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EUROPE'S PATHWAYS TO NET ZERO: THE ROLE OF RENEWABLE GASES AND FLEXIBILITY

REPORT

October 2024

Chi Kong Chyong

Report

Europe's Pathways to Net Zero: The Role of Renewable Gases and Flexibility

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About the Author

Dr. Chyong is an applied energy economist with over a decade of experience in economic analysis and operational research. He holds an MPhil in Technology Policy and a PhD in Energy Economics and Policy from the University of Cambridge. His research interests encompass energy system economics and market modelling, focusing on the impact of deep decarbonisation pathways on power, natural gas, LNG, and low-carbon fuels.

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Executive Summary

Europe stands at a crucial point in its journey towards achieving net zero GHG emissions by 2050. The ambitious decarbonisation goals are supported by various EU policy frameworks, such as the EU Energy System Integration Strategy, the EU Hydrogen Strategy, and the REPowerEU plan, which aim to reduce dependency on fossil fuels and increase the deployment of renewable energy. These initiatives are particularly important given the 2021/23 energy crisis following Russia's invasion of Ukraine, which has underscored the importance of energy security in transitioning to a low-carbon economy. This research addresses these challenges by focusing on the following research question: *How can Europe most cost-effectively transition to a net zero energy system while ensuring reliability and managing the inherent variability of renewable energy?*

To answer this question, we use a state-of-the-art energy system optimisation tool and model three scenarios, each designed to reach net zero GHG emissions by 2050. These three scenarios – **Reference**, **Flexible Demand**, and **Reliable** – are modelled to evaluate the impacts of energy system reliability and demand flexibility in Europe's transition to a net-zero energy system by 2050. The scenarios aim to capture key trade-offs between system costs (capital expenditure, CAPEX), energy prices, and infrastructure investments:

1. **Reference Scenario**: This reference scenario models limited demand-side flexibility, particularly in the operation of hybrid heat pumps, potentially due to a lack of real-time price signals. It assumes they operate in a baseload mode with minimal flexibility to respond to system imbalances, such as intermittent renewable generation and variable end-use demand. No capacity reserve to hedge against the intermittency of renewable production is modelled in this scenario. The Reference scenario is the benchmark against which the incremental benefits of demand-side flexibility and enhanced reliability are evaluated.

2. **Flexible Demand Scenario**: Building on the Reference scenario, this case assumes fully flexible hybrid heat pumps, which can respond optimally to system imbalances. This scenario focuses on understanding the benefits of introducing demand-side flexibility by comparing its performance with the Reference scenario, particularly regarding system cost reductions, efficiency improvements, and energy price impacts.

3. **Reliable Scenario**: This scenario extends the Flexible Demand case by including a capacity reserve to ensure system reliability in the face of increasing penetration of variable renewable energy (VRE). The aim is to evaluate the additional system costs and infrastructure investments required to hedge against the intermittency of renewable energy sources, comparing this scenario with the Flexible Demand scenario.

In the Reference scenario, Europe's energy transition is marked by a significant decline in fossil fuels and the growing prominence of renewable and low-carbon gases. Natural gas, which accounted for over 4,219 TWh in 2010, drops by more than 82% by 2050, while coal and oil products are entirely phased out. In their place, renewable hydrogen and biomethane emerge as crucial energy sources, with biomethane and synthetic methane (e-gas) growing from 366 TWh in 2030 to 1,278 TWh by 2050 and renewable hydrogen reaching 2,706 TWh in 2050.

In the power sector, wind and solar energy dominate the generation mix. Onshore wind capacity expands from 165 GW in 2020 to 759 GW by 2050, with offshore wind capacity reaching 451 GW and solar power over 1,000 GW. Nuclear energy remains an important low-carbon electricity supply source, contributing around 121 GW (4% of total capacity) in 2050, while Bioenergy with Carbon Capture and Storage (BECCS) plays an increasingly important role (49 GW, 2% of total) in balancing GHG emissions. In this Reference scenario, hydrogen storage sees the most substantial growth among storage technologies, accounting for over 72% of energy storage by 2050, as hydrogen becomes a key source to meet the net zero target.

Final energy consumption reflects the broader transition, with a sharp decline in natural gas use in buildings and industry. By 2050, electricity, hydrogen, and biomethane replace much of the demand for fossil fuels. In transport, diesel's share falls from 85% in 2030 to just 14% by 2050 as electric and hydrogen-powered vehicles take over.

While the Reference scenario reaches a net zero GHG emissions target by 2050, the scenario shows substantial increases in system CAPEX and energy prices due to limited demand-side flexibility, particularly in sectors such as buildings where hybrid heat pumps operate in a baseload mode with limited flexibility. In 2030, system CAPEX reaches €488 billion, 26% higher than the Flexible Demand scenario. Electricity prices in 2030 are higher by 500% compared to the Flexible Demand scenario (€414/MWh vs. €69/MWh). Similarly, hydrogen prices are higher by 573%, demonstrating how the lack of flexibility leads to significant inefficiencies, requiring extensive investments in energy infrastructure to meet demand.

Flexible Hybrid Heat Pumps	Capacity Reserve	System CAPEX, € billions	Energy Prices, 2030-2050, €/MWh	Key Findings
Reference Scenario				
No	No	488 (2030) 937 (2050) (26%-30% higher than Flexible)	Electricity: 414-275 (+500% vs Flexible in 2030; +24% in 2050) Hydrogen: 338-245 (+573% vs Flexible in 2030; +40% in 2050)	Baseline scenario with the elevated system costs and energy prices due to a lack of demand-side flexibility and without capacity reserve to ensure system reliability.

Flexible Hybrid Heat Pumps	Capacity Reserve	System CAPEX, € billions	Energy Prices, 2030-2050, €/MWh	Key Findings
Flexible Demand Scenario				
Yes	No	388 (2030) 718 (2050)	Electricity: 69-223 Hydrogen: 59-175	Demand-side flexibility reduces system strain, optimising renewable energy use and energy grid capacity and reducing the need for (electricity and hydrogen) infrastructure investments, which results in lower system costs and reduced energy prices compared to the Reference scenario.
Reliable Scenario				
Yes	Yes	412 (2030) 733 (2050) (2-6% higher than Flexible)	Electricity: 70-222 (+1% vs Flexible in 2030; -0.4% in 2050) Hydrogen: 60-174 (+2% vs Flexible in 2030; -0.6% in 2050)	The Reliable scenario adds a modest 6% increase in CAPEX compared to the Flexible scenario while maintaining nearly identical energy prices (even lower in 2050). The additional investments in capacity reserves ensure system reliability without significant price escalation.

By 2050, the costs in the Reference scenario remain elevated, with system CAPEX reaching €937 billion, which is 30% higher than in the Flexible Demand scenario. Electricity prices remain higher in the Reference scenario, at €276/MWh compared to €223/MWh in the Flexible scenario, while hydrogen prices are €245/MWh, 40% above the €175/MWh in the Flexible scenario. These results illustrate the persistent inefficiencies throughout the period due to the inability to optimise infrastructure and energy use effectively.

The Reliable scenario, which adds capacity reserves to manage renewable intermittency, introduces only marginal additional costs compared to the Flexible Demand scenario. In 2030, system CAPEX is €412 billion, just 6% higher than in the Flexible scenario, while electricity prices are €70/MWh, only 1% higher. Hydrogen prices in the Reliable scenario are similar to those in the Flexible scenario, at €60/MWh. By 2050, system CAPEX reaches €733 billion, representing a 2% increase compared to the Flexible scenario. Electricity prices reach €222/MWh, slightly lower than in the Flexible scenario, while hydrogen prices are €174/MWh. These results show that incorporating reserve capacity to ensure reliability incurs relatively modest investments in storage and energy networks while enhancing system reliability.

These findings highlight the critical importance of demand-side flexibility in achieving a cost-effective and secure energy transition. The comparison between the scenarios demonstrates that while the Reliable scenario requires slightly higher investments, it avoids potential price spikes and inefficiencies in the Reference scenario due to the flexible operation of hybrid heat pumps and tight reliability standards. The insights from this research lead to several key policy recommendations that can guide Europe’s energy transition:

- **Promote Demand-Side Flexibility**: Encourage the adoption of technologies and policies that enhance demand-side flexibility, such as dynamic pricing and smart appliances, to avoid the high costs (of electricity and hydrogen grid and storage investment) associated with inflexible energy demand. The modelling results show that the flexible demand scenario optimises the energy grid capacity by reducing domestic peak hour electricity demand (and hence electric grid capacity) while reducing reliance on hydrogen.
- **Promote Local and Decentralised Energy Systems**: The Flexible Demand scenario underscores the growing importance of local and decentralised energy solutions. These approaches enhance energy flexibility and reduce electricity and hydrogen transmission investments and losses by linking local renewable energy production with heating, cooling, and mobility systems.
- **Promote Supply-Side Flexibility**: Tightening reliability standards to promote investments in storage, backup generation, and grid capacity to manage the increasing intermittency of renewables.
- **Support the Deployment of Renewable Energy and Storage**: Accelerate the deployment of renewable energy (wind, solar, biomethane, and hydrogen) and invest in advanced storage solutions, particularly for hydrogen and thermal energy, to manage the variability of renewables and end-use demand.
- **Enhance Cross-Border Cooperation and Market Integration**: Promote regional energy markets and develop cross-border infrastructure, particularly electricity, methane and hydrogen, to optimise resource use and ensure energy security across Europe.

Thus, a cost-effective way to decarbonise European economies by 2050 while maintaining energy security and affordability is to promote demand and supply flexibility and accelerate the deployment of renewable energy and advanced storage technologies, supported by enhanced cross-border cooperation and market integration.

1. Introduction

Europe is at a critical juncture in its journey to meet the net zero GHG emissions target by 2050 (EC, 2021a), an ambitious and necessary goal in the face of escalating climate change. The European Union (EU) has set forth a comprehensive strategy to achieve this target, marked by a series of policy initiatives designed to transform the continent’s energy sector. These include the EU Energy System Integration Strategy (EC, 2020a), the EU Hydrogen Strategy (EC, 2020b), the EU Strategy on Offshore Renewable Energy (EC 2020c), the Renovation Wave (EC 2020d), Sustainable and Smart Mobility Strategy (EC 2020e), the EU Methane Emissions Reduction strategy (EC, 2020f), the EU’s Hydrogen and Decarbonised Gas Market Package (2021b), the Energy Performance of Building Directive (EC, 2021c), the Energy Efficiency Directive (EU, 2023).

The urgency of these initiatives has only intensified in recent years due to significant geopolitical and economic developments. The COVID-19 pandemic and the subsequent economic recovery have underscored the vulnerabilities in global energy markets, while Russia’s invasion of Ukraine in 2022 triggered a profound energy crisis in Europe and globally. The ensuing disruptions to energy supply chains, particularly the reliance on Russian fossil fuels, have accelerated the need for Europe to diversify its energy sources and enhance energy security.

In response to these challenges, the European Commission (EC) launched the REPowerEU plan in 2022, a bold initiative to reduce Europe’s dependency on Russian energy imports and increase the EU-wide renewable energy target from 32% to 45% by 2030. This plan encompasses a wide array of measures, including boosting energy efficiency in buildings and industries, promoting the use of heat pumps, and significantly expanding the production of renewable gases like biomethane and green hydrogen. These efforts are complemented by policies designed to stabilise the gas market in the near term, such as mandatory gas storage levels, joint purchasing of gas, and a market correction mechanism to cap excessive gas price spikes.

However, these policy initiatives face challenges. The energy transition requires the phasing out of fossil fuels and the large-scale deployment of new technologies, many of which are still in the early stages of development. As Chyong et al. (2024) highlighted, achieving the net-zero (NZ) emissions target by 2050 will necessitate unprecedented advancements in renewable energy, energy storage, and negative emissions technologies. Despite progress in some areas, the pace of development in crucial technologies such as hydrogen production, biomethane, and carbon capture and storage (CCS) has been slower than initially anticipated.

The complexity of this transition is further compounded by the need to maintain energy security and affordability while decarbonising the energy system. The increasing reliance on intermittent renewable energy sources like wind and solar and the need to electrify new uses introduces new challenges related to grid stability and integrating these technologies into the existing energy infrastructure. Moreover, the varying national decarbonisation pathways across EU Member States (MS) add another layer of complexity, as each country must balance its unique resource endowments, policy preferences, and economic conditions in the transition to a low-carbon economy. While electrification is widely regarded as a no-regret pathway for decarbonisation, it is essential to adopt a holistic system approach that addresses the complexities of balancing supply and demand – both spatially (through grid infrastructure) and temporally (via dispatchable generation, storage solutions, and demand-side flexibility). Without this broader approach, critical challenges inherent in the transition to a decarbonised energy system risk being overlooked.

Against this backdrop, this study explores a critical question: *How can Europe most cost-effectively transition to a net zero energy system while ensuring reliability and managing the inherent variability of renewable energy?* This research is particularly timely as Europe grapples with the twin challenges of ensuring a secure energy supply in the short to medium term while setting the foundation for a sustainable, net zero future by 2050.

To address this question, we employ a state-of-the-art energy system optimisation model to simulate three distinct scenarios for Europe’s energy transition: a Reference scenario, a Flexible Demand scenario that models hybrid heat pumps operating flexibly, and a Reliable scenario that includes additional reserve capacity to hedge against renewable intermittency. These scenarios are designed to capture the diverse range of system flexibility and reliability for Europe to reach its 2050 decarbonisation target.

The rest of this report proceeds as follows. The next section summarises the research methodology. Section 3 then presents the analysis of modelling results for the Reference scenario and compares it to the two alternative pathways. Then, in Section 4, we summarise key policy recommendations and conclude this research with a summary in the last section.

2. Research Methodology

This section outlines the scenarios modelled, research framework and modelling tool used in the report.

2.1. Scenarios and research framework

We model three scenarios to understand (i) the impact of ensuring energy system reliability due to increased penetration of VRE supply and (ii) the role of end-use demand flexibility (through fully responsive hybrid heat pumps) in Europe’s transition to a 2050 net zero energy system. All three scenarios modelled here reach net zero by 2050, with crucial differences outlined in Table 1.

Table 1: Modelling scenarios

Scenario	Name	Flexible Hybrid Heat Pumps	Capacity Reserve	Comment/Description
Scenario 1	**Reference**	No	No	This is our Reference scenario used as the benchmark to compare the other two scenarios. In this scenario, we model hybrid heat pumps operating in baseload mode, assuming a lack of price signals at the buildings level to encourage the technology to operate flexibly. We also do not model capacity reserve in this scenario.
Scenario 2	**Flexible Demand**	Yes	No	In this scenario, building on the Reference case, we assume flexible end-use energy demand (through fully responsive hybrid heat pumps) and no requirements for capacity reserve.
Scenario 3	**Reliable**	Yes	Yes	Building on the Flexible Demand scenario, we also model capacity reserve to hedge against low wind and solar periods.

First, we run the model to produce our Reference scenario, serving as the benchmark against which the incremental benefits of demand-side flexibility and enhanced reliability are evaluated. Thus, using this Reference scenario, we then model a second scenario (called the “Flexible Demand” scenario) to assess the implications of the flexibility of a sector coupling solution – hybrid heat pumps – considering their operational behaviour under optimal (fully responding to price signals – Flexible Demand scenario) and non-optimal (“limited ramp” for electricity-based heat pumps – Reference scenario) operating modes. Thus, comparing Scenarios 1 and 2, we can measure the benefits of introducing price signals at the buildings level to leverage the flexibility that hybrid heat solutions can provide.

Then, building on the Flexible Demand scenario, we model another case (called the ‘Reliable” scenario) requiring a dispatchable capacity reserve to hedge against renewable intermittency. Thus, comparing these two scenarios (Reliable vs Flexible), we gauge the impact of ensuring the security of supply under increasing penetration of intermittent renewables on the capacity mix, system costs and prices.

