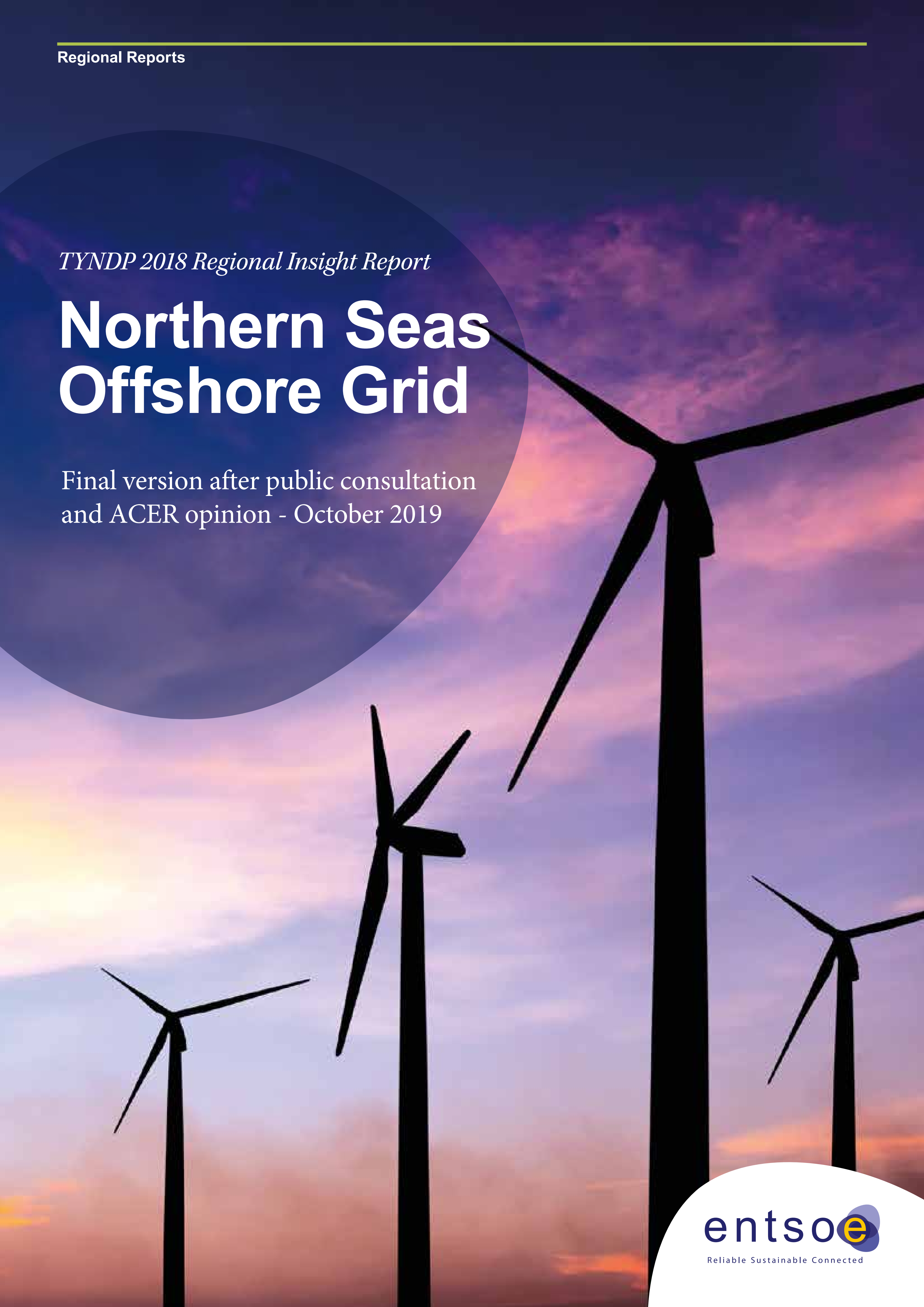
TYNDP 2018 Regional Insight Report

Northern Seas Offshore Grid

Final version after public consultation and ACER opinion - October 2019



Reliable Sustainable Connected

Contents

ENTSO-E Reports 2018

As an improvement to the TYNDP 2018 package, the Insight Reports have been categorised in order to help readers navigate through the document and focus on what readers might find of interest. The category of reports are:

— Executive Report – Contains the key insights of the whole TYNDP package through its two-year cycle.

— Regional Reports – Based on the four projects of common interest (PCI) regions, the reports focus on the regional challenges of the energy transition.

— Communication – These reports communicate how we have interacted with our stakeholders and improved the TYNDP package from 2016 to 2018.

— Technical – These reports give a deeper insight into the technical subjects, including how we use our data, and the technical challenges of energy transition.

We hope this guide is of benefit to all stakeholders.

Main Report

Regional Reports
- North-South Interconnections East
- North-South Interconnections West
- Northern Seas Offshore Grid
- Nordic & Baltics

Communication
- Stakeholder Engagement
- Improvements to TYNDP 2018

Technical
- Data and Expertise
- Technologies for
- Transmission
- Viability of the Energy Mix
- CBA Technical

Adequacy
- Mid-Term Adequacy Forecast

Section 1

Executive summary

This document addresses the development of electricity grid infrastructure in the geographical area covered by the Northern Seas offshore grid (NSOG), established by Regulation (EU) No. 347/2013 on guidelines for Trans-European energy infrastructure ('The Energy Infrastructure Regulation').

The area concerns integrated offshore electricity grid development in the North Sea, Irish Sea, Baltic Sea, English Channel and neighbouring waters to transport energy from renewable sources and to increase cross-border electricity exchange.

The geographical area of the NSOG region is covered by the ENTSO-E Regional Group North Sea (RGNS), plus Sweden, which is part of the Regional Group Baltic Sea (RGBS). Thus, both related Regional Investment Plans (RGIP), in particular the RGNS RGIP 2017, are highly relevant in this context. The NSOG region comprises four separate synchronous areas, with some existing interconnection between each area. In the TYNDP 2018 three separate scenarios for the year 2030 are analysed, which reflect different possible pathways to meet future EU decarbonisation targets, but all have common themes with regards to renewable generation. By 2030, the Nordic countries continue to be dominated by hydro generation and its associated seasonal dispatch pattern. Renewable output in GB and Ireland is mostly comprised of wind generation, while in Continental Europe there is a mix of both wind and solar generation. These technologies are subject to variable hourly output

The TYNDP 2018 scenarios demonstrate that the NSOG region has abundant renewable energy resources. Member States are already exploiting these to the extent that several offshore wind integration, as well as interconnection, projects across the region have been/are being put in service – such as the Nemo Link® interconnection between Great Britain and Belgium – with numerous more currently planned.

The TYNDP 2018 highlights three main boundaries in the NSOG region where additional reinforcement is particularly beneficial. These boundaries result from high price differences between the different synchronous areas as a result of structural changes to the generation portfolio with less thermal and more renewable energy sources (RES) production.
The three main boundaries are:
— I reland to Great Britain and Continental Europe— Great Britain to Continental Europe and Nordics; and
— Nordics to Continental West Europe.
In addition to these main boundaries, there exist a number of boundaries within the synchronous areas where a stronger grid is required to enable both:
— the overall efficient integration of the expected future generation portfolio; and
— the potential benefit of the main boundaries.

In particular, the grid in the Continental West Europe (CWE) area (Benelux, Germany and France) is heavily congested due to its central location in facilitating both north-south and west-east power flows.

In the TYNDP 2018, 82 projects consisting 144 projects are assessed in the NSOG region, many of which are designed to meet the challenges posed by the future generation portfolio, allowing resources to be shared across the region. A result of this is that transmission grids in Member States must transport larger and more variable power flows, and so a number of the assessed projects reinforce the transmission network to ensure this can occur.
It must be stated that the proposed electricity grid infrastructure projects in the NSOG region not only offer the benefits associated to integrated markets, yet also contribute to safe operation of the system.

The needs beyond 2030 have also been investigated, whereby the 2030 scenarios are extended further to 2040. The results show that there will be requirements for further reinforcement in the NSOG region beyond the project portfolio assessed as part of TYNDP 2018, if the generation portfolio in the region continues its ambitious decarbonisation.

Reaching this decarbonisation target requires a paradigm shift in the role of the electricity grid infrastructure. The pan-European electricity grid will play a crucial role in facilitating RES integration at a European scale, thus enabling the transformation of the energy mix. Ultimately, it will allow European 2050 climate and energy policy objectives to be met, aiming to maximise the decarbonisation of society.

The pathway towards 2030 and onwards to 2040 and 2050 is not set in stone and therefore the approach to develop the future grid is a modular one, delivering optionality to policy makers and incorporating flexibility to manage changes as they come along. This modular approach results in a regional project portfolio which:

- aims to maximise the potential of existing infrastructure, by upgrading the capacity of existing substations and corridors through the integration of phase-shifting transformers and the use of higher capacity conductors; and
- puts forward the development of new corridors, as the scale and magnitude of the energy transition means that reinforcing the existing substations and corridors alone will not always be sufficient.

The 2030 and 2040 analyses clearly show that by building the proposed infrastructure, significant positive effects will be seen, including:

- benefits to the climate through the increased RES penetration and resulting decrease in CO_2 emissions
- market integration across the region through reduced price differences; and
- stable security of supply despite massive changes in the generation fleet.

Future iterations of the TYNDP will give further shape to the future grid architecture. During this process, it remains fundamental that:

- the evolution of the interconnectors as well as the internal grids is synchronised across the region; and
- the solutions put forward provide an answer to the increasing complexity and evolving needs of the future energy system. As the future energy system will present many operational challenges, the coordination of grid infrastructure development with market rules and network codes will become increasingly important.

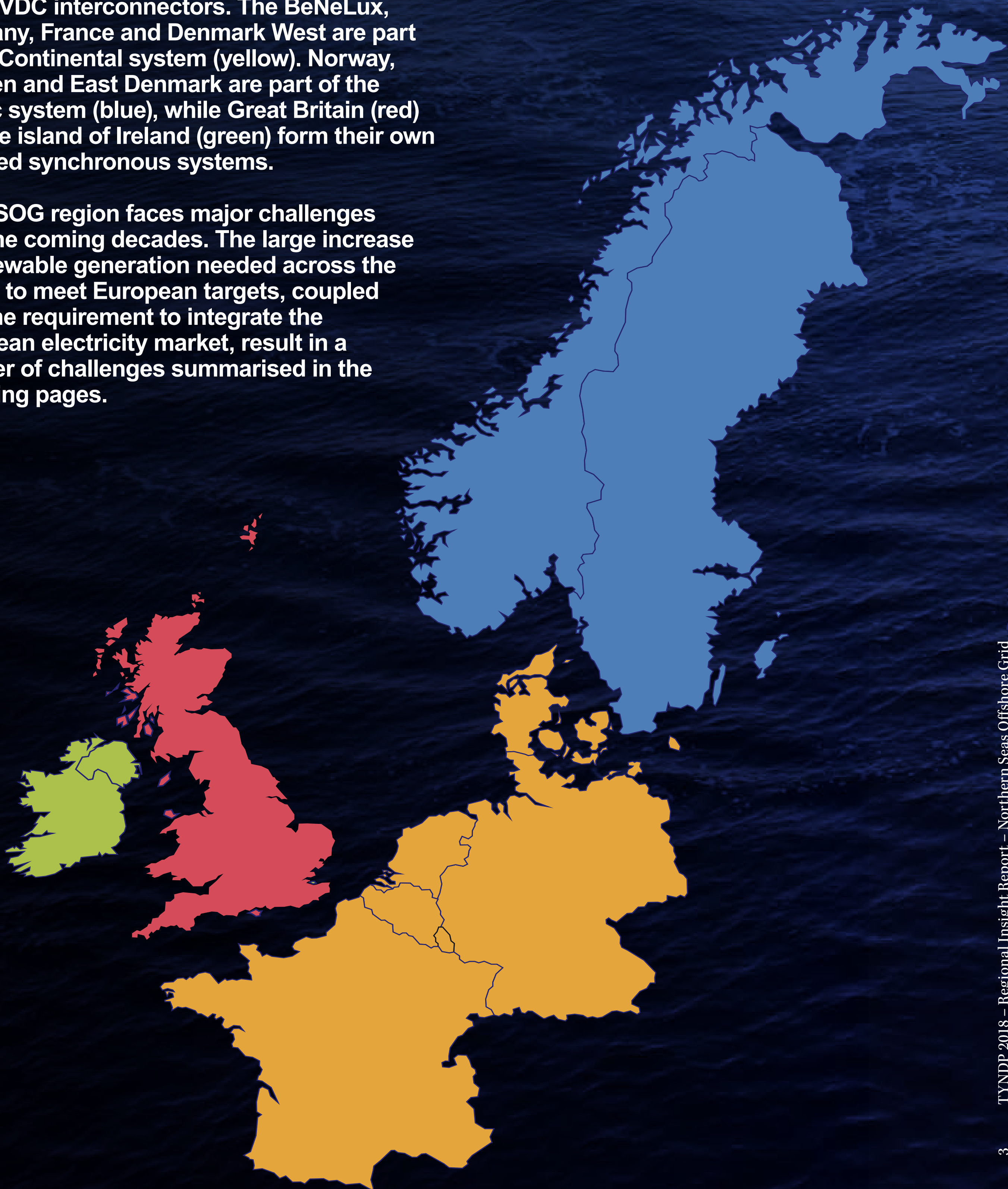
Section 2

Key messages of the region

The NSOG region comprises four separate synchronous systems, shown in Figure 2.1. The four synchronous areas are linked with HVDC interconnectors. The BeNeLux, Germany, France and Denmark West are part of the Continental system (yellow). Norway, Sweden and East Denmark are part of the Nordic system (blue), while Great Britain (red) and the island of Ireland (green) form their own islanded synchronous systems.

The NSOG region faces major challenges over the coming decades. The large increase in renewable generation needed across the region to meet European targets, coupled with the requirement to integrate the European electricity market, result in a number of challenges summarised in the following pages.

Figure 2.1: Synchronous areas of the NSOG region



2.1
Structural changes to the generation portfolio

There will be substantial change to the region's generation fleet over the coming decades, characterised by:

— **a shift from thermal to renewable generation**. The regional share of RES is expected to continue increasing, accounting for 55% to 65% of the total electricity production by 2030. As abundant renewable sources across the region (onshore and offshore wind, hydro and solar) are increasingly exploited, there is a reduction in thermal plant usage. Some older plants may close in the medium term

— **a reduction in nuclear generation**. The trend in the region is for a reduction in nuclear capacity, with planned phase-outs in Belgium and Germany, and partial phase-outs in France and Sweden. In GB, the level of nuclear generation varies depending on the scenario

— **a shift from coal to gas generation**. Existing coal-fired power plants are being phased out due to a combination of reaching their technical end of life and policies put in place to enable the carbon emission reduction of the generation portfolio.

2.2
Power flows across the region

The future generation portfolio will drive larger power flows across the NSOG region. The diverse nature of the generation is a major factor. The Nordics are dominated by hydro generation and its associated seasonal dispatch pattern. Renewable output in GB and Ireland is dominated by wind generation, while in Continental Europe there is a mix of both wind and solar generation. These technologies are subject to variable hourly output.

While the primary thermal generation in the region is gas, nuclear generation makes up a significant majority of thermal generation in France.

This generation diversity across the region drives market exchange opportunities and consequently power flows between the four synchronous areas and also between the Member States. These power flows increase and become more international as the distance between the consumer and the location where the cheapest available energy is being produced increases. As a result, there are a number of boundaries (see Section 4.3) within the region where the development of new transmission capacity will be necessary.

2.3
A requirement for new interconnection

Additional interconnection capacity is required across the region, between synchronous areas and Member States. This increased capacity will allow for the integration of renewable generation by enabling cross-border exchanges, which in turn will minimise curtailment and aid decarbonisation of generation production.

Additionally, increased cross-border exchanges help maintain security of supply across the region while also helping market price convergence.

This additional capacity will drive larger power flows across Member States' internal grids in the future. As a result, existing transmission corridors will have to be reinforced, or new corridors developed, to upgrade the internal grids to accommodate these developments.

2.4

Ensuring security of supply

The expected changes in the regional generation fleet might challenge the security of supply of all the synchronous systems of the region.

- The increased reliance on renewable generation means the weather will have a greater impact on the future energy system; there will be instances where there is low RES production in multiple adjacent countries
- At the same time, there is a phasing out of existing thermal generation (coal, nuclear and some older gas units).

Replacement capacity is required to guarantee an adequate electricity system and provision of certain system services. New flexible thermal (gas-fired) generation is assumed in the scenarios to take a central role in this replacement capacity. This generation is not necessarily economically viable in an energy-only market, hence (partially) relying upon capacity remuneration mechanisms.

Therefore, complementary measures including demand side response and the contribution of interconnectors are expected to be part of the strategy in mitigating security of supply risks.

Thanks to the sharing of resources, additional interconnection ensures security of supply in a more cost-effective manner compared to an isolated approach requiring more installed generation capacity on individual country level.

2.5

Ensuring security of supply

The increases in renewable generation can result in significant load ramps being experienced within countries, resulting from fast changes to variable generation output occurring at the same time as changes to the load profile. TSOs will subsequently face challenges in maintaining system balance, driving a need for flexibility across the region. This could be provided by various sources, including additional interconnection, storage, fast acting peaking generation and demand side response.

Storage could be beneficial to the system, particularly whenever new interconnection is not economically efficient. Short-term storage (for example, batteries and flywheels) and demand response have the potential to aid the system in terms of flexibility. However, these tend to respond to shorter-term events. Achieving full decarbonisation in the longer run (close to or beyond 2050) could require larger-scale solutions, which can respond to longer-term events, such as Compressed Air Energy Storage, power to gas and power to heat.

2.6

Changes since last Insight Report

For TYNDP 2016, projects were assessed against four scenarios in 2030, referred to as Visions 1 to 4. These scenarios were devised taking into consideration two main principles – the level of renewable generation and the extent of international collaboration. For TYNDP 2018, the scenarios and the underlying methodology have changed. This time, stakeholders have been fully involved in the scenario building process from the start, including defining the overall storylines and tendencies behind criteria. For 2030, there are three scenarios. Two of these are bottom-up scenarios, built on information provided by TSOs which align with the stakeholders' storylines. The third scenario is provided by an external party, in this case the European Commission (EC), with this being the first time an external scenario has been included in the TYNDP.

All scenarios represent different pathways to meet 2030 decarbonisation targets in the EU. For TYNDP 2018, each scenario has been assessed multiple times, each time using climate data from different years (referred to as climate years (CY) throughout the TYNDP). In total, 35 years were considered and three typical climate years subsequently selected which were broadly representative of all the years. As renewable generation develops, the weather will play a bigger role in determining when and where generation is dispatched. By using multiple climate years, projects are assessed against a greater range of potential future operating scenarios.

Offshore renewable generation levels for 2030 in TYNDP 2018 are not as ambitious as those in TYNDP 2016, and there have been changes to project portfolio in the NSOG region as a result. However, the individual offshore projects have once again been collated into one large-scale project and assessed as such in this TYNDP. Furthermore, a number of new initiatives, such as research projects and industry-wide collaboration on new visionary projects, are occurring in the NSOG region; these are discussed briefly in Section 6.1 and in more detail in the RGNS Regional Investment Plan.

Section 3

Regional scenario overview – Future perspectives

3.1
Scenario overview and main storyline

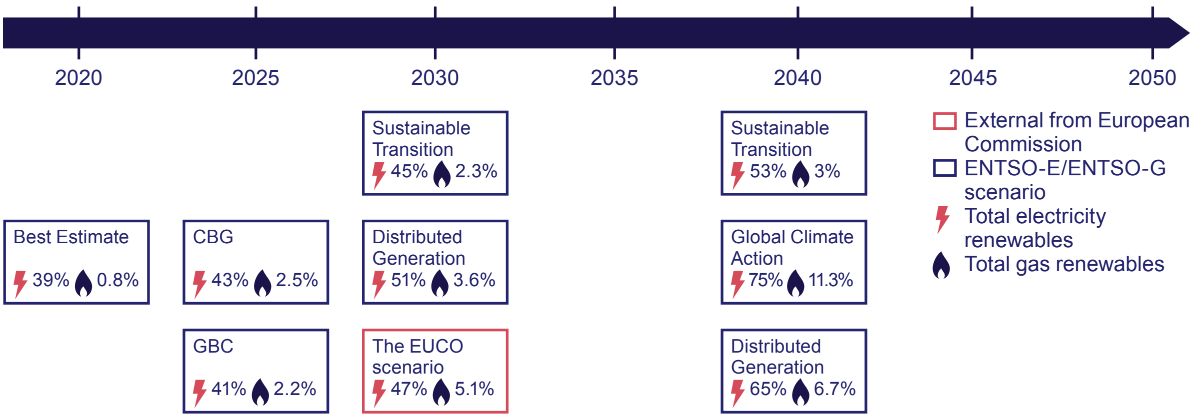
All scenarios detail electrical load and generation along with gas demand and supply, within a framework of EU targets and commodity prices.

The respective TYNDP scenarios include a Best Estimate scenario for short-term (2020) and medium-term (2025) time horizons, and three different storylines for the long-term (2030 – 2040) time horizons to reflect increasing uncertainty. All of the scenarios are on track to meet the decarbonisation targets set out by the EU by 2030. The scenarios from 2020 to 2030 are shown in Figure 3.1.

The full storylines, parameters and price assumptions supporting these possible futures and the methodology for building the scenarios are explained in the TYNDP 2018 Scenario Report[1].

The Best Estimate scenarios for 2020 and 2025 are based on a TSO perspective. While they reflect all national and European regulations in place, they do not conflict with any of the other scenarios. A sensitivity analysis regarding the merit order of coal and gas in the power sector is included for 2025 and the results are given as 2025 Coal Before Gas (CBG) and 2025 Gas Before Coal (GBC).

Figure 3.1: 2020 to 2030 scenario building framework for TYNDP 2018



The present study analysed the three following main scenarios for the 2030:

Sustainable Transition (ST)
This scenario will be achieved by replacing coal and lignite by gas in the power sector, leading to a quick and economically sustainable CO_2 reduction. The targets are reached through national regulation, emission trading schemes and subsidies, steady RES growth, moderate economic growth, and moderate development of electrification of heating and transport. The scenario is in line with the EU 2030 target, but slightly behind the EU 2050 target.

Distributed Generation (DG)
In this scenario, prosumers are centrally placed. The scenario DG represents a more decentralised development with focus on end user technologies. Smart technology, electric vehicles, battery storage systems and dual fuel appliances, such as hybrid heat pumps, allow consumers to switch energy depending on market conditions. An efficient usage of renewable energy resources is enabled at the EU level as a whole. The 2030 and 2050 EU emission targets are reached.

