2026 TECHNICAL REPORT

Energy Supply and Security Study

Regional Review of Global Energy Security, Energy Equity, and Energy Sustainability from an Electricity Energy Supply Perspective

Energy Supply and Security Study

Regional Review of Global Energy Security, Energy Equity, and Energy Sustainability from an Electricity Energy Supply Perspective

3002034603

The report has been produced by EPRI for the International Energy Agency's (IEA) Coal Industry Advisory Board (CIAB). It is based on analysis of publicly available information by EPRI.

The CIAB consists of a group of high-level executives from coal related enterprises. It was established by the IEA in July 1979 to provide advice to the IEA on a wide range of issues relating to coal. CIAB Members are drawn from 11 countries accounting for approximately 70–80 percent of world coal production and coal consumption. Members are drawn from major coal producers, electricity producers, other coal consuming industries and coal related organizations. The CIAB provides a wide range of advice to the IEA, through its workshop proceedings, meetings, work program and associated publications and papers.

Final Report, March 2026

EPRI Project Manager
M. Caravaggio

EPRI
3420 Hillview Avenue, Palo Alto, California 94304-1338 USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

THIS DOCUMENT WAS PREPARED BY THE ORGANIZATION NAMED BELOW AS AN ACCOUNT OF WORK SPONSORED OR COSPONSORED BY THE ELECTRIC POWER RESEARCH INSTITUTE, INC. (EPRI). NEITHER EPRI, ANY MEMBER OF EPRI, ANY COSPONSOR, THE ORGANIZATION BELOW, NOR ANY PERSON ACTING ON BEHALF OF ANY OF THEM:

(A) MAKES ANY WARRANTY OR REPRESENTATION WHATSOEVER, EXPRESS OR IMPLIED, (I) WITH RESPECT TO THE USE OF ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT, INCLUDING MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, OR (II) THAT SUCH USE DOES NOT INFRINGE ON OR INTERFERE WITH PRIVATELY OWNED RIGHTS, INCLUDING ANY PARTY'S INTELLECTUAL PROPERTY, OR (III) THAT THIS DOCUMENT IS SUITABLE TO ANY PARTICULAR USER'S CIRCUMSTANCE; OR

(B) ASSUMES RESPONSIBILITY FOR ANY DAMAGES OR OTHER LIABILITY WHATSOEVER (INCLUDING ANY CONSEQUENTIAL DAMAGES, EVEN IF EPRI OR ANY EPRI REPRESENTATIVE HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES) RESULTING FROM YOUR SELECTION OR USE OF THIS DOCUMENT OR ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT.

REFERENCE HEREIN TO ANY SPECIFIC COMMERCIAL PRODUCT, PROCESS, OR SERVICE BY ITS TRADE NAME, TRADEMARK, MANUFACTURER, OR OTHERWISE, DOES NOT NECESSARILY CONSTITUTE OR IMPLY ITS ENDORSEMENT, RECOMMENDATION, OR FAVORING BY EPRI.

EPRI PREPARED THIS REPORT.

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

Together…Shaping the Future of Energy®

© 2026 Electric Power Research Institute (EPRI), Inc. All rights reserved. Electric Power Research Institute, EPRI, and TOGETHER…SHAPING THE FUTURE OF ENERGY are registered marks of the Electric Power Research Institute, Inc. in the U.S. and worldwide.

ACKNOWLEDGMENTS

EPRI prepared this report.

Principal Investigator
M. Caravaggio

This report describes research sponsored by EPRI. Conducted with review from the International Energy Agency's Coal Industry Advisory Board with special acknowledgement to:

S. Tickell	Glencore
M. Jacobs	Yancoal
M. Nugen	Peabody
S. Teramana	LTI Global
J. Dutton	LTI Global
A. Yabumoto	JPower
P. Baruya	FutureCoal
K. Ball	Whitehaven Coal
N. Fisher	Thungela
C. Blessing	Uniper
H. Schiffer	RWE
S. Storm	EPRI
K. Bindemann	CIAB

This publication is a corporate document that should be cited in the literature in the following manner: *Energy Supply and Security Study: Regional Review of Global Energy Security, Energy Equity, and Energy Sustainability from an Electricity Energy Supply Perspective.* EPRI, Palo Alto, CA: 2026. 3002034603.

ABSTRACT

This report provides a global analysis of electricity supply across various regions with a focus on energy security. It examines how the energy supply has evolved in different regions and observed changes across the energy trilemma of energy security (reliability), energy equity (affordability), and energy sustainability. The focus for security is evaluating instances of energy supply inadequacy leading to blackouts, load shedding (rolling outages), or emergency measures to prevent regional system collapse. For energy equity, household/residential electricity rates (cents/kWh) are evaluated as a relative indicator between regions. For energy sustainability, the focus is on greenhouse gas emissions per unit of energy measured in grams of carbon dioxide equivalent per kWh (gCO2e/kWh), again as a relative indicator between regions. The study identifies systemic stress points and reliability risks. Key findings include the criticality of evaluating energy supply resources at different timescales. Annual timescales matter for energy sustainability, but affordability and reliability issues arise due to the need to match energy supply with use at every timescale, from seasonal to daily, hourly, minutely, or even down to seconds. Electricity supply must balance demand at a frequency of 60 or 50 Hertz (Hz). The study has found that in many regions, affordability of electricity has been challenged. The study also found that carbon dioxide intensity of electricity is reducing in every examined region.

Keywords

Electricity supply
Energy equity
Energy security
Energy supply
Energy sustainability
Generation
Reliability

EXECUTIVE SUMMARY

Deliverable Number: 3002034603

Product Type: Technical Report

Product Title: Energy Supply and Security Study: Regional Review of Global Energy Security, Energy Equity, and Energy Sustainability from an Electricity Energy Supply Perspective

Primary Audience: Electricity energy system planners

Secondary Audience: Stakeholders involved in energy system planning

KEY RESEARCH QUESTION

This research was conducted to understand how evolving energy supply dynamics impact energy security and reliability under changing conditions. It seeks to address the challenges posed by a changing energy supply mix. The study aims to determine what strategies are necessary to ensure energy supply adequacy and maintain system resilience in a future grid with diverse energy sources. A secondary research question was what the near-term implications are for coal in the electricity energy supply.

RESEARCH OVERVIEW

This research examined electricity supply and energy security challenges across various regions, emphasizing the energy trilemma of security, equity, and sustainability. It was conducted through a global comparative analysis using historical data, case studies of major regions, and quantitative evaluation of generation mixes, carbon intensity, and retail costs. Retail costs were chosen for examination instead of wholesale costs as they are more reflective of total system costs. The methodology included assessing the regional energy resource mix's ability to serve energy at different timescales (annually, peak days, peak hours) and system vulnerabilities that have arisen, such as high demand and low variable resource output periods. Data collection involved systematic evaluation of regions. Results are presented in a technical report featuring graphical representations, concluding with actionable recommendations for improving reliability when looking at an evolving energy mix. Overall, the study underscores the need for balanced progress on energy security and sustainability.

KEY FINDINGS

- Timescales are a critical dimension of energy security. While annual energy mixes inform sustainability goals, they provide a false sense of security regarding grid stability. Supply-demand mismatches can trigger system failures in seconds, as seen in the Iberian Peninsula frequency disturbances—or in minutes after several days of peak strain, such as in the 2021

Texas winter storm. To accurately assess risk, evaluations must include granular analyses of hour-by-hour demand and ramping capabilities under multiple scenarios.

- Affordability has reached a critical threshold in some of the regions examined. Germany and the United Kingdom stand out as high-cost leaders, characterized by a sharp divergence between domestic output and household expenses from 2015 to 2024.
  - United Kingdom: Domestic electricity generation fell by 24%, while nominal household prices surged from ~21 to ~39 euro cents (€c)/kWh.
  - Germany: Domestic production saw a 25% decline, with nominal household prices rising from ~30 to ~40 €c/kWh.
    - This correlation suggests that as these nations decommissioned firm domestic capacity, the resulting reliance on imports and volatile wholesale markets significantly impacted consumer affordability.
- In contrast to the European trend, China and India have maintained stable electricity rates despite surging demand. Both nations have prioritized energy security and industrial competitiveness by leveraging domestic coal to meet the bulk of their expanded energy needs over the last 20 years; in both countries, wind and solar energy provided <20% of electricity needs.
  - China: Total electricity production rose by 74% from 2015 to 2024. Notably, increased coal-fired generation accounted for over 40% of this growth, providing the "firm" base for the expansion.
  - India: Total production increased by 54%, with coal-fired generation meeting more than 70% of the new demand, reflecting a strategic reliance on indigenous fuel sources to keep costs predictable.
- By 2024, Asia’s electricity consumption surpassed that of the rest of the world combined. This marks a radical shift from 2000, when North America and the European Union (EU) were the primary consumers. While Western demand has remained stagnant due to efficiency gains and industrial outsourcing, Asia has seen explosive growth fueled largely by coal, which provides ~55% of the region's power.
  - China’s coal-fired generation alone (~5,800 TWh) exceeds the total electricity production of any other single nation.
  - In August 2025, China produced approximately 580 TWh from coal alone. To put this in perspective, China generated more electricity from coal in this single month than any individual EU nation produces from all sources in an entire year.
  - Most midsized developed nations produce less than 10% of what China generates from its coal fleet alone, highlighting a massive gap in industrial energy scale.
- In terms of sustainability and greenhouse gas (GHG) emissions, France remains the definitive leader among major economies. In 2024, France maintained an extraordinary emission intensity of ~41 grams of carbon dioxide equivalent per kWh (gCO2e/kWh), the lowest of any G20 nation.

  - France's carbon intensity is approximately three times lower than Spain's, four times lower than California’s, five times lower than the United Kingdom’s, and eight times lower than Germany’s.
  - This performance is anchored by a robust nuclear fleet, which accounts for 67% of total generation. Combined with hydro and wind, over 95% of French electricity is now low carbon.
  - Unlike regions with supply-demand mismatches, France’s reliance on nuclear provides a "firm" low-carbon base that supports both national grid security and massive electricity exports to its neighbors.
- As of 2024, coal remains a cornerstone of global electricity, followed by natural gas, hydro, and nuclear. While solar and wind are expanding rapidly, their intermittent nature leaves them unable to consistently meet peak demand without support. While battery storage has begun to address sub-hourly peaks, it introduces a secondary demand cycle on the grid to facilitate recharging.
  - Given the persistent reliance on coal in the world’s most energy-intensive regions, innovation must focus on technologies that align fossil fuel use with the energy trilemma:
    - Security: Enhancing the "dispatchability" and ramping speeds of existing plants.
    - Affordability: Maintaining the cost-curve advantages of domestic fuels.
    - Sustainability: Accelerating the deployment of high-efficiency, low-emission (HELE) technologies and carbon capture, utilization, and storage (CCUS).
  - Improving the environmental performance of the global coal fleet, rather than assuming its immediate disappearance, offers a more realistic pathway to meeting global climate goals without compromising regional stability.

Additional Findings

- Many regions, including North America, Asia, South America, and Europe, have faced events leading to load shedding or blackouts. In the United States, these events often coincide with the Department of Energy’s use of Federal Power Act Emergency Authority. Global examples of nationwide blackouts include Chile 2025 and the Iberian Peninsula 2025 (Spain and Portugal).
- California serves as a primary case study for the economic and operational challenges of high solar penetration. Despite aggressive deployment, the marginal value of solar continues to decline, leading to "negative pricing" and increased curtailment during springtime.
  - In February, March, and April, midday solar supply frequently exceeds demand, driving wholesale prices below zero.
  - While California exceeded 10 GW of battery capacity by early 2025, this has not reversed springtime curtailment.

  - Batteries have significantly mitigated "net peak" risks (the dangerous period in late summer evenings when solar fades but demand remains high), nearly eliminating the risk of summer rolling outages in California.
  - While 4-hour batteries have shaved the hourly gas peak, they have not reduced the total daily reliance on gas during summer.
  - Since 2019, the daily energy requirement from non-solar/non-wind/non-battery sources (primarily gas and imports) has remained largely unchanged, even with the addition of 20 GW of new solar and battery resources.
- Spain and Germany reveal a significant "displacement gap" where investments in renewable (solar and wind) capacity fail to significantly reduce the daily requirement for firm, non-renewable energy.
  - The German case: Between 2015 and 2024, Germany added nearly 90 GW of solar and wind capacity. Despite this massive build-out, the peak daily energy required from non-renewable resources (coal, gas, and imports) has decreased by less than 10% compared to 2015 levels.
  - The Spanish case: Similarly, Spain added 30 GW of solar and wind, yet the daily reliance on firm resources remains largely tethered to 2015 requirements.
  - These figures suggest that current renewable integration is creating a parallel system rather than a replacement system. Because solar and wind are non-dispatchable, the grid must still maintain almost the entire original "firm" fleet to meet demand during periods of low renewable output (the "Dunkelflaute," German for “dark doldrums”).
- The limits of weather-dependent generation were starkly illustrated in November 2024, when a region-wide Dunkelflaute stalled renewable output across the EU for approximately six days (140 hours).
  - Despite an installed wind and solar base exceeding 480 GW, average production during this period collapsed to just 39 GW.
  - For 140 consecutive hours, the entire EU27 fleet operated at less than 10% of its nameplate capacity.
  - This event demonstrates that a grid reliant on wind and solar must maintain nearly 100% redundancy in firm, dispatchable capacity (nuclear, gas, or coal) to prevent total system failure during prolonged atmospheric stagnation.
- In 2016, Germany was a cornerstone exporter for Central Europe. By 2024, the loss of "firm" nuclear baseload forced a structural reliance on imports, natural gas, and coal to stabilize the grid during peak demand.
  - Germany now faces a persistent price disadvantage:
    - Imports at peak: During periods of low renewable output (Dunkelflaute), Germany must import power at a high cost.
    - Negative price exports: During high-wind or high-solar periods, oversupply drives wholesale prices below zero, effectively forcing Germany to pay neighboring countries to take its excess energy.

  - This reliance on fossil-fuel peaking plants and high-carbon imports has kept Germany’s GHG intensity significantly higher than the EU27 average and many of its neighbors, like France.
- The energy transitions in Germany and the United Kingdom face a firmness floor; while total annual gas consumption may fluctuate, the peak daily reliance on gas-fired generation has reached record levels.
  - Record-breaking peaks: Contrary to expectations of a diminishing fossil fuel footprint, the highest daily peaks for gas-fired electricity generation in both nations occurred in 2024 and 2025.
  - This trend highlights that as coal and nuclear plants are decommissioned, natural gas has become the sole "balancing" resource capable of covering massive renewable shortfalls during periods of high demand.
  - The need to meet these intensifying peaks requires maintaining a vast, expensive, and under-utilized gas fleet and pipeline infrastructure, which contributes directly to the rising system costs passed on to consumers and represents an energy security risk.
- The 2025 Iberian Peninsula blackout has forced a fundamental shift in Spanish grid management, moving from a strategy of renewable maximization to one of must-run reliability.
  - Since the April 28 collapse, Spain has significantly increased the number of gas-fired units operating at all times. This ensures that the grid maintains sufficient reactive power and inertia services that the existing inverter-based renewable fleet could not adequately provide during the frequency disturbances that triggered the blackout.
  - The blackout was characterized by a "voltage chain reaction" where generation disconnections led to further voltage spikes. By keeping gas units synchronized to the grid even during periods of high solar/wind, the operator provides a "damping" effect that prevents localized faults from cascading into a peninsula-wide security issue.
  - This requirement for constant gas synchronization increases the floor of fossil fuel generation, effectively creating a limit on how much renewable energy can be utilized without risking system collapse.
- While France’s nuclear fleet provides a low-carbon baseline, its recent history reveals the "common mode risk" inherent in highly standardized energy systems.
  - France experienced a historic supply shock when stress corrosion cracking was discovered in auxiliary piping welds. This forced more than half the fleet offline simultaneously, reducing annual output by nearly 30% compared to 2021 (dropping from 360 TWh to 279 TWh).
  - France’s strategy of using a single, coherent reactor design significantly reduced construction and maintenance costs for decades. However, this same uniformity created a "common mode failure" vulnerability, where a single technical defect required a fleet-wide emergency inspection and repair program.

  - Although generation recovered to a six-year high in 2024, the fleet is aging; most reactors are entering their fourth or fifth decade of operation. This is an ongoing security-of-supply concern that will require investment to manage.
- After twenty years of stagnant electricity demand, the United States has entered a new era of rapid load growth, driven by the dual pressures of electrification and the artificial intelligence (AI) infrastructure boom.
  - Despite the ongoing energy transition, 2024 and 2025 saw record peak demand days for coal and gas. For the first time, winter peaks required over 9 TWh of thermal generation in a single day, highlighting that natural gas remains the reliability of last resort during extreme cold snaps (e.g., the January 2025 polar vortex).
  - Rapid demand growth is no longer a projection; it is an operational reality. The expansion of AI data centers is concentrated in specific hubs, creating localized energy security risks where load growth outpaces the construction of new transmission and firm generation.
  - As of early 2026, the U.S. grid faces a paradox: while solar and battery additions lead in new capacity, existing fossil fuel units are working harder than ever to bridge the gap during peak hours and weather anomalies.

WHY THIS MATTERS

These findings reveal the diverse challenges and systemic stress points in achieving the energy trilemma of energy security, energy equity (cents/kWh), and energy sustainability (gCO2e/kWh). They underscore the need for detailed evaluation of energy supply at high resolution (looking at every hour of a year) and considering all attributes of different energy supply resources to ensure that future energy supply mixes are resilient, affordable, and sustainable.

HOW TO APPLY RESULTS

The assumptions in modeling future energy scenarios are critical. This research can be used by modelers to design scenarios to test the validity of their assumptions. It is critical to evaluate over different timescales, particularly at high resolution, to ensure energy supply adequacy. It is similarly critical to evaluate resource mix attributes to ensure they can provide a resilient electricity supply across scenarios.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- EPRI has launched the Rapid Adaptation of grid Defense, Analytics and Resilience project to address risks revealed during the Iberian Peninsula blackout.
- EPRI has launched the DCFlex Initiative to determine how data centers can support and stabilize the electric grid while improving interconnection and efficiency.
- EPRI has launched its Emerging Fuels and Technologies portfolio to explore alternative fuel approaches that can yield improved reliability, affordability, and sustainability results.
- EPRI has completed its Resource Adequacy initiative to develop enhanced approaches for modeling the needs for future energy mixes.
- EPRI's Generation R&D portfolio explores all aspects of making energy supply safer, more affordable, more reliable, and more environmentally sustainable.

EPRI CONTACTS: M. Caravaggio, mcaravaggio@epri.com, Vice President Energy Supply Reliability

PROGRAM: Heat Rate and Flexibility: Generation Fleet Optimization, P223

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1. INTRODUCTION

Background and Objectives

Managing and maintaining electricity security and reliability of supply is becoming a significant challenge in many regions of the world. Many regions have faced blackouts, load shedding (rolling blackouts), and emergency conservation efforts. Regions have also seen significant affordability issues.

This report provides a global examination of the electricity system challenges observed as the energy supply mix has evolved, with examples from major economies such as the United States, Europe, and large growing countries such as China and India.

The objective of the report has been to examine electricity system energy security through the lens of the energy trilemma.

Energy Trilemma

Energy security: The ability to reliably meet current and future energy demand and to withstand and recover from system shocks

Energy equity: The ability to provide universal access to reliable, affordable, and abundant energy

Energy sustainability: The transition of a country's energy system to mitigate and avoid environmental harm and climate change impact

The report includes regional case studies examining energy security framed by energy equity and energy sustainability results for the region. For energy equity, affordability in terms of retail household/residential electricity rates in cents/kilowatt-hour (cents/kWh) is used to benchmark changes over time and for regional comparisons. For energy sustainability, the greenhouse gas (GHG) emission intensity of the electricity supply in terms of grams carbon dioxide equivalent per kWh (gCO2e/kWh) are used for benchmarking performance across different regions.

Examining regional results to date in energy transitions can yield insights on how to optimize progress while addressing the energy trilemma. The case studies developed in this report can be used to evaluate energy transition projections and modeling assumptions. They can also be used to develop approaches, which may yield better results in achieving solutions to the energy trilemma challenges.

Energy Security from an Electrical Energy Supply Perspective (Section 2)

Section 2 of this report provides a primer on electricity supply and how energy supply continues to evolve across the globe in different regions. A high-level summary of major electricity supply disruptions across the globe is provided. These include Pakistan 2023, Bangladesh 2022, Brazil 2023, Cuba 2024, Chile 2025, and the Iberian Peninsula 2025. A discussion of electricity frequency and the various other aspects of electricity supply is introduced as they are relevant for the security of electrical energy supply. A complete understanding of these concepts is not necessary to understand the following sections of the report, or the conclusions and recommendations that are developed, but a basic understanding of these aspects of electricity supply can be beneficial.

The importance of timescales for matching electricity supply and demand and the different attributes of the electricity supply are introduced in this opening section. Electricity supply and demand must balance at 50 or 60 Hertz (Hz) (cycles per second), with the correct attributes (e.g., voltage), or system collapse can rapidly occur. Mismatches between supply and demand can, within seconds to minutes, lead to security issues that can result in total system collapse (blackouts). On longer timescales, mismatches between supply and demand can also lead to security issues as well as structural affordability issues.

Energy security issues for electricity come in many degrees, with the most significant failure being a regional blackout, which is a complete system collapse. Ahead of a system collapse, load shedding may occur. Load shedding is a deliberate and temporary interruption of electricity supply to certain areas to balance the available electricity supply with demand. Colloquially, in many regions, this would be referred to as a “rolling blackout.” This is usually done to prevent the entire power grid from becoming overloaded and potentially failing. It helps balance the supply and demand of electricity, especially during peak usage times or when there are issues with power generation sources. Many regions across the globe have experienced events that have led to load shedding events. Ahead of potential load shedding events, emergency measures may be taken. In the United States, this often coincides with use of the Federal Power Act Emergency Authority where a maximum generation order may be authorized to suspend any environmental permit-related limitations on generation supply in order to avoid needing to conduct load shedding to avoid the potential for a blackout. This is an illustration of the connectivity of the energy trilemma. Use of these orders is a choice to temporarily reduce energy sustainability to address an acute energy security risk.

Energy equity is a complex topic that for the purposes of this report has been distilled to household/residential retail rates (cents/kWh) for benchmarking different regions. As an energy mix changes, it is possible to ensure energy security through increased investment. As such, looking at energy security alone cannot give a full picture of how the energy trilemma is addressed. In some case studies in the report, wholesale prices, as well as commercial and industrial retail rates, are also examined.

Energy sustainability is similarly a complex topic which needs to be considered when evaluating electrical energy supply mix results. The simplified benchmark approach for this report has been to look at the greenhouse gas emission intensity of the electricity mix for the evaluated regions. This is distilled into the grams of carbon dioxide (equivalent) per kilowatt-hour (gCO2e/kWh). This is a technical term, but, essentially, the higher the number, the higher the greenhouse gas emissions per unit of energy. Clearly, a more complete look at sustainability would involve many more factors. The carbon intensity benchmark was chosen as an important proxy to allow for comparisons across regions to help frame the energy security discussion.

Section 2 of this report provides a more comprehensive global summary of electricity supply resource mixes, relative energy equity in terms of the household/residential rate cents/kWh benchmark, and relative energy sustainability in terms of the gCO2e/kWh benchmark.

Case Studies (Sections 3 through 7)

Sections 3 through 7 contain case studies which present details on the electricity energy supply mix of the examined regions. The generation mix (TWh), i.e., actual energy production, and capacity mix (GW), i.e., the total installed capacity of power plants, will be presented. The performance of the region with respect to the energy trilemma aspects will also be presented.

Every case study begins with a 2015 to 2024 comparison benchmark; Figure 1 is an example of the benchmark figure.

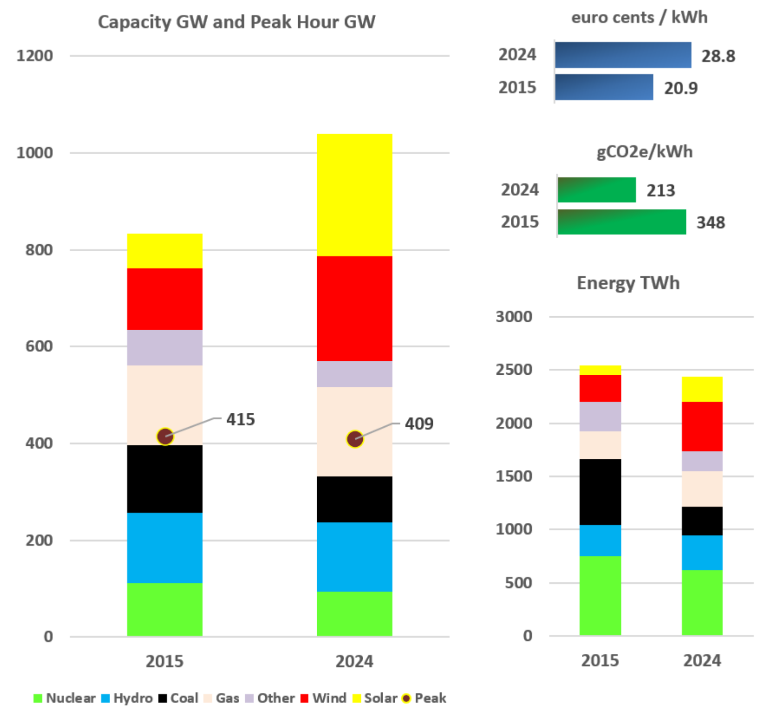


Figure 1. Case study benchmark example

The left side shows the nameplate capacity of power plants in the region in 2015 and 2024 along with the hourly peak demand in the region (in GW). The top right is the household/residential retail rate in 2015 and in 2024 (in cents/kWh). These are nominal values. Beneath that on the right is the greenhouse gas intensity in 2015 and 2024 (in gCO2e/kWh). The bottom right of each benchmark is the actual energy (generation) produced in 2015 and 2024 for the region (in TWh).

The benchmark chart is followed by a more detailed discussion of electricity supply and demand at different timescales and important and relevant trends seen in each region related to the energy trilemma but with the primary focus on energy security.

Europe Case Studies (Section 3)

Section 3 goes through the case studies for Europe, with a regional summary of the entire European Union (EU27) first. The subsequent regional case studies in Section 3 cover Germany, France, the United Kingdom, and Spain.

The Germany case study examines the trilemma result for an energy mix evolution which includes more solar and wind and the shutdown of nuclear power plants. In France, the case study looks at the results from an electrical energy supply that remains reliant predominantly on nuclear, with some incremental addition of solar and wind energy additions. For the United Kingdom, the results from an energy supply mix that has seen an increased adoption of wind and shutdown of coal are reviewed. In the Spain case study, results are presented for an energy supply that has increased adoption of solar and wind.

United States Case Studies (Section 4)

Section 4 goes through the case studies for the United States, with a regional summary of the entire United States, followed by regional case studies for Texas (Electric Reliability Council of Texas [ERCOT]), California (California Independent System Operator [CAISO]), and Pennsylvania-New Jersey-Maryland Interconnection (PJM) which is a large operating area covering all or parts of 13 states and Washington, D.C., including Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.

The Texas (ERCOT) case study examines the trilemma for an energy mix with increasing solar, wind, gas, and batteries in the energy supply, along with load growth. The California case study looks at increasing solar and batteries in the energy supply with limited load growth. In PJM, the case study looks at an energy supply which is increasingly reliant on gas, with continued reliance on nuclear and coal.

Asia Case Studies (Section 5)

Section 5 covers a case study for China and a case study for India.

The China case study examines a region with dramatic load growth, significant reliance on coal, and increasing solar, wind, hydro, and nuclear energy in the electrical energy supply. India is a region where there is also significant load growth, continued heavy reliance on coal, and expanding solar generation.

Australia Case Study (Section 6)

Section 6 covers a case study for Australia. Australia is a region with increasing solar, wind, and batteries in the energy supply, but where coal remains the largest share of the energy resource mix. Australia’s solar energy supply increases are notable as they include a very large portion of rooftop solar adoption, whereas in many other regions, solar development has been at the utility scale (i.e., large solar fields).

South Africa Case Study (Section 7)

Section 7 covers a case study for South Africa, where the energy mix continues to be dominated by coal but solar rooftop adoption has begun increasing.

Discussion, Conclusions, Recommendations (Section 8)

Section 8 closes the report with a data-driven discussion. Conclusions are summarized and recommendations made. The discussion includes an evaluation of the observed results, with respect to managing the energy trilemma, for the different energy supplies examined.

2. ENERGY SECURITY FROM AN ELECTRICAL ENERGY SUPPLY PERSPECTIVE

Key Information Point

Electricity grids are the world’s largest machines.

Electrical grids are often called the world’s largest machines. This is due to their interconnection, which provides security and stability but also can be a source of fragility when the system is operating at extremes. Large-scale grid collapses have occurred numerous times. Here is an abbreviated recent list:

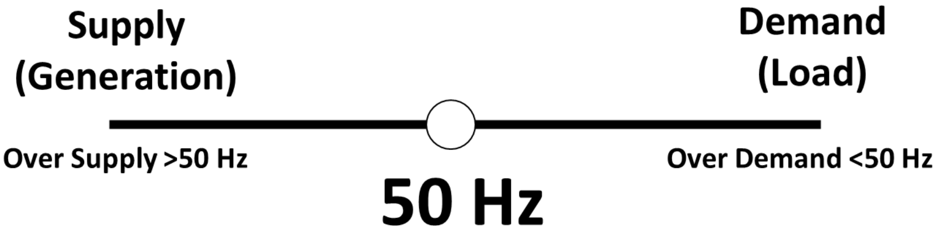
Table 1. Abbreviated list of recent blackouts

Country/ Region	Date	Link
Bali	May 2, 2025	https://www.cnn.com/2025/05/02/travel/bali-indonesia-power-outage-intl
Spain/Portugal	April 28, 2025	https://en.wikipedia.org/wiki/2025_Iberian_Peninsula_blackout
Puerto Rico	April 16, 2025	https://apnews.com/article/puerto-rico-blackout-easter-islandwide-
Panama	March 15, 2025	https://ticotimes.net/2025/03/16/nationwide-power-outage-hits-panama-after-generator-failure
Honduras	March 1, 2025	https://www.latinnews.com/honduras-hit-by-national-blackout.html
Chile	February 25, 2025	https://en.wikipedia.org/wiki/2025_Chile_blackout
Sri Lanka	February 9, 2025	https://en.m.wikipedia.org/wiki/Power_outages_in_Sri_Lanka#2025_blackouts
Cuba	February, March, October, and December 2024	https://en.wikipedia.org/wiki/2024%E2%80%932025_Cuba_blackouts
Brazil	August 15, 2023	https://en.wikipedia.org/wiki/2023_Brazil_blackout
Pakistan	January 23, 2023	https://en.wikipedia.org/wiki/2023_Pakistan_blackout
Bangladesh	October 4, 2022	https://en.wikipedia.org/wiki/2022_Bangladesh_blackout

In each case of grid collapse, electricity supply and demand, which must match every second—or more precisely every 50 or 60 times a second—had reached a point of no return. A 1% deviation in system frequency (0.5 Hz on a 50 Hz grid or 0.6 Hz on a 60 Hz grid) indicates a system operating at serious risk of collapse.

Key Information Point

Deviations from the nominal 50-Hz grid frequency correspond to escalating levels of system risk. Small deviations indicate a stable system while moderate deviations indicate corrective action is required and large deviations indicate severe instability and potential collapse.



49.900 - 50.100 Hz
No Issue
49.750 - 49.900 / 50.100 - 50.250 Hz
Action Needed
49.500-49.750 / 50.250 - 50.500 Hz
System at Serious Risk of Collapse

A large portion of the operation of the electricity system is about maintaining this balance. This involves ensuring supply (generation) can arrive at demand (load), or, in plain terms, that the electricity produced can reach the point of use. Here, voltages are critical.

Voltage is a local property of parts of a grid, that is, the voltage level at any given point in an electricity network can vary based on immediate, local conditions, rather than being the same everywhere. For example, the voltage in a neighborhood is different from that on a large overhead transmission line. Transformers are used to step-up or step-down voltages but have no impact on frequency.

So, a grid has a single frequency but can have multiple different voltages. Regulation of both is critical for electricity security.

All electricity-using devices and electricity-producing devices have voltages they expect to see or, more precisely, at which they are designed to operate. Voltages that deviate too far from expected values can damage equipment. On the generation supply side, generation resources are designed to regulate voltages but will disconnect if the actual voltage is too far from the expected (designed for) voltage. A primary cause for the generation-supply disconnection identified during the Iberian Peninsula blackout was based on voltage settings.

If a system collapses, it must be restarted. In electrical grids, this is known as a black start. Not all energy supply technologies are designed with the ability to black start. Many require electricity from the grid to start up. A collapsed grid typically takes 12–24 hours to restore, but under freezing conditions the restoration time could be much longer.

Key Information Point

Different energy supply technologies have different abilities to regulate voltages and frequency. They also have different overall availability.

EPRI has produced *Contributions of Supply and Demand Resources to Required Power System Reliability Services 2025*, [1] which includes a matrix as a guide for how different resources currently contribute to reliability services. Reliability services are each key to electricity security in different ways; the technical names of these services are below with a plain language description of how they contribute to reliability.

Voltage and Reactive Power Control

- The objective of voltage and reactive power control is to ensure that bus voltages remain within acceptable ranges throughout the network by balancing the production and absorption of reactive power in real time.

Short-Circuit Contribution

- Short-circuit contribution is a primary indicator of grid strength. A system with higher short-circuit strength is more robust and less susceptible to voltage fluctuations caused by varying load levels.

Frequency and Active Power Control

- Frequency control is the continuous balancing of electricity supply and demand. Because the grid has no inherent storage, any imbalance results in a frequency deviation. Balance is maintained across several timeframes:

- Inertial Response (0–2 seconds): The immediate, physical response to a frequency change.
  - **Synchronous Initial Response (SIR):** Provided by the kinetic energy stored in the rotating masses of traditional turbines and generators.
  - **Fast Frequency Response (FFR):** A synthetic response provided by inverter-based resources (like batteries) to mimic or augment traditional inertia.
- Primary Frequency Response (2–10 seconds): Often called Governor Control, this is the automatic adjustment of generator output to arrest the frequency drop.
- Secondary Control and Contingency Reserves (30 seconds–15+ minutes): The deployment of spinning reserves (synchronized units) and non-spinning reserves (fast-start units) to restore frequency to its nominal value (e.g., 50Hz or 60Hz) and relieve the primary responders.

Resource Availability

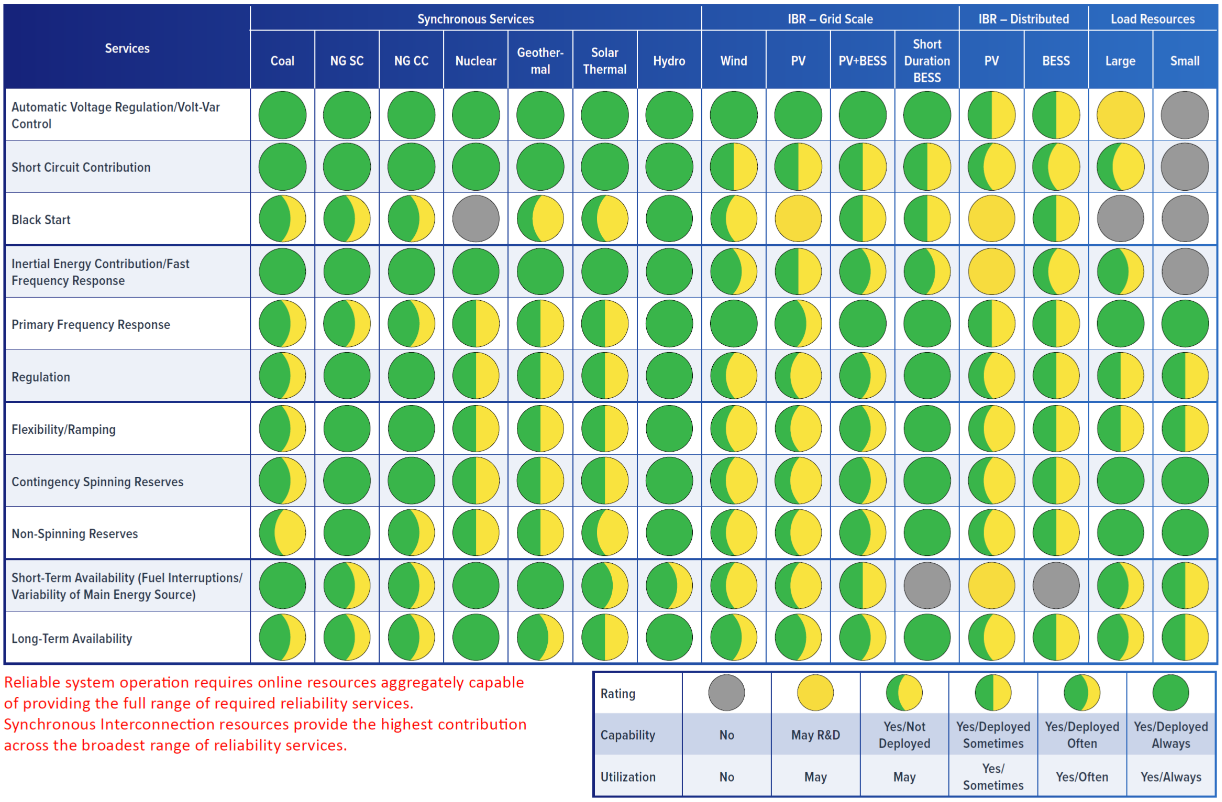
- This is the availability of resources with sufficient capacity to meet demand across all periods of the day and seasons of the year.

Black Start

- Equipment that can be started without support from the electricity grid or is designed to remain energized without connection to the remainder of the electricity grid.

Figure 2 provides a relative ability of different resources to provide reliability services. The details matter less than the general trend. The top two services relate to voltage control. Synchronous generators like coal-fired plants always deploy these (fully green). For inverter-based resources (IBR), this is not always deployed or available (increasing amounts of yellow). For distributed energy resources (DER), this occurs more often (e.g., rooftop solar). And for load resources (e.g., demand response) there is essentially no voltage control support.

WARNING: Relative rankings in table based on specific assumptions and disclaimers documented in white paper—do not use in isolation.
Relative scores are based on “typical” capabilities of resources presently being installed.



Services	Synchronous Services							IBR – Grid Scale				IBR – Distributed		Load Resources	
	Coal	NG SC	NG CC	Nuclear	Geother-mal	Solar Thermal	Hydro	Wind	PV	PV+BESS	Short Duration BESS	PV	BESS	Large	Small
Automatic Voltage Regulation/Volt-Var Control	●	●	●	●	●	●	●	●	●	●	●	◑	◑	🟡	○
Short Circuit Contribution	●	●	●	●	●	●	●	◑	◑	◑	◑	◔	◔	◔	○
Black Start	◕	◕	◕	○	◔	◔	●	◔	🟡	◑	◑	🟡	◑	○	○
Inertial Energy Contribution/Fast Frequency Response	●	●	●	●	●	●	●	◕	◑	◕	◕	🟡	◔	◕	○
Primary Frequency Response	◕	◕	◕	◑	◑	◑	●	●	◕	●	●	◑	◑	●	●
Regulation	◕	●	●	◑	◑	◑	●	◔	◔	◕	●	◔	◑	◑	◑
Flexibility/Ramping	◕	●	●	◑	◑	◑	●	◔	◔	◕	●	◔	◑	◑	◑
Contingency Spinning Reserves	◕	●	●	◑	◑	◑	●	◔	◔	◕	●	◔	◑	●	●
Non-Spinning Reserves	◔	●	◕	◑	◑	◔	●	◔	◔	◕	●	◔	◑	●	●
Short-Term Availability (Fuel Interruptions/ Variability of Main Energy Source)	●	◕	◕	●	●	◕	◕	◔	◔	◑	○	🟡	○	◕	◑
Long-Term Availability	◕	◕	◕	●	◕	◑	●	◕	◕	◕	●	◔	◑	◕	◑

Reliable system operation requires online resources aggregately capable of providing the full range of required reliability services.
Synchronous Interconnection resources provide the highest contribution across the broadest range of reliability services.

Rating	○	🟡	◔	◑	◕	●
Capability	No	May R&D	Yes/Not Deployed	Yes/Deployed Sometimes	Yes/Deployed Often	Yes/Deployed Always
Utilization	No	May	May	Yes/ Sometimes	Yes/Often	Yes/Always

Figure 2. Relative reliability contributions [1]

Similarly black start (third row) capabilities are still a matter of R&D for many non-synchronous sources of generation.

The next six rows of services cover frequency control at different timescales (from near instantaneous inertia and fast frequency response to several minutes or hours for non-spinning reserves). Synchronous generation again provides more of these services than is currently available for IBR at the grid or DER scale.

The last two rows cover energy availability. These services have system effects on overall grid stability through different timescales and are explored in more detail in the next section.

Timescales Matter – Energy Supply and Electricity Security

Figure 3 gives timescales that are relevant when looking at electricity energy security.

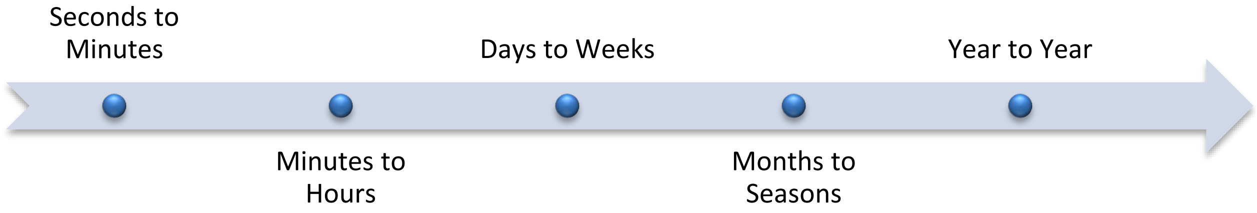


Figure 3. Electricity timescales

Blackouts and brownouts occur over the timescale of seconds to minutes. Having inadequate energy supply resources to respond to deviations in voltages and frequencies under these conditions can lead to system collapse.

Over minutes to hours, the electricity system's demand can move quickly or moderately; the speed at which the system's energy supply needs to move can impact the longevity of energy supply resources (power plants). The evolution from a ”duck curve” [2] to a ”canyon curve” (see Figure 4) in solar-rich regions like California, illustrate the differences in how net demand can evolve over time.

Key Information Point

Net demand is the total electricity demand less the generation supplied by variable energy resources (wind and solar). This represents the electricity demand that must be supplied by dispatchable resources. Significant intra-day fluctuations in net demand increase the need for frequent ramping, which can lead to accelerated plant wear and higher maintenance costs.

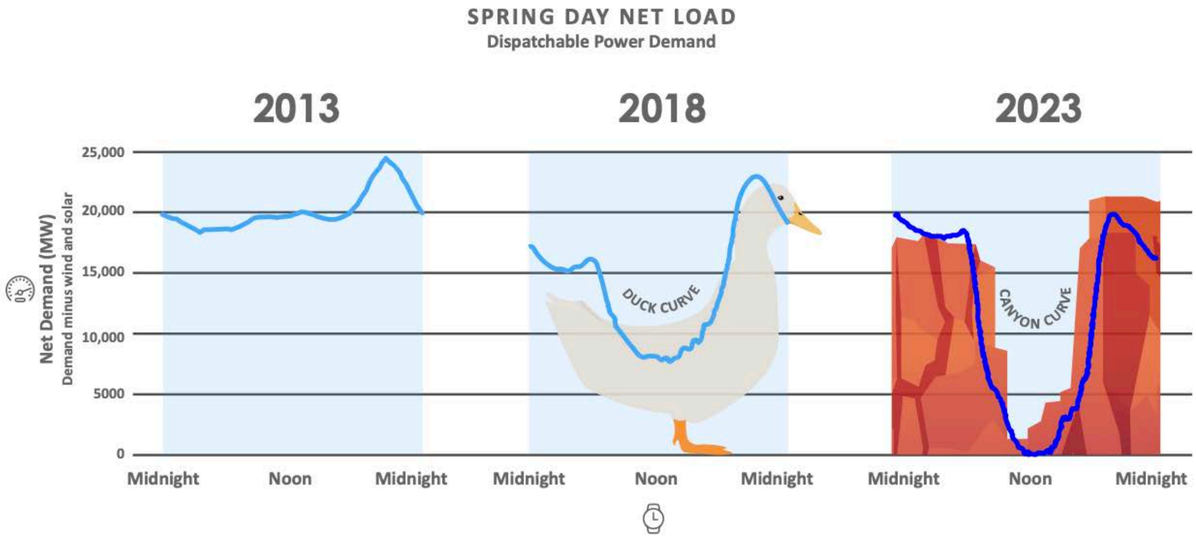


Figure 4. California Independent System Operator net demand evolution – duck to canyon curve (Data from [3])

Over days to weeks, electricity systems can face electricity supply challenges. These can be acute when there is a common mode of failure for the energy supply resources in the electricity system. For example, an electricity system reliant on several gas power plants on a single pipeline has a “single-point vulnerability,” where an issue on the pipeline can lead to a common-mode failure across a number of separate power plants. For systems reliant on high percentages of wind and solar, a Dunkelflaute represents a similar single point vulnerability to the security of the region’s electricity energy supply.

Key Information Point

Dunkelflaute is a German word for dark doldrums; it represents a prolonged period of still winds and low solar irradiance (overcast conditions). During these periods, wind and solar energy output can be significantly reduced.

Figure 5 illustrates a Dunkelflaute week in Germany. The chart shows the weekly electrical energy supply from wind and solar resources in Germany across each week in the year 2024. Week 45 represents a Dunkelflaute period. The energy from wind and solar resources this week is one-sixth the energy available on the weeks with the highest wind and solar energy.

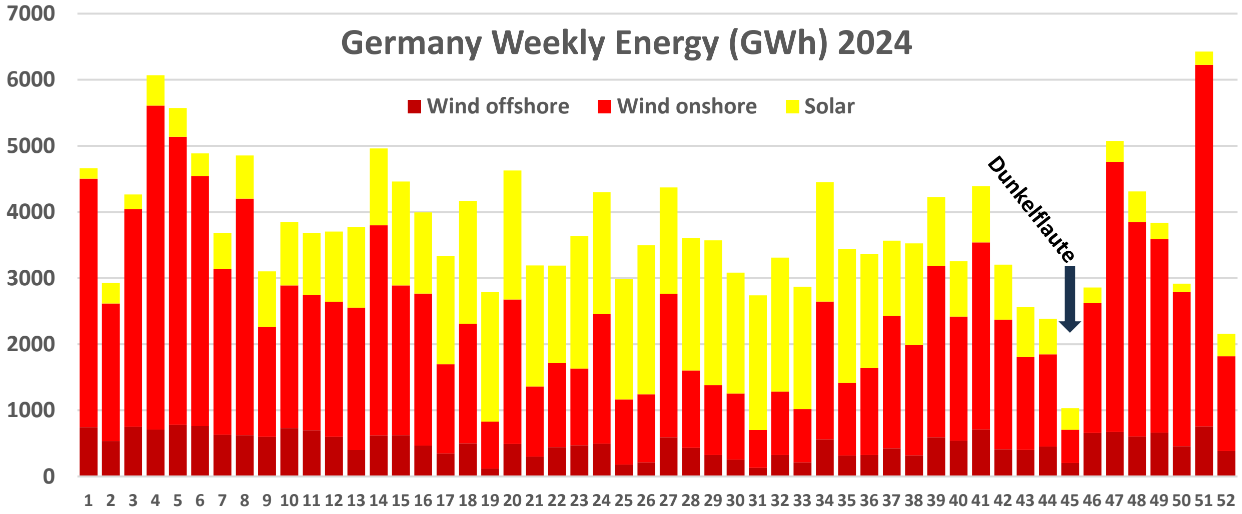


Figure 5. Germany weekly electrical energy supply from wind and solar in 2024 (Data from [4])

Looking at months and seasons, both the availability of energy supply and the demand for energy supply varies. Systems in regions with seasons typically have seasons with lower demand and seasons with higher demand. The daily shape of demand during these periods can significantly impact the ability to ensure electricity supply security.

Figure 6 illustrates an example for the continental United States with four illustrated 24-hour electricity supply periods: a winter day, a spring day, a summer day, and an autumn day. For the United States, the summer peak is typically greater than the winter peak. During the spring and the autumn days in the figure, electricity demand is much less than during the winter and summer days. On the summer day, there is a high evening peak persisting after sunset. On the winter day, there are typically two peaks, one before sunrise and one after sunset. The energy supply must be able to meet these seasonal peaks to ensure energy security. Adding complexity to this, electricity energy supply resources can vary by season for variable energy sources. Solar peaks in the summer, and wind varies by region. In large continental systems like the United States, wind resources hit a minimum in the summer (see Figure 7). As such, building solar resources can help serve energy demand in summer but provide little energy resources in winter. Conversely, wind provides better energy in winter but less in summer. Monthly energy demand in the United States peaks in the summer with additional peaks in the winter. The total energy envelope is of interest, but ultimately, supply and demand must match every minute. This nuance adds challenges for balancing the energy trilemma across the entirety of the year.

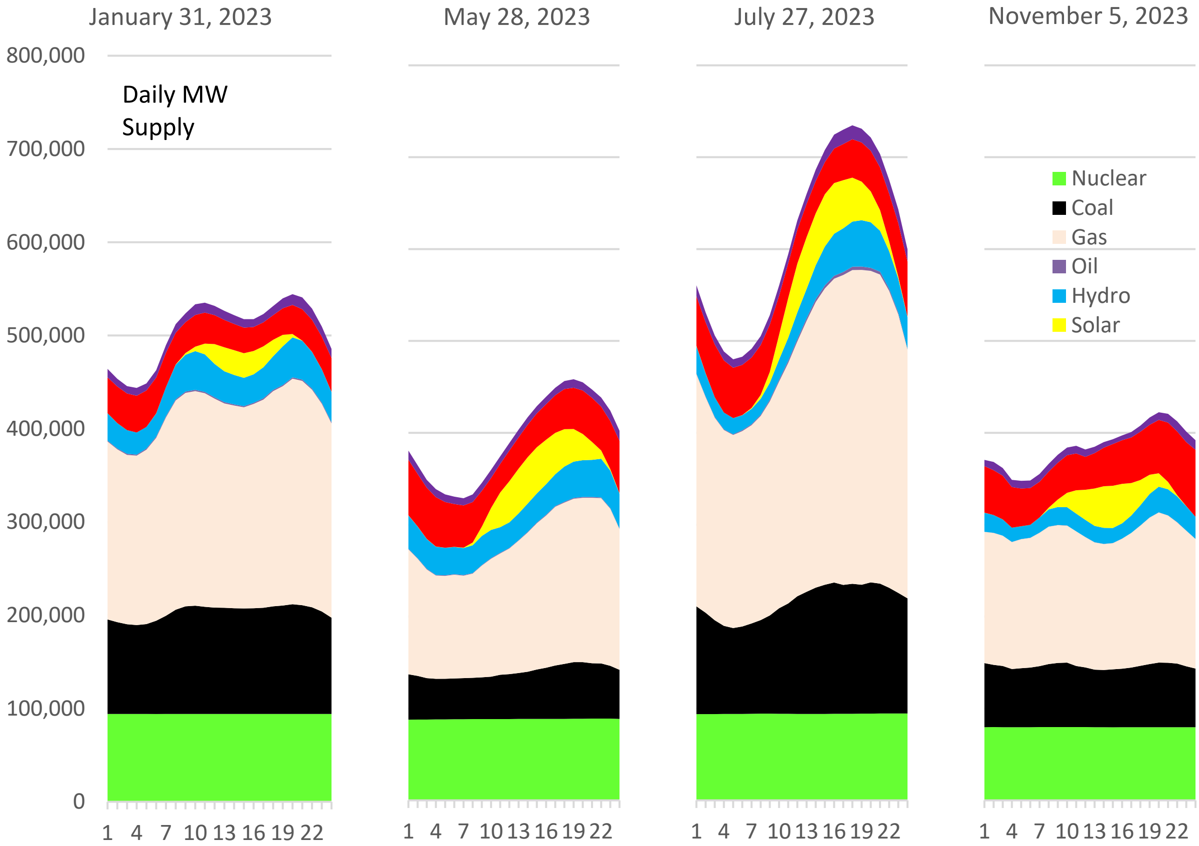


Figure 6. Lower 48 U.S. states' daily energy makeup: winter, spring, summer, and fall days 2023 (Data from [5])

The lower charts in Figure 7 all have different y-axis scales to illustrate the monthly trend for each resource versus itself. To understand the relative total contribution of each resource to each other resource, the top chart should be used.

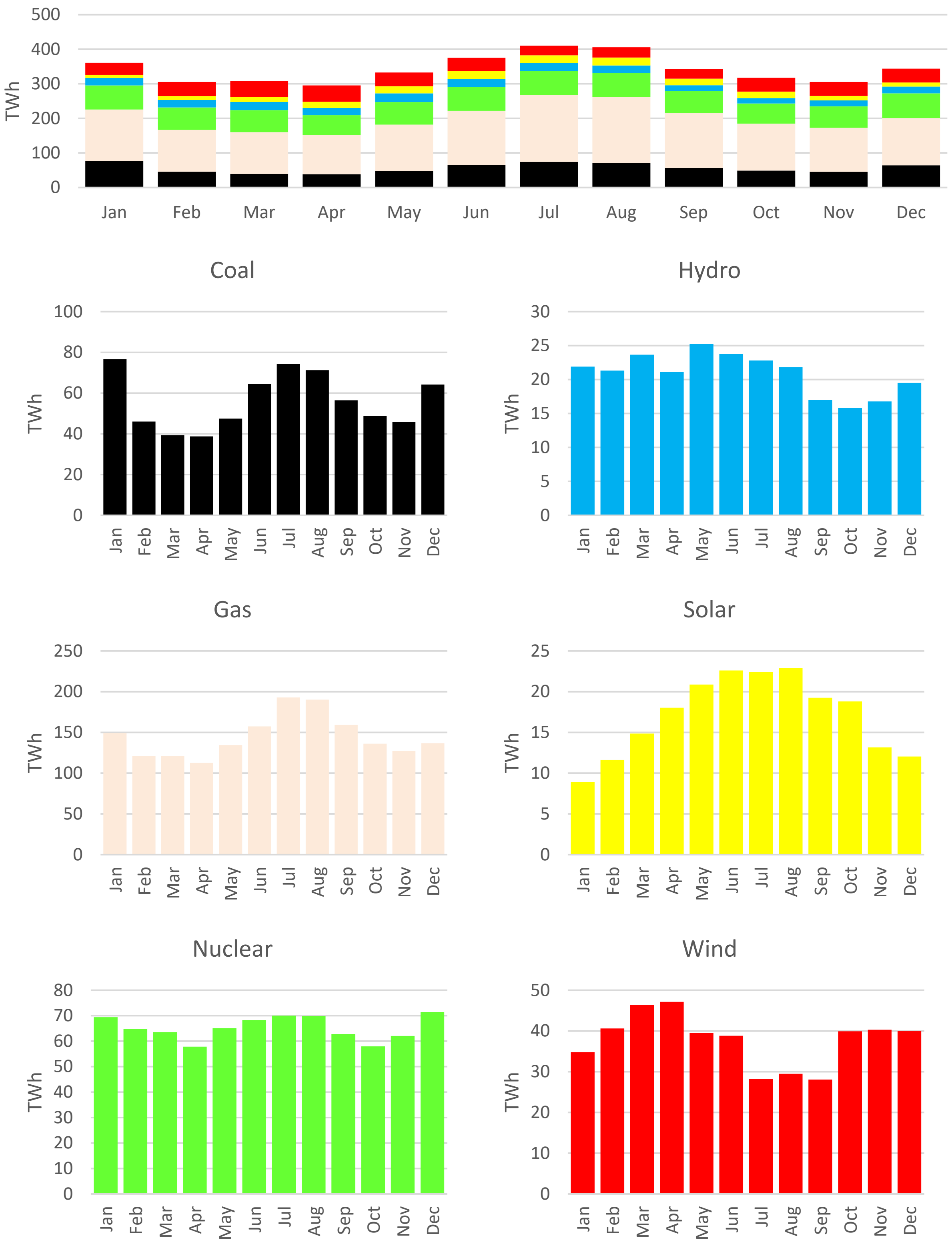


Figure 7. 2023 U.S. monthly electrical energy output (Data from [5])

Global Electricity Energy Supply

Figure 8 provides a level set on delivered electrical energy across the globe by resource. Coal was the leading source in 1985 and continues to be the leading energy source in 2024. In 2024, the top four resources were coal, gas, hydro, and nuclear. Solar and wind energy have recently been increasing, but coal, gas, hydro, and nuclear have also been increasing.

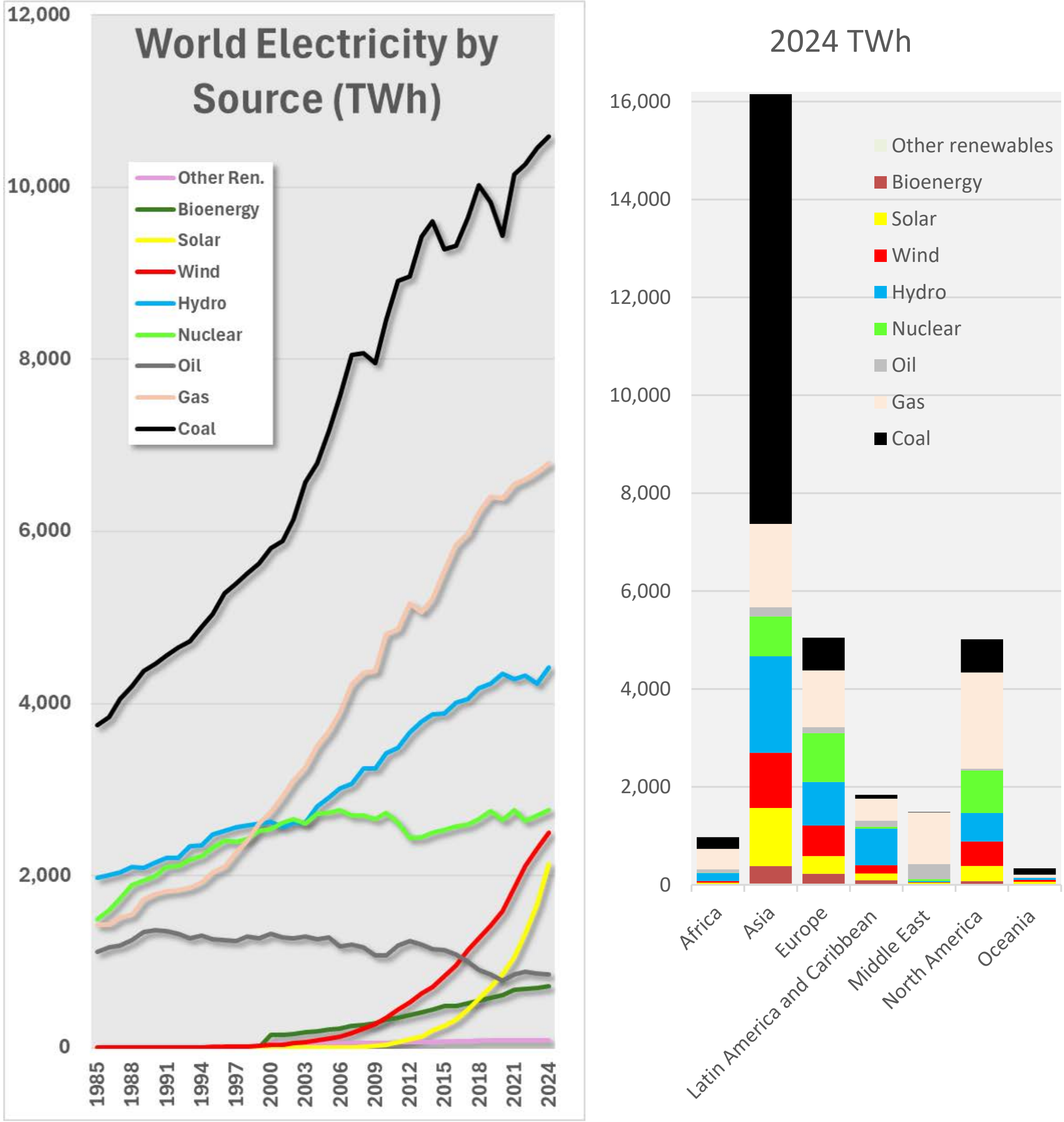


Figure 8. World electricity by source (Data from [6])

Of the three largest regions, Asia's electricity production is growing the fastest at a rate fourfold where it was in 2005, while energy production in North America and Europe has been essentially flat for the last twenty-plus years (see Figure 9).

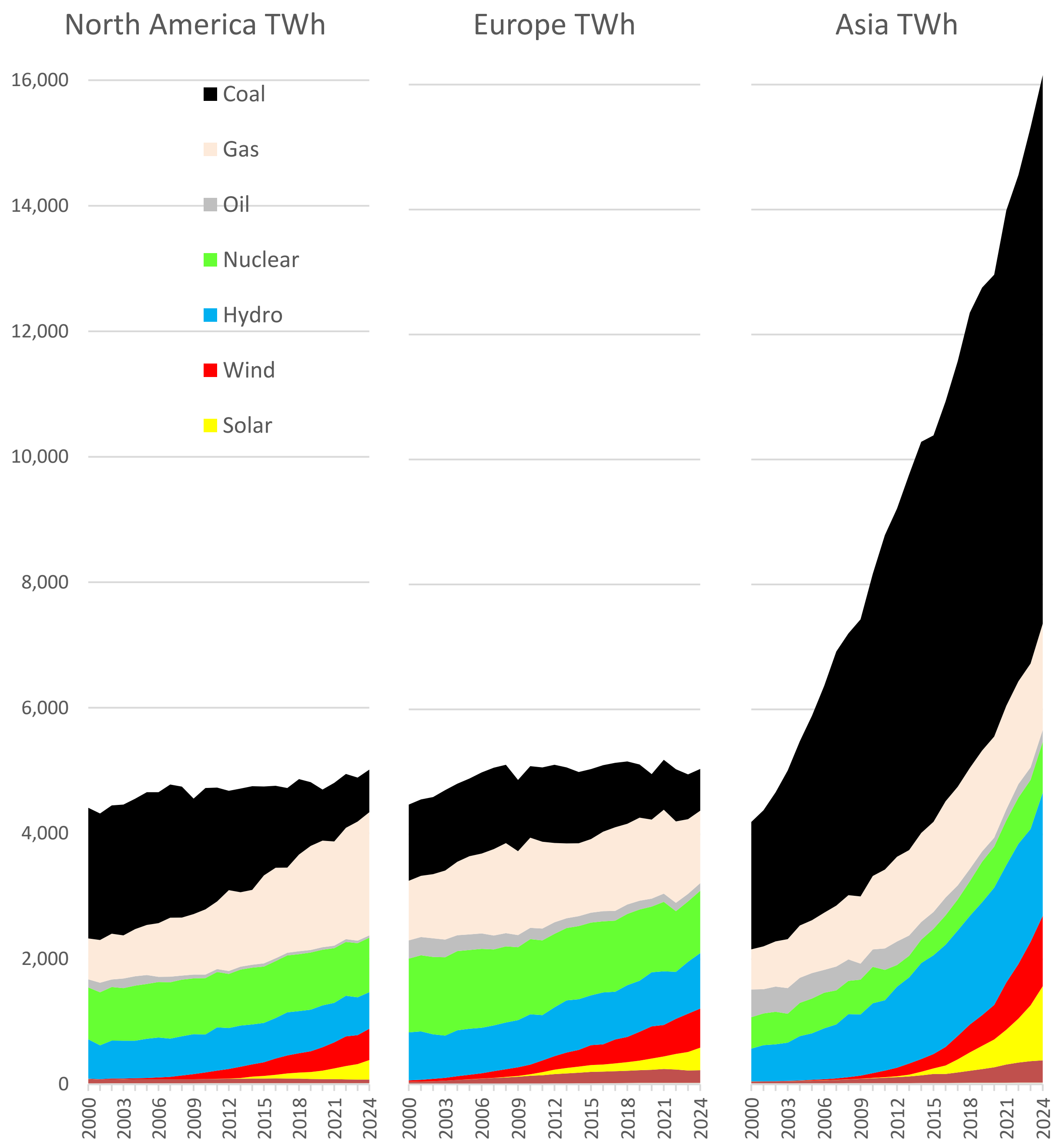


Figure 9. North America, Europe, and Asia electricity production (TWh) 2000–2024 (Data from [6])

In terms of carbon intensity of electricity production (gCO_2e/kWh), France leads the largest electricity-producing countries in the world with the lowest intensity. The notable increase in Japan’s intensity from 2011 to 2012 was because of the decision to shut down nuclear power production after the Fukushima earthquake on March 11, 2011. In Brazil, the increase from 2013 to 2021 was due to a series of droughts (see Figure 10).

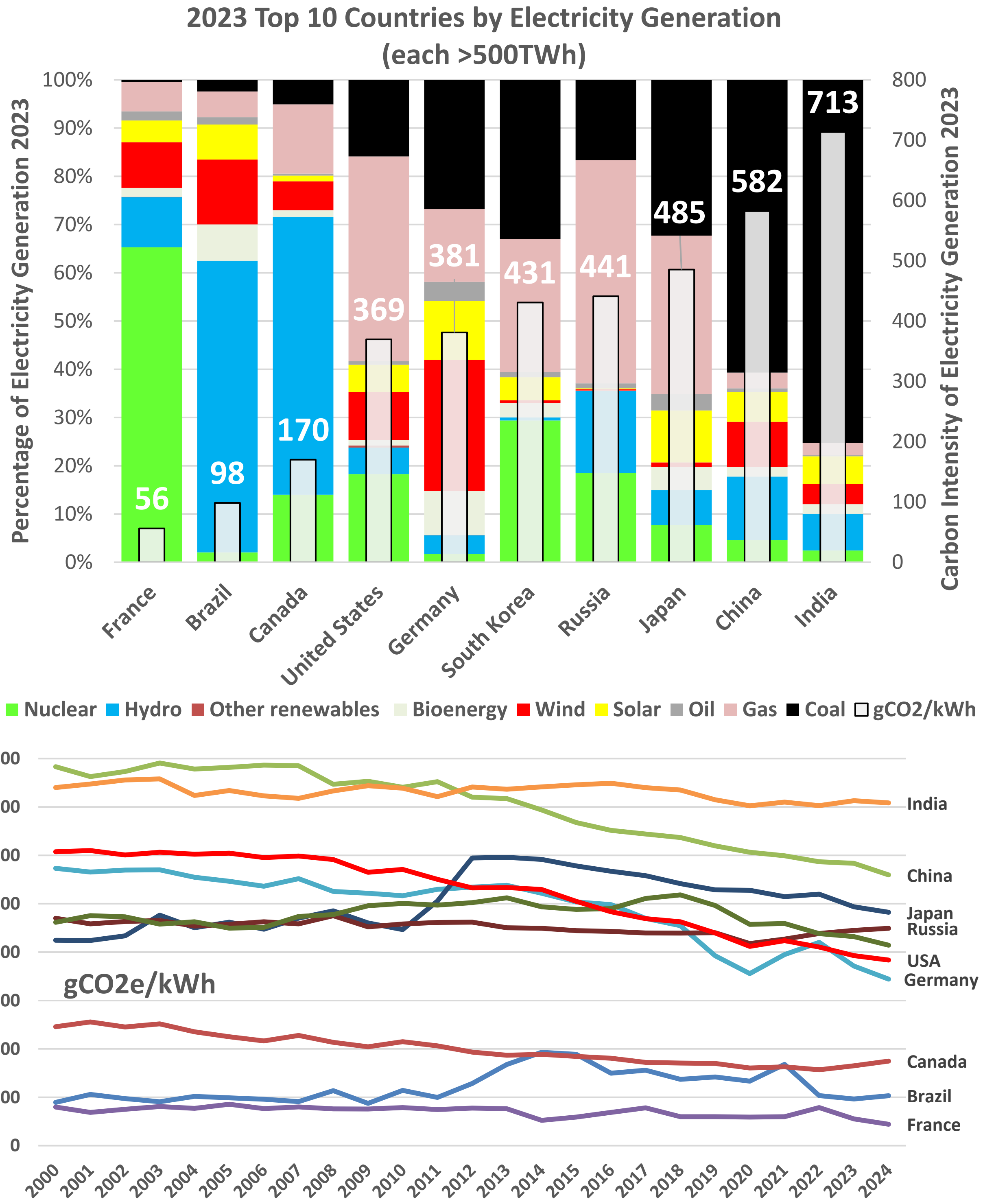


Figure 10. Carbon intensity of electricity production of larger electricity-producing countries (Data from [7])

Electricity cost varies significantly by region, as shown in Figure 11 and Figure 12. There are many drivers of electricity cost; in general, though, regions that have fossil fuel reserves and produce a large portion of their electricity from fossil fuels tend to have lower electricity rates.

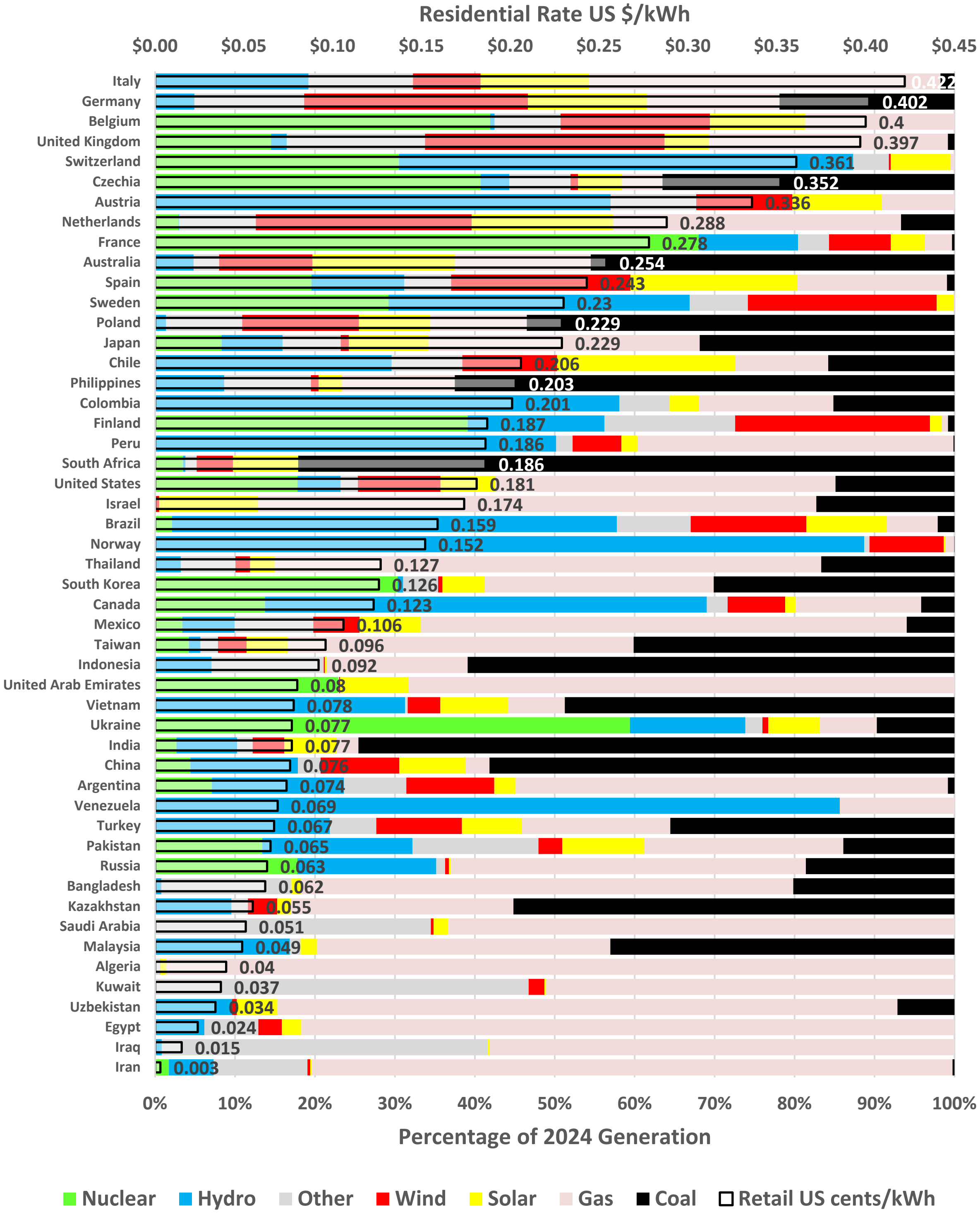


Figure 11. Top 50 countries by 2024 electricity production average residential rates 2023–2025 (Data from [8])

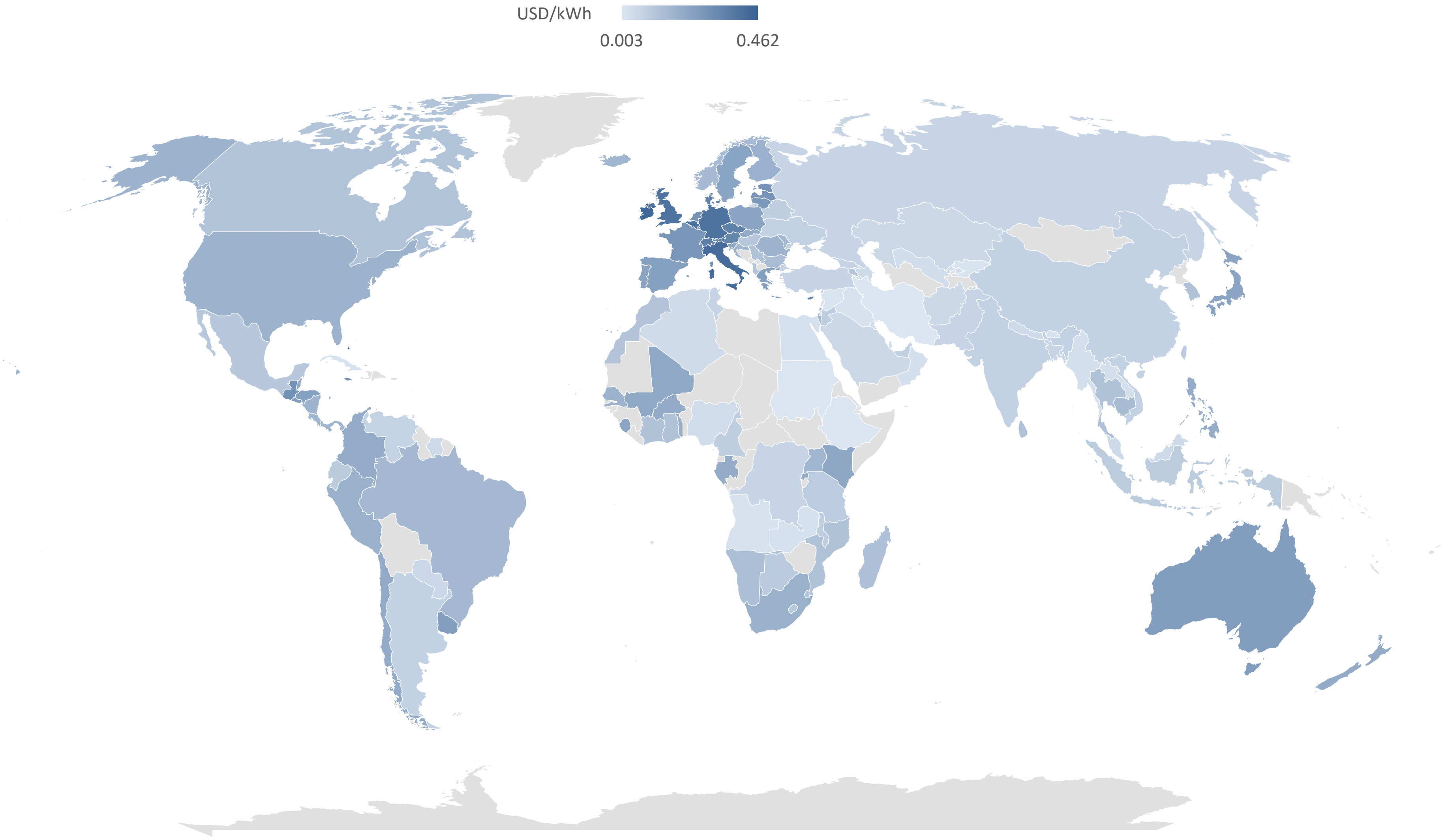


Figure 12. Global 2024 retail electricity rates (Data from [8])

3. EUROPE ENERGY SUPPLY

European Union Electricity Supply

Overview 2015–2024—European Union 27 (EU27)

Europe’s capacity, peak, energy, household rates, and carbon intensity of the electricity supply benchmarked for 2015 and 2024 are summarized in Figure 13.

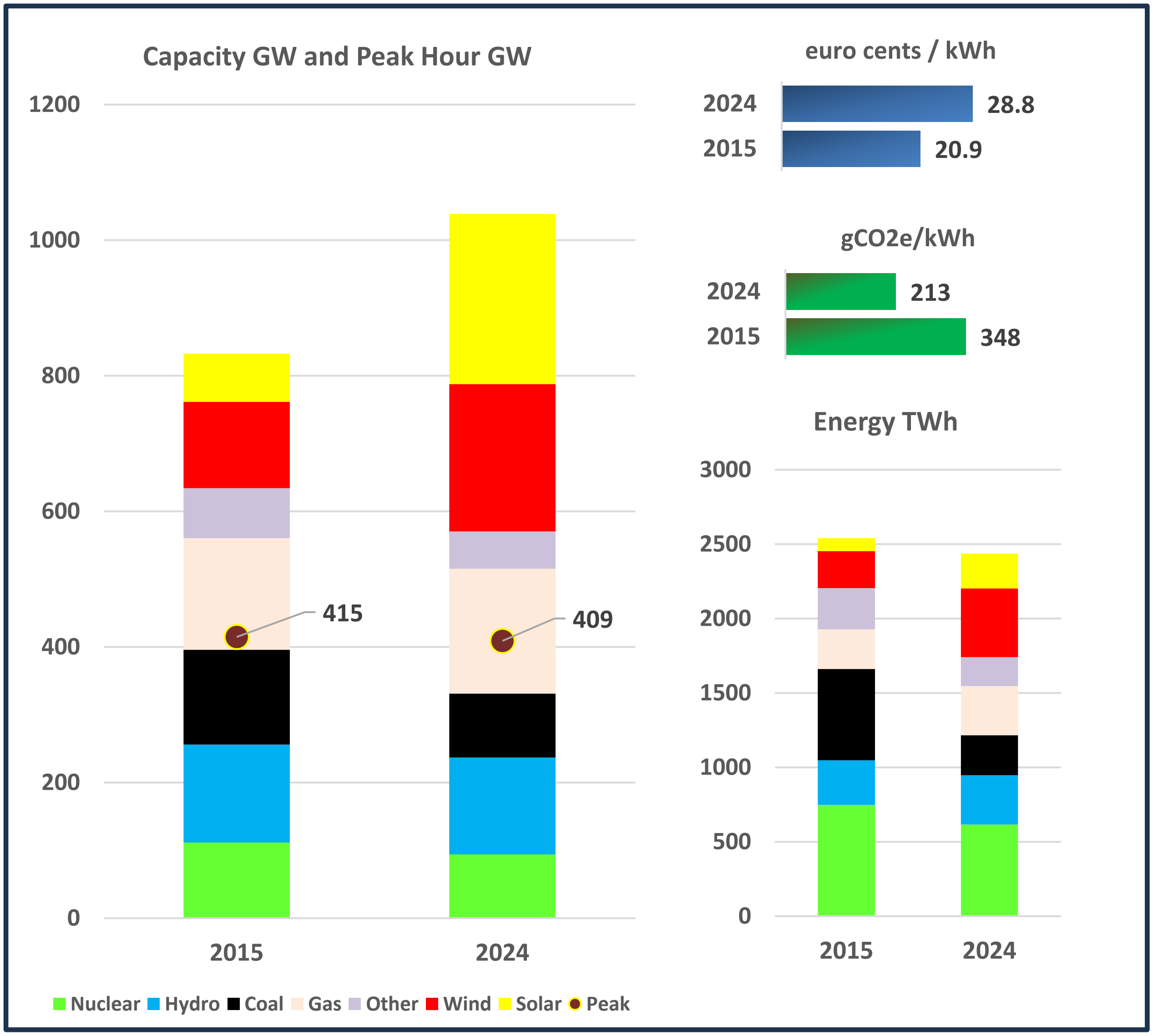


Figure 13. European Union 2015 and 2024 capacity and peak (GW), household rates (cents/kWh), carbon intensity (gCO2e/kWh) and energy (TWh) (Capacity and energy data from [4], rates from [9], and carbon from [7])

The EU27's electricity nameplate capacity has increased by 25% while total electricity consumption has dropped slightly by about 4%. The nominal household cost of electricity on a per-kWh basis has risen by 38%. The carbon intensity of the supplied electricity has reduced by 39%.

Figure 14 provides the 2024 winter and summer peak demand days.

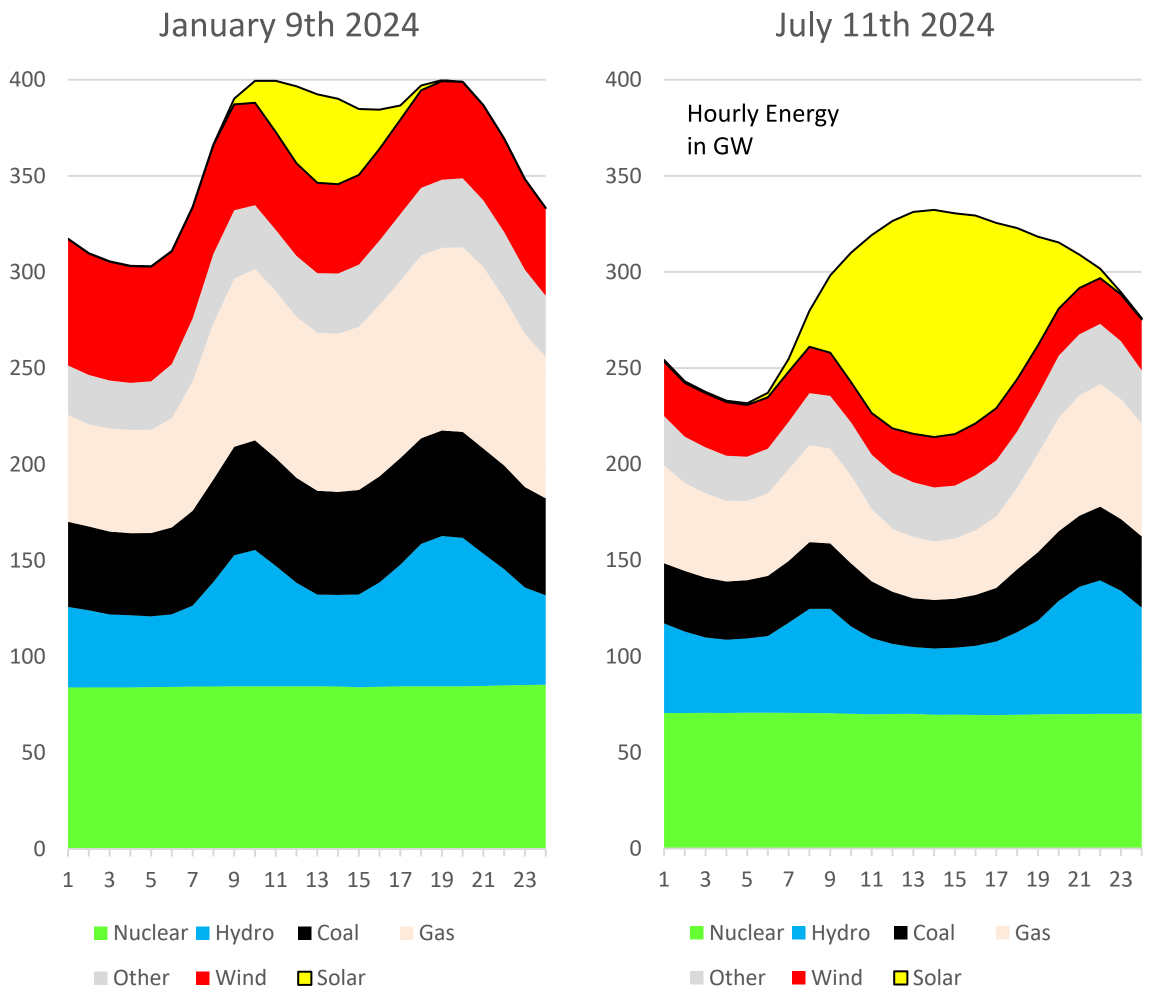


Figure 14. European Union peak winter and summer demand days 2024 (Data from [4])

The winter peak occurred at around 6 p.m. although a similar peak also occurred in the morning hours around 9 a.m. The summer peak occurred around 1 p.m. Nuclear output is greater in the winter as the EU27 is a winter peaking system.

Figure 15 examines the installed capacity and peak-demand-hour output of solar, wind, and nuclear resources in Europe for the summer and winter peaks in 2024. These resources are focused on as they would be at their full available output, whereas coal and gas assets would be dispatched based on the system demand.

During the peak demand hour in 2024, the total solar capacity (>250 GW) provided almost no energy as it was past sunset. Wind delivered 24% of its nameplate capacity, and nuclear delivered 90% of its nameplate capacity. For the daily energy demand, solar provided about 3% of the winter peak day and 15% of the summer peak day.

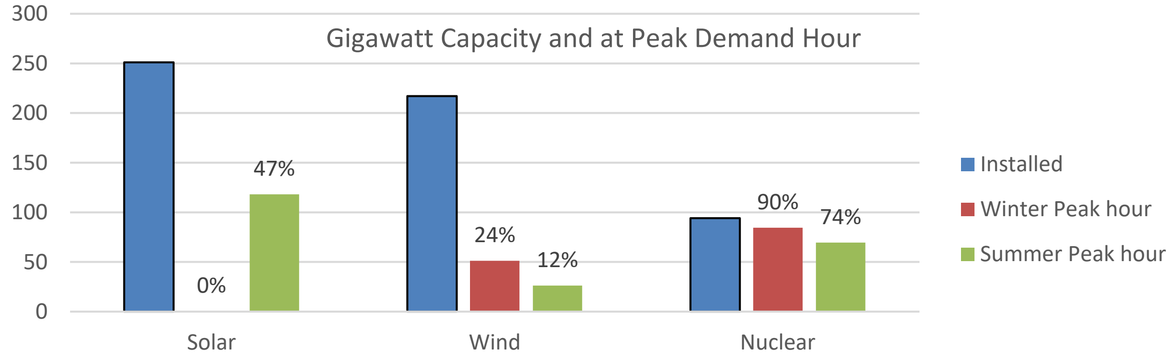


Figure 15. Solar, wind, nuclear installed capacity and output on peak winter and summer hour 2024 (Data from [4])

Figure 16 completes the peak day picture by looking at the daily energy total requirement. Nuclear provided the largest daily share of energy on the two peak days in 2024. In the winter, this was followed by gas. In the summer, hydro, gas, and solar were the leading secondary sources of electricity supply. The difference between the daily contribution of solar energy on the peak winter day and peak summer day are significant. Solar provided fourfold more energy on the peak summer day than on the peak winter day. The difference in wind energy production is also notable. On the peak winter day, wind provided twice the daily energy it provided on the peak summer day. For gas and coal, there is a similar difference between the winter and summer day electricity production as wind, but this is a decision based on demand. For wind, the energy delivered was the maximum available due to the electricity system dispatch order.