Using the Reference scenario, this research design establishes a consistent and coherent framework against which alternative pathways can be evaluated. The Reference scenario is a central reference, allowing for a systematic comparison with the Reliable and Flexible Demand scenarios. This approach is crucial for understanding how different policy choices and technological developments might shape Europe’s transition to net zero by 2050.

The findings of Chyong et al. (2024) underscore the inherent variability in potential pathways to net zero, with scenarios ranging widely in their reliance on electricity, renewable and low-carbon hydrogen, and bioenergy. In their study, the role of electricity in final consumption in 2050 varies significantly depending on the scenario, highlighting the diversity of possible outcomes. Using a single Reference scenario, this research acknowledges the broad spectrum of possible futures while providing a benchmark for detailed comparative analysis. The Reference scenario is not intended to capture the full range of possible outcomes but rather to offer a pathway that can be effectively compared against scenarios that introduce additional constraints, such as capacity reserve requirement in the Reliable scenario, or explore the implications of demand-side flexibility, as in the Flexible Demand scenario. In fact, as demonstrated in the rest of this report, the three modelled scenarios lead to different system configurations. At the same time, all three share the same starting point (2030) and the same climate target of reaching net zero by 2050.

This scenario framework enables a focused analysis of key variables – such as system capital expenditure, energy supply and prices, and the energy mix – under different assumptions while recognising the broader context of uncertainty and variability in future energy transitions, as Chyong et al. (2024) highlight.

2.2. Energy System Optimisation Model for Energy and Climate Policy Analyses

The energy system optimisation model is a partial equilibrium, linear programming optimisation model capable of a detailed representation of a modern and future energy system. It is an economic optimisation model. Its objective is to minimise total energy system costs, comprising capital and operational costs, while meeting exogenously defined (projected) end-user energy services demand, GHG emissions, and other constraints specified by the user (see Figure 1). For details of the mathematical formulation of the model, its data sources and assumptions, see Chyong et al. (2024).

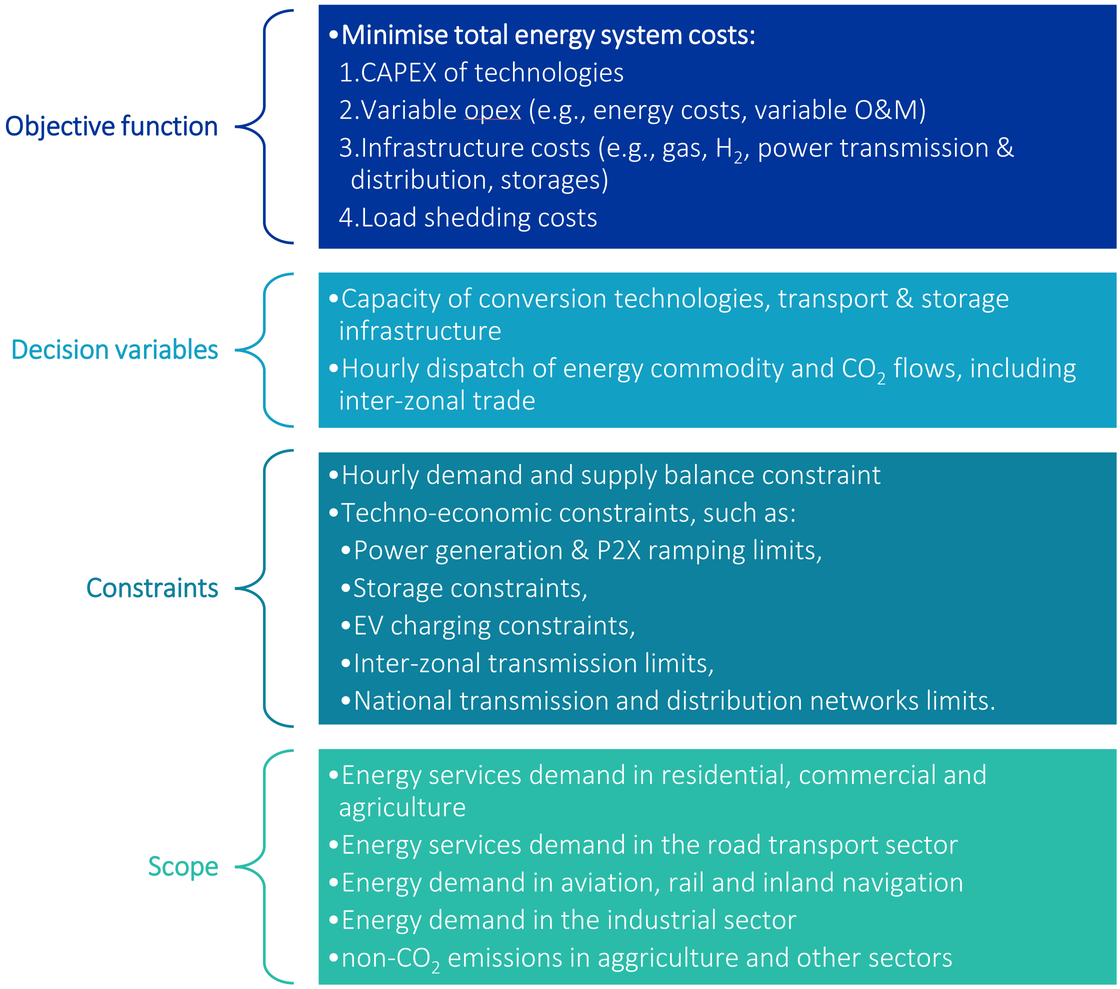
The model has been updated to represent 27 regions, allowing endogenous trade in primary energy commodities (Figure 2 and Table 2). The model covers hourly dispatch and operations of energy technologies and investment in capacities of power generation, end-use heat technologies, H_2 production, electricity-based fuels production (e-fuels), end-use road transport technologies (battery electric, BEV, internal combustion, IC, fuel cell electric, FCEV, etc.), storage and networks of CH_4, H_2, electricity and CO_2. The model covers the final consumption sectors – residential, commercial, transport, and industry – as follows:

- The buildings sector represents the final energy services demand of residential, commercial and energy use in the agriculture sectors;
- Road transport represents the final energy services demand for road activities of passenger cars, public road transport and heavy goods vehicles (HGV);
- Industry represents final energy consumption in the industrial sector;
- Other forms of transport represent final energy consumption through aviation, inland navigation, and rail transport activities.

In terms of supply and transformation technologies, the model takes into account:

- Primary energy supply: coal, uranium, biomass, natural gas, renewable electricity from hydroelectric, wind, solar, geothermal, marine, etc.
- The natural gas sector includes pipeline transport for natural gas and biomethane and LNG via ships as well as underground CH_4 storage;
- Secondary energy supply: diesel, gasoline, biomethane, hydrogen from electrolysis and methane reformation, electricity from thermal generation, and synthetic electrofuels (e-gas and e-liquid).
- Power generation (e.g., CCGT CH_4/H_2, nuclear, bioenergy, hydropower and other renewables, etc.) and storage technologies (e.g., electricity battery storage, hydro pumped storage, etc.) for the electricity sector;
- Cross-border trade in energy (primary and derived), including via electricity transmission and gas pipelines;
- End-use technologies (e.g., gas boilers vs heat pumps, BEV vs IC) and energies in buildings and transport sectors.

Figure 1: Summary of the model



Source: Chyong et al. (2024)

Figure 2: Geographical coverage and interconnections modelled for Europe

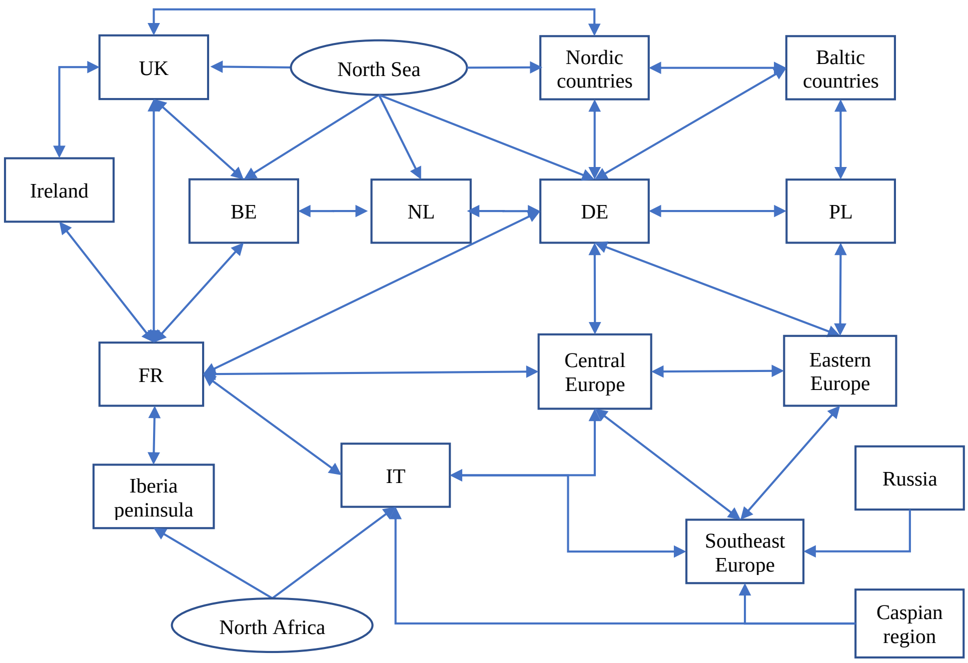


Table 2: Spatial resolution and aggregation in the model

Regions in the model	Countries & Comments
UK	United Kingdom (UK)
Ireland	Republic of Ireland
Nordic	Norway (NO), Sweden (SE), Finland (FI), Denmark (DK), pipeline export & import
BE	Belgium (BE), Luxembourg (LU)
DE	Germany (DE)
NL	Netherlands (NL)
FR	France (FR)
IT	Italy (IT)
Baltics	Lithuania (LT), Latvia (LV), Estonia (EE)
PL	Poland (PL)
Eastern Europe	Czech Republic (CZ), Slovakia (SK), Hungary (HU)
Central Europe	Austria (AT), Switzerland (CH), Slovenia (SL)
SEE	Bulgaria (BG), Greece (GR), Croatia (HR), Romania (RO), Malta (MT), Cyprus (CY)
Iberia	Spain (ES), Portugal (PT)
North Africa	Utility-scale solar generation, hydrogen, e-gas, pipeline and LNG export
North Sea	Offshore wind generation
Sub-Saharan Africa	LNG export
Russia	Pipeline gas and LNG export
Caspian region	Pipeline gas export
North America	LNG export
Australia	LNG export

Regions in the model	Countries & Comments
Middle East	LNG export
China	LNG import
Other Asia Pacific	LNG import
India	LNG import
Japan & Korea	LNG import
Rest of World	LNG import

2.3. Policy Measures Modelled in All Three Scenarios

This research analyses the role of renewable gases in transitioning from the 2030 Fit for 55 to 2050 Net Zero policy targets. We do so by updating the energy system model Chyong et al. (2024) developed and calibrating it to the energy scenario produced by the European Commission (EC). In particular, all three scenarios start in 2030, calibrating to and extending the 2030 Fit for 55 MIX scenario to reach a net zero (NZ) emissions target by 2050. The NZ target by 2050 aligns with the 1.5 TECH Net Zero 2050 (EC NZ 2050) scenario envisaged by the EC's long-term strategy.

All three scenarios reflect national preferences (e.g., no nuclear generation in Germany, extension of nuclear generation in Belgium or lifting a "de facto" ban on onshore wind[1] by the UK) and resource endowment differences (e.g., wind and solar resources) in reaching energy and climate policy targets. Any (European) analysis of the NZ pathways should consider national differences in resource endowment and public policy preferences towards certain technologies they will likely rely on as they decarbonise their economies. The modelled national pathways and scenarios are based on a review of published analyses and EU countries' long-term strategies to meet their Paris Agreement commitments and the energy union objectives.[2] The rest of this section briefly discusses the main policy measures implemented to model the three scenarios. It first discusses Pan-European measures and constraints and then summarises country-level constraints in the model.

Table 3 outlines the carbon price and emissions cap implemented in the three scenarios based on EC's scenarios. In particular, the carbon price is applied to the ETS and the building and road transport sectors, which aligns with the 2023 revisions of the ETS Directive[3]. The projection of the ETS carbon price is based on an interpolation of the 2030 price from the MIX2030 scenario and the 2050 carbon

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[1] Introduced in 2015 (see https://commonslibrary.parliament.uk/research-briefings/sn04370/) and to be abolished by the 2024 UK Labour Government.

[2] https://commission.europa.eu/energy-climate-change-environment/implementation-eu-countries/energy-and-climate-governance-and-reporting/national-long-term-strategies_en#long-term-strategies-received-as-of-1-february-2023

[3] https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets/ets2-buildings-road-transport-and-additional-sectors_en

price from the EC 1.5 TECH 2050 scenario, adjusted to 2021 price level. In addition to the carbon pricing, the three scenarios implement three pan-European GHG emission constraints. First, an overall emissions cap is introduced so that an optimal solution can be found with net zero emissions by 2050 for Europe. The second and third constraints are related to buildings and road transport emissions, so the total emissions from these sectors will not exceed the 2050 limit. This 2050 GHG limit is based on EC's NZ 2050 scenario. Thus, the three scenarios are optimised against these important policy measures and constraints.

Table 3: Assumed carbon price and GHG emissions cap in all three scenarios

	ETS* carbon price, €'21/tCO2	GHG emissions cap, mtCO2e		
		Total emissions	Buildings sector	Road transport sector
2030	48	2345	396	404
2035	132	1759	304	305
2040	216	1173	213	207
2045	300	586	122	109
2050	384	0	31	11

*Notes: costs and prices in the model are 2021; * ETS 1 and 2.Sources: own calculations based on the EC scenarios.*

Apart from these pan-European measures, we considered the following MS-level measures:

1. A set of constraints related to power generation capacity expansion in 2030-50 based on resource endowments, historical and expected build rates (2020-2030) of key renewable technologies (e.g., wind) and policy preferences (e.g., nuclear phase-out in Germany).

Importantly, we modelled subsidies (FiT tariffs) for key renewable technologies at the MS level (

Table 4

2. Table 4) and assumed that these subsidies would be gradually phased out by 2050. In 2020, €68 bn out of €88 bn was in the form of FiT/FiP subsidies (Enerdata and Trinomics, 2023). Other policy support instruments, such as RES quotas, direct transfers, and tax measures, which we do not model, account for the rest.

Table 4: Assumed FiT tariffs for RES technologies in all three scenarios

	FiT tariffs (€/MWh)			
	Solar*	**Wind**	**Bioenergy****	**Hydro**
Baltics	39	21	34	6
BE	255	71	73	25
CentEurope	198	39	143	2
DE	189	80	132	16
EastEurope	314	33	67	25
FR	228	51	182	6
Iberia	156	11	57	1
Ireland	233	36	210	0
IT	286	78	165	24
NL	141	76	0	0
Nordic	55	4	40	0
PL	98	0	2	0
SEE	77	20	29	0

Source: own calculations based on Enerdata and Trinomics study (EC, 2023);

*Notes: * Calculations for solar are based on actual solar generation, which may be lower due to curtailment, and behind-the-meter solar generation may not have been accounted for in these calculations, potentially inflating the per-unit solar subsidies; **applies to solids and gaseous.*

3. Modelling Results and Analysis

To analyse the implications of introducing demand-side flexibility, as represented by the Flexible Demand scenario, and ensuring system reliability, as shown in the Reliable scenario, we begin with a summary of the Reference scenario (§3.1), outlining, in particular, the role of renewable gases in reaching the 2050 net zero target. This Reference scenario assumes a lack of flexibility, particularly from hybrid heat pumps. It is the benchmark against which the incremental benefits of demand-side flexibility (Flexible Demand scenario, §3.2) and enhanced reliability (Reliable scenario, §3.3) are evaluated. Lastly, this section focuses on the economic and system implications of a robust European net-zero energy market against supply and demand shocks (§3.4).