Scenario “EUCO 2030”
In addition, for the year 2030 there is a third scenario based on the European Commission’s (EC) EUCO scenario for 2030 (EUCO 30). The EUCO scenario is designed to reach the 2030 targets for RES, CO_2 and energy savings, taking into account current national policies, like German nuclear phase-out. The EUCO 30 already models the achievement of the 2030 climate and energy targets as agreed by the European Council in 2014, but includes an energy efficiency target of 30%.

Global Climate Action (GCA)
In the 2040 scenarios, an additional scenario is provided. Global Climate Action is characterised by full speed global decarbonisation and large-scale renewables development in both electricity and gas sectors. The 2030 and 2050 EU emission targets are reached.

[1] https://tyndp.entsoe.eu/tyndp2018/scenario-report/

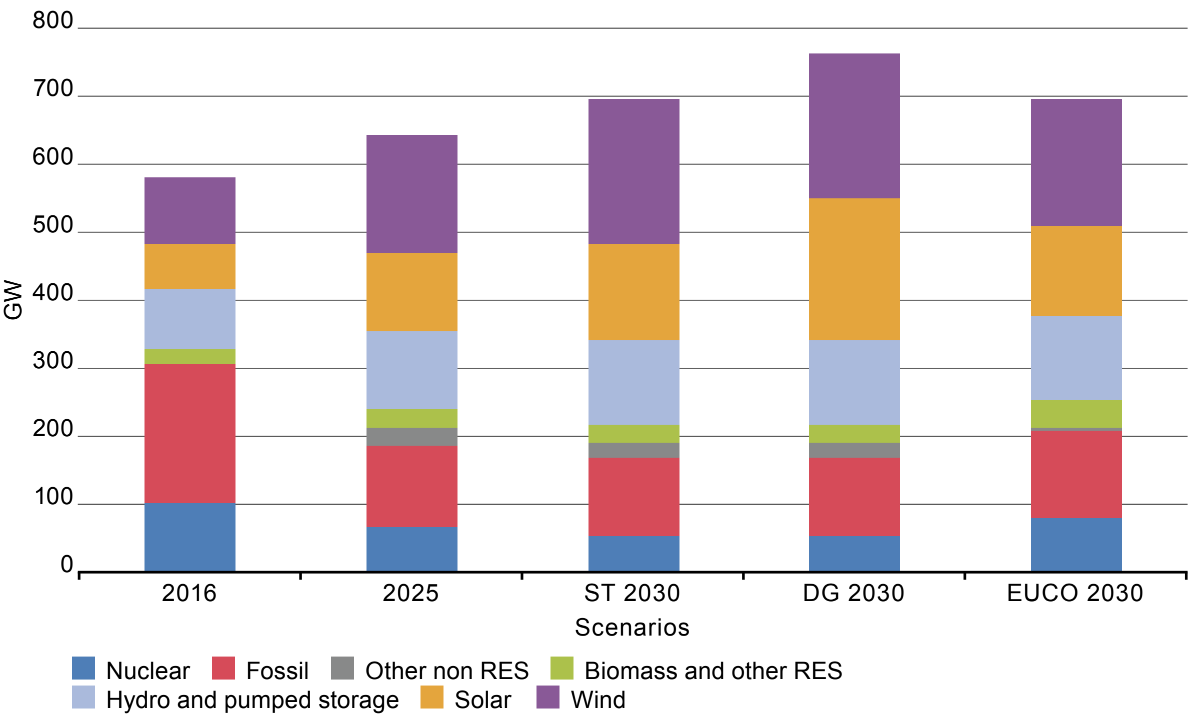
3.2
Scenario results and comparison

Summarised below are the results of the scenario process, covering the electricity sector in terms of installed generation capacities and production, demand, the evolution of CO_2 emissions and contributions from renewable energy sources. These results are presented at a regional level as de ned in Section 2. Relate gures per country can be found in the Annex. Figure 3.2 shows the installed generation capacities, and Figure 3.3 shows the generation production versus demand for the region for the timeframe 2016 – 2030, the 2040 timeframe can been seen in the Scenario Report.

In all cases, the information presented uses the weighted average of the three climate years for each scenario. The general trends in the generation portfolio that can be seen throughout the years include:
- From 2016, a reduction in nuclear generation capacity in all 2030 scenarios; the rate of closure is slower in the EUCO scenario;
- Large increases in wind and solar generation from 2016 to 2025 and on to 2030, with the DG scenario seeing the highest installed capacity;
- A significant decrease in fossil fuel capacity between 2016 and 2030, mostly driven by the closure of coal plants;
- An increase in biomass generation in all 2030 scenarios, most pronounced in the EUCO scenario; and
- An increase in hydro and pumped storage capacity by 2030 in all scenarios.

It should also be noted that, to ensure adequacy standards are met, new flexible thermal generation has been assumed in the TYNDP 2018 scenarios. This generation is not necessarily economically viable in an energy-only market, hence (partially) relying upon capacity remuneration mechanisms. The implications of this are, on the one hand, that benefits of additional grid capacity may be underestimated in the TYNDP 2018 analysis, and, on the other hand, it raises concerns about the present market's ability to incentivise sufficient generation capacity to ensure adequacy. This issue will be further investigated in coming TYNDPs.

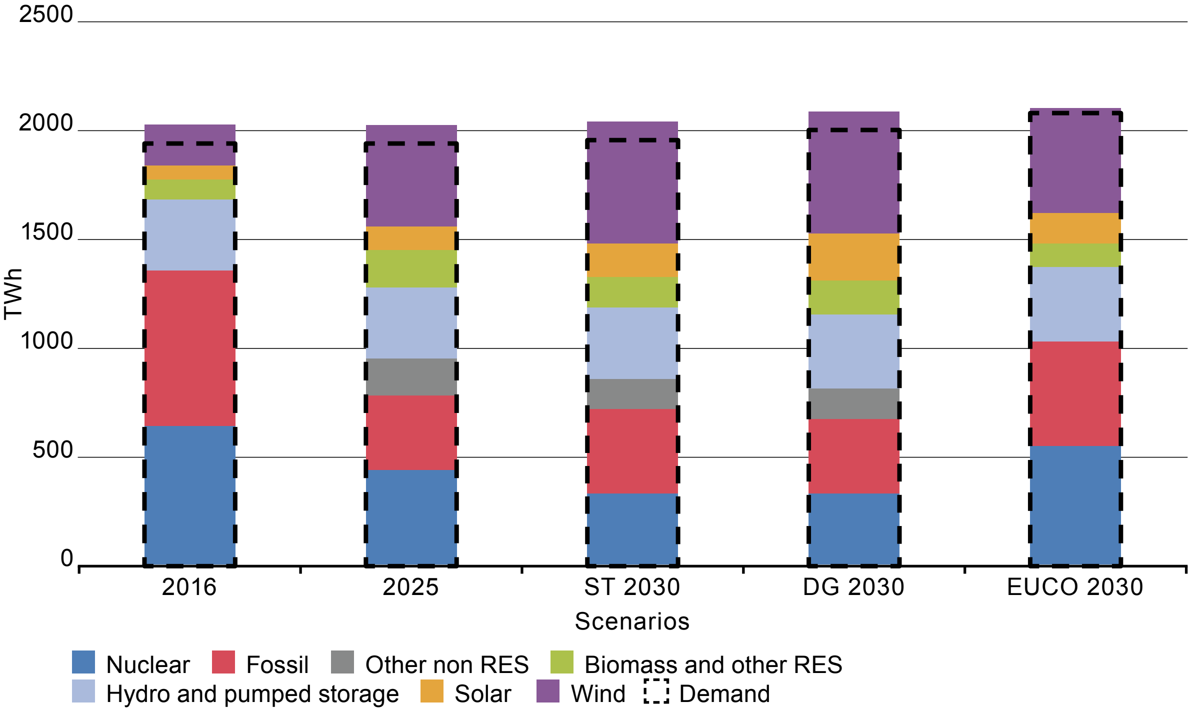
Figure 3.2: Installed capacities for 2016, 2025 and the 2030 scenarios in NSOG region



Reflecting the changes in installed generation capacities, Figure 3.3 shows a significant reduction in thermal generation production and a corresponding increase in wind generation production from 2016 to 2025 and the 2030 scenarios. Solar generation production also increases, but at a more moderate growth compared to production from wind generation, in spite of the large increase in installed solar capacity; this reflects the lower load factor associated with solar generation.

The EUCO scenario shows nuclear generation production comparable to that of 2016, while in the other scenarios there is a notable reduction in output.

Figure 3.3: Generation production and demand for 2016, 2025 and the 2030 scenarios



As demonstrated in Figure 3.3, the NSOG region is a net exporter of power in all scenarios. Looking closer, Figure 3.4 shows the energy balances for all countries in the region for the 2025 and 2030 scenarios. Again, these are determined using the weighted average of the three climate years for each scenario. The energy balance represents whether a country is a net importer or exporter of energy for a particular scenario. The trends are:

- A large energy surplus in Norway and Sweden in all scenarios, resulting from the large hydro and wind generation capacity across the countries
- France, with its large nuclear capacity, is a significant exporter in all scenarios
- GB and Ireland being exporters in ST only, almost neutral in DG and net importers in the EUCO scenario. Northern Ireland is generally a net importer, but is almost neutral in the EUCO scenario
- Germany being a significant energy exporter in ST and DG, however a significant importer in the EUCO scenario due to the slower growth of RES generation; and
- In the Benelux countries, Belgium and Luxembourg are net importers in all scenarios, however, the Netherlands is an exporter in both ST and DG, with the higher RES generation capacity.

Figure 3.4: Import/Export balances

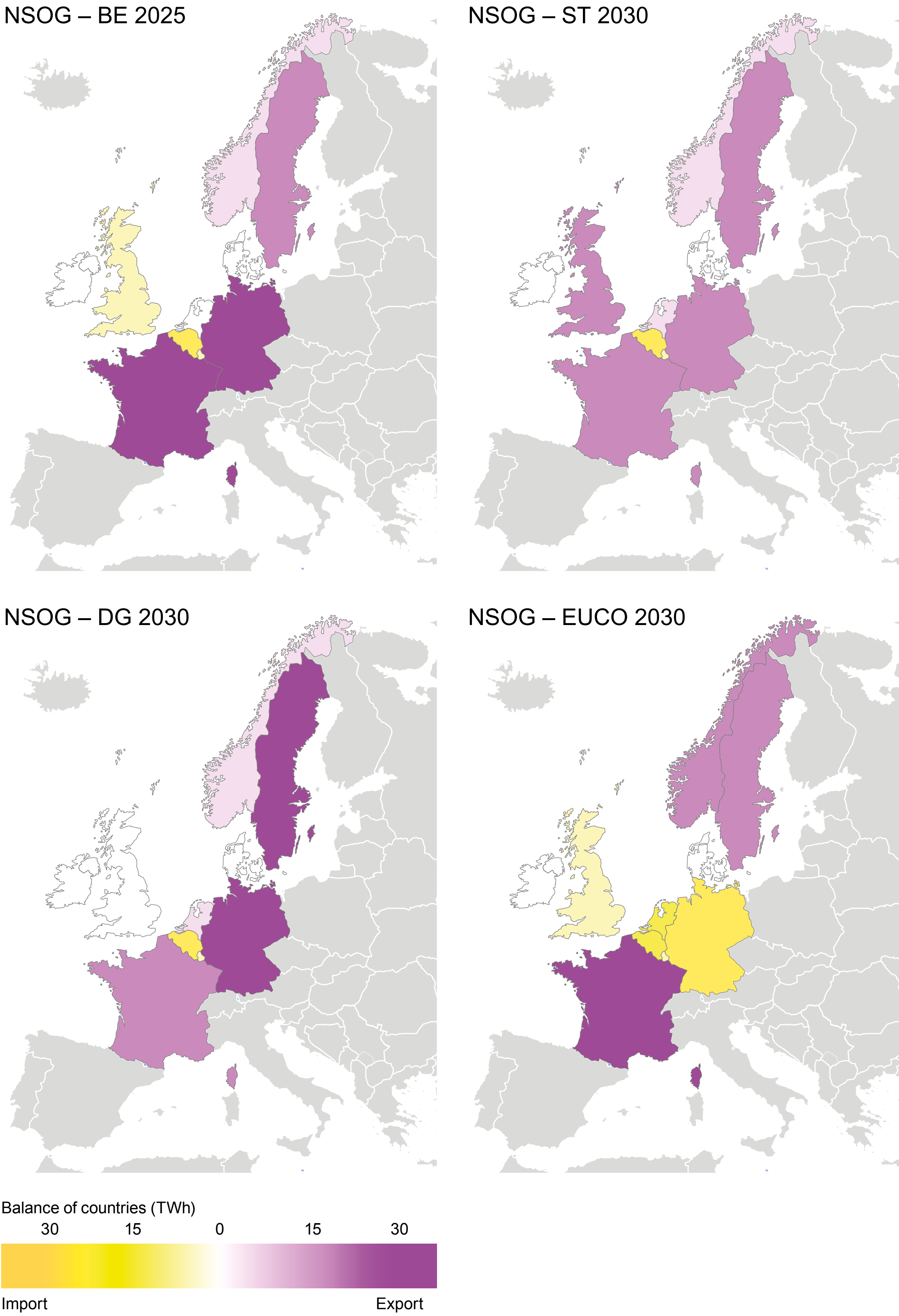
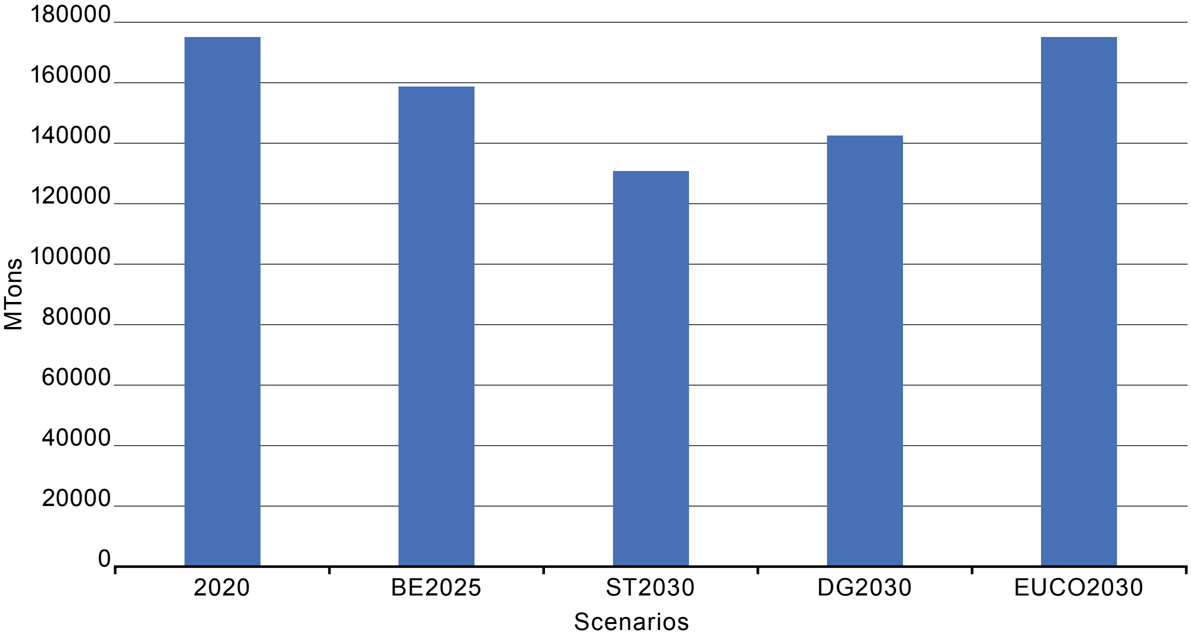
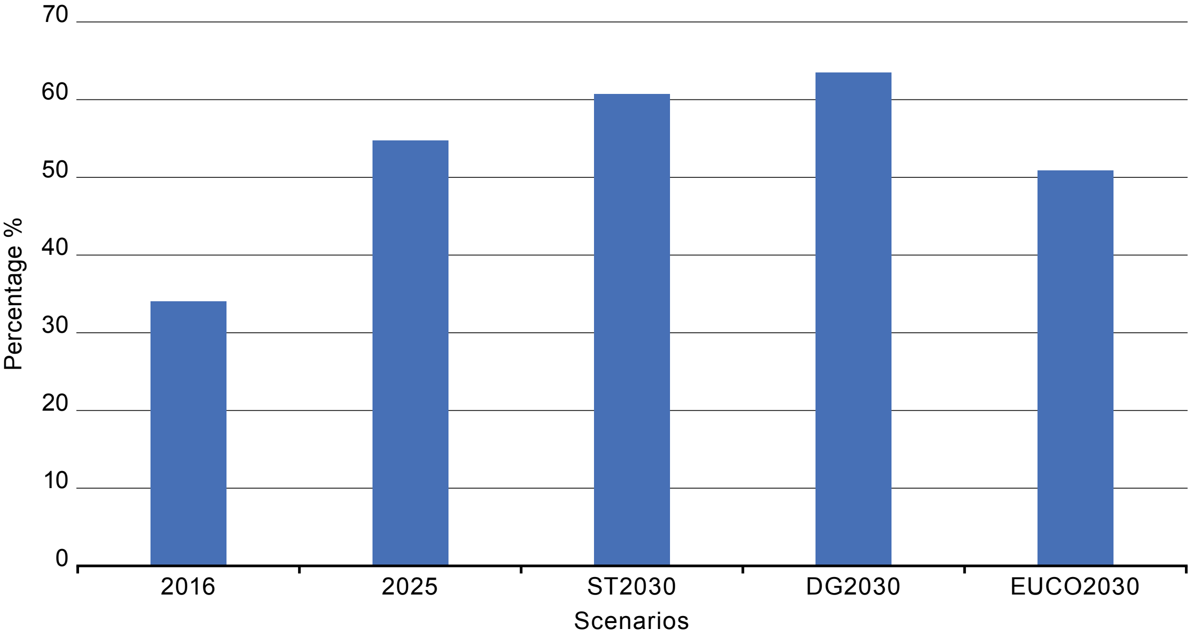


Figure 3.5 shows the CO_2 emissions and RES penetration for the region for 2025 and the three 2030 scenarios. Unsurprisingly, as the contribution from renewable generation as part of the overall generation production increases from 2016 to 2025 and on to 2030, CO_2 emissions in the region reduce.

The only exception is the EUCO scenario, with its lower levels of RES generation on the one hand and a more coal/lignite based fossil fleet compared to the other two scenarios on the other hand, resulting in larger CO_2 emissions than in the 2025, ST and DG scenarios.

Figure 3.5: CO_2 emissions (top) and RES contribution as a percentage of demand (bottom) for 2016/2020, 2025 and the three 2030 scenarios





All graphs in this section have been presented at a regional level; Section 7.3 in Annex A provides a graph displaying the information for each country within the region.

Section 4

Regional boundaries impact and main bottlenecks

This Section bridges the regional long-term needs 2040 (identified in the Regional Investment Plan 2017), via the interconnection targets for 2030 to the list and description of European and regionally significant boundaries. The storyline of this Section is schematically depicted in Figure 4.1.

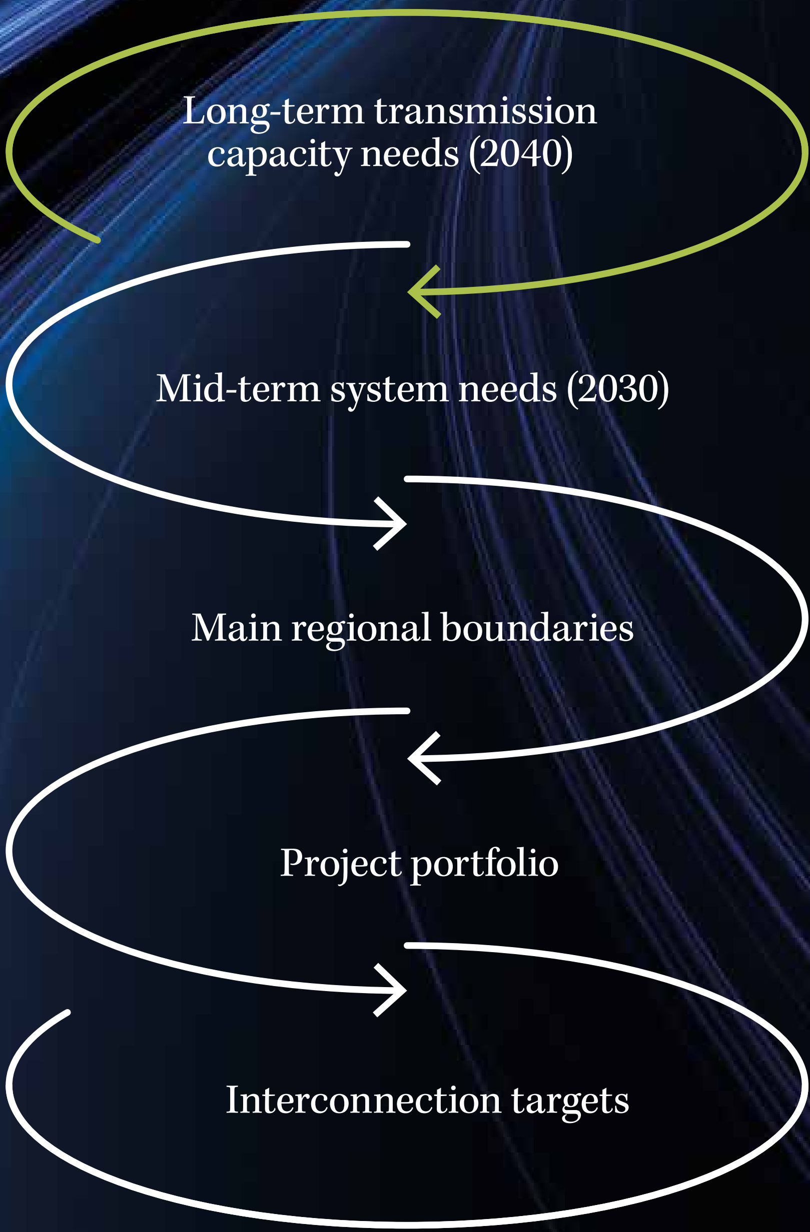


Figure 4.1: Study overview – Needs, targets and projects

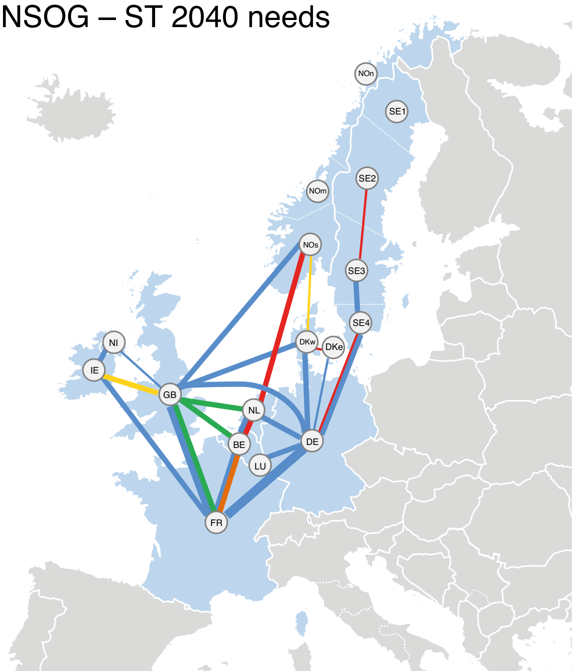
4.1

Main needs in the region

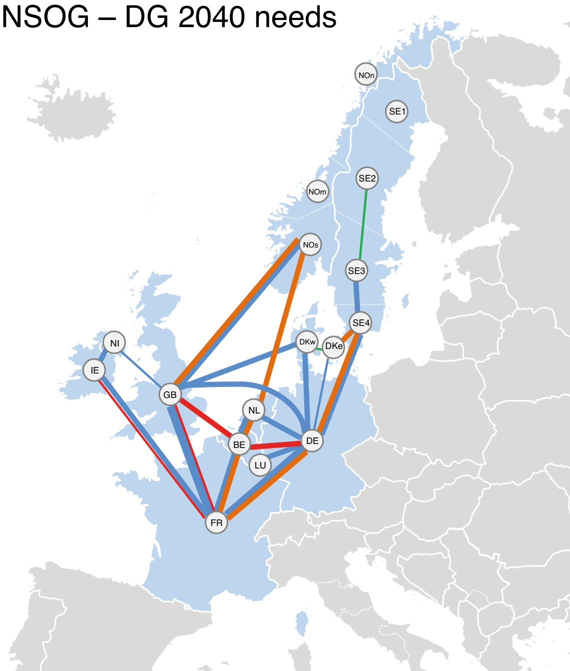
The North Sea Regional Investment Plan 2017[2] showed system needs for the 2040 horizon. The identified needs for increased capacities – evaluated with respect to market integration/socio-economic welfare, integration of renewables and security of supply – are displayed in Figure 4.2.

