LET THE SUN IN: CLEAN ENERGY IS THE CHEAPEST WAY TO MEET RISING DEMAND

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EXECUTIVE SUMMARY

Drive across Texas, and you'll see a building boom of unprecedented proportions. Dozens of giant data centers are under construction or recently finished; each one costs billions of dollars and consumes more power than a small city.

Texas's electricity demand is growing faster than any other state, up 20 percent in just five years, driven mostly by data centers and the state's rapid population growth. On the hottest day of the 2026 summer, the state's primary electricity market operator expects to use over 90 gigawatts (GW) of power, an increase of nearly 15 GW. That increase is more than New York City's entire demand on a hot summer day.

Competition and free enterprise reign supreme in Texas, and the state's electricity market has few barriers to entry. The market has responded by building a modern, efficient, and reliable portfolio of resources.[1] Since 2020, Texas's electricity market has added 28 GW of solar, 15 GW of utility-scale batteries, 15 GW of wind, and just 4 GW of natural gas power plants. That total is nearly a quarter of all new capacity added to the grid in the U.S. in the same time period, showing what happens when the cheapest, fastest-to-deploy resources are freed to meet growing demand.

Demand is accelerating nationwide, and many other states are running headlong into electricity system constraints. Abrupt and unpredictable federal actions are disrupting even the best-laid investment plans by forcing deteriorating coal plants to stay online, investing in expensive new gas plants, repealing tax credits for wind and solar power, and stalling development of planned and already under-construction clean power projects.

This policy approach is fundamentally at odds with the economic reality—clean energy continues getting cheaper and is the most economic option.[2]

To better understand how to best meet growing demand in today's changing landscape, we conducted a national analysis examining two futures for meeting electricity demand through 2030: one where the United States doubles down on fossil fuels as demand accelerates, consistent with the current federal policy approach, and another where America takes full advantage of clean energy to meet growing electricity use.

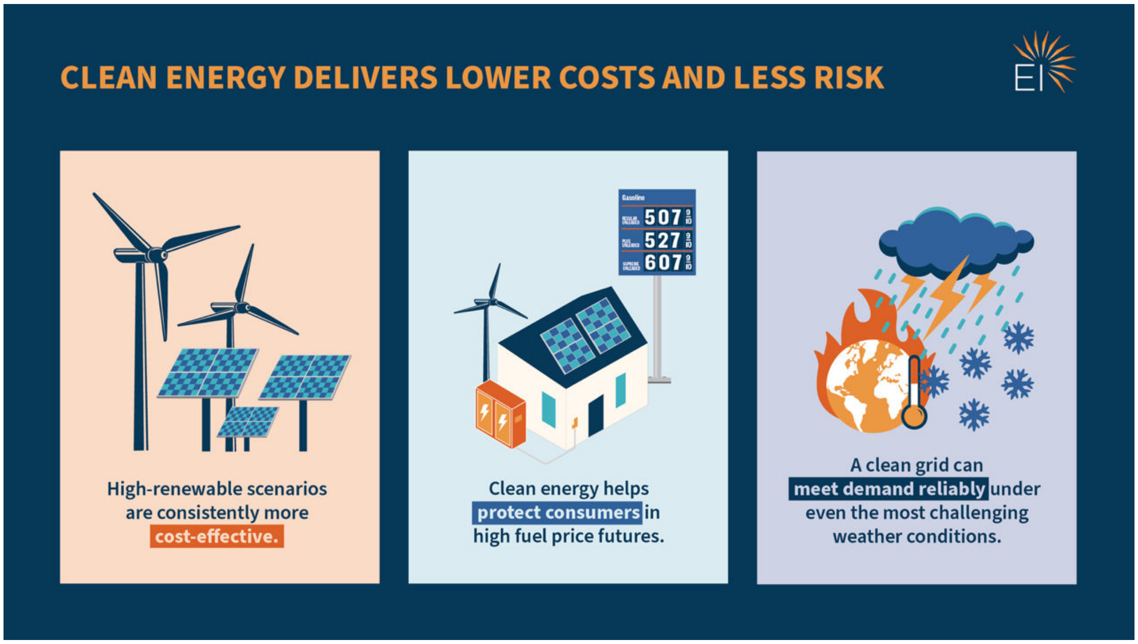
We found that meeting America's expected demand growth with a fossil fuel-heavy approach will add $29.7 billion annually to customer bills by 2030. However, the clean energy scenario reduces overall costs to meet load growth by $5.1 billion annually that year compared to a high fossil scenario, a savings of 17 percent.

These costs will be passed through to both existing and new customers, and policymakers in many states are working to ensure that large, rapidly growing customers like data centers pay their fair share.

This means the cost of meeting America's expected electricity demand growth will be significant, but using a clean energy portfolio will reduce the overall system cost. Accelerating solar, wind, and energy storage deployment will protect customers from high costs, price shocks, and pollution. Doubling down on fossil fuels would be more expensive, putting customers and communities at financial and environmental risk.

A spike in coal and gas prices like the U.S. saw in 2022—which could happen again due to events like booming electricity demand, geopolitical instability, and rising LNG exports—would push up electricity costs $40.5 billion per year under a fossil fuel-heavy scenario. Clean energy would reduce this spike by $8.4 billion, yielding total savings of $13.5 billion per year compared to relying on fossil fuels.

Our analysis shows the U.S. can meet growing demand with clean energy, and a clean, resilient grid can reliably meet demand under even the most challenging weather conditions.



This is a near-term outlook in a time of rapid transition. The electricity industry is making decisions today that will determine what gets built by 2030, and the stakes are high to get it right, so our policy recommendations looks toward that window for integration into the utility planning, permitting, and contracting process.

How America chooses to meet this moment will have long-term implications. If we prioritize affordability, we can meet the surging electricity needs of data centers and other growing loads in a way that costs less, produces less air pollution and contributes less to global climate change. If we fail to grasp this opportunity, consumers will instead be saddled with high costs and dirty air.

Key Analytical Findings:

- **Meeting demand growth primarily with fossil fuels will cost $29.7 billion per year by 2030. Accelerating clean energy can save consumers $5.1 billion per year by 2030, reducing the cost of meeting demand growth by 17 percent relative to a pathway that doubles down on coal and gas.**
- **Clean energy insures against volatile fossil fuel price risks. In a scenario that doubles down on coal and gas, a coal and gas price spike increases electricity costs by $40.5 billion per year relative to the base price case. Clean energy reduces this spike by $8.4 billion, resulting in total savings of $13.5 billion compared to the high fossil plan.**
- **Accelerating clean energy deployment is a no-regrets strategy, lowering costs even if anticipated demand growth does not arrive.**
- **The U.S. can meet growing demand with clean energy while building a reliable and resilient grid. A clean grid can meet demand reliably under even the most challenging weather conditions.**
- **A more affordable clean electricity grid is not a foregone conclusion. Policymakers can make it a reality by improving how we plan, procure, and build new resources.**

CLEAN ENERGY IS THE CHEAPEST WAY TO MEET SURGING DEMAND

Meeting demand growth primarily with fossil fuels will cost $29.7 billion per year by 2030. Accelerating clean energy can save consumers $5.1 billion per year by 2030, reducing the cost of meeting demand growth by 17 percent relative to a pathway that doubles down on coal and gas.

Two paths forward for the grid

Our electric grid is at a crossroads. Demand is growing faster than it has in decades but is running headlong into the constraints and slow pace of change of the electricity system. Abrupt policy shifts are disrupting even the best-laid investment plans. New large-scale generation of all kinds—including gas, wind, solar, battery storage, and nuclear—face barriers to speedy deployment. Some large customers like data center developers are increasingly taking matters into their own hands, proposing to bypass the grid by building their own power generation—primarily new gas plants, at least for now.[3]

Throughout 2025 and 2026, the federal government articulated a policy approach to meeting growing electricity demand that included blocking aging coal plants from retiring,[4] significantly investing in new gas plants,[5] removing tax credits for wind and solar energy, and impeding the development of planned and under-construction power projects via unprecedented permitting disruptions[6,7]. This policy approach is at odds with the economic reality—clean energy costs continue to fall, and solar and energy storage account for over three-quarters of new capacity additions expected this year.[8]

This paper models two scenarios for the near future of the grid through 2030. In one—the *high fossil scenario*—we reflect the current federal policy direction and model a pathway where clean energy growth is restricted, and demand growth is met primarily by retaining coal and building new gas. In the other—the *clean energy scenario*—we continue to deploy wind, solar, and energy storage at levels consistent with recent trends in deployment growth.[i]

We then compare each of these scenarios to an estimated cost of electricity generation in 2025 to assess the cost of meeting demand growth and reach an important conclusion: The U.S. can meet all forecasted load growth through 2030 with clean power while

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[i] In our clean energy scenario, we limit total solar capacity to 500 GW by 2030 and wind to 233 GW by 2030, including existing capacity. This is roughly consistent with 25 percent year over year growth in deployment starting from expected 2026 deployment, growing each year until 2030 for solar. For wind, this implies an annual growth rate of 12 percent from expected 2026 deployment.

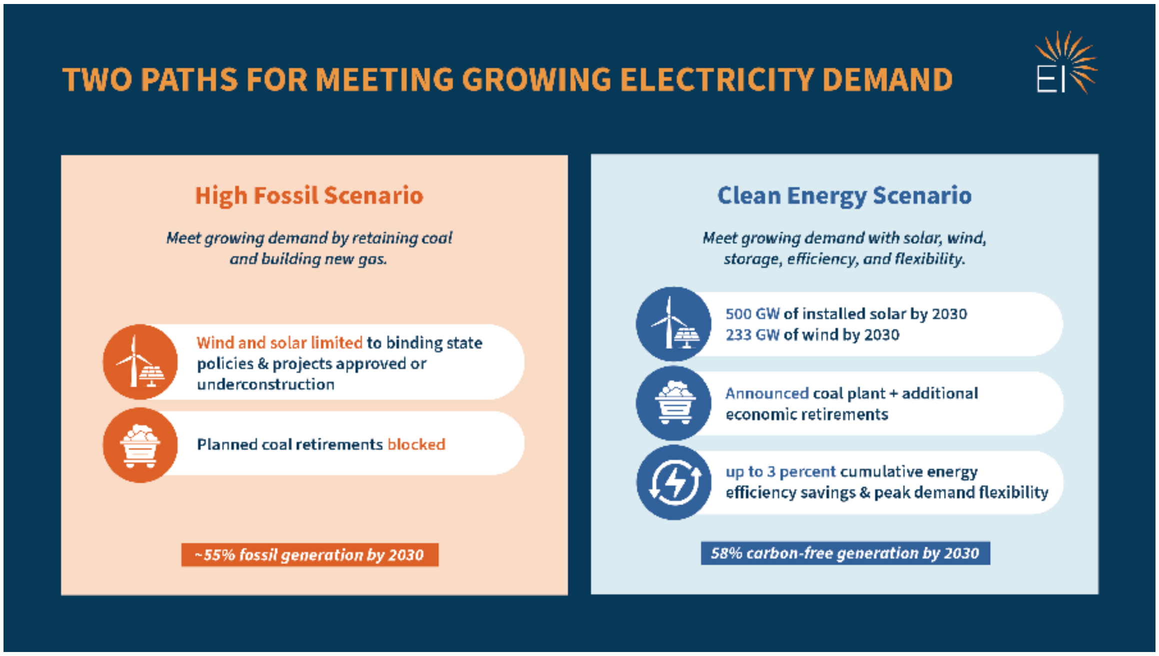
Figure 1. Estimates of U.S. electricity load growth through 2040

reducing coal and gas use for existing loads. And this clean energy pathway will cost less than doubling down on coal and gas to meet growing demand.

This study uses up-to-date, realistic estimates of grid conditions and opportunities. Both scenarios represent current laws, recent expectations of demand growth and fuel costs, and updated assumptions of resource costs. These updated assumptions include lower battery storage costs, increases in wind energy costs, and increases in natural gas plant costs amid supply chain constraints.

We also limit the application of federal investment and production tax credits to 175 GW of solar and 23 GW of wind based on recent estimates of the capacity of projects that will meet the deadline to commence construction this summer and qualify for tax credits.[9,10]

Alongside solar, wind, and energy storage, our clean energy scenario leverages resources on the demand side as part of the portfolio—incremental energy efficiency and demand flexibility. Demand-side resources help address rising costs and deployment constraints facing many supply side resources.



TWO PATHS FOR MEETING GROWING ELECTRICITY DEMAND

High Fossil Scenario

Meet growing demand by retaining coal and building new gas.

- Wind and solar limited to binding state policies & projects approved or underconstruction
- Planned coal retirements blocked

~55% fossil generation by 2030

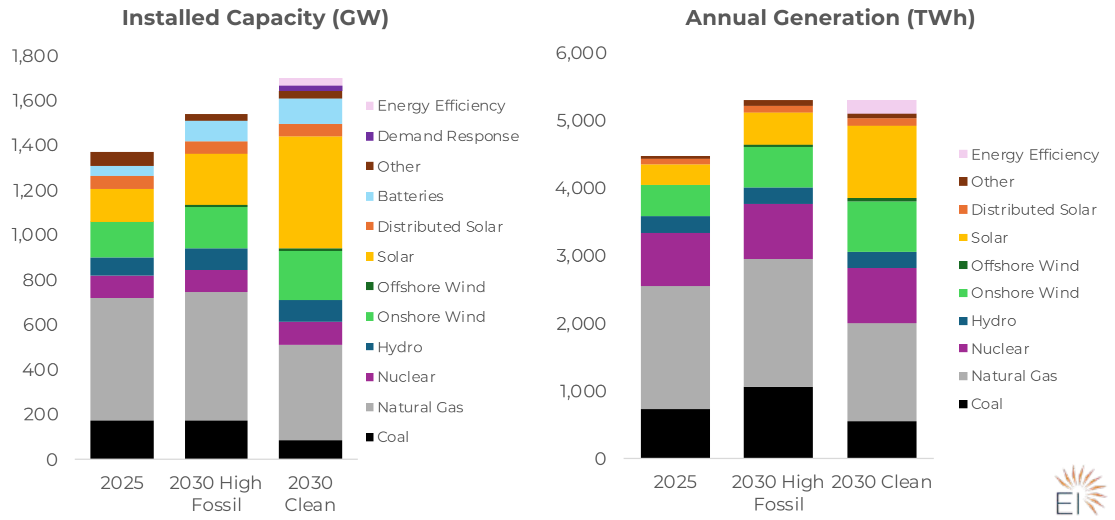
Clean Energy Scenario

Meet growing demand with solar, wind, storage, efficiency, and flexibility.

- 500 GW of installed solar by 2030
  233 GW of wind by 2030
- Announced coal plant + additional economic retirements
- up to 3 percent cumulative energy efficiency savings & peak demand flexibility

58% carbon-free generation by 2030

Figure 1. Capacity and generation in 2025 vs. 2030 High Fossil and Clean scenarios

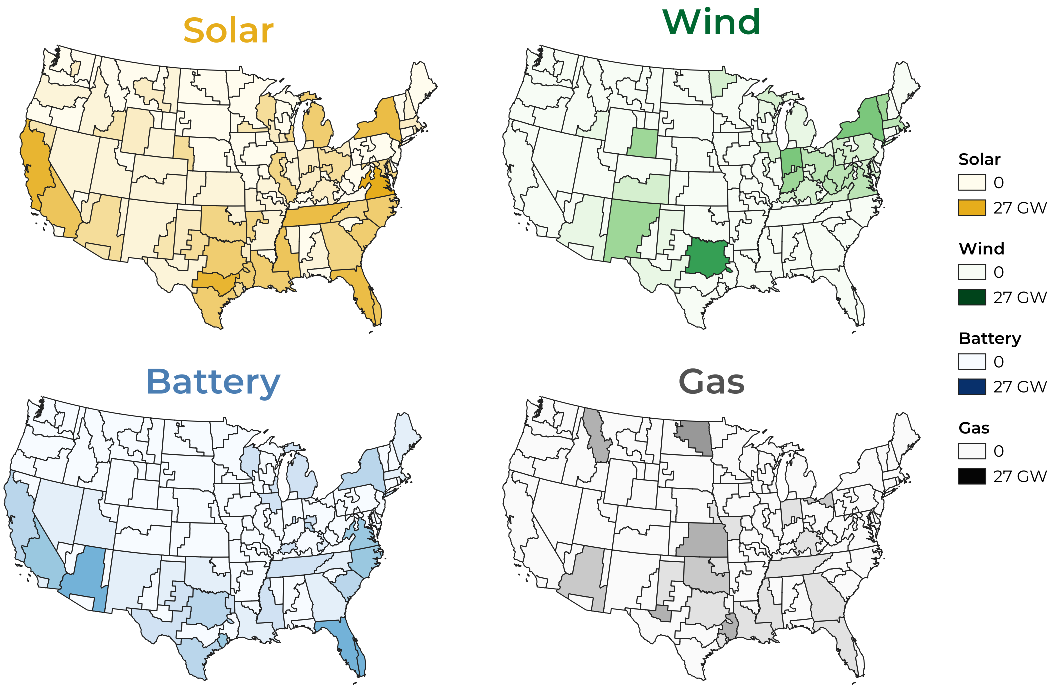


In addition to comparing the costs of these two scenarios under our base assumptions, we evaluated the performance of these systems when things don't turn out as expected. The rate of new demand growth and the price of fossil fuels like coal and gas are two of the biggest sources of uncertainty, so we conducted sensitivity analyses that looked at cases with spiking fuel prices and lower levels of demand growth.

