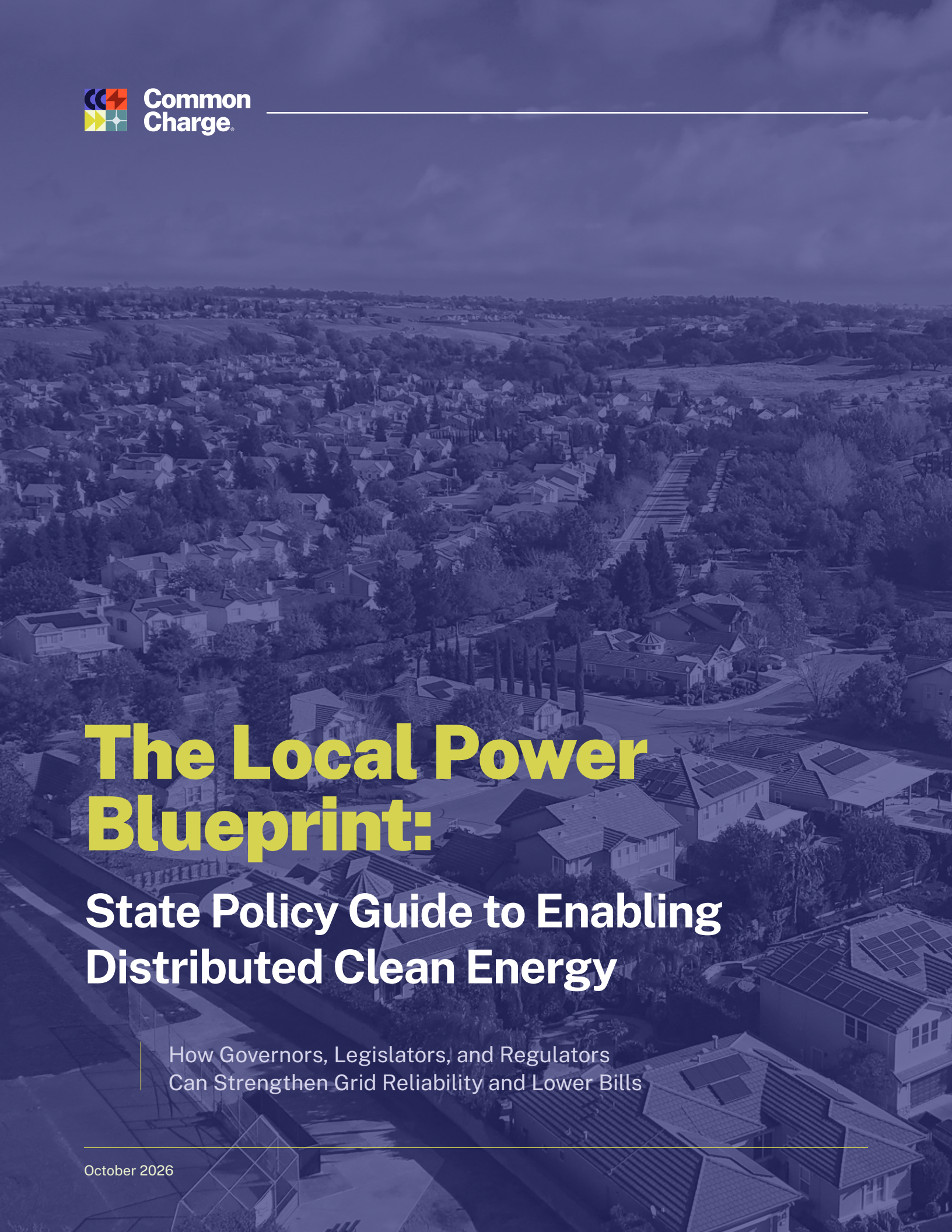
Common Charge



The Local Power Blueprint:

State Policy Guide to Enabling Distributed Clean Energy

How Governors, Legislators, and Regulators Can Strengthen Grid Reliability and Lower Bills

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ABOUT THE COALITION

Common Charge

Common Charge is a coalition of innovators, including consumers, nonprofits, and businesses, built to put power — literally — back in the people's hands by creating a reliable energy system that works for everyone, everywhere. Common Charge stands for an energy system where every family, business, and community holds the power — not just to use energy, but to shape it. Through policy action and fair market access, the coalition works to unlock consumer power and create a stronger, more affordable system that can be powered from everywhere.

Founded in September 2025, Common Charge works with state legislators, regulators, industry, advocates, and others to remove the barriers that stop local power systems from delivering their full value to the grid and to the people who depend on it.

For more information, visit *commoncharge.org*.

ABOUT THE DOCUMENT

The Local Power Blueprint

This document sets out Common Charge's policy priorities for states. It is intended to educate state legislators, governors, regulators, advocates, the press, and the public on successful, replicable policies to unlock local power.

The blueprint was developed by a coalition of practitioners and is focused on presenting tangible solutions in an accessible way. The blueprint includes general principles, summaries of policy examples, and links to additional resources. It can also guide the coalition's engagement and serve as a shared reference for member organizations advocating for common sense solutions at the state level.

PRINCIPLES

Common Charge's core policy principles

The Common Charge coalition has established the following four core principles to guide its work. The Local Power Blueprint was developed following these principles:

- Distributed assets should compete on a level playing field with utility investments in open and competitive markets for all the services they are capable of providing.
- The benefits of distributed assets should be accessible and available to all consumers.
- Distributed assets should be valued for the full range of benefits they provide to the grid, customers, and society.
- There should be no undue barriers for consumers to participate in distributed asset programs and markets.

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HOW TO

How to use this document

This document was developed as a resource for governors, legislators, regulators, other state officials, advocates, the press, and the general public.

The document can be read in whole or in part. Many topics are covered, providing a comprehensive view of policy options for affordable, reliable, local clean power. In this blueprint, readers can:

- Access policy recommendations, including clear summaries of existing policies
- Access links to source documents (e.g., bills, executive orders, PUC orders, etc.)
- Access a compendium of additional resources

DISCLAIMER

DISCLAIMER

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Executive Summary

For over a hundred years, our electricity system has been built around centralized power plants that send electricity across hundreds of miles of wires to where people work and live. Today, that system is straining under the weight of growing demand, aging infrastructure, and extreme weather, while every new plant or transmission line takes years to build and costs billions.

There is a better, cheaper, and faster way to keep the lights on and prices low: generate, store, and deploy power closer to where it's used, and use the system we have more efficiently.

Rooftop and community solar, home and neighborhood-scale batteries, electric vehicles, smart thermostats, and energy-efficient technologies can do the job of new power plants at a fraction of the cost and in a fraction of the time. This is local power — sometimes called distributed energy resources, virtual power plants, or community-generated power — and it is already working across the country.

Local power is the answer to today's grid challenges.

- Local power puts money back into the pockets of all consumers by lowering system costs, while often providing additional savings to participating businesses and households.
- It can provide energy and grid services at lower cost than new gas generation, without dependence on expensive fuels or volatile global energy markets.
- It can be deployed in weeks and months rather than years, where the grid needs it most.
- As electricity demand spikes, it is modular and can be built incrementally to track growing demand as it materializes rather than betting on wildly uncertain forecasts from data centers.
- Just like diversifying a portfolio reduces investment risk, distributing resources across many locations reduces dependence on any single asset and can limit the consequences of major failures.
- Local power both cuts demand and adds supply in the tightest hours, helping keep the lights on in people's homes and businesses running smoothly.
- Generating power closer to where it is consumed also reduces energy wasted in transmission and distribution, while reducing harmful and costly air pollution, making communities healthier.
- Batteries, demand response, managed charging, and other flexible resources are now best matched to manage today's demand patterns. They can respond in seconds, shifting use to when power is plentiful and cheap.

Fully realizing the promise of local power requires two simple things: (**I**) to produce and store more power locally, and (**II**) to make full use of the tools, the local resources, and the grid we already have.

The cheapest, fastest, most reliable power we can add to the grid is power produced closer to where it is used. We have the technology. At a time when leaders are looking for all solutions to meet soaring energy demand, this is a critical no-regrets strategy to deliver power fast while creating stable energy costs for all residents. It is time for state policymakers to set the legal and market rules that unlock local power across the country.

I. Produce more power locally, and do it fast.



WRITE CLEAR RULES OF THE ROAD FOR LOCAL TECHNOLOGY.

Home and community solar and batteries, electric vehicle charging, and microgrids all need clear rules that let them get built, connect to the grid, and pay owners for the value they provide. States should set targets for community power adoption, open up markets, and remove roadblocks holding these technologies back.



TURN GROWING DEMAND FOR ELECTRICITY INTO AN OPPORTUNITY, NOT A BURDEN.

Data centers and other massive new power users are creating unprecedented demand for electricity. Rather than let that growth strain the grid and raise everyone's bills, states should require these large loads to invest in local clean power and flexibility.



CUT THE RED TAPE AND FINANCING COSTS THAT SLOW DEPLOYMENT.

Outdated permitting and interconnection rules and costly financing can make an economically viable project sit on the shelf. States can streamline both to unlock billions in local power that is ready to go.



PAY PEOPLE FAIRLY FOR THE ELECTRICITY THEY PRODUCE AND THE SERVICES THEY PROVIDE TO THE GRID AND COMMUNITIES.

Local power only gets built at scale if the people building it are compensated for the real value it provides, including energy, capacity, avoided infrastructure, and more. Residential customers must also be compensated for shifting how and when they use electricity, just like large-scale users.



MAKE SURE EVERYONE CAN SHARE IN THE BENEFITS.

Renters, low-income households, small businesses, rural and Tribal communities, and other communities all stand to gain from cheaper local power. States should design programs accordingly.

II. Use the system we have more efficiently.



SET MANDATORY GOALS FOR USING LESS ELECTRICITY AND USING IT AT SMARTER TIMES.

States should require utilities to run multi-year programs that cut overall power use and help customers pull back when the grid is under the most strain. States that already do this see far greater results than those that do not, and the savings outweigh the cost many times over.



TURN LOCAL RESOURCES INTO NETWORKS THAT WORK BETTER THAN POWER PLANTS.

Home and community solar, smart thermostats, and large and small batteries are far more powerful when they are linked together and operated as a system. States should create the programs and rules that authorize these networks, and the technical infrastructure (data access, shared standards, coordination systems) that ensures devices deliver power at scale.



SET CLEAR TARGETS FOR UTILITIES, REWARD THEM FOR HITTING THEM AND PENALIZE THEM FOR FAILING TO.

To lower bills, utilities need to better control their costs. Under today's rules, utilities usually make money by building things, not by saving customers money. States should reform this structure so utilities follow clearer budgets, profit when they perform well (e.g., cut costs, improve reliability, put local resources to work), and are penalized when they miss the mark.



MAKE LOCAL POWER PART OF UTILITY PLANNING FROM THE START.

The cheapest power plant is the one you never have to build, but most utilities still default to building new facilities when demand for power increases. States should require utilities to show where the grid is strained, measure how much room is left, plan with local power in mind, allow local resources to compete on a level playing field against outdated infrastructure, and require proactive and transparent planning.



MAKE FINANCING AVAILABLE TO CUT UPFRONT COSTS.

Local power provides savings to consumers, but upfront costs can keep people out. States should open the door to the full range of ownership and financing tools, including third-party ownership and on-bill financing, so that these resources can be deployed at scale.

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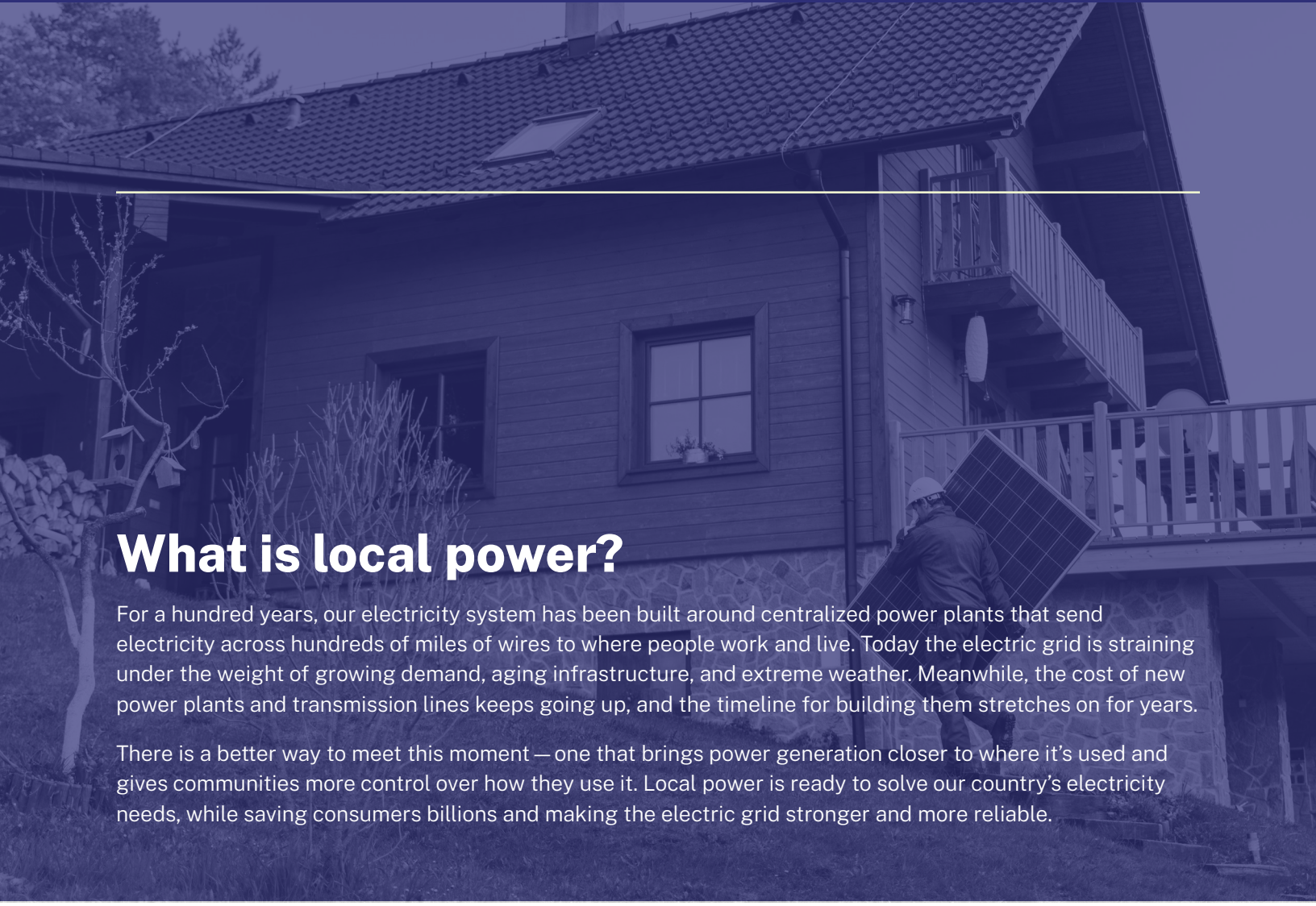
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What is local power?

For a hundred years, our electricity system has been built around centralized power plants that send electricity across hundreds of miles of wires to where people work and live. Today the electric grid is straining under the weight of growing demand, aging infrastructure, and extreme weather. Meanwhile, the cost of new power plants and transmission lines keeps going up, and the timeline for building them stretches on for years.

There is a better way to meet this moment — one that brings power generation closer to where it's used and gives communities more control over how they use it. Local power is ready to solve our country's electricity needs, while saving consumers billions and making the electric grid stronger and more reliable.

The electrical grid has two distinct systems. The transmission system moves large amounts of electricity long distances from a centralized power plant to a local transformer. The distribution system moves power much shorter distances to bring electricity into homes and businesses.

As demand for power increases, utilities usually respond by building a large power plant, connecting it to a large transmission line, and sending more electricity to the communities that need it. That approach may have worked, but it has led to a costly system that is simultaneously overbuilt and unable to respond to spikes in demand.

Technology has now advanced toward nimble systems of all sizes that can produce electricity locally where it is needed, store it until it is needed, and manage demand when it makes sense — all in the existing distribution system.

Local power has three main components:

- Generation — usually rooftop and community solar
- Storage — small and mid-size batteries, as well as electric vehicles
- Flexibility — technology and systems to manage where, when, and how electricity is used

These components can work on their own, at the household or business level. But they become more powerful when they are combined across a network, letting communities reduce their dependence on expensive power imported from centralized power stations and instead benefit from cheaper, reliable power generated closer to home — and postponing or even entirely avoiding the construction of costly infrastructure.



Generation

Rooftop solar powers homes, businesses, schools, and other buildings, and can send excess power back to the grid. Community solar sends power to nearby homes and buildings that do not have a roof that can sustain solar.



Storage

Home batteries store power generated by solar and discharge it at night and at times of high energy use. Mid-sized battery storage can be plugged directly into the local grid to provide power when demand is high and serve as backups for businesses and manufacturing facilities. And electricity can move both ways from electric vehicles (EVs), with owners charging their batteries when prices are low and sending power back to the grid when demand is high.



Flexibility

Many utilities have demand response programs. When electricity use is high, participants can voluntarily reduce their electricity consumption and get paid for using less energy. This kind of flexibility is made possible by the widespread adoption of energy efficiency and smart devices, including thermostats, heat pump water heaters, heat pumps, and EV chargers.

The real power of these assets is in their ability to be networked together and work as a system. Rooftop and community solar can generate as much energy as large power plants, and, thanks to battery storage and flexible devices, that energy can be deployed just as if it were coming from a power plant (these systems are commonly referred to as virtual power plants, VPPs, or community power networks). And with record numbers being installed every year, they offer a virtually limitless power supply, ready to support the grid exactly when it's needed most.[1]

Local power is also called "distributed power" or "distributed energy resources." These terms are used interchangeably in this blueprint.



How does local power drive affordability and reliability?

Electricity bills are climbing faster than Americans can keep up with, but nothing about this is set in stone. State policymakers write the rules that determine what gets built, who builds it, who profits, and who is left holding the tab. Without thoughtful action, this will not change.

We cannot wait. Costs being debated in utility proceedings today could show up on customers' bills within the next year. The window to change course is narrow; every month of delay and each unnecessary new power plant locks in wasteful spending that customers will pay off for decades.

All of us pay for waste. And we all save when power is generated, stored, and managed closer to where it is needed. When a neighbor's battery discharges on a hot summer night, or a well-insulated building simply needs less power to cool down, they are doing a job the rest of us would otherwise pay a utility to do.

Local power is the only solution that can arrive fast enough. New power plants and transmission lines take five to ten years to build. Local solar, batteries, efficiency, flexible demand, electric vehicles, and other distributed resources are here now and can be deployed in months, not years. If states want to bring bills down before another generation of costly infrastructure lands on them, they need to put local power to work now.

Below, we detail (a) the problem with the status quo, and (b) how local power can help.

The problem

Bills are too high, and the system that sets them works exactly the way it was designed. Utilities generate revenue and earn nearly all of their profit by spending on infrastructure, i.e., the poles and wires on the grid, and sometimes the power plants they build.[2] The more utilities build, the more they earn, with a return for their shareholders that is nearly guaranteed.[3] We need a better design. This incentive structure may have been reasonable 100 years ago, but it makes considerably less sense today, when cheaper, more customer-friendly solutions exist for the modern grid's needs.

Bills are rising for everybody, putting pressure on paychecks and business margins alike. Between 2020 and 2024, Americans saw their average electric bills increase by more than 20 percent.[4] Business customers experienced similar or greater bill increases: average commercial bills increased by more than 30 percent, while industrial bills increased by about 17 percent.[5]

Like bills, rates are increasing and show no signs of slowing down. Nationally, residential electric prices have risen 33 percent since 2019.[6] Between 2024 and 2025 alone, residential prices increased another five percent.[7] Some states have seen much higher surges.[8] Although inflation is widespread, electricity prices outpaced inflation: from December 2024 to December 2025, consumer electricity prices increased 6.7 percent, compared with 2.7 percent inflation overall.[9] This all adds up. Investor-owned utilities now project approximately $1.4 trillion in capital spending over the next five years, up from more than $1.1 trillion projected just a year earlier.[10]

American families are impacted. Residential prices are higher and have risen faster than commercial and industrial power prices,[11] drastically increasing the share of energy spending for households,[12] and placing financial pressure on the customers that are least able to afford energy.[13] In the Lower 48, the District of Columbia, and Puerto Rico, the poorest households spend over 11 percent of their income on electricity, almost twice what the U.S. Department of Energy considers to be a very high burden.

