance transmission infrastructure will be needed to serve new loads (Waite and Modi 2020, National Renewable Energy Lab 2021). The distribution grid—i.e. the periphery of the grid located closest to customers—has received less attention than generation and transmission, in part due to the difficulty of capturing the uniqueness of each individual circuit (Murphy *et al* 2021, p 25). In this paper, we take a spatially and temporally resolved approach to understanding how residential electrification and EV adoption might impact the distribution grid. Our spatial units of analysis are substations and distribution feeders, which are electric circuits that extend from a distribution substation and deliver electricity to end users. One feeder is composed of multiple line segments, and includes the conductors themselves along with equipment such as transformers, voltage regulators, and monitoring devices (PG & E 2017).

Specifically, we address the following question: in what ways will utilities need to upgrade the electric distribution grid to accommodate electrified loads, and what will those upgrades cost? We focus our study on light-duty transportation and residential electrification in the Pacific Gas & Electric (PG & E) service area in Northern California. We choose PG & E both because California has aggressive decarbonization goals and policies to support electrification, and because rich data on PG & E's distribution infrastructure are available. We use these data, which include a range of spatio-temporally explicit characterizations of energy consumption and distribution system capacity, to assess the extent to which distribution grid infrastructure within PG & E's utility territory can serve projected electricity needs. We provide a spatially- and temporally-explicit and system-specific analysis of the potential changes in electricity usage in PG & E's utility territory due to electrification. We compare these load shape changes to available distribution grid capacity. Where that capacity falls short of the estimated need, we report the amount by which distribution infrastructure needs to be expanded, including the potential cost of those expansions and the number of distinct upgrade projects that will need to be performed.

In what follows, we review the scholarship on grid upgrades related to electrification (section 1.1), discuss the policy context in our study area (section 1.2), describe our data and modeling approach (section 2), present and discuss the results (section 3), and conclude by discussing the implications of our results for electrification transitions in Northern California (section 4).

1.1. Residential electrification, EV adoption, and the distribution grid

There is a growing body of work characterizing grid-related impacts from electrification, including impacts on grid operations (Blonsky *et al* 2019, Sahoo *et al* 2019), interconnection practices and standards (Das *et al* 2020), and power generation and transmission (Murphy *et al* 2021, Waite and Modi 2020). Blonsky *et al* (2019) divide the distribution grid impacts of electrification into operations impacts (for instance, voltage regulation violations) and planning impacts (for instance, increasing the capacity of distribution lines). Researchers have studied the former by using local distribution feeder models, finding that both heat pumps and EVs may contribute to voltage violation issues, and by proposing voltage control strategies (Protopapadaki and Saelens 2017, Mufaris and Baba 2013, Al-Awami *et al* 2016). For the latter issue of grid planning, however, existing studies on electrification-driven distribution grid upgrade needs are generally spatially and temporally coarse. For example, studies of impacts in California project that residential electrification may shift peak demand from the summer to the winter (Hopkins *et al* 2018, Mahone *et al* 2019), potentially leading to fuller utilization of California's electric distribution grid infrastructure year-round (Mahone *et al* 2019). Yet these analyses do not estimate the specific type and magnitude of upgrades needed.

Because home heating and EV charging will create demands for electricity that vary spatially and temporally, estimating distribution grid impacts due to electrification requires spatially and temporally explicit models of electricity consumption. The characteristics of distribution grid infrastructure also vary spatially: research on distribution grid substations (Allen *et al* 2016, Burillo *et al* 2018, Sathaye *et al* 2011) and circuits (Brockway *et al* 2021) has identified correlations with geography and demographics, including the vulnerability of substations to climate change (Burillo *et al* 2018) and the ability of distribution circuits to accommodate distributed energy resources (Brockway *et al* 2021). Investigating the distribution grid impacts of electrification in a spatially and temporally coarse manner, then, is insufficient given the importance of the timing and location of new electric loads as well as the timing and location of the distribution grid's ability to serve them.

We are aware of four studies that use distribution model outputs to provide spatially-explicit estimates of distribution grid upgrade needs due to electrification. Two of these studies simulate distribution grids directly to identify available capacity. First, using building models and assumptions on EV penetration and charger locations, Gupta *et al* (2021) investigated how photovoltaic, heat pump, and EV deployment impact distribution grid reinforcement needs in Switzerland. This study used representative distribution feeder models from three municipalities to extrapolate grid upgrade needs for the entirety of Switzerland and found grid upgrade needs could total as much as 11 billion Swiss Francs. Second, in a project conducted by the Electric Power Research Institute (EPRI) (2022) for the municipal utility Seattle City Light (SCL), researchers assessed the distribution grid impacts of building, transportation, and industrial decarbonization. They found that, without load flexibility, SCL's distribution grid would need about 2 GW of upgrades—or nearly a doubling of its existing capacity. However the study also found that nearly every circuit has sufficient capacity to meet daily *energy* needs, suggesting that with aggressive load flexibility nearly all grid upgrades could be avoided.

Two other prior studies focus on PG & E's distribution grid and use publicly-available Integration Capacity Analysis (ICA) data from California investor-owned utilities (Integration Capacity Analysis Working Group 2017), which we describe in more detail in section 2.3. First, Brockway *et al* (2021) found wide variation in per-household grid capacity for new load in PG & E and Southern California Edison (SCE), and estimate that roughly 50 and 20% of households served by PG & E and SCE respectively are connected to circuits that can support more than 3 kW growth in peak demand per customer⁵. However they did not study the location-specific nature and timing of new load shapes. Second, focusing on EV impacts, Jenn and Highleyman (2022) studied upgrade needs for a 2030 scenario with 6 million statewide EVs. Using the Grid Needs Assessment data—a data set similar to the ICA, generated to evaluate near term upgrade needs rather than hosting capacity for new loads—along with EV charging profiles constructed from real EV charging sessions to study distribution capacity needs, they concluded that 443 of PG & E's feeders showed deficiencies that would likely require capacity upgrade projects by 2030.

Our paper aims to refine and expand on the methods of these prior studies by examining spatially-resolved load shapes that combine both residential and transportation electrification, by examining estimates of higher electrification rates associated with longer term decarbonization goals, by studying the impact of workplace versus residential charging scenarios, and by examining the possible role of demand response—in the form of smart EV charging—on mitigating circuit upgrade requirements.

⁵ This is roughly equal to the combined power draw from level 1 EV charging and space heating via an electric heat pump, but significantly less than the approximately 7 kW needed to support level 2 EV charging (Brockway *et al* 2021).

1.2. Electrification in Northern California

Our study is based in the PG & E service area in Northern California. PG & E is a combined natural gas and electricity investor-owned utility (IOU) in Northern California, with over 4 million natural gas and electricity customer accounts (Pacific Gas & Electric 2015).

The market share of these technologies is poised to grow further due to ongoing investments and regulations. To date, building electrification has been pursued through incentives, building code amendments (CARB 2021b), and municipal gas phaseouts (Gough 2021); state-level investment in building electrification is expected to total \$1 billion over the next two years (Velez and Borgeson 2022). EV adoption has been pursued through ambitious targets: in 2018, the state established a goal of 5 million zero-emission vehicles by 2030 (California Legislature 2018, Office of Governor Edmund G Brown Jr 2018), and executive order N-79-20 increased the goal to 100 percent of in-state sales by 2035 (Office of Governor Gavin Newsom 2020), for an anticipated total of approximately 8 million EVs in 2030 (Alexander *et al* 2021).

Northern California's shifting regulatory and planning context also provides an opportunity to investigate the distribution grid impacts of electrification. While a lack of data has posed a barrier to detailed analyses of the distribution grid, IOUs in California are now required to provide detailed, publicly-available data on distribution infrastructure, including the ability of distribution lines and substations to accommodate new loads, in their ICA maps (CPUC 2021c, CPUC 2022, Cooke *et al* 2018). These data are published to enable project developers to identify parts of the distribution grid where new resources can likely be sited without additional grid upgrades. However, because these data are public, they also provide an unprecedented opportunity for researchers to assess not merely the potential of an individual project, but also utility-scale capacity for new load. We discuss these data in more detail in section 2.3.

Changes in regulation also extend to considerations of electrification in grid planning. In California, electrification projections are just beginning to be incorporated into the state's electricity planning processes (CEC 2022a, CEC 2022b, CPUC 2021a) with respect to both systematic assessments of upgrade needs (CEC 2021a, PG & E 2021d) and upgrades undertaken through geographically targeted pilot projects (CPUC 2021d, Southern California Edison 2021).

2. Methods

This study investigates if and where the capacity of electric distribution networks might be exceeded by residential electrification and light duty electric vehicle adoption. For both residential electric heating appliance and electric vehicle adoption, we simulated a range of scenarios representing diversity in both adoption rates and charger access for electric vehicles. For each scenario, we found the difference between the projected demand increase due to residential heating electrification and electric vehicle adoption and the current hosting capacity limits of the distribution system. We additionally used utility filings to determine the cost of potential upgrades and compare upgrade needs to current upgrade practices. This section summarizes the datasets and modeling approach, and points to more detailed information in the appendices when needed.

