Affordability, Rates, and Clean Capital Efficiency: A Path for the Power Industry’s Turbulent Next Decade

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Executive Summary

Abundant, affordable, carbon-free electricity is a central driver of a sustainable economic future. For the past two decades, the utility industry has enjoyed relative stability, with low demand growth, low inflation and interest rates, declining generation costs, and a rarely problematic supply chain. Even through the financial crisis of 2008 and the COVID-19 pandemic of 2020, the industry sailed forward relatively smoothly, serving customers reliably while reducing carbon emissions, keeping rates reasonable, and providing solid financial returns.

This era appears to be over. Utility rates have begun to rise significantly due to high inflation, interest rates, materials costs, competition for a constrained supply chain, and aging or storm-damaged infrastructure. Carbon emission reductions have plateaued, and utility financial performance has declined. Above all, there has been a massive revival of demand growth – fueled substantially (but not only) by headline-grabbing data centers, creating unusually long and large connection delays.

These challenges are expected to escalate in the near term. Projected sales growth will demand unprecedented construction outlays, and supply chain constraints will further increase new electric equipment costs, which have already surged over the past decade. The magnitude of predicted capital spending increases will likely lead to another large wave of rate increase requests at a time when affordability concerns are already very high. Meanwhile, energy transition goals are slipping backward as many utilities turn to new gas power plants and/or deferred coal retirements to meet the surge in growth.

At a time when utilities can only push so much new investment into rates before triggering backlash, the most effective strategy for a distribution utility may be through an approach we call *clean capital efficiency* (CCE) – doing as much as possible to minimize and justify the buildout of expensive new infrastructure by using existing systems more intensively than in the past. While significant capital growth is going to be essential under almost any scenario, maximizing service through the existing system should act to keep rates lower and reduce customer dissatisfaction. Regulators may look more favorably on capital outlays that are demonstrably needed after a utility has shown strong and effective measures to minimize capital expenditures (capex) and cost and maximize throughput.

The CCE approach can help utilities pursue financially stable growth, rate moderation, and decarbonization simultaneously. Alongside system expansion, the strategies we recommend for implementing CCE include revised energy efficiency programs, accelerated demand flexibility programs, optimizing and possibly owning distributed energy resources, low-capital transmission expansion and distribution technologies, and leveraging off-balance sheet capital sources. None of these ideas is new, but they deserve a stronger emphasis in the coming era. However, they also present important process challenges, as the differences in types of resource options are large, the underlying demand drivers are highly uncertain and changing quickly, and trade-offs between options are complex.

This collection of recommendations should be part of a full-scale strategy, which should include integrated planning and execution as well as actions in the areas of supply chain planning and acquisition, transmission planning, regional market analysis, workforce preparedness, and strong attention to new rate structures.

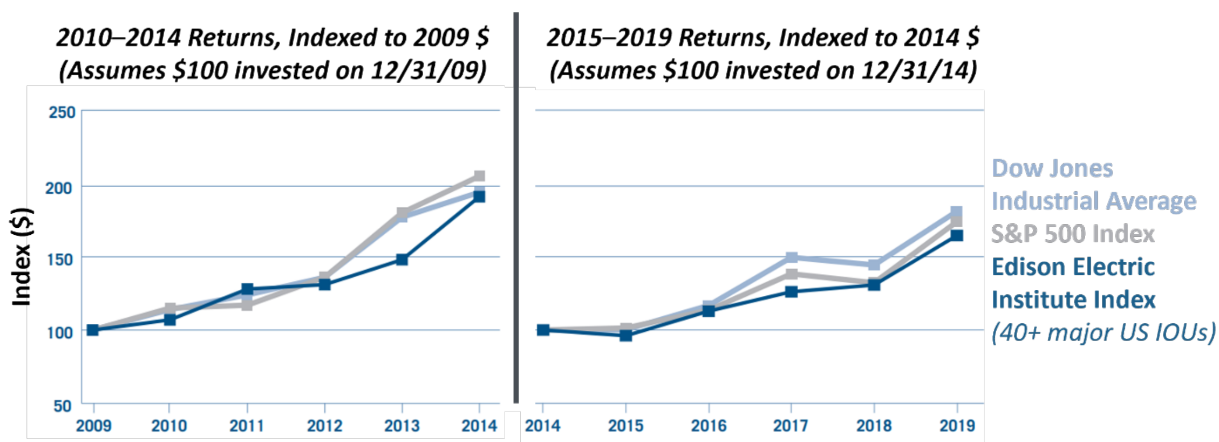
It will be essential for utilities to maintain strong lines of communication with their regulators and the full range of utility stakeholders as the industry moves forward. Balancing rate fairness, utility industry expansion, and other important system attributes will be challenging. Nonetheless, the coming era offers a unique opportunity to upgrade system architecture, improve financial performance, and relieve at least some of the escalating concerns over rates and affordability.

I. Introduction

Abundant, affordable, carbon-free electricity is properly seen as a central driver of a sustainable economic future. From online recreation to national defense, most of what we make, use, and do increasingly relies on technology powered by electricity. The growth of artificial intelligence (AI) shows signs of deepening this trend. Meanwhile, every plan for addressing the enormous costs of climate change requires a vastly expanded, fully decarbonized power grid. Most national net-zero plans call for roughly doubling the amount of delivered electricity by 2050, even before accounting for the substantial additional demand required by AI.[1]

Over the last two decades, a happy combination of circumstances enabled the electric utility industry to make substantial progress on its main responsibilities without much strife. Over this entire period, US retail sales increased about 0.6% per year, and average power bills increased about 2.7% – a bit faster than inflation but manageable.[2] Total industry carbon emissions peaked in 2007 and then dropped a full 33% by 2019.[3] Investor-owned utility (IOU) equity returns were on par with the stock market and credit ratings were stable; in 2019, for example, an index of 40 major US investor-owned electric utility stocks delivered a return of 25.8%, closely mirroring the performance of the Dow. Over the trailing 10-year period, the utility index closely tracked the Dow's returns, as shown in Figure 1.[4]

FIGURE 1: INVESTOR-OWNED ELECTRIC UTILITY STOCK RETURNS COMPARED TO THE MARKET



Sources and notes: Reflects reinvested dividends. All returns are annual. The 2014 EEI index contains 48 publicly traded investor-owned electric utilities, and the 2019 EEI index contains 40 publicly traded investor-owned electric utilities. See Edison Electric Institute, "2014 Financial Review" (2015) and "2019 Financial Review" (2020).

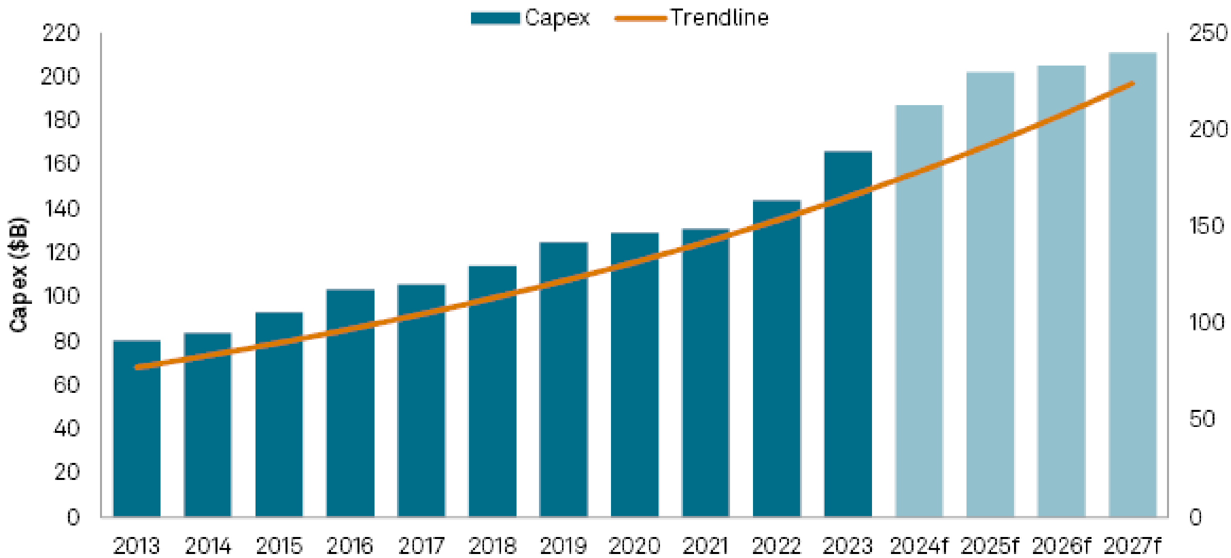
Even through the collapse of 2008 and the COVID-19 pandemic of 2020, which sometimes changed use patterns dramatically, the industry sailed more or less steadily forward.[5] Low demand growth, low inflation and interest rates, declining generation costs, and a relatively stable supply chain allowed the industry to serve customers reliably, reduce carbon emissions, keep rates reasonable, and provide solid financial returns.

