Ten-Year Network Development Plan 2020

Regional Investment Plan
Northern Seas

January 2021 · Version for ACER opinion

CONTENTS

1. EXECUTIVE SUMMARY

1.1 Key messages of the region - decarbonisation as the main driver

The Northern Seas Region faces major challenges in the coming decades. The European energy and climate policy set a target for a decarbonised Europe within 2050, which also includes full decarbonisation of the electricity sector by 2040. This is the main driver for the Northern Seas Region. The large increase in renewables and decrease of thermal generation, combined with decreased energy consumption but increased electrification, will result in several changes and challenges for the energy system. Smart sector integration seems to be one of the key elements for meeting the energy transition in an optimised manner. For the Northern Seas Region, the main changes and challenges are summarised as below:

Key messages:

Decarbonisation is the main driver leading for:

1. A fundamental change of the power generation mix
2. Decreased energy consumption, increased electricity consumption
3. Changed power flows across the region
4. Requirement for new interconnectors
5. Rapid expansion of offshore wind and offshore infrastructure
6. Smart sector integration optimising the decarbonisation
7. Ensuring flexibility and security of supply in the energy system.

1.1.1 A fundamental change of the generation portfolio

It is expected that there will be substantial changes to the region's generation fleet over the coming decades, as set out in this report. Some of these changes have already been ongoing for a number of years. To meet the climate goals of the Paris agreement, as well as those of the Green Deal policy, significant changes to the energy landscape are required. Due to the uncertainty of these changes, a number of ENTSO-E scenarios have been developed to reflect this (these are presented in Chapter 3).

From these scenarios, the following changes are expected in generation portfolio across the region:

1. **A shift from thermal to renewable generation**. The integration of renewable energy sources is fundamental for enabling the decarbonisation of the society. There is an abundance of renewable energy sources across the Northern Seas Region - onshore and offshore wind, solar and hydro power - that can be utilised. The increasing amounts of renewable energy sources are pushing carbon-based thermal power plants out of the market.

2. **A reduction in nuclear generation.** Despite a planned increase in nuclear capacity, as modelled in the market scenarios, in Great Britain (GB), the region's overall trend is for a reduction in the nuclear capacity, Belgium and Germany have planned a full nuclear phase out. France has planned a partial nuclear phase out.

3. **Decommissioning of coal generation.** Existing coal-fired power plants are being phased out, for two main reasons – they are reaching the technical end of life and there are policies being put in place to accelerate the reduction of carbon emissions from the generation portfolio. In the short term, generation by these plants will be (partially) replaced by gas-fired power plants. This will quickly realise significant reductions in carbon emissions, as natural gas is much less carbon intensive than coal. In the longer term, the carbon emissions should be reduced by either carbon capture storage or by using decarbonised gases.

1.1.2 Decreased energy consumption, increased electricity-consumption

Looking at European climate goals, there is a greater expectation for the European energy system become more efficient. This translates into a more effective use of energy across all the sectors, including industrial, commercial, transportation and domestic consumers, leading to a lower overall energy consumption. As a result, the total energy demand for Europe is expected to decrease. The electrification of (industrial) processes, i.e. using electricity as an energy carrier in applications where previously other vectors were used, shows a significant potential to increase overall energy efficiency, but will increase electricity consumption. Additionally, there are new areas of electricity consumption, such as data-centres, leading to further consumption increases.

In the coming decades, energy consumption is thus expected to decrease, while the electricity consumption is expected to increase. Electrification leads to an increase in the expected peak load driving the need for network to be reinforced.

1.1.3 Change in the power flows across the region

The transformation of the energy and power systems for both production and consumption will significantly impact the power flows across the electricity system. These changes, however, will follow existing transport patterns, but will significantly increase in magnitude (i.e. larger flows) and variability. The diverse nature of generation types is a major factor, and has the following characteristics:

- Norway relies on hydroelectric generation, with its associated seasonal dispatch patterns
- Renewable generation in GB and Ireland is dominated by wind, with its hourly variable output
- Continental Europe has a mix of wind, solar and gas-fired generation
- The generation portfolio in France includes a significant share of nuclear power.

In addition, offshore wind production in the Northern Seas is expected to increase considerably.

This diversity in generation across the region drives market exchange opportunities and consequently power flows between the four synchronous areas and the Member States. These power flows are hampered by a number of main boundaries, which have previously been identified both in the TYNDP 2016 (Ten-Year Network Development Plan) and the TYNDP 2018 between:

- Ireland <-> Great Britain and Continental Europe.
- Great Britain <-> Continental Europe and Nordics.
- Nordics <-> Continental West Europe (Denmark, Netherlands and Germany).

1.1.4 A requirement for new interconnectors

Additional interconnection capacity is required across the region, between synchronous areas and Member States. This additional capacity:

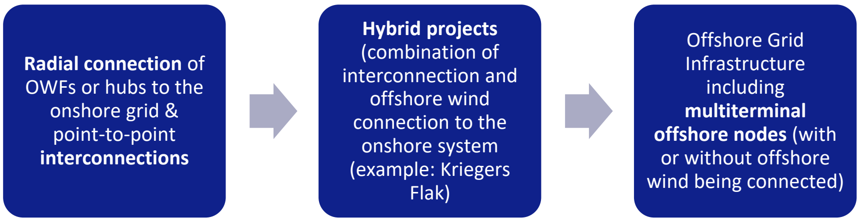
- allows for the integration of renewable generation, by enabling cross-border exchanges and therefore minimising curtailment;
- helps maintain security of supply as the region's generation fleet drastically changes;
- enables maximum decarbonisation through the sharing of clean energy from the diverse renewable generation sources on a European level;
- aids market price convergence through the sharing of cheapest available generation resources;
- provides the possibility for policymakers to reach adequacy through the sharing of generation resources in a more cost-efficient manner, as opposed to each country acting independently.

The additional cross-border capacities are expected to generate larger power flows across Member State's internal grids. As a result, existing transmission corridors will either need to be reinforced or new corridors identified and developed, together with future interconnectors.

1.1.5 Rapid expansion of offshore wind and offshore infrastructure

The installed offshore wind production in the Northern Seas has already exceeded 20GW. In the National energy and climate plans (reflected in the TYNDP 'National Trends' scenario), the installed offshore wind capacity in the Northern Seas is expected to be around 70GW by 2030 and 112GW by 2040. In addition to this, the Green Deal indicates a potential need for an installed offshore wind capacity of more than 200GW by 2050. The Northern Seas comprise of several interesting marine areas for installing offshore wind generation - the North Sea, the English Channel, the Irish Sea, Skagerrak and Kattegat. These seas experience high wind speeds and areas of shallow water, indicating a significant potential for offshore wind power.

Due to the significant increase in offshore wind generation, several questions arise how to best integrate it into the energy-market, eg, on financial instruments, regulatory aspects and on market-design. From a planning perspective, the most important question is which (on- and offshore) infrastructure is required to integrate this wind energy potential efficiently into the energy system. Since these wind farms will be built over a longer period, a stepwise development for realising the necessary infrastructure is the most likely. Such a stepwise development includes non-exclusive, but broader design concepts developing over time:



The speed of the required different infrastructure-steps is highly connected to the rate of offshore wind farm development. As the lead time for installing offshore wind farms is typically shorter than the required (on- and offshore) grid, it is important to prepare the grid for the expected wind potential in order to achieve the climate goals as soon as possible.

In TYNDP 2020, the abovementioned factors are discussed qualitatively from a strategic point of view.

1.1.6 Smart sector integration, optimises the decarbonisation

Smart sector integration (SSI) is a core instrument for cutting emissions in cost-effectively. SSI seeks the optimal solution for the entire energy system, and supports a cost-optimised path to zero emissions by 2050. Electricity would be used either directly in new sectors (eg, transportation and heating in buildings and industry) or to produce green hydrogen. Hydrogen may in turn be used in transportation, heating and even power generation (eg, in hours of scarcity) or to produce methane, fuels or ammonia, etc. The benefits of SSI arise from its variable character and the falling costs of wind and solar power. More detailed description around smart sector integration can be found in the scenario descriptions provided in Chapter 3 and related to ongoing projects and studies in the sector integration section in Chapter 5.2.

ENTSO-E is currently working on a multisectoral planning-programme, in which the cooperation between different sectors and energy-systems will be further described and analysed. A roadmap for coordinated multisectoral planning has recently been published[1] Before starting this, the TEN-E Regulation also needs to be adjusted in order to point out the different responsibilities. This adjustment of the Regulation is expected by the end of 2020.

1.1.7 Ensuring flexibility and security of supply in the energy system

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

The weather will greatly impact the future energy system, more so than it is today. While the Nordic system continues to be built on very high hydropower capacity, including large hydro reservoirs, the Continental, the British and Irish systems are (in all ENTSO-E scenarios) composed of large amounts of wind and solar generation units along with some thermal plants. The expectations of huge offshore windfarms in the Northern Seas leads to a more weather-dependent energy system.

The huge amount of new – usually limited - controllable RES generation, combined with decommissioning of thermal generation, will lead to a less flexible energy system, challenging the security of supply. Thus, actions are needed to increase the flexibility and to ensure security of supply both for short-term dynamic and more long-term seasonal time horizons:

- Interconnectors will ensure security of supply in a more cost-effective manner compared with an isolated approach that requires more installed generation capacity on an individual country level. Increasing the interconnector capacities will facilitate sending energy to those regions/synchronous areas where it may be needed.
- More flexible demand and generation (incl. RES) and different types of storage (pumps, batteries, etc.), in combination with a smart market-design will make the power system more flexible and better able to react to scarcity situations.
- Smart sector integration makes it possible to exchange energy between different sectors when required. This will increase the flexibility of the overall energy system. Ultimately, this will take security of supply to a new level.

[1] https://www.entsoe.eu/news/2020/07/16/towards-a-system-of-systems-entso-e-releases-roadmap-for-coordinated-multi-sectorial-planning/

1.2 Future infrastructure capacity needs

The changes to the generation portfolio and the resulting power flows across the region are driving the need for new transmission capacity. The transmission network will require reinforcing both on cross-border and internal levels. This Regional Investment Plan (RegIP) is investigating the potential for additional cross-border capacity increases and their impact on the transmission network in general.

The initial phases of the TYNDP 2020 process considered the development of new scenarios for 2025, 2030 and 2040, and assessed future system needs for the long-term-2040 horizon. Part of this work involved identifying cross-border capacity increases for the NT2040 scenario based on a single climate year. A European overview of these increases is presented in the European System Need report developed by ENTSO-E in parallel with the RegIPs 2020.

The identified capacity reinforcement needs for the Northern Seas Region are shown in Figure 1.1. The system needs for the 2040 horizon are being evaluated with respect to (1) market integration/socio-economic welfare, (2) integration of renewables and (3) CO2 emissions. For the Northern Seas Region huge investments are already planned, mainly to increase the capacity between the 4 synchronous areas of the region, see Table 1- These projects help closing the gap between today's transmission system and the medium-term needs by 2025. Additional needs are however seen on the horizon 2040. In general, the ongoing investments, as identified in earlier publications and the identified 2040-needs of the region are primarily described through the further integration between:

- Norway and Great Britain, due to price differences, the need for flexibility to optimise the RES generation (hydro/wind);
- 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 power-support to Continental Europe during scarcity situations (eg, low-wind periods);
- Great Britain and the Continental system (France, Belgium, Netherlands, Germany, Denmark), due to i) price differences, ii) better optimisation of the RES generation and iii) challenged security of supply during high demand/low variable RES (wind and solar) periods;
- Germany and France, Belgium and the Netherlands (east-west and north-south) due to i) optimisation of the production system and ii) challenged security of supply in high demand and low variable RES (wind and solar) periods;
- Ireland and Great Britain/France due to i) price differences, ii) optimisation of the RES generation and iii) challenged security of supply in low-wind periods.
- The development of the Northern Seas offshore wind power creates a need for further offshore and onshore development and an increased interconnection capacity between the different synchronous systems. The integration may be done in the steps described in Chapter 5,1 (radial connection, hybrid projects, multi-terminal offshore nodes).

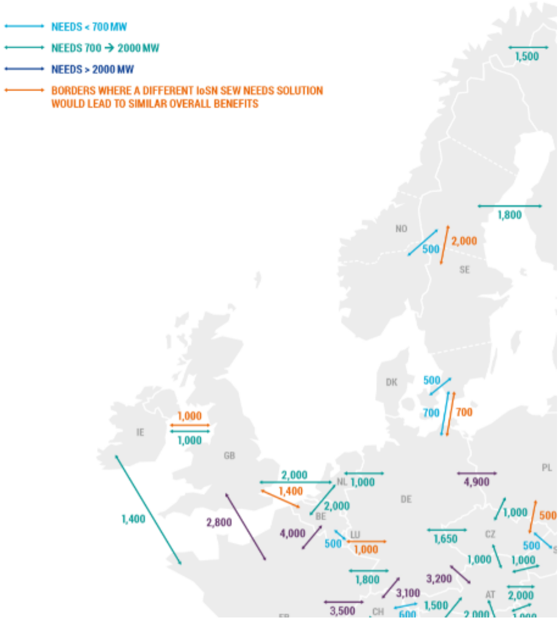


Figure 1.1: Cross-border capacity needs 2025-40 in the Northern Seas Region and additional capacity increases leading to similar benefits (in orange)

Benefits

If the 2040 needs identified in this study are be satisfied by capacity increases, the related benefits would have the impact below on the RGNS system:

- **17 €/MWh** reduction of the regional average marginal price for electricity generation
- **Up to 50€/MWh** reduction of the marginal cost spread between the region's countries, i.e. more aligned costs between adjacent areas reaching a level of below 5-10 €/MWh difference or even lower.
- **55 TWh** less curtailed variable RES
- **4.2 Mton** reduced CO_2 emissions
- **44 TWh** net export to other European regions.

Investments done before 2025 also benefit the region, as shown in previous TYNDPs.

The additional cross-border capacity post-2025 facilitates renewable energy sharing across the region. However, the consumer can only truly benefit if the transmission network is able to transport the corresponding power flows. This is a significant challenge since the power flows will become:

- more international, causing an increase in the distance between the consumer and the producer; and
- increasingly variable and less predictable as a result of the variable nature of the renewable energy sources - i.e. the location where the cheapest production is available can vary rapidly.

These changes will cause a paradigm shift in the role of the grid. Originally designed to connect central generation units to load centres, the electricity grid plays a crucial role in facilitating RES integration on a regional and European scale, 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 network analysis performed on the 2040 scenarios identified the congested areas of the grid and the corresponding need to develop new transmission capacity. With its highly meshed structure, dense population and central location, congestion is most pronounced in the Central Western European area. Additional cross-border capacity alone will not be sufficient. The internal grid needs to evolve accordingly allowing higher flows.

RGNS (that is, all the countries in the NSOG apart from Sweden) is on the way to closing the gap between today's grid and the 2040 needs. Many projects are already 'in the pipeline', i.e. with status 'under construction' and 'in permitting' thus being realised in the medium term, providing benefits to the region.

2. INTRODUCTION

2.1 Regional Investment Plans as foundation for the TYNDP 2020

ENTSO-E's Ten-Year Network Development Plan (TYNDP) is the planning reference for the pan-European electricity transmission network. Released every even-numbered year, it presents and assesses all relevant pan-European projects at a specific time horizon, as defined by a set of various scenarios that describe potential future developments and transitions of the electricity market. The TYNDP serves as a basis for derive the EU list of European Projects of Common Interest (PCI).

An essential part of the TYNDP 2020 package, the six Regional Investment Plans, address challenges and system needs at the regional level (Figure 2.1).

Figure 2.1 ENTSO-E's six system development regions

The regional investment plans are part of the TYNDP2020 package (the process is depicted in Figure 2.2), which also includes - among others - the report, "[Completing the map – Power system needs in 2030 and 2040]" and the Scenarios report, which describe the scenarios serving as basis for the IoSN2040 and the regional investment plans.

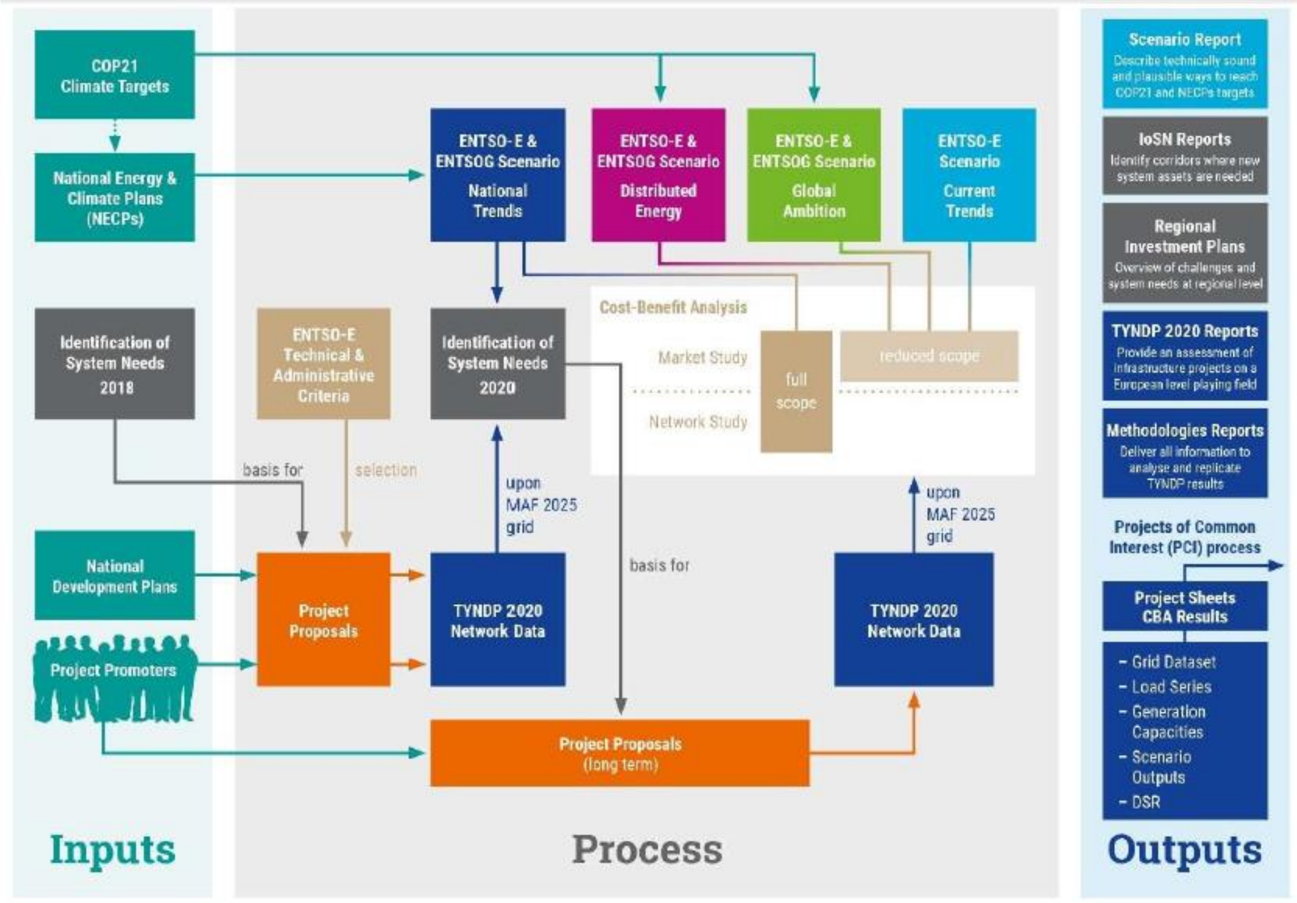


Figure 2.2 Overview of TYNDP 2020 process and outputs

2.2 Legal Requirements

Regulation (EU) 2019/943 Article 34 (recast of Regulation (EC) 714/2009) states that TSOs shall establish regional cooperation within ENTSO-E, and shall publish regional investment plans every two years. These indicate potentially interesting grid reinforcements on European level. Article 48 further states that ENTSO-E shall publish a non-binding, community-wide Ten-Year Network Development Plan (TYNDP), which shall be built on national investment plans and take into account regional investment plans and the reasonable needs of all system users and shall identify investment gaps.

In addition, the TYNDP package complies with Regulation (EU) Nº 347/2013, which defines new European governance and organisational structures that shall promote transmission grid development.

2.3 Scope and structure of Regional Investment Plans

The Regional Investment Plans are based on pan-European market study results, combined with European and/or regional network studies. They represent the current situation of the region as well as the expected future regional challenges, considering a 2040 time horizon. To illustrate circumstances that are particularly relevant to each region, available regional sensitivities and other available studies are included in the plans. The operational functioning of the regional system and associated future challenges may also be addressed.

As one of the solutions to the future challenges, the TYNDP project has performed market and network studies for the 2030 and 2040 time horizons on the National Trend scenario, in order to identify investment needs that can help solve these challenges.

In addition, the Regional Investment Plans list the regional projects from the TYNDP 2020 project collection. In the autumn of 2020, each of these projects will be assessed and presented in the TYNDP 2020 package.

The approach followed by the regional investment plans is summarised in Figure 2.3.

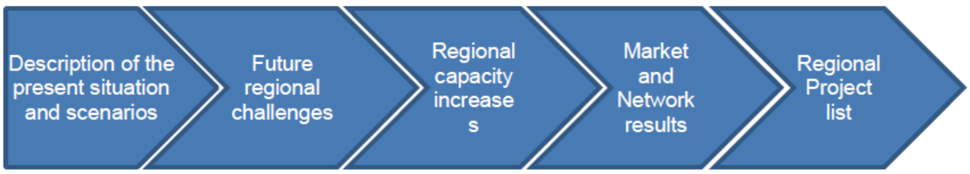


Figure 2.3 Mitigating future challenges – TYNDP methodology

The current document comprises seven chapters with detailed information at the regional level:

- Chapter 1 presents the key messages about the region
- Chapter 2 sets out in detail the general and legal basis of the TYNDP and regional investment plans, and provides a short summary of the general methodology used by all ENTSO-E regions
- Chapter 3 provides a general description of the current situation of the region. The future challenges of the region are also presented when describing the evolution of generation and demand profiles in the 2040 horizon, but considering a grid as expected by the 2025 horizon. This chapter also includes links to the respective national development plans (NDPs) of the countries of the region
- Chapter 4 includes an overview of the regional needs in terms of capacity increases and the main results from the market and network perspectives

- Chapter 5 is dedicated to additional analyses of offshore development and sector integration conducted inside the regional group or by external parties outside the core TYNDP process
- Chapter 6 contains the list of projects proposed by promoters in the region at the Pan-European level, as well as important regional projects that are not part of the European TYNDP process
- The Appendix includes the abbreviations and terminology used in the whole report as well as additional content and detailed results.

The actual Regional Investment Plan does not include the CBA-based (Cost-Benefit Analysis) assessment of projects. Such analyses will be developed as a second step and presented in the final TYNDP 2020 package

2.4 General methodology

The Regional Investment Plans build on the results of studies, called 'Identification of System Needs' (IoSN), which are conducted by a European team of market and network experts originating from the six regional groups of ENTSO-E's System Development Committee (SDC). The results of these studies have been discussed and - in some cases - extended with additional studies by the regional groups, to cover all relevant aspects in the regions.

The aim of the IoSN process is to identify investment needs for the 2040 horizon - triggered by market integration, RES integration, security of supply and interconnection targets - in a coordinated pan-European manner.

A more detailed description of this methodology is available in the report 'Completing the map – Power system needs in 2030 and 2040'.

2.5 The Northern Seas Region

The Regional Group Northern Seas (RG NS) under the scope of the ENTSO-E System Development Committee includes the following countries and TSOs (Figure 2.4 and Table 2-1).

Figure 2.4: ENTSO-E System Development Committee Northern Seas Region

The Regional Group Northern Seas comprises ten countries, which are listed - along with their representative TSO - in Table 2-1.

Table 2-1: ENTSO-E Regional Group Northern Seas membership

Country	Company/TSO
Belgium	ELIA
France	RTE
The Netherlands	TENNET
Germany	AMPRION, TENNET
Great Britain	NATIONAL GRID ELECTRICITY SYSTEM OPERATOR (ESO)
Ireland	EIRGRID / SONI
Northern Ireland	EIRGRID/ SONI
Denmark	ENERGINET
Norway	STATNETT
Luxembourg	CREOS

2.6 Evolution since the RegIP 2017

Since the publication of the previous RegIP 2017 (published for public consultation in January 2018), the progress of the projects included in TYNDP 2018 in terms of grid development is presented in the maps below. The left map shows those projects submitted to the TYNDP2018, while the right one shows the projects being submitted to the TYNDP20. Some projects have been / will soon be commissioned such as

- the NEMO link between Great Britain and Belgium
- the COBRA cable between the Netherlands and Denmark West.
- Krieger's Flak CGS between Germany and Denmark East (completion expected end of September)
- IFA2 between France and Great Britain (completion expected end of October)
- Part of "Step 3" Dollern-Kassø between Denmark West and Germany (completion expected during 2020)
- Alegro Project between Germany and Belgium (completion expected end of 2020)

Other projects changed their implementation status showing some progress.

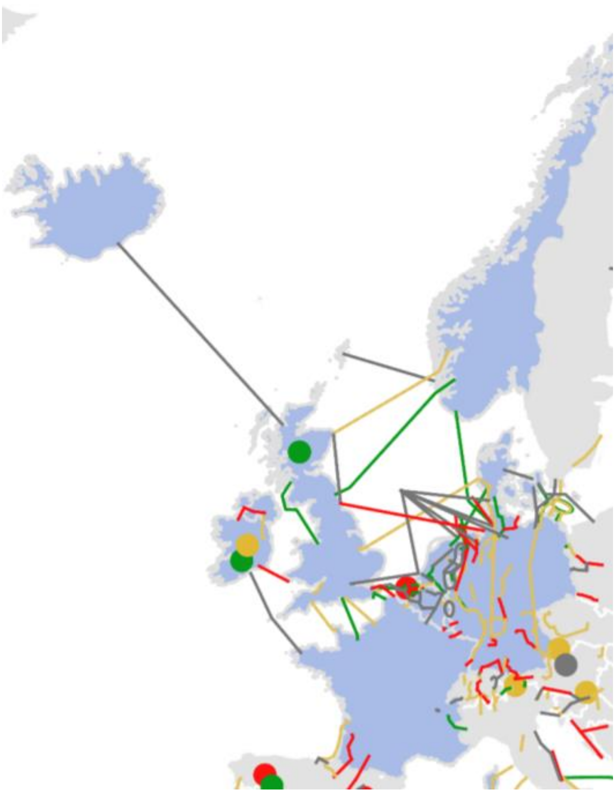


Figure 2.5: Map of TYNDP18 projects

Figure 2.6: Map of TYNDP20 projects

3. REGIONAL CONTEXT

3.1 Present situation

The Regional Group Northern Seas is comprised of four separate synchronous systems, as shown in Figure 3.1. The four synchronous areas are linked via HVDC interconnectors. Most of the countries in the region are part of the Continental system. Norway and East Denmark are part of the Nordic system, while Great Britain and the island of Ireland forms its own islanded synchronous system.

The majority of the grid is comprised of 220/275/380/400 kV overhead transmission lines. Norway also makes use of 300 kV circuits. In addition, 110-150 kV circuits are extensively used in the Danish and Irish transmission systems.

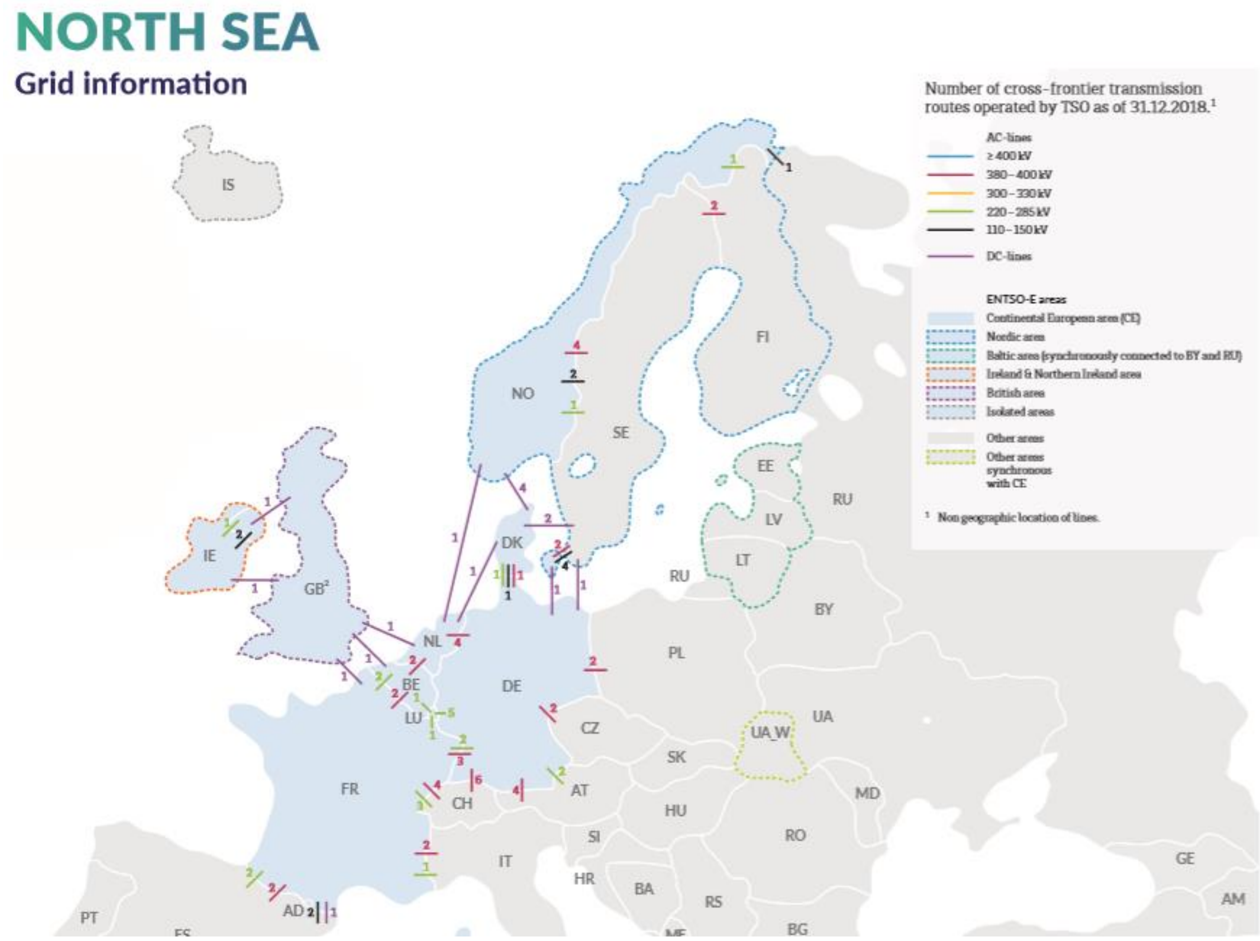


Figure 3.1: Synchronous areas and existing interconnections of the Northern Seas Region

3.1.1 Interconnection capacity in the region

Grid expansion since 2010

The transmission network in the Northern Seas Region has been greatly expanded since 2010. Approximately 4,500km lines (more than 50% of this in Germany) of pan-European interest have been built or upgraded. Seven new interconnectors have been commissioned since 2010, increasing the Region's interconnectivity by 5,800MW. These new interconnectors are (status 1 July 2020):

- NEMO link (GB-BE, 1000MW)
- Skagerrak 4 (NO-DKW, 700MW)
- Cobra Cable (DKW-NL, 700MW)
- East-West interconnector (IE-GB, 500MW)
- Niederrhein – Doetinchem (DE-NL, 1500MW)
- BritNed (GB-NL, 1000MW)
- BeDeLux – interim phase (LU-BE, 400MW).

For new connections or connection reinforcements planned for commissioning in the region during the next five years, see Table 3.1. The interconnected HVAC network in the Northern Seas Region, including projects under construction (status 1.1. 2019), is illustrated in Figure 3-2 and can also be found [here](). The Nordic and continental systems utilise 400 kV AC as the main transmission voltage level, and 220/130/110 kV AC as sub-transmission voltage levels.

Figure 3.2: Interconnected network of the Northern Seas Region, including projects under construction (status 1.1. 2019).

Figure 3.3 shows the current level of Net Transfer Capacity (NTC) within the Northern Seas Region, and Figure 3.4 the expected level in 2025. The NTC is the maximum total exchange capacity in the market between two adjacent price areas. These NTC values reflect that, from a market integration perspective, the continental system is strongly interconnected via AC interconnectors, whilst there are a number of offshore HVDC interconnectors linking Ireland and Great Britain - and also the Nordic system - to the continent.

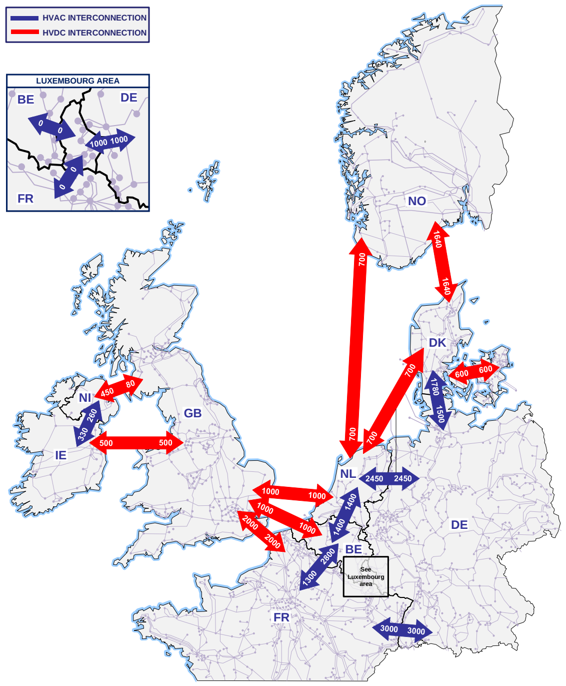


Figure 3.3: Current transfer capacities in the Northern Seas Region

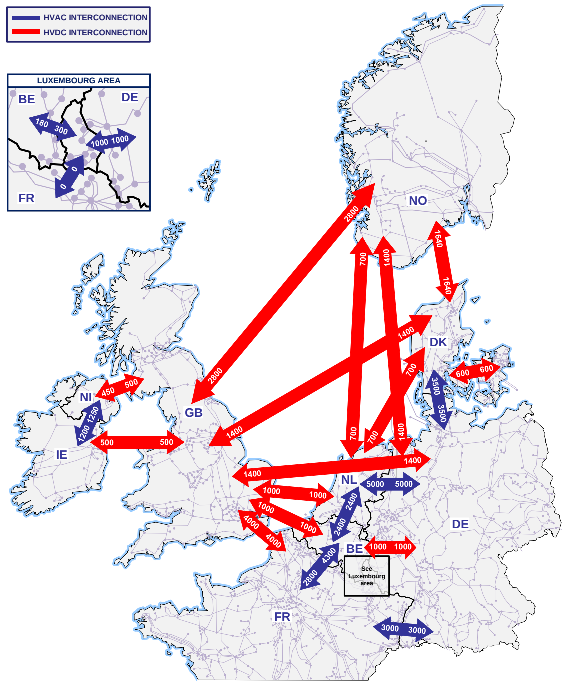


Figure 3.4: Transfer capacities in the Northern Seas Region in the TYNDP20 reference grid

Detailed information on the Reference Grid is given in Table 3-1.

