Grid Planning for Building Electrification

A Report by the
Energy Systems Integration Group's
Grid Planning for Building Electrification
Task Force

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PHOTOS

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Executive Summary

The increased electrification of buildings across the United States is being driven by technical advancements, cost reductions for some building technologies, consumer preferences, and policy goals for decarbonization. However, the effects of this load growth on the electric distribution system are often only a minor consideration in policymaking and long-term planning studies. The long lead time and useful life of power system equipment means that the decisions taken today are expected to support our society well into the 2060s and beyond. Distribution planning stakeholders can take steps today to establish a grid foundation that captures the new challenges presented by building electrification.

This report focuses on building electrification for the residential and commercial sectors, focusing most heavily on space heating, as this end use stands to most strongly impact demand.[1] Across all end uses, building electrification could require somewhere between 10% and 70% more electricity generation capacity than exists today depending on technology adoption and energy efficiency.

1 The electrification of transportation and industrial processes, and increased loads from electrolysis for hydrogen production or data centers, are considered out of scope.

Challenges in Planning for Increased Building Electrification

Electrifying buildings changes paradigms in grid planning, especially when combined with changes to the resource mix. Load impacts from building electrification will increase the seasonality and weather dependence of loads, as well as increase the vulnerability of the power system to extreme weather, largely due to heating demand. In some winter-peaking electrification futures, solar generation is misaligned with the time of highest demand—just before dawn when it's typically coldest. Additionally, building electrification requires the integration of traditionally independent planning processes for energy delivery systems (fossil fuel and electricity), which can change how planners weigh the pillars of reliability, resilience, affordability, and sustainability.

Building electrification can also present hidden risks when planners who have traditionally been oriented around summer peaks miss how building electrification can affect loads in the winter. Given the physics of today's heat pump technology, which may be more energy efficient than air conditioners when they are replacing older cooling technologies, some regions may see load *decreases* during the summer months. Distribution system planners may not see the significance of building electrification until faced with high demand on the coldest days in winter. A good understanding of these stressors is necessary to effectively plan the grid.

Building electrification requires the integration of traditionally independent planning processes for energy delivery systems, which can change how planners weigh the pillars of reliability, resilience, affordability, and sustainability.

Grid Planning Solutions for Building Electrification

Solutions in grid planning for building electrification can come in many forms. Some directly pertain to the distribution system, such as infrastructure upgrades or demand management approaches, and others simply help us plan more effectively. For example, by improving forecasting and holistically modernizing our planning approaches to better capture future grid stressors, the appropriate distribution system in each region can be designed. These improved planning methods can also help to identify new technologies, programs, rate designs, and other demand-management options that help to avoid the largest impacts of building electrification on the distribution system.

The Energy Systems Integration Group's Grid Planning for Building Electrification Task Force identified four priority areas to improve distribution system planning: improve forecasting, holistically modernize planning approaches, avoid the largest impacts by managing demand, and be proactive with grid upgrades.

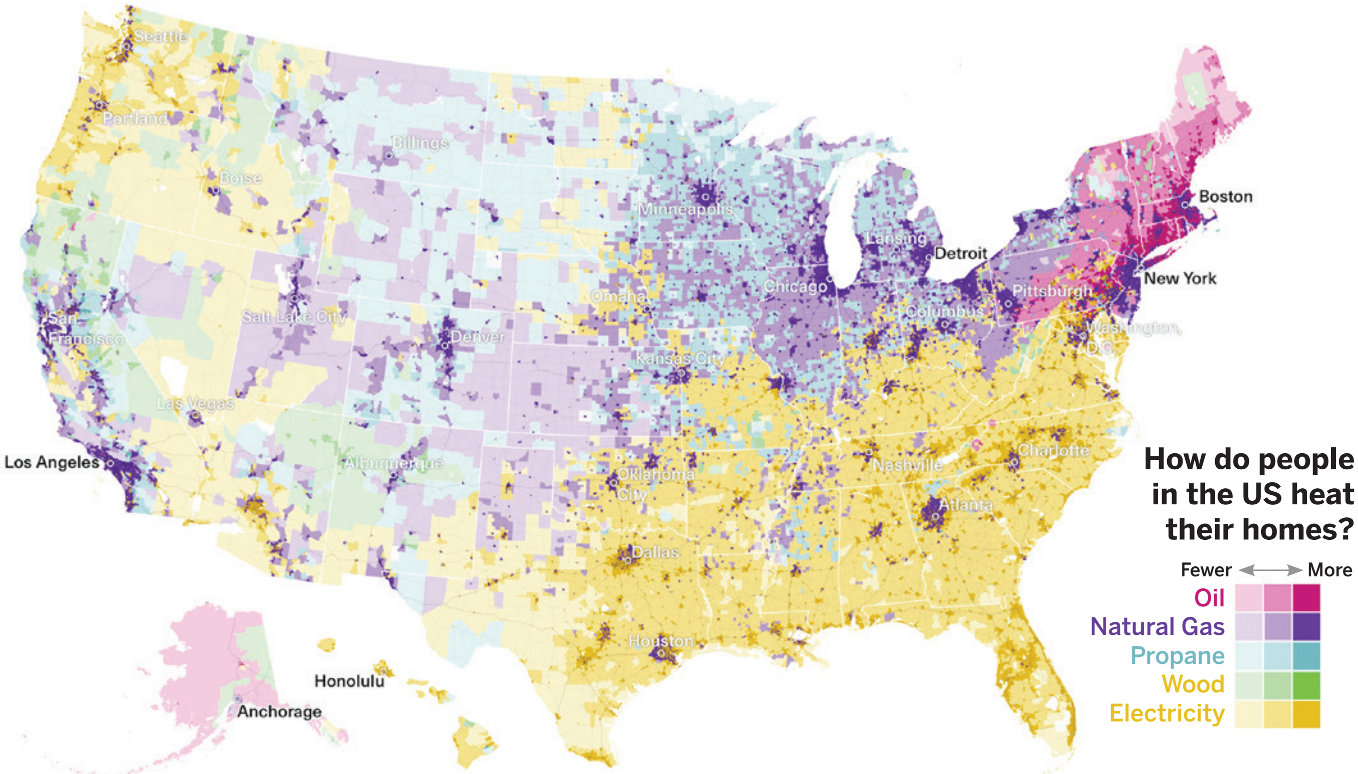
Improve Forecasting

Understanding how building electrification could shift load profiles is critical for grid planning. The load shape impacts of building electrification will vary substantially by location. Climate zones that do not suffer extreme cold events may not trigger the high demand caused by heat pumps going into back-up resistance heat mode. Some areas of the United States, like the Southeast and Texas, are already heavily electrified but are not yet at full electrification. There, incremental electrification of the remaining uses may see overall electricity use (MWh) *decline* from energy-efficient heat pump adoption replacing less-efficient older units or resistance heaters, while incremental electrification combined with cold winters could drive new peaks (MW). On the other hand, the adoption of electric heating in areas predominantly served with fossil fuels could result in a doubling of electricity use, affecting both peak power and total electricity needs.[2] Figure ES-1 (p. ix) shows how the primary fuel sources used for residential heating today vary across the country.

Impacts of building electrification on electricity distribution systems will vary locally by specific area or neighborhood. Even regions that already have high

2 A sampling of 80 customers by The Brattle Group found that electricity use rose 118% post-electrification (Sergici et al., 2023).

FIGURE ES–1
Primary Fuel Source for Residential Heating Across the U.S.



The primary energy sources used to meet residential heating needs varies significantly across the country, and the impacts of building electrification will vary by region.

Source: Stevens (2023); © maps.com.

levels of electric heating may see changes at the distribution level that require significant grid investments.

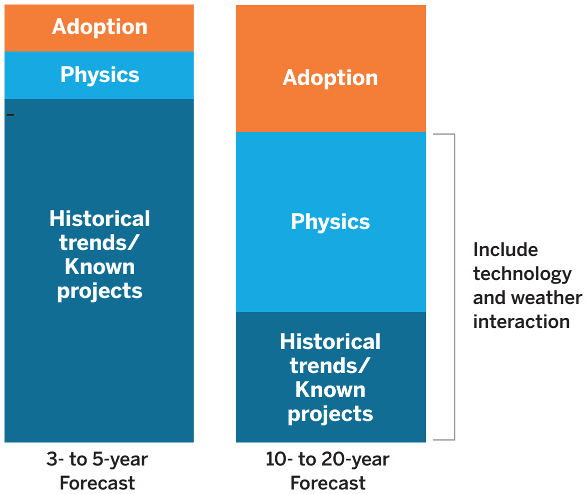
Forecasters and distribution planners can work together to better assess the impact of building electrification by:

- **Achieving a more granular understanding of technology adoption**. Key factors that can drive significant impacts from building electrification include: (1) adoption rates of electrification, (2) the types of heat pumps adopted, including the type of supplementary heat source (gas, electric, none), and (3) climate zone and potential for extreme cold that triggers the supplementary heat source.
- **Expanding the forecast horizon and factors considered.** By looking beyond the three- to five-year horizon often used in distribution planning, planners can better prepare the grid for the load growth expected from building electrification. Load forecasters and grid planners can employ physics-based models that capture chronological electricity load impacts via energy simulations of different types of buildings to understand how building electrification could affect load in different types of buildings (Figure ES-2, p. x).[3]
- **Establishing an end-use-specific baseline.** Building electrification alters some components of load more than others. To accurately understand the impact, a solid baseline of today's system, broken down by end use, is needed.
- **Incorporating weather impacts.** Typical meteorological years may miss weather events that are important to capture for grid planning decisions.

3 See, for example, ResStock at https://resstock.nrel.gov/ and ComStock at https://comstock.nrel.gov/.

FIGURE ES-2

Components of Building Electrification Load Forecasts by Forecast Horizon



Historical trends and known projects make up the majority of the inputs into short-term forecasts, but physics-based models and the adoption forecasts make up a larger percentage of the input factors in load forecasting as we look further into the future.

Source: Energy Systems Integration Group.

As space heating is electrified, we need to understand how extreme events occur and identify appropriate levels of extreme weather events to underpin planning. For example, if distribution planning aims to prepare for a 1-in-20-year weather event, the number and magnitude of these events need to be better characterized. It will be important to incorporate forward-looking climate change impacts on the severity and frequency of events.

Holistically Modernize Planning Approaches

As elements of the electricity system change, planning methods also need to evolve. Historically, planning on the power system primarily considered the single peak-load hour. However, severe weather, especially winter storms and cold snaps, can present longer-duration grid stress by increasing load for prolonged periods (EPRI, 2018). The electrification of space heating will exacerbate this stress, but distribution planners can adapt planning practices, beginning with the design criteria that inform equipment sizing, to address these infrequent high-load events driven by building electrification. Indeed, planning

for electrification requires a holistic analysis of the assumptions that drive grid planning decisions—assumptions that are embedded in design standards, planning and design processes, and load forecasts.

Equipment standards and the design conditions that inform their specification are a key area for reassessing planning practices. For pieces of distribution equipment ranging from service transformers to cable sizing to substations, sizing decisions are often based on a load forecast that accounts for some weather variability with headroom for incremental load growth and enabling circuit reconfigurations. For example, a piece of equipment may be designed for a 1-in-20-year peak, which affords 19 out of 20 years where conditions do not meet the designed peak demand, plus some headroom that allows the equipment to support adjacent circuits for reliability purposes. However, this approach may need to be revised, especially as forecasting becomes more advanced and buildings and transportation are electrified, for example, by allowing for more headroom for forecast error and/or embracing stochastic approaches to understand equipment impact from rare load conditions.

Opportunities for improving the planning approaches include to:

- **Expand beyond analyzing a single peak-load hour.** By looking beyond a single-hour peak-load forecast to more of a time-series analysis, planners can assess risks present in multiple hours of the year and the efficacy of solutions across chronologies.
- **Evaluate equipment standards.** Distribution system equipment standards are usually based on some combination of IEEE standards and local utility experience, with embedded assumptions about system conditions, demand diversity, and load growth. However, past practices may not be well suited for electrification-driven load growth, which may have different hourly load impacts. Distribution system planners will need to re-evaluate the underlying assumptions that drive equipment standards, including load diversity, the design conditions that account for outside temperatures or loading, and the planning margins for equipment sizing.
- **Use multiple scenarios.** As the industry moves toward more probabilistic methods, multiple scenarios can be used to evaluate different ways of addressing increased building electrification. Appropriate scenarios for evaluating building electrification stress the grid in different ways and incorporate a variety of technology solutions.

These new ways of analyzing the system are most effective when they inform new system designs, such as new equipment standards. While utility-specific standards facilitate planning for grid equipment appropriate to its service area, past practices may not be well suited for electrification-driven load growth. Building electrification provides an opportunity for planners to re-evaluate the underlying assumptions that drive equipment standards, including load diversity, the design conditions (e.g., how cold will it get?), and the planning margins for equipment sizing. These evaluations must also be balanced to minimize rate impacts.

The objectives and metrics for distribution planning may also need to shift. With increasing reliance on electricity systems to maintain habitable environments for society, distribution planning will increasingly need to design systems that reliably meet expectations. Key reliability and resilience metrics may need to change to capture impacts on energy equity and better emphasize the need to avoid long-duration outages, which are typically included only among the "major event days" in IEEE reliability metric calculations. These evaluations must also be balanced to minimize rate impacts.

Avoid the Largest Impacts by Using Energy Efficiency and Demand Management

Energy efficiency is more important than ever. While fuel switching from fossil fuels to electricity can increase demand, this increase can be mitigated through efficiency measures, reducing the grid impact of electrification. In the context of building electrification, the most important energy efficiency measures are those that maintain building temperature with minimal input from the grid, because of the long duration of winter reliability events. The term "thermal resilience" can be helpful in contextualizing building envelope improvements and distinguish them from other types of energy efficiency. Energy efficiency measures can benefit participating utility customers directly and benefit all customers by avoiding grid upgrades.

Another tool available to grid planners is load flexibility and grid-interactive buildings that respond to changing grid conditions. There are many untapped opportunities for grid interactivity today. The question facing grid planners is no longer just how to mitigate impacts of electrification on the grid but rather, how can we take advantage of opportunities to use the flexibility from grid-interactive buildings? Thirty percent of thermostats in the United States today are smart thermostats, and that number is growing. Their deployment can facilitate demand flexibility to address local (or bulk) system needs, if utility programs and tariffs are designed to tap into these capabilities. However, currently, energy efficiency and load flexibility are typically treated as static inputs in distribution plans, if addressed at all, rather than evaluated as a potential solution. Utilities can tap into their value by assessing the impacts of energy efficiency and load flexibility on future loads, at both the system level and distribution level through geotargeting initiatives, and potentially further incentivize the adoption of these grid-edge resources.

Touch the Grid Only Once When Making Upgrades, and Use a Coordinated Approach

As building electrification proceeds, planners will need to assess what grid upgrades will be needed, when, and where. The types of grid upgrades—and how they are prioritized—will directly result from the local approach to building electrification. For example, if the primary approaches are economic benefits to customers through program incentives and retail rates, technology adoption will be highly uncertain and grid upgrades largely reactive. Yet there would still be opportunities to prioritize future-ready infrastructure—physical and digital equipment that can support building electrification loads in the long term. In contrast, if a locale prioritizes targeted building electrification that identifies a specific location or neighborhood for electrification or equity-focused initiatives, distribution system planners can be more certain of the needs. The greater certainty of locations and magnitude of electrification will mean opportunities to upgrade electric distribution systems efficiently.

Defining objectives, approaches, and priorities and integrating planning processes for electricity and natural gas networks will create more cost-effective infrastructure overall, avoiding potentially redundant or short-lived infrastructure. Planning objectives and approaches flow from state and local policies, but regardless of the starting point and trajectory for a utility or region, clearly defined objectives and priorities across infrastructure domains can be used to design and evaluate potential distribution system solutions.

Building electrification creates an opportunity to better integrate energy systems and meet state and local policy goals for decarbonization, as long as we share best practices and plan appropriately.

Introduction

Technical advancements, policy goals, and customer preference are driving building electrification across the United States. Increased building electrification could lead to long-term, sustained load growth, reversing flat or declining load trends seen across the country over the past 15 years (U.S. EIA, 2024). Across all end uses, building electrification could require somewhere between 10% and 70% more electricity generation capacity than exists today depending on technology adoption and energy efficiency (Hopkins, Nadel, and Takahashi, 2020; Waite and Modi, 2020). Not only can building electrification increase loads, but it can also change load patterns, shift peak demand periods, and further increase the weather dependence of loads.

Building electrification refers to replacing equipment using natural gas, propane, and fuel oil with electric alternatives. It is occurring in both existing and new construction, and across commercial and residential buildings, and includes the major end uses of space and water heating in homes and commercial buildings as well as more minor end uses such as cooking (and, in homes, clothes drying). While the adoption of electric vehicles, proliferation of data centers, and electrification of industry will also impact loads, this report focuses on the electrification of residential and commercial buildings. (See *Charging Ahead: Grid Planning for Vehicle Electrification* for a companion report on electric vehicles (ESIG, 2024a).)

While new loads will affect generation and transmission needs, the distribution system will likely be impacted by building electrification first, with its smaller equipment and lower power transfer capabilities (EnergyHub, 2024) and the fact that electrification is not occurring evenly across the country but rather at a regional or local level. Building electrification will present a number of challenges including load growth during specific times of the year, increased

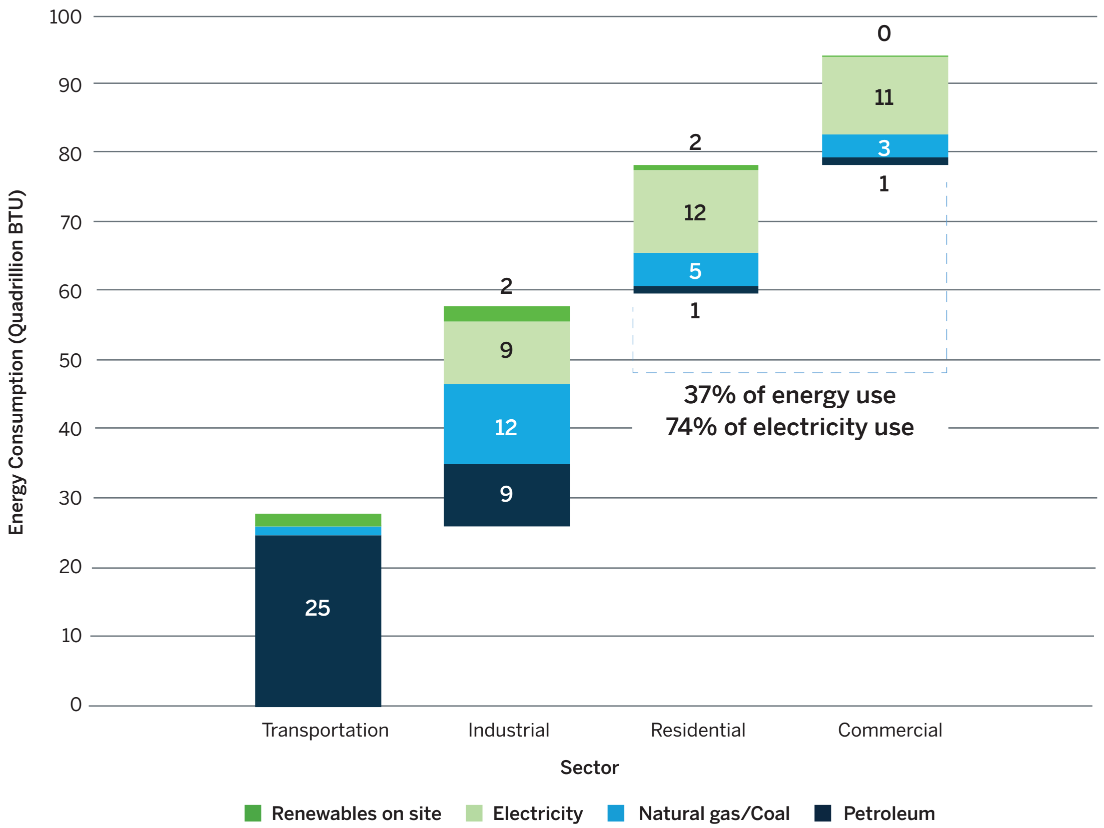
weather dependence of load, and rapid adoption of new electrification technologies that can outpace traditional distribution system planning.

Increasing Electrification of Buildings

Buildings today represent 37% of U.S. total energy consumption and 74% of electricity use (U.S. EIA, 2023c). Figure 1 (p. 2) shows energy use by sector and building energy use by fuel source.

FIGURE 1

Energy Consumption Across Sectors in the U.S. Economy in 2023



In the United States in 2023, residential and commercial buildings represented roughly 37% of overall energy use and 74% of electricity use.

Source: Energy Systems Integration Group; data from U.S. Energy Information Administration (2023c).

Different states across the country are at different levels of electrification. Transitioning the non-electric energy consumption to electricity could have dramatic effects on the electricity sector.

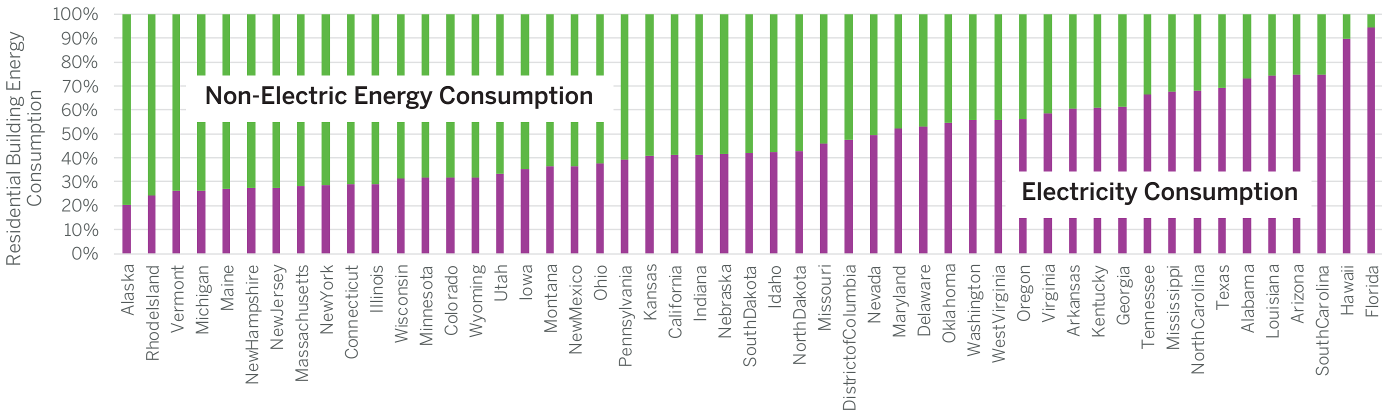
While over two-thirds (74%) of U.S. energy demand in the residential and commercial sectors is already served by electricity, the nature of this electricity consumption will change as new technologies are adopted and will vary by state and region. Figure 2 (p. 3) shows the break-down of energy consumption in residential buildings by state (U.S. EIA, 2023a), and Figure 3 shows the commercial building energy usage by region. Even in regions that already heat using electricity (South and Northwest), there are still large portions of energy usage that could be converted to electric.