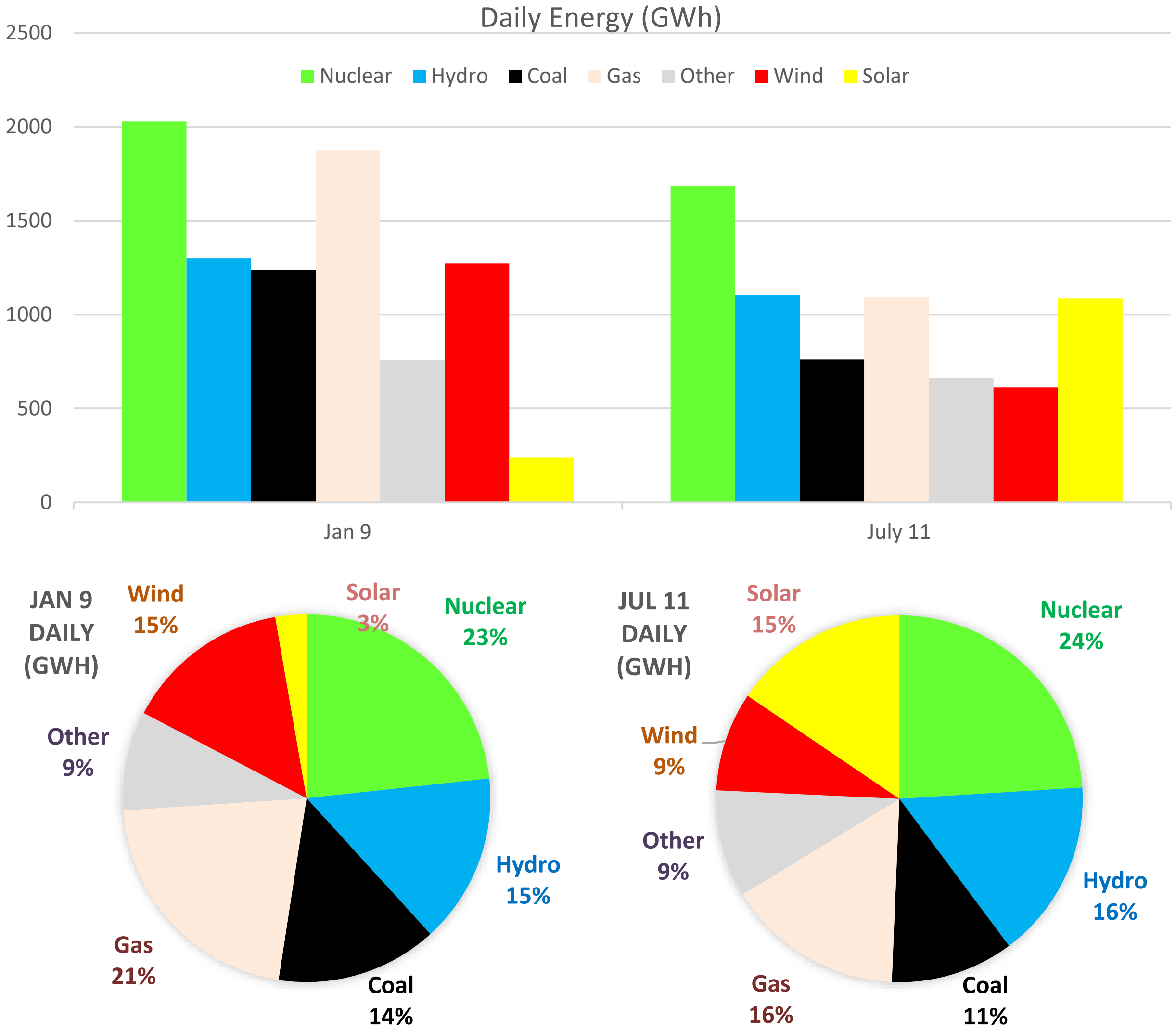


Figure 16. European Union 2024 winter and summer total electrical energy by resource (Data from [4])

To complete the electricity supply picture for the EU27 across all timescales in 2024, the monthly distribution of electrical energy supply by resource in EU27 is given in Figure 17, and the 2024 aggregate monthly electrical energy supply is illustrated in Figure 18. On a monthly basis, the peak energy demand months are winter months.

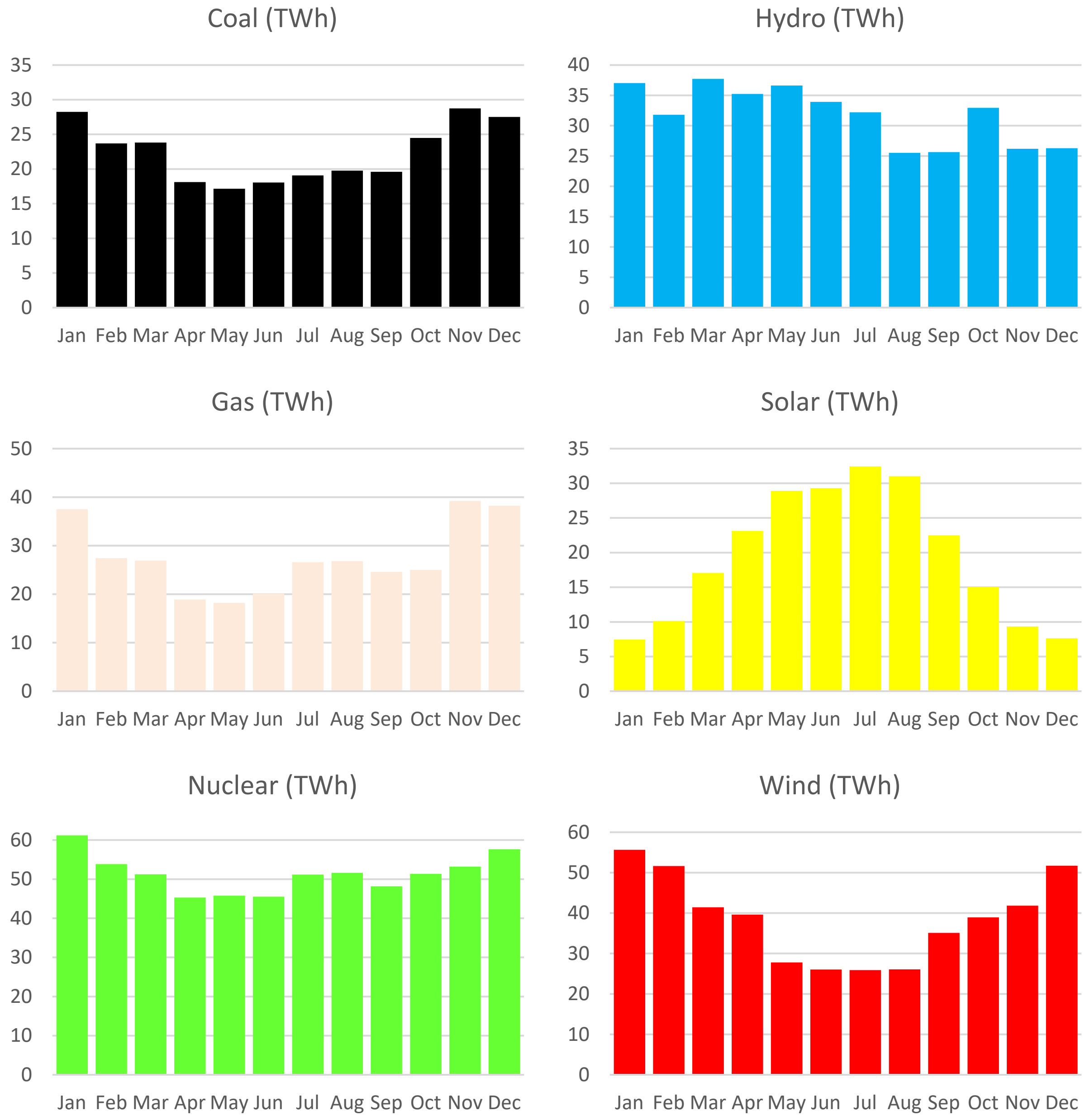


Figure 17. European Union 2024 monthly total generation energy by resource (Data from [4])

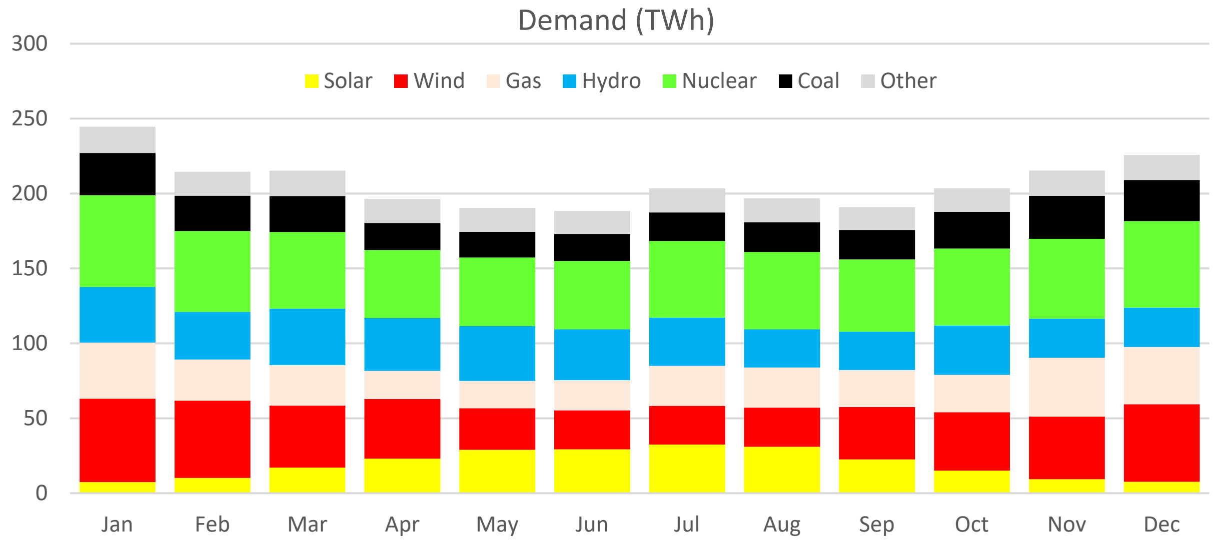


Figure 18. European Union 2024 monthly total demand (TWh) and resource makeup (Data from [4])

Table 2 quantifies the contributions of each resource on the peak day for 2024 (winter). The final column (Avg Day/Capacity) was derived by taking the annual GWh of energy for 2024 and dividing by 365 days, and the GW installed capacity.

Table 2. European Union peak – resource output on peak hour (18:00) on January 9, 2024

Resource	Installed Capacity (GW)	Peak Hour Output (GW)	Peak Day (GWh)	Peak Hour / Capacity	Peak Day /Capacity (GWh/GW)	Avg Day /Capacity (GWh/GW)
Coal	94	55	1,238	0.58	13.1	7.8
Gas	184	95	1,873	0.51	10.2	4.9
Nuclear	94	85	2,028	0.90	21.6	17.9
Hydro	142	78	1,301	0.55	9.2	6.4
Solar	251	<1	238	0.002	0.9	2.5
Wind	217	51	1,271	0.24	5.9	5.8
Peak		**409**	**8,821**			

The data in the table can be used to develop relative benefits of each asset, and this will be explored in more detail in the case studies. The ability of a resource to cover the marginal or peak hours and days avoids the need to build additional backup resources.

The peak hour/capacity factor (GW/GW) essentially represents how much GW of installed capacity was delivered at the peak GW demand hour in 2024. The higher the number, the more energy the resource provides per GW of installed capacity. For solar, the value was near zero, implying that scaling solar alone does not lessen the need for other generation resources in the winter peak of the EU27 and does nothing to reduce the need for other resources to deliver the peak hour demand of 409 GW.

The peak day/capacity (GWh/GW) represents how many GWh the resource provided per GW of installed capacity on the peak demand day.

The average (avg) day/capacity (GWh/GW) represents how many GWh the resources provided per GW of installed capacity on the average day in the year.

These ratios can be used to provide useful insights. For example, for the solar and nuclear values, the peak energy day value (bottom line of the table) divided by the peak day energy ratio in theory gives the amount of power plant capacity required by each type to cover the peak day. For nuclear, it would be around 408 GW of installed capacity to cover the daily energy requirement. Since the peak hour demand was 409 GW (which is greater than 408 GW), either slightly more installed capacity or some energy storage to shift energy from lower demand hours to the peak demand hours would be required. For solar, the calculation yields over 9,800 GW of installed capacity to provide sufficient energy on the peak day. And due to the peak hour being an early morning hour, the GW capacity to cover that peak hour would be an extremely high number or need to be covered entirely by energy storage capacity (GW) of sufficient duration (GWh) to cover the nighttime hours.

The difference between the energy delivered on the average day and on the peak day is also instructive. Essentially, as capacity that has a larger difference between these ratios' scales, the potential for negative pricing occurrences increases. This can have significant impacts for the economic viability of assets needed to cover the annual peak hourly and daily demand.

Key Information Point

A gigawatt is not a gigawatt is not a gigawatt.

While every resource has a nameplate capacity, its contribution to energy security is defined by its specific technical attributes rather than its peak output. A GW of intermittent solar photovoltaics (PV) does not provide the same dispatchability, inertia, or firm capacity as a GW of coal-fired generation.

Europe Trends

Figure 19 illustrates every hour of electricity production across the EU27 in 2024. The hourly electricity production overlays color-coded columns providing the installed capacity in the EU27. The installed capacity stacked column chart has the more dispatchable capacity at the lower and the more variable capacity at the higher part of the stack. The hourly electricity demand in the EU does not exceed the installed capacity of the more dispatchable generation sources in 2024 (nuclear, biomass, coal, gas, hydro). Essentially the EU27 has a nameplate capacity greater than twice its peak actual demand in GWs.

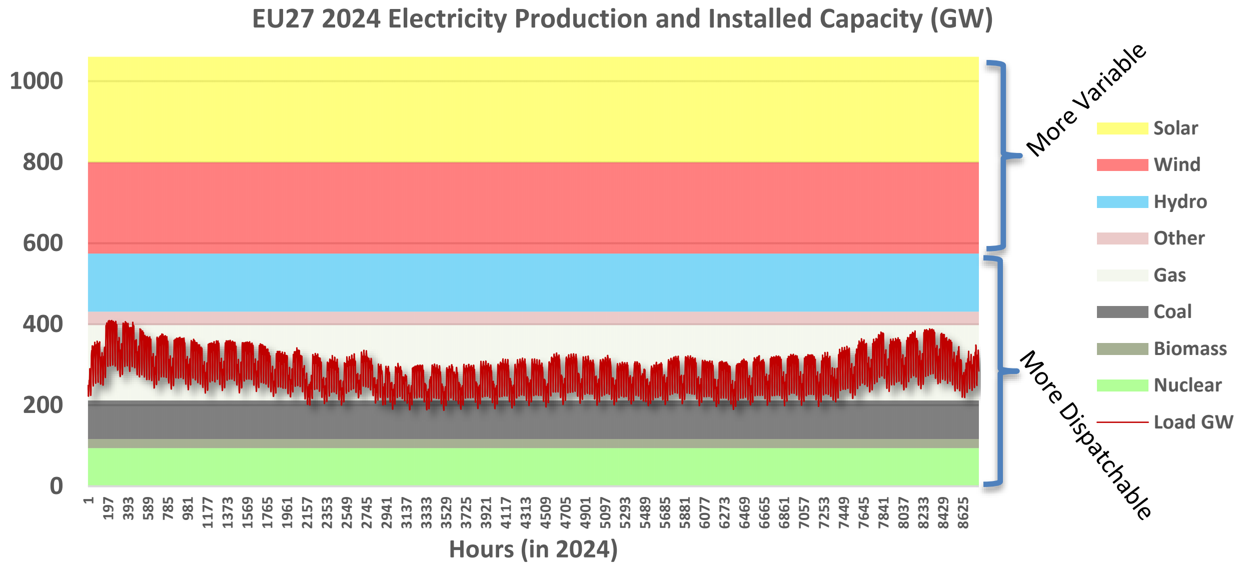


Figure 19. EU27 hourly electricity production compared to installed capacity in 2024 (Data from [4])

Figure 20 looks at just the wind and solar generation in 2024 and the installed capacity of these resources. With 483 GW total installed capacity, the combined wind and solar fleet in the EU27 reached a maximum of about 183 GW in 2024, with a minimum hour of 15 GW, and a median output of 75 GW. The Dunkelflaute week seen in the Germany weekly data (see Figure 5) is evident in the hourly data as well (hours 7400–7600).

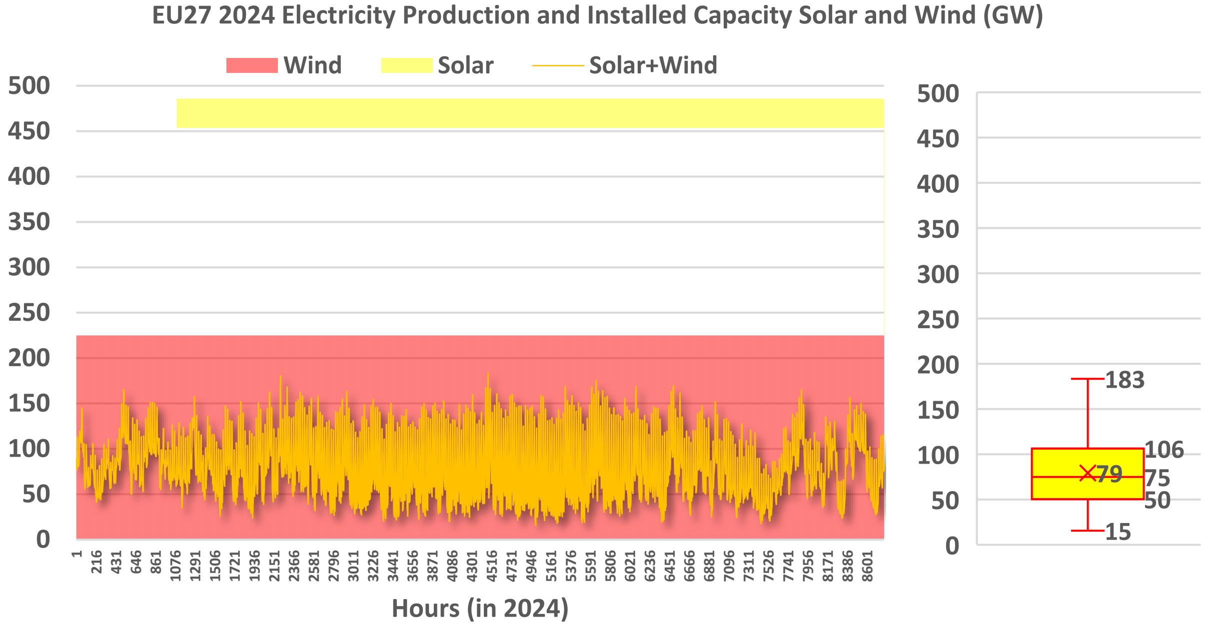


Figure 20. EU27 solar and wind capacity versus 2024 hourly output (Data from [4])

Figure 21 takes a closer look at the Dunkelfaute period across the EU27. During this Dunkelflaute period (~140 hours), the average wind and solar combined output was about 39 GW—less than 10% of the installed capacity—across the continent.

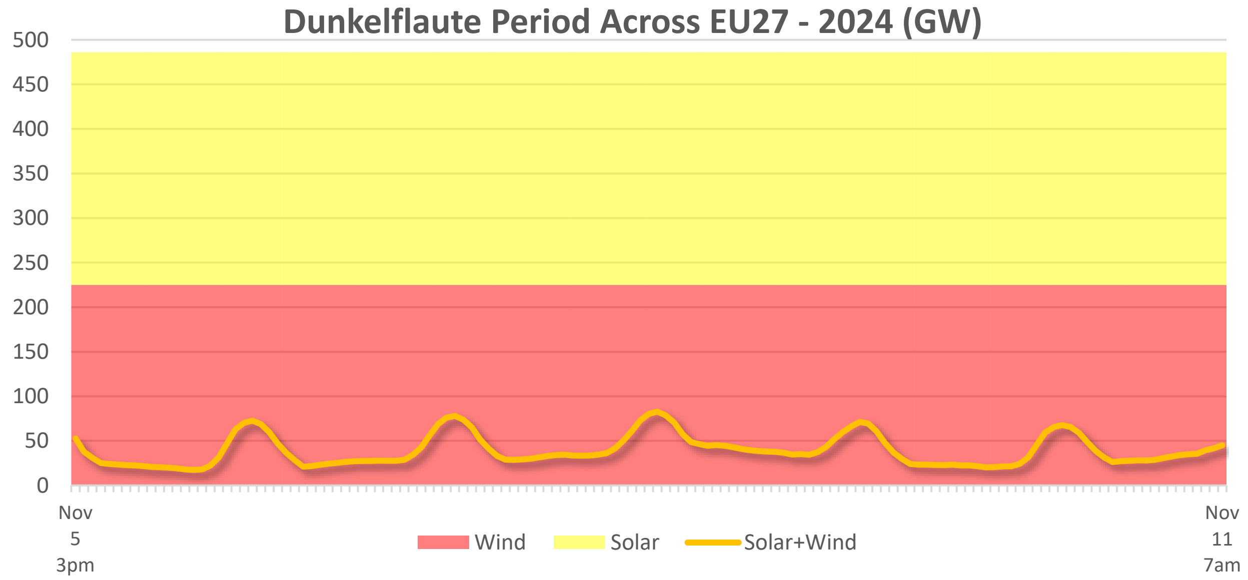


Figure 21. EU27 November 5 to November 11, 2024—Dunkelflaute period—wind and solar output versus installed capacity (Data from [4])

During this period, solar and wind energy covered less than 14% of the system demand despite the nameplate capacity being greater than the peak EU27 hourly demand in 2024 of 409 GW.

Europe Summary

Key Findings

- About 29% of Europe's (EU27) annual electricity production was from solar and wind resources in 2024. The average output from solar and wind was ~16% of nameplate capacity and at its lowest hour was ~3% of nameplate capacity.
- During the 2024 November Dunkelflaute period, the energy supply from wind and solar was less than 14% of the EU27's electricity demand.
  - The November Dunkelflaute was a continent-wide event where for a period of about six days, the average output from wind and solar was 10% of its nameplate capacity, with some evening hours less than 4%.
- The EU27 has among the most expensive electricity in the world as of 2024.
- The EU27 overall annual net electricity production has declined from 2015 to 2024 by about 4%.
- The EU27 is heavily reliant on nuclear, coal, hydro, and gas when solar and wind output is low and demand is high (e.g., winter peak day for 2024).
- The EU27 is a winter peaking system where solar energy provides little on-peak hour and little daily energy.
- The EU27 maintains enough dispatchable installed capacity (nuclear, biomass, coal, gas, and hydro) to cover its peak demand. The nameplate capacity of generation (1,038 GW) in the EU27 is more than double its peak hourly demand (409 GW).

- Cold winters with low winds and lower gas storage inventories appear to be the greatest risk periods for Europe.

Figure 22 provides a waterfall graph of energy (TWh) changes (top chart), a waterfall of capacity (GW) changes (bottom chart), and a breakdown of total energy (TWh) and capacity (GW) by resource for 2015 and 2024 (middle charts) for the EU27.

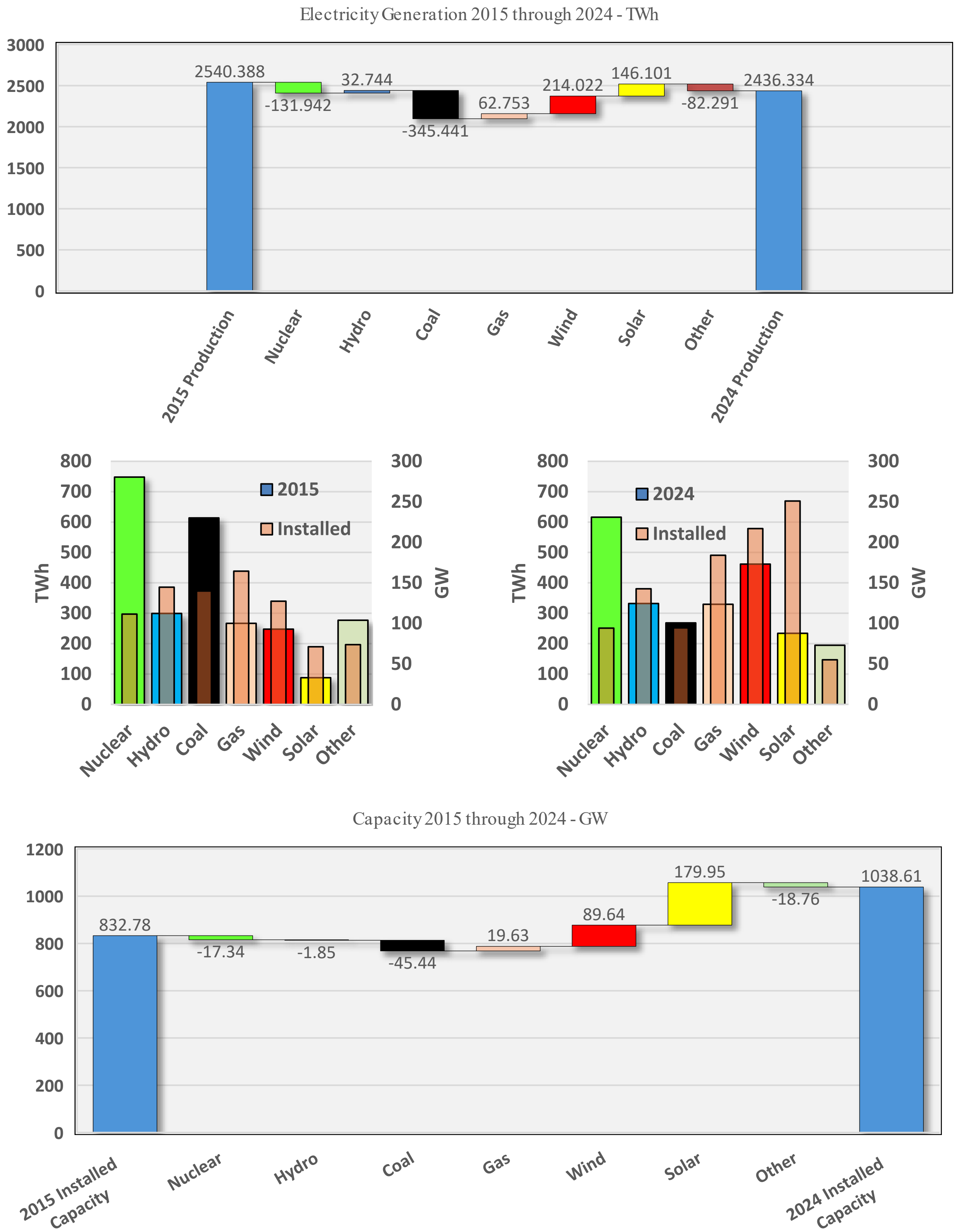
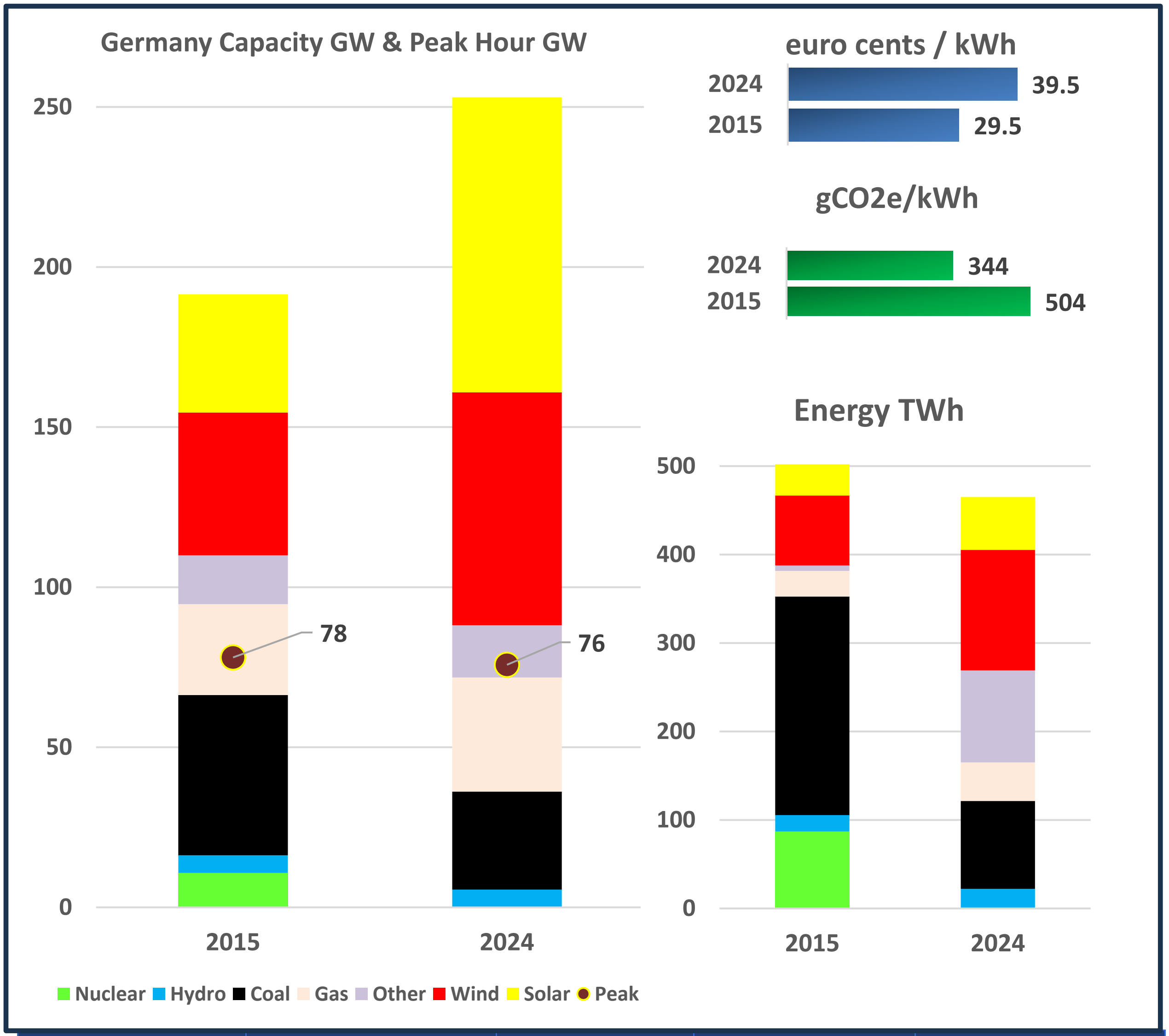


Figure 22. EU27 capacity and generation summary 2015 and 2024 (Data from [4])

Germany Electricity Supply

Overview 2015–2024—Germany



	Capacity	Energy	Price	CO2
2024/2015	132%	93%	134%	68%
2015 / EU27 2015			1.4	1.4
2024 / EU27 2024			1.4	1.6

Figure 23. German 2015 and 2024 capacity and peak (GW), household rates (cents/kWh), carbon intensity (gCO2e/kWh), and energy (TWh) (Capacity and energy data from [4], rates from [9], and carbon from [7])

Germany's capacity, peak, energy, household rates, and carbon intensity of the electricity supply are summarized in Figure 23. The table below the graphic compares Germany's progress over time (first row) and Germany's price and carbon intensity versus the EU27 average for 2015 and 2024 (row two and three).

The installed nameplate capacity of the German generation fleet in 2024 increased to 132% the 2015 nameplate capacity but delivered less energy than in 2015. The (nominal) price has climbed, but it is still at a constant ratio of 1.4 versus the average EU27 price in 2015 and 2024, which means that German's pay a premium versus the average EU27 rate, but this premium has not increased from 2015 to 2024. Germany's carbon intensity has dropped to 68% of the 2015 value, but this is 1.6 times the EU27 average in 2024, which was 1.4 times the EU27 average in 2015. This demonstrates that the rest of the EU27's carbon emission intensity has dropped faster than Germany's in the period, indicating that the path taken by other EU27 countries has resulted in a faster reduction in carbon emission intensity than Germany's path. This is due to the decision to close the remaining nuclear units in Germany during this period. As such, the German system is producing substantially more carbon emissions per unit of electricity production than the EU27 average.

The German energy transition from 2000 to 2025 has focused on the incorporation of solar and wind resources and the retirement of nuclear energy. Wind and solar resources are variable as illustrated in Figure 24.

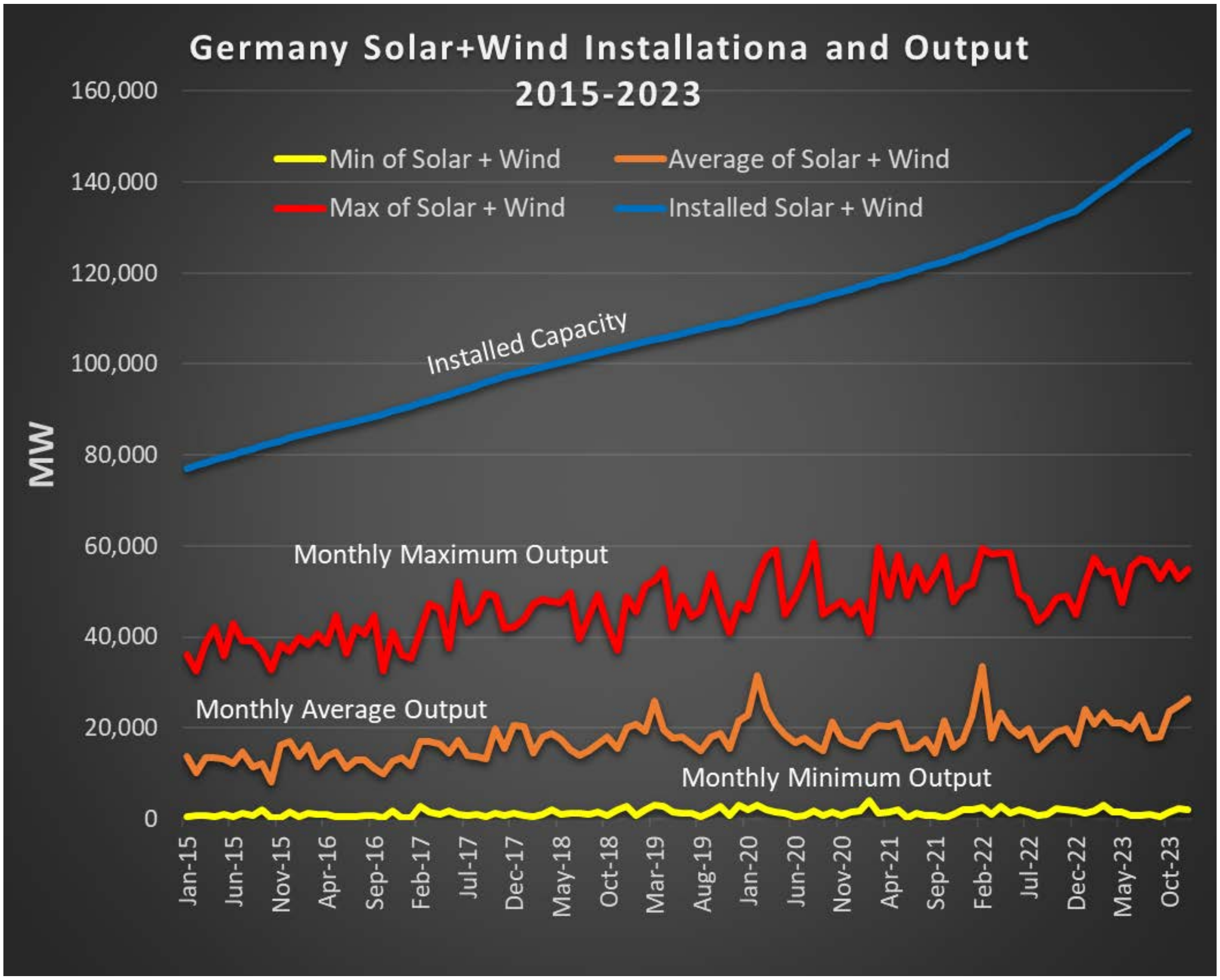


Figure 24. Germany solar and wind monthly maximum, average, and minimum hourly output and capacity (Data from [4])

The figure shows the increasing installed capacity of wind and solar in Germany (blue line) versus the maximum (red line), average (orange line), and minimum (yellow line) hourly output from these resources each month from 2015 to 2023. In every month, the minimum output hour is a fraction (<10%) of the installed capacity. This variability necessitates nearly 100% backup power in the form of dispatchable power plants (see Figure 23), where the combined coal, gas, hydro, and other (typically biomass in Germany) capacity (GW) exceeds the peak demand (GW), even with the significant increase in installed solar and wind capacity (GW). This variable capacity has not offset the need for dispatchable generation. The maximum is also a fraction of the installed capacity and, despite continued capacity additions, has not measurably increased since 2020.

Figure 25 provides the winter, summer, and net peak demand days for Germany in 2024. Wind and solar combined provided a significant portion of the energy on the peak winter and summer days. However, there were high demand days when the contribution of wind and solar was very low. The peak net demand day was December 11, 2024. On this day, the combined wind and solar energy contribution was less than 5% of the daily energy requirement.

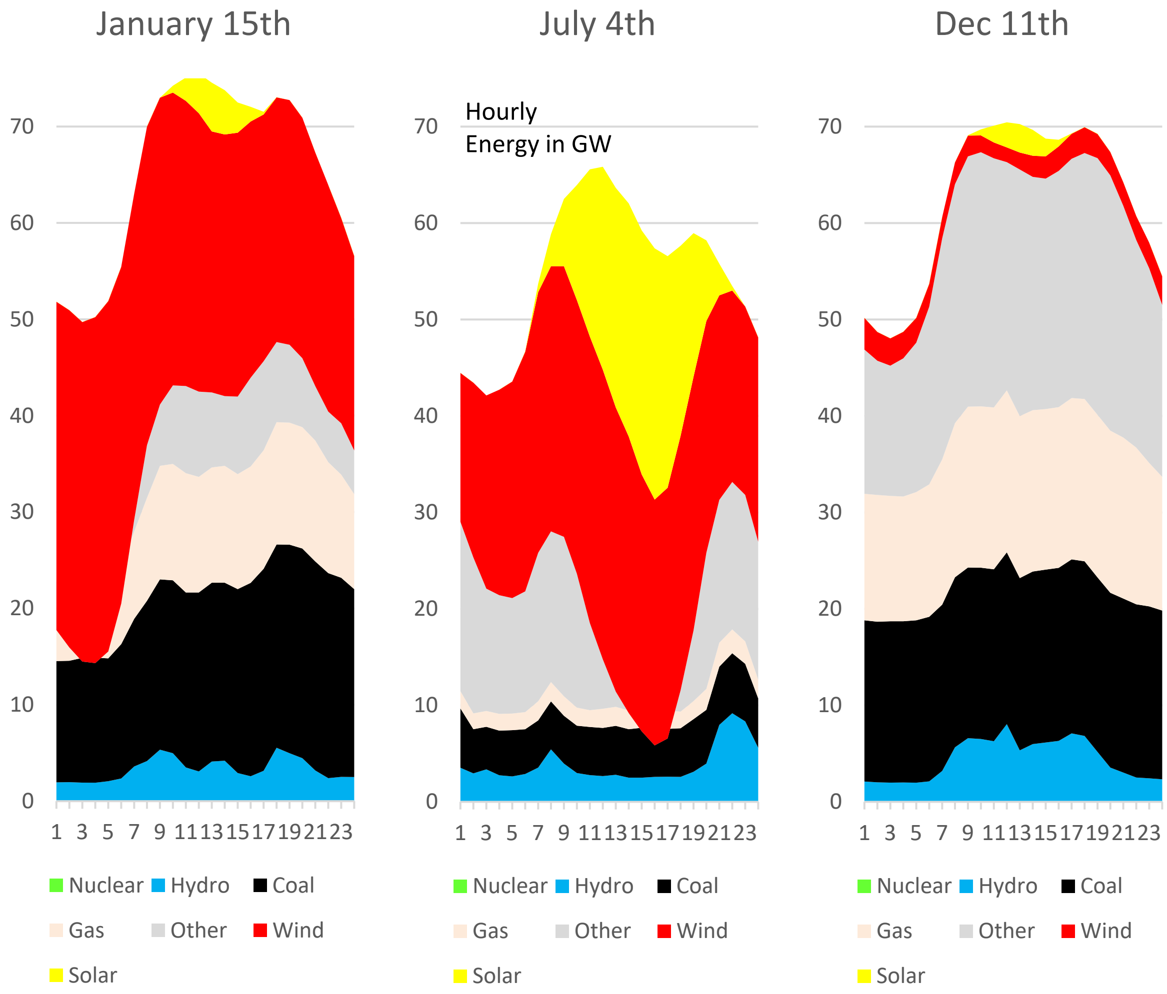
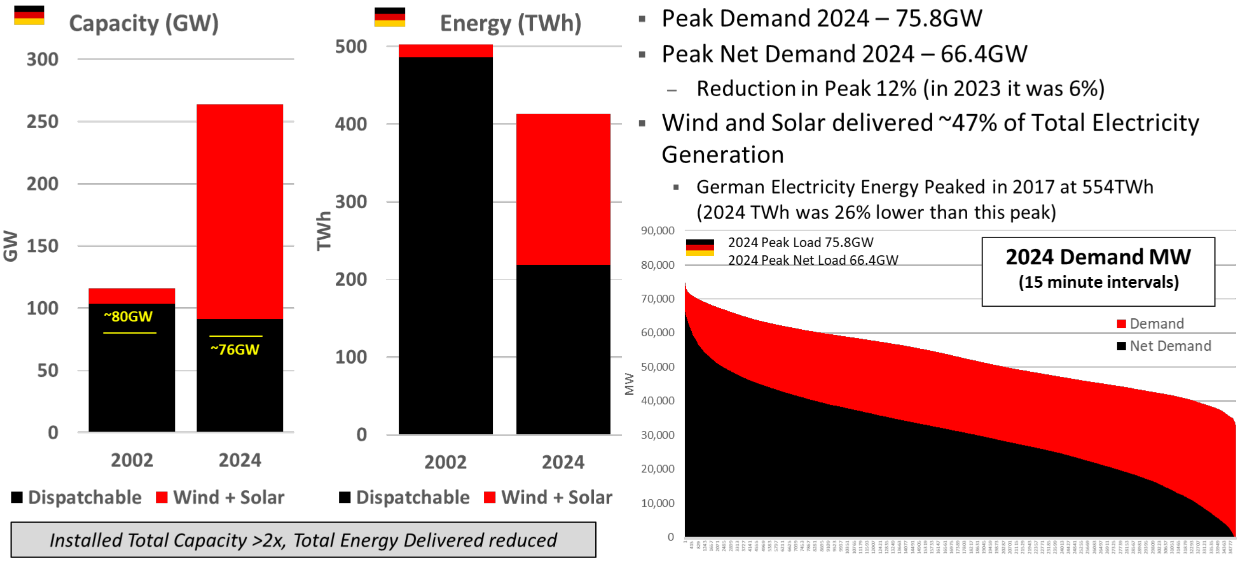


Figure 25. Germany peak winter, summer and net peak demand days 2024. (Net peak demand is the peak less wind and solar contribution.) (Data from [4])

Figure 26 takes a longer view of Germany's electricity energy system, from 2002 to 2024, and a more comprehensive view of 2024 (every 15 minutes of demand and supply). The installed capacity of wind and solar has dramatically increased, but the need for dispatchable capacity has remained essentially unchanged. During this period, the total amount of electrical energy produced in Germany has declined (peaked in 2017). In Figure 26, the electrical energy is presented as the net produced in Germany, whereas in Figure 23, energy is presented as consumed. Germany in 2024 now relies on net imports of electricity to satisfy annual demand.



- Peak Demand 2024 – 75.8GW
- Peak Net Demand 2024 – 66.4GW
  - Reduction in Peak 12% (in 2023 it was 6%)
- Wind and Solar delivered ~47% of Total Electricity Generation
  - German Electricity Energy Peaked in 2017 at 554TWh (2024 TWh was 26% lower than this peak)

Figure 26. Germany 2002 and 2024 installed capacity, energy, peak, and 2024 15-minute demand and net demand (Data from [4])

Figure 27 provides the peak hours versus installed capacity on the three reference days from Figure 25. The contribution of solar and wind energy on the peak hour of the net peak day is negligible.

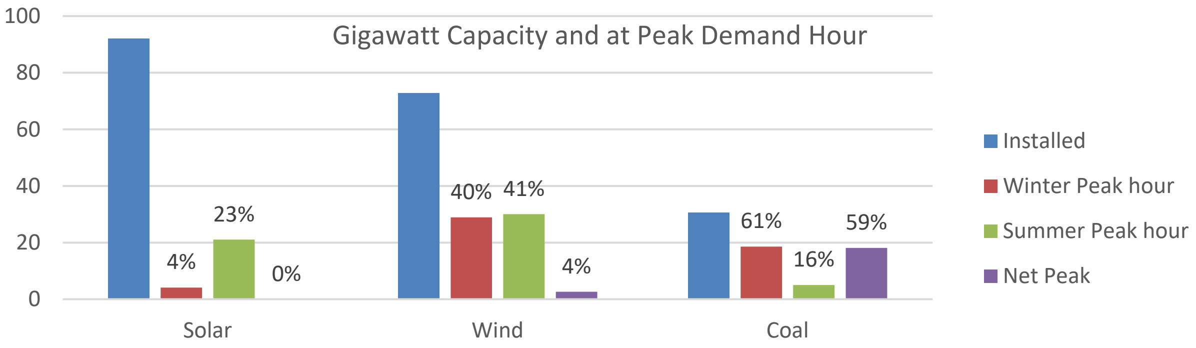


Figure 27. Solar, wind, and coal installed capacity and output on peak winter and summer and net peak hour 2024 (Data from [4])

Figure 28 provides the total energy breakdown on the three days. The other energy for the net peak day is largely made up of imports from France, the Netherlands, and Denmark. France’s electricity supply was predominantly nuclear on this day, the Netherlands’ was predominantly coal and gas, and Denmark’s was from biomass, coal, and gas with significant imports from Norway, Sweden, and the United Kingdom.

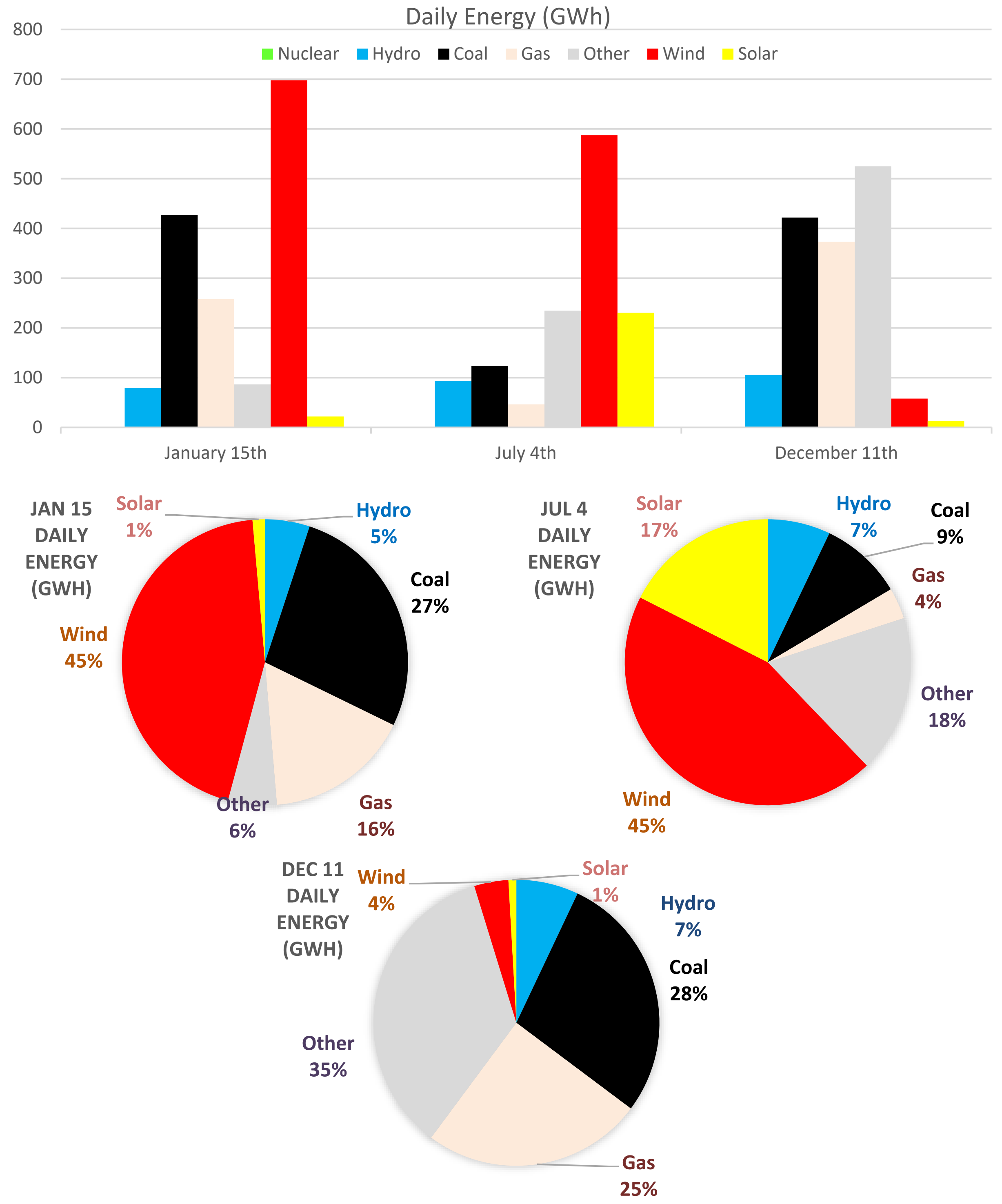


Figure 28. Germany 2024 winter and summer and net peak total electrical energy by resource (Data from [4])

Table 3 looks at the installed capacity, peak hour, and peak daily energy for coal, gas, solar, and wind in Germany on the three reference days to quantify the contributions of each.

Table 3. Germany winter peak day, summer peak day, and net peak resource outputs on peak hour

Winter peak—resource output on peak hour (11:00) and for the day—January 15, 2024

Resource	Installed Capacity (GW)	Peak Hour Output (GW)	Peak Day (GWh)	Peak Hour / Capacity	Peak Day / Capacity (GWh/GW)	Avg Day / Capacity (GWh/GW)
Coal	30.6	19	427	0.61	13.9	3.3
Gas	35.6	12	258	0.34	7.2	1.4
Solar	92.2	4	22	0.04	0.2	0.7
Wind	72.8	29	698	0.40	9.6	1.9
Peak		**75.4**	**1,571**			

Summer peak—resource output on peak hour (11:00) and for the day—July 4, 2024

Resource	Installed Capacity (GW)	Peak Hour Output (GW)	Peak Day (GWh)	Peak Hour / Capacity	Peak Day / Capacity (GWh/GW)	Avg Day / Capacity (GWh/GW)
Coal	30.6	5	124	0.16	4.0	3.3
Gas	35.6	2	46	0.06	1.3	1.4
Solar	92.2	21	231	0.23	2.5	0.7
Wind	72.8	30	587	0.41	8.1	1.9
Peak		**65.8**	**1,319**			

Net peak—resource output on peak hour (17:00) and for the day—December 11, 2024

Resource	Installed Capacity (GW)	Peak Hour Output (GW)	Peak Day (GWh)	Peak Hour / Capacity	Peak Day / Capacity (GWh/GW)	Avg Day / Capacity (GWh/GW)
Coal	30.6	18	422	0.59	13.8	3.3
Gas	35.6	17	373	0.47	10.5	1.4
Solar	92.2	0	13	0.00	0.14	0.7
Wind	72.8	3	58	0.04	0.8	1.9
Peak		**69.8**	**1,497**			

On the peak winter and summer days in Germany, the variable resources performed well in aggregate. However, solar underperformed in winter versus its average day output. On both the summer and winter peaks, wind significantly overperformed in 2024 versus the average day.

The net peak day provides additional insight. On this day, there is the maximum difference between load (demand) and solar and wind output. Both the peak hour and daily energy on this day far exceed the summer peak day in Germany and are nearly the same as the peak winter day in Germany. Gas and coal and imports were heavily relied on to ensure reliability of supply on this day. Coal provided a significant portion of the electrical energy needed on the peak winter day, and on the net peak day coal provided the largest share of domestic electricity. Germany was heavily reliant on imports on the net peak day.

Germany Trends

Germany's electricity demand has decreased over the last 20 years, both in terms of the peak demand hour and total annual electrical energy used. The cost of electricity has risen; although in terms of the period from 2015 to 2024, it remains consistent versus the average EU27 cost at a ratio of 1.4. That is notable though, as German electricity demand *decreased*, but the costs continued to trend with the EU27. In standard economics, when demand decreases for a stable supply, one would expect costs to decline as well, but this has not occurred. Greenhouse gas emission intensity for the electricity supply has decreased through the period, but not as quickly as across the rest of the EU27. Germany had a greenhouse gas intensity of electricity 1.4 times the EU27 average in 2015, and that factor has risen to 1.6 in 2024. The elimination of nuclear generation likely contributed to the increased emission intensity versus the EU27 average value.

Germany Import/Export

Germany went from a net exporter of electricity prior to the closure of the nuclear fleet to a net importer. In addition, in the past, it exported at high wholesale prices and imported at low wholesale prices; that shifted to exporting when prices were low (or negative) and importing when prices were high. This is not a rational approach but a function of the variable electricity supply resources Germany relies on.

Key Observation Point

From 2016 to 2024, the value of Germany's electricity exports changed by an estimated €5.3 billion—from a net revenue of €1.5 billion in 2016, to a net cost of €3.8 billion in 2024.

Figure 29 shows electricity prices and volumes of exports and imports of electricity for 2016, 2019, and 2024. The graphic on the left shows the full range, and the graphic on the right shows a compressed range. The annotation on the left gives the summation of each hourly interval for each of the three years. In 2016, Germany was a net exporter of about €1.5 billion of electricity based on day-ahead values of energy. By 2024, the trend had reversed, and Germany net imported €3.8 billion of electricity. Looking at the scatter plots, in 2016, Germany exported much more than it imported and generally exported at prices at or higher than import prices; in 2024, during most high-price intervals, Germany was importing power. Its exports were all at lower price intervals, and an increasing amount of the exports were at negative prices (paying neighbors to take surplus electricity). The bottom two graphics in the figure show the daily cross-border electrical energy trade for 2015 and 2024. It is clear Germany went from a net daily exporter in 2015 to largely a net daily importer in 2024.

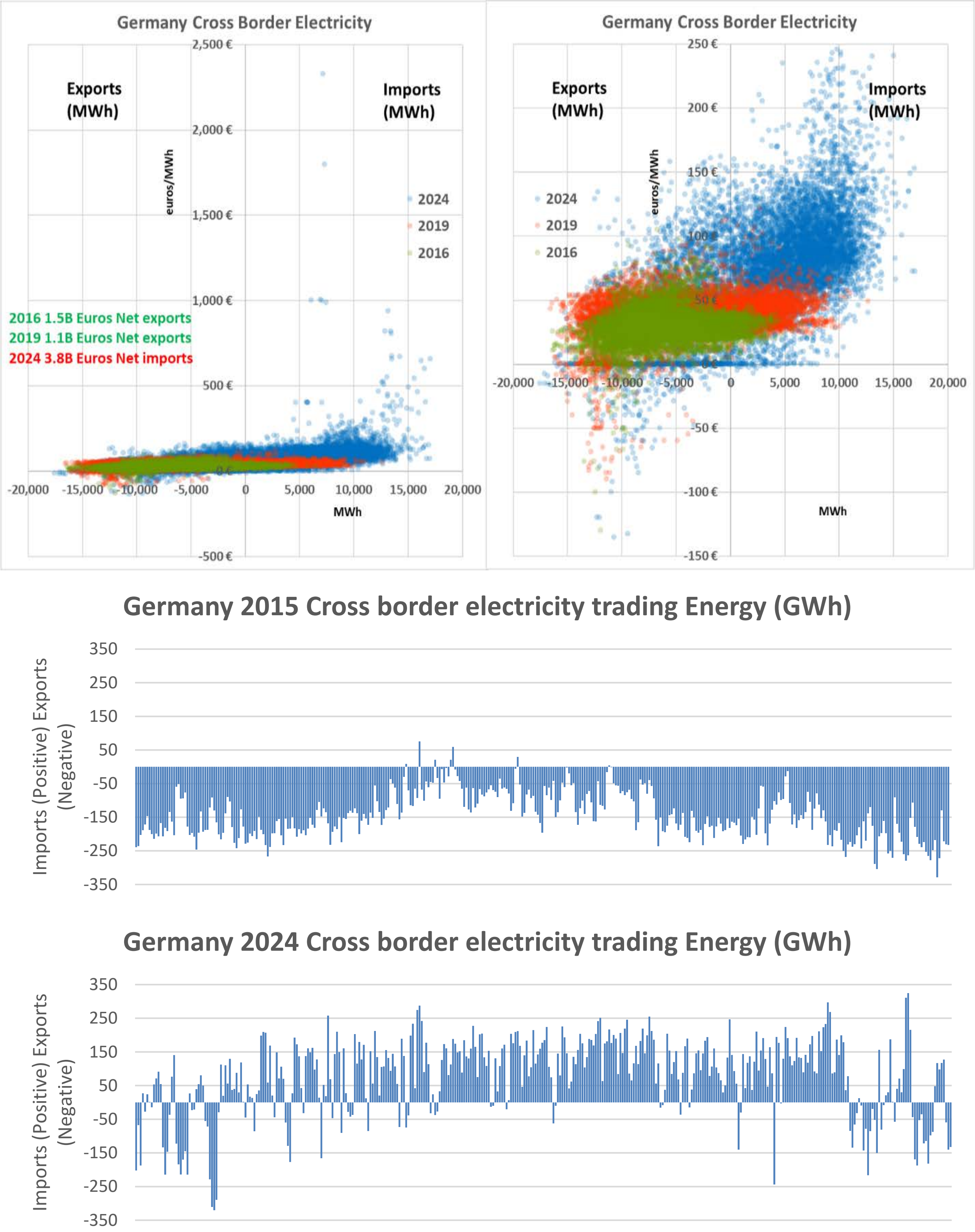
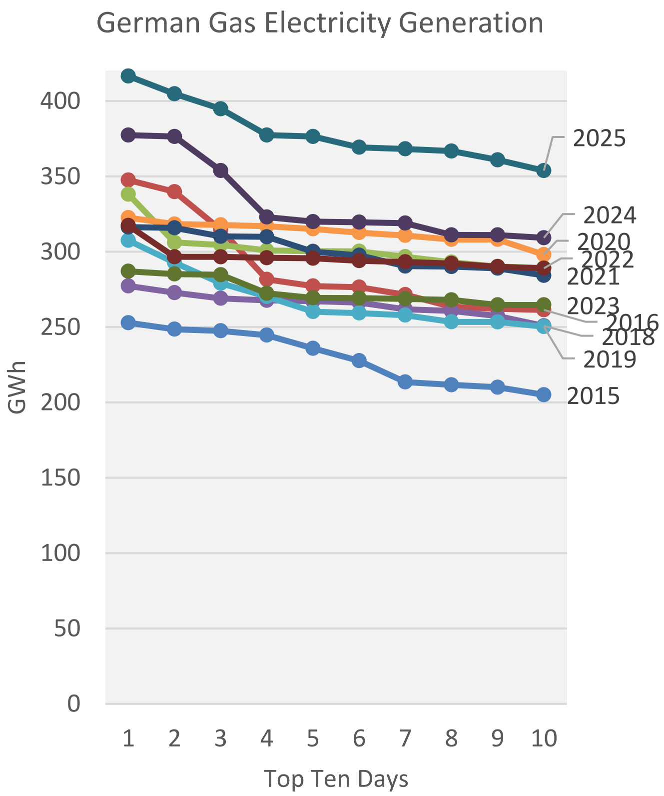


Figure 29. Germany exports and imports of electricity in MWh versus day-ahead prices (top) daily totals (middle, bottom) (Data from [4])

When wind and solar production is high in Germany, it is high in the rest of the EU, and when it is low in Germany, it tends to be low in the rest of the EU. When there is high wind and solar availability and low demand (springtime), wholesale prices drop; and when there is high demand and low wind and solar availability (still winter morning), wholesale prices increase significantly. Thus, Germany now exports when prices are low and must import when prices are high. This is a function of the electricity supply makeup.

Germany Gas Generation

The German electricity system reliance on gas during peak net demand periods is increasing, as illustrated in Figure 30. The top 10 daily uses of gas for electricity generation have all occurred in 2024/5. As Germany is reliant on gas imports and gas storage, this increasing reliance on peak days is an energy supply security concern. In January 2026, Germany used more gas for electricity generation than ever before, continuing the trend seen in Figure 30.



Day	Energy (GWh)
25.11.2025	417
26.11.2025	405
21.11.2025	395
12.12.2024	377
11.12.2024	376
15.01.2025	369
20.11.2025	368
21.01.2025	367
14.02.2025	361
13.12.2024	354

Figure 30. Germany gas use for electricity; graph on left shows top ten days per year, and table at right shows top 10 days in from 2015 to November 2025. (Data from [4])

Germany Peak Reduction

Looking across every hour in 2024, the peak demand in Germany was 75.8 GW. The peak hour less the solar generation was 74.7 GW (92.3 GW installed solar capacity) while the peak hour less wind generation was 69.0 GW (72.8 GW installed wind capacity) and less the combined wind and solar was 67.4 GW (167 GW combined installed capacity). Solar capacity in 2024 resulted in 0.01 GW/GW installed capacity reduction for other generation sources. Wind's ratio was 0.09 GW/GW installed, and the combined wind and solar ratio was 0.05 GW/GW installed.

Key Observation Point

In 2024, the combined wind and solar fleet in Germany reduced the need for other generation sources on the peak demand hour by 0.05 GW/GW installed.

The 167 GW installed wind and solar capacity reduced the 2024 peak demand hour of 75.8 GW to a net peak demand hour of 67.4 GW. This is a reduction of 8.4 GW.

This is well illustrated in the peak net load day (see Figure 25), where solar output on the peak hour was essentially 0, the daily energy was 0.14 GWh per GW installed, and wind output on the peak hour was 0.04 GW per GW installed and 0.8 GWh per GW installed. It would require greater than a 20-time increase in the current installed capacity for wind and solar to cover this load.

Figure 31 analyzes the peak reduction over the period from 2015 to 2024 from the addition of solar and wind generation. There have been significant additions of solar, wind, and battery capacity in the period. This has resulted in an appreciable increase in energy on an annual basis from wind and solar, and a decrease from non-wind and non-solar as the total annual energy need has remain largely constant. However, the peak daily energy requirement from non-wind and non-solar resources has not decreased as significantly.

The yellow column (left axis) is the installed nameplate capacity in GW of wind, solar, and battery capacity. It is increasing year over year. The orange column (left axis) is the annual energy from wind and solar in TWh; this is generally increasing year over year. The grey column (left axis) is the annual energy from non-solar and non-wind resources in TWh, which is generally decreasing year over year. The lines are daily peak energy from non-solar and non-wind resources in GWh (black line) and total annual energy in TWh (red line), both on the right axis.

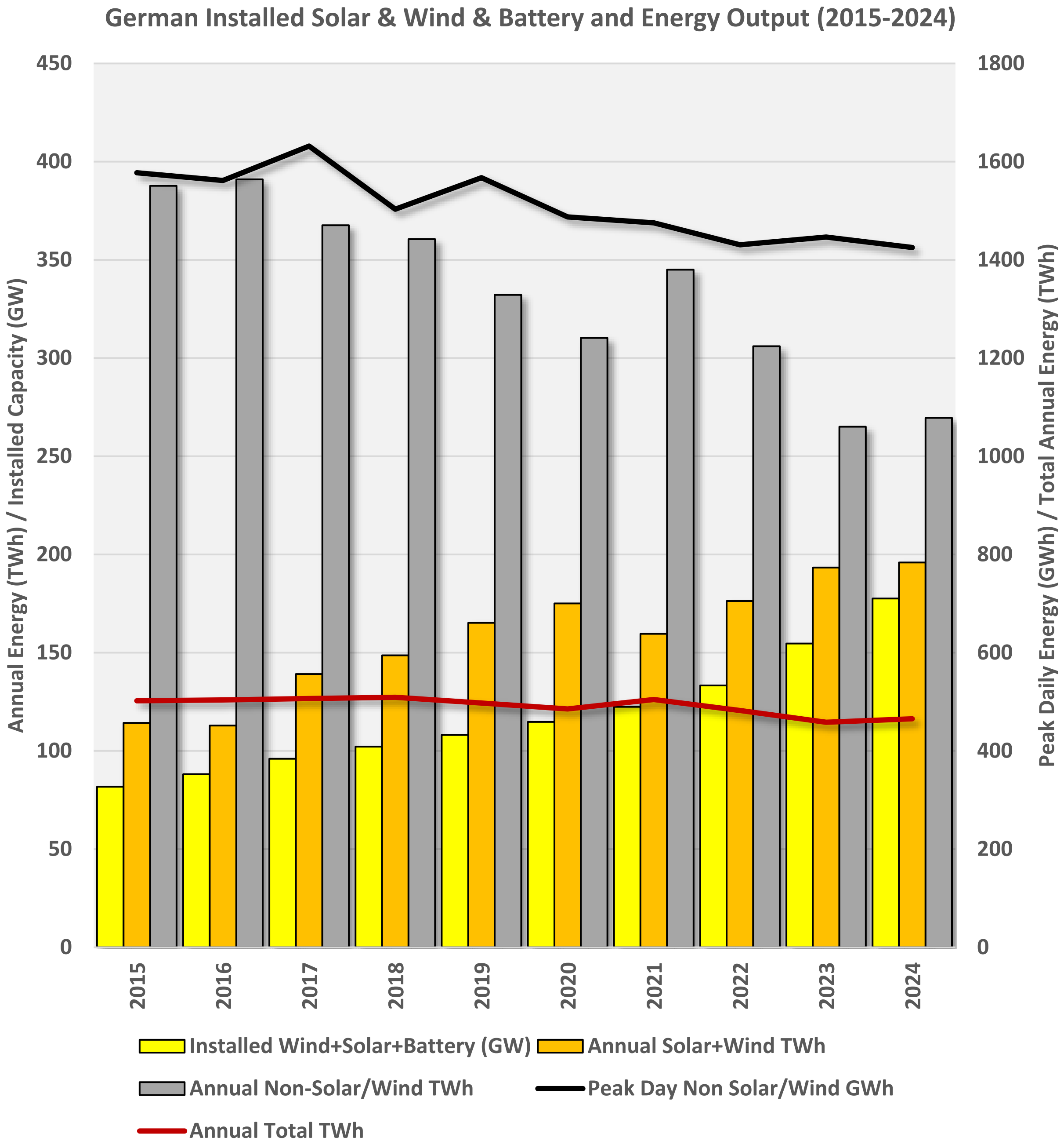


Figure 31. Germany wind, solar, and battery additions—annual energy and daily peak non-solar/wind energy 2015 to 2024 (Data from [4])

Figure 32 looks at the addition of solar, wind, and battery capacity versus the net effect on the annual non-solar and non-wind energy requirement and peak daily requirement versus 2015 as a baseline year. The much larger impact on annual energy versus peak day daily energy illustrates the challenge from variable energy resources. Despite increases in wind and solar capacity, Dunkelflaute periods each year ensure that there are days when the peak energy use from other resources remains relatively unchanged.

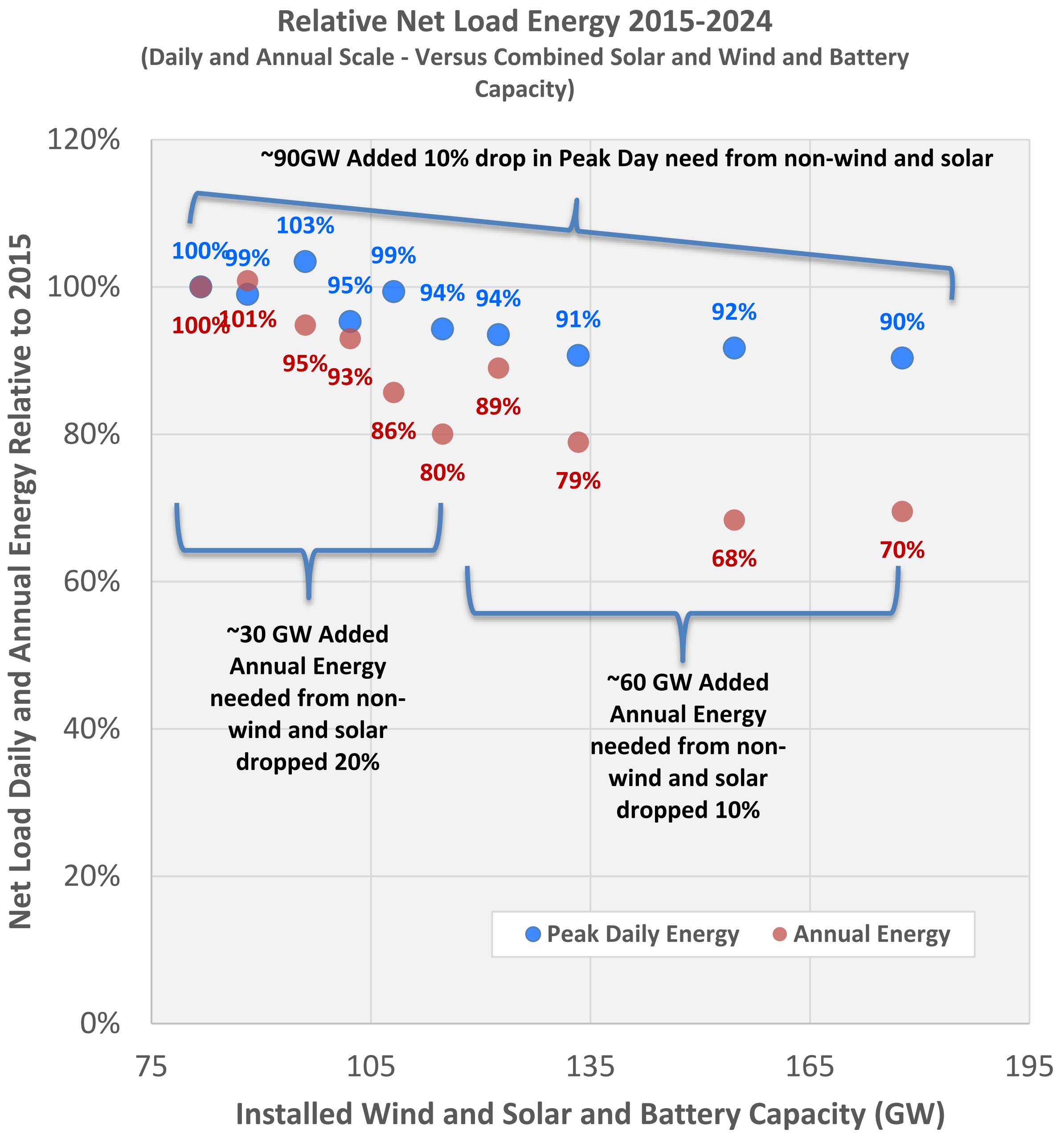


Figure 32. Germany relative net load energy 2015–2024 (daily and annual scale versus combined solar, wind, and battery capacity) (Data from [4])

Germany is highly reliant on the installed gas and coal generation fleet on the peak net load days (see Table 3). This can be a significant risk as reliability of conventional generation generally decreases with increased flexible operation (as does revenue—unless capacity payments are introduced) [10]. Increasing wind, solar, and battery capacity over the last 10 years has not reduced this reliance. Despite an addition of 90 GW of wind, solar, and battery capacity, the peak daily energy requirement from other energy resources has only decreased by 10% from 2015.

Germany Summary

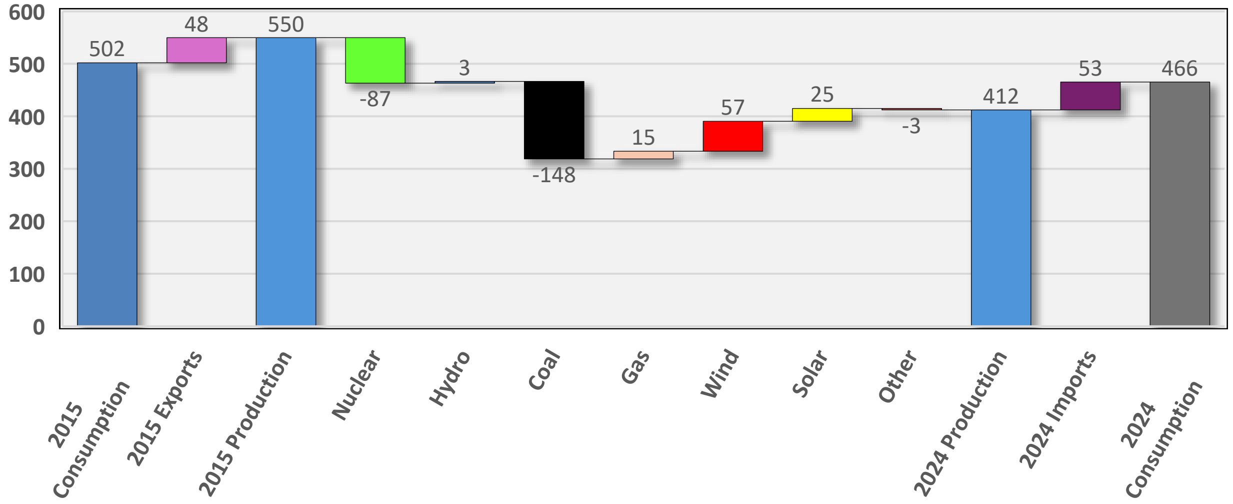
Germany has among the highest cost electricity in the EU and the world. It relies on imports when output from renewables is low and demand is high; this corresponds with times when wholesale prices are high. Germany exports at low or negative wholesale prices, when renewable output is high and demand is low. It is also increasingly reliant on its gas infrastructure. Germany has not had any significant disruptions in electricity supply, but its reliance on gas and imports is a potential concern for security of supply. Note over 90% of the gas consumption in Germany comes from imports https://www.iea.org/countries/germany/natural-gas. Overall, Germany is most at risk when gas storage for winter is low and there are low winds through the winter period.

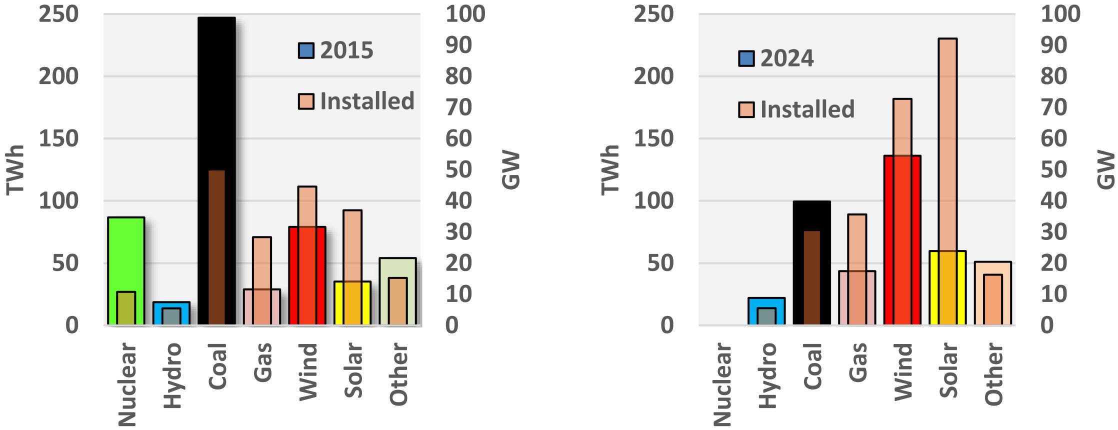
Key Findings

- Germany had 44% of its annual electricity production from solar and wind resources in 2024.
    - Germany's carbon intensity of electricity is well above the EU average in 2024, at a ratio of 1.6.
- Germany has the second most expensive electricity in the EU and among the most expensive electricity in the world as of 2024.
- Germany's overall annual net electricity production has been in decline since 2017 (554 TWh), reaching a 20+ year low of 412 TWh in 2024.
- Germany imports electricity on the highest price days in Europe and is highly reliant on imports on net peak demand days.
- Germany is heavily reliant on imports when domestic solar and wind output is low and demand is high. These imports are largely from nuclear, coal, gas, biomass, and hydro power plants.
- Germany is increasingly reliant on gas generation, with ten of the top ten days for gas generation in the last 10 years occurring in 2024/5.
- Germany's coal and gas fleet has a low utilization but still requires high utilization on winter and net peak days and hours:
    - Coal average usage 3.3 GWh/GW, peak usage ~14 GWh/GW installed capacity (winter peak day and net peak day).
    - Gas average usage 1.4 GWh/GW, peak usage ~11 GWh/GW installed capacity (net peak day).
    - This is a significant energy security risk as the reliability of these power plants reduces as they age and operate more flexibly.
- Germany imports more than 90% of the gas it consumes.
- Germany is a winter peaking system where solar energy provides little on-peak hour and little daily energy.
- Cold winters with low winds and lower gas storage inventories appear to be the greatest risk periods for Germany.

Figure 33 provides a waterfall graph of energy (TWh) changes (top chart), a waterfall of capacity (GW) changes (bottom chart), and a breakdown of total energy (TWh) and capacity (GW) by resource for 2015 and 2024 (middle charts) for Germany.

Electricity Generation 2015 through 2024 - TWh





Capacity 2015 through 2024 - GW

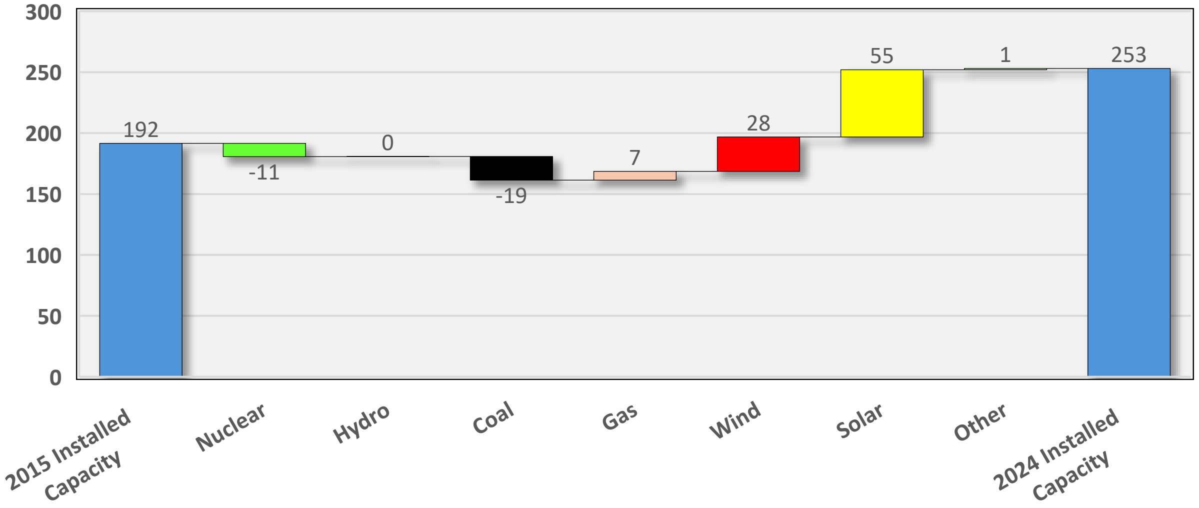
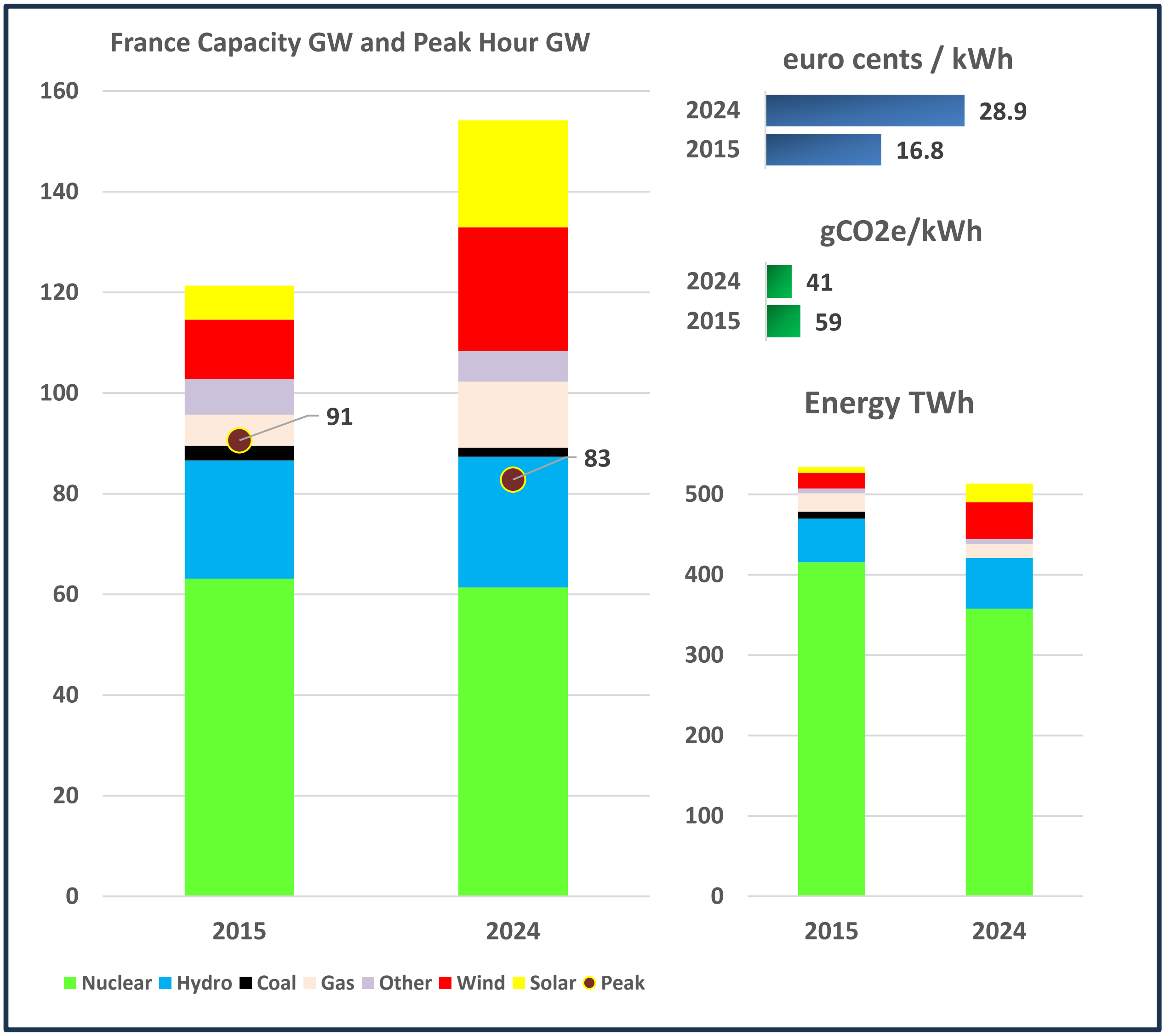


Figure 33. Germany capacity and generation summary 2015 and 2024 (Data from [4])

France Electricity Supply

Overview 2015–2024—France



	Capacity	Energy	Price	CO2
2024/2015	127%	96%	172%	75%
		2015 / EU27 2015	0.8	0.2
		2024 / EU27 2024	1.0	0.2

Figure 34. France 2015 and 2024 capacity and peak (GW), household rates (cents/kWh), carbon intensity (gCO2e/kWh), and energy (TWh) (Capacity and energy data from [4], rates from [9], and carbon from [7])

France's capacity, peak, energy, household rates, and carbon intensity of the electricity are given in Figure 34. The table below the figure shows France's progress over time (first line), and France's price and carbon intensity versus the EU27 average for 2015 and 2024 (lines two and three).

The installed nameplate capacity of the French generation fleet in 2024 increased to 127% the 2015 value but delivered less energy in 2024 than in 2015. The nominal price climbed from 2015 to 2024 and increased from a factor of 0.8 versus the average EU27 price in 2015 to roughly equivalent to the EU27 price in 2024. The carbon intensity decreased to 75% of the 2015 value and is a fraction of the average EU27 intensity in both 2015 and 2024, at a ratio of 0.2. This indicates that France continues to be a leader in terms of carbon emission intensity in the EU27.

Figure 35 provides the winter and summer peak demand days for France in 2024. Wind and solar combined provided little energy on the winter peak day (January 15). Solar did make a notable contribution to the lower summer peak in France on July 31.

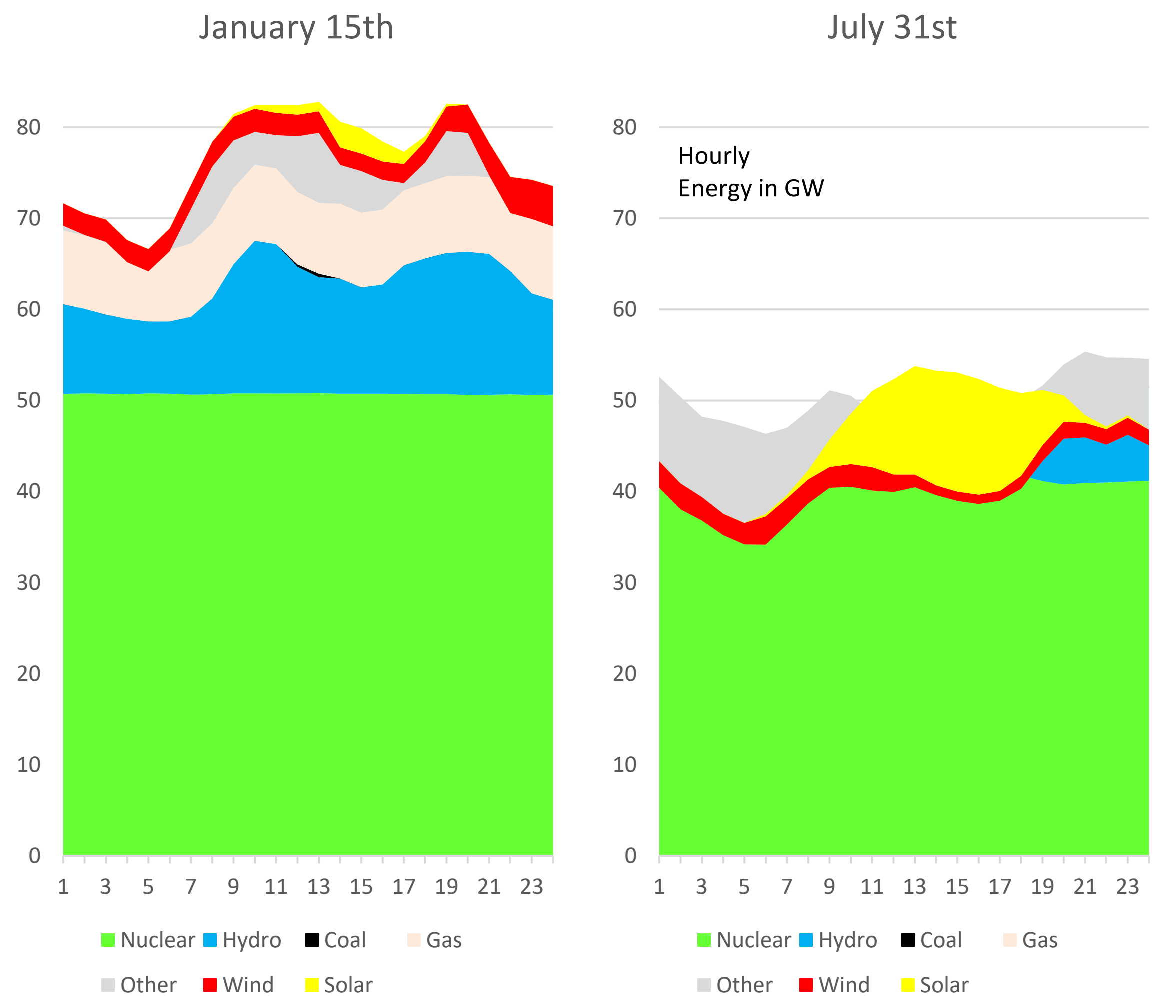


Figure 35. France peak winter and summer demand days 2024 (Data from [4])

The winter peak occurred at around 6 p.m. The summer peak occurred around 12 noon (the other peak later in the day includes exported energy). Figure 36 compares the installed capacity and output on peak hours. Nuclear provided significant output on both peaks while solar contribution on the peak summer hour is significant but negligible on the winter peak hour.

