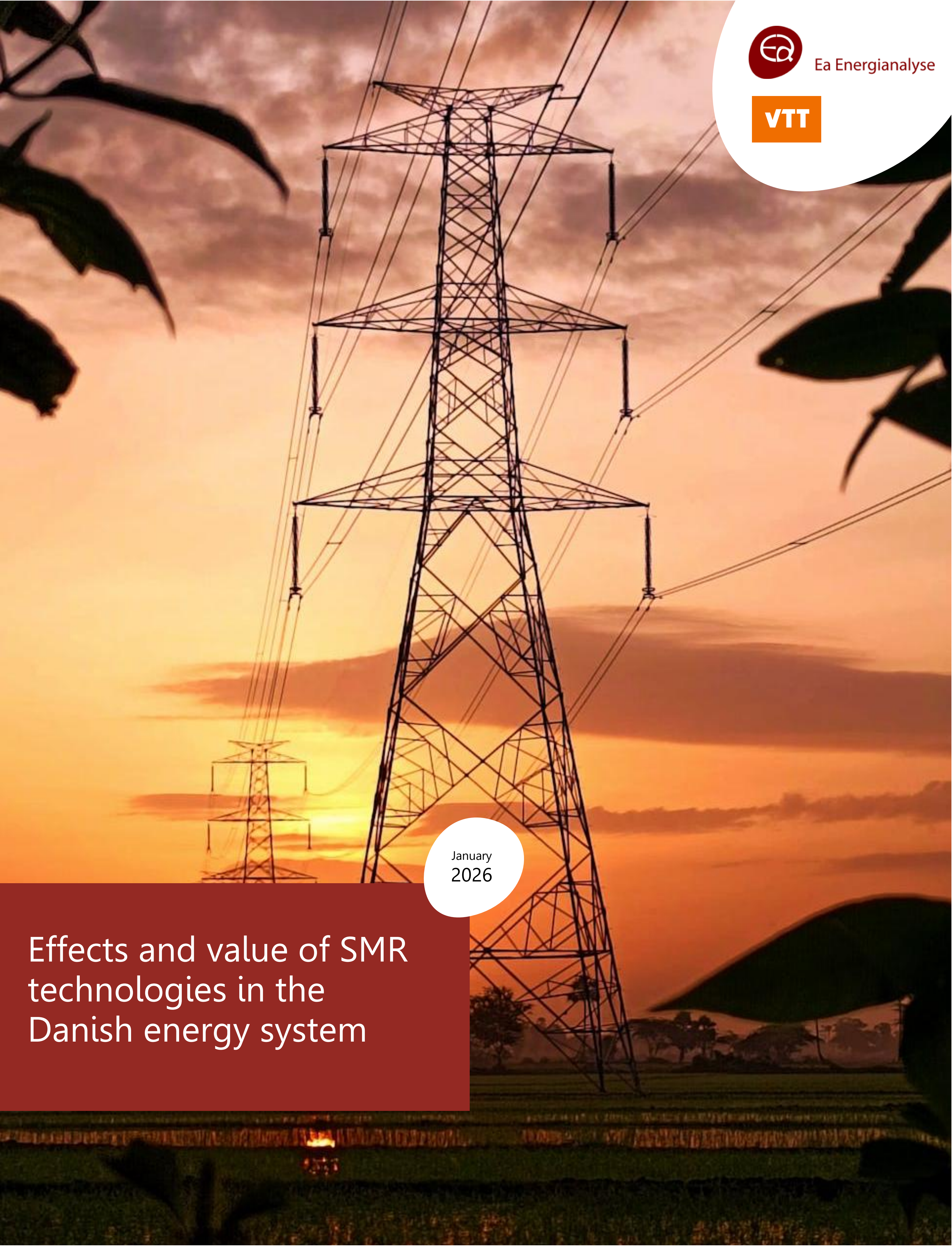

January 2026

Effects and value of SMR technologies in the Danish energy system

Task 2 report in the project "Analysis of SMR technologies in Denmark"

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Executive summary

The Danish Energy Agency has asked Ea Energy Analyses to investigate the possibilities and consequences of integrating the compact nuclear reactor technology called Small Modular Reactor technologies (SMR technologies) into the Danish energy system. The project covers two subtasks: 1) a technical analysis of SMR technologies in a Danish context 2) and a system analysis that will assess the effects and value of integrating SMR into the Danish energy system. This report constitutes the reporting of the system analysis part.

Methodology

The energy system model, Balmorel, has been used for the analysis. Balmorel is a basic partial equilibrium model based on economic optimisation. The model uses input in the form of demand projections, fuel and CO_2 prices, technology costs and characteristics, renewable energy resources, energy and climate policies and other significant parameters. The model minimises the total system costs and as part of this optimisation, the model points to feasible investments in capacities – for production, transmission and storage – as well as the optimal operation of the system over the year. The model thus performs an overall economic optimisation of the energy system.

A number of **main scenarios** have been set up to analyse the effects and value of SMR in the energy system (see Table 1). As shown, different levels of SMR capacity in Denmark is assumed implemented in the scenarios. In the SMR600 scenarios, 600 MWe of SMR as combined heat and power (CHP) is assumed implemented, and in the SMR1500 scenarios, 900 MWe of additional SMR capacity as power-only is assumed installed.

The scenarios also reflect different conditions regarding fuel & CO_2-prices, and development in electricity demand and renewable energy in Danmark:

- **Bal**: A development where the energy system for the European energy system including Denmark is based on economic optimisation. The consultant's best assessment of fuel and CO_2 prices as well as Denmark's electricity consumption is used.
- **KF25**: Assumptions from Climate Status and Projection 2025 (KF25)[1], which represent a frozen policy development, are assumed regarding electricity capacity development and electricity consumption for Denmark (fuel and CO_2 prices from AF25 are assumed).
- **AF25**: Assumptions from Analysis assumptions for Energinet 2025[2] (AF25) are applied regarding electricity capacity development for Denmark and electricity consumption as well as fuel and CO_2 prices.

In the Bal scenarios, the effects of the assumed SMR build-out on capacity investments in the system is based on optimisation. In contrast, in the KF25 scenarios, the SMR implementation is assumed to displace

[1] https://www.kefm.dk/klima/klimastatus-og-fremskrivning/klimastatus-og-fremskrivning-2025

[2] https://ens.dk/analyser-og-statistik/analyseforudsaetninger-til-energinet

solar PV expansion in Denmark, and in the AF25 scenarios, the SMR implementation is assumed to displace expansion of mainly offshore wind power and secondarily solar PV in Denmark.

Table 1. Overview of the main scenarios examined in the analysis. The scenarios have different levels of SMR implementation in Denmark and have been examined under different framework conditions. This gives a total of 9 different main scenarios which are here indicated by their name ("SMR0_Bal", "SMR0_KF25 etc.").

	Framework conditions		
	Bal	**KF25**	**AF25**
No SMR in Denmark	SMR0_Bal	SMR0_KF25	SMR0_AF25
600 MWe SMR in Denmark	SMR600_Bal	SMR600_KF25	SMR600_AF25
1500 MWe SMR in Denmark (600 MWe as CHP*, 900 MW-e as power-only)	SMR1500_Bal	SMR1500_KF25	SMR1500_AF25

*CHP: Combined Heat and Power. In the model: 300 MWe of the SMR CHP units is assumed placed in Copenhagen and the other 300 MWe assumed placed in Aarhus.
KF25: Climate status and projection 2025. AF25: Analysis assumptions for Energinet.

In addition, European investment scenarios (**EURSMR-scenarios**) are set up where the optimisation model is given the option to invest in the SMR technology in all countries in the modelled European system. In Denmark, the model is given the option to invest in both SMR CHP and SMR power-only capacity, while in the other European countries, only SMR power-only units are made possible for investment.

In the EURSMR scenarios, the feasibility of SMR investments is investigated under three different SMR cost development paths: a Pessimistic, Optimistic and a Central one. The cost development paths are based on the technical analysis within the SMR project.

Reference development
The modelling of the European energy systems shows a doubling of the total electricity demand towards 2050 as a result of considerable electrification. This comprises electricity for electric vehicles, hydrogen production (power-to-X), classic electricity demand, and electricity consumption for data centers, individual heating, and district heating. The demand increase is mainly expected to be covered by wind power and solar PV.

Overall, in 2050, the reference development without SMR point to a renewable energy generation share in the modelled European system of around 85% in 2050 where wind power and solar PV alone account for around 75%. For the case of the Danish energy system, the reference scenarios point to an even higher share of wind power and solar PV, reaching 94-98% in 2050.

The large amount of variable electricity generation from wind power and solar PV is balanced by the transmission system, a significant amount of batteries, power-to-X via hydrogen storages, electric vehicles via intelligent charging, and flexibility in the heating sector and backup power plants.

Effects on the power system
The modelling results show that power generation from an assumed build-out of SMR in Denmark will

mainly displace electricity generation from offshore wind and solar PV (see Figure 1). In the AF25 and KF25 scenarios, the displaced electricity generation happens predominantly in Denmark, as this lies in the definition of these scenarios. In the Bal scenario, where capacity development in Denmark is based on optimisation, between 70%-75% of the displaced generation takes place in Denmark and the rest in other parts of the European energy system in 2050. In the period before 2050, up to 50% of displacement happens outside of Denmark.

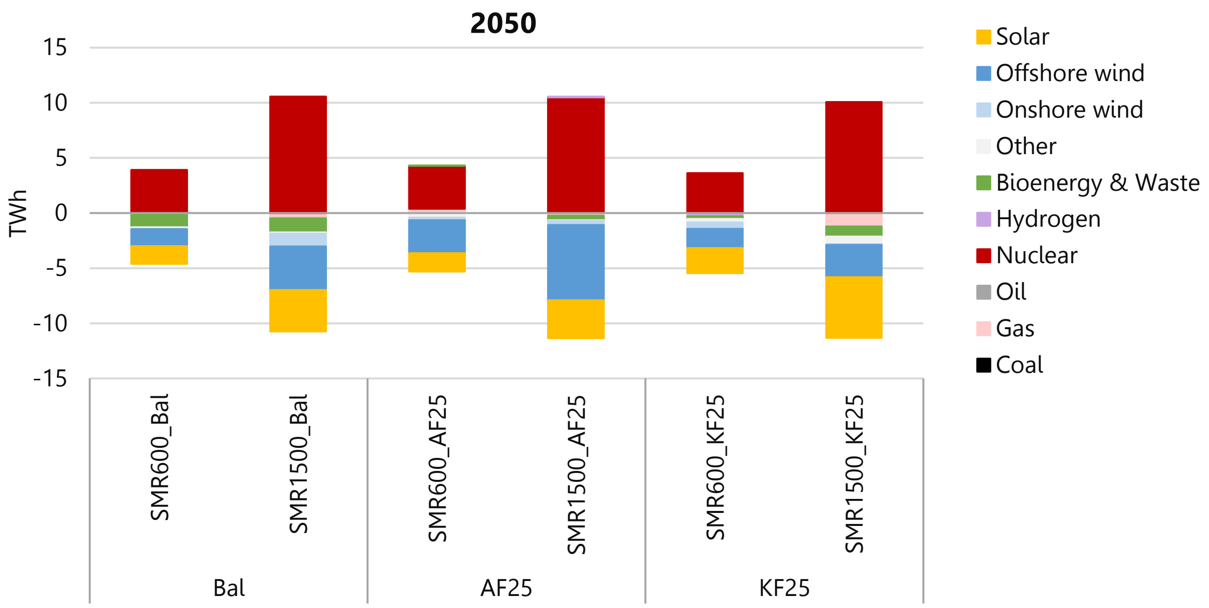


Figure 1. Change in electricity generation in 2050 in the modelled European energy system as a result of the implementation of SMR in Denmark. The figure shows changes compared to the given reference scenario without SMR.

Across all scenarios, the implementation of SMR in Denmark displaces an investment in gas fired capacity of a magnitude similar to the SMR power capacity, since SMR units are assumed to fulfil part of the capacity requirements in Denmark.

Effects on district heating

In all scenarios, 600 MWe of SMR capacity is assumed implemented as CHP units, distributed on 300 MWe (400 MW heat) in DK1 and 300 MWe (400 MW heat) in DK2. The SMR plants displace investments in biomass fired units and heat pumps, and in some cases also electric boilers. In total, the assumed SMR CHP implementation displaces a heat capacity (700-900 MW heat) that is approximately equivalent to the installed SMR heat capacity (800 MW heat). The SMR CHP plants displace heat generation from mainly biomass fired plants and heat pumps and to a modest extent also electric boilers.

Impact on trade balance and electricity import dependency

The installation of SMR improves Denmark's electricity trade balance on annual basis (increased net export or reduced import depending on scenario and year). The fact that the SMR implementation partly displaces heat pumps also contributes to the improved trade balance as the electricity consumption is also reduced.

Nevertheless, the modelling suggests that the SMR implementation results in a higher amount of hours with electricity import dependency (from 360 hours to 380-410 hours in the Bal scenarios). The explanation is that the total amount of firm dispatchable capacity is the same with and without SMR, but the amount of wind and solar capacity is lower. Therefore, the renewable energy generation in Denmark is lower, and the residual electricity demand thus higher, which yields a higher amount of hours with import dependency.

Impact on electricity prices

In the Bal scenarios, where capacities in Denmark are balanced, the average whole-sale electricity price in Denmark is moderately reduced in 2050; with around 0.4-1.0 €/MWh, as a result of the SMR implementation. In the AF25 and KF25 scenarios, the electricity price reduction is up to 3.7 €/MWh in 2050. An electricity price reduction in the model is expected, since SMR, which comprises a given power capacity with low variable generation costs, is assumed implemented. To which extent the illustrated price reduction would materialise into lower electricity price for the consumer, depends on the cost of SMR, and how a potential need for economic support is financed.

SMR revenue streams

The total revenue for the SMR owner is estimated to be around 83-138 € /MWh-e in 2040 and 2050 for the different scenarios. The value of electricity generation from SMR comprises the largest part of the total revenue (57-78%), but the heat revenue is also significant (12-33%) as well as the capacity revenue (8-12 %).

The high heat revenue potential means that the total revenue of SMR units is significantly higher if implemented as CHP plants instead of as power-only plants. In order for the capacity value to be reflected as a revenue stream, a capacity mechanism needs to be in place, which is not currently the case in Denmark.

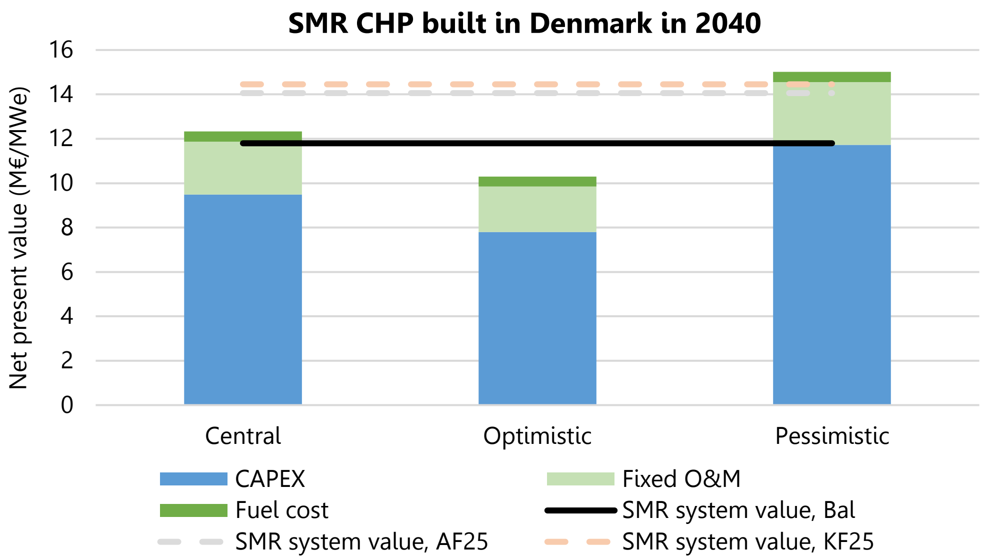
Impact on system cost

Results show a reduction of system cost in the integrated European energy system, excluding the cost of SMR. The cost reductions are mainly comprised by CAPEX savings on production and storage units, fuel and CO_2 costs, and O&M costs. The CAPEX saving is mainly comprised by displaced investments in solar PV, wind power, gas fired units, and biomass fired units. Almost all cost reductions take place in the Danish energy system, when taking the economic benefits of electricity trade into account (part of the electricity generation from SMR is exported).

The stakeholders obtaining the largest part of the system benefit is the SMR owner, who receives income from electricity sales, heat sales, and capacity market value (assuming a proper capacity market is in place). The second largest part of the system benefit is received by the electricity consumers in the form of lower wholesale electricity prices. Whether or not the gross benefits for different stakeholders result in net benefits depend on the cost of SMR and the potential financing mechanisms.

Feasibility of SMR in the Danish energy system

The feasibility of SMR from a system perspective is investigated by comparing the system value of SMR in Denmark with different estimated cost development paths for SMR (see Figure 2). It must be emphasised that estimates of future SMR investment costs are still very uncertain. More certain estimates based on actual data can be expected in 10-15 years (see the technical review report).



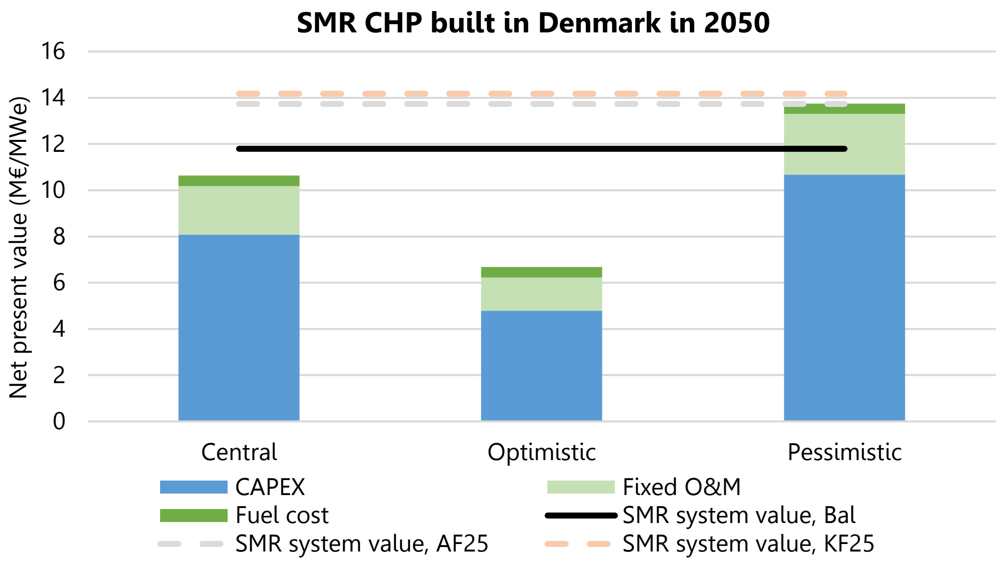


Figure 2. SMR system value vs. cost of implementing SMR as CHP in Denmark expressed in the net present value per MW-e. The SMR cost is given for the three different technology development paths (Central, Optimistic, and Pessimistic). The system value is extracted from the SMR600_Bal scenario where 600 MWe is assumed built as CHP in Denmark.

The Bal scenario results show that building SMR as CHP in Denmark in 2050 is feasible at both the Optimistic and the Central SMR cost development path (the value is higher than the cost). However, in 2040, it is only feasible in the Optimistic case and not far from being feasible in the Central cost development path. This shows that integrating SMR as CHP in Denmark in 2050 could potentially be attractive from a system perspective, if the technology is rolled out on a larger scale and costs are brought down sufficiently[3].

The Bal scenarios indicate that SMR as power-only in Denmark is not feasible in 2040, and in 2050, it is only feasible at the Optimistic cost development. As such the results illustrate that an important precondition in potentially achieving feasibility of an SMR integration in Denmark towards 2050, is to design the integration as CHP capacity, not as power-only.

The system value of both SMR CHP and SMR as power only is higher in the AF25 and KF25 scenarios, suggesting feasibility of CHP in the Central scenario already in 2040 and feasibility of power-only in 2050 in both the Central and Optimistic cost development path. In AF25 and KF25, the build-out of production capacity in Denmark is included as an assumption. This method results in significantly higher energy system costs than in the Bal scenario. Therefore, more costs are saved by changing the system and saved costs are precisely the definition of system value. In addition, fuel and CO_2 prices are higher, which also contributes to a higher value of SMR plants, especially in the KF-scenarios, which show higher electricity prices in Denmark.

European SMR investment scenarios

The optimisations where SMR is included as an investment option in the all modelled European countries, point to a feasible SMR CHP investment in Denmark of around 500 MW (in DK2) if the Central cost development materialises, and 1400 GWe (300 MWe in DK1 and 1109 MWe in DK2) if the Optimistic cost development is achieved. This confirms that the CHP-option is attractive (if feasible), and that the economy of deployment of SMR-CHP in Denmark is not crucially influenced by the deployment of SMR in Europe.

In the rest of Europe, the optimisation suggests an expansion of around 8.5 GW SMR as power-only towards 2050 at the Central cost development. This represents a rather limited expansion compared to the existing/planned nuclear power capacity in 2050 in the modelled European countries of around 100 GW. However, at the Optimistic cost development, the optimisation points to a European SMR investment of around 100 GW towards 2050, corresponding to a doubling of the nuclear power capacity. The results show, that the SMR technology need significant cost reductions if it is to reduce European power production cost.

3 The Central cost development scenario assumes a build out of 30 GW SMR in the advanced economies towards 2050 and a learning rate of 10%.

1. Introduction

The Danish Energy Agency has initiated an analysis to identify the possibilities and consequences of integrating the compact nuclear reactor technology called Small Modular Reactor technologies (SMR technologies) into the Danish energy system. SMR technologies are smaller than traditional nuclear power plants and are modular, so that SMR plants can be manufactured and transported fully assembled.

The analysis includes two subtasks:

- A **technical analysis** of SMR technologies in a Danish context.
- An **energy system analysis** that will assess the effects and value of integrating SMR into the Danish energy system.

This report constitutes the reporting of the energy system analysis itself.

The system analysis assesses how an integration of SMR in the Danish energy system towards 2050 will affect:

- Renewable energy expansion in Denmark and Europe
- Electricity generation in Denmark and Europe
- District heating capacity and production in Denmark
- The electricity price level in Denmark and the electricity price duration curve
- Technology-weighted electricity prices for wind power and solar PV as an expression of how SMR affects the economics of these technologies
- Electricity and hydrogen trade balance for Denmark
- Transmission expansion (and congestion revenue)
- Total system costs

The system value of SMR is identified as the change in total system costs (where the cost of SMR is excluded). To investigate the feasibility of SMR from a system perspective, the estimated system value of SMR is compared to different potential cost levels of the SMR technology. Moreover, based on this comparison, the potential need for government support for the SMR technology in Denmark is evaluated.

As a supplement to the economic analysis, the SMR revenue streams are also investigated.

The methodology behind the energy system analysis is described in Chapter 2. All economic data in the

report are expressed in €2025 (i.e. fixed prices).

2. Methodology and scenarios

2.1. The energy model applied

The Balmorel energy system model has been used to assess the system effects and value of SMR. The following section describes the model's logic and methodologies. The scenario framework is described in section 2.2 and 2.3, while the specific assumptions and ways to evaluate the value of SMR's are described in section 2.4 and 2.5.

Balmorel is a basic partial equilibrium model based on economic optimisation. The model uses input in the form of demand trends, fuel and CO_2 prices, technology costs and characteristics, renewable energy resources, energy and climate policies and other significant parameters. The model minimises the total system costs and as part of this optimisation, the model points to the most advantageous investments in capacities – for production, transmission and storage – as well as the optimal operation of the system over the year. The model thus performs an overall economic optimisation of the energy system. The operation optimisation corresponds to the merit-order methodology in the electricity market, where the cheapest production units are selected first. A wide range of results can be extracted from the model, such as capacities and production distributed by technologies/fuels, electricity prices, CO_2 emissions and system costs, etc. The overall principle of the Balmorel model is illustrated in Figure 3.

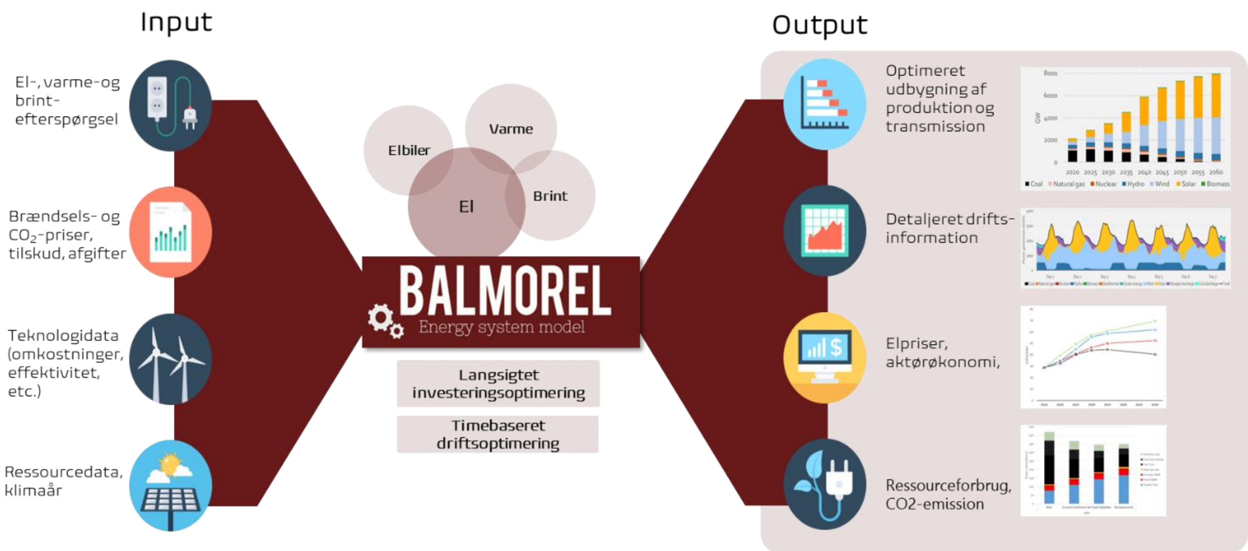


Figure 3. Overall structure of the energy system model used, Balmorel.

Ea Energy Analyses uses and develops different versions of Balmorel, for different countries/regions in the world and different adaptations of functionalities and level of detail. In the SMR analysis, the European

Balmorel base model is used, which represents the European market with regions that are close to the actual bidding zone boundaries, and also includes representation of several offshore wind regions. The European Balmorel model covers most of Europe, including the Nordic countries, the Baltic countries, Germany, Poland, the Czech Republic, Austria, Luxembourg, Italy, Switzerland, France, Belgium, the Netherlands, the United Kingdom, Spain and Portugal (see Figure 4).

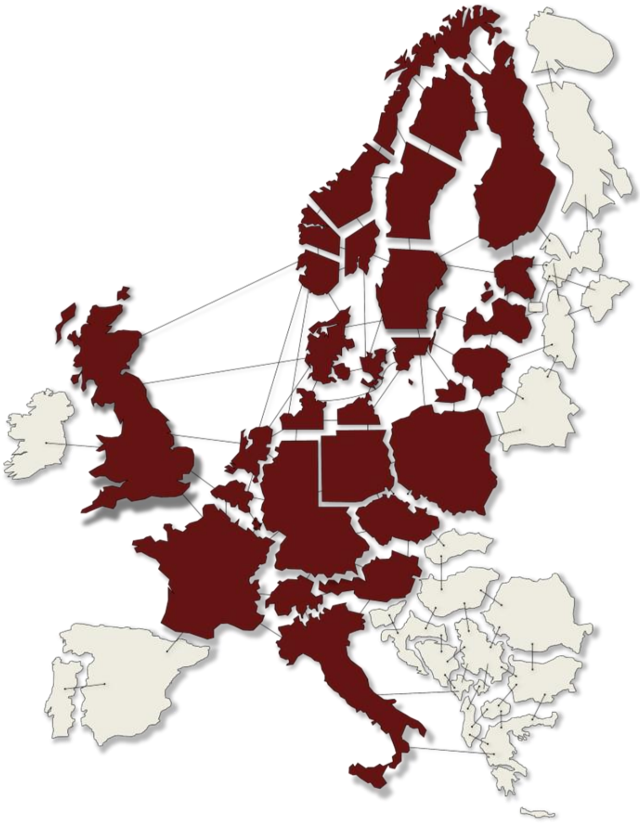


Figure 4. Illustration of the European countries and regions included in the energy model (the dark red markings). As shown, some countries in the model are divided into several regions. For Germany this reflects internal bottlenecks in the transmission system and for Denmark, Norway and Sweden it also reflects the specific bidding zones in the electricity market.

Technology options

With regard to possible investments in new production units in the model – e.g. onshore/offshore wind power, solar PV, gas turbines, biomass CHP plants, heat pumps, and batteries - technical and economic data for technologies (efficiency, technical lifetime, investment costs as well as fixed and variable operation and maintenance, etc.) are used, which are generally based on technology catalogues published by the Danish Energy Agency [4]. The technology catalogues constitute a uniform, generally accepted and updated basis for planning work and assessments within the energy sector and are widely used internationally. As part of the validation process behind the catalogues, the technology data has been subject to public consultation

[4] https://ens.dk/en/analyser-og-statistik/teknologikataloger .

among experts in the given field. The data used takes into account gradual technological improvements up to 2050.

In the optimisation, for each simulation year, total system costs are minimised, where all investment costs are annualised. A weighted average cost of capital (WACC) of 6 % (real rate) is applied. A lifetime of 25 years is generally applied in for model generated investments in production and storage units (e.g. wind power, solar PV, thermal production units, and storages). However, a lifetime of 40 years is applied for SMR technologies due to their longer lifetime[5]. The lifetime applied is based on considering both the technical lifetimes and economic lifetimes, i.e. a typical investment horizon. For infrastructure projects, i.e. power and hydrogen transmission, a lifetime of 40 years is assumed in the model.

*Table 2. Cost assumptions for selected key technologies in 2050. * LCOE for gas turbines includes cost for fuel and CO_2. Additional Danish CO_2-tax is not included, which would add cost by 30 €/MWh. ** Land lease incl. in O&M corresponding to approx. 2000 €/ha/year*

Technology (2050)	Technology investment M€/MW	Connection cost M€/MW	Grid reinforcements M€/MW	Total Inv. €/MW	Total O&M €/MW	FLH (hours)	LCOE €/MWh
Offshore AC (30-40m, 30 km)	1.8	0.9	0.08	2.8	0.05	4,800	55
Offshore DC (50-60m, 120 km)	2.1	1.4	0.08	3.5	0.05	5,000	65
Onshore	1.3	0.0	0.16	1.4	0.03	3,700	38
Solar PV**	0.2	0.0	0.12	0.4	0.01	1,100	38
Gas turbines, 1000 FLH	0.6	incl. tech inv.	0.03	0.6	0.02	1,000	155*
Gas turbines, 350 FLH	0.6	incl. tech inv.	0.03	0.6	0.02	350	279*
SMR	6.9	incl. in tech inv.	0 / 0.03	6.9	0.17	7,709	88

Energy and climate policies

National energy climate policies are implemented in the model where relevant, e.g. regarding phase out of coal power. However, CO_2-reduction targets for Europe as are not implemented in the model, such as a net zero emission target for 2050. Instead, the expected CO_2 quota prices development is driving the emission reduction in the model, which ensures a long-term energy system that is practically net zero (modest amounts of fossil fuel can however potentially still be present in the system).

