Electricity Demand Growth and Forecasting in a Time of Change

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BACKGROUND

Load forecasting, or projecting future peak demand and energy consumption, is a critical component of the electric power industry's responsibilities.[1] While many industries organize around predicted demand and supply, advanced planning is of particular importance to electric power utilities and system operators because, historically, electricity has had very little storage capability and long expansion lead times. In most cases, power production must match consumption at every moment.

To address the capacity and inventory challenge and to strategically plan for the future, utilities and system operators apply load forecasts to integrated resource plans (IRPs), long-term transmission plans, and various supply-side and demand-side programs to maintain the supply-demand balance at all times. Load forecasts are, therefore, the crucial first step to a reliable and affordable electricity system.

After more than two decades of stagnant electricity sales and peak load growth, the load forecasting landscape is evolving rapidly. The North American Electric Reliability Corporation's (NERC's) *2023 Long-Term Reliability Assessment* shows that aggregate industry-wide load growth projections have been fairly low and declining over the past few decades (see Figure ES-1 below). This trend has now dramatically reversed. NERC now projects that the compound annual growth rate (CAGR) for aggregate load will nearly double from 0.6% per year as projected in recent years to about 1.1% per year over the next 10 years. NERC notes that these growth rates "are higher than at any point in the past decade."[2] Similarly, a recent survey of Federal Energy Regulatory Commission (FERC) Form 714 filings from electric utility planners

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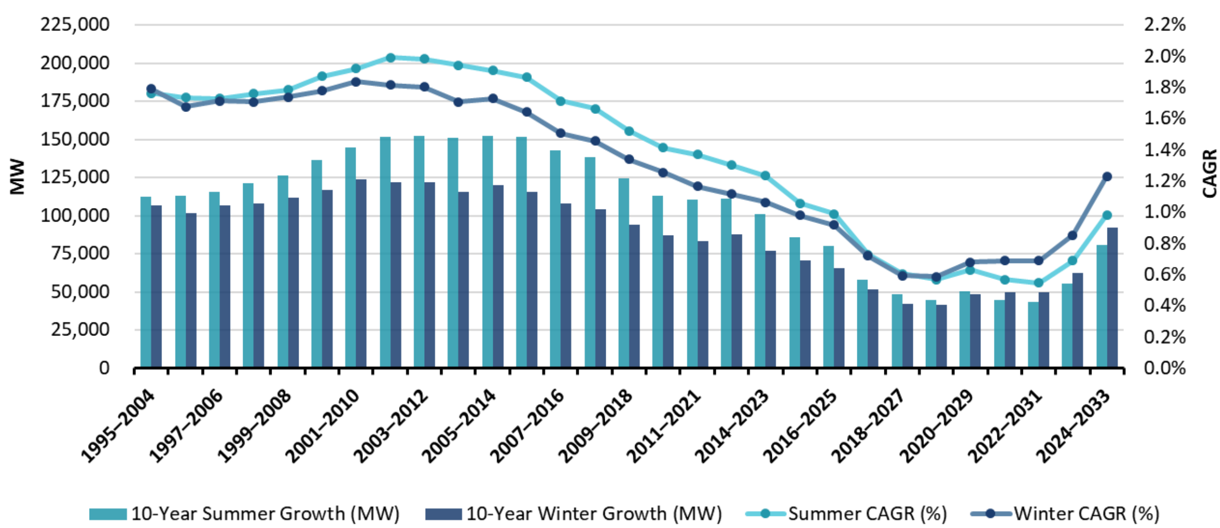
[1] The term energy consumption or energy usage (sometimes referred to as "sales") refers to the total demand for electrical energy during a time period and is measured in units of mega watt-hours (MWh), gigawatt-hours (GWh), or terawatt-hours (TWh). The term load or peak load refers to the highest single momentary demand for electricity, measured in mega, giga, or terawatts (MW, GW, or TW, respectively). Electric forecasters must plan to meet both sales needs over time and to meet peak loads, and we discuss both units in parallel throughout this report. When referring to both sales and peak loads together, we generally use the term *electricity demand*.

[2] NERC, "2023 Long-Term Reliability Assessment," December 2023, p. 33, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

found that five-year peak demand growth rates have increased from 2.6% in 2022 filings to 4.7% in those filed in 2023.[3]

The rapidly changing picture of demand drivers and new supply options, along with the changing nature and flexibility of loads, warrants looking at load forecasting from quite a different perspective. In today's world, where much of these new demand drivers are policy-driven, the risk of under- versus over-forecasting is asymmetric. With a climate strategy that relies heavily on clean electrification, the cost and long-lasting effects of under-forecasting may be much larger than those of over-forecasting — while still recognizing that large over-forecasts also have accompanying costs.

FIGURE ES-1: NERC 10-YEAR SUMMER AND WINTER PEAK DEMAND GROWTH AND RATE PROJECTIONS



Source: NERC, "2023 Long-Term Reliability Assessment," December 2023, p. 33, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

THE NEW DRIVERS OF LOAD

Several evolving electricity uses have contributed to this change, including a host of new and emerging demand drivers (see Figure ES-2 below). New demand drivers that are noticeable and recognized by the general public come from efforts to electrify the transportation and building sectors, prompted in part by federal and state strategies to reduce greenhouse gas (GHG) emissions across the economy. In a growing number of regions, there is also a rapid rise in demand from data centers to support the modern online economy and the growth of artificial

[3] John Wilson and Zach Zimmerman, "The Era of Flat Power Demand is Over," Grid Strategies, December 2023.

intelligence (AI), among other needs. These data centers require high-powered computational processing and associated cooling.

Another expanding source of demand growth comes from industrial and agricultural applications. The US government's renewed focus on domestic production – as evidenced by policies such as the Creating Helpful Incentives to Produce Semiconductors (CHIPS) and Science Act, the Infrastructure Investment and Jobs Act (IIJA), and the Inflation Reduction Act (IRA) – has spurred American reindustrialization and related demand growth. Beyond these load sources, cryptocurrency mining also adds significantly to forecasted demand growth.

As Figure ES-2 shows, the magnitude of the growth of these new loads is quite significant. Taking data centers (row A1) as an example, the driver's current 19 GW capacity is comparable to ISO New England's 2022 peak load of about 25 GW (net of distributed energy resources [DERs] and energy efficiency [EE]), and is almost double New York City's 2022 peak load, which is slightly short of 10 GW. A 9% CAGR indicates that data centers alone are projected to add load that is equivalent to that of New York City every five years or so.

Moreover, the additional loads shown in Figure ES-2 are likely underestimates, given how quickly and frequently some of these estimates have been revised – and almost always in the upward direction. The estimates in Figure ES-2 also do not include the new demand for electricity from the electrification of industrial processes, which may be substantial as companies rely on electrification as a key pathway to decarbonize their supply chains. The figure does not include two elements, which – when combined – are usually the largest component of the overall load: natural load growth associated with economic or population growth and other organic load growth. DERs, EE, and demand response (DR) have the potential to moderate the growth of both electricity consumption and peak load. However, the magnitude of the moderation effect will depend on geographical and temporal characteristics between these demand-side resources and the new load drivers, as well as the uncertainty associated with their availability and real-time responses.

FIGURE ES-2: ELECTRICITY DEMAND DRIVERS, POTENTIAL IMPACTS, AND GROWTH RATES IN THE US (50 STATES)

	Description	Current Capacity (GW)*	Approximate Growth Rate (CAGR)*	Approximate Growth by 2030 (GW)*
A1. **Data Centers**	Data centers underpin the online economy and support the growth of artificial intelligence.	19	9% through 2030	16
A2. **Onshoring & Industrial Electrification**	Electrification of the industrial sector is a major pathway to reduce emissions. New sources of electric demand are triggered by the onshoring of manufacturing activity, hydrogen production (e.g., electrolyzers), indoor agriculture, and carbon dioxide removal.	Industrial: 116 Hydrogen Production: 0.07 Indoor Agriculture: 6	Reindustrialization (near-term): 1% through 2025 Hydrogen: 132% through 2030 Indoor Agriculture: 10% through 2035	Reindustrialization: 4.9 Hydrogen: 25 Indoor Agriculture: 5.8
A3. **Cryptocurrency Mining**	Cryptocurrency mining is the process by which networks of computers generate and release new currencies and verify new transactions.	10–17 (estimated to be around 50% to 90% of data center load in the US)	Unknown and highly volatile (driven by cryptocurrency values, which fluctuate by external factors)	8–15
B1. **Transportation Electrification**	A growing number of customers purchase electric passenger vehicles as a more climate-friendly alternative to gas vehicles; medium- and heavy-duty vehicles, bicycles, motorcycles, and ferries can all operate on electricity.	6.8 (electric vehicles)	15% through 2040	8.4
B2. **Building Electrification**	Electrification is a major pathway to decarbonize buildings and can include space heating (e.g., heat pumps), water heating (e.g., heat pump water heaters), and cooking (e.g., electric/induction cook stoves).	50	0%–4% through 2050	7.4

* Based on a review of multiple sources. See Appendix for sources and notes.

THE TWO TYPES OF NEW LOAD DRIVERS

The new drivers documented in this report have varying characteristics that make load forecasting difficult. In general, the drivers can be placed into two main categories, which we label as "Type A" (loads that are large and discrete in size and are often characterized by higher uncertainty) and "Type B" (loads that are comparatively smaller and growth pattern is smoother).

Taking them in reverse order, we will begin our discussion with Type B.

Significant load growth from the electrification of transportation and buildings is consistent with many decarbonization pathway studies, which typically project long and sustained periods of high electric demand growth. The challenge to forecast these Type B loads centers on the enormous range of uncertainty regarding the trajectory, timing, and location of growth, which also varies by the electricity system (e.g., utility footprint) and often within systems as well. Load growth from electrification, which naturally requires replacing existing stocks, takes time to materialize and is usually geographically uneven. This contributes to higher levels of uncertainty in these forecasts.

Many utilities have already started to address Type B drivers in their load forecasts and planning processes. Figure ES-3 below illustrates the status of forecast driver inclusion for a sample of forecasting entities across the US. Because these new loads are oftentimes connected at the distribution level, it is also critical to conduct load forecasts at a more granular level (e.g., substation by substation) to ensure that the local network will be able to support all load growth. However, only a few entities in our survey have performed these more localized load forecasts.

Load increases from data centers, industrial processes, indoor agriculture, and cryptocurrency mining – Type A loads – present a different challenge. These loads are often quite large and lumpy (sometimes as large as an entire city). Their expansion is also often concentrated in certain areas. The development cycles for data centers, indoor agriculture, and cryptocurrency mining loads can be much shorter than the planning cycles for utilities, which typically look many years ahead.

In addition, the operations of some of these new loads can change suddenly due to market and policy-related shifts.[4] In extreme cases, some of these loads (e.g., those from indoor agriculture

[4] For example, a change in the value of cryptocurrency could impact the energy consumption of cryptocurrency load, or policy related to marijuana use will impact some indoor agriculture load.

and cryptocurrency mining) can unexpectedly disappear. Many of the new industrial processes – such as those for hydrogen and/or ammonia production – are often contingent on federal, state, or other incentives, and their timelines may also divert from traditional industry build-up schedules that utility planners have observed in the past. Finally, some of these loads may be able to provide flexibility, so the conventional assumption that planning requires building enough capacity to serve an inflexible peak load may no longer be true.

All of these factors make the growth of Type A loads an immediate planning and operational challenge, as well as a motivation for improved long-term forecasting. The challenges presented by Type A loads will not be met simply by improving forecasting; they also must include new short-run load planning techniques and new operating practices that we touch on only briefly later in this report.

The new dynamics of increased loads are further complicated by demand-side resources, such as EE and DR, which act to offset the potential load or sales growth. These can be large and are often cost-effective in freeing up supply increments for high-priority uses. In a looming era of electricity capacity and energy constraints, these resources should play an integral role in the overall utility forecasting and planning process.

FIGURE ES-3: INCORPORATION OF SELECTED MAJOR DEMAND DRIVERS BASED ON SAMPLE UTILITY PUBLIC FORECASTING DOCUMENTS

		Demand-Side Resources			Type B Load		Type A Load			
		EE	DR	DG	EVs	Electric Heating	Data Center	Indoor Agriculture	Electrolyzer	Industrial Onshoring
AZ	Arizona Public Service (APS)	✓	✓	✓	✓		✓			✓
AZ	Salt River Project (SRP)	✓	✓	✓	✓	✓	✓			
CA	City of Palo Alto	✓	✓	✓	✓	✓				
CA	CleanPowerSF	✓	✓	✓	✓	✓				
CA	Los Angeles Department of Water and Power	✓	✓	✓	✓	✓				
CA	Pacific Gas & Electric (PG&E)	✓	✓	✓	✓	✓				
CA	Southern California Edison (SCE)	✓	✓	✓	✓	✓				
CA	San Diego Gas & Electric (SDG&E)	✓	✓	✓	✓	✓				
CA	Sacramento Municipal Utility District (SMUD)	✓	✓	✓	✓	✓	✓	✓*		
CO	Black Hills	✓	✓	✓			✓*			
CO	Colorado Springs Utilities (CSU)	✓	✓	✓	✓	✓				
CO	Public Service Company of Colorado (PSCO)	✓	✓		✓	✓				
CO	Tri-State	✓*	✓*							
FL	Florida Power & Light (FPL)	✓	✓	✓	✓					
FL	Gainesville Muni	✓	✓	✓	✓					
FL	Jacksonville Electric Authority (JEA)	✓	✓	✓	✓	✓				
FL	Seminole CO-OP	✓	✓	✓						
GA	Georgia Power	✓	✓	✓	✓	✓	✓			✓*
IL	Ameren Illinois	✓	✓	✓						
IL	Commonwealth Edison (ComEd)	✓	✓	✓	✓*					
MD	Baltimore Gas and Electric Company (BGE)	✓	✓	✓	✓					
MD	Choptank	✓*	✓*	✓						
MD	Delmarva Power (DPL)	✓	✓	✓						
MD	Hagerstown	✓*	✓*	✓						
MD	PEPCO	✓	✓	✓						

		Demand-Side Resources			Type B Load		Type A Load			
		EE	DR	DG	EVs	Electric Heating	Data Center	Indoor Agriculture	Electrolyzer	Industrial Onshoring
MD	Potomac Edison	✓	✓	✓						
MD	Southern Maryland Electric Cooperative	✓	✓	✓						
MA	Eversource	✓	✓	✓	✓	✓	✓*			
MA	National Grid	✓	✓	✓	✓	✓	✓*			
MA	Unitil	✓*	✓*	✓	✓	✓				
NJ	Public Service Electric and Gas (PSE&G)	✓	✓	✓	✓	✓	✓			
NY	Central Hudson Gas & Elec Corp	✓	✓	✓	✓	✓				
NY	Consolidated Edison Co-NY Inc	✓	✓	✓	✓	✓				
NY	Long Island Power Authority (LIPA)	✓	✓	✓	✓	✓				
NY	Niagara Mohawk Power Corp.	✓	✓	✓	✓	✓				
NY	Orange & Rockland Utils Inc	✓	✓	✓	✓	✓				
TX	El Paso Electric	✓	✓	✓	✓					
VA	Appalachian Power Co	✓	✓				✓			
VA	Virginia Electric & Power Co	✓	✓	✓	✓	✓	✓			
WA	Puget Sound Energy (PSE)	✓	✓	✓	✓	✓	✓*	✓*		
CEC	California Energy Commission	✓	✓	✓	✓	✓				
MISO	Mid-continent Independent System Operator	✓	✓							
ISO-NE	ISO New England	✓	✓	✓	✓	✓				
NYISO	New York ISO	✓	✓	✓	✓	✓	✓		✓	
PJM	PJM Interconnection	✓	✓	✓	✓	✓	✓			✓*
SPP	Southwest Power Pool	✓	✓	✓	✓	✓				
ERCOT	Electric Reliability Council of Texas	✓	✓	✓	✓		✓*			

Notes: EV, DG, EE, and DR refer to electric vehicles, distributed generation, energy efficiency, and demand response, respectively. Cells with an asterisk (*) mean that the entity forecasted this particular driver to an extent but did not account for the likely long-term growth of the drive and/or the entity has multiple load forecasts and does not include the driver in all load forecasts. Tri-State notes that one of their R&D projects involves incorporating DERs into resource planning to account for the effects of rooftop solar and electric vehicles on load and peak forecasting, but it is unclear if this is a past or present endeavor. PSE&G is included based on a review of the PJM load forecast for the PSE&G load zone.

STATUS OF UTILITY FORECASTING EFFORTS AND OTHER MEASURES

As summarized in Figure ES-3, we find a wide spectrum among utilities in terms of how they recognize and account for these new drivers. Across the entire industry, a renewed focus on load forecasting is warranted, given the large new drivers, the rapidity of change, and the significant uncertainties surrounding the rate of growth. Traditional load forecasting methods typically assume that loads are inelastic, and that future needs can be addressed within a long planning horizon, usually measured in years. One of the first steps planners could take today is to comprehensively assess the various drivers, even if a sophisticated modeling approach is not yet available. The latter should come next after the new load types are better understood.

Applications of our findings are not limited to improving load forecasts. Proactively expanding the existing transmission and distribution networks will also help alleviate uncertainties associated with both the availability of new supplies and the nature and timing of new demands. Various studies show how enhancing transmission, including interconnection with neighboring systems, can improve reliability and resiliency. These enhancements are often thought of as long-term solutions. However, the same concept can be applied to accommodating new loads. For example, a meshed network – whether it be transmission or distribution – will provide more options for the utility to upgrade the system to accommodate new load compared to a radial line. Not only will these options generally lead to lower costs, but a meshed network provides higher levels of reliability and, often, resiliency as well.

Proactively looping (or meshing) existing lines that are radial based on an improved load forecast may be an example of a least-regret option that can be implemented immediately, partially in preparation for new loads. The uncertainty and speed of these new loads also suggest lower-cost investments, such as grid-enhancing technologies or storage,[5] that can be made much faster than traditional transmission and/or distribution investments could be utilized more, even if they are used as a temporary measure until a larger scale solution (e.g., a new transmission line) is put in place.

This report provides a preliminary, high-level look at the new major drivers of demand growth and the ways in which current forecasts appear to be including them in their forecasting – and, by extension, their overall planning – processes. We find that many utilities are making progress in including these drivers, but there is still much work to be done. We find that the drivers fall

[5] There are many types of grid-enhancing technologies that have been proven and implemented globally. Examples include dynamic line ratings, topology optimization, flexible alternating current transmission system (FACTS) devices, and storage as transmission, among others.

into two major categories, with implications for how utilities forecast and plan for these new loads. Finally, we note that steps the industry must take to meet the challenges of a new era of growth extend beyond improved forecasting, including expanded work on demand-side resources, system design, expansion planning, and the inclusion of new technologies. Nonetheless, improved forecasting remains the essential first step towards a reliable and affordable electricity system that powers both economic growth alongside full decarbonization in the decades ahead.