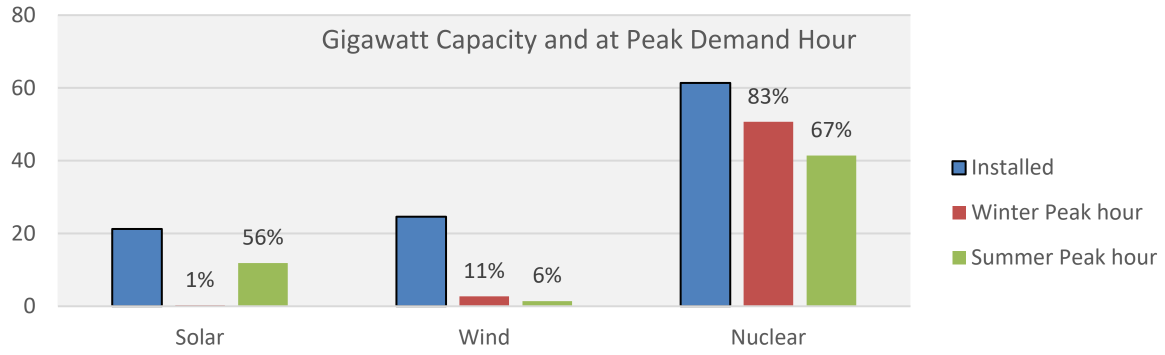


Figure 36. France solar, wind, nuclear installed capacity and output on peak winter and summer hour 2024 (Data from [4])

Figure 37 completes the peak day picture with the daily energy total, with a column chart depiction of the energy on the two peak days and pie charts below. In France, nuclear and hydro provided a majority of the daily energy required. The overall solar and wind energy contribution was minor. Gas contribution to the daily energy requirement was greater on the winter peak day than the summer peak day. The winter peak day required significantly more energy in France than the summer peak day, due in large part to electrical heating in France. Dispatchable gas and nuclear resources filled this gap. Solar (not surprisingly) provided more energy in the summer, even though the energy demand in the winter was significantly higher. This mismatch, at higher solar penetration, could drive more flexible daily operation of dispatchable power plants (recall the duck curve in Figure 4).

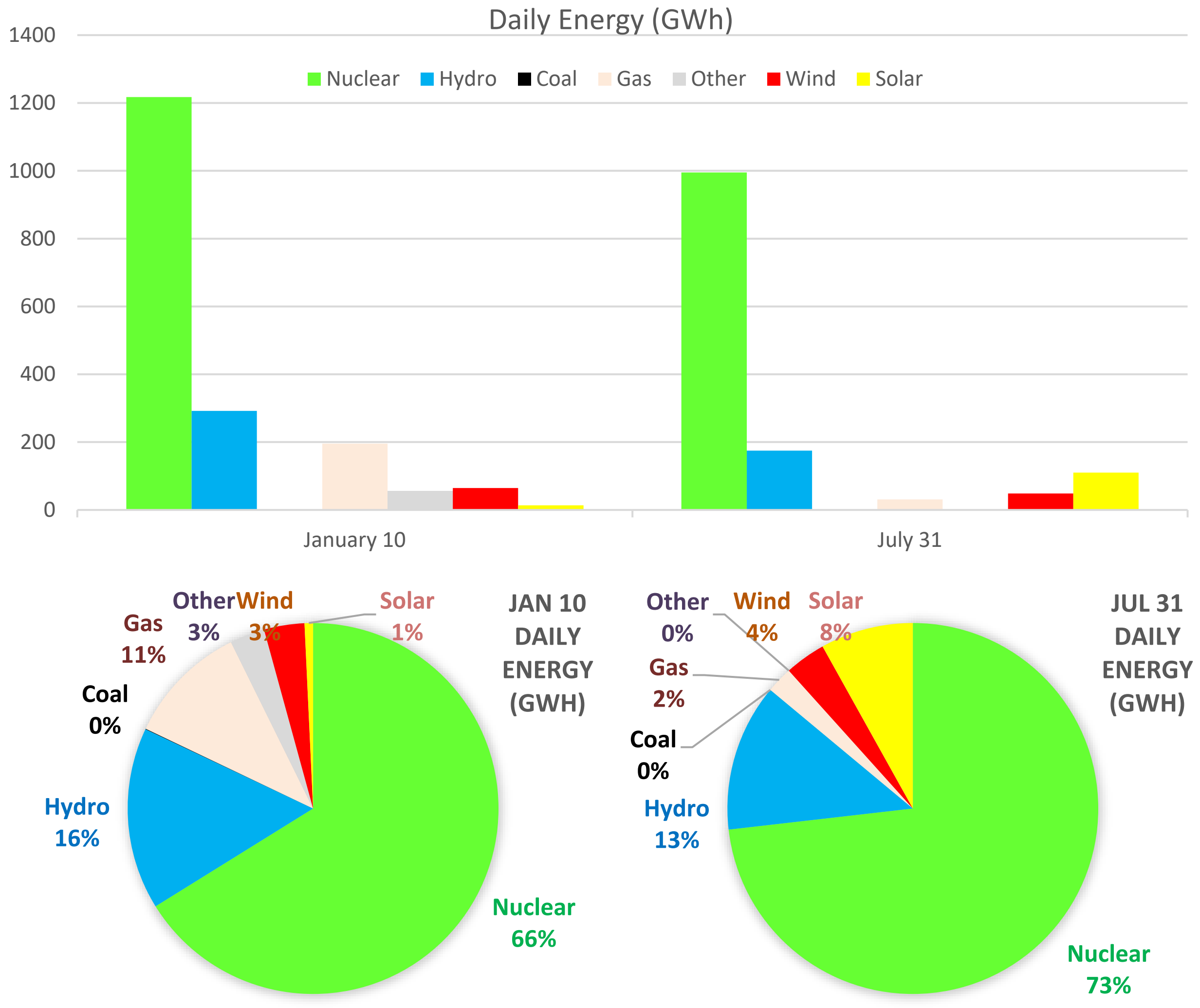


Figure 37. France 2024 winter and summer total electrical energy by resource (Data from [4])

Table 4 quantifies the relative contributions of the installed capacity to the peak hour and peak daily energy for gas, nuclear, hydro, solar, and wind in France on the peak day (winter day).

The peak hour/capacity factor (GW/GW) essentially represents how many GW of energy from the installed capacity were delivered at the peak demand hour in 2024. For solar, the value was near zero, implying that scaling solar alone does not lessen the need for other generation resources in France’s winter peak (does nothing to reduce the need for other resources to meet the peak hour demand of 83 GW).

The peak day/capacity (GWh/GW) represents how many GWh of energy the resource provided per GW of installed capacity on the peak demand day. The higher the number, the more energy the resource provided per GW of installed capacity on the peak demand day.

The avg day/capacity (GWh/GW) represents how many GWh the resources provided per GW of installed capacity on the average day in the year.

Table 4. France peak—resource output on peak hour (18:00) and for day—January 10, 2024

Resource	Installed Capacity (GW)	Peak Hour Output (GW)	Peak Day (GWh)	Peak Hour / Capacity	Peak Day / Capacity (GWh/GW)	Avg Day / Capacity (GWh/GW)
Gas	13	8	195	0.64	14.9	3.6
Nuclear	61	51	1,217	0.83	19.8	16.0
Hydro	26	15	292	0.60	11.2	6.6
Solar	21	0	14	0.01	0.64	3.0
Wind	25	3	65	0.11	2.6	5.1
Peak		**83**	**1,840**			

The peak energy day value (bottom line of the table) divided by the peak day energy ratio in theory gives the amount of power plant capacity required by each type to cover the peak day. For nuclear, it would be around 92 GW to cover the energy need. For solar, the calculation yields over 2,870 GW to provide sufficient energy on the peak day. And due to the peak hour being an early morning hour, the GW capacity to cover that peak hour is an extremely high number.

The difference between the energy delivered on the average day and on the peak day is also instructive. Essentially, as capacity scales the larger difference between these ratios, the potential for negative pricing increases (see Figure 29 showing the increased occurrence of negative pricing in 2024 versus 2022 versus 2019 for Germany).

France Trends

France Nuclear Generation

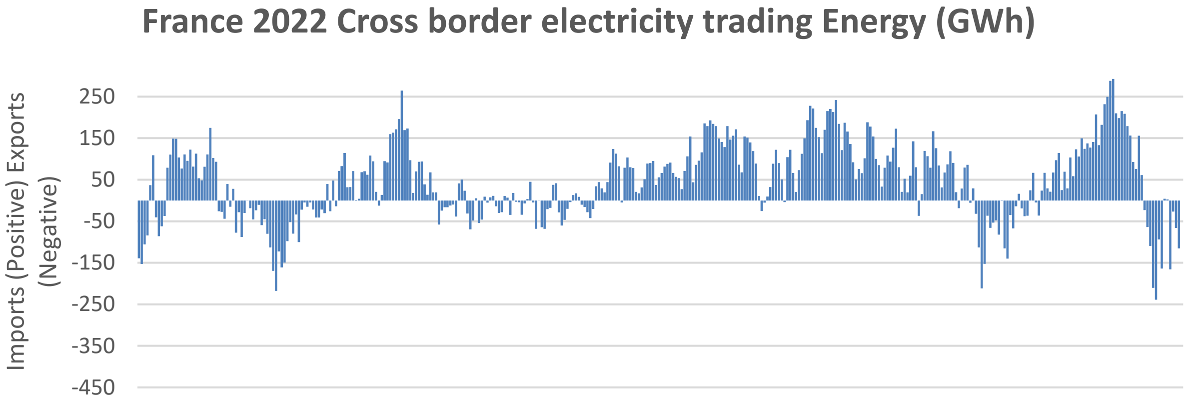
France's electricity supply security relies on nuclear fleet reliability, and as the nuclear fleet ages, this can be challenging. In addition, while the common design of France’s nuclear fleet reduced construction cost, it has introduced common modes of failure. In 2022, one such issue arose with stress corrosion cracking in piping affecting several units [11]. This required extended shutdowns for inspection and repair. Compared to 2021, France’s nuclear energy production was down about 20% in 2022 and 10% in 2023. As of 2024, production is back to 2021 levels (around 360 TWh per year). During 2022, the peak demand in France was 86.2 GW, the peak demand less what was covered by nuclear supply in 2022 was 40.6 GW, and the installed capacity in 2022 was 61.4 GW. So even in the poorly performing year, nuclear reduced the need for other generation resources (power plants) to cover electricity needs by ~0.74 GW/installed GW (in 2024, this ratio was 0.82 GW/installed GW).

The age of the nuclear fleet is a growing concern as many of the reactors have seen 40–50 years of operation. This can result in increased need for repair, especially if the fleet is required to operate more flexibly, which can introduce increased wear of the power plant components resulting in increased outages for maintenance and repair. Retirement of reactors is typically required sometime around 60 years of operation, although some may be able to operate for 80 or more years, which is currently being explored in the United States; the French, with a younger nuclear fleet, are not yet exploring this. High river temperatures during summer heatwaves sometimes force reactors to reduce output or shut down to comply with environmental regulations regarding cooling water discharge, leading to supply dips, but as France is winter peaking, this is not necessarily a significant system concern, although it can increase wholesale prices.

Fuel source can be a concern; the French nuclear fuel company Orano (formerly AREVA) has a strategy of wide geographic diversification to ensure supply security. The major uranium source countries include Kazakhstan, Niger, Namibia, Australia, Canada, and Uzbekistan. France processes the raw uranium to fuel in country, and recycles spent fuel in country.

France Import/Export

During the height of the nuclear maintenance concerns in 2022 France relied on imports. As of 2024 though, this reliance has reduced, and now France typically is a net daily exporter of electricity, as shown in Figure 38.


France 2022 Cross border electricity trading Energy (GWh)

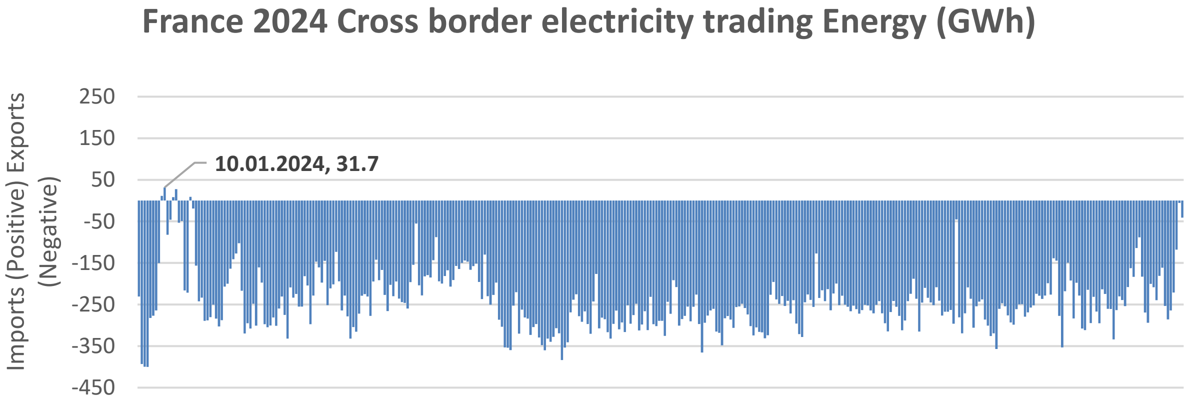

France 2024 Cross border electricity trading Energy (GWh)

Figure 38. France cross border electricity trading 2022 and 2024 (Data from [4])

France Summary

France maintains electricity costs around the EU27 average. It has the lowest carbon dioxide emission intensity of all large nations (see Figure 10). France does have some energy security risk associated with a reliance on common nuclear technology that is aging.

Key Findings

- France delivered 13% of its annual electricity production from solar and wind resources, 70% from nuclear, and 12% from hydro power in 2024.
    - France's carbon intensity of electricity is a factor of 0.2 of the EU27 average in 2024 and significantly better than all larger nations.
- France's electricity costs are on par with the average EU27 electricity cost.
- France's overall annual net electricity production has been relatively constant over the last 10 years at around 500–530 TWh per year, except for 2022 and 2023 due to the nuclear reactor repairs and 2020 due to the COVID pandemic and a reduction in electricity demand.
- France was a net importer of electricity on only five days in 2024. On its peak day, it imported under 2% of its daily electrical energy requirement.
    - In 2022, when the nuclear fleet had maintenance issues, France was frequently reliant on imports. In 2024, this is no longer the case.
- France relies on gas most heavily in January, but the country's overall use of gas has been on a downward trend.
- France has a diversified uranium supply, processes uranium into fuel domestically, and recycles spent nuclear fuel, which provides upstream resilience to the nuclear electricity energy supply.
- France is a winter peaking system where solar energy provides little on-peak hour and little daily energy.
- Cold winters with low nuclear reliability are the greatest risk to France's electricity supply due to the large winter peaks in France from electrical heating.

Figure 39 provides a waterfall graph of energy (TWh) changes (top chart), a waterfall of capacity (GW) changes (bottom chart), and a breakdown of total energy (TWh) and capacity (GW) by resource for 2015 and 2024 (middle charts).

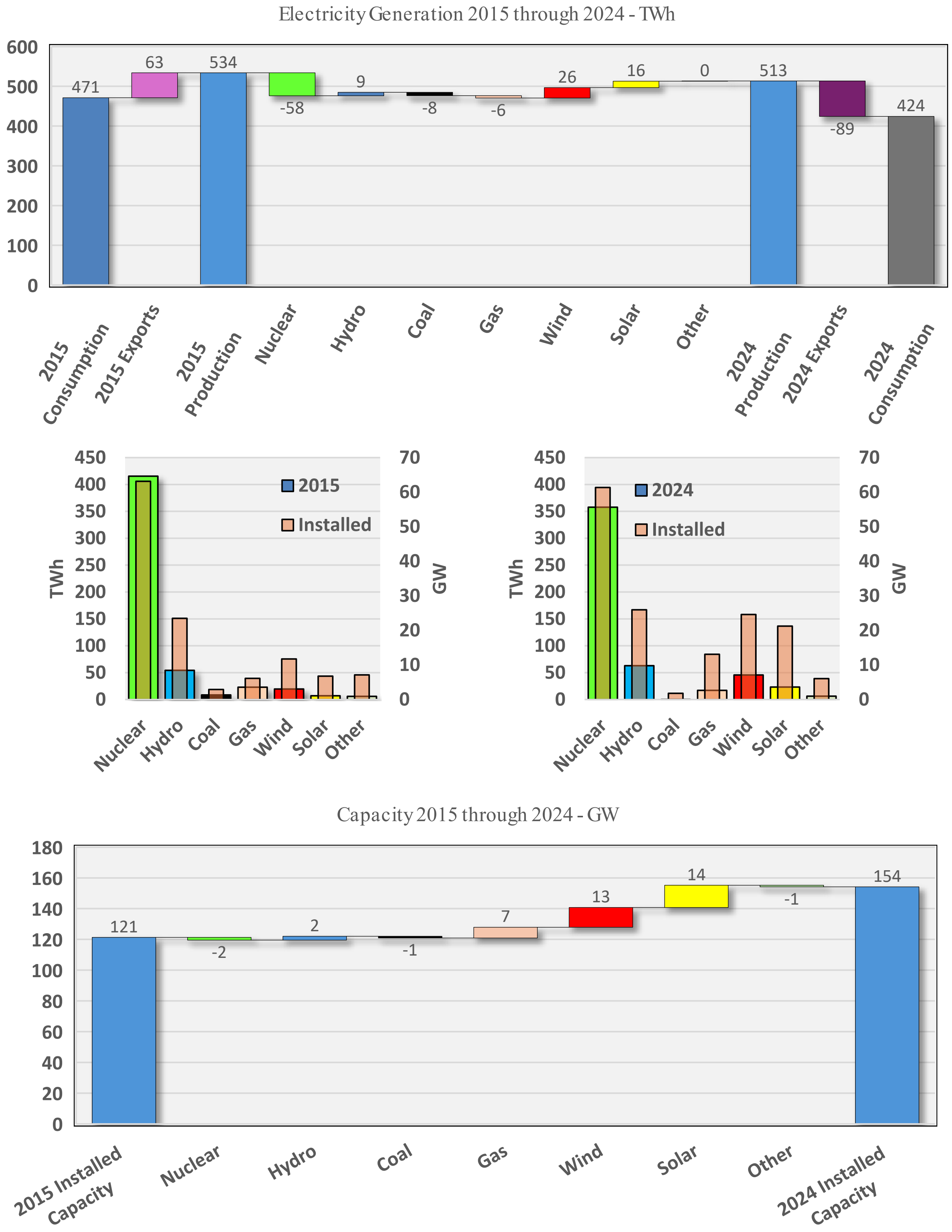
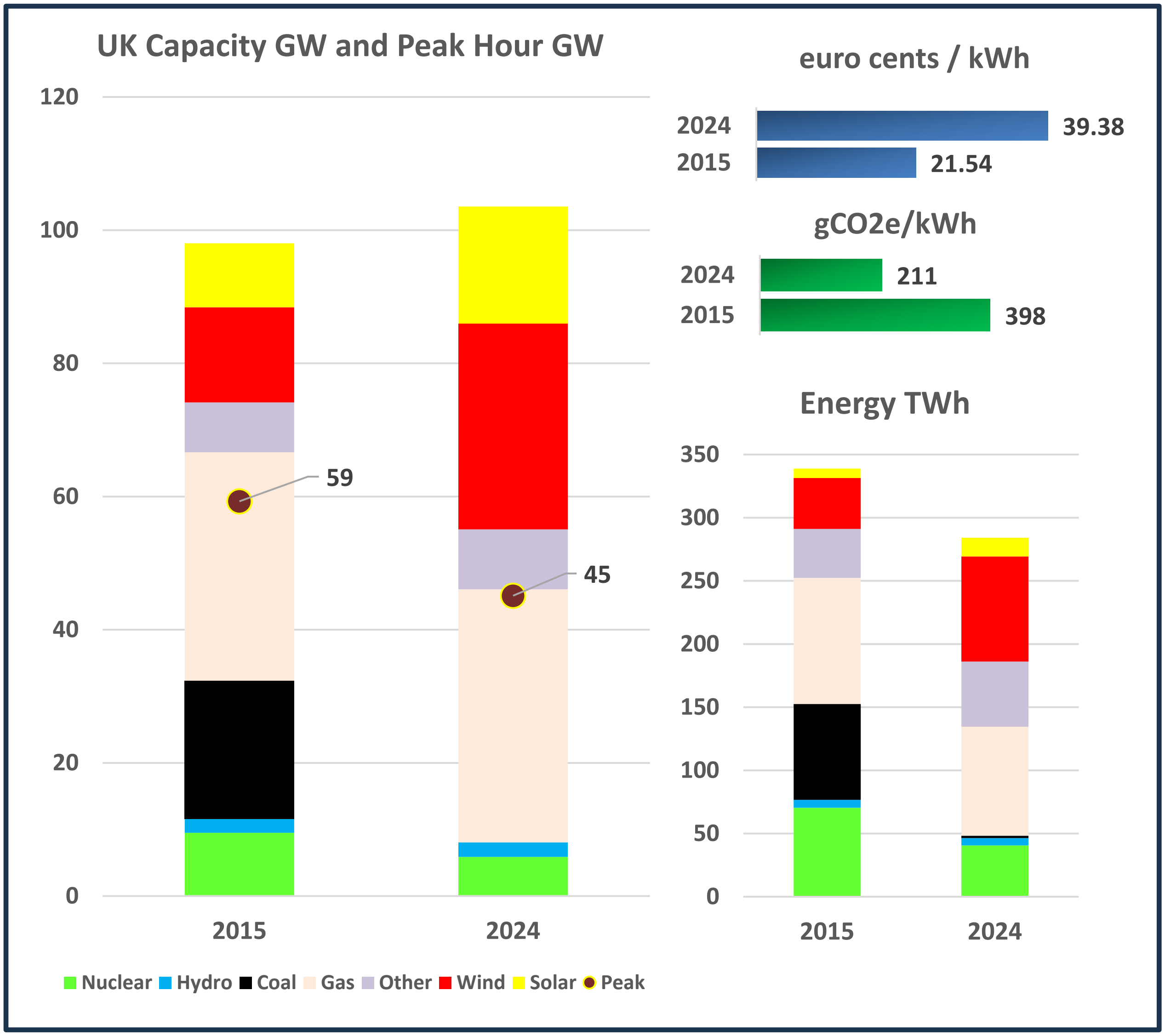


Figure 39. France capacity and generation summary 2015 and 2024 (Data from [4])

United Kingdom Electricity Supply

Overview 2015–2024—United Kingdom



	Capacity	Energy	Price	CO2
2024/2015	106%	84%	183%	53%
		2015 / EU27 2015	1.0	1.1
		2024 / EU27 2024	1.4	1.0

Figure 40. United Kingdom 2015 and 2024 capacity and peak (GW), household rates (cents/kWh), carbon intensity (gCO2e/kWh), and energy (TWh) (Capacity and energy data from [12], peaks from [13, 14], rates from [15], and carbon from [7])

The United Kingdom’s (UK) capacity, peak, energy, household rates, and carbon intensity of electricity is provided in Figure 40. The table shows UK progress over time (first line) and UK price and carbon intensity against the EU27 average for 2015 and 2024 (lines two and three).

In the period, the UK has seen a reduction in electricity production. Prices have significantly increased compared to the EU27 benchmark, where the price had been roughly on par with the EU27 average in 2015; they are now a factor of 1.4 times the EU27 average. The UK has had carbon intensity reduction slightly ahead of the average EU27 rate by a factor of 1.1. the EU27 average in 2015 and is at par with the EU27 average in 2024.

In addition to the reduction in total electrical energy, the peak hourly demand in the UK has reduced significantly.

Figure 41 provides the winter, summer, and net peak demand days for the UK in 2024.

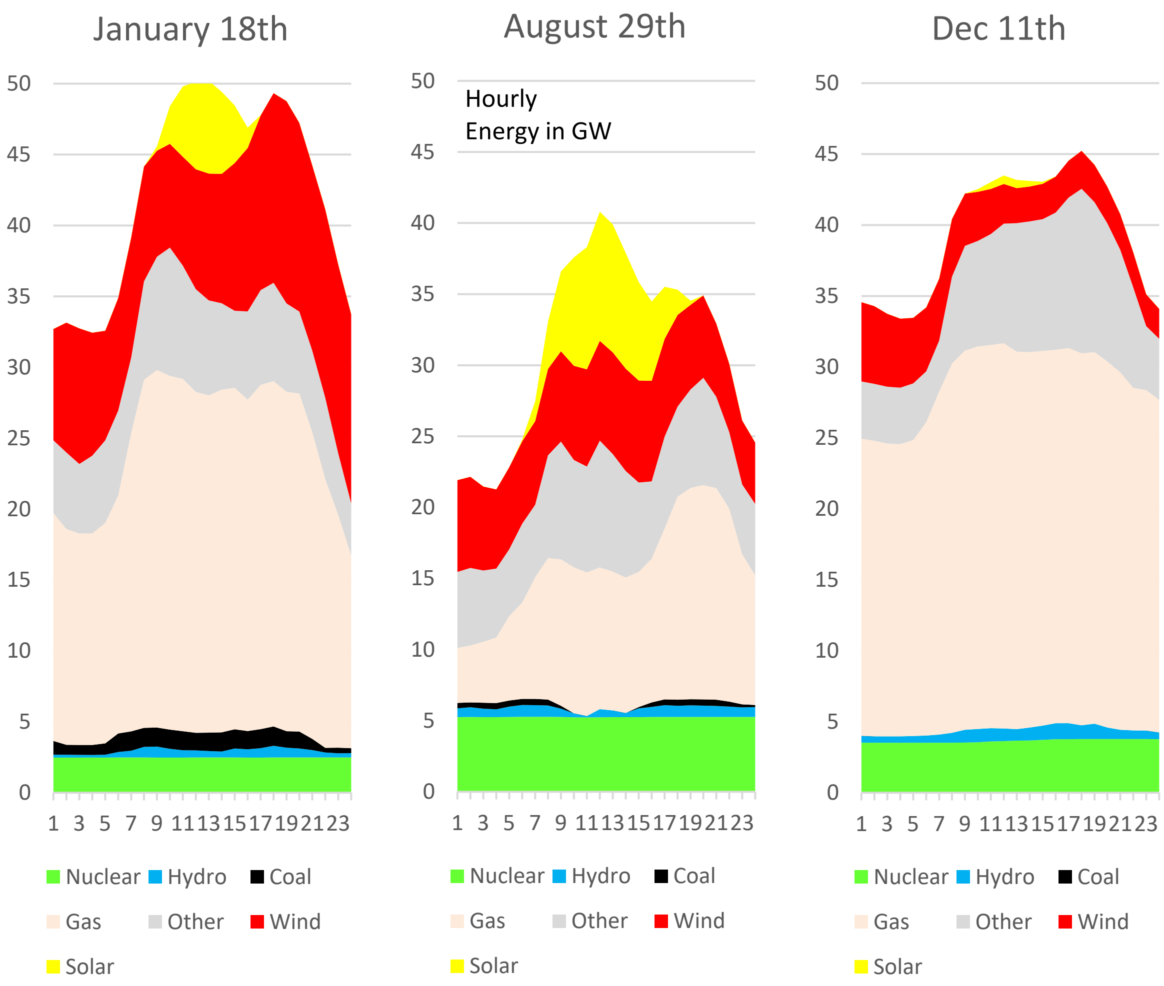


Figure 41. United Kingdom peak winter and summer and net peak demand days, 2024. (Net peak demand is the peak less wind and solar contribution.) (Data from [14])

Wind and solar combined provided a significant portion of the energy required on the peak winter and summer days in 2024. However, as was the case in Germany, there were high demand days when the contribution of wind and solar was very low. The peak net demand day was December 11, 2024 (this is the same day as in Germany in 2024, demonstrating a wide geographical scale reduction in wind and solar output).

Figure 42 provides the peak hours versus installed capacity on the three reference days from Figure 41.

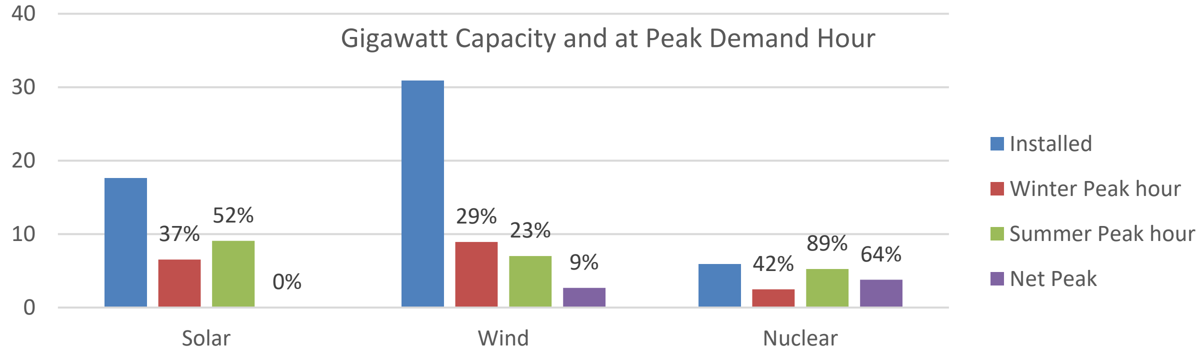


Figure 42. Solar, wind, and coal installed capacity and output on peak winter and summer and net peak hour, 2024 (Data from [12, 14])

On the net peak day, the nearly 20 GW of installed solar delivered no energy during the peak hour. Solar performed better during the summer and winter peak hours. The greater than 30 GW of wind delivered 9% of the nameplate capacity on the net peak day peak demand hour, 29% on the winter peak hour, and 23% on the summer peak hour. The nuclear fleet performed poorly on the 2024 winter peak day, delivering just 42% of the nameplate capacity. On the summer peak, 89% of nameplate was delivered on the peak hour and 64% on the net peak hour.

Figure 43 provides the total energy breakdown by the three days. The other energy for the net peak day is largely made up of imports and biomass. Gas was the largest source of electricity on the peak winter, summer, and net peak day. On the net peak day, over 60% of the daily required electrical energy came from gas generation. Solar delivered negligible energy on both the winter peak day and the net peak day. The UK completed its phaseout of coal in October 2024, which is reflected in the daily energy where there is a small contribution in the January winter peak day and August summer peak day but no contribution on the December net peak day.

Key Observation Point

In 2024, the United Kingdom relied heavily on gas generation on its peak days.

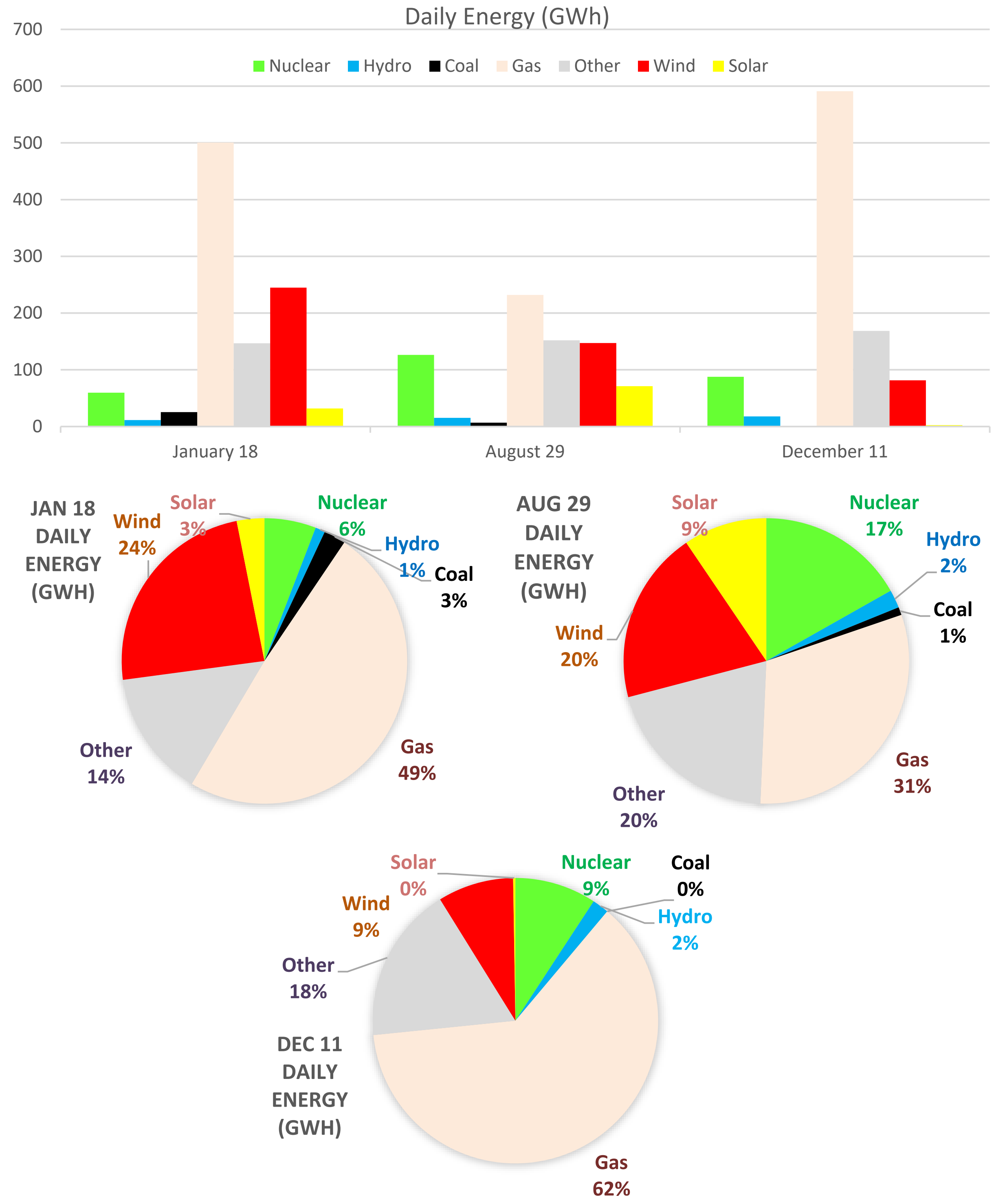


Figure 43. United Kingdom 2024 winter and summer and net peak total electrical energy by resource (Data from [14])

Table 5 quantifies the installed capacity and peak hour and peak daily energy for nuclear, gas, solar, and wind in the UK on the three reference days in more detail.

Table 5. United Kingdom winter peak day, summer peak day, and net peak resource outputs on peak hour

Winter peak – resource output on peak hour (12:00) and for day – January 18, 2024

Resource	Installed Capacity (GW)	Peak Hour Output (GW)	Peak Day (GWh)	Peak Hour / Capacity	Peak Day / Capacity (GWh/GW)	Avg Day / Capacity (GWh/GW)
Nuclear	5.9	2.5	60	0.42	10.1	6.9
Gas	38.0	23.8	500	0.63	13.2	2.2
Solar	17.6	4	32	0.37	1.8	0.8
Wind	30.9	29	245	0.29	7.9	2.7
Peak		**50.2**	**1,020**			

Summer peak – resource output on peak hour (11:00) and for day – August 29, 2024

Resource	Installed Capacity (GW)	Peak Hour Output (GW)	Peak Day (GWh)	Peak Hour / Capacity	Peak Day / Capacity (GWh/GW)	Avg Day / Capacity (GWh/GW)
Nuclear	5.9	5.2	126	0.89	21.5	6.9
Gas	38.0	10.0	232	0.26	6.1	2.2
Solar	17.6	9.1	71	0.23	4.0	0.8
Wind	30.9	7.0	147	0.52	4.8	2.7
Peak		**40.8**	**750**			

Net peak – resource output on peak hour (17:00) and for day – December 11, 2024

Resource	Installed Capacity (GW)	Peak Hour Output (GW)	Peak Day (GWh)	Peak Hour / Capacity	Peak Day / Capacity (GWh/GW)	Avg Day / Capacity (GWh/GW)
Nuclear	5.9	3.8	88	0.64	14.9	6.9
Gas	38.0	26.2	591	0.69	15.6	2.2
Solar	17.6	0	2	0.00	0.14	0.8
Wind	30.9	2.7	82	0.09	2.6	2.7
Peak		**45.2**	**949**			

For each of the peak days, gas provided the largest share of UK electrical energy (GWh). On the net peak day, the solar energy production was very low, with just 0.14 GWh/installed GW. On this day, the UK relied most heavily on the gas fleet, with the energy delivered over seven times greater than on the average day in the UK, which is a very large difference in peak use versus average use.

United Kingdom Trends

United Kingdom Gas Generation

The top three days for gas generation in the United Kingdom for the last 15 years (2009–2024) occurred on December 11, 12, and 13, 2024, as shown in Figure 44.

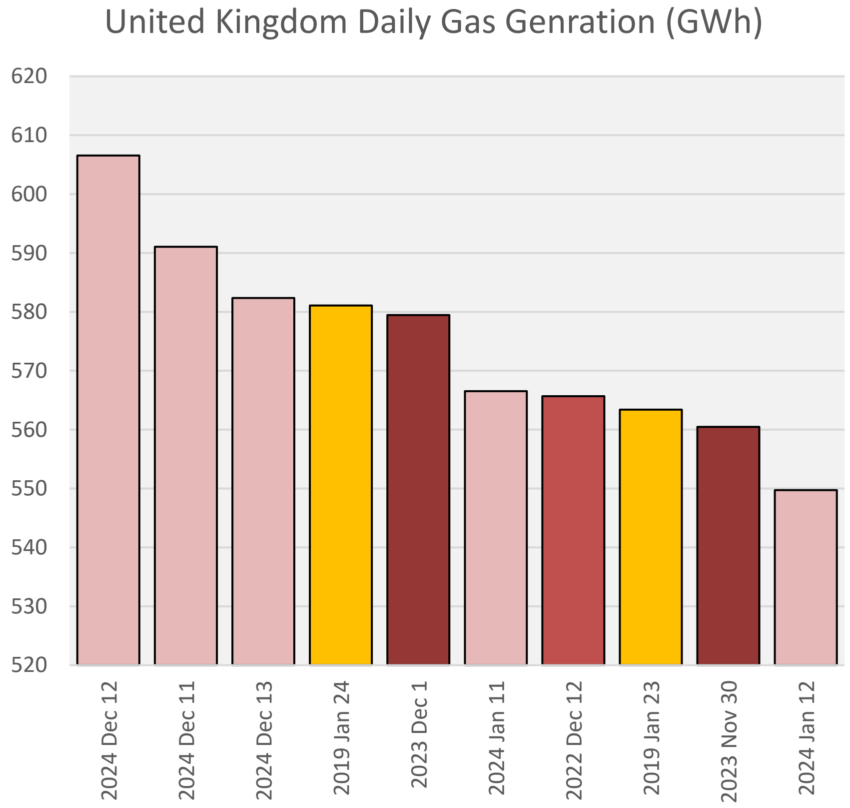


Figure 44. United Kingdom top gas generation days 2009–2024 (Data from [14])

This is despite 2024 being one of the lowest overall demand years for gas generation in the UK (see Figure 45). So, the UK is reducing its annual reliance on gas while simultaneously increasing its peak reliance on gas. This is not without risk because reliability challenges can arises when plants that are rarely run are relied on for meeting peak demand periods [10].

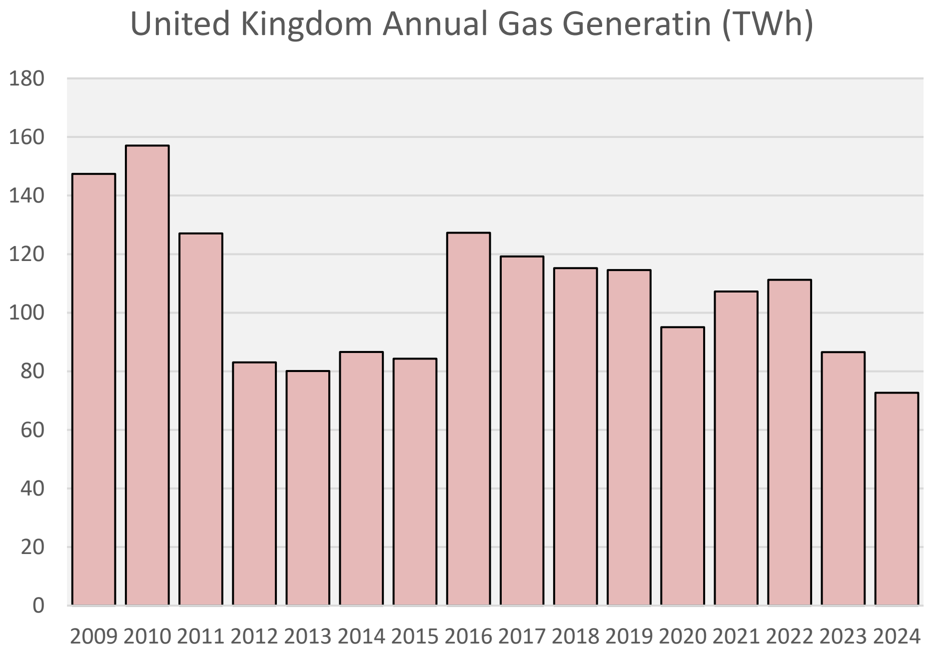


Figure 45. United Kingdom annual gas generation in TWh 2009–2024 (Data from [14])

The UK is also reducing its overall electricity consumption, which has been in decline since 2003 (see Figure 46). From 2003 to 2024, electricity use in the UK has reduced by nearly 30%.

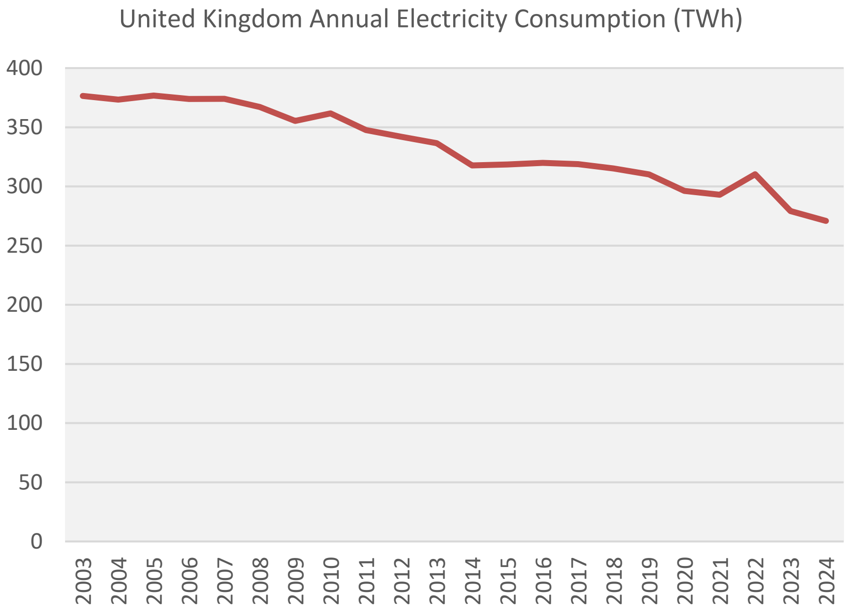


Figure 46. United Kingdom annual electricity consumption (Data from [16])

United Kingdom Coal Generation

Coal generation in the UK has ended as of October 2024. Nuclear and gas generation have also decreased on an annual basis while renewable generation, largely from wind and solar, has increased. The retail price of electricity in the UK has also increased dramatically due to the cost of gas (see Figure 47).

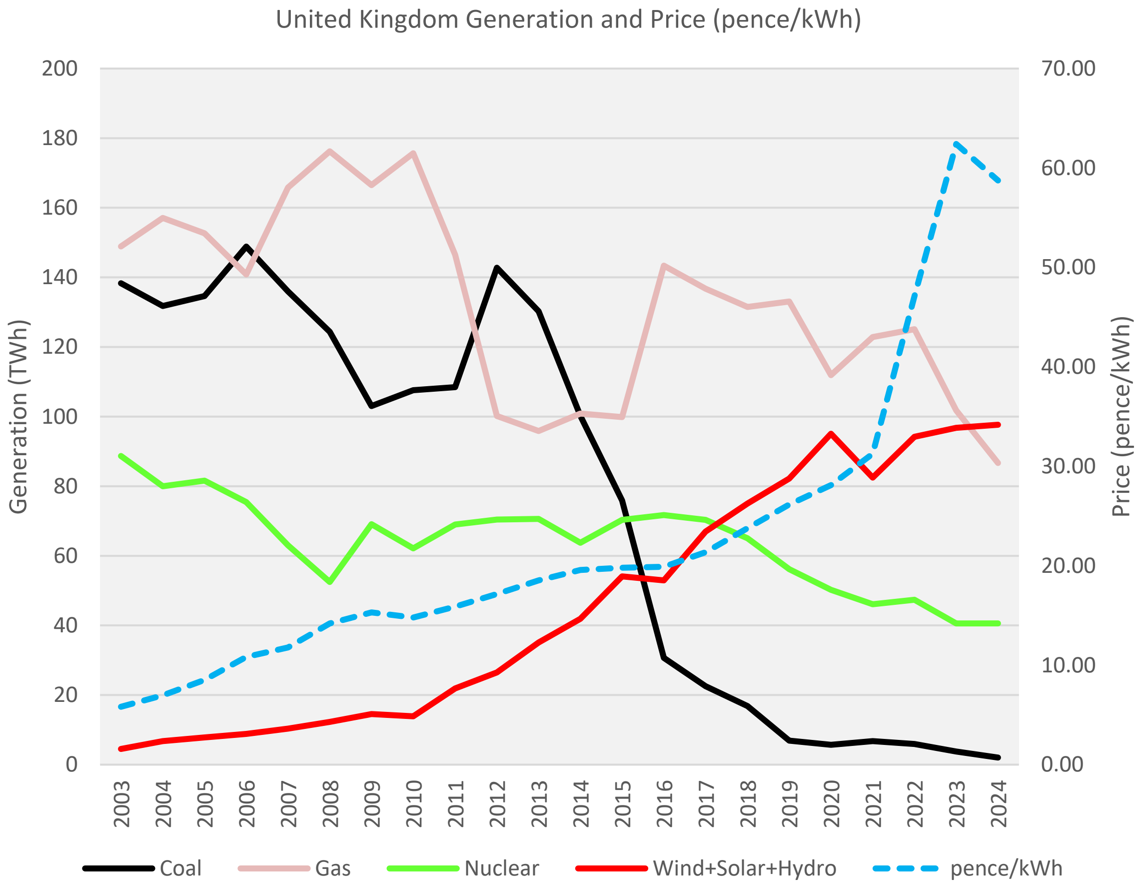


Figure 47. United Kingdom sources of generation and average net retail price (Data from [16])

Figure 48 is a set of generation supply curves for the UK using approximate marginal cost estimations for the various resources. The top two graphs show the current resource mix in the UK with two gas price scenarios. On the left is a low gas price, and on the right is a higher gas price (about 2.5 times the low gas price). Essentially, the case on the top right is representative of the current case in the UK. The bottom two graphs show the same scenarios, but this time with the assumption that no coal plants were closed after 2010. Marked on each graph is the clearing prices at the 60,000 MW supply point (assuming about an average capacity output from wind and solar of around 25%, which is roughly a demand of 40,000 MW, a typical demand in the UK). The clearing price impact, assuming there had been no coal closures after 2010, is significantly lower. Being increasingly reliant on gas as the main dispatchable source of electricity makes the electricity price in the UK very sensitive to global gas prices.

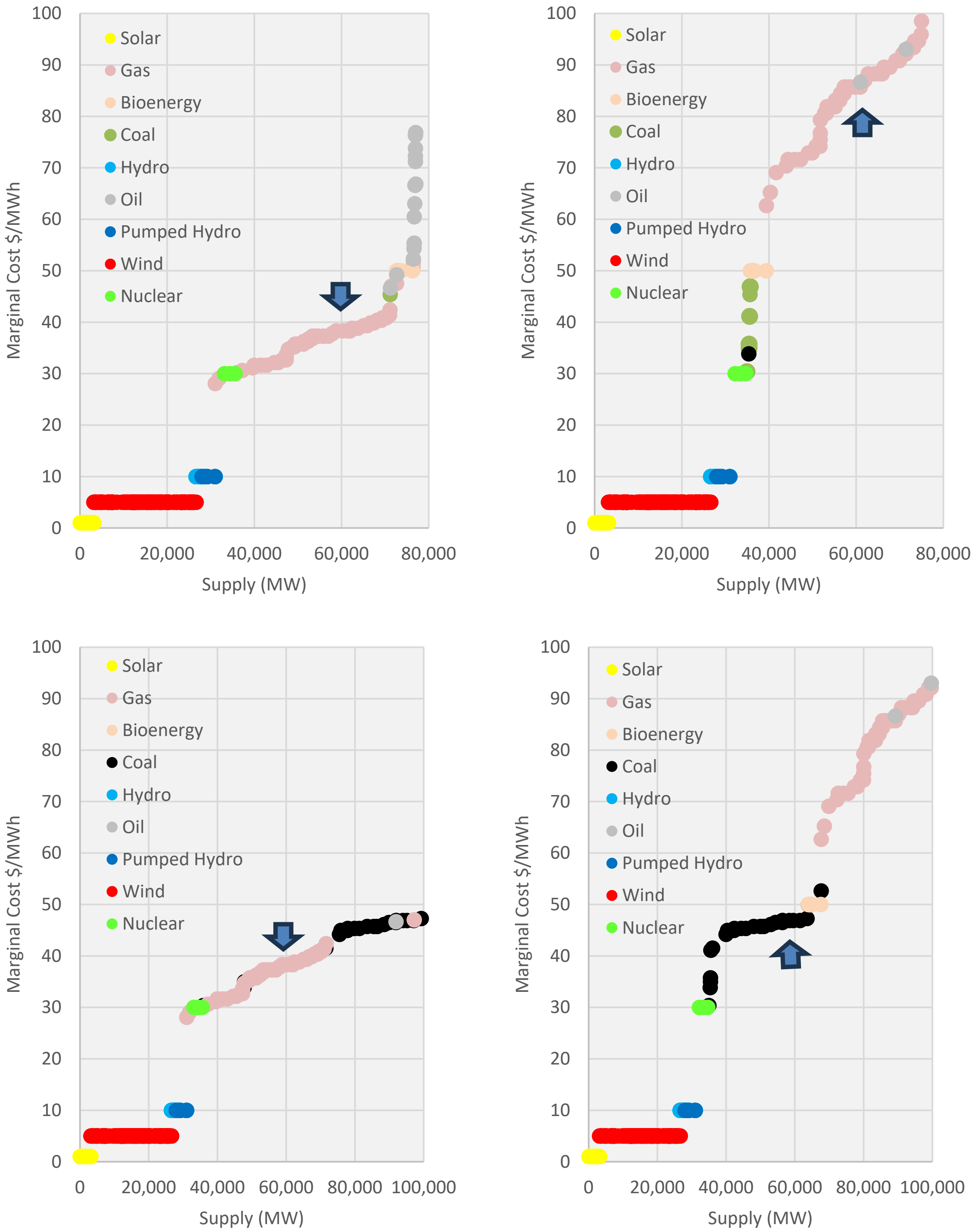


Figure 48. Illustrative United Kingdom generation supply curves: Top shows the current generation supply, and bottom shows with no coal closures after 2010. Left shows the low gas price, and right shows the high gas price (2.5 times low case). (Data from [16])

Key Observation Point

While coal carries a higher carbon footprint, its presence in the capacity mix provides a price stabilizer. Had these units remained available, they would have acted as a secondary “firm” resource decoupling a portion of the UK’s power costs from the recent volatility of the European natural gas market.

United Kingdom Summary

The UK’s electricity costs have increased dramatically and are currently around 1.4 times the EU27 average, having nearly doubled in nominal terms since 2015. The UK has a carbon emission intensity on par with the EU27 average; it lags significantly behind France but is ahead of Germany. The UK is very sensitive to gas prices and reliant on gas generation and has among the highest cost of electricity globally.

Key Findings

- The UK delivered 35% of its annual electricity production from solar and wind resources, 30% from gas, and 14% from nuclear power in 2024.
- The UK’s electricity cost was on par with the EU27 in 2015 but is now 1.4 times the average EU cost, a nearly doubling of the nominal price.
- The UK’s overall annual net electricity production has been in decline for the last 20 years, down 16% from 2015 and nearly 30% from 2003.
- The UK was a net importer of electricity in 2024. On its net peak day, it imported around 10% of its daily electrical energy requirement.
- The UK relies on gas year-round to meet net demand peaks. While annual gas usage is in decline, single-day gas requirements set new records in 2024 (despite a continued overall decline in electricity demand across the UK).
- The UK has a secure and diversified gas supply, but its electricity market is exposed to global gas price fluctuations; recent increases in gas prices in Europe have significantly increased the cost of electricity in the UK.
- The closure of the coal fleet has made the UK electricity market very sensitive to global gas prices.
- The UK is a winter peaking system where solar energy provides little on-peak hour and little daily energy.
- Cold winters with low gas storage levels are the greatest risk to the UK’s electricity supply.

Figure 49 provides a waterfall graph of energy (TWh) changes (top chart), a waterfall of capacity (GW) changes (bottom chart), and a breakdown of total energy (TWh) and capacity (GW) by resource for 2015 and 2024 (middle charts).

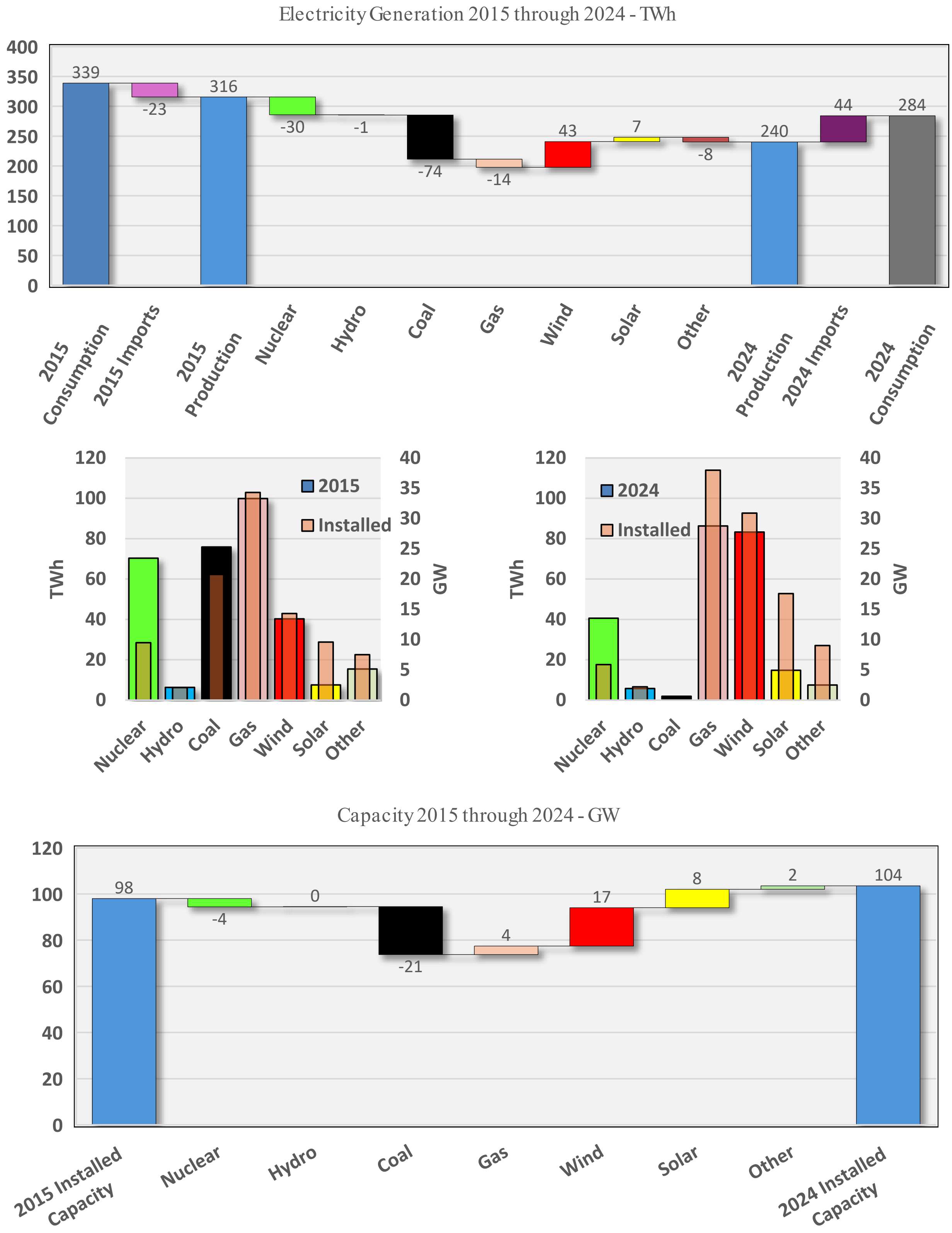
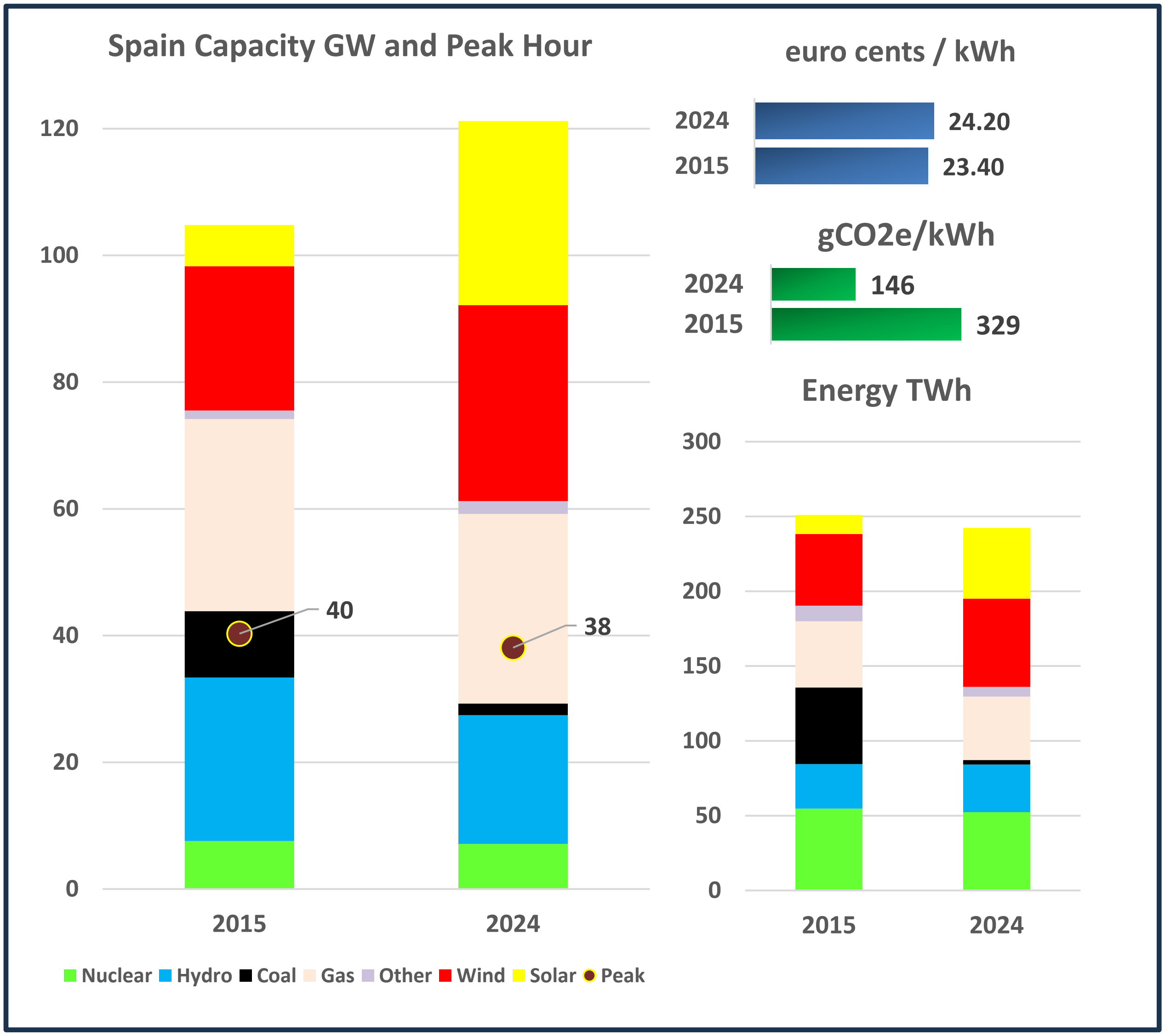


Figure 49. United Kingdom capacity and generation summary, 2015 and 2024 (Data from [16])

Spain Electricity Supply

Overview 2015–2024—Spain



	Capacity	Energy	Price	CO2
2024/2015	116%	98%	103%	43%
		2015 / EU27 2015	1.1	0.9
		2024 / EU27 2024	0.8	0.7

Figure 50. Spain 2015 and 2024 capacity and peak (GW), household rates (cents/kWh), carbon intensity (gCO2e/kWh), and energy (TWh) (Capacity and energy data from [4], rates from [9], and carbon from [7])

Spain's capacity, peak, energy, household rates, and carbon intensity of the electricity are provided in Figure 50. The table below the figure shows Spain's progress over time (first line), and Spain's price and carbon intensity versus the EU27 average for 2015 and 2024 (lines two and three).

The installed nameplate capacity of the Spanish generation fleet in 2024 increased to 116% of the 2015 value. The nameplate capacity in 2024 of ~120 GW was more than three times the peak demand (38 GW) in 2024. The price has remained relatively constant, resulting in a reduction from a factor of 1.1 of the EU27 average in 2015 to roughly 0.8 of the EU27 average in 2024. Similarly, Spain has made further progress on its carbon intensity, dropping from a factor of 0.9 to 0.7 of the EU27 average. The carbon intensity has dropped to 43% of the 2015 value, and it is well below the EU27 average but still significantly higher than France's.

Figure 51 provides the winter and summer peak demand days for Spain in 2024. Wind and solar combined provided little energy on the winter peak day (January 9). Solar and wind did make notable contributions to the lower summer peak in Spain on July 30.

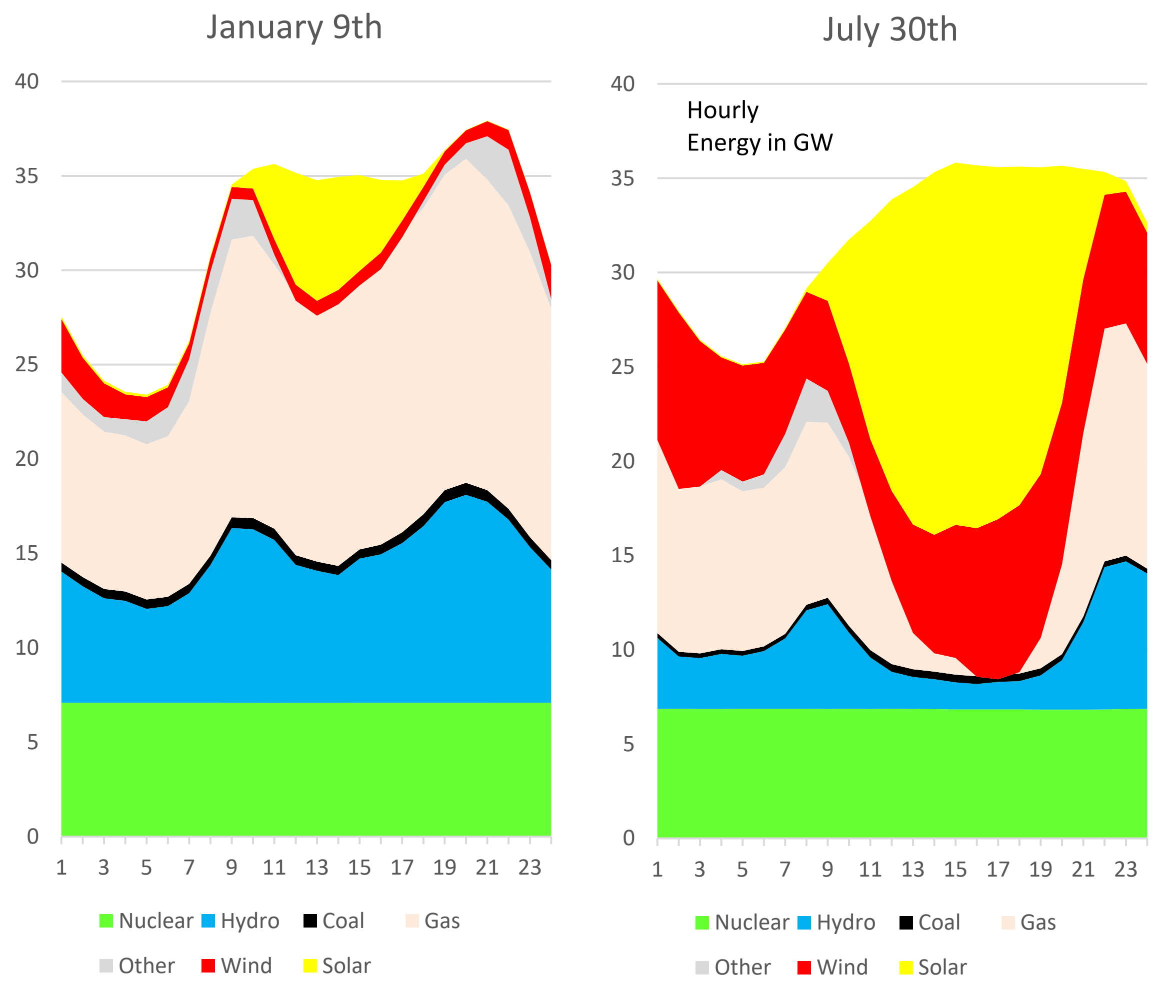


Figure 51. Spain peak winter and summer demand days, 2024 (Data from [4])

Figure 52 provides the output of the solar, wind, and nuclear resources in Spain on the peak winter and summer hours. Spain is winter peaking, and on the peak winter hour, solar provided no energy, wind provided 3% of its nameplate capacity, and nuclear delivered 100% of the nameplate capacity.

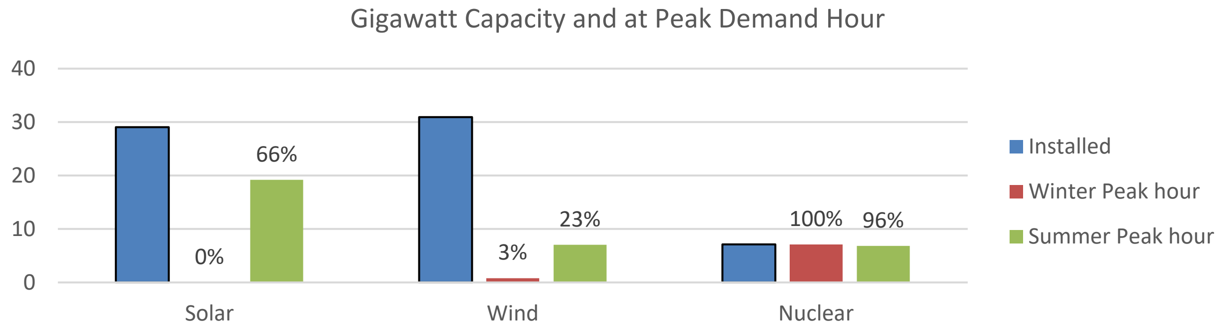


Figure 52. Spain solar, wind, nuclear installed capacity and output on peak winter and summer hour, 2024 (Data from [4])

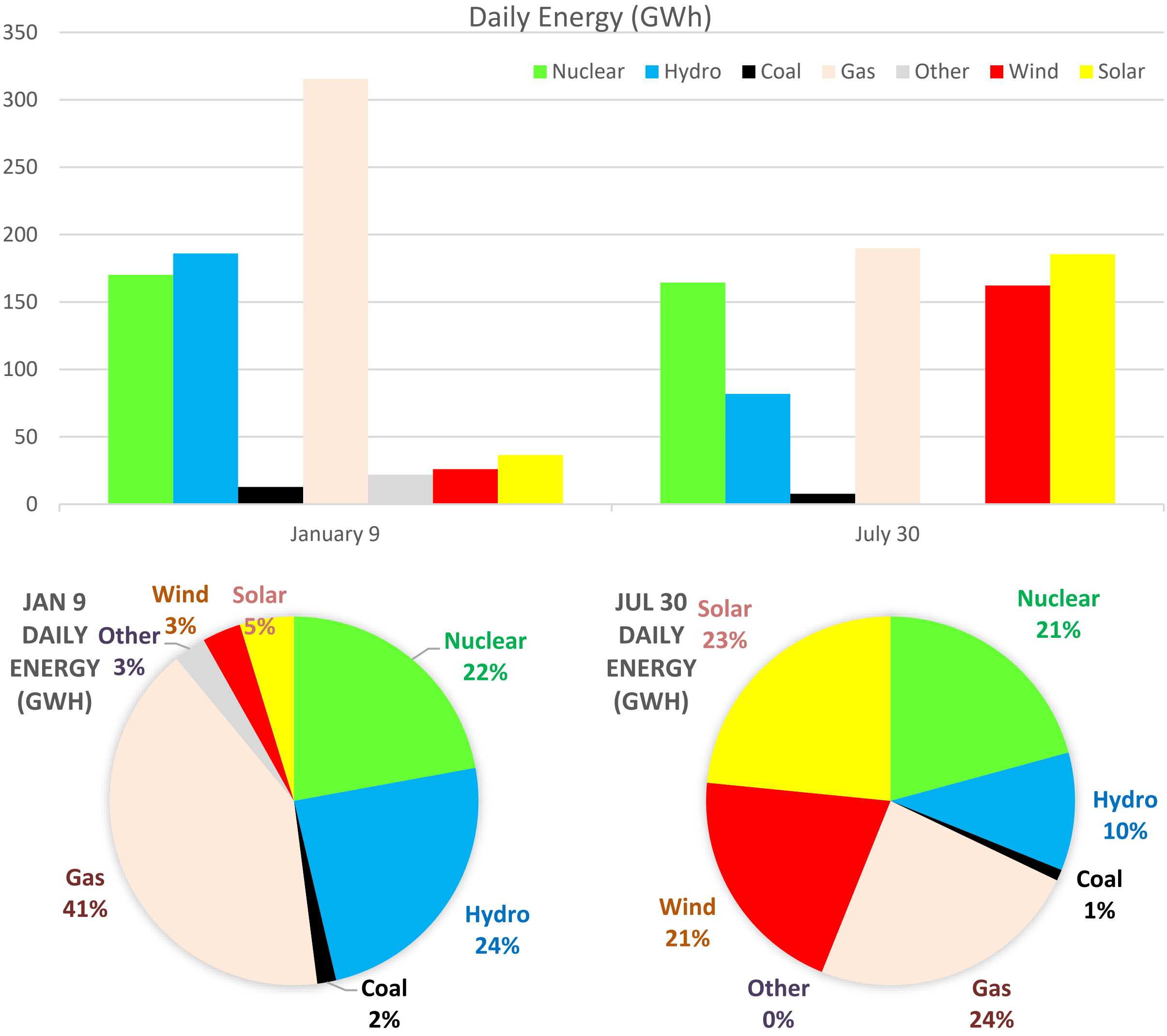


Figure 53. Spain 2024 winter and summer total electrical energy by resource (Data from [4])

Figure 53 provides the daily totals. On the peak winter day, nuclear, hydro, gas, and coal provided ~90% of the daily energy. On the peak summer day, solar and wind were able to provide over 40% of the daily energy.

Table 6 quantifies the peak breakdown for Spain on the peak winter day.

Table 6. Spanish peak – Resource output on peak hour (18:00) and for day – January 9, 2024

Resource	Installed Capacity (GW)	Peak Hour Output (GW)	Peak Day (GWh)	Peak Hour / Capacity	Peak Day / Capacity (GWh/GW)	Avg Day / Capacity (GWh/GW)
Gas	30	16	316	0.55	10.5	3.9
Coal	2	1	13	0.33	7.0	4.5
Nuclear	7	7	170	1.00	23.9	20.1
Hydro	20	11	186	0.52	9.1	4.3
Solar	29	0	36	0.001	1.3	4.5
Wind	31	1	26	0.03	0.8	5.2
Peak		**38**	**769**			

Looking from an energy basis, the combined solar and wind fleet of 60 GW delivered 62 GWh on the peak winter day, which is the equivalent of essentially one hour of full output across the 24 hours of highest demand in Spain in 2024. To cover the peak winter day in 2024, this fleet would need to be increased by over 12 times. This would be nearly 20 times the peak demand. Doing the same math for the nuclear performance on this day, the nuclear fleet would need to be increased by 4.5 times, resulting in a fleet of 32 GW, about 6 GW less than the peak demand on the day. This fleet would provide sufficient energy to cover the day. (Storage would be needed to move the energy to match it with the demand for the day.)

Key Observation Point

On January 9, 2024—the year's peak demand day in Spain—the combined wind and solar fleet demonstrated the challenge of intermittency. Despite having 60 GW of nameplate capacity, these resources generated a total of only 62 GWh over the entire 24-hour period. This represents a daily capacity factor of just over 4%, leaving the vast majority of the 750+ GWh daily demand to be met by gas, nuclear, and hydro.

The nuclear fleet, with only ~7 GW of capacity, delivered nearly 170 GWh that same day, outperforming a renewable fleet nearly nine times its size.

Spain Trends

Iberian Peninsula Blackout

Spain had a country-wide blackout on April 28, 2025. This is the most serious security of supply issue; the root cause analysis is still ongoing for this event by the European Network of Transmission System Operators for Electricity (ENTSO-E), an association representing 41 electricity transmission system operators (TSOs) from 34 countries across Europe. The main objectives and roles of ENTSO-E center on ensuring the security and coordinated operation of Europe's interconnected electricity system. See the ENTSO-E landing page for the latest on the blackout investigation [17].

At the time of the blackout, the Iberian Peninsula's electricity mix had a high share of inverter-based renewables (with solar PV alone near 60% of Spain's generation).

Key Technical Point

Inverter-based resources include wind, solar, and batteries, which use power electronics to connect to the grid instead of the spinning turbine-generators that coal, gas, nuclear, and hydropower plants use.

The event was preceded by several grid frequency oscillations (of magnitude 0.2 Hz to 0.6 Hz). The blackout sequence began with a localized initial fault, most likely the abrupt, automatic disconnection of two large generation units in southern Spain. This caused a massive, sudden loss of power that immediately led to significant voltage and frequency disturbances across the 400-kV transmission system. The system's inability to absorb this shock amplified the disturbances, triggering a cascade of protective disconnections of other generation units. This escalating system instability culminated in the islanding of the Iberian Peninsula from the rest of the European grid at the France interconnection, leading to the widespread electrical system collapse of the Iberian Peninsula. The blackout occurred within seconds (see Figure 54).

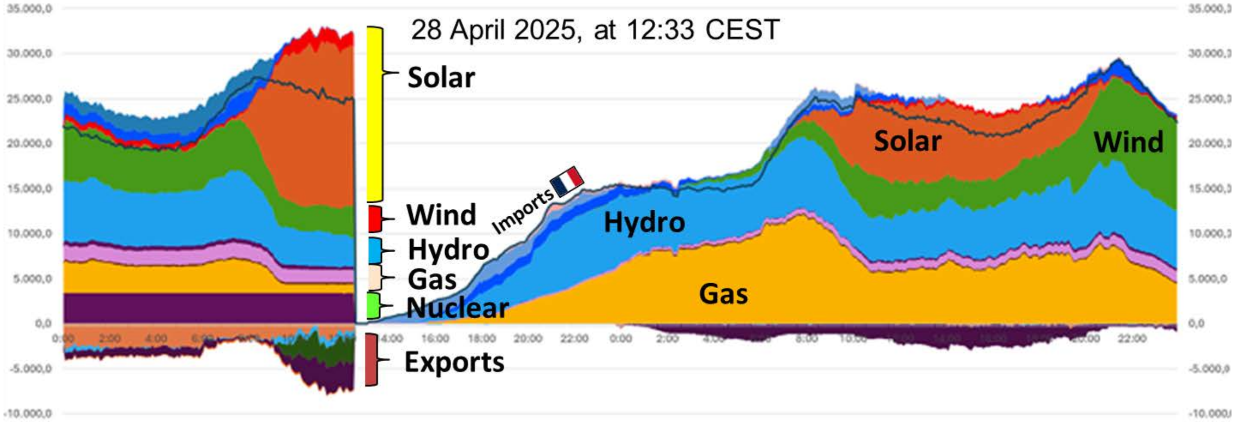


Figure 54. Spain electricity production April 28, 2025 (Modified from [17])

After the system collapse, the grid was re-established with imports, hydropower assets, and gas-fired power plant units (see Figure 54). Since the blackout, the Spanish grid has maintained many more gas units online continuously to provide additional system support (see Figure 55). Recall Figure 2 for the relative reliability contribution of different energy resources; running additional gas is currently the best option for Spain to enhance the security of the electricity system. Other measures will take significant new investment and time to implement. The out-of-market merit order running of additional gas-fired units also represents an incremental cost.

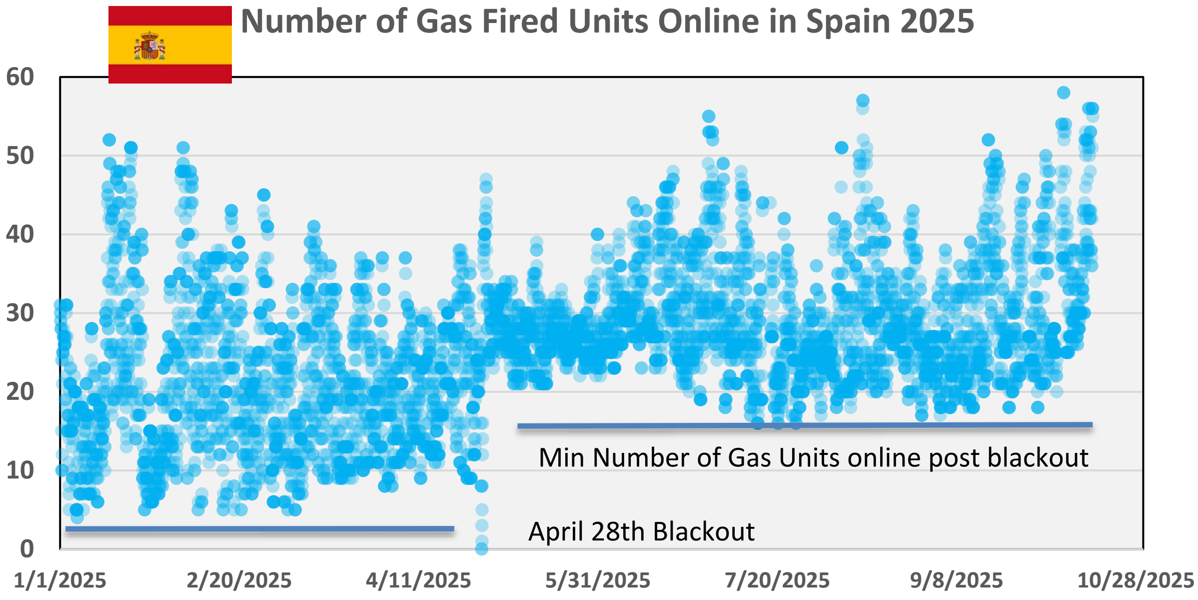


Figure 55. Spain number of gas-fired units online in each hour interval January 1 to October 2025 (Data from [4])

The blackout and the subsequent need to keep additional gas-fired units online to support the grid demonstrate a new challenge for secure electricity supply. It was not insufficient energy that led to a security issue but rather energy sources that, in their current configuration, could not deliver sufficient energy services to prevent a system collapse when upsets occurred, highlighting a system resiliency issue. This configuration sets up a dual challenge for the pursuit of increased wind and solar penetration; overabundance of these energy sources in off-peak periods can occur long before they are scaled to provide sufficient energy on the marginal winter or summer peak day. In Spain, the combined wind and solar, with a nameplate capacity of 60 GW, provided essentially 1 GW of energy on the peak winter demand hour in 2024.

Spain was not alone in having a country-wide blackout in 2025; Chile did as well. EPRI was contracted by Chile's Coordinador Eléctrico Nacional (CEN) to review the findings from its February 25, 2025 blackout [18]. One key similarity between the events is that the collapse of the northern electrical island after the separation was likely related to the inability to control the voltage. The role and performance of modern inverter-based resources (like solar and wind) in providing dynamic voltage control is an area requiring further work (see Figure 2). Table 7 provides the makeup of the grid in Spain and Chile, which both have a relatively high proportion of solar and wind resources versus the hourly peak demand. Both also have a nameplate capacity greater than three times the peak hourly demand.

Table 7. Spain and Chile electricity capacity by generation source in 2025 (Data from [4, 12, 19])

Generation Type	Spain [GW]	Chile [GW]
Solar PV	34	10
Wind	31	5
Gas & Oil	29.5	7
Hydro	20	6
Nuclear	7	0
Solar thermal	2.5	
Coal	1.8	4
Total	>125	>33
Hourly Peak	38	11

Spain Peak Reduction

Looking across every hour in 2024, the peak demand in Spain was 38.1 GW, the peak hour less the solar generation was 38.1 GW (29 GW installed capacity), the peak hour less wind generation was 37.2 GW (31 GW installed capacity), and the peak hour less the combined wind and solar was 37.1 GW (60 GW combined installed capacity). Solar capacity in 2024 resulted in no reduction in need for other generation to cover the peak annual hour. Wind's ratio of GW reduction was 0.03 GW/GW installed, and the combined wind and solar ratio was 0.002 GW/GW installed. Looking at the nuclear fleet, Spain reduced the peak in 2024 to 32.6 GW, or roughly 0.8 GW/GW installed.

This is well illustrated in the winter peak day (see Figure 51), where solar output on the peak hour was effectively zero, and the daily energy was 1.3 GWh/GW installed, and wind output on the peak hour was 0.03 GW/GW installed and 0.8 GWh/GW installed.

Figure 56 analyzes the peak reduction over the period from 2015 to 2024 as solar and wind capacity additions have been made. There have been significant solar and wind additions in this period, resulting in an appreciable increase in energy on an annual basis from wind and solar and a decrease from non-wind and non-solar as the total annual energy need has remained largely constant. While peak daily energy requirement from non-wind and non-solar resources did decrease from 2021 to 2023, it rebounded in 2024 to a similar value as in 2015.

The yellow column (left axis) is the installed nameplate capacity in GW of wind, solar, and battery capacity. It is increasing year over year. The orange column (left axis) is the annual energy from wind and solar in TWh, which generally increases year over year. The grey column (left axis) is the annual energy from non-solar and non-wind resources in TWh, which generally decreases year over year. The lines are daily peak energy from non-solar and non-wind resources (black line) in GWh, total annual energy (red line) in TWh, both on the right axis.

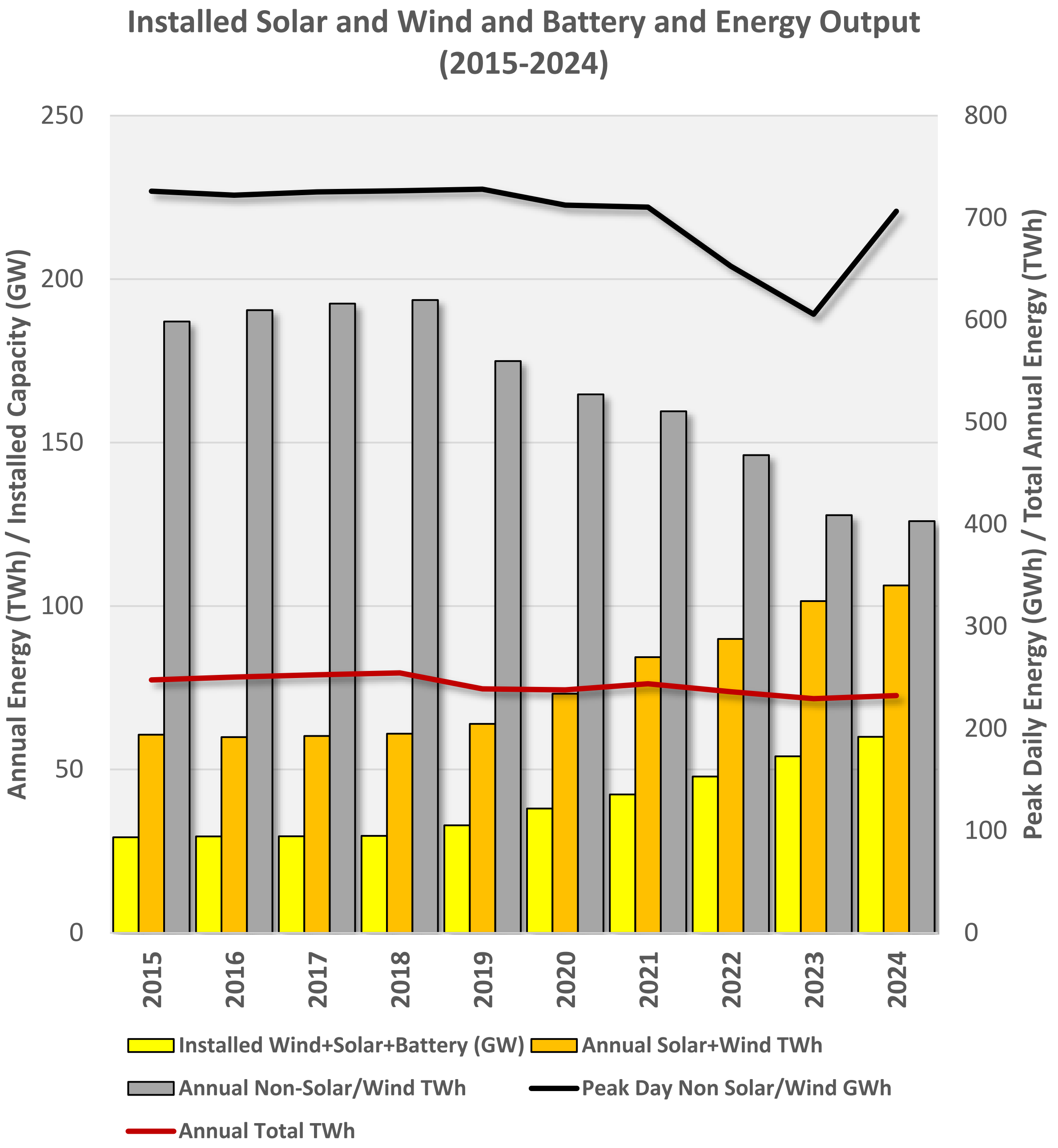


Figure 56. Spain wind, solar, and battery additions – annual energy and daily peak non-solar/wind energy, 2015 to 2024 (Data from [4])

Figure 57 looks at the addition of solar, wind, and battery capacity versus the net effect on the annual non-solar and non-wind energy requirement and peak daily requirement compared to 2015 as a baseline year.