That era is now firmly in the rear-view mirror. Utility rates have gone up considerably due to high inflation and interest rates, high materials costs and supply chain constraints, the need to replace aging and storm or fire-damaged infrastructure, and a revival of demand growth. Until 2020, total annual electric utility rate increase requests rarely topped $6 billion.[6] They hit $8 billion in 2021, $9 billion in 2023, and then almost $12 billion in 2024.[7] Across all but 12 US states, the *lowest* increase for this period was over 12% and the highest over 41%;[8] nationally, total household outlays for electricity rose by more than 25% in real terms.[9] Carbon emission reductions also plateaued, with total electric emissions hovering around 1.4 to 1.6 billion metric tons.[10]

Unsurprisingly, all of this has taken a toll on utilities' financial performance. Despite record rate increases and higher sales, electric utility revenues have not kept up with costs, and actual return on equity trended down this decade. Actual average returns on investment are currently below already-reduced authorized levels by approximately 1%.[11] Since 2020, utility stocks have roughly traded flat as the overall Dow returned more than 30%.[12] Reversing the pre-pandemic trend, utility credit downgrades by S&P Global exceeded credit upgrades by more than three to one.[13]

The combined challenges facing the industry are only likely to escalate in the near term. Most importantly, projected sales growth is rising at an unprecedented rate, requiring extremely high levels of new construction outlays to meet demand. As of last July, the projection of 2025 capital spending by investor-owned utilities was more than double 2014 spending in nominal dollars.[14] Based on their survey, S&P predicts utility capital expenditures (capex) will have increased almost one-third (30%) in only two years (2022–2024) and will continue increasing to a four-year total of nearly $800 billion by 2028.[15] (See Figure 2.) Last November, nine utilities serving data centers revised their forecasted capital spending upward by an average of 22% versus year-ago levels. "If you think about the next five to ten years," an equity analyst at Siebert Williams Shank recently said, "you're probably going to see this kind of rate of [capital spending] growth."[16]

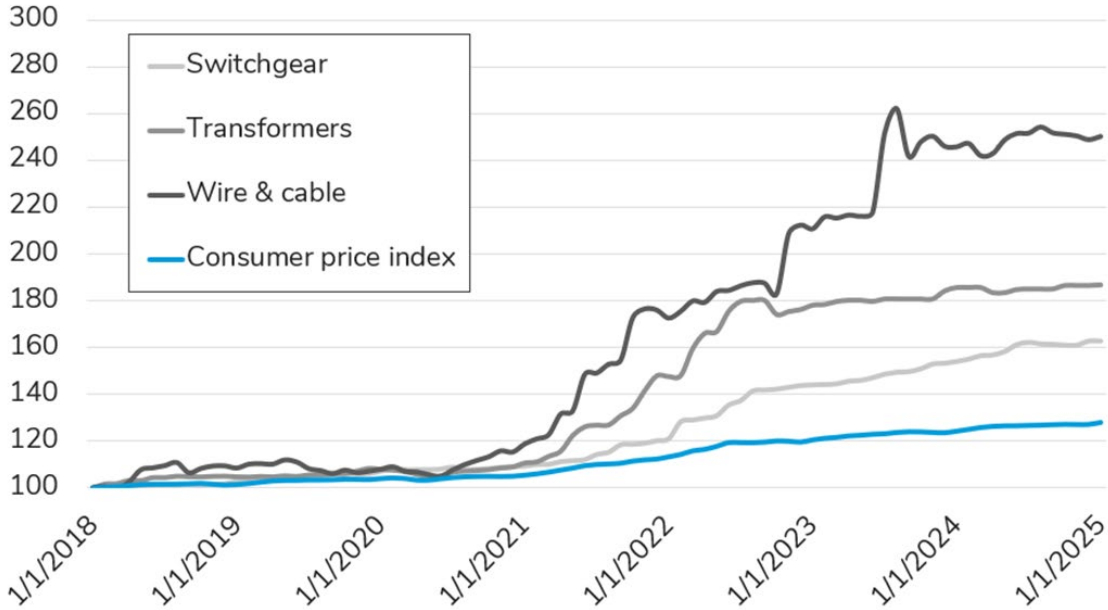
FIGURE 2: ENERGY UTILITY ACTUAL AND ESTIMATED CAPEX



Source: Regulatory Research Associates, a group within S&P Global Commodity Insights, "Energy utility capex projected to eclipse $790B from 2025 through 2028," *S&P Global Market Intelligence,* January 9, 2025. Data compiled December 23, 2024.

These capital outlays are taking place against a backdrop of supply chain limitations and a possible further resurgence of inflation. They will increase the costs of new electric equipment above current levels, which have already grown enormously in the past decade.[17] In just four years, raw copper prices have grown by 40%, and finished power transformers – after as much as a four-year wait – cost an average of 60–80% more.[18] Meanwhile, consulting firm ICF's model for the cost of power predicts wholesale power costs will increase by 19% in just the next three years.[19] Producer Price Indices for wire and cable, switchgear, and transformers have increased as much as 250% since 2018, far above the consumer price index, which was up only 30%.[20] (See Figure 3).

FIGURE 3: PRODUCER PRICE INDICES FOR CRITICAL POWER SYSTEM EQUIPMENT



Sources and notes: Indexed to January 1, 2018. Data from the St. Louis Federal Reserve FRED database, Producer Price Indices. See Andy Lubershane, "The Price of Power Grids," *Steel for Fuel* (April 7, 2025).

The magnitude of capital spending increases is sure to lead to a new wave of significant rate increase requests. Utility analysts at Sector & Sovereign Research (SSR) have calculated that 17 large utility companies (out of about 45) "may see [new] rate hikes above the rate of inflation between 2022 and 2027."[21] SSR co-head Hugh Wynne notes that this is an unusually large set of increases. "There were a lot of trends that were moving in a positive direction for the industry," Wynne said, "that are now going in the opposite direction." Credit rating agencies also expect a renewed rate case trend to continue.[22, 23] Perhaps one analyst from Guggenheim Securities put it most succinctly: "Rates are going to go higher, and there's not much you can do about it. It's kind of the new normal."[24]

Concern over regulators' (and the general public's) willingness to accept these rate increases is becoming widespread. Signaling a concern over regulatory recovery, S&P recently reported that capital investment plans are pressuring credit quality. S&P also notes that a high percentage of companies are operating with minimal financial cushion from their downgrade thresholds.[25]

Two Reuters reporters looking at utility capital plans express the view that "[utility] plans to raise rates sharply to offset higher costs may face regulatory hurdles."[26] A Brattle economist recently asked an experienced state regulator whether he sensed a higher-than-usual degree of rate concern amongst his peer regulators. He responded with a flat yes and volunteered that we could quote him directly.

Utility leaders are not being caught unaware. Affordability is at the top of the list of concerns for many. Like the regulators they answer to, however, they face substantial competing imperatives – an obligation to serve, a desire to help their service area grow, and a need to make their systems cleaner and more resilient.

There is one long-term silver lining to this cloudy picture. While unit electricity prices may be going up, electricity customers are switching to electric transportation, heating, or electrified industrial processes. The higher efficiency of these processes often means that total household or business outlays for energy decline, even under higher electricity prices.

Along with many other researchers, our Brattle colleagues have studied this and found that deep electrification – combined with modest energy efficiency – reduces average energy spending for both moderate and low-income households. For example, a 2022 Brattle study for New Jersey[27] found that moderate-income customers who electrified and improved energy efficiency could save 15% on their household energy bills by 2030 compared to their 2020 outlays after adjusting for inflation. Low-income customers also saved, albeit slightly less.[28]

Similarly, researchers at MIT recently released a study showing that shifting 80% of gas heat customers to electric heat would reduce total utility costs by 21–29% despite the higher growth in winter electric loads.[29] As the benefits of energy efficiency and electrification gradually take effect, both customers and the environment will be better off. But this will take time, and in the meantime, there will still be much focus on electricity prices.