Customers are losing access to power. One in six households nationwide is behind on their energy bills, heightening disconnection risks and creating $21 billion of unpaid balances in May 2025.[14] **In 2024, utilities issued 94.9 million final disconnection notices to residential electricity customers, leading to 13.4 million forced disconnection events**.[15] In other words, a meaningful share of the 143 million residential electricity customers nationwide lose access to power year after year due to an inability to pay, in the wealthiest country on earth.

High power prices are also a drag on our economy and limit our competitiveness in attracting investment. Power-dependent industries, such as manufacturing, mining, construction, and agriculture, are throttled by the high costs of power, reducing investments and job opportunities. The manufacturing sector alone accounts for roughly 70 percent of all electricity purchased by the U.S. industrial sector, making affordable power an important factor in where companies invest, expand, and create jobs.[16] To illustrate cascading impacts, manufacturing alone represents 10 percent of our gross domestic product[17] and employs nearly 13 million Americans.[18]

Grid reliability has become a growing concern. State regulators, grid operators, and the North American Electric Reliability Corporation (NERC) have all raised reliability concerns in recent years. In 2026, NERC's long-term reliability assessment found that the overall 10-year outlook was "worsening" throughout the North American bulk power system, attributing the risk to demand growth from data centers and artificial intelligence outpacing the addition of new generating resources.[19] Power shortages are supposed to be a once-in-a-decade event on the nation's largest regional grid, operated by PJM. But in a worst-case scenario modeled for Pennsylvania regulators, the risk rises to more than 13 days per year in 2030.[20]

The number of power outages that customers experience each year has already increased by 20 percent in the last decade, while total system downtime for the typical customer has tripled from 3.5 hours in 2015 to over 11 hours in 2024.[21] And when an outage occurred, the average time required to restore service increased from about 2.7 hours to 7.2 hours.[22]

More extreme weather brings new challenges, as the grid was not designed for the extreme weather we are now regularly facing. Power outages from extreme weather specifically have doubled in the past two decades as extreme weather events have increased in duration and frequency.[23] Aging, centralized infrastructure is more fragile than most people recognize, until a storm or heat wave exposes it. Winter Storm Uri left more than 4.5 million Texans without power, while Hurricane Maria effectively knocked out Puerto Rico's entire electric grid.

Today's grid, largely made of massive remote power plants, is susceptible to cascading blackouts. Extreme wildfire risk has forced entire regions to turn off power to millions of people even on a clear, sunny day when local power resources such as batteries, solar, and microgrids could have kept the power on.

A wave of new power demand without recent precedent, driven by data centers, electrification, and the reshoring of manufacturing, is compounding these issues.[24] The projected scale of this increase is unprecedented. NERC projected that summer peak demand could rise by 224 gigawatts over the next decade, or 69 percent more growth than NERC projected just one year earlier. The Midcontinent Independent System Operator (MISO), in particular, is now rated at high risk for 2028 and beyond, with escalating demand forecasts and data centers cited as the largest driver of that growth.[25] MISO covers 15 states, stretching from as far south as Texas and Louisiana to as far north as North Dakota, Minnesota, and Manitoba, Canada.

Speculation and uncertainty create risks for customers, which policymakers can and must address. For example, Texas alone has received requests to connect enough new demand to power 40 New York Cities.[26] Customers are vulnerable to two extremes: they may end up paying for speculation-induced power generation that is not needed or subsidizing infrastructure to meet unprecedented electricity demand from massive data centers.

DEEP DIVE

Data centers' impacts on utility rates and bills for customers

The net impact on customers of growing electricity demand is complex and location-dependent. Data centers will neither automatically increase nor decrease rates.[27] Policymakers should act today to ensure that data centers and other large users do not raise costs and instead provide immediate, tangible benefits to customers. Several factors influence the outcome, including how much spare capacity exists on the grid, how large and concentrated new electricity needs are, and how regulators allocate the costs and revenues from additional power sales to data centers.

Using existing capacity may lower prices. Where the grid has sufficient "headroom," additional electricity sales may make better use of infrastructure that customers are already paying for, spreading fixed costs over more sales.

But large and concentrated loads can still trigger major new costs. New demand may require new generation, transmission, substations, or other maintenance or upgrades. In addition, when demand spikes, power lines can get crowded ("congested"), and as cheap electricity cannot get to where it is needed, the grid falls back on turning on its most expensive power plants ("peakers"). We do not pay for these high prices just for the one peaker plant that gets turned on for a brief moment; in most wholesale markets, the very high peaker price will be applied to all resources on the system, creating a significant cost increase that could be avoided with local power.

Who pays and who benefits also depends on regulation. Even where additional costs are allocated to data centers through a dedicated customer class, administrative rules may assign the new revenues from additional power sales that could reduce rates to the data centers only, and not other classes of customers. In short, rates may go down on a utility-wide basis without actually lowering rates for most utility customers.

Timing creates additional risk. Utilities may pay for infrastructure that will last longer than what large load customers commit to. Different state rules may accelerate or defer when investments will land on people's bills. Large load customers backing out of investments early or altogether can leave customers to pay for the infrastructure they leave behind ("stranded assets").

Other risks include inadequate energy management from data centers that risks destabilizing the grid, or even poor siting resulting in uncontrolled grid spending to manage impacts.

In practice, when a distribution utility has to build a new substation or reinforce feeders to serve one large customer, and there is no clear regulatory standard for who pays and who benefits, costs and risks may be socialized onto people rather than borne by the facility that caused them.

Rate stabilization or decreases will require strong policy to protect customers from risks related to data centers, as well as guardrails for data center development, construction, and operation. Standards are necessary and no-regret solutions such as those in this blueprint exist. Flexibility tools such as batteries, demand response, or virtual power plants[28] are useful when seeking to integrate new loads and essential to maintain affordability.

Local clean power is the answer to today's challenges

To keep rates down as demand grows and requires new investments, utilities must aggressively control spending. Investing in local power is a no-regrets strategy that helps tackle all of the challenges above.

Grid challenge	Local power's answer
Growing electricity demand is putting pressure on rates for everyone	**Bill-saving**: Local power puts money back into the pockets of *all* consumers by lowering system cost, while often providing additional savings to participating businesses and households
New gas generation is expensive and exposes customers to fuel price volatility and national security risks	**Low cost**: Local power can provide energy and grid services at lower cost than new gas generation, without dependence on expensive fuels or volatile global energy markets
Slow interconnection queues, supply chain bottlenecks, and long construction timelines cannot keep pace with demand	**Fast and scalable**: Local power can be deployed in weeks and months rather than years, where the grid needs it most
Future demand is uncertain and customers can get stuck paying for unnecessary infrastructure	**Modular**: Local power can be built incrementally and track growing electricity demand as it materializes rather than betting on uncertain forecasts
Centralized grids are vulnerable to failures of major power plants and transmission lines, and extreme weather; losing a few nodes can take out wide areas	**Resilient:** Distributing resources across many locations reduces dependence on any single asset and can limit the consequences of major failures
Operators are finding it harder to keep supply and demand balanced	**More reliable:** Local power both cuts demand and adds supply in the tightest hours, helping keep the lights on and businesses running
We pay for electricity that never reaches us, lost as heat on long-distance power lines	**More efficient:** Generating power closer to where it is consumed reduces energy wasted in transmission and distribution
Burning fossil fuels to generate electricity produces pollution that harms people's health	**Clean**: Local clean energy reduces harmful air pollution, making communities healthier
The grid is old and designed for early 20th-century technologies, straining to keep up with fast-changing loads	**Modern and flexible**: Batteries, demand response, managed charging, and other flexible resources are best matched to manage today's demand patterns. They can respond in seconds, shifting use to when power is plentiful and cheap

Deployed at scale, the system-level savings from local power can be substantial. At its simplest, a rate is a fraction:

YOUR RATE (¢ per kWh) = **Spending** (the dollars the utility must recover) / **Electricity sold** (the kilowatt-hours we all buy)

Assume a hypothetical utility that recovers $100 million across 1,000 gigawatt-hours, for a rate of 10 cents per kilowatt-hour. From there, spending either climbs steeply or is kept under control, and demand either grows a little or a lot.



FIGURE 1 | *How spending and load growth combine to set rates. Figures are illustrative and hold spending constant across demand scenarios.*

All four scenarios include increased demand ("load growth"), but three out of the four scenarios result in increased rates. Of course, these numbers are entirely hypothetical, but this simple model clarifies the mechanics. **Growth alone will not rescue runaway spending**, and if that growth never arrives, customers pay for the spending anyway.

While states cannot decide how much demand will grow, they can decide how much utilities are allowed to spend to meet it and incentivize or require the use of local power to control costs. Because local power can be added in small increments as demand appears, it is the surest way to keep the top of the fraction above in check. It does so in several ways.

Avoid spending

01

USE WHAT WE HAVE

Local power can shift demand off the peak so existing wires and plants do more, and fewer new ones are needed.

Savings: *Plants and wires that never get built.*

Lower the cost

02

PICK THE CHEAPER OPTION

When power is needed, local solar, batteries, efficiency, and flexibility cost less than turning on an old gas plant or building a new one.

Savings: *A costly plant that is neither run nor built.*

Save in power markets

03

LOWER THE PRICE OF ALL POWER

The price of the costliest plant turned on during a demand peak is paid to every plant on the grid. When local power lowers demand, it lowers the price paid to all

Savings: *Every other plant, now being paid a lower price.*

Cut upgrade costs

04

TARGET LOCAL CONSTRAINTS

When one neighborhood's equipment is overloaded, batteries and flexible demand placed there cost far less than rebuilding a substation.

Savings: *A substation or line rebuild that is avoided.*

Postpone spending

05

BUY TIME

When local power pushes a needed build out a few years, customers go that long without paying for it, and if the demand does not materialize, they may never have

Savings: *Years of payments on a project not yet built.*

Use private capital

06

UNLEASH COMPETITION

When others are allowed to compete, households and developers can pay for local power themselves and that equipment stays off the utility's books, so everyone

Savings: *Not paying the utility's return on equipment it does not own.*

Cut waste

07

LOSE LESS ALONG THE WAY

Power generated closer to where it is used is not wasted by being sent over long distances, so less has to be generated and paid for.

Savings: *Power that no longer has to be generated.*

These resources have a long, proven track record, and the numbers below speak for themselves.

The cheapest power plant is the one we never have to build. The Brattle Group found that 60 gigawatts of virtual power plants could meet future grid needs at a cost $15 to $35 billion lower than the alternatives, including new gas plants, over ten years, while also providing more than $20 billion in additional societal benefits.[29] Similarly, fully embracing energy efficiency could save $4.8 trillion by 2050, or about $31,000 per U.S. household.[30] **These savings are shared with all customers while also providing additional revenue for program participants.**

Local power at work, by the numbers:

MEASURED BENEFITS

Avoid spending Lower the cost Save in power markets Keep the lights on	In **New England**, distributed solar and energy efficiency saved customers an estimated $224 to $246 million during a single weeklong heat wave in 2026. On the peak day, distributed solar supplied more than 25 percent of regional demand at times and helped reduce the afternoon peak by 2.3 gigawatts.[31]
Avoid spending Lower the cost Save in power markets	In **Vermont**, a virtual power plant program saved all customers $11 million in 2025. The following year, during the heat wave of July 2026 alone, the program saved all Green Mountain Power customers $6 million in a single peak hour.[32] The program has operated for over a decade and, even in early years, saved customers up to $3 million per year by reducing what the utility has to buy from the wholesale market during peak hours. Vermont's largest power resource by capacity is now a VPP.
Lower the cost Cut upgrade costs Keep the lights on	In **Texas**, the grid operator estimated about 1.5 gigawatts of distributed batteries had been installed by the end of 2024,[33] which is more power capacity than either of the large nuclear reactors operating southwest of Houston.[34] Battery installations have sped up since. A program compensating local power, primarily batteries of 1 megawatt or less, for energy and other grid services provided into the wholesale market grew nearly **20-fold in about two years**, from 15 to 293 megawatts by September 2026.[35] In addition, the Texas grid operator reports that the program "can be utilized to help reduce transmission cost and this is a key objective for the next phase of the pilot."[36] One company alone reported bringing 250 megawatts of batteries online in one year, with installations growing at 35 megawatts per month as of August 2026.[37]

Avoid spending Lower the cost Save in power markets	The U.S. Energy Information Administration reported that utility efficiency measures installed in 2024 are expected to save 281 terawatt-hours over their useful lives, or about 15 percent more electricity than was sold in the entire state of California in 2024.[38] These improvements produced annual electricity savings of 23.8 terawatt-hours and reduced peak electricity demand by 6.26 gigawatts **nationwide**.[39] This is enough to meet the peak power needs of all of southern Nevada, including the casinos and hotels of Las Vegas, even on the hottest day of the year.[40]
Avoid spending Lower the cost Cut upgrade costs Use private capital	In **Idaho** and **Utah**, Rocky Mountain Power's Wattsmart Batteries program enrolled more than 6,700 customer batteries by the end of 2025, representing nearly 40 megawatts,[41] about equivalent in size to a small gas turbine in Utah.[42] The utility uses the batteries to manage peak electricity demand, respond to imbalances, and reduce pressure on transmission.[43]
Avoid spending Lower the cost Use private capital	In **California**, home batteries participating in the state's virtual power plant delivered 453 megawatts of additional capacity by October 2025, enough to serve 340,000 to 450,000 California homes.[44] When combined with commercial and longer-duration batteries, the program delivered 484 megawatts in total,[45] essentially the capacity of a 500-megawatt natural-gas power plant, at a fraction of the cost and with none of the pollution.
Avoid spending Lower the cost Keep the lights on	Across the Tennessee Valley, covering **Tennessee** and parts of **Alabama**, **Georgia**, **Kentucky**, **Mississippi**, **North Carolina**, and **Virginia**, demand response programs reduced demand by 1.3 gigawatts during a record winter peak in January 2025, comparable to the power capacity of a large nuclear reactor. According to the Tennessee Valley Authority (TVA), this saved more than one million dollars in a single day by avoiding expensive wholesale power purchases.[46] TVA reports that it could access nearly 2 gigawatts of demand reduction in an emergency, equivalent in power capacity to about 1.5 large nuclear reactors. TVA describes it as "a significant resource for grid stability" and notes the program "consistently exceeds expectations, with performance levels over 100 percent."[47]

Use private capital Keep the lights on	In **Puerto Rico,** more than 90,000 customers participating in a territory-wide virtual power plant provided an average of 75 megawatts during generation shortfalls in 2026, helping reduce the risk of blackouts.[48] Demonstrating customer satisfaction, the program grew from about 24 megawatts of enrolled capacity in 2024 to 500 megawatts by late 2025, or a 20-fold increase.[49]
Avoid spending Lower the cost Save in power markets Keep the lights on	In **New York**, distributed solar reduced statewide peak electricity demand by about eight percent during the July 2026 heat wave, saving consumers an estimated $200 million in peak-grid costs.[50] A year earlier, New York's 265,000 distributed solar projects (totaling 7.8 gigawatts) reduced peak load by five percent during the June 2025 heat wave and saved consumers $90 million.[51]
Avoid spending Cut upgrade costs Postpone spending	In **New York**, regulators approved a $200 million budget in 2014 for Con Edison to meet rising demand in Brooklyn and Queens with local power,[52] deferring a substation estimated at $1.2 billion.[53] The program met its 52-megawatt target by 2018.[54]
Avoid spending Lower the cost Keep the lights on	In **Arizona**, the state's largest utility noted its VPP programs reduced demand by about 190 megawatts in 2024. More than 90,000 thermostats contributed about 160 megawatts, roughly comparable to the output of a traditional power plant. Arizona Public Service stated that its VPP program is now nearing 200 megawatts, equivalent to powering 31,200 Arizona homes, reducing the need to start up additional power plants during peak conditions.[55]
Avoid spending Cut upgrade costs	In **Massachusetts**, the ConnectedSolutions program returns more than $2 in benefits for every $1 spent, based on the distribution, transmission, and capacity costs it avoids.

PROJECTED BENEFITS

Avoid spending Lower the cost	In **Michigan,** energy efficiency programs implemented in 2023 are expected to save utility customers $1.4 billion over the lifetime of the improvements, returning $2.54 for every dollar spent.[56] These improvements reduce costs for all customers by reducing the cost of providing utility service ("cost of service"), including the need for new power plants.

Lower the cost Save in power markets	In **New York**, expanding distributed solar to 20 gigawatts and meeting the state's storage target is projected to lower energy costs by $1 billion in 2035, with more than half of the avoided costs occurring during the winter months.[57]
Avoid spending Lower the cost	In **Utah**, utility Rocky Mountain Power reported that its energy efficiency and demand response programs will deliver $126 million in net benefits over the lifetime of the improvements, after accounting for program costs.[58]
Avoid spending Lower the cost Cut upgrade costs	In **Michigan**, **North Carolina**, and **Virginia**, local power is projected to reduce power-system costs by $1.6 billion, $676 million, and $926 million annually, respectively, by 2030, through avoided energy, generation, transmission, and distribution costs.[59]
Avoid spending Lower the cost	In **Virginia**, a *near-term* local power portfolio is projected to provide $320.7 million in annual net savings, equivalent to about $100 per residential customer each year.[60]
Avoid spending Save in power markets Cut upgrade costs	In **California**, adding 5.4 gigawatts of community solar and storage is projected to save customers $6.5 billion over 20 years, including $4.2 billion from lower electricity prices, $4.6 billion from reduced capacity costs, and $910 million from avoided transmission and distribution spending, even after accounting for the higher cost of community-scale projects.[61]

Local power is cost-effective and can address capacity constraints on the system. By cutting demand on the grid when the system is most strained, local power can reduce the need to buy extraordinarily expensive capacity as illustrated in the Mid-Atlantic and Midwest (PJM) wholesale market, where capacity prices rose more than tenfold between the 2024/25 and 2026/27 delivery years.[62]

Local power can provide benefits that transmission-connected assets cannot, precisely because it is located where the electricity is being used. A battery, flexible building, or solar panel system located on a part of the grid that is running out of capacity can reduce the need to upgrade that circuit, substation, transmission line, or other equipment. Resources located where the grid is most constrained can be particularly valuable across the system, from distribution to transmission. For example, Base Power modeled a high-growth area in Texas and found that just a small number of batteries, if placed in the right locations, could prevent a transmission failure during periods of high demand.[63]

Local power relies on infrastructure that already exists, and the new infrastructure it does require is smaller and faster to permit and interconnect. Utilities will have to make investments enabling sensing and control of distributed resources. However, these improvements will not only enable integration of local power, but also boost tools and resources available to manage and maintain the grid at lower cost. In contrast, a new transmission line or large power plant carries the costs of years of permitting,

interconnection studies, and financing before it ever delivers a kilowatt-hour. These, along with the ongoing costs of fuel, have increased. For example, the costs of building natural gas-fired power plants increased by 66 percent, and the time it takes to build them increased by 23 percent between 2023 and 2025.[64]

Local power can be deployed quickly and track growing electricity demand more closely to control costs and maintain reliability. Distributed projects continue to move through the queue and reach completion considerably faster than centralized alternatives, delivering the "speed to power" that utilities and large customers alike have identified as a priority. Meeting present demand growth will require time and investment regardless of approach, but local power can maximize the usefulness of the existing distribution system as additional clean capacity gets developed and electricity demand trends become clearer.

Generation and flexibility located closer to homes and schools are also fundamentally more reliable due to diversification. A grid composed of thousands of small, distributed resources is structurally more difficult to disable than one that depends on a limited number of large power plants and transmission lines. The same logic applies at the household level: a home battery or rooftop solar system can maintain power to lighting, medical equipment, and refrigeration during a distribution outage, independent of the status of the wider grid.