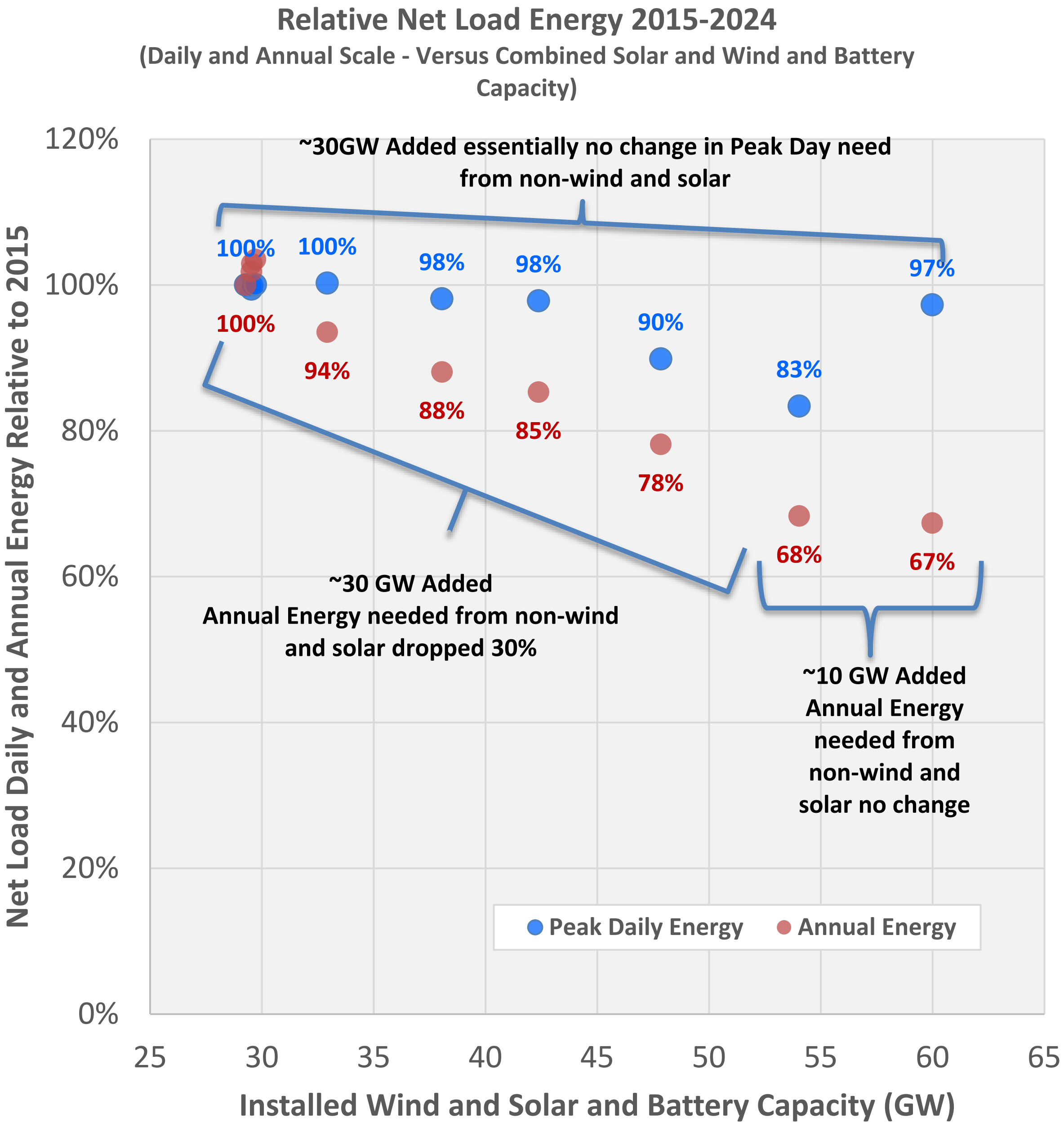


Figure 57. Spain relative net load energy, 2015–2024 (daily and annual scale versus combined solar, wind, and battery capacity) (Data from [4])

There is a much larger impact on annual energy compared to peak day daily energy, illustrating the intermittency challenge and a diminishing return on the solar and wind investment made. (Spain has very little battery capacity.) Notably, the large uptick in 2024 shows the challenge in predicting when there may be a larger need from non-intermittent sources.

Spain is highly reliant on the installed gas and nuclear generation fleet on the peak winter days (see Table 6).

Key Observation Point

Wind and solar additions are not replacing the physical power plants needed for the hardest days (peak day), and they have a diminishing annual energy reduction impact.

From 2015 to 2024, Spain doubled its solar and wind capacity, yet still needed 97% of its original backup fleet to be ready and able to cover its net peak days (highest demand days, with lowest solar and wind output). The annual energy required from non-wind and non-solar is also leveling off despite continued additions of solar and wind capacity.

This suggests Spain faces diminishing marginal returns where the addition of solar and wind is not replacing the need for near 100% backup power, and their contribution to further annual energy displacement is declining.

Spain Summary

Spain's electricity costs have remained relatively constant since 2015; this has resulted in the Spanish cost for electricity in 2024 to be a factor of 0.8 of the EU27 average cost. It has a 2024 carbon emission intensity around 0.7 of the EU27 average but still lags far behind France at 0.2 of the EU27 average.

Key Findings

- Spain delivered 44% of its annual electricity production from solar and wind resources, 22% from nuclear, 13% from hydro, and 18% from gas power in 2024.
- Spain's overall annual net electricity production has been steady since 2015.
- Spain was a net exporter of electricity in 2024. On its winter peak day, it was a net importer, with around 3% of its daily electrical energy requirement being imported.
- Spain's nuclear fleet performed exemplarily on its peak winter day in 2024. To replace the energy from the 7 GW of nuclear installed capacity, based on winter performance, would require over 120 GW of solar capacity or over 200 GW of wind capacity.
- Spain's grid collapse on April 28, 2025, highlighted a new security risk that has been mitigated since then by increased gas-fired power plant operation, but there is a significant cost associated with this.
- Spain has an elevated reliance on gas to meet winter peaks and daily energy requirements when wind output is diminished.
- Recent additions of wind and solar capacity have not resulted in significant increases in annual energy from wind and solar. The daily peak energy from non-wind and non-solar is still at the same level as 2015 despite the addition of ~40 GW of installed solar and wind capacity. (Spain's peak demand is 38 GW.)
- Spain is a winter peaking system where solar energy provides little on-peak hour and little daily energy.

- Spring and fall, when inverter-based resources are at high output, appear to be the greatest risk to Spain's electricity system, with the current mitigation being running more gas-fired units.

Figure 58 provides a waterfall graph of energy (TWh) changes (top chart), a waterfall of capacity (GW) changes (bottom chart), and a breakdown of total energy (TWh) and capacity (GW) by resource for 2015 and 2024 (middle charts).

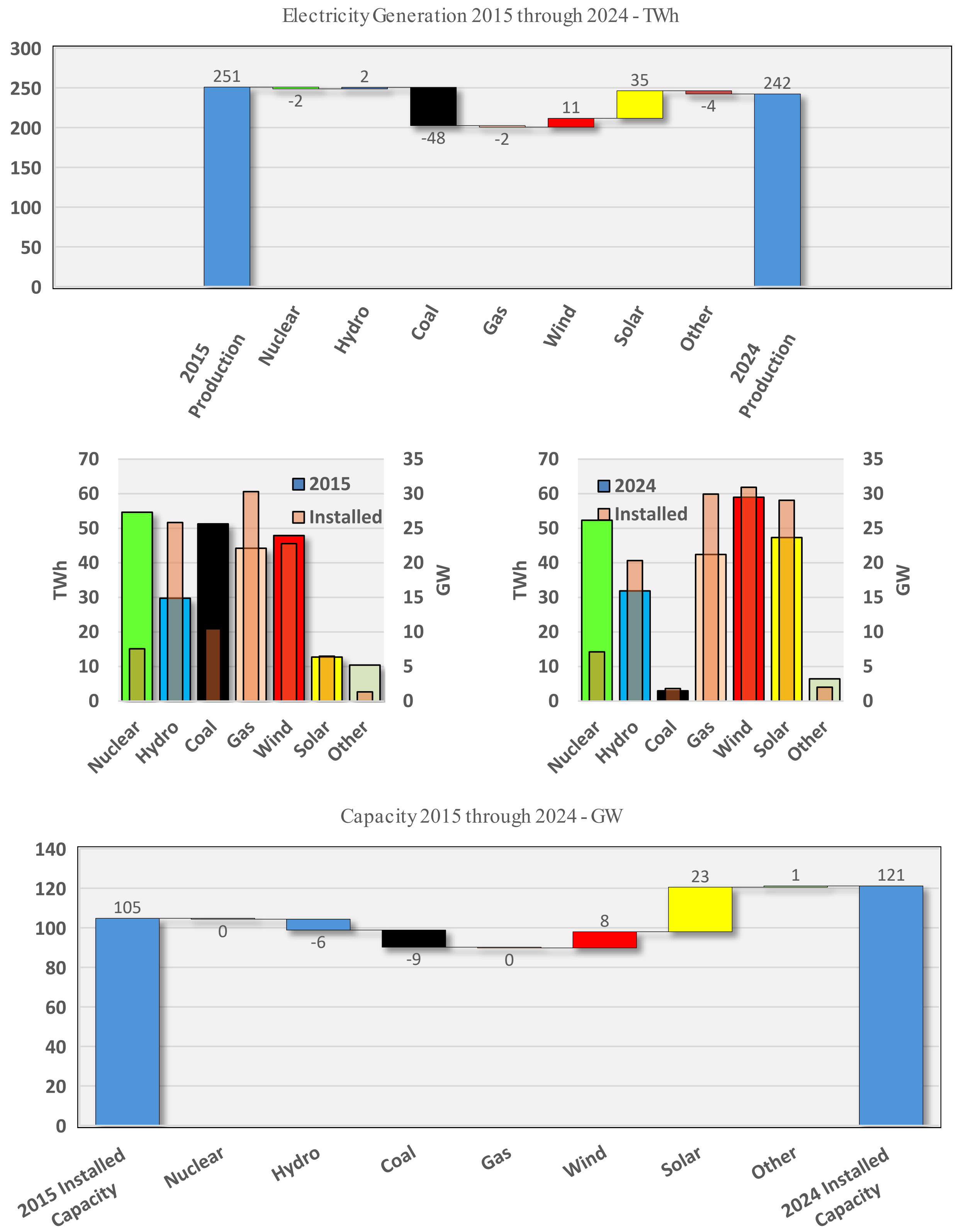


Figure 58. Spain capacity and generation summary, 2015 and 2024 (Data from [4])

4. UNITED STATES ENERGY SUPPLY

United States Electricity Supply

Overview 2015–2024—United States

The United States' capacity, peak, energy, residential rates, and carbon intensity of its electricity supply is summarized in Figure 59.

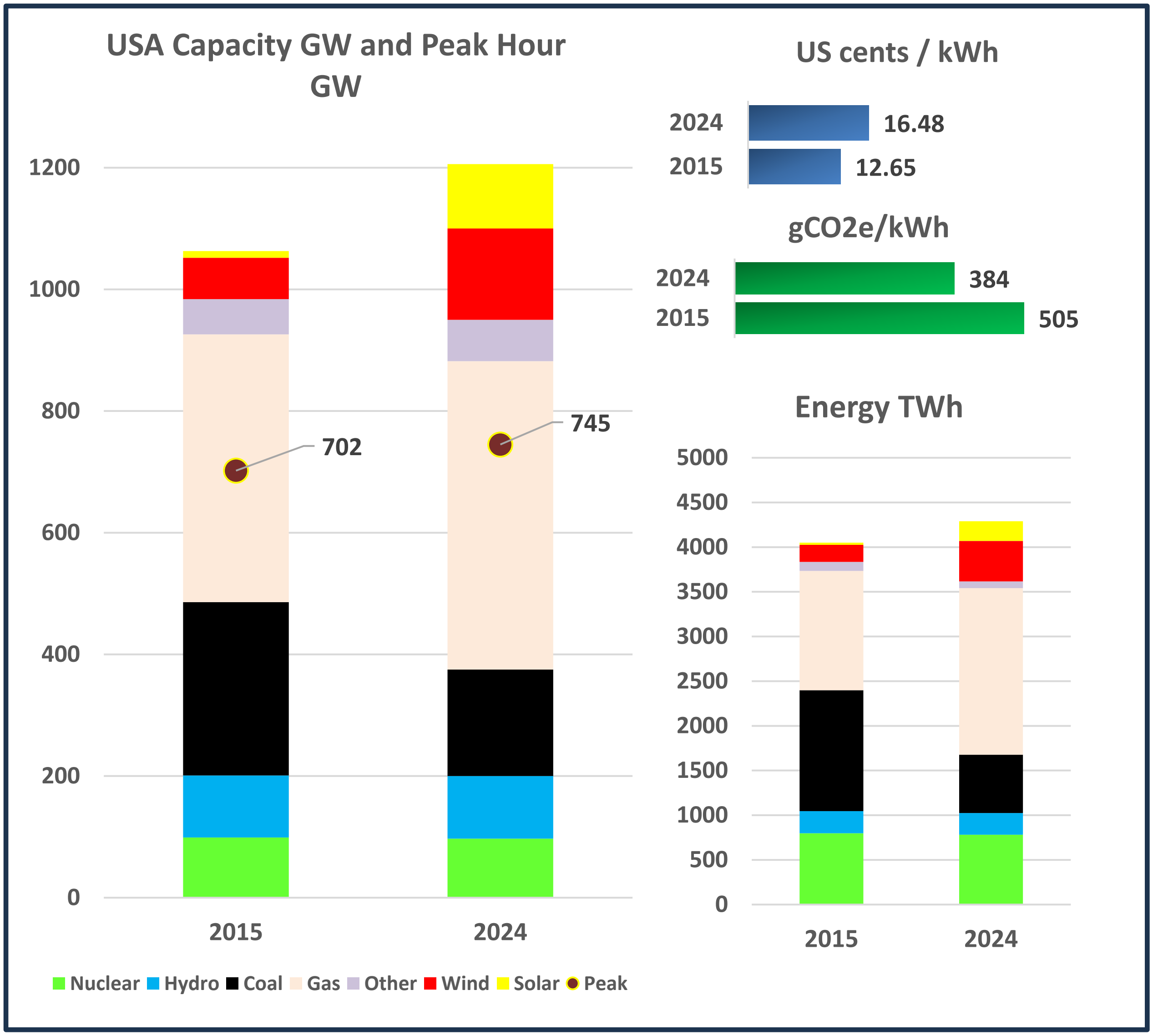


Figure 59. United States 2015 and 2024 capacity and peak (GW), household rates (cents/kWh), carbon intensity (gCO2e/kWh), and energy (TWh) (Capacity from [20], energy from [5], price from [21], and carbon from [7])

U.S. electricity nameplate capacity in 2024 increased by 13% from 2015. The household (residential) cost of electricity on a per-kWh basis rose by 30% over the same period. Meanwhile, the carbon intensity of the electricity supply dropped 24% , and the total electricity consumption increased by about 5%. As a region, in 2024, the United States had much lower electricity rates than the EU27, with residential rates about half the EU27 average price, but also an appreciably higher carbon intensity to the electricity supply. The U.S. carbon intensity is 1.8 times that of the EU27 average.

Figure 60 provides the 2025 winter and summer peak demand days.

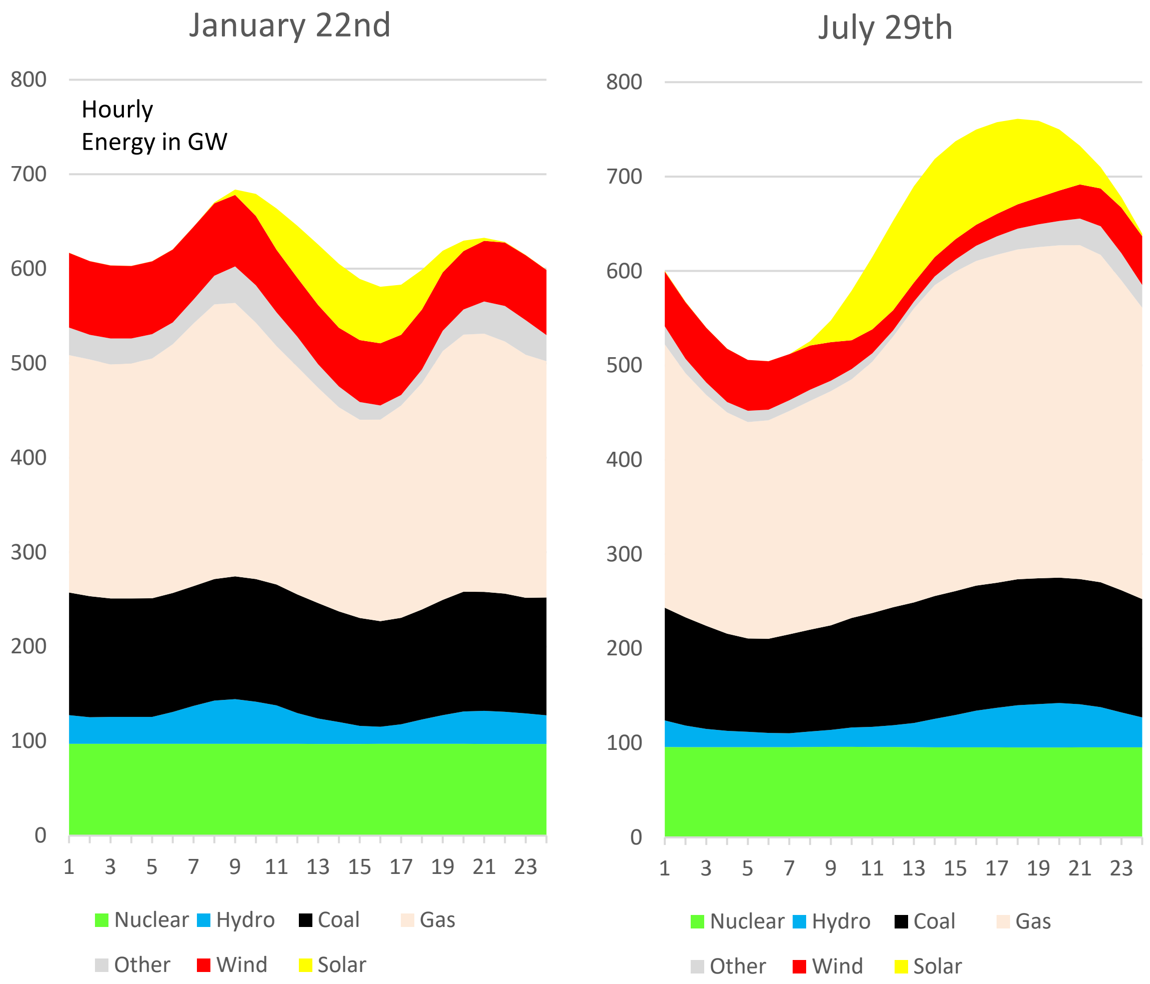


Figure 60. U.S. peak winter and summer demand days, 2025 (Data from 5])

The winter peak occurred at around 9 a.m. The summer peak occurred around 6 p.m. Figure 61 provides a breakdown of output on the peak winter hour and summer hour versus installed solar, wind, and nuclear capacity. For both peaks, there was high output from nuclear capacity. For solar, the summer peak-hour output was significantly better than the winter peak hour. For wind, the winter peak-hour performance was better than the summer peak hour.

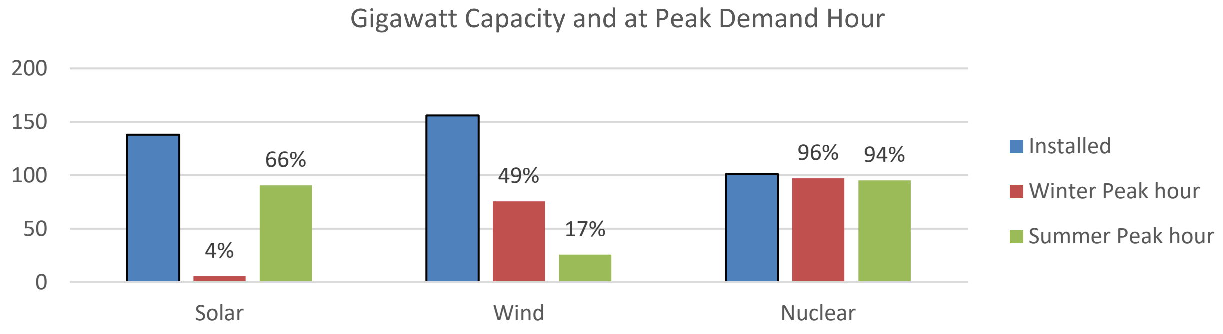


Figure 61. U.S. solar, wind, and nuclear installed capacity and output on peak winter and summer hour, 2025 (Data from [5, 20])

Figure 62 completes the picture for the peak winter and summer days in the United States. In both cases, gas provided the greatest amount of energy. In aggregate, gas and coal delivered over 60% of the required daily energy on the winter peak day and nearly 70% of the required daily energy on the peak summer day. Solar delivered a much larger share of the daily energy requirement on the peak summer day (7%) than the winter day (3%). Wind provided a much greater share of the winter daily energy requirement (11%) than the summer daily energy requirement (6%).

The overall summer peak daily energy requirement in 2025 was greater than the winter, which is a common occurrence in the United States. The peak-to-trough daily energy requirement was also much greater in the summer than in the winter with the summer peak around 250 GW greater than the low demand hour for the day (see Figure 60). In the winter, the peak-to-trough variation was only about 100 GW. For the summer peak day, solar, gas, coal, and hydro all contributed to ramping to cover the peak. For the winter, the peak ramp was principally contributed to by gas, coal, and hydro. Wind output was good during the peak hour, but there was no increase in wind output coinciding with the increasing demand seen at the 9 a.m. hour for the winter peak day (see Figure 60).

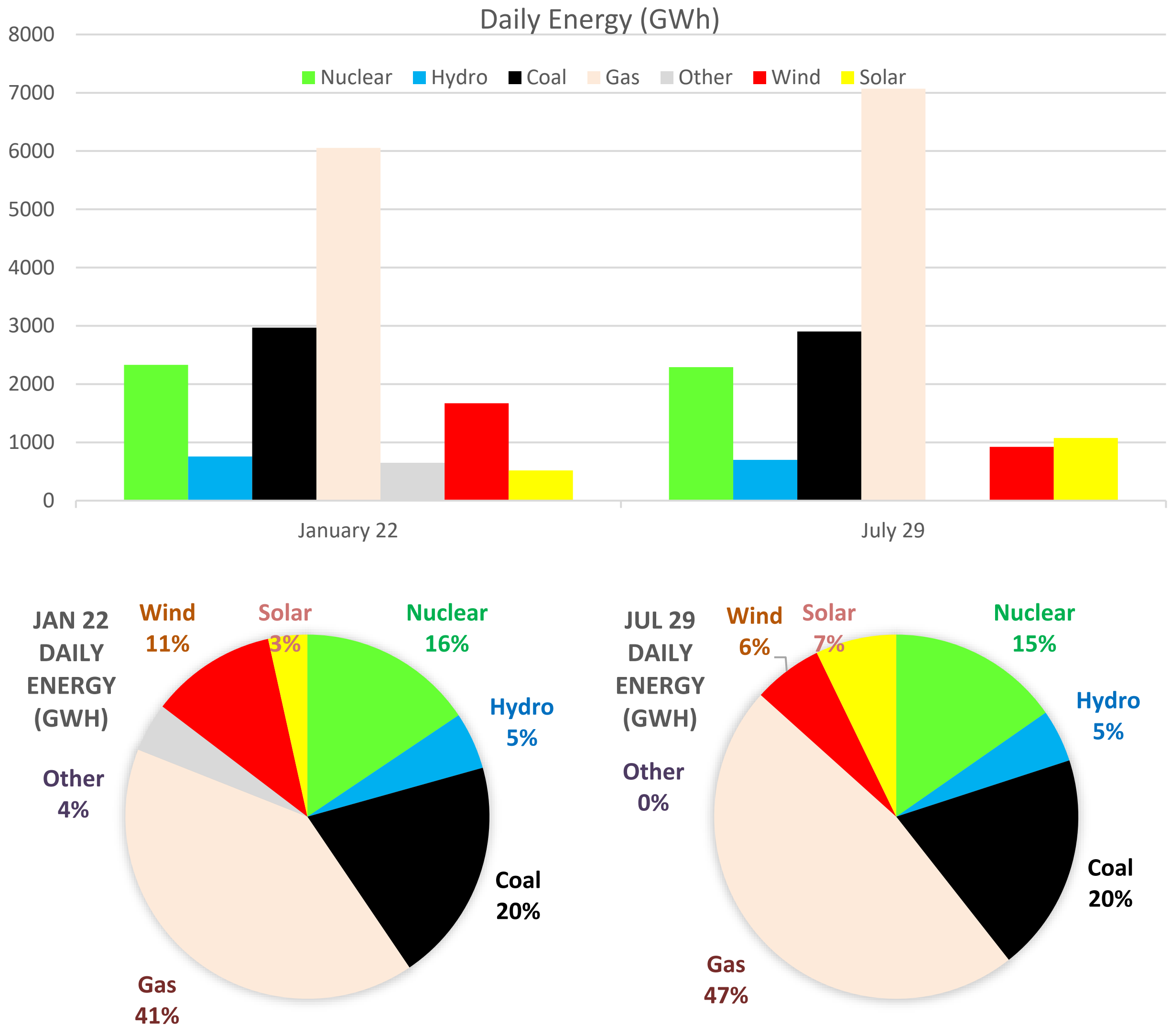


Figure 62. U.S. 2025 winter and summer peak total electrical energy by resource (Data from [5])

Table 8 provides a more detailed, quantified analysis of the winter and summer peak hour and days by the various energy resources—gas, coal, nuclear, hydro, solar, and wind.

For the winter peak, coal and nuclear provided the highest daily energy contribution per installed GW, as well as the highest peak hour output per unit capacity. Due to the larger installed capacity, gas provided the largest share of actual energy on the winter peak day. For the summer peak, a similar scenario occurred except more of the gas fleet is needed to meet the peak hour, so a higher value of peak hour per unit of capacity is seen.

For the winter peak, the solar output per unit of capacity was very low, and the total energy delivered was much lower than the average day for 2024. Wind performed better, with nearly 0.49 peak hour/capacity output and more energy delivered than on the average day. For the summer, this trend is reversed, with solar contributing well on the peak hour with better than normal energy output and wind contributing much less on the peak hour with less than the energy output it provides on an average day.

Table 8. U.S. winter and summer peak days' resource outputs on peak hour

Winter peak – resource output on peak hour (09:00) and for day – January 22, 2025 (winter capacities)

Resource	Installed Capacity (GW)	Peak Hour Output (GW)	Peak Day (GWh)	Peak Hour / Capacity	Peak Day / Capacity (GWh/GW)	Avg Day / Capacity (GWh/GW)
Gas	543	289	6,052	0.57	11.9	10.1
Coal	173	130	2,969	0.74	17.0	10.2
Nuclear	101	97	2,332	0.96	23.1	22.1
Hydro	103	47	759	0.46	7.4	6.4
Solar	135	0	1,673	0.04	3.8	5.6
Wind	155	3	519	0.49	10.7	8.3
Peak		**684**	**14,952**			

Summer peak – resource output on peak hour (18:00) and for day – July 29, 2025 (summer capacities)

Resource	Installed Capacity (GW)	Peak Hour Output (GW)	Peak Day (GWh)	Peak Hour / Capacity	Peak Day / Capacity (GWh/GW)	Avg Day / Capacity (GWh/GW)
Gas	508	349	7,070	0.69	13.9	10.1
Coal	172	133	2,902	0.78	16.9	10.2
Nuclear	98	95	2,292	0.97	23.4	22.1
Hydro	103	45	699	0.43	6.8	6.4
Solar	136	91	1,075	0.67	7.9	5.6
Wind	155	26	922	0.17	6.0	8.3
Peak		**761**	**15,352**			

U.S. Trends

Demand Review

Annual Trends

On an annual basis, U.S. electricity generation in TWh has not grown much in the last 25 years, with the typical annual production of just over 4,000 TWh. In more recent years, there are some indications of an increasing annual trend in electrical energy consumption, but this is still low-single-digit growth (see Figure 63).

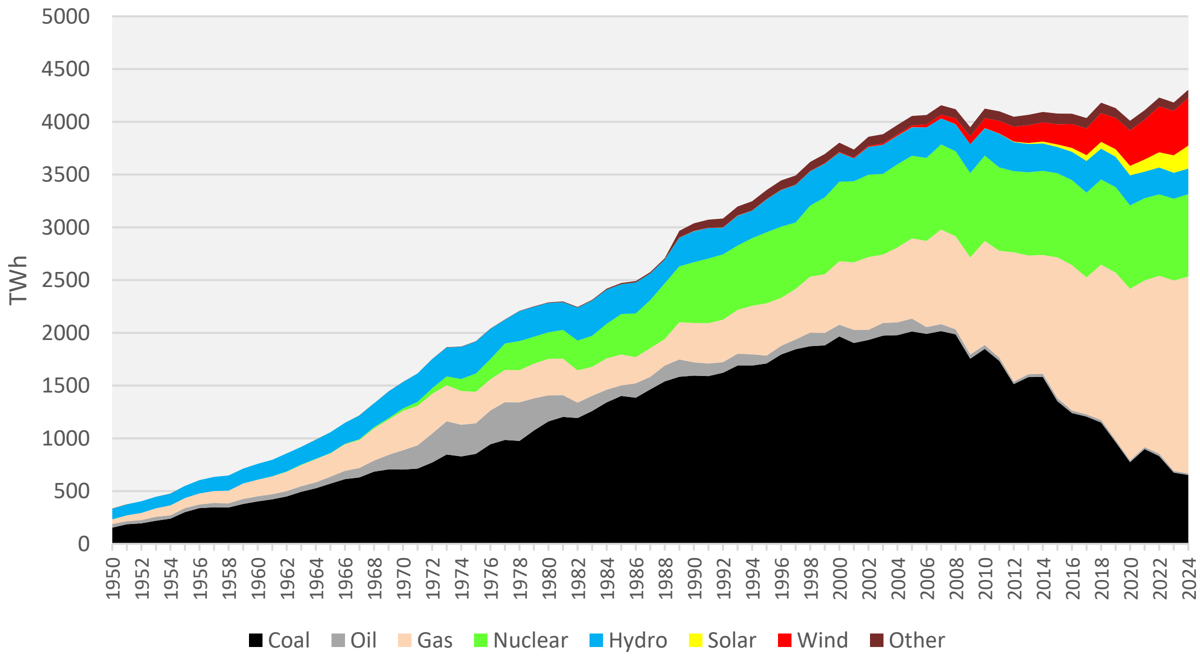


Figure 63. U.S. annual electricity generation (Data from [22])

Figure 64 illustrates the operating U.S. generation fleet, which was built over the last 75 years. The upper part of the figure aggregates and orders the fleet capacity (MW) by average year the fleet of units using the technology came into first operation. The lower part of the figure is the year-by-year addition of capacity (MW) from 1950 to 2024. From the upper figure, many technologies have not scaled (i.e., the MW capacity is trivial). For the technologies that have scaled, some are very old.

The hydro assets, on average, came into operation in 1954 (70+ years old), the coal assets in 1977 (nearly 50 years old), the nuclear assets in 1982 (40+ years old), the combined cycle gas turbine (CCGT) and combustion turbine (CT) fleet around 2000 (~25 years old), wind assets in 2012 (10+ years old), the solar fleet in 2018 (~8 years old), and the battery fleet in 2021 (~5 years old). These measurements are based on a per-unit basis; if based on a weighted for MW capacity basis, the fleets would be a few years younger.

From the winter and summer peak review, the highest on-peak output per unit of capacity was from the relatively old coal and nuclear fleet.

In the last 10 years, the overwhelming majority of generating assets built have been variable resources (wind and solar). More recently, batteries have become a major addition, but batteries are not a generating source; batteries move energy produced by other resources through time to address the low peak hour/capacity numbers. They do this at a cost of daily energy use since round-trip efficiency is less than 100%. This means more electricity is used to charge the batteries than can be recovered as useful electricity, depending on technology, at best at least 10% of the energy is lost.

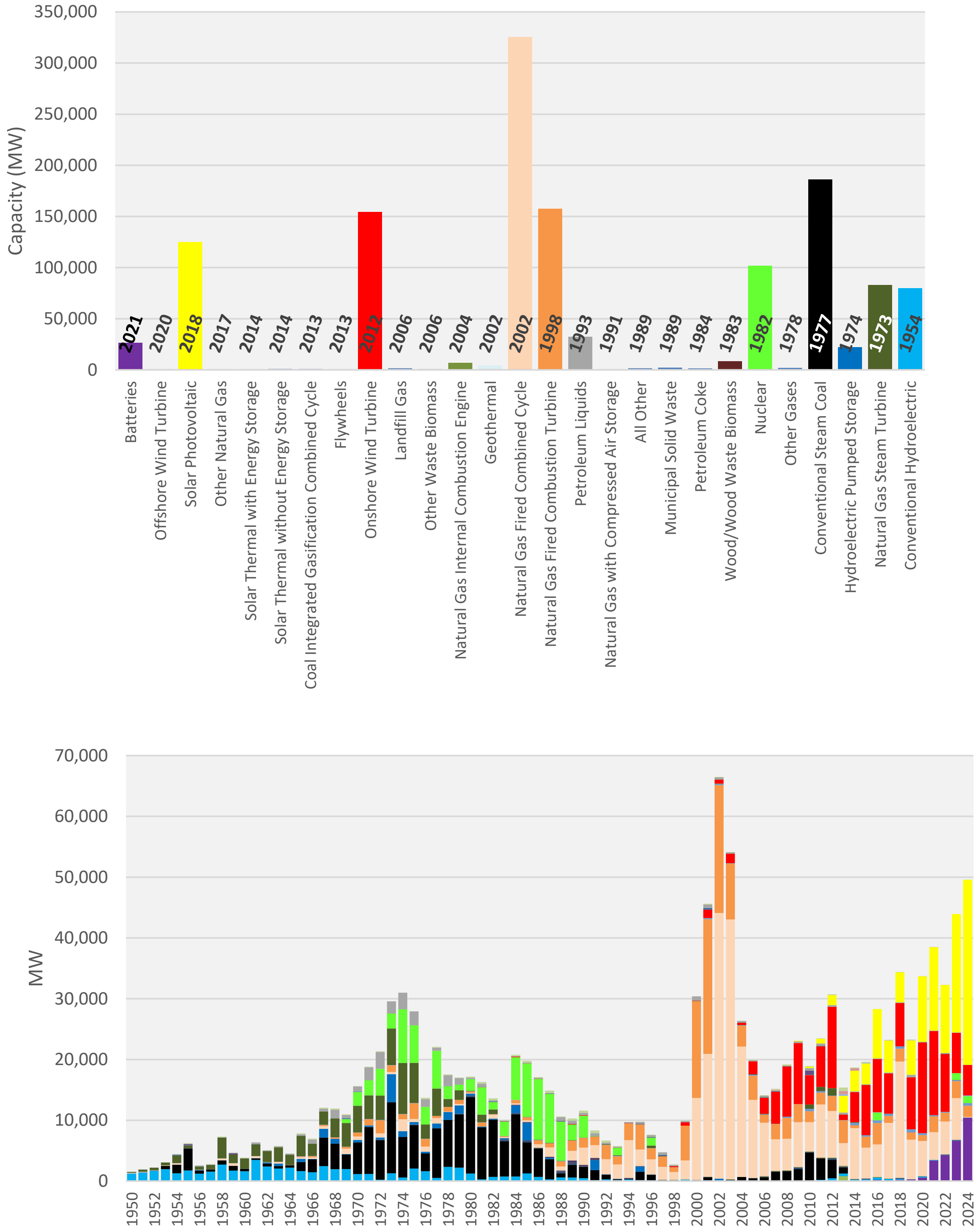


Figure 64. U.S. generation capacity (upper average operating year and total capacity, lower capacity, and actual operating year) (Data from [20])

Figure 65 provides the generation by resource as a linear chart. About 10 years ago, gas, on an annual basis, became the leading generation resource in the United States – moving ahead of coal, which had led since before 1950.

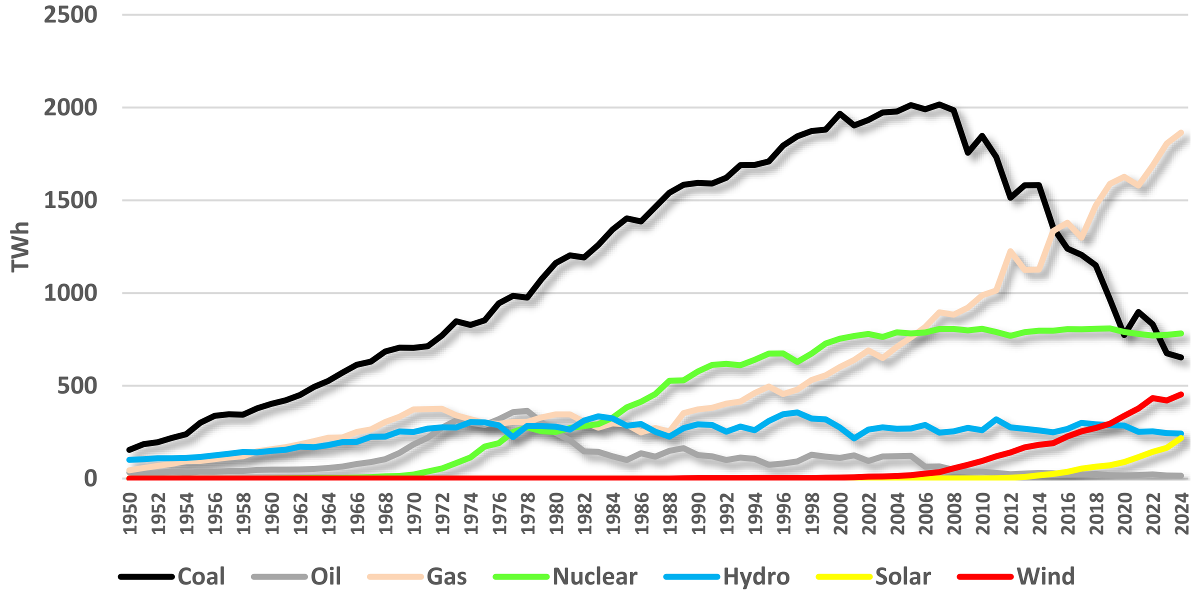
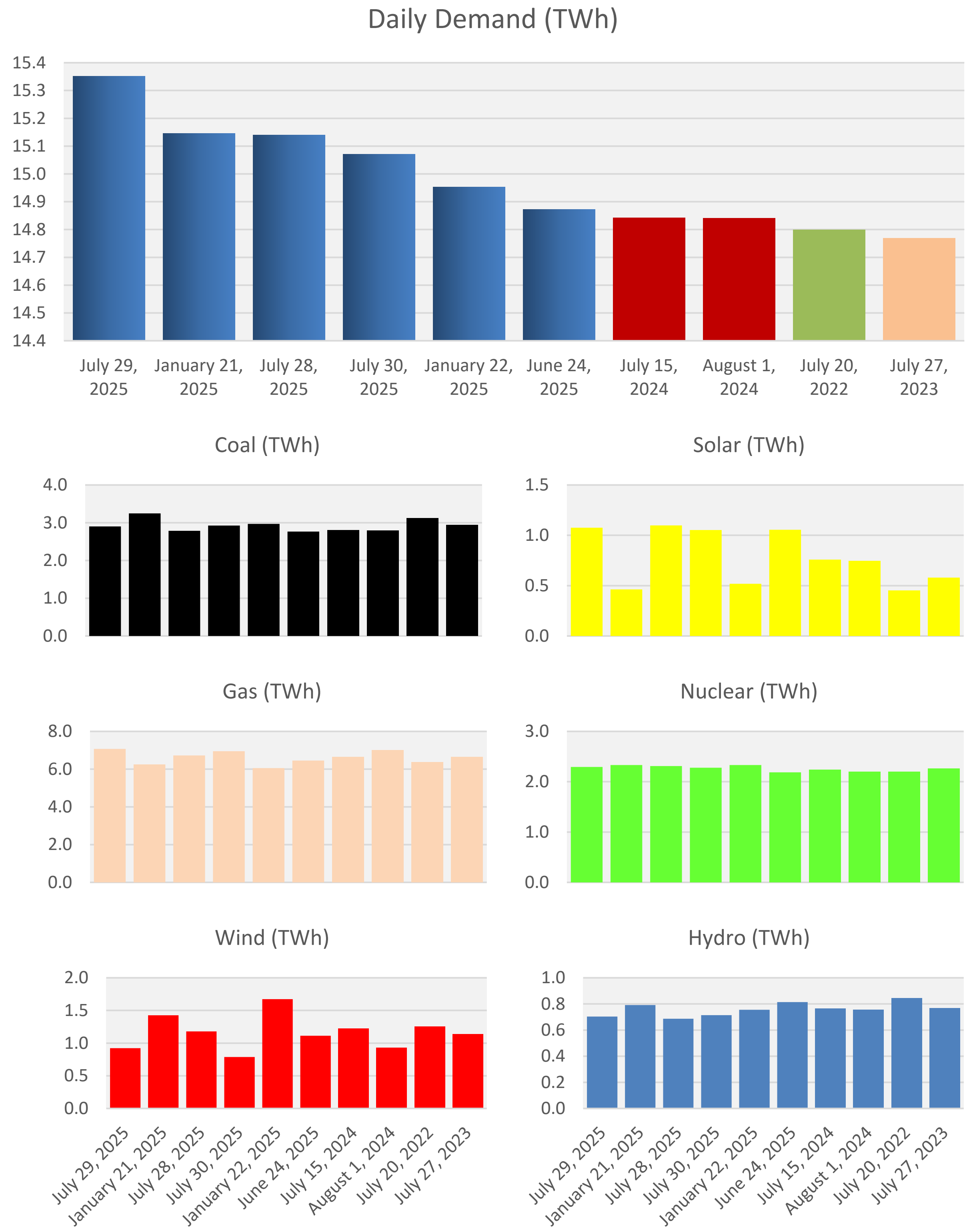


Figure 65. U.S. generation by resource, 1950–2024 (Data from [21])

Daily Peaks

Figure 66 is the top 10 daily peak energy requirements for the contiguous 48 U.S. states. The top graphic is the daily demand top ten, and the bottom six graphics show the corresponding total energy from each of the main electrical energy resources on those days. The top six days of all time occurred in 2025. For the first time ever, two of the top ten days occurred on winter days. Figure 67 replots the resource output on each of the top ten peak days so they are all on the same y-axis, making the large reliance on gas output for these days evident.

Winter storms [23, 24, 25, 26, 27, 28] and the interdependence of the gas-electric system [29] have been major sources of energy security supply risk over the last two decades in the United States.



Daily Demand (TWh)

Coal (TWh)

Solar (TWh)

Gas (TWh)

Nuclear (TWh)

Wind (TWh)

Hydro (TWh)

Figure 66. U.S. daily peak energy—contiguous 48 state’s top ten peaks (Data from [5])

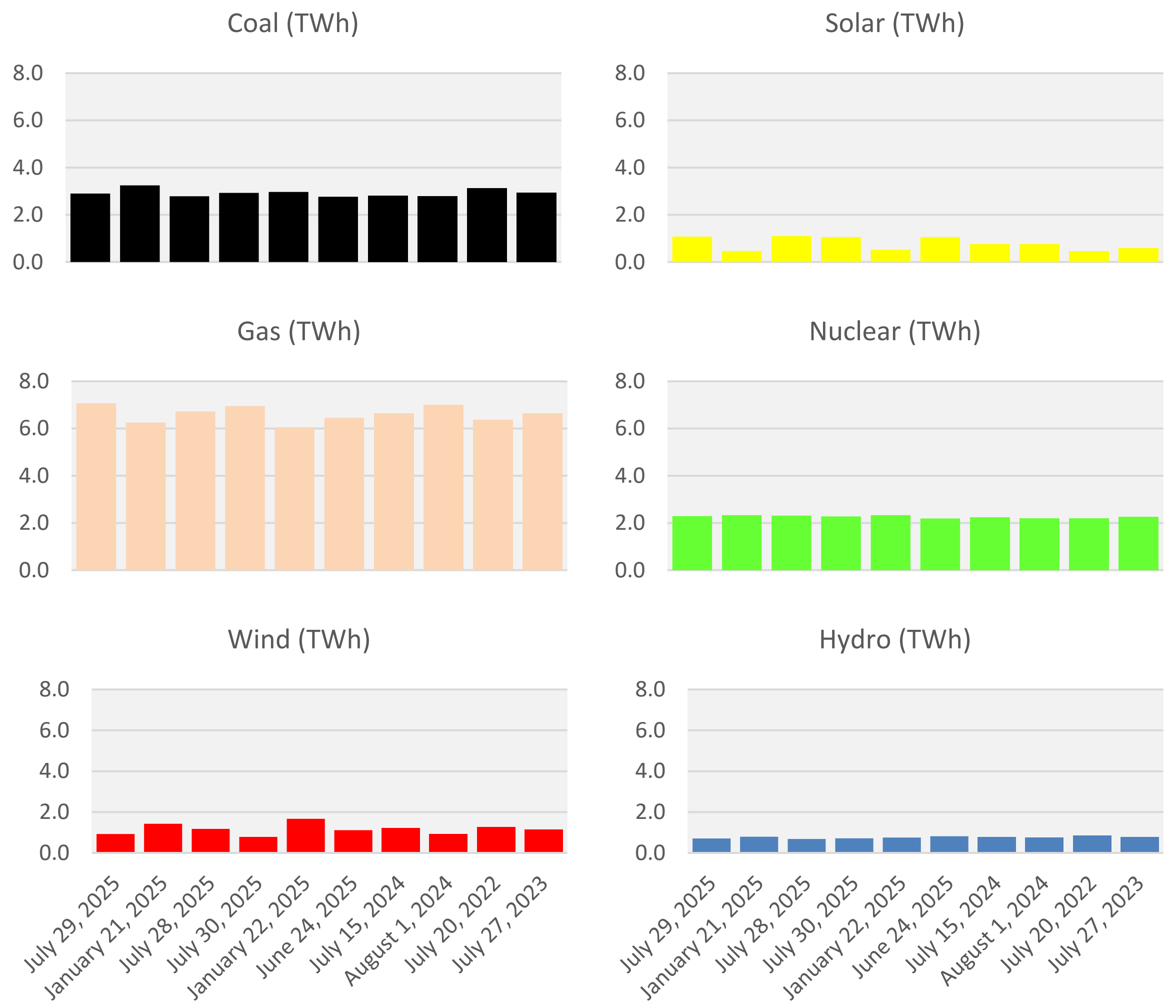


Figure 67. U.S. daily peak energy for lower 48 states' top ten peaks—by resource—on same y-axis scale (Data from [5])

Hourly Peaks

Figure 68 plots the U.S. lower 48 states' peak hours on a truncated scale starting at 550 GW (550,000 MW). Summer hourly peaks have recently been trending upward, with the 2025 peak being 60 GW greater than five years ago. Winter peaks have also been trending upward, at a much higher rate, with the 2025 peak 125 GW greater than four years ago. A typical nuclear reactor is 1 GW, so a 125-GW increase is an enormous increase in peak demand. The most significant driver for the increasing winter peak demand is the increasing adoption of electric heating (heat pumps). In very low temperatures, many heat pumps switch to emergency or auxiliary electric resistance heat. This method is significantly less efficient, resulting in a large increase in power usage [30].

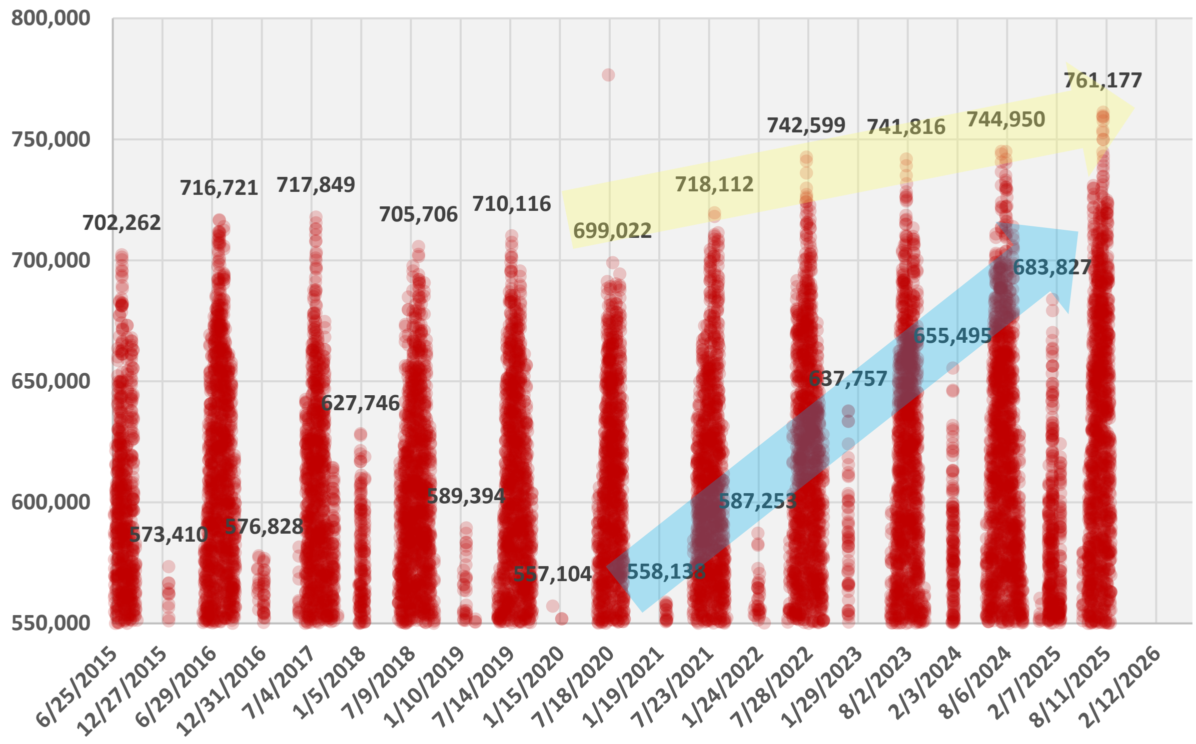


Figure 68. U.S. hourly peaks, June 2015–October 2025 in megawatts (MW) (Data from [5])

Key Observation Point

The U.S. grid maintains a high dependency on natural gas for peak demand, a vulnerability exacerbated by the shift toward winter peaking profiles. During extreme cold, the reliability of the gas fleet is challenged by simultaneous spikes in heating demand and physical supply disruptions, such as wellhead freeze-offs and pipeline pressure drops.

Coal and Gas Trends

Figure 69 provides an overview of U.S. coal and gas annual energy (TWh), installed capacity (GW), and daily energy delivered from the coal and gas fleet in MWh. The annual total energy from coal and gas has been relatively unchanged in the last six years. The combined installed capacity has declined by about 20 GW. The lower graphic has a truncated y-axis to show days where the total gas and coal requirement was greater than 9 TWh (9,000,000 MWh). Since 2018, the number of days meeting this minimum has been increasing, with only eight such days in 2018 and over 20 days in 2025 (up to November 1), including, for the first time ever, three such days in winter.

Overall, the United States has seen a reduction in coal and gas capacity while simultaneously experiencing more peak days that require more energy than ever from the remaining fleet.

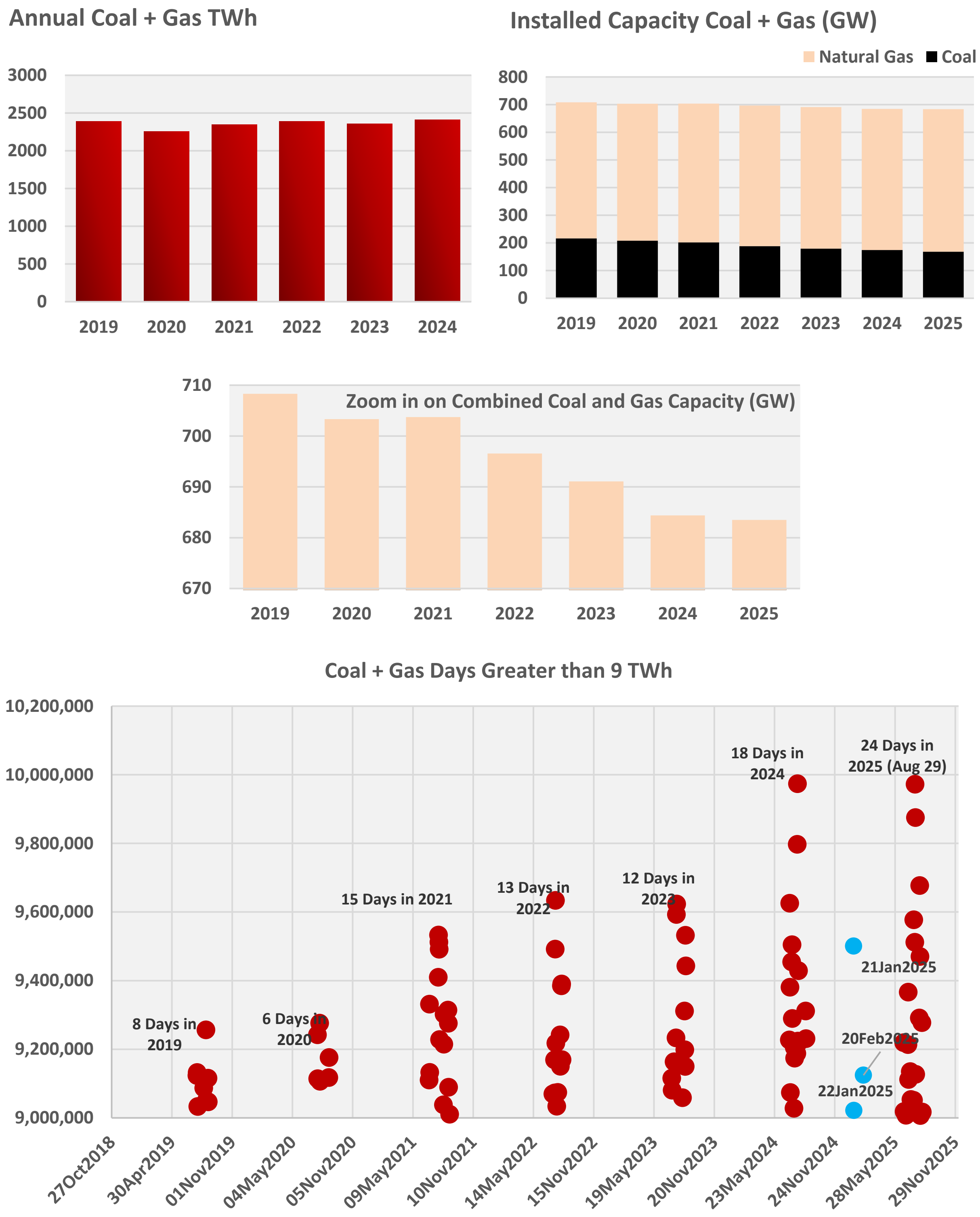
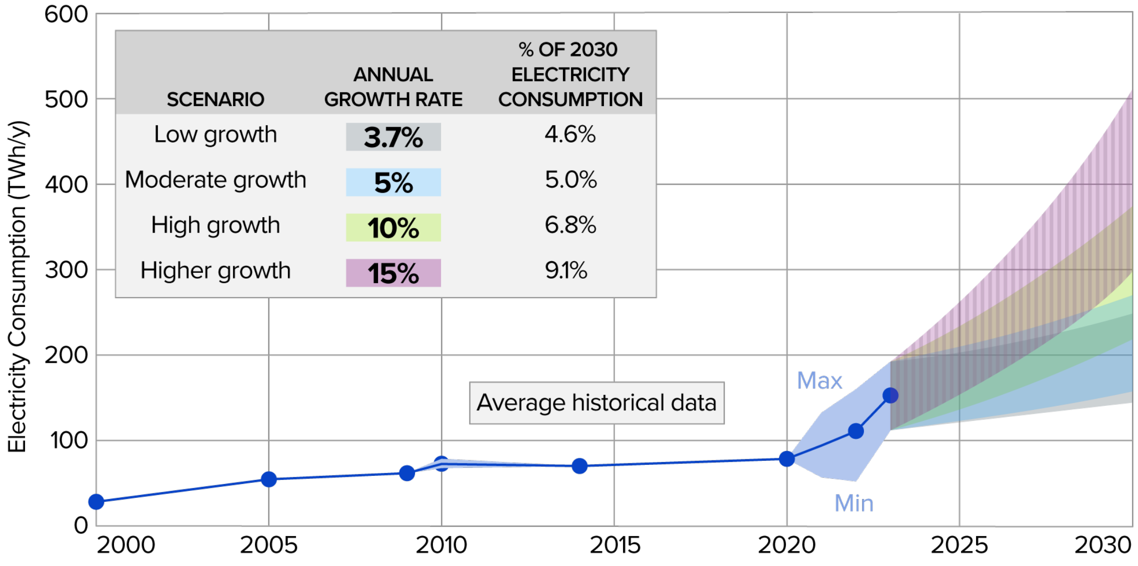


Figure 69. U.S. coal and gas daily energy requirement, 2018–November 2025 (Data from [5, 20])

Data Center Load Projections

Compounding the concerns regarding an aging fleet of dispatchable generation required to meet peak day demands is the significant growth in data center demand projected in the United States in the next five years. This growth is continually being revised upwards. Figure 70 is a May 2024 projection; updated versions will eliminate the low and moderate growth scenarios and include a 20% scenario.



SCENARIO	ANNUAL GROWTH RATE	% OF 2030 ELECTRICITY CONSUMPTION
Low growth	**3.7%**	4.6%
Moderate growth	**5%**	5.0%
High growth	**10%**	6.8%
Higher growth	**15%**	9.1%

Figure 70. U.S. data center power use and growth projections, from EPRI, Powering Intelligence, May 2024 [31]

In 2024 [32], this load growth had become a primary concern for long-term reliability in North America. The North American Electricity Reliability Corporation (NERC) long-term reliability assessments go into detail on a region-by-region basis, examining the risk to resource adequacy, including that from large-load growth like data centers [33].

United States Summary

U.S. electricity costs have increased significantly since 2015 but remain lower than the EU27 average cost (around half). Carbon emission intensity has decreased significantly in the period but is higher than the EU27 average (about 1.8 times). The United States has experienced some load shedding but no widescale blackouts since 2003.

Key Findings

- The United States delivered 16% of its annual electricity production from solar and wind resources, 43% from gas, 18% from nuclear, 15% from coal, and 6% from hydro power in 2024.
- Overall U.S. annual net electricity production has increased by 6% since 2015.

- The U.S. nuclear fleet's performance was exemplary on its peak winter and summer days in 2025. For the peak days, gas was the main source of generation at peak and to cover the daily energy requirement.
- The number of U.S. peak days for gas and coal generation energy requirement is increasing, despite the overall fleet capacity reducing over the last five years.
- The United States is seeing peak hourly and peak daily energy requirements increasing, with the winter peaks rising faster than the summer peaks; however, the summer peaks are still more common than the winter peaks.
- For both the winter and summer peaks, gas generation is the primary source of peak hour and daily energy supply.
- Since the 2003 Northeast blackout, the United States has generally seen its most significant security of energy supply issues during winter storms.
- NERC now identifies load growth (data centers) and gas-electric coordination as leading electricity reliability concerns.

Figure 71 provides a waterfall graph of energy (TWh) changes (top chart), a waterfall of capacity (GW) changes (bottom chart), and a breakdown of total energy (TWh) and capacity (GW) by resource for 2015 and 2024 (middle charts).

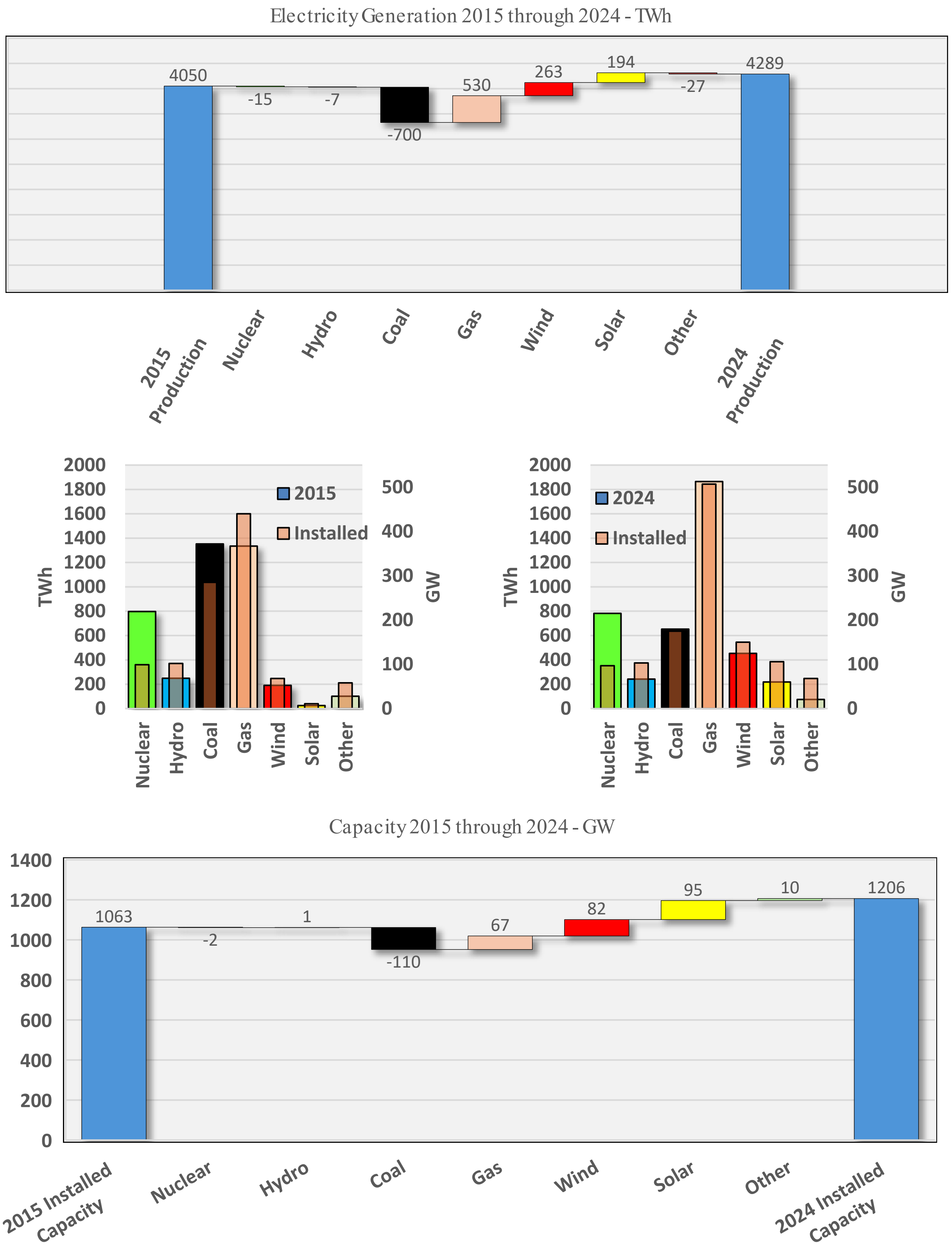
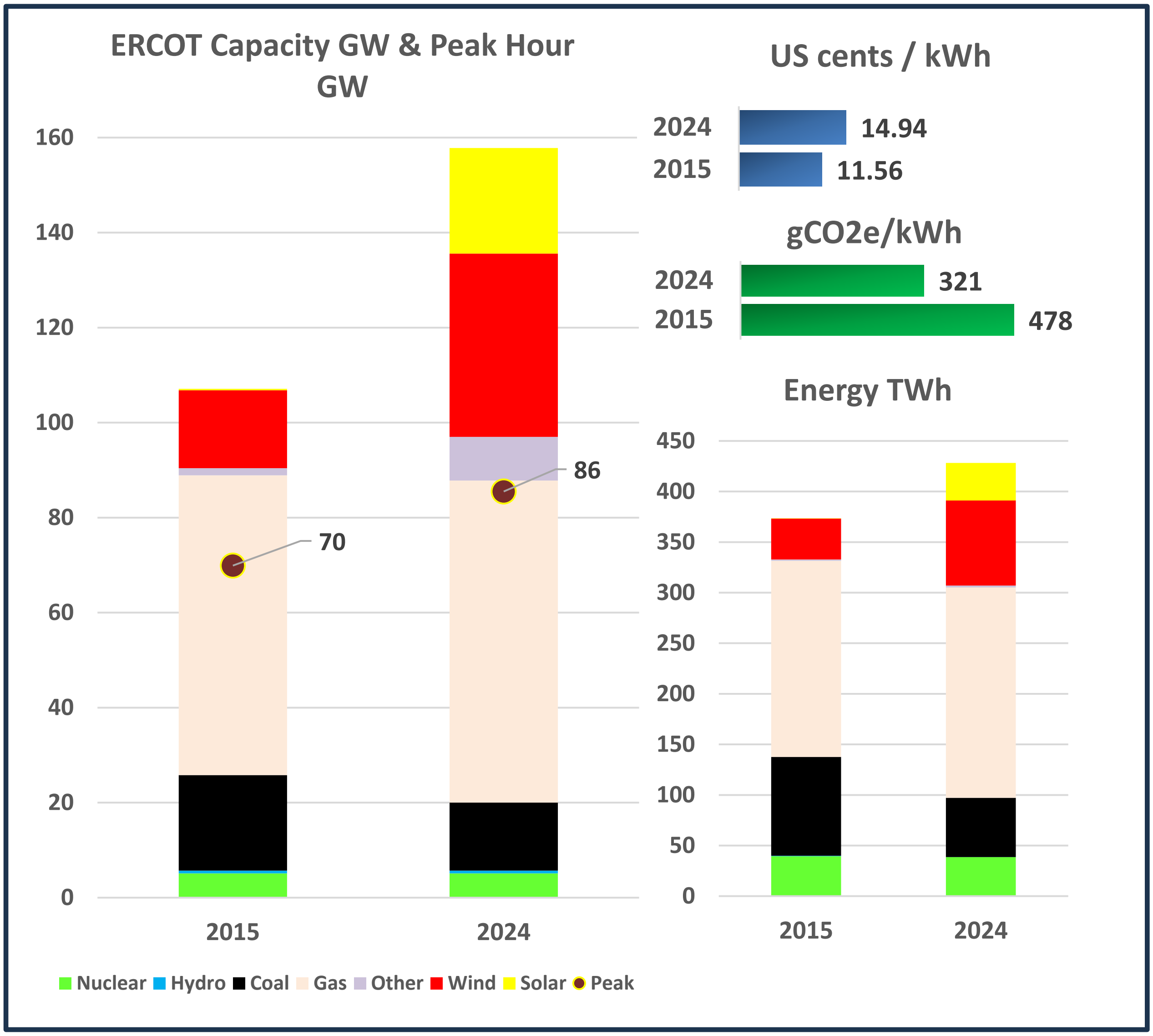


Figure 71. U.S. capacity and generation summary, 2015 and 2024 (Data from [5, 20])

Texas (ERCOT) Electricity Supply

Overview 2015–2024—ERCOT

The Electric Reliability Council of Texas's (ERCOT) capacity, peak, energy, and Texas's residential rates and carbon intensity of the electricity supply are summarized in Figure 72.



	Capacity	Energy	Price	CO2
2024/2015	147%	115%	129%	67%
		2015 / US 2015	0.9	0.9
		2024 / US 2024	0.9	0.8

Figure 72. ERCOT 2015 and 2024 capacity and peak (GW), household rates (cents/kWh), carbon intensity (gCO2e/kWh), and energy (TWh) (Capacity from [20], energy from [5], price from [21], carbon from [5, 34])

ERCOT is the independent system operator for most of the state of Texas. The table below the figure shows ERCOT's progress over time (first line), and ERCOT's price and carbon intensity compared to the U.S. average in 2015 and 2024 (lines two and three).

The installed nameplate capacity of the ERCOT generation fleet in 2024 increased to 147% of the 2015 nameplate capacity. The price has increased but remains a little lower than the U.S. average, at a ratio of 0.9. ERCOT has lowered its carbon intensity from 0.9 to 0.8 of the U.S. average. The carbon intensity has dropped to 67% of the 2015 value.

Figure 73 provides the 2024 winter and summer peak demand days.

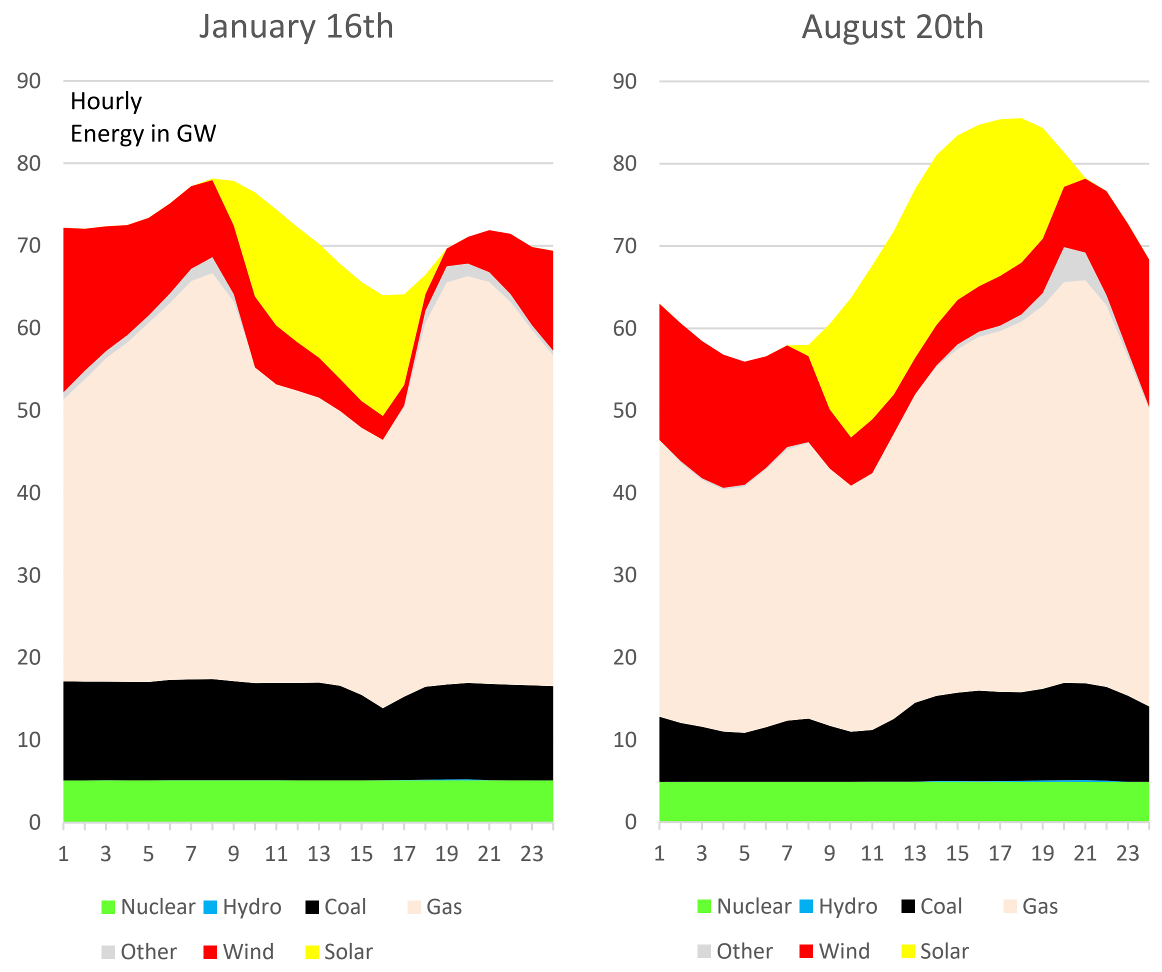


Figure 73. ERCOT peak winter and summer demand days, 2024 (Data from [5])

The winter peak occurred at around 8 a.m. The summer peak occurred around 6 p.m. During the winter peak hour, solar provided very little energy, wind provided about 24% of nameplate capacity, and nuclear provided 100% of nameplate capacity. On the summer peak, solar delivered 79% of nameplate capacity, wind delivered 16% of nameplate, and nuclear delivered 96% (see Figure 74).

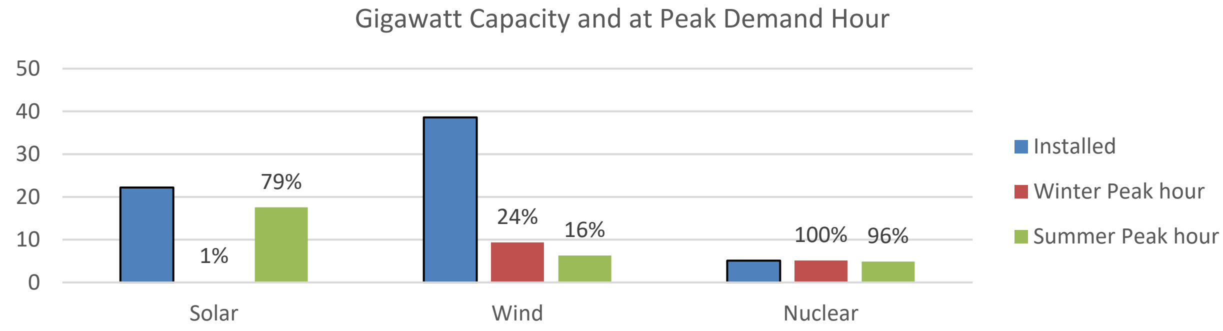


Figure 74. ERCOT solar, wind, and nuclear installed capacity and output on peak winter and summer hour, 2024 (Data from [5, 20])

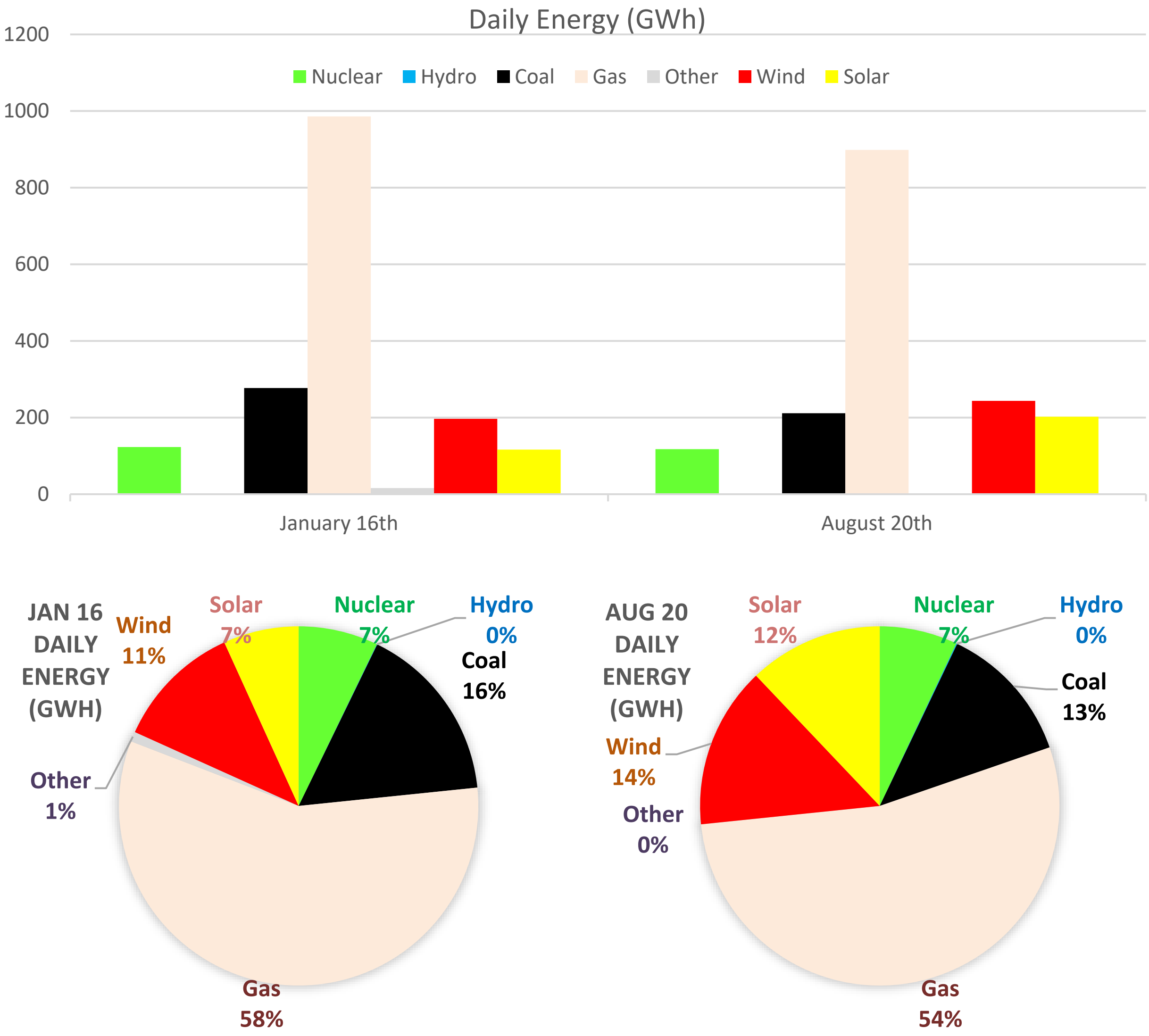


Figure 75. ERCOT 2024 winter and summer total electrical energy by resource (Data from [5])

Figure 75 provides the total electrical energy delivered on the two peak days in ERCOT. Gas provided over 50% of the energy required to meet the daily requirement.

Table 9 provides a more detailed analysis of the capacity performance on the peak days in 2024 for ERCOT. Nuclear peak hour and peak day energy delivery on both the winter and summer peaks was highest per GW installed capacity. The coal fleet was next highest, followed by gas, although due to the larger installed capacity of gas, it delivered the most total energy for both the winter and summer peak day.

Table 9. ERCOT winter and summer peak day's resource outputs on peak hour

Winter peak – resource output on peak hour (08:00) and for day – January 16, 2024 (winter capacities)

Resource	Installed Capacity (GW)	Peak Hour Output (GW)	Peak Day (GWh)	Peak Hour / Capacity	Peak Day / Capacity (GWh/GW)	Avg Day / Capacity (GWh/GW)
Gas	67.8	46	986	0.73	14.5	8.4
Coal	14.3	12	277	0.86	19.4	11.2
Nuclear	5.1	5.1	123	1.00	24.1	20.7
Solar	22.2	5.4	117	0.001	5.2	4.6
Wind	38.6	8.4	197	0.06	5.1	6.0
Peak		**77.9**	**1,716**			

ERCOT Summer peak – resource output on peak hour (18:00) and for day – August 20, 2024 (summer capacities)

Resource	Installed Capacity (GW)	Peak Hour Output (GW)	Peak Day (GWh)	Peak Hour / Capacity	Peak Day / Capacity (GWh/GW)	Avg Day / Capacity (GWh/GW)
Gas	67.8	45	898	0.66	13.3	8.4
Coal	14.3	10.8	211	0.75	14.8	11.2
Nuclear	5.1	4.9	117	0.96	23.0	20.7
Solar	22.2	17.6	244	0.79	9.1	4.6
Wind	38.6	6.3	202	0.16	6.3	6.0
Peak		**85.5**	**1,690**			

ERCOT Trends

Winter Storm Uri

Winter Storm Uri was the worst electricity energy security issue in the history of the Texas electricity supply. ERCOT load shedding peaked at 20 GW, over 200 people died, the costs are calculated in the hundreds of billions of dollars. The official FERC-NERC report provides rich detail on the event [35].

Key Information Point

> *"More than 4.5 million people in Texas lost power during the Event, and some went without power for as long as four days, while exposed to below-freezing temperatures for over six days. At least 210 people died during the Event, with most of the deaths connected to the power outages, of causes including hypothermia, carbon monoxide poisoning, and medical conditions exacerbated by freezing conditions."*
>
> FERC-NERC - Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States – page 9 [26]

Other important references documenting this event are the ERCOT board meeting records immediately after the event [36]. The most notable point from these records was that the grid came dangerously close to a complete collapse, as the frequency of the ERCOT system was below 59.4 Hz (1% deviation) for 4 minutes and 23 seconds. Nine minutes below this level would have led to a system collapse with cascading generator disconnects based on system configuration rules in ERCOT [37]. These are in place for protection of generation assets and to avoid permanent damage to power plants [38].

Key Information Point

> *"Texas' Power Grid Was 4 Minutes And 37 Seconds Away From Collapsing."* [39]
>
> **<59.4 Hz**
>
> **4 minutes 23 seconds**
>
> (>1% deviation)

This was not the first winter storm in Texas warranting a NERC report. In 2011, a similar event occurred [23] but had much less overall impact. Table 10 compares the two events and shows the 2021 event had an order of magnitude greater impact, with five times the peak load shed (turning off power for part of the grid to try and maintain the rest of the grid) and the load shedding lasting for a duration nearly 10 times longer.

Table 10. ERCOT 2011 versus 2021 event comparison (Based on data from [36])

	2011	2021
Maximum load shed requested (GW)	4	20
Duration of load shed request (hours)	7.5	70.5
Estimated peak load without load shed (GW)	59	77

Looking at the evolution of the energy supply capacity in ERCOT from 2011 to 2021 (see Figure 76), a great deal of wind and solar nameplate capacity had been added, some coal capacity had been shut down, and some gas generation capacity had been added.

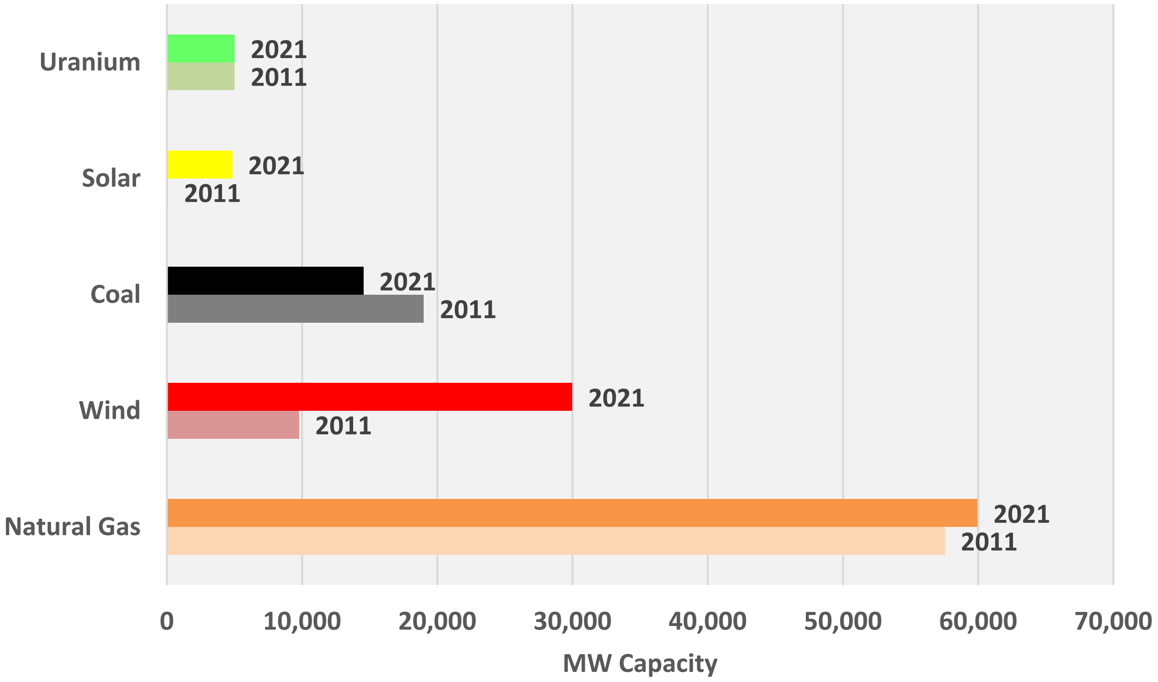


Figure 76. ERCOT generation capacity, 2011 and 2021 (Data from [20])

The most significant load shed hour during the Winter Storm Uri rolling outages was 7–8 p.m. on February 15, 2021 [26]. Figure 77 compares the installed capacity and output by resource on this peak load shed hour. There was no solar generation, wind generation was less than 2% of the nameplate capacity, gas generation was 48% of the nameplate capacity, coal generation was 55% of the nameplate capacity, and nuclear generation was 72% of the nameplate capacity. Referring to Figure 76, essentially none of the new solar and wind built since the previous winter's rolling outages provided any energy in this critical hour, and the existing gas, coal, and nuclear all underperformed in terms of reliability.

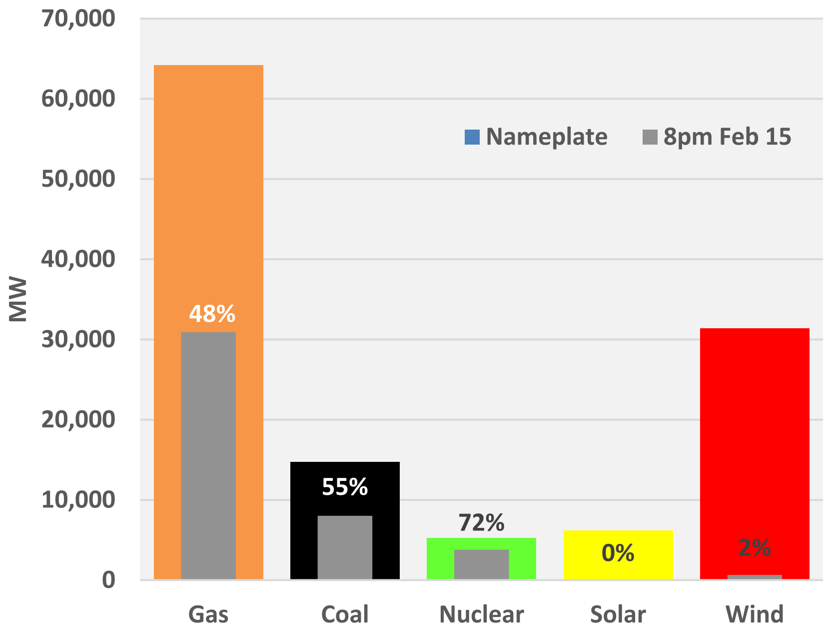


Figure 77. ERCOT generation output and nameplate capacity – peak load shed hour Winter Storm Uri (Data from [5, 20])

Figure 78 combines data from the 2011 and 2021 winter storm events. There is essentially no change in the dispatchable generation capacity available between 2011 and 2021; there is also no difference in the total peak load served. The difference in magnitude in terms of load shed is due to the increased peak demand load in 2021 compared to 2011.

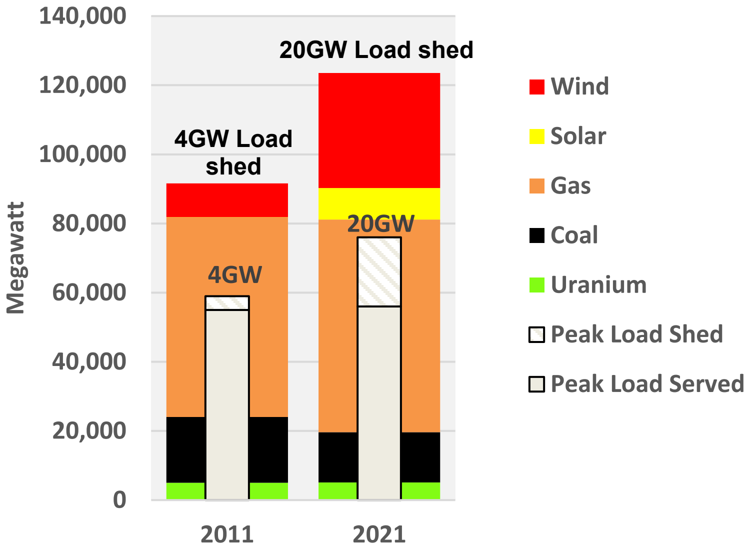


Figure 78. ERCOT capacity, peak load served, and peak load shed, 2011 and 2021 winter storm events (Data from [5, 20])

Wholesale Price Implications

Figure 79 provides the quarterly average day-ahead wholesale prices for ERCOT from 2015 to 2024. Essentially, the price spike associated with the inadequate energy supply during Winter Storm Uri resulted in an average quarterly price greater than the sum of the previous 15 quarters (3.75 years). Energy affordability can be redefined by energy security issues in single events.