Meanwhile, energy transition goals are also slipping backward. Along with many new wind and solar plants, many utilities are turning to new gas power plants and/or deferred coal retirements to meet the new surge in growth with reliability. GE Vernova reported that it booked 20 GW of new gas plant orders in 2024, double its orders in 2023.[30] According to the US Energy Information Administration (EIA), dry natural gas production is expected to increase by 2% in both 2025 and 2026, and US energy-related carbon dioxide emissions are expected to increase by 2% in 2025.[31]

These developments ensure that the industry's road ahead will not be smooth. Nonetheless, the coming era offers a unique opportunity to redirect resources toward a cleaner, more efficient, and cheaper system. There is a path through the roiling waters that can upgrade system architecture, improve financial performance, and relieve at least some of the escalating concerns over rates and affordability – maximizing the throughput of the system we have as we simultaneously and rapidly build on the fastest feasible path to decarbonization.

II. Everything Everywhere All at Once

"After almost two decades of relatively little change," the EIA wrote in January, "consumption of electricity grew 2%" in 2024. If the EIA's forecasted growth continues at this pace through 2026, it will be the first three straight years of growth since 2005.[32] Although the power needs for data centers (DCs) are the subject of much discussion these days, our use of electricity to power our lives requires about 96% of the system, with only a little over 4% currently going to DCs.[33]

As the country inevitably follows a path to a deeply decarbonized energy system, we should be preparing for this rate of steadily cleaner power growth for at least the next two decades. Even without factoring in DCs, achieving full electric decarbonization by 2050 will require, according to one account, an additional 1,889 TWh to electrify transportation, 502 TWh for commercial building operation, and possibly another 584 TWh for electrified industrial use.[34] These figures, plus the rest of our electric-dependent lifestyles, call for about 2.7% average annual sales growth through 2050. [35]

But even meeting our current level of growth is proving to be problematic. Already some utilities are finding it difficult to keep up with the pace of new requests for service, much less maintain their clean energy commitments. Delivering new megawatts (as distinct from "negawatts") today increasingly requires an added generating plant, a connection to the grid, enough transmission capacity to move the power, and expansion of the local wires (distribution system) to deliver the power to customers. Each of these is running up against unusually strong limitations:

- New plants of every type are much more expensive than existing plants and take longer to site and connect. Solar and wind projects now have a median waiting period of almost five years to get a new transmission connection; about eight-in-10 project megawatts give up before they complete the wait.[36]
- Planning, permitting, and building new transmission lines can often take a decade or more. There is much discussion on ways to accelerate grid build and an important new Federal Energy Regulatory Commission (FERC) planning order, but so far, "transmission in construction has yet to increase substantially," according to the North American Electric Reliability Council (NERC).[37] Moreover, the grid we have managed to build has often not been the right type to increase new deliveries.[38]

- Finally, and much less widely discussed, expanding the distribution system has become a major barrier to growth and is the highest overall source of capital outlays. Spending on local wires now approximately equals total expenditures on power generation plus transmission together – two-and-a-half times what it was 20 years ago, adjusting for inflation.[39] Aside from skyrocketing costs, the delays in obtaining this type of equipment have moved from months to years, and local land use and permitting issues are also causing delays. The median time to upgrade and build a new substation in California is now approximately four and nine years, respectively.[40]

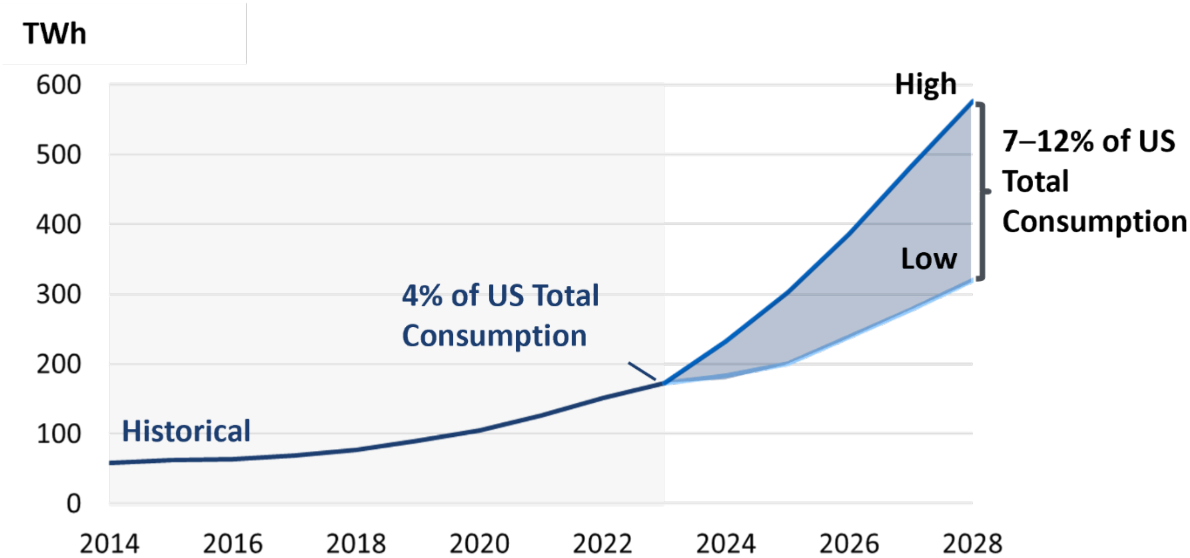
Increasingly, utilities must queue up new customers or customers who want to add large loads – such as electric vehicle (EV) chargers – and have them wait until there is enough fully deliverable power to meet their new demands. Although the concern is widespread, one good example is California, where in just 18 months, Southern California Edison received almost 500 new requests for large EV chargers, with a total capacity of 1.4 GW – more than the peak load of the city of San Francisco.[41] Connection delays across the state recently led to a new regulation that set a maximum waiting period for service.[42]

When one industry leader in another state was asked about serving DCs, they bluntly replied that "we don't have enough resources to meet what is already going on."[43] Meanwhile, electric utility carbon emissions increased an estimated 0.2% last year, reversing direction and well off the track towards a 2050 goal of full decarbonization.[44]

On top of this already-challenged growth, we now have a headline-grabbing explosion in power demand for DCs. US AI firms are locked in one arms race against each other and a second one against China – "the race of a lifetime to global dominance," in the words of one DC CEO.[45] There is immense uncertainty regarding the full magnitude and pacing of the power needed to support the surge in DCs, but even under conservative scenarios, the added strain on the system is significant.

Lawrence Berkeley National Laboratory (LBNL) estimates between 34 and 92 GW of added DC peak demand by 2028.[46]

FIGURE 4: HISTORICAL AND FORECAST DATA CENTER ENERGY CONSUMPTION



Source: Digitized from Arman Shehabi et al., "2024 United States Data Center Energy Usage Report," *Lawrence Berkeley National Laboratory (*December 2024).

At the bottom end of their range, DCs will add one New York state's worth of peak demand in only three years.[47] Many other pre-DeepSeek forecasts were higher, in the range of 15–17% growth annually or more.[48] If McKinsey & Company is right, just five years from now, one out of every 8 kWh in the US will be consumed by a DC.[49] If Morgan Stanley is right, utilities will be able to support only half of all 2030 DC demand – a shortfall of more than 25 GW.[50]

Among other effects, the rapid increase in DC load threatens to slow decarbonization efforts by extending the life of existing coal and gas plants and adding substantial new gas capacity. According to Bloomberg New Energy Finance (BNEF), almost two-thirds of the additional electricity generation needed to support worldwide DC demand will come from fossil resources. BNEF estimates that this will add 3.6 gigatons of carbon to the atmosphere by 2050, about 10% of this year's global greenhouse gas (GHG) emissions.[51]

III. The Three C's of 2030 Power

The problem with meeting the level of growth outlined in Section II is not so much an outright inability to build enough new generating plants, especially since increased energy efficiency (EE) and load flexibility should displace a good bit of this need. The true challenges can be summarized in three words: *control, connection,* and *cost*.

"Control" is the first of these "three C's," and refers specifically to the dispatchable – i.e., controllable – resources that will be required to keep pace with growing demand. According to reliability watchdog NERC, US demand will increase by about 150 GW by 2034 (this may or may not include all AI power demand, but let's assume it does).[52] The US has been adding well over 15 GW of rated capacity in the past few years; Texas alone claims it is now adding 1 GW *per month.*[53]

The problem is that almost all of these additions have been solar and wind, and that's also true of the 2,600 GW of proposed new plants requesting grid connection.[54] To keep the grid reliable, more controllable resources – including storage and load – are needed. These resources exist, but they cost substantially more than wind and solar, and they need more grid capacity to connect. In short, the first "C" (control) adds yet more fuel to the second two challenges, connection and cost.