The added batteries, wind, and solar resources work together with the other resources on the grid, including existing gas and coal capacity, to ensure the grid meets demand at every hour, in every region of the country. Importantly, the clean scenario requires less fossil capacity, and means coal and gas plants run less often than the high fossil case, with only 2,000 terawatt-hours (TWh) generated by coal and gas compared to 2,949 TWh in the high fossil case, a reduction of over 32 percent.

The clean energy scenario has more total installed capacity than the high fossil scenario but still produces significant cost savings. This is no accident—robust solar and wind deployment reduces how much coal and gas plants run, saving fuel costs, and batteries meet demand alongside existing power plants when solar and wind are not available. This scenario generates 38 percent of annual electricity from fossil fuels, with carbon-free sources reaching 62 percent by 2030.

Figure 2. New capacity additions by resource type and model zone – Clean scenario



A clean energy system generates the electricity needed to meet growing load and requires less fossil generating capacity. The clean scenario retains 511 GW of coal and gas capacity, 233 GW less than the 745 GW of coal and gas capacity in the high fossil case. The capacity decrease from gas and coal is similar—coal capacity is reduced to 84 GW from 172 GW in the high fossil pathway, while gas capacity is down to 427 GW, from 473 GW.

While the clean energy case also adds a similar amount of new gas capacity as the high fossil scenario, it is far outweighed by the economically driven retirement of aging, inefficient resources—mainly coal and some gas-powered steam turbines.

In the clean pathway, demand response cuts peak demand by 26 GW and energy efficiency shrinks it another 33 GW, reducing the need for conventional generators and batteries. Efficiency reduces demand in 2030 by 186 TWh, decreasing system costs.[ii]

[ii] Figure 1 and Table 2 summarize these results. 2025 installed numbers represent the operating capacity reported by EIA at the end of 2025. Demand response and energy efficiency totals reflect the new demand response and energy efficiency capabilities added between 2025 and 2030 in the model, while other resources reflect total installed capacity in 2030. To estimate the costs of the system in 2025 to meet load growth in 2030, we recreated the 2025 system in the model.

Table 1. Summary of modeling scenarios

<table>
<tr><th></th><th></th><th colspan="2">Scenario</th></tr>
<tr><th></th><th></th><th>High Fossil</th><th>Clean Energy</th></tr>
<tr><td rowspan="10">Model Assumption</td><td>New Clean Energy</td><td>Limited to binding state clean energy policies and projects that are approved or under construction</td><td>Reach 500 GW of installed solar and 233 GW of wind by 2030. These values are based on annual increases in deployment from 2025 to 2030 consistent with recent deployment growth rates.</td></tr>
<tr><td>Demand-Side Resources</td><td>No incremental efficiency or shiftable demand above baseline demand forecast</td><td>3.75% cumulative energy efficiency savings and shiftable demand up to 3% of peak demand</td></tr>
<tr><td>Coal and Gas Retirements</td><td>Planned coal and gas plant retirements blocked</td><td>Announced coal and gas plant retirements, plus additional economic retirements</td></tr>
<tr><td>New Gas</td><td colspan="2">Limit of up to 58 GW of new gas additions, based on expected turbine availability through 2030. New gas plant costs based on latest cost data for new gas plants under development by utilities across the country.</td></tr>
<tr><td>New Clean Energy Costs</td><td colspan="2">Based on NLR ATB estimates with regional adjustments. To align best with latest real-world costs, we assume ATB advanced case for batteries, ATB moderate case for solar, and ATB conservative case for wind.</td></tr>
<tr><td>Clean Energy Tax Credits</td><td colspan="2">New storage remains eligible for investment tax credit. Solar and Wind tax credits only available for up to 175 GW of solar and 23 GW of wind, based on estimates of projects that have met qualification deadlines. Some of this capacity is left unfinished in the High Fossil case.</td></tr>
<tr><td>Demand Growth</td><td colspan="2">Based on ICF forecast, approximately 21% growth in total electricity demand by 2030, 15% growth in peak demand</td></tr>
<tr><td>Fuel Costs</td><td colspan="2">Based on 2021-2025 average fuel costs by state. National natural gas futures for 2030 were found to align with this average of recent years.</td></tr>
<tr><td>Low Demand Case</td><td colspan="2">33% of base demand growth realized</td></tr>
<tr><td>High Fuel Cost Case</td><td colspan="2">Based on 2022 fuel costs, reflecting a recent fuel price shock</td></tr>
</table>

Table 2. Installed capacity and power generation by fuel type in High Fossil and Clean scenarios

	Installed Capacity			**Annual Generation**		
	2025 Actual	**2030 High Fossil Scenario**	**2030 Clean Scenario**	**2025 Actual**	**2030 High Fossil Scenario**	**2030 Clean Scenario**
Coal	171 GW	172 GW	84 GW	737 TWh	1,062 TWh	546 TWh
Gas	548 GW	573 GW	427 GW	1,807 TWh	1,888 TWh	1,454 TWh
Solar	148 GW	228 GW	500 GW	296 TWh	469 TWh	1,076 TWh
Wind	158 GW	193 GW	233 GW	464 TWh	630 TWh	786 TWh
Battery	42 GW	91 GW	114 GW	0 TWh	0 TWh	186 TWh
Efficiency		0 GW	33 GW			
Demand Response		0 GW	26 GW			

Note: Efficiency and demand response are shown as incremental from 2025 levels.

MODELING APPROACH

We modeled our core scenarios and sensitivity cases using the Switch open-source capacity expansion model. Switch co-optimizes construction, retirement and operation of generators and transmission to minimize costs while maintaining a reliable power supply. The dataset used for this study defines a 134-region model of the continental U.S., based on the National Lab of the Rockies (NLR) ReEDs model. For this modeling, we focused on a single study year—2030.

Input data was drawn from public sources using the PowerGenome data pipeline, with significant updates to reflect recent trends and market dynamics. For most resources, new-build generator costs come from NLR's Annual Technology Baseline. Fuel price forecasts were the average of state-level costs for power production in 2021–25 from the U.S. Energy Information Administration (EIA)'s State Energy Data System and Electric Power Operational Data products. Data on existing power plants come from EIA's Form 860 and 860M databases, supplemented with additional retirement data from Global Energy Monitor's Global Coal Plant Tracker. State clean energy standards were taken directly from ReEDS inputs.

We developed forecasts of peak and average electricity demand in each region based on maps published publicly by ICF. This forecast is consistent with utility and grid operator forecasts. We obtained hourly load shapes for 2023 from the NLR Electrification Futures Study (based on 2007-13 data) and then rescaled them according to the growth in peak and average load projected by ICF through 2030.

We supplemented resource cost data from NLR ATB with updated natural gas plant costs from GridLab/Halcyon that reflect the recent rise in new gas plant costs for plants under development by utilities. Based on a review of recent research and industry reports, we chose the "Moderate" ATB case for solar power costs, the "Conservative" case for wind, and the "Advanced" case for energy storage to align with recent industry data and cost expectations.

More details are included in Appendices 1 and 2. The software and data used for this study can be downloaded from https://github.com/EnergyInnovation/Switch-US-Load-Growth-2030.

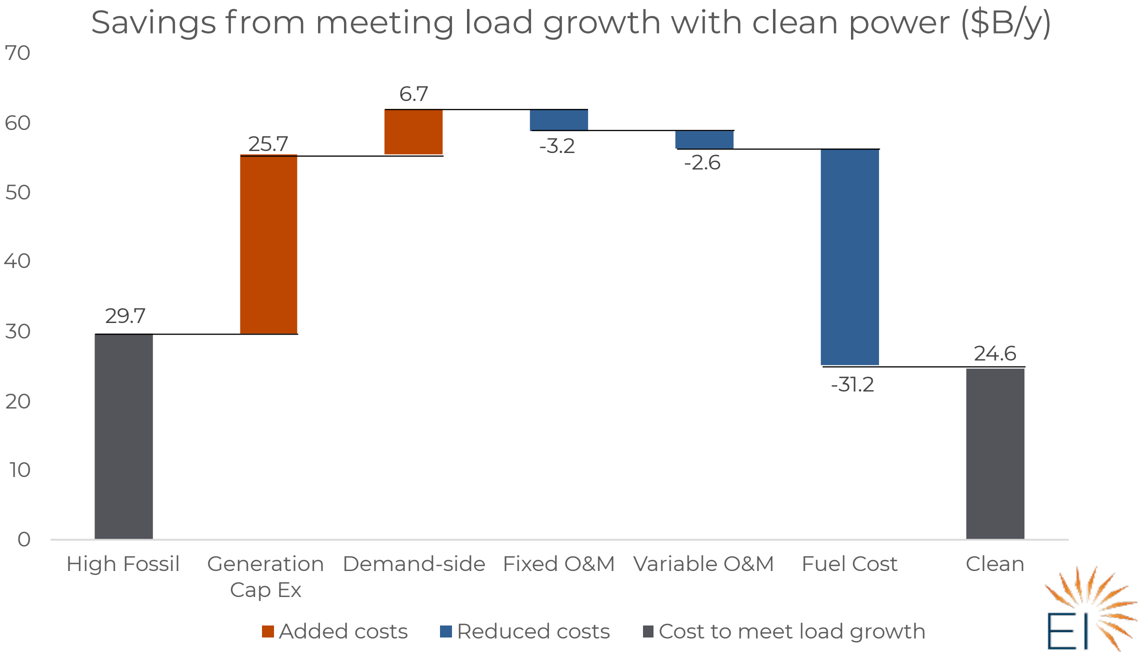
Clean energy costs less

Meeting demand growth with new clean energy saves electricity customers money. In the high fossil scenario, the cost to meet the new load that arrives between 2025 and 2030 totals $29.7 billion per year in 2030. The clean energy scenario costs $5.1 billion less per year in 2030 (Figure 3), reducing the cost of meeting growing demand by 17 percent.

These savings are primarily driven by $31.2 billion in fuel cost reductions, as well as avoided operation and maintenance (O&M) costs from aging coal and gas plants that are no longer economic to continue running. Since utilities typically pass fuel costs directly through to customer bills, reducing the amount of fuel used translates directly into savings, based on average fuel prices that will go up significantly if fuel prices spike, as explored later in this report. These savings are partly offset by increased capital investment required for clean energy systems, including the upfront costs of new solar, wind, and battery energy storage projects and the cost of demand-side investments like energy efficiency and demand flexibility.

While the ongoing maintenance costs of new clean energy resources are also included, solar, wind, energy storage, efficiency, and flexibility have no fuel costs to operate—and fuel savings more than pay for the upfront and ongoing costs of these resources.

Figure 3. Sources of savings between High Fossil and Clean scenarios



A clean energy system leverages the demand side

The cheapest and fastest way to meet rising demand on the grid is demand-side solutions like energy efficiency and demand flexibility. Typically, the grid is planned to ensure it has enough supply for the few hours per year when demand is highest. This means some power plants, transmission lines, and distribution lines are only used a small percentage of the time, creating an outsized cost relative to their contributions.

Anything that can help reduce or shift demand during those peak times can have a substantial impact on reducing overall costs. Energy efficiency can reduce demand on a permanent basis—for example, better insulation and more efficient heating and cooling systems mean buildings use less energy during hot summer afternoons or cold winter storms. Demand flexibility can actively shift when energy is used—for instance, by scheduling electric vehicles to charge when power is cheap and the grid is less constrained, or by making small, automated adjustments to temperature settings on smart thermostats.

These solutions are the fastest to implement because they don't require new power plants, and they help mitigate the risk of supply shortages if the industry cannot overcome gas turbine supply constraints and clogged interconnection queues. Pairing flexible solutions with new power plants can decrease overall costs significantly.

Efficiency and demand flexibility are not new solutions—utilities have long used energy efficiency to help reduce consumer costs, and even demand response programs have been around for decades. Now, these solutions are becoming increasingly desirable both for cost-savings as electricity rates rise and distribution grid upgrades come due, and for their ability to provide headroom on the grid in a short period of time.

Simultaneously, the technologies that can provide demand response including batteries, rooftop solar, and smart appliances, along with the software to aggregate and control them, are maturing quickly in deployment and sophistication. The U.S. Department of Energy (DOE) found in 2023 that 30-60 GW of these aggregated distributed resources, also known as virtual power plants (VPPs), were operating on the grid. The same report found this could expand to 80-160 GW by 2030, meeting 10-20 percent of peak load.[11]

Researchers have also identified high potential for demand flexibility from the data centers driving up demand forecasts. If these new loads could reduce electricity use for only a handful of hours annually, much of the existing projected demand could be met with the resources we already have today.[12] Data centers can provide flexibility through shifting computing loads[13] or using on-site resources like energy storage. There is also significant opportunity for data center operators to pay nearby customers to reduce demand during periods of grid stress, unlocking grid capacity.

Because of this high potential to meet rising grid demand with reduced investment, our clean scenario leverages efficiency and flexibility to help meet grid needs. To incorporate flexibility into the modeling, we first assume it is possible to achieve additional

MEETING GROWING DEMAND IN PJM

PJM is the nation's largest wholesale electricity market and ground zero for data center demand growth. The region includes Northern Virginia, which today hosts nearly a quarter of U.S. data center capacity and is the largest concentration of data centers anywhere in the world.

PJM is forecasting rapid increases in electricity demand over the next ten years. Region-wide, the market operator expects demand to grow nearly 50 percent by 2035, while its Northern Virginia territory could see demand grow 70 percent. Rising demand is straining the regional electricity market. Capacity market prices have surged in PJM as new supply—constrained by slow interconnection processes, local permitting challenges, supply chain fragility, and a changing policy environment—is unable to keep pace with rising demand. Federal and state politicians and stakeholders across the region are proposing significant reforms to meet rising demand and protect existing customers from surging prices.

Our modeling highlights that clean energy is critical to meet rising demand in PJM while building a modern, efficient and affordable electricity system. In our clean energy scenario, PJM builds 53 GW of solar, 19 GW of wind, 9 GW of batteries, and 2 GW of new gas by 2030, and deploys 12 GW of demand-side flexibility, while retiring 26 GW of aging, inefficient fossil capacity.

energy efficiency of up to 3.75 percent year-round load reduction by 2030 at an investment cost of $31 per megawatt-hour (MWh), based on 0.75 percent per year improvements for five years at a cost of $24/MWh in 2018 dollars[14]. We also allow the model to make 3 percent of load shiftable from any hour to any other hour of the same day, a more conservative projection than the DOE estimate of 80-160 GW of VPP potential.[15] We apply a cost of $43/kW-yr to purchase this shiftable capacity, based on the same DOE report. The clean pathway selects 26.3 GW of demand response and 32.9 GW of energy efficiency, with energy efficiency reducing overall generation by 186 TWh.