3.1. Reference scenario

We start our reference scenario analysis with fossil and low-carbon fuel supply evolution. Then, we discuss the modelling results for the power sector, storage and other flexibility technologies. Lastly, we will focus on final consumption sectors – buildings, industry and transport.

3.1.1. Fuel supply

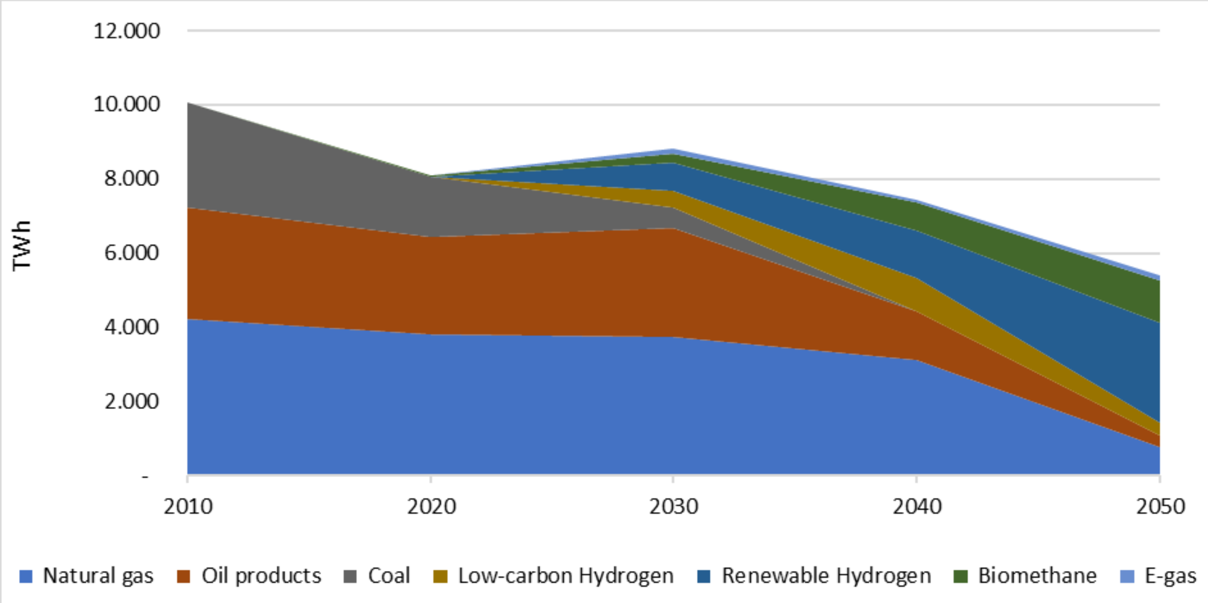
Figure 3 outlines the evolution of fossil fuel, renewable, and low-carbon gas supply in Europe from 2010 to 2050. The energy transition reflects a significant shift from traditional fossil fuels to renewable and low-carbon gases, driven by the need to decarbonise the energy system in alignment with Europe's climate goals. The period from 2020 to 2050 marks a rapid decline in coal and oil products, the reduced role of natural gas, and the emergence of renewable hydrogen, biomethane, and other low-carbon gases.

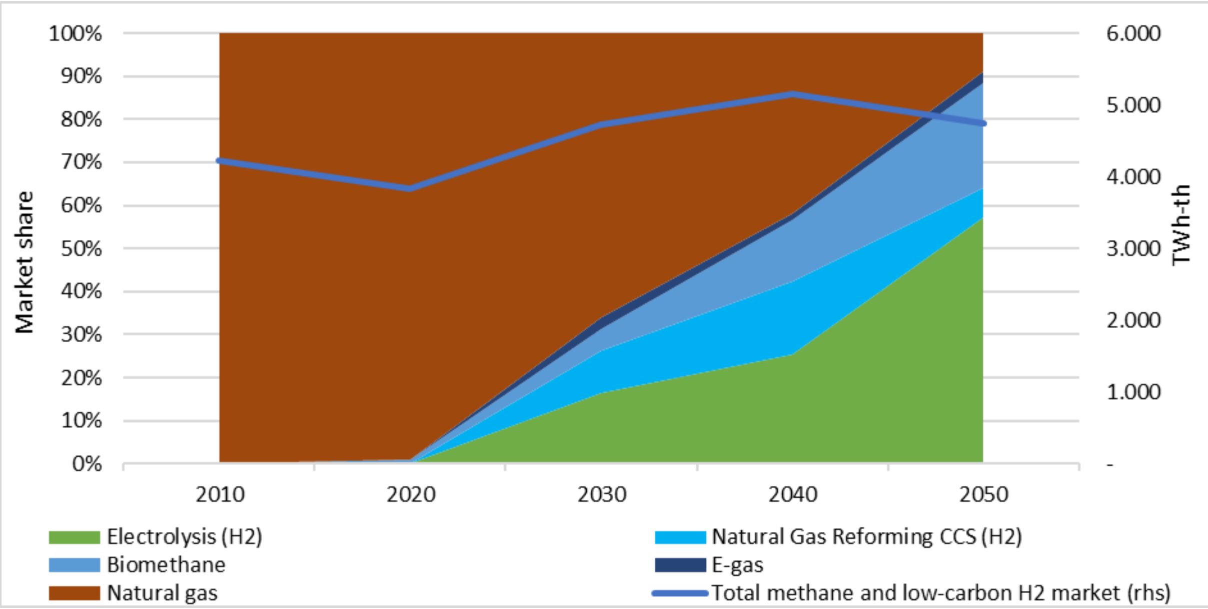
Natural gas was the dominant fuel at the beginning of the period, accounting for over 4,219 TWh of energy supply in 2010. However, by 2050, natural gas use is projected to drop to just 754 TWh – a decline of over 82%. Despite its historical significance, natural gas transitions from a baseload fuel to a backup role as renewable energy sources increasingly take precedence in the energy mix (see §3.1.2). The reduction in natural gas use is consistent with recent trends, as gas consumption has declined due to reduced demand and increased penetration of renewable energy sources.

Coal undergoes a significant decline, falling from 2,847 TWh in 2010 to near elimination by 2040. Notably, between 2010 and 2020, coal consumption in Europe decreased by 43%, primarily driven by the phase-out of coal-fired power plants and a shift towards natural gas and renewable generation. This trend has accelerated recently, with coal generation dropping by 26% in 2023 to 333 TWh, marking the most substantial annual percentage reduction since at least 1990. Consequently, coal's share in the EU's electricity mix fell to just 12%, the lowest level ever recorded (Ember, 2024). This transition aligns with climate policies modelled in our study, such as rising carbon prices, subsidies for renewable energy, and carbon emissions caps (see §2.3). Model projections further suggest that coal will no longer be part of Europe's energy supply by 2050, a trend already evident in the sharp decline in coal generation observed across the region in recent years.

Oil products also sharply decline, from 2,996 TWh in 2010 to just 332 TWh by 2050. This reduction is primarily driven by the electrification of transport and the adoption of alternative low-carbon fuels,

Figure 3: Evolution of fossil and low-carbon fuels supply in the Reference scenario





such as hydrogen, which reduce the demand for oil products, particularly in sectors like road transport. The trend aligns with the transport sector's ongoing electrification and decarbonisation strategies.

Biomethane and e-gas, which play a growing role in replacing natural gas, see significant growth. From a growing supply of 366 TWh in 2030, biomethane and e-gas are projected to reach 1,278 TWh by 2050, reflecting the importance of renewable gases in Europe's future energy system. Biomethane's early adoption is facilitated by its compatibility with existing natural gas infrastructure and lower carbon intensity. As the energy system becomes more decarbonised, biomethane provides a flexible, low-carbon solution, particularly in sectors where electrification may not be as cost-effective.

Low-carbon hydrogen (or blue hydrogen), produced through natural gas reforming with carbon capture and storage (CCS), plays a more significant role in the 2030s. By 2030, low-carbon hydrogen contributes 462 TWh to the energy supply, growing to 885 TWh by 2040, before declining to 325 TWh by 2050 as Europe transitions towards fully decarbonised energy sources. The initial prominence of blue hydrogen reflects its lower production costs and the existing infrastructure that supports natural gas reforming. However, blue hydrogen, even with CCS, cannot entirely eliminate greenhouse gas emissions, capturing approximately 90% of emissions, with residual emissions becoming increasingly critical as Europe tightens its emissions targets by 2050. We should note that supply chain emissions of gas and LNG delivered to Europe are not insignificant (on supply chain emissions of fossil fuel imports into Europe see, e.g., Chyong and Shahabuddin, 2024).

In contrast, renewable hydrogen, produced through water electrolysis powered by renewable electricity, gradually becomes the dominant hydrogen source. By 2030, renewable hydrogen contributes 775 TWh to the energy supply, rising significantly to 2,706 TWh by 2050. This transition from low-carbon to renewable hydrogen reflects the net zero GHG emissions target we modelled, underscoring the need for emissions-free energy sources to achieve this target.

One clear takeaway from the model results is the slight increase in the total methane and low-carbon hydrogen supply between 2030 and 2050. Over that period, the supply grows modestly from 4,717 TWh to 4,734 TWh. This increase is a notable shift compared to 2010 and 2020, when the market was almost entirely dependent on natural gas. In 2010, natural gas alone accounted for 4,219 TWh, and by 2020, it still dominated the market at 3,837 TWh. However, as we move into the 2030s, the energy mix starts to diversify. By 2050, the growing contribution of low-carbon and renewable gases – such as biomethane, hydrogen from electrolysis, and hydrogen produced through natural gas reforming with CCS – plays an increasingly important role.

3.1.2. Power sector

Figure 4 and

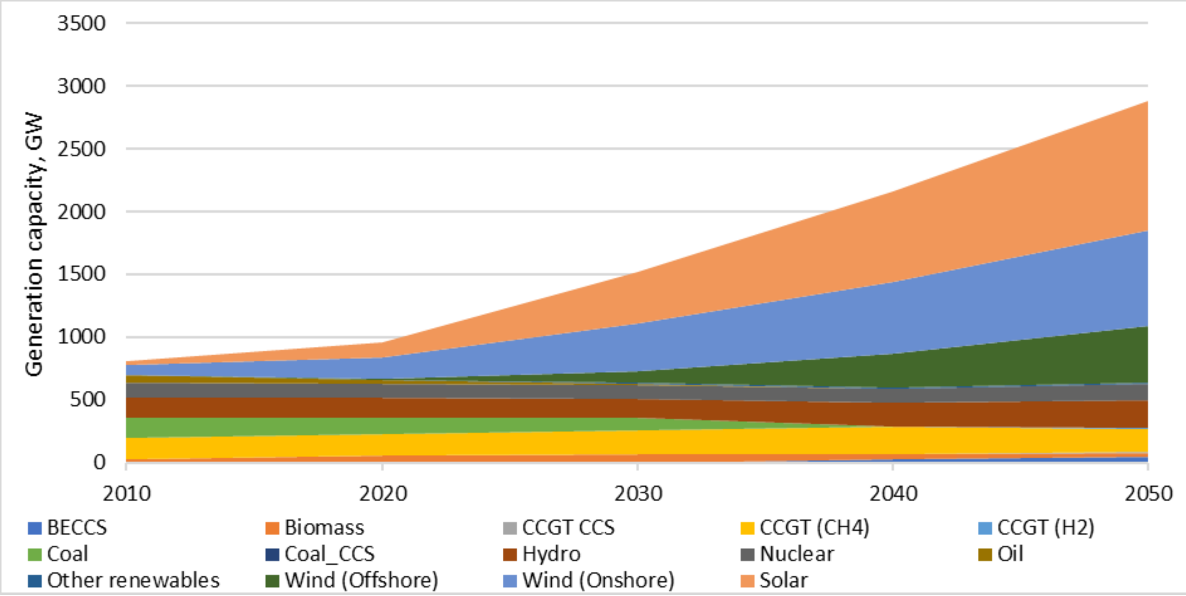
Like the fuel supply trend, coal generation capacity disappears from the mix entirely by 2040. In 2010, coal capacity was 155 GW, but by 2050, it is no longer part of the energy system due to the net zero target. The gas-fired generation remains in the picture but has a decreasing role. Traditional CCGT (CH4) capacity remains relatively stable, but its usage declines over time. By 2050, it is only used as a backup or peaking technology, with a capacity factor of just 5.3% (in 2050).

Further, CCGT CCS (natural gas with carbon capture and storage) shows a slight but notable presence, generating 29 TWh by 2050 with a capacity factor of 77.1%. This suggests that while the role of traditional natural gas diminishes, low-carbon electricity generation options like CCGT CCS will likely be part of the mix. At the same time, hydrogen-fired CCGT (H2) begins to emerge, with 10 GW of capacity by 2050. It has a minimal role, with just 0.2 TWh of generation by 2050 and a low capacity factor of 0.3%.

Though with varying trends, hydropower and biomass continue contributing to the energy mix. Hydro capacity increases from 150 GW in 2030 to 228 GW by 2050, providing a renewable electricity source with capacity factors around 46%. On the other hand, biomass generation declines, dropping from 438 TWh in 2030 to just 44 TWh in 2050, as other low-carbon technologies gradually replace it.

Overall, Europe’s power sector transitions toward a predominantly renewable and low-carbon future. Wind, solar, and hydropower provide the bulk of electricity generation by 2050, while nuclear, BECCS, and flexible technologies like CCGT (CH4) and CCGT CCS ensure system reliability. However, the intermittency of renewables will require ongoing integration of flexible and backup technologies to maintain a stable energy supply as fossil fuel use is phased out.

Figure 4: Generation capacity mix until 2050 in the Reference scenario



Notes: 2005-2020 are historical data from the EU Reference scenario (2021); 2025 is an interpolation between historical 2020 and modelled 2030; The data presented is for EU27+NO+CH+UK.

Table 5: Power generation by type and their running hours in the Reference scenario

	Generation, TWh/year			Implied capacity factors, % of installed capacity		
	2030	2040	2050	2030	2040	2050
BECCS	7.4	182.7	365.2	85.0%	83.2%	84.9%
Biomass	438.0	230.2	44.3	77.3%	58.6%	17.2%
CCGT (CH4)	174.7	210.5	84.6	10.2%	11.2%	5.3%
CCGT (H2)	0.0	0.0	0.2	N/A	1.4%	0.3%
CCGT CCS	6.6	0.0	28.9	75.7%	0.7%	77.1%
Coal	244.3	0.0	0.0	28.8%	0.0%	N/A
Coal_CCS	0.0	0.0	0.0	N/A	0.0%	0.3%
Hydro	611.8	743.8	930.7	46.6%	44.9%	46.6%
Nuclear	778.6	814.0	902.8	83.4%	80.9%	85.0%
Oil	2.5	0.0	0.0	1.6%	N/A	N/A
Other renewables	6.3	15.6	56.4	32.2%	25.6%	38.0%
Solar	628.9	1,120.5	1,610.7	17.7%	17.8%	17.9%
Wind (Offshore)	275.3	749.1	1,363.9	33.3%	31.3%	34.5%
Wind (Onshore)	864.9	1,344.3	1,911.1	25.8%	26.9%	28.8%

Notes: implied capacity factors were computed by dividing the projected generation by the installed capacity, assuming 100% utilisation over a year; the actual capacity factors could be higher as projected generation is net off curtailment.

outline the evolution of electricity generation by technology type, which largely follows the trend of the fuel supply. Europe's power sector is set for a dramatic transformation between 2030 and 2050, with renewables increasingly dominating while fossil fuels decline. Wind and solar power lead the way. Onshore wind capacity jumps from 165 GW in 2020 to 759 GW by 2050, while offshore wind capacity reaches 451 GW. Solar also sees rapid expansion, growing from 126 GW in 2020 to over 1,000 GW by 2050, making it a key component of the future energy mix. Despite the large increases in installed capacity, the relatively low capacity factors for solar (around 17.9%) and wind (34.5% for offshore, 28.8% for onshore by 2050) reflect the intermittent nature of these energy sources. As a result, backup solutions are still necessary to ensure a stable power supply (see §3.3).

