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Electrification and the grid

Implementing rate design, grid upgrades, and load flexibility to support electrification

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EXECUTIVE SUMMARY

This report provides electrification advocacy organizations, federal and state policy officials, utilities, and other industry participants with an overview of the grid implications of residential electrification and clean energy, as well as recommended solutions to create a reliable, affordable, and decarbonized grid.

There is wide recognition that the world needs to tackle climate change by rapidly electrifying customer loads and transitioning to carbon-free electricity. To successfully complete this transition we must accomplish three distinct tasks:

→ Generate 100% carbon free electricity

→ Electrify all our energy needs

→ Match variable supply and variable demand on the grid

With the rapid scaling and deployment of renewable energy, electrified transportation, and electrified heating in the residential sector, there is a clear pathway forward for items 1 and 2, but many questions remain for how we will match variable supply and variable demand on the future grid.

Increases in variable renewable energy (solar and wind) and accelerated electrification are creating an imbalance between supply and demand on the grid. This problem must be solved using least cost measures to realize full decarbonization. Otherwise, the escalating costs of meeting peak demand could result in continued increases in utility rates that would make electrification less cost effective and threaten this transition.

It is tempting to think we can solve the mismatch of supply and demand on the grid by increased build out of the electric grid alone, but while more grid enhancements and expansions are needed, expansion alone will likely take too long and cost too much to achieve our policy goals.

Luckily, there are many current opportunities to ensure this transition happens quickly while minimizing costs. The opportunities outlined in this report are listed in Table 1.

Table 1. Summary of opportunities

Solution Area	Opportunities
Rates	Reduce volumetric rates to incentivize electrification
	Use dynamic rates for load shaping
	Update net energy metering for rooftop solar
	Develop more innovative approaches to rate setting
	Align utility incentives with societal goals
Grid infrastructure	Expand interregional transmission
	Utilize Grid Enhancing Technologies (GETs)
	Implement other alternatives to new transmission
	Invest in comprehensive distribution grid planning
VPPs and Load Flexibility	Expand value streams for Virtual Power Plants (VPPs)
	Include VPPs in grid planning
	Standardize VPP operations
	Standardize device control capability
	Further expand the deployment of smart grid infrastructure

To turn these opportunities into realities, advocates for decarbonization through electrification should take the following actions. First, advocates should work within their regions to understand the local conditions, with a focus on: climate zone, state and local policies, renewable generation mix, the current penetration and forecasted growth of electrification, utility regulation, and the type of grid balancing authority present. Second, advocates should enter the discussion by participating in stakeholder engagement processes with: state and local governments, utility commissions and/or public utility boards, balancing authorities and/or transmission operators, the Federal Energy Regulatory Commission (FERC), and other federal representatives to support these opportunities.

Introduction

This report provides electrification advocacy organizations, federal and state policy officials, utilities, and other industry participants with an overview of the grid implications of residential electrification and clean energy, as well as recommended solutions to create a reliable, affordable, and decarbonized grid. The report focuses on electrification of home appliances and transportation, including heat pumps, heat pump water heaters, induction stoves, electric vehicles, battery energy storage, and rooftop solar. Although the report focuses on the residential sector, many of the findings also apply to small or medium commercial buildings. Electrification of large commercial buildings and industrial processes are out of scope for this report. This report is meant to provide the basis for advocacy positions, but stops short of recommending specific policies or regulations.

Report structure

This report aims to both understand the challenges to meeting future electrified loads with renewable energy and identify opportunities to address these challenges. The report contains four sections. The first section describes the general challenges to decarbonization, with subsequent sections devoted to specific opportunity focus areas as follows:

- **Grid Challenges to Decarbonization** - a summary of key concepts in grid management and high-level challenges to decarbonization through electrification and carbon-free electricity

- **Opportunity Area 1: Electric Rates** – how rate reform can be used to incentivize electrification and help with load shaping to better match supply and demand on the grid.
- **Opportunity Area 2: Grid Infrastructure Upgrades** – what grid infrastructure upgrades are needed to support increases in electrified load and variable renewable generation, and the challenges to the rapid development of this infrastructure to support the decarbonization transition. This discussion includes the role of Non-Wires Alternatives (NWAs) and Grid Enhancing Technologies (GETs) as alternatives that can be both faster to implement and lower cost than poles and wires upgrades.
- **Opportunity Area 3: Virtual Power Plants** – a discussion of how electrified homes – with heat pumps, electric vehicles, rooftop solar, and energy storage – can participate in virtual power plants and help match supply and demand on the local grid.

These three opportunity focus areas were chosen as they are all critical for the preparation of the grid for decarbonization, and they offer opportunities for advocate involvement.

How to use this report

This report is not intended to cover all the relevant issues for electrification and the grid, but is instead intended to provide a succinct summary for advocates, regulators, and policy makers who want to understand some of the most important challenges and potential solutions for achieving decarbonization through the expansion of electrification and deployment of carbon-free renewable energy.

Findings from this report have been generalized at a national level, but specific local actions must be tailored to local conditions. Advocates and policy makers should work to understand how these issues apply in their specific jurisdiction before taking action on these recommendations.

Grid challenges to full decarbonization

This section describes the decarbonization pathway of electrifying everything and some of the challenges with meeting all future loads with carbon-free energy.

The decarbonization pathway

There is wide recognition that the world needs to tackle climate change by rapidly electrifying customer loads and transitioning to carbon-free electricity. This approach not only cleans the electric grid, but also has the potential to eliminate all distributed sources of greenhouse gas emissions and other pollutants from building energy use and transportation. In addition to being extremely efficient and emitting zero pollution, many electric machines provide superior functionality than their fossil-fueled counterparts. For example, heat pumps maintain more consistent indoor temperatures than fossil fuel-fueled furnaces, and induction stoves heat faster and are easier to clean than gas stoves.

In the US, the Biden administration has stated a goal of achieving a carbon pollution-free power sector by 2035 and net-zero emissions no later than 2050. To decarbonize our electric grid, we will need to rely on a variety of carbon-free electricity sources, including solar, wind, hydro, geothermal, and legacy nuclear. We will also need significant amounts of energy storage and load flexibility to reliably match supply and demand on the electric grid. Energy storage itself can come in several different forms including pumped hydro, green hydrogen, batteries, electric vehicles, flow batteries and thermal energy storage. Improved energy storage continues to be an ongoing area of research and there are a variety of new technologies being developed to meet these needs, though many will need significant time to come to market and be commercialized at scale.

Expanding renewable generation

The quickest path to reaching 100% carbon-free electricity requires a massive increase in electricity generation from clean sources such as solar and wind. While existing nuclear and hydro are also sources of carbon-free electricity generation, it is unlikely that we can count on new generation from these sources to scale up quickly enough to accelerate this transition in the short term.

According to the National Renewable Energy Laboratory (NREL), to achieve 100% clean energy in the US in a least-cost scenario, 60 - 80% of electricity generation in 2035 would have to come from wind and solar up from 17% in 2023. As a result of decarbonization goals, federal and state incentives, and continued price declines in solar and wind generation, wind and solar energy are expected to make up 84% of new US power generation capacity in 2023.

Previous Rewiring America analysis estimates that to electrify our economy we need to increase electricity production 2 to 3 times over current levels by 2050. While doubling or tripling our energy production with renewables is achievable, we also have to consider when that energy is produced and when it is needed over the course of a day, a week, a month, or a year.

Matching supply and demand on the grid

A significant challenge in managing the electric grid is the need for supply and demand to match perfectly at every point on the grid in real time. This is true both at the macro level on the transmission system, as well as at the local level on individual feeders on the distribution system. This is a matter of matching the real-time **capacity** of the electrical system with the real-time **demand** from customers. Capacity is the measure of the supply of power that is available at any given point to dispatch on the grid, while demand is the power being drawn by customers at any given point. Both capacity and demand are measures of power in units of Watts, whereas energy (power consumed or generated over a period of time) is measured in Watt-hours (commonly kilowatt-hours, or kWh).

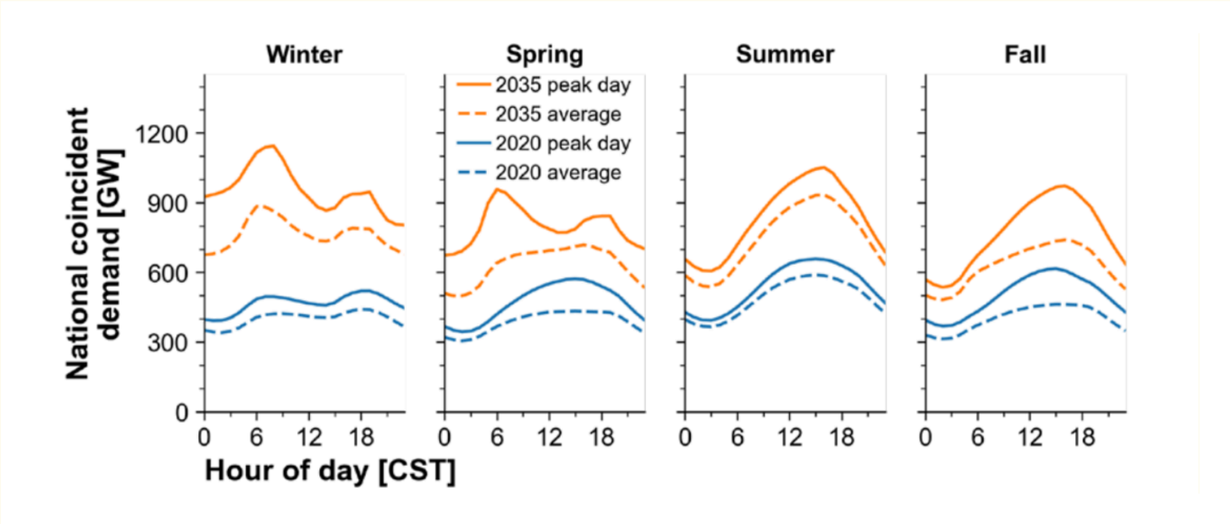
Solar and wind only generate power when the sun is shining and when the wind is blowing, so they are not **dispatchable** - they can not be turned on or ramped up at will whenever customer demand goes up. On the other side of the matching equation, hourly electricity demand is not as predictable as it has been in the past. This is due to large spikes in load when heat pumps or heat pump water heaters enter resistance heat mode, or when electric vehicles begin charging. Rooftop solar also serves a portion of demand on-site and can be widely variable from house to house due to passing clouds or other variable weather factors. While these effects are averaged out at a macro level, they can create much more variability and uncertainty on local distribution grids.

A key focus of grid planners is meeting peak demand, the point in the day/month/year where the power demand is highest. The electric grid components are sized at every point to ensure they have enough capacity to meet peak demand. This is referred to as resource adequacy and usually includes a factor of safety (called a **reserve margin**). The typical target reserve margin in North America is in the range of 10% - 20%.

Generation resources are typically dispatched based on their operating costs, with the cheapest resources (wind, solar and hydro, which have no fuel costs) dispatched first and the most expensive resources dispatched last - a concept known as **merit-order dispatch**. This results in peak demand being met by the most expensive resources, which drives up the cost of serving customers during peak times. Power plants that operate only during peak times are referred to as **peaker plants**, and sit idle for most of the year and are dispatched infrequently. To ensure these resources are economically viable and available when they are needed, significant **capacity payments** are paid for these systems in many parts of the country to have them available, regardless of how often they are used.

The NREL 100 Percent Clean Electricity by 2035 Study anticipates that overall US peak demand in 2035 will be more than double what it was in 2020, using their Accelerated Demand Electrification (ADE) scenario. Accelerated electrification results in growing winter and spring peaks in the early morning, and summer and fall peaks in the early evening.[1]

Figure 1 shows the results of load modeling by NREL for 2020 and 2035 in which loads on peak demand days are projected to increase and load shapes are expected to shift due to increased electrification and variable renewable generation. The highest peaks are expected to occur on winter mornings (highest point of yellow line in Winter graph) rather than summer afternoons as they do now (blue line in Summer graph). The new winter peak will be significantly higher than the current peak, requiring the build out of generating capacity that can meet the new highest demand days.

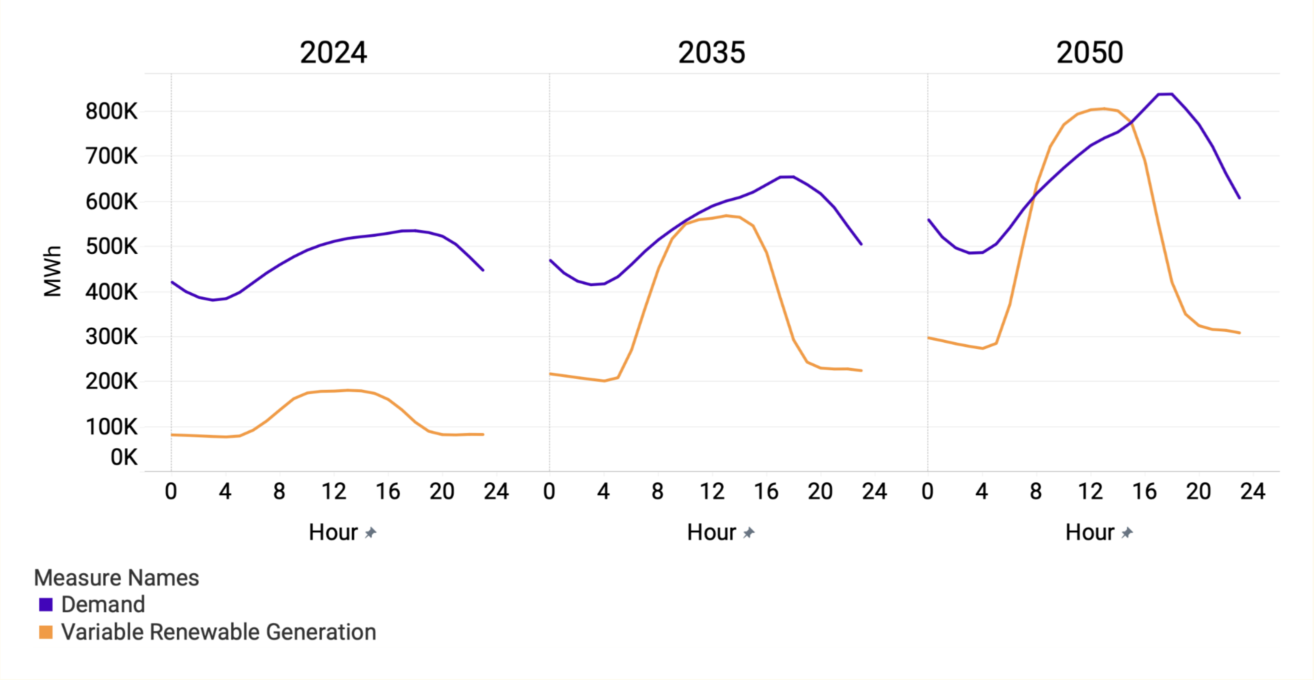


Source: NREL

[1] The NREL is generalized at a national level. It is important to note that present and future load profiles will vary significantly by region due to climate, the growth of distributed generation and the uptake of electrification. For regional load curves, NREL has published modeling results as part of its Cambium database. https://www.nrel.gov/analysis/cambium.html