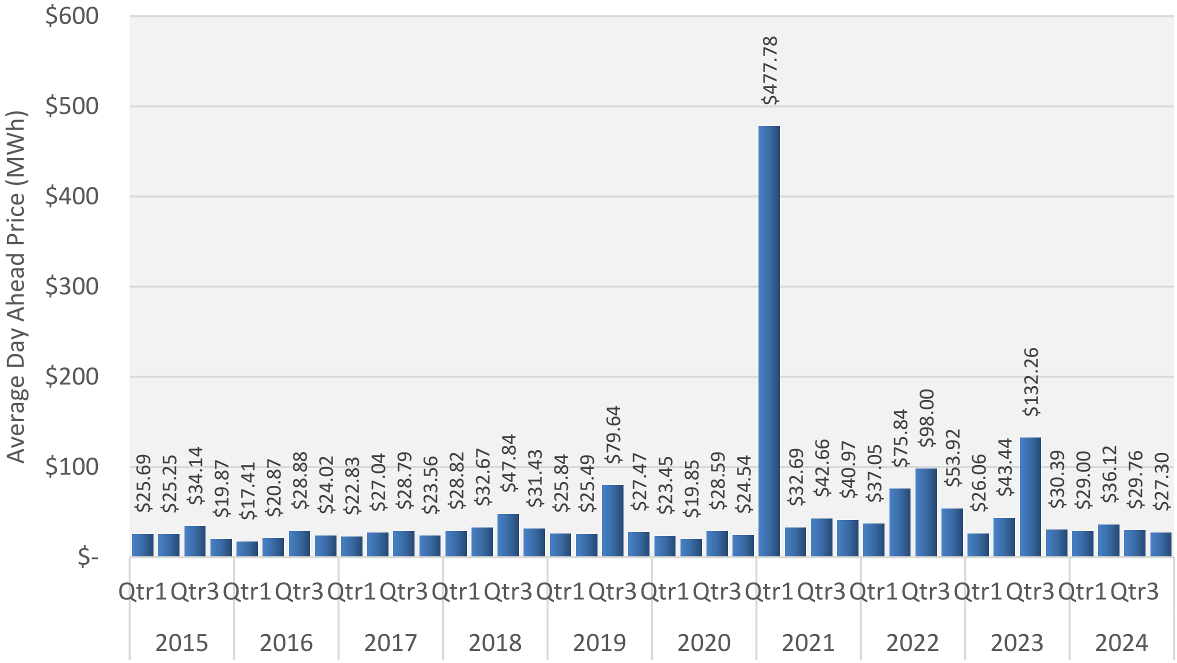


Figure 79. ERCOT wholesale quarterly average day-ahead prices, 2015–2024 (Data from [40])

Key Observation Point

The financial shock of Winter Storm Uri on ERCOT wholesale prices did not just exceed previous years, it dwarfed the combined wholesale costs of the preceding three years. This underscores a critical lesson in grid economics: without structural resilience, a single acute energy security event can cause a total decoupling of market prices from historical norms.

Sufficient Energy Supply to Meet Demand (Resource Adequacy)

EPRI has conducted extensive work since Winter Storm Uri examining the methods for determining sufficient electricity supply to meet anticipated demand, which is called *resource adequacy*. One key lesson has been that weather dependency for outages must be factored in. For a fuller understanding of resource adequacy and how this is changing, see [41].

Key Information Point

Resource adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. It requires maintaining a *planning reserve margin*, a buffer of extra capacity, to ensure the grid remains stable even during extreme weather or sudden plant failures.

ERCOT has transitioned to a Monthly Outlook for Resource Adequacy (MORA) [42], replacing the previous static seasonal approach. This new methodology provides a high-fidelity, probabilistic evaluation of every hour in a 24-hour cycle. By modeling variable outage rates, fluctuating demand, and the intermittent performance of renewables during marginal hours, the MORA recognizes that a “GW is not a GW.” This granular assessment is essential for managing a grid where technology attributes and their reliability vary significantly by the hour.

Figure 80 provides a look at the winter peak hour projected for the January 2026 MORA and the expected available capacity from each resource to meet this. Figure 81 provides the expected available capacity on the hour of highest shortage from the August 2025 MORA.

In each case, for ERCOT, solar is projected to provide no capacity despite an installed capacity of greater than 30 GW. Most of the available capacity is expected to be provided by dispatchable resources. Wind was expected to have 13.7 GW available at 9 p.m. in the August 2025 assessment (35% of the installed), and 16.3 GW at 8 a.m. in the January 2026 assessment (40% of the installed).

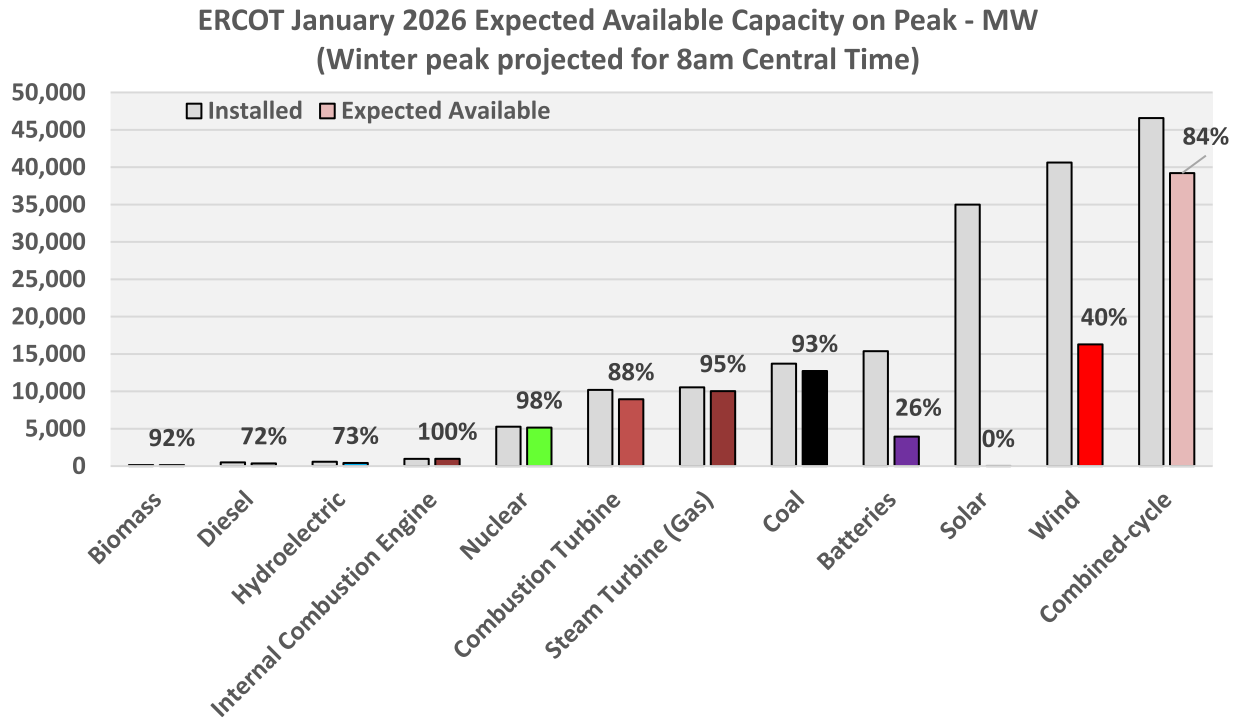


Figure 80. ERCOT January 2026 monthly outlook for resource adequacy – peak hour (8 a.m.) (Data from [42])

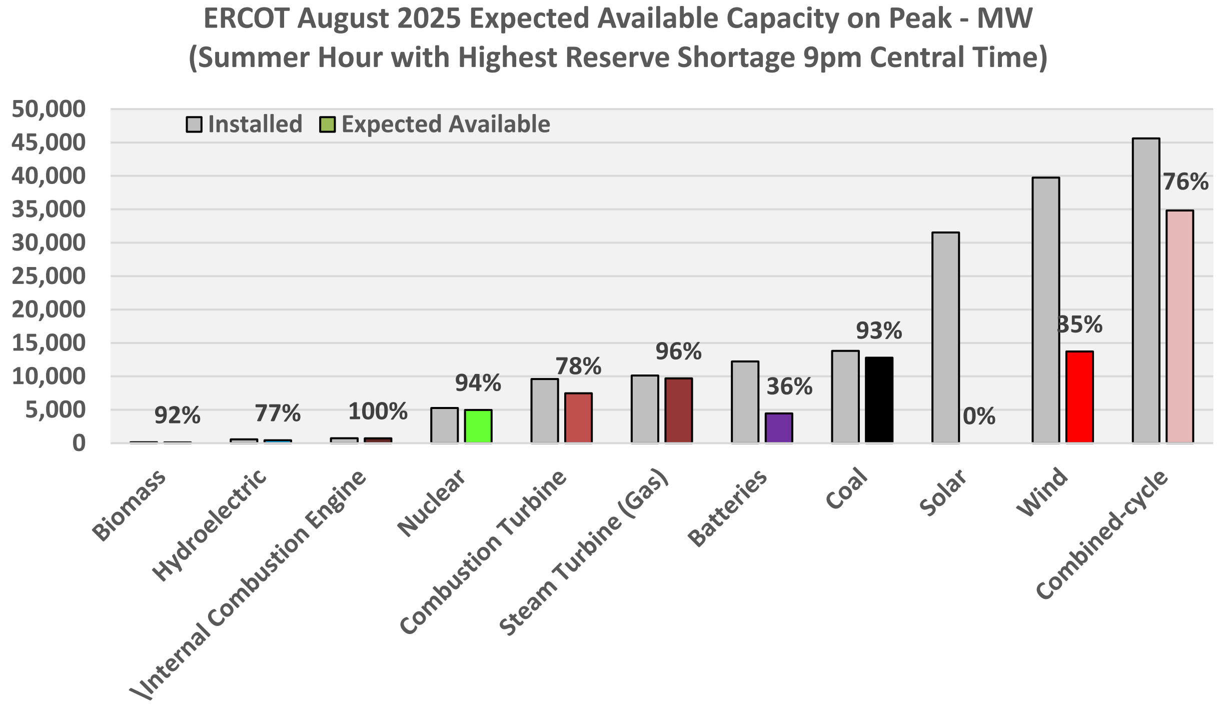


Figure 81. ERCOT August 2025 monthly outlook for resource adequacy – hour with highest reserve shortage (9 p.m.) (Data from [42])

Figure 82 looks at actual wind performance from August 2025 compared to the expected and installed. There were five days when the actual wind output on the 9 p.m. hour was less than 50% of the expected value. As a measure of installed capacity on the best day, only one day delivered 50% of the nameplate capacity. Figure 83 looks at nuclear performance in a similar fashion; nuclear delivered 94% or better of the installed capacity every day (and delivered 100% of the expected available output).

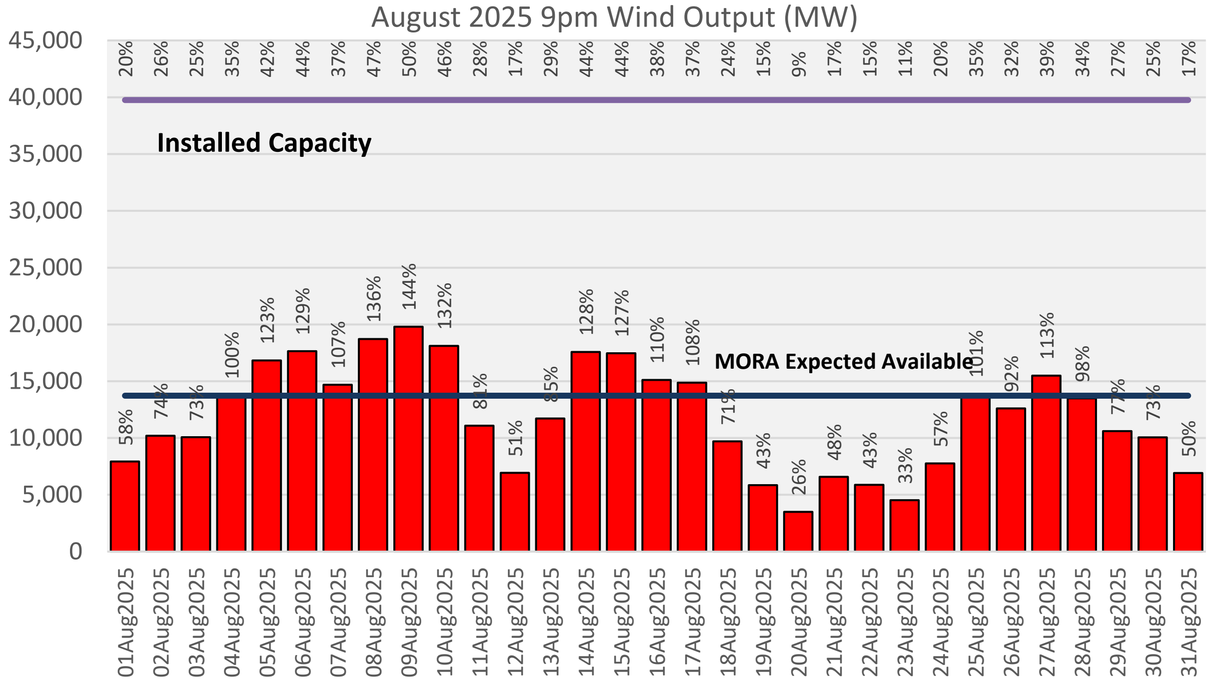


Figure 82. ERCOT August 2025 highest reserve shortage hour (9 p.m.) actual wind versus monthly outlook expected available and installed capacity (Data from [5, 20, 42])

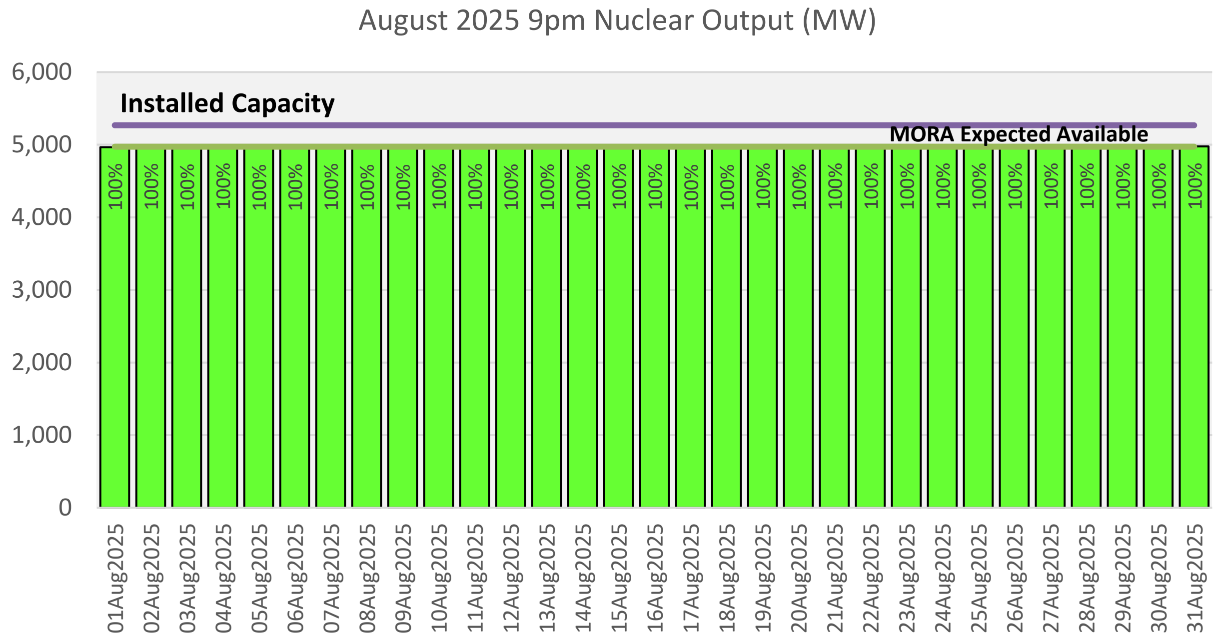


Figure 83. ERCOT August 2025 highest reserve shortage hour (9 p.m.) actual nuclear versus monthly outlook expected available and installed capacity (Data from [5, 20, 42])

Battery performance is given in Figure 84. In general, batteries performed as expected, but the expected is 36% of nameplate capacity in the August 2025 MORA.

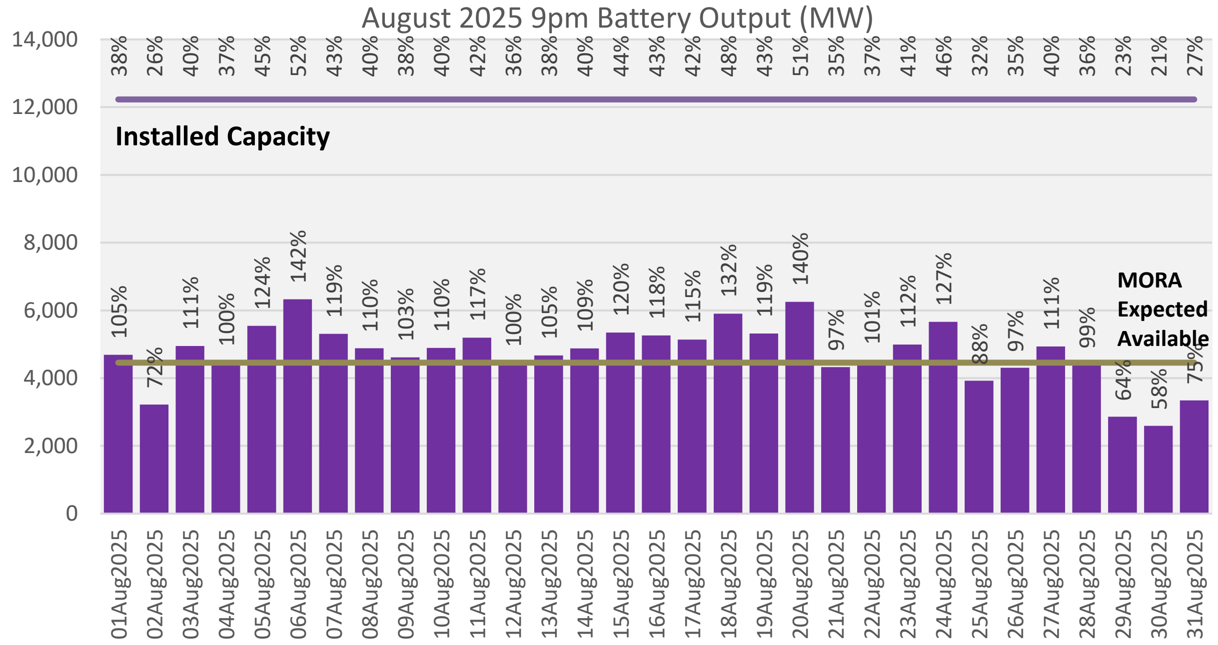


Figure 84. ERCOT August 2025 highest reserve shortage hour (9 p.m.) actual nuclear versus monthly outlook expected available and installed capacity (Data from [5, 20, 42])

Texas Electricity Rates

Wholesale prices for energy have minimal effect on retail rates. During Winter Storm Uri, wholesale electricity prices increased so that the monthly average for the February 2021 price was two orders of magnitude greater than typical values (>$1000/MWh versus ~$20/MWh). This had no impact on the monthly residential retail rate paid for electricity in February 2021. Commercial rates increased by about 4 cents per kWh, and industrial retail rates increased by about 5 cents per kWh (see Figure 85).

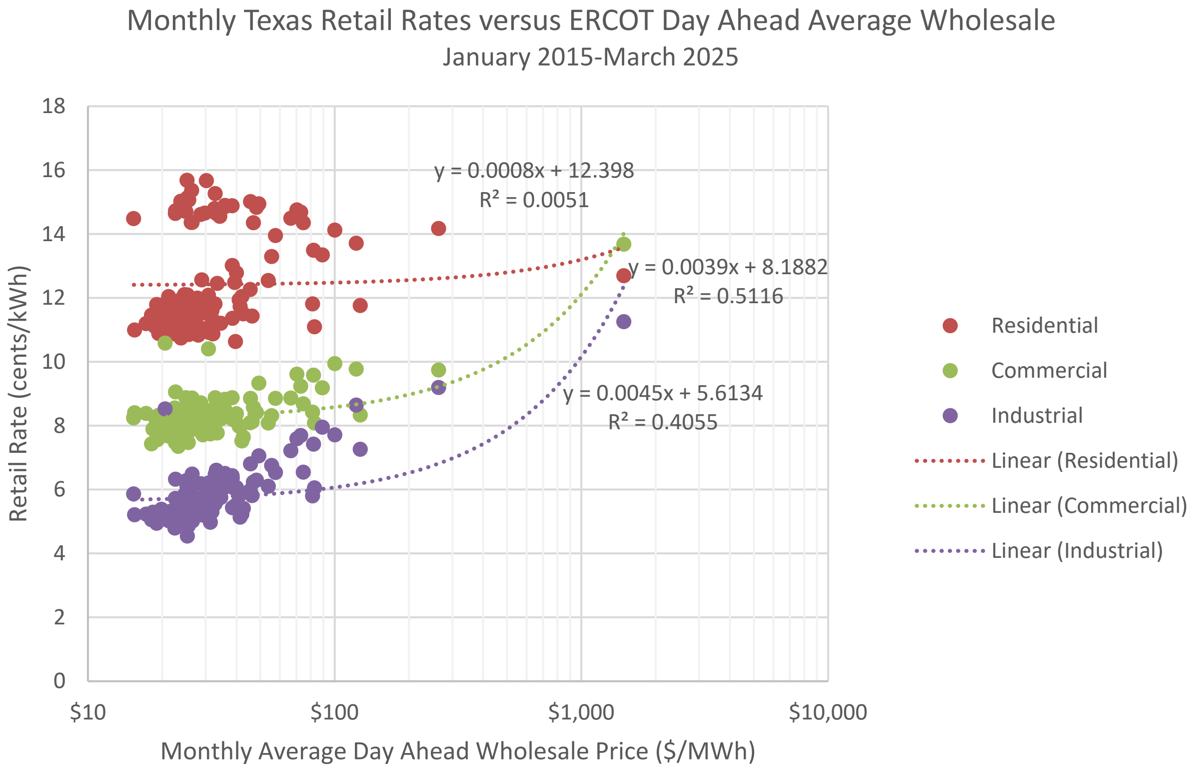


Figure 85. Texas monthly retail rates versus ERCOT monthly day-ahead average wholesale rates, January 2015 to March 2025 (Logarithmic x-axis) (Data from [21, 40])

Figure 86 provides the time series trend of retail rates in Texas from January 2015 to September 2025. Residential retail rates have climbed since February 2021 from ~12 cents/kWh to nearly 16 cents/kWh. Commercial and industrial rates have increased as well but more in the range of 1 cent/kWh.

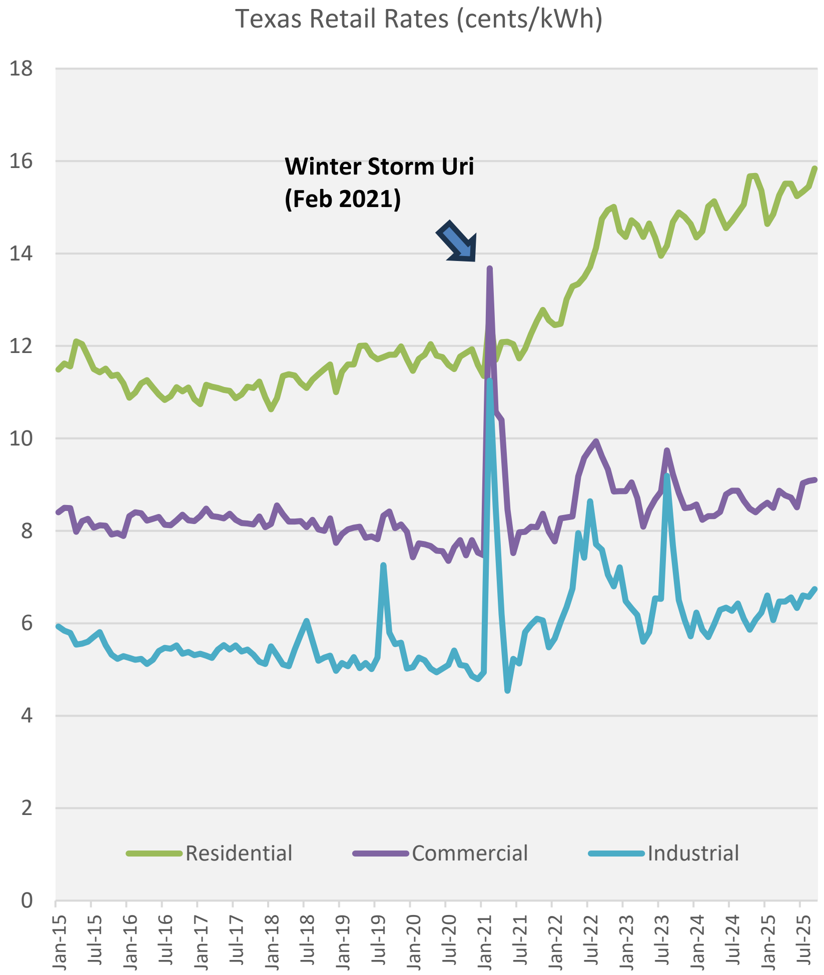


Figure 86. Texas retail rates, January 2015 to September 2025 (Data from [21])

ERCOT Peak Reduction

Looking across every hour in 2024, the peak demand in ERCOT was 85.5 GW, and the peak hour data is as follows:

- Less the solar generation—79.4 GW (22.2 GW installed capacity)
- Less wind generation—81.5 GW (38.6 GW installed capacity)
- Less the combined wind and solar—69.9 GW (60.8 GW combined installed capacity)
- Less the combined wind, solar, and batteries—67.6 GW (~69 GW combined installed capacity)

Solar installed capacity in 2024 resulted in ~0.27 reduction in need for other generation on GW/GW installed basis. Wind's ratio of GW reduction was 0.10 GW/GW installed, and the combined wind and solar ratio was 0.26 GW/GW installed. Looking at the nuclear fleet, it reduced the peak in 2024 to 80.7 GW, or roughly 0.9 GW/GW installed.

Figure 87 analyzes the peak reduction over the period from 2019 to 2024 from solar, wind, and battery installations.

The yellow column (left axis) is the installed nameplate capacity in GW of wind, solar, and battery capacity. It is increasing year over year. The orange column (left axis) is the annual energy from wind and solar in TWh, which generally increases year over year. The grey column (left axis) is the annual energy from non-solar and non-wind resources in TWh, which is generally stable year over year. The lines are daily peak energy from non-solar and non-wind resources (black line) in GWh total annual energy (red line) and in TWh, both on the right axis, and both are increasing.

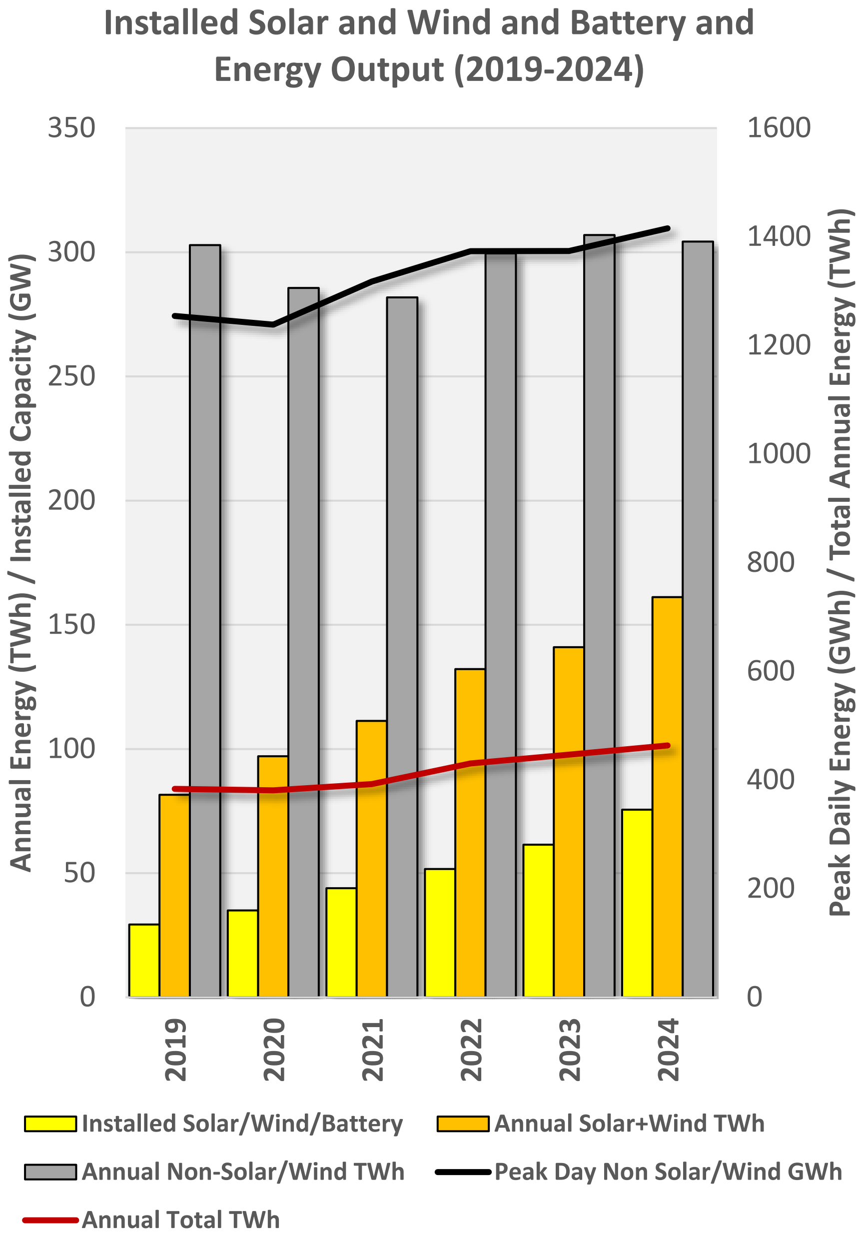


Figure 87. ERCOT wind, solar, and battery additions – annual energy and daily peak non-solar/wind energy, 2019 to 2024 (Data from [5, 20])

There have been significant additions of solar, wind, and batteries in the period, which have resulted in an appreciable increase in energy on an annual basis from wind and solar. Energy from non-wind and non-solar has remained relatively steady as total annual energy need has been increasing. The peak daily energy requirement from non-wind and non-solar resources has been on an upward trend throughout the period despite the addition of solar, wind, and battery capacity.

Figure 88 looks at the addition of solar, wind and battery capacity compared to the net effect on the annual non-solar and non-wind energy requirement and peak daily requirement compared to 2019 as a baseline year.

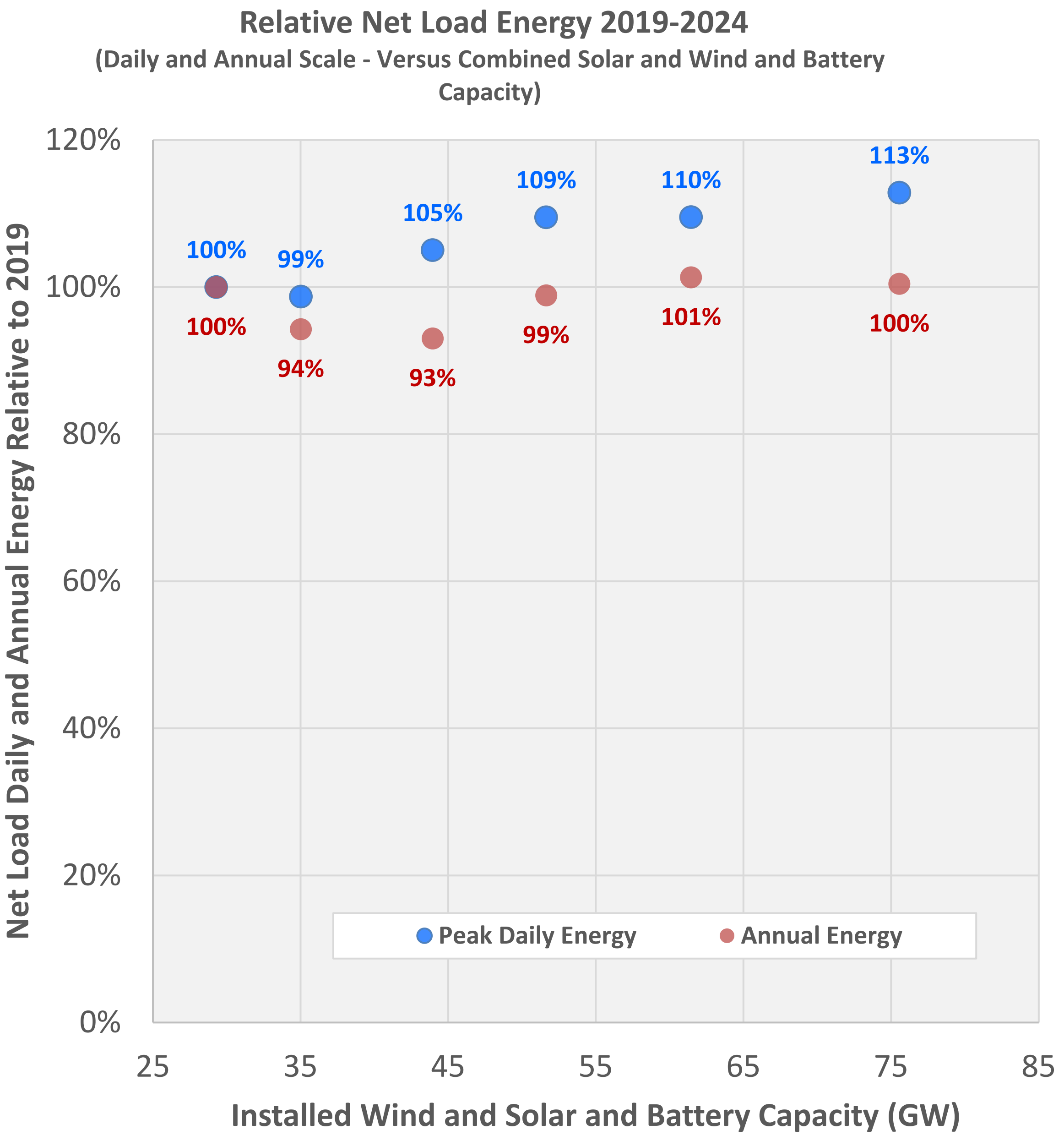


Figure 88. ERCOT relative net load energy, 2019–2024 (daily and annual scale versus combined solar, wind, and battery capacity) (Data from [5, 20])

Despite additions of wind, solar, and battery capacity, the annual energy supply required from other generation sources (i.e., from coal, gas, and nuclear) has not decreased. The peak daily energy need from non-wind/solar/batteries has also been increasing. Daily peak energy from non-wind and non-solar sources may remain resilient to reductions, even as batteries scale. Figure 89 illustrates the hourly resources for February 21, 2025, in ERCOT. This is the peak daily non-wind and non-solar energy day in ERCOT in 2025. The battery output and charging are also included in the figure (on the right). As battery round-trip efficiency is less than 100% (i.e., it takes more energy to charge the battery than can be discharged by the battery), use of batteries adds to the daily demand for electricity. They can reduce peak hour demand, but overall, more energy consumption is required to cover the difference between charging of the battery and what can be recovered when discharging. On a day like February 21, 2025, where there is limited solar and wind output, this additional energy requirement is likely to come from non-wind and non-solar resources. Adding more batteries increases the need for daily energy.

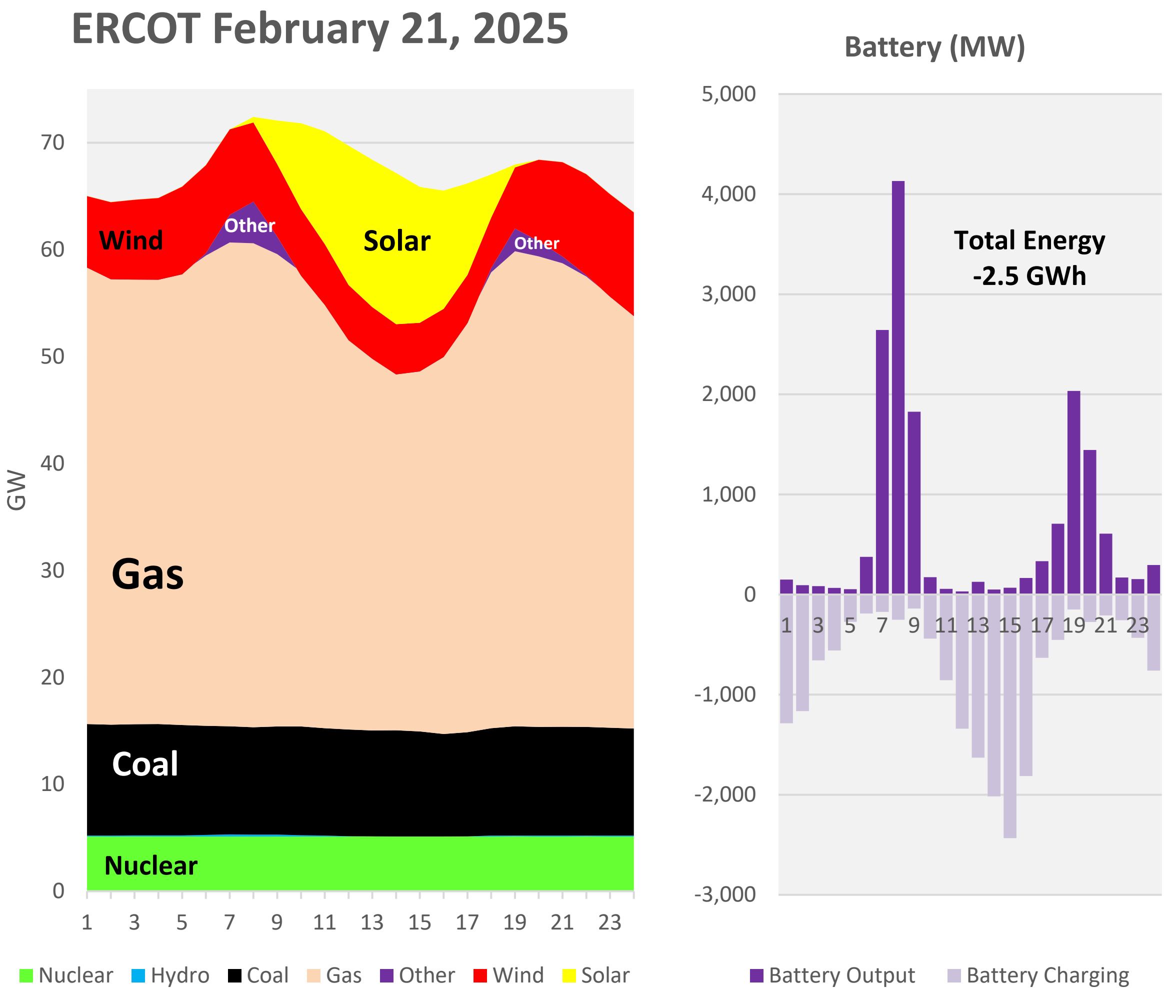


Figure 89. ERCOT February 21, 2025 (Data from [5])

Key Observation Point

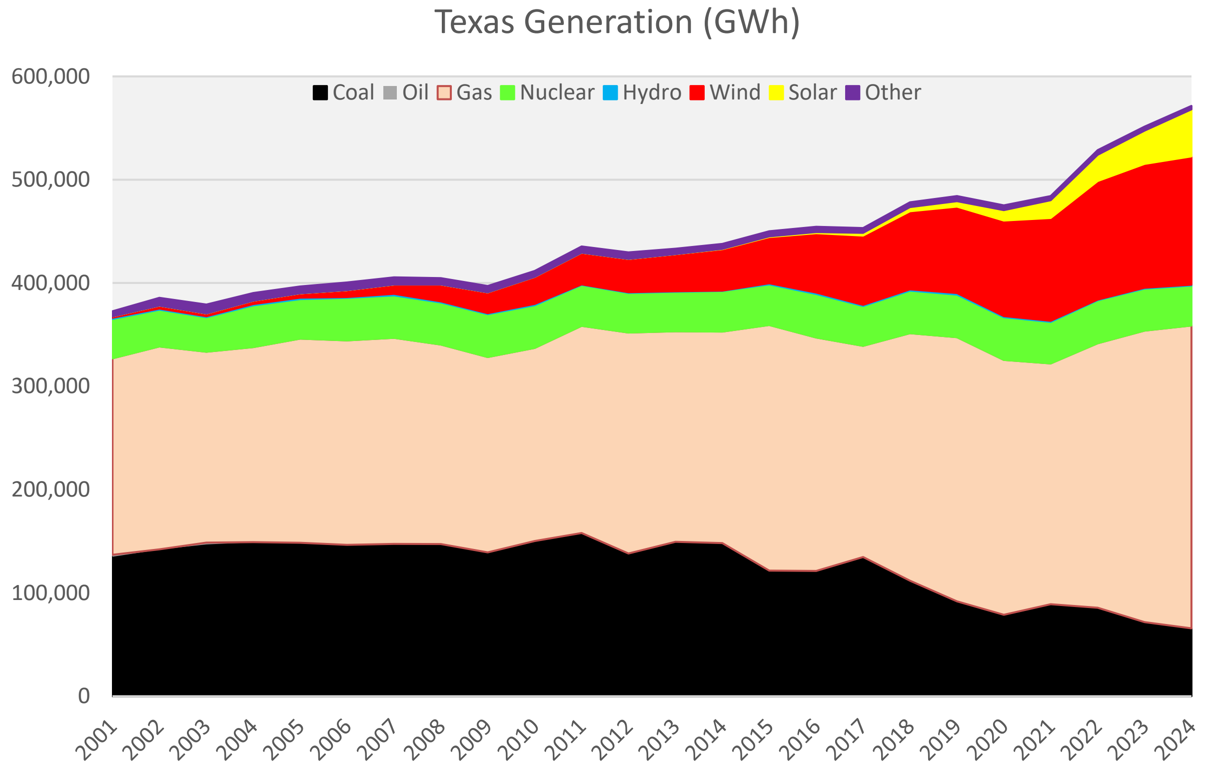
While battery storage effectively mitigates peak demand, it introduces a net increase in total daily energy consumption due to round-trip efficiency losses. On marginal days with low solar and wind output, batteries effectively act as an additional load on the grid. To maintain readiness for peak hours, they must be charged using dispatchable resources like gas or coal, paradoxically increasing the total fuel burned to satisfy the same end-user demand.

Demand Review

Annual Trends

On an annual basis, Texas electricity generation is growing quite rapidly. Figure 90 illustrates the growth in annual electricity generation in Texas from 2001 to 2024 in GWh (1,000 GWh = 1 TWh). From 2001 to 2009, there was limited annual growth. After the financial crisis until the end of the COVID pandemic in 2021, the annual electricity generation grew moderately. Since 2021 though, the annual growth has been much greater, driven by industrial energy demand and data center growth. The total electricity generation in Texas in 2024 was over 570 GWh, a 50% increase since 2001, while U.S. electricity demand on a whole grew by less than 10% over this period. The data includes the energy supply by resource. The upper part of the figure shows the resource mix as a stacked area chart and the lower as a line chart.

Gas generation in Texas has been the largest single source of electrical energy through the period and in recent years has been growing rapidly. Wind energy is the second largest source, with rapid growth in annual electricity production beginning in 2007. Solar has been the latest source of electricity within Texas to begin to grow, surpassing nuclear in 2024 in annual production (noting, though, that this is with an installed capacity of over 20 GW of solar versus an installed capacity of 5 GW of nuclear).



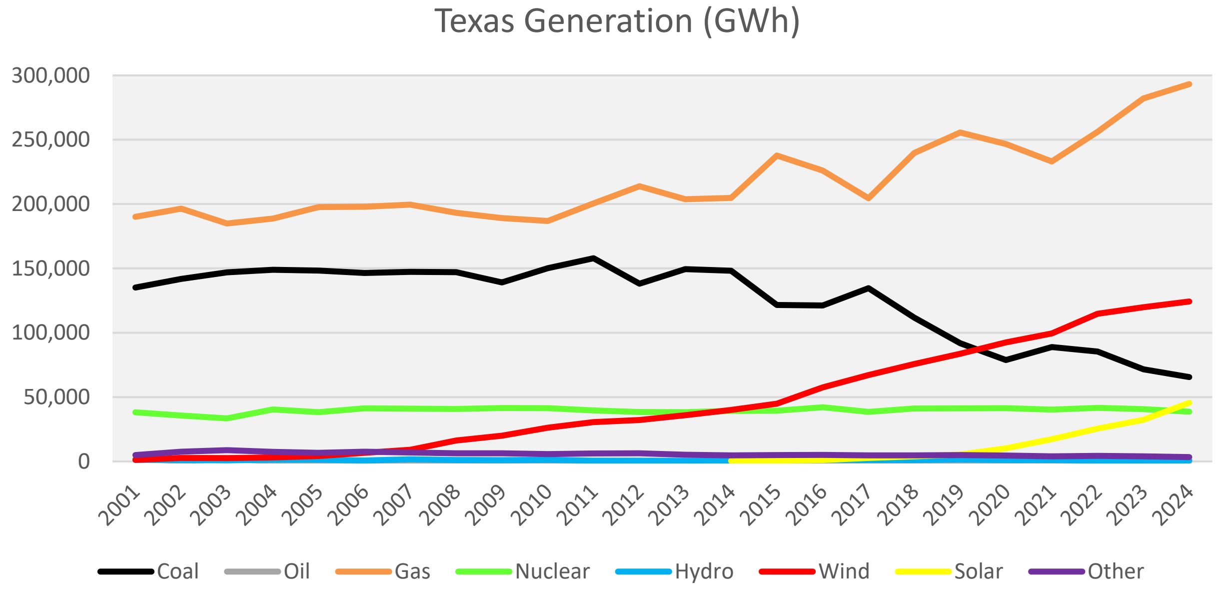


Figure 90. Texas annual energy (GWh) (Data from [21])

Daily Peaks

Figure 91 looks at the daily peak energy requirements for ERCOT. The number of both winter and summer daily peak days greater than 1.4 TWh has been increasing year over year. The highest demand days have been winter days in 2024 and 2025. This is notable as Texas's most severe electricity energy security events have been winter events. A rising need for peak electricity supply on winter days implies a greater challenge for the energy supply resources to cover the peak day energy requirements.

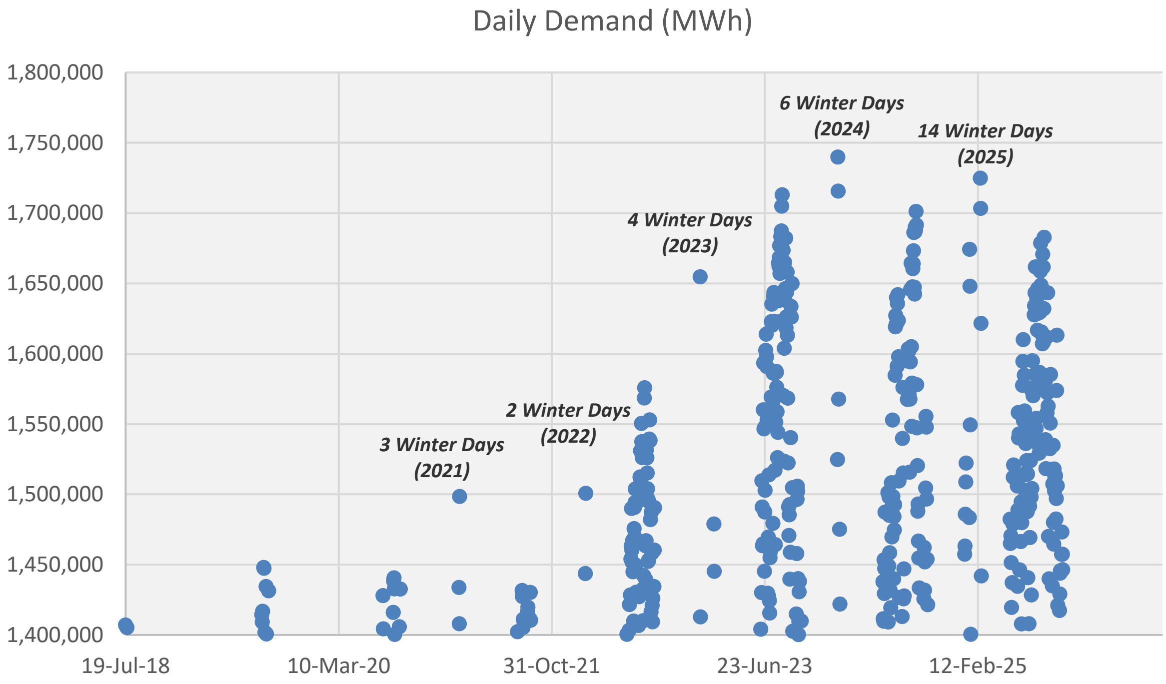


Figure 91. ERCOT daily peak energy requirements (MWh) (Data from [5])

Hourly Peaks

Winter hourly peaks have been increasing from a peak of ~70 GW in 2022 to over 80 GW in 2025. Summer hourly peaks had been increasing but decreased in 2025 (see Figure 92). With an expanding battery capacity basis, meeting hourly peaks may be less of a challenge in Texas/ERCOT in the future, but this does not alleviate daily energy security concerns and can increase the need for more energy to cover the daily requirement due to the load introduced by the batteries and their less than 100% round-trip efficiency.

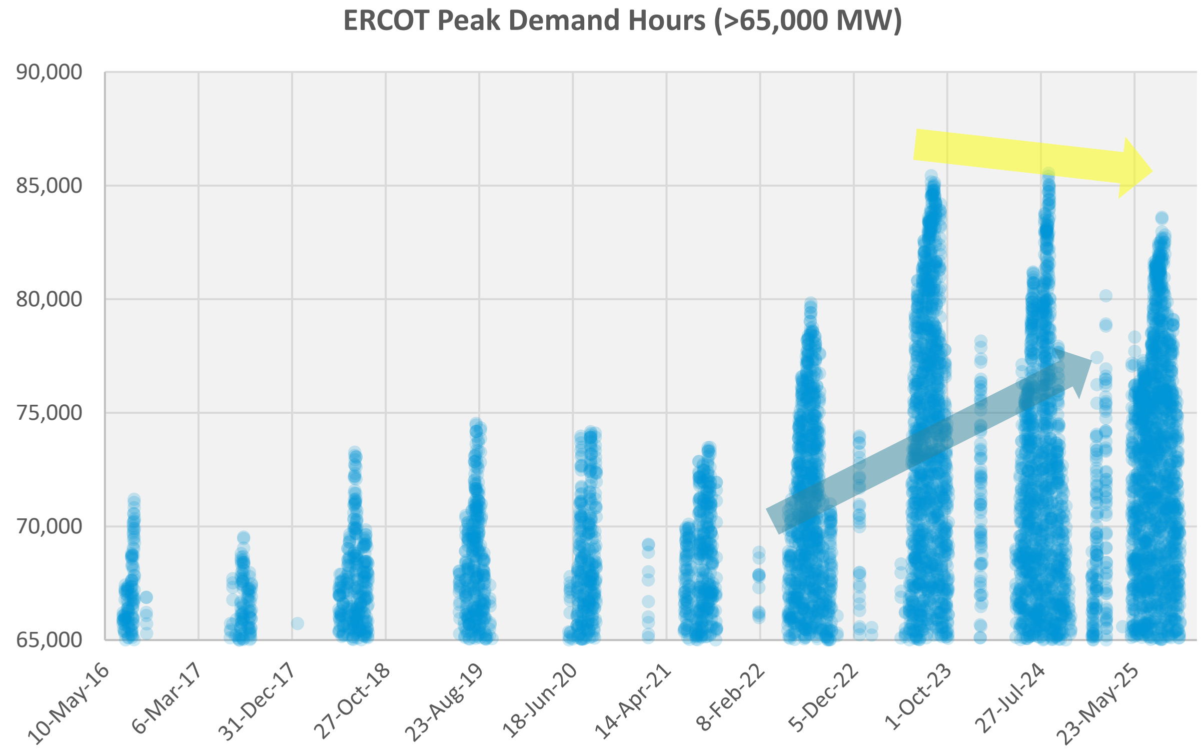


Figure 92. ERCOT hourly peak demand (Data from [5])

Load Growth

Significant additional large load growth is projected by ERCOT [43]. Peak hourly load is projected to increase from 85 GW in 2024/2025 to over 150 GW by 2034, with annual energy more than doubling in the period. Most of this projected load growth is data center related. Other major drivers include cryptocurrency, hydrogen production, and industrial growth. This will be a growing concern for all aspects of the energy trilemma for ERCOT.

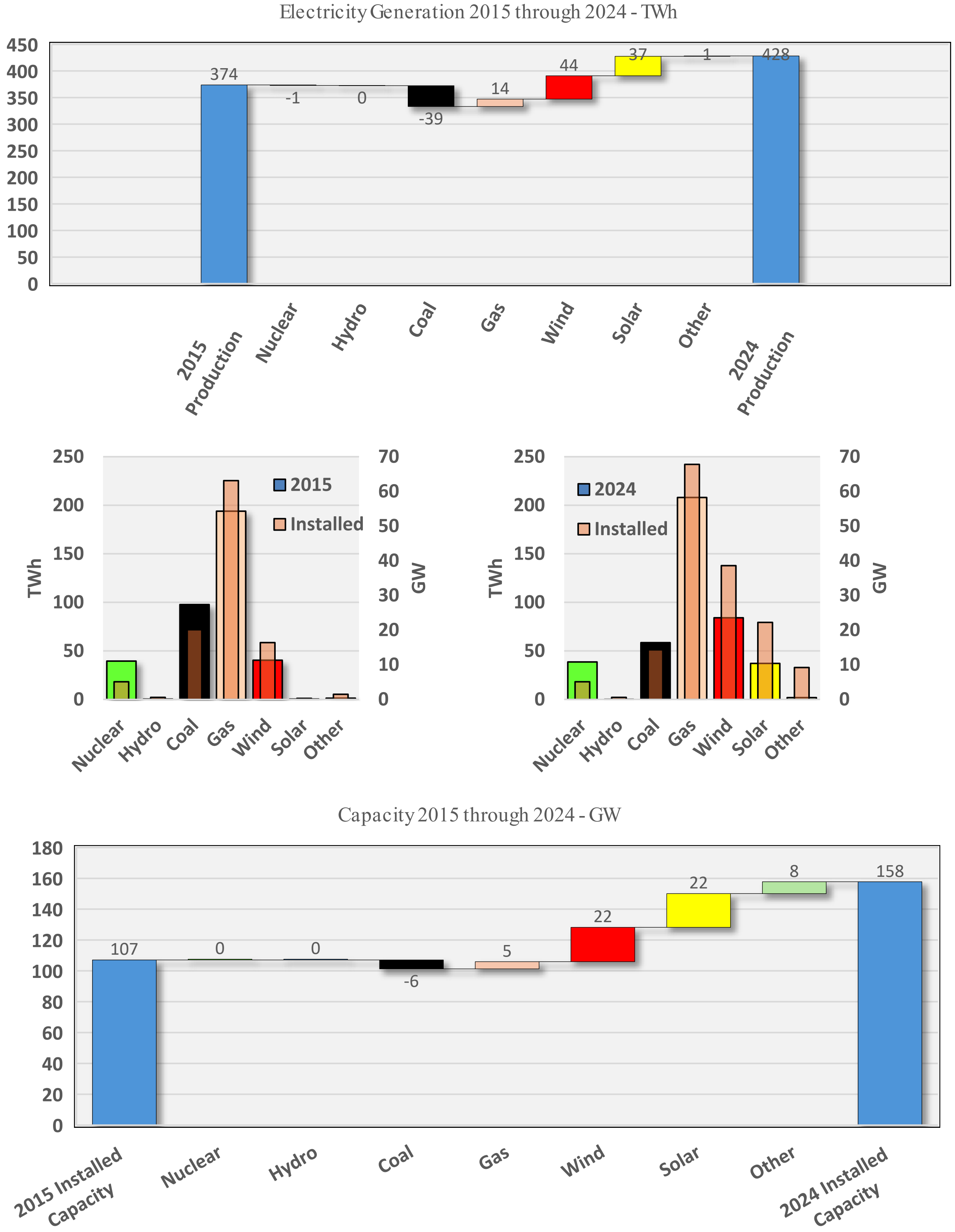
ERCOT/Texas Summary

ERCOT electricity costs have increased significantly since 2015 but remained at 0.9 of the U.S. average cost in 2024. Carbon emission intensity has decreased and was at 0.8 of the U.S. average in 2024. In 2021,ERCOT experienced the worst load shedding event in U.S. history in terms of impact to society, with significant loss of life and financial impact. Since then, reliability of supply has improved but winter reliability concerns remain.

Key Findings

- ERCOT delivered 28% of its annual electricity production from solar and wind resources, 49% from gas, 9% from nuclear, 14% from coal, and <1% from hydro power in 2024.
- ERCOT's overall annual net electricity production has increased by 15% since 2015.
- ERCOT's nuclear, coal, and gas fleets performed well on ERCOT's peak winter and summer days in 2024. For the peak days, gas was the main source of generation on peak and to cover the daily energy requirement. Solar on-peak hour production for the summer peak was also very high.
- ERCOT is a summer hourly peaking system; however, in recent years, winter peak hours have been increasing at a faster rate, with summer peaks relatively flat for 2023–2025.
- In 2024, ERCOT became a winter peaking system for daily energy requirements, which was repeated in 2025. The highest daily energy requirements in ERCOT history occurred on winter days in 2024 and 2025.
- ERCOT's peak daily energy requirement from non-wind/solar/battery generation is increasing, despite the overall fleet capacity not increasing.
- ERCOT's retail rates have risen since Winter Storm Uri, with residential rates seeing the greatest impact.
  - Dramatically elevated wholesale prices had no immediate impact on residential retail rates in Texas.
  - Elevated wholesale prices have had some impact on commercial and industrial retail rates, but these are muted (50 times increase in monthly wholesale prices during Winter Storm Uri resulted in <2 times increase in these rates).
- For both the winter and summer peaks, gas generation is the primary source of peak hour and daily energy supply.
- ERCOT has significant load growth forecast, with system requirements projected to double in the next 10 years.

Figure 93 provides a waterfall graph of energy (TWh) changes (top chart), a waterfall of capacity (GW) changes (bottom chart), and a breakdown of total energy (TWh) and capacity (GW) by resource for 2015 and 2024 (middle charts).


Electricity Generation 2015 through 2024 - TWh

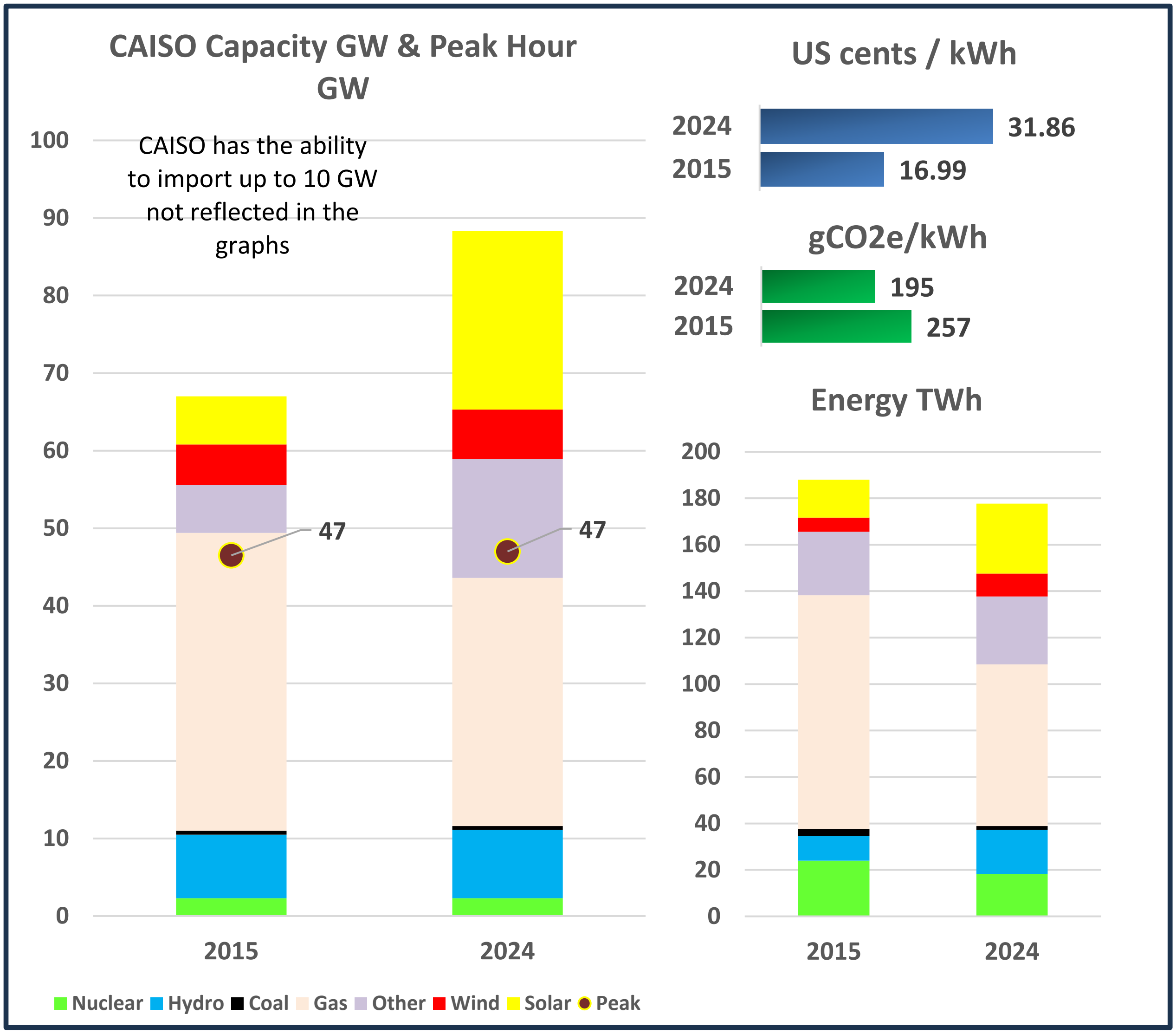
Capacity 2015 through 2024 - GW

Figure 93. ERCOT capacity and generation summary, 2015 and 2024 (Data from [5, 20])

California (CAISO) Electricity Supply

Overview 2015–2024—CAISO

California Independent Service Operator's (CAISO) capacity, peak, energy, and California's residential rates and carbon intensity of the electricity supply are summarized in Figure 94.



	Capacity	Energy	Price	CO2
2024/2015	132%	95%	188%	76%
		2015 / US 2015	1.3	0.5
		2024 / US 2024	1.9	0.5

Figure 94. CAISO 2015 and 2024 capacity and peak (GW), household rates (cents/kWh), carbon intensity (gCO2e/kWh), and energy (TWh) (Capacity from [20], energy from [5], price from [21], and carbon from [5, 44])

CAISO is the independent system operator for most of the state of California. CAISO's electricity nameplate capacity in 2024 increased by 32% since 2015, roughly double the peak demand in CAISO. The residential retail rate for electricity on a per-kWh basis has risen by 88% on a nominal basis, with prices 1.9 times the U.S. average in 2024. The carbon intensity of the supplied electricity has dropped 24%, but relative to the U.S. average, remains at 0.5 of the U.S. average (i.e., ahead of the average but unchanged from 2015). The total electricity consumption has dropped slightly, by about 5%.

Figure 95 provides the 2024 winter and summer peak demand days. CAISO does not really have a significant winter peak as the system is a summer peaking one.

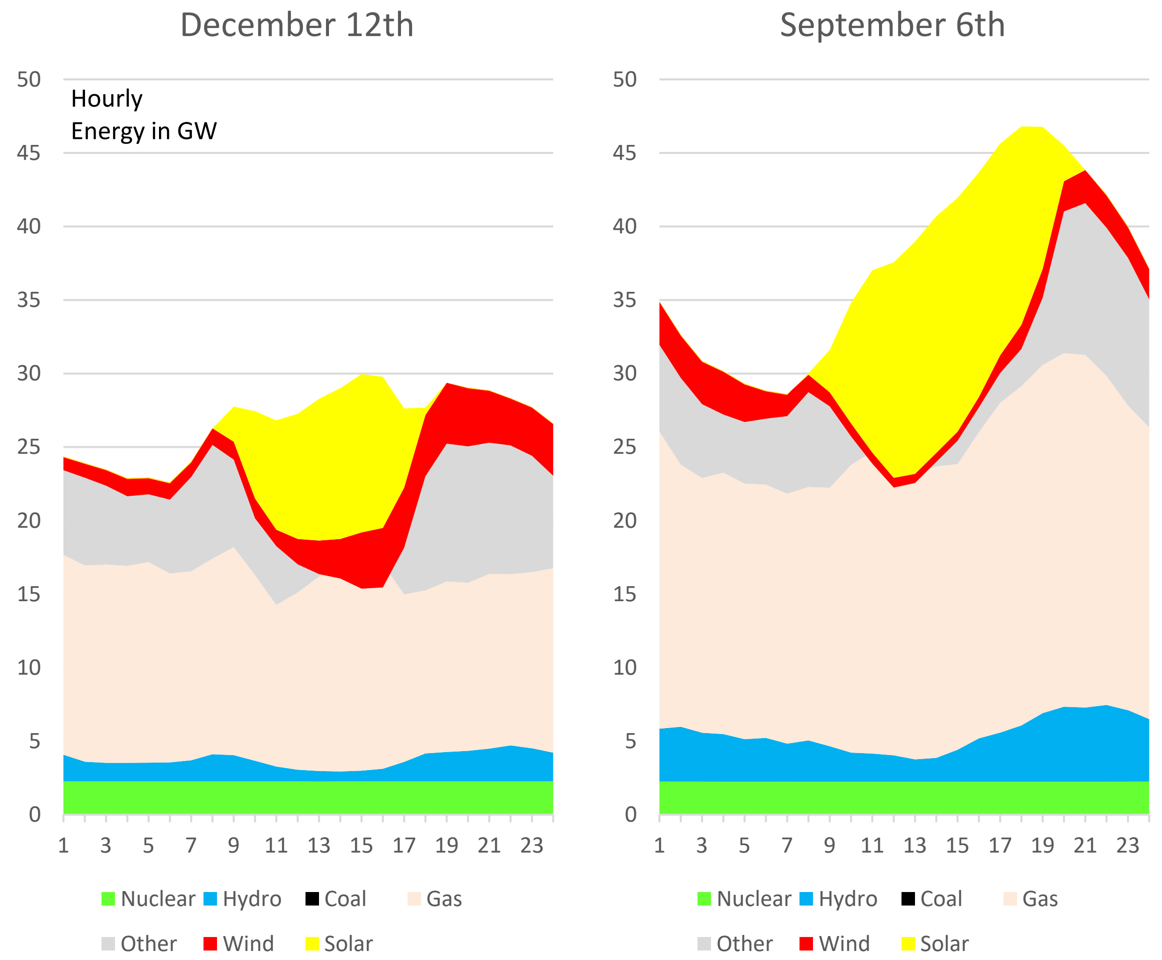


Figure 95. CAISO peak winter and summer demand days, 2024 (Data from [5])

The winter peak occurred at around 3 p.m. The summer peak occurred around 6 p m. During the winter peak hour, solar provided very little energy, wind provided about 19% of nameplate capacity, and nuclear provided 98% of nameplate capacity. On the summer peak, solar delivered 59% of nameplate capacity, wind delivered 26% of nameplate, and nuclear delivered 98% (see Figure 96). On a daily energy requirement basis, gas provided the largest share of the daily energy requirement (see Figure 97).

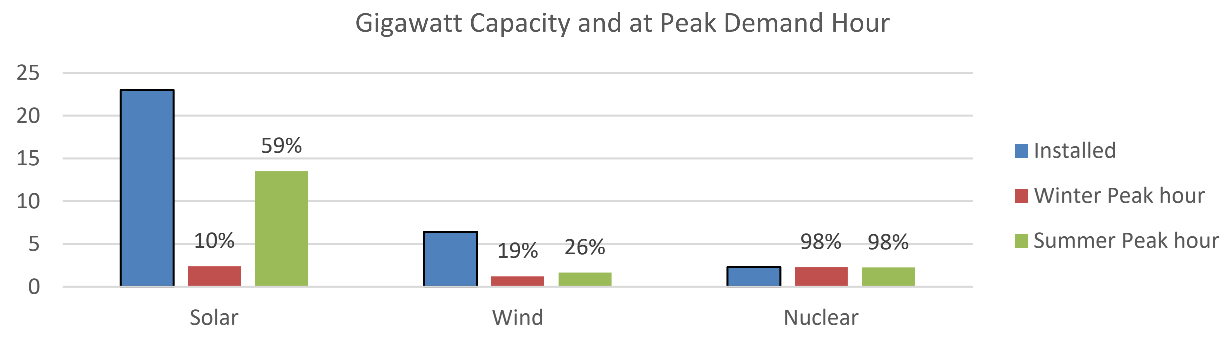


Figure 96. CAISO solar, wind, nuclear installed capacity and output on peak winter and summer hour, 2024 (Data from [5, 20])

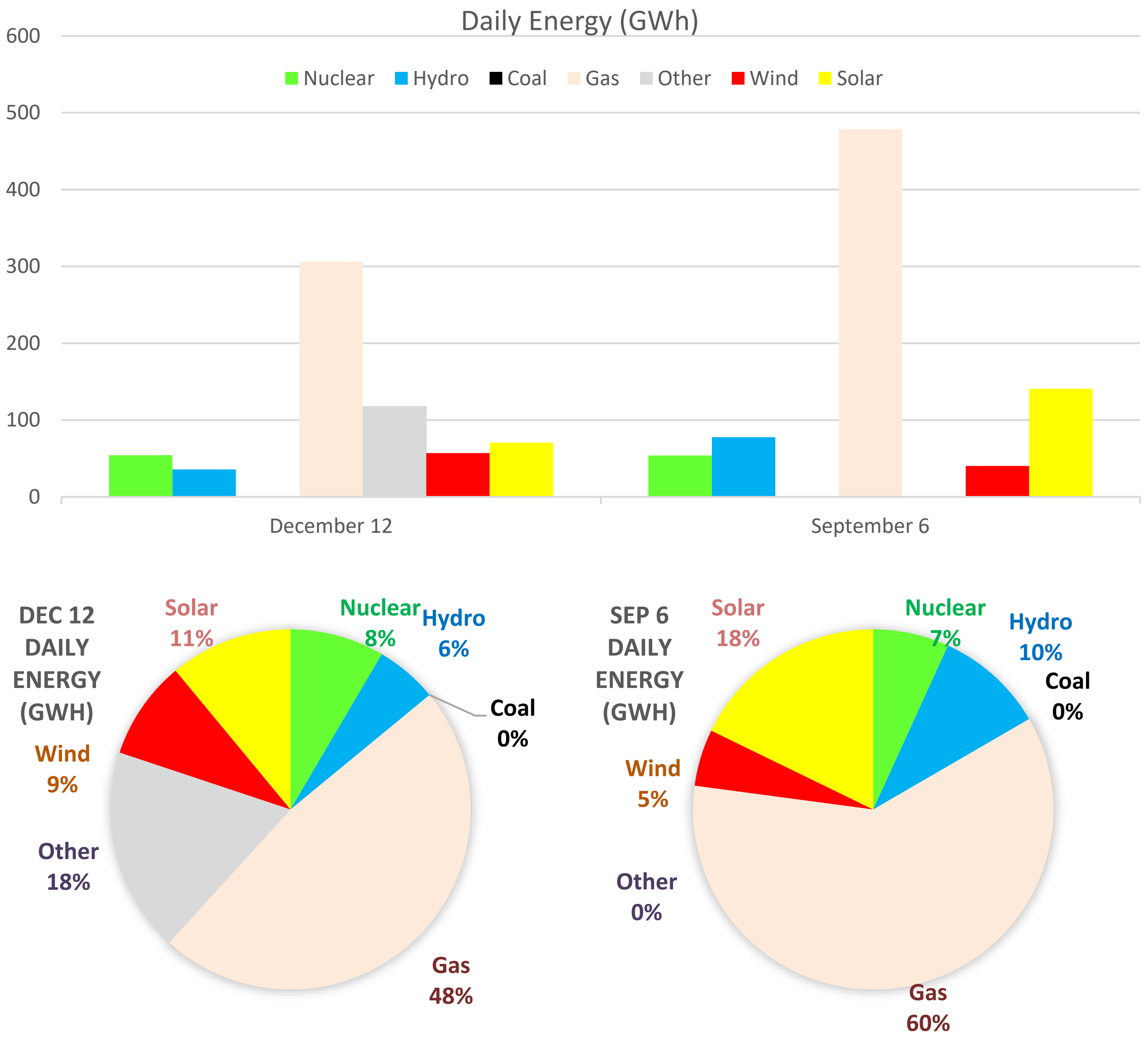


Figure 97. CAISO 2024 winter and summer total electrical energy by resource (Data from [5])

Table 11 provides a breakdown of the peak day in CAISO in 2024. On an energy basis, CAISO would have needed a combined ~150 GW of wind and solar to cover the peak summer day energy requirement, versus a daily peak of 47 GW. For nuclear, based on the 2024 performance, only about 38.4 GW would have been required. In both cases, storage would have been needed to cover the demand profile across each hour of the day.

Table 11. CAISO summer peak – resource output on peak hour (18:00) and for day – September 6, 2024

Resource	Installed Capacity (GW)	Peak Hour Output (GW)	Peak Day (GWh)	Peak Hour / Capacity	Peak Day / Capacity (GWh/GW)	Avg Day / Capacity (GWh/GW)
Gas	32	23	479	0.72	15.0	6.0
Nuclear	2.3	2.2	54	0.98	23.4	21.8
Hydro	8.8	3.8	78	0.43	8.8	5.9
Solar	23	13.5	141	0.59	6.1	3.6
Wind	6.4	1.6	40	0.26	6.3	4.2
Peak		**47**	**899**			

CAISO Trends

August 2020 Rolling Outage

In 2020, rolling outages occurred in California on August 14 and 15. There was a heat wave at the time, but the demand of 47 GW was significantly less than the peak demand in 2017 of greater than 50 GW [45]. The load shedding also did not occur at the peak demand hour but rather during the net demand peak as the sun was setting in the early evening. Figure 98 depicts the generation on August 14 and the load shed window. About 1 GW of load shedding occurred.

The need for load shedding was triggered not just by demand but also by a loss of supply, including the unexpected tripping offline of a 475 MW natural gas generator earlier that afternoon and the inability to secure sufficient imports because the extreme heat extended across the entire western United States.

On August 15, 2020, the following evening, another Stage 3 Emergency was declared at 6:25 p.m. (Stage 3 emergencies are declared in North America ahead of possible load shedding). That evening, CAISO ordered an initial load shed of 470 MW. This outage was briefer, however, as grid operators were able to secure emergency assistance and as wind generation quickly ramped up shortly after, allowing the load to be restored within about 20 minutes.

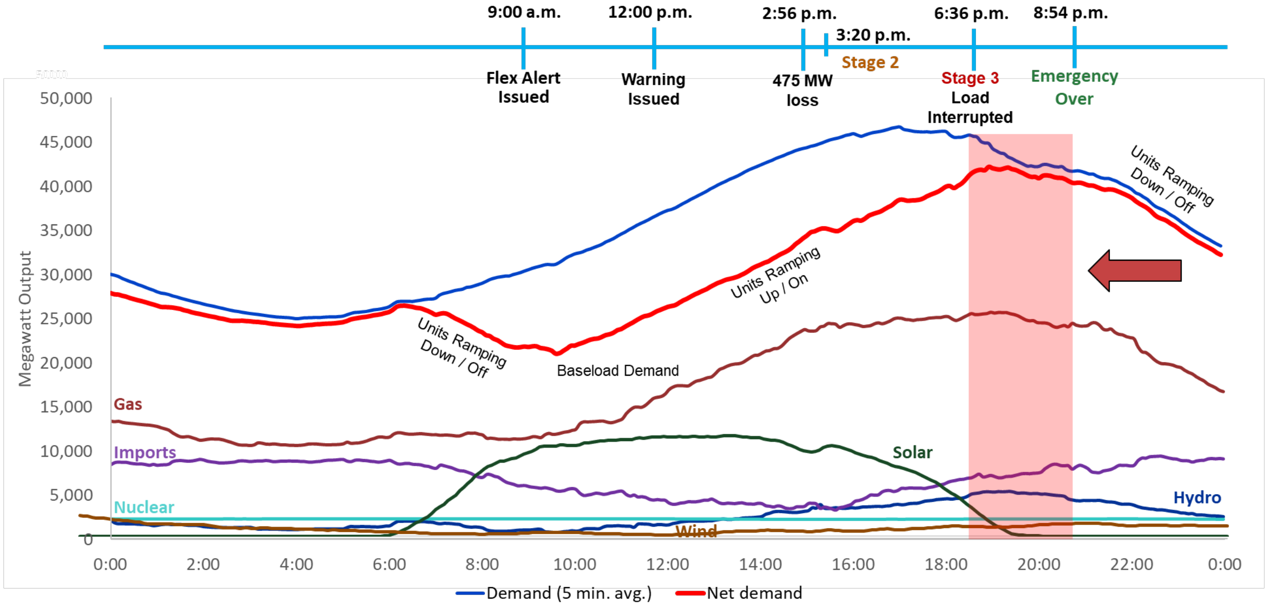


Figure 98. CAISO August 14, 2020, demand, energy supply, and rolling outage window (6:36–7:56 p.m.) (Data from [46])

Following these rolling outages, CAISO undertook changes to try and avert a reoccurrence. The next month, this included requesting an emergency order on September 6, 2020, from the Department of Energy (DOE) to allow the system to operate at maximum generation output levels "… notwithstanding air quality or other permit limitations" [47].

CAISO again requested and received a max generation emergency order from the DOE on September 10, 2021 [48].

To further secure supply, CAISO obtained 120 MW of temporary additional gas generators to meet the 2022 summer peak [49].

CAISO sought and received additional maximum generation emergency orders from the DOE on September 2 [50], September 7 [51], and an extension on September 8 [52]. Each of these represented the need to trade off energy sustainability for energy security to manage a high demand period.

Peak demand in CAISO in 2023 was down significantly, with the peak reaching 44.5 GW. In 2024, peak hourly demand occurred on September 5 and was 48.3 GW (the daily peak energy requirement occurred on September 6). The peak net demand period on September 5 was at 6:55 p.m. Gas provided 49% of the energy needed on this interval, followed by batteries at 13%. This is a significant change from 2020. While the gas output on the net peak hour was about the same, the battery output in 2024 was 6 GW greater; in the August 2020 rolling outages (load shedding), the battery output was less than 200 MW.

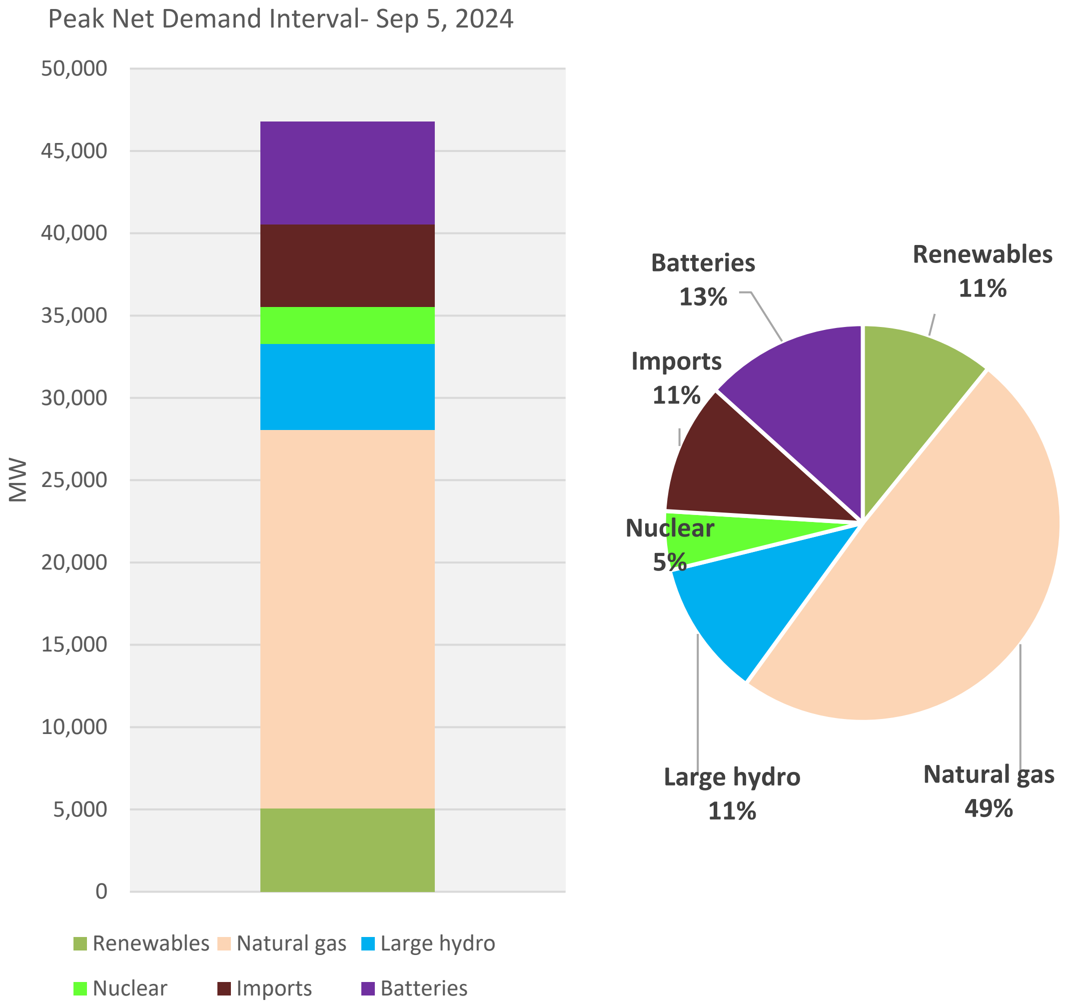


Figure 99. CAISO generation stack net peak interval on September 5, 2024 (6:55 p.m.) (Data from [46])

CAISO developed a root cause report for the August 2020 rolling outages which can be reviewed for further insights on this event [53].

Demand Review

Annual Trends

Figure 100 provides the generation sources for the total electric system in California from 2009 to 2024, including attribution of imports by generation sources (in the later years). Total electric use on an annual basis has been on the decline in California. Gas provides the largest share, with solar and wind increasing in share in recent years.

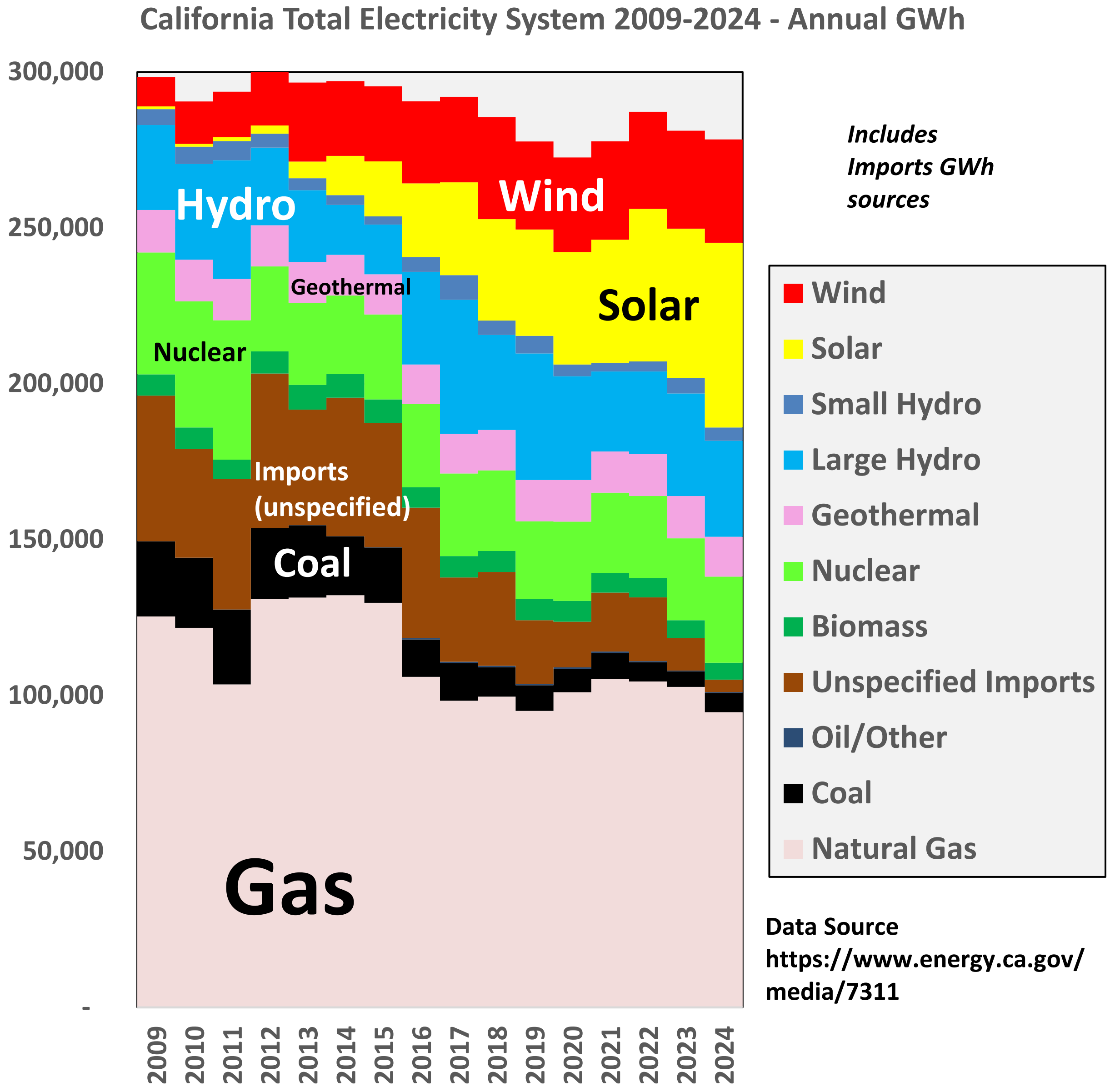


Figure 100. California total electricity system annual energy (includes attribution of imports) (Data from [54])

Daily Peaks

Figure 101 looks at the daily peak energy requirements in CAISO. These always occur in summer (typically late summer). September 7, 2022, was the peak day in the last 10 years. The peaks in 2023, 2024, and 2025 were all significantly less than the 2022 peak. They were all less than the September 1, 2017, peak as well.