Nuclear energy remains an integral part of the electricity mix throughout the period. Its installed capacity stays relatively constant, from 107 GW in 2030 to 121 GW by 2050. With high capacity factors

– above 80% – nuclear power consistently contributes to the low-carbon electricity supply, producing around 903 TWh (12% of the generation mix) by 2050.

Bioenergy with Carbon Capture and Storage (BECCS) becomes more prominent as a technology for achieving net zero emissions. By 2050, BECCS capacity grows to 49 GW, and it operates with a high capacity factor of about 85%, delivering a steady power supply while helping to remove CO_2 from the atmosphere. This technology is crucial for offsetting emissions from sectors where reductions are more challenging, making it essential to Europe's net-zero target.

Like the fuel supply trend, coal generation capacity disappears from the mix entirely by 2040. In 2010, coal capacity was 155 GW, but by 2050, it is no longer part of the energy system due to the net zero target. The gas-fired generation remains in the picture but has a decreasing role. Traditional CCGT (CH4) capacity remains relatively stable, but its usage declines over time. By 2050, it is only used as a backup or peaking technology, with a capacity factor of just 5.3% (in 2050).

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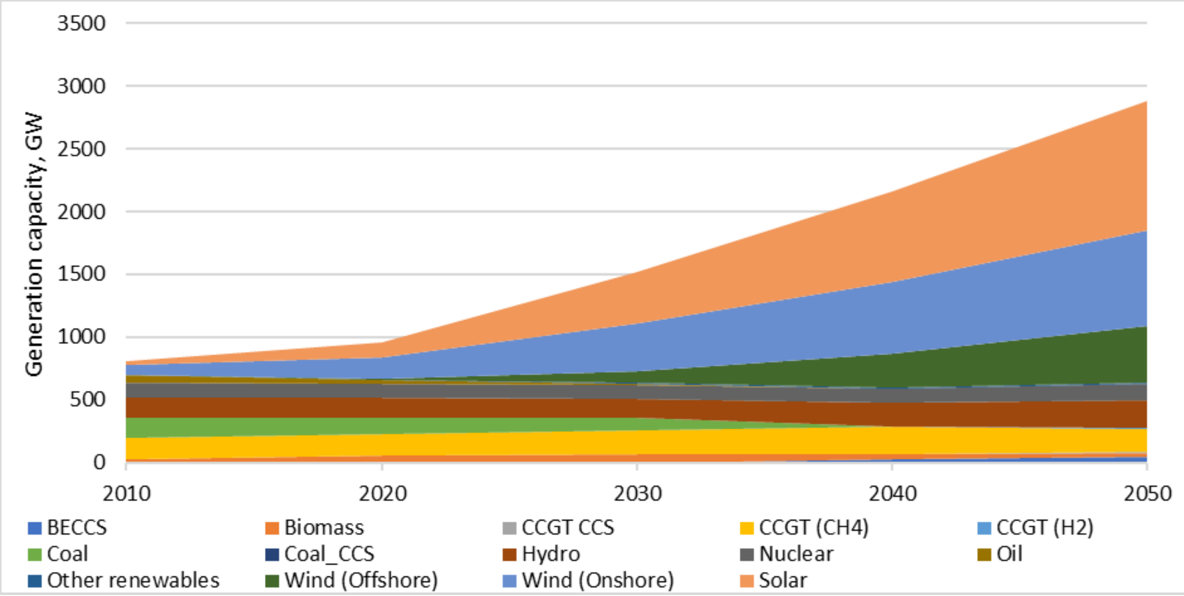
Overall, Europe's power sector transitions toward a predominantly renewable and low-carbon future. Wind, solar, and hydropower provide the bulk of electricity generation by 2050, while nuclear, BECCS, and flexible technologies like CCGT (CH4) and CCGT CCS ensure system reliability. However, the intermittency of renewables will require ongoing integration of flexible and backup technologies to maintain a stable energy supply as fossil fuel use is phased out.

Figure 4: Generation capacity mix until 2050 in the Reference scenario



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Coal_CCS	0.0	0.0	0.0	N/A	0.0%	0.3%
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Oil	2.5	0.0	0.0	1.6%	N/A	N/A
Other renewables	6.3	15.6	56.4	32.2%	25.6%	38.0%
Solar	628.9	1,120.5	1,610.7	17.7%	17.8%	17.9%
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Notes: implied capacity factors were computed by dividing the projected generation by the installed capacity, assuming 100% utilisation over a year; the actual capacity factors could be higher as projected generation is net off curtailment.

3.1.3. Storage and flexibility technologies

Table 6 and **Error! Reference source not found.** outline the evolution of energy and CO_2 storage capacity and renewable hydrogen and synthetic fuels production. In the Reference scenario, hydrogen storage is projected to undergo the most substantial growth among storage technologies, increasing from 101 TWh in 2030 to an enormous 1,150 TWh by 2050 (at the scale of existing methane storage in Europe). This increase represents an almost 11-fold increase over the two decades. In relative terms, hydrogen storage's share of total energy storage capacity rises from 9.7% in 2030 to 72.4% by 2050. This dramatic expansion highlights hydrogen's crucial role in storing surplus renewable electricity for later use, effectively balancing supply and demand, and such expansion aligns with the electrolysis capacity expansion in this Reference scenario **Error! Reference source not found.**).

Table 6: Storage capacity evolution in the reference scenario

	2030	2040	2050
CO2 (ktCO2)	75,001	226,250	377,500
Electricity (GWh)	368	315	280
Hydrogen (GWh)	101,353	61,140	1,149,803
Methane (GWh)	881,284	536,069	405,264

Table 7: Capacity of renewable hydrogen and synthetic fuels (GW) in the reference scenario

	2030	2040	2050
Water electrolysis	191.9	302.3	706.1
E-gas	19.5	11.0	25.7
E-liquid	3.5	251.0	152.4

Electricity storage, though playing a smaller role than hydrogen, remains an essential tool for short-term balancing and intraday flexibility. However, its capacity decreases slightly from 368 GWh in 2030 to 280 GWh by 2050. In relative terms, electricity storage's share of the total storage capacity decreases from 0.04% in 2030 to just 0.02% by 2050, reflecting a shift in focus towards longer-term, large-scale storage solutions like hydrogen and methane. This trend suggests that while battery and other electricity storage technologies remain important for short-term balancing, they become less dominant than hydrogen and methane storage for long-duration and seasonal storage.

In this Reference scenario, methane storage declines by 54% between 2030 and 2050. Some existing capacity may be converted to hydrogen storage as its role increases with renewable hydrogen expansion. Methane's share of the total storage capacity decreases from 84.5% in 2030 to 25.5% by 2050, indicating a more minor role as Europe moves toward decarbonisation, and the smaller capacity of methane storage is mainly to support renewable gas. Despite this decline, methane storage, along with biomethane and e-gas supply, remains an important tool for seasonal flexibility.

CO_2 storage expands rapidly to support carbon capture and storage (CCS) technologies, growing from 75 $mtCO_2$ in 2030 to 378 $mtCO_2$ by 2050, representing a 5-fold increase. This expansion is essential for reducing emissions from natural gas reforming (for low-carbon hydrogen production) and bioenergy with CCS (BECCS). The growing importance of CO_2 storage reflects the need to mitigate emissions from sectors where decarbonisation is challenging, making CCS a critical component of Europe's net-zero strategy.

Regarding renewable hydrogen and synthetic fuel production technologies, water electrolysis sees significant capacity growth, increasing from 192 GW in 2030 to 706 GW by 2050. This 3.7-fold expansion parallels the rise in hydrogen storage and demonstrates electrolysis' crucial role in converting excess renewable electricity into hydrogen, which can be stored and used when needed. Synthetic fuels, such as e-gas and e-liquid, also contribute to system flexibility but to a lesser extent than hydrogen. E-gas capacity fluctuates slightly, starting at 19.5 GW in 2030, dipping to 11.0 GW by 2040, and then rising to 25.7 GW by 2050. On the other hand, e-liquid grows dramatically from 3.5 GW in 2030 to 152.4 GW by 2050, showing its potential for decarbonising sectors like road transport.

3.1.4. Final consumption

The evolution of final energy consumption in Europe between 2030 and 2050 reflects the modelled transition to low-carbon fuels and electricity across the buildings, industry, and transport sectors. The results from Table 8 highlight significant shifts away from natural gas and oil, with a growing reliance on electricity, hydrogen, and biomethane, as well as the emergence of synthetic fuels in transport.

Natural gas continues to play an important role in the buildings sector in 2030, accounting for 34% of total energy consumption. However, by 2050, natural gas use declines sharply to just 4%, reflecting a transition towards more sustainable alternatives. This trend represents an overall reduction in natural gas consumption of nearly 90% over the two decades. The rapid decline in natural gas is aligned with Europe’s decarbonisation goals and efforts to phase out fossil fuels in residential and commercial heating with renewable gases (hydrogen and biomethane) and electricity. At the same time, electricity becomes increasingly important in the buildings sector, rising from 33% of total consumption in 2030 to 42% in 2050. The growing role of electrification reflects the adoption of electric heating technologies, which is crucial to reducing emissions in this sector.

Hydrogen also emerges as a significant energy source for buildings, accounting for 22% of consumption in 2030 and increasing to 26% by 2050. Hydrogen’s role in buildings will likely complement electrification. Biomethane sees even more dramatic growth, from 4% in 2030 to 23% by 2050, as it serves as a renewable alternative to natural gas, providing some flexibility through hybrid heat pumps (although, in this Reference scenario, the hybrid heating technologies are in passive mode). Overall, the total energy consumption in the buildings sector decreases from 4,926 TWh in 2030 to 4,138 TWh by 2050, reflecting efficiency improvements (via direct electrification of some heating demand) and the shift toward more sustainable energy sources.

In the industry sector, electricity shifts toward decarbonisation, rising from 45% of total consumption in 2030 to 60% by 2050. Natural gas, which still accounts for 42% of industrial energy consumption in 2030, declines rapidly to just 2% by 2050. This steep reduction, coupled with the rise in hydrogen, which reaches 15% of industrial energy use by 2050, highlights hydrogen’s role in decarbonising energy demand in this sector. Biomethane and biomass also see modest increases in their shares, with biomass accounting for 13% and biomethane for 5% of industrial energy consumption by 2050. The total energy consumption in the industrial sector remains relatively stable, declining only slightly from 2,313 TWh in 2030 to 2,297 TWh by 2050, reflecting somewhat limited improvements in energy efficiency.

The transport sector undergoes the most profound transformation between 2030 and 2050, with a significant shift from diesel and gasoline to low-carbon alternatives. Diesel still dominates the transport energy mix in 2030, accounting for 85% of total consumption. However, by 2050, its share plummets to 14%, reflecting the rise of electric vehicles, hydrogen-powered transport, and synthetic

Table 8: Final consumption by sectors and fuel shares in the reference scenario

	Buildings			Industry			Transport		
	2030	**2040**	**2050**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**
Biomass	0%	1%	1%	11%	12%	13%	3%	5%	8%
Biomethane	4%	11%	23%	3%	4%	5%	0%	6%	0%
Coal	0%	0%	0%	0%	0%	0%	0%	0%	0%
Diesel	3%	2%	0%	0%	0%	0%	85%	38%	14%
E-gas	2%	0%	0%	0%	3%	5%	0%	0%	0%
Electricity	33%	39%	42%	45%	52%	60%	2%	14%	22%
E-liquid	0%	2%	4%	0%	0%	0%	0%	26%	23%
Gasoline	0%	0%	0%	0%	0%	0%	6%	8%	0%
Hydrogen	22%	24%	26%	0%	7%	15%	0%	0%	33%
Natural gas	34%	21%	4%	42%	22%	2%	3%	3%	0%
Total Consumption, TWh	4,926	4,425	4,138	2,313	2,305	2,297	2,995	2,688	2,374

fuels. Electricity becomes a key energy source in transport, increasing from just 2% of total consumption in 2030 to 22% by 2050, driven by the widespread adoption of electric vehicles (EVs).

Hydrogen also plays a significant role in decarbonising transport, particularly for long-distance and heavy-duty applications. By 2050, hydrogen accounts for 33% of total energy consumption in transport, up from 0% in 2030. E-liquids, synthetic fuels produced from renewable electricity and carbon capture, also see significant growth in transport, increasing to 23% of total energy consumption by 2050. Gasoline is phased out entirely by 2050, while bioenergy plays a growing role, contributing 8% to transport energy consumption by 2050. The total energy consumption in the transport sector declines from 2,995 TWh in 2030 to 2,374 TWh in 2050, reflecting improvements in vehicle efficiency (switching from internal combustion to electric vehicles).

To summarise, across all sectors, the final consumption of natural gas drops significantly, particularly in buildings and industry, where its share declines to 4% and 2%, respectively, by 2050. The shift towards electricity, hydrogen, and biomethane indicates the need to support these energy vectors further in decarbonisation pathways.

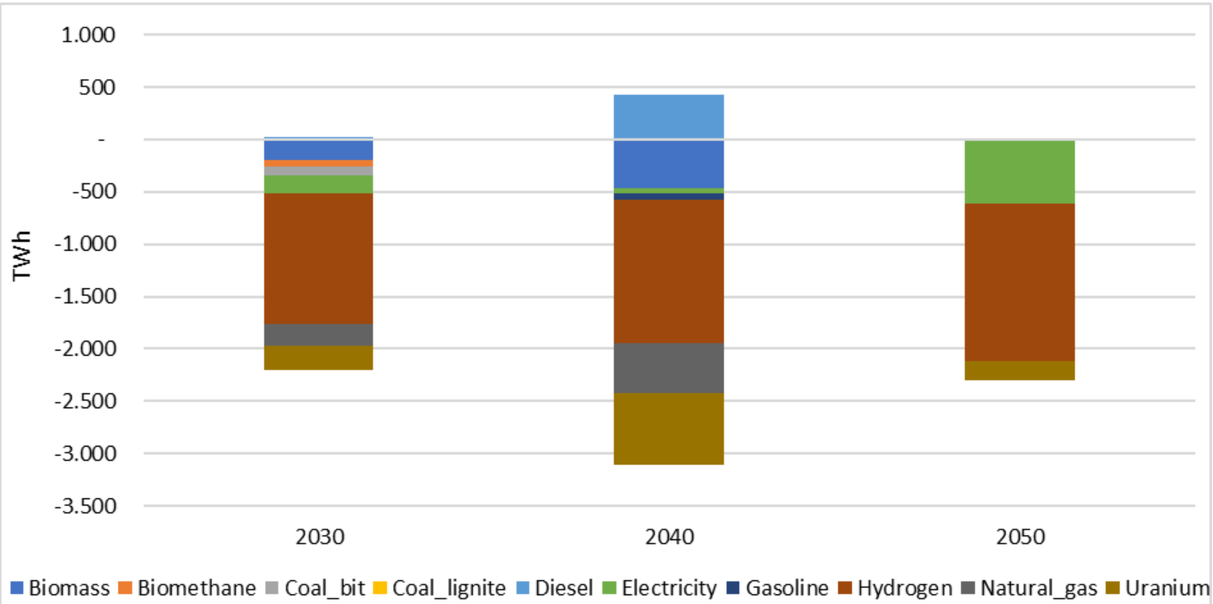
3.2. The role of sector coupling flexibility

This section compares the results for the Reference and Flexible Demand scenarios. This comparison provides key insights into how the lack of demand-side flexibility, particularly with hybrid heat pumps operating in baseload mode, impacts Europe’s pathway to net-zero emissions by 2050. The Reference scenario assumes hybrid heat pumps operate continuously with limited ability to respond to system imbalances, potentially due to a lack of dynamic pricing at the buildings level.[4] At the same time, in the Flexible Demand scenario, we model hybrid heat pumps to operate flexibly and respond to system imbalances. The analysis focuses on changes in fuel supply, power generation, storage capacities, and final energy consumption.