Geographical variations and technology vintages

The model takes into account geographical variations in the quality of the solar resource (solar radiation) and the wind resource (wind speed) in the different European countries and regions. This is reflected in

[5] Only relevant in the model in EURSMR-scenarios, where model generated investment in SMR is considered. In the Bal-, AF26, and KF25-senarios, the SMR investment costs are calculated separately, allowing for different lifetime and WACC assumptions in the post calculations of the SMR economy. Nevertheless, 40 years lifetime of SMR is also assumed in these scenarios.

different production profiles for wind power and solar PV depending on the geographical location. The production profiles express both the amount of annual electricity generation that can be achieved per capacity (can be expressed in full-load hours in a so-called capacity factor[6]) at the given location and the variation pattern itself. This is illustrated for the solar resource in Europe as an example in Figure 5. The same approach is used for geographical variations in the wind resource.

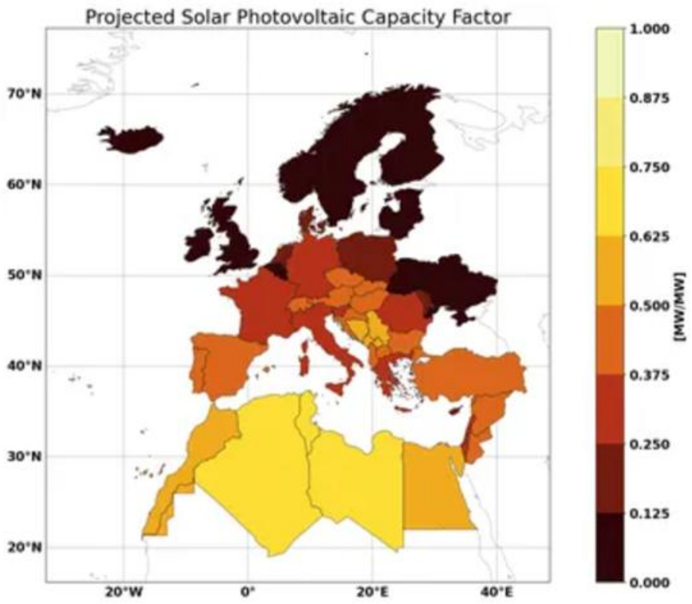


Figure 5. Illustration of how the modeling takes into account the geographical variations in the solar resource in Europe. The model thus takes into account that the solar resource is higher in southern Europe than in Northern Europe.
Source: https://cds.climate.copernicus.eu/datasets/sis-energy-pecd?tab=overview

The production profiles for wind power and solar PV technologies originate from the Pan-European Climate Database (PECD version 4.2), which is produced by the Copernicus Climate Change Service in collaboration with ENTSO-E. The energy variables in this dataset are derived from ERA5 which is the underlying weather model[7]. The resulting data is a reproduction of historical weather at an hourly time resolution across the continent, which ensures that the simultaneity is reflected across countries/regions. Thus, the modelling takes into account, for example, periods when production from wind turbines is relatively high in several areas at the same time. In the model, historical weather data for the year 2014 are used consistently for both wind and solar PV production and variations in demand.

The model also considers that the gradual technological progress in wind turbines and solar PV affects the production profiles. This reflects that newer technologies can achieve higher annual electricity generation than older technologies.

[6] Full load hours: Electricity generation in MWh per MW capacity. Capacity factor: Annual electricity generation divided by the maximum electricity generation the plant could theoretically produce annually if it runs at full capacity throughout the year.

[7] https://cds.climate.copernicus.eu/datasets/sis-energy-pecd?tab=overview

Model type, aggregation and foresight

Like most energy models, the model is deterministic. This means that all inputs and assumptions are fixed and known in advance. This means that if you give the same inputs, you always get the same output. However, by setting up different scenarios, each with their own assumptions, you can examine a wide range of outcomes.

The Balmorel version used has so-called perfect foresight for each simulation year. This means that each scenario in the model is optimised based on knowledge of the conditions over the entire year.

In large energy models like Balmorel, it is necessary to use time aggregation in the investment optimisation itself to enable reasonable model run times (approximately 0.5-1.5 days per scenario). Subsequently, operational optimisation with hourly resolution is used to reflect the variations hour by hour over the year.

Demands and flexibility

The model includes both classic electricity demand and electricity for data centres, individual heating, district heating, electric vehicles, and power-to-X. The model takes the following demand-side flexible measures into account:

- Electricity for power-to-X can be flexible depending on the model generated investments in hydrogen storages and electrolysis capacities.
- Electric vehicles demand includes all electricity for road transport. This demand is assumed flexible, and an increasing share can be shifted using a storage capacity that corresponds to 4 hours of demand. Thus, the modelling accounts for smart charging but not Vehicle-to-grid solutions.
- Electricity for individual heating includes electricity consumption for space heating in buildings, which is modelled as heat demand. The demand is supplied by heat pumps, direct electric heating, and electric boilers. Approximately 1/3 of the individual heat demand is considered flexible, with an option of shifting it by utilising a storage capacity corresponding to 2 hours of demand.
- Electricity for district heating is based on model optimisation and comprise electricity consumption for large heat pumps and electric boilers. This electricity demand can be flexible depending on heat storage capacities (existing/planned and invested capacities) and other heat storage units available in the given district hearing area.
- The level of flexibility in the classic demand is assumed to increase from 0% in 2020 to 10% in 2050 of the average hourly demand. The demand can be moved for 2 hours by paying an activation price. This demand includes industry that also have flexibility to move production to low price hours.

Electricity and hydrogen transmission and trade

In the optimisation of the modelled European energy system, the model can utilise transmission of electricity between the different countries and power regions. In this regard, existing/planned transmission capacities are included, and the model can invest in additional transmission capacities.

Correspondingly, in satisfying the hydrogen demand assumed in the different countries, the model can utilise transmission of hydrogen between the different countries and regions to the extent allowed by existing/planned and invested hydrogen transmission lines. In the model, part of the European hydrogen demand can be met by imports either via pipelines or via shipping. Thus, the electricity demand for hydrogen production in the model will be a result of the optimisation and will depend on how competitive European electricity generation is with hydrogen import options (explained further in Appendix, section 6.4).

As common in this type of energy models, each power region is modelled as a "cobber plate", i.e. excluding potential bottlenecks in the internal grid in each power region. This also means that the distributions grid is not modelled as such. However, in cost estimations, internal grid costs are accounted for based on a more generic approach.

Also when it comes to hydrogen, potential bottlenecks in the distribution of hydrogen within each power region are not modelled. As such, an internal hydrogen distribution grid is assumed in place in each region. Nevertheless, transmission of hydrogen between regions/countries, are constrained by the hydrogen pipeline capacities in the model.

Power adequacy and reserves
The model takes into account that production plants and transmission lines, etc. are out of operation for part of the year due to technical failures or planned inspections.

Balmorel ensures sufficient power capacity in the investment optimisation to cover electricity demand throughout the year. In addition, from a security of supply perspective, a given amount of firm dispatchable capacity can be defined as minimum requirement in each country. It is however not a probabilistic power adequacy model (like the SYSIFOS model) that analyses shortage events based on Monte Carlo simulations of various potential outages on power plants and transmission lines etc. and gives outputs such as loss of load expectation (LOLE) and expected energy not served (EENS). A more detailed description of the general principles of the Balmorel model can be found here:
https://www.ea-energianalyse.dk/wp-content/uploads/2020/06/Balmorel_UserGuide.pdf [8].

2.2. Main scenarios

Different SMR implementation levels and framework conditions

A number of scenarios have been set up to analyse the effects and value of SMR in the energy system. The scenarios reflect, firstly, different degrees of SMR integration into the system:

- **SMR0**: Reference scenario without SMR.
- **SMR600**: SMR capacity of 600 MW electricity assumed to be established in Denmark from 2035. The assumed SMR capacity includes:
  - 300 MW electricity implemented in DK1 as cogeneration (400 MW heat).
  - 300 MW electricity implemented in DK2 as cogeneration (400 MW heat).
- **SMR1500:** SMR capacity of 1500 MW electricity assumed to be established in Denmark from the year 2035. The SMR capacity includes:
  - 300 MW electricity implemented in DK1 as cogeneration (400 MW heat).
  - 300 MW electricity implemented in DK2 as cogeneration (400 MW heat).
  - 300 MW electricity implemented in DK1 as a power-only plant.

[8] since the model is continuously being further developed, there may be some differences between the model version used in the SMR analysis and this general model description.

- 600 MW electricity implemented in DK2 as a power-only plant.

The part of the SMR capacity that is assumed to be cogeneration is, for calculation purposes, in the model placed in Aarhus (DK1) and Copenhagen (DK2). These two district heating systems are the largest in Denmark and can therefore take best advantage of the large heat production capacity of the SMR plants.

In scenarios with the SMR capacity of 1500 MW-e, a higher capacity is assumed in DK2 than in DK1 based on where the highest need in the electricity system is assessed to be.

The different degrees of SMR implementation have also been investigated under different framework conditions:

- **Bal**: The development of the energy system for the European energy system including Denmark is based on economic optimisation (i.e. capacity investments are balanced). At the same time, the consultant's best guess for fuel and CO_2 prices as well as Denmark's electricity consumption is used (see Appendix).
- **KF25**: Assumptions from Climate Status and Projection 2025 (KF25)[9], which represent a frozen policy development, are assumed regarding electricity capacity development and electricity consumption for Denmark (fuel and CO_2 prices from AF25 are assumed, see Appendix).
- **AF25**: Assumptions from the publication "Analysis assumptions for Energinet 2025"[10] (AF25) are assumed regarding electricity capacity development for Denmark and electricity consumption as well as fuel and CO_2 prices (see Appendix).

The combination of the two different dimensions – the degree of SMR integration and the different framework conditions – indicates the overall range of the main scenario that has been set out (see Table 3).

Table 3. Overview of the main scenarios examined in the analysis. The scenarios have different degrees of SMR implementation in Denmark and have been examined under different framework conditions. This gives a total of 12 different main scenarios which are indicated by name ("SMR0_Bal", "SMR0_KF25 etc.").

	Framework conditions		
	Bal	**KF25**	**AF25**
No SMR in Denmark	SMR0_Bal	SMR0_KF25	SMR0_AF25
600 MW electricity SMR in Denmark	SMR600_Bal	SMR600_KF25	SMR600_AF25
1500 MW electricity SMR in Denmark	SMR1500_Bal	SMR1500_KF25	SMR1500_AF25

*KF25: Climate status and projection 2025. AF25: Analysis assumptions for Energinet. EURSMR: SMR plants are assumed to be deployed in the European energy system broadly and not only in Denmark.

In the Bal scenarios, the effects of the assumed SMR build-out on capacity investments in the system is based on optimisation. In contrast, in the KF25 scenarios, the SMR implementation is assumed to displace

[9] https://www.kefm.dk/klima/klimastatus-og-fremskrivning/klimastatus-og-fremskrivning-2025

[10] https://ens.dk/analyser-og-statistik/analyseforudsaetninger-til-energinet

solar PV expansion in Denmark, and in the AF25 scenarios, the SMR implementation is assumed to displace expansion of mainly offshore wind power and secondarily solar PV expansion in Denmark (see further details in Appendix 6.6).

The analysis examines the system effects and the value of establishing SMR in Denmark. Within each scenario group - Bal, KF25 and AF25 - the focus is therefore on comparing the scenarios with SMR (SMR600 and SMR1500) with the given reference scenario without SMR (SMR0).

When analysing the feasibility of SMR, the feasibility of SMR as CHP and as power-only is analysed separately. The analysis of the SMR CHP case is based on the difference between the SMR600 scenarios (SMR as CHP) and the reference scenarios without SMR. The analysis of the SMR power-only case is based on the difference between the SMR1500 scenarios and the SMR600 scenarios, thereby focusing on the effects of the additional 900 MWe SMR as power-only capacity.

2.3. European SMR investment scenarios

The fact that the effect of SMR is examined under three different framework conditions in Denmark – investment optimisation, AF25 development and KF25 development – contributes to uncovering a broader outcome range and thus increases the robustness of the analysis.

In addition, a group of scenarios are set up where the optimisation model is given the option to invest in the SMR technology in all countries in the modelled European energy system at different SMR investment cost levels. This scenario group is named **EURSMR**-scenarios.

The EURSMR scenarios firstly contribute to investigating the economic feasibility of the SMR technology at different technology cost levels to analyse the sensitivity towards the SMR technology costs. Secondly, the scenarios allow to analyse the profitability of SMR in a situation where SMR is potentially rolled out broadly in Europe, which could affect electricity prices and thus the revenue for SMR's in Denmark.

The cost of SMR is based on the three different cost development paths defined in the technical analysis of the project, representing different assumptions of technology development and build-out of SMR in the advanced economies.

- **Central** scenario: SMR technology cost development assuming a moderate technology cost in 2035, a significant build out of SMR in the advanced economies towards 2050 (30 GW), and a learning rate of 10%.
- **Optimistic** scenario: SMR technology cost development assuming a lower technology cost in 2035, a considerable build out of SMR in the advanced economies towards 2050 (around 150 GW), and a learning rate of 12.5%.
- **Pessimistic** scenario: SMR technology cost development assuming a higher technology cost in 2035, a limited build out of SMR in the advanced economies towards 2050 (12 GW), and a learning rate of 8.0 %.

In the model, investment in SMR combined heat and power units (CHP) is only assumed allowed in Copenhagen and Aarhus (corresponding to the two areas where SMR CHP is modelled in the Bal, AF, and KF-scenario). In all other areas in Denmark and in the other European countries, the SMR investment option is modelled as power-only units (condensing power units).

The data applied in the model for SMR electricity generation units is given in Table 4. Construction cost for SMR have been included based on assuming a construction period of 4 years.

Table 4. Technology cost projections for SMR power-only units assumed in the three different scenarios. EURSMR_Central, EURSMR_Optimistic, and EURSMR_Pessimistic.

			2035	2040	2045	2050
Central	Investment cost	M€/MW	9.6	8.2	7.4	6.9
	Capitalised interest during construction	M€/MW	1.2	1.0	0.9	0.9
	Total investment cost	M€/MW	10.8	9.2	8.3	7.8
	Fixed O&M	k€/MW	174	153	140	134
Optimistic	Investment cost	M€/MW	8.6	6.7	5.2	4.0
	Capitalised interest during construction	M€/MW	1.1	0.8	0.7	0.5
	Total investment cost	M€/MW	9.7	7.5	5.8	4.5
	Fixed O&M	k€/MW	160	130	108	90
Pessimistic	Investment cost	M€/MW	10.7	10.2	9.7	9.2
	Capitalised interest during construction	M€/MW	1.3	1.3	1.2	1.2
	Total investment cost	M€/MW	12.0	11.5	10.9	10.4
	Fixed O&M	k€/MW	190	183	175	169

A learning rate of 10.0 %, 12.5 %, and 8.0 % is assumed in the Central, Optimistic and Pessimistic scenario, respectively.

For SMR CHP units, an additional investment cost of 0.24 M€/MW and an additional fixed O&M cost of 5.7 k€/MW is assumed compared to SMR power-only plants.

In the Balmorel model, the SMR technology costs are annualised based on a 40-year period and 6 % real WACC.

The scenarios created do not attempt to cover the full potential outcome space of the results but reflect what has been selected to investigate within the framework of the project.

Projections of future developments for energy systems and prices are generally associated with uncertainty and should be interpreted with due caution.

2.4. System integration

An electricity system with large shares of solar and wind requires investments in infrastructure and requires that the system has resources to maintain the balance between generation and demand in every hour, including during periods with low or no electricity generation from solar and wind. In the analysis, all costs related to integrating solar and wind are included:

Price-responsive electricity demand

Demand-side resources will increasingly help ensure system balance when it is economically attractive for the individual consumer. In particular, electric boilers and heat pumps in district heating systems, electrolysis plants, and electric vehicles are expected to contribute. The analysis includes projections of price-responsive electricity demand in Europe, and the model is also able to make investments that provide additional flexibility (electrolysis, heat pumps, electric boilers, electricity-, heat- and hydrogen storage, etc.).

Capacity requirements (resource adequacy)

To ensure generation adequacy across weather years and outage events, the model includes an overall requirement for firm dispatchable capacity[11] across the entire modelled area. In addition, it is assumed that each country is required to host a share of this capacity locally. This reflects an expectation that in the future countries will impose requirements for firm dispatchable capacity to ensure that security of electricity supply can, to a large extent, be managed within their own system. Solar and wind cannot contribute to this capacity requirement, whereas thermal generation and hydro power with reservoirs can, including SMRs. Batteries are not considered as firm capacity here as they will not be able to deliver capacity over a longer period due to limited storage volume. This requirement applies to all scenarios.

The required amount of firm dispatchable capacity is estimated based on the following steps:

- Hourly dispatch optimisation to evaluate capacity needs in the given system
- Comparisons and assessment of the result for firm dispatchable to the main system scenario evaluated in ENTSO-E's European Resource Adequacy Assessment for 2035.

For the modelled countries in Europe the total required minimum capacity is estimated to 470 and 525 GW in 2035 and 2050 respectively (see Figure 6). For comparison, ERAA assesses a system with around 430 GW firm capacity in 2035 (adjusted for geographical scope). For each of the modelled countries in Europe, the national minimum requirement for firm dispatchable capacity is estimated based on the following assuptions:

- 2/3 of the system wide need for firm dispatchable capacity has to be distributed on the individual countries. The remaining 1/3 can be placed based on model optimisation
- The individual countries share of the 2/3 placed nationally is based on the share that the national inflexible electricity demand constitutes of the total system inflexible electricity demand.

Following this methodology, the need for need for firm dispatchable capacity in Denmark is estimated to approximately 5600 MW in 2050 (see Figure 6).

[11] Thermal power generation and hydro reservoir plants. While other technologies (such as batteries), are dispatchable, they depend on the state of charge, and are thus not assumed to be eligible for this specific requirement.

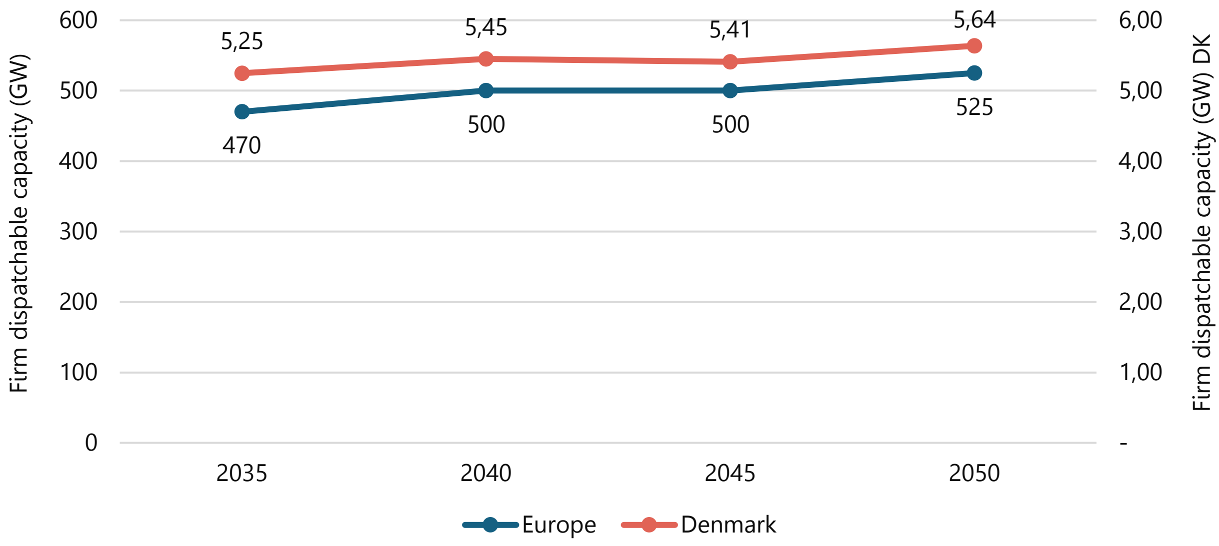


Figure 6. Estimated need for firm dispatchable capacity for the modelled European energy system in total and for Denmark. Thermal plants (coal/gas/oil/biomass-based, SMR) and hydropower with reservoir are assumed to be able to deliver firm dispatchable capacity.

Operating reserves (system security)

To ensure secure system operation, the analysis requires that a certain volume of operating reserves (FRR) is available in every hour. These reserves do not participate in the spot market and are held to manage unexpected events such as generation outages or forecast errors in electricity demand and wind and solar generation.

Structure of the reserve requirement

The required volume of operating reserves is dimensioned dynamically and consists of two components:

1. A minimum reserve requirement for general system operation
2. An additional, variable reserve requirement that depends on the level of wind and solar generation in the given hour

The minimum reserve level reflects today's requirements for manual reserves. For Denmark, this requirement is assumed to be approximately 900 MW. This minimum level is assumed to be fully covered by firm dispatchable capacity, ensuring a reliable and controllable reserve base at all times. In addition to the minimum requirement, extra reserves are required to manage forecast uncertainty associated with variable renewable generation. For each MWh/h of expected wind and solar generation, reserve capacity corresponding to at least 3.5% of the expected output must be available. This requirement represents the share of balancing needs that is secured in advance through TSO capacity procurement of ancillary services. The amount is based on Energinet's latest needs assessment[12], where it is specifically pointed out that forecast errors for wind and solar in the day-ahead market are increasingly becoming the dimensioning factor for the need for FRR. Energinet therefore plans to procure reserve capacity for upward regulation depending on the day-ahead forecasts for wind and solar. For example, they estimate—subject to considerable uncertainty—that

[12] Outlook for ancillary services 2024-2040, Energinet (2024)

the need could rise to 2,300 MW in 2040, with an installed wind and solar capacity of 65 GW. A simple translation of this is that upward regulation reserves must make up at least 3.5% of the expected production from solar and wind. In principle, these reserves can be provided by dispatchable generation units as well as by flexible consumption. Dispatchable generation units could, in principle, also potentially be wind and solar production that is withheld.

This 3.5% requirement covers only reserves procured ex ante by the TSOs and does not include additional balancing energy that may be procured during the operating hour through voluntary bids. If the wind- and solar-related reserve requirement exceeds the 900 MW minimum, the total operating reserve requirement is increased accordingly.

While the minimum reserve requirement is assumed to be met by firm dispatchable capacity, the additional, variable reserve requirement may also be provided by other types of reserve resources, including:

- Wind and solar generation operating below available capacity
- Flexible electricity demand, such as electrolysers, heat pumps, and electric boilers

Balancing cost

In any given hour, activation of operating reserves (predominantly aFRR and mFRR) may be needed, with costs for upward or downward regulation that differ from the day-ahead spot price. This results in an imbalance cost for generation units or demand that are out of balance relative to the operating schedule. Balancing costs are not calculated directly in the model but are added based on an assessment of historical data. The balancing costs vary for different stakeholders depending on their portfolio characteristics, forecast quality and bidding strategies, and to our knowledge public statistical cost data is not available. However, in recent years, balancing costs of around 2 €/MWh have been reported, while older references point out different levels across Europe ranging up to 4 €/MWh.[13] The actual balancing costs depend on a number of factors:

- Forecast uncertainty from day-ahead markets to the hour of operation
- Amount of imbalances handled in intra-day markets (at lower cost)
- Direction of imbalance compared to system needs (helping the system can incur income instead of costs)
- Pricing of imbalances and resulting spread to Day-Ahead price.
- Supply and cost for flexible resources in the system.

The balancing cost can be calculated by multiplying the imbalance (MWh) with the price spread between day-ahead prices and the imbalance price. The evolution of this price spread since 2015 is shown on Figure 7. Note, that the imbalance prices are subject to pricing methodologies, which have changed considerably in March 2025, and sparked increased imbalance prices.

[13] https://greenpowerdenmark.dk/nyheder/vindmoelleejere-maa-stoppe-produktionen-dyre-timer, EWEA: Balancing responsibility and costs of wind power plants (2025)

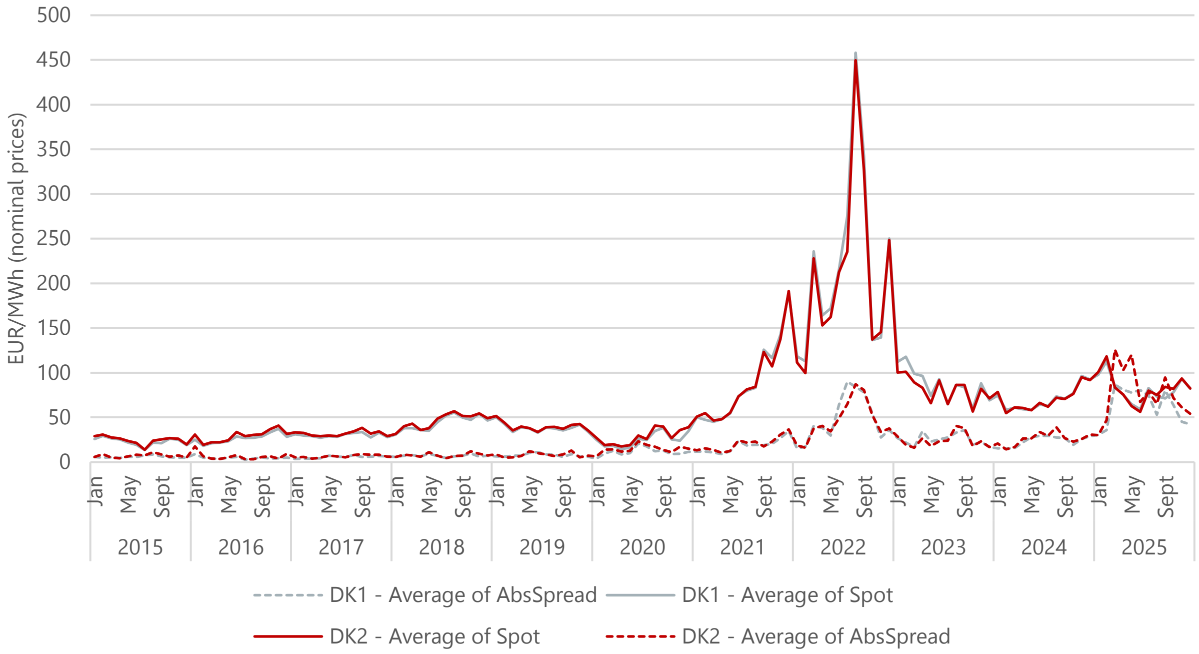


Figure 7: Monthly average day-ahead (spot) prices and absolute spread to imbalance prices (AbsSpread). Source: Energidataservice and own calculations.

Simplified assumptions are applied to illustrate balancing costs for wind and solar generation, given an assumed spread between imbalance prices and Day-Ahead prices. The assumptions used are summarised in Table 5.

Forecast uncertainty is assumed to be 20% of expected wind and solar generation. Of this forecast error, 25% is assumed to be corrected through intraday market trading, while the remaining share results in imbalances settled in the balancing market.

Of the resulting imbalances, 33% are assumed to help the overall system balance. Any potential revenues from such favourable imbalances are not included in the calculations and are instead assumed to offset balancing costs in the intraday market. The remaining 67% of imbalances are assumed to increase system imbalances and therefore incur balancing costs.

Apart from the assumption on the split between imbalances that help or worsen system balance, no explicit correlation is assumed between imbalance prices and the actual size or direction of wind and solar forecast errors. Simplified assumptions can help illustrating balancing cost, given a certain spread between imbalance prices and Day-Ahead prices.

Table 5. Assumptions for illustrative calculation of balancing cost.

	Assumption
Forecast uncertainty	20%
Share of forecast errors handled in Intraday markets	25%
Share of imbalances helping system	33%
Share of imbalances increasing system imbalance	67%

Table 6. Illustrative balancing cost for historic years based on simplified assumptions.

	DK1			DK2		
€/MWh (nominal)	Average Spread	Average Day-Ahead	Balancing cost	Average Spread	Average Day-Ahead	Balancing cost
2015	5.9	22.9	0.6	7.0	24.5	0.7
2016	4.8	26.7	0.5	6.4	29.4	0.6
2017	5.7	30.1	0.6	6.5	32.0	0.7
2018	7.0	44.0	0.7	7.8	46.2	0.8
2019	7.8	38.5	0.8	8.2	39.8	0.8
2020	11.6	25.0	1.2	14.6	28.4	1.5
2021	18.3	88.2	1.8	20.2	88.0	2.0
2022	48.2	219.3	4.8	46.2	210.0	4.6
2023	25.3	86.7	2.5	24.4	81.3	2.5
2024	23.7	70.8	2.4	26.2	70.7	2.6
2025	62.8	81.1	6.3	76.7	82.6	7.7

In the long term, imbalance prices are expected to reduce to levels comparable to the period from 2021-2024 (with exception of 2022, which was heavily influenced by extraordinary high Day-ahead prices). Increasing availability of short-term flexibility in the system could even reduce imbalance-prices, but in the absence of actual modelling of provision of balancing services, the assumption of historical levels excluding outliers due to high day-ahead prices (2022) and assumed temporary market imbalances (2025) has been applied. Therefore, balancing costs of 2 €/MWh for wind and solar power have been applied. With the assumptions applied for the illustrative calculations, this corresponds to a price spread between day-ahead prices and imbalance-prices of 20 €/MWh.

Electricity infrastructure

When expanding with new power capacity, the necessary investments in reinforcement of the local distribution grid are included in the investment costs for the individual technologies. Necessary investments associated with solar and wind are specified based on applicable grid connection charges. The grid related costs comprise the following elements:

- Cost for connection to the point of common coupling. Includes transformer to relevant voltage level and cables. Depends on distance to the relevant substation in the grid and voltage level. Included in technology assessments in the technology catalogue

- Cost for upgrades of the grid substation and upgrade needs in the surrounding grid. Depends on the voltage level and the status of the surrounding grid in terms of capacity and balance (production or consumption dominated)
- Variable tariffs covering the TSO's general costs. In Denmark, variable production infeed tariffs are currently around 0,065 €2025-cent/kWh and balancing tariffs around 0,07 €2025-cent/kWh. Those tariffs apply widely for production and are not included in system simulations (but the system costs related to balancing wind and solar power are, see section on balancing above)

The costs for upgrades of the grid substation and upgrade needs in the surrounding grid are included in the model optimisation when adding new generation capacity. Cost estimates are based on grid connection fees of the Danish transmission and distribution grid operators[14]. These tariffs vary widely, depending on the location and the voltage level from around 30.000 €2025/MW to 220.000 €2025/MW.

*Table 7. Assumptions on cost for grid upgrades when installing new generation capacity. * For new thermal generation, half of the potential new generation is assumed to be placed at existing plant sites or in consumption dominated grid areas, reducing the cost for grid upgrades.*

	Offshore wind	Onshore wind	Solar PV	New thermal*
Grid upgrade cost (€2025/MW)	84 000	156 000	115 000	34 000

Different developments in generation capacity can significantly affect both the need for investments in interconnectors and the value of existing and new interconnection capacity between neighbouring bidding zones. Such transmission investments are endogenously optimised in the model, and their costs are included in total system costs. Conversely, if a given scenario (e.g. an SMR-based scenario) reduces or avoids the need for interconnector expansion, the associated avoided investment costs are counted as a system value.

