

Powering Denmark in 2050

An Evaluation of
Climate-Neutral Power Systems

CONDENSED VERSION

A STUDY BY QUANTIFIED CARBON

FOR DANISH NUCLEAR ALLIANCE

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ABOUT THIS PUBLICATION

This report has been produced by Quantified Carbon (QC) on commission from the Danish Nuclear Alliance. The analytical framework, scenario design, modelling, and conclusions presented in this work are the authors'.

The study is published in two versions. The full report documents the complete methodology, assumptions, results and appendices, for readers who want to examine the analysis in detail. The condensed version (this document) presents the main findings and policy implications in a shorter format and refers to the full report for supporting detail.



ABOUT QUANTIFIED CARBON

We are an international consultancy firm providing complex problem solving, modelling, and optimisation to support decarbonisation of energy systems and industries.

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Executive Summary

In 2025, the Danish Government announced its intention to revisit the 1985 parliamentary decision that excluded nuclear power from Danish energy planning, as part of the broader development of a climate-neutral Danish energy system. The question, however, is broader than nuclear alone. Climate neutrality does not prescribe a single technology configuration, and several plausible 2050 power systems can satisfy the climate objective while differing materially in cost structure, security of supply, market behaviour, resource requirements and exposure to external developments. This study therefore explores structurally different climate-neutral Danish power systems and compares the capabilities, dependencies and risks they create.

The role of nuclear energy in Denmark has been examined in recent academic work^{1,2} and, most recently, in the system analysis commissioned by the Danish Energy Agency from EA Energianalyse and VTT³. The EA/VTT study evaluates the system value of introducing specified SMR capacity into defined future pathways. The present study takes a different analytical perspective. Rather than asking only how nuclear performs when introduced into a largely predefined future system, it explores a wider option space of structurally different 2050 configurations, varies cost uncertainty across all major technologies, and evaluates outcomes beyond monetised system cost. System cost remains central, but self-sufficiency, market profitability, price volatility, critical-material demand, grid requirements and dispatchable capacity are also treated as policy-relevant system characteristics. In particular, the degree of Danish self-sufficiency is made visible as a policy variable rather than being left as an implicit outcome of cost optimisation.

The modelling first optimises Danish capacity for a representative historical weather year, then stress-tests the resulting systems against the cold, low-wind scarcity event of January 1985 and adds gas-turbine and battery capacity where required for resource adequacy. The final systems are simulated across 33 historical weather years. Three methodological choices are especially important.

1. Technology costs are varied consistently across nuclear, wind, solar, batteries and other major technologies through five cost cases, rather than treating uncertainty in nuclear costs in isolation.
2. Neighbouring European generation capacity is pre-optimised on a common reference case and then held fixed while Danish alternatives are compared, preventing changes in neighbouring investment from absorbing part of the difference between Danish system choices. The flip side is that the results may understate what closer cross-border coordination could achieve.

¹ Thellufsen et al., (2024) Cost and system effects of nuclear power in carbon-neutral energy systems

² Aarflot Moen, K, et al., (2025), The Total Costs of Energy Transitions with and Without Nuclear Energy

³ EA Energianalyse (2026), Analyse af atomkraft i Danmark

- Quantified Carbon's electricity-market model (cGrid) uses rolling short-term price forecasts to dispatch storage and flexible demand, reducing the reliance on the perfect-foresight assumption common in conventional long-term capacity-expansion models. The resulting capacity-expansion results are independently cross-checked using PyPSA, an open-source power-system optimisation model.

Seven Danish scenarios are compared. Balanced is the common reference case, using reference technology costs and reference flexibility assumptions with no scenario-specific capacity constraint. From this baseline, Offshore, Solar and Nuclear directions are explored through a balanced variant and a more fully committed variant. The full Offshore and Solar scenarios exclude nuclear by design, while the Nuclear scenarios progressively improve nuclear cost assumptions and allow greater deployment. The scenarios are not forecasts; they are designed to reveal how the system changes as different foundational technologies become more or less available and competitive.

The modelled Danish electricity system grows substantially, with reference demand increasing from around 38 TWh in 2025 to 102 TWh in 2050. Wind remains a major source of generation across the scenarios, while the contributions from other technologies vary considerably. [Figure 1](#) compares the installed capacity and generation shares of the Offshore, Balanced and Nuclear scenarios alongside the 2025 power system. These three scenarios represent the most structurally distinct configurations, while the Solar scenarios converge towards mixes that more closely resemble the Offshore direction.

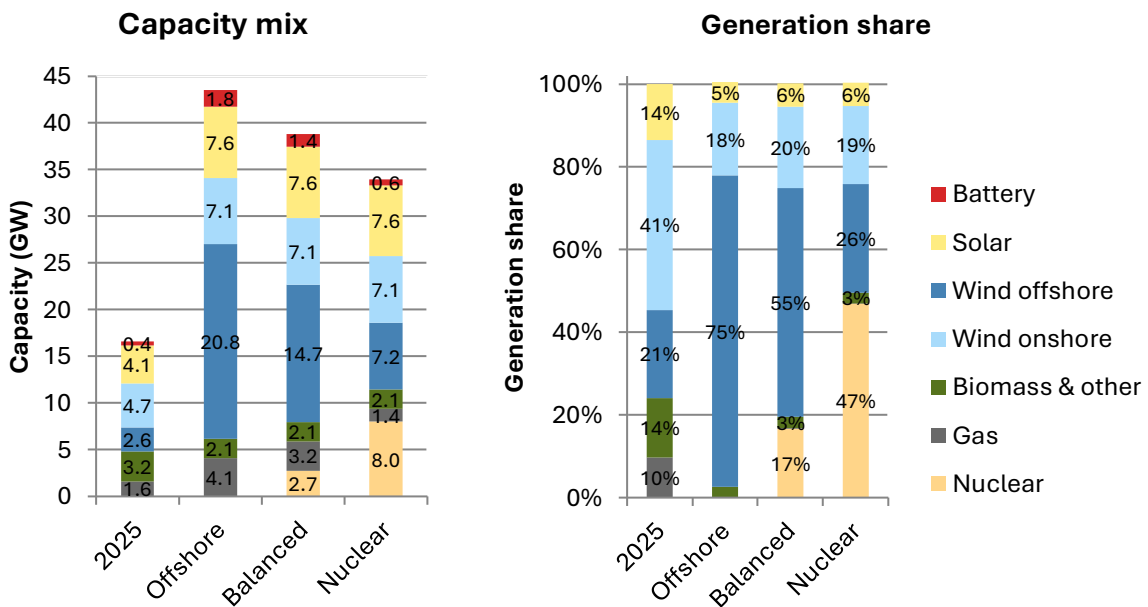


Figure 1. Capacity mix (left panel) and generation share (right panel) split by technology for Offshore, Balanced and Nuclear scenarios alongside the 2025 power system.

Main results

Performance across the three most structurally distinct scenarios is summarised below. Offshore represents the most wind-dependent direction, Balanced the diversified reference case, and Nuclear the direction with the largest share of clean firm generation. Light shading indicates better relative performance within each metric and dark shading worse performance; the table is a comparative dashboard rather than an overall score.

Table 1. Selected results for the Offshore, Balanced and Nuclear scenarios. Negative import cost indicates net export revenue. Shading shows relative performance within each metric and does not constitute an overall ranking.

Category	Parameter	Offshore	Balanced	Nuclear
Self-sufficiency	Import cost (€/MWh)	9.0	1.8	-11.5
	Gas consumption (TWh)	1.0	0.6	0.1
	Demand coverage (%)	55	61	80
Competitiveness	System cost incl. imports (€/MWh)	78	71	69
	Costs escalation (€/MWh)	26	30	40
	Average price (€/MWh)	73	78	72
	Price volatility vs Balanced	-2%	0%	-8%
	Profitability gap (€/MWh)	+12.7	-1.2	+0.9
Environmental & climate impact	Emissions vs 2025	-82%	-82%	-82%
	Minerals use (kt) vs Balanced	+17%	0%	-18%
	Land use (km ² · 10 ³)	1.0	1.1	1.1
Grid & operational safety	Grid upgrade cost (€/MWh) vs Balanced	+28%	0%	-31%
	Dispatchable capacity (GW) vs Balanced	6.2 (-22%)	8.0 (0%)	11.4 (+43%)

Across all modelled scenarios, lifecycle emissions decrease by approximately 82% relative to 2025. Land-use differences are also limited within the metric used, which excludes the sea area occupied by offshore wind. When evaluated using common Reference technology costs, system costs, including import costs, remain relatively close across the three main configurations: €78/MWh in Offshore, €71/MWh in Balanced and €69/MWh in Nuclear. More substantial differences emerge in self-sufficiency, market profitability, infrastructure requirements and exposure to cost escalation.

Relative to Balanced, the Offshore direction has lower exposure to technology-cost escalation, but exhibits higher import costs, lower domestic demand coverage during stressed hours, greater critical-material and estimated grid requirements, and a system-

wide profitability gap of around €13/MWh driven largely by revenue cannibalisation. The Nuclear direction achieves higher domestic demand coverage, lower import costs and gas consumption, lower critical-material and estimated grid requirements, and greater dispatchable capacity. Its principal disadvantage is greater exposure to capital-cost escalation and project-delivery risk.

The central Offshore-Nuclear trade-off is consequently not well described as simply 'cheap versus expensive'. It is a question of where uncertainty is concentrated. The Nuclear direction concentrates more uncertainty on the cost side through capital cost, financing and project delivery. The Offshore direction concentrates more uncertainty on the revenue side through capture-rate erosion and market profitability at high deployment levels. Both directions may require state involvement, but for different reasons and through different instruments. A diversified configuration such as Balanced spreads these exposures rather than concentrating them in a single technology direction.

The Solar direction provides an additional useful boundary case. Even when solar and battery assumptions and short-duration flexibility are made more favourable, only limited additional utility-scale solar is built. Once nuclear is excluded, the system instead becomes more dependent on wind, flexibility and exchange with neighbouring regions.

The comparison with the EA/VTT study is important because methodological choices have material consequences for the result. When nuclear is excluded, the resulting supply mixes are relatively similar. Once nuclear is available, larger differences emerge. A central difference is the value captured by offshore wind at high penetration: this study finds offshore-wind capture rates of roughly 75% in Balanced and 65% in Offshore, compared with about 95% (derived) in the EA/VTT case. The studies also use somewhat different technology costs and produce different average market-price levels. These differences shift the point at which further offshore wind remains attractive relative to firm generation. The studies are therefore not contradictory; they explore different parts of the uncertainty range. The EA/VTT study provides a detailed assessment along specified pathways, while the present study shows that when the option space is widened and market profitability is treated explicitly, nuclear enters the reference-cost optimisation and provides benefits across several system indicators beyond total cost.

Denmark's high level of interconnection is central in every scenario. Average prices, price volatility and producer revenues are strongly influenced by the surrounding European system, which limits how far domestic technology choices alone can determine market outcomes. This makes the characteristics Denmark can influence directly more important: the amount of domestic firm generation, reliance on imports during stressed periods, exposure to fuel and material supply chains, and the scale of domestic grid expansion. Interconnection remains highly valuable, but the degree to which Denmark relies on neighbouring countries for firm capacity is itself a strategic choice. Demand growth also changes the relative value of the technology directions: nuclear plays a larger role in the higher-demand sensitivity and a smaller role in the lower-demand case, while offshore wind has greater relative value at lower levels of Danish demand.

Implications for decision-makers

1. Self-sufficiency should be treated as an explicit policy choice.

The scenarios span materially different levels of import dependence, gas consumption and domestic demand coverage during stressed conditions. A climate-neutral Danish power system without nuclear is feasible in the model, but different technology choices lead to different levels of reliance on neighbouring systems. The level of self-sufficiency Denmark wishes to maintain therefore deserves explicit treatment in the policy process.

2. Technology directions have different timing and demand characteristics.

Offshore wind builds on existing Danish industrial capability and is more readily deployable in the near term. Nuclear requires development of regulatory, industrial and workforce capabilities and is therefore principally a longer-term option. Its relative value increases in the higher-demand sensitivity, while offshore wind has greater relative value at lower demand.

3. Both directions depend on policy frameworks that address different risks.

Nuclear is more exposed to capital-cost and project-delivery risk, while very high offshore-wind deployment is more exposed to market-revenue risk and cannibalisation. Both may therefore require state involvement, but for different reasons and through different instruments.

4. A diversified system reduces exposure to either direction failing to develop as expected.

A diversified configuration such as the Balanced scenario distributes these risks rather than concentrating them. The trade-off is symmetric: they capture less of the upside if either nuclear or offshore wind develops more favourably than expected, but they also reduce the exposure if either direction fails to materialise as assumed.

The study does not seek to identify a single optimal configuration. Its contribution is to make visible what different system directions require, what capabilities they provide and where their respective uncertainties and dependencies lie. The choice and prioritisation of those directions remain with decision-makers.

1 Introduction

The future role of nuclear power has become an increasingly prominent topic in European energy policy, alongside continuing debate over the appropriate balance of variable renewables, storage, demand-side flexibility and dispatchable generation. In Denmark, nuclear power has been excluded from energy planning since 1985, while recent policy discussions have reopened the question of whether nuclear technologies should be considered as part of the country's long-term energy options. That question sits within a broader challenge: how should a substantially larger and climate-neutral Danish electricity system be configured by 2050?

Climate neutrality does not determine a single technology mix. Different combinations of wind, solar, nuclear, storage, flexible demand and cross-border exchange can satisfy the climate objective while producing different cost structures, market outcomes, infrastructure requirements and dependencies. Over a 2050 horizon, these differences matter because today's policy decisions can preserve or foreclose future options long before the final system configuration is known.

This report has been produced by Quantified Carbon (QC) on commission from the Danish Nuclear Alliance. The analytical framework, scenario design, modelling, and conclusions presented in this work are the authors'. Quantified Carbon⁴ is an international consultancy performing modelling and analysis of decarbonisation pathways for energy systems and industries. Recent work includes power system studies for Sweden, Germany, Poland, and Finland^{5,6,7,8,9}, with contributions used by the Swedish Government in national energy policy formation, cited in the European Commission's Nuclear Illustrative Programme, and applied in work for the United Nations Economic Commission for Europe¹⁰. The present study extends this body of work to the Danish power system in 2050, drawing on the modelling capabilities and analytical methods developed in those previous studies.

The analytical perspective differs from studies that ask how one technology performs when introduced into an otherwise predefined future system. Instead, this study explores structurally different end-state configurations and evaluates them across more than cost alone. The main scenarios vary technology costs and supporting flexibility assumptions, while the evaluation considers system costs, market prices and profitability, self-sufficiency, resource adequacy, critical-material requirements, estimated grid-upgrade costs and dispatchable capacity. The study thereby focuses on

⁴ <https://www.quantifiedcarbon.com/>

⁵ Quantified Carbon (2023), Nordic Power Systems for a Competitive and Sustainable Economy

⁶ Quantified Carbon (2025), Swedish power systems robust for 300 TWh

⁷ Quantified Carbon (2024), Power System Expansion Poland

⁸ Quantified Carbon (2025), Role of Nuclear in Germany's Decarbonisation

⁹ Quantified Carbon (2025), Power System Expansion Germany

¹⁰ Quantified Carbon (2025), Understanding the Full System Costs of the Electricity System.

the trade-offs and dependencies associated with different system designs rather than identifying a single cost-optimal pathway.

The report should also be read with its scope in mind. It represents the Danish power system in 2050 rather than the year-by-year transition from today. Neighbouring European capacity is pre-optimised and then held fixed across the Danish scenarios; the Danish grid is not represented at detailed nodal level; and stochastic outages, balancing markets and several ancillary services are outside the modelled scope. These limitations are discussed in Section 3.5 and are important when translating the comparative results into implementation decisions.

The remainder of the report is organised as follows. Section 2 defines the study objective and explains how the analysis complements the recent Danish Energy Agency study by EA Energianalyse and VTT. Section 3 presents the modelling workflow, pre-optimisation of neighbouring regions, treatment of weather years, scenario framework and key limitations. Section 4 sets out the assumptions on demand, flexibility, technology costs and build-out constraints. Section 5 presents the main results, including capacity and generation, adequacy, system costs, electricity-market outcomes, self-sufficiency, sensitivities, comparison with the EA/VTT study and estimated grid-upgrade costs. Section 6 brings these results together in a comparative dashboard and discusses the broader risks, dependencies and policy-relevant trade-offs that sit partly outside the model.

2 Study

2.1 Objective

The overall question that has guided this work is:

OBJECTIVE:

Based on an integrated modelling and scenario framework, the study explores alternative climate-neutral Danish power systems in 2050. It evaluates diverse technology supply mixes – including wind, solar, and nuclear – to assess how different configurations can ensure a cost-effective, sustainable, and robust power system.

The objective is to provide a transparent, technology-neutral and analytically grounded foundation for policy discussions on Denmark's long-term energy system development.

2.2 How the current study complements others

One of the primary motivations for the current study is the lack of system studies that properly evaluate the role of nuclear energy with Denmark as the focus region.

However, two recently published academic papers do address this topic. Furthermore, following the Danish Government announcement of a study on the role of nuclear energy in Denmark, the Energistyrelsen (Danish Energy Agency) has published a study conducted by EA Energianalyse and VTT¹¹.

Thellufsen et al. (2024)¹² compare renewable- and nuclear-based configurations of a carbon-neutral Danish energy system and find the nuclear-based ones more costly. Aarflot Moen et al. (2025)¹³, a team of Norwegian researchers from NTNU, revisit the question with a more thorough cost sensitivity analysis covering nuclear, VRE and weather conditions, and instead obtain limited cost differences between systems with and without nuclear. This highlights the uncertainties in cost optimisation, a conclusion also reached in our work¹⁴. What sets the current work apart from Aarflot Moen et al. (2025) is its focus beyond costs, offering a transparent assessment of broader system performance paving the way for insights of greater relevance to policymaking.

¹¹ EA Energianalyse (2026), Analyse af atomkraft i Danmark

¹² Thellufsen et al., (2024), Cost and system effects of nuclear power in carbon-neutral energy systems

¹³ Aarflot Moen, K, et al., (2025), The Total Costs of Energy Transitions with and Without Nuclear Energy

¹⁴ Quantified Carbon (2025), Swedish power systems robust for 300 TWh

2.2.1 EA and VTT study on SMR technologies in Denmark

Following the Danish government's decision to evaluate the potential role of nuclear energy in Denmark, the Danish Energy Agency issued a tender for a system analysis¹⁵. The final report by EA Energianalyse and VTT¹⁶ similarly emphasises “the possibilities and consequences of integrating Small Modular Reactor (SMR) technologies into the Danish energy system.”