Local power provides additional benefits beyond electricity service. Reduced pollution and emissions produce public health gains and broaden economic development opportunities in states, while strengthening energy security. In the Carolinas, for instance, the U.S. Environmental Protection Agency (EPA) estimated that the public health value of distributed solar and storage alone amounted to five to eight cents per kilowatt-hour.[65] In the Mid-Atlantic region, EPA estimated this health benefit to be over 10 cents per kilowatt-hour for efficiency programs.[66]

Local power is also particularly well matched to a grid with rapidly changing demand such as the one created by data centers. Batteries, demand response, managed EV charging, and other flexible resources can respond to changing grid conditions almost instantly. This includes keeping the grid frequency steady ("frequency response"), smoothing second-to-second fluctuations ("regulation"), and helping manage sudden increases and decreases in demand ("ramping").

Local power is a no-regrets strategy for controlling rising grid costs. It allows states to add capacity incrementally, closer to when and where demand actually materializes, rather than committing customers years in advance to large generation and distribution investments that may ultimately be unnecessary. Proactive use of local resources can reduce or defer expensive distribution upgrades, better track uncertain growing electricity demand, and avoid rebuilding the grid reactively. Allowing third-party ownership and competition can also bring private capital into the system without automatically adding a utility return on equity to every investment, helping deliver needed capacity more efficiently and at lower cost.

Local power is the first building block of a grid that is inherently more local, flexible, and multidirectional, regardless of the pace at which other elements of the transition unfold.

Barriers remain that state policymakers can address. This blueprint shows you how.

What can states do to advance affordability and reliability with local power?

Improving grid reliability and making electricity bills more affordable while addressing load growth, at scale and quickly, demands (I) that we produce and store more power closer to where it is consumed, locally, and (II) that we use our local resources and grid better.

Local distributed power is a plain common-sense approach.

I.

II.



I. Produce more power locally, where it is consumed, and do so quickly

The cheapest, fastest, most reliable power we can add to the grid is power produced closer to where it is used. Rooftops, parking lots, schools, warehouses, and community spaces across America are ready to generate, store, and deliver electricity at a fraction of the cost and time of building large new power plants or hundreds of miles of transmission lines. Many states, however, are still missing the legal and market architecture to let it happen at scale.

There is a clear playbook to produce more power locally for states. States should:

1. Establish clear rules of the road for local power;
2. Turn the growing demand for electricity into an opportunity, not a burden;
3. Cut the red tape and financing costs that slow deployment down;
4. Compensate customers and producers fairly for the electricity they produce and all the services they provide; and
5. Make sure everyone can share in the benefits.

I.1 ESTABLISH CLEAR RULES OF THE ROAD SO ALL FORMS OF LOCAL CLEAN GENERATION AND STORAGE CAN BE BUILT AND COMPENSATED

Not every type of local energy resource has a clear legal home in every state. Standalone batteries cannot always be installed on distribution grids or receive compensation for all of the services they provide. Electric vehicles sit idle in parking lots instead of being allowed to feed power back to the grid. Solar markets are capped and constrained even though the sun is free and abundant. And microgrids face a maze of rules that make them impractical to build despite their strong resilience and reliability benefits.

States should enable each distributed technology, set targets for local power production, and remove the arbitrary caps that prevent markets from growing to meet demand.

I.1.1 Enable distributed technologies

To allow local systems to address affordability and reliability now, states should further enable distributed technologies so they provide maximum value to the grid and consumers. EVs can be integrated into the grid, community solar can grow, microgrids can provide direct reliability and resilience services, and new types of retail products such as plug-in solar or permissionless batteries and appliances can lower consumers' bills if they are given clear legal frameworks to do so.

I.1.1.a Turn electric vehicles and chargers into flexible grid resources through managed charging and bidirectional charging rules

EVs represent a significant untapped resource for the grid; most cars, school buses, delivery vehicles, and fleets sit parked 95 percent of the time.[67] With the right rates, technology, and customer protections, EVs can charge when electricity is cheaper and cleaner, reduce charging during peak periods, and send power back to buildings or the grid, deferring or avoiding costs of grid upgrades and saving money for all ratepayers. In addition, states should empower competitive EV charging providers to participate in the marketplace.

States and public utility commissions should require utilities to offer managed charging programs, time-varying rates for fleet and residential charging, and clear rules for bidirectional charging participation. Programs should reward customers and fleets for charging at times when the grid is not stressed; protect drivers' mobility needs; support school buses and commercial fleets as flexible resources; and create standard interconnection, metering, and compensation rules for bidirectional chargers.

Further, public charging programs should address the "renter's penalty," where public DC fast-charging stations cost up to six times more than charging at a single-family home, limiting uptake of useful tools for affordability.

In addition, competitive charging providers should have the flexibility to integrate on-site solar generation, battery storage, microgrids, and advanced energy management systems alongside chargers. These integrated energy platforms can reduce peak demand, improve local reliability, lower operating costs, provide backup power during outages, and defer or reduce the need for costly distribution system upgrades.

STATE EXAMPLES | Managed and bidirectional charging

LEGISLATORS. Maryland required utilities to file "time-of-use" tariffs and directed regulators to adopt rules to interconnect and compensate for bidirectional EV charging systems, and California directed regulators to develop vehicle-grid integration strategies so transportation electrification programs maximize achievable and cost-effective grid benefits.

REGULATORS. New York regulators required and approved managed charging programs across utility service territories. Those programs are designed to give EV drivers an alternative to whole-home time-of-use rates and reward charging behavior that reduces stress on the grid. The private sector is expected to build, own, and operate EV charging stations.

RESOURCES

ACEEE	• *Innovative Utility Strategies Expand Equitable Access to EV Charging*
Vehicle Grid Integration	• *Resources Page*
Business Korea	• *Gas Stations Allowed to Store Solar Power for EV Charging*
Local Energy Rules	• *A Co-op's Transactive Energy Rate Pilot*
Advanced Energy United	• *EV Ready Grid Guidebook: A Practical Guide to Policies that Prepare the Grid for Electric Vehicle Adoption at Scale*
GRID Alternatives	• *Utility Brief–Affordable EV Charging for Low-Income Renters and Multifamily Housing* • *Utility Playbook–Creating an Affordable EV Charging Program for Low-Income Renters and Multifamily Housing*
Varghese, Menon, and Ermagun	• *Equitable distribution of electric vehicle charging infrastructure: A systematic review*
RMI	• *Electrification 101: Ensuring Equitable EV Charging Access*

I.1.1.b Allow for community solar

Community solar has long been a solution for renters, multifamily residents, small businesses, and low-income households to lower their power bills even when they do not own the building, the site is not suitable for rooftop solar, or other financial factors stand in the way. It is also a great opportunity for those with suitable space to host installations that create additional revenue for their communities. Community solar generates power closer to where it is used, reducing strain on the transmission system and unlocking the local distribution grid's full value.

To make this possible, **states should enable markets with legislation complemented by smart market rules that both favor competition and prioritize and guarantee customer savings.** Nineteen states and the District of Columbia already have community solar legislation.[68] Market rules can ensure that bill credits reflect the value that the project delivers to the grid and to communities. No more, no less.

States should establish a competitive, market-based community solar program that provides fair compensation for projects, transparent and efficient interconnection and billing, strong consumer protections, and broad customer eligibility so renters, homeowners, businesses, and public institutions can participate. States also should include dedicated provisions to expand access for low-and moderate-income (LMI) households through meaningful participation targets, guaranteed bill savings, flexible income verification (including self-attestation and categorical eligibility), utility accountability, consolidated billing, and coordinated outreach to maximize enrollment and long-term program success.

STATE EXAMPLES | Community solar

LEGISLATORS. In Illinois, a community solar program guarantees that low-income customers receive at least 50 percent of the value of the power produced and requires no upfront subscription fee. Illinois also includes strong customer protections and fair compensation. New Jersey and Colorado both require that over half of every community solar project's capacity be subscribed by low-income households and guarantee subscribers a minimum bill discount.

In Minnesota, a 2023 community solar program required that at least 30 percent of a community solar garden's capacity be subscribed by LMI subscribers and at least 55 percent by LMI customers, public interest subscribers, or affordable housing providers. Consolidated billing is available for all subscribers.

REGULATORS. New York regulators established a system by which utilities must compensate all of the values that distributed energy resources provide to the grid, including energy and capacity but also local benefits such as grid stress relief, demand reductions, or environmental benefits. This "Value of Distributed Energy Resources" tariff or "VDER" means that community solar is compensated based on when and where each project delivers value rather than at a single flat rate. **It has supported more than 2 gigawatts of community solar deployment in New York, which is enough electricity to run the entire New York City subway system twice over, or to power every household in Buffalo, Rochester, and Syracuse combined**.

GOVERNORS. In 2025, New Jersey expanded its community solar program enough for approximately 450,000 households to benefit, adding more installed capacity than the state's two-reactor Salem nuclear power station. The program expansion was approved by regulators in 2026.

RESOURCES

Coalition for Community Solar Access (CCSA)	• *Policy Guidebook,* a companion to *Model Legislation*
CCSA	• *Policy Solutions for Inclusive Solar Access*
Institute for Local Self-Reliance	• *State Community Solar Scorecard* • *State Policy Comparison Table*
CCSA	• *Recommended Best Practices for Community Solar Consumer Protection*
CCSA	• *The Economic Impact of Community Solar*

I.1.1.c Enable microgrids with clear legal frameworks and keep critical services powered

States should make it easier to develop microgrids that can keep critical services powered during outages and provide value to the grid during normal conditions. States should clarify that community, campus, and multi-customer microgrids can legally interconnect and operate without being treated like monopoly utilities.

A microgrid is a local energy system that combines load, generation, storage, controls, and the ability to operate either connected to the larger grid or independently when the grid goes down, making it especially valuable for facilities that must keep operating during emergencies, such as hospitals, schools, emergency shelters, water and wastewater facilities, public safety buildings, multifamily housing, or community resilience hubs.

In many states, laws and regulations were written for a one-utility and one-customer model, making it difficult or impossible for a microgrid to connect multiple buildings, cross a street, serve several critical facilities, or export power to the grid.[69]

States should also create clear microgrid definitions, authorize multi-customer microgrids, establish interconnection and operating rules, and create microgrid tariffs that define fair terms for grid access, establish compensation pathways for the services microgrids provide (e.g., energy export or peak reduction), and develop frameworks to value the costs that microgrids help postpone or avoid.

STATE EXAMPLES | Microgrids

LEGISLATORS. Oregon established the country's first mandate to create a comprehensive state regulatory framework for community-owned microgrids. HB 2066 authorized local governments to designate microgrid zones with special land-use rules and directed Oregon regulators to develop compensation frameworks for the services microgrids provide to the grid, allowing excess energy to be sold to utilities on a nondiscriminatory basis. HB 2065 streamlined interconnection by allowing third-party engineers to evaluate connection requests and requiring utilities to approve or deny applications based on published technical standards rather than discretionary review.

New Hampshire mandated that the state energy office initiate an investigative proceeding to identify barriers to microgrid deployment and provide recommendations to the legislature and regulators. The New Hampshire Department of Energy provided initial recommendations in a Phase I of the process, including defining microgrids, providing evaluation criteria for pilots, and removing regulatory barriers to adoption. The legislature then initiated a second phase of the investigation to develop pilots.

Maine enacted legislation exempting qualifying private multi-customer microgrids from the state's right-of-way law and giving regulators the criteria to review and approve individual project applications based on size, technical feasibility, and resources used. **An approved microgrid does not become a regulated public utility simply by providing service to participating customers, specifically enabling third-party-owned multi-customer microgrids.**

Connecticut established the country's first state microgrid grant and loan program in 2012, born out of severe weather events that caused widespread outages. The program has been expanded multiple times, most recently in 2023, and requires projects to serve critical facilities, guarantee nearly three weeks of island-mode operation, use low-emissions resources, and prioritize vulnerable communities.

Colorado created a Microgrids for Community Resilience Grant Program funding solar-plus-storage and other clean microgrid projects at community facilities in areas served by cooperative electric associations and municipally owned utilities, with a focus on outage-prone and underserved rural communities.

REGULATORS. Oregon's rulemaking to establish a microgrid regulatory framework is underway in 2026. The proceeding's initial focus is on developing a system-wide microgrid services tariff for single-customer microgrids, as well as a community-led process for approving microgrid zones.

Michigan regulators opened a docket to improve electric grid reliability and the energy resilience of critical facilities following significant storms. In December 2025, the commission approved a staff proposal outlining 13 resilience recommendations, including investigating barriers to integrating single-customer microgrids and distributed energy resources into the utility system that could improve critical facility resilience.

RESOURCES

Think Microgrid	• *2024 State Scorecard*
NARUC	• *Essential Guide to NARUC Microgrids Resources*
New Hampshire Department of Energy	• *New Hampshire DOE Microgrid Investigation Report*
Think Microgrid	• *Policy Tracker*
Lawrence Berkeley National Lab	• *Microgrid Regulatory Barriers Report*
Local Energy Rules	• *The Oregon Trail To Community Microgrids*

I.1.1.d Allow and support plug-in solar and batteries

States should allow plug-in solar and plug-in batteries that lower bills with little to no exports to be installed without first seeking approval from the utility. Such policy is especially important for plug-in solar systems, for which a requirement to obtain interconnection approval for one to four panels is a significant deterrent.

Germany's experience demonstrates how quickly these systems scale once the rules are clear; **in just a few years following legislative clarity, estimates put the installed base of plug-in solar in Germany near four million systems, together delivering on the order of 3 gigawatts of daytime generation without putting any pressure on the grid.[70]**

There are two relevant categories of products: plug-in solar, which consists of small solar panels with advanced electronics that produce little to no export; and plug-in batteries or appliances (e.g., ovens) with batteries that do not export to the grid.[71] They both typically plug into an outlet and begin working immediately, and do not require a utility contract, utility approval, or a permit. They usually do not require electricians or panel upgrades.[72]

States should establish these technologies as their own category in law, exempt from interconnection and other requirements for traditional rooftop solar, and bar utilities from demanding approval, fees, or additional equipment. They should pair this with sensible guardrails, such as a wattage ceiling on exports and certification from a nationally recognized testing laboratory.[73]

For states facing rising bills and constrained capacity, it is local supply that can be deployed quickly and cheaply. Legislators are acting across the country; in 2026, plug-in solar bills were considered across 36 states and the District of Columbia.

STATE EXAMPLES | Plug-in technologies

LEGISLATORS. In 2025, Utah became the first state to legalize a "portable solar generation device" category, i.e., a movable system of no more than 1,200 watts that plugs into a standard 120-volt outlet, carries a certification from UL or an equivalent nationally recognized laboratory, and meets the current National Electrical Code, and declared it exempt from interconnection requirements, exempt from any interconnection agreement, and outside the net-metering program entirely. The law bars utilities from requiring approval before a customer installs one, from charging any related fee, and from demanding extra equipment; it also requires "anti-islanding" so the device cannot energize a line during an outage.

In 2026, Colorado enacted its own bill, which, in addition to the above, voids any covenant or restriction that unreasonably prohibits or restricts the installation, use, or operation of plug-in solar, and classifies it as an energy efficiency measure. This prevents homeowners associations from prohibiting it. The export limit in Colorado is set at 1,920 watts. The act specifies that utilities are not liable for any damage caused by a plug-in solar device and requires that installation be in accordance with fire and building codes.

As of October 2026, several additional states have passed legislation to allow plug-in solar, including California, Connecticut, Maine, Maryland, New Hampshire, Vermont, and Virginia.

RESOURCES

Clean Energy States Alliance	• *What States Need to Know About Plug-In Solar*
Latitude Media	• *New York is Becoming a Plug-In Battery Test-Bed*
Bright Saver	• *Which States Are Moving Plug-In Solar Legislation?*
DSIRE Insight	• *Plug-In Legislation: Bills Defining Portable Solar Propagate Across the Country*
Catalyst	• *The Rise of Permissionless Batteries*
CalNEXT	• *120V Induction Stoves with Battery Backup*
Local Energy Rules	• *DIY Plug-In Solar Is On The Way*
Bright Saver, Brooks Engineering, Permit Power	• *Safety of Plug-in Solar*

I.1.2 Set targets and procurement for local and community-scale storage and solar+storage

States should set a target for local storage and community-scale solar+storage, require that utilities deploy these resources to meet the target based on the tools available in-state, and count only resources that can perform when the grid needs them.

States can establish binding targets for energy storage deployment for both front-of-the-meter and customer-sited storage, because both can reduce peak demand and support system-wide affordability, enhance reliability, and defer infrastructure costs. In fact, many states already have. Targets should be divided into clear distributed energy resource categories such as behind-the-meter residential and commercial storage (including paired with solar); front-of-the-meter storage connected to the distribution system; storage paired with community-scale solar; storage serving public, community, or critical facilities; and bidirectional EV charging systems.

State targets have usually been expressed in megawatts only, but to promote attributes that support grid needs, distributed energy resource storage targets should also include other attributes, such as how long batteries can provide capacity during peak or grid-stress periods. Short-duration batteries that look large on paper but cannot support the grid through longer peak, reliability, or outage events may be more or less valuable in a given state depending on local grid needs.

	Power capacity	Energy capacity	What it means
Battery A	100 MW	100 MWh	Can discharge 100 MW for 1 hour
Battery B	100 MW	400 MWh	Can discharge 100 MW for 4 hours
Battery C	25 MW	400 MWh	Can discharge 25 MW for 16 hours

Table 1: Examples of power vs. energy capacity in batteries

Once a target is set, utilities must be required to identify pathways for procurement/compliance within a defined timeframe and under their applicable state rules, so that the storage actually gets built in a timely manner. These pathways may range from "competitive solicitations," where the utility chooses partners to deploy storage based on a request for proposals that includes clear criteria, to "standard offer-style" programs, where the utility sets the rules of the program and anyone who meets the rules and provides the services (in this case local storage) can be compensated.[74] Both are traditionally reviewed by regulators to ensure that public policy goals are met.

Resources should count toward the target only if they can be dispatched, aggregated, or otherwise operated to reduce local peaks, provide capacity during grid-stress hours, support resilience, or shift locally produced power into the hours when it is most valuable. In practice, performance should be measured with workable measurement and verification ("M&V") rules that show whether storage actually helped the grid when called. For behind-the-meter

batteries, this should mean measuring at the battery itself ("device-level telemetry"), rather than relying only on the customer's whole-building meter.

States should also make clear who is allowed to provide these resources; independent developers, aggregators, community solar providers, public entities, and customer-owned systems that meet the same eligibility and performance requirements should all be able to participate in order to promote competition and to lower costs for customers. States should apply the same cost-effectiveness standards to utilities and non-utilities alike and ensure that the allocation of risks for construction and performance produces the best outcome for ratepayers and helps create a broader market for local capacity.

STATE EXAMPLES | Storage targets

LEGISLATORS. Virginia requires that at least 35 percent of covered storage facilities placed into service be purchased from, or owned by, parties other than the utility, and requires utility storage plans to include a goal that at least 10 percent of storage projects be installed behind the meter. Virginia also directs its regulators to adopt regulations that include competitive solicitations, behind-the-meter incentives, non-wires alternatives programs, and peak demand reduction programs. In 2026, Virginia expanded its storage framework significantly and extended procurement requirements through 2045.

In Massachusetts, the legislature directed utilities to procure approximately 5 gigawatts of energy storage by July 31, 2030, and rather than treating all storage as a single bucket, explicitly separated the target by duration: mid-duration (4 to 10 hours), long-duration (10 to 24 hours), and multi-day (24+ hours).

In Illinois, the Clean and Reliable Grid Affordability Act established an overall storage target and a $250 per kilowatt-hour rebate for distributed storage, including storage paired with distributed generation, storage paired with community solar projects, and standalone distributed storage. It also created a scheduled-dispatch virtual power plant program for storage rebate recipients, with participating systems dispatching on summer weekdays during specified late-afternoon peak hours, although dispatch commitments for standalone storage are voluntary. It further directed the Illinois Power Agency to evaluate an Illinois Storage for All program linked to Illinois Solar for All.