2.5. Evaluation of system value of SMR

In the SMR scenarios, other investments in electricity and heat production in the system are adjusted according to the following main principles:

- In the SMR-Bal scenarios and in the EURSMR scenarios, the system adjustment is determined by the model's optimisation routine.
    - In the SMR-Bal scenarios, the model optimisation adjusts the surrounding system to best match the defined SMR-capacities.
    - In the SMREUR scenarios, model optimisation finds the optimal balance between SMR-capacities and other generation capacity.
- In the SMR-KF25 and SMR-AF25 scenarios, solar PV and offshore wind capacity in Denmark is reduced by an amount (measured as potential electricity generation) corresponding to the electricity generation delivered by the modelled SMR plants. The same combined heat and power (CHP)

[14] https://energinet.dk/el/elmarkedet/tariffer/aktuelle-tariffer/, https://elnet.dk/nettariffer-priser-gebyrer/tilslutningsbidrag-produktion

capacity as in the reference is assumed. In addition, district heating production capacities are adjusted as part of the model's optimisation.

For each SMR scenario, a system value is calculated. The system value is defined as the total cost reduction compared with the reference and is calculated excluding the costs of establishing and operating the SMR plants themselves. The system value can be compared with SMR costs, which are projected in three different scenarios based on the analyses in Part 1 (the technical analysis): optimistic, central, and pessimistic cost trajectories.

If the system value proves to be higher than the expected SMR costs, deployment of SMRs is beneficial from a socio-economic perspective in the scenario in question. If the system value is lower, the opposite applies. However, the societal costs of developing the necessary regulatory frameworks to manage nuclear power safely and to attract investment in nuclear power have not been priced.

SMR can create value for the system by reducing the following cost:

- **Alternative generation cost for electricity and heat**
  - CAPEX and OPEX for other generation capacities: When introducing SMR, less capacity from other sources is needed
  - Fuel and emission cost: When introducing SMR, system dispatch will be adjusted, potentially leading to cost savings on fuels and emission
- **Flexibility needs**
  - Changes in generation capacity from wind and solar power can impact flexibility needs in terms of e.g. energy storage (electricity, heat, hydrogen), electrolyser capacity, heat pumps and electric boilers for district heating)
- **Energy infrastructure**
  - Transmission buildout: The need for interconnection capacity (electricity and hydrogen) buildout between bidding zones can be affected by SMR, which can lower cost. However, minimum levels of interconnection buildout towards 2037 are maintained across all scenarios.
  - Electricity grid upgrades: When expansion of other generation capacities (mainly wind and solar) is reduced, associated grid upgrade cost for bidding-zone internal grids can also be reduced. New SMR-capacity is assumed to be established at existing power-plant sites or at sites with sufficient grid capacity, and thus without the need for grid upgrades and associated costs. This assumption is vulnerable to the actual site choices.
- **Capacity requirements**
  - The minimum requirements for firm dispatchable capacity are kept constant across scenarios. However, SMR-capacities are expected to contribute to this requirement, thus lowering the need for alternative investments to fulfil the need
- **Reserve cost**
  - SMR's can contribute to reducing cost for capacity reserves in two ways:
    - Lowering the need for reserves by reducing the buildout of wind and solar power and the associated reserve needs
    - Providing reserves. However, since SMR's are expected to have low marginal production costs, economic optimisation will under most circumstances not lead to

choosing SMR's for providing operation reserves, as it would require running below rated capacity.

- **Balancing cost**
    - Activation of reserves for providing balancing power can be reduced, if buildout of wind and solar power is reduced.

3. Reference development

This chapter presents the results that illustrate the general development of the energy system. Here, results from the scenarios without SMR in Denmark are shown.

3.1. The European power system

Significant electrification is expected in energy systems across Europe. This can be seen from Figure 8, which shows the development of the total electricity consumption in the modelled European energy system. As shown, the model analysis points to almost a doubling of the total electricity consumption in the system from 2025 to 2050, which is mainly due to a significant increase in electricity consumption for electric vehicles, hydrogen production (power-to-X), classic electricity consumption and data centres and secondarily also increased electricity consumption for individual heating and district heating production.

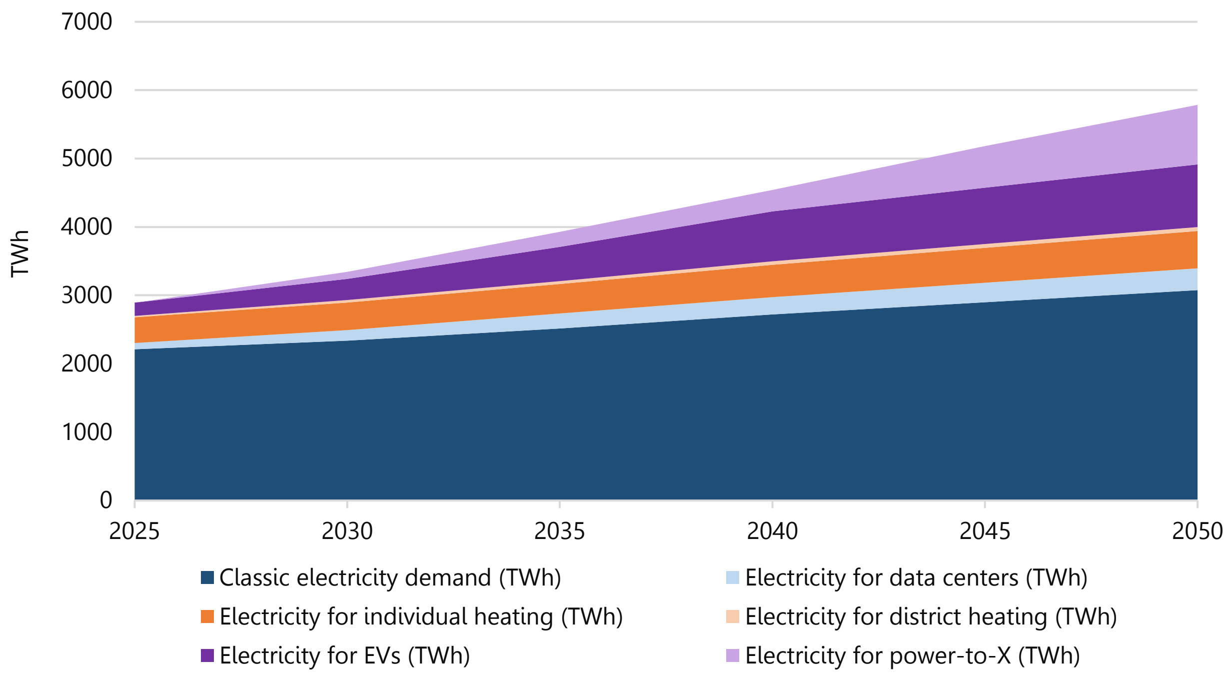


Figure 8. Electricity consumption development for the overall modelled energy system in Europe (SMR0_Bal scenario). Electricity for district heating and partly also electricity for power-to-X is a result of the optimisation.

The modelling indicates that the increase in European electricity consumption towards 2050 will primarily be covered by the expansion of wind power and solar PV (see Figure 9). This is driven by the economic competitiveness of wind and solar energy as well as ambitious energy and climate policies. It should be mentioned here that the power capacity of traditional nuclear power and hydropower in Europe is based on knowledge of existing and planned capacities in the respective countries (not optimisation). In addition, the model takes into account national policies for phasing out coal power.

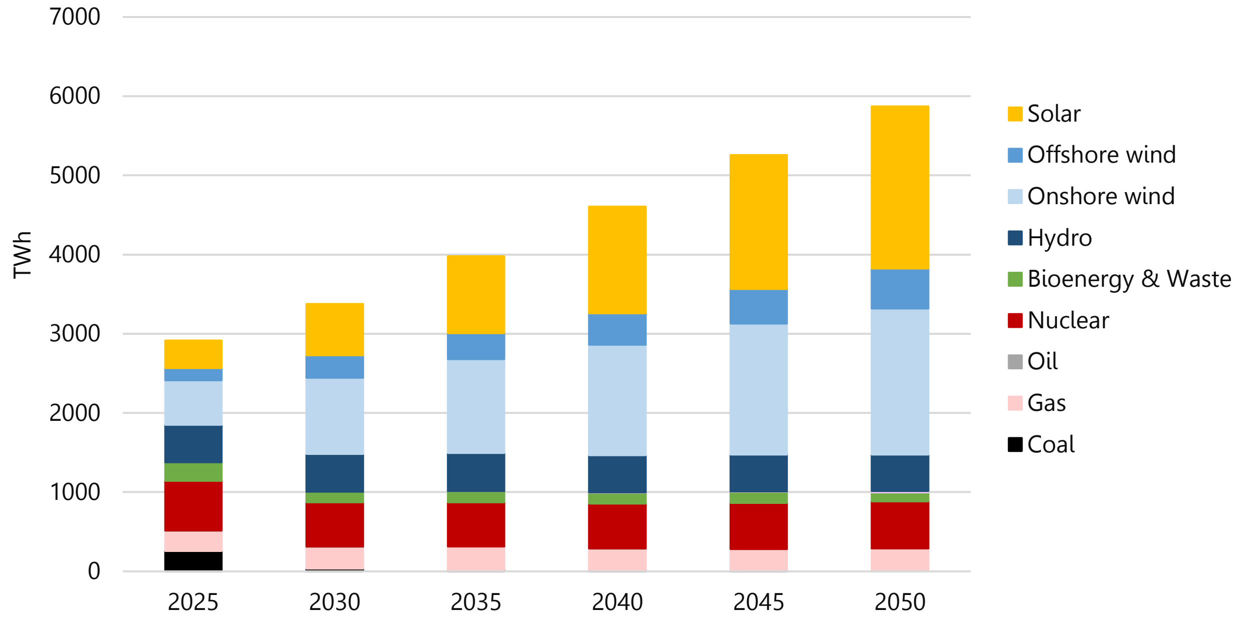


Figure 9. Electricity generation for the modelled European energy system (for the SMR0_Bal scenario).

Renewable energy accounts for a full 74% in 2030 and 85% in 2050 in the modelled European energy system, and wind power and solar PV alone account for 56% of production in 2030 and 75% in 2050[15].

In the model, gas represents natural gas and green gas of natural gas quality. Gas is prices as natural gas and the cost of the CO_2 content is accounted for via the CO_2 price (as for other fossil fuels). It is assumed that green gas of natural gas quality will be priced as natural gas including the CO_2 cost. As such, gas in the model represents gas of natural gas quality, fossil or green, and towards 2050, it will to an increasing degree represent green gas.

The development in power capacity for the modelled European energy system towards 2050 is shown in Figure 10. The capacity of solar PV is relatively large due to a relatively low number of full load hours compared to, for example, onshore and offshore wind[16]. The economic optimisation points to a significant roll-out of batteries resulting in a total capacity of 70 GW in 2030 and 350 GW in 2050[17] .The batteries contribute with significant flexibility to the system and thereby support the integration of the varying electricity generation from the increasing amounts of wind and solar in the system.

In addition, a number of other factors contribute to the system integration of wind and solar: In particular, power-to-X via hydrogen storage constitutes a large flexible electricity consumption in the future energy system, as does electricity for electric vehicles via intelligent charging. Flexible operation of individual heat pumps and flexibility in the district heating system via heat storage and various production options (large

[15] These shares are based on the SMR0_Bal scenario. Similar levels are identified for the SMR0_KF25 scenario and the SMR0_AF25 scenario.

[16]New solar power plants (field systems) typically have around 800-1500 full load hours, while onshore and offshore wind typically have around 3000-4500 full load hours.

[17]It should be mentioned here that the modeling of batteries only reflects the spot market and not system services. The profitable capacity of batteries may thus be underestimated.

heat pumps, electric boilers and thermal plants) also contribute to a certain extent, as well as flexibility in classic electricity consumption to some degree. Finally, the transmission system between countries and regions helps to support the integration of wind and solar in Europe (see Figure 11).

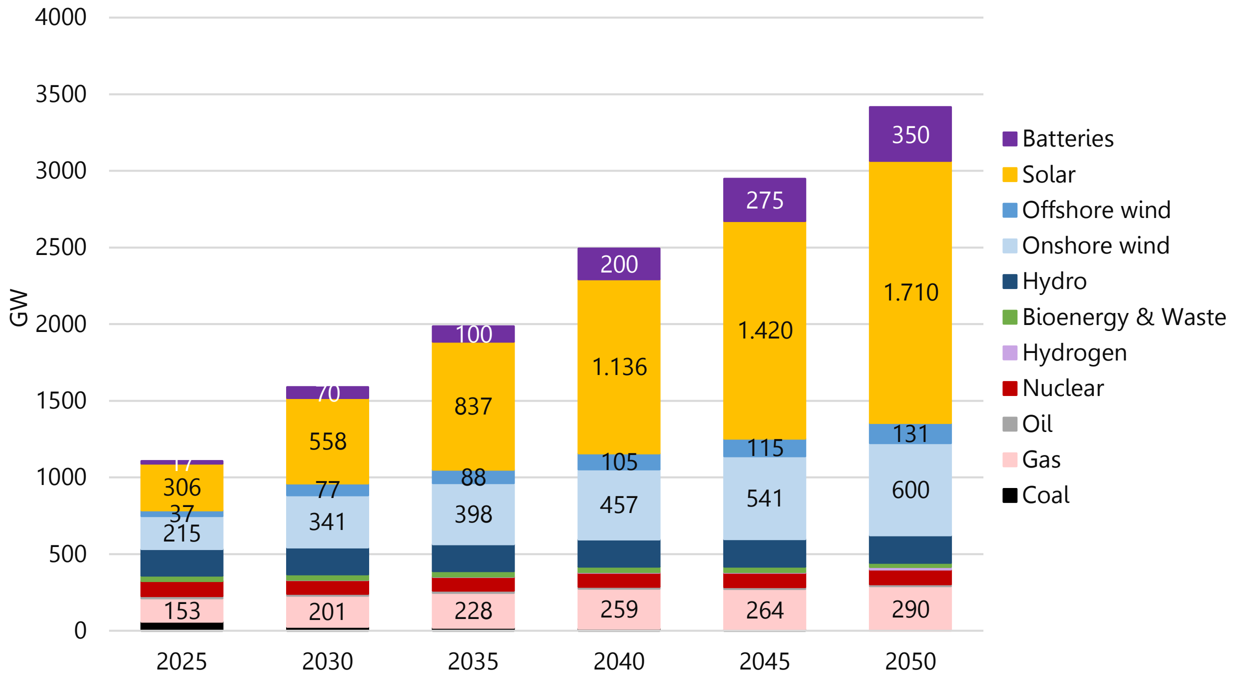


Figure 10. Power capacity for the modelled European energy system (for the SMR0_Bal scenario).

Figure 10 shows an increase in gas capacity in the modelled European system from around 150 GW in 2025 to around 290 GW in 2050. This reflects the increasing need for dispatchable capacity due to the increase in electricity consumption and the share of wind and solar in the generation mix. In 2050, gas capacities thus contribute significantly to covering the total need for firm dispatchable capacity of around 525 GW identified in the model.

The optimisation points to a very limited expansion of transmission capacity in Europe beyond what is contained in existing and planned infrastructure projects up to 2037. Thus, the model identifies a profitable transmission expansion of around 12 GW towards 2050 compared to a total existing/planned capacity of approximately 179 GW in 2050[18]. The limited transmission expansion is related to the fact that the analysis uses recently published data for transmission investment costs in the Danish Energy Agency's technology catalogue[19], where the investment cost for transmission is estimated to be significantly higher than Ea Energy Analyses has previously assumed. In addition, the assumed requirement for firm dispatchable capacity in the model somewhat reduces the profitability of closer interconnection of the countries' electricity

[18] The model generated transmission expansions include e,g. connections between Germany and France & Poland; between France and Italy, Belgium, Switzerland, and Luxembourg; between Norway and Finland; and between Poland and Switzerland.

[19]Source: https://ens.dk/analyser-og-statistik/teknologikatalog-transport-af-energi

systems. A map of the total transmission capacity in 2050 between different countries and regions in the system is shown in Figure 11.

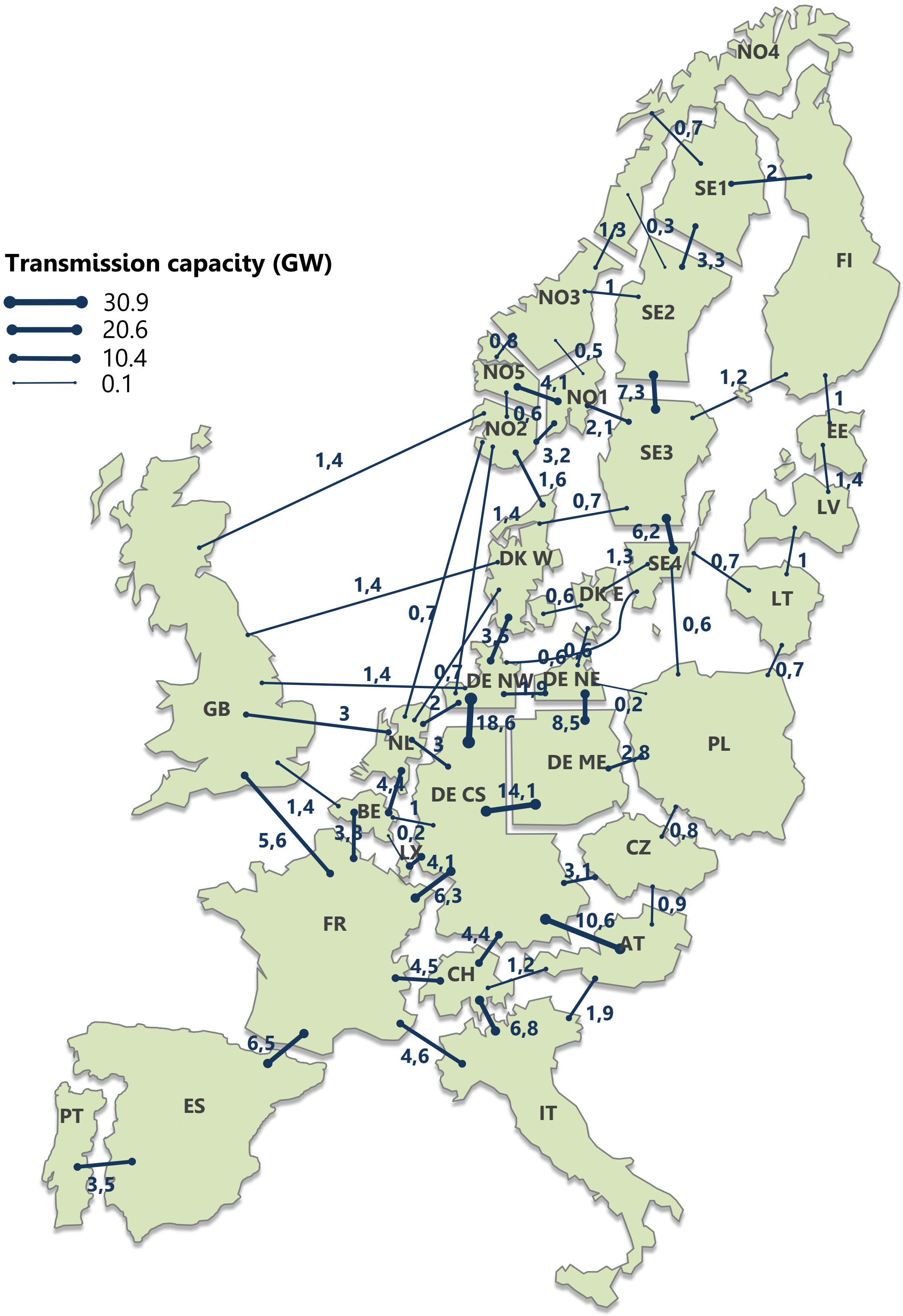


Figure 11. Electricity transmission capacity between countries/regions in 2050 in the optimisation of the modelled European energy system. The transmission capacities are based on existing/planned capacities up to 2037 and any additional investments from 2040 to 2050 in the economic optimisation model.

3.2. The Danish power system

The development in the Danish electricity consumption in the reference scenarios without SMR is illustrated on Figure 12. As for the European energy system in general, the electricity consumption for power-to-x and district heating is a result of the optimisation and to not reflect input data.

As shown, all three reference scenarios point to considerable increase in the total Danish electricity demand from 2050 to 2050: more than a doubling in the SMR0_Bal and SMR0_KF25 scenario and even more than a quadrupling in the SMR0_AF25 scenario. In the SMR0_AF25 scenario, the electricity consumption for power-to-X is particularly high due to a large net export of hydrogen from Denmark as a consequence of the large RES expansion assumed in this scenario (see Figure 15).

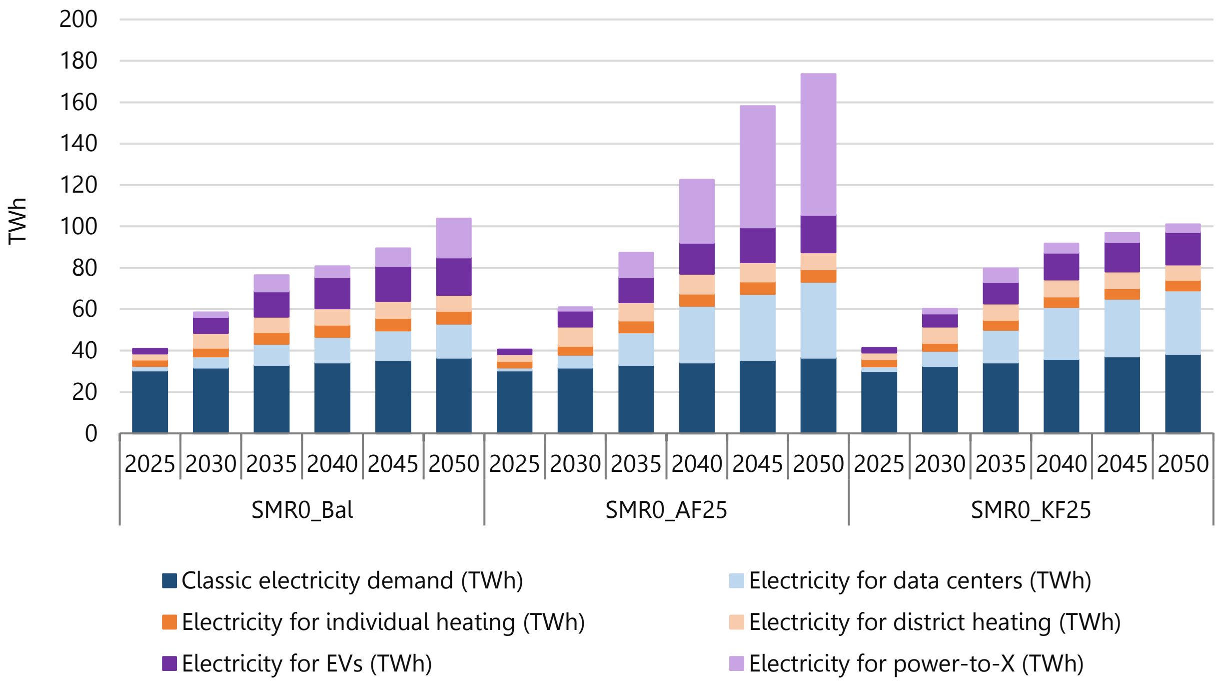


Figure 12. Development in the Danish electricity consumption in the three reference scenarios without SMR. Electricity for district heating and partly also electricity for power-to-X is a result of the optimisation.

The electricity generation mix in Denmark towards 2050 for the reference situation without SMR is shown in Figure 13 for the three different scenarios, i.e. for SMR0_Bal, SMR0_AF25, and SMR0_KF25.

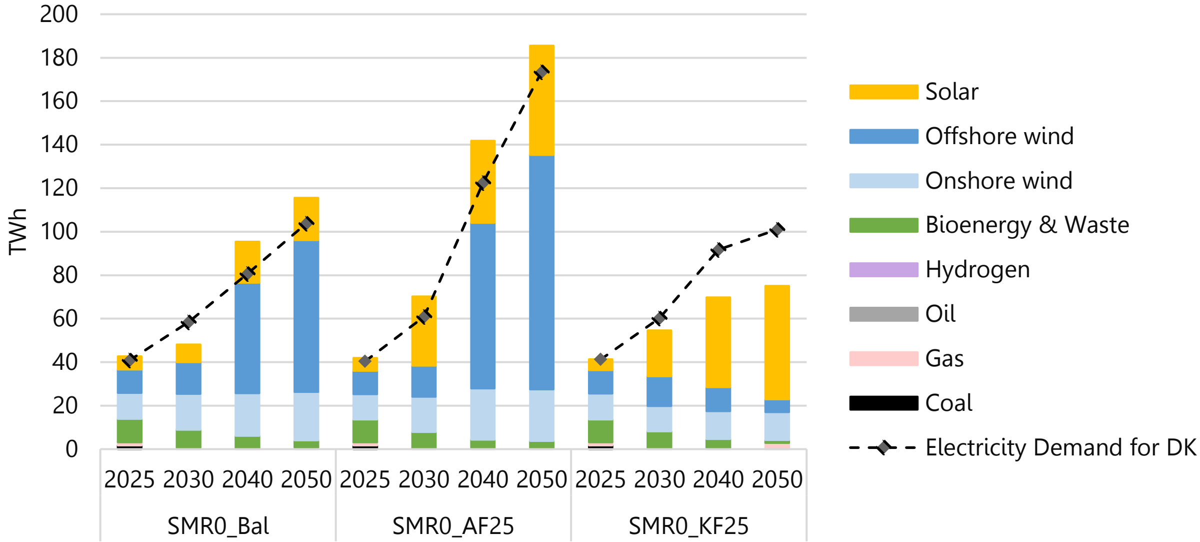


Figure 13. Electricity generation in Denmark in the reference scenarios without SMR.

The power capacity in Denmark is similarly shown in Figure 14.

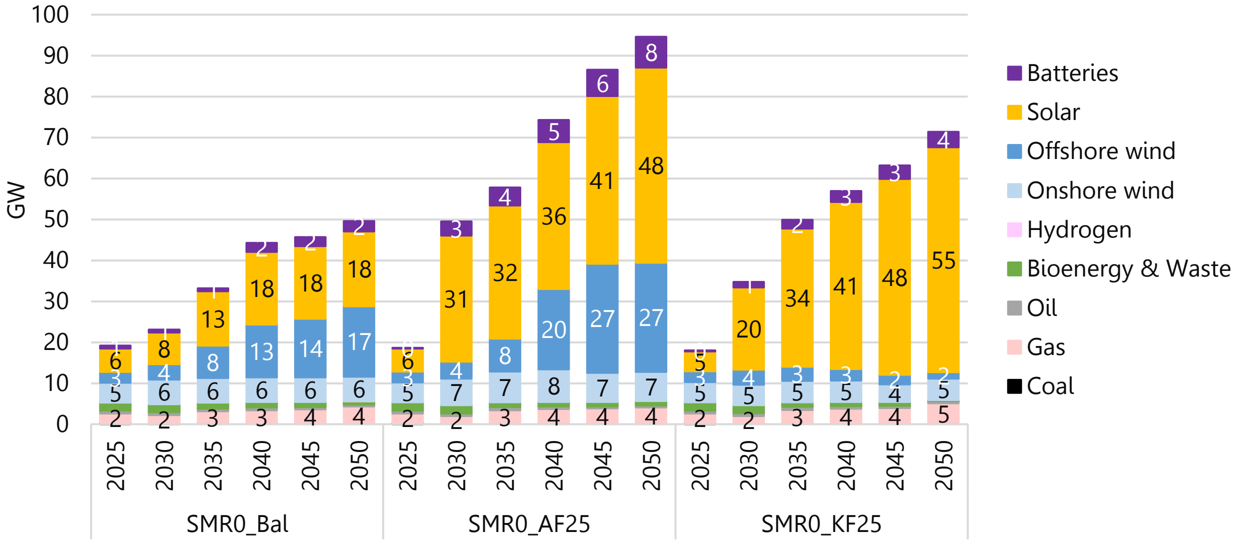


Figure 14. Power capacity in Denmark in the reference scenarios without SMR (SMR0_Bal here abbreviated Bal, SMR0_AF25 here abbreviated AF25 and SMR0_KF25 here abbreviated KF25).

It can be seen that wind power and solar PV dominate the future electricity generation in Denmark in all three reference scenarios with a total share reaching 81-89% in 2030 and 94-98% in 2050. However, the amount of total renewable energy expansion included in the reference scenarios varies and the distribution of offshore wind and solar PV in particular also varies. In the SMR0_AF25 scenario, a significant renewable energy expansion is assumed compared to in the SMR0_Bal scenario where the expansion is based on economic optimisation. Conversely, the renewable energy expansion assumed in SMR0_KF25 scenario is lower than in the SMR0_Bal scenario and at the same time solar PV in KF25 accounts for the majority of the expansion.

Denmark's net export of electricity and hydrogen in the reference scenarios without SMR is illustrated in Figure 15. The figure shows that in the Bal scenario, where the Danish capacity development is based on optimisation, Denmark is a net exporter of electricity and hydrogen in the long term. This is in line with the results presented in Figure 13, where electricity generation in Denmark is the long term larger than the demand.

In the SMR0_AF25 scenario, where a significant Danish renewable energy expansion is assumed, the long-term net export of hydrogen is particularly high. In contrast, the low renewable energy expansion assumed in the KF25 scenario results in Denmark being a net exporter of electricity towards 2050.

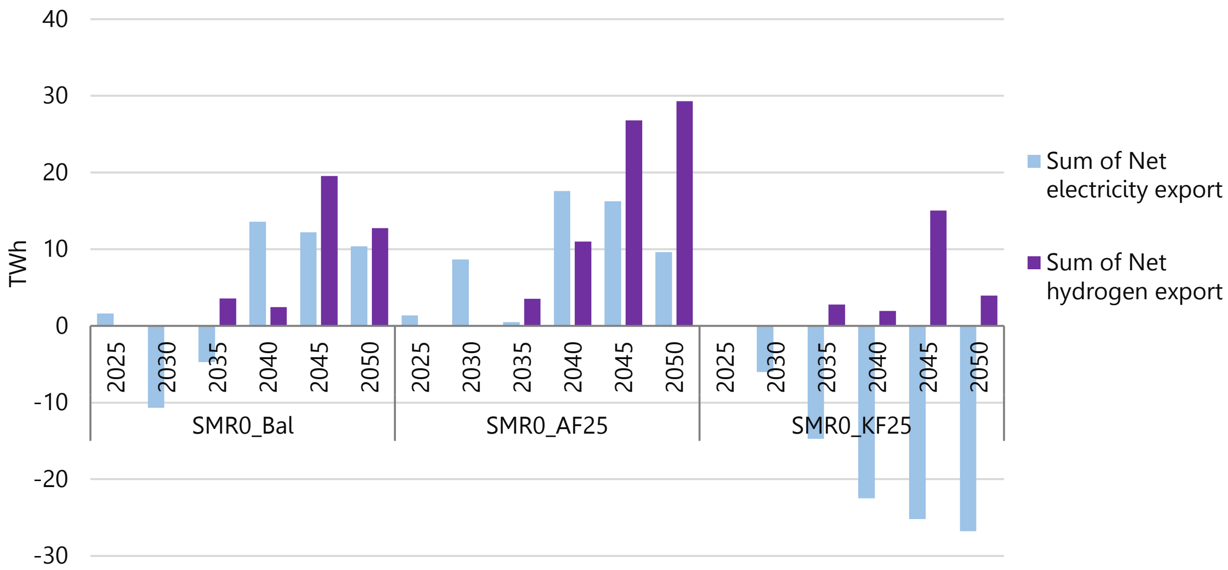


Figure 15. Net export of electricity and hydrogen in the three reference scenarios without SMR.