The differences in fuel supply between the Flexible Demand and Reference scenarios demonstrate the impact that end-use demand flexibility can have on energy supply patterns (

). The Flexible Demand scenario results in significantly lower hydrogen supply across the board, with reductions of 1,243 TWh in 2030 and 1,500 TWh in 2050, leading to an average reduction of 1,370 TWh/year. This trend indicates that flexible hybrid heat pumps allow the system to reduce reliance on hydrogen by better integrating intermittent renewables with end-use (direct electrification of) demand. In line with this trend, the electricity supply also decreases in the Flexible Demand scenario, with a reduction of 611 TWh in 2050, contributing to an average decrease of 277.7 TWh/year. This reduction is driven by a reduced need for hydrogen, as hybrid heat pumps can shift electricity consumption to periods when renewable energy is abundant. Natural gas supply also declines under the Flexible Demand scenario, with an average reduction of 230.2 TWh/year by 2050, driven by a reduced demand for low-carbon hydrogen production.

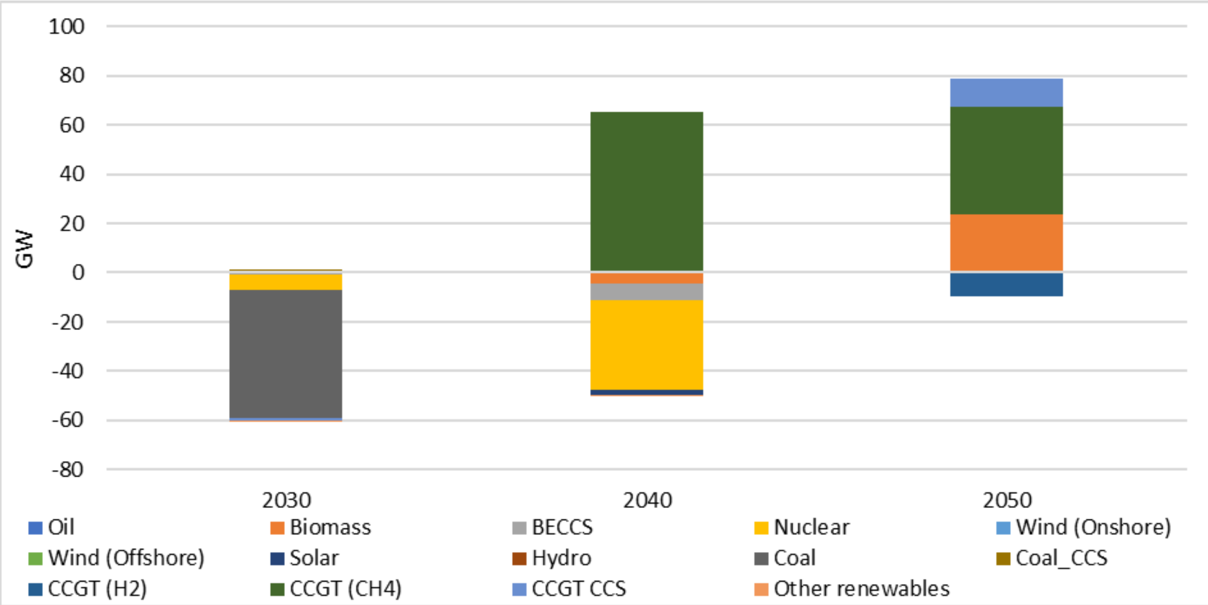
Figure 5: Changes in fuel supply in the Flexible Demand scenario compared to the Reference scenario

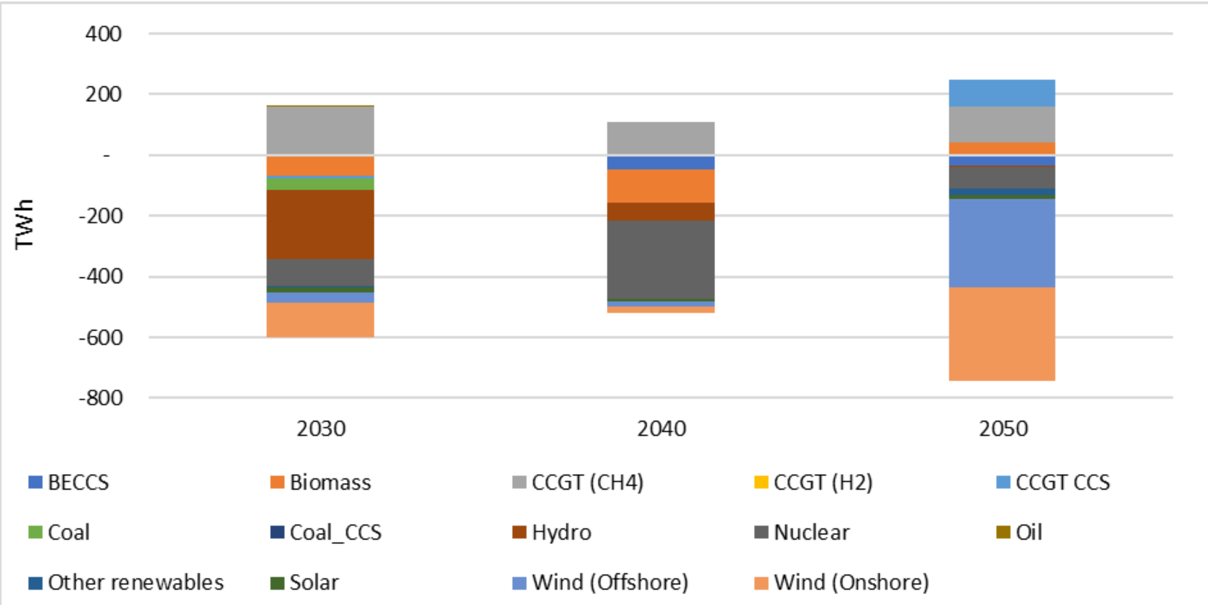


[4] It is worth noting that even under inflexible operating modes, hybrid heat pumps can contribute to peak shaving of the heat demand under cold conditions.

Notes: The electricity supply shown here includes wind and solar generation; the hydrogen supply includes electrolysis and steam methane reformation.

Figure 6: Changes in electricity generation (upper plot) and capacity (bottom plot) in the Reference scenario compared to the Flexible Demand scenario



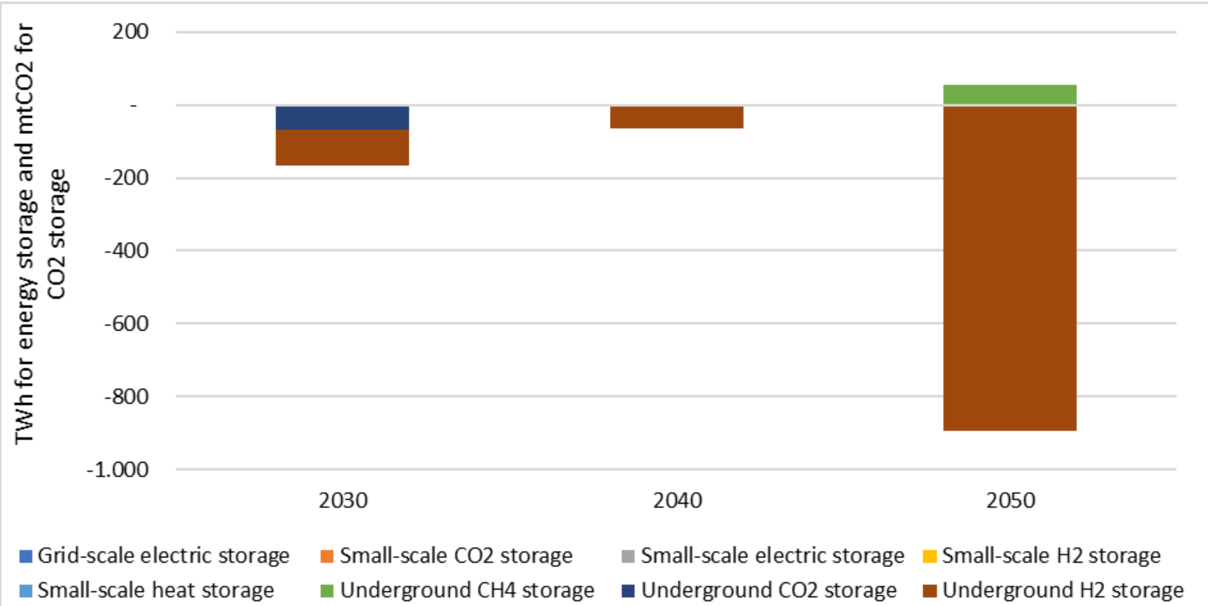


The shift toward flexibility in demand leads to notable changes in electricity generation capacity. In the Flexible Demand scenario, CCGT (CH4) capacity increases by 65 GW in 2040 and 44 GW in 2050, resulting in an average increase of 36.4 GW/year. This increase is due to the decline in natural gas demand for producing low-carbon hydrogen, making gas supply more available for electricity production. However, other technologies see reductions in capacity. Nuclear capacity drops by 37 GW by 2040, with an average decline of 14.3 GW/year. This trend reflects a more efficient use of renewables facilitated by flexible hybrid heat pump technologies. BECCS capacity also falls, with a decrease of 6 GW in 2040, due to the improved integration of intermittent renewables under flexible demand.

Regarding electricity generation, the Flexible Demand scenario leads to notable shifts compared to the Reference scenario. Hydro generation, for example, decreases by 229 TWh in 2030, with an average decline of 97 TWh/year by 2050. The reduction in hydro generation may result from more efficient use of storage and other flexibility measures, reducing the need for flexible generation from hydropower. In line with the evolution of installed generation capacity, nuclear generation also sees a substantial decline, with a reduction of 88 TWh in 2030 and 260 TWh in 2040, resulting in an average decrease of 140 TWh/year by 2050. This trend highlights the decreased need for constant baseload power from nuclear plants, as flexibility allows the system to match renewable supply with demand better. Meanwhile, CCGT (CH4) generation increases, with an additional 160 TWh in 2030, contributing to an average increase of 130 TWh/year by 2050.

One of the most significant changes between the two scenarios is in hydrogen storage capacity (Figure 7). The underground hydrogen storage capacity experiences a sharp reduction in the Flexible Demand scenario, decreasing by 101 TWh in 2030, 61 TWh in 2040, and a massive 895 TWh by 2050. This trend follows the one for the hydrogen fuel supply. It indicates that the need for long-duration hydrogen storage diminishes substantially under the Flexible Demand scenario. Using hybrid heat pumps with renewable gas (biomethane) and flexible demand management reduces the reliance on hydrogen for long-term storage, as the system can better align energy demand with renewable generation. However, there is an increase in small-scale hydrogen storage by 950 GWh in 2050, contributing to an average increase of 0.08 TWh/year. This result suggests that hydrogen still plays a role in short-term and intra-day flexibility, where smaller-scale hydrogen storage can balance local renewable generation and consumption fluctuations.

Figure 7: Changes in storage capacity in the Reference scenario compared to the Flexible Demand scenario



Grid-scale electricity storage shows minimal changes compared to the Reference scenario. By 2050, there is a slight increase of 1 GWh. This negligible shift indicates that flexible demand does not significantly impact large-scale electricity storage because the flexibility of hybrid heat pumps reduces the need for extensive large-scale electricity storage. On the other hand, small-scale electric storage capacity sees a slight increase of 22 GWh by 2050. This finding suggests that while large-scale electricity storage remains relatively stable, decentralised and small-scale electric storage has a role in managing local electricity demand and helping to balance short-term fluctuations in renewable generation.

Underground methane storage exhibits notable changes in the Flexible Demand scenario. While methane storage decreases by 2,637 GWh in 2030 and 1,704 GWh in 2040, it increases by 53,684 GWh in 2050. The higher capacity of methane storage by 2050 indicates that in a flexible demand scenario, methane storage coupled with renewable gas and hybrid heat pumps provides daily and seasonal flexibility for balancing longer-term supply and demand fluctuations. In the Flexible Demand scenario, underground CO2 storage experiences reductions, which follows the reduced need for low-carbon hydrogen. Lastly, small-scale heat storage sees a reduction across all timeframes, decreasing by 47 GWh in 2030, 121 GWh in 2040, and 128 GWh by 2050. This decline reflects the increased flexibility of hybrid heat pumps, which can better manage heat demand and reduce the need for standalone heat storage solutions.

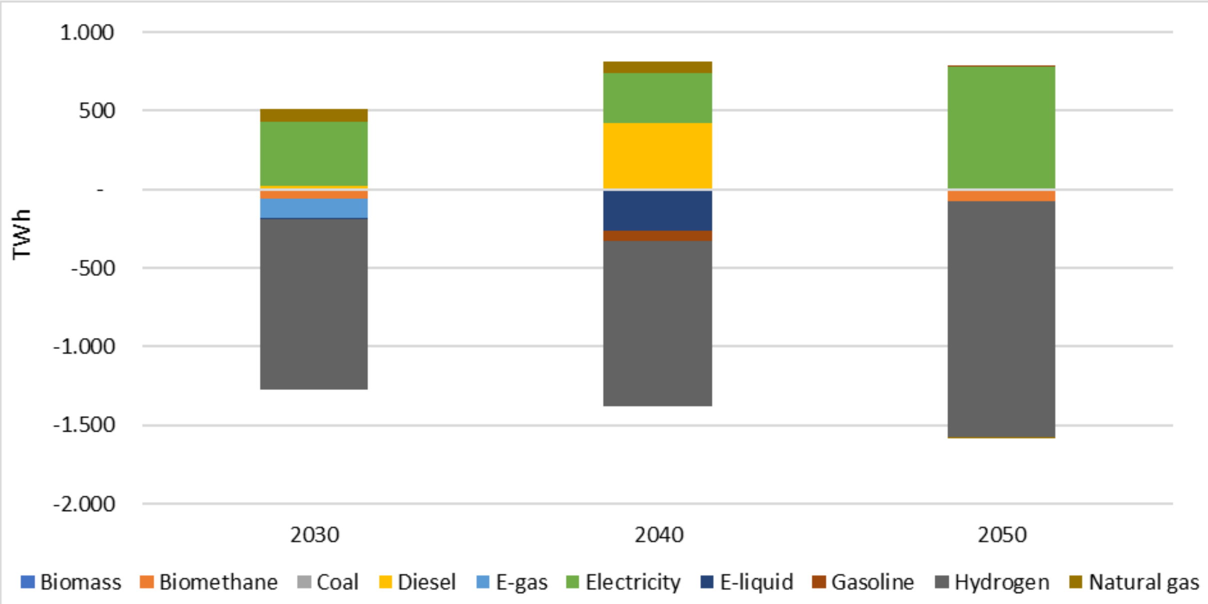
The comparison between the Flexible Demand and Reference scenarios highlights shifts in final energy consumption across key energy carriers (Figure 8). Electricity consumption sees a dramatic increase in the Flexible Demand scenario compared to the Reference scenario. By 2030, electricity consumption is 408 TWh higher, with increases of 314 TWh in 2040 and 779 TWh in 2050, averaging 500 TWh/year. This increase suggests that flexible demand scenarios, which allow for better load-shifting (via flexible hybrid heat pumps) and the ability to consume electricity during periods of high renewable generation, lead to more significant overall electricity usage. The ability to shift demand away from peak periods and toward times when renewable energy is abundant helps reduce reliance on fossil fuels. Thus, flexible hybrid heat pumps increase the system's ability to utilise clean electricity.

On the contrary, hydrogen consumption significantly declines in the Flexible Demand scenario. By 2050, hydrogen consumption is reduced by 1,501 TWh, and the average reduction across the period is 1,211 TWh/year. The decreased hydrogen consumption reflects the improved flexibility of hybrid heat pumps, allowing for better matching between intermittent renewable supply and direct electrification of heating demand.