This framing primarily focuses on assessing the effects of introducing a specific technology into an otherwise implicitly defined future energy system. Such an approach corresponds to a marginal technology-entry perspective, where the central question concerns how the addition of a new generation technology interacts with existing market actors and structures.

This perspective is particularly suited to shorter-term analysis, where investment, infrastructure, and policy trajectories are more constrained. Over the 2050 horizon examined here, however, the structure of the future system is not yet fixed by prior commitment, and more than one structurally distinct configuration remains reachable. Climate neutrality does not prescribe a single technology configuration. Instead, different combinations of generation, flexibility, infrastructure, and demand evolution may satisfy climate objectives while leading to distinct cost structures, risk profiles, and resilience characteristics.

Sound long-term energy policy therefore benefits from first clarifying the range of plausible end-state system configurations before evaluating individual technologies within them.

Against this background, the current study by Quantified Carbon adopts a long-term and technology-neutral perspective with the objective presented in Section 2.1.

2.2.2 Current study design in relation to the EA study

Although the objective framing sets certain analytical boundaries, the study by EA Energianalyse and VTT provides substantial insight into the potential role of nuclear power in Denmark¹⁷. It represents the most comprehensive system-based assessment to date within the Danish context.

EA/VTT combines a detailed SMR technology review with Balmorel modelling across a broad European geography. It includes heat and hydrogen coupling, wind and solar expansion, demand-side flexibility, three Danish demand pathways, multiple nuclear cost assumptions and investment development from 2025 to 2050 in five-year

¹⁵ Energistyrelsen (2025-2026): Opgavebeskrivelse vedr. levering af analyse af SMR teknologiers indpasning og effekter i det danske energisystem

¹⁶ EA Energianalyse (2026), Effects and value of SMR technologies in the Danish energy system

¹⁷ EA Energianalyse & VTT (2026), Effects and value of SMR technologies in the Danish energy system

increments. Specified SMR capacities of 600 MW and 1,500 MW are introduced exogenously, after which the rest of the system is re-optimised and their system value is assessed against a no-nuclear reference.

The present study complements that pathway analysis in three respects. It explores a wider set of structurally different 2050 end states, varies cost uncertainty across all major technologies and compares Danish choices against the same pre-optimised neighbouring system. It also evaluates system cost alongside self-sufficiency, prices and volatility, market profitability, critical-material use, estimated grid requirements and dispatchable capacity. [Table 2](#) summarises the main differences.

Table 2. Key differences between the EA Energianalyse and VTT (2026)¹⁸ and the current Quantified Carbon study.

Aspect	EA Energianalyse and VTT study (2026)	Quantified Carbon study
Main analytical question	Effects and system value of introducing specified SMR capacity into defined future pathways	Characteristics and trade-offs of structurally different climate-neutral 2050 power-system configurations
Time perspective	Pathway-oriented analysis	2050 end-state analysis
Weather years	Capacity expansion on weather year 2014	Capacity expansion on weather year 1991; resource adequacy dimensioned on weather year 1985; evaluated on 33 weather years
Neighbouring capacity	Co-regional capacity expansion	Pre-optimised on a reference scenario and held fixed during Danish capacity expansion
Technology cost uncertainty	Multiple nuclear cost assumptions; other technology development largely specified	Cost uncertainty varied across all major technologies
Demand variation	Three substantially different Danish demand scenarios	Focus on 102 TWh, with 64 TWh and 138 TWh sensitivities
Evaluation framework	Broad monetised system-cost assessment, including balancing, grids and adequacy mechanisms	System costs plus additional indicators for prices, volatility, self-sufficiency, resources and operational considerations

¹⁸ EA Energianalyse & VTT (2026), Effects and value of SMR technologies in the Danish energy system

3 Methodology

The study follows a five-step modelling workflow, illustrated in [Figure 2](#). All steps from pre-optimisation through evaluation (steps 2–5) are carried out using the electricity market modelling tool cGrid, Quantified Carbon's proprietary capacity expansion and dispatch model. An independent verification of the capacity expansion results (step 3) is performed using the open-source model PyPSA. Modelling tools are further introduced in [Section 3.1](#).

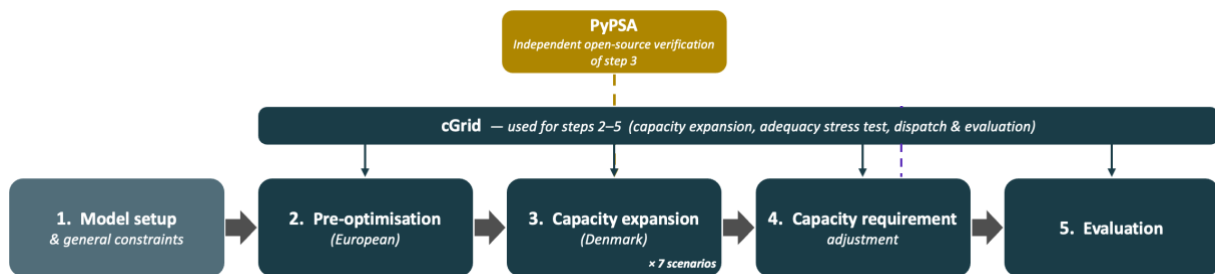


Figure 2. Flowchart of overarching model workflow.

The five steps are described below.

Step 1: Model setup establishes the common modelling environment and general constraints that underpin all subsequent steps. This includes key assumptions, relating to CO₂ and commodity prices, electricity and heat demand, demand-side flexibility, technology costs, and exogenous constraints on existing thermal capacity and expansion limits for offshore wind and residential solar, as documented in [Section 4](#).

Step 2: Pre-optimisation determines a fixed European generation and storage mix, given assumed cross-border transmission capacities, that is held constant across the subsequent Danish scenario simulations. This ensures that differences in results between scenarios reflect Danish system choices rather than variations in the surrounding European system. The rationale for this approach is described in [Section 3.2](#), while the results are presented in [Section 5.1](#).

Step 3: Capacity expansion optimisation is performed for the Danish power system mix for the seven main scenarios. The scenarios are defined by three technology directions: nuclear, offshore wind and solar, while demand-side flexibility and technology-cost assumptions enable structural variations in power system mixes. The scenario framework is introduced in [Section 3.4](#).

Step 4: Capacity requirement adjustment augments each of the seven optimised mixes from step 3 with gas peaking capacity and battery storage as needed to satisfy resource adequacy requirements. The adequacy assessment is based on one period of extreme scarcity in the weather year of 1985.

Step 5: Evaluation assesses the seven final Danish systems across four dimensions: cost and economics, security of supply, environment and resources, and system integration in Sections 5 and 6.

3.1 Modelling

3.1.1 cGrid

Many long-term capacity expansion studies rely on linear, cost-optimising models with perfect foresight of the full time series of weather-driven generation and demand. This can lead to overly optimistic dispatch of storage and flexible demand, and it can understate how market dynamics and price formation affect investment incentives. We therefore complement conventional capacity expansion modelling with additional steps that are designed to be more realistic and policy relevant.

First, candidate 2050 system configurations are tested across multiple historical weather years, rather than relying on a single "typical" year. This helps quantify robustness to interannual variability and identify problematic combinations of conditions (e.g., periods with correlated low wind output and reduced hydro inflows), which can materially affect prices, adequacy and the value of different technologies. In our Nordic case study with academic collaborators (Cox et al., 2026)¹⁹, this approach is demonstrated by evaluating outcomes across 33 historical weather years (1983-2015).

Second, we use our proprietary non-linear electricity market model cGrid to mitigate the intra-year perfect-foresight limitation in conventional capacity expansion planning. Rather than optimising storage and flexible assets with full knowledge of the year ahead, cGrid uses rolling short-term price forecasts to guide dispatch and bidding decisions for price-responsive assets. Cox et al. (2026) provide historical validation of cGrid.²⁰

For Denmark, with high shares of wind, strong cross-border market integration, and growing interest in long-duration flexibility (e.g., PtX/hydrogen), these methodological elements provide a practical way to stress-test policy-relevant questions about robustness, price volatility and security of supply, and to ensure that conclusions are not driven by a single weather year in the evaluation (capacities are sized on weather year 1991) or by unrealistic operational foresight.

Understanding the expanding wind fleet is important for both near-term deployment and long-term capacity expansion because capture prices affect market profitability. [Figure 3](#) compares observed and modelled monthly capture prices for onshore wind in DK1.

¹⁹ Cox et al. (2026) Strategic capacity expansion planning in hydro-dominated power systems: Insights from the Nordics

²⁰ Cox et al. (2026) Strategic capacity expansion planning in hydro-dominated power systems: Insights from the Nordics

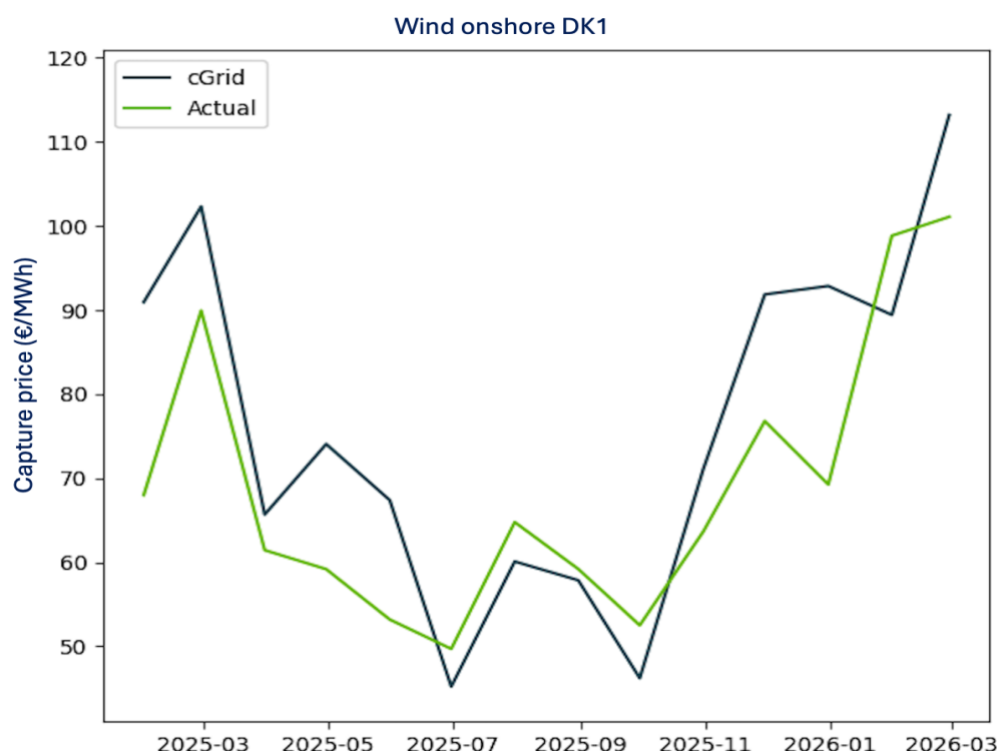


Figure 3. Comparison of modelled and observed monthly average capture prices for onshore wind in DK1, 2025 to early 2026.

3.1.2 PyPSA – open source

As mentioned earlier, an independent verification of the cGrid methodology has been performed using PyPSA²¹ (Python for Power System Analysis), an open-source modelling framework designed for large-scale optimisation of electricity and multi-energy systems. PyPSA enables both capacity expansion planning and dispatch within a unified optimisation framework, making it particularly suitable for long-term decarbonisation studies. PyPSA is widely used in both academic and policy-oriented studies, particularly in European system modelling^{22 23}.

Because cGrid is proprietary, the open-source PyPSA model provides a transparent cross-check of the capacity-expansion results and a basis for future development beyond this study. The PyPSA model geography, component representation and iterative solve workflow are documented in Sections 3.1.2.2–3.1.2.7 and Figures 6–8 of the full report.

²¹ <https://pypsa.org/>

²² Brown et al. (2018) Synergies of sector coupling and transmission reinforcement in a cost-optimised, highly renewable European Energy System

²³ Victoria et al. (2019) The role of storage technologies throughout the decarbonisation of the sector-coupled European energy system

3.2 Pre-optimisation to establish exchange with neighbouring regions

The regions included in the modelling and assumed transmission capacities are shown in Figure 4. A modest set of new or strengthened interconnections across the EU is assumed compared with 2025. The corresponding interconnector-capacity assumptions are set out in Section 3.2 and Table 3 of the full report.

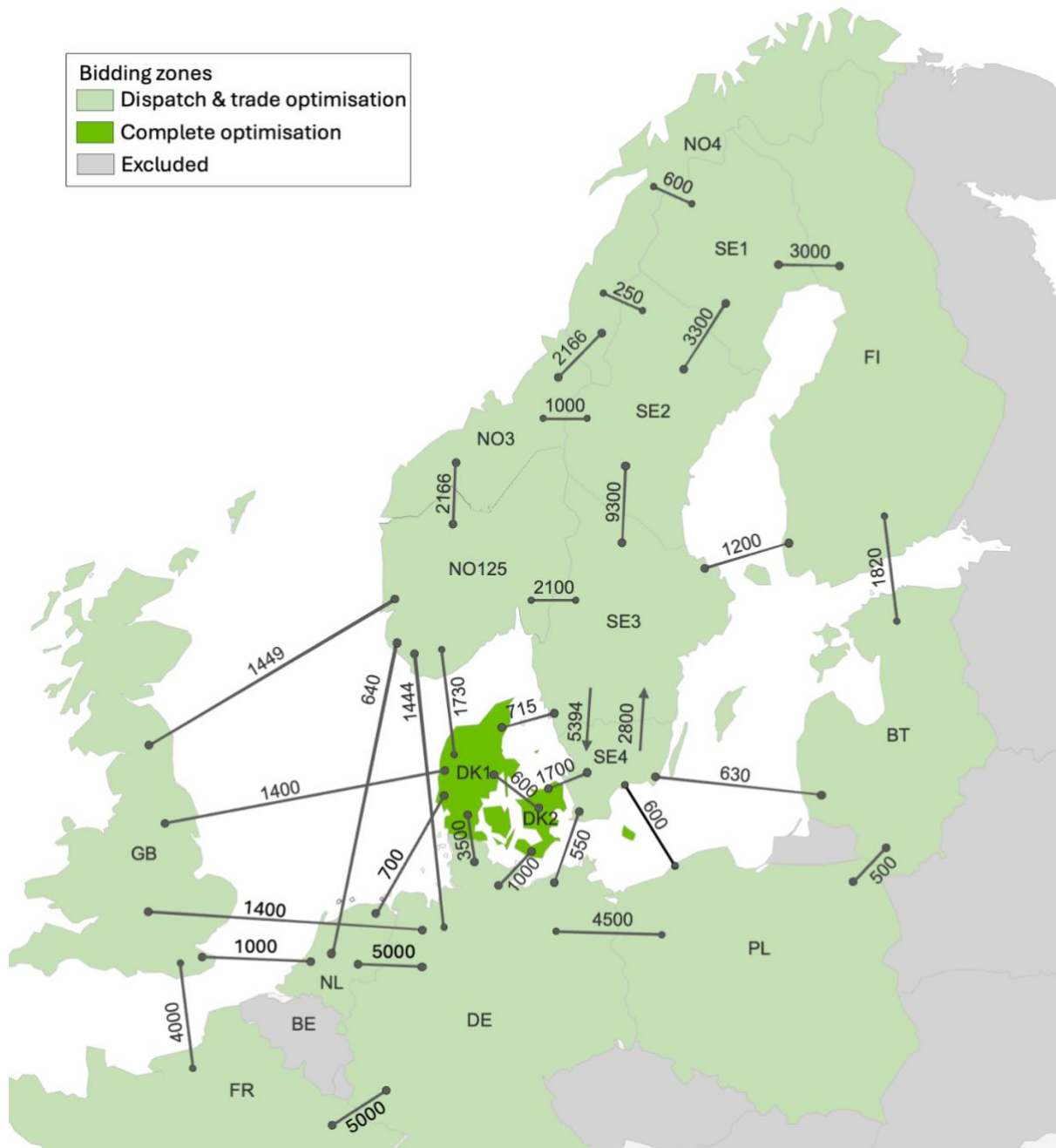


Figure 4. Geographical boundaries showing the regions included in the modelling and how they are treated in the optimisation. The lines represent transfer capacities in the model, and the numbers indicate the associated net transfer capacity (MW), NTC, for the model year 2050. The zones NO125 and BT represent a merger of NO1, NO2 and NO5 and the Baltic zones, respectively. Although not visible in the figure, Spain has also been included in the model.

In this study, we have included international trade by defining the necessary inputs, i.e. installed generation capacity per power type and load and its flexibility, for all areas outside Denmark. The Danish power system, which is small, is greatly affected by assumptions about future power systems in neighbouring countries. In this work, we have chosen to use pre-optimisation of generation capacities outside Denmark's borders instead of jointly optimising all countries in the study for all scenarios. The approach is intended to avoid assuming that neighbouring countries optimally adjust their generation fleets in response to each Danish technology choice.

The pre-optimisation has been carried out using the "Balanced" scenario as a starting point. Here, limits have been set for nuclear, onshore wind and gas power with carbon capture based on each country's energy policy. In contrast, solar and offshore wind have been given free rein to expand as long as they are economically viable, as area conflicts are easier to manage for these power sources. The power systems identified through the pre-optimisation have then been used in all scenarios in the study.

One alternative option would have been to co-optimize all countries, which could potentially capture coordination gains between Denmark and other countries. For example, if Denmark builds a system with a low share of dispatchable power, it may be more profitable for neighbouring countries to invest in such production, and vice versa. This would in turn reduce the difference between the scenarios, as neighbouring countries could compensate for Denmark's choice.

Our rationale is that full co-optimisation may overstate the extent to which neighbouring systems would adjust in response to Danish choices, because energy-policy and investment decisions are made nationally rather than through a single European optimisation. Holding neighbouring capacity fixed therefore provides a common external system against which the Danish scenarios can be compared. This choice does not imply that cross-border coordination is absent; rather, it prevents changes in neighbouring investment from absorbing part of the difference between Danish system configurations.

3.3 Weather years – capacity expansion and adequacy assessment

To capture multiannual variability in renewable generation and demand, which is fundamental to power systems with high shares of variable renewable generation, the study uses 33 weather years covering 1983–2015^{24, 25}. Weather-driven time series are generated using the Weather2Energy tool, which converts climate data into consistent profiles for wind, solar and temperature-dependent demand. The multi-year dataset captures a wide range of meteorological conditions, including extreme years, and supports analysis of adequacy, prices and interannual variability.