Table 3-1: Overview of transmission projects by 2025 (under construction or in permitting – included in the TYNDP20 Reference Grid)

Project ID	Project name	Promoter(s)	TSO / Non-TSO	Countries	Status	Commissioning year
37	NordLink	TenneT-DE, Statnett	TSO	DE-NO	**Under construction**	2020
39	Step 3 DKW-DE	TenneT-DE, Energinet	TSO	DE-DK	**Under construction**	2020
25	IFA2	National Grid, RTE	TSO	FR-GB	**Under construction**	2020
92	ALEGrO	Elia, Amprion	TSO	BE-DE	**Under construction**	2020
172	ElecLink	ElecLink	Third party	FR-GB	**Under construction**	2020
110	North Sea Link	National Grid, Statnett	TSO	GB-NO	**Under construction**	2021
173	FR-BE: PSTs Aubange-Moulaine	Elia, Rte	TSO	FR-BE	**Under construction**	2021
208	N-S Western DE_section North_1	TenneT-DE, Amprion	TSO	DE	**Under construction**	2021
23	FR-BE: Avelin/Mastaing-Avelgem-Horta HTLS	Elia, Rte	TSO	FR-BE	**Under construction**	2022
258	Westcoast line	TenneT-DE	TSO	DE	**Under construction**	2022
262	Belgium-Netherlands: Zandvliet-Rilland	Elia, TenneT-NL	TSO	BE-NL	**Under construction**	2022
106	ZuidWest380 West	TenneT NL	TSO	NL	**Under construction**	2022
348	NoordWest380 NL	TenneT-NL	TSO	NL	**Under construction**	2023
167	Viking Link	Energinet, National Grid	TSO	DK-GB	**Under construction**	2023
104	Wahle-Mecklar	TenneT-DE	TSO	DE	**Under construction**	2024
309	Neuconnect	Frontierpower	Third party	GB-DE	In permitting	2022
81	North South Interconnector	SONI, Eirgrid	TSO	IE-GB	In permitting	2023
183	DKE-DE, Westcoast	TenneT-DE, Energinet	TSO	DE-DK	In permitting	2023
78	South West Cluster	National Grid	TSO	GB	In permitting	2024
254	HVDC Ultranet Osterath to Philippsburg	Amprion, Transnet	TSO	DE	In permitting	2024
190	Northconnect	Northconnect	Third party	NO-GB	In permitting	2024
103	Reinforcements Ring NL phase I	TenneT-NL	TSO	NL	In permitting	2025

3.1.2 Power generation, consumption and exchange in the Northern Seas Region

The total annual power consumption in the Northern Seas Region is approximately 1,750 TWh, of which around 60% is consumed by Germany and France. From 2010 until 2018, the peak load of 305 TW remained stable, while renewable generation capacity has significantly increased, as shown in Figure 3.5. The dominant RES generation is from wind, solar and hydro, which have grown from 31% of region's generation capacity in 2010 to 47% in 2018, due to increases in wind and solar capacity.

Thermal fossil fuel-fired generating capacity has decreased in the Nordic countries while slightly increasing in continental Europe. The German nuclear phase-out is already clearly visible in the graphs. The continental and Nordic markets currently have sufficient thermal production capacity to cover demand during periods of low energy production from variable renewable sources or during dry years with low hydro production. However, due to the increase of RES (mainly wind and solar) and the reduction in conventional and nuclear power plants, the region is becoming increasingly dependent on imports in high-demand, low-RES situations.

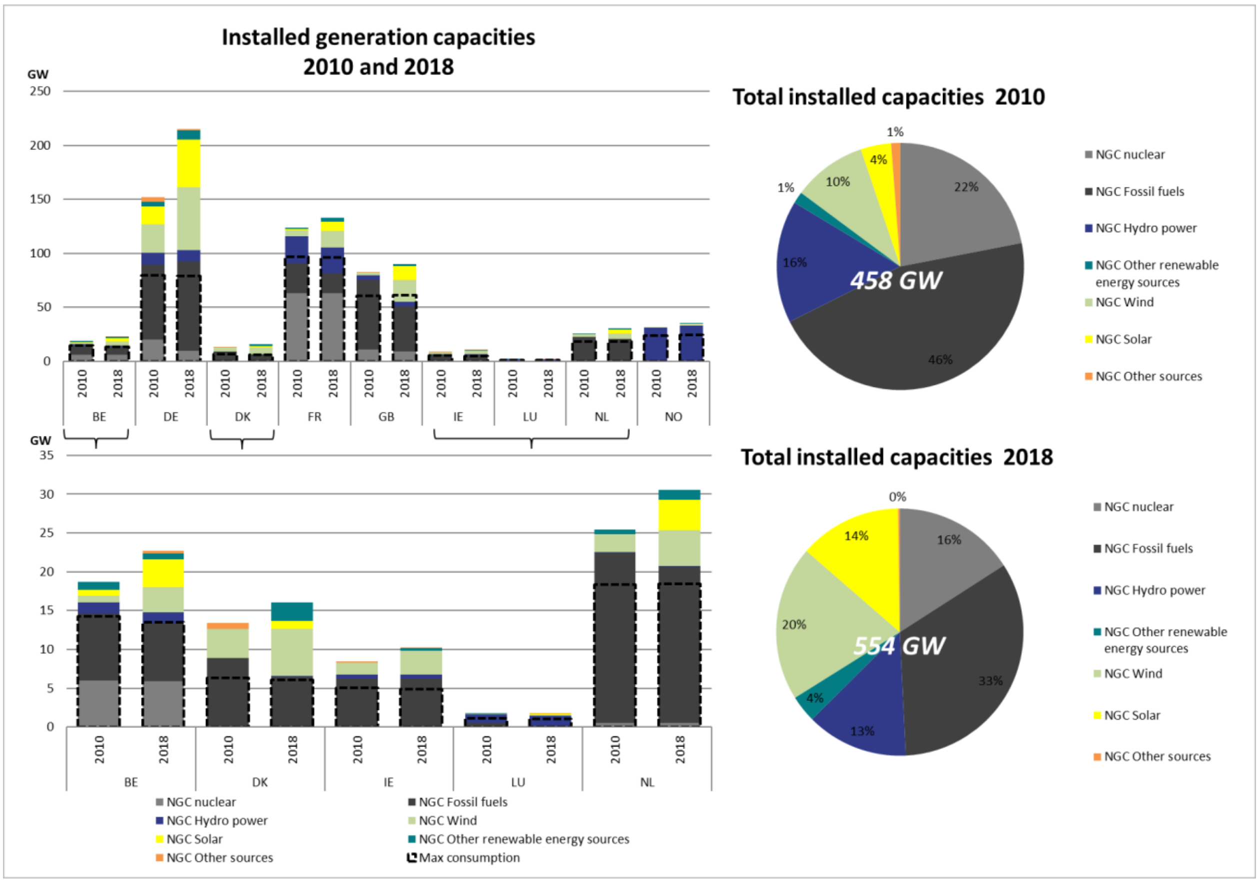


Figure 3.5: Installed generation capacities by fuel type and maximum consumption in the Northern Seas Region in 2010 and 2018.

The Nordic power system is dominated by hydropower, followed by nuclear, wind power and combined heat and power (CHP). Most of the hydropower plants are located in Norway. In a year with normal inflow, hydropower represents approximately 100% of annual electricity generation in Norway. Between a dry and wet year, the total generation originating from hydropower varies by up to 60–70 TWh. Consumption in the Nordic countries is characterised by a high amount of electrical heating and energy-intensive industry.

The overall power balance in the region is positive, and the region is an energy exporter. Germany and France have a comfortable annual energy surplus, while Belgium, Denmark, Luxembourg, the Netherlands and Great Britain show deficits. In an average year, Ireland has a neutral annual power balance. The significant increase in RES generation in Germany has replaced production from nuclear plants but has only slightly reduced fossil fuel-based generation, while significantly increasing exports.

The development of generation and demand in the Northern Seas Region is shown in Figure 3.6.

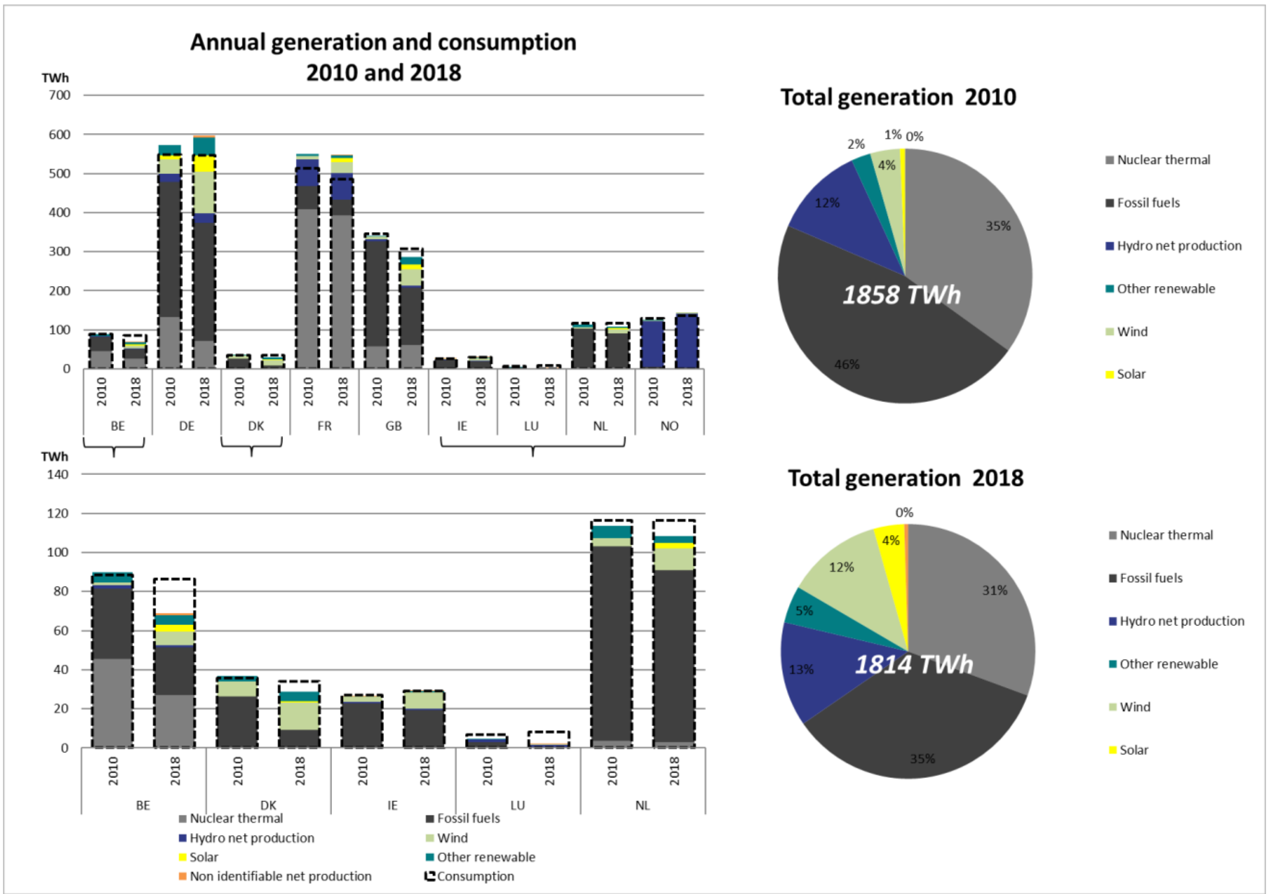


Figure 3.6: Annual generation by fuel type and annual consumption in the Northern Seas Region in 2010 and 2018.

Electricity production in the continental part of the Northern Seas Region is dominated by thermal power, except in the Danish power system, which is dominated by wind and other renewable energy sources (RES). These already supply >60% share of consumption. Consumption in the area is less temperature dependent than in Nordic countries.

The cross-border flows in 2018 are shown in Figure 3.7, and the development in cross-border exchanges 2010-18 is presented in Figure 3.8. The region shows important exchanges between importing and exporting countries as well as power transits across countries. A large power flow increase 2010-18 can be seen, eg, from Germany to the Netherlands or from France to Great Britain and France to Belgium. In the Nordic countries, the flow pattern varies greatly from year to year, as a result of variations in hydrological inflow (both 2010 and 2018 were dry years, with 2010 notably drier). In wet years, exports from Norway are typically much higher than during dry ones. Continental system variations are more frequent, changing from hour to hour, due to the weather-related nature of variable RES such as wind and solar energy.

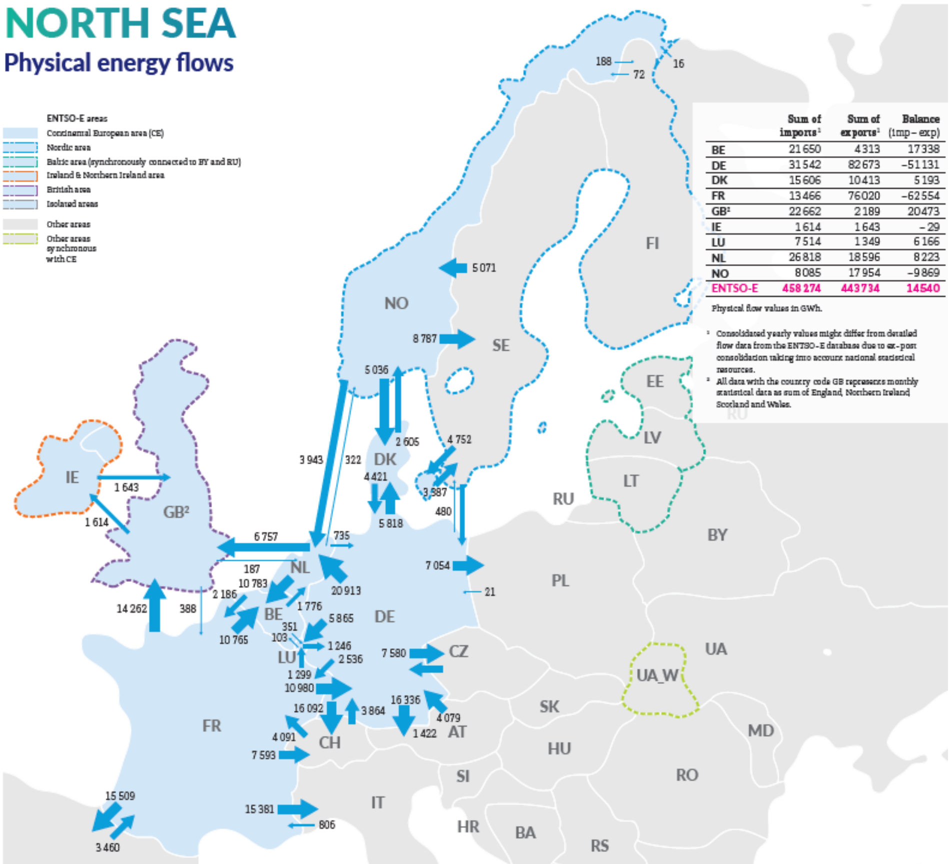


Figure 3.7: Cross-border physical energy flows (GWh) in the Northern Seas Region in 2018.

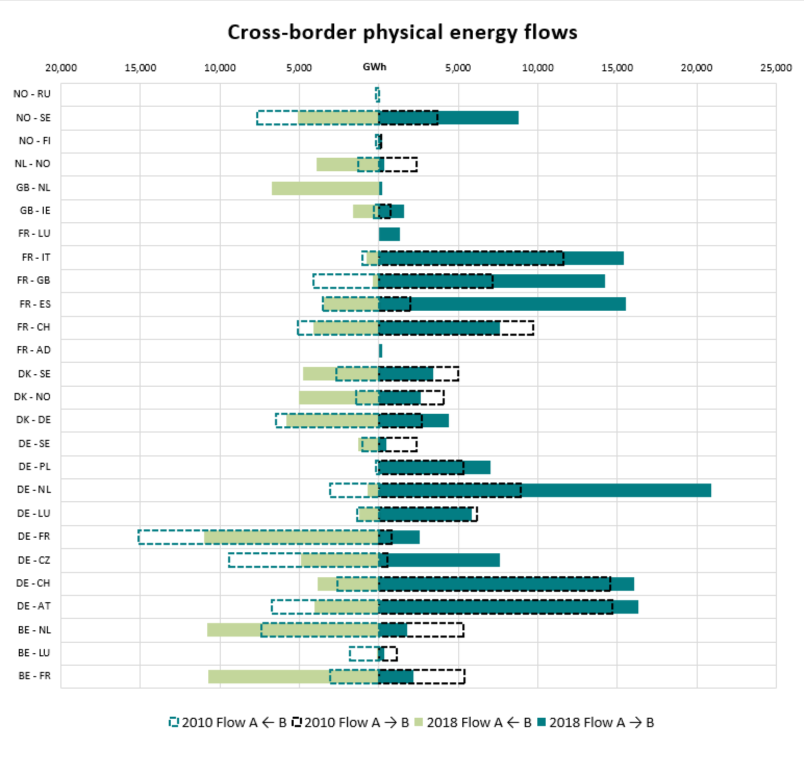


Figure 3.8: Cross-border physical energy flows (GWh) in the Northern Seas Region in 2010 and 2018.

3.1.3 Grid Constraints

The countries of the North Sea region are already relatively well connected. Further interconnectors are currently under construction or planned, see Table 3.1.

The internal expansion of the transmission network is vital for avoiding future network bottlenecks. It can facilitate cross-border market trade as well as internal market flows, and can ensure that the electricity supplied can physically arrive at the load demand centres. Satisfying the identified needs of this IoSN analysis at hand is expected to further trigger internal reinforcement needs, which have not been analysed in detail in this report.

Another motivation for reinforcement of internal networks is to facilitate RES integration. Renewable energy sources are often built far from the demand centres. To achieve the Paris climate targets, it is therefore of great importance to minimise possible network constraints between renewable production and demand. As can be seen in the TNYDP 2020 project list[2] and in Appendix 1 of this report, extensive measures for the successful integration of renewables are planned, particularly in Belgium, France and Germany, as set out in Appendix 2.

[2] https://tyndp.entsoe.eu/documents --- *"TYNDP2020 project portfolio"*

3.2 Description of the scenarios

The TYNDP2020 Scenario edition, published in May 2020, represents the first step in quantifying the long-term challenges of the energy transition on the European electricity and gas infrastructure.

The joint work of ENTSO-E and ENTSOG, stakeholders as well as over 80 TSOs covering more than 35 countries, has provided a basis for allowing assessment for the European Commission's Projects of Common Interest (PCI) list for energy, as ENTSO-E and ENTSOG progress to develop their respective TYNDPs.

We strongly recommend that the readers familiarise themselves with the content included in the TYNDP 2020 Scenarios Report and visualisation platform, as these will provide full transparency on the development and outcomes of the scenarios mentioned in this report.

3.2.1 Scenario Storylines

The joint scenario-building process presents three storylines for TYNDP2020; key parameters and drivers of the storylines are summarised in Figure 3.9 and Figure 3.10:

Figure 3.9: Key parameters for the scenario storylines

1. **National Trends (NT),** the central policy scenario, based on the Member States' National Energy and Climate Plans (NECPs) as well as on EU climate targets. NT is further compliant with the EU's 2030 Climate and Energy Framework (32% renewables, 32.5% energy efficiency) and the EC 2050 Long-Term Strategy, with an agreed climate target of 80 – 95% CO2-reduction compared to 1990 levels.

2. **Global Ambition (GA),** a full energy scenario in line with the 1.5° C target of the Paris Agreement, envisions a future characterised by economic development in centralised generation. Hence significant cost reductions in emerging technologies such as offshore wind and Power-to-X are led by economies of scale.
3. **Distributed Energy (DE**), a full energy scenario also compliant with the 1.5° C target of the Paris Agreement, presents a decentralised approach to the energy transition. On this basis, prosumers actively participate in a society driven by small-scale decentralised solutions and circular approaches. Both Distributed Energy and Global Ambition reach carbon neutrality by 2050.

Bottom-up scenario: This approach of the scenario-building process collects supply and demand data from gas and electricity TSOs.

Top-down scenario: The "Top-Down Carbon Budget" scenario-building process is an approach that uses the 'bottom-up' model information gathered from the Gas and Electricity TSOs. The methodologies are developed in line with a carbon budget approach.

Full energy scenario: a full energy scenario employs a holistic view of the European energy system, thus capturing all fuel and sectors, as well as a full picture of primary energy demand.

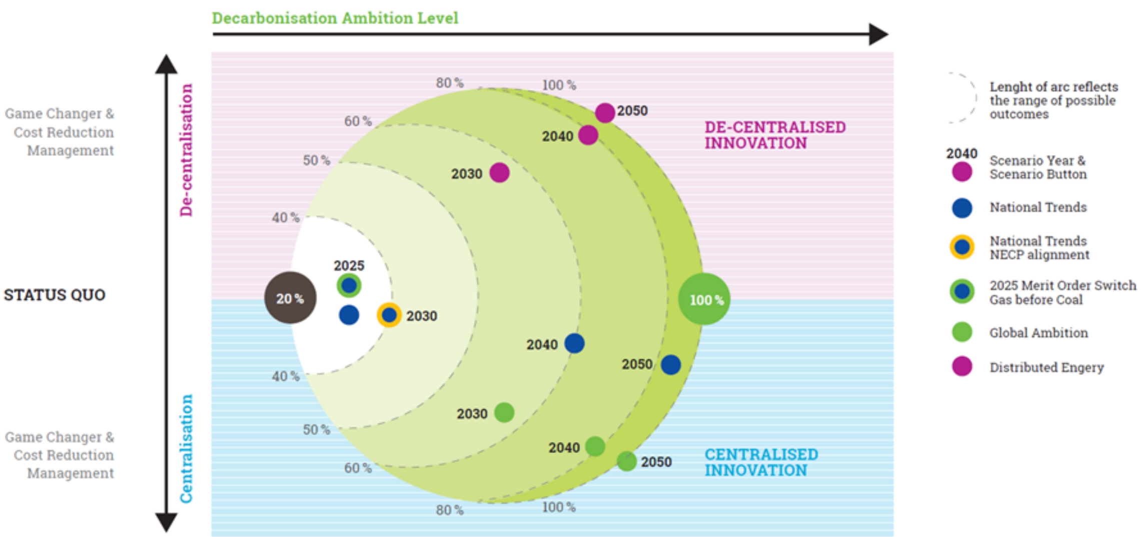


Figure 3.10: Key drivers of scenario storylines [Scenario building report].

3.2.2 Selective description of electricity results.

To comply with the 1.5° C targets of the Paris Agreement, carbon neutrality must be achieved by 2040 in the electricity sector and by 2050 in all sectors.

Distributed Energy and Global Ambition (also referred to as 'COP21 Scenarios') scenarios are meant to assess sensible pathways for reaching the target set by the Paris Agreement for the COP 21: 1.5° C, or at least well below 2° C by the end of the century. For the purpose of the TYNDP scenarios, this target has been translated by ENTSO-E and ENTSOG into a carbon budget of staying below +1.5° C at the end of the century with a 66.7% probability.

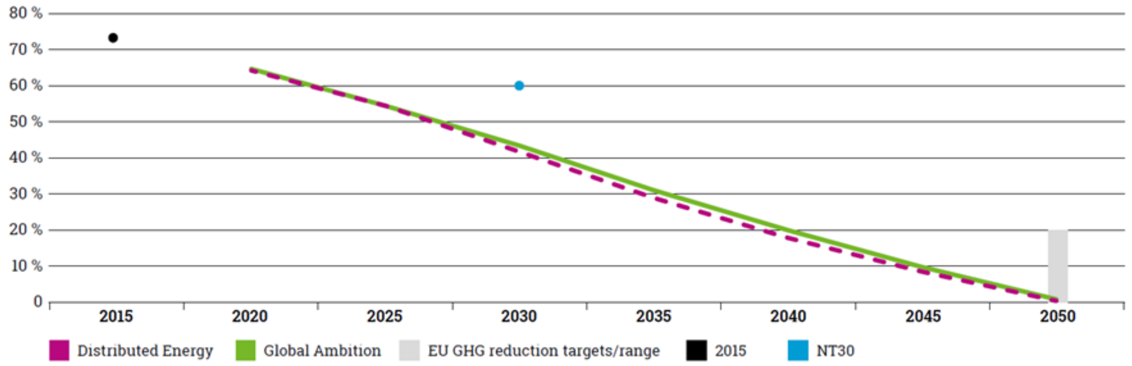


Figure 3.11: GHG Emissions in ENTSOs' Scenarios compared to 1990 level

To optimise conversions, the direct use of electricity is an important option resulting in progressive electrification throughout all scenarios

The scenarios show that higher direct electrification of final use demand across all sectors increases the need for electricity generation.

Distributed Energy is the scenario storyline with the highest annual electricity demand, hitting around 4,300 TWh by 2050. The results for scenarios show that there is the potential for year-on-year growth for EU28 direct electricity demand. Figure 3-12 provides annual EU-28 electricity demand volumes and the associated development of the electricity demand for the specified periods.

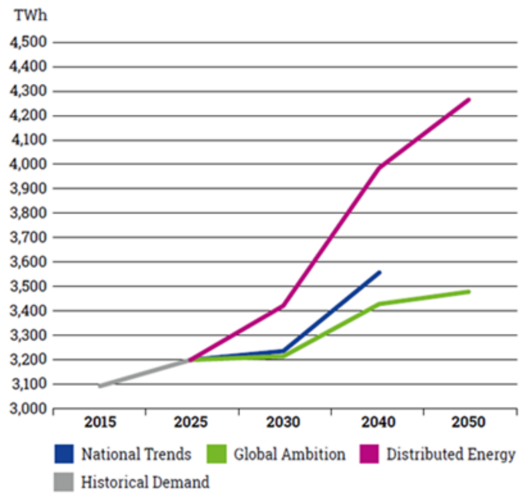


Figure 3.12: Direct Electricity Demand per Scenario (EU28)

The growth rates for the storylines show that, by 2040, National Trends is centrally positioned in terms of growth between the two more ambitious top-down scenarios, Distributed Energy and Global Ambition. The main reason for the switch in growth rates is due to the fact that Global Ambition has the highest levels of energy efficiency, whereas for Distributed Energy, strong electricity demand growth is linked to high electrification from the high uptake of electric vehicles and heat pumps, dominating electrical energy efficiency gains.

In the COP21 Scenarios, the electricity mix becomes carbon neutral by 2040.

In EU28, electricity from renewable sources will meet up to 64% of power demand by 2030 and 83% by 2040. Variable renewables (wind and solar) will play a key role in this transition as their share in the electricity mix grows to over 40% by 2030 and over 60% by 2040.

The remaining renewable capacity consists of biofuels and hydro. All figures stated above exclude power dedicated for P2X use, which is assumed to be entirely from curtailed RES, and newly build renewables that are not grid-connected, and therefore not considered in this representation.

To move towards a low-carbon energy system, significant investment in gas and electricity renewable technologies is required.

Distributed Energy is the scenario with the highest investment in generation capacity, driven mainly by the highest level of electrical demand. It mainly focuses on the development of solar PV, the technology with the lowest load factor. As a result solar PV-installed capacity will be higher compared to offshore or onshore wind, to meet the same energy requirements. The scenario shows a larger growth in onshore wind after 2030. In 2030, 14% of electricity will be produced from solar with 30% from wind - 44% in total. In 2040, 18% of electricity will be generated from solar and 42% from wind 60% in total. This scenario also sees the least amount of electricity produced from nuclear of all three scenarios, providing 16% by electricity in 2030 and 10% by 2040.

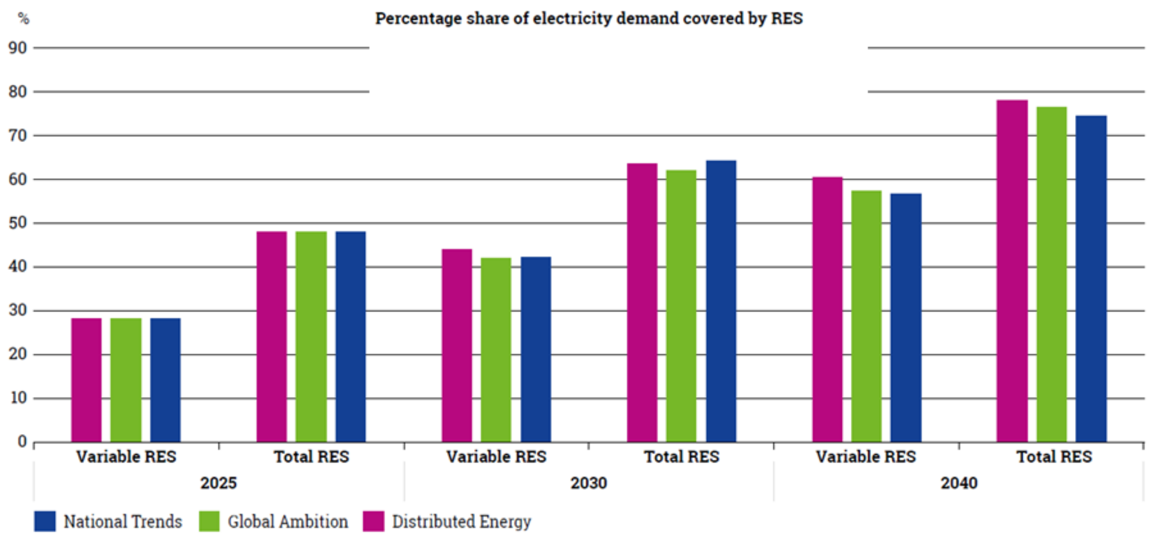


Figure 3.13: Percentage share of electricity demand covered by RES

Global Ambition has a lower electricity demand, with a general trend of higher nuclear and reduced prices for offshore wind. Consequently, the capacity required for this scenario is the lowest, as more energy is produced per MW of installed capacity in offshore wind, with nuclear used as baseload technology providing 19% of energy by 2030 and reducing to 12% by 2040. In 2030, 10% of electricity will be produced from solar and 32% from wind - 42% in total. In 2040, 13% of the electricity will be generated from solar and 45% from wind - 58% in total.

National Trends is the policy-based scenario. The variable renewable generation is somewhere between the two top-down scenarios. In 2030, 12% of electricity will be produced from Solar and 30% from wind - 42% in total. In 2040, 14% of the electricity will be generated from solar and 42% from wind - 56% in total. A considerable amount of electricity will still be produced from nuclear in 2030 - 17%, reducing to 12% by 2040.

Share of coal for electricity generation decreases across all scenarios. This is due to national policies on coal phase-out, such as that stated by the UK and Italy or planned by Germany. Coal generation will move from 10% in 2025 to 4-6% in 2030, reaching negligible amounts in 2040, which will represent an almost complete phase-out of coal.

Considerations on other non-renewable (mainly smaller scale CHPs) sources are important for decarbonisation. As it stands, carbon-based fuels are still widely used in CHP plants throughout Europe. This includes oil, lignite, coal and gas. In order to follow the thermal phaseout storylines, oil, coal and lignite should be phased out by 2040 and replaced with cleaner energy sources. Gas will contribute to decarbonisation through increasing shares of renewable and decarbonised gas.

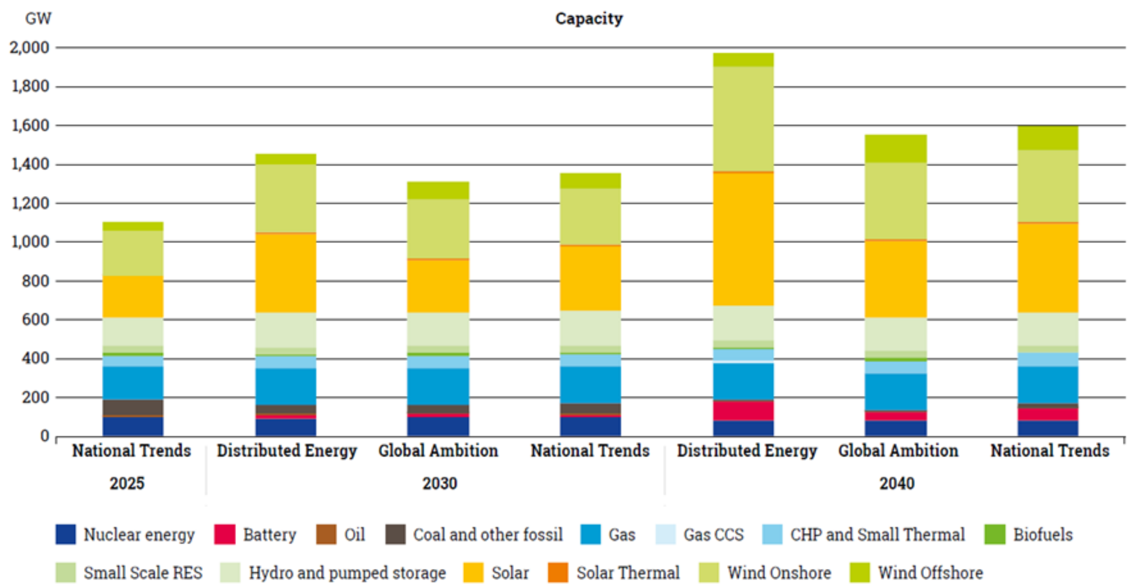


Figure 3.14: Electricity capacity mix

Sector integration – an enabler for (full) decarbonisation.

For the ENTSOs, sector integration describes interlinkages between gas and electricity production and infrastructure. Major processes here are gas-fired power generation, Power-to-Gas (P2G) and hybrid demand technologies. ENTSOs' scenarios are dependent on further development of sector integration; without these, interlinkages a high or even full decarbonisation in the energy sector will not be reached.

Assuming a switch from carbon-intensive coal to natural gas by 2025, 150 MtCO2 could be avoided in the power generation. With increasing shares of renewable and decarbonised gases, gas-fired power plants become the main 'back-up' for variable RES in the long term. Distributed Energy even shows a further need for CCS for gas-fired power plants to reach its ambitious target of full decarbonisation of power generation by 2040.