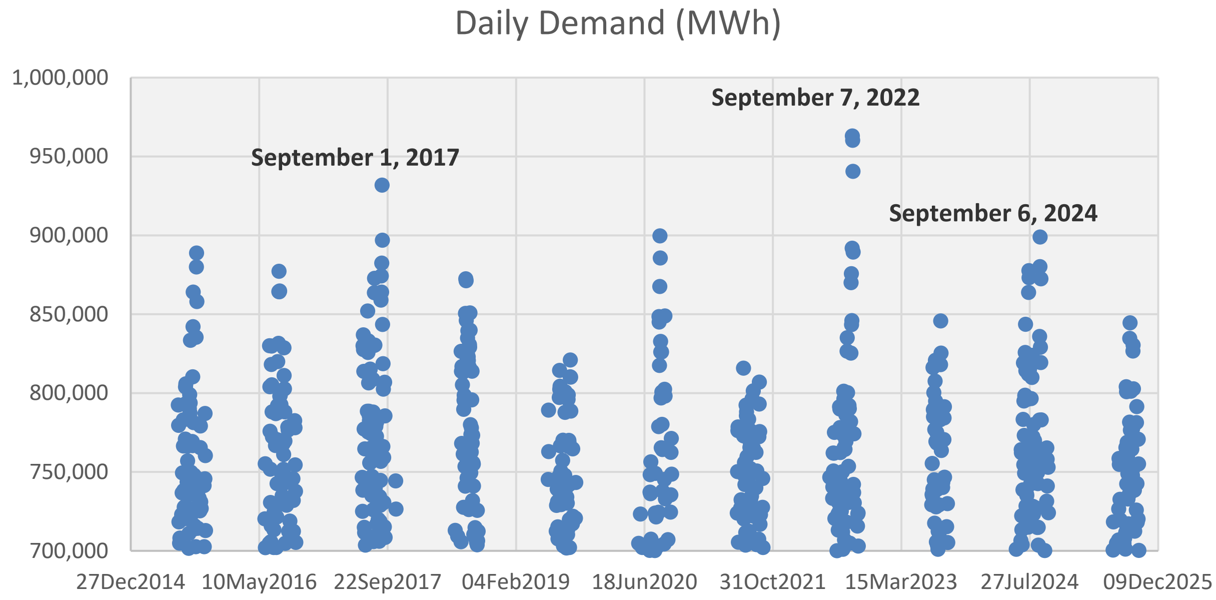


Figure 101. CAISO daily demand peaks, 2015–November 2025 (Data from [5])

Hourly Peaks

Summer hourly peaks peaked in September 2022. The hourly peak in 2025 was 7 GW below the 2022 peak in CAISO.

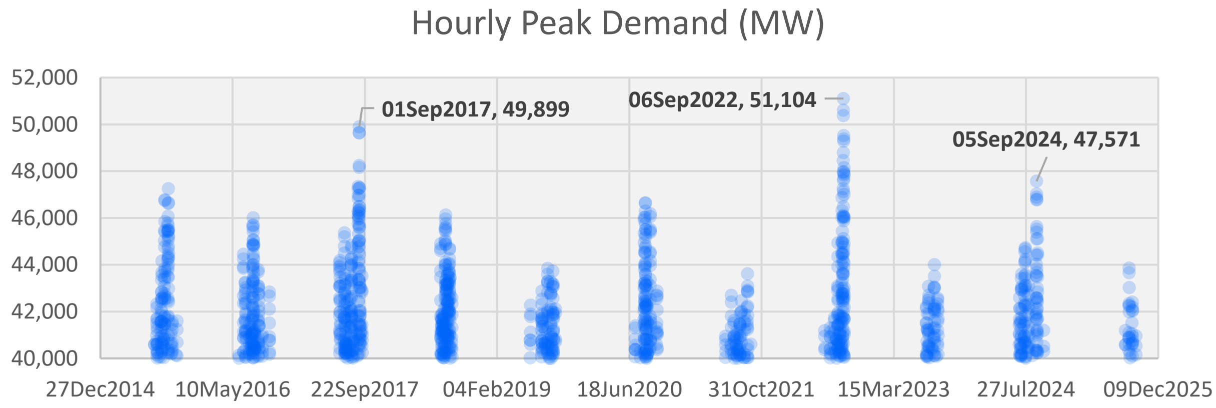


Figure 102. CAISO hourly demand peaks, 2015–November 2025 (Data from [5])

Curtailment

Renewable curtailment in CAISO has been increasing year over year but is primarily a springtime occurrence, with most curtailment being solar curtailment, thus daylight-hour curtailment.

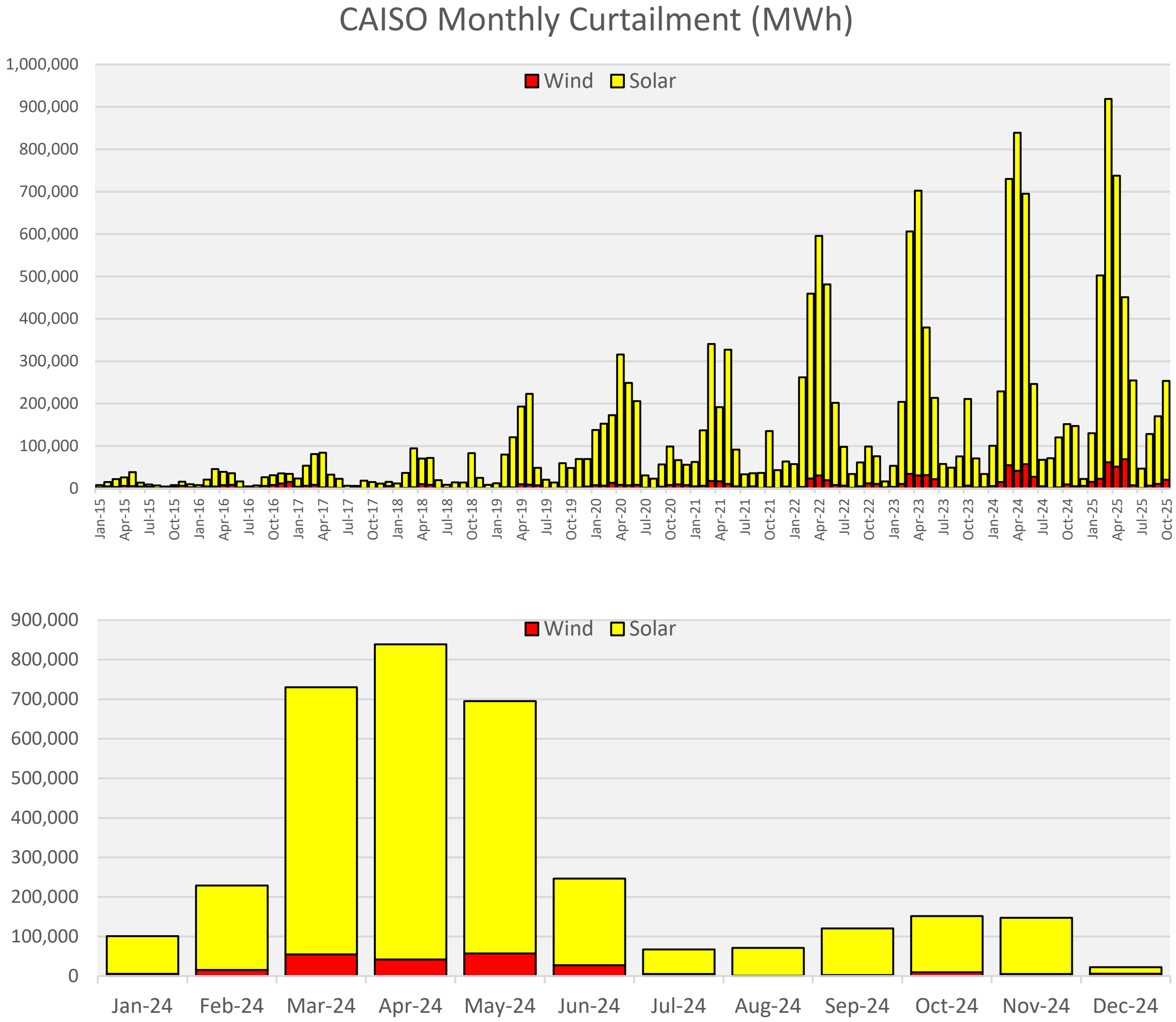


Figure 103. CAISO solar and wind curtailment (upper=2015 to October 2025, lower=2024) (Data from [55])

Despite significant battery additions (see Figure 104) the amount of curtailment in spring continues to rise (see Figure 103).

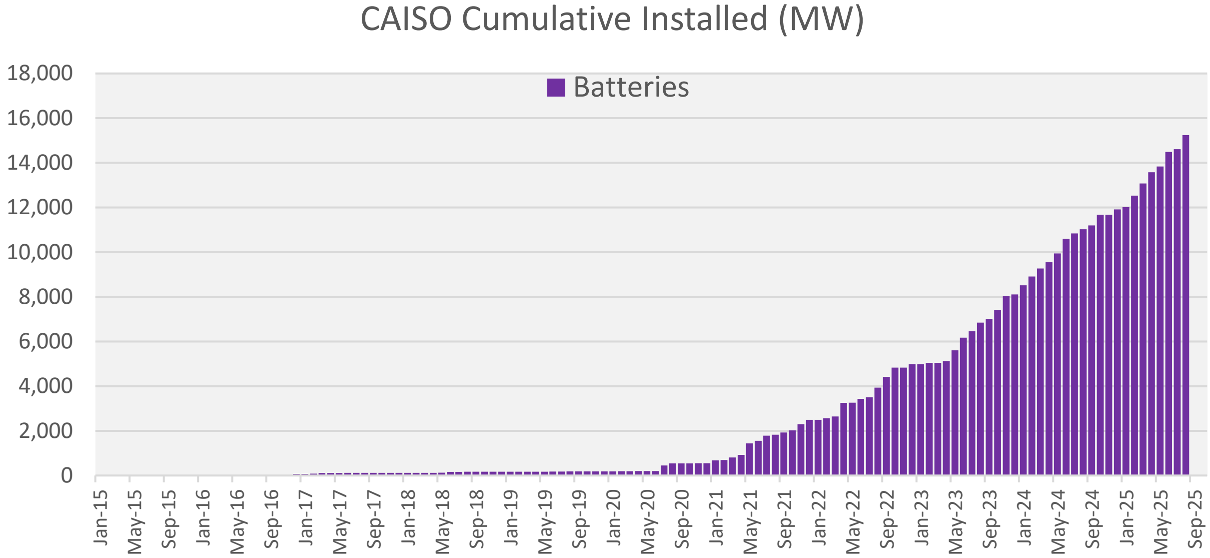


Figure 104. CAISO installed capacity of batteries (MW) (Data from [20])

Value of Solar

The high curtailment of solar during spring hours corresponds to lower hourly zonal day-ahead (DA) prices. Figure 105 takes the zonal hourly prices and hourly zonal solar generation for each year and graphs them by month as an estimate of the monthly fleet market revenue. The total calculated revenue is given for each year, as is the total installed capacity.

Electricity prices in California were high with elevated gas prices, and gas often set the clearing price in 2022. This year had the best revenues for solar, 2024 was the lowest, and for the months of March, April, and May, the revenues based on day-ahead prices would all be negative.

For 2025, daytime day-ahead prices are negative during the day as well (see Figure 106).

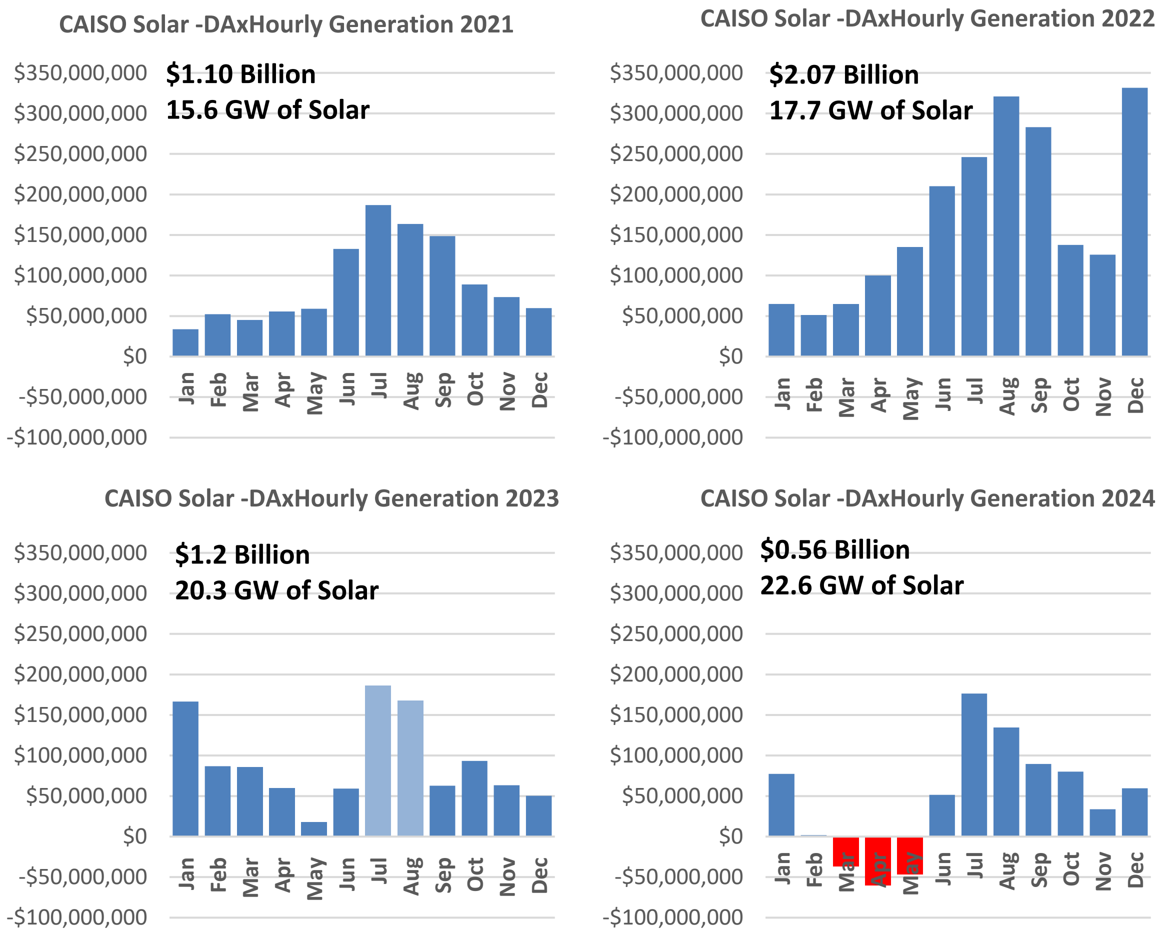


Figure 105. CAISO solar generation times day-ahead generation, 2021–2024 (Data from 5, 56])

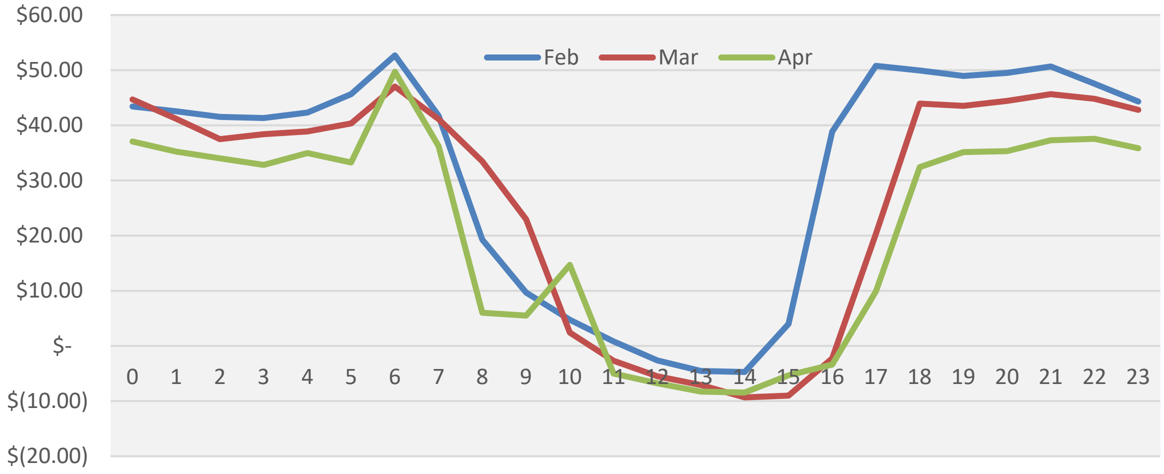


Figure 106. CAISO 2025 February, March, April, day-ahead prices ($/MWh) (Data from [56])

CAISO Peak Reduction

Figure 107 analyzes the peak reduction over the period from 2019 to 2024 from solar, wind, and battery installations. The yellow column (left axis) is the installed nameplate capacity in GW of wind, solar, and battery capacity. The orange column (left axis) is the annual energy from wind and solar in TWh. The grey column (left axis) is the annual energy from non-solar and non-wind resources in TWh.

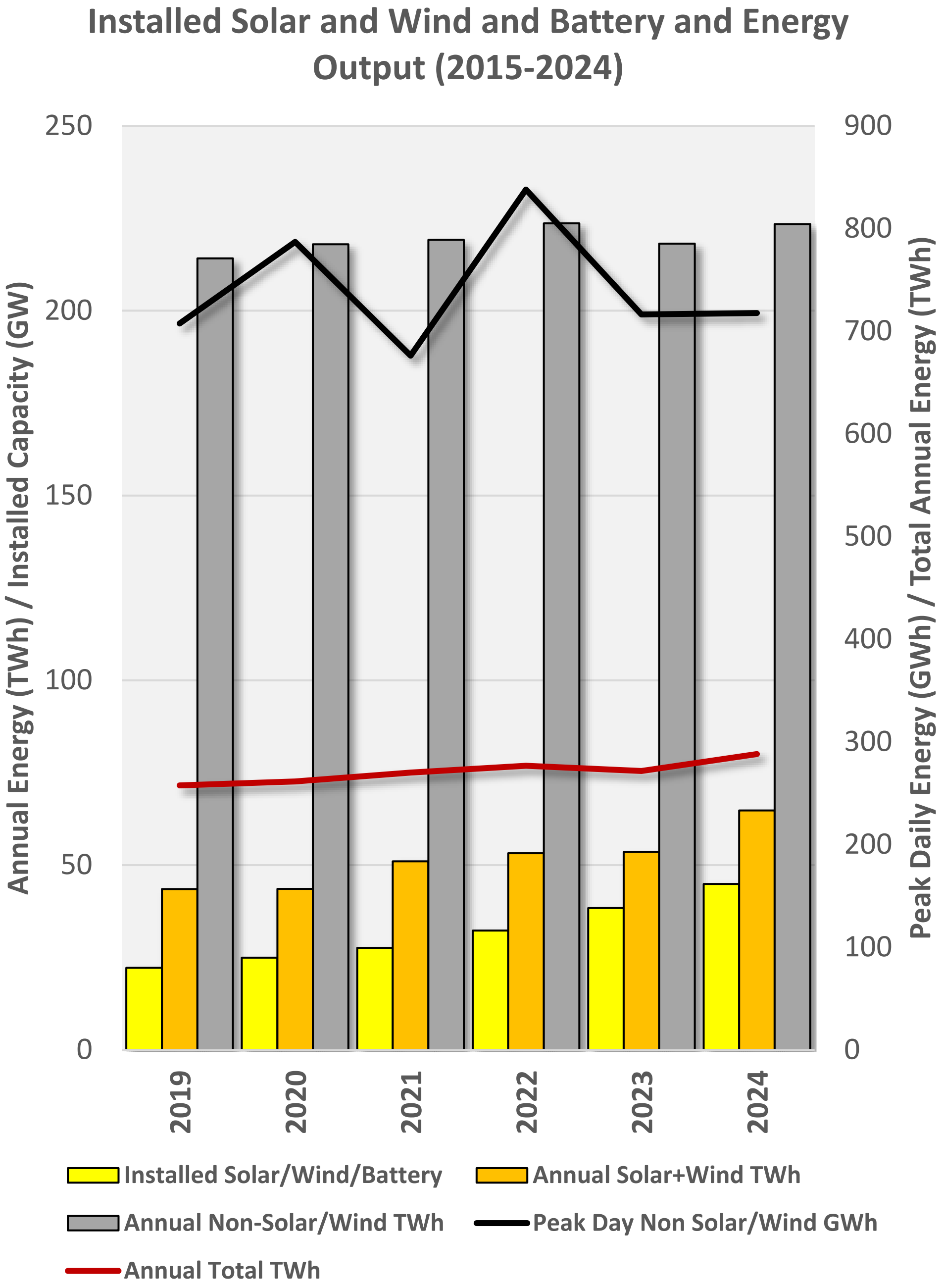


Figure 107. CAISO wind, solar, and battery additions – annual energy and daily peak non-solar/wind energy, 2019 to 2024 (Data from [5, 20])

The lines are daily peak energy from non-solar and non-wind resources (black line) in GWh and total annual energy (red line) in TWh, both on the right axis.

There have been additions of solar in this period, which has resulted in an appreciable increase in energy on an annual basis from wind and solar; energy from non-wind and non-solar has remained relatively steady, as has total annual energy. The peak daily energy requirement from non-wind and non-solar resources has been steady (with a few swings) despite the additions of solar, wind, and battery capacity.

Figure 106 looks at the addition of solar, wind, and battery capacity compared to the net effect on the annual non-solar and non-wind energy requirement and peak daily requirement versus 2019 as a baseline year.

Daily peak energy requirement is unchanged, and annual energy is down only 7% after the addition of more than 20 GW of solar, wind, and battery capacity.

Key Observation Point

As was the case for Spain, wind, solar, and battery additions in California (CAISO) are not replacing the physical power plants needed for the hardest days (peak day) and are having less of an annual energy reduction impact.

From 2019 to 2024, CAISO increased the nameplate capacity of wind, solar, and battery by 23 GW, yet still needed 100% of the original (2019) backup fleet energy to be ready and able to cover its net peak days (highest demand days, with lowest solar and wind output).

This suggests California, like Spain, faces a diminishing marginal return, where the addition of solar and wind, even with a sizable capacity of batteries added, is not replacing the need for near 100% backup power to cover peak days' daily energy needs.

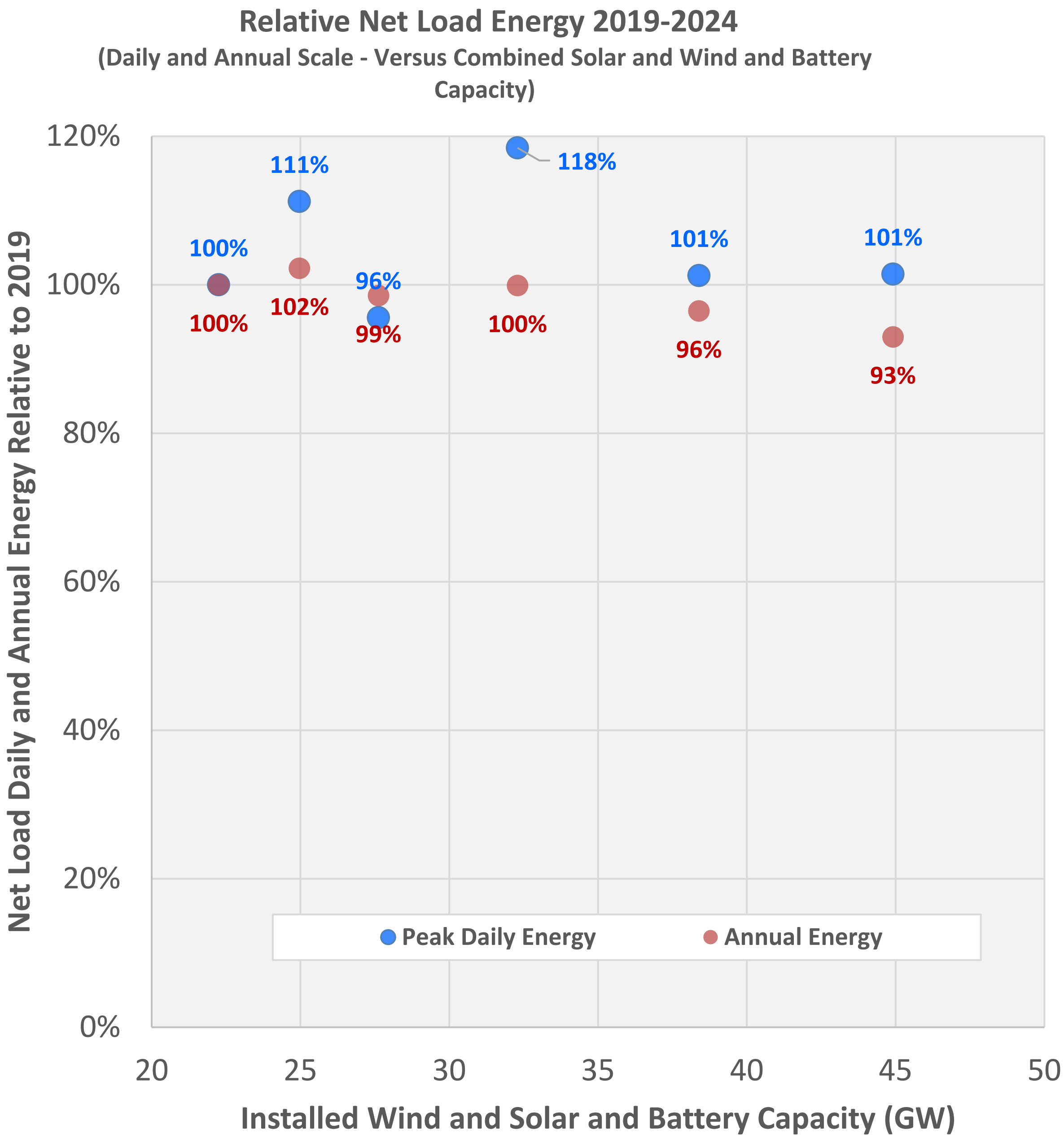


Figure 108. CAISO relative net load energy, 2019–2024 (daily and annual scale versus combined solar, wind, and battery capacity) (Data from [5])

Value of Generation

Figure 109 looks at the energy supply and average wholesale price in CAISO in 2025 on the peak summer day and a typical spring day.

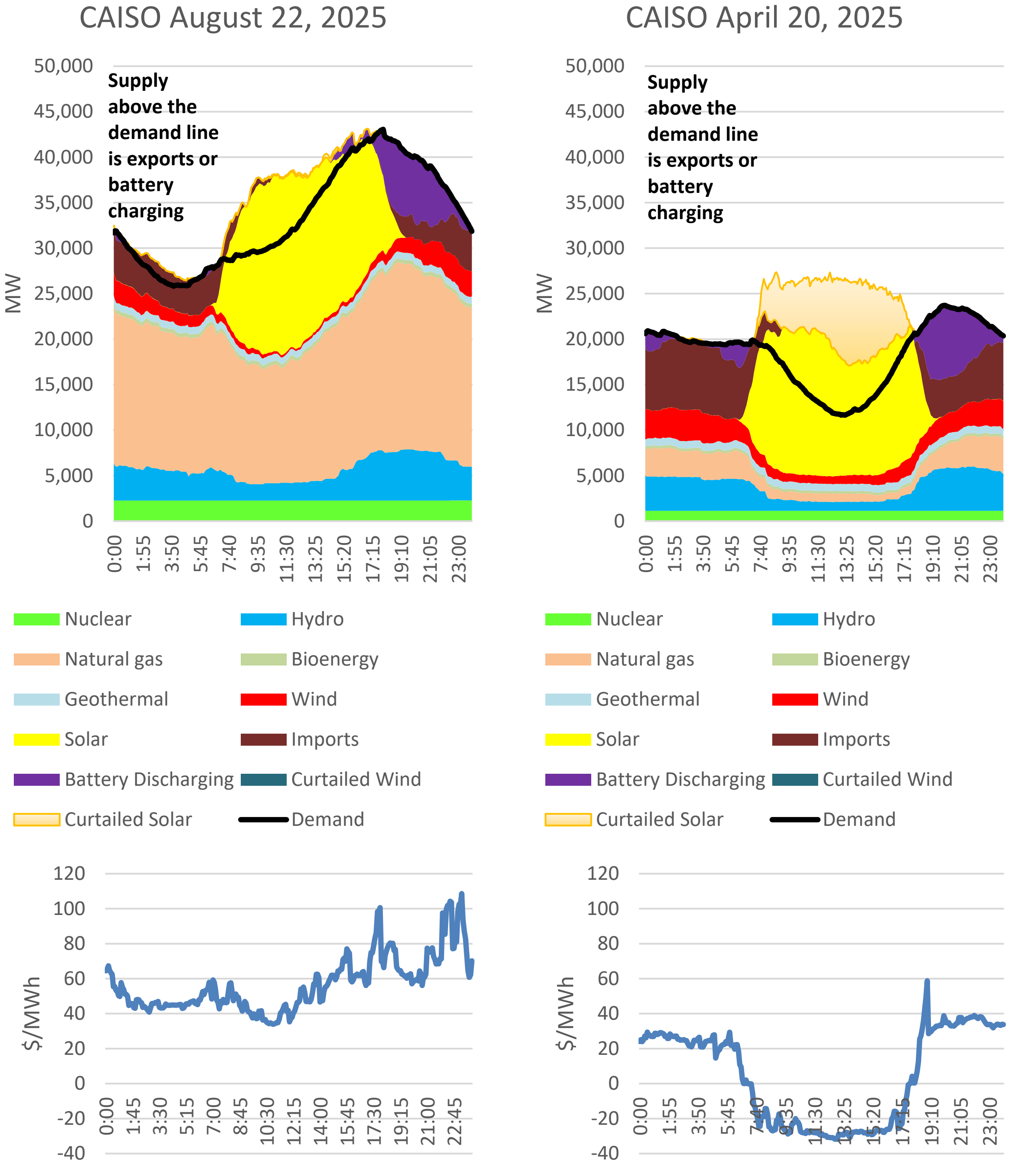


Figure 109. CAISO 2025 peak summer day (August 22) and typical spring day (April 20) (Data from [46, 56])

There is nearly the same installed capacity on the two days. On the April 20 spring day, there is significant daytime curtailment and negative prices. On the August 22 summer day, there is little curtailment and higher prices throughout the day. Table 12 does a calculation of the value of each resource on the two days by multiplying the price by its corresponding MW output. The installed capacity in CAISO as of the end of October is also included.

Table 12. CAISO value of resources – August 22, and April 20, 2025

	22-Aug	20-Apr	Installed MW
Battery Value	$819,896	$2,196,990	15,241.0
Solar Value	$9,184,783	$ (3,513,820)	24,184.7
Nuclear Value	$3,086,643	$119,012	2,323.0
Hydro Value	$5,089,723	$1,197,224	8,805.6
Gas Value	$22,873,619	$833,110	32,122.8
Wind Value	$1,912,493	$719,909	6,394.7

Figure 110 normalizes the value on the two days by the installed capacity. For every asset except batteries, more value is realized on the summer day.

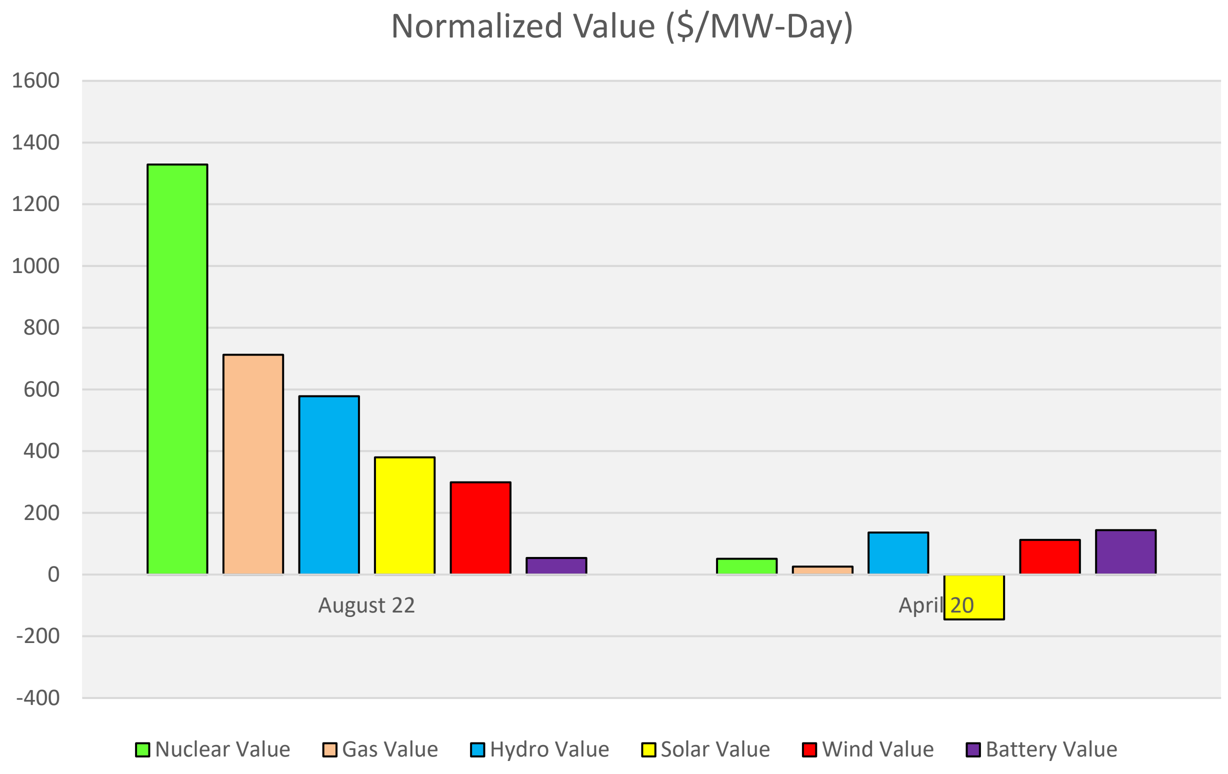


Figure 110. CAISO normalized value by resource ($/MW-Day) for August 22, 2025 and April 20, 2025 (Capacity data from [20])

Solar has a negative value in the spring. This is a serious economic challenge to future additions of solar generation. Planned additions of solar for CAISO are nearly always collocated with batteries of similar size (see Figure 111). Collocating solar and batteries allows solar to avoid the negative prices and dispatch when prices are higher. This improves operational value but increases capital costs. Resource adequacy payments cover this additional cost; solar in California in 2025 has no value for resource adequacy unless paired with four hours of storage.

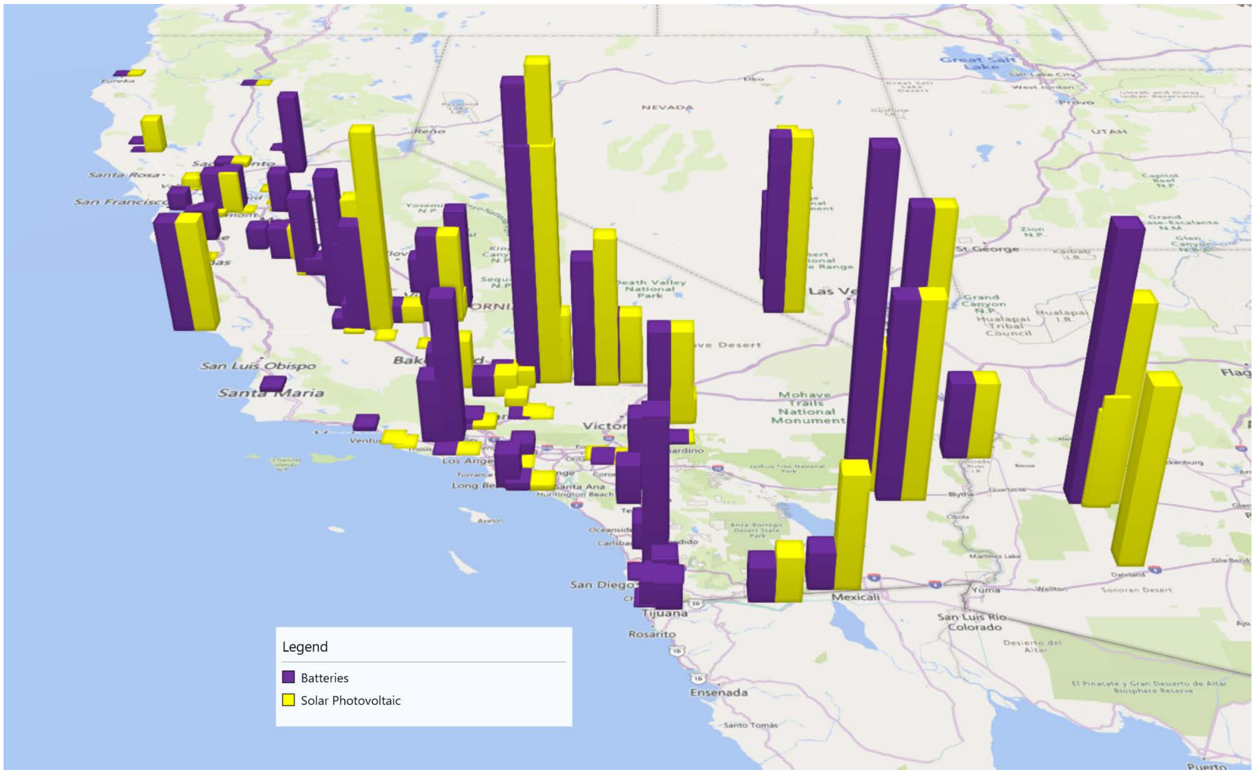
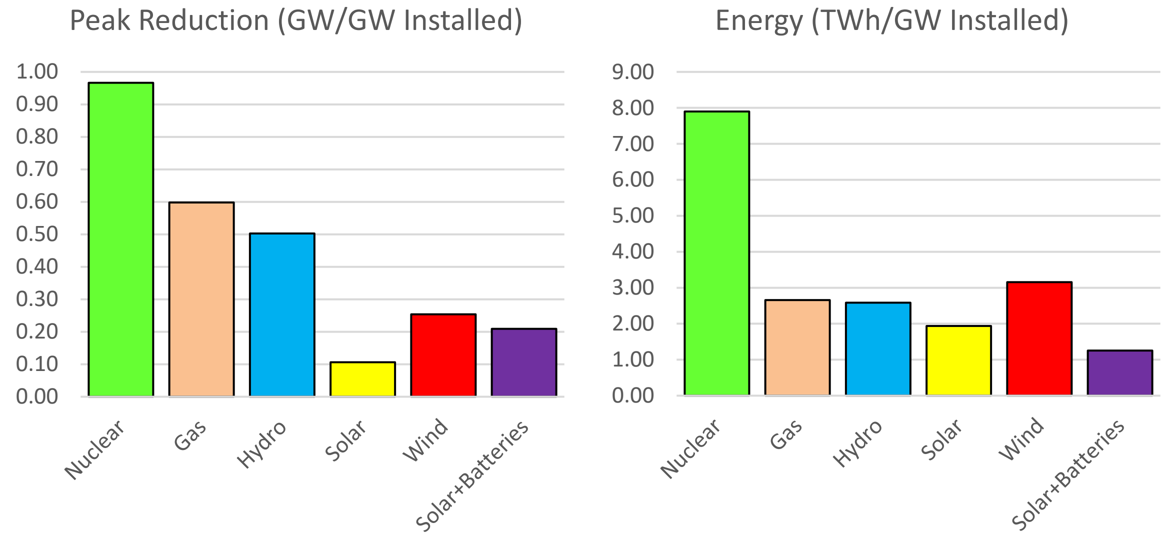


Figure 111. CAISO planned additions of solar and batteries (Data from [20])

Figure 112 looks at the peak reduction for the entire year (evaluating every hour) and energy produced in the year 2024 by each resource. The top of the figure normalizes the value for each resource by dividing by the nameplate capacity. The table below gives the raw and calculated figures for 2024. Nuclear installed capacity provides the greatest reduction in peak demand per installed capacity (GW) and the most energy per installed capacity (GW). Nuclear reduced the need for other generation to meet peak throughout the year at 0.97 GW/GW installed. Solar had the lowest peak reduction of 0.11 GW/GW installed; when combined with batteries, this improved to 0.21 GW/GW installed. For energy, nuclear delivered 7.9 TWh/GW installed. Solar was significantly lower at 1.94 TWh/GW installed, but when paired with batteries, dropped to 1.25 TWh/combined GW installed.



	Installed (GW)	Peak Reduction (GW)	Annual Energy (TWh)	Peak Reduction (GW/GW Installed)	Energy (TWh/GW Installed)
Nuclear	2.323	2.245	18.4	0.97	7.90
Gas	32.121	19.208	85.4	0.60	2.66
Hydro	8.806	4.426	22.8	0.50	2.58
Solar	23.094	2.453	44.7	0.11	1.94
Wind	6.352	1.612	20.0	0.25	3.16
Solar+Batteries	34.769	7.269	43.6	0.21	1.25

Figure 112. CAISO 2024 peak reduction by generation resource and annual energy (Data from [5, 20])

CAISO/California Summary

CAISO electricity costs have increased dramatically since 2015 and are 1.9 times the U.S. average cost in 2024. Carbon emission intensity has decreased but remains at 0.5 of the U.S. average in 2024, as the rest of the country has also decreased. CAISO experienced significant load shedding in August of 2020 and needed to add temporary generators in 2021/22 to rely on emergency max generation orders in September 2020, 2021, and 2022. Since this period, though, CAISO has not experienced additional significant energy security issues.

Key Findings

- California delivered 33% of its annual electricity production from solar and wind resources, 34% from gas, 10% from nuclear, and 13% from hydro power in 2024.
- California's overall annual electricity use has declined by 6% since 2015, with CAISO production dropping 5%. In-state electricity production has increased across California by 10%, with imports declining to lead to the overall system reduction.

- CAISO’s nuclear, gas, and solar fleets performed well on CAISO’s peak hour, as CAISO only has a summer peak. For overall daily energy requirements, gas and nuclear performed best on the peak day on a per-GW installed capacity basis. Gas provided the majority of the daily energy due to the large fleet.
- CAISO is a summer hourly peaking system, and since 2022, the daily and hourly annual peaks have been lowering with a slight downward trend.
- CAISO curtails a significant amount of renewable energy in the springtime, mostly solar. In recent years, this has resulted in mid-day prices being negative on the average day in February, March, and April. This has significantly reduced the annual value of the solar fleet. Planned solar generation in CAISO is increasingly paired with batteries collocated due to this limitation on the value of solar generation alone.
- CAISO’s peak daily energy requirement from non-wind/solar/battery generation has been steady since 2019, and the annual energy from these sources is down 7% in that time. Over this period, CAISO has added ~22 GW of solar and batteries.
- California’s retail electricity rate has been increasing at a rapid rate, nearly doubling between 2015 and 2024 on a nominal basis.
- CAISO faces its greatest reliability concerns during hot, late-summer periods when the sun sets earlier in the day. The addition of over 10 GW of batteries over the last several years (mostly each of 4-hour duration) has reduced this risk, and CAISO has not needed to request an emergency max generation order since 2022.

Figure 113 provides a waterfall graph of energy (TWh) changes (top chart), a waterfall of capacity (GW) changes (bottom chart), and a breakdown of total energy (TWh) and capacity (GW) by resource for 2015 and 2024 (middle charts).

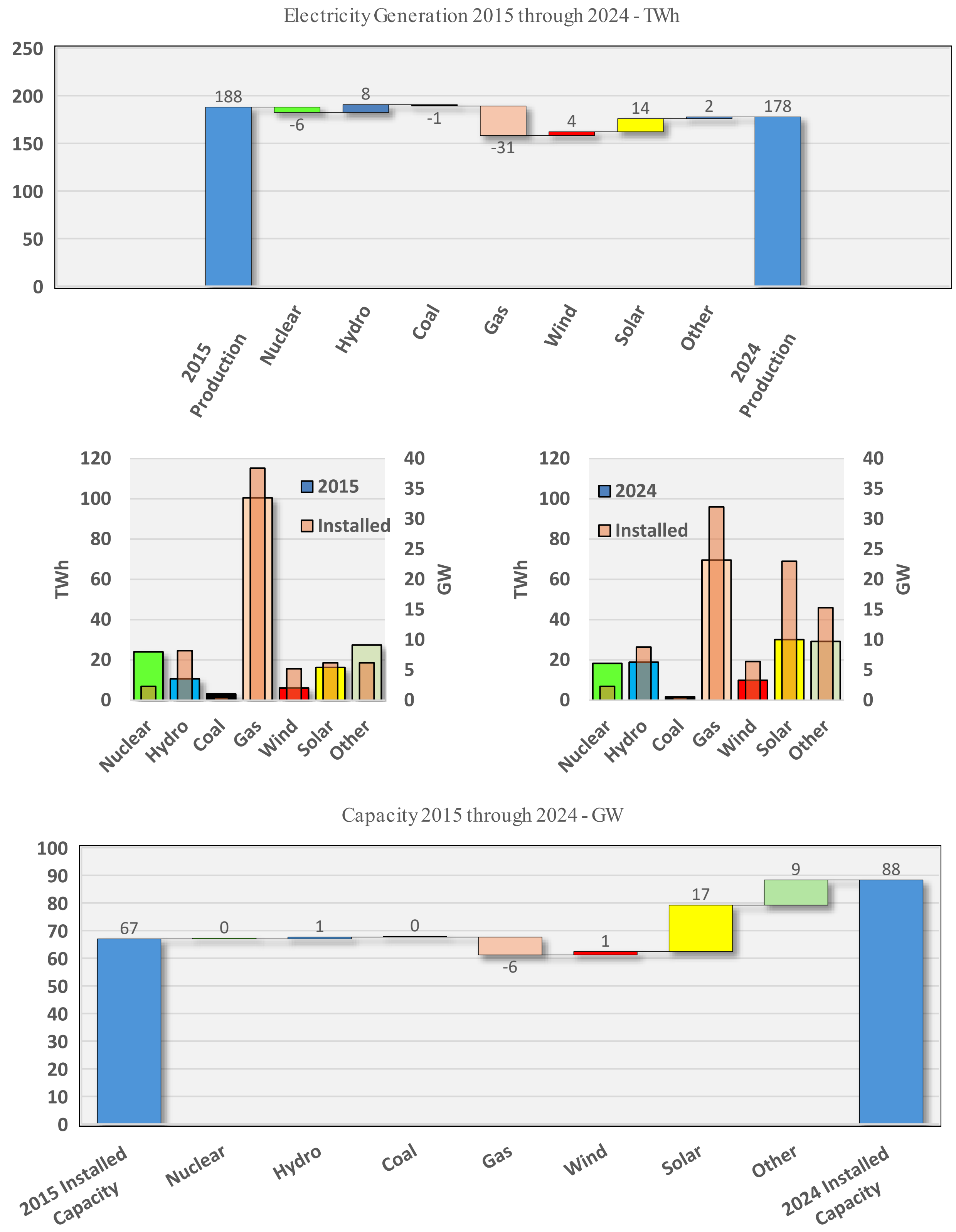
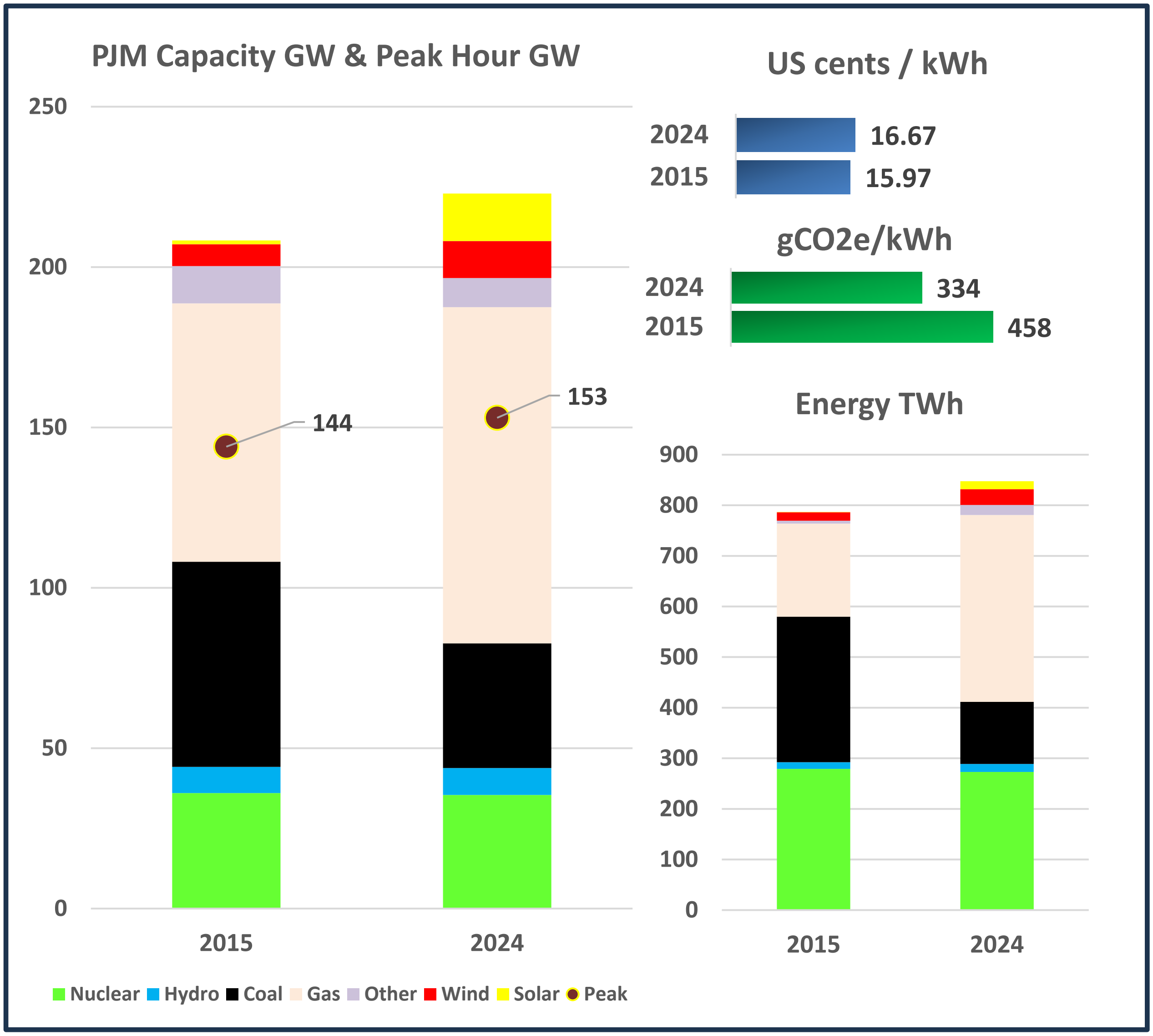


Figure 113. CAISO capacity and generation summary, 2015 and 2024 (Data from [5, 20])

PJM Electricity Supply

Overview 2015–2024—PJM

Pennsylvania-New Jersey-Maryland Interconnection's (PJM) capacity, peak, energy, residential rates (blend of PA, NJ, IL, MD, VA, WV, OH), and PJM-specific carbon intensity of the electricity supply are summarized in Figure 114.



	Capacity	Energy	Price	CO2
2024/2015	107%	108%	104%	73%
		2015 / US 2015	1.3	0.9
		2024 / US 2024	1.0	0.9

Figure 114. PJM 2015 and 2024 capacity and peak (GW), household rates (cents/kWh), carbon intensity (gCO2e/kWh), and energy (TWh) (Capacity from [20], energy from [5], price from [21], and carbon from [5, 57])

PJM's electricity nameplate capacity in 2024 increased by 7% from 2015. The residential retail rate for electricity on a per-kWh basis rose by 4%, with prices now on a par with the U.S. average, having been 1.3 times the U.S. average in 2015. The carbon intensity of the supplied electricity has dropped 27% but remains at 0.9 of the U.S. average (ahead of the average but unchanged from 2015). Total electricity consumption increased by 8%.

Figure 115 provides the 2024 winter and summer peak demand days; PJM has both a summer and winter peak.

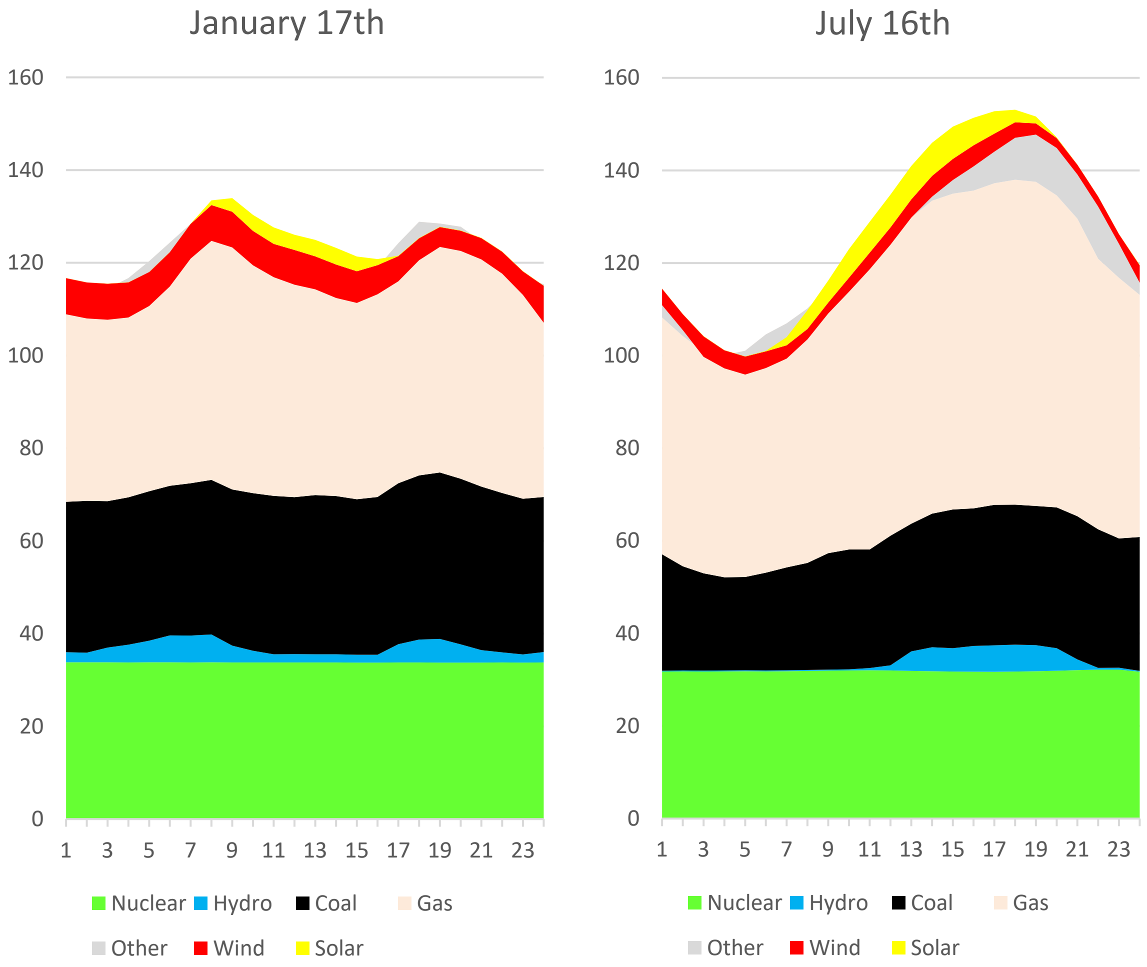


Figure 115. PJM peak winter and summer demand days, 2024 (Data from [5])

The winter peak occurred at around 9 a.m. The summer peak occurred around 6 p.m. Solar output on the winter hour peak was 20% of nameplate and 18% in summer. For wind, the output was 67% of nameplate in winter and 29% in summer. For nuclear, it was greater than 90% for both hour peaks (see Figure 116). Daily energy was filled mostly by nuclear, coal, and gas on each of the peak days (see Figure 117).

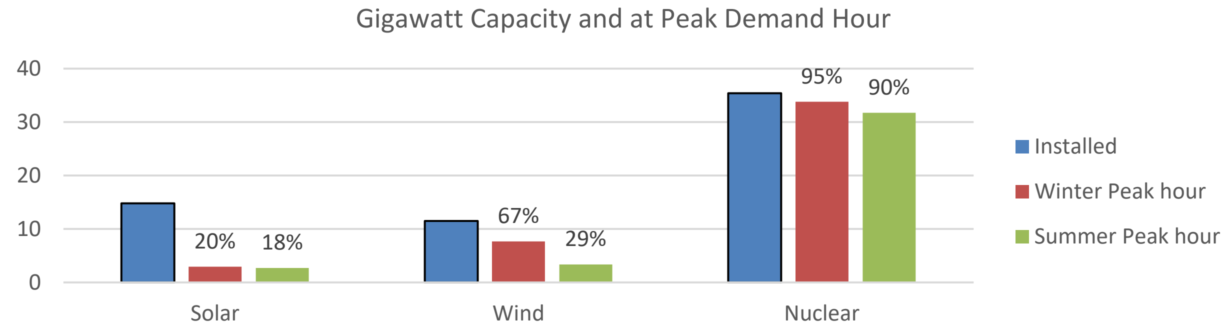


Figure 116. PJM solar, wind, nuclear installed capacity and output on peak winter and summer hour, 2024 (Data from [5, 20])

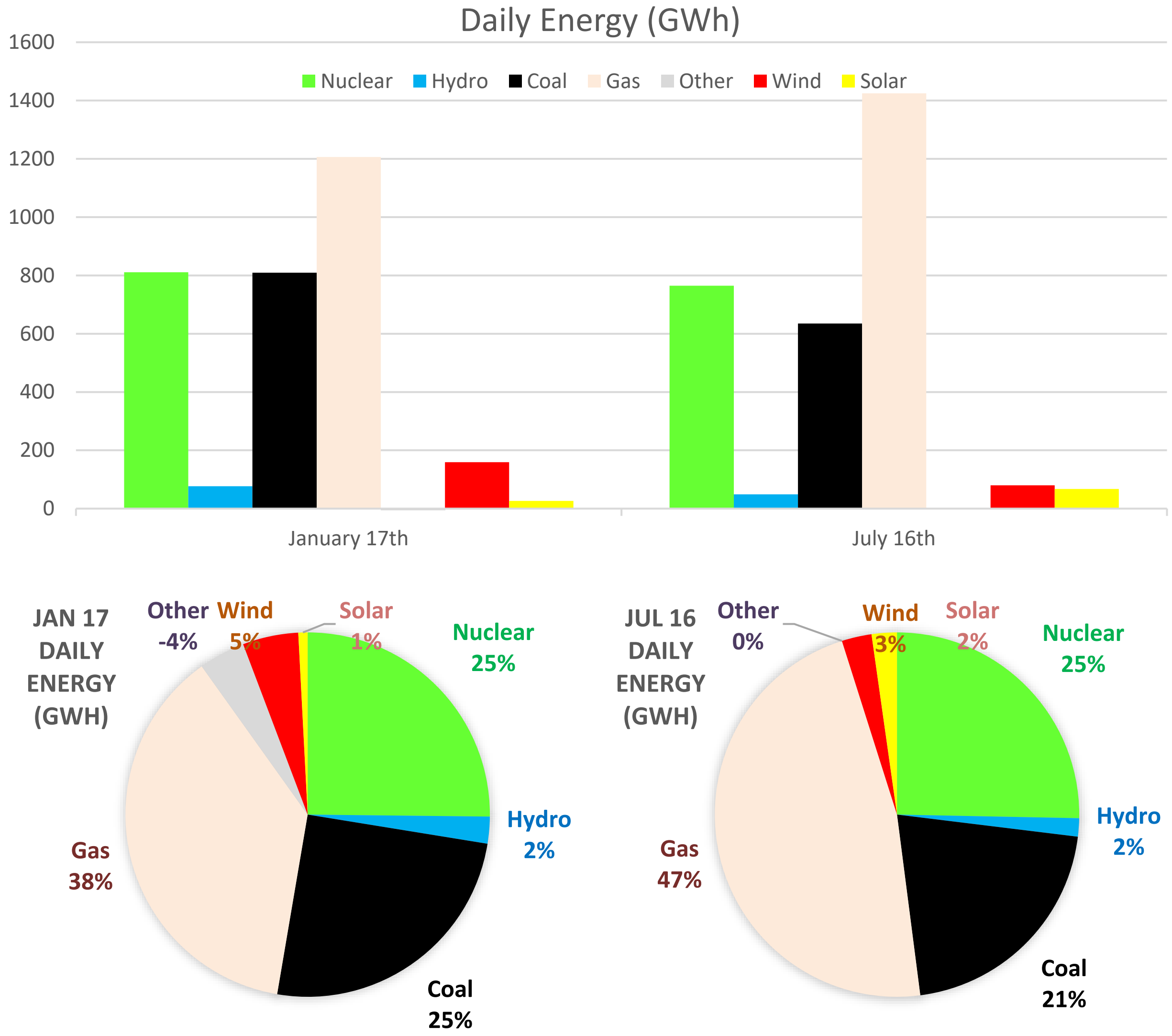


Figure 117. PJM 2024 winter and summer total electrical energy by resource (Data from [5])

Table 13 provides a breakdown of each of the main resources for PJM on the peak winter and summer days. Wind performed well for PJM on the winter peak, but much less so on the summer peak. For daily energy, solar performed much better in summer than winter, but for both the peak summer and peak winter hour, the GW output/GW installed was the lowest of the resources. Nuclear provided the greatest on-peak hour output and peak day energy per unit of installed capacity, with coal doing the next best for both days.

Table 13. PJM winter and summer peak days' resource outputs on peak hour

Winter peak – resource output on peak hour (09:00) and for day – January 17, 2024

Resource	Installed Capacity (GW)	Peak Hour Output (GW)	Peak Day (GWh)	Peak Hour / Capacity	Peak Day / Capacity (GWh/GW)	Avg Day / Capacity (GWh/GW)
Gas	104.8	55.4	1,206	0.53	11.5	9.7
Coal	38.9	33.7	809	0.87	20.8	8.6
Nuclear	35.4	33.8	811	0.95	22.9	21.1
Solar	14.8	2.9	159	0.20	1.8	2.9
Wind	11.5	8.4	197	0.67	13.8	7.4
Peak		**133.9**	**2,957**			

Summer peak – resource output on peak hour (18:00) and for day – July 16, 2024

Resource	Installed Capacity (GW)	Peak Hour Output (GW)	Peak Day (GWh)	Peak Hour / Capacity	Peak Day / Capacity (GWh/GW)	Avg Day / Capacity (GWh/GW)
Gas	104.8	70.2	1,425	0.67	13.3	9.7
Coal	38.9	30.3	635	0.78	14.8	8.6
Nuclear	35.4	31.7	765	0.90	23.0	21.1
Solar	14.8	2.7	68	0.18	9.1	2.9
Wind	11.5	3.4	80	0.29	6.3	7.4
Peak		**153.1**	**3,061**			

PJM Trends

Winter Storms

Winter Storm Elliott (2022) [27] and a polar vortex in 2014 [24] both impacted PJM, resulting in record peaks for the time. Winter Storm Elliott did not result in any extreme actions by PJM (e.g., load shedding) but did push the system into emergency conditions. During the 2014 polar vortex, PJM did perform a voltage reduction as an emergency action to maintain load [24]. PJM produced its own Winter Storm Elliott report with more details on this energy security event [58]. In both cases, PJM experienced wide scale generator outages associated with freezing [59].

In 2024, PJM performed much better during Winter Storm Gerri [60] in addition to the overall North American power system performing much better in 2024 than previous winters, as captured in a January 2025 NERC-FERC report [28].

Capacity and Effective Load Carrying Capability

Capacity market costs in PJM have been escalating due to demand growth and an evolution of the rating of capacity. In 2024, PJM received approval to rate capacity using an effective load carrying capacity (ELCC). This is a calculation by resource class of the ability of the resource to cover the most difficult-to-serve electricity demand hours.

The increase in capacity costs in PJM has received significant attention, prompting the implementation of a price cap for the 2026/27 delivery year. Although many factors contributed to rising capacity costs, the increase from ~$2 billion per year to $14+ billion per year coincided with the implementation of the ELCC rules. The aggregate cleared capacity after the change was less than the amount that cleared prior to ELCC adoption. Before ELCC, different resources received different allocations for capacity, and those values were calculated rather than fixed. The same is true today. However, following ELCC adoption, the capacity value for all resources declined. Table 14 gives the capacity auction results over the last several years.

Table 14. PJM capacity auction results, 2023/2024 to 2026/2027 ([Data from [61–64])

Delivery Year (Starts June 1)	Auction Held	Clearing Price ($/MW-day)	Cleared Capacity (MW)	Total Cost to Load (Approximate)
2023/2024	June 2022	$34.13	144,871	$2.2 Billion
2024/2025	December 2022	$28.92	147,479	$2.2 Billion
2025/2026	July 2024	$269.92	135,684	$14.7 Billion
2026/2027	July 2025	329.17 (Cap)	134,311	$16.1 Billion

PJM's ELCC methodology for calculating the capacity value of resources was formally accepted by FERC in January 2024. The new ELCC method went into effect for the 2025/26 delivery year capacity market auction. It is an effort to capture the true value of different resources on the hardest-to-serve hours. This resulted in a reduction in the calculated available capacity for the auction across all asset types. More detailed descriptions on methodologies for calculation of ELCCs are available [65].

Figure 118 looks at the calculated ELCC of different types of asset types. Each is a calculation of the expected contribution of the resource capacity in the given year. The ELCC value of a nuclear GW is much higher than for a solar or wind asset based on the PJM ELCC calculations.

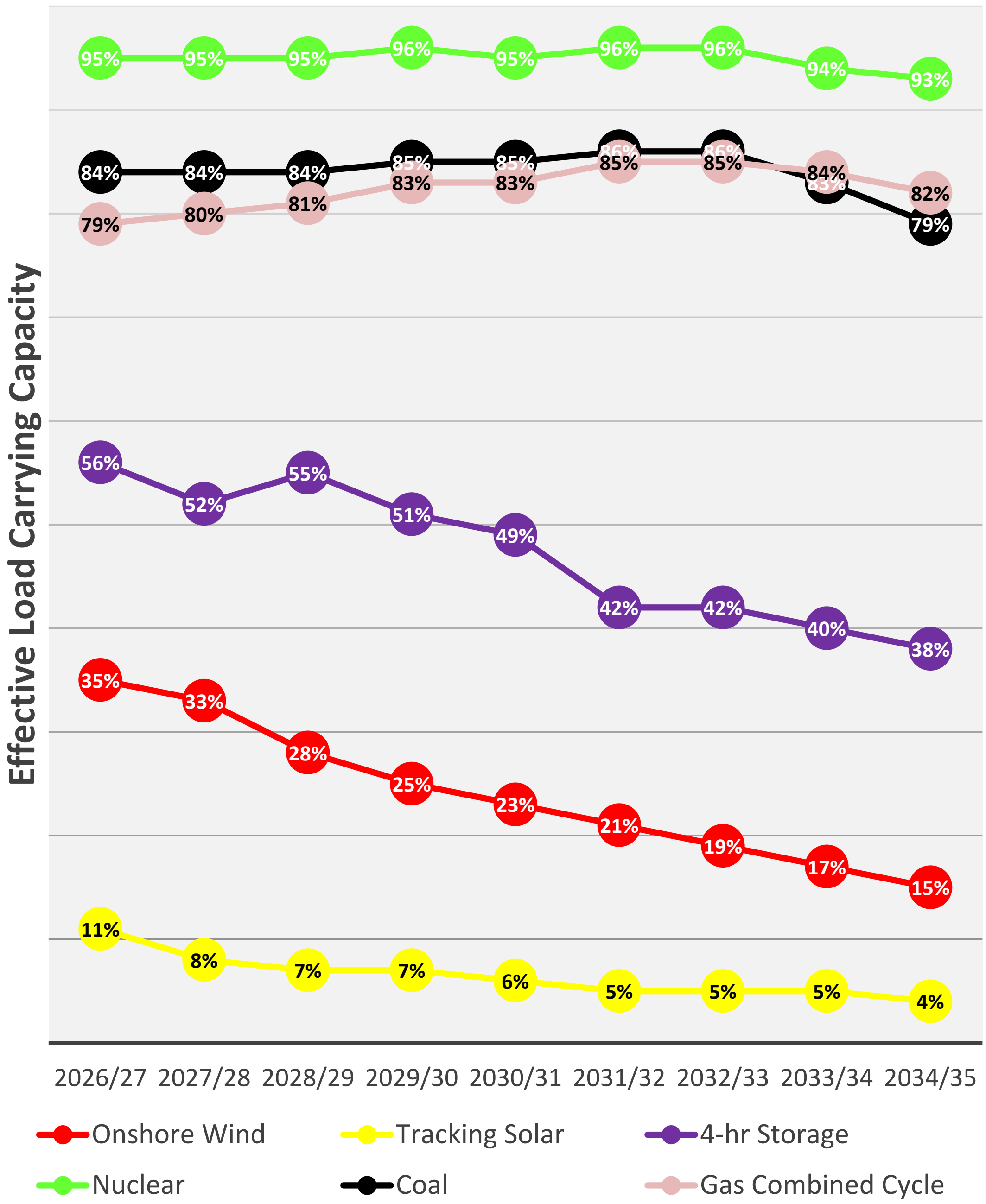


Figure 118. PJM effective load carrying capacity (Data from [66])

Figure 119 normalizes the values for the 2026/27 auction and the 2034/35 auction by dividing by the coal ELCC. This gives a proxy for how much of the different generation types in terms of GWs would be required to replace a GW of coal on the hardest to serve hours in PJM.

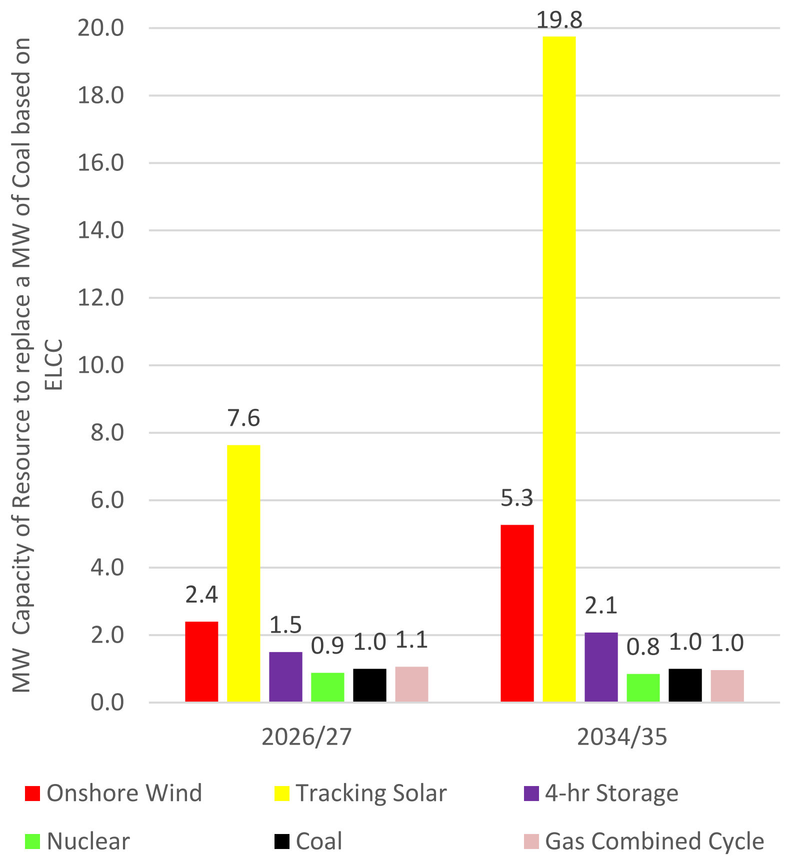


Figure 119. PJM capacity comparison based on ELCC (normalized based on coal ELCC) (Data from [66])

Key Observation Point

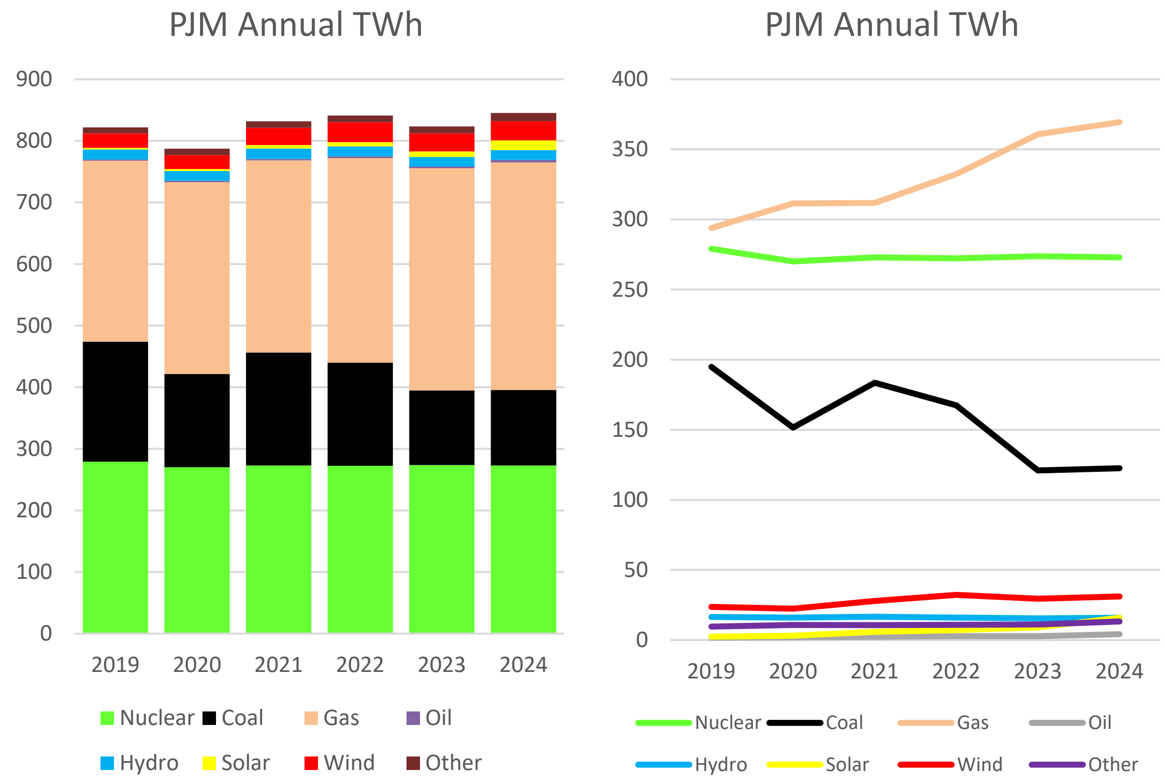
PJM's ELCC ratings confirm that a "GW is not a GW." For the 2026/27 delivery year, PJM accredited solar resources at just 8–11% of its nameplate capacity, compared to 95% for nuclear and 83% for coal. This massive 10-to-1 ratio highlights that on the PJM grid, dispatchable thermal resources provide nearly 10 times the capacity value of solar when the system is under the most stress.

This decline is driven by the *saturation factor:* as more solar is added to the grid, the period of highest risk shifts away from sunny afternoons toward the "net peak" at sunset. Consequently, each new GW of solar provides diminishing marginal utility to grid reliability, as the energy it produces increasingly overlaps with existing supply rather than addressing the hours of actual scarcity.

Demand Review

Annual Trends

Figure 120 is the annual electrical energy in PJM from 2019 to 2024 by energy supply resource. On the left is a stacked column, and on the right is a line chart by resource. Gas generation continues to climb on an annual basis in PJM, and coal had been declining but leveled off in 2024. Total generation on an annual basis has remained relatively unchanged through this period.


PJM Annual TWh

PJM Annual TWh

Figure 120. PJM annual energy (TWh) (Data from [5])

Daily Peaks

Figure 121 looks at the daily peak energy requirements for PJM. Daily energy requirements have remained relatively unchanged over the last several years; however, 2025 set both summer and winter records for daily energy requirements.

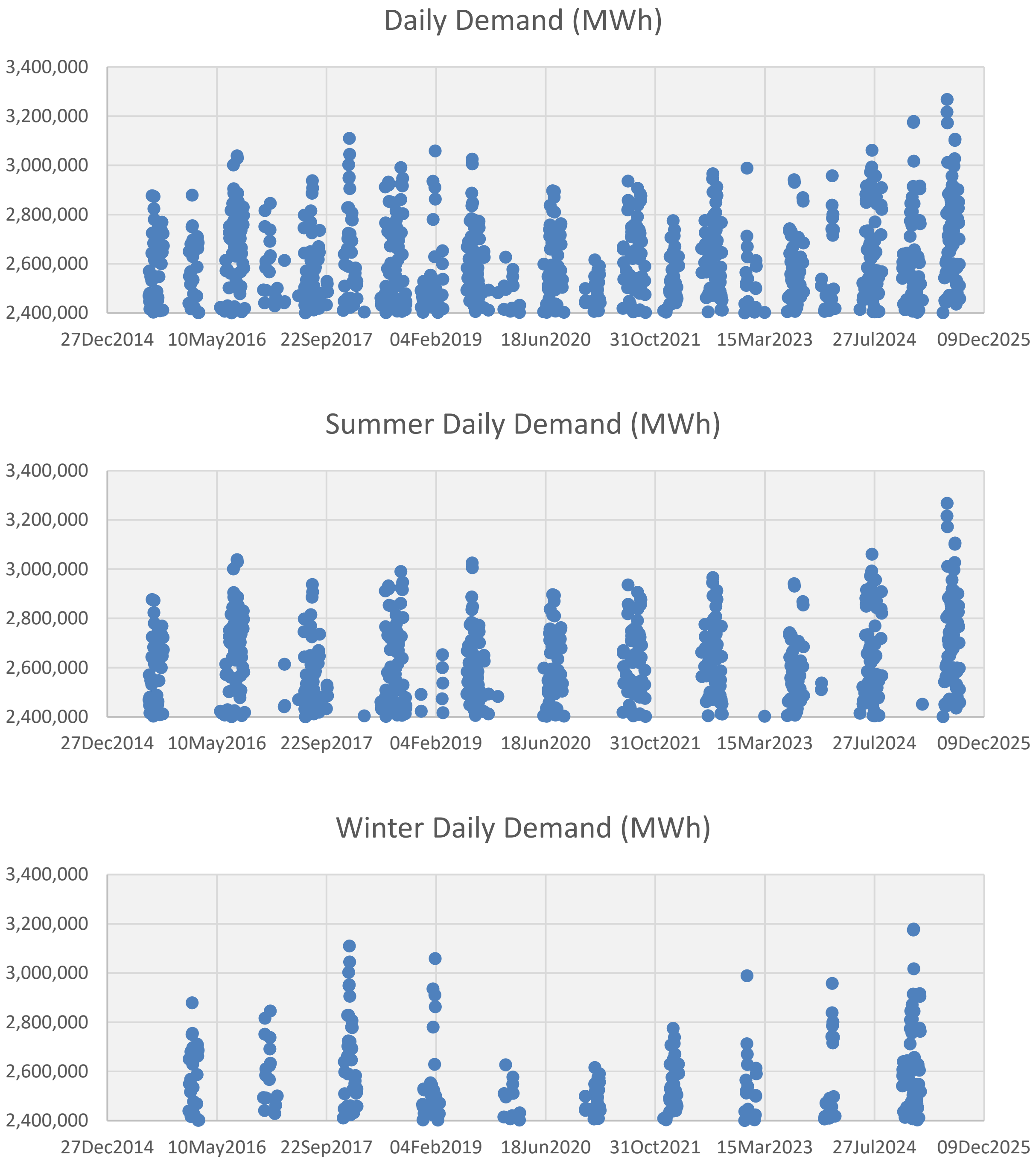


Figure 121. PJM daily peak energy requirements (MWh) (all top, summer middle, and winter bottom) (Data from [5])

Hourly Peaks

In recent years, both winter and summer hourly peaks have been climbing. In 2025, PJM experienced its highest summer and winter hourly peak in the last 10 years.

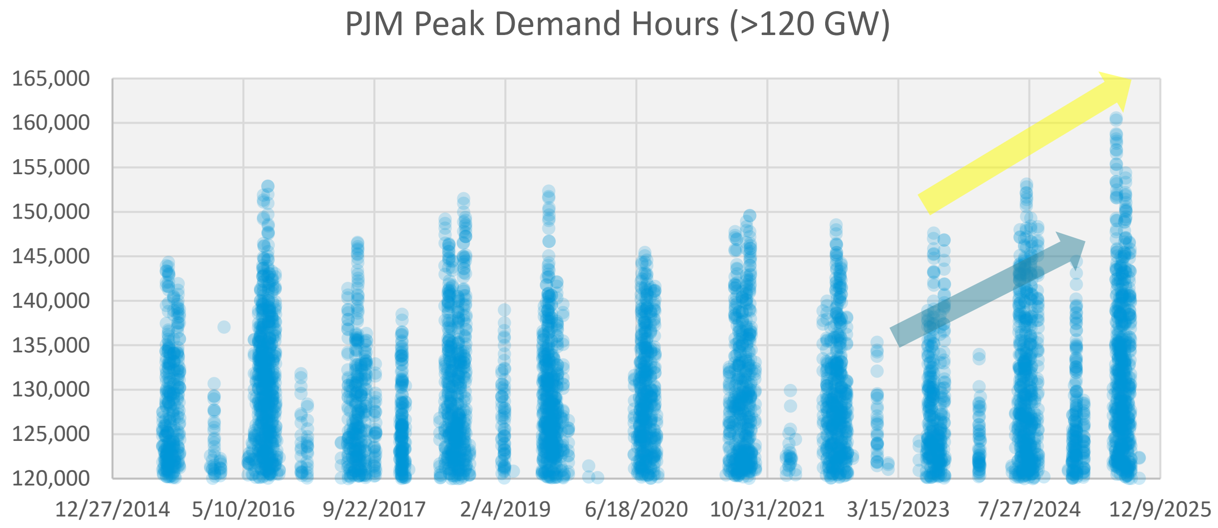


Figure 122. PJM hourly peak demand (Data from [5])

Load Growth

Load growth is projected by PJM [67]; the summer peak is forecasted to be 209,923 MW in 2035, a 10-year increase of 55,779 MW, and reaching 228,544 MW in 2045, a 20-year increase of 74,400 MW. Winter peak load in 2034/35 is forecasted to be 198,175 MW, a 10-year increase of 62,048 MW, and reaching 218,760 MW in 2044/45, a 20-year increase of 82,633 MW.

In most zones in PJM, the development of data centers is highlighted as a major source of the load growth. As seen in Figure 120, for the last 10 years, peak loads have consistently remained in the 145,000 to 155,000 MW range, with 2025 being the first year in the last ten where load exceeded 160,000 MW.

PJM Summary

PJM electricity costs have only increased slightly from 2015 to 2024, although increases in capacity auctions are causing upward pressure on rates now. In 2015, PJM rates were 1.3 times the U.S. average, but in 2024, due to a lower rate of increase in PJM, the rates were on par with the U.S. average residential rates. Carbon emission intensity has decreased but remains at 0.9 of the U.S. average as the rest of the U.S. has also decreased. PJM executed voltage reductions during the 2014 polar voltage to maintain grid stability and was in emergency conditions, during Winter Storm Elliott (2022). In more recent winter storms, PJM has performed better.

Key Findings

- PJM delivered 6% of its annual electricity production from solar and wind resources, 44% from gas, 32% from nuclear, 14% from coal, and 2% from hydro power in 2024.
- PJM's annual electricity use in 2024 increased by 8% since 2015.

- PJM’s nuclear, gas, and coal fleets performed well on both summer and winter peak hours and days. Solar did as well on the summer peak. Gas provided the largest share of the daily energy due to the large fleet.
- PJM has both a summer and winter peak, and in 2025, the winter and summer peaks were the highest they have been in the last 10 years, both on an hourly basis and a daily energy requirement basis.
- PJM’s capacity costs have increased dramatically with the adoption of effective load carrying capacity. For solar, wind, and storage, ELCC calculated values drop in future years due to saturation.
- PJM faces its greatest reliability risks in winter due to higher levels of generation outages. This was a prominent issue in both the polar vortex of 2014 and Winter Storm Elliott.
- Load growth in PJM is projected for the next ten years to be far more than it was in the last ten years where hourly peak loads essentially remained constant.

Figure 123 provides a waterfall graph of energy (TWh) changes (top chart), a waterfall of capacity (GW) changes (bottom chart), and a breakdown of total energy (TWh) and capacity (GW) by resource for 2015 and 2024 (middle charts).

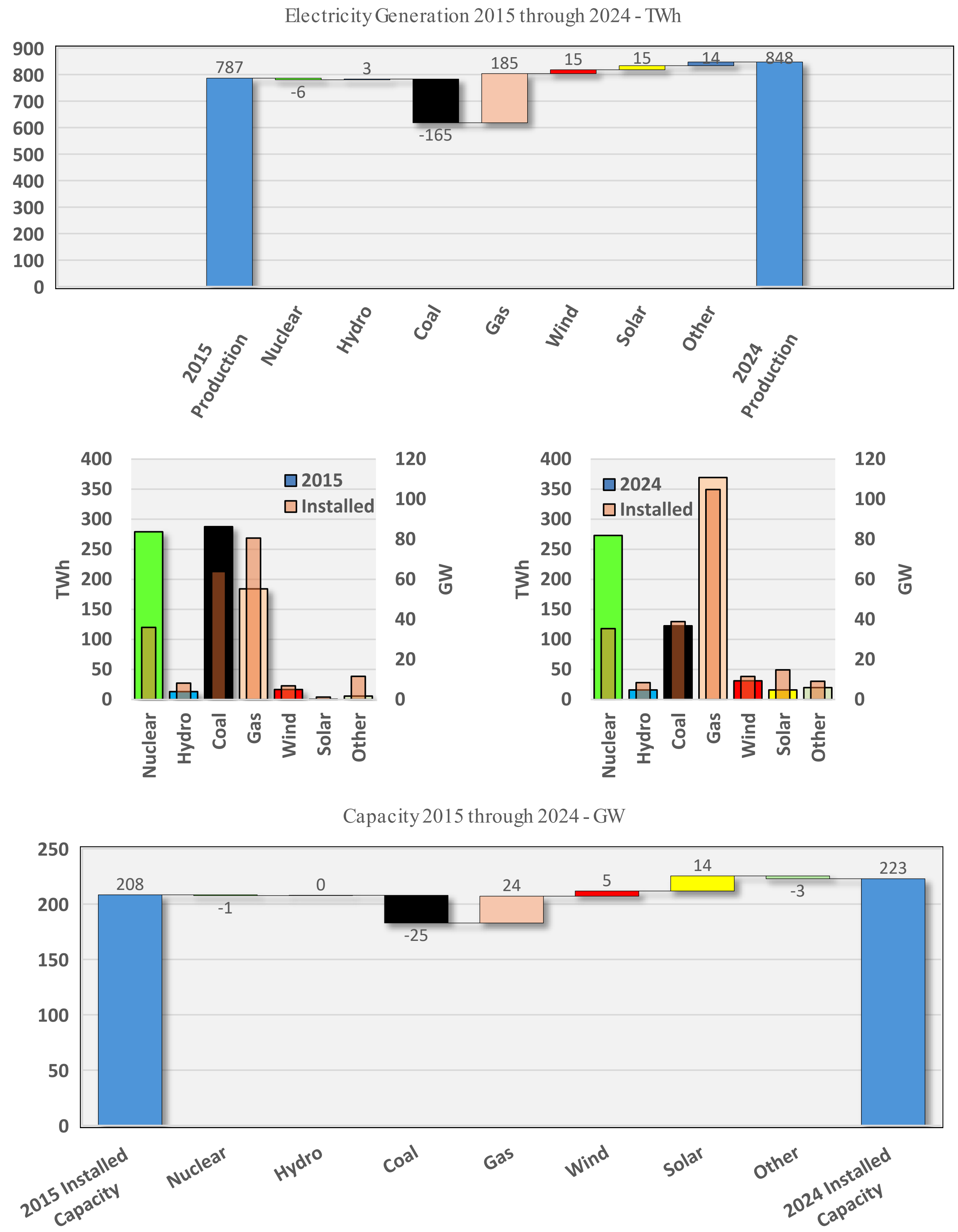


Figure 123. PJM capacity and generation summary, 2015 and 2024 (Data from [5, 20])

5. ASIA ENERGY SUPPLY

China Electricity Supply

Overview 2015–2024—China

China's capacity, peak, energy, residential rates, and carbon intensity of the electricity supply are summarized in Figure 124.