²⁴ Cox et al. (2026) Strategic capacity expansion planning in hydro-dominated power systems: Insights from the Nordics

²⁵ Quantified Carbon (2025), Swedish power systems robust for 300 TWh.

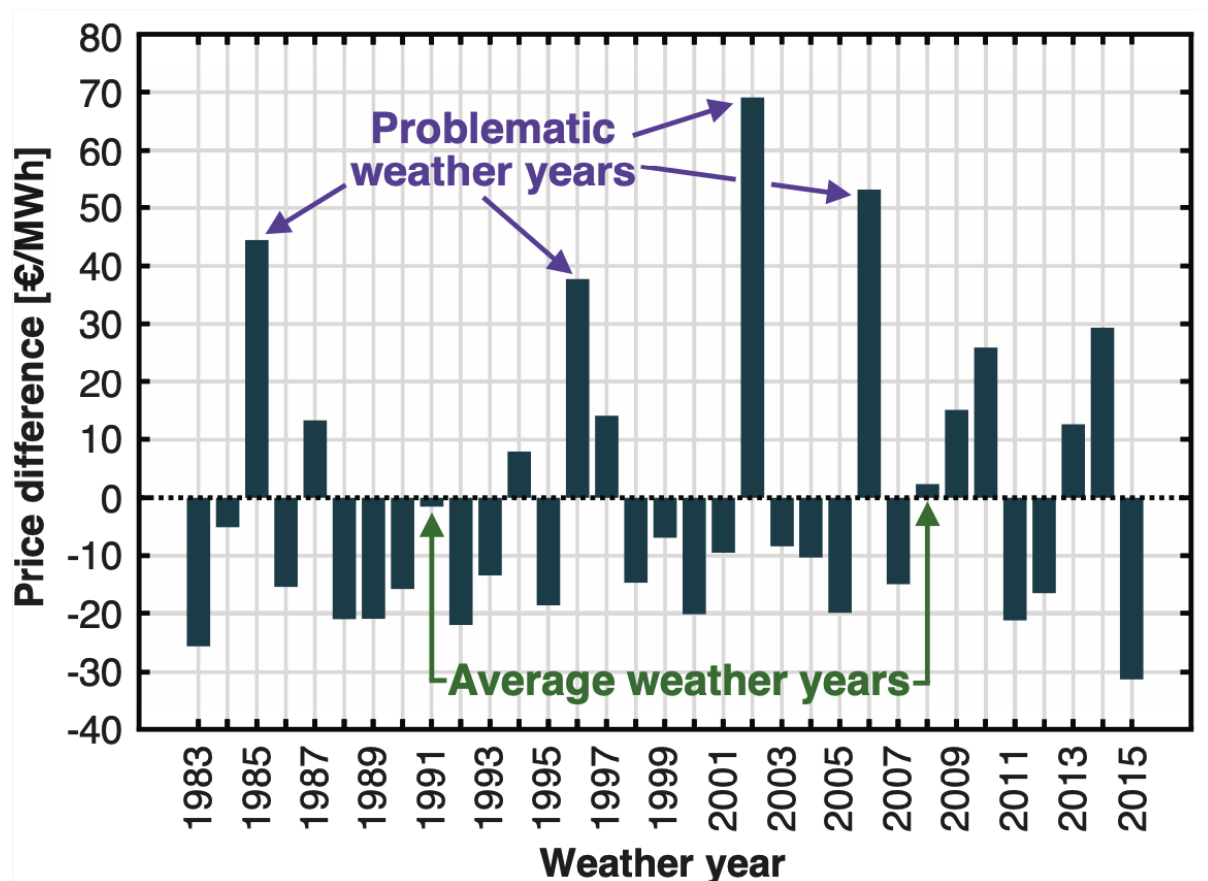


Figure 5. Relative deviation of yearly modelled electricity price across 33 weather years (1983–2015) averaged over all bidding zones included in model. Based on evaluation by Cox et al.

The characteristics of the weather-year set employed in the current study are illustrated through the deviation to the average market price for all bidding zones included in the model in Figure 5. The year 1991 exhibits the lowest deviation and was therefore chosen as a representative year for capacity expansion. This means that it is considered to be average in terms of weather-driven market conditions. With this analysis it becomes possible to identify problematic weather years as well. Weather years 1985, 1996, 2002, and 2006 emerge as those with the highest average yearly electricity prices. Weather year 1985 naturally also features reduced supply, however, it also features a short-duration one-day event at the end of January with extreme system stress across Europe.

On this basis, the study uses the 1985 January event to perform resource adequacy assessment. The capacity adjustment is designed so that no loss-of-load events occur across the 33 simulated weather years. This deterministic approach does not include the stochastic outage assessment undertaken in the European Resource Adequacy Assessment (ERAA)²⁶. The ERAA, in particular, aims to evaluate loss of load expectation and estimated energy not served over a shorter-term and more constrained horizon than

²⁶ ENTSO-E (2025), European Resource Adequacy Assessment 2025 Edition.

the current study. The capacity requirement adjustment is presented in more detail in Section 5.3.

3.4 Scenario framework

A set of seven scenarios is developed to explore alternative pathways for the Danish power system. The scenario definitions are presented in Table 3 and visualised in Figure 6.

The Balanced scenario serves as the common reference point, applying reference-level cost assumptions across all technologies with no scenario-specific capacity constraints (common expansion limits, such as about 7 GW of onshore wind, apply to all scenarios) and therefore the least constrained expansion. From this baseline, three technology directions are explored, each representing a potentially foundational supply source for the future Danish energy system: a Nuclear direction, an Offshore wind direction, and a Solar direction.

The purpose of these directions is not to identify the most likely outcome, but to explore the characteristics and implications of structurally different technology mixes, thus testing more extreme ends of the option space rather than clustering around the Balanced scenario. Each direction is defined by two scenarios of increasing ambition: a balanced variant that takes a moderate first step in the directional push, enabling a more informed reading of how results shift as you move away from the Balanced scenario, and a fully committed variant that pursues the direction to its logical extreme.

Making a technology direction viable at scale requires more than optimistic cost assumptions for that technology alone. Two further adjustments are therefore applied. First, the technology cost trajectory is set progressively more optimistic for the technology in focus. Optimistic-1 is applied in the balanced variant and Optimistic-2 in the full variant (see Section 4.3). Second, for the variable renewable directions (Offshore and Solar), demand-side flexibility assumptions are adjusted to better reflect the capabilities and system needs of those technologies: long-duration flexibility (hydrogen production) for the Offshore direction, and short-duration flexibility (EVs, residential commercial, heating) for the Solar direction as detailed in Section 4.2.2.

Nuclear capacity limits require separate treatment. In an unconstrained optimisation, nuclear expansion can jump to implausibly large values as cost assumptions improve, departing from a realistic deployment trajectory. The caps applied in the Nuclear scenarios are therefore anchored to the nuclear capacity that emerges from the least constrained Balanced scenario. The caps have been set at approximately 2× and 4× the level obtained in the Balanced scenario, respectively. In the Offshore and Solar directions, where nuclear is not the technology of focus, the cap is set to roughly half the Balanced level, limiting its role without excluding it entirely. In the full Offshore and Solar scenarios, nuclear is prohibited altogether.

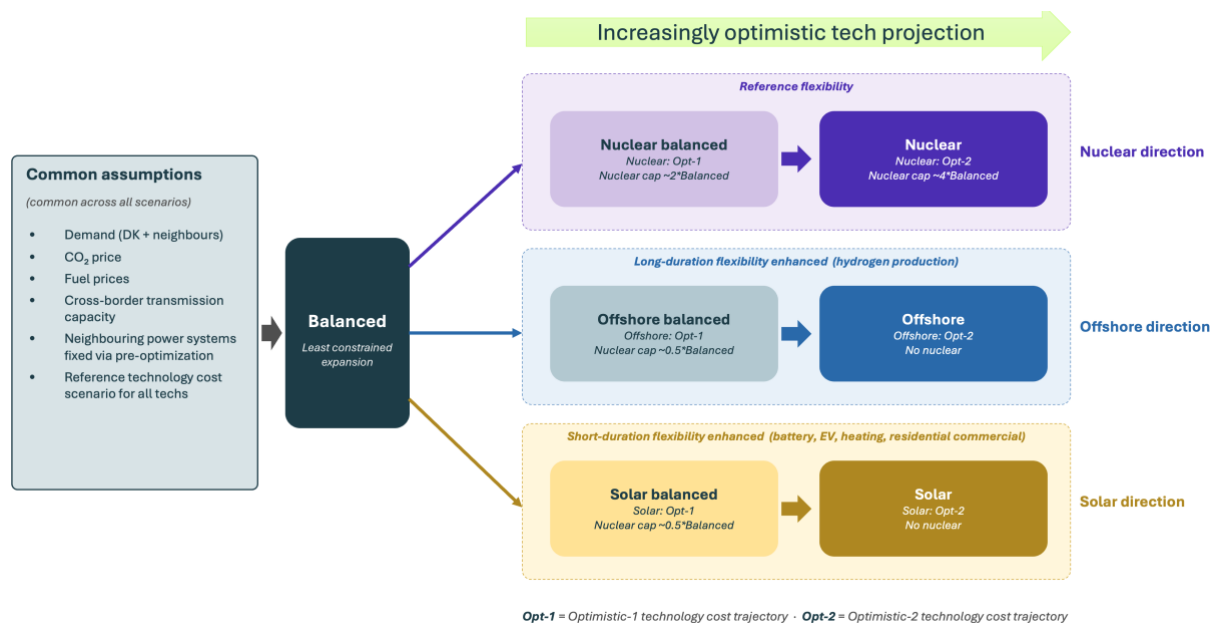


Figure 6. Scenario creation flow chart.

Table 3. Supply scenario definitions.

Scenario	Nuclear SMR cost	Offshore wind cost	Solar & battery cost	Demand-side flexibility	Nuclear cap
Balanced	Reference	Reference	Reference	Reference	No cap
Offshore Balanced	Reference	Optimistic-1	Reference	Optimistic, long-duration (H ₂)	~0.5 × Balanced
Offshore	—	Optimistic-2	Reference	Optimistic, long-duration (H ₂)	0
Solar Balanced	Reference	Reference	Optimistic-1	Optimistic, short-duration (EV, heating, residential commercial)	~0.5 × Balanced
Solar	—	Reference	Optimistic-2	Optimistic, short-duration (EV, heating, residential commercial)	0
Nuclear Balanced	Optimistic-1	Reference	Reference	Reference	~2 × Balanced
Nuclear	Optimistic-2	Reference	Reference	Reference	~4 × Balanced

3.5 Scope and key modelling limitations

The following limitations are most important when interpreting the results. Detailed numerical assumptions are presented in Section 4.

- **2050 end-state, not pathway.** The modelling represents a 2050 system configuration and does not optimise the year-by-year transition from today. Annual build-out rates, permitting, siting and supply-chain constraints are therefore represented only indirectly through technology assumptions and capacity limits.
- **European system and transmission.** Neighbouring generation capacity is pre-optimised and held fixed across Danish scenarios. Only transmission between bidding zones is represented; detailed Danish transmission and distribution networks are outside the modelling scope.
- **Demand and flexibility.** Demand-side flexibility is specified exogenously. The costs of enabling demand response and hydrogen production, transmission and storage infrastructure are not included in electricity-system costs.
- **Market scope.** The model focuses on the day-ahead energy market. Capacity markets, balancing services and short-term ancillary services such as frequency regulation and inertia are not explicitly optimised.
- **Resource adequacy.** The capacity adjustment tests the modelled systems across 33 historical weather years, including the January 1985 stress event, but does not perform a stochastic outage assessment.
- **Technology and infrastructure scope.** Existing fossil-fuelled Danish plants are assumed to retire, while gas turbines may be added for adequacy. CCS, pumped storage and hydrogen-fuelled gas turbines are not included as expansion options in Denmark.
- **Grid and operational follow-up.** The study does not provide detailed analysis of frequency stability, voltage, black start or local grid constraints. These issues would require separate follow-up analysis.

The results should therefore be interpreted as a long-term power-system comparison rather than a complete engineering design of a future Danish electricity system. The complete model configuration, constraints and exogenous assumptions are retained in Section 3.5 of the full report.

4 Assumptions

4.1 CO₂ emissions and commodity prices

The current study assumes a long-term CO₂ price of 132 €/tCO₂, aligned with the recent EA/VTT study²⁷. This reflects progressively tighter emissions constraints by 2050, although it is less stringent than assumptions in some earlier studies, which use around €200/tCO₂ in 2025 prices²⁸.

Likewise, long-term natural-gas prices are assumed to settle at 27 €/MWh_{th}, aligned with the recent EA/VTT study²⁹. Hard coal is set at 12 €/MWh_{th}, biomass at 30 €/MWh_{th} and uranium at 1.65 €/MWh_{th}.

4.2 Demand and flexibility

Electricity demand is modelled across six categories with distinct drivers and flexibility characteristics: electric vehicles, electrolyzers, industry, data centres, heating, and residential/commercial demand.

Data centres are treated as purely inflexible baseload with a flat hourly profile throughout this study. In practice, data centres typically feature behind-the-meter flexibility, such as on-site batteries and backup generators, primarily to manage operational security and local grid constraints³⁰. For the current system-level analysis, this means that the associated flexibility is assessed on a front-of-meter basis. Capturing this potential is left for future work.

4.2.1 Demand scenarios

Denmark's electricity demand is projected to grow substantially to 2050, driven by the electrification of transport, heating, industry, and the emergence of new loads including hydrogen production and data centres. The current study's reference scenario reaches approximately 102 TWh by 2050, up from around 38 TWh today, nearly three times the current level, as shown in [Figure 7](#).

²⁷ EA Energy Analysis & VTT (2026), Effects and value of SMR technologies in the Danish energy system.

²⁸ ERAA (2023), Proposal of Commodity Prices for Call for Evidence.

²⁹ EA Energy Analysis & VTT (2026), Effects and value of SMR technologies in the Danish energy system.

³⁰ ENTSO-E (2026). Data centres and the power system: expected trends, challenges and opportunities.

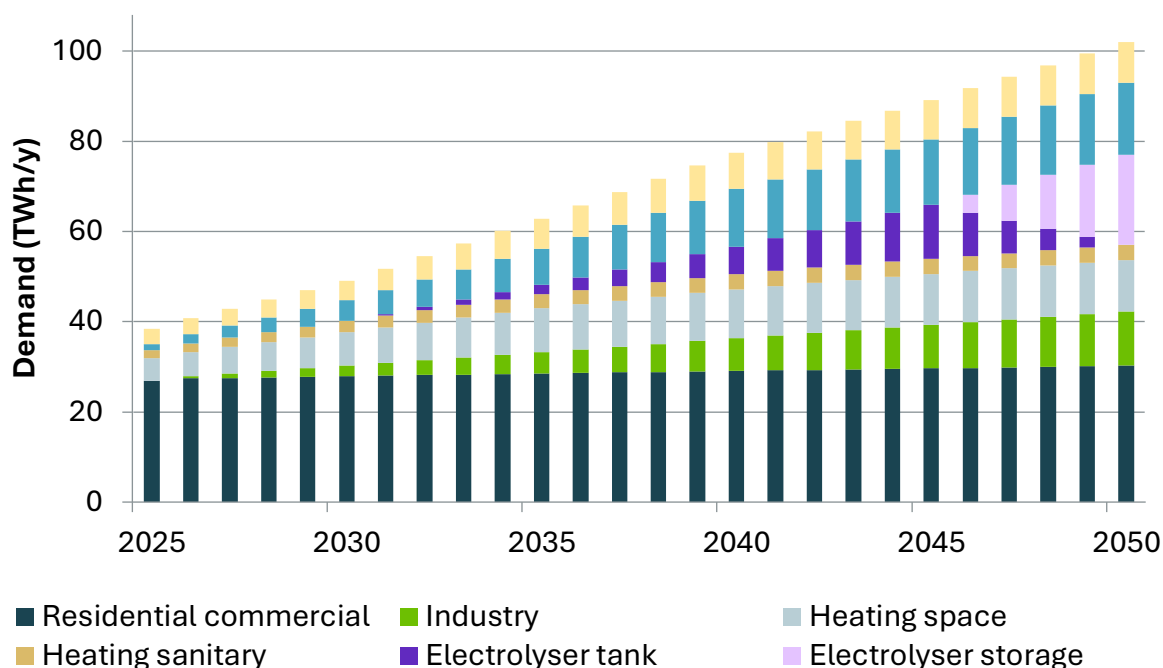


Figure 7. Reference demand scenario with categories and development until 2050.

The demand scenario projections have been inspired by two complementary Danish national studies. KF25 (*Klimastatus og Fremskrivning*)³¹ describes where Denmark is headed under currently decided policies. AF25 (*Analyseforudsætninger*)³² takes a more fundamental stance, asking what the energy system must look like to fulfil Denmark's climate targets. For the reference scenario's electricity demand, we additionally draw on the Balmorel-based scenario developed by EA Energy Analysis³³. Notably, the demand scenarios explored in the current work should not be interpreted as forecasts but rather as representative of projections in related long-term system studies.

Beyond the reference, two demand growth scenarios test how demand growth affects system design across the technology directions. The optimistic scenario (totalling 138 TWh) reflects a direction where Denmark, and Europe more broadly, takes on a larger role in the green transition: higher electrolyser deployment for e-fuel and hydrogen export, faster transport electrification, and stronger industrial electrification. In this scenario, data centre growth is more constrained, reflecting policy choices that prioritise electrification over data infrastructure. The conservative scenario (totalling 64 TWh) goes in the other direction, with slower climate action, limited hydrogen ambition, minimal industrial electrification, and more modest transport uptake but considerable growth of data centres.

³¹ Klima-, Energi- og Forsyningsministeriet (2025), *Klimastatus og -fremskrivning 2025 (KF25)*

³² Energistyrelsen (2025), *Analyseforudsætning til Energinet 2025 (AF25)*, Datasættet for grundforløb

³³ EA Energy Analysis & VTT (2026), *Effects and value of SMR technologies in the Danish energy system*.

Most of the increase in the reference case comes from new or expanding electricity uses rather than underlying residential demand. Electrolysers represent the largest source of uncertainty, ranging from 5 TWh in the conservative scenario to 50 TWh in the optimistic scenario; data centres reach 16 TWh in the reference case, while electrified heating reaches around 15 TWh across scenarios. EVs and industrial electrification provide additional growth.