On the other hand, P2G becomes an enabler for the integration of variable RES and an option to decarbonise the gas supply. Hydrogen and synthetic methane allow for carbon-neutral energy use in the final sectors. Distributed Energy is the scenario with the highest need for P2G, requiring about 1500 TWh of power generation per year with 493GW of capacities for wind and solar in 2040 to produce renewable gas. Sector integration in National Trends - with the assumption that P2G generation is limited to "curtailed electricity" - envisages 12 TWh of power generation with 22GW of P2G to produce renewable gas.

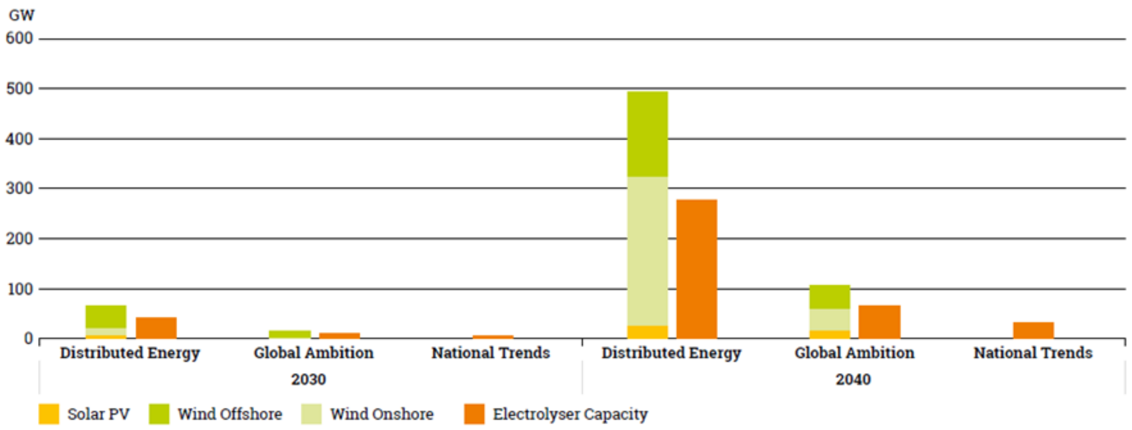


Figure 3.15: Capacities for hydrogen and derived fuels production

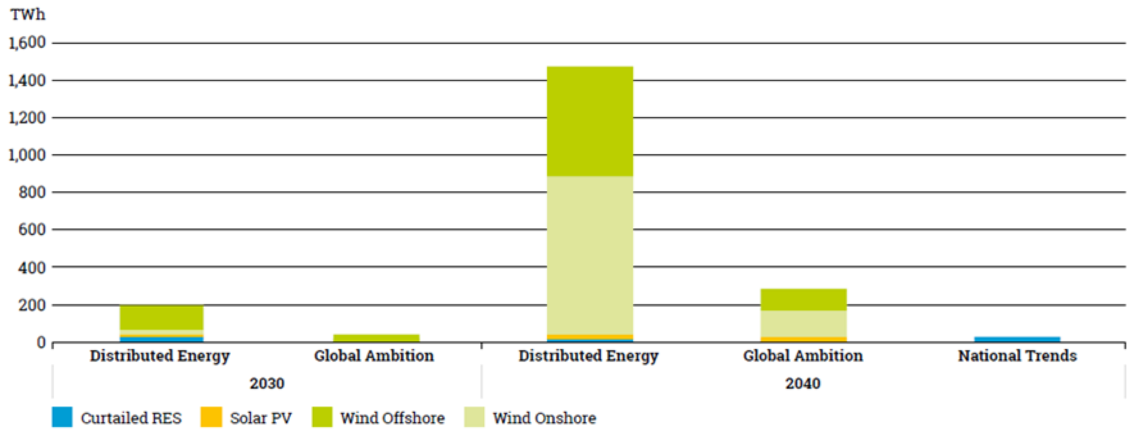


Figure 3.16: Generation mix for Hydrogen and derived fuels production

3.3 Future Challenges of the Region

The following section provides an insight into the scenario 'National Trends' for the Northern Seas region. Simulations of the 2040 NT scenario applied on the 2025 reference grid[3] study revealed the following future challenges that the future energy system would face without any additional investments in electricity infrastructure beyond 2025.

- Fundamental change of the generation portfolio
- Need to satisfy increasing electricity demand and security of supply
- Need to integrate huge quantities of offshore wind generation
- Change in the flow across the region – grid congestions
- High price differences between market areas
- High amounts of RES curtailment and CO2 emissions
- Ensuring flexibility in the energy system.

3.3.1 Fundamental change of the generation portfolio

The Northern Seas power plant fleet has evolved over many decades. To limit climate change, an evolution to technologies with low or zero emissions are needed; a renaissance of coal is therefore out of the question. Established and emerging technologies, such as renewable energies, gas fired power plants and nuclear power plants, are available for the future.

Variable renewables (wind and solar) will play a key role in the energy transition, as their share in the electricity mix grows to over 54% by 2030 and over 62% by 2040. Thanks to the sharp drop in investment costs over the past ten years, these technologies are now competitive. The remaining renewable capacity consists of biofuels and hydro power.

The capacity shares of nuclear and coal-fired power plants will be reduced to 3% and 9% respectively by 2030 and to 1% and 6% by 2040. Germany, France, Great Britain and the Netherlands have announced coal phase-outs for the future. In Belgium, the coal phase-out has already been completed. As a result, the currently-installed capacity of hard coal will fall sharply by 2030.

Thermal capacities are reduced overall, not only due to national phase-out policies but also to the fact that some generation units will no longer be economically viable, due to reduced running hours or reaching the end of their lifespan. This will have a considerable impact on the structure of power prices, which are increasingly influenced by variable RES.

3.3.2 Need to satisfy increasing electricity demand and security of supply

Following the European trend, final electricity demand is rising in all Northern Seas countries. Electricity demand is set to increase further because of rising household incomes, higher electrification of transport and heat as well as a growing demand for digital connected devices and data centres. Hence, these higher electrification trends are dominating the trend of increases in electrical efficiency for consumption in the NT scenario. In Figure 3-17, the final electricity demand according to the National Trends scenario for the years 2025, 2030 and 2040 is shown, as well as the delta of increase between the years 2025-40.

[3] *for more detail on the reference grid, readers should refer to the IoSN main report*

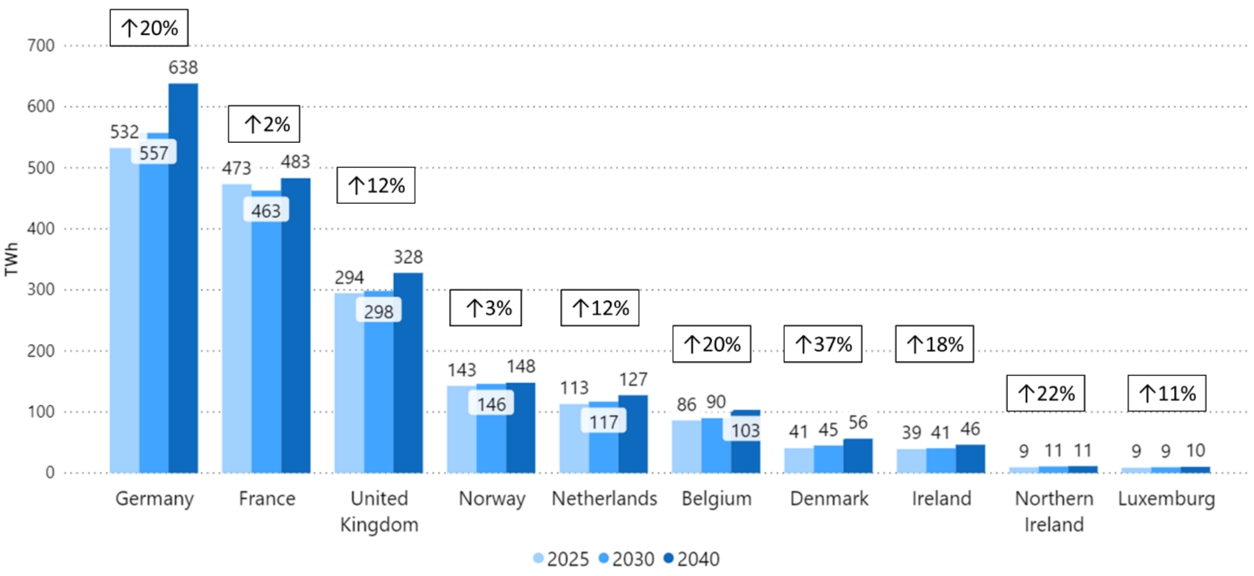


Figure 3.17: Final electricity demand and delta of increase for the National Trends scenario

The increasing electrification is already helping to unlock substantial efficiency gains and achieve a wide range of other benefits, including replacement of conventional fossil-fuel-based technologies by electric vehicles, heat pump systems and electrical stoves. Decarbonised electricity provides a platform for reducing CO2 emissions in other sectors through electricity-based fuels such as hydrogen or through synthetic liquid fuels.

Following the EU's long-term goal, National Trend is set to reach 80-95% decarbonisation by 2050. Although the commonly agreed target for 2030 is 40% greenhouse gas (GHG) emission reduction, the latest adoptions to the 2030 climate and energy framework (32.5% improvement in energy efficiency, 32% share for renewable energy) will consequently deliver higher GHG emission reductions. According to the National Trends scenario, the Northern Seas is following a steady path of emission reduction between 2025-40, as depicted in Figure 3.18.

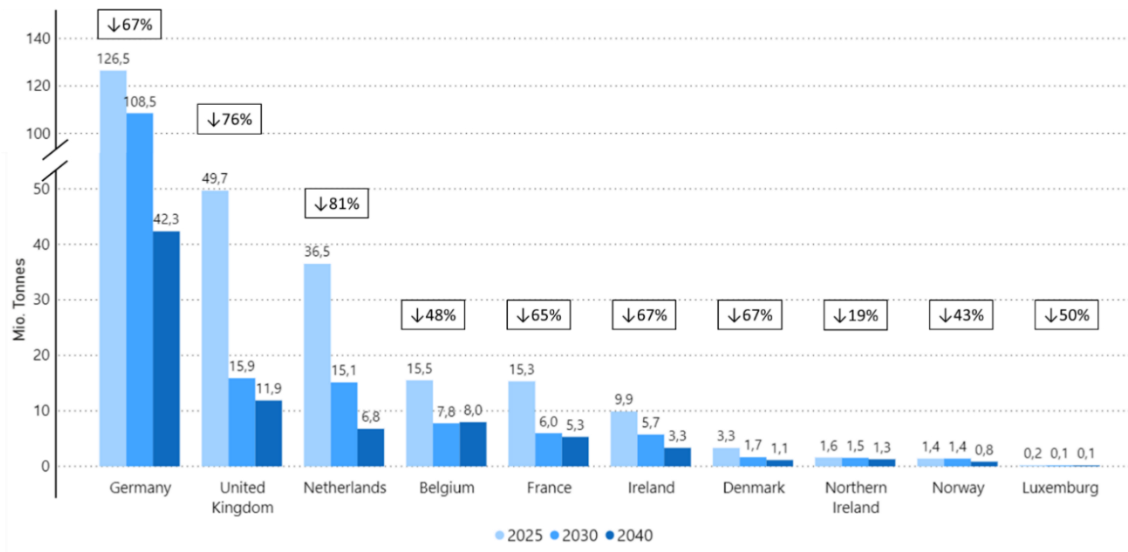


Figure 3.18: GHG Emissions from electricity generation and delta of reduction for the National Trends scenario

Security of supply

As in the last Regional Investment Plan 2017, unserved energy demand generally remains a limited concern in the Northern Seas region, particularly relative to the countries' annual demands. The key reason for this is the fact that scenarios are constructed to be in line with adequacy standards. To reach such adequacy standards though new, flexible thermal generation is assumed in the scenarios. This new thermal generation is not necessarily economically viable in an energy-only market and hence - at least partially - may have to rely on existing or new capacity-remuneration mechanisms. Thanks to the sharing of resources, interconnectors ensure security of supply in a more cost-effective manner with a nationally isolated approach, which would require greater installed generation capacity at an individual country level.

3.3.3 Need to integrate of huge amounts of offshore wind generation

With the addition of 3,615MW in 2019, the Northern Seas region has achieved a total instalment of 21,867GW offshore wind capacity, which corresponds to 4,964 wind turbines across ten countries.[4] This represents 99% of the total offshore capacity fleet in Europe. A country-by-country breakdown is given in Table 3-2.

Table 3-2: Overview of grid-connected offshore wind power projects at the end of 2019

Country	No. of wind farms connected	Cumulative capacity (MW)	No. of turbines connected	Net capacity connected in 2019 (MW)	No. of turbines connected in 2019
GB	40	9,945	2,225	1,760	252
Germany	28	7,445	1,469	1,111	160
Denmark	14	1,703	559	374	45
Belgium	8	1,556	318	370	44
Netherlands	6	1,118	365	0	0
Finland	3	70,7	19	0	0
Ireland	1	25,2	7	0	0
Norway	1	2,3	1	0	0
France	1	2	1	0	0
Total	102	21,867	4964	3,615	501

In addition, the latest research quantifies the projection of European offshore deployment for the short- and mid-term from an estimated 100GW for 2030 to a range of between 400-450GW[5] for 2050. Note that WindEurope assumes that part of this 450GW will not be directly connected to the electrical grid.[6] ENTSO-E's scenario report makes similar assumptions for both 'top-down' scenarios, which include a significant amount of off-grid offshore wind capacity to supply hydrogen production and derived fuels production. In 2040, the directly used and the off-grid offshore capacity adds up to 189GW and 244GW for the Global Ambition and Distributed Energy scenarios for EU28.

[4] *WindEurope: "Offshore wind in Europe" – key trends and statistics 2019, Feb 2020*
[5] *European Commission's 1.5 Long Term Strategy (1.5 Life and 1.5 Tech)*
[6] *WindEurope "Our energy, our future", November 2019*

For the Northern Seas Region, ENTSO-E and ENTSO-G central policy scenario 'National Trends' foresees an offshore capacity increase of 90% between 2020-25, thus reaching 41GW in 2025. Further projections follow the same pattern with 69GW and 112GW in 2030 and 2040 respectively.[7] Table 3-3 shows the installed offshore capacities (direct usage) for the three TYNDP 2020 scenarios for the Northern Seas Region and its relation to the total European fleet in brackets:

Table 3-3: Installed Offshore capacities (GW) in the Northern Seas and related to EU28 (%) - direct electricity usage only. Capacities for hydrogen and derived fuels production are not included.

Scenario	2030	2040
National Trends	69 (88%)	112 (85%)
Distributed Energy	53 (95%)	66 (85%)
Global Ambition	76 (88%)	105 (72%)

The resource potential for offshore in the Northern Seas region, as well as its capacity factors in several areas, is high. The cost of offshore wind generation has fallen substantially in the last decade, making it an attractive contributor to the European Green Deal. However, there are still several challenges to overcome in terms of its system integration.

Today, curtailment remains one of the most significant challenges for offshore integration into the Northern Seas systems. This is particularly the case in Ireland, which is poorly interconnected to other electrical systems, or in countries like Germany, where the roll-out of infrastructure is holding back the development of wind generating units. In addition, a wide number of conventional generators are under must-run obligations to provide the necessary flexibility to the system, thus leading to a stagnant supply side. These units are needed for reserve mechanisms, reactive power and voltage control mechanisms. However, this means that a portion of RES energy would need to be curtailed. However, according to the CEP, since 1 January 2020, RES generators (particularly wind) have an obligation to be balanced and also to provide balancing services, thus changing the overall picture. Additionally, RES such as wind energy are able to provide system services, but this needs to be triggered by respective market products calling for their contribution, which are not currently in place in all countries.

For the IoSN study, a conservative modelling approach has been applied that does not take into account national market rules, but rather assumes a so-called 'perfect market' across Europe.

An overview of the resulting RES curtailment for the National Trends scenario in 2030 and 2040 is provided in Figure 3.19. A trade-off must be made between the interests of electricity consumers, for example by means of effective competition, and the owners/investors of offshore generating plants needing high enough revenues to see their investment paid off.

[7] *See 2020 scenarios and data:* https://tyndp.entsoe.eu/scenarios/

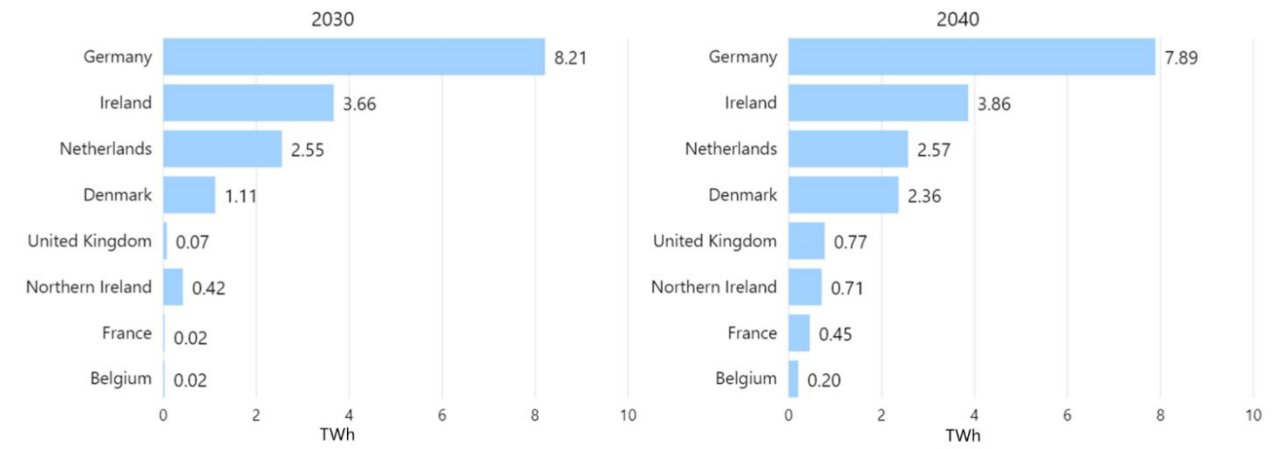


Figure 3.19: Curtailed offshore energy in the Northern Seas region according to the National Trends scenario

Figure 3.19 indicates that the amount of offshore curtailment in 2040 increases compared to 2030 for all countries with the exception of Germany, It shows that developing the required onshore grid at the same rate as the offshore grid will be challenging the coming decades.

Onshore grids were developed step-by-step over almost a century. The offshore transmission infrastructure and related onshore connections and reinforcements will need to be built in only a few decades. It is clear that to achieve this unprecedented onshore and offshore expansion will demand a holistic approach to planning, combining the fields of grid and spatial market integration, engineering, construction and financing. ENTSO-E has identified numerous basic pillars required for a successful offshore development: supporting offshore wind integration in electricity systems over time, space and sectors, promoting system security, cost efficiency and the ambitions of the European Green Deal. For a complete insight, please refer to ENTSO-E's Position Paper on Offshore Development (link).

3.3.4 Change in the Flow across the Region - Grid congestions

Reaching the level of cross-border exchanges that result from the needs identified in the IoSN SEW-based Needs and relying on the National Trends scenario for 2030 and 2040 will create new needs for reinforcing internal networks in the European national grids. Therefore, national TSOs will need to analyse the situation of internal grids within the national framework as well as within the European framework, to ensure that internal grids can accommodate future flows and are fit-for-purpose in the energy transition.

3.3.5 High price differences between market areas

As shown below in Figure 3.20, the average annual marginal cost differences in the NT scenario 2040 would still show significant spreads between market areas in the Northern Seas Region if no additional interconnections between market areas were realised after 2025. The cost spreads shown are highly sensitive to the market scenario under consideration and the climate year, as well as the underlying assumptions in terms of generation portfolio and demand profiles.

In general - as written in the Interconnection Target Expert Group's report, validated by the EC - Member States should aim at yearly average price differentials as low as possible (with 2€/MWh being the threshold requiring further reinforcement investigations). This ensures peak demand will be met through national capacity as well as from interconnections and ensures maximum RES integration by having sufficient interconnection capacity for import and export. In order to attain the interconnection targets, it remains essential to investigate and invest in more interconnection between market areas. This way, an efficient internal energy market can be obtained, one which guarantees competitive electric wholesale prices, subject to a positive societal cost benefit analysis.

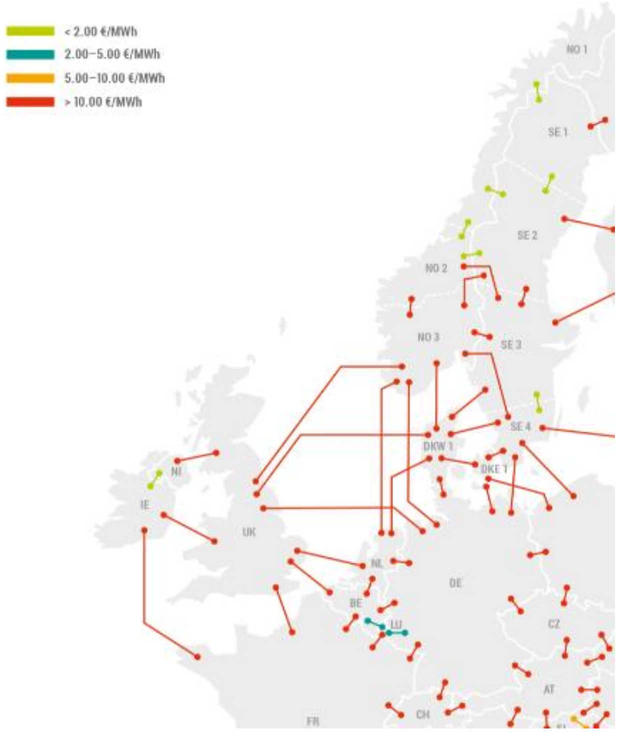


Figure 3.20: Difference in marginal costs between neighbouring bidding zones in 2040, in 'No investment after 2025'

3.3.6 High amounts of RES curtailment and CO2 emissions

As shown in Figure 4.6 and Figure 4.9 in Chapter 4, further reducing RES generation curtailment is a key driver for reducing overall CO2 emissions. Building further interconnections will help, particularly compared to those cases where no further investments would follow after 2025. The avoided RES curtailment increases in both 2030 and 2040 by building more interconnections, as do the CO2 emissions reductions, but not in a perfect linear fashion. The amount of RES in the Northern Seas Region is reaching levels where, in 2040, the already cheap and low-carbon intensive nuclear production seems likely to be displaced. In order to further reduce carbon emissions in the region and consequently the entire European power system, more storage technologies (both electrical like pumped hydro and chemical like P2X) would likely be needed. This is in addition to more cross-border (and supporting internal) grid reinforcements for countries with the lowest carbon-emitting potential or where the most promising synergy potential can still be found considering cross-correlation of RES production with electricity demand. In particular, smart sector integration can, to an extent, help further reduce overall CO2 emissions and RES curtailment levels, as described further in Chapter 5.2.

An unfavourable location of P2X systems can trigger unnecessary additional expansion needs in the electricity grid and the gas networks. To ensure efficient grid expansion, the location of P2X systems should therefore be carried out as part of a coordinated system planning.

3.3.7 Ensuring flexibility in the energy system

TSOs are responsible for ensuring and maintaining the instantaneous system balance between generation and demand, both on a national level as well as on their respective synchronous area level. With significant increased shares of variable renewable generation, such tasks become increasingly challenging and depend largely on the available means (e.g., both availability and amount of controllable generation – from all technologies) to control the system balancing needs (variability of the residual load ramps between and within subsequent hours). When considering both the average case as well as the higher percentiles of future market scenarios, all countries experience large ramps when considering their residual peak loads. In general, expected residual load ramps are increasing and will require an increase in flexibility (control means) across the region. This could be provided by various sources, including additional interconnections (which can provide access to control means outside of national control areas), storage and more fast-acting peaking units and demand response.

With the expected increase of significant amounts of offshore wind power (as well as other RES), which needs to be integrated into the power system, the operational and flexibility challenge becomes ever more apparent. Here we refer to Chapters 5.1.4, 5.3 and 5.4, which provide further details.

4. REGIONAL RESULTS

4.1 Future additional cross-border infrastructure needs

To analyse system needs by 2030 and 2040, ENTSO-E determined the combination of potential increases in cross-border network capacity that minimises the total system costs, composed of total network investment (including costs of related necessary internal reinforcements for most borders) and generation costs. To do that, a panel of potential network increases was proposed to an optimiser, who identifies the most cost-efficient combination. To take into account the mutual influence of capacity increases, the analysis was performed simultaneously for all borders. The combination of network increases to minimise costs identified through this process is called the 'SEW-based needs'.

The identification of system needs is a partial exercise that investigates one specific dimension of future system needs, which is where increasing cross-border capacity would be most cost efficient. Planning electricity transmission infrastructure requires considering a whole range of indicators, including not only costs but also, for example, the benefits of projects in terms of security of supply, reduction of CO2 emissions and other benefits. It is therefore possible that a project receives a positive CBA even when it is on a border that is not included in the best combination of capacity increases identified by the System Needs study.

4.1.1 IoSN 2030

Figure 4.1 and Figure 4.2 provide an overview of the cross-border capacity increase needs selected by the algorithm from the IoSN 2030. Within the Regional Group Northern Seas, the interconnectivity of the grid increases in order to be able to benefit from the presence of cheap nuclear electricity in France. The scenarios of the TYNDP 2020 correspond to slower pace of nuclear decommissioning in France in accordance with the last French energy law ("PPE: Programmation Pluriannuelle de l'Energie").

Thus, several interconnections linking France to its neighbours have been identified. The same is valid for Germany as the other country in the region with an energy surplus - supplying the Benelux countries - also needing stronger links between themselves. The identified needs in Denmark relate only to the Eastern part (Nordic synchronous area). Links to the Western Danish system have either been just commissioned (DKW-NL) or part are of the Reference Grid as they are under construction (DKW-GB) or in permitting (DKW-DE).

No interconnections with Norway within the regional group are proposed in the IoSN 2030. This is surprising, as the price spread between Norway and other countries is considerable. One of the reasons that no new capacity is proposed in IoSN is that in the Reference Grid, three new interconnectors from Norway are already assumed (2800MW NO-GB, 1400MW NO-DE). Further on, the IoSN analyses do not fully monetise factors like SoS and flexibility. In the IoSN-analyses, new capacity from Norway was not selected, as the benefits did not outweigh the required costs. This does not mean that interconnections with Norway would not be interesting in the future, in the event that the cost for HVDC technology decreases.

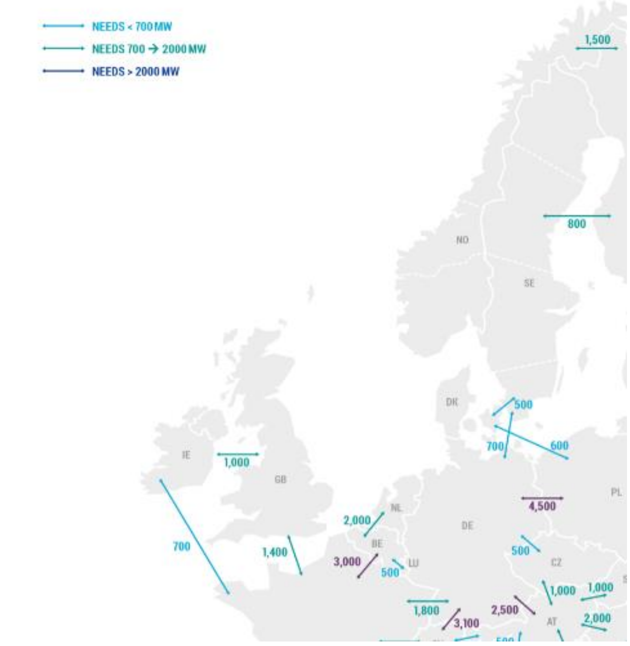


Figure 4.1: IoSN - SEW based needs 2030 (inMW)

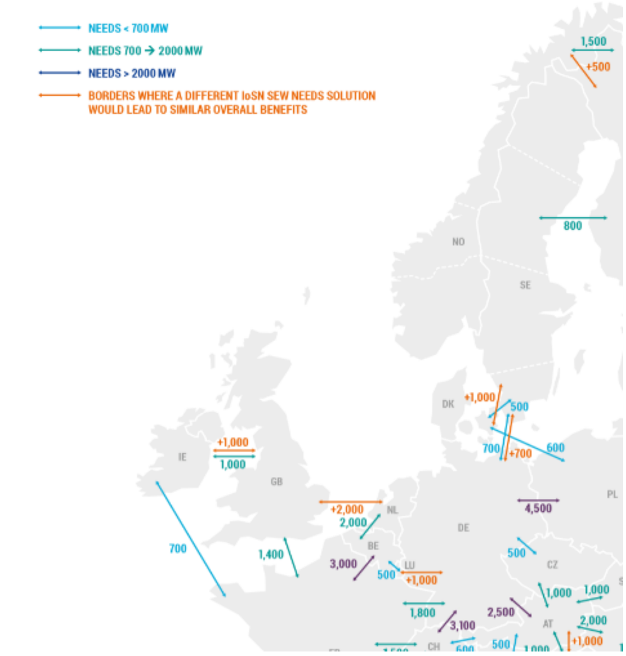


Figure 4.2: IoSN - SEW based needs 2030 (inMW) – and additional good capacity increases

Ireland and Northern Ireland form a unified wholesale electricity market area known as the Single Electricity Market (SEM). Therefore, the needs identified between the island of Ireland and Great Britain could be satisfied by capacity increases in either Ireland or Northern Ireland. The above figures show a basic set of identified needs (Figure 41) and an additional set of identified promising capacity increases (Figure 42). Satisfying some of the orange needs in Figure 42 (not all) on top of the basic set of needs turned out to provide similar benefits as meeting the basic set of needs alone.

Considering the sensitivity of the analysis on the cost estimates used for the optimisation process, these possibilities must be considered in order to not misdirect the sound development of the required solutions. This is particularly important in the subsequent steps, where further analyses such as environmental impact, viability, benefits beyond SEW and refined costs are carried out to complement the identified needs.

4.1.2 IoSN 2040

Figure 4.3 and Figure 4.4 provide an overview of the cross-border capacity increase needs selected by the algorithm of the IoSN 2040. Within the Regional Group Northern Seas, the interconnectivity of the grid needs increases in order to benefit from:

- A large amount of uncorrelated wind, as a sizeable volume of offshore production will be divided over a substantial area resulting in a decrease in curtailment
- The presence of cheap nuclear electricity in France. The scenarios of the TYNDP 2020 correspond to a slower pace of nuclear decommissioning in France, in accordance with the last French energy law (“PPE: Programmation Pluriannuelle de l’Energie”).

Several interconnections linking France to its neighbours have been identified. A number of needs have also been identified for Germany and its neighbours, exchanging the variable RES (wind and solar) when required. Stronger links between Great Britain and the continent are needed, as well as further links facilitating transits through the Benelux countries to/from Germany. The needs identified in Denmark relate only to the Eastern part (Nordic synchronous area). Links to the Western Danish system are either just commissioned (DKW-NL) or part of the Reference Grid, as they are under construction (DKW-GB) or in permitting (DKW-DE).

No interconnections with Norway within the regional group are proposed in the IoSN 2040. This is surprising, as the price spread between Norway and other countries is considerable. One of the reasons that no new capacity is proposed in IoSN is that in the Reference Grid, three new interconnectors from Norway are already assumed (2800MW NO-GB, 1400MW NO-DE). Further on, the IoSN analyses do not fully monetise factors like SoS and flexibility. In the IoSN-analyses, new capacity from Norway was not selected, as the benefits did not outweigh the required costs. This does not mean that interconnections with Norway would not be interesting in the future, in the event that the cost for HVDC technology decreases.

Ireland and Northern Ireland form a unified wholesale electricity market area known as the Single Electricity Market (SEM). Therefore, the needs identified between the island of Ireland and Great Britain could be satisfied by capacity increases in either Ireland or Northern Ireland.

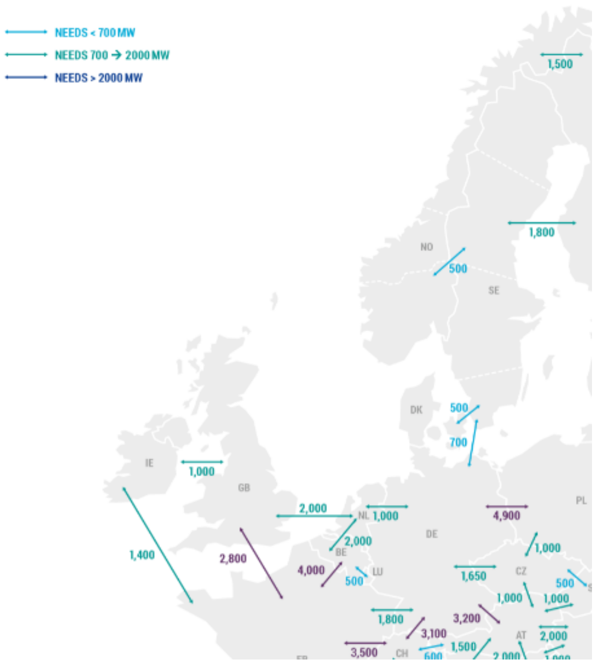


Figure 4.3: **IoSN – SEW based needs 2040 (in MW)**

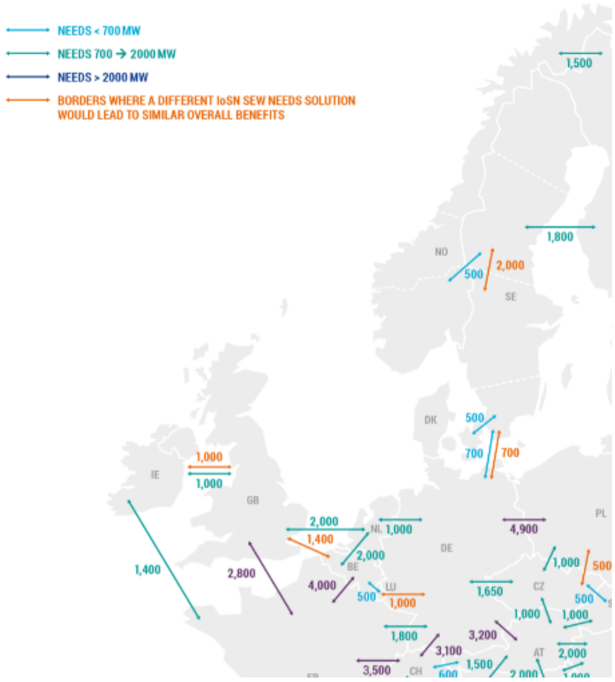


Figure 4.4: **IoSN – SEW based needs 2040 (in MW) – and additional capacity increases (in orange)**

Considering the sensitivity of the analysis on the cost estimates used for the optimisation process, these possibilities must be considered in order to not misdirect the sound development of the required solutions. This is particularly important in the subsequent steps, where further analyses such as environmental impact, viability, benefits beyond SEW and refined costs are carried out to complement the identified needs.