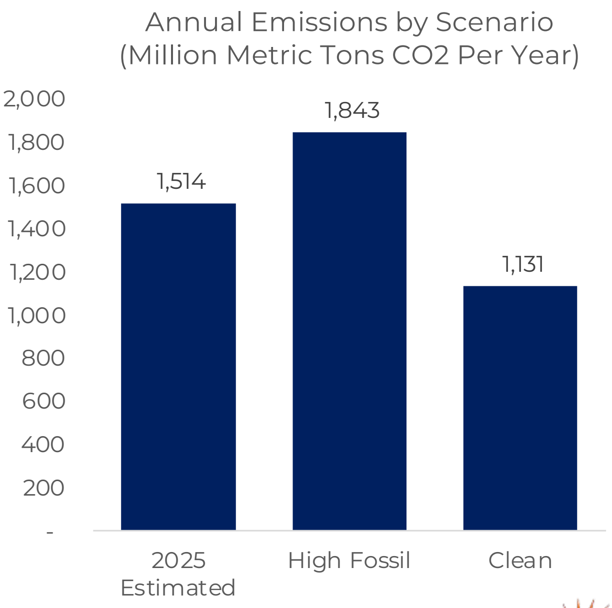
A clean energy system protects our health and climate

Burning fossil fuel creates pollution. Pollutants like nitrogen oxides (NO_X) and sulfur dioxide (SO_2) emitted by coal and gas power plants lead to the formation of ozone and particulate matter pollution, which can substantially harm human health. Recent estimates of air pollution impacts on mortality rates and life expectancy in exposed populations suggest coal and gas plants in the U.S. cause 4,000 to 9,000 premature deaths each year.[16]

Burning fossil fuels also creates carbon dioxide (CO_2) emissions, the primary greenhouse gas driving climate change. In 2025, the electricity sector emitted 1.5 billion metric tons of CO_2, nearly a quarter of total emissions from all sectors in the U.S.[17] While the electricity sector is still a major emitter of greenhouse gases, emissions reductions from the power sector, particularly from abated coal use, are responsible for almost all U.S. emissions reductions in the last two decades.

However, a boom in gas generation has significant implications for greenhouse gas emissions. While gas-fired generation directly emits roughly half of the CO_2 pollution for each unit of electricity output compared to a typical coal plant, it also causes methane leakage, which itself is a powerful greenhouse gas. One pound of methane traps the same amount of heat in the atmosphere as over 28 pounds of CO_2 (measured over a 100-year period, although methane's warming effect is more pronounced over shorter time periods), and even a small amount of gas leaking out of gas wells, pipelines, and power plants can outweigh the direct emissions reductions from coal-to-gas switching.[18] Locking in gas use only increases the risk of already accelerating extreme weather and climate impacts.

Figure 4. Annual CO_2 emissions on all three scenarios



The scenarios modeled in this study show clean energy's benefits go far beyond dollars saved. Meeting demand growth with clean energy protects communities from health-harming air pollution, while reducing climate risks. The clean energy scenario lowers CO_2 emissions from 2025 levels by 25 percent by 2030, while the high fossil scenario results in 22 percent higher CO_2 emissions compared with 2025.

CLEAN ENERGY PROTECTS CUSTOMERS FROM VOLATILE COAL AND GAS PRICES

Clean energy insures against volatile fossil fuel price risks. In a scenario that doubles down on coal and gas, a coal and gas price spike increases electricity costs by $40.5 billion per year relative to the base price case. Clean energy reduces this spike by $8.4 billion, resulting in total savings of $13.5 billion compared to the high fossil plan.

Fossil fuel prices are historically volatile; geopolitical uncertainty and extreme weather can rapidly change the cost of fuels used to generate electricity. Fuels like gas and coal are traded commodities, and even small, short-lived changes to supply or demand can lead to wild swings in prices.

Fuel costs make up a significant share of electricity generation costs, and in many markets a generator burning coal, gas, or oil is setting the marginal price of electricity in nearly every hour of the year, inherently linking electricity prices with markets for fuels. These volatile fuel prices are often passed through directly to retail electricity users and are an important factor in rising retail electricity bills in the U.S.[19]

In 2022, the Russian invasion of Ukraine drove natural gas prices in Europe to record highs. In the U.S., natural gas prices jumped by a factor of four in months as exports surged to capture high prices abroad. Today, geopolitical risk is rearing its head again as the war in Iran and subsequent shipping restrictions through the Strait of Hormuz leads to surging global oil prices.

In the U.S., natural gas markets have remained insulated as export capacity is fully utilized. Even though international prices for natural gas have spiked, the U.S. does not have the capacity to export more, limiting pressure on domestic prices for now. But with significant new natural gas export capacity coming online in late 2026 and over the next several years[20], insulation from global gas market volatility is likely temporary.

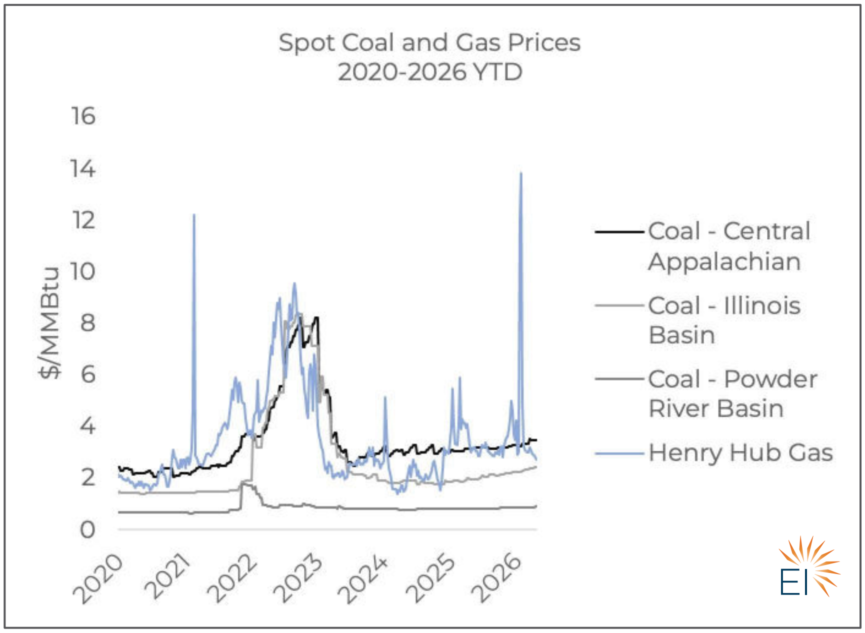
Geopolitics aren't the only driver of fossil fuel price volatility – extreme weather also plays an important role. Extreme cold, for instance, drives up demand for natural gas to heat homes and run power plants, while freezing wells and gathering pipelines reduce supply when demand is highest. In February 2021, Winter Storm Uri caused natural gas prices to surge as high as 100 times above typical levels in Texas and Oklahoma.

But these cost impacts can last far longer than the extreme weather event itself: Electricity and gas customers often pay back the costs for decades. In Oklahoma, for instance, consumers will pay nearly $4.5 billion over 25 years from Winter Storm Uri.[21]

While natural gas is the poster child for price volatility, other fuels are not immune. Following the Russian invasion of Ukraine in 2022, Eastern U.S. coal prices surged alongside natural gas prices, as coal supply is relatively inflexible but coal users were willing to pay more for fuel to compete with high natural gas prices. Some coal generators locked in higher prices during this time that persist today.[22]

According to Energy Innovation's 2025 Coal Cost Update, these include plants like West Virginia's Mountaineer and Mitchell, which paid 93 percent and 79 percent more for fuel in 2024 than in 2021, and Indiana's R.M. Schahfer, which paid 81 percent more for fuel per MWh energy generated.[23] High fuel prices are typically passed through directly to customer bills without regulatory scrutiny.

Figure 5. Historical Spot Coal and Gas Prices



Clean energy resources including wind, solar, efficiency, demand flexibility, and energy storage can protect customers from volatile fuel costs. These resources have no fuel cost; instead, most of their cost is up-front capital investment plus predictable O&M costs. When utilities build or purchase power from wind, solar, and energy storage resources, they lock in a portion of their overall power needs at a fixed, predictable cost for the life of a project or contract, avoiding the need to buy fuel or wholesale power linked to volatile fuel commodity markets.

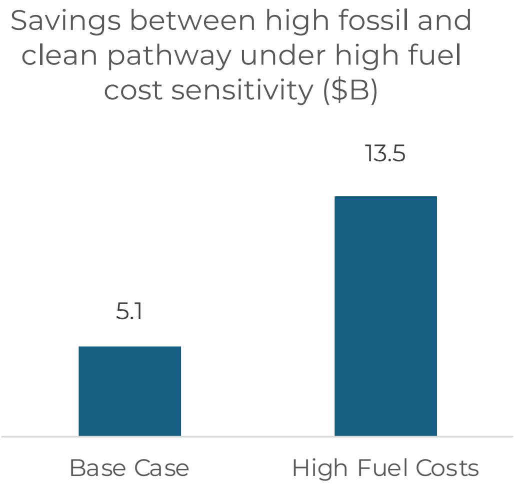
Nuclear and geothermal have similar benefits, though they are different in cost profile, operations, and risk. Both insulate from fossil fuel risk, require high upfront capital investment, and can be part of an economic portfolio beyond 2030 as new technologies mature and come down in cost. Given the long lead time for building new nuclear and geothermal power plants, our modeling did not consider new nuclear and geothermal power by 2030 beyond a handful of plants already under construction.

To evaluate the ability of a cleaner electricity system to protect customers from volatile fuel prices, we modeled a sensitivity case where the electricity system experiences similar fuel price levels to those experienced in 2022. This case shows that under high fuel costs, a cleaner system is an even better deal.

In the high fuel cost scenario, the fossil-driven pathway requires $70.3 billion in new spending annually to meet load growth and price spikes, while the high renewable case requires $56.8 billion to meet the same needs. This means that while both scenarios have an increased cost, savings from the clean pathway, relative to the fossil-driven pathway, increase by a factor of 2.6, from $5.1 billion saved in our base assumption to $13.5 billion saved under the high fuel costs scenario.

It is also worth noting that the very act of following the high fossil pathway would itself increase fossil fuel prices and the likelihood of price spikes, as higher fuel consumption for electricity production competes with other uses. On the other hand, the clean pathway will reduce fuel demand, likely decreasing prices overall and the risk of fuel price spikes. We did not model these multiplier effects in this study.

Figure 6. Savings from clean pathway under base case fuel costs or high (2022) fuel costs



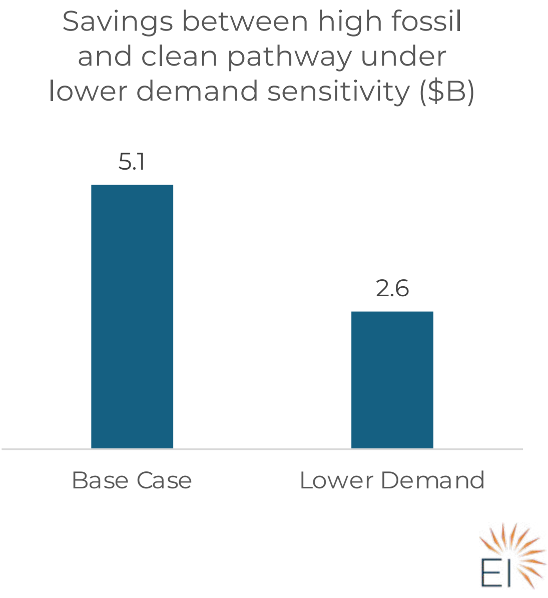
IF DEMAND GROWS SLOWLY, CLEAN RESOURCES LOWER RISK

Accelerating clean energy deployment is a no-regrets strategy, lowering costs even if anticipated demand growth does not arrive as quickly.

While demand is rising, no one knows exactly how much more or how much quicker it will continue to grow. Recent reporting suggests half of data centers planned to come online in 2026 have been delayed or canceled, in part because of supply chains for key components like electrical transformers and switchgear, as well as access to power supply and other development hurdles.[24]

Near-term forecasts from market operators and utilities are getting trimmed as load fails to materialize as quickly as originally anticipated.[25] Long-term projections see a wide range of uncertainty, with total data center demand varying by a factor of two by 2030.[26]

Figure 7. Savings from following clean pathway under base assumptions or with low demand growth



Policymakers and regulators face challenging trade-offs because of this uncertainty. Decisions about the future electricity system need to be made now, given long lead times to plan, procure, and build new generation resources. The trick is making decisions that minimize costs and regrets, even if the future does not play out as expected.

Flexible solutions reduce the risk of stranded assets (power plants built but not needed) because they require less capital investment and can provide a range of grid services even if loads don't fully materialize. Since clean power acts primarily as a fuel-saver, it also produces savings by avoiding purchase of fuel, whether demand rises or not.

To address these factors, we evaluated how the costs of a clean energy system compare to a high fossil system under a sensitivity case where we build a system to meet higher demand growth, but growth is much slower than expected. To test this, we took the amount of capacity built in each scenario under higher load forecasts as a given, and evaluated the costs of each scenario if just one-third of the demand growth modeled under our base assumptions by 2030 were to materialize.

We found that even if only 33 percent of demand growth manifests, a clean energy system still saves $2.6 billion per year relative to a high fossil system (Figure 7). The additional solar, wind, energy storage, and flexible capacity built to meet higher demand continues to yield substantial savings in fuel and operating costs.

RAPID, UNCERTAIN DEMAND GROWTH

For over a decade, electricity demand remained flat as energy efficiency gains offset underlying growth. That era is over. In 2025, electricity demand in the U.S. increased by 2.1 percent. And the projections going forward point toward growth rates not seen in many decades, with some projecting over 30 percent growth in electricity use by 2030.

The primary driver of this surging demand is the rapid rise of data centers being built for artificial intelligence computing needs, on top of rising demand from electrification of transportation, buildings, and re-shored manufacturing capacity. Data center growth is particularly uncertain; data center developers are in a rush to secure land and power, and utilities are facing a barrage of speculative and sometimes duplicative service requests. Utilities and their regulators face a monumental task in determining how much to plan for: under-build and risk high prices and reliability challenges, over-build and saddle customers with unnecessary costs.

While utilities nationwide are seeing data centers proposed in their territory, the growth is highly concentrated in a handful of markets. Northern Virginia (a.k.a. data center alley) hosts nearly a quarter of current U.S. data center capacity and a significant number of new proposals, but hot spots are spread across the country, from Arizona to Georgia, Michigan to Texas.

Growing but uncertain electricity demand

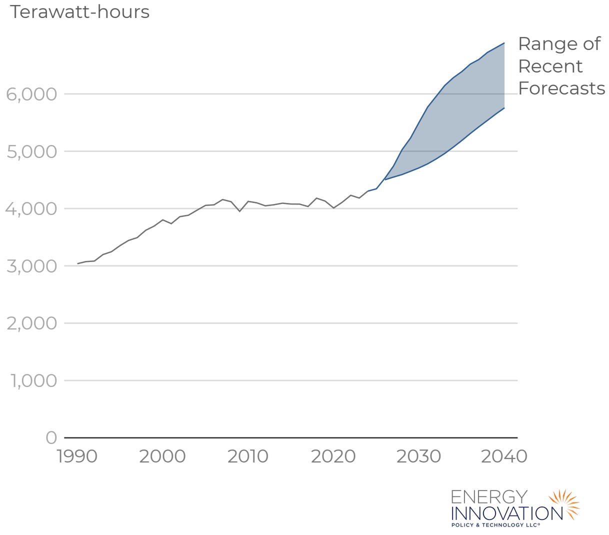


Chart: Energy Innovation · Source: EIA, Brattle Group

CLEAN ENERGY CAN RELIABLY MEET HIGH DEMAND GROWTH

The U.S. can meet growing demand with clean energy while building a reliable and resilient grid. A clean grid can meet growing demand under even the most challenging weather conditions, while continuing to retire aging, inefficient fossil power plants.

Rapid demand growth is increasing reliability concerns across the country. In January 2026, the North American Electric Reliability Corporation (NERC) found a growing number of regions where demand could outrun supply in the next five years unless new resources are built quickly.[27]

In PJM, the latest capacity auction did not secure enough generation to cover the region's target reserve margin for the 2027/28 delivery year, despite market prices hitting the highest level allowed.[28] Every day, new headlines highlight worries that we won't have enough power to meet rising demand.

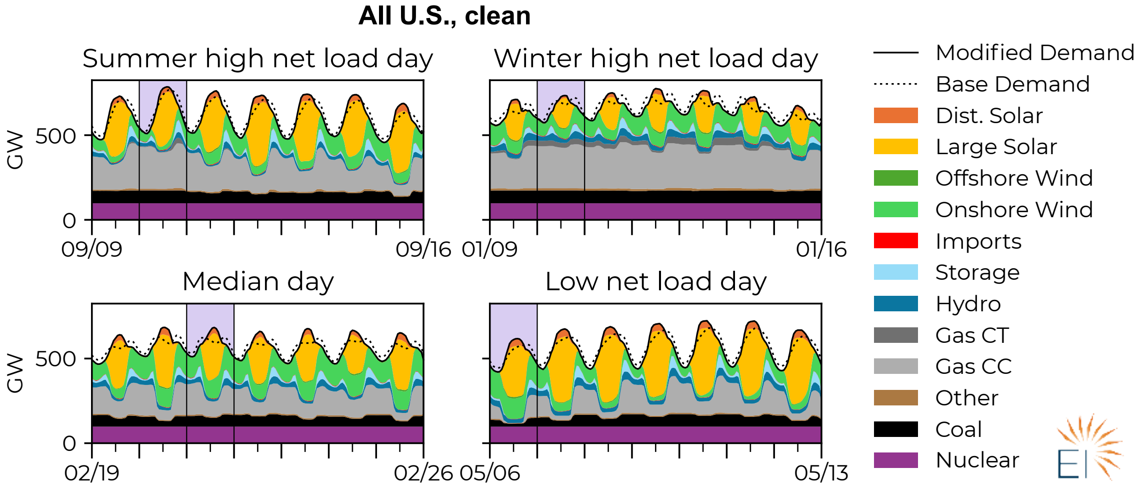
These concerns are driven by the inability to connect new resources fast enough to keep up with projected demand. Across the country, it takes an average of five years for a plant to come online after making an initial request to connect to the grid, with more than half of this time simply waiting for interconnection approval.[29] Local siting, permitting, and policy uncertainty are also significant contributors to project delays.[30]

As grid operators and utilities manage rising demand and slow resource additions, they are also increasingly grappling with the impact of extreme weather—particularly extreme cold—on coal and gas power plants and fuel supplies.