4.2.2 Flexibility scenarios

As introduced earlier, each demand category is characterised by its own hourly load profile and flexibility potential. In the modelling framework, demand-side flexibility is represented by two mechanisms: load shifting and demand reduction (cutting). Both operate on market price signals. Shifting exploits price differences within a time window determined by storage capacity, while cutting increasingly reduces demand when prices exceed a threshold.

Relative to a peak load of around 15 GW, the conservative, reference and optimistic flexibility cases correspond to roughly 10%, 20% and 30% flexible capacity, respectively. Electrolysers provide the largest contribution, with EVs, residential/commercial demand and heating adding shorter-duration flexibility.

The technology directions use different flexibility assumptions. In the reference case, 5% of residential/commercial demand, 50% of heating and EV demand, 20% of industry and 80% of electrolyser demand are shiftable, while data centres remain inflexible. The Offshore direction increases long-duration electrolyser flexibility, the Solar direction increases short-duration flexibility, and the Balanced and Nuclear directions use the reference assumptions. Broader high/low flexibility sensitivities are examined in Section 5.7. Detailed demand profiles, flexibility shares and enabling assumptions are available in Section 4.2, Figure 12, Figure 15 and Tables 5–6 of the full report.

4.3 Overview of cost assumptions

Technology costs are a central driver of capacity-expansion results, so assumptions and financing are treated explicitly. The reference WACC is 6%, with 4% and 8% used in the optimistic and conservative cases. Construction financing is represented through an interest mark-up equal to half the WACC over the construction period, and capital recovery is set to two-thirds of technical lifetime. All monetary values are expressed in real 2025 euros, pre-tax.

4.3.1 Technology cost uncertainty

The assumptions draw on a broad range of historical data, current market conditions and forward-looking projections. They are designed to reflect structural trends while avoiding reliance on any single project or data point.

Cost assumptions are cross-validated against Danish and international sources, including the Danish Energy Agency, IEA, IRENA and NREL, with European and Danish

conditions given particular weight. The year 2040 is used as the central cost reference, reflecting the period in which much of the investment required for the 2050 system would take place.

Five technology-cost cases are used: Conservative-2, Conservative-1, Reference, Optimistic-1 and Optimistic-2. They capture uncertainty in industrial learning, supply chains, permitting and project execution, and financing conditions. The Reference case represents a harmonised central estimate; the outer cases combine progressively more adverse or favourable technology and financing assumptions.

Capacity-factor assumptions also account for gradual saturation of high-quality sites and increased curtailment, so declining LCOE is not driven solely by optimistic performance assumptions. [Table 4](#) shows the resulting LCOE inputs used in the modelling. The underlying source review, technology-specific cost trajectories and modelling assumptions are documented in Sections 4.3.1–4.3.6 and Appendix D of the full report.

Table 4. Estimated levelised cost of electricity inputs (EUR/MWh) for the technologies whose costs vary across scenarios. The values cover the electricity market only; potential heat revenues from nuclear generation are excluded.

Technology cost scenario	Nuclear SMR	Solar	Wind offshore nearshore	Wind offshore (bottom-fixed)	Wind onshore	Gas OC
Conservative-2	134	62	76	88	60	550
Conservative-1	108	53	66	76	51	510
Reference	86	42	53	64	41	470
Optimistic-1	60	38	47	58	36	440
Optimistic-2	49	33	40	50	31	410

4.4 Capacity build-out: limits, fixed expansion, and existing fleet

Capacity expansion combines endogenous investment with exogenous assumptions and technology-specific upper bounds. The model therefore represents feasible 2050 end-state configurations rather than unconstrained theoretical potential.

Because the model represents 2050 only, it does not optimise the annual build-out pathway from today. Permitting, siting and supply-chain constraints are therefore reflected indirectly through technology assumptions and capacity limits rather than explicit year-by-year deployment constraints.

4.4.1 Wind and solar expansion

Onshore and offshore wind and utility-scale solar expand endogenously, subject to wind capacity limits, while residential solar is specified exogenously.

Onshore wind

The model assumes that additional onshore wind capacity is primarily achieved through repowering rather than extensive greenfield development. The upper bound for onshore wind is set at approximately 7 GW. This value is based on the 1000 m distance scenario reported by the Joint Research Centre³⁴ and is consistent with a conservative interpretation of Danish land-use constraints.

Offshore wind

Offshore wind is represented in distance-based categories because grid-connection and installation costs vary by location. The assumed potential is 11.1 GW nearshore, 24.6 GW offshore and 25.9 GW farshore; the farshore potential is not used in the modelled scenarios.

Solar PV

Solar PV is divided into exogenous distributed residential solar and endogenous utility-scale solar. The residential solar capacity is 7.6 GW in 2050 across all scenarios, based on AF25³⁵. Additional utility-scale solar PV is allowed as an endogenous investment option.

4.4.2 Existing thermal power plants

The modelling assumes projected installed capacity relating to existing thermal power plants according to AF25^{36,37}.

Most existing Danish thermal capacity is assumed to retire before 2050, consistent with AF25. A smaller residual thermal fleet remains exogenously, while additional open-cycle gas turbines can be added later through the adequacy adjustment described in Section 5.3. Detailed wind and solar potentials, the existing thermal fleet and the heat-sector assumptions are documented in Sections 4.4–4.5 and Table 9 of the full report.

³⁴ JRC/EIGL (2025) The Onshore Wind Potential of the EU and Neighbouring Countries

³⁵ Energistyrelsen (2026), Monthly Energy Statistic, Electricity

³⁶ Energistyrelsen (2025), Analyseforudsætning til Energinet 2025 (AF25), Datasættet for grundforløb

³⁷ Energistyrelsen (2026), Monthly Energy Statistic, Electricity

5 Results

5.1 Pre-optimised neighbouring regions

Figure 8 presents the results of the pre-optimisation of the power system mix in the entire model geography for 2050 and compares this with the current system in 2025. The current electricity system in 2025 is dominated by dispatchable power generation, which accounts for more than 60% of annual electricity production, while wind and solar power account for 36%. By 2050, the electricity system has undergone a major transition towards an almost entirely climate-neutral power system. Driven by electrification, total generation has increased by around 75% in the modelled system, from 2280 TWh in 2025 to 3990 TWh in 2050. Further emissions reductions are achieved, reaching around a 90% decrease compared with 1990. Wind and solar power then make up 55% of the electricity mix, while nuclear power's share has decreased and high-emission coal generation has been mostly phased out. System flexibility is ensured through battery storage, gas-fired power plants with and without CCS, and flexible demand from electric vehicles, heating and hydrogen production. It is worth emphasising that as a result of electrification, electricity consumption increases in all countries, typically by 50–100% compared with today.

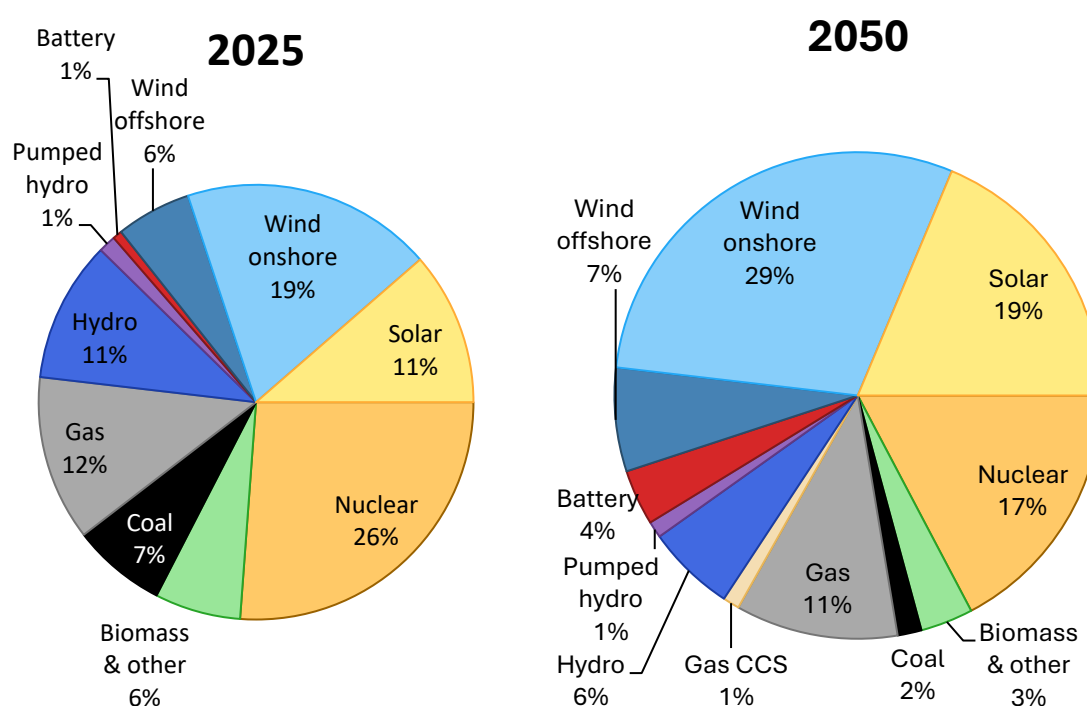


Figure 8. Share of annual electricity generation by technology for the entire model geography for the year 2025 (left panel, totalling 2280 TWh) and the modelled year 2050 (right panel, totalling 3990 TWh).

Although dispatchable generation accounts for a smaller share of output in 2050, installed dispatchable capacity still increases in absolute terms in the pre-optimised European system. The corresponding capacity and country-level results are shown in Figures 18–19 of the full report.

5.2 Capacity and generation mix

This section presents the main characteristics of the seven Danish power-system scenarios analysed in this study. Installed gas-turbine and battery-storage capacity is determined by the capacity-requirement adjustment (step 4 in Figure 2), presented in Section 5.3. The other technologies are determined by the capacity-expansion optimisation (step 3 in Figure 2).

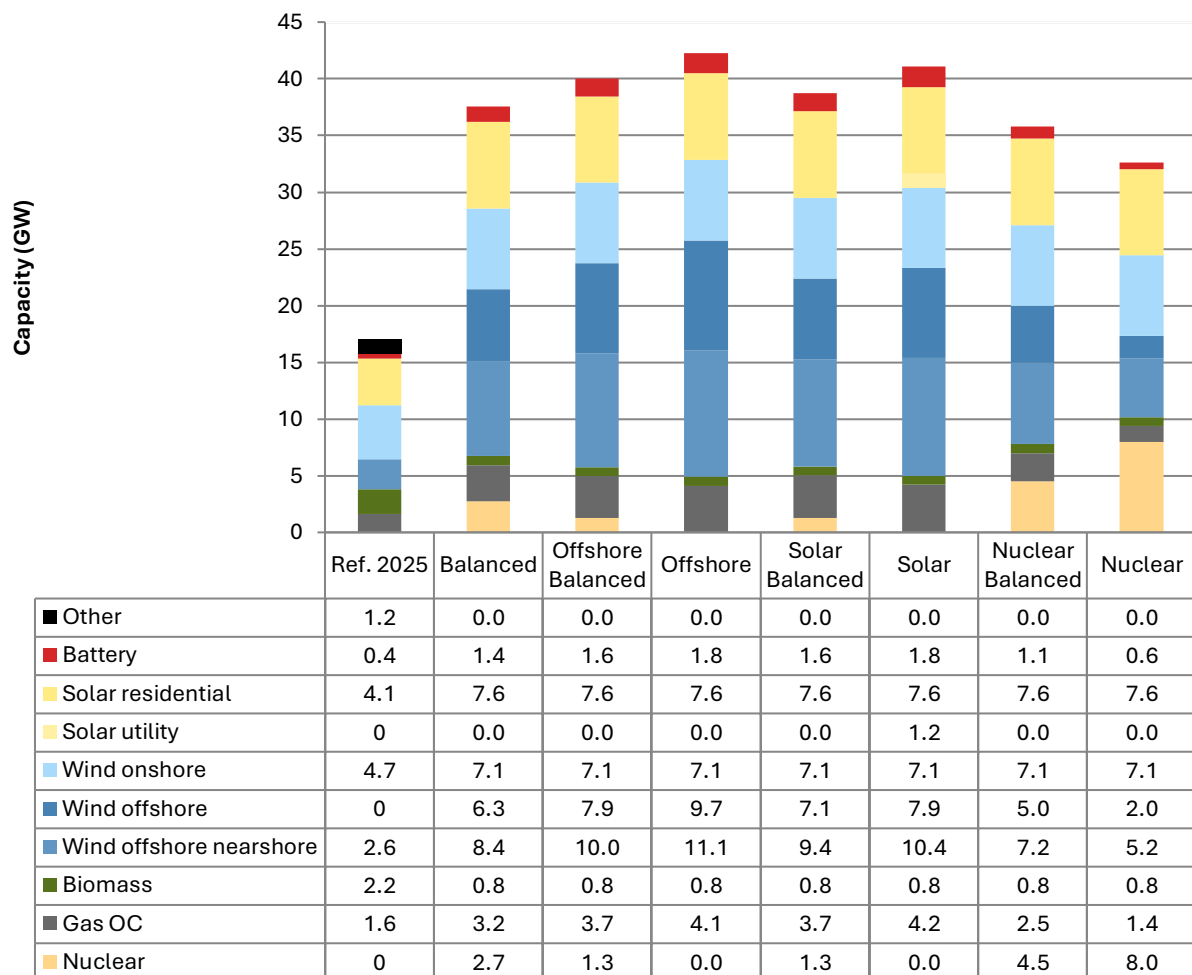


Figure 9. Installed capacity in various technologies on a national level across modelled scenarios. For *Ref. 2025*, *Solar residential* covers all installed solar capacity, including utility-scale, and the category *Other* includes: oil, waste and unspecified as per EnergyCharts³⁸.

The combined installed capacity (Figure 9) ranges from 32.6 GW (scenario: Nuclear) to 42.2 GW (scenario: Offshore). These two scenarios simultaneously exhibit the highest and lowest share of installed dispatchable capacity, 31.2% and 11.7%, respectively. Across scenarios, the average share of dispatchable capacity is 18%. Across all

³⁸ EnergyCharts (2026), *Installierte Netto-Leistung zur Stromerzeugung in Dänemark in 2025*

scenarios, the onshore wind potential is fully exploited. This is consistent with the technology's maturity and low modelled cost. Furthermore, apart from the Solar scenario, the model selects little additional utility-scale solar PV. This is mainly because the exogenous expansion of 7.6 GW of residential solar already affects market prices and lowers future capture rates, reducing its modelled market profitability. In addition, neighbouring regions, particularly Germany, show substantial solar build-out, adding to regional cannibalisation.

Although combined capacity remains at a relatively similar level, the scenarios exhibit structurally different technology mixes. Apart from the Nuclear scenario, wind (all technologies) represents at least 53% of installed capacity, reaching as much as 67% in the Offshore scenario. Battery-storage capacity remains relatively constant at 1.4–1.8 GW, except in the nuclear-heavy scenarios (Nuclear Balanced and Nuclear), where it falls to 1.1 GW and 0.6 GW respectively, indicating a lower modelled value for battery storage when more dispatchable generation is available. Installing approximately 15 GW on average across scenarios in offshore projects translates into more than full realisation of AF25 assumptions (13.9 GW in 2040) concerning grid-connected wind parks in both DK1 and DK2.

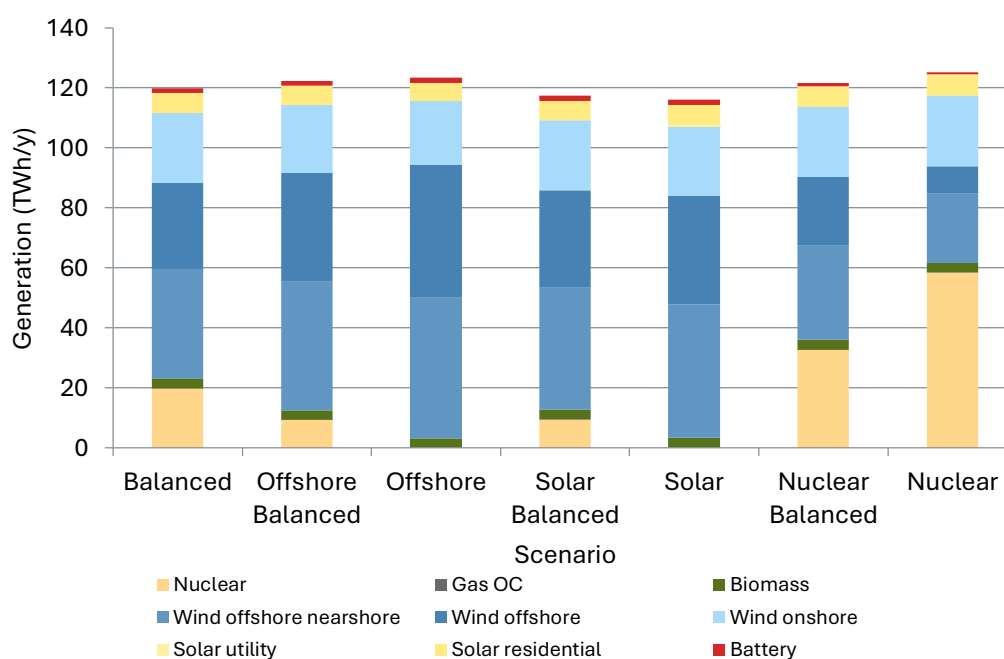


Figure 10. Total electricity generation across all scenarios with individual contributions from each technology.

Across the analysed scenarios, total electricity generation (Figure 10) is around 119 TWh/year, ranging from 114 TWh/year in Solar to 124 TWh/year in Nuclear. This variation stems from how relatively cost-effective it is to expand supply capacity in Denmark compared to import. For instance, the Nuclear scenario assumes lower nuclear generation costs in Denmark. In contrast, the Solar scenario prohibits nuclear and keeps offshore wind at reference technology costs; although solar has the lowest generation cost, the model assigns it limited additional system value. Apart from the Nuclear

scenario, wind is the backbone of electricity generation with shares ranging from 65% (Nuclear Balanced) to 92% (Offshore). Nuclear contributes 8% to 47% where allowed and is absent from the Offshore and Solar scenarios by design.

The remaining technologies make relatively small contributions: solar PV supplies about 6% on average, biomass around 3%, and open-cycle gas less than 0.1%, consistent with its role as a peaking resource for adequacy. Zone-level DK1/DK2 capacity distributions and the full daily dispatch results are available in Figure 21 and Section 5.3 (Figures 23–24) of the full report.