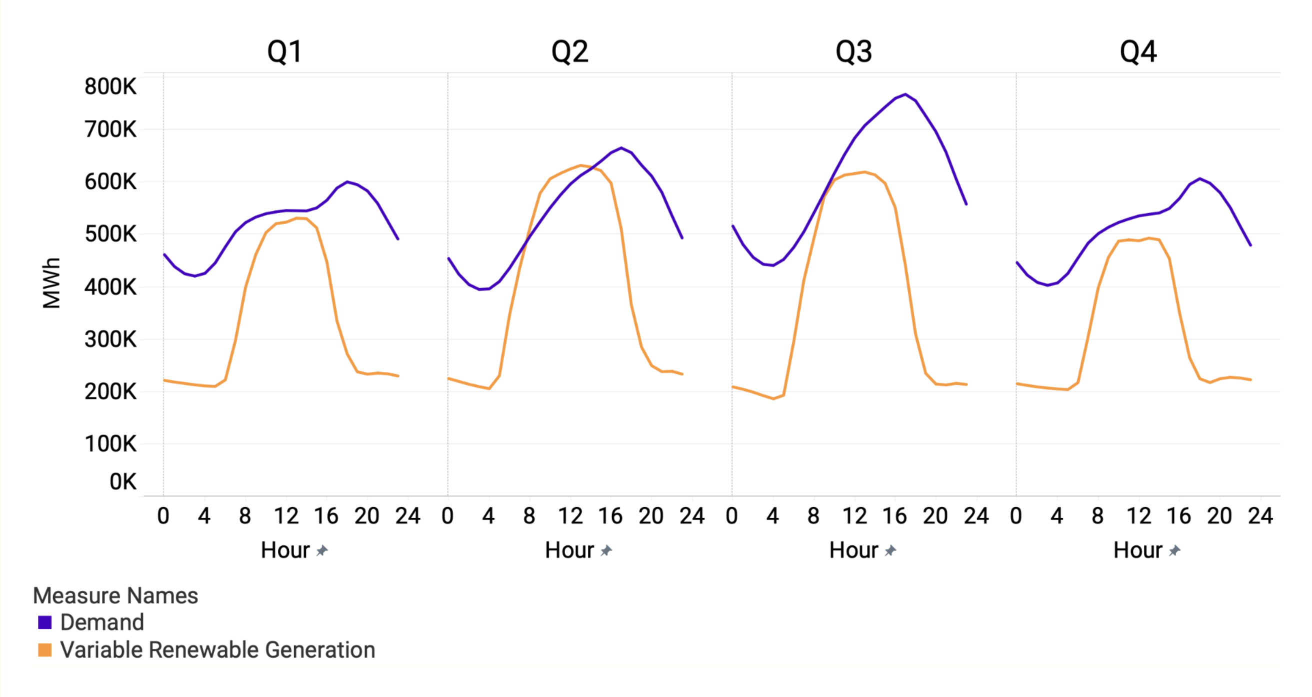
Figure 1. NREL Modeled peak demand for the US in 2035 due to accelerated electrification

Figure 2 shows modeled average daily demand curves (in purple) and variable renewable generation from wind and solar (in orange) for 2024, 2035, and 2050 using data from NREL's "mid-case with 100% Decarbonization by 2035" scenario. These projections show how wind and solar generation will be insufficient to power peak demand given that variable renewable generation peaks midday while demand peaks in the evening after the sun has gone down. The challenge of powering these increased loads with 100% carbon-free energy will involve filling in the gaps between these demand and generation curves in the early morning and evening.



Source: [NREL Cambium Database]
Figure 2. Forecasted average hourly generation and load by year

This challenge will vary on a seasonal basis. Figure 3 shows the same modeled data for 2035 by season. This shows the increased demand in summer evenings in Q3, and the increase in load due to electrified heating in the early mornings in the colder weather months of Q1 and Q3.

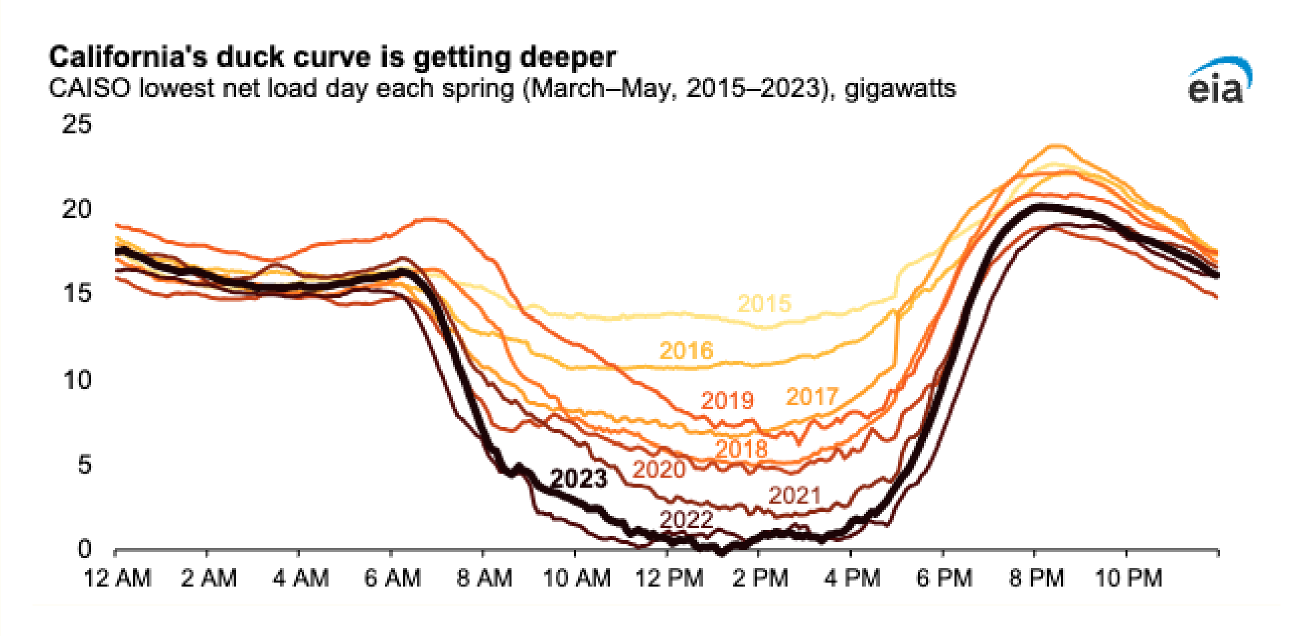


Source: NREL Cambium Database

Figure 3. Forecasted average hourly generation and load by quarter for 2035

These challenges will also vary regionally based on a number of factors including weather / climate zone, existing and forecasted generation mix, and the current and future penetration of electrification. For example, California is already experiencing challenges in matching supply and demand due to the increased penetration of renewables. California has low heating demand, so the primary challenge with electrification will be meeting the increased demand from electric vehicles. California also has a high penetration of solar generation, which has led to the famous "duck curve" for net load (system load minus variable renewable generation). As shown in Figure 4, a steep evening ramp of demand requires conventional fossil fuel generation to quickly ramp up output as the abundant solar supply recedes and demand stays high. This dynamic is worst in the spring when sunshine is abundant and air conditioning demand is still low.

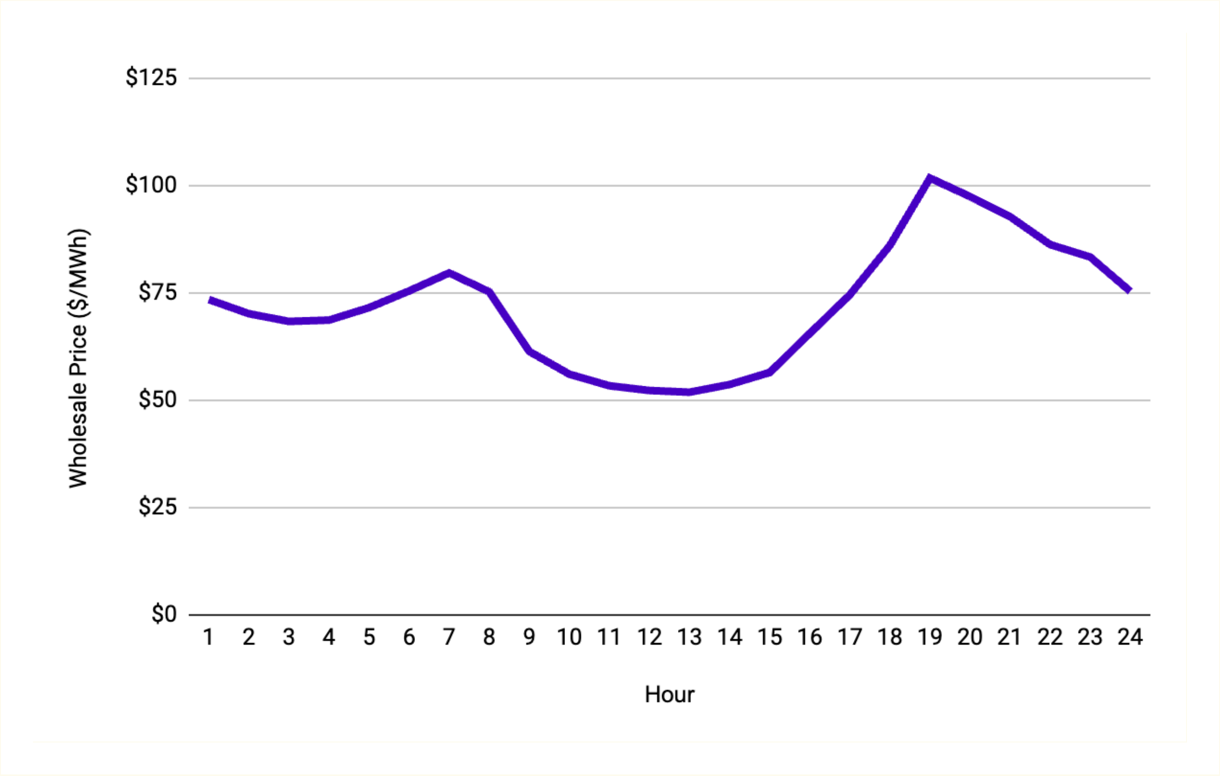
This results in significant solar curtailments in the spring months due to over-generation and transmission congestion that prevents moving excess solar generation to regions on the grid where it could be used. High solar curtailments result in reduced revenue for solar generation, which makes these resources less competitive. This effect also results in high costs for serving peak demand due to the large amount of dispatchable capacity required to quickly ramp up in the evening to meet peak demand.



Source: [EIA]

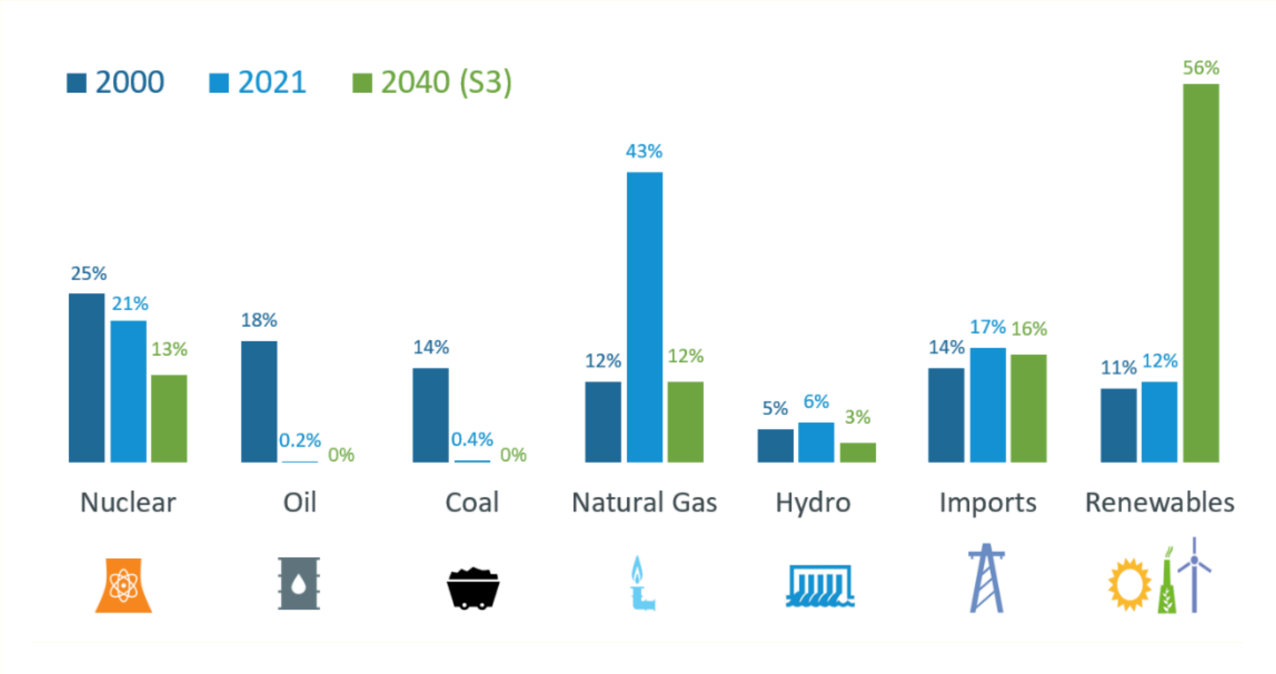
Figure 4. Duck curve of net generation on the lowest net load day of the year 2015 -2023

The high penetration of solar energy midday and the need for fast ramping natural gas resources to meet peak demand both affect the price paid for energy on the California Wholesale Market for electricity. Figure 5 shows the average daily wholesale electricity price by hour in California in 2022, where on-peak wholesale prices were roughly twice as high as those in the middle of the day when solar is abundant.