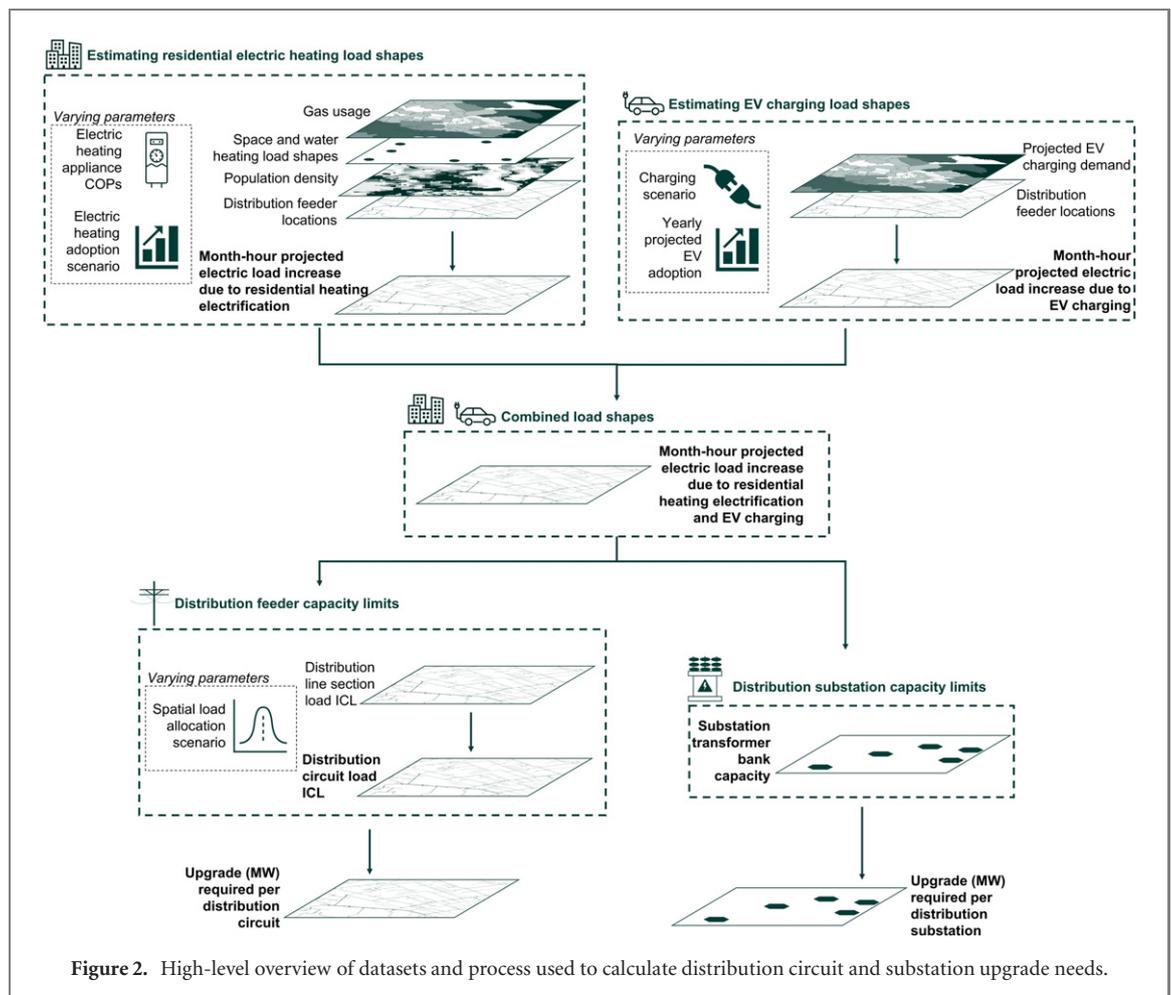
Our approach is summarized in figure 2. As explained in section 2.1, we constructed spatially and temporally granular estimates of electricity demand due to residential electrification with a combination of gas usage data, simulated load shapes, population density and distribution feeder locations. We also generated location-specific light duty electric vehicle load shapes with existing projections of statewide electricity demand and knowledge of the number of customers on each distribution feeder. As explained in section 2.2, we then combined these load shapes in a variety of scenarios to explore the implications of different electrification timelines and spatial distributions. Then, as explained in section 2.3, using the ICA data, we evaluated if and by how much distribution circuit and substation capacities could be exceeded; we examined a range of scenarios to capture uncertainty in ICA capacity numbers.

The data sources used to determine distribution circuit and substation upgrade needs are summarized in table 1. We conclude this section with a description of our approach to estimating upgrade costs in section 2.4.

2.1. Estimating residential electric heating and EV charging load shapes

The load shapes we constructed for electrified residential loads and EV charging were spatially aggregated to the distribution circuit-level, and computed with month-hourly resolution. A month-hourly temporal resolution refers to the 288 unique combinations of months and hours in a year (e.g. January at 3 PM). We chose these spatial and temporal resolutions to facilitate comparison to the ICA data, which we describe below.

Residential electrification. To estimate load shapes for residential electrification, we used a combination of (i) residential gas usage data reported by PG & E to understand the spatial resolution of current non-electrified residential energy demands for heating within the study area, (ii) space and water heating load shapes (the hourly usage of energy) to understand how heating needs are distributed temporally, (iii) a population density



grid upsampled to a $10\text{ m} \times 10\text{ m}$ resolution to allocate heating demands to circuits, and (iv) location data for distribution circuits. We note that this process is similar to earlier efforts to allocate EV charging demand to circuits based on population density (Hecht *et al* 2020).

We assumed that all the gas used by residential customers follows the load shapes of space and water heating. This assumption is supported both by the relative share of gas usage and appliance saturation for space and water heating versus other end uses, and by prior findings on the load shapes of other major end uses, including cooking, that find that peak energy usage for cooking is coincident with water heating. We discuss the data behind this assumption further in supplementary section 2.

We layered the ZIP codes on the gridded population data. Where ZIP codes spanned more than one grid cell, we assumed that gas usage within a ZIP code was distributed proportionally to the $10\text{ m} \times 10\text{ m}$ gridded population within that ZIP code. To obtain month-hour estimates of electricity load shapes due to electrification, space and water heating load shapes were first normalized over each month, and then combined with monthly gas usage data and appliance specifications (see section supplementary section 4 for details). For gas appliances, we utilized the median efficiency and energy factor values specified in supplementary section 3. For electric appliances, we calculated electric loads assuming both the median COP values and the 95th percentile of COP values specified in supplementary section 3 to understand the effect of improving equipment performance on the need for distribution grid upgrades. This process yielded a month-hour electricity load shape for each grid cell; to obtain results at a circuit level, each grid cell was assigned to the nearest circuit, and the demand was summed across each circuit (see section supplementary section 5 for details).

This process allowed us to identify the projected increase in electricity use per circuit and month-hour if all residential electricity use for heating is electrified, but residential electrification will not happen all at once: technology uptake depends on costs, appliance turnover rates, market readiness, and consumer willingness to electrify. To estimate possible rates of electrification we used scenarios from the National Renewable Energy Laboratory's Electrification Futures Study (Mai *et al* 2018). Focusing on the reference, medium, and high cases, we applied the projected percentage changes in electricity demand under those scenarios to the total expected new demand under full electrification to estimate new circuit-level demand in 2030, 2040, and 2050 (supplementary section 6).

Table 1. Data sources, descriptions, and spatial and temporal resolutions for data used to calculate distribution circuit and substation upgrade needs.

Dataset	Spatial resolution	Temporal resolution	Description	Source
Gas usage	ZIP codes	Monthly	Residential customer gas usage data (total therms) from January–December 2019 for ZIP codes that intersect with PG & E’s gas and electricity service area.	Pacific Gas & Electric 2021
Space and water heating load shapes	10 simulated locations in CA	Hourly	Load shapes for a one year period, disaggregated by end use, created by the US Department of Energy (DOE) from building simulations as well as surveyed residential energy usage data; last updated in 2013.	Department of Energy 2021
Population density	100 m × 100 m grid cells, upsampled to 10 m × 10 m resolution	n/a	2020 California population density estimates, constructed from census data, tax parcel boundaries, and building footprint data.	Depsky <i>et al</i>
Heating appliance efficiencies	CA	n/a	Median, 5th, and 95th percentiles of efficiencies, energy factors, and coefficients of performance (COPs) of appliances certified by the California Energy Commission (CEC) for both gas and electric space and water heating.	CEC 2021b 2022
Projected electric heating penetration	CA	Annual	Reference, medium, and high heating electrification scenarios from the National Renewable Energy Laboratory’s Electrification Futures Study; calculated demand growth to 2030, 2040, and 2050.	Mai <i>et al</i> 2018
Projected EV charging demand	Counties	10 min increments, aggregated to hourly level	Estimated charging patterns for a 24 h period in California calculated by the CEC for chargers serving multi-unit dwellings, workplace, public, and DC fast chargers, for three charging scenarios (selected from 12) based on assumed technology access, energy demand, and consumer behavior, and charging location (residential, public, work, and DC fast charging).	Alexander <i>et al</i> 2021
Projected EV penetration	CA	Annual	Approximations for the number of EVs in PG & E’s service area in 2030, 2040, and 2050, based on anticipated number of EVs needed to meet California’s climate goals in 2030, vehicle turnover rates, and internal combustion engine vehicle ban timelines in California.	Alexander <i>et al</i> 2021
Distribution circuit locations	Distribution circuit	n/a	Location of individual distribution circuits and name of substation to which each circuit connects	Pacific Gas & Electric 2020

(continued on next page)

Table 1. Continued.

Dataset	Spatial resolution	Temporal resolution	Description	Source
Distribution line segment integration capacity limit	Distribution line segment	Month-hourly	The additional demand (MW) that can be connected to a line segment without any thermal or voltage violations.	Pacific Gas & Electric 2020
Substation transformer bank capacity	Distribution substation	n/a	The total demand (MW) that can be served by a distribution transformer.	PG & E 2021c

We recognize that warmer temperatures due to climate change might (a) reduce the need for electric heating and (b) increase the use of heat pumps for space cooling. While we do not, in this paper, aim to construct possible load shapes for different warming scenarios, we do use historical and projected temperature data to identify where in the study area we may see impacts on electricity demand and, in turn, upgrade needs due to warming temperatures. Our process is described in supplementary section 11; we return to the results in supplementary section 11 in section 3.