Figure 4.2: Identified capacity increase needs from 2020 to the three 2040 scenario grids[3]

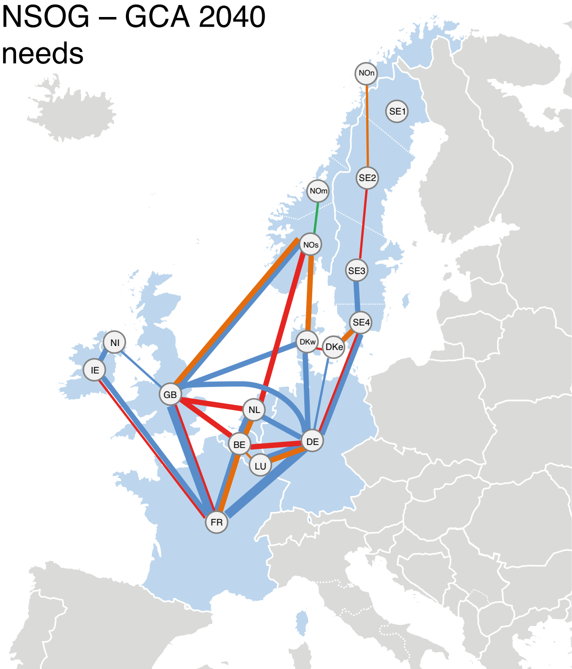
NSOG – ST 2040 needs



NSOG – DG 2040 needs



NSOG – GCA 2040 needs



Justi ation
- SEW
- RES
- SoS
- RES and SoS
- SEW and RES

Level of increase
- <500 MW
- 501 to 1500 MW
- >1500 MW

[2] https://www.entsoe.eu/Documents/TYNDP%20documents/TYNDP2018/rgip_NS_Full.pdf
[3] "Increases identified in TYNDP 2016" refers to the reference capacities of TYNDP 2016 for 2030 which for some borders had been adjusted for the TYNDP 2018 purpose. Projects commissioned in 2020 are not included as increases.

Following the pan-European Investigation of System Needs process, the main needs for additional capacity increases identified in the NSOG region were:

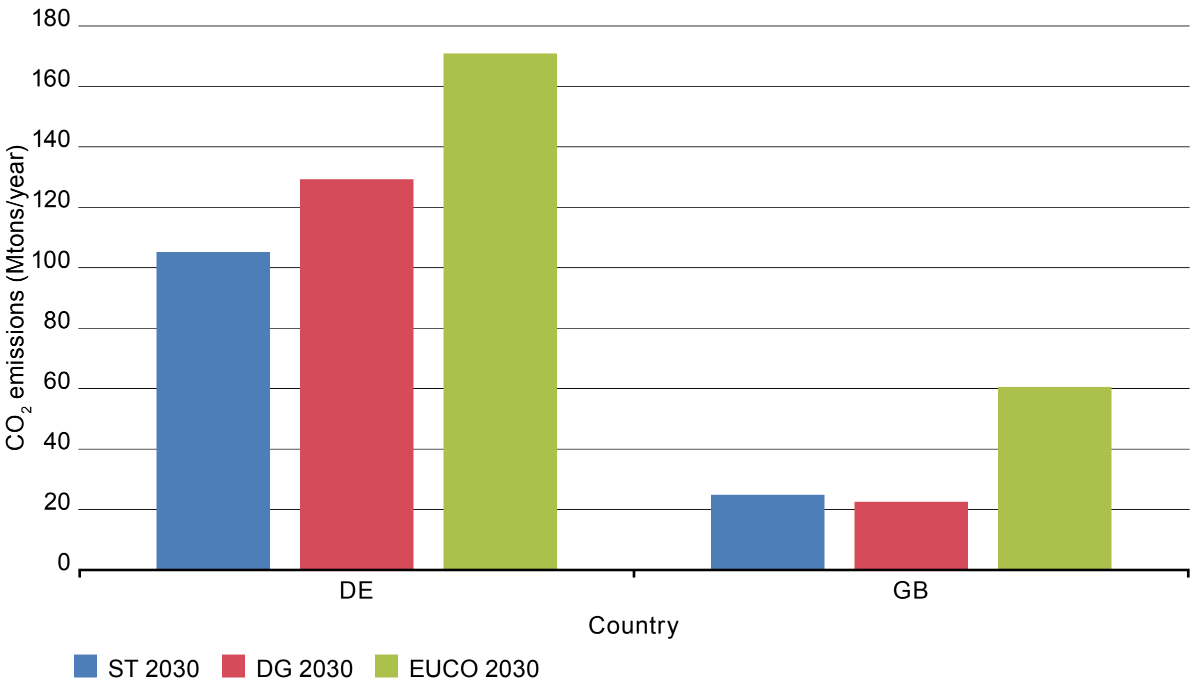
- Further integration between Norway and GB, due to price differences and the need for flexibility to optimise the RES generation (hydro/wind)
- Further integration between Norway and the synchronous Continental system, due to i) price differences, ii) the need for flexibility to optimise the RES generation (hydro/wind) and iii) provision of support to continental security of supply in high demand and low variable RES (wind and solar) periods
- Further integration between Great Britain and the Continental system, due to i) price differences, ii) better optimisation of the RES generation and iii) challenged security of supply in high demand/ low variable RES (wind and solar) periods
- Further integration between Germany and France, Belgium, Netherlands (east-west and north-south) due to i) optimisation of the production system and ii) potential to optimise the sharing of resources to ensure challenged security of supply in high demand and low-variable RES (wind and solar) periods
- Further integration between Ireland and Great Britain/France) due to i) price differences, ii) optimisation of the RES generation and iii) challenged security of supply in high demand and low RES (wind and solar) periods.

To highlight the challenges in the region, a 'no action' situation is considered. Each 2030 scenario is implemented on the 2020 grid, identifying drivers for development to enable the integration of the future generation portfolio associated with each scenario.

Figure 4.3 presents the CO_2 emission, RES spillage and unserved energy in each country associated with the 'no action' situation for each scenario; Figure 4.4 shows the cross-border price differences.

The effect of grid expansion can be found in Section 4.3.

Figure 4.3: Results of running the 2030 scenarios on the 2020 grid



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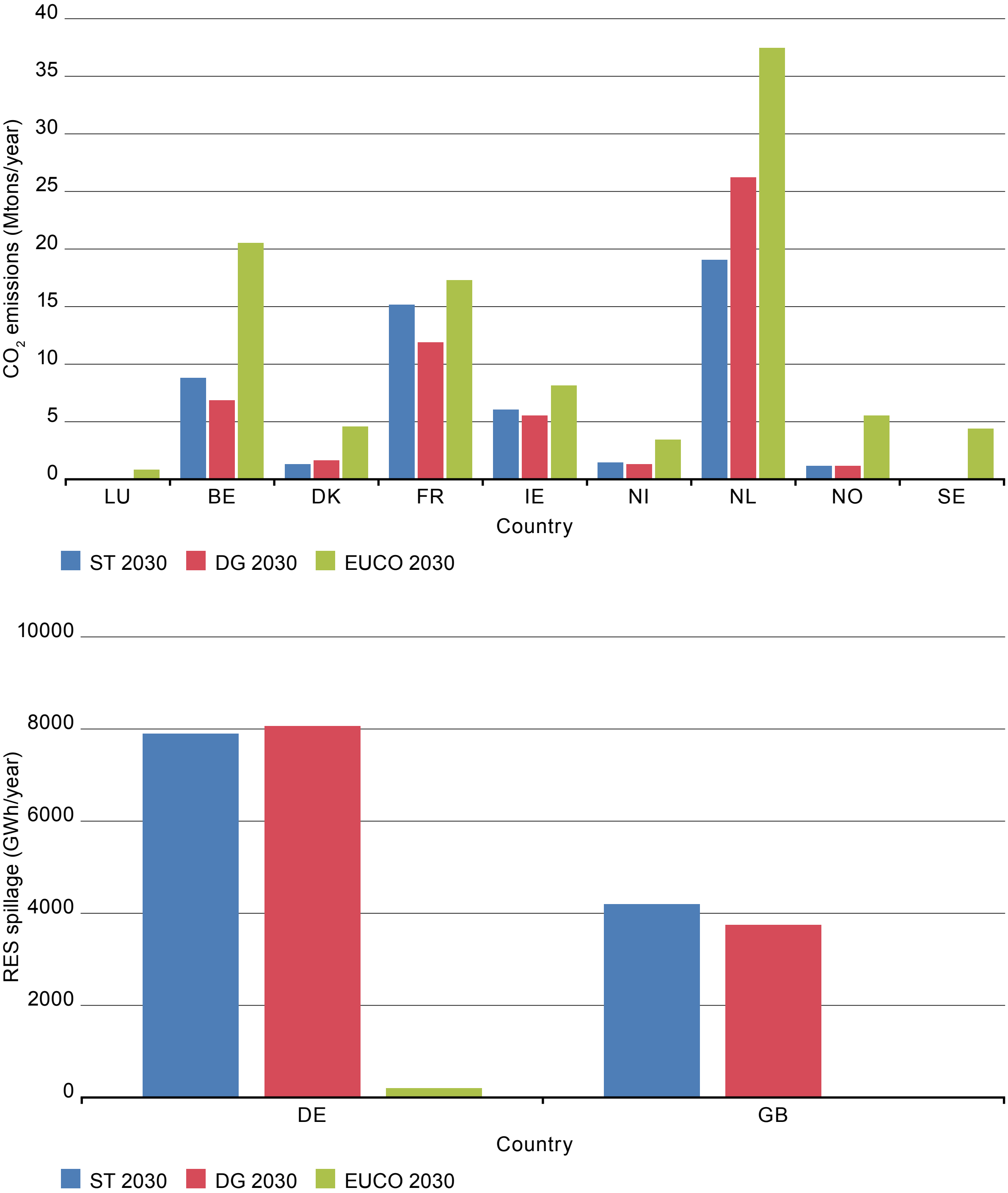

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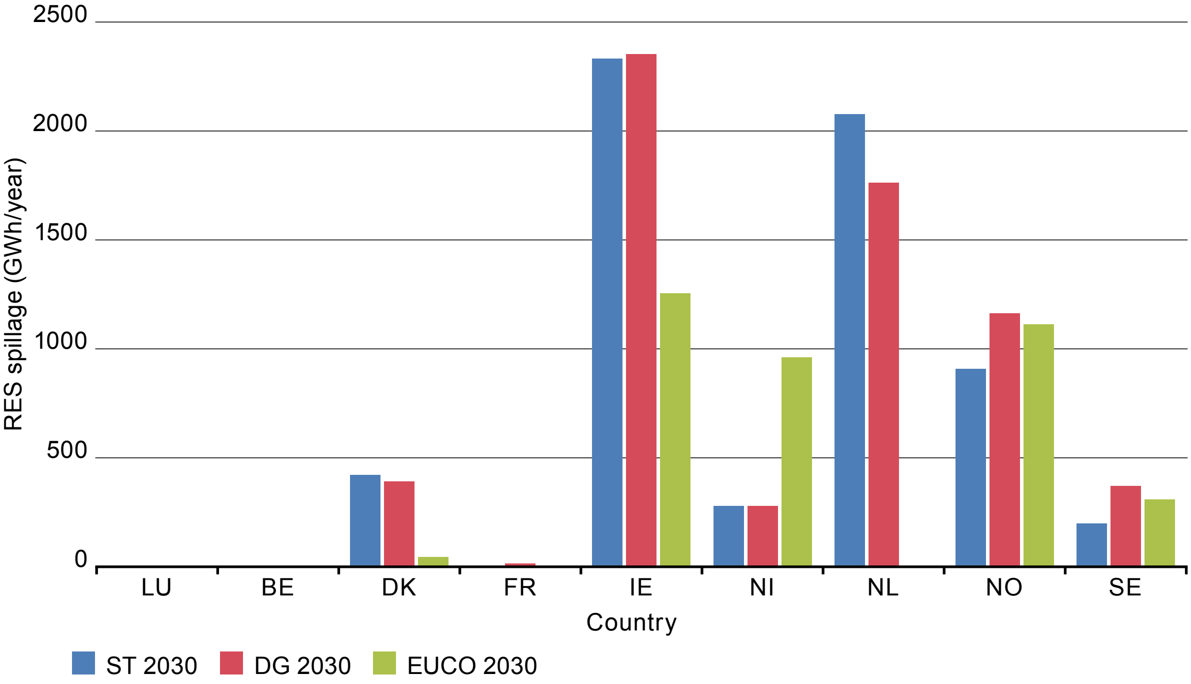


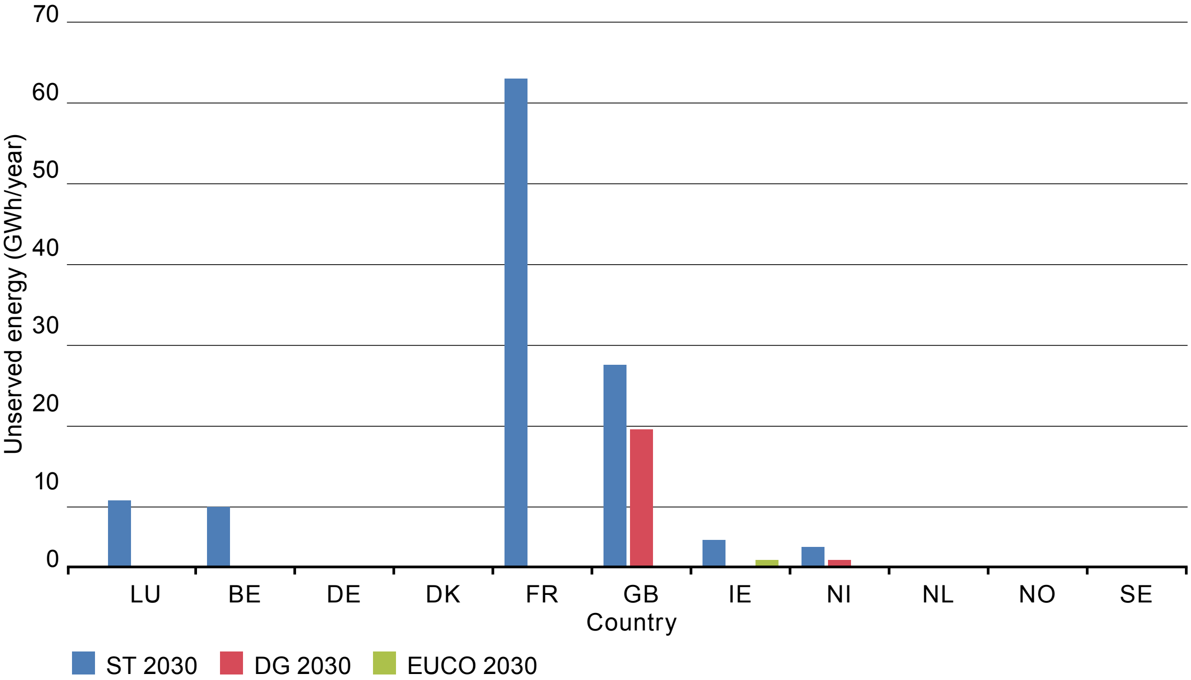
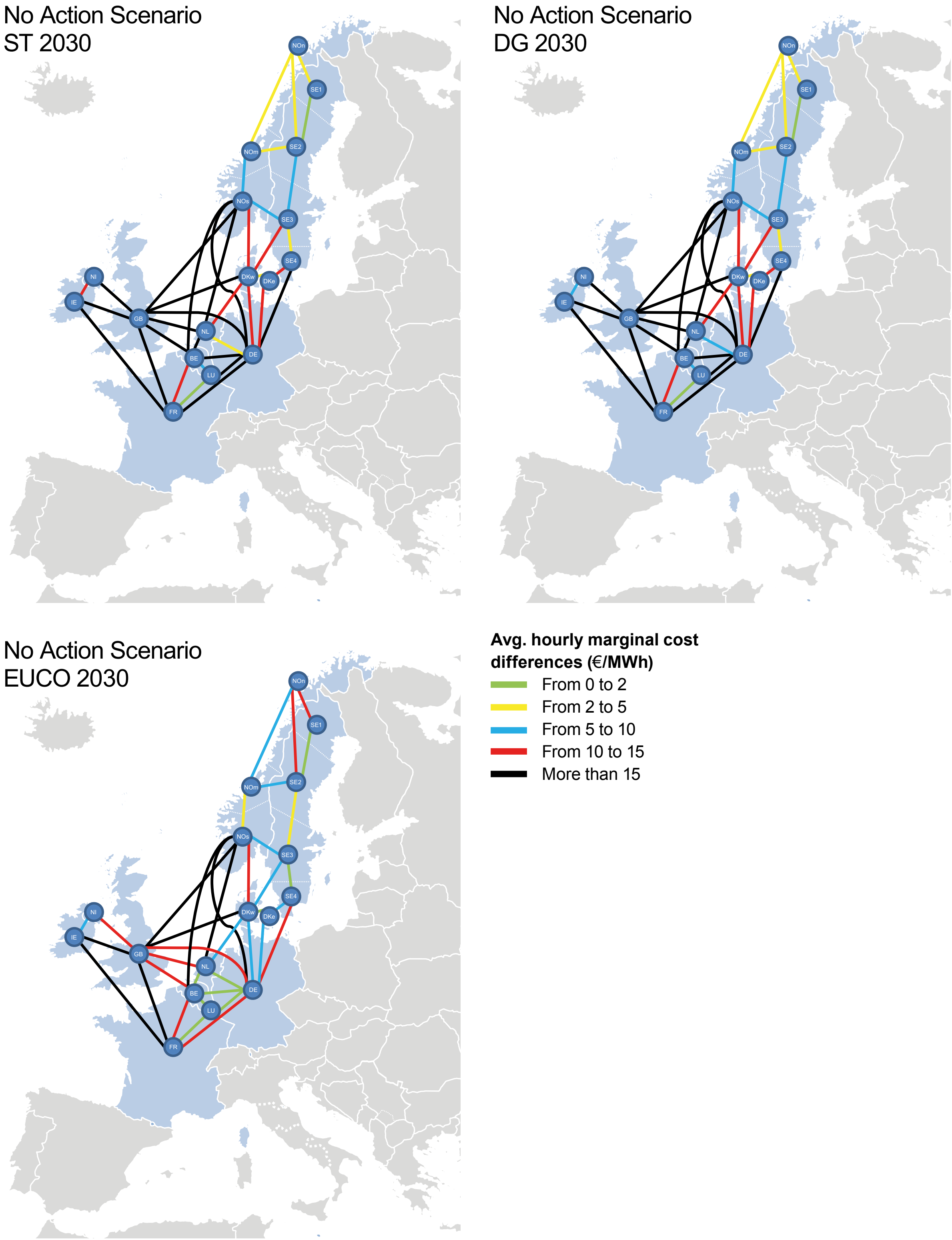


Figure 4.4: Cross-border price differences when running the 2030 scenarios on the 2020 grid



The results indicate that development in the region is required to:

— reduce CO_2 emissions across the region, by the sharing of either renewable generation or more efficient thermal generation;
— maximise the integration of renewable generation by reducing the RES curtailment observed in many countries for the ST and DG scenarios in particular; and
— reduce the large cross-border price differences observed, particularly between the island of Ireland, Great Britain, the Nordics and Continental Europe.

The results show that even for the 'no action' situation, there is no significant security of supply risk. The highest unserved energy figure observed is c.60 GWh in France for the ST scenario – representing 0.02% of the countries annual demand.

The key reason for this is the fact that the scenarios are constructed to be in line with adequacy standards. To reach these adequacy standards, new flexible thermal generation is assumed in the scenarios. This new thermal generation is not necessarily economically viable in an energy-only market, hence (partially) relying upon capacity remuneration mechanisms.

Thanks to the sharing of resources, interconnectors ensure security of supply in a more cost-effective manner compared to an isolated approach, which requires greater installed generation capacity at an individual country level.

Alternatively, if the level of installed generation capacity is maintained, the addition of additional interconnection capacity will reduce the amount of unserved energy.

4.2
Main boundaries in the region

A boundary is defined by major barriers preventing optimal power exchanges between countries or market nodes which, if no action is undertaken, leads to high price differences between countries, RES spillage and risk to security of supply.

The changes to the generation portfolio – a significant RES increase driving higher power flows across the region – are the main drivers of these boundaries.