Source: [LBNL renewables and wholesale electricity prices (ReWEP) tool]
Figure 5. The evolution of California wholesale prices 2012 -2022

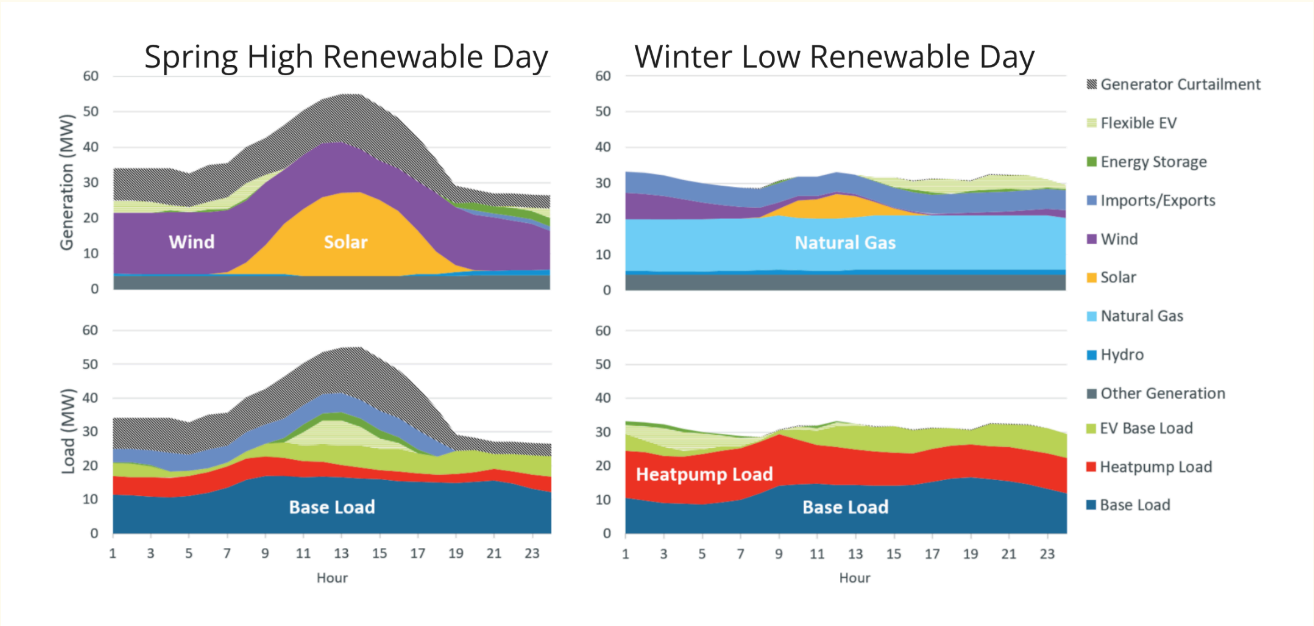
In New England, the Independent System Operator of New England (ISO-NE) developed a future grid reliability study looking at future supply and demand curves through 2040 under a variety of scenarios. Figure 6 shows the anticipated change in resources needed to meet electricity demands in 2040 under their Scenario 3 for "deep decarbonization" (S3). This shows the phase out of oil and coal and the rapid increase in renewables by 2040. It also shows the significant recent increase in natural gas capacity that will be scaled back by 2040 in favor of more renewables.



Source: [ISO NE 2021]

Figure 6. Percent of total system resources by fuel type for ISO-NE by year under a deep decarbonization scenario

Figure 7 illustrates some of the challenges of managing the grid with high penetrations of wind and solar. It shows that wind and solar can meet nearly all demand during high renewable days, but on high renewable spring days, renewables will overproduce and must be curtailed (gray area in top left graph). However, regional wind and solar will not produce enough on low renewable winter days, forcing the region to rely on natural gas and imported power (blue areas on the top right graph) to meet significant heat pump heating loads when sufficient wind and solar are not available.

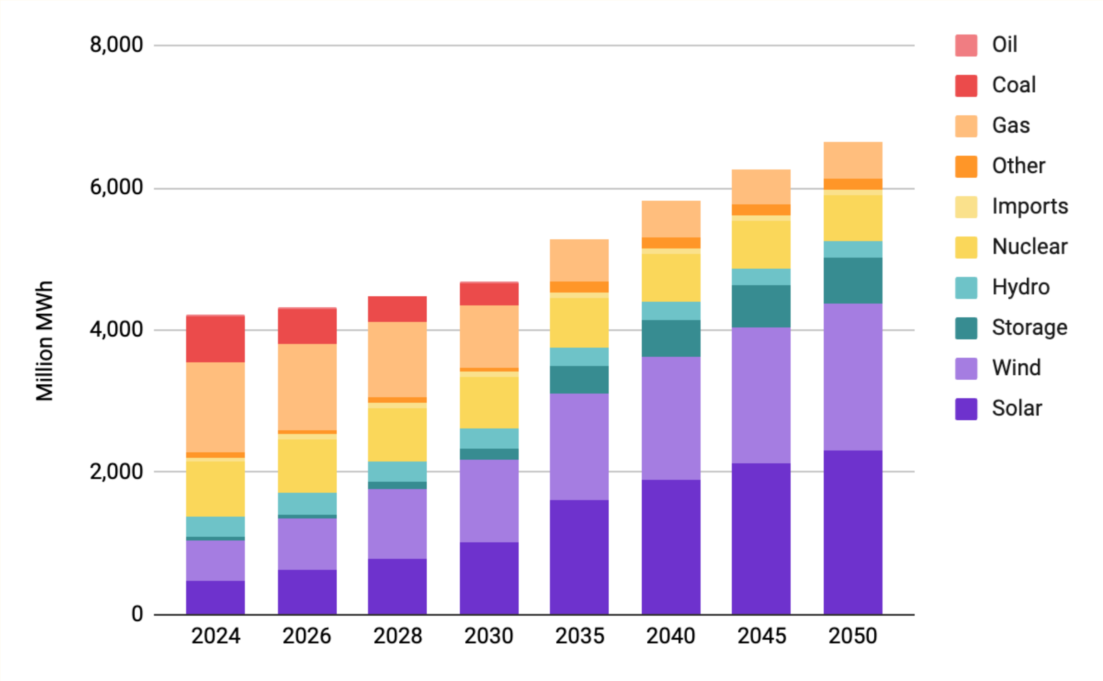


Source: [ISO NE 2021]

Figure 7. Generation and load profiles for a high renewable day and a low renewable day in new england in 2040 under a deep decarbonization scenario

Both the California and New England examples suggest that regional solar and wind alone will not be able to meet all of the projected demand. As we add more wind and solar to the grid, we must also plan for ways to meet peak demand when regional wind and solar are not available. In the short term, a reliable grid requires significant dispatchable resources such as expensive natural gas-fired peaker plants, which need to be given significant capacity payments to be economically viable because they only operate during relatively few peak hours over the course of a year. In the longer term, a 100% clean grid will need to meet that need with mostly non-fossil sources. Figure 8 shows modeled values for the changing generation mix using data from NREL's "mid-case with 100% Decarbonization by 2035" scenario. This scenario shows over 84% of generation coming from carbon free sources (solar, wind, storage, nuclear, hydro) starting in 2035, up from 51% in 2024.[2]

[2] The NREL model achieves net decarbonization primarily by assuming carbon capture and storage on gas generation starting in 2035.

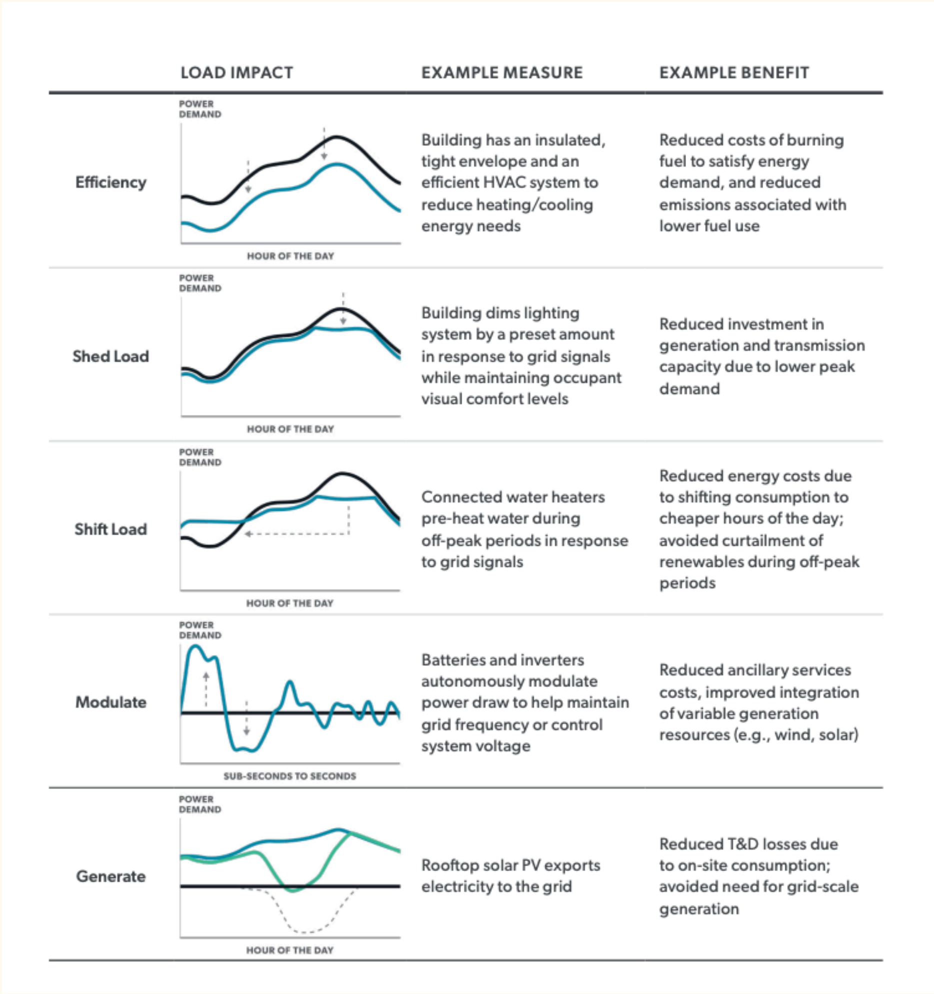


Source: NREL Cambium Database https://www.nrel.gov/analysis/cambium.html
Figure 8. The evolving generation mix

The most straightforward approach to dealing with the issues associated with matching supply and demand on the grid would be a rapid and significant build out of grid transmission and distribution infrastructure. However, this is likely not the lowest cost approach, nor is it the fastest given that new infrastructure projects often face significant opposition and delays.

Load flexibility of electrified machines

An important tool for helping match supply and demand on the grid is load flexibility, or the ability to change load curves to better match supply curves. There are a number of different approaches to load flexibility, as illustrated in Figure 10.



Source: LBNL

Figure 10. Different approaches for load flexibility for buildings

Electric machines have varying degrees of load flexibility. Electric loads with **high flexibility** are loads where the usage is not rigidly time dependent and/or technical solutions exist to shift the load without affecting customer utility or comfort. Highly flexible loads include: electric vehicle chargers, water heaters, dishwashers and clothes dryers. For electric vehicles, load can be pushed outside peak periods daily by scheduling charging to begin later in the evening. This should not affect the customer, provided they can get enough charging done before they need the vehicle next. For heat pump water heaters, load can be pushed outside peak periods daily without affecting customers by preheating water to higher temperatures (often with a mixing valve installed for safety reasons) or using a larger tank so that the tank does not have to heat the water during peak periods.

Electric loads with **moderate flexibility** are loads that can be shifted occasionally but not regularly. A good example of a load with moderate flexibility is **heating and air conditioning**, which is difficult to shift regularly without affecting customer comfort, but can be shifted occasionally when the grid is stressed. For example, many demand response programs shift load using connected thermostats, but may be limited to only short and/or a limited number of events per month.

Loads with **low flexibility** cannot be shifted much without affecting customer comfort. For example, **electric cooking** is inflexible because it usually occurs just prior to set meal times. Many other household appliances are also inflexible because they are more or less always operating (e.g., refrigerators and freezers). These loads are difficult to shift and so may only be applicable to emergency demand response programs looking to maximize load shed to avoid a grid outage.

Supporting smart grid infrastructures

An important element for implementing load flexibility efforts is the availability of the supporting smart grid infrastructure, primarily Advanced Metering Infrastructure (AMI, also known as "smart meters"). This hardware measures energy consumption at regular intervals and relay that data back to the utility/aggregator for analysis. Smart meters are necessary for implementing dynamic utility rates and for measuring and reporting the impact of Virtual Power Plants (VPPs) and other load flexibility programs. This interval data usually must be measured every hour or shorter (e.g., every 15 minutes). AMI deployments continue to increase in the US, with a roughly 69% penetration in 2021 and a forecasted uptake of around 90% by 2030. This rise in AMI deployments is partly due to smart meter investments as part of the 2009 Federal American Recovery and Reinvestment Act (ARRA). To take advantage of many of the opportunities highlighted in this paper, regions will have to continue to invest in this metering infrastructure, and any region interested in deploying these opportunities should check on the status of AMI as a possible prerequisite for deployment.

Building the grid of the future at the lowest cost

A key concept for understanding barriers to building out the grid of the future is how Investor Owned Utilities (IOUs) are regulated and how they earn a profit for their investors.[3] This concept is vital for understanding how utility rates are set and how utilities make investment decisions for building out the grid. The rate setting process (rate cases) for IOUs are decided by Public Utility Commissions (PUCs). In rate cases, the PUC determines a revenue requirement for the utility. This is the amount of revenue they can recover through customer rates for electricity. The basic equation for the revenue requirement for a regulated utility is:

Revenue Requirement = Rate Base Investment x Rate of Return + Operating Expenses[4]

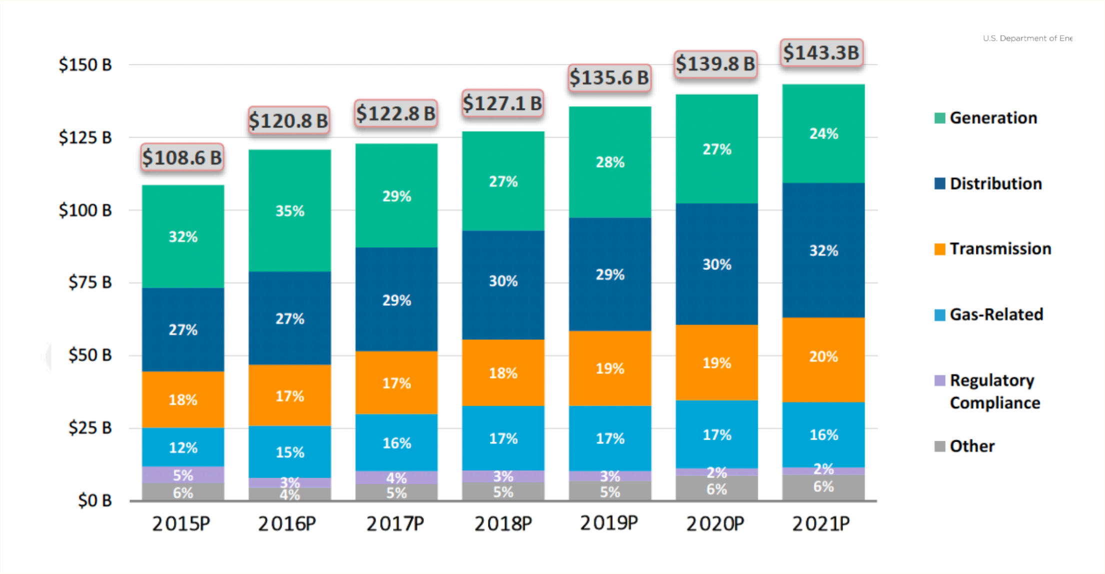
What this means in practice is that regulators allow utilities to provide a guaranteed rate of return[5] for their investors based on "rate-based" grid infrastructure investments that have been approved to be recovered through rates. Once determined, the revenue requirement is used in conjunction with load forecasts to calculate retail electricity rates by apportioning it across customer classes based on their forecasted load.

To meet peak demand, utilities are incentivized to build more rate-based infrastructure, such as new poles and wires within their own service territory. These investments provide additional profit for their shareholders, which is based on the rate of return from these investments. Many lower cost options like load flexibility and interregional transmission typically cannot be rate-based and therefore there is less incentive for utilities to invest in these solutions.[6]

This system made more sense when load growth was slow and predictable, but in a world with rapid load growth and increasingly complex grid dynamics it could lead to rapidly escalating utility rates. If PUCs continue to incentivize utilities to invest in capital-intensive local grid upgrades, rather than encouraging them to consider lower cost alternatives such as NWAs and VPPs, customer rates could continue to rise, which will make electrification less cost-effective and less competitive compared to continued reliance on fossil-fuels.