I. Introduction: A Time of Rapid Change in Electricity Demand

Across the US energy industry, it is widely recognized that nationwide electricity sales and peak loads have been nearly stagnant for more than two decades. US electricity sales have grown at a tepid rate, averaging less than 0.6% per year since 2000. While much research indicates that the US has not tapped anywhere near the full potential of EE, EE programs deployed to date have helped bring electricity sales growth close to (and sometimes below) zero for many years. Annual peak loads have also grown quite slowly, moderated in part by DR programs.

This picture of slow growth in electricity demand is now changing rapidly in many parts of the country. While some utilities remain in the prior slow-growth regime or expect moderate demand growth, others are reporting the highest level of annual demand growth in 20 years and an unprecedented inrush of new interconnection requests. The new, much higher projection of electricity demand growth is coming from a host of new demand drivers, notably electrification associated with climate and industrial policies and the rapid rise in data center power demand. The observed increases show similarity with those projected in decarbonization pathway studies, many of which predict long periods of relatively high electric demand growth. At the same time, there is a very high level of dispersion in current and forecasted growth rates and an enormous amount of uncertainty regarding the timing, location, and the associated trajectory of growth in each utility area.

A change to a sustained era of high electricity growth has great implications on local, state, and federal policies, from local solar zoning rules to global supply chain geopolitics. It is equally clear that the utility industry’s direct response to this new era of growth, along with responses to the broader policy issues, should all begin with the best possible load forecasts, including recognition of geographic differences that will drive different growth rates and the essential role of managing large long-term uncertainties.

This report provides a preliminary view of the current state of electric utility demand forecasting and the degree to which the new demand drivers are being incorporated into the forecasting process. We emphasize that this view is neither a comprehensive review of the state of electric power forecasting nor a critique of any one entity’s forecasting method or results. Instead, we assess (1) the relative magnitude and timing of demand from the drivers that appear to have the largest influence on demand growth and (2) the qualitative degree to which a roughly representative sample of electric forecasters appears to be incorporating these drivers into their forecasting processes. Our review includes three drivers that act to reduce the rate of electricity consumption and peak load growth – DG, EE, and DR – because no picture of future demand growth is complete without fully accounting for these resources.

In brief, our analysis finds that:

- The combined speed and magnitude of the new growth drivers point towards a sustained period of very high electric demand growth for many parts of the country. However, it is likely that growth will vary substantially across regions and smaller areas (even within a given utility's footprint), highlighting the importance of forecasting specific to each area's circumstances.
- The potential to moderate the growth of both electricity consumption and peak load through DG, EE, and DR is large. However, the degree of moderation will likely also vary substantially across areas, and net load growth is likely. This highlights the need for advanced and granular forecasting that fully includes these resources.
- Public documents show that many utilities have made significant progress in incorporating these changing drivers into their forecasts. Other entities appear to have recognized some or all of the drivers but have not yet adapted their forecasts to include them. In general, very few forecasts appear to reflect the full set of new drivers.

The report's findings present an important snapshot of an industry in transition, bringing into focus the need for and urgency of accurate load forecasting and recognizing the need for further work to assess the status of demand forecasting. This includes analyzing the effectiveness of different forecasting methods and techniques in capturing magnitude, timing, and geographic dimensions, along with uncertainty factors of each of the specific new drivers.

The remainder of the report is organized into four sections. Section II reviews the major drivers and their magnitudes, which together paint a rough picture of the range of likely demand growth futures in the industry. Section III briefly surveys a sample of utility forecasts to assess the apparent degree of inclusion of the new drivers. Section IV contains a short discussion of the costs of utility mis-forecasting, and Section V summarizes and concludes.

II. The New Drivers of Electric Demand

Electricity usage and patterns in the US are evolving rapidly, triggered by many factors – notably, changes in policy, technology (costs and advancements), and structural macroeconomic factors. After decades of steady growth, US electricity consumption growth slowed in the early 2000s to a plateau that lasted well into the late 2010s and subsequently plummeted in 2020 during the COVID-19 pandemic. Accordingly, forecasts of electricity usage moderated over the 2000–2020 period. For example, the US Energy Information Administration (EIA) previously anticipated anemic growth would continue for much of the 2020s. However, in the most recent years (post-COVID-19), new load growth patterns began to emerge, responding to improvements in new energy technologies, policies (such as the Infrastructure Investment and Jobs Act, the Inflation Reduction Act, and the CHIPS and Science Act), and the growth of industries that require energy-intensive inputs.

Figure 1 below summarizes the major drivers that affect load growth and load pattern. It includes the following drivers: data centers, onshoring and industrial electrification, cryptocurrency mining, transportation electrification, building electrification, distributed generation, energy efficiency, and demand response.

The number of data centers is growing rapidly to meet increasing data usage from streaming services, social media, mobile devices, and cloud computing, just to name a few. The emerging fields of AI and machine learning require massive computational power and storage, fueling demand for data center infrastructure and, with it, the demand for electricity. These loads tend to run constantly.

At the same time, an increasing number of companies are looking to decarbonize their industrial processes via electrification. The US government's embrace of strategic industrial policies has led to renewed investments in domestic manufacturing, and more companies are siting their facilities in the US to take advantage of financial incentives and mitigate geopolitical risks. Notable among these developments is the country's push to develop hydrogen hubs around the country. Many of the hubs have a strong focus on "green" hydrogen produced through electrolyzers using electricity generated from clean energy resources, such as solar and wind. In parallel, interests in carbon dioxide removal (CDR) technologies such as direct air capture, an energy-intensive chemical process where carbon dioxide is pulled from the atmosphere, continue to grow. Indoor agriculture is another driver that continues to grow as states change their policies to allow for certain agricultural products. Collectively, these industrial drivers will significantly increase the demand for electricity.

Cryptocurrency mining facilities require a massive amount of electricity to power and cool their equipment, and typically operate around the clock with high load factors. Power supply costs are the largest component of cryptocurrency mining facilities' operating costs and are a key consideration when deciding where to site new facilities. Cryptocurrency mining load can provide operational flexibility by responding to price signals.

FIGURE 1: MAJOR DRIVERS THAT AFFECT LOAD GROWTH AND LOAD PATTERN

	Description
A1. **Data Centers**	Data centers underpin the online economy and support the growth of artificial intelligence.
A2. **Onshoring & Industrial Electrification**	Electrification of the industrial sector is a major pathway to reduce emissions. New sources of electric demand are triggered by the onshoring of manufacturing activity, hydrogen production (e.g., electrolyzers), indoor agriculture, and carbon dioxide removal.
A3. **Cryptocurrency Mining**	Cryptocurrency mining is the process by which networks of computers generate and release new currencies and verify new transactions.
B1. **Transportation Electrification**	A growing number of customers purchase electric passenger vehicles as a more climate-friendly alternative to gas vehicles; medium- and heavy-duty vehicles, bicycles, motorcycles, and ferries can all operate on electricity.
B2. **Building Electrification**	As a major pathway to decarbonize buildings, electrification can be used for space heating (e.g., heat pumps), water heating (e.g., heat pump water heaters), and cooking (e.g., electric/induction cook stoves).
C1. **Distributed Generation (DG)**	Rooftop solar and battery energy storage systems allow customers to lower electricity bills and increase resilience.
C2. **Energy Efficiency (EE)**	Energy efficiency technologies or programs fulfill the same consumer needs with less energy.
C3. **Demand Response (DR)**	Demand response includes tools that change the way customers interact with the grid and can result in more dynamic load patterns.

Decarbonization efforts have led to the added electrification of various sectors, most notably transportation and buildings. Previously perceived as an option for a niche market, electric vehicle (EV) sales have surged, surpassing expectations from just a few years ago. Similarly, building electrification has gained momentum in recent years; for example, sales of heat pumps in 2022 outpaced sales of gas furnaces.[6] Together, these drivers are poised to contribute to new demand and demand patterns for electricity and associated services.

Finally, DG in the form of solar and energy storage, along with demand-side management (DSM) such as EE and DR programs, has been proven to help manage electricity demand and will remain vital and cost-effective tools for offsetting future electricity needs.

Among these load drivers, we observe two distinct load types (which we will refer to in this report as "Type A" and "Type B"), each with different implications for grid planning. Sometimes called "step loads" or "point loads," Type A loads are large and discrete in size and are often characterized by high uncertainty. These loads can be built within months, a much shorter timeframe than utilities' multi-year planning cycles. Furthermore, their operations can change with macroeconomic and policy-related factors.[7]

Compared to Type A loads, Type B loads are smaller, and their growth pattern is smoother. Type B loads include EVs and electric heating and cooling. Type B load's relatively steady nature is conducive to modeled forecasts, and a planned, steady system buildout can accommodate these load types. Although Type B may appear more granular at the bulk system level, their concentration in specific pockets of the distribution system renders them "lumpy," meaning large and discrete in size, in those locations. For example, an EV charging hub represents this type of load. When Type B loads emerge at larger scales (e.g., fleet conversion of conventional buses to electrical buses), they can exhibit some of the same characteristics as Type A loads, necessitating proper planning and investments for the respective areas.

Both Type A and Type B loads can be challenging to forecast for the above reasons, and the tools to incorporate them into load forecasts and integrate them into the grid can vary. Figure 2 below provides additional information on the two load types and their potential impacts on the grid.

We next discuss each of these load drivers in more detail.

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[6] Maria Virginia Olano, "Chart: Americans bought more heat pumps than gas furnaces last year," *Canary Media*. Via https://www.canarymedia.com/articles/heat-pumps/chart-americans-bought-more-heat-pumps-than-gas-furnaces-last-year.

[7] For example, cryptocurrency loads are not tied to the region in the way that traditional loads are, as mining operations can shut down or depart to a different area with little warning. Further, these discrete loads may cause "land rush" issues, where the potential customers have the incentives to add themselves to the queue of new loads to be served by the system, but the cost of not following through is minimal.

FIGURE 2: CHARACTERISTICS OF DIFFERENT LOAD TYPES

	Type A	Type B
Description	Large discrete loads; more "lumpy" in occurrence.	Small and more distributed load; more gradual in growth.
Grid Impacts	• Impacts are highly regional/at specific locations, typically at the generation and transmission level • Shorter planning horizon	• Impacts are regional but more spread out at the distribution level • Longer planning horizon
Forecast Challenges	• Some speculative loads (e.g., cryptocurrency mining) may not materialize, or may depart with little advance warning • Less able to be forecasted in advance/less foresight	• Can be forecasted with greater foresight due to similar planning experience (e.g., new community development or adoption trends from elsewhere), but sharp load increase after a certain adoption level (assuming S-curve profile)
Potential Solutions	• Traditional generation and transmission capacity expansion to ensure resource adequacy • Use surplus generation and transmission capacity • Create capacity by more aggressive load flexibility • Leverage onsite generation • Transparent processes for large load interconnection	• Execute system buildout under the assumption of steady expansion • Leverage load flexibility tools to optimize distribution grid usage • Offset with increased energy efficiency
Examples	Data centers, manufacturing plants, hydrogen electrolyzers.	Electric vehicles, heat pumps.

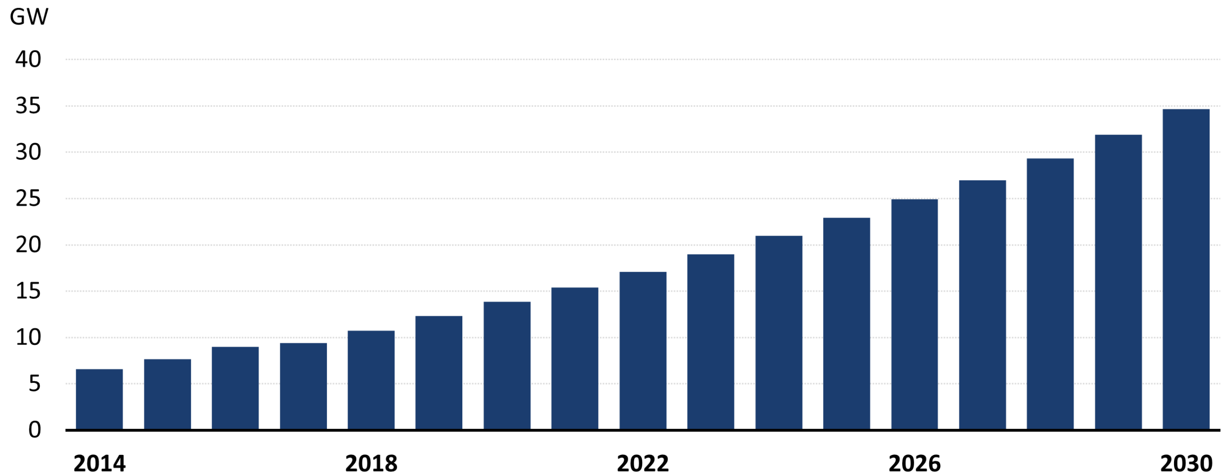
A1. Data Centers

Data centers have become a significant driver of load increase in many parts of the US as the infrastructure to support the modern online economy, AI, and other sectors expands. Data centers are highly energy-intensive; according to the US Department of Energy (DOE), data centers consume 10 to 50 times more energy per unit of floor space compared to a standard commercial office building and amount to about 2% of all electricity consumption today.[8]

[8] US Department of Energy, "Data Centers and Servers." https://www.energy.gov/eere/buildings/data-centers-and-servers.

According to one estimate, the total electricity demand from data centers is about 19 GW today.[9]

FIGURE 3: US DATA CENTER DEMAND GROWTH



Notes and source: Demand is measured by power consumption to reflect the number of servers a data center can house. Demand includes megawatts for storage, servers, and networks. From McKinsey & Company, "Investing in the Rising Data Center Economy." https://www.mckinsey.com/industries/technology-media-and-telecommunications/our-insights/investing-in-the-rising-data-center-economy.

Looking forward, data centers are poised to continue to add substantial demand for electricity.[10] A 2023 study estimates that the demand for electricity from data centers in the US will approximately double by the end of the decade to about 35 GW, an equivalent CAGR of nearly 10% (see Figure 3 above). Another study reports findings of similar magnitude, where energy consumption from data centers is expected to triple from 130,000 GWh to 390,000

9 S&P Global Market Intelligence, "Power of AI: Wild predictions of electricity demand from AI put industry on edge." https://www.capitaliq.spglobal.com/apisv3/spg-webplatform-core/news/article?KeyProductLinkType=2&id=77859037.

10 The power requirements for a small, medium, and large data center are 1–5 MW, 5–20 MW, and 20–100 MW, respectively. To put it in scale, 1 MW equals roughly enough electricity for the instantaneous demand of 750 homes at once. *See* Mary Zhang, "Data Center Power: A Comprehensive Guide." *Dgtl Infra*. Via https://dgtlinfra.com/data-center-power/; and California ISO, "Understanding Electricity." *CAISO*. Via http://www.caiso.com/about/Pages/OurBusiness/Understanding-electricity.aspx.

GWh by 2030.[11] We note that others find that the growth in energy usage from data centers may be slower and moderated by recent energy efficiency trends.[12]

Among US utilities, Dominion Energy serves the largest data center market in the world.[13] The utility expects tremendous growth in power demand from data centers, increasing from about 3 GW today to over 7 GW in 2030 and 15 GW by 2040.[14] For reference, the current summer peak load for the Dominion area is about 22 GW.[15] At the regional transmission organization (RTO) level, PJM serves about 45% of the electricity demand from US data centers (a large part of which are located in Dominion Energy's service territory).[16] The dramatic increase in the number of data centers in the Virginia region has resulted in constraints within the energy infrastructure, and companies are looking to areas such as the Southeast (e.g., Atlanta) and Midwest (e.g., Ohio and Illinois) for further growth.[17]

On the operational front, many data centers have thus far required relatively constant and stable energy input with little flexibility in adjusting their energy usage pattern because they are serving inflexible workloads, such as banking systems or hospital servers. As a result, data centers cannot readily reduce their energy usage during system peak hours. However, the landscape is beginning to change. First, nearly half of the energy consumption of data centers comes from cooling.[18] Advances in cooling technology could alter the energy consumption of future data centers. Second, the flexibility associated with their operations is evolving. One

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11 Boston Consulting Group (BCG), "The Impact of GenAI on Electricity: How GenAI is Fueling the Data Center Boom in the U.S." https://www.linkedin.com/pulse/impact-genai-electricity-how-fueling-data-center-boom-vivian-lee/. According to the study, MISO, CAISO, PJM, and the Southeast will be home to the largest data center capacity by 2027.

12 Eric Masanet, et al., "Recalibrating global data center energy-use estimates." *Science* 367, 984–986(2020). Via https://www.science.org/doi/10.1126/science.aba3758.

13 David Kidd, "The Data Center Capital of the World Is in Virginia." *Governing.com*. Via https://www.governing.com/infrastructure/the-data-center-capital-of-the-world-is-in-virginia#

14 Dominion Energy, "Dominion Energy 2023 15-Year Data Center Plan." https://www.pjm.com/-/media/committees-groups/subcommittees/las/2023/20231018/20231018-item-03a---dominion-large-load-request.ashx.

15 PJM, "PJM Load Forecast Report," January 2024. https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx.

16 S&P Global Market Intelligence, "Power of AI: Wild predictions of electricity demand from AI put industry on edge." https://www.capitaliq.spglobal.com/apisv3/spg-webplatform-core/news/article?KeyProductLinkType=2&id=77859037.

17 Coldwell Banker Richard Ellis (CBRE), "North America Data Center Trends H2 2022." *CBRE*. Via https://www.cbre.ca/insights/reports/north-america-data-center-trends-h2-2022.

18 The International Energy Agency's 2024 Electricity Report assumes data center load to be roughly 40% for processors, 40% for cooling, and 20% for the associated IT equipment. See: Eren Cam et al., "Electricity 2024: Analysis and Forecast to 2026." International Energy Agency. Via https://www.iea.org/reports/electricity-2024.

leading technology company has recently introduced a DR pilot to decrease electricity consumption in its data centers during periods of high stress on local power grids, which involves shifting non-urgent computing tasks to different times and locations without affecting the regular services used by customers.[19] Sidewalk Infrastructure Partners has recently issued a "call to action" report to increase data center load flexibility, foreshadowing additional progress in this area.[20] We discuss DR programs further in Section II.C3.

A2. New Large Industrial Loads

Ambitious climate policy, coupled with industrial and technology policies, have led to a surge in economic activity across a number of sectors, many of which require large energy inputs. Such activity includes the onshoring of new manufacturing facilities that were previously located overseas, as well as the electrification of industrial processes that historically have utilized fossil fuels to meet their energy needs; new industry, such as hydrogen production through electrolysis; indoor agriculture; and development of CDR technologies. Although the timing and magnitude of these drivers will vary by region, these activities will result in large demand increases for electricity in the coming years.