This section covers the main boundaries in the NSOG region. Using a methodology established within the framework of the interconnection targets 2030, the consequences of not resolving the issues at these boundaries are highlighted. High price differences are also an issue at boundaries, and these are also discussed.

Three European boundaries were identified in the TYNDP 2016 in the NSOG region, highlighted in yellow in Figure 4.5. These boundaries are:

— Ireland to Great Britain and Continental Europe;
— Great Britain to Continental Europe and Nordics; and
— Nordics to Continental Europe.

Analysis shows that these boundaries are still valid in TYNDP 2018.

In addition to these three main boundaries, there exist a number of regionally important boundaries related to the long-term needs. In particular, as highlighted in the system needs report, the grid is heavily congested in the Continental West Europe (CWE) area (Benelux, Germany and France). This is due to its central location in facilitating both north-south and west-east power flows. These regionally important boundaries are highlighted in Figure 4.5 in grey.

Figure 4.5: Investment needs and main boundaries

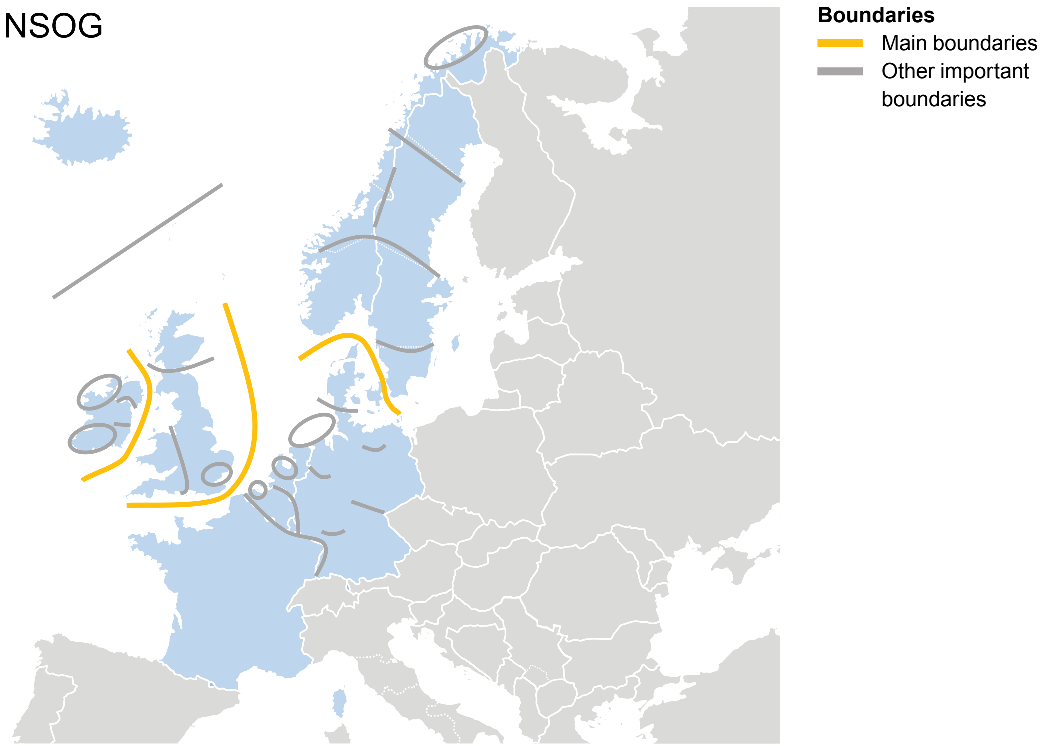


Table 4.1 details the capacity for all scenarios for the three boundaries in the NSOG region. The 2027 capacity describes the reference grid, 2035 capacities result from the project collection of the Identification of System Needs process and the 2040 capacities were identified as scenario capacities for each scenario. Further information can be found in the relevant 2017 Regional Investment Plans.

Table 4.1: Boundary capacities in the NSOG region

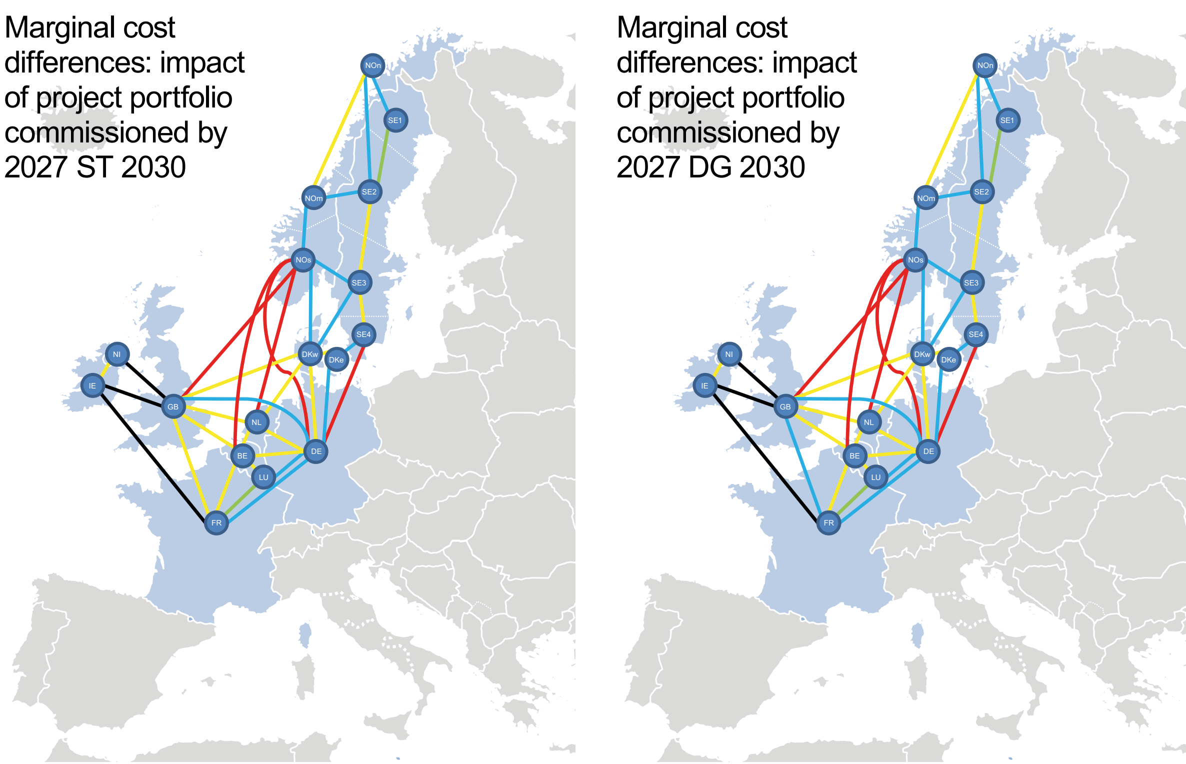
Scenario	Ireland to Great Britain & Continental Europe [GW] (East => / <= West)	Great Britain to Nordics and Continental Europe [GW] (same both directions)	Nordics to Continental Europe West [GW] (North => / <= South)
2016	0.95/0.58	3	4.94/5.4
2020	0.95/0.58	4	6.34/6.8
2027	0.95/0.78	14.4	7.02/7.56
2035 ST, DG, EUCO	2.15/1.98	19.8	7.72/8.26
2040 ST	2.7	16.1	9.04/9.5
2040 DG	2.2	14.6	10.4/10.5
2040 GCA	2.2	15.1	10.04/11.5

4.3
Socio-economic benefits and capacity changes on boundaries

All the scenarios studied, except for EUCO, include an increase in renewable generation and a decrease in CO_2 emissions, the magnitude and quantity of which varies according to each scenario. Without additional grid development, however, the full range of benefits will not be realised, as demonstrated in Section 4.1. The regional changes in price differences with the reference grid projects implemented are summarised in Figure 4.6.

Comparing Figure 4.6 to the 'no action' maps in Figure 4.4, it is clear that implementing the reference grid aids a decrease in cross-border price differences. This is very obvious considering GB to Continental Europe, where price differences have fallen from over €15/MWh to between €2 and €5/MWh. Improvements are also noted between the Nordics and Continental Europe, and within the Continental Europe area itself. Large price differences remain to the island of Ireland, and to the Nordics, both from GB and from Continental Europe.

Figure 4.6: Price differences with reference grid projects implemented in the NSOG region



Avg. hourly marginal cost differences (€/MWh)

- From 0 to 2
- From 2 to 5
- From 5 to 10
- From 10 to 15
- More than 15

Figure 4.6 continued:

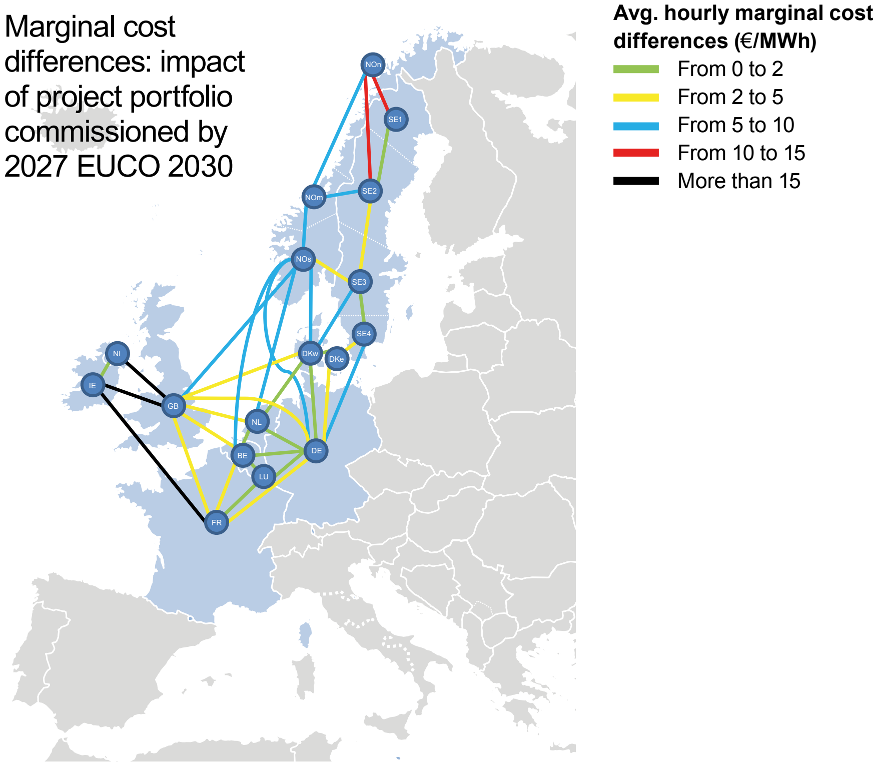


Figure 4.7 shows the price differences after having implemented the projects up to 2035. These additional projects decrease price differences even further.

The degree to which the prices reduce varies according to the scenario. Due to how it was constructed, the EUCO scenario shows the greatest degree of cross-border price reduction on all but a few boundaries within northern areas of the Nordics.

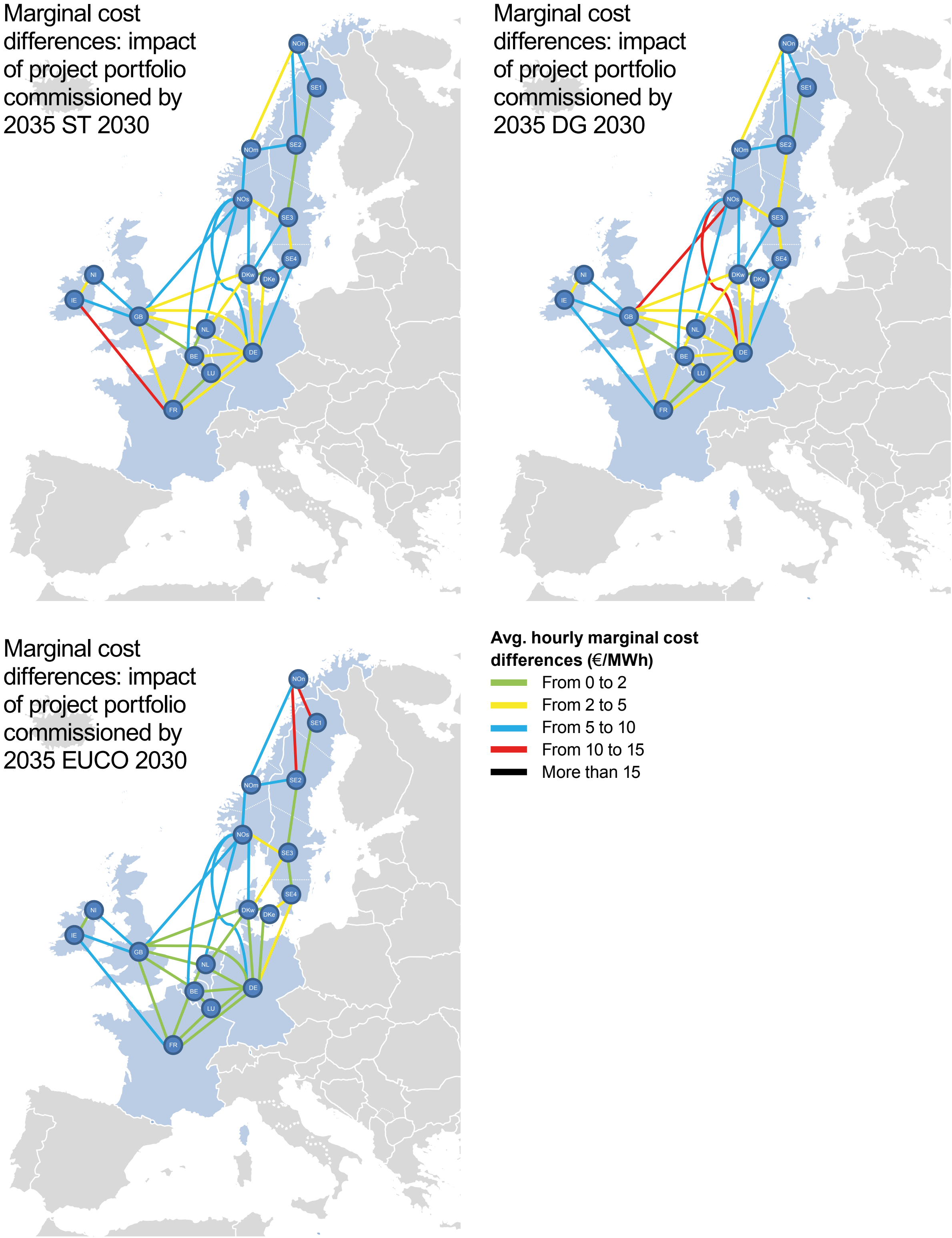
Figures 4.8, 4.9 and 4.10 show the development of the Social Economic Welfare (SEW) in the case of uniform capacity increases across the three main boundaries in the NSOG region. The benefits depend on the scenario and on the number of projects already having crossed the boundary before the investigated project is built.

The SEW-boundary capacity curves provide an indication of the value of increasing capacities across boundaries beyond the reference capacity, which is an isolated view on the development of regional variable generation cost, called "SEW" indicator in the Cost Benefit Analysis (CBA). However, it is important to note it is not the only benefit considered in the CBA, but other benefits such as RES integration or CO_2 savings are also part of the multi-criteria CBA. Additionally, it is important to note that the curves neither consider the cost of potential projects beyond 2020, nor the losses, potentially introducing further costs.

Thus, the SEW indicator's value in the graphs below should not be confused with the 'net value for society' project promoters may have in mind when using the same terminology to describe the aforementioned components being combined and depreciated.

Where the SEW benefits compensate the cost of a project, the net value for society is ensured through the project's market integration benefit. In other cases, the (combination of SEW with) other benefits of the projects (highlighted through the other CBA indicators and/or additional benefits) may be the trigger for a project. On the other hand, the lack of a net value for society may indicate that the scope/design of the project should be revised, or alternative solutions such as a storage project should be investigated.

Figure 4.7: Price differences with all TYNDP 2018 projects implemented in the NSOG region



4.3.1 Ireland to Great Britain and Continental Europe

The expected development of renewable generation on the island of Ireland will necessitate stronger interconnection of the Irish system with Great Britain and Continental Europe. Investments across this boundary, by both TSOs and third party promoters, allow these resources to be exploited, and play a role in the development of the Northern Seas Offshore Grid.

The analysis shows that projects between both Ireland and GB, and Ireland and Continental Europe, have high benefits. Some of the proposed projects make use of the dedicated connection of renewable generation in Ireland to supply GB, enhancing their associated benefits.

Beyond the planned investments in place by 2030, there is significant potential for further capacity increases. However, given uncertainties in the exploitation of the large RES resource of the island of Ireland, as well as potential large-scale demand connections, no definitive 2030 target is provided here.

Figure 4.8: SEW vs. boundary capacity – Ireland to Great Britain and Continental Europe

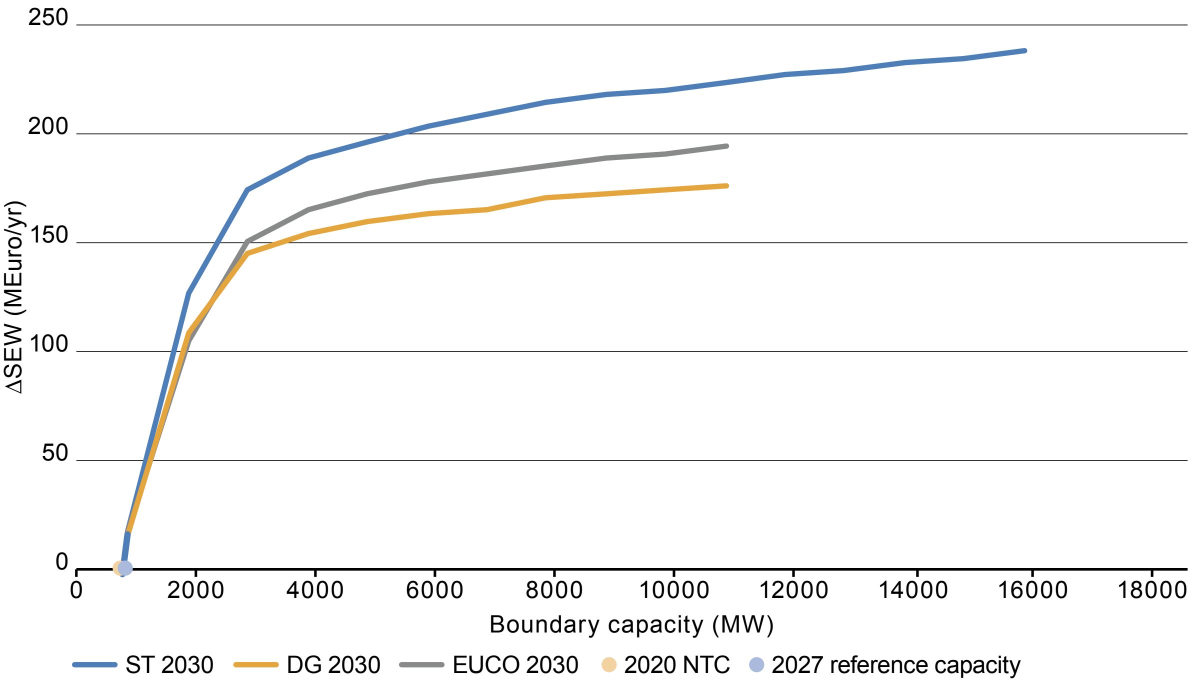


Table 4.2 TYNDP 2018 projects for ‘Ireland to GB and Continental Europe’ boundary

Project ID	Name	Commissioning	NTC (MW)
107	Celtic Interconnector	2026	700
286	Greenlink	2023	500

4.3.2 Great Britain to Continental Europe and Nordics

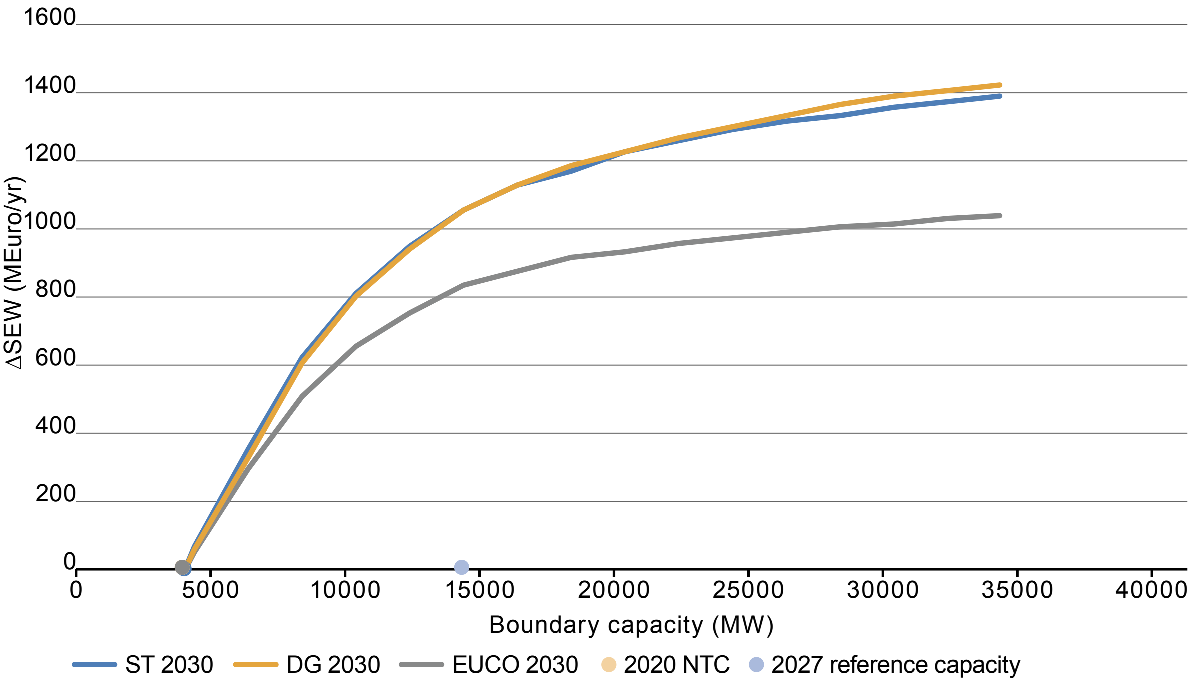
Similar to the island of Ireland, the transition from thermal to RES generation, alongside the replacement of coal with gas generation, will require stronger interconnection of GB with both the Nordics and Continental Europe. Additional capacity across this boundary will allow the integration of the RES generation, and security of supply, by linking together three areas of differing generation portfolios.