Buildings are expected to drive considerable electricity load growth in most regions of the country over the next few decades as building energy consumption—largely related to heating demand—shifts from fossil fuels to electricity. Figure 4 (p. 4) shows building electricity growth increasing across scenarios (Langevin et al., 2023).

In the United States, the majority of the non-electric energy consumption is for space heating. For example, Figure 5 (p. 5) breaks down energy consumption in

FIGURE 2

Residential Energy Consumption by Fuel Type in 2020

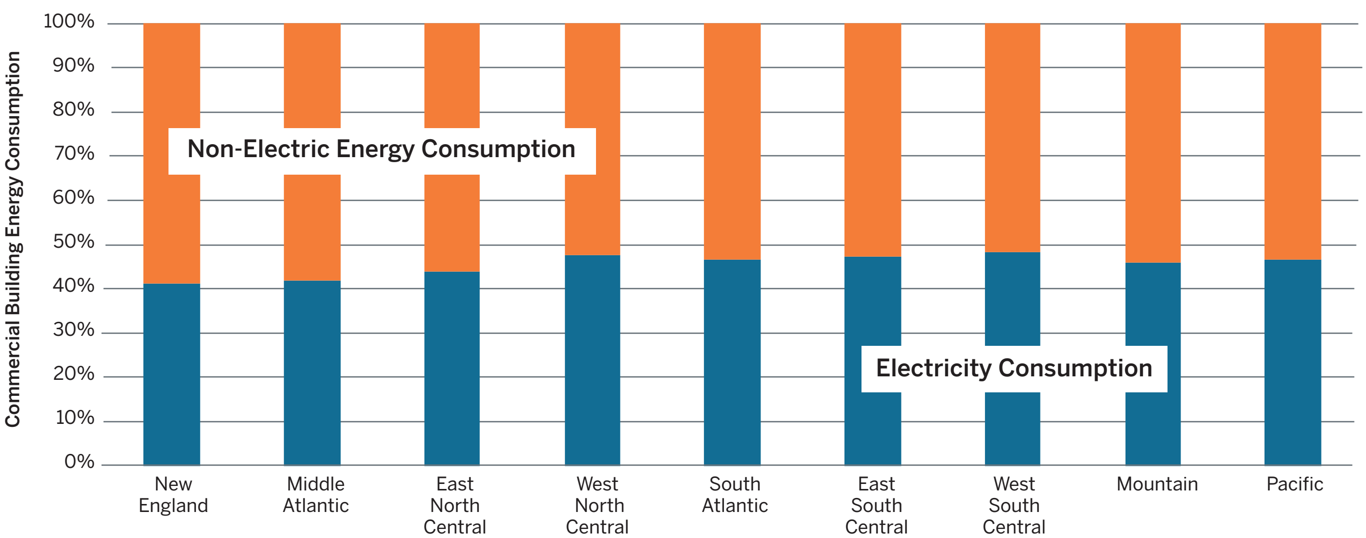


Different states across the country are at different levels of electrification. Transitioning the non-electric energy consumption to electricity could have dramatic effects on the electricity sector.

Source: Energy Systems Integration Group; data from U.S. Energy Information Administration (2023a).

FIGURE 3

Energy Consumption in Commercial Buildings by Fuel Type and Region

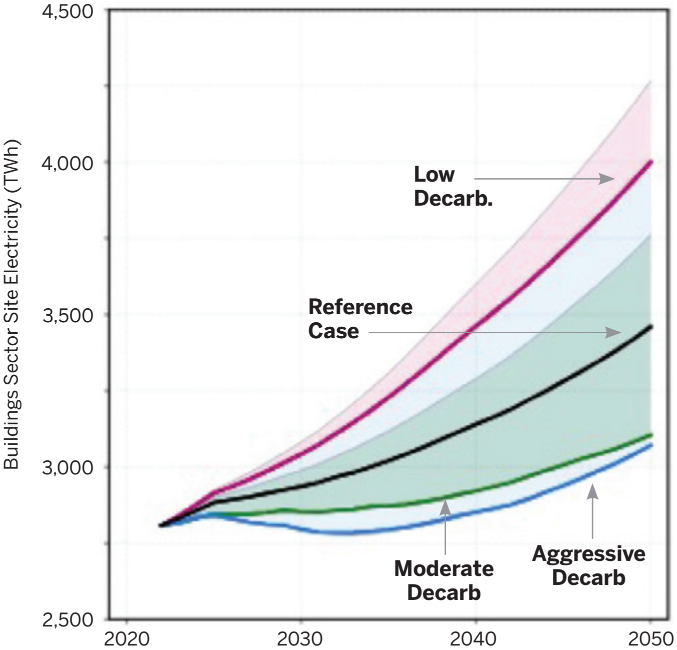


Different regions across the country are at different levels of electrification in commercial buildings. Transitioning the non-electric energy consumption to electricity could have dramatic effects on the electricity sector.

Source: Energy Systems Integration Group; data from https://www.eia.gov/consumption/commercial/data/2018/index.php?view=consumption, Table C17-C19.

FIGURE 4

Annual Building Electricity Use Across the U.S. Under Various Future Scenarios



Building sector site electricity usage is expected to increase over the coming decades across the U.S. and across scenarios.

Source: Langevin et al. (2023); Lawrence Berkeley National Laboratory (https://buildings2050.lbl.gov/).

In the United States, the majority of the non-electric energy consumption is for space heating. Heat pumps are often used to electrify both space and water heating while also providing air conditioning and have been used for decades in many parts of the country.

commercial buildings showing that most space heating, water heating, and cooking in these buildings is fueled by natural gas. Fuel switching from gas to electricity would increase electricity demand, and space heating uses four to six times more energy than water heating or cooking. Given that space heating demand is the largest and most weather dependent (U.S. EIA, 2023a), this report is largely focused on the electrification of space heating. Water heating is the second largest energy end use, making building electrification principally concerned with heating. Heat pumps are often used to electrify space and water heating while also providing air conditioning and have been used for decades in many parts of the country.

Figure 6 (p. 5) shows that the electrification of heating will impact different regions to different degrees based on their primary heating sources today.

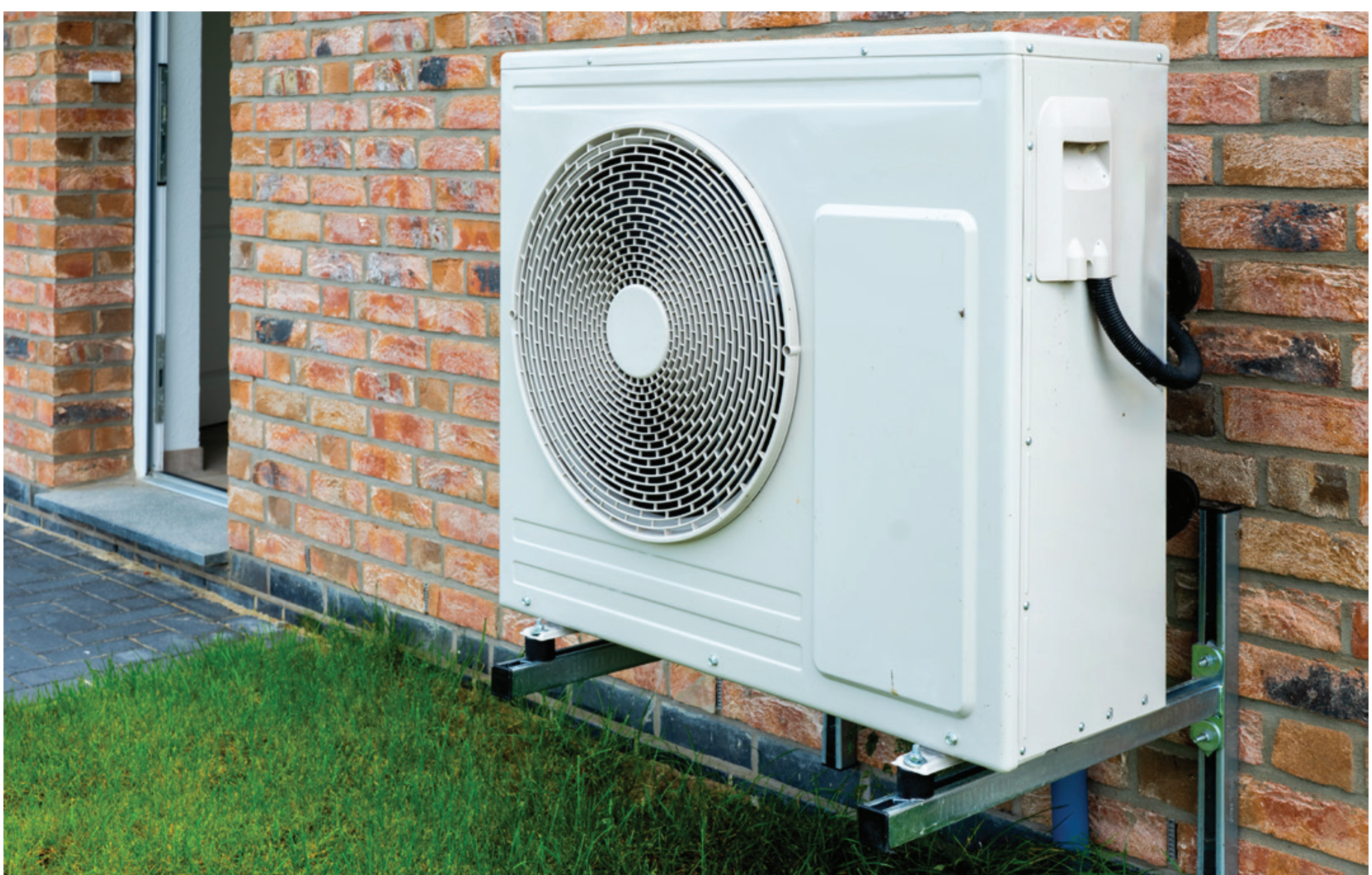
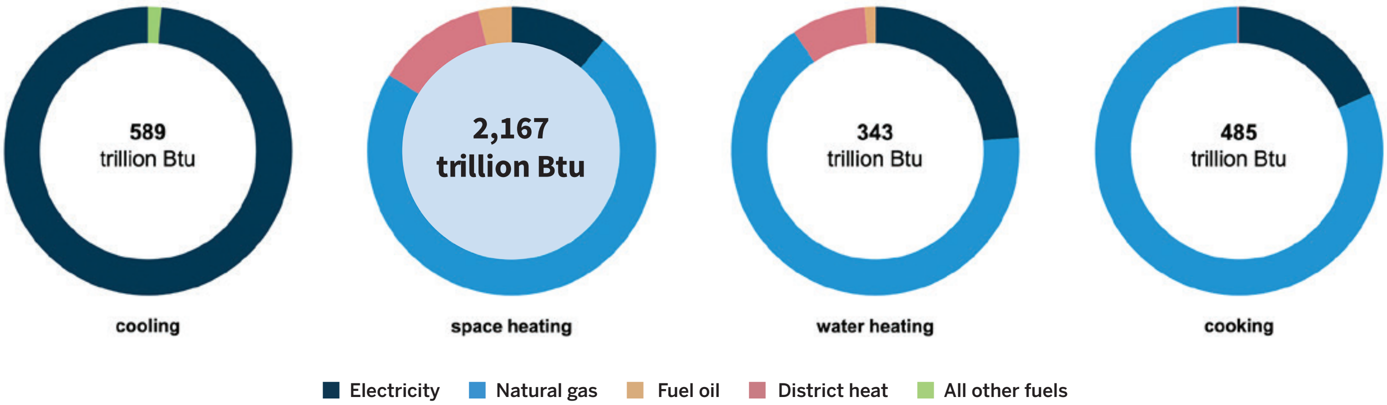


FIGURE 5

Energy Consumption by Major Fuel and Selected End Uses, 2018

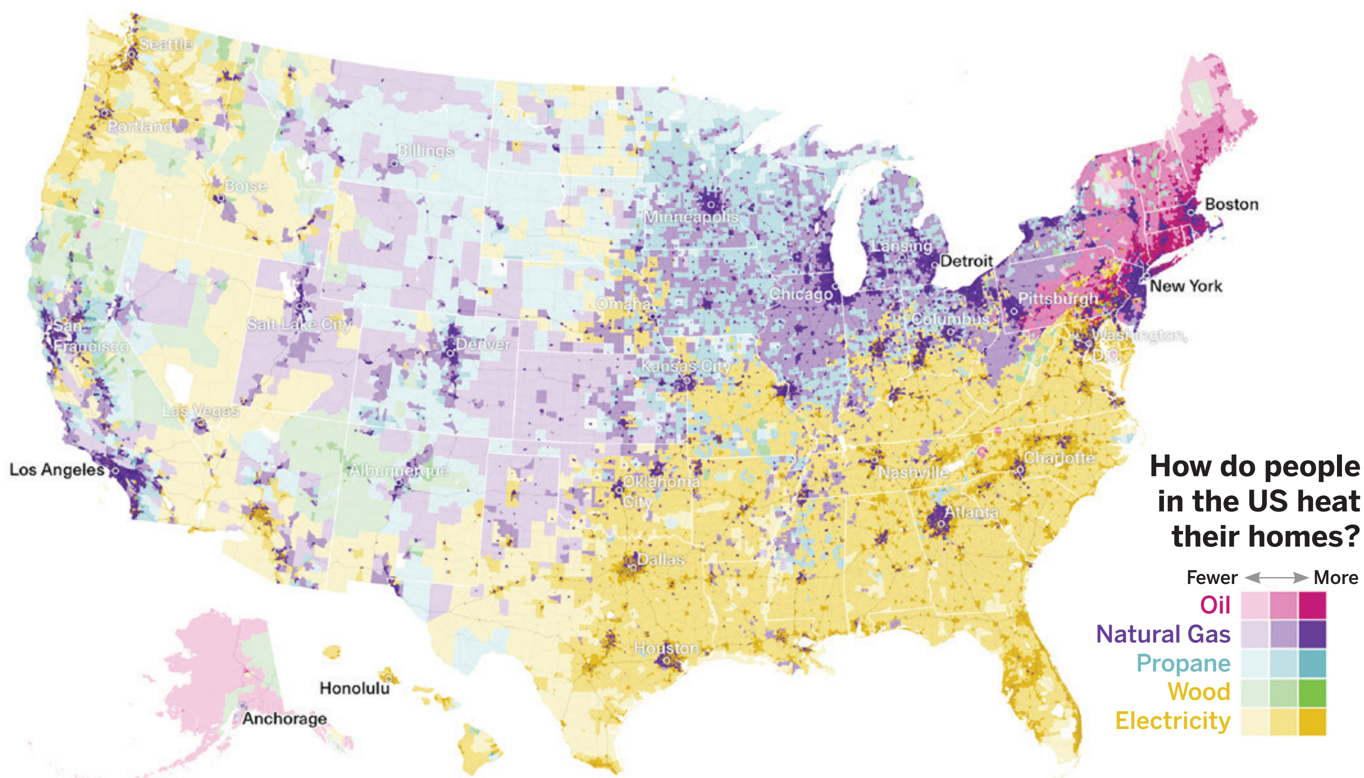


While the commercial building end-uses of space heating, water heating, and cooking all have significant non-electric energy consumption, the magnitude of energy used in space heating dwarfs that of water heating or cooking.

Source: U.S. Energy Information Administration (2022). 2018 Commercial Buildings Energy Consumption Survey (https://www.eia.gov/consumption/commercial/data/2018/pdf/CBECS%202018%20CE%20Release%202%20Flipbook.pdf).

FIGURE 6

Primary Fuel Source for Residential Heating Across the U.S.



The primary energy sources used to meet residential heating needs varies significantly across the country, and the impacts of building electrification will vary by region.

Source: Stevens (2023); © maps.com.

Challenges Accompanying Increased Building Electrification

If electrification were simply going to target new building construction on newly built electrical circuits, design of the power system to support new buildings would be more straightforward. Distribution lines, transformers, and service connections could be sized for electrification at the outset. However, most electrification will occur in existing buildings served by existing distribution system infrastructure. Today's grid was not designed to meet electric heating demand in many parts of the country, and constraints on the grid, ranging from power transfer capabilities to supporting infrastructure, such as more heavily loaded poles and space for transformers in yards, vaults, or ground-floors of high-rise buildings, will present barriers that will require investments in time, money, and infrastructure to resolve.

New Winter Peaks

Building electrification has important consequences for distribution planning. The effects of building electrification will be most pronounced in the winter in regions where space heating currently uses natural gas, propane, or oil. While heat pump adoption can potentially lead to lower summer peaks when existing cooling equipment is replaced with more efficient options, heat pumps that *introduce* electrified space conditioning represent new electric loads, potentially leading to increases in peak loads. Poorly insulated or poorly weatherized commercial and residential buildings can further increase power demand. Depending on how heat pumps are sized relative to buildings' heating needs, they are sometimes accompanied by a supplemental source of heat.[4] If the supplemental heat source is electric resistance coils, this can lead to spikes in electricity consumption from inefficient resistance heating that coincide with load that is already elevated from increased heating needs of the region.

Sudden Appearance of Prolonged Winter Peaks

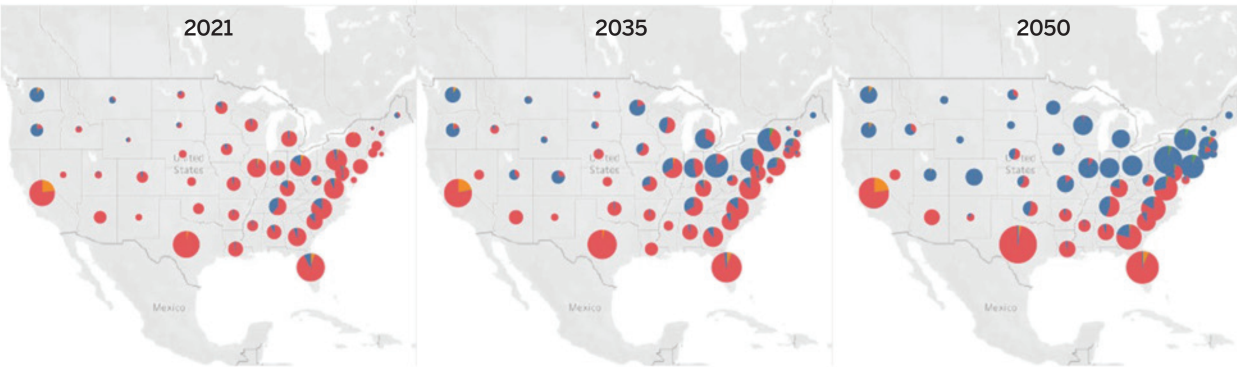
While many types of loads—like electric vehicles and data centers—are expected to grow tremendously in the near future, the energy consumption of these loads will be spread fairly evenly throughout the year. But as space heating electrifies, many regions will see large shifts in the seasonality of their load. In 2022, about 46% of retail utilities were winter-peaking.[5] However, winter-peaking utilities represent only 27% of retail electricity sales. The electrification of space heating could significantly increase the share of utilities that are winter-peaking and the overall amount of electricity that they are expected to provide. Winter peaks bring new challenges, as discussed below. Figure 7 (p. 7) shows how winter hours may take a larger share of the top 100 load hours of the year across many states as building electrification unfolds. Figure 8 shows the 2023 load forecast for the New York Independent System Operator (NYISO, 2023), which

4 As discussed throughout, there are many options for heat pump technology, including ductless mini-split units, which typically do not have back-up heaters.

5 Based on utility data reported to the U.S. Energy Information Administration on Form EIA-861 for 2022 (Operational_Data_2022.xlsx). Of the 1,310 "Investor Owned, Cooperative, Municipal, and Political Subdivision" utilities, 599 reported a winter peak demand greater than or equal to their summer peak demand. These 599 utilities are spread across 46 states (all except for Delaware, New Hampshire, New Jersey, and Rhode Island, and the District of Columbia).

FIGURE 7

Seasonal Breakdown of Forecasted Top 100 Load Hours for the Contiguous United States



Winter hours may take a larger share of the top 100 load hours of the year across many states as building electrification proceeds.

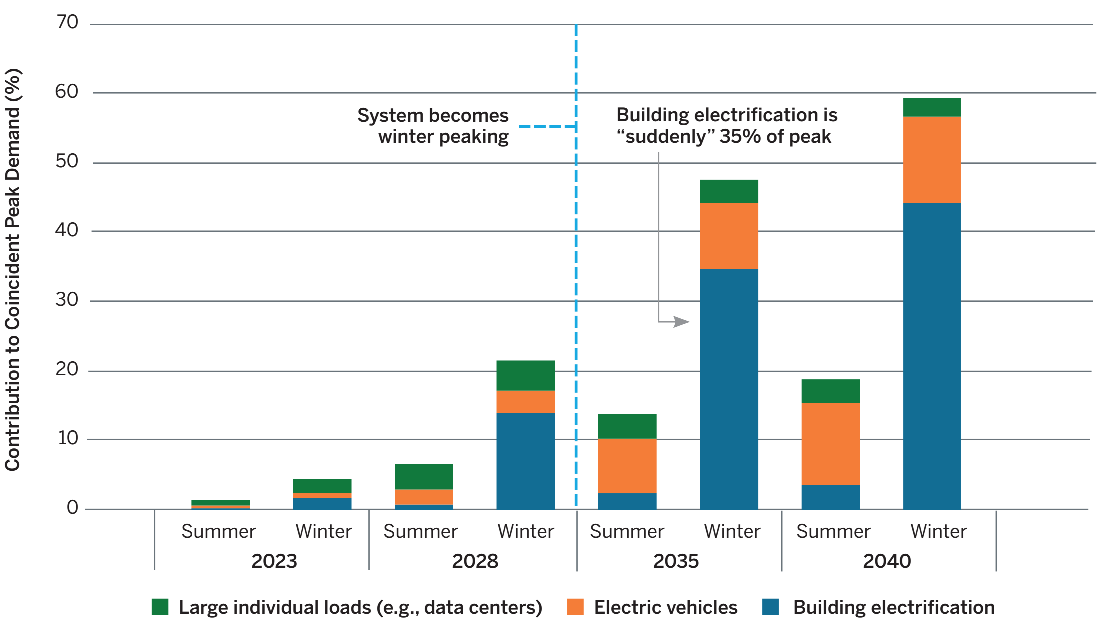
Source: Jones (2023).

highlights the dramatic changes brought on by building electrification. In New York, building electrification is forecast to shift it to a winter-peaking system, driving over 40% of the system peak by 2040.

While winter-peaking systems are not new, they bring new challenges. Winter storms are more likely to elevate load for several days without the diurnal patterns of summer-peak load profiles (see Figure 13, p. 14). Increased

FIGURE 8

Component Breakdown of New York Peak Demand Forecast



Building electrification makes up a large portion of the peak load forecast in New York as the system is forecasted to become winter-peaking between 2028 and 2035.

Source: Energy Systems Integration Group; data from New York Independent System Operator (2023).

load for prolonged periods can deteriorate grid-edge equipment, which is typically designed to serve peak demands for short durations, and can lead to component failures. Overload failures can occur throughout the grid, including in distribution systems, where equipment is often unmonitored. Grid failures during extreme winter weather events pose much more risk to human health and wellbeing than do summer peaks (PNNL, 2023).