[3] According to EIA-861dataset, IOUs served 67% of US electricity customers in 2022, with the remaining customers split between cooperatives and publicly owned utilities.
[4] For more information on the structure of utilities and regulatory models, see RAP's 2016 report: Utility Regulation in the US: A Guide, Second addition.
[5] The rate of return is also determined by the PUC. The average ROE on utility infrastructure in Q1 2023 was 9.71%.
[6] NWAs provide options for using the grid we have more efficiently to avoid building out new poles and wires, load flexibility aims to move load out of peak periods to avoid or defer the need for new generation and grid infrastructure, and interregional transmission helps move energy across long distances to compensate for the variable nature of renewable energy.

Figure 11 shows how capital expenditures for IOUs have shifted in favor of grid infrastructure, with transmission and distribution spending (orange and dark blue) increasing from 45% to 52% of spending, while generation spending (green) has fallen from 32% to 24% between 2015 and 2021.



Source: [LBNL]()
Figure 11. Capital expenditures by investor owned utilities

Since 2020, the Levelized Cost of Energy (LCOE) of utility-scale wind [has dropped 60%]() and utility-scale solar [has dropped 75%](). As the cost of new generation falls due to increased low-cost wind and solar generation, we would like overall utility costs, and therefore electricity rates, to fall as well. This will not happen if the infrastructure costs of meeting peak demand are rising.

What we do not want is for increased electrification and low cost wind and solar to create upward pressure on rates and thereby make further electrification less cost effective. What we want is for these forces to create downward pressure on rates and make electrification more cost effective and create positive feedback to drive our transition to 100% clean energy quickly and cheaply, as shown in Figure 14.

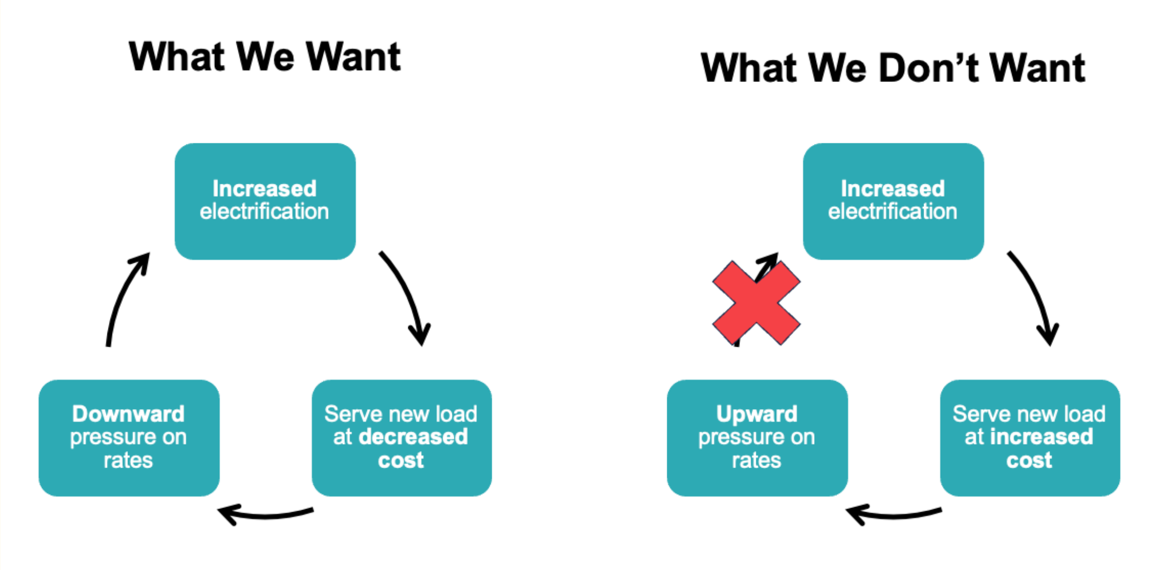


Figure 14. Electrification rate feedback cycles

Opportunity 1: Rate design

The changing nature of our electrical loads and generation profiles requires rethinking electric utility rate design. Done correctly, rate reform should be used to: 1) create an incentive for electrification, 2) help match supply and demand on the grid, and 3) ensure a more equitable energy transition. This section will discuss some basic concepts of rate design and make recommendations for how PUCs, utilities, and other policy makers can use these concepts to design effective rates for the future grid.

Basics of rate design

This section provides a basic overview of rate design principles and rate types.

Rate design process

The first step in the rate design process is determining the utility revenue requirement, as discussed in the previous section. For IOUs the revenue requirement is determined by multiplying the rate-based investments by the allowed rate of return and adding in operating expenses. Next, the revenue requirement is allocated to the different customer classes (e.g., residential, commercial, industrial) to determine how much revenue should be recovered through rates from each class. Then, a load forecast is estimated for each customer class. The revenue requirement and load forecast are then used to determine the rate. In the simplest version, the revenue requirement can simply be divided by the number of kWh from the load forecast, which would give a flat $/kWh rate to cover all hours of the year. But there are many other more complex rate designs, many of which are discussed below.

Rate types

The three basic rate components covered by utility rates are:

1. Fixed charges / service fees – these charges are for cost components that typically do not vary by usage and are divided amongst customers equally. Costs typically recovered through fixed charges include the costs of billing customers and other administrative costs.
2. Volumetric rates ($/kWh) – these charges are assessed per kWh of electricity usage, and can be split into a delivery component to cover the cost of the grid infrastructure to deliver energy to a customer, and the energy component to cover the cost of generating electricity. Volumetric rates can take many forms, which are discussed in more detail below.
3. Demand charges ($/kW) – demand charges are assessed based on the maximum demand (power) consumed by a facility. Demand charges are typically a part of large commercial and industrial customer bills, and typically are not used for residential customers. Demand charges can be a significant portion of the bills for large customers and can motivate them to reduce their maximum usage, which can reduce their contribution to peak demand.

For volumetric rates, there are three main rate types to consider:

1. Flat – rates that are consistent from hour to hour over the course of a year.
2. Block – rates that are flat for a set kWh usage amount (or "block") and then can go up after exceeding that usage amount in a month.
3. Dynamic – rates that vary over specific time periods.
    a. Time-of-Use (TOU) – rates that vary over the course of a day and/or season. The intention of these rates is to give customers an economic signal to move usage to lower cost periods that occur regularly, such as in the middle of the night when there is cheap wind power available, or the middle of the day when there is cheap solar power available. TOU rates are typically lower for "off-peak" hours

like nights and weekends, and higher for “peak” hours when the grid is stressed and closer to capacity. In areas of high solar penetration there may also be a “super off-peak” period with very low rates during midday when solar generation is high.

b. Critical Peak Pricing (CPP) – rates that can rise significantly during occasional grid stress events that happen a few times a year. These rates give customers a strong economic signal to reduce usage during the few hours of the year when the grid is capacity constrained. Customers are given advance notice of these events. These rates act similarly to a demand response event.
c. Peak Time Rebate (PTR) – rates that are the “carrot” alternative to the CPP “stick.” These rates give customers credits for reducing consumption during grid stress events. This approach is more customer-friendly than CPP, but is difficult to implement due to the “but for” nature of the customer credit – in order to determine how much credit to give, the utility must estimate how much a customer actually reduced their demand from what they otherwise would have used “but for” the PTR event.
d. Real-Time Price (RTP) – rates that vary by hour over the course of the day and are usually tied to the wholesale price of energy. Rates are typically published a day ahead, and will disincentivize usage when the grid is stressed and prices are high because they are tied to wholesale prices.
e. Transactive Energy – a system where individual users and generators within a distribution area can buy and sell power among themselves based on the value of the energy as determined by a transactive energy system that acts as a local market mechanism for matching supply and demand.

This report primarily focuses on the dynamic rates that are being developed today. Figure 15 shows a graphical representation of how prices can vary over the course of the day for some of these dynamic rates.

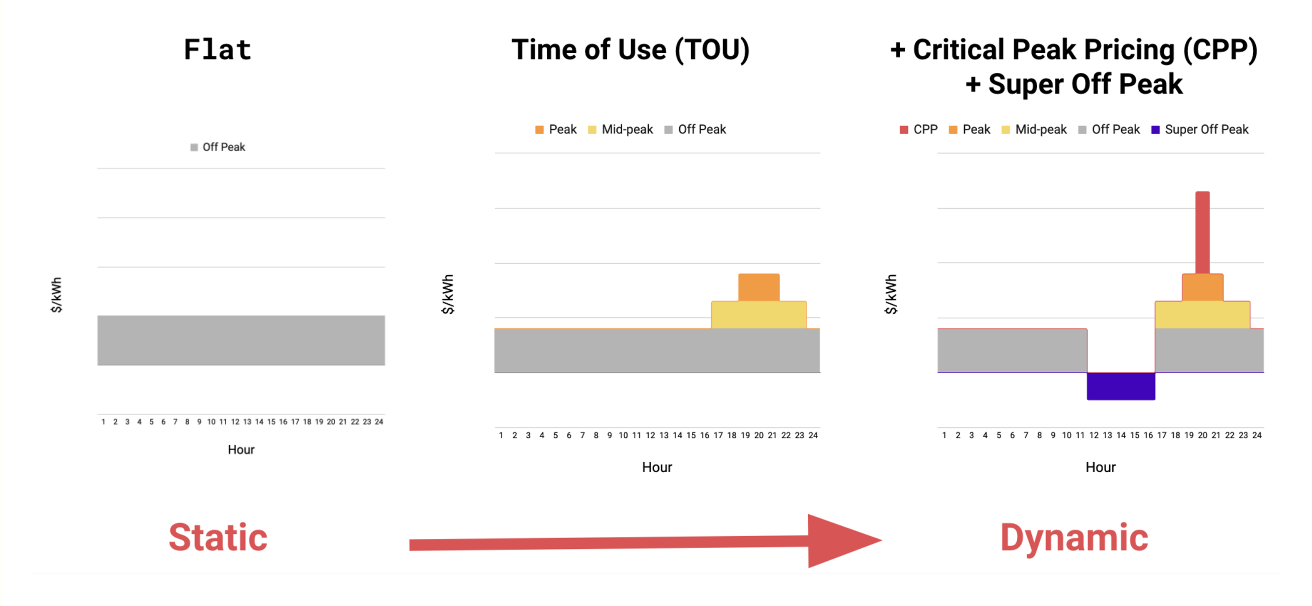
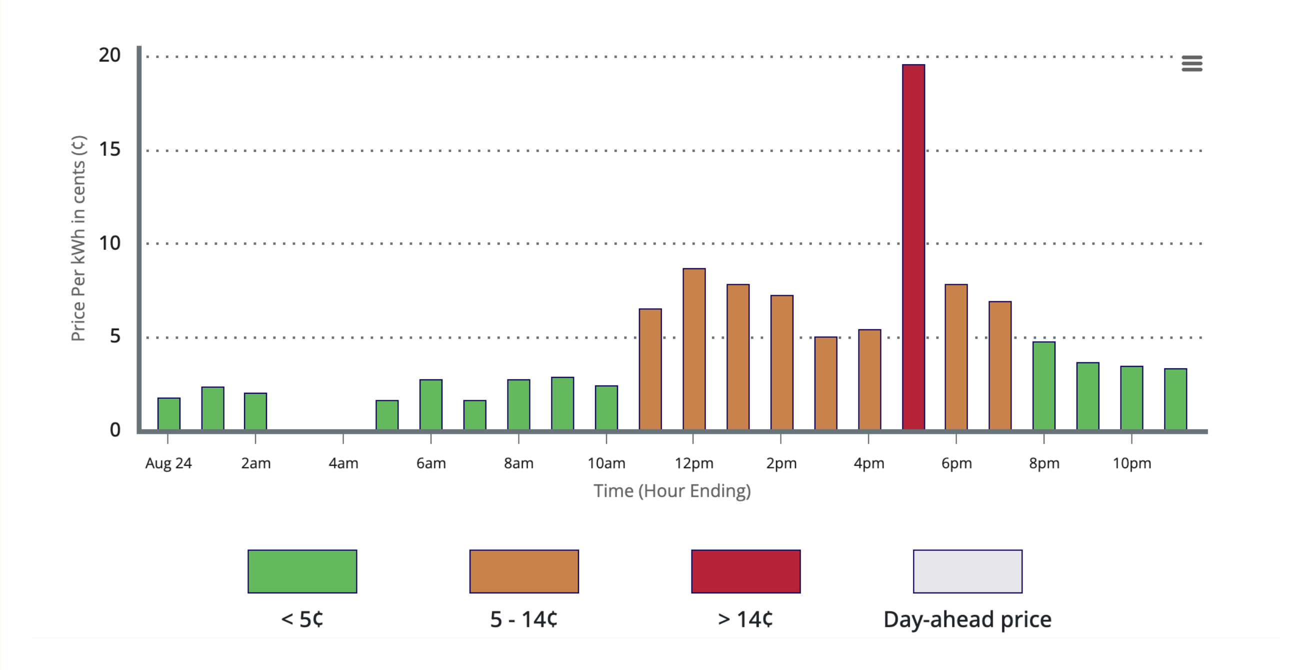


Figure 15. Illustration of static and dynamic rate types

The most dynamic rate types are RTP rates, which vary over the course of a day in response to wholesale prices. Figure 16 provides an example of one of these rates. To date, these rates are mostly offered to large commercial and industrial customers though there are some pilots for residential customers. Real time rates create many challenges for residential customers, such as confusion over high variability in electricity bills month to month, lack of customer focus on energy prices to manually adjust usage for energy savings, and lack of automated devices to automatically respond to price signals. Real time prices could be especially problematic for low-income customers that cannot afford premium smart devices to create energy savings by shifting energy usage. Despite these challenges, the California Public Utilities Commission (CPUC) is interested in moving toward fully dynamic rates for all customers in California to advance demand flexibility.



Source: ComEd

Figure 16. ComEd real time prices for August 24th, 2023 during a heat wave

Net Metering

As the cost of solar panels has continued to fall and concerns about climate change have increased, more and more customers are opting for installing distributed rooftop solar on their homes and businesses. These systems are typically sized to provide yearly energy production in line with the yearly usage of the building. But, because the output profile of solar panels is not the same as the customer usage profile, customers must take energy from the grid when the sun is not shining, and sell it back to the grid when their solar production outstrips their usage. To provide a strong incentive for the installation of solar panels, states have adopted forms of **Net Energy Metering (NEM)**, where any extra solar power exported to the grid when solar production exceeds the building load is credited back to the customer at a set rate, often the same retail rate the customer pays to buy power from the grid. If the customer's total energy production is close to their total energy use, this will leave the customer with a net zero electricity bill at the end of the year.

Cost Causation

The principle of **cost causation** states that rates should properly allocate revenues based on how costs are incurred by the utility. This ensures an economically efficient price signal where the price to consume a kWh of electricity accurately reflects the cost to produce that kWh at the time it is consumed. For example, costs incurred by utilities to build out additional grid infrastructure to accommodate peak demand periods are “fixed” for the year, since the cost is the same no matter how much or little it is needed over the course of the year.