Investments across the boundary will play a key role in delivering European market integration, as well as developing the Northern Seas Offshore Grid infrastructure.

The analysis shows that projects between the Nordic and GB systems have high benefits, however, there are also high costs due to the long distances involved. Substantial price differences remain between the Nordics and British system in all scenarios.

As demonstrated in Figure 4.9, the reference grid capacity for this boundary has changed since TYNDP 2016. Previously it was 10.2 GW. For the TYNDP 2018 analysis, it is 14.4 GW.

Figure 4.9: SEW vs. boundary capacity – GB to Continental Europe and Nordics



This significant increase results in a corresponding decrease in SEW benefits for all projects assessed as part of this border. As shown in Figure 4.9, the reference capacity now aligns with the flatter, saturated area of the curve. As projects are assessed against this capacity, there is less of a SEW benefit available to the project. This is discussed in further detail in Section 4.5.

Table 4.3: TYNDP 2018 projects for 'GB to Continental Europe and Nordics' boundary

Project ID	Name	Commissioning	NTC (MW)
25	IFA2	2020	1000
74	Thames Energy Cluster	2019	1000
110	Norway-GB NSN	2021	1400
121	Nautilus (2nd interconnector Belgium-UK)	Earliest 2028	1400
153	France-Alderney-Britain	2022	1400
167	Viking DKW-GB	2022	1400
172	ElecLink	2020	1000
190	NorthConnect	2022	1400
247	AQUIND Interconnector	2022	1800
260	New GB-NL Interconnector	2030	1000
271	Conceptual Northern Seas Offshore Grid Infrastructure	See Section 6	
285	GridLink	2022	1400
294	Maali	2025	600
309	NeuConnect	2022	1400

4.3.3 Nordics to Continental Europe

The Nordic system is dominated by hydro generation and its associated seasonal dispatch pattern. The larger neighbouring Continental system has a mix of thermal, nuclear, wind and solar generation. Interconnection across this boundary will allow a better sharing of resources in the region, by exploiting the hydro generation pattern.

Figure 4.7 shows that despite a slight increase in reference capacity compared to TYNDP 2016, there is still plenty of additional SEW benefit available for projects across the boundary in the ST and DG scenarios, given the high CO_2 prices in both and the high solar output in the DG scenario. Benefits on this boundary are primarily driven by integrating RES generation and utilising flexible Nordic hydro in the Continent. Therefore, scenarios with high CO_2 price (ST, DG) and high solar PV generation in the Continent (DG) are showing the highest benefits.

Figure 4.10: SEW vs. boundary capacity – Nordics to Continental West Europe

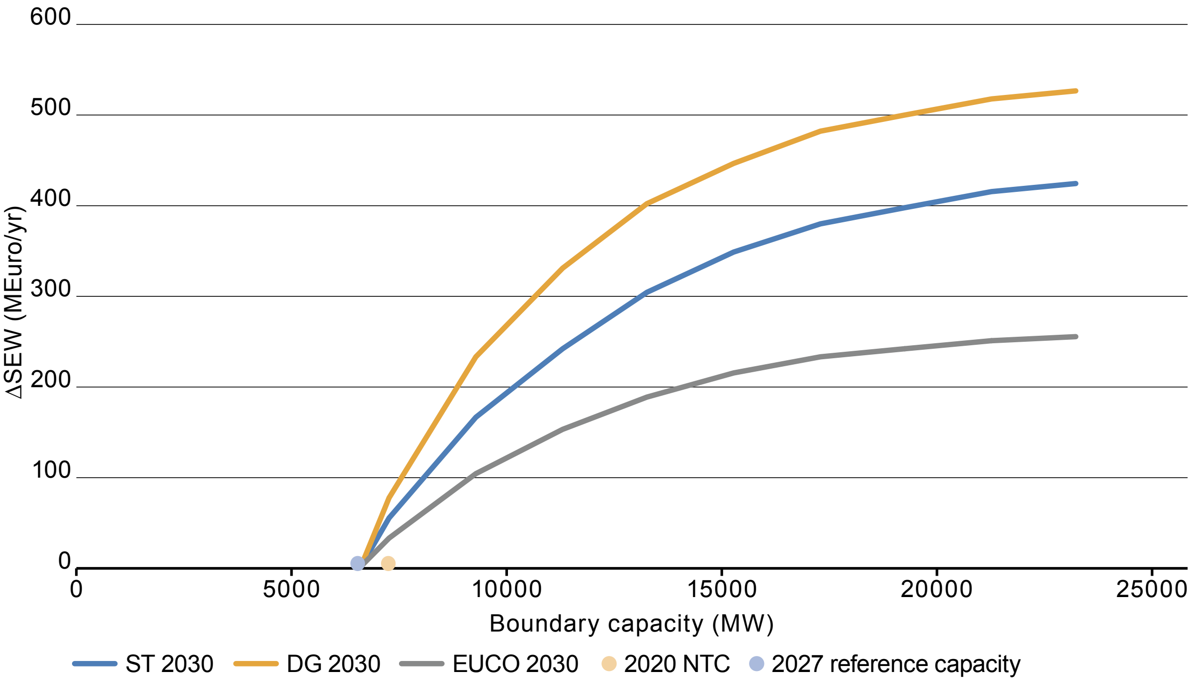


Table 4.4: TYNDP 2018 projects for 'Nordics to Continental West Europe' boundary

Project ID	Name	Commissioning	NTC (MW)
37	NordLink	2020	1400
176	Hansa PowerBridge 1	2026	700
267	Hansa PowerBridge 2	2030	700

4.4
Regional mid-term targets

In October 2014, the European Council endorsed the proposal by the European Commission (EC) of May 2014 to extend the current 10% electricity interconnection target (defined as import capacity over installed generation capacity in a Member State) to 15% by 2030.

To make the 15% target operational, the EC decided to set up an Expert Group (EG) – composed of industry experts, organisations, academia, NGOs, ACER and ENTSO-E/G – to provide specific technical advice. In November 2017, the EC published a report[4], elaborated by the EG, introducing a methodology using the following 3 criteria:

- **Minimising price differentials:** recommendation of 2€/MWh for the wholesale price difference between market areas as the indicative threshold to consider developing additional interconnectors. This trigger focuses on increased market integration and lower prices for the benefit of all.
- **Meeting electricity demand through domestic generation and imports**: recommendation that the sum of all nominal transmission capacity is at least above 30% of the peak load. This trigger contributes to guaranteeing sufficient security of supply.
- **Decarbonisation of the EU energy system by enabling export potential of excess renewable production**: recommendation that the sum of all nominal transmission capacity is at least above 30% of all renewable installed generation capacity. This trigger ensures effective renewable integration is maximised.

The multi-criteria assessment helps to identify where urgent action is required. A country being below the thresholds for one or more of the above criteria is urged to investigate options to develop interconnection capacity. In addition, countries lying between the 30% and 60% thresholds for the security of supply and/or RES integration criteria are recommended to regularly investigate options to further develop interconnection capacity.

The report introduces a very important precondition when evaluating options to further develop interconnection capacity, namely that the actual implementation of such a project is subject to positive socio-economic and environmental impact CBA analysis.

The charts in Figures 4.8 and 4.9 show the results for the NSOG region when applying the criteria to the three 2030 scenarios of TYNDP 2018. Figure 4.11 shows results when the interconnection targets are compared to the 2020 grid. This highlights where there is a shortfall in meeting the targets if no further action is undertaken. Figure 4.12 illustrates the outcome with the grid assumed by 2027, thus integrating the contribution of the majority of the TYNDP 2018 project portfolio. The studies are based on a number of assumptions, including:

- that all scenarios are assumed adequate
- the nominal cross-border capacity is based on the total physical capacities of all interconnectors, and does not include any restrictions based on system security criteria (such as mitigating possible overloads resulting from N-1 contingencies); and
- price differentials between bidding zones are limited to those for which either an interconnector currently exists or for which projects have been assessed as part of the CBA phase of this TYNDP 2018. They are hence not necessarily fully exhaustive.

[4] https://ec.europa.eu/energy/sites/ener/files/documents/report_of_the_commission_expert_group_on_electricity_interconnection_targets.pdf

Figure 4.11: Interconnection targets for the three 2030 scenarios, applied to the 2020 grid

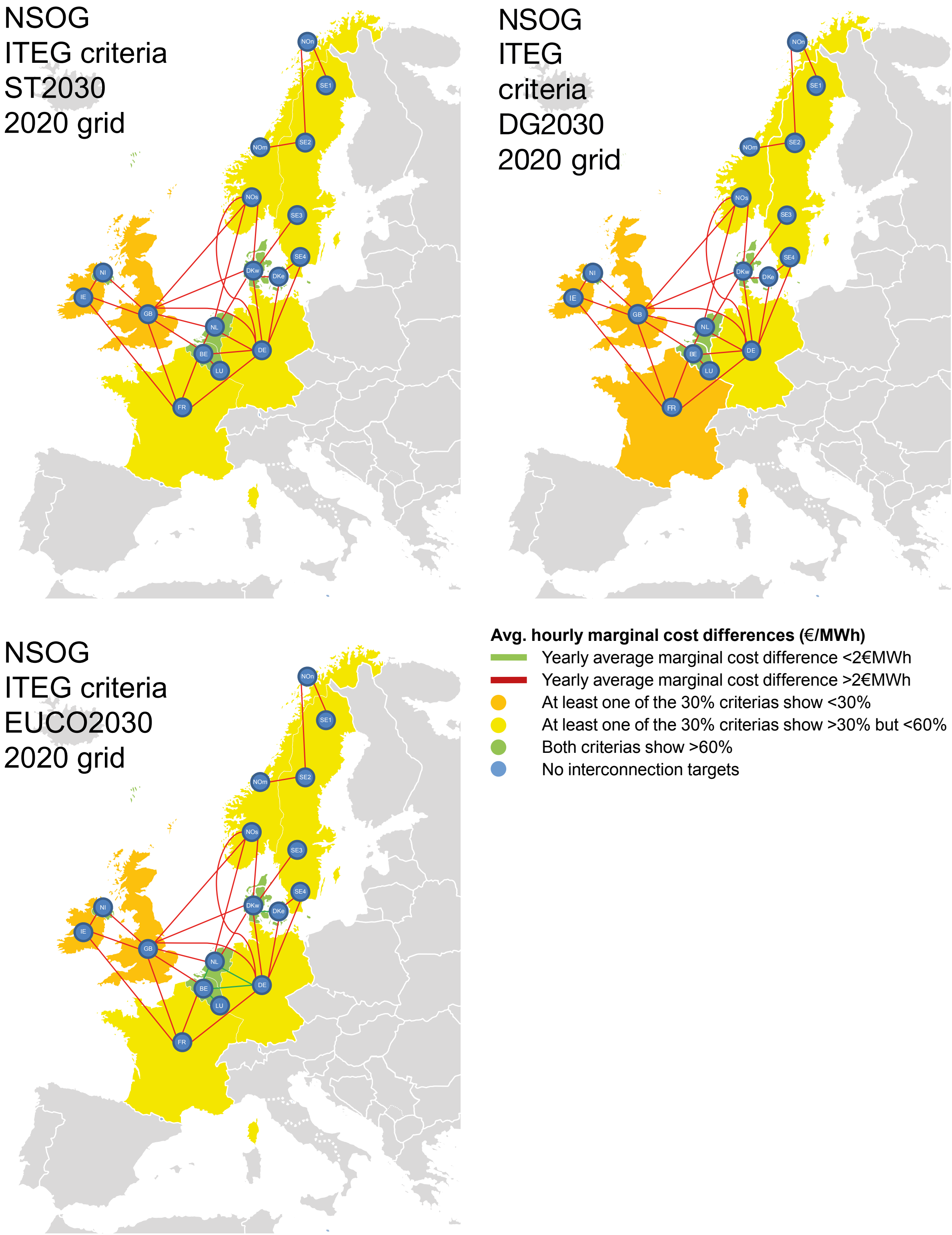
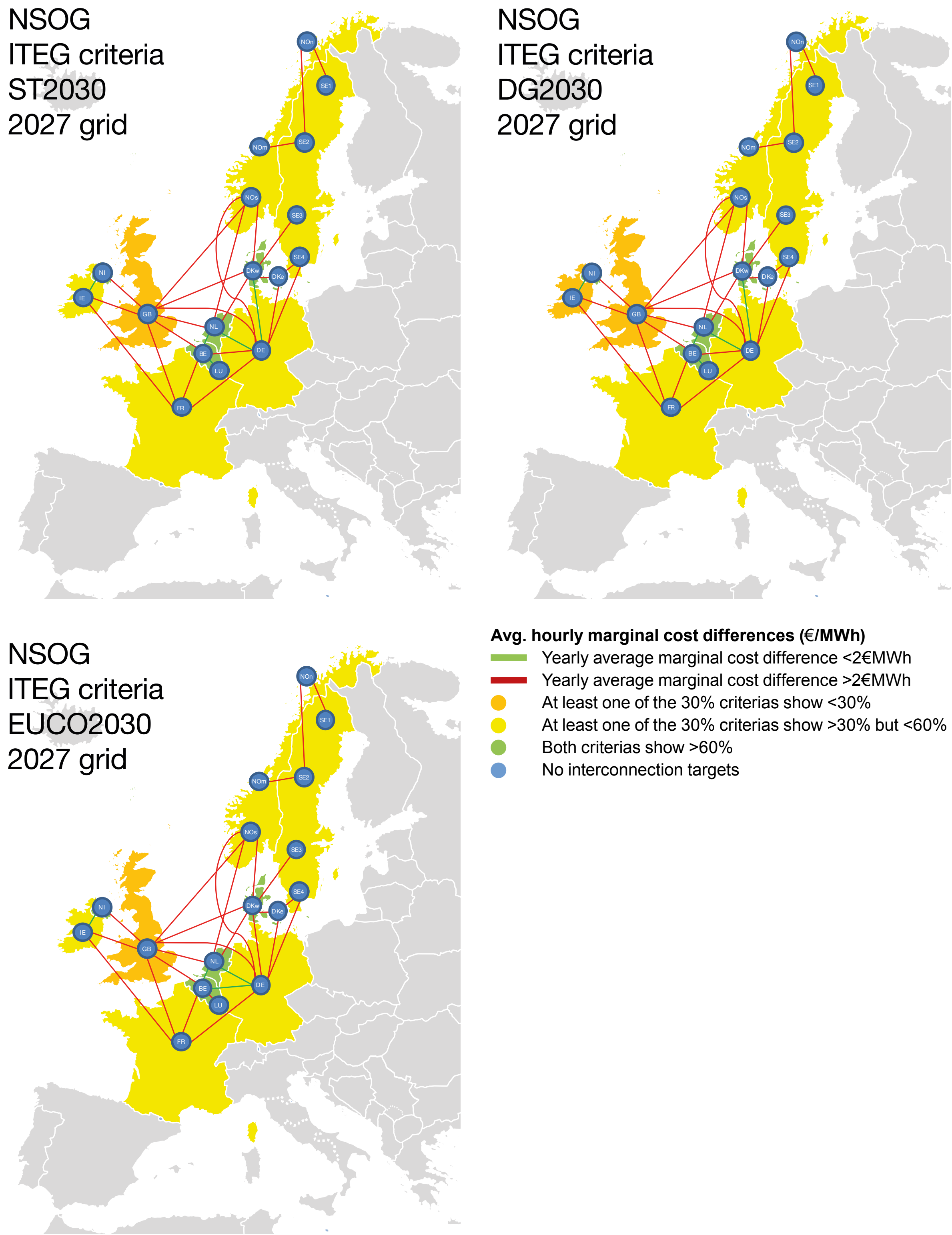


Figure 4.12: Interconnection targets for the three 2030 scenarios, applied to the 2027 grid



The results show that:

— in spite of implementation of the reference grid project portfolio, there is still a need for further development to GB to ensure the 30% criteria are met and cross-border price differences are reduced below the €2/MWh level

— price differences across many borders for both ST and DG scenarios remain above the €2/MWh level, across both the main European boundaries and also the regionally important boundaries

— given the highly meshed nature of the Continental Europe network, the Benelux countries and Denmark exceed the 60% level with respect to the 30% criterion with the 2027 grid; Sweden does likewise. Development to these countries from those not meeting the criteria could therefore be beneficial.

A more detailed look at the cross-border price differences is shown in Annex 7.2.4.

4.5
Differences between TYNDP 2016 and TYNDP 2018 project indicators

As a result of updated scenarios, scenario assumptions and improvements to the methodology used as part of the CBA 2.0, there are notable differences to the CBA results for projects within the NSOG region for TYNDP 2018 when compared to TYNDP 2016. These differences include:
- a reduction of 30% in SEW and RES values for projects across the region[5]
- a reduction in CO_2 indicators; and
- an increase in losses associated with projects.

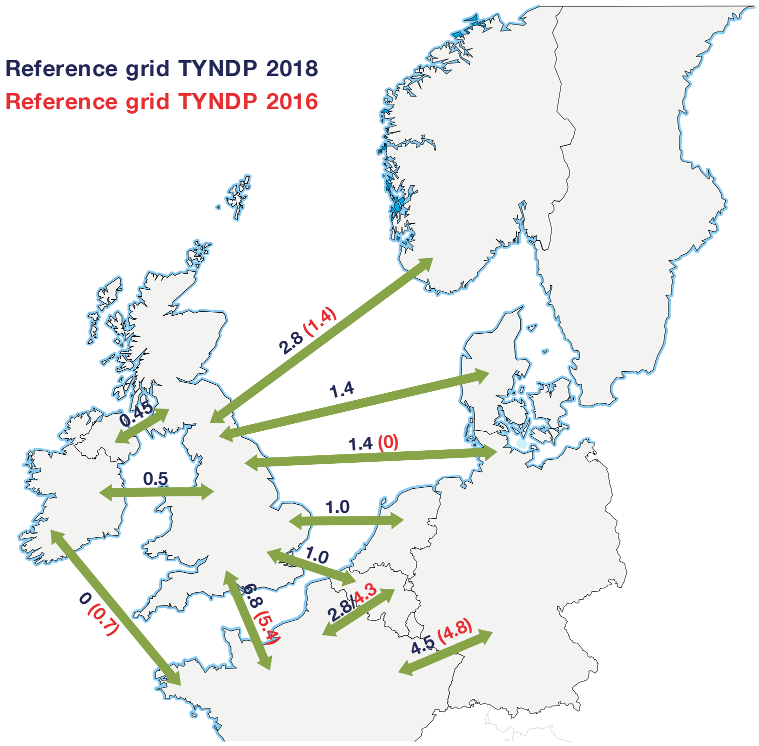
Continued improvements to the assumptions and the methodology mean that projects can appear more beneficial in one TYNDP and less beneficial in the next, or vice-versa. These effects are caused by multiple reasons, which tend to interact with each other. Some of the main trends affecting projects within the NSOG region are discussed below.

4.5.1 Changes to the reference grid

For TYNDP 2018, the guidelines on how the reference grid is composed have been tightened; the reference grid is now defined by:
- today's existing grid, plus
- projects under construction; and
- projects commissioned by 2027 with proof of commencement of the national permitting process.

This generally led to a decrease of cross-border capacity in the reference grid on certain boundaries. On the other hand, since 2016 several projects have advanced their development and qualify to be part of the reference grid, leading to an increase across some boundaries. Such an increase is most pronounced on the main boundary between GB and Continental Europe/Nordics, despite regulatory uncertainty for some projects (esp. on some UK – Continent border projects, see ACER report of 11/07/2018 on the progress of electricity and gas projects of common interest, annex-IV PCI specific information – electricity). For TYNDP 2018, the reference capacity on this boundary is set to 14.4 GW, an increase of 4.2 GW compared to 10.2 GW in TYNDP 2016. Figure 4.13 shows how the reference capacities in the NSOG region have changed from TYNDP 2016 to TYNDP 2018.

Figure 4.13: Reference grid capacities (in GW) around GB in TYNDP 2016 (red) and 2018 (black)



[5] Only comparable projects between TYNDP 2016 and TYNDP 2018 have been included, representing about 50% of all regional projects.

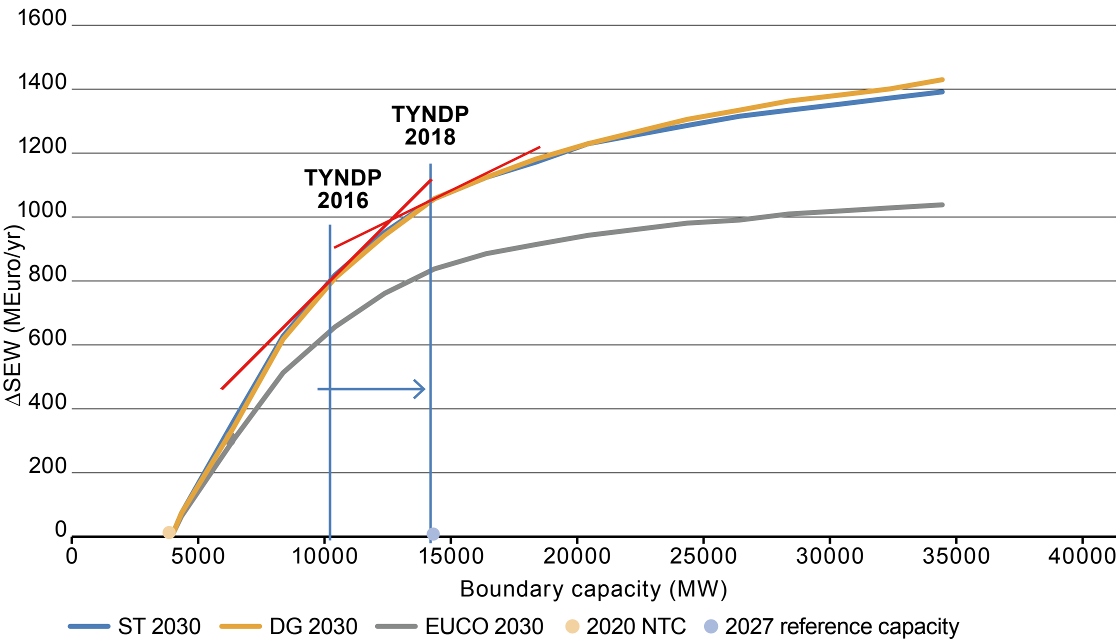
Through application of the CBA methodology, the project under assessment is always assumed to be the last project being built on top of a series of other projects assumed to be already in operation. Thus, with an increased reference capacity across a particular boundary, there is less benefit available for the project being assessed. This is a careful and conservative approach which drives the SEW values lower for all projects associated with that boundary.