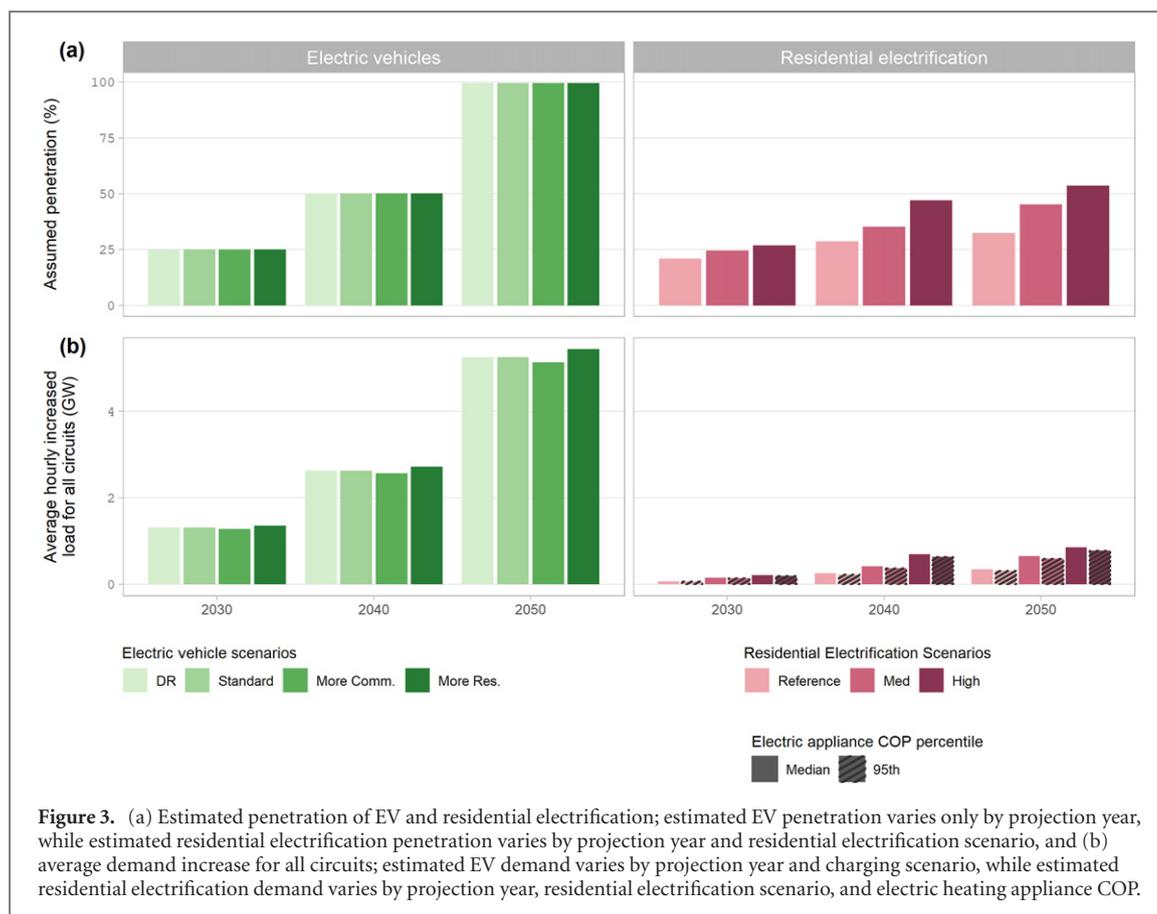
Electric vehicle charging. To estimate future load shapes for EV charging, we used a combination of EV charging projections to understand the possible spatial and temporal distributions of EV electric demand, EV penetration projections to estimate the number of EVs in the study area, and circuit location data to assign EV charging demand to circuits. EV charging projections⁶, as calculated by the CEC, represented a range of charging scenarios and charging types⁷ as specified in table 1. For each scenario, we averaged the charging demands in each hour to yield an hourly mean demand for each charger type. We then aggregated demands by customer type: residential level 1 and level 2 charging were summed into an overall residential demand that will be distributed among PG & E's residential customers, and workplace, public, and DC fast charging were summed into an overall demand to be distributed among PG & E's commercial customers.

We compared the aggregated residential and commercial charging profiles across 12 charging scenarios, and selected three scenarios that offered a variety of load profile distributions across customer types (supplementary section 7.2): standard, more commercial, and more residential. However, as the models used to generate the charging profiles assume time-of-use rates that drop at midnight (consistent with existing EV tariffs, e.g. PG & E's EV2-A), all three scenarios exhibit a significant increase in charging demand at midnight. This highly idealized scenario does not reflect, at a minimum, the likelihood that tariffs and smart charging incentives would be structured to avoid large spikes in charging demand in a high-EV future. We posit that a demand response (DR) program targeted at residential nighttime charging could flatten this peak and thereby alleviate strain on the distribution grid. To evaluate the potential impact of such a program, we created an additional DR scenario, based on the standard scenario, that smooths the residential nighttime charging peak by evenly distributing residential charging demand in hours 10pm to 5am. Finally, we allocated the hourly power demand from these scenarios to PG & E circuits by the total proportion of PG & E residential and commercial customers that each circuit serves.

This process allowed us to identify the projected increase in electricity use per circuit, month-hour, and charging scenario for the 8 million EVs anticipated in 2030 to meet California's climate goals (Alexander *et al* 2021). PG & E serves about 40% of California's population, and we estimate that the same proportion, or 3.12 million, of these EVs will be charging in PG & E's territory in 2030. Approximately 30.4 million vehicles were registered in California in 2020 (Federal Highway Administration 2021). Executive order N-79-20 (Office of Governor Gavin Newsom 2020) banned the sale of internal combustion engine vehicles in California after 2035. As vehicles have a less than 15 years turnover rate, this suggests that all or nearly all light-duty vehicles in California in 2050 will be net-zero, and we assumed that many of them will be EVs. We doubled our estimate of EVs in 2030 to estimate adoption in 2040, and doubled it again to estimate adoption in 2050. This yielded an estimated 12.49 million EVs in PG & E's territory in 2050, which roughly corresponds to the 12.2 million (40% of 30.4 million) EVs we would expect if all of today's vehicles were electric. We scaled the projected demand profiles by two and four to estimate the hourly charging profile of EVs in PG & E's territory in 2040 and 2050. For more, see supplementary section 7.

⁶ County-level results are provided for the expected deployment of chargers serving multi-unit dwellings, as well as workplace, public, and DC fast chargers. PG & E serves all or part of 47 of California's 58 counties, and we assumed that all chargers located in those counties will serve PG & E customers. This is approximately 39% of the chargers expected to be deployed in 2030 (Alexander *et al* 2021, table C-15), and we assumed that the total charging demand in PG & E's territory will be 39% of the statewide total.

⁷ Charging was assumed to occur at level 2 for public and workplace charging, except in scenario 10 where estimates of level 1 charging for public and work are also provided.



Figures 3 and 4 demonstrate how the varying parameters shown in figure 2 impact estimates of technology penetration, demand, and load shapes.

2.2. Combining residential electrification and EV scenarios

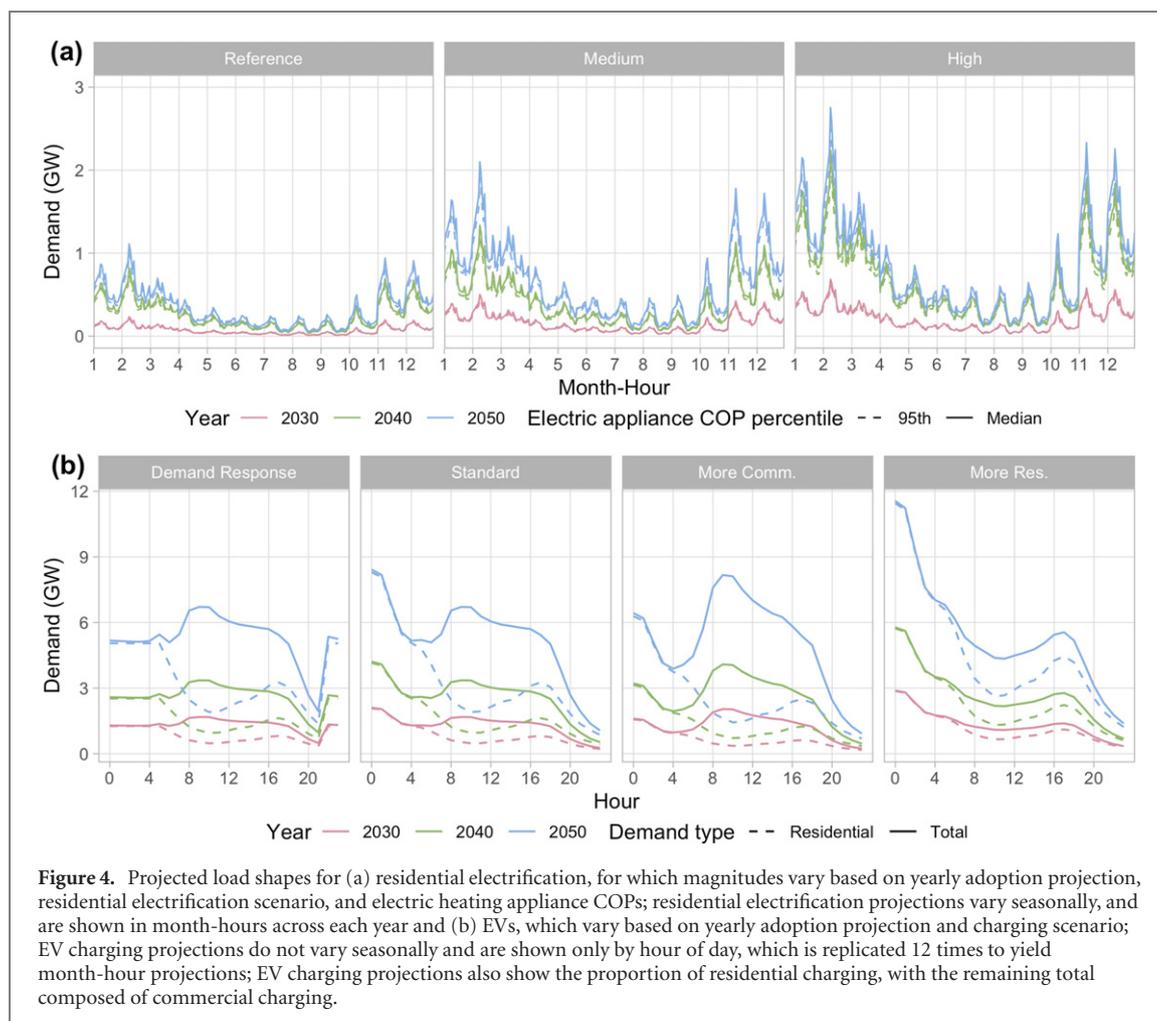
To consider the combined impact of residential electrification and EV adoption, we constructed three combined scenarios (table 2). These scenarios each consist of adding one residential electrification scenario and one EV charging scenario. We selected scenarios to reflect a plausible projection with relatively low vs high impact on residential circuits, and additionally account for the potential impact of a DR program for residential nighttime EV charging. Scenario A uses the medium scenario for residential electrification (reflecting the expected impact of continuing supportive policy in California, relative to the reference scenario) and the more commercial scenario for EV charging. Scenario B uses the high scenario for residential electrification and the more residential scenario for EV charging. Scenario C uses the high scenario for residential electrification and the DR scenario for EV charging.