Natural gas consumption increases by 84 TWh in 2030 and 72 TWh in 2040 before leveling off in 2050. This increase in gas consumption is in the transport sector, especially in 2030-2040, when the GHG emissions reduction target still allows the fuel to be used in this sector due to its relative abundance in the Flexible Demand scenario (less gas for low-carbon hydrogen production). Diesel consumption increases in 2040 under the Flexible Demand scenario, rising by 426 TWh. The rise in diesel use is in response to lower consumption of synfuel (e-liquid) due to lower hydrogen supply in the Flexible Demand scenario.

E-gas consumption experiences mixed results in the Flexible Demand scenario, with reductions of 120 TWh in 2030 and 4 TWh in 2040, followed by a slight reduction of 0.1 TWh in 2050. E-gas, a synthetic fuel produced from hydrogen and CO2, plays a reduced role under flexible demand due to lower requirements for the fuel in the building sector, which under the flexible demand scenario is substituted by renewable electricity facilitated by flexible hybrid heat pumps. Similarly, e-liquid consumption declines predominantly in the transport sector, with a reduction of 251 TWh in 2040 and an average decrease of 86 TWh/year. Biomethane consumption sees a slight reduction of 47 TWh/year (7% lower than average consumption in the Reference scenario) in the Flexible Demand scenario relative to the Reference scenario due to a more flexible demand side management facilitated by the hybrid heat pump technologies allowing for more efficient integration of intermittent renewable electricity in final consumption.

Figure 8: Changes in final consumption in the Flexible scenario compared to the Flexible Demand scenario



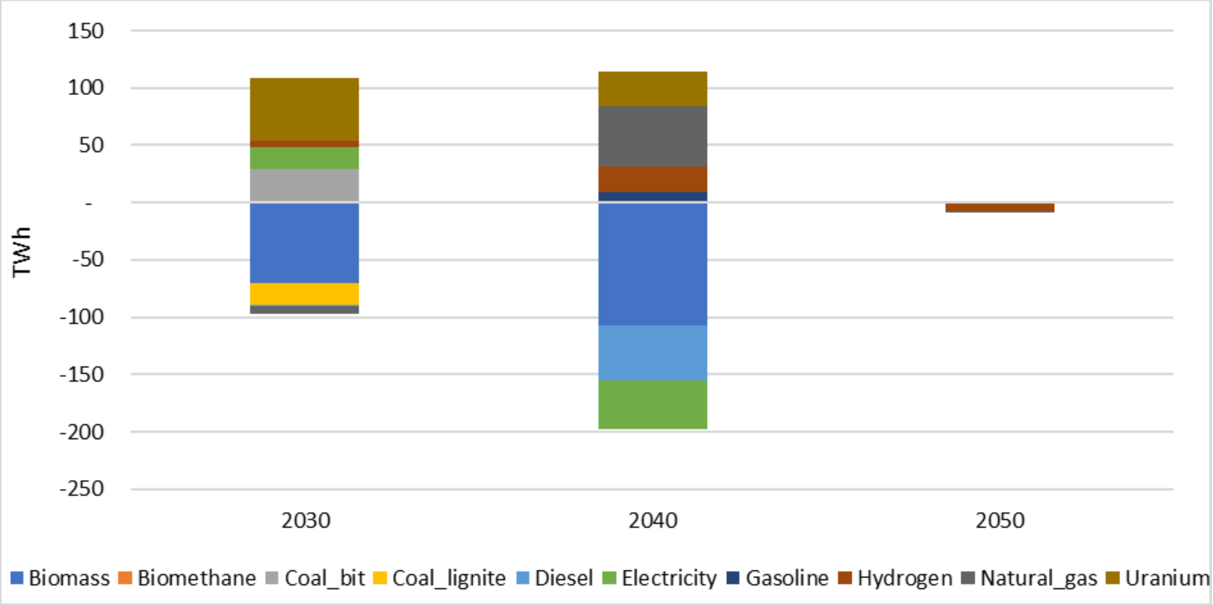
3.3. Impact of Intermittency of Renewables

We explicitly modelled the requirements for reserve capacity to mitigate the risks of intermittent renewable energy supplies. The model chooses optimal deployment of intermittent renewable electricity capacity against additional costs of providing the reserve capacity, given policy constraints (such as meeting emissions targets). This section compares the Reliable and Flexible scenarios to gauge the impacts of introducing reserve capacity on fuel supply, power generation and storage, and final consumption. The question we aim to answer here is what is required to make a future energy system both flexible and reliable.

The Reliable scenario, which imposes more stringent reliability requirements, leads to noticeable changes in fuel supply (**Error! Reference source not found.**).

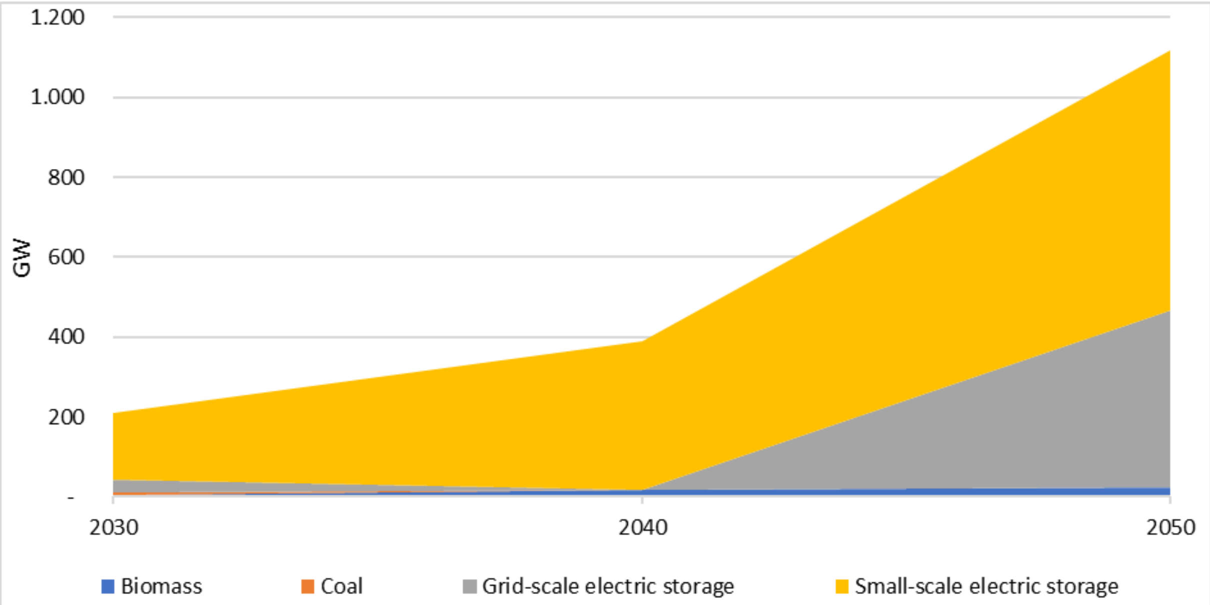
Natural gas supply increases by an average of 15.2 TWh per year, primarily due to its increased role in low-carbon hydrogen production. In the Reliable scenario, this shift is driven by an average annual increase of 8.9 GW in natural gas SMR with CCS capacity from 2030-50. The reduced availability of curtailed energy from wind, solar, and hydro in the Reliable scenario further reinforces the need for low-carbon hydrogen, as less excess renewable energy is available for renewable hydrogen production. Overall, hydrogen supply increases by an average of 6.6 TWh/year. Biomass supply decreases by an average of 59.2 TWh per year (Figure 10).. This decrease in biomass supply is linked to the Reliable scenario's demand for dispatchable generation capacity that can hedge against low renewable generation periods. Since dispatchable capacity from bioenergy is reserved to ramp up when needed, its generation decreases in this scenario relative to the generation from biomass in the Flexible Demand scenario.

Figure 9: Changes in fuel supply in the Reliable scenario compared to the Flexible scenario



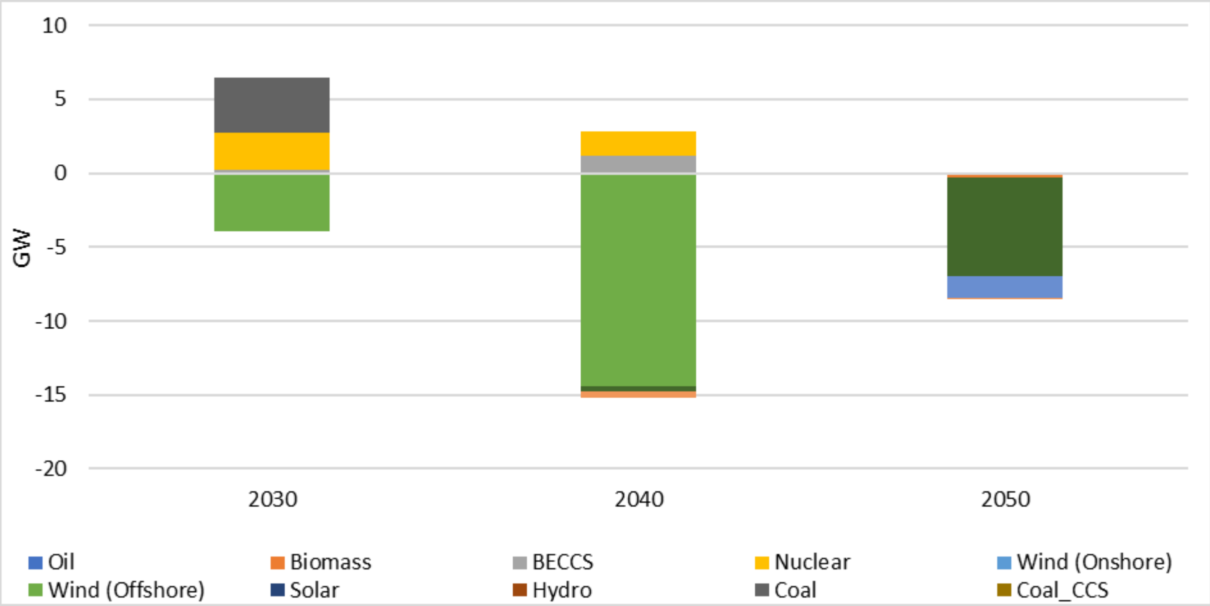
Notes: The electricity supply shown here includes wind and solar generation; the hydrogen supply includes electrolysis and steam methane reformation.

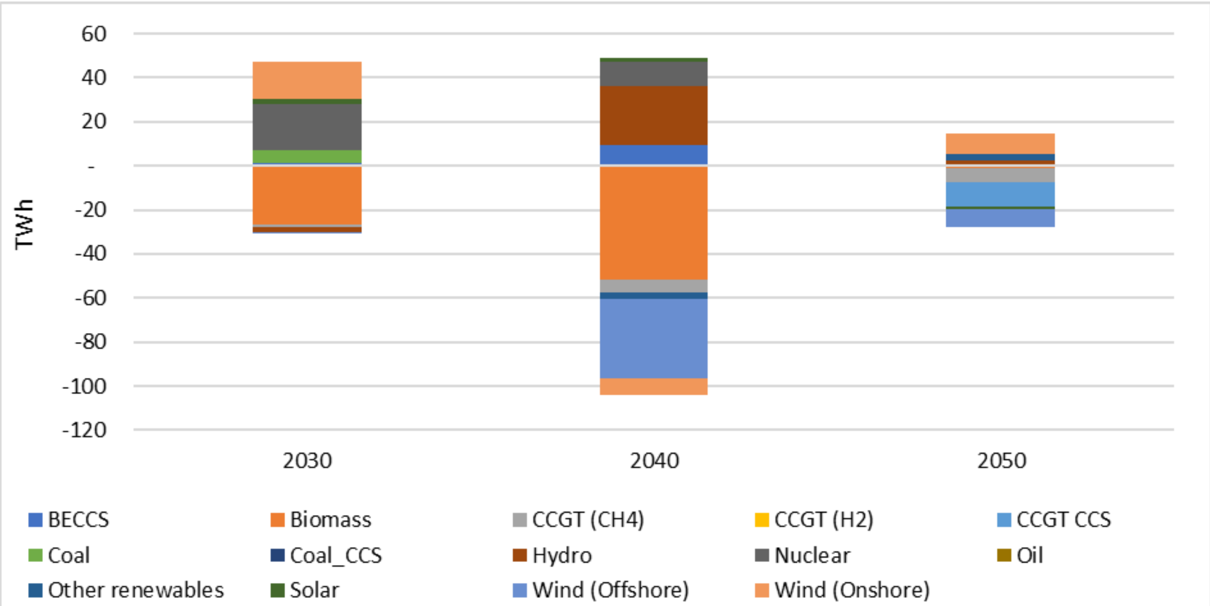
Figure 10: Reserve capacity to mitigate risks of intermittency of renewable energy supply



Bituminous coal supply sees an increase of 29.6 TWh in 2030 only. Then, no changes in coal supply 2040-50 as climate targets and high carbon prices make coal uneconomic and infeasible in the decarbonised system we model. At the same time, the lignite coal supply decreases by 19 TWh in 2030, so we see a net increase of ca. 10 TWh of coal in 2030 due to the requirement for reserve capacity. Diesel supply decreases by 16.4 TWh annually, underscoring the system's broader transition from fossil fuels.

Figure 11: Changes in electricity generation (upper plot) and capacity (bottom plot) in the Reliable scenario compared to the Flexible scenario





The Reliable scenario causes shifts in power generation (

), with some technologies seeing increased generation despite unchanged capacity, suggesting reduced curtailment. Solar generation, for instance, increases by an average of 0.8 TWh per year, even though its capacity remains similar across the two scenarios. This reduction in curtailment indicates that solar energy is being utilised more efficiently in the Reliable scenario, where the implicit curtailment costs are higher due to the need for grid stability via increased storage coupling with wind and solar energy. The more efficient use of solar energy reduces the need for additional electrolysis capacity, evidenced by an average annual decrease of 31.3 GW.

