MAINTAINING A STABLE ELECTRICITY GRID IN THE ENERGY TRANSITION

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INTERNATIONAL CENTRE FOR SUSTAINABLE CARBON

CIAB

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PREFACE

This report has been produced by the International Centre for Sustainable Carbon (ICSC) for the International Energy Agency's Coal Industry Advisory Board (CIAB). It is based on a survey and analysis of published literature, and on information gathered in discussions with interested organisations and individuals. Their assistance is gratefully acknowledged. It should be understood that the views expressed in this report are our own and are not necessarily shared by those who supplied the information, nor by our member organisations.

The ICSC was established in 1975 and has contracting parties and sponsors from: Australia, China, Italy, Japan and South Africa.

The overall objective of the International Centre for Sustainable Carbon is to continue to provide our members, the International Energy Agency (IEA) Working Party on Fossil Energy and other interested parties with definitive and policy relevant independent information on how various carbon-based energy sources can continue to be part of a sustainable energy mix worldwide. The energy sources include, but are not limited to coal, biomass and organic waste materials. Our work is aligned with the UN Sustainable Development Goals (SDGs), which includes the need to address the climate targets as set out by the United Nations Framework Convention on Climate Change (UNFCCC). We consider all aspects of solid carbon production, transport, processing and utilisation, within the rationale for balancing security of supply, affordability and environmental issues. These include efficiency improvements, lowering greenhouse and non-greenhouse gas emissions, reducing water stress, financial resourcing, market issues, technology development and deployment, ensuring poverty alleviation through universal access to electricity, sustainability, and social licence to operate. Our operating framework is designed to identify and publicise the best practice in every aspect of the carbon production and utilisation chain, so helping to significantly reduce any unwanted impacts on health, the environment and climate, to ensure the well-being of societies worldwide.

The ICSC is organised under the auspices of the International Energy Agency (IEA) but is functionally and legally autonomous. Views, findings and publications of the ICSC do not necessarily represent the views or policies of the IEA Secretariat or its individual member countries.

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 currently drawn from 12 countries accounting for approximately 70-80% of world coal production and coal consumption. Members are drawn from major coal producers, electricity producers, other coal-consuming industries and coal-related organisations. The CIAB provides a wide range of advice to the IEA, through its workshop proceedings, meetings, work programme and associated publications and papers.

ABSTRACT

Economies depend on reliable, stable, cost-effective electricity grids and associated systems. Interruptions to supply have a direct impact on business, society and economies. This report provides an overview of electric power grids in the energy transition from system fundamentals to the complexities associated with future technical solutions, potential impact on system security, resilience and cost. It highlights the emerging risks associated with proposed and ongoing changes to current systems and the associated market environment as well as market developments which may jeopardise previously stable and secure power systems. Costs and cost analysis including the limitations of the commonly adopted levelised cost of electricity (LCOE) metrics and wider system costs, are discussed. In particular, the role, characteristics and associated value of, and need for, dispatchable power capability in the energy system are reviewed, especially in the context of the increasing share of variable renewable power generation. A role for abated fossil power is reviewed and the associated benefits that can be realised as part of the energy transition. Insight is provided into grids, associated developments and challenges being experienced across several key regions including parts of Asia-Oceania Europe and the USA.

Many regions are on course for increased grid-based risks to societies and economies, the impacts of which are starting to be felt, for example in parts of Europe and several US states. Therefore, a more holistic approach to the adoption of variable renewable energy (VRE, mainly wind and solar) is needed including the provision of adequate dispatchable power capability to manage the risks associated with the increasing deployment of VRE. At the same time dispatchable power capability, currently used to backup VRE technologies, is being decommissioned with an associated risk to reliability and security of electricity supply. Regions will develop their own pathways towards decarbonisation reflecting local current and projected future demand needs, addressing opportunities, available resources, challenges and constraints. Accordingly, there is likely to be a continued important and urgent need for abated fossil power plant to help accelerate and facilitate transition as well as to manage the costs. In some regions this will include addressing and appropriately managing the issue of existing and new fossil power plants in the context of meeting future energy requirements, whilst ensuring necessary levels of resource adequacy, system stability reliability, cost and dependability. Modern grids have developed to be robust systems, tolerant to extreme events and have reliably served the needs of society in a secure and affordable manner for many decades. The major concern raised by this report is the real and emerging risk that this will be compromised by current developments, with significant associated adverse impacts on both society and the energy transition agenda.

ACRONYMS AND ABBREVIATIONS

AC	alternating current
AEMO	Australian Energy Market Operator
aFRR	automatic frequency restoration reserves
APS	Announced Pledges Scenario, IEA
BECCS	biomass energy carbon capture and storage
BEIS	Department for Business, Energy and Industrial Strategy, UK
BESS	battery energy storage system
C&I	commercial and industrial
CAES	compressed air energy storage
CAISO	Californian Independent System Operator, USA
Capex	capital expenditure
CBR	converter-based resources
CCC	Committee on Climate Change, UK
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CCUS	carbon capture, utilisation and storage
CEA	Central Electricity Authority, India
CERC	Central Electricity Regulatory Commission, India
CF	capacity factor
CfD	contract for difference
CH_4	methane
CO_2	carbon dioxide
$CO_{2\text{-eq}}$	carbon dioxide equivalent
CSIS	Center for Strategic and International Studies, USA
DACC	direct air carbon capture
DACCS	direct air carbon capture with storage
DC	direct current
DESNZ	Department for Energy Security and Net Zero, UK
DFS	Demand Flexibility Service, UK
DNO	distribution network operator
DOE	Department of Energy, USA
DSM	demand side management (of load)
DSO	distribution system operator
DSR	demand side response
EC	European Commission
EHV	extra-high voltage
EHVAC	extra high voltage alternating current
EIA	Energy Information Administration, USA
EMDE	emerging markets and developing economies
ENTSOE	European Network of Transmission System Operators for Electricity
EPRI	Electrical Power Research Institute

ERCOT	Electric Reliability Council of Texas, USA
ERoEI	energy return on energy invested
ERoI/eROI	energy return on investment
ESMAP	Energy Sector Management Assistance Programme
ESO	energy system operator
EU	European Union
FCoE	full cost of electricity
FCR	frequency containment reserves
FERC	Federal Energy Regulatory Commission, USA
FFR	fast frequency response
FIT	feed in tariff
FRR	frequency restoration reserves
GB	Great Britain
GCCSI	Global Carbon Capture and Storage Institute
GDP	gross domestic product
GGA	Global Geothermal Alliance
GHG	greenhouse gas
GVA	gigavolt amp
H_2	hydrogen
HVDC	high voltage direct current
IBR	inverter-based resource
IC	internal combustion
ICSC	International Centre for Sustainable Carbon
IEA	International Energy Agency
IFPSH	International Forum on Pumped Storage Hydropower
IHA	International Hydropower Association
IPCC	Intergovernmental Panel on Climate Change
IPP	independent power producer
IRA	Inflation Reduction Act, USA
IRENA	International Renewable Energy Agency
IRR	internal rate of return
ISO	independent system operator
ISO-NE	Independent System Operator New England, USA
JETP	Just Energy Transition Partnership
LACE	levelised avoided cost of electricity
LAES	liquid air energy storage
LCOE	levelised cost of electricity
LCOH	levelised cost of heat
LCOS	levelised cost of storage
LCOT	levelised cost of transmission
LDES	long-duration energy storage
LFP	lithium-ion phosphate
LLNL	Lawrence Livermore National Laboratory, USA

LNG	liquefied natural gas
LOLE	loss of load expectation
MEGS	Modelling Energy and Grid Services
mFFR	manual frequency restoration reserves
MISO	Midcontinent Independent System Operator, USA
NDC	Nationally Determined Contribution
NEM	National Electricity Market, Australia
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory, USA
NH_3	ammonia
NMC	nickel manganese cobalt
NMR	nuclear micro-reactor
NOx	nitrogen oxides
NPV	net present value
NREL	National Renewable Energy Laboratory, USA
NTPC	National Thermal Power Corporation
NYISO	New York Independent System Operator
NZE	net zero emissions scenario, IEA
OCGT	open cycle gas turbine
OECD	Organisation for Economic Co-operation and Development
Opex	operational expenditure
PJM	Pennsylvania New Jersey Maryland Interconnection, USA
PPA	power purchase agreement
PRIMRE	Portal and Repository for Information on Marine Renewable Energy
PSE	Polskie Sieci Elektroenergetyczne, Poland
PV	photovoltaic
PWR	pressurised water reactor
RMI	Rocky Mountain Institute, USA
RTO	regional transmission organisation
SAIDI	System Average Interruption Duration Index
SDGs	Sustainable Development Goals, United Nations
SDS	sustainable development scenario, IEA
sLCOE	simple levelised cost of energy
SLCOE	system levelised cost of electricity
SMP	system marginal price
SMR	small modular reactor
SPP	Southwest Power Pool, USA
SSE	Scottish and Southern Energy, UK
STEPS	stated policies scenario, IEA
TEC	total economic cost
TNO	transmission network operator
TPED	total primary energy demand
TSC	total system cost

TSO	transmission system operator
UHV	ultra-high voltage
UHVAC	ultra-high voltage alternating current
UHVDC	ultra-high voltage direct current
UKAEA	United Kingdom Atomic Energy Authority
UN	United Nations
UNECE	United Nations Economic Commission for Europe
VALCOE	value adjusted LCOE
VPP	virtual power plant
VRE	variable renewable energy (primarily wind and solar power)
VSM	virtual synchronous machine

Note: all monetary values are in United States dollars ($) unless otherwise stated.

UNITS

€	Euro
gCO_2/kWh	grammes of carbon dioxide per kilowatt-hour
GW	gigawatt, 1000 million watts
GWh	gigawatt hour, 1000 million watt-hours
kW	kilowatt, thousand watts
kWh	kilowatt-hour, 1000 watt-hours
MBtu	million British thermal units
Mt	million tonnes
Mt/y	million tonnes per year
MVA	megavolt-ampere
MW	megawatt, million watts
MWe	megawatt electrical energy
MWh	megawatt-hour
PLN	Polish Zloty
tCO_2/y	tonnes of carbon dioxide per year
TW	terawatt, one million megawatts
TWh	terawatt-hour, one million megawatt-hours

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EXECUTIVE SUMMARY

THE ELECTRICITY GRID NETWORK IS ESSENTIAL FOR EVERYTHING WE DO. ENSURING SECURE, DEPENDABLE AND AFFORDABLE ELECTRICITY SUPPLY IS A PRIORITY

The modern world relies on access to affordable, dependable power, delivered by a secure and robust electricity grid network. There is almost a total reliance on electricity grids to support systems, processes, data management, communications, healthcare, supply chains as well as essential services such as water and food supply management. Anything which affects the ability of grids to deliver power on a reliable and secure basis, at a reasonable cost, risks societal and economic disruption. Electric power grids have been carefully managed, monitored, and governed by stringent regulations and operational practices refined over many years. They have evolved over more than a century and traditionally been based on large, dispatchable point power generation sources. There are more than 80 million km of grid network globally and this is expanding by 2.3 million km/y (IEA, 2023d) with repair, replacement and upgrade required in addition to expansion.

Electricity supply and demand must always be balanced. System stability requires constant equilibrium between power generation and consumption, even as demand fluctuates. Grids operate within a protected narrow frequency band. When demand exceeds supply, such as when a power plant fails, the associated drop in system frequency can result in widespread problems, if not managed appropriately. Therefore, if system frequency is not restored within a limited time window (typically nine minutes) existing power plants operational on the system can enter controlled shutdown as a protection mechanism. If system frequency falls further, system collapse may occur, with associated loss of energy to the entire system. During Storm Uri in 2021, the Texas grid, operated by the Electric Reliability Council of Texas (ERCOT), came within 'four minutes thirty-seven seconds from a total collapse' which would have resulted in a state-wide blackout of their 90 GW peak system. Almost half its power generation was lost, narrowly avoiding catastrophic impact on the region and its population, which would have taken weeks to restore. As it was, there was power failure to five million people with a further 11 million impacted by power interruptions. There were 246 attributed deaths and an economic impact of around $200 billion. Texas is far from being an isolated case of significant blackout with examples in Argentina, Bangladesh, India, South Australia and the UK.

The approaches being taken to reduce power sector emissions in line with the Paris Agreement, specifically, the addition of variable renewable energy (VRE), mainly wind and solar, are transforming electric power grids while they are being relied on more. Demand is growing with increasing electrification, and the share of VRE feeding into the grid is expanding. Correspondingly, as the deployment of VRE technologies increases, large dispatchable generating capacity, used to support and back up the intermittency of VRE, is being phased out. New VRE capacity being installed are smaller units, greater in number to facilitate a level of bulk load, and often located in remote areas, both on-land and offshore. Deployment of more VRE based generating capacity and the associated intermittent nature of power generation (being exposed to the vagaries of the weather) plus the age of much of the grid, extreme weather events, and system congestion, mean that considerable investment is required for the upgrading and expansion of electricity grids. Such investment and expansion are not keeping pace with VRE deployment and dispatchable power capacity phase out, with associated risk to sensitive supply demand management needs.

The less predictable nature of VRE makes it harder to continuously match electricity supply and demand. The more VRE on the system, the larger the challenge.

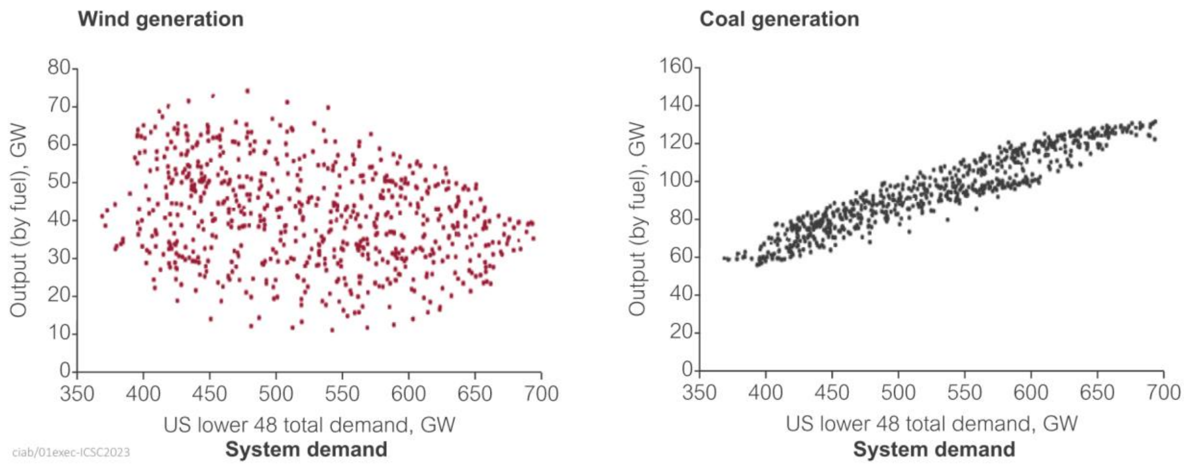

Figure 1 Correlation of output with demand for generation sources, June-July 2023, USA (Caravaggio, 2023)

Figure 1 illustrates the fundamental difference of VRE compared to other forms of generation in terms of delivering power on demand. There is little correlation between power generation and demand in the wind power example, and a strong one for dispatchable power.

It is therefore important to understand the supply-related risks. Many risk drivers are evolving simultaneously including the issues related to ageing infrastructure and increasing power demand due to the increased drive for electrification. Some regions have simultaneous demand increases related to economic development or population growth. Many areas are likely to see power demand double over the next 20 years.

There are issues due to grid congestion, and reinforcement requirements to handle the higher loading. Extreme weather events are more frequent and severe; increasing dependence on grids increases the risk of terror and cyber-attack. There are additional risks associated with change, affordability, speed of deployment, supply chains and materials availability as well as planning, policies and market reforms, altering how systems are operated, governed and rewarded. There is potential risk from an over-reliance on VRE in maintaining a stable, dependable, and affordable system, as efforts to decarbonise are accelerated.

THERE IS A LOOMING RELIABILITY CRISIS IN OUR ELECTRICITY MARKETS'
(COMMISSIONER JAMES DANLY, US FEDERAL ENERGY REGULATORY COMMISSION)

This statement, although referring to the US situation, reflects the broader findings of this CIAB study, the objective of which is not to conduct new research, but to assess and consolidate relevant related issues based on a review of existing materials and evidence in the public domain. The aim is to produce a report offering context and overview to maintaining grid and associated system security and reliability in the energy transition. This includes assessment and understanding of the implications of decisions being made concerning energy supply with respect to system stability, reliability, security, cost, and deliverability at a whole system level. Given the implications of decisions being taken, it is essential associated decision making is on a best-informed objective basis. This report supports a holistic approach to help ensure the road to net-zero is a smooth one.

"YOU FORGOT TO BUILD THE ROAD" – IT'S TIME TO 'RING THE ALARM BELLS' ON ELECTRICITY GRID EXPANSION AND MODERNISATION AROUND THE WORLD, OR RISK PUTTING THE BRAKES ON THE TRANSITION
(DR FATIH BIROL, IEA, JULY 2023)

MANAGING THE IMPACT OF VRE ON THE ELECTRICITY SUPPLY NETWORK

VRE integration requires grid adaptation. Many grid systems have some VRE capacity but also rely on legacy dispatchable power assets and interconnection to maintain security and reliability of supply. In addition, integration of VRE requires energy storage, curtailment, re-dispatch, grid modification, grid forming inverters and synchronous compensation, consumer flexibility, wholesale price volatility and market reform.

When only 25% of peak capacity is installed as VRE, issues become apparent:

- how to accommodate intermittent and variable output;
- reduced electrical inertia to ride through fault conditions;
- output is weather and time dependent, and non-dispatchable, therefore requiring backup generation availability;
- reduced capability to move bulk power from where it is produced to where it is needed;
- difficulty adding capacity rapidly due to small individual unit or plant sizes; and

- market volatility caused by over-supply and deficits, which may be good for energy traders, but not for system reliability management.

Therefore, there is a need for potentially expensive system-wide mitigations to integrate the higher VRE share being demanded.

BALANCING THE GRID AND WHERE WILL SYSTEM FLEXIBILITY COME FROM?

VRE is largely enabled by taking advantage of the flexibility of pre-existing systems but here there is a paradox. As system flexibility needs increase, flexible power assets that have enabled VRE are being decommissioned. If this continues, there may no longer be adequate flexible dispatchable capacity. Capacity derating factors associated with VRE, confirm VRE is not dependable in times of system stress and so other means are needed to provide flexibility.

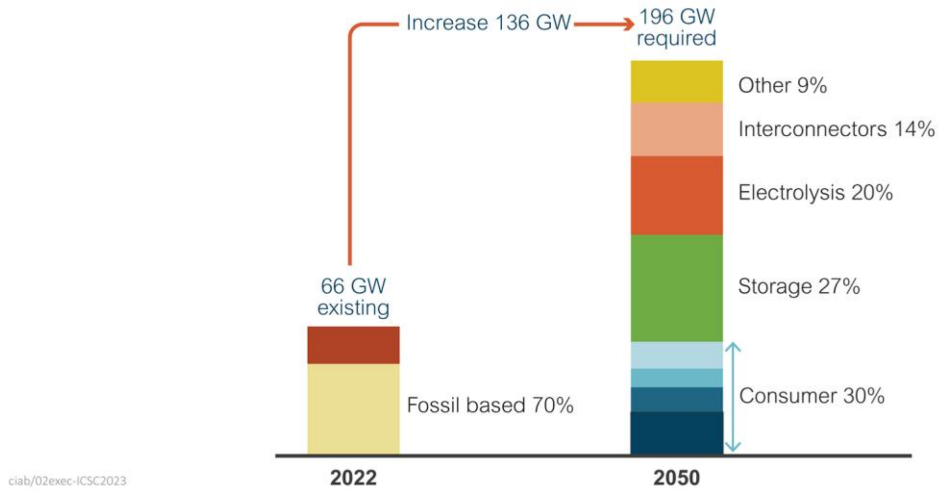

Figure 2 Total installed electricity system flexibility by 2050, UK (GW) (National Grid ESO, 2023)

Figure 2 illustrates a 2050 scenario with a huge increase in flexibility demand evident but also an almost complete elimination of existing flexibility capacity. Yet it is *not* proven that reliance on consumer demand management, storage and interconnectors will be adequate, dependable, or cost-effective to satisfy needs at national scale in the future.

> SYSTEM FLEXIBILITY IS THE CORNERSTONE OF ELECTRICITY SECURITY. CHANGING DEMAND PATTERNS AND RISING SOLAR PV AND WIND SHARES DOUBLE FLEXIBILITY NEEDS IN THE IEA ANNOUNCED PLEDGES SCENARIO BY 2030 AND INCREASE THEM ALMOST FOURFOLD BY 2050'
> (IEA, OUTLOOK FOR ELECTRICITY, 2022)

Recent statements from the IEA reinforce that electricity security requires 'flexibility', which might also be written as 'dispatchability'.

IS SURPLUS VRE CAPACITY THE ANSWER?

Building excess VRE capacity is an option, but may not be a solution in still, dark winter periods for example. Building more interconnectors to share surplus power may not be sufficient, as similar weather patterns can be continent-wide. The cost of overbuilding is high and materials and resource intensive; also, the more VRE, the lower the load factor under average conditions.

Alternatives include shifting demand or introducing new industries which can absorb the surplus power, such as production of electrolytic hydrogen. However, the generation production costs would still need to be covered by energy sales and new industries would need to be viable businesses even accounting for the variability of the renewable energy surplus.

WHAT ARE THE CLEAN DISPATCHABLE POWER OPTIONS?

There is a range of clean dispatchable power options available, often complementary in nature. A resilient system is typically one with a broad technology portfolio able to adapt to a variety of different circumstances. A portfolio approach is likely to be better positioned to deliver decarbonisation needs.

Figure 3 illustrates the effect on relative system decarbonisation cost of excluding options from the portfolio, with particular emphasis on the impacts of removing carbon capture and storage (CCS) as an option. System decarbonisation is far more costly when CCS is not an option, *especially* if national solutions are based on VRE and storage only.

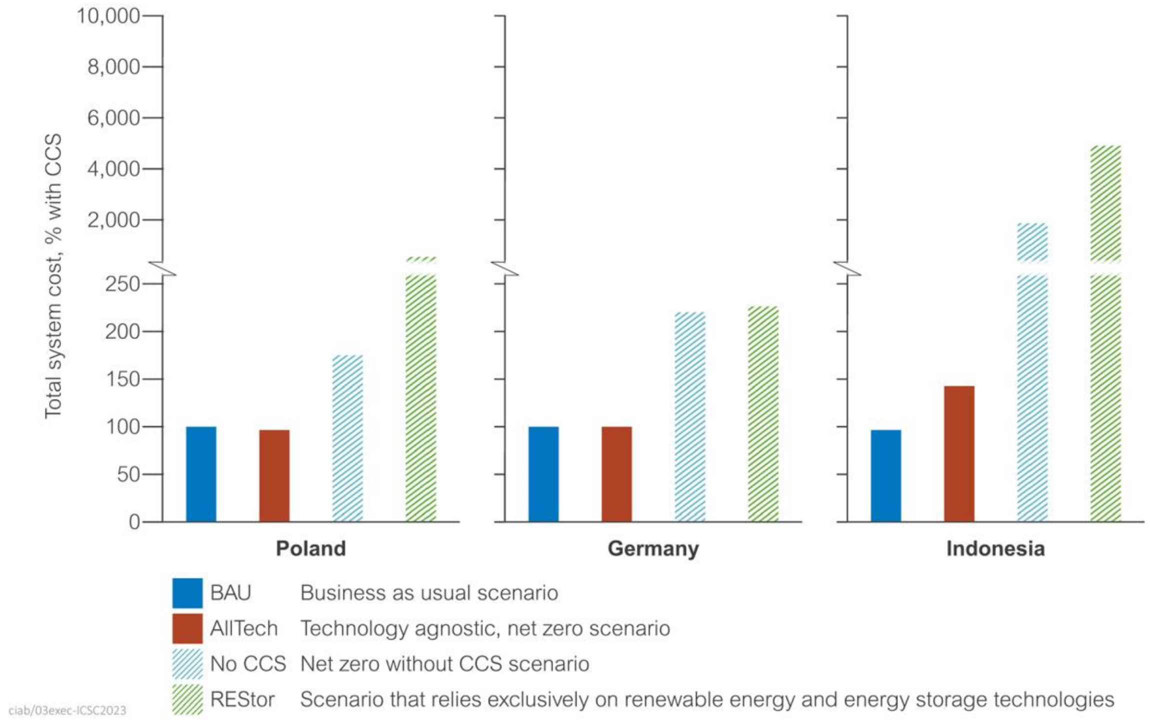

Figure 3 Total system net zero cost comparison by technology mix (Pratama and Mac Dowell, 2022)

It is therefore critical for a reliable, low cost, power system, that viable technologies are not excluded. Action is clearly needed on decarbonisation but on a cost effective, secure and deployable basis.

Dispatchable technologies are required not only for smoothing out variations in VRE output but also, critically, to bridge extreme system events, especially those of significant duration.

A MORE HOLISTIC AND TECHNOLOGY AGNOSTIC APPROACH CAN DELIVER A FASTER, MORE ACHIEVABLE, AND LOWER COST TRANSITION TO NET ZERO

CAPACITY FACTORS UNDERPIN FINANCIAL VIABILITY

Having a diverse energy mix is one thing; how often, and at what capacity it is operated relative to the optimal economic case is another and is critical to the affordability and business model of any future option. The selection of future modification and retrofit options is dependent on assumed capacity factors.

Figure 4 illustrates how choices might be affected in the case of CCS. There is an inversion of the most economic options depending on the assumed capacity factor of the plant; CCS is significantly more economic unless capacity factors are very low. Low-capacity factors, and high flexibility requirements, not only impact operational costs, but also, the viability of providing critical dispatchable plant in the future.

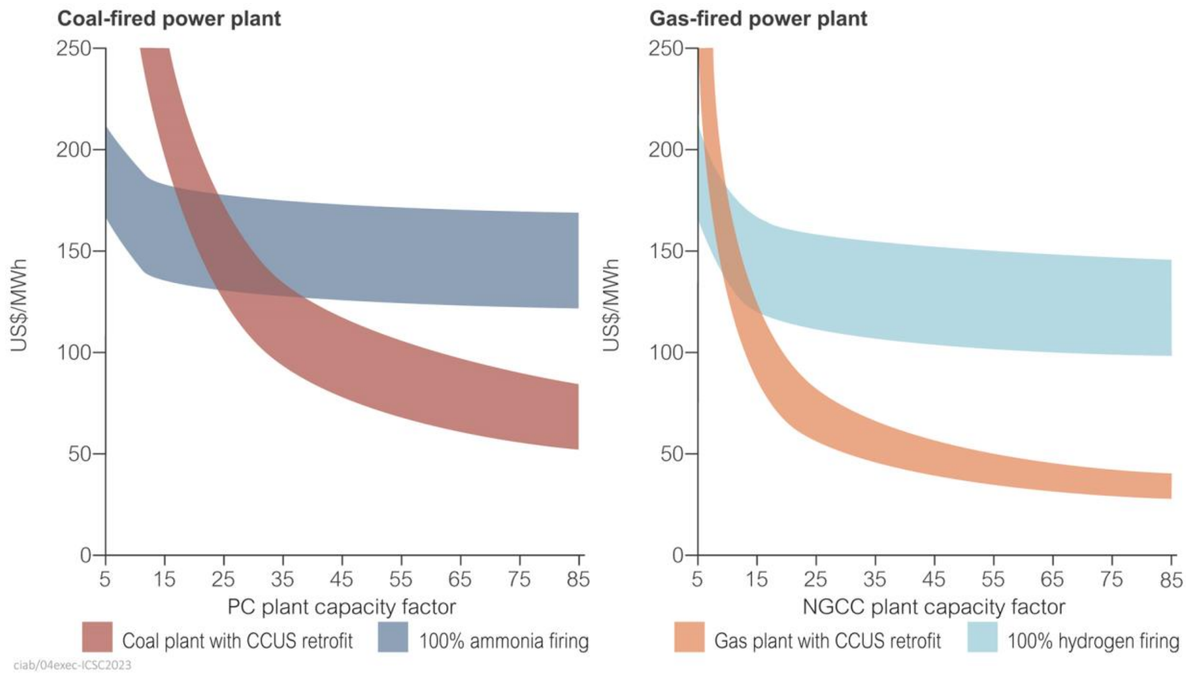

Figure 4 Additional costs of ammonia, hydrogen abatement of existing fossil plants (IEA, 2023h)

UNDERSTANDING AND CALCULATING TOTAL SYSTEM COST

Calculating cost is complex and cannot be simplified and generalised. Costs differ in time and place for the same thing, and are continually distorted by taxes, incentives, project and market conditions. Only cost ranges exist and can overlap widely for a range of technology options meaning that any of the overlapping options could be the least cost in particular circumstances.

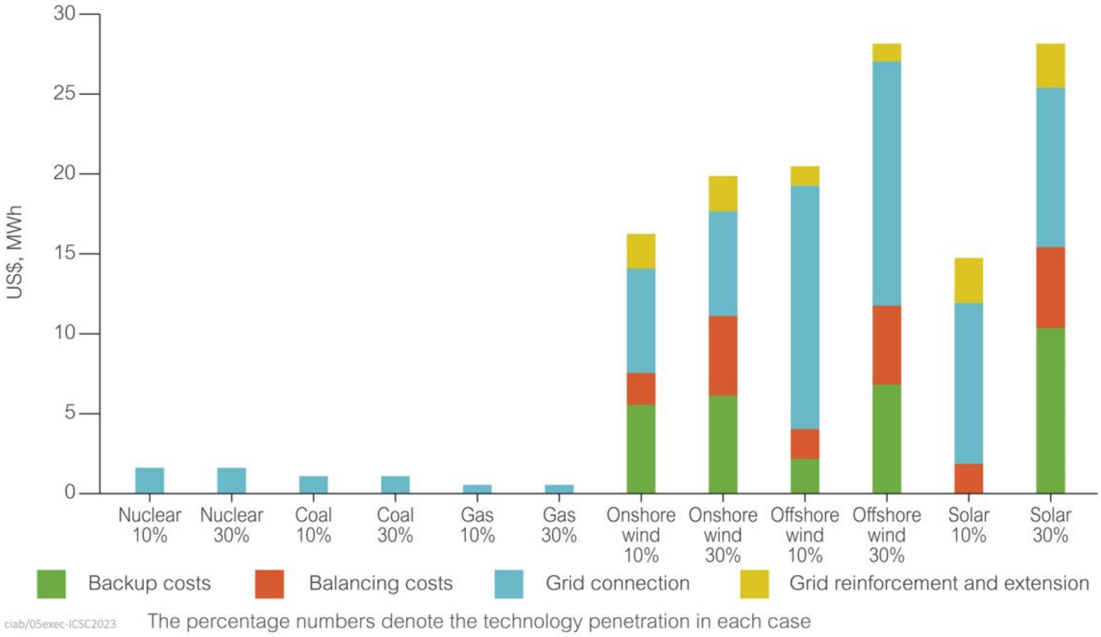

Figure 5 Grid-level system integration costs of technologies in the USA (Watt-Logic, 2023)

Standard levelised cost of electricity (LCOE) can only be used for comparison where the impact of options considered are identical outside the boundary of the cost calculation. However, system wide impacts are generally not included in plant LCOE calculations and so LCOE cannot be used directly to compare the economics of dispatchable and non-dispatchable power sources. For VRE technologies this means firming, networks, storage and system stability costs fundamentally change the messages portrayed by most LCOE figures (*see* Figure 5). To calculate the full cost impact, many factors need to be considered to offer a valid comparison, including permitting, connection, extension, reinforcement, interconnection, synchronous compensators, grid forming inverters, energy storage, curtailment, redispatch, voltage regulation, backup dispatchable generation, taxes, incentives, subsidies, levies, rebates, mandates, market price volatility, consumer flexibility, and regulatory changes. Additionally, the ‘cost’ a consumer sees is not the project or plant cost, but the total system cost impact, reflected in consumer prices. This price includes a large share of costs for transmission and distribution networks but also government costs, taxes, levies and incentives. So, assuming a correlation between LCOE and consumer price is not correct.

Flaws in LCOE calculation are widely known, as illustrated by the quote from EPRI, and have been the subject of many technical papers, yet it continues to be used and quoted on a regular basis.

> ‘LCOE IS BARELY MORE THAN A BACK OF THE ENVELOPE CALCULATION. THEY DO NOT EVALUATE HOW THE MARKET VALUE AND ANCILLARY SYSTEM COSTS OF TECHNOLOGIES VARY AS THE STATE OF THE SYSTEM EVOLVES OVER THEIR FUTURES’ (EPRI, 2020)

MODELLING LIMITATIONS

Models offer insights, stimulate useful discussion and problem solving. However, they can provide a false sense of security. Outputs may appear to be factual with precise numbers, trends, and graphics, yet they vary in their ability to represent real world conditions, costs, and deployment. Many models are flawed due to their narrow scope, assumptions, or over-simplifications, or a failure to consider related issues and systems like markets, supply chains, regulation and real-world business models. Modelling gets harder as systems become more complex and interconnected with more stakeholders and combinations of options.

Multiple models are needed with varied scopes and focus, addressing both the macro issues and the granular detail, down to modelling the actual physical systems, users and timelines. They should all be run against a wide range of scenarios to develop a robust picture of possibilities and constraints.

In terms of failure prevention, the most important things to model are extreme events – rare circumstances which place highest demand on the system and test resilience. The MEGS model, developed for use on the Australian National Electricity Market (NEM), is a good example. It considers not only capacity, carbon and cost, but also grid system inertia, stability and firming. Models of this type show a characteristic trend of increasing cost with decarbonisation, with a clear exponential trend for deeper decarbonisation levels, as illustrated in Figure 6.

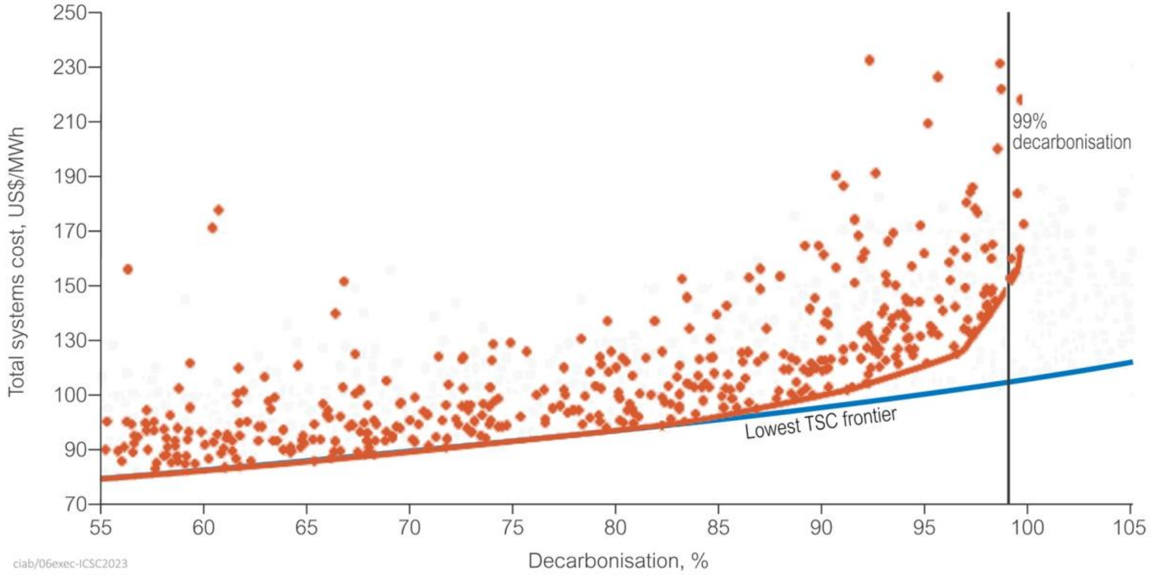

Figure 6 3000 scenarios of the MEGS model for the Australian NEM (Boston and Bongers, 2021)

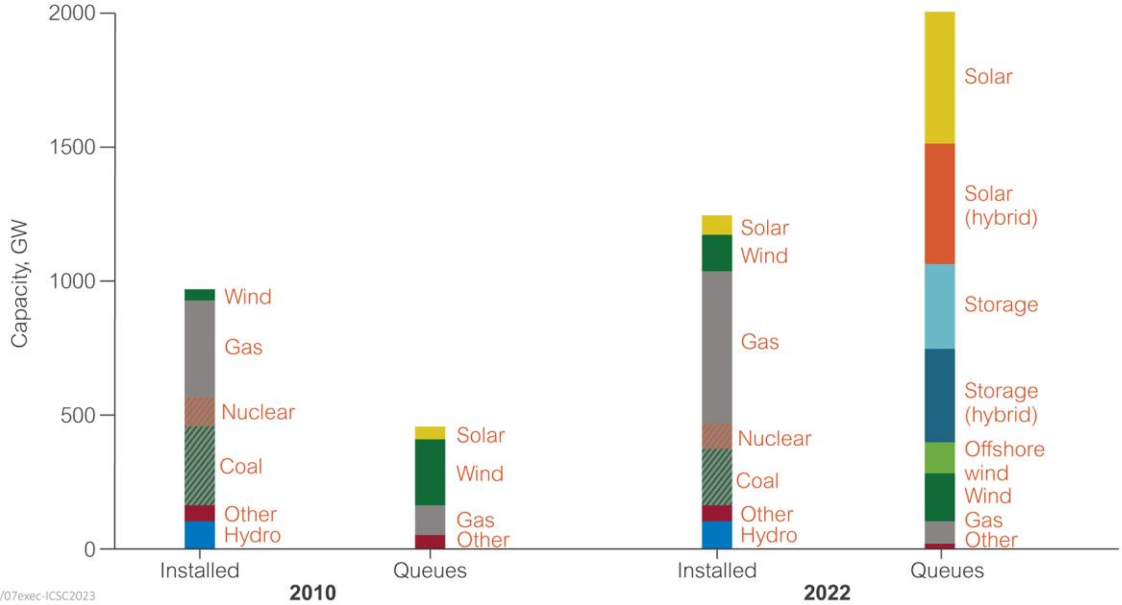

Figure 7 Comparison of US installed and queued capacity, 2010-2022 (Rand and others, 2023)

Technology installation takes time. High-capacity options typically take 6–12 years to reach commercial operation, and grid developments can take 5–15 years to implement. Figure 7 shows US installed capacity and the queue for approval of new capacity projects for 2010 and 2022; capacity awaiting permitting in 2022 was almost twice the total currently installed generation fleet. Globally, over 3000 GW of renewable capacity awaited permitting in 2023. Thus, for any technology option, decisions need to be made sufficiently in advance (15 years or more) to enable planning and deployment before that option becomes critical to the system.

MATERIALS AVAILABILITY AND INTENSITY TO DELIVER ON VRE DEMAND

Materials requirements, on an electricity output basis, are much higher for VRE technologies than large dispatchable assets. Table 1 illustrates major construction material requirements for a range of generation technologies and shows intensity is around 32 times greater for VRE technology.

TABLE 1A RELATIVE CONSTRUCTION MATERIAL BY TECHNOLOGY, T/TWH (WORLD NUCLEAR ASSOCIATION, 2021)

	Coal	Gas CC	Nuclear	Hydro	Wind	Solar PV
Concrete and cement	870	400	760	14,000	8,000	4,050
Iron/steel	310	170	165	67	1,920	7,900
Copper	1	0	3	1	23	850
Aluminium	3	1	0	0	35	680
Glass	0	0	0	0	92	2,700
Silicon	0	0	0	0	0	57
Total metals	314	171	168	67	**1978**	**9430**

TABLE 1B RELATIVE CONSUMPTION OF CRITICAL MINERALS BY TECHNOLOGY (WORLD NUCLEAR ASSOCIATION, 2021)

	Plant, t/MW	Indicative, CF, %	TWh/y	Operational lifetime, y	Lifetime, TWh	Plant, t/TWh
Coal	2.5	85	7.5	50	375	7
Nuclear	5.3	85	7.5	60	450	12
Gas	1.2	60	5.2	30	156	8
Solar	6.8	25	2.2	25	55	**124**
Onshore wind	10.1	35	3.1	25	78	**130**
Offshore wind	15.5	35	3.1	25	78	**200**

CC = combined cycle, CF = capacity factor

A similar calculation is provided in the lower chart for critical minerals where an intensity of 17 times higher is indicated. Critical minerals are becoming a contested resource with demand set to outstrip supply on the current net zero pathway. The numbers in Table 1 relate only to direct material requirements and exclude materials associated with other system requirements like grid expansion, storage, and backup power generation. The IEA's 2023 grid report highlighted that 80 million km of grid network needs to be built by 2040, requiring over double the annual copper and aluminium supply relative to 2021 to meet a net zero scenario.

ELECTRICITY SUPPLY MARKET CONCERNS

Regulators and operators are raising concerns about system reliability. In the Australian NEM, system operator AEMO has forecast that system reliability standards could be breached in some areas by 2025 on the current path.

VRE heavy systems around the world rely on gas and coal power plants and interconnectors for continuity of supply. Extreme flexibility demands are being made on these plants, to accommodate the high volatility of VRE output, with associated consequences on integrity, efficiency and operating costs. There are also reports of VRE costs increasing, and of new VRE projects no longer being economically viable, with auctions under-subscribed and suppliers requiring state aid. Areas with high VRE share also seem to be the ones with the highest, rather than the lowest, consumer power prices.

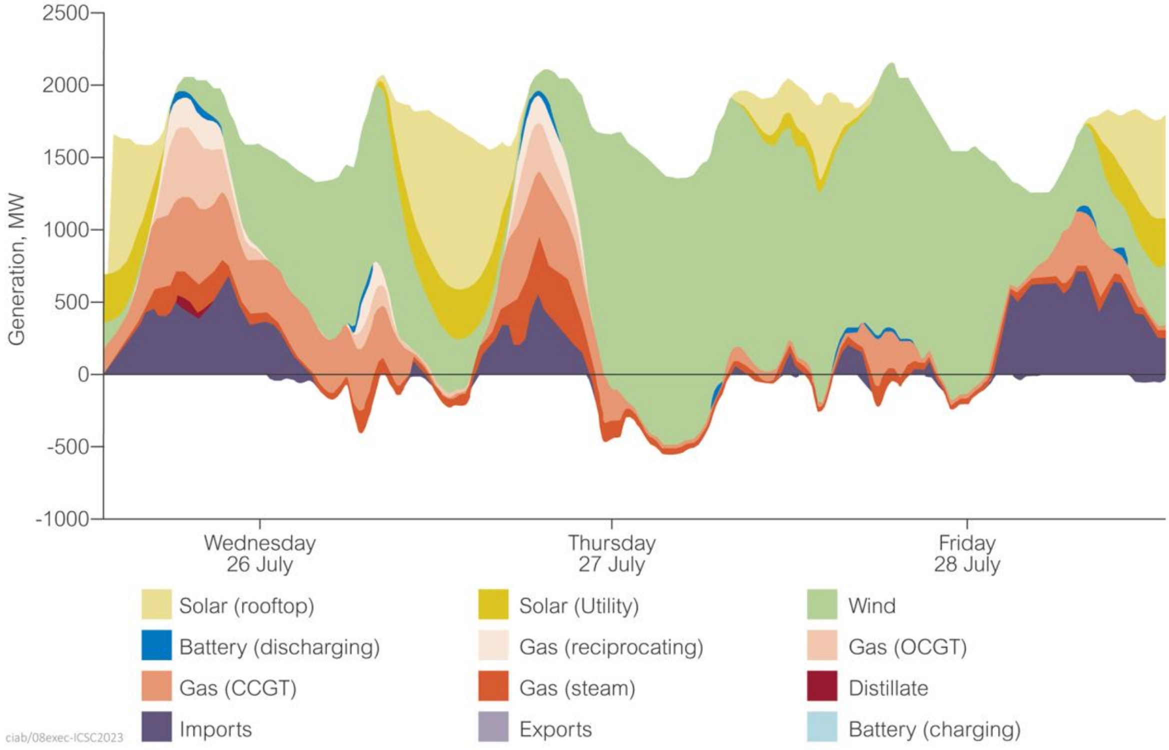

Figure 8 The grid in South Australia, July 2023 (Hunt, 2023)

Figure 8 illustrates that late on 26 July in South Australia there was more wind energy than total system demand. However only 24 hours earlier, wind and solar output was near zero and system load was carried almost entirely by natural gas and interconnectors. This illustrates not only the real-world issue of the surplus-deficit cycling of VRE, but also the reliance of system stability on dispatchable power, whether from the same grid, or adjacent grids via interconnectors.

It is precisely these alternate surplus and deficit cycles associated with VRE that future markets and systems must be designed to accommodate seamlessly and at national scale.

VRE IS NOT A COMPLETE SOLUTION ON ITS OWN, BUT ONLY PART OF ONE. DISPATCHABLE CAPACITY REMAINS A NECESSITY TO ENABLE VRE TO FUNCTION

KEY MESSAGES

- Grids are vast and complex; modern society relies on them.
- They must be dependable under all conditions.
- Grid system related risks are diverse, evolving and increasing.
- VRE requires additional measures, beyond minor capacity share, to ensure stable dependable and cost-effective systems can be deployed.
- VRE technologies are resource intensive compared with other large capacity low-carbon dispatchable power options.
- Currently, cost analysis is not sufficiently transparent to identify the total cost impacts of energy and technology options.
- A balanced and technology agnostic approach must be adopted to ensure timely, lowest cost decarbonisation.
- Storage, interconnection and demand management alone are not sufficient to guarantee system dependability under all conditions.
- Dispatchable power remains a necessity and is critical to ensure system security and reliability.
- Different starting points, drivers, and constraints, lead to different paths and speed of change by geographic region.
- Abated fossil fuel has the potential to reduce the cost of, and to accelerate, grid decarbonisation at global scale and help address decarbonisation challenges in regions still reliant on fossil fuels.
- As yet, no major grid system has demonstrated a reliable, affordable transition pathway to net zero.

KEY RECOMMENDATIONS

- Modelling needs to focus more on resilience to extreme events than business as usual.
- Cost comparisons between options should only be made on real-world cost bases including the impacts on the wider energy system. Simple plant LCOE analysis should not be used and should be avoided wherever possible.
- Sufficient dispatchable generation remains essential until any proposed alternatives are demonstrated, deployed and proven.
- Policies and finance mechanisms need to be fit for purpose and explicit about differentiating between abated and unabated fossil fuel to transition optionality.

‘CURRENT TRENDS INDICATE THE POTENTIAL FOR MORE FREQUENT AND MORE SERIOUS LONG DURATION RELIABILITY DISRUPTIONS, INCLUDING THE POSSIBILITY OF NATIONAL CONSEQUENCE EVENTS’
(JAMES B ROBB CEO, NERC)

Electricity grids must provide dependable, affordable, stable and secure power for our societies and economies, and this *must* continue to be our priority throughout the low carbon energy transition.

1 INTRODUCTION

The scale and urgency of actions needed to address issues associated with climate change are well recognised and acknowledged. Changes to current and future energy supply and management are a significant part of any solution. The electricity system, together with the increasing electrification of other sectors, has a critical part to play in enabling a global energy transition. To date, the focus of the energy transition has largely been on the deployment of variable renewable energy (VRE) technologies, mainly wind and solar, with associated emphasis on the phase out of fossil power assets, predominantly coal. However, the needs, constraints, dependencies, opportunities, practicalities and costs associated with operating, maintaining and upgrading the electricity supply network to support the transition are less well understood or appreciated. This includes the associated equipment, infrastructure and processes. Recent projections regarding the scale of system modification, upgrade and expansion required to accommodate the significant deployment of VRE sources with the associated intermittency management challenges have raised concerns over the affordability, credibility and deliverability of proposed solutions. This includes whether such systems will continue to be able to deliver basic capacity, electrical grid system stability and security of supply requirements. Therefore, there is a mismatch between the increasing drive for, and emphasis on, VRE deployment as the main solution to enabling a low carbon electricity supply and the need to meet energy dispatch challenges, combined with a lack of understanding of the costs, and therefore costs to the consumer, resulting from a narrow approach solution.

Electricity grids are a vital part of everyday life for society and economies and yet their stability and function are taken for granted. This report provides a holistic overview of power grids in the context of the energy transition. It explains the implications and impacts of choices and decisions being made, especially in respect of the accelerated roll-out and deployment of non-dispatchable power sources in the form of VRE technologies. The intermittency of renewable energy creates challenges in electricity supply that need to be managed if reliability, continuity and security of electricity supply are to be maintained. The study identifies a higher level of real-world complexity and interaction of elements than is commonly assumed in much of the reporting. It is important to consider the broader scope and system boundary of the whole energy system, rather than just the power generation technologies, in order to avoid errors in interpretation of data. The issue of cost is covered in detail, explaining why the commonly used levelised cost of electricity may be misleading and inappropriate in determining lowest system and consumer cost for a given level of decarbonisation.

Dispatchable options for power generation within a low carbon framework are outlined together with their suitability for the system. The opportunity to decarbonise fossil fuel generation and its potential role in accelerating and reducing the cost of transition, including in countries still reliant on them is considered, including their positive impacts on system reliability and stability.

Various geographic regions are described in terms of their electricity grids, situation and outlook, highlighting that all regions have their own starting points, operational characteristics, constraints and opportunities. How systems develop, and which solutions are most appropriate will depend on these local and regional factors. There is no 'one size fits all' formula for global decarbonisation of the energy supply system, in particular the electricity supply system.

So, what are these systems, how do they work, why are they so critical? What are the emerging risks related to these systems and how should they best be managed? Why are the issues of cost, technology deployability, system stability and reliability so important? How might system scenarios develop? This report seeks to support a best-informed approach to delivering a cost aware, reliable and secure electricity system transition. The report takes the reader from the fundamentals of power systems, how and why they have developed as they have, to the power market, power system technologies, operation and security. It proceeds to a deeper appreciation of the significance of intermittent and variable power sources and the knock-on impacts and implications on the wider system and consumers. It is written from a fact-based objective viewpoint using material and associated evidence in the public domain. Whilst not exhaustive in each aspect the reader will gain a more complete understanding and appreciation of the challenges and the risks and benefits of alternative solutions. With so much at stake concerning climate change whilst maintaining energy security, the report seeks to help support and facilitate a best-informed approach to strategic thinking and decision-making.

"YOU FORGOT TO BUILD THE ROAD,
IT'S TIME TO 'RING THE ALARM BELLS' ON ELECTRICITY GRID EXPANSION AND MODERNISATION AROUND THE WORLD, OR RISK PUTTING THE BRAKES ON THE TRANSITION"
(DR FATIH BIROL, IEA, JULY 2023)

2 THE ELECTRICITY GRID

2.1 KEY MESSAGES

Electricity grids and the associated systems are essential to everyday life. They underpin economic activity and growth and the costs of their provision are reflected in price of goods and services. Developed for reliable, dependable operation, they are based on careful design, high standards, monitoring and control. Supply and demand are balanced at all times due to the electrical energy immediacy even as the demand itself varies over daily and seasonal cycles.

The extent of new connection requirements, new loads, behind-the-meter and distributed generation resources, and new market mechanisms, are making grid systems more complex in both operation and forecasting. This rapid evolution with new demands placed on legacy systems not designed for them carries challenges and drives a need for adaptation and change. Age, extreme weather, system congestion, increasing demand and changing power generation characteristics are concerns that need to be addressed.

The evolution of these systems while continuing to upgrade and refurbish older system elements is a significant task that will require high levels of resources and finance and will take decades to complete. New technologies will create new options and improve operational efficiency, unlocking capacity previously unavailable, but the challenges remain daunting.

ELECTRICITY GRIDS ARE THE FORGOTTEN ELEMENT IN THE ENERGY TRANSITION

2.2 WHAT IS AN ELECTRICITY GRID?

This chapter outlines the fundamentals of power grids. It covers architecture, scale and complexity, operational requirements, failure and protection, markets and pricing and their current evolution, emerging risks and future development. Understanding this context is important for the rest of the report.

In this study, the term ‘grid’ primarily refers to the ‘electricity system’ comprising power sources, transformations and distribution of that power from source to consumers. Therefore the ‘grid’ represents all system aspects providing electrical energy from source to society.

2.2.1 The immediacy of electrical energy

Power generation mainly occurs through two methods. The primary method involves rotating an electrical generator’s shaft using various rotational energy sources. In this process, the interaction between magnetic fields and conductors in both rotating and static components generates electrical energy; contrasting with the operation of electric motors, where electricity induces mechanical work.

Generator rotation is often driven by thermal power plants that produce steam through boiler systems and expand it using steam turbines. Most power plants, including those using coal, nuclear, biomass, gas, oil and waste, operate on thermal cycles, generating substantial heat as a by-product. Alternatively, wind, water, expanding gas in turbines, blades, impellers, or other mechanical torque sources, such as engines, can also turn the generator shaft. The second primary method is solar photovoltaic (PV), where static components convert light exposure into direct electrical energy.

Electricity is immediate, stemming from the interaction of charged subatomic particles, and electric and magnetic fields within conductors, adhering to established physical laws. Consequently, electrical systems adhere to scientific principles and regulations, with their operation contingent upon satisfying these criteria. Electricity flows essentially instantly from source to users, without time delays or energy storage. It lacks reserves or stockpiles, resulting in a one-to-one energy input-output relationship at any given moment.

The immediacy principle is pivotal in electrical systems, demanding a constant equilibrium between power generation and consumption for system stability. Although Sections 3.6.5 and 4.5.5 explore opportunities and technologies for electricity storage, it is important to recognise that electricity cannot be batch-produced or conveniently stockpiled to buffer supply and demand fluctuations. Sustaining a balance between supply and demand remains imperative to avert system failure in any single synchronous grid system.

2.2.2 Connecting generators and consumers

To supply energy, power sources must link with consumers, necessitating an intricate and functional system. Within each building, networks of wires interconnect numerous devices and systems, including lighting, heating, cooking, cooling, ventilation, process equipment and power outlets. Building-level connections then extend to street, town, district and city levels, creating a comprehensive network that physically links all consumption to all generation. This expansive connected web continuously undergoes maintenance and adaptation to accommodate evolving power sources and consumers. Every component within electrical systems is physically interconnected via conductors, with electrical separation solely achieved through switches deployed across the grid and local networks.

2.2.3 Grid architecture

The term ‘grid’ essentially describes the physical system configuration as an intricate network of lines and interconnections spanning a vast area. In the context of conductor systems, the terms ‘grid’ and ‘network’ are often used interchangeably, encompassing both transmission (typically high voltage) and distribution (typically low voltage) systems, leading to an overlap in their common usage.

Energy losses within electrical systems primarily result from heat generation, a consequence of electrical current interacting with resistance in various components. Lowering resistance or current diminishes heat generation and, subsequently, losses. However, reducing current at a fixed voltage also reduces the power transferred within the system. Furthermore, as cable distances increase, so does the resistance between locations. To address this challenge, electrical systems induce electrical flows in magnetically coupled devices known as transformers, using the properties of alternating current (AC). These transformers enable system designers to transform electrical power from one current and voltage to another while preserving the same power. The relationship between voltage and current at constant power is inversely proportional, allowing for the transmission of high-power levels across lengthy distances using high voltages and low currents, thereby minimising heat-related effects and losses. This lower current also permits smaller, lighter conductors and less substantial supporting systems, offering additional advantages.

Modern power systems initially generate power at high voltages, subsequently elevating the voltage further for bulk transmission along the major lines. As power approaches its destination, the voltage is reduced to levels more suitable for end-users and their devices. This tiered voltage approach creates a layered architecture within electricity grids, to which various generators and users connect. Globally, electricity systems encompass voltage levels ranging from approximately 800 kV to around 120 V AC. For instance, in the UK, system voltages typically include 400 kV, 132 kV, 33 kV, 11 kV, 400 V and 230 V. The supply system to deliver this power is shown in the diagrammatically simplified arrangement in Figure 1 (Beardmore, 2020).

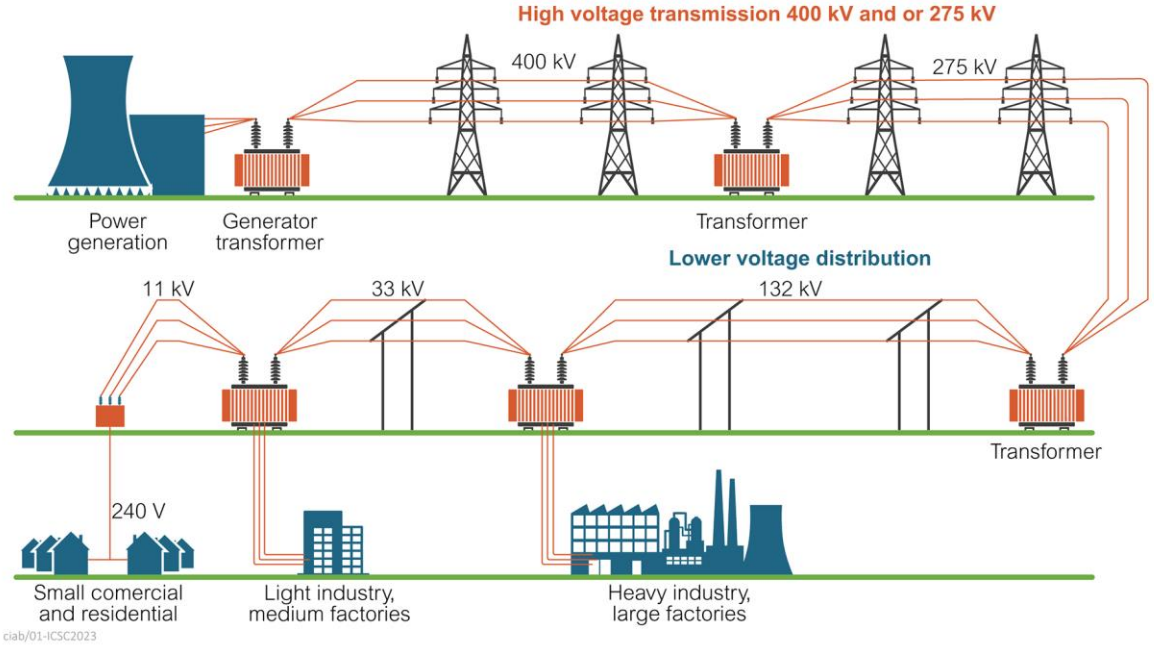

Figure 1 Simplified illustration of UK electricity system infrastructure (Beardmore, 2020)

In electrical systems, various devices and processes may operate at distinct voltage levels. For instance, industrial complexes connect to higher voltage systems, allowing them to absorb substantial power quantities at a single location, necessitating specialised switchgear and distribution setups. In contrast, residential consumers typically connect at lower voltage levels, featuring strict maximum current limits safeguarded by fuses and cut-outs. Large power plants are akin to industrial facilities and interface with the grid for electricity supply to initiate and maintain site systems and services.

Higher voltage networks require heightened safety measures to prevent short circuits and ensure safety. Consequently, these networks are often physically segregated from their surroundings, employing tall towers and robust insulation. They are vital national infrastructure, forming the nation's electricity grid core. The extensive high-voltage electricity system in Europe is represented simplistically in Figure 2.

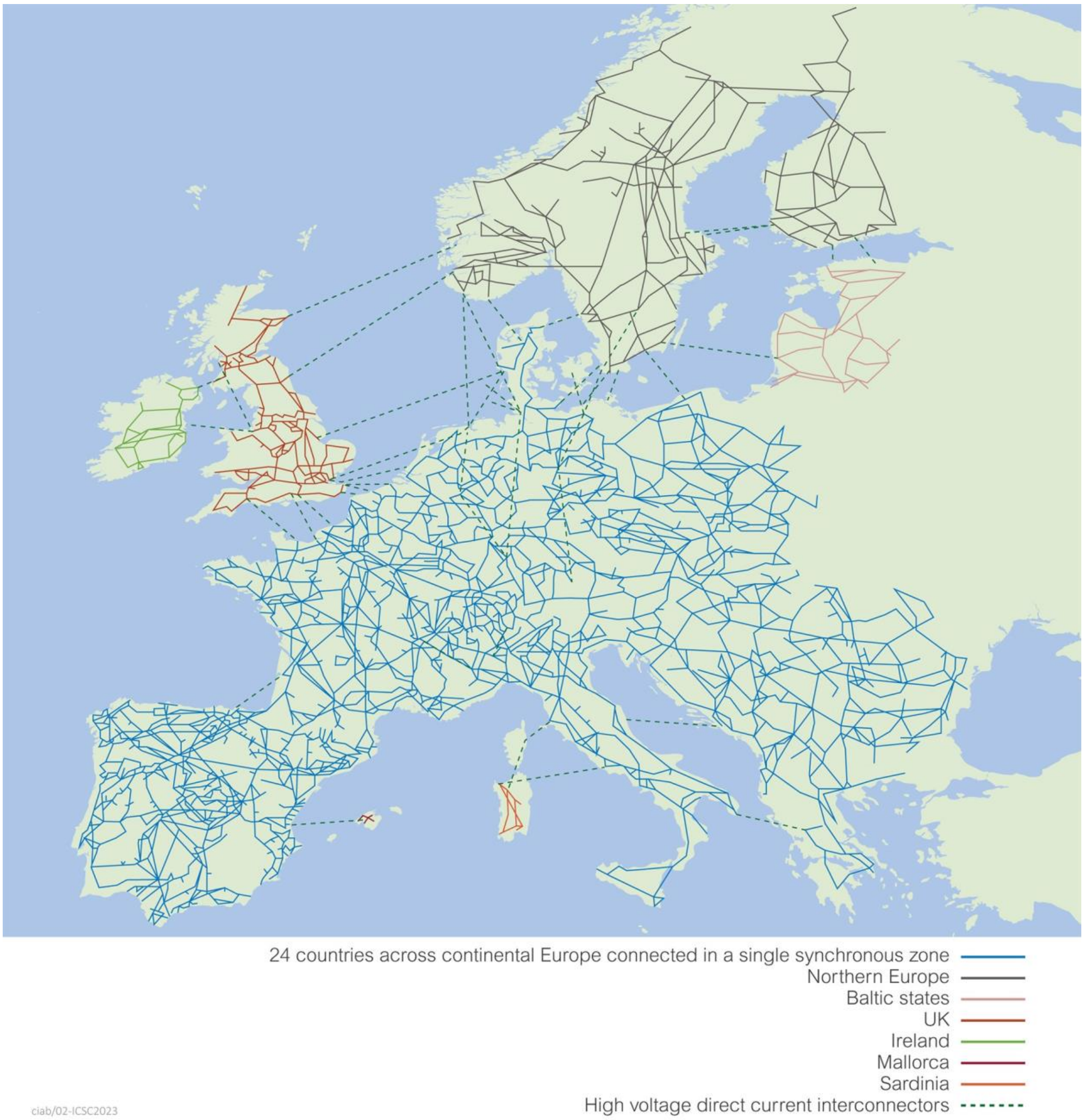

Figure 2 Synchronous zones of the European power system (Hofmann and others, 2020)

The figure displays a single synchronous zone encompassing 24 continental European countries. Additional zones are depicted for northern Europe, the Baltic states, the UK, Ireland, Mallorca and

Sardinia. Dark green lines represent various high-voltage direct current interconnectors, which are further discussed in Section 3.6.2.

In an AC voltage, current and power adhere to a sinusoidal amplitude waveform. This waveform operates at a common frequency for a given system, ensuring that all interconnected components share the same frequency, leading to their classification as synchronous zones. Conversely, zones with differing frequencies or phase shifts in their waveform are not directly interconnected. Consequently, owing to historical factors and despite certain consolidations, numerous separate 'synchronous grids' persist worldwide, operating under distinct jurisdictions (*see* Figure 3) (Hofmann and others, 2020).

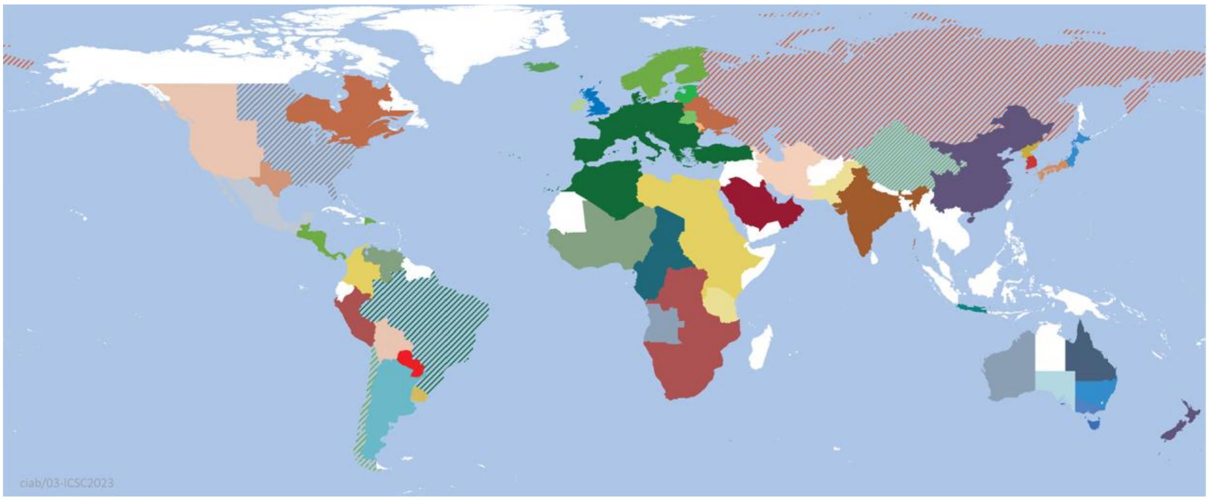

Figure 3 Wide area synchronous electricity grids of the world (Wikimedia Commons, 2021)

As transmission distances get longer it becomes more economical to transmit power by high-voltage direct current (HVDC) rather than AC. However, this requires expensive converter stations at both ends to provide the energy conversions to and from AC and DC. This provides an opportunity to couple different synchronous zones since the electrical characteristics of the two AC systems are accommodated by the converter technology.

Figure 4 shows future commitments to the expansion of HVDC networks across some European countries to better interconnect the various power grids and enable strategically important power transfer in either direction (Tariq, 2022). Countries or regions connected in the same synchronous grid do not need this technology to exchange power but the flows between regions will be measured for reporting and market accounting purposes.

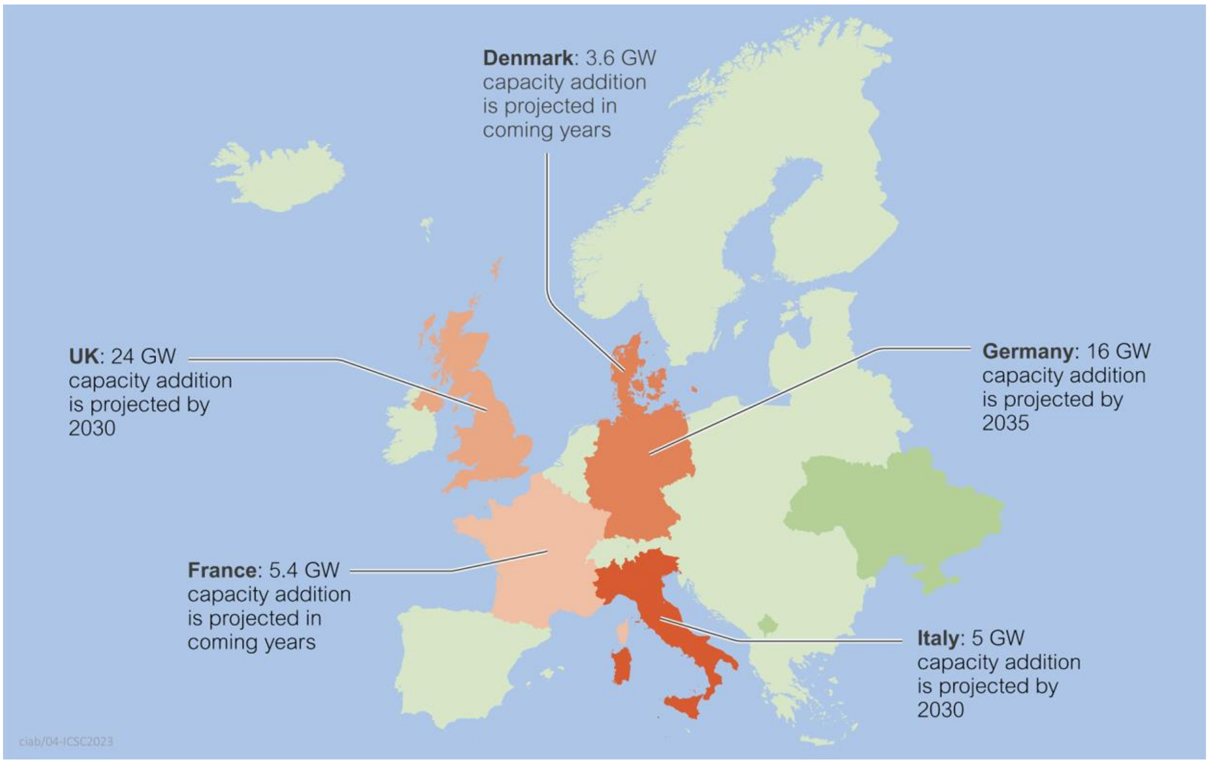

Figure 4 HVDC roll-out activity by leading investors in Europe (Tariq, 2022)

2.2.4 Equipment and systems

Grids comprise cables, wires, physical structures, conduits and tunnels to house them. All the voltage transformations throughout the system require thousands of transformers with various capacities and voltage levels. The system must also connect and disconnect suppliers or consumers or even other systems, safely and reliably. They need to be able to monitor energy flows, electrical and physical parameters at many points in the system and detect abnormalities and issues so that preventative or emergency measures can be taken. Monitoring and protection systems are generally automated and backed up with manual monitoring and over-rides.

2.2.5 Scale and complexity

There are hundreds of millions of kilometres of HV cables and lower voltage wires stretching out over nations and continents, as well as within every square metre of centres of consumption. They connect everything to everything else in real-time across towns, cities, states and countries. Globally these systems deliver around 28,500 trillion watt-hours of energy annually (Ember, 2023), forecast to more than double by around 2050 (McKinsey & Company, 2022).

Electricity grids are a great engineering achievement, developed and rolled out progressively over the last 100 years. The massive scale of such systems in developed nations is relevant when setting objectives for scaling up or replacing existing systems to meet future energy system aspirations. The US and European grids are often described as the largest man-made machines on the planet; the US grid alone has around 260,000 km of HV transmission grid. Globally there are more than 80 million km of transmission and distribution power grids, and it has grown by around 23 million km over the last 10 years (2.3 million km/y average) (IEA, 2023d). The IEA estimates for total transmission and distribution system lengths together with age are illustrated in Figure 5.

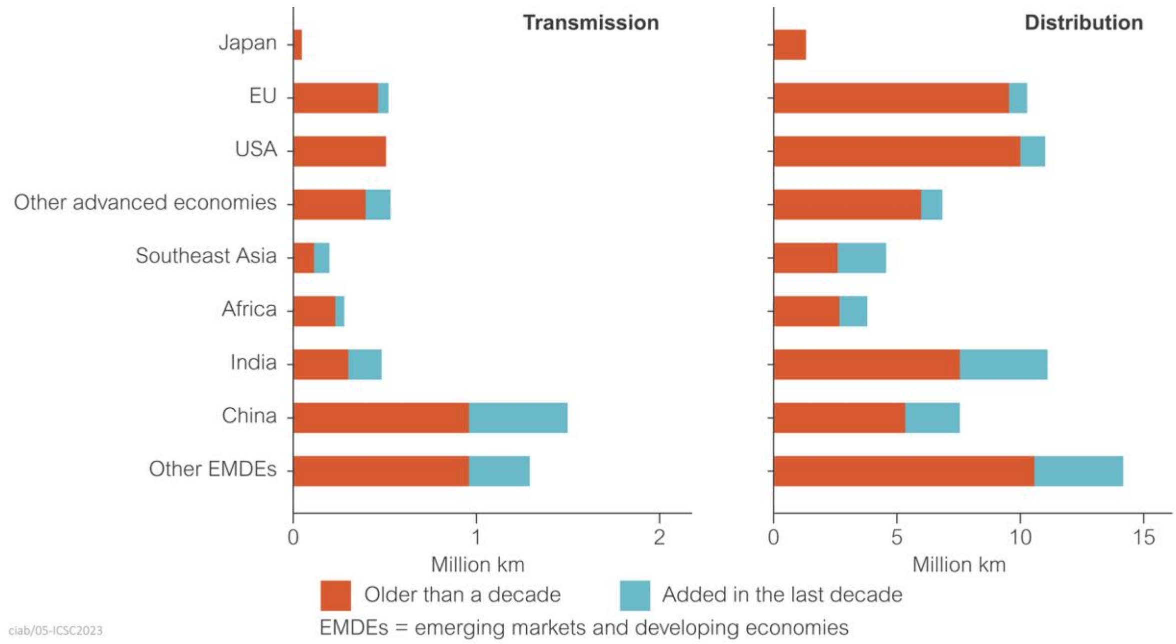

Figure 5 Transmission and distribution system scale and age by country (IEA, 2023d)

The modern-day centralised electricity systems in developed nations with high-capacity central generation assets, regional operators and comprehensive grids wrapped in standards and regulations are the result of incremental, practical and economic evolution. Large and centralised grids are driven by the benefits of economies of scale and the ability to deliver reliable power supply, consistently, within tight technical specifications in an economic way for consumers.