The combined scenarios reflect both different levels of demand on residential circuits as well as the potential impact of demand response. This approach is valuable in showing how grid needs respond to increasing demands from RE and EV (by comparing the results from scenario B to the results from scenario A) as well as how grid needs respond to demand response for EVs (by comparing the results from scenario C to the results from scenario B). These scenarios do not represent all possible trajectories; it is possible, for instance, that Northern California could experience high electricity demand for EVs but not for REs, or vice versa. We discuss these sources of uncertainty in more detail in section 3.3.

2.3. Calculating upgrade requirements for distribution circuits and substations

PG & E's Integration Capacity Analysis (ICA) data set (PG & E 2021b) was generated for project developers to understand what parts of the distribution grid are likely to be suitable for new electricity loads and generation sources. We use these data to obtain the locations of distribution circuits and the capacity limit in MW, which refers to the ability of distribution circuits to host additional demand without upgrades at each month-hour. Here we describe the ICA data and our approach to using it, including our method for addressing uncertainty in the limits provided by the data.

We utilized two qualitatively different forms of distribution system data for our analysis. The first of these are PG & E's uniform load integration limit data. To produce these limits, PG & E divides each of the 3043



feeders on its system into hundreds to thousands of individual segments. PG & E computes segment-level load limits by running power flow studies on distribution feeder models: after adding existing hourly loading taken from customer meter data along the length of each feeder, PG & E adjusts the simulation to incrementally raise the load on the segment in question until a voltage or thermal limit is exceeded⁸ in the simulation (PG & E 2022a). PG & E reports the maximum amount by which they incrementally increased load before exceeding a limit on a given segment as that segment's voltage or thermal load limit. In our study, we treated the minimum of the two limits at a given hour as the overall hosting capacity for new load on that segment in that hour (Integration Capacity Analysis Working Group 2017).

Importantly, the ICA data provide maximum allowable demand per segment under the assumption that no additional demand appears on any other segment. Yet in high electrification scenarios, most segments will host new electricity loads, though there is uncertainty regarding where new EVs may plug in and residential gas loads may be electrified. To manage this uncertainty, we observed that segments nearest to the head of a feeder will have the most capacity for new load (because voltage drops along the length of a feeder, and feeders are sized with the largest conductors nearest to the feeder head), and conversely the segments nearest to the end of a feeder will have the least capacity for new demand. Therefore we assumed that the maximum and minimum reported feeder segment load limits are upper and lower bounds, respectively, to the capacity an entire feeder could host when load is distributed along its length. We further assumed that, because all new loads are unlikely to be concentrated on a single segment, these bounds are wider than likely hosting capacity limits. We therefore report our results at the 90th, 50th, and 10th percentiles of the segment hosting capacities within each circuit. To calculate circuit capacity upgrade needs, we subtracted the remaining capacity on each circuit from the new load estimated in our electrification scenarios at each month-hour, and we found the

⁸ Exceeding a voltage limit implies the simulation records an out-of range voltage somewhere on the circuit; PG & E currently uses a lower limit of 118 V. Exceeding a thermal limit implies any piece of equipment is predicted to experience a power flow amount in excess of its rated capacity.

Table 2. Summary of electrification scenarios used in this analysis.

Type	Scenario	Description
Residential electrification (Mai <i>et al</i> 2018)	Reference	'Business-as-usual outlook' with 'only incremental changes', 'excludes dramatic policy, technological, societal, or behavioral shifts'. Adoption 'roughly follows current trends'. This scenario corresponds to a 17.5% increase in the number of homes electrified between 2021 and 2050.
	Medium	'Accelerated adoption' of technologies 'that is plausible but not transformational'; 'technical, economic, and consumer preference obstacles remain'; adoption often remains in diffusion or early-adopter stages. This scenario corresponds to a 33.2% increase in the number of homes electrified between 2021 and 2050.
	High	'Assumes a more favorable set of conditions for electrification— including a combination of technology breakthroughs, policy support, and underlying societal and behavioral shifts that yield an electrification transition'. Despite being aggressive, it 'does not reflect full technical potential for electrification'. This scenario corresponds to a 43.5% increase in the number of homes electrified between 2021 and 2050.
EV charging (Alexander <i>et al</i> 2021)	Standard	Designed to mirror observed charging behavior and incorporate evolving technology and market conditions. 67% of plug-in EVs have access to home charging.
	More commercial	Low residential access: 50% of vehicles have access to overnight charging, shifting demand to more commercial daytime charging.
	More residential	High residential access: 95% of vehicles have access to overnight charging, shifting demand to residential charging.
	Demand response	Constructed by smoothing residential nighttime charging from 10pm to 5am; otherwise, the same as the standard scenario.
Combined scenarios	Scenario A	Intended to depict overall lower demand on residential circuits: for each circuit, a sum of the medium scenario for residential electrification and the more commercial scenario for EV charging.
	Scenario B	Intended to depict overall higher demand on residential circuits: for each circuit, a sum of the high scenario for residential electrification and the more residential scenario for EV charging.
	Scenario C	Intended to depict overall higher demand but with the addition of demand response for residential nighttime EV charging: for each circuit, a sum of the high scenario for residential electrification and the demand response scenario for EV charging.

Table 3. Circuit and substation upgrade costs from PG & E's DDOR (PG & E 2021c) for planned distribution grid investments (supplementary section 10). Values for circuits are based on the reported costs of planned feeder and line section upgrades ($n = 187$); values for substations are based on the reported costs of planned bank upgrades ($n = 67$).

Grid need (MW)	Circuit upgrade costs (\$/kW)			Substation upgrade costs (\$/kW)		
	25th pctl.	Median	75th pctl.	25th pctl.	Median	75th pctl.
<1	445.71	1875.00	5791.67	9935.00	18 863.43	28 982.79
≥1 & <2	251.84	1368.89	2092.89	3594.99	4740.03	6980.09
≥2 & <4	196.76	673.35	1447.55	2927.93	3978.38	4468.75
≥4 & <8	268.65	438.14	785.30	1137.16	2004.70	2570.87
≥8	237.23	367.85	586.32	634.01	887.62	1189.14

maximum difference to evaluate the greatest need across the year, recording negative differences as zero (i.e., no upgrade need). To obtain PG & E-wide upgrade needs in different scenarios, we summed the need across all circuits. For more detail, see supplementary section 8.

We note that California utility's ICA data have received significant scrutiny, in part because load limits were reported as zero for a large fraction of segments in early releases of these data. These zero values stood in contrast to studies associated with a second data set used in utility distribution planning processes known as the Grid Needs Assessment (GNA) (PG & E 2021d), which shows far fewer circuits with existing upgrade needs. In January of 2021, the CPUC ordered utilities to improve ICA process transparency and data validation (CPUC 2021b). In February of 2022, PG & E released its first annual *ICA Refinements Report* (PG & E 2022a) in which it described its ICA data generation process, as well as past and planned activities to improve ICA data quality. In that report PG & E explain that their modeling process and output has been stable since February of 2020, and that the fraction of feeder segments listed with zero capacity has decreased from 65% to 22%. Furthermore, in supplementary section 10 we compare ICA data at different percentiles of segment hosting capacity to the GNA data (which are not resolved at the segment level), and we show that although the data sets do not perfectly match⁹, there is good agreement between the 90th percentile of the ICA segments and the GNA data. We take these refinements, transparency and agreement between data sets as an indication that the data are reliable, if not perfectly precise, estimates of remaining load integration capacity. However, it is worth bearing in mind that, while the conclusions we draw in this study are based on the best available estimates of load integration capability, these estimates are the output of a third-party modeling process that is evolving over time.