ONSHORING AND INDUSTRIAL ELECTRIFICATION

Recent policies aim to accelerate the onshoring of manufacturing and industrial electrification, both activities that would lead to the increase of more Type A loads. For example, through the Inflation Reduction Act (IRA) of 2022, the US has authorized over $350 billion in federal funds for clean energy development and manufacturing through tax credits.[21] Often tied to domestic manufacturing content, these tax incentives will motivate companies to relocate their facilities to the US. In addition, the CHIPS and Science Act focuses on onshoring semiconductor manufacturing and innovation processes, spurring approximately $210 billion in private investment in domestic semiconductor production facilities. The Infrastructure Investment and

[19] Varun Mehra and Raiden Hasegawa, "Supporting Power Grids with Demand Response at Google Data Centers." *Google Cloud*. Via https://cloud.google.com/blog/products/infrastructure/using-demand-response-to-reduce-data-center-power-consumption

[20] SIP, "Data Center Flexibility: A Call to Action." Via https://static1.squarespace.com/static/65e8fa08c461de679be90d0d/t/65ef4eadc4b8d53b84ccfd9e/1710182063168/SIP_Data+Center+Flexibility+-+A+Call+to+Action.pdf.

[21] US Senate Democrats, "Inflation Reduction Act One Page Summary." Via https://www.democrats.senate.gov/imo/media/doc/inflation_reduction_act_one_page_summary.pdf.

Jobs Act (IIJA) prioritizes investments in American infrastructure, with billions of dollars going to the rail industry, highways, airports, and other infrastructure projects.[22, 23]

While the full impact of these policies will not be felt immediately, there are already a significant number of plans to construct new manufacturing facilities. Between January 1, 2021, and March 1, 2023, companies announced more than 150 onshored manufacturing facilities in the US, representing an annual electricity usage of over 13,000 GWh per year, or 1.5 GW in new demand, assuming a 100% load factor.[24] Many of the new facilities will focus on producing components for the clean energy supply chain, such as battery cells, photovoltaic cells, and metal refining processes.

The impact varies by region. The Southeast emerges as the favored region for onshoring activity, attracting disproportionally large investments, particularly in the EV and battery industries. In contrast, the Upper Midwest and New England have experienced essentially no industrial demand growth to date. Figure 4 below illustrates the geographic variation in the load impacts from these announcements. Assuming the industrial sector's current electric demand is 116 GW, the additional load represents a near-term CAGR of about 1% through 2025.[25] However, this may be an underestimate given the pace at which new facilities are announced and the largely untapped potential for industrial electrification.

Beyond the onshoring of manufacturing, climate policies have led to increased electrification of existing domestic manufacturing processes. This electrification occurs because of technological improvements that allow historically fossil-powered processes to be completed using electricity, and it is encouraged by incentives that make electricity more economical than fossil fuels for many end-users. The impact of industrial electrification could be very large; for

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22 Semiconductor Industry Association, "CHIPS-Science-Act-Fact-Sheet.pdf." *Semiconductors.org*. Via https://www.semiconductors.org/wp-content/uploads/2023/08/CHIPS-Science-Act-Fact-Sheet.pdf

23 The White House, "Fact Sheet: The Bipartisan Infrastructure Deal." *Whitehouse.gov*. November 2021. Via https://www.whitehouse.gov/briefing-room/statements-releases/2021/11/06/fact-sheet-the-bipartisan-infrastructure-deal/.

24 Electric Power Research Institute, "Reindustrialization, Decarbonization, and Prospects for Demand Growth." *EPRI*, July 2023, pg. 2. https://www.epri.com/research/products/000000003002027930. We note that the 100% load factor (flat load profile throughout the year) assumption is a high estimate.

25 Current industrial energy consumption from US Energy Information Administration, "Annual Energy Outlook 2023." Via https://www.eia.gov/outlooks/aeo/data/browser/#/?id=2-AEO2023&cases=ref2023&sourcekey=0.

example, a DOE study indicates fully electrifying industrial processes could double electricity demand in the US.[26]

FIGURE 4: PEAK LOAD IMPACT (MW) FROM NEW ONSHORED MANUFACTURING ANNOUNCEMENTS BY ELECTRICITY MARKET REGION TO DATE

	EV/ Battery	Fuel / Plastic/ Chemical	Metals	Semiconductor/ Electronic	Solar	Wind	Transportation	Other	Total
Southeast	327.3	34.1	8.3	-	25.5	-	-	0.4	**395.6**
Mountain-South	30.3	2.0	-	170.9	1.6	-	-	-	**204.8**
Ohio Valley	98.6	4.1	78.7	-	3.5	-	0.0	0.0	**185.0**
MISO-East	127.5	20.0	-	-	-	-	0.0	-	**147.5**
South Atlantic	129.8	0.0	1.3	-	1.0	-	-	-	**132.1**
California	32.3	-	54.8	0.1	9.3	-	-	-	**96.5**
Mid-Atlantic	-	78.9	0.2	-	0.5	-	6.5	5.5	**91.6**
Florida	-	-	-	85.0	-	-	-	-	**85.0**
MISO-South	2.3	52.4	27.4	-	-	-	-	0.0	**82.1**
New York	12.5	-	-	0.4	0.4	46.8	-	-	**60.1**
Texas	0.1	52.1	-	-	1.5	-	-	-	**53.7**
SPP	22.8	-	-	-	-	-	0.1	-	**22.9**
Pacific	11.6	-	-	-	-	-	-	-	**11.6**
MISO-North	-	-	0.6	-	0.2	-	-	2.0	**2.8**
New England	-	-	0.0	-	-	-	-	2.0	**2.0**
Mountain-North	0.6	-	-	-	-	-	-	-	**0.6**
Total (MW)	**795.7**	**243.6**	**171.3**	**256.4**	**43.5**	**46.8**	**6.6**	**10.0**	**1,573.9**

Sources and notes: Table adapted from Electric Power Research Institute, "Reindustrialization, Decarbonization, and Prospects for Demand Growth," July 2023, pg. 3. Some values show up as 0.0 due to rounding. Mid-Atlantic region includes DE, MD, NJ, PA, and Washington, DC; South-Atlantic includes NC, SC, and VA; Southeast includes AL, GA, MS, and TN; Ohio Valley includes KY, OH, and WV; MISO-East includes IL, IN, and MI; MISO-South includes AR, LA, and MO; MISO-North includes IA, MN, ND, and WI; Mountain-North includes CO, ID, MO, and WY; Mountain-South includes AZ, NV, NM, and UT; Pacific includes OR and WA; SPP includes KS, OK, NE, and SD.

In all likelihood, not all industrial processes will be electrified as the US transitions to a clean economy, as some industrial processes will still be carried out by a combination of clean fuel resources and traditional fossil fuels combined with CDR processes. However, there is significant interest in adopting industrial heat pumps, electric boilers, and thermal storage for steam – all of which would substantially increase demand for electricity. Studies looking at the most economically efficient decarbonization pathways for the US indicate annual electricity

[26] United State Department of Energy, "Pathways to Commercial Liftoff: Industrial Decarbonization." September 2023, pg. 70. Via https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf

consumption from the industrial sector will grow to 100,000 GWh–900,000 GWh by 2050, which is up to over 20% of the US's current annual electricity consumption.

HYDROGEN PRODUCTION

Clean hydrogen is emerging as an attractive low-carbon alternative fuel and energy carrier that can be key to reducing GHG emissions from sectors that are difficult to decarbonize, such as heavy industry and long-distance transport. Globally, more than 550 GW of installed hydrogen electrolyzer capacity would be needed by 2030 for the world to be on pace to achieve net zero emissions by 2050.[27] For reference, 550 GW is roughly three-quarters of the peak demand for electricity for the entire US today. This level of growth would be dramatic: the current global cumulative capacity of electrolyzers hovers around 3 GW. The US is still a minor player with less than 3% (0.07 GW) of global electrolyzer capacity, with an additional 3.6 GW of planned capacity as of May 2023.[28] As explained further below, electrolyzers are not included in most current electricity load forecasts.

The US federal government has made substantial investments in domestic clean hydrogen production, aiming to scale the nascent industry to about 10 million metric tons per year by 2030.[29] To support these Type A loads, the DOE estimates that the industry could require as much as 200 GW of new renewable generation across the country. By 2050, production could scale by as much as 50 times its current level.[30] At the center of this effort are the seven regional clean hydrogen hubs, targets of the $7 billion funding that the IIJA authorized to jumpstart the market for clean hydrogen (see Figure 5 below).[31]

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[27] Francesco Pavan, "Electrolysers," International Energy Agency. Via https://www.iea.org/energy-system/low-emission-fuels/electrolysers.

[28] US Department of Energy, "Electrolyzer Installations in the United States." *Energy.gov.* Via https://www.energy.gov/eere/fuelcells/articles/electrolyzer-installations-united-states.

[29] US Department of Energy, "The Pathway to: Clean Hydrogen Commercial Liftoff." *Energy.gov*. Via https://liftoff.energy.gov/clean-hydrogen/.

[30] There is also investment into pink hydrogen (produced using nuclear energy). The nuclear plants involved in the proposed projects have an average remaining operating license of about 17 years. The hydrogen production volume is expected to be too small have material impact on future extension decisions. *See* Figueroa, Josh, et al., "DOE Regional Clean Hydrogen Hubs Program (H2Hubs)." *The Brattle Group*. Via https://www.brattle.com/wp-content/uploads/2023/12/DOE-Regional-Clean-Hydrogen-Hubs-Program-H2Hubs.pdf.

[31] The White House, "Biden-Harris Administration Announces Regional Clean Hydrogen Hubs to Drive Clean Manufacturing and Jobs." *Whitehouse.gov*. October 2023. Via https://www.whitehouse.gov/briefing-room/statements-releases/2023/10/13/biden-harris-administration-announces-regional-clean-hydrogen-hubs-to-drive-clean-manufacturing-and-jobs/.

FIGURE 5: HYDROGEN HUBS SELECTED TO RECEIVE DOE FUNDING

DOE Project Name	States	Type of Hydrogen	DOE Funds	Estimated Production	Target Sectors
Appalachian Hydrogen Hub	WV, OH, PA	Green, Blue, Biohydrogen	$925 million	N/A	Ammonia, chemicals, industrial, heavy-duty transport, mining, data centers, distribution centers, Sustainable Aviation Fuel (SAF), gas utility blending, residential fuel cells
California Hydrogen Hub	CA	Green, Biohydrogen	$1.2 billion	6,820 mtpy in 2023; up to 17 million mtpy by 2045	Heavy-duty transport, power generation, port operations
Gulf Coast Hydrogen Hub	TX, LA	Green, Pink, Blue	$1.2 billion	1.8 million mtpy	Ammonia, refining and petrochemicals, industrial, heavy-duty transport, transit authorities, ports, SAF, marine fuel (eMethanol), power generation
Heartland Hydrogen Hub	MT, ND, SD, MN, WI	Green, Pink, Blue	$925 million	N/A	Fertilizer, industrial, SAF, power generation, gas LDC blending
Mid-Atlantic Hydrogen Hub	PA, DE, NJ	Green, Pink, Blue	$750 million	990 thousand mtpy by 2032	Industrial, refineries, heavy-duty transportation, transit authorities
Midwest Hydrogen Hub	IL, IN, MI	Green, Pink, Blue	$1 billion	N/A	Agriculture, industrial, manufacturing, heavy-duty transportation, SAF, gas utility blending
Pacific Northwest Hydrogen Hub	WA, OR, MT	Green	$1 billion	N/A	Fertilizer, refiners, industrial, heavy-duty transport, SAF, marine fuel, long-duration energy storage

Note: "Mtpy" refers to metric tons (tonnes) per year. Green hydrogen is from renewable resources, pink hydrogen is from nuclear, and blue hydrogen is from natural gas with carbon capture. See DOE Regional Clean Hydrogen Hubs Program (H2Hubs) (brattle.com).

Among the seven hubs, California is expected to be the largest, with a forecasted production of 17 million tonnes of hydrogen per year by 2045. The state would need nearly 300 GW of renewable generation to achieve this goal. For reference, the state's current total electric generation capacity is about 85 GW, and only a third of that is solar or wind.[32] Recognizing the major investments in grid infrastructure needed to develop the hub, the state directed the

[32] *See* Josh Figueroa, et al., "DOE Regional Clean Hydrogen Hubs Program (H2Hubs)." *The Brattle Group*. Via https://www.brattle.com/wp-content/uploads/2023/12/DOE-Regional-Clean-Hydrogen-Hubs-Program-H2Hubs.pdf.

California Energy Commission (CEC) as part of its 2023 and 2025 *Integrated Energy Policy Reports* to study and model the potential growth of hydrogen and the role that the fuel can play in decarbonizing the electric and transportation sectors.[33]

INDOOR AGRICULTURE

Indoor agriculture, particularly in regions where recreational cannabis cultivation is legal, can pose challenges to the existing grid. As Type A loads, cannabis cultivation requires high energy input to provide the necessary light spectrum, environmental control, automated irrigation systems, and CO_2 enrichment systems needed to create an ideal environment for plant growth.

Over half of all cannabis growers operate exclusively indoor facilities, and these indoor growth facilities consume 18 times more energy than outdoor facilities.[34] Indoor cannabis cultivation can consume approximately 150 kWh per square foot annually, 12 times that of the average energy consumption of a commercial building in the US.[35] This translates to annual energy usage of 0.75 GWh for small facilities and over 5 GWh for larger users.[36] According to one estimate, cannabis cultivation currently accounts for 1% of the annual electricity consumption in the US, with projections indicating an anticipated increase to 3% by 2035.[37]

As of September 2022, there were over 13,000 legal cannabis farms licensed in the US, including both indoor and outdoor facilities (see Figure 6 below).[38] Colorado, Oregon, and California are home to some of the largest crop concentrations in the country. According to a

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[33] The 2023 draft report explores how much hydrogen production would be required to replace all energy that the CEC's 2022 Scoping Plan Update anticipates coming from fossil fuels in the energy sector in 2045 and fossil fuel consumption, including vehicles, air, sea, and rail, in the transportation sector in 2040. The 2023 draft study finds that 1.5 million tons of hydrogen would be enough to power all gas generation in 2045, an additional 1 million of tons would be required for the transportation sector, and in total would require nearly 50 GW of new renewable capacity. *See* California Energy Commission Staff, "2023 Integrated Energy Policy Report." *California Energy Commission*. Via https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2023-integrated-energy-policy-report.

[34] Lee Hoffman and Liana Feinn, "Putting the 'Green' in Renewable Energy at Cannabis Grow Facilities." *Pullman & Comley*. May 2023. Via https://www.pullcom.com/newsroom-publications-Putting-the-Green-in-Renewable-Energy-at-Cannabis-Grow-Facilities.

[35] US Energy Information Administration. "2018 Commercial Buildings Energy Consumption Survey (CBECS)." Via https://www.eia.gov/consumption/commercial/data/2018/ce/pdf/c14.pdf.

[36] American Public Power Association. "Managing New Electric Loads in a Challenging Industry." *American Public Power Association*, p. 28. Via https://www.publicpower.org/system/files/documents/Managing-New-Electric-Loads-Cryptocurrency-Mining-Cannabis-Facilities.pdf.

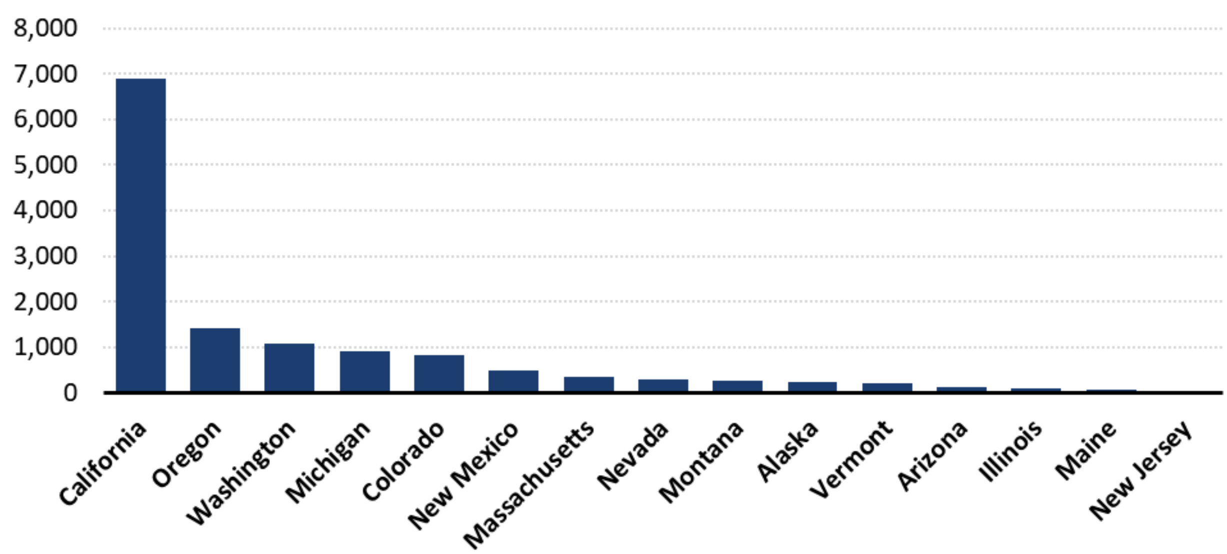
[37] Hoffman and Feinn, "Putting the 'Green' in Renewable Energy at Cannabis Grow Facilities."

[38] David Downs and Amelia Williams, et al., "Leafly Cannabis Harvest Report 2022." *Leafly*. Via https://leafly-cms-production.imgix.net/wp-content/uploads/2022/11/04104710/Leafly-Crops-Report-2022.11.4corrected.pdf.

2023 study, the US cannabis market is expected to expand at a compound annual growth rate of 14.2% from 2023 to 2030.[39]

Because of the delicate requirements for cultivating high-quality plants, energy demand from indoor agriculture facilities is generally not interruptible.[40] These facilities therefore cannot operate flexibly to help optimize the operation of the grid, especially at the distribution level. Efforts to address the energy impact of indoor cannabis cultivation are underway and include energy-efficient lighting and climate control innovations, as well as technological improvements to enable cultivators to pursue high yields with lower overall energy consumption. Going forward, stringent regulatory frameworks related to environmental standards in cannabis cultivation may lead to further changes in energy usage as cultivators adjust their practices to comply.

FIGURE 6: NUMBER OF ACTIVE LEGAL CULTIVATION LICENSES BY STATE



Source: Leafly Cannabis Harvest Report 2022.

39 Grand View Research. "U.S. Cannabis Market Size, Share & Trends Analysis Report By End-use (Medical, Recreational, Industrial), By Source (Marijuana, Hemp), By Derivative (CBD, THC), And Segment Forecasts, 2023 - 2030." *Grand View Research*. Via https://www.grandviewresearch.com/industry-analysis/us-cannabis-market.

40 American Public Power Association, "Managing New Electric Loads in a Challenging Industry." *American Public Power Association*. Via https://www.publicpower.org/system/files/documents/Managing-New-Electric-Loads-Cryptocurrency-Mining-Cannabis-Facilities.pdf.

CARBON DIOXIDE REMOVAL

A growing scientific consensus underscores the important role of CDR solutions in any comprehensive strategy to achieve net-zero carbon emissions.[41] CDR methods range from nature-based carbon sequestration solutions (e.g., remove CO_2 from the atmosphere by increasing the natural carbon stocks held in trees, soils, wetlands, and other natural areas) to engineered solutions (e.g., use technology to remove CO_2 from the air and ocean and store it in sediment, rock minerals, or geological formations).