In 2021, during Winter Storm Uri, abnormally cold weather swept across Texas and other states in the South-Central U.S. While consumers turned on the heat and drove up demand, frozen gas pipelines and equipment shut off significant fuel supply, preventing gas power plants across the region from getting fuel delivered. Many power plants were frozen and unavailable to generate power. Over 30,000 MW of generation was unavailable for several days, with gas accounting for an outsized portion of outages.[31] In December 2022, Winter Storm Elliot struck much of the eastern U.S., again freezing coal and gas plants and fuel supplies.[32]

Our analysis is designed to ensure a reliable electricity system. To test this, we implemented a robust methodology to achieve a reliable system across a wide range of weather conditions. We tested both the clean and high fossil scenarios with a seven-year hourly production cost model, using weather data from 2007–13, to identify any days and hours where the model would be unable to meet demand. We then added those "challenging days" to the investment optimization model and required that it build a mix of resources that would meet demand and provide adequate reserves even on those difficult days. We repeated this process until each plan was able to fully cover demand and reserves across every day in the seven-year dataset.

Figure 8. National hourly system operation ("Modified Demand" includes effects of energy efficiency, demand flexibility, exports, and battery charging)



Clean energy works in concert with the whole portfolio of electricity system resources. Figure 8 shows national, hourly electricity production for weeks that include different types of weather conditions, including summer and winter days with high net demand (unusually high load paired with unusually low wind and solar resources), a day with median load and renewable output, and a day with unusually high renewable output and low demand.[iii]

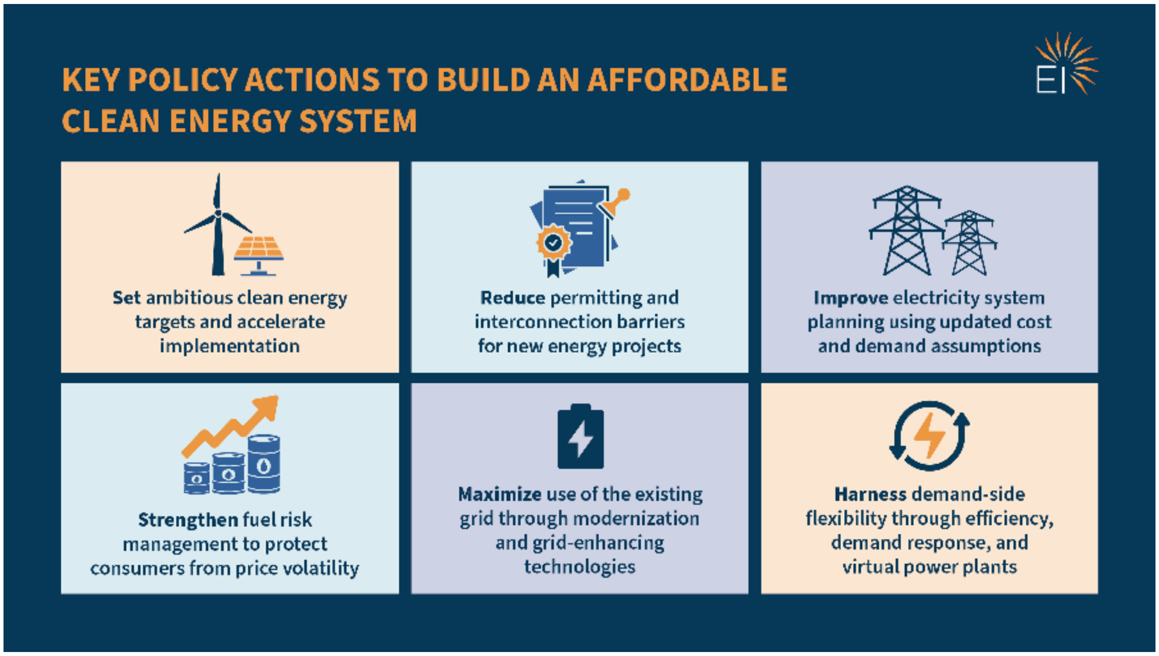
Solar, wind, energy storage, and existing coal, gas, nuclear, hydroelectric, and other sources of power work together on each of these days to meet demand. Solar is well-aligned with the daytime peak, but storage is needed for the end of the day, after sunset, and for winter mornings before sunrise. Wind is complementary to solar output in many regions—with wind power performing better in evenings and on days with less solar generation.

Together, these resources reduce the burden on existing generators even on the toughest days, saving significant fuel costs and allowing inefficient and expensive, aging power plants to retire even as demand grows. Regional and interregional sharing of power via transmission lines are both instrumental to ensuring reliability, especially during extreme weather events. Additional regional detail on system operations is shown in Appendix 3.

[iii] The high and low net load days have the greatest gap between the load percentile and renewable production percentile for that region in the seven-year dataset; the median day has load and renewable output with the smallest total difference from the median.

POLICYMAKERS CAN ENCOURAGE COMPETITION AND CUT RED TAPE

The U.S. electricity system is a product of policy and regulation, as well as economics. Utilities and their decision-making are shaped by regulatory processes and rules. Energy project development is shaped by the rules for permitting and interconnecting power projects to the grid. While clean energy is a cheaper way to meet growing electricity demand, policymakers and regulators have a critical role in turning this potential into reality.



KEY POLICY ACTIONS TO BUILD AN AFFORDABLE CLEAN ENERGY SYSTEM

Set ambitious clean energy targets and accelerate implementation

Reduce permitting and interconnection barriers for new energy projects

Improve electricity system planning using updated cost and demand assumptions

Strengthen fuel risk management to protect consumers from price volatility

Maximize use of the existing grid through modernization and grid-enhancing technologies

Harness demand-side flexibility through efficiency, demand response, and virtual power plants

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A more affordable clean electricity grid is not a foregone conclusion. Policymakers can make it a reality by improving how we plan, procure, and build new resources.

Six policy actions detailed in Table 3 can enable a cheaper, cleaner electricity system that reduces risks for customers. These policy actions are laid out in far greater detail in a separate policy report, available at https://energyinnovation.org/report/let-the-sun-in-clean-energy-is-the-cheapest-way-to-meet-rising-demand/.

Policymakers can set and retain goals for clean energy deployment, while working to reduce barriers to building resources, improving electricity system planning, managing fuel price risk, getting more out of the existing transmission system, and harnessing the potential of demand side resources including efficiency and flexibility.

Table 3. Key policy actions to build an affordable clean energy system

Policy Action	Key Decisionmakers	Specifics
Set ambitious targets	• Governors • State Legislatures	• Set and retain targets for clean energy • Prioritize implementing and removing barriers to achieving these goals
Reduce barriers to building new resources	• Governors • State Legislatures • Utility Regulators • Local Governments	• Improve state and local permitting processes • Accelerate interconnection processes • Improve community engagement and benefits for communities that host infrastructure • Enable clean energy parks for faster energization and local economic development
Improve electricity system planning	• Utility Regulators • State Legislatures	• Use up-to-date, market-based planning assumptions • Evaluate economics of both new and existing resources • Utilize competitive procurement and allow different resource types to compete to serve grid needs • Enable customer-driven procurement of clean energy (clean transition tariffs) • Identify opportunities for regional coordination
Encourage better fuel risk management	• Utility Regulators • State Legislatures	• Evaluate fuel price risk and impact of price spikes during planning • Utilize fuel cost sharing to incentivize utilities to manage fuel price risk
Get more out of the grid	• Governors • State Legislatures • Utility Regulators • Local Governments • Federal Energy Regulators	• Measure and improve grid utilization • Incentivize flexibility from customers and demand-side resources • Use advanced transmission technologies to increase usable grid capacity at low cost • Use existing points of interconnection to connect new power plants
Harness the Demand Side	• Utility Regulators • State Legislatures	• Transparent distribution system planning to identify demand-side opportunities • Automate permitting for customer resources • Support flexible interconnection • Enable virtual power plants as a grid resource

Leadership is needed at all levels of government—from federal energy regulators to governors and state legislatures, to utility regulators and local governments.

This time of change and upheaval in the electricity sector presents enormous opportunity. Growing clean energy to meet surging electricity demand can deliver lower costs, cleaner air, and less risk for customers. The industries of the future need not rely on an electricity system of the past.

APPENDIX 1: KEY INPUTS AND ASSUMPTIONS

Table 4 below summarizes the key inputs and assumptions used for this study. Exact details can be found in the study repository at:

https://github.com/EnergyInnovation/Switch-US-Load-Growth-2030..

Table 4. Key inputs and assumptions

Item	Source and description
Model zones	134 zones, corresponding to ReEDS CONUS model, as implemented by the PowerGenome team[33]
New resource limits	New gas: up to 58 GW by 2030, based on estimates of turbine availability through 2030. New solar: up to 500 GW installed by 2030, including existing and currently under construction. New wind: up to 239 GW installed by 2030, including existing current under construction. We assumed no new nuclear power could be built before 2030.
Existing generator capacity and performance	EIA Form 860 database for 2024[34], updated from EIA Form 860M database for March 2026[35], including approved and under-construction resources and planned retirements. Coal plant retirements were also updated from the January 2026 version of the Global Energy Monitor Global Coal Plant Tracker.[36]
New generator costs and performance	NLR ATB 2024[37] for solar, wind and battery storage. Natural gas plant costs from Gridlab/Halcyon[38]. Based on a review of recent research and industry reports, we chose the "Moderate" ATB case for solar power costs, the "Advanced" case for energy storage and the "Conservative" case for wind power, which better align with industry cost expectations. Investment tax credit of 30% was applied to battery storage but not other new-build technologies.
Generator interconnection costs	Interconnection costs from PowerGenome for model-selected onshore wind ($75-$1303/kW), offshore wind ($913-$1998/kW) and utility-scale solar ($95-$915/kW). $0 for all other resources.
Generator operating parameters	Full-load efficiency from NLR ATB 2024 for new plants and from EIA Form 923 data[39] for existing plants. We assume part-load fuel consumption follows a straight line from 20% of full-load fuel at zero output up to full-load fuel at full output, based on typical performance of thermal plants (this sets the fuel requirements to provide spinning reserves). Minimum up- and down- times, minimum load, ramp rate limits and startup fuel follow standard PowerGenome settings[40], except we set the minimum load for nuclear plants to 100% instead of 50% [41].

Item	Source and description
Generator operation and maintenance costs	Fixed, variable, and startup O&M for thermal power plants follow standard PowerGenome settings. Data for new natural gas power plants come from NLR ATB 2024. Fixed and variable O&M costs for existing plants originate from EIA[42]. Startup O&M costs for thermal generators come from the Western Wind and Solar Integration Study.
Renewable and hydro generator time profiles and resource potential	Wind and solar time profiles and resource potential were modeled by the PowerGenome team using NLR reV software for PowerGenome CPAs on ReEDS zones. Capacities and time profiles for existing large hydro were also provided by the PowerGenome team. Geothermal and small hydro use flat profiles de-rated based on EIA historical production.
Generator outages	Forced & scheduled outages for most generators from NERC GADS statistical brochure for all units for 2020-24[43]; wind outages from NERC GADS wind metric brochure for 2018–23[44]; solar outages are the median for 2008-22 from NLR study[45]; battery outage estimate from California Energy Storage Alliance[46]. All generators were de-rated according to forced outage rates at all times, reflecting the expected unavailability of part of the fleet at any given time. The capacity expansion model was also required to schedule the specified number of planned outages for each generator at some point during the year, but this requirement was lifted for the resource adequacy stage on the assumption that outages would not be scheduled during critical periods.
Transmission capacity and losses	Existing transfer capability between zones from ReEDS input files[47] (REFS2009 version). We assumed no new transmission capacity could be added before 2030. Transmission losses between zonal hubs (0–8.8%) from the PowerGenome project[48]. T&D losses between zonal hub and customer were set to 3.87% to achieve total T&D losses of 5% in 2024 calibration tests, matching EIA estimates.[49]
Demand	Peak, average, and shape of 2023 loads from NLR Electrification Futures Study. We then applied multipliers and offsets at a zonal level to reach the ICF growth forecast for 2030[50].
Fuel costs	Fuel cost forecasts were based on state-level historical fuel costs for electricity production from EIA State Energy Data System,[51] with fallback to EIA Electric Power Operational Data[52] for missing values. The base forecast for each fuel in each state was the average from 2021–25. The "peak" forecast was a recurrence of the 2022 price. (All converted to real 2025 dollars.)

Item	Source and description
Sample day selection	All sample days use synchronized loads and renewable resource profiles, based on weather in 2007-13, shifted to 2030. Economic days: 19 days selected via the k-means clustering method to span the range of weather conditions found across the seven-year period, plus the single day with the highest load Reliability days: iteratively added days with the most unserved load from full 2007-13 set, as described in Appendix 2, up to 20 total. (Actual additions were 4 reliability days for High Fossil case, 12 for Clean.)
Spinning reserve margin	Spinning reserve margin equal to 3% of load plus 5% of wind and solar output at all times, based on a conservative rule developed for the NLR Western Wind and Solar Integration Study.[53]
Planning reserve margin	Planning reserve margin of 2% for all reliability days, meaning the system must be able to serve 2% higher loads everywhere, above and beyond forced outages, transmission losses, and spinning reserve requirements. If the maximum reliability days (20) were added, PRM for the reliability days could then be raised incrementally until all-weather reliability is reached (see Appendix 2); that was not necessary for this study. Economic days did not have a PRM. All economic and reliability days also have spinning reserves, T&D losses and forced outage rates, as noted above, which are normally included as part of NERC PRM reporting.
Environmental policies	30% investment tax credit for battery storage and wind and solar generators already under construction. Credit-eligible solar capacity (175 GW) from Wood Mackenzie, converted from DC to AC with an inverter ratio of 1.3.[54]; wind capacity (23 GW) from Crux[55]. 2030 clean energy standards, renewable portfolio standards, minimum deployment standards and renewable energy credit trading rules from NLR ReEDS[56]. We applied a cost of $33.43/tCO$_2$ for all carbon emissions in California, Washington, and New York, and for emissions beyond the cap in Regional Greenhouse Gas Initiative states. This value is based on the average of California and Washington carbon prices in 2024.
Energy efficiency options	The Clean case assumes it is possible to achieve up to 3.75% reduction in load in all hours at an investment cost of $31/MWh. (The model cannot choose the times of reduction, only the zone and percentage.) This is based on 0.75% /year improvements for 5 years at a cost of $24/MWh in 2018 dollars[57].
Demand response options	The Clean case assumes it is possible to make 3% of load shiftable from any hour to any other hour of the same day. This is more conservative than the DOE estimates of 80-160 GW of VPP potential[58] (in an 800 GW system). We apply a cost of $43/kW-yr to purchase this shiftable capacity, based on the same DOE report.