The second form of data we use in our analysis relates to substation transformer banks. All net demand that is served by feeders connected to a particular substation must be fed by current passing through these transformers. Their capacity limits may, in some cases, be even lower than the capacity limits of circuits served by that substation. Therefore, in addition to evaluating circuit limits as above, we also evaluated the potential for substation upgrades needs. To do so, we used 2021 substation capacities reported in GNA data of PG & E's Distribution Deferral Opportunity Report (DDOR) (PG & E 2021c). For each electrification scenario, we added the existing substation loading from the GNA data to the month-hourly electrification scenario load, found the maximum month-hourly loading for each substation, and subtracted the reported substation capacity from that value. To obtain total upgrade needs in different scenarios, we summed the maximum difference across only those banks where upgrades are needed. For more, see supplementary section 9.

2.4. Upgrade costs

We used data from PG & E's DDOR (PG & E 2021c) to estimate the cost of performing circuit and substation upgrades to mitigate identified needs. These data, downloaded directly from PG & E's Distribution Investment Deferral Framework (DIDF) map (PG & E 2022b), contain estimates of grid needs and the investments needed to address them. We used the costs and magnitude of planned investments to calculate estimates of upgrade costs in \$/kW, which we then applied to our calculated upgrade needs. Observing significant evidence of economies of scale in the data (i.e., larger projects have a lower per-kW cost), we separated projects into size categories prior to calculating upgrade costs (table 3). For more, see supplementary section 10.

⁹ We do not expect the GNA and ICA data to match perfectly, since they are developed by different processes for different purposes (PG & E 2022a). Notably, the GNA uses future load forecasts to assess upgrade needs, which includes a consideration of distributed energy resource (DER) growth alongside load growth (PG & E 2022a). However they describe the same pieces of infrastructure, so we should expect the data values to be correlated. Note that we generated results with ICA data where possible because it is developed for the specific purpose of evaluating how much additional capacity circuits have for new load. This is in contrast to the GNA data, which is developed to identify which circuits require upgrades in the near future.

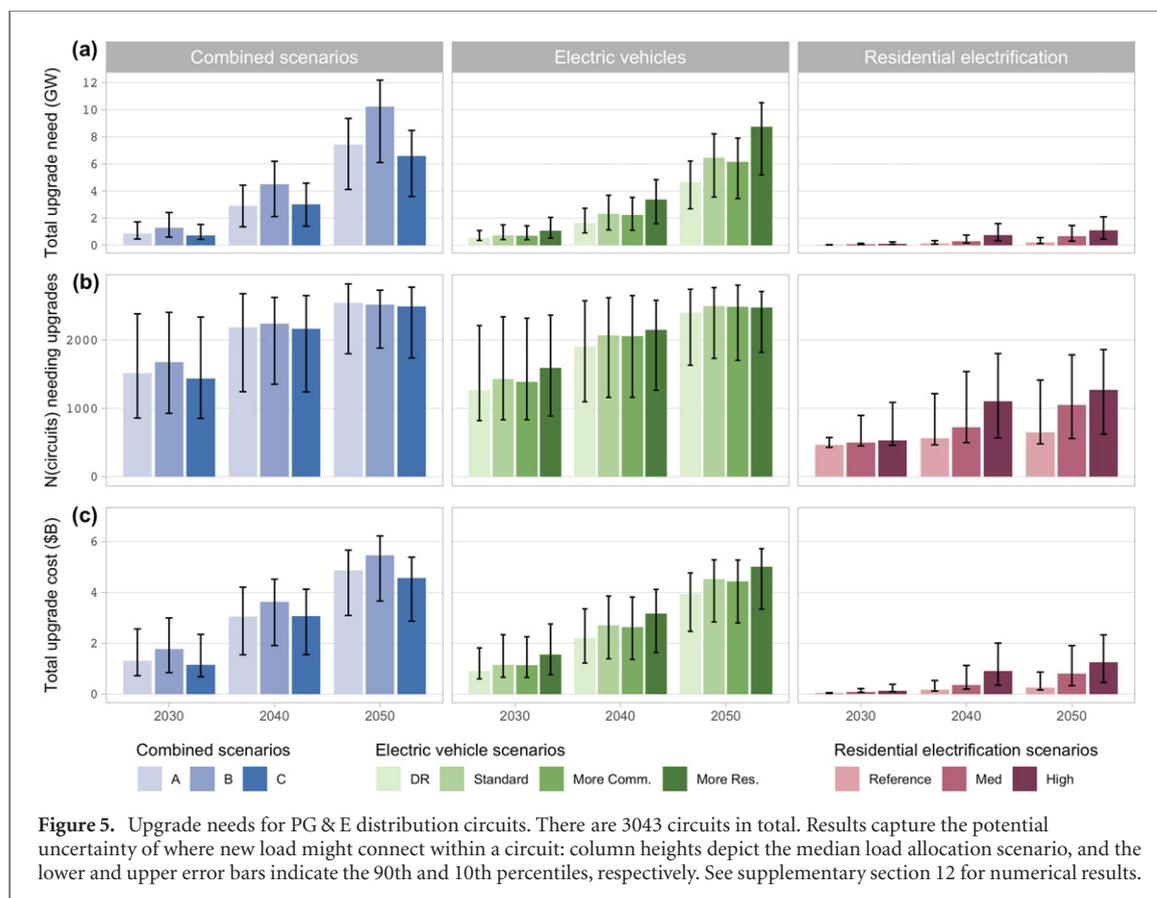


Figure 5. Upgrade needs for PG & E distribution circuits. There are 3043 circuits in total. Results capture the potential uncertainty of where new load might connect within a circuit: column heights depict the median load allocation scenario, and the lower and upper error bars indicate the 90th and 10th percentiles, respectively. See supplementary section 12 for numerical results.

3. Results and discussion

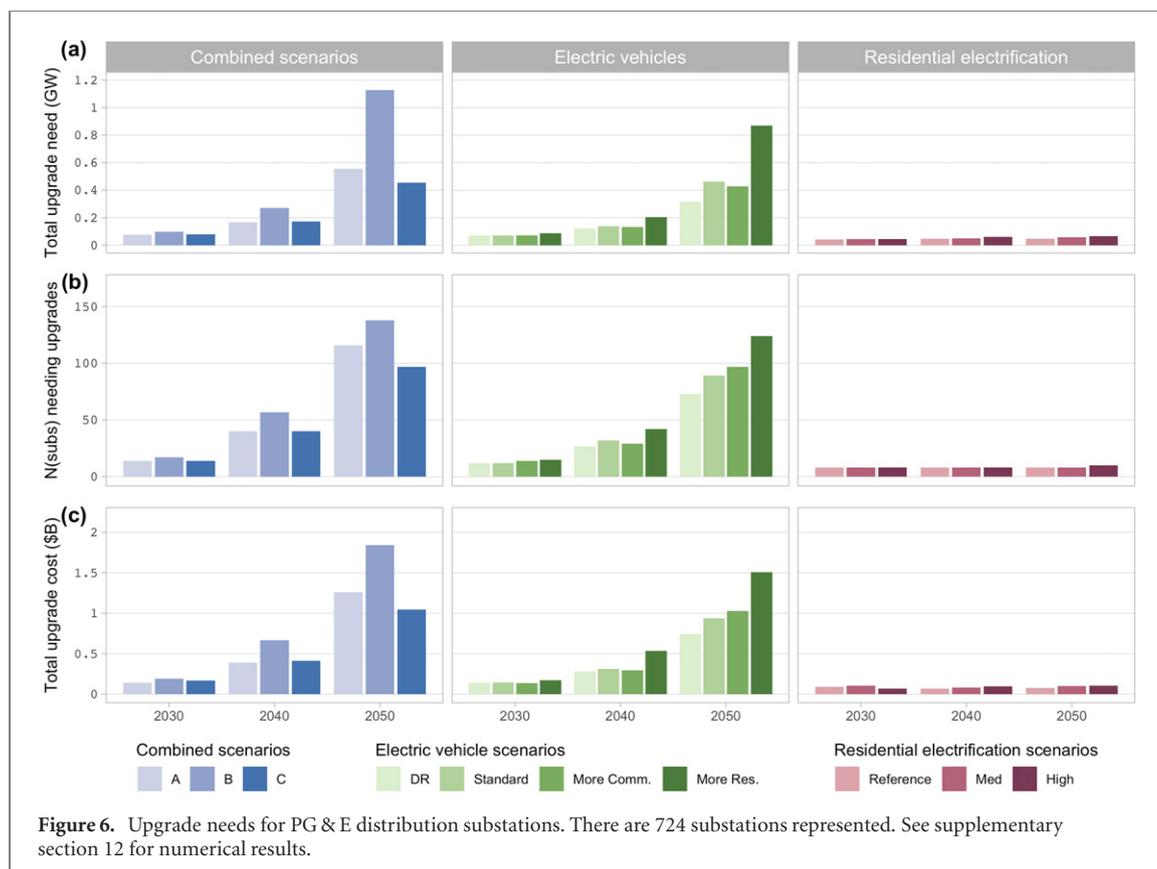
For each electrification scenario, we report grid upgrade needs for PG & E's distribution circuits and substations in gigawatts (GW), the number of circuits requiring upgrades, and estimated upgrade costs using PG & E's reported per-kW project costs. Our results are summarized in figures 5 and 6 for distribution circuits and substations, respectively.

Our estimations of distribution circuit and substation upgrade needs vary based on a number of assumptions and parameters. In reporting results, we show the variation of results based on scenarios outlined in table 2 for each yearly adoption projection as well as based on spatial load allocation scenarios. Because we find that electric heating appliance COPs lead to little change in load shapes for each circuit (as shown in figure 4); we report results for only the median electric space and water heating appliance COP (as reported in supplementary section 3).