Focus of This Report

The Energy Systems Integration Group convened the Grid Planning for Building Electrification Task Force to discuss the challenges throughout the grid planning process from multiple perspectives, identify gaps in distribution system planning for building electrification, discuss ways to address these gaps, and articulate promising practices and next steps aligned with the forecasted levels of electrification. The task force included grid planners from across North America, equipment and software providers, state utility regulators, officers from municipal and state energy offices, researchers, and consultants active at the intersection of building energy usage and grid planning.

This report identifies the needs and opportunities for grid planning for building electrification, with a particular emphasis on distribution systems. The primary audiences are utility planners, utility regulators and other state decision-makers, building managers, equipment manufacturers, demand response aggregators, and others. With rapid changes in technologies and policies, plans must remain nimble to meet distribution system needs. The themes, concepts, and areas of emphasis conveyed in this report will continue to evolve as we gain more experience with new and expanding electrified end uses.

Main Elements of Building Electrification

Building electrification is defined here as the replacement and initial installation of energy-consuming equipment in commercial and residential buildings with electrically powered technologies—i.e., fuel-switching from fossil fuels to electricity.[6] Electricity already supplies the majority of energy for many end uses in buildings, with the major exceptions being space and water heating, cooking, and clothes drying. In the United States, space heating is the building end use that directly consumes the most energy from fossil fuels. As such, the electrification of space heating, primarily through heat pump adoption, will drive the greatest growth in energy demand. Water heating is the next most significant end use in terms of potential load growth due to building electrification. Figure 9 (p. 10) shows the energy consumption in commercial buildings and identifies that space and water heating are the predominant end uses. Figure 10 (p. 11) shows how most natural gas is used in residential buildings for space heating, which represents the largest opportunity for electrification.

The focus of this report is on the electrification of space heating, and to a lesser extent water heating, as these end uses will meaningfully increase load and thus affect distribution system planning. The electrification of cooking in restaurants, clothes drying in laundromats, and livestock heaters at farms can have distribution system and building-level impacts, but these are of secondary importance compared to electrification of space and water heating across all building types.

Heat Pumps

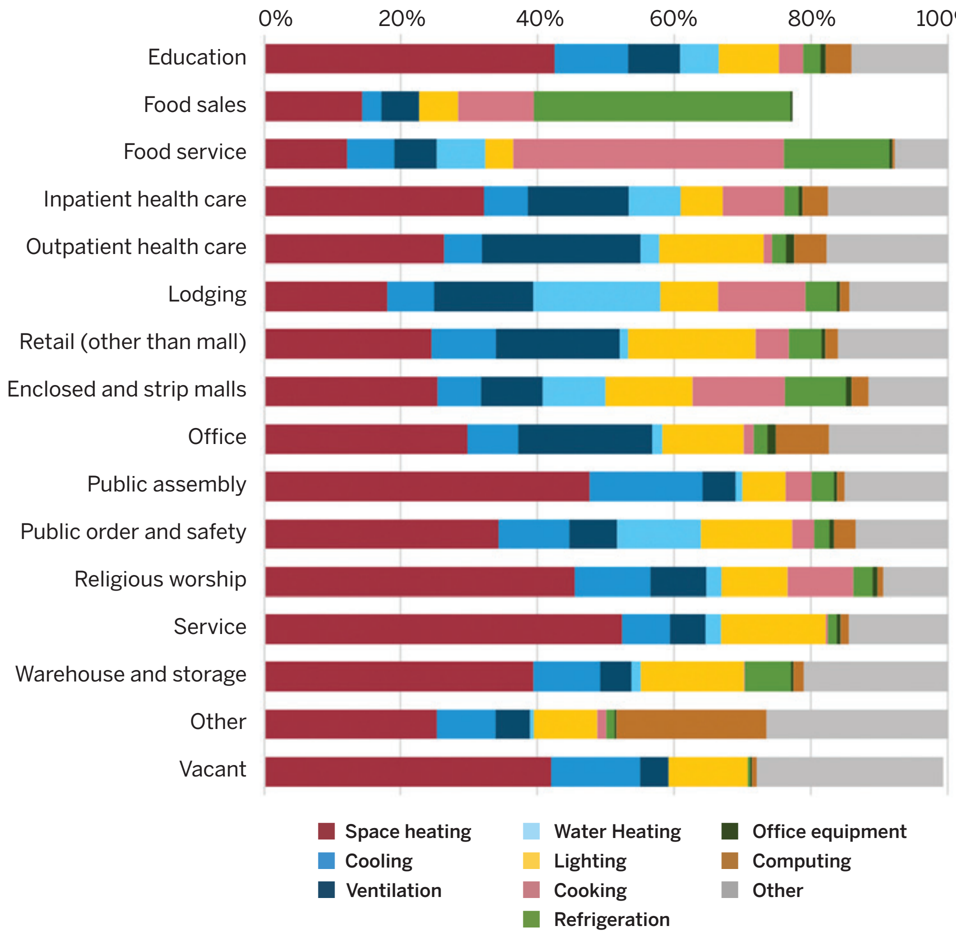
Throughout this document, discussion of the electrification of heating applies to both residential and commercial buildings (and to a lesser extent some industrial applications), electriciation that is often principally enabled through heat pumps. (See Box 1, p. 11.)

Air-source heat pumps achieve heating or cooling by transferring heat either from outside the building to the inside (for heating) or from the inside air to the outside (for cooling). The vast majority of heat pumps in use today are air source (U.S. DOE, 2024b), either air-to-air or air-to-water. Air-to-air is the dominant type in the U.S. and in many other parts of the world where air

6 Building electrification does not cover all aspects of building decarbonization, which often includes addressing embedded carbon within building materials such as concrete and steel. This report does not assess the efficacy of building electrification as a decarbonization measure, which depends on the carbon intensity of the electricity generation mix. And, due to the emphasis on grid planning, discussions on service panel upgrades are intentionally minimal.

FIGURE 9

Fuel Consumption by End Use and Building Type for Commercial Buildings



Space and water heating make up the majority of building energy use in commercial buildings of all types. Building electrification is primarily oriented around converting this energy consumption to electricity.

Source: U.S. Energy Information Administration (2022a).

conditioning is common. Air-to-water heat pumps are currently much less common in the U.S. but are rapidly growing in European countries where heating has traditionally been provided with hot water from a boiler circulated through radiators (Wilson et al., 2024).

Ground-source heat pumps (also known as geothermal heat pumps) use buried pipes to extract heat from the ground. These are generally more efficient than air-source heat pumps but are much more expensive to install and require a suitable outdoor area where they can be installed underground. However, they could be a cost-effective solution relative to air-source heat pumps in cold regions. A recent gas decarbonization study evaluating strategies in Minnesota found that the total cost of a full electrification scenario with aggressive deployment of ground-source heat pumps would be lower than the scenario with mostly air-source heat pumps, when considering the cost of grid upgrades and the capital costs of customer-side electrification (deLeon et al., 2024).

Newer heat pump water heaters are being developed for smaller residential uses that only require 120 volt circuits instead of 240 volt circuits, which results in lower peak

BOX 1

Heat Pumps

Heat pumps transfer heat from one place to another via a thermodynamic heat exchange: a heat pump can be thought of as an air conditioner that can run in reverse to either heat or cool. While heat pumps have been used for decades across much of the southern U.S., they are being increasingly adopted in other regions because of new improvements in technology that improve efficiency (through cold-climate heat pumps) and the implementation of policy goals encouraging decarbonization and electrification.

Most residential heat pumps use between 3,500 and 9,000 kWh annually to provide heating and air conditioning to a home. The electric power draw of a heat pump heating system can increase by several times in extreme temperatures, especially when supplemental resistive heating is required. Heat pumps also provide space and water heating to commercial buildings with the same basic principles at a larger scale.

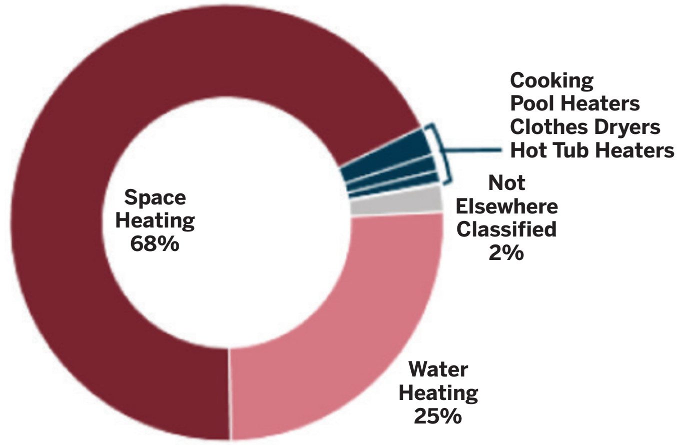
Heat pumps perform well in extreme heat or cold as long as they are sized properly. Heat pump technology has improved in the last few years, and they can keep indoor temperatures comfortable even in subzero outdoor temperatures. Cold-weather heat pumps incorporate advanced designs to operate with greater capacity and efficiency at outdoor temperatures below 32°F. These models use a different refrigerant and can run at variable speeds that match a larger range of temperature needs, generally suitable for temperatures down to -20°F, at which point they may require back-up heating sources, such as resistance heating.

While heat pumps can also be considered an efficiency improvement for cooling because they are generally more efficient than the air conditioning technology they replace, it is when they are used for heating that they often constitute a new load, as they are replacing natural gas or oil as the heating fuel.

For more information on heat pump variants, readers are encouraged to review the many U.S. Department of Energy resources available, including https://www.energy.gov/heat-pumps.

FIGURE 10

Residential Natural Gas Consumption by End Use, 2020



Space and water heating make up the majority of natural gas use in residential buildings, which is the form of energy most targeted for disruption through building electrification.

Source: U.S. Energy Information Administration (2023b).

loads but also longer water heating times. In some commercial applications, the same heat pump can be used for both water heating and space conditioning. Packaged heating, ventilation, and air conditioning (HVAC) units, often mounted on commercial rooftops and called rooftop units, provide ventilation, air conditioning, and heating to many different types of large buildings. Existing rooftop units can be replaced with all-electric or dual-fuel packaged air-source heat pumps.

Supplemental Heat Sources Sometimes Used Together with Heat Pumps

Heat pumps are often installed with a supplemental heating source. Some are hybrid or dual-fuel systems, which use a heat pump to meet the cooling load and

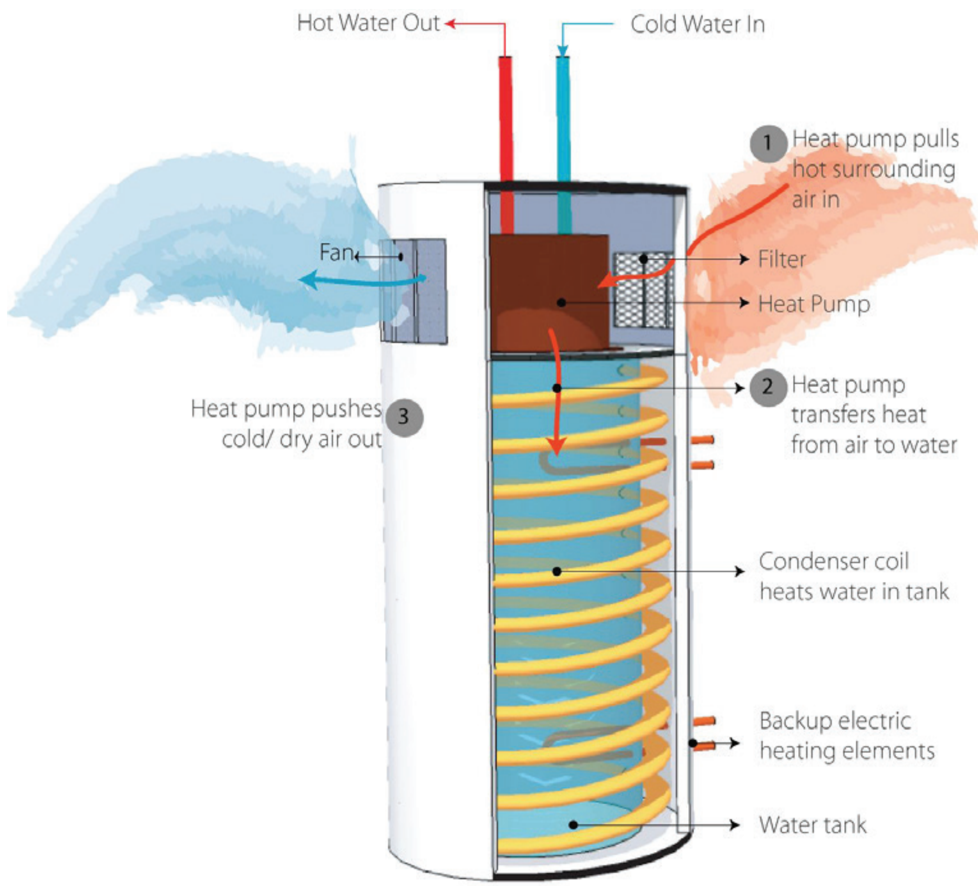
In some commercial applications, the same heat pump can be used for both water heating and space conditioning. Packaged HVAC units provide ventilation, air conditioning, and heating to many different types of large buildings.

majority of the heating load, but switch to gas or another fossil fuel in cold temperatures when the heat pump is more expensive to run or if it cannot provide sufficient output to meet a building's full heating load in cold temperatures. Other heat pumps use electric resistance supplemental heating elements. Still another strategy for supplemental heating is to retain the existing fuel-fired furnace, boiler, or other heating equipment after the installation of the new heat pump.

The integration of resistance heating as applied to heat pump water heaters is shown in Figure 11. Heat pump water heaters represent a newer electric water heating technology that is typically two to four times more efficient than electric resistance water heating (the primary heating source of many water heaters today). As when a heat pump is used for space heating, resistance heating can kick in when the heat pump cannot meet the building's water heating demand.

FIGURE 11

Components of a Heat Pump Water Heater, Including Back-up Resistance Heating



Heat pump water heaters can use supplemental electric resistance heating elements to meet hot water needs during periods of high demand. These same elements are common in heat pumps designed to condition air.

Source: Pacific Northwest National Laboratory.

The Challenge Presented by Building Electrification

Distribution planners are tasked with prioritizing when and where grid upgrades are needed to meet consumer, policymaker, and stakeholder expectations of reliability, safety, and sustainability. While programs and policies can encourage electrification in specific locations, building owners' choices will usually drive adoption. Planners are tasked with prioritizing grid upgrades equitably in a way that allows both for electrification initiatives for large buildings and for small home upgrades. And regulatory, accounting, and cost allocation rules must be aligned with the overarching objectives of the region to ensure cohesive planning across fuels, networks, and service providers.

The increasing weather dependence of power demand during winter weather events is central for distribution system planning for building electrification. This increase can be observed when electrification is paired with extreme temperatures, but it can be masked by mild temperatures as electrification takes place over time. The load impacts from winter events also tend to involve prolonged periods of high demand, whereas typical summer peak-load profiles more strongly follow diurnal rhythms, with a break at night. These shifts in how demand behaves can have implications across grid planning, from the types of analysis that need to be performed to the solutions best suited to address the challenges.

Increasing Weather Dependence

Just as wind and solar generation is increasing weather dependence on the supply side, building electrification will increase the weather dependence of electricity demand, especially in winter. To account for this change, system planning—and distribution equipment sizing—will need to move beyond average values in typical weather to take into account how a variety of realistic conditions affect the distribution system. In short, building electrification is expected to make a system that is already highly weather-dependent even more so.

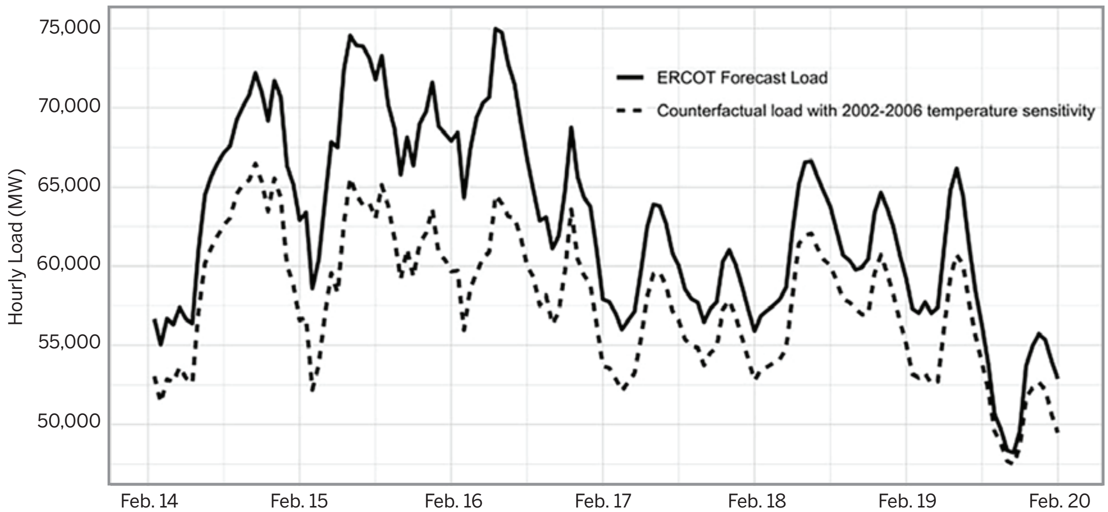
To account for the increased weather dependence of electricity demand, system planning—and distribution equipment sizing—will need to move beyond average values in typical weather to take into account how a variety of realistic conditions affect the distribution system.

Weather-dependent challenges were noticeable during recent winter storms in 2021 and 2022. The Tennessee Valley Authority experienced new record peak demands each of the last two winters, setting a new winter peak in December 2022 and a new single-hour peak in January 2024, which surpassed the previous peak from August 2007 by 3 percent (TVA, 2024). A study performed in 2022 also showed that loads in Texas are more sensitive to cold temperatures today than they were in the first decade of the 21st century (Schaffer, Quintero, and Rhodes, 2022). Figure 12 (p. 14) compares an actual load forecast during Winter Storm Uri in 2021 with an estimate of how load would have behaved in the Electric Reliability Council of Texas (ERCOT) territory if it had the temperature sensitivity of loads in the 2004–2006 time frame. While controlling for increased demand overall, this figure shows, with a counterfactual example, that the temperature-sensitivity of load has already increased in Texas in the past 15 years.

Common among these recent weather events are sustained periods of high loads. Winter events can represent

FIGURE 12

Simulated ERCOT Load During Winter Storm Uri



While controlling for increased demand overall, this figure shows, with a counterfactual example, that the temperature-sensitivity of load has already increased in Texas as the 21st century has progressed.

Source: Schaffer, Quintero, and Rhodes (2022).

prolonged periods of elevated load as space heating drives higher demand. While summer heat waves can last several days, summer load profiles typically return to normal levels at night. Winter load profiles also have a diurnal pattern that follows household and commercial activities, but during extreme cold periods the troughs are much shallower (Figure 13, p. 15). This changing load profile increases the need for distribution equipment that can provide high levels of energy for prolonged periods.

Given how load shapes will change with building electrification, analysis based on peak-hour demand provides insufficient context to make equipment sizing decisions. Distribution system equipment may be able to provide sufficient capacity to meet the peak-hour demand but may not be designed to transfer power for prolonged periods. In the case of transformers, prolonged high loads can decrease equipment life if the internal parts are unable to cool. In addition, demand response programs and battery storage are challenged during prolonged periods of grid stress, as they are often designed to provide capacity for several hours but are then unable to continue to help meet system demands.

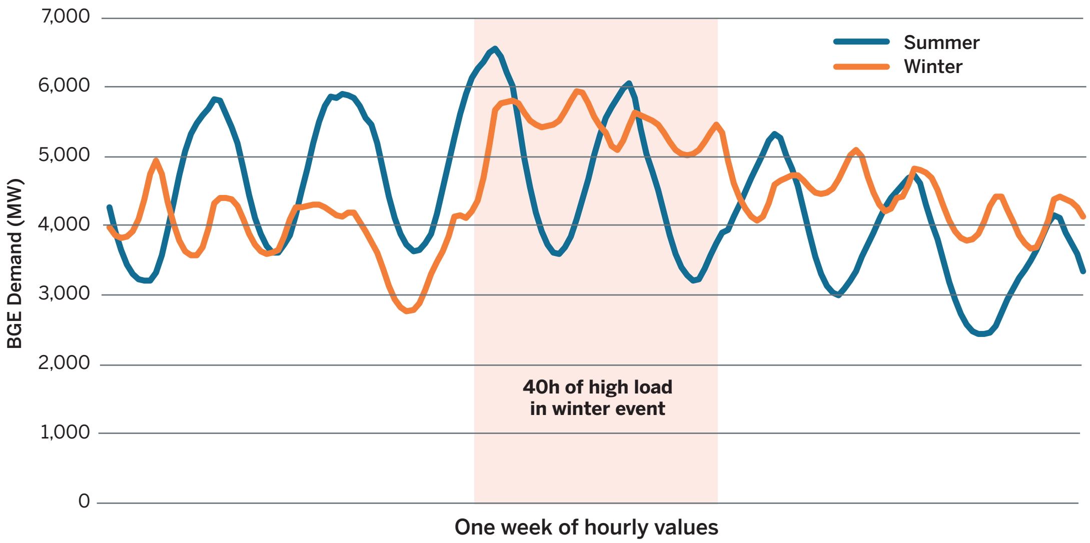
The winter risk of the electrification of heating may not reveal itself for many years if no outlier cold snap occurs that drives a switch from normal heat pump operation to supplemental resistance heating.

Potential for the Addition of New Loads to Outpace Utility Planning

Recent experience in Maine, Canada, and elsewhere has shown that building electrification can occur rapidly, especially when incentives are high for initial installation and the path to subsequent bill savings is more direct (Buckley, 2024). While utilities have time to plan for new building developments and industrial facilities, individual building retrofits can happen virtually overnight and without warning. Distribution utilities have awareness of building-level electric panel upgrades, but in general, they may have less time to upgrade distribution system infrastructure when adoption occurs quickly, compared with the historical load growth over the past decade or two.

FIGURE 13

Winter Peak Loads Versus Summer Peak Loads for the Baltimore Gas and Electric Territory in 2022



Electricity demand in Baltimore Gas and Electric (BGE) during Winter Storm Elliot (December 2022) and during August 2022 (peak annual demand). While the summer peak single hour was a higher overall load, the energy delivered across a 40-hour period was higher during the winter peak load event. These prolonged periods of elevated load are common in winter cold snaps as natural societal patterns drive load during the day and cold temperatures keep load elevated at night.

Source: Energy Systems Integration Group; data from U.S. Energy Information Administration Form 931.