2.3 GRID OPERATION

Power grids need to be carefully managed and monitored. This is a huge responsibility, governed by stringent regulations and standards. Continuity, maintenance of the system, affordability and safety is paramount. This section describes how it is achieved in typical grid systems.

2.3.1 Forecasting

Traditionally, grid operators had the formidable task of confidently forecasting future electricity demand since grid storage was limited. This task becomes more manageable as energy user numbers increase, thanks to an aggregation effect that smooths individual user actions, yielding characteristic demand patterns. These patterns tend to exhibit characteristic profiles throughout the day and on similar weekdays. Moreover, reasonably predictable seasonal fluctuations in demand profiles can be anticipated. Adjustments can also be made for forecasted weather changes, annual demand shifts, market technology evolution like heat pumps, electric vehicles, air conditioning and even significant events such as televised sports or national broadcasts. Precise demand forecasting remains an ongoing challenge, varying by country, region, location and events.

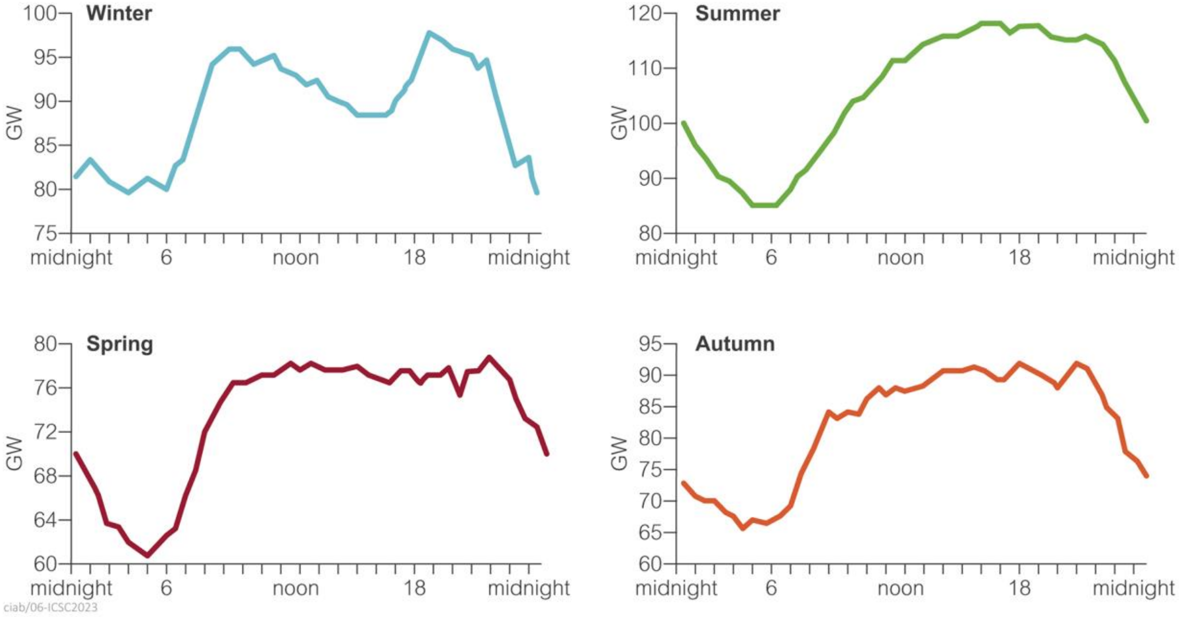

Figure 6 Illustrative variations in daily and seasonal demand profile, PJM region, USA (PJM, 2023)

Demand variation depends on the context and the loads within the system. For example, regions with hot summers and widespread air conditioner usage tend to experience higher summer loads compared to winter, while cold regions may observe the opposite trend. Figure 6 presents typical demand profiles for the Pennsylvania New Jersey Maryland (PJM) operating region in the USA, illustrating demand variations throughout a typical day and the contrasting shapes and magnitudes between seasons (PJM, 2023). In this region, summer peak demand surpasses spring peak demand by approximately 50%, with summer's minimum daily demand still matching spring's maximum daily demand. Additionally, summer daytime peaks are about 40% higher than their counterparts on typical seasonal days. These demand fluctuations necessitate real-time supply adjustments to maintain grid stability. Although these figures represent averages, they demonstrate the demand forecasting concept and aggregation impacts within a large-scale system.

2.3.2 Balancing supply and demand

Various methods harmonise to maintain the balance between supply and demand. Typically, a scheduling mechanism aligns the bulk of supply capacity with anticipated demand. This scheduling occurs in advance, often based on declared operational costs, accounting for availability issues, constraints and planned outages. Some arrangements result from bilateral contracts between suppliers and energy consumers. A comprehensive assessment is then conducted to ensure sufficient supply exists to meet expected demand, along with an operational margin.

The system operator possesses tools and options to secure additional supply, remove supply or curtail loads to sustain system equilibrium. These actions adhere to system operating rules and obligations, with a predetermined order established through a transparent bidding or 'merit order' process, guided by well-established procedures.

2.3.3 Controlled parameters

Some controlled parameters are described in this section.

Frequency Regulation: all devices, including motors and generators, connected to the power system operate at the same frequency. Any change in frequency impacts the speed of these devices and can disrupt systems relying on a stable power frequency, thus, system operators rigorously control the system's frequency. If instantaneous demand surpasses supply, or vice versa, the system's frequency tends to fluctuate. Swift measures are taken to restore it to the desired range.

Voltage Management: devices are designed for specific system voltages, so suppliers must maintain voltage within acceptable limits at the point of use. Additionally, electromagnetic interactions between devices can cause a slight separation between voltage and current waveforms, known as the phase angle or power factor disparity. This results in 'reactive power', which the system operator must keep within acceptable limits.

Load Balancing: efficient power distribution is crucial to avoid overloading points or areas within the grid. It should also allow for rapid load transfers to alternative circuits in case of faults or trips, ensuring a continuous power supply. Load management is especially vital in areas with known congestion or constraints. These constraints can result from excessive generation in one location, long power transmission distances, limited alternative pathways due to planned or unplanned outages, insufficient capacity investments or significant short-term demand fluctuations for which the system was not originally designed. Often termed 'thermal' constraints, they are due to the associated component heating, which must be limited to safeguard the system's integrity and lifespan.

Figure 7 provides an overview of measures and timescales for managing system parameters to maintain acceptable limits. Further details are available in Sections 2.3.5, 2.4, 3.3 and 3.6.

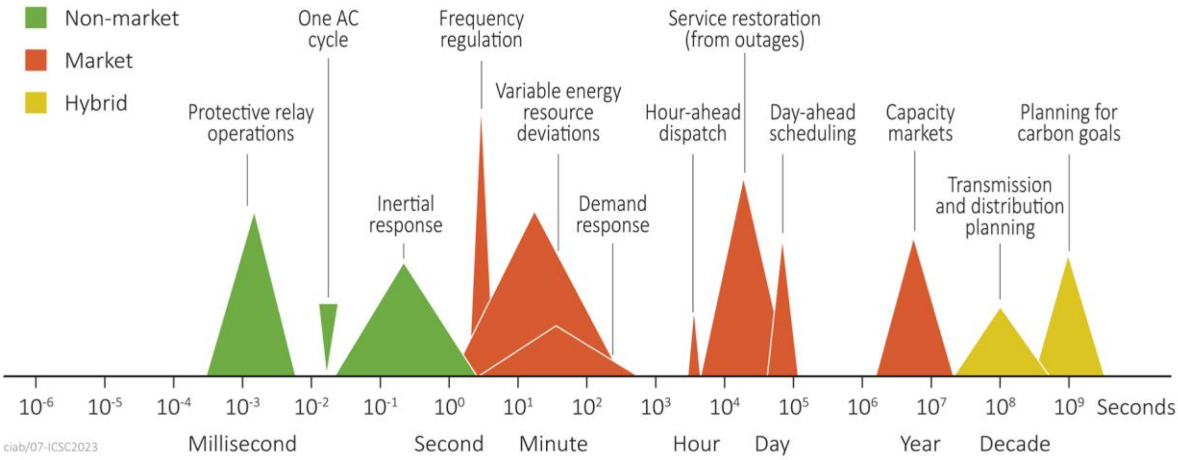

Figure 7 Measures and timescales for stabilising the grid (Lockwood, 2020)

In 2014, the EU regulator ACER introduced new market categories within the continental grid, such as frequency containment reserves (FCR) for rapid responses within 30 seconds (equivalent to primary response) and frequency restoration reserves (FRR), with activation times ranging from 30 seconds to 15 minutes and the option for automatic or manual activation (aFRR and mFRR). These categories roughly correspond to secondary and tertiary response mechanisms (Lockwood, 2020). This is illustrated in Figure 8.

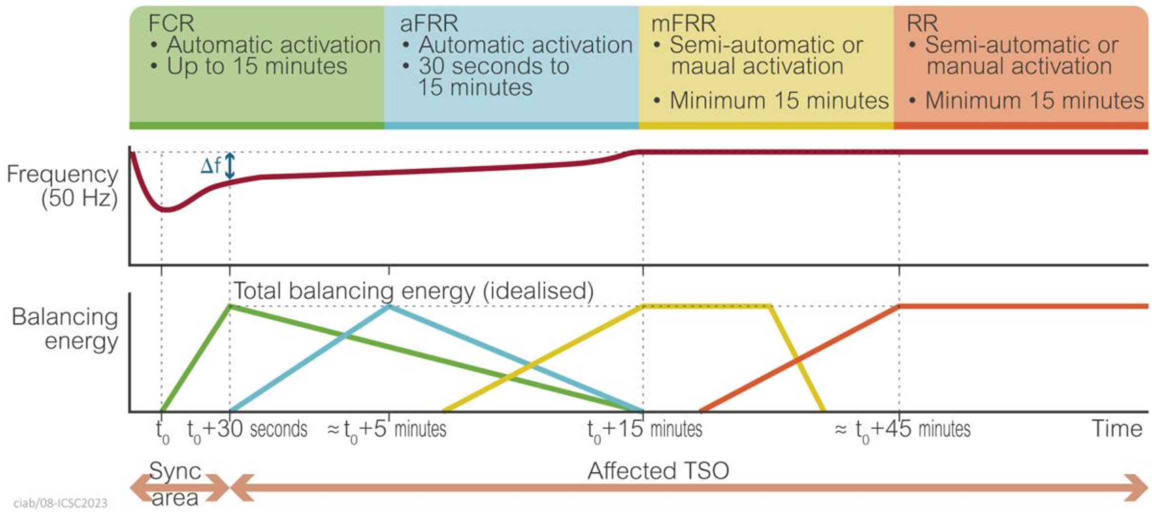

Figure 8 Three categories of reserve used for system balancing in Europe (Lockwood, 2020)

2.3.4 Organisation and governance

The power system is a complex network of stakeholders and assets that must function smoothly while meeting various demands and objectives. Effective control and oversight are essential for ensuring reliability and safety. Typically, a grid has an operator responsible for the day-to-day management and who may also oversee lower voltage levels, or a separate distribution system operator may handle this responsibility. At a higher level, government officers or regulators are appointed to supervise operating companies and make decisions in the national interest. The rules governing the electricity system's design and operation are detailed and strictly defined. Participants typically require formal approval through licenses or certifications, subject to verification through audits. Generators only supply power to the grid on the system operator's request, based on a dispatch system that considers forecasted loads and real-time system monitoring.

The organisations involved in the power system can vary based on system size, political regime and commercial practices. They may be state-owned or private entities and competition among private organisations for similar services can exist. In certain areas, 'vertical integration' allows businesses to generate, distribute and sell power to customers, while, in others, the separation between these levels promotes independence and market-based competition. Generators in such systems are often profit-driven enterprises, while grid operators are typically regulated, operating within budgets and guidelines established by the state or regulator.

The number of organisations involved depends on the network's fragmentation across the region. Some regions have a single unified system, while others operate multiple systems concurrently to provide comprehensive coverage. At the power generation level, independent power producers manage their assets independently, while energy companies may oversee a fleet of assets spanning multiple countries and regions.

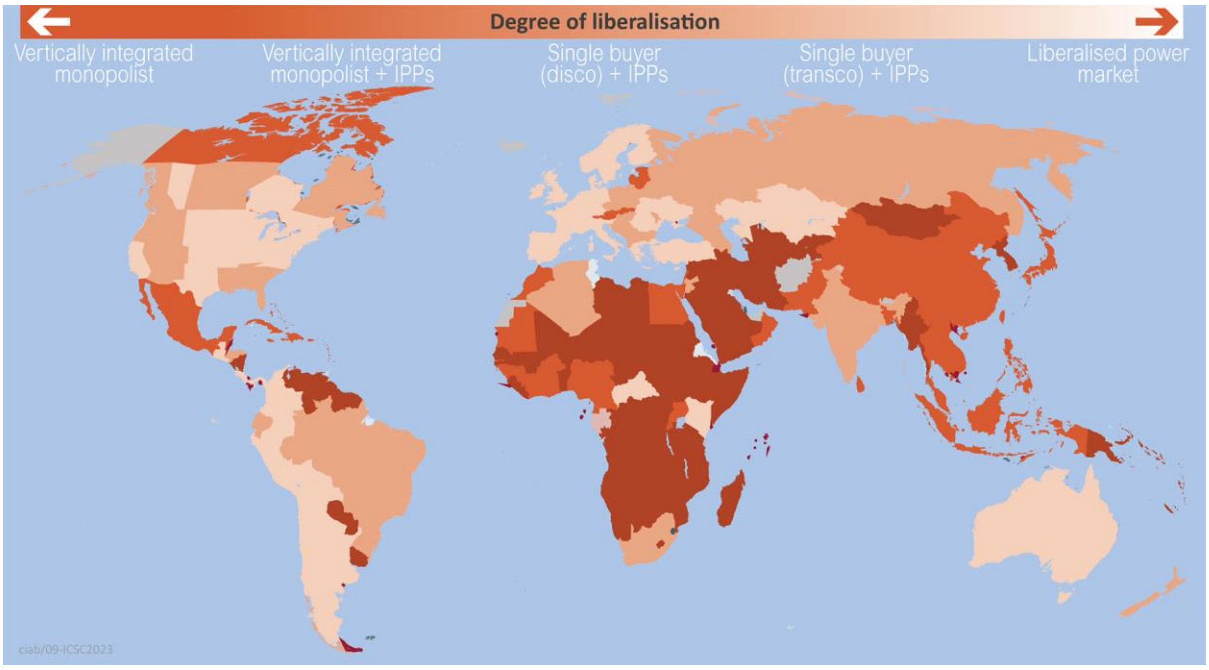

Figure 9 Extent of global energy markets liberalisation (Lockwood, 2020)

Figure 9 shows the range of liberalisation in the various power markets globally. Variation of governance and market arrangements translates to different approaches to technology adoption, investment and operation, bringing different advantages and disadvantages, opportunities and risks (Lockwood, 2020).

2.3.5 Market mechanisms

In a basic power market, each power generator calculates and submits its generation cost, along with dynamic characteristics, capacity and connection limitations. A central entity collects this data creating a merit order 'stack' of available plants, which are dispatched to meet demand; all generators receive income equivalent to the costliest generator to promote efficiency and cost-saving incentives.

Many markets have introduced power exchanges, where electricity is contracted between generators and retailers based on wholesale prices. Grid operators primarily manage imbalances on a minute-by-minute basis. Generators and consumers can also establish bilateral power purchase agreements independently, securing longer-term supply at formula-based prices rather than real-time wholesale rates.

Exceptions include payments for system stability services such as frequency response and spinning reserve. Additionally, individual plants may be constrained due to infrastructure issues, leading to special payments. Operation costs can be genuine or commercially derived based on strategy. Generators can be compensated for strategic reserve capacity or participate in capacity markets, where reserve capacity is auctioned to meet system operator requirements. Power markets generally fall into the categories shown in Table 1.

TABLE 1 POWER MARKET CATEGORISATION

Market	Purpose
Capacity market	Provides generation capacity if needed
Energy market	Involves wholesale or spot market trading, including day-ahead and intra-day contracts. May be managed by the system operator or separately through power exchange. Bilaterial trades are included
Ancillary services market	Offers grid stability support services
Balancing market	Managed by the system operator to address unexpected capacity shortfalls

Futures, Power Purchase Agreements (PPAs) and options are contractual variations within the energy market. All these markets collaborate to ensure sufficient, stable and reliable generation at optimal prices.

Wholesale market-based power prices differ from customer prices, as additional costs cover handling, margins, system usage fees and variations by energy type or tariff option. End-user prices are typically higher than generation costs.

Electricity trading across grid boundaries is common, with market prices determined by forecasted demand, supply, fuel costs and plant availability. Prices can be volatile, varying by region, time of day, or year. Energy trading can be profitable, with prices potentially becoming negative during periods of surplus renewables or soaring due to plant outages and high fuel costs. Market prices can fluctuate significantly over a short timeframe, while generation costs remain relatively stable (*see* Figure 10) (AleaSoft Energy Forecasting, 2020).

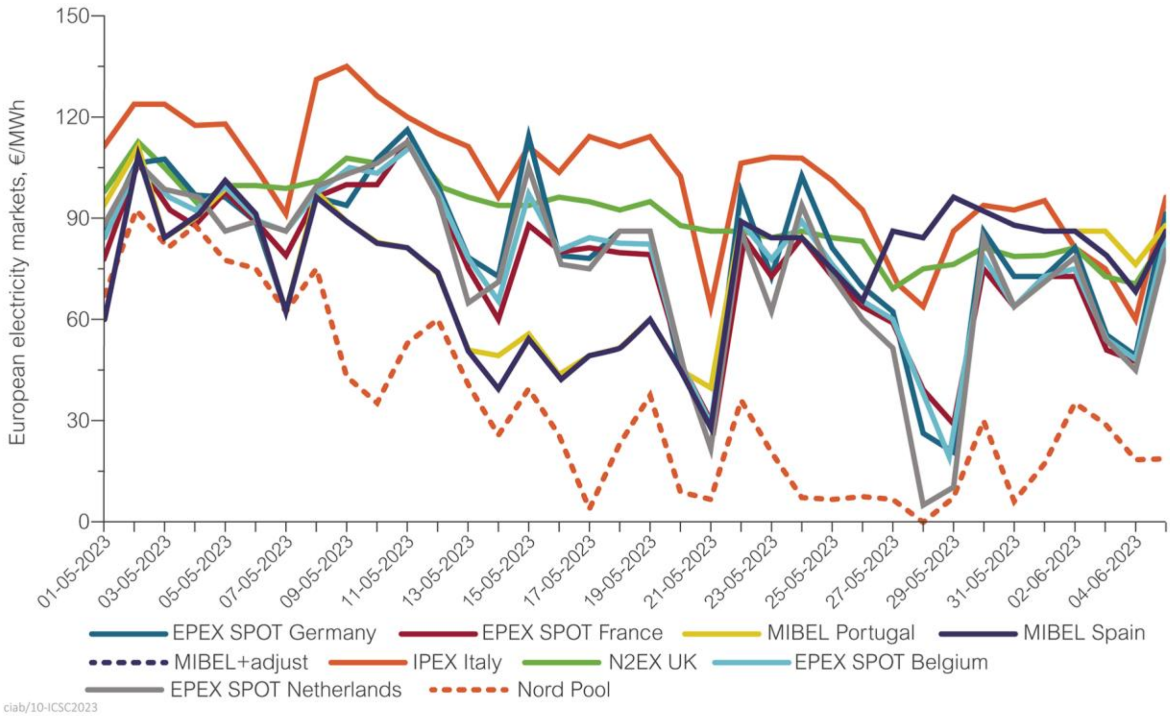

Figure 10 Illustration of floating spot power prices in Europe, May-June 2023 (Aleasoft Energy Forecasting, 2023)

In August 2023 the power prices in Texas rose approximately 60-fold from their normal levels due to high demand, hitting 4700 $/MWh due to sustained high temperatures (Malik, 2023), illustrating potential volatility. Fluctuations in wholesale and spot prices are typically smoothed out by the energy retailer who contracts for power in advance and sets user tariffs based on long-term costs. Businesses buying in the spot market will be directly exposed to the full price fluctuation impact. Thus, the power price and the power cost are not the same from the consumer and generator perspectives.

2.4 GRID INSTABILITY AND FAILURE

Power grids in much of the world have a reliability of over 99%. In Great Britain for example, the standard for the grid is to engineer the system to ensure a loss of load expectation (LOLE) below three hours per year, or 0.034%, which is 99.966% reliability (National Grid ESO, 2022a). This is achieved by careful design, operation and management. Figure 11 illustrates current typical data regarding hours per year consumers might expect to be without power (IEA, 2023d). It shows that consumers in advanced economies expect to have power available, without interruption.

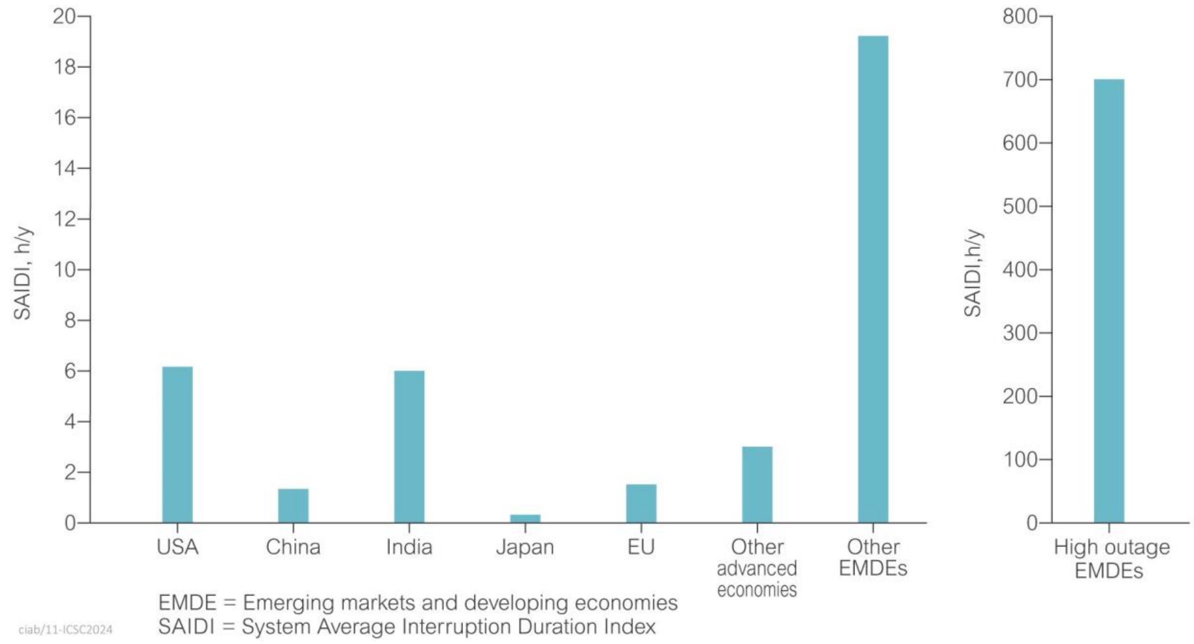

Figure 11 Consumer power supply interruptions, 2016-2020 (IEA, 2023d)

Grid failures and power cuts occur for reasons including rapidly evolving systems where management of supply and demand is challenging, economic or political unrest, temporary or persistent integrity and fault or availability-related issues. Even in well-managed grids failures can occur, sometimes on an epic scale. One blackout in India in 2012 affected 620 million people (Boddapati and Nandikatti, 2020). Even in developed countries managing blackouts can be a challenge, with incidents rising due to the increased frequency and severity of extreme weather events.

2.4.1 Stability and continuity

Grids prioritise stability and continuous operation, closely monitoring real-time conditions and taking corrective actions if instability is detected.

Power outages can be local issues unrelated to the grid and differ from blackouts. Blackouts involve a rapid or systemic shutdown of the power system across a wide area due to detected instability, resulting in a complete loss of power. Blackouts occur instantaneously and without prior consumer warning. To restore service, the blacked-out area undergoes a black start procedure.

In contrast, a 'rolling blackout' is a planned and controlled process initiated by a grid operator when concerns arise about potential instability. Power is systematically removed from specific areas in a rotational fashion for specified durations to safeguard overall system stability. This approach distributes inconvenience among users.

A brownout occurs when voltage levels on the grid drop, causing a temporary reduction in power quality. Equipment may exhibit abnormal behaviour, such as dimming lights, protective devices activating, or control systems malfunctioning. These conditions are typically transient.

In some cases, system operators may detect an unplanned and adverse situation jeopardising the system's integrity. In such instances, they may opt to 'load-shed', intentionally disconnecting system areas to reduce power demand and protect the remaining part until the shed loads can be restored. Load shedding follows a priority order that considers critical infrastructure or facilities. Similar to a blackout, there is no advance notice of supply loss.

2.4.2 Faults and cascade failure

All systems are susceptible to faults including the electricity system. This is not normally seen since the system design ensures resilience to faults, with some system redundancy and alternative options to keep the power flowing. However, equipment malfunction or failure, triggering protective devices, breakages, short circuits, overcurrent events and overheating all happen in real systems often caused by weather, but also by defects, malicious activity or maintenance and investment deficiency.

Design standards usually ensure that systems are adequately protected to detect and take action to prevent faults from spreading. This involves supply tripping to a certain system section, often with attempts to re-supply in case of a transient fault condition caused by wind or tree branches. If the fault persists, then the system will remain protected until repairs can be made.

Grid interconnection can cascade local issues system-wide. Well-designed systems use monitoring, prediction and protection features for rapid fault detection and isolation. Power rerouting through unaffected areas maintains supply continuity, enabled by redundancy and alternate energy paths. Fault accumulation or load transfers to stressed parts due to weather-related factors can cause overcurrent conditions and cascading trips.

Falling frequency poses widespread problems when demand exceeds supply. Grids operate within a narrow frequency band with embedded protection systems. During falling frequency, common in events like power plant loss, a limited window (typically nine minutes) must restore frequency. Afterwards, power plants enter controlled shutdowns, with the supply loss lowering frequency and risking system collapse. In Texas storms in 2021, the Electric Reliability Council of Texas (ERCOT) reported a near collapse when almost half its power generation was lost, narrowly avoiding complete failure with extensive load shedding. Failure would have required a lengthy black start process, taking weeks to restore power during high-demand, adverse weather conditions (Flores, 2021).

Systems aim to contain these events and prevent spread, but they can still cause large-scale outages, as in the 2003 North American blackout, where an unusual combination of circumstances resulted in 61,800 MW lost to around 50 million consumers in Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut and New Jersey and the Canadian province of Ontario (Office of Electricity, 2023). Extreme stress on the system significantly increases the likelihood of blackout. Subsequent preventative measures were reported in detail (USDOE, 2006).

Another cascade failure occurred in Bangladesh in 2022, when a tripped transmission line caused power plant failures and a blackout affecting 130 million people (Le Monde, 2022). Similarly, in early 2023, a transmission system fire in Argentina triggered protection systems, resulting in power loss for around 20 million people (Gilbert, 2023).

2.4.3 Restarting

A power grid collapse is a major event. Generators and consumers become disconnected and energy to the entire system is lost. The grid is not available to provide power to restart anything and although backup power may be available for some services and facilities, such power sources are generally only designed to operate for a matter of hours independently of central power supply.

System restart, or a black start, is achieved by using auxiliary generators with independent energy sources to produce sufficient power to start larger sources and restore power to a system section. These parts are then grown progressively and merged until the system is restored, involving a lengthy process of hundreds of separate installations and millions of customers over a wide area. It involves some risk which necessitates careful planning, coordination and robust processes, varying from several hours to days. In cases where the grid failure was associated with some damage, the time taken to restore power to certain system areas could be much longer.

During a black start, the loads on the system must be managed so that they do not outweigh the supply. This usually means consumers will be disconnected until their supply system is ready and sufficiently stable to accept them back onto it. Reintroducing loads takes time and is subject to certain priority supply areas.

2.5 DEPENDENCE ON ELECTRICITY GRIDS

Grids are essential to modern life. They power industries, services, societies and economies. Yet, they only become a priority to the public when they fail and the power stops. Inconvenience is one aspect, but an unexpected power failure can lead to real distress, suffering and even death. Power failure during heatwaves or severe winter conditions can leave the vulnerable in danger. It can disrupt industrial production causing damage and loss, interrupt supply chains, essential provisions, affect traffic management and more. Blackouts can even lead to civil disorder and unrest over relatively short timescales. As dependence on grids increases, for example through electrification of economies, the more severe are the consequences of power failure.

The cost of power outages in selected countries in 2021 is shown in Figure 12, in terms of the frequency and scale of events and the area they impact (IEA 2023d).

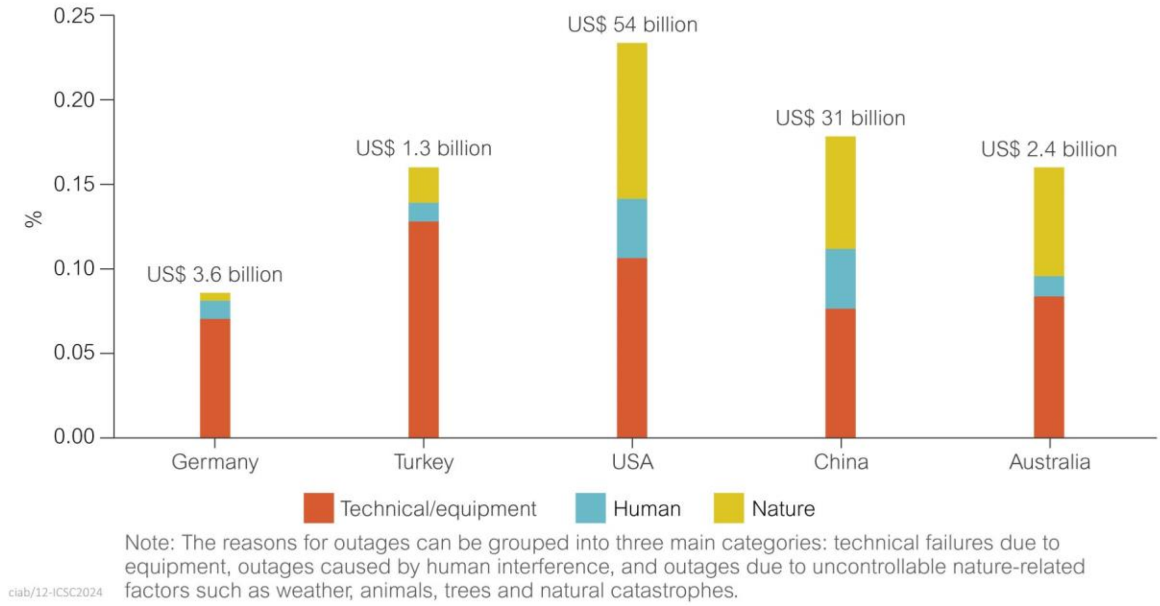

Figure 12 Estimated economic impact of grid-related outages by cause as a share of GDP in selected countries, 2021 (IEA, 2023d)

The risk of power failure may not be widely perceived because of the systems that are in place to identify and control the factors that might lead to interruptions in supply. The system includes flexible and reserve generating assets, multiple options for routing power between supply and demand locations, maintenance regimes, monitoring, automation, codes, standards, regulations and regulators. Grids are designed and managed with the primary objective of reliability and dependability, which is normally achieved. Electricity grids in developed nations are some of the most reliable systems on the planet, even though they are some of the largest and most complex. Grid integrity should not be compromised.

WE DEPEND ON ELECTRICITY GRIDS FOR EVERYTHING WE DO. ENSURING DEPENDABLE AND AFFORDABLE ELECTRICITY GRIDS SHOULD BE A HIGH PRIORITY

2.6 HOW GRIDS ARE CHANGING

Grids were designed to generate and distribute electricity economically and reliably to consumers within a region. The systems were usually owned and operated by the state, with the operators having supply monopolies and developing ever bigger centralised generation sources, higher voltage and longer networks as well as more advanced control forms and protection. The result was a central high-voltage grid backbone, numerous large central power plants located strategically around the country, close to demand and complex lower-voltage distribution networks. These large central assets ran mainly on fossil fuels which could be produced, shipped and stored or else piped to the point of use, guaranteeing that energy would be available when needed even if demand were to surge.

This model is changing to one where power supply assets are far smaller in size and greater in number, located in places new to generation and often remote from where the energy is needed. Large generating assets which ensured electrical stability are being retired or closed. Thus, the need for storage and advanced control methods is rising rapidly simply to maintain normal and stable daily power supplies.

Technologies and requirements are being applied to an infrastructure that was not designed for this scenario. Needs and challenges are emerging which will require major changes to infrastructure, markets and systems and more intervention and control than previously.

2.6.1 Technological developments

Increasing computing power and intelligence drive complex grid system modelling and design. Materials and techniques improve, while enhanced monitoring and data collection inform global research, innovation and demonstration projects. This results in improved grid efficiency, cost reduction and insights into adapting systems to changing generation sources and consumption patterns.

Smart grids, employing digital technologies, facilitate two-way communication among devices, producers and consumers. Equipped with sensors, controls, data collection and metering systems, smart grids optimise power flow and storage, enhancing system effectiveness.

As grids handle heavier loads with tighter margins, fixed line ratings become less suitable. Dynamic line rating reassesses power line ratings based on ambient and loading conditions. It allows load adjustments according to actual capability, actively managing thermal capacity ratings. This approach supports VRE integration in congested grid areas, reducing curtailment costs and maximising capacity.

VRE sources, utilising power electronics, require grid-forming technologies and static/synchronous converters to stabilise the system, as they differ from traditional generators in response characteristics.

Innovations extend to construction technology, facilitating efficient system deployment, such as high-voltage direct current systems for interconnectors and remote energy sources and support towers for transmission lines.

Numerous organisations modernise grids to adapt to market changes and adopt new technologies. The Gridwise Alliance (2021), for instance, supports research and technology dissemination, recently outlining opportunities and developments in areas like integrated planning, system visibility, real-time operation, consumer and energy services engagement and emerging grid architecture (Gridwise Alliance, 2021). These developments are highlighted in Figure 13.

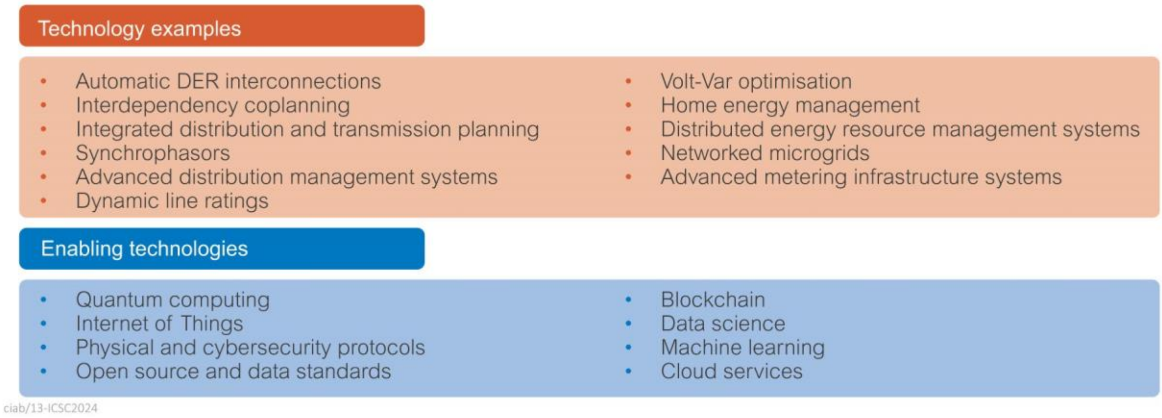

Figure 13 Grid modernisation technology portfolio components (Gridwise Alliance, 2021)

2.6.2 Decarbonisation of electricity supply

Decarbonisation entails increased electrification, which necessitates upgrading system capacities to serve both existing consumers and new energy uses. Implementing these changes across vast territories with millions of consumers presents substantial challenges.

Some countries have long operated low-carbon grids due to historical factors and local resources, such as France, Iceland and Norway. Recent decarbonisation efforts in others have involved large scale fuel switching, for example coal to gas and the adoption of wind and solar power generation. This shift has led to a proliferation of distributed resources. It is transforming grids by replacing reliable, dispatchable resources with variable resources located diversely and with more connections. Consider offshore wind farms, for instance. Power generated at sea must be transmitted to inland areas where it is needed, necessitating significant grid redesign, expansion and reinforcement. To accommodate VRE characteristics, a substantial increase in energy storage is required, along with seamless integration into electrical systems.

2.6.3 Decentralisation

More local power generation and advanced control options have sparked renewed interest in small-scale power installations within lower voltage networks at residential and commercial levels. This transforms the power system from a centralised generation and transmission model to one where power generation and consumption occur at various points in the network, challenging traditional one-way flow assumptions, which present forecasting and system management challenges.

Decentralised power generation encompasses diverse sources like energy from waste, agricultural digesters, reciprocating engines, small-scale wind and rooftop solar. These sources are increasingly accompanied by small or large-scale batteries, which may operate alongside or independently from other distributed sources. System operators now prioritise visibility into these systems, together with emerging demands such as electric vehicles and heat pumps, to anticipate system behaviour under various conditions.

2.6.4 Politics

The development of the energy sector is partly due to political responses to climate change. There is much work carried out in looking at, communicating, and debating options and costs. Part of this relates to the emergence of electrical grids as a major bottleneck to the deployment of new technologies and installations that policies have incentivised. The policies and targets set by governments fundamentally shape the markets, economics and power system performance. However, they can also create tensions and pressures for grid development.

2.7 EMERGENT GRID RISKS

There have always been risks associated with the operation of the electricity grid; some of the traditional ones are highlighted in Figure 14, with possible mitigations (Boston, 2012).

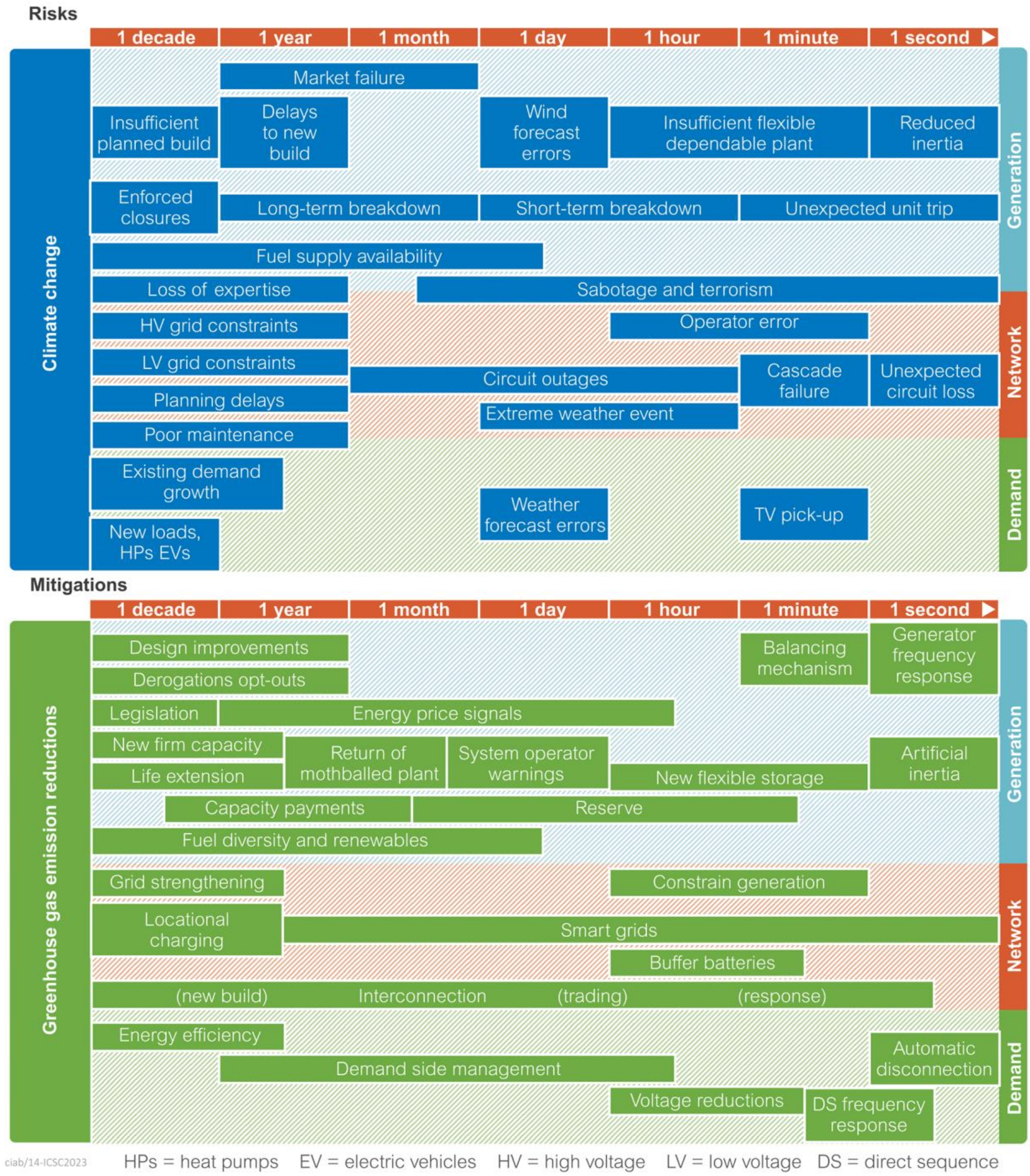

Figure 14 Examples of system risks and mitigations (Boston, 2012)

This section considers the main risk elements during the energy transition.

2.7.1 Generation portfolio

Grids have operated on a relatively static mix of power generation sources for decades. There has been a small drift in shares between coal, nuclear, oil and gas, particularly in the decline of oil in the 1970s and the 'dash for gas' of the 1990s. Now the generation portfolio is undergoing a rapid change. The technology shift with the decommissioning of legacy plants and the introduction of technologies with different attributes and characteristics creates constraints and issues not envisaged when the grids were designed.

2.7.2 Fault handling

Grid operators have specific requirements for controlling parameters that must be met to maintain network stability and allow it to recover from disturbance. They typically include inertia, short circuit levels, voltage, and fault ride-through. The addition of more variable renewables to the system, which are connected to it through power electronic devices, often referred to as converter-based resources (CBR), or inverter-based resources (IBR) tends to cause short circuit levels to be reduced compared to legacy synchronous generators; whereas a higher current is required to ensure system stability. Although developments are in progress, it is an issue requiring management as VRE share grows. Grid-forming technologies and synchronous compensators will be required to replace the services previously offered by synchronous generators, which are being decommissioned.

Inverter-based resources can be prone to tripping unexpectedly depending on how they are configured. In 2023 the US Federal Energy Regulatory Commission (FERC) asked the National Electricity Reliability Council to draft reliability standards for wind, solar and storage IBRs due to rising concern over experiences of these resources tripping offline; 16 since 2016 with an average loss of around 1000 MW (Howland, 2023). The standards are due to come into force by 2030.

2.7.3 Evolution of demand

Apart from changes in national demographics, industrial bases or economic development, there are new developments and policies which will cause significant shifts in demand for the grids to cope with. Developments include technologies such as vehicle-to-grid, vehicle-to-home, behind-the-meter generation by micro-renewables, micro-grids, embedded energy storage, grid-scale storage, thermal storage, power to gas, distributed and community level generation, demand side management and flexibility services and aggregators. These may increase or decrease demand, and some will do both, at different points in time. It is a complex landscape, and many assumptions are necessary to develop an overall view of what future grids will need to be able to do and in what time sequence and scale. Potential impacts, with understanding enhanced by pilots, can help lead the way. However, there are many uncertainties regarding the speed of change and magnitude of impact, which brings into question the ability of grids to absorb it.

2.7.4 Ageing grid assets

As grids developed over the last hundred years or more, standards and practices evolved which led to standardisation and design stabilisation. Physical assets have limited lives, so replacements and upgrades are required as technologies improve, and requirements change. One estimate stated that in the US grid for example, 225,000 km of transmission lines require replacement simply to maintain the status quo, with no consideration for expansion or increase in capacity (Marsh McLennan, 2023).

Similarly, it is estimated that 70% of the US grid is over 25 years old (USDOE, 2022) and 40% of the European grid is over 40 years old (Eurelectric, 2023). Existing asset scale and their age mean that this is a future risk which will require substantial investment and monitoring. The IEA (2023d) has shown that the largest shares of the oldest grids are in the developed economies where 50% or more of the grid is more than 20 years old (*see* Figure 15).

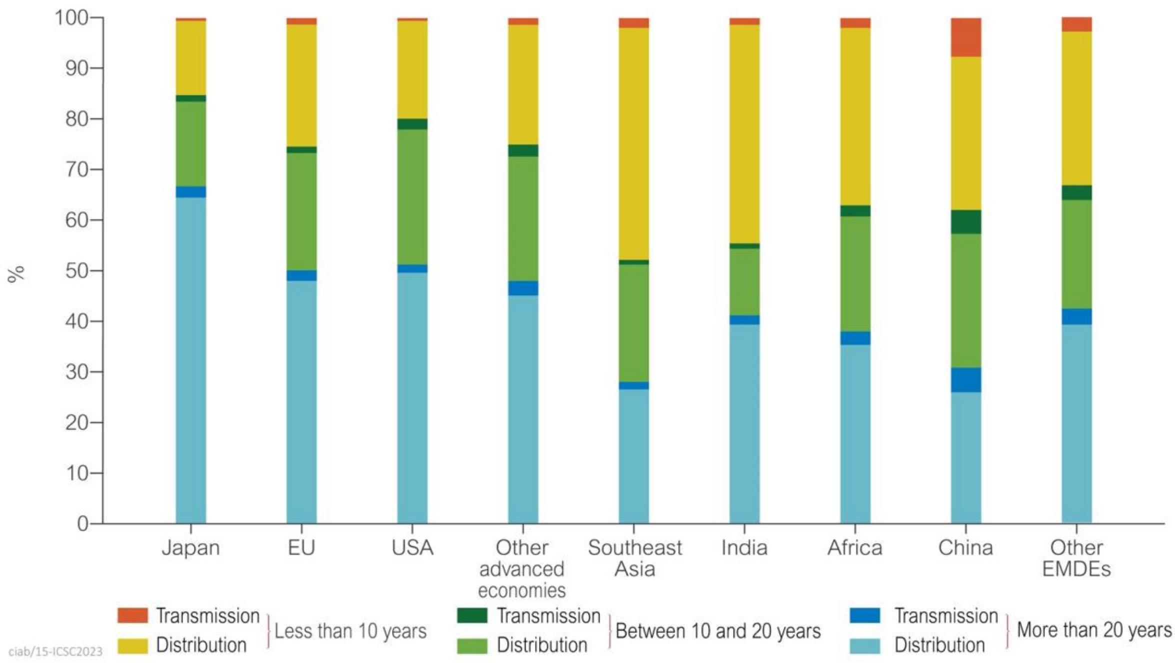

Figure 15 Share of grid length by age for selected countries (IEA, 2023d)

2.7.5 Storage capacity

Energy storage deployment on grids is rapidly increasing. According to the IEA (2023g), global battery energy storage is projected to grow from 28 GW in 2022 to 970 GW by 2030, with an annual addition of 120 GW needed to meet demand. Although this represents substantial capacity, it remains small compared to the overall system size. Ideally, storage capacity should be added at a rate that matches the deployment of VRE to ensure VRE sources integrate smoothly. However, in practice flexibility present in the pre-existing system is relied on instead. Market ability to deploy sufficient energy storage presents a significant risk, as there is no mandatory requirement or direct link between VRE deployment and storage.

The economic case for adding storage can be challenging. Grids experiencing frequent power supply imbalances, with large fluctuations in availability, tend to have a strong business case for implementing storage technologies, especially for daily balancing and cycling multiple times each year. However, as more storage is added, its economic viability becomes less clear, particularly when it is used less frequently, or other measures are employed to compensate for supply-demand imbalances. This raises questions about whether free markets can adequately provide storage in line with the system's needs, as they become less profitable when used infrequently. Nevertheless, infrequent use does not imply a lack of practical value or the absence of need within the system. Ensuring that storage capacity matches VRE growth in a timely manner can reduce future risks to power supply continuity, especially given the retirement and decommissioning of existing infrastructure.

2.7.6 Modelling and forecasting

Various net zero emission (NZE) system models exist, serving as valuable tools to comprehend potential actions, associated costs, challenges and diverse outcomes. However, all the models possess limitations and inaccuracies. Mathematical models are inherently restricted by their design, defined interaction scope, underlying assumptions, simplifications and the credibility of the input data. The electricity grid and NZE goals encompass intricate landscapes with numerous interdependencies, spanning regions and sectors, yielding a multitude of potential outcomes, even for identical decision sets. Many critical factors remain excluded from these models or are insufficiently emphasised, leading to oversimplified outputs relative to the real-world complexity. When working with such models, it is imperative to scrutinise what is omitted but could significantly impact results and subsequent decision-making. Factors such as market dynamics, resource availability, price fluctuations, geopolitical events, weather extremes and natural disasters often elude these models' focus. Most concentrate on evaluating a limited set of technical parameters amenable to mathematical representation. Furthermore, some pivotal factors, such as commodity prices, often rely on models that have historically demonstrated inaccuracies. This presents an enormous challenge when determining investments amounting to hundreds of trillions of euros. Changing course later in the system's evolution can be time-consuming and costly, even when necessitated by evidence. Models offer insights and indications constrained by their design parameters, but they do not furnish definitive answers or a precise glimpse into the future.

2.7.7 Time horizon expectations

Ongoing progress assessment and climate change challenges have driven governments to set targets and policies including key dates for progress towards achieving net zero, either for economies as a whole or specifically for power grids. Some areas have made good progress while others have not, resulting in progressively more demanding changes to achieve the objectives set. This questions whether the measures and milestones forecast are defined top-down by aspiration, or bottom-up by the likelihood that they can be achieved in practice.

Development to the current point has taken many decades of continual improvement based on lessons learned. To add capacity, replace or expand these systems is a huge undertaking typically involving billions of euros for each part. New power plants, connections and transmission lines typically go through rounds of scoping, feasibility, costing, budgeting planning, permitting approval, financing and construction that can easily take 5–15 years per project overall. If these schemes have dependencies with other considerations, such as repair and replacement cycles or political cycles, then additional delays of years can be introduced. There is therefore a strong apparent mismatch between the aspirations for change and the associated assumptions on the timeline with the reality of physically achieving it. Figure 16 shows the capacity addition queue for the US system operator regions, with over 2000 GW generation and storage capacity across more than 10,000 projects awaiting connection approval at the end of 2022 (Rand and others, 2023). In fact, it is estimated that the new connection request volume is approaching twice the current capacity of the entire existing power generation fleet. This includes the effect of pauses in new requests declared by PJM and Californian Independent System Operator (CAISO) in 2022 due to the high incoming request volume and excessive backlog. PJM also declared it would pause the new request review until at least the end of 2025.

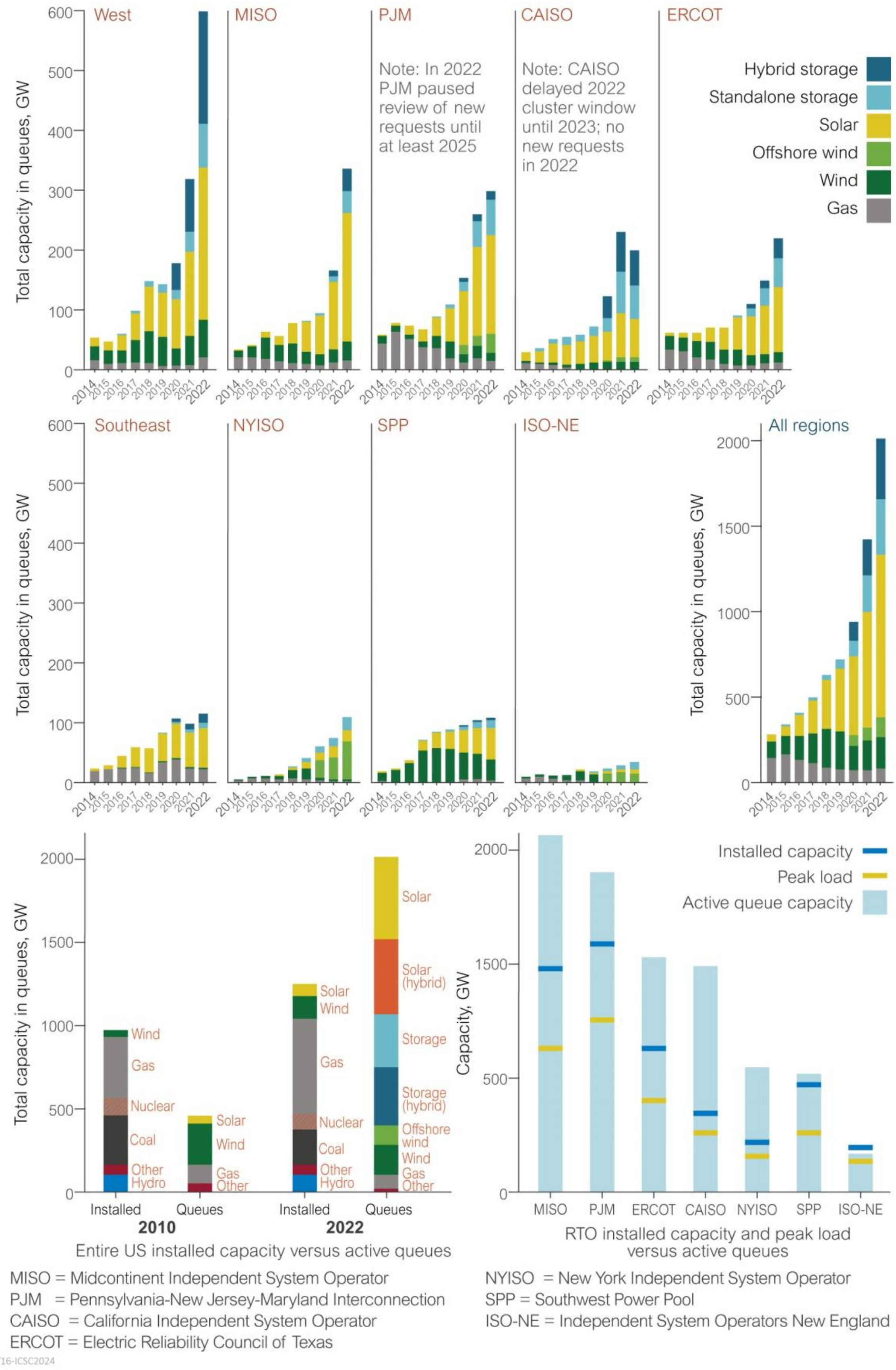

Figure 16 Grid connection queues by type and region, USA (Rand and others, 2023)

The mismatch in expectations and delivery practicalities creates risks that programme goals will not be achieved and that the reliability, affordability and systems integrity itself will not be maintained through the transition. As the IEA (2023d) commented 'grids are becoming a bottleneck for transitions to net zero emissions'.

2.7.8 Environmental

Apart from climate change-related risks, there is another increasingly significant environmental threat. Power systems, which predominantly exist in open environments, traverse diverse terrains over vast distances, making them challenging to monitor, control and safeguard. Damaged conductors and supports caused by storm and tree contact are a risk to electrical transmission. 96% of power outages in the USA during 2020 were attributed to severe weather or natural disasters (Sypher, 2021). While regular maintenance is conducted to ensure safe clearances around power lines, they can still be damaged, triggering system interruptions.

Between 2000 and 2021, it is estimated that the USA experienced 1542 major events due to extreme weather, with the majority resulting from high wind and rain (Climate Central, 2022). Winter weather accounted for 22% of these events, with 29 outages linked to severe heat and 37 to wildfires, primarily occurring in the last five years. Texas, Michigan, California, North Carolina and Pennsylvania are the top five states reporting weather-related power outages (Climate Central, 2022). As climate change intensifies extreme weather events in frequency and severity, storm-related damage incidents to electrical systems are expected to rise. Additionally, freezing temperatures, ice accumulation, flooding, extreme heat and wildfires can all lead to system failures. The time required for repair or power restoration varies significantly based on the issue's location and nature.

The Texas experience in 2021 demonstrated that power systems inadequately prepared for winter conditions can fail when temperatures drop below the norm, resulting in equipment failures, including frozen gas pipelines supplying power plants with fuel, precisely when power is needed for heating (University of Texas, 2023).

Adverse and extreme weather also jeopardises the reliable and sufficient delivery of power, especially during high-demand periods. Stone and others (2023) investigated the potential consequences of a hypothetical blackout in Phoenix, Atlanta and Detroit, USA, during extreme heat conditions, with a 48-hour power restoration timeline. For Phoenix alone, they estimated that half the population would require emergency medical treatment, resulting in 13,000 fatalities. When extrapolated to larger or multiple areas, these figures could be greater, with similar impacts anticipated for polar storm condition failure analyses.

2.7.9 Economic

The ability of countries and regions to adequately finance power systems and to build and maintain them to a high standard, varies widely. Budgetary pressures and diversity of investment priorities can lead to cost increases and investments being cut or deferred leading to an increase of risk of failure or obsolescence.

Much of the world's power system is old and approaching replacement. Coupled with the emerging requirement to almost double system capacity in most regions due to climate change-related energy policies, as well as economic or population and industrial growth in some areas, the investment requirements are significant. One study estimated that to reach net zero by 2050 the US power system would require in the order of a $1.7–2.6 trillion investment (Williams and others, 2020). Globally, Bloomberg estimates that the global grid investment requirement to 2050, has increased by 50% in just three years from their estimate of $14 trillion in 2020 to $21 trillion in 2023 (BloombergNEF, 2023). In 2023 the IEA stated that grid investment globally needs to double to over €600 billion per year to stay on track for decarbonisation (IEA, 2023d). Given the emergent nature of the demand for components and parts to build this infrastructure, it may also fuel future cost inflation and scarcity.

2.7.10 Cyber security

As reliance on computerised systems increases, so does the risk of disruption from cyber-attacks. The World Economic Forum (2019) identified large-scale cyber-attacks in the top five risks to the world in its 2019 Global Risk Report. (They estimated that a cyber-attack on the US power grid could incur costs of around $1 trillion.

The prevalence of attacks on power grids including cyber-attacks is growing with 163 instances per year reported in 2022 (Malik, 2023a). An example of the effectiveness of cyber-attacks in destroying critical infrastructure was the use of the Stuxnet virus by the USA and Israel in 2010 to destroy nearly 1000 nuclear enrichment centrifuges at Natanz, Iran (Vacca, 2017). In Ukraine cyber-attacks on the power system occurred in 2015 with a power outage including Kyiv, taking up to six hours to restore power, affecting 225,000 people (IEA, 2023d). The same source reports that in 2016 grid control equipment was disrupted, believed to be by malware directly manipulating equipment, leading to a 200 MW outage for about one hour.

2.7.11 Terrorism

As critical infrastructure, electricity systems are a potential target for terrorist activity. For example, a terrorist attack on electricity infrastructure at the Metcalf Transmission Substation in Moore County, USA in 2013 caused around $15 million in direct damage and affected 17 transformers at the site (Grid Assurance, 2023; California Public Utilities Commission, 2018). It also involved the severing of communication cables and the use of military-style weapons. It is believed the objective was to cut the power supply to Silicon Valley and its associated businesses with severe consequences (Memmott, 2014). In 2022, sabotage of the Nord Stream II gas pipeline between Russia and Germany again highlighted the risks of potential terrorist attacks on exposed critical energy infrastructure (CSIS, 2022).

2.7.12 Energy policy

In the USA, the 2023 Reliability Risk Priorities Report (NERC, 2023) for the first time publicly identified energy policy as one of the top five risks to system reliability. It cited increased focus and mandates on decarbonisation, decentralisation and electrification driving rapid change in the energy sector and the need for improved collaboration and coordination. Such pressures and speed of change exist in many countries; whenever changes are made swiftly there is potential for misalignment or emergent issues to cause unforeseen problems at short notice. NERC (2023) notes the increasing dependency between electricity and natural gas and the importance of effective interfaces between energy system stakeholders as concerns. The energy system is a technical one based on supply, demand and engineering solutions to ensure continuity and safety. It is therefore important that policies are set with an adequate understanding of, and planning for, their impacts at a technical and practical level.

Conversely, grids are also a significant risk to energy policy. The IEA (2023) evaluated the impact of grids not evolving to meet requirements. The knock-on impacts on the deployment of solar and wind generation and the evolution of coal and natural gas for power, together with power sector CO_2 emissions were estimated (*see* Figure 17).

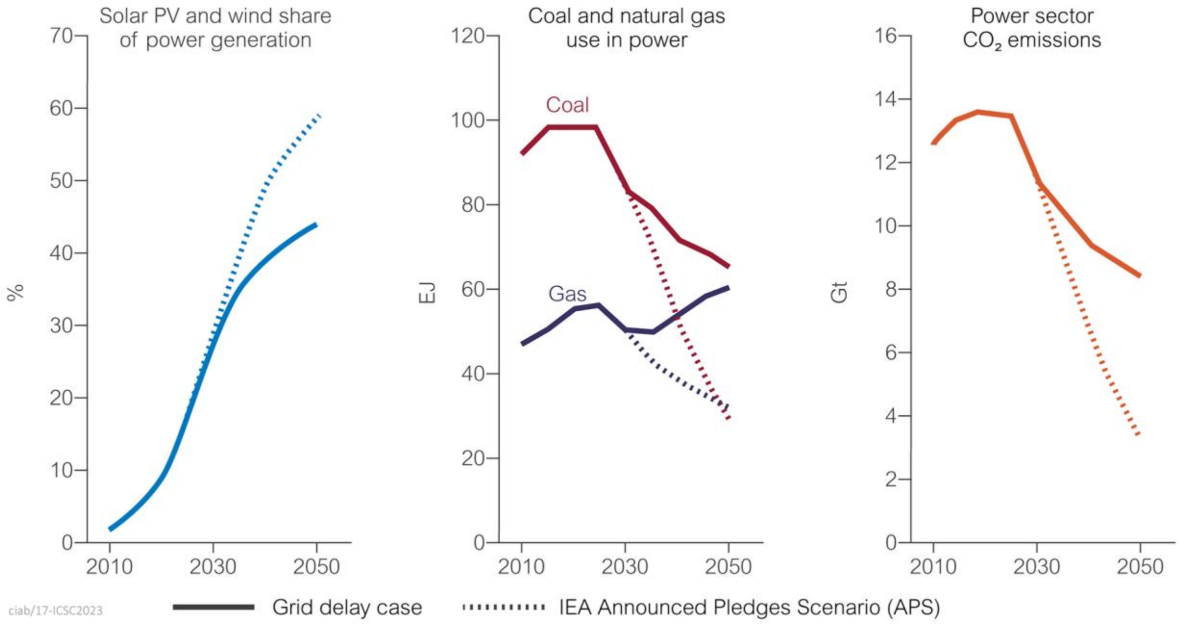

Figure 17 Potential impacts of grid delays on transition, IEA Announced Pledges Scenario (APS) vs Grid Delay Scenario (IEA, 2023d)

Figure 17 shows that in a grid-constrained scenario, the wind and solar share in power generation is reduced by around 25% relative to the target whilst coal use reduction slows considerably and gas use rises significantly, even above historic levels.

2.7.13 Supply chain

Power systems are physical in nature and require not only materials and parts but also complex specialist equipment and elements like high-voltage cables, circuit breakers and large power transformers. The manufacturing capacity for many of these items is limited and so the lead times for components are becoming extended. In late 2022, the American Public Power Association (Ditto, 2022) reported that the waiting time for distribution power transformers had extended from typically three months to almost 18 months with some suppliers quoting timescales of multiple years for delivery. Costs have risen significantly and the availability of key components, not only for the energy transition but for maintaining the existing system, has become an issue. Many countries face similar backlogs and waiting lists for vital items. The energy transition is expected to require around 80 million km of new power lines between 2023 and 2050. These need to be produced, shipped and installed; before that can happen, access is required to the materials and minerals needed to make them at an economic price. Implementation will also require a skilled workforce of appropriate size and geographic location.

Transmission and distribution systems also require large quantities of materials like copper, aluminium and electrical steel. Figure 18 shows the significant increase in raw materials requirements to deploy grids at the scale needed to meet the IEA APS and NZE scenarios, with total demand more than doubling for the net zero scenario by 2030 (IEA, 2023d). It is unclear whether supply chains for extraction, processing and manufacture will be capable of meeting this demand increase within the timescale projected.

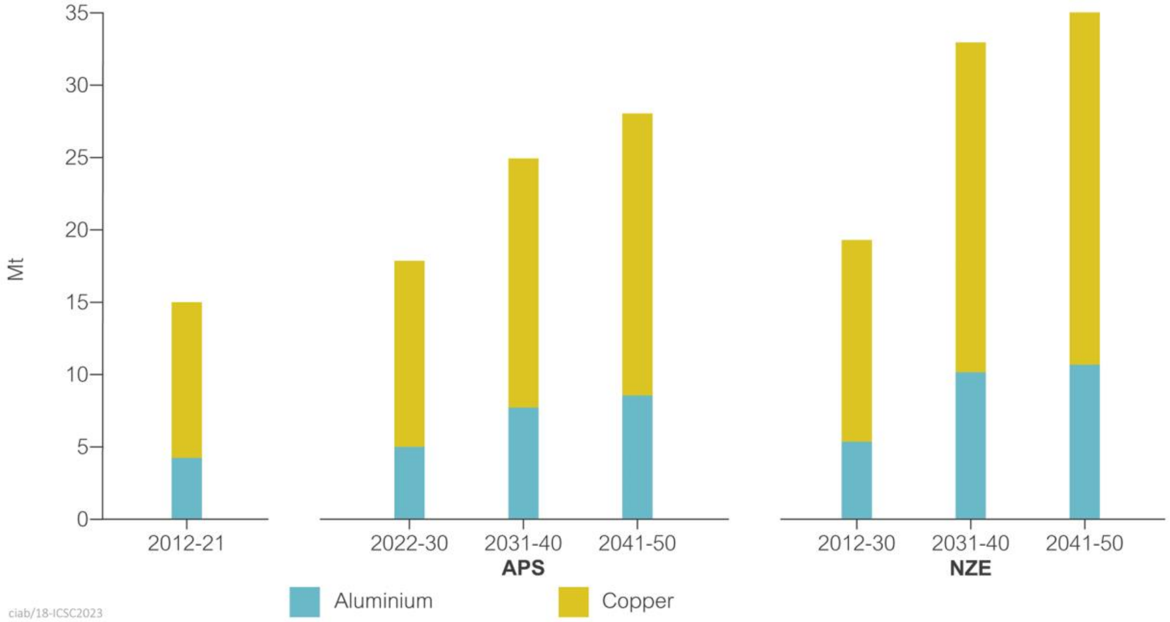

Figure 18 Annual transmission and distribution material needs; IEA APS & NZE scenario (IEA, 2023d)

3 VARIABLE RENEWABLE ENERGY AND GRID TRANSITION

3.1 KEY MESSAGES

VRE brings some welcome benefits to electricity systems from a sustainability and carbon intensity perspective. However, it also brings challenges. Addressing these is a complex task with many interactions and effects which are not immediately apparent. Each challenge and mitigating action has its own implications, timescales, costs and issues.

Deployment to date, even at low peak capacity share has led to significant volatility in power markets, especially during low-demand periods and favourable wind and solar power production. In the absence of storage to smooth output, VRE variability is challenging to integrate into the system without large impacts on other plants and systems. VRE is not a solution to a clean power supply on its own but part of a solution.

Another challenge is providing sufficient capacity to cover demand, dependable provision and grid electrical stability. This was inherent in previous portfolios, but the characteristics of VRE mean that it does not provide the same level of dependability or electrical stability.

Storage, curtailment, re-dispatch, backup generation, grid modification, grid forming inverters and synchronous compensation, consumer flexibility, system interconnection, wholesale price volatility and even market reform and incentives are all elements of the VRE deployment story beyond the generation itself.

The net effect is that VRE deployment as a basis for any energy transition goes far beyond a simple consideration of generation technology preference. The full impacts of increasing VRE share are extensive. Whilst there are possible solutions for the issues raised by VRE, many are not yet implemented beyond the concept or demonstration stage. Only when high VRE proportions have been implemented over extended periods, without support from legacy systems, will it be clear if the projections and models are correct. In the meantime, there is much work to be done and lessons to be learned. This significance will vary from system to system based on the share of peak demand and the characteristics of the rest of the systems of which they are part. Those with large volumes of dispatchable capacity, hydro, nuclear and energy storage will be better insulated from the adverse impacts of weather-dependent wind and solar in their energy systems.

GRID STABILITY IS INCREASINGLY RELIANT ON TECHNOLOGIES WHICH ARE FUNDAMENTALLY DEPENDENT ON THE WEATHER

3.2 WHAT IS VARIABLE RENEWABLE ENERGY?

Wind turbines operate by harnessing the wind to turn their generators and consequently, their output is dependent on wind conditions at any point in time. Similarly, solar PV systems only produce power when the light reaching them is sufficient to do so and output varies with solar intensity. System weather dependency creates scenarios where output is variable and, at worst, intermittent, with gaps in output that other technologies need to fill. Conversely, output can also be higher than anticipated or desired which can also create issues in power management.

3.3 BENEFITS AND DEPLOYMENT

Renewable energy is important to reduce CO_2 emissions from the power sector and to meet climate change mitigation goals. It has been demonstrated that by displacing some generation previously provided by fossil fuels and legacy production technologies, power generation-related average system CO_2 emissions can be significantly reduced (Tierney and Bird, 2020). However, as the proportion of VRE on grids increases, the implications of the variable nature of output becomes a system management issue. It is also not certain that adding more VRE will result in reduced carbon intensity. Johnson (2022) noted that the UK has also not seen a significant reduction in average carbon intensity since 2018 despite continuing to roll out VRE. Others have commented that marginal emissions are increasing, reducing or even negating the effectiveness of electrification measures to reduce carbon emissions overall (Holland and others, 2020, 2021). The EU carbon intensity from power generation also increased in 2022, by 6% on the previous year, despite continued build-out of renewables (EEA, 2023). The stalling carbon intensity of California is touched on in Section 6.5.1.

3.4 WHY IS VRE OF SPECIAL INTEREST FOR GRIDS?

VRE raises challenges with respect to scheduling and balancing power supplies and maintaining a stable and dependable system, and also some outstanding questions regarding its overall affordability and practicality when taking into account the full system boundary. This section considers the nature of VRE whilst a more detailed consideration of costs is given in Chapter 5.

3.4.1 Inertia

Traditionally, all generators connected to the grid operated at the same frequency, known as the system frequency. For thermal power plants, which were the majority of generation assets historically, their generators were linked to steam turbines that rotated at high speeds, typically 50 to 60 rotations per second (50 or 60 Hertz), with each turbo-generator rotor assembly often weighing many hundreds of tonnes. This resulted in a substantial amount of dynamic energy stored in the rotors across the system. Solar PV systems, by contrast, lack any moving parts, therefore, do not operate at the system frequency; they rely entirely on power electronics to create sinusoidal power output for the grid. While wind turbines have large rotating components, they operate at low speeds and are designed to be as light as possible.