3.1. Total capacity needs

Focusing first on total new capacity additions (the top rows of figures 5 and 6), total GW upgrade needs increase in time for each electrification scenario considered across all metrics evaluated. We find much larger capacity upgrade needs, in GW, for the EV scenarios than for residential electrification scenarios. This is true for both distribution feeders and substations. As a result, the upgrade needs in GW prompted by the combined electrification scenarios is nearly the same as the GW required just due to EV adoption. This result is consistent with prior findings that greater overall new electricity loads are expected from vehicles than from residential electrification (Mai *et al* 2018), and it remains true even for the DR scenario, in which night time EV demand is spread uniformly across the hours 10pm to 5am.

Focusing on the combined residential electrification plus EV charging scenarios, we find that, without measures to limit a midnight peak in EV charging due to large price shifts in an EV tariff, scenario A—which assumes most EV charging happens at commercial locations—requires fewer GW of capacity additions than scenario B, which assumes most charging happens at home. Scenario C—the demand response scenario—leads to the smallest need for both substation banks and feeders, but this need is only marginally less than scenario A (i.e., high commercial without demand response) case. We take two important points from these results. First, workplace (i.e. commercial) charging has distribution grid impacts that are comparable to



managed residential EV charging; this is surprising because commercial EV charging happens closer to commercial peak demand periods, and one might expect therefore that it would constrain distribution grids more. Considering that California’s daytime electricity prices are generally lower during hours of high solar production, this suggests that workplace charging may be cheaper for utilities (and, depending how distribution upgrade costs are passed through, to customers as well) than night time residential charging.

Second, measures to manage the timing of demand can have important impacts on distribution circuit capacity needs, and will likely be a critical tool to limit infrastructure expenditures in high electrification scenarios. We note, however, that this conclusion does not carry over to the *number* of required projects; we discuss this issue in section 3.2.

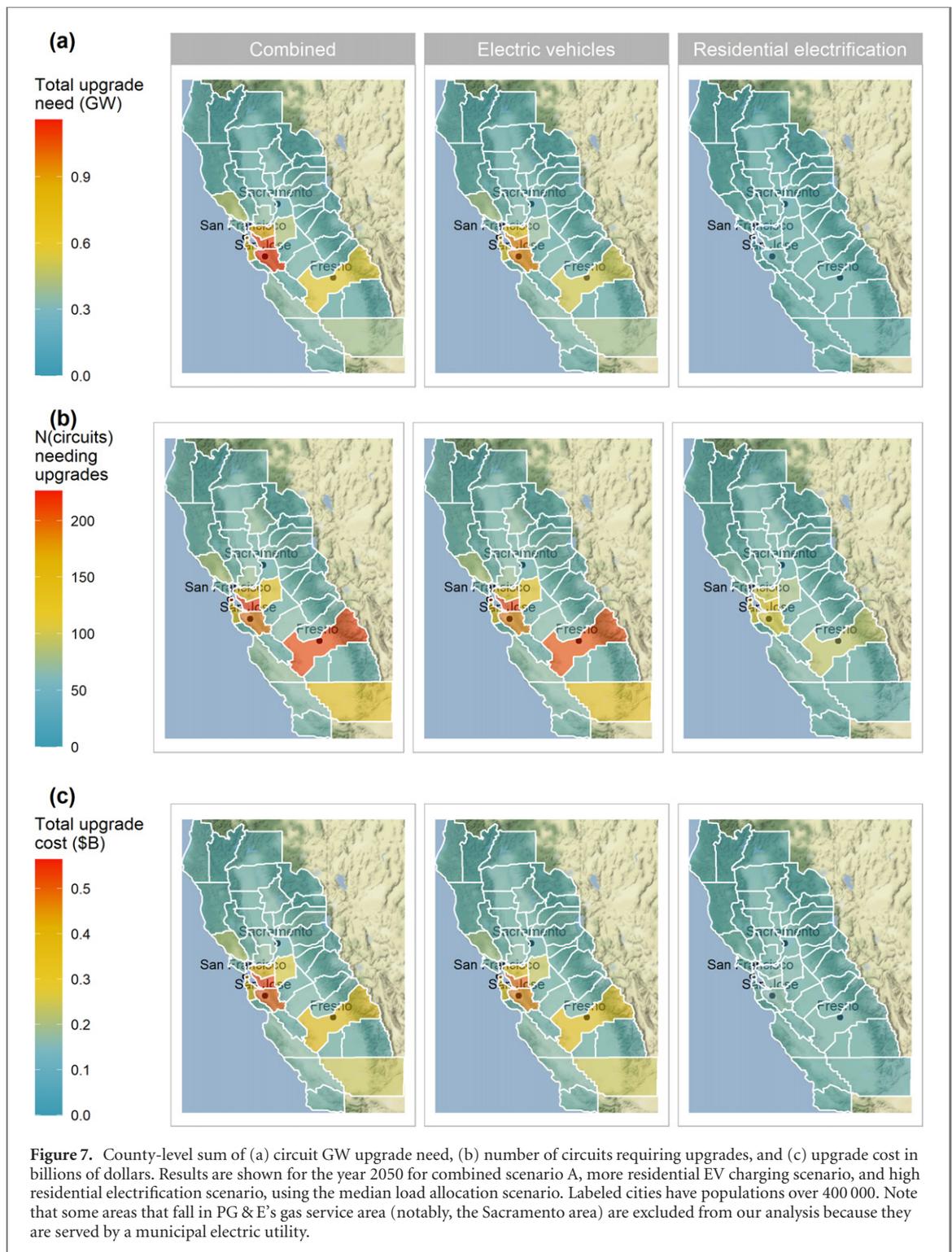
We also observe regional variation in GW of capacity upgrades, with the highest need in counties within the more densely populated 9-county San Francisco Bay Area as well as within Fresno County, as shown in figure 7, which maps total needs by county in a 2050 high residential electrification adoption and EV charging demand scenario (scenario C).

3.2. Number of upgrade projects

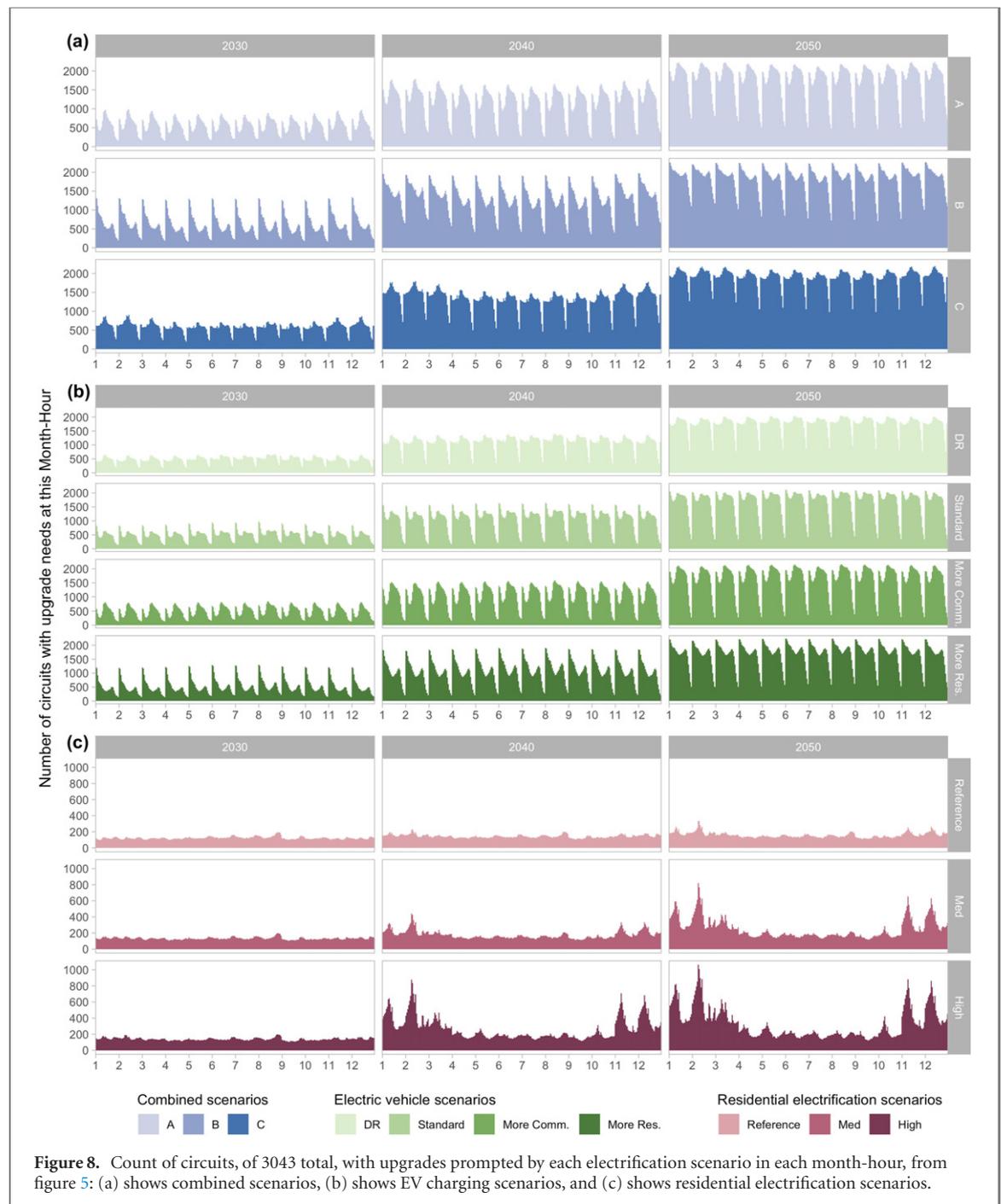
As with capacity needs, the number of circuits whose capacity is exceeded due to electrification (middle rows of figures 5 and 6) also increases in time, as more customers electrify. However, in strong contrast to capacity needs, the number of projects requiring upgrades is less affected by where electrification is concentrated and the timing of hourly demand. This is particularly true for feeder limits: even in the DR scenario, the number of circuits needing upgrades does not substantially decrease, as might be expected if a significant number of upgrades were prompted by the EV charging midnight peak. Rather, midday and even off-peak charging alone prompt upgrades on many circuits: we see this when tallying the circuit limit violations in each month-hour by each scenario (figure 8).