In the model, the planned 4 GW hydrogen pipeline from DK1 to Germany, expected around year 2030-2031, is included from 2035 and onwards. In addition, towards 2050 the model invests in hydrogen pipelines from Denmark to Norway and Germany; in total around 1.2 GW, 2.5 GW, and 0.2 GW in the SMR0_Bal scenario, SMR0_AF25 scenario, and the SMR0_KF25 scenario, respectively.

The development in the average electricity price in Denmark in the different reference scenarios is shown in Figure 16.

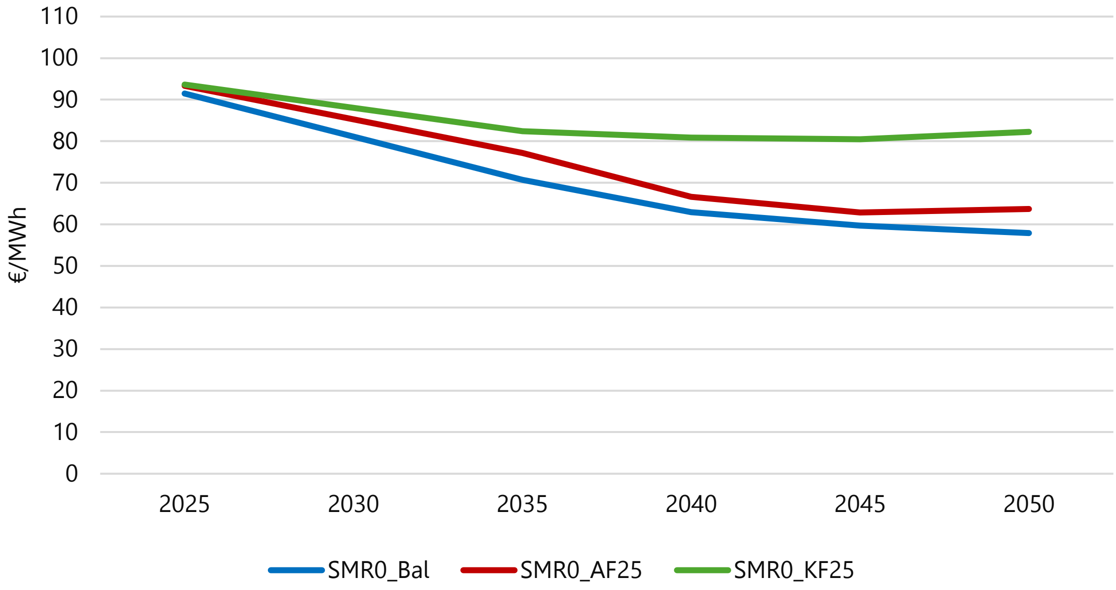


Figure 16. The development of the average electricity price in Denmark in the different reference scenarios without SMR. For simplification, the electricity price is shown as a simple average of the electricity price in DK1 and DK1 (in the figure, the electricity price for 2030 is based on interpolation).

The electricity price level in Denmark (and in the European energy system in general) will fall towards 2050 as a result of the significant expansion of renewable energy. Also, the electricity price development towards 2050 shows more fluctuations in prices with a higher amount of very low and high prices in the market.

The SMR0_AF25 and SMR0_KF25 scenario show higher electricity prices in Europe due to the higher assumed fuel and CO_2 quota prices compared to in the SMR0_Bal scenario. Additionally, the scenarios have different Danish capacity developments, which also affects the resulting electricity price. As such, in the SMR0_KF25 scenario, there is limited renewable energy expansion compared to the demand (see Figure 13 and Figure 12), and therefore shows the highest electricity prices in Denmark among the three scenarios.

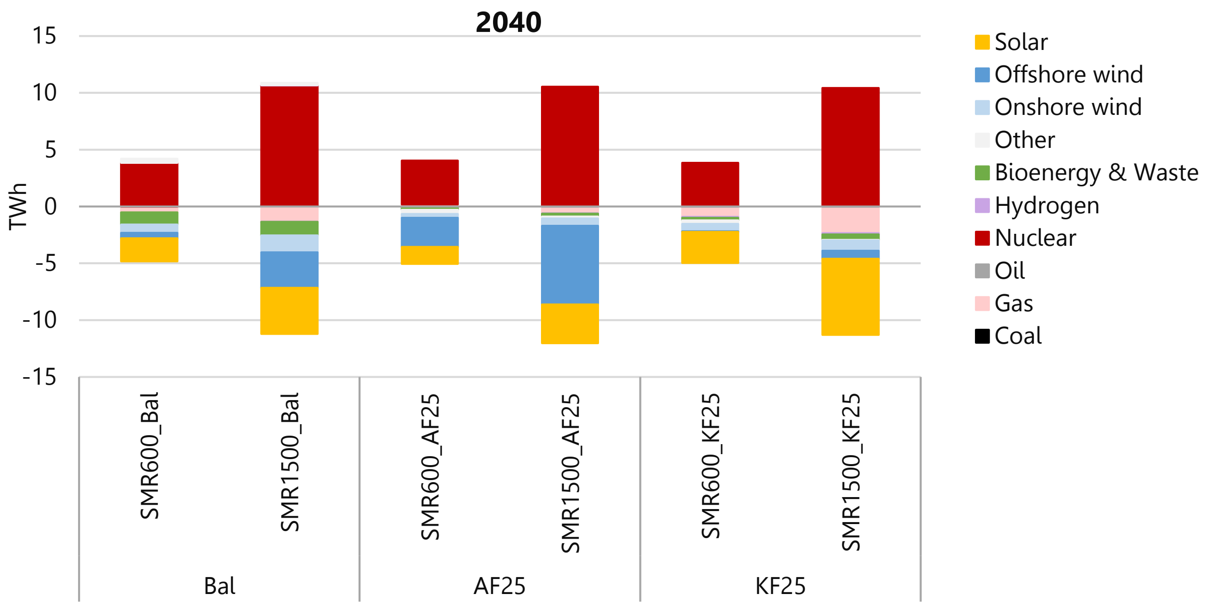
4. System effects and value of SMR

This results chapter focuses on the system effects and the value of SMR. Here, the SMR scenarios are compared with the given reference scenario without SMR.

4.1. Impact on electricity generation and capacity

Impacts on the European power system

Figure 17 shows how the total electricity generation in Europe is affected by the assumed implementation of SMR in Denmark. The figure shows changes compared to the given reference scenario without SMR, where positive values show increased electricity generation and negative values show reduced (displaced) electricity generation. To limit the number of figures, the focus is on the years 2040 and 2050.



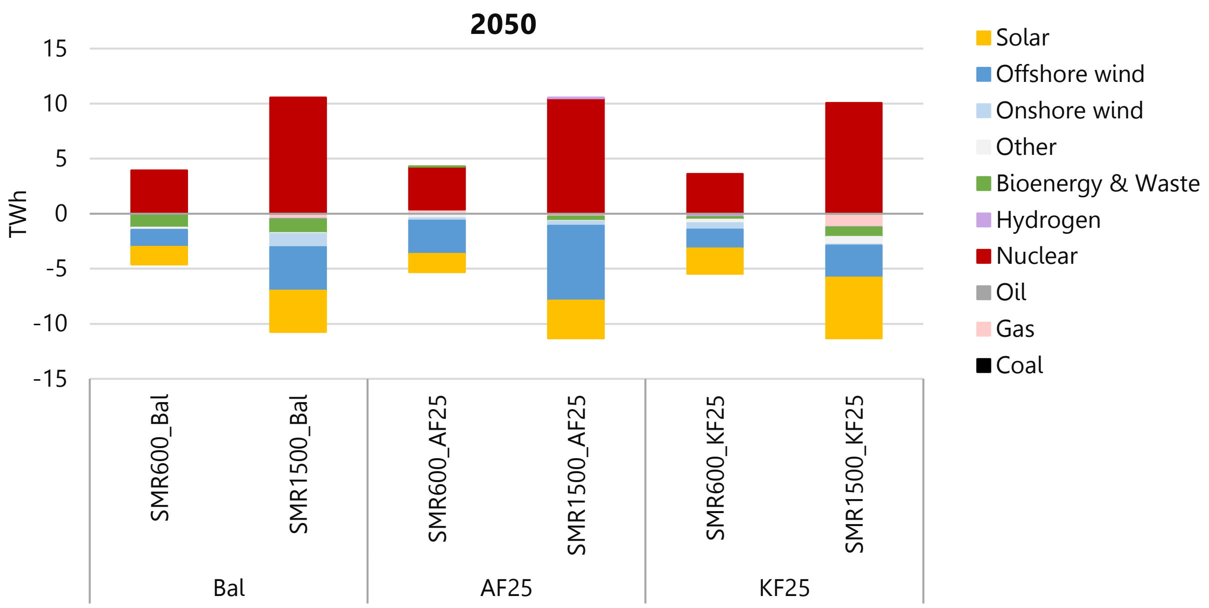
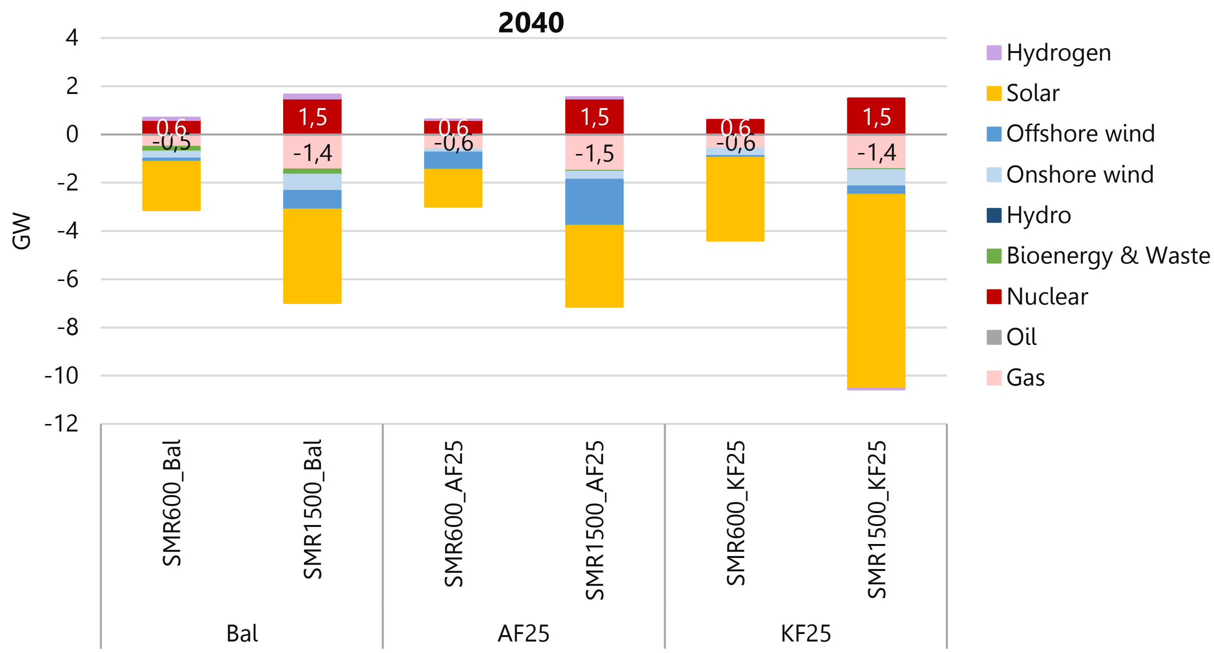


Figure 17. Change in electricity generation in 2040 and 2050 in the modelled European energy system as a result of the implementation of SMR in Denmark. The figure shows changes compared to the given reference scenario without SMR (the SMR0 scenario for the Bal, AF25 and KF25 scenario groups, respectively).

It can be seen that electricity generation from nuclear power in Europe increases by approximately 3.6-3.9 TWh in the scenarios where an SMR capacity of 600 MW electricity is assumed implemented (the SMR600 scenarios) and increases by 10.0-10.6 TWh in the SMR1500 scenarios. This primarily displaces electricity generation from offshore wind and solar PV in the form of reduced expansions (see Figure 18). This is in line with the fact that wind and solar predominantly covers the increase in annual electricity consumption in the reference development (see Figure 9). Onshore wind is typically more competitive than offshore wind, but the onshore wind potential is already fully exploited in the model in 2040 in many countries (including Denmark) before the assumed SMR implementation. Therefore, it is primarily expansion with offshore wind and not onshore wind that SMR displaces (i.e. the marginal wind power expansion is in many cases comprised by offshore wind power).

Some electricity generation from biomass- and gas-fired plants is also displaced, as generation from this type of plants is used in the balancing of wind power and solar PV.



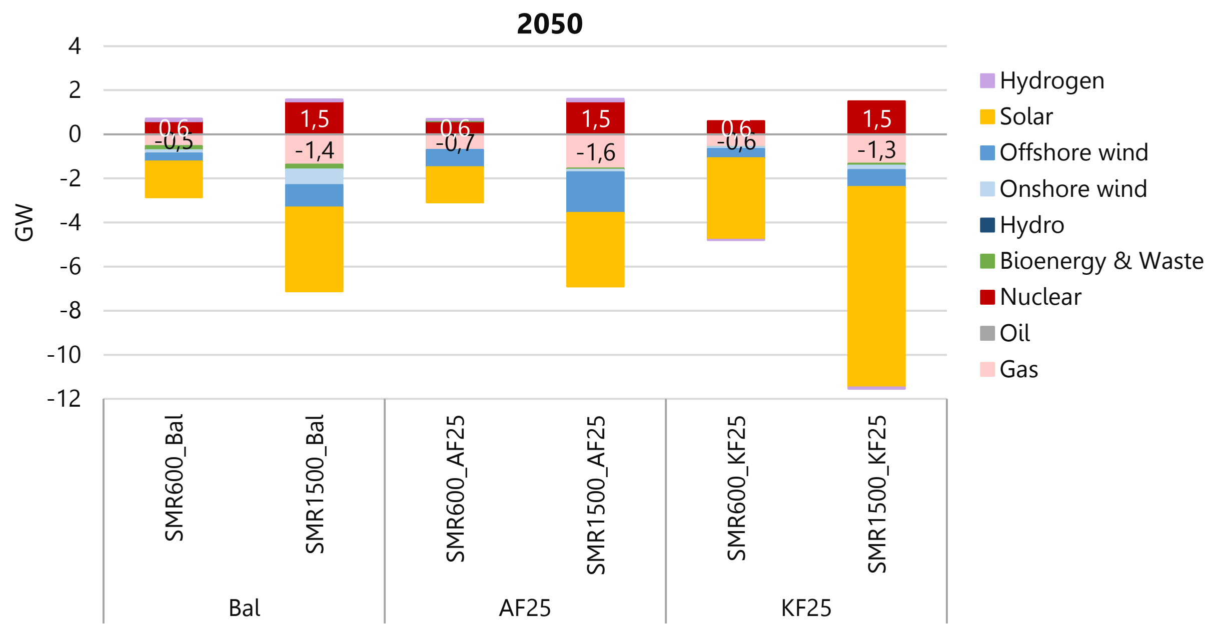


Figure 18. Change in power capacity in 2040 and 2050 in the modelled European energy system as a result of the assumed implementation of SMR in Denmark. The figure shows changes compared to the given reference scenario without SMR (the SMR0_Bal, SMR_AF25, and the SMR0_KF25 scenario respectively).

Apart from the displaced expansions of wind power and solar PV, Figure 18 illustrates that the implementation of SMR in Denmark displaces gas fired capacity expansions in Europe; more or less equivalent to the SMR power capacity: 0.5-0.7 GWe gas fired capacity in the scenarios where 0.6 GWe SMR capacity is implemented and 1.3-1.6 GWe gas fired capacity in the scenarios where 1.5 GWe SMR capacity is implemented.

In addition to the shifts shown in the electricity generation itself, there are modest changes in, among other things, hydrogen production in Europe and hydrogen imports to the continent, which results in small changes in total electricity consumption in Europe. Therefore, the increased electricity generation from nuclear power in the figure does not necessarily correspond exactly to the total displaced electricity generation.

Impacts on the Danish power system

Figure 19 and Figure 20 shows the displaced electricity generation and power capacity in Denmark, as a result of the assumed SMR implementation.

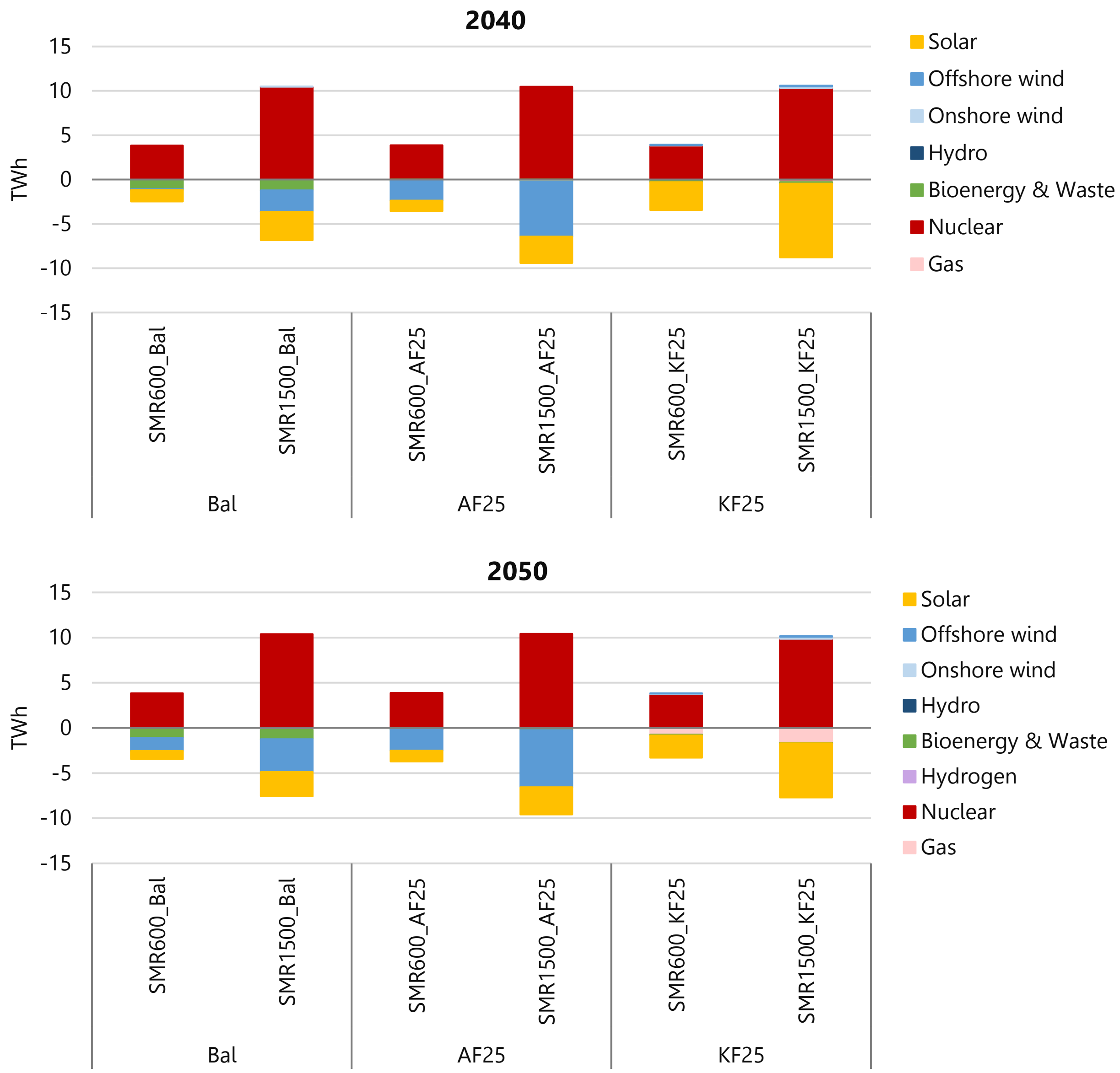
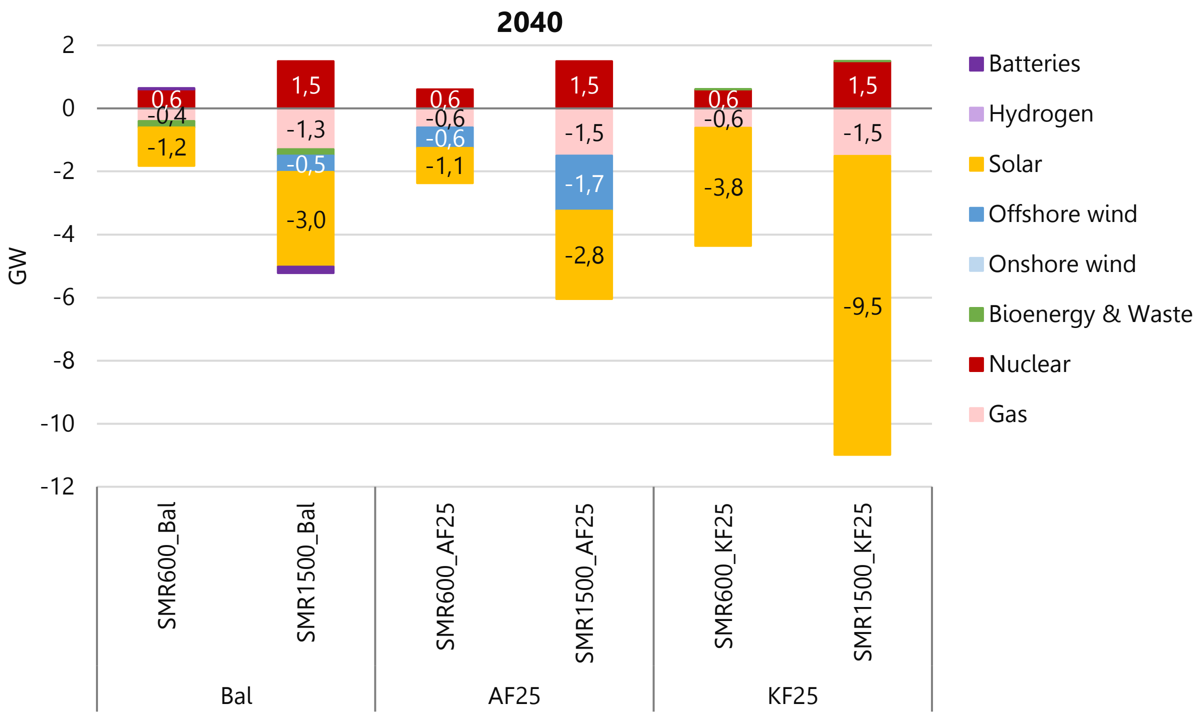


Figure 19. Change in Denmark's electricity generation in 2040 and 2050 in the model as a result of the implementation of SMR in Denmark. The figure shows changes compared to the given reference scenario without SMR (the SMR0 scenario for the Bal, AF25 and KF25 scenario groups, respectively).



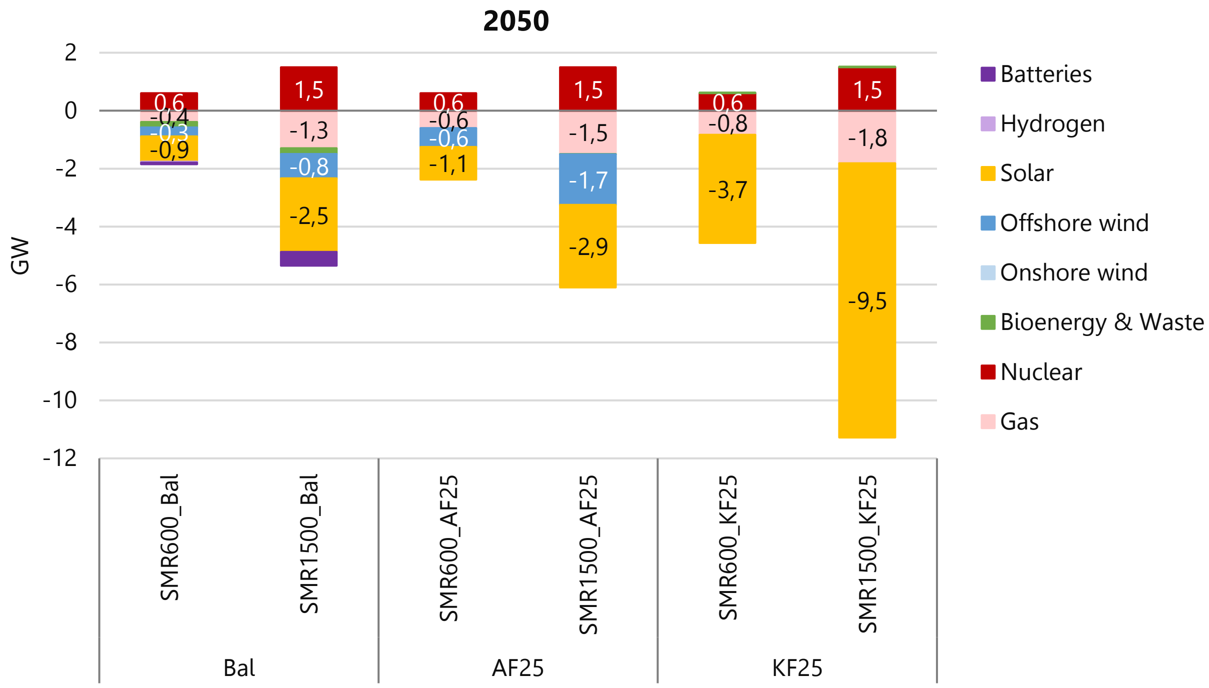


Figure 20. Change in Denmark's power capacity in 2040 and 2050 in the model as a result of the implementation of SMR in Denmark. The figure shows changes compared to the given reference scenario without SMR (the SMR0 scenario for the Bal, AF25 and KF25 scenario groups, respectively).

In Denmark, too, it is primarily electricity generation from solar PV and offshore wind that is displaced in the form of reduced expansion (secondary displacement of thermal electricity generation from biomass and gas). For the KF25 scenarios, the figure illustrates the assumption that SMR implementation displaces solar PV expansion in Denmark. Correspondingly, the AF25 scenarios illustrate the assumption that SMR primarily displaces offshore wind expansion (approx. 70% in terms of generation) and secondarily solar PV expansion (approx. 30% in terms of generation) in Denmark. In line with the assumption, the displaced electricity generation in Denmark in the AF25 and KF25 scenarios is seen to correspond approximately to the increased SMR electricity generation. However, for the KF25 scenario, for example, the reduction in solar PV electricity generation is smaller than SMR electricity generation. This is because the lower solar PV capacity in the SMR scenario results in a reduction in curtailment (waste) of electricity generation from solar PV.

In the Bal scenarios, where capacity development in Denmark is based on optimisation, the reduction in Danish electricity generation is only about half as large as the added electricity generation from SMR. This means that about half of the displacement occurs in the rest of the European energy system (primarily occurs in continental Europe and secondarily in the other Nordic countries).

Across all scenarios, the implementation of SMR in Denmark displaces an investment in gas fired capacity in Denmark of a magnitude similar to the SMR power capacity. As such, around 0.4-0.8 GW gas fired power capacity is displaced in the SMR600 scenarios and around 1.3-1.8 GW gas fired power capacity is displaced in the SMR1500 scenarios. This is an effect of the firm dispatchable power capacity provided by SMR resulting in a reduced need for other dispatchable units in Denmark. As such, the displaced gas capacity identified in the European system mainly comprises capacities in Denmark.

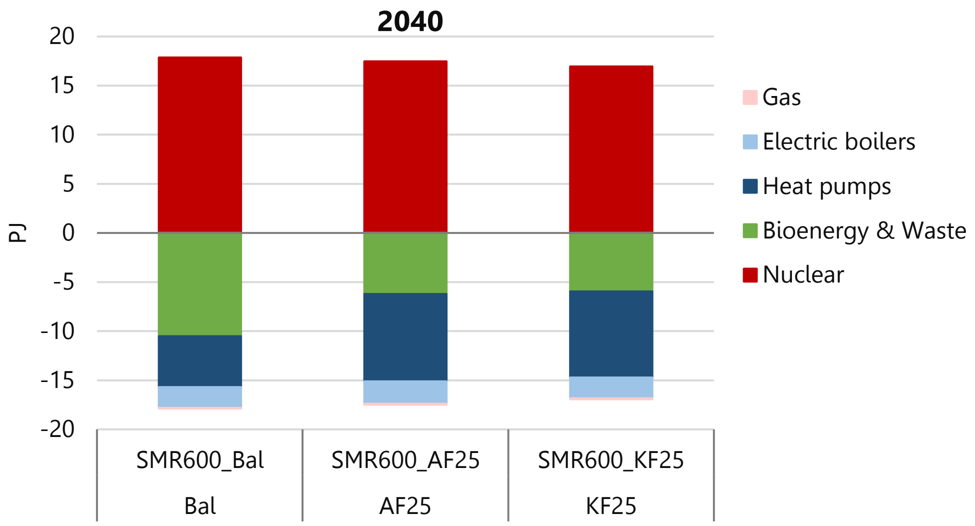
4.2. Impact on electricity transmission expansion

The energy systems analysis does not indicate that the implementation of SMR in Denmark will have a significant effect on the feasibility of transmission expansions in Europe. As such, the level of feasible transmission expansion in the European energy system identified in the optimisation, is practically identical in the reference scenarios without SMR in Denmark, as in the scenarios with SMR in Denmark.

4.3. Impact on district heating generation and capacity

As mentioned, the full SMR capacity in the SMR600 scenarios is assumed to be combined heat and power plants, including capacities of 300 MW electricity and 400 MW heat in DK1 (for the calculation assumed in Aarhus) and 300 MW electricity and 400 MW heat in DK2 (for the calculation assumed in Copenhagen). The additional SMR capacity deployed in the SMR1500 scenarios is assumed to be power-only capacity, and thus, the heat capacity is the same as in the SMR600 scenarios.

Figure 21 shows how the total district heating production in Denmark is affected by the assumed implementation of SMR. More specifically, the figure shows the total production change in the two district heating areas where SMR is assumed to be established in terms of calculation. The change in heat production is almost identical in the SMR600 and SMR1500 scenarios, due to identical SMR heat capacities, and therefore only the SMR600 scenarios are shown.