5.3 Capacity requirements

The capacity and generation mixes in the Danish scenarios were first evaluated in an energy-only market (cf. today's day-ahead market), representing the third step of the methodology (see Figure 2). The capacity expansion optimisation was performed on a weather year representing average market conditions, and therefore representative market revenues for the technologies considered for investment.

Beyond cost-effective energy supply under average conditions, the final systems are also tested for generation adequacy under extreme weather. Dispatchable resources may additionally contribute to frequency, voltage, restoration and other operational services, but these services are not modelled directly in this study. The capacity requirement described below should therefore be interpreted primarily as a resource-adequacy and robustness adjustment rather than a complete assessment of operational security.

Generation adequacy was stress-tested using an extreme event on 19 January 1985. This event has been identified and characterised in the Swedish context during previous work³⁹ and has also been described in Section 3.3. The following analysis also informs the discussion of Danish self-sufficiency.

The January 1985 weather year contains one of the most demanding resource-adequacy events in the dataset. Low wind production contributes to a wider regional generation shortfall, combined with cold weather that drives up electricity demand for heat supply. Although the event duration is comparatively short, prices rise across essentially the entire modelled European system, indicating that this event is driven to a substantial extent by generation scarcity in continental Europe, not by Danish conditions alone. We use this event as a reasonable case for dimensioning capacity requirements. It is not necessarily the only suitable event; what matters is that the chosen case is paired with a thorough evaluation of system performance, which the subsequent analysis provides.

The unadjusted Balanced simulation produces a loss-of-load event of approximately 400 MW. Potential biomass CHP reserves and an N-1 contingency are then incorporated in the post-modelling balance shown in Figure 11.

³⁹ Energiforsk (2025), Så får industrin tillräckligt med el till 2035 – bilagor till slutrapport.

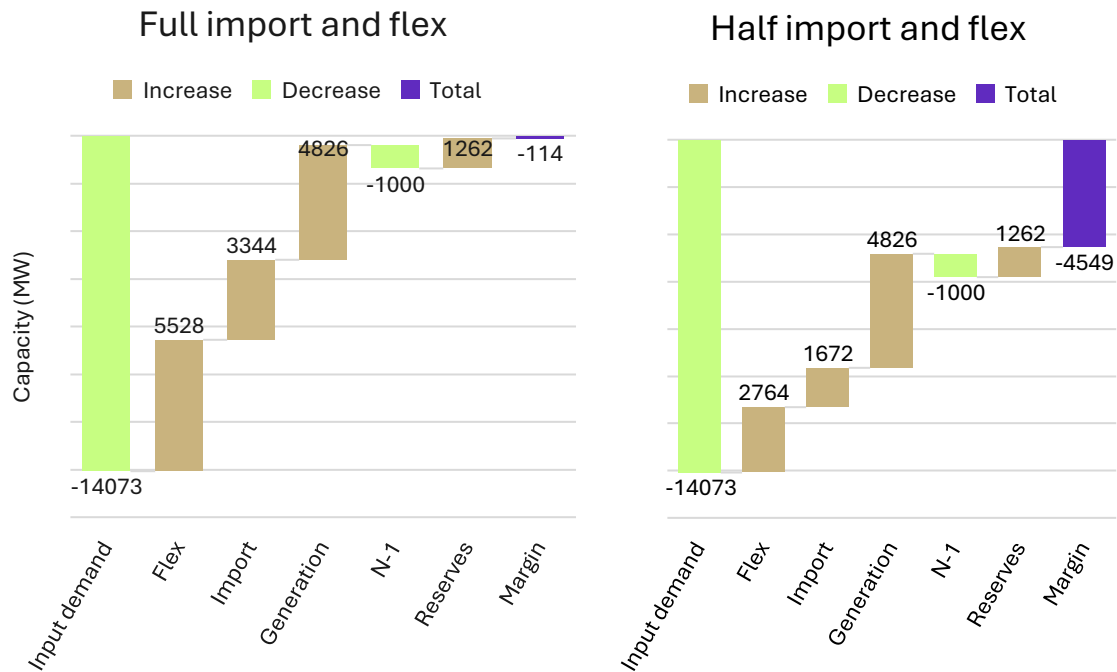


Figure 11. Power system balance in the Danish power system split up by components in the Balanced scenario for the 1985-01 event. Full, 100%, and half, 50%, availability of import and flex in the left and right panel, respectively.

To test robustness against simultaneous dependence on neighbouring systems and demand-side flexibility, the study applies an additional stress-test assumption in which only 50% of modelled imports and flexibility are counted as available during the extreme event. This is not a forecast of actual availability, but a deliberately conservative assumption used to determine an additional dispatchable-capacity requirement. It reflects uncertainty over cross-border support during regional scarcity and over whether modelled flexibility will materialise at full scale.

With imports and flexibility counted at 50%, the Balanced scenario has a 4.5 GW shortfall. The study assumes that 70% of the missing capacity is supplied by open-cycle gas turbines and 30% by battery storage. This split is a modelling assumption rather than an optimised result: batteries provide fast, short-duration response, while gas turbines can sustain supply during longer scarcity periods.

The additional gas turbines are treated as reserves and dispatch only above 500 €/MWh, preserving the energy-market outcomes from the capacity-expansion step. With the added capacity, no loss-of-load events occur across the 33 simulated weather years.

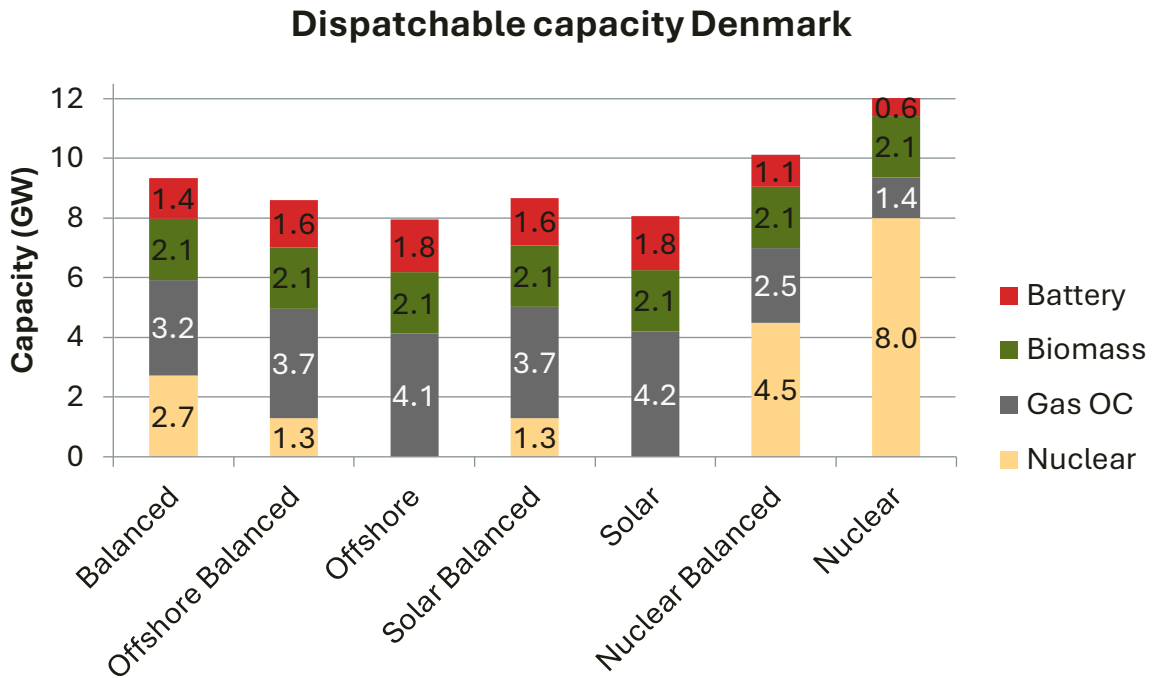


Figure 12. Installed dispatchable capacity in Denmark by technology and across scenarios.

Figure 12 shows the resulting dispatchable capacity, including Battery and Gas OC, after the capacity-requirement adjustment. Excluding Battery, dispatchable capacity is 8 GW in the Balanced scenario and ranges from 6.2 GW in Offshore to 11.4 GW in Nuclear. This includes 1.3 GW of biomass CHP capacity that is not normally activated in the model but could contribute during system-stress conditions. Additional demand-response and supply-composition results for the January 1985 event are shown in Figures 26–27 of the full report, with the complete adequacy analysis retained in its Section 5.4.

5.4 Generation and capacity costs

Generation and capacity costs have been determined for all scenarios investigated in the current study and are presented according to technology contributions or cost types: investment costs, fixed costs, variable costs, import costs and excluded costs. These costs are annual, 'levelised' costs, meaning that the investment costs are spread evenly over the economic lifetime of the technology. Presented values are absolute costs normalised to total power demand of 102 TWh in the reference scenario, unless otherwise indicated.

Costs include annualised investment, fixed and variable operation, fuel, CO₂ and net electricity trade. Offshore connection costs are included, while balancing services, existing-network reinvestment and the separate onshore grid proxy in Section 5.9 are excluded.

Figure 13 shows generation and capacity costs after the capacity-expansion optimisation, but before the capacity-requirement adjustment, for the 1991 reference weather year. At this stage, the Balanced scenario has the highest costs because the directional scenarios assume technology-cost reductions, greater flexibility, or both. Denmark is a net exporter of electricity in all scenarios; however, all except Nuclear Balanced and Nuclear show positive net import costs. This means that export revenues in the Nuclear Balanced and the Nuclear scenarios decrease total costs. No CO₂ costs are observed here because the gas-turbine capacity additions are made after the capacity-expansion optimisation.

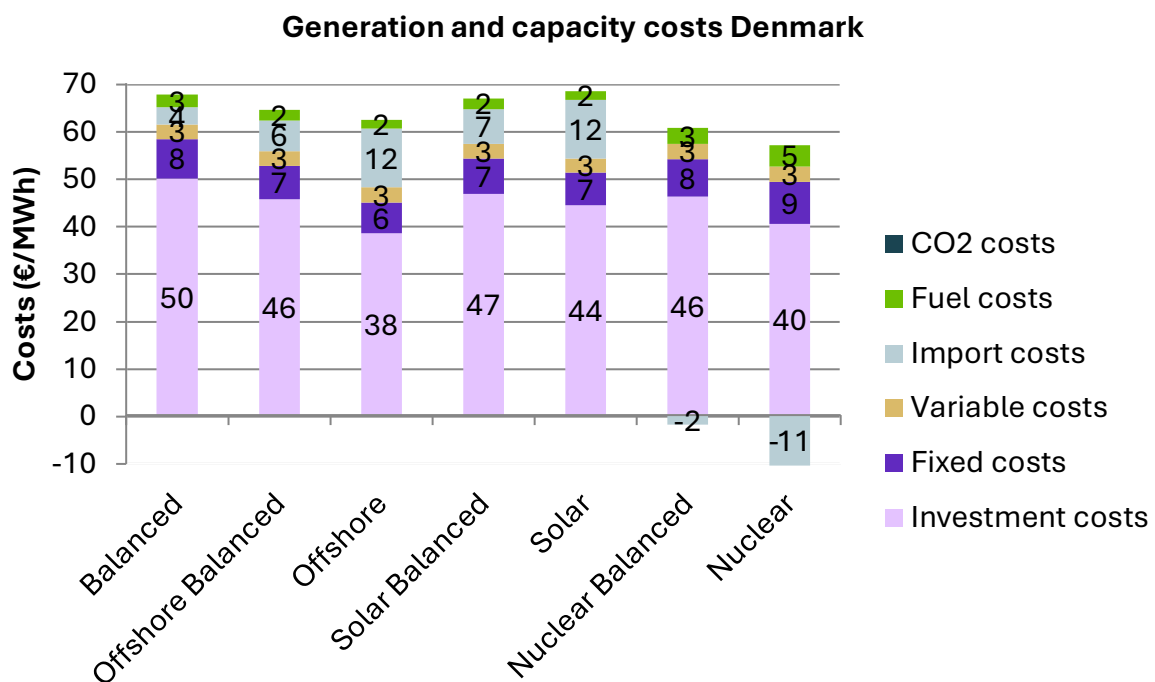


Figure 13. Generation and capacity cost, including import costs, normalised to annual demand broken down by cost component across main scenarios for the resulting system of the capacity expansion optimisation step (step 3 in Figure 2).

To further evaluate system costs, the study introduces adequacy capacity and Reference cost normalization on top of the generation and capacity costs as shown in Figure 14. The technology-cost normalisation step adjusts all technologies to Reference costs, separating the structure of each optimised system from the favourable assumptions used to construct the directional scenarios.

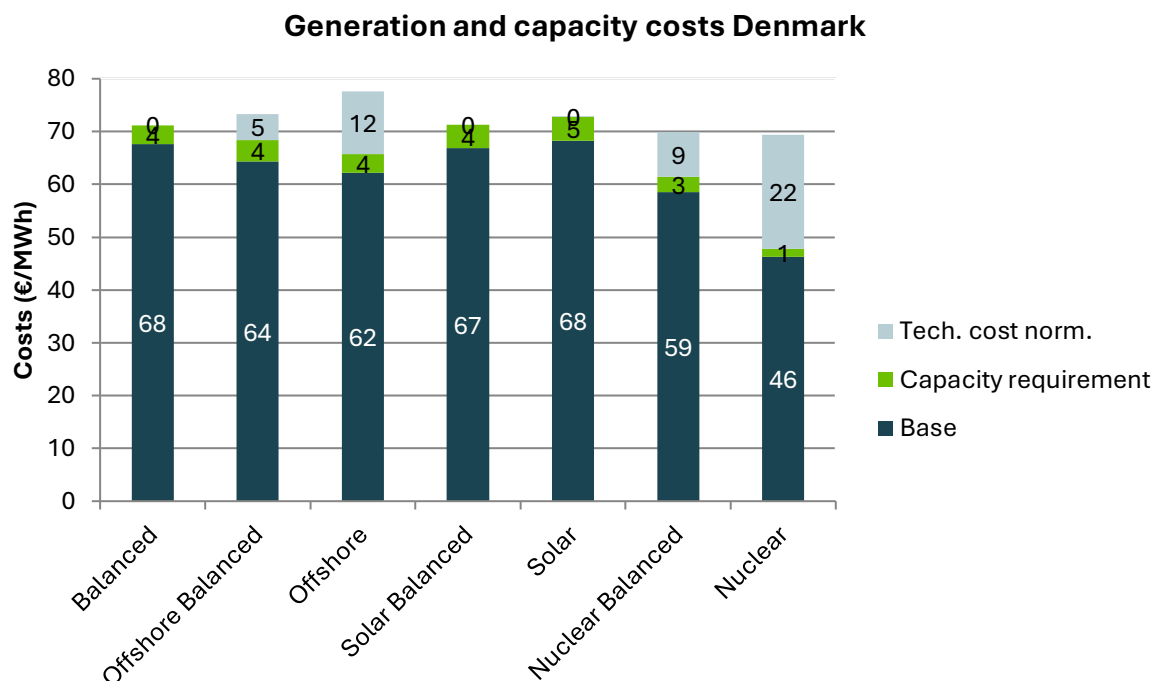


Figure 14. Generation and capacity cost, including import costs, normalised to annual demand broken down by cost variation across main scenarios.

Considering the overall costs of the Base cost variation, the nuclear-heavy scenarios show the lowest costs (46 €/MWh and 59 €/MWh for Nuclear and Nuclear Balanced, respectively) followed by Offshore (62 €/MWh) due to their lower cost assumptions and/or export revenues. The lower costs in the nuclear-heavy scenarios illustrate the larger potential cost benefit if the more optimistic nuclear cost assumptions materialise, compared with the Offshore scenario. This reflects the relatively stronger reduction in technology costs for nuclear compared to offshore wind.

Following the capacity requirement of battery and gas turbines, investment costs increase in line with the additional capacity. These additional investment costs range from 1–5 €/MWh. However, these additional costs are compensated by decreased import costs as the gas turbines and battery storage reduce Denmark's import dependence, which helps explain why the capacity-requirement cost in the Balanced scenario (4 €/MWh) is similar to that in the Offshore scenario (4 €/MWh). Due to already demonstrating net export revenues before the capacity requirement, the nuclear-heavy scenarios, combined with smaller capacity additions, show the lowest cost impact from the capacity requirement (3 and 1 €/MWh, for Nuclear Balanced and Nuclear, respectively). Overall, the capacity requirement costs are relatively limited with a 5% increase in the Balanced scenario.

Folding in the Tech. cost norm. variation enables a fairer comparison between the scenarios. Under this normalisation, the Offshore and Nuclear scenarios show the largest cost increases, at 12 and 22 €/MWh respectively, because their capacity mixes were optimised under more favourable technology-cost assumptions. As per design, the

Balanced scenario shows no cost addition in the technology cost normalisation. In total, costs including import costs remain relatively close to the Balanced scenario at 71 €/MWh, ranging from 69 €/MWh (-3%) in Nuclear to 78 €/MWh (+9%) in Offshore. The normalised difference indicates the scale of additional revenue recovery that could be required if Reference technology costs materialise; possible support mechanisms are discussed further in Section 5.5.3.

5.5 Electricity market

The price of electricity is a key determinant of both the functioning of the energy market and the wider economy. It affects industrial competitiveness, household electricity costs and investment incentives for new electricity generation. Scenario analyses, such as this one, often focus on system costs, which can be linked to the average electricity price required for producers - such as wind developers - to reach profitability in the modelled scenarios. At the same time, the electricity price is affected by how the power system balances local production and trade with other countries. Depending on the scenario, the system may lean more or less towards imports and exports, which leads to electricity prices varying both in Denmark and throughout the model. A holistic view of both system costs and electricity prices is therefore required to understand the economic conditions of the future power system.

However, a discussion of electricity prices is incomplete without considering price volatility, that is, how electricity prices vary over time. Price fluctuations can be caused by factors such as fuel prices and capacity constraints such as power plants or transmission, but this study focuses in particular on weather-dependent variations.

5.5.1 Average prices

Figure 15 presents the average yearly prices for all weather years. DK1 and DK2 are shown together because their average prices differ by only around ± 2 €/MWh. Despite the very different system structures, yearly average day-ahead prices vary only from -8% to +6% relative to the Balanced scenario. This is a consequence of Denmark's large interconnectivity in the market relative to its system size. This ultimately means that neighbouring regions set the price for most hours. Nevertheless, the scenarios that expand the most capacity locally in Denmark (Offshore and Nuclear) show the lowest prices, as expected. Compared to the average market price of the power system in 2025, all scenarios exhibit a decrease (with the Balanced scenario at -5% and Nuclear reaching the maximum at -13%). This reflects the assumed technology-cost reductions across the modelled technologies.