4.2 Market Results

4.2.1 2030 IoSN

Within the National Trends 2030 scenario, the fuel mix within the Region is one-third based on nuclear or thermal generation (nuclear, fossil, gas and others non-renewables), supplemented with a large share of variable RES and hydro power, when assuming current grid conditions (Figure 4.5). The curtailed energy is substantially less than within the National Trends 2040 scenario, although it still adds up to 49 TWh for the whole Region (Figure 46). The total of curtailed energy is equivalent to 3% of native demand within the Region.

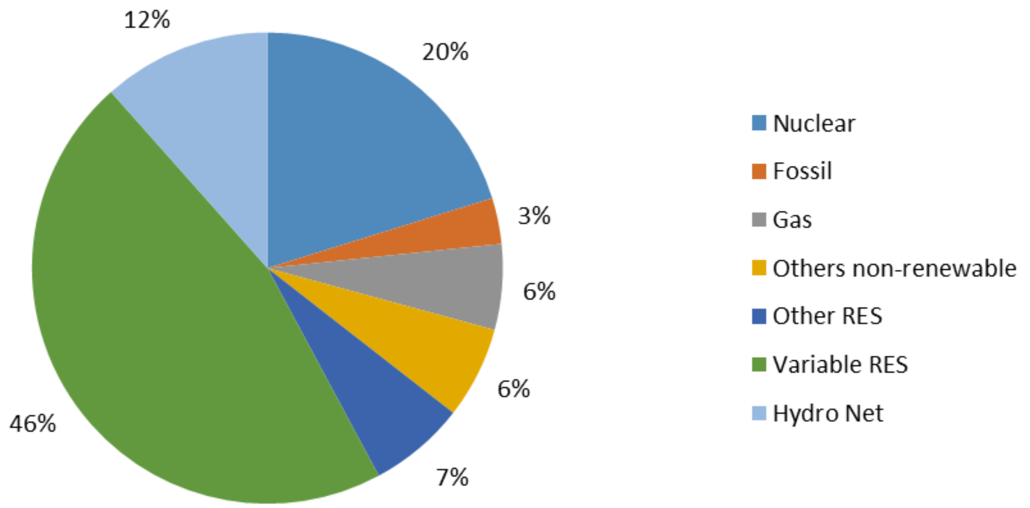


Figure 4.5: Energy mix NT2030 with 2020 reference grid

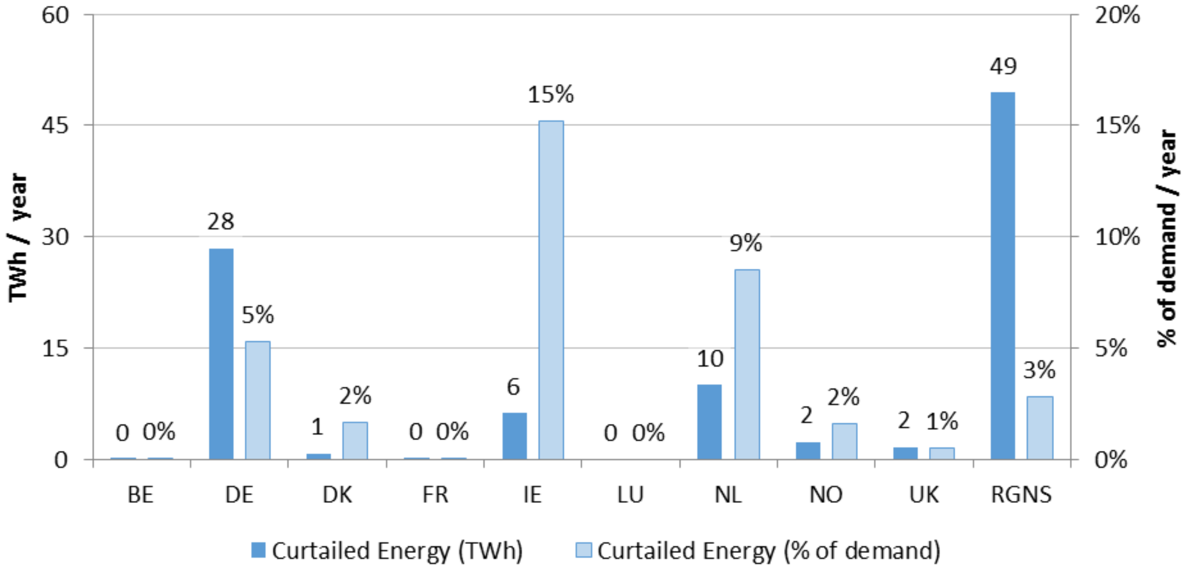


Figure 4.6: Curtailed variable RES -energy NT2030 with 2020 reference grid

The integration of this potential RES energy and facilitation of sharing the remaining nuclear and thermal generation across borders will be the main drivers for interconnections. Figure 4.7 shows that the investments planned between now and 2025 will have a notably positive effect on the integration of RES.

Further evolution of the economically feasible interconnection capacity (SEW-based needs) allows for an additional 35 TWh of Regional variable RES to be integrated into the system compared with the 2020 reference grid. This will reduce total curtailment to 15 TWh, equivalent to less than 1% of the regional demand. Furthermore, nuclear generation will increase as more grid allows nuclear generation to displace more expensive thermal generation within and outside the Region. The same effect will be observed for fossil fuels, which comprises German lignite production displacing more expensive lignite, hard coal and gas generation within and outside the Region.

Removing any bottleneck within the grid (copperplate) will amplify these effects and reduce the curtailment to zero.

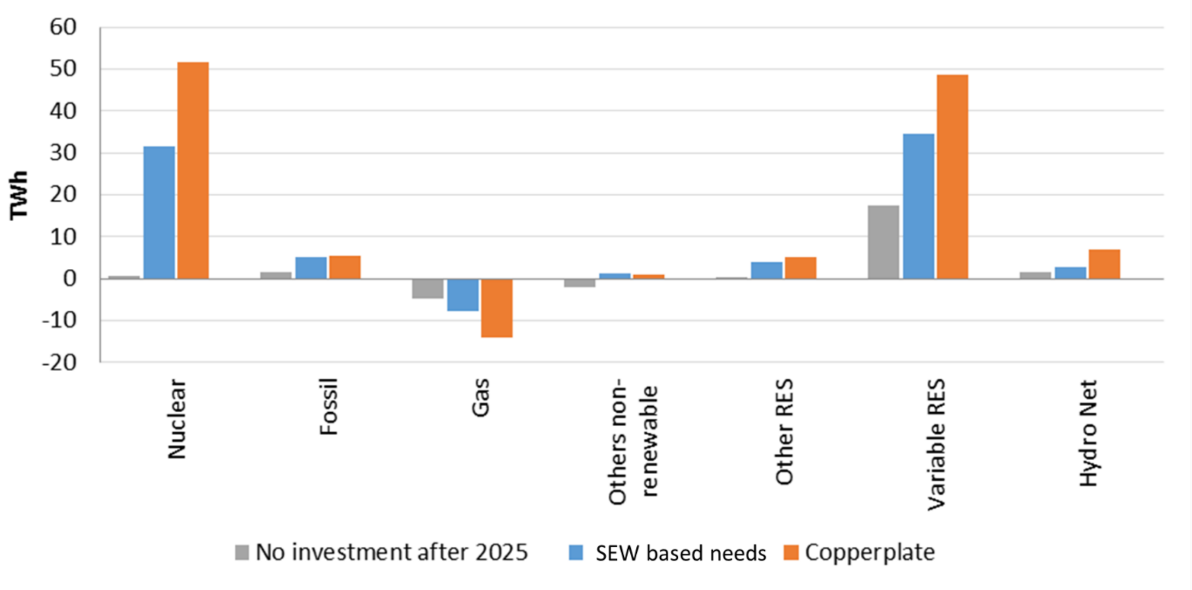


Figure 4.7: Changes in Energy Mix of the Region relative to the 2020 reference grid (positive values represents an increase in generation)

The resulting SEW-based needs increases the net position of the region to 74 TWh; this can be seen in Figure 4.8. On the full IoSN perimeter, a decrease of 60 Mton of CO2 emissions is observed. However, the increase of German lignite generation will increase the CO2 emissions within Germany and will have a positive net effect of 1.8 Mtons in CO2 emissions of the region, as shown in Figure 4.9.

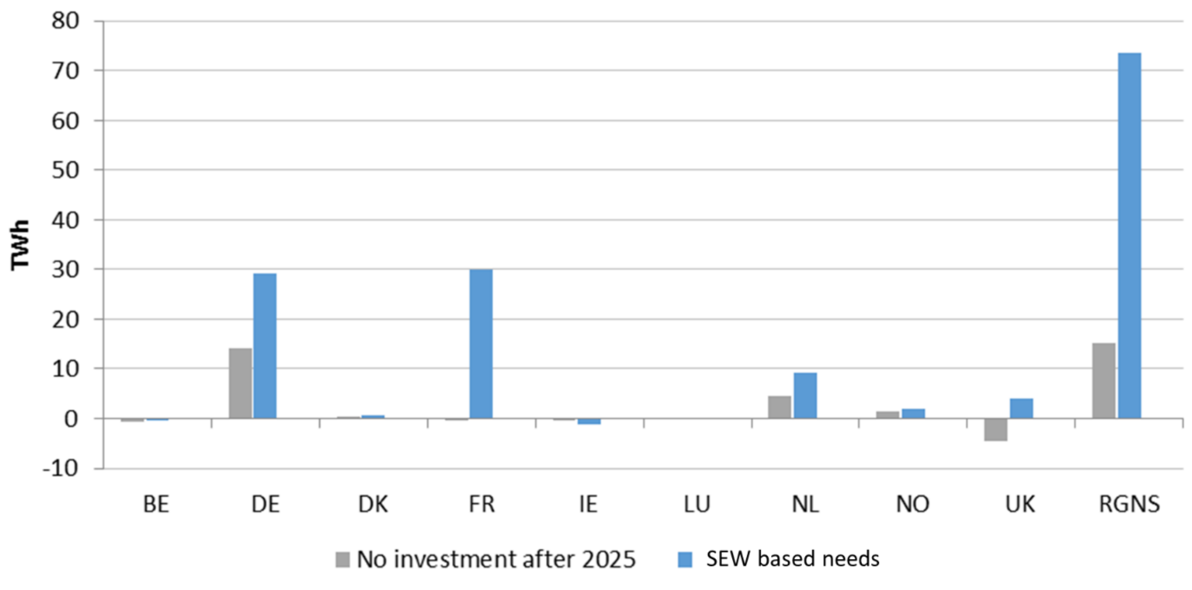


Figure 4.8: Changes in net balance within the Region relative to the 2020 reference grid (positive values represents an increase in net export or decrease in net import)

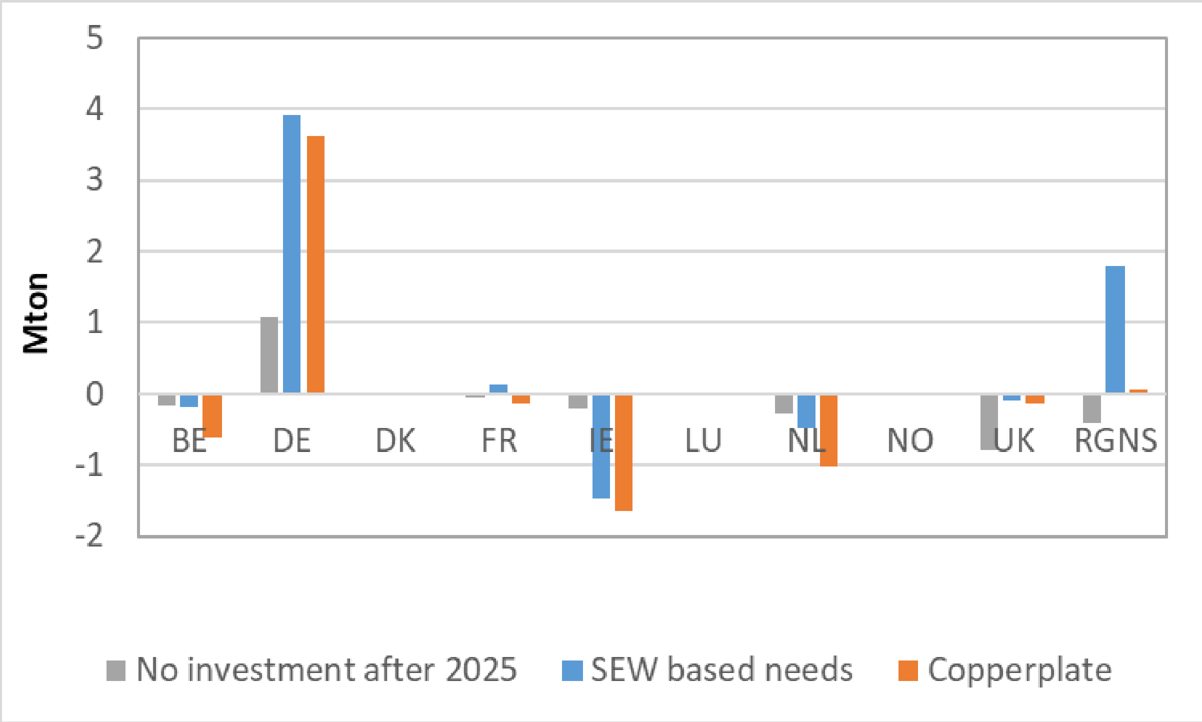


Figure 4.9: Changes in CO2 Emissions relative to 2020 reference grid (positive indicates an increase)

In Figure 4.10 to Figure 4.12, it becomes clear that building more grid by 2030 compared to 2025 (i.e. SEW-based needs or copperplate) that overall average marginal prices will tend to converge, but will actually increase compared to 2025.

This is in line with the increased net export position of the Northern Seas Region in 2030, as shown in Figure 4.8 and the slightly increased CO2 emissions of our Region, as seen in Figure 4.9. It shows that in the 2030 horizon, the Northern Seas Region is likely to displace more polluting and expensive thermal generation from other Regions (Southern and Eastern parts of Europe) with both RES and, at times, more efficient thermal generation. This relative price inflation and CO2 increase effect on sub Region level seems temporary when looking at Figure 4.17 to Figure 4.20 which cover the 2040 horizon. These price and CO2 increases in the region may seem undesirable at first sight, but will ultimately lead to a more optimal European energy system, one which supports and enables CO2 reduction and social economical welfare creation in both the short-term and long-term.

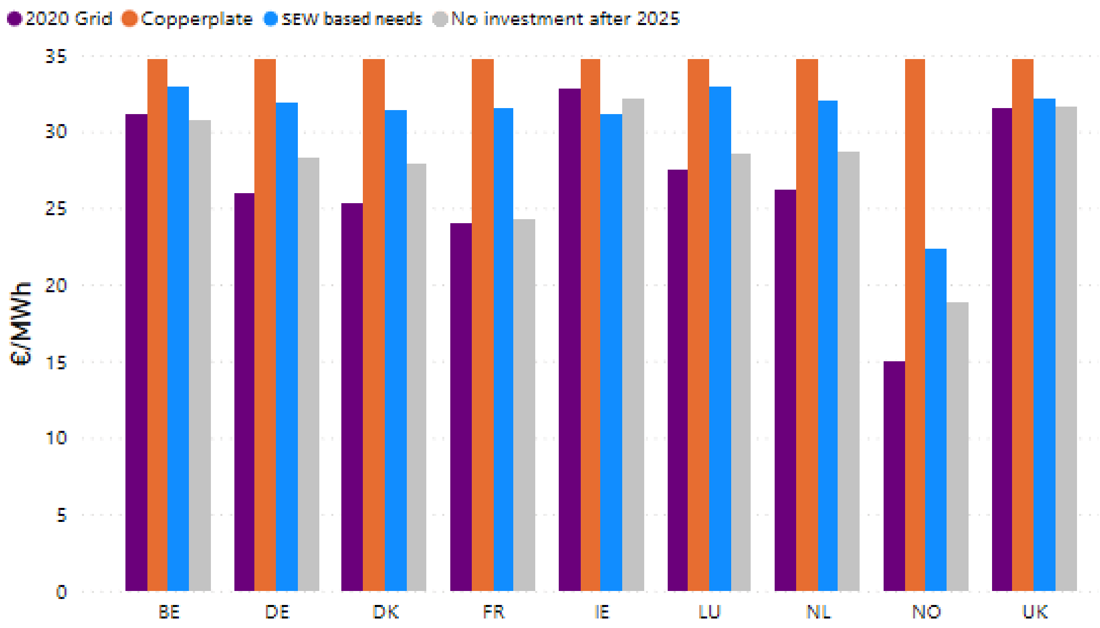


Figure 4.10: Average marginal prices in €/MWh in 2030

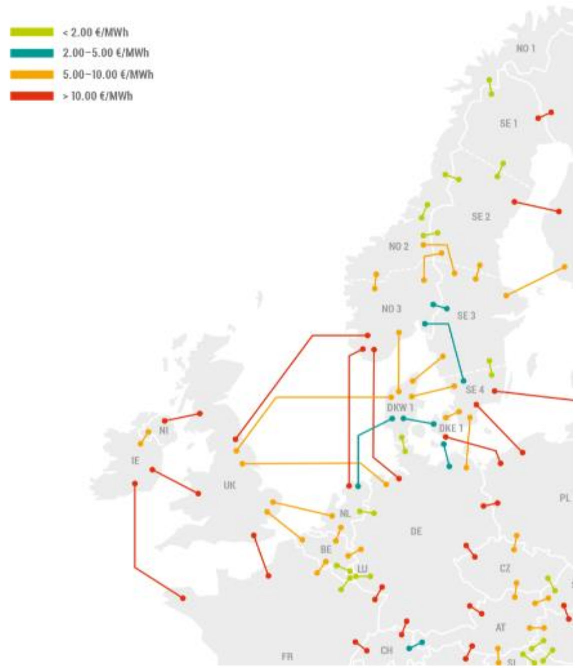


Figure 4.11: Difference in marginal costs between neighbouring bidding zones in 2030 in 'No investment after 2020' case

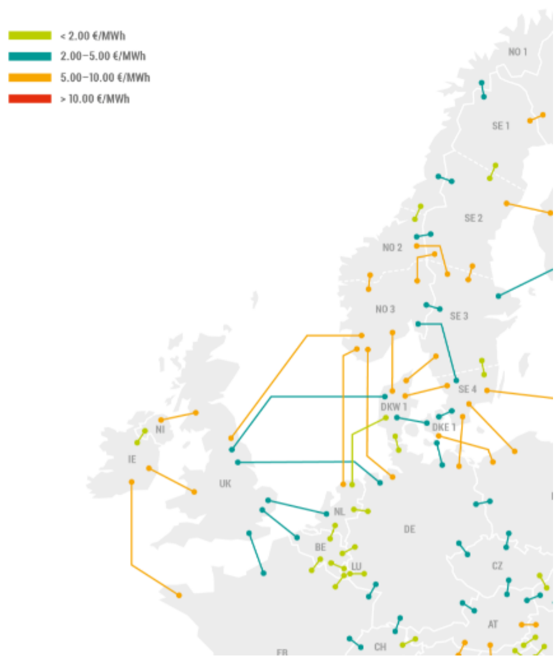


Figure 4.12: Difference in marginal costs between neighbouring bidding zones in 2030 and the SEW-based needs 2030

4.2.2 2040 IoSN

Within the National Trends 2040 scenario, the fuel mix within the Region will be dominated by a large share of variable RES (wind and solar) and hydro power, combined with nuclear energy and gas-powered generation, as shown in Figure 413. Hard coal and lignite production (grouped as 'fossil' in the diagram) play a marginal role. The Northern Seas Region is characterised by significant amounts of variable RES curtailment (Figure 4.14). The total amount of curtailment energy is equivalent to 7% of native demand within the Region in case the 2025 grid will not be expanded.

> Curtailed energy is energy that cannot be accommodated by the system. Momentary generation and demand should be equal at all times. An excess of momentary generation leads to curtailment, and is reported as curtailed energy. A typical underlying reason for curtailment is excess variable renewable infeed in combination with too-low flexibility from demand and nuclear / thermal power stations (often subject to so called 'must run requirements', based on technical or system-service related issues. As such, curtailed energy is offset against variable wind and solar (variable RES) infeed. This curtailed energy can be seen as a potentially CO2-free and a zero-cost energy source. Within the text this curtailed energy is referred to as (potential) variable RES.

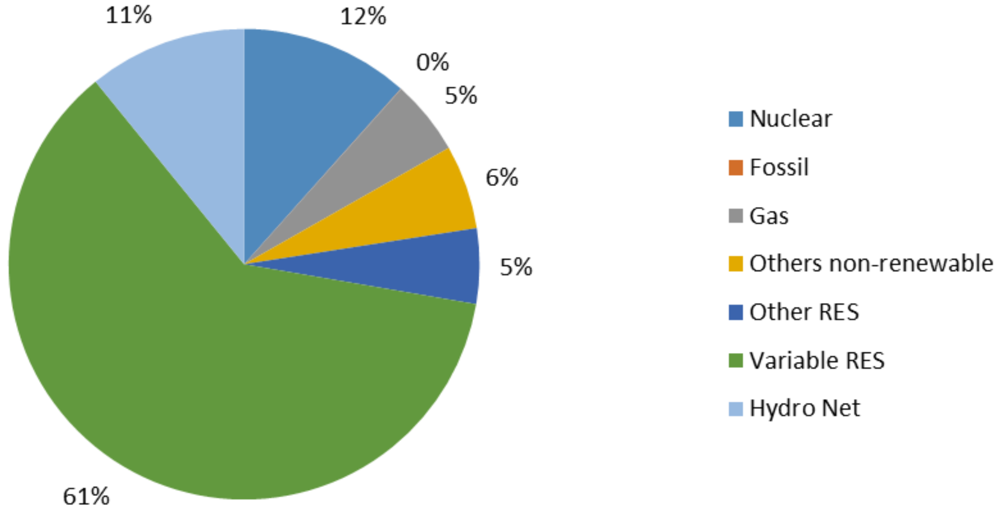


Figure 4.13: Energy mix NT2040 with 2025 reference grid

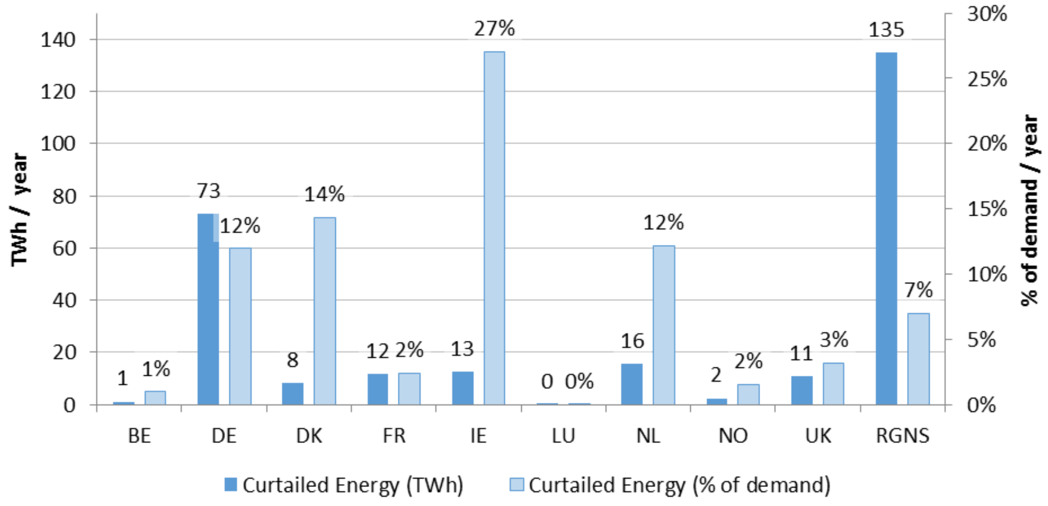


Figure 4.14: Curtailed wind-energy NT2040 with 2025 reference grid

The integration of this potential RES energy is the main driver for interconnections, subject to the condition that these interconnections show a positive cost-benefit assessment. The 'Identification of System Needs' study shows that the SEW-based needs allows for an additional 55 TWh of regional variable RES to be integrated into the system (see Figure 4.15). This 55 TWh is equivalent to about 3% of the regional demand, and has a minor impact on the energy mix of the region.

The SEW-based needs also allows for a small amount of nuclear energy and gas-powered generation (mainly from GB) to displace thermal generation within the system during hours with low RES infeed. Removing any bottlenecks within the European grid (a copperplate) leads to an additional variable RES integration of 99 TWh compared with the 2025 reference grid, which displaces both nuclear and thermal generation.

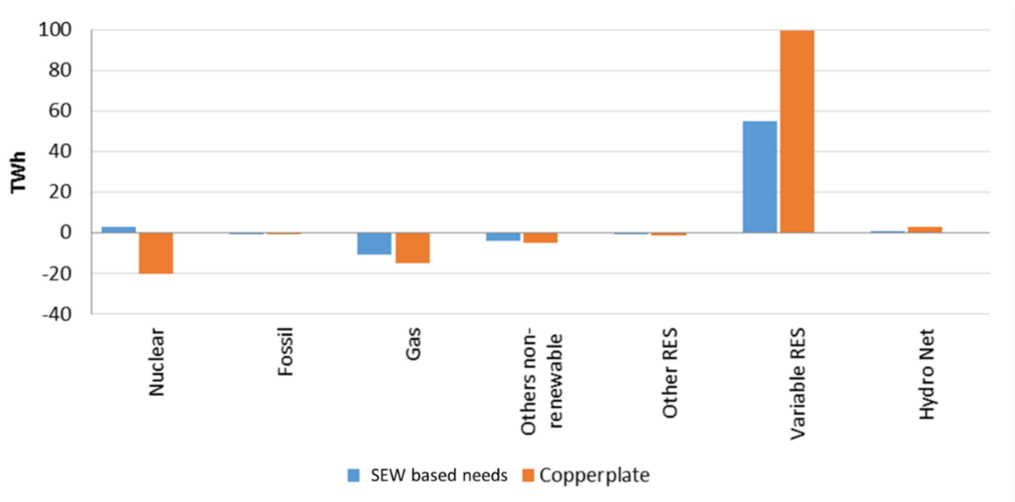


Figure 4.15: Changes in energy mix of the region relative to the 2025 reference grid (positive values represents an increase in generation)

The displacement of thermal generation by variable RES and nuclear power happens both within and outside the region, boosting its net position to 44 TWh (Figure 4.16). The shift from thermal generation towards renewables also implies a reduction of CO_2 emissions within the whole system. In the region, satisfaction of the SEW-based needs leads to 4.2 Mton decrease in CO_2 emissions compared to the 2025 reference grid, as shown in Figure 4.17. Removing any bottlenecks within European grid would see a decrease of 6.1 Mton.

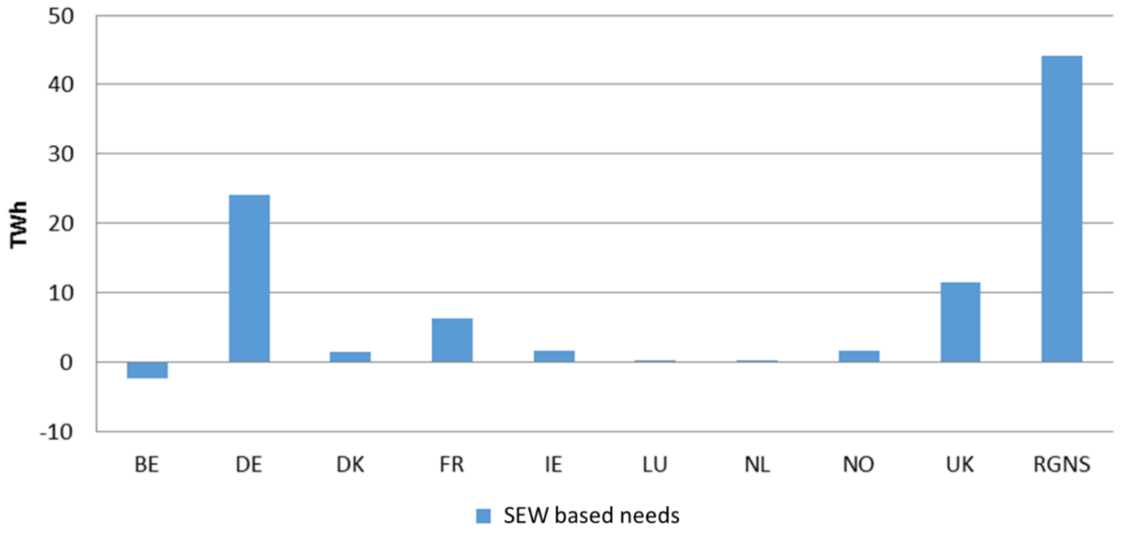


Figure 4.16: Changes in net balance within the Region with the SEW based needs, relative to the 2025 reference grid (positive values represents an increase in net export or decrease in net import)

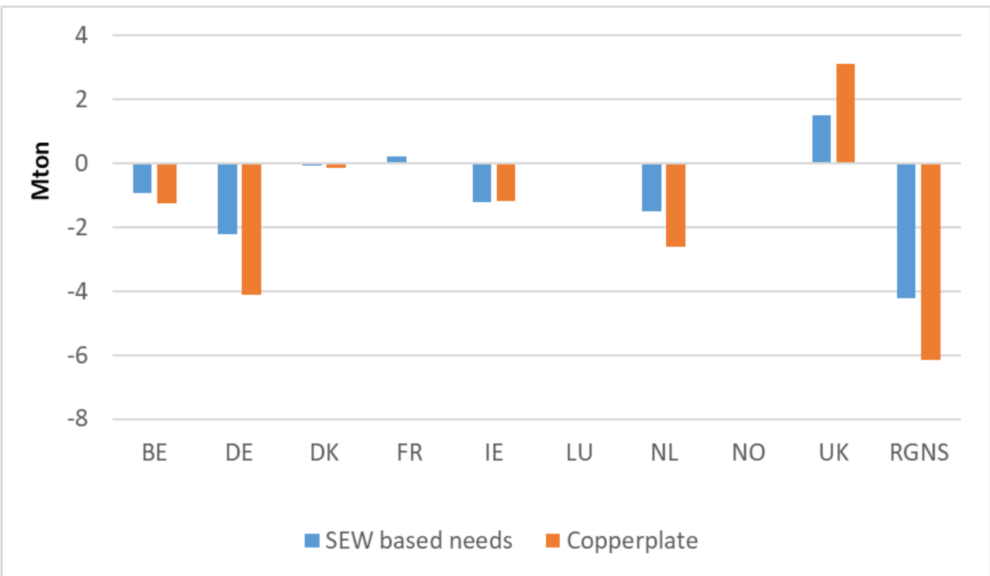


Figure 4.17: Changes in CO2 Emissions relative to 2025 reference grid (positive indicates an increase)

Average marginal prices are expected to decrease and largely converge within the region with the SEW-based needs in place, as shown in Figure 4.18. Without investment after 2025, average marginal prices for most countries expected are to be much higher. As the amount of installed RES in the Northern Seas Region and neighbouring regions grows, together with an increasing level of interconnections within the Region and towards others, the overall average marginal prices further decrease due to greater opportunities for the import and export of power. This is despite increasing marginal costs for thermal generation in 2040 compared to 2030 and despite increasing electricity demand and peak load increases, as can be seen from the NT market scenario assumptions.

By building more interconnections, the RES curtailment avoided increases in both 2030 and 2040, as do the CO2 emissions reductions, but not in a linear fashion. Indeed, the amount of RES in the Northern Seas Region is reaching levels where, in 2040, the already cheap and low carbon-intensive nuclear production seems likely be displaced. In order to further reduce carbon emissions of the Region and consequently the entire European power system, it is likely that more storage technologies (both electrical, like pumped hydro and chemical, like P2X) would be needed. In addition there would be a need for more cross-border grid reinforcements towards those countries with the lowest carbon-emitting potential or where the most promising synergy potential can still be found, considering cross-correlation of RES production with electricity demand.

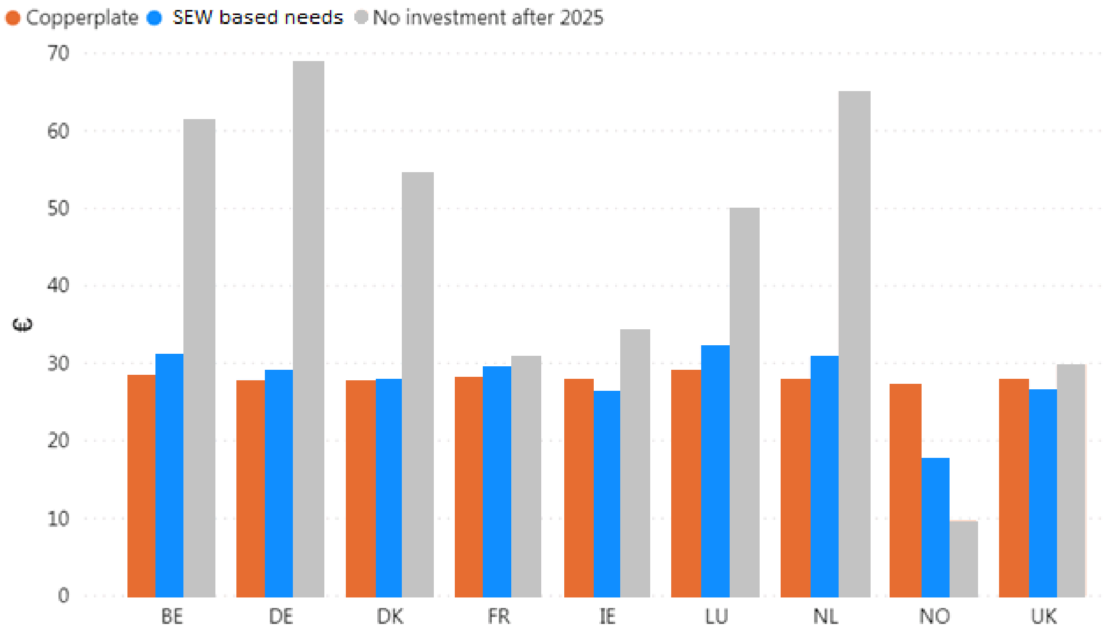
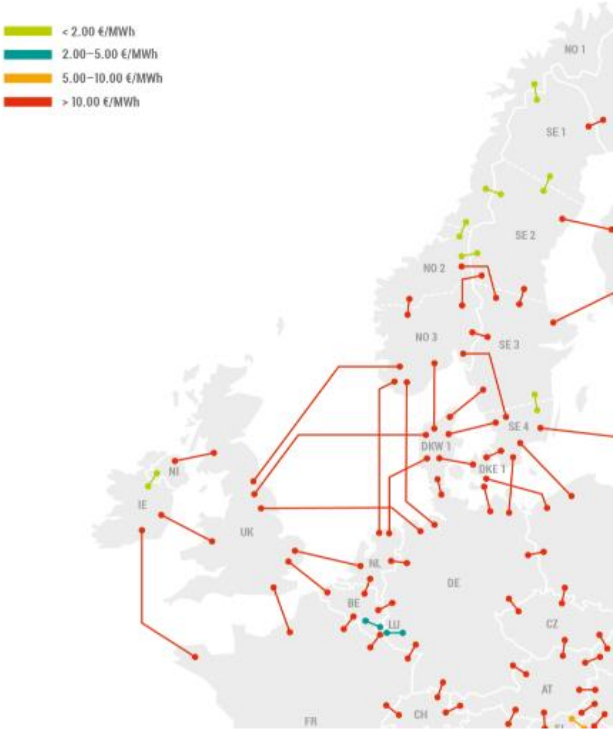


Figure 4.18: Average marginal prices in €/MWh in 2040

Figure 4.19 and Figure 4.20 below show the marginal cost spread between neighbouring bidding zones, leading to the conclusion that satisfying the SEW-based needs leads to significant reductions in price spreads across the region. Not all reductions are immediately visible in the map; for example, the spread between Norway and the Netherlands appears to remain high. However, in reality it is actually is reduced significantly from a level of about EUR 60 /MWh to a level of just about EUR 10 /MWh. The same is valid for the spread between Ireland and France, which reduces from EUR 39 €/MWh down to EUR 13 /MWh. Nevertheless, zeroing electricity market differences between neighbouring countries is not an objective in itself, as local conditions and grid development costs must be taken into account.