Of these, direct capture of atmospheric CO_2 via chemical reactions is the most energy-intensive: capturing a ton of CO_2 requires around 1.2 MWh of electricity.[42] For context, a natural gas plant generates about 0.5 tons of CO_2 per MWh, less than half of what is required for direct capture. If the direct capture is done through solar, each MWh produced from natural gas-fueled generation would require around 20 acres of solar panels powering direct air capture to be net zero emissions.[43] Nonetheless, direct air capture has attracted significant investments, in part because of the technology's high carbon sequestration potential and its scalability. While technology deployment is nascent, it is prudent for load forecasters to monitor progress in this space.

A3. Cryptocurrency Mining

Cryptocurrency mining is a relatively new load type that started around the mid-2010s. It is the process by which networks of computers generate and release new currencies and verify new transactions. Cryptocurrency mining facilities typically operate around the clock with high load factors, and they require a large amount of electricity to power and cool their equipment.

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41 Intergovernmental Panel on Climate Change . "Global Warming of 1.5 °C: An IPCC Special Report on the Impacts of Global Warming of 1.5 °C Above Pre-industrial Levels and Related Global Greenhouse Gas Emission Pathways, in the Context of Strengthening the Global Response to the Threat of Climate Change." 2018.

42 Mark Dwortzan, "Affordable direct air capture: myth or reality?" *MIT Joint Program on the Science and Policy of Global Change*. Via https://globalchange.mit.edu/news-media/jp-news-outreach/affordable-direct-air-capture-myth-or-reality.

43 Each MWh of natural gas generation produces around half a ton of emissions. *See* Energy Information Administration, "How Much Carbon Dioxide is Produced per Kilowatthour of U.S. Electricity Generation?" Via https://www.eia.gov/tools/faqs/faq.php?id=74&t=11). Assuming a capacity factor of 80%, each MW of capacity generates 3,504 tons of emissions each year which in turn would require 4,204 MWh of renewable energy. A 1MW solar farm sits on around 10 acres of land (*see* Jessi Wyatt and Maggie Kristian, "The True Land Footprint of Solar Energy." *Great Plains Institute*. Via https://betterenergy.org/blog/the-true-land-footprint-of-solar-energy/). Assuming a solar capacity factor of 25% would mean 19.2 acres of land would be needed.

Power supply costs are the largest component of cryptocurrency mining facilities' operating costs and are a key consideration when deciding where to site new facilities.[44] Because the purpose of cryptocurrency mining loads is to generate new currencies rather than serve the needs of third-parties, as other types of loads often do, it can more easily ramp its demand up and down in response to changes in market conditions, such as cryptocurrency and electricity prices.

The flexibility of cryptocurrency mining load is not limited to its operations. They tend to have greater location flexibility relative to other types of load. Cryptocurrency mining facilities can be constructed in trailers or shipping containers and moved to parts of the system with excess capacity and favorable power prices. These facilities also require a relatively small number of employees to operate, making it relatively easier to relocate. A typical cryptocurrency company only has approximately 18 full-time employees, including remote employees not at the mining facility.[45]

Cryptocurrency mining load's demand response capability and location flexibility can provide benefits to electric utilities – for example, by using excess generation or transmission capacity on the system. At the same time, these Type A loads can create challenges for planning and securing the capacity and energy needed to serve them.[46] In areas of the country that experience long generation interconnection queues, the process of adding new resources to the grid has lengthened substantially and become more costly. On the other hand, relative to traditional data centers and other large loads such as a manufacturing facility, cryptocurrency mining operations can be "mobile," introducing another dimension of uncertainty in the

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44 Will Canny, "Only Bitcoin Miners With Low Power Costs and High Sustainable Energy Mix Will Survive: JP Morgan," CoinDesk, June 23, 2023. Via https://www.coindesk.com/business/2023/06/23/only-bitcoin-miners-with-low-power-costs-and-high-sustainable-energy-mix-will-survive-jpmorgan/.

45 American Public Power Association, "Managing New Electric Loads in a Changing Industry," April 2023, p. 16. Via https://www.publicpower.org/system/files/documents/Managing-New-Electric-Loads-Cryptocurrency-Mining-Cannabis-Facilities.pdf. Note that the study found the number of full-time employees ranged from zero to 110 with a median of 18 employees.

46 For example, setting up a cryptocurrency mining facility may take 9 to 12 months or longer; *see* Mathew Mazzuchi, Xander Hector, Spencer Anderson, and Houlihan Lakey, "Cryptocurrency Mining for Power Suppliers." *Project Finance NewsWire*. December 2021, pp. 1-4. Norton Rose Fulbright. Via https://www.projectfinance.law/media/5690/pfn_1221.pdf. For example, in CAISO, a reasonable lead time for new transmission additions, particularly given the substantial investment involved, would be 8 to 10 years. In all regions, the typical duration from interconnection request (IR) to interconnection agreement (IA) was 35 months in 2022. 2022–2023 Transmission Plan. *See also:* California ISO, "2022-2012 Transmission Plan." Via https://www.caiso.com/InitiativeDocuments/Revised-Draft-2022-2023-Transmission-Plan.pdf; Lawrence Berkeley National Laboratory. "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2022." *Lawrence Berkeley National Laboratory*. Via https://emp.lbl.gov/sites/default/files/queued_up_2022_04-06-2023.pdf.

planning process, and complicated cost recovery questions arise in the event that such loads depart. The ability of cryptocurrency mining loads to quickly shut down and move its operations exacerbates the utility's potential stranded asset risk.

Today, cryptocurrency load customers consume approximately 0.9% to 1.7% of total US electricity usage; their electricity usage is assumed to be comparable with the electricity usage of all US conventional (i.e., non-cryptocurrency asset) data centers.[47] However, projecting future electricity demand from cryptocurrency mining is difficult for several reasons – starting with the fact that there are multiple types of cryptocurrencies. This leads to uncertainties about the number of cryptocurrency types that will emerge, how popular they will become, and which consensus mechanisms they will adopt.

Second, the construction of new cryptocurrency mining facilities and operations of these facilities are driven by macroeconomic factors outside of a utility's control. Compared to traditional loads, their growth rates are also unpredictable. For example, Basin Electric Power Cooperative had no sizable cryptocurrency mining load through the first half of 2022. This demand grew quickly over the last quarter of 2022 and reached approximately 200 MW by the middle of 2023. Third, their facilities' locational flexibility and ability to ramp up or down operations in response to market dynamics make forecasting even harder. Perhaps because of these factors, there are not many projections for cryptocurrency mining loads. NERC, in its *2023 Long Term Reliability Assessment*, states that "ERCOT continues to see a large volume of interconnect requests from cryptocurrency mining: 9 GW have had planning studies approved of 41 GW that are currently requested." Texas accounts for almost 30% of current cryptocurrency mining activity in the US today.

Given these factors, and the fact that the cryptocurrency landscape is constantly evolving, it is likely that – in the coming years – future load growth will continue to be difficult for utilities to anticipate.

[47] The White House, "Climate and Energy Implications of Crypto-Assets in the United States," September 2022, p.15. Via https://www.whitehouse.gov/wp-content/uploads/2022/09/09-2022-Crypto-Assets-and-Climate-Report.pdf.
As of August 2022, electricity consumption of cryptocurrency mining was estimated to be 36 to 66 billion kWh per year, compared to 72 billion kWh per year for all US conventional (i.e., non-cryptocurrency-asset) data centers.

B1. Electric Vehicles and Other Mobility

The electrification of the transportation sector, most notably passenger cars and trucks, will have a major impact on future electricity consumption. In 2022, about 1% of all light-duty vehicles registered in the US were EVs.[48] While light-duty EV stock has grown rapidly over the last decade, expanding from under 100,000 vehicles in 2012 to 3 million in 2022, the electrification potential in the transportation sector is greater than in other sectors.[49]

As shown in Figure 7 below, as of 2016, around 50% of all energy consumed in the residential and commercial building sectors already came from electricity, while only 0.1% of energy consumption for transportation came from electricity.[50] In addition, the transportation sector surpassed the electric power sector as the largest carbon-emitting sector in 2017, putting a spotlight on the sector as decarbonization efforts intensify.[51]

Electrification is also an emerging pathway to decarbonize other modes of transportation. For instance, there is a growing market for electric-powered shorter-haul flights, with over 60 companies currently developing some form of electric air travel as a way to reduce emissions from the aviation industry.[52] Major airlines such as Air Canada have promised electric-powered domestic flights in the next five years, though the low energy density with battery storage has made long-haul flights much more challenging to electrify, and clean fuels such as hydrogen remain the primary solution proposed.

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[48] US Department of Energy, "Alternative Fuels Data Center: Vehicle Registration Counts by State." Via https://afdc.energy.gov/vehicle-registration?year=2022.

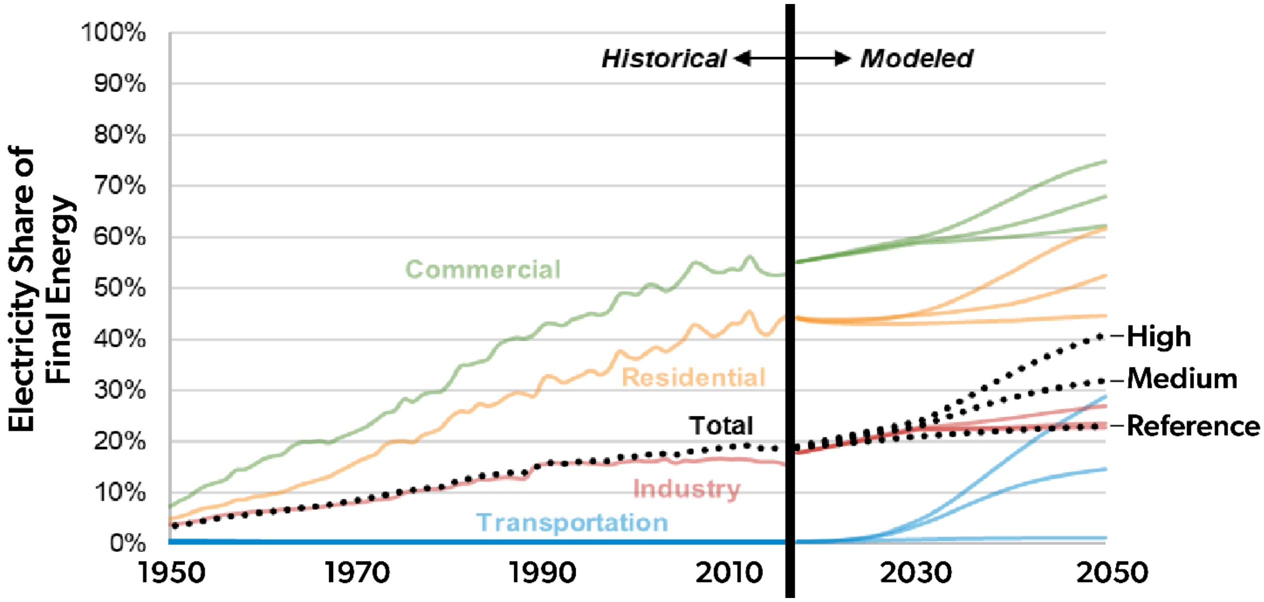
[49] International Energy Agency, "Global Electric Car Stock, 2010-2022." Via https://www.iea.org/data-and-statistics/charts/global-electric-car-stock-2010-2022.

[50] Trieu Mai, Paige Jadun, Jeffrey Logan, et al., "Electrification Futures Study." *National Renewable Energy Laboratory*, 2018. Via https://www.nrel.gov/docs/fy18osti/71500.pdf.

[51] US Environmental Protection Agency, "Fast Facts: 1990–2017 National-Level U.S. Greenhouse Gas Inventory." Via https://www.epa.gov/sites/default/files/2019-04/documents/2019_fast_facts_508_0.pdf.

[52] Coco Liu, "It's Boom Times for Startups Trying to Electrify Aviation." *Bloomberg*. Via https:/www.bloomberg.com/news/articles/2023-11-10/when-will-we-get-electric-airplanes?leadSource=uverify%20wall.

FIGURE 7: ELECTRICITY SHARE OF FINAL ENERGY CONSUMPTION



Source and notes: Moderate Technology Advancements are shown. Historical and modeled data have slightly different scopes and, therefore, are not fully comparable. Notably, modeled data omits fossil fuel extraction and refining. However, differences amount to only a few percentage points between the 2016 historical data and the 2017 modeled data. Visual adjustments and interpolations were used for the modeled data (for 2017–2030) in the figure shown. From NREL's Electrification Futures Study, page xvi.

Similarly, there is potential for electrifying short-distance ferries, given that the energy density of storage is currently not good enough to work in long-distance international shipping.[53] Auxiliary services such as ports also have electrification potential, including those for cargo handling and requiring ships to use electricity from the port when docked rather than continue running their respective engines for power supply. For example, the Port of Houston consumes around 750 GWh of electricity for cargo handling equipment, and this electric consumption could increase to 1,800 GWh–3,300 GWh by 2050.[54]

The transport industry's electricity use is projected to become a substantial fraction of total electric consumption. The National Renewable Energy Laboratory (NREL) estimates that by 2030, about 40% of passenger vehicle sales will be EVs, with another 20% of sales plug-in hybrid

[53] Rapid Transition Alliance, "Making waves: Electric ships are sailing ahead." Via https://rapidtransition.org/stories/making-waves-electric-ships-are-sailing-ahead/.

[54] Ellen Schenk, et al., "Macroeconomic and Environmental Impacts of Port Electrification: Four Port Case Studies." *US Maritime Administration*. Via https://www.maritime.dot.gov/sites/marad.dot.gov/files/2020-09/Port%20Electrification%20MARAD%20Final%20Report.pdf.

vehicles.[55] NREL finds that the additional load from these vehicles will be 750,000 GWh by 2050 and will increase peak hourly load by 150 GW. Various studies corroborate these estimates, finding that annual EV energy usage in the US could rise to around 500 TWh by 2040 (a 1,850% increase from 2023 usage levels)[56] and as high as 1,140 TWh by 2050 (representing 26% of total US electric consumption).[57]

Medium- and heavy-duty vehicles only make up 10% of the US vehicle stock but contribute 28% of emissions from all vehicles because of their higher load capacity and greater vehicle miles traveled.[58] Long-haul vehicles use more energy per mile and require larger batteries, making them more challenging to electrify. However, there has been progress towards electrification, especially for school and transit buses that have shorter driving distances. Some states are requiring manufacturers to sell a percentage of zero-emission trucks as part of their sales, and national policies, such as the IIJA and the IRA, have promoted electrification within this sector.[59] Medium- and heavy-duty EVs, which typically go into service (and are also replaced) as a fleet, will lead to different load forecasting challenges from light-duty vehicles owned by individuals or small businesses.

While EVs represent a significant load driver and will also push peak load higher, the exact magnitude of their net impact on peak load is less clear. For example, CEC expects that EVs will be responsible for around 8% of energy consumption by 2035, contributing 5% to peak energy demand.[60] In contrast, the California Public Utility Commission (CPUC) projects that EV loads

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[55] Arthur Yip, Christopher Hoehne, Paige Jadun, et al., "Highly Resolved Projections of Passenger Electric Vehicle Charging Loads for the Contiguous United States." *National Renewable Energy Laboratory*, 2023. NREL/TP-5400-83916. Via https://www.nrel.gov/docs/fy23osti/83916.pdf.

[56] PricewaterhouseCoopers (PwC), "EV charging growth: How can power and utilities prepare?" Via https://www.pwc.com/us/en/industries/energy-utilities-resources/library/ev-charging-power-and-utilities.html.

[57] Peter Fox-Penner, Will Gorman, and Jennifer Hatch, "Long-term U.S transportation electricity use considering the effect of autonomous-vehicles: Estimates & policy observations." *Energy Policy 122*, issue C, 2018; pp. 203-213. Via https://econpapers.repec.org/article/eeeenepol/v_3a122_3ay_3a2018_3ai_3ac_3ap_3a203-213.htm.

[58] Moaz M. Uddin, "The Medium- and Heavy-Duty Electric Vehicle Market: Plugging into the Future Part I." *Great Plains Institute*. Via https://betterenergy.org/blog/the-medium-and-heavy-duty-electric-vehicle-market-plugging-into-the-future-part-i/.

[59] *Ibid*.

[60] California Energy Commission, "California Energy Demand Update, 2022-2035." Via https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2022-integrated-energy-policy-report-update-2.

will be responsible for a much larger 40% of peak load by 2035.[61] Some of the differences may come from the fact that the CPUC study did not consider any additional mitigation, such as dynamic rates or flexible load management strategies beyond the current status quo, and these types of strategies will be key in managing the flexible EV loads of the future. Nevertheless, the significant difference between estimates for the same state and the same year illustrates the large uncertainties involved.

EV adoption and the associated electric load will not be distributed evenly across the US due to travel behavior, vehicle preferences, technology adoption, and policy decisions. NREL and PWC both project that EV sales will be highest on the coasts, particularly in California and New England. Other areas of high growth include Colorado, Texas, and Florida. California is the frontrunner for EV sales, in part because of the state's policies supporting charging infrastructure accessibility and reducing the upfront purchase price through EV rebates.[62] In addition, EVs are suitable to the driving requirements and preferences of the state's large share of wealthy urban drivers.[63] These characteristics are shared by states that are on the front end of the EV adoption timeline.

EV charging may also follow seasonal patterns, even within a limited geographical footprint. For example, in the city of Cambridge, home to several large universities in Massachusetts, EV charging will likely peak during winter rather than the summer. At the same time, Cape Cod, known as a summer vacation destination that is less than 80 miles from Cambridge, would likely have EV charging to peak during the summer. Given this difference, the combined impact on the annual peak load of the region may not be as high as the energy consumption changes observed locally at Cambridge or Cape Cod, respectively, potentially masking the challenges that may be forthcoming.[64]

We note that while EVs can generally be considered Type B loads, concentrations of EVs in certain areas can collectively behave like large Type A loads and place severe strain on the

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[61] Kevala, Inc., "Electrification Impacts Study Part 1: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates." California Public Utilities Commission, Energy Division. Via https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K423/508423247.PDF.

[62] Alternative Fuels Data Center, "Electricity Laws and Incentives in California." *US Department of Energy*. Via https://afdc.energy.gov/fuels/laws/ELEC?state=CA.

[63] Wealthy urban areas in the Bay Area have EV adoption sales as high as 40% of all new cars. *See* Emmet White, "25% Of California Passenger Vehicle Sales Are Now Electrified." *Autoweek*. Via https://www.autoweek.com/news/a44773527/california-ev-sales-record-2023/.

[64] Sean Morash, "Evolving Grid Planning Practices for Electric Vehicles." *Energy Systems Integration Group*. Via https://www.esig.energy/event/webinar-evolving-grid-planning-practices-for-electric-vehicles/.

distribution system, especially if charging is not coordinated.[65] This may be a particular concern with medium- and heavy-duty electric vehicle fleets (e.g., electric delivery vans), whose simultaneous charging demand at a central depot could quickly overwhelm the local distribution system, even though a system-level load forecast would predict system stability.