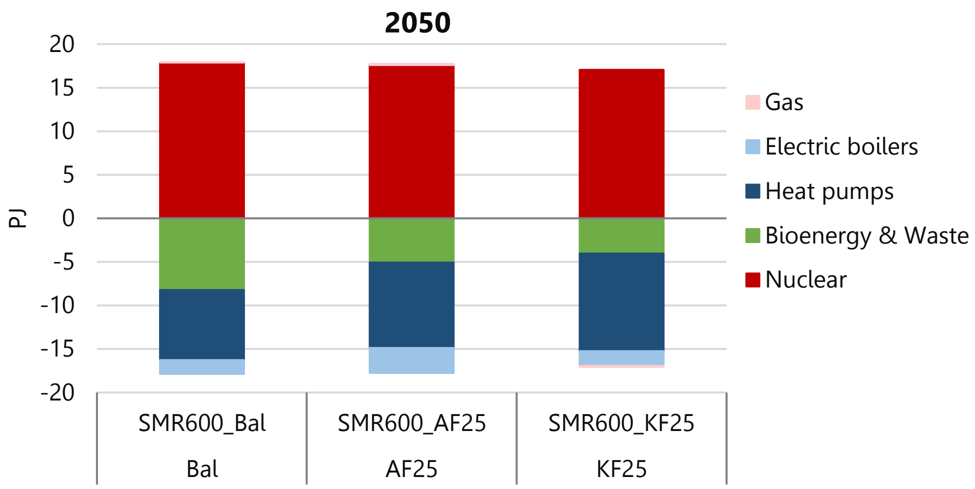


Figure 21. Change in district heating generation in 2040 and 2050 in the model as a result of the implementation of SMR in Denmark. The figure shows changes compared to the given reference scenario without SMR (the SMR0 scenario for the Bal, AF25 and KF25 scenario groups, respectively). Any derived changes in district heating areas without SMR are not included in the figure.

It can be seen that the district heating production from SMR primarily displaces heat generation from biomass and heat pumps and to a lesser extent heat generation from electric boilers. This is because biomass and heat pumps supplemented by electric boilers constitute competitive district heating production under the applied preconditions. This thus constitutes the long-term marginal district heating production that is displaced by SMR.

As illustrated in Figure 22, the SMR implementation in the SMR600 scenarios also displaces district heating capacity expansions in Denmark.

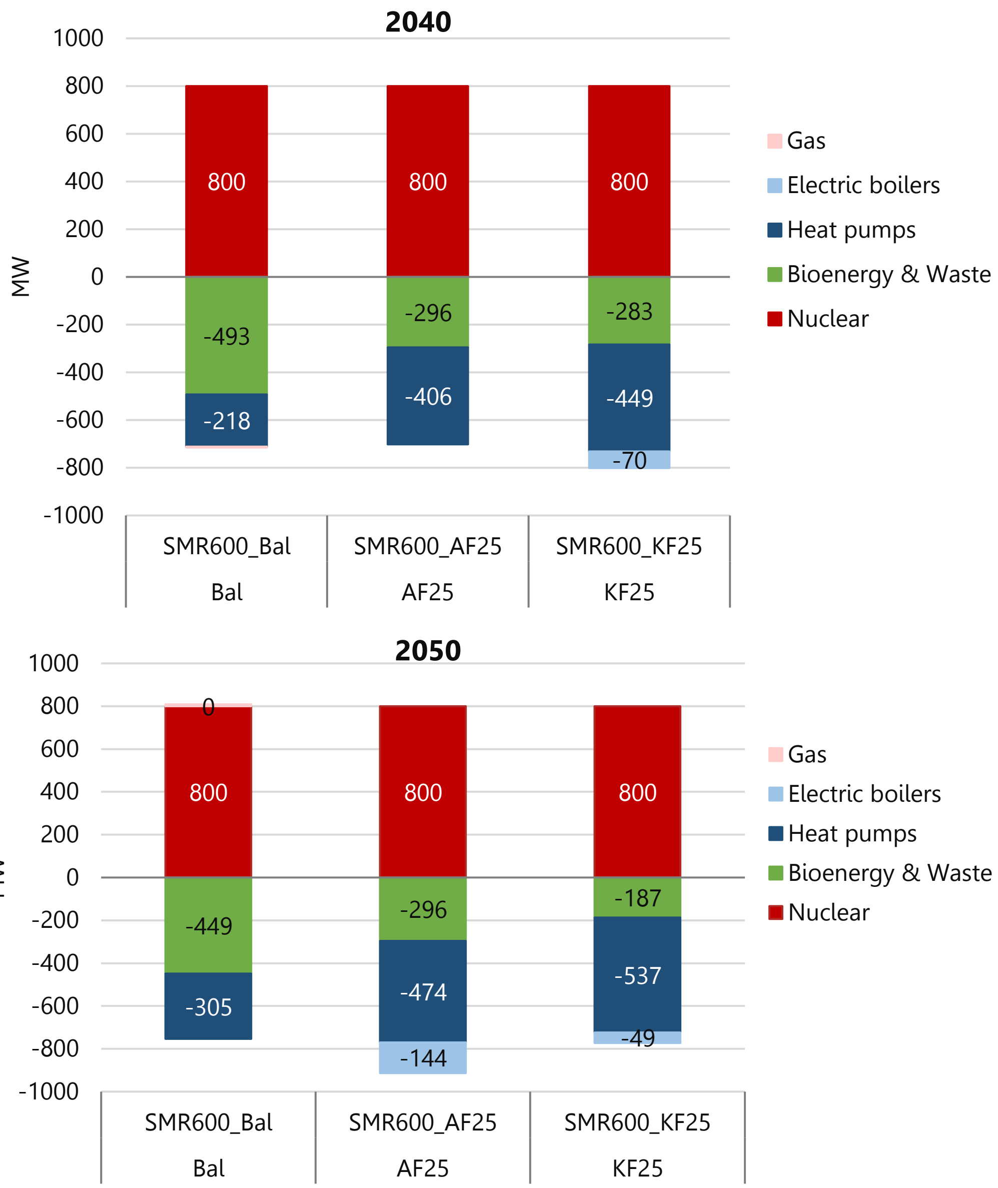


Figure 22.. Change in Denmark's district heating production capacity in 2040 and 2050 in the model as a result of the implementation of SMR in Denmark. The figure shows changes compared to the given reference scenario without SMR (the SMR0_Bal, SMR0_AF25, and the SMR0_KF25 scenario). Any derived changes in district heating areas without SMR are not included in the figure.

As shown, the assumed implementation of 800 MW heat capacity from SMR in Denmark mainly displaces investments in biomass fired plants (190-500 MW heat) and heat pumps (220-540 MW heat), and in some cases also electric boilers (up to 50-140 MW heat). Overall, the SMR CHP implementation displaces a total heat capacity of around 700-900 MW heat capacity, depending on the scenario and year, i.e. a capacity more or less equivalent to the installed SMR heat capacity.

4.4. Impact on the electricity and hydrogen trade balance

Denmark's electricity trade balance in the different scenarios is shown in Figure 23.

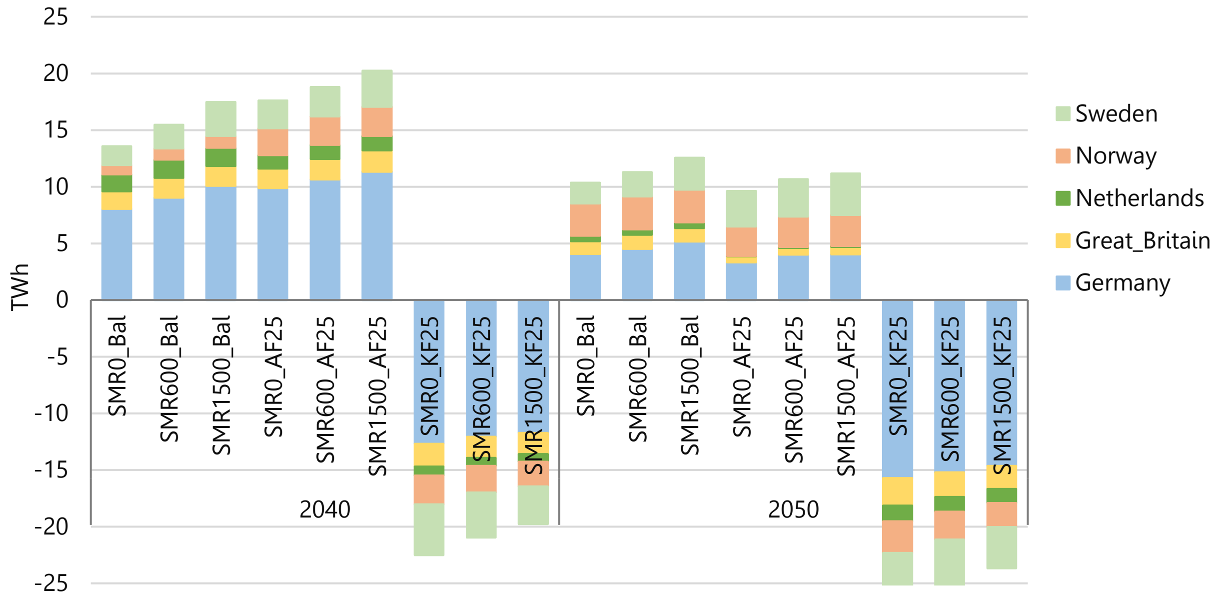


Figure 23. Denmark's electricity trade balance in 2040 and 2050 in the different scenarios. Positive values express net electricity exports and negative values express net electricity imports.

When comparing the SMR scenarios with the scenarios without SMR (SMR0), it is seen that implementing SMR improves Denmark's electricity trade balance. Thus, Denmark's net electricity exports increase in the Bal and AF25 scenarios and net electricity imports decrease in the KF25 scenarios. This is because of the assumed implementation of SMR, which has low variable costs, and also because Danish electricity consumption is decreased, as the SMR's displace heat pump production in the district heating areas. It can be noted that an assumed large-scale implementation of another technology with low variable costs, e.g. wind power or solar PV would also improve Denmark's electricity trade balance.

Figure 24 shows that Denmark's hydrogen trade balance is more or less unaffected with the implementation of SMR. However, in the Bal- and AF-scenarios for 2050 the export of hydrogen increases moderately in some cases as a result of the SMR implementation. The models generated investments in hydrogen pipelines between Denmark and other countries are not affected by the SMR implementation.

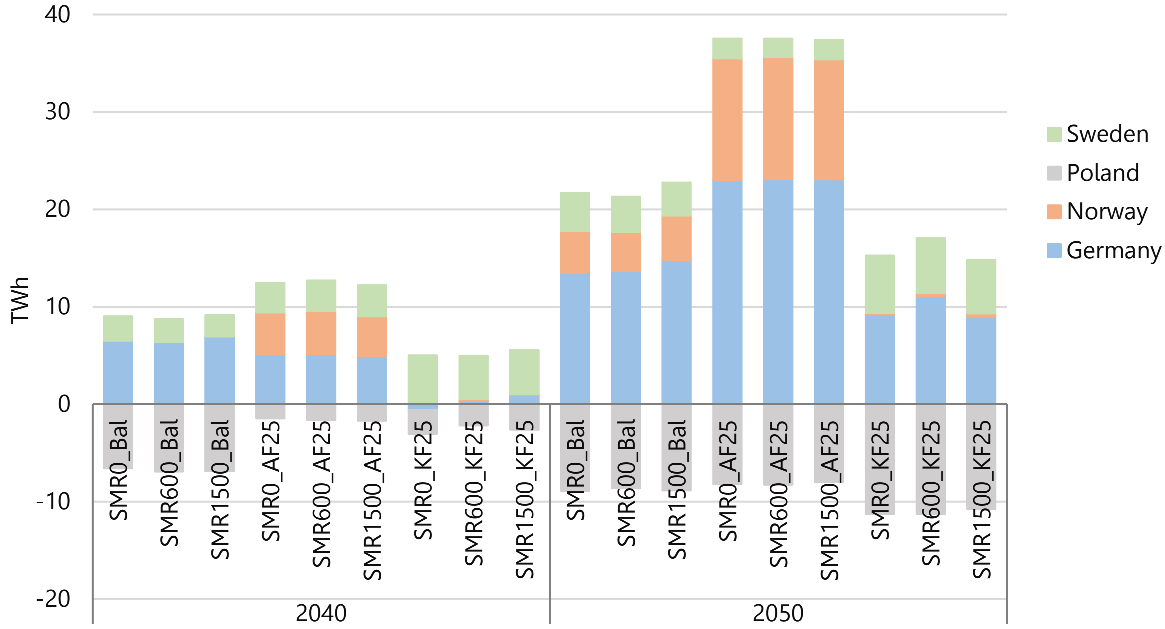


Figure 24. Denmark's hydrogen trade balance in 2040 and 2050 in the different scenarios. Positive values express net hydrogen exports and negative values express net hydrogen imports.

4.5. Impact on electricity prices

Figure 25 shows the change in the average electricity price in Denmark as a result of the assumed SMR implementation.

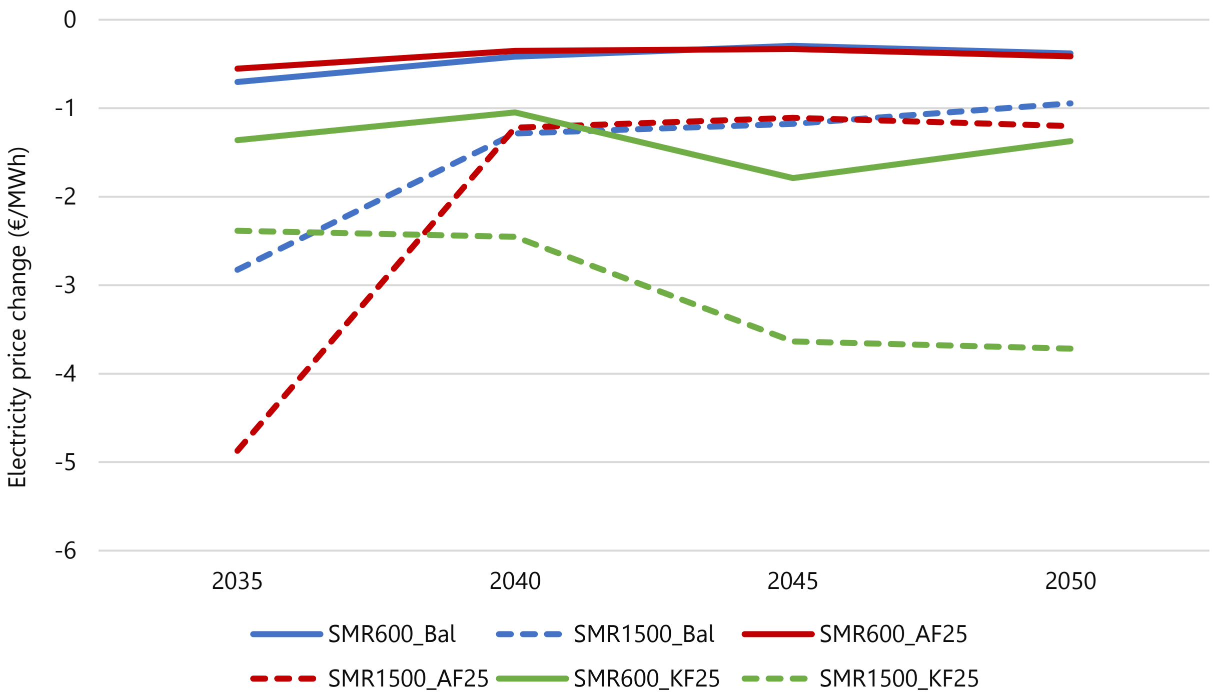


Figure 25. Changes in the average whole-sale electricity price in Denmark as a result of an SMR implementation in Denmark for the different scenarios. The figure shows changes compared to the given reference scenario without SMR (the SMR0_Bal, SMR0_AF25, and SMR0_KF25 scenario, respectively). For simplification, the electricity price is shown as a simple average of the electricity price in DK1 and DK2.

Figure 25 shows that the average whole-sale electricity price level in Denmark will be reduced by approximately 0.3-4.9 €/MWh over the period as a result of the assumed SMR implementation, depending on the year and the scenario (0.4-3.7 €/MWh in 2050). An electricity price reduction in the model is expected, since SMR has a given amount of power capacity with low variable generation costs is assumed implemented in the scenarios. This would also have been the case if comparing scenarios with and without e.g. a given wind power or solar PV capacity. To which extent the illustrated price reduction would materialise into lower electricity price for the consumer, depends on the cost of SMR, and how a potential need for economic support is financed.

In the Bal scenarios, where capacities in Denmark are balanced, the electricity price is reduced with around 0.3-2.8 €/MWh over the period (0.4-1.0 €/MWh in 2050). The electricity price reduction is highest in the short term where the power capacity is relatively low compared to the electricity demand due to modelled constraints on build-out of solar and wind. In the short term, the need for new power capacity in the reference situation (SMR0) is therefore highest, which yields a higher electricity price impact of implementing SMR.

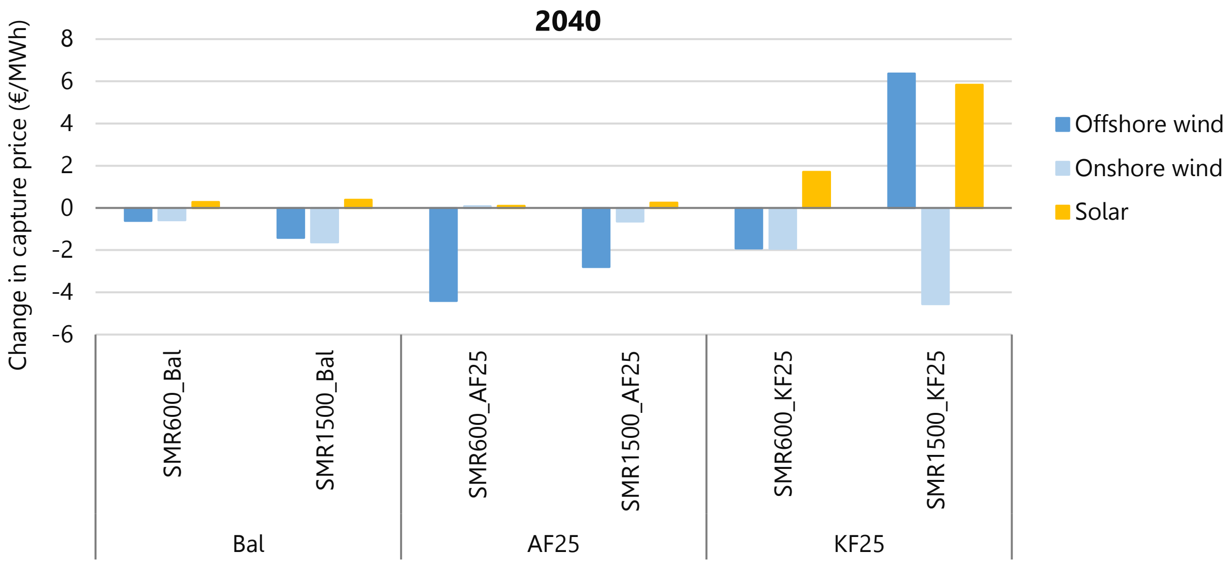
The electricity price impact of SMR in the AF25 scenarios is similar to the impact in the Bal scenarios. However, the electricity price reduction of 1500 MWe SMR in 2035 is higher in the AF25 scenario than in Bal scenario. This is likely due to the higher electricity price levels in AF25 than in Bal (due to the higher fuel and CO_2 prices assumed in AF25).

The electricity price impact of SMR in the KF25 scenarios is higher than in the Bal scenarios. This reflects a high system imbalance in the reference situation in KF25, due to a rather low power capacity development compared to what is optimal according to the system optimisation.

4.6. Impact on capture prices for wind power and solar PV

Figure 26 shows how the implementation of SMR in Denmark affects the technology-weighted electricity price (capture price) for wind power and solar PV in Denmark. In the Bal-scenario, capture prices for wind are reduced by 0.4-1.6 €/MWh in 2040 and 2050. In the AF25 scenarios, the reduction in offshore capture prices is higher (2.8-6.6 €/MWh) since there the assumed offshore wind capacity is relatively high in AF25. This makes the offshore capture price more sensitive to the addition of SMR into the system.

In the KF25 and AF25-scenarios, the SMR-production is assumed to have a higher impact on the reduction of solar PV and wind power production in Denmark than in the Bal scenario. As a consequence, the capture price is in some cases increased with the implementation of SMR, e.g. for the case of solar PV in KF25.



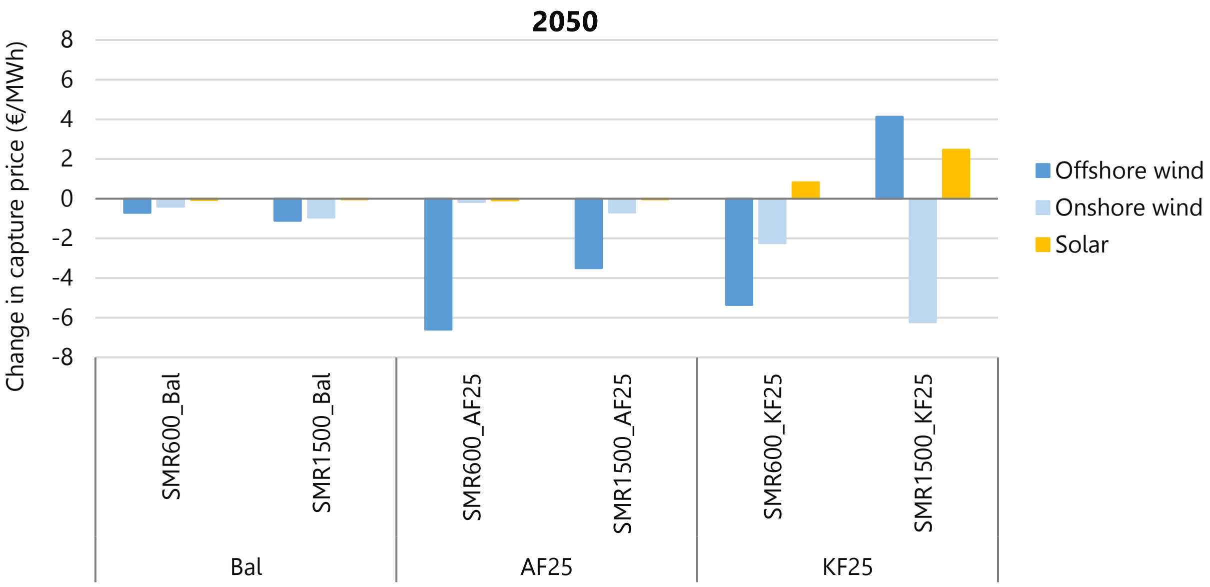


Figure 26. Change in the capture price for solar PV (field systems), onshore wind and offshore wind in Denmark as a result of SMR implementation. The figure shows changes compared to the given reference scenario without SMR (the SMR0 scenario for the Bal, AF25 and KF25 scenario groups, respectively). The technology -weighted electricity price for offshore wind constitutes an estimate for new radially connected offshore wind in Denmark.

4.7. Impact on security of supply indicators

As shown in section 4.4, the assumed SMR implementation results in increased net electricity export or reduced import on an annual basis. As mentioned, this is a natural effect of an assumed implementation of a technology with low variable costs. In the following, it is investigated to which extent Denmark's dependency of electricity import over the year is affected by the SMR implementation.

The residual electricity demand, i.e. demand minus generation from wind power and solar PV, shows the need for electricity import or dispatchable generation. In the following graphs and tables, the traditional residual demand over the year has been expanded to also subtract the firm dispatchable capacity. This measure indicates the dependency on electricity import. The resulting graph for Denmark for the Bal scenarios, show around 360-410 in 2050, where Denmark is dependent on electricity import (the hours in the left side of Figure 27, where residual demand is higher than the available dispatchable capacity).

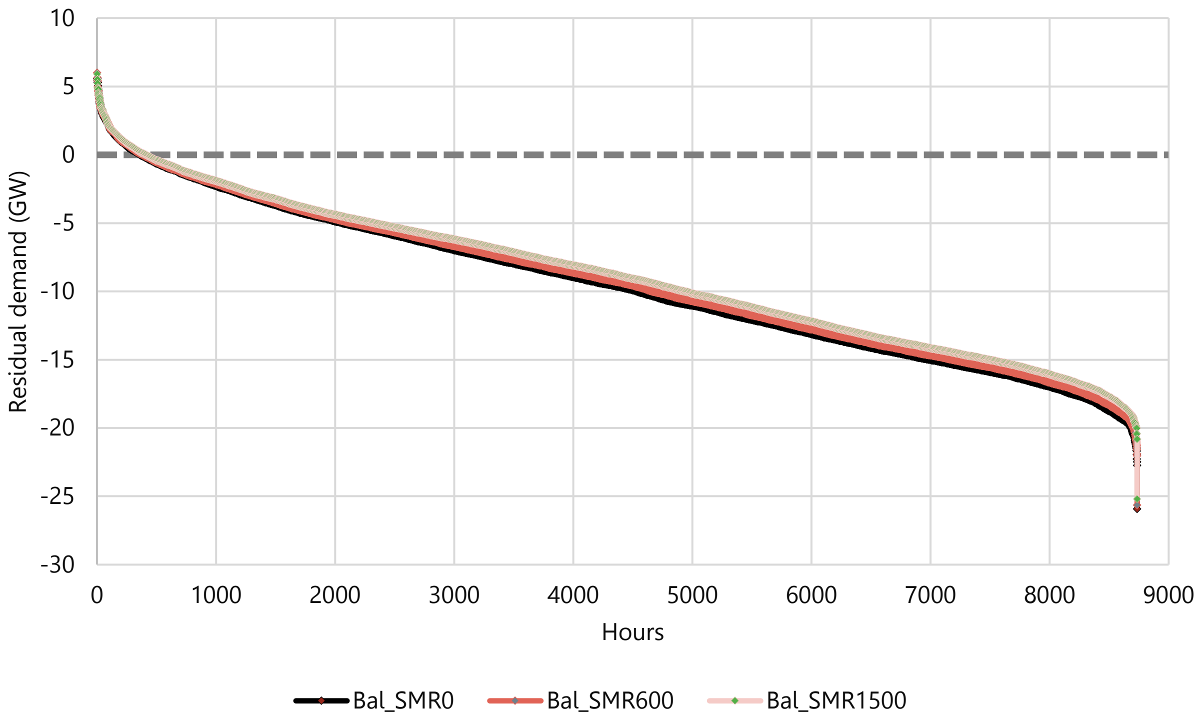


Figure 27 Residual demand minus firm dispatchable capacity. Bal scenarios, 2050 for Denmark.

Across the Bal scenarios, it is found that introducing SMR capacity results in a higher amount of hours with electricity import dependency (from 360 hours to 380-410 hours). This might be surprising, considering the fact that the annual electricity trade balance is improved with the SMR implementation. The explanation is that the SMR capacity both displaces an equivalent amount of gas turbine capacity (since same amount of firm dispatchable capacity is ensured across scenarios), plus other power capacities, mainly wind turbine and solar PV (see Figure 18). Therefore, the renewable energy generation in Denmark is lower, and the residual electricity demand thus higher. Since the firm dispatchable capacity is at the same time unchanged, the amount of hours with import dependency is thus increased.

The amount of hours with electricity import dependency and the maximum import need (GW) for both the Bal, AF25, and KF25 scenarios is shown in Table 8. The AF2 and KF25 scenarios confirm the same overall result as found in the Bal scenarios: that implementing SMR capacity results in a higher amount of hours with electricity import dependency.

The maximum import need over the year (GW) is in some cases increased with the SMR implementation, while in other cases it is reduced or on same level.

Table 8 Electricity import dependency in the scenarios in terms of hours and maximum import need. Calculated based on the residual demand, minus thermal capacity.

	Scenario	Hours with import need (# of hours)	Max import need (GW)
2040	SMR0_Bal	305	5.2
	SMR600_Bal	315	5.2
	SMR1500_Bal	345	5.1
	SMR0_AF25	426	7.8
	SMR600_AF25	456	7.3
	SMR1500_AF25	499	7.6
	SMR0_KF25	2,333	6.9
	SMR600_KF25	2,384	6.8
	SMR1500_KF25	2,487	6.7
2050	SMR0_Bal	360	5.6
	SMR600_Bal	379	6.0
	SMR1500_Bal	410	5.9
	SMR0_AF25	516	8.6
	SMR600_AF25	536	8.6
	SMR1500_AF25	571	8.5
	SMR0_KF25	3,481	7.8
	SMR600_KF25	3,830	7.4
	SMR1500_KF25	4,014	7.4

4.8. Impact on capacity payments and reserve cost

Capacity payments

The imposed capacity requirements for the modelled system and individual countries result in capacity payments based on the marginal cost of fulfilling the requirements. The marginal units fulfilling the requirements are natural gas turbines, which achieve little to no generation in the power market (around 350 full load hours, depending on location and year). Therefore, capacity payments are close to the cost of establishing and maintaining the units. Cost assumptions for this are based on regular open cycle gas turbines, resulting in capacity payments around 70.000 €/MW/year in 2035 and 65.000 €/MW/year in 2050. Units optimised for mainly delivering capacity could prove to show lower costs, reducing this capacity payment. Introducing SMR only marginally affects the system wide capacity payments, but the SMR units will have a value for the system reflecting this marginal value. On a system basis, introduction of SMR in Denmark increase total capacity payments a little (below 0,05%), because the marginal units are affected by lower income in high price hours.

Reserve cost

The minimum requirement for operational reserves to be delivered by firm dispatchable capacity is fulfilled by the least efficient power plants. Those power plants also have a role in fulfilling overall capacity requirements, and therefore the marginal cost of providing operational reserve is only owed to the opportunity cost lost when not being able to participate in the electricity market. As the power plants have high marginal cost, the potential income generated in high price hours is low. Therefore, marginal cost for fulfilling the minimum requirements for operational reserves is around 200 €/MW/year in 2035, reducing to 100 €/MW/year in 2050. However, these cost levels require income from capacity payments.

The operational reserves dimensioned dynamically and provided by a wider range of units show cost around 6.700 €/MW/year in 2035, reducing to around 1.750 €/MW/year in 2050, as the units providing these services have opportunity cost related to not being able to participate in the power market in the given hour. These prices are significantly below today's ancillary service prices. Dynamically dimensioned reserves are mainly provided by hydro power, batteries, flexible demand (heat pumps) and to a smaller extent variable renewable energy (running below maximum power) and thermal power plants. Introduction of SMR reduces the need for reserves as the amount of wind and solar in the system is reduced. However, the impact is low, as it only affects dimensioning of reserves in hours with high penetration of wind and solar power. On average, reserve needs are reduced by up to 20 MW/hour in the SMR1500 scenario. While technically feasible (when in operation), SMR does not provide reserves to the system, since it is more beneficial to run the SMR units at high capacity factors to provide electricity and heat generation instead of backup capacity.

Both the cost of minimum requirements for operational reserves as well as the cost of dynamically dimensioned reserves are heavily correlated to the income some of the participating units can receive from capacity mechanisms. Whether the introduction of SMR has a value within capacity markets or reserve provision is therefore also a question of market setup and the distribution between the different categories.

Balancing cost

Balancing cost reflects the cost of activating the reserves close to the operational hour, and the difference of doing so instead of planning the according dispatch in the day-ahead market. The activation cost is not modelled explicitly, and cost impacts when introducing SMR are therefore based on an analysis of statistics as explained in section 2.4.