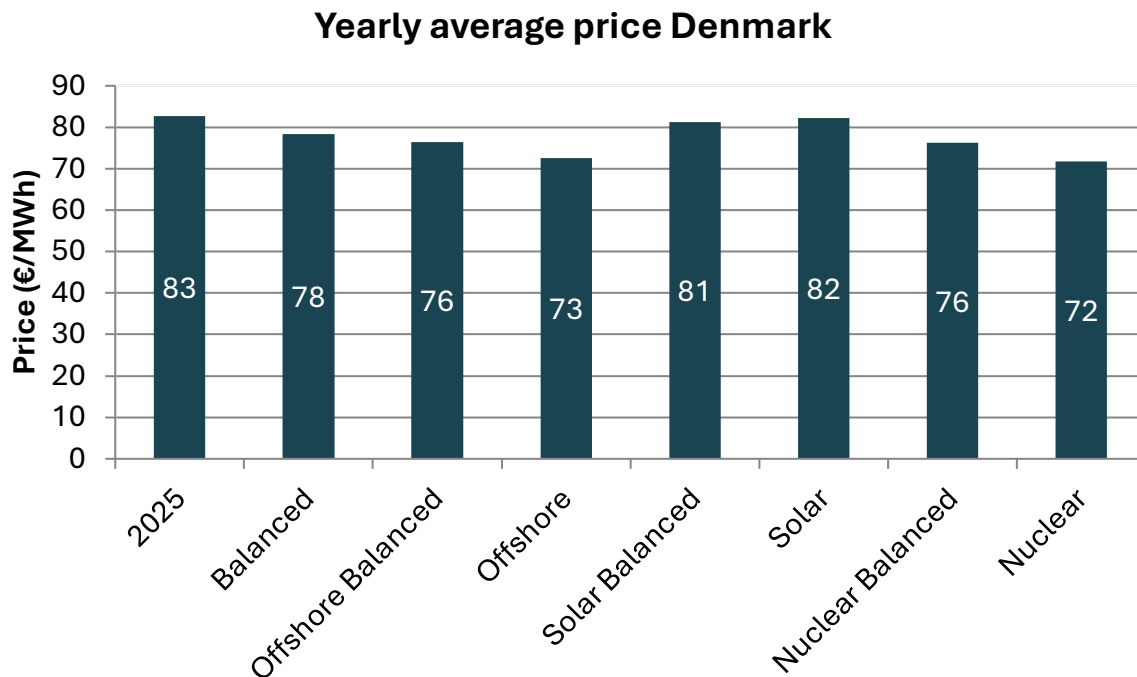


Figure 15. Yearly average market price for all weather years across the scenarios.

5.5.2 Price volatility

Across the seven 2050 scenarios, weather-driven price volatility varies only modestly because Denmark is strongly coupled to neighbouring markets. Relative to Balanced, Offshore is 2% lower, Nuclear Balanced 3% lower and Nuclear 8% lower. All future cases are nevertheless much more weather-sensitive than the 2025 reference: the composite volatility measure is about 260% higher in Balanced, reflecting the larger share of weather-dependent generation across the interconnected European system. The full quarterly distributions are shown in Figure 36 of the full report.

5.5.3 Market profitability

By comparing market revenues and technology costs we can assess their relative profitability under market conditions. A positive value means market revenues exceed the LCOE – the technology is cost-recovering at market prices. A negative value means market revenues fall short of the LCOE, so the technology does not recover its assumed costs from market revenues alone.

At actor level, offshore wind in the Offshore scenario and nuclear in the Nuclear scenario fall short of their Reference LCOE by roughly €12/MWh and €9/MWh respectively. This shows that both directions may require targeted support or risk-sharing, even though the underlying risks differ. The full technology-level comparison is retained in Figure 38 of the full report.

Figure 16 presents profitability for the Reference technology cost scenario from the system perspective, normalised to total demand and including Battery and Gas OC. The results show, as expected, the profitability gap for Battery and Gas OC, as these technologies were not expanded in the capacity expansion optimisation and were introduced following the capacity requirement adjustment presented in Section 5.3. This analysis only considers day-ahead energy market revenues. Battery storage may also earn revenues from balancing-service markets and other services that are not represented in the current model. Correspondingly, Gas OC could potentially obtain revenue from reserve or capacity markets, the latter of which could also involve nuclear power.

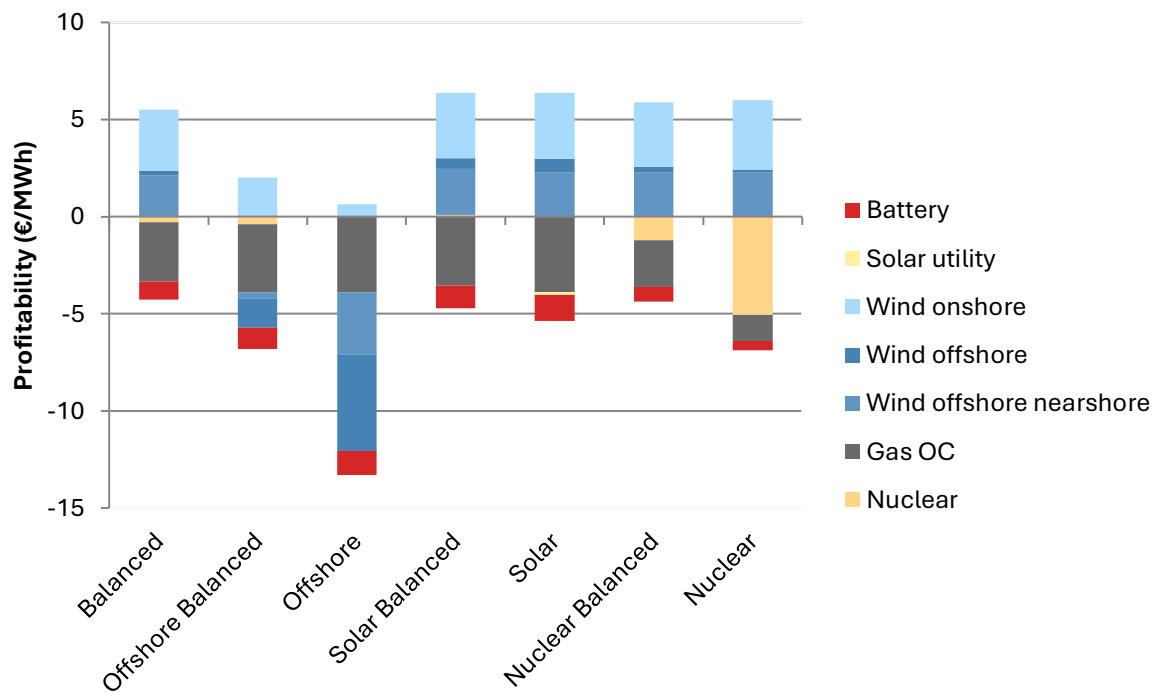


Figure 16. Profitability based on the Reference technology cost scenario and values normalised to total demand by technology across the scenarios.

Summed across technologies and normalised to demand, Offshore Balanced and Offshore have the largest system-wide profitability gaps, at about €5/MWh and €13/MWh respectively, while the other scenarios are close to zero under Reference costs. The gap in wind-heavy systems reflects revenue cannibalisation: correlated production depresses the prices received by the wind fleet. A near-zero system total does not mean every individual technology is financeable without support, because gains and shortfalls across technologies offset each other. Conservative-cost results and the full technology-level analysis are retained in Table 12 and Figures 38–40 of the full report.

5.6 Degree of self-sufficiency

Self-sufficiency is evaluated through three complementary indicators: electricity trade and import costs, gas consumption, and the share of demand that can be covered by domestic generation during the most challenging hours.

5.6.1 Imports and import costs

Analysing electricity imports or trade requires care in how the metric is defined. Aggregating net exchange over a year, where net exports cancel against net imports, can substantially understate actual dependence on imported electricity. For a small grid like Denmark with interconnection capacity exceeding total domestic demand, real net imports (the sum of importing hours) and real net exports (the sum of exporting hours) are distinct phenomena and should be assessed separately. Equally important is the hourly distribution: the number of importing hours and, crucially, the share of demand covered by imports in those hours, which aggregate annual figures obscure. Finally, the monetised trade incorporates the value of energy and therefore ultimately provides information on potential import dependence.

Figure 17 illustrates daily Danish exchange and DK1 market prices for the 2025 reference and the Offshore, Balanced and Nuclear scenarios. All future scenarios show broadly similar timing in the direction of exchange and in price movements, while the 2025 reference is less volatile. The main differences concern the magnitude of trade and the price level: the Offshore scenario generally has the largest imports and exports, while the Nuclear scenario shows the smallest variation.

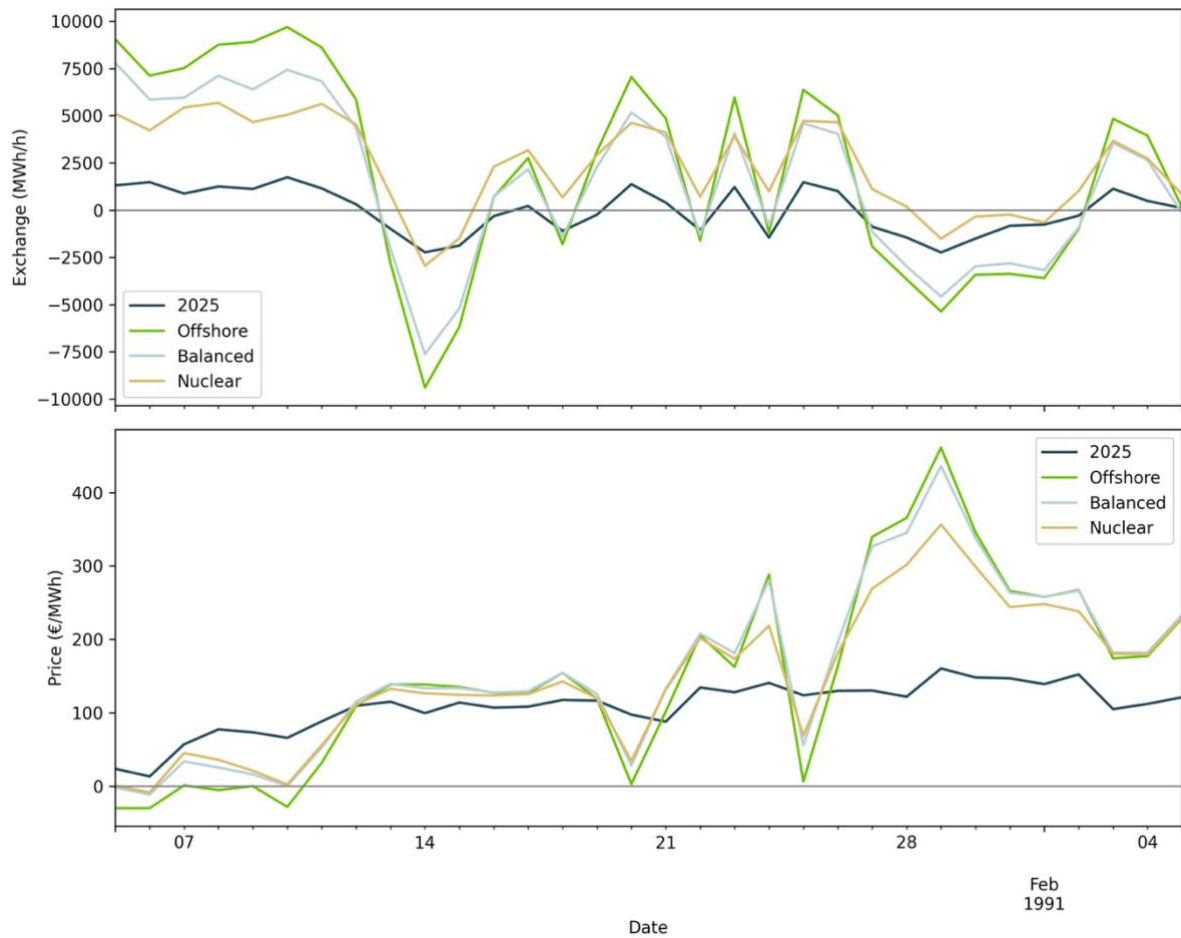


Figure 17. Daily average exchange for the Danish power system (top panel) and market price in DK1 (bottom panel) zoomed in on the early period weather year 1991 across the 2025 reference, Offshore, Balanced and Nuclear scenarios. For the exchange, positive and negative values represent net export and net import, respectively.

Figure 18 shows the duration curve of exchange over the full 1991 weather year. The 2025 reference imports electricity in 57% of hours. This falls to around 35% in the Balanced and Offshore scenarios and to 20% in the Nuclear scenario.

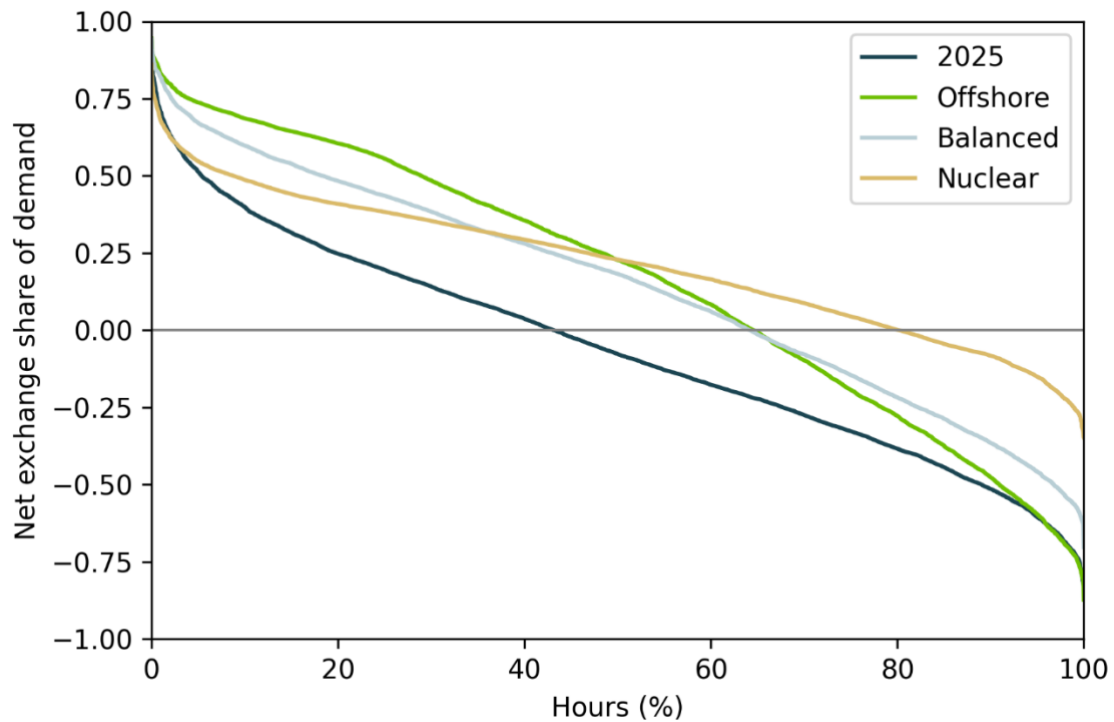


Figure 18. Duration curve of exchange normalised to demand for weather year 1991 across the 2025 reference, Offshore, Balanced and Nuclear scenarios. For the exchange, positive and negative values represent net export and net import, respectively.

Figure 19 compares annual net imports and exports across all scenarios. All the future scenarios modelled show a positive net export on an annual basis. The Balanced scenario has net exports of 15 TWh, while Solar and Nuclear show the lowest and highest levels at 11 TWh and 21 TWh respectively. The scenarios with the largest domestic generation, Offshore and Nuclear (see Figure 10), also show the largest net exports, while Solar has the lowest domestic generation and the lowest net exports. Notably, the 2025 power system shows a contrasting net trade level of -2 TWh on average.

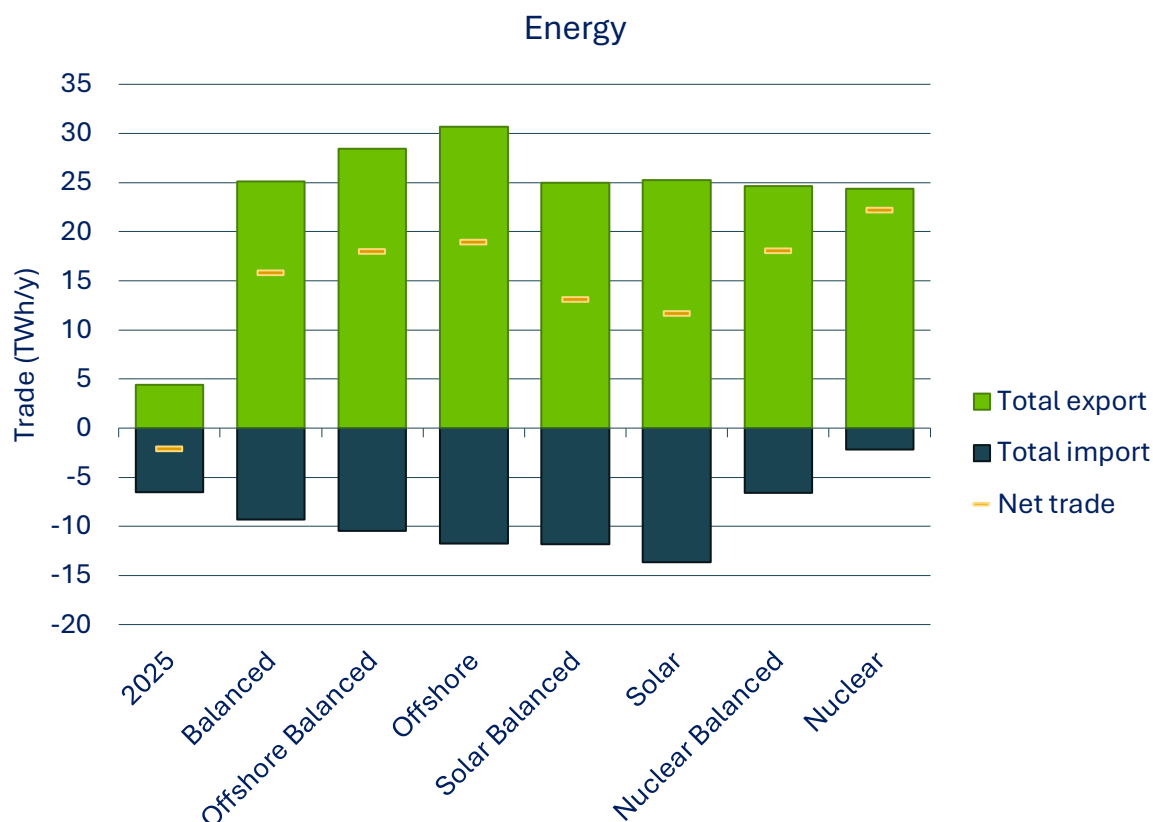


Figure 19. Yearly trade for weather year 1991 in Denmark across the scenarios. For the trade, positive and negative values represent net export and net import, respectively.