The calculation of the 'average marginal prices' and 'differences of marginal costs between neighbouring bidding zones' differs: The 'average marginal prices' refer to a country, whereas the cost-spreads refer to the interaction between two bidding zones.



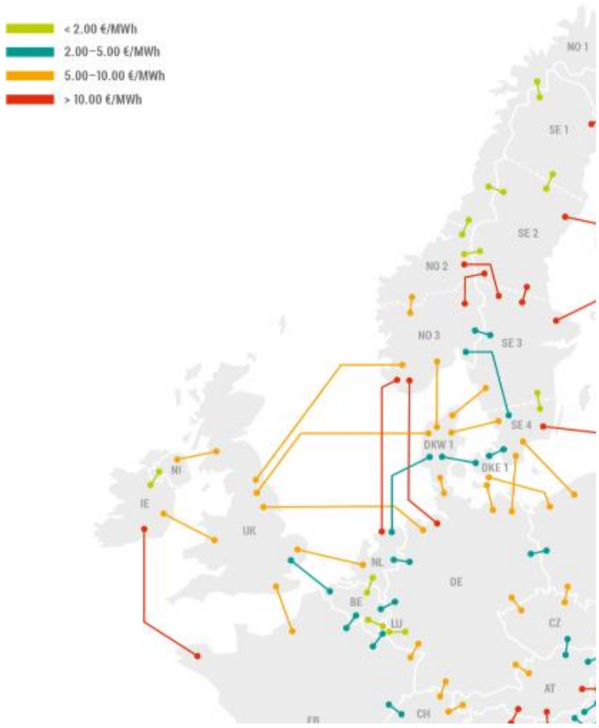


Figure 4.19: Difference in marginal costs between neighbouring bidding zones in 2040, in 'No investment after 2025'	Figure 4.20: Difference in marginal costs between neighbouring bidding zones in 2040, in the SEW-based needs 2040

4.1 Network Results

4.1.1 2030 IoSN

For IoSN 2030, no grid studies have been performed to complete the market analysis based on a NTC model. It is not possible to give a view on specific constraints on the grid, particularly on the internal grid.

4.1.2 2040 IoSN

For IoSN 2040, the zonal model approach gives a view on the grid constraints, even on potential internal bottlenecks, but such information is highly dependent on the granularity of the zones.

Additional internal reinforcements are needed to make the NT scenario feasible from the network point of view. This implies integrating considerable amounts of additional renewable power generation and to accommodate both new power flows profiles and higher volumes, both internal and cross border.

For the German system, the need to reinforce the North-South axis is confirmed, as the reference grid does not include the internal HVDC projects except Ultranet.

For the French system, the analysis carried out in the framework of the TYNDP 2020 IoSN confirms some areas of fragility on the French network. These had already been identified in the French national development plan although with a higher level of congestion, due to a more advanced energy transition (2040 horizon in the TYNDP vs. 2035 in the French national development plan) and an increase in exchange capacities on all borders.

An expert analysis was carried out to integrate the costs of internal reinforcements into the IoSN analysis. Nevertheless, the extent of internal reinforcements is highly dependent on many variable factors whose level of granularity is finer than that of the IoSN analysis: the precise location of RES generation and nuclear decommissioning, for example. Furthermore, while it is possible to estimate the impact of a cross-border reinforcement on the internal network, it is much more complex to anticipate the impact of a set of reinforcements such as the one found in the IoSN analysis. Here, almost all the borders revealed a strong need for reinforcement, without a more in-depth study. Such a detailed study would require the prior confirmation of certain assumptions concerning energy transition in France and its neighbouring countries.

A limited amount of internal projects are already included and assessed in TYNDP 2020, and there are some projects presented in Chapter 6 as regional projects that would allow solving some of these future problems. However, it is too soon to define the reinforcements needed for 2040 in detail, as the volumes of RES and the precise location of generation in the region should be more clear.

4.2 Comparison of the results between the two publications (IoSN 2018 vs 2020)

Comparing IoSN2018 (Figure 4-21 and Figure 4-22) with IoSN2020 results (Figure 4-23) with the same zonal modelling approach, the main factors that strongly affect the results and provide the main reasons for the differences in the results are the market scenarios themselves (and the climate year under consideration). Additionally, the reference grid used in 2017 was based on the 2020 time horizon, while the TYNDP 2020 uses a reference grid based on the 2025 time horizon. The TYNDP 2020 reference grid is more conservative, i.e. it includes fewer interconnections compared to the previous TYNDP edition, resulting in higher capacity needs for the 2040 horizon across the total system.

Although the results of both IoSN studies show some differences, ENTSO-E considers them consistent, confirming the usefulness of the zonal methodology approach. The methodology still requires continuous evolution, improvement and consistency checks in future IoSN releases.

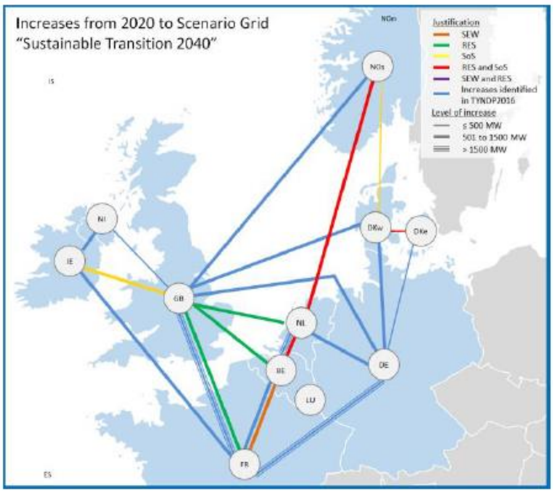


Figure 4-21: IoSN 2018: NTC Model

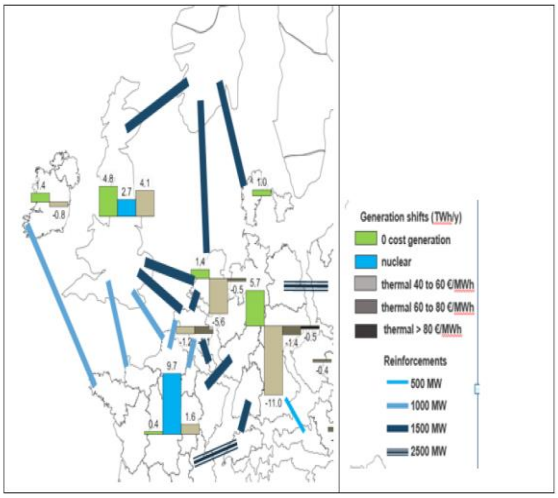


Figure 4-22: IoSN 2018: Zonal Modelling Test

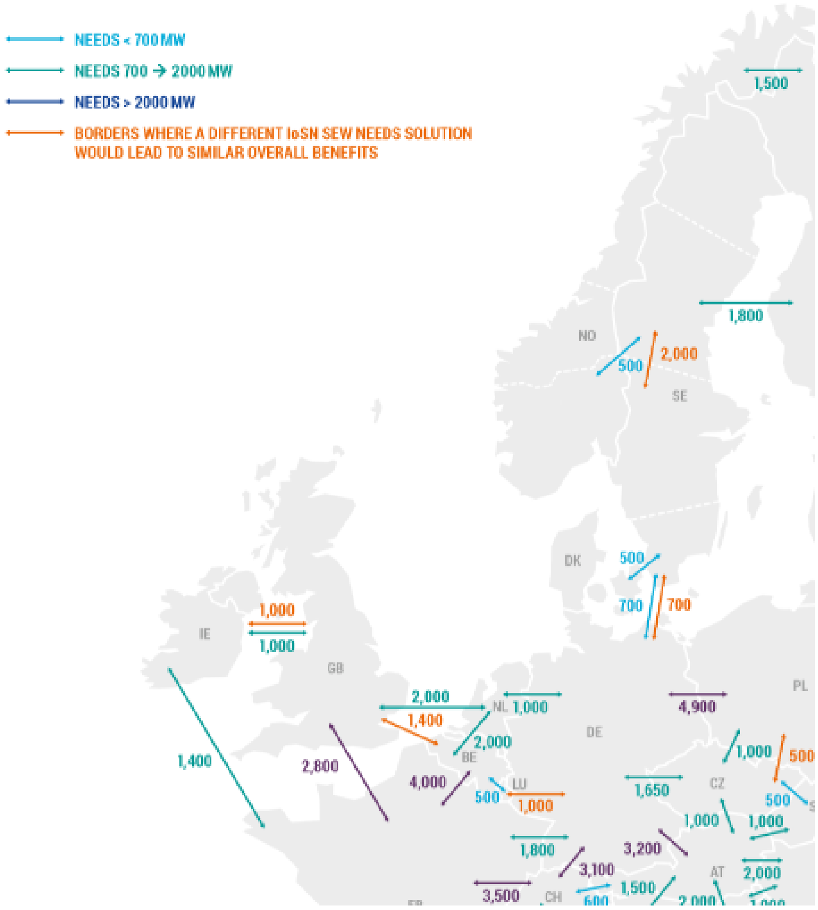


Figure 4-23: IoSN2020 – 2040 needs compared to 2025 reference grid

When zooming in on the Northern Seas Region, following observations are noteworthy between and within the Synchronous Areas. These are based on Figure 4-21, Figure 4-22 and Figure 4-23 above, comparing IoSN2040 needs from RegIP2020 to RegIP2018 for the National Trends (NT) & Sustainable Transition (ST) market scenarios:

GB-CE:

- Total additional interconnection needs by 2040 have grown in IoSN2020, with 0.4GW to 1.8GW compared to IoSN 2018 to further integrate GB with CE. This is likely driven by increased generation mix (RES & non-RES) complementarity – allowing for further SEW increases. The amount of RES production in the NT market scenario considered increased compared to the ST scenario from IoSN2018 whereas the amount of coal production has decreased.

NO-GB/CE:

- Seemingly 1.4GW less need between NO-CE and no more additional needs for NO-GB. It seems other, more indirect (longer) pathways to integrate the Norwegian hydro power energy (excess RES) into the GB / CE systems could also be beneficial to the system, for instance via Sweden / Finland and the Baltics, or indirectly via GB. Such a conclusion is, of course, highly dependent on the accuracy of the estimated internal reinforcement costs and those of the interconnections themselves for the considered grid projects in the IoSN exercise. In any case, it seems that large price spreads and hence opportunity for socioeconomic welfare gains remain between the interconnection of NO with GB/CE, which might be captured in future with reduced project costs.

CE:

- Mainly relatively higher integration of France with neighbouring bidding zones – an additional 0.5GW up to 3GW on certain individual bidding zone borders in IoSN2020 compared to IoSN2018. This is likely due to differences in the NT scenario in IoSN2020 compared with the ST scenario in IoSN2018 in terms of level of nuclear production. Around 10GW of additional nuclear capacity would remain in the NT scenario compared to the previous ST scenario, as a result of the most recent policy changes in France.
- Depending on the further evolution and implementation of market rules, the number of additional interconnections needed might differ - in particular in relation to the current minRAM 70% rule of the Clean Energy Package.

GB-NO-CE:

- As mentioned in Section 5.1, the IoSN 2020 model setup assumes implicit radial connections for the additional offshore wind generation. The potential development of hybrid projects and multi-terminal solutions in the Northern Seas Region, will also drive the level of interconnection required between and within synchronous areas, which is currently insufficiently captured by the IoSN 2020 methodology.

Island of Ireland-GB/CE:

- The identified needs in 2018 and 2020 are broadly similar. There is a continued need for further interconnection between the island of Ireland and France, and the island of Ireland and Great Britain. It is important to note that Ireland and Northern Ireland form a unitary wholesale electricity market area known as the Single Electricity Market (SEM). Therefore, the needs identified between the island of Ireland and Great Britain could be satisfied by capacity increases in either Ireland or Northern Ireland.

5. ADDITIONAL REGIONAL STUDIES

5.1 Northern Seas Offshore Grid Infrastructure

5.1.1 Anticipating the Future

The European Commission's 'Clean Energy Package' and the 'European Green Deal' anticipate the increasing role of offshore wind power in the decades up to 2050. The Northern Seas are expected to host the majority part of this, as they do already. However, offshore development is only one of multiple aspects that need to be considered when developing future energy systems.

Currently, around 20GW of offshore wind capacity is installed in the Northern Seas, comprising the North Sea, the Irish Sea, the English Channel, Skagerrak and Kattegatt. In June 2019, the ministries of the adjacent Northern Seas countries agreed on an offshore level of 70GW for these waters by 2030. ENTSO-E refers to these waters, as the wind generation will be connected to the RGNS countries causing related flows across the region.

According to the Commission's 1.5 Long Term Strategy, European offshore wind capacities are going to increase to ~400-450GW (1.5 Life and 1.5 Tech) by 2050. WindEurope assumes a share of up to 212GW being installed in the North Sea basin.[8]

These prospects imply a potential tenfold increase over the next 30 years. WindEurope points at the necessity to accelerate the installation rate from today's 3.6GW in 2019 to 7GW/yr by 2030, and 18GW by 2050 to reach 450GW in European waters.[9] It is obvious that unprecedented grid and spatial[10] planning, engineering, construction and financing efforts will be required offshore to facilitate the large-scale roll-out of offshore wind and other offshore RES.

Thus, time pressure is high, both on offshore generation developers and on infrastructure developers. The European onshore electricity infrastructure has been built within a century, while offshore electricity and the necessary onshore grid extension is expected to be in operation in only a few decades. This requires holistic planning of concepts and infrastructure building over time, space and sectors.

The region is undergoing massive changes in its overall production portfolio, as onshore electricity production will also change, with fossil power plants being closing or changing fuel by 2040, when - according to the European "Clean Energy Package" - the power system has to be free of fossil resources. At the same time, decarbonisation of other sectors will evolve. All these developments imply massive changes in electricity flows across Europe and the need for infrastructure and other means to use offshore wind energy efficiently. These other means will cover, for example, market arrangements, sector integration including P2G and P2X.

Since the day wind energy was introduced into electricity systems, the distance between electricity generation and the consumer increased. This trend will continue due to growth in offshore wind production with increasing distances to shore – implying increasing average connection costs - as available nearshore areas

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[8] *WindEurope, Report "Our energy, our future" November 2019: https://windeurope.org/wp-content/uploads/files/about-wind/reports/WindEurope-Our-Energy-Our-Future.pdf*

[9] *Press release 6.2.2020: https://windeurope.org/newsroom/press-releases/europe-installs-a-record-3-6-gw-of-offshore-wind-in-2019/*

EU Directive on Maritime Spatial Planning (2014/89/EU).All coastal EU MSs have to prepare cross-sectorial maritime spatial plans by 2021 have already been exploited. Space for offshore wind generation and cable routing to shore is limited, due to the need to preserve maritime biodiversity and uses. The same is valid onshore, as electricity must be further transported to the consumer in a way consistent with offshore grid developments. During system development, it is also important to consider that the lead time for offshore generation is shorter than that for infrastructure, and that operation will be impacted by variable production patterns that will need to be considered during planning.

Besides technical and regulatory issues, the main challenge will probably be the public acceptance of the required new infrastructure. The general public is convinced of the need and utility of greener energy, but expects to be involved from the early onset of new infrastructure developments. Although TSOs are committed to increasing public participation and minimising the environmental footprint of on- and offshore infrastructure, this puts increasing pressure on the timing, as new infrastructure is often not accepted easily.

The TYNDP 2020 scenarios reflect the above offshore developments as they have been agreed by the ministries of the NSOG region.[11] For RGNS countries, the scenarios add up to 78GW offshore wind by 2030 and up to 114GW by 2040. The NT 2030 and GA 2030 are, for the next decade, on track with the ministerial agreement, while DE2030 is below this level, as shown in Figure 5.1.

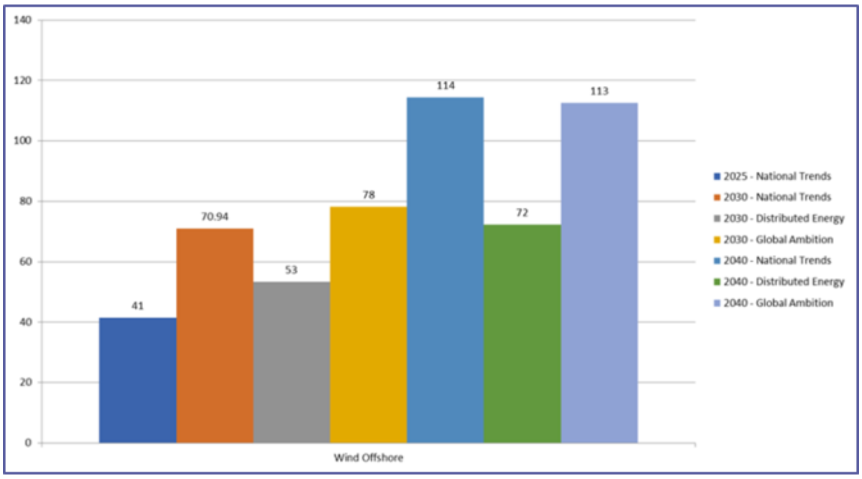


Figure 5.1: Offshore wind in RGNS Countries – (no distinction between different waters)

Table 5-1 shows the installed offshore wind capacities per scenario broken down for each country considering the sea basins as described above.[12]

Compared to the TYNDP18 scenarios, showing a spread of 40-60GW in 2030 and of 85-127GW in 2040, the development in this year's edition assumes higher installation rates in the next decade but is less optimistic for the second decade to come (Table 5-1).

[11] *NSOG = Northern Seas Offshore Grid. This Corridor is defined in the TEN-E regulation 347/2013 and comprises countries around the Northern Seas: Belgium, Denmark, France, Germany, Great Britain, Ireland, Luxembourg, Netherlands, Northern Ireland, Norway, Sweden*

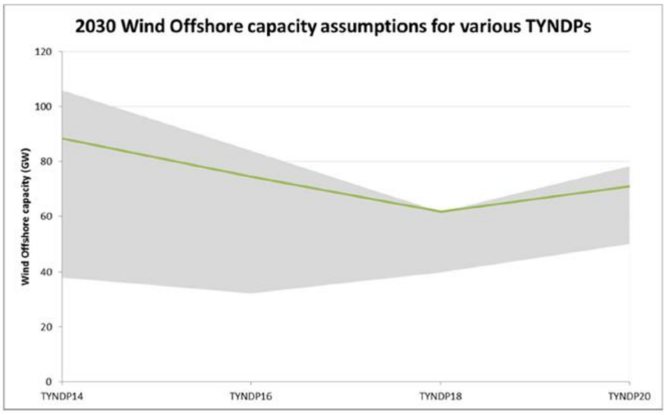
[12] *The waters differ from WindEurope's publications, where numbers refer to the North Sea basin only.*

Table 5-1: Offshore Wind in Northern Seas waters in the ENTSO-E scenarios – direct electricity usage only. Capacities for hydrogen and derived fuels production are not included in this table (see also Chapter 3.3.3.)

[MW]	Today[13]	NT 2025	NT 2030	DE 2030	GA 2030	CT2030	NT 2040	DE 2040****	GA 2040****
BE	1,556	2,271	4,271	4,300	5,301	2,300	6,072	6,200	6,030
DE*	7,445 (~= 6445 NS + 1000 BS)	10,464	16,717	17,000	20,000	16,717	34,902	20,000 (BS: =2.4GW)	23,229 (BS: 2.4GW)
DKW**	1,700 (= 1280 NS + 420 BS)	1,600	3,100	3,065	3,687	3,065	6,100	6,135	8,235
FR00***	2	2,920	4,920 (=2,5 NS+ 2,42 AO))	3,000	4,920 (=2,5 NS+ 2,42 AO))	3,000	8,364	5,000	12,400
GB	9,945	17,635	24,800	17,635	29,935	17,635	34,995	21,035	36,765
IE	25.2	30	3,500	1,030	1,530	1,000	4,800	1,280	1,900
NI	0	0	300	0	0	0	470	0	0
NL	1,118	5,200	11,300	6,720	10,000	4,500	16,151	5,900	16,500
NO	2.3	0	0	0	136	0	0	0	0
Sum NS	**21,796**	**40,120**	**68,908**	**52,750**	**75,509**	**48,217**	**111,854**	**65,550**	**105,059**

* BS projects excluded ** Kriegers Flak (KF) & DKE excluded *** Figures are for French waters from Mediterranean to North Sea (when specified : NS= North Sea, AO = Atlantic Ocean). **** no distinction between waters

As RES generation develops in line with the 2030 targets and reflects political policy at a national level, a trend observed from TYNDP 2014 to TYNDP18, with decreasing assumptions on offshore wind capacity reversed in TYNDP20 scenarios and increases to TYNDP16 levels of about 70GW. While the uncertainty of the range across several editions of the TYNDP decreases (grey area Figure 5.2), the bottom-up scenarios show a decreasing trend, which turned slightly upwards for this year's edition. The reason may be decreasing costs, allowing the installation of wind farms located further from shore.



13 Source (without distinction of Northern Seas / Baltic Sea): https://windeurope.org/wp-content/uploads/files/about-wind/statistics/WindEurope-Annual-Offshore-Statistics-2019.pdf

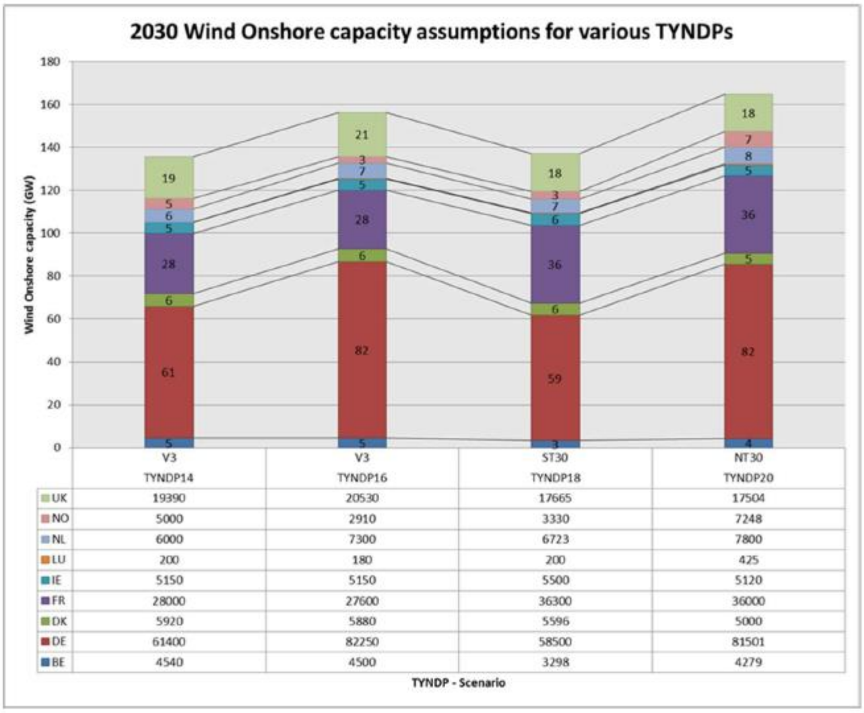
Figure 5.2: Assumptions on offshore capacity from TYNDP14 to TYNDP20

In 2011, ENTSO-E came up with its first analysis on offshore development, concluding that - for the investigated scenario including 83GW of offshore wind in the Northern Seas by 2030 -the region would benefit from coordination in order to harvest potential synergies and savings. These conclusions have been further refined in the joint study performed by RGNS for the Northern Seas countries' offshore grid initiative (NSCOGI) in 2012, investigating offshore levels between 55GW and 117GW in 2030.

Since then, several studies, political initiatives and projects have evolved. A short summary has been given in the RGSN RegIP 2017[14] and the NSOG report 2018[15].

ENTSO-E always also considers offshore generation development and related investigations which are ongoing on national level. Many countries are investigating several scenarios, including a spread of offshore wind generation capacities. These scenarios are used to prepare the onshore grid on time to be able to further transport the energy to the consumer. As lead times of offshore wind production is shorter than lead times for onshore infrastructure development, TSOs prepare for long-term planning and coordinate inside ENTSO-E to develop robust solutions.

Figure 5-3 shows that the bottom-up collected "best estimate" assumptions on the future do not vary over time, both for offshore development and related to onshore development. While the overall estimate increases over time, there appeared to be, however, a 20GW decrease for this region in TYNDP18 estimates, mainly caused by modified German figures.



	V3 TYNDP14	V3 TYNDP16	ST30 TYNDP18	NT30 TYNDP20
UK	19390	20530	17665	17504
NO	5000	2910	3330	7248
NL	6000	7300	6723	7800
LU	200	180	200	425
IE	5150	5150	5500	5120
FR	28000	27600	36300	36000
DK	5920	5880	5596	5000
DE	61400	82250	58500	81501
BE	4540	4500	3298	4279

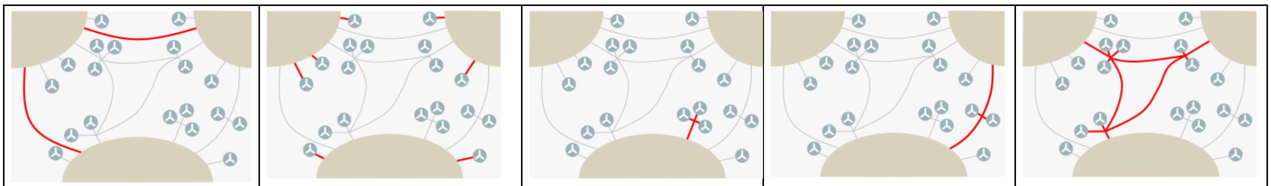
[14] https://docstore.entsoe.eu/Documents/TYNDP%20documents/TYNDP2018/rgip_NS_Full.pdf

[15] https://tyndp.entsoe.eu/Documents/TYNDP%20documents/TYNDP2018/consultation/PCI%20Region/ENTSO_TYNDP_2018_NSOG.pdf

Figure 5.3: Assumptions for onshore capacity across various TYNDPs – bottom-up scenarios

5.1.2 Modular Design

Building on joint investigations on offshore grid infrastructure, ENTSO-E expects that the Northern Seas Offshore Grid Infrastructure will be composed of various technologies (AC and DC) and of various designs developing in parallel, as shown by the principle sketches (Elements of the Offshore grid infrastructure (c.f. NSCOGI study 2012)[16].



i) Point-to-point IC	ii) Radial offshore park-to-shore	iii) Radial hub-to-shore	iv) Hybrid project	v) Multi-terminal offshore hubs

Figure 5-4: Elements of the Offshore grid infrastructure (c.f. NSCOGI study 2012)

The above designs can also be understood as development stages: real examples for stages i) through iv) already exist, for iv) as an initial pilot and projects in planning, while examples for stage v) multi-terminal offshore hubs do not yet exist (Figure 5.5). Designs iii) through v) can also comprise solutions including other forms of energy (eg, energy hubs including sector integration solutions or substituting offshore petroleum consumption at oil platforms).

Steps i) through iii) have been applied during the last decades. Step iv), the hybrid solution, is seen in pilot projects such as Krieger's Flak CGS, while other hybrid projects are in the planning phase (North Sea Wind Power Hub (NSWPH). The higher the wind power, the greater the need for options of where to send, or where use, the energy. Smart sector integration will increasingly be applied in this context (see Chapter 5.2).

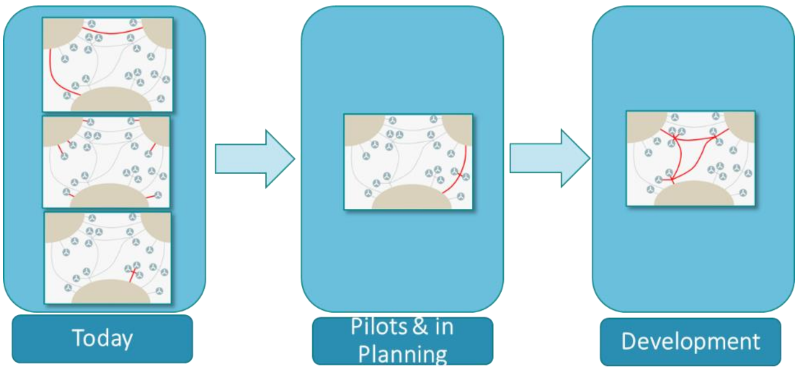


Figure 5.5: Potential development of offshore grid infrastructure (flow chart).

[16] *See 'ENTSO-E Position on Offshore Development, May 2020' [link].*

The grid developments of the Northern Seas may serve as an example. These above developments could evolve in the Northern Seas to something similar to what is shown in the map below (Figure 5-6):

i. Country-to-country subsea interconnections

ii. Radial offshore wind connections (single park) to shore

iii. Radial offshore wind connections (several parks via hubs) to shore

iv. Hybrid projects, (combination of offshore wind connections and interconnections), and

v. Multiterminal offshore platforms combining interconnections (with or without offshore wind being connected).

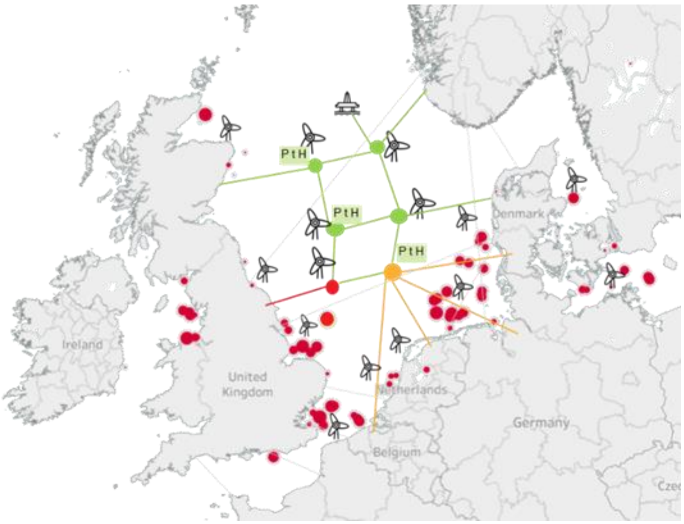


Figure 5-6: Potential development of offshore grid infrastructure (principle sketch, red dots represent existing OWFs).

For the modular and stepwise offshore grid development, ENTSO-E expects that choices will be made on a case-by-case basis, evaluating technical and economic parameters.

However, alongside this organic growth, decisions always also include a long-term system view, and are therefore to some extent influenced by assumptions on developments of the overall system. With these, regularly updated TYNDPs - an overview of infrastructure developments and projects for a long-term time horizon - are given, thus ensuring that infrastructure planning in relation to offshore grid developments is supported.

A compact hybrid offshore design could be envisaged in some cases, where the scheduling and technology required for interconnection and wind connection (DC or AC / voltage level) are matched. In any case, the cooperation between all stakeholders of all countries involved is essential.

During the last two years, the potential to use hybrid projects has been further investigated in a consultancy study[17] performed for the North Seas Countries Energy Collaboration (NSEC). This identified five out of 20 potential hybrid projects, with an aim at four being completed by 2030. The NSEC seeks to pave the way in their current workplan from 2020 onwards.

[17] *https://ec.europa.eu/energy/en/studies/hybrid-projects-how-reduce-costs-and-space-offshore-developments*

5.1.3 Needs Identification and its Limitations

Figure 5.7 shows the results of the 2030 IoSN analysis against the 2025 Reference Grid. As many projects will already be built before 2025, there are not many projects that cross the Northern Seas by 2030. Further corridors need to be expanded by 2040, as shown in Figure 5.8. Results confirm the 2030 needs, which are complemented by further connections.

In both figures, it is obvious that the need for hybrid projects - i.e. the combination of interconnections and offshore generation units - is not identified in both time horizons. The reason for this is that the current IoSN methodology has been designed to assess cross-border reinforcement needs, not to identify these project types.

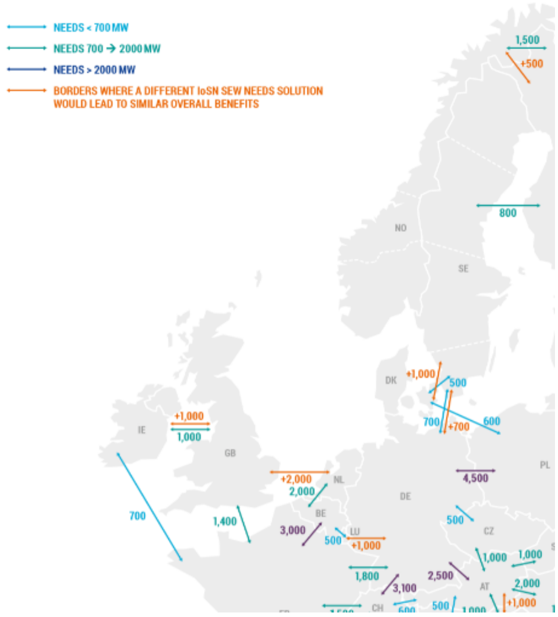


Figure 5.7: IoSN - SEW based needs 2030 (in MW) – and additional good capacity increases

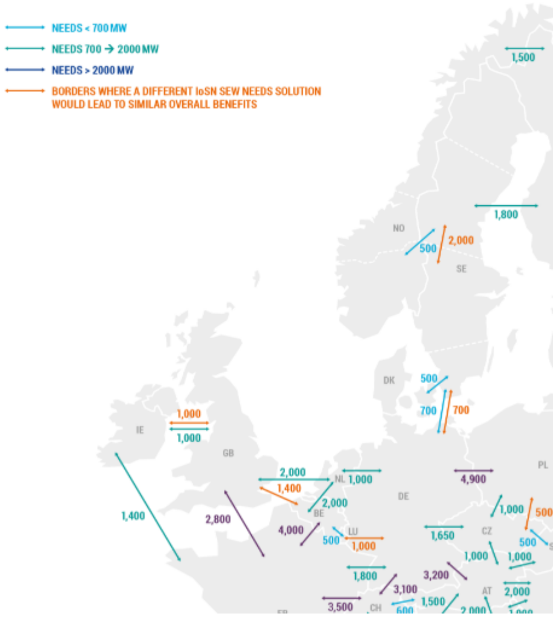


Figure 5.8: IoSN - SEW based needs 2040 (in MW) – and additional good capacity increases

For the IoSN study, the generation capacities for offshore wind are part of the scenarios, meaning that connection costs are treated as externalities, which may represent a high deviation from overall cost optimality. The study does not focus on the optimal connection of (all types of) generation, as this is not part of the current ENTSO-E mandate.