This fact is illustrated in the SEW/boundary capacity curve for the GB to Continental Europe/ Nordics boundary, presented in Figure 4.14. It shows that the total number of projects in the reference grid shifts the reference boundary capacity towards the saturated area of the curve – i.e. the area where the curve flattens out.

The result of this is that all 13 projects crossing the GB to Continental Europe/Nordics boundary see lower SEW indicators in TYNDP 2018 compared to TYNDP 2016.

This may indicate that for this boundary with TYNDP 2018, the level of economically viable NTC in the sense of the CBA 2.0 monetised indicators may be questioned and is probably lower than the NTC value in the reference grid.

Figure 4.14: Comparison reference grid's boundary capacity TYNDP 2016 vs TYNDP 2018 – GB to Continental Europe and Nordics



Taking into account the large investments associated with HVDC cross-border connections, the viability of all projects associated with a saturated boundary needs careful consideration. There might be competing projects included, of which not all will materialise.

4.5.2 Changes to the fuel prices

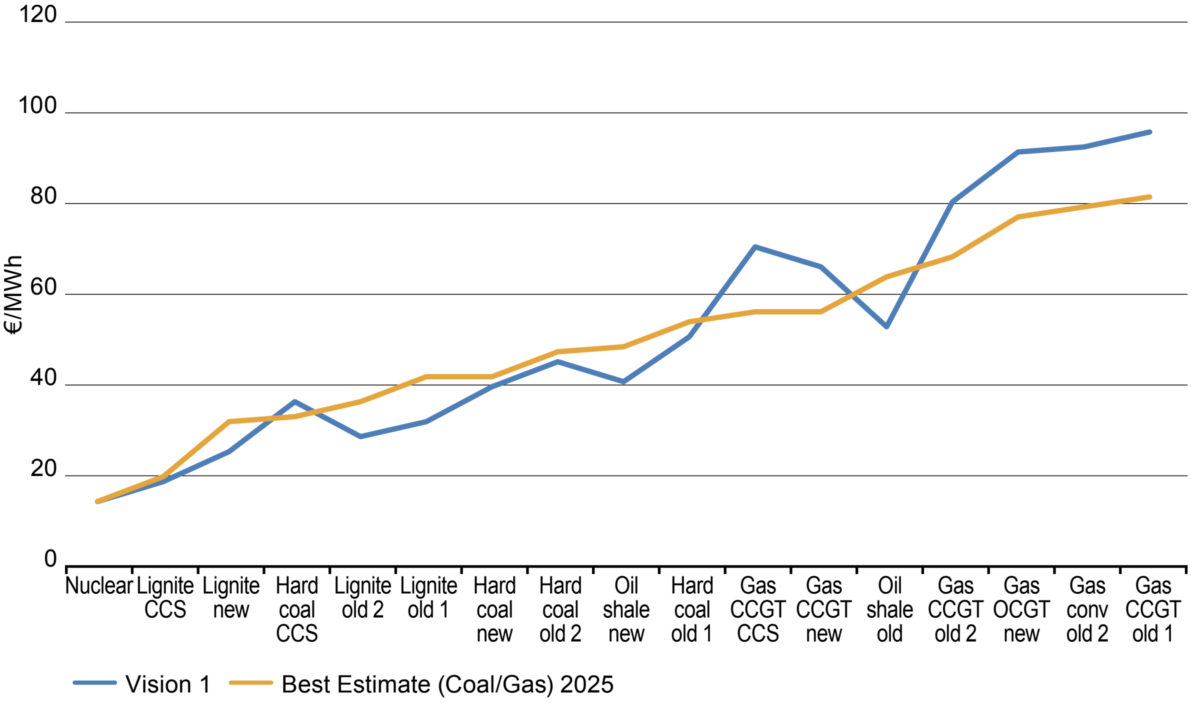
In TYNDP 2018, there is a general reduction in the assumed fuel prices used for the CBA analysis. Additionally, there is a lower price spread between differing thermal plant types. This is demonstrated in Figure 4.15, where the TYNDP 2016 Vision 1 fuel price assumptions are compared to the 2025 BE prices used in TYNDP 2018.

The fuel prices are arranged from lowest to highest for each fuel type for 2025 BE, indicated with the red line. The equivalent fuel price for each technology used in TYNDP 2016 is shown with the blue line. While coal and lignite prices are comparable, there is a notable reduction in gas prices used in TYNDP 2018.

This results in lower SEW values for new projects, mainly impacting projects on the large Continental European system. The lower overall thermal prices reduce the benefits provided by projects, resulting in lower SEW indicators.

In addition to the lower fuel prices that explain this effect shown in Figure 4.15, lower SEW values can also be explained by a higher uniformity of generation capacities, which further reduce the price spreads in the market.

Figure 4.15: Marginal price spreads: example TYNDP 2016 Vision 1 versus TYNDP 2018 BEST 2025



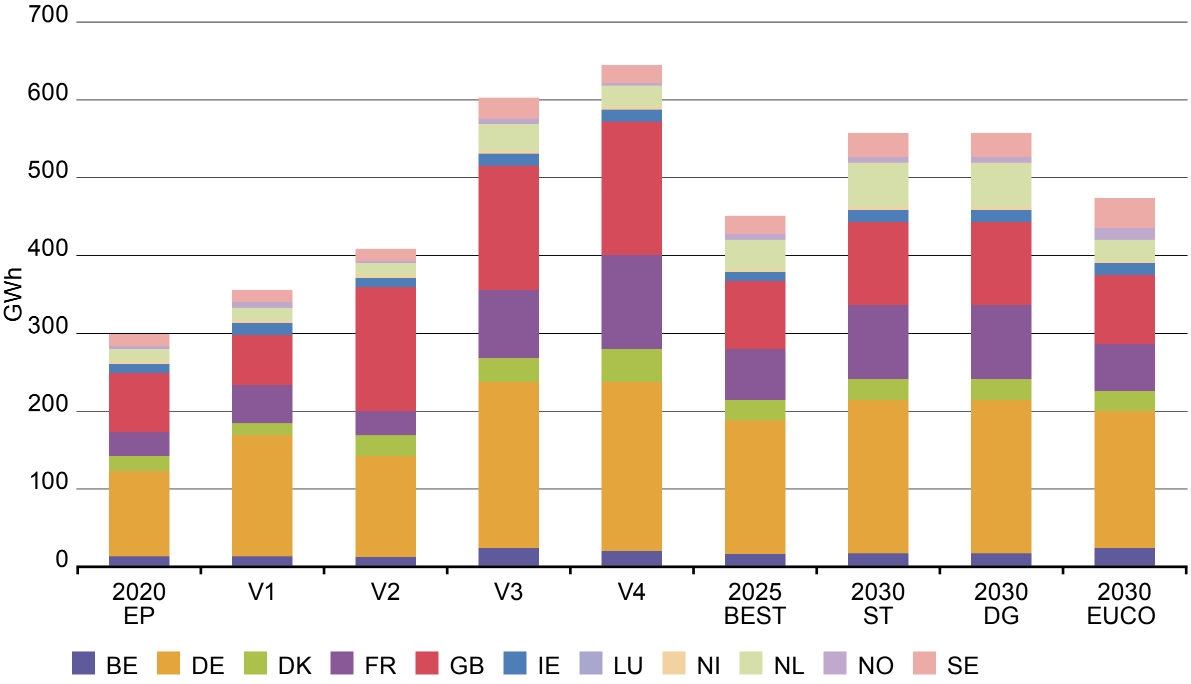
4.5.3 Updated renewable energy assumptions

For TYNDP 2018, the scenarios have been built according to storylines consulted on with stakeholders and, in the case of the EUCO scenario, provided by a third party. Therefore, whilst the scenarios incorporate comparable overall quantities of RES generation to TYNDP 2016, the distribution and location of this generation has changed. Examples of these changes include:

— a reduction in offshore wind around GB in TYNDP 2018 compared to TYNDP 2016
— smaller variations in onshore wind capacities between the scenarios, with all being close to the levels in Visions 3 and 4 (the high RES scenarios) from TYNDP 2016; and
— the inclusion of the distributed generation scenario in TYNDP 2018, where significant RES development occurs at the customer level, rather than large-scale grid connections.

Figure 4.16 shows the installed wind capacities in the NSOG region for 2020 and the 2030 Visions 1 to 4 from TYNDP 2016 (on the left) and 2025 and the three 2030 scenarios from TYNDP 2018 (on the right). It shows that the installed wind generation for the TYNDP 2018 scenarios lies within the 2030 envelope of the TYNDP 2016 Visions, without reaching the extremes of Visions 3 and 4.

Figure 4.16: Energy generated by wind in the NSOG region

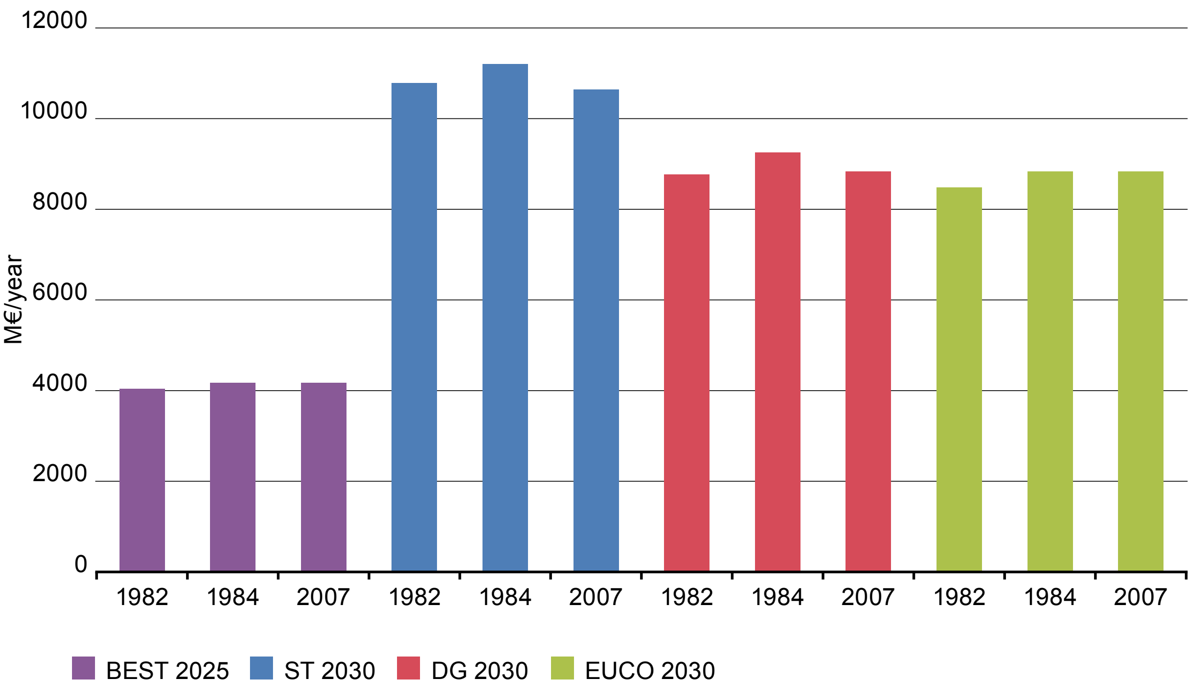


As a result, both the RES and CO_2 indicators are impacted. The trends trigger an optimised need for interconnection amongst the scenarios, reflecting potential European collaboration on RES support schemes.

4.5.4 The use of multiple climate years

For the current TYNDP, multiple climate years have been considered in the CBA assessment; 35 climate years have been clustered into 3 representative years and used during the CBA calculations. For TYNDP 2016, just one climate year was used in the analysis, i.e. 2011. At a high level, the NSOG region's sensitivity to climate year impact is low, as shown in Figure 4.17.

Figure 4.17: Climate year sensitivity of the region



At a country level, however, the choice of climate year has a more significant impact. These include: Countries with a large quantity of hydro generation, e.g. the Nordic countries, see a higher influence of wet/dry/normal years than non-hydro based countries. Projects connecting to these countries tend to see an increase in SEW and RES indicators.

Countries with a large proportion of wind generation, both onshore and offshore, will experience effects relating to the short-term variability of the generation output. This increasingly drives either international exchanges or the need for other flexibility options.

4.5.5 Increased losses

The increase of interconnection capacity enables power to flow from one side of Europe to the other, in line with political objectives. In many cases, these power transfers are accompanied by an increase in grid losses.

Additionally, some projects facilitate entirely new flows which would not be possible without the project. This phenomenon has been observed for several projects in the NSOG region during their CBA assessments, and these new flows again drive an increase in losses.

These increased losses can be interpreted as the price to pay for fulfilling the European energy targets. In general, the assessment of losses variations induced by new projects has been improved in TYNDP 2018 when compared to TYNDP 2016, especially for monetisation. A comprehensive all year round simulation and European-wide calculation has been applied to obtain a view on the region's losses. The monetisation of losses based on an hourly basis (TYNDP 2018) rather than a yearly pan-European marginal cost (TYNDP 2016) has a significant impact on the monetised results, for a number of projects, as no particular deviation could be noticed when comparing results in volume. The new monetisation principle (marginal cost, hourly basis) represents a simplified worst case assumption, but it should be kept in mind that in reality different regulations exist on how to cover the cost of losses.

The results should be treated with caution, as a result of the very high sensitivity of losses to generation assumptions, in particular the location of generation units.

Section 5

Grid development in the region

The TSOs and third party project promoters in the region are already making plans to meet the needs identified and discussed in Section 4 and the “Identification of Needs” package. Projects already under construction, applying for permissions and in the planning phase are among those subject to CBA assessment in TYNDP 2018. In spite of this, there is still a gap in meeting the potential 2040 needs.

5.1
Projects being assessed in the TYNDP

To accommodate the energy transition and help the region to meet the challenges described before, a large number of projects are required in the NSOG region (82 Projects consisting of 144 Investments). Figure 5.1 shows the promoted projects in the region for TYNDP 2018 that will be CBA assessed (except projects being under construction, i.e. close to commissioning).

Figure 5.1: Promoted projects in NSOG region

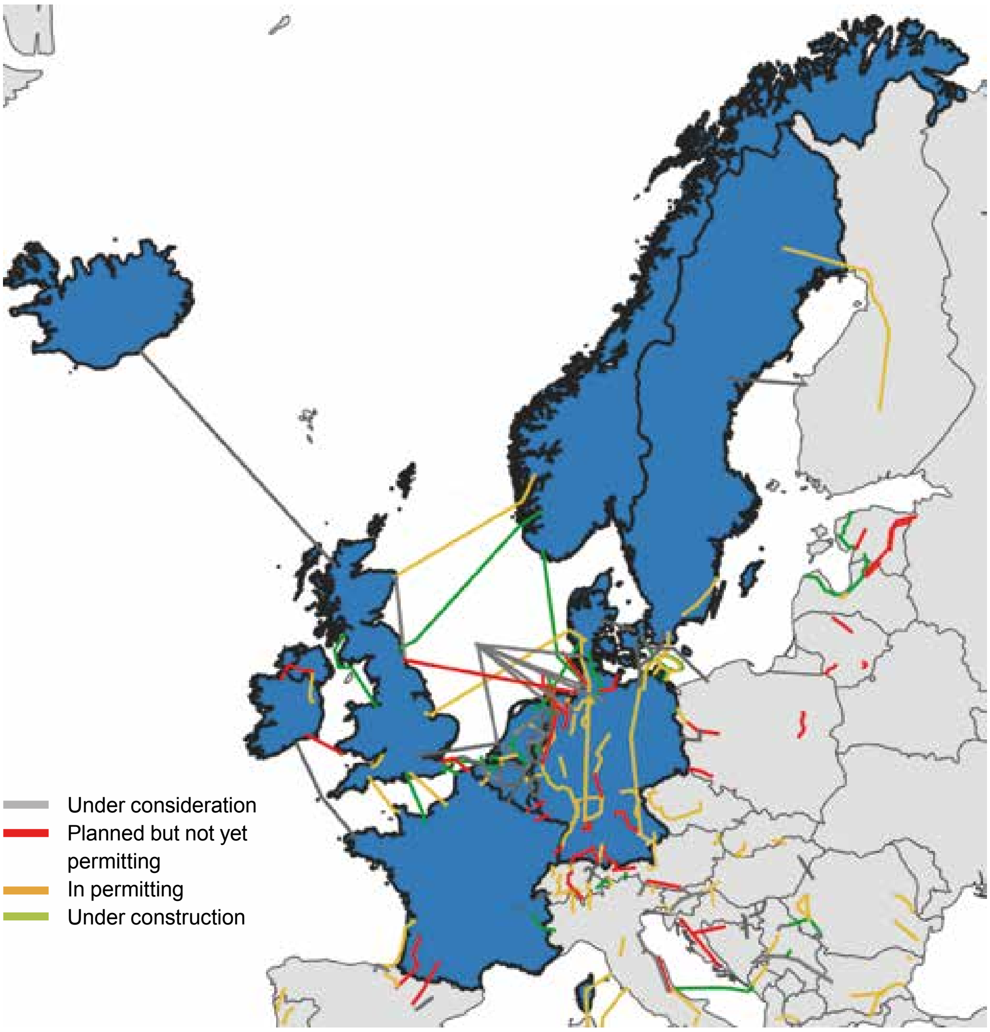


Figure 5.1 clearly shows how the islanded systems of Great Britain and Ireland, as well as the Nordic region, will become much more integrated with the Continental European system with the implementation of the planned project portfolio. This will allow the diverse spread of renewable generation across the region to be fully exploited and shared amongst Member States. Accommodating this generation, and the resulting large power flows, requires a strengthening of onshore grids. Figure 5.1 shows a number of projects in the Benelux area and Germany are planned to meet this requirement.

5.2 Monitoring the projects of the region

The status of the development of the region's investments is shown in Figure 5.2. The vast majority of projects are expected to be completed in advance of 2025. Several projects are already under construction. There are four categories of projects – 'under construction', 'in permitting', 'planned but not yet permitting' and 'under consideration' – and within the NSOG region, the projects are almost equally divided between the four categories.

Figure 5.3 indicates that the majority of the capacity increases result from the projects that are assumed to be commissioned by 2025. The acquisition of the necessary permits on time is an important enabler to make this happen. A large amount of capacity is under consideration for years beyond the 2030 scenarios.

Figure 5.2: Number and status of investments in the NSOG region

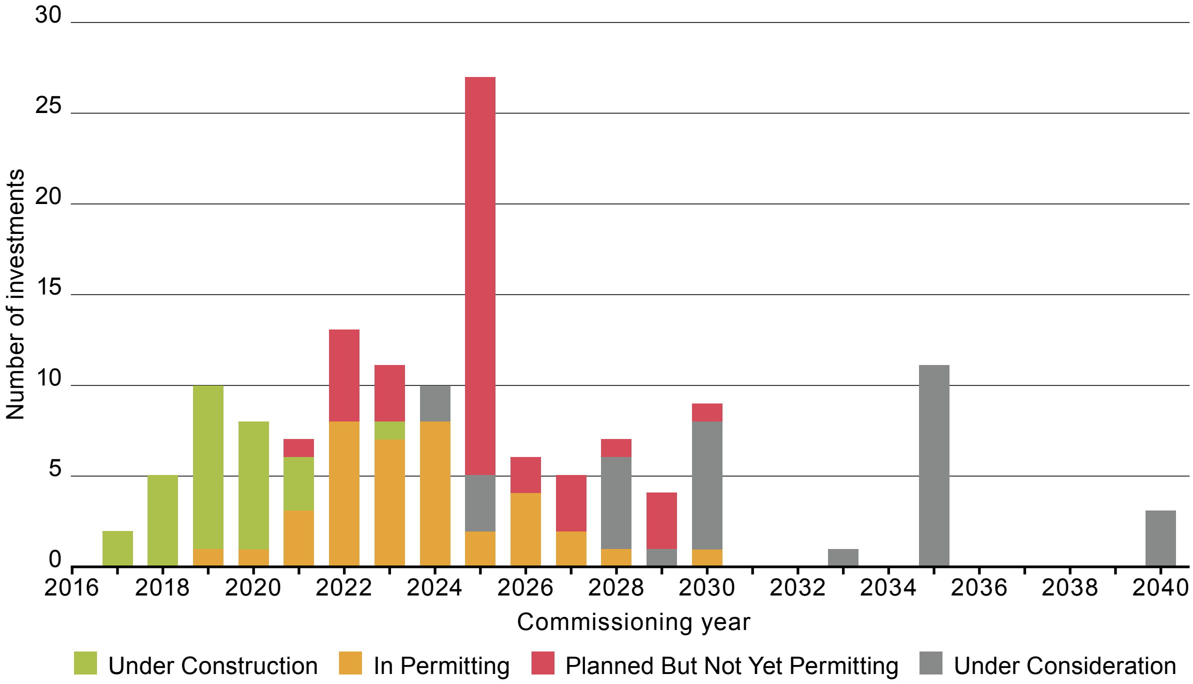


Figure 5.3: Capacity and status of investments in the NSOG region

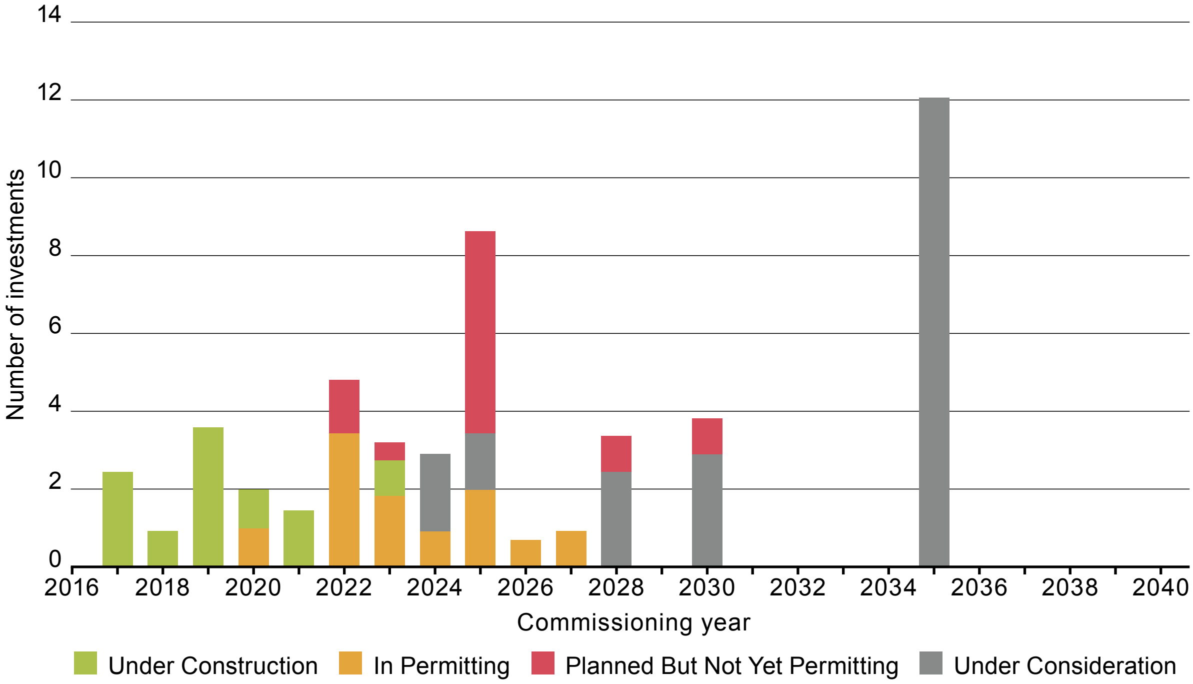


Figure 5.4 shows the types of projects in the region. Traditionally, grid development has almost exclusively comprised overhead line HVAC circuits. Figure 5.4 shows that both undergrounding and HVDC technology play a more prominent role in the future grid development. Just half of the promoted projects are overhead line developments, with cables – onshore and subsea – making up 40% of the portfolio.