In contrast, the direct cost of generating energy does vary for electricity generators, as each kWh produced from a given generator has levelized costs associated with the capital equipment and the fuel costs for production.[7] These costs make sense to recover through volumetric $/kWh rates and should be closely tied to the avoided cost of energy production, which is the cost of generating the marginal kWh of electricity that the customer would be consuming.

Contrary to the principle of cost causation, past rates have primarily recovered all costs through flat volumetric $/kWh rates, but to improve cost causation it is important to ensure that the costs of consuming electricity are more effectively aligned with the costs of producing and delivering that energy. For example, the cost of producing solar energy when the sun is shining is much lower than the cost of serving peak demand with natural gas peaker plants after the sun sets. The principle of cost causation would therefore necessitate that the retail rate be higher in the evening or early morning during system peaks than it is in the middle of the day. Cost causation would be improved by using dynamic rate structures as discussed above.

Overview of Challenges

This section provides an overview of the current challenges to using rates to help manage the future grid.

Rising rates create a disincentive for electrification

The increasing costs of meeting peak demand could lead to rate increases that will create disincentives to electrify, and therefore threaten the clean energy transition. It is important that IOU profit models and future rate designs minimize this barrier by putting downward pressure on electric rates.

Flat rates don’t incentivize load flexibility

In the past, residential ratemaking has been a straightforward process, where utilities determined their revenue requirement based on rate-based investments, and then divided that

[7] Levelized costs take the capital costs of building the facility divided by the total number of kWh expected to be generated over the useful life of the equipment. Renewables like wind and solar do not consume fuel, so their costs are solely based on the levelized costs of building and maintaining the facility.

revenue requirement by the forecasted kWh to be delivered over the year. This gives a flat $/kWh rate to charge customers for every kWh used. This approach made sense when both the supply and demand on the grid were somewhat steady and predictable, but as we face more complex grid dynamics, rates should provide economic signals to customers to incentivize load flexibility. As variable renewable generation like wind and solar create complex grid dynamics, it is important for new rates to reflect the variable costs of supplying energy for different hours of the day and days of the year. PUCs and utilities across the country are looking at more dynamic rate structures to provide this economic signal to customers. According to Energy Information Administration (EIA) data, just under 10% of residential utility customers were on dynamic rates in 2022, and 48% of those customers are in California, where default TOU rates were rolled out in 2020. 80% of available dynamic rate options in 2022 were TOU rates.[8]

Net metering for rooftop solar does not help meet peak demand

NEM can create challenges when the penetration rate of solar power is very high. Once solar penetration is high, wholesale prices can be very low during times of high solar output and low load, because the grid is flooded with cheap solar power. Net metering laws that require utilities to compensate solar customers close to retail rates, especially if those retail rates are flat and therefore depart sharply from wholesale rates, are overpaying them for energy that could otherwise be procured on the wholesale market at a fraction of the cost. This is contrary to the principle of cost causation and does not provide an incentive to store or shift the power to help meet peak demand when wholesale prices are higher. Furthermore, continuing to overpay customers for solar exports will result in increased solar energy during hours of solar overgeneration, which creates a positive feedback loop that will continue to exacerbate the grid management problem.

Opportunities

Meeting our clean energy goal of decarbonization through electrification requires a rethinking of rate design for the modern grid. Regulators overseeing rate making should focus on the following opportunities:

1. Reduce volumetric rates to incentivize electrification
2. Use dynamic rates for load shaping

[8] EIA Form 861 data indicates that 13 million residential customers were on dynamic rates in 2022 out of 140M total residential customers from EIA's electric sales data. The Form 861 data indicates that 347 of the 429 dynamic rates offered by utilities were TOU rates.

3. Update net energy metering for rooftop solar
4. Develop more innovative approaches to rate setting
5. Align utility incentives with societal goal

Reduce volumetric rates to incentivize electrification

Future rates should create incentives for customers to move away from fossil-fueled machines and towards electrified machines that can be powered by clean energy. New rate designs can create these incentives by reducing volumetric rates ($/kWh) and recovering costs through alternate means. By lowering the volumetric rate, the financial benefit of switching home energy use from fossil fuels to electricity will increase and be more attractive to consumers. To ensure this change does not encourage increased energy use during peak periods, this approach could be paired with dynamic rates, including higher rates during peak periods and lower rates during off-peak and super-off-peak periods. In the creation of appropriate rate levels, regulators should determine the breakeven rate where the cost of electrification is equivalent to fossil-fueled alternatives, and aim for rates that are below the breakeven rate for electrified customers.

Volumetric rates could be lowered to more closely match the avoided cost of energy, or the actual cost that would have been spent generating the marginal kWh of electricity. Many of the costs of servicing customer load come from building out new grid infrastructure to meet increasing peak demand, which could be more properly recovered through other rate components like fixed charges or CPP rates. Reducing volumetric rates all the way to the avoided costs could result in fixed costs that are too high to be politically viable, but any shift from volumetric rates to fixed costs could help improve cost allocation and provide an incentive for electrification.

Regions with colder climates where peak demand currently occurs in the summer could adopt seasonal rates with lower winter rates. This creates an incentive for heating electrification by lowering the volumetric cost of energy in the winter, when the cost of serving winter load is lower. This approach also leads to better allocation of grid costs to summer peaks through higher summer rates. Note that this approach may not be applicable to winter peaking utilities, or may have to be modified over time for areas where increased heating electrification causes a switch to a winter peak.

Use dynamic rates for load shaping

Load shaping and flexibility can help to move electric load outside of peak times, reducing energy supply costs and reliance on fossil-fuel peaker plants. Future rates could create incentives for load shaping and load flexibility by:

1. Adopting dynamic rates, such as TOU rates, that incentivize pushing flexible loads outside of peak periods. This will provide more available capacity during peak times to serve loads with less flexibility like heating, air conditioning and electric cooking.
2. Considering device-specific rates for flexible loads, such as electric vehicles (EVs) and water heaters. These rates could have high peak rates to push these loads outside of peak periods, but would not affect the cost of less flexible loads which would be covered by the standard residential rate. These rates could be metered using separate utility meters or device telematics. These rates could also be $0 or negative during "super off-peak" times when renewable energy is plentiful, to incentivize usage during these periods, especially in areas with frequent negative wholesale prices and/or significant solar curtailment.
3. Using CPP rates to provide economic signals for load flexibility. These rates lower the standard volumetric charges but have very high rates during peak events when the grid is stressed. Customers that shift load during these events will save money on their bills, while those using large amounts of energy in these periods will help cover the high costs of serving peak demand.

Update net energy metering for rooftop solar

In areas of high solar penetration, customers should be incentivized to install energy storage, or utilize EV batteries for their storage capacity. Rates that compensate solar energy export near wholesale market costs incentivize customers to store solar energy during high solar output hours, and to use that energy to offset usage or export to the grid during peak demand hours with high wholesale market prices. States that have implemented or are considering NEM reforms include California, Hawaii, Arizona, and Utah.

Develop more innovative approaches to rate setting

In addition to the more standard rate setting strategies mentioned above, there are other innovative approaches to rate reform that could be pursued. These opportunities include:

1. Regions could pursue new electrification-specific rates. Examples of this include giving fuel switchers a marginal cost of energy (kWh) budget to account for the increased load, or multi-year fixed bills that share the risks of electrification with utilities.[9]
2. Efforts to improve cost allocation should also aim to make utility bills more equitable by ensuring the costs of generating and delivering energy are not borne unfairly by low-income and other disadvantaged customers. One approach that is currently being considered is to vary fixed costs based on a scale of customer maximum usage or income.[10] Another is ratepayer caps, such as Percentage of Income Payment Programs (PIPPs) that ensure energy bills are capped at a certain percentage of income for low-income ratepayers.
3. Other fixed costs not related to energy use or meeting peak demand - such as costs for wildfire mitigation, stranded assets, or low income assistance - could be paid for by state and/or local governments as societal costs. Covering these costs through more progressive tax structures, such as income taxes, would also be more equitable than covering them through fixed charges or volumetric charges on utility bills, which might be overly burdensome to low-income customers.

Align utility incentives with societal goals

Policy efforts could also focus on better regulation by legislatures and PUCs to ensure that utilities are incentivized to meet societal goals such as decarbonization and reducing electricity bills.

Utilities should be incentivized to meet the challenges of decarbonization with the lowest cost solutions. For example, in Performance-Based Regulation (PBR) models, the allowed utility rate of return can be adjusted based on performance measured by predefined metrics.[11] These adjustment mechanisms are known as Performance Incentive Mechanisms (PIMs). Current areas of focus for these PIMs include:

1. Meeting renewable, clean energy or emissions-reduction goals
2. Encouraging new technologies, including DERs and smart grid technologies
3. Improving peak-load management
4. Enhancing reliability and resilience

[9] For a discussion of these alternative rates, see Leveraging the rise of the prosumer to promote electrification.
[10] California has begun developing income-graduated fixed charges as part of its Demand Flexibility Rulemaking (R.22-07-005).
[11] For more information on PBR, see the National Conference of State Legislatures (NCSL) or the National Association of Regulatory Utility Commissioners (NARUC) websites.

5. Addressing issues related to energy equity
6. Accommodating electric vehicles or other forms of beneficial electrification

PBR and PIMs can help ensure that utility incentives are aligned with those of ratepayers and the public, while advancing decarbonization and equity objectives. In this way, utilities that fail to meet societal targets would earn lower rates of return, which would lower the revenue requirement and thereby reduce customer rates.

Another option would be to shift from IOU models to public non-profit utilities, which eliminates the need to earn a profit off new investments.

Case study examples

Table 1 provides examples of new innovative rates across the country.

Table 1. Innovative rate examples

Utility and Rate	Description
Burbank Water and Power Electric Vehicle TOU rate (Burbank, CA)	• Seasonal TOU rate • Lower volumetric charges in winter • Summer peak is \$0.1812 • Off peak energy rate is \$0.00 • Graduated fixed customer charge based on panel size ranging from \$14 - \$22 - Largest fixed charge is for customers with a service panel over 200A
Oklahoma Gas and Electric Smart Hours	• TOU rate • Variable peak pricing with peak rates of: Standard 0.13 \$/kWh, High 0.26 \$/kWh, Critical 0.48 \$/kWh
ComEd Hourly Pricing	• Real-time rate at the hourly market price • Includes demand charge
Pepco Peak Energy Savings Credit	• Peak Time Rebate of \$1.25/kWh that gives customers a credit for reducing energy on peak days
New Hampshire Electric Cooperative	• Real time rate which includes: generation, capacity and transmission components

Transactive Energy Rate	• Rate can apply directly to devices using telematics data for billing
Central Maine Power Electrification Rates	• Electric Technology Rate - includes a higher fixed charge and lower volumetric rates • Heat Pump Rate - same as electrified technology rate, but with higher rates in summer and lower rates in winter
Duke Energy North Carolina EV Subscription Pilot	• Flat monthly rate of $19.99 for up to 800 kWh of EV charging • EV charging is measured through the vehicle using the Open Vehicle Grid Integration Platform (OVGIP)

Table two provides PBR case studies.

Table 2. Examples of PIMs for strategic demand reduction (SDR) under a PBR framework

State	Key Design Features	Maximum Available Incentive
Hawaii	Initial, one-time incentive based on achievement of peak demand reduction target through direct procurement	Lesser of 5% of aggregate annual contract value or $500,000
Michigan	Up to 15% of demand response costs on a sliding scale based on demand response capacity, growth rate achieved, and NWA assessment costs	15% of demand response spending
Texas	1% of net benefits for every 2% of demand reduction goal exceeded	10% of net benefits
Vermont	Percentage of total approved budget based on performance on several outcomes, including winter / summer peak demand reduction	2.5% of total approved budget
Rhode Island	Cash reward (exempt from utility ROE cap) based on achievement of peak demand reduction, structured as a shared savings mechanism	45% of net benefits

Source: [ACEEE & Energy Innovation]

Opportunity 2: Grid upgrades

One of the most straightforward technical solutions to the issues described in this report is the additional buildout of traditional grid infrastructure on the distribution and transmission grids. Distribution infrastructure will help ease congestion on a local level, while interregional transmission will help move wind and solar energy long distances to even out regional variations in weather and load. Unfortunately, there are many barriers to building out this infrastructure, and building additional “poles and wires'' is not always the fastest or cheapest solution because of the high costs and long lead times of many of these projects. Other NWAs that ease congestion on the grid can often be implemented faster, and in many cases more cost-effectively, than traditional poles and wires. This section discusses challenges to building new grid infrastructure, opportunities to overcome those challenges, as well as viable alternative approaches to building new infrastructure.

Overview of grid infrastructure

This section provides an overview of the grid architecture, and the current challenges to expanding grid infrastructure to help manage the future grid.

Utility industry structure

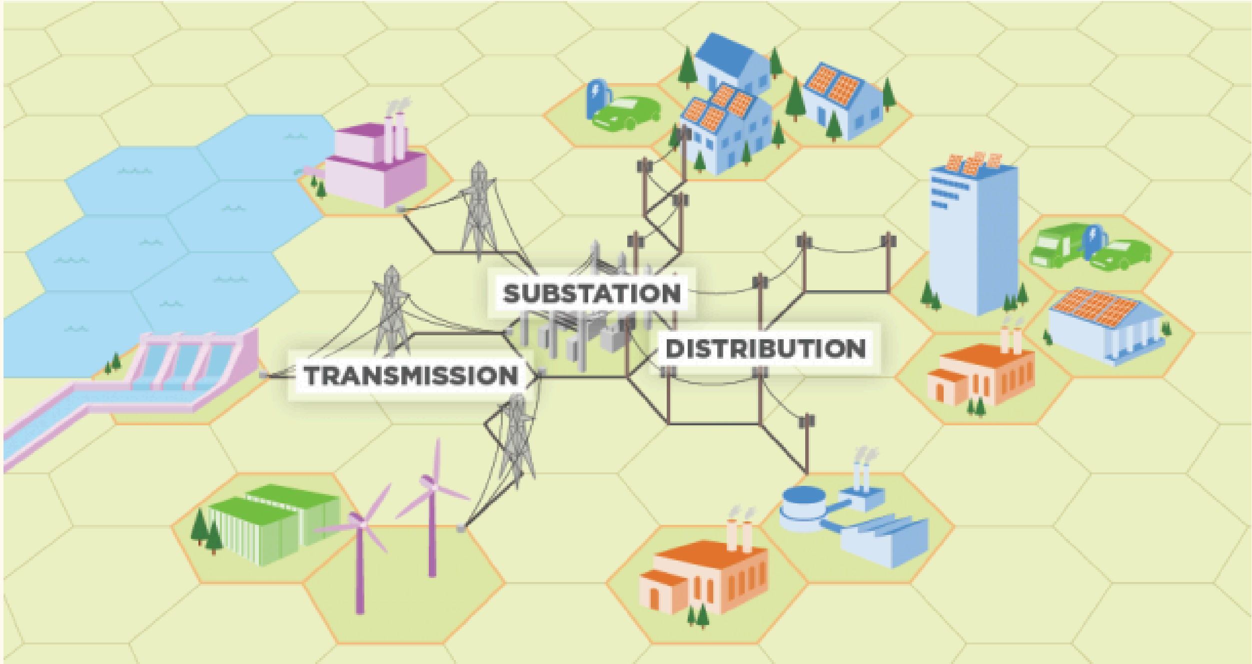
The utility industry is primarily structured around four main components:

1. Generation - produces electric power
2. Transmission - moves power from generators to substations
3. Distribution - distributes power from substations to customers
4. Retail energy provider - sells energy to customers

Historically, many utilities were vertically integrated and provided all four services listed above. Starting in the 1990s, many states pushed to restructure, or “deregulate,” utilities on the theory that only the distribution component constitutes a natural monopoly, and the three other areas should be open to competition. While vertically integrated utilities still exist, generation and transmission can be owned by third parties in many states, and in some states customers are free to purchase energy from different retail energy providers than their default utility. In these cases, customer bills include both distribution charges from the distribution utility, and separate charges from the retail energy provider. Distribution charges typically have the same basic rate structure (e.g., flat, TOU) as the energy charges.