This distinction is crucial because synchronous generators have dynamic energy which plays a key role in the stability of the legacy grid. Immediate fluctuations in supply and demand would initially try to affect the connected generator's rotational speed. However, to significantly alter the speed of all interconnected generators would require an enormous change in the total momentum of the generators. This fluctuation process only added or extracted small amounts of momentum from the generator rotors with negligible impact on speed, smoothing out disruptions within the wider system. When large, high-speed masses are replaced with lightweight, low-speed or static ones, the system becomes inherently less stable and less resilient to disturbance.

Figure 19 illustrates the reduction in inertia in the UK grid as the generation mix has changed (National Grid ESO, 2022b). This reduction represents a gradual erosion of the grid's natural stability. Consequently, questions arise about how inertia-related effects of VRE will impact future system stability as their capacity share increases, particularly as older, more stabilising assets are retired.

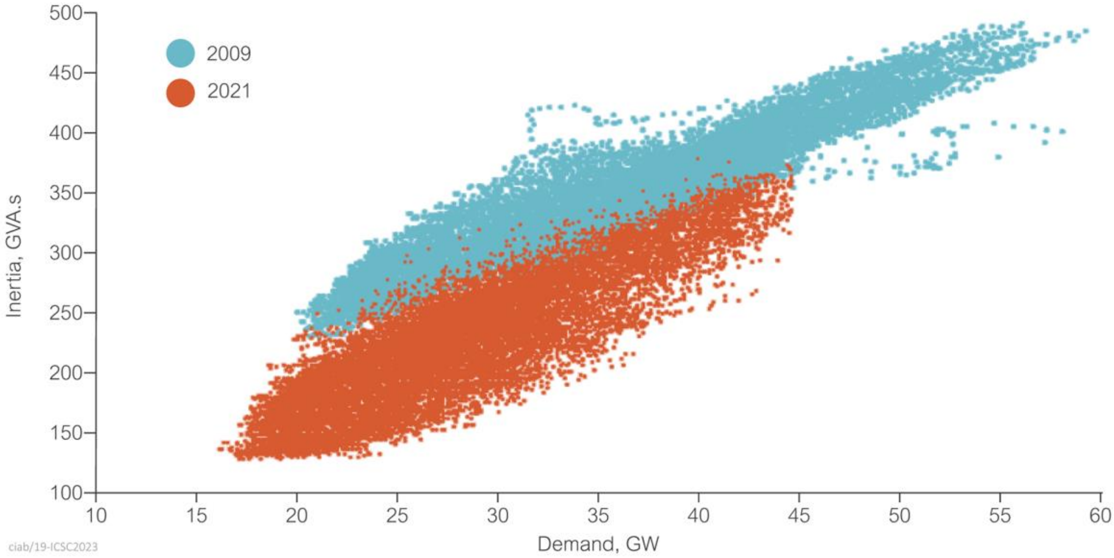

Figure 19 Reduction of inertia on the UK electricity system, 2009-2021 (National Grid ESO, 2022b)

Grid operators acknowledge this challenge and actively monitor the situation. Typically, systems adhere to specific standards that impose limits on system inertia. Researchers have discovered that VRE sources can provide some inertia-related services to the grid, although at a reduced level. Nevertheless, the ongoing development and testing of new grid-forming inverter technology show promising results. Batteries or renewables connected to the grid through these advanced inverters can generate what's known as 'synthetic inertia' (Siemens, 2023; Gamesa Electric, 2023).

Synthetic inertia acts quickly and significantly helps compensate for the loss of physical inertia caused by the retirement of rotating thermal plants. An experiment involving a Virtual Synchronous Machine (VSM) conducted in Great Britain concluded in 2020 that 'From the tests completed, the VSM unit could deliver inertial response during frequency disturbances and providing reactive power support during voltage disturbances, which aligns well with the behaviour of a synchronous generator' (National Grid ESO, 2020).

Additionally, the system can incorporate rotating masses operating at synchronous speed but not connected to power-producing machinery like steam turbines. These components, known as 'synchronous condensers' essentially function as spinning generators without power input. When an abrupt increase in demand occurs, the condensers' mass and speed resist the frequency change in a manner similar to traditional power plants (ABB, 2023; Skinner, 2023; Uniper, 2023).

Many experts believe that a reduction in required inertia levels, exemplified by the actions of National Grid in the UK, combined with the natural inertia provided by wind turbines and other inertia-containing systems such as energy from waste, biomass, nuclear and hydro units, along with synthetic inertia systems and synchronous condensers, will be sufficient to stabilise system frequency (Denholm and others, 2020). However, this hypothesis has yet to be confirmed at scale, as the technology is still evolving and deployment levels remain relatively small compared to the increasing global demand resulting from the energy transition.

3.4.2 Variable and intermittent output

Perhaps the most significant challenge of wind and solar is their variable and intermittent power output which depends on the weather, season and time of day. Solar power intermittency is clear, with power generation only possible during daylight hours and even then, only when the solar intensity is sufficient to transfer energy to the panels for conversion to electricity. However, for power systems where the supply must be matched to demand this kind of generation has limited value. Figure 20 illustrates the issue by showing power output (MW) plotted against demand over time (Caravaggio, 2023). Nuclear power, while reliable tends to run at continuous steady output. The dispatchable technologies respond to needs by varying their output, while the output from wind and solar power bears little relation to the demand; the chart for wind even suggests a decrease in output during higher demand.

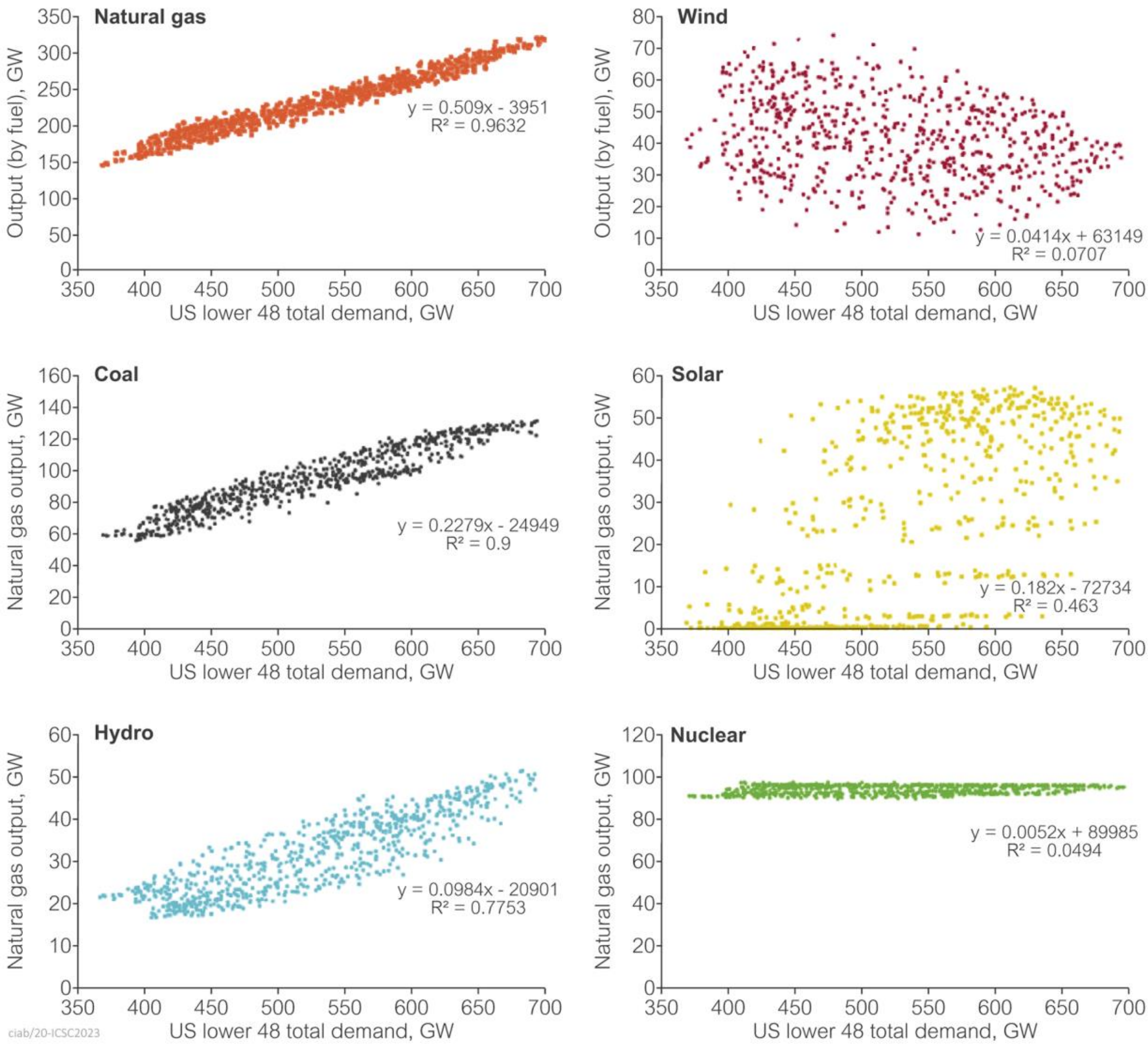

Figure 20 Correlation of output with demand for generation sources, USA, July 2023 (Caravaggio, 2023)

Figure 21 offers another insight into the total generation (in GWh), offered by wind and solar in Europe. The blue line for Germany, where capacity is high, illustrates the variability issue (Aleasoft Energy Forecasting, 2023). Over the six-week period, the solar output varied by a factor of 10 and the wind by a factor of more than 35, with both technologies showing some clear periods of very low outputs and very high peaks.

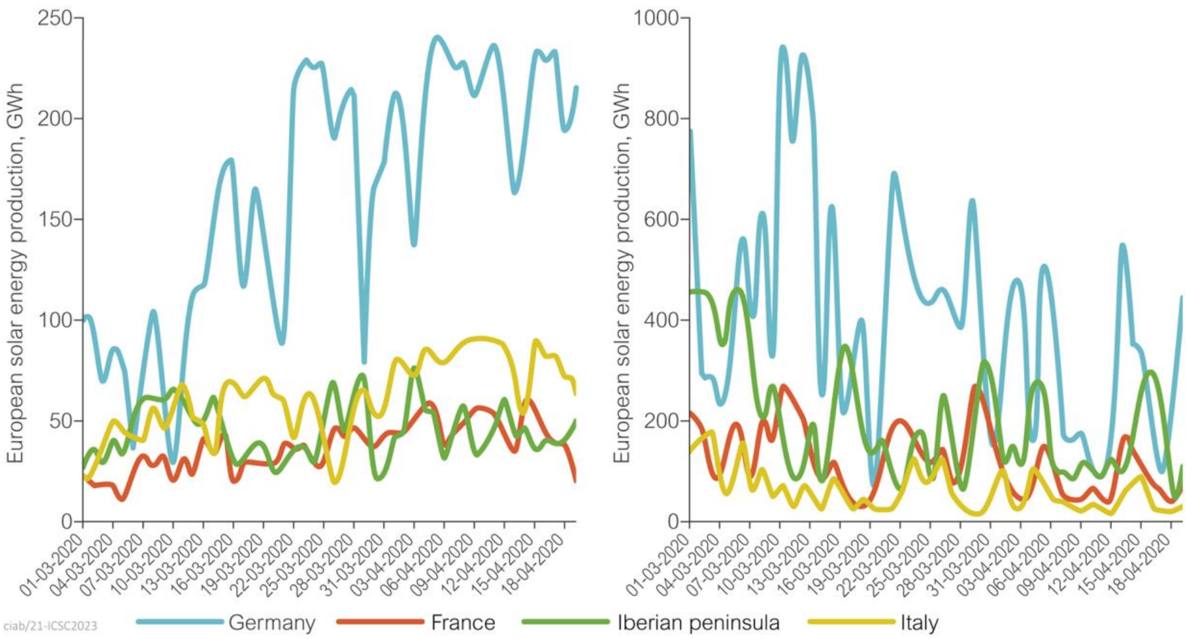

Figure 21 Fluctuations in output from variable wind and solar sources (AleaSoft Energy Forecasting, 2020)

From a system operator's perspective, the less predictable nature of VRE output presents significant issues in matching supply and demand at all points in time. The greater the capacity of these sources in the system, the larger the challenge and the bigger the surplus or deficit can be relative to ideal conditions. As the contribution of hydro resources is limited largely by terrain and the contribution from fossil power assets diminishes, the issue will become amplified.

VRE peaks and troughs suggest that additional systems are required to counter their effects and/or the existing forms of dispatchable generation must be retained in an environmentally acceptable form for some time. Adding VRE to a power system is therefore not simply an alternative to traditional power sources on its own but is part of a wider, complex solution.

3.4.3 Surplus management

The operating share of any capacity type as a proportion of prevailing demand varies with both the installed capacity of that technology type and the demand, as well as the environmental conditions. If sufficient VRE is installed to cover a high load share in periods of low demand it may only cover a small share during high demand periods. Importantly, the converse is also true. Designing a system for a high VRE share during higher demand periods can easily lead to a surplus during low demand periods which then has to be curtailed at a cost. If there is a large difference between peak and minimum demand then this installed capacity effect gets amplified further, creating either a shortage at high demand or a surplus at low demand, or both together.

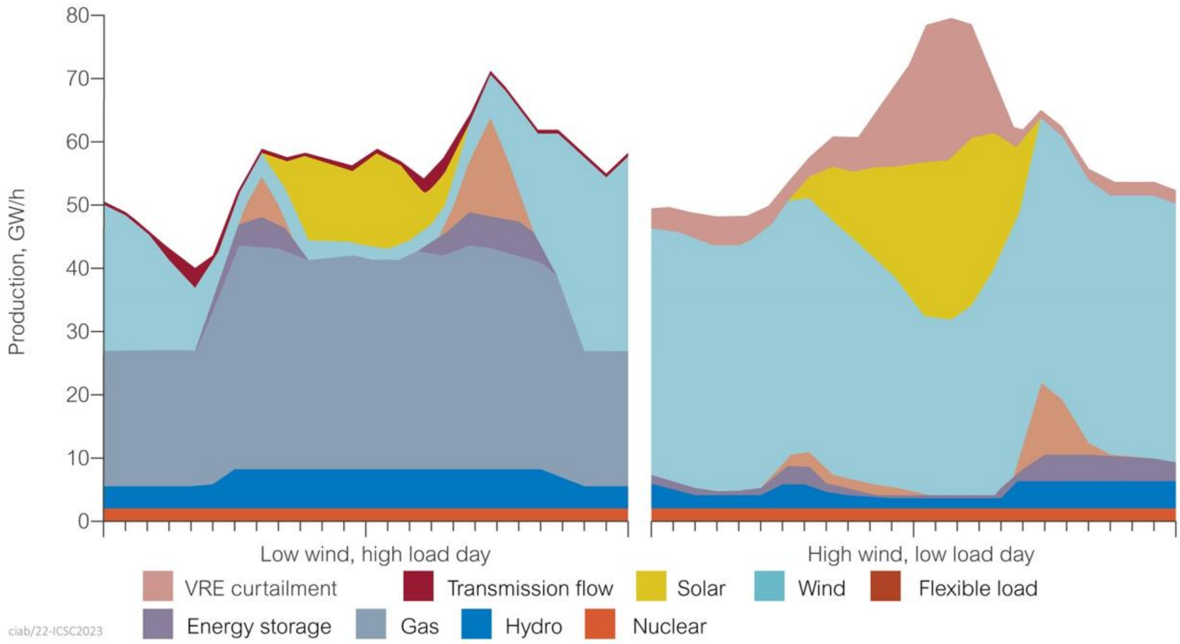

Figure 22 Impact of VRE output variability on generation mix (Willaims and others, 2021)

Figure 22 illustrates modelling work done for a US northeastern state in 2050 (Williams and others, 2021). In the high wind low load day, to the right, there is too much wind capacity, solar and wind cover most demand and VRE curtailment is needed to protect the system. For the same portfolio on a low wind high demand day, to the left, the majority of demand is met by gas. Although this is only a hypothetical model with high VRE share, these effects are apparent in some systems, for example, South Australia and California (*see* Sections 6.5.1 and 6.5.3) (Bartholomew, 2023; Hunt, 2023). In those systems, VRE output is regularly in excess and deficit, requiring alternately curtailment, export and storage and storage release, imports and backup dispatchable power plant.

It has been suggested that the shortfall problem during unfavourable conditions can be resolved by deploying surplus capacity to ensure output is nearly always possible (for example, Perez and others, 2019). However, there are problems with this approach. First, unfavourable weather conditions sometimes occur over continental scale areas. Under these conditions capacity overbuilding may not resolve the intermittency issue. Second, the overbuilding cost is high and additional to the base cost VRE. Third, the more VRE is built, the lower the permissible load factor under average conditions due to surplus effects. Even in the UK where VRE still represents a minority electricity share, it is proposed that by 2030 under an accelerated pathway there may be a generation surplus 50% of the time (National Grid ESO, 2023). Some suggest that one way to resolve that problem would be to shift demand into those periods or to introduce new industries which can absorb the surplus power, for example in producing electrolytic hydrogen for long-term energy storage (CCC, 2023; Harrison, 2023; Bastemeijer, 2023). However, the generation production costs would still need to be covered by energy sales and the new industries would need to be viable businesses even accounting for the variability of the VRE surplus. If those businesses required predictable and stable energy supplies, then the model would not work without yet more excess capacity, giving rise to the same problem again.

3.4.4 Seasonality

The seasons have an impact on VRE output, depending on the geographic location. Seasonal demand will also vary, but not necessarily in line with output. This makes certain periods of the year more challenging, depending on the country and region. In northern latitudes winters tend to be cold and dark, meaning demand is high and solar generation is low. This can lead to problematic periods of high demand during dark and calm winter conditions. For other regions, the most significant issue could be during peak summer evenings when solar power has declined but demand is high due to air conditioning loads. Hence the seasonality impact on VRE is not consistent by region. This is likely to influence the selection of mitigation measures that are most appropriate, by region. Seasonal variability will also impact hydropower as its available capacity depends on long-term wet and dry weather cycles.

Potential seasonal variability needs to be factored into any analysis, modelling and simulation, to ensure that capacity planning and reliability can be managed, even for extreme variations in conditions.

3.4.5 Annual variability

Many analyses use averages when considering profiles for VRE capacity, but much can depend on the differences in the weather patterns between one year and the next. This is evident for hydropower where dry cycles can inhibit available capacity, perhaps for several years in succession.

For wind and solar power, annual variability is best characterised by the number, duration, severity and clustering of extreme weather events. They can vary significantly depending on phenomena including solar cycles, natural disasters, El Niño and La Niña events, movements in the ocean or high-level air currents as well as shifts in weather patterns and trends caused by climate change itself.

In 2021 the utility SSE (2021) reported that its renewable assets in the UK had produced 32% lower output than expected between April and September following an unusually dry and calm summer period. This demonstrates the difficulties in practice of being able to anticipate and mitigate against output variability due to weather events.

3.4.6 Location

VRE resources are often located in areas with premium conditions for wind and solar intensity. These tend to be open spaces away from developments and may be spaces preserved for other reasons such as nature. This can result in certain areas having a high concentration of resources and others, perhaps where the demand is more concentrated, having a low concentration. This can lead to a requirement to move huge amounts of energy over long distances through a system not designed for that purpose. This is most clear for offshore or high-ground-based wind. Without extensive system modification and investment this results in major energy flow constraints due to capacity and thermal ratings. Such constraints can also lead to a requirement to re-dispatch generation in the marketplace by the system operator, incurring charges.

Figure 23 shows the projection by National Grid ESO for the UK electricity system of likely annual constraint costs due to this mismatch of VRE resource location and demand (National Grid ESO, 2022b).

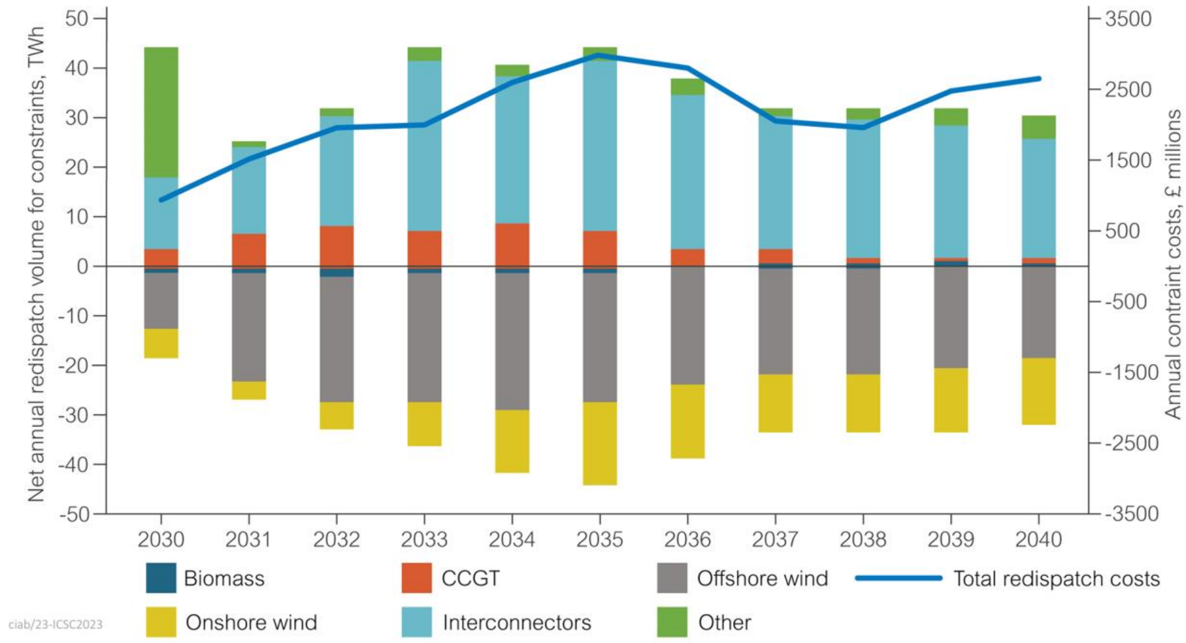

Figure 23 Impact of system constraints on the re-dispatch of generation (National Grid ESO, 2022b)

Many countries are planning or currently installing substantial additional grid infrastructure to move VRE-based energy around the system more effectively. Project examples include two new DC links in the UK, Eastern Green Link 3 and Eastern Green Link 4 (National Grid, 2023) to deliver 4 GW of renewable energy from Scotland to mainland England and the 700 km HVDC SuedLink project in Germany to move surplus wind energy from the north to the industrial south (TenneT, 2023).

3.4.7 Number of connections

The relatively small capacity of individual VRE installations compared to legacy central power plants means that many additional connections to the grid system are required. Storage and backup power generation facilities increase these requirements further. This creates a huge volume of additional projects and a big increase in the asset number which needs to be managed by the network operators. In total, the number of connections can differ by orders of magnitude for equivalent firmed capacity.

3.4.8 Demands on non-VRE assets

Since the demand profile is fixed by users and VRE is inherently intermittent the dispatchable generators in any system must mirror this variability in order to compensate for it, accounting for any storage. Thus, assets which were designed to run under steady design load conditions are required to cycle operations more frequently, increase their speed of response and ramp times and operate under transient off-design conditions. This reduces their life and increases wear and tear, reducing their operational efficiency and increasing operational costs. The lower load factors will also have a negative impact on the economics of operating those assets and may lead to some no longer being economically viable to provide essential support to the system. The cost penalties of operating coal-fired plants flexibly to cope with the renewable power source intermittency was investigated by the ICSC and found that costs can escalate by orders of magnitude in some cases (Sloss, 2016).

3.4.9 Impact on total system costs

It is uncertain what the combined impact on total system cost of all these factors is and it can only be calculated by comprehensive modelling of a specific system and scenario. However, it is clear from analysis carried out by Imperial College London (Pratama and Mac Dowell, 2022) Red Vector (Boston and Bongers, 2021) and others, that whilst the cost impact may be low during the early stages of integration they increase significantly and rapidly as the share of VRE increases. This is also reflected in the Lazard (2023) analysis which clearly indicates a large differential, perhaps cost multiples, between the unfirmed and firmed levelised costs of VRE technologies, taking into account the wider system implications. This is an area where further work is required since no reference found during the preparation of this document provided a comprehensive analysis of all the factors which would add up to the total system cost from the adoption of VRE. Costs are discussed in detail in Chapter 5.

3.5 WILL VRE IMPACT GRIDS?

VRE is having an impact on grids. VRE operating characteristics mean that existing grids will have to adapt significantly, both physically and in the way they are operated to enable their integration. Whether VRE can be accommodated without leading to continuity issues or power quality remains to be seen, since most grids still only have a small VRE capacity share and rely heavily on legacy baseload and dispatchable plant together with interconnection to keep their systems stable and secure.

3.5.1 Why haven't we seen issues already?

Although VRE build-out has been growing fast this century, deployed VRE is still only a small proportion of the overall energy system. Even in countries where VRE penetration has been rapid and has reached relatively high levels, legacy systems remain in operation and carry load for much of the time. The legacy systems provide a buffering effect for early VRE deployment complementing the variable output with responsive backup and stabilisation services which enable the systems to continue operating. In effect, a layer of VRE has been added to an existing system which was already capable of doing the job on its own.

For the UK market, Figure 24 shows how system operator intervention re-dispatches power to meet system demand has been changing over time as the VRE share has increased. In 2008 the re-dispatch level needed was less than 20% of system demand. More recently, high VRE proportions have resulted in up to around 130% re-dispatch relative to system demand due to scheduled supplies being unable to provide power when needed. Thus, the system operator has progressed from providing only a moderating role of supply, through providing more frequent interventions, to providing a high volume of sometimes large interventions to maintain a stable grid. It is notable that interventions reaching 100% of demand are already seen at a renewable share of 45% (assumed to include all renewables, not just VRE) with significant future growth planned.

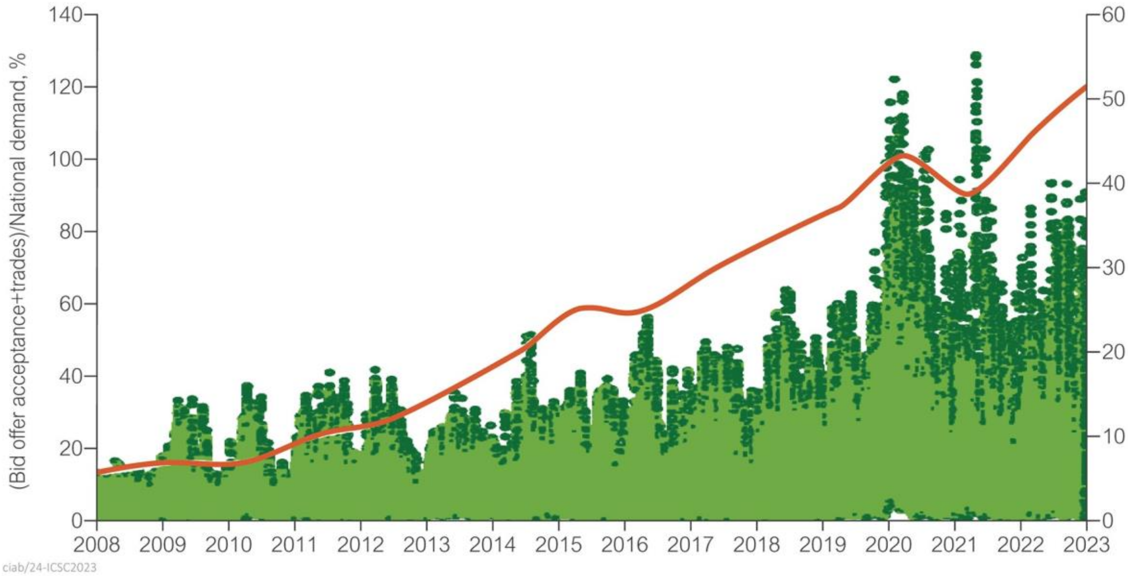

Figure 24 Increasing system operator interventions with increasing VRE (McLeavey-Reville, 2023)

As the energy transition progresses and legacy systems and assets are decommissioned, while more VRE is deployed, more stresses will start to be noticed. Whether these stresses impact supply continuity will depend on the measures that are implemented to counter them. Some stresses may be physical, some may be in markets and mechanisms to guard against adverse scenarios.

The IEA defines six VRE integration phases for energy systems, originally from its work in 2019 (IEA, 2021c, 2019). These phases together with their key attributes and estimated positions of selected countries are illustrated in Figure 25. Phase descriptions provided by the IEA have been replicated from their report in Table 2 (IEA, 2018).

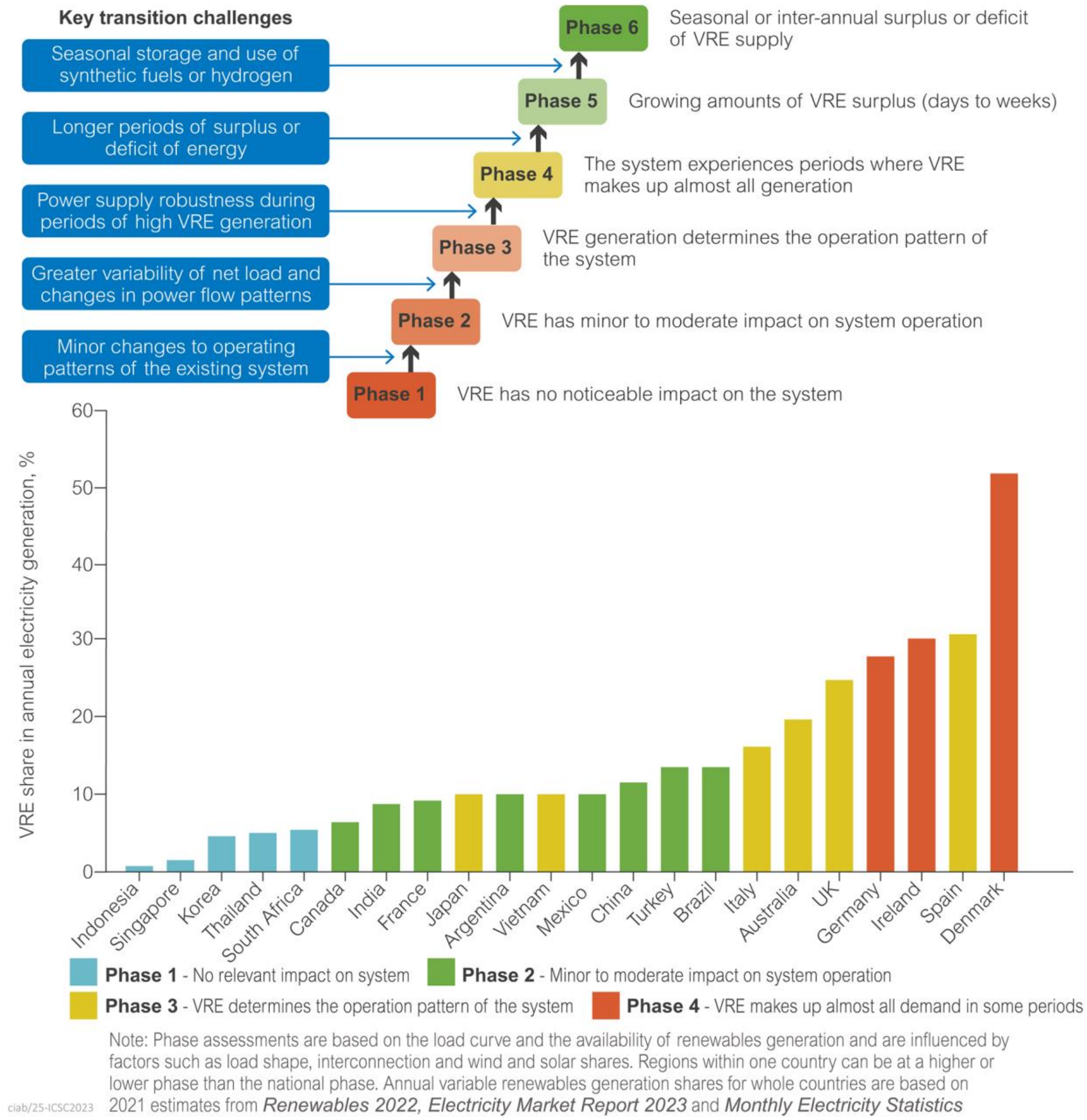

Figure 25 IEA VRE integration phases (IEA, 2019, 2023)

TABLE 2 IEA SIX PHASES OF VRE INTEGRATION (IEA, 2018)

Stage of integration	Conditions
Phase 1	First VRE plants are deployed, insignificant at system level; effects are localised.
Phase 2	More VRE plants are added, changes between load and net load are noticeable. Upgrades to operating practices are usually sufficient to achieve integration.
Phase 3	Supply-demand imbalances prompt systematic system flexibility beyond what can easily be supplied by existing assets and operational practices.
Phase 4	VRE provides the majority of electricity demand during certain periods requiring changes in operational and regulatory approaches. Ability to respond to unexpected disruptions becomes a stability concern. Regulatory changes may be needed to ensure systems continue to operate effectively.
Phase 5	More VRE plants mean output frequently exceeds power demand leading to curtailment of VRE output. Shifting demand, electrification and interconnection to other systems may mitigate this issue. It is possible that in some periods demand is entirely supplied by VRE without any thermal plants on the high-voltage grid.
Phase 6	Meeting demand during periods of low wind and sun availability is the major challenge. This phase can be characterised by the need for seasonal storage and use of synthetic fuels.

The number of countries entering the higher phases will progress rapidly as VRE technology deployment is accelerated to meet national net zero targets.

3.5.2 Is a 100% VRE system possible?

Theoretically, a 100% VRE system may be possible and there is literature pointing towards that as a potential future reality (Breyer and others, 2022). In some specific locations depending on the available resource mix, demand and flexibility, it could be possible. However, in most cases, the practical and economic aspects of delivering dependable and affordable grid at national scale do not align with a 100% renewable system, especially where heavily dependent on VRE. This is due to the VRE systems output being fundamentally dependent on variable weather. This typically then requires large quantities of energy storage, the ability to import power from other independent systems, the building of ‘excess’ VRE capacity and provision of another layer of energy-absorbing industries to use the excess and even application of curtailment. All this must be operated with variable, unpredictable and overall, lower load factors. This is technically feasible but undesirable from a cost, complexity and implementation perspective.

3.5.3 Modelling the impacts of VRE on the system

Three key challenges arise in modelling and interpreting VRE effects on the power system.

First, model outputs may not accurately reflect total VRE costs. Depending on the model’s scope and purpose, it may primarily focus on direct capital and operating costs, neglecting other significant considerations. These factors include ensuring system stability and operability to meet reliability standards, particularly at higher shares of VRE.

Second, real-world complexity often gets oversimplified or omitted in modelling. Such simplifications, while necessary to prevent over-complication or excessive data requirements, can obscure critical details for designing future systems. For instance, many models assume continued reductions in renewable energy costs, despite recent data suggesting cost increases (Ferris, 2023) due to market factors like supply and demand, financing costs, raw materials, interest rates and stakeholder profitability concerns (Le Dain, 2023). Models typically overlook market dynamics and unstable commodities, potentially leading to unaccounted-for costs and interactions, such as wholesale price volatility caused by VRE output variability or geopolitical events. Additionally, certain technology options, even low-carbon ones, might be excluded at the modelling stage.

Third, modelling often neglects extreme events and scenarios, creating a potential blind spot in designing robust grid systems. Model solutions must undergo testing against extreme scenarios, considering event scale, sequence and duration. The Royal Society (2023) emphasises the need for decades of hourly weather data to adequately characterise power system requirements, highlighting the importance of annual variability over seasonality. However, historical data may not fully represent future extremes.

Thus, this report suggests a shift in focus from modelling to real-world experiences with VRE integration, including its impacts, benefits, opportunities, costs and risks. These experiences can then inform the refinement and improvement of modelling approaches through backward comparisons, offering better insights and explanations for deviations observed between model outputs and real-world outcomes. Grid design is about reliability and dependability of supply and so those events which could impact that are the most important to evaluate. What seems clear is that the system value of VRE reduces, the higher the share they hold in the portfolio (IEA, 2020b).

THE SYSTEM VALUE OF VARIABLE RENEWABLES SUCH AS WIND AND SOLAR DECREASES AS THEIR SHARE IN THE POWER SUPPLY INCREASES
(IEA, 2020)

3.6 MITIGATION OF VRE IMPACTS ON THE SYSTEM

As the share of VRE increases, mitigation measures become necessary. Even if VRE is 'over-built', mitigation actions will still be required to cope with a large surplus of generation and redundant assets during extended periods.

3.6.1 Dispatchable power

In traditional power systems, supply is provided by a certain amount of inflexible 'baseload' generation, running essentially at design capacity with more flexible but dispatchable plants making up the difference between that baseload and actual demand. Baseload typically includes nuclear power, new highly efficient large-scale power plants or hydropower and dispatchable plants are generally based on coal, oil or gas. As VRE was introduced, these flexible dispatchable assets continued to maintain the balance of supply and demand, mirroring the variations in output. This has continued as the share of VRE has increased. When considering how best to mitigate the VRE output variability, the established grid management practice is to use low-carbon dispatchable generation sources. The key to dispatchable resources is that they are available and dependable. This is a valuable concept in the wide-scale power system operation.

3.6.2 Interconnectors

Interconnectors between grid systems have a dual purpose since they are bi-directional. In times of capacity shortfall, they can import much needed power and during surplus, they can be used to export useful power. The direction of flow depends on the relative state of the systems at either end of the interconnector and the prices offered. Interconnectors are an increasingly necessary energy grid feature stimulated by VRE deployment. Figure 26 illustrates Germany's interconnector capacity evolution to 2030 indicating an increase in imports, in particular from low-carbon intensity sources in France and Denmark (Samseth and others, 2021).

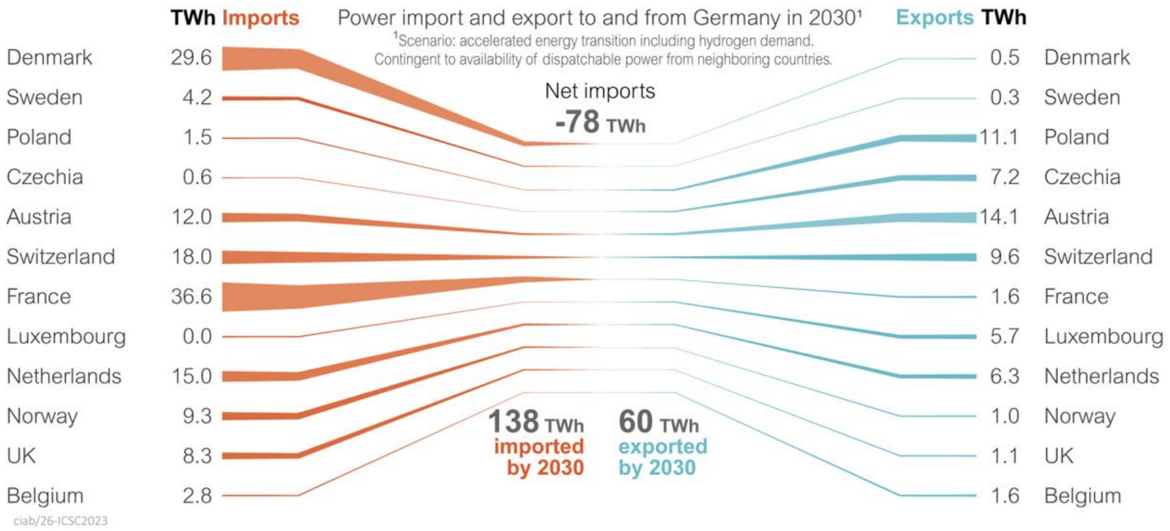

Figure 26 Possible evolution of interconnector flows for Germany to 2030 (Samseth and others, 2021)

3.6.3 Demand management

Supply and demand need to be kept in balance at all times. In the past, this meant supply had to be modulated to meet demand. Some propose that in the future we should move towards a system where demand is modulated to meet supply and there have been numerous demand flexibility trials around the world (IRENA, 2019a; RMI, 2018; AREA, 2023; National Grid ESO, 2023). The extent to which this is possible will depend on the consumer base, the equipment type and processes they operate and their willingness and availability to participate.

Many trials have been done with consumer engagement to demonstrate how demand management markets and processes might work. It is not clear what reliable contribution demand management will make, but many consumers lack the knowledge or technology to implement it. In the USA, OhmConnect in California raised funding for investment in a 550 MW consumer response programme aimed at providing the system with 'dispatchable' demand capacity to add flexibility to the system (Wilson Sonsini, 2020). Participants signing up to the programme will be paid for their flexibility. In the UK the network operator launched a Demand Flexibility Service (DFS) in the winter of 2022/23 to access additional system flexibility. 1.6 million households and businesses took part in the scheme delivering 3.3 GWh cumulative electricity reduction during high demand periods (ESO, 2022). This yielded information which will feed into future evolution of the service, including participants' motivation and behaviour.

Although smart meters are being rolled out in many areas and some smart appliances and devices exist, their application in the way they were intended is lacking and most are operated purely for data accessibility rather than energy optimisation.

Energy-intensive industrial users have participated in various demand management programmes for years and suppliers and large users tend to ensure alignment before taking action.

3.6.4 Curtailment

In the case of excess capacity, system transmission constraints, or the non-availability of flexible demand, VRE has to be curtailed. This means taking the assets out of operation, preventing power supply. This is already standard practice at relatively low shares of VRE where the energy cannot, for various reasons, be exported. For example, it was reported that in 2022 Great Britain curtailed wind power sufficient to power one million homes even though wind only represented 24.7% of total generation in 2022 (Carbon Tracker, 2023; DESNZ, 2023). Curtailment represents lack of asset utilisation and additional system cost due to curtailment payments, which are usually passed on to consumers via system operator charges in electricity bills.

The ratio of VRE sources may also have an impact on the total level of curtailment. Analysis for the UK market, for example, suggested that a ratio of 20% solar to 80% wind produced the least need for curtailment (Royal Society, 2023).

3.6.5 Storage

Energy storage provides two services for mitigating VRE impacts on the system. First, it can release energy into the system when VRE output is lower than demand. This can be from seconds to minutes, hours, or for diurnal applications. The technical storage capability to assist the energy system based on capacity and discharge duration is shown in Figure 27.

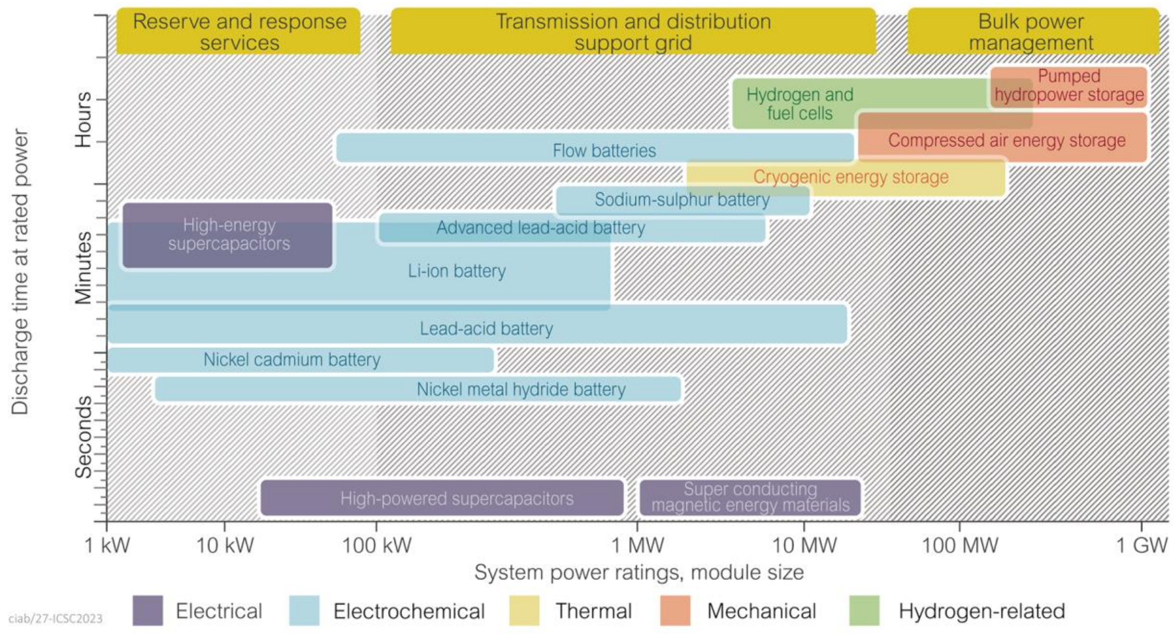

Figure 27 Power output and discharge duration characteristics of energy storage (Moller and others, 2017)

Second, storage absorbs excess energy that is produced but not required. It therefore tends to reduce the peaks and troughs in output, time-shifting energy from one period to another, albeit with additional costs and energy losses in the process. The energy storage characteristics and costs mean it is normally required to offer it for a range of purposes and services to make the business case work. Long-duration storage is generally not a consideration since the costs would be prohibitive in the current commercial context. Instead, there is a focus on short-term frequent cycle storage along with other services and payments. Such services are illustrated in Figure 28 (Malchman, 2022).

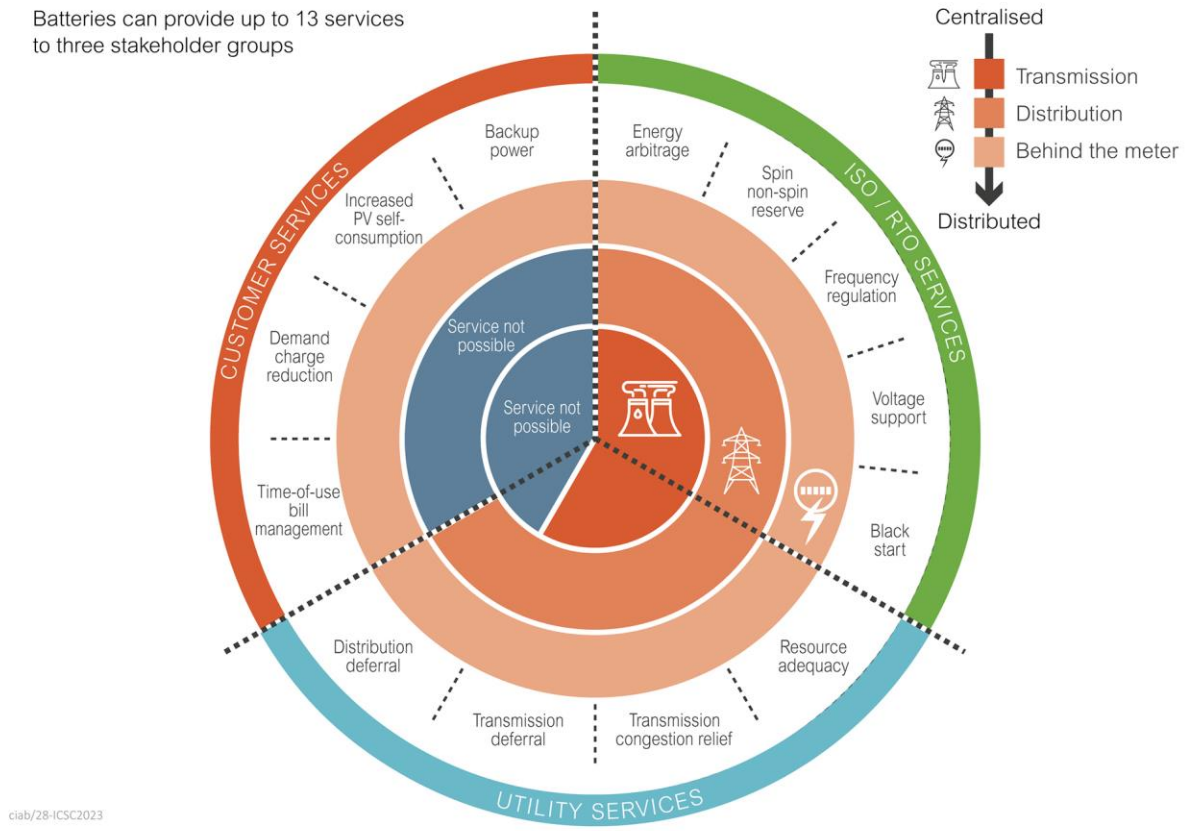

Figure 28 Range of services provided by energy storage to the energy system (Malchman, 2022)

How these uses and income streams break down, may be specific to the application and technology. However, a utility-scale battery might expect the largest income share to come from wholesale electricity trading, a large proportion from providing frequency regulation services and a smaller share from capacity payments (Brogan and others, 2020; Schmidt, 2023). For behind-the-meter applications, the benefits would mainly be to consumers in reducing electricity purchase costs through time-shifting power imports.

There are technologies in development which promise to significantly reduce stationary battery storage costs and displace lithium-ion for higher capacity systems. These include vanadium redox batteries (Adeniran and others, 2022) and those based on sodium-sulphur offering up to four times the storage capacity of lithium (University of Sydney, 2022; Energy-Storage News, 2023).

There are challenges for energy storage, both technical and economic. They include having the capacity to store sufficient energy to have an impact on a nation's massive energy production system, compared to the readily understood and achievable storage for specific local applications.

This section introduces storage as one method to mitigate the impact of VRE; Section 4.5.5 considers its potential as a dispatchable power option; further information on potential volume requirements is given in Sections 4.3 and 4.5.8.

3.6.6 Grid-forming technologies

Grid-forming technologies provide the system with services formerly provided by legacy thermal power generation assets. They are an enabler for inverter-based power resource integration like wind, storage and batteries into the system. Thus, they can provide services including frequency, voltage and power factor support as well as fast frequency response and black start capability. These developments are a watershed moment in the ability of new low-carbon technologies to mimic and replace services inherent in legacy power plants.

The technology is new and not installed beyond early demonstrations. Therefore, this is not a deployed solution, but a necessary and emerging one which requires further investment to be deployed at scale. Until it is, services from other sources like traditional mechanical synchronous inertia will be required to maintain stable and compliant systems.

3.6.7 Synchronous condensers

In the absence of adequate grid-forming technology to inverter-based resources, synchronous condensers may be used to help provide stability to the system (ESMAP, 2019). They are large rotating generators without a prime mover which spin at the frequency determined by the system. If the frequency deviates, these rotating masses use their inertia and stored energy to resist the change thereby providing a stabilising effect. Synchronous condensers may either be purpose-designed or be created through the modification of existing power generators by deactivating the prime mover. Examples of both are in normal service (*see* Section 3.4.1).

3.6.8 Modulating nuclear

Nuclear power plants are widely operated at design, baseload conditions; startups and shutdowns are carried out under carefully controlled conditions and rates of change (Garwood, 2023). However,. several countries operate nuclear plants successfully with some flexibility; the overall system effect is governed by their share in the portfolio(*see* Section 4.5.2). Smaller, more flexible plants may offer increased ability for nuclear to support system load variation, however, the extent to which this will be possible is not well understood. Nuclear as a dispatchable power technology is discussed in Section 4.5.

3.6.9 Market design

A higher share of VRE is a major change compared with 10 or 20 years ago. The physical differences, technical requirements and needs, but also the planning, deployment, operation and coordination of supporting systems needed is different. Management will be demanding with more players, complexity and uncertainty in the system. In many cases, this might mean devolving management to lower levels within the distribution system to ease pressure at the transmission level.

It will likely involve more consumer participation and smart devices and systems, more monitoring, data collection and processing and more difficulty in forecasting. The system will need to self-correct, automatically compensating for variable weather-based generation and demand. The system will extend out to loads including air conditioners, heat pumps, electric vehicles, distributed generation and storage. This will require new systems, processes, rules and regulations and probably new organisational design and governance to facilitate it. Pricing may be driven in real-time or fixed periods by scarcity, automatically or voluntarily encouraging higher or lower demand during surplus and shortfall. The difference in location between energy sources and demand centres may mean a tendency towards locational pricing.

These changes will extend into the basic market designs, where systems set up for generation and demand in the past could easily become outdated and drive unintended behaviour and investments. This will likely include a rethink or redesign of capacity markets, incentive schemes, support programmes such as contracts for difference and changes to the wholesale market. Fixing income for renewable operators based on system marginal price may also be changed to break the link between generation subject to carbon tax and fuel cost effects, from that which is not. This would have significant implications for the economics of operating a range of assets relative to current markets.

Even resource adequacy planning processes are becoming contentious, since planning was traditionally mainly around total capacity, and may well not be the best way to ensure reliability and stability in the future. US regulatory authorities understand the strains and risks associated with tight capacity margins and the premature retirement of dispatchable generation (Energy Central, 2023). Without some kind of regulatory change, it is unclear how this challenge can be resolved.

The exact nature of these changes is not clear. There will be much consultation and experimentation. However, it seems unlikely that the current systems and procedures can remain unchanged in power systems where a high proportion of VRE is deployed.

THERE IS A “LOOMING RELIABILITY CRISIS IN OUR ELECTRICITY MARKETS”
(US FERC)

4 FIRM AND DISPATCHABLE POWER

4.1 KEY MESSAGES

There are many generation and storage technology options available to system operators to help stabilise grids and ensure dependable energy supply. They include interconnectors, although their long-term dependability of supplies is not guaranteed. Stability requires power that is dispatchable on demand and can be relied on during times of system stress due to high consumer demand, reduced output, system abnormalities or any combination of the three.

A range of potential options is outlined and a qualitative judgement of their merits to electricity system operation is provided based on industry experience and research for this study.

Table 3 provides such a qualitative summary for discussion. It is subject to a range of caveats and is offered to stimulate more thought regarding the value of dispatchable power and its attributes in a holistic way to the system. It has been necessary to make some simplifications and generalisations to make this classification. In general, the table should be read as pertaining to the 'whole system', therefore large capacity and specifically, to their role in supporting dispatchability. Note that it does not include their role in CO_2 emissions reduction.

TABLE 3 TECHNOLOGIES AND THEIR APPLICABILITY AS DISPATCHABLE AND FIRM SOURCES OF POWER FOR STABLE GRIDS

Generation technlogy	Capacity	Flexibility	Firm	Maturity	Infrastructure	Existing assets	Duration	Location	Efficiency	Life	Cost	Attractiveness
Fossil												
Natural gas	High	High	Yes	High	Lots	Many	Days-months	Many	High	Long	Medium	High
Coal	High	High	Yes	High	Lots	Many	Days-months	Many	Medium	Long	Medium	High
Fuel oil	High	High	Yes	High	Lots	Some	Days-months	Many	Medium	Long	Medium	High
Diesel and kerosene	Medium	High	Yes	High	Lots	Some	4-24 hours	Many	Low	Medium	Medium	Limited
Nuclear												
Conventional	High	Low	Yes	High	Lots	Many	Days-months	Some	Medium	Long	High	Limited
SMR	High	Low	Yes	Low	Some	None	Days-months	Some	Medium	Medium	Medium	Low
NMR	Low	Low	Yes	Low	Some	None	Days-months	Many	Medium	Short	Medium	Low
Interconnectors	High	High	No	High	Lots	Some	4-24 hours	Some		Long	High	Limited
Renewables												
Hydro	High	Medium	Maybe	High	Lots	Many	Days-months	Some	High	Long	High	Limited
Bioenergy	Medium	High	Yes	High	Some	Some	Days-months	Some	Medium	Long	Medium	Limited
Wind	Low	Low	No	Medium	Lots	Many	4-24 hours	Many		Medium	High	Limited
Solar	Medium	Low	Maybe	Medium	Lots	Many	4-24 hours	Many		Medium	High	Limited
CSP	Low	Low	Maybe	Medium	Lots	Some	4-24 hours	Few	Medium	Medium	High	Low
Geothermal	Low	Medium	Yes	Medium	Some	Some	Days-months	Few	Medium	Medium	High	Low
Marine	Low	Low	Maybe	Low	None	None	Up to 4 hours	Few		Short	High	Low
Waste-to-energy	Low	Low	Yes	High	Lots	Many	4-24 hours	Many	Medium	Long	Low	Low
Storage technologies	**Capacity**	**Flexibility**	**Firm**	**Maturity**	**Infrastructure**	**Existing assets**	**Duration**	**Location**	**Efficiency**	**Life**	**Cost**	**Attractiveness**
Pumped hydro	High	High	Maybe	High	Lots	Many	4-24 hours	Some	High	Long	Low	High
Compressed gas	Medium	High	No	High	Some	Some	4-24 hours	Some	High	Long	Medium	Limited
Batteries	Medium	High	No	Medium	Lots	Many	4-24 hours	Many	High	Short	Medium	High
Supercapacitors	Low	High	No	Meduim	Lots	None	Up to 4 hours	Many	High	Short	High	Low
Flywheel	Low	Medium	No	Low	Some	Some	Up to 4 hours	Many	High	Medium	Medium	Limited
Gravity	Low	Medium	No	Low	Some	Some	Up to 4 hours	Some	High	Medium	Medium	Low
Liquid air	Medium	High	No	Low	Some	Some	4-24 hours	Many	Medium	Medium	Medium	Limited
Hydrogen	Medium	High	Maybe	Low	None	None	Days-months	Few	Low	Medium	High	Limited
Ammonia	Medium	High	Maybe	Low	Some	None	Days-months	Few	Low	Medium	High	Limited
Other	Low		No	Low		None		Few			High	Low

Table 3 shows that there are many options and attributes that need to be balanced when making investment or policy decisions. Equally, the attractiveness of some options may vary over time or under different regional or long-term scenarios.

Fossil plants continue to provide much needed dispatchable power, even in high VRE share regions, enabling their integration into grids. This requirement does not appear set to change since credible alternatives have not yet emerged or been proven. As progress is slower than required to achieve national objectives of net zero by mid-century or beyond, there will be further pressure to speed the deployment of VRE and the closure or abatement of other supplies. As SSE have indicated, the use of fossil plant with CCS may be a way to accelerate decarbonisation whilst reducing the overall costs of transition.

It seems likely that some of the remaining fossil plants will need to be abated to continue to operate. The higher the share of VRE in the power generation fleet the more critical maintaining a fleet of dispatchable generating capacity will become.

Two key roles for dispatchable low carbon fossil power are apparent. The first is to ensure that grids are not exposed to potential blackout events due to the intermittency and variability associated with VRE. This is likely a role for low load factor, low-cost assets that are quick to respond. The second is for higher load factor, carbon abated, flexible fossil assets which can contribute high volumes of low carbon power using proven technologies. These are likely to be a mix of new abated plants, such as the 2 GW coal-fired Longdong facility in China or retrofit plants like the Prairie County 816 MW facility in the USA. Such plants can add large volumes of low-carbon power to energy systems quicker and more simply than can many smaller distributed renewables, whilst simultaneously providing the electricity grid with a wider range of essential high-value services for stability, control, resource adequacy and firming.

The application of this strategy will depend on local opportunities, constraints, risks and current status. For regions currently dependent on fossil fuels, it could lead to more rapid progress towards decarbonisation at lower cost and less disruption than deployment of a vast replacement portfolio of new renewable assets or attempting fuel switching.

ADDRESSING GRID STABILITY THROUGH THE ENERGY TRANSITION IS NOT ABOUT ELIMINATING OPTIONS, IT'S ABOUT USING WHAT IS AVAILABLE FOR BEST PRACTICAL, AFFORDABLE, EFFECTIVE AND TIMELY BENEFIT

4.2 WHAT IS FIRM AND DISPATCHABLE POWER?

Matching power supply to demand is fundamental. Any mismatch creates problems and if those extend beyond the design limits of the system then disruptions can result. 'Dispatch' is the process whereby the system operator allocates instructions to supply power to support foreseen requirements. In this report, 'dispatchable' power includes any power source which can deliver on-demand, supporting system needs for additional capacity. Sometimes referred to as 'firm' generation, which tends to mean 'dependable' sources for the purposes of forward planning, more than flexible.

Dispatchable power is fundamentally available at all times, at short notice. Thus, generation that is already operating at maximum output, is not available, or whose output is not able to be increased on request does not contribute to the dispatchable pool. Dispatchable power does include sources in the system which may have reserves able to be released on request.

4.3 THE NEED FOR FIRM AND DISPATCHABLE POWER

System operators plan available power supplies and reserves in advance to ensure sufficient supply. Despite this, the actual supply required in any period is never known until that time comes; it is only predicted. This means discrepancies occur which require addressing in real time. Issues also regularly arise due to unforeseen events in parts of the system or with other generators, which can be significant. As the proportion of VRE in the grid increases, alterations in weather or demand profile compared to expectation can also lead to significant additional quantities of 'dispatchable' power requirement.

SYSTEM FLEXIBILITY IS THE CORNERSTONE OF ELECTRICITY SECURITY. CHANGING DEMAND PATTERNS AND RISING SOLAR PV AND WIND SHARES DOUBLE FLEXIBILITY NEEDS IN THE APS BY 2030 AND INCREASE THEM ALMOST FOURFOLD BY 2050 (IEA, OUTLOOK FOR ELECTRICITY, 2022)

For the UK market, the system operator anticipates that system flexibility needs will grow almost three-fold from 2022 to 2050 (National Grid ESO, 2023). This represents a huge increase in flexibility, and it is also assumed that the flexibility provided by fossil fuels, currently 70% of the total, will be phased out within that period, replaced by other forms of flexibility provision (*see* Figure 29).

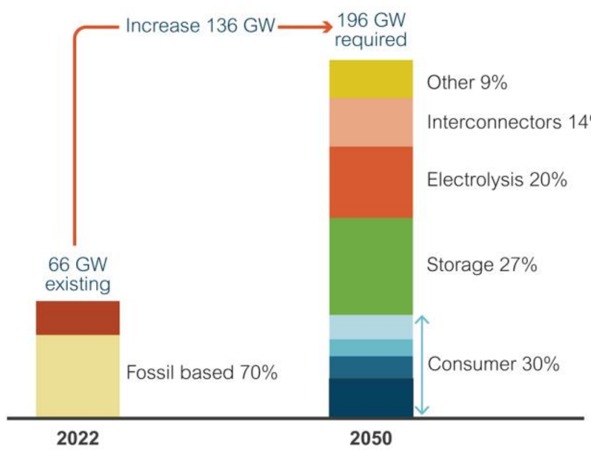

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Figure 29 Total installed electricity system flexibility (GW) by 2050, UK (National Grid ESO, 2023)

Normally, dispatchable sources are considered as those reliant only on the action of the operator and owner to turn them on, up, down or off. Largely these systems are therefore those operating with reserves of fuel or connected to a fuel supply line or another significant energy source capable of supporting delivery instantly and continuously. VRE are not generally considered dispatchable since their ability to provide power depends on the weather or time of day. To account for this, the output from VRE sources which can be considered dependable in times of system need is calculated by multiplying the design capacity by a derating factor. This is effectively the firm 'capacity credit', which is expected to be available even under extreme conditions.

Figure 30 illustrates some of the implications of moving towards an increasingly VRE-based system, for the UK market. Whilst the expected number of 'tight' supply periods is expected to reduce, the duration of those periods is expected to be considerably longer (Keay-Bright and Sunnocks, 2023). At all points in this transition, there will be wide variation in the actual durations experienced. However, the expected change in average duration shows a significant move towards time periods which could not be covered by current energy storage solutions. This is due to limitations on the economic size, or total storage capacity, of those installations. This indicates an increasing risk that demand cannot be met by supply unless those periods can be covered by an alternative reserve or firm, dispatchable capacity.

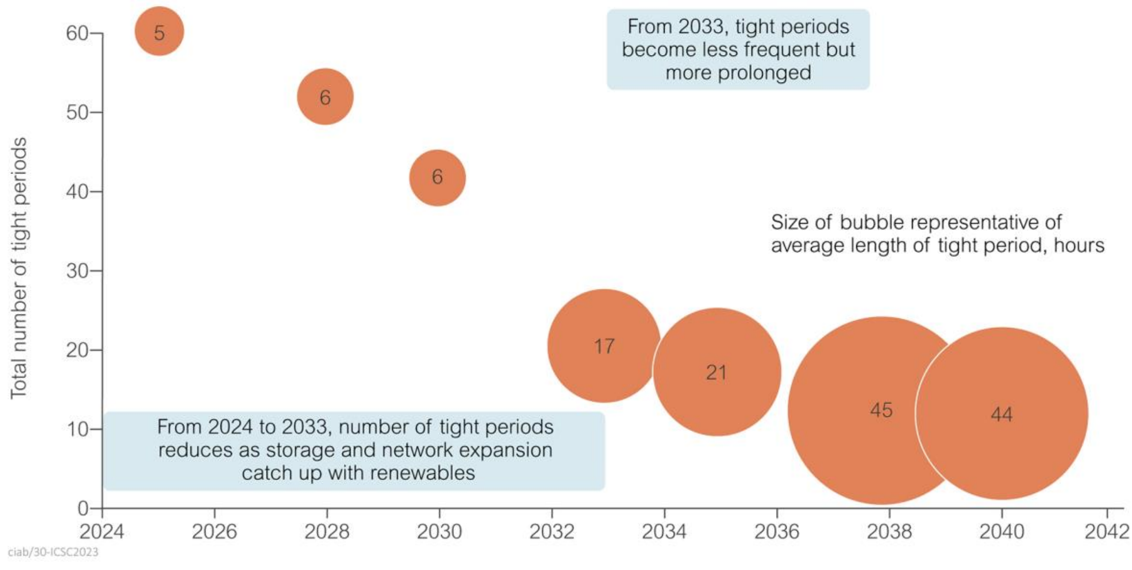

Figure 30 'Tight' periods become less frequent but longer, UK example (Keay-Bright and Sunnocks, 2023)

Modelling work in the Australian National Electricity Market (NEM) (*see* Section 6.5.3 and Figure 58), reveals similar concerns that short-term energy stores are not capable of ensuring continuity of energy supply during some of the shortfall periods that would be expected to occur in VRE-based systems

(Boston and Bongers, 2021). This is true even where short-term stores are more than adequate to buffer normal daily and weekly energy fluctuations of VRE capacity at national level.

This ongoing need for future dispatchable power is driven by two main factors discussed below.

4.3.1 Extreme events

Extreme events fall outside some normally assumed range or percentile probability. It is common to exclude them as part of modelling and prediction work since the likelihood of such events is low. This approach is inadequate for electricity grids since the result of not accounting for these instances is blackouts. Extreme events result from various factors including weather, markets, technical problems, terrorism, and political and geopolitical problems. The fact that an event occurs infrequently, is still a major concern for design, reflected in the fact that most grids have very high reliability standards, even legal requirements in terms of ensuring required annual levels of system availability and reliability. Planning should make allowances for multiple coincident adverse factors rather than single events.

This concept of the rarest events being precisely the most important to plan for, is hard to model and to achieve. However, it is a vital part of maintaining stable power supplies. It is partly why, historically, diversity of sources of supply has helped ensure reserve capacity.

THE MORE INFREQUENT AND EXTREME GRID EVENTS ARE EXACTLY THE ONES WE MUST PREPARE FOR THE MOST

4.3.2 Storage limitations

Bridging challenging times with energy stores is also affected by the sequence of events. Commercially viable storage facilities have relatively limited total storage capacity, even if maximum power output and response time are high. They also generate revenues based on frequent cycling of that capacity. If all storage starts at full and there are opportunities for it to be topped up in between uses, then supply issues problems are avoided. However, if storage facilities are not full at the start of a sequence of events or are not available, or there are no opportunities to replenish their stored energy as events unfold, then the shortfalls in supply are exposed directly to the system and ultimately to consumers. The way these events unfold can vary considerably even for the same system. In 2023 ERCOT proposed measures to limit the minimum state of capacity of stores bidding into flexibility services to ensure they can provide a reliable contribution to the system when required (Howland, 2023).

The quantity of storage required to bridge an extreme event at large scale is extremely high and would be used infrequently, tending to make it an uneconomic proposition with a problematic business model. Storing hours of energy can be done technically at a cost, but storing days and weeks of energy at national scale is a different proposition to small, local short-term buffers. Dispatchable generation capacity may provide a more cost-effective solution for these less frequent situations of high demand.

The UK experienced some of these issues in 2022-23 when it was not possible to store VRE for periods of high demand. Coal-fired plant owners were asked by the government to consider extending the life of plants slated for closure, to reduce the risk of power supply failure. The BBC's climate correspondent was reported as saying 'As yet there are no economical grid-scale energy-storage solutions that can see the country through a spell of cold weather that coincides with a lull in the wind and that is unlikely to change for many years to come' (BBC, 2023).

The USA is also seeing the consequences of limited dispatchable capacity, with severe fluctuations in real-time electricity prices as a result. Figure 31 illustrates this weather-related sensitivity for ERCOT, Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), Pennsylvania New Jersey Maryland Interconnection (PJM), New York Independent System Operator (NYISO) and Independent System Operator New England (ISO-NE) system in the USA in December 2022.

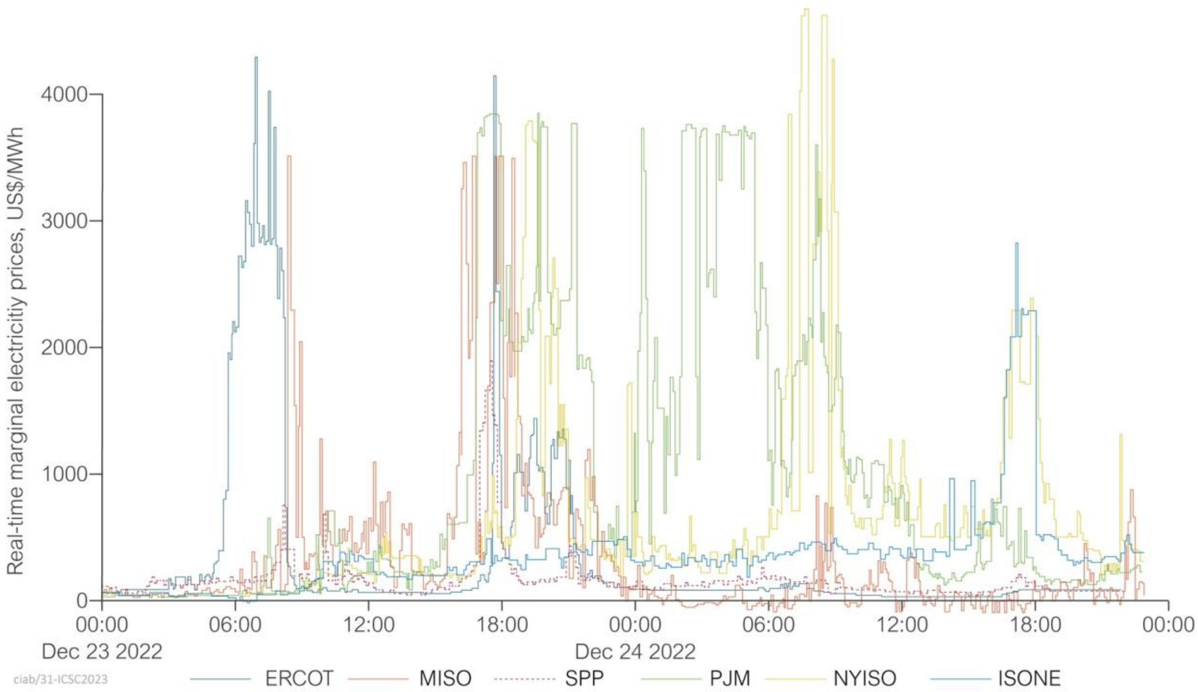

Figure 31 Weather sensitivity of grids with low dispatchable generation margins, December 2022, USA (Bartholomew, 2022)

The ongoing need for dispatchable generation in systems incorporating large shares of VRE is therefore essential, as concluded by the IEA (2023).

4.4 FACTORS INFLUENCING THE SELECTION OF DISPATCHABLE SOURCES

Various factors and attributes make certain technologies more attractive as dispatchable generation options. These may include those shown in Table 4.