However, the results of the current IoSN study, merged with detailed information of offshore power plants, will allow project promoters to define new, potentially hybrid projects, thus proposing new steps towards future modular offshore grid infrastructure. The benefits delivered by these types of projects, with the details of the offshore power plants, will later be assessed in the cost-benefit analysis process of the TYNDP.

TSOs have the responsibility for ensuring that combined networks across land and sea are developed, built and operated in a secure, cost-efficient and sustainable way. Their responsibility covers the application of a long-term global system view comprising the complete generation portfolio (rather than a single generation type only) and considering technology developments, while also planning and coordinating across borders.

With the TYNDP, ENTSO-E delivers the reference for holistic and integrated on- and offshore grid planning. However, considering the expected increase in offshore generation capacities, future TYNDPs may analyse the offshore grid infrastructure in more detail. Methodologies would need some related development, eg, consideration of all benefits of these different project types should properly be ensured. For the identification itself, a different methodology would need to be applied. RGNS provided a study to NSCOGI in 2012. The same methodology has been applied in the Horizon 2020 Research project, "PROMOTioN[18]". These changes come on top of other methodology adoptions triggered by the requirements derived from the Clean Energy Package, such as consideration of internal bottlenecks during NTC calculation and the evolution of a flow-based modelling. This should optimally be done with a range of simulation tools on several scenarios that are representative of a sufficient spread in order to deduce robust messages. What can be delivered practically is often closely linked to the time and resources available for the simulations.

The above is also clearly reflected in ENTSO-E's recently published, 'Position Paper on Offshore Development'[19] from May 2020, stating that key positions on necessities are:

- Holistic planning over time, space and sectors and timeliness:
    - Holistic planning and coordinated development of on- and offshore transmission systems are needed to ensure timely development, low costs for end consumers and electricity systems that are both technically sound and environmentally friendly.
- A modular and stepwise approach based on consistent planning methods:
    - This is necessary to achieve an integrated European maritime transmission network, including pooled assets such as hybrid projects. This regional investment plan provides a regularly updated and consistent planning support tool.
- Interoperability unlocking smarter integrated and secure system operations:
    - With an increasing share of variable generation, a *one system* view of both on- and offshore is essential for preserving the required security margins in the system while enhancing smart solutions. ENTSO-E and TSOs will continue to carry out fundamental system engineering studies and standardisation in order to achieve vendor interoperability of offshore HVDC systems.
- Keeping energy bills and environmental footprint low through innovation:
    - Several innovative cost and environmental footprint-reduction measures have already been identified (eg, standardisation, hubs, hybrid projects, multiuse platforms) and implemented by TSOs. Further solutions and cooperation will be developed in order to meet common climate targets and reduce costs.
- A future-proof regulatory framework.[20]

To facilitate the implementation of the abovementioned pillars, ENTSO-E calls on policymakers to ensure that:

- The application of **consistent unbundling rules** for on- and offshore systems in order to ensure neutrality, non-discrimination, fair competition and security of supply.
- Regulatory frameworks of different Member States should **incentivise forward-looking and anticipatory investments**, and must be made mutually compatible.

[18] *See project homepage: https://www.promotion-offshore.net/*

[19] *ENTSO-E Position on Offshore Development. https://www.entsoe.eu/2020/05/29/entso-e-position-on-offshore-development/*

[20] *the Commission has recently opened the TEN-E-regulation.*

- **Governments provide confidence** in market- and system-operation setups, in order to provide a robust framework and financial security for investors. The allocation of responsibility for grid development and operation to TSOs is consistent with a holistic and 'one system' approach and provides transparency for investors.
- **Regarding hybrid projects**, flexible rules concerning the contribution by each member state to European climate targets should be developed. The concept of offshore bidding zones may be a promising solution as it could facilitate efficient integration into the electricity market of offshore generation connected to two or more bidding zones, also if connected as a hybrid project under current regulatory and legal framework.

5.1.4 Operational challenges

The long-term planning view is strongly connected to operational aspects, ensuring proper functioning of the overall system which comprises assets that span decades.

The Northern Seas Region is already today characterised by relatively high variable RES shares. Some countries even experience the amount of installed capacities of variable RES (wind and PV) in the range of peak demand, creating some challenges for balancing the system. This is valid for, eg, Denmark, where vRES installations exceed the peak demand (110%), or the Island of Ireland with 78% (Table 5.2). However, both areas differ fundamentally in their operational options to balance the system; DK is much more strongly connected to its neighbours (same level of interconnections and storage capacity versus peak demand), while the Island of Ireland can work with 41% interconnections and storage. Both areas still retain the same amounts of non-variable generation (120% and 125% respectively).

Table 5.2: Penetration level: Installed capacities vs. peak demand

		today	
[%]	Non-variable Gen	Variable Gen	Interconnections & Storage
DK	~120	~110	~100
IE+NI	~125	~78	~41

The countries of the Northern Seas Region expect increasing levels of variable RES related to peak demand, as indicated in Figure 5-9. This means that operational aspects concerning both balancing and stability and security issues get more attention as well, and phenomena, which are experienced in small systems such as on the Island of Ireland, will spread across larger areas (see also Chapter 5.3).

The expected offshore developments and system operation (onshore and offshore) must be integrated and optimised as a single system, applying similar methodologies and approaches. An integrated "one system" approach is a prerequisite for ensuring secure and long-term, cost-efficient system operation. It helps to identify the needs and realise the potential for system flexibility, in order to manage variability of RES generation and loads, and ensuring the required security margins of the system.

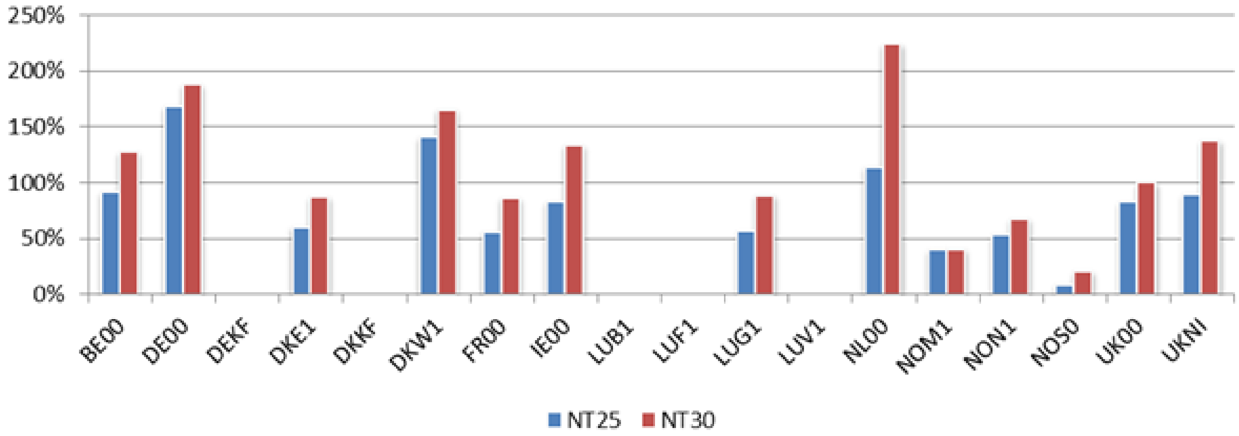


Figure 5-9: Wind and PV capacity as % of peak demand (without pump storage & DSR)

Balancing issues

Situations that can be challenging during system operations include high wind and low demand, as a massive share of variable RES with a locally high degree of simultaneous generation patterns causes steep ramps at onshore connection points. Figure 5.10 indicates the relationship between variable RES and minimum demand for the NT25 and NT30 scenarios for RGNS countries.

Steep ramps call continuously for more-advanced flexibility to satisfy operational flexibility such as ancillary services. Flexibility can be provided by, eg, new products in balancing markets, which could be provided by other sectors as well. Thus, while on the one hand a high share of offshore wind unlocks the potential for decarbonising other sectors, these sectors are, on the other hand, able to deliver important services to the electricity sector. A global system view is needed to organise this effectively.

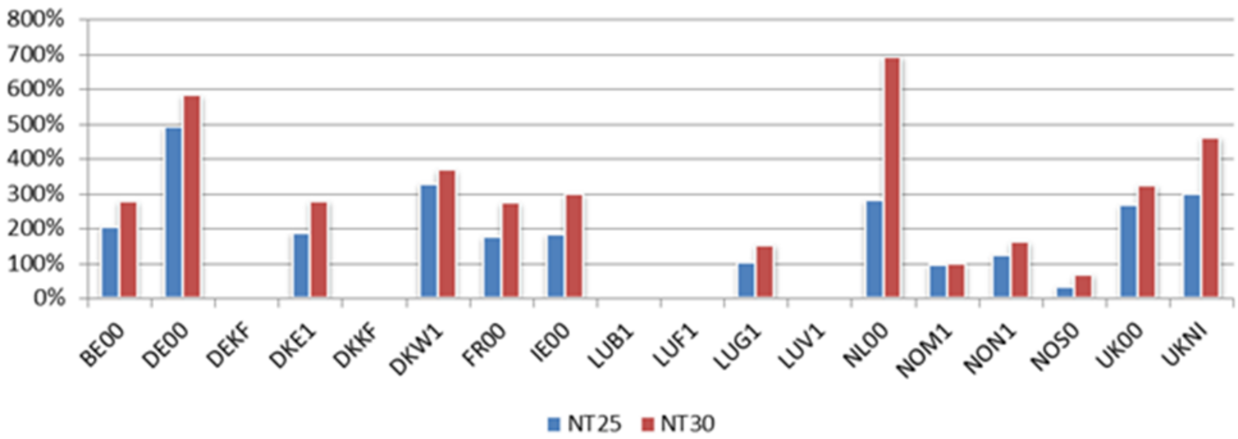


Figure 5.10: Wind and PV capacity as % of minimum demand (without pump storage & DSR)

Usually, balancing issues in systems with high share of variable RES are tackled by:

- Further infrastructure to smoothen the variable generation out across larger regions (including interconnections)
- Improved RES forecasting
- Shorter dispatch intervals, triggering an adjustment of market designs
- Increasing flexibility of the non-RES power park
- Demand-side flexibility
- Storage, and
- Smart sector Integration, releasing additional sources of flexibility.

The above list of options is used to different extend in different energy systems.

System security

Very high shares of variable renewables can depend on the system, have adverse effects on frequency stability, voltage stability, admissible line loading and voltage profiles. This is already seen in small isolated systems today (see Chapter 5.3), but can be expected in larger areas in the next decades as well, if the evolution of the system is not carefully planned.

Variable RES are often connected via power electronic inverters to the transmission grid, thereby replacing synchronous machines, which so far provided important ancillary services. This creates operational challenges, such as a decrease in system inertia and short circuit length, and is subject to inverters' fault behaviour. Systems and technical requirements need to be prepared in a timely manner (see also Chapter 5.3).

5.1.5 Subsea Projects in the Pipeline by 2030

The Northern Seas Offshore Grid Infrastructure collates the individual foreseen subsea projects, listed in Table 5-3, into a single building block. The constituent projects, however, will ultimately be developed by the various project promoters on a modular basis, with each following their own project plan. Figure 5.11 and Table 5.3 give an indication of the current status of the promoted subsea and supporting onshore projects up to 2030.

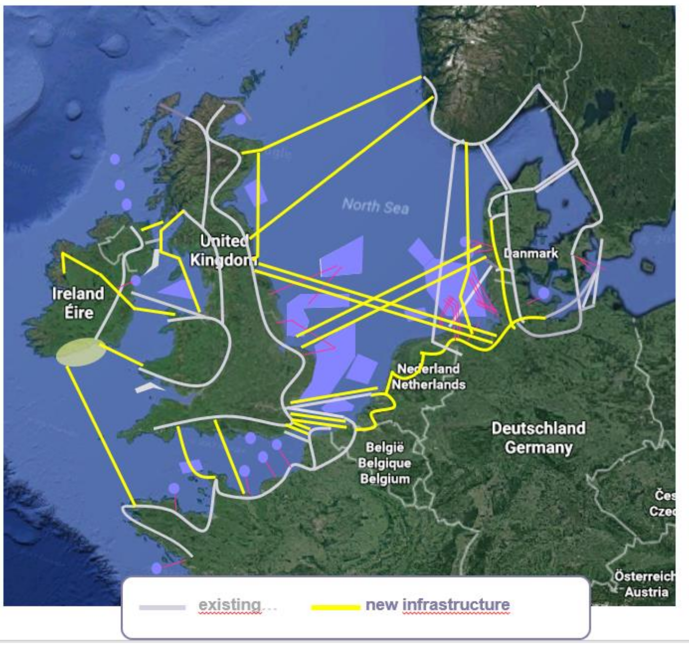


Figure 5.11: Offshore Grid Infrastructure by 2030 as submitted to the TYNDP20

Table 5.3: Projects developing the offshore potential in the Northern Seas towards 2030

Countries	Project ID	Project Name	Com-missioning	Offshore interconnection Capacity [MW]	TYPE {RefGrid*, PINT}
FR, GB	25	IFA 2	2020	1,000	RefGrid
FR, GB	153	France – Alderney – Britain (FAB)	2025	1,400	PINT
FR, GB	172	Eleclink	2020	1,000	RefGrid
BE, GB	121	Multi- purpose HVDC link „Nautilus"	2028	1,400	PINT
FR, IE	107	Celtic Interconnector	2026	700	PINT
GB, NO	110	North Sea Link	2021	1,400	RefGrid
GB, NO	190	NorthConnect	2024	1,400	RefGrid
DE, NO	37	NordLink	2020	1,400	RefGrid
DKW, GB	167	VIKING link	2023	1,400	RefGrid
FR, GB	247	AQUIND Interconnector	2023	2,075	PINT
FR, GB	285	Gridlink	2024	1,400	PINT
GB, NL	260	Multi-purpose HVDC interconnection	2030	2,000	PINT
IE, GB	286	Greenlink	2023	500	PINT

GB, DE	309	NeuConnect	2022	1,400	RefGrid
GB, IE	349	MAREX Organic Power Interconnector	2025	750	PINT
GB, NI	1040	LirIC	2027	700	PINT
GB, BE	1049	Cronos Energy Ltd	2025	1,400	PINT
GB, DE	1050	Tarchon Energy Ltd	2028	1,400	PINT
GB, DKW	1051	Aminth Energy Ltd	2028	1,400	PINT

*RefGrid = part of the Reference Grid, i.e. before 2025.

**PINT = Put one IN at a time (i.e. projects on top of the Reference Grid)

Cost-benefit assessment of the aggregated Northern Seas Offshore Grid Infrastructure.

The assessment of the aggregated Northern Seas Offshore Grid Infrastructure has been performed considering all 19 individual projects as a single large project according to the CBA 3.0 guidelines. Cost-benefit indicators have been calculated based on the outputs of four market tools and evaluating simulations of three climate years. Since TYNDP 2018, some projects have been commissioned (eg, NEMO link (GB-BE) and COBRA cable (NL-DK). In addition, three new project ideas have entered the picture (projects 1049-1051, i.e. GB to BE, DE and DKW).

Of course, each individual project will be at different stages in its development; however, the intention of this exercise is to show the value to the region of the aggregated infrastructure.

The cost-benefit assessment of the constituent projects will be included in the project sheets of the TYNDP package being published later this year. Some are due to be commissioned by 2020, whilst others are not scheduled for completion before 2030. Table 5-3 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. It must be stressed that not only offshore wind generation but also 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.

Key Results:

The Northern Seas Offshore Grid Infrastructure comprises 19 individual projects, developing into a global scheme that:

- delivers socio-economic benefits of between €1.4 bn and €1.6 bn per year

- facilitates additional RES generation of between 13.5 TWh and 19.2 TWh per year, and

- reduces annual CO2 emissions by between 12.270 Mt and 15.940 Mt.

The detailed CBA results for both the 2025 and 2030 NT scenario are presented in Table 5-4 and 5.5. The socioeconomic benefits provided by the seven projects that are part of the reference grid and expected before the year 2025 exploit the main share of the overall “JUMBO” benefits, while the remaining six PINT projects expected by 2025 find themselves in a more saturated situation. The other indicators are more similar between both project groups

For the time horizon 2030, the socioeconomic welfare (SEW) indicator is differs less between both project groups, also stating higher needs in the second part of this decade.

Table 5.4: CBA indicators for scenario NT2025

CBA indicators for NT 2025 Scenario			RefGrid projects	PINT projects	JUMBO (=RefGrid+PINT)
ΔSEW	min	M€ / year	347.25	148.24	495,49
	average	**M€ / year**	**454.16**	**178.34**	**632.49**
	max	M€ / year	528.45	191.93	720.11
ΔSEW_CO2	min	M€ / year	55.25	32.28	89.82
	average	**M€ / year**	**81.64**	**39.04**	**120.68**
	max	M€ / year	103.25	51.93	144.93
ΔSEW_RES	min	M€ / year	69.64	67.32	138.23
	average	**M€ / year**	**96.34**	**79.47**	**175.81**
	max	M€ / year	118.09	88.02	206.11
ΔCO2	min	tonnes / year	-4,489,162.60	-2,257,742.57	-6,301,120.38
	average	**tonnes / year**	**-3,549 687.59**	**-1,697 206.74**	**-5,246,894.32**
	max	tonnes / year	-2,402,180.84	-1,403,358.38	-3,905,037.41
ΔRES	min	MWh / year	1,420,925.28	1,381,884.09	2,823,901.07
	average	**MWh / year**	**2,021,756.81**	**1,660,727.31**	**3,682,484.12**
	max	MWh / year	2,523,111.90	1,872,149.36	4,395,261.26

Table 5.5: CBA indicators for scenario NT2030

CBA indicators for NT 2030 Scenario			TOOT projects	PINT projects	JUMBO (=RefGrid+PINT)
ΔSEW	min	M€ / year	804.48	614.45	1 429.37
	average	**M€ / year**	**912.43**	**631.74**	**1 544.17**
	max	M€ / year	1 000.44	644.20	1 640.71
ΔSEW_CO2	min	M€ / year	181.07	161.94	343.48
	average	**M€ / year**	**227.45**	**170.79**	**398.24**
	max	M€ / year	262.97	185.86	446.21
ΔSEW_RES	min	M€ / year	207.49	309.18	521.55
	average	**M€ / year**	**270.37**	**360.52**	**630.89**
	max	M€ / year	325.37	386.46	710.97
ΔCO2	min	tonnes / year	-9,391,893.05	-6,637,917.46	-15,936,034.19
	average	**tonnes / year**	**-8,123,093.76**	**-6,099,809.96**	**-14,222,903.72**
	max	tonnes / year	-6,466,958.94	-5,783,398.94	-12,267,316.81
ΔRES	min	MWh / year	5,340,847.82	7,971,018.59	13,453,519.31
	average	**MWh / year**	**7,168,411.71**	**9,498,477.53**	**16,666,889.24**
	max	MWh / year	8,817,340.53	10,418,607.48	19,235,948.01

5.2 Smart Sector Integration

This chapter gives some examples of current activities in the region on sector integration, without claiming to reflect the complete picture of the countries' activities. The examples comprise demonstration projects, studies, etc.

5.2.1 Belgium

The climate targets set out by the European Commission is pushing all sectors to decrease their carbon emissions. The integration of more renewable energies such solar power, on- and offshore wind, etc., is an efficient way to decarbonise the electrical system.

The heat, chemical, transport sectors are also looking for efficient ways to lower their CO2 emissions. In these sectors, part of this reduction can be achieved efficiently - and on a relatively short term - by tapping into the potential of electrification. Those industries or activities that are difficult to electrify are looking at the possibility of using alternative decarbonised energy vectors to fossil fuels. Smart sector integration – through the process of P2X - and a high penetration of renewable energy sources in the electrical system - could be a solution to create the alternative decarbonised energy vectors.

Decarbonisation of the energy sector is not the only advantage of smart sector integration. Coupling the different energy vectors allows the best of the different worlds to be combined: the storage and flexibility capabilities of molecule driven or heat vectors and the efficient integration, transport and use of RES energy through electricity. With high RES penetration, and when located close to large RES-hubs, P2X facilities can also reduce the amount of RES curtailment. Therefore, it is important that the location of large P2X facilities should be aligned between the gas and electricity TSO's. Facilities such as electrolysers can also provide balancing and frequency restoration services to the electrical system. Although electrolysers show a great deal of promise, this technology is not yet mature and will only have significant impact in the longer term (> 2040). On the other hand, the existing gas system can be used as a large seasonal energy storage facility.

The amount of RES penetration in the electrical system for P2X to contribute to the decarbonisation of, for example, the gas sector is estimated to be achieved in 2040 at earliest. However, P2X facilities could help with global decarbonisation before 2040 when powered by otherwise spilled/curtailed RES energy. The economic viability of P2X now and in the future remains a question mark but could be influenced by policymakers by for example subsidising green hydrogen or increasing the CO2 price.

The fact that Belgium is small country and is often importing electricity, could affect the possible full load hours of electrolysers in a negative way. The potential for large amount of renewable energy sources is limited due to the size of the country and the need for import indicates low potential for renewable energy excesses on average.

Presently, no targets have been set for power-to-gas by the Belgian government, but this could change quickly, as P2X is a hot topic within Europe. A first power-to-hydrogen facility is planned for Zeebrugge harbour in Belgium. The project is called Hyoffwind and plans to instal a new medium-scale electrolyser. The final investment decision will be taken in the summer of 2020 and the project promotors - which includes the Belgian gas transmission system operator – have indicated that subsidies will be required to achieve a positive business case. A second project is investigating the possibility of installing an electrolyser in Oostende harbour, but the project is at an earlier stage.

5.2.2 Denmark

Currently, more than 60% of the Danish total annual electric energy demand is addressed by renewable energy sources (RES), with about 45% being provided by variable RES (wind and solar PV) and the majority of the remained by biomass. Aiming for a 100% RES share of electricity by the year 2030 and a 70% reduction of GHG emissions compared to a 1990 reference, the country is entering the next phase for a future where not only the electricity sector, but all energy sectors, have to be fossil-free, which is the Danish political target for 2050.

To identify economic viable pathways for the country's further decarbonisation, the Danish TSO is investigating how sector integration could pave the way. A related study was published in 2019[21]. The simulations built on the regional development of Northern Europe between 2030-40, as described in the TYNDP18 edition along with additional assumptions on sector integration in neighbouring countries. The analysis applies an integrated way of planning of multiple sectors, i.e. the electricity, heat, gas and transport sectors, including potentials for P2G and P2X.

In Denmark, coupling of the electricity and heat sectors has already been realised for several decades. A widespread district heating system, including CHPs with large heat storage tanks, facilitates a certain degree of decoupled production of heat and/or power, providing flexibility to the high VRES system. Some electric boilers acting on market terms convert cheap surplus electricity into heat. The electricity and gas sectors are implicitly coupled via the Danish TSO Energinet, which is responsible for both systems, thus capturing synergies through joint planning.

For the aforementioned study, the energy system has been modelled through 'energy plants', which are simulation models of multiple integrated sectors. These models can be understood as CHP units extended by additional functionalities, such as eg, electrolysis and gasification. These plants operate on market terms, i.e. at low prices as electricity consumers, and at high prices as electricity producers (Figure 5.12).

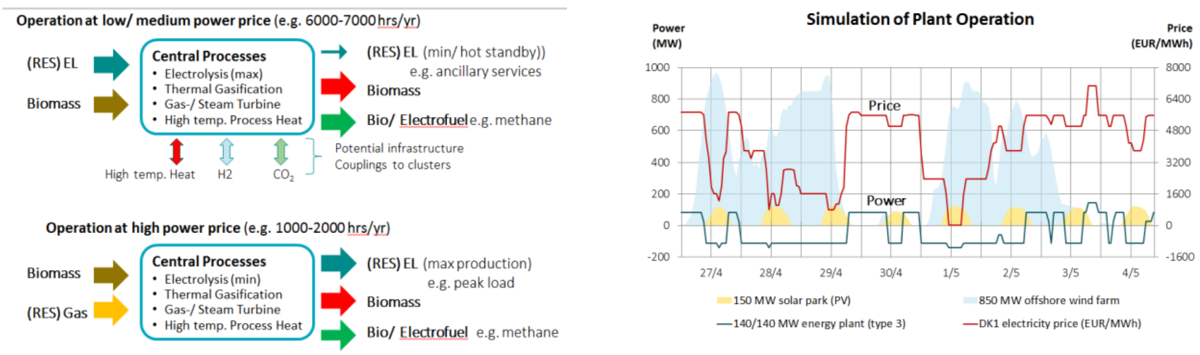


Figure 5.12: Principle of an energy plant and its operation
(source: Energinet. Figure published with permission of Energinet)

The underlying ENTSO's European scenarios point at a further significant increase of wind/solar energy in the whole Northern Seas Region. This reduces options for sharing extreme large amounts VRES across countries with highly correlated VRES. Nevertheless, simulation results show that average electricity prices will continue

[21] *Energinet; "System perspective 2035", available at https://en.energinet.dk/Analysis-and-Research/Analyses/System-Perspective-2035*

to be competitive and regionally aligned, even when the whole regional electricity production changes towards high share of variable renewable energy sources.

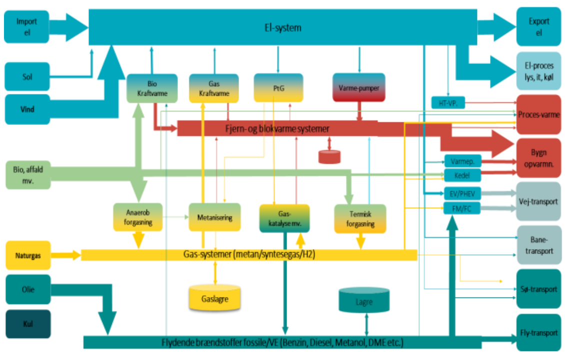
However, there will be periods with extreme high or low prices due to weather conditions, faults or maintenance activities. These periods increase economic opportunities for installing further flexible electricity demand, such as heat pumps, power-to-gas devices or Power-to-X (P2X) applications.

The latter convert cheap surplus electricity via electrolysis and a parallel gasification of organic material or synthesis with nitrogen into high-value products such as synthetic fuels, fertilizers, plastic, etc., thereby reducing the need for fossil resources and contributing to other sector's decarbonisation while increasing the value of VRES. Building on the governments' technology catalogue, P2X already seems feasible at competitive prices by 2030, as the levelized cost of energy (LCoE) of VRES is assumed to be well below the price for natural gas by then.

The study has shown that by advanced use of sector-coupling combined with a strong international grid, the Danish energy targets are feasible. Some of the advantages of multi-sector planning are demonstrated, as this provides answers which are urgently needed when developing a cost efficient and securely functioning decarbonised future.

Table 5.6: Simulated energy flow in DK ... fully decarbonised

(source: Energinet. Figure published with permission of Energinet)



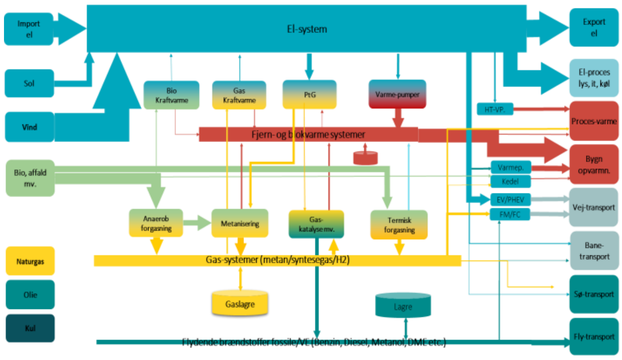


Figure 5.13: 2035 | Figure 5.14: 2050

As electrification plays a major role in the decarbonisation of more than the power sector alone, and although the electric peak load and the amount of installed variable RES are already at the same level, the government initiated further investigations into how an additional massive amount of offshore wind could best be integrated, including considerations of transformation into other forms of energy at suitable locations. So far, results show that P2G and P2X are capable of delivering high operational flexibility to the electricity system, thereby decreasing the number of hours with electricity prices at zero, facilitating their cost coverage.

Further studies have been published both by Energinet alone[22] and together with partners,[23] investigating in more detail how the 70% target can be reached by exploiting large-scale offshore wind, how potential energy islands could contribute in this context and how PtX, hydrogen and the gas and electricity infrastructures could further support this process.

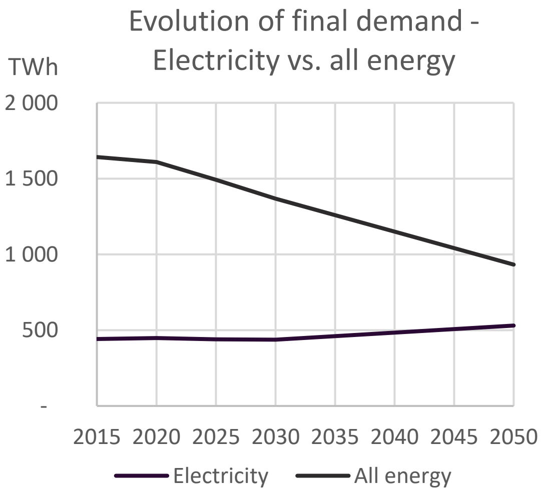
[22] https://en.energinet.dk/About-our-reports/Reports/PtX_strategic_action_plan

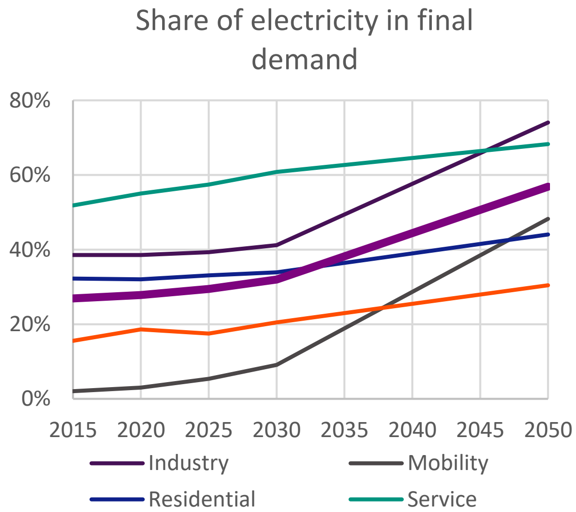
[23] https://energinet.dk/Om-publikationer/Publikationer/PTX-gamechanger-rapport

5.2.3 France

Policy framework

France's energy climate plan is targets carbon neutrality by 2050. The National Low Carbon Strategy (SNBC) defines a pathway combining strong energy efficiency and the massive electrification of all sectors. The electrification level is expected to increase from the current 25% to around 55% by 2050. The generation mix will be diversified with a massive development of RES and a reduction of the share of nuclear generation.





Source : data from SNBC/AMS scenario

In 2035, their shares in the power production should reach 50%.

Gas is still expected to play a significant role in the final consumption (around 20% in 2050), originating from biomass and electricity through electrolysis.

The Multi-Annual Energy Plan (PPE) defines intermediate targets up to 2028.

The ambition of developing a new hydrogen economy is emblematic of the energy transition. In France, the state has initiated the following actions:

- Publishing a hydrogen roadmap, launching 18 actions to foster low-carbon hydrogen development. As part of these actions gas and electricity system operators have published studies analysing hydrogen impact on their respective infrastructure
- Defining a 40 TWh target for low carbon hydrogen in 2050 (SNBC), and
- Setting intermediate binding targets for low-carbon hydrogen in the industrial sector: 10% of the demand in 2023 and between 20% and 40% in 2028.

RTE deliverables related to sector integration

Reaching carbon neutrality will require the optimal use of energy resources, energy carriers and flexibility solutions. Sector integration technologies (such as electrolysers) are explicitly considered part of the solution. Their role will be twofold: activating the fields of optimisation at the interface between sectors, and taking advantage of cheap wind and solar to further electrify the economy directly or through the decarbonation of other energy carriers.

RTE, the French TSO, is involved in preparing this future energy system by providing technical, economic and environmental analyses of pathways to a carbon neutral energy system and by testing technical solutions. On the 2035 time horizon, the Generation Adequacy Report published in 2017 showed that the anticipated 50% share of dispatchable power generation (nuclear and a small share of CCGT) should prevent major RES integration challenges; security of supply can be ensured.

On the 2050 time horizon, RTE has been appointed by the ministry to jointly investigate - with the IEA - the technical and economic challenges of a 100% RES scenario for comparison with a nuclear/RES generation mix scenario.

By building these bridges, sector integration widens the scope of these system analysis. Enhanced knowledge of new technologies and the ability to model the overall energy system are prerequisites for any meaningful assessments from a resilience or efficiency perspective.

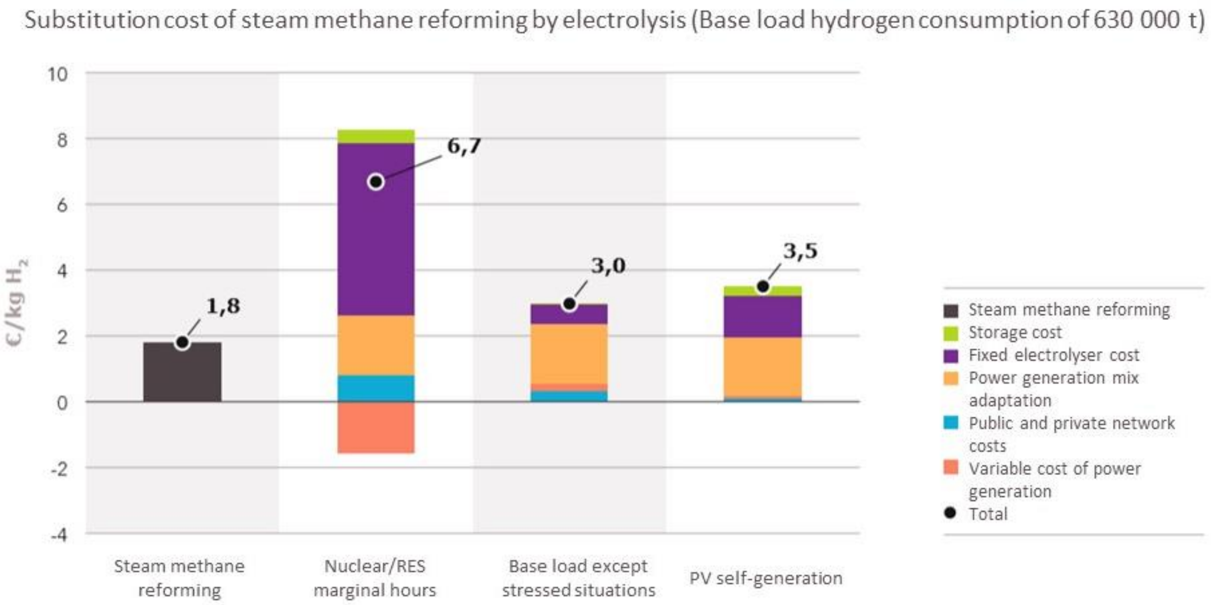
For that purpose RTE continues to develop its knowledge in cooperation with players of various sectors (gas, mobility, heating and building sectors).