We see that a significant portion of PG & E’s three thousand circuits are expected to need upgrades under these scenarios by 2030, while the number of substations needing upgrades increases more strongly across years.

These results prompt us to consider the magnitude of this work effort relative to PG & E’s existing pace of upgrades. To better visualize the pace of needed upgrades, we plot the number of circuits and substations needing upgrades per year for each time period of analysis (figure 9). These numbers indicate a need for between 95 and 260 (median of 160–187) feeder projects per year until 2030 (supplementary section 12); if all projects are

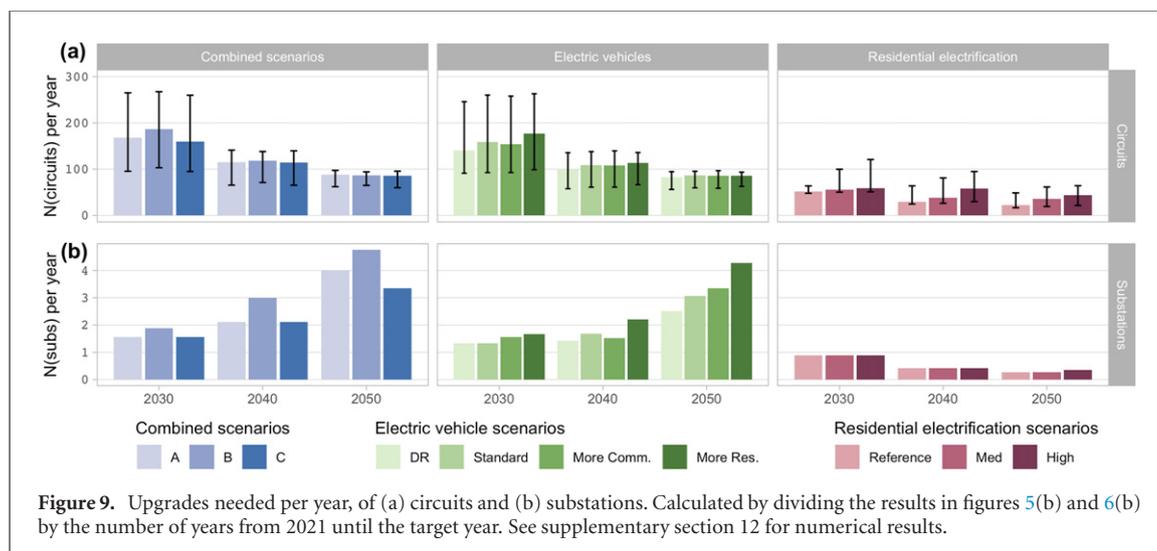


distributed between the time of writing and 2050, the number of feeder projects per year is below 100. According to this analysis, we anticipate a very small number of substation projects (2 to 5 per year). To put these numbers in context, in their 2021 DDOR report, PG & E estimated needing to complete approximately 56, 87, and 53 feeder and line section upgrades in 2021, 2022, and 2023, respectively (PG & E 2021c) (supplementary section 10). Expected substation bank upgrades were highest in 2024, with 18 banks needing upgrades that year, all at separate substations and for capacity reasons (supplementary figure 11). Comparing this number to our results in figure 9, suggests that we may be substantially undercounting substation upgrades; PG & E's current planned substation upgrades for 2024 exceed our estimate of needed upgrades for 2030 in some scenarios. This may occur because we sum bank capacity to evaluate total substation capacity due to insufficient data to evaluate bank limits alone (supplementary section 9).



Our projections for the number of annual circuit upgrades needed are higher, and significantly higher at the top end of our range of estimates, than PG & E's expected pace of upgrades, suggesting the importance of planning ahead for increased electrification. This is true for both EV adoption and residential electrification: even the relatively small added loads from residential electrification may trigger, as soon as 2030, upgrade needs that exceed PG & E's current pace of upgrades. However we also note that our estimates have a broad range: at the low end of the range, the impacts to PG & E's distribution system may be manageable within their typical three to five year planning cycle, and at the top end of the range PG & E would likely have a very large backlog of projects.

Compared to Jenn and Highleyman (2022), who similarly assess the distribution grid impacts of EVs, we project a larger number of projects in their study year of 2030. This is likely due to modeling assumptions and data; we study high EV penetrations, include residential electrification, and use ICA feeder segment data. On the other hand, Jenn and Highleyman use the GNA data and study only EV charging impacts. However, our bottom line conclusions—that the number projects needed to accommodate electrification goals exceeds PG & E's historical and planned rates of upgrade projects—are similar.



The need for accelerated upgrades raises questions about supply chains and labor in the electric distribution sector. Successfully performing distribution upgrades requires having access to equipment (e.g., transformers, circuit breakers, cables, switches, etc) as well as the staff to plan and implement these investments. Nationwide, electric utilities are increasing their investments in transmission and distribution infrastructure (Aniti 2021). These efforts have already been hampered both by the availability of equipment and trained workers. In particular, supply chain shortages and service delays have made it more difficult for utilities to obtain the equipment they need (Loeff 2022), impeding progress on grid modernization and decarbonization efforts (Thomson and Motyka 2021). Such shortages increased due to global supply chain issues during the COVID-19 pandemic. However, electric sector supply chain vulnerabilities predate the pandemic and are expected to continue, due in part to geographic concentrations of key suppliers and raw materials, manufacturing capacity, competition from the automobile industry, and the unique characteristics of equipment such as power transformers (Tsisilile 2022, Nguyen *et al* 2022, Thomson and Motyka 2021, Kivrak 2019).

Moreover, energy sector labor shortages created challenges for electric utilities even before the pandemic (Maize 2018, McNabb *et al* 2006, Ashworth 2006). Evidence of longer interconnection timelines due to upgrade bottlenecks already exists (Bruggers 2022, Penn 2021). These results point to the importance of demand-side workforce policies like apprenticeship programs in facilitating electrification and climate goals. Assessments of labor practices in the energy sector in California point to the Los Angeles Department of Water and Power (LADWP)'s Utility Pre-Craft Training Program, for instance, as a model to train entry-level workers for utility careers, including careers as line workers (Zabin *et al* 2020). The variation in upgrade needs by geography, as shown in figure 7, indicates that in some regions, municipal and county governments and local labor and environmental organizations may have an added role to play in facilitating workforce policies alongside state and utility actors.

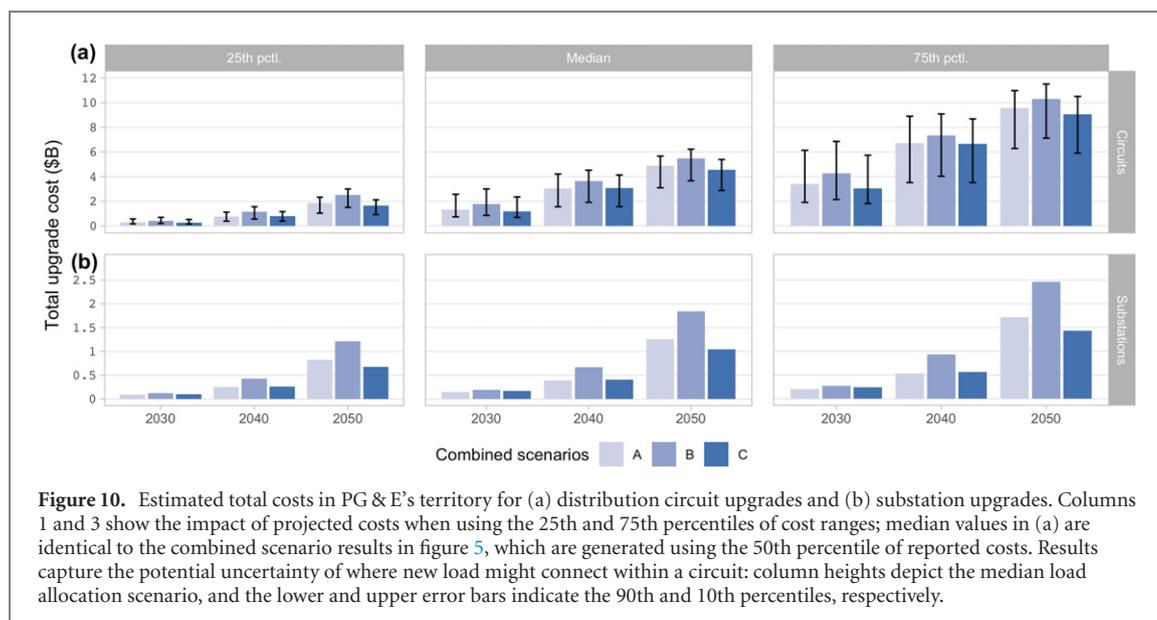
The pre-existing and separate trends in utility equipment supply chains and labor already pose risks for grid investments even in the absence of a significant ramp-up of circuit upgrades, suggesting that we may observe increasing bottlenecks, longer timelines, and higher costs for grid modernization efforts. However, our results also suggest that widespread transportation and heating electrification present an opportunity for added investment in demand-side workforce programs.