TABLE 4 ATTRIBUTES RELEVANT TO DISPATCHABLE GENERATION OPTIONS

Attribute	Relevance
Ability to store fuel	This guarantees that energy can be produced when needed independently of external sources. It might include any plant where a tank of fuel or a stockpile can be created.
Connection to fuel supply	If fuel is not stored locally, there may be a connection that provides a continuous supply of fuel from remote reservoir or source. This might be the case for hydro, gas, coal and oil assets.
Availability of required resource without imports	In the event of trade interruption or emergency, generators not requiring imports, at least for a period of time, will provide higher security of supply.
Cost of energy source	This would have to be matched to its benefits to the system. If it is rarely used, then it becomes more costly.
Cost of keeping the asset available if not in use	Dispatchable plants may need to sit idle for extended periods in readiness, without incurring excessive standby costs.
Capital investment required	High capital plants require high load factors to ensure return on investment over their useful life. Since dispatchable plant may not have a high load factor, lower capital cost may be preferred.
Speed of response to demand requests	Dispatchable generation must respond when requested as the speed of response, and the ramp rate has a value to the system operator.
Capacity of contribution	The greater the capacity of the asset the more value it has to the system operator, all things being equal.
Flexibility	The ease and regularity with which a technology can increase and decrease its output including stop-start cycles is of value.
Maturity of technology	Dispatchable plant needs to be dependable and this generally implies well proven technology.
Ability to work with current infrastructure and supply chains	Dispatachable plant which are not fully compatible with the existing infrastructure and supply chains have a high risk of leading to availability or reliability problems.
Duration of output once requested	The ability to sustain output once operational is important. If output cannot be sustained then the technology is only of transient use and can itself lead to the need for more, or alternative, dispatchable capacity.
Possible range of locations to site the asset	The dispatchable plant should be located at a point in the system where its output is most useful and easily absorbed.

Dependability is considered carefully in the design and implementation of capacity market schemes, because of its importance. This is particularly true in the case of renewable and storage resources offering capacity-related services. Figure 32 illustrates an assessment by TenneT (transmission system operator for the Netherlands and operator of 25,000 km of networks across the Netherlands and Germany) of selected technologies and their 'derating factors' to derive the dependable dispatchable output to be expected during periods of scarcity (Zappa, 2023). It shows that wind and solar are not considered dispatchable. Batteries and demand side response are considered dispatchable but the degree of dispatchable capacity depends on their type and size. It is notable that the 8-hour battery can only provide services for a maximum of eight hours, but system stress events could last 1–2 weeks, intermittently or in succession over that period.

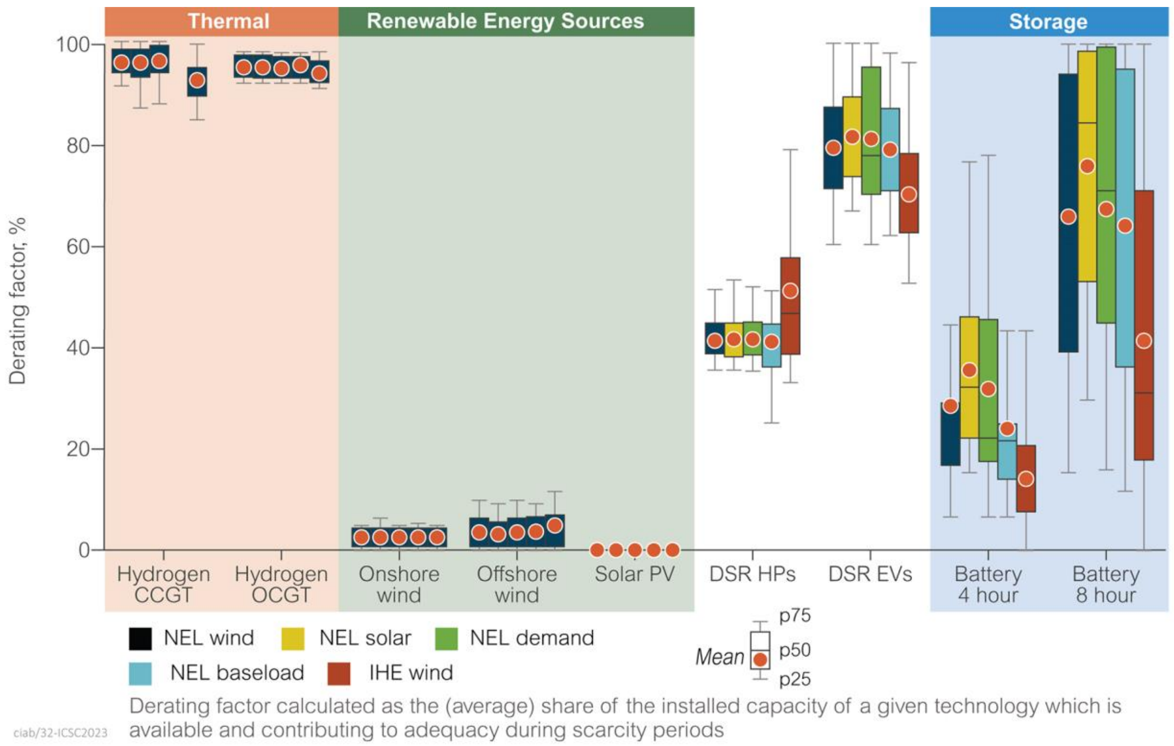

Figure 32 Derating factors applied to selected technology types for capacity, the Netherlands (Zappa, 2023)

In the UK, to determine the capacity that is likely to be delivered, the actual offered capacity is multiplied by the derating factor. Onshore wind has a derating factor of 8% with around 11% for offshore wind. This means that only 8% and 11% of capacity is expected to be available during times of system stress. Although higher than in the TenneT example it is still ten times lower than the nameplate capacity of those sources. For solar PV the figure is approximately 4%. For comparison, the derating factors for other plant are:

- Open cycle gas turbine (OCGT), reciprocating engines, oil fired steam generators – 95%;
- Combined cycle gas turbine (CCGT), hydro, tidal – 91%;
- Biomass and energy from waste – 88%;
- Coal – 80%;
- Nuclear – 78%;
- Demand side response – 71%.

TenneT separates the value for different types of demand side response (DSR), for example, heat pumps or EVs, of approximately 40% and 80% respectively (Zappa, 2023). For battery storage, the situation is more complicated as derating factors vary and depend more on battery size. They range from 9% to 95% with the lower ratings for batteries of short duration capacity.

4.5 DISPATCHABLE POWER OPTIONS

4.5.1 Fossil fuels

Fossil fuels have inherent advantages when it comes to providing dependable, dispatchable power. They are abundant natural resources and important strategic global reserves. The extraction, technologies, industries and supply chains for their utilisation are highly developed, together with the skills and resources to implement them effectively at significant global energy share.

Fossil fuels provided around 62% of global electricity supplies in 2021 (EIA, 2023c) and are unlikely to disappear from the global energy mix in the medium term. Thus, they should be considered as options and their merits, issues and mitigations analysed accordingly. It is important that fossil fuels are made low carbon by increasing efficiency of use, cofiring and the use of CCUS. These areas have been studied extensively by bodies including ICSC, the Global CCS Institute, the IEA and others. See sections 4.6.1 and 4.6.2 for more detail on carbon capture for fossil fuels .

Natural gas

In 2021, natural gas power plants contributed approximately 22.2% of electricity generation (Jones, 2022). These plants have emerged as the preferred choice for high-capacity flexible electricity generation in many countries due to their relatively low capital costs, rapid development and high-power output.

Typically, gas power plants are of the CCGT design, prioritising energy efficiency by incorporating an additional steam-powered generation loop. In contrast, OCGT systems are simpler, cheaper to construct and provide quick response times, making them suitable for rapid backup generation. These are commonly referred to as 'peakers' or 'load lopping' plants. Some combined cycle plants can be designed or modified to offer open cycle operation as an option, either as a permanent or adaptable feature.

Gas turbine power plants are widely considered the benchmark for dispatchable power generation and are increasingly deployed globally. Their economic viability and effectiveness hinge on a stable supply of natural gas and market prices. Throughout history, the price dynamics between coal and gas power generation have fluctuated due to shifts in global energy markets. While demand for steam coal appears to be plateauing or declining, natural gas demand for power generation continues to rise. Consequently, it is possible that coal may become a more cost-effective power production option than gas in the long term, depending on regional taxes and levies related to carbon emissions.

Gas systems benefit from being connected to large gas reserves through national infrastructure, ensuring a dependable supply and streamlined distribution. Although liquefied natural gas (LNG) can be used this requires storage and transportation which raises overall cost. While established natural gas networks and industries exist in regions like the USA and Europe, many countries lack such infrastructure, which can limit the deployment of natural gas-based options.

Reciprocating engines fuelled by natural gas also offer dispatchable power options and are commonly used in small reserve power, combined heat and power (CHP), or local energy system applications. However, for the purposes of this study, these solutions, while valuable in their respective applications, are deemed insufficient in capacity and cost-effectiveness to meet the demands of future national grid-scale dispatch requirements in a high VRE scenario.

Natural gas has lower CO_2 emissions per unit of energy than coal, resulting from its chemical composition and higher process efficiency in commonly deployed utilisation technologies, for example, CCGT compared to boiler-based systems. However, concerns about methane emissions, a potent greenhouse gas with over 82 times the heat-trapping potential of CO_2 over a 20-year period and 28 times more over a 100-year timescale, have been raised (RMI, 2023). Methane has contributed approximately two-thirds as much warming as CO_2 over the past century (IPCC, 2023). Detecting and measuring methane emissions globally remains difficult, but both coal and natural gas extraction and processing release methane into the atmosphere. Recent aerial detection methods are challenging traditional assumptions and reporting practices for methane leakage, with some studies suggesting that these leakages could negate or even reverse the perceived climate advantages of natural gas over coal (*see* Figure 33) (RMI, 2023).

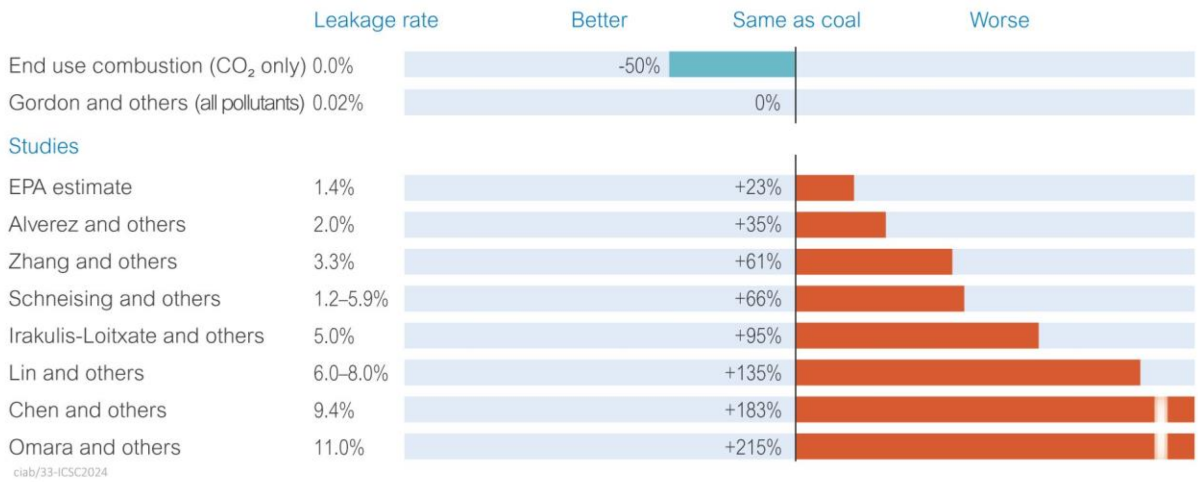

Figure 33 US climate impact studies for methane versus coal as fuel source (RMI, 2023)

Leakage has also been used to undermine the case for natural gas power plants with CCS or the use of natural gas with CCS to produce low-carbon hydrogen which would then be used for power generation. with one study stating the carbon footprint of natural gas-derived hydrogen to be 20% higher than using natural gas directly (S&P Global, 2021). Thus, methane leakage is an important topic which merits more research, and the IEA has highlighted the need for action to address it (IEA, 2023f).

Gas plant decarbonisation options for gas are considered further in Sections 4.6.1 and 4.6.2.

Coal

Coal generated around 36.5% of global power generation in 2021, the largest share of any single energy source (Jones, 2022). Global Energy Monitor (2023) reports there are currently over 6500 coal units in operation (2095 GW), with over 400 in construction (204.2 GW) and nearly 640 announced, or in the pre-permit or permitted stage of development (353.3 GW). Coal-fired units are available in a range of sizes and have flexible characteristics suitable for load following or baseload operation.

Coal utilisation technologies have developed over the decades, with the most efficient plants now approaching 50% efficiency, compared to a global average of about 37.5% (Zhu, 2020). Emissions can be reduced further by coal type selection and processing, cofiring with biofuels, ammonia, or installing CCUS. Supercritical CO_2 cycles could also be applied to coal-fuelled plants and represent a potential future option for clean power (Zhu, 2017).

Coal is an abundant resource in many areas and a key economic energy option (Chapman, 2022). In some areas, notably parts of Asia, it remains the cheapest local power generation option from a whole system perspective. Decarbonisation options for coal are considered further in Sections 4.6.1 and 4.6.2.

Fuel oil

The use of heavy fuel oil thermal power plants declined following the oil crisis of the 1970s and the advent of cheaper and more efficient power generation options. However, there could be a future role for oil-fired power plants as peaking or reserve plants due to their relatively simple plant construction and ability to store high capacities of energy in large, utility-scale fuel tanks.

Heavy fuel oil can also be used in reciprocating engines; however, these would have significantly smaller output capacity compared to thermal equivalents. For example, Grain Power Station in the UK had oil-fired units of 660 MW capacity, whilst a reciprocating engine using fuel oil might only have a maximum capacity of 10–20 MW.

Diesel and kerosene

Diesel and kerosene-based generation is an option, especially for applications involving reciprocating engines and small gas turbines. Such plants are compact, relatively quick to deploy and can store fuel locally sufficient to last for hours, but not generally for days. Often these plants are associated more with standby generation for critical infrastructure and black start capability of power plants rather than for supporting national demand due to their small size at typically single-digit MW outputs.

4.5.2 Nuclear

Historically, nuclear power in civilian power systems has been based on large, centralised generation plants. More options are emerging with the advent of small modular reactors (SMR) and nuclear micro-reactors aiming to address some of the concerns and shortfalls of the larger systems. In 2021 just under 10% of global power generation was from nuclear plants (EIA, 2023c) and nuclear power remains one of the few high energy density, large scale, low carbon power generation options. Due to the lack of operational carbon emissions, its long plant lifetime and high load factors, nuclear has the lowest total lifetime carbon emissions, of 5.5 $gCO_{2\text{-}eq}$/kWh, according to the UNECE (2022). Its land requirement per kWh is also lower than all other technologies reviewed (UNECE, 2022).

Conventional

Conventional nuclear power plants are high energy density, low carbon, clean, thermal cycle-based installations. Typically, unit capacity is in the range 300–>1000 MWe; the largest is around 1750 MWe (IAEA, 2023). Being thermal cycle-based they can also export large quantities of heat to district heating systems, a practice more common in Eastern Europe. Their disadvantages are the high capital cost, long planning and construction times, and poor public perception issues. They are not as flexible as fossil fuel plants in terms of load range, but they can be ramped up to around ±63 MW per minute between the limits of full output and 50% capacity (Patel, 2019). How much this represents in terms of overall system flexibility capacity will depend on the share of nuclear power in the portfolio.

Conventional nuclear plants also have the potential to be turned on and off on a longer term, possibly seasonal, basis. However, their capital cost tends to require that they operate at design output throughout their life to maintain reliability and recover investment whilst minimising system stresses. France, due to its high share of nuclear capacity has experience in modulating the output of its nuclear facilities to help manage national supply needs and Canada also modulates nuclear output to enable better integration of varying availability of hydropower.

Small modular reactors

There are around 70 designs of SMR in development (UNECE, 2022). SMRs can be pre-built off-site and then installed and commissioned on-site with only limited additional work. They have a smaller footprint than conventional nuclear plants and typically capacities are 20–300 MW. Capacities can be extended by adding more modules and modules can be removed and returned for refurbishment or decommissioning. Additionally, waste materials may be left in the modular reactors long term, easing concerns about fuel handling, waste and contamination potential. This modularity allows the designs to be approved and permitted in advance, easing planning and construction.

Various companies offer SMRs commercially and some have significant order books in place for roll-out. One company, Last Energy is offering a prefabricated modular pressurised water reactor (PWR) based SMR which can be delivered to site in less than two years producing 20 MW of power or up to 83 MW of heat with a capacity factor of 95% and a design life of over 40 years (Last Energy, 2023).

SMRs are often described as flexible; however, this is more due to modularity, lower cost, ease of installation and therefore flexibility in deployment scenarios, rather than to operational flexibility. Like other nuclear plants, they can also use their thermal energy for multiple applications which adds to their potential flexibility as a low-carbon energy solution.

Micro-reactors

Nuclear micro-reactors (NMRs) have passive safety characteristics and such a small footprint that they can be transported by truck and located almost anywhere. They have the modularity, construction and deployment benefits of SMRs but with a larger number of potential distributed energy uses. Typically, NMRs would be in the power range 1–20 MW and may be able to operate for 10 years without refuelling. When maintenance is needed the reactor can be removed from site and replaced with another.

Fusion

Fusion energy is eagerly awaited by those working in the energy sector. With no carbon emissions, an abundance of fuel, high energy density, and safe, reliable high-capacity operation with small amounts of inert helium gas as the only by-products, the potential advantages of fusion technology are obvious (UKAEA, 2023). Although it has been discussed and researched for decades, in recent times there have been developments along the path to commercial development, especially the first achievement of net energy output, or 'ignition', in December 2022 at the Lawrence Livermore National Laboratory, USA (LLNL, 2022). Private companies and collaborative and national bodies are working on its development. At present however, there are no commercial power generation reactors in operation or even any reactors capable of sustaining the export of power for any significant period. There is still a long way to go with development and demonstration before scaling up and rolling out is a serious prospect. Fusion therefore remains a 'future technology', albeit with great potential, in terms of commercial and wide-scale power generation. Were it to achieve market-ready status, it is unlikely that its output could be considered dispatchable in the context of accommodating transient output from VRE.

4.5.3 Interconnectors

Interconnectors can serve as virtual power plants for regions, negating the need for additional generation plant capacity investments. Countries such as Norway, Denmark and specific regions such as California and South Australia, which have the potential to generate surplus clean energy beyond their domestic needs, can capitalise on the growing demand for low-carbon electricity by exporting power to other nations and regions through interconnectors. For instance, Denmark, with a substantial share of both renewable and VRE, has an interconnector capacity that exceeds its peak national demand, in addition to its local power generation. The use of interconnectors may be driven by factors such as electricity costs, carbon emission targets, surplus or deficit capacity management, or a combination thereof, aligning with strategic national and commercial objectives.

The cost of interconnectors varies significantly based on factors like distance, route complexity and installation requirements. Land-based interconnectors typically range from €0.35 to €2 billion per 1000 km, while sub-sea interconnectors can cost between €0.675 and €8 billion per 1000 km. Numerous variables influence actual costs, including terrain, cable specifications, voltage, power capacity and expenses related to planning, permitting and project management. Energy losses typically amount to approximately 1.4–1.6% for a pair of converters and around 3% per 1000 km for the transmission lines (Binkerink and Gallachoir, 2019). While interconnectors are considered high-cost infrastructure, they hold strategic importance. However, their significance and the challenges they pose in terms of protection over long distances make them susceptible to targeted attacks.

The utility of interconnectors as a source of dispatchable power for a grid is a subject of debate (Watt-Logic, 2018). In theory, they can contribute to grid stability, but this relies on the availability and timely delivery of their capacity.

Figure 34 presents an assessment of the likelihood of interconnectors providing import potential for Great Britain. The data suggest that interconnectors are typically either fully available for import or not available at all. Assessing specific risk levels at different times is challenging because it depends on concurrent conditions at the interconnector's other end. For instance, the Netherlands interconnector has a 25% to30% chance of providing zero imports during a stress event, but between 65% and 70% of the time, it is likely to offer full import capacity. This highlights the complexity of treating interconnectors as equivalent to dispatchable generation and ensuring resource adequacy. The reliability of interconnectors between different countries can vary widely based on factors like quantity, capacity and the characteristics of the connected markets or regions.

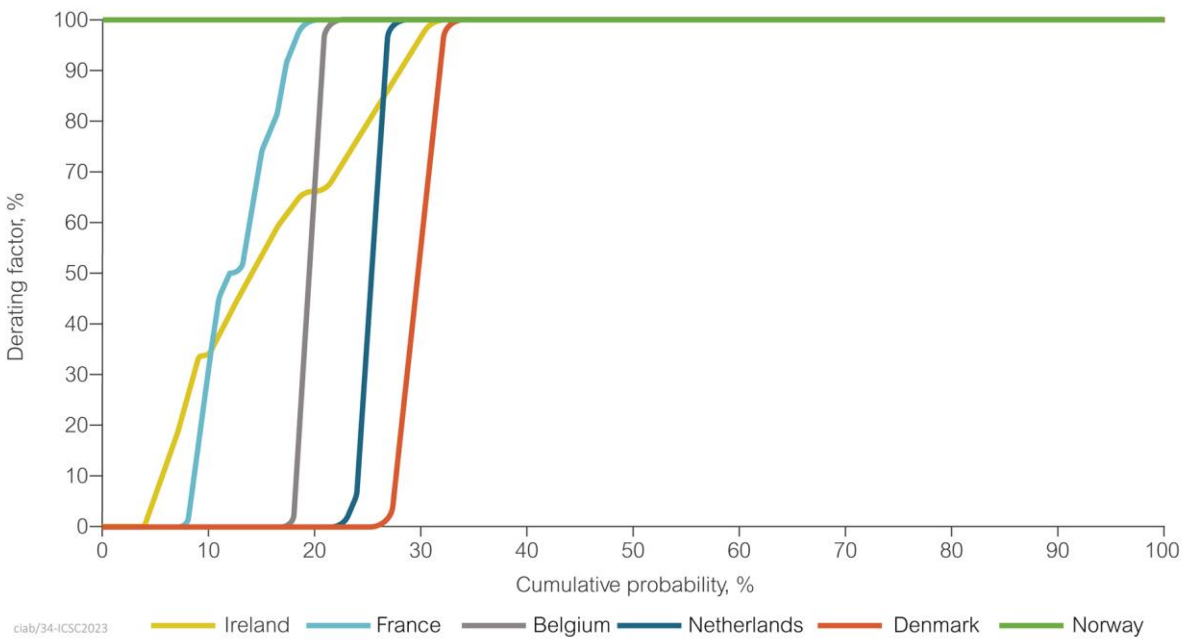

Figure 34 Assessment of Great Britain interconnector de-rating factors, base case (National Grid ESO, 2022a)

Analyses of the dependability of power from interconnections have been carried out (National Grid ESO, 2022a), but uncertainty remains about how it will play out in practice. Anticyclone or ‘dunkelflaute’ type events can affect wide areas of Europe simultaneously, which may dramatically restrict the ability of nations to produce and share power at those times, even if under normal circumstances there would be room for intra-European exchanges.

Many projects have been considered to exploit the resources of one region and route the power created there to another for consumption. Such schemes are generally expensive due to the capacity which would be required to make their use significant, increased dependency on the source location or nation and the creation of a strategic infrastructure target which is difficult to protect. Nevertheless, there is a growing market for interconnectors and there are feasibility projects considering connections reaching thousands of kilometres.

The EU has set targets for the required level of interconnector provision at the national level (European Commission, nd). Each country is required to achieve grid interconnection capacity sufficient to export 15% of the generated power in that country to neighbouring territories by 2030. This follows a previous target of 10% by 2020. However, the regulation also states that each new interconnector is subject to a socioeconomic and environmental cost-benefit analysis and is to be implemented only if the potential benefits outweigh the costs. These targets are driven partly by concern regarding the variable and low load factors of VRE sources constituting the bulk of new capacity additions in Europe.

Europe is reported to have the world's largest interconnected grid, with more than 400 interconnectors and around 93 GW of cross-border transmission capacity, and a further 23 GW in construction or advanced permitting, by 2025 (Thomas and Patel, 2023). The European electricity association ENTSO-E estimates an additional 64 GW (+55%) of additional capacity needs to be built between 2025-30 costing an estimated €10 billion, and that demand on the industry servicing these needs will increase between six- and seven-fold in 2030, relative to typical demand seen in the period 2010-19 (Thomas and Patel, 2023).

Thus, interconnectors can be valuable in general terms for integration, balancing and commercial and strategic needs, but are not necessarily a reliable solution to providing dispatchable capacity in times of local system need.

4.5.4 Renewable options

Hydro

Hydropower is the largest source of global renewable electricity representing around 15.5% of total global power generation in 2021 (EIA, 2023c), with many decades of experience in its deployment and use. Its high capacity combined with a relatively dependable energy supply and reliable technology has made it globally popular. However, projects based on the creation of large dams are controversial due to the need to flood large areas of land. They are also massive engineering challenges, with a high capital cost, but these projects then provide clean reliable power over a long lifespan and can be refurbished to maintain performance.

Output from hydropower is flexible and has been cited by the IEA (2023) as the second most important form of dispatchable generation for flexibility after thermal plant. The proportions of energy sources providing grid flexibility services globally is represented in Figure 35.

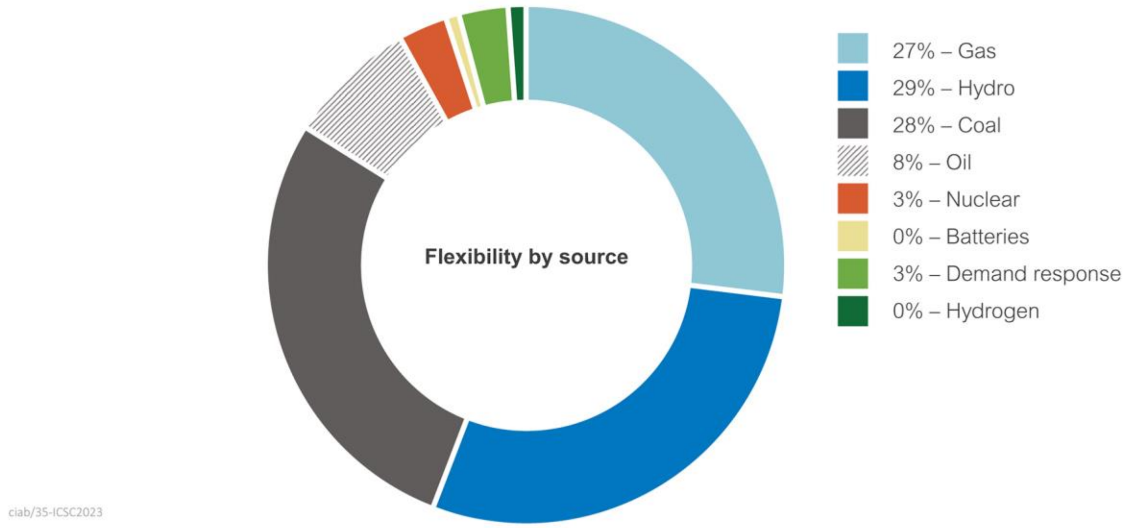

Figure 35 Global electricity system flexibility by source (IFPSH, 2021; IEA, 2021)

Hydro is therefore valuable as a low-carbon dispatchable resource. In 2021 the IEA estimated the total equivalent stored energy in hydro reservoirs globally in relation to dedicated storage technologies. The results are shown in Figure 36 with around 1500 TWh of storage in hydro reservoirs, 170 times more than the global fleet or pumped hydro facilities and 2200 times more than all battery storage including all EVs. In Europe, half of this associated stored energy is located in Norway and Sweden alone.

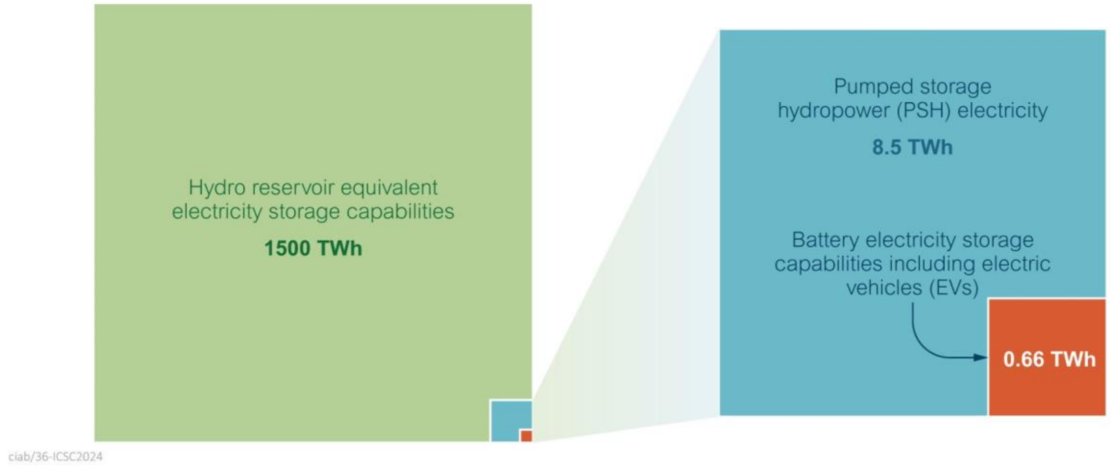

Figure 36 Relative energy stored in hydro reservoirs globally (IEA, 2021a)

One major disadvantage of hydro is that its output is ultimately dependent on the weather. It is a less acute issue than wind and solar, but there are seasons or even years when hydro output is compromised by temperature or rainfall. These inter-annual variations can be significant and may lead to consecutive years of high or low output for which mitigation will be required.

Lead times for new hydro projects are among the longest of any generation technology and their location is limited by natural terrain and climate. Countries, such as Norway, with an abundance of hydro sources, typically have low-carbon intensity of electricity and fewer issues in accommodating VRE into their systems and can often also export surplus hydropower to other countries.

Wind

Wind power is fundamentally dependent on the weather. It is the major form of VRE and continues to grow in response to policies to curb climate change. Along with solar power, wind power is the second fastest growing source by capacity, generating around 6.6% of global power in 2021, almost four times that achieved only 10 years previously (EIA, 2023c). Wind and solar represented 80% of new capacity additions in 2022.

Provided the ambient conditions are favourable and the asset is not generating power, then technically it could be considered dispatchable at that point in time. However, the potential to generate, and the continuity and stability of that generation are weather dependent, so not controllable unlike other dispatchable assets. Wind assets are being offered into capacity markets to provide backup generation, which may sound strange due to its variable nature. Where wind is bid in this way, a heavy discounting or 'derating factor' is used to derate output to allow for the uncertainty of actual generation, typically with significantly less than 10% of output being considered dependable in times of system stress, depending on system operator and location. While this approach may be acceptable for day-to-day operations, subject to suitable penalties for failing to generate, it is unlikely that even strong derate factors can ensure dependable reserve from wind during widespread calm conditions. Wind, again along with solar power, is a technology which may be subject to system operator curtailment in times of favourable wind output conditions, especially when combined with low demand, depending on the design and capacity of the energy system to which it is connected.

Solar

Solar PV is similar to wind in its consideration to qualify as dispatchable power, although even more restricted in terms of potential to generate due to inevitable diurnal cycles. The daytime capacity factors for PV are also highly variable dependent on cloud cover and season. These effects vary depending on geographic location and time of year, but solar is undoubtedly a highly variable and intermittent form of power generation which would be hard to consider in general terms as firm or dispatchable. Along with wind power, solar power is the fastest growing source by capacity, generating around 3.8% of global power in 2021 (EIA, 2023c), over 15 times that achieved only 10 years previously. Solar may also be subject to system operator curtailment.

Bioenergy

Bioenergy can be considered both firm and dispatchable provided adequate stores of fuel exist for the duration of output required. Typically, this would be the main constraint around biofuels for dispatchable generation. Bioenergy feedstocks are typically in relatively limited supply, and this means that total contribution to energy flows will likely be small. Biomass and waste combined, the distinction often being a rather grey area with some wastes being biogenic, contributed only around 2.3% to global power generation in 2021 (EIA, 2023c) even though they represent around two-thirds of all renewable energy consumed for all purposes (IRENA, 2022). There are competing uses for biomaterials for making products, chemicals and transportation fuels for difficult to decarbonise uses such as aviation, as well as directly for low carbon heat which may impact their availability as fuels for power generation.

The main concerns regarding biomass as firm and dispatchable generation option are the feasible, ecological, environmental, ethical and economically realistic quantities of suitable materials that may be available for power generation (IRENA, 2022). Biomass with carbon capture and storage (BECCS). is seen as an important tool in reaching net zero as it has the potential to deliver negative emissions. BECCS has been studied extensively with numerous projects planned or in development (Jones and others, 2023). As such it isn't currently clear if BECCS would be a baseload operation due to its critical role in achieving net zero, or 'usefully dispatchable' in the context of balancing VRE output variations. BECCS is the most saleable negative emissions technology available currently and carbon removals from projects currently in development could reach just under 50 $MtCO_2$/y by 2030 (IEA, 2023b). In the UK, Drax have outlined proposals for installing CCS on two of its four biomass-fired units, with construction potentially starting in 2024 and eventually capturing up to 8 $MtCO_2$/y (Drax, 2021).

Geothermal

Historically geothermal energy has been reserved for geographic areas where high temperature conditions exist close to the earth's surface. Around 80 countries use geothermal energy for heating and cooling purposes (IRENA, 2023a). One of these is Iceland, located on top of the mid-Atlantic ridge, which has 754 MWe of geothermal power generation capacity, approximately 30% of its total generation and it provides 90% of heat for the city of Reykjavik. Iceland's primary source is hydro. In 2022, the total global installed geothermal power generation capacity was approximately 14.6 GW, representing around 0.2% of total global power generation capacity (IRENA, 2023b).

The main advantages of geothermal energy are its low cost and its ability to operate year-round at high-capacity factors. This allows it to provide firm, dispatchable electricity and, if incentivised, ancillary services to the electricity system (IRENA, 2023a). However, geothermal energy is impractical for most regions, due to a lack of suitable installation locations; the cost, due to the extensive exploration and drilling involved; and it may not be viable due to concerns over the potential impact on the environment or ground stability. There have been recent developments in geothermal energy relating to improved mapping and drilling technologies. There are also new approaches which can be deployed in a wider range of locations than previously thought possible. One such system is being promoted by Eavor (2023), a company which claims its technology can provide baseload, scalable, dispatchable, low-carbon power using its Eavor-Loop technology (Eavor, 2023).

Geothermal energy remains a small share of power generation with applicability limited to a few geographic areas. It is possible that in the future it may become more widespread and make a useful addition to grids but currently, it cannot be considered of significant potential for dispatchable power. IRENA (2023) continues to support its growth through coordination and facilitation of the Global Geothermal Alliance (GGA), promoting dialogue and knowledge share to increase geothermal deployment for power and heat worldwide.

Marine energy

Marine energy resources are considerable but have proven difficult to exploit economically. Many devices and options have been developed to exploit wave and tidal movement, but they have failed to become mainstream power generation options. Future developments and demonstrations are expected, but they are still far from becoming a core generation technology with a significant market share. There were only 22 operational, grid connected marine power generation sites globally in 2023 with a combined maximum output of around 0.27 GW (PRIMRE, 2023).

Waste to energy

Recovering energy from waste is increasing due to concerns about the amount of landfill and the ability to restrict emissions from waste to energy plant. Waste to energy plant recover energy from those materials which can be used for power or heat and cooling and enables the further separation and recovery of useful materials for reuse.

As a power generation technology, energy from waste has a limited overall, if valuable, potential as fuel availability is relatively low. A waste plant might have an electrical output of only around 20 MW whilst a large conventional power plant can be 2000 MW or more. Also, the main purpose of energy from waste plant is to process waste. They are therefore typically not run as power generation plants but disposal units, operating in accordance with the incoming waste stream which cannot be stopped. This, combined with small installed capacity at global scale, approximately 20 GW (Wood Mackenzie, 2023), 0.25% of global power plant capacity (EIA, 2023c) and expansion only in accordance with essential waste processing needs, suggests a negligible role in providing dispatchable generation.

4.5.5 Storage

Storage is often not considered as 'dispatchable generation' because it only releases energy previously stored, rather than contributing 'new energy' to the system. However, several forms of storage can be called to release electrical energy into the system on demand, making them dispatchable energy sources. In this report, energy storage is considered 'duration limited dispatchable generation' (DLDG). A general classification of storage technologies is illustrated in Figure 37.

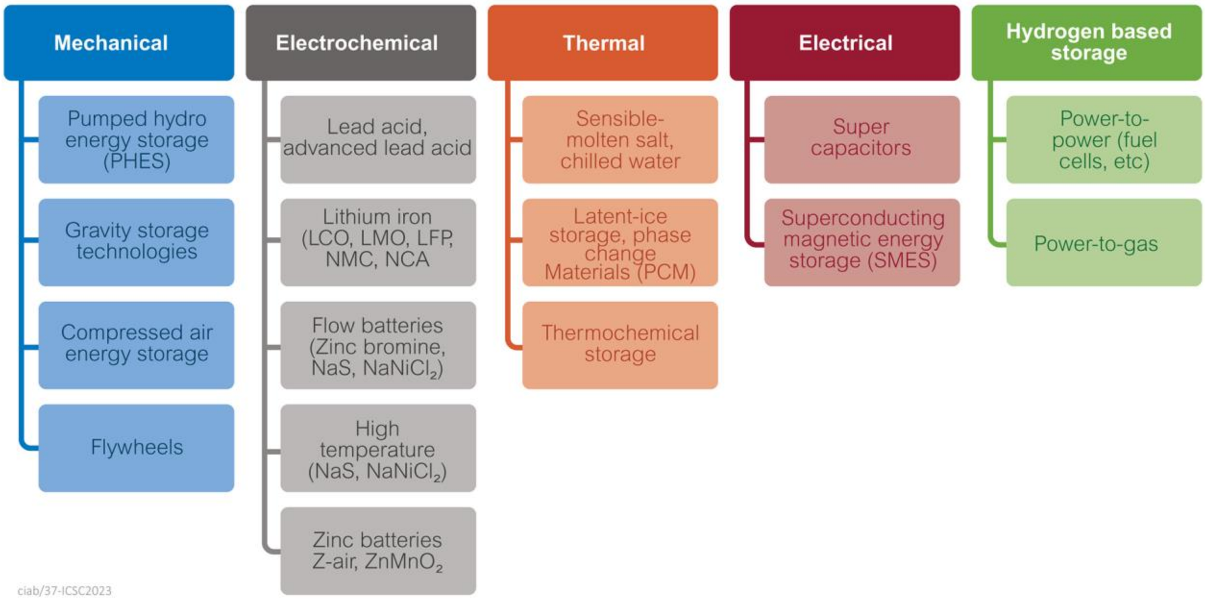

Figure 37 Classification of energy storage technologies (Malchman, 2022)

There are a number of storage options available, which is increasing as new technologies are developed, but each technology tends to have capabilities and characteristics suited to solving particular challenges only. The issue is that their output is severely time limited. As mentioned in Section 3.6.5, while storage for specific local applications is readily understood and achievable, storing energy for the whole system would be a monumental task requiring massive quantities of storage capacity. Storage is therefore typically only considered for providing short term support services to the system or helping to time-shift supply within-day.

The only economic, large scale, energy storage technology capable of providing large volumes of energy to the system for periods exceeding a few hours is pumped hydro, despite the growth in battery installations (*see* Figure 38) (China Energy Storage Alliance, 2020).

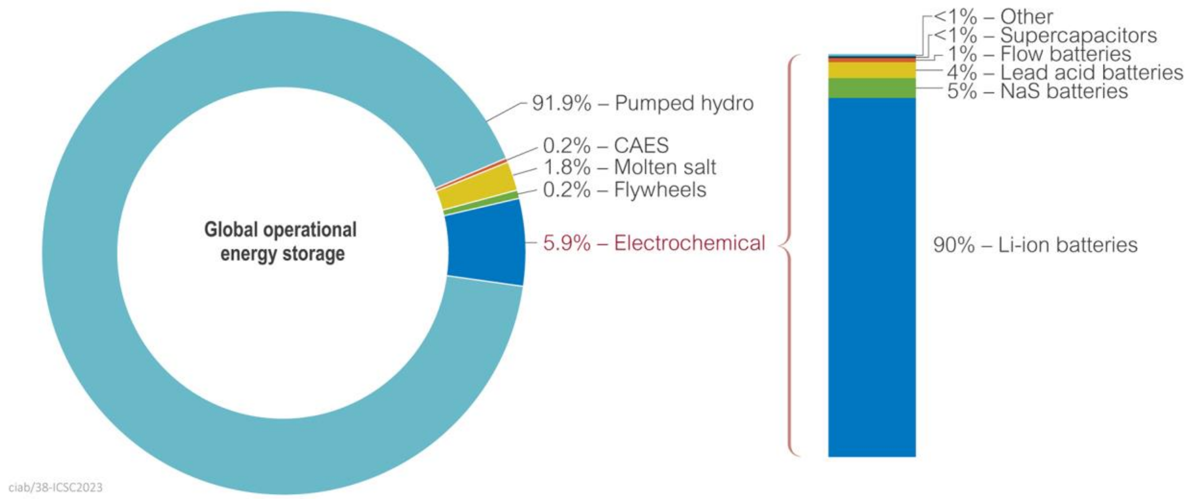

Figure 38 Global total operational energy storage project capacity (China Energy Storage Alliance, 2020)

When reviewing energy storage installations or progress in deployment it is important to understand how they are described. A 10 MW installation and a 10 MWh installation may be either a 10 MW installation that can run for 1 hour from full capacity or a 1 MW maximum output facility that can run for up to 10 hours. The maximum power output (instantaneous) and energy stored (total) are two different, but related, energy attributes. For immediate term system support the power output and response time of the system are more relevant. However, when considering bridging gaps in VRE generation it is the total storage capacity and not the power that is more important since this determines the useful duration.

Storage systems may play other roles in the power generation system in addition to power output, as indicated in Figure 39.

Role	Application	Description	PHES	CAES	Flywheel	Lithium-ion	Sodium-sulphate	Lead-acid	VRFB	Hydrogen	Supercap
	1 Energy arbitrage	Purchase power in low-price and sell in high-price periods on wholesale or retail market	●	●		●	●	●	●	●	
System operation	2 Primary response	Correct continuous and sudden frequency and voltage changes across the netowork			●	●	●	●	●	●	●
	3 Secondary response	Correct anticipated and unexpected imbalances between load and generation	●	●	●	●	●	●	●	●	●
	4 Tertiary response	Replace primary and secondary response during prolonged system stress	●	●		●	●	●	●	●	
	5 Peaker replacement	Ensure availability of sufficient generation capacity during peak demand periods	●	●		●	●	●	●	●	
	6 Black start	Restore power plant operations after network outage without external power supply	●	●	●	●	●	●	●	●	●
	7 Seasonal storage	Compensate long-term supply disruption or seasonal variability in supply and demand	●	●					●	●	
Network operation	8 T&D investment deferral	Defer network infrastructure upgrades caused by peak power flow exceeding existing capacity	●	●		●	●	●	●	●	
	9 Congestion management	Avoid re-dispatch and local price differences due to risk of overloading existing infrastructure	●	●		●	●	●	●	●	
Consumption	10 Bill management	Optimise power purchase, minimise demand charges and maximise PV self-consumption				●	●	●	●	●	
	11 Power quality	Protect on-site load against short-duration power loss or variations in voltage or frequency			●	●	●	●	●	●	●
	12 Power reliability	Cover temporal lack of variable supply and provide power during blackouts				●	●	●	●	●	

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Figure 39 Qualitative evaluation of energy storage system type and application (Schmidt and others, 2019)

Pumped hydro

Pumped hydro represents around 94% of total energy storage capacity and have the capacity to store around 9 TWh of electricity globally (IHA, 2023). It has been successfully used worldwide for decades as a source of storage and emergency power to the system. It has a relatively high efficiency and is widely used by system operators in balancing the electrical system. Pumped hydro locations are typically limited by a requirement to have two large reservoirs with a certain elevation to each other, not separated by more than a certain maximum linear distance. Water is pumped to the higher elevation during times of surplus or low-cost energy and released to the lower elevation though water turbines when there is energy demand. Response is fast and support can be provided for a matter of hours allowing system support in a range of modes (*see* Figure 40) (IEA, 2021a).

Plant type	Hydro	OCGT	CCGT	Hard coal
Start-up time (cold start for thermal)	< 5–20 minutes	5–10 minutes	120–240 minutes	300–600 minutes
Minimum load (% of Pnom)	35–45%	40–50%	40–50%	25–40%
Average ramp rate (% of Pnom/min)	80–100%	8–12%	2–4%	1–4%

OCGT = Open-cycle gas turbine CCGT = Combined-cycle gas turbine Pnom = Normal power

Technically some hydro turbines can operate at lower minimum loads than those indicated (as low as 20%), but operators prefer not to run them below 35% of Pnom as this may shorten the turbine's lifetime

Energy capabilities	Reservoir	Pumped storage	Run-of-river
Inertial response	🟢	🟢	🟢
Voltage support	🟢	🟢	🟢
System strength	🟢	🟢	🟢
Black-start capabilities*	🟢	🟡	🟡
Fast start	🟢	🟢	🟢
Ramping capbility	🟢	🟢	🟡
Scheduling adequacy	🟢	🟡	🟡
Intraday flexibility	🟢	🟢	🟡
Inter-day flexibility	🟢	🟢	🔴
Demand-side response	🔴	🟢	🔴
Baseload power generation	🟢	🟡	🟢
Daily storage of water	🟢	🟢	🟡
Seasonal storage of water	🟢	🟡	🔴

🔴 Low or no capability 🟡 Moderate capability 🟢 High capability

* Black start capabilities depend on special plant features

Note: This indicative assessment includes hydro energy and system support capabilities. Values may differ from plant to plant

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Figure 40 Flexibility capabilities of hydropower (IEA, 2021a)

The example in Figure 41 for Austria illustrates the role of pumped storage and reservoir hydro in accommodating changes in system demand and in taking advantage of lower overnight power prices to replenish pumped hydro reserves.

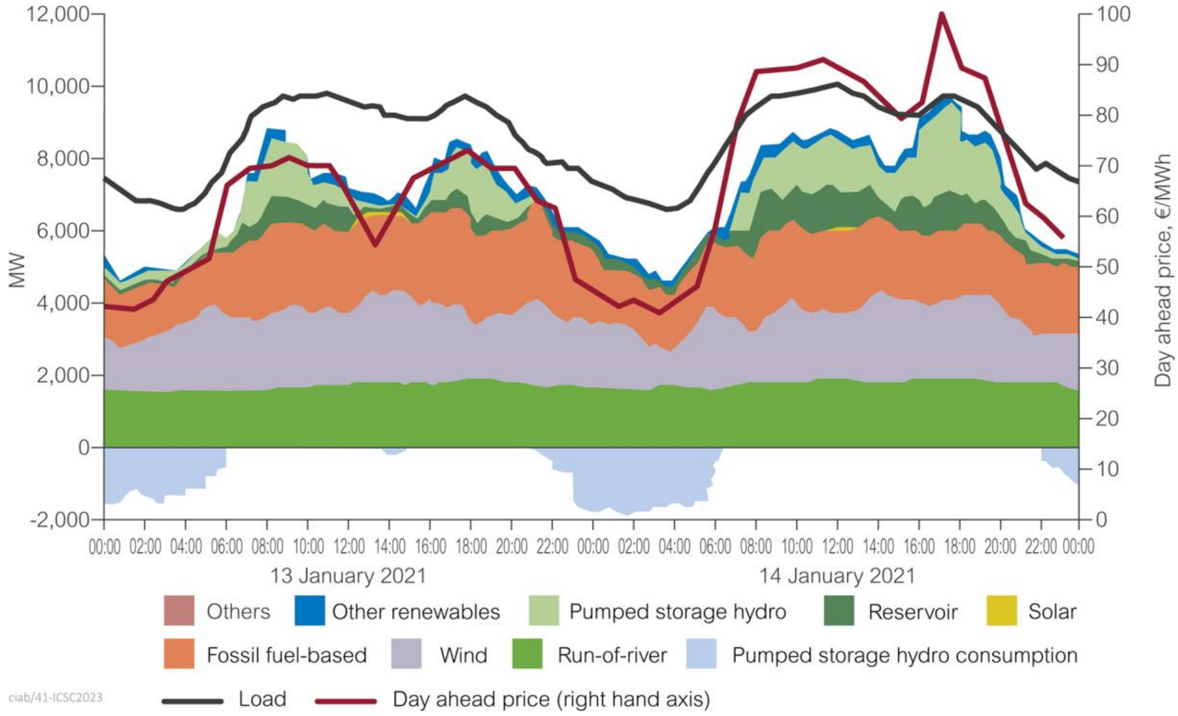

Figure 41 Austria hourly dispatch data 13-14 January 2021 (IEA, 2021a)

The IHA (2023) reports over 100 projects in development, the potential to raise capacity by 50% by 2030 and that many studies have identified thousands of new potential sites for its deployment (IHA, 2023).

Batteries

Batteries are a valuable way to store and recycle energy over short duration periods even at relatively high-power levels. A range of battery chemistries is being developed and deployed to suit various applications with different benefits and costs. Such storage, typically able to discharge for up to four hours can be useful to absorb and shift energy, filling troughs on a diurnal basis.

Batteries may be considered dispatchable as they can be controlled and discharged if required. There are two fundamental issues: batteries only serve a useful dispatch purpose if they are already charged; even if a battery starts fully charged, it has fixed capacity and becomes discharged. Without adequate opportunity to recharge, which normally exists for diurnal cycling, use for longer term demand purposes can result in depleted batteries, not able to recharge. Thus, for multiple stress events in short succession, battery storage capacities can be depleted easily. Building bigger batteries is not the solution as the capacity required would be huge and the low frequency of use would make them prohibitively costly (Royal Society, 2023).

The UK National Grid ESO and AFRY modelled the potential ability of energy sources to provide security of supply during stress events, including batteries with six hours storage and concluded that the loss of load expectation (LOLE) was unacceptably high if batteries were relied on to cover such events. This is shown in the heat map in Figure 42 (AFRY, 2022).

Loss of load expectation (LOLE) of each scenario, hours

– The technologies available in 'Gas CCS, H_2 and battery storage', 'Nuclear, H_2 and battery storage' and H_2 and battery storage' are able to restore the system to a reliability in line with requirement

Case	2025	2028	2030	2033	2035	2038	2040
'Consumer transformation' (reference)	0.6	1.0	0.8	0.3	0.6	0.9	0.9
'Gas CCS, H_2 and battery storage'	0.6	0.8	0.7	1.4	1.9	0.4	0.3
'Nuclear, H_2 and battery storage'	0.6	0.8	0.7	0.7	2.0	0.5	0.4
'H_2 and battery storage'	0.6	0.9	0.8	0.7	1.6	0.6	0.4
'Battery storage'	0.6	0.8	0.7	12.7	27.9	15.1	9.3

– The build option available in the 'Battery storage only' case are not sufficient to meet the LOLE defined by the reference scenario (around 1 hour per year)

– In this case we have built over 120 GW of battery capacity and the LOLE is still substantially greater than the target

– In this scenario, batteries with up to 6 hours duration of storage are not sufficient to compensate for the capacity removed from the 'Consumer transformation' scenario

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Figure 42 National Grid ESO modelling of GB LOLE during system stress events (AFRY, 2022)

AFRY (2022) concluded that batteries were not the solution to provide dispatchable power and other dependable and clean sources of electricity would be needed to meet the required levels of reliability.

Compressed gas

Compressed air energy storage (CAES) uses compressors to inject air under pressure into vessels or caverns during periods of energy surplus or low power price. The air is then released and heated through turbines to produce electrical power. The thermal management of compression and expansion is a critical element of these systems. Response and efficiency are good; however, capacity may be rather limited.

Liquid air

Liquid air energy storage (LAES) stores energy by cleaning, compressing and liquifying air, putting it into cryogenic storage before re-gasifying it and expanding it through a turbine to produce electricity. The technology is claimed to have a high energy density, simple modular construction, moderate efficiencies of around 55%, a long service life of 40 years and a long-duration storage capability with few restrictions on its location. The prominent company in this field is Highview Power which, having demonstrated the technology at 5 MW scale, is working on a 50 MW, 300 MWh plant in the UK. It is suggested they are planning to develop up to six projects in Australia, with the first being 90 MW, 1170 MWh capacity (Highview Power, nd).

CO_2 battery

A variation on this theme has been introduced by the company Energy Dome, which uses CO_2 as the working fluid, which is transitioned from liquid to gaseous form and back for storage. The technology is claimed to have advantages over both CAES and LAES of lower cost and more options for site location, with no cryogenic storage required (Energy Dome, 2023).

Flywheel

Modern flywheel technology is an option for short-duration energy storage. Flywheels use a dual function generator-motor connected to a heavy mass with low friction mounting to store kinetic energy. They have a high-power density, a long life of around 20 years, a high efficiency of 85–95%, are simple and carbon-free, providing storage for hours. Although some special techniques and materials are used for integrity and to reduce losses, flywheels are less complex than many other forms of storage or generation. The technology is deployable in a wide range of locations without reliance on a high level of critical minerals. Flywheels are useful in helping to stabilise the system through fast frequency response support.

Gravity

Whereas flywheels exploit kinetic energy for storage, gravity systems exploit potential energy. This means lifting and suspending a heavy mass which can be dropped later using a generator to generate power as it falls and using that generator as a motor to re-elevate the mass later. Such systems are not considered commercially viable in most cases. These systems have been considered in recent work by ICSC (Reid, 2023) in respect of utilisation and repurposing of existing coal mines and shafts.

Hydrogen

Hydrogen is being researched extensively as a long-duration energy storage solution and option for power generation. Although the costs are high and round-trip efficiency is low, there are few other options for large-scale, high-capacity, long-term energy storage, as hydrogen can be stored for months or years and discharged for days and weeks continuously when required. In concept, hydrogen produced during times of surplus generation, and low power prices, would be used as a blended gas or in fully converted or purpose-designed gas turbine plants to generate power as needed for system balancing purposes and to support baseload during times of low VRE output. Although a hydrogen industry, including storage and transport, has existed for many decades to supply hydrogen for industrial and agricultural purposes, the scale required for power systems would be substantially larger, raising questions about the cost and economics of such new infrastructure, especially if, as is the case for long-duration energy storage (LDES), it is used infrequently. A more detailed review of both the hydrogen economy and hydrogen production methods from coal has been prepared by the ICSC (Zhu, 2023; Kelsall, 2021).

Figure 43 shows that this technology is inefficient at storing and recovering energy, which is a problem in terms of energy conservation and for the economic viability of using hydrogen for storing electricity. Since the low efficiency is primarily a function of basic thermodynamic principles associated with conversions, processing and storage, the losses are largely fundamental to the processes involved and not impacted by the state of development or scale of deployment.

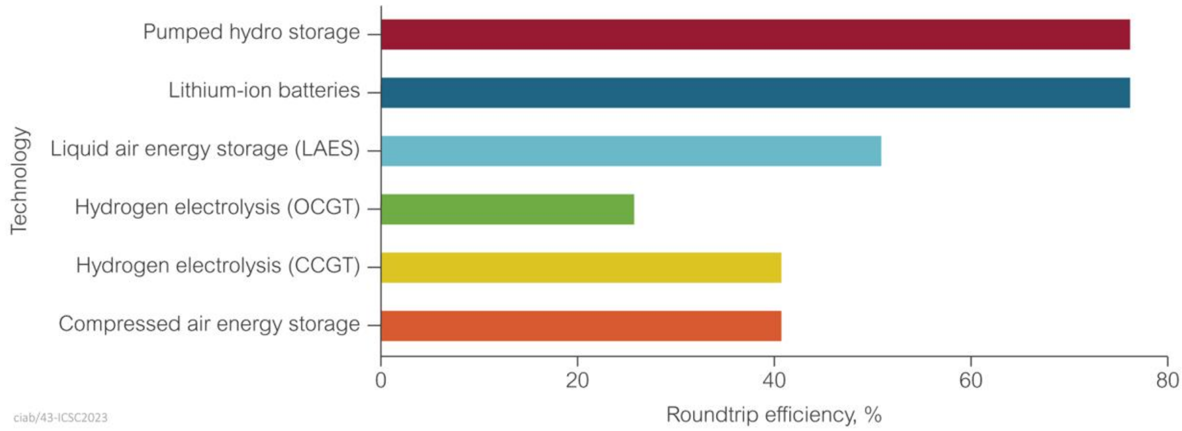


Figure 43 Comparative lifecycle efficiency of hydrogen storage (Energy Systems Catapult, 2022)

The cheapest production method today is steam methane reforming of natural gas and it is the main method used for industrial production. Adding CCS reduces carbon emissions. The most favoured current low-carbon production method involves using renewable electricity to make hydrogen from water using electrolysis. This method is used to produce about 1% of hydrogen currently (Zhu, 2023). Electricity from electrolytic hydrogen costs around three times as much as that produced from natural gas or coal (Kelsall, 2021). Other production methods under investigation include the ‘cracking’ of methane into hydrogen and solid carbon, thermochemical cycles using heat from clean sources such as nuclear plants, clean production from other feedstocks like coal and variants on electrolysis, such as using seawater rather than fresh water. These are yet to be proven at commercial scale.

Hydrogen, like ammonia, discussed below, may be economical for transport of energy over long distances by pipeline or ship, typically of over 4000 km, which could be a factor in its consideration for energy storage (Miao and others, 2021). The breakeven costs will depend on capacities, conversion losses, commodity price and storage and handling facilities amongst others. Ammonia is likely to be more economical than hydrogen for transport over the longest distances.

Hydrogen as a fossil fuel plant carbon abatement option is considered in Section 4.6.1.

Ammonia

Ammonia is an important feedstock for fertiliser production. However, in the context of the energy transition, it is primarily an alternative and easier means to store and transport low-carbon hydrogen by bonding it to nitrogen. Similar cost and efficiency issues will apply to ammonia as for hydrogen including the costs of conversion to ammonia itself and splitting to hydrogen again if that step is also required. Ammonia is a hazardous and toxic chemical for which stringent handling and storage requirements are required. Ammonia can however be used directly as a fuel and cofired in coal power plants as well as being used in the chemical industry. The ICSC has published a study investigating the potential role of ammonia in the clean energy transition (Zhu, 2022) concluding that ammonia may have a role in energy-intensive sectors.

Ammonia as a fossil fuel plant carbon abatement option is considered in Section 4.6.1.

Other technologies

Other forms of energy storage exist including thermal storage via resistance heating with the subsequent generation of steam from the stored heat for energy recovery and generation. These are not currently considered significant at commercial scale for inclusion.

4.5.6 Virtual power plants

If distributed generation and storage facilities are aggregated together, they can be applied to the system as a 'virtual powerplant' (VPP). A VPP can contribute power when required through the smart control of all the participating resources. It could contribute to actual generation, albeit likely at the low-voltage end of the network. In 2019 Tesla announced it would develop the world's largest VPP in South Australia using the solar and storage facilities of 50,000 households. By 2023, 4000 homes had been equipped with a further 3000 approved for addition (Lambert, 2023).

4.5.7 Active demand management

Active demand management can apply additional loads to absorb power, or it can reduce demand to ease stress on the system. Although demand reduction is not strictly dispatchable power, it will have a similar impact to adding a similar amount of additional generation and therefore altering the balance of supply and demand. The question is therefore how much demand can be shed, how fast and how reliably? Some forms of demand management have been used for decades in relation to certain industrial and commercial loads by network operators. The more recent rise in demand for flexibility and concerns over supply shortages associated with commodity prices, environmental events and the roll-out of VRE has given rise to many trials and even commercial systems implementing demand management. These range from simple pricing triggers to more complex systems involving mobile apps and aggregations with specific permissions and constraints set by participants. The extent to which this can contribute to system balancing long term and at scale is not known. More work is needed to establish the answer.

4.5.8 Scale and deployment

For dispatchable sources to contribute meaningfully to the energy transition they must be dependable, responsive and economic. They should also be available in sufficient capacity to make a difference at the system scale and across a variety of locations. They need to be assets that have the potential to be deployed with confidence and in timescales which allow their planning and construction before the point in time when they are needed by the system.

Part of the scale question is also the quantity of dispatchable power that might be required to firm up a given system. This can only be answered for a specific system where there is a detailed knowledge of it, the context and environment, future planned development and operational history. However, it is possible to propose a simple estimation method to identify what could be appropriate in generic terms.

Storage has two main uses, bridging extreme conditions which is addressed by long-term energy storage and short-term smoothing of the intermittent nature of VRE. Storage requirements can be estimated in power and energy stored if those uses are separated. It is helpful to consider the smoothing of solar and wind resources separately. By assuming that new additions need to be self-smoothing so as not to impose on the existing system, the approach can be simplified. This is indicative for purposes of estimation and illustration.

Solar PV example

Table 5 explains a method which might be used to approximate solar and storage requirements relative to a simple load profile. The example states the assumptions and simplifications used and aims to provide a solar storage solution which does not rely on the rest of the system to meet demand. The output is then normalised to provide an idea of how this might transfer to other situations.

TABLE 5 APPROXIMATING SOLAR AND SHORT-TERM STORAGE TO SERVE A LOAD, EXAMPLE

SOLAR STORAGE APPROXIMATION	
Assumptions	1 GW nominal daylight demand Profile of 1 GW for 10 hours of the day and 0.5 GW for 14 hours – the 10 hours represent daylight and the 14 hours represents darkness Solar capacity factor 15% (global average 2021, EIA) Storage depth of discharge cycle – 60% Storage round trip efficiency – 70% Storage used to maintain load requirement across the full day No storage for long-term extreme events included
Approximation	Initial indication of total daily energy to be provided 17 GWh ((1 x 10)+(0.5 x 14)) Initial indication of peak power 1 GW (peak demand) Average output expected over the full day from 1 GW array 3.6 GWh (1 x 24 x 0.15) (for simplicity of calculation assume peak output for 3.6 h rather than variable) Energy to be pulled from storage during the 24 h 13.4 GWh Uplift for storage round trip losses 19.1 GWh (13.4/0.7) Which must be provided during 3.6 h in addition to the 1 GW daylight demand Practical output needed from solar array 6.3 GW (1 + (19.1/3.6)) Total energy required during the day 22.7 GWh (3.6 + 19.1) Energy to storage 19.1 GW Store size adjusted for depth of discharge 31.8 GWh (19.1/0.6) Power rating of store 5.3 GW (peak output to store 6.3–1)
Conclusion	To cover a demand of 0.71 GW average over 24 hours of this hypothetical profile PV array required – 6.3 GW nameplate Plus storage of 5.3/31.8 GWh
Normalising	Per 1 GW average daily demand – need 8.9 GW PV array, nameplate capacity Plus 7.5/44.8.4 GWh storage for short term output smoothing only

Wind example

Table 6 provides a similar explanation for approximating a wind-storage solution that does not (at least on average) impose on the rest of the system to support demand.

TABLE 6 APPROXIMATING WIND AND SHORT-TERM STORAGE TO SERVE A LOAD, EXAMPLE

WIND STORAGE APPROXIMATION	
Assumptions	1 GW nominal daylight demand Profile of 1 GW for 10 hours of the day and 0.5 GW for 14 hours The 10 hours represents daylight and the 14 hours represents darkness Wind output is random over the 24 hour period (and day-day) Wind capacity factor 25% (global average 2021, EIA) Storage depth of discharge cycle – 60% Storage round trip efficiency – 70% Storage used to maintain load requirement profile across the day On average half day and night demand needs time shifting No storage for long term extreme events
Approximation	Initial indication of total daily energy to be provided 17 GWh ((1 x 10)+(0.5 x 14)) Initial indication of peak power 1 GW (peak demand) Initial indication of daily energy from 1 GW wind system is 6 GWh (1 x 24 x 0.25) (for simplicity of calculation assume peak output for 6 h then zero rather than variable) Energy to be pulled from storage during the 24 h is 11 GWh Uplift for storage losses 15.7 GWh (11/0.7) Which must be provided in 6 hours in addition to a potential 1 GW demand Practical output needed from the turbines is 3.6 GW (1 + (15.7/6)) Total energy required during the day 21.7 GWh (15.7 + 6) Energy to storage 15.7 GWh Store size adjusted for depth of discharge 26.2 GWh (15.7/0.6) Power rating of store 3.1 GW (3.6–0.5)
Conclusion	To cover a demand of 0.71 GW average over 24 hours of this profile Wind turbines required 3.6 GW nameplate Storage of 3.1/26.2 GWh
Normalising	Per 1 GW average daily demand need 5.1 GW turbines nameplate Plus 4.4/36.9 GWh storage for short term output smoothing only

Appropriate short-term storage needs could therefore be estimated roughly and simplistically for solar and wind as a function of the solar or wind capacity or both. This includes a range of assumptions and simplifications which would normally be expected to be determined through modelling and simulation work. However, the numbers illustrate that the required capacity additions on a nameplate basis are many times greater than the nominal size of demand they serve and that for self-smoothing, a substantial capacity and power rating of storage is also necessary at the same time.

If it was required to estimate the dispatchable generation required to bridge extreme events then a different approximation method could be used. In the method shown in Table 7, the dispatchable plant is not smoothing short-term variations but only bridging long term and occasional shortfalls such as Dunkelflaute events in Europe.

TABLE 7	APPROXIMATION OF DISPATCHABLE GENERATION REQUIRED TO FIRM VRE OVER EXTREME EVENTS, EXAMPLE
DISPATCHABLE GENERATION EXAMPLE	
Assumptions	100 GW nominal peak demand system Planned average VRE 50% peak demand – 50 GW actual (average) VRE capcacity factor 25% (global wind average assumed, EIA 2021) Extreme conditions VRE output down to 10% nameplate Assume peak demand 10 h and remaining 14 h/d 50% peak Maximum cumulative net days drawdown of storage under extreme conditions – 10 Dispatchable power for covering extreme events only, not for smoothing out variability Dispatchable generation availability – 85%
Approximation	200 GW nameplate VRE capacity required (50/0.25) Extreme event VRE remaining output 20 GW (0.1 x 200) Shortfall during peak demand 30 GW (50–(0.1 x 200)) Adjust for plant reliablity 35.3 GW (30/0.85) System total shortfall during low demand period is zero Dispatchable energy needed 3 TWh (10 x 30 x 10)
Conclusions	Additional backup dispatchable capacity required 35.3 GW (during peak) Total output 3 TWh total per year (assuming a single 10 day extreme period) Effective capacity factor <1% (3/(35.3 x 8760) To bridge extreme conditions for 200 GW nameplate VRE, 50 GW average peak period output in a 100 GW system where VRE is targeted to achieve 50% of peak demand
Normalising	Per 1 GW VRE delivered average capacity 0.7GW, 60 GWh of dispatchable capacity would be needed Or 70% of the average power output of the VRE (35.5/50)

Should the target share of VRE relative to peak demand be higher, as is the target in many countries, then significantly more additional standby dispatchable generation would be required to ensure supply.

If LDES was to be used instead of dispatchable generation then another approximation could also be used to scope what that might look like, as a comparison. This is shown in Table 8. Here the storage is not being used for smoothing short-term variation but only to bridge rare long-term events.

TABLE 8	APPROXIMATION OF LDES REQUIRED TO FIRM VRE OVER EXTREME EVENTS, EXAMPLE
LDES EXAMPLE	
Assumptions	100 GW nominal peak demand system Planned average VRE 50% peak demand – 50 GW actual (average) VRE capacity factor 25% (global wind average assumed, EIA 2021) Extreme conditions: VRE output down to 10% nameplate output Assume peak demand 10 h and remaining 14 h/d 50% peak Maximum cumulative net days drawndown of storage under extreme conditions – 10 LDES for bridging extreme conditions only, not for VRE smoothing Storage starts the period full Storage extraction efficiency 70% Minimum acceptable store level – 20%
Approximation	200 GW nameplate VRE capacity required (50/0.25) Extreme event VRE remaining output 20 GW (0.1 x 200) Shortfall during peak demand 30 GW (50–(0.1 x 200)) System total shortfall during low demand period is zero LDES output needed to balance out drawdown days 3 TWh (10 x 30 x 10) Adjust for LDES efficiency 4.3 TWh (3/0.7) Adjust for minimum storage level reserve 5.35 TWh (4.3/0.8)
Conclusion	LDES power required 30 GW (during peak) LDES storage capacity required 5.3 TWh total To bridge extreme conditions for 200 GW nameplate VRE, 50 GW actual average output In a 100 GW nominal system where VRE is targeted to achieve 50% of peak demand
Normalising	Per 1 GW VRE delivered average capacity, 0.6 GW, 106 GWh of LDES would be needed Or 60% of the average power output of the VRE (30/50)

Storage and additional dispatchable capacity requirements will be reduced where it is assumed the pre-existing power system can absorb some of these transient effects due to existing system characteristics. The opposite is true if average VRE levels in excess of 50% of peak demand are required.

Overbuilding VRE capacity is a possibility, but would be costly, resulting in redundancy for much of the time and higher overall lifetime average costs. Additionally, overcapacity is likely to be impacted to the same extent, possibly 90%, by weather extremes and so may not be able to provide the necessary backup in times of greatest need.

Interconnection and demand side management

There is an argument that demand-side management and interconnectors would lessen the need for dispatchable generation. However, there are counterarguments that extreme demand, system abnormalities and safeguarding operating margins balance those effects. For example, 10% demand side reduction in response to pricing or system signals, maximum importing of 25% on multiple interconnectors having a combined nominal rating of 20% of peak system capacity, 5% higher peak demand than expected, 5% lack of capacity due to system abnormalities like trips or storm damage and 5% margin protection would all net out to zero contribution overall. It may be better to assume any gains from this mix of factors are a bonus and design the underlying system in terms of matched storage for short-term smoothing and dispatchable power for long-term VRE shortfall so that the system is robust on its own.

4.6 DISPATCHABLE FOSSIL POWER AND THE TRANSITION

This study has shown that dispatchable fossil power will remain a key technology and requirement of energy systems throughout the energy transition. This section considers the options for these technologies and industries to continue to play a vital role whilst contributing to climate change mitigation objectives.

4.6.1 Carbon abatement options

There are various carbon abatement options for fossil-fired power plants. The key ones are summarised here. For detail, the reader is referred to reports from the ICSC.

Gas switching and cofiring

For coal-fired plants, there is an option to cofire natural gas or convert fully and cease the use of coal. Whilst gas is a fossil fuel the direct combustion emissions intensity is lower than for coal as a fuel source. On a $kgCO_2$ per unit of heat basis natural gas as a fuel source produces less than 60% of the CO_2 of bituminous coal (EIA, 2023b). The benefits from cofiring or fuel switching are generally not sufficiently beneficial to justify the cost and complexity of conversion since natural gas is not a sufficiently low-carbon fuel. The performance of the converted plant may also be lower than the original design and in all cases is lower than a purpose-designed gas plant of similar capacity. Additionally, gas may not be available at coal plant locations.

Biomass cofiring and conversion

Biomass for cofiring and conversion has been studied extensively, including its sustainability for the purposes of use in power generation (Adams, 2014; Zhang and Meloni, 2020; Demirbas, 2003; CCC, 2018).

For cofiring biomass and conversion of fossil plants, 20% cofiring biomass is normally feasible if there is sufficient fuel and the load factor allows. 100% conversion is possible, as achieved at Drax power station, UK. Four 660 MW coal-fired units have been converted to biomass to provide 2.6 GW total biomass power production capacity or around 6% of total UK demand. This has resulted in the large-scale long-distance shipping of wood pellets from North America to the UK for combustion (Jones and others, 2023).

Such conversions are rare and challenging. Cofiring may be a more practical and economic solution in many cases. Where cofiring is combined with other technologies such as CCS, it can be sufficient to enable fossil fuel plants to operate in a carbon-neutral way, or possibly even slightly carbon negative.

Hydrogen and ammonia

Hydrogen and ammonia were introduced in Section 4.5.5 in respect of storage. They can be transported, piped or shipped for use as substitute fuels for decarbonisation when produced by low carbon means. They can then be used to generate low-carbon power. Just how low carbon and efficient that process is will depend on the energy used to produce, transport and use it, but typically energy losses will be heavy, which will be reflected in the costs. The costs may however be offset by the reduced requirement for additional process plant related to CCS, dependent on load factor (*see* Figure 44 later in this section).