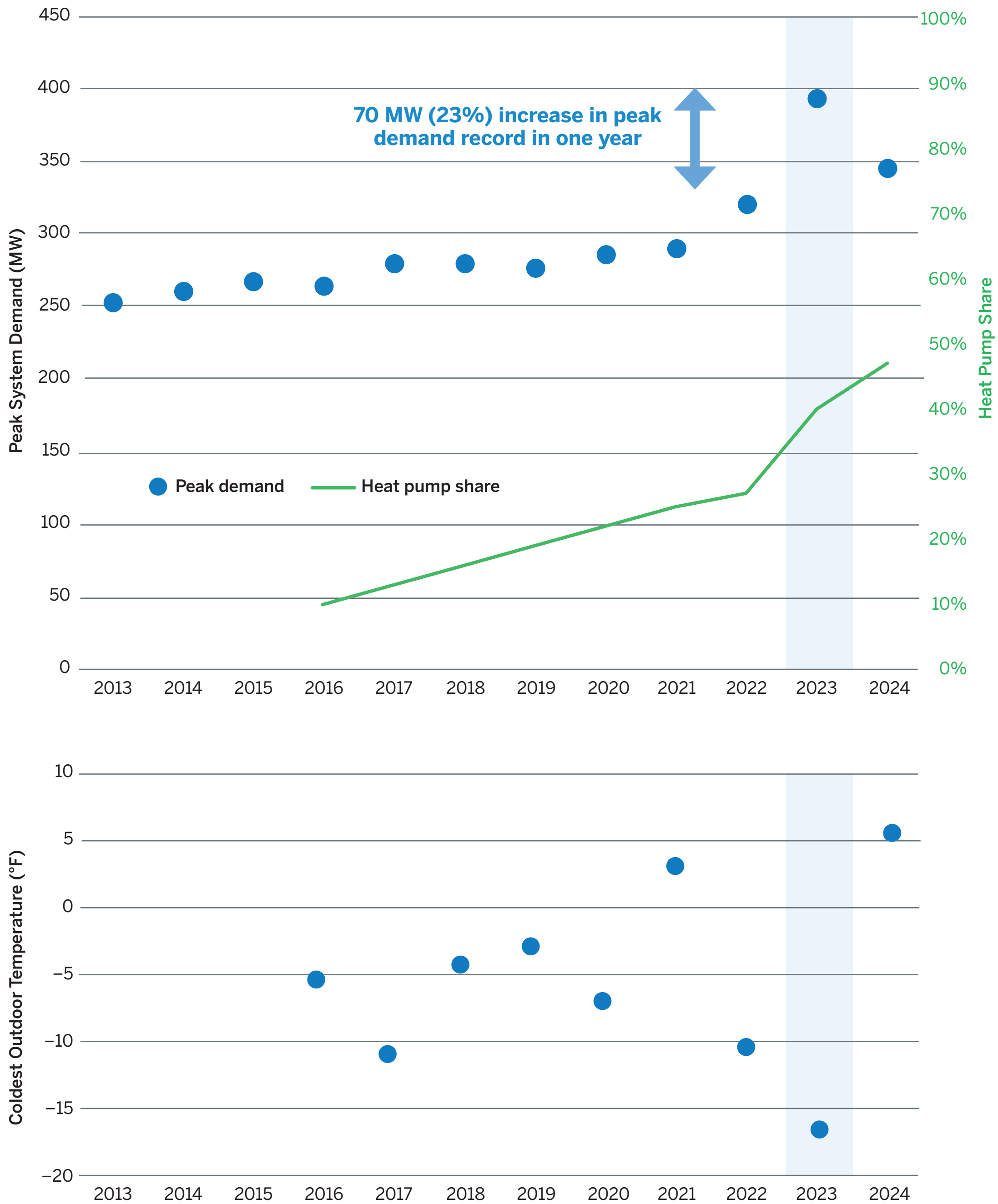
Furthermore, the winter risk may not reveal itself for many years if no outlier cold snap occurs that drives a switch from normal heat pump operation to supplemental resistance heating. In this case, heat pump adoption can build up slowly across many years without spikes in loads, and then the switch to resistance heating during a prolonged cold snap causes significant spikes in demand. Grid planning practices need to evolve to track lurking risks and to design solutions to meet the need.

The Canadian province of Prince Edward Island (PEI) provides key insights on how building electrification can affect the distribution system. PEI's Net Zero Free Heat Pump program has been providing incentives for up to 100% of the cost for consumers to install heat pumps since 2015. In July 2024, the program that effectively provides a free heat pump was extended to Islanders with annual household net income of US$122,000 or less (CBC News, 2024). The program has spurred a rapid rise in electrification on the island, with more than 7,000 new heat pumps replacing oil furnaces since December 2021 (Yarr, 2023), achieving almost 50% total adoption.

For grid planners, 7,000 newly electrified homes may not seem like much, particularly as the impact of incremental increases in numbers of heat pumps can be masked by normal temperatures. Although PEI has been a winter-peaking system throughout the last decade, a cold snap in early 2023 saw it set a new peak demand record by more than 70 MW, exceeding the previous peak observed in the winter of 2022 by 23% (Reinvented, 2024) (Figure 14, p. 16). This event appears to be driven by cold temperatures and many heat pumps deployed with supplemental resistive heating, and not a jump in peak demand resultant from crossing some threshold above a certain percentage of space heating electrification. This illustrates the potential for lurking risk, where buildings can electrify over many years without a large impact on load until a cold weather snap shows the inherent underlying peak demand risk.

FIGURE 14

Prince Edward Island Peak Demand and Heat Pump Share



The electrification of space conditioning in Prince Edward Island has been growing steadily since 2016, and the peak demand increases on the system appeared relatively modest until 2023, when high space heating electrification coincided with very cold temperatures. Peak demand returned to a lower level in 2024 with mild temperatures.

Source: Energy Systems Integration Group; data from Yarr (2023) and Reinvented (2024).

The adoption of cold-weather heat pumps and energy efficiency measures such as insulation and weatherization can help mitigate the cold-temperature risk, reducing the supplemental heating needed in the first place and allowing the building to better retain heat when supplemental heating is needed.

A prolonged cold snap presents challenges across multiple hours and days. Once the demand on PEI broke through the previous system peak at 5:00 pm on February 3, 2023, it stayed above that mark for 27 of the next 31 hours (Extreme Weather Watch, 2024). However, there are options available to avoid this type of lurking risk. The adoption of cold-weather heat pumps—specifically designed for climates like this—and energy efficiency measures such as insulation and weatherization can help mitigate the cold-temperature risk, reducing the supplemental heating needed in the first place and allowing the building to better retain heat when supplemental heating is needed. These cold-climate heat pumps are rapidly evolving for performance at lower and lower temperatures.

Grid Planning Solutions for Building Electrification

Solutions in distribution system planning for building electrification can come in many forms, including infrastructure upgrades or demand management approaches, and improved forecasting and modernizing planning techniques to better capture future grid stressors. These improved planning practices can also help to identify new technologies, programs, rate designs, and other demand management options that help to avoid the largest impacts of building electrification.

While energy efficiency and load flexibility will be important solutions to avoid the largest impacts of building electrification, they cannot mitigate the need for new equipment altogether. In some areas, distribution upgrades will be required. Identifying the appropriate upgrades will be vital, as buildings can electrify quickly in areas with favorable incentives, and the impact of building electrification may be masked by mild temperatures. To keep pace, the grid planning solutions identified in this report require changes both within annual planning processes, such as considering the full extent of expected electrification, and outside of annual planning analysis, such as assessing the long-term suitability of standard distribution system equipment. Through careful planning and consideration of a full suite of solutions—including energy efficiency, flexibility, and distributed energy resources, along with infrastructure upgrades—decision-makers can develop distribution systems that will meet long-term power demand while avoiding unnecessary upgrades.

Improve Forecasting

Distribution system planners have always made decisions without perfect foresight on how local grid needs will evolve. While forecasting is not perfect for any type of load, modern forecasting practices can better inform grid planning decisions by providing ranges of likely futures. The variety of ways that building electrification can unfold means that forecasting requires the best data, probabilistic methods, and scenarios to inform grid planning.

The first step in distribution planning is to forecast potential futures so that upgrades can be prioritized based on estimates of the quantity, type, and timing of new loads under multiple scenarios.[7] Historically, load was often evaluated at the composite level, without insight into load growth by specific end use. However, given both policy- and technology-driven electrification, it is increasingly important to use end use–level forecasting that captures specific technology adoption scenarios in both an annual and hourly (including weather impacts) time frame.

Through careful planning and consideration of a full suite of solutions—including energy efficiency, flexibility, distributed energy resources, and infrastructure upgrades—decision-makers can develop distribution systems that will meet long-term power demand while avoiding unnecessary upgrades.

7 As the industry moves toward probabilistic forecasts, scenario-based forecasting captures a range of potential futures and offers analysts clear insights on the drivers of change.

To develop future scenarios of building electrification impacts, we need an understanding of the current status and ongoing adoption of end-use technologies. For example, by designing mechanisms to track the electrification of space heating early, planners can collect valuable information as new technology is adopted, such as the kind of supplemental heating available to a heat pump and at what temperature the supplemental heat is used. This information can be collected via surveys or as part of rebate programs and is vital to establishing and maintaining a solid baseline.

Not all building electrification is equal. Instead of using a single addition or scalar for peak load, modeling building electrification requires bottom-up, 8,760 load profiles developed across multiple weather years that include weather events. Without these types of profiles, it is difficult for distribution planners to make informed decisions about grid equipment, such as transformers, which are expected to support grid needs for many years across many weather events.[8] Likewise, nationwide trends in building electrification are insufficient to make distribution infrastructure decisions, as they do not inform a particular circuit's electrification trajectory, including when consumers will electrify and what type of technologies they will adopt.

Best practices for building electrification forecasting to guide analysis include: to evaluate the full extent of future building electrification by expanding the forecast horizon and broadening the factors considered; to take into account how buildings are used when establishing a baseline; to incorporate weather and climate impacts in forecasting, especially for heating; and to use multiple sources for forecasts to understand trade-offs, variables, and key assumptions driving forecasts.

Expand the Forecast Horizon and Broaden the Factors Considered

While individual electrification projects can be executed quickly, the long lifetime and slow turnover of space heating and water heating equipment mean that building electrification impacts in both the commercial and residential sectors will accumulate over many years, and, as discussed above, mild winter weather could potentially mask these impacts. Therefore, load forecasts that appropriately capture building electrification will need to look beyond the 3 to 10 years typically considered in distribution planning. Moreover, load forecasts will need to include the potential impact of extreme weather so that grid planners can plan for the full range of system conditions. Forecasts can also consider the trade-offs of various technology adoption scenarios—such as better cold-weather performance of heat pumps—on both energy (kWh) and peak demand (kW).

The Grid Planning for Building Electrification Task Force identified three key inputs into developing weather-normalized load forecasts for building electrification:

- **Historical trends:** Energy, peak, and chronological forecasts based on historical performance
- **Policy and economic factors:** Adoption of electrified end uses because of policy and economic factors
- **Physics-based models:** Chronological electric load impacts developed via energy simulations of changing end use (e.g., ResStock, ComStock)

Understanding recent trends—the broad characteristics and weather-sensitivity of load—is helpful for forecasting the near future. Within a distribution planning context, these historical trends are typically supplemented with "known projects," such as new commercial or residential buildings, that may increase or decrease the load on a distribution circuit. Historically, these two factors have been sufficient for planning in part because regular planning refreshes allow for improved forecasts and continual inclusion of recent trends. However, recent historical trends must be supplemented as new technologies are adopted that make historical trends less predictive of the future.

Policy and economic factors are also a key input into load forecasting. Jurisdictions motivated by decarbonization and air quality improvements may establish policies that accelerate the adoption of building electrification technologies. For example, in California, regional and state air quality districts are proposing zero-emission appliance standards that could have large impacts on

8 Grid equipment has historically had a useful life of (and been depreciated over) 45 years or more (Eversource, 2023).

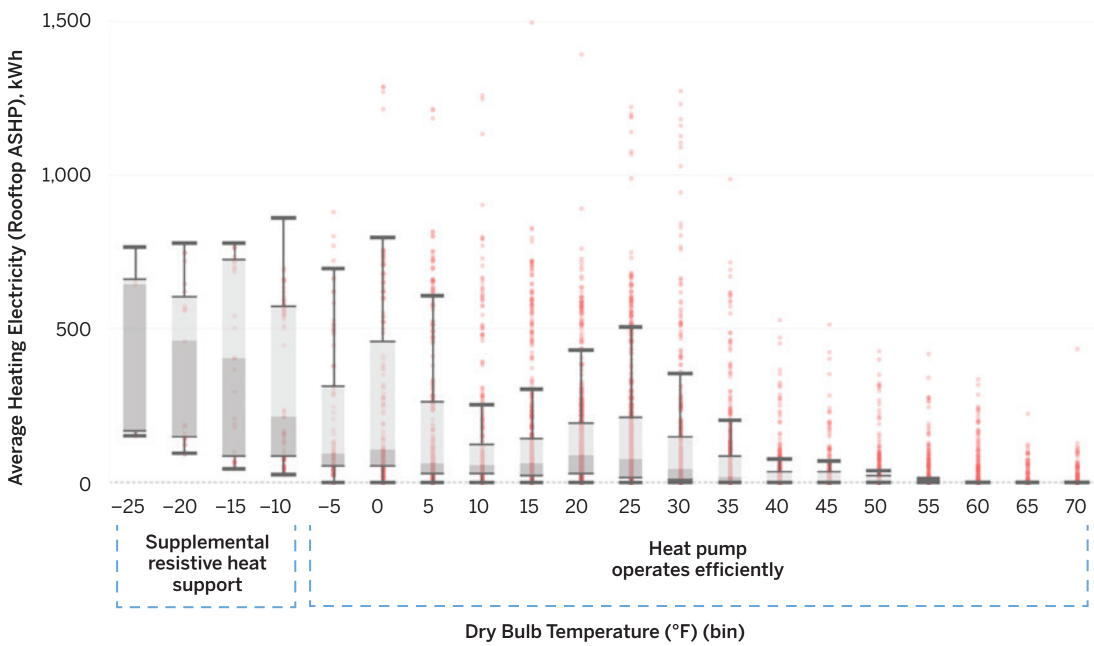
the availability of new gas space and water heaters starting in the late 2020s. Where a municipality has created incentive programs for a certain measure, such as commercial building envelope improvements, the anticipated impacts of that technology will need to be reflected in the load forecast. Forecasts can also consider recent federal expansion of electrification and efficiency incentives, as well as regional economic activity associated with economic growth and population growth that can influence load profiles. In the near term, these economic factors are outweighed by variability in weather patterns, but they can be powerful drivers of long-term load forecasts.

Physics-based simulations of building energy use, such as public datasets from ResStock and ComStock, can help planners anticipate the load impacts of electrification.[9] These models simulate how power demand would change given changes to the energy-related characteristics of individual buildings. They allow for the isolation of changes in end use, such as how a heat pump may operate across a range of temperatures in Minnesota, as shown in Figure 15. The performance of many individual building simulations can be combined to understand load profiles.

The relative importance of each of these factors changes as forecasts project further into the future. As shown in Figure 16 (p. 21), historical trends and known projects make up the majority of the inputs into short-term forecasts, but physics-based models and the incorporation of policy and economic factors make up a larger percentage of the input factors in load forecasting as we look further into the future.

FIGURE 15

Hourly Heating Demand Output from the ComStock Simulation Tool for a Single Strip Mall in Minnesota



Publicly available outputs from tools like ComStock, shown here, can help planners understand the implications of different temperatures on load under different technology adoption scenarios. Calibrating the outputs of these tools to reflect existing building characteristics and load is recommended to glean the best insights for distribution planning.

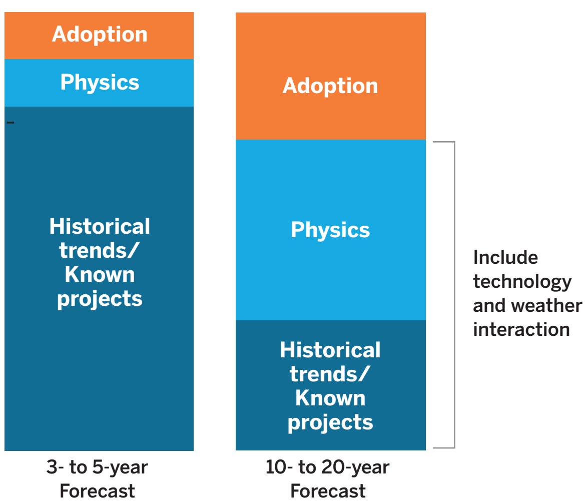
Note: ASHP = air-source heat pump.

Source: National Renewable Energy Laboratory ComStock AMY 2018, release 2024.1, 2024. Single retail strip mall in MN with measure 1: Heat Pump RTU and weather for Wadena, MN (170331-1.parquet, G270110_2018.csv).

9 See https://resstock.nrel.gov/ and https://comstock.nrel.gov/.

FIGURE 16

Components of Building Electrification Load Forecasts by Forecast Horizon



Historical trends and known projects make up the majority of the inputs into short-term forecasts, but physics-based models and the adoption forecasts make up a larger percentage of the input factors in load forecasting as we look further into the future.

Source: Energy Systems Integration Group.

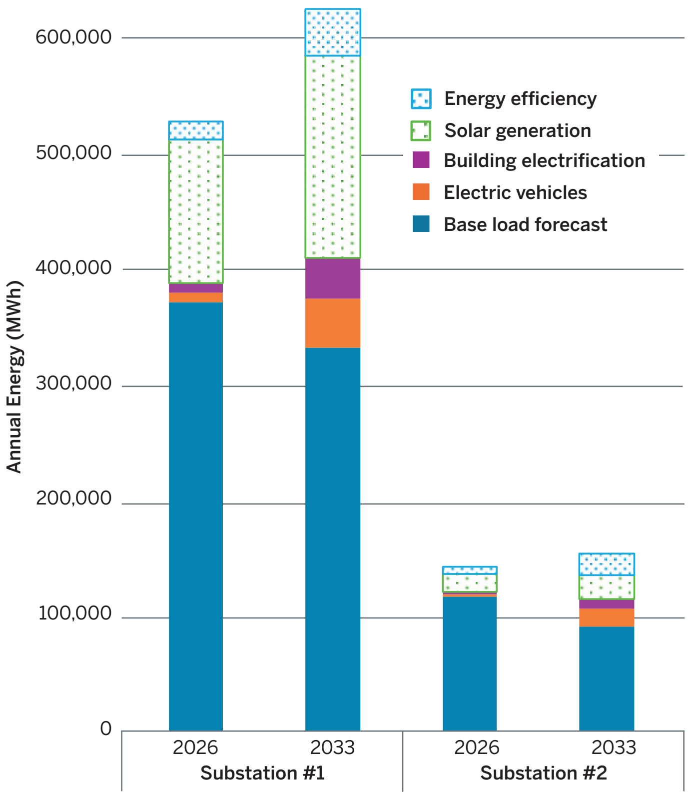
With distribution forecasting, utilities can also use data from individual customer meters to understand how quickly building electrification is happening on different parts of the system. For example, if a given customer's monthly consumption increases significantly from one winter to the next, the space heating in that home or business has likely electrified. If the utility has at least hourly interval meters, a load research program, or survey and data collection efforts, electrified customers' data can be studied to understand the relationship between load and temperature for the newly electrified space heating. These patterns could be extrapolated to understand the impact of further load growth at different points on the system.

Consider How Buildings Are Used, to Establish a Clear Baseline for Load Forecasting

With the forecasting horizon and key inputs established, forecasters need to establish a solid starting point. While today's load is relatively well understood in aggregate, there may not be a thorough understanding of each component of that load—commercial space heating, residential refrigeration, etc. The accuracy of forecasting

FIGURE 17

Annual Energy Forecast for Two Substations in Central Hudson Gas and Electric



End use–specific forecasting can capture changing power demands at granular levels, including hourly impacts. Here, substation #1 is expected to have far more load growth by 2033 from building electrification and electric vehicles than substation #2, even with increases in energy efficiency and solar generation. Within the graphic, the solid bars represent the components of net load, while the patterned bars capture what load would have been without the impact of energy efficiency and solar.

Source: Energy Systems Integration Group; data from Central Hudson Gas and Electric (2024).

can be improved by including more building types and segmenting load across both end use and building use. A commercial space serving coffee will have very different needs than a small concert venue. As the end uses change, historical aggregate trends may no longer apply. The importance of establishing a clear baseline of today's load will grow as building electrification greatly impacts some end uses and has no impact on others. The net effect of these end use–specific changes will be a shift in both the total energy provided by the electric power system and the temporal load profile of that electricity consumption.

Figures 17 and 18 (p. 23) show how baseline energy usage can be modified with end use–specific changes at the distribution level to capture shifting annual energy demands and, ultimately, hourly power demands across a range of weather conditions.

Information is needed on the types of buildings at a level granular enough to inform distribution planning, as the same technology adopted in different types of buildings can have very different effects. Figure 19 (p. 24) illustrates the variability in building electrification potential across a distribution system, showing the proportion of dwelling units that have electric heat for each census tract in Massachusetts, as reported in the American Community Survey. Areas with a high percentage of existing electric resistance heating are likely to see load decreases as consumers adopt heat pumps, whereas areas with a low percentage of existing electric heating would be more likely to see load increases.

Existing methods to characterize building stocks are available, but planners should be aware of the caveats embedded in these datasets. For example, the U.S. Energy Information Administration's Residential Energy Consumption Survey (RECS) dataset is a survey of occupied dwelling units with state-level geographical resolution.[10] But analysts should exercise caution in applying the statistically sampled data to local levels. Similarly, tax data that capture business types may be useful for aggregated analysis but may not be sufficiently geographically granular to accurately describe building stocks on the distribution system. Planners can supplement these datasets with surveys of their territory.

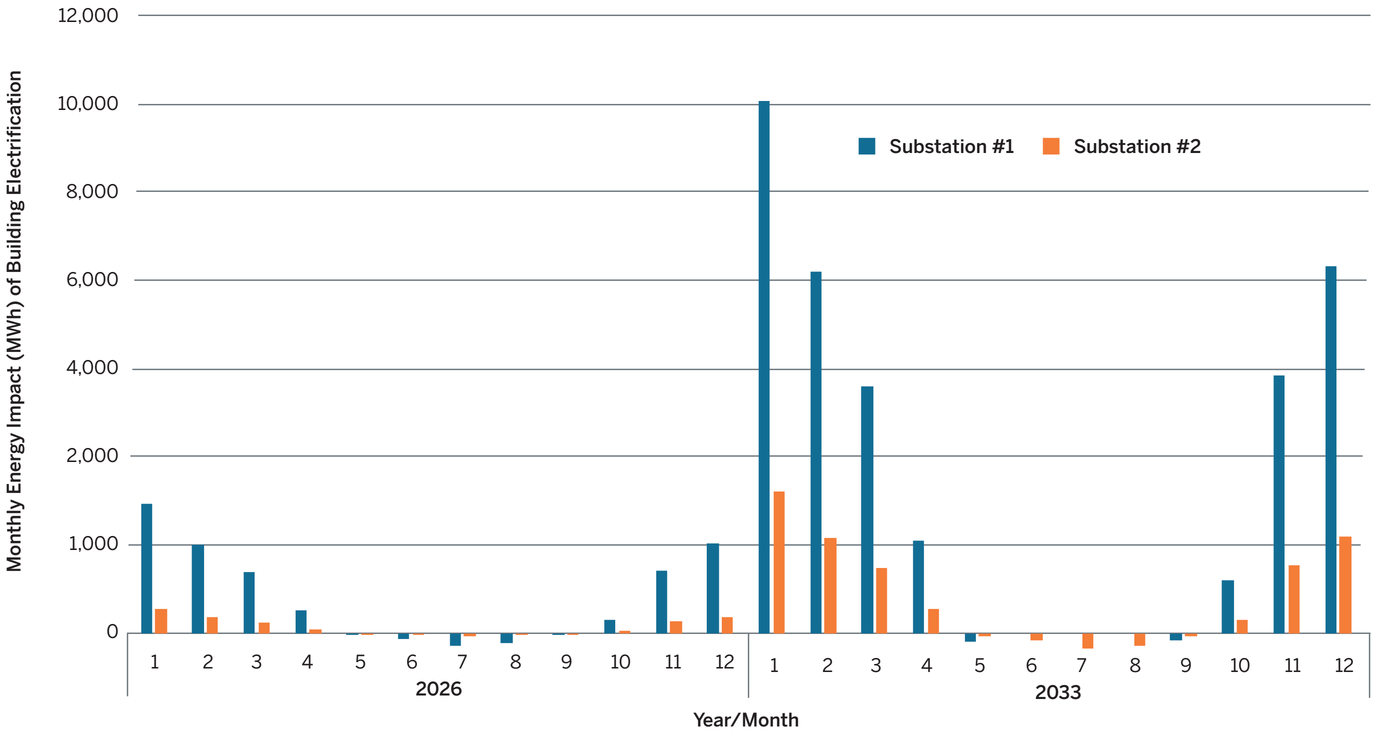
Utilizing Gas Usage Data to Understand Local Heating Demand

In most urban areas in the United States, building electrification involves moving energy demand currently met by natural gas to the electricity network. To the electric distribution planner, this demand will present as new load during new times of the year, but gas distribution planners have a long history of serving this demand. By including gas usage data, electric distribution planners

10 https://www.eia.gov/consumption/residential/.