Distribution vs transmission infrastructure

The electric grid consists of the distribution grid and transmission grid, connected by substations as pictured in Figure 17.



Source: US EPA

Figure 17. The basic architecture of the electric grid

The **transmission grid** delivers power from interconnected generators to substations. These transmission lines are typically built and owned by utilities, but can also be built and owned by third parties. Transmission lines run at very high voltages, to move power more efficiently over long distances, and can either be **alternating current (AC)** or **direct current (DC)**. Most transmission and distribution lines are AC, but interregional connections use high voltage direct current (HVDC) lines. These lines move power very efficiently across long distances, but are more costly to interconnect with because of the need to convert from DC back to AC for the distribution grid.

In general, the **distribution grid** is owned, operated, and maintained by utilities. The distribution grid delivers power from substations to homes and businesses serviced by the utility. Distribution grids also increasingly interconnect **Distributed Energy Resources (DERs)** such as solar panels and energy storage systems. Some DERs, like rooftop solar, are **Behind the Meter (BTM)**, meaning that they are co-located with loads behind the customer's utility meter. Other DERs, such as community solar or other larger solar arrays that are under 5 MW, are not BTM but are also typically located on the distribution system.

ISOs, RTOs and oher balancing authorities

The grid has a number of **balancing authorities** across the country, shown as circles in Figure 18 below. The balancing authorities are responsible for matching supply and demand on the grid within their territory, and also planning for (and sometimes managing) regional transmission projects. This includes meeting resource adequacy requirements set by the **North American Energy Reliability Commission (NERC)** by ensuring there is enough generation capacity to meet projected demand. Balancing authorities can vary in size and scope, from aggregations of many utilities to a single utility. In certain regions of the country, the balancing authorities are **Independent System Operators (ISOs)** or **Regional Transmission Operators (RTOs)**[12], which manage transmission and wholesale energy markets in the region. The seven ISOs and RTOs are also listed in Figure 18.

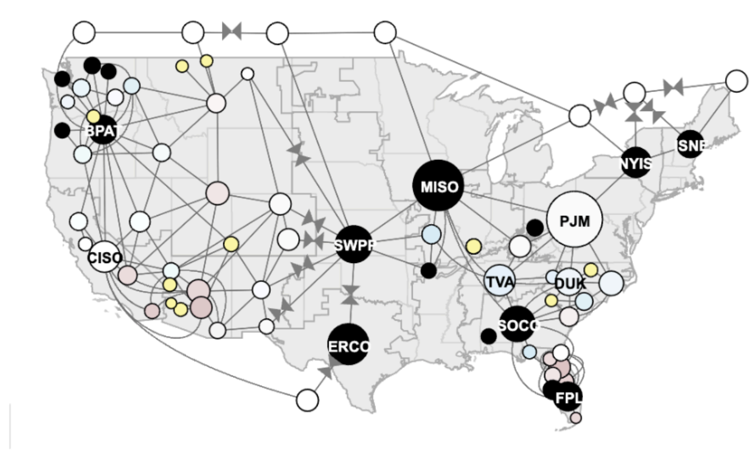


Figure Label	ISO/ RTO Name (Common Acronym)
CISO	California ISO (CAISO)
ERCOT	Electrical Reliability Council of Texas (ERCOT)
MISO	Midcontinent ISO (MISO)
ISNE	New England ISO (ISO-NE)
NYIS	New York ISO (commonly NYISO)
PJM	PJM Interconnection (PJM)
SWPP	Southwest Power Pool (SPP)

Source: EIA

Figure 18. US electric power regions

[12] While ISOs and RTOs historically have slightly different meanings, the two are mostly synonymous in the roles described in this research, and can be used interchangeably.

Outside ISOs and RTOs, balancing authorities do not include wholesale markets and energy is either provided by vertically integrated utilities or bought and sold through bilateral contracts between generators and utilities.

Transmission Infrastructure

In discussing the need for transmission, it is important to distinguish between two specific types of transmission:

1. Regional transmission delivers power within a single region – a single ISO, RTO, balancing authority, or a single utility service area.
2. **Interregional transmission** delivers electric power between two or more electric grids located in different regions. This type of transmission is done at very high voltages to move power over long distances efficiently.

The **Federal Energy Regulatory Commission (FERC)** regulates the interstate transmission of electricity in the US, but does not have substantial control over transmission planning, siting, or permitting for interstate electric power lines. Therefore, these lines require negotiation among a number of different stakeholders and many different federal permits, as well as separate permits for each state involved.

Challenges

This section provides an overview of the current challenges posed by the lack of sufficient grid infrastructure.

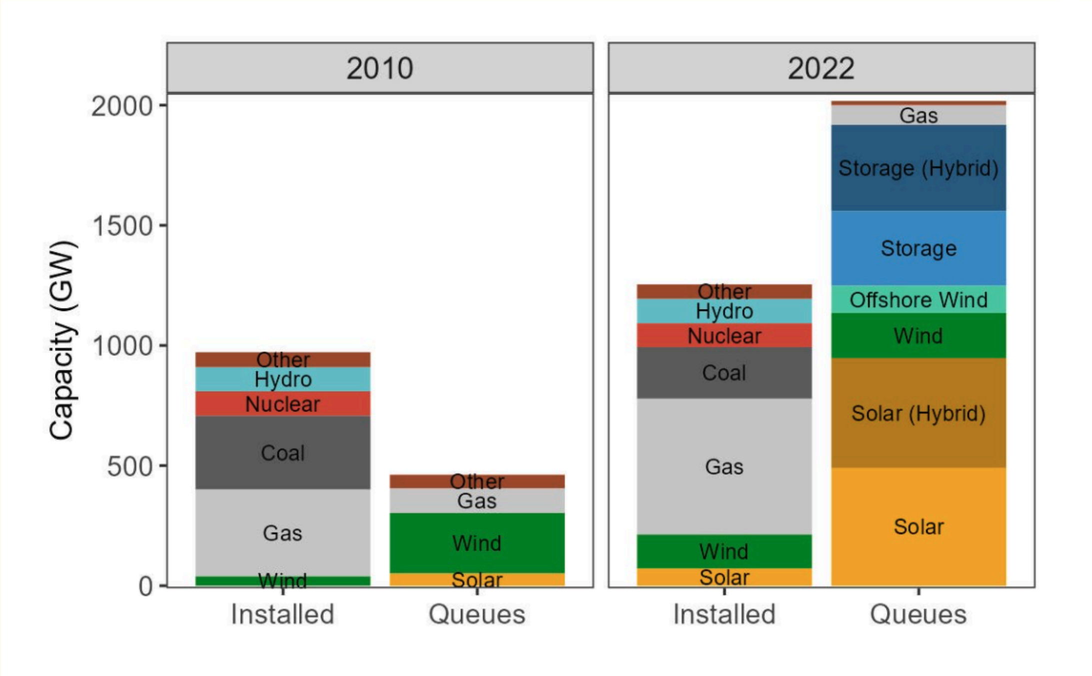
The need for more transmission

NREL has estimated that the United States needs to build between 1.3 and 2.9 times our current transmission capacity to meet our target of 100% clean electricity by 2035, but the recent annual growth rate of transmission infrastructure has only been 1% a year. At an annual growth rate of only 1%, it would take 70 years to double the available transmission capacity, which would be far too long to meet both short- and long-term policy goals around decarbonization.

Between planning, permitting and construction, the buildout of new transmission infrastructure is a resource- and time-intensive process, with the average new transmission project taking 10 years or more from conception to completion. There are currently 36 transmission projects ready to start construction in the near future, but that only covers 10% of what is needed to reach a zero-carbon grid. Because of the rapid uptake of electrification and the desire to decarbonize our electricity supply quickly, we simply do not have the time to solve these problems solely with new transmission lines.

Delays in renewable interconnection

The lack of long-distance interregional transmission is already threatening the energy transition by delaying the ability to interconnect new wind, solar, and energy storage to the grid. Figure 19 shows data from LBNL representing the more than 10,000 projects that were awaiting interconnection in 2022, consisting of 1,350 GW of generation and 680 GW of storage. While this shows enough potential clean energy sources to surpass our current generation mix, only a small fraction of these projects are likely to be built as historically only 21% of projects awaiting interconnection get built.



Source: LBNL

Figure 19. 2022 interconnection installed and backlog capacity resource type compared to 2010

To speed up and streamline interconnection timelines FERC has made recent interconnection reforms through Order 2023. Order 2023 provides a number of different reforms, most notably, moving from a “First-Come, First-Served” serial process to a “First-Ready, First-Served” cluster study process. These current reforms are helpful for clearing the current queues, but are not sufficient to enable significant additional renewable generation capacity on the grid. This can only be accomplished through the building of additional transmission infrastructure and/or enacting NWAs to ease grid congestion.

Challenges on the distribution grid

The main challenge on the distribution grid relates to making upgrades in a cost-effective manner that puts downward pressure on utility rates. While most utilities feel they have a handle on residential electrification loads and distributed generation, they typically address these issues with incremental increases in distribution infrastructure based on short-term need. This is in part driven by the utility profit model described in section 1.3, which leads to upgrades that are rate-based (thus profitable), without sufficient consideration of lower cost options like NWAs. The concern is that rapid electrification and adoption of distributed solar generation could lead to substantial increases in the need for rate-based distribution infrastructure, which would increase electricity rates and total energy costs over time.

Current distribution planning cycles may be too short and disconnected to effectively plan for the long-term effects from rapid electrification and DER deployment. For example, if a utility upgrades a line transformer to account for a customer interconnecting an electric vehicle, they may have to upgrade that same transformer again following additional EV adoption in the neighborhood. This could lead to increased costs in the long run, which could be avoided with a longer-term planning horizon.

The current short-term planning processes may also be too isolated from other planning processes such as Integrated Resource Plans (IRPs), which plan for future bulk power system needs (i.e. generation and transmission). Coupling these planning processes together could help manage the overall system more efficiently and cost effectively.

Opportunities

There are four main opportunities to address the challenges posed by our existing grid infrastructure:

1. Expand interregional transmission
2. Utilize Grid Enhancing Technologies (GETs)
3. Implement other alternatives to new transmission
4. Invest in comprehensive distribution grid planning

Expand interregional transmission

Additional interregional transmission infrastructure is needed to even out the variability of clean energy over a larger area, and thereby increase the resiliency and efficiency of the grid without building more localized generation resources. Unfortunately, most new transmission planning and deployment happens at the regional or utility-level. The specific barriers and solutions to building more interregional transmission are described with the five 'P's, described in Table 2 below.

Table 3. The barriers and solutions to interregional transmission build out

	Challenges	**Opportunities**
Planning	● Separate planning processes enacted by utilities, ISOs, RTOs and other regional planning entities have not spurred the development of new interregional lines. ● Existing planning scenarios do not sufficiently cover the conditions of the future grid including: 1) increased electrification, 2) buildout of variable renewable energy, and 3) increasingly extreme weather.	● The Department of Energy (DOE) or FERC could mandate transmission be built where needed to help surmount the obstacles to interregional transmission, and plan for lines that will actually be built. ● Planning requirements should include conditions of the future grid.
Permitting	● No federal/national oversight of permitting. The 2005 Energy Policy Act (EPAct) authorized DOE to identify National Interest Electric Transmission Corridors (NIETCs) to give FERC backstop siting authority over new transmission lines, but to date, the execution of this authority has been blocked in court. ● Projects must go through a number of permitting processes – some at the state/county level, and others at the national level. Local permitting must be completed for each state/county separately.	● FERC could assert responsibility for permitting of interregional lines similar to their authority for natural gas pipelines and/or Congress could explicitly grant them this authority. ● In 2021 Congress amended FERC's backstop siting authority, and DOE is expected to release additional guidance on NIETCs that should help approval of future interregional lines in cases where states are holding up approvals.

Paying	• Costs for interregional projects are typically allocated based on the benefits to project stakeholders, but determining and allocating these benefits require difficult negotiations between stakeholders. • FERC provides some guidance on cost allocation, but it is insufficient to determine who counts as a beneficiary. • Not all benefits of interregional transmission are included for cost allocation.	• FERC could provide further guidance on cost allocation for interregional lines, and include a wider range of benefits in the cost allocation framework such as lower costs, reduced risk of grid outages, and greater resilience in extreme weather.
Participation	• Streamlining permitting should not happen at the expense of environmental and/or equity concerns of these projects.	• Stakeholders should be engaged early and often to identify issues early, and to consider alternative approaches for projects that are identified as problematic from an environment or equity perspective. Stakeholders could also be provided with financial resources to participate.
Process	• There is no standard process for developing these projects. • The lack of standard and transparent processes for these projects creates a large level of uncertainty for project success which makes attracting capital for these projects difficult.	• A federal agency could study existing processes, and provide best practices or standardize a process for these projects.

Source: CATF

Utilize grid enhancing technologies

Grid Enhancing Technologies (GETs) are one of the approaches to increase the capacity of the current transmission system without building new poles and wires. GETs are technology solutions that use advanced sensors and control algorithms to move more power through the existing grid safely and efficiently. A recent report from the Brattle Group found that the use of GETs could double capacity for new resources to interconnect to the grid. While these technologies are not new, they have not yet been used extensively in the US.

The three most commonly referenced GETs are:

1. **Dynamic Line Ratings (DLRs)** - Hardware and/or software used to update the rated capacity of existing transmission lines based on real-time and forecasted weather conditions. Often, this approach establishes new limits that safely allow more energy to transfer across existing infrastructure under favorable conditions. For example, on windy days the wind provides natural cooling for the wires, which means more power can be moved through the wires safely based on thermal limits.
2. **Power Flow Controllers (PFC)** - Hardware and software used to push or pull power, helping to balance overloaded lines and underutilized corridors within the transmission network. PFCs allow power flow to run in different directions at different times of the day, and allow the whole system to be controlled more efficiently.
3. **Topology Optimization** - A software technology that identifies reconfigurations in the grid to route power flow around congested or overloaded transmission elements, taking advantage of the meshed nature of the bulk-power grid.

Recent studies have shown that GETs can be very cost effective compared to traditional infrastructure, with faster implementation and quicker payback periods. While there are no requirements to utilize GETs in the US, FERC's Order 2023 requires transmission providers to investigate alternative transmission technologies in their interconnection cluster studies, but it does not force them to implement specific solutions.

Implement other alternatives to new transmission

We can also improve the capacity of the current grid by upgrading the lines themselves with higher capacity wires, a process called **reconductoring**. This increases the capacity of the system without the time-consuming process of permitting new transmission corridors.