REGULATORS. New York approved a roadmap to deploy 6 gigawatts of energy storage by 2030, or at least 20 percent of the state's peak electricity load. The roadmap includes separate pathways for "bulk storage," "retail storage," and "residential storage,"[75] including 1,500 megawatts of retail storage and 200 megawatts of residential storage supported through state incentive programs.

Connecticut's regulators established the Energy Storage Solutions program, administered by the state's green bank with two utilities, to deploy 580 megawatts of customer-sited storage to support the state's goal of 1 gigawatt of storage by 2030 goal through compensation both upfront and with performance payments tied to active dispatch.

New Jersey's Garden State Energy Storage Program separates transmission-scale and distributed storage into distinct phases: Phase 1 procures at least 1 gigawatt of transmission-scale storage through competitive bidding, while Phase 2 is expected to focus on smaller front-of-the-meter and behind-the-meter systems connected to local distribution grids, using both fixed and performance-based incentives.

UTILITIES. Pacific Gas and Electric (PG&E) set a goal to enable electric vehicles in its service territory to provide approximately 550 megawatts of flexible load by 2030 through vehicle-grid integration, including managed and bidirectional charging. The California Energy Commission's 2026 bidirectional-charging roadmap models the potential scale of the resource, including up to 5 gigawatts of peak-load reduction from vehicle-to-home charging by 2030 and lays out steps to enable deployment. It does not yet establish those modeled levels as state targets.

RESOURCES

Coalition for Community Solar Access (CCSA)	• *Integrating Distributed Solar and Storage: The Keystones of a Modern Grid*
Clean Energy States Alliance	• *Table of State Energy Storage Targets and Progress*
Solar Energy Industries Association	• *Vision for American Energy Storage*

I.1.3 Remove program caps that prevent distributed resource markets from growing

States should replace rigid caps with scalable, adjustable program designs. States' goals should be to move away from "stop building when the cap is hit" to "keep building when local resources are cost-effective, reliable, clean, and useful to the grid and community."

Caps are ceilings limiting how much of a technology is allowed to exist or participate in a market. They are usually set by a utility tariff or a program rule, and when that ceiling is hit, new customers are turned away, developers stop investing, and the market stalls. Caps do not necessarily relate to the capacity of the grid to handle more distributed assets or to the usefulness of these assets to the grid, especially in a period of load growth.

There are two distinct types of caps worth addressing. **Participation caps** are limits on how much of a technology can access a tariff or program, regardless of whether any subsidy is involved. For instance, net metering aggregate caps restrict how much solar can participate in the net metering tariff. Massachusetts caps net metering participation at 7 percent of each utility's system peak load, and when the cap was hit in 2017, an estimated $78 million in projects stalled as a result, unrelated to whether solar impacted grid conditions.[76] Alaska caps net metering participation at just 1.5 percent of a utility's average retail demand, a threshold so low that at least three of the state's major utilities have already hit it, and regulators opened a proceeding in 2024 to consider raising it to 20 percent.[77]

The second type is an **incentive program cap**, which limits the total megawatts eligible for a financial incentive such as a rebate, a guaranteed payment rate, or a bill credit. While these may have a more defensible rationale, a rigid hard cap is still a blunt tool. New Jersey's community solar program hit its 150-megawatt annual registration ceiling in early 2025 with utility territories oversubscribed and closed to new projects. The state removed the cap as an analysis by The Brattle Group showed that installing 3,000 megawatts of community solar in New Jersey by 2030 would save ratepayers an estimated $905 million.[78]

The legitimate concerns behind caps, such as cost containment (particularly where the cap is associated with a budget), grid operational management, and program quality, can be addressed with better tools: transparent cost-benefit analysis, declining incentive blocks, performance requirements, locational signals, and periodic commission review. Where a specific circuit has a real constraint, requiring the utility to identify it and create a pathway to resolve it is a better solution than just stopping deployment statewide.[79]

States should replace rigid caps with scalable program designs. **Participation in retail net metering or successor tariffs should not be subject to aggregate capacity limits; fair compensation rules that reflect the actual costs and benefits of exports are a better instrument.** Community solar and storage incentive programs should include revision or expansion triggers when demand exceeds available capacity and projects meet performance and consumer protection requirements.

STATE EXAMPLES | Removing caps

LEGISLATORS. New Jersey removed the state's 150-megawatt annual community solar registration cap and authorized 3,000 megawatts of new capacity to be registered by December 31, 2029, roughly twelve times what had been built to date. Virginia required the release of an additional 525 megawatts of shared solar capacity by July 1, 2026, including a dedicated portion for low-income subscribers, and established a predictable process for future program expansion triggered automatically when existing capacity reaches 90 percent subscription.

RESOURCES

National Association of State Energy Officials	• *National Standard Practice Manual*
Clean Coalition	• *Non-Energy Benefits and Social Costs: Properly Valuing Distributed Generation*
Clean Energy States Alliance and Applied Economics	• *Energy Storage Benefit-Cost Analysis, A Framework for State Energy Programs*

I.2 TURN THE GROWING DEMAND FOR ELECTRICITY INTO A LOCAL POWER OPPORTUNITY FOR AMERICANS

States should require new "large load customers," some with deep pockets, to use local clean power to lower and stabilize costs for people and to not only protect but also improve the grid. With unprecedented load growth creating strain on the grid and uncertainty on customers' bills, large loads should be required to be part of the local customer-centered solution.

Data centers, advanced manufacturing facilities, warehouses, and other large new customers have added enormous new demand to the electric grid and will continue to do so. The US accounted for 45 percent of electricity consumption from data centers globally in 2024, and data centers are on course to account for almost half of all growth in US electricity demand between now and 2030.[80] But grid infrastructure built to serve this expansion, such as new substations, transmission infrastructure, and generation, takes years to permit and build, and lasts decades on a utility's proverbial books.

For more background information on how large loads influence rates, please refer to page 17.

Local, clean, flexible power assets bring opportunities to avoid building generation capacity, avoid capacity purchases, defer transmission costs, defer distribution costs, lower peak energy prices, and lower congestion costs.

There should be two conditions for large load customers such as hyperscale data centers to access the grid or build infrastructure: large loads should be required to manage their impact on rates and the grid by (**I.2.1**) directly or indirectly funding "virtual power plants" (VPPs), including in host communities; and (**I.2.2**) participating in efficiency and demand response programs.

I.2.1 Require large loads to directly or indirectly fund local power as a condition of grid access

States should require large new customers seeking grid access to contribute to local, customer-sited energy solutions, including in host communities, as a condition of siting, permitting, and interconnection. These obligations should be implemented via "large load tariffs"[81] and through local community benefit agreements.

States should ensure that energy bills do not increase for people as a result of data centers' construction and operation. Large load customers should be required to guard communities against these risks, among other things by funding and deploying local power.

The requirement for large load customers to fund virtual power plants can be structured in several ways depending on the state and local conditions, the wants and needs of communities, the availability of existing funding deployment vehicles, and the state's overall policy goals. Directing these investments in the host communities has the benefit of improving community outcomes, but distributed energy resources can be deployed to provide wholesale and retail level benefits.

Wholesale vs. retail (state) energy markets: what it means, in plain English

- **RETAIL (STATE) LEVEL BENEFITS**
  - **Locational distribution VPPs:** "Reduce load here, during these hours, so we can delay or avoid building or expanding this feeder, transformer, or substation, or to unlock capacity to allow large load customers to interconnect."
  - **Traditional retail VPPs:** "Reduce demand across the entire utility system when electricity is most expensive or the grid is under the most stress, enabling the utility to lower its wholesale capacity, transmission, and power-supply costs while also providing distribution-level benefits."
- **WHOLESALE LEVEL BENEFITS**
  - **Wholesale capacity distributed power:** "Provide or eliminate a certain megawatts of capacity obligation from the relevant larger grid system/regional transmission organization so the system does not have to procure that much additional capacity for a large load."

I.2.1.a Create funding pathways for data centers to deploy local power

States should direct large loads to choose among the following pathways and encourage a variety of models, allowing the private sector to innovate to tackle load growth and affordability with local, dispatchable clean power. In all cases, the obligation should be sized to reflect the load's actual grid impact.

Large load customers could be required to fund (**a**) aggregators, (**b**) utility programs, and/or (**c**) dedicated funds to deploy customer-sited energy solutions. **These are not mutually exclusive, and do *not* dictate whether the assets funded are ultimately owned by customers or other third parties.** Community or nonprofit partnerships may prove particularly useful to deploy these funds.

a) Fund aggregators. A data center can contract with a third-party aggregator to enroll and dispatch customer-sited distributed energy resources, delivering VPP capacity as a service. The aggregator can receive payment either through a bilateral contract with the data center, or via a utility contract ("offtake"), and/or by participating in a wholesale capacity market. Depending on the structure used, "capacity credits" demonstrating that the capacity was delivered by the VPP can be allocated to the data center and be used to reduce the utility's capacity obligation that must be procured from the wholesale market, or the capacity credits can be delivered directly through the wholesale market.

This model supports competitive, third-party-driven distributed energy resources markets and keeps asset ownership with customers rather than utilities. The key challenge is that capacity credit mechanisms at the state level are new and not yet

standardized, and **will require states to develop clear accreditation frameworks** to ensure it reduces their capacity obligation**.**

Alternatively, the large load could own the distributed assets directly while hiring an aggregator to operate and dispatch them, giving the data center direct control over performance but requiring it to bear the capital risks of assets it does not necessarily understand well, while removing opportunities for customers to reap the benefits of ownership.

b) **Fund utility programs**. A state could also require that large loads pay a utility, which then deploys the capital into distributed energy resources or VPP programs off-site. The utility may contract a third-party aggregator to enroll and dispatch customer-sited resources, or direct funds into existing demand-side management budgets with a view to providing bill relief through its programs (including low-income energy efficiency and distributed energy, VPPs, weatherization, rebates, etc.). This model is well-suited to vertically integrated states where the utility has existing customer relationships and program infrastructure, or where a robust program already exists — and can be used to reduce the utility's capacity obligation. We do not recommend that utilities be allowed to use such funding to own assets directly as utility ownership will stifle the competition needed to keep prices down and the utility does not have a built-in financial incentive to maximize utilization.[82]

c) **Contribute to dedicated funds supporting local clean power**. States can also require that large loads contribute capital to a public financial intermediary such as a state green bank, a state renewable energy fund, or even a Community Development Financial Institution (CDFI), which in turn would deploy funds using established programs and community relationships. This model is well-suited to jurisdictions with mature public institutions that can stack utility incentives, federal tax credits where available, and private capital to maximize deployment per dollar. Funding deployed this way could be used in part for relief aimed at income-qualified families, nonprofit community service providers, and/or disadvantaged communities.[83] Here the large load has no control over specific deployments, but benefits from the fund's existing infrastructure and community relationships. This model produces community benefits but does not produce a capacity instrument (i.e., something showing utilities that load was reduced or that generation happened) for the data center. The assets would have to be rolled into a VPP or dedicated program in a next step for capacity credits to materialize.

I.2.1.b Implement standards via large load tariffs with capacity accreditation options

States should require utilities to develop tariffs that apply to all large new customers above a specified threshold and require regulators to adopt them only if they follow set rules and standards aimed at advancing affordability and reliability. These rules and standards, to be created by states during an inclusive stakeholder process including residential customers and businesses, should at minimum include grid impacts, ratepayer protection (particularly against rate increases and stranded asset risk), and capacity accreditation mechanisms.

The tariffs, developed by the utilities and to be approved by regulators, should in turn both detail investment in the ways described above and implement said rules and standards.

Large load customers are not all created equal, however, and policy should account for more than one type of large load. Historically, most data centers had smaller loads and connected to the distribution system under state jurisdiction. Hyperscale data centers over 100 megawatts are now connecting to the transmission system instead, and bringing their own flavor of grid impacts due to their immense scale. Hyperscalers can provide significant amounts of funding for communities due to their strong capitalization, and as such they should be held to the highest standards.

A basic tariff should define how capacity from distributed resources is measured, verified, and credited against the large load's capacity needs. Data centers connected to either the transmission or the distribution grid can use the pathways above and provide benefits to the system. In practice, different types of accreditation may be required because the credits will compensate for different types of benefits from VPPs (see the box on page 42).[84] Capacity accreditation of distributed, dispatchable resources should follow system needs and not add unwarranted complexity, and it should be informed by the stakeholder process referred to above.

States should also actively coordinate with their regional independent system operator or regional transmission organization to ensure that the state's capacity accreditation method for distributed resources is reflected in system planning and load forecasts so that the capacity reduction benefits can be realized for ratepayers, and to allow local power resources to participate in wholesale markets without undue burdens.

STATE EXAMPLES | Funding local power

LEGISLATORS. New Jersey requires its regulators to create standards for a new large load tariff for data centers, with a to-be-defined threshold no higher than 50 megawatts, and directs utilities to file a dedicated rate class and tariffs. Each utility must create a "demand-reduction trade program" allowing any data center to fund verified demand flexibility elsewhere on the system and receive the resulting capacity benefit. Large data centers that commit to new clean generation or storage, or qualifying demand reductions, receive prioritized interconnection; during system emergencies, they are curtailed ahead of residential customers. The tariffs must allocate costs attributable to large data centers, including infrastructure built solely or primarily to serve them, to those customers rather than other ratepayers. Large data centers must generally guarantee payment for at least 85 percent of requested electricity supply for 10 years, backed by financial security, to protect customers from stranded costs.

Virginia requires its large investor-owned utilities (Dominion and Appalachian Power) to propose voluntary demand-flexibility programs for customers with at least 25 megawatts of demand. The law allows those large loads to meet demand flexibility targets by funding or purchasing "capacity reduction credits" from other customers, including through weatherization, heat pumps, efficiency, demand response, customer-sited storage, and virtual power plants. Utilities may work with residential and other customers, cooperatives, and third-party providers, and regulators must guard against shifting program costs to other ratepayers. Unlike the New Jersey example above, the Virginia statute does not create an explicit link between those credits and wholesale capacity obligations.

Minnesota charges qualified large-scale data centers with peak demand of 100 megawatts or more an annual fee of $2 million to $5 million, scaled by peak demand, to fund low-income energy conservation, weatherization, and related programs. No capacity credit is returned to the data center, but a similar structure could be used to fund distributed assets that qualify for capacity accreditation.

New York's Homegrown Energy Act, introduced in 2026, would require data centers seeking 20 megawatts or more of electric service to either provide a discount on residential utility bills in their host community or directly fund the installation of distributed resources — heat pumps, heat pump water heaters, rooftop solar, and behind-the-meter batteries — for residential customers in the host communities where a data center is located, with priority for low-and moderate-income households and disadvantaged communities. New York's Public Service Commission would be required to implement the program through a time-bound rulemaking with community input.

Illinois' proposed POWER Act, also introduced in 2026, would require hyperscale data centers to pay for the grid costs they impose and to support their load with new clean energy and capacity. It would create a "bring your own" clean energy and capacity framework that can include new solar, storage, demand response, energy efficiency, operational flexibility, and VPPs. Data centers that bring new, deliverable clean capacity could qualify for firm service and faster interconnection, while load not backed by such capacity would be subject to mandatory flexibility.

REGULATORS. In 2025, Kansas regulators approved Evergy's Large Load Power Service tariff for new or expanded customers. In addition to protective measures for ratepayers,[85] the tariff includes an optional rider that allows large-load customers to enter into negotiated agreements with the utility to fund (i.e., pay for or help finance) the procurement of selected clean energy or distributed resources, with the customer receiving any agreed bill or renewable energy credit. This includes demand-side management, energy efficiency, and battery storage, to reduce peak impacts and support grid reliability.

Oregon approved a one-cent-per-kilowatt-hour surcharge on very large data centers served by Portland General Electric above the 100-megawatt threshold, funding efficiency, grid repairs, and local generation for energy-burdened customers. Unlike other models (such as New Jersey's), no capacity credit is returned in this model. Tying the surcharge to funding VPPs and other forms of local power that directly offset a data center's load would more closely tie the surcharge to benefits for all ratepayers.

HYPERSCALERS. Rather than simply asking utilities to build more generation to meet Google's new load, in 2026, Google announced a three-year "Bring Your Own Capacity" (BYOC) deal with Voltus to deploy 100 megawatts annually in the PJM region through distributed assets aggregated in a virtual power plant. Voltus aggregates batteries, smart thermostats, and flexible assets, and delivers capacity directly to the utilities. Voltus then registers the aggregated capacity with the wholesale market operator, PJM, and PJM recognizes the capacity,[86] meaning the obligation of the utilities in whose territory Google's load is located to procure capacity would be satisfied. The details of how the utilities and Google allocate the credits to Google's load are not public. This was the first known instance of a hyperscaler directly funding a VPP, and it aggregates residential, commercial, and industrial distributed resources. In October 2026, Voltus and Google announced that the initial 100 megawatts were oversubscribed and committed to developing 1 gigawatt in this way, or about half a Hoover Dam.

RESOURCES

Energy Innovation	• *Dodging the Firm Fixation for Data Centers And The Grid*
International Energy Agency	• *Energy Demand from AI chapter*
Cisco	• *What Is A Hyperscale Data Center*
Latitude Media	• *Google is Voltus's first 'bring-your-own-capacity' customer*
Sierra Club	• *Large Load Tariffs*

I.2.2 Require large loads to participate in demand response and efficiency

States should require large new loads above a defined threshold to enroll a portion of their demand in demand response programs, participate in utility-managed load flexibility programs, or demonstrate measurable operational flexibility as a condition of service.

In addition to investing in a large pool of distributed resources, a data center or large manufacturing facility that can reduce or shift its load by 10 or 20 percent on short notice is worth as much to a stressed grid as an equivalent amount of new generation. Many large loads have demonstrated the ability to shift significant load by hours without operational impact. A much-quoted 2025 study from Duke University found that the grid could absorb 76 to 126 gigawatts of new load, including from data centers, if that load could be reduced ("curtailed") for 0.25 to 1 percent of the time.[87] Data centers would not need to shut down, but only to shift their use or briefly reduce their consumption for 2 to 3 hours on average at a time during the grid's highest-stress hours.

This flexibility could help reduce or delay the need for costly new grid infrastructure. Grid Strategies forecasts roughly 90 gigawatts of peak load linked to data centers through 2030, falling squarely within the range the Duke study suggests the grid could absorb through flexibility alone.[88]

To put it more plainly, a little flexibility could absorb a new load equal to roughly 10 to 17 percent of the existing power that the entire United States uses at peak, without a single new power line or generator, helping relieve pressure on people's power bills.[89]

Programs should distinguish between the ability to quickly lower demand during grid stress events ("emergency curtailment") and demand response triggered by price signals during peak periods. Both provide value and both should be required or strongly incentivized to maximize affordability and reliability benefits.

For large loads that cannot curtail operations, storage, either on-site or off-site through VPP programs, as well as energy-efficiency improvements and demand-response enrollment, can provide an equivalent flexibility service by discharging during peak periods or grid emergencies, thereby reducing the net grid draw of the facility without interrupting operations. States should not accept on-site fossil fuel generation (e.g., via diesel or gas generators) as an alternative to demand response or battery storage, given local health, noise, and environmental impacts of these outdated technologies.

STATE EXAMPLES | Data center flexibility requirements

LEGISLATORS. New Jersey, in the same law behind the demand-reduction trade program described in Section I.2.1, requires that regulators specify what qualifies as an eligible "demand reduction" for that trade program, including incremental energy-efficiency improvements, demand-response enrollment, behind-the-meter energy storage, and managed electrification. A data center can satisfy part of its obligation by funding efficiency upgrades elsewhere on the system, on the same footing as funding storage or demand response. Separately, the law incentivizes data centers to develop and utilize methods to increase energy efficiency at their own facilities, including technologies that capture and utilize their own waste heat.