FIGURE 18

Monthly Energy Forecast for Two Substations in Central Hudson Gas and Electric



Annual energy forecasts only capture part of the story for building electrification. In this example, which is representative of many forecasts, building electrification increases load in the winter months and *decreases* load in the summer months as new heat pumps replace old and inefficient air conditioning units.

Source: Energy Systems Integration Group; data from Central Hudson Gas and Electric (2024).

can improve their forecasts, particularly when hourly gas data are used to understand heating demands at a highly localized level. Thermostat run-time data may also be useful to provide hourly heating demand shapes, but these data do not translate directly to gas usage. Moreover, even if planners know the gas usage profile, it would be an imperfect translation to electricity system impacts because of the different performance characteristics of electric and fossil fuel heaters. Still, gas heating demands can be informative. They can be used in scenario analysis and to help prioritize areas for coordinated energy efficiency and grid upgrades.

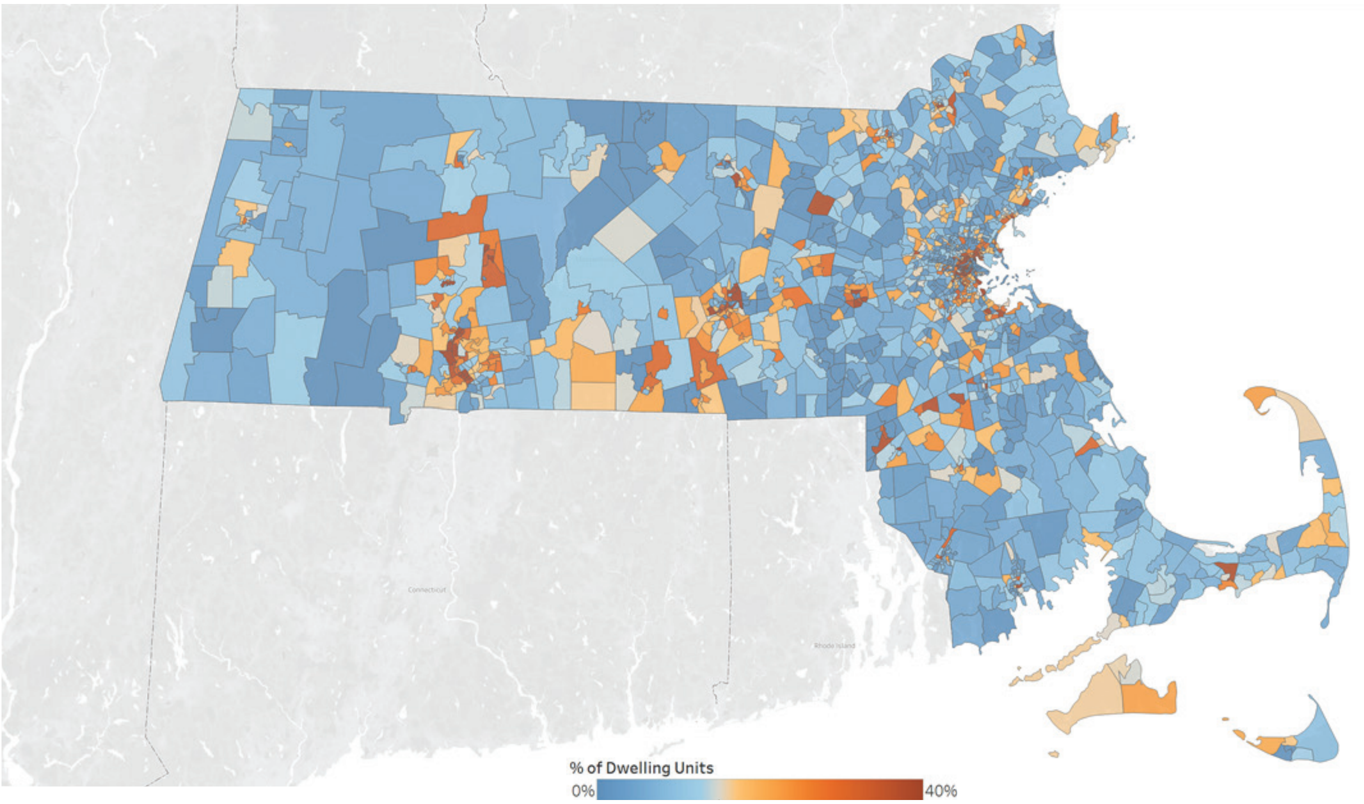
Developing a Baseline Using Publicly Available Tools

The LA100 study, which detailed how Los Angeles could achieve its ambitious goal of 100% renewable energy by 2045, provides a blueprint for how an energy usage baseline can inform shifting end-use characteristics (Hale et al., 2021). LA100 researchers developed electricity demand forecasts by first characterizing the local building stock and baseline energy demand within the Los Angeles Department of Water and Power (LADWP) service territory using publicly available ResStock and ComStock tools.[11] The researchers calibrated simulated consumption to observed historical power demand to ensure realistic near-term results. From there, they created technology adoption scenarios and simulated these scenarios to forecast electricity demands. Similar work has been done to calibrate and validate the ResStock and ComStock models for the contiguous United States and their resulting public datasets using real-world advanced metering infrastructure and end-use submetering data (Wilson et al., 2022). One can extract aggregate and

11 https://resstock.nrel.gov/ and https://comstock.nrel.gov/.

FIGURE 19

Percentage of Dwelling Units with Electric Heat by Census Tract in Massachusetts



The impact of building electrification across the distribution system will largely depend on highly variable starting points. Areas with a high percentage of existing electric resistance heat are likely to see load decreases as consumers adopt heat pumps, whereas areas with a low percentage of existing electric heat would be more likely to see load increases.

Source: Cadeo; data from U.S. Census Bureau (2019).

individual customer end-use load profiles for the baseline building stock and "what if" adoption scenarios in relevant geographies (e.g., county, state) from the public datasets and use them as a starting point for utility demand forecasting. As was done in LA100, these data can be calibrated to observed historical power demand to achieve a more accurate starting point for understanding the impact of building electrification in a particular service territory.

Gleaning Information from Fully Electrified Buildings

Some buildings are already fully electrified, and their performance can be informative for forecasters and grid planners willing to explore the advanced metering infrastructure data. Given the relatively nascent state of heat pump adoption in some regions, there is an opportunity to track technology adoption from the beginning (e.g., air-source vs. ground-source heat pumps) and design surveys and programs such that they can be informative to grid planners.[12] National Grid's Future Grid Plan in Massachusetts presented data on heat pump adoption by sub-region in its territory, which helps it understand where growth is needed to achieve the state's policy goals (National Grid, 2023).

The performance of electrified buildings can also be insightful for calibrating model results, for example, how

12 Information such as the primary type of technology implemented, any back-up heating measures available, and how the occupant plans to use the technology can be key indicators to power demand.

heat pumps are performing when deployed. Similar to the California Distributed Generation Statistics website,[13] the TECH Clean California initiative is a good example of how deployed heat pump performance can be tracked and made available to stakeholders.[14] The TECH Clean California program gathers, anonymizes, and aggregates heat pump adoption and performance data on a county level across different heat pump technologies. This type of practice and data sharing is needed across regions to provide both planners and operators with more information.

A Need for Ongoing Data Collection

Ongoing data collection is needed as buildings are electrified because of the different practices of heating, ventilation, and air conditioning contractors in sizing and outfitting units. While guides exist for selecting and appropriately sizing this equipment (commonly referred to as Manual J and Manual S), equipment sizing practices can vary as contractors make informed decisions about building characteristics. The effect of heating, ventilation, and air conditioning equipment sizing in practice is that extreme temperatures that exceed the conditions for which heating or cooling equipment is designed (typically 1st and 99th percentile temperatures for 30 years of weather)[15] do not necessarily lead to greater load; instead, the equipment may run at full power while the inside temperature does not reach the thermostat setpoint. The net implication is that the power system would see lower peak loads than would be expected based on the heating needs of the building. Ongoing data collection and education are needed to ensure that load forecasts align with the building electrification that is actually occurring in a region.

Incorporate Weather and Climate Impacts in Forecasting, Especially for Heating

Building demand will be increasingly weather-dependent with electrification of space heating. Therefore, to capture the weather sensitivity of loads it is useful to disaggregate building electrification changes by end use, rather than attempt to directly forecast a macro peak demand and energy requirement when only some portions of the load are changing. The New York Independent System Operator's Building Electrification Forecast for New York State uses a heat transfer model that identifies the heating requirements for buildings and adjusts the performance of heat pumps and supplemental heat according to outdoor air temperature (Maniaci, 2023).

Because space heating electrification will increase the weather dependence of electricity demand, the typical meteorological year (TMY) approach commonly used in load forecasting for building electrification and building energy modeling may miss outlier events that drive grid investments. Some work has been done to consider extreme meteorological year (XMY) weather in building energy simulations (Brown and Rajkovich, 2020), but more work is needed to capture the range of weather conditions that may unfold. Similarly, building electrification load forecasts are often built from typical meteorological year approaches, which can miss important implications for grid planning.[16]

13 https://www.californiadgstats.ca.gov/.

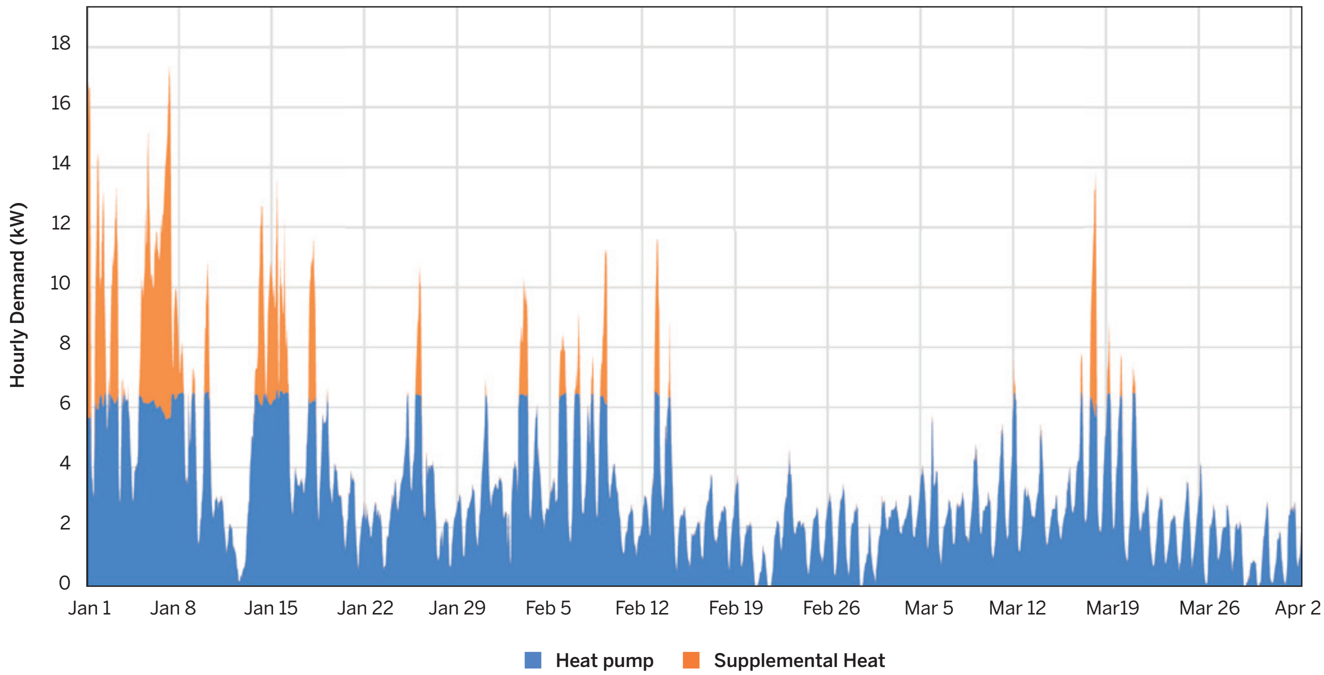
14 https://techcleanca.com/.

15 https://www.ashrae.org/file%20library/technical%20resources/standards%20and%20guidelines/standards%20addenda/169_2020_a_20211029.pdf.

16 To be clear, composite load forecasts are typically derived using some combination of historical data and climate projections that provide the basis for probabilistic forecasts and are not as commonly underpinned by a typical meteorological year.

FIGURE 20

Hourly Loads of Heat Pump and Supplemental Heat in an Example Single Family Home in New York



Heating demand is highly variable based on outdoor air temperature. Because inefficient supplemental heating (orange on the chart) is often needed during cold weather, spikes in building electrification heating demand are driven by weather. Capturing the weather sensitivity of building electrification is vital for load forecasting and grid planning. In this example installation, supplemental power was required whenever heat pump demand exceeded 6 kW.

Source: Maniaci (2023).

Appropriate modeling of weather impacts across a range of temperatures is needed to better understand the variability in load. For example, Figure 20 provides an example of the variation in power demands given the range of temperatures experienced in Albany, New York, in a single year. Forecasters and distribution planners need better visibility into power system demand given high levels of building electrification and different weather conditions. This image highlights that a "typical day" can look very different than a high load day.

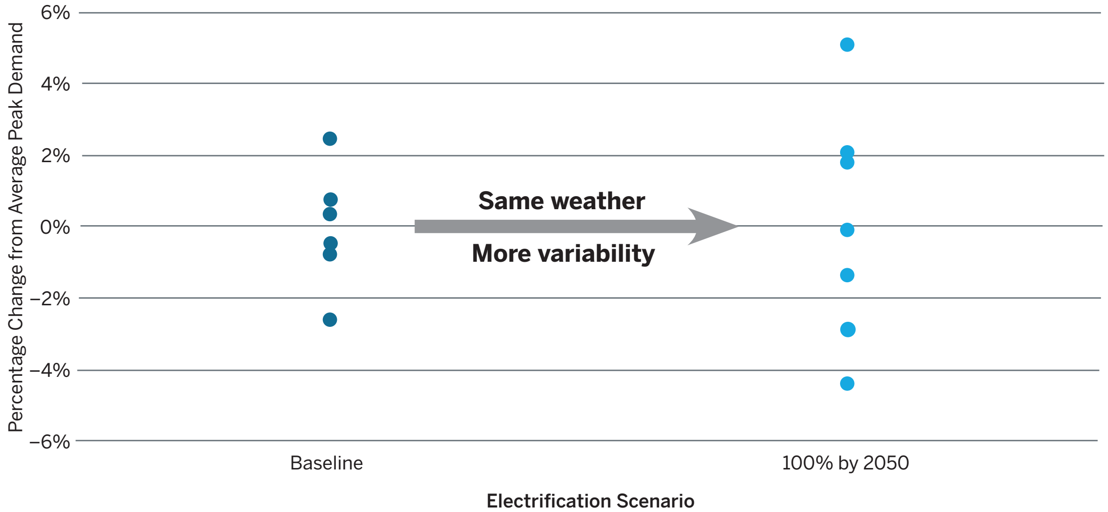
The net effect of this variability in heating demand will be an increasing uncertainty due to weather impacts in load forecasts from building electrification, particularly in the winter. This is already seen in areas with high electrification, where winter peak variability is often higher than year-to-year summer peak variability.

Forecasters and distribution planners need better visibility into power system demand given high levels of building electrification and different weather conditions. A "typical day" can look very different than a high load day.

This concept is illustrated in Figure 21 (p. 27) which examines the winter peaks of different electrification scenarios in simulated data in New York. Importantly, the electrification scenarios presented in the figure differ in more than just building electrification assumptions, but the increased spread is indicative of the building electrification embedded in the scenarios. This increased variability magnifies the need to plan using probabilistic techniques with multiple scenarios.

FIGURE 21

Simulated Peak Winter Demand in New York in 2035 Under Different Electrification Scenarios



Consistent with observed historical trends in winter-peaking systems, the variability in peak demand is expected to increase with building electrification. The figure shows that the baseline peak load (built from projections from the U.S. Energy Information Administration's Annual Energy Outlook for 2022) is 2.5% lower than average with mild temperatures and 2.2% higher with cold temperatures, a 4.7% spread. With the same weather but increased electrification (from buildings and other sources), the spread nearly doubles to 9.1% on top of an increase in average peak demand.

Source: Energy Systems Integration Group; data from Evolved Energy Research and the National Renewable Energy Laboratory.

Climate change presents an additional layer of complexity and uncertainty, as weather increasingly deviates from historical norms. Climate change–induced storms could further contribute to load variability; not only is load likely to become more sensitive to weather events, but the weather events themselves are likely to become both more severe and more frequent.

Use Multiple Sources for Forecasts to Understand Trade-offs, Variables, and Key Assumptions Driving Forecasts

Top-down forecasts—those primarily derived from macro factors—allow policy shifts to be considered, while bottom-up forecasts, which derive forecasts from more granular data, can quickly incorporate local knowledge in the analysis. Blending the two leads to the most informed outcome. While bottom-up analyses are data-intensive, they provide the most granular insights for distribution planning. Load forecasters have historically provided deterministic point estimates of load for distribution planning—a single, best estimate of the future.

Blending top-down and bottom-up forecasts—including both macro factors and more granular data—leads to the most informed outcome.

However, going forward, forecasters will need to both expand their building energy expertise and provide context around forecasts. Multiple forecasts or scenarios that capture some of the uncertainty of technology adoption, weather, and location can also be informative to planners. Sharing the key uncertainties and variabilities in a digestible format is an essential service.

Sources of uncertainty in planning are growing with electrification. Load forecasters need to be able to communicate the trade-offs, variables, and key assumptions that drive different possible outcomes. Forecasters can also discuss with internal and external stakeholders plans to appropriately capture the relevant variables

TABLE 1

Potential Practices for Forecasting Building Electrification Futures

Planning Attribute	Forecasting characterizes and quantifies building electrification by end use and provides a range of possible futures.
Good practices	A building electrification forecast includes the use of physics-based models to assess the impact of end-use electrification. Multiple scenarios are used to assess building electrification futures, including the adoption of different technology types. Example: Fort Collins Utilities and Lawrence Berkeley National Laboratory developed a baseline efficiency and a high-efficiency scenario to evaluate the impact of low, medium, and high levels of electrification on 15 distribution circuits.
Better practices	End-use demand baselines are established with specifics about local building types and uses. Example: California's Commercial End Use Survey estimated electricity and natural gas consumption, energy use, and hourly whole-building load profiles for the 12 commercial building types in 3 utility service territories.
Best practices	Multiple weather years are simulated to capture the impacts of building electrification beyond the typical meteorological year (TMY). Example: Evolved Energy Research and the National Renewable Energy Laboratory have multiple weather years of load with different levels of electrification publicly available as part of the Regional Energy Deployment System (ReEDS) Model.

Practices identified by members of the Grid Planning for Building Electrification Task Force.

Source: Energy Systems Integration Group.

that inform analysis and ultimately decision-making.[17] Table 1 gives useful practices for load forecasting as building electrification progresses.

Modernize Grid Planning Approaches

Grid planning techniques, particularly for the distribution system, will need to evolve with increased building electrification. To meet the challenge, changes will be needed to the inputs into the planning practices, analytical methods to assess distribution system upgrades, and metrics for success.

Beyond load forecasting, the inputs embedded in distribution planning include:

- The scenario (design conditions) according to which standards and plans are made, including outside temperatures or storm conditions
- The thresholds that trigger further analysis for circuits
- The margin that is reasonable for new equipment (planning standards)

Based on distribution needs usually identified from simulations, distribution planners select from a set of standardized equipment to meet identified grid needs. The specifications for these standard pieces of equipment may need to change as planners consider the design conditions and load profiles that drive equipment-sizing decisions.

The specifications for standard pieces of distribution equipment may need to change as planners consider the design conditions and load profiles that drive equipment-sizing decisions.

More specifically, the electrification of heat in commercial and residential buildings means that we need a more detailed evaluation of how future extreme weather events, especially cold weather events, will impact grid equipment. Planners considering their equipment sizing need to understand how cold it may get, how often, and

17 The section "A Need for Coordinated and Integrated Planning" includes a more complete discussion of the roles of various stakeholders.

for how long, particularly as climate change impacts weather. Additionally, the scenarios chosen around heating technology adoption can reveal differing grid needs. For example, buildings with efficient thermal envelopes may ride through cold snaps with infrequent heat input while inefficient buildings may need near-continual heat input. These inputs inform the load and ambient conditions that the distribution system will be designed to support, a process that requires thoughtful collaboration and scenario evaluation to understand the inflection points.

Improvements to design criteria definition can include extending the criteria from a single worst hour to a multi-hour analysis (or even analyzing all 8,760 hours of the year) and considering the impact of customers' choices on electricity demand—e.g., their use of energy efficiency measures and load flexibility technologies. These planning scenarios may also include other industry trends, such as transportation electrification, distributed energy resources, and enhanced analytics on equipment aging.

Building electrification is another driver for grid planners to look at more than a single snapshot of power demand, regardless of how that snapshot was developed. Planners should consider chronology (24 hours at least) and uncertainty (multiple scenarios, which could themselves have different "1-in-X years" forecasts) in load to have the full context to develop grid plans.

The modernization of distribution planning requires aligning thought processes with the new realities introduced by building electrification. Distribution planners also need to ensure they are planning for the right objectives. For example, reliability and resilience metrics that exclude "major event days" may expose certain segments of the distribution system to prolonged outages. The demand side is becoming more dynamic with electric vehicles, distributed generation and storage, increasingly weather-dependent load, and grid-interactive technology adoption. Grid planning philosophies and practices need to account for these changes from the core assumptions and analysis capabilities through the metrics used to evaluate success.