APPENDIX 2: MODELING METHODOLOGY

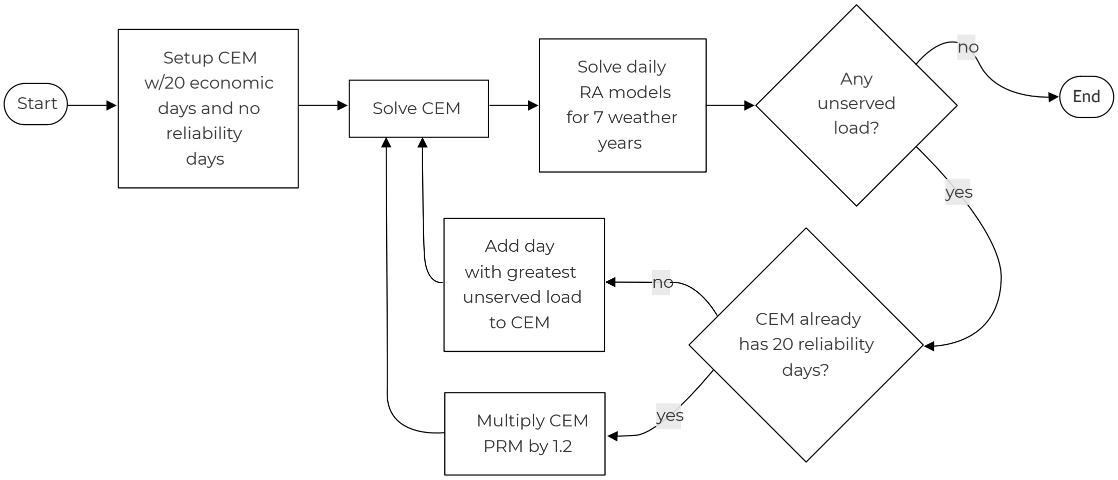
Switch is open-source software that can identify cost-optimal investment plans for electric power systems under a wide range of policy, technology, and demand assumptions. It uses a collection of probability-weighted sample days to represent the range of weather conditions that the power system could encounter, then co-optimizes investment choices over multiple years and operational choices on each of the sample days. It is formulated as a large-scale linear or mixed-integer optimization problem that minimizes the present value of all system costs over a multi-decade planning horizon using established numerical optimization techniques. Costs include capital investments in generation, storage, and transmission, as well as fixed and variable operating costs, fuel purchases, and policy compliance costs. The model represents decisions with high spatial and temporal resolution—typically time steps of 1–3 hours and dozens to hundreds of zones—while also capturing long-term investment dynamics through discrete, multi-year planning periods.

Switch's detailed representation of power systems enables consistent co-optimization of generation, storage, demand response, transmission expansion, and other system elements. It enforces physical constraints such as generator availability, ramping limits, reserve requirements, and transmission limits, and policy constraints like renewable portfolio standards or emissions caps. The model uses chronological time series for each sample day to capture variability in load and renewable generation, as well as for scheduling storage and demand response between different hours in a continuous period. Its modular architecture allows users to include or exclude components (e.g., unit commitment, transmission expansion, demand-response options) depending on the research question and computational requirements. This combination of temporal and spatial detail and technical flexibility makes it ideally suited to assess the integration of important new electricity options such as renewable power, battery storage, and demand-side flexibility. More details on Switch can be found at https://switch-model.org/ and in Johnston et al. 2019[59].

For this study, we ran Switch repeatedly in two stages, creating candidate capacity investment plans, then testing them for reliability under all available weather conditions, then adjusting the capacity planning model to create a more reliable plan, until satisfactory reliability was achieved. This process was designed to be technology-neutral, adapt automatically to different shares of renewable power, and consistently achieve reliability while minimizing system cost, with a reasonable amount of computational effort. Figure A1 outlines the stages, and we describe them in more detail below. The code and data for all these steps are available at https://github.com/EnergyInnovation/Switch-US-Load-Growth-2030.

In the first step, Switch was run in a capacity expansion model (CEM) stage to choose a least-cost, reliable plan for each technical or policy environment—high-fossil or clean—based on a collection of sample days. These sample days included two groups: "economic days" and "reliability days". The economic days were chosen by k-means clustering to represent the range of weather conditions found in our full dataset of 2007-13 weather. They were given probability weights based on how many days from the 7-year dataset were closest to each one. For this study, we initially chose 20 sample days this way, including the day with the highest peak load.

Figure A1. Diagram of iterative process to achieve reliable power system design



K-means clustering is good at representing the common conditions for the power system, which drive the economic viability of renewable versus fossil resources for everyday use. However, it tends to leave out "tail" conditions, such as days with unusually high loads or unusually low wind and sun, that occur rarely but can cause energy shortfalls that must be avoided. Therefore, the CEM also included difficult, low-probability "reliability days", which the power system must also be able to accommodate. In our work, the CEM started with no reliability days, and then reliability days were added as difficult days were found in the iteration. We also applied an extra planning reserve margin (PRM) of two percent on the reliability days to create some additional headroom and ensure the process reached reliability sooner. The PRM was implemented by requiring the system to meet loads two percent higher than expected in all hours of that day. We assigned the reliability days a zero probability for economic purposes, since with the reserve margin they represent "worse than worst" days that are beyond the range expected to occur in a seven year period; however, the model was nevertheless required to be able to serve them (it was not given the option to shed loads, even under these very rare circumstances).

The second model stage was a resource adequacy (RA) stage, where we tested whether each of the two plans would be reliable across all the days of weather in the seven-year dataset. This consisted of running Switch with a frozen investment plan from the CEM for each individual day of weather. This arrangement is conservative in that it requires load on each day to be served with power available on that day: there was no option to store power on one day for use on another. This means that if the system could satisfy load on one day of this type, it could satisfy it for several identical days or weeks in a row if needed. In the RA stage, the PRM was relaxed because the goal was to design a system that would be just-adequate across all seven weather years, similar to the standard utility practice of designing for 1-day-in-10-years of shortfall. In this stage, Switch was also given the option of shedding load, but at a very high cost of $10,000/MWh ($10/kWh). This ensured the model would meet load if it was possible, and if not, give a precise estimate of how much load could not be served. After testing all 2,555 days from the sample set with each plan, we identified the single day for each plan that had the most total unserved load (in GWh, not GW) and added that day to the set of reliability days for that CEM. This process was repeated until all three plans reached a point where they could serve all 2,555 weather days with no shortfalls.

Our plan was to add up to 20 reliability days, and then, if the system still had unserved load, incrementally raise the PRM in the CEM stage instead of adding additional reliability days, to limit the size of the CEM. However, this was not needed in this case.

This process did not explicitly address the impact of unexpected outages at power plants. Instead, we assumed that a fixed fraction of plants would be out of service at any time, based on their forced outage rate, and required an additional 2 percent PRM on the reliability days in the CEM stage. This combination ensures that some extra capacity is available most of the time, to allow for some periods with outages beyond the average forced outage rate. Consequently, for an actual shortfall to occur, an unusually high number of plants would have to go on forced outage on the same day as unusually difficult to serve weather, which is a low-probability event.[iv] However, more traditional resource adequacy modeling with Monte Carlo plant outages and local constraints would be needed before making final investment plans.

APPENDIX 3: DETAILED MODELING RESULTS

This appendix contains more details on model results. The first section shows graphs of national statistics for clean power production, emissions, and costs for the clean and high-fossil scenarios under all future conditions considered in the report. The second section contains tables of generation capacity, additions, retirements, and annual production in 2030 for each scenario, for each region of the U.S. The third section has plots of hourly power production for select weeks, for each region of the U.S. These show the

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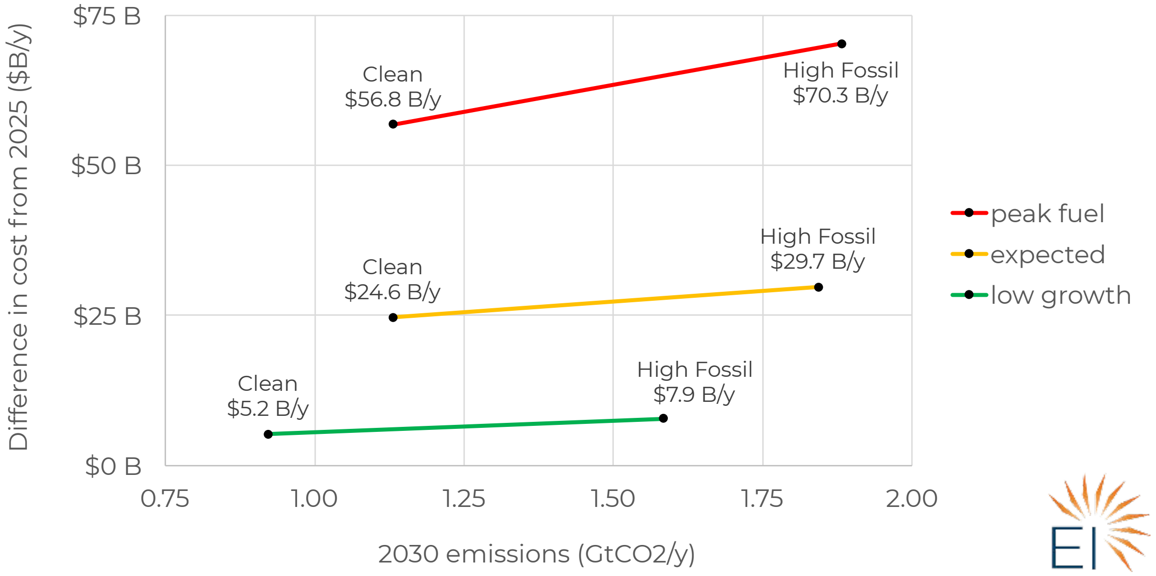
[iv] For example, with 1600 power plants with a 5 percent chance of being forced out of service on a given day, the chances of having 7 percent out on a given day (corresponding to the 5 percent average plus 2 percent PRM) would be about 0.015 percent or one day in 7000. To have a nationwide shortfall, this would need to coincide with a high-load/low-renewable day of the type in the reliability set, which occur on the order of once per year. However, this is a rough approximation, which doesn't account for the likelihood of simultaneous weather-driven plant outages on very cold or very hot days.

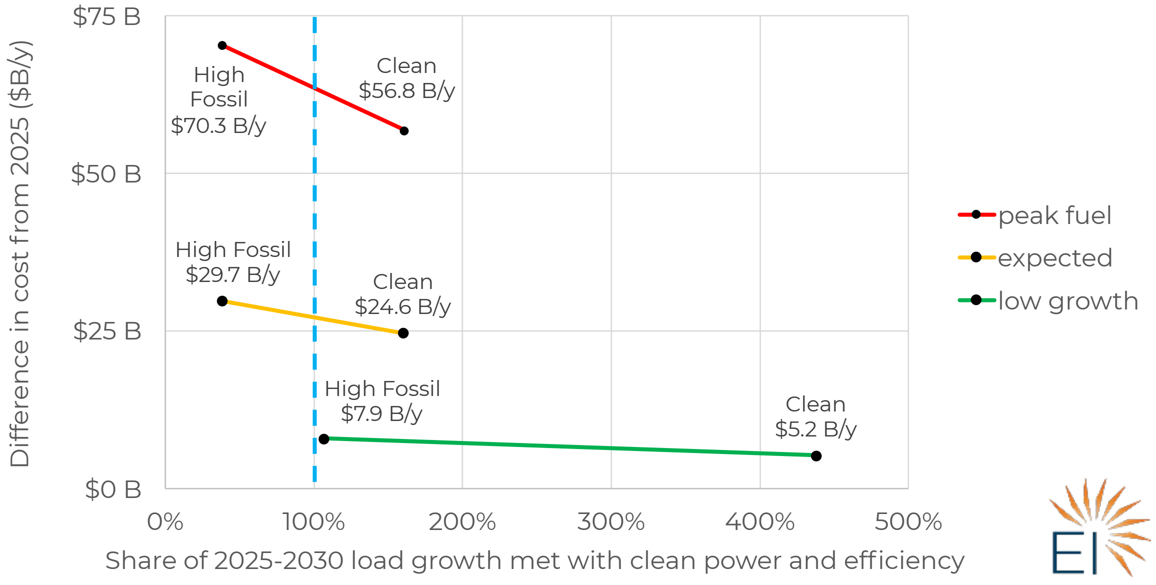
weeks containing days with high, median or low net load for each region, based on testing with seven years of weather data.

National Summary Statistics

Cost of serving load growth vs. CO2 emissions for clean and high fossil scenarios under expected conditions or with high fuel costs or low demand growth



Cost of serving load growth vs. share of growth served with clean power and energy efficiency, under expected conditions or with high fuel costs or low demand growth



Regional Capacity and Energy Mix

Electricity generation capacity and production, All U.S., clean

Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal	171.6		87.4	84.3	545.7
Gas CCGT	312.6	14.9	26.6	299.5	1,430.7
Gas CT	149.7	8.4	37.2	117.9	8.7
Gas Peaker	81.6	0.4	72.0	9.7	14.4
Nuclear	99.9			99.9	805.7
Convent. Hydro	72.8			72.8	249.6
Onshore Wind	157.7	65.3		223.0	742.9
Offshore Wind	0.2	9.6		9.8	43.0
Large Solar	150.5	349.6		500.0	1,076.0
Dist. Solar				54.8	100.0
Geothermal	3.0	0.1		3.1	25.1
Pumped Hydro	23.2			23.2	−14.6
Batteries	42.5	71.0		113.5	−23.3
Other	29.7		0.8	29.1	34.5
U.S. Imports					22.7
Energy Efficiency		32.9		32.9	186.0
Demand Response		26.3		26.3	

Electricity generation capacity and production, All U.S., high fossil

Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal	171.6			171.6	1,061.6
Gas CCGT	312.6	20.2		332.8	1,838.4
Gas CT	149.7	8.4		158.2	12.3
Gas Peaker	81.6	0.4		82.1	36.8
Nuclear	99.9			99.9	805.7
Convent. Hydro	72.8			72.8	249.7
Onshore Wind	157.7	25.3		183.0	587.1
Offshore Wind	0.2	9.6		9.8	43.0
Large Solar	150.5	77.9		228.3	469.3
Dist. Solar				54.8	99.6
Geothermal	3.0	0.1		3.1	25.1
Pumped Hydro	23.2			23.2	−12.7
Batteries	42.5	48.5		91.0	−17.5
Other	29.7		0.8	29.1	34.8
U.S. Imports					22.7
Energy Efficiency					
Demand Response					

Electricity generation capacity and production, CAISO, clean

Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal					
Gas CCGT	21.2		5.2	16.0	47.8
Gas CT	11.6			11.6	
Gas Peaker	4.5		4.5		
Nuclear	2.2			2.2	18.1
Convent. Hydro	9.0			9.0	25.9
Onshore Wind	6.4	0.1		6.6	26.4
Offshore Wind					
Large Solar	24.1	35.7		59.8	141.1
Dist. Solar				15.5	29.0
Geothermal	2.0			2.0	15.9
Pumped Hydro	3.9			3.9	−2.7
Batteries	14.8	6.7		21.5	−4.8
Other	0.8			0.8	3.2
U.S. Imports					
Energy Efficiency		2.2		2.2	13.5
Demand Response		1.8		1.8	

Electricity generation capacity and production, CAISO, high fossil

Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal					
Gas CCGT	21.2			21.2	94.8
Gas CT	11.6			11.6	
Gas Peaker	4.5			4.6	
Nuclear	2.2			2.2	18.1
Convent. Hydro	9.0			9.0	25.9
Onshore Wind	6.4	0.1		6.6	26.4
Offshore Wind					
Large Solar	24.1	6.2		30.3	70.0
Dist. Solar				15.5	29.0
Geothermal	2.0			2.0	15.9
Pumped Hydro	3.9			3.9	−1.6
Batteries	14.8	6.7		21.5	−4.7
Other	0.8			0.8	3.3
U.S. Imports					
Energy Efficiency					
Demand Response					

Electricity generation capacity and production, ERCOT, clean

Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal	12.7		2.4	10.3	68.8
Gas CCGT	40.0	1.4	5.3	34.7	108.7
Gas CT	10.1	2.2	2.8	8.7	
Gas Peaker	12.2	0.2	12.2		
Nuclear	5.1			5.1	41.3
Convent. Hydro	0.5			0.5	0.5
Onshore Wind	35.7	14.4		50.1	147.5
Offshore Wind					
Large Solar	28.9	44.4		73.3	150.7
Dist. Solar				6.4	11.2
Geothermal					
Pumped Hydro					
Batteries	13.6	11.9		25.5	−6.9
Other	0.9			0.9	0.9
U.S. Imports					
Energy Efficiency		3.1		3.1	18.1
Demand Response		2.5		2.5	

Electricity generation capacity and production, ERCOT, high fossil

Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal	12.7			12.7	86.9
Gas CCGT	40.0	1.4		41.4	222.7
Gas CT	10.1	2.2		12.3	
Gas Peaker	12.2	0.2		12.4	
Nuclear	5.1			5.1	41.3
Convent. Hydro	0.5			0.5	0.5
Onshore Wind	35.7	1.9		37.6	97.4
Offshore Wind					
Large Solar	28.9	15.8		44.7	84.6
Dist. Solar				6.4	11.3
Geothermal					
Pumped Hydro					
Batteries	13.6	11.9		25.5	−6.7
Other	0.9			0.9	0.9
U.S. Imports					
Energy Efficiency					
Demand Response					