Similarly, onshore wind generation increases by 6.3 TWh per year on average, without significant changes in capacity, indicating that this technology is also facing less curtailment. Hydro follows the same trend, with its generation increasing by 8.6 TWh per year on average despite no changes in

Figure 12: Changes in storage capacity in the Reliable scenario compared to the Flexible scenario

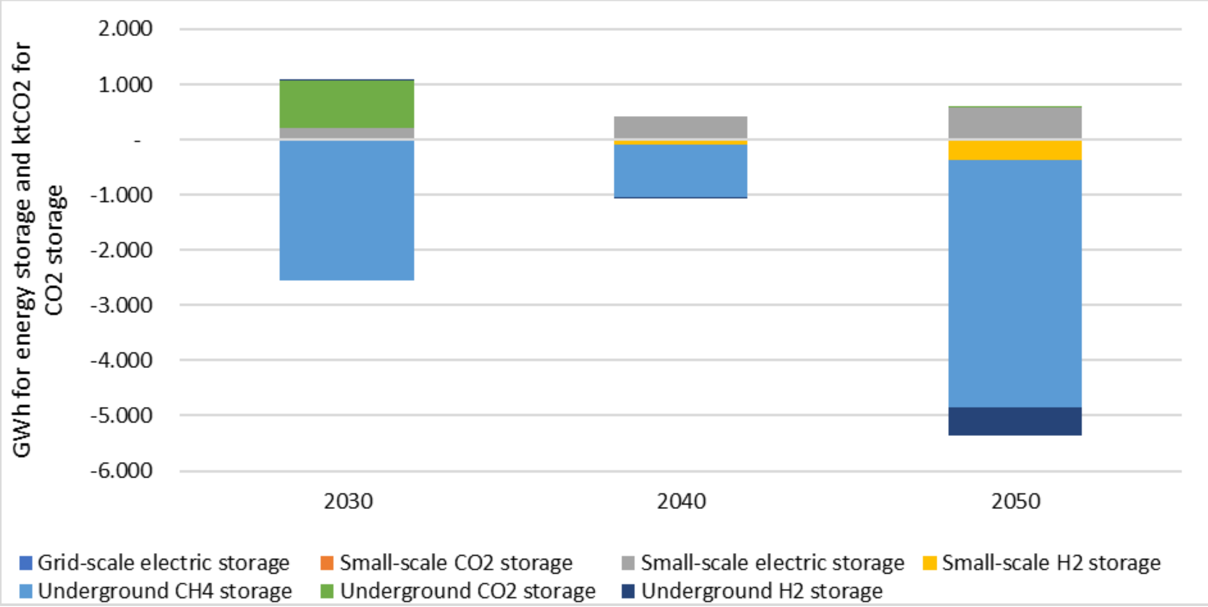
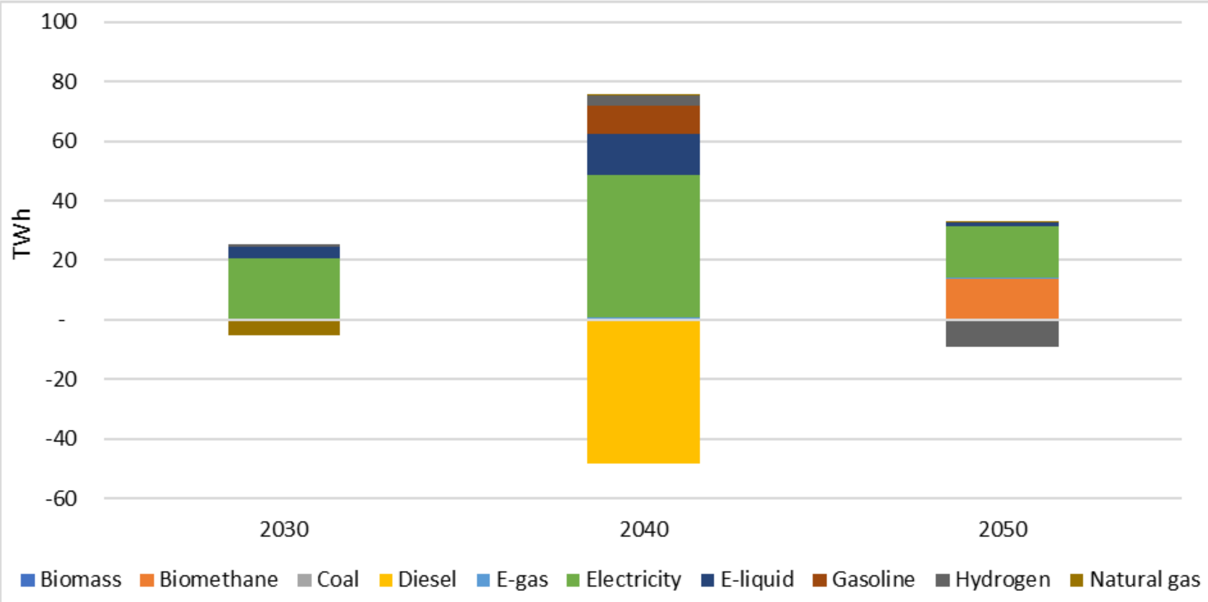


Figure 13: Changes in final consumption in the Reliable scenario compared to the Flexible scenario



capacity. These trends demonstrate that the Reliable scenario reduces curtailment across multiple renewable technologies, enhancing overall electricity supply efficiency. In contrast, offshore wind generation decreases by 14.8 TWh per year on average, reflecting the higher costs associated with ensuring its reliability compared to onshore wind, solar, and hydro. Nuclear generation increases by 10.8 TWh per year on average due to marginally higher installed capacity in the Reliable scenario compared to the Flexible Demand scenario.

The storage capacity adjustments (Figure 12) in the Reliable scenario highlight the system's need to manage increased variability (including minimising curtailment). The average annual increase of 0.4 TWh in small-scale electric storage reflects the growing demand for dispatchable capacity to hedge against the intermittency of renewables.

Conversely, small-scale hydrogen storage decreases by 0.2 TWh yearly, while underground hydrogen storage decreases by 0.2 TWh yearly. This decrease suggests a shift from hydrogen as a primary storage medium, favouring other solutions like electricity storage for short-term grid stability. Underground natural gas storage decreases by 2.7 TWh per year, which is less than 1% of the methane storage capacity in the Flexible scenario.

The Reliable scenario induces significant shifts in final energy consumption (Figure 13), particularly towards increased electrification and reduced reliance on fossil fuels. On average, natural gas consumption decreases by 15.2 TWh annually, driven by the shift towards more electrified solutions across various sectors. This is supported by an average annual increase of 28.6 TWh in electricity consumption, reflecting the more efficient use of renewable electricity due to reduced curtailment. Hydrogen consumption increases by 12.3 TWh per year, driven by the need for dispatchable low-carbon fuels in processes where electrification is challenging. This increase is closely tied to the rise in low-carbon hydrogen production, compensating for the reduced availability of curtailed renewable energy for renewable hydrogen production.

The increased efficiency of these technologies underscores the system’s adaptation to higher reliability standards. By making curtailment more costly (by imposing reserve capacity requirement), the Reliable scenario effectively incentivises more efficient use of renewable energy, reducing the need for additional capacity in electrolysis and shifting focus towards direct electrification. This reduction in curtailment has broader implications for cost and resource allocation within the energy system. The system reduces wasted energy and maximises output from existing renewable capacities by minimising curtailment. This trend, in turn, reduces demand for additional renewable hydrogen production, shifting focus towards low-carbon hydrogen that is more aligned with the Reliable scenario’s requirements for dispatchable low-carbon fuels.

Thus, the reduction in curtailment of solar, onshore wind, and hydro, the increased reliance on nuclear and low-carbon hydrogen, and the increase in storage capacities collectively highlight the system’s adaptation to the modelled reliability standards. These changes underscore the complexity of balancing decarbonisation goals with the need for a stable and reliable energy supply.

3.4. The Economic and System Implications of Transitioning to a Resilient Net-Zero Energy Market

This section examines the economic and system implications of the transition to a net-zero energy system in Europe, focusing first on system peak hour demand and cross-border flows (§3.4.1) and then on capital expenditures (§3.4.2.) and energy prices in the three scenarios modelled: Reference, Flexible, and Reliable. By comparing these scenarios, we assess how varying levels of system flexibility and reliability requirements influence the system capacity, costs of the energy transition and the potential economic burden on consumers.

3.4.1. Implications on System Capacity

Analysing system peak hour demand, cross-border peak flow, and their common patterns and key differences reveal interesting insights into how the modelled scenarios impact the energy system

Table 9: Estimated total system peak hour demand and cross-border flow, GW

	Total System Peak Hour Demand, GW			Total Cross-border Peak Flow, GW		
	2030	2040	2050	2030	2040	2050
Reference Scenario						
Electricity	887.2	1,138.2	1,622.6	221.7	327.8	435.3
Hydrogen	286.3	466.1	824.5	50.2	125.3	128.3
Methane	1,623.3	1,310.3	720.9	402.6	289.5	190.6
Flexible Scenario						
Electricity	879.4	1,118.80	1,592.70	234.1	395.2	498.9
Hydrogen	9.6	193.9	571.7	1.8	13.8	86.8
Methane	1,714.60	1,477.60	888.1	425.7	299.1	154.2
Reliable Scenario						
Electricity	905.9	1,105.7	1,597.6	222.5	374.4	482.0
Hydrogen	11.3	193.9	510.9	2.1	24.2	84.5
Methane	1,716.8	1,490.6	889.5	428.7	302.6	157.4

Notes: total is the sum of peaks for all countries and regions in the model.

(**Error! Reference source not found.**). When comparing the Flexible scenario to the Reference scenario, a clear trend emerges in electricity peak demand, with the Flexible scenario showing consistent reductions. Electricity peak demand drops by 7.71 GW in 2030 (-0.87%), 19.42 GW in 2040 (-1.71%), and 29.92 GW in 2050 (-1.84%) relative to the Reference scenario. This reduction highlights the effectiveness of flexible hybrid heat pumps, shifting demand to align better with renewable availability, flattening the peaks and easing pressure on the electricity grid.

On the other hand, methane (natural gas) peak demand increases in the Flexible scenario, rising by 91.35 GW (+5.63%) in 2030, 167.36 GW (+12.77%) in 2040, and 167.19 GW (+23.18%) in 2050 compared to the Reference scenario. This increase reflects a shift in the demand burden from electricity to methane network, as flexible hybrid heat pumps reduce electricity peaks to methane as a backup. In contrast, hydrogen peak demand decreases dramatically in the Flexible scenario, with reductions of 276.69 GW (-96.66%) in 2030, 272.28 GW (-58.41%) in 2040, and 252.78 GW (-30.65%) by 2050. These reductions suggest that the flexibility introduced by hybrid heat pumps diminishes the need for a hydrogen network. This trend is similar to the hydrogen fuel supply and demand trends observed in the preceding analysis.

In the Reliable scenario, the introduction of reserve capacity slightly alters peak demand trends. Electricity peak demand is higher by 26.42 GW (+3.00%) in 2030 and by 4.90 GW (+0.31%) in 2050 compared to the Flexible scenario, indicating that the reserve capacity marginally adds upward pressure on the electricity grid to ensure reliability during peak periods.

The differences between the Reliable and Flexible scenarios are relatively small for natural gas, with peak demand increasing by +2.16 GW (+0.13%) in 2030 and +13.00 GW (+0.88%) in 2040. By 2050, this difference narrows to +1.38 GW (+0.15%). This trend indicates that methane grids contribute to the reliability of the energy system dependent on intermittent renewables. Hydrogen, meanwhile, shows minimal changes between the two scenarios, with an early increase of 1.78 GW (+18.61%) in 2030 but a reduction of 60.77 GW (-10.63%) by 2050. This trend indicates that the capacity reserve, designed to mitigate renewable intermittency, reduces the need for hydrogen grid capacity, particularly in 2050, when renewable capacity is at its peak. This reduction is due to the higher and more efficient utilisation of renewable energy (see §3.3), which lessens the reliance on hydrogen to balance intermittency through the renewable hydrogen production pathway.

When analysing cross-border peak flows, the Flexible scenario shows higher electricity flows compared to the Reference scenario, increasing by 12.4 GW (+5.59%) in 2030, 67.4 GW (+20.56%) in 2040, and 63.6 GW (+14.61%) by 2050. This result indicates that flexible demand via hybrid heat pumps facilitates more significant cross-border electricity trade due to improved integration of renewable energy and optimised electricity grid utilisation domestically and across borders. On the other hand, hydrogen cross-border flows drop significantly in the Flexible scenario, with reductions of 48.4 GW (-96.42%) in 2030, 111.5 GW (-89.01%) in 2040, and 41.5 GW (-32.34%) in 2050. These reductions reflect a diminished role for hydrogen in cross-border balancing when domestic systems become more efficient at managing peak demand.

For natural gas, the cross-border flows increase by 23.1 GW (+5.73%) in 2030 compared to the Reference scenario, but this increase diminishes over time, with only 9.6 GW (+3.32%) in 2040 and a reduction of 36.4 GW (-19.10%) by 2050. This result suggests that cross-border natural gas trade remains crucial in the early years but gradually gives way to other fuels as the system decarbonises. Thus, as the energy system decarbonises with a flexible demand side, local methane grids become more critical than cross-border trade due to the much lower scale of the (local) renewable gas market in 2050 than the scale of the existing Pan-European natural gas market.

Comparing the Reliable scenario to the Flexible scenario, cross-border electricity flows decrease slightly by 11.6 GW (-4.96%) in 2030, 20.8 GW (-5.26%) in 2040, and 16.9 GW (-3.39%) in 2050. With the reserve capacity modelled, the Reliable scenario reduces the need for cross-border electricity exchanges to manage peak demand, as domestic systems are better equipped to handle supply-demand imbalances. Hydrogen cross-border flows increase marginally in the early years, by 0.3 GW (+16.67%) in 2030 and 10.4 GW (+75.36%) in 2040, before decreasing by 2.3 GW (-2.65%) in 2050. This result suggests that hydrogen cross-border trade plays a backup role in the Reliable scenario, but its importance diminishes over time. Natural gas cross-border flows are slightly higher in the Reliable scenario compared to the Flexible scenario, with increases of 3.0 GW (+0.71%) in 2030 and 3.5 GW (+1.17%) in 2040, though by 2050, the difference is only +3.2 GW (+2.08%). This trend points to the continued importance of natural gas for cross-border flows under the Reliable scenario.

Thus, the Flexible scenario reduces electricity peak hour demand while increasing cross-border electricity flows. This trend underscores how demand-side flexibility can alleviate domestic electricity demand while enhancing electricity trade across borders, as surplus renewable energy is exported to neighbouring countries. For methane, the trends are more nuanced: while system peak demand for methane increases in the Flexible scenario, cross-border flows show a more variable pattern, increasing in the early years but declining by 2050. This finding suggests that methane remains critical for managing domestic peak loads through 2050 but becomes less necessary for international energy trade as the size of the methane market is relatively small in 2050 to justify higher cross-border trade.

On the other hand, hydrogen experiences significant reductions in both system peak demand and cross-border flows in the Flexible scenario. This observation demonstrates that adopting flexible hybrid heat pumps and other demand-side measures reduces the reliance on the hydrogen grid for domestic and cross-border balancing. However, the Reliable scenario shows that reserve capacity introduces a modest increase in cross-border flows for hydrogen and methane in the early years. However, this reliance decreases by 2050 as the system becomes more self-sufficient and integrated with renewable energy.

The Flexible scenario optimises the energy grid capacity by reducing domestic peak hour electricity demand (and hence electric grid capacity) and increasing cross-border electricity flows while reducing reliance on hydrogen. While maintaining reserve capacity for reliability, the Reliable scenario slightly increases cross-border energy transfers, particularly for hydrogen and natural gas, in the early years. However, by 2050, both scenarios converge toward a decarbonised energy system with reduced cross-border reliance on fossil fuels and a more efficient use of renewable energy resources.

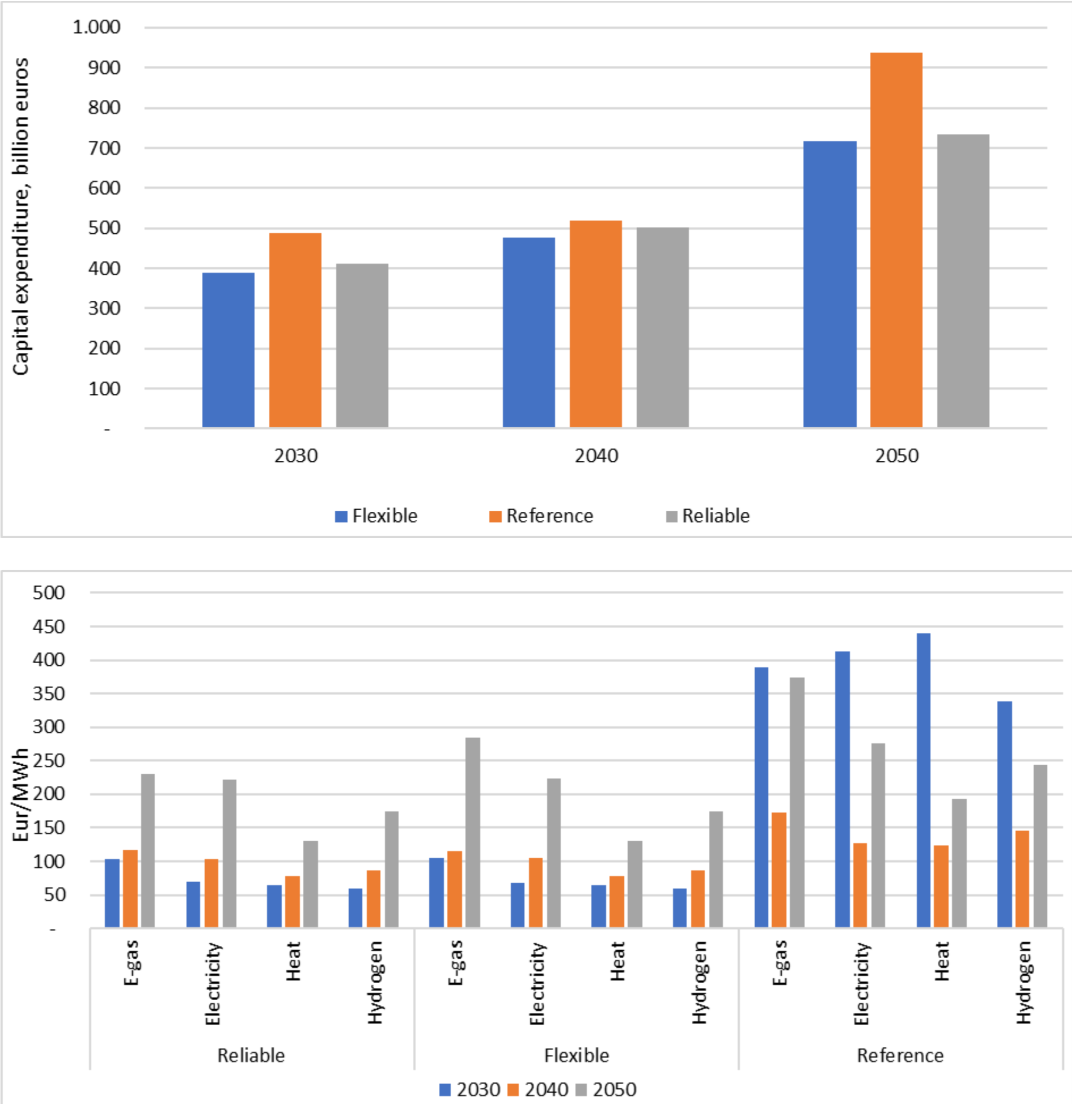
3.4.2. Implications on investment and prices

In the Reference scenario, the energy system operates under the assumption that demand-side flexibility is limited, particularly concerning the operation of hybrid heat pumps, which are modelled as not fully flexible (e.g., due to lack of dynamic price signals). This scenario relies on conventional backup generation and expanded storage and network infrastructure to manage fluctuations in demand, resulting in relatively higher capital expenditures (CAPEX, Figure 14, upper plot) and energy prices (Figure 14, bottom plot) over time.