To address this concern, some utilities, including those in New York State, have implemented distribution level forecasts to model load growth at the distribution level and effectively integrate DERs into their systems.[66] Despite these efforts, EVs may prove a challenge to the distribution system, especially as grid requirements escalate in earnest in 2030 and distribution planning processes only occur with a short-term (e.g., every other year) outlook.

Finally, while vehicle electrification will result in material load increases on the US power system, vehicle charging is flexible and, through load flexibility and careful planning, can have a reduced impact on the system.

B2. Building Electrification

The electrification of the building sector will have a sizable impact on electricity load in future years. Currently, energy needs for both residential and commercial buildings are met through a mix of fossil fuels like natural gas, oil, propane, and electricity. As shown in Figure 8 below, 46% (green sections of the left pie chart) of total end-use energy for the building sector in the US, including lighting, refrigeration, cooling, and plug loads, comes from electricity, making up approximately 436,000 GWh of annual electricity consumption, or about 50 GW assuming a flat load profile.[67] However, heating (both space and water heating) – the most energy-intensive building electricity end-use, comprising 49% (solid sections of the left pie chart in Figure 8) of the total building energy end-use – is primarily done with fossil fuels in much of the US.[68] Only

[65] EnergyHub, "From obstacle to opportunity – How managed charging can mitigate the distribution impacts of EV charging." Via https://www.energyhub.com/resource/from-obstacle-to-opportunity-how-managed-charging-can-mitigate-the-distribution-impacts-of-ev-charging/.

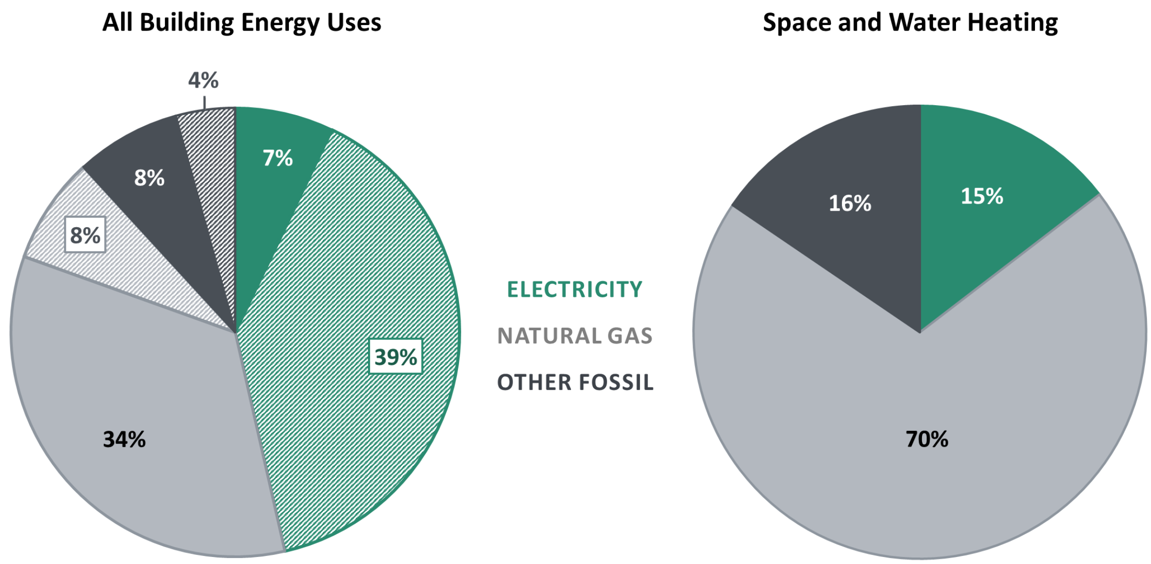
[66] Con Edison, "Distributed System Platform." Via https://www.coned.com/en/our-energy-future/our-energy-vision/distribution-system-platform; and Central Hudson, "Central Hudson Distributed System Implementation Plan." Via https://jointutilitiesofny.org/sites/default/files/CH%202020%20DSIP.pdf.

[67] Some of the remaining energy use comes from the combustion of carbon neutral materials such as wood or biofuels. *See* US Energy Information Administration, "Annual Energy Outlook 2023," Table 4 and Table 5. Via https://www.eia.gov/outlooks/aeo/tables_ref.php.

[68] US Energy Information Administration, "Annual Energy Outlook 2023," Table 4 and Table 5. Via https://www.eia.gov/outlooks/aeo/tables_ref.php.

15% (green section of the right pie chart in Figure 8) of space and water heating needs are met through electricity.

FIGURE 8: BUILDING END-USE ENERGY USE BY FUEL TYPE



Solid slices indicate energy used for space and water heating. Dashed slices represent energy being used for all other end uses.

Approximately 50% of total building end use energy is used for space or water heating.

Source and notes: Data comes from AEO 2023, Table 4 and Table 5 for both commercial and residential buildings. The numbers above do not account for losses in the electricity sector. The category labeled "other fossil" includes other fossil fuels (e.g., distillate fuel oil and propane) in addition to some carbon-neutral resources (e.g., wood and biofuels).

Studies indicate varying degrees of energy consumption and peak load growth due to building electrification. NREL's first *Electrification Futures Study* (EFS) from 2018 finds that under the High Electrification scenario, the nationwide peak load in 2050 will be approximately 33% higher than the Reference case. The EFS also emphasizes that, compared to other types of electrification, building electrification has a particularly outsized impact on peak load as a result of heating/cooling load shapes.[69] The Integration Analysis from the New York Scoping Plan projects up to 27,000 GWh of total annual growth in energy usage by 2050 due to building

[69] Trieu Mai, Paige Jadun, Jeffrey Logan, et al., "Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States," *National Renewable Energy* Laboratory, 2018; pg. xv. Via https://www.nrel.gov/docs/fy18osti/71500.pdf.

electrification, representing 19% of New York's current annual energy consumption.[70] Moreover, the study expects New York's power system to peak in the winter by 2035 as a result of heat pump adoption.

In regions with lower heating demand, building electrification will lead to comparatively lower demand growth. For example, a 2018 CEC study finds that there will be limited load growth from the building sector as a result of electrification as the state of California decarbonizes by 2050. The CEC study finds that a further increase in electrification will be offset by efficiency gains.[71] In particular, states with aggressive climate goals are likely to transition away from gas heating applications. In fact, a number of studies have found that electrifying heating use in the building sector is often a critical component of the most economically efficient decarbonization pathway.[72]

The impact of Type B loads arising from building electrification – particularly the electrification of heating and cooling processes – on the electricity sector will affect peak electricity demand more than annual electricity sales. Peak loads across the entire US are driven by either heating or cooling needs. Since cooling is already powered by electricity, the shift to electric heating will be the most important impact of building electrification. Many utilities whose customers currently rely on fossil fuel-powered furnaces or boilers will likely experience a system peak shift from summer afternoon to winter evening as the adoption of heat pumps continues in the future.

The extent to which electrification of the building sector (space heating in particular) will affect peak load and the impact it will have on the existing distribution system depends on the type of electric heating technologies customers will choose to adopt. Currently, electric resistance heaters account for the majority of electric heaters in the country. However, electric resistance heaters are highly inefficient, especially compared to electric heat pumps. A 2023 study found that conversions of existing electric resistance heaters to heat pumps have the potential to

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70 New York State Climate Action Council Scoping Plan, "Integration Analysis Technical Supplement, Section I, Annex 2: Key Drivers and Outputs." Via https://climate.ny.gov/Resources/Draft-Scoping-Plan.

71 Amber Mahone, Zachary Subin, Jenya Kahn-Lang, et al., "Deep Decarbonization in a High Renewables Future: Updated Results from the California PATHWAYS Model." *California Energy Commission*, June 2018; p. 38. Publication Number: CEC-500-2018-012. Via https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2018-012.pdf.

72 *See*, *e.g.*, Low-Carbon Resources Initiative, Electric Power Research Institute, and GTI Energy, "LCRI Net-Zero 2050: U.S. Economy-Wide Deep Decarbonization Scenario Analysis." *EPRI.com*. Via https://www.epri.com/research/products/000000003002024993; and New York State Climate Action Council Scoping Plan, "Integration Analysis Technical Supplement, Section I, Annex 2: Key Drivers and Outputs." Appendix G. Via https://climate.ny.gov/resources/scoping-plan/-/media/project/climate/files/Appendix-G.pdf.

reduce the winter peak in Texas by 10 GW by 2030.[73] 10 GW is roughly equivalent to the 2022 peak load for New York City. This indicates the potential to decrease winter peaks in parts of the country, such as the Southeast, that currently have a high penetration of electric resistance heaters.[74]

Heat pump adoption is increasing across the US as the technology continues to improve along with its economics, reflecting the financial incentives from the federal and state governments.[75] As Figure 9 below shows, heat pump sales are now higher than gas furnace sales. Southern states, which have historically observed high penetrations of electric heating technologies in the form of electric resistance, have been at the forefront of this new adoption trend, with an increasing number of customers in these states purchasing heat pumps.[76] Air-source heat pumps are now, in aggregate, the cheapest combined heating and cooling technology in the US for consumers when combining the fixed and operating costs of the systems over their expected lifetimes (see Figure 10 below).

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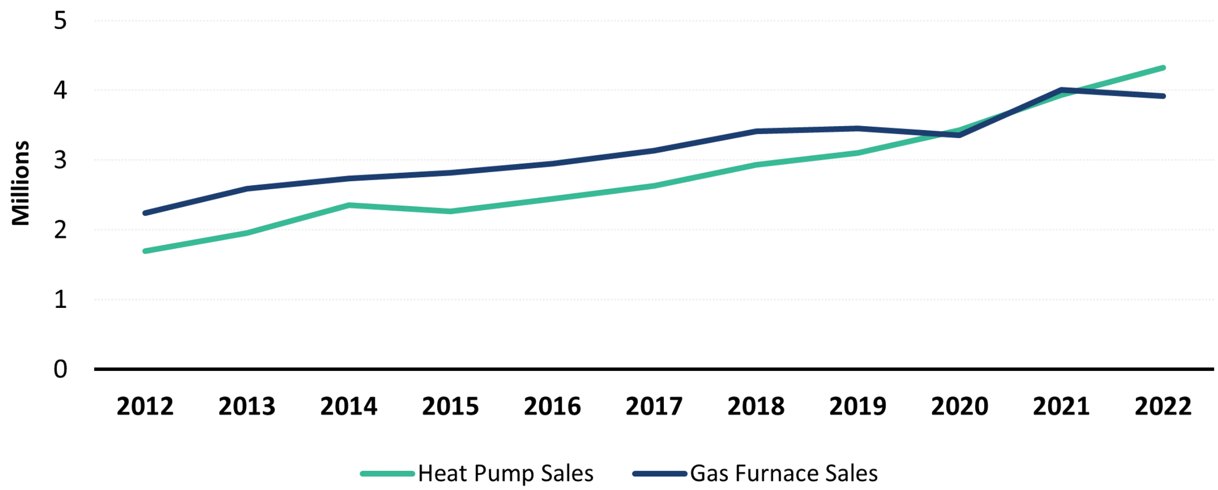
[73] American Council for an Energy-Efficient Economy, "Energy Efficiency and Demand Response: Tools to Address Texas' Reliability Challenges," August 2023, pg. 41. Via https://www.aceee.org/sites/default/files/pdfs/energy_efficiency_and_demand_response_-_tools_to_address_texass_energy_reliability_problems_-_encrypt.pdf.
The difference is specific heat pump technology may significantly impact the peak load of heating from buildings. Standard air-source heat pumps generally do not have the ability to cover all of a building's heating needs at temperatures below a certain temperature threshold. The temperature threshold is specific to an individual building as it is dependent on the efficiency of the heat pump, the customer's heating preferences, and how the heat pump was sized when installed into the home. Often, heat pumps are sized such that the heat pump is capable of meeting all of the building's cooling needs, however, when the peak heating demand is greater than the peak cooling demand for a building, as is often the case for residential building in cold climates, the customer needs to rely on backup heating from either electric resistance heaters or backup furnaces to meet their heating demand on the coldest days.

[74] Steven Nadel, "Coming Electrification Will Require the Grid to Evolve," *American Council for an Energy-Efficient Economy*. February 10, 2023. Via https://www.aceee.org/blog-post/2023/02/coming-electrification-will-require-grid-evolve.

[75] The IRA provides federal incentives for heat pumps covering 30% of the total cost in addition to an additional $8,000 tax credit for low-income households.

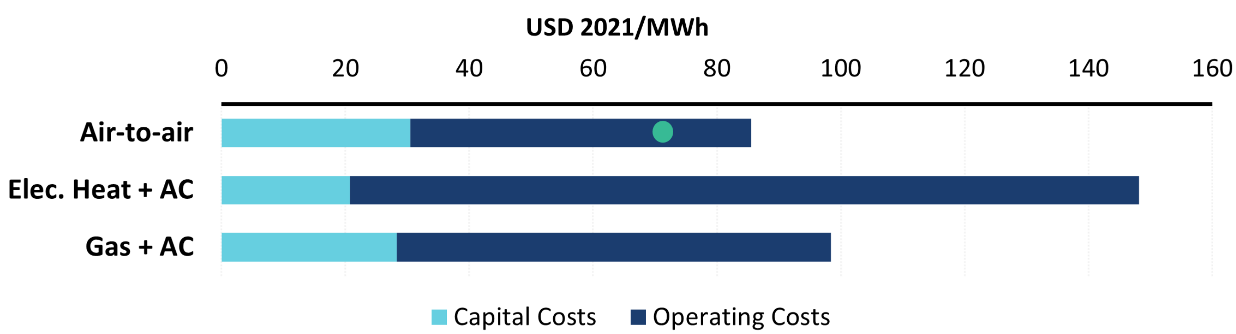
[76] Zachary Strauss, "Residential U.S. Heat Pump Market Update: Trends and Developments." *Atlas Buildings Hub*, August 2023. Via https://atlasbuildingshub.com/2023/08/18/2020-residential-u-s-heat-pump-market-update/. We note that building electrification poses particular challenges for low-income and constrained rental properties.

FIGURE 9: HEAT PUMP AND GAS FURNACE SALES FROM 2012 TO 2022



Sources and notes: *Canary Media*, Chart: Americans Bought More Heat Pumps than Gas Furnaces Last Year, February 10, 2023; original data from Air-Conditioning, Heating, and Refrigeration Institute.

FIGURE 10: LEVELIZED COST OF HEATING AND COOLING IN THE UNITED STATES



Sources and notes: International Energy Agency, The Future of Heat Pumps: Executive Summary, November 2022. Values include both the installed cost of unit operation and the operating costs over the system's lifetime. Light blue represents the capital costs, dark blue represents the operating costs, and the green dot indicates the levelized cost of ownership after adjusting for available subsidies.

C1. Distributed Generation

DG from solar and storage resources has increased significantly in recent years. As shown in Figure 11 below, the total installed distributed solar capacity grew from 7 GW to 40 GW over the 2014–2022 period, a five-fold increase.[77] For comparison, the total US renewable energy capacity in 2022 reached over 345 GW.[78]

More recently, the introduction of new utility programs and state policies fueled the expansion of distributed storage capacity.[79] At the same time, we note that changes in California's regulations over the compensation scheme for distributed solar and storage could dampen the demand for these distributed resources in what was traditionally a major market for distributed generation.[80]

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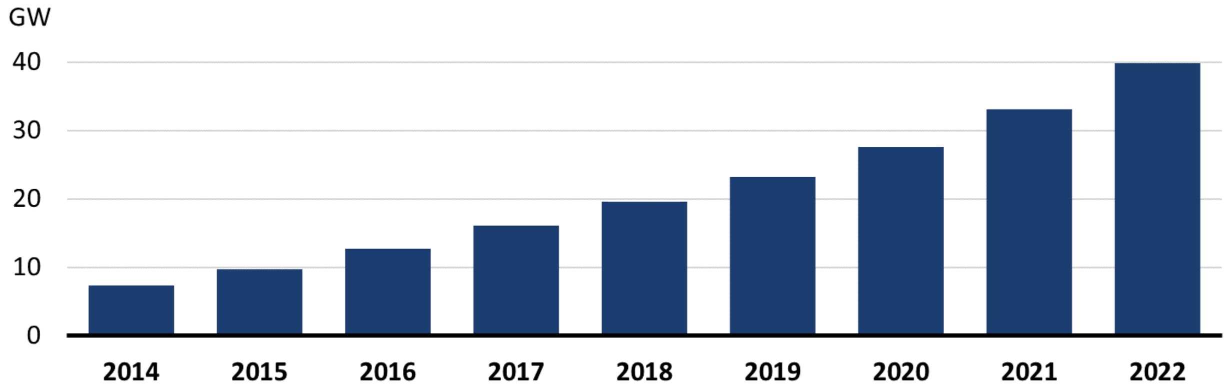
77 These values include all solar installations under 1 MW in size, typically small enough to connect directly into the distribution system.

78 National Renewable Energy Laboratory, "2014 Renewable Energy Data Book," 2014, pg. 11. Via https://www.nrel.gov/docs/fy16osti/64720.pdf; EIA, "Electric Power Monthly, Table 6.2.B. Net Summer Capacity Using Primarily Renewable Energy Sources and by State, December 2023 and 2022 (Megawatts)." Via https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_6_02_b.

79 *See* Green Mountain Power, "News Release: GMP's Request to Expand Customer Access to Cost-Effective Home Energy Storage Through Popular Powerwall and BYOD Battery Programs is Approved." August 18, 2023. Via https://greenmountainpower.com/news/gmps-request-to-expand-customer-access-to-cost-effective-home-energy-storage-is-approved/; Vermont Public Utilities Commission, Order on Case No. 23-1335-TF, August 17, 2023 pg. 3. Via https://s3.documentcloud.org/documents/23930878/135809408571174onbase-unity_4129703845439947985406349.pdf. Green Mountain Power's (GMP) residential storage program has been extremely popular amongst customers, approximately 2,500 customers are already participating in the program with a cumulative installed storage capacity of 22 MW, and there is a waitlist of over 1,000 additional customers. As a result of the popularity and the benefits distributed storage provides to the grid, the Vermont Public Utilities Commissions approved a request by GMP to remove the 5 MW annual cap on storage deployments through the program allowing broader access for GMP's customers. Additionally, other utilities such as the Jacksonville Electric Authority, NV Energy, and the Salt River Project have distributed storage incentives. State-wide distributed storage incentives are available in New York, California, Oregon, and Maryland. *See* Ashreeta Prasanna, Kevin McCabe, Ben Sigrin, and Nate Blair, "Storage Futures Study: Distributed Solar and Storage Outlook: Methodology and Scenarios." *National Renewable Energy Laboratory*. July 2021; p. 6. NREL/TP-7A40-79790. https://www.nrel.gov/docs/fy21osti/79790.pdf.