Hydrogen and ammonia cofiring or conversion may be more attractive where there are limited alternative options. For example, if nuclear power is not an option, there are limited available wind and solar sites, interconnection is difficult or prohibitive, and there are few other local fuels available or sites to sequester carbon.

Since hydrogen is difficult and hazardous to handle and store it can be converted to ammonia to simplify the process. Although there is some international hydrogen trade and shipment associated with the industrial gas market, the ammonia market is more established, due to its use in fertiliser for agriculture. Both hydrogen and ammonia can be used in power plants as low-carbon fuels either for cofiring or conversion and this has been investigated by the ICSC (Zhu, 2022, 2023; Kelsall, 2021).

Hydrogen is normally applied in gas turbines as a percentage blend up to around 20% in some existing conventional turbines and up to 100% in specially designed ones. Ammonia is already used to some extent in coal power plants for emissions control of nitrogen oxides (NOx) and particulates, but only in small quantities. Ammonia is generally suggested for either cofiring with coal in a proportion of around 20% or for full conversion. The use of both hydrogen in gas turbines and ammonia in coal power plants is in the early stages of evaluation and demonstration even though intent has been declared to scale up activities on both (Wood Mackenzie, 2022; Siemens Energy, 2023). Wood Mackenzie (2022) estimate that ammonia firing of thermal plants could result in a demand of 200 Mt/y of ammonia by 2050. "When looking at power generation, ammonia is one available option to be used directly either by itself or by cofiring with no reconversion cost needed. Our analysis shows on average the delivered cost of low-carbon ammonia to Japan is expected to fall 60% from 1250 $/t currently to under 500 $/t by 2050."(Prakash Sharma, Wood Mackenzie).

The approximate increase in costs for firing hydrogen and ammonia as full replacement fuel on gas and coal plant is shown in Figure 44, compared with the cost of retrofitting CCS. The data show a high-cost premium for both, relative to CCS unless the load factor is very low.

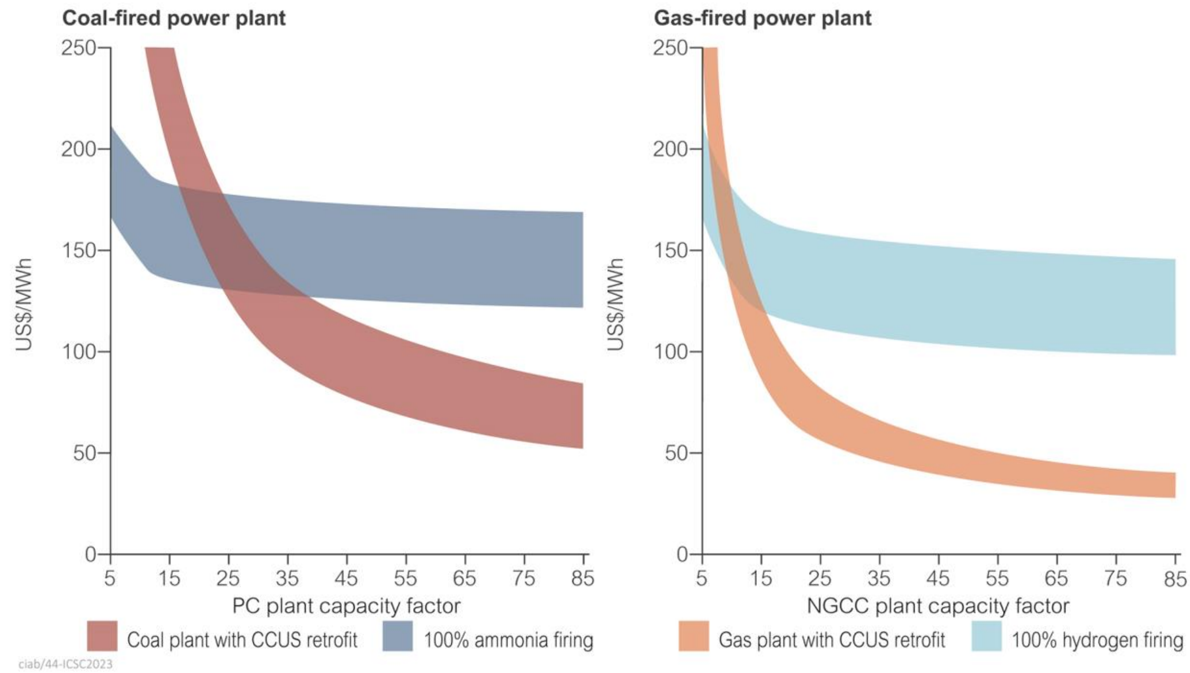


Figure 44 Additional costs of ammonia, hydrogen abatement of existing fossil plants (IEA, 2023h)

The processes involved with making, handling, storing and using both hydrogen and ammonia are energy-intensive, which has an impact on life cycle emissions.

China Energy has successfully conducted a pilot-scale verification of ammonia cofiring in a 40 MW coal-fired boiler, with an ammonia cofiring ratio of 35%. Initial research suggests that the impact on unit operation is minimal, while fuel consumption and NOx emissions are optimised compared to conventional coal combustion (Atchison, 2022).

IHI Corporation has constructed a 10 MW ammonia cofiring demonstration facility and JERA, Japan's largest power generation company, has established a roadmap for ammonia/hydrogen cofiring technology. Promising results were obtained from the 20% ammonia cofiring test at the Hekinan 1000 MW thermal power plant in October 2021. It has been demonstrated that ammonia cofiring facilitates complete combustion of coal powder and ammonia gas, while the proportional increase in NOx emissions from the ammonia cofiring ratio can be significantly reduced through staged combustion methods (Sheng, 2023).

For coal-fired boilers of limited remaining life or where future generation is expected to be infrequent, low-carbon ammonia may represent a means of lessening environmental impact without requiring carbon capture. However, as a means of energy storage, the round-trip efficiency of ammonia for cofiring is around only 25%, lower than alternative storage technologies (Sheng, 2023).

If the use of hydrogen and ammonia is driven by the need for decarbonisation and is not for long-term storage then it may be more economical and practical to produce them on demand. This has the benefit of being able to exploit existing storage and infrastructure. This is the approach taken by hydrogen-consuming industries today. It will, however, only be an option where the location using the hydrogen or ammonia, has the raw resources to run the production process.

Alternatively, other technologies such as the supercritical CO_2 cycle may provide similar or better results to using hydrogen or ammonia where suitable sequestration sites are available.

Offsets, buy-back and direct air carbon capture

Fossil plants also have the option to negate their emissions through mechanisms such as carbon credits and buy-back schemes or investment in direct air carbon capture (DACC). It is suggested that these methods would be most appropriate only for negating residual emissions, for example after a retrofit with CCS or fuel conversion, rather than to compensate for unabated emissions (Climate Council, 2023). In the case of DACC, the costs are higher than those for CCS retrofits and direct air carbon capture with storage (DACCS) may not be commercially viable until after 2040 (GCCSI, 2022a; Sievert and others, 2023).

Carbon capture

The IEA (2020c) states that 'Carbon capture, utilisation and storage technologies have important roles to play in decarbonising global power systems. Owners of existing plants as well as those under construction can retrofit carbon capture technologies to protect their assets and avoid the potential 'lock in' of emissions, in particular in Asia with a large and relatively young fleet of existing fossil-fuelled plants'. They show an increasing role for both new and retrofit carbon capture on coal and gas plants in their Sustainable Development Scenario (SDS). The IEA Net Zero by 2050 Roadmap (IEA, 2021b) also states that 'Retrofitting coal and gas fired capacity with CCUS or cofiring with hydrogen-based fuels enables existing assets to contribute to the transition while cutting emissions and supporting electricity security'. The report adds that the best opportunities are at the larger and more recent sites with space for retrofit equipment and proximity to sequestration locations or demand for CO_2 use. It is suggested that the greatest opportunities for coal based CCUS are in China and the USA for gas-based CCUS (IEA, 2021c).

Pratama and Mac Dowell (2022) have analysed several regions to evaluate the relative costs of decarbonisation. They found that in all cases the costs of deep decarbonisation are significantly higher if CCS is not part of the implemented solution. Figure 45 shows the results of such an analysis for Indonesia.

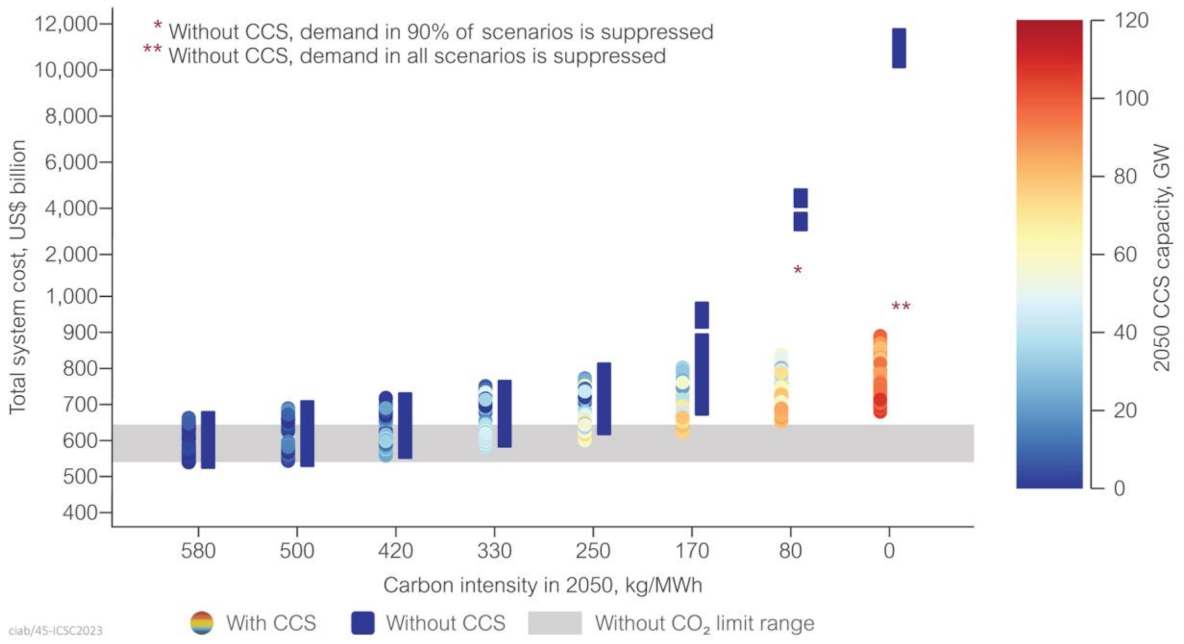


Figure 45 Impact of CCS utilisation on total system costs for decarbonisation (Pratama and Mac Dowell, 2022)

A 2019 report that targeted regional studies found that the cost of decarbonising the UK power system would be about 50% higher if carbon capture was not available. In Poland it would be 2.5 times higher and in New South Wales, Australia it would be twice as high (IEA, 2020c). A recent study conducted on behalf of SSE for the UK market concluded that CCS was the most feasible option to accelerate national decarbonisation (LCP Delta, 2023). It also stated that deployment of 7 GW of CCS by 2030 would be cost-optimal, whilst 9 GW would enable emissions of <30 gCO_2/kWh by 2030. Deploying CCS, in this case using natural gas, would accelerate decarbonisation, reduce costs and reduce carbon, without increasing total gas consumption.

Carbon capture technology is not new but has been evolving with performance improving and costs falling. It has been reviewed extensively by the ICSC. It is broadly separated into three classifications.

Post-combustion carbon capture is essentially the cleaning of boiler flue gases using solvents to extract CO_2 before release into the atmosphere. This is then removed from the solvent, compressed and sent for use or sequestration.

Oxyfuel firing is a modification to the normal combustion process using pure oxygen for the combustion process with the fuel together with recycled flue gasses as the combustion medium. At equilibrium this allows the circulating gases to be rich in CO_2 which makes capture and removal much more effective.

In **pre-combustion carbon capture** the fuel is first processed to split the hydrogen and carbon in the fuel with the capture of the CO_2 component. This leaves a hydrogen-rich gas which can be used in the power plant.

4.6.2 Status of carbon capture

CCS is non-negotiable in order to reach NZE according to the IPCC (2023), IEA (2020), McKinsey & Company (2023a) and others and there are a large number of facilities in operation (*see* Figure 47). The current capture rate is in the order of 40 Mt/y.

Consequently, carbon should be removed and sequestered from a wide range of industrial, process and power sources, worldwide. The CO_2 will be stored in locations including aquifers, caverns and oil and gas wells. There is believed to be potential for around 700 CCS hubs globally and storage locations have been identified and proven for a capacity of 577 $GtCO_2$. East Asia is a potential location for many of these future sites due to the availability of storage locations according to McKinsey & Company (2023a).

The global status of CCS projects, distribution by region and sequestration site type and most significant developments over 2022-23 are shown in Figure 46, Figure 47 and Table 9 (GCCSI, 2022b; 2023).

	Operational	In construction	Advanced development	Early development	Operation suspended	Total
Number of facilities	30	11	78	75	2	196
Capture capacity, Mtpa	42.5	9.6	97.6	91.8	2.3	243.9

ciab/46-ICSC2023

Figure 46 Summary of the status of CCS projects globally (GCCSI, 2023)

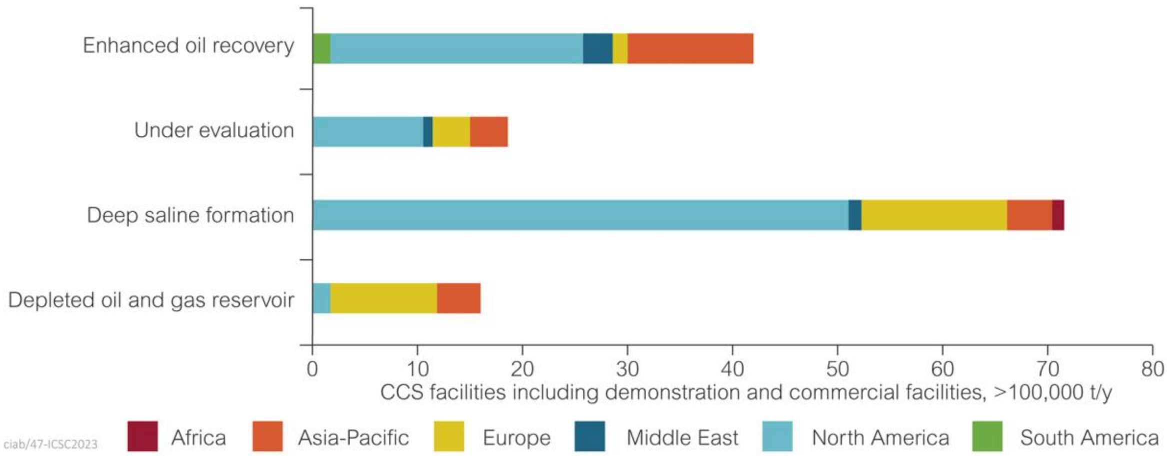


Figure 47 Distribution of global CCS projects by region and type of sequestration (GCCSI, 2022b)

Policy is a key enabler of CCS and recent developments allow a growth in project activity, with a 102% year on year increase reported in 2023 (GCCSI, 2023). The EU Net Zero Industry Act targets 50 $MtCO_2$/y storage by 2030 while the UK CCUS Net Zero Investment Roadmap sees 20 to 30 $MtCO_2$/y of capacity operational by 2030. In the USA, the Inflation Reduction Act is expected to increase CCS deployment to 250 $MtCO_2$/y by 2030. Japan's Long-Term Roadmap (2023) targets first commercial operations by 2030 with longer term aim for 240 $MtCO_2/y$ by 2050. Saudi Arabia has also announced a target for 44 $MtCO_2/y$ of storage by 2035 (GCCSI, 2023).

TABLE 9	SIGNIFICANT RECENT CCS PROJECT DEVELOPMENTS (GCCSI, 2022B, 2023)
1	Drax power station in the UK announced the world's single largest BECCS project, of 8.0 Mt/y capacity across two units
2	Three projects became operational in China in 2023: Asia's largest coal-power plant CCS facility, the first offshore CO_2 storage facility, and carbon capture at an oil refinery.
3	Support for seven CCS networks announced in Japan that will capture CO_2 for storage in the offshore waters off Japan and in the wider Asia-Pacific region.
4	Jubail Industrial City, Saudi Arabia, one of the world's largest CCUS hubs, will start operating by 2027 with a capacity of up to 9 $MtCO_2/y$ in its first phase, supporting Saudi Arabia's aim to extract, use and store 44 $MtCO_2/y$ by 2035.
5	In Australia, the Bayu-Undan project by Santos has moved into Front End Engineering and Design (FEED). This project will capture CO_2 from LNG production in Darwin and transport it via pipeline across the maritime border beween Australia and Timor-Leste for offshore geological storage. A key feature of this project is repurposing an existing natural gas pipeline for CO_2.
6	The Klemetsrud Waste-to-Energy CCS project in Norway moved to 'in construction' having secured funding. This is the first commercial-scale CCS project applied to a waste-to-energy facility.
7	Glacier CCS Project – capture technology firm, Entropy, commissioned a CO_2 capture facility on a natural gas-fired reciprocating engine, the first of its kind at commerical scale and an important milestone given the global importance of future capture from natural gas combustion streams.
8	ORCA, the world's first commerical DACCS facility, was commissioned in Iceland. Its follow-up, the MAMMOTH proect, was announced.
9	In the USA construction commenced on the first large-scale DAC project, STRATOS, and operations are planned to start in 2025. The project aims to capture up to 500 $ktCO_2/y$.
10	Occidental, in partnership with DACCS technology company Carbon Engineering, announced that construction will commence on a 500 kt/y DAC project in the Permian Basin,USA. The plant is said to be capable of scaling up to 1 Mt/y capacity. This is in the context of Occidental's stated plans to develop a fleet of 70–135 such facilities around the world by 2035.

The USA leads global CCS facility growth with 73 new projects since 2022 (GCCSI, 2023). In 2022, Canada (19 new projects), the UK (13), Norway (8), Australia, the Netherlands and Iceland (6 each) also made significant contributions. In Canada 19 hubs were awarded under the provincial TIER system plus six sequestration hub agreements were announced in Q1 2022 (GCCSI, 2023). Newcomers in Europe, such as Bulgaria, Poland and Finland, are entering the CCS market, thanks to the EU Innovation Fund's grant programme (GCCSI, 2022b).

In the USA, the Infrastructure Investment and Jobs Act allocated over $12 billion for CCS and related activities. The Inflation Reduction Act enhances the 45Q tax credit, promoting CCS deployment by modifying construction timing, lowering capture thresholds and expanding transferability. The IRA may increase deployment of carbon capture in the USA by as much as 13-fold by 2030 according to some analyses (GCCSI, 2023). States including Pennsylvania, West Virginia, North Dakota and California have advanced CO_2 storage legislation and introduced support programmes for CCS.

North America has two operational large-scale slipstream CCUS facilities retrofitted to existing coal-fired power plants: Petra Nova, Texas and the Boundary Dam project in Canada. Petra Nova, the largest post-combustion carbon capture system on a coal-fired power plant, designed for up to 90% capture at 240 MW, captures up to 1.4 $MtCO_2$/y and became operational in 2016 (Patel, 2023b). A USDOE-supported report on retrofitting the 816 MW Unit 2 coal-fired Prairie State Generating Station in Illinois was published in 2022. Capture costs are estimated at 43.42 $/ton over the facility's planned 30-year life treating the full gas stream (Obrien and others, 2022).

In Europe, Denmark has allocated €5 billion in subsidies for CCS, Norway has committed NOK1 billion (US$100 million) to support three large gas-based hydrogen projects and four of the seven projects selected under the EU's Innovation Fund's first call were CCS projects. The UK Government released its CCUS Investment Roadmap, outlining plans for four CCUS low-carbon industrial clusters by 2030, with the East Coast and HyNet clusters being the initial selections (HM Government, 2023).

In June 2023 operations began at the China Energy Investment Corporation's coal-fired Taizhou power plant (Reuters, 2023a). This is the largest coal power carbon capture project in Asia and the third largest in the world. The facility is set to capture 500,000 tCO_2/y. There are around 40 other carbon capture projects in China, which combined, capture around 3 $MtCO_2$/y. China has significant sequestration potential and further large-scale coal carbon capture projects are in development.

Huaneng is constructing a 1.5 $MtCO_2$/y coal-fired power CCUS project in the Ordos basin, expected to be the world's largest. The Longdong CCS project is part of a 10 GW energy complex, including renewable energy and a new 2 GW coal-fired power plant, planned to start operating in 2023 (Proctor, 2023; Kelsall, 2021). In Japan, J-Power initiated testing at its Osaki CoolGen Capture demonstration project, capturing CO_2 from a 166 MW IGCC plant, and expanding capture technologies at operational coal-fired power plants.

A comprehensive study of CCUS in China (Lockwood, 2018) concluded that from a cost perspective, China could realistically proceed to retrofit a significant portion of the country's coal fleet by 2035, provided that adequate policy incentives were introduced. Analysis by Fan and others (2019) indicated that CCUS retrofit of coal-fired power plant could only become viable from an investment viewpoint if the decarbonised electricity price increased to 0.75 ¥/kWh (around 0.1 $/kWh), equal to the feed-in tariff (FIT) of solar PV and biomass power, when the investment value could exceed that of wind power generation projects in China. As the performance and costs of CCS improve with more project experience, this breakeven level may now be lower.

Natural gas plants may also need to incorporate CCUS to achieve NZE, which would increase their capital and operational costs. The US EIA (2023a) reports that the overnight cost of a CCGT plant with 90% carbon capture is nearly 2.7 times that of a multi-shaft gas plant without CCS, with substantially higher fixed and variable operating expenses. If these plants operate at low load factors, the effective cost per unit of energy could rise, raising concerns about their financial viability. Capacity or strategic system reserve programmes may help offset these costs, but they would need to offer significantly higher incentives than those typically seen for marginal plants.

Research by IRENA (2019) indicates that the flexibility of gas-fired plants can be further improved to achieve ramp rates more than double those of current facilities (IRENA, 2019b). Additionally, studies by Bui and others (2020) suggest that incorporating CCS does not necessarily reduce the ramp rates of CCGT plants if suitable control mechanisms are implemented.

There is growing interest in alternative power generation cycles, particularly the supercritical CO_2 cycle (Zhu, 2017). This technology has been commercialised by NET Power (NET Power, 2023), offering advantages such as a small footprint, lower costs, higher efficiency and the ability to generate power from natural gas with a high degree of carbon capture, using CO_2 as the working fluid instead of steam. NET Power's first-of-a-kind 50 MWth clean energy plant in Texas, operational since 2018, uses Allam Cycle technology and aims to make zero emissions natural gas-fired power generation competitive (IEA, 2020c). Plans for a world-first utility-scale natural gas-fired power plant with near-zero emissions, producing nearly 300 MW of carbon-free power, are underway at Occidental's site near Odessa, Texas, with partners including Constellation Energy Generation, Baker Hughes and 8 Rivers Capital, targeting operation by 2026 (NET Power, 2022).

4.7 COMMERCIAL VIABILITY

For any technology to be widely deployed in a sustainable manner, it must be commercially viable, either on its own or due to long-term support mechanisms. This will have an impact on the technologies used for the decarbonisation of power supplies. Three categories of measure are relevant when considering implementation from this angle: new additional loads designed to absorb power during periods of excess, energy storage and standby dispatchable power generation.

Issues of storage are covered in Section 4.5.5. Additional loads, such as new industries created to absorb more energy, also have their own special considerations, and are not covered in this study.

As discussed in Sections 3.6.5, 4.3 and 4.5.5, energy storage is currently neither practical nor economic to ensure security of supply and interconnectors will neither have the capacity nor dependability to ensure adequate import of power. This suggests that additional standby dispatchable power generation is required to prevent blackouts. Technically this is achievable with abated or unabated fossil or other biomass-based fuels. The issue is the business case for those assets to exist.

Normally a new power plant of any kind would be expected to operate at close to design conditions on a continuous basis for many years to generate returns for its owners and operators. This mode of operation also ensures peak performance and reliability, minimising damage and maintenance costs. Under normal conditions, capacity factors for new assets are generally >80%. Yet in a future energy system where those assets are only acting in a peaking or standby capacity to ensure stability and reliability the capacity factor may be far less and the cycling of those assets far higher, with possibly only a 10% load factor (Williams and others, 2020). The exact figure depends on a range of factors for which detailed modelling would be required.

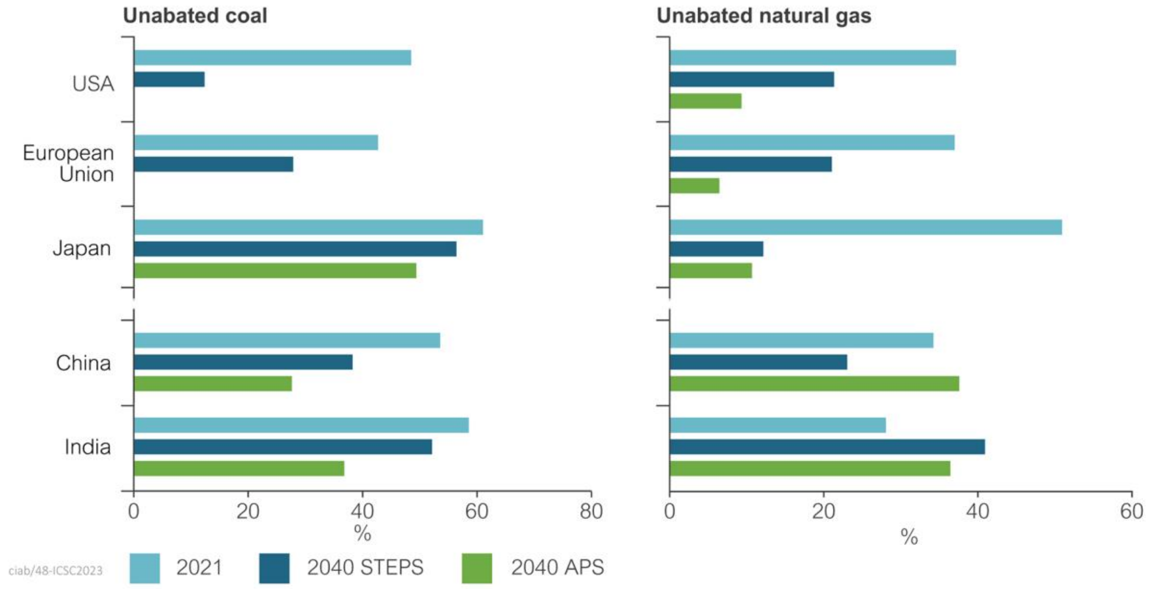


Figure 48 Projected capacity factors for unabated coal and natural gas, 2021 and 2040 (IEA, 2023d)

Figure 48 shows estimated future load factors for unabated coal and gas plants to 2040. It indicates low-capacity factors compared to design. As much of the fossil plant will have been retired before 2040, the question arises about the viability of replacements. Operation at such a low-capacity factor would result in a significant increase in the effective costs of production from those sources, perhaps by four- or five-fold, and result from the dispatchable power being used to back up VRE.

Future energy systems will need to compensate for dispatchable resources so they can achieve an acceptable business return when operating only for short periods. The capacity markets to date have not had to provide such a level of incentive since they typically only involve a small pool of capacity, and those assets were only using the capacity payment to supplement their base operating model.

This is a key point to be resolved. Three possible solutions are:

- Make the standby plants as cheap and simple as possible and pay some form of strategic reserve fee sufficient to make the business case work. This would imply less focus on the environmental performance of those plants due to low cumulative operating hours and therefore low absolute impact. This approach may not be acceptable in areas with net zero targets or an inability to offset those emissions elsewhere.
- Ensure that low-carbon technologies are used, and the market designed so they operate at sufficient load factor and remuneration to make the business model work. The assets would earn their costs through valuable services to the system whereas in the former case, they would simply represent a cost burden to the system which must be paid.

- Implementation of market mechanisms to reimburse the costs of very low-capacity factor assets as a means of strategic national or regional system long-term reliability reserve. This is similar to current capacity markets but for longer periods of time and sufficient to enable investment in new assets of this type before the system calls on their use.

5 GRID STABILITY AND COST OF ELECTRICITY

5.1 KEY MESSAGES

A single cost comparison of technology options does not exist. There are a range of possible costs for each technology based on context and the ranges often overlap. Thus, the cheapest technology option may be reversed in two different applications. The costs for a specific technology and location at a specific point in time given the nature of the system it is being added to must be assessed on a case-by-case basis. Overall costs and all low-carbon technologies should be considered. As Figure 49 illustrates, removing options can significantly increase the costs of solutions (Pratama and Mac Dowell, 2022). Taking a technology-agnostic approach and focusing instead on outcomes is likely to lead to a more stable and economic solution while still allowing room for innovation and competition.

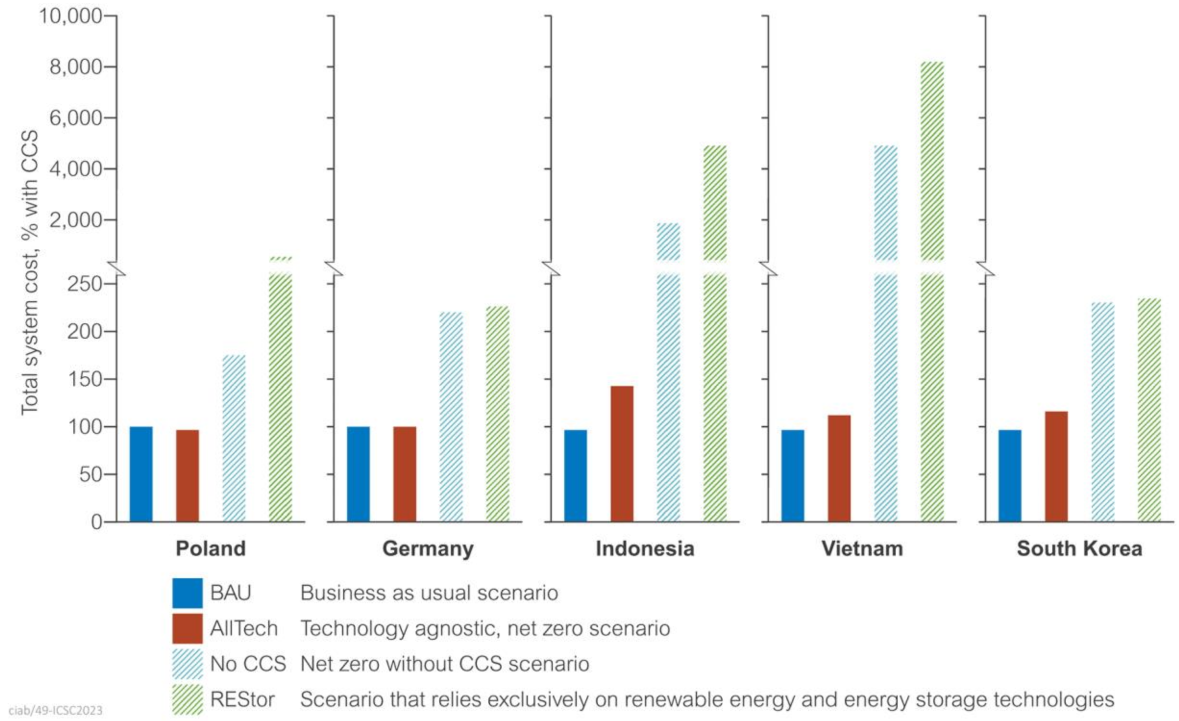


Figure 49 Total system net zero cost comparison by technology mix (Pratama and Mac Dowell, 2022)

Levelised cost of electricity (LCOE) can be a useful metric in some circumstances, but it can be inappropriate and misleading in others. The use of LCOE is confused by different formulations of the metric which can result in different numbers from the same base data. Some system models have acknowledged the fundamental flaws of using traditional LCOE values in comparisons and now address total system costs for a more realistic assessment of the cost impacts of transition. These more comprehensive analyses indicate a significant increase in the total cost of electricity over time and an exponential increase in costs as decarbonisation proceeds. This is largely due to recognising the need to maintain the reliability and dependability of the overall system with granular attention to time and extreme events compared to a focus only on capacity. Omitting these costs is a misrepresentation of the costs of energy transition and misleading in terms of the cost of some new technologies being deployed.

> "LCOE IS BARELY MORE THAN A BACK-OF-THE-ENVELOPE CALCULATION
> THEY DO NOT EVALUATE HOW THE MARKET VALUE AND ANCILLARY SYSTEM COSTS OF TECHNOLOGIES VARY AS THE STATE OF THE SYSTEM EVOLVES OVER THEIR FUTURES."
> (EPRI, 2020)

Data reviewed in this report indicate that while subsidised LCOEs for VRE can lead to those technologies appearing at much lower cost, the removal of subsidies and addition of other costs such as system firming capacity can reverse the relative cost positions, without changing any other parameters and assumptions.

The broader 'cost' of choices on the natural environment and economy and demands on supply chains should also be considered. These additional factors are more challenging to attribute a value to but remain important. However, access to raw materials, alongside cost and practicality of deployment may well be something that limits the viability of what is achievable.

5.2 WHAT DO WE REALLY MEAN BY 'COST'?

There is a difference between price and cost. The price of electricity is what you pay for it, while the cost is the underlying necessary expenditure to produce and deliver it. In modern economies these two things have become separated and the gap between them extremely variable.

Figure 50 illustrates how the price a consumer pays for electricity is different to the average wholesale power price (Ofgem, 2021). It shows that many costs are spread across all units of electricity sold and all users, even if they are associated only with specific technologies or parts of systems. Not all costs may even be included in the consumer bill. Special government tax breaks, grants and support schemes for example, may reach the suppliers by other routes and be charged to consumers via non-energy bill-related taxation.

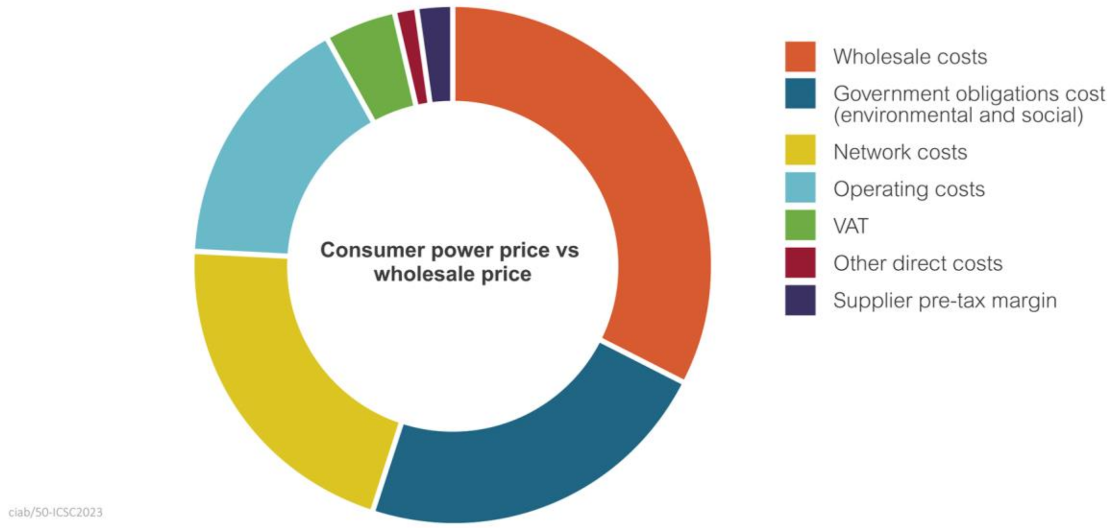


Figure 50 Breakdown of consumer power price versus wholesale price (Imperial College, 2023; Ofgem, 2021)

Government obligations include items like contracts for difference (CfD) schemes which provide price guarantees to new plant operators, often a fundamental part of the deployment of new technology. They do not include the costs of generators in complying with the emissions trading scheme, effectively a carbon levy, which would be included in the wholesale cost of power generation. Network costs include charges for balancing the system and system investments, which are rising significantly. The prices consumers pay vary by location, supplier, tariff type and other factors such as total consumption and type of system connection.

Figure 51 illustrates this across various European countries. 2019 was selected as it was prior to the unusual impacts of the recent gas price crisis, in order not to distort the data. It highlights the large variation in both prices paid, government and network charges. In contrast, the average wholesale European power price in the same period (trading market price) was around 40 €/MWh. The chart also shows the drop in prices in 2020 due to the impact on demand of the Covid-19 pandemic.

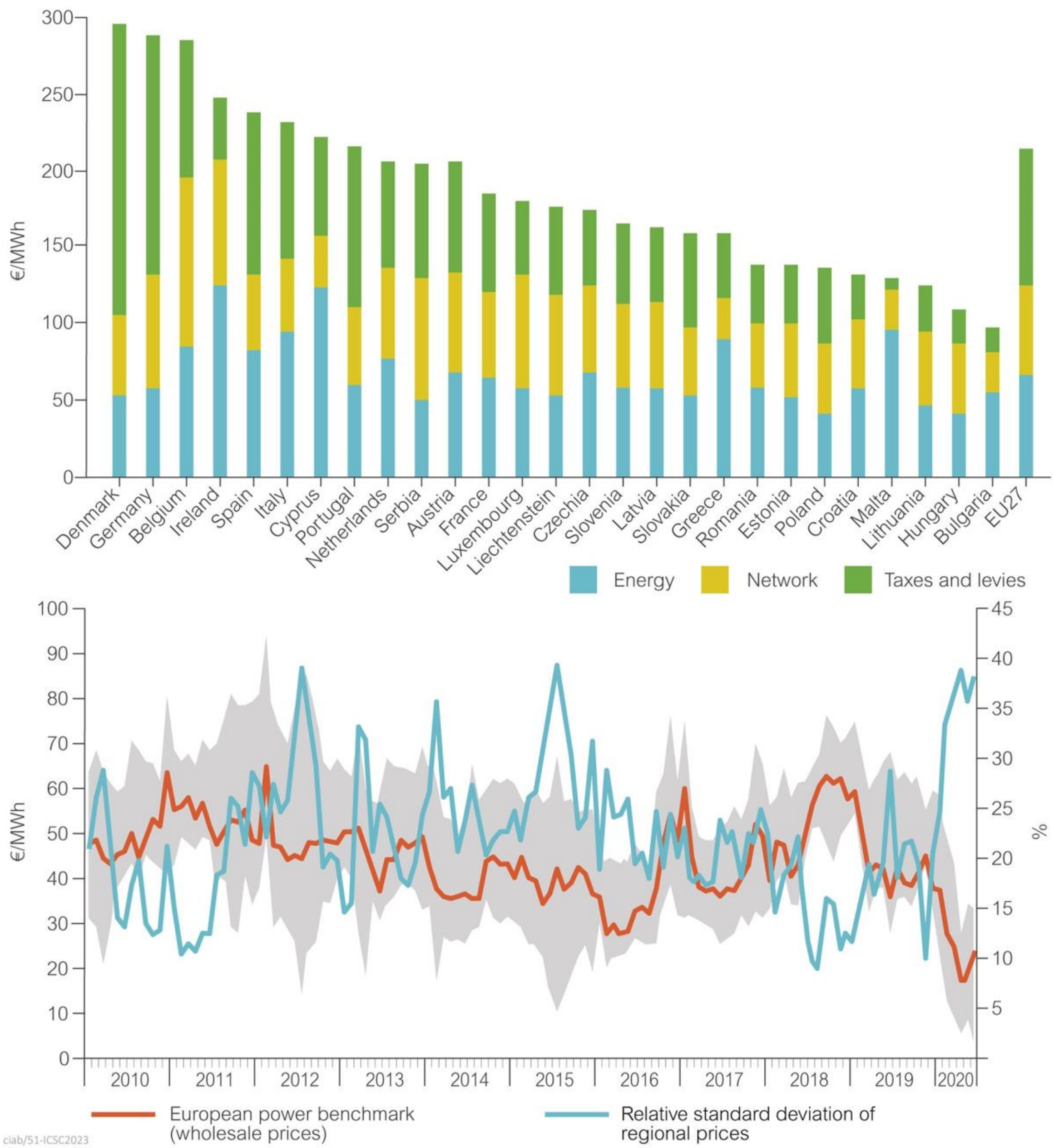


Figure 51 Household (2019) and wholesale electricity prices in the EU (European Commission, 2020)

The 'cost to whom', is therefore also a major consideration, whether it is cost to the power generator to build and operate, to the state, to the consumers, or to economies. Other indirect costs of energy do not appear in bills such as broader environmental or social impacts. Thus, there are many possible interpretations of 'cost' depending on the boundaries considered, which may be selected to present a favourable view for those recommending a particular option.

5.2.1 Direct asset cost components

Operational asset costs are typically separated into fixed and variable costs. Fixed and variable costs combined contribute to the direct costs for any operational asset of a given type. A summary of some of the broader direct technology choice-related cost categories is provided in Table 10.

TABLE 10	DIRECT COSTS ASSOCIATED WITH PROJECTS OF DIFFERENT TECHNOLOGY TYPES
CATEGORY	**COMPONENT**
Capital	Capital cost, Capex is the cost of procuring a new facility or installation. These costs are often quoted when comparing different techologies even though they do not represent all costs. In electricity systems Capex is usually expressed as €/MW or a similar unit.
Planning and project	Installation and construction of major infrastructure projects typically go through a long period of feasibility assessment, proposal writing, consultations, planning applications and approvals from a variety of bodies; tendering; construction management and commissioning. These planning and project costs and associated teams and consultants can be expensive, and involve many stakeholders, over many years.
Land	Purchase or lease of land and acquiring the rights to lay cables, pipes and install access is a cost. The extent of the ownership needed and over what area may be a significant cost or constraint to the viability of a project.
Finance	Projects require funding, usually involving borrowing and risk. This has its own costs, including the 'cost of capital', which is related to risk premiums, interest rates and economic outlook, markets and political stability and policy.
Operation and maintenance	Once the system is procured, built and commissioned there is operational expenditure, Opex, associated with the ongoing operation and maintenance of the facility. Control, monitoring, reporting, inspections, replacements and repairs, fuel, consumables, salaries, utilities, compliance and rent are in this category.
Incentives, taxes and subsidies	A range of other payments either impose a charge on, or provide an incentive for, construction and operation. This may include corporation tax, carbon taxes, emissions trading schemes, renewable levies, obligation payments, tariffs, tax breaks and incentives, capital allowances, subsidies, government funding arrangements and more. The impacts of these are often difficult to establish and vary widely by location and region, and point in time. A good example of this is carbon taxes which add a premium to the underlying cost of generation but vary widely globally.
Depreciation	Assets that have a value in the market reduce in value over time due to age and obsolescence and potential resale, reuse or recycling value.
Decommissioning	At the end-of-life assets need to be decommissioned and the land restored for other uses. The decommissioning costs of electricity assets vary widely but are often ignored in analyses. All technologies will require dismantling, recycling, land restoration, removal of underground and overground works and cables, and decontamination and any other necessary measures.

5.2.2 Asset attributes and operating environment

Costs associated with technology choices are not all technical, academic and predictable. They can be impacted by a range of real-world environmental and context effects and dependencies based on what already exists. The actual cost of future assets may therefore not be what is suggested by table-top calculations and models (*see* Table 11).

TABLE 11 COSTS ASSOCIATED WITH ASSET ATTRIBUTES AND OPERATIONAL ENVIRONMENT

CATEGORY	COMPONENT
Service life	All assets have a useful service life after which they must be replaced, which may differ from the original design life. In the context of understanding realised costs, the actual operating life is what matters. If an asset with a design life of 25 years runs for 50 years then the specific cost of output will drop. It is important to be realistic about the achievable operating lives of assets rather than making cost calculations based on design lives.
Utilisation	The utilisation load factor, or capacity factor, for an asset has a similar impact on cost to the design life and a large bearing on the apparent levelised costs of technologies. An asset with average output of 2% of rating will not have the same relative costs as one with 60% of rating even for exactly the same installation and technology. The lower the capacity factor of an asset the less it recovers investment and the more expensive it becomes on a levelised cost basis.
Efficiency	Efficiency impacts costs through both the design efficiency and the variation of that efficiency with off-design operation. Design efficiency is usually that of maximum continuous output. Operating efficiency is that achieved over the full range of operating conditions and could easily be less than half that of design conditions. In both cases efficiency will impact costs and feed into the levelised cost. Efficiency is directly linked to utilisation and so how an asset is deployed will effect the efficiency obtained irrespective of design. Where the use of one technology changes the use of another, it will incur a hidden cost due to changes in efficiency elsewhere.
Asset replacement	It is often possible to refurbish, upgrade, replant or extend an existing asset in order to improve efficiency, output, flexibility, environmental performance, remaining life or any combination of these. This may provide a route which is faster, cheaper, easier to permit, connect and integrate and makes best use of existing infrastructure, facilities, skills, supply chains and resources than a completely new asset in a new location. Most cost comparisons do not adequately explore these options.
Geopolitical	Increasingly there are unpredictable cost impacts and risks related to the type of assets and their fit into regional, national or international policies, strategies and targets. Risks and potential hidden future costs are also present related to geopolitical issues which may impact the prices of commodities or abililty to trade in critical raw materials, skills, parts and equipment. Such issues are emergent and although they may be significant are not easily predicted.

5.3 TECHNOLOGY COSTS

Relative technology cost is a fundamental consideration in future energy system analyses. Lazard, a long-established investment bank, undertakes research and generates market insights for publication. They publish an annual paper on the LCOE with Roland Berger, the international management consultancy. LCOE is discussed in more detail in Section 5.7. However, in concept it is a calculation methodology that seeks to take into account both the capital and operating costs of an asset or system over its useful life and to normalise these costs against the lifetime useful output of the asset. For electricity this results in a lifetime equivalent price per unit of electricity which can then be compared between technology options.

This section uses 2023 Lazard and Roland Berger data (Lazard, 2023). Any cost data should be taken only on the basis and context in which it was produced. The variability in cost data between organisations and time periods suggests that all such data sets are only approximations. There is no single cost or comparative table of options that conveniently provides an enduring ranking of options.

Rather, there is a range of costs for each option which often overlap and vary by location and point in time. Thus, cost rankings are only indicative unless calculated to a specific application at a specific point in time.

The Lazard data makes some correction to more basic LCOE values produced by other sources to bring costs closer to reality. Lazard (2023) note that even though some account is made for system cost, this is not exhaustive, and many costs are not explicitly included in their analyses. Such exclusions include: the impact of taxation arrangements; required network upgrades; connection issues; congestion and curtailment costs associated with location, which would include balancing and redispatch costs; systems side permitting costs; market redesign costs; environmental regulation compliance costs and associated charges. Also excluded are political, social and environmental externalities. The value of by-products like ash, gypsum and exported heat are also not included in the analysis which focuses only on electricity. The figures presented are based on the fuel price assumptions of Lazard and may differ for various regions, particularly for natural gas where a US figure of 5.96 €/GJ has been assumed.

It is also noted that the Lazard analysis appears to allocate firm capacity credits to wind and solar in these examples which are significantly higher than those declared by other system operators. This would increase the firming costs beyond those proposed by Lazard and widen the gap between new renewables and conventional technologies in favour of conventional technologies. The approach taken to firming estimation and cost addition for variable renewables by Lazard also appears to be optimistic, potentially underestimating the actual dispatchable generation requirement and cost. If this is true, then the firmed costs from Lazard would actually still be over-optimistic, presenting a more favourable case for VRE than would otherwise be the case.

Thus, the following discussion is a commentary based on publicly available and respected market costs analysis, although the focus of this report is more on the principles than the exact numbers.

5.3.1 Generation

The base set of Lazard cost comparisons for generation are shown in Figure 52. The data show a wide range of possible costs for all technologies. This means that the relative cost of a technology depends on the context and circumstances of that installation as much as on the technology itself. The data also show that renewable technologies cannot be assumed to be lower cost than conventional technologies.

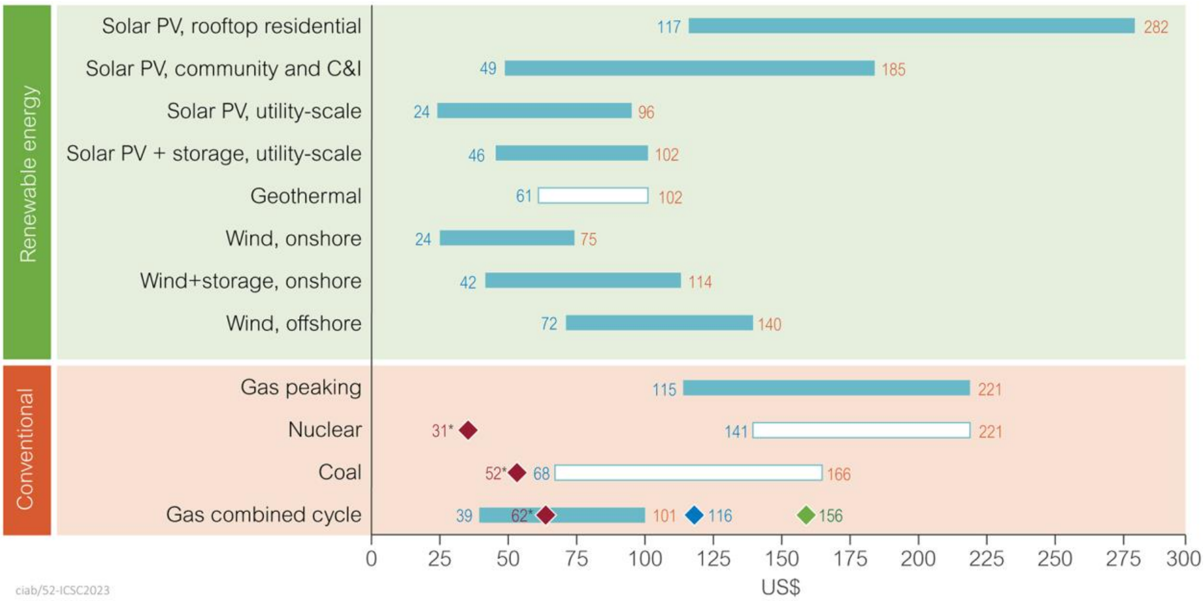


Figure 52 Unsubsidised levelised cost of new plant (excluding firming), $/MWh (Lazard, 2023)

The items in the chart marked (*) represent the unsubsidised marginal cost of operating existing depreciated coal, gas and nuclear assets at typical existing US capacity factors. These would vary with different capacity factors. The high end of the coal price illustrated includes installation of 90% carbon capture technology. The blue marker for gas plant assumed 20% hydrogen from fossil fuel with CCS and the green marker assumed natural gas with 20% low-carbon hydrogen blend. 100% hydrogen in gas turbines and ammonia cofiring in coal plants is not considered in this analysis but is discussed elsewhere (*see* Sections 4.5.5 and 4.6.1). Lazard (2023) also indicates that gas-peaking plants are relatively expensive. Rooftop solar PV can also be seen in this data to be a high-cost power generation option.

Figure 53 illustrates that existing asset costs fall well within the cost range associated with new solar and wind assets. The data suggest that either could be the cheapest depending on the specific installation in question with a wide range of cost ratios possible between new and existing assets.

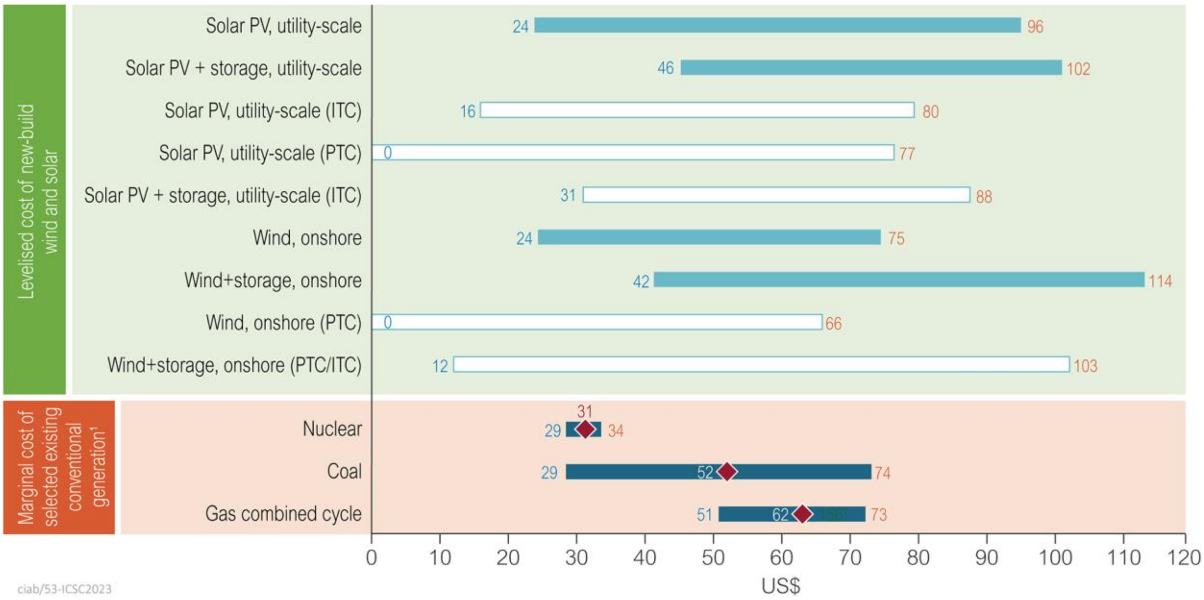


Figure 53 Levelised cost new renewables versus existing plants (excluding firming), $/MWh (Lazard, 2023)

Figure 54 shows that there has been a large reduction in the costs of wind and solar over previous years, particularly prior to 2012, but this decline has slowed. For the first time in 17 years of analyses, the data show an increase in the costs of new solar and wind installations. These may well continue to increase due to rising demand and supply chain issues as well as prevailing macro-economic conditions (Jacob, 2022).

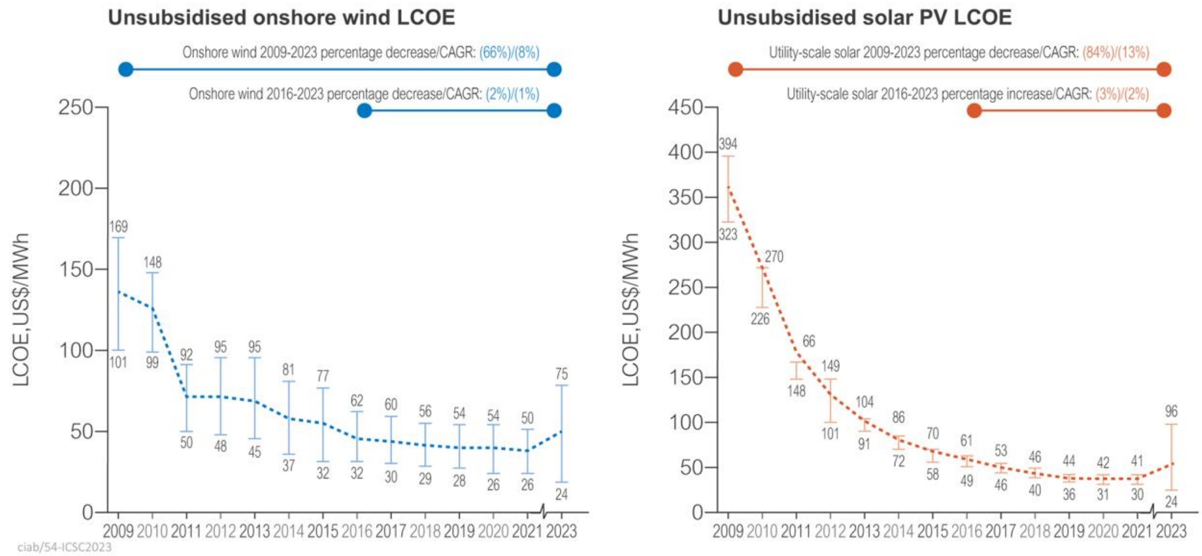
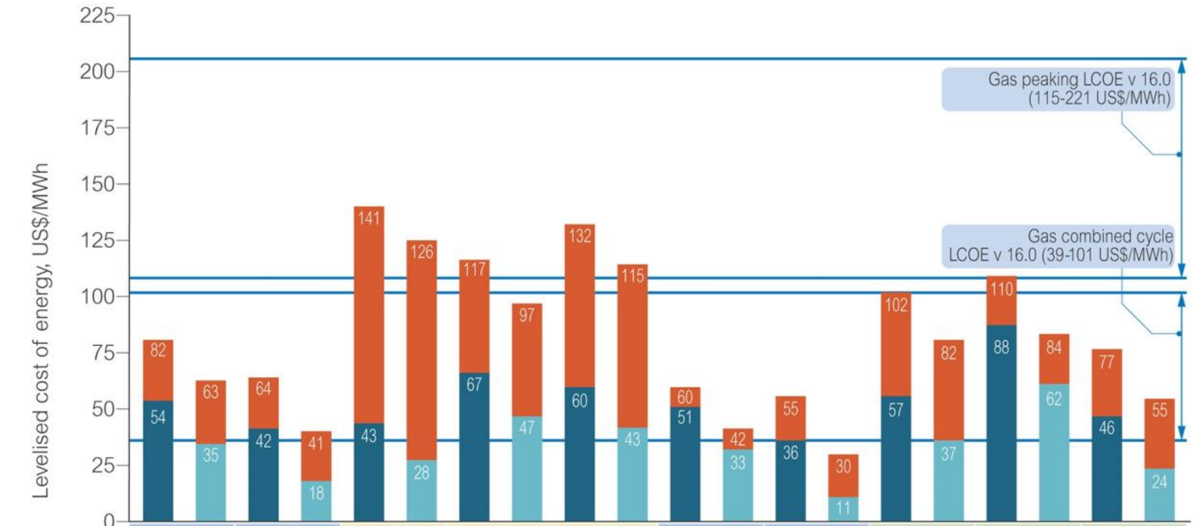


Figure 54 Unsubsidised onshore wind and solar PV costs trend (excluding firming) (Lazard, 2023)



	Solar	Wind	Solar	PV+storage	Wind	Solar	Wind	Solar	PV+storage	Wind
ELCC	50%	16%	7%	51%	15%	85%	17%	38%	70%	15%
Capacity factor	20%	43%	25%	25%	30%	21%	50%	19%	19%	39%
Resource penetration	3%	25%	32%	32%	19%	1%	56%	5%	5%	7%
	MISO		CASIO			SPP		PJM		

Figure 55 Adjustment of cost of technologies for subsidies and firming, USA example (Lazard, 2023)

Figure 55 illustrates some of the difficulty of cost comparisons, particularly the costs of VRE technology with respect to system impact. An attempt was made to estimate the additional cost of firming intermittent and variable resources to provide value to the grid. This was achieved by considering the average cost of new capacity required in parallel to firm the VRE capacity in accordance with Lazard's methodology. Selected solar and wind options are presented for each of four network regions of the USA (MISO, CAISO, SPP and PJM).

This illustration shows that the difference between subsidised cost, in blue, and unsubsidised cost including firming cost, is substantial. Across the range of cases presented, the difference between the unsubsidised firm cost and the subsidised cost alone is a factor of around 2.8. In many cases, it is significantly cheaper to build new CCGT plant than to deploy wind and solar resources with the actual, plus firming, costs being cheaper in 50% of cases presented and the low end of the new CCGT price, less than all wind and solar cases. The data also show problems comparing costs where actual unsubsidised costs, subsidies and cost of firming vary between grid regions. This is a good example of the complexities of analysis and the dangers of making assumptions based on oversimplified data.

From Figure 55 the levelised cost of production of an existing coal plant retrofitted with CCS can be estimated to be approximately in the range 104–149 $/MWh, 127 $/MWh average, compared to the stated upper bound figure for new coal with CCS of 166 $/MWh. Taking averages from data for the US network regions it seems that firming multiplies unsubsidised cost of solar by 1.87 and wind by 1.78, approximately 1.8 overall. Applying a firming factor of 1.8 to the mean values of levelised cost from Figure 52 results in Figure 56.

	Subsidised cost US$/MWh	Unsubsidised cost US$/MWh	Unsubsidised cost with firming (UCF) US$/MWh	Relative UCF cost vs existing coal	Relative UCF cost vs existing coal with CCS	Relative UCF cost vs new coal with CCS
Existing coal	52	52	52	1.00	0.41	0.31
Existing coal with CCS	127	127	127	2.44	1.00	0.77
New coal with CCS	166	166	166	3.19	1.31	1.00
Utility solar PV	33.3	60	108	2.08	0.85	0.65
Utility onshore wind	24	49.5	89.1	1.71	0.70	0.54
utility offshore wind	–	106	190.8	3.67	1.50	1.15
Gas peaker	168	168	168	3.23	1.32	1.01
Residential rooftop PV	-	199.5	359.1	6.91	2.83	2.16

*Firming has not been applied to the two storage technologies since it has been assumed they are being used for firming. If they were being used as capacity then an additional firming factor would need to be applied.

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Figure 56 Comparison of calculated relative levelised costs for selected technology options, $/MWh

These data now show that building new renewable assets and decommissioning existing conventional plants is not the cheaper option, since the replacements will be approximately 2–4 times more costly on a firmed $/MWh basis. This contrasts with the simple costs which might suggest they are, being over 50% cheaper based on subsidised LCOE, excluding firming. It also suggests that new gas-peaking plants are an expensive option.

5.3.2 Storage

The costs of energy storage are sensitive to the assumed mode of operation. In most cases, storage systems are designed for a ‘stack’ of income streams (*see* Section 3.6.5), with a focus on the frequency of charge and discharge cycles to ensure payback. Systems which cycle half as often will have half the opportunity to earn revenue and therefore be more costly on a levelised basis. Therefore, the cycle frequency for storage systems is analogous to the capacity factor for power generation plant. The total capacity of a storage facility also has a significant impact on cost which is non-linear. Figure 57 illustrates this point, showing a potentially large variation in costs resulting from changes to these parameters.

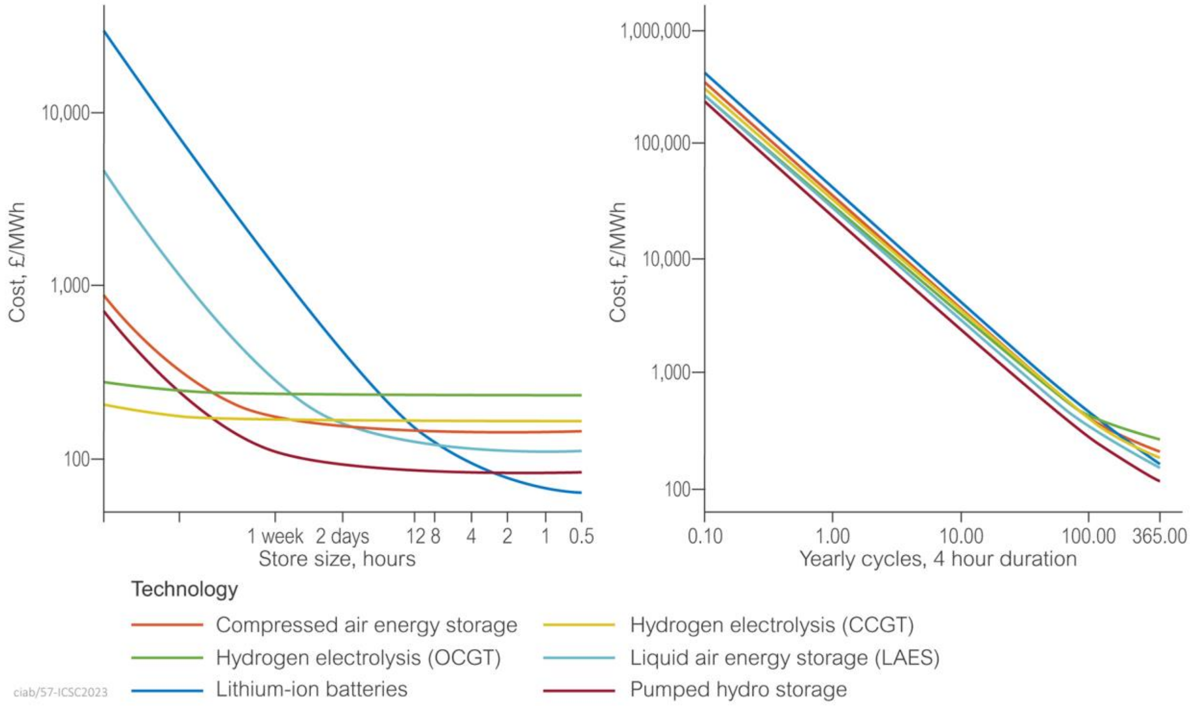

Figure 57 Impact of store capacity and use cycles on cost (Energy Systems Catapult, 2022)

As noted in Section 4.5.5, storage systems have both a power capacity and a total storage capacity. There is a trade-off and impact of cost between the peak MW capacity and the total MWh storage facility which needs to be considered as grid connection costs could be affected.

Lazard (2023) has also undertaken analysis of the levelised costs of storage (LCOS). Similar exclusions apply to the cost data as discussed in Section 5.3.1. The analysis does not include resource extraction, end-of-life disposal, or safety hazards. Lazard considers the dominant market players of batteries using lithium iron phosphate (LFP) and lithium nickel manganese cobalt oxide (NMC) chemistries, but not all forms of storage. The various use case analyses are outlined in Figure 58.

In front of the meter	1	Utility scale (standalone)	• Large scale energy storage system designed for rapid start and precise following of dispatch signal. Variations in system discharge duration are designed to meet varying system needs (such as short-duration frequency regulation, longer-duration energy or capacity) – To better reflect current market trends, this report analyses one, two and four hour durations
	2	Utility scale (PV + storage)	• Energy storage system designed to be paired with large solar PV facilities to better align timing of PV generation with system demand, reduce curtailment and provide grid support
	3	Utility scale (wind + storage)	• Energy storage system designed to be paired with large wind generation facilities to better align timing of wind generation with system demand, reduce curtailment and provide grid support
Behind the meter	4	Commercial and industrial (standalone)	• Energy storage system designed for behind-the-meter peak shaving and demand charge reduction for C&I users – Units often configured to support multiple commercial energy management strategies and provide optionality for the system to provide grid services to a utility or the wholesale market, as appropriate, in a given region
	5	Commercial and industrial (PV + storage)	• Energy storage system designed for behind-the-meter peak shaving and demand charge reduction for C&I users – Systems designed to maximise the value of the solar PV system by optimising available revenue streams and subsidies
	6	Residential (standalone)	• Energy storage system designed for behind-the-meter residential home use – provides backup power and power quality improvements – Depending on geography, can arbitrage residential time-of-use (TOU) rates and/or participate in utility demand response programmes
	7	Residential (PV + storage)	• Energy storage system designed for behind-the-meter residential home use – provides backup power, power quality improvements and extends usefulness of self-generation (eg PV + storage) – Regulates the power supply and smooths the quantity of electricity sold back to the grid from distributed PV applications

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Figure 58 Use case descriptions for LCOS analysis (Lazard, 2023)

Storage systems are often compared using metrics of power, peak output, energy capacity and total energy stored. The discussion here is confined to capacity, $/MWh and it is assumed that the power is adequate for the required purpose.

As seen earlier the apparent cost of storage is also influenced by subsidies. The costs shown include the average charging cost for standalone systems but not for the hybrid systems, including own generation. Figure 59 indicates costs of utility-scale 4-hour, 100 MW battery storage in the range 200–257 $/MWh for the scenario used, average 229 $/MWh and residential standalone storage in the range 1215–1348 $/MWh, average 1282 $/MWh, again for a 4-hour duration system with 6 kW power rating.

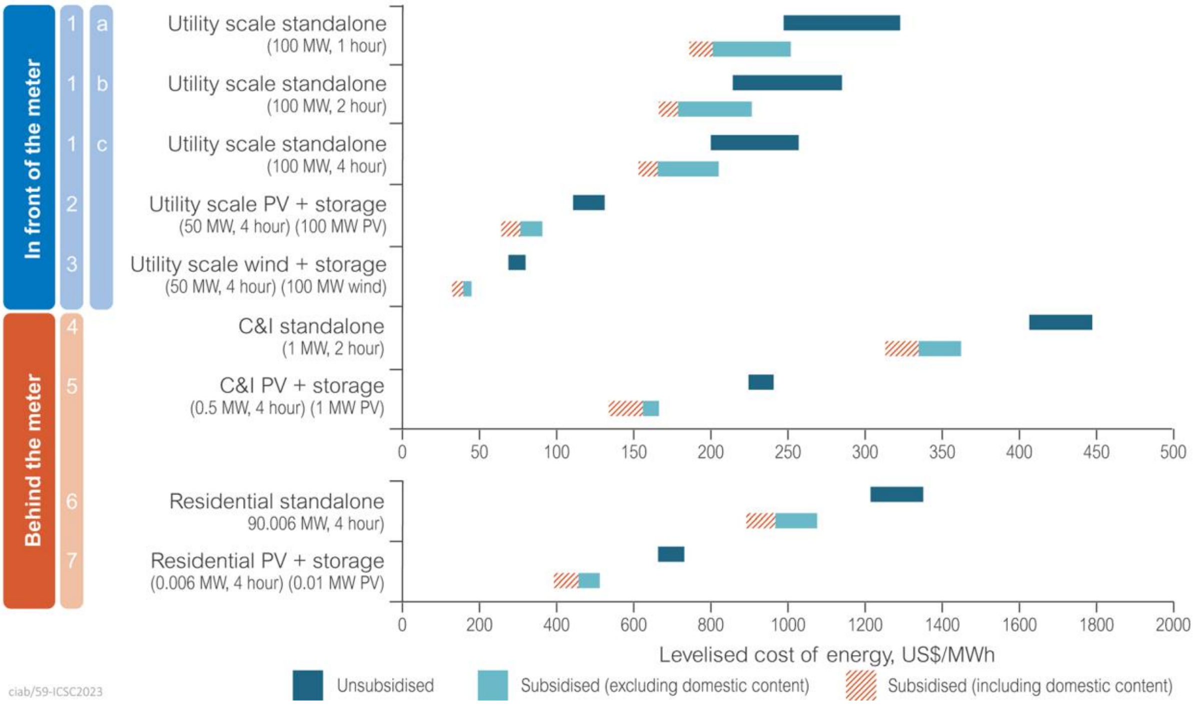

Figure 59 LCOS analysis of various storage application cases (Lazard, 2023)

The data indicate that behind the meter, domestic, commercial and industrial systems are significantly more costly for supply than utility-scale systems, by a factor of about 5.6 in this example. This is to be expected given normal considerations of economies of scale for technology installations.

Figure 52 showed the upper bound for new coal including 90% CCS was 166 $/MWh. This suggests that energy from a 4-hour stand-alone utility-scale battery storage would be nearly 40% more costly than this, even excluding consideration of the wider system value offered by a large utility-scale thermal plant. Assuming from the prior example 127 $/MWh for existing coal retrofitted with CCS, the battery would be 80% more costly and behind-the-meter storage would cost ten times more. Storage cost data can be used to modify Figure 56 to include the cost of power from utility and residential storage for comparison with the central generation options. The results are shown in Figure 60.

	Subsidised cost US$/MWh	Unsubsidised cost US$/MWh	Unsubsidised cost with firming (UCF) US$/MWh	Relative UCF cost vs existing coal	Relative UCF cost vs existing coal with CCS	Relative UCF cost vs new coal with CCS
Existing coal	52	52	52	1.00	0.41	0.31
Existing coal with CCS	127	127	127	2.44	1.00	0.77
New coal with CCS	166	166	166	3.19	1.31	1.00
Utility solar PV	33.3	60	108	2.08	0.85	0.65
Utility onshore wind	24	49.5	89.1	1.71	0.70	0.54
utility offshore wind	–	106	190.8	3.67	1.50	1.15
Gas peaker	168	168	168	3.23	1.32	1.01
Residential rooftop PV	–	199.5	359.1	6.91	2.83	2.16
Utility storage 100 MW, 4h	204.5	229	229	4.40	1.80	1.38
Residential 6 kW, 4h	982.5	1282	1282	24.65	10.09	7.72

ciab/60-ICSC2024

Figure 60 Relative calculated levelised cost for selected technology options including battery storage, $/MWh

A broader comparative analysis of energy storage technologies has been published by the USDOE (Viswanathan and others, 2022) and the summary is illustrated below for reference.