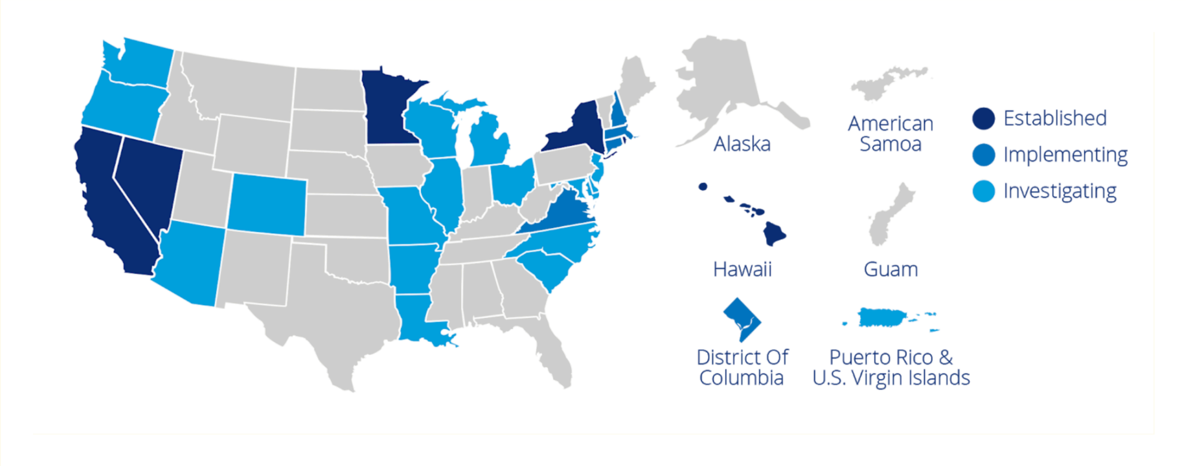
Another potential NWA is **Storage as Transmission**, which uses strategically located energy storage like batteries instead of building new transmission lines. One example of how storage as transmission could work is in helping with "N+1" redundancy on the transmission system. N+1 redundancy is meant to ensure that the system will not fail if a single transmission line is abruptly taken out of service. By locating energy storage at each end of a long-distance line, the storage could temporarily act in place of the transmission line (by charging on one end and discharging on the other) while power is rerouted, allowing time for the lost line to be brought back online.

We could also look to develop new transmission capacity along existing rights of way, including siting transmission infrastructure along highway rights of way.

Invest in comprehensive distribution grid planning

Utilities should take a longer-term planning approach to achieve the lowest long-term costs of distribution infrastructure upgrades. This should include a focus on NWAs, VPPs (discussed below in Section 4), and other low-cost approaches to serving load. In some cases, this may require PUCs to reconsider how IOUs are incentivized, and consider alternative approaches to existing revenue requirement calculations, such as performance-based regulation.

PUCs and utilities should also consider more comprehensive distribution system planning, such as **Integrated Distribution Planning (IDP)**. IDP involves longer-term planning, which coordinates planning of transmission, distribution and generation. It also considers all solutions, including VPPs and other NWAs that could be lower cost than traditional upgrades. Figure 20 shows states that have either established, are implementing, or are investigating IDP.



Source: SEPA

Figure 20. The status of IDP implementation in US states and territories

Case study examples

Table 3 provides examples of efforts and resources from across the country to improve grid infrastructure buildout.

Table 3. Grid infrastructure examples

Category	Description
Improving the Planning and Permitting of Interregional Transmission	● The Biden Administration has asked Congress to take up legislation to streamline the processes for siting and permitting transmission lines. The administration's plan also includes streamlining interagency permitting to reduce the federal permitting time to 2 years. ● A number of Congressional proposals have aimed to address transmission permitting reform. ● The Department of Energy has released a proposed framework for designating NIETCs for specific transmission projects. ● FERC has an existing rulemaking related to Transmission Planning and Cost Allocation. ● FERC has also established an active Joint Federal-State Task Force on Electric Transmission.
Alternatives to New Transmission	● The WATT Coalition has information on GETs, including case studies of GETs being used around the world. ● Connecticut's Framework for an Equitable Modern Grid is "seeking to establish a transparent and competitive process for comparing potential non-wires alternative solutions against traditional distribution system capacity upgrades and other utility expenses to ensure that ratepayer benefits are maximized." ● NY-BEST has published a white paper on storage as a transmission asset, and includes case studies. ● New York State has included NWAs as part of its Reforming the Energy Vision (REV) initiative. Information on opportunities to provide NWAs to NY utilities can be found on the REVConnect Website. ● The Smart Electric Power Alliance (SEPA), E4 the Future, and the Peak Load Management Alliance (PLMA) collaborated on a report consolidating case studies on NWAs across the country.

Regional Transmission and Distribution Planning Initiatives	• CAISO's transmission planning process more closely coordinates with utilities, and considers alternatives to transmission including energy storage and demand response. • The Smart Electric Power Alliance has developed a framework for IDP. • Minnesota launched a Grid Modernization investigation in 2015 and approved IDP requirements for utilities in 2018. • Lawrence Berkeley National Labs provides training and resources on IDP as part of the DOE Grid Modernization Laboratory Consortium.

Opportunity 3: Virtual power plants and load flexibility

Grid operators on both the transmission and distribution systems should consider managing peak demand and grid congestion by utilizing VPPs and other forms of load flexibility. This approach can both reduce peak demand by reducing load during peak times (e.g., a summer evening), and reduce curtailment of renewable energy by increasing load during times of peak renewable generation (e.g., the middle of the day for solar). In these ways, VPPs and load flexibility can provide an alternative to building more dispatchable, carbon-fueled generation or long-distance transmission, and can also increase the utilization of renewable energy on the grid. This section discusses challenges to implementing VPPs and load flexibility, and opportunities to help build these resources at scale.

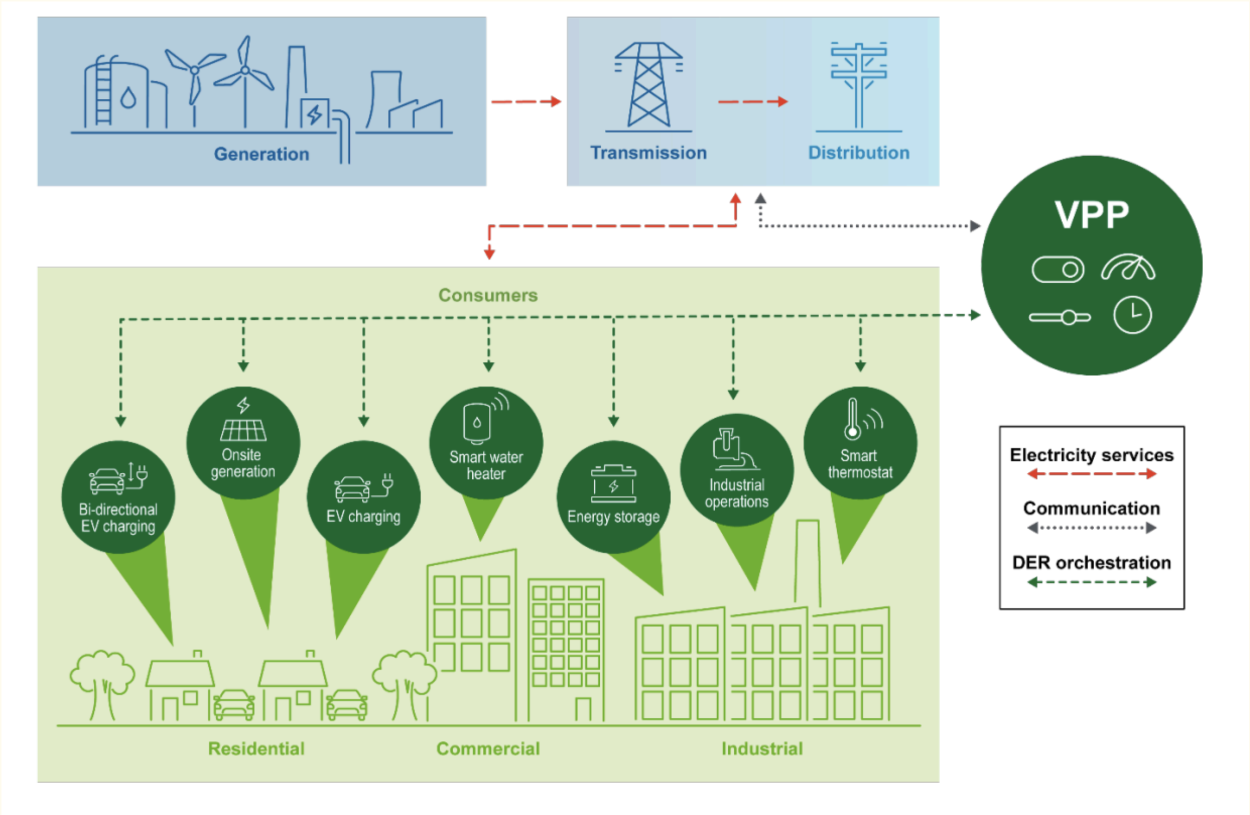
Overview of virtual power plants

This section provides an overview of VPPs and load flexibility.

Definition

A VPP is a dispatchable load made up of an aggregated combination of different DERs such as energy storage, EV chargers, water heaters, and smart thermostats. The dispatchable VPP can help match supply and demand on the grid by operating like a "peaker" plant, providing load reductions during peak hours, and thereby reducing the need for additional fossil-fueled peak generation capacity. VPP aggregators can dispatch VPPs during the highest priced hours of the year to help provide peak capacity to the grid, and receive wholesale market revenues and/or reduce the costs to utilities of meeting increasing peak demand. VPPs with significant energy storage can also charge during times when renewable energy is plentiful and low-cost, which also helps avoid curtailment of these resources. In applicable wholesale markets, VPPs can bid and be compensated for energy delivery similar to generation resources. They also provide value to utilities by reducing energy procurement costs by reducing load during high-priced hours, or by reducing load in emergency situations to prevent grid outages.

A basic diagram of the structure of a VPP is shown in Figure 20. While VPPs can provide additional services to the grid, the focus in this report is the use of VPPs as load flexibility resources to reduce peak demand and provide resource adequacy for the grid.



Source: [DOE 2023]

Figure 20. VPP structure and the role of VPP aggregator

VPPs require complex control systems that integrate with a variety of other systems and data formats. These systems are often referred to as **Distributed Energy Resource Management Systems (DERMS)** and are used to perform multiple functions including: 1) enrolling customers,

2) collecting customer meter data, 3) dispatching DERs in the aggregation, 4) calculating VPP performance, and 5) submitting necessary data to wholesale markets for settlements. In some cases, one system can perform most or all of these functions, but often different systems might be relied on for different parts of VPP operations.

VPPs typically rely on direct control of connected devices to maximize participation and the impact of VPP dispatches. VPP aggregators dispatch DERs integrated into their VPPs using DERMS, and can connect to devices through a variety of technologies including: WiFi, Zigbee, and even FM radio. Once connected, the aggregators use either proprietary APIs (Application Programming Interfaces) or communication standards such as: OpenADR, IEEE CTA-2045, and the Open Vehicle Grid Interface Platform (OVGIP).

The value of VPPs

According to the VPP Liftoff Report published by the DOE Loan Program Office in September 2023, VPPs are well positioned to "expand the US grid's capacity to reliably support rapid electrification while redirecting grid spending from peaker plants to participants and reducing overall grid costs." The report suggests that a tripling of current VPP capacity would contribute 10-20% of peak demand reduction by 2030. A PEPCO/Brattle study also found that flexible demand could reduce the utility's peak capacity by 14%.

Brattle also forecasts that VPPs could provide resource adequacy at 40-60% the cost of alternative options like gas peaker plants and grid-scale batteries. In addition to these direct cost savings, the report indicates that 60 GW of VPPs could add $20 billion in societal benefits over a 10-year period. This includes carbon emission reductions, energy resilience, and transmission and distribution infrastructure deferral. Table 4 provides a summary of VPP value streams.

Table 4. VPP value streams

VPP Value Stream	Value Recipient	Description
Customer bill savings	Customer	Where TOU prices are available to customers, load shifts from VPP dispatches can move load out of high-priced peak TOU periods.
Customer incentives	Customer	VPP aggregations can pay individual participants in cash or utility bill credits.
Energy	Aggregator and/or Utility	VPPs provide a reduction of electricity demand at peak times when energy prices are at a premium. To monetize this, VPPs can bid into applicable wholesale markets in a

		similar manner to generation and earn market revenues. FERC Order 2222 mandates access to wholesale markets for DERs and standardizes requirements. Utilities also get value from avoiding energy purchases when prices are high.
Capacity / resource adequacy value	Aggregator and/or Utility	VPPs can provide capacity value by filling resource adequacy requirements, though challenges exist in determining the "firm" capacity of a VPP (i.e., the number of MW that can be reliably provided).
Grid upgrade deferrals	Utility	By reducing peak demand on the grid during times of high congestion, VPPs can defer investment in grid upgrades (distribution and/or transmission) that would otherwise be required to service increasing loads.
Greenhouse gas emissions reductions	Aggregator and/or Utility	Load shifts from VPP dispatches can reduce the need for fossil-fueled peaker plants, and reduce curtailment of renewables. This provides both societal benefits and potential revenue streams in carbon markets.

Device participation in VPPs

VPPs are aggregations of different device types, and the optimal participation model for load flexibility will vary by device type. It depends on the level of flexibility of the device, whether the energy usage is typically on peak or off-peak, and whether dynamic rates are applicable. Table 5 provides a summary of possible load flexibility participation models by device type.

Table 5. Load flexibility participation models

Flexibility Level	Examples	Participation Models
High - can be moved with little effect on the customer	• Water heating with oversized tanks and/or preheating • EV charging • Energy storage for solar self consumption	• Address through TOU rates to consistently move loads (permanent load shift) • Otherwise can participate in VPPs
Medium - can be moved occasionally with some effect on the customer	• Space conditioning (A/C, electric heat, heat pumps) • Energy storage for backup power	• Participate in demand response programs through VPPs • Address through dynamic rates like Critical Peak Pricing or Real-Time prices

Low - cannot easily be moved without affecting the customer	• Baseload appliances (always on) • Electric cooking (often on at peak times) • Other plug loads	• Participation is difficult • Can possibly be included in emergency demand response programs

As discussed earlier under Opportunity 1, Rate Design, some loads with high flexibility, such as water heaters and EV chargers, could have their load permanently pushed out of daily peak periods using effective TOU rates. This reduces load on both the normal days and the VPP event days when a VPP would normally be dispatched. Therefore, there is no load difference to measure between event days and non-event days to measure the load impact for a VPP. This inherently creates a conflict between implementing "permanent" load shifting through TOU rates (where load is shifted out of peak periods every day) and event-based demand response through VPPs (where load is shifted out of peak periods only on certain days). In cases where there are no TOU rates, or where customers do not shift loads based on TOU rates, these devices could be effectively enrolled in VPPs.