80 California Solar + Storage Association, "Impact of NEM-3 on California's Renewable Energy Progress and Solar Jobs." November 2023. Via https://static1.squarespace.com/static/54c1a3f9e4b04884b35cfef6/t/6568c37150268f14081b4895/1701364595998/State+of+the+Industry+CALSSA+11.30.23.pdf.

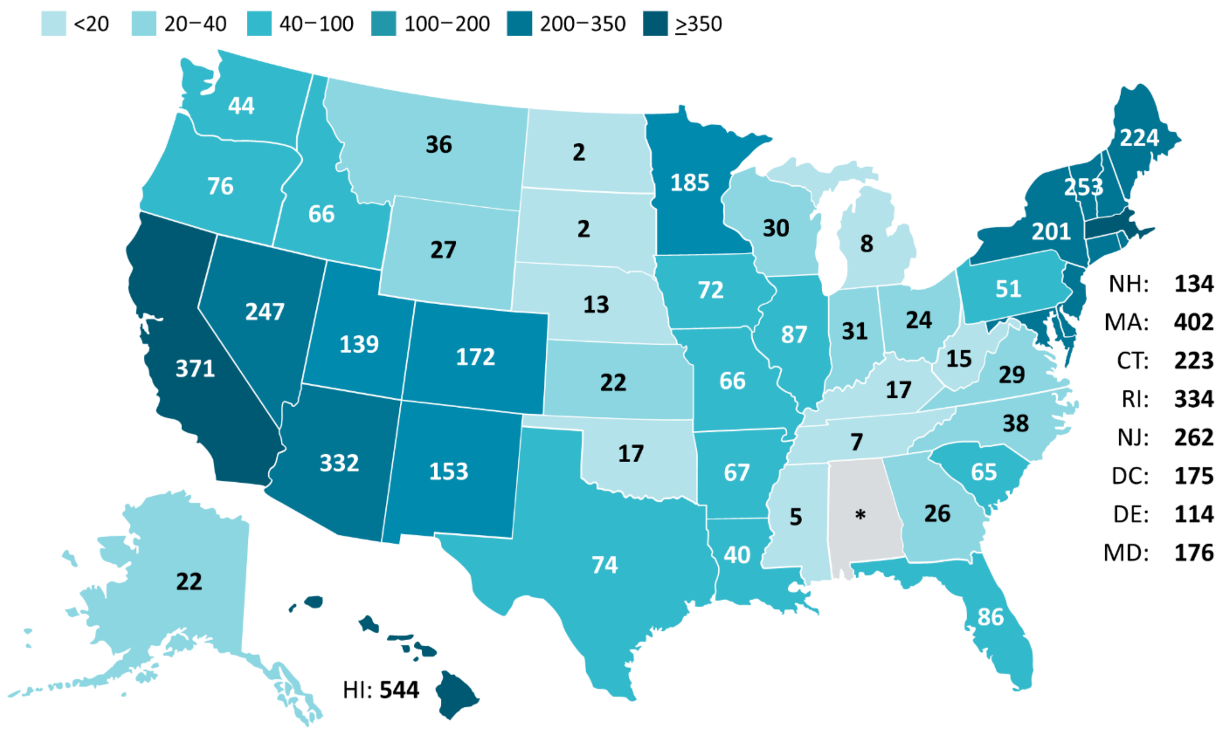
FIGURE 11: DISTRIBUTED SOLAR CAPACITY IN THE UNITED STATES FROM 2014 TO 2022



Sources and notes: EIA, "Record U.S. small-scale solar capacity was added in 2022," September 11, 2023. Small-scale solar refers to solar installations with a capacity of 1 MW or less.

The deployment of distributed solar and storage resources thus far is geographically uneven, but as the economics of these resources continue to improve, we expect adoption will be more widespread. Figure 12 below shows that as of 2022, the level of distributed solar deployment as a proportion of each state's population was highest in the West, New England, and the state of Hawaii. Indeed, areas with higher retail electricity prices tend to have higher levels of DG adoption because of the resulting shorter payback period. We also observe that regions with high solar irradiance tend to have higher deployment of distributed solar, as solar generation is more productive in those regions. Further, states with stronger emissions policies are more likely to establish incentives encouraging the adoption of distributed generation.

FIGURE 12: DISTRIBUTED SOLAR CAPACITY RELATIVE TO THE STATE'S POPULATION (WATTS PER CAPITA)



Sources and notes: Institute for Local Self-Reliance, The State(s) of Distributed Solar—2022 Updates, April 19, 2023. No data was reported for Alabama.

DG is likely to play a major role in the US energy system as the country continues its energy transition. According to a recent study, the US will need to install 197 GW to 347 GW of distributed solar to reach net zero by 2050, with this capacity being concentrated most heavily in California, the Southeast, and the Southwest.[81] The EIA forecasts that about 224 GW of distributed solar capacity will be installed by 2050.[82] Another DOE study estimates 140–260 GW of distributed solar to be installed by 2050 as the US reaches its net zero target.[83]

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[81] These numbers come from the "Central" and "100% Renewable" scenarios. *See* B. Haley, Ryan Jones, Jim Williams, et al., "Annual Decarbonization Perspective: Carbon Neutral Pathways for the United States 2022." *Evolved Energy Research*, 2022. Via https://www.evolved.energy/post/adp2022. Approximately 45% of total distributed solar capacity is projected in these regions by 2050 in the "100% Renewable" scenario. The "Central" scenario indicates the least cost pathway to reach net-zero GHG emissions by 2050; it includes the fewest constraints on technology and resource availability.

[82] US Energy Information Administration, "Annual Energy Outlook 2023," Tables 21 and 22. Via https://www.eia.gov/outlooks/aeo/tables_ref.php.

[83] United States Department of Energy and National Renewable Energy Laboratory, "Solar Futures Study," September 2021. Via https://www.energy.gov/sites/default/files/2021-09/Solar Futures Study.pdf.

As solar capacity continues to come online, peak load net of solar will shift into hours without solar generation, and the capacity benefits for additional solar installations will be muted. In other words, while aggregate solar nameplate capacity may grow to over 250 GW, this will probably not reduce net peak loads by 250 GW in total.

Behind-the-meter (BTM) storage adoption has been limited to date, with nearly all capacity installed alongside solar and concentrated in California and Hawaii. However, adoption is likely to increase in the future as battery technology improves and the costs for customers to install BTM storage systems decline over time.[84, 85] Moreover, distributed storage technologies are already economically efficient for some commercial and industrial customers who place a high value on reliability or who could reduce their demand charge.

C2. Energy Efficiency

EE refers to technologies or programs that fulfill the same consumer needs with less energy. Since the 1970s, EE has played a significant role in offsetting energy consumption. State and utility EE programs for residential customers typically provide incentives for homeowners to improve insulation, install energy-efficient windows, upgrade HVAC systems, and adopt other measures to reduce energy consumption. State and utility EE programs aimed at commercial and industrial (C&I) sectors may focus on energy audits, retrofits, and the adoption of energy-efficient technologies to enhance the overall efficiency of business operations.

EE programs reduce the amount of energy use required to provide a service. This can partially alleviate the strain on existing energy infrastructure by reducing peak demand, potentially delaying the need for expensive upgrades or expansions of power generation and distribution systems. For C&I customers, increasing EE and power management of existing equipment, such as motor systems, can substantially reduce costs. For example, the adoption of the right-sized motors and/or installation of a variable frequency drive, which dynamically adjusts electric input into a motor, could save 115,000 GWh per year across both sectors, translating into energy cost savings of $13.2 billion.[86]

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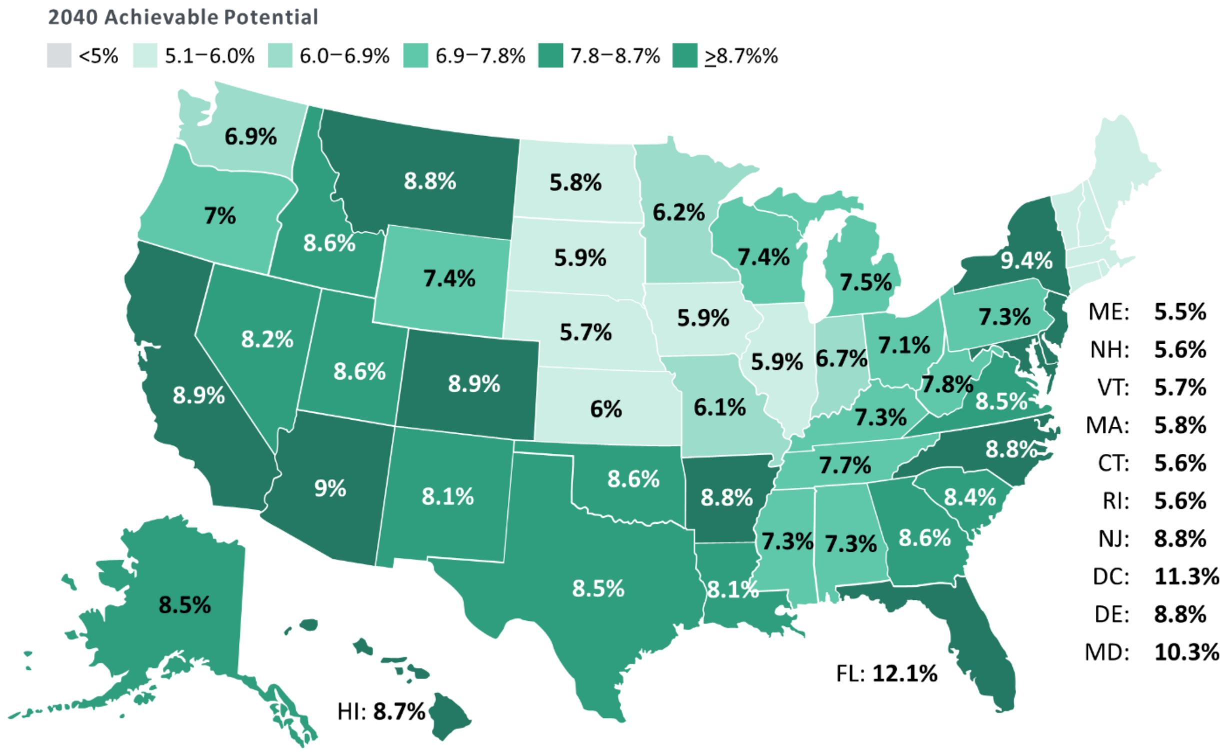
[84] Galen Barbose, et al., "Behind-the-Meter Solar+Storage: Market Data and Trends." *Lawrence Berkeley National Laboratory*. Via https://eta-publications.lbl.gov/sites/default/files/btm_solarstorage_report_-_factsheet.pdf.

[85] Julian Spector and Dan McCarthy, "Chart: Lithium-ion battery prices are falling again." *Canary Media.* Via https://www.canarymedia.com/articles/batteries/chart-lithium-ion-battery-prices-are-falling-again.

[86] Prakash Rao, Paul Sheaffer, Yuting Chen, et al., "US Industrial and Commercial Motor System Market Assessment Report, Volume 3: Energy Saving Opportunity." *Lawrence Berkeley National Lab*. Via https://escholarship.org/content/qt16x3d348/qt16x3d348.pdf.

A 2022 report from the American Council for an Energy-Efficient Economy (ACEEE) shows that in 2021, the aggregated incremental savings (i.e., reduction in consumption) from utility and public benefits electricity programs amounted to 0.68% of sales, equivalent to 26,000 GWh. Ranking by the net incremental electricity savings retail sales in 2021 as a percentage of volume reduction, the top five states are California (2.22%), Michigan (1.83%), Massachusetts (1.83%), Maryland (1.82%), and Rhode Island (1.78%).[87]

FIGURE 13: TOTAL ENERGY EFFICIENCY ACHIEVABLE POTENTIAL IN 2040, AS A PERCENTAGE OF ADJUSTED BASELINE SALES BY STATE



Sources and notes: EPRI, "US Energy Efficiency Potential through 2040: Summary Report," July 2019.

A 2019 EPRI study finds that EE programs have the potential to curtail electricity consumption by over 365,000 GWh by 2040. This would result in an 8% reduction in the annual electricity consumption in 2040, as projected by EIA's 2023 Annual Energy Outlook.[88] Florida, Washington, DC, Maryland, New York, and Arizona are projected to be the top five jurisdictions with the

87 Sararika Subramanian, Weston Berg, Emma Cooper, et al., "2022 State Energy Efficiency Scorecard." *American Council for an Energy-Efficient Economy*. 2022. Via www.aceee.org/research-report/u2206.

88 US Energy Information Administration, "Annual Energy Outlook 2023," Table 8. Via https://www.eia.gov/outlooks/aeo/data/browser/#/?id=8-AEO2023&cases=ref2023&sourcekey=0.

highest EE reduction as a percentage of projected adjusted baseline sales in 2040 (see Figure 13).[89]

Historically, the US federal government's role in EE was largely limited to setting appliance efficiency standards and substantial R&D. Since then, the federal role in EE has expanded. The 2022 IIRA includes $8.8 billion in rebates for home EE and electrification projects, including upgrading to environmentally friendly energy systems and appliances.[90] The DOE has projected that these rebates will result in annual savings of up to $1 billion on energy bills for households.

C3. Demand Response

DR programs – sometimes called flexible load programs – encourage customers to shift the timing of energy-intensive activities to periods of lower demand or higher renewable energy generation to alleviate system peaks. For example, pricing programs such as time-of-use rates, where electricity rates vary based on the time of day, can be designed to encourage customers to use more electricity during lower-demand periods, when costs are lower, and reduce energy usage during periods of highest stress on the grid, contributing to peak load reduction. DR programs are becoming increasingly important with the increase of flexible loads, such as EV charging and electric heating, and the increase of variable renewable energy resources. According to FERC, there was approximately 29 GW of peak load savings from retail demand response programs in the United States in 2021 and 32.9 GW of demand response participation in RTOs and ISOs in 2022 (though they are not purely additive).[91]

Many utilities and a growing number of private aggregators offer DR programs. According to the EIA, as of 2022, only 6.6% of all US energy consumers participated in a retail DR program. Participation is highest in Maryland and Delaware, where nearly 45% of customers are enrolled in at least one program. In contrast, almost no customers in Washington state or New Jersey are participating in DR programs.[92]

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[89] EPRI, "US Energy Efficiency Potential Through 2040." Via https://www.epri.com/research/programs/063638/results/3002014926.

[90] US Department of Energy, "DOE Provides States and Territories with Retroactive Rebate Resource, Updates FAQs." November 28, 2023. Via https://www.energy.gov/scep/slsc/home-energy-rebate-program/articles/doe-provides-states-and-territories-retroactive.

[91] FERC, "2023 Assessment of Demand Response and Advanced Metering." December 2023. Via https://cms.ferc.gov/media/2023-assessment-demand-response-and-advanced-metering

[92] US Energy Information Administration, "Annual Electric Power Industry Report, Form EIA-861 detailed data files." Via https://www.eia.gov/electricity/data/eia861/.

The adoption of DR programs is likely to depend heavily on the incentive structure in place and consumer attitudes toward these programs. NREL's EFS projects that a 20% participation rate in these programs is an achievable target (this is currently the average participation rate in the top 10 states) and could reach as high as 60% by 2050 in an enhanced scenario.[93]

Under the High Electrification Enhanced scenario, NREL estimates that nearly 1,200,000 GWh of load (representing 17% of total energy demand and 51% of transportation loads) would be flexible enough to participate in some sort of DR program. Optimizing DR under NREL's Enhanced High Case scenario could ultimately reduce capacity requirements across the US by around 170 GW, compared to a base case scenario with around 25 GW of peak load reduction. Similarly, a Brattle study identifies 200 GW (20% of peak load) of cost-effective load flexibility potential in the US by 2030,[94] and a US DOE report finds that demand flexibility in residential and commercial buildings could result in a quadrupling of peak demand reductions by 2030.[95]

DR programs have enormous potential, but their success is not guaranteed. With only 6% of the population currently participating in some form of load management, reaching higher levels aligning with the total cost-effective peak load reduction potential discussed above would require a significant increase in the level of participation. The base case in NREL's EFS study shows current levels of DR will persist through 2030, and the NERC *2023 Long-Term Reliability Assessment* estimates an annual capacity-equivalent growth rate of only 0.55%.[96] Final DR savings likely will exceed these baseline estimates as end consumers more actively engage with their energy consumption and adopt flexible energy technologies, energy becomes more expensive, and utilities and other entities introduce new DR and virtual power plant (VPP) programs.

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93 Yinong Sun, et al., "Electrification Futures Study: Methodological Approaches for Assessing Long-Term Power System Impacts of End-Use Electrification." *National Renewable Energy Laboratory*. Via https://www.nrel.gov/docs/fy20osti/73336.pdf.

94 Ryan Hledik, et al., "The National Potential for Load Flexibility: Value and Market Potential Through 2030." *The Brattle Group*. Via https://www.brattle.com/insights-events/publications/brattle-study-cost-effective-load-flexibility-can-reduce-costs-by-more-than-15-billion-annually/.

95 Andrew Satchwell, et al., "A National Roadmap for Grid-Interactive Efficient Buildings." *US Department of Energy*. Via https://gebroadmap.lbl.gov/A%20National%20Roadmap%20for%20GEBs%20-%20Final.pdf. See also Jennifer Downing et al., "Pathways to Commercial Liftoff: Virtual Power Plants," *US Department of Energy*. Via https://liftoff.energy.gov/wp-content/uploads/2023/10/LIFTOFF_DOE_VVP_10062023_v4.pdf

96 NERC, "2023 Long-Term Reliability Assessment." Via https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf. We note that NERC's projection does not appear to include retail demand response.

While many cryptocurrency mining operations with deferrable and price-sensitive loads have taken advantage of DR programs, innovation may allow traditional data centers to operate more flexibly and respond to real-time grid conditions. Cryptocurrency mining loads can enroll in a DR program when available and receive compensation for curtailing their electric consumption when the grid is under stress or when electricity prices are high. Under the right conditions, the financial payoff can sometimes be very lucrative; for example, during an unprecedented state heatwave, a cryptocurrency load in Texas voluntarily cut energy consumption and earned $31.7 million in credits.[97]

Leading technology companies are also seeking innovative approaches to manage electricity demand from their data centers. For example, Microsoft plans to use renewable natural gas generators at a new data center in San Jose, California, "to provide electrical power to support the data center uses during utility outages, certain onsite electrical equipment interruptions or failure, and for load shedding, demand response, and BTM resource adequacy ancillary services."[98]

97 MacKenzie Sigalos, and Jordan Smith, "Texas paid bitcoin miner Riot $31.7 million to shut down during heat wave in August." *CNBC*. Via https://www.cnbc.com/2023/09/06/texas-paid-bitcoin-miner-riot-31point7-million-to-shut-down-in-august.html.

98 California Energy Commission, "San Jose Data Center." Via https://www.energy.ca.gov/powerplant/backup-generating-system/san-jose-data-center.