Electricity generation capacity and production, ISONE, clean

Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal	0.1		0.1		
Gas CCGT	13.7		1.7	12.1	47.2
Gas CT	1.5			1.4	
Gas Peaker	0.7		0.7		0.1
Nuclear	3.4			3.4	27.2
Convent. Hydro	1.3			1.3	6.1
Onshore Wind	1.7	3.2		5.0	19.7
Offshore Wind		3.5		3.6	17.0
Large Solar	3.4	3.5		6.9	14.0
Dist. Solar				5.7	10.3
Geothermal					
Pumped Hydro	1.9			1.9	−1.3
Batteries	0.8	1.6		2.4	−0.4
Other	6.1			6.1	4.3
U.S. Imports					7.2
Energy Efficiency		1.0		1.0	5.6
Demand Response		0.8		0.8	

Electricity generation capacity and production, ISONE, high fossil

Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal	0.1			0.1	
Gas CCGT	13.7			13.7	57.0
Gas CT	1.5			1.5	
Gas Peaker	0.7			0.7	0.1
Nuclear	3.4			3.4	27.2
Convent. Hydro	1.3			1.3	6.1
Onshore Wind	1.7	2.9		4.7	18.4
Offshore Wind		3.5		3.6	17.0
Large Solar	3.4	0.4		3.8	7.7
Dist. Solar				5.7	10.1
Geothermal					
Pumped Hydro	1.9			1.9	−1.1
Batteries	0.8	1.1		1.9	−0.4
Other	6.1			6.1	4.3
U.S. Imports					7.2
Energy Efficiency					
Demand Response					

Electricity generation capacity and production, MISO, clean

Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal	56.7		33.4	23.3	151.9
Gas CCGT	45.5	6.6	2.6	49.6	259.6
Gas CT	30.2	0.7	14.5	16.3	2.9
Gas Peaker	17.2		15.0	2.2	5.1
Nuclear	13.6			13.6	109.9
Convent. Hydro	4.1			4.1	14.0
Onshore Wind	41.5	16.8		58.2	193.9
Offshore Wind					
Large Solar	21.7	70.2		91.9	198.3
Dist. Solar				2.5	4.7
Geothermal					
Pumped Hydro	2.7			2.7	−0.8
Batteries	0.8	9.6		10.4	−1.7
Other	4.6			4.6	7.2
U.S. Imports					9.4
Energy Efficiency		6.0		6.0	34.8
Demand Response		4.8		4.8	

Electricity generation capacity and production, MISO, high fossil

Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal	56.7			56.7	359.7
Gas CCGT	45.5	6.9		52.5	319.5
Gas CT	30.2	0.7		30.9	0.2
Gas Peaker	17.2			17.3	8.7
Nuclear	13.6			13.6	109.9
Convent. Hydro	4.1			4.1	13.9
Onshore Wind	41.5	1.9		43.3	136.7
Offshore Wind					
Large Solar	21.7	12.6		34.3	69.1
Dist. Solar				2.5	4.7
Geothermal					
Pumped Hydro	2.7			2.7	−1.3
Batteries	0.8	4.3		5.1	−0.6
Other	4.6			4.6	7.2
U.S. Imports					9.4
Energy Efficiency					
Demand Response					

Electricity generation capacity and production, NYISO, clean

Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal					
Gas CCGT	11.4		3.1	8.3	17.1
Gas CT	2.7			2.7	
Gas Peaker	9.5		9.5		
Nuclear	3.4			3.4	27.0
Convent. Hydro	4.0			4.0	22.8
Onshore Wind	2.7	5.6		8.4	32.0
Offshore Wind	0.1	1.7		1.9	9.2
Large Solar	3.1	19.5		22.6	46.9
Dist. Solar				2.8	5.0
Geothermal					
Pumped Hydro	1.4			1.4	−1.0
Batteries	0.3	3.6		3.8	−0.5
Other	3.7			3.7	1.5
U.S. Imports					5.5
Energy Efficiency		1.2		1.2	6.6
Demand Response		0.9		0.9	

Electricity generation capacity and production, NYISO, high fossil

Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal					
Gas CCGT	11.4			11.4	26.8
Gas CT	2.7			2.7	
Gas Peaker	9.5			9.5	
Nuclear	3.4			3.4	27.0
Convent. Hydro	4.0			4.0	22.8
Onshore Wind	2.7	6.3		9.1	34.8
Offshore Wind	0.1	1.7		1.9	9.2
Large Solar	3.1	18.2		21.3	44.4
Dist. Solar				2.8	4.8
Geothermal					
Pumped Hydro	1.4			1.4	−0.9
Batteries	0.3	1.5		1.8	−0.2
Other	3.7			3.7	1.4
U.S. Imports					5.5
Energy Efficiency					
Demand Response					

Electricity generation capacity and production, Non-RTO South, clean

Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal	31.4		24.5	6.9	43.4
Gas CCGT	75.2	1.3	0.3	76.1	394.9
Gas CT	37.8	0.4	3.9	34.4	1.6
Gas Peaker	12.1		6.8	5.2	3.5
Nuclear	32.4			32.4	260.9
Convent. Hydro	11.2			11.2	26.8
Onshore Wind	0.4			0.4	1.0
Offshore Wind					
Large Solar	28.9	81.7		110.5	233.2
Dist. Solar				6.5	11.4
Geothermal					
Pumped Hydro	6.6			6.6	−3.5
Batteries	1.9	17.9		19.7	−3.1
Other	5.4			5.3	9.6
U.S. Imports					
Energy Efficiency		7.1		7.1	38.7
Demand Response		5.7		5.7	

Electricity generation capacity and production, Non-RTO South, high fossil

Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal	31.4			31.4	182.6
Gas CCGT	75.2	2.7		77.9	478.8
Gas CT	37.8	0.4		38.3	1.6
Gas Peaker	12.1			12.1	7.7
Nuclear	32.4			32.4	260.9
Convent. Hydro	11.2			11.2	26.8
Onshore Wind	0.4			0.4	1.0
Offshore Wind					
Large Solar	28.9	7.6		36.4	75.7
Dist. Solar				6.5	11.4
Geothermal					
Pumped Hydro	6.6			6.6	−3.1
Batteries	1.9	10.6		12.5	−1.6
Other	5.4			5.3	9.6
U.S. Imports					
Energy Efficiency					
Demand Response					

Electricity generation capacity and production, Non-RTO West, clean

Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal	18.8		10.5	8.4	50.3
Gas CCGT	31.7	2.2	3.5	30.4	139.8
Gas CT	12.5	1.1	7.4	5.3	0.7
Gas Peaker	5.0	0.1	4.6	0.5	2.4
Nuclear	5.2			5.2	41.7
Convent. Hydro	38.2			38.2	140.8
Onshore Wind	24.5	9.1		33.6	109.0
Offshore Wind					
Large Solar	23.4	23.9		47.3	101.9
Dist. Solar				7.9	14.5
Geothermal	1.0	0.1		1.1	9.2
Pumped Hydro	1.1			1.1	−0.6
Batteries	9.3	7.2		16.5	−3.5
Other	0.6			0.6	2.4
U.S. Imports					0.5
Energy Efficiency		3.4		3.4	19.8
Demand Response		2.7		2.7	

Electricity generation capacity and production, Non-RTO West, high fossil

Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal	18.8			18.8	102.6
Gas CCGT	31.7	5.5		37.2	182.4
Gas CT	12.5	1.1		13.6	0.8
Gas Peaker	5.0	0.1		5.1	3.1
Nuclear	5.2			5.2	41.7
Convent. Hydro	38.2			38.2	140.9
Onshore Wind	24.5	9.1		33.6	109.1
Offshore Wind					
Large Solar	23.4	9.1		32.5	66.7
Dist. Solar				7.9	14.5
Geothermal	1.0	0.1		1.1	9.2
Pumped Hydro	1.1			1.1	−0.5
Batteries	9.3	7.0		16.3	−2.9
Other	0.6			0.6	2.6
U.S. Imports					0.5
Energy Efficiency					
Demand Response					

Electricity generation capacity and production, PJM, clean

Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal	34.3		11.4	22.9	151.1
Gas CCGT	61.9	1.6	1.1	62.5	405.3
Gas CT	32.7		3.5	29.2	3.4
Gas Peaker	9.6		8.0	1.7	3.3
Nuclear	32.7			32.7	263.4
Convent. Hydro	2.9			3.0	8.2
Onshore Wind	6.3	14.7		21.0	77.3
Offshore Wind		4.3		4.4	16.8
Large Solar	14.6	48.2		62.8	133.0
Dist. Solar				7.0	12.9
Geothermal					
Pumped Hydro	5.2			5.2	−4.5
Batteries	0.5	9.7		10.2	−1.6
Other	5.9		0.7	5.1	5.1
U.S. Imports					
Energy Efficiency		6.9		6.9	37.7
Demand Response		5.5		5.5	

Electricity generation capacity and production, PJM, high fossil

Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal	34.3			34.3	219.7
Gas CCGT	61.9	1.9		63.9	431.7
Gas CT	32.7			32.7	9.5
Gas Peaker	9.6			9.6	16.6
Nuclear	32.7			32.7	263.4
Convent. Hydro	2.9			3.0	8.2
Onshore Wind	6.3	1.9		8.1	27.7
Offshore Wind		4.4		4.4	16.8
Large Solar	14.6	4.9		19.5	39.1
Dist. Solar				7.0	12.9
Geothermal					
Pumped Hydro	5.2			5.2	−3.9
Batteries	0.5	3.9		4.4	−0.3
Other	5.9		0.7	5.1	5.1
U.S. Imports					
Energy Efficiency					
Demand Response					

Electricity generation capacity and production, SPP, clean

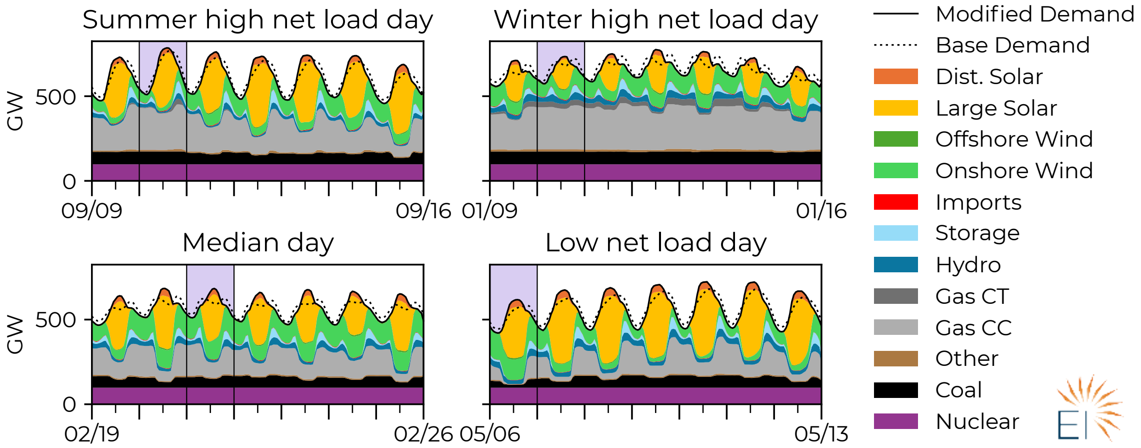
Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal	17.6		5.1	12.5	80.1
Gas CCGT	11.9	1.7	3.9	9.7	10.3
Gas CT	10.6	3.9	5.1	8.2	0.1
Gas Peaker	10.6		10.6		
Nuclear	2.0			2.0	16.3
Convent. Hydro	1.6			1.6	4.5
Onshore Wind	38.4	1.2		39.6	136.0
Offshore Wind					
Large Solar	2.4	22.5		24.9	56.9
Dist. Solar				0.5	0.8
Geothermal					
Pumped Hydro	0.4			0.4	−0.3
Batteries	0.6	2.9		3.5	−0.6
Other	1.9			1.9	0.4
U.S. Imports					
Energy Efficiency		2.0		2.0	11.2
Demand Response		1.6		1.6	

Electricity generation capacity and production, SPP, high fossil

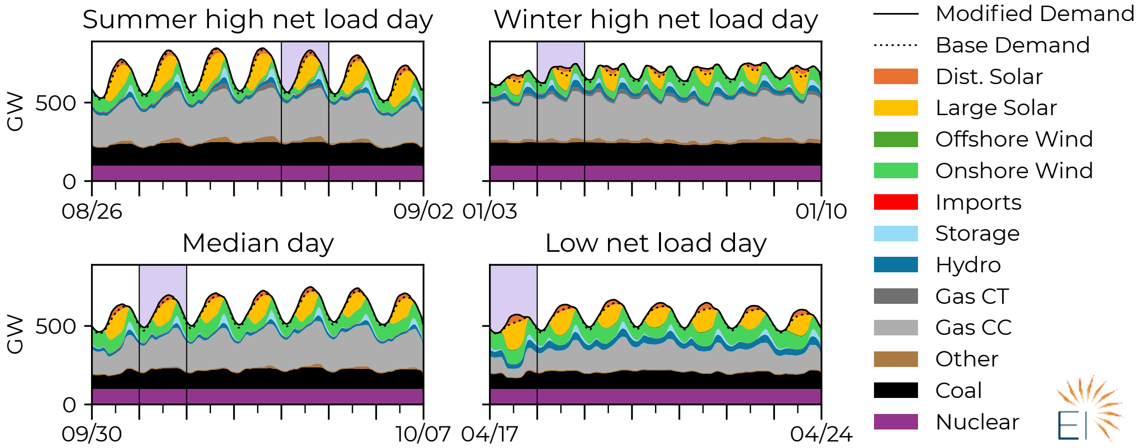
Technology	2025 capacity (GW)	Capacity added (GW)	Capacity retired (GW)	2030 capacity (GW)	Production (TWh)
Coal	17.6			17.6	110.1
Gas CCGT	11.9	1.7		13.6	24.7
Gas CT	10.6	3.9		14.5	
Gas Peaker	10.6			10.6	0.7
Nuclear	2.0			2.0	16.3
Convent. Hydro	1.6			1.6	4.5
Onshore Wind	38.4	1.2		39.6	135.6
Offshore Wind					
Large Solar	2.4	3.1		5.5	12.0
Dist. Solar				0.5	0.9
Geothermal					
Pumped Hydro	0.4			0.4	−0.3
Batteries	0.6	1.4		2.1	−0.2
Other	1.9			1.9	0.4
U.S. Imports					
Energy Efficiency					
Demand Response					