RESOURCES

Duke University	• *Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in U.S. Power Systems*
Climate Cabinet	• *Taming Data Center Turmoil Series*
Rewiring America	• *Homegrown Energy*
Alliance to Save Energy	• *Bridging the Load Gap: A Collaborative Path for Utilities, Hyperscalers, and Customers*

I.3 CUT THE RED TAPE AND FINANCING COSTS THAT SLOW DEPLOYMENT DOWN

The cost of batteries and solar has plummeted, but "soft" costs, such as permitting, interconnection, or financing, still bog down projects. Outdated utility processes, inconsistent rules across territories, bureaucratic permitting requirements, and expensive capital can make a project uneconomical even when the hardware is cheap.

States can cut these costs dramatically by (I.3.1) streamlining interconnection and permitting rules and (I.3.2) making public financing cheaper and more available. Doing so can unlock billions in projects that are already economically viable but sitting on the shelf.

Due to delays, the simplest and most standardized systems are impacted by red tape and soft costs that make Americans pay considerably more for local power systems than in other countries or block projects entirely. Analysis by the nonprofit Permit Power showed that **if home solar costs dropped to levels seen in peer countries, more than 18 million households could afford solar and batteries that cannot do so today, providing immediate bill relief and delivering cumulative savings of $1.2 trillion** over the life of their solar and battery projects.[90]

According to the National Laboratory of the Rockies, almost a quarter of projects that start the permitting process are canceled, and installers cite permitting issues as the leading cause.[91] Installers also report charging more due to unrecovered development costs that are passed on to the next customers.[92]

I.3.1 Remove the soft costs associated with red tape

Utility and local government processes have created bottlenecks for (I.3.1.a) interconnection and (I.3.1.b) permitting of local power. States should tackle both swiftly.

I.3.1.a Enable fast and predictable interconnection

States should require statewide, predictable interconnection rules so distributed resources can connect quickly and fairly. Utilities should not be able to indefinitely delay energy resources connecting to the distribution grid. States should pair changes to the process utilities follow with changes in engineering standards appropriate for the size of interconnected resources. Governance reform is necessary so that standards do not stagnate. **This includes adopting best-in-class procedures, incorporating storage-specific rules and processes, streamlining equipment approvals, requiring transparency and independent dispute resolution, developing enforcement mechanisms where necessary, and creating flexible interconnection tariffs.**

States typically have interconnection rules in place, but most are insufficient to allow distributed energy resources to be deployed at scale or are behind the technology advancements that can be used to reduce costs and increase speed to interconnection.

- "Front-of-the-meter" interconnection (i.e., the connection of larger community-scale solar, batteries, and other local resources to the local grid) is often delayed for several compounding reasons. Utilities design their processes inefficiently (e.g., serial hand-offs, manual studies, inconsistent screening),[93] and there is limited staff capacity with regulators because the work is highly technical and dispersed across tariffs, engineering standards, and IT systems. Storage faces its own hurdles when it is studied by utility staff as both load and generation under unrealistic "worst-case charging" assumptions instead of enforceable operating parameters and controls.
- "Behind-the-meter" interconnection (i.e., the connection of smaller customer-sited resources such as home solar, home batteries, commercial-scale batteries, or bidirectional EV charging systems) faces similar hurdles. Applications get stuck in a review phase for weeks, and customers have little to no insight as to their status. Utility engineers use overly stringent evaluations, with opaque modeling and assumptions, or neglect to allow for well-established technologies that bolster grid stability to claim that a new system would jeopardize the grid. Meanwhile, certified equipment like meter socket adapters or power control systems that reduce the need for costly home upgrades, and installer-led meter pulls that streamline the process by reducing wait times for utility staff, remain prohibited in most service territories.

In addition, patchworks of rules are not conducive to efficient deployment; instead, standards, rules, and processes should apply statewide across investor-owned utilities, rural electric cooperatives, and municipal utility territories to create much-needed consistency and predictability within states.

Practical solutions exist that tackle engineering, processes, and governance. States should do the following:

- **Adopt statewide interconnection rules aligned with IREC Model Procedures.** The Interstate Renewable Energy Council's (IREC)'s 2023 Model Interconnection Procedures are the most widely shared best-practices baseline for states to modernize interconnection rules and keep them current. The rules define three clear pathways for different types of projects: *Fast Track* for low-risk projects (residential solar, small batteries, EV charging), *Supplemental Review* for moderate-complexity projects, and *Full Study* for grid-impacting projects. Small projects, under 50 kilowatts, are well understood and use standardized equipment with well-known and tested impact, and should be automatically slated within the Fast Track pathway. In addition, the rules set firm utility timelines for each pathway with "stop-the-clock" rules (i.e., utility delays pause the clock, not the customer), and require utilities to provide standardized cost estimates upfront and prohibit unlimited restudies that add significant time to the process.
- **Incorporate IEEE 1547-2018 advanced inverter settings, streamline equipment approvals, and create a storage-specific pathway.** States should define default inverter settings clearly in rules and require utilities to accept pre-certified equipment meeting safety standards without additional custom testing. States should also require that utilities simplify the approval of certified meter socket adapters and

authorize their use in the primary customer meter socket, ensuring customers can avoid the burden of costly and unnecessary electrical panel upgrades when connecting local power. For behind-the-meter systems, utilities should also be required to allow for use of certified power control systems to limit export power and to use import/export capacity rather than nameplate capacity when assessing an applicant's impact on the grid. For storage, states should replace worst-case charging assumptions with "operational parameters" (export limits, charge/discharge schedules, telemetry where appropriate) so study assumptions match real-world behavior.

- **Require timelines, transparent queues, and independent dispute resolution.** Regulatory agencies should establish and approve formal timelines for tasks throughout the interconnection process, which are regularly enforced with penalties and incentives, and reviewed and reduced over time. Utilities should be required to publish interconnection queues online showing project status and such timelines by technology type and size, and states should establish or improve enforcement mechanisms, such as an ombudsperson or independent technical dispute process that allows customers to escalate disputes when utilities delay interconnection without cause.
- **Develop enforcement mechanisms through legislative action where PUC authority is weak or undefined.** If utility regulators lack enforcement tools, legislatures should mandate periodic interconnection rule updates (e.g., every three to five years), require statewide metrics reporting (queue wait times, study costs, completion rates), and authorize performance incentives or penalties tied to cycle time. States should also fund utility IT modernization and hosting capacity buildouts so utilities can process applications faster.
- **Create a pathway to connect systems with streamlined back-and-forth with the utilities.** For front-of-the-meter systems, utilities should submit, and commissions should approve, optional flexible interconnection tariffs. Moving towards more streamlined interconnection would help projects understand what system design is acceptable to utilities before even making a request, in order to limit unnecessary back-and-forth communication. Visibility and clear communication as well as accountability during the process would help contain costs and create greater certainty.

STATE EXAMPLES | Interconnection

LEGISLATORS. The Minnesota legislature directed its regulators to create a dedicated Interconnection Ombudsperson to resolve interconnection disputes between distributed energy applicants and utilities without forcing every disagreement into a formal, months-long contested proceeding. The parties resolve the dispute through mediation and the Ombudsperson steers a matter into the formal complaint process only when necessary. The office reviews utility interconnection policies to find and reduce the causes of recurring disputes, convenes interconnection stakeholders, and publishes data for a transparent and accountable process.

Colorado will require its largest utility (Xcel) to let interconnection customers hire a utility-approved third-party contractor to perform interconnection studies and upgrade work, with the utility reviewing and inspecting the work. A working group will study methods to incorporate this provision, with a report due December 15, 2026, and implementation filings due January 1, 2027.

Delaware requires electric suppliers to adopt IREC's Model Interconnection Procedures within 12 months of each new edition, replacing prior language that treated the model only as a nonbinding guide. Regulators may set and enforce mandatory interconnection processing timelines with consequences for suppliers that miss them, and utilities may recover the costs of implementation.

REGULATORS. California's Electric Rule 21 governs interconnection to investor-owned utilities' distribution systems (and certain transmission-jurisdiction facilities) and is the main procedural/technical framework for the state. California regulators maintain Rule 21 materials and have continued modernization activity. New York's Standardized Interconnection Requirements (SIR) apply to distributed generators and energy storage systems 5 megawatts or less interconnected in parallel with utility distribution systems. Illinois' Distributed Energy Resources Interconnection Standard is codified in Illinois Administrative Code Title 83, Part 466 and applies generally to distributed energy resource facilities with capacity equal to or less than 10 megavolt-amperes on utility distribution systems.[94]

New York and Massachusetts replaced the "first project pays for everything" default with pro rata cost-sharing: when a shared upgrade like a new feeder or substation transformer lets several distributed projects connect, each pays only its share of the cost in proportion to its interconnecting capacity. Minnesota is building the same approach under a 2023 law directing regulators to spread necessary upgrade costs across the projects that trigger them. In all three states (as well as in New Jersey and Illinois), regulators are engaged in efforts to move away from a reactive approach to Proactive Distribution System Planning, discussed in more detail in Section II.4.

New York also sets standardized business-day deadlines for key interconnection steps, including 60 business days for completion of a Coordinated Electric System Interconnection Review (CESIR), the detailed engineering study that determines what system upgrades a project requires and what they will cost. Utilities must provide customers with real-time application status through online portals and file monthly queue inventories with the Public Service Commission, which publishes them as circuit-level data.

New Jersey overhauled its interconnection rules in 2026 after a four-year stakeholder process and directed that a project be screened on its export capacity rather than its nameplate rating, so a resource that limits what it sends to the grid is judged on what it actually exports: a 50-kilowatt system capped at 25 kilowatts of export now qualifies for the fastest review. It also recognized accepted export-control methods, including certified power control systems, drawn from Oregon, New Mexico, and Illinois.

RESOURCES

Interstate Renewable Energy Council	• *Model Interconnection Procedures*
CCSA	• *Integrating Distributed Solar and Storage: The Keystones of a Modern Grid*
U.S. Department of Energy and Lawrence Berkeley National Lab	• *i2X program overview and DOE's DER Interconnection Roadmap*
National Laboratory of the Rockies	• *Evaluating the Role of Pre-Application Reports in Improving Distributed Generation Interconnection Process*
Electric Power Research Institute	• *The Hosting Capacity Process Primer*

I.3.1.b Fast and predictable permitting

States should streamline permitting and inspections so standard projects can move quickly while still meeting safety requirements. Routine clean energy installations should not be slowed by outdated paperwork, excessive fees, or inconsistent local processes.

In too many places, a routine distributed project runs a gauntlet of inconsistent local requirements, reviews by multiple departments, weeks of waiting, and an in-person inspection scheduled at the installer's expense. These hurdles are rarely about safety but instead reflect outdated local habits. The variation between jurisdictions is itself a major cost, since an installer working across a dozen towns faces a dozen different processes. States can make permitting for distributed resources fast, standardized, safety-focused, and cheap.

For customer-sited systems, states should require instant permitting and offer a standard state-hosted platform: for a code-compliant distributed project (e.g., solar, storage, an EV charger, or a panel upgrade), an online platform checks the design against the electrical code and issues the permit on the spot, with no back-and-forth and no staff time. In addition, states should ensure there are clear and consistent statewide procedures, such as one standardized application and uniform code requirements, with no local amendments to building-safety codes, since national and state codes already account for climate and geography. Once a system is built, installers should be able to perform remote inspections and submit photos or video for review by the permitting office or a licensed third party, at no greater cost or delay than an in-person visit.

For larger front-of-the-meter systems that still need full review, states should add permit shot clocks (i.e., firm deadlines for a jurisdiction to act) with automatic approval where legally appropriate if the clock runs out, and extend reasonable fee caps to eligible small commercial systems, so community-scale projects are not stalled.

STATE EXAMPLES | Permitting

LEGISLATORS. A number of states already bar localities from adding their own amendments: Connecticut, Florida, Kentucky, Massachusetts, Michigan, Montana, New Jersey, Ohio, Rhode Island, and Wisconsin apply a single uniform statewide building code including for rooftop solar and home batteries so requirements do not shift from one town to the next.

California limits review to health and safety, requires a standardized expedited process, and caps inspections at one. In 2022, legislation directed local authorities to adopt automated instant permitting for rooftop solar and home batteries. Maryland and New Jersey likewise mandate instant permitting, New Jersey on a platform the state itself manages. Texas and Florida take a complementary route, letting installers use licensed third-party inspectors and engineers to permit and inspect. On cost, Colorado has ratcheted down solar permit fees across three laws since 2011, and California has tightened its fee caps twice since first setting them in 2012.[95]

California's proposed Heat Pump Access Act would require cities and counties to post information online, and to implement an online automated permitting process for the swap-out of a residential heat pump water heater or residential heat pump HVAC system that does not require a new electrical panel or structural work. The system would issue permits in real time to a licensed contractor that meets certain criteria. Another proposed bill in California would require remote inspections to be made an option.

RESOURCES

Permit Power	• *As Cheap as Our Peers*
SolarAPP+	• *Automated Permitting Process*
National Laboratory of the Rockies	• *Safe and Fast Permitting Using NREL's SolarAPP+ Continued To Grow Throughout 2023*
SolarAPP+ Foundation, MassPIRG, and Guilford (CT)	• *SolarAPP+ Overview and Testimonial Webinar*
Frontier Group	• *Solar Permitting Scorecard*
Local Energy Rules	• *Reducing Redtape to Slash Solar Costs*

I.3.2 Expand state financing tools to lower the cost of capital

Public finance can lower perceived risk and bring private capital into markets that otherwise leave people behind. States should use green banks and clean energy financing authorities to make distributed energy resources easier to finance and even cheaper. Green banks could support financing for low-and moderate-income households, affordable multifamily housing, public buildings, nonprofits, small businesses, and community-scale projects that may not qualify for low-cost private capital on their own.

Rather than simply offering grants, green banks use small amounts of public dollars to reduce lenders' and investors' perceived risk through tools such as loan-loss reserves, subordinated debt, interest-rate buydowns, guarantees, warehouse facilities, bridge financing, predevelopment support, and Property Assessed Clean Energy (PACE).

States should explicitly direct their green banks and financing authorities to develop or use these tools to support the deployment of distributed solar, solar-plus-storage, standalone batteries, heat pumps, managed EV charging, microgrids, efficiency, and VPP-ready portfolios, working alongside private-sector financing institutions.

As with all financial products, strong customer protections are essential to ensuring fairness and risk mitigation for the benefit of people.

States should build these public financing tools at both the wholesale and retail levels, capitalize green banks or clean energy financing authorities, authorize them to use credit enhancements, direct them to prioritize underserved customers and grid-constrained locations, and coordinate and stack their products with utility programs so publicly financed distributed energy resources also deliver measurable grid and societal value.

STATE EXAMPLES | Green banks

LEGISLATORS. Connecticut created the nation's first green bank by statute in 2011, and it now anchors the state's retail distributed energy resources market by combining financing, incentives, contractors, and technical assistance. Its Smart-E loan offers low-rate, flexible-term financing for more than 90 home energy and resilience upgrades through participating contractors and local lenders, backed by loan-loss reserves and other credit enhancements that make unsecured clean-energy lending possible. The Green Bank also administers targeted distributed energy resources programs beyond ordinary home loans: Energy Storage Solutions lowers battery costs through upfront and performance incentives, and Solar MAP+ helps affordable multifamily housing providers, municipalities, and state agencies access solar and storage with technical and financing support.

REGULATORS. New York capitalized the NY Green Bank through its Public Service Commission as a wholesale model to provide flexible capital to developers, property owners, service providers, and investors where conventional financing is not yet available, filling market gaps rather than displacing private lenders. Michigan seeded Michigan Saves, now an independent nonprofit green bank, to reach the retail and community level: it connects homeowners and businesses to clean-energy financing through lender and contractor networks, and offers bridge financing to nonprofits and governments installing solar, storage, and geothermal while they await federal elective-pay tax credits.

RESOURCES

Connecticut Green Bank	• *Resource Library*
Connecticut Green Bank	• *Connecticut Green Bank Annual Report 2025*
Montgomery County Green Bank	• *Residential Programs*
Yale Center for Business and the Environment	• *Home-Efficiency Financing with Sealed and NY Green Bank*
Yale University	• *Connecticut Green Bank Case Study*
U.S. Environmental Protection Agency	• *Clean Energy Finance: Green Banking Strategies for Local Governments*
Yale Insights	• *Can Green Banks Scale Clean Energy?*
Michigan Saves	• *Home Page*

I.4 Compensate customers and producers fairly for the electricity they produce and the services they deliver to the grid and communities

Producing more local power — whether from behind-the-meter systems sited at customer locations or from larger front-of-the-meter installations — requires that producers of local power be compensated fairly for the full services they provide to the grid and its users. This includes energy, capacity, and other services and values such as avoiding transmission and distribution costs, providing local grid benefits or shifting power over time, and other benefits provided to communities. **Only where customer-generators are fairly compensated will projects materialize at scale and provide the reliability and affordability benefits that states seek.**

Similarly, power consumers should be fairly compensated for adjusting their behaviors in ways that provide significant value to the grid in terms of reliability and affordability, and that help meet other state policy goals such as climate change mitigation and public health.

Rate design shapes when and how much power people draw, and compensation and program design reward the local generation and flexibility they deliver back. As a result, states should be mindful of how rate design and compensation interact, and plan them together.

States should adopt compensation rules that recognize when and where local resources and customer-sited generation help the grid and communities, providing energy, capacity, avoided infrastructure, locational value, and non-energy benefits like pollution reduction, with clear and durable signals for producers to export power at the times and places it is worth the most. Because these resources are flexible, they can continue to provide significant value over time as grid conditions change or high-cost periods shift.

Electricity costs more when demand is high and the grid is strained, so displacing periods of high demand is one of the most effective ways to keep costs down. States should give customers the option of time-varying rates so they can create grid-scale savings as well as save money by shifting flexible uses of electricity to the hours when power is cheaper, cleaner, and easier to deliver, with bill protections and clear customer education.

STATE EXAMPLES | Fair compensation

REGULATORS. New York's Value of Distributed Energy Resources tariff ("VDER," or "Value Stack") replaced flat, volumetric net-metering credits with monetary compensation for the specific values a resource delivers (i.e., energy and capacity, plus local benefits like demand reduction, locational grid-stress relief, and environmental value) so a project is paid for *when* and *where* it produces. It applies primarily to distributed resources in front of the meter, from on-site generation and storage to community solar.

Minnesota's Value of Solar methodology established a utility-specific, long-term $/kWh tariff for distributed solar as an alternative to net metering. It values avoided fuel and price risk, operations and maintenance, generation and reserve capacity, transmission and distribution capacity, line losses, and environmental externalities such as CO_2 and air pollution. Hourly solar production, peak coincidence, grid losses, panel degradation, and a 25-year project life are incorporated into a levelized rate. Value of Solar compensation is available for projects in Minnesota's first Community Solar Garden program established in 2013.

Most VPP programs establish compensation levels based on the ratepayer value provided to ensure that they support energy affordability and are durable. In most cases, compensation is set as a $/kW for average performance during events and applies for a set period of time (typically 5 to 10 years). Because of this approach, the programs can maintain strong benefit-cost ratios while also supporting the deployment of new resources.

For example, Massachusetts' ConnectedSolutions provides greater than a 2:1 benefit-to-cost ratio based on avoided distribution, transmission, and capacity costs. In Connecticut, the Energy Storage Solutions Program is designed so that non-participant bills decrease by $2 for every $1 spent in the program (i.e., a 2.0 score under the strict "Ratepayer Impact Measure" test). In Colorado, Xcel's Advanced Virtual Power Plant program calculated the avoided transmission, capacity, and distribution value, which resulted in its compensation value being set at $238/kW/year.

RESOURCES

National Association of State Energy Officials	• *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*
Local Energy Rules	• *The Truth Behind California's High Electricity Bills*

I.5 MAKE SURE EVERYONE CAN SHARE IN THE BENEFITS

Every American, regardless of income, location, or circumstance, deserves the right to participate in and benefit from local energy, and states must act to guarantee that access. States should design programs so renters, multifamily residents, low-income households, small businesses, rural customers, Tribal communities, nonprofits, and disadvantaged communities writ large can participate and benefit.