Accelerating transmission connection, the second "C," is one of the industry's toughest and most enduring challenges. New federal and state policies are beginning to help – LBNL's optimistic what-if scenario sees a doubling of annual grid connections by 2028 – but even this is well below the crucial need for speed.[55] NERC, with great concern, points out that, in 2024, the industry failed to build and connect anywhere near the new capacity it predicted it would add only one year earlier. The shortfall between actual and planned additions was an astonishing 40 GW.[56] "Simply put," one NERC executive says, "our infrastructure is not being built fast enough to keep up with the rising demand."[57]

And then there is the third "C," cost. Nearly everything we have discussed so far adds to costs, whether for generation, transmission, or distribution. From raw materials to complex finished products, worldwide demand for energy is driving the costs of every part of the system up substantially. Tariffs and other geopolitical actions will add still more to unit prices.

Beyond the costs of serving additional load, most utilities also face greatly increased outlays for replacing aging infrastructure, restoration following severe weather events, and investments to make their systems more resilient. In fact, over half of utility transmission and approximately two-thirds of distribution capex is not for expansion but for replacement and resilience.[58] Investments the Edison Electric Institute (EEI) categorizes as "adaptation, hardening, and resilience" are now 37% of all distribution capital spending.[59] Beyond capital outlays, utilities must also now pay more for insurance, wildfire and storm damage litigation, and preventive operating expenses such as tree trimming.[60]

To be fair, not all utilities and all regions have the same level of constraint on their expansion. Several utilities across the country are expanding their systems rapidly and are eager to serve DCs as well as all other new loads. The Omaha Public Power District expects to double its generating capacity within the next five years.[61] Georgia Power's expectations of load growth by the mid-2030s from DCs and economic development customers recently tripled, and Texas is laying plans to triple its entire state system in that same time frame.[62] However, even some of these fast-growing locations now have expanding connection wait lists, and they face the same supply chain cost increases and delays as everyone else.[63]

IV. The Implications for Utilities

As a result of all of this, the outlook for distribution utilities is one of greatly increasing stress. The growth in demand from both existing and new customers may outstrip new supplies, perhaps for the better part of the next decade. Over that same period, supply chain costs will rise. Meanwhile, many customers will wait longer for interconnections or upgrades, and many more will suffer longer weather-related outages.

There is growing activity to help meet the looming shortages through accelerated supply-side expansion. Proposals along these lines include permitting reform designed to enable faster transmission growth, as well as calls to delay planned fossil plant retirements and add more gas capacity.

That said, while utilities face intense pressure to focus on meeting load growth and controlling rates, many still recognize the importance of stewarding their companies away from carbon amid what scientists have clearly identified as a global climate emergency. That suggests that additions to generating plants should follow the fastest and most straightforward path to full decarbonization that is allowed by economic and technical constraints.[64]

However, there is a different issue with trying to build our way out of these problems, and that is the sheer cost and time required. Sound permitting reform – and, more importantly, better transmission planning processes – are sorely needed, but they will likely take years to implement and will do little to lower supply-chain-induced cost increases.[65] Indeed, the faster utilities unleash building against a supply chain that itself has expansion constraints, the more they risk driving prices up.

These insights are the inspiration for this paper and the set of recommended strategies that help pursue growth, rate control, and decarbonization all at once. In short, the best strategy for a distribution utility may be to do as much as possible to reduce the buildout of expensive new plants of any kind by using its current system more intensively than in the past. Of course, even with these efforts, there will be no escaping the need to add capital and raise rates. Pushing as much service through the existing system as possible is probably the best one can do to keep rates down and minimize customer dissatisfaction and defection.

At first glance, this might sound like a terrible financial strategy for utilities. After all, the profits of regulated utilities are tied formulaically to the amount of capital deployed. Particularly for utilities that still own generation, one would think that the era of seemingly endless need to add capital would be a golden era of earnings growth.

But when added capex repeatedly raises the price of power to all customers, as will be the case for the foreseeable future, there is only so much new investment one can push into rates before backlash sets in. When this occurs, there are a variety of steps regulators can take to ensure utility investors share the pain. In a climate like this, regulators should look more favorably on capital outlays that are demonstrably needed despite strong and effective measures to minimize capex and maximize throughput.

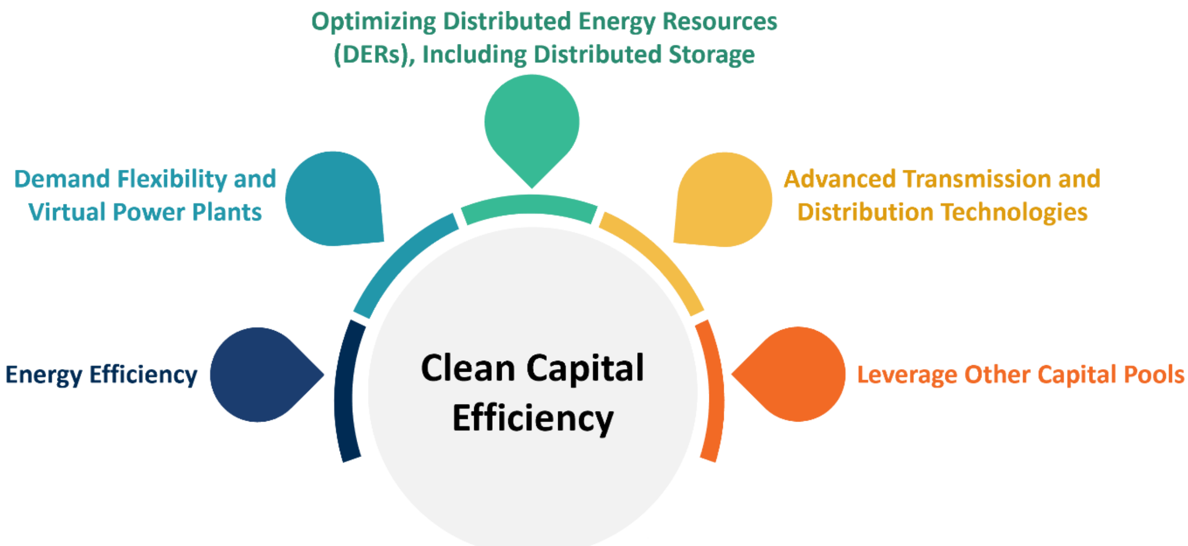
In other words, in the coming era, regulatory goodwill may be more valuable on the margin than the sheer opportunity to build. Regulatory approvals may be best earned by approaching growth a little differently.

V. Clean Capital Efficiency (CCE)

What are the strategies to achieve CCE, maximizing throughput in an era of high demand, very high costs, and supply constraints? Every utility's approach will necessarily be a little different, but five overarching strategies stand out:

- Revising EE strategies, including (but not limited to) beneficial electrification;
- Accelerating demand flexibility (DF) programs, including virtual power plants (VPPs);
- Optimizing distributed energy resources (DERs), including distributed storage;
- Maximizing low-capital transmission expansion and distribution technologies, such as grid-enhancing technologies (GETs); and
- Leveraging other capital sources that reduce utility capex without sacrificing overall system efficiency.

FIGURE 5: THE FIVE STRATEGIES OF CLEAN CAPITAL EFFICIENCY



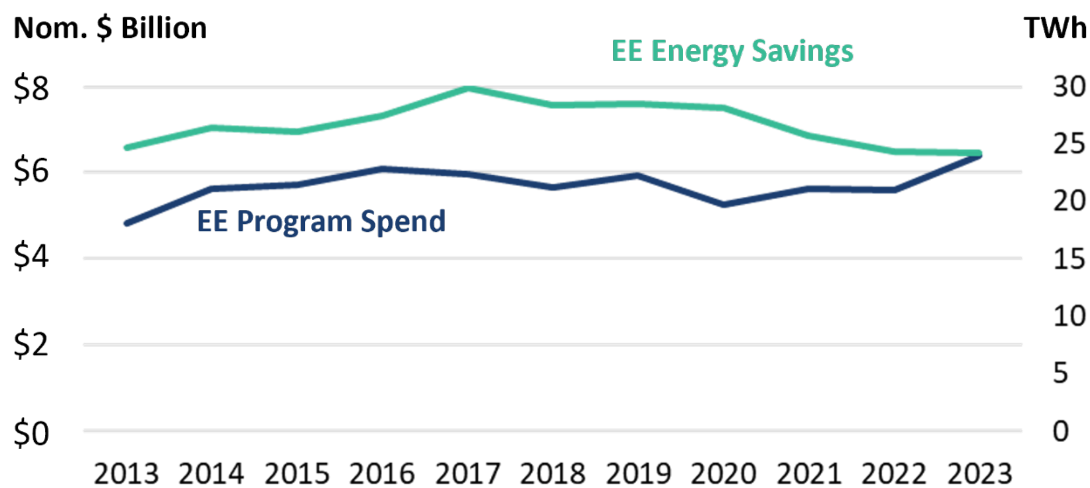
None of these ideas are new, and none are panaceas or one-size-fits-all solutions. Each has been analyzed, debated, and deployed in the industry – some for decades. Typically, they have been financially benchmarked against supply-side expansions that were often viewed as less expensive, more profitable, and/or less administratively cumbersome. Under those conditions, these strategies did not frequently rise to become top priorities.