III. How Electric Forecasts Are Changing

To understand the extent to which the electricity industry has appeared to incorporate the demand drivers and load modifiers described in Section II in their long-term forecasts, we reviewed a sample of forecasts published by key forecasting entities. As noted earlier, we stress that this is not a complete industry-wide survey, nor is it an in-depth review of any one particular forecast. Instead, it is a preliminary snapshot of the state of forecasting based on publicly available information, providing an indicator of how various entities have been incorporating new load drivers into their forecasting and, thus, planning activities.

To form our view, we attempted to create a reasonably representative (though not scientifically selected) sample of forecasts from utilities and independent system operators (i.e., RTOs and ISOs) and a few governmental units. Our method of creating the sample consisted of two major steps:

- First, we examine regions and states in which the drivers of interest have the highest level of activity. For example, for EVs, we selected the top 10 states with the highest number of EVs on the road.[99]
- Second, we identify a group of median entities within the state based on their total sales MWh as reported in EIA Form 861.[100] Often, the identified group consists of entities whose forecast documents were not publicly available. In those instances, we substituted entities with those that had publicly available forecast documents. We observed that investor-owned utilities tend to post their studies more than other utility types.

Figure 14 below displays our sample of forecasting entities and the apparent inclusion of some of the major drivers from Section II. As Figure 14 shows, virtually all sampled forecasting entities included EE in their forecasts, a testament to the success of the decades-long industry push to recognize the importance and potential of this resource. Fewer (but still an overwhelming majority) of the entities in our sample included DR and DG in their load forecasts.

99 They are California, Florida, Texas, Washington, New Jersey, New York, Illinois, Arizona, Georgia, and Colorado. The final list of states in our study reflects states that experience the highest level of activity across the different drivers.

100 We filter for Investor Owned, Municipal, Political Subdivision, and Retail Power Marketer.

While EVs are relatively new to the market, the majority of the sampled utilities also include them in their forecasts. Notably, several of the Maryland utilities and the largest Illinois utilities did not include EVs in their forecasts,[101] even though both states have ambitious EV goals (300,000 zero-emissions vehicles by 2025 for Maryland and 1 million EVs by 2030 for Illinois[102]). All but one independent system operator, MISO, account for EVs in their forecasts.

The results are more mixed for electric heating.[103] All surveyed New York entities include electric heating in their load forecasts, as do the largest utilities in Colorado, Massachusetts, and Washington – states with policies to cut significant emissions from the building sector. On the other hand, the Sacramento Municipal Utility District is the only sampled California utility that includes heating electrification in its forecast, even though the state has embraced electrification as the main decarbonization pathway for buildings. We note that only a few entities include forecasts of these Type B drivers at the distribution level.[104]

Among the Type A drivers, data centers are most commonly mentioned. However, few utilities mention data centers in their load forecasts, in part because the market for data centers is, at the moment, highly geographically concentrated. More generally, many of the surveyed entities include large loads in their planning documents when the loads are already known (e.g., a data center that is under construction); only a few utilities include some sort of forecast for this type of load. NYISO is the only entity that includes electrolyzers in its forecast. Direct air capture is

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[101] ComEd includes EVs in the billing determinant forecast used in the rate case filings but does not explicitly account for EVs in the load forecast provided to the IPA and used for the procurement of new resources.

[102] Maryland Department of the Environment, "Zero Emission Vehicle." Via https://mde.maryland.gov/programs/air/mobilesources/pages/zev.aspx and Office of Governor JB Pritzker, "Illinois Takes Bold Climate Action." Via https://www2.illinois.gov/IISNews/23893-Climate_and_Equitable_Jobs_Act.pdf.

[103] Some drivers, including electric heating, may not be highly relevant to a forecast. For example, in some very mild climate areas, electric heating may not grow significantly, while in others cannabis cultivation is minimal. We therefore do not expect every driver to show up as significant in every forecast in our sample, and the absence of the mention of a driver should not be automatically seen as a significant omission without further inquiry.

[104] Based on our survey, the utilities and jurisdictions that estimate distribution level impacts for these new drivers are ERCOT for electric vehicles, National Grid (MA), and the Joint Utilities of New York;
Sanem Sergici, et al., "ERCOT EV Allocation Study: Methodology For Determining EV Load Impact At The Substation Level." *The Brattle Group*. October 13, 2022. https://www.brattle.com/wp-content/uploads/2023/01/ERCOT-EV-Allocation-Study.pdf; National Grid, "Achieving Our Commonwealth's Climate Goals: An Electric Load Forecasting Overview." May 11, 2023. Achieving Our Commonwealth's Climate Goals: An Electric Load Forecasting Overview; New York Joint Utilities, "Supplemental Distributed System Implementation Plan." *New York State Department of Public Service Docket 16-01444*. Via https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=16-M-0411.

not mentioned in any of the documents that we reviewed, which is expected given the technology's low readiness level.

FIGURE 14: INCORPORATION OF SELECTED MAJOR DEMAND DRIVERS BASED ON SAMPLE UTILITY PUBLIC FORECASTING DOCUMENTS

		Demand-Side Resources			Type B Load		Type A Load			
		EE	**DR**	**DG**	**EVs**	**Electric Heating**	**Data Center**	**Indoor Agriculture**	**Electrolyzer**	**Industrial Onshoring**
AZ	Arizona Public Service (APS)	✓	✓	✓	✓		✓			✓
AZ	Salt River Project (SRP)	✓	✓	✓	✓	✓	✓			
CA	City of Palo Alto - (CA)	✓	✓	✓	✓	✓				
CA	CleanPowerSF	✓	✓	✓	✓	✓				
CA	Los Angeles Department of Water and Power	✓	✓	✓	✓	✓				
CA	Pacific Gas & Electric (PG&E)	✓	✓	✓	✓	✓				
CA	Southern California Edison (SCE)	✓	✓	✓	✓	✓				
CA	San Diego Gas & Electric (SDG&E)	✓	✓	✓	✓	✓				
CA	Sacramento Municipal Utility District (SMUD)	✓	✓	✓	✓	✓	✓	✓*		
CO	Black Hills	✓	✓	✓			✓*			
CO	Colorado Springs Utilities (CSU)	✓	✓	✓	✓	✓				
CO	Public Service Company of Colorado (PSCO)	✓	✓		✓	✓				
CO	Tri-State	✓*	✓*							
FL	Florida Power & Light (FPL)	✓	✓	✓	✓					
FL	Gainesville Muni	✓	✓	✓	✓					
FL	Jacksonville Electric Authority (JEA)	✓	✓	✓	✓	✓				
FL	Seminole CO-OP	✓	✓	✓						
GA	Georgia Power	✓	✓	✓	✓	✓	✓			✓*
IL	Ameren Illinois	✓	✓	✓						
IL	Commonwealth Edison (ComEd)	✓	✓	✓	✓*					
MD	Baltimore Gas and Electric Company (BGE)	✓	✓	✓	✓					
MD	Choptank	✓*	✓*	✓						
MD	Delmarva Power (DPL)	✓	✓	✓						
MD	Hagerstown	✓*	✓*	✓						

		Demand-Side Resources			Type B Load		Type A Load			
		EE	**DR**	**DG**	**EVs**	**Electric Heating**	**Data Center**	**Indoor Agriculture**	**Electrolyzer**	**Industrial Onshoring**
MD	PEPCO	✓	✓	✓						
MD	Potomac Edison	✓	✓	✓						
MD	Southern Maryland Electric Cooperative	✓	✓	✓						
MA	Eversource	✓	✓	✓	✓	✓	✓*			
MA	National Grid	✓	✓	✓	✓	✓	✓*			
MA	Unitil	✓*	✓*	✓	✓	✓				
NJ	Public Service Electric and Gas (PSE&G)	✓	✓	✓	✓	✓	✓			
NY	Central Hudson Gas & Elec Corp	✓	✓	✓	✓	✓				
NY	Consolidated Edison Co-NY Inc	✓	✓	✓	✓	✓				
NY	Long Island Power Authority (LIPA)	✓	✓	✓	✓	✓				
NY	Niagara Mohawk Power Corp.	✓	✓	✓	✓	✓				
NY	Orange & Rockland Utils Inc	✓	✓	✓	✓	✓				
TX	El Paso Electric	✓	✓	✓	✓					
VA	Appalachian Power Co	✓	✓				✓			
VA	Virginia Electric & Power Co	✓	✓	✓	✓	✓	✓			
WA	Puget Sound Energy (PSE)	✓	✓	✓	✓	✓	✓*	✓*		
CEC	California Energy Commission	✓	✓	✓	✓	✓				
MISO	Mid-continent Independent System Operator	✓	✓							
ISO-NE	ISO New England	✓	✓	✓	✓	✓				
NYISO	New York ISO	✓	✓	✓	✓	✓	✓		✓	
PJM	PJM Interconnection	✓	✓	✓	✓	✓	✓			✓*
SPP	Southwest Power Pool	✓	✓	✓	✓	✓				
ERCOT	Electric Reliability Council of Texas	✓	✓	✓	✓		✓*			

Note: Cells with an asterisk indicate that the entity forecasted this particular driver to an extent but did not account for the likely long-term growth of the driver and/or the entity has multiple load forecasts and does not include the driver in all load forecasts. Tri-State notes that one of their R&D projects involves incorporating DERs into resource planning to account for the effects of rooftop solar and EVs on load and peak forecasting, but it is unclear if this is a past or present endeavor. NJ Energy Master Plan is included since some New Jersey utilities use it as their load forecasts.

We observe a wide spectrum of how the surveyed entities recognize and account for these new drivers. Some appear more advanced than others, although the large variation may be in part driven by needs. A utility that does not consider cryptocurrency load or indoor agriculture may do so because those loads are not permitted by local laws. Thus, it is premature to compare or rate the quality of forecasting methods based on these initial observations.

Furthermore, Figure 14 reflects a snapshot of the data available today, which could be a few years old, and we understand that utilities are working to improve their load forecasting. For example, Figure 15 below summarizes the evolution of key load drivers that forecasters in New York have been considering over the past three years. Shaded components indicate changes were made from previous years.

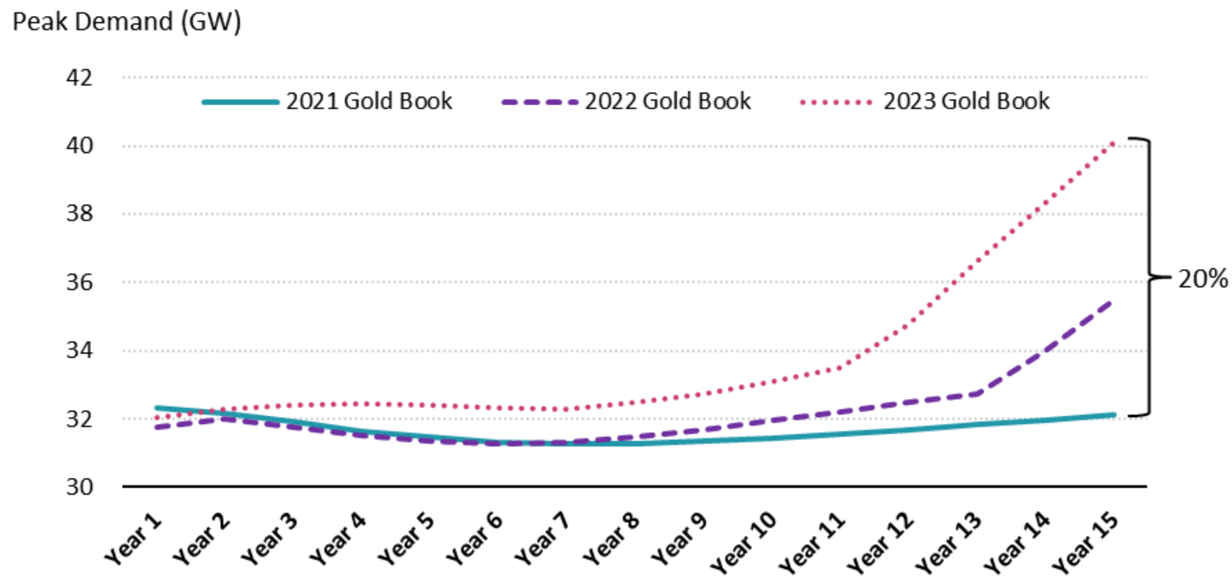
FIGURE 15: KEY LOAD DRIVERS IN NYISO FORECAST OVER THE YEARS

NYISO Forecast Components	2021 Forecast	2022 Forecast	2023 Forecast
Energy Efficiency	• Large EE gains	• Significant EE gains • Peak reductions	
BTM Solar PV	• 6,000 MW DC by 2026	• 6,000 MW DC by 2024 • 10,000 MW DC by 2030	• 6,000 MW DC by 2024 • 10,000 MW DC by 2031
BTM Non-Solar DG	• 500+ MW by 2035		• 600+ MW by 2040
Electric Vehicles	• 4.3 million EVs in 2040 • Unmanaged charging	• 5.3 million EVs in 2035 • Increasingly managed charging over time	• 6 million EVs in 2040 • Increasingly managed charging over time
Energy Storage (total behind-the-meter plus wholesale)	• 3,000+ MW by 2029 • 10,000+ MW by 2051	• 5,000+ MW by 2030 • 12,000+ MW by 2050	• 1,000 MW+ BTM by 2030 • 2,000+ MW BTM by 2045 • Does not include wholesale storage
Non-EV Electrification /Building Electrification	• Medium electrification (space heating and other end uses)	• High electrification (80% of residential electric heating by 2050)	• Significant electrification (60% of residential electric heating by 2050)
New Large Loads	N/A		• New large loads considered
Electrolysis	N/A		• No electrolysis

Source: 2021–2023 NYISO Load & Capacity Data Report (Gold Book).

The inclusion of some of the new load drivers has impacted their load forecast as well, as shown in Figure 16 below. This figure, looking 15 years ahead, shows the peak demand forecast changed by approximately 20%, largely because of the inclusion of the new drivers. This clearly illustrates the importance of comprehensively including the various drivers, even without a sophisticated, complex technique for assessing the impact. That should come next after the new load types are better understood.

FIGURE 16: PEAK DEMAND FORECASTS FOR NEW YORK



Source: 2021–2023 NYISO Load & Capacity Data Report (Gold Book).

As the industry continues to support economic growth while aiming to meet decarbonization goals, accurate load forecasts as an important input into a cost-effective and economically efficient power system planning process become more important than ever. In the next section, we discuss the costs and implications of over- and under-forecasting and how their significance is evolving with the drive to electrify and decarbonize the economy.

IV. The Costs of Over- and Under-Forecasting

The previous sections discussed the new load drivers, which are largely policy-driven, and how various utilities have incorporated such drivers in their forecasts. However, given that these are relatively new drivers with varying magnitudes and directions of impact, and given that some drivers are flexible, it becomes increasingly important to understand the effects of over- and under-forecasting these drivers individually and together with other factors that make the total load.

It is well understood that systemic and significant over- or under-forecasting imposes a variety of substantial costs and risks on electric consumers. Persistent under-forecasting can lead to:

- Reduced reliability and increased outages as reserve margins decline and there is little or no spare capacity on the system. Ample industry research and our own personal experiences demonstrate that outages are costly, and costs vary substantially depending on the outage duration and frequency.[105]
- Accelerated and sometimes mandatory use of EE and other load management measures. In some cases, these measures may be economically and environmentally positive, but in others, they may raise costs or lower the quality of service.
- Rationing of new service connections or expansions by location, type of load, type of customer, or other criteria. This rationing inevitably leads to lower rates of economic and job growth, relocation of industrial and commercial customers, and other economic development penalties.
- Less urgency to build and interconnect new energy sources and prolong the life and operation of older generation assets, which tend to be more expensive and higher emitting.
- Greater use of non-electric fuels and/or self-supply of electricity. This may, in some cases, accelerate the pace of total system decarbonization, but just as often increases total GHG emissions, especially if done quickly.

[105] See, for example, "Cost of Power Interruptions to U.S. Electricity Consumers," Kristina Hamachi LaCommare and Joseph H. Eto, Ernest Orlando Lawrence Berkeley National Laboratory, 2004. Via https://www.osti.gov/servlets/purl/908489.

Forecasters have long targeted the highest level of peak demand as their key forecast objective, and it is well understood that in most systems, the peak is strongly influenced by weather (i.e., temperature and humidity). However, the increasing frequency of extreme weather events adds an additional potential cost of under-forecasting. In addition to the fact that temperature extremes are systematically widening, severe weather events are more frequently knocking out portions of both demand and supply resources. Under-forecasting can lead to systems being less resilient and reliable because they have fewer options for managing weather-driven outage events.

As the industry learned in the 1980s, over-forecasting can also lead to major challenges. The main consequence of the widespread over-forecasting during this period was financial and reputational. Due in part to conclusions that utilities had not forecasted accurately, regulators punished many utilities by disallowing the costs of building new capacity.[106] In this period, there were 50 separate instances in which regulators did not allow utilities to recover the costs of building 37 different generating plants; these disallowances totaled over $19 billion.[107] Two utilities were driven into bankruptcy by overcapacity and cost overrun disallowances.

These disallowances led utilities to become extremely cautious about over-forecasting load and building plants that regulators found unnecessary. Writing in 1989, Paul Joskow noted that "[f]ew utilities appear willing to build large base-load facilities, even in areas where additional capacity is needed" as a consequence of power plant disallowances.[108] Concern over the tensions between uncertain future demand and the hesitation to construct new capacity led to the industry's first model explicitly designed to incorporate the cost of forecasting incorrectly on the costs of electric service – EPRI's famous "over-under" model.[109] Although the model did not become part of the standard utility planning framework, it established the fact that utility planners could quantify the costs and benefits of a range of utility system outcomes rather than basing decisions on a single expected outcome case. Public unhappiness with high rates and the perception that utilities were unable to forecast and plan properly, combined with a broader

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[106] Cost overruns in the construction of large coal and nuclear plants played an important role prompting regulatory disallowances, but forecasting also played a part. *See*, P. Fox-Penner, "Allowing for Regulation in Forecasting Load and Financial Performance*." Public Utilities Fortnightly*, January 7, 1988.

[107] Thomas P. Lyon and John W. Mayo, "Regulatory Opportunism and Investment Behavior: Evidence from the U.S. Electric Utility Industry" (January 2000). Available at SSRN: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=224258 or http://dx.doi.org/10.2139/ssrn.224258.

[108] Paul L. Joskow, "Regulatory Failure, Regulatory Reform, and Structural Change in the Electrical Power Industry," *Brookings Papers: Microeconomics*, 1989, p.161, quoted in Lyon and Mayo, op. cit., p.4.

[109] Charles Clark, Thomas Keelin, Robert Shur, Users Guide to the Over/Under Capacity Planning Model, Decision Focus, Inc. 1979, EPRI Report EA-1117.

deregulation movement, led to the introduction of competition into wholesale markets and retail choice adoption in about half the US states.