Reconsider Core Planning Assumptions, Including Equipment Standards

Planning for electrification requires a holistic analysis of the assumptions that drive grid planning decisions—assumptions that are embedded in design standards, planning and design processes, and load forecasts. Equipment standards typically use a set of conditions to capture realistic stressful situations for grid equipment, such as hot summer days and cold snaps, and typically include emergency ratings that allow for circuit reconfiguration as necessary. These standards rely on load diversity to allow smaller equipment to serve the composite load profile than would be possible if the maximum demand for every end use was simply added together.

The design conditions that drive equipment sizing are likely to change with building electrification. This goes beyond simply increased peak demand. In cold snaps, for example, the parameters driving system designs will shift as (1) the load profile remains elevated for an extended period, (2) the ambient conditions help to naturally cool rising temperatures within grid equipment, and (3) supplemental resistive heating for heat pumps kicks in, changing the power factor of loads and therefore changing the voltages along a circuit.

These design conditions are a critical input into the equipment deployed on the grid. Sizing decision for distribution equipment ranging from service transformers to circuits to substations are often based on a load forecast that accounts for some weather variability with headroom for incremental load growth and enabling circuit reconfigurations. For example, a piece of equipment may be designed for a 1-in-20-year peak, which affords 19 in 20 years where conditions do not meet the designed peak demand, plus some headroom that allows the equipment to support adjacent circuits for reliability purposes. Planners can consider whether this methodology continues to make sense, especially as forecasting becomes more complex and buildings and transportation are electrified.

Reconsidering equipment standards for building electrification requires a strategic shift that goes beyond typical distribution planning activities. Historically, another substation or distribution circuit would be built if customers required more power capabilities. But as utilities look toward the long-term needs of customers, they may consider larger equipment sizing and increasing system voltages rather than building more infrastructure with low power transfer capabilities, particularly in areas where land acquisition for a new substation is challenging.

Since the shift up in voltage class (from 4 kV to 12 kV, for example) is an expensive investment, leading utilities have staged this investment and architectural shift by upgrading equipment as it is due for replacement or by serving all new construction with the upgraded voltage class. A similar strategy has been used for most pieces of grid equipment, including service transformers. Over time, the entire utility service territory will be upgraded to accommodate higher loading levels, and utilities only need to touch each piece of equipment once. This strategy can be followed to allow for more electrification of buildings and vehicles at a pace that attempts to balance customer demand and costs.

Since the shift up in voltage class is an expensive investment, leading utilities have staged this investment and architectural shift by upgrading equipment as it is due for replacement or by serving all new construction with the upgraded voltage class.

Evaluate Load Diversity

When considering the impact of building electrification on the distribution system, it is important to evaluate the diversity of demand. The demand profile for a single electrifying building will not compound in a linear way as additional buildings electrify. For example, customers may turn down their heat while they are on vacation at different times of the year and use laundry machines at different times of the day or week. The asynchronization of these loads means that distribution infrastructure can be planned to meet a lower demand than if the individual peak loads were simply added together. Utilities have always leveraged diversity in their distribution standards and load forecasts,[18] but many of today's diversity assumptions are based on historical data. There is relatively little data on diversity factors of buildings in cold climates as electrification progresses.

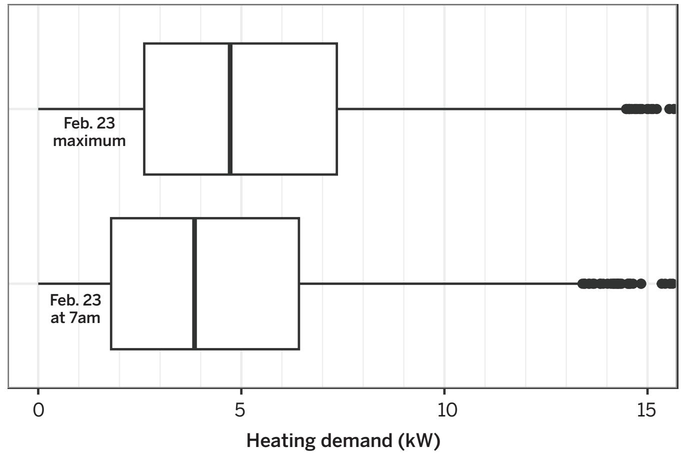
Recent work done in California suggests that fully electrified buildings have a significant amount of diversity in their load profiles. Across metered homes in the Southern California Edison territory and modeling simulations performed on residences in Sacramento, the aggregated peaks at all-electric homes were in line with aggregated peaks at dual-fuel communities at both the service transformer and substation levels (Wen, 2020; Murphy, Pigman, and Mims Frick, 2024). Figure 22 shows the results from simulation efforts in Sacramento to understand the diversity of building heating demands when faced with similar temperatures. These similar peaks were due to the diversity factor among customers. It is important to note that these studies were performed in relatively warm climates, where cooling needs in the summer are the primary electricity demand. Similar analyses are needed in cold climates and with a larger sample size.

There is, however, a limit to the amount of load diversity that can exist on the distribution system. In the United States, most service transformers serve relatively few households, often less than 10 (Taylor and Christian, 2023). With so few customers, there is little diversity available in behavior and a relatively greater likelihood that small numbers of heat pumps switching to supplemental resistive heating on the same street could cause a problem. Diversity assumptions and the implications for distribution planning should be carefully evaluated at a granular level to identify system bottlenecks where diversity benefits are not as likely to materialize.

Not every utility will need to perform independent research on this topic. Early experiences from leading utilities can inform other utilities in similar climates, expediting the development of best practices and avoiding some sensor and software investments.

FIGURE 22

Variation in Residential Heating Demand During a Simulated Cold Snap Due to the Diversity of Loads



Building simulations for the Sacramento Municipal Utility District service territory found a wide range in heating demands when looking across buildings faced with the same weather. The variation in the magnitude and timing of residential peak demand during the cold snap suggests that planning for winter morning peaks should consider both a diversity of buildings and the coincidence/non-coincidence of their load.

Source: Murphy, Pigman, and Mims Frick (2024). © The Regents of the University of California, Lawrence Berkeley National Laboratory.

Move Beyond a Single Peak Hour and into Multiple Hours in Summer and Winter

Traditionally, distribution planners evaluated system needs during a single peak demand hour with some uncertainty embedded in the peak demand evaluated. However, as planning processes and data improve, planners can evaluate more than a single hour in determining investment needs.

Improved planning capabilities also come at a time when chronology and the demand profile are growing in importance. Ideally, planners would use a full hourly chronology that captures all 8,760 hours of the year to understand grid stress throughout the year. At a minimum,

18 The concepts of coincident and noncoincident peaks highlight the benefits of load diversity. Xcel Energy's 2023 Integrated Distribution Plan articulated how the coincidence of peaks leads to "substation transformer peak load [that] is proportional to, but usually less than, the sum of the feeder circuit peak loads served from that substation transformer" (Xcel Energy, 2023). PJM's 2024 load forecast report provided forecasts for each of PJM's 21 transmission zones and showed that if each of the noncoincident peaks were simply added together, PJM would expect summer peaks to be about 7 GW (~4.5%) higher than is forecasted after the diversity of loads is considered (PJM, 2024).

planners can broaden their analysis from a peak hour snapshot to at least a peak day or week in summer and winter. By modeling grid updates based on a stressful day or week in each season, different solutions' impact over a realistic chronological scenario can be assessed. For example, a non-wires solution such as a battery can be used to reduce the peak demand on a circuit, but needs to have been charged prior to the peak and will likely need to recharge afterwards. Some utilities have already expanded beyond single-hour analysis because of the growth in variable energy resources like solar and wind. In some cases, new modeling frameworks and software upgrades will be needed to enable chronological analysis of the distribution system.

The importance of considering chronology when planning for newly electrified loads is already recognized by some utilities, which consider the top handful of hours (or more) of the year when evaluating the need for distribution upgrades.[19] For example, after an initial screening, a utility may evaluate the full 8,760 loading on a circuit and assess the need for and feasibility of upgrades. By expanding beyond a single peak-hour analysis, planners can better capture the full context of stress on distribution equipment, which can accumulate over time. As load factors change with building electrification, evaluating multiple hours will help to maintain equipment integrity, and the loss of equipment life associated with sustained high loads can be assessed.

In addition to assessing multiple hours, planners can evaluate multiple scenarios of building electrification futures. Scenario analysis can consider:

- Prolonged winter storms
- The adoption of a wide variety of technologies, for example, assuming a higher level of ground-source heat pumps, including different supplemental heating sources
- Varying levels of energy efficiency (e.g., building envelope improvements), demand flexibility, and grid-integrated efficient buildings[20]
- The societal implications of building electrification, including its impact on local communities and energy equity

19 New York Public Service Commission. Case 15-E-0751. Order Regarding Value Stack Compensation. April 18, 2019.

20 https://gebroadmap.lbl.gov/

Distribution planners are just beginning to use scenario analysis to understand potential futures. For example, DTE Electric's 2021 Distribution Grid Plan included scenarios for increased electrification, more catastrophic storms, and high adoption of distributed generation (DTE Electric Company, 2021). Scenarios run explicitly for building electrification have not yet been implemented broadly across the industry, but some states are beginning to specify that load forecasts for distribution systems need to account for levels of building and transportation electrification.

Improve Reliability and Resilience Metrics for an Electrified Future

Grid planners have been rethinking reliability and resilience as power systems change. Beyond an increased expectation of reliability and resilience as we increase our dependence on electricity by electrifying more end uses, bulk system planners have been rethinking resource adequacy and metrics used to evaluate system reliability, as discussed in ESIG's report *New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements* (ESIG, 2024b). Similarly, utilities and researchers are developing resilience metrics that capture customer-level impacts and synthesizing the process steps needed to develop resilient systems (Snyder and Morash, 2020; Culler et al., 2021).

These efforts often supplement IEEE Standard 1366, which defines "major event days" (MEDs) and provides guidance on calculating standard metrics with and without major event days.[21] Jurisdictions adapt the IEEE Standard 1366 definition to their locales. Generally, major event days occur when many customers experience an outage on the same day, usually from severe weather. Distribution system planners are increasingly considering MEDs in grid hardening initiatives, but the impacts of severe weather will affect reliability and resilience in multiple ways and continue to grow in importance as society increasingly relies on the electric distribution system to fuel more end uses.

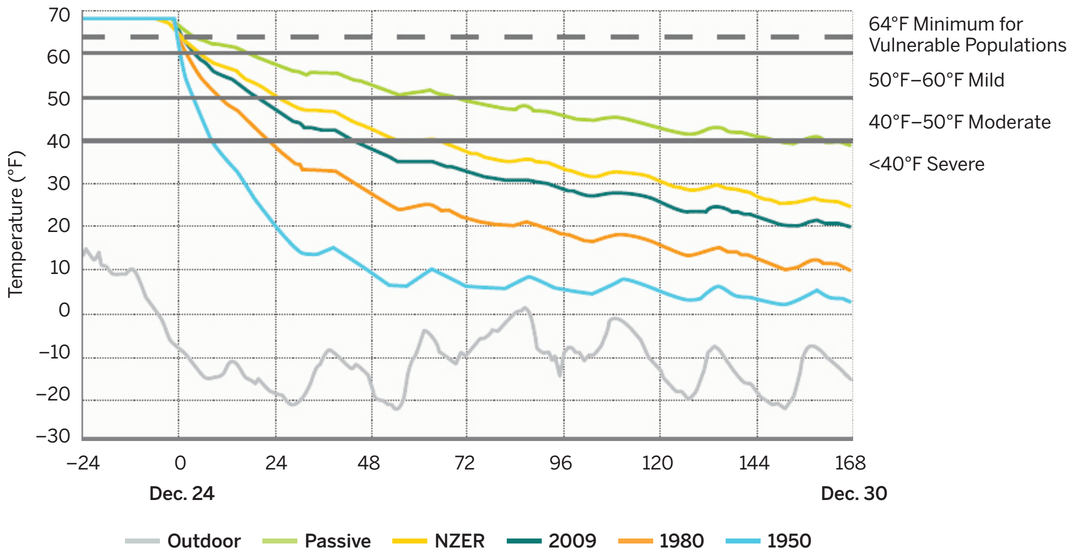
By analyzing the impact of different types of power interruptions on different segments of the population, grid planners can prioritize investments that have the greatest value, whether measured through economic, equity, or public health metrics, rather than treating all interruptions equally. Researchers are increasingly making tools available to simulate the impacts of customer-level power interruptions, including the Lawrence Berkeley National Laboratory's Power Reliability Event Simulation Tool (PRESTO) and Power Outage Economics Tool (POET), and a number of tools and publications from the National Renewable Energy Laboratory.[22] For example, a recent project analyzing the economic impact of widespread, long-duration power interruptions in Commonwealth Edison's (ComEd's) service territory around Chicago found that "high-income households experience proportionately larger losses to consumption during a one-day power interruption, but low-income households experience proportionately larger

21 Distribution system reliability is often discussed in terms of the System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and their "customer"-derived alternatives CAIDI and CAIFI. Commonwealth Edison highlighted the importance of MEDs in its 2023 Multi-Year Integrated Grid Plan, noting that the system average interruption duration per customer served (SAIDI) in 2020 was 32 minutes for the year, but when "major event days" were included, that number rose to 332 minutes.

22 The Power Reliability Event Simulation Tool (PRESTO) simulates the timing and duration of individual customer-level power interruptions for any county in the continental U.S.; see https://presto.lbl.gov/home. The Power Outage Economics Tool (POET), which is currently a prototype, estimates the economic impact of widespread, long-duration power interruptions (see Larsen et al. (2024)). The National Renewable Energy Laboratory also has a number of tools available, including the customer damage function calculator, aimed to help facility owners estimate the difference in power outage costs with and without resilient systems; see https://www.nrel.gov/security-resilience/metrics-valuation.html.

FIGURE 23

Indoor Temperature Degradation of Different Types of Buildings in Power Outages During Winter Storms



Simulated indoor temperatures for housing with different levels of energy efficiency when faced with prolonged power disruption. The chart shows that more efficient buildings can maintain safe and comfortable indoor conditions for longer than inefficient designs.

Source: Ayyagari, Gartman, and Corvidae (2020); Rocky Mountain Institute.

losses during the longest power interruptions" (Larsen et al., 2024). In another study, the duration of an outage during winter storms impacted indoor air temperature differently depending on building age (Ayyagari, Gartman, and Corvidae, 2020). As shown in Figure 23, a home with an inefficient building envelope became too cold in these simulations for vulnerable populations and uncomfortable for everyone else within just a few hours of a power outage.

Increased reliability and resilience are not just about grid upgrades: energy efficiency is critically important to maintain indoor air temperatures during reliability events (Frick, Carvallo, and Schwartz, 2021). Planning practices need to better capture the reliability and resilience value of energy efficiency. Grid planners also need to adapt their metrics to address the risks presented by electrified futures and to achieve policy goals, such as those related to equity.

Share Information Across Natural Gas and Electricity Planning

Coordinated and integrated planning across natural gas and electric utilities is widely seen as a way to better manage the costs and feasibility risks of decarbonization. For example, the Massachusetts Department of Energy Resources recently found that "coordinated and comprehensive planning between electric and gas utilities is needed to facilitate the energy transition" and "any proposed investments will have to take place in the context of joint electric and gas system planning."[23]

Beyond sharing different types of data, such as metering and locational data, process changes could be useful for distribution planners considering integrated planning. One process that should be straightforward is to align the forecasts between natural gas and electricity planning with respect to a future electrification trajectory. Gas network planners and electricity system planners should

23 https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18297602

be aligned on future electrification, to minimize redundant infrastructure that could result from inconsistent forecasts. Moreover, gas network planners may have design criteria that are useful for electric distribution system planning (e.g., plan the gas network to support a negative 5-degree design day).

Coordination across natural gas and electric distribution network planners can be challenging to different utilities for different reasons. For example,

- Dual-commodity utilities, providing customers with both gas and electricity, are challenged by the sheer magnitude of integrated gas and electricity planning, as gas and electric distribution system planning have in the past been separate exercises.
- Single-commodity utilities, providing either electricity or gas, are further challenged because of potentially conflicting incentives or asymmetrical data and analysis capabilities.

Early projects have identified opportunities for cost savings that make confronting these challenges worthwhile. One approach is zonal electrification, wherein all customers served by a hydraulically independent section of gas pipeline fully electrify their buildings, thereby eliminating the need for gas service and allowing for that pipeline section to be decommissioned. Coordinated planning can help prioritize these targeted electrification initiatives by identifying areas where gas leakage is high or where a near-term upgrade on the gas system could be avoided.

A project recently completed in Northern California found that repurposing the savings from avoided gas pipeline replacement could be used to help address customers' upfront costs of electrification (Gold-Parker et al., 2024). These approaches have been designed to overcome gas rate pressures for low- and middle-income gas customers that can occur if those customers cannot pay the remaining costs of home electrification and are left to support a gas network with a declining user base. Because of the nuance of these programs and customer interests, the industry is still uncertain about how these will evolve over time.

These early integrated projects can help to inform priorities for building electrification. The Northern California project found that targeted electrification will likely be more cost-effective in neighborhoods with fewer customers per mile of gas main. This finding relates to how the benefits of avoided pipeline replacement scale (as dollars per mile) relative to the costs of upgrading customer equipment (as dollars per customer). With more miles of avoided pipeline costs per customer, the incentive for upgrading customers' electric equipment grows. Cost-effectiveness will also depend on the costs of any necessary investment in the electricity grid to

TABLE 2

Potential Practices for Modernizing Planning Approaches

Planning Attribute	Distribution planning approaches evolve to capture the challenges presented by building electrification, including infrastructure requirements, chronological assessments, and the metrics and objectives used in planning.
Good practices	• Distribution system needs are determined by evaluating days (not hours) of grid stress. • Distribution system needs are determined by using multiple forecast scenarios. Example: Ameren Illinois used multiple scenarios to determine grid needs, including a change in base load that looked at hotter-than-normal summers.
Better practices	• Equipment standards are re-evaluated taking into account growing needs from electrification and load diversity. Example: DTE Energy is proposing to upsize its distribution system from a legacy 4.8 kV system in part to provide "capacity for future load growth, including electrification load."
Best practices	• Distribution planning metrics and incentives are aligned with the expectations of the local area, including equity, reliability, and resilience. Example: A number of jurisdictions are rethinking their metrics and incentives in light of electrification, although this remains an aspirational best practice for now.

Practices identified by members of the Grid Planning for Building Electrification Task Force.

Source: Energy Systems Integration Group.

support increasingly electrified buildings. Table 2 gives useful practices for modernizing planning approaches.

Avoid the Largest Impacts by Managing Demand

Before a utility makes physical infrastructure investments in the distribution system, planning for building electrification can consider mitigations that can diminish, defer, or eliminate the need for such upgrades. New technologies, demand-side management programs, rate designs, and other mitigations can be considered in distribution planning processes to help address building electrification challenges, increase distribution system utilization, and potentially reduce costs, while providing opportunities for all consumers to reduce energy bills. Incorporating these changes will require significant coordination and information-sharing among utility processes and departments, especially between their planning, programs, and rates functions. However, if done well, these mitigations can be helpful both in the near term, while building electrification is in the early stages, and for future grid design to help keep down total distribution system costs in the longer term.

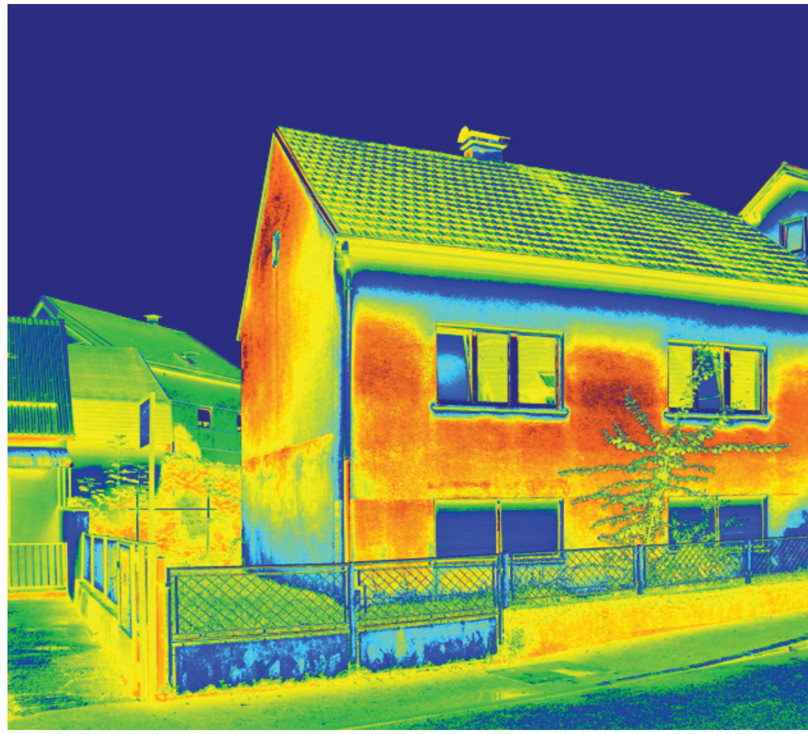
Before a utility makes physical infrastructure investments in the distribution system, planning for building electrification can consider mitigations that can diminish, defer, or eliminate the need for such upgrades.

Start with Energy Efficiency

Energy efficiency has a long history as an effective alternative to traditional supply-side resources in utility planning. An example of its early application is represented in the California Loading Order, which notes that energy efficiency should be the first resource explored by utilities for meeting demand (CPUC, 2003). In the context of building electrification, energy efficiency is more important than ever. A recent U.S. Department of Energy National Blueprint for the Buildings Sector made energy efficiency its first strategic objective and established a target of reducing on-site energy use intensity in buildings by 35% by 2035 and 50% by 2050 relative to 2005 levels. These targets are ambitious, outpacing the 31% reductions in energy use intensity achieved since 1980, which saw the introduction of the first building energy codes and equipment standards (U.S. DOE, 2024a).

Energy Efficiency in the Context of Building Electrification

The emphasis on the type of energy efficiency changes slightly in the context of building electrification. Energy efficiency of buildings can be improved two ways: (1) a “widget” approach in which the equipment providing heating ventilation and air conditioning services is more efficient, and (2) a whole-system approach in which the heating or cooling *needs* of the building are reduced—such as through an improved building envelope (better construction of walls and windows) or through behavioral approaches, such as by occupants’ keeping temperatures of homes, business, and hot water to levels that reduce cooling/heating needs. Of greatest interest are energy efficiency measures that help to maintain building temperature while minimizing grid impact during long-duration reliability events. For example, the thermal mass of a building can act as thermal storage, and increasing the building envelope efficiency can act to increase the duration of that thermal storage. Energy efficiency measures can benefit participating utility customers directly, as well as all customers when grid upgrades are avoided.