But these are not typical times for the industry. In the present moment, each of the five strategies deserves a stronger look.

Energy Efficiency (EE)

EE is a vast resource, but within the realm of electric utilities, it has been a modest, if popular, part of the resource mix. In the past few years, utility efforts have diverged sharply between beneficial electrification, which boosts electricity sales and improves EE, and traditional EE, which reduces sales revenue while increasing utility costs. Energy savings from the latter have been trending gradually downward, with savings from the 53 largest electric utilities dropping over 5% between 2018 and 2021.[66] Figure 6 illustrates trends in annual EE spending and resulting energy savings across all US electric utilities from 2013 to 2023.

FIGURE 6: US ELECTRIC UTILITIES, ENERGY EFFICIENCY ANNUAL SPEND AND ENERGY SAVINGS



Sources and notes: EE program spend (dark blue line) shown on left-hand axis and energy savings (green line) shown on right-hand axis. Data shown for all electric utilities that reported data to EIA. See EIA, "Form EIA-861," 2013–2023 data files, accessed April 21, 2025.

Obviously, any measures that reduce total customer energy spend, including non-electric fuel savings, should be under intensive consideration in states where rates are going up. It is not clear that electrification gets sufficient credit for reducing home heating or gasoline outlays. Also, it may be time to consider transitioning programs – or measure-specific cost-effectiveness rules away from individual programs – toward portfolios of measures. It is important to consider the co-benefits of greater efficiency, such as contributions to climate mitigation and other state policies and goals, alongside rate and bill impacts.

To this end, the American Council for an Energy-Efficient Economy (ACEEE) recommends that states adopt EE resource standards (EERS), state commitments to achieving an ambitious level of cost-effective savings. These standards set a target for total savings from EE over time. The ACEEE finds that the 26 states that have set these targets achieve about three times as much savings as states without targets in percentage terms (0.85% versus 0.28% of sales).[67] But whether a state chooses an EERS approach or some other pathway, there could not be a better time to seriously refresh and rescale utility efficiency efforts.

More generally, though, the entire scope of utility involvement in EE is due for a rethink. It may be best that EE should be more intensively integrated into sectoral decarbonization policies, such as building codes or the many relevant Inflation Reduction Act (IRA) programs that are not directly within utilities' control. Among its many provisions, the IRA allocates $8.8 billion in federal funding for home EE and electrification upgrades as part of the Home Energy Rebate program, and, as the ACEEE states, "Utility co-funding and collaboration will play a critical part in advancing the market transformation outcomes of the Home Energy Rebates."[68] It is also worth considering whether the slightly growing trend of utility partial or full ownership of behind-the-meter (BTM) efficiency assets should expand. It is a good time for bolder, out-of-the-box thinking.

Demand Flexibility (DF) and Virtual Power Plants (VPPs)

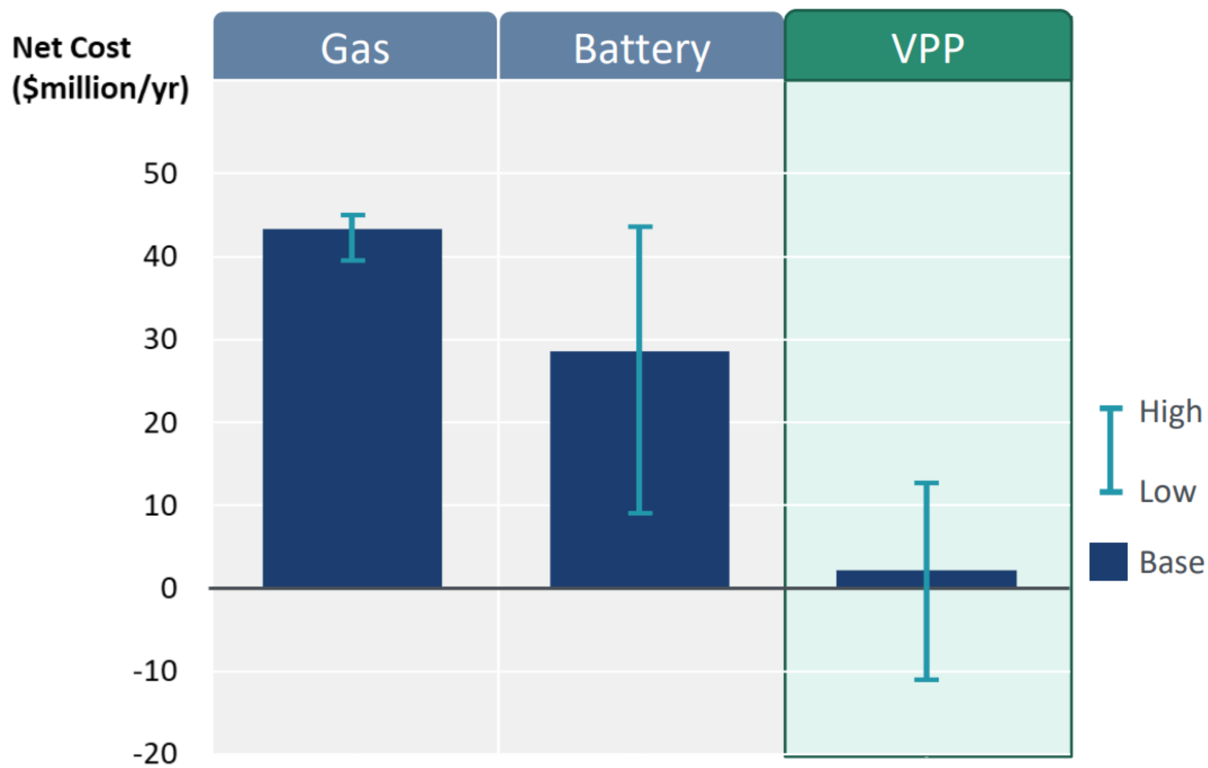
VPPs utilize consumer energy technologies – such as smart thermostats, batteries, EV chargers, grid-interactive water heaters, and building automation systems – to reduce, shift, or generate electricity when needed. VPPs essentially extend traditional demand response (DR) programs by providing these services around the clock and using a growing suite of technologies that not only control load but also produce electrons.

The untapped potential for VPPs is dramatic. Recent analyses by the US Department of Energy (DOE) and Brattle place the total addressable market for VPP deployment anywhere between 80 GW and 160 GW by the end of the decade.[69] That is more than three times the DR capability that currently exists in the US and could account for up to 20% of national peak electricity demand. A key driver of this potential is the exponential increase in the adoption of DERs, such as EVs and BTM batteries, that is expected in the coming decade.

In the current environment of sudden load growth and resource constraints, a critical feature of VPPs is the speed at which their capacity can be added to the system. VPPs are not subject to the interconnection queue delays that are currently limiting the deployment of large-scale resources; they essentially can be "built" at the speed at which customers are enrolled in a new program.[70] For example, in Ontario, Canada, EnergyHub enrolled 100,000 smart thermostat customers to build a 90 MW VPP in only six months.[71]

In addition to scaling quickly, VPPs offer resource adequacy at a fraction of the cost of conventional alternatives. Another recent Brattle study found that VPPs can provide the same level of resource adequacy as gas peakers and utility-scale batteries at only 40–60% of the net cost.[72]

FIGURE 7: NET COST OF PROVIDING 400 MW OF RESOURCE ADEQUACY



Sources and notes: Costs shown in 2022 dollars and reflect the range observed across all sensitivity cases. Costs are net of societal benefits (i.e., GHG emissions, avoidance, and resilience value) and power system benefits (energy, ancillary services, and T&D deferral value). See Ryan Hledik and Kate Peters, "Real Reliability: The Value of Virtual Power," The Brattle Group (May 2023).