Ensuring that low-and moderate-income (LMI) households access local power is not just a matter of fairness but also of grid impact; the National Laboratory of the Rockies found that LMI households accounted for as much as 42 percent of all residential rooftop solar technical potential in the country and that on-site solar could offset 85 to 92 percent of a low-income household's electricity use, versus about 70 percent for wealthier homes.[96] This is just one technology among the many distributed resources that could work to reduce grid stress, reduce rates for everyone, and reduce bills for these households.

Fortunately, there are many successful policies to pull from to support LMI access to local power, but they need to be designed intentionally. States should allow a broad range of third-party ownership models such as leases and power purchase agreements, backed by real consumer protections, and equitable on-bill financing that allow families to access local power at no upfront cost so that projects are cash-flow positive on day one. Bulk purchasing campaigns such as Solarize or Thermalize can be organized with support from local municipalities and state agencies or green banks to further reduce costs.

Dedicated LMI carve-outs and enforceable targets that reserve a meaningful share of program capacity and funding for the customers most often left behind are also critical to ensure that developers pay attention to this underserved segment of customers. In addition, states should provide predevelopment support such as grants, technical assistance, workforce development, and other readiness funding to cover the costs necessary to prepare for, design, and deploy community-serving projects. State green banks are particularly well suited to help LMI markets organize and get off the ground.

In addition, states can prioritize charging infrastructure in underserved communities, invest in curbside and pole-mounted solutions for renters lacking off-street parking, and ensure managed charging programs include low-income protections and include low-income protections and rates that do not discriminate against renters so grid benefits are shared broadly.

STATE EXAMPLES | Benefits for low-income households

LEGISLATORS. Connecticut set a low-income storage carve-out within its statewide storage goal of 1,000 megawatts of energy storage by 2030 and directed its regulators to build a program with enhanced incentives for low-income customers, underserved communities, and small businesses. Illinois expanded Illinois Solar for All in 2021 as a result of legislative action, and the award-winning program has delivered over 2,500 low-income installations from residential to community solar. California developed a robust set of incentives to grow distributed energy resource adoption in disadvantaged communities such as no-cost rooftop solar for income-qualified homeowners and an established Solar on Multifamily Affordable Housing (SOMAH) program that invests up to $100 million per year toward a 300-megawatt target by extending on-site solar benefits to tenants in affordable multifamily housing. New Mexico created a statewide community solar program that reserves 30 percent of capacity for low-income customers and service organizations and created the Local Solar Access Fund, a $20 million dedicated source of grants for solar and storage in Tribal, rural, and low-income communities and a model for predevelopment and readiness support. New York requires that disadvantaged communities receive at least 35 percent, with a goal of 40 percent, of the benefits of the state's clean energy and energy efficiency spending.

REGULATORS. California regulators have been overseeing the Self-Generation Incentive Program (SGIP) program since 2001, which offered incentives for installing paired solar and energy storage technology at low-income residential properties, supporting low-income, medically vulnerable, and wildfire-affected customers to install batteries at little or no cost. The current iteration of the program offers incentives for solar and storage at low-income residential properties. Connecticut designed its Energy Storage Solutions with higher performance-based incentives for underserved and LMI households. Massachusetts' 2025-2027 Mass Save plan targets heat pumps in the state, including for LMI residents and renters, and designates communities where income-qualified customers and renters get no-cost weatherization, electrification, and heat pumps.

GOVERNORS. Maine hit the state's goal of 100,000 heat pumps two years early and administratively set a new target of 175,000 more by 2027. The governor proposed the enabling bill in 2019, which reserved 15,000 installations for income-eligible households, with a dedicated MaineHousing heat pump program and enhanced $2,000 rebates for Low Income Home Energy Assistance Program (LIHEAP) recipients. Virginia partnered with two organizations to establish a statewide optional solar group purchasing initiative. The reverse auction, i.e., a Solarize campaign, will reduce the cost of purchasing solar and batteries for homeowners. The state supports communication to households.

RESOURCES

Local Energy Rules	• *Scaling Up Home Energy Investment*
GRID Alternatives and Vote Solar	• *Low-Income Solar Policy Guide*
NAACP	• *Equitable Solar Policy Principles*
Just Solutions	• *Energy Affordability Policy Library*

II. Use local power, the grid, and the tools we have more efficiently

Meeting demand growth without driving up rates means using what is already on the grid, not just building more of it. This starts with making smarter use of our resources and prioritizing efficiency, demand response, and flexibility. Millions of batteries, solar panels, EV chargers, smart thermostats, water heaters, and building controls are already installed across the country, and most of them are not being used to their full potential.

Utilities make planning and investment decisions every day that can either unlock or entirely foreclose the value that local resources provide, including larger resources such as community-scale assets that sit in front of the meter and provide more or less value based on location.

In addition, the lack of access to financing still acts as a barrier for customers, limiting opportunities to scale reliable and cheap technologies.

To use local power resources and the grid more efficiently and bring down costs, states should:

1. Set targets for and support statewide energy efficiency and demand response programs;
2. Turn local resources into networks that work better than power plants;
3. Set clear targets for utilities and reward them for hitting them;
4. Prioritize local power in utility planning processes; and
5. Make available financing structures that decrease upfront costs.

II.1 SET TARGETS FOR AND SUPPORT STATEWIDE ENERGY EFFICIENCY AND DEMAND RESPONSE STANDARDS

All states in the nation should require a binding, multi-year energy efficiency and demand response standard and target. Twenty-six states and the District of Columbia already have energy efficiency resource standards (EERS) and states with binding targets (often established through EERS) achieve substantially greater electricity savings than states without such requirements.[97] States should complement those energy-savings requirements with binding demand-response targets that require utilities to achieve measurable reductions in peak demand. As further detailed in Section II.3 below, utilities do not have an incentive to pursue efficiency on their own.

EERS are an effective strategy for states to produce utility-wide energy savings. The U.S. Energy Information Administration reported that utility efficiency programs with measures installed in 2024 are expected to save 281 terawatt-hours over their useful lives, or about 15 percent more electricity than was sold in the entire state of California in 2024.[98] These improvements produced annual electricity savings of 23.8 terawatt-hours and reduced peak electricity demand by 6.26 gigawatts **nationwide.[99]** This is enough to meet the peak power needs of all of southern Nevada, including the casinos and hotels of Las Vegas, even on the

hottest day of the year.[100] **States with binding efficiency standards account for 82 percent of those energy savings in 2023**.[101]

Repeated annual targets compound over time and in turn produce significant savings for everyone. State evaluations have shown that these programs can return more than twice their cost to customers. For example, Michigan's 2023 programs will deliver $1.4 billion in lifecycle savings, or $2.54 for every dollar spent.[102] These savings come from reducing the utility's cost of service, including avoided generation costs that would otherwise be recovered through rates. **Fully embracing energy efficiency could save $4.8 trillion by 2050, or about $31,000 per U.S. household.[103]**

Some states set a fixed percentage-of-sales savings goal that increases on a defined schedule, and others require utilities to acquire all cost-effective efficiency without a fixed ceiling. Either approach should meet the same underlying test and the standard should be binding and multi-year.

Energy efficiency and demand response should have separate but coordinated performance requirements. Energy-efficiency targets can measure incremental annual and lifecycle energy savings, while demand-response standards require a defined amount of verified load reduction or load shifting during the hours when it is most valuable to the system. A state should direct its regulators to establish multi-year peak-demand reduction targets, expressed in megawatts, based on an independent assessment of cost-effective demand-response potential.

State commissions should use the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources to establish a jurisdiction-specific cost-effectiveness test and require utilities to apply that test consistently to energy efficiency, demand response, and other distributed resources.

Lastly, states should fund the standard through a dedicated charge collected on customer bills, sized to cover the full cost of the programs needed to meet it, administered separately from the utility's other revenue.

STATE EXAMPLES | Energy efficiency targets

LEGISLATORS. Colorado requires regulators to establish both energy-savings and peak demand reduction goals for investor-owned utilities. Utilities must achieve savings equal to at least 5 percent of 2018 retail electricity sales and peak-demand reductions equal to at least 5 percent of 2018 retail system peak demand by 2028. The commission may establish interim goals and allows utilities to recover program costs and receive performance-based incentives.

Illinois requires large electric utilities to file multiyear energy-efficiency plans. Through 2026, the statute requires cumulative persisting annual savings of 17.9 percent for ComEd and 13.6 percent for Ameren, measured against adjusted 2014-2016 baselines. Beginning in 2027, both utilities must achieve incremental annual savings equal to a percentage of retail sales. Ameren also has an incremental coincident peak-demand savings goal. Illinois regulators allow utilities to recover reasonable and prudently incurred program costs through an approved tariff or formula rate.

Michigan requires annual incremental savings beginning in 2026 equal to 1.5 percent of electric sales and 0.875 percent of natural-gas sales. Regulated providers recover the actual costs of approved programs through customer rates and charges. A companion provision requires the Public Service Commission to assess statewide potential for both energy waste reduction and demand response every four years.

Massachusetts requires three-year utility efficiency plans to acquire all available energy-efficiency and demand-reduction resources that are cost-effective or less expensive than supply. California directed state regulators to establish annual targets designed to achieve a cumulative doubling of statewide electricity and natural-gas energy-efficiency savings by January 1, 2030.

RESOURCES

American Council for an Energy-Efficient Economy	• *Next Generation Energy Efficiency Resource Standards Update*
American Council for an Energy-Efficient Economy	• *The 2025 State Energy Efficiency Scorecard*
National Association of State Energy Officials	• *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*

II.2 TURN LOCAL RESOURCES INTO NETWORKS THAT WORK BETTER THAN TRADITIONAL POWER PLANTS

Proven technologies now allow us to turn power up or down, or reduce or shift demand, where and when we need it and when we need it by connecting grid assets into networks called virtual power plants (VPPs). They can offer benefits similar to or better than traditional power plants, but these technologies only work at scale if states guarantee both market access and utility cooperation.

Deploying VPPs at scale requires building (**II.2.1**) the programs and rules that authorize and promote these networks in states, and (**II.2.2**) the systems that make those programs possible.

II.2.1 Build the programs and rules that authorize and promote networked resources in states

All states should require utility programs, competitive procurements, and retail tariffs to drive utility use of local resources, and work to open wholesale electricity markets to participation by people and businesses. Specifically, states should require utilities to offer VPPs and demand response programs for their customers, and hold utilities to real targets and timelines. Those programs should be open to independent, verified, third-party aggregators on technology-inclusive, non-discriminatory terms, so customers can choose who manages their resources.

Compensation should be performance-based and reflect the value each resource delivers (e.g., by location, by time of day, and by the specific grid service provided) so that a battery relieving a constrained circuit on a summer evening is paid for what it is actually worth.

By networking batteries, EV chargers, thermostats, water heaters, solar-plus-storage systems, and building controls using aggregated networks and demand response, customers and the providers they choose can deliver capacity, flexibility, reliability, and other grid services, faster and at lower cost than building new utility-scale generation or grid infrastructure. These resources could be rolled into a VPP program regardless of whether they are located in front of or behind the meter.

States should also scrutinize whether program terms facially unrelated to technology eligibility, such as mandatory charging windows, can effectively exclude bidirectional EV charging from an otherwise open program.[104]

Importantly, using these local resources puts money back in everyone's pockets — both those with devices, who are paid for their devices' performance, and those without, who benefit from a lower-cost resource.

The resources are already here — in homes and businesses across the country — and most of them sit idle. As of 2024, less than 20 percent of the country's installed distributed capacity was enrolled in a VPP; and as of 2025, only 45 percent of residential battery capacity was enrolled.[105] Further, as of 2025, 38.6 gigawatts of VPPs were enrolled.[106] In 2023, the U.S.

Department of Energy estimated that growing this solution at scale by deploying 80 to 160 gigawatts of VPPs by 2030, i.e., roughly tripling the then-current scale, could serve approximately 10 to 20 percent of peak demand and save on the order of $10 billion per year in grid costs, redirecting money from peaker plants back to the customers who provide the service.[107]

Critically, that capacity is *cheap,* as VPPs can meet peak needs at 40 to 60 percent of the cost of conventional resources.[108] Allowing new resources to be pooled, controlled, and compensated would unlock an even greater opportunity.

The movement towards VPPs builds on our country's long and successful history of implementing demand response programs. The technology is well-established; **as of 2026, 28 states, from Arizona to Wyoming, operated 68 battery VPP state programs or pilots, with another 10 programs or pilots pending implementation across an additional four states.[109]**

In 2020, Federal Energy Regulatory Commission (FERC) Order No. 2222 directed the regional grid operators to open their capacity, energy, and ancillary-service markets to aggregations of distributed resources.[110] Some wholesale markets have been delayed in this implementation or included rules that still restrict distributed resources from participating in wholesale markets. In states where demand response or distributed power can participate in wholesale markets, states must now extend that proven approach through programs that customers and aggregators can join, including eliminating aggregator barriers. In states where wholesale markets still do not have fully implemented FERC 2222 rules to allow for distributed power participation in wholesale markets, or where barriers remain, state policymakers should engage with grid operators to inform and accelerate the process.

When states leave these resources on the sidelines, customers can end up paying twice: once for equipment already in homes and businesses, and again for power plant and grid upgrade costs that this equipment could have helped avoid.

STATE EXAMPLES | Virtual power plants

LEGISLATORS. Colorado, Maryland, Virginia, and Illinois have all enacted laws requiring investor-owned utilities to file or develop VPP programs that aggregate customer-sited, behind-the-meter resources. Colorado also required its largest utility to competitively procure front-of-the-meter dispatchable distributed generation paired with storage from independent developers. The utility can dispatch during system peaks and grid events and defer distribution system upgrades. Colorado regulators set the program rules, and utilities may not own the assets. Colorado's "DDG" model allows the front-of-the-meter solar-plus-storage resources to keep producing value for customers when they are not being dispatched for grid needs (i.e., through bill credits, subscription arrangements, or other utility-administered compensation mechanisms such as power purchase agreements). During dispatch events, the storage component provides a grid service according to utility-defined operating parameters.

Following these successes, other states are taking notice. More than a dozen have considered VPP legislation over the past two years.

GOVERNORS. On her first day in office, New Jersey Governor Mikie Sherrill directed the Board of Public Utilities to develop a VPP program within 180 days. Governors in Massachusetts and Oregon have issued executive orders that include VPP-related directives as part of broader planning and mandates.

REGULATORS. Texas regulators created the Aggregated Distributed Energy Resources (ADER) pilot implemented by the Texas grid operator, ERCOT. The ADER pilot was designed to let aggregated customer-sited resources (batteries, solar-plus-storage, controllable loads, thermostats, water heaters, and EV chargers) be pooled and operated as dispatchable grid resources. The pilot has grown in phases, with each phase expanding what the resources can provide and how much capacity can enroll. In March 2026, ERCOT raised the participation cap to 500 megawatts. It is now drafting the rule changes that would make ADER participation permanent, and has said it is aiming to file them in late 2026.

In Massachusetts, Rhode Island, and New Hampshire, National Grid, Eversource, and Rhode Island Energy run ConnectedSolutions, one of the largest and most established utility-run battery and demand-response VPPs in the country: customers let the utility discharge their behind-the-meter batteries or adjust their thermostats during peak events (or otherwise participate in demand response programs) and earn performance-based pay each summer. The aggregated fleet stands in for expensive, polluting peaker plants. In Massachusetts, the program is now beginning to pay for locational services and value. Through ConnectedSolutions+, National Grid and Eversource offer higher incentives to customers in specific, grid-constrained "Plus areas." National Grid's use of a flexibility marketplace also moves from broad peak-shaving programs toward more competitive, locational procurement of distributed energy resource flexibility from aggregators, businesses, batteries, EVs, and other distributed resources.

In Colorado, regulators are implementing the VPP and DDG mandates above for both behind-the-meter and front-of-the-meter resources through the utility's 2025-2029 Distribution System Plan, requiring it to establish a 125-megawatt VPP and procure at least 50 megawatts of third-party-owned, distribution-connected solar-plus-storage sited by a locational-value methodology and solicited competitively from independent developers.

Michigan and Missouri state regulators reversed long-standing rules to allow third-party demand-response aggregators to enroll large commercial and industrial customers into wholesale markets, allowing the grid to withstand extreme weather conditions.[111]

Puerto Rico approved the permanent Customer Battery Energy Sharing program, aggregating batteries into a territory-wide VPP. The program, operated by LUMA, Puerto Rico's transmission and distribution utility with third-party aggregators, grew from about 24 megawatts of enrolled capacity in 2024 to 500 megawatts by late 2025, with more than 90,000 participating customers by summer 2026.[112] The speedy rise of the program was enabled by the auto-enrollment features started in 2025 and reauthorized by regulators in 2026.

UTILITIES. Some utilities have built VPPs without waiting for a mandate. Green Mountain Power (GMP) in Vermont has run a residential battery VPP since 2015, and in early years saved customers up to $3 million per year by reducing what the utility has to buy from the wholesale market during peak hours. **In 2025, GMP's VPP saved $11 million, and during the heat wave of July 2026 alone, GMP's VPP saved all GMP customers $6 million in one peak hour**.[113] GMP's Bring Your Own Device program allows customers to use batteries when the grid is down but batteries are otherwise controlled by the utility to reduce system costs. **Vermont's largest power resource by capacity is now a VPP.**

RESOURCES

Clean Energy States Alliance, VPP Acceleration Initiative	• *VPP 101 webpage*
Solar United Neighbors	• *Model VPP Legislation and Tariff,* based on the ConnectedSolutions model
Massachusetts Clean Energy Center	• *Grid Services Study*
Canary Media	• *Massachusetts tries a market for distributed energy to tame grid costs*
Local Energy Rules	• *Smart Homes, Stronger Grids, Thanks to Distributed Power Plants*
Ohm Analytics	• *2025 VPP Market Report Executive Summary*
U.S. Federal Energy Regulatory Commission	• *FERC Order No. 2222 Explainer: Facilitating Participation in Electricity Markets by Distributed Energy Resources*
EnergyHub	• *The VPP Maturity Model*
EnergyHub	• *Tapping into the power of battery VPPs*

II.2.2 Build the systems that make cooperation possible

VPPs work best when utilities can see the resources on their grid, when any vendor can compete to serve them, and when everyone involved has good information to act on.

States should require all three: **(a) utility coordination systems that give utilities the visibility to manage tens of thousands of distributed resources at scale; (b) open, interoperable standards that let any device or provider participate to promote customer choice; and (c) accessible, usable data that lets every participant see what the grid needs and how their resources are performing.**

II.2.2.a Support utility coordination with platforms/DERMS

Better operational visibility to enable the participation of distributed resources is valuable to the grid. **States should require utilities to develop the capabilities needed to actively coordinate local energy resources and integrate these resources into distribution system operation.** These platforms and capabilities can be contracted out by utilities.

Distributed Energy Resource Management Systems, or DERMS, are one set of platforms that enable this coordination and integration. DERMS are not strictly required to operate every type of VPP, and different DERMS serve different functions: edge DERMS help enroll, dispatch, measure, and settle participating resources, while grid or enterprise DERMS help utilities integrate those resources into distribution-system operations and manage them within local grid constraints. These systems involve different functionalities and levels of investment. However, as VPPs evolve toward more sophisticated models, including those providing locational grid services, responding in real time, and coordinating distribution and wholesale market needs, DERMS or equivalent utility-side capabilities may become more valuable.

Generally, regulators should consider DERMS investments as part of facilitating VPPs, and require utilities to demonstrate use cases and interoperability with third-party platforms before approving spending.

STATE EXAMPLES | DERMS

LEGISLATORS. Illinois' 2026 Clean and Reliable Grid Affordability Act requires large utilities to establish VPP programs through tariffs and expressly addresses DERMS integration, third-party DERMS providers, and recovery of DERMS-related costs. The tariffs must allow aggregators to participate in the utility's DERMS, receive dispatch signals and other communications, provide measurement and verification data, and receive program payments directly from the utility. Utilities may contract with third-party DERMS providers, and participating aggregators must be capable of receiving event signals either from the utility or its contracted DERMS provider. **Importantly, utilities may not delay VPP implementation because DERMS capabilities are unavailable**. The law also requires utilities to recover reasonably and prudently incurred DERMS-provider, IT, operations and maintenance, and other implementation costs.