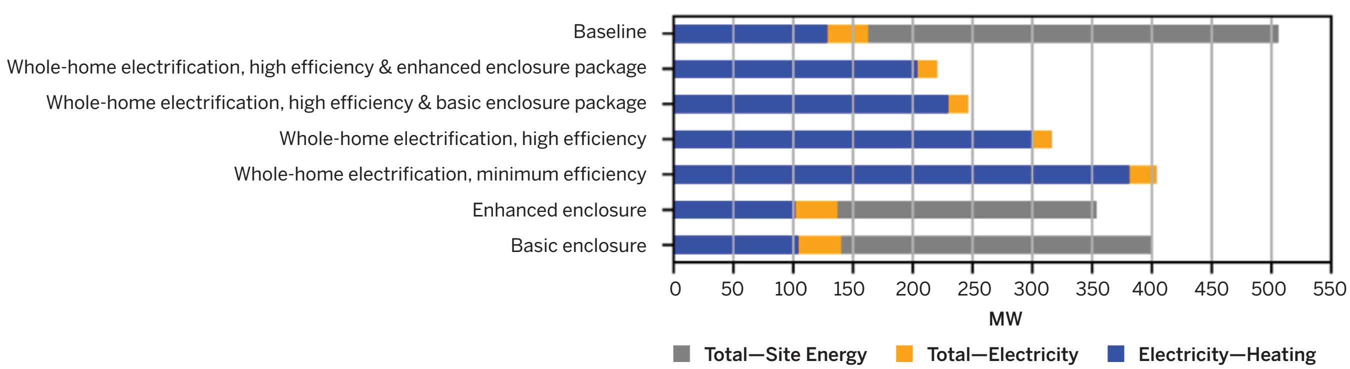


The term “thermal resilience” can be helpful in contextualizing whole-system improvements versus other types of energy efficiency (Kesik, O’Brien, and Ozkan, 2019). The two thermal resilience aspects most relevant to building electrification are:

- **Thermal autonomy:** How long a building maintains comfortable indoor conditions without inputs from active systems, such as the power grid
- **Passive habitability:** How long a building remains habitable and prevents exposure to life-threatening conditions, such as hypothermia, during extended power outages that coincide with extreme weather events

FIGURE 24

Impact of Energy Efficiency and Building Enclosure Upgrades on Modeled System Peaks, Jan. 1, 2050



Roughly 40% of the peak winter load was eliminated when modeling the impact of energy efficiency and building enclosure upgrades on whole-home electrification scenarios in Pierre, South Dakota, which was selected because of the extreme cold temperatures seen in the dataset.

Source: Maxim and Grubert (2024).

Energy Efficiency Benefits in Cold Climates

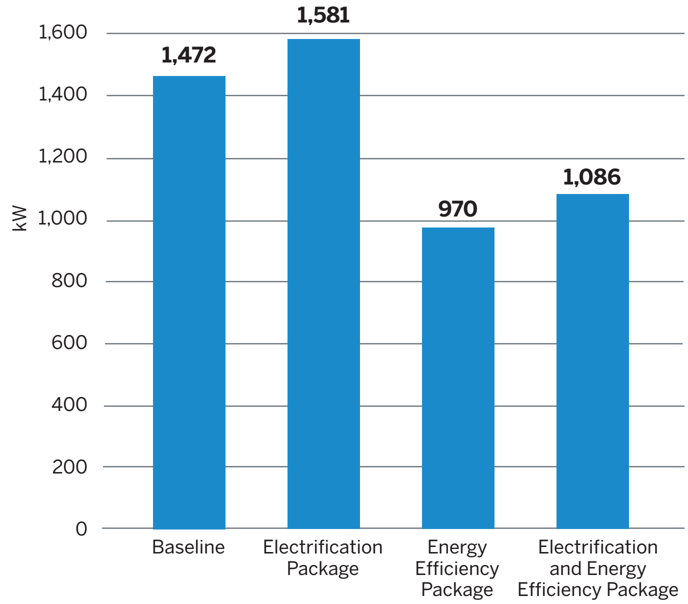
Energy efficiency helps address daily energy needs and reduces peak load requirements, which then reduces grid stress and infrastructure needs. Figure 24 (p. 37) shows the impact of energy efficiency for equipment (such as heat pumps) and for building envelope (enclosure) improvements (Maxim and Grubert, 2024). The potential load reductions are large. For example, in a scenario where residential loads were fully electrified, peak demand for Pierre, South Dakota, could be reduced by around 40% when high-efficiency end uses, such as heat pumps, and building envelope upgrades are employed.

Energy Efficiency Benefits in Commercial Districts

In commercial buildings, energy efficiency measures implemented in concert with electrification can mitigate increases in peak demand that may occur with electrification alone. A recent study from Lawrence Berkeley National Laboratory compared electrification and energy efficiency measures (together and separately) in 54 commercial buildings in two districts of San Francisco, where, in 2019, about one-fifth of the city's emissions were from commercial buildings, largely from natural gas combustion (Hong et al., 2023). (Unlike some of the other examples in this report, San Francisco has a Mediterranean climate with mild winters and cool summers.) The electrification scenario included replacing gas systems with heat pumps and heat pump water heaters, and energy efficiency measures including insulation and lighting. In one district, electrification resulted in a slight reduction of peak electricity demand, energy efficiency measures reduced peak demand by 40.2%, and the combination of electrification and efficiency reduced peak demand by 40.4%. In the other district, Fisherman's Wharf, electrification increased peak demand by 7.4% (Figure 25), due to fuel switching for cooking and laundry end uses. The efficiency measures alone reduced peak demand by 34.1%, and the combination of the electrification and efficiency measures reduced peak demand by 26.3%. These results show that even where electrification increases peak demand, energy efficiency measures implemented in concert with electrification can mitigate and even reverse that increase. Moreover, the energy efficiency measures affected multiple hours of the load profile, not just the peak hour, as shown in Figure 26 (p. 39).

FIGURE 25

Peak Electricity in the Fisherman's Wharf District of San Francisco Comparing Electrification and Energy Efficiency Packages to Baseline



A recent study from Lawrence Berkeley National Laboratory compared electrification and energy efficiency measures (together and separately) in 54 commercial buildings in two districts of San Francisco. In the Fisherman's Wharf district, electrification increased peak demand by 7.4%. The efficiency measures alone reduced peak demand by 34.1%, and the combination of the electrification and efficiency measures reduced peak demand by 26.3%. These results show that even where electrification increases peak demand, energy efficiency measures implemented in concert with electrification can mitigate and even reverse that increase.

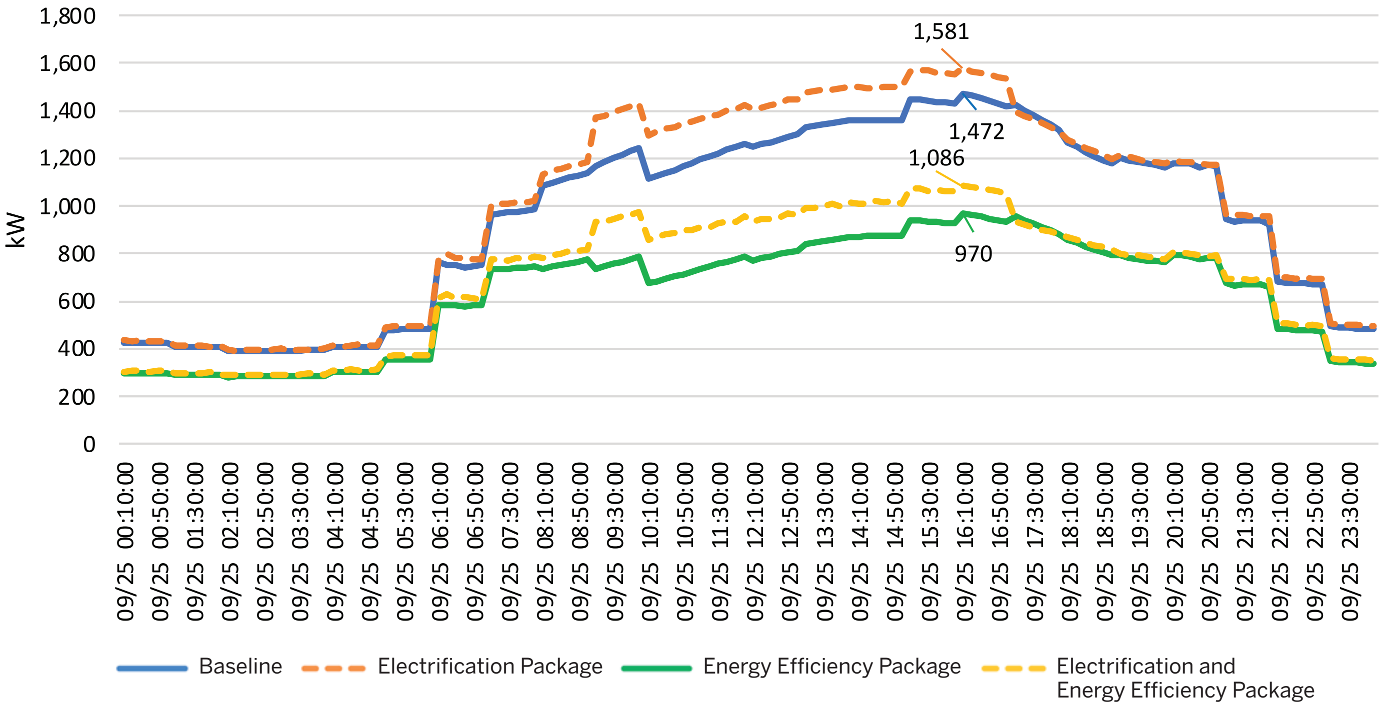
Source: Hong et al. (2023).

Ability of Energy Efficiency to Avoid the Largest Potential Impacts of Electrification

Recent analysis by Synapse Energy Economics in the state of Oregon examined the efficient electrification of commercial and residential buildings (Takahashi et al., 2022). The study compares aggregated demand during four peak winter days from both residential and commercial buildings in 2020 and in a fully decarbonized scenario in 2050. With efficient appliances and building improvements, it showed that long-term loads may not increase dramatically even in an area that has 80% of today's commercial space heating served by natural gas, avoiding what could be a significant increase with less efficient electricity usage.

FIGURE 26

Fisherman's Wharf 10-Minute Interval Power Profile on Peak Demand Day



A recent study analyzed the impact of electrification and energy efficiency measures on the Fisherman's Wharf commercial district. The 10-minute profile from the peak demand day shows that these measures can lead to impacts during different parts of the day.

Source: Hong et al. (2023).

Today, nearly equal shares of households have electric resistance and gas heating in the study region. Replacing the gas furnaces with electric heat pumps led to an increase in building load, while replacing the electric resistance with more efficient heat pumps led to decrease in building load. The net result was a small decrease in electricity demand for residential space heating. Residential electricity demand for space/water heating, cooking and drying in 2050 was 17% lower than in 2020 in this study, due to such effects.

Commercial space heating, which is 80% fueled by natural gas today, became the second-largest major load as gas furnaces were replaced with heat pumps. As a result, commercial building electricity demand for space/water heating, cooking, and drying in 2050 was projected to be 105% higher than in 2020. The load factor also decreased as the load becomes more "peaky" due to this additional midday and evening heating load.

While a doubling of electricity demand for major commercial end uses may sound scary, when residential and commercial building electrification were considered in aggregate with efficiency measures, the 2050 peak demand increase from major end uses was only 10% higher than in 2020, reflecting a 0.3% annual growth rate. When other loads were included, the total annual growth rate was 0.5 to 0.6%, comparable to historical rates.

Modeling Energy Efficiency in Distribution Planning and Targeting Incentives Toward the Most Impactful Measures

The effect of energy efficiency on power demand in different weather conditions is rarely modeled in distribution system planning. Historically, utilities have assumed load profiles for grid planning models to be static inputs that did not vary according to the weather or the availability of supply- or demand-side resources. Even when the impacts of energy efficiency and time-varying rates are included in grid planning, they too are often modeled as static profiles—not changing in response to underlying weather conditions (Carvallo and Schwartz, 2023). However, treating them as static inputs masks the value these resources can provide, which can grow in extreme weather conditions. For example, energy efficiency or demand response measures can help mitigate risk under the highest load conditions—a winter cold snap—directly offsetting the need for new distribution system capacity and generation (Nadel, Amann, and Chen, 2023).

Studies show that the cost of energy efficiency can be far more affordable than that of new generation (Lewin, 2023; Frick et al., 2021). This same logic applies to distribution upgrades: energy efficiency can be a non-wires alternative to defer or reduce the need for new distribution equipment (Frick, Schwartz, and Price, 2021). In the case of building electrification, energy efficiency is arguably more important than battery storage or other forms of demand response, even if it is not dispatchable, because it has no duration limitations.

Given the apparent value of energy efficiency, programs supporting equitable access to energy efficiency upgrades are a powerful tool. Utilities could consider incentives as part of the planning process, targeting incentives toward the most impactful upgrades.

When considering how to plan the grid for building electrification, improved energy efficiency can be a key part of the solution. Given the apparent value of energy efficiency, programs incentivizing and supporting equitable access to energy efficiency upgrades are a powerful tool. For both new and existing programs, utilities could consider incentives as part of the planning process, for example, by targeting incentives toward the most impactful upgrades.

Leverage Load Flexibility and Grid-Interactive Efficient Buildings

Another set of tools available to grid planners involves load flexibility and grid-interactive buildings that respond to changing grid conditions (Carvallo and Schwartz, 2023). Building energy management systems in both commercial and residential settings, along with aggregation technologies, offer more opportunities to manage peak demand from individual buildings as well as aggregations of buildings. Load flexibility can take many forms, from simple temperature setpoint adjustments

Coordinated and optimized control or "orchestration" of behind-the-meter resources allows end-use equipment and loads to be scheduled and dispatched to achieve any number of objectives, including reducing a building's peak consumption.

to dispatching behind-the-meter resources such as batteries.

Coordinated and optimized control or orchestration of behind-the-meter resources allows end-use equipment and loads to be scheduled and dispatched to achieve any number of objectives, including reducing a building's peak consumption. Functionally, building energy orchestration could stagger loads such that the heating, ventilation, and air conditioning system; electric vehicle charging; and water heater are not running at the same time (are not coincident). Moreover, loads could be aligned with local solar power generation—for example, manipulating the operation of the heating and cooling system with pre-heating or pre-cooling strategies—to minimize the impact on the building's electric panel, the local distribution circuit, and the broader power system. Such orchestration—sometimes referred to as grid-interactive efficient buildings—could help avoid distribution upgrades in addition to helping customers avoid the cost of electrical panel upgrades.[24]

> "The extent to which consumers (residential, industrial, and commercial) embrace dynamic tariffs and thermal storage will have a significant impact on balancing the energy system. The electrification of heat has the potential to significantly increase peak electricity demands, and so the adoption of smart controls, thermal storage and [demand response] for heating systems plays an important role in mitigating this increase and reducing the need for additional generation capacity and electricity network reinforcement." **— National Grid ESO**

Untapped Opportunities for Grid Interactivity

There are untapped opportunities for grid interactivity today. In the United States today 30% of thermostats are smart thermostats, and that number is growing (Meier, Daken, and Rainer, 2022). The deployment of these thermostats can facilitate demand flexibility to address local (or bulk) system needs, if utility programs and tariffs are designed to tap into these capabilities. The U.S. Department of Energy recently estimated that virtual power plants—the coordination of behind-the-meter resources such as smart thermostats for grid benefits—could save 30 to 60 GW of peak demand in 2024 (4% to 8% of U.S. peak demand) and 80 to 160 GW of peak demand in 2030 (10% to 20% of peak demand).[25] The same paper identifies a lack of valuation for grid edge resources as a key barrier to deployment of demand flexibility measures, indicating the importance of planning to establish value and ultimately aligning utility incentives to identify value.

Research leveraging smart thermostat data shows that programs can be designed to induce desired behavior more effectively than they currently do. For example, research on customers' tendencies to opt out of demand response events revealed that a higher percentage of homes were unoccupied in a region than were participating in the demand response event (Sarran et al., 2021). Targeting demand response events toward unoccupied homes, which may still have a high thermostat setpoint, could allow utilities to increase grid interactivity and avoid occupant discomfort. Another study of summer demand-response events found that roughly 25% of program participants manually overrode before the event, 13% overrode mid-event, and 36% of events resulted in rebound consumption that needed to be managed (Tomat et al., 2022). Research also generally suggests that shorter events result in fewer opt-outs (Sarran

24 https://www.energy.gov/eere/buildings/grid-interactive-efficient-buildings

25 https://liftoff.energy.gov/vpp/

et al., 2021). Demand response programs can generally leverage these findings by designing programs and events that maximize participation (minimize opt-outs) and grid benefits.

To avoid triggering supplemental resistive heating during extreme weather events, a thermal energy storage system—such as hot water or heated metals or bricks—can charge based on signals from grid operators days or weeks in advance of an expected weather event.

The applicability of demand response research and practical experience across jurisdictions and in addressing winter events still needs to be evaluated. But sharing such information helps to address uncertainties in program performance that have led some distribution planners to discard demand response as a potential resource. Further technological improvements could also make load flexibility an enticing potential resource, including the use of distributed thermal energy storage in the form of hot or cold water, ice blocks, or heated metals or bricks. To avoid triggering supplemental resistive heating during extreme weather conditions, a thermal energy storage system can charge based on signals from grid operators days or weeks in advance of an expected weather event. Implementing thermal energy storage in tandem with heat pump adoption could reduce and defer the magnitude of grid upgrades required. All of these opportunities build from improved thermal resilience in buildings, which can allow buildings to maintain comfort without additional electric input.

Assessing Load Flexibility's Range of Performance

Consideration of load flexibility as a distribution planning solution is sometimes met with skepticism about the reliability of demand response measures. These conversations often treat performance as binary—load flexibility is either there or it isn't—rather than recognizing that there is a range of performance that can be used in planning. Testing, data sharing, and a collaborative mindset allow planners to evaluate

the suitability of load flexibility to help address the challenges of building electrification.

Addressing the data and perception gap for load flexibility requires enhanced data-sharing mechanisms to leverage the growing availability of information, as well as data-sharing and coordination among different utility departments and functions (such as between departments managing customer programs and distribution planning). This is particularly important as jurisdictions grapple with building electrification–driven grid needs that appear during times of the year that have historically seen little need for additional assessment. Efforts can also be directed toward sharing of measurement and verification data, development of programs to enhance performance, fostering grid operator trust, and refining planning tools. Finally, different incentivization mechanisms can be considered by utilities and state regulators to appropriately value load flexibility. Table 3 (p. 43) gives useful practices for avoiding the largest impacts by managing demand.

Planning efforts can consider a range of performance for load flexibility. Testing, data sharing, and a collaborative mindset allow planners to evaluate the suitability of load flexibility to help address the challenges of building electrification.

TABLE 3

Potential Practices for Avoiding the Largest Impacts by Managing Demand

Planning Attribute	Demand-side mitigations are included in the suite of options for grid planning, particularly including energy efficiency.
Good practices	• Energy efficiency modifiers are aligned with technology forecasts and weather driving building electrification. • Demand charges are aligned with coincident peaks that drive investment in bulk system and distribution infrastructure. Example: San Diego Gas and Electric has a rate with a demand charge that varies based on the customer's coincident demand with the top 200 hours of its distribution circuit's load.
Better practices	• Demand flexibility is included as a potential resource in distribution planning, including behind-the-meter orchestration to minimize premise-level constraints. Example: While the details of how the controls are used in distribution planning are unclear, Silicon Valley Power's program for building energy control retrofits helps avoid premise-level constraints.
Best practices	• Customer programs and incentives are designed and updated to address the challenges presented by grid planning, including winter weather risk. Example: Portland General Electric has demand response programs designed to meet summer and winter peaks with one customer enrollment process.

Practices identified by members of the Grid Planning for Building Electrification Task Force.

Source: Energy Systems Integration Group.

Touch the Grid Once When Making Grid Upgrades

Energy efficiency and load flexibility measures in both residential and commercial buildings hold promise for making better use of existing grid infrastructure, but they can only go so far. Grid upgrades will eventually be required for the scale of electrification that is envisioned as necessary for economy-wide decarbonization. As building electrification proceeds, planners will need to assess what grid upgrades will be needed, when they are needed, and where they need to be located. A longer planning horizon brings visibility to future needs even if a shorter investment cycle is proposed. However, the crux of the planning challenge is how to make these investments so that they do not slow down electrification but also do not unnecessarily or prematurely overbuild the distribution system, which has cost implications and potential for under-utilized assets.

The question of whether some version of strategic investment is more appropriate than traditional just-in-time investments depends on the region's approach to building electrification. On the one hand, if electrification is dependent solely on utility program incentives and rates, then the lack of certainty of technology adoption may not justify specific upgrades. On the other hand, if utilities or local agencies target specific geographical areas or customer types, then distribution system investments that ensure the grid is fit for the near future may be more appropriate and have less risk. Either way, there are opportunities to invest in future-ready infrastructure—physical and digital equipment that can support building electrification loads over the long term—that are appropriate under any electrification approach.

There are opportunities to invest in future-ready infrastructure—equipment that can support building electrification loads over the long term—that are appropriate under any electrification approach.

The distribution system upgrade strategy differs from the modernizing planning approaches section above in that it involves the decision-making components of specific projects and areas. When deciding how to deploy infrastructure, decision-makers across the electricity industry (utilities and regulators) must find the right balance between being too proactive (leading to an overbuilt and expensive grid) and being too reactive (leading to delays in customer approvals and missed policy targets). An approach that enables future-ready grid upgrades has utilities identifying and justifying grid needs and regulators aligning incentives with holistic objectives.

Upsize Equipment to Support Increased Power Needs

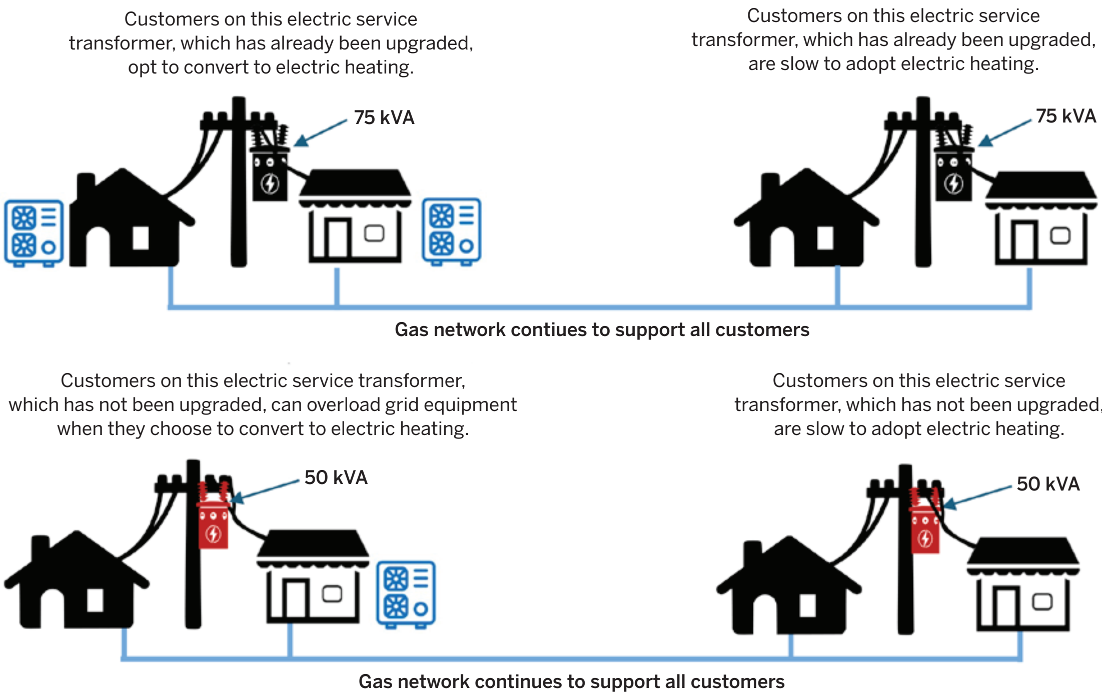
Each utility has a set of equipment standards and planning criteria that informs equipment sizing and planning decisions. For example, a specific substation may be a candidate for upgrades once it reaches a certain percentage of loading. Typically, design standards for equipment such as distribution transformers, conductors, fuses, and even poles and fasteners are re-evaluated only every 10 to 20 years; however, these standards are currently being reassessed by leading utilities facing growing loads from building (and transportation) electrification. Utility equipment standards are usually based on some combination of IEEE standards and experience, with embedded assumptions about system conditions and load growth. While utility-specific standards allow each utility to plan for grid equipment appropriate to its service area, past practices may not be well suited for electrification-driven load growth, which may have different hourly load impacts.