4.9. SMR revenue streams

In the following, the revenue streams for the SMR owner are calculated in the different scenarios. This covers the revenue from electricity and heat sales as well as income on an assumed capacity market. The different revenue streams are estimated as follows:

- **Revenue from electricity sales**: Calculated as electricity generation from SMR in each hour multiplied by the electricity price in each hour. This represents the revenue from electricity sales on the day-ahead spot market. In the model, the electricity price in each hour reflects the marginal cost of supplying an extra electricity demand.
- **Revenue from heat sales**: Given by the district heat generation from SMR in each hour multiplied by the heat price in each hour. In the model, the heat price in each hour reflects the marginal heat production cost. As such, the estimated heat value does not take heat contracts with potential alternative pricing of the heat generation into account.
- **Capacity market revenue**: Calculated as the power capacity of the assumed SMR implementation in Denmark multiplied with the power capacity value identified in the system optimisation. The power capacity value is found as the marginal cost of dispatchable power in the system and is given as the shadow value of the model constraint ensuring sufficient dispatchable power (e.g. 5600 MW

in Denmark and 525 GW in the modelled European power system in 2050). The capacity value assumes that such a capacity market is in place.

The SMR revenue streams are estimated for each model simulation year, based on the prices, generation levels and capacities for the given year (see Figure 28).

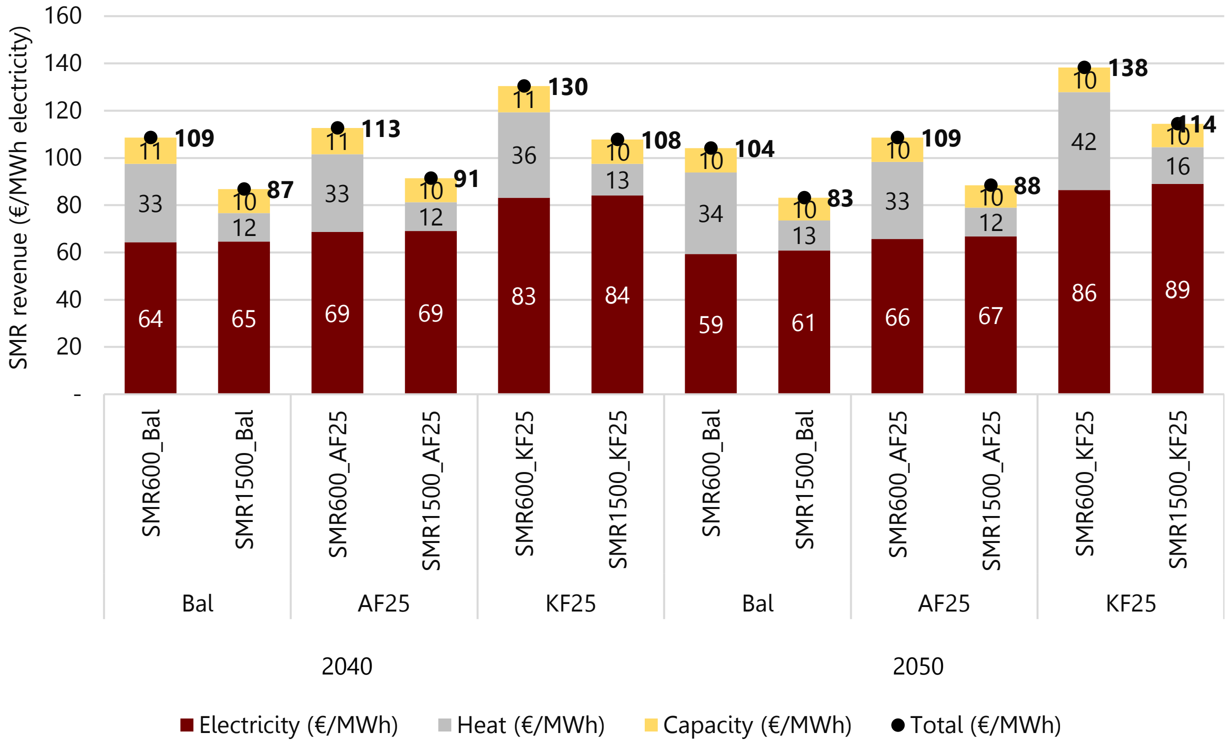


Figure 28. SMR revenue streams in the modelled scenarios.

As shown, the total SMR revenue is estimated to be around 83-138 € /MWh-e in 2040 and 2050 for the different scenarios. The electricity generation from SMR comprises the largest part of the total revenue (57-78%), but the heat revenue is also significant (12-33%) as well as the capacity revenue (8-12 %).

Heat sales comprise a lower share of the total revenue in the SMR1500 scenarios than in the SMR600 scenarios, since the additional 900 MW-e of SMR capacity in the SMR1500 scenarios alone comprises power generation capacity, and not CHP capacity.

Figure 28 shows that the total revenue of SMR per MWh is significantly higher in the SMR600 scenarios, where SMR is implemented as CHP, than in the SMR1500 scenarios, where the additional SMR capacity is installed as power-only units. This shows that the total revenue of SMR units is higher if implemented as CHP instead of as power-only units.

Moreover, the results show that the capacity revenue comprises a significant part of the total SMR revenue. The capacity revenue is not necessarily fully reflected in the current market.

4.10. System value

Illustrations of system value

The system value of SMRs can be illustrated in several ways. The main methodology used to evaluate SMR value is described in section 2.5. In this report, the illustrations are based on model results showing changes in fundamental system cost, supplemented by estimates for elements not covered by the model (notably balancing costs).

Fundamental system cost represents the total cost of supplying electricity, heat, and hydrogen demand in the modelled area for each simulation year. It includes:

- CAPEX for generation and storage assets, and for electricity and hydrogen transmission (including direct grid connection as well as reinforcement in surrounding transmission and distribution grids).
- Fixed and variable O&M for generation, storage, and electricity/hydrogen transmission.
- Fuel and CO_2 costs.
- Balancing costs.
- Electricity imports and exports.
- Hydrogen imports and exports.
- Congestion rents on electricity and hydrogen transmission.

When system costs are calculated for the *entire modelled European system*, total electricity import/export costs and congestion rents sum to zero. These elements therefore only matter when analysing system costs for a specific country or region. The same principle applies to hydrogen import/export between countries/regions and to congestion rents on hydrogen transmission.

Stakeholder perspective
Impacts on different stakeholder groups can be illustrated by allocating components of the fundamental system cost to each group, while accounting for payments between stakeholders (for example, transfers between electricity consumers and producers). Summed across all stakeholders, the net impact equals the fundamental system cost change.

Reporting formats
To make results easier to interpret, system value in each simulation year can be presented as:

- M€/year,
- €/MWh of *potential* SMR electricity generation (i.e., full output whenever available, limited only by technical availability), or
- Net present value (NPV) in M€/MW over a defined period, which allows for accounting of variations in system value over time.

Assessing steps in SMR deployment
The scenario set also allows assessment of staged SMR deployment in Denmark:

- SMR600 vs. SMR0 estimates the value of introducing 600 MW_e CHP units.
- SMR1500 vs. SMR0 estimates the value of introducing 600 MW_e CHP + 900 MW_e condensing units.
- SMR1500 vs. SMR600 isolates the incremental value of adding 900 MW_e condensing units on top of the CHP deployment.

Note that the incremental comparison (SMR1500 vs. SMR600) will typically assign slightly higher value to the CHP units, because the first MW added to the system often has higher marginal value than the last.

As an alternative, technology-specific value can be estimated by comparing SMR1500 vs. SMR0 and then distributing total system value between CHP and condensing units based on relevant drivers (e.g., capacity, electricity generation, and heat generation, depending on cost category). As with the stakeholder allocation, any split between technology types changes the *distribution* of value but not the *total*, which is defined by the change in fundamental system cost.

System value of SMR

Figure 29 shows how the assumed implementation of SMR in Denmark impacts the total system costs in Denmark and in the modelled European system. The cost of SMR is not included here (CAPEX as well as OPEX). Therefore, the figure does not show whether there is an overall net cost reduction of the SMR roll out in Denmark.

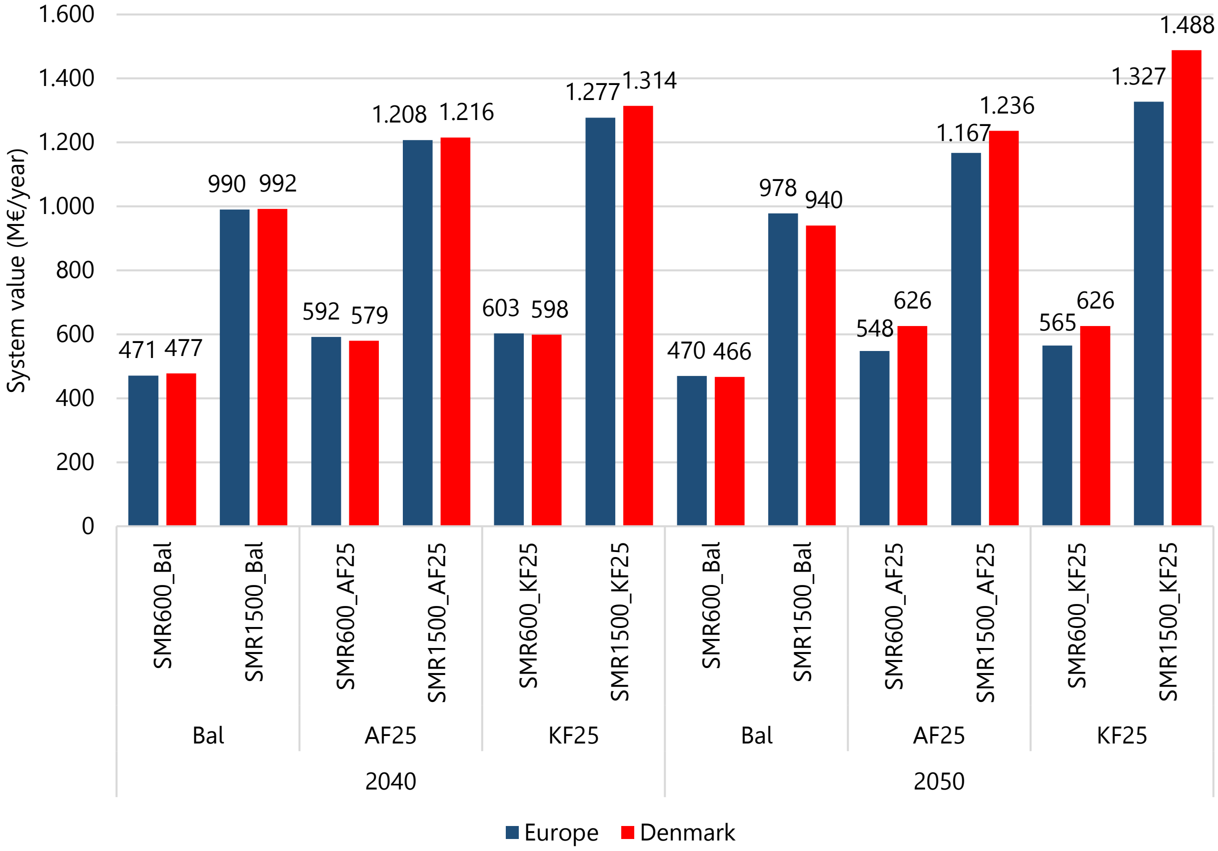


Figure 29. The system value (system cost reduction) of the assumed SMR implementation for Denmark and for the modelled European energy system, respectively. The value is shown annualised for 2040 and 2050 for the different scenarios. The value of SMR must be compared with the cost of SMR, which is not included in the figure.

Figure 29 reveals that practically the full system benefit of an SMR implementation in Denmark belongs to the Danish energy system. When viewing the system benefit for Denmark, the improved electricity trade balance from the SMR implementation also plays a role (part of the electricity generation from SMR is exported).

As shown, in some cases, the system benefit in Denmark is somewhat higher than for Europe. This reflects the impact of low-cost electricity generation from SMR in Denmark, resulting in higher electricity trade renues for Denmark and lower electricity trade revenues for other European countries. This can in some scenarios result in a higher system benefit for Denmark than Europe. As expected, there is a larger absolute system benefit in the SMR1500 scenarios where the SMR capacity is larger.

Figure 30 illustrates how the SMR system benefit in the European energy system in 2050 is distributed on different cost categories.

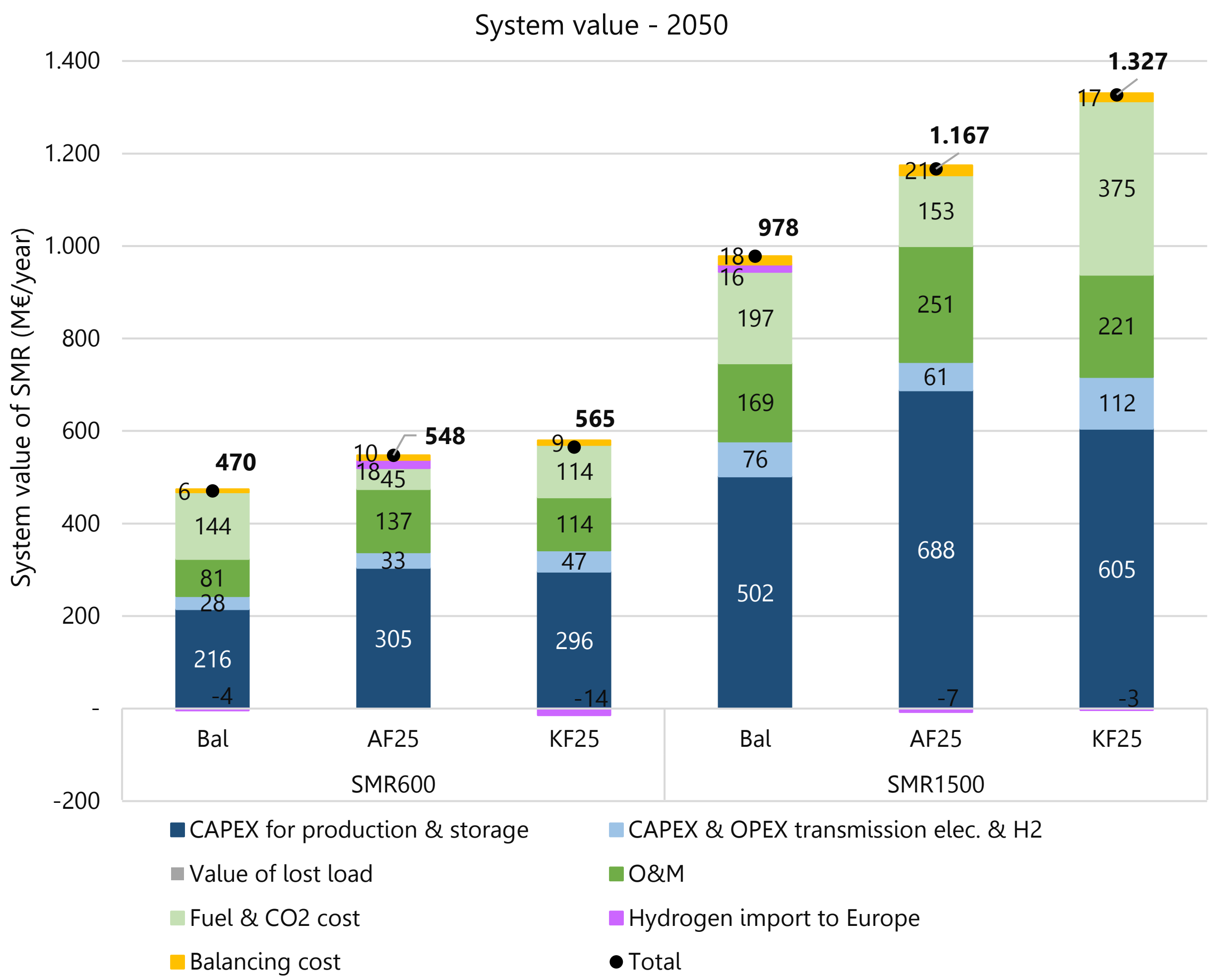


Figure 30. The system value (system cost reduction) of SMR Europe in 2050 in the Bal, AF25, and KF25 scenarios distributed on cost categories.

A large part of the system benefit is comprised by CAPEX savings on production and storage units, fuel and CO_2 costs and O&M costs. Compared to the Bal-scenarios, AF-scenarios show higher CAPEX-savings related to the predefined replacement of offshore wind in Denmark. In KF-scenarios, the higher electricity prices reflect the fact, that savings from thermal based electricity production (biomass and gas) have higher importance and increase the total system value.

The major share of CAPEX savings is related to reduced buildout of wind and solar power, but also savings on gas turbines (providing firm capacity in the scenario without SMR) and biomass based district heating plants contribute to the savings (see Figure 31). In the AF25 scenarios, the CAPEX savings on offshore wind account for a larger share, since this is defined in the scenario setup. Similarly, CAPEX savings on solar PV account for a larger share in KF25-scenarios.

The buildout reductions of offshore wind and solar PV in AF and KF-scenarios are capacity reductions on units which provide relatively low system benefits due to the concentrated buildout in Denmark, with limited options for adjustment of local system integration measures (fixed to the defined scenarios). Therefore, the calculated system benefit of SMR is higher in the AF and KF-scenarios, than in the Bal-scenarios.

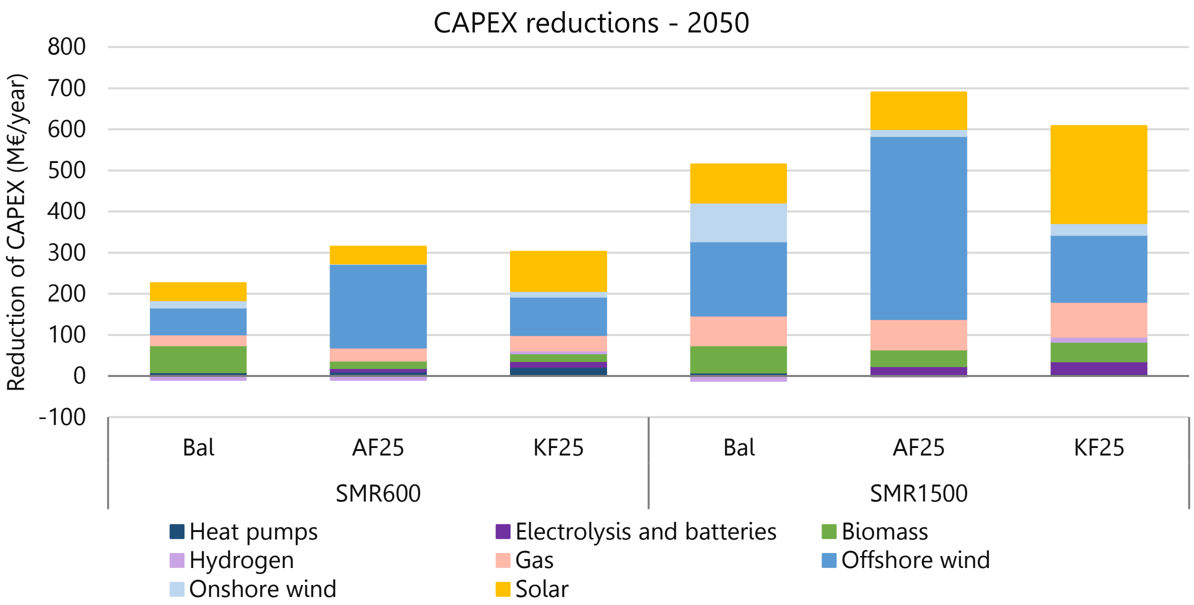


Figure *31. Detailed view of CAPEX savings on production technologies and storages in the European energy system in 2050 in the Bal, AF25, and KF25 scenarios (savings in the European energy system).*

Figure 32 shows how the system cost reduction, i.e. benefit of SMR in the European power system for the Bal scenario is distributed on stakeholders in 2050.

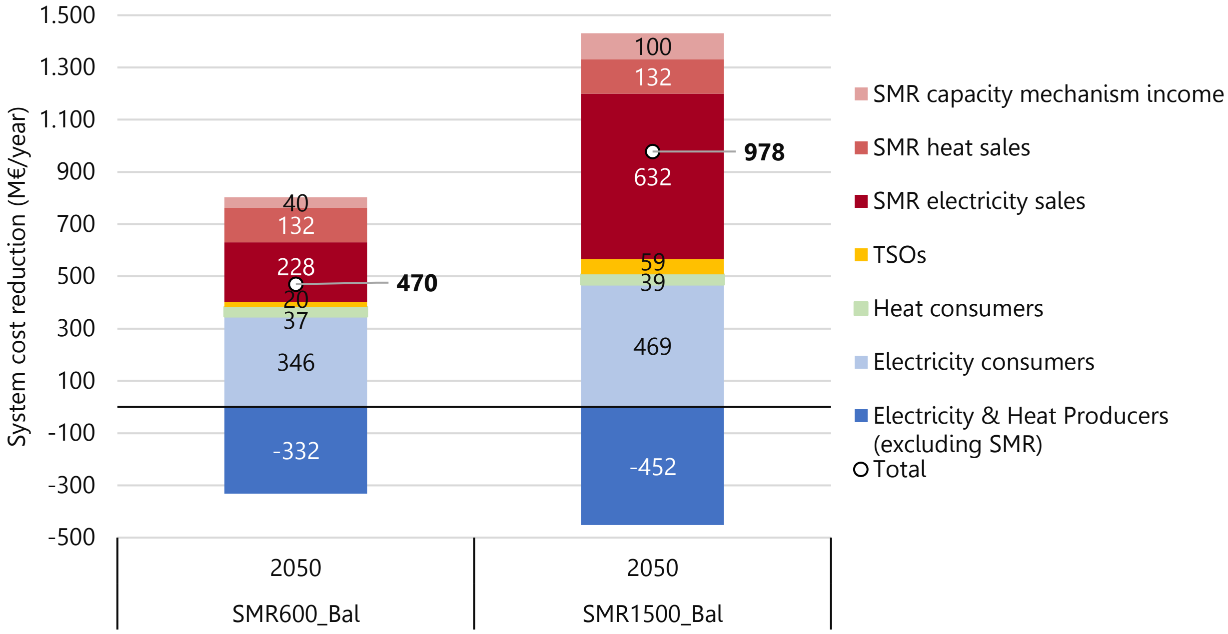


Figure 32. The system cost reduction, i.e. benefit of SMR in the Bal scenarios distributed on overall stakeholders in 2050 (value in the European energy system)

As illustrated, the stakeholder obtaining the largest system benefit is the SMR owner, who receives income from electricity sales, heat sales and capacity mechanism. As mentioned, the cost of SMR is not included in these figures. To which extent the SMR owner would be met by a net cost reduction thus depends on the cost of the SMR.

The second largest part of the system benefit is received by the electricity consumers in the form of electricity purchase at lower prices. System benefits are also received by heat consumers as a result of lower heat prices and by TSO's due to increased congestion rents.

Other electricity and heat producers (other than the SMR owners) are faced with increased costs as a result of reduced revenues from electricity and heat sales. This is an effect of the displaced electricity and heat generation and the electricity and heat price reduction resulting from the SMR implementation.

4.11. Economic feasibility of SMR

In this section, the estimated system value of SMR i.e. the system cost reduction estimated in Section 4.10, is held up against the expected cost of the SMR technology. This comparison can indicate to which extent an investment in SMR in Denmark is likely to be feasible from a system perspective.

The extracted SMR system values have been estimated for both the Bal scenarios, the AF25 scenarios, and the KF25 scenarios. However, in the interpretation most weight is given to the Bal scenario, where the capacity development is balanced. In the AF25 scenarios, there is a relatively high capacity expansion in Denmark, which means that capacity displaced by SMR has relatively low value. This means that the system value of SMR is high compared to a balanced market development of the system. Correspondingly, the KF25 scenario represents a frozen policy development with relatively low renewable energy expansion in Denmark compared to the projected demand. This means that there is high value of adding new capacity to the system, and this also yields a high value of implementing SMR in Denmark compared to a balanced market development of the system.

The cost of SMR is based on the three different cost development paths defined in the technical analysis of the project, representing different assumptions of technology development and build-out of SMR in the advanced economies.

- **Central** scenario: SMR technology cost development assuming a moderate technology cost in 2035, a significant build out of SMR in the advanced economies towards 2050, and a learning rate of 10 %.
- **Optimistic** scenario: SMR technology cost development assuming a low technology cost in 2035, a considerable build out of SMR in the advanced economies towards 2050, and a learning rate of 12.5 %.
- **Pessimistic** scenario: SMR technology cost development assuming a high technology cost in 2035, a limited build out of SMR in the advanced economies towards 2050, and a learning rate of 8.0 %.

For a more detailed description of the three SMR cost development scenarios, see section 2.3.

The SMR system values and costs are expressed in net present value (NPV) per SMR power capacity (MWe). The NPV is calculated assuming an SMR lifetime of 40 years and expresses the net present value in the implementation year. The calculations are made for an SMR implementation in 2040 and 2050, respectively. In the NPV calculation, the SMR system value identified in the model in 2040 and 2050 is extracted and values in years from 2040 to 2050 based on linear interpolation. The SMR value after 2050 is assumed to be the same as in 2050. Nevertheless, the identified SMR value in 2040 and 2050 are similar. As such, the main difference from the 2040 and 2050 investment case is the difference in the SMR cost.

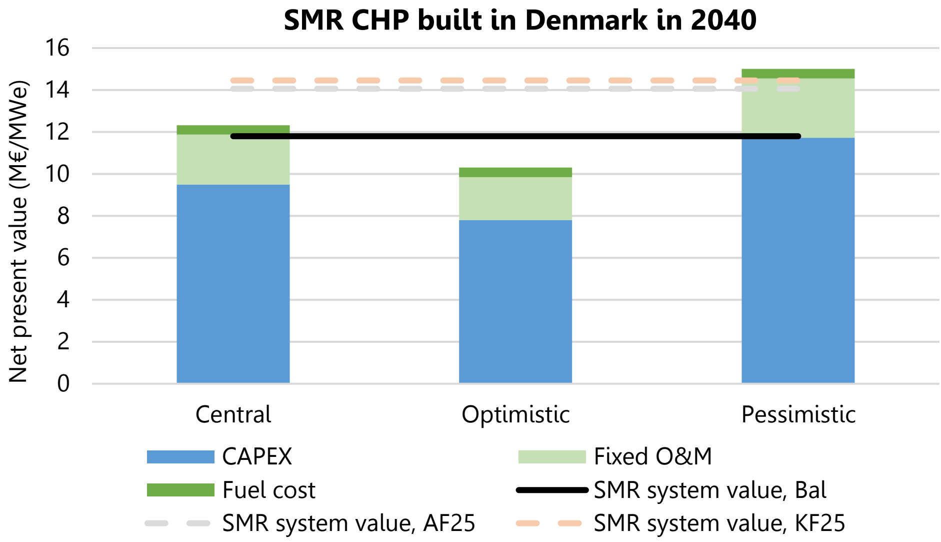
Decommissioning costs and scrap value of SMR after 40 years has not been excluded since the balance of these two counteracting cost elements at the long-term point of decommissioning, i.e. year 2080-2090, is highly uncertain. The SMR costs are based on the technology vintage year corresponding to the year in which SMR is considered implemented, i.e. 2040 or 2050. In the assumed CAPEX for SMR, construction costs are included based on assuming a construction period of 4 years.

The value versus cost comparison is made separately for a case of building SMR as a CHP and a power-only plant, respectively. The illustrated system value of SMR CHP unit is extracted from the SMR600 scenario, where 600 MWe of SMR CHP capacity is built (distributed evenly on DK1 and DK2). The illustrated system value of SMR as power-only is estimated as the system value of the SMR power-only capacity added in the SMR1500 scenario. As such, the system value of SMR as power-only is extracted as the difference between the system value in the SMR600 scenario and the SMR1500 scenario.

In the assumed CAPEX for SMR, construction costs are included based on assuming a construction period of 4 years.

Feasibility of SMR as CHP

The feasibility of integrating SMR CHP into the Danish energy system in 2040 and 2050, respectively, is illustrated on Figure 33. This feasibility is illustrated by comparing the SMR system value with the SMR costs. The estimated system value is shown for an SMR implementation in each of the Bal, AF25, and KF25 scenarios (the lines). The SMR cost is illustrated for the three different development paths: Central, Optimistic, and Pessimistic.



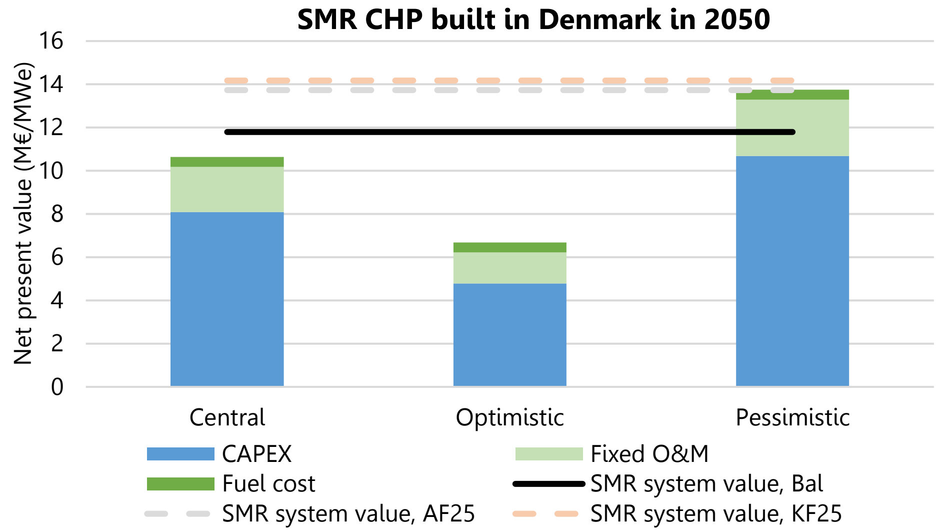


Figure 33. SMR system value vs. cost of implementing SMR as CHP in Denmark expressed in the net present value per MW-e. The SMR cost is given for the three different technology development paths (Central, Optimistic, and Pessimistic). The system value is extracted from the SMR600_Bal, SMR600_AF25, and the SMR600_KF25 scenario, respectively, where 600 MWe is assumed built as CHP in Denmark.

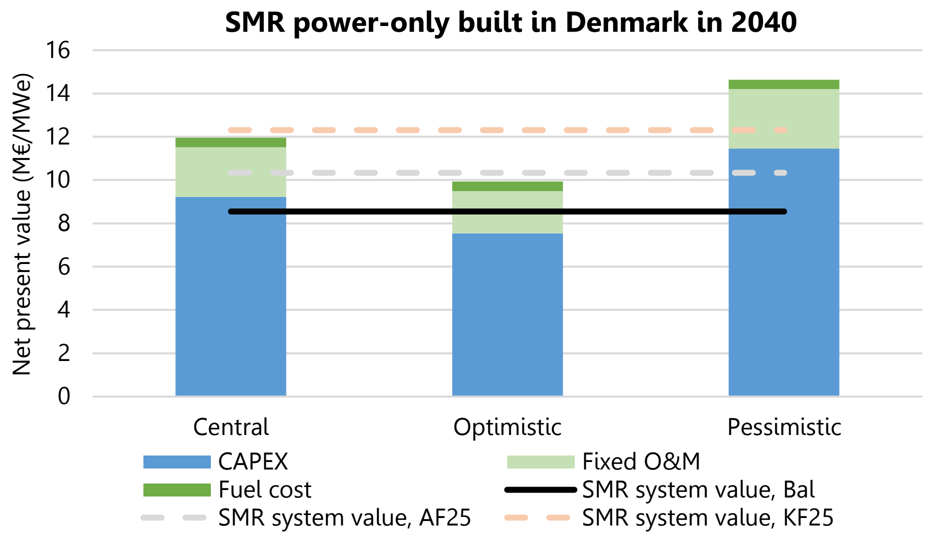
Figure 33 illustrates that the future cost of SMR varies significantly depending on whether the Central, Optimistic, or Pessimistic development path is observed. Moreover, the SMR cost is expected to be significantly lower in 2050 compared to in 2040.