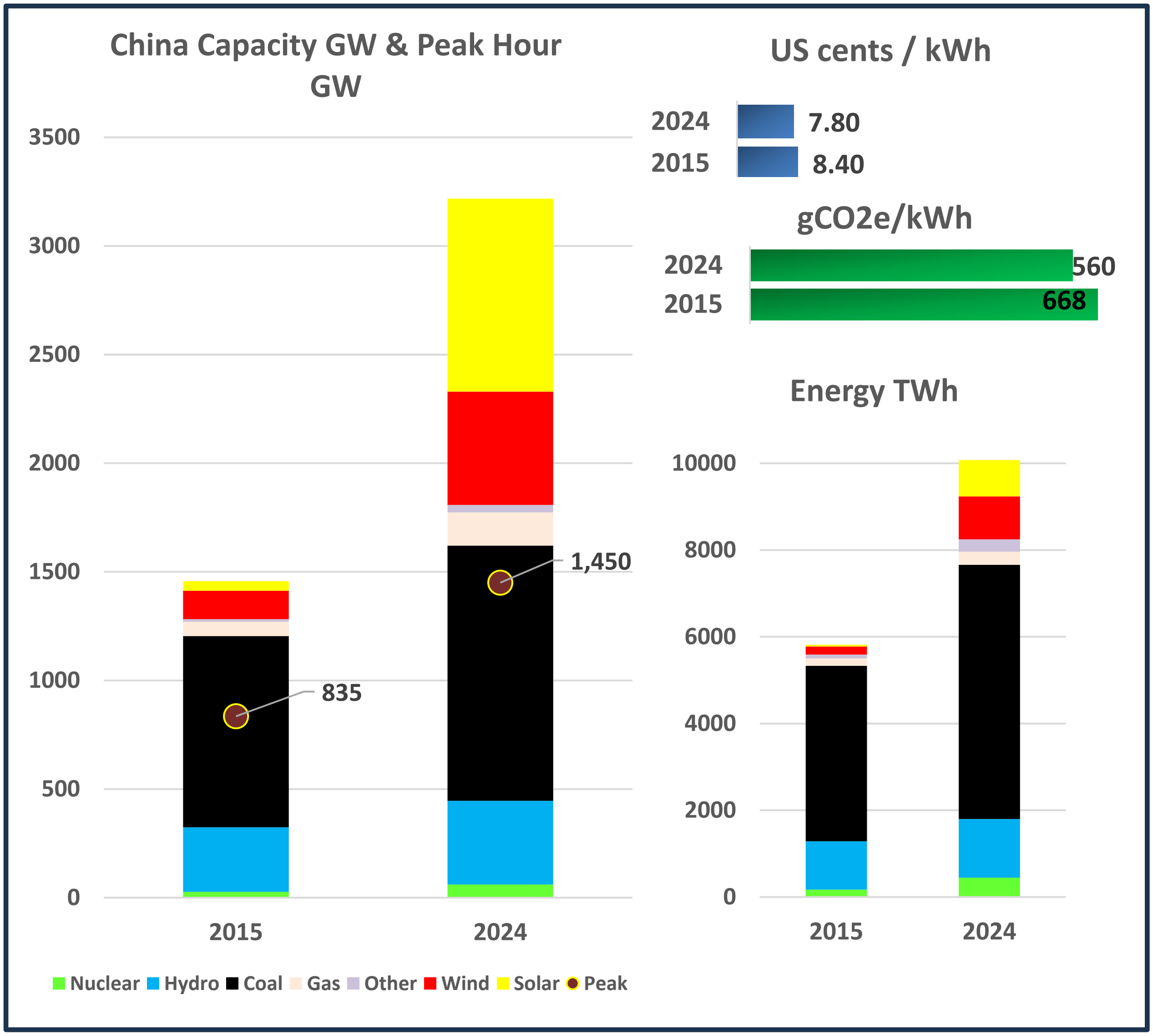


Figure 124. China 2015 and 2024 capacity and peak (GW), household rates (cents/kWh), carbon intensity (gCO2e/kWh), and energy (TWh) (Capacity and energy data from [12], rates from [68, 69], and carbon from [7])

China's electricity nameplate capacity has increased by over 100%, and generation has increased by over 70% from 2015 to 2024. The cost of electricity on a per-kWh basis remained relatively constant. The carbon intensity of the electricity dropped 17% over the period. As a region, China has much lower electricity rates than the United States and much, much lower electricity rates than the EU27. China has a higher carbon intensity electricity supply than the United States and much higher intensity than the EU27.

China has both a winter and summer peak. The summer peak is generally higher than the winter peak. Unlike the United States and EU, there is no readily available source of generation by resource at the hourly level for China. So, a detailed look at peak demand periods is not possible.

It is worth noting that the peak demand is less than the total capacity of dispatchable resources (nuclear, coal, gas, and hydro).

China Trends

The buildout of solar and wind resources over the last ten years in China has been significant in terms of GW of capacity (see Figure 124). The energy contribution from these resources is more modest. Figure 125 illustrates the difference; the 2024 GW capacity is on the left and the 2024 energy from each resource is on the right.

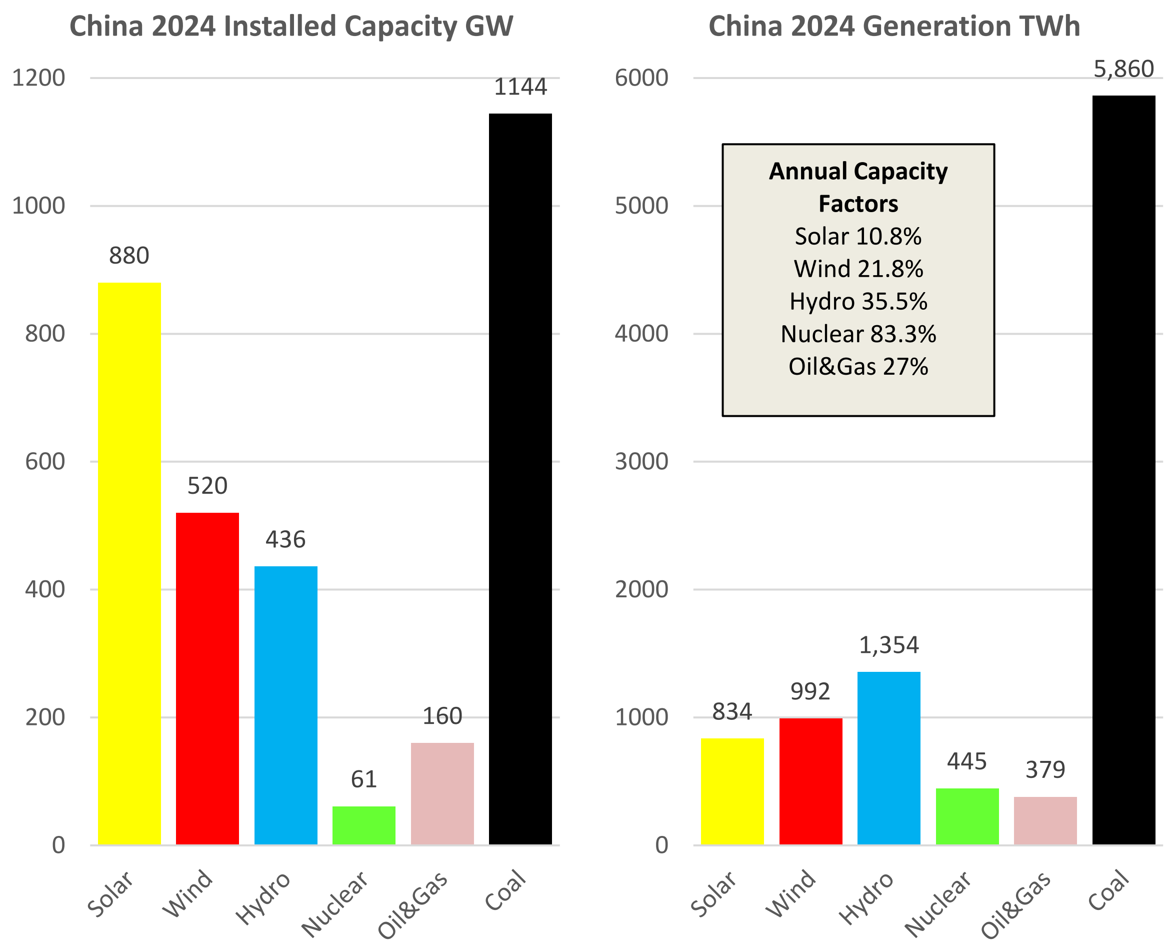


Figure 125. China 2024 energy (TWh) and capacity (GW) by resource (Data from [12])

In Figure 126, the 2024 annual energy (TWh) is divided by the installed capacity (GW) for each of the main resources. Nuclear provides significantly more TWh of annual energy per unit of installed capacity than the other resources. Solar provides the least.

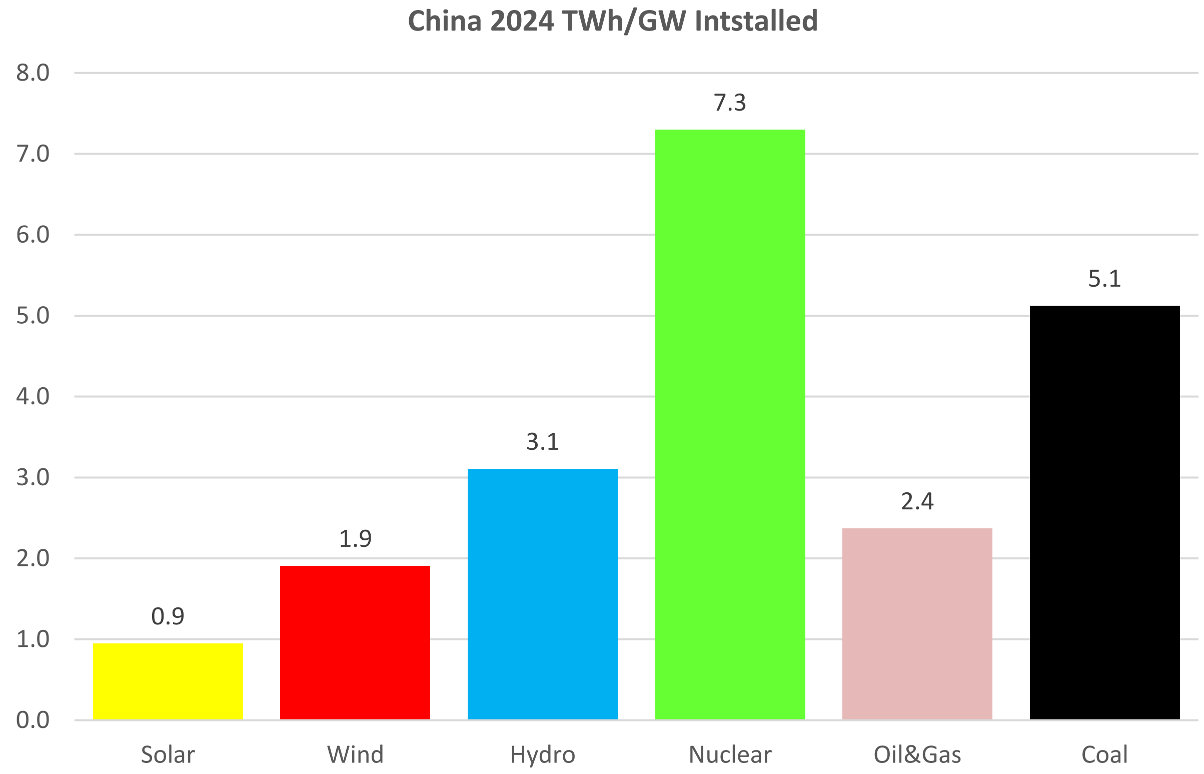


Figure 126. China 2024 TWh/GW installed capacity (Data from [12])

Generation Trends

As seen in Figure 124, generation in China electricity energy use and capacity has grown significantly since 2015. Figure 127 shows the generation of each resource since 1985. Coal generation has been growing steadily for 40 years and is the largest source of electricity in China by a significant margin. Hydropower has also grown significantly, especially in the last 20 years, but the growth looks modest compared to that of coal. More recently, in the last 10 years, wind and solar have begun to grow. In 2025, solar energy is likely to surpass wind generation but remain less than hydropower generation. In the 40-year period, coal generation only declined in one year (2015).

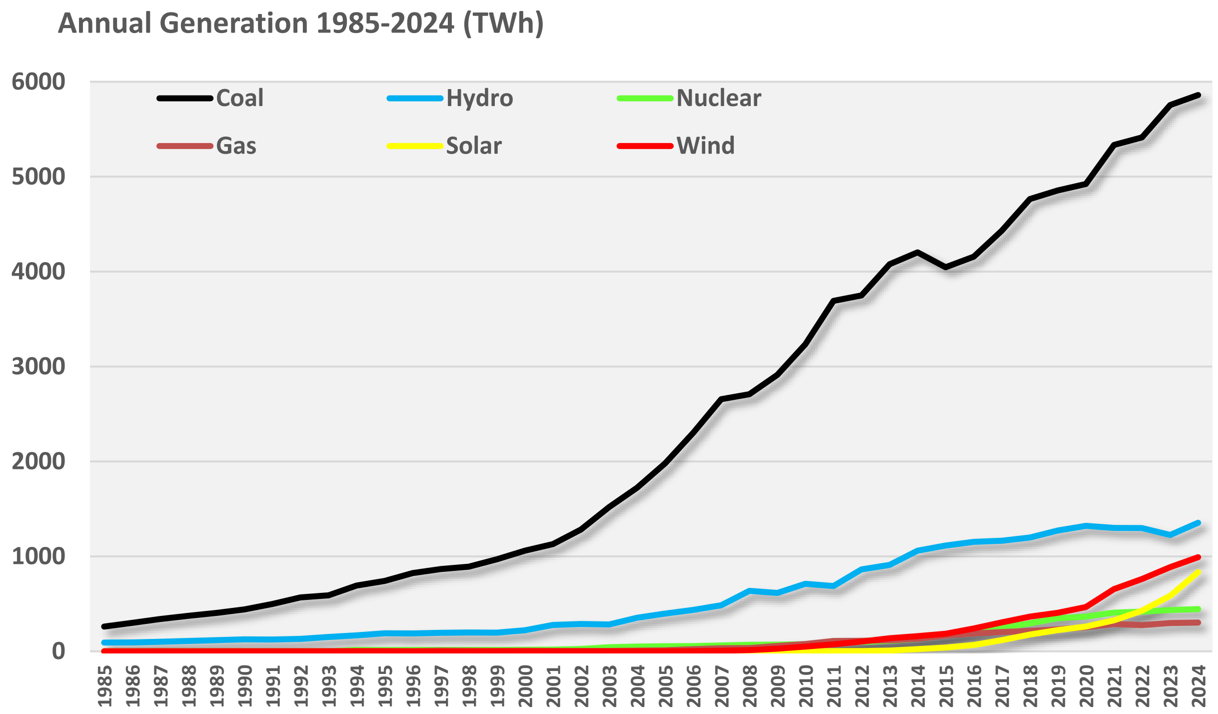


Figure 127. China annual generation, 1985–2024 by resource (Data from [6])

Figure 128 shows monthly coal generation in China from January 2018 to October 2025. There is a general upward trend for each month. However, in more recent years (2024 and 2025), there have been months with annual declines and months with annual increases. Notably, August 2025 saw the highest monthly generation from coal ever for China, at nearly 580 GW (which is more than the annual total electricity consumption for Germany).

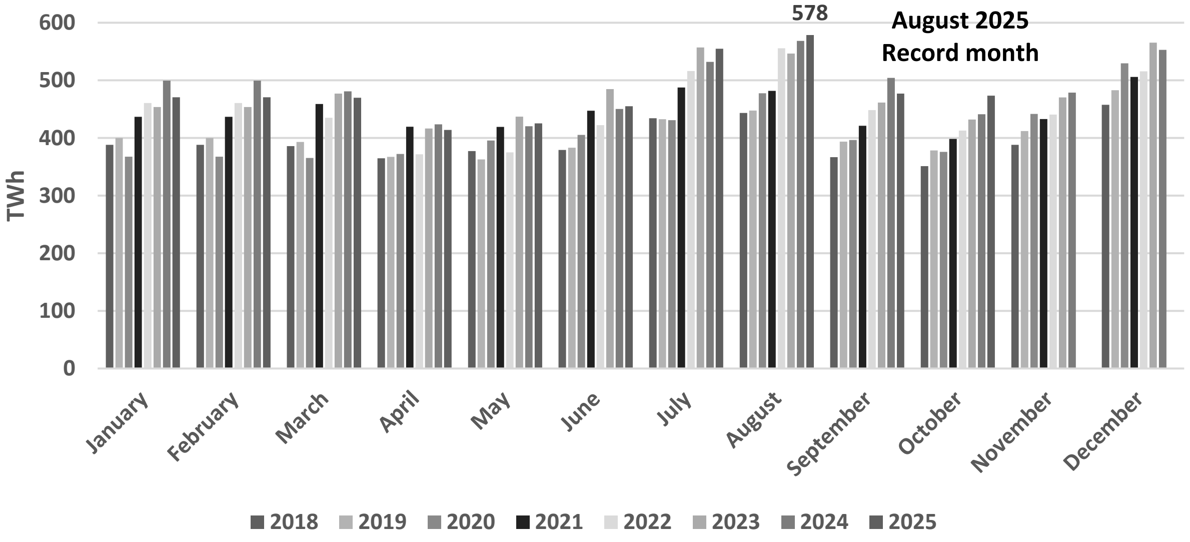


Figure 128. China monthly coal-fired generation in TWh, 2018–2025 (October) (Data from [12])

Figure 129 provides a side-by-side comparison of monthly generation from January 2021 to October 2025 for coal and solar in China. Coal-fired generation significantly outpaces generation from solar despite the growing solar GW capacity.

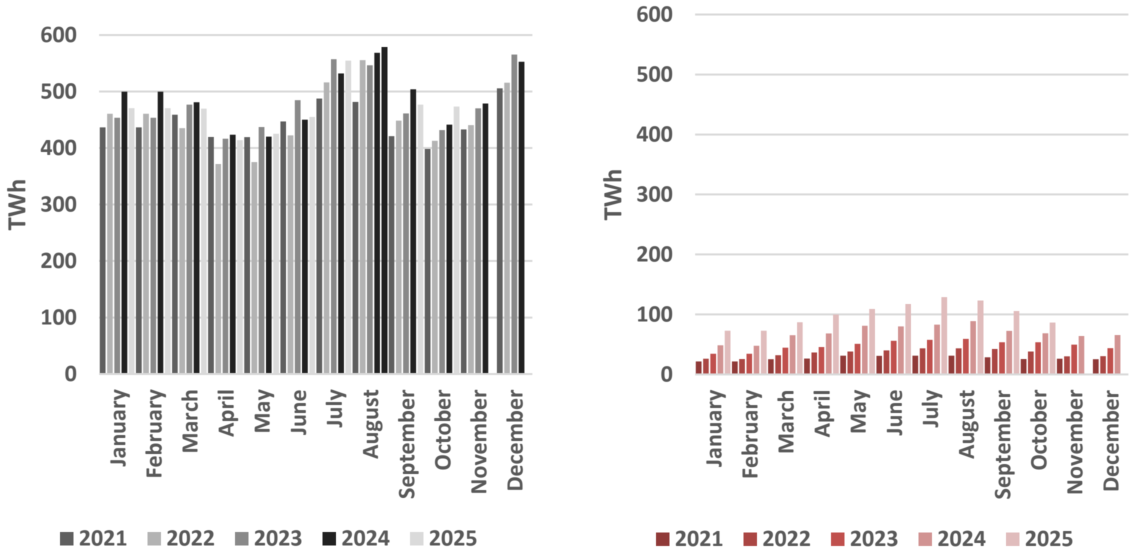


Figure 129. China monthly solar and coal generation (TWh), 2021–2025 (October) (Data from [12])

Electricity Supply Challenges

From the end of 2020 to the summer of 2022, China had several periods of power use restriction.

In December 2020, Hunan, Jiangxi, and Zhejiang provinces faced power use restriction orders as a result of high demand and insufficient electricity supply, in part due to insufficient fuel reserves [70]. From 2017 to 2021, the December increase in demand compared to November hit a peak in 2020 (see Figure 130). There was a significant increase in demand in December 2020 compared to November 2020—an 87 TWh increase—whereas in other years, this increase is typically <65 TWh. Note: coal is relied on to manage this monthly increase as hydro resources tend to reduce production in December versus November and wind and solar are generally unchanged from November to December (see Figure 130).

There were also a series of rolling outages in late summer 2021 when demand was increasing, but coal prices were elevated and electricity prices capped. This prevented coal units from being economically dispatched to meet the surge in demand [71].

The most recent rolling outages were during the late summer of 2022 in Sichuan, where drought conditions and a heat wave combined to lead to energy supply issues [72].

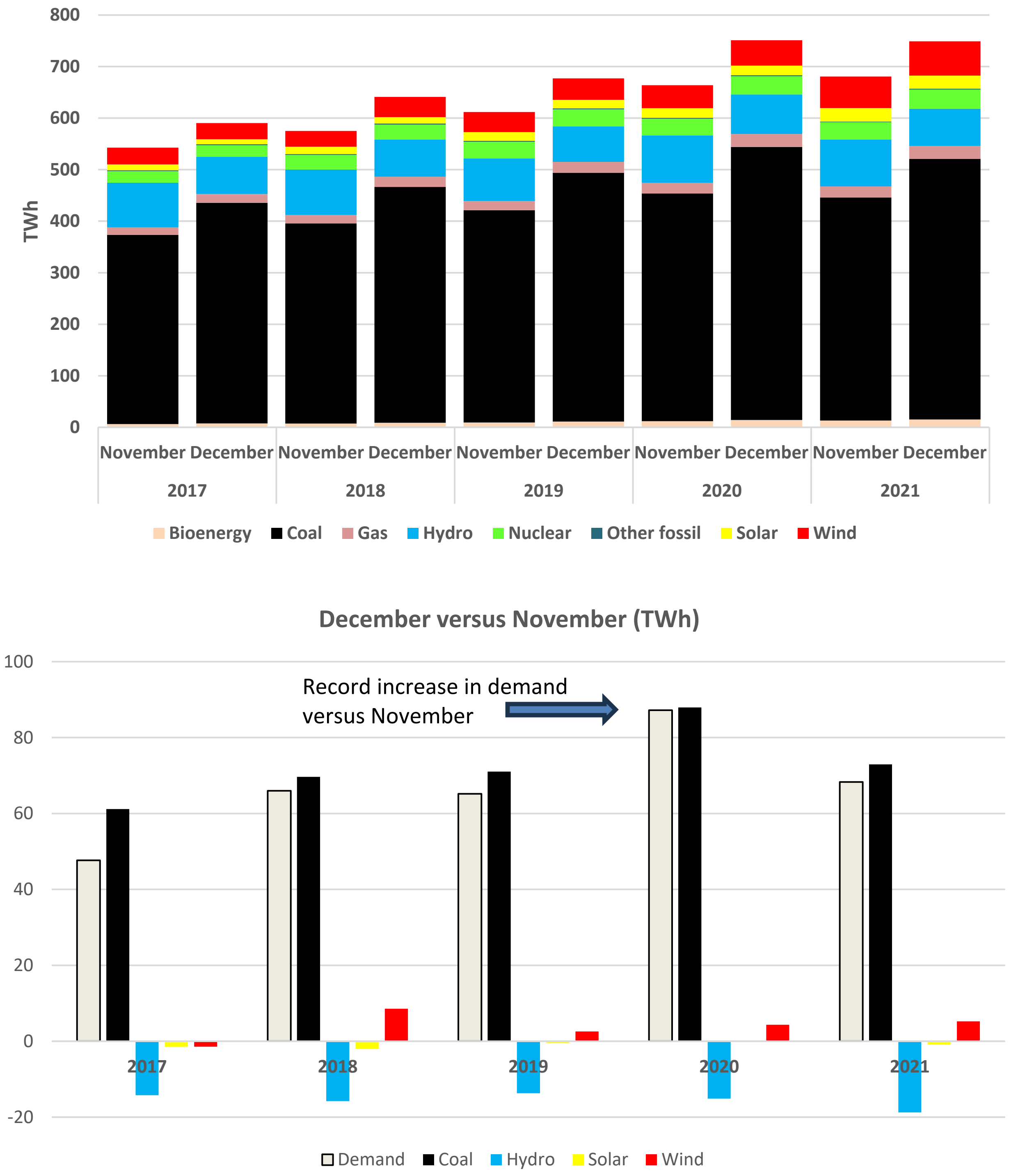


Figure 130. China December versus November energy supply – All sources on top, delta for demand, coal, hydro, solar, and wind below (2017–2021). (Data from [12])

China has significantly increased its coal-fired generation construction since 2021 with more than 200 GW currently under construction (see Figure 131).

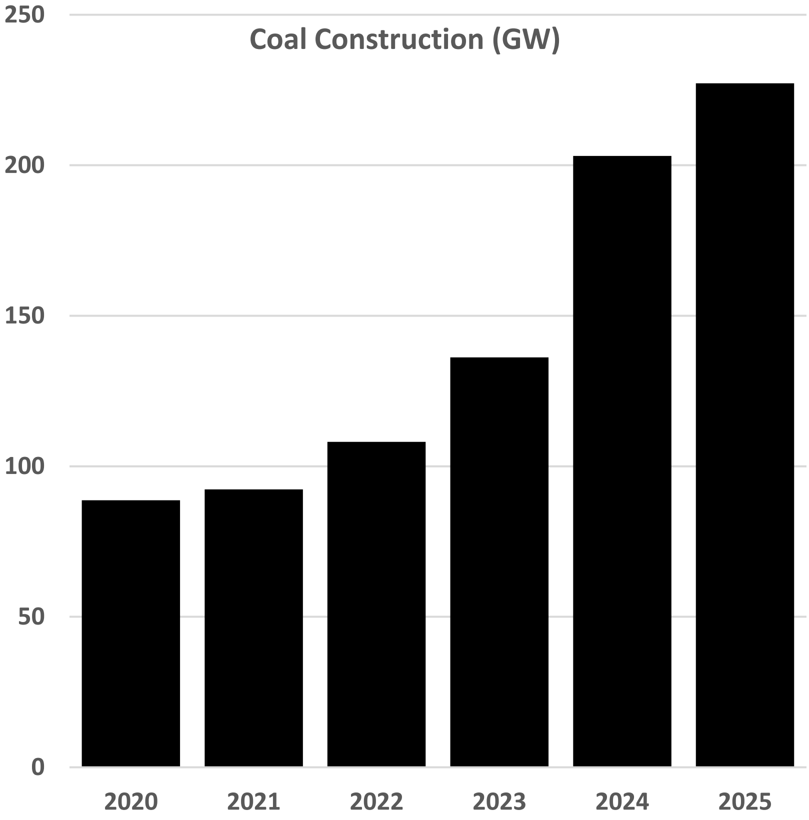


Figure 131. China coal-fired power plant capacity under construction, 2020–2025 (Data from [73])

Figure 132 looks at construction of all resources in 2025 in China. Due to variations in length of time for construction, these numbers are not adjusted for added capacity.

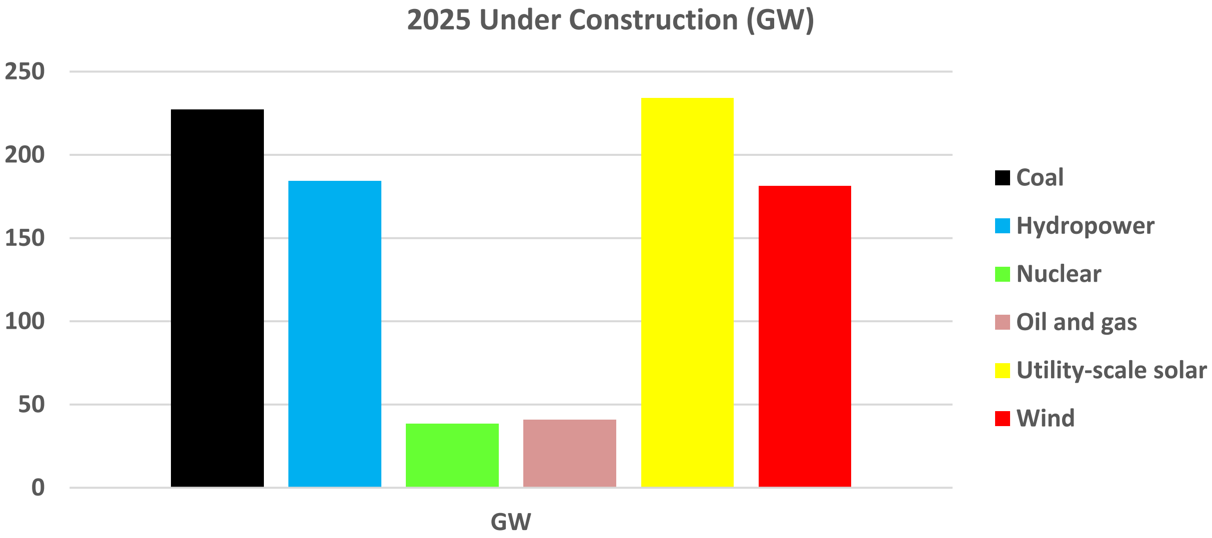


Figure 132. China 2025 power plant capacity under construction (Data from [74])

Generally, the construction time for power plants is shortest for solar, followed by gas and wind, then coal, with hydropower and nuclear taking the most time to construct. Applying the energy per installed capacity by resource from Figure 126, the capacity under construction can be re-stated as approximate energy delivered on an annual basis from these resources.

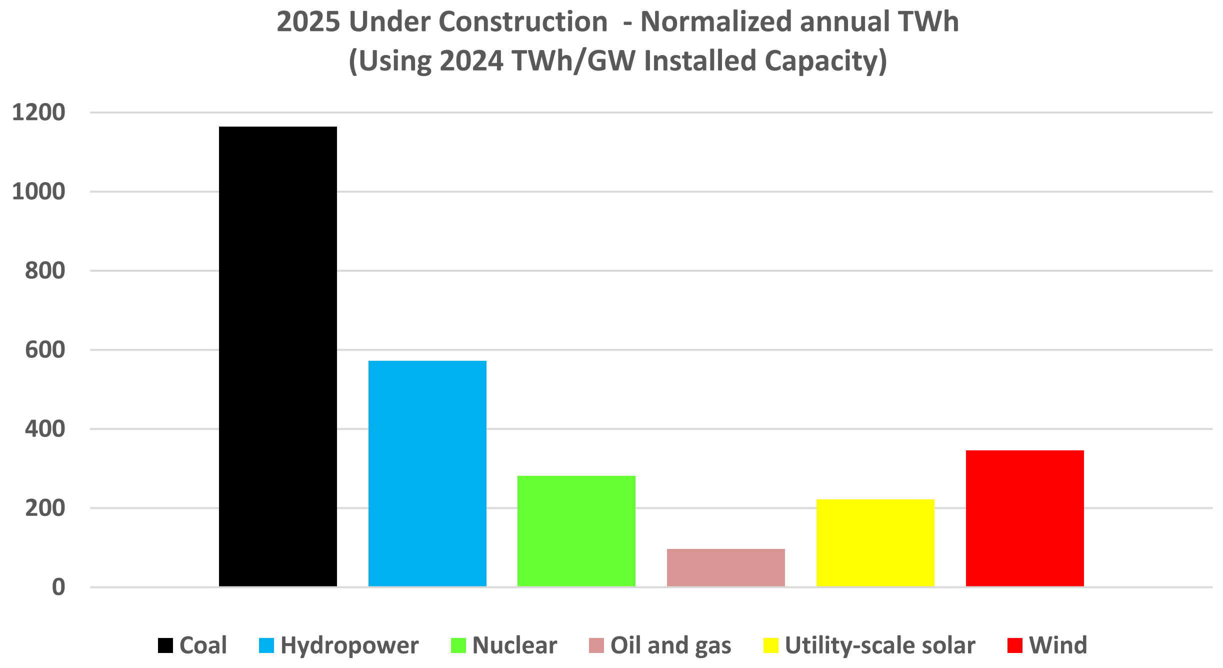


Figure 133. China under construction, normalized in terms of approximate energy production (TWh/year) (Data from [12, 74])

China Electricity Production 2024 Scale

Figure 134 shows the scale of electricity production from mainland China compared to the next 20 largest regions. China produces far more electricity; China's coal-fired production alone is greater than the electricity production of any other nation. The United States' entire electricity production in 2024 was only 75% of China's coal-fired production (and not even 50% of its total production).

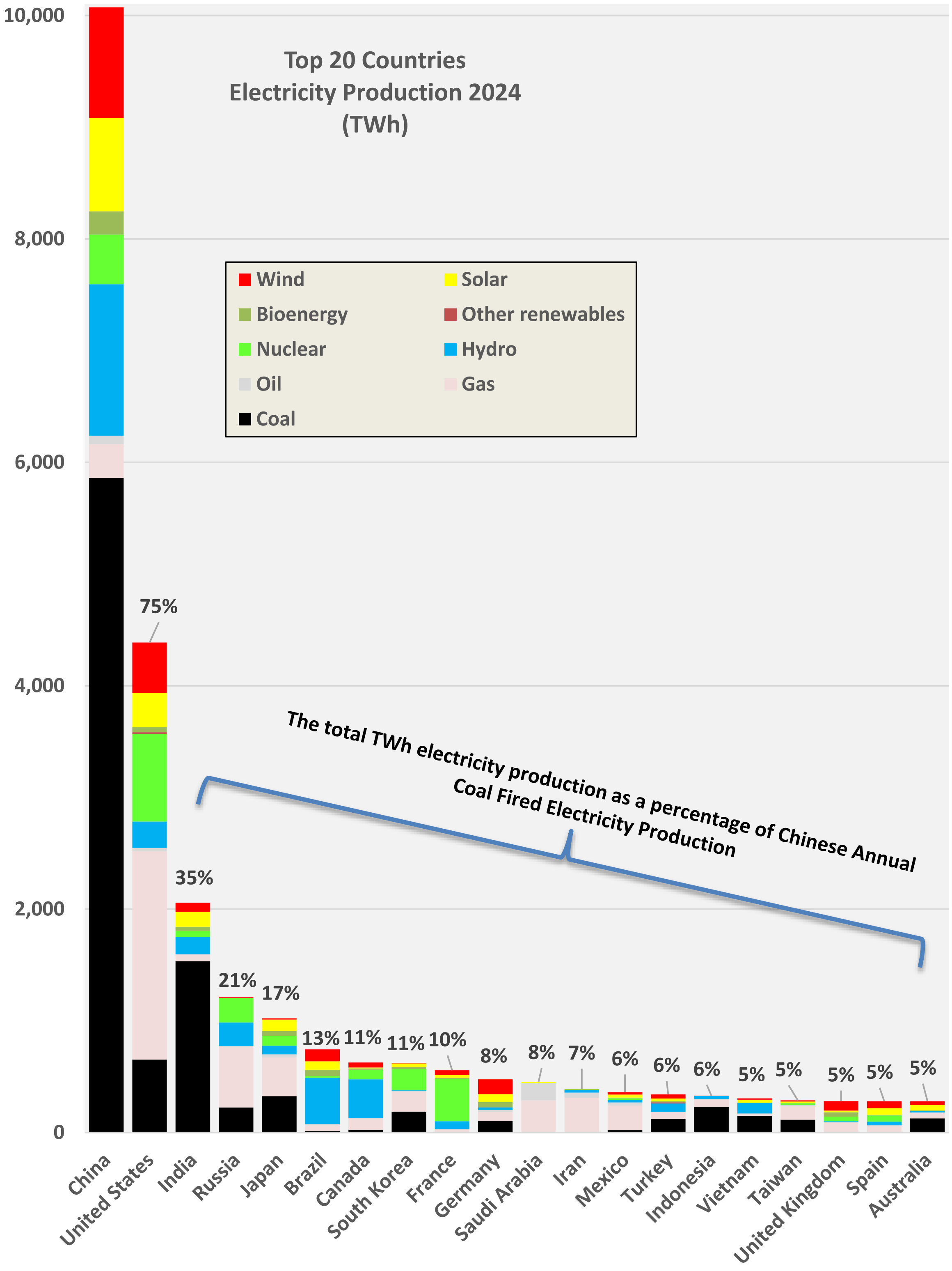


Figure 134. Top electricity-production regions in 2024 compared to China electricity production (Data from [6])

China Summary

China’s electricity costs have remained consistent from 2015 to 2024; they are about half of the 2024 U.S. costs and a quarter of EU27 costs. Carbon emission intensity has decreased but is much higher than the United States and over double the EU27 average. China had experienced energy supply challenges in 2020, 2021, and 2022 but has added extensive generation supply since then and avoided recurrence of these events. This generation addition includes coal, solar, wind, nuclear, and hydropower, with some gas power.

Key Findings

- China delivered 18% of its annual electricity production from solar and wind resources, 58% from coal, 4% from nuclear, 13% from hydro, and 3% from gas power in 2024.
- China’s overall annual system electricity use has increased by over 70% since 2015. Its electricity production is significantly greater than every other region in the world, with its coal generation alone surpassing the generation of any other country.
- China’s coal fleet is relied on to provide extra generation when demand is higher, which occurs in both summer and winter. In August 2025, China set a record for electricity generation from coal at just under 580 TWh, which is more than any European nations’ annual total electricity production from all sources.
- China has faced reliability of supply in both late summer and winter. The vast increase in generation assets in recent years has seemed to arrest occurrences of these challenges.

Figure 135 provides a waterfall graph of energy (TWh) changes (top chart), a waterfall of capacity (GW) changes (bottom chart), and a breakdown of total energy (TWh) and capacity (GW) by resource for 2015 and 2024 (middle charts).

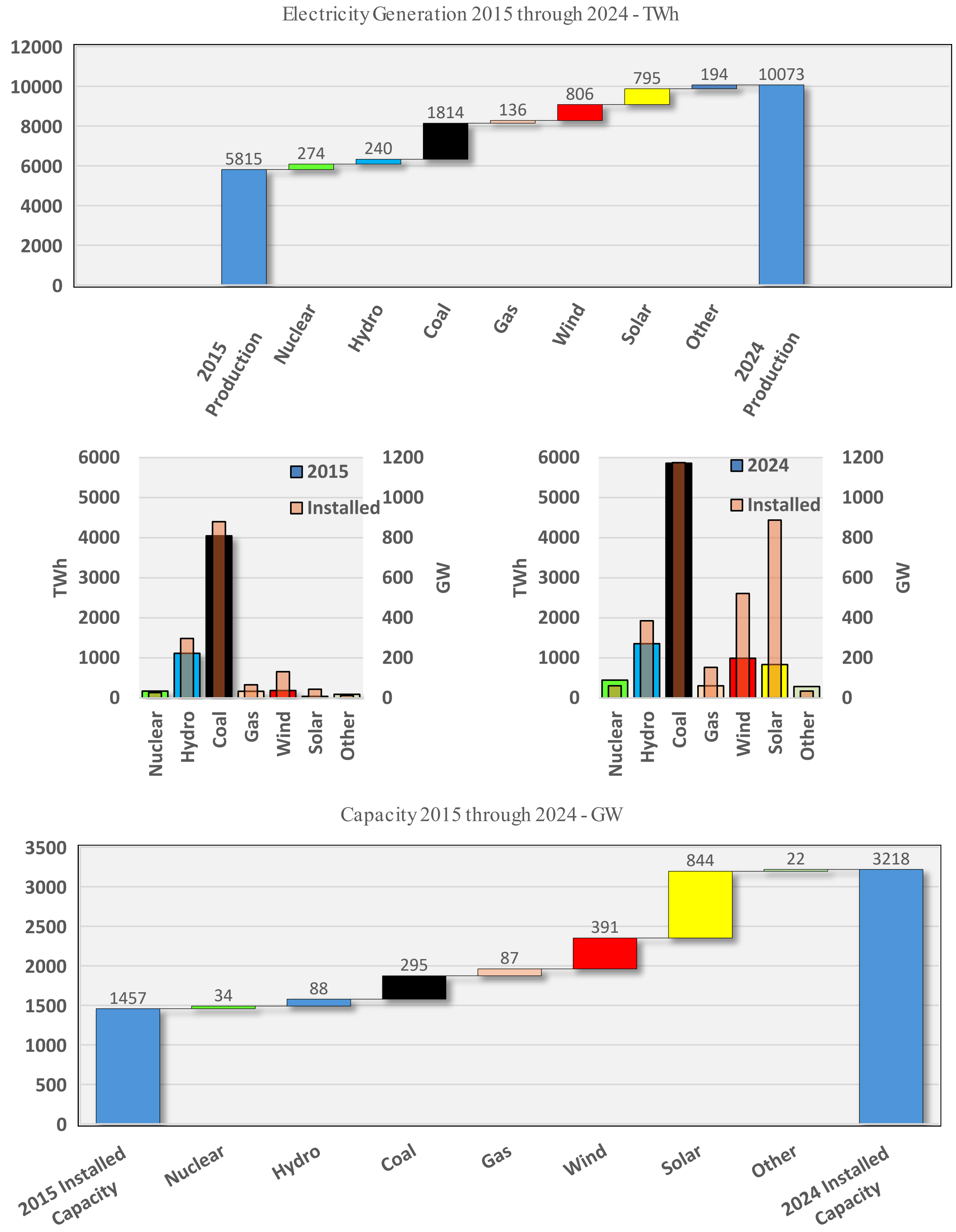


Figure 135. China capacity and generation summary, 2015 and 2024 (Data from [12])

India Electricity Supply

Overview 2015–2024—India

India’s capacity, peak, energy, residential rates, and carbon intensity of the electricity supply are summarized in Figure 136.

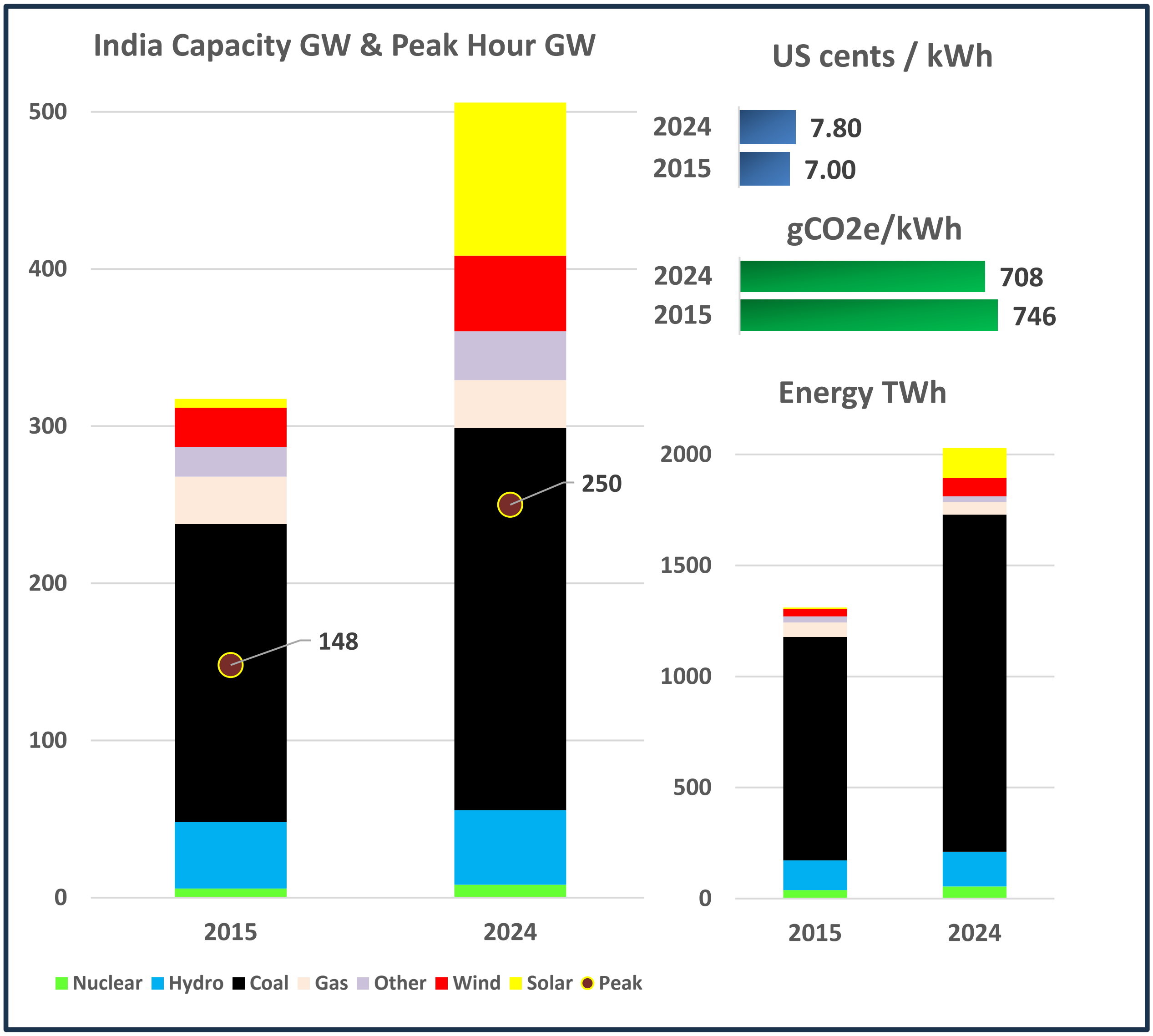


Figure 136. India 2015 and 2024 capacity and peak (GW), household rates (cents/kWh), carbon intensity (gCO2e/kWh), and energy (TWh) (Capacity and energy data from [12], rates from [75], and carbon from [7])

India’s electricity nameplate capacity increased by ~60% and generation increased by ~55% from 2015 to 2024. The cost of electricity on a per-kWh basis remained relatively constant. The carbon intensity of the supplied electricity dropped 5%. As a region, India has much lower electricity rates than the United States, and much, much lower electricity rates than the EU27 (comparable to China). India has a higher carbon intensity electricity supply than the United States, a much higher intensity than the EU27, and is even higher than China.

India is a summer peaking system. The summer peak is typically in May or June preceding the monsoon season. Unlike the United States and EU, there is no readily available source of generation by resource at the hourly level for India, so a detailed look at peak demand periods is not possible.

It is worth noting that the peak demand is less than the total capacity of dispatchable resources (nuclear, coal, gas, and hydro).

India Trends

The buildout of solar resources over the last ten years in India has been significant in terms of GW of capacity (see Figure 134). The energy contribution from these resources is more modest. Figure 137 illustrates the difference: the 2024 GW capacity is on the left, and the 2024 energy from each resource is on the right.

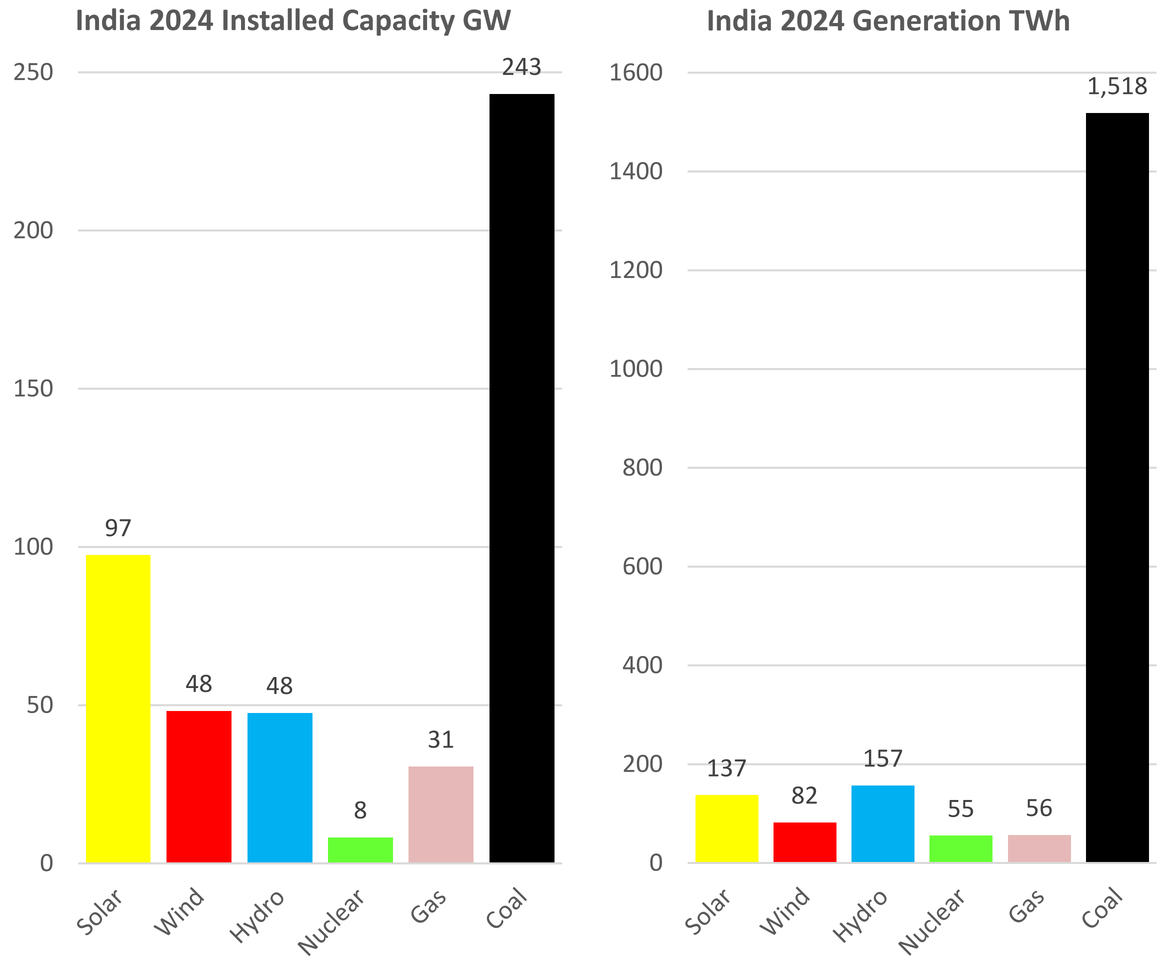


Figure 137. India 2024 energy (TWh) and capacity (GW) by resource (Data from [12])

In Figure 138, the 2024 annual energy (TWh) is divided by the installed capacity (GW) for each of the main resources. Nuclear is far and away the largest provider of TWh per unit of installed capacity; solar provides the least.

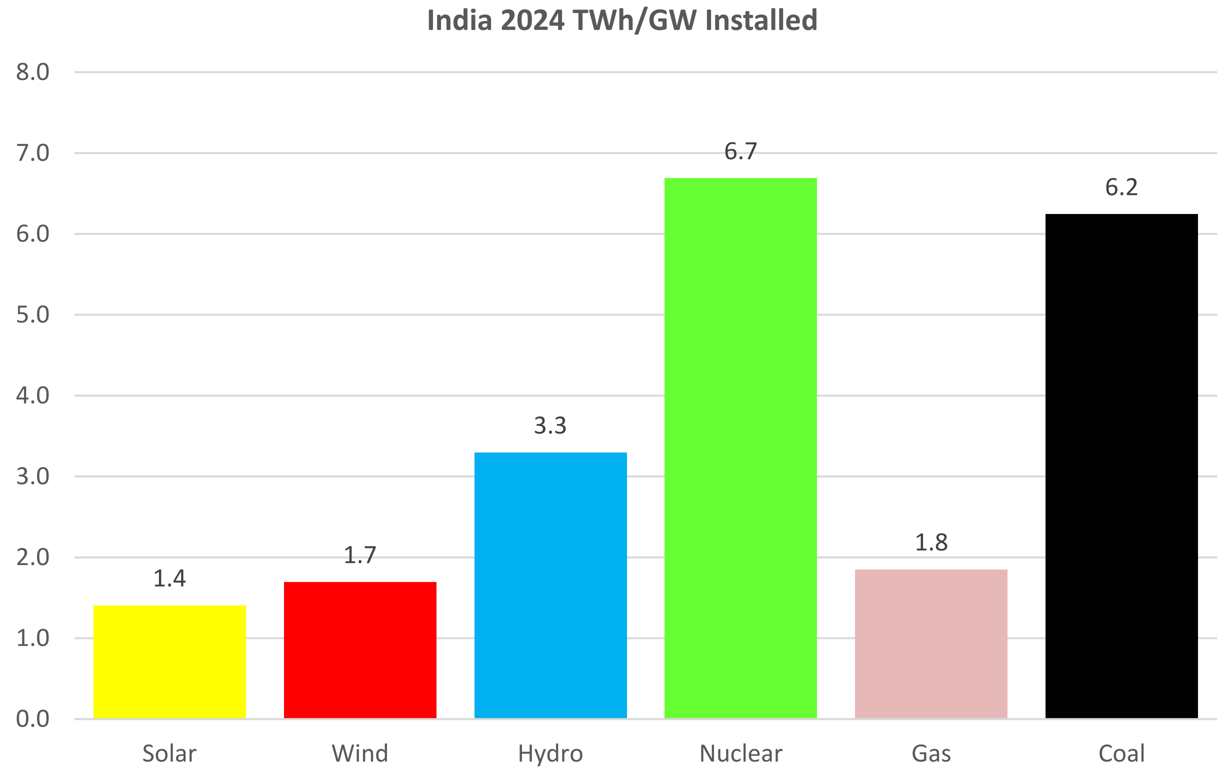


Figure 138. India 2024 TWh/GW installed capacity (Data from [12])

Generation Trends

As seen in Figure 136, generation in India has grown significantly since 2015. Figure 139 shows the generation of each resource since 1985. Coal generation has been growing steadily for 40 years and is the largest source of electricity in India by a significant margin. Very recently, solar generation has begun to grow as well. In the 40-year period, coal generation only declined in one year (2020), although it plateaued in 2019 at nearly the same value as 2018.

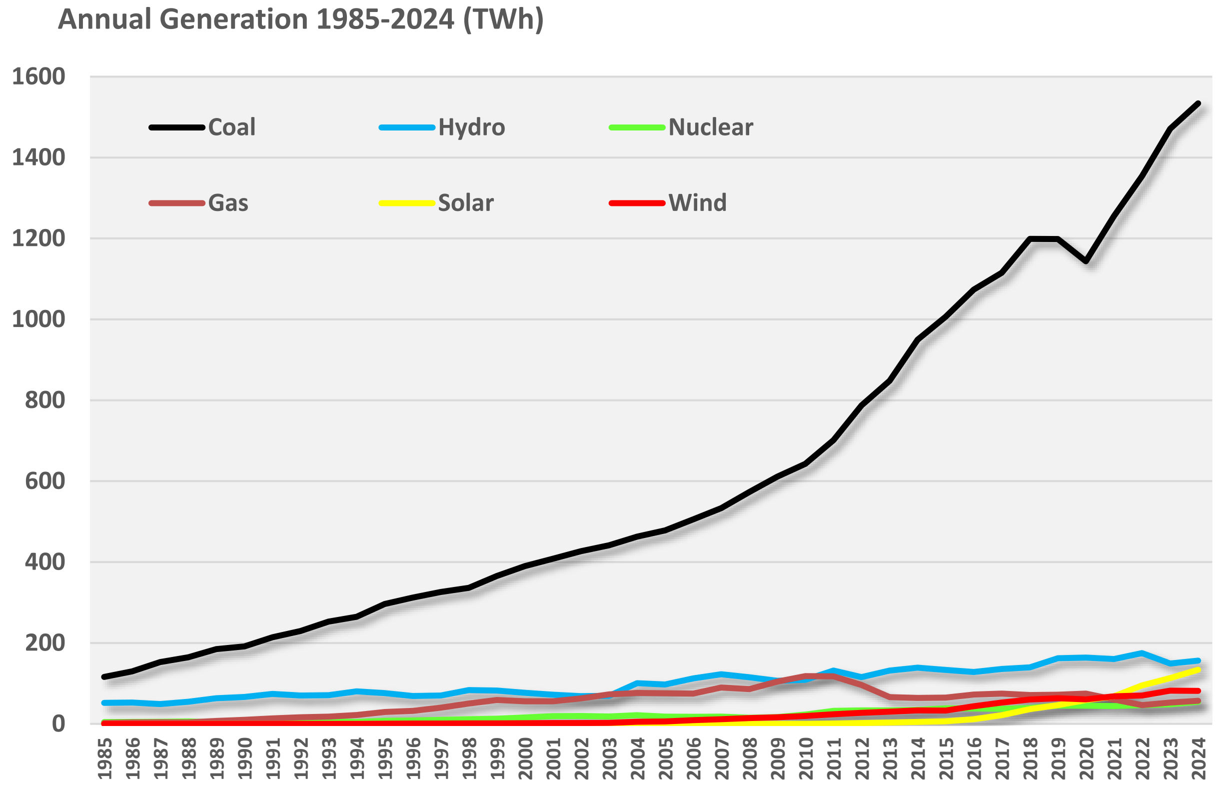


Figure 139. India annual generation, 1985–2024 by resource (Data from [6])

Electricity Supply Challenges

In 2021 after the pandemic, India faced electricity shortages from inadequate coal supply. In 2022, 2023, and 2024, India faced load shedding challenges due to heatwaves.

Figure 140 looks at the construction of all resources in 2025 in India. Due to variations in length of time for construction, these numbers are not equivalent for adding capacity.

Generally, the construction time for power plants is shortest for solar, followed by gas and wind, then coal, with hydropower and nuclear taking the most time to construct. Applying the energy per installed capacity by resource from Figure 138, the capacity under construction can be re-stated as approximate energy delivered on an annual basis from these resources (see Figure 141).

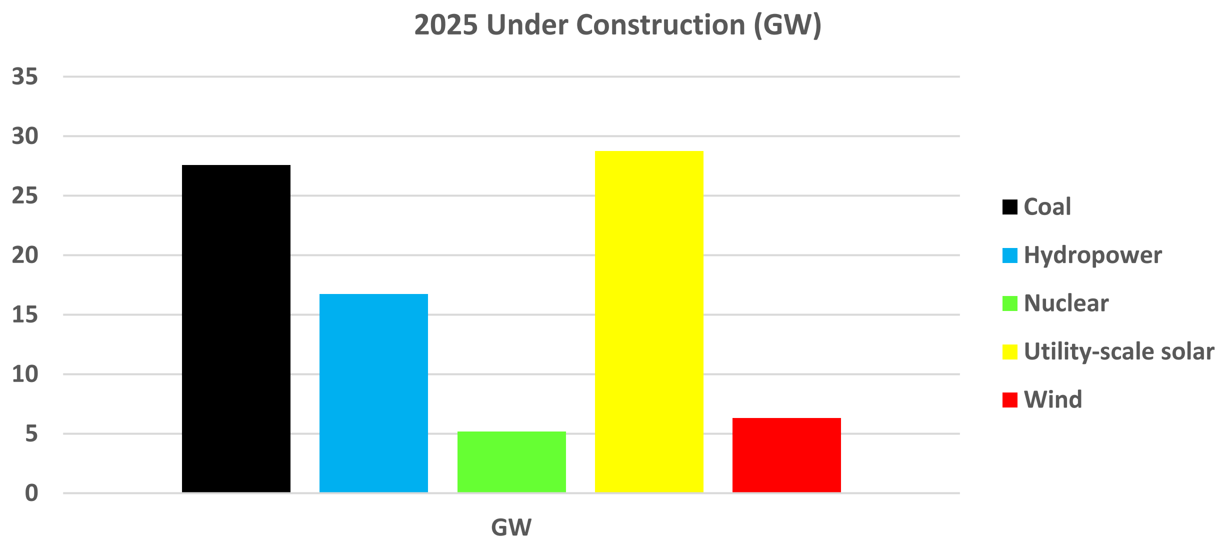


Figure 140. India capacity under construction, 2025 (Data from [74])

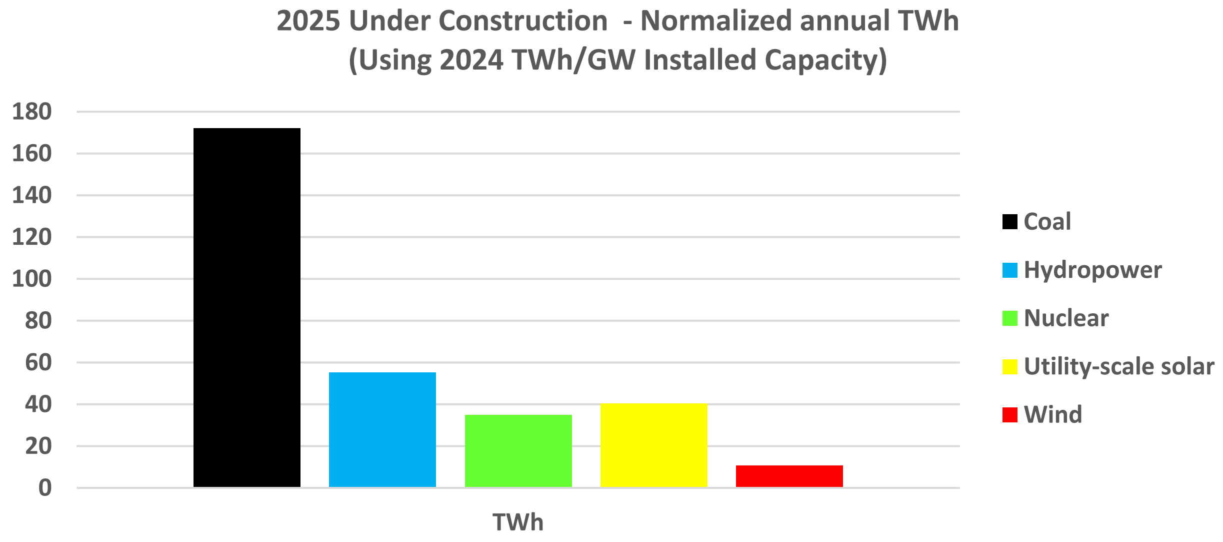


Figure 141. India under construction, normalized in terms of approximate energy production (TWh/year) (Data from [12, 74])

India Summary

India electricity costs have remained consistent from 2015 to 2024 at about half of current U.S. costs, a quarter of EU27 costs, and slightly less than China's costs. Carbon emission intensity has decreased but is much higher than the United States, over double the EU27 average, and greater than China. India has experienced energy supply challenges from 2020 to 2024 but has added extensive generation supply and managed 2025 without significant incidents. This generation addition is led by coal and solar on a nameplate GW basis.

Key Findings

- India delivered ~11% of its annual electricity production from solar and wind resources, ~75% from coal, ~3% from nuclear, 8% from hydro, and 1% from gas power in 2024.
- India's overall annual system electricity use has increased by over 50% since 2015. Its electricity production is growing significantly faster than other regions examined (except for China).
- India relies on its coal fleet to provide extra generation when demand is higher, which occurs in the summer months.
- India has faced reliability of supply in summer. The increase in generation assets in recent years has led to fewer challenges in 2025, but the summer period remains a risk for India.

Figure 142 provides a waterfall graph of energy (TWh) changes (top chart), a waterfall of capacity (GW) changes (bottom chart), and a breakdown of total energy (TWh) and capacity (GW) by resource for 2015 and 2024 (middle charts).

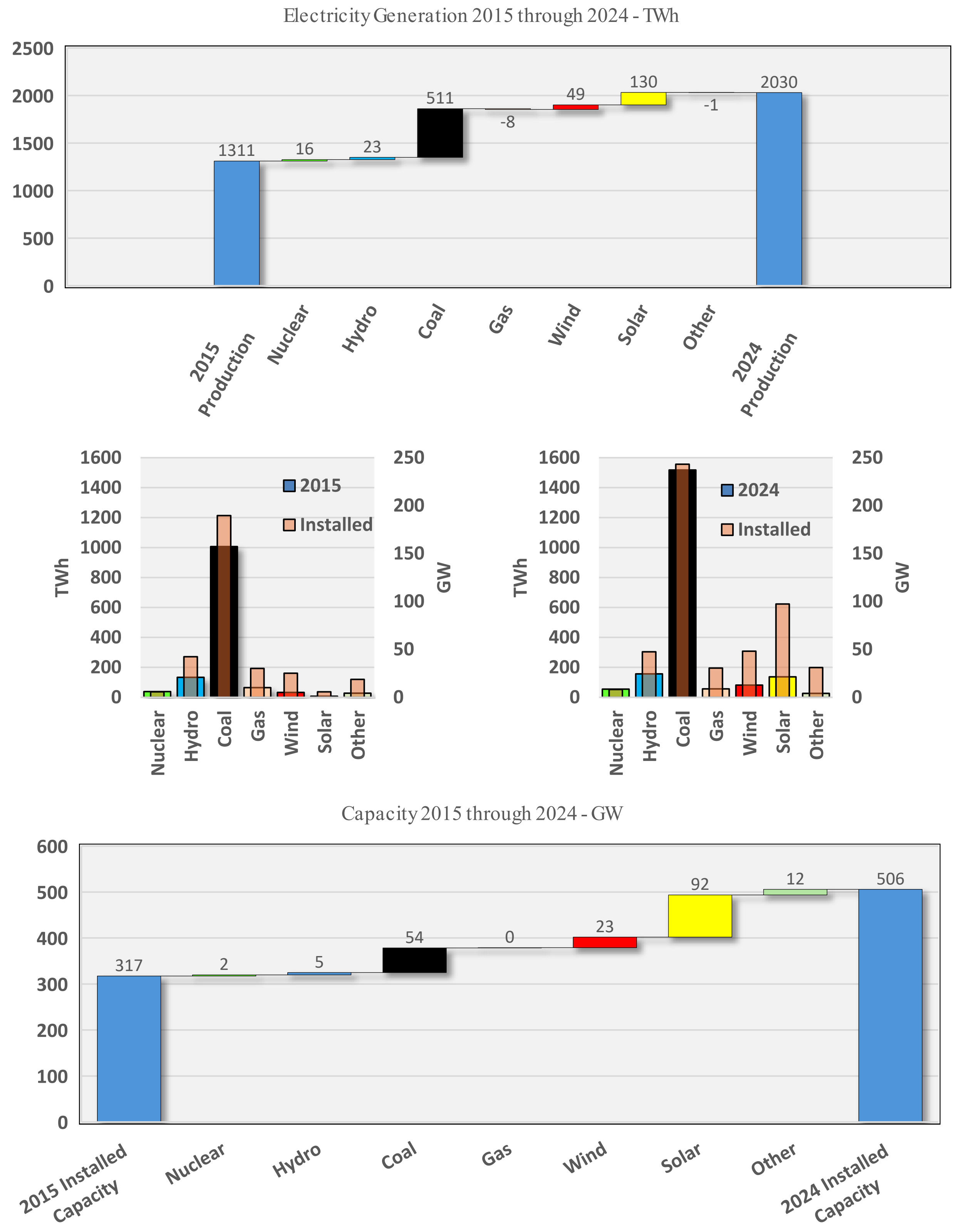


Figure 142. India capacity and generation summary, 2015 and 2024 (Data from [12])

6. AUSTRALIA ENERGY SUPPLY

Australia Electricity Supply

Overview 2015–2024—Australia

Australia's capacity, peak, energy, residential rates, and carbon intensity of the electricity supply are summarized in Figure 143.

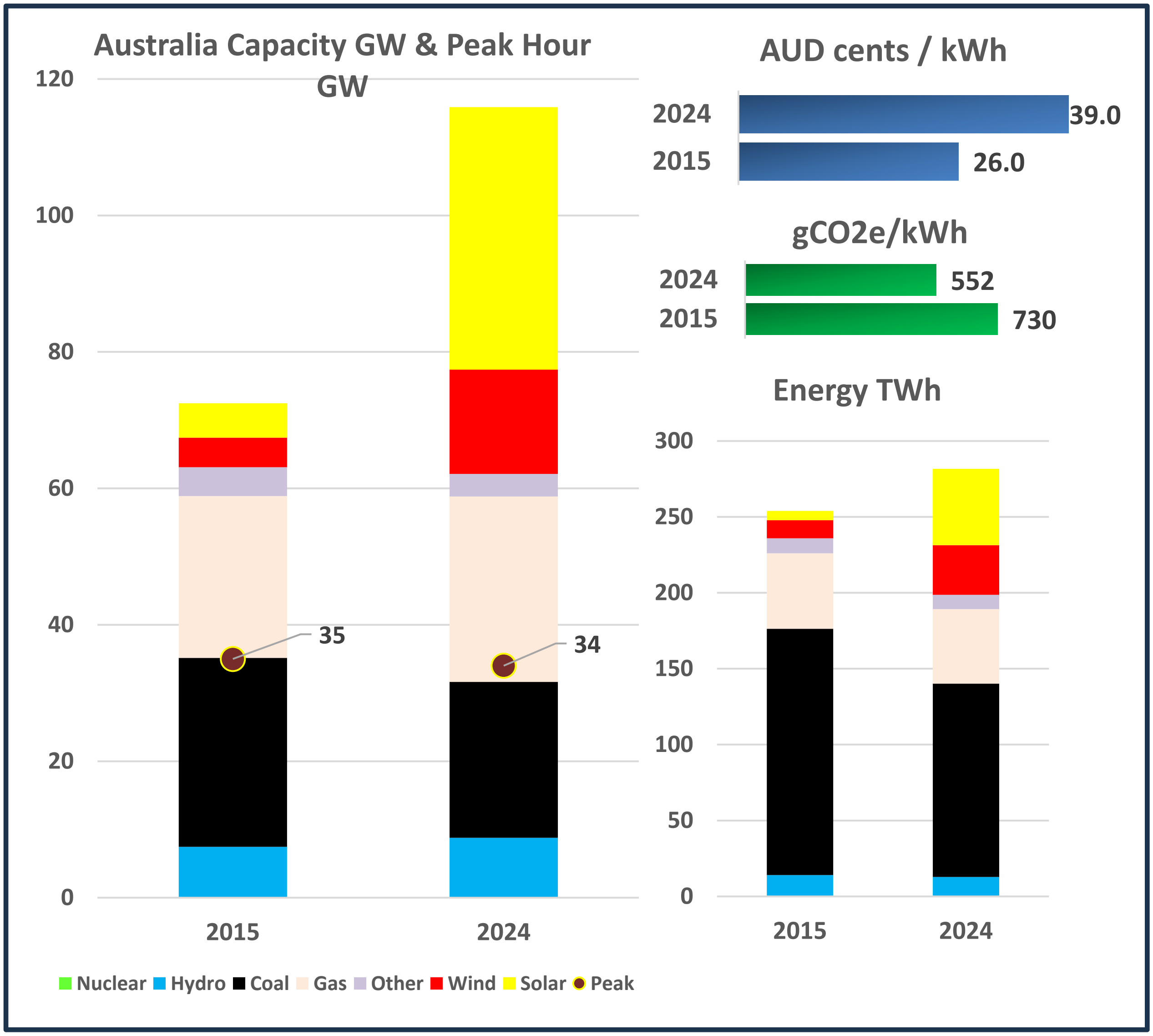


Figure 143. Australia 2015 and 2024 capacity and peak (GW), household rates (cents/kWh), carbon intensity (gCO2e/kWh), and energy (TWh) (Capacity and energy data from [12], rates from [76, 77], and carbon from [7])

The solar values include rooftop capacity and energy, with about two thirds of the total of each being from rooftop solar. The installed capacity in Australia has increased by nearly 60% since 2015 while energy from this capacity has increased 11%. The price has climbed, but in general it is lower than EU27 average prices and higher than U.S. average prices. The carbon intensity has reduced in a similar in magnitude to China's; however, costs are over three times those in China.

Figure 144 provides a monthly breakdown for 2024 by technology/fuel.

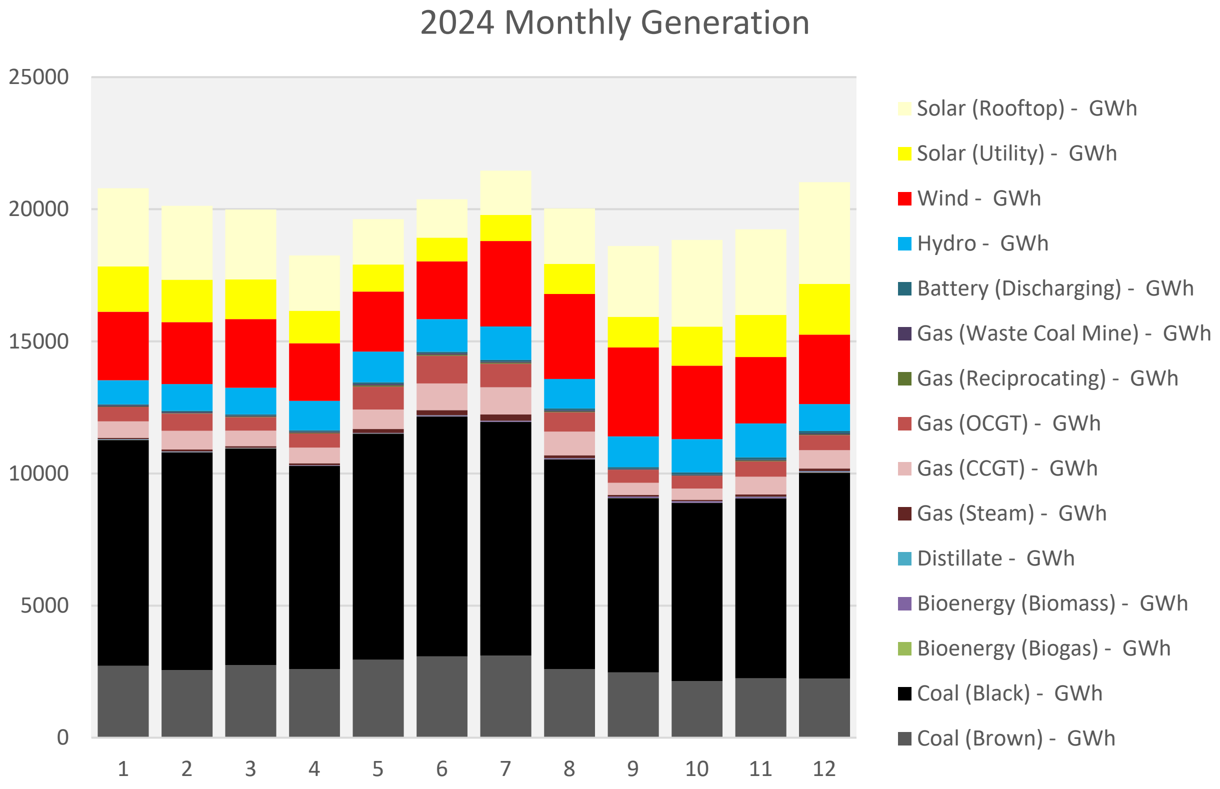


Figure 144. Australia monthly generation, 2024 by technology (Data from [78])

Figure 145 gives a breakdown of 2025 daily electricity generation in Australia ordered by coal and gas generation share. On the minimum day, the daily share was 40%; on the maximum day, the share was greater than 70%. Full hourly data for the last year is not readily available, but the extremes (minimum and maximum) will be lower for the minimum and higher for the maximum at an hourly resolution.

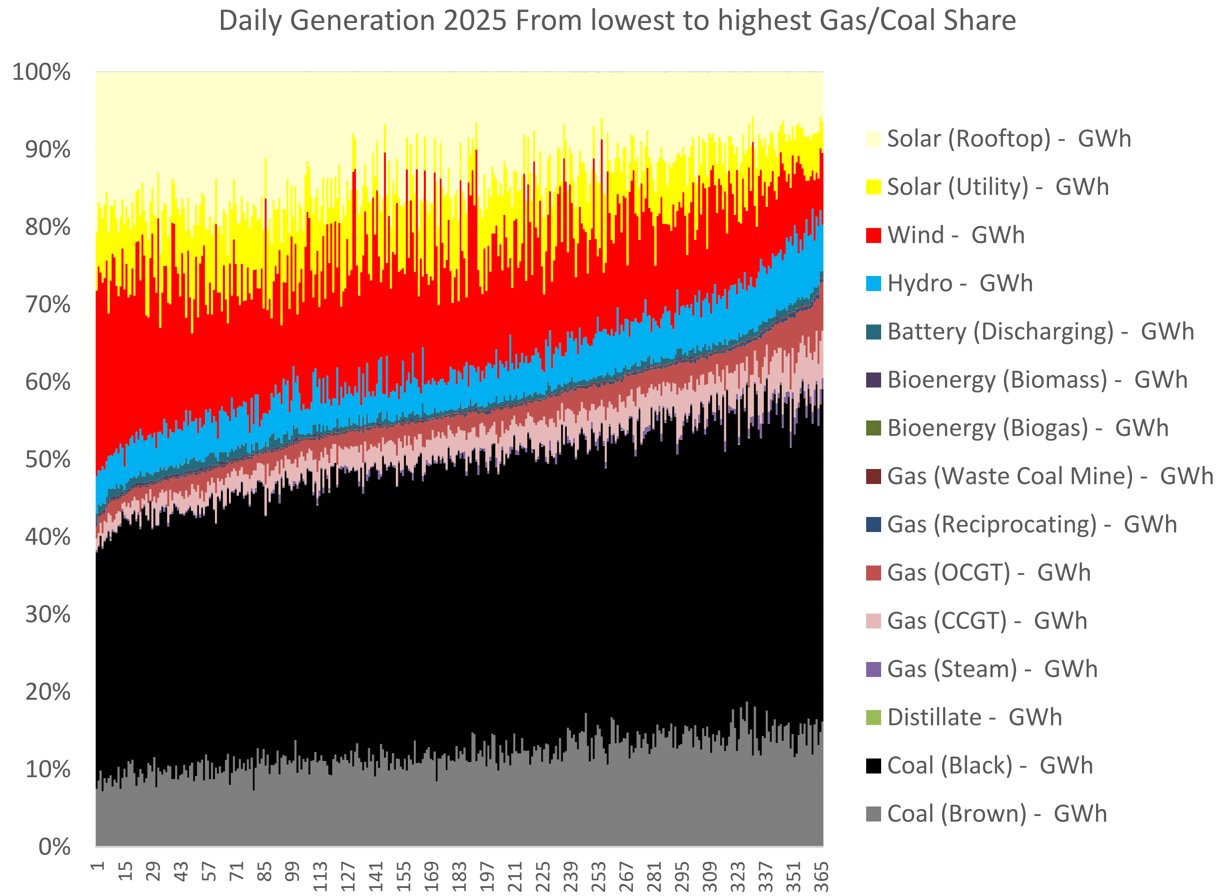


Figure 145. Australia daily generation share ordered by coal/gas share (Data from [78])

Australia Trends

The buildout of solar and wind resources over the last ten years in Australia has been significant in terms of GW of capacity (see Figure 143). The energy contribution from these resources is significant but is each less than half of the coal fleet energy contribution. Figure 146 illustrates the difference: the 2024 GW capacity is on the left and the 2024 energy from each resource is on the right.

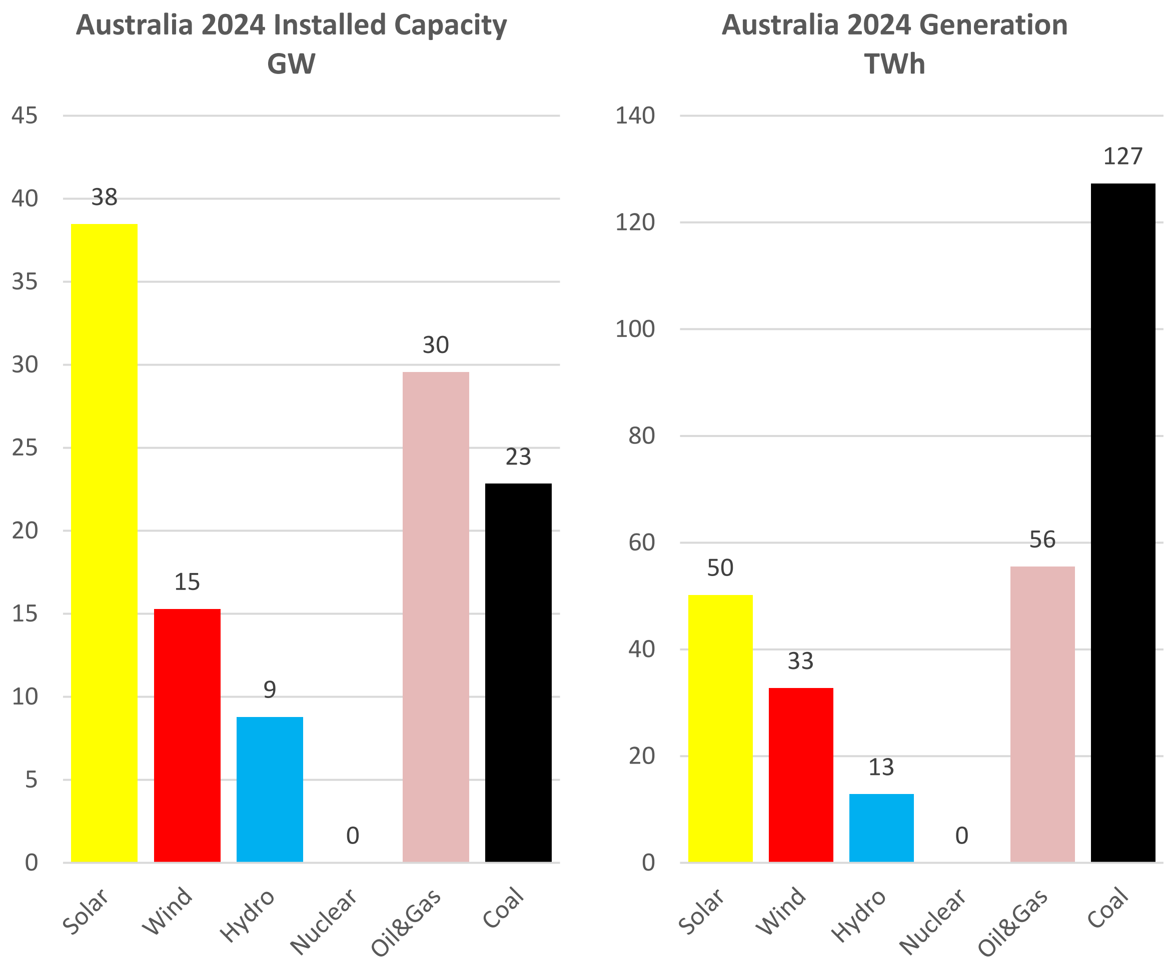


Figure 146. Australia energy (TWh) and capacity (GW) by resource (Data from [12])

In Figure 147, the 2024 annual energy (TWh) is divided by the installed capacity (GW) for each of the main resources. Coal provides the largest amount of annual energy in TWh per unit of installed capacity; solar provides the least.

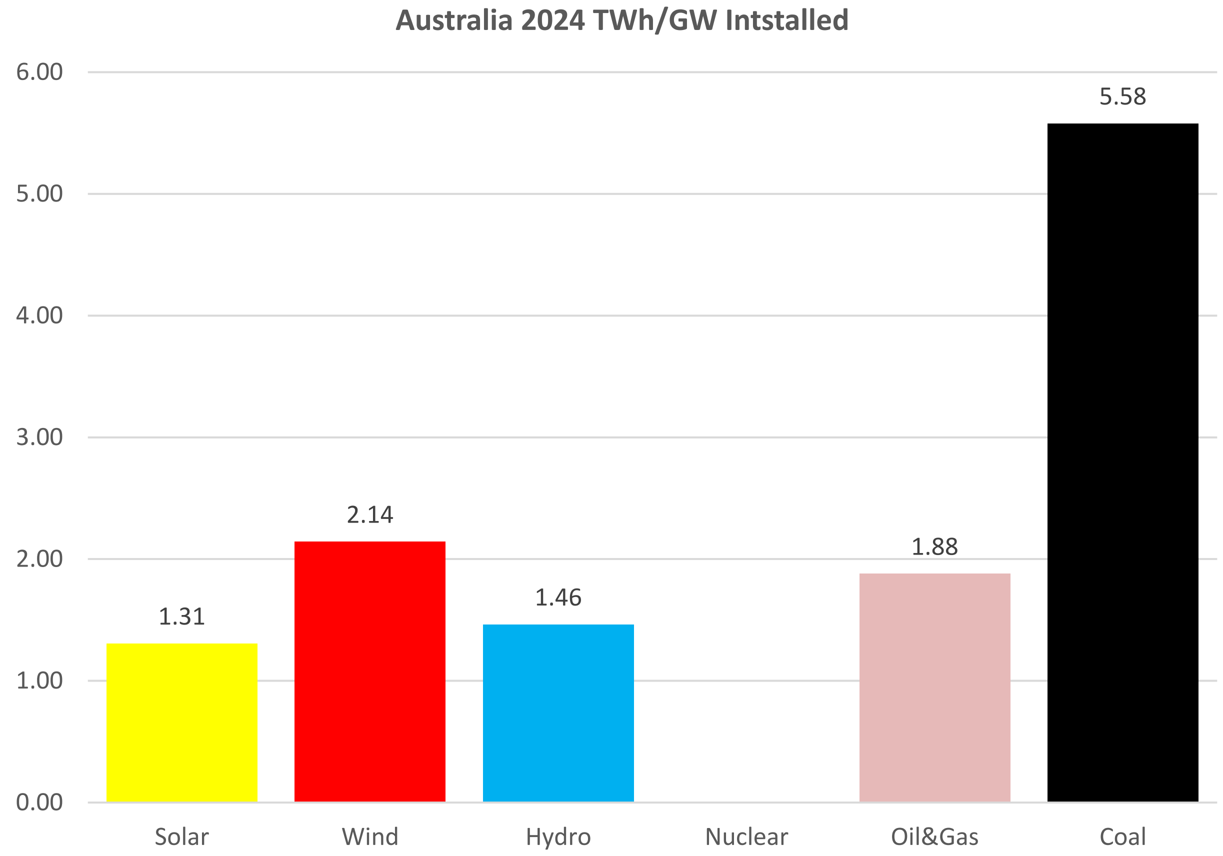


Figure 147. Australia 2024 TWh/GW installed capacity (Data from [12])

Generation Trends

As seen in Figure 143, generation in Australia has grown some since 2015. Figure 148 shows the generation for each resource since 1985. Coal generation grew for 20 years and is the largest source of electricity in Australia, but over the last 20 years, there has been a decline with periodic upswings; however, coal is still the largest source of electricity in Australia by a significant margin. Gas generation grew in the early 2000s but has been relatively steady in the last ten years. Wind generation also began increasing in the early 2000s but has more recently leveled off and is still surpassed by gas generation. Solar generation began growing in the 2010s and is now the second highest generation source after coal.