Other loads with less flexibility, such as space heating and air conditioning, can effectively be deployed in VPPs as these loads are typically operational during peak times. Since dispatching these devices can affect customer comfort, there is a tradeoff between dispatching more regularly (increasing the value of the VPP), and dispatching less often (to not overly burden the customer and keep them voluntarily enrolled). Typical dispatch volumes of these programs can be roughly 20 times per year or less, and programs may also have limits on dispatches by month, or the number of days they can dispatch in a row.

Lastly, energy storage is a great candidate for VPP participation. This will typically be a whole home battery, but in some cases individual appliances are being equipped with batteries to provide backup operation and load flexibility.[13] Energy storage can be ideal for VPP participation because it is often purchased for other reasons (e.g., backup generation), but can be underutilized day-to-day. Instead of staying idle, this storage can be dispatched to discharge by the VPP to reduce customer load, or dispatched to charge during high renewable hours to soak up extra clean energy and reduce renewable curtailments. To ensure that capacity remains for the primary use, the storage can only be partially utilized by a VPP. In addition to stationary battery energy storage systems, there is considerable excitement around using the rapidly growing fleet of EVs to participate in VPPs using **vehicle to grid (V2G)** technology. V2G has the

[13] Batteries also allow devices that typically operate at 240V to be retrofit-ready to operate with a standard 120V plug.

potential to drastically increase the capacity of VPPs, with an estimated 300 - 540 GWh of new storage capacity from EVs forecasted to be added to the grid each year from 2025 to 2030

Challenges

This section provides an overview of current challenges to expanding VPPs to help manage the future grid.

VPP complexity

VPPs allow load flexibility to act similarly to a power plant, but there are numerous factors that make implementing and operating a VPP more complex than traditional fossil fuel generation. Most of these factors come from the distributed nature of a VPP built out of residential and small commercial customers.

As an example, to provide the minimum 100 kW capacity for a wholesale market aggregation that meets requirements set out by FERC Order 2222, an aggregator would need at least 100 smart thermostats participating in events, and consistently delivering at least 1 kW of load reduction. That is, 100 customers must: 1) sign up for the program, 2) authorize access to their meter data, and 3) authorize the aggregator to control their thermostat. For each of these steps there are significant concerns around data security in the sharing of customer **Personal Identifiable Information (PII)**. Once the aggregation is set up, the aggregator must dispatch the resource, and in order for a household/business to perform, their device must maintain connectivity and the customer must not opt out of the event, or override the thermostat controls during the event. Once the customers have been dispatched, the load reduction, or "performance," of the resource must be measured, which relies on complex data-intensive calculations. These calculations rely on the aggregation of all the customer meter data and the development of counterfactual baselines, typically using either meter data from past similar days, or a control group of non-participants.

Limited value streams for VPPs

While studies have shown that VPPs can be cost effective at scale, many regions have limited access to many of these value streams. For example, not all regions have wholesale power markets, and, while FERC order 2222 should provide wider availability to wholesale markets for VPPs, some ISOs/RTOs have proposed timelines as long as 2030 before full integration.

In addition, one of the great potential promises of VPPs is to provide value by reducing congestion or deferring infrastructure investments on the distribution grid. Currently, this value can only be captured by utilities, but they are mostly incentivized to invest in more physical infrastructure rather than lower-cost solutions like VPPs.

Lack of consideration in grid planning

As discussed earlier under Opportunity 2, Grid Upgrades, VPPs are not evaluated equally in grid planning. This is due to a combination of:

1. Low awareness of VPPs
2. A lack of confidence in the ability of VPPs to produce reliable capacity
3. A lack of incentives to invest in NWAs (including VPPs) instead of traditional rate-based infrastructure

Opportunities

The best way to reduce the risks of VPPs is to build scale through larger aggregations, which will: 1) reduce the performance risk from individual customers, and 2) reduce the cost per customer.

To build VPPs at significant scale, it is critical to:

1. Expand value streams for VPPs
2. Include VPPs in grid planning
3. Standardize VPP operations
4. Standardize device control capabilities
5. Further expand the deployment of smart grid infrastructure

Expand value streams for VPPs

To achieve the full potential of VPPs, we must continue to open up new value streams to ensure they are cost-effective across multiple regions. These value streams include:

1. **Wholesale market revenues** – FERC Order 2222 requires that all ISOs and RTOs in the US provide access to wholesale markets for load flexibility. This is important, as it allows independent third parties to earn revenue for VPPs instead of having only utilities be able to use VPPs to generate value.

2. **Capacity / resource adequacy payments** – These are payments for a resource to be available when dispatched, typically paid in $/kW-month. Utilities will pay for available capacity to meet resource adequacy requirements set by the NERC. For resources to get capacity payments they must have a firm capacity value, or a measure of the kWs that they can guarantee are available when dispatched. Capacity payments can be a lucrative value stream for energy producers.
3. **Distribution value** – In a Distribution System Operator (DSO) model, VPPs could get payments for offering distribution value, similar to how ISOs and RTOs work for transmission.[14]
4. **GHG reduction value** – VPPs can have environmental benefits by reducing reliance on fossil fuel generation, and decreasing curtailments of carbon-free renewable generation. Robust carbon markets with carbon prices that more closely match the social cost of carbon would help VPPs monetize their services. In addition, a standardized way to calculate the secondary carbon impacts of VPPs (e.g., the ability of VPPs to allow for a higher penetration of renewables, and for renewables to operate at higher load factors over time) would help boost the value of these resources.

Include VPPs in grid planning

As the market for VPPs continues to develop, they should be evaluated with traditional upgrades as a part of comprehensive grid planning. For example, IDP has the promise of including VPPs as a solution to distribution constraints. In addition, utilizing PBR to incentivize utilities to fix grid constraints with lower cost solutions would help incentivize investments in VPPs over costly new infrastructure.

Standardizing VPP operations

On the flip side of increasing the value of VPPs, we can also seek to reduce the costs of developing and deploying VPPs. As noted above, the deployment of a VPP involves a number of complex steps. Each of these steps can have multiple unique and often proprietary solutions from different technology vendors and VPP aggregators. One way to lower the barrier to entry of new VPP providers, and to ensure cost-effectiveness at scale, is to standardize VPP operations to lower costs and provide program flexibility between vendors.[15] Some examples of operations to be standardized include:

1. **Resource management** – Standardization of some of the operations, data flows and formats that these systems rely on could help streamline the development of VPPs at

[14] One example of a state pursuing this model is Maine, which has signed legislation to study the feasibility of a DSO model for the state.
[15] The DOE VPP Liftoff Report provides a detailed review of opportunities for standardizing VPP operations.

scale. One example to be considered is automatic enrollment (with an opt-out provision) to maximize customer participation.

2. **Performance measurement** – VPPs must rely on counterfactual baselines to determine resource performance. The methodologies for determining these baselines can vary widely. A more standardized approach to measuring VPP performance would help VPP developers more easily scale programs between regions/utilities. In addition, standardized methodologies for forecasting VPP performance would help integrate VPPs into grid planning.
3. **Utility data authorizations** – the requirement for third party VPP providers to get customer authorization for meter data release can create a barrier to enrollment. Methods to get this authorization vary from signed paper forms to online forms or APIs. Standardization of these authorizations would streamline customer enrollment.
4. **Data security** – much of the data needed to run VPP operations can include sensitive customer data, including PII and usage data. Robust data security standards for VPPs could help mitigate concerns for unauthorized access to data. VPPs should be protected so that unauthorized third parties cannot gain access to VPP controls and adversely affect customers or the grid.

Standardizing device control capability

To bring down the cost of implementing VPPs, advocates should focus on the use of open standards whenever possible. They should also encourage free access to the control APIs for devices, as the connection fees many device manufacturers charge can take a significant portion of the value of the connected device in the VPP. Progress on this has begun with CTA-2045 becoming required for water heaters in Washington and Oregon. California is also considering standards in this area as part of their California Flexible Appliance Rulemaking. At a national level, EPA's ENERGY STAR program has voluntary requirements for connected functionality for grid communications.

Further expand the deployment of smart grid infrastructure

Smart meters/AMI may be required for effective VPP deployment, and other smart grid components can contribute to the management of the grid. For example, most line transformers, which provide the final step down of voltage on the distribution grid and serve a handful of customers, lack the ability to measure usage in real-time. Utilities worry that multiple new EVs on a single line transformer could overwhelm the circuit with concurrent charging. Smart transformers could allow utilities to monitor transformer capacity, and moderate EV charging on the circuit to avoid overuse or the need for another transformer upgrade.

A similar approach could be taken within a household utilizing a smart panel to manage the load, keeping the peak demand under the threshold that would trigger a costly utility service upgrade.

Case study examples

Table 6 provides example VPP programs and reports.

Table 6. VPP programs and reports

Category	Description
VPP Program Examples	• Green Mountain Power runs a Bring Your Own Device Battery Energy Storage Program to reduce load during peak times. • Aggregate Distributed Energy Resource (ADER) pilots for ERCOT (Electric Reliability Council of Texas) are aggregating distributed resources for the wholesale market. • Sunrun has bid a VPP consisting of residential solar and batteries into the NE-ISO wholesale market. • In response to rolling grid outages in 2020, the California Emergency Load Reduction Program (ELRP) was established to help avoid rotating outages during peak summer electricity usage periods.
VPP Reports	• The DOE Report, Pathways to Commercial Liftoff: Virtual Power Plants, provides a review of the commercial state of VPPs, with recommendations for reducing barriers to deploying VPPs at scale. • The Brattle report, Real Reliability: The Value of Virtual Power, analyzes the cost effectiveness of VPPs and provides example programs across the country. • The RMI report, Virtual Power Plants, Real Benefits, provides an overview of VPP impacts and barriers to scaling VPPs, and provides example programs across the country. • The E4 the Future / PLMA / SEPA report, Non-Wires Alternatives: Case Studies From Leading US Projects, includes NWA projects that could also be considered VPPs.

Conclusions

While there are many existing challenges to planning the grid of the future that will accommodate increased electrification powered by 100% clean energy, there are many opportunities to overcome these challenges. These opportunities take many forms, but all require the understanding that we need to start designing for this future grid, and reform legacy policies that lack the appropriate dynamism needed for a fully decarbonized future.

The energy sector is not known for moving quickly on reform, but we may not have the luxury of time for this transition. The Biden administration has set a goal of a decarbonized power sector by 2035, the historically low cost of renewables has resulted in the vast majority of new generation capacity coming from renewables, and households are rapidly adding both electric vehicles and electric heat pumps to the grid. We must implement commonsense reforms to enable the transition from fossil-fueled machines to clean, electric machines.

These commonsense reforms include reforming electric rates to make electrification more cost competitive, and provide load shaping to address rising peak demand. When setting new rates, utilities and PUCs should include the following best practices for future rate design:

1. Incentivize electrification by lowering volumetric rates, including seasonal rates, and investigate innovative new electrification-specific rate ideas.
2. Incentivize load shaping and flexibility through dynamic rates such as TOU and CPP rates, and pursue net energy reforms where solar penetration is high.
3. Improve cost allocation and rate equity by reassessing how the costs of peak demand are recovered through rates, and move societal costs to be paid through progressive taxes or graduated fixed charges, instead of regressive rate structures.
4. Update IOU profit models using PBR to ensure utility incentives match societal goals.

Reforms should also include updating the grid itself, both by increasing the capacity of the transmission and distribution systems, and by investing in new technologies that can increase the capacity of the current grid more efficiently than building new poles and wires. The right technologies exist to implement cost effective NWAs, but regulatory barriers and misaligned incentives currently prevent sufficient progress towards these low-cost solutions. To properly upgrade our physical grid to handle increased electrification and renewable energy, the following reforms should be explored:

1. Expansion of interregional transmission through planning for the grid of the future, streamlining permitting for projects spanning several states, and determining cost allocation methodologies that account for expanded benefits of new transmission.
2. Implementing alternatives to new transmission lines using GETs, storage as transmission, reconductoring, and installing new transmission along existing rights of way (like federal interstate highways).
3. Longer-term planning of distribution systems, and alternative incentive mechanisms to drive utilities to lower long-term distribution costs through least-cost measures.
4. Managing congestion on existing grid infrastructure using DERs and VPPs.

Lastly, we should harness the potential for shifting loads and reducing peak demand through electric machines. This can be done using large aggregations of dispatchable load flexibility through VPPs. While VPPs are being deployed across the country, there are still barriers that limit the scale of these offerings. Opportunities to help VPPs scale include:

1. Opening up additional value streams for third party VPPs, such as wholesale market values, and the distribution value of limiting local congestion on the grid.
2. Including VPPs in grid planning, such as IRPs and IDPs,
3. Lowering the costs of participant acquisition and VPP management by standardizing VPP operations.
4. Adopting standards and requirements for device communications and control functionality to increase the number of devices that are VPP-ready for participation in load flexibility offerings.
5. Continuing to expand the installation of the AMI (e.g., smart meters) needed to measure VPP performance.

Getting involved

Many of the challenges and opportunities discussed above will vary significantly based on a range of local attributes including:

1. Weather/climate zone
2. State policies (e.g., climate goals, NEM, state-level incentives)
3. Existing generation mix
4. Rooftop solar penetration
5. Electric vehicle penetration
6. Existing/future load profiles
7. Balancing authority type (e.g., ISO, RTO, other)

The first step in getting involved is understanding these issues at the local level and determining which of the challenges described in this paper create the biggest barriers to expanding electrification and renewables in your area.

Second, work to understand the existing policy landscape, and look for opportunities to voice your support for new policies that help expand electrification and renewable energy in your area. Consider the following areas of action:

1. Contact representatives in Congress and ask them to support transmission and interconnection reform bills, as well as bills that support electrification and renewable energy.
2. Contact the FERC Office of Public Participation (OPP) to learn about new orders in development and how to submit comments.
3. For advocates in areas covered by ISOs/RTOs, engage to offer comments and support for new transmission plans, and robust implementation of FERC Order 2222 to allow VPPs to participate in wholesale markets.
4. Understand state-level policies, and contact your state representatives to voice support for bills expanding electrification, renewable energy and reforms covering utilities in your state.
5. Engage with PUCs and/or public utility boards to voice support for utility rate reform, and for updating utility incentive mechanisms to spur investment in the lowest long-term cost solutions for our expanding and evolving grid infrastructure.

By beginning to take action now and supporting these common sense policies, we can help ensure the fastest transition possible to a fully electrified future powered by 100% clean energy.

Appendix A. List of abbreviations

AMI	Advanced Metering Infrastructure
API	Application Programming Interface
BTM	Behind the Meter

CPP	Critical Peak Pricing
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management Systems
DOE	Department of Energy
EIA	Energy Information Administration
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GETs	Grid Enhancing Technologies
IDP	Integrated Distribution Planning
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
ISO	Independent System Operator
NEM	Net Energy Metering
NERC	North American Energy Reliability Commission
NIETC	National Interest Electric Transmission Corridor
NREL	National Renewable Energy Laboratory
NWAs	Non-Wires Alternatives
PBR	Performance-Based Regulation
PII	Personal Identifiable Information
PTR	Peak Time Rebate
PUC	Public Utility Commission
RTO	Regional Transmission Operator
RTP	Real-Time Price
TOU	Time-of-Use
VPP	Virtual Power Plant

Appendix B. Resources / further reading

ACEEE, Equity And Electrification-Driven Rate Policy Options, September 2023, https://www.aceee.org/white-paper/2023/09/equity-and-electrification-driven-rate-policy-options

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