One reason for the attractive economics of VPPs is that they leverage assets that have already been deployed at the grid edge for other reasons, such as cooling or transportation. Additionally, by being located downstream at the grid edge, VPPs are able to maximize cost savings by "stacking" a variety of value streams, sometimes including deferred distribution or transmission capex.

Greater reliance on VPPs will require utilities to get comfortable with a different way of managing the power grid. Orchestrating the control of hundreds or thousands of small-scale resources located across a utility service territory – while still ensuring the comfort and convenience of participants – is a complex undertaking. But that complexity can be overcome. Pilots can help to iron out operational challenges before scaling, and the software needed to manage DERs is rapidly increasing in sophistication.

Further, experience has shown that DF and VPPs can be a prominent and impactful resource in a utility's portfolio. For example, Otter Tail Power, an investor-owned utility in Minnesota, can reduce its system peak demand by 15% through a portfolio of programs that are utilized regularly for both economic and reliability benefits.[73] In Utah, Rocky Mountain Power has 20% of all residential customers enrolled in its programs, amounting to over half a gigawatt of capacity.[74] Based on interviews with companies such as these, a recent Brattle and LBNL study identified 30 strategies for increasing enrollment that are common among successful large-scale DF and VPP offerings.[75] Among these impactful – and highly feasible – strategies are a seamless customer sign-up process and well-structured financial incentives.

By paying consumers fairly rather than corporations for grid services, VPPs are a unique emerging opportunity for utilities to engage their customers in the energy transition. For any utility, no-regrets next steps are to better understand the achievable potential, define relevant use cases, and develop a blueprint that leverages the utility's current capabilities and infrastructure as an initial platform to deploy and scale VPPs.

Optimizing Distributed Energy Resources (DERs), Including Distributed Storage

Beyond VPPs, there may be other opportunities to improve distribution system throughput by improving distribution system design and operation. For example, advanced distribution control systems can sometimes significantly increase the ability of circuits to host distributed solar or EV chargers on a heavily loaded circuit. Proactive grid upgrades and guided DER placement (including storage) can reduce system buildout requirements on the local wires as well as upstream.

In some cases, utility ownership (behind or in front of the meter) may be useful to facilitate taking advantage of the full value stack that DERs can provide to the system, with benefits and costs allocated fairly. In its latest utility strategy review, consulting firm Deloitte recommended using DERs and "resilience resources" in combination with large plant builds, noting that, "[W]hile these [various DER] solutions may seem isolated, they are expected to continue to converge and could continue to create synergies for a more reliable and sustainable electricity infrastructure."[76]

Advanced Transmission and Distribution Technologies

An expanding suite of low-capital technologies is becoming better established as a means of increasing throughput on transmission and distribution systems. This technology suite includes dynamic line ratings (DLRs), advanced AC load controls, grid topology optimization, and other similar measures, as well as advanced or high-performance conductor (HPC) transmission cables. Together, the FERC has referred to these as "advanced transmission technologies" (ATTs).

FERC Commissioner Judy Chang recently emphasized the importance of using ATTs when drafting long-term transmission plans needed to meet expected load growth. Speaking at the Energy Bar Association's annual meeting, Chang stated: "Planners in transmission utilities absolutely should be using the cutting edge, best in class, advanced technologies when building out our network…[To] squeeze as much as possible out of existing grid and new grid, we need to use the best technologies."[77]

As with all other elements of the power network, ATTs must be fitted to each system properly in order to provide high value. As experience with these technologies grows, however, the benefits are becoming more evident. ATTs can dramatically increase transfer capacity with relatively small outlays, reduce congestion and production costs, and improve reliability and resilience. A recent Brattle report surveys the use of ATTs in a variety of settings and finds many highly successful actual-use cases, including:[78]

- HPCs that reduced losses by at least 20% in tests conducted by Hydro Quebec;
- The use of HPCs by Southern California Edison on a recent new line increased capacity by 40%, reduced construction time from 48 to 14 months, and eliminated tower replacement costs;
- Use of DLRs by ISO New England during the 2017–2018 "Bomb Cyclone" storm added 200 MW to a critical tie line between New York and New England, reducing congestion and reliability threats; and

- DLRs installed by Great River Energy paid for themselves in a single day in July 2024 when they enabled the utility to avoid curtailing excess wind generation and reduce operating costs.

Studies that go beyond these actual-use cases find even higher benefits for the use of ATTs to their full potential across larger systems. A 2016 study of advanced system controls across PJM found the potential for a 24% reduction in new line miles and 45% less reconductoring for savings of $267 million a year. The associated savings in production costs were even higher, at $623 MM/yr. A recent DOE *Pathways to Commercial Liftoff* report estimated that these technologies could reduce transmission and distribution infrastructure buildout by at least $5 billion over the next five years, even before accounting for production cost savings and lower carbon emissions.[79]

As the examples above suggest, there is already much work underway at utilities across the country to deploy ATTs as quickly and widely as possible. However, in some instances, there are barriers to the greater use of these solutions, such as regulatory policies or internal utility planning procedures, that make deployment more difficult. Moreover, any new technology or business process applied to the grid has to be introduced carefully (e.g., with cyber-protection in mind). Within these constraints, these solutions should be maximally supported by both policymakers and utilities.

Leveraging Other Capital Pools

Some utility policies that have been around for decades, such as state EE tax credits, have had the effect of funding energy system capital from sources other than utilities. Encouraging more utility reliance on non-rate base capital might seem like the ultimate heresy against the traditional utility model. Even so, utilities that have found their balance sheets under pressure are increasingly evaluating other funding sources.

Most recently, the Inflation Reduction Act of 2022 contains hundreds of billions of dollars of tax benefits that, among other effects, reduce the cost of utility-funded capital expenditures – and, therefore, rates – and shift the financing of the electric system away from power bills to tax bills. In addition, a number of utilities are receiving loan guarantees from the DOE that reduce the cost of large projects. On January 16, 2025, the DOE awarded $22.9 billion in guarantees to eight electric utilities for capital projects ranging from new distribution lines to large renewable plants.[80] The following day, the Department awarded a single $15 billion guarantee to Pacific Gas and Electric for a huge portfolio of projects.[81] Even in Texas – ordinarily a free-market state

– the government has established a $7.2 billion low-interest loan program to encourage developers to build more dispatchable resources and is already considering proposals totaling $5.34 billion.[82]

One could also view the recent moves by DC developers to install grid-connected (BTM) generation near their facilities as utility capex displacement. These moves may be primarily motivated by the goal of reducing time-to-connect, but – depending on the allocation of costs versus payments – they could have the effect of lowering the path of rates for everyone else by reducing utility cost per unit of sales.

VI. Conclusion

The collection of actions we are calling clean capital efficiency (CCE) is by no means the full four corners of a complete utility strategy. There are important additional elements in a full-scale strategy, including actions in the areas of supply planning and acquisition, transmission planning, workforce preparedness, and rate structures, just to name a few.[83] Helping customers to understand the benefits of electrification, including the large savings on fuel outlays, is a particular messaging challenge.

More generally, the ingredients of CCE should not be siloed but rather combined into fully integrated planning and execution. This in itself presents notable process challenges, as the differences in the types of resource options are significant, the underlying demand drivers are highly uncertain and changing quickly, and the trade-offs between options are analytically complex.