Energy volumes alone do not show when electricity is imported or exported, or at what price. [Figure 20](#) captures this dynamic by showing export revenues, import costs and monetised net trade. The monetised results differ markedly from the energy-based comparison: net export revenues generally remain lower than net import costs.

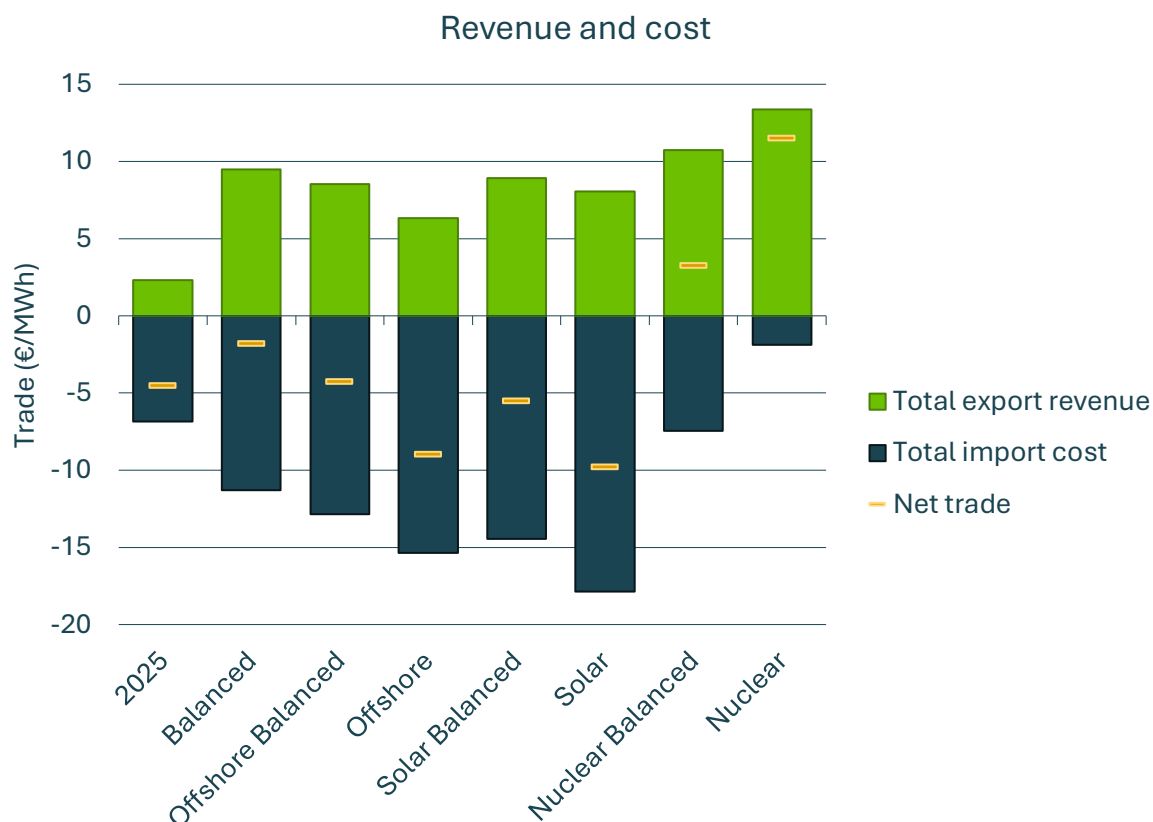


Figure 20. Monetised trade normalised to total demand in Denmark for weather year 1991 across the scenarios. For the trade, positive and negative values represent net export revenues and net import costs, respectively.

The 2025 reference displays a net trade of -4.5 €/MWh compared to the Balanced scenario at -1.8 €/MWh. Moving towards the Offshore and the Solar scenarios, net values decrease to approach -10 €/MWh. The more nuclear-heavy scenarios show the opposite trend with decreasing import costs and increasing export revenues with positive net values of 3.3 €/MWh and 11.5 €/MWh for the Nuclear Balanced and Nuclear scenarios, respectively.

These results are explained by the increased variation of supply dispatch in the Offshore and Solar due to a larger share of weather-dependent generation combined with lower clean firm capacity. With lower clean firm capacity, the model relies to a greater extent on neighbouring countries to balance the system. Because weather conditions can be correlated across northern Europe, there is a high probability that neighbouring regions experience low wind and solar production at the same time as Denmark, leading to price coupling and a greater need for imports during periods of high prices. This leads to both higher electricity prices and import costs and indicates a generally higher vulnerability of these power systems.

Systems with lower clean firm capacity and greater import dependence may therefore be more exposed to external factors, such as political decisions in exporting countries,

weather conditions in neighbouring countries or bottlenecks in the transmission network. Conversely, the scenarios with more clean firm capacity in Denmark provide more exports to neighbouring regions during challenging conditions, reducing Denmark's exposure to price shocks and contributing additional supply across the model geography.

5.6.2 Gas consumption

Gas consumption is limited because the turbines are assumed to act as reserves and are dispatched only during periods of extreme scarcity, defined by prices exceeding 500 €/MWh. The resulting levels of around 1 TWh are considerably below Danish power-sector gas consumption of about 5 TWh in 2025. The low gas consumption is conditional on the study's assumption that new gas turbines act as reserves and dispatch only at prices above 500 €/MWh. Allowing them to participate freely in the energy market would materially increase fuel use; that sensitivity is retained in the full report.

5.6.3 Demand coverage at extremes

Alongside average outcomes, it is important to examine extreme conditions. It is often these peaks that, in practice, govern and dictate how the power system is dimensioned and designed. The ability of the system to handle extreme situations, such as unusually high demand or sudden generation outages, is crucial to ensure robust and stable operation. Extremes also increase the need for reserves, both in terms of generation capacity and storage, as well as on the capacity of the infrastructure to handle high load flows and potential bottlenecks.

To investigate this, the analysis considers demand coverage from domestic supply during the 1,000 worst hours across the 33 weather years. The worst hours have been defined by their lowest demand coverage. This provides a physical supply perspective (generation potential) that complements the cost-oriented trade analysis in Section 5.6.1. Generation potential represents available domestic supply, while realised generation (actual market dispatch in the model) shows the extent to which imports and demand-side flexibility substitute for domestic generation in these stressed hours.

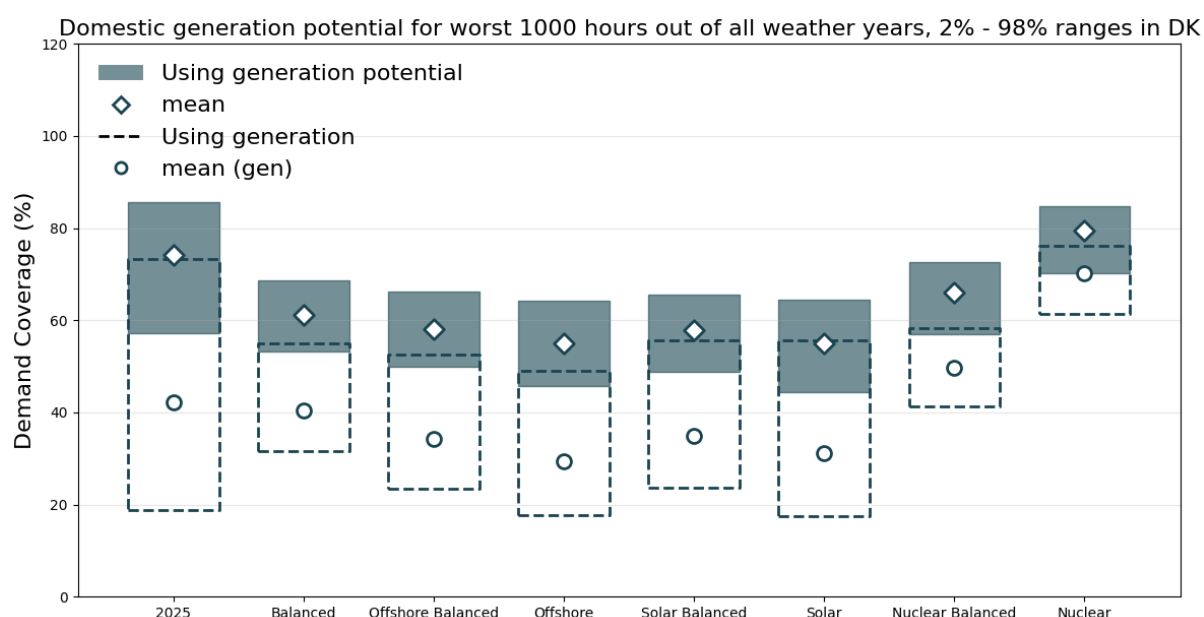


Figure 21. Demand coverage by realised generation and generation potential and their spread in Denmark during the worst 1000 hours across all weather years under different scenarios. The worst hours have been defined by their lowest demand coverage.

For the future scenarios, generation-potential demand coverage generally decreases relative to 2025, moving from 74% to 61% (-18%) for the Balanced scenario. The Solar and Offshore scenarios show the largest decrease with 55% (-26%) and the Nuclear Balanced scenario 66% (-11%) while the Nuclear scenario is the one exception to the trend with an increase to 80% (+7%). These results are a direct consequence of the installed dispatchable capacity in the different scenarios as presented in Figure 12.

Considering the realised generation, the results paint a slightly different picture. The 2025 system achieves a demand coverage of 42% which is very similar to the Balanced scenario of 40% (-4%). The Offshore scenario exhibits the lowest coverage of 30% (-30%) while the more nuclear-heavy scenarios show a clear increase to 50% (+18%) and 70% (+66%) in the Nuclear Balanced and Nuclear scenarios, respectively. Lower realised domestic coverage in the Offshore and Solar scenarios is enabled by greater demand-side flexibility and imports. The realised generation here reflects the results for import costs, see Section 5.6.1, reflecting Denmark's domestic supply contribution during periods of scarcity. The detailed import model and supporting trade outputs are retained in Section 5.7.1 and Appendix E of the full report.

5.7 Demand and flexibility scenario variations

The capacity expansion optimisation was investigated against two demand growth scenario variations, at 138 and 64 TWh, compared with 102 TWh in the Reference case, and two flexibility variations, presented in Section 4.2.2, to test the sensitivity of the results. Figure 22 presents the change in installed capacity for these scenario variations

when compared to the Balanced scenario. Additional demand and flexibility sensitivity results are provided in Section 5.8 and Figure 50 of the full report.

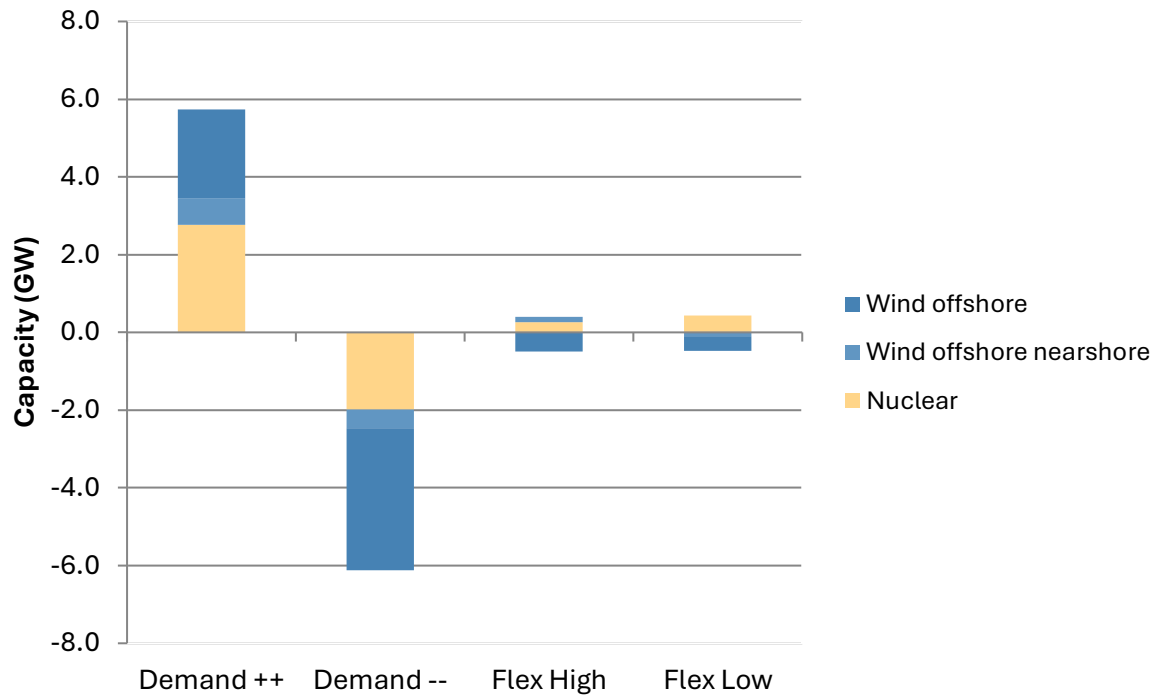


Figure 22. Change in installed capacity for scenario variations compared to the Balanced scenario.

When varying the flexibility, only small changes in the resulting mix are observed. Somewhat unexpectedly, both the low- and high-flexibility scenarios result in slightly more installed nuclear capacity. Lower flexibility reasonably increases the value for firm capacity. One possible explanation is that small increases in flexibility reduce the need for nuclear ramping and improve its capture rate relatively more than that of offshore wind.

Demand-growth variations have a considerably larger impact on the resulting generation mix. In the optimistic demand scenario, the increased demand is covered by a combination of offshore wind and nuclear, with a greater increase in nuclear, whose share in the generation mix rises from 17% to 26%. The opposite is observed for the conservative demand scenario, where the share of wind increases from 75% in the Balanced scenario to 83% while nuclear decreases to 6%.

Across these sensitivities, generation and capacity costs vary from -0.9% to +5.5% relative to the Balanced scenario, while average prices vary from -1.3% to +0.6%. The larger effect is therefore on the capacity mix rather than on the modelled average market price.

5.8 Model comparisons

An open-source PyPSA implementation was used as a cross-model check of the cGrid capacity-expansion results. Despite differences in model structure and dispatch assumptions, the comparison produces broadly similar system configurations. Detailed capacity, generation and dispatch comparisons are retained in the full report; the condensed version focuses here on the policy-relevant comparison with the Danish Energy Agency's EA/VTT study. Those cross-model results are reported in Sections 5.9.1–5.9.4 and Figures 51–59 of the full report.

5.8.1 Comparison to the EA study

As described in Section 2.2.2, the EA/VTT study and the present study ask related but different questions and use different modelling approaches. In the present study, only Danish capacity is optimised across scenarios while the pre-optimised neighbouring system is held fixed. EA/VTT co-optimises capacity across a wider geography and models both 2040 and 2050.

In the EA/VTT study, investment decisions between model years are myopic, meaning that each model year is optimised without anticipating later conditions. The present study instead evaluates a single 2050 end state. These choices make the two studies complementary: EA/VTT provides more pathway detail, while the present study explores a wider set of structurally different Danish end-state configurations.

Figure 23 compares the capacity mix in the EA study's SMR0_Bal scenario with the Offshore, Balanced and Nuclear scenarios in this study.

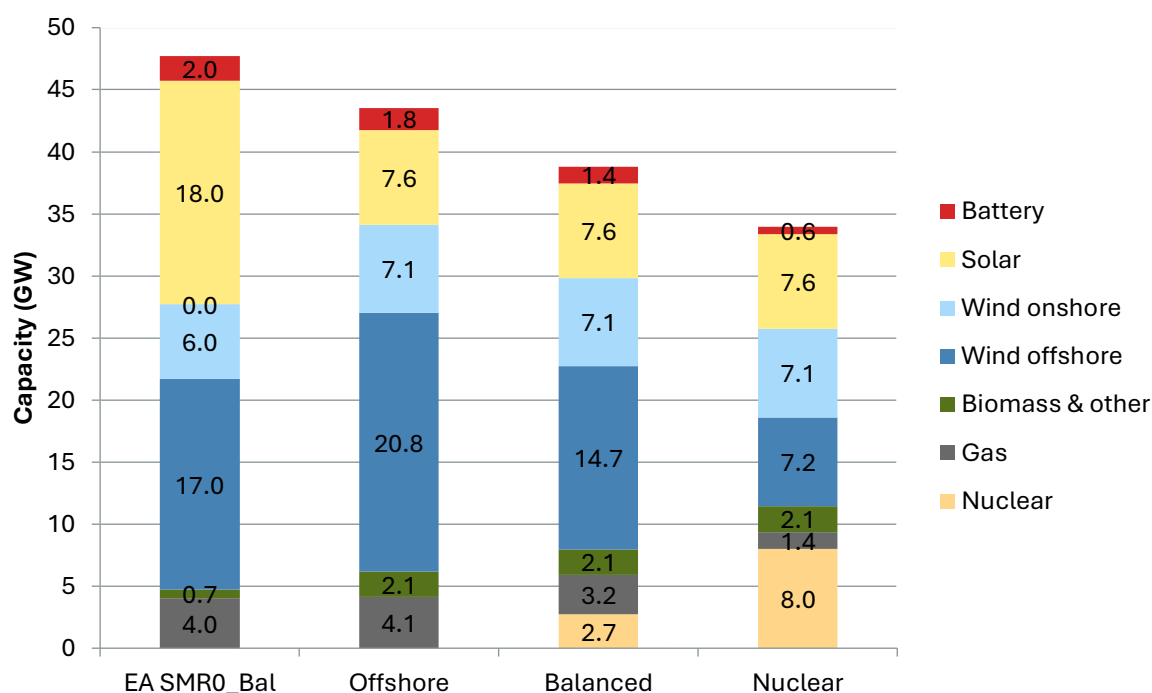


Figure 23. Installed capacity in the EA/VTT study compared with three scenarios from this study.