In 2030, total system CAPEX in the Reference scenario is €488 billion. This figure rises to €520 billion by 2040 (+6.6%) and continues to increase to €937 billion by 2050, representing a 92% rise over the 2030 value. The steady growth in CAPEX is driven by significant investments in energy infrastructure (storage and network infrastructure), particularly hydrogen storage and network, to ensure system stability without demand-side flexibility.

Energy prices also rise sharply in the Reference scenario. Electricity prices start at €414/MWh in 2030, dropping to €275/MWh by 2050 (-33.6%) as renewable integration improves, but these values remain higher than the other scenarios. Hydrogen prices follow a similar trend, starting at €338/MWh in 2030 and declining to €245/MWh by 2050 (-27.5%). These persistent price levels reflect the additional system costs related to managing demand peaks without flexible heat pump operation, requiring expensive investments in backup infrastructure.

Figure 14: Capital expenditure (upper plot) and energy prices (bottom plot) in the modelled scenarios



Notes: for prices, the units for electricity are Eur/MWh-e, while for fuels, the units are in Eur/MWh-th

As modelled in the Flexible Demand scenario, introducing demand-side flexibility in the form of fully responsive hybrid heat pumps results in notable improvements in both CAPEX and energy prices relative to the Reference scenario. By enabling hybrid heat pumps to shift demand in response to price signals, the system can more efficiently balance supply and demand, reducing reliance on expensive backup generation, storage and grid infrastructure.

In 2030, CAPEX in the Flexible Demand scenario is €388 billion, representing a 20.5% reduction compared to the Reference scenario. By 2040, CAPEX increases to €476 billion, marking a 22.8% reduction from the Reference scenario's CAPEX of €520 billion. In 2050, the gap widens further as CAPEX in the Flexible Demand scenario rises to €718 billion, 23.4% lower than the €937 billion required in the Reference scenario. These reductions highlight the substantial cost savings enabled by demand-side flexibility.

Energy prices also improve significantly under the Flexible Demand scenario. Electricity prices are €69/MWh in 2030, a reduction of 83.3% compared to the Reference scenario (€414/MWh). By 2040, electricity prices in the Flexible Demand scenario rise to €105/MWh, still 17.4% lower than the €127/MWh seen in the Reference scenario. By 2050, electricity prices in the Flexible Demand scenario reach €223/MWh, 19.1% lower than the Reference scenario's price of €275/MWh. Similarly, hydrogen prices are 82.5% lower in 2030, dropping from €338/MWh in the Reference scenario to €59/MWh in the Flexible scenario. By 2050, hydrogen prices are €175/MWh in the Flexible scenario, 28.6% lower than in the Reference scenario (€245/MWh). These price reductions illustrate how a flexible system, where demand can be adjusted to match the availability of renewable energy better, can significantly lower the costs of integrating renewables into the grid.

The Reliable scenario introduces further measures to ensure the stability of the energy system, with a particular emphasis on maintaining reserve capacity. While this scenario adds some marginal costs, the additional investment is relatively modest compared to the reductions already achieved in the Flexible Demand scenario.

In 2030, CAPEX in the Reliable scenario is €412 billion, just 6.2% higher than the Flexible Demand scenario (€388 billion) but still 15.6% lower than the Reference scenario. By 2050, CAPEX in the Reliable scenario rises to €733 billion, which is only 2.1% higher than in the Flexible Demand scenario but 21.8% lower than in the Reference scenario. The relatively small increase in CAPEX reflects the marginal cost of enhancing system reliability via additional infrastructure investments (storage and grid). Investments in additional storage capacity, network infrastructure, and reserve generation capacity are balanced by improved system efficiency (e.g., reduced curtailment of renewables) and reliability (having enough dispatchable capacity to cover potential shortfall in wind and solar generation).

Energy prices in the Reliable scenario closely track those in the Flexible Demand scenario, with only slight differences. In 2030, electricity prices are €70/MWh, just 1.4% higher than in the Flexible Demand scenario. By 2050, electricity prices in the Reliable scenario are €222/MWh, 0.5% lower than in the Flexible Demand scenario (€223/MWh). These lower prices in later periods are due to improved efficiency of renewables generation (see §3.3), having access to more storage and network capacity, reducing the amount of curtailment and hence lowering prices. Hydrogen prices also remain close, starting at €60/MWh in 2030 (1.7% higher than in the Flexible scenario) and reaching €174/MWh in 2050, just 0.6% lower than in the Flexible scenario. These minor variations indicate that the additional investments required for reliability are marginal and result in a cost-efficient and robust system against fluctuations in renewable energy supply.

To summarise, the Reference scenario, characterised by a lack of demand-side flexibility, imposes significantly higher capital costs and energy prices on the system, reflecting the need for large-scale investments in backup generation, storage and network infrastructure. By introducing demand-side flexibility in the Flexible Demand scenario, both CAPEX and energy prices decrease considerably, highlighting the value of flexible hybrid heat pumps in integrating renewables more efficiently. The Reliable scenario adds marginal costs to ensure system stability, but these costs are minimal relative to the gains achieved through increased reliability. Thus, transitioning to a flexible and reliable energy system delivers significant economic benefits compared to the inflexible Reference case, paving the way for a more cost-effective and resilient energy transition.

4. Policy Recommendations

Given the context of the energy transition in Europe and the findings from modelling the Flexible, Reliable, and Reference scenarios, several key policy recommendations can be made to balance the objectives of meeting climate targets, ensuring energy security, and maintaining affordability.

Promote Demand-Side Flexibility

The significant cost and price increases identified in the Reference scenario underscore the critical importance of demand-side flexibility in mitigating energy system costs and enhancing efficiency. The modelling results highlight the value of flexible demand, particularly through the operation of hybrid heat pumps that respond to dynamic pricing signals. It is, therefore, essential to prioritise policies that promote demand-side flexibility to avoid the high costs and inefficiencies associated with inflexible energy demand.

In addition to hybrid heat pumps, other demand-side management strategies – such as smart appliances, home energy management systems, load shifting, vehicle-to-grid (V2G) technologies, and the integration of distributed energy resources (DERs) and microgrids – will be instrumental in enhancing system flexibility and supporting the cost-effective transition to net zero. Thus, four general recommendations emerge in this respect:

1. **Incentivise the Adoption of Smart Technologies**: Provide subsidies, tax incentives, or other financial support for adopting smart appliances, home energy management systems (including hybrid heating systems), and electric vehicles with V2G capabilities.
2. **Expand Demand Response Programs**: Encourage the participation of both residential and industrial consumers in demand response programs, offering attractive financial incentives and ensuring that these programs are accessible and easy to use.
3. **Promote Dynamic Pricing**: Introduce or expand dynamic pricing schemes to give non-vulnerable consumers real-time price signals that encourage flexible energy use. To maximise their effectiveness, ensure that these schemes are accompanied by consumer education and support.
4. **Enhance Regulatory Frameworks**: Adapt regulations to support the integration of distributed energy resources, microgrids, and demand-side flexibility into the broader energy system.

Promote Local and Decentralised Energy Systems

As decarbonisation efforts intensify, local energy solutions and decentralised systems are becoming increasingly important, as seen from our modelling of the Flexible Demand scenario. This shift potentially entails connecting decentralised renewable energy production with local heating, cooling systems, and energy communities while integrating local city planning, building renovation initiatives, and mobility strategies. Local energy systems can enhance energy flexibility and security while reducing transmission grid capacity requirements and losses.

Promote Supply-Side Flexibility

Tightening reliability standards considering the cross-sectoral impacts of intermittent renewables and variable end-use demand to promote storage, backup generation, and grid capacity investments. The Reliable scenario demonstrates that tightening reliability standards by promoting investments in storage, backup generation, and grid capacity to manage renewable intermittency results in only modest cost increases while delivering significant benefits. Compared to the Flexible Demand scenario, CAPEX rises by just 6% in 2030, with energy prices increasing by less than 3% through 2050. These small cost increments ensure greater system reliability without significantly burdening consumers.

Support the Deployment of Renewable Energy and Storage

1. **Accelerate the Deployment of Renewable Energy**: All three modelled scenarios underscore the critical role of wind, solar, biomethane and renewable hydrogen in achieving net zero targets. Policies should continue to support the rapid deployment of these renewable energy sources. Streamlining permitting processes, providing stable long-term incentives, and investing in grid infrastructure to integrate these renewable energies are essential.

2. **Invest in Advanced Energy Storage Solutions**: Expanding storage capacities, particularly for hydrogen and thermal storage, is vital for managing the variability of renewable energy and ensuring a stable energy supply. Policies, therefore, should be in place to incentivise developing and deploying advanced storage technologies, including hydrogen and thermal energy storage, which are crucial for maintaining grid stability as renewable penetration increases.

We should note that, in practice, with the increasing role of embedded storage solutions, such as those associated with electric vehicles and thermal systems, the distinction between demand-side flexibility and storage is becoming increasingly blurred.

Enhance Cross-Border Cooperation and Market Integration

The findings from the model regarding cross-border peak flow and system peak capacity suggest two recommendations:

1. **Promote Regional Energy Markets**: The integration of regional energy markets in Europe can enhance energy security by enabling cross-border electricity and gas flows, optimising the use of renewable resources, and balancing supply and demand across the continent. Policies should focus on harmonising regulations on cross-border trade, improving interconnection capacity, and fostering cross-border cooperation to create a more integrated and resilient European energy market.

2. **Facilitate Cross-Border Hydrogen Infrastructure**: As hydrogen becomes an essential energy carrier, developing cross-border hydrogen infrastructure, such as pipelines and storage facilities, will be crucial for creating a pan-European hydrogen market. This will enable the efficient distribution of hydrogen from regions with abundant renewable resources to those with higher demand, supporting Europe’s overall decarbonisation effort.

5. Conclusions

The transition to a net-zero energy system by 2050 in Europe presents a multifaceted challenge that requires balancing decarbonisation, affordability, and energy security – the well-known energy policy trilemma. This research sought to answer a critical question: *How can Europe most cost-effectively transition to a net zero energy system while ensuring reliability and managing the inherent variability of renewable energy?* By modelling and analysing three scenarios – Reference, Flexible Demand, and Reliable – we explored how different system flexibility and reliability requirements impact the energy transition’s costs, energy prices, and technology deployment.

In the Reference scenario, which assumes limited demand-side flexibility, the European energy system faces elevated cost and efficiency challenges as it transitions toward decarbonisation by 2050. System inefficiencies arise without fully responsive hybrid heat pumps and other demand-side management strategies. Total system CAPEX in the Reference scenario reaches €488 billion in 2030 and rises to €937 billion by 2050, representing a 30% increase over the Flexible Demand scenario. Energy prices in the Reference scenario also spike, with electricity prices reaching €414/MWh in 2030, nearly 500% higher than in the Flexible scenario, and hydrogen prices surging to €338/MWh, an increase of 573%. These cost increases underscore the inefficiencies of a system reliant on more expensive backup generation, storage solutions and expanded grid (especially hydrogen network) to meet demand without the benefit of flexible, responsive energy use.

In contrast, the Flexible Demand scenario assumes fully responsive hybrid heat pumps, leading to significant cost reductions and improved system efficiency. By aligning energy demand more closely with renewable energy availability, the Flexible scenario reduces total system CAPEX by 26% in 2030 compared to the Reference scenario. By 2050, CAPEX reaches €718 billion, substantially lower than the Reference scenario (30% lower). The introduction of demand flexibility also drives significant reductions in energy prices, with electricity prices falling to €69/MWh and hydrogen prices to €59/MWh in 2030. These findings highlight the critical role of demand-side flexibility in mitigating costs and optimising the use of renewable energy and infrastructure investments. The Flexible scenario also reduces electricity peak demand by up to 1.84% by 2050, reflecting how flexible hybrid heat pumps help flatten peaks and ease electricity grid pressure.

The Reliable scenario, which adds reserve capacity to address renewable intermittency, shows only marginal cost increases compared to the Flexible Demand scenario. System CAPEX rises by just 6% in 2030, and by 2050, the gap narrows further, reflecting the modest financial impact of additional storage and backup generation investments. Energy prices in the Reliable scenario remain closely aligned with the Flexible scenario, with electricity prices rising by less than 3% by 2050. These results demonstrate that tightening reliability standards – through investments in grid capacity, storage, and backup generation – ensures a reliable energy supply with minimal additional costs. The Reliable scenario also reduces the need for cross-border electricity flows, making the system more self-sufficient and resilient to renewable intermittency while maintaining efficiency gains from the Flexible scenario. The insights from this research lead to several key policy recommendations that can guide Europe’s energy transition:

- **Promote Demand-Side Flexibility**: Encourage the adoption of technologies and policies that enhance demand-side flexibility, such as dynamic pricing and smart appliances, to avoid the high costs associated with inflexible energy demand.
- **Support the Deployment of Renewable Electricity and Storage**: Accelerate the deployment of wind and solar power and invest in advanced storage solutions, particularly for hydrogen and thermal energy, to manage the variability of renewables and ensure a stable energy supply.
- **Facilitate the transition to renewable and Low-Carbon Fuels**: Support the development and integration of renewable fuels like green hydrogen and biomethane, which will play critical roles in decarbonising sectors that are difficult to electrify.
- **Enhance Cross-Border Cooperation and Market Integration**: Promote regional energy markets and develop cross-border infrastructure, particularly for hydrogen, to optimise resource use and ensure energy security across Europe.

To conclude, the insights from this study illustrate that a cost-effective way to decarbonise European economies by 2050 while maintaining energy security and affordability is to promote demand-side flexibility, accelerate the deployment of renewable energy and advanced storage technologies, and facilitate the transition to low-carbon fuels, supported by enhanced cross-border cooperation and market integration.

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cerre Centre on Regulation in Europe

Avenue Louise 475 (box 10)
1050 Brussels, Belgium
+32 2 230 83 60
info@cerre.eu
www.cerre.eu

Centre on Regulation in Europe (CERRE)
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