The results show that in the Bal scenarios, building SMR as CHP in Denmark in 2040 is only feasible at the Optimistic SMR cost development (value is higher than the cost), and not far from being feasible at the Central cost development path). Building SMR CHP in 2050 is feasible also for the Central cost development.

As shown, the system value of SMR CHP is higher in the AF25 and KF25 scenarios, suggesting feasibility in the Central scenario already in 2040. In AF25 and KF25, the build-out of production capacity in Denmark is included as an assumption. This method results in significantly higher energy system costs than in the Bal scenario. Therefore, more costs are saved by changing the system. Saved costs are precisely the definition of system value. In addition, fuel and CO_2 prices are higher, which also contributes to a higher value of SMR plants, especially in the KF-scenarios, which show higher electricity prices in Denmark.

Feasibility of SMR as power-only

The figure below illustrates the feasibility of integrating SMR as power-only into the Danish energy system in 2040 and 2050, respectively.



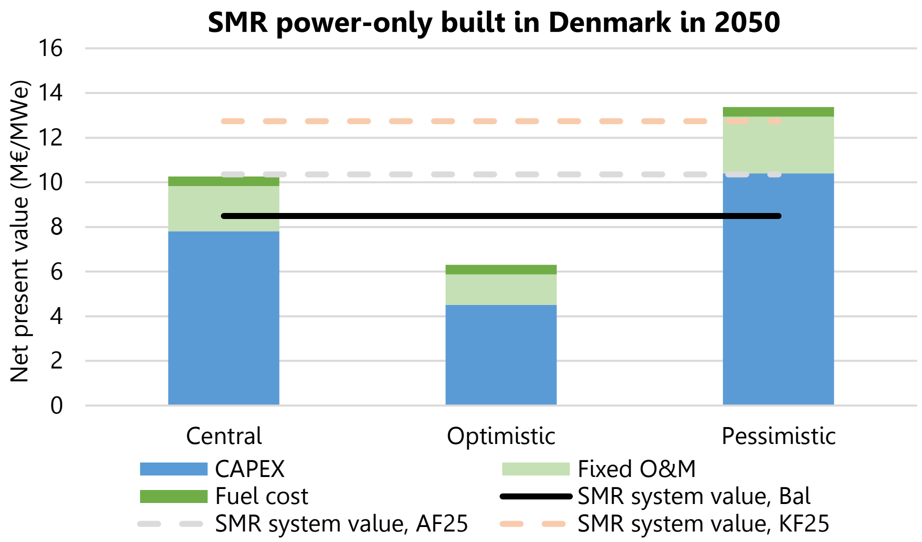


Figure 34. SMR value vs. cost of implementing SMR as power-only units in Denmark expressed in the net present value per MW-e. The SMR cost is given for the three different technology development paths (Central, Optimistic, and Pessimistic). For each scenario package (Bal, AF, and KF), the system value is extracted based on the difference between the SMR1500 scenario and the SMR600 scenario, equivalent to analysing a build-out of 900 MWe SMR power-only capacity in Denmark.

When comparing the with Figure 33, it is evident that the value vs cost balance is significantly less attractive when SMR is built as a power-only plant, compared to when built as a CHP plant. As such, SMR as power-only in Denmark is not feasible in 2040, and in 2050, it is only feasible at the Optimistic cost development. This illustrates that utilisation of excess heat from SMR for district hearting provides an additional system benefit, which is higher than the marginal technology cost of enabling cogeneration.

In the AF25 scenarios, SMR as power-only is not feasible in 2040 in any of the three cost development paths; however, in 2050, the system value breaks even with the costs in the Central cost development and feasibility is achieved at the Optimistic cost development. In the KF25 scenarios, the feasibility is further improved. As for the feasibility of CHP-plants, the better options in AF25 and KF25-scenarios are owed to the scenario building with fixed assumptions, leading to higher system cost in the reference (SMR0), as well as higher electricity prices because of higher fuel and CO_2-prices.

5. European SMR investment scenarios

In this chapter, the results from the EURSMR scenarios are presented, where model-based investments in SMR is allowed as part of the optimisation. The feasibility of SMR investments is investigated under three different assumed scenarios for build-out in advanced economies over the world, resulting in different SMR cost developments: Pessimistic buildout, Optimistic buildout and a Central estimate of the buildout. The cost development scenarios are based on the technical analysis within the SMR project.

The scale of future build-out of SMR is uncertain given the fact that the first SMR commercial reactor is yet to be built. Against this background, each of the cost development scenarios should be given equal weight in the results interpretation. The SMR cost levels applied in the model in the different scenarios have been further explained in section 2.3.

Figure 35 shows that at Pessimistic SMR cost development, investment in SMR is not feasible in the European energy system towards 2050 (no model generated SMR investments observed). At the Central SMR cost development, the optimisation yields a SMR expansion of around 8.5 GW towards 2050. This represents a rather limited expansion compared to the total existing/planned nuclear power capacity in the modelled European countries of around 100 GW in 2050.

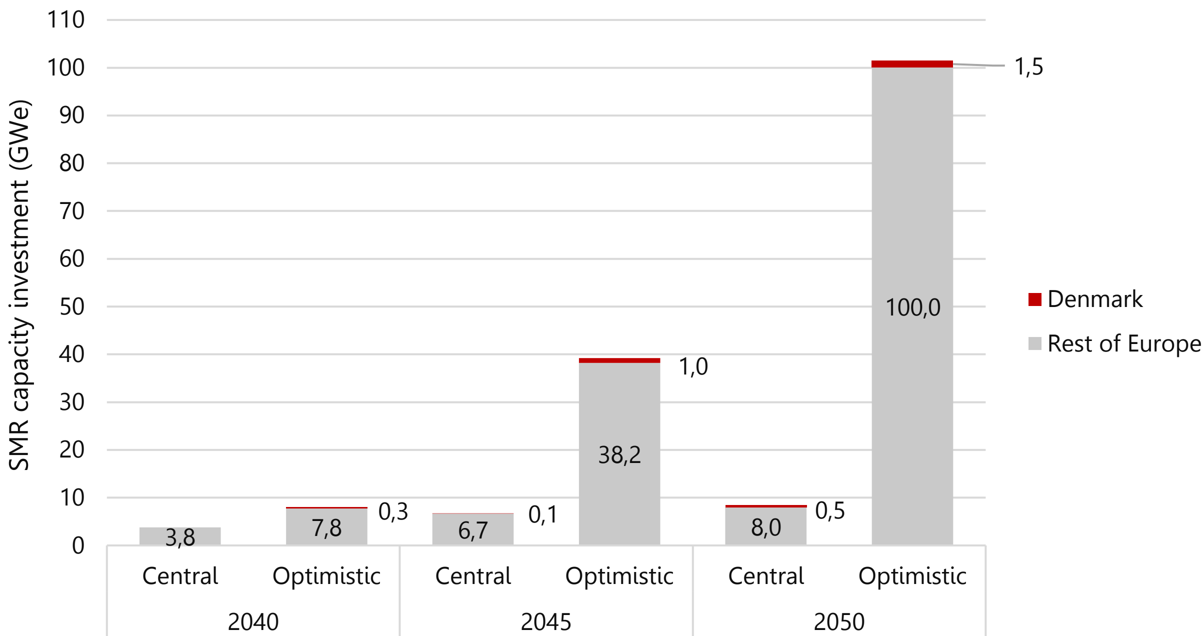


Figure 35. Total model generated investment in SMR in the modelled European energy system in the Central, Optimistic, and Pessimistic scenario SMR cost development scenario, respectively.

At the optimistic SMR cost development, the optimisation points to a total SMR investment of around 101.5 GW towards 2050. This corresponds to a doubling of the current nuclear power capacity in the modelled European system.

As shown, the model results suggest that SMR investment in Denmark in 2040 is only feasible at the Optimistic cost development and the same result practically also applies for 2045 (only 0.1 GWe, i.e. 100 MWe, SMR investment in the Central scenario). In 2050, the EURSMR scenarios point to a feasible SMR CHP investment in Denmark of 0.5 GWe in the Central cost scenario and 1.4 GWe in the Optimistic cost scenario.

The difference in the results for Denmark versus Europe as a whole reflect that the feasibility of SMR implementation depends on the conditions in the given country, As such, the fact that the model finds feasibility in SMR investment in some countries already from 2040 in the Central cost development, can be due to e.g. higher electricity prices levels and/or less competitive alternative capacity expansion options, resulting in higher system benefit of installing SMR. Overall, the results illustrate that the feasibility of SMR technologies is sensitive to the future SMR cost development.

Only in Denmark, the model is given the option to invest in both SMR CHP and SMR power-only units, while in the other European countries, only SMR power-only units are made possible for investment. In Denmark, the full SMR investment identified in the optimisation is comprised by CHP units. As such, investment in SMR power-only units is not found feasible in Denmark, since SMR CHP and/or other technology options are more attractive. This is in line with the results of the Bal-, AF25-, and KF25-scenarios, which showed a that the system value vs cost balance for SMR implementation in Denmark is significantly better for SMR CHP than SMR power-only unit. This EURSMR scenarios also confirm overall result of the feasibility analysis in section 4.11: that at the central cost development path, SMR could be feasible in 2050 if implemented as CHP.

As shown on Figure 36, the optimisation points to the largest part of the SMR build-out to be placed in DK2. The invested SMR CHP units are placed in the two large district heating areas where investment in SMR-CHP units is assumed to be allowed in the model (Copenhagen and Aarhus).

It can be observed that identified feasible investments in SMR in Denmark towards 2050 in the Central/Optimistic scenario is around the same level as the SMR capacity levels assumed in the SMR600 and SMR1500 scenarios, i.e. 500-1400 MWe (in the investment optimisation) versus 600-1500 MWe assumed in the SMR600-SMR1500 scenarios. This confirms that the SMR capacity levels analysed in the SMR600/SMR1500 scenarios are of a reasonable magnitude.

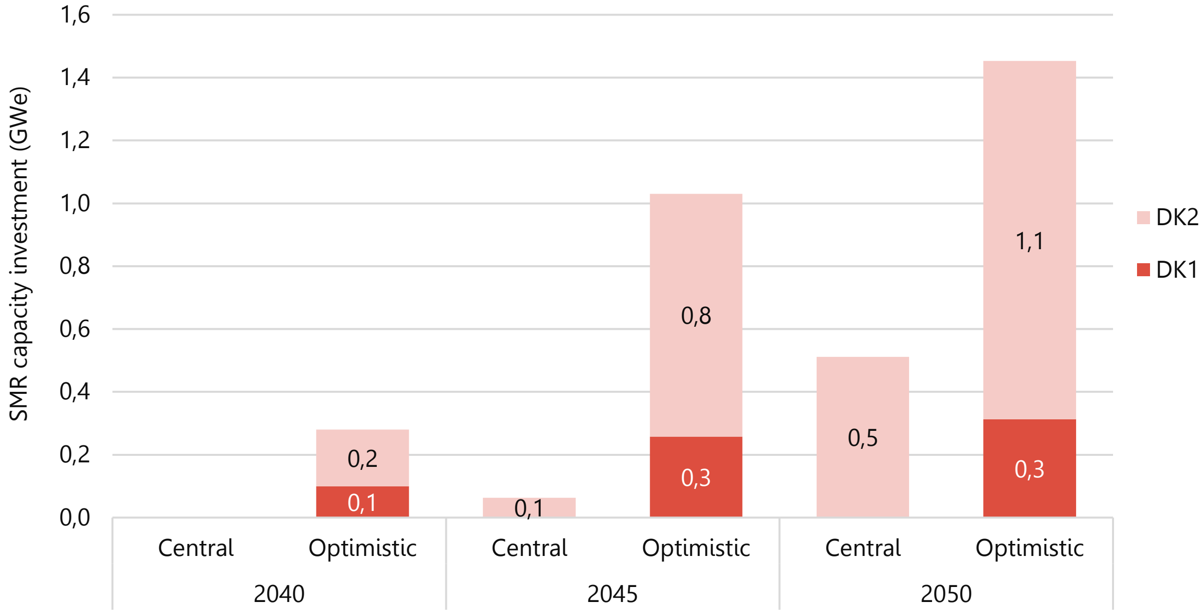


Figure 36. Model generated SMR investment in DK1 and DK2 in the Central, Optimistic, and Pessimistic SMR cost development scenario.

6. Appendix

6.1. SMR data assumed in the scenario analysis

In the system analysis, the SMR scenarios assume that a given SMR capacity has been implemented in Denmark and the optimisation does not allow for further investment in SMR in Denmark. The only SMR data that is significant for the scenario results are therefore data that affect the actual production from the SMR plants in the overall system optimisation; i.e. efficiency, variable costs, outage time, ramp rate and start-up costs, etc.

The technical and economic data for the SMR plants assumed in the system analysis are given in Table 9.

Table 9. Technical and economic SMR data assumed in the model.

Parameters	Value	Background
Electrical efficiency, condensing operation	0.33	Average of the four selected SMR technologies from the technical analysis
Resume	0.15	Assessment from VTT
Cm	0.6	Assessment based on how the heating side is expected to be dimensioned
Variable D&V cost	0	Based on data from VTT (O&M costs are estimated to be 100% fixed, not variable)
Ramp rate (percent capacity per minute)	5%	Average of the four selected SMR technologies from the technical analysis
Minimum load (percent)	38%	Average of the four selected SMR technologies from the technical analysis
Planned outage (pct.)	6%	Approximately 3 weeks of planned annual audit is assumed
Unforeseen outage (pct.)	6%	Overall rating
Total outage (pct.)	12%	Total planned and unplanned outage
Capacity factor (pct.)	88%	Defined as 100% minus total outage
Start-up costs (€/MW)	350	Based on data for nuclear power plants

6.2. Fuel and CO_2 prices

The Bal scenario and the EURSMR scenario package

In the projection of fuel and CO_2 allowance prices, forward prices are used in the short term, which best reflect the market conditions in this time perspective. Prices are expected to converge from forward prices to long-term equilibrium prices in 2030. For 2030 and onwards, fuel prices are based on the International Energy Agency's (IEA) World Energy Outlook 2024 (WEO). Here, a median of:

- Stated Policies (STEPS) scenario which reflects current and future policies, government announcements and industrial efforts (e.g. climate targets) and
- Announced The Pledges scenario, which reflects a development where the political ambitions of the various countries are assumed to be implemented, even though they have not yet necessarily been translated into realised policies.

For natural gas, a higher price than the IEA price for Europe is used to take into account that natural gas will primarily be imported in the form of LNG in the future. The price is based on the price for Asia, which represents LNG imports that are expected to constitute the marginal supply to Northern Europe.

The fuel price projection used is illustrated in Figure 37 for selected fuels.

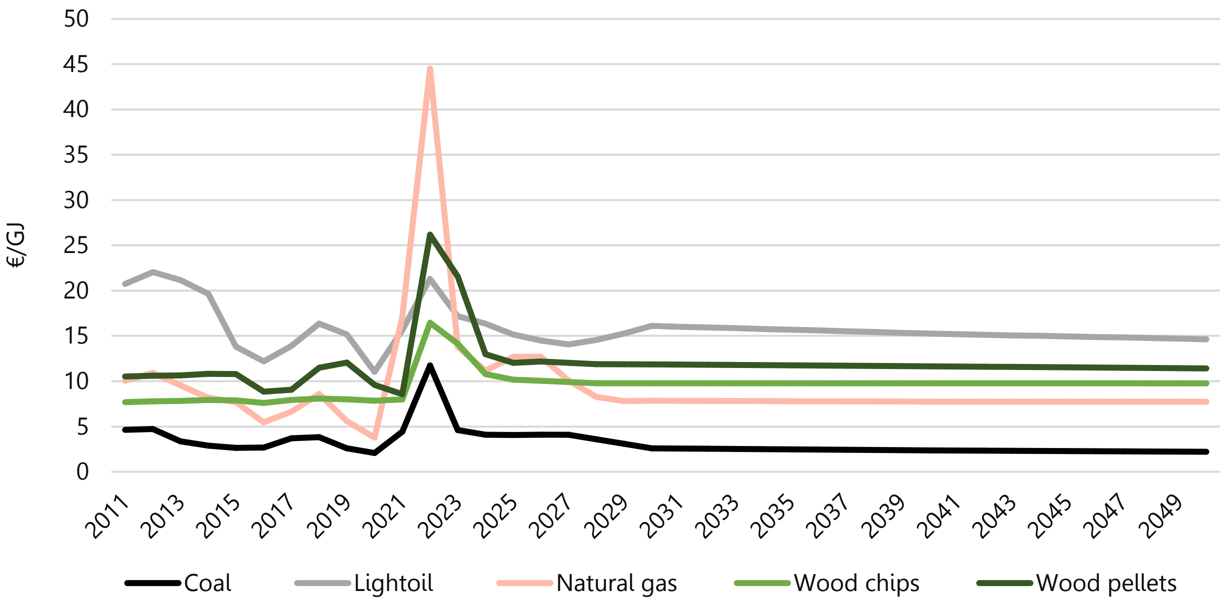


Figure 37. Fuel prices used as assumed in the Bal scenario package. The prices shown are given at a central plant including transport costs. The model differentiates between transport costs for central and decentralised plants. Fuel prices are given at lower calorific value.

The IEA has published World Energy Outlook 2025 at the end of the project period. Ea Energy Analyses has therefore checked for any updates in fuel prices in relation to the prices used based on WEO2024. The most important fuel price is the natural gas price, as this has the greatest impact on the electricity price. As shown, there is no significant change in the gas price in WEO2025 versus WEO2024 (see the STEPS scenarios Figure 38.

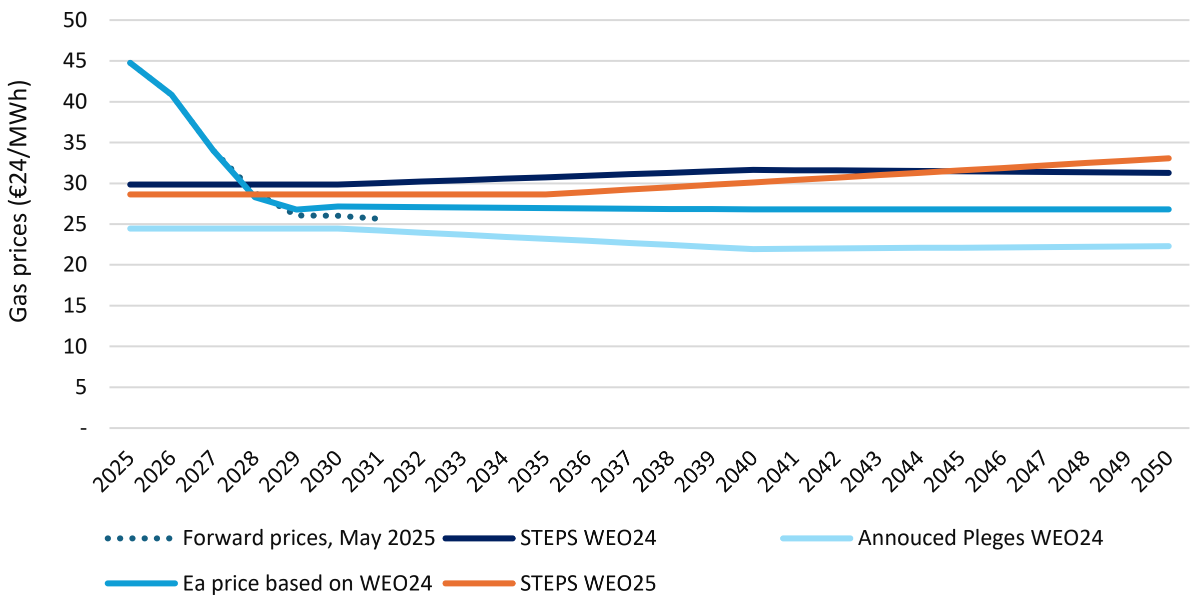


Figure 38. Comparison of natural gas prices in WEO2025 versus WEO2024.

In the model, the transition to a long-term carbon-neutral European energy system in 2050 is driven by the applied carbon allowance price development and not by a precise net-zero emissions target. This is based on the experience that a carbon-neutrality target for Europe would make the model prohibitively heavy to run. This approach means that small amounts of natural gas may still be present in the modelled energy system in 2050.

The CO_2 price used is based on forward prices up to and including 2026. For 2030 and onwards, the CO_2 price is based on Ea's estimate for the long-term development of the CO_2-price. This estimate includes an assessment of the current global political situation where less focus is put on climate policies and more on reducing consumer costs of energy. The CO_2 price in 2027-2029 is estimated assuming a gradual convergence towards the long-term price in 2030.

The assumed CO_2 quota price is shown in Figure 39.

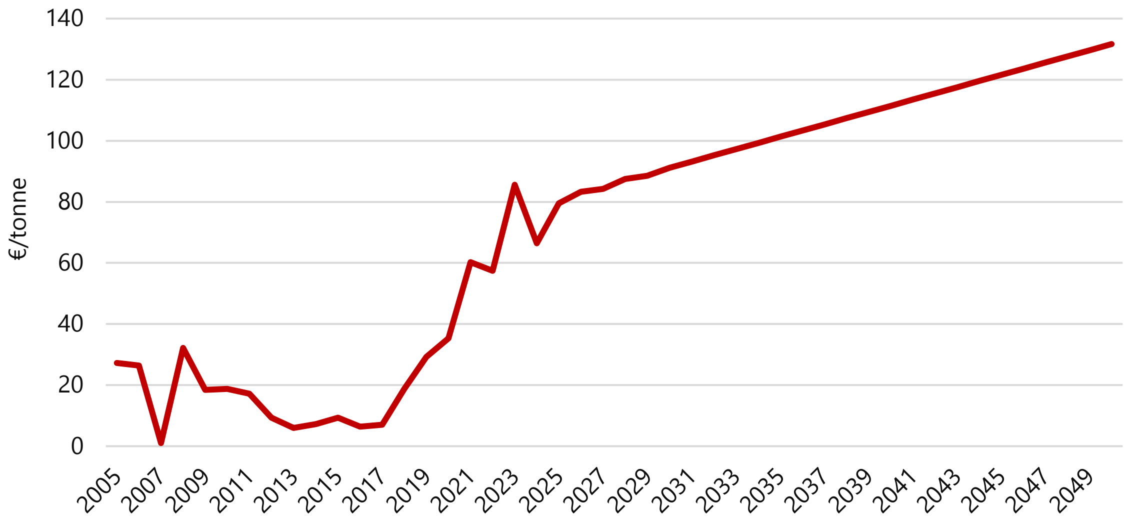


Figure 39. CO_2 allowance price assumed in the Bal scenario package.

As shown, the CO_2 quota price is assumed to be high, also towards 2030. However, current prices are also to some extent influenced by high gas prices.

For Denmark, the CO_2 tax is also included (11 € /tonne in 2025, 54 € /tonne in 2030-2050).

The AF and KF scenario package

The AF and KF scenario package use the same fuel and CO_2 prices as in AF25 (see fuel prices for selected fuels on Figure 40.

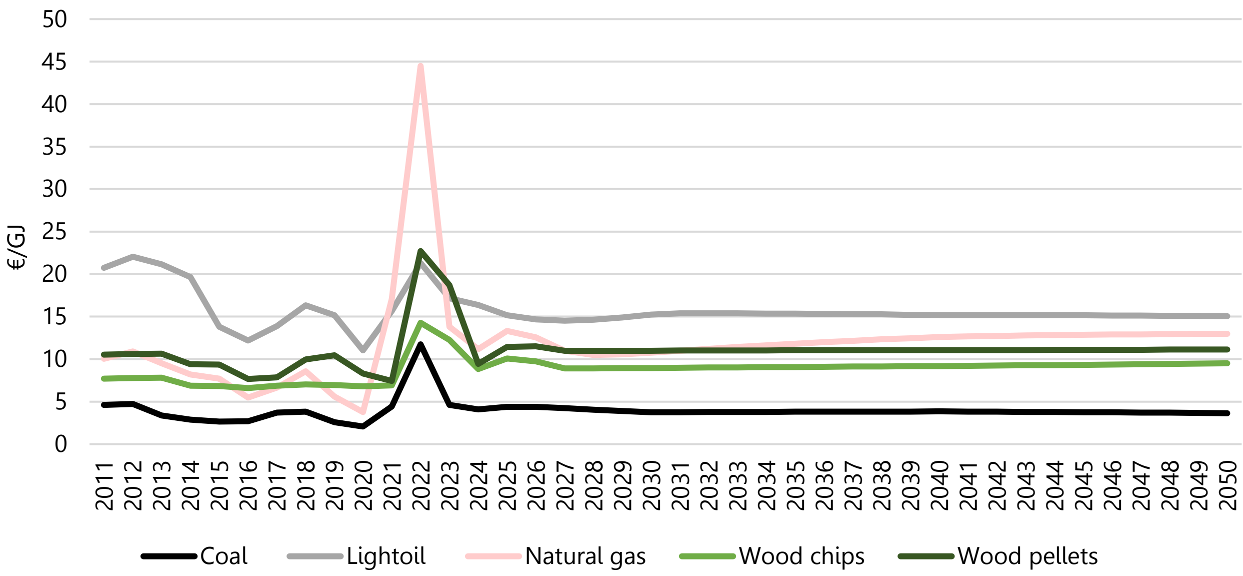


Figure 40. Fuel prices assumed in the AF and KF scenario package. The fuel prices are directly based on AF25. The prices shown are given at a central plant including transport costs. The model differentiates between transport costs for central and decentralised plants. Fuel prices are given at lower calorific value.

6.3. Electricity and hydrogen demand for Denmark

KF and AF scenario package

In the AF and KF scenario package, electricity demand data for Denmark is used from KF25 and AF25, respectively. This includes both **classic** electricity demand, electricity for **data centres**, electricity consumption for **individual heating**, and **electric vehicles**. Similarly, **hydrogen demand** for DK is based on AF25 and KF25, respectively (see Table 10 and Table 11).

Table 10. Electricity demand and hydrogen demand for Denmark assumed in the KF25 scenario package (electricity demand includes network losses).

TWh	2025	2030	2035	2040	2045	2050
Classical electricity demand	30.1	32.5	34.2	35.9	37.2	38.4
Electricity for data centres	2.4	7.3	15.9	25.2	28.0	30.7
Electricity for individual heating	3.3	3.9	4.7	4.9	5.0	5.1
Electricity for electrically powered vehicles	2.0	6.4	10.3	13.0	14.3	15.6
Hydrogen requirement	0.7	1.8	1.8	1.9	2.0	2.0

Table 11. Electricity demand and hydrogen demand for Denmark assumed in the AF25 scenario package (electricity demand includes grid losses).

TWh	2025	2030	2035	2040	2045	2050
Classical electricity demand	30.5	31.9	33.0	34.3	35.4	36.6
Electricity for data centres	1.4	6.1	15.9	27.3	32.0	36.6
Electricity for individual heating	3.1	4.3	5.6	6.0	6.0	6.1
Electricity for electrically powered vehicles	2.2	7.8	12.1	15.1	16.8	18.1
Hydrogen requirement		1.1	5.2	9.6	13.8	18.8

The electricity consumption for district heating production from large heat pumps and electric boilers is based on the model's optimisation.

The Bal scenario and the EURSMR scenario package

In the Bal scenario and the EURSMS scenario package, the consultant's best guess for Denmark's future electricity and hydrogen demand is used. The **classic** electricity demand as well as the electricity consumption for **individual heating** and **electric vehicles** is based on AF25.

As in the KF/AF scenario package, **the electricity consumption for district heating production is** based on the model's optimisation.

The electricity demand for **data centres** in the period up to 2035 is based on a recent projection from the think tank EMBER on the expansion of data centres [20]. EMBER estimates the growth in data center demand from 2024 to 2035 and predicts, for example, for Denmark, that demand will increase by a factor of 5 during this period (see Figure 41). For the period 2035 to 2050, we assume 50% lower annual absolute growth factors compared to the period 2024 to 2035.

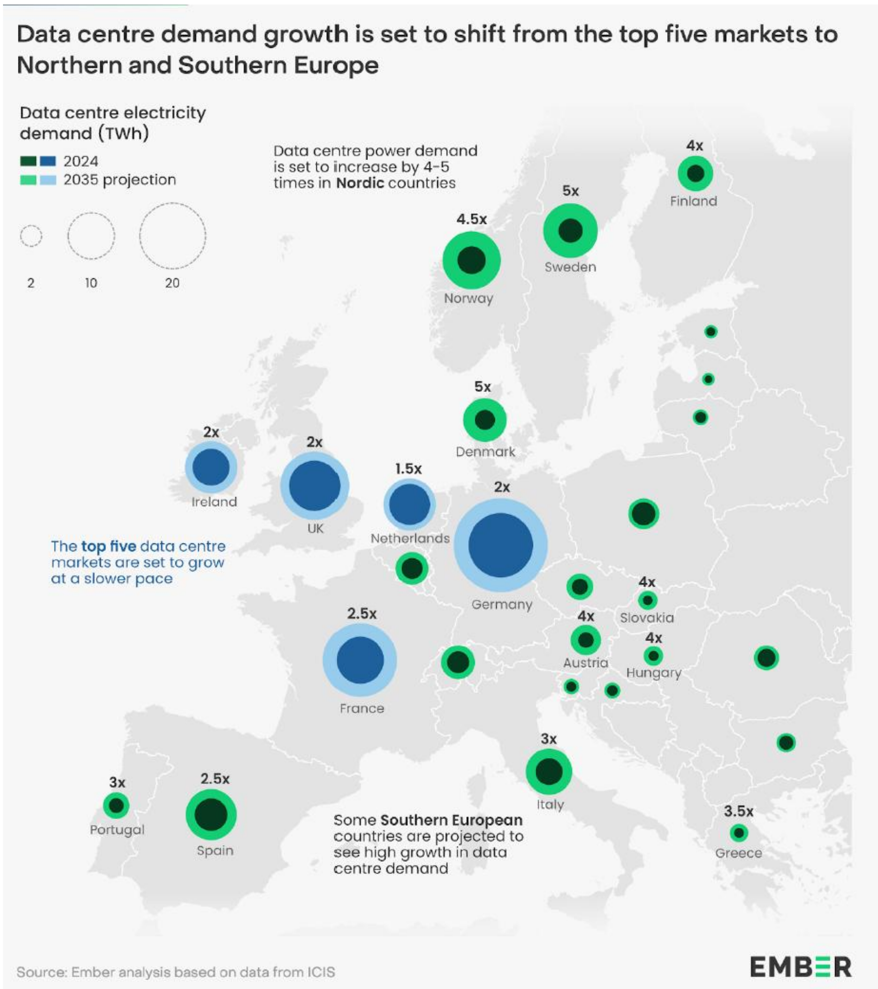


Figure 41. Assumed increase in electricity demand for data centers in Europe based on study by EMBER.

[20]*https://ember-energy.org/latest-insights/grids-for-data-centres-ambitious-grid-planning-can-win-europes-ai-race/grids-for-data-centres/#data-centre-deployment-requires-grid-availability.

The assumed development in Denmark's classic electricity demand, electricity for data centres, electricity for electric vehicles and individual heating is shown in Table 12.