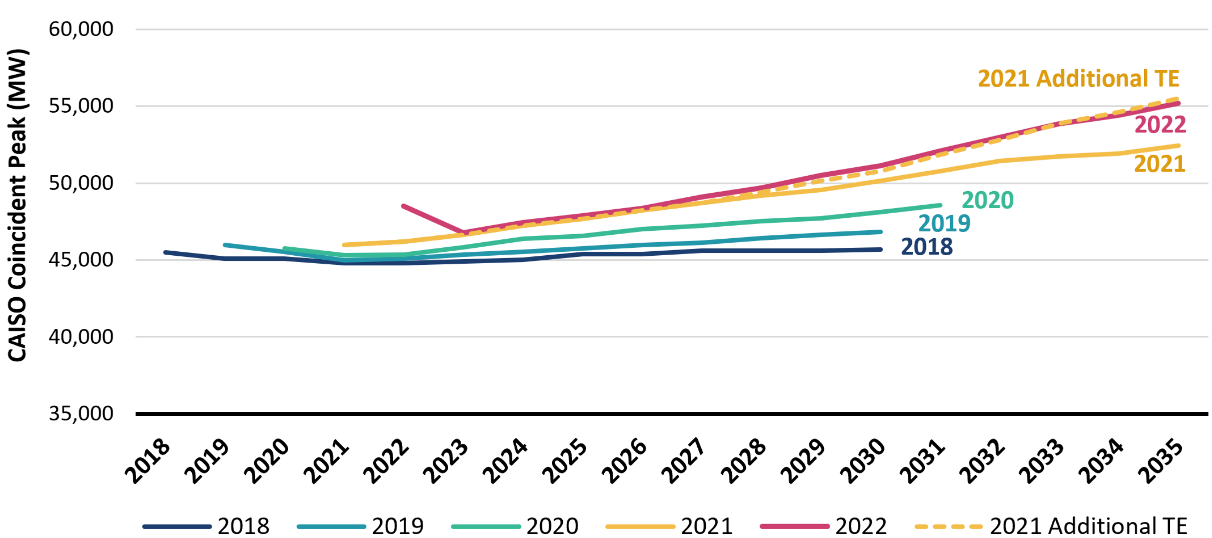
This period of over-forecasting prompted many improvements in electric forecasting techniques. The industry incorporated price elasticity and the effects of uncertainty much more thoroughly into their forecasting models. Utilities also began to disaggregate sources of growth within their forecasts and model individual change drivers, such as the growth of electric heating, more carefully. These improvements laid the groundwork for the current cohort of forecasting models that are now in need of the next generational update.

OVER- AND UNDER-FORECASTING IN THE CURRENT ENVIRONMENT

Alongside the broad, long-term trend towards greater low-carbon electricity, the growth of the new drivers of electric demand chronicled in this report suggests that we are entering an era in which the balance of forecasting risks tilts toward underestimates rather than overestimates.

As noted in Section III, many of the new drivers are on trajectories that differ significantly from those reflected in current forecasting models. Tellingly, long-term forecasts of load elements associated with the new drivers – notably EV adoption and data center load – have shown a pattern of annual upward revisions. This is illustrated in Figure 17 below, which shows how forecasts of California's coincident peak have increased steadily since 2018. Though upward forecast shifts like this never last forever, while they are occurring, they often indicate a need for model recalibration/retraining.

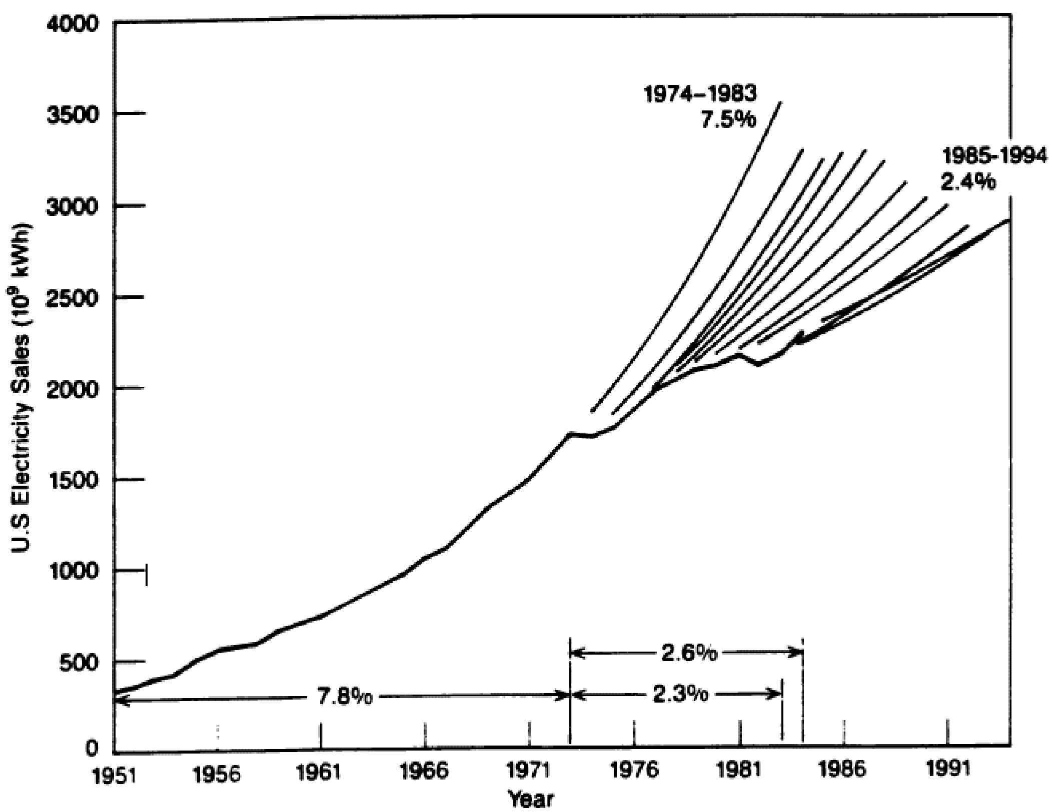
FIGURE 17: CALIFORNIA DEMAND FORECAST CHANGES OVER TIME



Source: California Energy Commission, *Draft 2023 Integrated Energy Policy Report*, November 13, 2023.

These upward revisions are a striking mirror image of the long string of annual *downward* load forecast revisions made by electric utilities in the 1970s (see Figure 18 below) – a figure that became known as the "NERC fan." The figure represents the aggregation of each year's forecasts by all the utilities then overseen by NERC. Starting in 1974, every year's subsequent 10-year forecast projected significantly less growth than the year before. In addition to being lower, every subsequent year's forecast proved to be closer to accurate, demonstrating a slow trend towards improvement in forecasting models.

FIGURE 18: THE "NERC FAN"



Source: "The NERC Fan in Retrospect and Lessons for the Future," Charles R. Nelson, Stephen C. Peck, and Robert G. Uhler. *The Energy Journal*, Vol. 10, No. 2 (April 1989), pp. 91–107. https://www.jstor.org/stable/41322355.

During this period, the industry devoted considerable resources to understanding the sources of error in forecast models and improving them. As explained in a 1983 review of electric utility load forecasting practices, utilities were struggling with how to incorporate three new and changing load drivers in particular: price elasticity of demand, which had up until recently been largely ignored; future economic growth, which had become less homogeneous and predictable than in the recent past; and the effects of energy conservation policies and programs, which were quite new to the industry at the time. The report noted that:

> …At present, conservation measurement is not a precise or rigorous science because forecasters have little experience with it and there is little historical data on which to base projections. Although the impacts of price-induced conservation and building and appliance efficiency standards can be factored into forecasts…, the impacts of utility-sponsored conservation programs are difficult to quantify.

Four decades later, the industry has extensive experience measuring the effects of efficiency programs, policies, and markets, and ample experience building these resources into forecast models.[110] The present challenge is to update today's forecast models to incorporate the latest generation of load drivers and their trends – the modern-day cousins of the then-new factors that emerged four decades ago – at a more granular level for both location and timing.

Another difference between the present and the 1980s may be that, in today's world, where many of these new loads are policy-driven (e.g., decarbonization or industry onshoring policies), the risk of under- vs over-forecasting is asymmetric. The cost and long-lasting effect of under-forecasting appear to be much larger than those of over-forecasting. Yet, over-forecasting could lead to higher costs (as history shows), resulting in waning support for the policies that triggered these new load drivers.

Finally, it may be prudent to err on the side of higher supply plans because there are unusually high levels of uncertainty regarding the supply chain for many types of resources, from electrical switchgear to metals and minerals needed for many supply and delivery technologies, including DERs, today. Historically, the industry has typically not faced such constraints and, therefore, has not experienced a need to build a buffer into its supply plans.

[110] See, for example, A. Faruqui, S. Sergici, and K. Spees, "Quantifying the Amount and Economic Impacts of Missing Energy Efficiency in PJM's Load Forecast." *The Brattle Group*. September 2014.

V. Conclusion

Demand for electricity is poised to increase at a level that the industry has not experienced in recent decades, driven largely by increasing consumption of electricity from the industrial sector, along with a push to electrify many parts of the US economy. In this report, we identified and discussed these main drivers: data centers, industrial electrification, cryptocurrency mining, transportation electrification, and building electrification. In addition, distributed generation, energy efficiency, and demand response will grow substantially and contribute very important resources to the mix.

The exact magnitude and timing of new load growth will vary by driver and geography, and the exact amounts will also be moderated by the available amounts of demand-side resources (DG, EE, and DR). In the near term, Type A loads, characterized by large and discrete size, can potentially pose significant issues if the planning process does not catch up with the speed at which these loads materialize. Utilities with high immediate load growth need both a near-term action plan and a long-term forecasting-and-action plan – a significant and rather unusual challenge.

Type B loads pose a different challenge, oftentimes because their overall (or average) growth appears small and/or gradual. The challenges Type B loads lead to are more geographical, with potentially high growth in one region, while another region may not see any growth associated with that demand driver. The variance could even be within an area or utility footprint, requiring a much more granular approach to load forecasting. We note that when Type B loads emerge at larger scales (e.g., fleet conversion of buses to electrical buses), they can exhibit some of the same characteristics as Type A loads.

The dynamics associated with the new load drivers are further complicated by demand-side resources, such as EE and DR, which can offset the potential load growth. In addition, the combination of the inelastic (historically observed) and flexible (new and emerging) loads warrants looking at load forecasting from quite a different perspective, including what it means to under- and over-forecast for loads with these new characteristics.

In today's world, where many of these new loads are policy-driven (e.g., decarbonization or industry onshoring policies), the risk of under- vs over-forecasting is asymmetric, with the cost and long-lasting effect of under-forecasting being much larger than those of over-forecasting.

And yet, over-forecasting could result in higher costs, leading to waning support for the policies that triggered these new load drivers in the first place. The balance is delicate.

Overall, we find a wide spectrum among utilities on how they recognize and account for these new drivers. A renewed focus on load forecasting as an industry is needed, given the magnitude and uncertainty of load growth and the change in load characteristics that makes the underlying assumption of the traditional load forecasting tools potentially obsolete (i.e., loads are inelastic, and their future needs can be addressed through the existing utility planning horizon, which is oftentimes measured in years, and it requires many complex models to develop these forecasts). One of the first steps may be to comprehensively include the various drivers, even without a sophisticated, complex technique for assessing the impact. The latter should come next after the new load types are better understood. In general, we find there is still much progress that is urgently needed.

Applications of our findings are not limited to simply projecting the peak load and energy consumption. Proactively expanding the existing transmission and distribution networks will help alleviate the uncertainty associated with these loads materializing. These can be either in the long or short term. Various studies show how enhancing transmission, including interconnection with neighboring systems, can improve reliability and resiliency (e.g., storm-hardening) or lower generation and interconnection costs while speeding up that process. These enhancements are oftentimes thought of as long-term solutions. However, the same concept can be applied to accommodating new load in the shorter term at a smaller scale.

For example, a meshed network – whether it be transmission or distribution – will provide more options for the utility to upgrade the system to accommodate a new load compared to a radial line. Not only will these options lead to lower costs, but a meshed network provides higher levels of reliability and, often, resiliency as well. Proactively looping (or meshing) existing lines that are radial based on an improved load forecast may be an example of a least-regrets option that can be implemented immediately, partially in preparation for new loads. The uncertainty and speed of these new loads also suggest low-cost investments, such as grid-enhancing technologies[111] that can be installed much faster than the traditional transmission and/or distribution investments, could be utilized more, even if they are used as a temporary measure until a larger scale solution (e.g., a new transmission line) is put in place.

[111] There are many types of grid-enhancing technologies that have been proven and implemented globally. Examples include dynamic line ratings, topology optimization, flexible alternating current transmission system (FACTS) devices, and storage as transmission, amongst others.

The uncertainty in load could also impact utilities' business in other ways. For example, in December 2023, the Los Angeles Department of Water and Power (LADWP) issued a Request for Proposal (RFP) for Partnership Opportunity Participating in Transmission Projects. This open RFP seeks collaboration with other utilities or third parties to develop transmission projects with the aim of helping LADWP reduce the costs and risks of transmission projects, including those associated with uncertainty of future load. A number of utilities are now filing for tariffs targeting new large loads, including cryptocurrency mining and data center loads. Additionally, FERC is expected to issue its final ruling for improving regional transmission planning and cost allocation, which will likely require transmission service providers to utilize high-demand planning scenarios in regional transmission plans.

The report's findings present an important snapshot of an industry in transition, bringing into focus the need for and urgency of a new, more granular load forecasting. It concludes that further work is needed to assess the status of demand forecasting, including the effectiveness of different forecasting methods and techniques in capturing magnitude, timing, and geographic dimensions, along with uncertainty factors of each of the specific new drivers. Additional research and action will be useful for bringing about a future electric system that is reliable, affordable, and the keystone of a decarbonized growing economy.

Appendix

FIGURE A-1: ELECTRICITY DEMAND DRIVERS, POTENTIAL IMPACTS, AND GROWTH RATES FOR THE US (50 STATES). NOTE THAT THE LAST COLUMN SHOWS ANNUAL GROWTH *IN* 2030 (INSTEAD OF TOTAL GROWTH *BY* 2030, AS SEEN IN FIGURE ES-2)

	Description	Current Capacity (GW)	Growth Rate (CAGR)	Approximate Annual Growth in 2030 (GW)
A1. **Data Centers**	Data centers underpin the online economy and support the growth of artificial intelligence.	19	9% through 2030	2.9
A2. **Onshoring & Industrial Electrification**	Electrification of the industrial sector is a major pathway to reduce emissions. New sources of electric demand are triggered by the onshoring of manufacturing activity, hydrogen production (e.g., electrolyzers), indoor agriculture, and carbon dioxide removal.	**Industrial:** 116 **Hydrogen Production:** 0.07 **Indoor Agriculture:** 6	**Reindustrialization (near-term):** 1% through 2025 **Hydrogen:** 132% through 2030 **Indoor Agriculture:** 10% through 2035	**Reindustrialization (near-term)**: 0.7 **Hydrogen:** 14.2 **Indoor Agriculture:** 1.1
A3. **Cryptocurrency Mining**	Cryptocurrency mining is the process by which networks of computers generate and release new currencies and verify new transactions.	10–17 GW (estimated to be around 50% to 90% of data center load in the US)	Unknown and highly volatile (driven by cryptocurrency values, which fluctuate by external factors)	1.5–2.7 (based on historical trends against data centers)
B1. **Transportation Electrification**	A growing number of customers purchase electric passenger vehicles as a more climate-friendly alternative to gas vehicles; medium- and heavy-duty vehicles, bicycles, motorcycles, and ferries can all operate on electricity.	6.8 (electric vehicles)	15% through 2040	1.6
B2. **Building Electrification**	Electrification is a major pathway to decarbonize buildings and can include space heating (e.g., heat pumps), water heating (e.g., heat pump water heaters), and cooking (e.g., electric/induction cook stoves).	50	0%–4% through 2050	0.0–2.4

Sources and notes: CAGR estimate is based on available data, and the growth rate does not necessarily stop after the last year in the period. Historical and future **data center** peak load estimates from S&P Global Market Intelligence. **Cryptocurrency mining** estimates are based on historical observations from The White House Office of Science and Technology Policy. **Reindustrialization** capacity is calculated using energy consumption estimates and assuming a conservative load factor of 100%. Current reindustrialization energy consumption is current industrial energy consumption as reported in EIA AEO, and reindustrialization energy consumption additions are from EPRI. Current **hydrogen electrolyzer** capacity is from US DOE current installations. The CAGR is based on 25 GW of forward additions from the US DOE's Liftoff Study. **Indoor agriculture** peak load estimates assume a load factor of 75% since lighting is one of the biggest loads for indoor agriculture and farms operate with 18 hours of daylight. Current and future additional indoor agriculture energy consumption based on Pulman and Comley estimates that cannabis currently accounts for 1% of US energy consumption, and this will grow to 3% (paired with total energy consumption from EIA AEO). Current **electric vehicle** peak load is based on US Drive assumption of an additional 1.5 kW per vehicle and a current vehicle stock from PWC. Future peak load-based NREL's Highly Resolved Projections of Passenger Electric Vehicle Charging Loads for the Contiguous United States. **Building electrification** capacity comes from the annual consumption in 2022 of 436,000 GWh, as shown in AEO 2023, then converted to GW assuming a flat load profile. Building electrification CAGR comes from a review of publicly available state-level studies, including the Massachusetts CECP study, the Maryland Electrification Study, and the New York CAC Integration Analysis; the values shown are a range from these studies. The lower end of the CAGR (zero growth rate) reflects scenarios in which customers replacing energy-intensive electric resistance heaters with heat pumps leads to lower energy consumption.

Glossary

ACEEE	American Council for an Energy-Efficient Economy
AI	Artificial Intelligence
BTM	Behind-the-Meter
C&I	Commercial and Industrial
CAGR	Compound Annual Growth Rate
CDR	Carbon Dioxide Removal
CEC	California Energy Commission
CHIPS	Creating Helpful Incentives to Produce Semiconductors (CHIPS and Science Act)
CO_2	Carbon Dioxide
CPUC	California Public Utility Commission
DER	Distributed Energy Resources
DG	Distributed Generation
DOE	Department of Energy
DR	Demand Response
DSM	Demand-Side Management
EE	Energy Efficiency
EFS	Electrification Futures Study
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
EV	Electric Vehicle
FACTS	Flexible Alternating Current Transmission System
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas

GMP	Green Mountain Power
GW	Gigawatt (1,000,000,000 Watts)
GWh	Gigawatt Hour (1,000,000,000 Watt Hours)
HVAC	Heating, Ventilation, and Air Conditioning
IIJA	Infrastructure Investment and Jobs Act
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
ISO	Independent System Operator
kWh	Kilowatt Hour (1,000 Watt Hours)
LADWP	Los Angeles Department of Water and Power
mtpy	Metric Tons Per Year
MW	Megawatt (1,000,000 Watts)
MWh	Megawatt Hour (1,000,000 Watt Hours)
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York ISO
PWC	PricewaterhouseCoopers
R&D	Research and Development
RFP	Request for Proposals
RTO	Regional Transmission Organization
SAF	Sustainable Aviation Fuel
TW	Terawatt (1,000,000,000,000 Watts)
TWh	Terawatt Hour (1,000,000,000,000 Watt Hours)