The EA scenario has a comparable offshore-wind build-out to the Offshore case in this report, but favours substantially more solar and has the lowest dispatchable capacity of the compared systems despite the largest overall capacity.

Table 5 compares average prices, offshore-wind capture prices and capture rates. EA/VTT uses weather year 2014, whereas this study uses 1991, which complicates a direct comparison. In the weather-year analysis used here⁴⁰, 1991 is the representative year and 2014 is the fifth most expensive weather year. The average capture price is largely determined by the LCOE of the marginal resource, for the EA and Offshore scenarios that is offshore wind and for the Balanced scenario that is nuclear.

As can be seen by comparing the 2025 values with the Balanced and Offshore scenarios, increasing penetration of wind into the energy system both lowers the capture price and capture rate. This is consistent with price cannibalisation: a large wind fleet experiences correlated weather, so output rises at similar times and depresses market prices during high-generation hours. The EA scenario does not show the same pattern: a large wind build-out is accompanied by a higher capture rate, suggesting less revenue cannibalisation, despite being the marginal resource and therefore setting prices in the hours it generates most. In the EA report, offshore wind runs at 4,800 full-load hours and has an LCOE of €55/MWh. If we assume that the model expands until wind reaches its

⁴⁰ Cox et al., (2026), Strategic capacity expansion planning in hydro-dominated power systems: Insights from the Nordics

profitability limit and the average electricity price in 2050 is €58, we get a capture rate $55/58 = 0.95$.

Table 5. Average market price, capture price and capture rate for offshore wind in weather year 1991. *EA SMR0_Bal is for weather year 2014.

	Average price	Capture price	Capture rate
2025	76	64	84%
EA SMR0_Bal*	58	55	95% (derived*)
Balanced (cGrid)	DK1: 78 DK2: 77	DK1: 60 DK2: 55	DK1: 78% DK2: 72%
Offshore (cGrid)	DK1: 71 DK2: 74	DK1: 48 DK2: 45	DK1: 68% DK2: 61%

* Estimated based on capture price divided by average price, inferred from the EA capacity expansion results where profitability requirement is included.

Differences in time horizon, capacity-expansion geography and weather-year treatment are summarised in [Table 2](#) and further differences, including grid reinforcement and foresight assumptions, are documented in Section 5.9.5 of the full report. The comparison should therefore be read as an explanation of why the results differ, not as a like-for-like model benchmark.

5.9 Grid upgrade costs

For electricity infrastructure upgrades, the study follows assumptions used by EA Energianalyse⁴¹ (Table 7 page 25 of their report). The calculation is used as a first-order proxy for incremental grid costs rather than a detailed network model.

Projected total grid-upgrade costs range from €1.2 billion in the Nuclear scenario to €2.3 billion in the Offshore scenario. Assuming a 40-year capital-recovery period and 6% WACC, annualised costs normalised to 102 TWh of demand are shown in [Figure 24](#). Within this proxy, larger build-outs of non-dispatchable capacity, often located farther from major demand centres, result in higher assigned grid-reinforcement costs. The calculation advantages scenarios that can use existing sites, because those sites are assumed to require less grid reinforcement. Under a conservative sensitivity in which dispatchable units are treated as “New thermal” using the EA/VTT assumptions (Table 7, p. 26), grid-upgrade costs increase by 13% on average, ranging from 7% for Solar to 22% for Nuclear. Relative to Balanced, the Offshore result is 28% higher and the Nuclear result is 31% lower.

⁴¹ Ea Energianalyse (2026), Effects and value of SMR technologies in the Danish energy system

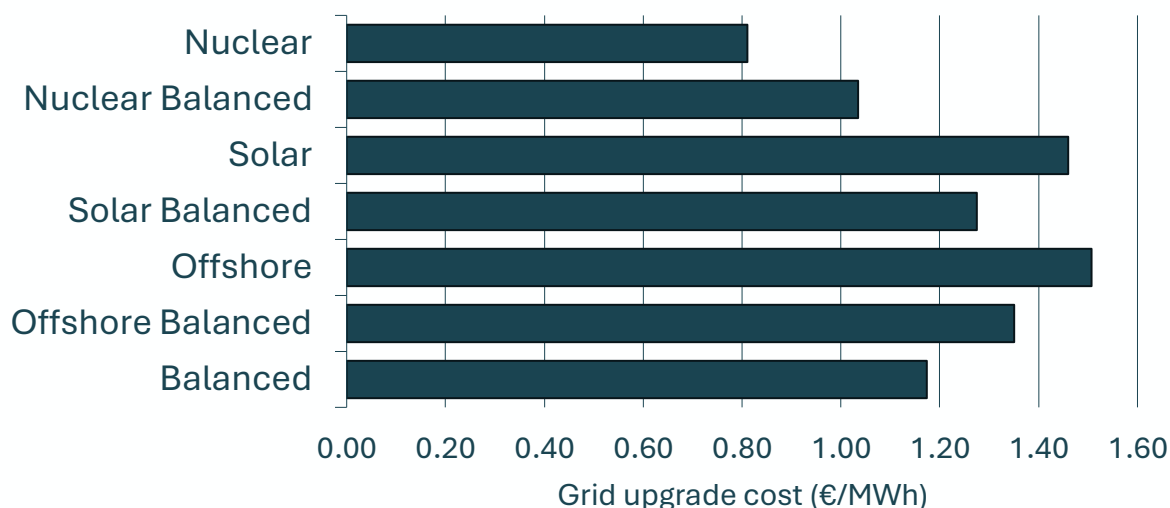


Figure 24. Annualised grid upgrade cost, normalised to total demand of 102 TWh, in each scenario.

Although these incremental grid costs are small relative to total generation and capacity costs, grid delivery can still constrain implementation because connection, permitting and public consultation have long lead times. Reusing existing sites and corridors can therefore reduce both cost and delivery risk. The calculation is a first-order proxy based on standard connection charges, not a detailed network model. The full methodology and brownfield-site screening are provided in Section 5.10 and Figures 62–63 of the full report.

6 Summary analysis

Section 6 brings together the quantitative results from Section 5 and considers the trade-offs most relevant when comparing the scenarios. The indicators do not constitute a complete assessment of Denmark's future power system, but they broaden the comparison beyond system cost to include self-sufficiency, market outcomes, environmental and resource impacts, and grid and operational considerations. The final part of the section discusses risks and dependencies that are not fully captured in the modelling.

6.1 Summary table – comparing scenarios

Table 6 brings together the thirteen indicators used in the study. Table 7 defines how each indicator is quantified and should be read alongside the matrix. The values should be read as a comparative dashboard rather than as a single ranking: several indicators involve policy judgements, and the relative importance assigned to them depends on Danish priorities. The profitability gap denotes the difference between generation and capacity costs and day-ahead market revenues aggregated across technologies.

Table 6. Compiled results across indicators of self-sufficiency, competitiveness, environmental and climate impacts, and grid and operational characteristics for Danish power-system scenarios in 2050.

Parameter/Scenario	Balanced	Offshore Balanced	Offshore	Solar Balanced	Solar	Nuclear Balanced	Nuclear
Import cost (€/MWh) vs 2025	1.8 (-60%)	4.3 (-5%)	9.0 (+99%)	5.5 (+22%)	9.8 (+120%)	-3.3 (-170%)	-11.5 (-350%)
Gas consumption (TWh) vs 2025	0.6 (-87%)	0.8 (-84%)	1.0 (-79%)	0.8 (-83%)	1.1 (-77%)	0.4 (-92%)	0.1 (-98%)
Demand coverage (%) vs 2025	61 (-18%)	58 (-22%)	55 (-26%)	58 (-22%)	55 (-26%)	66 (-11%)	80 (+7%)
System cost incl. imports (€/MWh) vs Balanced	71 (0%)	73 (+3%)	78 (+9%)	71 (0%)	73 (+2%)	70 (-2%)	69 (-3%)
Costs escalation (€/MWh) vs Balanced	30 (0%)	28 (-6%)	26 (-11%)	27 (-10%)	24 (-18%)	33 (+12%)	40 (+35%)
Average price (€/MWh) vs 2025	78 (-5%)	76 (-8%)	73 (-12%)	81 (-2%)	82 (0%)	76 (-8%)	72 (-13%)
Price volatility vs Balanced	0%	2%	-2%	5%	8%	-3%	-8%
Profitability gap (€/MWh)	-1.2	4.8	12.7	-1.6	-1.0	-1.5	0.9
Emissions (gCO ₂ eq/kWh) vs 2025	23.1 (-82%)	23.2 (-82%)	23.2 (-82%)	22.9 (-82%)	23.2 (-82%)	23.2 (-82%)	23.4 (-82%)
Minerals use (kt) vs Balanced	292 (0%)	318 (+9%)	341 (+17%)	304 (+4%)	324 (+11%)	275 (-6%)	241 (-18%)
Land use (km ² · 10 ³)	1.1	1.1	1.0	1.1	1.1	1.1	1.1
Grid upgrade cost (€/MWh) vs Balanced	1.2 (0%)	1.4 (+15%)	1.5 (+28%)	1.3 (+9%)	1.5 (+24%)	1.0 (-12%)	0.8 (-31%)
Dispatchable capacity (GW) vs Balanced	8.0 (0%)	7.0 (-12%)	6.2 (-22%)	7.1 (-11%)	6.3 (-21%)	9.0 (+13%)	11.4 (+43%)

Table 7. Description of quantified parameters in [Table 6](#).

Parameter	Description
Import cost (€/MWh) vs 2025	Represents net import cost from Danish power imports normalised to demand in the model for weather year 1991 compared to 2025 power system reference.
Gas consumption (TWh) vs 2025	Represents gas consumption (thermal energy value) of natural gas-fired power plants in the model as average of 33 weather years compared to 2025 power system reference.
Demand coverage (%) vs 2025	Represents demand coverage by generation potential (installed supply capacity) for the 1000 worst hours by supply-demand balance and compared to the 2025 power system reference.
System cost incl. imports (€/MWh) vs Balanced	Represents absolute generation and capacity costs normalised to annual demand when using reference technology cost assumptions compared to the Balanced scenario. Import costs/export revenues are included. See also Section 5.4 .
Costs escalation (€/MWh) vs Balanced	Increase in technology costs (€/MWh, normalised to annual demand) when the scenario's own capacity mix is costed at Conservative-2 instead of Reference technology costs. The capacity mix and dispatch are unchanged, and import and fuel costs are excluded. The percentage compares this increase with Balanced. See also Section 5.4 .
Average price (€/MWh) vs 2025	Represents the average Danish electricity price across the 33 weather years, compared with the corresponding 2025 power-system reference. See Section 5.5.1 .
Price volatility vs Balanced	Represents a composite measure based on the quarterly-price interquartile range (25th–75th percentiles) and the 1st–99th percentile range, compared with the Balanced scenario. It captures weather-driven variation only and excludes variation in fuel prices. See Section 5.5.2 .
Profitability gap (€/MWh)	Difference between generation and capacity costs and day-ahead market revenues for Reference technology cost scenario assumptions aggregated across all technologies for each scenario. The sign convention is the inverse of the profitability values shown in Figure 16 . See also Section 5.5.3 .
Emissions (gCO₂eq/kWh) vs 2025	Values for Danish generation (production-based, imports excluded) normalised to annual demand are given based on 735 for gas OC, about 230 for biomass, 48 for solar, 12 for nuclear, 12 for offshore wind and 11 for onshore wind in g CO ₂ eq/kWh. 2024 value has been assumed 130 g CO ₂ eq/kWh according to ElectricityMaps .
Minerals use (kt) vs Balanced	Calculated based on installed production capacity for different technologies and IEA (2022) compared to the Balanced scenario.
Land use (km² · 10³)	Calculated using 43 m ² /MWh for onshore wind, 21 m ² /MWh for utility-scale solar, 1 m ² /MWh for nuclear and 0.8 m ² /MWh for gas turbines. Biomass, residential solar and the sea area used by offshore wind are excluded.
Grid upgrade cost (€/MWh) vs Balanced	Calculation based on estimated investment cost for grid expansion relating to new supply capacity, incorporating brownfield vs greenfield sites for thermal power plants compared to the Balanced scenario.
Dispatchable capacity (GW) vs Balanced	Calculation based on installed capacity of biomass CHP, nuclear power and gas turbines (batteries excluded) compared to the Balanced scenario.

All scenarios achieve similarly low lifecycle emissions, at around 23 gCO₂eq/kWh and

approximately 82% below the 2025 reference, because fossil gas is used only to a limited extent in a reserve role. Land-use differences are also small within the metric used here, since all directions build onshore wind to the modelled limit and offshore wind is excluded from the land-use calculation. Offshore wind nevertheless expands substantially in all directions, and associated sea-area, permitting and stakeholder constraints are outside the quantified land-use metric. The following subsections compare the three technology directions.

6.1.1 Solar direction

Relative to the Balanced scenario, the Solar direction combines less dispatchable capacity with more short-duration demand-side flexibility. Even as solar and battery costs become progressively more favourable, utility-scale solar expands only marginally, reflecting its low modelled market profitability under the assumed Danish and neighbouring-system conditions. The full Solar scenario is therefore analytically useful not simply as a 'solar future', but as a nuclear-excluded comparison in which offshore wind remains at reference cost. It is not a pure 'Balanced without nuclear' counterfactual, because solar and battery costs and short-duration flexibility are made more favourable. The resulting system performs worse than Balanced on import cost, demand coverage, average price and weather-driven price volatility, while performing better on cost escalation and the system-aggregated profitability gap. Critical-mineral use, estimated grid-upgrade costs and dispatchable capacity are broadly similar to the Offshore direction.

6.1.2 Offshore direction

The Offshore direction combines larger offshore-wind fleets with greater long-duration demand-side flexibility. Relative to Balanced, it has lower domestic demand coverage in extreme hours, higher import costs, higher critical-mineral use and higher estimated grid-upgrade costs. Reference-case system costs are higher, while exposure to technology-cost escalation is lower. Average prices and weather-driven volatility remain broadly comparable to Balanced. Its principal economic vulnerability is the profitability gap created by revenue cannibalisation as the wind fleet expands.

6.1.3 Nuclear direction

The Nuclear direction, with larger shares of clean firm generation, improves self-sufficiency: import costs fall, demand coverage in extreme hours rises, and gas consumption reaches the lowest levels modelled. Average prices and weather-driven volatility are also lower than in Balanced, while the system-aggregated profitability gap remains small. The principal downside is greater exposure to cost escalation, reflecting uncertainty in nuclear capital costs. The Nuclear scenarios also require less critical-material use and lower estimated grid-upgrade costs, while providing more dispatchable capacity.

6.1.4 Risk-benefit trade-offs

Across the three directions, the trade-off is therefore less a simple 'cheap versus expensive' comparison than a question of where uncertainty is concentrated. The Solar direction provides a useful boundary case: even with favourable solar and battery assumptions, the model adds only limited utility-scale solar and the full scenario becomes more dependent on wind, flexibility and exchange once nuclear is excluded. The Offshore direction concentrates more uncertainty on the revenue side: costs escalate less under conservative technology assumptions, but high deployment depresses the revenues captured by wind. The Nuclear direction concentrates more uncertainty on the cost side: capital cost and project delivery drive the widest cost-escalation range. Its small system-aggregated profitability gap does not mean nuclear projects would be financeable without support; at actor level, directed risk-sharing or support may still be required under reference cost assumptions. The Nuclear direction also has lower critical-mineral demand, lower estimated grid-upgrade costs and more dispatchable capacity than Balanced. These indicators point to different system characteristics, but the model does not directly quantify frequency stability, black-start capability or other ancillary services, so they should not be interpreted as a complete operational-security assessment.

6.2 Implementation considerations

The quantitative results do not capture all implementation considerations. The three issues below are especially relevant when translating the scenario comparison into policy.

Both the Nuclear and Offshore directions depend on favourable industrial development and stable policy frameworks, but Denmark starts from different positions. Offshore wind builds on an established Danish ecosystem, while nuclear would require regulatory, supply-chain and workforce capabilities. Early nuclear deployment may require public risk-sharing for construction and financing risk; offshore wind may require revenue stabilisation that explicitly addresses cannibalisation.

Denmark's interconnection makes prices and producer revenues dependent on European developments. More domestic firm generation reduces reliance on imports during stressed hours, while a more wind-heavy system depends more on neighbouring dispatchable generation when wind output is low. Interconnection remains valuable, but the degree of reliance on neighbouring investment decisions is a strategic choice.

Demand growth and timing also matter. Nuclear plays a larger role in the high-demand sensitivity and a smaller role in the low-demand case. Existing offshore capabilities make additional wind more plausible in the near term, while nuclear is primarily a longer-term option that requires early capability development. Hydrogen flexibility reduces adequacy needs in the Offshore cases but does not materially change the overall comparison.

6.3 Conclusion

All modelled directions heavily rely on wind power. The central difference is what complements the wind fleet.

The Nuclear direction has the lowest Reference cost among the Offshore, Balanced and Nuclear cases and provides the strongest self-sufficiency outcomes: higher domestic demand coverage in stressed hours, lower gas use and import costs, lower weather-driven volatility, lower critical-material demand and estimated grid-upgrade costs, and more dispatchable capacity. Its principal downside is the greatest exposure to capital-cost escalation and project-delivery risk.

The Offshore direction can build on an established Danish industry and has lower exposure to technology-cost escalation. At very high deployment, however, it has higher import costs, lower domestic demand coverage, greater critical-material and grid requirements, and the largest system-wide profitability gap because correlated wind output depresses captured market revenues.

Demand growth, timing and the surrounding European system affect the relative value of the different directions. Additional offshore wind is more readily deployable in the near term, while nuclear is a longer-term option that requires early development of regulation, skills and institutional capacity. Both directions may require state involvement, but for different reasons and to manage different risks.

The objective of this work has been to provide a transparent, technology-neutral, and analytically grounded foundation for policy discussion on Denmark's long-term energy system development. The study therefore does not identify a single optimal configuration. Instead, it shows that the different system directions create materially different capabilities, dependencies and risk exposures. A diversified configuration such as the Balanced scenario can distribute these risks rather than concentrating them in either direction, while also capturing less of the upside if one develops more favourably. The choice and prioritisation of these directions remain with decision-makers.

The intended contribution is to move the policy conversation away from a binary choice between technologies and towards a comparison of what different system configurations require, what capabilities they provide and how their risks and dependencies are distributed.



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