Regional Dispatch for Select Weeks

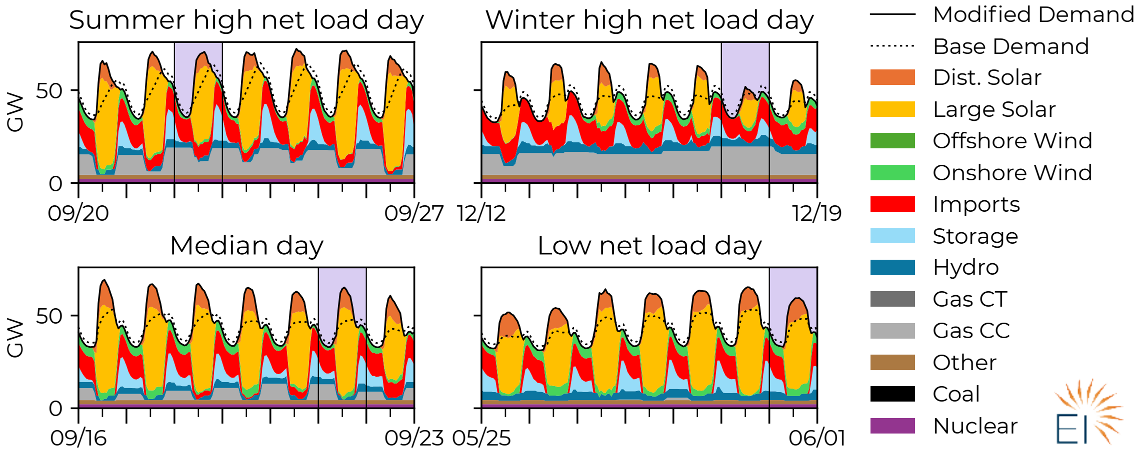
All U.S., clean

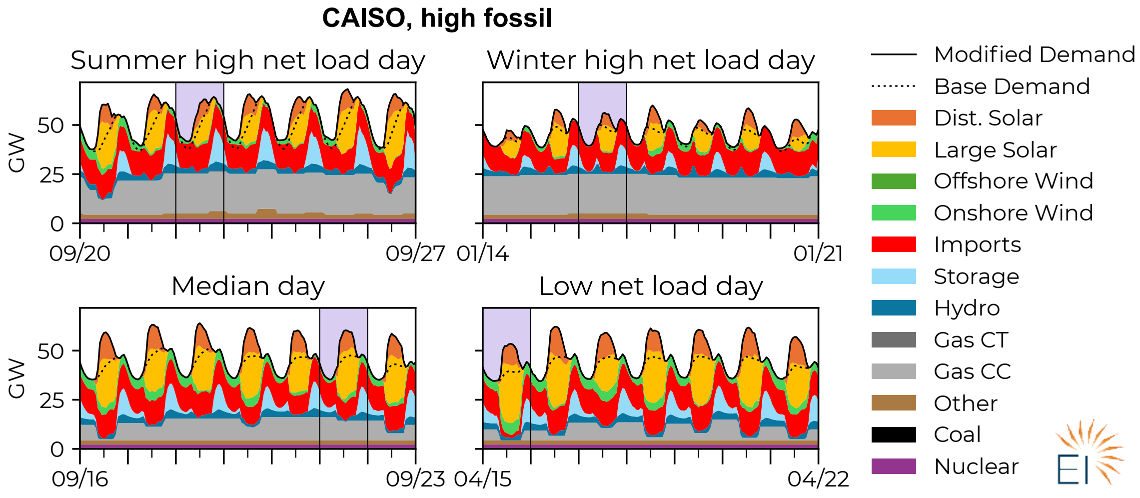


All U.S., high fossil



CAISO, clean





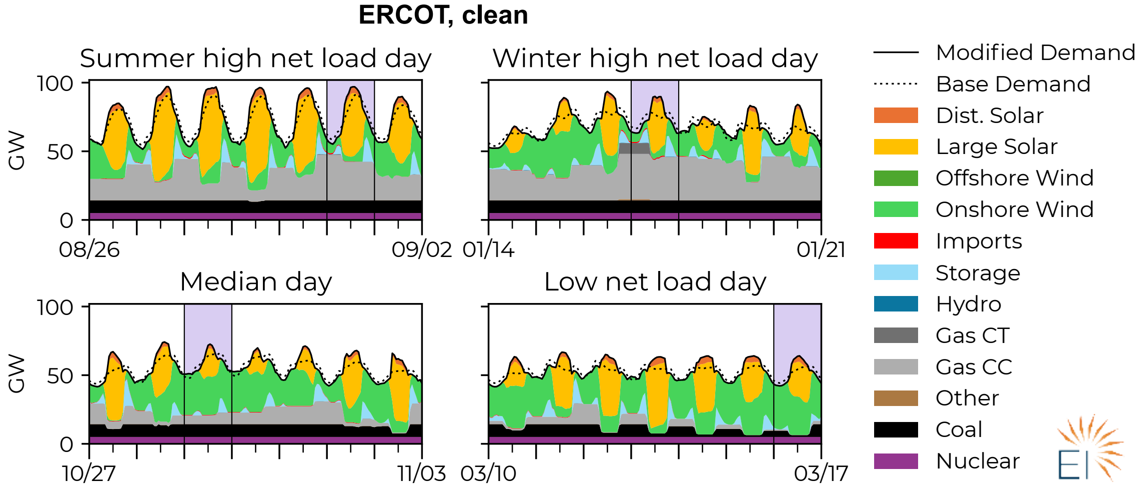
CAISO, high fossil

Summer high net load day

Winter high net load day

Median day

Low net load day



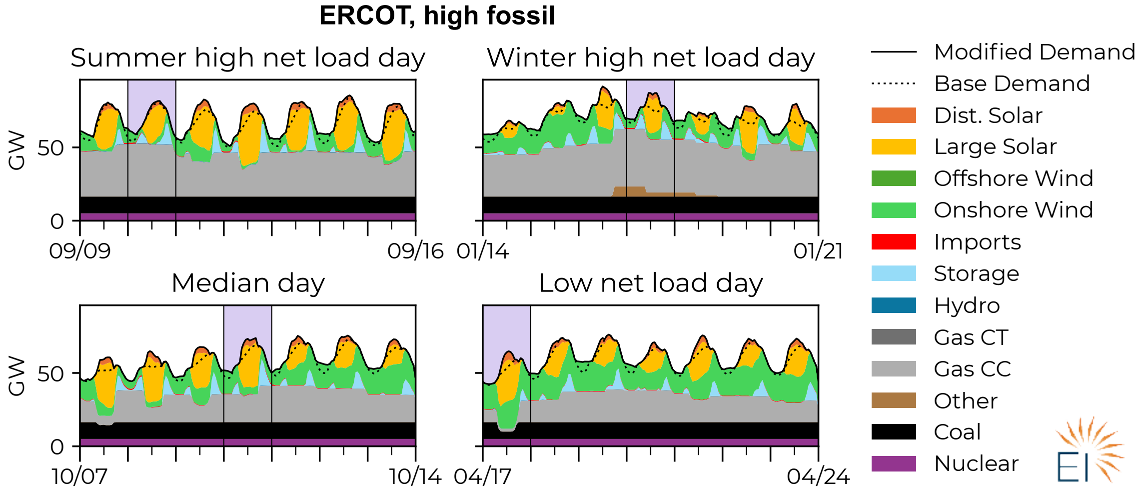
ERCOT, clean

Summer high net load day

Winter high net load day

Median day

Low net load day



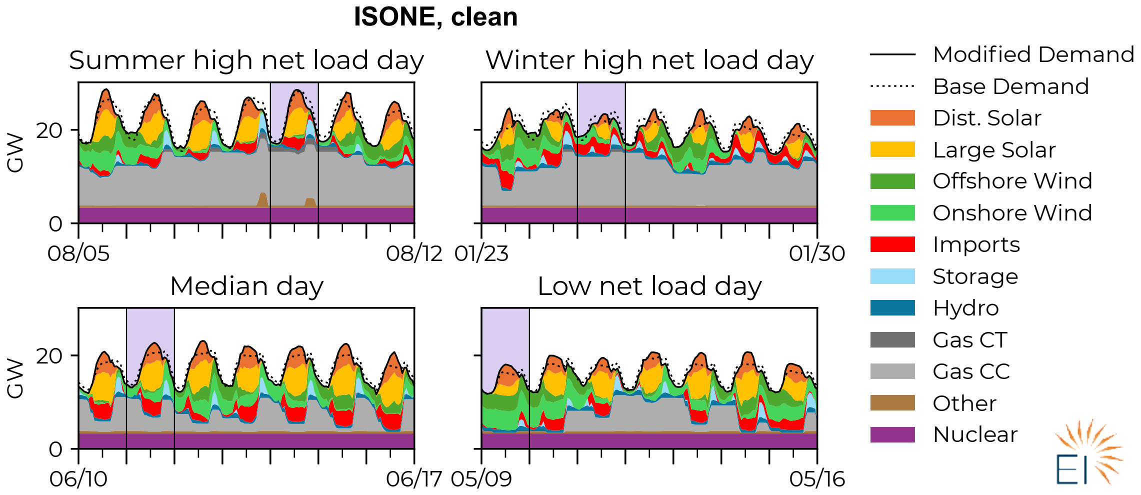
ERCOT, high fossil

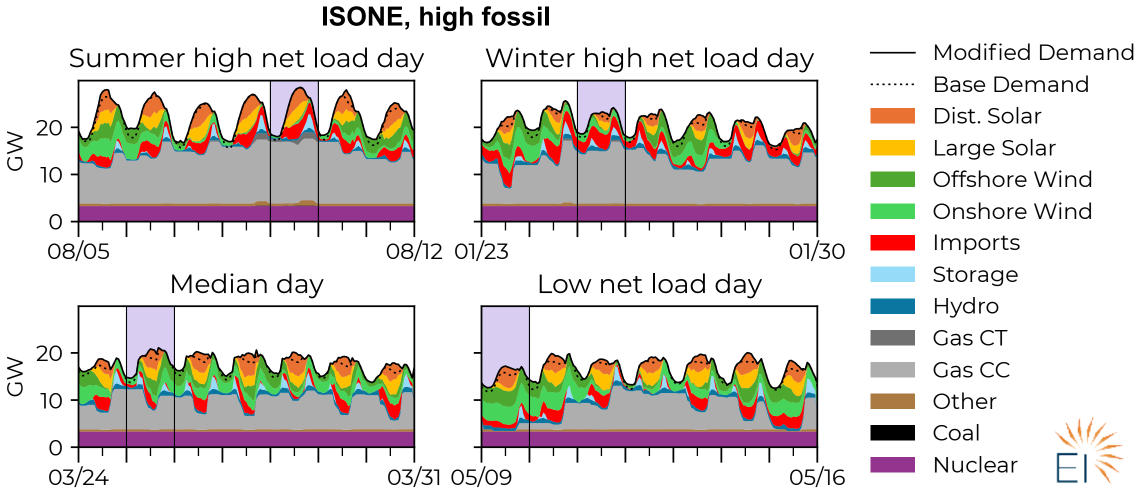
Summer high net load day

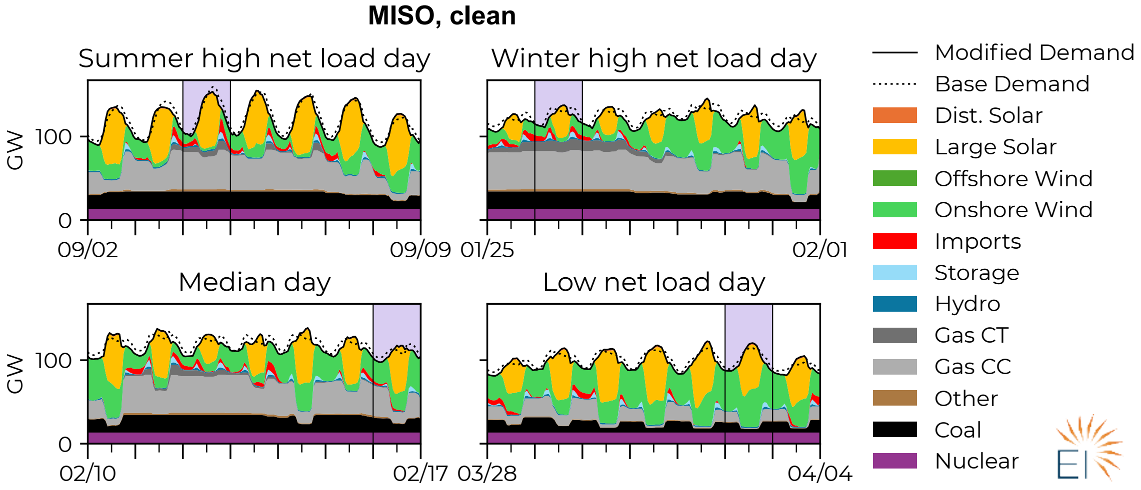
Winter high net load day

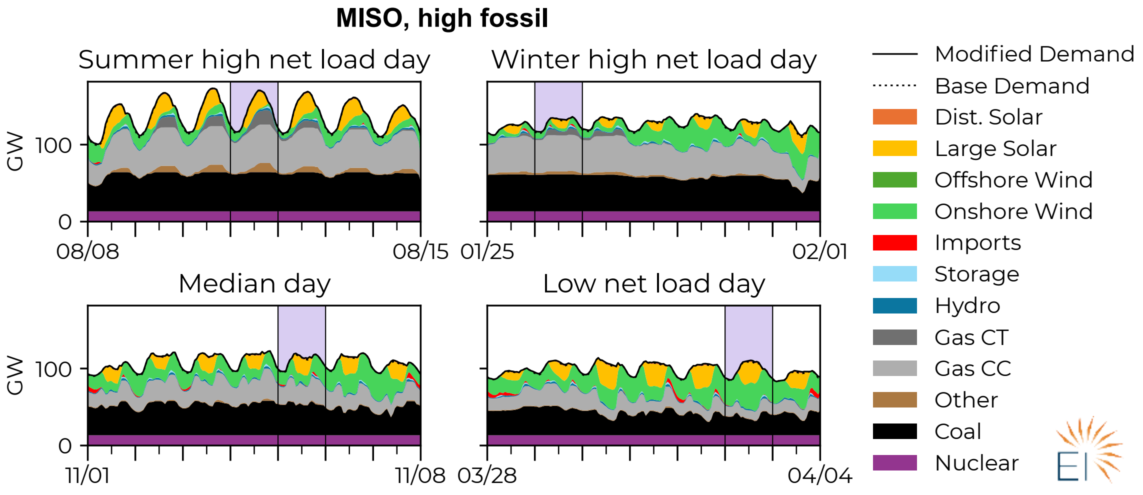
Median day

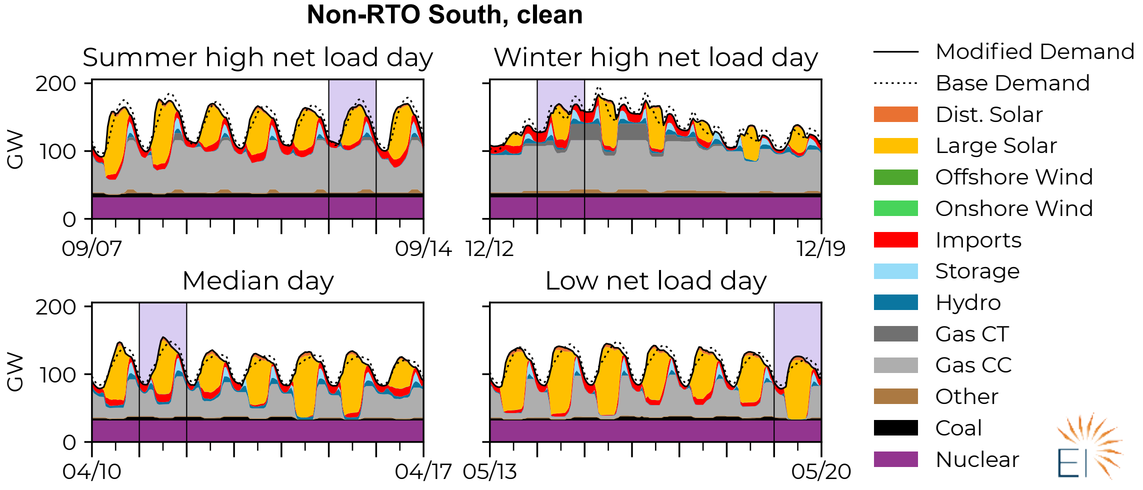
Low net load day

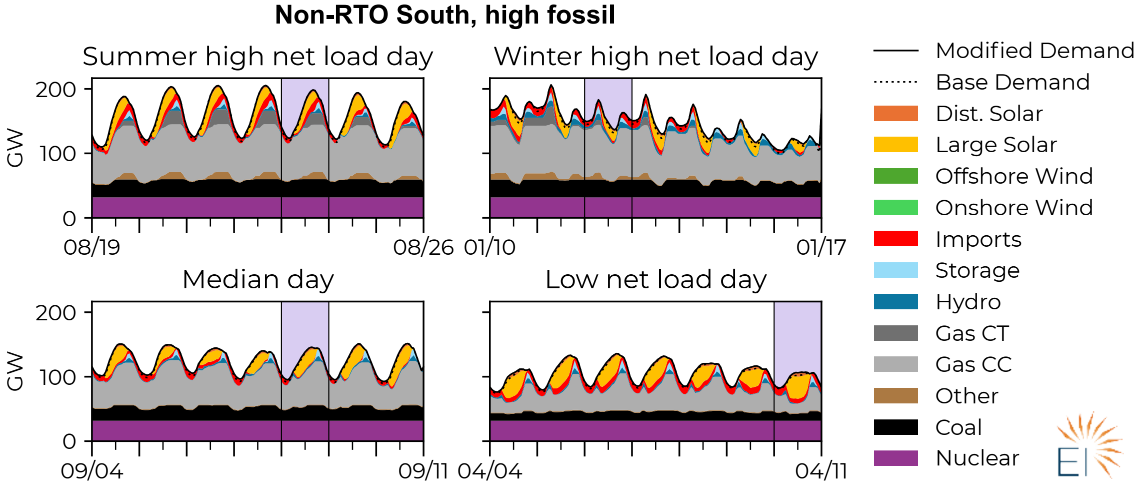

ISONE, clean

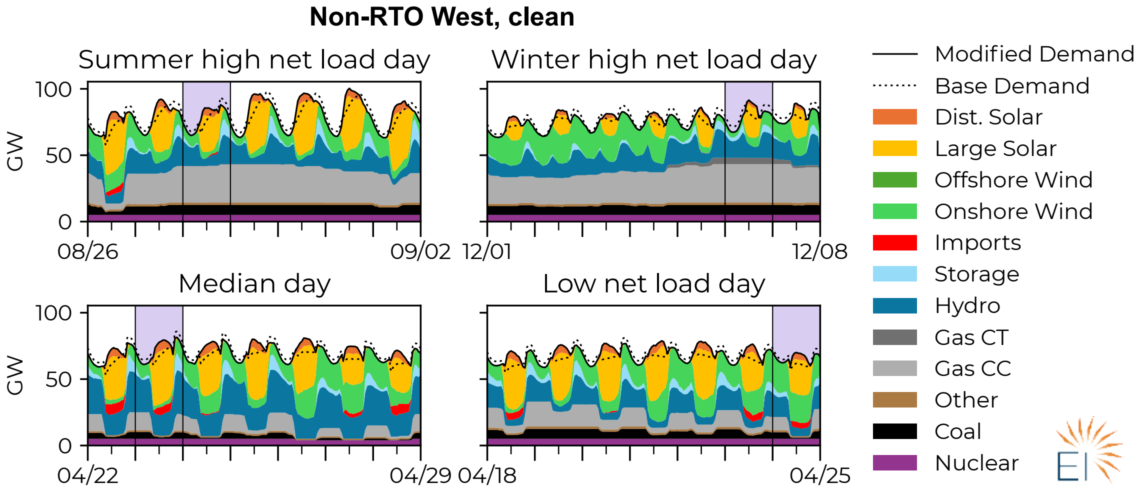

ISONE, high fossil

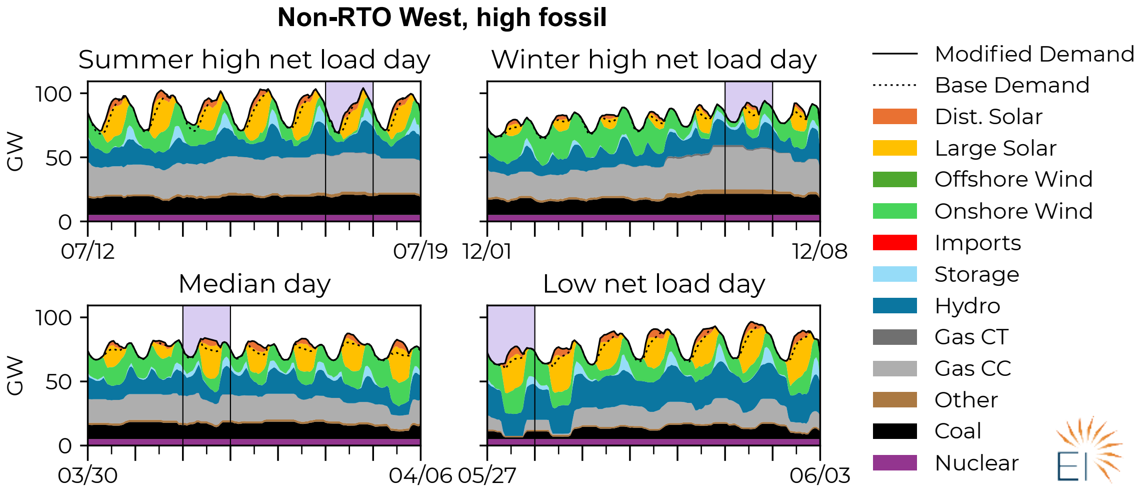

MISO, clean

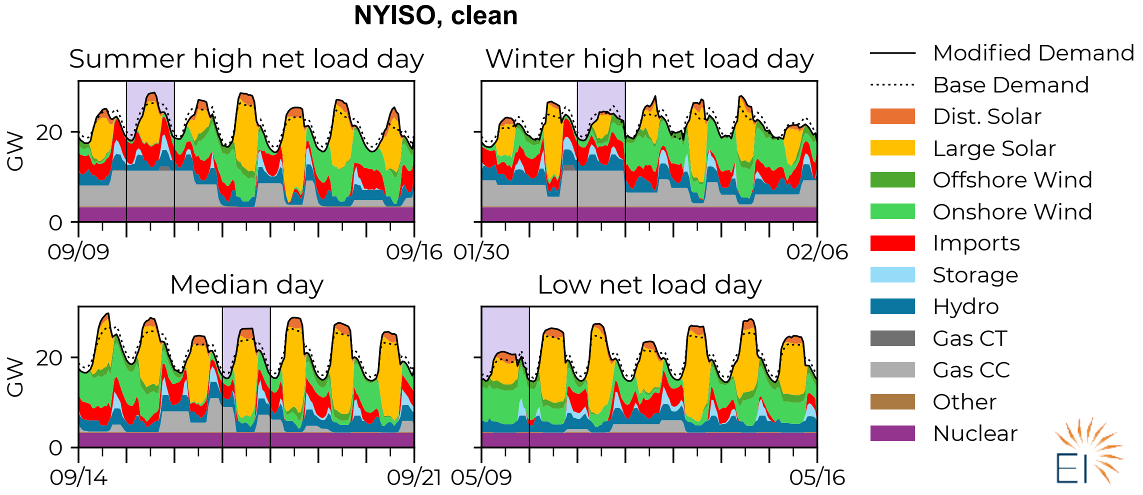

MISO, high fossil

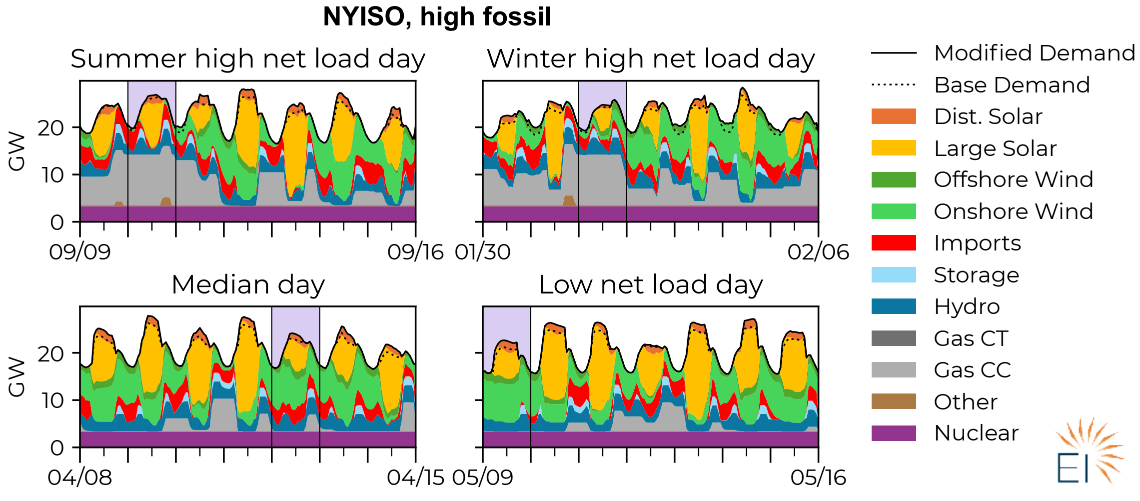

Non-RTO South, clean

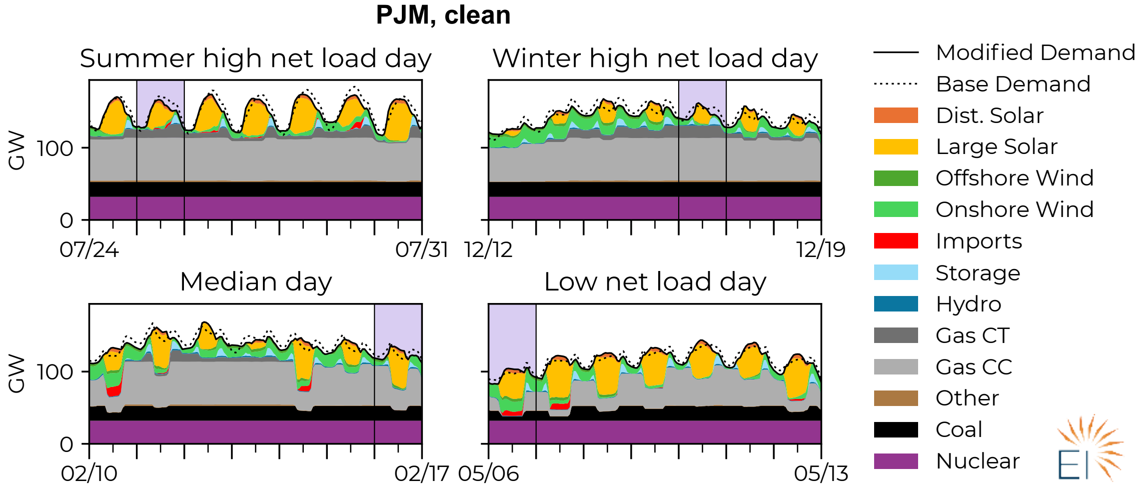

Non-RTO South, high fossil

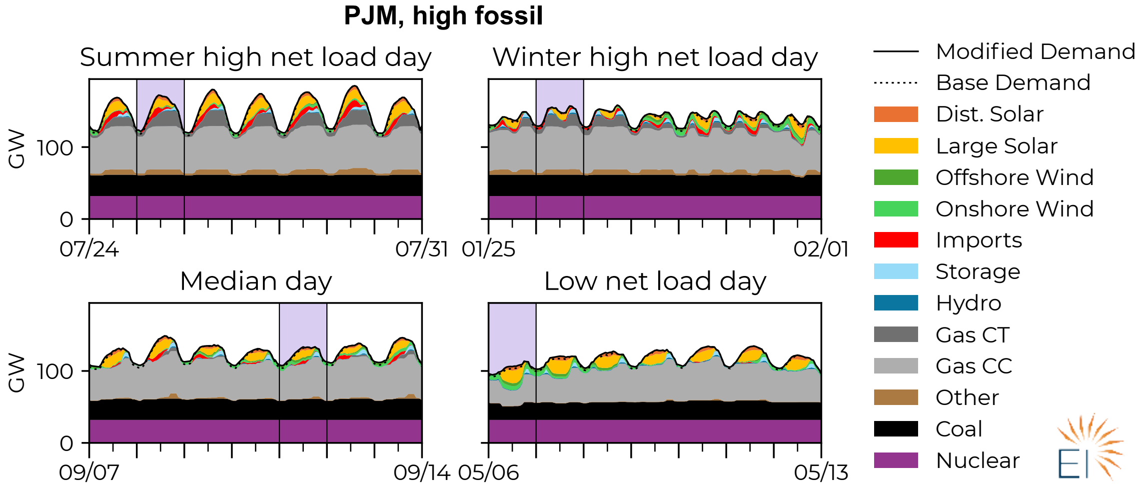

Non-RTO West, clean
Summer high net load day
Winter high net load day
Median day
Low net load day
GW
100
50
0
08/26
09/02
12/01
12/08
04/22
04/29
04/18
04/25
Modified Demand
Base Demand
Dist. Solar
Large Solar
Offshore Wind
Onshore Wind
Imports
Storage
Hydro
Gas CT
Gas CC
Other
Coal
Nuclear

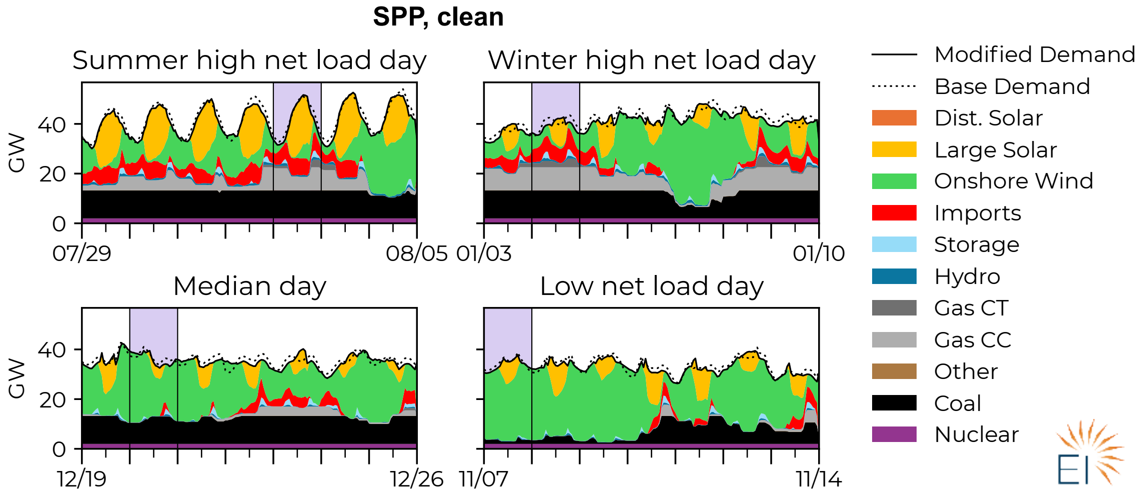