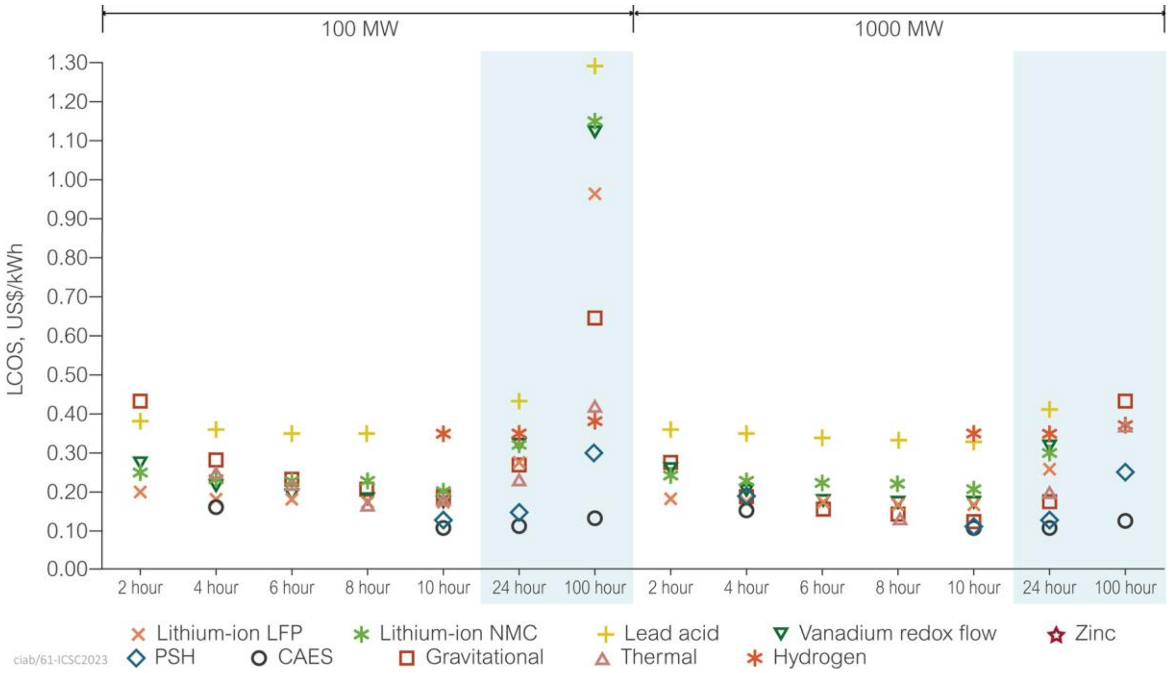

Figure 61 Comparison of estimated LCOS by technology, capacity and duration (Viswanathan and others, 2022)

Figure 61 confirms the known assumption and market observation that batteries are more cost-effective for short-duration storage and that compressed air or pumped hydro are more economical for longer-duration storage. It also shows the 100 MW 4-hour lithium-based battery costs around 190 $/MWh, within the range of the subsidised Lazard data of 154–205 $/MWh.

Work by the Royal Society on the UK energy system, based on analysis of 37 years of real weather data concluded that, for its current, nominally, 60 GWe peak 330 TWh/y system, 100 TWh of long-term energy storage would be needed in 2050 to support a high renewable energy net zero scenario (Royal Society, 2023). This is around 5000 times larger than the largest pumped hydro facility in the UK and approaching one-third of the current total national annual demand. This forecast takes considers likely increases in demand growth due to the electrification of the economy over that period and what would be required to be stored for periods extending into years in order to ensure security of supply.

5.4 'SYSTEM' COSTS

Thus far, the costs associated with the generation assets only have been considered. However, there are additional considerations when considering the relative costs of technologies.

Transmission and distribution

The backbone of the electricity system is the high voltage transmission network which needs to maintain a stable core of power to the system. At lower voltages, networks become increasingly granular and complicated as power is distributed to all users. This system network needs to be built, operated and maintained, at a cost. Usually, this cost is 'socialised' across the users of the system in the form of transmission and distribution use of system charges.

Losses

A small proportion of energy is lost in the passage of power from the generator to the user across the systems. The loss is typically around 6–7% in total for power systems in the developed world. There is also a small loss due to theft which in most places is insignificant. The cost of these losses will also appear in the prices paid by consumers.

5.5 INTEGRATION COSTS OF VRE

5.5.1 Connection

All generators require connection to the system, which has a cost. VRE systems have far more connections than large central generation assets. Historically, large central generation plants may have had a capacity of 2 GW per location. Assuming 2 GW central plant was replaced by 1 GW of wind at 25% capacity factor, 4 GW installed total and 1 GW of solar at 10% capacity factor, 10 GW installed total and that the wind and solar farm sizes were 200 MW and 50 MW each, then instead of one connection to the system, 220 would be required. This highlights not only the huge increase in connection costs, but also the increased effort and time required in their planning and implementation.

If storage is included to smooth the intermittent nature of VRE then the number of connections increases. Hypothetically, if 20% of the 2 GW VRE capacity was time-shifted within a day, 9.6 GWh, then 48 battery storage facilities of 200 MWh would be needed, bringing the total connections to 268. If backup power plants are still required to provide electricity during periods of high demand when the weather is cold, dark, calm or still, for example, then they will also need connections to the system. Therefore, the total number of connections to the system required to enable a VRE-based architecture is far higher than in a centralised generation scenario.

5.5.2 Curtailment

Excess capacity of VRE as a solution to its variability leads to an additional issue. When generation conditions are favourable, they can provide more energy than the system requires. In the absence of demand to absorb it, this excess must be curtailed. This means that plants able to generate are forbidden to do so, to protect the electricity system. Such curtailment incurs a cost to the system operator and therefore the wider economy. The higher the share of VRE in the total mix, the higher the frequency and magnitude of curtailment and cost. Paying power plants not to operate is an additional cost burden. Curtailment can be problematic even for a relatively small share of VRE as a percentage of peak system capacity and is most prominent during periods of low seasonal demand.

In the UK where wind energy contributes about 25% to the system's total supply, the system operator already incurs high curtailment costs, expected to increase fourfold by 2030 (National Grid ESO, 2022b). This is due to the variability of the resource and the location relative to demand and the capabilities of the installed network. Thus, curtailment can be necessary while at the same time, additional reserve capacity may be brought online at high cost to satisfy demand in the region which cannot be served by the VRE.

5.5.3 Distances and reinforcement

Renewable sources are often in remote locations. Network costs to connect these locations and transmit the energy to where it is needed can therefore be high, both capital and operational. The distances involved may be so great that HVDC is the most economic option for these connections. Connections and lines may also need to be routed through many different properties, requiring extensive planning, consultation and negotiation.

Even if the distances are not large, the connection point to the main system needs to be able to support the new in-feed. If the original system was not designed for this, then reinforcement may be needed for a major influx of power at those locations. In the absence of such reinforcements, output from the new capacity may become constrained by the system's ability to absorb and distribute it.

Although these costs are not directly associated with the technology used, they are attributable to the technology choice.

The IEA (2023) concluded that 80 million km of new and refurbished grids will be required between now and 2040 to meet climate change mitigation ambitions, the equivalent of the entire current global grid. In addition, around half of the existing grids will need to be replaced by that time. The report outlines expansion plans for various countries, summarised in Table 12.

TABLE 12 GRID EXPANSION PLANS OF SELECTED COUNTRIES (IEA, 2023)

Country and horizon	Expansion capacity	Investment	Methodology factors
USA By 2030, 2035 and 2040 (National Transmission Needs Study 2023)	Regional transmission: 47,300 GW-mi (2035), 115,000 GW-mi (2040) Interregional capacity: 157 GW (2030) 655 GW (2040)	The highest is Larson and others $2,210 billion with a 98% clean energy share in 2050	Expansion modelling studies by certain institutions Congestion, voltage limit, stability limite, thermal limit Others: adequate clean energy, curtailent, resilience, electrification and non-wire alternatives
European Union 2025-2040 (TYNDP 2022)	TYNDP (mainly cross-border) 88 GW; 18,000 km (AC) 25,000 km (DC)	TYNDP (mainly cross-border) €140 million ($147 billion) REPowerEU (full grid) €583.8 billion ($614 billion) by 2030	1. Scenario building, 2. System needs study, 3 CBA (zone clustering, climatic year) Sustainability criteria (such as renewables integration, CO_2)
Japan Toward 2050 (Master plan)	Interregional: 14 GW (Eastern), 2.8 GW (Western), 2.7 GW (FC) Interregional: N/A	Interregional: JPY 6–7 trillion ($46–53 billion)	Interregional: CBA (fuel cost, GHG cost, adequacy, loss etc) Interregional: revenue cap (reliability, peak demand, paper flow, N-1)
China 2025 (14th Five-Year Plan) 2030	Interprovincial, to 2025: 60 GW Interregional and interprovincial 2025-2030: 70 GW	CNY 2.4 trillion ($356 billion) (SGCC 2021-2025) CNY 0.67 trillion ($99 billion) (CSC 2021-2025)	System cost analysis based on geographical allocation of resources (such as clean energy bases) and different scenarios for demand forecast. Planning done at the provincial and national levels
India 2022-2027 (NEP Volume-II Transmission, 2019)	Interregional: around 60 GW	N/A	Consider certain criteria (such as N-1, thermal ratings, voltage ratings) Surplus/deficit (for long term)
Brazil 2023-2032 (PDE 2032)	41,000 km, 120,000 MVA	BRL 158.3 billion (Brazilian Real) $31 billion	The plan considers the economic aspect and technical aspect to compare with alternatives
Korea 2022-2036 (10th BPLE 2023)	35,190 C-km (2021)->57,681 C-km (2026) 348,580 MVA (2021)->517,500 MVA (2036)	N/A	N/A
Indonesia 2021-2030 (RUPTL 2021)	47,723 km 76,662 MVA	N/A	Consider some criteria (N-1), regional substation and transformer needs, demand, land use) to meet Indonesian and international standards
Australia 2022-2050 (2022 ISP)	10,000 km (Step Change Scenario as a central scenario)	AUS$12.7 billion (scenario weighted) ($9 billion)	Scenario building Modelling analysis CBA analysis

Notes: CBA = cost benefit analysis; C-km = circuit kilometres, CSG = China Southern Grid; FC = frequency converter; FYP – Five-Year Plan; GHG = greenhouse gas; GW = gigawatt-miles (1 mile = 1.61 km); MVA – megavolt amperes; SGCC = State Grid Corporation of China; TYNDP = Ten Year Network Development Plan; NEP = National Electricity Plan; PDE = Ten Year Energy Expansion Plan; BPLE = Basic Plan for Long-Term Electricity Supply and Demand; RUPTL = National Electricity Supply Business Plan; ISP = Integrated System Plan; N/A = not available

Wind and solar power generation was added at a share of some 40% over the last two decades but is forecast to be 80–90% over the next two decades which will impact connection requirements. Failing to deploy grids at the scale and pace required would lead to a substantial increase in CO_2 emissions relative to targets, putting climate ambitions at risk and increasing dependency on natural gas (IEA, 2023d).

MODERN AND DIGITAL GRIDS ARE VITAL TO SAFEGUARD ELECTRICITY SECURITY DURING CLEAN ENERGY TRANSITIONS
(IEA, 2023)

5.5.4 System impact and mitigation

A range of mitigations are necessary to incorporate VRE smoothly into the system whilst ensuring reliability, stability and affordability.

First, there is a fundamental requirement to ensure sufficient power can be dispatched to the system to meet demand when VRE output is low. This requires the provision of adequate energy storage and dependable backup generation capacity. Both storage and low-capacity factor backup generation are specific costs attributable to the VRE use but are generally not included in the stated costs of VRE as a technology choice.

In addition to ensuring sufficient capacity, power system resilience and power quality must be addressed. Sufficient synthetic and physical inertia needs to be available on the system to ensure resilience and stability. This means that for periods of high VRE operation, additional grid-forming inverter technology and synchronous compensators will need to be deployed in sufficient numbers and capacity to satisfy the system requirements formerly provided inherently by large thermal generation systems. These systems are required for providing fast response injections of power which currently installed VRE typically is not able to provide. These are additional costs to the system and are seldom included in cost analyses (ESIG, 2022).

System operators will manage more individual generators than previously due to the lower average capacity plus the large number of storage facilities that will be required. High levels of curtailment will be needed in times of surplus and high levels of re-dispatch will be needed due to the non-dependable nature of VRE sources in times of high demand. These all incur additional system costs.

For markets to be able to accommodate and manage the large number of additional components required and to do so in a smart and dynamic way while maintaining cost effectiveness and competition, it is likely that large scale market reforms will be needed. Such market reform changes are typically long and costly processes involving a high level of stakeholder engagement, consultation and alignment. In the past, they have also included mechanisms and subsidies which support more expensive technology introduction or added complexity.

5.5.5 Integration of VRE

Thus, the inclusion of significant and increasing shares of VRE into any power system will incur major additional costs associated with:

- Number of new connections;
- Location and distances of new connections relative to demand centres;
- Provision of huge capacities of energy storage;
- Provision of flexible, low-capacity factor backup generation for extended calm and dark periods;
- Provision of sufficient new system inertia and fast frequency response capability;
- Generation curtailment;
- Far higher levels of operational re-dispatch; and
- Fundamental market reforms and new mechanisms.

These costs are in addition to the basic levelised cost of VRE technology based on simple Capex and Opex. Even though significant, these costs rarely appear explicitly in the literature.

Integration costs can be location and project specific and complex to estimate. Figure 62 from the OECD illustrates the relative costs of system integration across a selection of technologies and how those costs depend on the scenario, increasing the more VRE is deployed (Watt-Logic, 2023).

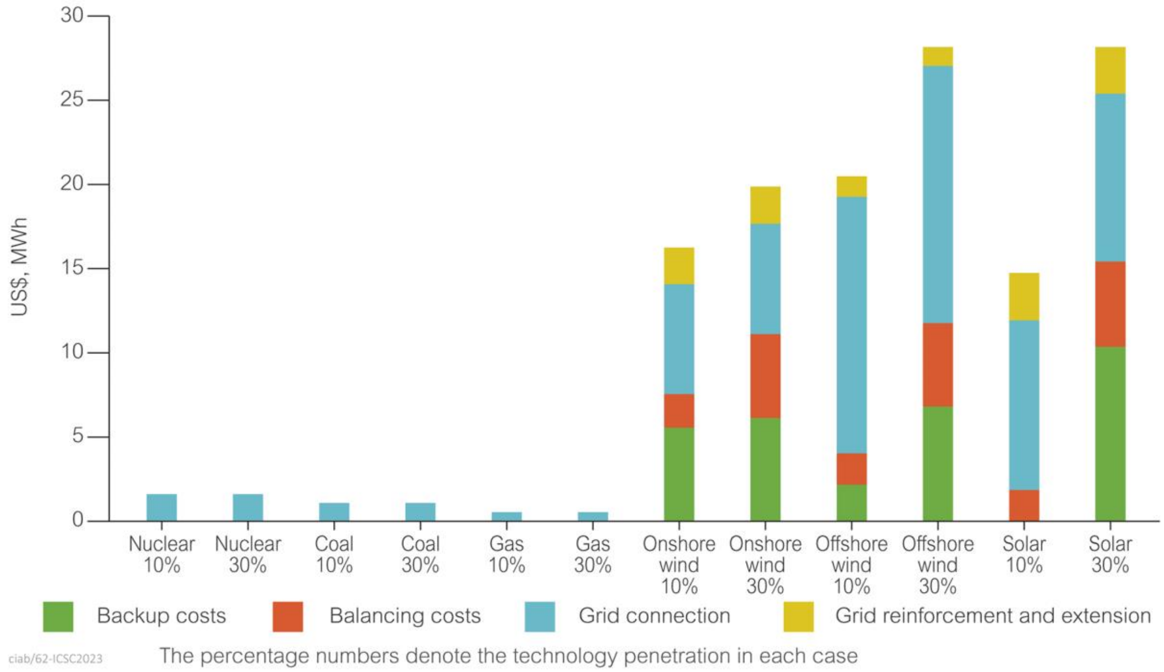

Figure 62 Grid-level system integration costs of technologies in the USA (Watt-Logic, 2023)

5.5.6 Transparency

Costs need to be understood, planned for and communicated, so they can flow into the necessary calculations to derive system designs that are practical and deliverable at the lowest cost. The waiting lists for new grid connections, spare parts, concern over raw materials availability, skilled workers and budgets indicate an escalation of new connections and lack of availability to meet aspirations (S&P Global, 2022a; Mooney, 2023; Conference Board, 2023).

The fact that costs are not single values but overlapping ranges that vary by location, context and point in time is key to appreciating the complexities of system options. Information about the full relative costs of policy choices and incentive schemes on consumer prices also needs to be transparent to avoid a total lack of association between consumer cost and supplier cost.

In reality, generation assets are added and subtracted from an existing system of a given composition. The benefit or detriment caused by each incremental change varies depending on the starting point. This must be considered in system models evaluating energy transition. This applies not only to the operational and capacity characteristics of the grid but the total cost implications.

5.6 OTHER INDIRECT COSTS

Although many cost components can be attributed to specific assets, processes or systems, some costs related to the energy system and transition are less transparent.

5.6.1 Inflation of goods and services

The cost of energy not only impacts the competitive position of industries but feeds directly into inflation through the prices of goods and services to consumers. Consequently, any decisions which raise the overall cost of the electricity system will tend to decrease the competitiveness of industry and increase inflation. This effect was seen during the energy cost escalation precipitated by Russia's invasion of Ukraine, resulting in elevated gas and electricity prices and an increase in inflation in 2021-2023.

5.6.2 Government support schemes

Direct government support is not typically recognised within the normal market and billing processes. Grants, credits, tax allowances, subsidies and state aid, may all be direct to certain companies or projects or demonstrations. Such costs are therefore not itemised in energy bills but will be seen by consumers in their general economic impact since they will effectively be paid for from taxation or government borrowing.

5.7 BASES OF COST REPRESENTATION

Comparing electricity system costs is complex, a non-linear problem with many interactions making analysis involved, usually leading to a broad range of simplifications and assumptions. At the end of this process, a range of numbers are produced which need to be compared with sensitivity and scenario analyses carried out to see how robust they are to change. Even assuming a single number could come out of analysis what would be the basis on which it is represented? This section considers that in more detail, specifically with respect to LCOE.

5.7.1 Levelised cost of electricity

Capital cost and operating cost are familiar cost elements, but they do not mean much on their own. It is not easy to compare generation assets with different capacity outputs and ratios of capital to operating cost. A 'levelised cost' therefore takes into account both the capital and operating costs of the asset or system over its useful life and attempts to normalise all costs against the lifetime useful output of the asset.

LCOE, sometimes called levelised cost of energy, is relatively simple to calculate, quick, convenient and useful. It is therefore commonly used expressed as €/MWh (or $/MWh) produced. For LCOE care needs to be taken to understand if the value applies to power, heat, or both. In its simplest form, the formula can be represented as:

$$LCoE = \frac{Initial\ investment\ Cost + \sum_{1}^{n} Annual\ operating\ cost}{\sum_{1}^{n} Annual\ electricity\ production}$$

Where n is the number of years lifetime of the asset.

Levelised cost can be a useful metric, but the context of its use needs to be considered. It assumes the costs of everything associated with the entities being compared, other than the capital and operating costs, are the same. When applied to power generation options this means assuming that the plants are in the same location, with the same grid connection and with the same impacts on the wider system. This may be similar between some technologies, but it is clearly different for others. Comparing the LCOE of a natural gas and coal power plant may be valid but comparing the LCOE of a coal and solar power plant is not as they do not provide the same services and utility, or value, to the system. Therefore, there is no direct cost comparison. This means a comparison of LCOE would not provide a true comparison of the overall costs of delivery, only the localised asset production costs on a simplified basis. See the discussion on generation and storage cost in Sections 5.3.1 and 5.3.2 where incorporating even a limited part of the external costs can be seen to change conclusions drawn from such numbers.

LCOE represents the break-even power price (cost per unit of electricity) an owner would need for investment in that option to break-even, rather than a reflection of the value, or overall cost of that solution to the market when considering the wider system, societal and economic costs, or the costs that consumers would bear.

LCOE values do not represent a sound basis for comparison of total cost unless the boundary is extended to include the total system. It is only a fair comparison where the other cost impacts beyond the boundary considered for the calculation are identical.

However, LCOE indications may encourage investors and owners to build plants with the lowest LCOE in a given market. This is because LCOE reflects the costs to themselves quite well, even if it does not reflect the cost to the system as a whole. This problem could be rectified by apportioning the system costs of an asset to that asset, at both construction and during operation, such that those costs would be felt by the operator and included in their LCOE calculations. Normal practice however is to socialise those costs across all users and consumers of the system.

Theoretically, it is possible for a technology to, at the same time, appear to be the cheapest from a simple LCOE perspective whilst also being the most expensive to the broader system and consumers.

5.7.2 Variations of form

Within the broad definition of 'LCOE' there are many variations on how the calculation is performed, the inclusions and exclusions, the processing of the values and the assumptions made in estimating output, income and costs.

One differentiation might be in the investment required. In many instances, this may be considered as capital cost, but it should include the total lifetime investment, such as any additional capital costs and decommissioning costs, waste recycling and disposal and returning land to its original state.

Additionally, the costs may reflect incentives, levies, taxes and similar which can make a significant difference to the economic viability of a project. It is important to understand if these are included and at what rate and period so that the impacts of policies and transient circumstances can be better understood. Plants receiving credits or penalties based on policy, rather than actual cost, will have distorted LCOE values. Similarly, if constraints or mandates apply to outputs then these should be made explicit.

Another modification is to apply discounting to the values in the equation to reflect the time value of money. This practice is common for LCOE calculations and results in the expression using net present values (NPV) rather than overnight costs. When the NPV of a project is zero the project's internal rate of return (IRR) is equal to the discount rate, or:

$$NPV_{project} = NPV_{revenues} - NPV_{costs} = 0$$

- The basic formula from Section 5.7.1, including splitting the operating cost into its fixed and variable components, then becomes more like the form commonly used by the UK Department for Business, Energy and Industrial Strategy (BEIS, now the Department for Energy Security and Net Zero, DESNZ) (Aldersey-Williams and Rubert, 2019).

$$LCOE_{BEIS} = \frac{NPV_{Costs}}{NPE} = \sum_{t=1}^{n} \frac{C_t + O_t + V_t}{(1+d)^t} / \sum_{t=1}^{n} \frac{E_t}{(1+d)^t}$$

Where: t is the period from year 1 to n, Ct the capital (and decommissioning) cost in period t, Ot is the fixed operating cost in period t, Vt the variable operating cost (including or excluding other incentives and taxes) in period t, Et is the electricity supplied in period t, d is the discount rate applied and n is the year of operation.

Simple levelised cost of energy

The USDOE's National Renewable Energy Laboratory (NREL) defines LCOE in terms of the annual cost of energy using the following formula to derive the Simple Levelised Cost of Energy (sLCOE):

$$sLCOE = \quad LCOE_{NREL} = \frac{C_o{}^*CRF + O}{8760^*CF} + f^*h + V$$

and

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

Where: C_o is the overnight capital cost, O the fixed operating cost, CF the capacity factor, f the fuel cost, h the heat rate, V the variable operating cost, I is the interest rate and n is the number of repayments to pay back the capital.

Here an annuity-based capital cost recovery factor is included. The purpose of this equation is to calculate the minimum price at which energy must be sold for an energy project to break even.

Total cost of energy

Total cost of energy (TCOE) is a variation on LCOE that tries to build in the cost of financial return with an annuity formula based on the whole project life. It assumes capital cost is financed by an annuity.

$$TCOE = \frac{\sum_{t=1}^{n} C_t + O_t + V_t + F_t}{\sum_{t=1}^{n} E_t}$$

Where: F_t is the cost of financing during each year.

This metric is, however, not consistent with conventional LCOE calculation where costs are discounted.

Levelised avoided cost of electricity

Levelised avoided cost of electricity (LACE), used by the US Energy Information Administration (EIA), weighs the relative costs of generating electricity from one source against another by using the avoided cost of the alternative energy source.

$$LACE = \frac{\sum_{t=1}^{Y}(marginal\ generation\ price_t * dispatched\ hours_t) + (cap\ payment * cap\ credit)}{annual\ expected\ generation\ hours}$$

LACE does not include external costs or other grid service values like services and flexibility. Since the calculation requires knowledge of marginal generation price, some detailed market modelling is needed (*see* Figure 63).

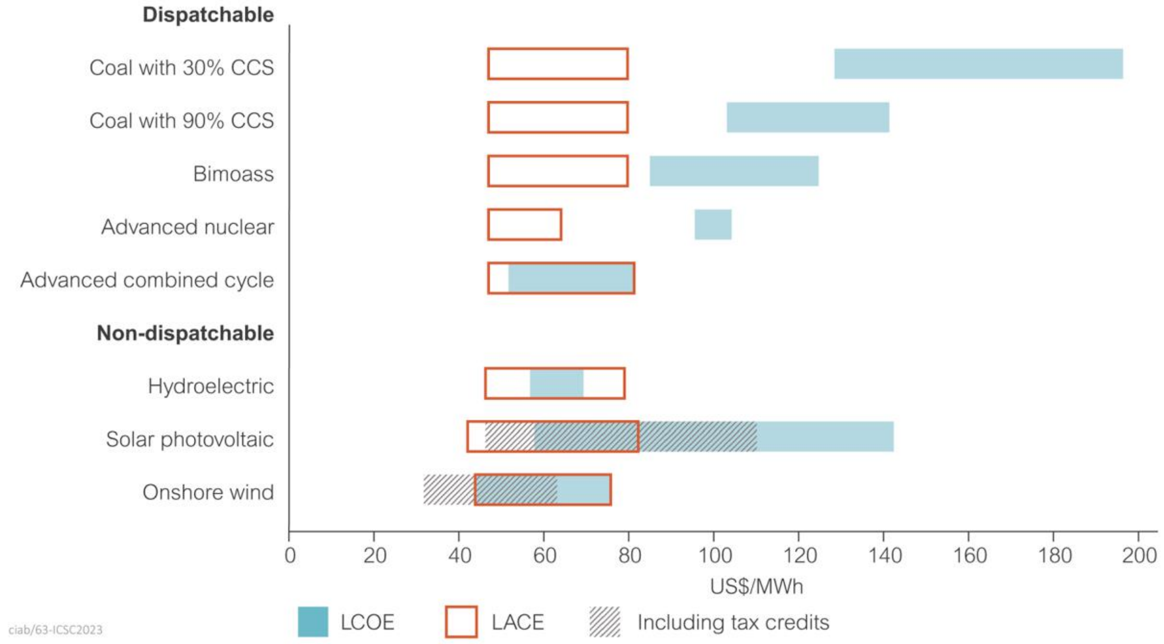

Figure 63 Discrepancy between LCOE and LACE including tax credits, \$/MWh (EIA, 2017)

System levelised cost of electricity

System levelised cost of electricity (SLCOE) provides a broader view of costs by including a component related to system integration.

$$SLCoE = LCoE + IC$$

and

$$IC = RSC - \frac{TEG - EG}{TEG} TSC_0$$

Where: IC is the integration cost, TEG is total energy generated in the system by all technologies, EG is the energy generated by the selected technology, TSC_0 *is the total system cost.*

Included in the integration costs may be changes to the cost of balancing, grid constraints and connections, firming capacity backup cost, low load factors for thermal plant and curtailment costs. As with LCOE this formula is less able to assess technologies which have value but contribute little or no energy to the system and requires modelling of the entire energy system to determine the total system cost (Ueckerdt and others, 2013).

Value adjusted levelised cost of energy

The value adjusted levelised cost of energy (VALCOE) was developed by the IEA. This variant includes elements reflecting energy, capacity and flexibility. They are calculated by the IEA using market data and an hourly electricity market model. The formula is:

$$VALCOE_x = LCOE_x + (\overline{SMP} - EV_x) + (\overline{CV} - CV_x) + (\overline{FV} - FV_x)$$

Where: SMP is the system marginal price, EV is the energy value of the technology, CV is the capacity value of the technology, FV is the flexibility value of the technology.

In this calculation energy needs to be delivered to generate income, which devalues the provision of other grid services, and the location of the asset has no influence on outcomes.

Total system cost

Total System Cost (TSC) is claimed to be a complete cost metric and is based on knowledge of the full grid system. It reveals different values for the same asset added to grids of different initial composition and characteristics (Boston and others, 2021). TSC is calculated by the following:

$$TSC_y = \sum_{a=1}^{amax} (CRF \times CAPEX_{a,y} + FOC_{a,y} + VOC_a \times EG_{a,y})$$

Where: CRF is the capital recovery factor, Capex is the capital cost, FOC is the fixed operating cost, VIC is the variable operating cost and EG is the energy generated by the asset.

TSC does not define prices but represents the calculated cost that would need to be recovered through taxes or retail charges to cover system costs. It is particularly appropriate for determining the impacts of additions on the system in terms of increases or decreases in cost and the impact on consumer bills.

The cost of this improved insight is that the calculation of TSC requires extensive modelling and system knowledge. Even then it would not provide a full evaluation of a technology in terms of operability under specific scenarios, which would still require comprehensive and complex dynamic modelling and simulation.

System cost of replacement energy

The system cost of replacement energy (SCoRE) provides a means to identify the value of the contribution of a technology based on the difference it makes to TSC (Byrom and others, 2021). It has been used to evaluate the addition of low emissions technologies to the grid, displacing high-emission technologies while maintaining grid inertia within defined limits. The formula for SCoRE is:

$$SCoRE_a = \frac{TSC_a - TSC_0}{EG_a}$$

Where: TSC_0 and TSC_a are the total system cost before and after the technology is added and EG_a is the energy generated by the technology.

Since it relies on knowledge of TSC it also requires a comprehensive model and expertise to calculate and still tends to devalue assets which provide valuable grid services but have low or no total generation.

Application of the SCoRE methodology within the modelling energy and grid services (MEGS) model for the Australian NEM has revealed some insights relative to other more simplistic estimations of cost. Using this metric, calculations over a vast number of scenarios reveal a tendency for exponential increase in costs of the system the further it progresses towards decarbonisation and particularly in response to the continued addition of VRE generation. This is attributed to the acknowledgement of wider system requirements and costs as the portfolio of assets evolves. These results are consistent with other studies such as those from Imperial College London (*see* Figure 64) (Aunedi and others, 2021).

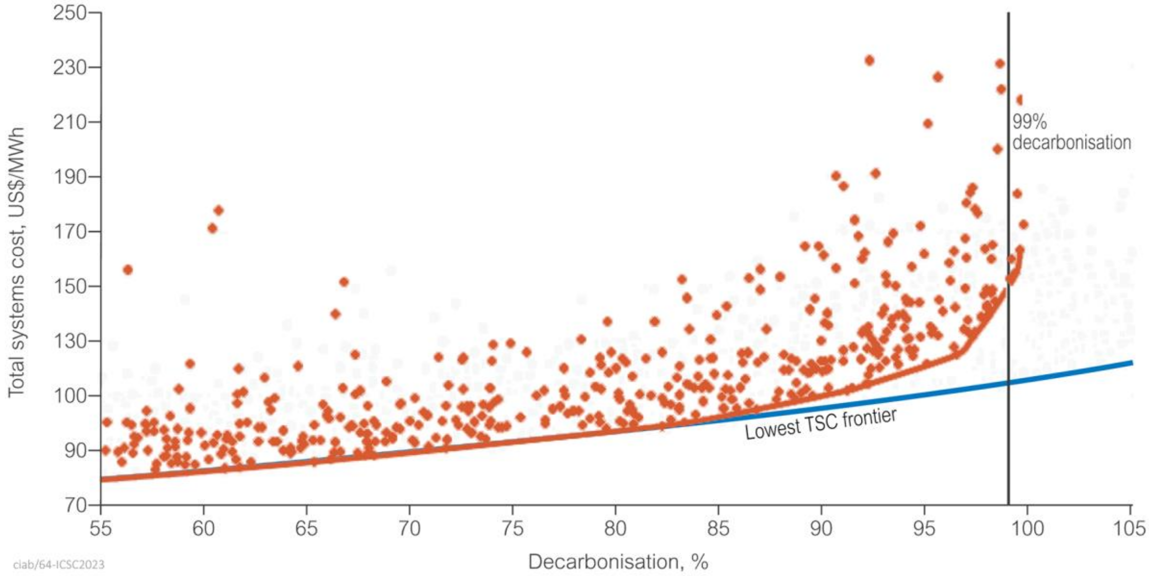

Figure 64 3000 Scenarios of the MEGS model for the Australian NEM (Boston and Bongers, 2021)

Energy return on energy invested

The energy return on investment (eRoI) or energy return on energy invested (eRoEI) is not strictly a financial cost comparative metric but has been used to compare the relative 'value' of generation technologies. It is included in the discussion here for completeness. It is a measure of the energy released from a source relative to the energy expended in enabling that capacity to be realised.

Goehring and Rozencwajg (2022) have argued that technology selection should be biased more towards eRoEI than financial metrics due to the impact of this measure on an economy and its ability to grow. They also cite nuclear power as the highest eRoEI technology option at around 100 compared to wind and solar, after adjustment for intermittency and redundancy, of around just 3.5 . The

(Corporate Finance Institute, 2023) suggests that for a technology to be considered a viable commercial investment it requires an eRoI of 7 or above and that eRoI above 10 is required to avoid unstable price fluctuations (*see* Figure 65).

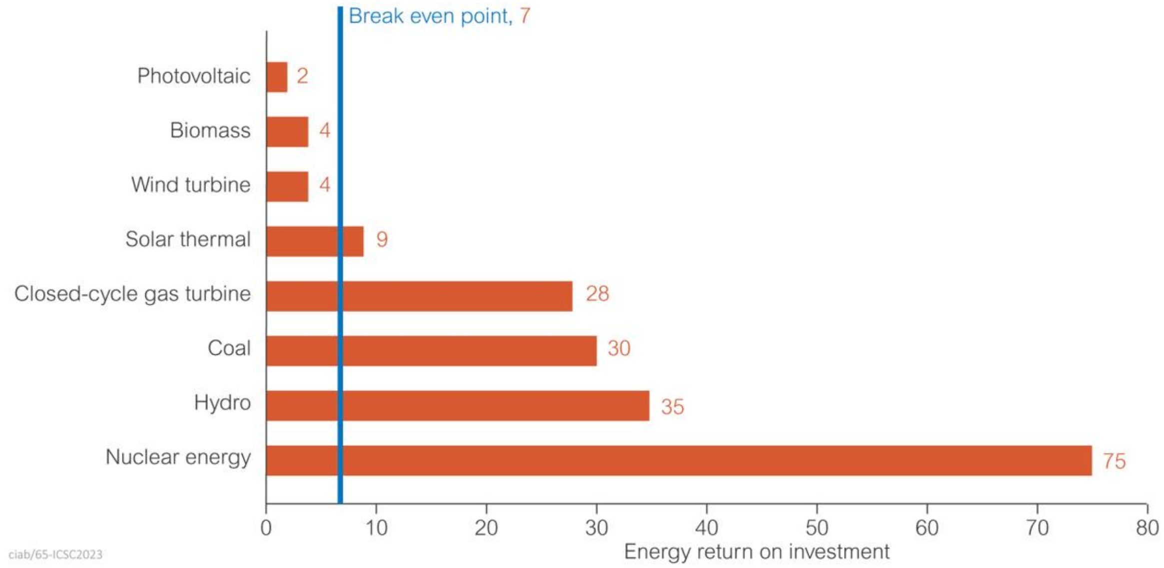

Figure 65 eRoI comparison of selected technologies (Corporate Finance Institute, 2023)

Like LCOE, eRoEI is subject to a range of scope, estimation and calculation-related variations which can lead to widely varying results depending on the source. Although interesting in the context of technology choice impact evaluation and its broader implications, it is not currently a widely used metric.

Other measures

Other measures in common use include levelised cost of storage (LCOS), representing the discounted cost per unit of discharged electricity over the life of a storage facility (Schmidt and others, 2019).

$$LCOS\left[\frac{\$}{MWh}\right] = \frac{Investment\ cost + \sum_{n}^{N}\frac{O\&M\ cost}{(1+r)^{n}} + \sum_{n}^{N}\frac{Charging\ cost}{(1+r)^{n}} + \frac{End\text{-}of\text{-}life\ cost}{(1+r)^{N+1}}}{\sum_{n}^{N}\frac{Elec_{Discharged}}{(1+r)^{n}}}.$$

Where: n is the year up to lifetime N and r is the discount rate.

Alternative formulations also exist for both levelised cost of transmission (LCOT) and levelised cost of heat (LCOH).

Thus, there are various methods of calculating the cost of electricity, many of which include more factors and detailed LCOE.

5.7.3 Uncertainties and interdependencies

LCOE does not generally consider all externalities, even where they have a causal link and significant cost. Even so, it is subject to a range of uncertainties and interdependencies which reduce the reliability of values obtained by it.

Fundamentally the calculation requires prediction of not only actual output, dependent on its ability to supply power and the demand for that supply, but also the value of costs that might make up the annual operating cost over the operational life. In both cases, there is uncertainty, which increases the further into the future the prediction is made. In the case of power plants, the projections are a long way into the future where many factors are not known and may change. Evidence is not available in many cases to provide a high level of confidence in the assumptions. Estimates, forecasts and predictions can be significantly in error due to a range of factors including supply chains, weather, global events, economic health, changes of political policy, market reforms, technological developments and discoveries, lessons learned and adverse incidents of various kinds, for example.

5.7.4 Total economic cost

The author proposes that a more valuable metric might extend even further to a total economic cost (TEC) comparison between options. In concept, this could include other associated factors relating to impacts on trade, industry, inflation and employment, beyond the immediate assets and system to which it is related. TEC would indicate how choices made relate to the wider economy and total national net costs.

Whilst TEC is an aspiration, useful at national economic level and considered, at least in principle, at policy level, it goes beyond the scope of what most analysts in the energy sector can cover and would need far more data to evaluate. This extends to making value comparisons between a range of non-comparable factors likely involving political preferences and strategic motivations.

Schernikau and others (2022) propose the use of a full cost of electricity (FCOE) metric which integrates a far more comprehensive range of factors than traditional approaches. Their methodology incorporates: the cost of building, fuel, operating, electricity transportation and balancing, storage, backup, cost to the environment, recycling, space, materials input, lifetime and energy return on investment. But this metric is not in common use.

5.8 PARALLEL CONSIDERATIONS

Most evaluations include direct costs when comparing technologies. However, other factors should also be recognised since although they may not be reflected in the direct price of those technologies, they impact the value that will be felt and influence environments into which those technologies are deployed.

5.8.1 Deployability

A wide range of technological options and possibilities for generating and using energy continue to be developed using new computational analyses, manufacturing techniques and processes, materials, coatings and composites. All technological developments have an evolutionary life cycle from ideas and concepts through to designs, prototypes, demonstrators, pilots, small-scale commercial installations and then scale-up and roll-out. This includes the scaling up of supply chains, manufacturing, distribution, installation and support bases. These development cycles, even with modern methods, typically take several decades even for relatively simple technologies.

Standards and regulations may also need to be developed involving various stakeholders. The true costs of implementation together with realistic future forecasts of price and capacity take time to emerge. This needs to be done in parallel with other potentially competing and better technologies which may take over as preferred solutions. So, whilst there are many technology options with potential, some will not be deployed at a significant scale to make an impact on the markets in the near term.

In terms of energy supply, technologies in this category include nuclear fusion, geothermal energy, better batteries and capacitors, new composites, superconductors and advanced power cycles. Larger versions of technologies demonstrated at a smaller scale, but far from being able to hold a major market share fit into this category.

Figure 66 illustrates the time taken to deliver new power projects of different types; the green and red blocks indicate the range of likely timescales in years. Delays associated with grid connection which may extend timelines further are not included. There are large differences in timeline according to technology, but this might not be an indicator of long-term value. Current policies, incentives and uncertainties regarding future legislation and costs, may push developers and investors to select projects with shorter timelines to reduce risk exposure. This may not be beneficial overall so market mechanisms should recognise the ongoing role of longer lead-time projects.

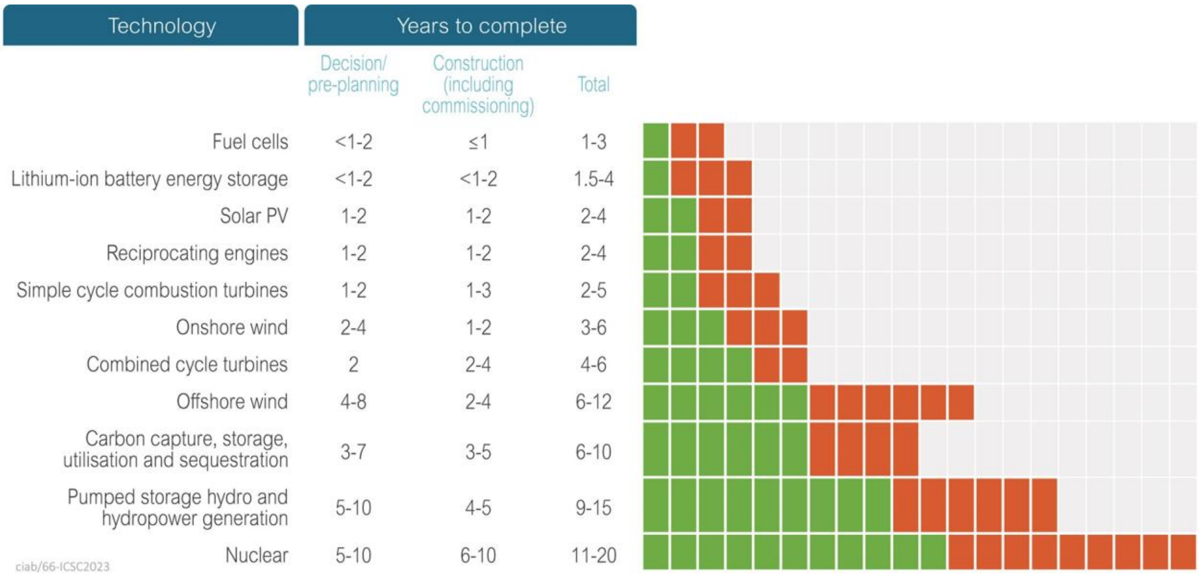

Figure 66 Time to deploy existing technologies (EPRI, 2023)

The chart does not reveal the scale of the projects. Some may be quick to complete, but are also relatively small in capacity, meaning many more projects would be needed to have the same system impact. This may lead to supply chain and deployment issues with negative feedback on the timelines. In all cases, forecasts, market conditions and aspirations should be defined in a way which highlights the demand for solutions sufficiently early for them to be deployed before the point they are needed in service. A proactive approach to planning and deployment is needed.

Today there are unprecedented levels of investment in future energy systems, but they are based primarily around wind and solar, representing 80% of new capacity additions in 2022 (Bloomberg, 2023). They are attractive based on simple LCOE, carbon emissions and project time to deploy, but may create a significant risk of locked-in costs should alternative solutions or data emerge over the next decade favouring other solutions or options with better deployability or operability characteristics (Foxton, 2002; Eitan and others, 2023).

5.8.2 Environment and resources

Electricity systems are being transformed by the focus on climate change mitigation. However, carbon dioxide produced directly from power plants is not the only environmental consideration. The production of any physical asset involves the mining and processing of materials, production of parts, construction and eventual decommissioning and disposal or recycling. This creates a lifecycle 'bubble' of environmental impacts ranging from mining, habitat impacts, consumption of scarce natural resources, production and processing-related emissions and discharges which also need to be attributed to the technology.

Materials

Table 13, based on USDOE and IEA data, shows the relative amounts of materials required to deploy a selection of generation technologies normalised to electricity production. The data suggest that new

VRE technologies consume approximately 32 times the construction materials for the same power output as conventional legacy technologies over their life. This excludes the additional impacts of new network infrastructure and storage technologies required to integrate those VREs effectively into the power system.

TABLE 13 RELATIVE CONSTRUCTION MATERIAL CONSUMPTION BY TECHNOLOGY, T/TWH (WORLD NUCLEAR ASSOCIATION, 2021)

	Coal	Gas CC	Nuclear	Hydro	Wind	Solar PV
Concrete and cement	870	400	760	14,000	8,000	4,050
Iron/steel	310	170	165	67	1,920	7,900
Copper	1	0	3	1	23	850
Aluminium	3	1	0	0	35	680
Glass	0	0	0	0	92	2,700
Silicon	0	0	0	0	0	57
Total metals	314	171	168	67	1978	9430

CC – combined cycle; PV – photovoltaic

The quantities of carbon-intensive steel, concrete and glass required for wind and solar solutions are far higher than that for conventional technologies.

Similar analysis can be extended to consider the critical minerals required for those technologies which is shown in Table 14. The data show the consumption of critical minerals for VRE technologies is approximately 17 times that of equivalent power generation from conventional sources. Again, these figures exclude additional resources that would also be needed for the additional transmission systems and storage technologies.

TABLE 14 RELATIVE CONSUMPTION OF CRITICAL MINERALS BY TECHNOLOGY (WORLD NUCLEAR ASSOCIATION, 2021)

	Plant, t/MW	Indicative, CF, %	TWh/y	Operational lifetime, y	Lifetime, TWh	Plant, t/TWh
Coal	2.5	85	7.5	50	375	7
Nuclear	5.3	85	7.5	60	450	12
Gas	1.2	60	5.2	30	156	8
Solar	6.8	25	2.2	25	55	124
Onshore wind	10.1	35	3.1	25	78	130
Offshore wind	15.5	35	3.1	25	78	200

CF – capacity factor

At its July press briefing on the 2023 market report on critical minerals, the IEA described that if all known new mining proposals go ahead there may be sufficient critical mineral availability to meet the Announced Pledges Scenario (APS) (IEA, 2023c). However, the NZE scenario would require three times that supply of critical minerals. Since mining proposals typically face huge challenges and delays in reaching implementation, the success rate of proposals is often low.

If it is assumed that one-third of the existing developments described proceed through to production and they are in time to contribute, this would still be at least nine times lower than that needed for the NZE scenario. This suggests the specific consumption of critical minerals will become an issue in the near term as demand overtakes supply even though diversification of sources is underway.

Land

All technologies used will occupy space and have a visual impact. They may also affect the accessibility of those spaces, displace other land uses, and impact communications or security networks or wildlife.

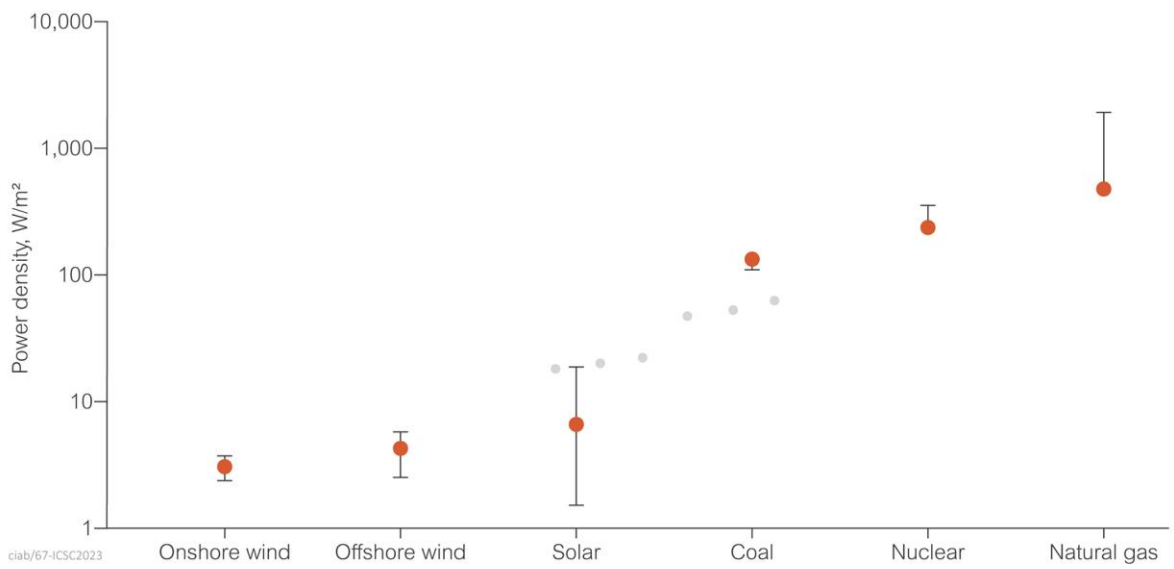

Figure 67 Power density of selected generation sources, W/m^2 (Gross, 2020)

Differences in land areas required for different technologies, as shown in Figure 67, are generally of one to two orders of magnitude (Gross and others, 2020). This means that some technologies will be more obtrusive and have a greater visual impact than others. This may be of concern in areas of natural beauty, or where land availability is an issue or costly. It could make some technology options unviable.

By-products

By-products from power plants can also have environmental consequences, both positive and negative. On the negative side, adverse emissions are heavily monitored and regulated to meet best practice standards. On the positive side thermal power plants produce heat which often feeds into district heating schemes or industrial processes avoiding energy needs from other sources. Coal-fired plants are also major producers of ash and gypsum, both being used in construction and road-building industries (Reid, 2020).

5.8.3 Economic impact

The economic impacts of electricity system choices are massive. Actions which raise the overall cost of the electricity system will tend to decrease the competitiveness of industry and increase inflation. Industries may then choose to relocate to regions with lower basic costs, taking further revenues from the economy. Examples of this have been reported in the German market with some industrial firms relocating or deciding to invest elsewhere (Alkousaa and others, 2022).

5.8.4 Socio-political

Energy is not just a technical or ethical choice but also has political and social implications. From a political standpoint, party positions and commitments set policies which have wide implications and the severity and timing of those will impact the degree to which they impose a tangible cost. Reversing such policies in accordance with the cycles of power will also represent a significant cost, affecting the projects, workforce and businesses which have been set up or disbanded due to prior policies and commitments.

In the political and social context, public opinion counts. Whether the public accepts or demands certain activities and policies limits what will be possible and how much it might cost. The electricity sector has a long history of public objection to development including nuclear power plants, windfarms, solar parks, grid infrastructure, fossil plants and associated mining developments. Policies that drive more buildout of infrastructure which raises higher levels of objection will tend to lose support and create higher demands in relation to consultation and planning and acquisition of rights and wayleaves. This has been seen in grid projects such as the 800 km SuedLink in Germany, initiated in 2013 and planned to deliver power by 2022. Due to opposition, it will not deliver power until 2026-2028, 4–6 years later than planned and with an estimated increase in cost from €4 billion to €10 billion (S&P Global, 2016; TransnetBW, 2023).

6 REGIONALITY AND DEVELOPMENT

6.1 KEY MESSAGES

The opportunities, drivers, costs, issues, priorities and constraints for electrical system development differ around the world. The starting point of each country, in terms of position, economics, population or demand characteristics sets the context for what is achievable, over what timeframe. Countries are at different points on the pathway to decarbonisation. Their paths will not be the same and neither will be the costs or implications for their economies and societies.

The energy and climate policies of countries and regions define which technologies are permitted, financeable, supported and economically viable to deploy. In Australia, Europe and the USA there is a strong political drive to phase coal use down, or out completely, for power generation, including in Poland. This does not specifically exclude new abated plants, but the appetite for them is low and they are not incentivised or promoted in the same manner as renewables. In India coal remains dominant in the mix but the plants currently in the pipeline may be the last to be built. In China, coal will continue to play a significant part in the mix for the foreseeable future, including new plants and potentially CCS in the longer term. Decarbonisation is a high-priority topic and other clean options including nuclear, hydro, wind and solar are being deployed at pace.

Operational economics will continue to be important for coal plants but the successful demonstration of CCS at scale seems to be vital to keep the option for coal open into the future. This will be alongside the evolving experience of VRE adoption. Should this prove to be rapid, low cost and reliable then the option for clean coal is not likely to be explored with vigour. If, however, the challenges, costs, system reliability and deployment timeline for VRE prove problematic then abated coal remains a potentially economic, high-capacity, reliable and deployable solution in countries with extensive coal reserves. It is notable that in its Coal in Net Zero Transitions report the IEA (2022) made the following statement.

> "IN THE NZE SCENARIO GLOBAL COAL USE FALLS BY 90% BY 2050 AND THE GLOBAL POWER SECTOR IS COMPLETELY DECARBONISED IN ADVANCED ECONOMIES BY 2035 AND WORLDWIDE BY 2040."
> (IEA, 2022)

Coal only has a long-term role in any region if abatement can be demonstrated at scale, policy permits the construction of new, or retrofitting of existing, plants and the local economics, reliability and deployment timeline can be shown to be favourable relative to other low-carbon alternatives. Arguably the overall economics and reliability of most low-carbon options, particularly in terms of total system cost and as described in this report, are still emerging and being understood.

Recent stress events in Texas and California show that even in advanced economies the impact of VRE on power system capacity and stability should not be underestimated. Failures of systems only occur at the last moment and, from a consumer perspective, instantaneously.

Although VRE occupies a small share of the actual generation volume, the occurrence of system and market stress issues resulting from it is widespread with volatile market prices and concerns over lack of supply during high-demand periods and excess supply during low-demand periods. These issues are set to become more severe as the share of VRE grows.

The issue that grid systems face is related to the accommodation of large shares of non-dispatchable variable and intermittent sources irrespective of their energy source. Such types of power generation require many additional measures which means the costs and implications spread wider than the immediate levelised cost of those generation technologies. This impacts not only system stability and reliability but also system cost, prices to consumers and taxpayers and the sustainability of business models for stakeholders operating in the market.

There are many analyses and much data in the public domain regarding cost comparisons and projections. Irrespective of this, electricity prices to consumers do not seem to be falling as VRE share increases and anecdotally those areas such as California, Denmark, and Germany with high VRE share appear to have some of the most expensive electricity while those with a lower share like Poland have some of the cheapest electricity in their region. Due to the complexities involved, it is not possible to say if this is the result of adding a higher share of VRE. However, it is not proven that VRE is decreasing the overall cost of electricity provision.

Rapidly developing economies and regions with abundant coal resources and limited access to affordable gas, nuclear power, hydroelectric or multiple interconnections to neighbouring countries will face the hardest challenges in system development. Those with ageing fleets may transition as a matter of course as older assets are retired but those with modern plants will seek to maximise return on those assets. In these regions, affordability and reliability of supply will be paramount to ensure continued economic activity and social development.

6.2 WHY ISN'T THERE A SINGLE SOLUTION?

This chapter highlights some of the reasons behind differences in power supply and infrastructure choices and status between regions. Several regions are examined in more detail to illustrate diversity, challenges and similarities.

There are a range of optimal grid solutions for energy transition, depending on the scenario, context and points in time; they vary with the specific characteristics, constraints and priorities of different regions.

6.2.1 History and current status

The status of electricity grids is an important starting point as they are large, constitute a high-value asset base, and form critical national infrastructure. Existing systems need to be developed in the direction of future needs. As each region has a different starting point with respect to the size, design, use of their grids and associated assets, this influences which next steps are the most appropriate and the speed of transition.

6.2.2 Local options and constraints

Some countries have energy policies which promote or exclude certain technology options. In Germany, nuclear power has been removed as an option from the future energy mix (BASE, 2023) and the UK has 2024 as the target date by which all unabated coal plant will be withdrawn from service (GOV.UK, 2021). Other areas may not have access to technology, labour or supply chains but may have incumbent industries suited to delivering other solutions at large scale. For example, if a nation has access to abundant reserves of fossil fuels, while other options are constrained, it is likely that the known, abundant, affordable and accessible option is the default choice.

6.2.3 Geography and demographics

The size of a population has an obvious bearing on the power system required to serve it. Also important is the location and distribution of that population, the land area of the region and the terrain that networks must cross to connect and supply the population and associated industry. Therefore, the scale and complexity of grids may vary greatly for countries of equivalent population or equivalent land area depending on distribution or concentration and proximity to potential energy sources.

Some energy technologies and options may not be feasible for certain areas but key strategic sources for others. Examples include access to the coastline for commodity imports and export or offshore wind, proximity to neighbouring countries and grids for interconnections, availability of rivers and mountains for hydropower, or flat open spaces for energy crops, onshore wind and solar farms, and underground geological features for carbon sequestration.

6.2.4 Climate

The geography and climate of a region can affect its ability to respond to climate change. For example, regions with high solar radiation intensity, a large wind resource, high rainfall, hot springs or large forests will benefit from high renewable energy potential. Other regions without favourable natural resources need alternative means to ensure an adequate and dependable energy supply.

Climatic characteristics also have an impact on energy demand. Some temperate regions have relatively stable demand across the seasons. Regions subject to high temperatures and droughts will typically experience elevated demands during those periods and require substantial additional grid capacity to be available for that purpose. Similarly, regions subject to extreme cold during winter months will see high demand and need systems able to cope with that. In some instances, both may be true with the risk of both high demand in winter and in summer but less in spring and autumn.

6.2.5 State of economic development

The level of economic development can have a significant bearing on the extent of electrification and industrial energy consumption. Grid requirements and options in developing nations with a prevalence of rural communities for example may differ from those for a region with high population density or large industrial centres. This can extend to the affordability of solutions and the timescales in which they could be implemented. Priorities and ability to act will differ widely.

6.2.6 Market design and regulation

For any given context, demand profile and supply landscape, how grids operate and the potential to change can be influenced significantly by market design. Some regions have a centralised approach with mandated measures whilst others have a liberalised system with devolution of technology choices, investments and modes of operation. Market mechanisms and incentives, tax and support regimes, carbon or capacity markets, merit orders or bilateral trading can all influence what may or may not be economic, attractive or possible. Furthermore, the development and implementation of new market designs or regulatory measures may be necessary for certain future options to be possible.

6.3 DEVELOPMENT DRIVERS

Changes and transitions are the results of triggers and drivers. There are generally a wide number of drivers, considerations and issues, which have a range of effects. In the 2020s global energy transition, the overriding driving factor is the concern around climate change and the release of greenhouse gases. Within this context, much of the focus is on CO_2, fossil fuels, power generation and specifically CO_2 from coal-based power generation. Not only is coal from power generation already a minor and reducing, proportion of total global greenhouse gas emissions (<20% in 2020, (Larson and others, 2021)), but the fundamental purpose and design of the electricity system is not based on environmental needs, rather those of energy demand and security of supply to support economies and societies. This leads to some understandable divergences in development approaches and priorities.

6.3.1 Existing infrastructure

Existing infrastructure influences optimal solutions and has an impact on development priorities. Modern grids include a high level of digitalisation, automation and capability, unlike old systems. Older grids may also not be of sufficient capability to handle future needs and due to age, condition or technology may require replacement. So, there may be a significant need for energy system refurbishment and modernisation to provide a solid foundation for the energy transition.

Factors mentioned earlier in this chapter have shaped the existing grid systems. If the country is large and transmission distances are long, then exploitation of distant resources could be prohibitive. Some large countries like Australia, do not have a uniform distribution of electrical infrastructure. It is concentrated around the major urban centres primarily with a relatively linear geospatial distribution along the east coast. This contrasts with mainland Europe which has a highly meshed system with dense and comprehensive coverage of the land mass. These physical, historically driven differences will impact future costs when it comes to new source integration.

6.3.2 Evolution of demand

The increasing demand on grids for decarbonisation and electrification has been discussed. There are more fundamental factors such as population growth, industrialisation and economic development in many places. This increases demand and consumption across a range of resources including electricity. It means that some countries are facing huge electricity demand increases in the coming decades irrespective of gains in efficiency. For these countries, simply being able to meet demand may be the number one priority irrespective of technology options.

6.3.3 Generation portfolio

Existing generation portfolios vary widely. Some countries have systems based around renewable energies (Brazil, Canada, Iceland, New Zealand, Norway, and Sweden). Some have a large share of nuclear power (France, Finland and Ukraine), some are heavily based on coal (Australia, China, India, Indonesia, Poland, South Africa, and Turkey) and some have transitioned to be dependent primarily on natural gas (Argentina, Italy, Russia, UK and USA). Thus, each country has its own starting position and carbon intensity. The existing portfolio represents industries with workforce, skills, jobs, infrastructure, supply chains, manufacturing, construction and trading activity. They are often linked to either the natural resources or the national economy in a way which makes them a key part of society.

The options for each country vary, and the choice may be more challenging at a practical and economic level and the transition will be progressive over a longer period. The size of the asset base is also significant since the larger the existing installed capacity, the bigger the job to replace it.

6.3.4 Security of supply

The energies and processes related to power supply are important in terms of security of supply. This is often considered in the 'trilemma' of balancing cost, environmental impacts and security of supply. Renewable energies including solar and wind may be seen as important to achieving greater security of supply for electricity and energy independence. This is evident in the EU following the gas crisis precipitated by the war in Ukraine, which increased concerns about energy security. Such changes not only impact the availability of power to a nation but also their balance of trade, especially where fuel or electricity can be exported to neighbouring regions.

SECURITY OF SUPPLY IN POWER SYSTEMS IS DETERMINED PRIMARILY BY DIVERSITY IN THE GENERATION PORTFOLIO

6.3.5 Cost

The ability to pay is a key development factor for any region. In wealthy countries with stable development status and population, and steady or falling energy demand it may not be an issue to add a small cost burden to stimulate an energy transition. Some countries may see the transition as an additional industrialisation or export opportunity which may influence their direction. Cost may be a greater issue in economies subject to their own transition and development, instability or growth, rise in population or increasing industrialisation. Under such circumstances incurring additional costs for environmental improvement may be less compelling.

6.4 GRID DEVELOPMENT LOGIC

Electrical system development is a complicated topic beyond the scope of this report, but there are some concepts and issues which are relevant in the context of appropriate evolution.

6.4.1 Grid centric approach

Although there are non-electricity system-related drivers for change, any modifications or transitions of the electricity system should be based on sound analysis of practical, technical and economic requirements of systems in fulfilling their purpose. This means solutions should supply sufficient electrical capacity in accordance with demand – reliably, securely, affordably and within the prevailing constraints first. The question then is how much of each option can be used to satisfy policy or political requirements while being compliant with the overriding requirements of the system.

Notable in this regard are some of the ‘levers’ that system operators may wish to exert to relieve pressure at the concept or design stage and avoid addressing the core issues. These include relaxation of standards relating to, for example, system inertia requirement, black start capability, system reliability standards or loss or load probability and reserve capacity. Also, shifting from a system which supplies energy to meet demand, towards one where consumers are required to flex their requirements in response to system stress.

The other key lever is interconnection, where system operators might effectively ‘outsource’ the supply and stability problem to a neighbouring system. The contribution of such measures to system design should ideally be secondary and not the prime basis for system evolution.

The estimation of dispatchable capacity requirement is addressed in Section 4.5.8.

6.4.2 Modelling

This report proposes an approach which follows regional sensitive evolution with steps guided by a general methodology like that shown in Table 15.

TABLE 15	CONSIDERATIONS IN APPROPRIATE REGIONAL DEVELOPMENT
1	Existing all-inclusive cost of power and affordability fo any future changes (this is not the consumer price but the true full system cost)
2	Projected change in peak electricity demand over the next 20-30 years including population, economic development, industrialisation, efficiency and electrification
3	Existng capacity and mix of power generation assets, their economic life and the emerging capacity gap for normal economic retirement
4	Availability and cost of natural and traded resources for power generation in that location
5	Cost and practicality of upgrading and life extending existing assets as options
6	Location of the demand and resource centres and existing delivery infrastructure limitations
7	Practical deployment rates for each new capacity source capped at the economic limit for each option
8	For each technology, the typical capacity factor specific to that location to ensure correct total technology capacity calcuation
9	The derate/firming capacity factor which can be relied on as dispatchable load for testing system stress conditions
10	Add to these costs the time and cost penalities associated with new infrastructure and assets
11	Model the permulation of option combinations and relative timing to achieve the speed and cost of transition required within the specified constraints
12	Check the solution for adequate system reserve capacity, inertia and black start capability
13	Potential and realistic beneficial moderating contribution which might be achieved from demand flexibility and interconnection
14	Test the solution against a wide range of extreme weather and other events and scenarios including critical asset failure tolerance. The focus here should be on achiieving a compliant system under the worst scenarios and not some lesser 'most of the time' criteria
15	Only accept solutions which are capable of providing at least the same level of system reliability as in the past and permit the required total system growth in a way which is secure, reliable and affordable

To arrive at robust conclusions a large range of scenarios need to be modelled and simulated using both hypothetical data and large volumes of real data including extreme and unusual events. This should include long-term calculations and dynamic operability modelling at granular scale to assist understanding of how the system might react and respond during a sequence of events. Three issues are particularly relevant – deployment limits, sequence effects and market effects.

Deployment limits

There are significant challenges associated with deployability and deployment timelines (*see* Section 5.8.1). Models often assume the market provides what is required as it is needed, rather than limiting deployment. Models should have realistic limitations built in, to account for deployment rates and delays as well as incorporating trigger periods sufficient to initiate concepts, planning and project proposal and permitting. The current global backlog of grid connection requests is an example of how the real-world constraints for deployment were not taken into account in past models.

Sequence effects

The second is the timing of capacity additions reflecting the evolution of costs and requirements at that time. In the early stages of decarbonisation, the costs of adding VRE in small amounts in the most attractive sites where the rest of the system can smooth out any intermittency are much lower than adding the same capacity later, when the best sites have been used and the system requires more mitigation to integrate the VRE. This means costs and benefits are evolutionary and models need to anticipate this effect.

Market effects

Models should be able to evaluate and reflect likely market and economic changes, growth, demand, interest rates, cost of capital and carbon price, both locally and globally. Global supply chains, demand-based prices, crises in resources or labour, manufacturing, skills or facilities all have an impact on assumed costs and timelines to deliver. Therefore, sensitivity to, and expectations of, market-related effects and feedback is required for models to be realistic. Systems cannot therefore be modelled in isolation as snapshots in time, separated from the markets with which the modelled systems need to interact. They are a similar risk to achieving the desired outcomes as the comparison of options themselves.

6.4.3 Global aggregation

Not every system needs to be developed in the same way, but the global objective remains. Electricity supply systems will transition at different speeds. The overall impact of the changes is important, with higher priority placed on the areas where the most impact can be realised.

GLOBAL CHALLENGES, LOCAL SOLUTIONS

6.5 REGIONAL EXAMPLES

Selected regions are described in the following sections. They use extracted and calculated characterisation data for comparative purposes covering population, economic activity and generation portfolio in terms of capacity, output, utilisation and VRE share. As an indication of longer-term trends, EIA data have been included for the years 2011 and 2021 with comparisons made between those years and between specific countries, their regions and the world. 2021 is used as the most recent complete data set, but the relative values and trends are of most value and interest.

Table 16 shows global energy and economic data. The same general format has been applied in subsequent tables for regions and countries. Capacity and generation values are shown as both total absolute values and as percentage breakdown by technology type. The capacity utilisation percentages are the percentages associated with each technology type independently. Changes between 2011 and 2021 are shown as a percentage relative to 2011.

TABLE 16 HIGH-LEVEL GLOBAL PERSPECTIVE

Based on data from EIA database, September 2023 *EIA regional continental classification basis*	WORLD		
	2011	2021	10 year change (%)
Population (millions)	707.47	7,907.8	12
GDP (2015$PPP basis)	98,608	136,287	38
Energy intensity (mBtu per person)	76.5	76.4	0
Electricity consumption (TWh)	19,444	25,343	30
Installed capacity (GW)	5,349	8,013	50
Fossil fuels (%)	66	55	-16
Nuclear ($)	6.9	4.7	-32
Renewables (%)	24.1	37.8	57
Hydroelectricity (%)	17.1	14.8	-13
Geothermal (%)	0.2	0.2	-2
Tide and wave (%)	0.0	0.0	16
Solar (%)	1.3	10.6	715
Wind (%)	4.1	10.3	150
Biomass and waste (%)	1.4	1.9	30
Hydroelectric pumped storage (%)	2.7	2.2	-20
Wind and solar as % total installed capacity	5.4	20.9	286
Generation (TWh)	21,226	27,295	29
Fossil fuels (%)	67	62	-9
Nuclear (%)	12	10	-17
Renewables (%)	21	29	38
Hydroelectricity (%)	16	15	-5
Geothermal (%)	0.3	0.3	8
Tide and wave (%)	0.0	0.0	-6
Solar (%)	0.3	3.8	1,115
Wind (%)	2.0	6.6	223
Biomass and waste (%)	1.8	3.3	34
Wind and solar as % generation	2.4	10.4	341
Overall capacity utilisation (%)	45.3	38.9	-14
Fossil fuels (%)	46.1	43.3	-6
Nuclear (%)	77.9	82.0	5
Renewables (%)	39.0	29.4	-25
Hydroelectricity (%)	43.3	40.7	-6
Geothermal (%)	74.9	71.4	-5
Tide and wave (%)	30.4	21.2	-30
Solar (%)	10.8	13.9	28
Wind (%)	22.6	25.1	11
Biomass and waste (%)	55.6	49.0	-12

These data suggest that in 2011 the average global utilisation of solar and wind was 10.8% and 22.6% respectively. This includes all types, locations and climates and reflects that wind and solar are generally used when capacity is available. For fossil fuels, nuclear, hydro and biomass, the figures were 46.1%, 77.9%, 43.3% and 55.6% respectively. The figures shown for fossil fuel plant may be lower than expected since they reflect total output, and total installed capacity and usage varies widely between plants according to market conditions and purpose. Much of this capacity will be in standby or marginal operation mode. Unlike solar and wind, therefore, the numbers represent less the achievable utilisation, but rather that obtained from how they are deployed.

Wind and solar capacity has grown substantially from around 2–3% of generation in 2011 to over 10% in 2021 with an installed capacity share of around 21%. Thus, in 2021 approximately 90% of generation was still from non-solar and wind sources and 62% was from fossil fuels. However, over this period fossil fuel and nuclear output decreased by 9% and 17% as output from wind and solar increased more than four-fold.

Population increased by around 12% in the period with electricity consumption increasing by around 30%, outstripping population growth.

6.5.1 USA

The focus in this section is on the USA and regions within it which may be indicators of future issues facing other US states. Data in Table 17 characterises and compares both continental North America and the USA and compares the USA to the global totals. Note that in this table and those that follow, comparisons between country, region and the world are ratios between the values of the target country and its region and the world.

The USA comprised 15% of global installed generation and electricity production despite having only 4% of the global population; energy intensity by population is 3.85 times the global average. Wind and solar contributed approximately 13% to total generation in 2021 and had relatively high utilisation of 19.9% for solar and 32.7% for wind, possibly attributable to the regional characteristics of where those resources were most concentrated. Fossil fuel generation reduced by 12% between 2011 and 2021 but still contributed 60% to electricity supply in 2021. The VRE share of installed capacity in the USA is still low at about 8% below the world average, whereas the generation from wind and solar was about 25% more than the global average as a share of the generation mix. The USA has about 25% of the global installed nuclear capacity and 29% of global electricity generated from nuclear power. The USA accounted for 81% of the power produced in North America.