II.2.2.b Require open standards and interoperability to promote customer choice

States should require standard communication protocols, standardized interfacing software (APIs), and interoperable devices wherever practical.

The highly decentralized nature of local power systems is their strength; this is the reason they are cheaper, faster to install, and can bring economic and other benefits to a broader set of stakeholders than traditional top-down infrastructure. **Customers should be able to choose among devices, vendors, aggregators, and service providers, and utilities should be able to coordinate distributed energy resources safely without requiring proprietary systems that lock out competition and consumer choice.**

Programs can require distributed resources, aggregators, and utilities to use open standards to support secure dispatch, telemetry, verification, and customer choice.

In addition, utility distributed energy resource programs should use open communication protocols that allow secure, multidirectional data exchange among utilities, customers, distributed energy resource providers, and aggregators. Programs should use standard "APIs," which are common digital connections that allow different companies' software to speak to one another, for VPP management.

For example, standard APIs should be used for customer enrollment, customer consent, telemetry, dispatch, measurement, verification, and settlement so that multiple vendors and aggregators can participate without custom utility-by-utility integrations.

Regulators should also encourage common customer onboarding, authorization, and consent interfaces across utilities so customers, third-party owners, and distributed energy resource providers do not have to navigate entirely different processes in each service territory.

Technology evolves rapidly and so will the associated standards. **Programs should be able to adopt updated standards and new capabilities as they emerge.** In addition, common standards will be most important at the interface between systems, such as between an aggregator and a utility's grid DERMS. Those same standards may not need to apply to each individual device type. In fact, the purpose of an integration layer such as a DERMS is to bridge any potential gap between devices and utility systems. Programs should maintain outcome-oriented interoperability standards to ensure broad access for different technologies and devices and maintain flexibility in how individual devices meet those requirements.

STATE EXAMPLES | Standards enabling customer choice

REGULATORS. In California, every distributed energy resource interconnecting with the state's three large investor-owned utilities has been required to communicate using IEEE 2030.5, implemented through the Common Smart Inverter Profile (CSIP), a single, statewide profile that lets any certified inverter, aggregator, or gateway "plug and play" across utility territories rather than requiring a custom integration for each one.

UTILITIES. In Utah, Rocky Mountain Power's Wattsmart program requires IEEE 2030.5 for enrolled devices. The protocol allows the utility's Distributed Battery Grid Management System to handle real-time telemetry, status tracking, and dispatch control across diverse hardware.

PROGRAM IMPLEMENTERS. In Connecticut, the Energy Storage Solutions program maintains clear technical standards for participating technologies and any equipment that can demonstrate compliance with these standards is able to participate in the program. The required standards include UL 1741 SA, UL 9540, UL 1973, IEEE 1547-2018, and ability to communicate with the DERMS. This ensures that all eligible technologies can participate, providing consumers with more choice of contractors and equipment providers.

RESOURCES

California Public Utilities Commission	• *Rule 21*
SunSpec Alliance	• *CSIP Certified Product Registry*
IEEE Standards Association	• *IEEE 1547* is the underlying interconnection and interoperability standard referenced across most state distributed energy resource programs.
OpenADR Alliance	• *Governs the demand-response signaling layer (utility/aggregator-to-device event signals), and is distinct from IEEE 2030.5's device-communication layer.*
CTA/EcoPort, CTA-2045 Certified Products	• *Is the technical standard published by the Consumer Technology Association most commonly cited for water heaters and other grid-interactive appliances.*

II.2.2.c Make data accessible, usable, and useful

States should ensure customer data is accessible, usable, and useful, so customers, communities, utilities, and clean energy providers have the information they need for optimal participation and coordination. Distributed energy resource markets cannot work if information is trapped in utility systems, delivered in unusable formats, or shared through slow manual processes. Transparent, open access to data is essential for the full value of local energy to be realized and accountable to all.

Customer meter data sharing platforms should adopt the Green Button standard for data format and include all necessary data for customers to participate in VPPs and the wholesale market to avoid redundant and bespoke data sharing platforms. Green Button is a technical standard for utility customer energy data that standardizes how usage and billing information is formatted and, through "Connect My Data," how customers can securely authorize utilities to share that data with third-party service providers.

At minimum, this means utilities should make available interval usage data, customer-specific billing and account information, the geospatial and nodal data required for market participation, and each customer's program participation and eligibility status, all through APIs[114] and bulk transfer. Customers should not have to rely on unsafe workarounds like emailing, credential sharing, or screen scraping to use their own information.

Data should move in both directions. Utilities should be able to share grid needs, operating limits, and planning information with customers, providers, and aggregators. Meanwhile, providers and aggregators should be able to report enrollment, availability, dispatch response, telemetry, and performance back to utilities.

The data should be timely, location-specific, and good enough to support real grid decisions. It should be close to real-time and circuit-level where feasible, and granular enough for dispatch, measurement, verification, and settlement. **There should be minimum data-quality rules and a clear process for fixing missing or incorrect data, including data warranties from utilities, since utilities remain the sole source of this information and aggregators otherwise bear wholesale market penalties for inaccurate settlement data they did not generate and cannot independently verify.**

Access should be fair as well as functional. State regulators should make clear that customers own their data and are able to share it with any third party they choose, quickly and without unnecessary friction. Utilities should not be able to use their control over customer data as a competitive advantage over the VPPs and aggregators who depend on it, whether through unapproved terms and conditions imposed on data recipients or structural favoritism toward their own programs or affiliates. And access should be reliable, not just available in principle. Utilities should commit to platform performance and uptime, validated through real-world end-to-end testing, and held to quantitative metrics so data is both continuously accessible and being accessed in practice.

The platform should also work for customers and improve over time. Customers should have simple, fast, commission-approved ways to authorize data sharing, with single sign-on and clear error messages where possible, and a real ability to act without delay. Utilities that follow this process in good faith, transferring data securely and without recklessness, should not bear liability for a third party's later misuse. Regulators, utilities, customers, and providers should have regular ways to flag problems and expand the platform as VPP programs mature.

STATE EXAMPLES | Data

LEGISLATORS. Connecticut enacted an "Energy Data Bill of Rights," establishing data access as a customer right rather than a discretionary utility courtesy. Illinois' Utility Data Access Act initiates a commission proceeding to guarantee customer-directed data exchanges, and mandates the inclusion of all necessary data and available usage data points for data recipients to comply with reporting requirements to which they are subject, including any such usage data that the utility possesses.

REGULATORS. Maryland's Order on Electric Utilities' VPP/DER Conceptual Reports and Office of Cybersecurity Status Report requires the adoption of a statewide data exchange platform. The platform must incorporate the pillars of data privacy, customer authentication and authorization, data standardization, and third-party registration and onboarding. It must be certified periodically by the Green Button Alliance, at a cadence to be determined by a working group. The request for proposals criteria must also promote a secure, customer-friendly experience with the platform. In Illinois, regulators and utility Ameren Illinois ran a formal stakeholder process through 2025, including a Green Button Connect requirements gathering workshop, to modernize the state's data-sharing infrastructure.

RESOURCES

Green Button Alliance	• *U.S. initiatives tracker* includes links to regulations and initiatives state by state
Mission:Data	• *Green Button Explorer* provides a map to investigate the status of Green Button adoption in your state
NARUC	• *Compendium of Standards and Requirements for Utility Customer Energy Data Access* lists commission actions on customer data access as of 2025
Local Energy Rules	• *Smarter Rules for Smart Meters* with Mission:Data
Mission:data	• *Green Button Scorecard*

II.3 SET CLEAR TARGETS FOR UTILITIES, REWARD UTILITIES FOR HITTING THEM, AND PENALIZE THEM FOR FAILING TO

To state the obvious: to lower rates, utilities need to control their costs.

States should therefore establish rules that align shareholder interest with public interest to accelerate deployment of cheaper, cleaner, more reliable local power, to control costs, and to deliver better service to customers. Utilities should make money by serving customers well, e.g., cutting costs, keeping the lights on, and connecting clean local power quickly, not simply by selling more power. They should also be penalized when they do not meet these goals for lack of trying.

Traditional utility regulation often rewards capital spending more than cost savings. Under traditional cost-of-service regulation, a utility earns its profit on the capital it builds and owns, i.e., the poles, wires, substations, and in some cases the power plants in its rate base. Integrating a customer's battery or running a virtual power plant is typically booked as an operating expense that does not earn a return, so that even when local power is cheaper and faster, the rules and system give the utility a reason to build instead.

Customers pay a hefty price for that bias; the investor-owned utilities' (IOU) trade association Edison Electric Institute noted that IOUs plan to spend more than $1.4 trillion in capital over the next five years, up from more than $1.1 trillion projected just a year earlier,[115] much of it flowing through a system that rewards building over saving. The eventual cost to ratepayers will be substantially larger as financing costs and the utilities' return on equity get factored into rates over time.

The tools for reform, known as "performance-based regulation," are well understood and have been used in several states. But while the mechanics exist, the mandate to use them is often missing, making policy intervention especially valuable.

Performance-based regulation is a broad umbrella. It includes: multi-year rate plans, which provide utilities with something equivalent to a multi-year budget that incents them to control costs; revenue decoupling, which separates a utility's earnings from how much electricity it sells, removing the reason to resist efficiency and customer-owned generation; performance incentive mechanisms or "PIMs," which tie a portion of revenue to whether utilities achieve certain results instead of solely how much they spend; and shared savings mechanisms, which let a utility keep a portion of the money saved when a cheaper option, such as a non-wires alternative, beats a traditional build, returning the rest to customers.[116]

More than two dozen states have adopted or explored performance incentive mechanisms[117] that attach rewards and penalties to specific goals that will help achieve reliability and affordability: interconnection timelines, hosting capacity, virtual power plant enrollment, demand flexibility, grid utilization, and non-wires deployment. These goals can include broader policy goals such as human health, equity, or economic development.

States should also scrutinize capital spending directly to counter the bias noted above, and consider platform models — including an independent distribution system operator — so the

entity that plans and operates the distribution system is not also the one competing to own every resource on it.

Penalties for failure to hit mandated targets should be borne by the utility's shareholders, not ratepayers, and must be sufficiently material (e.g., basis-point deductions on their authorized rate of return) to incentivize meaningful change in utilities' performance.

Trust in utilities is at an all-time low. A 2026 poll from consumer advocacy group PowerLines found that 76 percent of Americans want stronger utility oversight.[118] Rules should be set to ensure that the decisions made by state public utilities commissions are fair and that decisionmaking and processes are balanced.

Without clear expectations and rewards or penalties from state leaders, utilities will continue to lack the incentives and systems to prioritize the public interest and states' policy goals.

STATE EXAMPLES | Performance-based regulation

LEGISLATORS. Colorado lets its largest utility, Xcel, earn a return on the technology that makes a virtual power plant possible. Rather than leaving the foundational, operating, and information-technology investments needed to run the program as no-return operating costs, the law lets Xcel recover them with a return at the utility's weighted-average cost of capital through a "grid modernization adjustment clause." The program's operation and maintenance expenses run through the same clause, but as pass-through costs without a return.

REGULATORS. New York lets utilities earn revenue from distributed solutions rather than only capital. Under the Reforming the Energy Vision (REV) framework, regulators directed ratemaking reforms so utilities could earn from non-wires alternatives, platform services, and performance outcomes, rather than only from traditional capital investment. In later utility-specific rate cases, that framework was implemented through a "share of net benefits" incentive by which New York State Electric & Gas and Rochester Gas & Electric keep up to 30 percent of the net benefits from non-wires alternatives, while 70 percent benefit customers through avoided costs and reduced revenue requirements. Certain New York utilities can also earn more from enrolling more customers in managed charging.

Minnesota expanded its energy-savings program so that utilities can earn rewards not only for traditional energy efficiency, but also for shifting energy use to better times and helping customers switch to cleaner, more efficient electric equipment.

Hawaii created an interconnection-performance incentive that rewarded the utility for faster approval of interconnection for distributed energy resources, and penalized it for falling behind, tying utility earnings to service quality.

North Carolina's Active Load Management Incentive splits verified net savings 30 percent to the utility and 70 percent to ratepayers for utility-or third-party aggregated control of distributed resources up to 20 megawatts.

RESOURCES

National Association of Regulatory Utility Commissioners (NARUC)	• *Performance-Based Regulation State Tracking Map*
RMI	• *PIMs Database, Emergent Performance Mechanisms Across the United States*
NARUC	• *Demand Flexibility within a Performance-Based Regulatory Framework*
NARUC	• *PBR State Working Group Webinar: RMI Presentation on Performance Incentive Mechanisms Database*
Local Energy Rules	• *Greetings From Hawaii, Where Utility Profit Depends on Performance*
Local Energy Rules	• *Five Tactics for Fighting Utility Rate Gouging*
Regulatory Assistance Project	• *Decoupling Design: Customizing Revenue Regulation to Your State's Priorities*
RMI	• *Transforming the Way We Serve Vulnerable Communities: Performance Incentive Mechanisms and Beyond*
Just Solutions	• *Performance-Based Regulation of Electric Utilities - States Lead The Way*

II.4 PRIORITIZE LOCAL POWER IN UTILITY PLANNING PROCESSES

States should take active measures so that the cheap, clean, and reliable resources already sitting on the local grid are included and prioritized in utility planning to fully reap their valuable benefits as core grid assets.

The cheapest power plant is the one you never have to build. Yet, most utilities default to planning new substations, transmission lines, or centralized resources as answers to almost every problem, even though local power resources are faster to deploy, cheaper in many cases, and put money back in customers' pockets instead of adding to their bills for the foreseeable future.

Fixing this requires (**II.4.1**) making local problems and possible solutions visible, (**II.4.2**) ensuring utilities measure and make public how much space is left to accommodate new local power on the grid, (**II.4.3**) making utilities plan with local power in mind, (**II.4.4**) requiring that utilities evaluate and procure local power solutions from third parties when they are cheaper, letting them compete on equal footing with wires and generation, and (**II.4.5**) proactively planning for predictable growth.

II.4.1 Require analysis that makes local problems and solutions visible

Local solutions cannot be deployed to solve problems nobody can see. States should require utilities to publish grid needs assessments that identify constrained circuits, aging assets, load growth, and reliability needs; to identify openly where distributed resources could defer or avoid a planned grid investment; to study the specific grid services local resources could provide; and to keep public hosting-capacity maps and interconnection-queue dashboards current so the data is actually useful. The value of this information decays quickly, so it should be refreshed on a regular cadence (monthly or better).

Requiring utilities to show where the grid is strained and where local resources can help is a low-effort and low-cost coordination step to ensure that distributed resources are deployed first in places where the grid is congested, aging, or under pressure from growth. When that information is public, developers, aggregators, communities, and regulators can bring targeted local solutions to the places that need them instead of guessing.

STATE EXAMPLES | Visibility of local problems and solutions

REGULATORS. California requires its investor-owned utilities to publish Integration Capacity Analysis maps, which are hosting-capacity maps developed through regulators' Distribution Resources Plan proceeding. These maps show, circuit by circuit across thousands of nodes, how much distributed capacity the grid can absorb without costly upgrades. The maps are updated monthly and are now used to help fast-track interconnection, turning what used to be a private utility calculation into a public planning tool. Similarly, Colorado requires its investor-owned utilities to include a hosting-capacity web portal as part of their distribution system plans, alongside forecasts, grid-needs assessments, and non-wires-alternative cost-benefit methodologies.

New York's Joint Utilities publish hosting-capacity maps for both solar and battery storage and file regular Distributed System Implementation Plans (DSIPs) with the Public Service Commission that document grid conditions, forecasts, and integration plans. The maps have been refined from feeder-level to more granular section-level data, and the utilities are moving toward annual updates of both the solar and storage maps.

RESOURCES

IREC	• *Validation Is Critical to Making Hosting Capacity Analysis a Clean Energy Game-Changer*
U.S. Department of Energy	• *U.S. Atlas of Electric Distribution System Hosting Capacity Maps*
IREC	• *Hosting Capacity Analysis*
National Laboratory of the Rockies and IREC	• *Data Validation for Hosting Capacity Analyses*

II.4.2 Measure and improve grid utilization

States should require that utilities measure and improve grid utilization. Imagine a closed fridge. No one would decide to purchase a whole new fridge ahead of Thanksgiving before opening the door to find out how much space is left. As grids are planned for the most extreme conditions (e.g., the middle of a heat wave with all AC units in a region running on high), grids are by nature overbuilt. Some "headroom" is a key feature of grid reliability as it currently operates. However, nobody outside utilities currently can open the metaphorical fridge door, meaning regulators, customers, and, critically, competitors with cheap local power options must guess how much room is actually left on the grid. This stops everyone from finding cheaper fixes to use the space that is already there more efficiently.

States should require utilities to open the door by measuring and publishing standard grid utilization metrics.[119] The Brattle Group estimates that making better use of the existing grid could save consumers more than $100 billion over the next decade.[120]

States should require these metrics be reported down to the feeder and substation level on a regular cadence, to show where capacity is not used well, and where flexibility could have the most impact.

Examples of grid utilization metrics[121]

	In plain English	In grid-speak	We care because this helps us...
Max use	When electricity use is highest, how much of the system is being used?	Ratio of distribution system peak load to total distribution electric grid capacity	...**find spare capacity**, see opportunities to reduce peaks and free up capacity, and understand whether upgrades could be avoided when problems are caused by a small number of peak hours.
Overall use	Overall, how much power is the distribution system actually delivering compared with how much it is built to deliver?	Ratio of current electric load delivered to total potential deliverable electric load over the distribution system	...**see how much or little existing infrastructure is being used**, identify opportunities to connect additional customers without upgrades, and determine whether we could make better use of the grid we already have before building more.
Losses	How much electricity is lost along the way?	Percentage of kilowatt-hours of electricity lost during the distribution process or by the distribution system	...**see how efficiently the system is delivering electricity**, identify places where losses could potentially be reduced by using local power, and track whether system efficiency is improving over time.

States should also require that utilization data feed directly into utility planning and investment review, so a utility asking customers to fund a new substation or line has to first show that the capacity it already has is being used *well*. While this process must include utilities as a central partner, it should be driven by the public utilities commission and actively solicit and support the participation of a broad range of stakeholders to prioritize the public interest over shareholder profit.

STATE EXAMPLES | Grid utilization

LEGISLATORS. Virginia enacted a first-in-the-nation grid utilization law. The law directs utilities to petition regulators for the approval of grid utilization metrics. The petition has to include an assessment of the performance of the current electric distribution and transmission systems "as compared with optimal utilization of existing electric grid assets." In approving the metrics, regulators are required to include a timeline for utilities to increase electric grid utilization and a description of how these metrics may inform future decisions on cost recovery for capital investments. Regulators are directed to use that reporting to evaluate non-wires alternatives, including storage, distributed generation, and virtual power plants.

RESOURCES

Brattle, Utilize Coalition, and GridLab	• *The Untapped Grid: How Better Utilization of the Power System Can Improve Energy Affordability*
Duke University, Norris et al	• *Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in U.S. Power Systems*

II.4.3 Mandate utilities include local power in planning

Visibility is not enough if utilities are free to ignore what they see when they plan our grid. States should mandate that utilities include local power in planning processes.

Too many utilities still plan for the future as though every new need must be met with traditional infrastructure, with distributed resources penciled in at the margins, if at all. **States should require utilities to consider and include dispatchable customer generation, local generation, storage, demand response, energy efficiency, managed charging, and flexible load into their distribution planning and other planning processes from the start. Distributed resources should be planned for as supply-side resources in their own right.**

In practice, utilities should be required to forecast both where demand is growing (from building electrification, EV charging, and large loads) and how much distributed supply and flexibility is coming online so that local resources are counted early enough to actually change decisionmaking processes.

In addition, distribution planning, resource planning, transportation electrification, resilience, and large-load interconnection have historically run in separate planning silos. Coordinating these processes can be highly valuable because a local resource that solves a problem in one plan is invisible if it is never allowed into the room where another siloed plan is made. In restructured states where no utility files an integrated resource plan at all, states may need to create that coordinating process themselves.