3.3. Costs of distribution system upgrades

Figures 5(c) and 6(c) show that upgrade costs increase roughly in proportion to capacity upgrade needs, and that the total investment requirements are in the range of several billions of dollars. In this section we explore these costs in more detail.

To further evaluate the potential cost impacts, we consider how investment needs might change under both lower and higher cost scenarios. Specifically, we compare the result of using the median reported values for per-kW bank costs (for substations) and feeder and line section costs (for circuits) to the 25th and 75th percentiles of the costs of PG & E's planned investments (table 3).

We note again that these cost estimates are based on utility-projected near-term costs, and they are intended to give only a plausible range. Further, the appropriate percentiles of costs (or alternative values) to use in this analysis merit further investigation. Relative to near-term estimates, actual future costs could fall due to learning-by-doing, as more technologies are scaled and deployed (Rubin *et al* 2015, Sagar and Zwaan 2006). Actual future costs could rise due to bottlenecks, including equipment and staff shortages, as utilities seek



to prepare their grids for demand growth due to electrification. While both impacts are plausible, we posit that the magnitude of needed investments alongside the other bottleneck trends discussed above are more likely to lead to increasing costs, potentially even beyond what we can predict on the basis of historical cost patterns.

Due to the broad range of uncertainty we incorporate in our feeder cost models, the distribution of costs we report in figure 10 is quite large—with cumulative 2050 costs ranging from \$1 billion to more than \$10 billion. Most of this variation is driven by cost uncertainty; at median costs, all three combined scenarios fall in the range of \$4.5 to \$5.5 billion. These cost numbers are substantial, but spread over the period from now to 2050, they are a fraction of PG & E's current annual distribution spending: the California Public Utilities Commission approved PG & E to spend \$2.23 billion on electric distribution capital projects in 2020 (CPUC 2020), and PG & E forecasts approximately \$4 billion in electric distribution capital expenses from 2022 through 2026 (the actual spending is subject to CPUC approval) (PG & E 2021a, exhibit 4).

3.4. Sources of underestimation, overestimation, and uncertainty

Our approach is subject to several assumptions and modeling omissions that may lead to underestimates, overestimates, and/or uncertainties in upgrade need and cost assessments.

In this section, we qualitatively discuss how each of these modeling choices might impact results and point to avenues for future work.

Reasons our estimates could be low. Our approach assumes that background demand growth—loads that are not attributable to residential heating or EV charging—can be neglected in PG & E's service area. However, demand growth is known to increase over time, in part due to growing population (Johnson *et al* 2022). Additionally, we do not consider that electric heat pump adoption will enable space cooling as well as space heating, which will increase electricity demands and might create additional peak demands for electricity in summer months, which may prompt more upgrades. As we show in supplementary section 11, which explores temperature projections from 10 general circulation models (GCMs), peak hot temperatures as well as cooling degree days are projected to increase throughout PG & E's service area in 2030, 2040, and 2050, which will exacerbate electricity demand for space cooling. These rising temperatures will also contribute to electric equipment derating (Brockway and Dunn 2020), another factor that would increase upgrade needs. Finally, we calculate upgrade needs assuming that utilities will upgrade feeders to provide just enough electricity to meet projected demands, but utilities may plan upgrades with additional headroom in case of unforeseen demand growth; planning for this headroom would lead to greater upgrade needs.

Reasons our estimates could be high. We assume that only distribution grid upgrades can address integration capacity limits that are exceeded by projected electricity demands. In reality, other operational changes can be made, including load transfer and switching (where the load is transferred to a different, nearby feeder than the one nearing its limit) as well as changes to voltage regulation equipment. However, publicly available distribution system data does not make known where these operational changes are possible (particularly load transfer or switching); a more detailed understanding of both distribution system configurations and operator and distribution engineer decision-making would be needed to explore the potential of these operational changes to avoid upgrades. Additionally, non-wires alternatives, including either rooftop or community solar

paired with energy storage, could mitigate the need for upgrades by providing electricity on-site for electrified loads. This impact could be significant (Clack *et al* 2020, Gupta *et al* 2021), and it is an area that merits concerted future work. Furthermore, our current method for constructing EV charging demand response scenarios is not feeder-specific; greater reductions in capacity need could be possible if demand from electrified loads is shifted strategically to hours with the most room for new demand on each feeder.

Major sources of uncertainty. Finally, our estimates are subject to several sources of uncertainty. Notably, the trajectories of electric heating and EV adoption; policies, incentive and rebate program design and funding, and the upfront costs of electric heating appliances and EVs may accelerate or delay the scenarios outlined in this paper, and could lead to regional concentrations of technology adoption. Beyond uncertainties in technology adoption, there are uncertainties in the technologies themselves and the needs they serve. For example, changes in public transit or modalities of work could lead to more or less EV adoption. Additionally, uncertainties exist in the underlying ICA data (see section 2.3). To manage this uncertainty, we compared different methods of spatially allocating load along distribution feeders, and we found that using the 90th percentile of ICA segments as the feeder load integration limit gave us results that are roughly aligned with GNA data. Still, because the ICA data generation process is constantly reevaluated, these results should be re-assessed as PG & E refines their data generation process. Finally, we do not consider the impact of climate change on heating needs. As we show in supplementary section 11, the median coldest temperature in 2030, 2040, and 2050 is projected to be colder than current cold peaks in some parts of the study area, and warmer in others. Thus, some parts of the study area may have higher peak electricity demands for heating in future years, prompting more upgrades, while others may have lower peak electricity demands.

These sources of under- and over-estimation and uncertainty point to avenues for future empirical and modeling work. Specifically, future empirical work might investigate how electricity load shapes change for residents who install space heating and consequently have additional access to space cooling. Future modeling work might explore potential future load shapes for space heating and cooling alongside climate change projections, assess the potential of solar and storage to avoid grid upgrades, and consider feeder-specific DR schemes.

4. Conclusions

Residential electrification and EV adoption, both necessary measures for climate change mitigation, require additional electricity usage. This electricity demand will vary spatially and temporally, but it will also vary based on technology adoption rates, equipment efficiencies, and EV charging patterns. Many aspects of infrastructure planning need to adapt to electrification; among them is distribution grid planning.

This paper evaluates how distribution infrastructure planning need to change by constructing load shapes for electrified residential heating and EV charging using a combination of bottom-up modeling and existing projections. We combined these load shapes with data on PG & E's distribution circuit and substation load integration capacity limits to quantify where and when residential heating electrification and EV charging might exceed infrastructure limits, prompting upgrades. We calculated the potential cost of upgrades using existing cost data from PG & E, and compared the projected rate of upgrades to current upgrade practices. We determined upgrade needs and costs for the years 2030, 2040, and 2050, and observed differences in results based on EV and residential electrification adoption timelines, EV charging scenarios, and cost estimates.

Our analysis leads to six key conclusions. First, relative to EVs, residential electrification leads to far fewer impacts on distribution feeder capacity and needs for upgrade projects, even in our highest penetration scenario. Second, the timing of EV charging can reduce the GW upgrade requirements for distribution feeders: workplace charging and smart residential charging lead to lower GW upgrade requirements than a residential charging scenario in which many EVs begin charging at midnight. Third, our analysis projects that the *number* of feeder and substation upgrade projects needed to meet aggressive electrification goals could exceed PG & E's current rate of upgrades, especially in the next decade. Distribution grid upgrades, then, may pose a bottleneck to electrification goals, necessitating workforce expansion or investment in non-wires alternatives like demand response and storage to reduce the required volume of infrastructure upgrade projects. Fourth, in contrast to the upgrade need in GW, the choice of EV charging scenario—even those with demand response—have little impact on the projected number of upgrade projects. Fifth, the projected upgrade needs are spatially heterogeneous; we find that they are more concentrated in counties in the San Francisco Bay Area and in parts of the Central Valley, including Fresno County. Sixth, and finally, we project that the total cost of these upgrades will be at least \$1 billion and potentially more than \$10 billion. These costs need to be taken into consideration with expected demand growth, within detailed rate base calculations, and in concert with appliance upgrade costs to fully understand their ultimate impacts on annual ratepayer expenditures.

Our modeling approach is subject to some limitations and opportunities for future analysis, as discussed in detail in section 3.4. In particular, when we capture known sources of uncertainty in distribution system capacity and upgrade costs, the range of potential future impacts is substantial, and new modeling processes need to identify ways to reduce this uncertainty. Another critical opportunity for future analysis is to consider the value of feeder-specific demand response, storage and distributed energy resources. These types of measures could be deployed quickly and in a modular way and could significantly offset the distribution capacity expansion work and costs projected in this study.

Our results prompt several recommendations for practices and policies to support future electrification. First, utilities can reduce the uncertainty of future capacity upgrade needs by updating their load integration modeling processes to capture plausible scenarios for electrification along distribution circuits, as well as likely mitigation strategies (such as low cost switching operations versus higher cost infrastructure upgrades). Second, our results align with policies that support workplace EV charging, because we find that workplace EV charging has some of the smallest distribution circuit impacts, and because this charging occurs during periods of the day when wholesale electricity prices are typically low.

Finally, our findings are relevant to ongoing discussions on resourcing, labor, and pricing in the electric utility sector. Distribution grid infrastructure is subject to pre-existing trends of lack of equipment availability and a shrinking workforce that could contribute to bottlenecks in electrification, particularly considering that we find that many circuit upgrade needs are relatively near-term. Our results suggest that programming and research on measures that can ease these bottlenecks, including workforce training, is essential to facilitate electrification.

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Data availability statement

The data that support the findings of this study are available upon reasonable request from the authors.

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