Distribution planners today must prioritize between conservatism of planning margin for equipment sizing and minimizing near-term rate impacts from potentially oversized equipment. In addition, changes to equipment standards are not just in support of increased electrification; they are also needed to address existing and future challenges around reliability and resilience. Updated equipment standards can lay the foundation for increased power transfer to enable electrification and can enable system reconfigurations to assist reliability and resilience.

Even as adoption scenarios and technology futures related to building electrification are not knowable with precision in advance, utilities can deploy future-ready infrastructure in a manner similar to supporting grid needs for electric vehicles (ESIG, 2024a). Future-ready infrastructure and updated design standards will change distribution system planning across multiple paths:

FIGURE 27

Options for Upgrading Grid Equipment to Enable Building Electrification with Targeted Electrification



By strategically upgrading service transformer sizing, the utility can enable customer choice and promote equitable technology adoption. The benefits of future-ready upgrades, including avoided future upsizing, need to be evaluated against grid constraints delaying electrification programs and maintaining both natural gas and electricity networks.

Source: Energy Systems Integration Group.

- When replacing existing equipment, larger-capacity future-ready infrastructure can be used.
- Additional margin to support building electrification can be incorporated from the beginning of the planning process.
- As planners continue to collect performance data and adoption information, planning standards can be updated.

Figure 27 shows the benefits and challenges with this approach, where an upsized service transformer enables customer choice to electrify.

Benefits of Future-Ready Distribution System Equipment

The economic benefits of future-ready distribution system equipment capable of meeting system requirements over the long term center on the fact that the physical grid equipment is only one part of the cost of replacing aging infrastructure. The marginal cost of a higher-capacity transformer is often small when the total system cost is evaluated including installation, engineering, and approval processes. Moreover, installing higher-capacity equipment will likely avoid the cost of replacing or supplementing the equipment in a few years as more building electrification technologies are adopted. While the economic case can be compelling on its own, recent work in Los Angeles identified upsizing distribution grid equipment as a key equity strategy, making a case to "coordinate grid upgrade programs with other programs . . . so that the grid does not create a barrier for [home electrification] deployment" (Palmintier et al., 2023). Upsizing transformers can reduce potential barriers in terms of both costs and time for all customers to electrify. Considering both the economic and equity benefits, this

Considering both economic and equity benefits, the strategy of adopting future-ready equipment can be a key enabler for electrification.

strategy of adopting future-ready equipment can be a key enabler for electrification.

The challenge with future-ready grid upgrades is the risk of overbuilding while technology and adoption are uncertain. Overbuilding the distribution system would result in stranded and underutilized assets that raise rates and generally increase the cost of power delivery. Policy and regulatory decisions will be needed to balance the risk of overbuilding with the risk of failing to meet public policy goals.

Consider the Full Extent of Electrification

Distribution equipment is expected to remain useful for more than 45 years, so infrastructure decisions made today will need to support the full electrification policy of 2050 and beyond. However, there exists a mismatch between long-term planning and near-term challenges. Building electrification can occur in particular pockets, and three-phase systems can be challenged when one or more customers adopt heat pumps for space heating on a particular phase of the distribution system but not on the other two phases. When the power demands across phases are balanced, more power can be delivered through the feeders. While the short-term solution for uneven adoption might be a simple rebalancing across phases, repeated use of such patches could create bottlenecks down the road. A more complete solution would identify the electrification anticipated in a given region and design the distribution system to meet those long-term needs, rather than send multiple crews to the area over years to rebalance.

The planning mismatch can also occur in long-term planning efforts themselves as planners fail to consider the full extent of electrification. For example, recent work analyzed the impact of electrification on loads in the District of Columbia and found that electrification is not expected to increase loads such that they exceed substation capacity by 2032 (DC DOEE, 2023). However, the study did not evaluate whether upgrades may be needed beyond 2032 to support the District's 2050 goals. If new distribution equipment is needed before 2032, it should be added in a way that also meets longer-term growth expectations—proactively investing for the future rather than replacing equipment twice. Some states, including Washington and Massachusetts, are driving grid planners to coordinate natural gas

FIGURE 28
Upgrading Grid Equipment to Enable Building Electrification with Targeted Electrification

This region has targeted electrification, outfitting every home with new heat pumps and performing all necessary grid upgrades upon conversion, including any upstream upgrades, such as at the substation.

By coordinating electricity grid upgrades with gas network planning, the overall cost of energy could be optimized. To achieve this level of coordination with respect to electrification, policymakers, regulators, and customers must be aligned on actions supporting gas system decarbonization and electrification. Such a strategy increases the importance of reliability and performance throughout the power system by consolidating energy delivery systems into one form.

Source: Energy Systems Integration Group.

and electricity system planning as the electrification of residential and commercial buildings progresses.[26] One opportunity is to simply ensure that plans around the amount of electrification are consistent. For example, when a given community fully electrifies, distribution planners can design systems that suitably address the full extent of electrification efficiently, as Figure 28 (p. 46) shows. At the same time, natural gas planners can effectively retire the network serving these areas. These situations make the electric distribution system planner's job easier as electrification is certain across locations, timing, and technology choices. Distribution planners can design the system, prioritizing any necessary upgrades, based on known conditions.

Changes will also be needed in gas system planning. New work on "targeted electrification" and "non-pipeline alternatives" has illustrated how geographically targeted building electrification could provide opportunities to avoid gas pipeline replacement projects, capturing significant savings that could be returned to ratepayers and/or used to incentivize or subsidize electrification adoption (Walsh et al., 2024; Gold-Parker et al., 2024). However, targeted electrification in this manner is a large policy and regulatory step that effectively removes gas as an option. Improving coordination between gas and electricity planning may help to recognize where these opportunities can provide meaningful savings.

The scale of planning needed to support full building electrification requires a holistic perspective. Where "touching the grid once" in typical suburban distribution circuits may be straightforward equipment upsizing, managing building electrification in dense urban areas represents a large infrastructure project that can require more than local distribution upgrades and may take decades to plan and construct. Addressing electricity delivery needs in these dense urban environments could require transmission upgrades and can be particularly challenging in underground systems, where space is limited and expansion can encroach on other infrastructure, such as water and roads.

The full extent of electrification sometimes requires upgrading existing systems that were not designed to support building electrification. One example is district

26 For Washington state, see Chapter 80.86 RCW, Washington Decarbonization Act for Large Combination Utilities (https://app.leg.wa.gov/RCW/default.aspx?cite=80.86&full=true). For Massachusetts, see Investigation by the Department of Public Utilities on its own motion into the role of local gas distribution companies as the Commonwealth achieves its target 2050 climate goals, D.P.U. 20-80-B (https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18297602).

TABLE 4

Potential Practices for Making Future-Ready Infrastructure Decisions

Planning Attribute	Upgrades to distribution system equipment to facilitate building electrification are fully assessed and coordinated with other utility initiatives, such as equity and reliability.
Good practices	• The suitability of distribution system voltage classes is assessed to determine whether they support long-term load growth, and equipment standards are upgraded as necessary. • A longer planning horizon and multiple electrification adoption scenarios are used in distribution planning to understand how forecasted electrification will impact grid needs. The longer planning horizon brings visibility to future needs even if a shorter investment cycle is proposed. Example: Eversource uses a 2050 demand assessment to inform the size and scale of investments prioritized over the next 10 years.
Better practices	• The development of equipment standards considers the chronological impact of weather on demand. • Electrification and energy efficiency incentives are developed and aligned with grid capabilities and near-term grid plans. Example: The city of Denver has higher rebates available for cold-climate heat pumps than for other types of heat pumps.
Best practices	• Diversified loading profiles are regularly assessed from representative samples of customers and used to assess equipment standards. • Natural gas and electricity network planning are coordinated to identify efficient opportunities for a holistic energy plan. Example: Massachusetts recently found that any proposed investments in natural gas or electric distribution systems "will have to take place in the context of joint electric and gas system planning."

Practices identified by members of the Grid Planning for Building Electrification Task Force.

Source: Energy Systems Integration Group.

energy systems,[27] which are pipes under many major cities that deliver steam or chilled water, depending on the season, through these thermal networks. The Denver thermal system, for example, has been in operation since 1880 and is key to providing space and water heating in dense downtown areas. Replacing this network with electric alternatives would require large power delivery capability, likely involving transmission-level upgrades, and significant undergrounding. At the same time, buildings currently served by these steam systems would need to be retrofitted with a heat transfer mechanism more aligned with electrification, such as water-source heat pumps. In this context, "touching the grid once" and making the suitable upgrades would require decades of development and fundamental shifts in the infrastructure supporting modern society. Table 4 gives useful practices for making future-ready infrastructure decisions.

27 In the United States there are 5,800 district energy systems in operation as of 2012, serving about 6.5% of commercial buildings (Cooper and Rajkovich, 2012).

Conclusions, Recommendations, and Next Steps

Jurisdictions grappling with building electrification are starting from different points and will face different challenges as winter cold snaps hit some areas harder than others. Across each region, steps can be taken to ensure that the distribution system is prepared to meet the needs of society as we electrify more commercial and residential buildings, specifically, their space heating. There is much to learn about the most effective pathways to electrify heating, and a spirit of collaboration will help planners, forecasters, policymakers, and other stakeholders to identify the best paths forward. Adopting whole-energy-system thinking is important to achieve state and local policy goals (National Grid ESO, 2023).

A Need for Coordinated and Integrated Planning

Preparing the distribution system for increased building electrification requires coordinated and integrated planning efforts to achieve multiple objectives simultaneously. Concerted efforts are needed by utilities, policymakers, regulators, and stakeholders to ensure that grid solutions both achieve policy goals and meet other grid needs effectively and efficiently. At the same time, changes will be needed inside buildings themselves, where space may be limited or equipment may be difficult to retrofit (although, with careful planning, the same heat pump

can be used to condition both space and water needs within a building). These competing priorities with traditionally segmented decision-making will need to be integrated to achieve building electrification ambitions.

More specifically, the Grid Planning for Building Electrification Task Force identified the need for coordination in planning to:

- Identify mechanisms to supply society's overall energy requirements across both gas and electricity
- Align transmission and distribution upgrades with resource plans and customer expectations
- Create incentive programs based on identified grid needs that support residential and commercial efficiency measures and the upfront costs of new equipment, including for disadvantaged customer groups and renters
- Offer retail rates that encourage electrification and grid interactivity, such that they can be relied upon by distribution planners

Other opportunities for coordination are between the utility and non-utility stakeholders. This begins with empowering residential and commercial consumers with knowledge about how their electricity decisions impact the grid and about incentives available to them. Equipment installers also play a critical role in designing and deploying the right systems to achieve the holistic objectives of building electrification most efficiently and affordably. Collaborative efforts between utilities and advocates for social equity can also help enable building electrification in a manner that is both inclusive and equitable to ensure that disadvantaged communities are not left behind.

Integrated planning allows for coordination across objectives, consistent data and information flows, and the identification of solutions that include a holistic view of value streams. Multi-objective decision-making can be used to evaluate all possible options, from new voltage regulators to rebates for grid-interactive efficient appliances, to meet the various expectations of the distribution system while considering cost and reliability. Although the starting point for building electrification is different across the country—based on primary heating fuels, public policy goals, and historical efforts—clear

Integrated planning allows for coordination across objectives, consistent data and information flows, and the identification of solutions that include a holistic view of value streams.

prioritization of available actions, such as the options listed below, can be used in designing and evaluating potential grid solutions.

Distribution planners in different jurisdictions will be looking to lawmakers and regulators for help in prioritizing actions to take in planning for building electrification, with prioritization of actions to take today depending on a jurisdiction's emphasis on:

- **Maximum financial benefits for customers.** Appliance and equipment incentives and retail rates can be designed to meet building electrification objectives and anticipate electrification where financial benefits are greatest to the customer.
- **Certainty around electrification requirements.** A few jurisdictions have established requirements for electrification at end of life for certain gas appliances (DiChristopher, 2023). This can improve certainty around electrification location and timing, and help overcome mismatches in how the natural gas network and electric grid infrastructure topologies serve particular areas. A single gas distribution pipe may cut across multiple electric distribution circuits, creating situations where electrification of a neighborhood served by a single gas distribution system requires upgrades across multiple electricity substations.
- **Specifically targeted building opportunities.** Residential and commercial buildings and equipment can be prioritized for electrification based on cost-effectiveness. By considering the cost-effectiveness of upgrades on the customer side and grid side, distribution planners can enable building electrification in the most cost-effective locations first.
- **Equitable solution.** Electrification can be targeted in locations with low-income households, poor air quality, or low adoption of air conditioning, and expanded metrics can be used in utility planning

and investment decision-making to ensure that equity is taken into account in distribution planning for high levels of building electrification.

- **Mechanisms for fuel switching.** Potential upgrades to the natural gas infrastructure can be examined to see whether capital costs would be more efficiently used for upgrades to the electricity network. For example, when a gas main is due for replacement, there may be an opportunity to invest in the electricity system rather than upgrade equipment that does not support long-term electrification. Electric distribution system planners can work with their gas network counterparts to plan a holistic energy system efficiently and safely, but are far more likely to do so given legislative and regulatory direction.

Whose Responsibility Is This?

While more will be asked of distribution planners as residential and commercial buildings become increasingly electrified, all stakeholders have a role in informing the grid planning process, both within and outside of the electric utility. Distribution planners can be informed by a variety of groups within the electric utility, and they can reciprocate by sharing their perspectives and impact analyses across the organization.

Open dialogue and honest assessments of feasibility, with rigorous and holistic benefit-cost analysis and distributional equity analysis, can reveal building electrification approaches that work for everyone.

In addition to collaboration within a utility, robust planning will need to be informed by engagement with external parties. Importantly, distribution planning analysis can inform regulators and policymakers about the implications of certain electrification pathways. Open dialogue and honest assessments of feasibility, with rigorous and holistic benefit-cost analysis and distributional equity analysis, can reveal building electrification approaches that work for everyone.

Each stakeholder contributes unique strengths to the grid planning process:

- **Load forecasters.** Communicate how the magnitude and locational distribution of loads may change over time depending on results of different scenarios

- **Equipment standards engineers.** Collaborate with planners to identify equipment best suited for evolving needs
- **System operators.** Provide perspective on daily challenges and feasibility of grid plans, whether for the distribution or bulk system
- **Utility program administrators.** Share details on customer interests and on energy efficiency and load flexibility program performance
- **Generation and transmission planners.** Collaborate to align grid capabilities across the interconnected system
- **Distribution planners.** Develop plans and identify trade-offs and costs of alternative scenarios
- **Policymakers.** Establish goals and processes to achieve desired outcomes
- **Regulators.** Evaluate the prudence of proposed investments relative to established regulations
- **Gas network planners.** Share information and expertise on gas utilization and upgrade or replacement plans
- **Heating, ventilation, and air conditioning contractors.** Design and install equipment aligned with best practices for a region, including appropriate sizing of heat pumps
- **The public.** Provide input to help decision-makers prioritize initiatives and participate in utility programs

As cross-organization and external collaboration grows in importance, some utilities have recognized a need for an integrated team that lightens the burden on distribution planners by facilitating dialogue or screening requests from various entities, while allowing individuals to focus on their strengths. Sacramento Municipal Utility District's Distributed Energy Resource [DER] Strategy team is one example of tying together groups within a utility that were previously siloed. National Grid in the U.S. Northeast has an internal Integrated Gas and Electric Planning Working Group that meets regularly to discuss best practices and exchange ideas on how to enable building electrification effectively. In this instance, National Grid benefits from serving parts of New York with both natural gas and electricity as a dual-fuel utility. Utilities may need to partner with other utilities or local jurisdictions to establish such a group, underscoring the importance of external collaboration.

Including Equitable Electrification from the Beginning

Opportunities to promote equity with building electrification include the use of equitable utility infrastructure upgrades that provide access to all customers, low-income energy efficiency programs, and on-bill financing programs. Leveraging rebates, tax credits, and low-cost financing, such as those provided through federal incentives, can also make a meaningful difference in increasing affordability and equitable outcomes. These tools will also inform effective grid designs when they are closely integrated with distribution planning from the beginning. Energy efficiency is discussed above as a key solution to avoid the largest potential impacts of building electrification, and these programs can be designed with equity and energy burdens in mind, while also addressing distribution grid challenges.

Equity and energy burdens on lower-income households are particularly important considerations in the context of building electrification because of adoption trends and fixed costs for electricity and gas networks (SCE, 2020). As more and more commercial and residential customers convert to electric heating, the demand for natural gas will decrease, leaving the fixed costs of natural gas transportation, storage, and distribution spread over a smaller customer base (Ong et al., 2021). Because of the upfront investment required for building electrification, late adopters will be disproportionately from disadvantaged communities unless steps are taken to drive an equitable transition, such as providing adequate infrastructure and designing incentives and rebates specifically with equity in mind.

The equity consideration is also present when it comes to who pays for electricity grid upgrades to support increased building electrification. Some jurisdictions may allow for the cost of grid upgrades that support electrification to be spread across all ratepayers. When only wealthier customers adopt electric heating and the grid upgrades are paid for by all customers, lower-income households can be stuck with a bill for something that they do not yet use. To avoid such inequities, rate base approaches may be accompanied by provisions that track how the benefits are distributed, ensuring that wealthy early adopters do not use all of the newly expanded grid for their electrification and crowd out future electrification.

A holistic approach to electrification can help to ensure equity beyond grid upgrades, including, for example, costs to perform upgrades within buildings themselves. In the United States, of people with the bottom quartile in net worth, 88% are renters (Desilver, 2021), and many live in multifamily properties. Landlords may need to pay for electrical panel and service upgrades spurred by electrification,[28] and they may delay electrification if these costs do not readily translate into energy savings or higher rents. Renters seeking to electrify, whether to save money, to avoid indoor health concerns from gas appliances, or for decarbonization reasons, may be stymied by this split incentive problem.

Key Actions

No single solution will solve distribution planning for building electrification for all systems. Building electrification is a complex topic at the intersection of different sectors, and it is starting at different places across the country, with different motivations for change and distinct challenges presented by weather and geography. All of this makes it challenging to develop broadly applicable actions that jurisdictions can take. However, through a collaborative approach, the Grid Planning for Building Electrification Task Force prioritized the following areas for action today, which include changes throughout the planning process:

- **Improve forecasting:** Expand the forecast horizon; gain a more granular understanding of technology adoption, including supplementary heat sources for heat pumps and whether heat pumps are designed for

28 In some places, multi-family building owners may be forced to pay for distribution equipment upgrades spurred by building electrification—and either delay electrification as a result or pass this cost on to tenants—while costs for similar upgrades in support of single-family housing would be rate-based and spread across all customers. California recently adjusted the rules to "socialize across all ratepayers the costs of service line extensions and electrical distribution infrastructure for EV charging" (California Public Utilities Commission Decision D.22-11-040, November 2022). A similar line of inquiry may be useful for building electrification.

cold climates; establish a clean baseline; incorporate a deeper understanding of weather impacts including extreme events and potentially forward-looking climate impacts; and use multiple scenarios

- **Holistically modernize planning approaches:** Align analysis with new challenges by considering the equipment standards that are used to serve load, move beyond a single peak hour analysis, and ensure that metrics, including reliability and resilience, are aligned with broad grid planning objectives
- **Avoid the largest impacts by managing demand:** Create a foundation in energy efficiency and the thermal resilience of buildings while using new technology to unlock additional load flexibility
- **Touch the grid only once when making grid upgrades and use a coordinated approach:** Consider the full extent of electrification in designing a coordinated approach to grid planning

Actions to take in grid planning for building electrification can come in many forms, including those that pertain directly to the distribution system, such as infrastructure upgrades or demand-management approaches, and those that simply help us plan better. By improving forecasting and holistically modernizing planning approaches to better capture future grid stressors, the appropriate distribution system in each region can be developed. These improved planning methods can also help to identify new technologies, programs, rate designs, and other demand-management options that help to avoid the largest impacts of building electrification.

Next Steps

Fully electrified buildings are already common in some parts of the country. As distribution planners in new areas face new building electrification, there are opportunities to learn from previous efforts. There is also an opportunity to coordinate grid planning for building electrification with other efforts, such as enabling transportation electrification and distributed generation. As we take these first steps in implementing changes, there will be a need to learn from early successes and to reassess or adjust as conditions and forecasts change.

While much of distribution system planning has traditionally been handled by utilities, the role of state legislators, regulators, and other stakeholders external to the utility will continue to grow as the implementation of building electrification continues. Moreover, the distribution planners will need help from technical colleagues, such as forecasters, program administrators, and natural gas network designers, as they wrangle new problems and identify new solutions. And no single utility needs to solve these hard challenges alone. Collaboration and additional research are needed to share lessons learned as deployment progresses.

This report identified a variety of opportunities for industry thinking to evolve. Some of those could be further spurred by additional research, including on:

- The economics of future-ready infrastructure designs
- The impact of load diversity on distribution equipment sizing
- The impact of increased sub-hourly variability on distribution equipment aging
- The suitability of 1-in-10 forecasts to capture distribution equipment risk under high electrification
- How to consider "major event days" in reliability and resilience investments
- Demand response and load flexibility performance during winter weather events
- The best practices and sufficient practices to characterize building stocks and building uses (coffee shop vs. concert hall) at levels granular enough to inform distribution planning

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When air conditioning loads transformed customer demand in the 1960s and 1970s, grid planners innovated by pairing large grid build-outs with demand response. Thanks to their lead, we know that we can handle large demand growth; we have done it before. However, we need to quickly understand the magnitude of change that comes with building electrification and take action. Given the multi-billion-dollar scale of these distribution planning decisions across industries, coordinated and holistic planning is essential to design grid architecture that effectively and equitably enables building electrification. Grid planning for building electrification is a chance to more deeply connect energy systems and build a platform for an entirely sustainable future.

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Grid Planning for Building Electrification

A Report by the Energy Systems Integration Group's Grid Planning for Building Electrification Task Force

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The report is available at https://www.esig.energy/grid-planning-for-building-electrification.

To learn more about ESIG's work on this topic, please send an email to info@esig.energy.

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

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