TABLE 17 CHARACTERISTIC DATA FOR NORTH AMERICA AND THE USA

Based on data from EIA database, September 2023 *EIA regional continental classification basis*	NORTH AMERICA				USA				
	2011	2021	10 year Change (%)	2021 vs World	2011	2021	10 year Change (%)	2021 vs Region	2021 vs World
Population (millions)	4,604	497.4	8	0.06	311.7	3.320	7	0.67	0.04
GDP (2015$PPP basis)	20,125	25,123	25	0.18	16,637	20,530	23	0.82	0.15
Energy intensity (mBtu per person)	257.7	239.5	-7	3.13	310.8	294.7	-5	1.23	3.86
Electricity consumption (TWh)	4,670	483.6	4	0.19	3,887	3,979	2	0.82	0.16
Installed capacity (GW)	1,249	1,425	14	0.18	1.051	1,117	12	0.83	0.15
Fossil fuels (%)	70	58	-17	0.19	75	62	-17	0.88	0.16
Nuclear ($)	9.2	7.8	-16	0.29	9.6	8.1	-16	0.86	0.25
Renewables (%)	19.0	32.3	69	0.15	13.4	27.9	107	0.71	0.11
Hydroelectricity (%)	13.3	12.3	-8	0.15	7.5	6.8	-9	0.46	0.07
Geothermal (%)	0.3	0.3	-3	0.25	0.2	0.2	-4	0.72	0.18
Tide and wave (%)	0.0	0.0	-12	0.04	0.0	0.0	–	–	–
Solar (%)	0.2	7.3	4,353	0.12	0.1	8.0	5,411	0.90	0.11
Wind (%)	4.1	10.8	162	0.19	4.3	11.3	159	0.86	0.16
Biomass and waste (%)	1.2	1.6	29	0.15	1.2	1.6	30	0.85	0.13
Hydroelectric pumped storage (%)	1.8	1.6	-10	0.13	2.1	2.0	-8	0.99	0.13
Wind and solar as % total installed capacity	4.3	18.2	323	0.87	4.5	19.2	328	0.61	0.92
Generation (TWh)	4,997	5,129	3	0.19	4,104	4,165	1	0.81	0.15
Fossil fuels (%)	63	56	-11	0.17	68	60	-12	0.87	0.15
Nuclear (%)	18	17	-4	0.32	19	19	-3	0.89	0.29
Renewables (%)	19	27	40	0.18	13	21	65	0.64	0.11
Hydroelectricity (%)	15	13	-10	0.16	8	6	-20	0.39	0.06
Geothermal (%)	0.4	0.4	-7	0.22	0.4	0.4	4	0.79	0.18
Tide and wave (%)	0.0	0.0	-100	0.00	0.0	0.0	–	–	–
Solar (%)	0.1	3.6	2,661	0.18	0.1	3.9	2,657		0.16
Wind (%)	2.6	8.5	222	0.24	2.9	9.1	211		0.21
Biomass and waste (%)	1.6	1.6	-2	0.13	1.7	1.6	-6		0.11
Wind and solar as % generation	2.8	12.1	336	1.16	3.1	13.0	325		1.25
Overall capacity utilisation (%)	45.7	41.1	-10	1.06	44.6	40.4	-9		1.04
Fossil fuels (%)	41.1	39.3	-4	0.91	40.5	39.1	-3		0.90
Nuclear (%)	87.9	90.5	3	1.10	88.9	93.0	5		1.13
Renewables (%)	46.5	34.6	-26	1.17	42.9	30.9	-28		1.05
Hydroelectricity (%)	50.1	43.9	-12	1.08	46.4	37.1	-20		0.91
Geothermal (%)	74.5	64.5	-13	0.90	72.6	71.4	-2		1.00
Tide and wave (%)	14.8	0.0	-100	0.00	–	–	–		–
Solar (%)	35.8	20.0	-44	1.44	43.8	19.9	-55		1.43
Wind (%)	29.2	32.2	10	1.29	30.0	32.7	9		1.31
Biomass and waste (%)	61.1	41.4	-32	0.85	62.0	40.8	-34		0.83

Since 2011, fossil fuel and nuclear power generation have reduced by 12% and 3% respectively but with capacity decreasing by 17% and 16%, while renewables capacity has doubled. Population increased by 7% over the period and GDP grew by 23%, below the 38% of the world.

The transmission system in the USA is one of the largest, spanning around 11.3 million km of transmission and distribution lines and incorporating nearly 3000 different utilities. The transmission system is operated by many different system operators with a mix of seven larger 'independent system operators' and many smaller utility system operators. They are shown in Figure 68 and listed in Table 18.

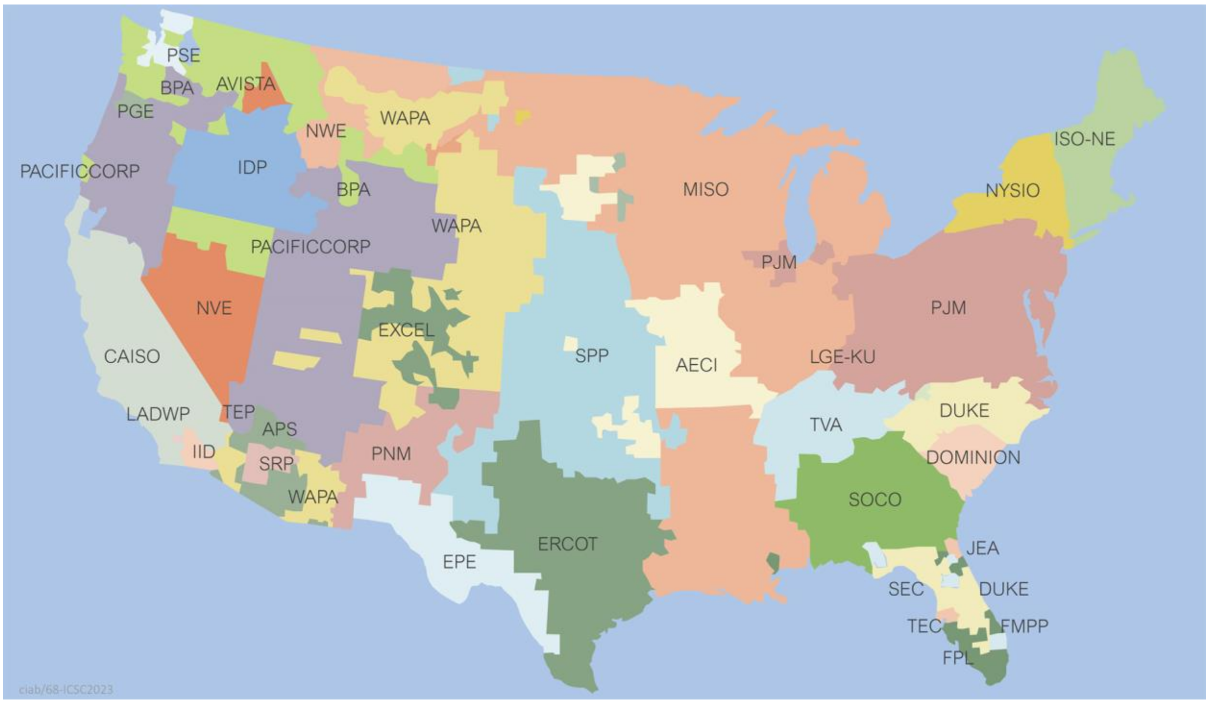

Figure 68 Transmission system operators in the USA (LBNL, 2023)

TABLE 18 TRANSMISSION SYSTEM OPERATORS					
ISO/RTOs	**Other (non-ISO) transmission operators**				
PJM	Southern Company	Associated Electric Corp	LG&E & KU Energy	Portland General Electric	Public Service Co of NM
MISO	Tennessee Valley Authority	PSCO	Salt River Projects	Idaho Power	Avista
ERCOT	Duke/Progress	Santee Cooper	NV Energy	Florida Municipal Power Pool	El Paso Electric
SPP	WAPA	Georgia Transmission Corp	Navajo-Crystal	Tri-State G&T	Imperial Irrigation District
NYISO	Florida Power & Light	Arizona Public Service	Dominion	Jacksonville Electric Authority	Platte River Power Authority
CAISO	Bonneville Power Administration	LADWP	Puget Sound Energy	Tucson Electric Power	Black Hills Colorado
ISO-NE	Pacific Corp	Seminole Electric Coop	Tampa Electric Co	NorthWestern	Cheyenne Light Fuel and Power

The US grid comprises three separate synchronous zones separated by interconnectors, illustrated in Figure 69, including a connection to the system of Quebec in the north.

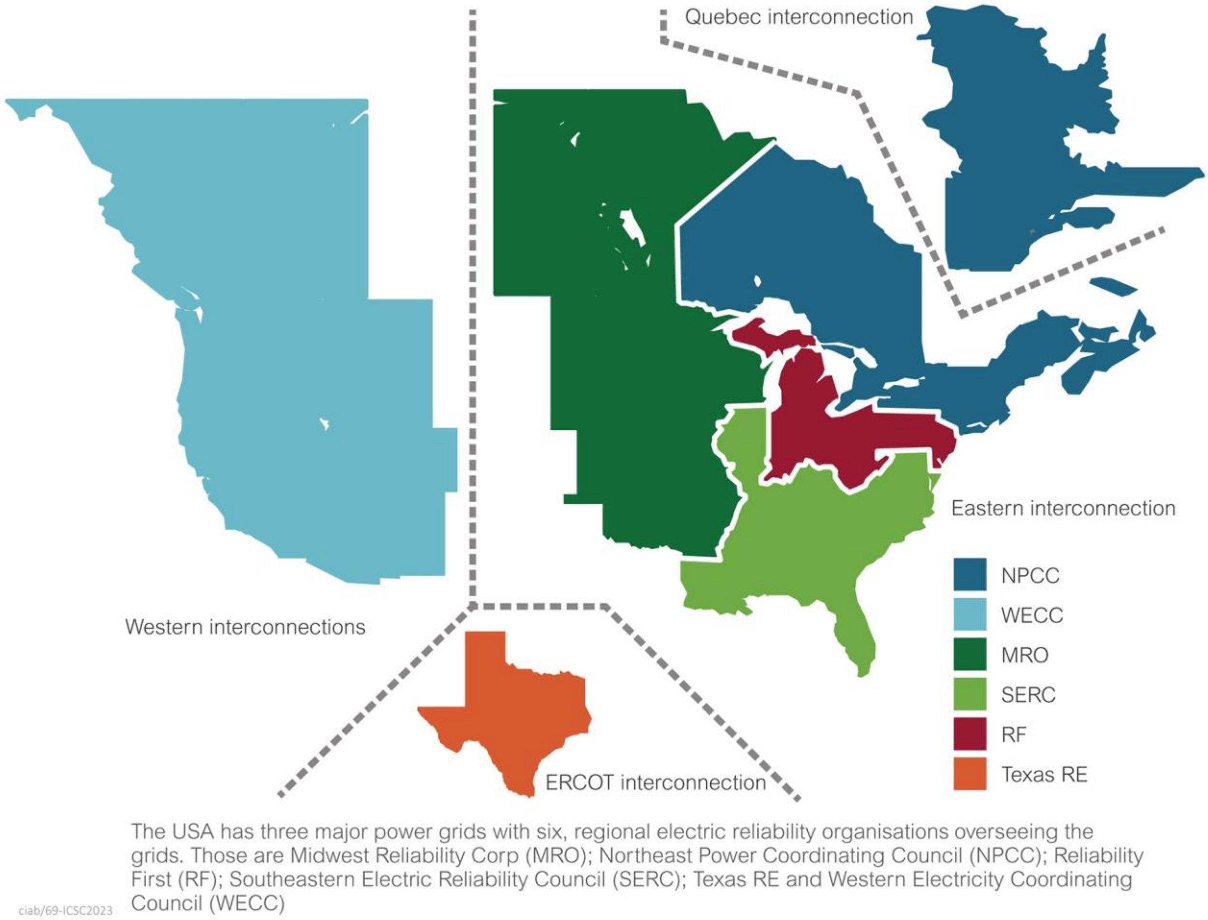

Figure 69 Power grid areas, interconnectors and reliability organisations of the USA (Maqsood, 2021)

As shown by the number of transmission grid operators, reliability organisations and federal-level regulators, there are many stakeholders and interfaces in the USA. This means that the burden of coordination and negotiation to bring about changes or collaboration is demanding.

Adverse events and attacks on the system occur and lessons are learned and incorporated into the system. The most notable power failure incident was in 2003 when a blackout affected millions of people across a huge area (*see* Section 2.4.2). An extensive list of recommendations, including thousands of km of additional infrastructure construction, were implemented to prevent reoccurrence. Such events have prevented the central importance of power grids from being forgotten.

> "THE FOUNDATION OF OUR CLIMATE AND CLEAN ENERGY GOALS IS A SAFE, RELIABLE AND RESILIENT ELECTRIC GRID."
> JENNIFER M GRANHOLM, US SECRETARY OF ENERGY 2022

The US transmission system is an ageing asset with much replacement, expansion and investment needed. Some sources have put this figure at around $2 trillion to achieve net zero (Williams and others, 2021). Bloomberg reports that although the Infrastructure Investment and Jobs Act and Inflation Reduction Act (IRA) have added $29 billion of federal funding to the grid an increase of around $80 billion in annual investment is needed to be on track for net zero (BloombergNEF, 2023) (*see* Figure 70).

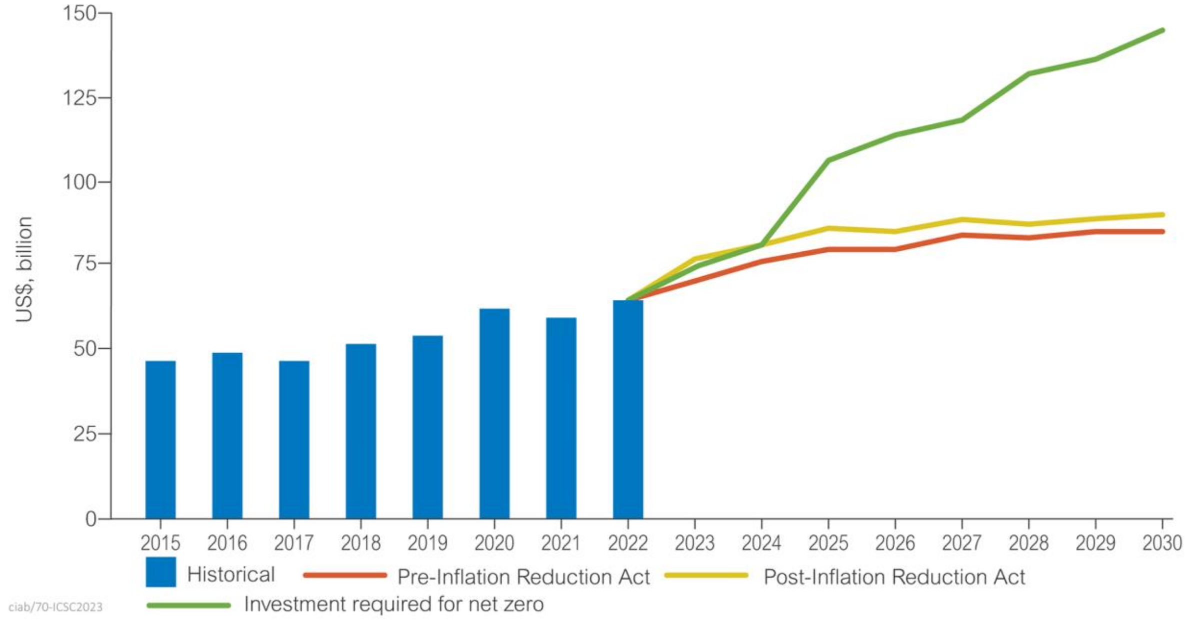

Figure 70 Grid investment required in the USA to align with net zero requirements (BloombergNEF, 2023)

BloombergNEF (2023) also report that of the estimated $21 trillion for global grid investment by 2050, one-third would be for China and the USA alone.

There has been a surge in grid connection requests stimulated recently by the tax incentives introduced in the IRA. This has led to a large backlog in connection requests for most kinds of generation, particularly for new wind, solar and storage facilities. At the time of writing (October 2023) there were approximately 3000 active connection requests pending. Historically, a high proportion of requests are eventually withdrawn and those that do proceed take many years on average to be approved. Figure 71 shows the trend of this activity in the USA.

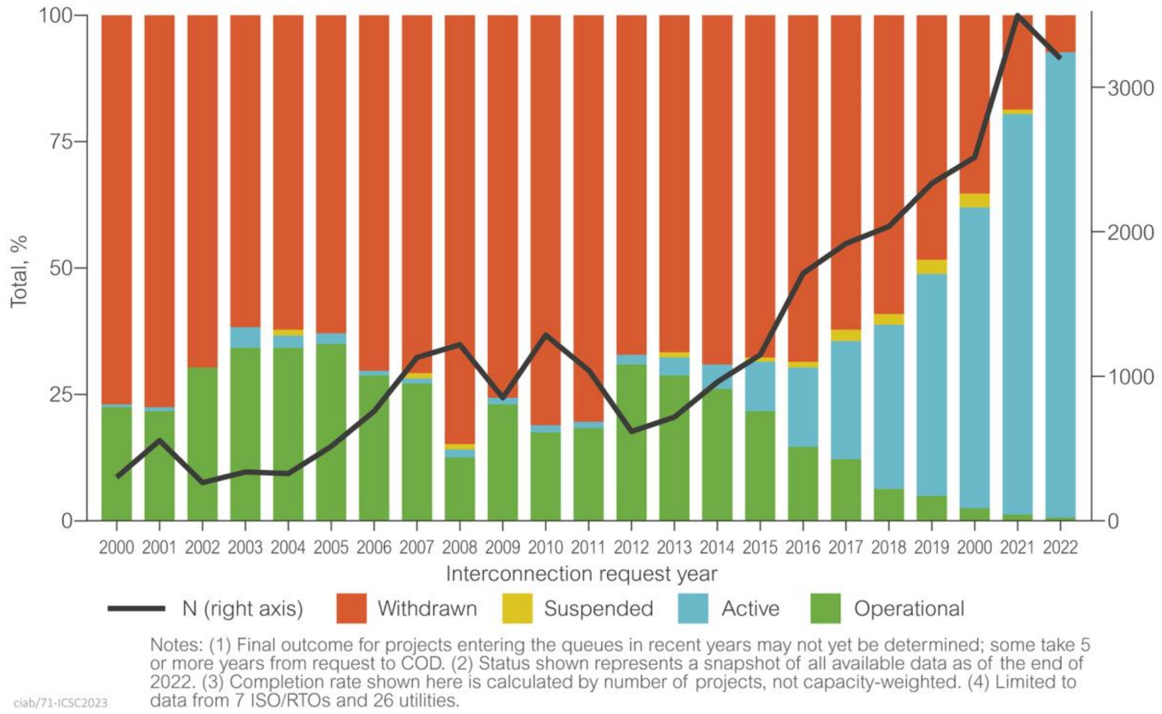

Figure 71 Completion rate of grid connection requests in the USA (Rand and others, 2023)

The USA has a large gas turbine fleet, good gas infrastructure and an abundant supply of relatively cheap natural gas, which is also exported. This makes switching to gas generation a relatively easy and achievable proposition and one that is attractive for new dispatchable, flexible plant. The IRA has also resulted in an 85 $/t tax credit for CCS, but it remains to be seen how much this will accelerate its deployment.

Despite coal reserves, the economics of coal generation are less attractive due to the availability of cheap gas and incentives for renewables; older marginal coal plants are closing. This is causing concern regarding resource adequacy and the retention of sufficient flexible and dispatchable power to cover periods of low VRE generation (NERC, 2023). This is about replacing like-for-like levels of power, and about accommodating future demand which is rising in some areas (*see* Figure 72).

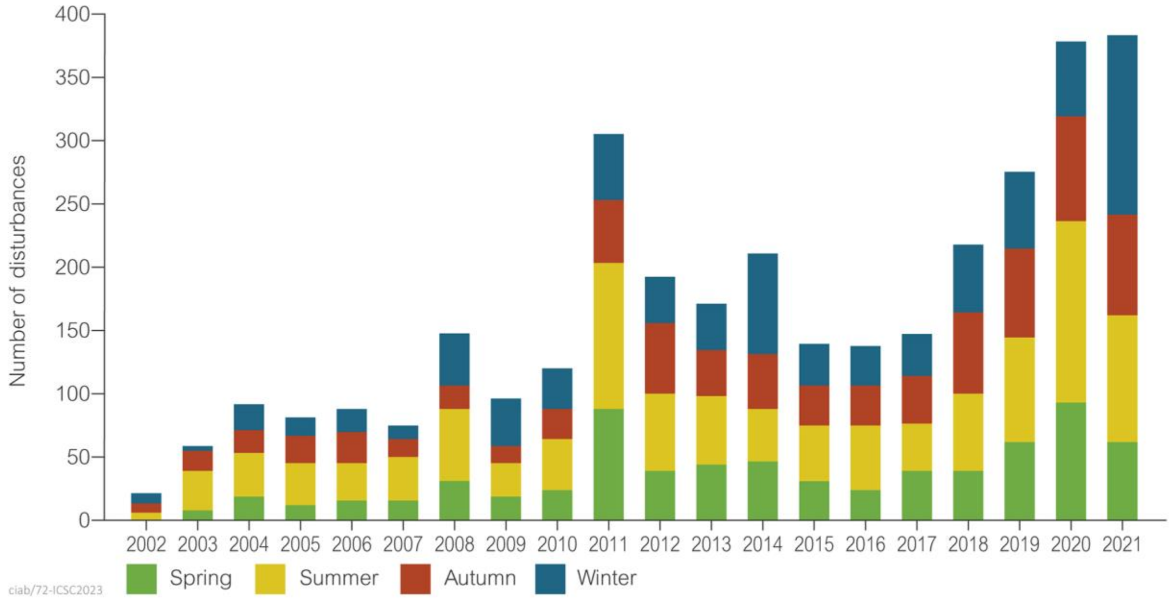

Figure 72 Grid disturbances in the USA over time, by season (Watt-Logic, 2023)

Figure 73 illustrates the North American Electricity Reliability Council's (NERC) concern about the emergent levels of resource adequacy in the USA. Adding to this they warned "The system is close to its edge...managing the pace of retirements is critical".

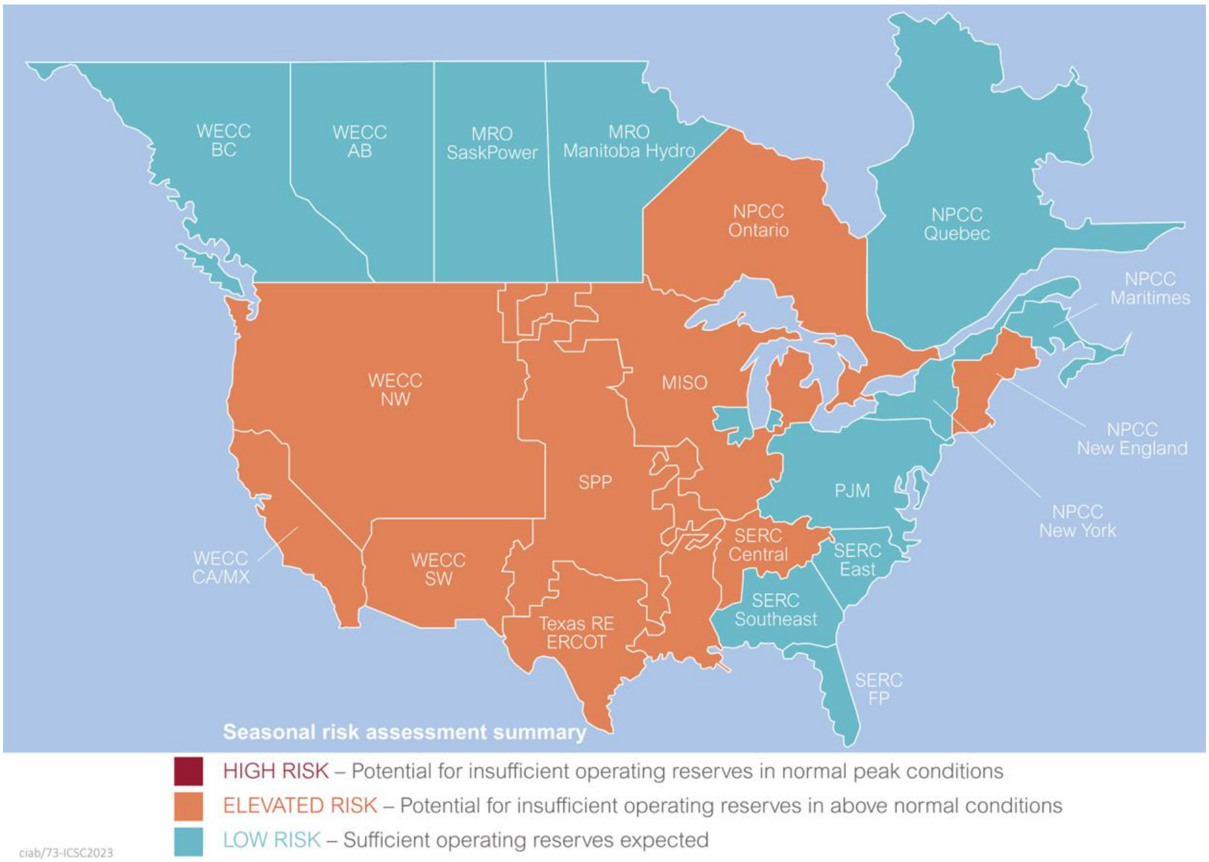

Figure 73 NERC summer reliability risk area summary, 2023 (NERC, 2023)

The Federal Energy Regulatory Commission (FERC) USA has expressed its concern to the Senate that resource adequacy is at risk in many transmission regions. Although levels of generation are adequate under 'normal' conditions, in most regions they are not considered adequate under abnormal conditions.

"THE ARITHMETIC DOESN'T WORK. THIS PROBLEM IS COMING. IT'S COMING QUICKLY. THE RED LIGHTS ARE FLASHING."
(US FERC, MAY 2023)

NERC undertakes regular summer, winter and future resource adequacy assessments and raises areas of concern for action by the local system operators. Some have questioned whether these adequacy assessments continue to be a robust method for ensuring reliability of the system since they tend to focus mainly on installed capacity rather than a probabilistic assessment of being able to cover demand during stress events with conditions not favourable for VRE generation (Mauch and others, 2022). The assessments do not consider the provision of other system services and support such as inertia, which are the responsibility of the local utilities.

The USA does not operate a single carbon trading scheme but has mechanisms depending on the region which effectively put a price on carbon and incentivise a move to lower carbon sources of generation. This is in parallel with mechanisms to ensure the provision of adequate capacity through resource adequacy reviews and capacity markets. Some measures operate at federal level, for example, the IRA, and some only at state level. The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 emissions reduction programme operational in 12 north east states of the USA. Participants include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia. Emitters must purchase allowances from the state and the proceeds are invested into related energy, environment and social interventions (RGGI, 2023).

Texas

Texas is the only US state to have its own independent power grid, operated by ERCOT. It spans more than 74,000 km of transmission lines and includes over 650 power generation facilities supplying over 26 million customers (Minton, 2020).

The grid's total operational capacity, as of January 2023, was 142.6 GW up 9.1 GW from the end of 2021 and includes 54.5 GW nameplate capacity of solar and wind. ERCOT data (S&P Global, 2023b) shows the projected peak demand to be within the capacity of thermal plant, assuming full availability (*see* Figure 74).

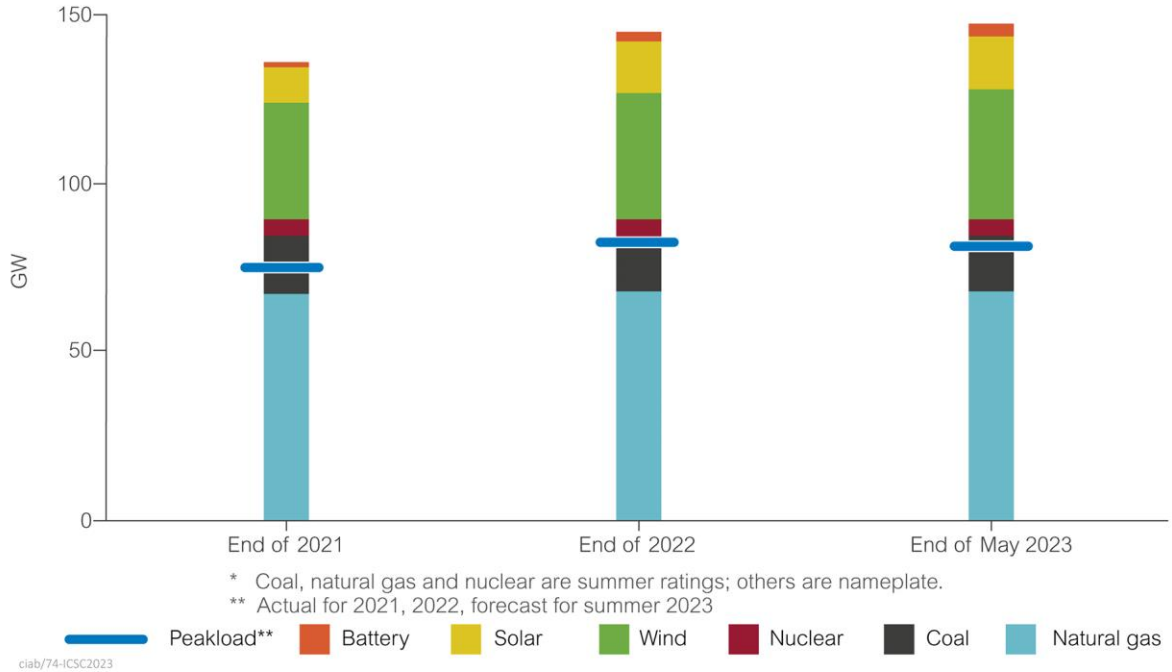

Figure 74 ERCOT generation capacity by type, peak-loads, GW (S&P Global, 2023a)

In recent years Texas has experienced periods of system stress due primarily to extreme weather events, both hot and cold. These periods have led to high demand and reduced output from some generation assets. Relatively limited interconnection to other parts of the USA has strained resources within the local system. During 13-16 February 2021, this culminated in a high level of load shedding during extreme cold to avoid wholesale grid collapse. More than 4.5 million Texans were without power for two days. There were 246 deaths and around $195 billion in damages attributed to this incident, the worst of this type in Texan history (Walsh, 2022).

ERCOT depends on natural gas for dispatchable power (*see* Figure 74). In the 2021 winter storm power plants struggled to cope with the cold and some gas pipelines froze, significantly impacting power generation capacity. Figure 75 illustrates how events unfolded in Texas during the 2021 freeze on 16 February that led to load shedding to restore system frequency within acceptable limits. The system came within only minutes of a full grid failure.

Although the consequences of the storm and resulting load shedding were tragic, the consequences of whole grid collapse would have been far worse. Important lessons regarding adequate winterisation were learned.

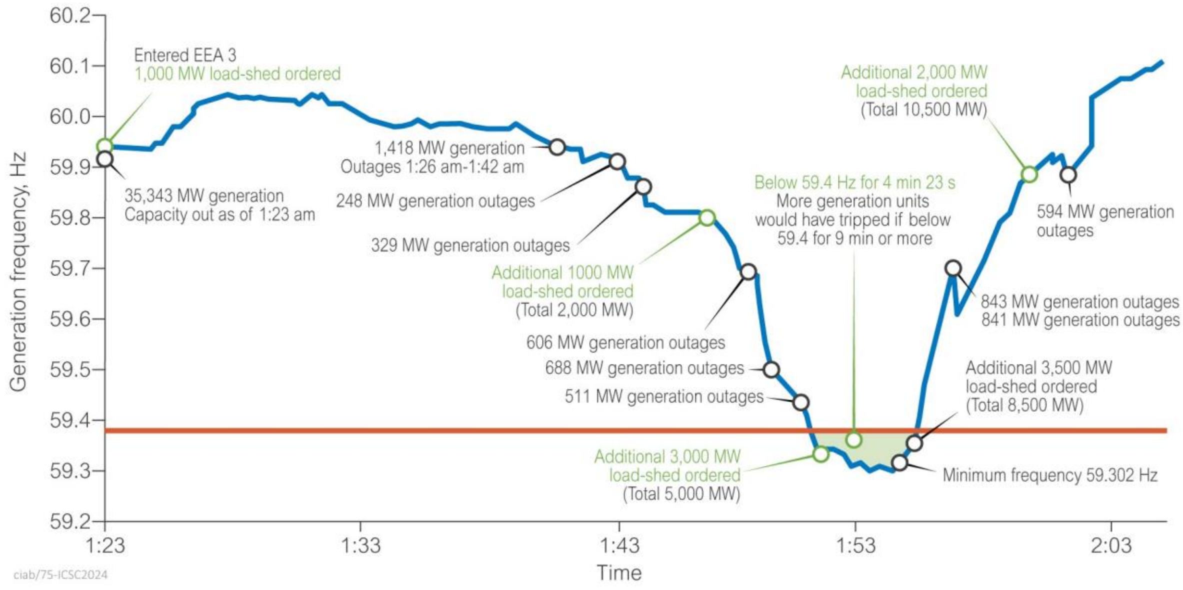

Figure 75 Load shedding to restore system frequency in Texas, 2021 (Maqsood, 2021)

Such events highlight how abnormal conditions combined with other technical and non-technical issues can escalate into a crisis. During such conditions, the issues of dispatchable generation and resource adequacy become paramount to achieve safety and continuity of services. The failure to deliver power in this instance was due to multiple factors impacting both renewable and non-renewable assets but it highlights the potential extreme effect of weather on the system and the need to plan for such extremes.

Texas experienced resource adequacy issues during 2023 due to excessive heat. In 2020 ERCOT forecast a peak demand of 81.6 GW in 2023. But in August 2023 the actual peak load was 85.46 GW, and ten new records were set. In comparison, the peak up to August 2019 was only 74.8 GW.

This frequent breaking of records has stretched resources. Solar power provided much-needed support during daylight, but its non-availability in the evenings and at night was a significant problem and resulted in ERCOT issuing 11 conservation calls to the public between June and September 2023 in order to safeguard the system. Additionally, on 6 September an Energy Emergency Alert (EEA) Level 2 was issued due to low operating reserves, which is one level below that where controlled outages may be imposed.

This also impacts power price. Reuters (2023) reported that real-time power prices were over 4000 $/MWh for more than an hour on 7 September 2023 after hitting the grid's $5000 price cap for about an hour on 6 September. Next-day power prices at the ERCOT North hub also hit a two-week high of 611 $/MWh. This compares with an average of 101 $/MWh up to that point in 2023, 78 $/MWh in 2022 and a 2018-22 average of 66 $/MWh (Disavino, 2023). This illustrates the economic impact of grid operating margins and technology choices.

In principle 142.6 GW of installed capacity is more than adequate to satisfy 85.464 GW of demand if the capacity is dispatchable when needed.

California

California has a population of around 39 million, expected to reach 55 million by 2050. It has a grid system operated by CAISO spanning approximately 41,800 km. Electricity consumption from the CAISO system is approximately 278 TWh/y and reached a peak load of approximately 52 GW in September 2022.

The CAISO region has made significant progress in decarbonising its power supply and deploying renewable generation technology. California has a high potential for solar generation but until recently has relied heavily on natural gas and imported power from neighbouring regions. The generation profile for 2021 is characterised in Table 19. For this period natural gas was responsible for 37.9% of generation and total imports for approximately 30% of consumption. Solar and wind contributed 14.2% and 11.4% respectively, and a total of 24.6% was VRE, with nuclear and large hydro contributing 18.5%. In 2022 the planned retirement of 2256 MW of nuclear capacity at Diablo Canyon in 2024-25 was postponed by Senate Bill 846, enabling the plant to remain in operation for an additional five to ten years reducing future reliance on natural gas. State law prevents the construction of any new nuclear power plants.

TABLE 19 TOTAL SYSTEM ELECTRICITY GENERATION (CALIFORNIA ENERGY COMMISSION, 2021)

Fuel type	California in-state generation, GWh	Percent of California in-state generation, %	Northwest imports, GWh	Southwest imports, GWh	Total imports, GWh	Percent of imports, %	Total California energy mix, GWh	Total California power mix, %
Coal	303	0.2	181	7,788	7,969	9.5	8,272	3.0
Natural gas	97,431	50.2	45	7,880	7,925	9.5	105,356	37.9
Oil	37	0.0	–	–	–	0.0	37	0.0
Other (waste, heat, petroleium, coke)	382	8.5		68	83	0.1	465	0.2
Nuclear	16,477	6.2	68	524	9,281	11.1	25,758	9.3
Large hydro	12,036	0.0	524	12,042	13,620	16.3	25,656	9.2
Unspecified	–	65.2	12,043	8,156	18,887	22.6	18,887	6.8
Total thermal and non-renewables	126,666	2.8	21,017	21,017	57,764	69.1	184,431	66.4
Biomass	5,381	5.7	864	864	890	1.1	6,271	2.3
Geothermal	11,116	1.3	192	192	2,098	2.5	13,214	4.8
Small hydro	2,531	17.1	304	304	304	0.4	2,835	1.0
Solar	33,260	7.8	220	220	6,199	7.4	39,458	14.2
Wind	15,173	34.8	9,976	9,976	16,381	19.6	31,555	11.4
Total renewables	67,461	100.0	11,555	11,555	25,872	30.9	93,333	33.6
Total system energy	194,127		32,572	32,572	83,636	100	277.764	100

Senate Bill 100 sets a 60% renewable portfolio standard goal by 2030 and requires that by 2045 renewable and zero-carbon resources must supply 100% of electric retail sales to end-use customers. In its 20-year transmission outlook report CAISO estimates $30.5 billion will need to be invested in the state's electrical transmission system for new high-voltage AC and DC lines to connect the resources required to achieve its emissions reduction goals. As part of this plan the 'Starting Point' scenario forecasting requirements for 2040 called for a reduction in gas-fired generation of 15 GW and a total of 37 GW of installed battery capacity, 4 GW of long-duration storage, over 53 GW of utility-scale solar, 2 GW of geothermal and over 24 GW of wind generation. A total of 120.8 GW of capacity, with the expectation of an additional 18.9 GW of behind-the-meter solar generation, is required to supply an anticipated peak load of 73.9 GW occurring during the summer months (CAISO, 2022).

The drive for decarbonisation has resulted in a progressive change in the net load profile of the system with incremental reductions in net load during daylight hours. This has been termed a 'duck curve'. This shape has become extreme and has been referred to as a 'canyon' by EPRI (Patel, 2023a). Figure 76 illustrates the progression of this net load profile from 2015 to 2023. In 2023 the net load became negative, representing an excess of generation requiring curtailment and export due to excessive production.

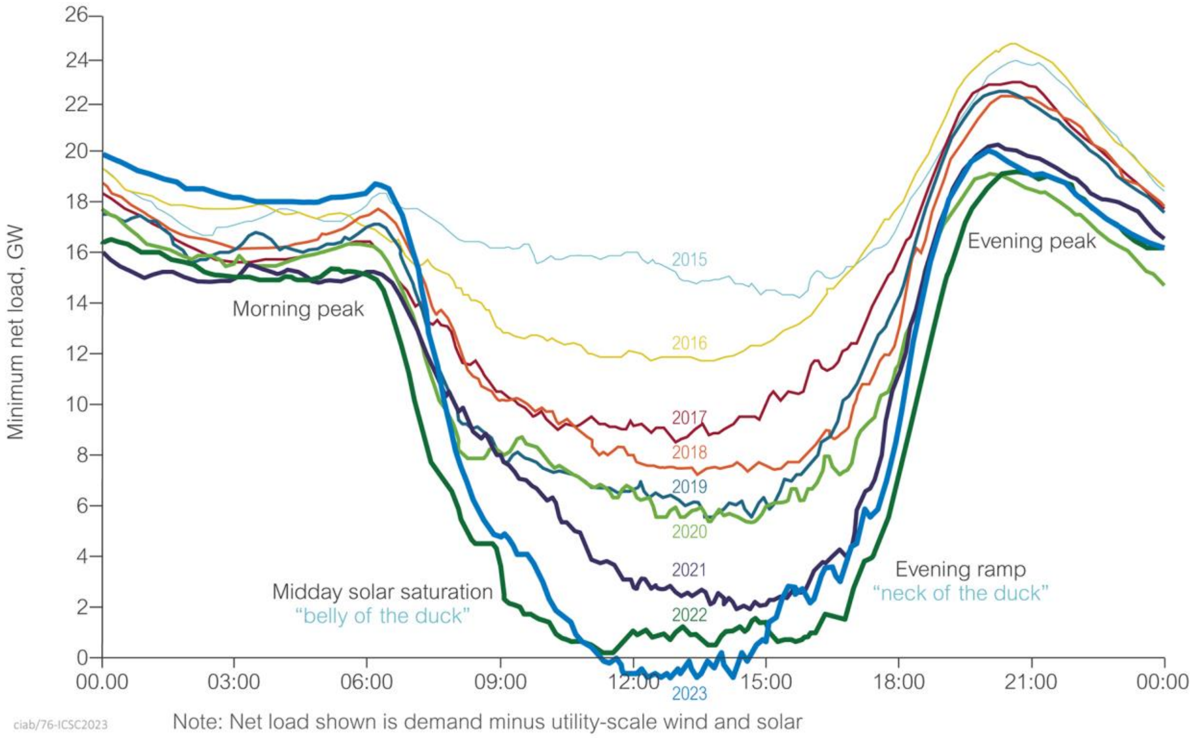

Figure 76 The evolution of California's 'duck curve' net load profile (Bartholomew, 2023a)

High levels of production and the ability to export power can be a problem for a system operator. Figure 77 gives an example of a weekend in April 2023. During the day, solar power provided a large share of system generation which fell away as evening came. Conversely, the demand was lower at midday and solar power needed to be curtailed, even after accounting for charging up energy storage and exporting power. When solar reduced in the evening, dispatchable plant had to be deployed and ramped rapidly to satisfy demand, including switching exports to imports and drawing down storage charged earlier during the day. So, even for an interconnected system with hydro and batteries, having a significant proportion of solar is sufficient to require curtailment. In this example, fossil fuel assets and power imports are necessary to support the system outside daylight hours.

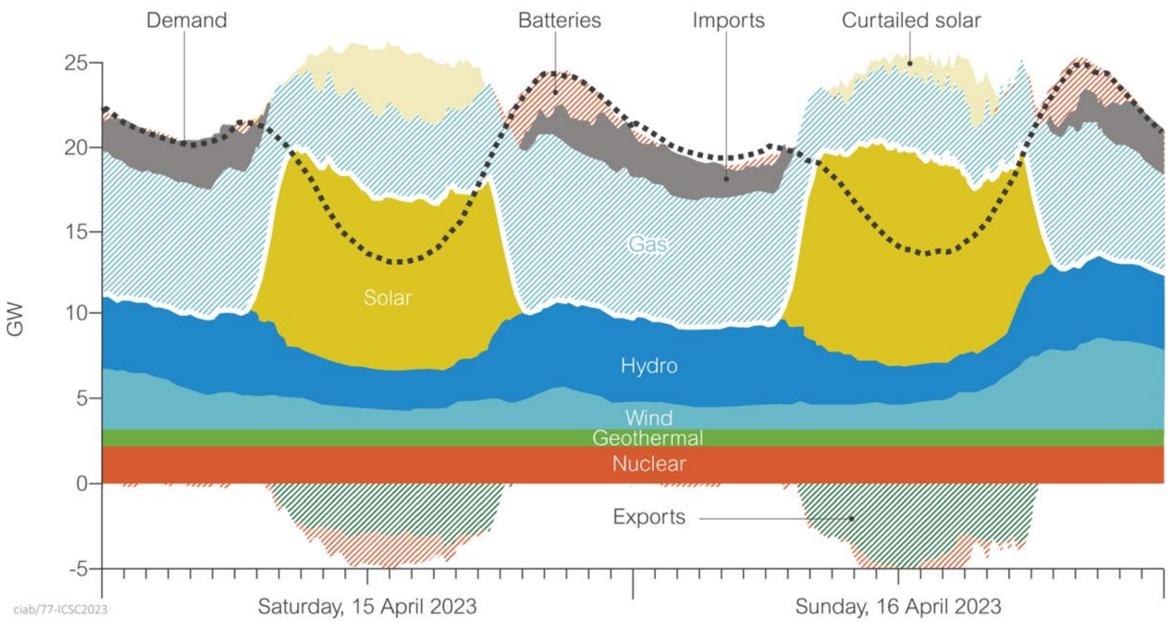

Figure 77 The daily challenge to manage California's VRE-heavy power system (Bartholomew, 2023b)

The California example highlights the issues around intermittency, and some of the concerns about costs, since prices swing heavily depending on whether there is a surplus or shortfall in power. During times of high demand, typically extreme heat for California, and limited variable resources when imports are already at maximum operating capacity, margins can become tight.

California has come close to rolling blackouts due to tight margins, most recently in the summer of 2022 when there were ten consecutive days of voluntary conservation alerts culminating in CAISO reaching its highest system alert level (California ISO, 2022). Daily average power prices rose to 600 \$/MWh and the real-time market reached 2000 \$/MWh. CAISO attributed its ability to avoid blackouts during this period to conservation measures of consumers and to the approximately 3.5 GW of storage that had been added since mid-2020 (Howland, 2022). At the same time, California has seen a steady and exponential increase in the need to curtail wind and solar generation. California currently represents 13% of all US grid connection requests for electricity storage.

Conlon (2023) pointed to a potential phenomenon of emissions intensity failing to decrease in California as the share of solar and wind in the portfolio increases. Figure 78 shows how, although the minimum emissions have reduced over time, the average has not. This is believed to be due to the increasing need for gas-fired backup, which due to rapid cycling and high ramp rates, is operating at low efficiency, outweighing the gains from renewable power. Empirically other regions are also showing a similar pattern of stalling carbon intensity reductions.

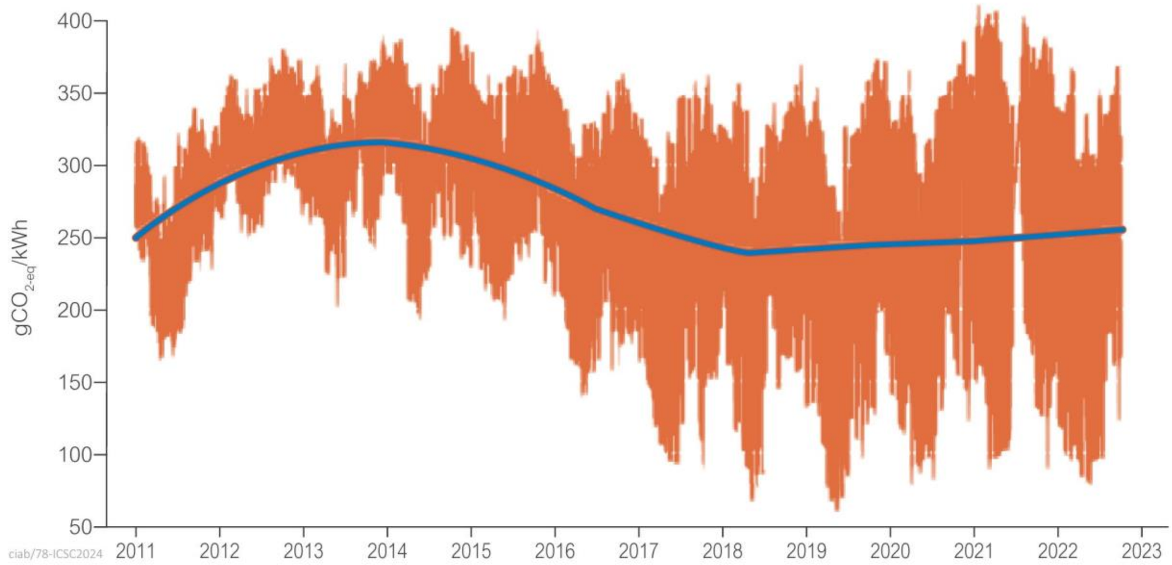

Figure 78 Carbon intensity variation with time, California, hourly January 2011-September 2022 (Chalmers, 2023)

California shows that the road to decarbonisation is neither easy nor cheap. Even with only 25% of generation from VRE, against the backdrop of its Senate Bill 100 and having strong interconnection and 4 GW of battery storage, the system still reaches extreme stress conditions resulting in both high-power prices and heavy curtailments.

Other regions

There is common concern that assets necessary for grid stability are being retired too quickly as system demand due to electrification is growing and replacement generation is predominantly from intermittent resources. In the Senate Energy and Natural Resources Committee hearing in June 2023 addressing the topic of reliability and resiliency of grid services, the President and CEO of PJM Interconnection stated, "If these trends continue our models show an increased risk of having insufficient resources later this decade to maintain the reliable electric service that consumers expect" (US Senate Committee on Energy and Natural Resources, 2023).

In the MISO region, 18,300 MW of coal plant has been retired since 2015 (America's Power, 2023). Installed capacity has increased by around 4200 MW over the past five years and yet at the same time its ability to cover peaks in demand dependably has reduced by 8300 MW overall. In MISO capacity zones 1–7 capacity prices in 2022-23 were reported to be 50 times the values recorded in the auction for the previous year. MISO reported that 'these zones have an increased risk of needing to implement temporary controlled load sheds'. New EPA rules relating to 'best available technology' are forecast to result in further closures, and it is anticipated that half the coal fleet is likely to retire before 2030 without intervention, the majority in the 2026-28 timeframe. MISO's increasing frequency of declarations of emergency, and during times not seen before, has prompted reforms to its methods of resource adequacy assessment (MISO, 2022).

Summary and opportunities

The US power system is large and mature, incorporating a wide range of generation technologies. It covers many regions with different climates, resources and population density. However, the complex nature of its stakeholder structure and responsibilities and the need for investment, grid expansion and reinforcement, coordination and collaboration are an area of risk. In addition, the methodology of focusing only on 'capacity' as a resource adequacy measure may be outdated as the share of VRE in the system rises and future demand evolves to meet new loads and environmental conditions.

The Texas example highlights that historic demand and weather patterns cannot be relied on in terms of ensuring high levels of resource adequacy and that generation assets must be 'weatherised' to be able to generate power in both extreme temperatures. It also demonstrates that system failures, even in a modern society with a mature grid, are a real threat with serious consequences and costs.

Some questions have been raised regarding the degree of interconnection of the ERCOT grid region (Cohn, 2022). However, the underlying problem is likely one of rising demand, extreme events and lack of capacity. The retirement of further dispatchable assets in Texas should be undertaken with caution given these experiences and consideration given to adding more dispatchable generation.

California has strong solar resources, often in excess of local needs, in the absence of either higher-capacity interconnections or high volumes of additional storage capable of time-shifting the surplus to periods of darkness. Adding storage would help with system self-sufficiency and the avoidance of solar curtailment, but there would be round trip storage losses, plus the costs of the storage facilities to consider. Storage would also not provide protection in the event of extended periods of low solar intensity. The question for California is therefore whether it is cheaper and more reliable to introduce stronger interconnections to provide security of supply or to build more clean dispatchable power within its own system.

Even with the current high volume of solar capacity, sufficient to cause significant forced PV curtailment, the system still relies on a proportion of fossil fuel for around half the day to ensure continuity of supply and exposes those assets to daily steep system ramping up and down to balance the VRE capacity. EIA data also shows that California has an average retail power price of 22.33 cents/kWh compared to the US average of 12.36 cents/kWh (EIA, 2022).

"NERC IS CONCERNED THAT THE PACE OF CHANGE IS OVERTAKING THE RELIABILITY NEEDS OF THE SYSTEM. UNLESS RELIABILITY AND RESILIENCE ARE APPROPRIATELY PRIORITISED, CURRENT TRENDS INDICATE THE POTENTIAL FOR MORE FREQUENT AND MORE SERIOUS LONG DURATION RELIABILITY DISRUPTIONS, INCLUDING THE POSSIBILITY OF NATIONAL CONSEQUENCE EVENTS."
(JAMES B ROBB, CEO, NERC)

6.5.2 Europe

The European power grid is a well-developed and highly interconnected system with good geospatial coverage. It spans regions with different resources and diverse shares of generation technologies incorporating areas favourable for wind and solar generation such as the North Sea for offshore wind, southern Europe for solar power and other areas rich in hydro resource or nuclear power.

Europe has the EU Emissions Trading Scheme (ETS) which establishes a value for carbon and has increased the costs for carbon emitting generation relative to low carbon sources. Incentive schemes such as feed-in tariffs, contracts for difference payments, levies and obligations in different nations have also driven market conditions for the deployment of renewable energy technologies.

The EU is a strong advocate of decarbonisation with a legally binding target for net zero greenhouse gas emissions by 2050. Under the European Climate Law, the EU committed to reduce its net greenhouse gas emissions by at least 55% by 2030, relative to 1990. The 'Fit for 55' package of legislation obliges all sectors of the EU economy to meet this target. Through its REPowerEU plan, it proposes to increase the EU's 2030 target for renewables to 45% in the EU mix, 169 GW more than the original 'Fit for 55' package, including the deployment of almost 600 GW of solar power by 2030. Like many regions, Europe also suffers from a backlog of applications for grid connection and many years of delays to deploy projects. It therefore also proposes to revise the Renewable Energy Directive to speed up the permitting process for renewable energy projects, including grid infrastructure and designate renewable energy as an 'overriding public interest' (EC, 2022).

A coal phase-out is in progress in Europe and there is a commitment in most countries in the region to phase out all existing unabated coal by 2030 in order to meet the requirements of the Paris Agreement, the Fit for 55 targets, and in line with IEA net zero roadmap calling for the phase out of unabated coal in advanced economies by 2030. The EU is also calling for a move towards the elimination of all unabated fossil fuels in energy systems globally 'well ahead' of 2050 (Abnett, 2023). In the UK, a country with a historically large coal generation share, the government has targeted achieving a net zero electricity system by 2035 (Department for Business, Energy and Industrial Strategy, 2021) and has one remaining coal-fired power plant scheduled for closure in 2024.

Much of the early decarbonisation of power in the EU since the 1990s was due to a fuel shift towards gas-fired generation from coal for dispatchable power. Gas-fired power remains dominant; to decarbonise it, CCS will be required. But most decarbonisation has been from the introduction of renewables combined with the closure or reduced running of fossil fuel plants.

The characteristic data for the European continental region is shown in Table 20.

TABLE 20 CHARACTERISTIC DATA FOR THE EUROPEAN CONTINENTAL REGION

Based on data from EIA database, September 2023 *EIA regional continental classification basis*	EUROPE			
	2011	2021	10 year change (%)	2021 vs World
Population (millions)	609.8	639.9	5	0.08
GDP (2015$PPP basis)	21,632	25,329	17	0.19
Energy intensity (mBtu per person)	135.7	125.2	-8	1.64
Electricity consumption (TWh)	3,367	3,430	2	0.14
Installed capacity (GW)	1,065	1,322	24	0.17
Fossil fuels (%)	51	38	-26	0.11
Nuclear ($)	11.8	8.6	-27	0.30
Renewables (%)	32.3	49.0	52	0.21
Hydroelectricity (%)	15.2	14.0	-8	0.16
Geothermal (%)	0.1	0.3	71	0.23
Tide and wave (%)	0.0	0.0	-11	0.46
Solar (%)	5.1	14.1	175	0.22
Wind (%)	9.0	17.3	92	0.28
Biomass and waste (%)	2.8	3.3	18	0.29
Hydroelectric pumped storage (%)	5.3	4.7	-12	0.36
Wind and solar as % total installed capacity	14.2	31.5	122	1.51
Generation (TWh)	3,620	3,672	1	0.13
Fossil fuels (%)	50	37	-25	0.08
Nuclear (%)	24	21	-16	0.28
Renewables (%)	26	42	63	0.20
Hydroelectricity (%)	15	17	14	0.15
Geothermal (%)	0.3	0.6	107	0.25
Tide and wave (%)	0.0	0.0	5	0.52
Solar (%)	1.3	5.2	301	0.19
Wind (%)	5.1	13.4	162	0.27
Biomass and waste (%)	4.3	5.9	36	0.34
Wind and solar as % generation	6.4	18.7	190	1.79
Overall capacity utilisation (%)	38.8	31.7	-18	0.82
Fossil fuels (%)	38.3	31.6	-18	0.73
Nuclear (%)	80.3	75.6	-6	0.92
Renewables (%)	31.2	27.3	-12	0.93
Hydroelectricity (%)	38.1	38.7	2	0.95
Geothermal (%)	78.9	78.1	-1	1.09
Tide and wave (%)	24.9	24.0	-3	1.13
Solar (%)	9.9	11.8	19	0.85
Wind (%)	21.9	24.5	12	0.98
Biomass and waste (%)	60.5	56.9	-6	1.16

The data show that Europe has about 8% of the global population. Population is increasing slowly, and GDP grew at 17% over the period, similar to the USA, but about half that of the global average. Europe consumes about 14% of global power with an energy intensity of 1.64 compared to the global average. It has approximately 17% of global power generation capacity with around 30% of global nuclear and 21% of global renewables by capacity. Wind and solar generated around 18.7% of its power in 2021, an increase of about three times over the previous ten years, with average solar and wind capacity utilisation of 11.8% and 24.5% respectively. Over the ten-year period fossil fuel and nuclear power generation have decreased by 25% and 16% respectively whilst total renewables have increased by 63%. Fossil fuels contributed 37% of power production in 2021, representing about 11% of the fossil fuel produced electricity globally. VRE has grown rapidly and reached 80% above the global average as a share of generation. This growth has started to create some difficult market conditions in terms of periodic excess supply and negative prices. However, the total VRE capacity and overall VRE share of the generation mix is still relatively low on an overall basis at 31.5% and 18.7%. This indicates that as the share continues to increase, significant market volatility is likely to emerge which will need to be addressed to ensure all necessary stakeholders can maintain viable business models.

Poland

Table 21 shows that most of Poland's power (82%) is generated from fossil fuels. This compares to the world at 62% and the European continent at 37%. This is because Poland has substantial coal resources and a lack of nuclear and hydro compared to the rest of Europe. However, wind and solar combined make up 12% of generation, higher than the global average, and similar to the USA at 13%, having increased almost six-fold over the last ten years. This has enabled a reduction in fossil fuel use of around 11% while total generation increased by 12%. Poland is expected to be the last major EU economy to have less than 50% clean power in 2030, with a target of 36% compared to other EU countries ranging from 65–100% (Czyzak, 2023).

TABLE 21 CHARACTERISTIC DATA FOR POLAND					
Based on data from EIA database, September 2023 *EIA regional continental classification basis*	POLAND				
	2011	2021	10 year change (%)	2021 vs Region	2021 vs World
Population (millions)	38.1	37.7	-1	0.06	0.00
GDP (2015$PPP basis)	924	1,263	37	0.05	0.01
Energy intensity (mBtu per person)	107.9	90.7	-16	0.72	1.19
Electricity consumption (TWh)	133	158	19	0.05	0.01
Installed capacity (GW)	35	55	57	0.04	0.01
Fossil fuels (%)	87	67	-23	0.07	0.01
Nuclear ($)	0.0	0.0	–	–	–
Renewables (%)	7.6	29.7	292	0.03	0.01
Hydroelectricity (%)	1.6	1.1	-32	0.00	0.00
Geothermal (%)	0.0	0.0	–	–	–
Tide and wave (%)	0.0	0.0	–	–	–
Solar (%)	0.0	14.0	487,351	0.04	0.01
Wind (%)	5.2	12.7	146	0.03	0.01
Biomass and waste (%)	0.8	1.9	140	0.02	0.01
Hydroelectric pumped storage (%)	5.1	3.3	-36	0.03	0.01
Wind and solar as % total installed capacity	5.2	26.7	416	0.85	1.28
Generation (TWh)	149	167	12	0.05	0.01
Fossil fuels (%)	91	82	-11	0.10	0.01
Nuclear (%)	0	0	–	–	–
Renewables (%)	9	19	109	0.02	0.00
Hydroelectricity (%)	2	1	-10	0.00	0.00
Geothermal (%)	0.0	0.0	–	–	–
Tide and wave (%)	0.0	0.0	–	–	–
Solar (%)	0.0	2.3	1,970,012	0.02	0.00
Wind (%)	2.1	9.7	354	0.03	0.01
Biomass and waste (%)	5.2	5.1	-1	0.04	0.01
Wind and solar as % generation	2.1	12.0	462	0.64	1.15
Overall capacity utilisation (%)	48.8	34.7	-29	1.10	0.89
Fossil fuels (%)	51.1	42.3	-17	1.34	0.98
Nuclear (%)	–	–	–	–	–
Renewables (%)	57.3	21.7	-62	0.79	0.74
Hydroelectricity (%)	46.8	44.1	-6	1.14	1.09
Geothermal (%)	–	–	–	–	–
Tide and wave (%)	–		–	–	–
Solar (%)	2.0	5.7	187	0.48	0.41
Wind (%)	20.2	26.5	31	1.08	1.06
Biomass and waste (%)	319.2	93.4	-71	1.64	1.91

The energy intensity of Poland is around 28% lower than the European continental average. Population is stable but GDP is growing showing a 37% increase over the period.

Ownership and operation of Poland's electricity infrastructure (generation, transmission and distribution) is concentrated within a few companies that are owned or controlled by the state treasury (IEA, 2022c). The Polish grid is well-established (*see* Figure 79). Geographic coverage with HV transmission is good including over 15,000 km of lines. In 2020, Poland's maximum technical interconnection capacity was 11.8 GW which is high relative to peak demand and spread between various interconnectors and countries. The system includes interconnections to Germany, Czechia, Slovakia and Ukraine with ten HV AC lines. The interconnections to Sweden and Lithuania use DC lines (IEA, 2022c). Peak demand as recorded in February 2021 was 27.62 GW when winter temperatures fell to below -20°C.

Storage capacity is limited with 1.7 GW, 7.6 GWh of pumped hydro in 2020 and a negligible quantity of battery storage. The national strategy EPP2040 sets a target for 1 GW of non-pumped hydro storage by 2040. Every year the TSO publishes a 5-year adequacy assessment, considering expected market developments and possible supply shortages. In 2018, Poland established a capacity market mechanism to address concerns over the adequacy of generation capacity (IEA, 2022c).

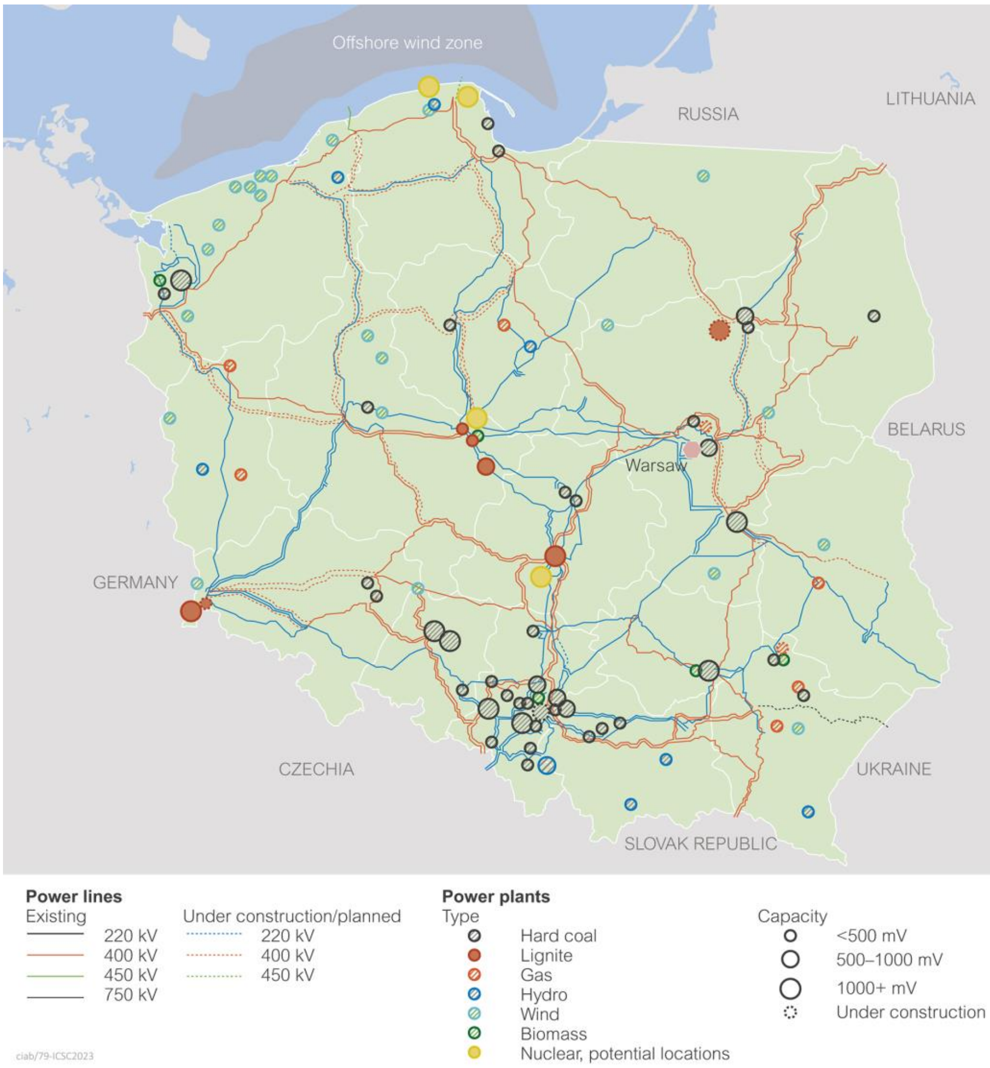

Figure 79 Polish electricity grid (IEA, 2022c)

Government support for solar PV has made Poland one of the fastest growing PV markets in the EU. From 2016 to 2021, Poland's PV capacity increased from 0.2 GW to 7.7 GW, driven mostly by residential deployment of small-scale distributed PV systems (5.9 GW). Poland also has a comprehensive and well-designed offshore wind strategy that has resulted in deals for 5.9 GW of capacity to come online by 2027 and plans for at least 11 GW by 2040 (IEA, 2022b). Poland has a target for renewable energy share in electricity generation of 32% by 2030. According to Czyzak(2023), 100 GW of renewable capacity may be feasible by 2040, including 36 GW of onshore wind, 18 GW of offshore wind and 44 GW of solar.

As a member of the EU, Poland needs a pathway to discontinue unabated coal generation by 2030. In 2020 the government and mining unions signed a social contract which discontinues the mining of hard coal in Poland by 2050. This does not cover the mining or use of lignite. As with other European countries, fuel switching to gas is seen as a means towards decarbonisation with growth of 40 TWh/y expected between 2019 and 2040 (Czyzak, 2023). The extent of this transition to gas may be limited by concerns regarding energy dependency and market risk exposure.

The move to renewable energy has received some criticism. In September 2023, the Polish grid operator Polskie Sieci Elektroenergetyczne (PSE) announced a 'danger period' and asked some users to reduce consumption after margins became tight and triggered intervention. This was attributed to lower than anticipated VRE output combined with limited coal reserves resulting from low stocks after ceasing Russian coal imports and longer-term issues related to unfavourable market conditions for coal plant operation (Reuters, 2023b). In April 2023, PSE declared an over-supply of VRE and ordered solar and wind facilities to shut down to protect the system due to limitations of the flexibility of its coal plants already online. This had been done previously in 2022 due to an excess of wind power. On 31 December 2022, wind generated almost 40% of Polish power, despite curtailment. This makes Poland another example of a country where even a limited total system share of VRE can cause significant short-term issues due to variability of output depending on total demand and prevailing weather and market conditions.

Poland is introducing nuclear power to its system aiming for the first reactor with a capacity of 1–1.6 GW to be in operation by 2033 and for six reactors with a total capacity of 6–9 GW to be in operation by 2043. The International Atomic Energy Agency (IAEA) has approved the Polish nuclear programme and the first plant at Lubiatowo-Kopalino in the province of Pomerania will start construction in 2026 (Shaw, 2023). The government estimates that by 2040, nuclear energy could account for up to 16% of generation (IEA, 2022b).

Transition in the Polish electricity system and its associated costs were considered for the ICSC by Pratama and Mac Dowell (2022). Their work mapped out a potential lowest-cost strategy for Poland's transition to net zero by 2050 using the full range of technology options available. The results are shown in Figure 80.

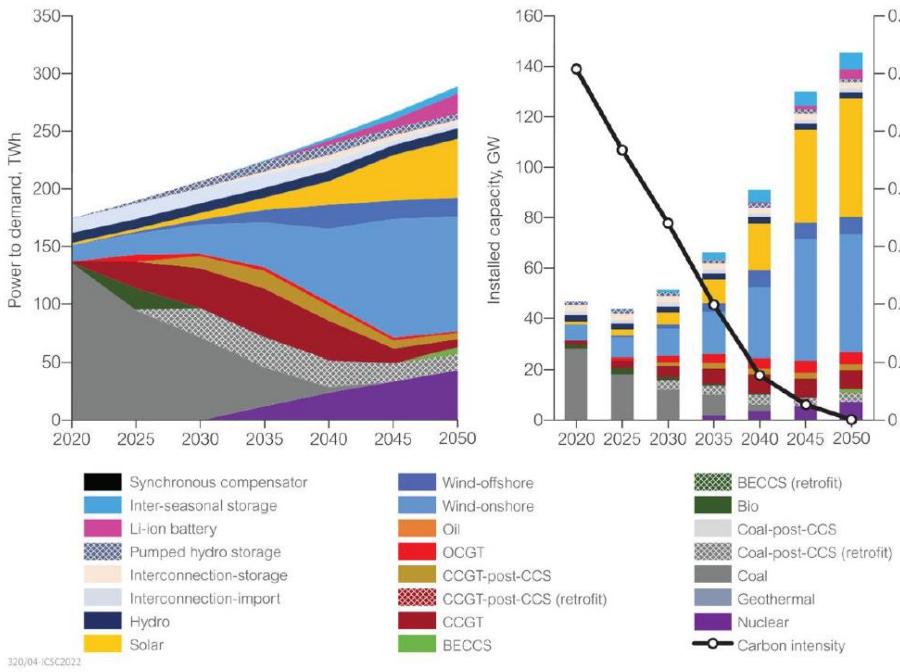

Figure 80 Pathway to net zero transition in Poland in an 'all-tech' scenario (Pratama and Mac Dowell, 2022)

Their work shows the expected trend of increasing total system cost with deeper levels of decarbonisation and a substantial difference in cost between those scenarios where CCS was included and those where it was not. This point is illustrated by Figure 81 which shows the high potential of CCS technology to reduce overall system costs in achieving net zero while making use of large-scale existing assets.

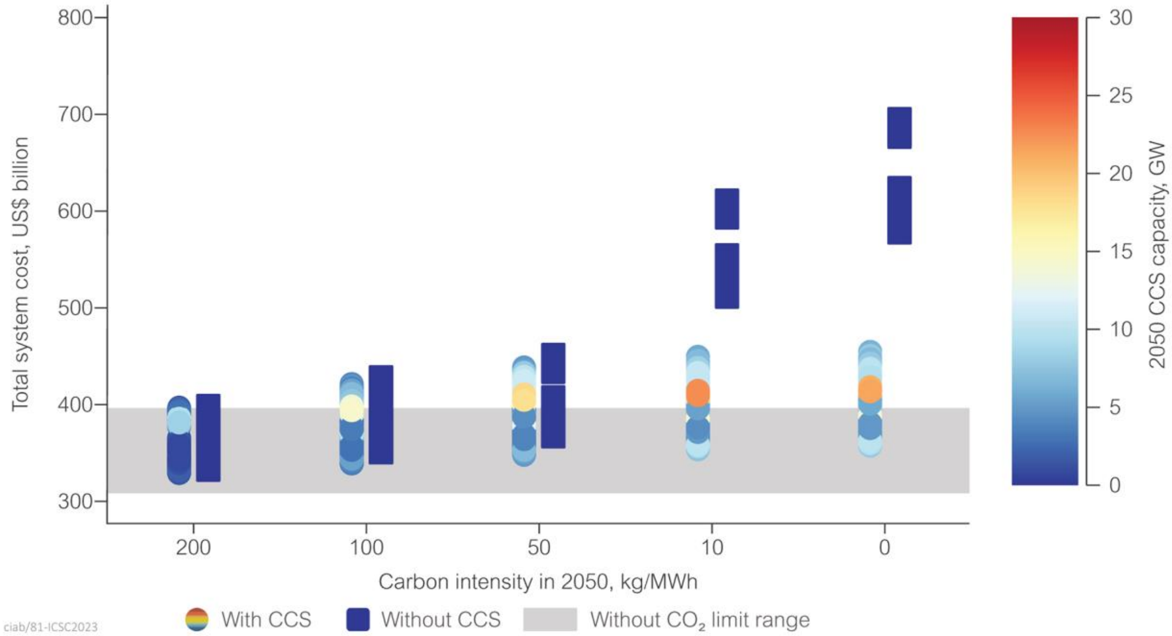

Figure 81 Role of CCS in reducing system decarbonisation cost (Pratama and Mac Dowell, 2022)

Poland is updating its future energy strategy paper for 2040. The draft of this paper, not finalised at the time of writing (October 2023), indicates an evolution of the electricity supply portfolio to 2040 (*see* Table 22).