Non-RTO West, high fossil
Summer high net load day
Winter high net load day
Median day
Low net load day
GW
100
50
0
07/12
07/19
12/01
12/08
03/30
04/06
05/27
06/03
Modified Demand
Base Demand
Dist. Solar
Large Solar
Offshore Wind
Onshore Wind
Imports
Storage
Hydro
Gas CT
Gas CC
Other
Coal
Nuclear

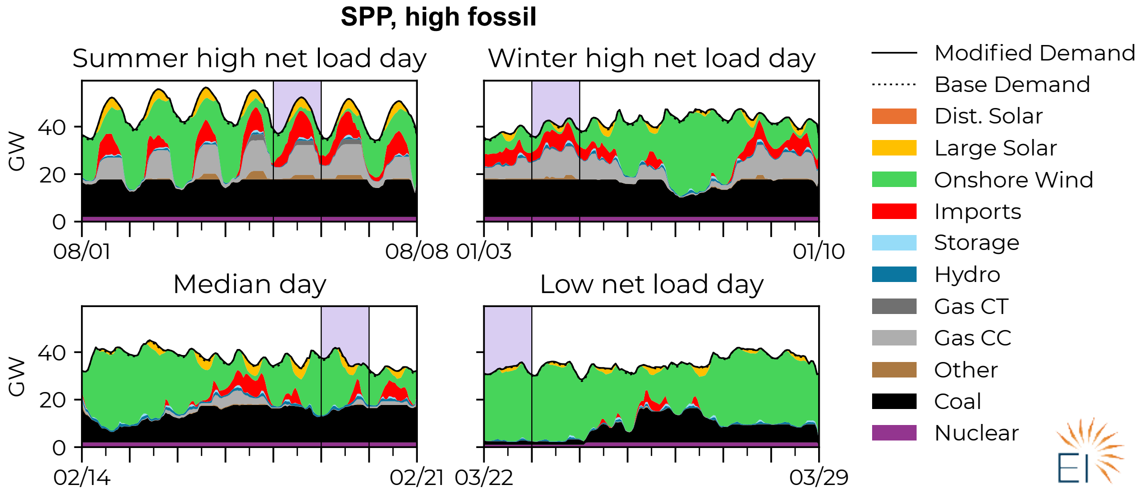

NYISO, clean
Summer high net load day
Winter high net load day
Median day
Low net load day
GW
20
0
09/09
09/16
01/30
02/06
09/14
09/21
05/09
05/16
Modified Demand
Base Demand
Dist. Solar
Large Solar
Offshore Wind
Onshore Wind
Imports
Storage
Hydro
Gas CT
Gas CC
Other
Nuclear


NYISO, high fossil
Summer high net load day
Winter high net load day
Median day
Low net load day
GW
0
10
20
09/09
09/16
01/30
02/06
04/08
04/15
05/09
05/16
Modified Demand
Base Demand
Dist. Solar
Large Solar
Offshore Wind
Onshore Wind
Imports
Storage
Hydro
Gas CT
Gas CC
Other
Nuclear
EI


PJM, clean
Summer high net load day
Winter high net load day
Median day
Low net load day
GW
0
100
07/24
07/31
12/12
12/19
02/10
02/17
05/06
05/13
Modified Demand
Base Demand
Dist. Solar
Large Solar
Offshore Wind
Onshore Wind
Imports
Storage
Hydro
Gas CT
Gas CC
Other
Coal
Nuclear
EI


PJM, high fossil
Summer high net load day
Winter high net load day
Median day
Low net load day
GW
0
100
07/24
07/31
01/25
02/01
09/07
09/14
05/06
05/13
Modified Demand
Base Demand
Dist. Solar
Large Solar
Offshore Wind
Onshore Wind
Imports
Storage
Hydro
Gas CT
Gas CC
Other
Coal
Nuclear
EI





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