- Hydrogen

RTE report focuses on the ability of the French electricity system to produce low-carbon hydrogen.

Up to 2035, the main value of low-carbon hydrogen produced by electrolysis will be to foster the decarbonisation of industry.

The analysis highlights that the costs and the CO_2 emissions related to hydrogen production will strongly depend on electrolysis running patterns: RES or nuclear marginal hours, baseload or even in a self-consumption mode with PV.



Source: RTE study on low carbon hydrogen

Electrolysers can provide storage/flexibility services to the electricity system. Nevertheless the French electricity system does not show such need until 2035. Beyond 2035, the role of hydrogen as energy storage has to be assessed, depending on the future energy mix.

Electrolysers are also able to provide ancillary services, but the related economic value compared to other flexibility sources is insufficient to provide the sole basis of a business model.

- Mobility

In 2019, RTE released - in cooperation with AVERE-France (the French association for the development of e-mobility, and part of the AVERE European network) - a study analysing the system impact of a wide range of electricity mobility scenarios up to 2035. The report covers different aspects, such as the number of vehicles, charging solutions, autonomous cars, auto-consumption and battery manufacturing.

It shows that electric mobility has strong potential for reducing CO2 emissions and can deliver flexibility to the electricity system through smart charging approaches even without the need of Vehicle-to-Grid technologies.

- Heating

In 2020, RTE will release – in cooperation with ADEME (the French Environment and Energy Management Agency) a report on heating in the building sector.

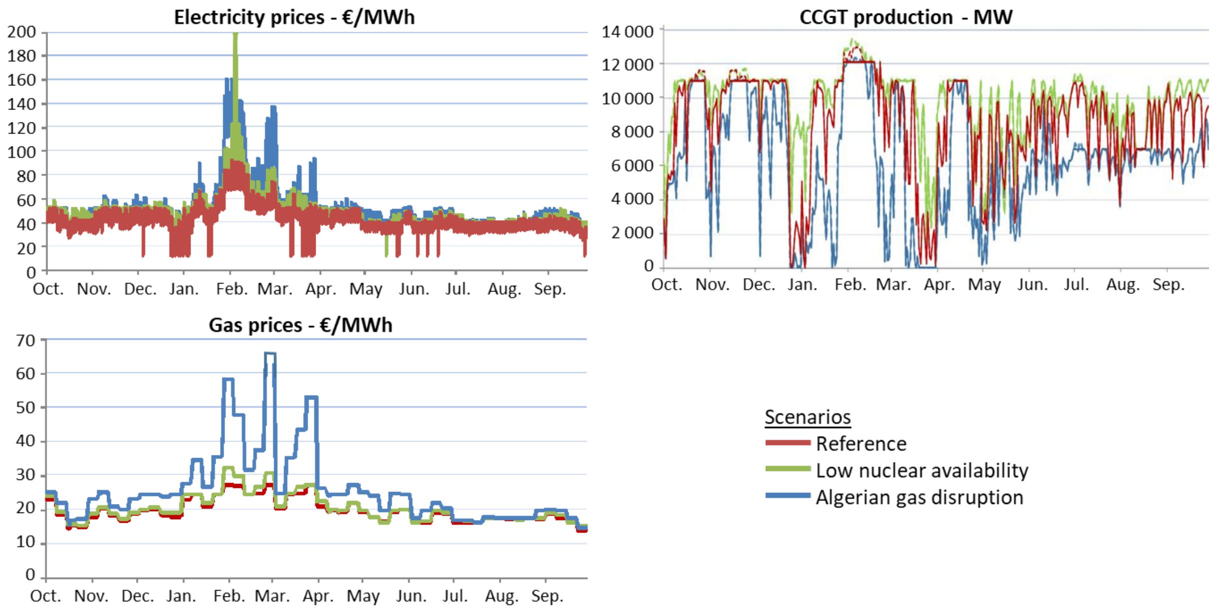
AntartesSimulator : a multi-energy carrier modelling tool

antaressimulator

In order to tackle the challenges of understanding tomorrow energy systems, RTE has developed the capabilities of its energy system modelling tool, Antares, in a number of directions (some in collaboration with GRTgaz):

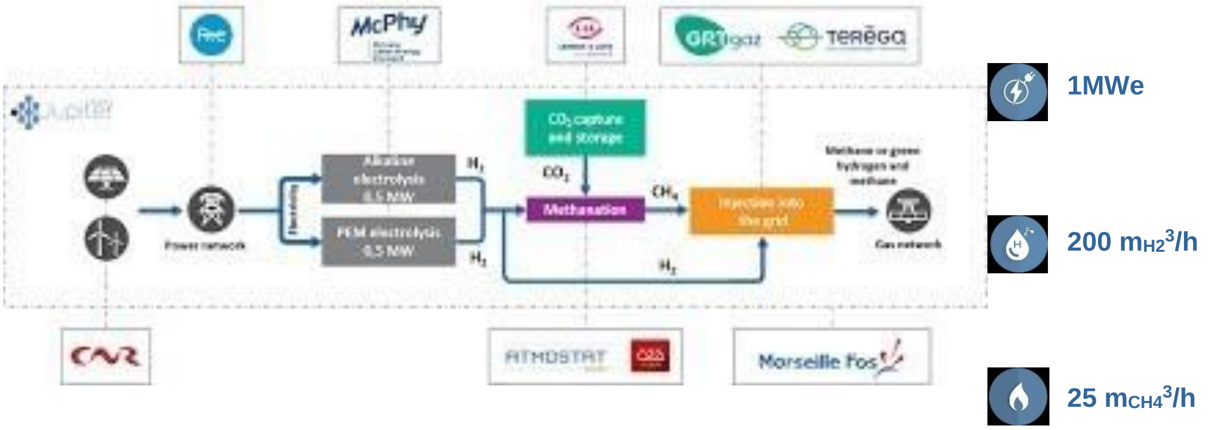
- Open-source access, in order to foster transparency and cooperation between regions and sectors, and
- Multi-energy capability covering electricity, methane and hydrogen, in order to model energy conversion and hybrid technologies.

Joint electricity and gas modelling has already had a direct benefit when assessing the impact of supply-stressed situations on energy prices. As part of a joint study, RTE and GRTgaz recast the 2012 climatic year modelling alternatively with a fictitious disruption of gas supply from Algeria and low availability of nuclear power plants, such as occurred during winter 2016/2017. The following graphs show the value of joint modelling with Antares for cross-impact analysis on electricity and gas prices and CCGT production.



Power-to-Gas pilot – Jupiter 1000

As is the case with hydrogen, Power-to-Gas (P2G) is an emblematic technology of sector integration. It is the best-known representative of wider range of Power-to-X technologies. In order to better understand the potential role of this technology, RTE has joined the Jupiter 1000 consortium project led by GRTgaz.



Source: Jupiter 1000 website

The project consists of a pair of 0.5MW electrolysers (one alkaline and one PEM) combined with a catalytic methanation stage for producing synthetic methane from hydrogen with CO2 captured from an industrial process. The facility can inject both pure hydrogen - up to a 6% (by volume) dilution - and synthetic methane in the gas transmission network.

The pilot will provide intelligence on the technical behaviour of P2G (particularly the flexibility of the different electrolysis technologies) and the different use cases (eg, network injection, industrial feedstock, mobility…).

5.2.4 Germany

Connecting electrons and molecules: ELEMENT EINS.

The climate targets set out in the Paris agreement, along with the increase of renewables in the German electricity system, fostered a discussion on technological options for decarbonising energy sectors other than electricity (such as heating, mobility and some industry). TenneT, Thyssengas and Gasunie plan to integrate a ~100MW electrolyser into the grid, to push power-to-gas (P2G) as a technology for supporting the integration of RES into the broader energy system, thereby achieving ambitious climate targets. The main aims of this initiative are to make the first steps with P2G by:

- stablising the electricity grid
- creating flexibility for system operation
- limiting curtailment of wind energy
- reducing future need for grid expansion, and
- Using the gas grid as a storage unit

This is part of the TenneT vision for an integrated energy system. The P2G technology is seen as a promising option, as it enables the use of renewable energy in different sectors by either direct or indirect means. The project ELEMENT EINS will be accompanied by a research project to gain in-depth insights into the relevance of P2G and its interactions in an integrated energy system.

Construction and operation of the ~100MW electrolyser is planned in six steps, each with an installed electrical capacity of about 15-20MW. It is planned to commission the first module in 2022. After 2028, all five modules will be integrated into the transmission and gas system. Potential, system-integrating locations in the North of Germany for connection of the electrolyser were evaluated in the context of a technical feasibility study until the end of 2019.

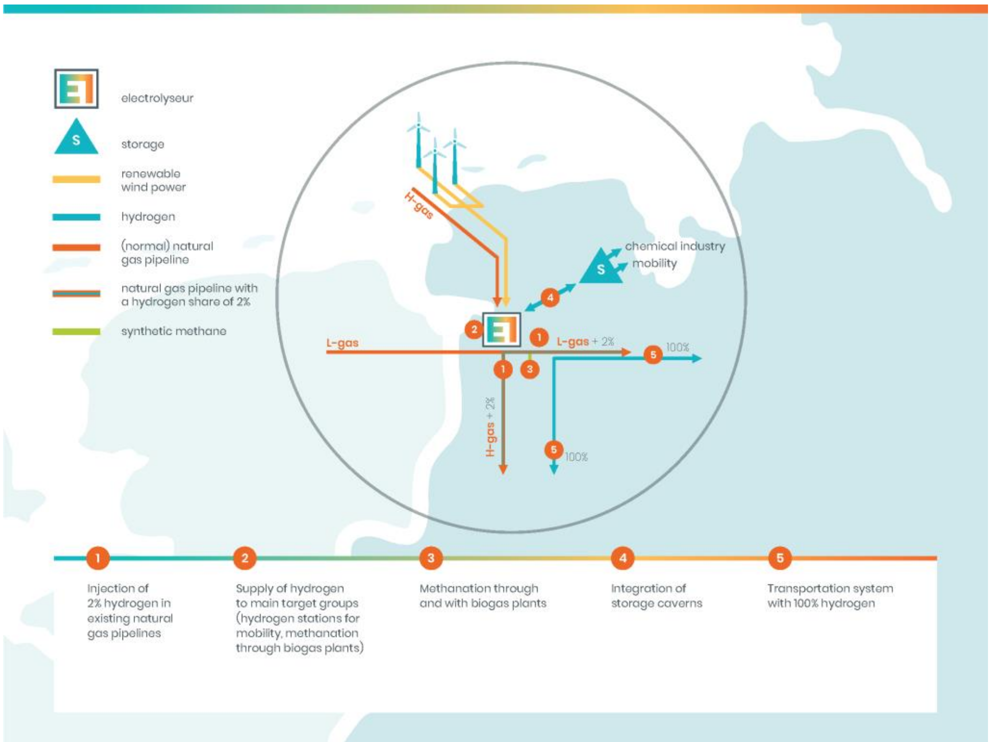


Figure 5.15: Element One (source: Tennet – published with permission of Tennet)

Sector integration at the system level: hybridge

Amprion and Open Grid Europe are planning the first large-scale P2G plant in Germany to convert electricity from renewable energy sources into hydrogen. A suitable location for the hybridge pilot project is in southern Emsland; on the border between Lower Saxony and North Rhine-Westphalia there is an ideal intersection between electricity and gas grids.

The following is planned: An electrolyser with an electrical input of 100 megawatts will be installed near one of Amprion's substations and connected to Amprion's electricity grid. Based on this, all future ways of integrating hydrogen into the energy system in the hybridge project will be tested: OGE plans to convert parts of its existing gas network for the exclusive transport of pure hydrogen. Companies located near the new hydrogen pipeline can use the green hydrogen. In the further course of the project, the provision of hydrogen filling stations in the mobility sector - for example in motor vehicles or trains – will also be possible. In addition, gas storage facilities will be also be converted in future in order to temporally decouple the supply of renewable energy sources from the demand for hydrogen. The storage facilities can then take in hydrogen instead of natural gas and feed it back into the hydrogen network. This way, a reliable supply of hydrogen based on renewable energy can be efficiently realised.

Adding hydrogen to natural gas networks is another option that will be tested in the project. The green gas can then also be used for other purposes, such as heating. As part of the OGE network, the hydrogen network will be connected to both the transmission network and to regional local natural gas networks. OGE ensures that a limited amount of hydrogen can be added to the natural gas in compliance with current regulations. When these options have been exhausted, hydrogen together with CO2 can be used to produce methane via methanation and fed into the natural gas grid.

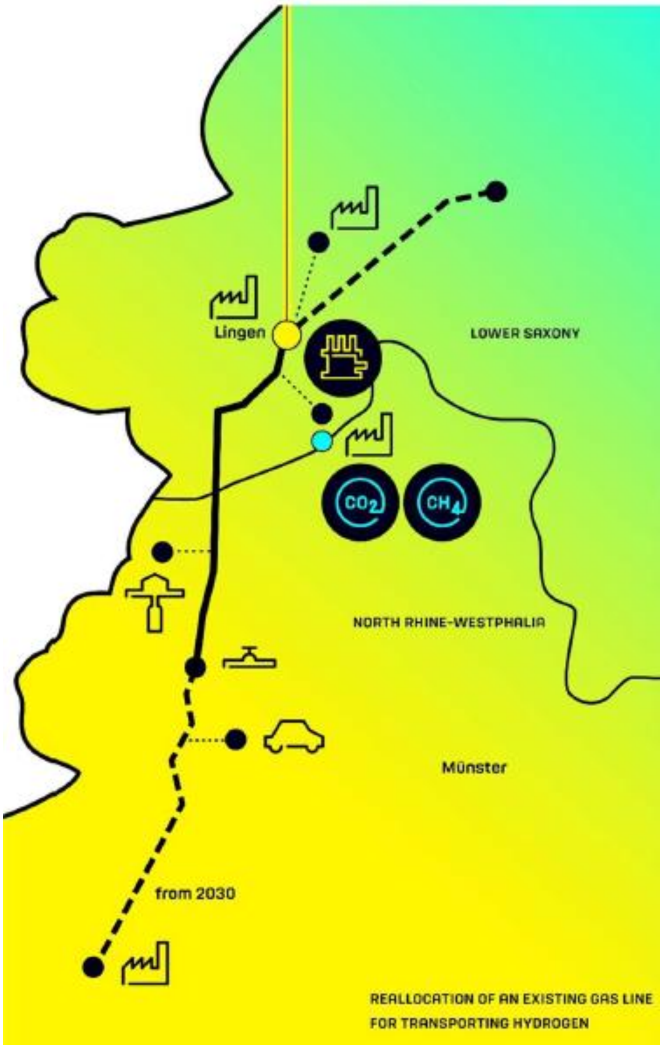


Figure 5.16: hybridge (source: Amprion – published with permission of Amprion)

The technological prerequisites for the construction of the plant are already in place. If the legal and regulatory authorities consent to the project, Amprion and OGE can begin the approval process and construction in the near future.

A consistent development of non-discriminatory third-party access

A fundamental feature of the liberalised energy market is the fact that energy traded is at no time 'owned' the carriers, that is to say the system operators. System operators are remunerated for their transmission services via a regulated network charge. The infrastructure is provided to third parties without discrimination. If you now couple the electricity and gas infrastructures at the system level, this fundamental principle can and must be maintained. The model for the future will therefore be adjusted to the regulatory framework. As with the current electricity or gas network infrastructure, the sector transformer will be planned, built, operated and financed via network charges by the transmission system operators. This transformation will take place between two regulated sectors - namely the electricity grid and the gas transmission network.

Since the 'bridging capacity' between the systems is limited, network operators will auction the capacity of the sector transformer at any time to traders or direct customers. Here too, third-party access is the fundamental non-discriminatory principle. As a result, the electricity and gas trading markets will thus be linked and allow competition between the two commodities. The proceeds of the auctions will be used by network operators to reduce network charges. This principle has been applied now for many years within the electricity sector at the cross-border interconnectors.

5.2.5 Great Britain

In Great Britain, sector integration between power and gas can currently be seen in the form of gas-fired electricity generation (G2P). For example, gas demands are becoming more variable as the output from gas-fired power stations increasingly mirrors the output from weather-dependent renewable generation.

However, going forward we are also likely to see sector integration in the form of P2G, as hydrogen begins to be produced using electrolysis. This is in addition to potential shifts in energy demand between gas and electricity (eg, some natural gas heating converting to electricity, etc).

In the Future Energy Scenarios (FES) 2019, the Two Degrees and Community Renewables scenarios met the previous GB carbon target of an 80% reduction in greenhouse gas emissions by 2050. Both of these scenarios include production of hydrogen by electrolysis - mostly to meet demand in the transport sector. However, in these scenarios, electrolysis could be one of the solutions for mitigating against the potential oversupply of electricity during some periods of the year. The hydrogen produced through this technology could possibly be stored and utilised during system stress or cold weather situations by feeding it into generators.

However, due to the low conversion efficiency, other solutions such as battery storage, interconnectors and demand-side response appear set to take priority over using the stored hydrogen gas to generate power.

This could change with the recent move to a Net Zero 2050 target, as there is an expectation that hydrogen may need to play a greater role. In the Two Degrees scenario of FES 2019, hydrogen is formed via methane reforming, using natural gas combined with carbon capture and storage (CCUS) to ensure that it is low carbon. This method of producing hydrogen is currently cheaper than electrolysis and, in Two Degrees, was used for heating and industrial demand as well as in transport. The forecast cost of electrolysis is continually falling and, in a Net Zero scenario with high hydrogen demand, if this demand was to be met by electrolysis it would represent significant sector integration between gas and power. This coupling would be extended further if hydrogen produced using electrolysis was then used to generate electricity (eg, in cold weather or periods of system stress).

These types of sector integration will form part of the Whole System Strategy that National Grid ESO is leading on in order to support net zero by 2050.

5.2.6 Ireland and Northern Ireland

Sector integration in Ireland and Northern Ireland will become more evident in the future through the increasing integration of energy end-use and supply-side sectors with one another. This includes the electrification of end-use sectors such as heating and transport as well as the further integration of the electricity and gas sectors.

EirGrid and SONI capture this sector integration in their respective scenario planning processes.

EirGrid and SONI produce scenarios for Ireland and Northern Ireland respectively. The scenario processes are called 'Tomorrow's Energy Scenarios (TES) Ireland' and 'Tomorrow's Energy Scenarios (TES) Northern Ireland'. The most recent set of scenarios were developed in 2019 and are available at the following links:

- TES 2019 Ireland here[24]
- TES 2019 Northern Ireland here.[25]

Planning for a range of credible futures, through the use of multiple scenarios, helps to manage the risk of uncertainty. Future iterations of the EirGrid and SONI scenarios will capture the expected evolution of sector integration.

All scenarios in TES Ireland and TES Northern Ireland envisage a significant increase in the electrification of heat and transport through the use of electric vehicles and heat pumps. This trend has been evident for some time in both Ireland and Northern Ireland as well as in other jurisdictions. More details for Ireland and Northern Ireland can be found at the links above. The rest of this section will focus on sector integration of the electricity and gas sectors, and in particular the emerging coupling in the form of P2G.

Similar to other jurisdictions, sector integration between power and gas in Ireland and Northern Ireland is currently evident in the form of gas-fired electricity generation (G2P). This type of sector integration will continue to be important in the transition to a low-carbon energy future.

In the future, sector integration in the form of P2G will also likely play a role. P2G is the process of using electricity to produce hydrogen via electrolysis, or, in a consecutive step, using hydrogen together with carbon dioxide to produce methane via methanation.

In TES 2019 Ireland, P2G is seen as an enabler of sector coupling and experiences growth in scenarios featuring high demand for renewable gas. As seen from the electricity system, P2G is a load increase. Such flexibility becomes beneficial during times where variable renewable energy curtailment would otherwise occur, thereby increasing realised renewable energy capacity factors.

Figure 5.17 shows the capacities for pumped hydro-energy storage (PHES), battery-energy storage (BES), demand-side management (DSM) and P2G for different study years and three different scenarios - Centralised Energy ('CE'), Delayed Transition ('DT') and Coordinated Action ('CA'). The increase in power to gas capacity, and thus the positive impact of P2G on curtailment levels, is particularly seen in the period between 2030-40.

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[24] http://www.eirgridgroup.com/customer-and-industry/energy-future/
[25] http://www.soni.ltd.uk/customer-and-industry/energy-future/

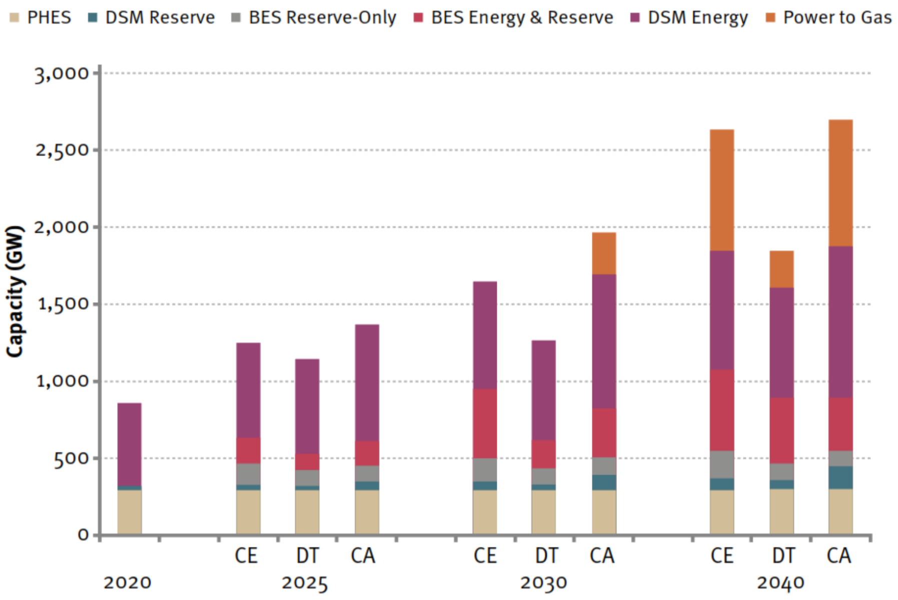

Figure 5.17: Storage, DSM and power to gas installed capacity

In TES 2019, Northern Ireland - similar to TES Ireland -P2G is seen as an enabler of sector coupling and experiences growth in scenarios with high demand for renewable gas.

In the longer term, seasonal storage will play an important role in electricity systems with high levels of weather-dependent generation. Power to gas developments may allow for the seasonal storage of gas produced from renewable electricity.

The share of methane and hydrogen sourced from P2G is given in Figure 5.18. The scenario 'Addressing Climate Change' has the highest share of P2G, due to a higher consumer demand for renewable gas in heating and transport.

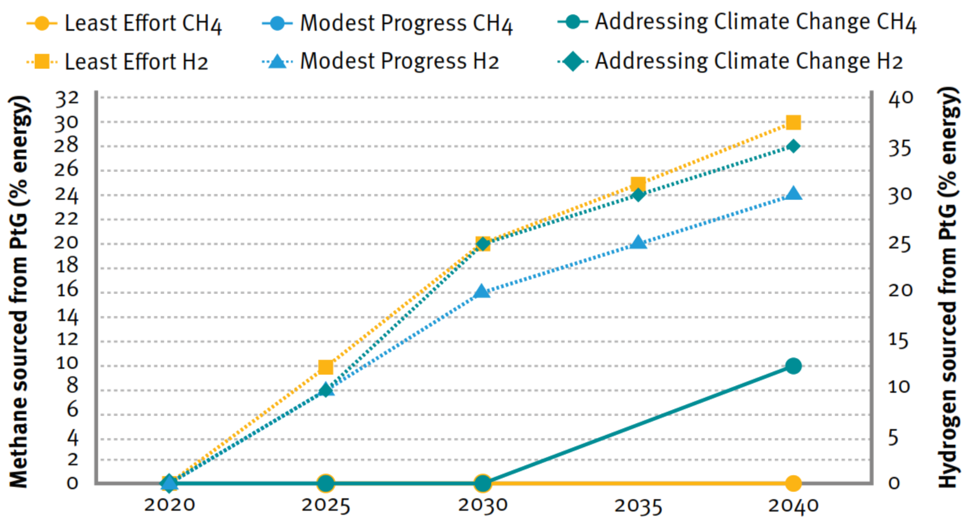

Figure 5.18: Proportion of methane and hydrogen supplied by power to gas

5.2.7 Luxembourg

Luxembourg is historically an energy importing country, as no primary resources are available. Its energy consumption will continue to increase, despite important efficiency gains expected in all energy sectors and significant developments of RES generation, particularly PV and on-shore wind.

The main drivers are the steady increase of the population of Luxembourg from 610.000 in 2019 to 1.100.000 by 2050, new electricity applications such as heating, eMobility and eTransport being connected to the electricity grid and additional big energy consumers such as mega data centres.

Despite significant increases of electricity generation based on PV and wind, Luxembourg will remain a net energy-importing country, with no congestions expected on the transport grid due to the high in-feed of the distributed RES generation.

The ambitious RES development will increase the need for additional flexibility solutions. Generation and load patterns will significantly change up until 2040, making use of smart integrated solutions including smart grid solutions in the distribution grid. The smart meter roll-out (target 95% of metering devices) in the electricity and gas distribution grid will be finalised by the end of 2020. Smart grid applications based on real-time customer data will be implemented from 2025-30, allowing for smart applications including demand-side response, short and mid-term storage coupled with other energy systems as gas, hydrogen or eMobility.

In regard to eMobility, the national infrastructure plan foresees a total of 800 public charging stations for electric vehicles in both public spaces and park and ride parking spaces by 2020. In addition, a national infrastructure plan for fast-charging stations is currently under preparation.

Looking at 2030, hydrogen can play a key role in energy supply trough sector integration of electricity, heat and transport, especially if the energy losses in production and conversion are improved through electrolysis and the efficiency of fuel cells developed for transport. Luxembourg wants to work closely with other EU Member States on regional solutions. The potential of P2G infrastructure and storage applications being integrated into the electricity grid to solve potential regional congestions is under investigation by the Luxemburgish TSO Creos.

5.2.8 The Netherlands

The (discussion about the) energy transition has picked up speed the past years in the Netherlands. As follow up of the Dutch Energy Agreement [reference], a broad societal discussion has taken place to translate CO2 and RES targets for 2030. This resulted in a Climate Agreement [reference] with policy proposals for sectors such as transportation, agriculture and energy. This Climate Agreement has fed the National Renewable Energy Action Plan of the Netherlands (NREAP) [reference]. The Dutch NREAP aims at a 49% reduction of greenhouse gasses by 2030 through cost-effective measures. As 80% of the CO2 emissions is energy related, the reduction target is especially impacting the energy system. To reach the target a combination of electrification and large share of renewables is anticipated.

Electrification strongly contributes to a sustainable mobility sector, industry and build-up environment. By stimulating electric vehicles and charging infrastructure, the government aims to reduce the sale of new ICE-passenger cars to zero by 2030. Driven by the decision to eliminate natural gas for heating, heat-pumps will have a significant contribution in space heating within the build-up environment. The industry sector is also investigating the possibilities for CO2-free industrial heat systems, such as power-to-heat.

The increase of variable renewables in the energy mix increases the need for flexibility within the electricity system. This flexibility can come from the integration of the gas and electricity system. The ambition for 2030 is to have 3-4GW of electrolyser capacity realised to create green hydrogen.

Looking beyond 2030 makes clear that more needs to be done. TenneT investigated together with Gasunie how the energy system can continue to function well in the future. This "Infrastructure Outlook 2050" study shows the requirements and limitations of a future energy system based on solar and wind energy for the Netherlands and Germany.

To meet the 2050 emission targets set in the Paris Climate Agreement, the energy transition will require a complete overhaul of the current fossil fuel-dominated energy system. Electricity produced from sun and wind is seen as the main source of energy by 2050. To meet the demand of industry and sectors, which are difficult to electrify, a major part of the renewable energy has to be converted to molecules (such as hydrogen). Therefore, power-to-gas (P2G) will act as a cornerstone in the future.

Coupling power and gas grids also gives the energy system valuable flexibility and transport capacity. Although electricity storage is expected to be widely available by 2050, only gas storage will provide a solution for seasonal storage in a system based on solar and wind power. The location, capacity and operation of P2G installations must be aligned with both electricity and gas TSOs to avoid additional bottlenecks due to the electricity demand of these installations.

5.2.9 Norway

The report "An electric Norway – from fossil to electricity" shows potential future scenarios for reducing Norwegian greenhouse gas emissions. Smart sector integration is an important part of this decarbonisation.

Norway is a frontrunner in electrifying the transport sector. Tax policy for the last decade for electric cars and light vehicles has led to huge electrification in this sector. In recent years other transport-sectors have also become increasingly electrified; eg, buses, boats and ferries.

There are also plans for several other sector-coupling investments (P2G), e.g., hydrogen and ammonia production. Currently, there are several plans for large-scale hydrogen production, both as blue hydrogen (hydrogen from methane in combination of carbon capture) and green hydrogen. The sites for green hydrogen are typically in the north with large RES potential, however with very long distances to larger energy consumption.

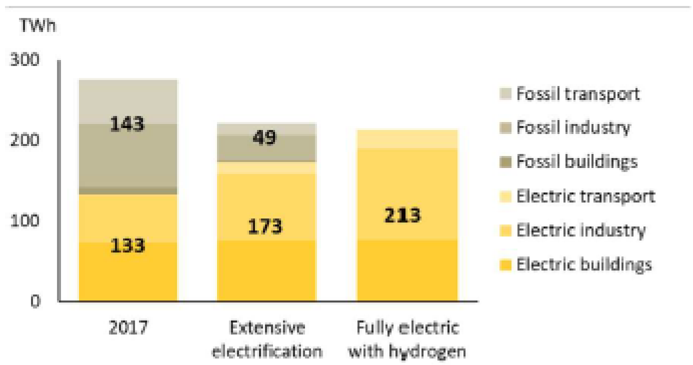

Figure 5.19: Trend in primary energy use with an increasing level of electrification

The report "An electric Norway – from fossil to electricity" show that electrification will be a fundamental factor in reducing Norwegian greenhouse gas emissions. If most of current fossil-based energy is replaced with electricity, this see an increase in power consumption of 30–50 TWh per year. With equivalent growth in renewable power generation, this will result in a halving of Norway's greenhouse gas emissions. To achieve zero emissions in the energy system, hydrogen may be a good option. According to the report, production of hydrogen for a fully decarbonised Norway could lead to a further increase of 40 TWh of electricity-consumption.

5.3 Challenges of operation with high variable RES

The integration of a large volume of renewable generation proposed for the Northern Seas Region presents a number of operational challenges requiring innovative solutions. Several studies are ongoing and are discussed in this section.

The island of Ireland comprises two jurisdictions, Ireland and Northern Ireland, which are operated as one electricity market, the Single Electricity Market (SEM). The SEM is a small system and is not synchronously connected to either Great Britain or continental Europe.

It has a high penetration of renewable generation, approximately 40% RES-E in 2020, the vast majority of which is non-synchronous renewable generation. As a small island with a high penetration of non-synchronous renewable generation, the issues experienced and identified in IE and NI may also become relevant to other countries in the region as their generation portfolios develop.

The large increase in penetration of non-synchronous renewable generation has led to several challenges. The following issues when operating a grid with a high penetration of renewable generation have been detected:

- a higher Rate of Change of Frequency (RoCoF) on the system,
- a reduced transient stability of the system,
- voltage dips arising from slow post fault recovery of wind farms leading to frequency dips, and
- a need for credible, reliable performance from thermal generation.

As a small island with a high penetration of renewable generation, the issues experienced and identified in IE and NI may also become relevant to other countries in the region as their generation portfolios develop.

5.3.1 System non-synchronous penetration

To simplify matters, a metric was derived to consider all operation constraints. This metric is referred to as the System Non-Synchronous Penetration (SNSP). The total amount of non-synchronous generation (renewable generation and HVDC interconnection imports) is considered against the total synchronous generation operating at all times. To meet 2020 renewable energy targets, there is a requirement for at least 75% SNSP. This would allow curtailment to be kept low enough to allow renewable generation to remain investable.

A report in 2010 investigated the operational range of the SEM synchronous system in 2020, and the results are shown in Figure 5.20; the findings of the report remain valid. The green area represents a range where there are no technical challenges; therefore up to 50% SNSP could be achieved. The red area represents a range where technical issues jeopardise stable operation, i.e. beyond 75% SNSP. The report concluded that operation up to 75% SNSP could be achieved with a number of ‘additional adaptions to the power system’.

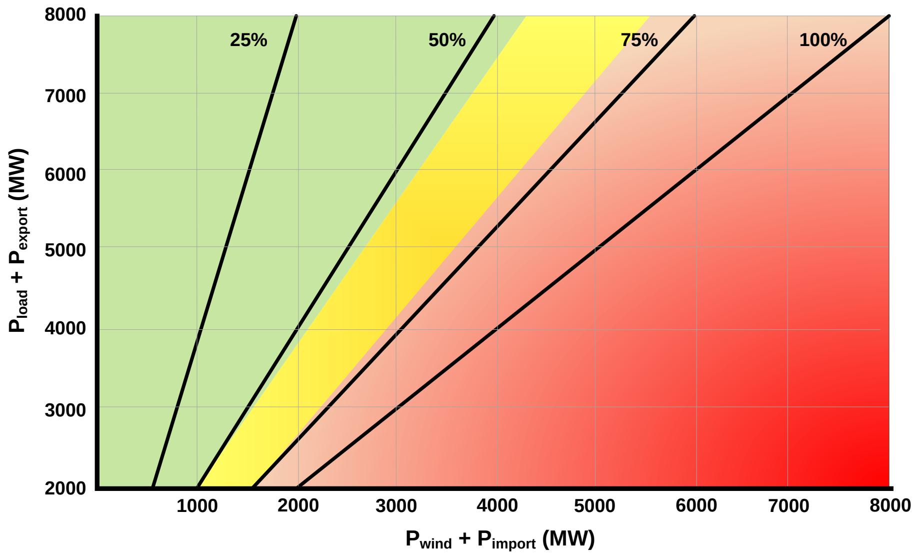

Figure 5.20: Allowable operation range of the SEM synchronous system by 2020

The DS3 (Delivering a Secure Sustainable Power System) programme was set up by the Irish TSOs to manage the challenges of operating a system with a high penetration of renewable generation. Currently, the all-island power system is operated up to 65% SNSP. This will increase to 70% and 75% in due course. A number of requirements were identified to meet this target:

- An increase in the allowable RoCoF limit from 0.5 Hz/s to 1.0 Hz/s
- A reduction in the number of minimum thermal generators dispatched at all times
- A reduction in the minimum inertia required at all times
- The introduction of a Fast Frequency Response (FFR) system service
- An improved voltage control strategy at both transmission and distribution levels, and
- Better management of voltage-induced frequency dips at high levels of SNSP.