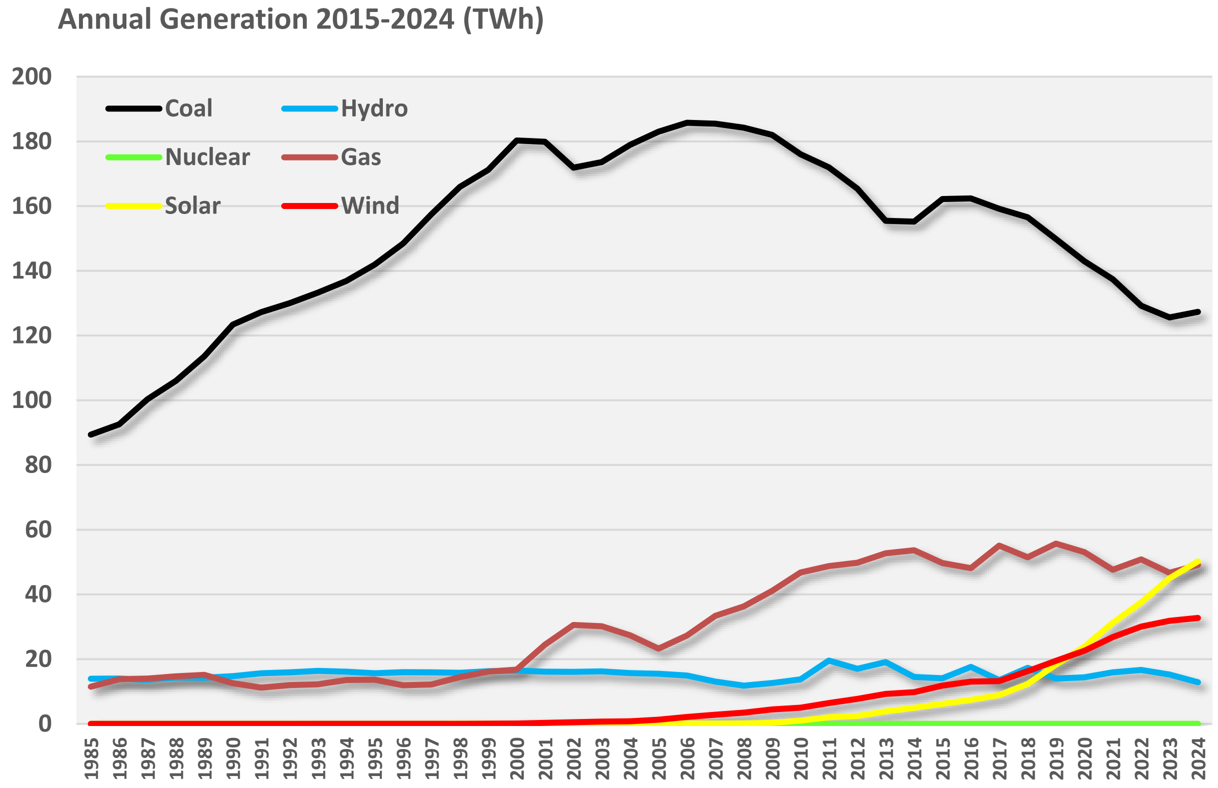


Figure 148. Australia annual generation, 1985–2024 by resource (Data from [6])

Electricity Supply Challenges

The 2022 East Coast Energy Crisis (June 2022) was a systemic failure rather than a physical one, leading to the first-ever suspension of the National Electricity Market (NEM).

Blackouts were avoided through emergency interventions. The Australian Energy Market Operator (AEMO) had to take control of the entire market for nine days. When global coal and gas prices spiked (due to the war in Ukraine), AEMO rules capped prices to protect consumers based on a rolling average value, which led generators to be unable to participate in the market as it was more expensive to produce than the price cap allowed. AEMO was forced to direct generators to turn on and stay on to prevent massive load shedding across New South Wales and Queensland. This was a period of elevated demand, with an increased reliance on coal and gas generation and diminished solar output [79].

The Callide Power Station explosion (May 2021) caused the most severe sudden loss of generation in the history of the NEM. A catastrophic failure and explosion occurred in the C4 turbine at the Callide Power Station in central Queensland, leaving approximately 470,000 customers across Queensland without power. Most power was restored within hours, but the Callide C unit remained out of operation for years, tightening Queensland's power supply for an extended period [80].

Severe weather and "Bushfire Safety" outages are recurring challenges for the Australian electricity system.

South Australia

Figure 149 is the daily electricity share by resource for South Australia for 365 days (December 15, 2024 to December 14, 2025), with the days ordered from least reliance on gas/imports to greatest. On the least reliant day, only 2% of the daily energy need came from gas and imports (November 17, 2025). On the most reliant day, over 80% of the daily energy need came from gas and imports (June 26, 2025).

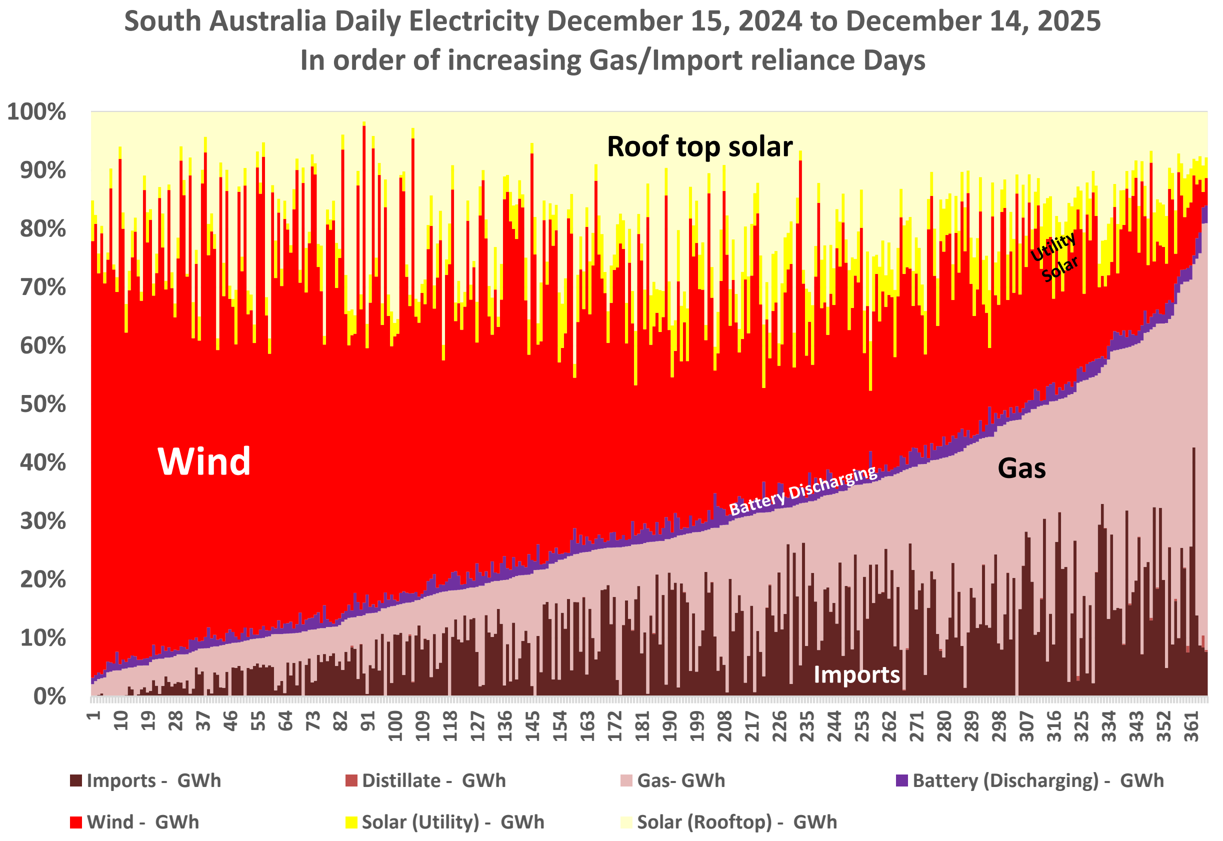


Figure 149. South Australia, December 15, 2024 to December 14, 2025, daily energy use by resource (from least to most gas + imports share) (Data from [78])

Figure 150 provides the installed capacity for South Australia in 2025 and includes the import capacity from Victoria, as well as the energy generation by resource. The weighted average emission intensity of imports during this period was ~770 gCO2e/kWh. The Victoria brown coal fleet emission intensity for the corresponding period was ~1190 g/kWh, implying that up to 65% of the imports were coal-fired generation from Victoria.

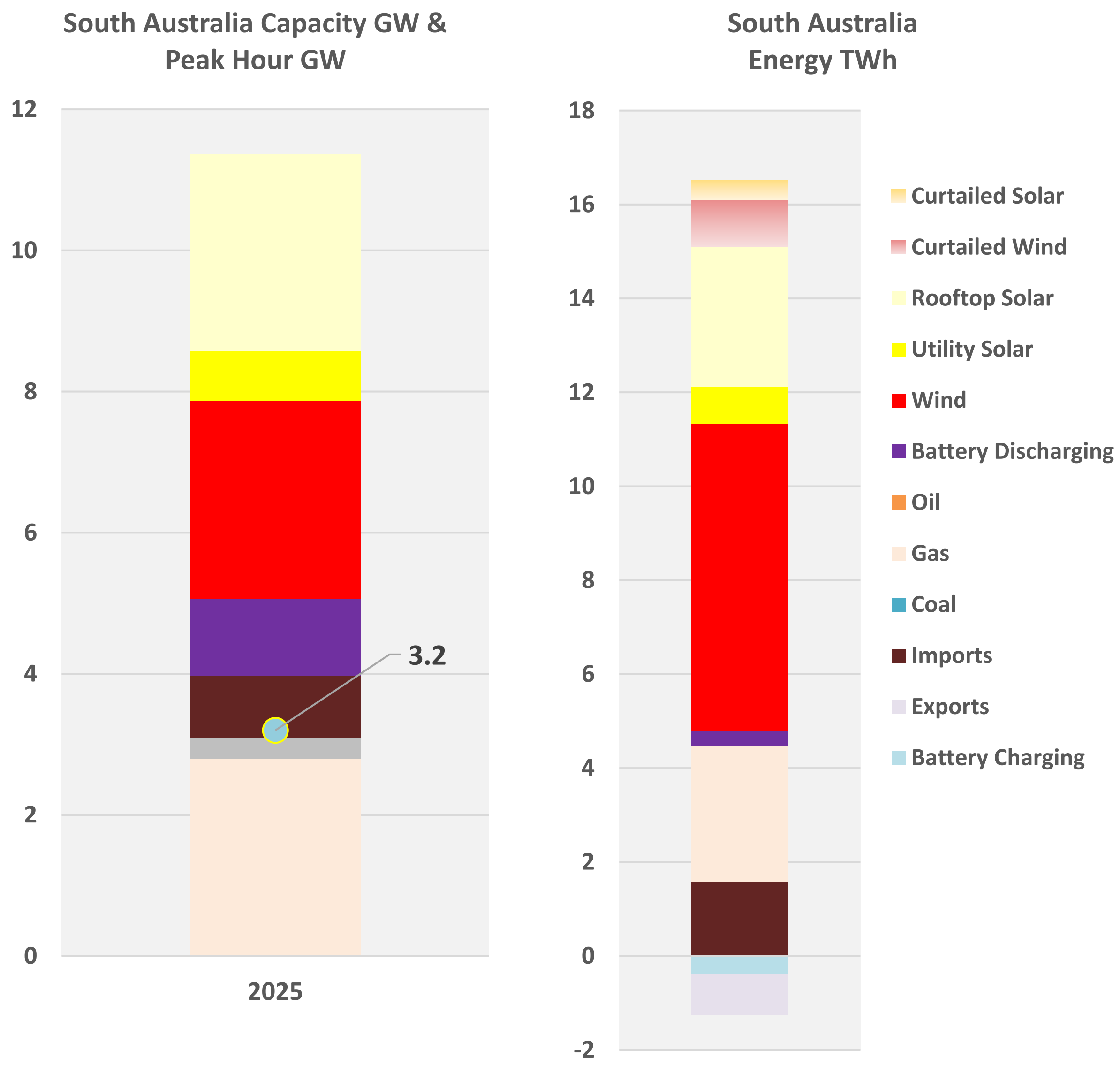


Figure 150. South Australia 2025 capacity (GW) and generation (TWh) (Data from [78])

Figure 151 provides the time series daily energy data for the period. The highest reliance on gas/imports tends to occur during the winter.

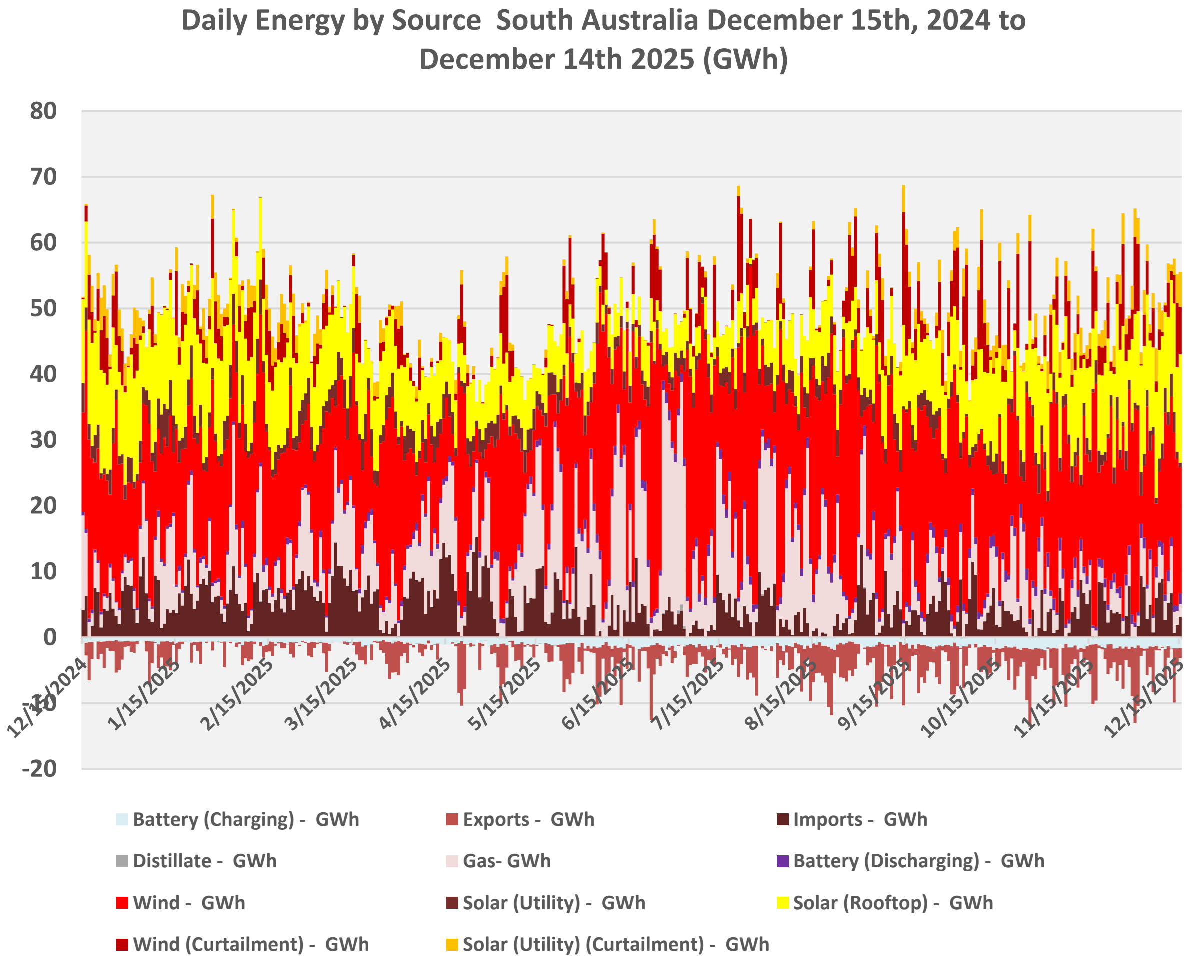


Figure 151. South Australia daily energy by resource, December 15, 2024 to December 14, 2025 (Data from [78])

Figure 152 provides the overall evolution of the South Australian energy mix from 2000 to 2025. During this period up to current day, South Australia has electricity prices about 30% higher than the rest of Australia. South Australia's in-state production of electricity has a carbon intensity of ~140 gCO2e/kWh, but including imports, the annual average carbon intensity of electricity consumed in South Australia is a little greater than 200 gCO2e/kWh, about four times greater than the emission intensity of France.

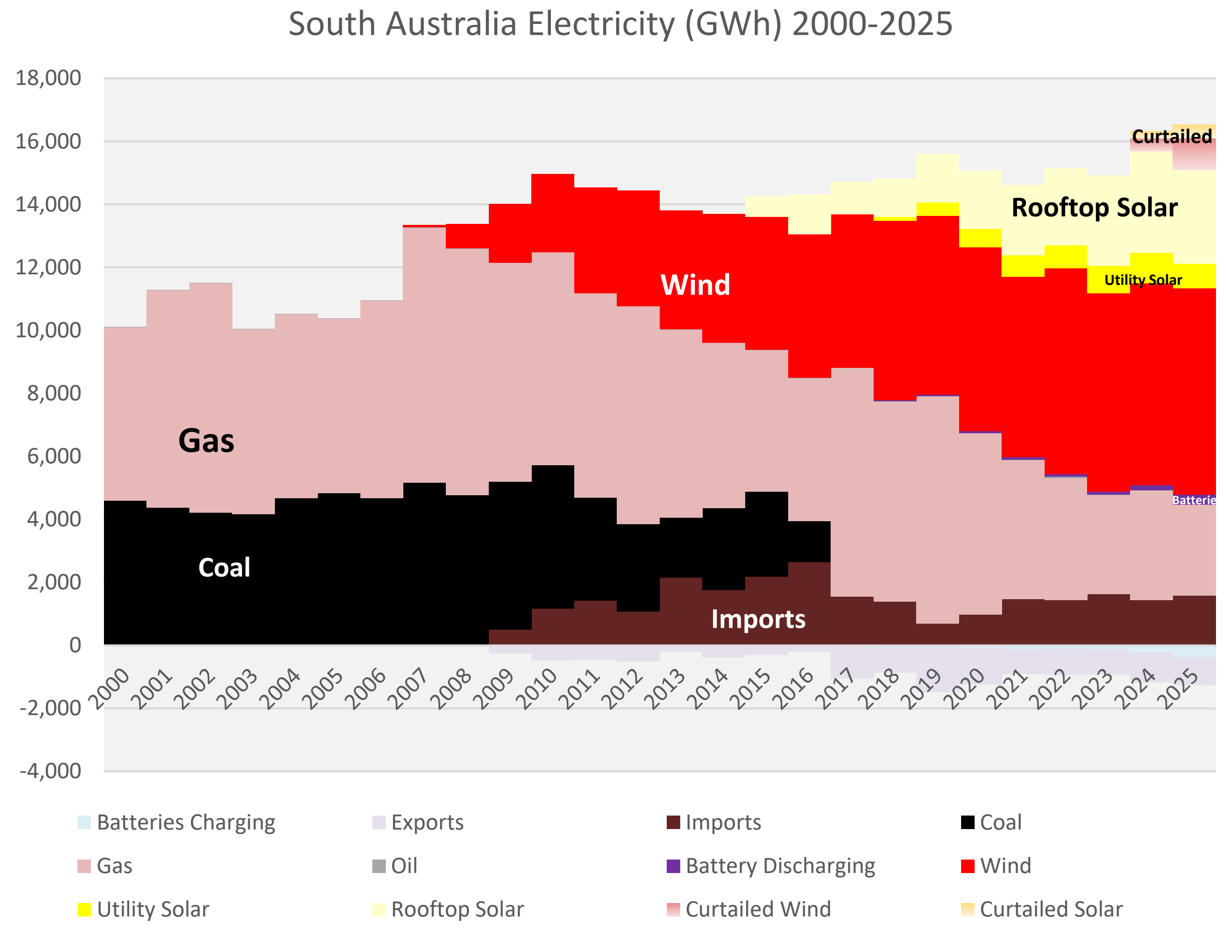


Figure 152. South Australia annual energy, 2000–2025 (GWh) (Data from [78])

Australia Summary

Australia’s electricity costs have increased significantly from 2015 to 2024. They are greater than the U.S. average price but still less than the EU27 average price. The average rates in 2024 were more than three times China’s average price. Carbon emission intensity has decreased and is currently similar to China’s. Australia experienced energy supply challenges in 2022, but this was due to market setup. South Australia has electricity prices ~30% higher than the rest of Australia, a carbon similar to the EU27 average (about four times higher than France’s), and receives up to 11% of its annual electricity energy from imports, with imports representing up to 40% of the daily electricity energy on some days.

Key Findings

- Australia delivered ~30% of its annual electricity production from solar and wind resources, 45% from coal, 5% from hydro, and 17% from gas power in 2024.
  - South Australia delivered ~70% from solar and wind resources, 20% from gas, and 10% from imports on an annual basis; the daily percent covered by gas/imports was as little as 2% to over 80% of the daily energy consumption.

- Australia’s overall annual system electricity use has increased by 10% since 2015, with the nameplate capacity increasing 60%.
- Australia’s daily share of electricity from coal and gas varied in 2025 from a low of 40% to over 70%.
- Australia has had periodic reliability issues associated with energy supply; part of this had been a market structure designed to protect rate payers that led electricity production to be uneconomical.

Figure 153 provides a waterfall graph of energy (TWh) changes (top chart), a waterfall of capacity (GW) changes (bottom chart), and a breakdown of total energy (TWh) and capacity (GW) by resource for 2015 and 2024 (middle charts).

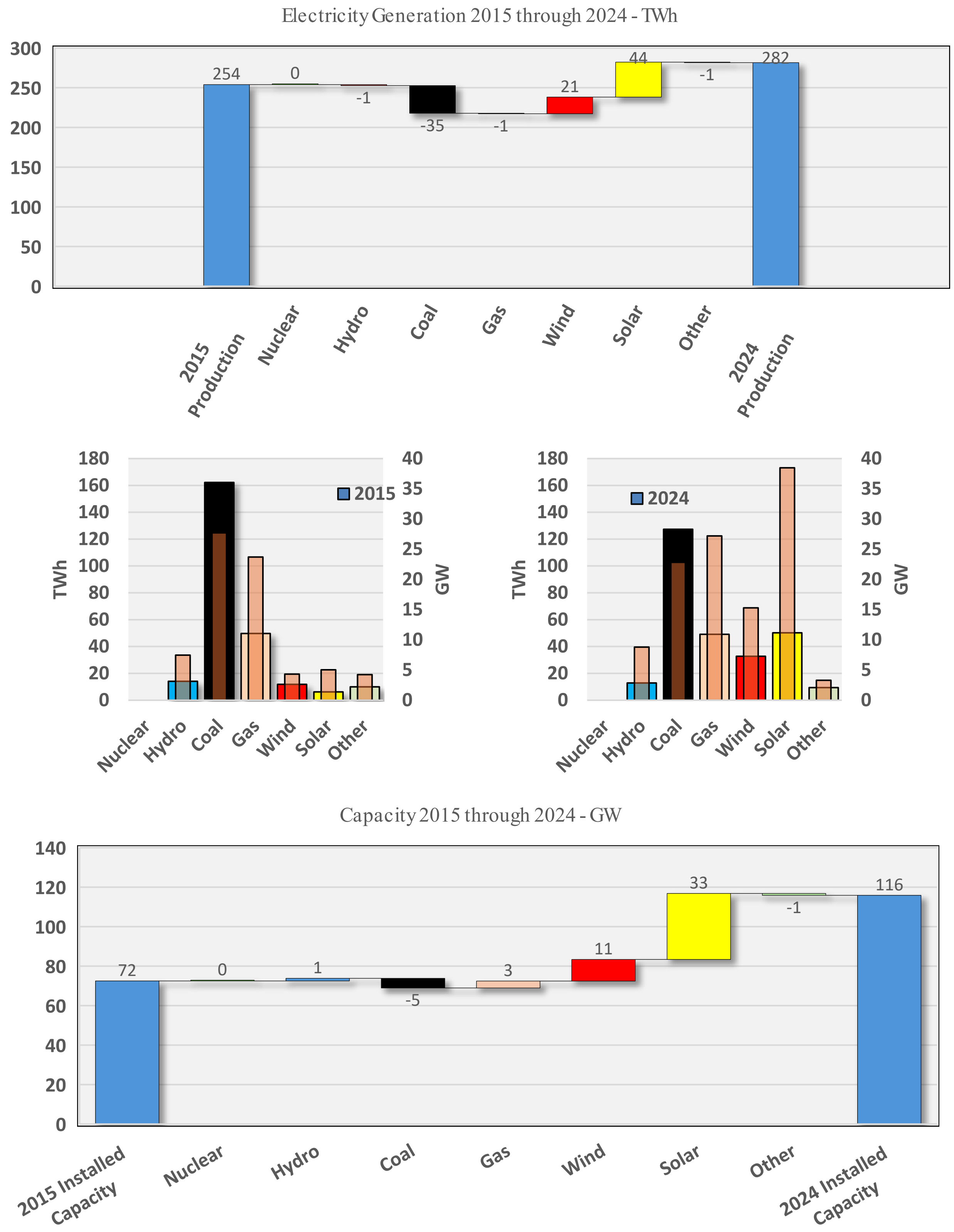


Figure 153. Australia capacity and generation summary, 2015 and 2024 (Data from [12])

7. SOUTH AFRICA ENERGY SUPPLY

South Africa Electricity Supply

Overview 2015–2024—South Africa

South Africa's capacity, peak, energy, residential rates, and carbon intensity of the electricity supply are summarized in Figure 154.

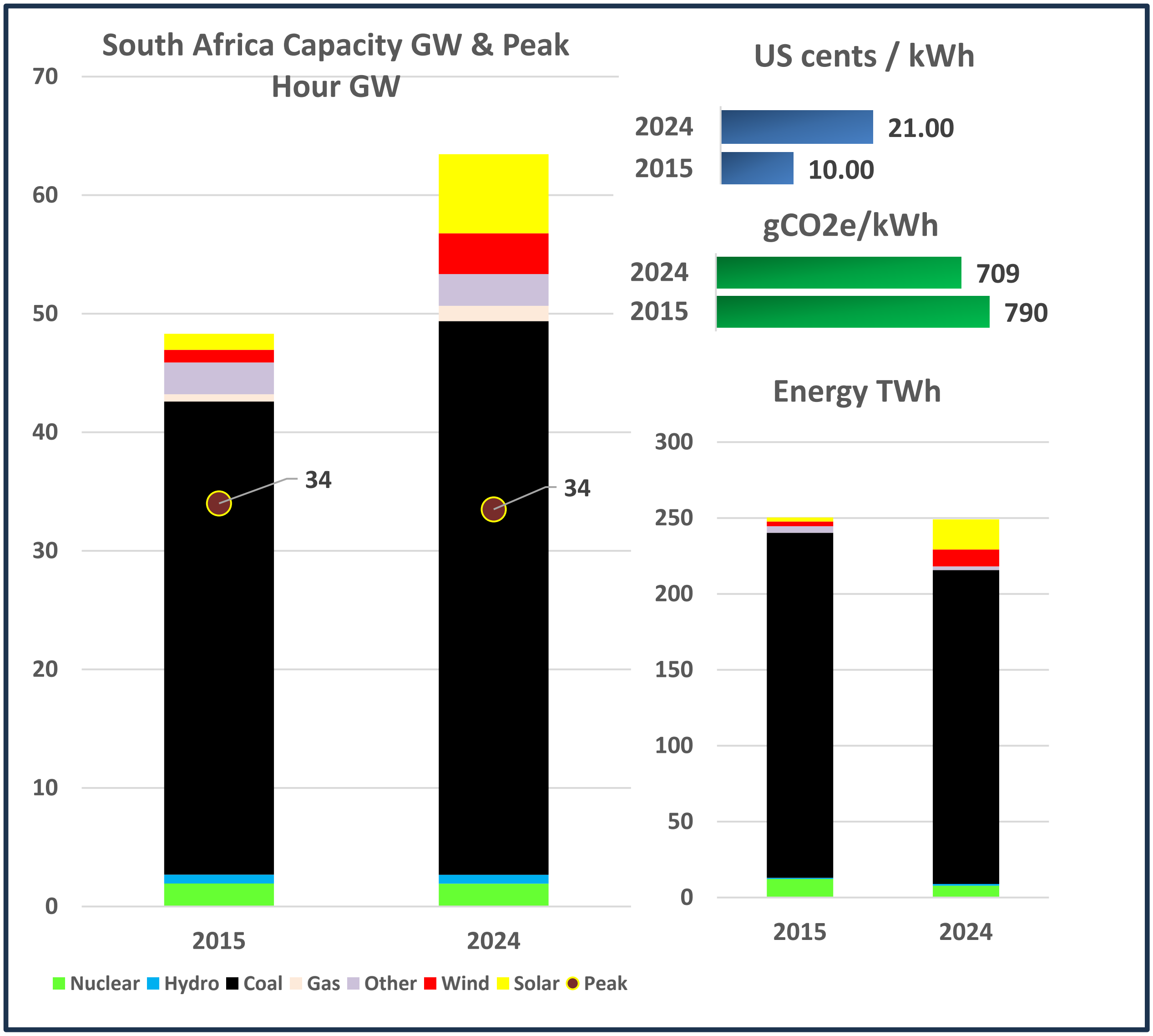


Figure 154. South Africa 2015 and 2024 capacity and peak (GW), household rates (cents/kWh), carbon intensity (gCO2e/kWh), and energy (TWh) (Capacity and energy data from [12], rates from [81, 82], and carbon from [7])

South Africa's installed capacity has increased by over 30% since 2015; however, energy from this capacity has decreased slightly. The price has more than doubled; it is slightly higher than the United States but still significantly lower than EU prices. The carbon intensity has reduced – similar in magnitude to India's, but costs are over twice the cost in India.

Figure 155 provides a monthly breakdown for 2024 by fuel during the monthly demand peaks in winter.

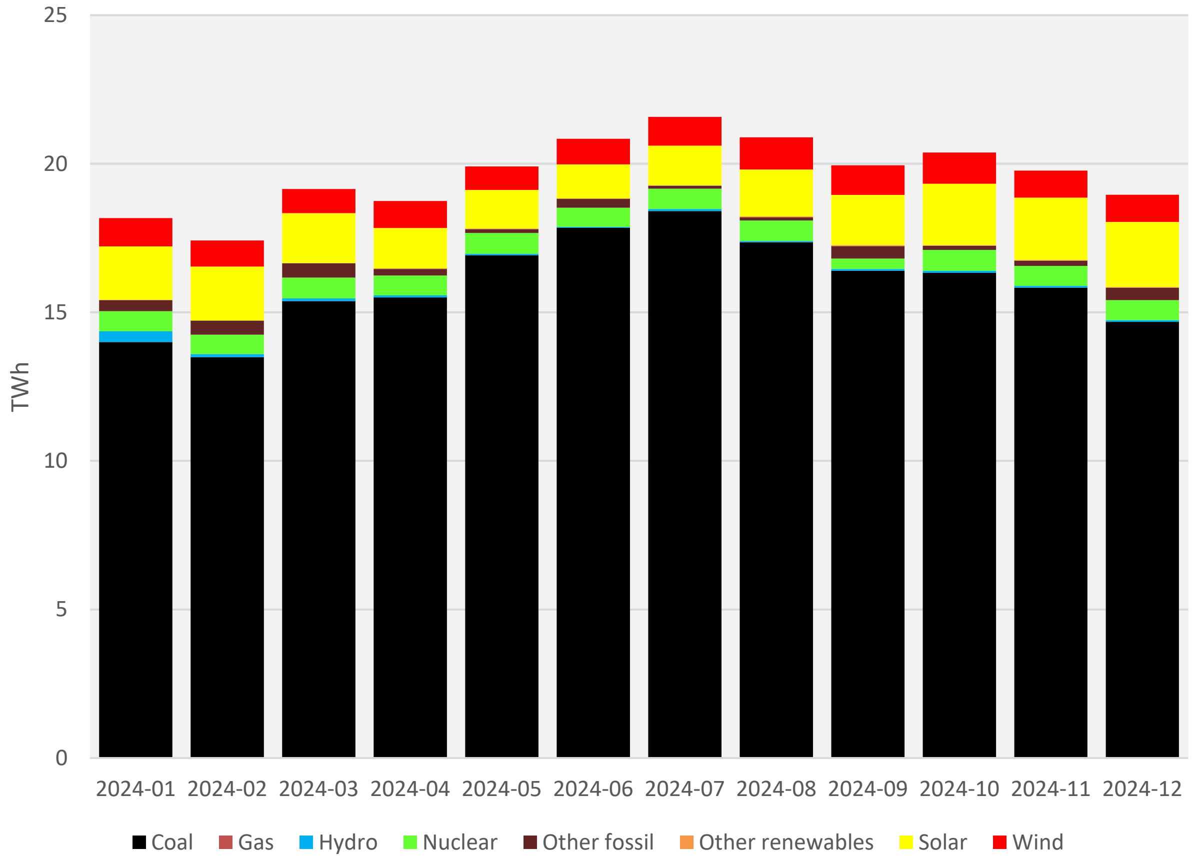


Figure 155. South Africa monthly generation, 2024 by fuel (Data from [12])

South Africa Trends

South Africa has added some solar capacity since 2015 (see Figure 154) but remains reliant on coal for most generation (TWhs). Major life extension work on one of the South African nuclear reactors has been ongoing in 2024, significantly reducing the output from the South African nuclear fleet.

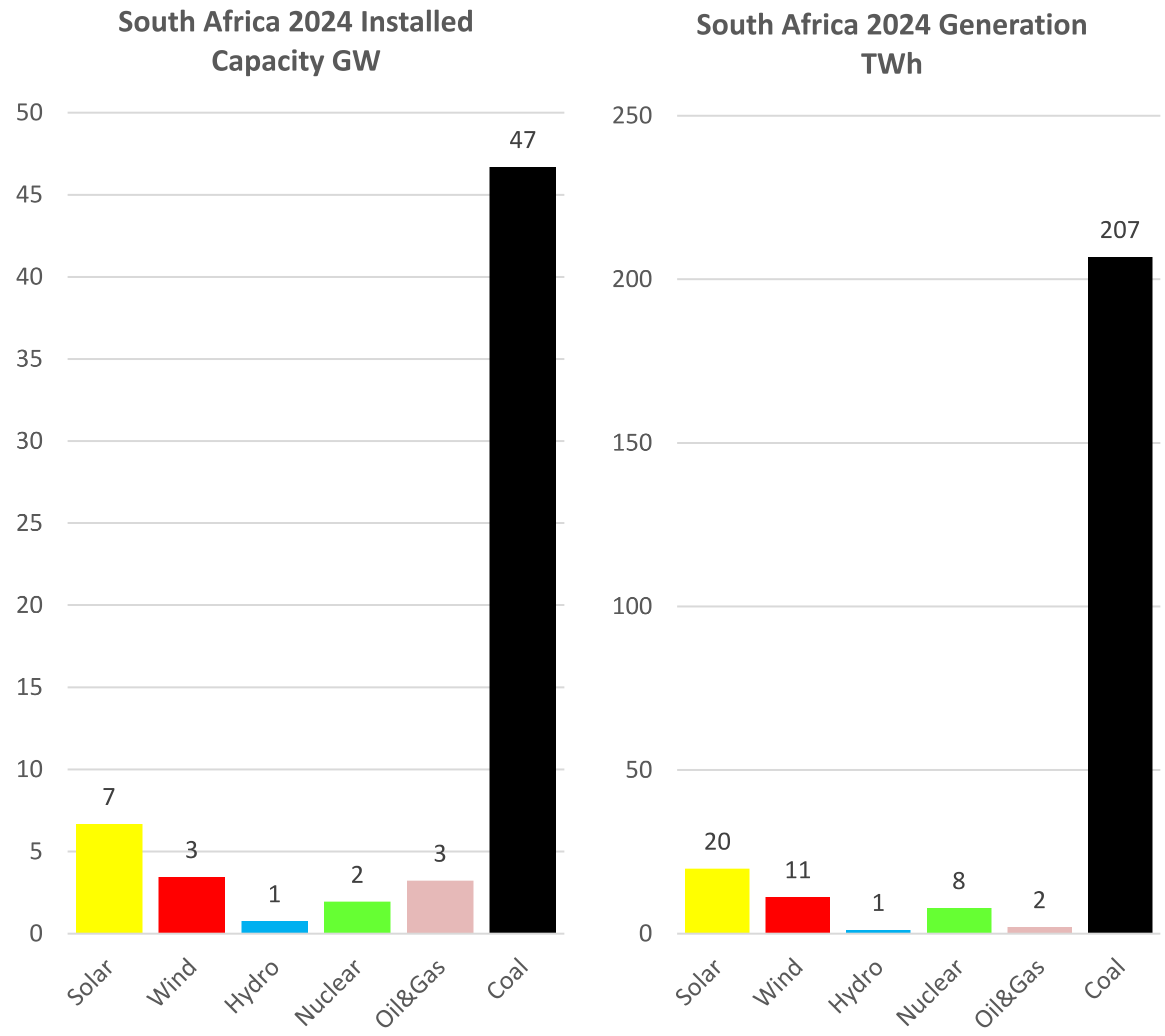


Figure 156. South Africa energy (TWh) and capacity (GW) by resource (Data from [12])

Generation Trends

As seen in Figure 154, generation in South Africa has declined slightly since 2015. Figure 157 shows the generation of each resource since 1985. Coal generation grew for 20 years and is the largest source of electricity in South Africa. Over the last 20 years, there has been some decline, with an upswing in 2024. Coal remains the dominant source of electricity in South Africa by a significant margin. In the last five years, solar generation has begun to increase but is not a major share of total generation.

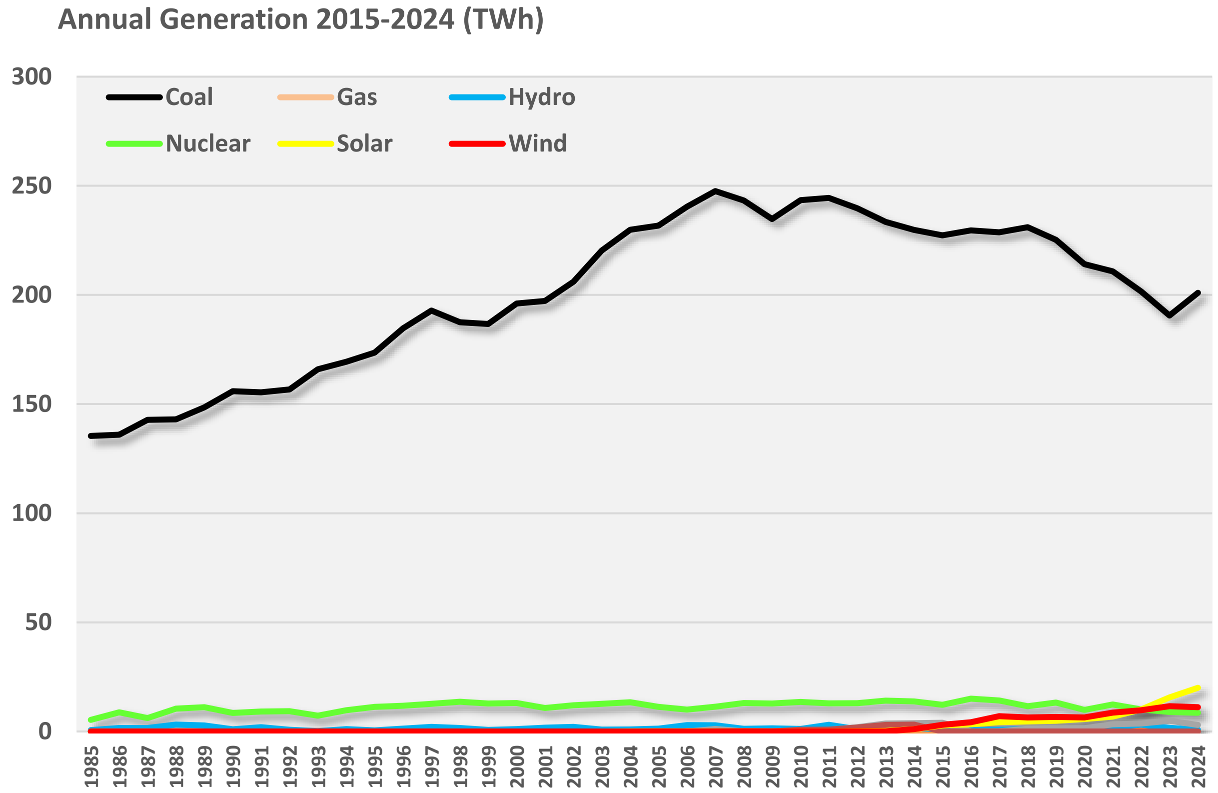


Figure 157. South Africa annual generation, 1985–2024 by resource (Data from [6])

Electricity Supply Challenges

South Africa has faced shifting challenges in the electricity supply. Issues increased after the pandemic, with 2022 and 2023 having a very high number of days with load shedding. This was followed by a more stable supply in 2024 and 2025 (see Figure 158). This reduction has been in part due to improved coal power plant generation (in 2024 coal generation output increased by over 10 TWh, a 6% increase from 2023) in addition to significant increases in solar (over 5 GW), much of it rooftop solar [83].

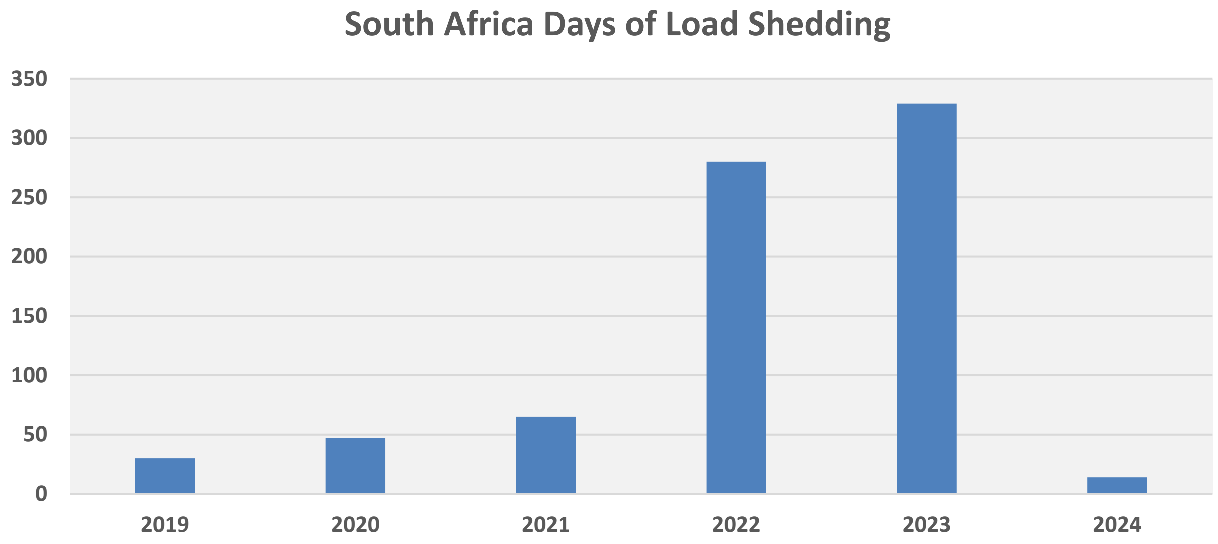


Figure 158. South Africa days of load shedding (Data from [84, 85])

South Africa Summary

South Africa’s electricity costs increased significantly from 2015 to 2024. They are greater than the U.S. average price, but still less than the EU average price. They are more than twice the Indian average price. Carbon dioxide emission intensity has decreased and is currently similar to India’s. South Africa has experienced significant load shedding, but with increased solar and improved coal performance, recent years have seen less issues.

Key Findings

- South Africa delivered ~12% of its annual electricity production from solar and wind resources, 83% from coal, and 3% from nuclear power in 2024.

Figure 159 provides a waterfall graph of energy (TWh) changes (top chart), a waterfall of capacity (GW) changes (bottom chart), and a breakdown of total energy (TWh) and capacity (GW) by resource for 2015 and 2024 (middle charts).

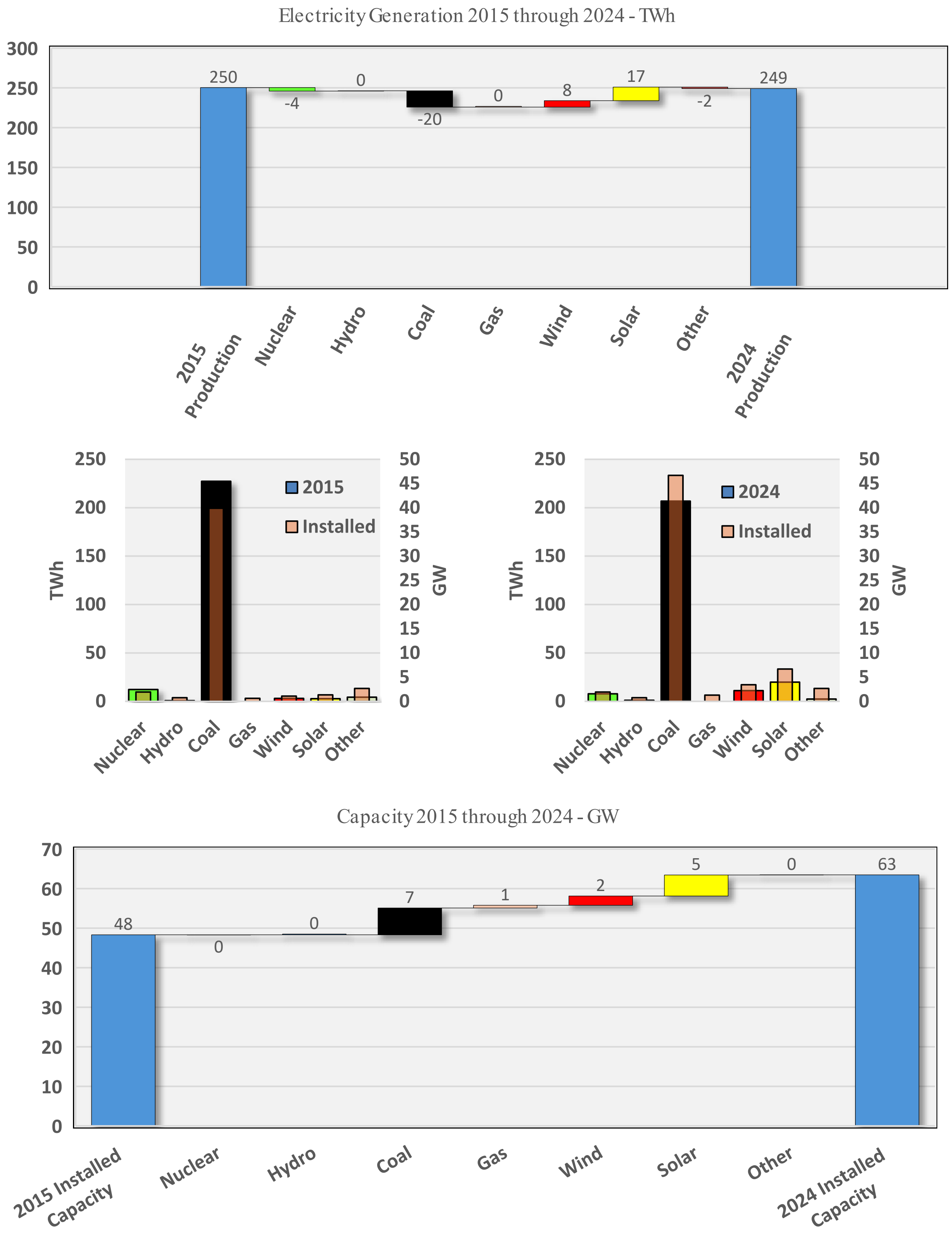


Figure 159. South Africa capacity and generation summary, 2015 and 2024 (Data from [12])

8. DISCUSSION, CONCLUSIONS, AND RECOMMENDATIONS

Discussion

Timescales Matter

Annual, seasonal, weekly, daily, hourly, and sub-hourly timescales are all relevant when thinking about the energy trilemma for electricity. As shown in the sections above, Iberian Peninsula Blackout and Winter Storm Uri, electricity security collapses in seconds to minutes. Mismatches in seasonal, weekly, and daily energy supply and demand can introduce energy equity concerns and economic viability concerns. This is highlighted by the change of Germany from a net importer to net exporter (see section above, Germany Import/Export), and the changing value of solar in California (see Value of Solar) with the recent springtime wholesale value of solar generation being negative,. In California, it is increasingly uneconomical to build solar without battery energy storage collocated with it (see Figure 111). As highlighted by the Iberian Peninsula Blackout, springtime risks from changes in the reliability services (see Figure 2) of the available energy mix can have a significant impact on security and necessitate changing the market operation to reduce this risk. In the case of Spain, this has led to the increased use of gas-fired power plant units (see Figure 55), which has introduced new costs to address reliability risks. Winter Storm Uri demonstrated that an affordability gain in a quiet market can be instantly wiped out by a single security collapse (see Figure 79). It will be informative to observe how costs evolve in Spain as it addresses security concerns demonstrated by the Iberian Peninsula Blackout.

In several regions, an effort was made to look at how increasing variable resources and storage led to a reduction in energy needs from other resources on an annual and daily basis. In Spain and Germany, about a 30% reduction in annual energy from non-wind and non-solar resources was achieved from 2015 to 2024, but less than a 10% reduction was achieved in daily peak energy from non-solar and non-wind. This was despite a 90 GW addition of solar and wind resources in Germany through the period and a 30 GW addition of solar and wind in Spain. Neither region had demand growth, and Germany actual had demand reductions (see Germany Peak Reduction and Spain Peak Reduction). A similar analysis for Texas (ERCOT) and California (CAISO) was conducted over the 2019–2024 periods. In both cases, there was no annual reduction in energy needed from non-wind/ solar/batteries, as well as in the daily peak energy. In fact, for Texas, daily peaks have grown (see ERCOT Peak Reduction and CAISO Peak Reduction). In the most recent year, neither Spain nor Germany have shown an annual reduction in need from non-wind and non-solar energy (similar to Texas and California). This indicates diminishing returns on these generation resource investments.

Affordability

Germany and the United Kingdom have the highest electricity rates in terms of absolute value in the examined regions. Germany's increase from 2015 to 2024 is somewhat in line with other regions. In terms of the rate of increase, the UK and California are standouts, both increasing by greater than 80% from 2015 to 2024. South Africa also had a large magnitude increase over the period, but its rates remain mid-tier for the regions examined.

Germany and the UK led in terms of reduction in electricity production over the period; both reduced electricity output by about a quarter from 2015 to 2024.

China and India led in terms of lowest cost electricity rates in absolute terms; both also did not have any appreciable increase in the 2015 to 2024 period, which coincides with leading growth in terms of electricity production for the examined regions. With both regions increasing electricity production by over 50% during the period, China now produces more electricity from coal alone than any other nation or region in the world produces from all sources combined. Monthly records for China coal-fired generation continue to be set in 2025, (see Generation Trends).

Sustainability

France leads in terms of the lowest greenhouse gas intensity of electricity by a wide margin. None of the examined regions come close to France in terms of this metric. France has accomplished this through the adoption of nuclear energy, which is both low emitting and able to deliver on peak demand hours as well as across peak demand days. Nuclear energy in this way can displace the need for other generation sources. Spain, the next leading region, emits more than three times the greenhouse gas emissions per unit of electricity produced; California and the UK emit more than four times as much, and Germany and the United States are in the range of eight times as much.

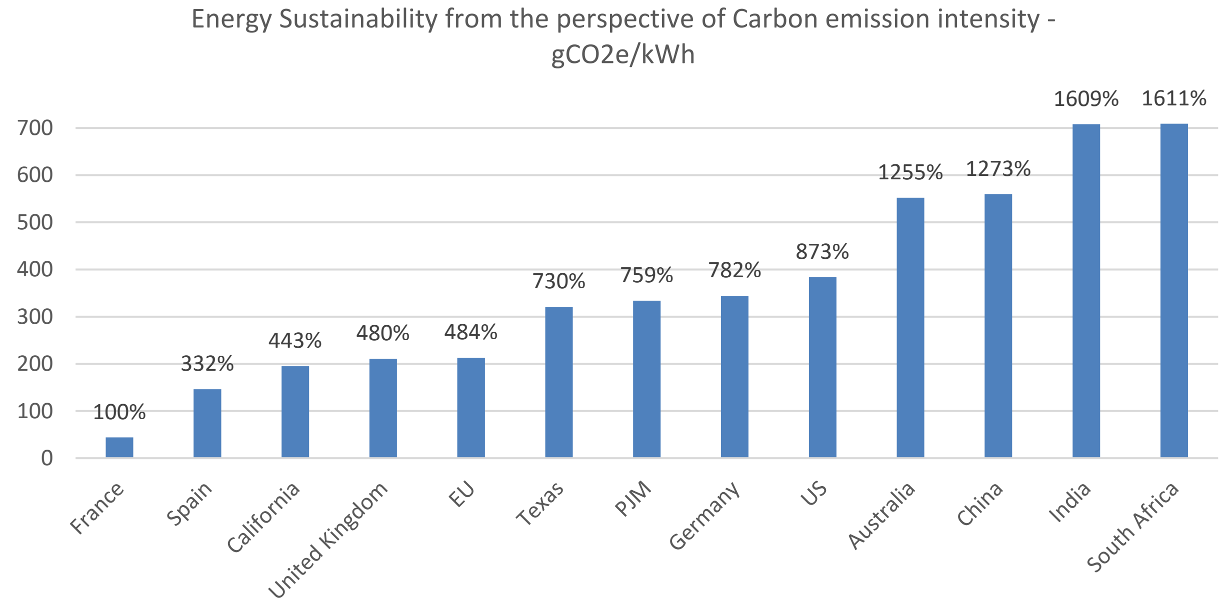


Figure 160. Relative carbon dioxide intensity of electricity supply, 2024

Security

All the regions examined have had some issues with electricity. Spain, with the recent nationwide blackout, and Texas, with the near blackout in 2021, are standouts. While Spain's nationwide blackout was larger in terms of outage, the impact from the winter rolling outages in Texas in 2021 associated with Winter Storm Uri was far worse. With hundreds of deaths and over $100 billion (USD) in financial impact, Winter Storm Uri demonstrated that system collapses can dwarf affordability gains (see Figure 79).

Trilemma

Figure 161 summarizes results from this study, with arrow direction showing prices on a nominal basis. Figure 162 provides the same information in terms of real 2024 prices. While real prices are more relevant to economists, public perceptions of affordability can be significantly influenced by nominal changes over time.

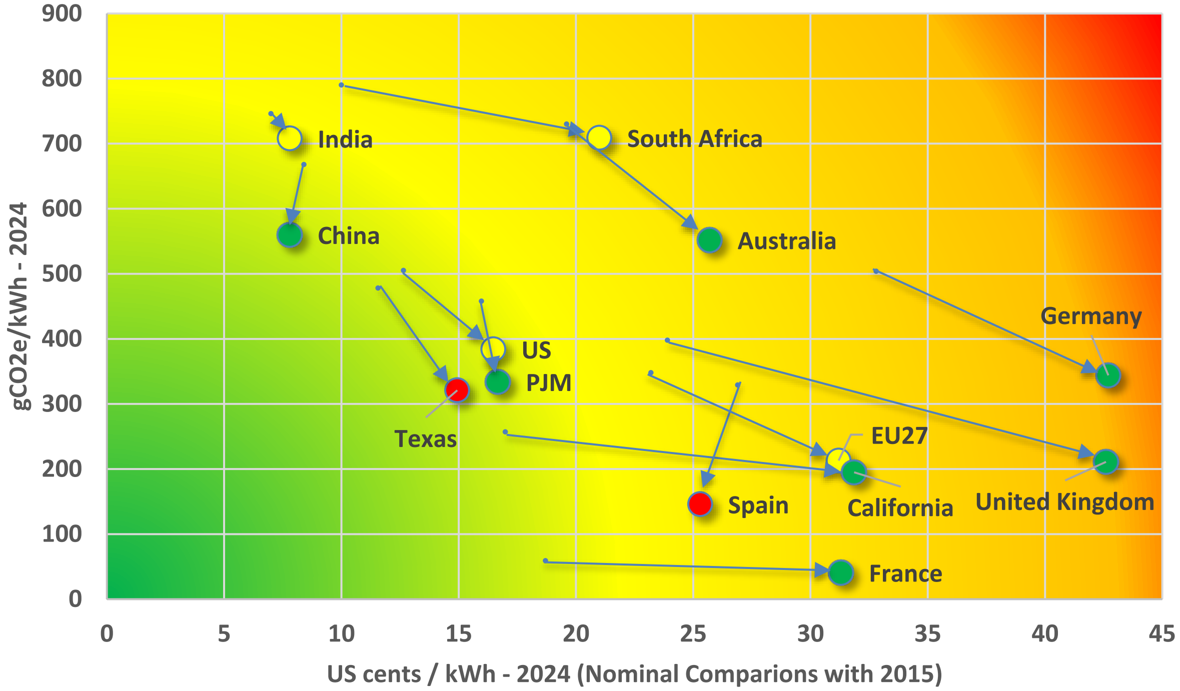


Figure 161. 2024 trilemma results for examined regions – red dots have had major security issues, yellow have had recent significant security issues, and green have had limited recent significant security issues. Arrows show progress from 2015 in nominal price terms.

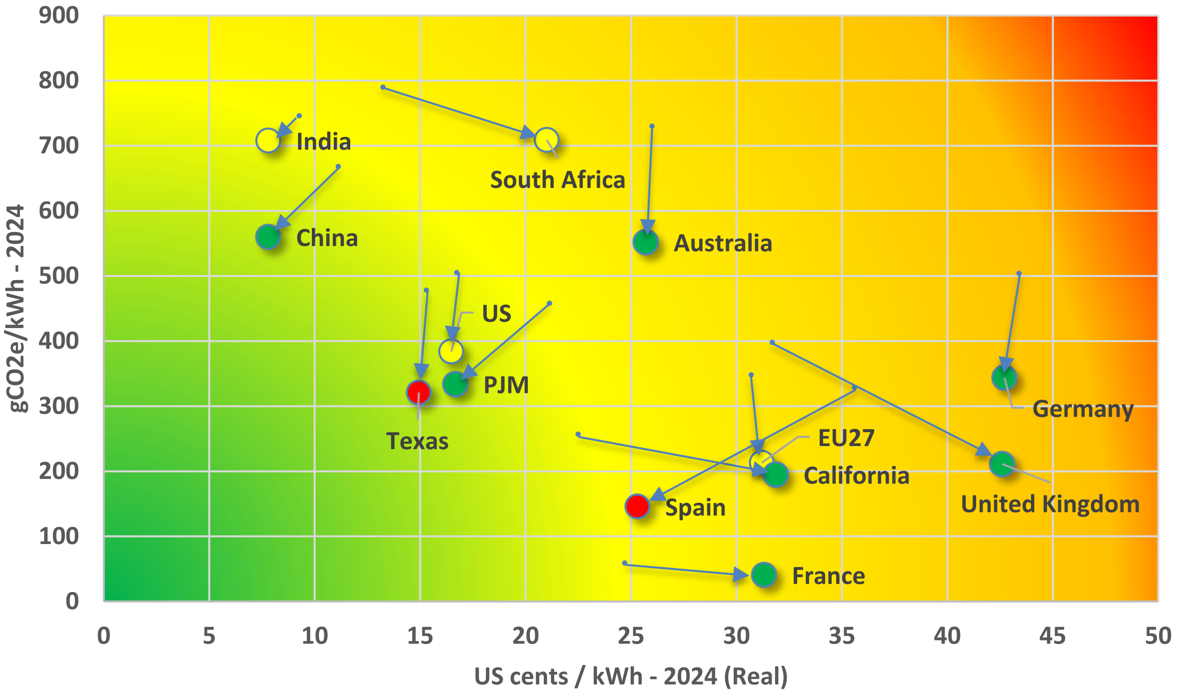


Figure 162. 2024 trilemma results for examined regions – red dots have had major security issues, yellow have had recent significant security issues, and green have had limited recent significant security issues. Arrows show progress from 2015 in real price terms.

Conclusions

This research was conducted to understand how evolving energy supply dynamics impact energy security and reliability under changing conditions. It sought to address the challenges posed by a changing energy supply mix. It is clear from this work that there is no single answer for achieving optimal results when it comes to the energy trilemma. However, several key findings have been established, which can provide insights into paths that may be more successful.

A secondary research question was, “What are the near-term implications for coal in the electricity energy supply?” For this question, the answer is clear: coal will remain a dominant source of electricity in Asia. With Asia already by far the largest electricity producing region in the world—while also growing much more rapidly than the rest of the world—it is imperative to improve on the environmental emission performance of coal-fired generation to achieve meaningful improvements in the global electricity mix. Technology advancements which improve coal generation’s ability to deliver energy security, energy equity, and energy sustainability will have substantial global benefit.

Key Findings

- Timescales are a critical dimension of energy security. While annual energy mixes inform sustainability goals, they provide a false sense of security regarding grid stability. Supply-demand mismatches can trigger system failures in seconds, as seen in the Iberian Peninsula frequency disturbances, or in minutes after several days of peak strain, such as in the 2021 Texas winter storm. To accurately assess risk, evaluations must include granular analyses of hour-by-hour demand and ramping capabilities under multiple scenarios.
- Affordability has reached a critical threshold in some of the regions examined. Germany and the UK stand out as high-cost leaders, characterized by a sharp divergence between domestic output and household expenses from 2015 to 2024.
  - United Kingdom: Domestic electricity generation fell by 24% while nominal household prices surged from ~21 to ~39 €c/kWh.
  - Germany: Domestic production saw a 25% decline, with nominal household prices rising from ~30 to ~40 €c/kWh.
    - This correlation suggests that as these nations decommissioned firm domestic capacity. The resulting reliance on imports and volatile wholesale markets significantly impacted consumer affordability.
- In contrast to the European trend, China and India have maintained stable electricity rates despite surging demand. Both nations have prioritized energy security and industrial competitiveness by leveraging domestic coal to meet the bulk of their expanded energy needs over the last 20 years. In both countries, wind and solar energy provided <20% of electricity needs.
  - China: Total electricity production rose by 74% from 2015 to 2024. Notably, increased coal-fired generation accounted for over 40% of this growth, providing the "firm" base for the expansion.
  - India: Total production increased by 54%, with coal-fired generation meeting more than 70% of the new demand, reflecting a strategic reliance on indigenous fuel sources to keep costs predictable.
- By 2024, Asia’s electricity consumption surpassed that of the rest of the world combined. This marks a radical shift from 2000, when North America and the EU were the primary consumers. While Western demand has remained stagnant due to efficiency gains and industrial outsourcing, Asia has seen explosive growth, fueled largely by coal, which provides ~55% of the region's power.
  - China’s coal-fired generation alone (~5,800 TWh) exceeds the total electricity production of any other single nation.
  - In August 2025, China produced approximately 580 TWh from coal alone. To put this in perspective, China generated more electricity from coal in this single month than any individual EU nation produces from all sources in an entire year.
  - Most midsized developed nations produce less than 10% of what China generates from its coal fleet alone, highlighting a massive gap in industrial energy scale.

- In terms of sustainability and GHG emissions, France remains the definitive leader among major economies. In 2024, France maintained an extraordinary emission intensity of ~41 gCO2e/kWh, the lowest of any G20 nation.
  - France's carbon intensity is approximately three times lower than Spain's, four times lower than California’s, 5 times lower than the United Kingdom’s, and eight times lower than Germany’s.
  - This performance is anchored by a robust nuclear fleet, which accounts for 67% of total generation. Combined with hydro and wind, over 95% of French electricity is now low carbon.
  - Unlike regions with supply-demand mismatches, France’s reliance on nuclear provides a "firm" low-carbon base that supports both national grid security and massive electricity exports to its neighbors.
- As of 2024, coal remains a cornerstone of global electricity, followed by natural gas, hydro, and nuclear. While solar and wind are expanding rapidly, their intermittent nature leaves them unable to consistently meet peak demand without support. While battery storage has begun to address sub-hourly peaks, it introduces a secondary demand cycle on the grid to facilitate recharging.
  - Given the persistent reliance on coal in the world’s most energy-intensive regions, innovation must focus on technologies that align fossil fuel use with the energy trilemma:
    - Security: Enhancing the "dispatchability" and ramping speeds of existing plants
    - Affordability: Maintaining the cost-curve advantages of domestic fuels
    - Sustainability: Accelerating the deployment of high-efficiency, low-emission (HELE) technologies and carbon capture, utilization, and storage (CCUS)
  - Improving the environmental performance of the global coal fleet, rather than assuming its immediate disappearance, offers a more realistic pathway to meeting global climate goals without compromising regional stability.

Additional Findings

- Many regions, including North America, Asia, South America, and Europe, have faced events leading to load shedding or blackouts. In the United States, these events often coincide with the Department of Energy’s use of Federal Power Act Emergency Authority. Global examples of nationwide blackouts include Chile 2025 and the Iberian Peninsula 2025 (Spain and Portugal).
- California serves as a primary case study for the economic and operational challenges of high solar penetration. Despite aggressive deployment, the marginal value of solar continues to decline, leading to "negative pricing" and increased curtailment during springtime.
  - In February, March, and April, midday solar supply frequently exceeds demand, driving wholesale prices below zero.
  - While California exceeded 10 GW of battery capacity by early 2025, this has not reversed springtime curtailment.

  - Batteries have significantly mitigated "net peak" risks (the dangerous period in late summer evenings when solar fades but demand remains high), nearly eliminating the risk of summer rolling outages in California.
  - While 4-hour batteries have shaved the hourly gas peak, they have not reduced the total daily reliance on gas during summer.
  - Since 2019, the daily energy requirement from non-solar/non-wind/non-battery sources (primarily gas and imports) has remained largely unchanged, even with the addition of 20 GW of new solar and battery resources.
- Spain and Germany reveal a significant "displacement gap" where investments in renewable (solar and wind) capacity fail to significantly reduce the daily requirement for firm, non-renewable energy.
  - The German Case: Between 2015 and 2024, Germany added nearly 90 GW of solar and wind capacity. Despite this massive build-out, the peak daily energy required from non-renewable resources (coal, gas, and imports) has decreased by less than 10% compared to 2015 levels.
  - The Spanish Case: Similarly, Spain added 30 GW of solar and wind, yet the daily reliance on firm resources remains largely tethered to 2015 requirements.
  - These figures suggest that current renewable integration is creating a parallel system rather than a replacement system. Because solar and wind are non-dispatchable, the grid must still maintain almost the entire original firm fleet to meet demand during periods of low renewable output (the Dunkelflaute).
- The limits of weather-dependent generation were starkly illustrated in November 2024, when a region-wide Dunkelflaute stalled renewable output across the EU for approximately six days (140 hours).
  - Despite an installed wind and solar base exceeding 480 GW, average production during this period collapsed to just 39 GW.
  - For 140 consecutive hours, the entire EU27 fleet operated at less than 10% of its nameplate capacity.
  - This event demonstrates that a grid reliant on wind and solar must maintain nearly 100% redundancy in firm, dispatchable capacity (nuclear, gas, or coal) to prevent total system failure during prolonged atmospheric stagnation.
- In 2016, Germany was a cornerstone exporter for Central Europe. By 2024, the loss of firm nuclear baseload forced a structural reliance on imports, natural gas, and coal to stabilize the grid during peak demand.
  - Germany now faces a persistent price disadvantage:
    - Imports at peak: During periods of low renewable output (Dunkelflaute), Germany must import power at a high cost.
    - Negative price exports: During high-wind or high-solar periods, oversupply drives wholesale prices below zero, effectively forcing Germany to pay neighboring countries to take its excess energy.

  - This reliance on fossil-fuel peaking plants and high-carbon imports has kept Germany's greenhouse gas intensity significantly higher than the EU27 average and many of its neighbors, like France.
- The energy transitions in Germany and the UK face a firmness floor: while total annual gas consumption may fluctuate, the peak daily reliance on gas-fired generation has reached record levels.
  - Record-breaking peaks: Contrary to expectations of a diminishing fossil fuel footprint, the highest daily peaks for gas-fired electricity generation in both nations occurred in 2024 and 2025.
  - This trend highlights that as coal and nuclear plants are decommissioned, natural gas has become the sole "balancing" resource capable of covering massive renewable shortfalls during periods of high demand.
  - The need to meet these intensifying peaks requires maintaining a vast, expensive, and under-utilized gas fleet and pipeline infrastructure, which contributes directly to the rising system costs passed on to consumers and represents an energy security risk.
- The 2025 Iberian Peninsula blackout has forced a fundamental shift in Spanish grid management, moving from a strategy of renewable maximization to one of must-run reliability.
  - Since the April 28 collapse, Spain has significantly increased the number of gas-fired units operating at all times. This ensures that the grid maintains sufficient reactive power and inertia services that the existing inverter-based renewable fleet could not adequately provide during the frequency disturbances that triggered the blackout.
  - The blackout was characterized by a "voltage chain reaction" where generation disconnections led to further voltage spikes. By keeping gas units synchronized to the grid even during periods of high solar/wind, the operator provides a "damping" effect that prevents localized faults from cascading into a peninsula-wide security issue.
  - This requirement for constant gas synchronization increases the floor of fossil fuel generation, effectively creating a limit on how much renewable energy can be utilized without risking system collapse.
- While France's nuclear fleet provides a low-carbon baseline, its recent history reveals the "common mode risk" inherent in highly standardized energy systems.
  - France experienced a historic supply shock when stress corrosion cracking was discovered in auxiliary piping welds. This forced more than half the fleet offline simultaneously, reducing annual output by nearly 30% compared to 2021 (dropping from 360 TWh to 279 TWh).
  - France's strategy of using a single, coherent reactor design significantly reduced construction and maintenance costs for decades. However, this same uniformity created a common mode failure vulnerability, where a single technical defect required a fleet-wide emergency inspection and repair program.
  - Although generation recovered to a six-year high in 2024, the fleet is aging; most reactors are entering their fourth or fifth decade of operation. This is an ongoing security-of-supply concern that will require investment to manage.

- After twenty years of stagnant electricity demand, the United States has entered a new era of rapid load growth, driven by the dual pressures of electrification and the AI infrastructure boom.
    - Despite the ongoing energy transition, 2024 and 2025 saw record peak demand days for coal and gas. For the first time, winter peaks required over 9 TWh of thermal generation in a single day, highlighting that natural gas remains the reliability of last resort during extreme cold snaps (e.g., the January 2025 polar vortex).
    - Rapid demand growth is no longer a projection; it is an operational reality. The expansion of AI data centers is concentrated in specific hubs, creating localized energy security risks where load growth outpaces the construction of new transmission and firm generation.
    - As of early 2026, the U.S. grid faces a paradox: while solar and battery additions lead in new capacity, existing fossil fuel units are working harder than ever to bridge the gap during peak hours and weather anomalies.

Recommendations

Prioritize Energy Security (Reliability and Adequacy)

1. **Transition from "Energy" to "Attributes" Planning:** Planning must continue to move beyond covering annual megawatt-hours (MWh) needs. Markets must be redesigned to value and compensate for attributes: *Inertia, Frequency Response, and Reactive Power.*

   Potential Action: Understand when approaching a "Must-Run" requirement for synchronous condensers or gas units in high-variable resource zones (as Spain did post-2025) to provide the attributes necessary to survive sub-second anomalies.

2. **8,760-Hour Stress Testing:** Move away from "average day" or "peak summer" modeling.

   Potential Action: Require modeling of 24/7/365 net load scenarios that include a Dunkelflaute event (e.g., six+ days of <10% VRE output). If the grid cannot survive this without load shedding, the resource mix is inadequate.

Address Energy Equity (Affordability)

1. **Shift Focus to Total System Cost:** Low wholesale prices (or negative prices) can be signs of system stress, not efficiency.

   Potential Action: Use retail electricity rates as a primary key performance indicator for policy success. If wholesale prices are low but retail prices are rising 80% (as in the UK and California), hidden costs of backup, transmission, and balancing must be understood to ensure affordability.

2. **Mitigate the "Value Deficit" for Exports:** Germany's model of paying neighbors to take excess power is an economic drain.

Potential Action: Incentivize long-duration energy storage (LDES) (10+ hours) and demand-side industrial flexibility (e.g., hydrogen electrolysis) that can soak up excess spring solar rather than dumping it on neighbors at a loss.

Support Energy Sustainability (Environmental Performance)

1. **Embrace "Firm Low-Carbon" Diversity:** France is the leader, but its "common mode risk" is a warning.

   Potential Action: Support a heterogeneous nuclear fleet (e.g., mixing large-scale pressurized water reactors (PWRs) with various small modular reactor (SMR) designs) to ensure that a single metallurgical flaw does not pose a common failure risk.

2. **The "Pragmatic Coal" Strategy for Asia:** Since coal is not disappearing in Asia, a more sustainable approach would be focusing on the decarbonizing of coal and improving emission profiles.

   Potential Action: Accelerate international partnerships for HELE technology and CCS. Every 1% efficiency gain in China’s coal fleet can have a larger global impact than the entire energy transition of smaller nations.

Adaptive Planning for the AI Era

1. **On-Site Firm Generation for Large Loads:** Data centers are large new loads bringing a significant opportunity to scale new generation technologies.

   Potential Action: Revise interconnection rules to encourage large data centers to collocate with or fund firm baseload generation technologies that can address all aspects of the energy trilemma. There is significant opportunity to scale new nuclear, geothermal, long duration energy storage, and CCS technologies to power these new loads.

9. REFERENCES

2. *Program on Technology Innovation: Contributions of Supply and Demand Resources to Required Power System Reliability Services 2025*. EPRI, Palo Alto, CA: 2025. 3002031840.
3. California ISO. "What the Duck Curve Tells Us About Managing a Green Grid." Fast Facts, 2016, https://www.caiso.com/documents/flexibleresourceshelprenewables_fastfacts.pdf.
4. "Supply and Renewables." California ISO, https://www.caiso.com/todays-outlook/supply.
5. Bruno Burger and Leonhard Gandhi. "German Public Electricity Generation in 2025: Wind and Solar Take the Lead for the First Time." Energy Charts, December 31, 2025, https://www.energy-charts.info/.
6. "Hourly Electric Grid Monitor: U.S. Electricity Overview (U.S. Lower 48)." U.S. Energy Information Administration, https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.
7. Hannah Ritchie and Pablo Rosado. "Electricity Mix." Our World in Data, Updated January 2024, https://ourworldindata.org/electricity-mix.
8. "Lifecycle Carbon Intensity of Electricity Generation, 2025." Our World in Data, Updated January 26, 2026, https://ourworldindata.org/grapher/carbon-intensity-electricity.
9. "Electricity Prices." GlobalPetrolPrices.com, 2025, https://www.globalpetrolprices.com/electricity_prices/.
10. "Electricity Prices for Household Consumers—Bi-annual Data (from 2007 Onwards)." Eurostat, Updated November 21, 2025, https://ec.europa.eu/eurostat/databrowser/view/nrg_pc_204/default/table?lang=en.
11. *Impact of Cycling on the Operation and Maintenance Cost of Conventional and Combined-Cycle Power Plants*. EPRI, Paolo Alto, CA: 2013. 3002000817. https://www.epri.com/research/products/000000003002000817.
12. "Nuclear Power in France." World Nuclear Association, Updated January 14, 2026, https://world-nuclear.org/information-library/country-profiles/countries-a-f/france.
13. "Electricity Data Explorer." Ember Energy, https://ember-energy.org/data/electricity-data-explorer/.
14. "Britain's Electricity Explained: 2024 Review." National Energy System Operator, January 7, 2025, https://www.neso.energy/news/britains-electricity-explained-2024-review#:~:text=Managing%20electricity%20demand%20across%20the%20year%20It,3:30am%20at%2015%2C074MW%20showing%20the%20seasonal%20differences.
15. "Historic Generation Mix and Carbon Intensity." National Energy System Operator, https://www.neso.energy/data-portal/historic-generation-mix.
16. "Domestic Electricity Prices in the EU." Service.co.uk, November 27, 2025, https://assets.publishing.service.gov.uk/media/6926c9b3a245b0985f03407b/table_561.xlsx.
17. "Historical Electricity Data: 1920 to 1924." United Kingdom Government, Updated July 31, 2025, https://www.gov.uk/government/statistical-data-sets/historical-electricity-data.

18. "28 April 2025 Blackout." European Network of Transmission System Operators for Electricity, Updated October 3, 2025, https://www.entsoe.eu/publications/blackout/28-april-2025-iberian-blackout/.
19. "Review for CEN's Root Cause Analysis Report of 25th February 2025 Chilean Power System Blackout." EPRI, February 25, 2025, https://www.coordinador.cl/wp-content/uploads/2025/08/EPRI-Review-CEN-blackout-investigation.pdf.
20. "Reportes." Coordinador Eléctrico Nacional, 2004, https://www.coordinador.cl/reportes/documentos/reporte-energetico/2024/.
21. "Preliminary Monthly Electric Generator Inventory (Based on Form EIA-860M as a Supplement to Form EIA-860)." U.S. Energy Information Administration, January 26, 2026, https://www.eia.gov/electricity/data/eia860m/.
22. "Electricity Data Browser." U.S. Energy Information Administration, https://www.eia.gov/electricity/data/browser/.
23. "Electricity." U.S. Energy Information Administration, https://www.eia.gov/electricity/data.php.
24. Federal Energy Regulatory Commission and the North American Electric Reliability Corporation. *Report on Outages and Curtailments During the Southwest Cold Weather Event on February 1-5, 2011: Causes and Recommendations*. North American Electric Reliability Corporation, Atlanta, GA. 2011, https://www.nerc.com/globalassets/our-work/reports/event-reports/sw_cold_weather_event_final.pdf.
25. *Polar Vortex Review*. North American Electric Reliability Corporation, Atlanta, GA, 2014, https://www.nerc.com/globalassets/our-work/reports/event-reports/polar_vortex_review_29_sept_2014_final.pdf.
26. Federal Energy Regulatory Commission and the North American Electric Reliability Corporation. *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018*. North American Electric Reliability Corporation, Atlanta, GA. 2019, https://www.nerc.com/globalassets/our-work/reports/event-reports/south_central_cold_weather_event_ferc-nerc-report_20190718.pdf.
27. Federal Energy Regulatory Commission and the North American Electric Reliability Corporation. *The February 2021 Cold Weather Outages in Texas and the South Central United States*. North American Electric Reliability Corporation, Atlanta, GA. 2021, https://www.nerc.com/globalassets/our-work/reports/event-reports/february_2021_cold_weather_report.pdf.
28. Federal Energy Regulatory Commission and the North American Electric Reliability Corporation. *Inquiry into Bulk-power System Operations During December 2022 Winter Storm Elliott*. North American Electric Reliability Corporation, Atlanta, GA. 2023, https://www.nerc.com/globalassets/our-work/reports/event-reports/winter_storm_elliot_report.pdf.
29. Federal Energy Regulatory Commission and the North American Electric Reliability Corporation. *January 2025 Arctic Events: A System Performance Review*. North American Electric Reliability Corporation, Atlanta, GA. 2025,

https://www.nerc.com/globalassets/programs/event-analysis/25_arctic_storms_performance_review_0416.pdf.

30. “Electric-Gas Interdependence.” North American Electric Reliability Corporation, https://www.nerc.com/initiatives/electricgas-interdependence.
31. “Electricity Use Is Becoming More Common for Residential Heating.” U.S. Energy Information Administration, October 10, 2025, https://www.eia.gov/todayinenergy/detail.php?id=66324.
32. *Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption*. EPRI, Paolo Alto, CA, 2024, 3002028905.
33. *2024 Long-Term Reliability Assessment*. North American Electric Reliability Corporation, Atlanta, GA. Corrected 2025, https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.
34. *Long-Term Reliability Assessment*. North American Electric Reliability Corporation, Atlanta, GA. Corrected 2026, https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.
35. “Texas: State Profile and Energy Estimates.” U.S. Energy information Administration, https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_co2/eu/co2_eu_TX.html&sid=TX.
36. “Final Report on February 2021 Freeze Underscores Winterization Recommendations.” Federal Energy Regulatory Commission, November 16, 2021, https://www.ferc.gov/news-events/news/final-report-february-2021-freeze-underscores-winterization-recommendations.
37. “Urgent Board of Directors Meeting – Teleconference Available by Webcast.” Electronic Responsibility Council of Texas, February 24, 2021, https://www.ercot.com/calendar/02242021-Urgent-Board-of-Directors.
38. “Current Nodal Operating Guides.” Electronic Responsibility Council of Texas, https://www.ercot.com/mktrules/guides/noperating/current.
39. “ERCOT Fundamentals Training Manual.” Electronic Responsibility Council of Texas, https://www.ercot.com/mp/data-products/data-product-details?id=OPG-160-M.
40. Matt Largey, “Texas' Power Grid Was 4 Minutes and 37 Seconds Away from Collapsing. Here's How It Happened.“ KUT News, February 24, 2021, https://www.kut.org/energy-environment/2021-02-24/texas-power-grid-was-4-minutes-and-37-seconds-away-from-collapsing-heres-how-it-happened.
41. “ERCOT (Energy Reliability Council of Texas).” Energy Online, https://www.energyonline.com/Data/GenericData.aspx?DataId=23&ERCOT___Day-Ahead_Price.
42. “Resource Advocacy.” EPRI, https://www.epri.com/resource-adequacy.
43. “Resource Adequacy.” Electronic Responsibility Council of Texas, https://www.ercot.com/gridinfo/resource.
44. “Load Forecast.” Electronic Responsibility Council of Texas, https://www.ercot.com/gridinfo/load/forecast.

45. "California: State Profile and Energy Estimates." U.S. Energy information Administration, https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_co2/eu/co2_eu_CA.html&sid=CA
46. "California ISO Peak Load History 1998 through 2023," California ISO, https://www.caiso.com/Documents/CaliforniaISOPeakLoadHistory.pdf.
47. "Today's Outlook," California ISO, https://www.caiso.com/todays-outlook/supply.
48. "Federal Power Act Section 202(c)—CAISO, September 2020, U.S. Department of Energy, https://www.energy.gov/oe/articles/federal-power-act-section-202c-caiso-september-2020.
49. "Federal Power Act Section 202(c)—CAISO, September 2021, U.S. Department of Energy, https://www.energy.gov/oe/federal-power-act-section-202c-caiso-september-2021.
50. "Temporary Emergency Power Generators Used for First Time to Support Statewide Energy Grid During Heat Wave," California Department of Water Resources, https://water.ca.gov/News/News-Releases/2022/Sep-22/Temporary-Emergency-Power-Generators-Used.
51. "Federal Power Act Section 202(c)—CAISO, September 2022, U.S. Department of Energy, https://www.energy.gov/ceser/federal-power-act-section-202c-caiso-september-2022.
52. "Federal Power Act Section 202(c)—CAISO, September 2022, U.S. Department of Energy, https://www.energy.gov/ceser/federal-power-act-section-202c-caiso-september-2022.
53. "Federal Power Act Section 202(c)—CAISO, September 2022, U.S. Department of Energy, https://www.energy.gov/ceser/federal-power-act-section-202c-caiso-september-2022.
54. "Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave, California ISO, January 13, 2021, https://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.
55. "Total System Electric Generation 2009–2024 with totals," California Energy Commission, https://www.energy.ca.gov/media/7311.
56. "Managing the evolving grid," California ISO, https://www.caiso.com/about/our-business/managing-the-evolving-grid.
57. "CASIO Day-Ahead Price," LCG Consulting Energy Online, https://www.energyonline.com/Data/GenericData.aspx?DataId=22&CAISO___Day-Ahead_Price.
58. "Emission Rates in PJM Reach All-Time Low," PJM Inside Lines, https://insidelines.pjm.com/emission-rates-in-pjm-reach-all-time-low/.
59. "Winter Storm Elliott Even Analysis and Recommendation Report, PJM, July 17, 2023, https://pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx.
60. "PJM Releases Winter Storm Elliott Report," PJM Inside Lines, https://insidelines.pjm.com/pjm-releases-winter-storm-elliott-report/.
61. "Winter Storm Gerri," PJM, https://www.pjm.com/-/media/DotCom/about-pjm/ensuring-a-reliable-energy-transition/winter-storm-gerri.pdf.

62. “2024/2025 RPM Base Residual Auction Results,” PJM, https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-report.ashx.
63. “2024/2025 RPM Base Residual Auction Results,” PJM, https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-report.ashx.
64. “2026/2027 Bas Residual Auction Report,” PJM, July 22, 2025, https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf.
65. “2026/2027 Bas Residual Auction Report,” PJM, July 22, 2025, https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf.
66. “Capacity and Reliability Planning in the Era of Decarbonization,” Energy+Environmental Economics, August 2020, https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf.
67. “Preliminary ELCC Class Ratings for period Delivery Year 2026/27 – Delivery Year 2034/35,” PJM, https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/preliminary-elcc-class-ratings-for-period-2026-2027-through-2034-2035.ashx.
68. “2025 PJM Long-Term Load Forecast Report,” PJM, January 24, 2025, https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf.
69. Chang Liu, Boqiang Lin. Is increasing-block electricity pricing effectively carried out in China? A case study in Shanghai and Shenzhen. Energy Policy, Volume 138, 2020, 111278, https://www.sciencedirect.com/science/article/abs/pii/S0301421520300379.
70. “Average household electricity prices in China from September 2020 to June 2025,” Statista, https://www.statista.com/statistics/1373587/household-electricity-price-china/.
71. “Load-shedding in southern China, what happened?” AlphaESS, January 19, 2021, https://www.alphaess.com/load-shedding-in-southern-china,-what-happened?#:~:text=On%20Dec.,%2Dyear%20growth%20of%2014.1%25.
72. “The 2021 Energy Crisis: Implications for China's Energy Market and Policies,” The Oxford Institute for Energy Studies, March 2022, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2022/03/OEF-131.pdf.
73. Jingyi Li, Jidong Wu, Youtian Yang, Rumei Tang. Economic consequences of compound drought-heatwave induced power deficits: evidence from Sichuan's 2022 power crisis. Sustainable Cities and Society, Volume 130, 2025, 106639, https://www.sciencedirect.com/science/article/abs/pii/S221067072500513X.
74. “Explore data in the Global Coal Plant Tracker,” Global Energy Monitor, https://globalenergymonitor.org/projects/global-coal-plant-tracker/dashboard/.
75. “Explore data in the Global Integrated Power Tracker,” Global Energy Monitor, https://globalenergymonitor.org/projects/global-integrated-power-tracker/dashboard/.
76. “Financial Studies & Analysis Division,” Government of Industry Ministry of Power Central Electricity Authority, https://cea.nic.in/financial-studies-assistance-division/?lang=en.
77. “2015 Residential Electricity Price Trends,” AEMC, https://www.aemc.gov.au/markets-reviews-advice/2015-residential-electricity-price-trends.

78. “Residential Electricity Price Trends 2024,” AEMC, https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2024.
79. “Tracker,” Open Electricity, https://explore.openelectricity.org.au/energy/au/.
80. “NEM market suspension and operational challenges in June 2022,” Australian Energy Market Operator, August 2022, https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2022/nem-market-suspension-and-operational-challenges-in-june-2022.pdf.
81. “Trip of multiple generators and lines in Central Queensland and associated under-frequency load shedding on 25 May 2021,” Australian Energy Market Operator, October 2021, https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2021/trip-of-multiple-generators-and-lines-in-qld-and-associated-under-frequency-load-shedding.pdf.
82. “Tariffs & Charges, 2015/16,” Eskom, https://www.eskom.co.za/distribution/wp-content/uploads/2021/07/2015-16.pdf
83. “Schedule of Standard Prices for Eskom Tariffs 1 April 2024 to 31 March 2025 for Non-Local Authority Supplies, and 1 July 2024 to 30 June 2025 for Local Authority Supplies,” Eskom, https://www.eskom.co.za/distribution/wp-content/uploads/2025/03/Schedule-of-standard-prices-2024_25-V1.pdf.
84. “Total solar capacity,” Our World in Data, https://ourworldindata.org/grapher/installed-solar-pv-capacity?country=~ZAF.
85. “Annual and Statistical Reports,” Eskom, https://www.eskom.co.za/heritage/annual-and-statistical-reports/.
86. “Group Annual Results 2025,” Eskom, September 30, 2025, https://www.eskom.co.za/wp-content/uploads/2025/09/Eskom-results-presentation-2025.pdf.

About EPRI

Founded in 1972, EPRI is the world's preeminent independent, non-profit energy research and development organization, with offices around the world. EPRI's trusted experts collaborate with more than 450 companies in 45 countries, driving innovation to ensure the public has clean, safe, reliable, and affordable access to electricity across the globe. Together…Shaping the future of energy.®

PROGRAM

Heat Rate and Flexibility: Generation Fleet Optimization, P223

For more information, contact:

EPRI Customer Assistance Center
800.313.3774 • askepri@epri.com

3002034603 **March 2026**

EPRI

3420 Hillview Avenue, Palo Alto, California 94304-1338 USA • 650.855.2121 • **www.epri.com**