In addition to the types of projects in the region, Figure 5.4 also indicates the status of the projects. As shown, over half of the promoted projects are progressing on time or ahead of schedule compared to TYNDP 2016. Additionally, over 20% of the projects promoted in TYNDP 2018 are new additions to the TYNDP 2016 portfolio.

Looking at total lengths of circuit built in Figure 5.5, it is clear that HVDC is a prominent technology type in the region. 65% of all TYNDP 2018 projects assessed within the NSOG region comprise AC technology; 35% of the projects are DC based. This high share of DC projects is not unexpected; to enable the integration of the anticipated renewable generation, the NSOG region requires additional cross-border capacity. Many of the projects integrate the islanded systems of GB and Ireland with continental Europe. The Nordic system also becomes more integrated with GB and continental Europe. These interconnections require significant amount of subsea HVDC cables, strengthening the connections between the four synchronous areas. Additionally, in Germany some major onshore projects connecting the north to the south of the country are planned to apply HVDC technology.

Figure 5.4: Promoted projects in the NSOG region – project type (l) and status (r)

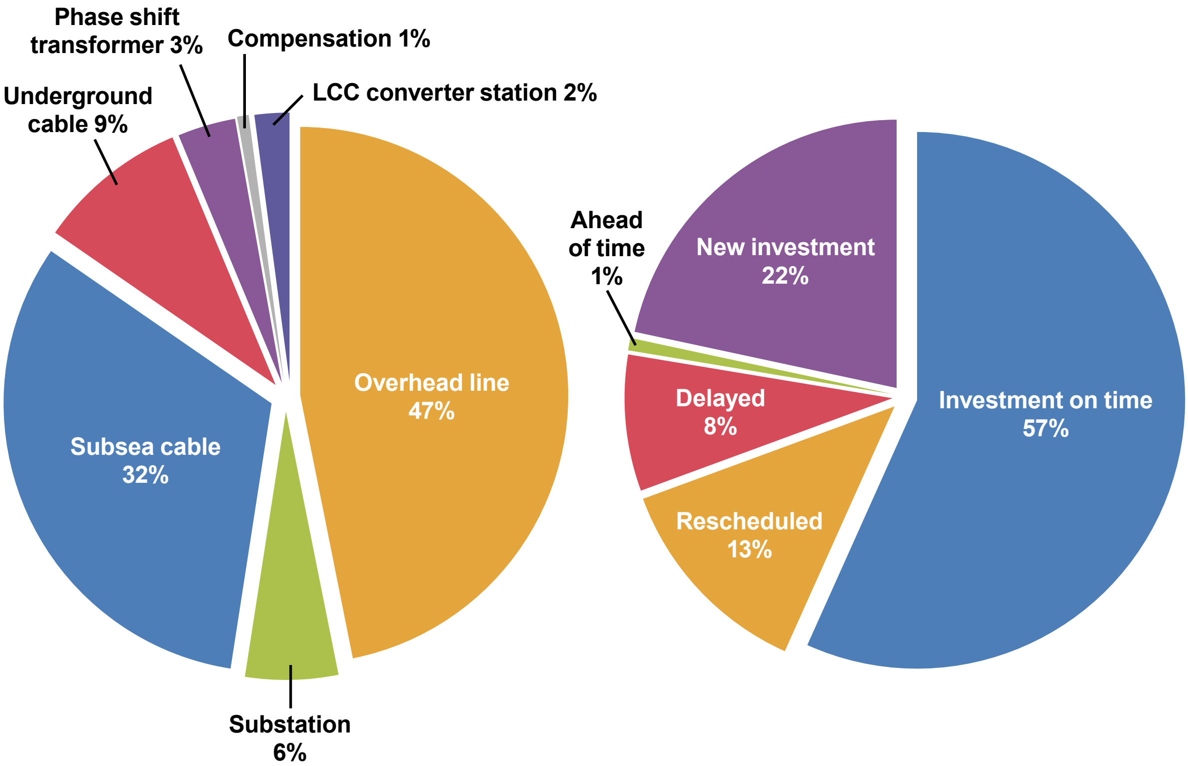
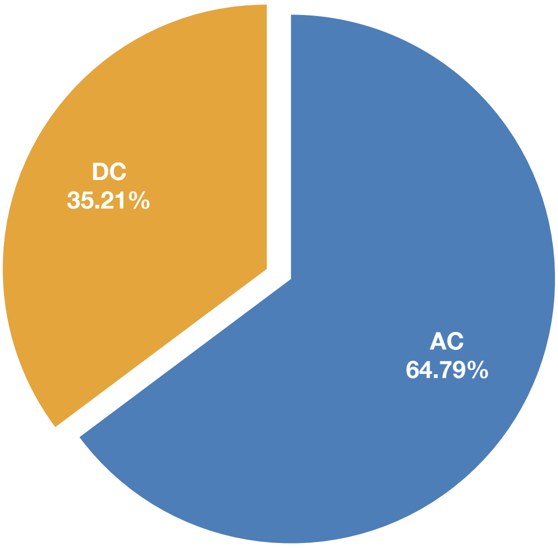
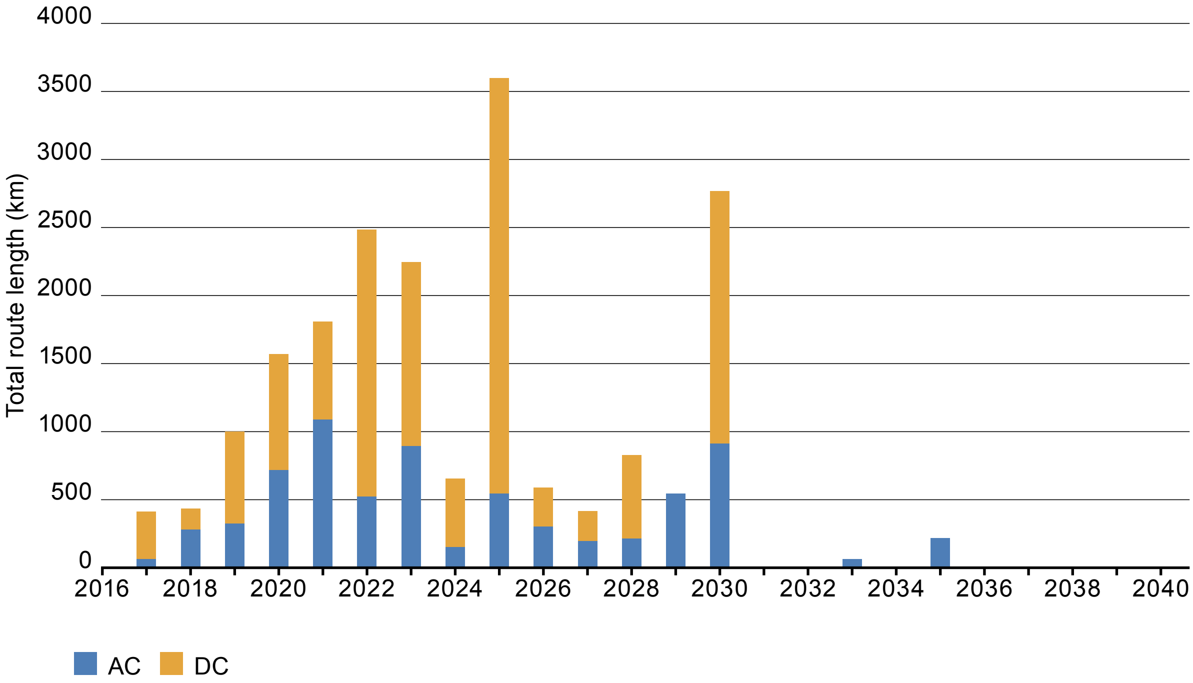


Figure 5.5: Promoted projects in the NSOG region – type (top) and route line length (bottom)





Section 6

Other important information for the region

6.1 Offshore RES and offshore infrastructure development

The NSOG region comprises a number of marine areas – the North Sea, the English Channel, the Irish Sea, Skagerrak and Kattegat. These seas experience high wind speeds, and also areas of shallow water. Both of these characteristics mean there is the potential for the development of significant quantities of offshore RES generation.

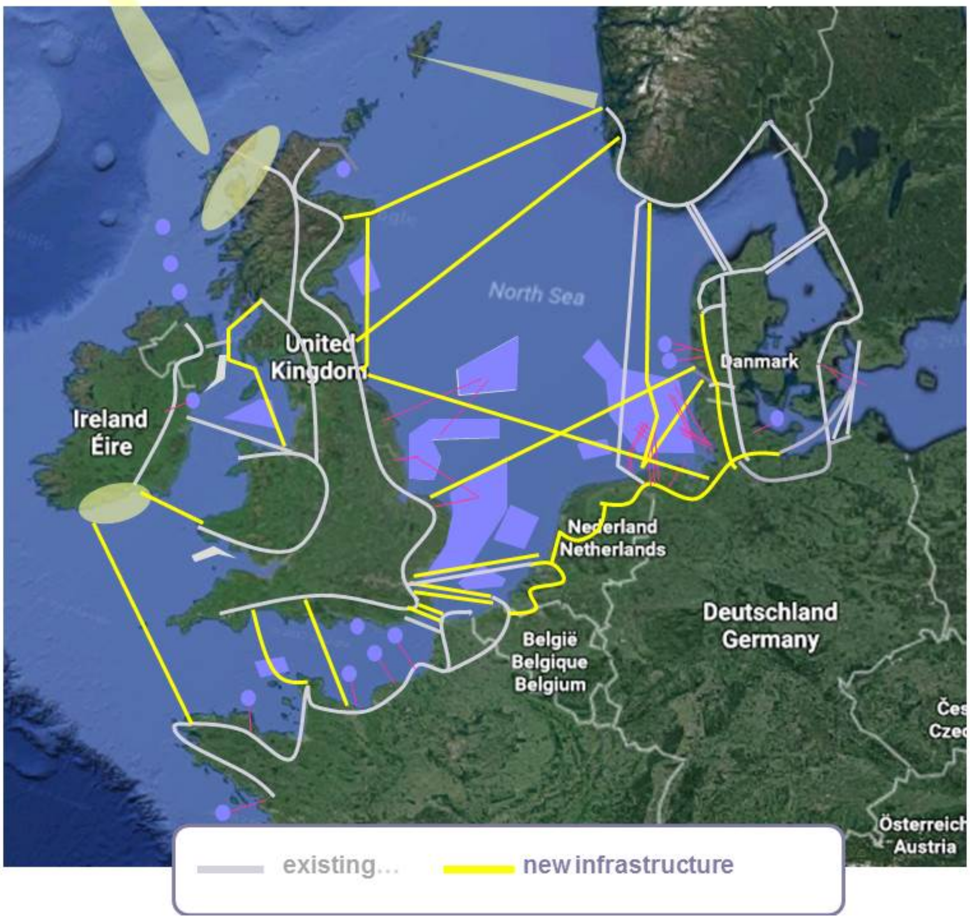
A consequence of this potential generation will be the requirement for significant offshore infrastructure development in the Northern Seas. In general, the offshore grid infrastructure has already been under development for several decades, and will continue evolving. Already, ambitious offshore grid initiatives and projects in the region are ongoing. These initiatives include:

- collaborations at a political level (North Seas Countries Energy Collaboration (NSCEC))
- new research projects (PROMOTioN); and
- industry level collaboration on visionary projects (North Seas Wind Power Hub (NSWPH)).

More detailed information on these initiatives can be found in the published RGNS Regional Investment Plan.

The integration of offshore generation and related implications on the infrastructure was previously analysed by North Sea Countries' Offshore Grid Initiative (NSCOGI), a predecessor to the NSCEC. Under this umbrella, ENTSO-E's Regional Group, Northern Seas (RGNS), who is also responsible for the present report, had delivered the related technical study. The study was based on offshore wind assumptions delivered by the Member States. Comparing these assumptions to TYNDP 2018 scenarios, at a country level the expectations on offshore RES development are lower than during the NSCOGI investigations. However, the political awareness and stakeholder expectations with regards to offshore infrastructure development have increased over the same period. Previous results from the NSCOGI studies are still valid in principle; however, the location of some of the elements, and the year of realisation, may have changed.

Figure 6.1: Draft offshore grid infrastructure TYNDP 2018 ("Project 271")



TYNDP 2018 includes the latest version of the Northern Seas Offshore Grid Infrastructure project 271, indicated in Figure 6.1.

The Northern Seas Offshore Grid Infrastructure collates the individual foreseen subsea projects, listed in table A.1 in the Annex, into one building block. The constituent projects, however, will ultimately be developed by the various project promoters on a modular basis. Additionally, the NSWPH (project 335), envisaged for after 2035, is assessed in the TYNDP 2018.

6.1.1 Project assessment

The assessment of the aggregated Northern Seas Offshore Grid Infrastructure has been performed considering all 22 individual projects are one big project. Of course, each individual project will be at different stages of their development, however, the intention of this exercise is to show the value to the region of the aggregated infrastructure.

The CBA of the constituent projects are included in the project sheets. Some are due to be commissioned by 2020, whilst others are not scheduled for completion until 2030. Table A.1 in the Annex includes the latest assumed completion dates of all constituent projects. The considerable number of infrastructure projects in the Northern Seas area will deliver significant regional benefits.

As RES generation develops in line with 2030 targets, and reflects political policy at a national level, a trend observed in TYNDP 2016 continues – that is, a decrease in assumed offshore wind capacity. From 110 GW in 2014 to 80 GW in 2016, in TYNDP 2018 the offshore wind capacity in the NSOG region is now 60 GW. As stated above, in spite of this decrease, the political interest in offshore grid infrastructure within the region has increased over the same period.

Table 6.1 shows both the onshore and offshore wind assumptions for all scenarios in the TYNDP 2018 process. It must be stressed that the overall complete generation fleet and fuel mix at both ends of an interconnector is, amongst other things, a decisive motivation for single individual components.

In general, the results of the TYNDP 2018 simulations confirm the results from TYNDP 2016.

Table 6.1: Assumed installed wind capacities in the NSOG region in TYNDP 2018

	2020	ST 2030	DG 2030	EUCO 2030	ST 2040	DG 2040	GCA 2040
Onshore wind (GW)		142	142	137	170	185	197
Offshore wind (GW)	24	59	59	40	86	86	127

6.1.2 Key 2018 results

The Northern Seas Offshore Grid Infrastructure comprises 21 individual projects, developing into a global scheme which:

- has total infrastructure costs of between €14bn and €27bn
- delivers socio-economic benefits of between €1.3bn and €2.4bn per year
- facilitates additional RES generation of between 13.8 TWh and 19.2 TWh per year; and
- reduces annual CO_2 emissions by between 7,500 kt and 15,000 kt.

The CBA results for 2025 and the three 2030 scenarios are presented in Table 6.2.

Table 6.2: TYNDP 2018 CBA assessment results for project 271

	BE 2025	ST 2030	DG 2030	EUCO 2030
Cost (€ bn)	13.7 – 27.4	13.7 – 27.4	13.7 – 27.4	13.7 – 27.4
SEW (€m/yr)	1,303	2,391	2,108	1,838
CO_2 (kt/yr)	-8,489	-14,923	-9,003	-7,487
RES (GWh/yr)	17,756	19,507.9	19,238.6	13,840.4

The Northern Seas Offshore Grid Infrastructure will develop in a modular approach, using a range of all available technologies (AC and DC) and be composed of a variety of designs, i.e. a combination of radial/meshed/hubs/hybrid elements. Cooperation amongst countries and stakeholders is key in order to harvest the benefits for the region.

6.2
PLEF Generation Adequacy Assessment

The Pentalateral Energy Forum (PLEF) is the framework for regional cooperation in Central Western Europe (AT-BE-DE-FR-LU-NL-CH) towards improved electricity market integration and security of supply. The further development of a coordinated approach to security of supply in the Pentalateral region was defined as one of the key objectives by the governments of the PLEF countries.

As part of this framework, the TSOs of the PLEF countries have performed two Generation Adequacy Assessments (GAA) studies within the last four years.

The first GAA was issued in 2015. It was based on the political declaration of the PLEF from 7 June 2013, and provided a first probabilistic analysis on electricity security of supply in Europe conducted from a regional perspective. As a result, the ability to perform joint regional Generation Adequacy Assessments was improved across the PLEF countries. The resulting methodology has since been used by ENTSO-E as part of its Mid-Term Adequacy Forecast (MAF).

In June 2015, a second political declaration was issued seeking further milestones on security of supply, market integration and flexibility. It included the aim for further improvements to the common methodology used to assess security of supply at a regional level. Following this, the relevant TSOs committed to publishing a bi-annual report on the status of security of supply in the central western European region, commencing in 2017.

The June 2015 declaration was followed with a roadmap, prepared together with the relevant TSOs, defining the contents of the next adequacy study. It aimed to improve the methodology based on experiences from the first GAA. The TSOs have since worked together to carry out the new study establishing an improved level in adequacy assessment.

The second Pentalateral Generation Adequacy Assessment[6], published in January 2018, had two main objectives – the development of state of the art methodologies (including high quality data collection and enhanced adequacy modelling), and provision of the best possible adequacy assessment for the PLEF region. This resulting adequacy assessment was performed for both a short-term (2018/2019) and a medium-term (2023/2024) horizon. The results of the study show that adequacy margins will become tighter on the mid-term horizon (2023/2024).

A main achievement of the study is the implementation of a Flow Based (FB) approach at a regional level. The approach for FB-Market-Coupling (FB-MC) is a significant step towards a more realistic modelling of operational planning in practice nowadays. Additionally, the future potential of demand side flexibilities and their contribution to generation adequacy has been studied in greater detail. The study also highlights the key role played by planned interconnection projects, which not only enhance market integration but also increase the security of supply. The grid projects considered in the PLEF region up to 2023/24 improve the level of security of supply within the region, particularly in Belgium and France. Without them, the loss of load expectation (LOLE) from these two countries would exceed 10 hours by 2023/24. This would be two to three times greater than the LOLE for the same countries in the base case.

Furthermore, probabilistic approaches such as the ones used in this PLEF GAA are key to assess the security of supply contribution of future interconnectors. A method based on probabilistic assessments is currently being evaluated within the framework of the ENTSO-E CBA.