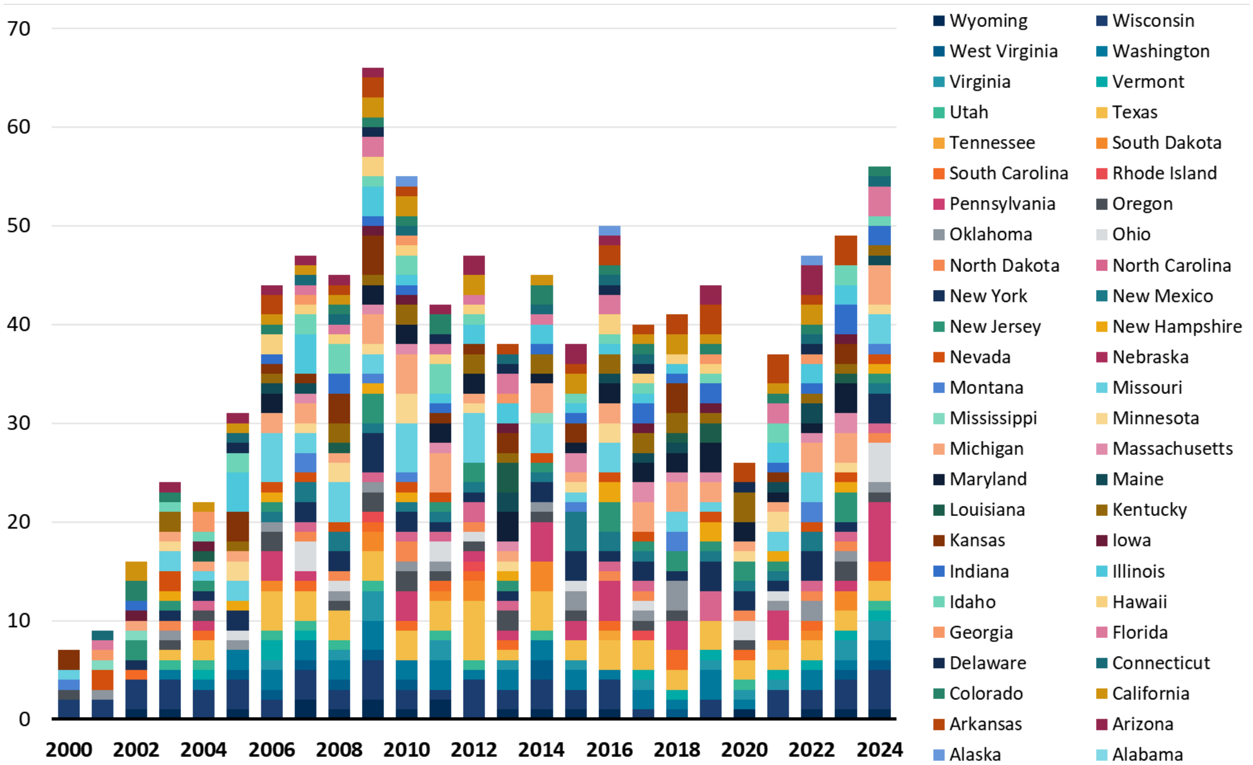
Nevertheless, business-as-usual resource planning will not suffice in the coming turbulent decade. David Springe, director of the National Association of State Utility Consumer Advocates, recently said that "regulators will have to have a vision for how to keep costs from spiraling and ultimately landing on utility customers." [84]

Utilities should bring their own vision of how to address these concerns to the table, and CCE can be an important part of the plan. It may not be especially easy to implement, but if done successfully, it will help ensure that the US power system remains reliable, affordable, clean, and financially stable while supporting a robust, clean, and growing national and global economy.

APPENDIX

Electric Utility Rate Proceedings: Recent History and Prospects

FIGURE A1: TOTAL NUMBER OF ELECTRIC RATE CASES PER STATE (2000–2024)

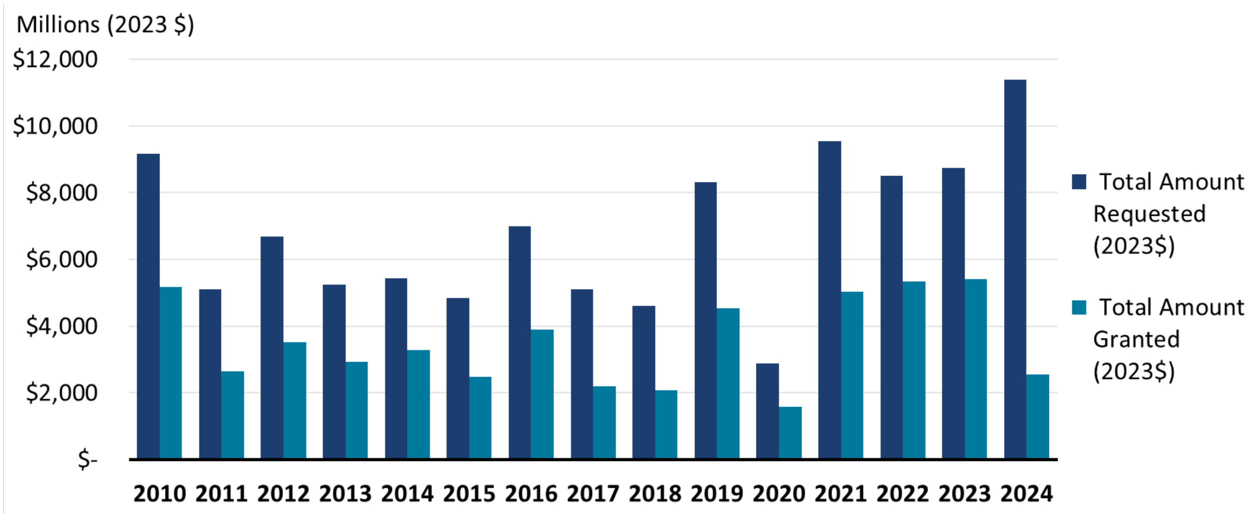


Source: S&P Capital IQ Pro data.

As shown in Figure A1, the number of state jurisdictional electric utility rate case filings in the US rose steadily from 2000 to 2007, marking the end of a quieter era when costs, demand, and rates were all relatively stable. Since then, rate filings have been somewhat cyclical. While the pace of rate case filings increased significantly in 2023 and 2024 when compared to activity in recent years, this was not the most active filing period in the last 25 years. The year 2009 was the most active year for rate case filings since 2000, likely reflecting a delayed response to the crash of 2008.

However, the number of annual cases, while important, does not tell the whole story. As shown in Figure A2, when adjusted for inflation, the aggregate amount requested from 2021 to 2024 was roughly $35.5 billion (in 2023 real dollars). This is more than the total aggregate amount granted in the previous 10 years combined.

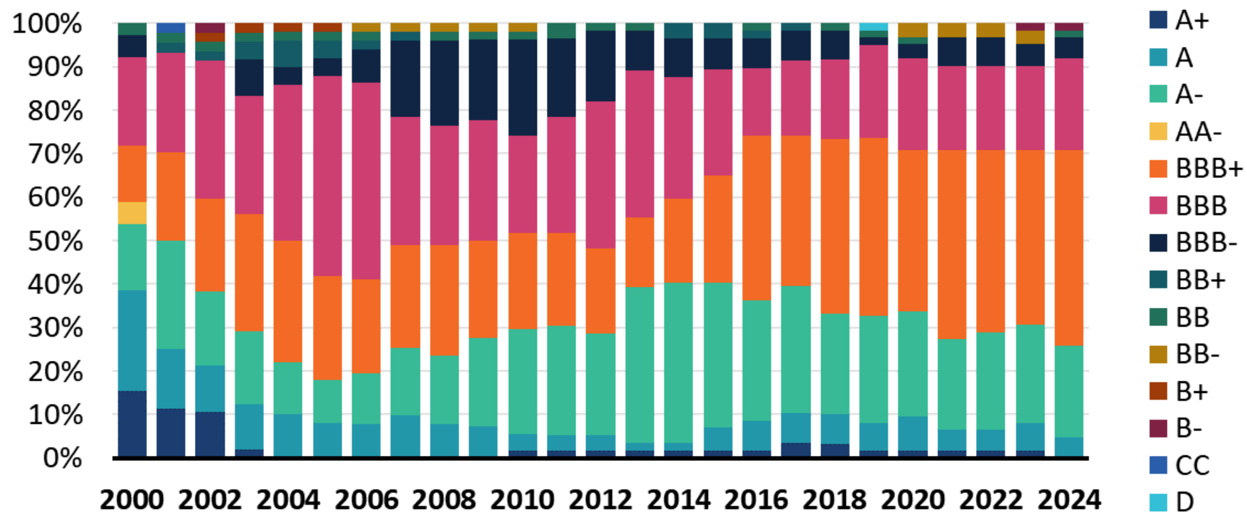
FIGURE A2: AGGREGATE ANNUAL AMOUNT REQUESTED IN ELECTRIC RATE CASE FILINGS (2010–2024)



Source: S&P Capital IQ Pro data.

The industry's average credit quality has also declined over the last 25 years. The phenomenon is most evident at the top end. As shown in Figure A3, in 2000, approximately 59% of the industry held 'A' category ratings (AA- to A+), whereas in 2024, the percentage of A-rated electric utilities was reduced by more than half to approximately 26%. At least until recently, the middle of the ratings distribution had shifted slightly positively from BBB to BBB+, and the overall credit picture was decent. However, this picture is likely to change as the industry moves forward in the new era.

FIGURE A3: S&P RATINGS FOR US-REGULATED ELECTRIC UTILITIES (2000–2024)



Source: S&P Global Ratings data.