Further, assumptions used to value distributed resources should be transparent and open to public participation, including those relating to avoided costs, benefit-cost inputs, and the valuation methods used for capacity, energy, flexibility, and resilience. In addition, all risks and benefits of the assets being compared should be taken into account, including their social and environmental costs, which can be quite significant.

STATE EXAMPLES | Inclusion of local power in planning

LEGISLATORS. Colorado directed its regulators to require investor-owned utilities to file distribution system plans for commission approval, including the evaluation of non-wires alternatives. Regulators later established a biennial filing cadence, so distribution planning in Colorado is now a recurring, reviewable public proceeding rather than an internal utility exercise. Illinois requires large utilities to file multi-year integrated grid plans every four years, developed through stakeholder workshops led by independent third-party facilitators, and to report grid performance by location with significant oversight from regulators.[122]

Massachusetts requires each electric company to file an Electric Sector Modernization Plan with the regulators every five years. The law created a Grid Modernization Advisory Council of stakeholders that reviews and makes recommendations on the draft plans before regulators rule on them, forcing utilities to justify their assumptions to outside experts.

Massachusetts' Grid Services Study, led by the Massachusetts Clean Energy Center, brought together relevant state agencies, the state's utilities, and different stakeholder groups, including from disadvantaged communities. The study developed a framework for how the state and utilities should look at compensation of distributed energy resources based on location-specific services to the distribution system, including recognizing the use of value stacking for distributed resource owners. It also framed (but did not create) a Grid Services Compensation Fund as a distribution-level flexibility compensation mechanism to pay for location-specific distribution services.

RESOURCES

Institute for Local Self-Reliance
- *Why Utilities in Minnesota and Other States Need to Plan for More Competition*

II.4.4 Require utilities to evaluate and procure local solutions before building expensive infrastructure

Based on this transparent, coordinated, and local power-inclusive planning, utilities should be required to evaluate non-wires alternatives *and* procure distributed local energy solutions where they can solve grid problems, and deliver clean electrons at low cost. Local generation, storage, demand response, and efficiency should be considered before building new poles, wires, substations, or expensive and polluting new generation.

States should require all-source procurement: distributed energy resource portfolios must be allowed to bid against generation, transmission, and storage investments on the same terms. Distributed resources may not always be the solution, but utilities should have to look, show their work, and let third parties bid before families are asked to pay for expensive infrastructure. This could mean requiring that projects above a certain capital expenditure be screened for non-wire alternatives, opening competitive solicitations to aggregators and other third parties, using locational targeting as may be relevant, preventing utility ownership or procurement preferences from excluding third-party providers, measuring and verifying progress, and reporting publicly on why an alternative was accepted or rejected.

STATE EXAMPLES | Local power first

LEGISLATORS. Maine's *Act To Reduce Electricity Costs Through Nonwires Alternatives* built an independent check directly into the utility investment process. Before a significant transmission or distribution investment proceeds, an independent Nonwires Alternative Coordinator, an outside expert retained through the Office of the Public Advocate, investigates whether a distributed alternative could defer or reduce the need for the capital project.

REGULATORS. In 2026, Michigan implemented a screen-before-you-build principle into enforceable form in Consumers Energy's rate case. The commission characterized the utility's existing demand-response and smart-thermostat programs as "essentially one form of VPP," and directed the utility to model aggregated distributed generation and virtual power plants as selectable resources in its planning. It also issued a prospective warning that future capital-investment proposals that fail to account for VPPs "may be disallowed" as unreasonable or imprudent, shifting the burden onto the utility to show a wires build beats the distributed alternative before ratepayers fund it.

In a classic example, New York regulators let Con Edison spend up to about $200 million on distributed and demand-side alternatives instead of building a roughly $1 billion substation in the Brooklyn-Queens Demand Management program. Con Edison hit its load-reduction target under budget, and the program was later extended.

RESOURCES

Local Energy Rules

- *Who Needs Transmission Wires Anyway?*

II.4.5 Proactively plan for predictable growth

Utilities should not wait until customers are already standing in an interconnection queue before planning grid upgrades that are reasonably foreseeable. States should require proactive distribution system planning that forecasts where electrification, distributed generation, storage, EV charging, and loads are likely to increase demand for distribution capacity, and identifies cost-effective investments before individual projects trigger them.

This kind of anticipatory planning can avoid long interconnection delays, reduce piecemeal upgrades, and help ensure that new local power and new loads can connect where they provide the most value. Regulators should require transparent forecasts and scenarios, consider flexible load and distributed resources as alternatives to traditional upgrades, and evaluate whether proposed investments are likely to be well utilized.

STATE EXAMPLES | Proactive planning

LEGISLATORS. Massachusetts requires electric utilities to file Electric Sector Modernization Plans that "proactively upgrade" the distribution system for growing distributed energy resources, storage, electrification, and future demand. The plans must forecast growth, identify needed upgrades, and evaluate alternatives including load management and flexible demand.

Massachusetts also requires 10-year forecasts of EV charging demand and associated distribution-grid needs, with utilities then planning infrastructure to accommodate that growth. Proposed investments must be evaluated against alternatives and shown to provide net benefits to customers.

RESOURCES

Massachusetts Department of Public Utilities, Electric Power Division	• *Background and Procedural Requirements on Electric Sector Modernization Plans*

II.5 MAKE AVAILABLE FINANCING STRUCTURES THAT DECREASE UPFRONT COSTS

While being the sources of power that are cheapest and fastest to deploy, distributed resources will not scale if customers cannot afford the upfront cost. **States should allow the market to use the full range of financing tools and credit support types to make local energy resources financially practical for more people.** These well-trodden pathways are still not available nationwide.

II.5.1 Provide opportunities for third-party ownership to reduce customer costs and ensure performance standards

States should clarify that third-party ownership is lawful for customer-sited resources, including solar and solar-plus-storage, and that entering into those agreements does not by itself make the third-party owner a regulated public utility. In doing so, states have an opportunity to enact stronger consumer protections, ensuring equipment and service warranties, cancellation and contract rules, salesperson licensing, and system production and performance guarantees.

Third-party ownership or "TPO" is commonly used to provide lower-cost energy solutions for homes and businesses. A developer installs, owns, and maintains distributed energy resources on a customer's property while the customer pays the third-party owner for the equipment, power, or services, instead of finding a loan. A third-party ownership contract can be a power purchase agreement or a fixed monthly fee, usually through a lease with little to no upfront cost.

Third-party ownership has become more important due to federal tax changes.[123] Solar projects that utilize third-party ownership are still able to access a 30 percent tax credit for a limited time. Batteries can still access the full value of these credits until 2033.[124] The Lawrence Berkeley National Laboratory reports that third-party ownership expands customer solutions to more low-and moderate-income families.[125] But using this option for customers comes down to a technicality: many states either do not have laws clarifying the structure is legal, or outdated utility laws define anyone who "sells" electricity as a "utility," making financing a behind-the-meter home energy system by a third party impossible, and creating costs and confusion for customers.

At least 29 states, plus Washington, D.C., Puerto Rico, and the Northern Mariana Islands, now explicitly authorize power purchase agreements.[126] Only three states have express bans on third-party ownership, and the remaining states have limited or no market clarity on this issue. The proportion of third-party-owned systems varies greatly by state, with some states like Hawaii seeing upwards of 80 percent third-party-owned residential installations for new systems in 2024, and average residential third-party ownership rates reaching 43 percent nationwide.[127]

STATE EXAMPLES | Third-party ownership

LEGISLATORS. Colorado has allowed the owner or operator of a solar electric generation facility located on a customer's owned or leased property to sell electricity to that customer since 2009. In Florida, while power purchase agreements are not allowed, customers can sign third-party owned lease contracts. In contrast, in Wisconsin, where there is still ambiguity, We Energies objected to a Milwaukee third-party solar arrangement on the grounds that the developer would be acting as a public utility. Legal uncertainty has continued to chill the market there ever since.[128] In Minnesota, a cap on the number of customers (25) to which a third-party ownership company can sell has led to overall market confusion.[129]

RESOURCES

North Carolina Clean Energy Technologies Center	• *3rd Party Solar PV Power Purchase Agreement (PPA)*

II.5.2 Authorize and require utilities to offer on-bill financing

A bank loan shuts a lot of people out of local power because it requires good credit, and because people usually cannot take out loans to improve buildings they do not own. States should authorize utilities to offer on-bill financing for a range of local power options to provide saving opportunities to a broader number of people.

On-bill financing (also called "inclusive utility investment") attaches the cost of a local power upgrade to the meter rather than the person. The utility pays the upfront cost of the upgrade (such as efficiency measures, solar-plus-storage, or another distributed resource) and the customer repays it through a monthly charge on their utility bill, set below the savings the system produces. There is no credit check or debt, and ownership is not required to participate.

The obligation belongs to the meter so it transfers automatically to the next occupant if a customer moves, letting renters and low-income households who are shut out of most financing options participate on the same terms as anyone else. This also bypasses the notorious tenant-landlord split incentive problem. Landlords benefit from building improvements that they do not have to pay for, and renters benefit from immediate savings on their utility bills and have no continuing obligation when they move away.

States should authorize utilities to offer on-bill financing across the full range of distributed energy resources — efficiency, solar-plus-storage, and other distributed resources alike — with consumer protections that cap the monthly charge below expected savings and require the utility or program administrator to keep the upgrade in working order for as long as the customer is paying for it. Where a program finances an asset the customer could eventually own outright, like a solar-plus-storage system, states should also require a clear path to ownership once the utility's investment is paid off.

STATE EXAMPLES | Inclusive utility investment

REGULATORS. Missouri regulators approved Ameren Missouri's Pay As You Save (PAYS) program as part of the utility's Missouri Energy Efficiency Investment Act framework. The approved settlement allowed Ameren to operate PAYS as a program, provide $5 million in financing in 2021 and $10 million in 2022, charge participants a 4 percent financing cost, and later roll the PAYS-financed regulatory asset into the rate base with typical cost-of-capital treatment.

UTILITIES. Roanoke Electric Cooperative in North Carolina has run its Upgrade to $ave program since 2015, enrolling more than 10 percent of its residential customer base in efficiency and demand-response upgrades (weatherization, HVAC, Wi-Fi thermostats, and water-heater load controls) with no credit check required, demonstrating the model at scale.

RESOURCES

U.S. Environmental Protection Agency	• *Inclusive Utility Investments: Tariffed On-Bill Programs*
ENERGY STAR	• *Inclusive Utility Investment Resource Center*
Local Energy Rules	• *Scaling Up Home Energy Investment*

Endnotes

1 When a battery or solar system is plugged directly into the local grid it is often referred to as a "front-of-the-meter" system. When a home battery and rooftop system is connected directly to a building, it is often referred to as "behind-the-meter." Both of these can be a part of a virtual power plant.

2 In the 1990s, many U.S. states restructured their electric utility markets, separating (or "unbundling") generation from transmission and distribution and opening generation to wholesale competition. FERC's Order 888 in 1996 required utilities to provide open, non-discriminatory access to their transmission lines, and roughly half the states, including California, Texas, and much of the Northeast and Mid-Atlantic, allowed retail customers to choose their electricity supplier. In restructured states, utilities are usually barred from owning generation assets, which they must instead buy on the wholesale market, but it is not a universal rule and other structures exist.

3 This so-called "capex bias" is exceedingly well-documented, and has been studied since the 1960s. For example, see Averch and Johnson, *Behavior of the Firm Under Regulatory Constraint*, American Economic Review, December 1962, and Werner and Jarvis, *Rate of Return Regulation Revisited*, Journal of Public Economics, July 2026.

4 U.S. Energy Information Administration, *Electric Sales, Revenue, and Average Price*, Table 5A, Average Monthly Bill-Residential, 2020 and 2024 editions

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69 For instance, "utility-franchise laws" give incumbent utilities the exclusive or primary right to provide electric service in a particular territory, enabling them to argue that if a community microgrid serves more than one customer, the microgrid developer is unlawfully "selling electricity" inside the utility's service territory. A similar logic applies in states where the definition of public utilities is defined by the number of people served, triggering public utility commission oversight, rate regulation, and other rules normally used for regulated utilities. "Right-of-way restrictions" govern who can place wires, conduits, or other infrastructure across public streets, sidewalks, or utility corridors, and can restrict how microgrids connect across buildings that are on a different parcel. Microgrids can be prohibited by state or local rules from developing such a system, unless the project is owned by the utility or has received special

permission. For example, this would prevent a hospital and an emergency shelter across the street from one another from being connected to the same microgrid despite obvious resilience benefits.

70 Paulos, *What States Need to Know About Plug-In Solar*, CESA, June 2026

71 Permissionless storage could be standalone batteries plugged into a wall or an appliance such as an induction range or water heater with a battery inside. They can draw a small, steady load from a standard 120-volt outlet, store energy when it is cheapest and cleanest, and release it on demand, creating customer savings. For example, a plug-in battery that charges midday and discharges in the evening will shift household load off the peak and lower the most expensive hours on the bill, providing residential and commercial customers instant bill relief, particularly where demand charges or peak tariffs exist.

72 Note that some plug-in technologies do require electricians to install properly rated outlets, among other things, depending on how they are structured or installed.

73 A list of nationally recognized testing laboratories is available on *OSHA's website*. UL Listing or Certification is commonly required for distributed energy resources. UL (Underwriters Laboratories) is an independent safety science company that tests and certifies electrical and energy equipment against established safety standards.

74 There are other models, including some using credit mechanisms that work slightly more akin to Renewable Portfolio Standards (RPS). However, distributed storage targets are not the same as RPS. RPS generally require electricity providers to supply a certain share of annual electricity sales from renewable generation whereas a distributed storage target requires the deployment of local storage that can be used when and where the grid needs it, thereby creating usable local capacity that can reduce costs, improve reliability, and make local renewable generation more valuable.

75 See State of New York Public Service Commission, *Order Establishing Updated Energy Storage Goal and Deployment Policy*, June 20, 2024: "Residential energy storage is usually small, at an average of less than 10 kW, and can be developed and installed quickly, giving the customer added resiliency during black outs and the ability to participate in utility demand response programs. Retail projects, sized under 5 megawatts, have a considerably longer development time, averaging three years (...)."

76 Note that certain classes of smaller and on-site-load facilities are now cap-exempt. See *Mass. Gen. Laws Chapter 164, Section 139* and Solar Energy Industries Association, *Analysis: Current Net Metering Cap Stalls $78 Million of Solar Projects in Massachusetts,* October 2017

77 Alaska Energy Transparency Project, *RCA Considering Changes to Net Metering Regulations*, November 2024

78 NJ Senate Democrats, *Gopal Bill to Expand Access to Community Solar Projects Advances*, June 2025. The analysis is attributed to The Brattle Group and described as commissioned by Solar Landscape. The underlying report is not publicly available.

79 For an example of recommendations for NLR relating to net-metering caps, see National Laboratory of the Rockies, Heeter et al., *Status of Net Metering: Assessing the Potential to Reach Program Caps*, September 2014

80 International Energy Agency, *Energy and AI*, April 2025

81 A tariff is a set of rules, approved by the state, that says how much a utility can charge and what customers can and cannot do. Utilities typically must "file" their rates and rules with a state regulator (i.e., the Public Utilities Commission).

82 A key risk is that funds may be absorbed into existing utility programs without additive impact, and utility asset ownership can foreclose the third-party aggregator market.

83 "Disadvantaged communities" has different legal definitions across state lines. Initiative for Energy Justice, *J40 and Community Definition: U.S. State Approaches to Defining Disadvantaged Communities and Benefits Allocation*, 2022

84 When a data center draws from the bulk system, VPPs located on distribution feeders miles away could be in a different utility service territory entirely. For instance, a VPP funded by a hyperscaler at the transmission level will be beneficial because it could reduce system-wide capacity needs and will require FERC Order 2222 aggregation to count. When a data center draws from the distribution system, VPP assets can be located on the same feeder or substation. The distribution utility may prefer that data centers plugged locally focus on reducing impacts on a few

specific constrained locations.

85 E.g., long-term service commitments, minimum bills, collateral, exit fees, and direct assignment of customer-specific upgrade costs

86 The specific pathway through which PJM credits this capacity — whether the resource clears through a Reliability Pricing Model auction (the "capacity market"), is transferred or assigned through another mechanism, is included in a load-serving entity's Fixed Resource Requirement or capacity position, or something else — has not been made public.

87 Duke University, Norris et al, *Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems*, February 2025

88 Grid Strategies, Wilson et al, *Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers*, November 2025

89 Peak demand for the Lower 48 states reached 759,180 megawatts on July 29, 2025. See U.S. Energy Information Administration, *U.S. electricity peak demand set new records twice in July*, August 5, 2025

90 Permit Power, *As Cheap As Our Peers*, October 2025

91 National Laboratory of the Rockies, *Evaluating the Impact of Residential Contract Cancellations in the United States*, January 2022

92 National Laboratory of the Rockies, *Exploring the link between project delays and cancellation rates in the U.S. rooftop solar industry*, June 2021

93 Challenges and policy solutions relevant to the poor design of utility incentives are addressed in Section II.3.

94 And not under FERC/MISO/PJM jurisdiction

95 California solar/battery permit-fee limits: SB 1222 (2012), tightened by *AB 1414* (2017) and *AB 1132* (2023). Colorado: *HB 11-1199* (2011), *SB 17-179* (2017), *HB 21-1284* (2021).

96 Sigrin and Mooney, *Rooftop Solar Technical Potential for Low-to-Moderate Income Households in the United States*, April 2018

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105 Ben Hertz-Shargel, *U.S. DOE shows that virtual power plants are very real*, January 2025 and Ohm Analytics, 2025 VPP Market Report Executive Summary, January 2026

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108 Ryan Hledik and Kate Peters, Brattle, *Real Reliability: The Value of Virtual Power*, May 2023

109 Clean Energy States Alliance, *BVPP Table*, February 2026

110 U.S. Federal Energy Regulatory Commission, *Order No. 2222: Fact Sheet*, September 2020

111 FERC Order 719 "opt-outs" were reversed for commercial and industrial customers in MISO and SPP markets. Voltus.co, *Voltus Drives Energy Transition Victory as Missouri Commission Votes Unanimously to Support Consumer Access to Wholesale Power Markets*, October 16, 2023

112 LUMA, *LUMA Integrates Customer Batteries and Grid Upgrades to Meet Peak Summer Energy Demand*, July 2026

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115 Edison Electric Institute, *Industry Facts*, 2026 and Edison Electric Institute, Strengthening America's Energy Infrastructure to Increase Reliability & Lower Costs, 2025

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117 National Association of Regulatory Utility Commissioners, *Performance-Based Regulation State Tracking Map*, updated in 2024, accessed in 2026

118 Powerlines, *Utility Bills Are Rising Q1 2026 Report*, May 2026

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120 The Brattle Group, *New Brattle Report Finds Better Utilization of Existing Power Grid Could Save U.S. Consumers More Than $100 Billion in the Next Decade*, March 2026

121 See *Virginia* legislation.

122 Pew reports that when the Illinois Commerce Commission approved the first ComEd and Ameren plans in December 2024, it cut ComEd's proposed spending by roughly 25 percent and Ameren's by about 75 percent as a direct result of forcing utilities to justify their builds. See *Pew Charitable Trusts, Distributed Energy Can Unleash the Resilient, Affordable Grid of the Future*, April 2026.

123 Before July 4, 2025, homeowners could claim 30 percent Investment Tax Credits for direct ownership of solar. The 30 percent Investment Tax Credit remains in effect for third-party owned solar until December 31, 2027 under certain conditions. See Clean Energy States Alliance, *OBBBA Tax Credits Summary Diagram*, September 2025.

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125 Berkeley Lab, *New Berkeley Lab report on solar-adopter income and demographic trends*, December 2024

126 Five additional states authorize leases but not power purchase agreements. North Carolina Clean Energy Technologies Center DSIRE, *3rd Party Solar PV Power Purchase Agreement (PPA)*, May 2026

127 Berkeley Lab, *U.S. Distributed Solar and Storage 2025 Data Update*, October 2025

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