[6] PLEF GAA 2.0 publication links:
Link to 2nd PLEF GAA report,
Link to common statement by Ministries on 2nd PLEF GAA report,
Link to TSO statement on 2nd PLEF GAA report

Section 7

Annex

7.1

Projects developing into the conceptual project "Northern Seas Grid Infrastructure"

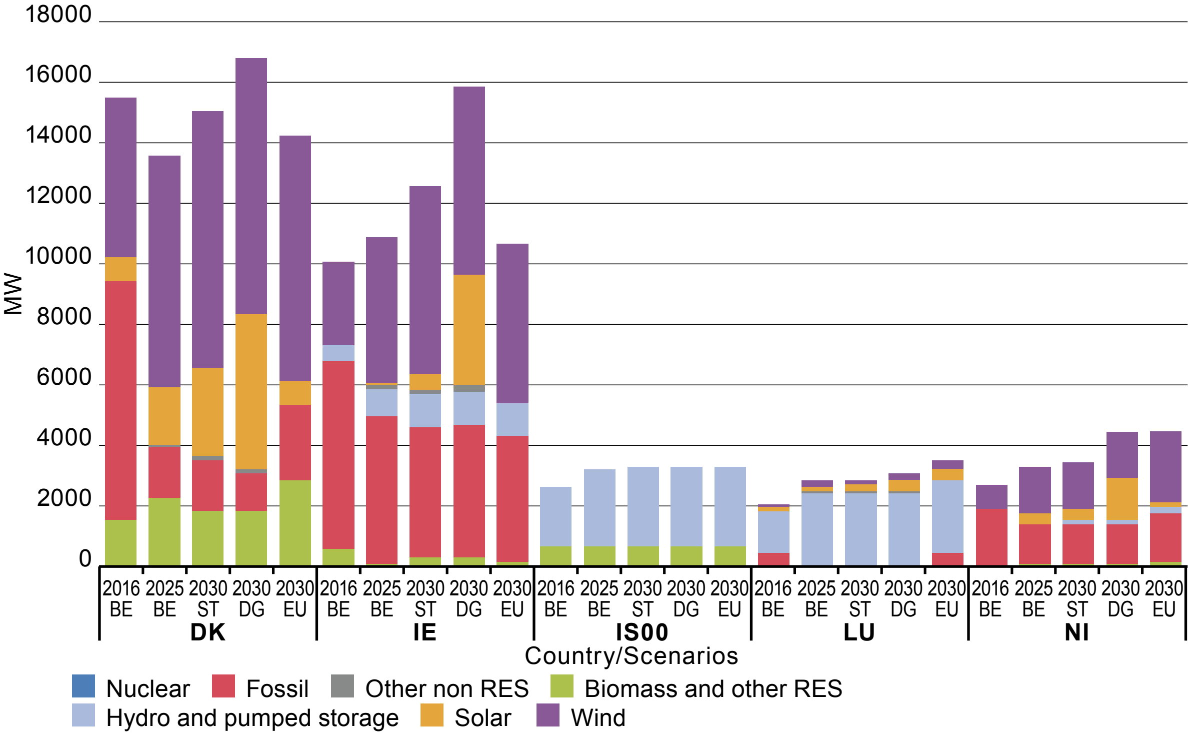
Table A.1: Projects developing the offshore potential in the Northern Seas towards 2030

Country(ies)	Project ID	Name	Commissioning	Offshore IC capacity (MW)
FR, GB	25	IFA2	2020	1000
DE, NO	37	Nordlink	2020	1400
DKW, NL	71	COBRA Cable	2019	700
BE, GB	74	Thames Energy Cluster	2019	1000
BE	75	Modular offshore grid	2020	1000
FR, IE	107	Celtic Interconnector	2026	700
GB, NO	110	North Sea Link	2021	1400
BE	120 329 340	Modular offshore grid phase 2 (120) New onshore corridors Stevin-Avelgem (329) & Avelgem-Center (340)	2026-2028	2000
BE, GB	121	Nautilus (2nd interconnector Belgium-UK)	Earliest 2028	1400
FR, GB	153	France-Alderney-Britain	2022	1400
DKW, GB	167	Viking link	2022	1400
FR, GB	172	ElecLink	2019	1000
GB, NO	190	NorthConnect	2022	1400
FR, GB	247	AQUIND Interconnector	2022	2000
GB, NL	260	New GB-NL Interconnector	2030	1000-2000
FR, GB	285	GridLink	2022	1400
GB, IE	286	Greenlink	2023	500
GB, NO	294	Maali	2025	600
DE, GB	309	NeuConnect	2022	1400
GB, IS	214	Interco Iceland-UK	2030	1000

7.2
Country charts

7.2.1 Installed generation capacity

Figure 7.1: Installed generation capacities per country for 2016, 2025 and 2030 scenarios



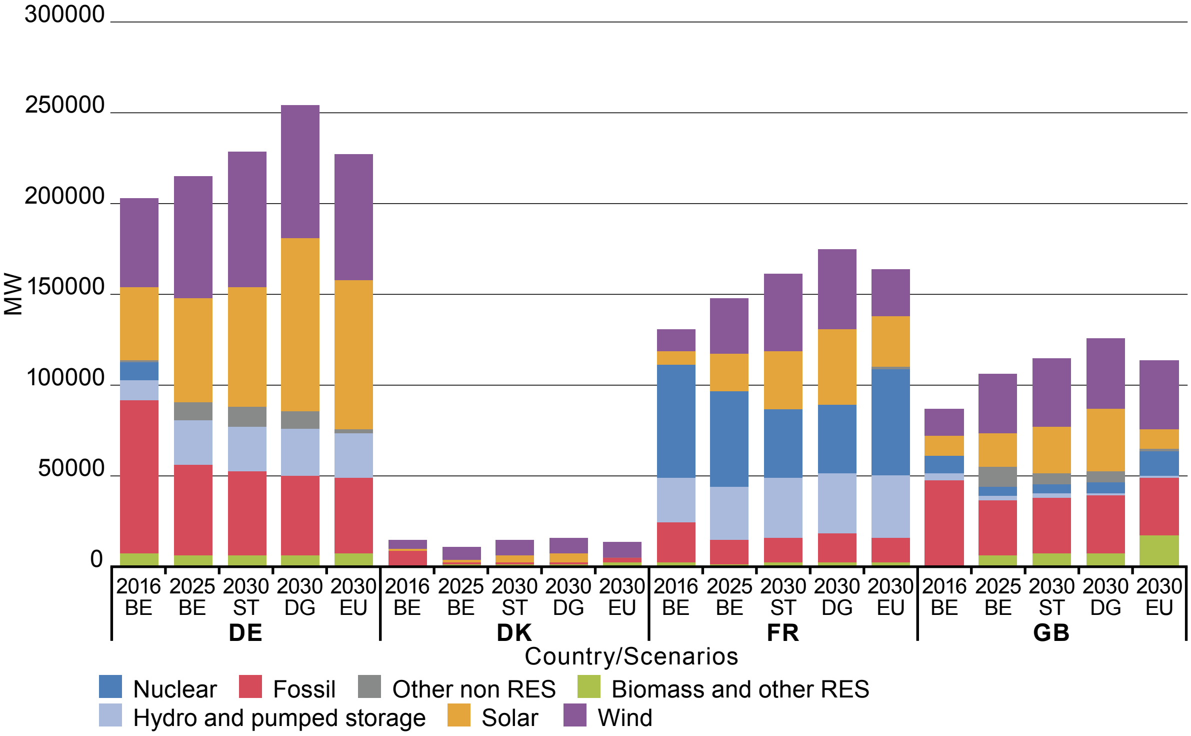
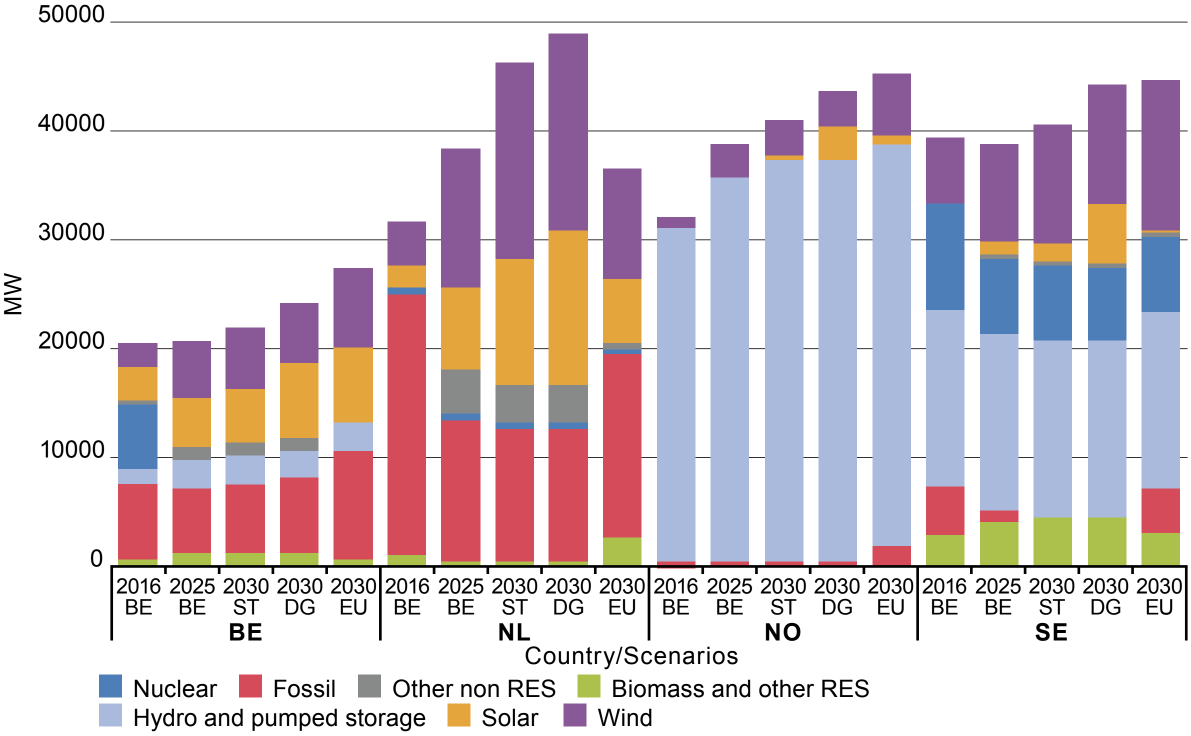


Figure 7.1: Installed generation capacities per country for 2016, 2025 and 2030 scenarios



7.2.2 Generation and demand charts

Figure 7.2: Generation production and demand per country for 2016, 2025 and 2030 scenarios

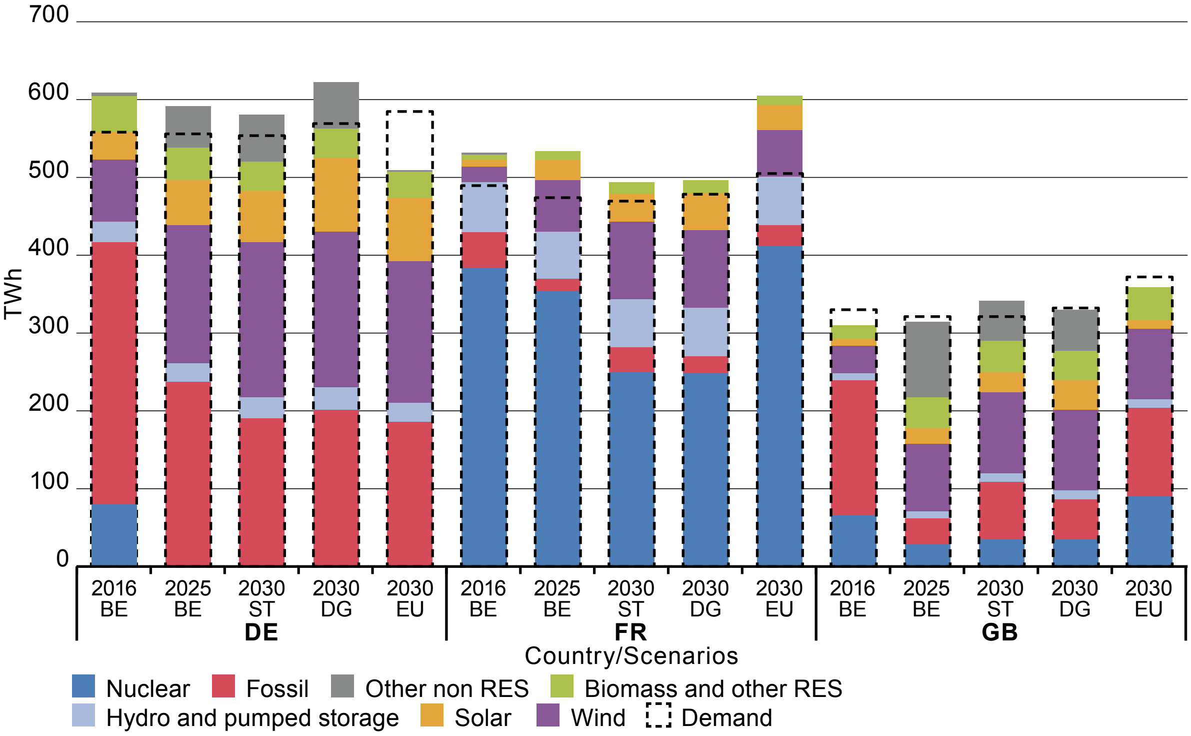
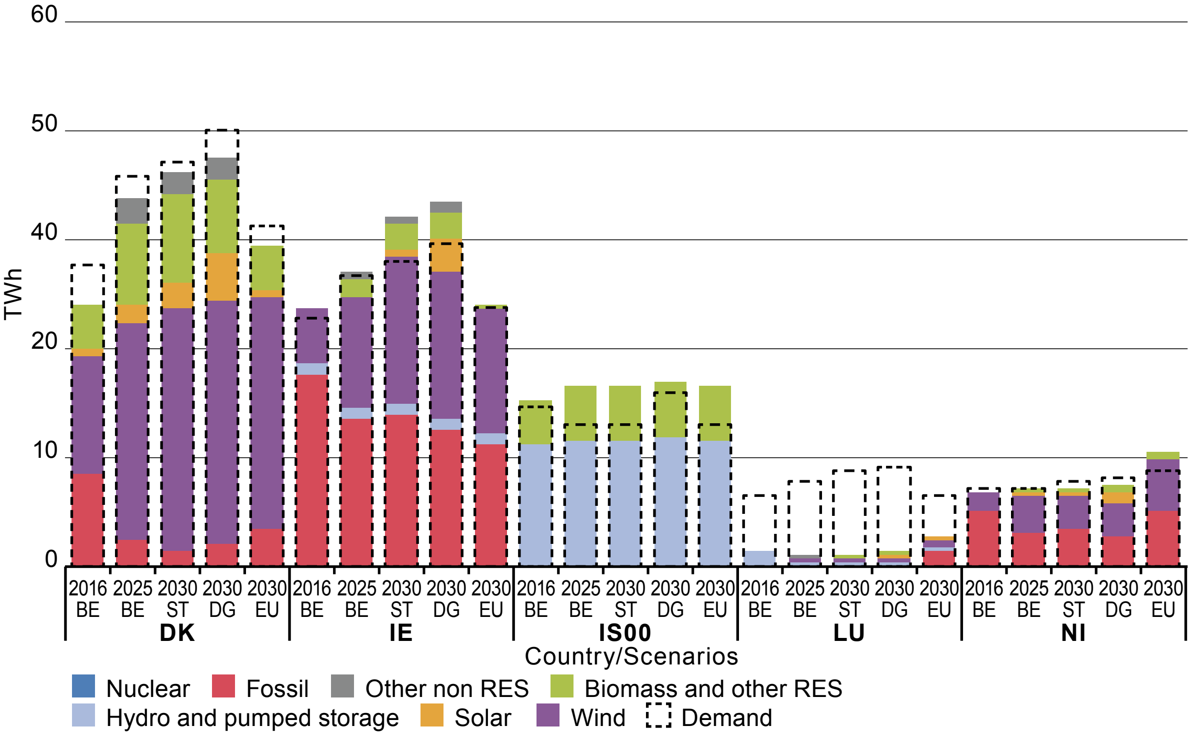
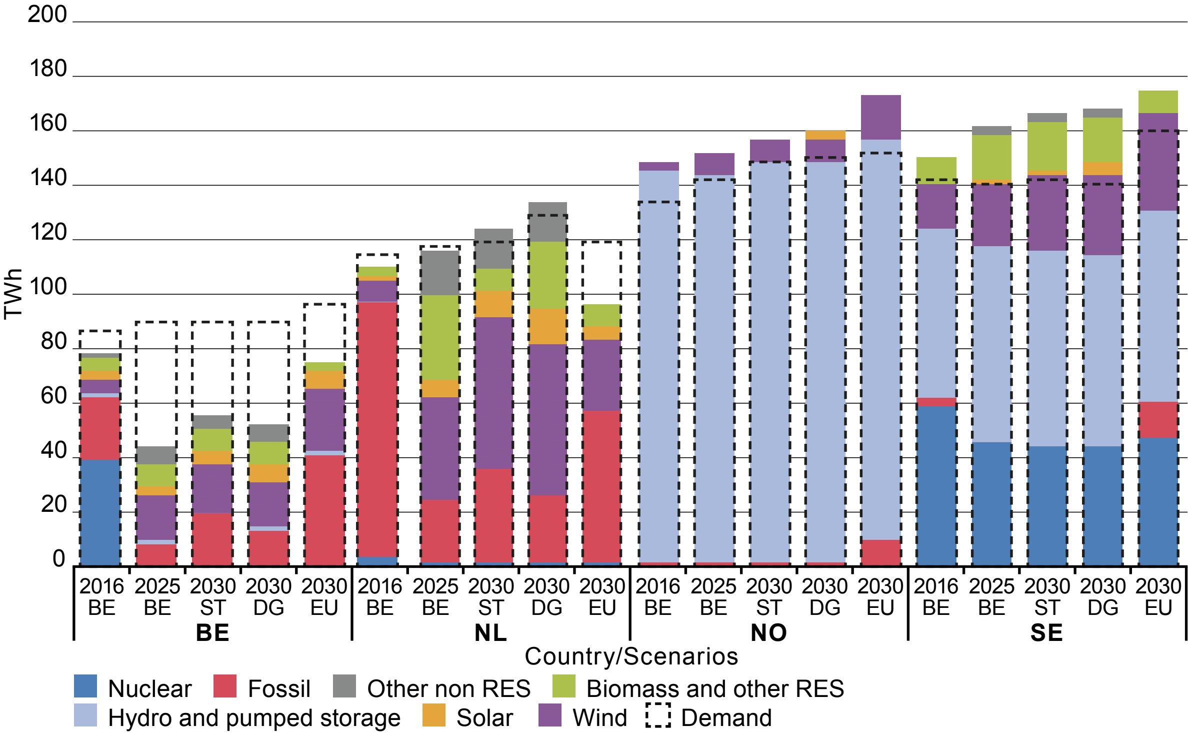


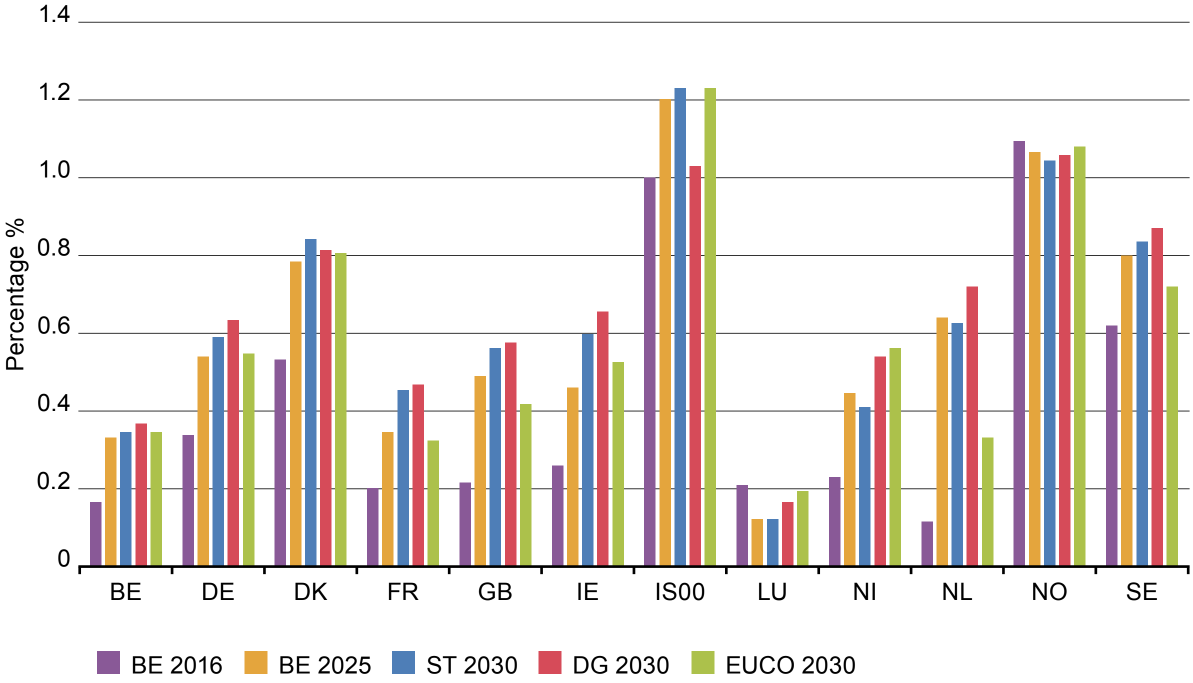
Figure 7.2 continued: Generation production and demand per country for 2016, 2025 and 2030 scenarios





7.2.3 RES as a percentage of demand charts

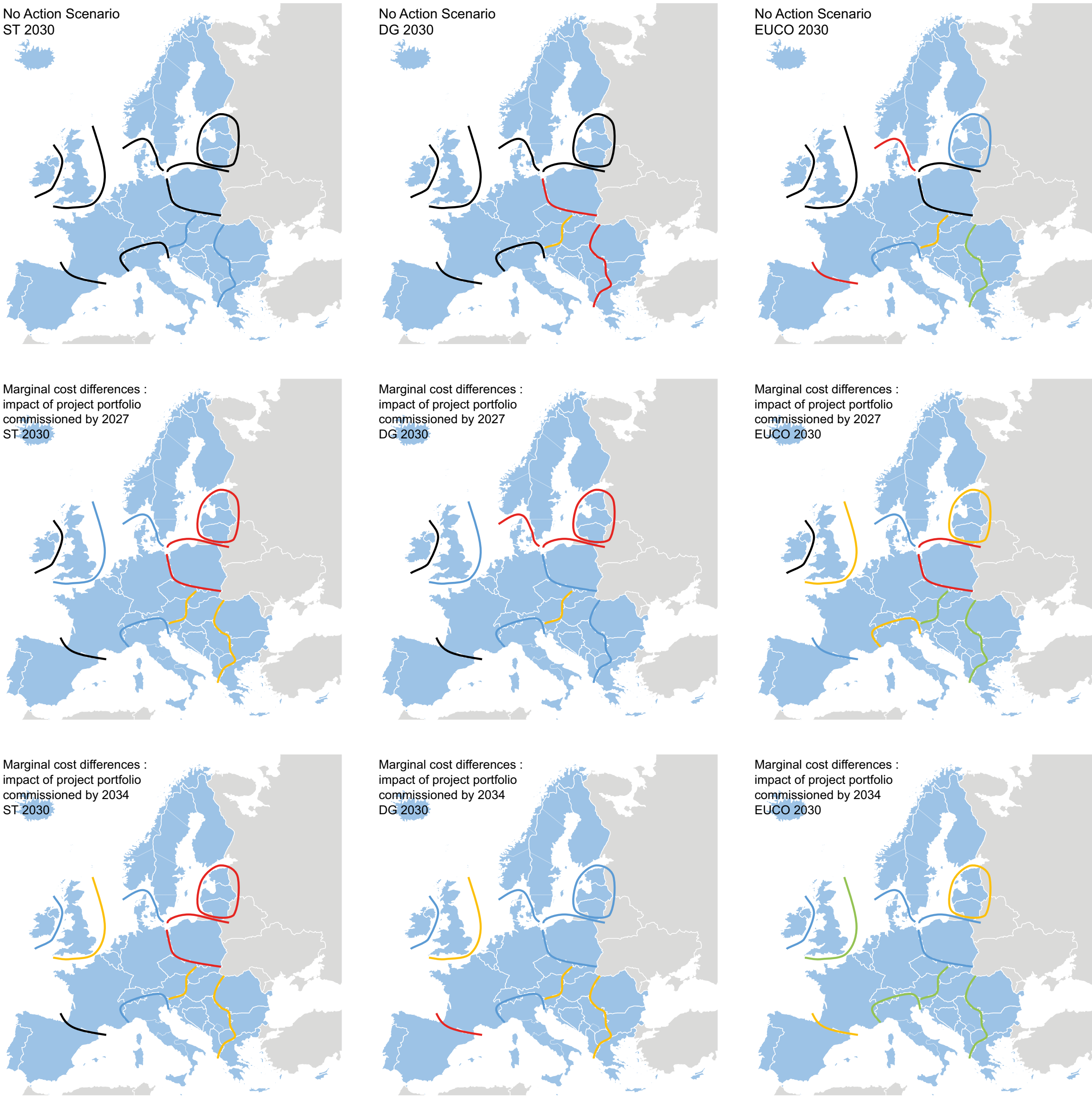
Figure 7.3: Total RES generation as a % of the demand per country for 2016, 2025 and 2030 scenarios



7.2.4 Price differences per boundary

Figure 7.5: Price difference across the main boundaries for the three 2030 scenarios: no action

Sustainable Transition 2030 | **Distributed Generation 2030** | **EUCO 2030**



Avg. hourly marginal cost differences (€/MWh)

- From 0 to 2
- From 2 to 5
- From 5 to 10
- From 10 to 15
- More than 15

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