Table 12. Electricity demand and hydrogen demand assumed for Denmark in the Bal and EURSMR scenario packages (the demands includes grid losses).

TWh	2025	2030	2035	2040	2045	2050
Classical electricity demand	30.5	31.9	33.0	34.3	35.4	36.6
Electricity for data centres	2.1	5.3	10.3	12.3	14.4	16.4
Electricity for individual heating	3.1	4.3	5.6	5.9	6.0	6.1
Electricity for electrically powered vehicles	2.2	7.8	12.1	15.1	16.8	18.1
Hydrogen demand		1.9	2.1	2.4	2.9	3.5

Hydrogen demand for Denmark is based on the same approach as for Europe in general.

6.4. Electricity and hydrogen demand for other countries in Europe

The assumed development in Europe's energy demand is developed with ENTSO-E's Ten-Year Net Development Plan 2024 (TYNDP 2024 Distributed Energy scenario) as a starting point. The scenario assumes that the EU Commission's goal of a CO_2-neutral Europe by 2050 and that the resulting electrification will be fulfilled. However, developments over the past year and a half show, that the framework conditions are not in place to ensure such a rapid expansion of both electricity and especially **hydrogen demand** in Europe as is contained in REpowerEU and TYNDP2024. Therefore, demand developments have been adjusted. In the long term, increased focus on direct electrification improves the overall economy of the transition, increases direct electricity demand, and reduces the need for hydrogen. However, in the short term, towards 2030, direct electricity demand develops slower, and in 2050, development is still 10 years behind assumptions in the TYNDP. For hydrogen demand, the following has been applied:

- European hydrogen production in 2030 is assumed to be 1/5 of the production indicated in REpowerEU, corresponding to 2 million tonnes of hydrogen rather than 10 million tonnes of hydrogen. This also includes the European regulation regarding minimum levels for the use of RFNBO fuels in 2030 and 2035.
- After 2030, hydrogen production is expected to gradually increase to help ensure a NetZero system by 2060. The hydrogen demand development in TYNDP 2024 is assumed shifted by 10 years, such that hydrogen demand projected for 2040 in TYNDP 2024 is instead assumed to materialise in 2050. This reflects that indirect electrification via hydrogen remains among the most costly decarbonisation options, combined with the currently observed slow pace of

hydrogen project development and deploymentas well as persistent uncertainties related to costs, infrastructure availability, and regulatory frameworks.

- Direct electrification contains more mature technologies than indirect electrification via hydrogen. In achieving the net-zero system in 2050, direct electrification is therefore assumed to be higher than in TYNDP24.

Additionally, the following adjustments are also assumed compared to TYNDP24:

- A larger share of Europe's demand for green fuels is assumed to be covered via imports of liquid P2X-based fuels.
- Hydrogen-based fuels are expected to outcompete some applications of methane (shipping).

The assumed development in classic electricity demand, electricity for data centers, individual heating and electric vehicles, as well as hydrogen demand for the total modelled European electricity system is shown below.

Table 13. Assumed electricity demand and hydrogen demand for the entire European system for all scenarios (gross electricity demands, i.e. including network losses).

TWh	2025	2030	2035	2040	2045	2050
Classical electricity demand	2,212	2,339	2,517	2,720	2,898	3,076
Electricity for data centres	91	151	219	252	285	318
Electricity for individual heating	376	401	426	473	508	544
Electricity for electrically powered vehicles	193	310	501	728	822	917
Hydrogen demand	91	183	385	649	913	91

The **electricity consumption for district heating,** electricity for large heat pumps and electric boilers is based on the model's optimisation and is therefore shown as output from the model.

In the model, parts of the European hydrogen demand can be met by imports either via pipelines or via shipping. Thus, the electricity demand for hydrogen production in the model will be a result of the optimisation and will depend on how competitive European electricity generation is with hydrogen import options.

Hydrogen imports via pipelines are assumed to be possible from 2040 from North Africa to Spain (maximum 18.75 GW) and Italy (maximum 18.75 GW), respectively. The further transmission of hydrogen up through Europe from Spain and Italy is limited by limiting the possible investment in hydrogen pipelines from Spain to France to a maximum of 15 GW from 2050 and a maximum of 25 GW from 2050; and by limiting the possible investment in hydrogen pipelines from Italy to other European countries to a maximum of 15 GW from 2040 and a maximum of 25 GW from 2050.

In addition, the model includes a maximum willingness to pay for hydrogen based on the principles of the RFNBO regulation, which aims for hydrogen to be based on renewable energy. Thus, the model assumes a maximum willingness to pay for hydrogen, corresponding to the production price of hydrogen from fossil-based electricity [21]. This ensures that hydrogen production in the modelled scenarios is based solely on electricity from renewable energy and not fossil fuels.

As mentioned, some of the electricity consumption (electricity for hydrogen production and district heating production) is a result of the optimisation. The development in the total resulting electricity consumption is therefore shown in the results chapter. All other things being equal, the necessary electricity consumption needed to cover the hydrogen consumption will be greater than the hydrogen consumption due to the energy loss in the electrolysis plant [22]. Conversely, hydrogen production in Europe may be lower than hydrogen consumption to the extent that part of this is covered by imports or part of the hydrogen consumption cannot be covered by renewable energy-based electricity.

6.5. Flexibility in electricity demand

Flexibility in the different electricity consumption categories is modelled as follows:

- An increasing share of the **classic electricity demand** is assumed to be flexible (from 0% in 2020 to 10% in 2050) and can be shifted for 2 hours by paying an activation price. This demand includes industry, which also has the flexibility to shift production to low-price hours.
- **Electricity for electric vehicles** includes all electricity for road transport. This demand is flexible and an increasing share can be shifted using a storage capacity equivalent to 4 hours of demand. The modelling therefore takes into account smart charging. Vehicle -to -grid solutions are not modelled.
- **Electricity for Individual heating** includes electricity demand for space heating in buildings, which is modelled as heating demand. The demand is covered by heat pumps, direct electric heating and electric boilers. Approximately 1/3 of the individual heating demand is considered flexible, with the possibility of shifting it by using a storage capacity equivalent to 2 hours of demand.
- **Electricity for district heating** is based on model optimisation. Heat pumps and electric boilers are among the options for meeting the district heating demand. Other district heating options are fuel-based production from heating boilers only or cogeneration production, as well as heat storage for flexible operation.
- **Electricity for hydrogen production** is flexible to the extent that the optimisation invests in hydrogen storage. Storage in hydrogen tanks is assumed to be possible in all simulation years, as it is a mature technology. In addition, it is assumed to be possible to invest in hydrogen storage in salt caverns, depleted gas fields and rock formations from the year 2040. This is in light of the fact that

[21] The maximum willingness to pay is set at 133 €/MWh of hydrogen, corresponding to the production price of hydrogen based on electricity from the type of plant that is assessed to have the lowest variable electricity generation costs: the most efficient natural gas-based electricity generation plant in the model (57% electricity efficiency in condensing operation).

[22] Electricity-to-hydrogen efficiency of approximately 62-70% for alkaline electrolysis in 2030-2050 assumed based on the technology catalogue.

this hydrogen storage technology is more immature and that it will take a number of years to establish larger hydrogen storage of this type.

- Modelled investment costs for hydrogen storage take into account that some countries have geological formations that allow access to cheap salt cavern storage (e.g. Germany, the UK, the Netherlands, Poland and Denmark) [23], while other countries (e.g. Sweden and Finland) are limited to the more expensive option of storing hydrogen in rock formations. The investment costs for salt cavern storage are assumed to be €2.4/kWh in 2030 and gradually decrease to €1.4/kWh in 2024/2050. [24]For hydrogen storage in rock formations, the investment costs are assumed to be twice as high as for salt cavern storage, based on Papadias & Ahluwalia (2021) [25].

6.6. Development in power capacity

KF25 and AF25 scenario package

The power capacity development in Denmark in the KF25 scenario for the reference scenario without SMR (KF_SMR0) is based on KF25. Similarly, the generation capacity in the reference scenario AF_SMR0 is based on AF25.

In the KF/AF scenarios with SMR capacity, it is assumed that SMR will displace the following:

- **The KF scenarios**: SMR displaces investments in solar PV expansion in Denmark.
- **The AF scenarios**: SMR displaces investments in solar PV and offshore wind in Denmark as well as investments/electricity generation in other countries as part of the optimisation.The following is assumed:
  - 2035: Displaced electricity generation is made up of 70% offshore wind electricity generation in Denmark and 30% solar PV electricity generation in Denmark in the form of reduced investments. The percentage distribution is estimated based on AF25. Displaced offshore wind is made up of reduced overplanting on Hesselø, Nordsøen I (middle) and Aflandshage.
  - From 2040: this will be replaced by overplanting on Energiø Bornholm and part of the additional offshore wind in DK1.

indicates what is specifically assumed in the KF25 and AF25 scenarios regarding the displacing expansion of offshore wind and solar PV as a result of the SMR implementation.

Table 14 indicates what is specifically assumed in the KF25 and AF25 scenarios regarding the displacing expansion of offshore wind and solar PV as a result of the SMR implementation.

[23]The same low cost level is assumed for countries with the ability to store hydrogen in depleted gas fields.

[24]Source: Danish Energy Agency, Technology Catalogue for Energy Storage (https://ens.dk/analyser-og-statistik/teknologikatalog-energilagring).

[25]Mass storage of hydrogen, International Journal of Hydrogen Energy (https://www.sciencedirect.com/science/article/abs/pii/S0360319921030834 , https://www.osti.gov/servlets/purl/1840539 ,)

Table 14. Assumptions about what SMR displaces in power capacity investments in Denmark in the KF25 and AF25 scenario packages. The corresponding displaced electricity generation is also indicated. In addition, SMR can potentially displace electricity capacity and electricity generation in the rest of the European energy system depending on the scenario and the result of the optimisation.

		SMR capacity (MW)	SMR electricity generation (TWh)	AF25		KF25
				Offshore wind displacement (TWh)	Solar PV displacement (TWh)	Solar PV displacement (TWh)
SMR600	2035	600	3.7	2.6	1.1	3.7
SMR1500	2035	1500	10.5	3.9	1.8	10.1
	From 2040	1500	10.5	7.4	3.1	10.1

The Bal and EURSMR scenario package

For the Bal and EURSMR scenarios with/without SMR, the power capacity is based on planned capacities, political objectives and the economic optimisation of the overall European energy system. This applies to both production capacities in Denmark and other countries. The method behind this optimisation is explained in more detail below.

Optimizing electricity generation capacities in Europe

In the optimisation, in each simulation year, the European energy system can invest in new generation capacity to meet energy demand. The model will choose the composition of generation capacity that is most economically advantageous from a system perspective, while also taking into account storage options and transmission, etc.

The development of new capacity is driven in the model by the development of demand, technology costs and resource assumptions. However, important policy objectives are taken into account, including minimum expansion of renewable energy in the short term, plans for the phase-out of coal and planned nuclear and hydropower capacity.

Solar PV and onshore wind

For solar PV and onshore wind, the assumptions include expectations for minimum expansion up to 2030 based on TYNDP 2024 (the low scenario).

After 2025, the expansion is generally assumed to be market-based, i.e. the projects are to be financed on the electricity market without subsidies. In addition, country-specific capacity limits for onshore wind and solar are used to reflect a realistic implementation that takes into account resource potentials as well as planning and grid constraints at local level. The approach to modelling the expansion of wind and solar capacity is illustrated in. The gradual increase in the maximum wind/solar capacity reflects that planning/grid constraints are taken into account in the expansion, while the maximum capacity in 2050 reflects the resource potential.

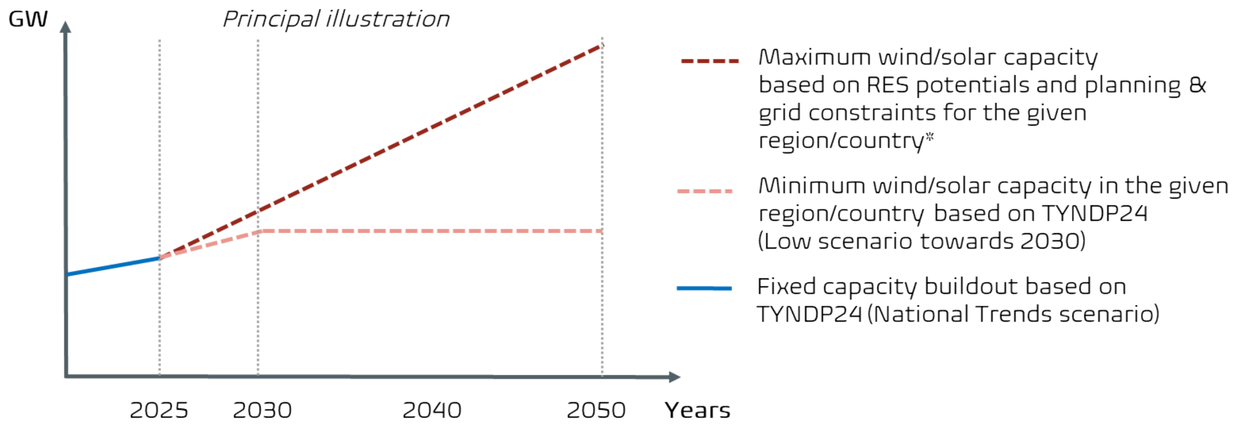


Figure 42. Principle illustration of how wind and solar PV capacity is modelled (translate FIG to DA).

The potentials for **solar power plants** are generally estimated based on allocation of 1.5% of agricultural land and unused land in the given country/region (with the exception of a few countries where a source with more specific data is available).

The onshore wind potentials are initially derived from realistic potentials for Germany, scaled to other countries/regions based on technical potentials in the EU Joint Research Centres Data Catalogue (EN-SPRESO, 2023 [26]). For countries where more precise sources are available, these are used instead. For example, the onshore wind potential for Finland is based on data from Gasgrid.

Offshore wind

Towards 2030, the expansion of offshore wind capacity in the different countries is based on the expected expansion in "Wind energy in Europe: 2024 Statistics and the outlook for 2025-2030" ([27]and the expected offshore wind capacity for 2030 is set as the minimum capacity for the following years). For the period from 2031 to 2050, the model can invest in additional offshore wind capacity. Such additional investments will take place to the extent that they are economically viable in the given offshore wind areas, i.e. that the revenues match the annual investment and operating costs.

As investments will be solely on a market basis, any subsidies for offshore wind are not taken into account. Other relevant model limitations include that all offshore wind in 2030 can only be connected radially to the "home country", the country where it is installed. After 2034, offshore wind can also be connected to neighbouring countries if economically viable.

Offshore wind farms modelled in the North Sea and the Baltic Sea are illustrated in Figure 43. Similarly, offshore wind potentials are also defined for the Mediterranean and the Atlantic (with lower accuracy).

[26] https://data.jrc.ec.europa.eu/collection/id-00138 .

[27] https://windeurope.org/intelligence-platform/product/wind-energy-in-europe-2024-statistics-and-the-outlook-for-2025-2030/ .

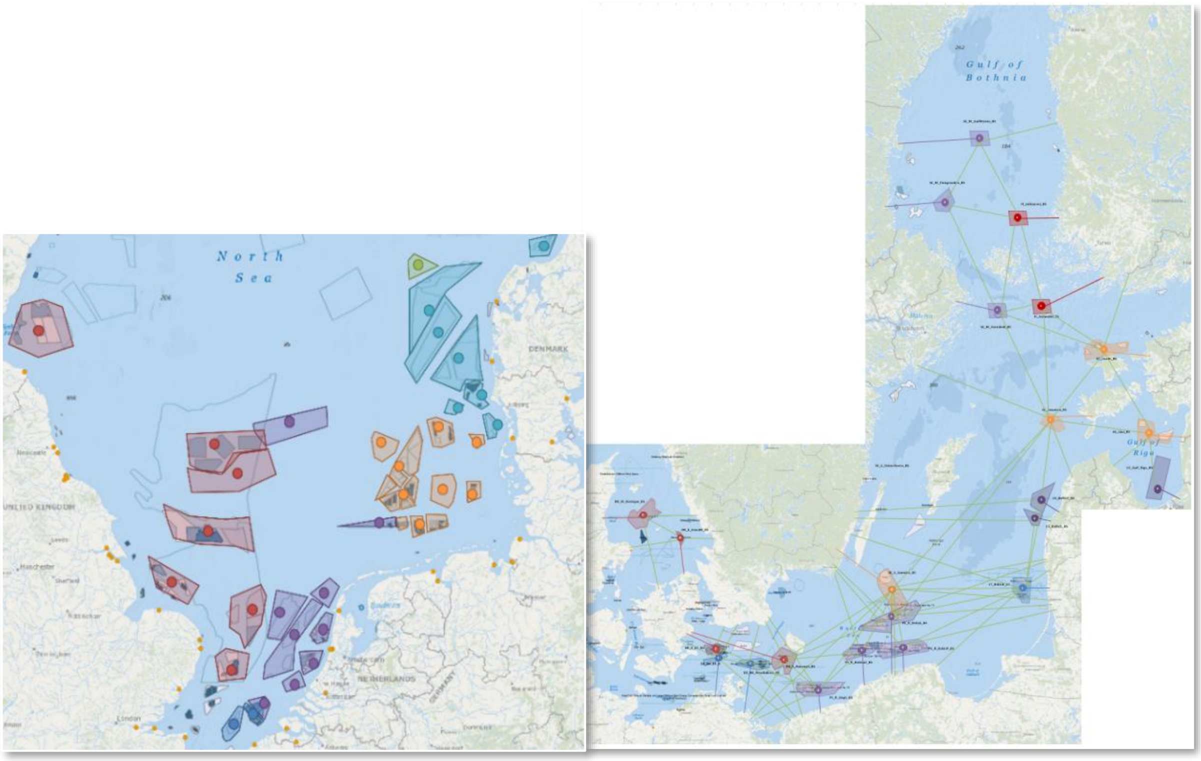


Figure 43. Offshore wind farms in the North Sea (left figure) and the Baltic Sea (right figure).

The Balmorel model contains information on offshore wind locations, including depth, distances, capacity potentials and wind resources. The main sources of information are the 4C Offshore database, previous work for the European Commission on Baltic Sea Potentials (BEMIP) and the MERRA2 wind resource dataset. As existing databases on specific locations have not mapped the full offshore potential, information on specific locations is combined with estimates of the total potential from the JRC ENSPRESO database by scaling offshore potentials at known locations to reach the total potential over a wider region. Generation profiles are based on wind speeds and assumptions about aggregate power curves for future wind farms. The off-shore areas can be connected either radially or in a meshed grid (see Figure 44).

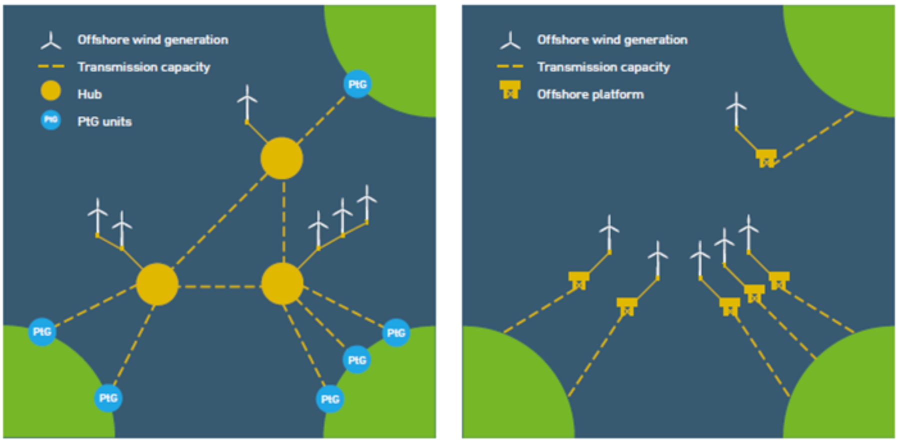


Figure 44. Illustration of offshore grid connections (left figure) vs. radial connections (right figure). Source of illustration: North Sea Wind Power Hub).

For computational reasons, the number of potential combinations of potential connections in the model is limited to those considered most relevant.

Nuclear power

Nuclear power capacity is exogenously determined in the model based on the TYNDP 2024 National Trends scenario for all countries except France and Sweden. France and Sweden are expected to maintain current nuclear power capacity levels through reinvestment and replacement of existing plants. In light of the latest announcements from the Swedish government, the following Swedish nuclear power expansions are assumed: 2.5 GW in 2040, 3.75 GW in 2045 and 5.0 GW in 2050. The total nuclear power capacity in the European model area is around 98 GW in 2025 and 95 GW in 2050.

Thermal capacity

For thermal capacity, current plans for the closure of coal-fired capacity are taken into account. In addition, the closure of thermal capacity (and investments) is determined by the model, i.e. the plants are closed when the earnings on the electricity market are no longer sufficient to cover the fixed costs. For biomass and biogas-fired units, a minimum capacity is ensured based on ENTSO-E's Transparency Platform [28]and expected levels in the TYNDP National Trends scenario. Investments in biomass-fired capacity (wood chips, pellets and straw) are limited to 30 GW by 2030 (corresponding to fuel consumption of around 1,900 PJ) to reflect the limited current portfolio of new biomass capacity. Towards 2050, the biomass limit is relaxed to 40 GW.

Specific prerequisites for Denmark

In the Bal and EURSMR scenarios, a given power capacity has been determined in the reference scenario without SMR (Bal-SMR0) based on the consultant's best guess for the development. The following can be highlighted, among other things,

[28] https://transparency.entsoe.eu/

- For Denmark, the Danish expansion with offshore wind is based on the development of existing offshore wind from AF25 as well as the offshore wind offers of 3 GW (2 GW in the North Sea (Central and South) and 1 GW at Hesselø) as well as 3 GW of offshore wind on Energiø Bornholm.

6.7. Electricity transmission

In the model, the countries are divided into power regions, which capture the most significant capacity constraints in electricity transmission. In the Nord Pool countries, these regions coincide with the price zones in Nord Pool. The German electricity market has one price zone (together with Austria), despite capacity constraints in the internal grid. However, Germany is modelled as four price zones, connected by transmission links. This is done to achieve a better representation of the actual operation of the German electricity system by taking into account internal bottlenecks.

Towards 2037, the development of the European transmission network is based on the planned expansion in ENTSO-E's TYNDP2024. Known deviations from this plan are taken into account, e.g. that there is no political support in Sweden for the realization of the Hansabro connection to Germany. The assumed transmission capacities in 2037 based on TYNDP24 are illustrated in Figure 45.

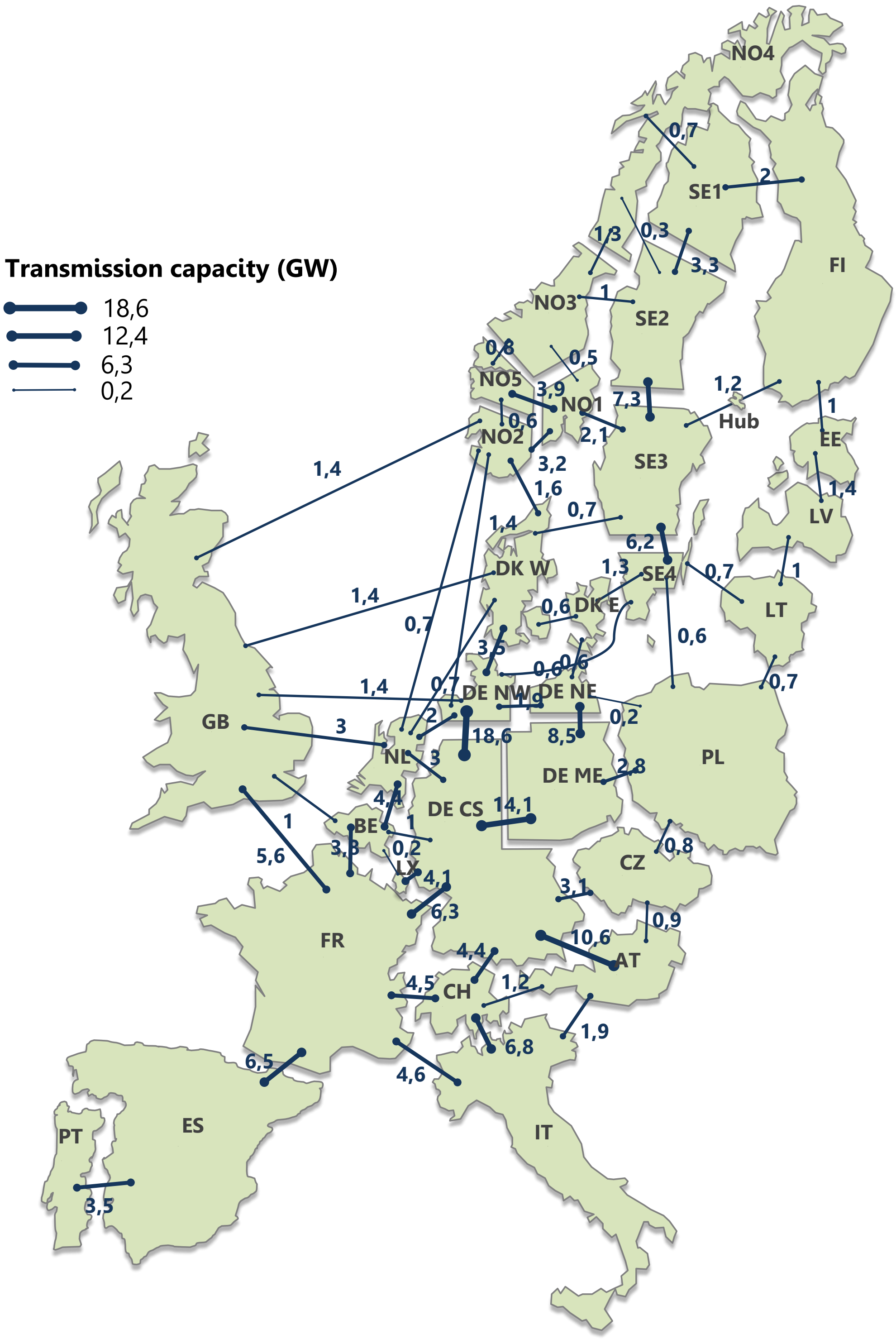


Figure 45. Existing and planned electricity transmission capacity assumed up to and including 2037 in the model.

From 2040, the transmission capacity in the model can be further expanded based on optimisation, where the model establishes new transmission facilities between the countries/bidding zones where it is most profitable. To capture the limited inertia in establishing transmission lines due to political processes, permits, project development and construction phase, etc., the expansion is limited to a maximum of 500 MW per 5-year interval per transmission corridor [29].

6.8. Hydrogen transmission

Up to 2035, the capacity for hydrogen pipelines has been determined based on screening of currently planned hydrogen pipeline projects (see Figure 46). Only hydrogen pipeline projects that are assessed to have a relatively high certainty of completion are included. For example, plans to connect the Baltic countries, Sweden, Finland, Poland and Germany with hydrogen transmission are not included among the determined connections.

The planned hydrogen pipeline from Denmark (DK1) to Germany of 4 GW has been implemented, it is assumed that this can only be used for hydrogen export from Denmark to Germany [30]. The pipeline project is assumed to be completed after 2030, i.e. in the optimisation, it is available from 2035 (the first subsequent simulation year).

[29] Maximum 1000 MW per 5-year interval for expansion of internal transmission in Germany.

[30] In connection with the hydrogen infrastructure project, a minimum electrolysis capacity of 0.5 GW of hydrogen is used in DK1.

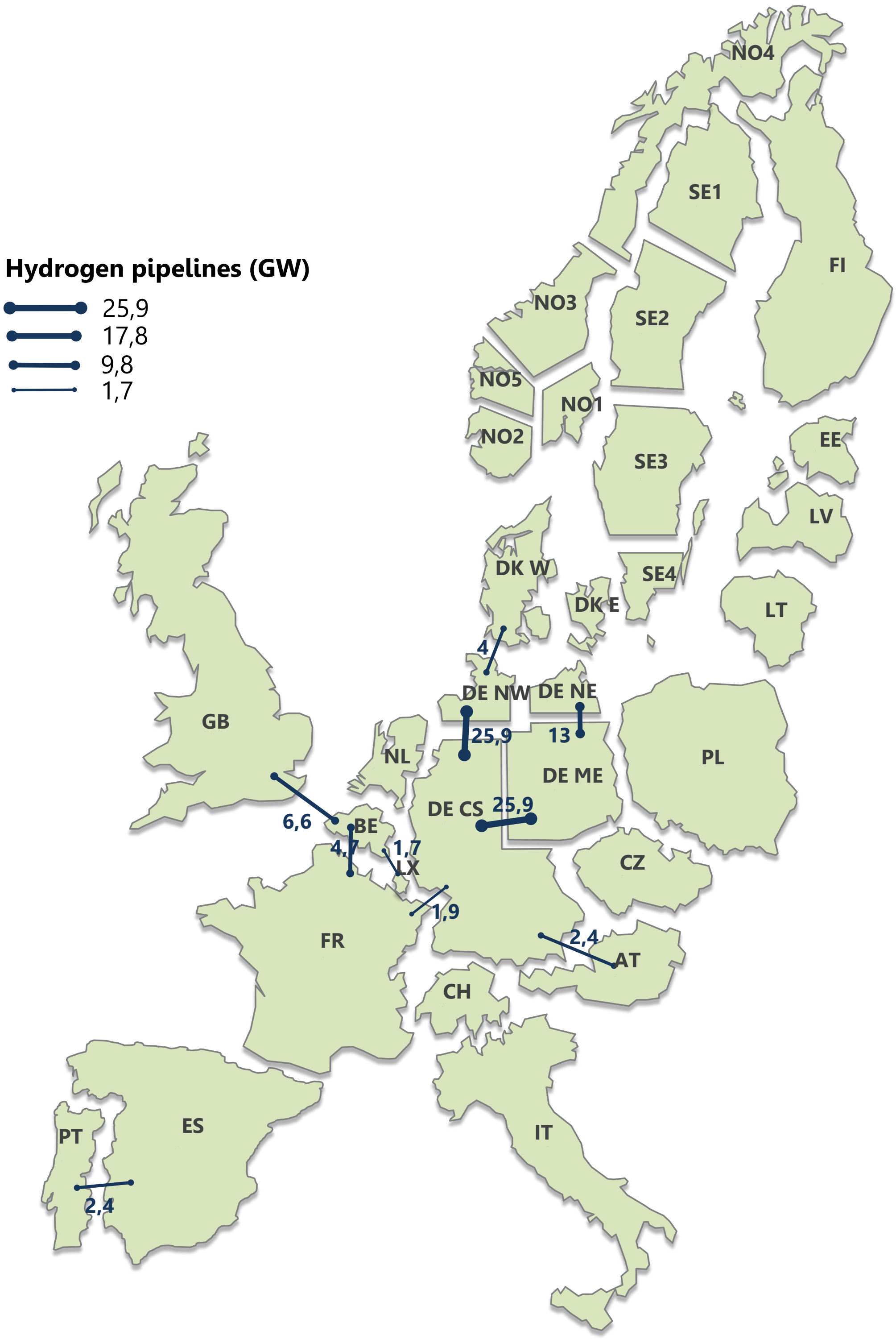


Figure 46. Existing and planned hydrogen transmission capacity assumed in the model up to and including the year 2035.

From 2040, further investments in hydrogen transmission are possible in the optimisation and will occur to the extent that it is advantageous from a European system economic perspective.