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[47] It is unlikely that data center load growth will continue to grow at double-digit annual compound growth rates for a decade or more. As DeepSeek has demonstrated, advances in model training, computational efficiency, chip cooling, and other surprises are quite likely to moderate data center growth. In addition, new carbon-free power sources such as small modular fission reactors (SMRs) and fusion generators may be commercially viable by then, expanding our options. But most of this will not help the industry conquer the next decade of growth, some of which is already sitting in request-for-service queues across the country. For this period, a different strategy is needed. In summer 2024, the peak demand for the entire New York Independent System Operator (ISO) was only 29 GW; see New York ISO, "NYISO Summer 2024 Hot Weather Operations" (November 15, 2024), p. 12, https://www.nysrc.org/wp-content/uploads/2024/11/7.3.3-Summer-2024-NYISO-Hot-Weather-Operating-Conditions-EC-Final-Attachment-7.3.3.pdf.

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[49] McKinsey & Company, "How data centers and the energy sector can sate AI's hunger for power" (September 17, 2024), https://www.mckinsey.com/industries/private-capital/our-insights/how-data-centers-and-the-energy-sector-can-sate-ais-hunger-for-power#/.

[50] Stephen Byrd, Personal Communication, Morgan Stanley (December 16, 2024). Under Byrd's leadership, Morgan Stanley has published several important reports analyzing data center load.

[51] Shoko Oda, et al., "AI to Prop Up Fossil Fuels and Slow Emissions Decline, BNEF Says," *Bloomberg* (April 15, 2025), https://www.bloomberg.com/news/articles/2025-04-15/ai-to-prop-up-fossil-fuels-and-slow-emissions-decline-bnef-says?cmpid=BBD043025_GREENDAILY&utm_medium=email&utm_source=newsletter&utm_term=250430&utm_campaign=greendaily.

[52] NERC forecasts summer peak demand to increase by over 132 GW and winter peak demand to increase by 149 GW, see NERC, "2024 Long-Term Reliability Assessment," p. 31.

[53] Per LBNL researchers, between 2020 and 2024, US capacity has increased by approximately 25 GW/year, see Gorman et al., "Grid Connection Barriers to Renewable Energy Deployment in the United States," *Joule*, Vol. 9, Issue 2 (February 19, 2025), p. 5, https://www.sciencedirect.com/science/article/pii/S2542435124005038; for

Texas data see Doug Lewin, "Can We Triple Power Sources in 15 Years?," Texas Energy and Power Newsletter (January 13, 2025), https://www.douglewin.com/p/can-we-triple-power-sources-in-15.

[54] Historically only about 20% of the capacity in the queue has been completed, but that would yield sufficient power to meet NERC's forecast provided that sufficient controllable resources were also built; see Gorman et al., "Grid Connection Barriers," p. 3.

[55] Gorman, et al., *op cit.*

[56] NERC, "2024 Long-Term Reliability Assessment," p. 24, https://www.sciencedirect.com/science/article/pii/S2542435124005038.

[57] Quoting John Moura, NERC Director of Reliability Assessments and Planning Analysis; see Robert Walton, "Explosive Demand Growth Puts More than Half of North America at Risk of Blackouts," *Utility Dive* (December 18, 2024), https://www.utilitydive.com/news/explosive-demand-growth-blackouts-NERC-LTRA-reliability/735866/.

[58] Edison Electric Institute, "Industry Capital Expenditures" (2024), p. 6, https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Finance-And-Tax/Industry-Capital-Expenditures.pdf.

[59] *Ibid.*

[60] Storm and wildfire risks led to 21 utility credit downgrades since 2018. Two S&P analysts write: "Transformative change is well underway in the U.S. power sector, and balance sheets are increasingly under pressure to cope with heavy capital investments both to decarbonize and harden the grid. Utilities are also increasingly deploying capital to update the transmission grid to accommodate the rapid increase in new renewable generation and load growth. While all these issues are important to credit quality, we believe that wildfire risks may be the most difficult to manage for the most exposed IOUs due to contingent litigation risks." See Loughlin, Kyle and Daria Babitsch, "Wildfire-Exposed U.S. IOUs Face Increasing Credit Risk Without Comprehensive Solutions," S&P Global (November 6, 2024), https://www.spglobal.com/ratings/en/research/articles/241106-wildfire-exposed-u-s-investor-owned-utilities-face-increasing-credit-risks-without-comprehensive-solutions-13297812#:~:text=Canada%2C%20EMEA%2C%20APAC-,Wildfire%2DExposed%20U.S.%20Investor%2DOwned%20Utilities%20Face%20Increasing,Credit%20Risks%20Without%20Comprehensive%20Solutions&text=For%20investor%2Downed%20regulated%20utilities,deterioration%20is%20a%20growing%20reality. Additional useful material is in S&P Global, "A Storm Is Brewing: Extreme Weather Events Pressure North American Utilities' Credit Quality" (November 9, 2023), https://www.spglobal.com/ratings/en/research/articles/231109-a-storm-is-brewing-extreme-weather-events-pressure-north-american-utilities-credit-quality-12892106.

[61] K. Kaufmann, "Is Public Power a Better Model for Meeting Data Center Demand?," *RTO Insider* (December 12, 2024), https://www.rtoinsider.com/93800-is-public-power-better-model-data-center-demand/#/.

[62] Stanley Dunlap, "Georgia Power says data center growth will cause electricity demands to triple in next decade" (December 2, 2024), https://georgiarecorder.com/2024/12/02/georgia-power-says-data-center-growth-will-cause-electricity-demands-to-triple-in-next-decade/. See also Doug Lewin, "Can We Triple Power Sources in 15 Years?"

[63] Tom Kleckner, "ERCOT Faces Uphill Battle to Meet Large Loads," *RTO Insider* (January 6, 2025), https://www.rtoinsider.com/94968-ercot-faces-uphill-battle-meet-large-loads/. See also Doug Lewin's newsletter for doubts concerning Texas' plans, "The Texas Energy and Power Newsletter" (2024), https://www.douglewin.com/.

[64] Our work modeling pathways to net zero indicates that, in some cases, adding modest amounts of low-capacity-factor gas generation that can later be converted to decarbonized fuels can unlock large amounts of added near- and medium-term carbon-free energy. Such additions are part of a rapid, feasible path to decarbonization.

[65] Joe DeLosa III et al., "Regulation of Access, Pricing, and Planning."

[66] Mike Specian et al., "2023 Utility Energy Efficiency Scorecard," ACEEE (August 2023), p. 8, https://www.aceee.org/sites/default/files/pdfs/U2304.pdf. According to ACEEE Director Steven Nadel, the (yet unpublished) 2024 data indicates a welcome upturn in utility EE spending (unpublished communication, Steven Nadel, January 2025).

[67] Jasmine Mah et al., "Next Generation Energy Efficiency Resource Standards Update," *ACEEE* (January 2025), pp. iv, 1, https://www.aceee.org/research-report/u2501.

[68] Jennifer Amann, "Residential Retrofit Programs to Complement Federal Rebate Programs Series, Brief 3: Leveraging Federal Investments for Long Term Market Transformation," *ACEEE* (April 28, 2025), Residential Retrofit Programs to Complement Federal Rebate Programs Series, Brief 3: Leveraging Federal Investments for Long Term Market Transformation | ACEEE.

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[74] Ryan Hledik et al., “Distributed Energy, Utility Scale: 30 Proven Strategies to Increase VPP Enrollment,” prepared for US DOE (December 2024), https://emp.lbl.gov/publications/distributed-energy-utility-scale-30.

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[78] Bruce Tsuchida et al., *Incorporating GETs and HPs into Transmission Planning Under FERC Order 1920*, prepared for ACORE (April 2025), https://www.brattle.com/insights-events/publications/brattle-experts-highlight-the-pitfalls-and-opportunities-of-alternative-technologies-under-ferc-order-1920-in-new-report-prepared-for-acore/. See also *Unlocking the Queue with Grid-Enhancing Technologies,”* The Brattle Group, prepared for the WAAT Coalition (February 2024), https://www.brattle.com/insights-events/publications/grid-enhancing-technologies-shown-to-double-regional-renewable-energy-capacity-according-to-study-by-brattle-consultants/.

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[80] Brad Plumer, “Energy Dept. Backs $22 Billion in Loans to Reshape U.S. Power Grids,” *The New York Times* (January 16, 2025), https://www.nytimes.com/2025/01/16/climate/us-utilities-loan-energy.html.

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