TABLE 22 NET INSTALLED TECHNOLOGY CAPACITY IN THE PORTFOLIO, MW (%) (MINISTRY OF CLIMATE AND ENVIRONMENT (MKIŚ), 2023)

	2025		2030		2035		2040	
	Units: MW and percentage in parentheses							
Zero emission power capacity	33,135	(50)	50,740	(57)	72,425	(67)	95,465	(74)
Renewables power capacity	33,135	(50)	50,440	(57)	69,025	(64)	87,625	(68)
Nuclear power capacity	0	–	300	(0)	3,400	(3)	7,840	(6)
Coal power capacity	24,398	(38)	19,493	(22)	14,335	(13)	10,095	(8)
Hard coal power capacity	17,878	(28)	12,973	(15)	10,998	(10)	9,412	(7)
Lignite power capacity	6,520	(10)	6,520	(7)	3,337	(3)	683	(1)
Gas power capacity	5,732	(9)	13,009	(15)	13,115	(12)	13,107	(10)
Other	2,543	(4)	5,528	(6)	8,518	(8)	11,068	(9)

This transition aspiration indicates a substantial shift towards renewable capacity in the coming years and a rapid reduction in coal use, albeit not a total coal phase-out as called for by the EC. The share of coal indicated by capacity suggests a significant reduction from previous estimates that coal would still hold a 38% share of electricity production in 2035 and 28% in 2040 (Polish Electricity Association, 2022). There are however some questions regarding these deployment targets, particularly if those for nuclear power are achievable considering deployment timeline experience elsewhere (*see* Section 5.8.1 and Figure 66).

Summary and opportunities

Europe is pressing ahead with ambitious action and targets for decarbonisation of electricity supply. Whether this can be achieved practically and economically and to what extent the rapidly increasing VRE capacity can be managed with respect to grid and market stability remains to be seen. Arguably the share of VRE is still relatively low on an annual basis even though there are reports of very high shares in certain regions on low demand days where conditions are favourable for high VRE output. As Europe has a variety of resources and a well-interconnected system with plans for further interconnection capacity, this may reduce the severity of impacts from a high share of VRE. However, more storage will be required, and the retirement of existing fossil fuel plants will test the ability of system planners to manage that transition while maintaining acceptable levels of reliability. This ambitious rate of change may also increase costs to the consumer, either directly through energy prices or indirectly through taxation.

"THERE IS NO GREEN FUTURE FOR EUROPE WITHOUT AN UPGRADED POWER GRID"
KADRI SIMSON, EU COMMISSIONER FOR ENERGY

Poland is often cited as a country with high carbon intensity and reliance on coal. However, it also has around 12% of its generation from wind and solar (2021 data) compared to a global average of around 10.4% and challenging growth targets for renewables and nuclear. There remains large potential for the development of additional renewable capacity together with a pressing need for energy storage to manage intermittency.

Poland's coal fleet is relatively old, has low efficiency and is inflexible. For reasons of age and policy this fleet will be refreshed with new capacity of different technology. It seems unlikely to include new coal-fired plant. Although CCS may be an option for Poland it would not be retrofitted to assets nearing the end of their operating lives. Poland's efforts to develop its solar, offshore wind resources and introduce nuclear power generation will continue to assist its reduced use of fossil fuels. However, it seems likely that more dispatchable generation will be needed than is present in the current plan.

Poland needs to accelerate its expansion of the transmission and distribution systems to accommodate an increasing share of renewables, support electrification and ensure a stable and reliable system. The chief executive of Polish grid operator PSE, Tomasz Sikorski, told Reuters that Poland's transmission and distribution grids will need $116 billion (PLN500 billion) of investment by 2040 (Jones, 2023).

"INVESTMENT IN RENEWABLE ENERGY SOURCES IS NOT ONLY ABOUT BUILDING INSTALLATIONS, IT IS ALSO ABOUT THE HUGE COSTS OF DEVELOPING DISTRIBUTION SYSTEMS AND THE TRANSMISSION SYSTEM"
(MAŁGORZATA KOZAK, DIRECTOR OF MARKET DEVELOPMENT AND CONSUMER AFFAIRS
POLISH ENERGY REGULATORY OFFICE (URE))

6.5.3 Asia-Oceania

The Asia-Oceania continental region contains more than half of the global population and is undergoing rapid economic development with associated rising energy demand. Current energy intensity is below the global average. The characteristic data for the Asia-Oceania continental region as defined in the EIA data set are shown in Table 23.

TABLE 23 CHARACTERISTIC DATA FOR THE ASIA-OCEANIA CONTINENTAL REGION

Based on data from EIA database, September 2023 *EIA regional continental classification basis*	ASIA AND OCEANIA			
	2011	2021	10 year change (%)	2021 vs World
Population (millions)	3,927.3	4,289.8	9	0.54
GDP (2015$PPP basis)	35,584	57,002	60	0.42
Energy intensity (mBtu per person)	55.0	64.2	17	0.84
Electricity consumption (TWh)	7,844	12,665	61	0.50
Installed capacity (GW)	2,027	3,853	90	0.48
Fossil fuels (%)	71	57	-20	0.50
Nuclear ($)	4.2	2.6	-39	0.26
Renewables (%)	21.6	38.3	77	0.49
Hydroelectricity (%)	16.5	13.3	-20	0.43
Geothermal (%)	0.2	0.2	-27	0.41
Tide and wave (%)	0.0	0.0	125	0.50
Solar (%)	0.6	13.1	2,093	0.59
Wind (%)	3.4	10.2	202	0.48
Biomass and waste (%)	0.9	1.5	76	0.39
Hydroelectric pumped storage (%)	3.0	2.1	-31	0.46
Wind and solar as % total installed capacity	4.0	23.4	486	1.12
Generation (TWh)	8,499	13,447	58	0.49
Fossil fuels (%)	79	69	-12	0.55
Nuclear (%)	5	5	-3	0.26
Renewables (%)	16	26	62	0.44
Hydroelectricity (%)	13	14	4	0,43
Geothermal (%)	0.3	0.3	-14	0.42
Tide and wave (%)	0.0	0.0	-2	0.48
Solar (%)	0.1	4.3	3,074	0.56
Wind (%)	1.3	5.5	323	0.41
Biomass and waste (%)	1.0	2.0	93	0.41
Wind and solar as % generation	1.4	9.9	583	0.95
Overall capacity utilisation (%)	47.9	39.8	-17	1.02
Fossil fuels (%)	53.1	48.4	-9	1.12
Nuclear (%)	61.8	81.3	32	0.99
Renewables (%)	35.0	26.6	-24	0.91
Hydroelectricity (%)	37.6	40.6	8	1.00
Geothermal (%)	73.9	72.1	-2	1.01
Tide and wave (%)	56.5	20.4	-64	0.96
Solar (%)	10.9	13.1	20	0.95
Wind (%)	18.4	21.5	17	0.86
Biomass and waste (%)	56.3	51.3	-9	1.05

Table 23 shows that fossil fuel accounted for 69% of generation in 2021, but with the share down 12% over the last 10 years, while the share of wind and solar increased approximately seven-fold. The areas differ widely in terms of their access to natural gas, and many have limited or no national natural gas infrastructure. As a result, coal, a commodity with abundant local resources, is often used for power, process and heating purposes. As economies expand, coal is inherently a key part of that expansion strategy which ensures an affordable and secure power system and builds on existing knowledge, supply chains and infrastructure.

China

China is a huge country, home to approximately 18% of the world population and has a large global influence economically, in commodity markets, environmentally and politically. It is industrialised and consumes 30% of global electricity. It covers many diverse geographic regions and has substantial coal resources but limited natural gas. China contributes more than half of the total global investment in the energy transition (BloombergNEF, 2023). The characteristic data for China as defined in the EIA data set are shown in Table 24.

TABLE 24 CHARACTERISTIC DATA FOR CHINA

Based on data from EIA database, September 2023 *EIA regional continental classification basis*	CHINA				
	2011	2021	10 year change (%)	2021 vs Region	2021 vs World
Population (millions)	1,358.6	1,427.1	5	0.33	0.18
GDP (2015$PPP basis)	13,397	26,638	91	0.45	0.19
Energy intensity (mBtu per person)	90.1	115.7	28	1.80	1.51
Electricity consumption (TWh)	4,183	7,806	87	0.62	0.31
Installed capacity (GW)	1,067	2,356	121	0.61	0.29
Fossil fuels (%)	72	53	-27	0.57	0.28
Nuclear ($)	1.1	2.3	105	0.54	0.14
Renewables (%)	25.2	43.3	72	0.69	0.34
Hydroelectricity (%)	20.1	15.1	-25	0.69	0.30
Geothermal (%)	0.0	0.0	8	0.00	0.00
Tide and wave (%)	0.0	0.0	25	0.00	0.00
Solar (%)	0.3	13.0	4,385	0.61	0.36
Wind (%)	4.3	14.0	222	0.83	0.40
Biomass and waste (%)	0.4	1.3	193	0.51	0.20
Hydroelectric pumped storage (%)	1.7	1.5	-10	0.45	0.21
Wind and solar as % total installed capacity	4.6	27.0	483	1.16	1.29
Generation (TWh)	4,465	8,152	83	0.61	0.30
Fossil fuels (%)	80	66	-18	0.58	0.32
Nuclear (%)	2	5	160	0.58	0.15
Renewables (%)	18	29	63	0.69	0.30
Hydroelectricity (%)	15	16	3	0.70	0.30
Geothermal (%)	0.0	0.0	9	0.00	0.00
Tide and wave (%)	0.0	0.0	71	0.00	0.00
Solar (%)	0.1	4.2	7,081	0.59	0.33
Wind (%)	1.6	7.5	376	0.82	0.34
Biomass and waste (%)	0.9	1.7	95	0.52	0.21
Wind and solar as % generation	1.6	11.7	615	1.19	1.12
Overall capacity utilisation (%)	47.8	39.5	-17	0.99	1.02
Fossil fuels (%)	53.4	49.4	-7	1.02	1.14
Nuclear (%)	83.2	87.4	5	1.07	1.07
Renewables (%)	33.6	26.4	-21	0.99	0.90
Hydroelectricity (%)	36.2	41.0	13	1.01	1.01
Geothermal (%)	55.2	55.3	0	0.77	0.77
Tide and wave (%)	20.0	27.4	37	1.34	1.29
Solar (%)	9.6	12.7	32	0.97	0.91
Wind (%)	17.3	21.2	22	0.99	0.85
Biomass and waste (%)	95.0	52.3	-45	1.02	1.07

GDP has grown by 91% over the 10-year period with electricity energy consumption increasing 87%. Installed power generating capacity has more than doubled. Fossil fuels constitute 66% of generation although their relative share has reduced by 18%. Solar and wind as a share of generation has increased more than seven-fold resulting in wind and solar output nearly 40% higher than Europe. 30% of the world's hydroelectric power generation is in China.

China Southern Power Grid Company Limited is a centrally managed state-owned key enterprise, with the State-owned Assets Supervision and Administration Commission of the State Council as the investor. The company is responsible for investing, constructing and operating the power grid in the southern region. Inner Mongolia Power (Group) Co Ltd is a large, wholly state-owned power grid enterprise directly under the Inner Mongolia Autonomous Region. It is responsible for the construction and operation of the central and western power grids in the autonomous region, covering an area of 720,000 km^2 (*see* Figure 82) (Sheng, 2023).

The Chinese power grid was estimated at almost 1,300,000 km in 2020, only for lines over 220 kV and was growing at a rate of approximately 60,000 km/y (CEIC, 2021). Peak demand in the Chinese grid system is expected to reach 1370 GW in 2023, 80 GW (6.2%) higher than in 2022 (Zhijian, 2023).

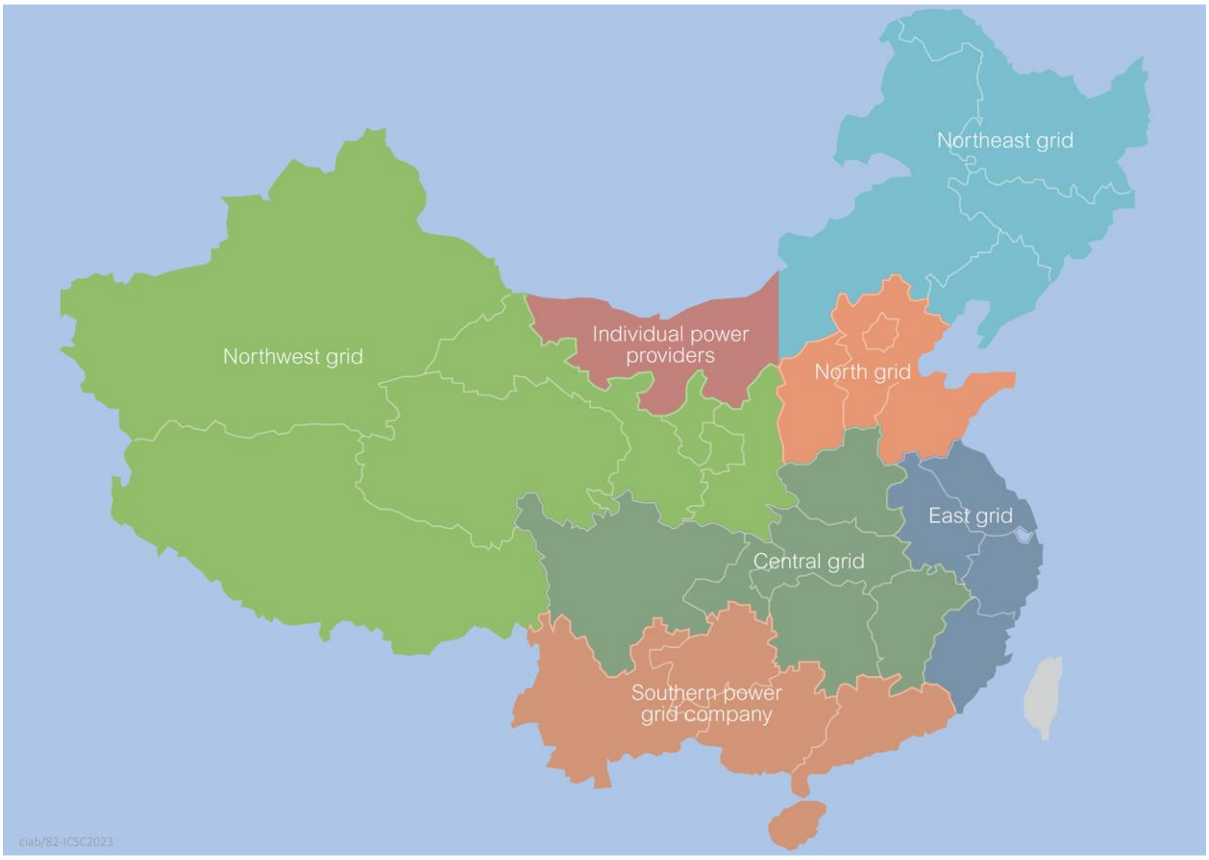

Figure 82 China's power grid (based on Stratfor, 2012)

Since 2002 when the state monopoly of the power system was withdrawn, the electricity market has gradually been opened to competition and reform, with increasing separation between the state-owned grid and the power generation plants and market. By 2030 it is expected there will be a unified electricity market across all China with integrated design and joint operation of medium to long term, spot and ancillary service markets across all technologies, aimed at promoting the optimal use of national generation assets. According to (Hove, 2023), intra-provincial trading accounts for more than 80% of the market-traded electricity in China. The rest is traded inter-provincially, rising in share – with fluctuations – from 17.9% in 2017 to 19.7% in 2022. The volume of electricity traded on the intra-provincial market totalled 4218 TWh in 2022, compared with 1036 TWh on the inter-provincial market, both amounts being three times higher than in 2017 (Fang and others, 2023).

The power grid of China is operated by State Grid Corporation of China, China Southern Power Grid Company Limited and Inner Mongolia Power (Group) Co Ltd. State Grid Corporation of China is a centrally managed wholly state-owned company covering 26 provinces. Its power supply accounts for 88% of the national territory, serving a population of over 1.1 billion.

In 2020, China announced its 30/60 climate policy framework, outlining a goal of achieving peak carbon emissions by 2030 and climate neutrality before 2060. Efforts are being made to increase the flexibility of existing and new coal- and gas-fired plants together with options for battery storage and new pumped hydro regulate voltage. The aim of this work is to mitigate the challenges associated with VRE. It is recognised that peak shaving flexible plants are an additional cost and that total system costs will see a rapid increase as a result (Sheng, 2023).

Electrification is seen as key to emissions reductions overall and demand-side management is acknowledged to have an important role in managing supply and demand. System development also includes improvement to the coordination of planning and construction of new assets, transmission infrastructure, and the establishment of effective capacity mechanisms and markets.

The output from VRE sources is a challenge, both in its timing relative to power demand and its geographic location. The central and eastern regions account for 70% of demand but the solar resources are concentrated in the west, wind in the north and hydropower in the southwest. China is also not immune to the system stresses caused by variability. In May 2023, the Shandong spot energy market experienced 22 consecutive hours of negative power prices with generators effectively paying consumers to increase consumption of electricity due to oversupply. The negative prices coincided with a period of low demand. In addition, 80% of the coal-fired power generation in the province is combined heat and power, the output of which can be regulated to a limited extent. Such negative price incidents occurred previously in both December 2019 and 2021. These incidents highlight the need for flexibility, storage and interconnection of adequate capacity (S&P Global, 2023a).

In 2022, the period of extreme heat and low rainfall dried up the Yangtze River, reaching the lowest level on record in some parts, resulting in power shortages in Sichuan and Yunnan provinces, dependent on hydroelectricity. Officials curtailed supply to factories to ensure people could run air conditioners at home (Bloomberg, 2023).

China is continuing to invest in its electricity grids. In 2023, Xin Baoan, chair of China's State Grid Corporation stated that $329 billion would be invested in transmission in the plan period 2021-25. China Southern Power Grid also committed a further $99 billion. High- and ultra-high voltage DC lines will be built to connect new renewable sources to demand centres. According to Shenwan Hongyuan Securities, $15 billion will be invested in converters in the period up to 2030. Everbright Securities also expects

$66 billion to be invested in UHVAC and UHVDC lines (typically 800–1100 kV) in the same period. State Grid currently has 33 UHV lines, AC and DC, with a combined inter-provincial and inter-regional transmission capacity of 300 GW (Wantenaar, 2023). China accounts for over one-third of the world's transmission grid expansion in the past decade, having constructed over half a million km of transmission lines (IEA, 2023d).

Given the fleet of modern and efficient coal-fired power plants in China and the ongoing planning and construction of new coal-fired facilities, China is a strong market for CCS. This could decarbonise a large portion of the power system while ensuring adequate grid stability and dispatchable power. Ammonia cofiring is also being investigated as an option for older coal plants or for infrequent operations. Section 4.6.2 provides further detail on the status of CCS including projects in China where potential is high and large-scale implementation is beginning.

China's National Development and Reform Commission (NDRC) said in a March 2022 document outlining energy policy, that the world's largest coal user 'will rationally build advanced coal-fired power plants based on development needs.' Consequently, China plans to build some 100 new coal-fired power plants to back up wind and solar capacity.

Thus, China will likely continue to use coal in the coming decades but with a decreasing share and increasing application of technologies to reduce its environmental impact such as CCS and cofiring ammonia (Sheng, 2023).

In November 2023 China introduced a capacity payment scheme for coal-fired power plant to improve energy security, aimed at assisting coal plants in transitioning to provide flexible backup power rather than being rewarded only for output (Hove, 2023).

India

At 1,425.7 million people India has recently overtaken China as the world's most populous country with a population almost four times greater than reported in the 1951 census (United Nations, 2023). India has also moved up the ranking becoming the world's fifth-largest economy in 2023 (International Monetary Fund, 2023).

Over the period 2011-21 the population grew by around 12% compared to only 5% growth for China (EIA data). Electricity consumption grew by 71% over the same period. The characteristic data for India as defined in the EIA data set are shown in Table 25.

TABLE 25 CHARACTERISTIC DATA FOR INDIA

Based on data from EIA database, September 2023 *EIA regional continental classification basis*	INDIA				
	2011	2021	10 year change (%)	2021 vs Region	2021 vs World
Population (millions)	1,259.5	1,410.4	12	0.33	0.18
GDP (2015$PPP basis)	5,583	9,507	70	0.17	0.07
Energy intensity (mBtu per person)	18.4	23.4	27	0.36	0.31
Electricity consumption (TWh)	842	1,443	71	0.11	0.06
Installed capacity (GW)	239	469	96	0.12	0.06
Fossil fuels (%)	71	66	-7	0.14	0.07
Nuclear ($)	2.0	1.4	-28	0.07	0.02
Renewables (%)	24.8	31.4	26	0.10	0.05
Hydroelectricity (%)	16.3	10.0	-39	0.09	0.04
Geothermal (%)	0.0	0.0	–	–	–
Tide and wave (%)	0.0	0.0	–	–	–
Solar (%)	0.2	10.6	4,369	0.10	0.06
Wind (%)	6.7	8.5	27	0.10	0.05
Biomass and waste (%)	1.5	2.3	47	0.18	0.07
Hydroelectric pumped storage (%)	2.0	1.0	-49	0.06	0.03
Wind and solar as % total installed capacity	7.0	19.1	174	0.82	0.91
Generation (TWh)	1,045	1,702	63	0.13	0.06
Fossil fuels (%)	81	77	-4	0.14	0.08
Nuclear (%)	3	3	-7	0.06	0.02
Renewables (%)	17	20	20	0.10	0.04
Hydroelectricity (%)	13	10	-22	0.09	0.04
Geothermal (%)	0.0	0.0	–	–	–
Tide and wave (%)	0.0	0.0	–	–	–
Solar (%)	0.1	4.0	2,668	0.12	0.06
Wind (%)	2.3	4.6	95	0.10	0.04
Biomass and waste (%)	1.7	1.8	3	0.11	0.05
Wind and solar as % generation	2.5	8.5	243	0.87	0.82
Overall capacity utilisation (%)	49.9	41.4	-17	1.04	1.06
Fossil fuels (%)	56.5	48.4	-14	1.00	1.12
Nuclear (%)	69.1	73.9	7	0.91	0.90
Renewables (%)	33.6	26.4	-21	0.99	0.90
Hydroelectricity (%)	38.3	40.3	5	0.00	0.99
Geothermal (%)	–	–	–	–	–
Tide and wave (%)	–	–	–	–	–
Solar (%)	30.1	15.5	-49	1.18	1.12
Wind (%)	17.4	22.2	28	1.03	0.89
Biomass and waste (%)	55.5	32.3	-42	0.63	0.66

Despite being home to 18% of the world's population, India only consumes about 6% of global electricity and has an energy intensity nearly 70% below the world average. India is both the world's second-largest producer and second-largest consumer of coal, according to the EIA and fossil fuel electricity provided 77% of supply in 2021; the share is slightly reduced compared to ten years earlier.

Solar and wind growth rates are high; solar is growing quickly with almost 10% of total generation capacity, approximately 46 GW, added over the last ten years. India generates approximately 8% of the world's fossil fuel-based electricity, around the same as Europe in 2021. Wind and solar were 8.5% of actual generation in 2021 achieving a utilisation of 15.5% for solar and 22.2% for wind with renewables as a whole constituting 20% of power generation.

NTPC is India's largest power generator, owning nearly 18% of the country's operating capacity. Its assets include India's largest power plant, the 4760 MW coal-fired Vindhyachal Super Thermal Power Station in Madhya Pradesh, comprising 13 units built between 1987 and 2015. NTPC is 51% government-owned (S&P Global, 2022b).

Coal reserves are concentrated in the central and eastern parts of the country. Hydroelectric resources are mainly centred around the Himalayan range in the north and northeast. Wind and solar potential are mainly concentrated in states like Tamil Nadu, Andhra Pradesh, Karnataka, Rajasthan, Maharashtra, Gujarat and Ladakh. The major load centres are in the central part including Northern, Western and Southern regions. This geographic mismatch of resource and demand centres necessitates strong long-distance grid connections to transfer power.

A single national grid was established by the end of 2013, connecting all five regional grids. From 2013 to 2023 approximately 183,700 km of transmission lines were added to improve power flow within the country and ease congestion and curtailment. India now has one of the largest interconnected grids in the world with approximately 475,000 km of HV transmission network incorporating a number of 400–800 kV high voltage interconnectors (*see* Figure 83).

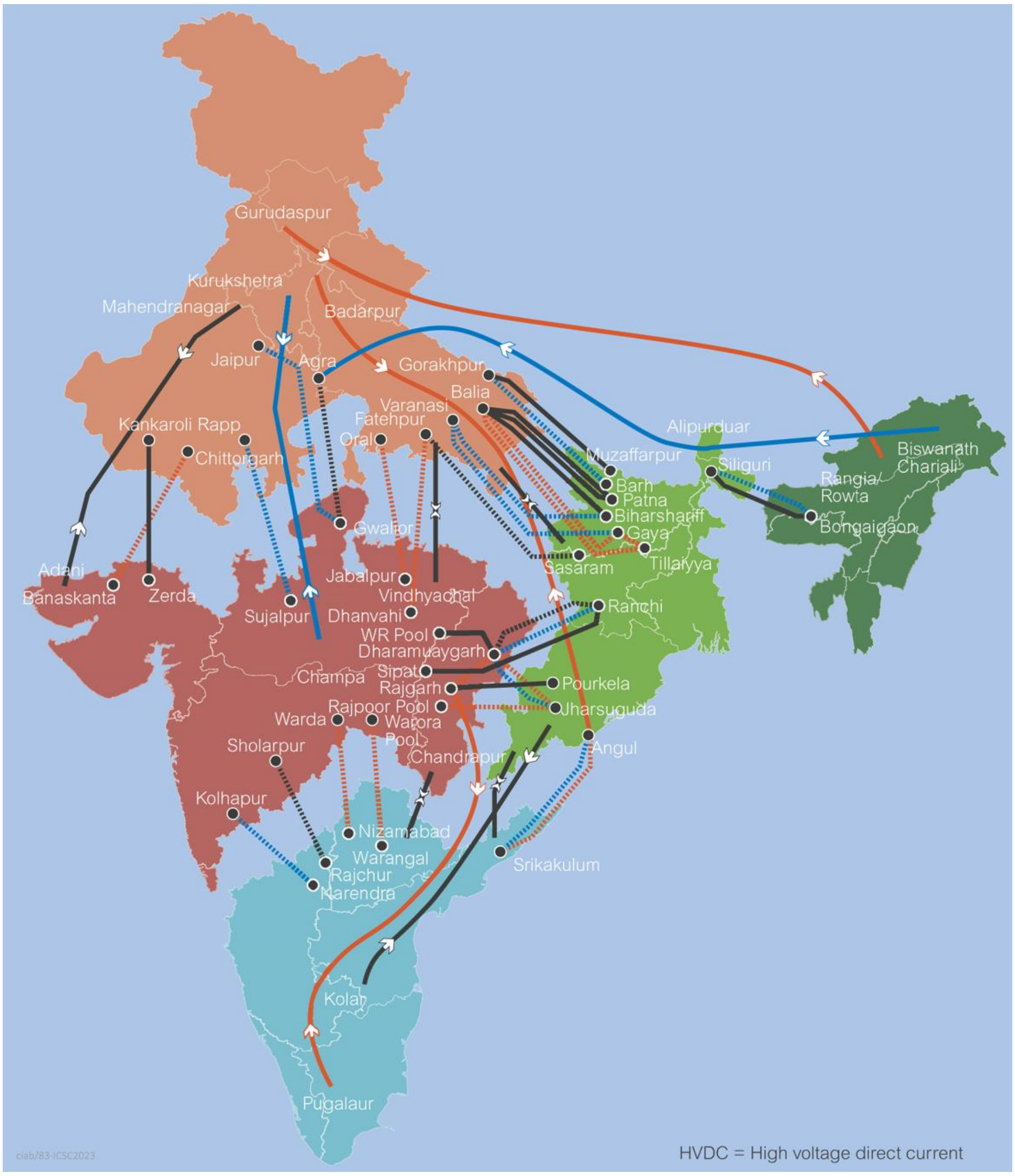

Figure 83 **The Indian transmission system operational areas and interconnections (Sharma and Shah, 2015)**

The Central Electricity Authority (CEA) prepared a Network Electricity Plan II (Transmission) setting out developments up to 2032 (Ministry of Power, 2023a). The government also set a target for 50% cumulative electric power installed capacity from non-fossil fuel-based energy resources by 2030 and a renewable energy capacity of 500 GW (S&P Global, 2022b). It is estimated that India would need investments totalling $223 billion to meet the 2030 target. To enable this, about 51,000 km of transmission lines and 4,33,500 MVA of transformation capacity is expected to be added to the ISTS network at an estimated cost of about $29.3 billion. These transmission schemes include various high capacity 765 kV and 400 kV EHVAC transmission lines and ±800 kV and ±350 kV HVDC lines (BloombergNEF, 2023d).

Power Grid Corporation of India Limited (POWERGRID), a Schedule 'A', 'Maharatna' Company operating under the Ministry of Power, is engaged in the bulk transmission of power through its EHVAC (up to 765 kV level) and ±800/±500 kV HVDC transmission network. POWERGRID is a listed company; the Government of India has a 51.34% holding and the balance is held by institutional investors and the public. POWERGRID owns and operates around 176,109 km of extra high voltage (EHV) transmission lines across the country and 275 EHV AC and HVDC sub-stations with transformation capacity of more than 512,001.4 MVA (Ministry of Power, India, 2023c).

India's grids have experienced much change and absorbed a large increase in VRE; more change is coming. $2.1 trillion investment in electricity grids will be needed during 2022-50 with the total grid length doubling to over 20 million km. Over 43% of this investment will be required for long-distance transmission of power (BloombergNEF, 2023). Driving this expansion of grid infrastructure is the foreseen expansion of wind and solar power to 3000 GW by 2050 supported by 572 GW of low carbon dispatchable capacity. Bloomberg projects that India will reach 114 GW of coal with CCS, 54 GW of gas with CCS and 97 GW of nuclear capacity along with batteries and pumped hydro. India's power sector is still estimated to consume 162 Mt/y of coal in 2050 even in their net zero scenario.

Gupta and Akshoy (2018) noted that there is limited interest in the domestic demonstration of CCUS technology in India, due mainly to concerns over public reaction to underground CO_2 storage. The Government of India has supported CCUS since the early 2000s, but little has been invested beyond R&D. Areas of R&D include algae-based capture at gas plants, oxyfuel combustion and solvent-based research at pilot scale. There is limited knowledge of India's CO_2 storage potential, and most estimates are based on studies conducted in 2008. It should be noted that the Damodar Valley basin, which covers a major coal producing area in northern Jharkhand, is considered potentially favourable for storage, subject to further investigation (Adams and others, 2021).

Although India has around 28.2 GW of new supercritical coal units in the pipeline it was reported by Reuters in May 2023 that a clause had been altered in the final draft of the revised National Electricity Policy (NEP) which would effectively agree to a need for no further new coal plants. However, the draft also proposed the delaying of retirement for old coal power plants until energy storage for renewable power becomes financially viable. This includes approximately 13 GW of plant which had previously been earmarked for closure (Singh, 2023; Ministry of Power, 2023b). A study by the ICSC (Zhu, 2021) made some practical and policy recommendations for how India can meet its growing energy demand with its domestic coal reserves, while reducing emissions of CO_2 and improving air quality.

India has suffered major grid failures in the past due to various factors including undersupply and overloading of parts of the network during periods of high demand and maintenance. On 30 July 2012 the northern grid collapsed leaving 350 million people in the dark for 14 hours. On 31 July 2012 a blackout affected 20 of 28 states impacting 700 million people. The impacts were widespread and disruptive. At the beginning of July 2012, repeated power cuts during a spell of 40°C-plus heat prompted hundreds of residents to vandalise electricity substations in the new city of Gurgaon outside Delhi. Rioters assaulted energy company officials, holding some hostage and blocking roads in several parts of the city (Guardian, 2012).

> "THERE WILL OBVIOUSLY BE SOME AGITATION IN URBAN AREAS, WHICH HAVE BECOME VERY RELIANT ON ELECTRICITY … THERE COULD BE RIOTS; THERE COULD BE PROTESTS"
> (HARRY DHAUL, INDEPENDENT POWER PRODUCER'S ASSOCIATION OF INDIA)

India has suffered from curtailment issues and congestion related to the geographic location of power plants in the past but has also suffered recently from weather-related effects. In 2022 the country suffered power outages and threatened economic growth due to high demand. In February 2023 the government invoked an emergency ruling under Section 11 of the electricity laws for some of the country's biggest power plants to operate at full output 'in the larger public interest' to avoid a repeat occurrence (Bloomberg, 2023). In August 2023 during a particularly dry period, peak demand hit a record 243.9 GW, 7.3 GW more than available capacity and higher than the previous summer's high of 215 GW. This caused a surge in coal power generation to meet demand as hydropower output fell to 14.8% of demand compared to a more typical 18.1% in the same period the year before (Aljazeera, 2023). This indicates India's pressing need for reliable dispatchable power. Solar power may not meet summer night-time power requirements in the absence of adequate energy storage. It is not unusual for many regions of India to be subject to rolling blackouts to preserve the grid in times of high demand or energy shortage.

For the medium-term, analysis has been undertaken by the Government of India Ministry of Power Central Electricity Authority in its Report on Optimal Generation Mix 2030 (Ministry of Power, 2023d). Various scenarios and needs are considered resulting in the conclusions shown in Table 26.

TABLE 26 LIKELY INSTALLED CAPACITY IN 2030 IN DIFFERENT SCENARIOS, MW (MINISTRY OF POWER, 2023D)

Scenario	Base case	Conservative scenario	High demand, (5%)	High hydro	Higher BESS cost
Hydro*	53,860	53,860	53,945	62,434	53,945
PSP	18,986	17,256	5,350	24,736	18,986
Small hydro	5,350	5,350	18,986	5,350	5,350
Coal and lignite	251,683	248,243	254,603	25,1683	25,3283
Gas	24,824	24,824	24,824	24,824	24,824
Nuclear	15,480	12,080	15,480	15,480	15,480
Solar	292,566	270,566	292,566	292,566	292,566
Wind	99,895	75,396	99,895	99,895	99,895
Biomass	14,500	14,500	14,500	14,500	14,500
Total	**777,144**	**722,128**	**780,202**	**791,468**	**778,829**
Fossil installed capacity	276,507	273,067	279,427	276,507	278,107
Non-fossil installed capacity	500,637	449,061	500,775	514,961	500,722
Battery energy storage system, MW/MWh	41,650 208,248	45,703 228,515	49,377 246,885	22,613 113,065	33,356 166,780
* excluding hydro imports from neighbouring countries					

The high hydro scenario assumed accelerated construction of the hydro project pipeline while the high battery energy storage system (BESS) cost scenario considers the impacts of higher market prices for storage driven by demand or other factors. The scenarios show some variation, but coal and lignite continue to be present at around 250 GW of capacity. Battery energy storage needs vary widely from 22.6 GW/113.1 GWh to 49.3/246.9 GWh depending on the assumptions made. Natural gas remains a minor share of capacity at around 3%. The VRE from wind and solar will reach 50% of installed capacity although the combination of nuclear, hydro, biomass and fossil installed capacity in the base case is around 28% higher than the record peak demand seen in 2023. This indicates a relatively high level of firm and dispatchable capacity in relation to total demand even though the VRE share of installed capacity would also be relatively high.

On 19 December 2023, immediately prior to the publication of this report, the Press Information Bureau issued more details on the status of power generation and future expectations in India. It stated that a further 464 GW of capacity would be added by 2032. On 31 October 2023 the total monitored installed capacity was 425.7 GW of which 239.3 GW was fossil fuel, of which 213.7 GW was coal, including lignite. It also said that that an additional 87.91GW of thermal (excluding nuclear) plant would be added between 2023 and 2032 to ensure uninterrupted power supply to meet the nation's growth (PIB, 2023). Total installed capacity in 2032 is projected to be 900.4 GW including 616 GW of carbon free sources, approximately 486 GW of which is expected to be solar and wind.

Australia

Australia is the largest country in Oceania and the world's sixth-largest country (CIA, 2023). It covers many geographically different areas and holds a wealth of mineral resources from which its economy has benefitted for many decades. Coal is a major export commodity and coal for power generation is the largest single energy source. The characteristic data for Australia as defined in the EIA data set are shown in Table 27.

TABLE 27 CHARACTERISTIC DATA FOR AUSTRALIA

Based on data from EIA database, September 2023 *EIA regional continental classification basis*	AUSTRALIA				
	2011	2021	10 year change (%)	2021 vs Region	2021 vs World
Population (millions)	22.4	25.7	15	0.01	0.00
GDP (2015$PPP basis)	999	1,265	27	0.02	0.01
Energy intensity (MBtu per person)	251.9	230.3	-9	3.59	3.01
Electricity consumption (TWh)	226	237	5	0.02	0.01
Installed capacity (GW)	64	94	47	0.02	0.01
Fossil fuels (%)	79	56	-28	0.02	0.01
Nuclear ($)	0.0	0.0	–	–	–
Renewables (%)	17.4	41.0	136	-.03	0.01
Hydroelectricity (%)	8.9	6.1	-31	0.01	0.00
Geothermal (%)	0.0	0.0	-32	–	–
Tide and wave (%)	0.0	0.0	–	–	–
Solar (%)	3.9	34.4	529	0.05	0.03
Wind (%)	3.3	9.6	186	0.02	0.01
Biomass and waste (%)	1.3	0.9	-28	0.02	0.01
Hydroelectric pumped storage (%)	4.1	2.6	-36	0.03	0.01
Wind and solar as % total installed capacity	7.2	34.0	371	1.45	1.62
Generation (TWh)	241	247	2	0.02	0.01
Fossil fuels (%)	89	71	-20	0.02	0.01
Nuclear (%)	0	0	–	0.00	0.00
Renewables (%)	11	29	159	0.02	0,01
Hydroelectricity (%)	7	6	-14	0.01	0.00
Geothermal (%)	0.0	0.0	–	–	–
Tide and wave (%)	0.0	0.0	–	–	–
Solar (%)	0.6	11.4	1,865	0.05	0.03
Wind (%)	2.8	10.6	275	0.04	0.01
Biomass and waste (%)	0.9	1.1	29	0.01	0.00
Wind and solar as % generation	3.4	21.9	546	2.23	2.10
Overall capacity utilisation (%)	43.1	30.1	-30	0.75	0.77
Fossil fuels (%)	48.8	37.9	-22	0.78	0.88
Nuclear (%)	–	–	–	–	–
Renewables (%)	27.8	21.3	-23	0.80	0.72
Hydroelectricity (%)	33.7	29.6	-12	0.73	0.73
Geothermal (%)	113.7	0.0	-100	0.00	0.00
Tide and wave (%)	0.0	0.0	–	–	–
Solar (%)	6.4	14.0	118	1.07	1.01
Wind (%)	36.4	33.3	-9	1.55	1.33
Biomass and waste (%)	29.1	36.3	25	0.71	0.74

The split between output from fossil and renewable sources in 2021 was 71% and 29% respectively and Australia is a nuclear-free country. Wind and solar produced 21.9% of the output, more than twice the global average, with utilisation from solar and wind assets being 14% and 33.3% respectively. Fossil fuel output share decreased by 20% during the ten-year period to 2021.

Australia's commitment to transitioning towards renewable power enabled renewables to reach 36% of demand in mid-2023 with expectations of reaching 40% by the end of that year and a target of 82% by 2030 (Clean Energy Regulator, 2023; Economist, 2023). The intermittent nature of wind and solar renewable energy has stimulated commitment to some large energy storage projects including batteries such as the Victorian Big Battery of up to 300 MW and 450 MWh (Victoria State Government, 2023c) and large new pumped hydro in the form of Snowy 2.0, at 2000 MW, 175-hour energy storage (Snowy Hydro, 2023). Intermittency, together with concern over infrastructure costs, has also stimulated debate on the introduction of nuclear power to Australia (Tsikas, 2023).

Australia's renewable energy resource is distributed widely over the country with predominance of wind energy in the south. In June 2022, the Australian Government submitted a revised 2030 Nationally Determined Contribution (NDC), pledging a 43% reduction of greenhouse gas emissions by 2030 from 2005 levels, an increase from the previous government's target of 26–28%. This target was legislated together with the NDC commitment to achieve net zero emissions by 2050 in the Climate Change Act 2022. In the NEM, the Australian Electricity Market Operator (AEMO) expects renewable energy to account for 83% by 2030 as part of the Step Change Scenario, which is aligned with the Australian Government's plans of reaching 82% of renewables in the national electricity mix (IEA, 2023a).

Although Australia is still far from achieving these targets there are signs of stress in the system. The CEO of AEMO reported that curtailment of renewables has increased by 40% over the year from 2022 to 2023 (Peacock, 2023). Like other countries, Australia is experiencing a need to curtail while at the same time expanding the resources being curtailed.

Figure 84 shows the concentration of the Australian power grid in the regions with the highest population and demand. The grid extends to around 918,000 km and is one of the longest networks in the world (Energy Networks Australia, 2021). The power system is owned and managed by a mix of private and government-owned organisations, responsible for security and reliability. The networks of Western Australia and the Northern Territory are isolated from the rest of the country. The electricity grid on the east coast, forming the NEM is the longest interconnected electricity network in the world (Energy Networks Australia, 2021). The NEM has been fully functional as an energy market since 1998 when competitive markets were created for generation and retail which were separated from transmission and distribution which remained regulated monopolies. The NEM had a peak demand of 32.6 GW in the 2022-23 period. The networks of Victoria and South Australia are 100% privately owned.

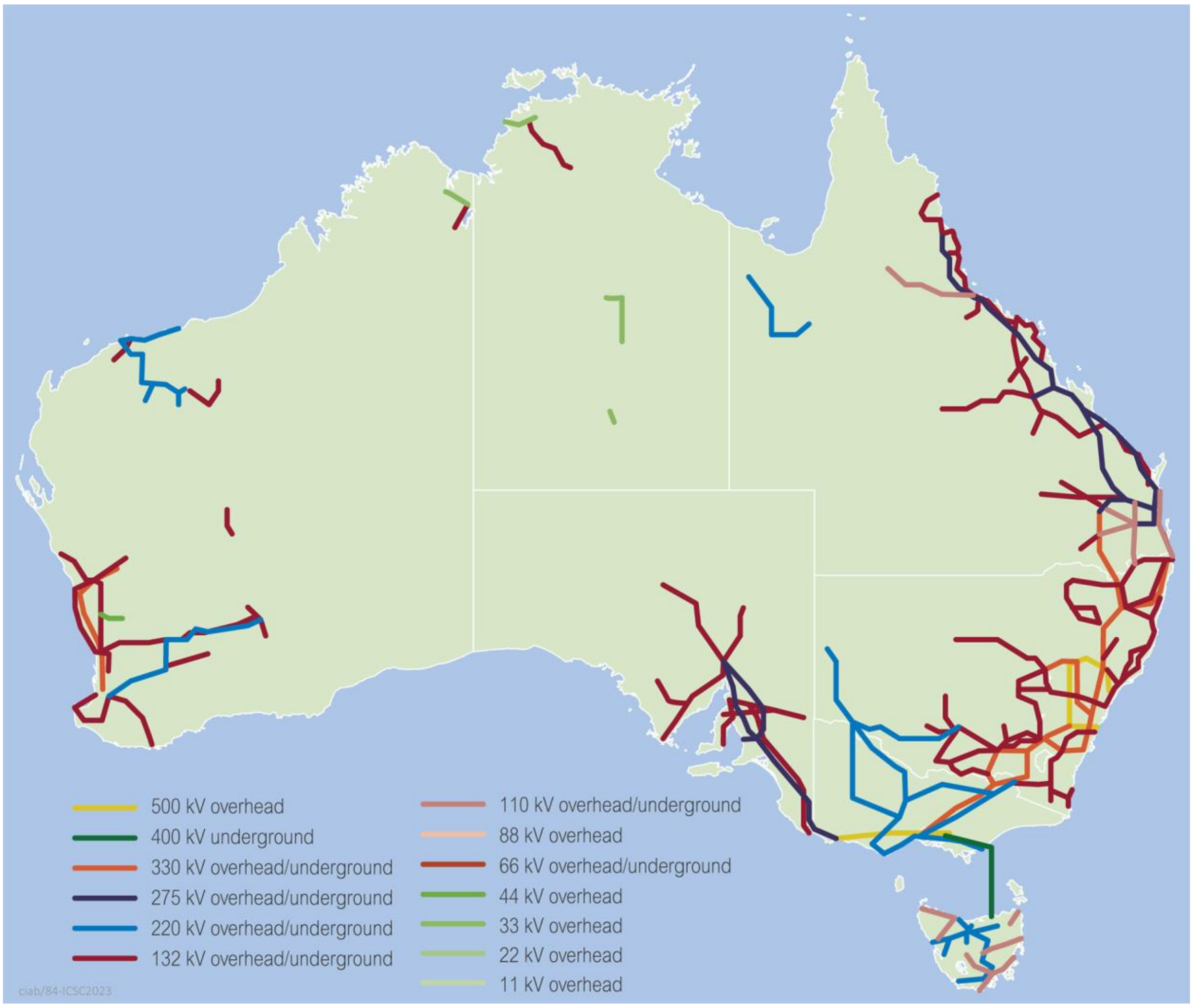

Figure 84 Australia's transmission networks (Energy Networks Australia, 2021)

Boston and others (2022) considered the likely impacts of heavy dependence on renewables on the Australian NEM and modelled the potential variations in output, including for filling and discharging storage facilities. In this scenario there were sufficient renewables to fill storage and, at times, require curtailment. However, there were still periods when storage becomes depleted and, without other measures in place, blackout of the grid would be a likely outcome, shown as the black regions in Figure 85.

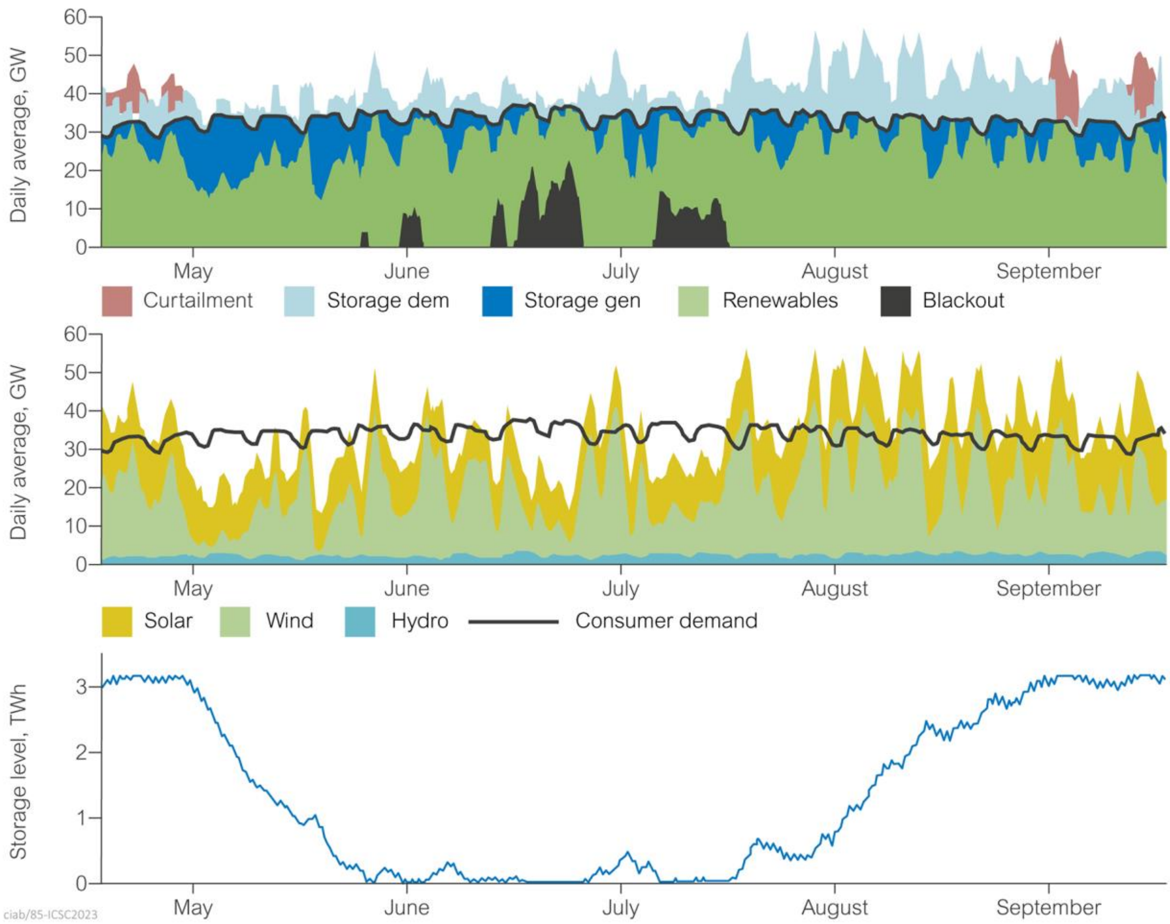

Figure 85 Modelling renewable drought impact in the Australian NEM (Boston and others, 2022)

Numerous studies, including some referenced in this report (Boston and others, 2022; AEMO, 2023b), have looked closely at the potential impacts on reliability and dependability of a move towards a higher share of VRE on the system. The current system operates at high reliability, but Figure 86, shows an expectation that on the current path, the reliability standard will be breached in multiple transmission regions in the near future and possibly as early as 2025. Figure 86 is from AEMO's 10-year reliability outlook for the National Electricity Market including the 2023 energy adequacy assessment projection. Such timescales are within the time it takes to plan and implement mitigating measures at large scale including permitting and grid connection approvals, highlighting the pressing nature of the issue.

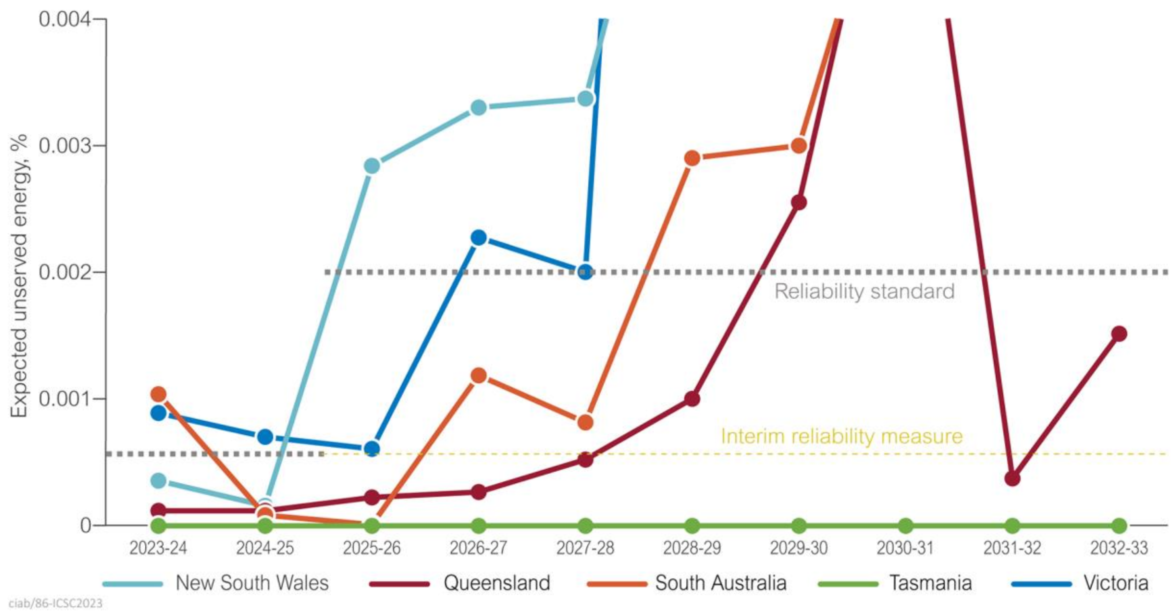

Figure 86 Reliability shortfall forecast for the Australian grid from 2023-2033 (AEMO, 2023b)

Under the Rewiring the Nation programme of the Powering Australia plan, Australia will invest $20 billion to modernise its grids, adding new interconnections and reinforcement to ease power flows and connect renewables and storage (Australian Government, 2023a).

In November 2023 the Australian Government (2023b) announced that the reliability of electricity to consumers would be improved through the expansion of the existing Capacity Investment Scheme (CIS) and National Energy Infrastructure Partnership. This includes the government underwriting investments in new renewable generation and storage expected to result in 9 GW of dispatchable capacity.

South Australia

South Australia has a peak demand of only around 2.6 GW, less than a single large power plant in many places. It provides around 70% of its electricity from renewable sources. This is expected to rise to 85% by 2026, with a target of 100% by 2030 (Government of South Australia, 2023). Its last coal station was retired in 2016 when the Heywood interconnector to other states was increased in capacity to 650 MW. There is also a Murraylink interconnector with a 220 MW rating and project EnergyConnect will add a further 900 km long 800 MW interconnector to New South Wales with an additional connection to Victoria. This will provide the state with a large interconnection capacity as a proportion of peak demand. Around 40% of homes have rooftop solar installations. Major wind farms in South Australia are located at Hornsdale, Lake Bonney, Hallett, Snowtown and Cape Jervis.

In December 2022 South Australia covered its local demand for over ten consecutive days with 100% wind and solar energy. Rooftop solar contributed around 26% overall and at times up to 92% of local demand. Utility solar was 'heavily curtailed' in this period because of the impact of negative system prices on embedded rooftop PV (Parkinson, 2022). This is believed to be a world first for a gigawatt scale energy system and clearly illustrates the unusual and interesting nature of this region with respect to system operation. In September 2023 for a short period, rooftop PV generated 101.1% of South Australia's power demand (Global Power Energy, 2023).

However, South Australia has also experienced price volatility. Figure 87 illustrates the challenges of managing extreme variation in VRE resources on a high VRE penetration system. Although the VRE resource was capable of satisfying demand at some points in time, at others the system relied heavily on imports through interconnectors and dispatchable fossil fuel power. In this example, the system does not work without both interconnection and high capacity of dispatchable power sufficient to meet peak load, even with large-scale battery storage in the state.

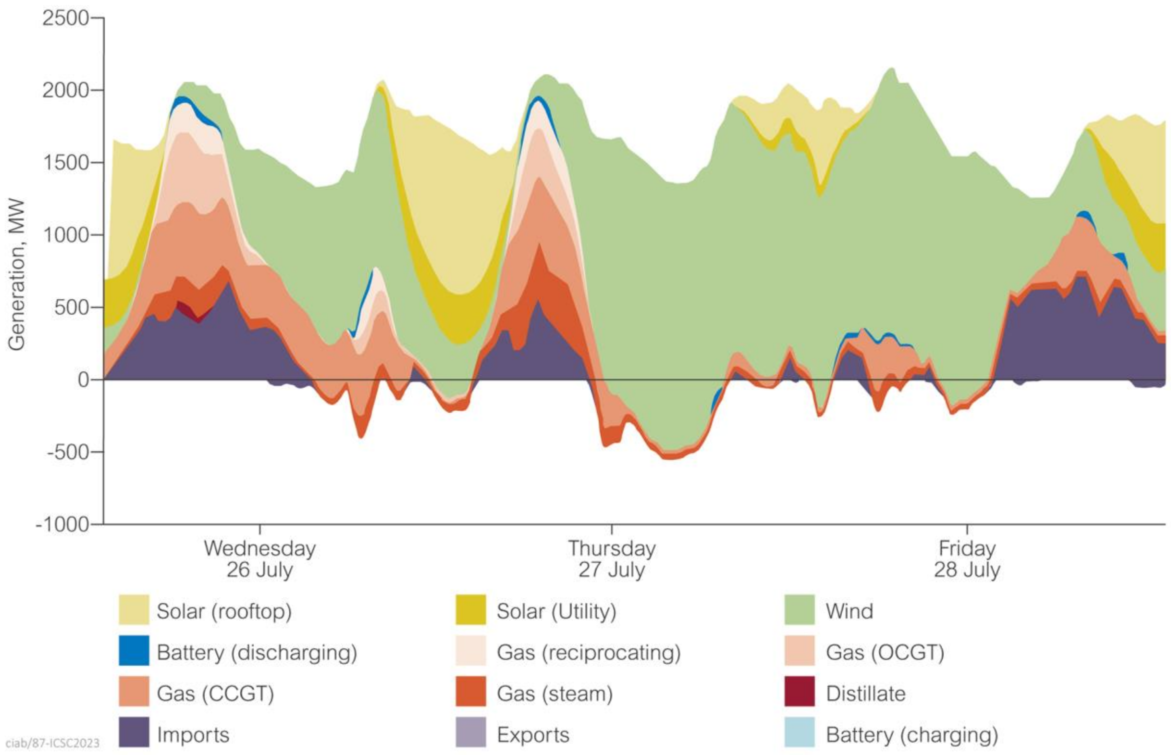

Figure 87 Variability in VRE generation in South Australia, July 2023 (Hunt, 2023)

In 2016 a statewide blackout occurred during adverse weather conditions. AEMO (2017) concluded that the protection systems in some of the wind farms were the cause. Following the event, South Australia installed more storage capacity including the Hornsdale Tesla battery storage system which was the largest in the world at the time.

South Australia has a higher-than-average retail electricity price as shown by Table 28 which has the April 2023 retail rates for Victoria, Queensland, New South Wales and South Australia.

TABLE 28 RETAIL ELECTRICITY RATES IN AUSTRALIA, APRIL 2023 (CANSTAR BLUE, 2023)

State	Average elelctricity usage rates, AUS¢/kWh
Victoria	20.95
Queensland	25.61
New South Wales	28.66
South Australia	36.13

Without detailed analysis, it is not clear why this is the case. However, it does appear empirically to be a common position for grids with a larger share of VRE in their electricity mix than their neighbours (Prakapenka, 2023).

The Australian Department of Climate Change, Energy, Environment and Water announced the Capacity Investment Scheme for Victoria and South Australia on 30 August 2023. The scheme will target 600 MW of dispatchable renewable capacity with 4-hour equivalent duration across the two states. The interconnected nature of the South Australian and Victorian grid means both states will benefit from projects on either side of the border (Australian Government, 2023c).

Victoria

Renewables paired with storage will gradually replace Victoria's coal-fired generation with a target renewable energy share of 40% by 2025 and 50% by 2030 with the intention to legislate for targets of 65% by 2030 and 95% by 2035. For this reason, the state is investing in grid infrastructure local to its renewable energy resource areas to strengthen the system and facilitate potential additional capacity a. It is envisaged that this infrastructure investment will unlock10 GW of capacity across its 'renewable energy zones'. Six of these were identified by AEMO's Integrated System Plan in Central North, Gippsland, Murray River, Ovens Murray, South Victoria and Western Victoria. The peak demand on the Victora grid is approximately 9 GW.

The VicGrid organisation has been allocated a budget of AUS$540 million to fund the grid relating to these zones (Victoria State Government, 2023a). This will include new links of VNI West (KerangLink), Western Renewables Link, and Marinus Link as well as offshore wind connection and the Kerang energy storage system. The state's energy storage targets include 2.6 GW by 2030 and at least 6.3 GW by 2035 (Victoria State Government, 2023c). The Victorian Big Battery is a project for a 300 MW, 450 MWh battery connected to the HV transmission system, consisting of 210 Tesla Megapacks; it has a 250 MW contract with AEMO (Neoen, 2023). Victoria will also benefit from the new Capacity Investment Scheme.

In September 2023 the operating demand for Victoria hit a record low of 2.068 GW beating the previous record set in December 2022. At this time rooftop solar contributed nearly 47% of total power generation. This highlights the volatility of a system where overnight such capacity contributes nothing to generation supply and an equivalent quantity of other capacity needs to be online.

AEMO also reported that in the period January to March 2023, the interconnectors between Victoria and New South Wales and Tasmania were at full capacity for 42% and 57% of the time respectively. This illustrates that power transfer capacity limits between regions are being reached on a regular basis by limitation of infrastructure.

In the face of these targets and measures, including the phasing out of existing dispatchable generation the increasing risk of blackouts in Victoria has been raised (Financial Review, 2023). AEMO reported that Victoria and South Australia faced an increased risk of blackouts during the summer as higher demand was forecast due to El Niño effects. It warned that failure to replace ageing coal plants with clean power fast enough combined with potential shortages of coal and gas have significantly raised the risk of blackouts across the grid. Also, the imminent closure of almost two-thirds of Australia's coal-fired fleet by 2033 required urgent investment to 'keep the lights on' (AEMO, 2023b).

'DELAYING GENERATOR RETIREMENT HAS THE POTENTIAL TO ADDRESS MEDIUM-TERM RISKS IF NECESSARY'
(AEMO)

Summary and opportunities

Australia has a challenge to transition from fossil fuels but has some good renewable resource potential if dispersed widely over its geographic area. It does not have nuclear power and is unlikely to approve its adoption. Although storage and transmission improvement projects are underway, some including Snowy 2.0 and the Genex Kidson project in north Queensland have reported delays and escalating costs. The estimated cost of Snowy 2.0 has doubled from the initial estimate to AUS$12 billion. This fact, combined with South Australia having the highest retail electricity prices in the country, and the extent of grid infrastructure reinforcement plus the provision of dispatchable power plant raises questions about the overall cost and affordability of the proposed transition path.

One of the options often used to reduce the risk of high VRE share is interconnection. In South Australia interconnection is enabling the state to spill surplus power and import supportive power as required. However, at the country level, Australia does not have a single fully interconnected grid or interconnection to adjacent countries with a diversity of energy sources on which to depend. Security of supply must therefore be ensured from indigenous generation sources.

Issues of reliability are emerging in the near term for the Australian power grid, possibly within only a few years without further action to make the system more robust.

“TO ENSURE AUSTRALIAN CONSUMERS CONTINUE TO HAVE ACCESS TO RELIABLE ELECTRICITY SUPPLIES, IT’S CRITICAL THAT PLANNED INVESTMENTS IN TRANSMISSION, GENERATION AND STORAGE PROJECTS ARE URGENTLY DELIVERED”
(DANIEL WESTERMAN, CEO, AEMO)

AEMO and Net Zero Australia report that AUS$1.5 trillion will have to be spent by the end of the decade to stay on track to meet its emissions targets for 2050.

With no nuclear power but the world’s third largest coal reserves at a proven economic demonstrated resource of around 150,000 Mt, existing coal asset base and supply chains, CCS could be a key element in maintaining clean dispatchable generation into the future while renewables grow in share and the challenges of maintaining a stable and dependable power grid are resolved.

7 CONCLUSIONS

Objective consideration of grids and the wider electricity system, the technologies deployed and their potential implications, reveals a set of interactions and effects which are not apparent when simply considering preference or cost of generation technologies. Stable, reliable, low carbon and affordable electricity systems are the result of technical, practical, political, economic, environmental and social choices. The following five conclusions capture many of the key points and emerging messages from this study.

7.1 WE ARE MOVING TOWARDS INCREASED GRID-BASED RISKS TO SOCIETIES AND ECONOMIES

Grids and associated systems are critical infrastructures for modern life. Capacity and continuity of supply are expected, and affordability is required to support economic growth, industries and other consumers. The environment surrounding electricity grids is changing rapidly and many pressures and tensions are becoming apparent as countries race to deploy new or alternative power generation and electrification increases in order to decarbonise our economies. This puts operational demands on legacy systems that they were not designed for and requires expansion of grids including new connections, extensions and upgrading at a pace not seen before. Legacy power generation plants are reaching end-of-life, being phased out to comply with policies, or becoming uneconomic to operate due to changes in the market environment. These assets generally had operational characteristics which helped ensure grid stability and reliability of power. Their retirement, whether planned or premature, must be matched by adequate measures in new additions to ensure not just reliable and dependable capacity but also the technical support services that these systems used to offer. Complexity in the networks, technologies, data and communications, control and number of stakeholders is increasing rapidly. Growing complexity and more interfaces inherently creates more risk.

Modelling such complex systems with a wide variety of potential scenarios and technology options is a rapidly growing and demanding activity. The volumes of data required, permutation of scenarios that must be run and levels of system that need to be evaluated are huge and costly, making clear outcomes and messages difficult and increasing the scope for error or misinterpretation. Thus, there is a wide range of different outcomes for models of different levels of complexity and using different data sets. Yet those models are the indicator relied on for likely impacts on future cost, feasibility of deployment and operability and essentially, reliability, under all reasonably foreseeable conditions. The need for higher physical and virtual world resilience to withstand extreme weather events, cyber-attack and terrorist action is apparent at the same time as consumers are becoming more dependent on the services and utility provided by grids.

The transition calls for such rapid grid development that supply chains for equipment and systems and for the raw materials to manufacture them and resources to install them will become under severe pressure. It is not clear if this will become a constraint; however, even the permitting processes have not been able to keep pace with requests for new grid connections. New grid connections require investment and markets designed so that investors can recover their costs. Should these costs be passed on to consumers, resulting in higher bills, or should power supplies become unreliable and disruptive, there is a risk that support for the energy transition itself may weaken. Policy and decision-makers should be aware of the critical role of grid systems and acknowledge the heightened environment of grid-related risk in order to ensure a smooth and successful energy transition.

7.2 A MORE HOLISTIC APPROACH TO VRE DEPLOYMENT AND ALTERNATIVE OPTIONS IS NEEDED

Sustainable and renewable energy has played a role in energy systems for a long time and recent increases in deployment of VRE have enabled a reduction in carbon intensity. This will continue; however, sustainability and renewable energy are not the only criteria for power generation. Grids are fundamentally systems governed by both markets and physics and they have requirements that must be met at all times to continue to function. Due to the immediacy of the power network, demand must be balanced with supply in real-time, requiring dispatchable power sources. Solar and wind are forms of renewable energy that, although having high value and low carbon credentials, are fundamentally dependent on the weather and are not dispatchable. This poses challenges for their integration into power systems in high proportions. Since the deployment of energy storage is not sufficient to smooth out the variability in wind and solar generation, the need for satisfying system flexibility is falling to legacy plant and equipment. This has to work hard to ramp up and down meeting system needs exacerbated by VRE. Weather dependency also means that under extreme weather conditions, output can be severely affected. This is particularly problematic for calm, dark periods and made worse when they coincide with periods of high system demand. Although capacity may perform well on average, the variability and the extremes are more important from the system and consumer perspective. This variability is not only an issue of shortfall against expectation but also one of excess. In conditions favourable for VRE, market prices can collapse and even become negative as systems try to shed excess generation, ultimately resulting in curtailment of VRE to protect the system. This creates volatility in markets and is problematic for investors and new projects in terms of assessing likely project returns. Such volatility appears to be occurring at relatively low proportions of VRE share in generation and these effects are likely to become more extreme. It is also causing additional curtailment and re-dispatch costs to system operators which will ultimately be borne by consumers. Lastly, the issue of transparency of cost for VRE has become an obstacle to an impartial and fair assessment of VRE options in relation to other low-carbon power options. The LCOE metric, used extensively for many years is now being used in an inappropriate way . Relative costs between technologies based on simple LCOE are different to those based on total system cost, reflecting the cost impacts of technology choices on the grid and market as a whole. Therefore, total system cost should be the metric used for cost comparison. Costs and impacts also vary not only by technology but by region and in accordance with the composition and state of development of the rest of the system. This means that a cost order as it relates to one project, place and point in time cannot be assumed to be representative of other projects, places, or points in time.

7.3 CURRENT TRANSITION TRAJECTORY RISKS LEADING TO INADEQUATE DISPATCHABLE POWER ON GRIDS

It is apparent that age, policy, and market conditions are leading to the retirement of a large quantity of dispatchable power plants in many areas, including the USA. This is creating concern amongst system operators, regulators, and observers, that resource adequacy and system reliability are being put at risk by the energy transition. Retirements are proceeding faster than replacements in some areas leading to forecast shortfalls of generation under extreme event conditions. This could have a devastating impact and costly results on businesses and lives. Most replacement power plants are not dispatchable and new storage capacity is not sized to match and backup VRE additions. Thus, system flexibility demands are not decreasing, but increasing at a time when the ability to service that flexibility is decreasing. Resource adequacy assessment should consider not only nameplate capacity, but dependable capacity in times of system stress and the availability of system stability services at all times. Although storage and interconnectors have some dispatchability they are either limited in duration or dependability when considering the wider markets. High-capacity dispatchable generation is required to provide dependable capacity and system support and this may need to be up to 90% of the VRE generation share at peak times. Long-duration energy storage has been investigated by many as a potential alternative to dispatchable generation, but an affordable solution has yet to be deployed. This means dispatchable power plants continue to be needed and these should become low carbon to contribute to the transition.

7.4 REGIONS DEVELOP ACCORDING TO THEIR OWN OPPORTUNITIES, CHALLENGES AND CONSTRAINTS

Each region has its own development history and reasons for its current status, which also applies to their grids. The fuel mix and generation portfolio vary in size, coverage and technology. The ability to pay for the energy transition is not uniform and neither is access to the fuels, technologies and resources to implement it. Regional market size brings another dimension to the significance of carbon intensity and global impact, and this can become a hidden weighting behind numbers making them misleading at first sight. Neither the market and pricing structures for goods and services are the same, nor the approach to national energy reserves, taxation, policy and regulation and incentives. So, grid infrastructure and system development and energy transition will also vary by region and will occur in different ways and speeds. What matters most is that appropriate and proportionate measures are taken in each region to reach the total global climate objectives in a timely, affordable and reliable manner. No major country or energy grid has yet demonstrated a significant recent transition from high carbon to low carbon and there are no blueprints from which to assure progress in other regions.

But it is important to learn from the progress in those regions where high levels of progress are being made in terms of what is possible, the benefits, implications and the total costs.

7.5 ABATED FOSSIL POWER HAS THE POTENTIAL FOR MORE RAPID, SECURE AND AFFORDABLE DECARBONISATION

Modelling has demonstrated that the total system costs of transition for an energy system increases and does so almost exponentially for higher levels of decarbonisation. That cost also increases as technology solutions are removed from the possible options. In particular, a solution based on VRE and storage may have the highest total system cost in providing a year-round dependable and stable system. Therefore, abated fossil fuel options should not be excluded from consideration in respect of securing a path for transition if cost, reliability and CO_2 emission reduction are the objectives. In fact, the existing high installed capacity of fossil fuel power assets, some of which are relatively young or new, provides an opportunity to exploit already planned, financed and constructed plant for abated power generation. This conclusion only relates to low- and no-carbon fossil fuel power solutions. Such plant, already built, may have a future operating life of 50–60 years and the retrofitting of CCS could both reduce decarbonisation and system costs and accelerate decarbonisation. This is particularly relevant in regions such as China and India where there is a high dependence on fossil fuels and construction of fossil fuel plants continues. The costs and benefits of abated plants are dependent on operational capacity factor. This is something that such projects will need to reconcile. Operation at high load factors would provide maximum speed and quantity of emissions displacement but low load factors may be required for some plant to operate in flexibility mode. Low-capacity factor operations would likely require some form of strategic system security payment to be commercially viable. Such clean power plants could therefore support capacity, security and stability of supply, while also accelerating the transition and reducing total system costs.

8 RECOMMENDATIONS

This report has reviewed a wide range of issues relevant to the development of electricity grids. Based on this holistic view of the energy system and considering the findings and conclusions leads to the following recommendations for future energy systems.

1. LCOE should not be used as a comparative metric between dispatchable and non-dispatchable power sources due to wider system cost implications that are not captured in its calculation.
2. Comparisons between grid-related technology options should be based on total system wide impacts and costs, including those of real-world markets and how such choices impact total cost to consumers.
3. Any modelling on which policy and investment decisions are made must adequately take account of extreme and concurrent events which may reasonably be expected in the future. More focus should be placed on these than average conditions where a reliable power supply would be expected.
4. System operators must ensure that adequate dispatchable power generation remains present in their systems to mitigate the low dependability of VRE capacity and take measures to avoid the premature retirement of existing dispatchable assets until suitable replacements are present in the system.
5. Policies and finance mechanisms should clearly differentiate between unabated and abated new fossil fuel plant investments and projects in terms of future deployment and support.

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