In June 2020, EirGrid and SONI commenced a 1 Hz/s RoCoF trial. This will inform the transition to higher levels of SNSP.

5.3.2 Operation beyond current limits

Consideration is being given to how to ultimately operate the system with a SNSP beyond 75%. Several developments have occurred in recent years to suggest this may be possible. These include:

- an improved dynamic reactive response from wind farms
- the extensive use of appropriately located synchronous compensators
- changes to the renewable energy portfolio due to an increase in PV applications, and
- new technologies, such as demand side management, energy storage and rotating stabilisers.

Further interconnection with neighbouring systems will also potentially be a requirement.

Increased coordination between transmission and distribution system operators, along with enhanced regulatory and policy support, will also likely be required. This is particularly true given that customers will become more active participants in future, with domestic-scale generation and technologies such as electric vehicles having a larger impact on the generation and demand balance.

Ultimately, by 2030, the SNSP limit must increase to 95%[26]. This is in order to achieve the 2030 RES-E target of 70% in Ireland and enable a similar target for Northern Ireland. EirGrid and SONI are developing a programme - similar to the aforementioned DS3 programme - to determine the roadmap to 2030. In order to help achieve these ambitious goals, EirGrid and SONI are also currently deeply involved in the EU-SysFlex project which is an EU Horizon 2020 project. The project is described below.

EU-SysFlex

EU-SysFlex is a unique consortium of 34 members comprising transmission and distribution system operators, aggregators, technology providers, research and academic institutions as well as consultancies. They are located in 15 countries across Europe.

One of the primary goals of the project is to examine the pan-European power system with at least 50% of electricity demand on an annual basis being met by RES. The transition towards a decarbonised power system considers increasing levels of variable non-synchronous renewable technologies such as wind and solar.

Tasks in the EU-SysFlex project include:

- identifying the needs, and associated solutions, of the future power system with a high share of renewables
- creating a plan to provide practical assistance to power system operators across Europe
- recommending enhancements to market design and regulation to enable new business solutions;
- conducting seven industrial-scale demonstrations testing new flexibility and system services, and data management and exchange, and
- identifying a long-term roadmap to facilitate the large-scale integration of renewable energy across Europe.

Project Deliverable 2.4 'Technical Shortfalls for Pan European Power System with High Levels of Renewable Generation' was published in April 2020. This describes the detailed technical power system studies performed and the scarcities identified for three synchronous power systems (the Ireland and Northern Ireland system, the Nordic system and the synchronised Continental European system). The technical scarcities studied were divided into a number of categories: frequency stability; voltage stability; rotor angle stability; network congestion and system restoration. Mitigation measures for the technical scarcities identified will be evaluated in future project deliverables, thus enabling the formulation of a roadmap to facilitate power system decarbonisation.

The EU-SysFlex project commenced in November 2017 and is scheduled to be completed in November 2021. More information on the EU-SysFlex project and intermediate publications can be found on the project website.

[26] http://www.eirgridgroup.com/about/strategy-2025/EirGrid-Group-Strategy-2025-DOWNLOAD.pdf

5.4 Controllable Devices

The proportion of RES is increasing much more quickly than the necessary grid expansion required to transport it. Consequently, this is creating temporary bottlenecks in transmission. To help transmission system operators to solve these congestions, HVDC are of course considered bypassing these congested areas. but TSOs already implements projects such as Dynamic Line Rating and other controllable devices to be commissioned in short- or mid-term horizons (before or around 2025). Considering such devices, three solutions proposed by TSOs and approved by national regulators can be presented in this chapter.

As the generation and demand connected to the network changes, network power flows change and circuits can become unevenly loaded (eg, some circuits reach their maximum capacity while others are well below their limits). Installing power flow controllers allows TSOs to provide the Electricity System Operator with the tools to quickly reduce the congestion that limits renewable generation, with minimal impact on communities and the environment):

As power flow controller, some Phase Shifter transformers (PST) are under construction or planned to be commissioned around 2025, with and others before 2030. Compared with the Common Grid Model (CGM) used in TYNDP2018, TYNDP2020 reference CGM includes additional PSTs. Such devices give a rather rapid response to alleviate congestion, but large-scale coordination is necessary to operate them properly.

Second, R&D projects help TSOs to control power flows. Modular power flow control technology is planned to be installed on OHLs or in substations, are to be installed to increase power transfer capability by making better use of its existing network.

Third, in the region, some TSOs received agreement from their respective NRAs to experiment with a dual-storage solution to alleviate congestion. The substations where these devices will be installed have been selected to achieve an optimal impact on these congestions.

5.5 PLEF – Generation Adequacy Assessment

The Pentalateral Energy Forum is the framework for regional cooperation in Central Western Europe (AT-BE-DE-FR-LU-NL-CH) for improved electricity market integration and security of supply. Ministry representatives of the Pentalateral Energy Forum (PLEF) member states are working in close cooperation with NRAs and TSOs on different energy-related topics in different subgroups:

- SG1 Market: CWE FBMC, XBID
- SG2 Adequacy: Crisis management and Risk preparedness, Generation adequacy assessment, Capacity mechanism
- SG3 Flexibility: DSR, Hydrogen

TSOs from the Pentalateral Energy Forum (PLEF) member states (Austria, Belgium, France, Germany, Luxembourg, Switzerland and The Netherlands) prepared the third edition of the Pentalateral Generation Adequacy Assessment study, PLEF GAA 3.0.

5.5.1 PLEF ++ Generation Adequacy Assessment study PLEF GAA 3.0.

The Pentalateral Energy Forum is the framework for regional cooperation in Central Western Europe (AT-BE-DE-FR-LU-NL-CH) for improved electricity market integration and security of supply. TSOs of the seven countries cooperating in the Pentalateral Energy Forum (PLEF) - Austria, Belgium, France, Germany, Luxembourg, the Netherlands and Switzerland (PLEF countries/region) - are assessing the adequacy in the Penta region, as mandated by the Political Declaration of the Pentalateral Energy Forum of 7 June 2013.

The third edition of the PLEF GAA, published in 2020, continues to provide a probabilistic analysis of electricity security of supply in Europe. By focusing on a regional perspective, it makes it possible to better assess generation adequacy jointly, on a regional scale covering the PLEF countries.

The knowhow on methodology, as developed by the PLEF TSOs during the first and second PLEF GAA, was transferred and applied within the association of European Electricity TSOs (ENTSO-E) in the Midterm Adequacy Forecast (MAF). Nowadays, significant methodological evolutions also occur with-in the Midterm Adequacy Forecast (MAF) group of ENTSO-E and therefore the PLEF GAA also profits back from the ENTSO-E work. Furthermore, the PLEF TSO still relies significantly on methodological evolutions by national TSOs within national studies.

The definition of the sensitivities – Low Gas and Low Nuclear/Low NTC CH was performed in collaboration with Ministries, Regulators and TSOs in the PLEF group and has turned out to have major added value for this third Regional adequacy assessment. These sensitivities provide so-called 'stress test' situations for the region, to, eg, test its resilience.

Compared with the second assessment, the following important areas of improvement have been considered:

- The usage of a flow-based (FB) model as the standard methodology. In the second edition, the flow-based methodology was implemented for the short-term horizon (2018/2019) only since the modelling approach relied on historic flow-based data. For the third assessment, the time horizon 2025 was considered and the flow-based approach needed to be enhanced. Flow-based modelling for the mid-term horizon taking into account all implemented grid investments for the considered time horizon (2025) and including the 70% minRAM requirements from CEP.
- A dedicated analysis on critical hours has been performed, including a comparison with historical situations.
- Regarding the climate database, an important improvement is the inclusion of hydrological data by ENTSO-E within its Pan-European Climate Database (PECD). While in the second edition only three degrees of water availability were combined with climatic input data for renewables, the third edition considers the evolved ENTSO-E PECD, which assigns different historic inflow values to each climate year.

The results for the PLEF base case 2025 show that LOLE values do not (significantly) exceed the reliability standards set by some of the PLEF countries. Both in the base case and the sensitivities analysed, for all countries of the PLEF Region (except for the Netherlands) LOLE is above zero. The two sensitivity analyses show that adequacy risks can occur, since LOLE values significantly exceed the reliability standards set by some of the PLEF countries.

PENTA Pentalateral Energy Forum	PLEF 2025 Base Case		PLEF 2025 Low Gas (-7,5GW)		PLEF 2025 Low Nuclear (-2,9GW)/ Low NTC CH	
Area	ENS [MWh]	LOLE [h]	ENS [MWh]	LOLE [h]	ENS [MWh]	LOLE [h]
AT	819	1,7	2004	3,8	1055	2,3
BE	3706	3,3	15290	8,1	5328	4,6
CH	98	0,2	1178	1,4	4001	2,9
DE[1]	2440	0,6	6526	1,6	2927	0,7
FR	9766	3,3	22543	7,1	15847	4,6
LU[1]	31	0,6	83	1,6	37	0,7
NL	0	0,0	0	0,0	0	0

6. APPENDICES

Appendix 1.

A1: Pan-European Projects

The TYNDP20 project portfolio has been published on the ENTSO-E Website: https://tyndp.entsoe.eu/documents -> "TYNDP2020 project portfolio"

A2: Regional Projects

In this chapter, the NS projects of 'regional' and 'national' significance are listed. These are needed for substantial and inherent support to the Pan-European projects, which will be published on central level inclusion into the future transmission systems. These are critical links to facilitate regional and pan-European flows and reach the European Climate targets. All these projects include an appropriate description and the main driver; why they are designed to be realised in the future scenarios, together with the expected commissioning dates and evolution drivers in case they were introduced in the past Regional Investment Plans.

There are no criteria for the regional significance projects inclusion in this list. These are included based purely on the project promoter's decision as to whether the project is relevant for inclusion.

In the table below, projects of regional and national significance in NS region are listed.

Country	Project Name	Investment		Expected Commissioning year	Description	Main drivers	Included in RegIP 2017?
		From	To				

FRANCE	Lille-Arras	Avelin	Gavrelle	2021	An existing 30-km 400-kV single-circuit OHL in the Lille area will be substituted by a new double-circuit 400-kV OHL.	Security of supply and RES integration; the project aims to ensure the security of supply, taking into account RES generation variability	Yes
FRANCE	Sud Aveyron			2022	New substation on the 400-kV Gaudière-Rueyres line for local RES integration.	RES integration	Yes
FRANCE	Eguzon-Marmagne 400kV	Eguzon	Marmagne	2022	Reconductoring existing 400kV OHL (maintenance)	Maintenance, RES integration and market integration	Yes
FRANCE	Long term perspective “Façade Atlantique”			>2030	Upgrade of the north-south 400kV corridor between Nouvelle Aquitaine and the Loire valley, under study.	RES integration and market integration	Yes
FRANCE	Long term perspective “Rhône – Bourgogne”			>2030	Upgrade of the north-south 400kV corridors between Lorraine and Alsace and Franche-Comté, between Champagne-Ardenne and Bourgogne and in the Rhone valley. Upgrade of the 400kV east-west corridors between Languedoc and the Rhone valley and in the West of Provence. Under study.	RES integration and market integration	No
FRANCE	Long term perspective “Normandie – bassin parisien”			>2030	Upgrade of the north-south 400kV corridor between Normandy and Paris basin, under study.	RES integration	No
FRANCE	Long term perspective “Massif central – Centre”			>2030	Upgrade of the north-south 400-kV corridors in the Massif central-Centre, under study.	RES integration and market integration	Yes
Germany		Pulgar (DE)	Vieselbach (DE)	2024	Construction of new 380 kV double-circuit OHL in existing corridor Pulgar - Vieselbach (104 km). Detailed information given in Germany’s Grid Development.	RES integration / Security of supply	yes
Germany		Hamburg/Nord (DE)	Hamburg/Ost (DE)	2030	Reinforcement of existing 380 kV OHL Hamburg/Nord - Hamburg/Ost. Detailed information given in Germany’s Grid Development.	RES integration	yes

Germany		Hamburg/Ost (DE)	Krümmel (DE)	2030	New 380 kV OHL in existing corridor Krümmel - Hamburg/Ost. Detailed information given in Germany's Grid Development.	RES integration	yes
Germany		Elsfleht/West (DE)	Ganderkesee (DE)	2030	New 380 kV OHL in existing corridor for RES integration between Elsfleth/West, Niedervieland and Ganderkesee	RES integration	yes
Germany		Dollern (DE)	Alfstedt (DE)	2029	New 380-kV-OHL in existing corridor in Northern Lower Saxony for RES integration	RES integration	yes
Germany		Alfstedt (DE)	Elsfleth/West (DE)	2029	New 380-kV-line Alfstedt - Elsfleth/West in existing corridor for RES integration	RES integration	No
Germany		Emden (DE)	Halbemond (DE)	2029	New 380-kV-line Emden - Halbemond for RES integration. Contruction of new substation Halbemond	RES integration	No
Germany		Conneforde (DE)	Unterweser (DE)	2030	New 380-kV-OHL in existing corridor for RES integration in Lower Saxony	RES integration	yes
Germany		Wolmirstedt (DE)	Klostermansfeld (DE)	2030	New 380 kV OHL in existing corridor for RES integration between Wolmirstedt - Klostermansfeld	RES integration	yes
Germany		Klostermannsfeld (DE)	Schraplau/Obhausen – Lauchstädt (DE)	2030	New 380 kV OHL in existing corridor between Klostermannsfeld - Schraplau/Obhausen - Lauchstädt. Detailed information given in Germany's Grid Development.	RES integration	yes
Germany		Point Kriftel (DE)	Farbwerke Höchst-Süd (DE)	2022	The 220 kV substation Farbwerke Höchst-Süd will be upgraded to 380 kV and integrated into the existing grid.	RES integration / Security of supply	yes
Germany		Several		2030	Vertical Measures in the Amprion zone	RES integration / Security of supply	yes
Germany		Büttel (DE)	Wilster/West (DE)	2030	New 380-kV-line in extisting corridor in Schleswig -Holstein for integration of RES especially wind on- and offshore	RES integration	yes
Germany		Brunsbüttel (DE)	Büttel (DE)	2030	New 380-kV-line Brunsbüttel - Büttel in existing corridor for RES integration	RES integration	No
Germany		Wilster/West (DE)	Stade/West (DE)	2030	New 380-kV-line Wilster/West - Stade/West in existing corridor for RES integration	RES integration	No
Germany		junction Mehrum (DE)	Mehrum (DE)	2021	New 380-kV-line junction Mehrum (line Wahle - Grohnde) - Mehrum including a 380/220-kV-transformer in Mehrum	RES integration	yes
Germany		Borken (DE)	Mecklar (DE)	2023	New 380-kV-line Borken - Mecklar in existing corridor for RES integration	RES integration	yes
Germany		Borken (DE)	Gießen (DE)	2030	New 380-kV-line Borken - Gießen in existing corridor for RES integration	RES integration	yes
Germany		Borken (DE)	Twistetal (DE)	2023	New 380-kV-line Borken - Twistetal in existing corridor for RES integration	RES integration	yes

Germany		Wahle (DE)	Klein Ilsede (DE)	2021	New 380-kV-line Wahle - Klein Ilsede in existing corridor for RES integration	RES integration	yes
Germany		Birkenfeld (DE)	Ötisheim (DE)	2021	A new 380 kV OHL Birkenfeld-Ötisheim (Mast 115A)	Security of supply	yes
Germany		Bürstadt (DE)	BASF (DE)	2021	New line and extension of existing line to 400 kV double circuit OHL Bürstadt - BASF including extension of existing substations.	RES integration / Security of supply	yes
Germany		Neuenhagen (DE)	Vierraden (DE)	2022	Project of new 380 kV double-circuit OHL Neuenhagen - Vierraden - Bertikow with 125 km length as prerequisite for the planned upgrading of the existing 220 kV double-circuit interconnection Krajnik (PL) – Vierraden (DE Hertz Transmission). Detailed information given in Germany's Grid Development.	RES integration / Security of supply	yes
Germany		Neuenhagen (DE)	Wustermark (DE)	2021	Construction of new 380 kV double-circuit OHL between the substations Wustermark and Neuenhagen with 75 km length. Support of RES and conventional generation integration, maintaining of security of supply and support of market development. Detailed information given in Germany's Grid Development.	RES integration / Security of supply	yes
Germany		Pasewalk (DE)	Bertikow (DE)	2023	Construction of new 380 kV double-circuit OHLs in North-Eastern part of 50HzT control area and decommissioning of existing old 220 kV double-circuit OHLs, incl. 380 kV OHL Bertikow - Pasewalk (30 km). Support of RES and conventional generation integration in North Germany, maintaining of security of supply and support of market development. Detailed information given in Germany's Grid Development.	RES integration / Security of supply	yes
Germany		Röhrsdorf (DE)	Remptendorf (DE)	2025	Construction of new double-circuit 380 kV OHL in existing corridor Röhrsdorf - Remptendorf (103 km)	Security of supply	yes
Germany		Vieselbach (DE)	Mecklar (DE)	2027	New double circuit OHL 380 kV line in existing OHL corridor. Detailed information given in Germany's Grid Development.	RES integration	yes
Germany		Area of Altenfeld (DE)	Area of Grafenrheinfeld (DE)	2029	New double circuit 380 kV OHL in existing corridor (27 km) and new double circuit 380 kV OHL (81 km). Detailed information given in Germany's Grid Development Plan.	RES integration	TYNDP 2016
Germany		Gießen/Nord (DE)	Karben (DE)	2025	new 380-kV-line Gießen/Nord - Karben in existing corridor for RES integration	RES integration	yes
Germany		Herbertingen/Area of Constance/Beuren (DE)	Gurtweil/Tiengen (DE)	2030	Upgrade of the existing grid in two circuits between Gurtweil/Tiengen and Herbertingen. New substation in the Area of Constance	Security of supply	no

Germany		Schraplau/Obhausen (DE)	Wolkramshausen (DE)	2030	New 380 kV OHL in existing corridor between Querfurt and Wolkramshausen. Detailed information given in Germany's Grid Development.	RES integration	no
Germany		Marzahn (DE)	Teufelsbruch (DE)	2030	AC grid reinforcement between Marzahn and Teufelsbruch (380 kV cable in Berlin). Detailed information given in Germany's Grid Development.	Security of supply	no
Germany		Güstrow (DE)	Gemeinden Sanitz/Dettmannsdorf (DE)	2025	New 380 kV OHL in existing corridor between Güstrow - Bentwisch - Gemeinden Sanitz/Dettmannsdorf. Detailed information given in Germany's Grid Development.	RES integration	no
Germany		Bentwisch (DE)	Bentwisch (DE)	2025	This investment includes a new 380/220 kV transformer in Bentwisch.	RES integration	no
Germany		Güstrow (DE)	Pasewalk (DE)	2030	New 380 kV OHL in existing corridor between Güstrow – Siedenbrünzow – Alt Tellin – Iven – Pasewalk. Detailed information given in Germany's Grid Development.	RES integration	no
Germany		Wolkramshausen (DE)	Vieselbach (DE)	2030	New 380 kV OHL in existing corridor between Wolkramshausen - Ebeleben - Vieselbach. Detailed information given in Germany's Grid Development.	Security of supply	no
Germany		Bürstadt (DE)	Kühmoos (DE)	2023	An addtional 380 kV OHL will be installed on an existing power poles.	RES integration / Security of supply	no
Germany		Wolmirstedt (DE)	Wahle (DE)	2026	New 380 kV OHL in existing corridor between Wolmirstedt - Helmstedt - Hattorf - Wahle. Detailed information given in Germany's Grid Development.	RES integration	yes
Germany		Wolmirstedt (DE)	Mehrum/Nord (DE)	2030	New 380 kV OHL in existing corridor between Wolmirstedt - Helmstedt - Gleidingen/Hallendorf - Mehrum/Nord. Detailed information given in Germany's Grid Development.	RES integration	no
Germany		Oberbachern (DE)	Ottenhofen (DE)	2029	Upgrade of the existing 380 kV line. Detailed information given in Germany's Grid Development.	RES integration / Security of supply	no
Germany		Urberach (DE)	Daxlanden (DE)	2024	Upgrade of existing 380-kV-lines in the region Frankfurt-Karlsruhe	Res integration	No
Germany		Daxlanden (DE)	Eichstetten (DE)	2028	Upgrade of existing 220-kV lines from Daxlanden via Bühl, Kuppenheim and Weier to Eichstetten to 380 kV	Res integration	No
Germany		Pulverdingen(DE)	Engstlatt (DE)	2030	Upgrade of existing 380-kV corridor between Pelverdingen - Oberjettingen and Oberjettingen - Engstlatt. Extension of substation Pulverdingen is included.	Res integration	No
Germany		Kreis Segeberg (DE)	Siems (DE)	2026	New 380-kV-line Kreis Segeberg - Siems in existing corridor for RES integration	RES integration	TYNDP 2018
Germany		Lübeck (DE)	Göhl (DE)	2027	New 380-kV-line Lübeck - Göhl for RES integration. Contruction of new substation in Göhl	RES integration	TYNDP 2018

Germany		Grafenrheinfeld (DE)	Großgartach (DE)	2025	Additional 380 kV circuit and reinforcements in existing corridor between Grafenrheinfeld and Großgartach;	RES integration	TYNDP 2018
Germany		Raitersaich (DE)	Altheim (DE)	2028	New 380-kV-line Raitersaich - Altheim in existing corridor for RES integration	RES integration	TYNDP 2018
Germany		Redwitz (DE)	Schwandorf (DE)	2025	New 380-kV-line Redwitz - Schwandorf in existing corridor for RES integration	RES integration	TYNDP 2018
Germany		Güstrow (DE)	Wolmirstedt (DE)	2022	New 380 kV OHL in existing corridor between Güstrow - Parchim/Süd - Perleberg - Stendal/West - Wolmirstedt. Detailed information given in Germany's Grid Development.	RES integration	No
Germany		Grid of TransnetBW		2035	Construction of several reactive power compensation systems in the area of the TransnetBW GmbH	Res integration	No
Germany		Krümmel (DE)	Wahle (DE)	2030	Including Ad-hoc-Maßnahme Serienkompensation Stadorf-Wahle	RES integration	No
Germany		Bechterdissen	Ovenstädt	2030	Reinforcement of existing 380-kV-line between Bechterdissen and Ovenstädt	RES integration	No
Germany		Großkrotzenburg (DE)	Urberach (DE)	2027	Reinforcement of existing 380-kV-line between Großkrotzenburg and Urberach	RES integration	No
Germany		Wilhelmshaven 2 (DE)	Fedderwarden (DE)	2030	New 380-kV-line Wilhelmshaven 2 - Fedderwarden for RES integration	RES integration	No
Germany		Redwitz (DE)	Border Bayern/Thüringen	2021	Reinforcement of existing 380-kV-line between Redwitz - Border Bayern/Thüringen	RES integration	No
Germany		point Blatzheim (DE)	Oberzier (DE)	2025	Reinforcement of existing 380-kV-line between point Blatzheim and Oberzier	Res integration	No
Germany		Landesbergen (DE)	Mehrum/Nord (DE)	2030	New 380-kV-line Kreis Segeberg - Siems in existing corridor for RES integration	RES integration	No
Germany		Höpfingen (DE)	Hüffenhardt (DE)	2030	Additional 380-kV line between Höpfingen and Huffenhardt	Res integration	No
Germany				bis 2030	phase-shifting transformers in the Saarland	Res integration	No
Germany		Hanekenfähr (DE)	Gronau (DE)	until 2030	reinforcement of existing/ new 380-kV-line between Hanekenfähr and Gronau	Res integration	No
Germany				2023	Ad-hoc phase-shifting transformers in the Ruhr region	Res integration	No
Germany		Hamburg/Ost (DE)		2022	4 PST in substation Hamburg/Ost	RES integration	no
Germany		Hanekenfähr (DE)		2023	Ad-hoc-phase-shifting transformers in Hanekenfähr	Res integration	No
Germany		Oberzier (DE)		2023	Ad-hoc-phase-shifting transformers in Oberzier	Res integration	No

Germany		Wilster/West (DE)		2023	New phase-shifting transformers in Wilster/West	RES integration	No
Germany		Würgau		2023	New phase-shifting transformers in in Würgau	RES integration	No
Germany		Pulverdingen(DE)		2023	New phase-shifting transformer in Pulverdingen	Res integration	No
Germany		Twistetal		2025	New phase-shifting transformers in Twistetal	RES integration	No
Germany		Güstrow (DE)		2025	4 PST in substation Güstrow	RES integration	no
Germany		Lauchstädt + Weida (DE)		2025	This investment includes two new 380/220 kV transformers in Lauchstädt and a new 380/220 kV transformer in Weida	RES integration	no
Germany		Osterburg (DE)	Wolmirstedt (DE)	2030	New 380 kV OHL in existing corridor between Osterburg - Stendal/West - Wolmirstedt. Detailed information given in Germany's Grid Development.	RES integration	no
Germany		(substations Lauchstädt, Altenfeld, Röhrsdorf, Ragow, Siedenbrünzow, Hamburg, Neuenhagen) (DE)		2030	Installation of reactive power compensation (eg. MSCDN, STATCOM ...) in 50Hertz control area (substations Lauchstädt, Altenfeld, Röhrsdorf, Ragow, Siedenbrünzow, Hamburg, Neuenhagen)	RES integration / Security of supply	no
Germany		Audorf/Süd	Ottenhofen (DE)	2025	100MW grid booster in substations Audorf/Süd and Ottenhofen	RES integration	No
Germany		Grid of TenneT (DE)			Construction of several reactive power compensation units in grid of TenneT (DE)	RES integration	No
Germany		Hattingen (DE)	Linde (DE)	until 2030	Reinforcement of existing OHL between Hattingen and Linde	Res integration	No
Germany		Enniger		2025	phase-shifting transformers in Enniger	Res integration	No
Germany					Several reactive power compensation systems in the area of the Amprion GmbH	Res integration	No
Germany		Kühmoos		2024	Upgrade of substation Kühmoos in Southern Germany	Res integration	No
Germany		Kupferzell		2025	500MW grid booster in substation Kupferzell	Res integration	No
Germany		Siedenbrünzow (DE)	Osterburg (DE)	2025	Reinforcement of existing 380 kV OHL Siedenbrünzow – Güstrow – Putlitz – Perleberg – Osterburg	RES integration	no
Germany		Graustein (DE)	Bärwalde (DE)	2025	Reinforcement of existing 380 kV OHL Graustein - Bärwalde	RES integration	no

Germany		Ragow (DE)	Streumen (DE)	2025	Reinforcement of existing 380 kV OHL Ragow - Streumen	RES integration	no
Germany					Grid reinforcements in the region Büscherhof	Res integration	No
Germany					Grid reinforcements in the region Aachen	Res integration	No
Germany					Grid reinforcements in western Rhein region	Res integration	No
Germany		Conneforde (DE)	Samtgemeinde Sottrum (DE)	2030	New 380-kV-line Conneforde - Sottrum in existing corridor for RES integration	RES integration	TYNDP 2018
Germany		Großgartach (DE)	Endersbach (DE)	2030	Grid reinforcements in existing corridor between Großgartach and Endersbach. Extension of substation Wendlingen is included	Security of supply	TYNDP 2018
Germany		Mecklar (DE)	Bergrheinfeld/West (DE)	2031	New 380-kV-line Mecklar - Bergrheinfeld/West for RES integration	Res integration	TYNDP 2018
Germany		Dollern (DE)	Landesbergen (DE)	2026	New 380-kV-line Dollern - Landesbergen in existing corridor for RES integration	Res integration	TYNDP 2018
Germany		Conneforde (DE)	Cloppenburg (DE)	2026	New 380-kV-line Conneforde - Landkreis Cloppenburg in existing corridor for RES integration	Res integration	TYNDP 2018
Germany		Cloppenburg (DE)	Merzen (DE)	2026	New 380-kV-line Landkreis Cloppenburg - Merzen for RES integration	Res integration	TYNDP 2018
Denmark	Endrup-Idomlund	Endrup	Idomlund	2022	Upgrade of existing 150 kV line to 400 kV	RES integration, Security of Supply	TYNDP18
Belgium	Modular Offshore Grid II	Coast (BE)	Offshore (BE)	2028	The development of an offshore modular grid to enable the connection of an additional 2GW of offshore wind power	Res integration	TYNDP18
Belgium	Ventilus	Avelgem (BE)	Coast (BE)	2028	The development of a new axis 380 kV between the coastal region and the inner country in order to integrate an additional 2GW of offshore wind power and the possibility to connect a new interconnector.	Res integration Security of Supply Market integration	TYNDP18
Belgium	Boucle du Hainaut	Courcelles (BE)	Avelgem(BE)	2028	The development of a new axis 380 kV between Avelgem and Courcelles to integrate an additional 2GW of offshore wind power and the possibility of a new interconnector.	Res integration Security of Supply	TYNDP18

						Market integration	
Belgium	Internal Belgian Backbone Center-East: HTLS upgrade Massenhoven-VanEyck-Gramme-Courcelles-Bruegel-Mercator	Massenhoven (BE) VanEyck (BE) Gramme (BE) Courcelle (BE) Breugel (BE) Mercator (BE)	VanEyck (BE) Gramme (BE) Courcelles (BE) Breugel (BE) Mercator (BE) Massenhoven (BE)	2024 2029 2033 2035 2025 2030	The upgrade of the existing 380 kV backbone of the Belgian grid to High Temperature Low Sag conductors to unlock potential additional cross-border capacity.	Security of Supply Market integration	TYNDP18

Appendix 3. Links to national development plans

Table 6-1 provides a link to the development plan of all countries in the Northern Seas Region, where available.

Table 6-1: ENTSO-E Regional Group Northern Seas countries national development plans

Country	Company/TSO
Belgium	https://www.elia.be/en/infrastructure-and-projects/investment-plan/federal-development-plan-2020-2030
France	https://www.rte-france.com/fr/article/evolution-du-reseau-electrique-francais-l-horizon-2035 https://www.rte-france.com/sites/default/files/sddr2019_synthese_gb_ok.pdf
The Netherlands	https://www.tennet.eu/nl/bedrijf/publicaties/investeringsplannen/
Germany	https://www.netzentwicklungsplan.de/de
Great Britain	https://www.nationalgrideso.com/research-publications/network-options-assessment-noa
Ireland	http://www.eirgridgroup.com/site-files/library/EirGrid/TDP-2019-2028-Final-For-Publication.pdf
Northern Ireland	http://www.soni.ltd.uk/media/documents/SONI-TDPNI-2019-2028.pdf
Denmark	https://energinet.dk/Om-publikationer/Publikationer/RUS-plan-2018
Norway	https://www.statnett.no/globalassets/for-aktorer-i-kraftsystemet/planer-og-analyser/nup-og-ksu/statnett-nettutviklingsplan-2019.pdf
Luxembourg	https://www.creos-net.lu/actualites/actualites/article/scenario-report-2040-public-consultation.html

Appendix 4. Glossary

Term	Acronym	Definition
Agency for the Cooperation of Energy Regulators	ACER	An EU Agency established in 2011 by the Third Energy Package legislation as an independent body to foster the integration and completion of the European Internal Energy Market both for electricity and natural gas.
Baltic Energy Market Interconnection Plan in electricity	BEMIP Electricity	One of the four priority corridors for electricity, as identified by the TEN-E Regulation. Interconnections between Member States in the Baltic region and the strengthening of internal grid infrastructure to end the energy isolation of the Baltic States and to foster market integration. This includes working towards the integration of renewable energy in the region.
Bottom-Up		This approach of the scenario-building process collects supply and demand data from Gas and Electricity TSOs.
Carbon budget		This is the amount of carbon dioxide the world can emit while still having a likely chance of limiting average global temperature rise to 1,5 ° C above pre-industrial levels, an internationally-agreed-upon target.
Carbon Capture and Storage	CCS	Process of sequestrating CO2 and storing it in such a way that it will not enter the atmosphere.
Carbon Capture and Usage	CCU	Captured CO2, instead of being stored in geological formations, is used to create other products such as plastic.
Combined Heat and Power	CHP	Combined heat and power generation.
Congestion revenue / rent		Revenue derived by interconnector owners from the sale of the interconnector capacity through auctions. In general, the value of the congestion rent is equal to the price differential between the two connected markets multiplied by the capacity of the interconnector.
Congestion		A situation in which an interconnection linking national transmission networks cannot accommodate all physical flows resulting from international trade requested by market participants, because of a lack of capacity of the interconnectors and / or the national transmission systems concerned.
	COP21	21st Conference of the Parties to the United Nations Framework Convention on Climate Change, organised in 2015, where participating states reached the Paris Agreement.
Cost-benefit analysis	CBA	Analysis carried out to define to what extent a project is worthwhile from a social perspective.

Curtailed electricity		Curtailed electricity is a reduction in the output of a generator from otherwise available resources (e. g. wind or sunlight), typically on an unintentional basis. Curtailments can result when operators or utilities control wind and solar generators to reduce output to minimise congestion of transmission or otherwise manage the system or achieve the optimum mix of resources.
Demand side response	DSR	Consumers have an active role in softening peaks in energy demand by changing their energy consumption according to the energy price and availability.
e-Highway2050	EH2050	Study funded by the European Commission aimed at building a modular development plan for the European transmission network from 2020 to 2050, led by a consortium including ENTSO-E and 15 TSOs from 2012-15 (to e-Highway2050 website).
Electricity corridors		Four priority corridors for electricity identify by the TEN-E Regulation: North Seas offshore grid (NSOG); North-south electricity interconnections in western Europe (NSI West Electricity); North-south electricity interconnections in central eastern and south eastern Europe (NSI East Electricity); Baltic Energy Market Interconnection Plan in electricity (BEMIP Electricity).
Energy not served	ENS	Expected amount of energy not being served to consumers by the system during the period considered, due to system capacity shortages or unexpected severe power outages.
Grid transfer capacity	GTC	Represents the aggregated capacity of the physical infrastructure connecting nodes in reality; it is not only set by the transmission capacities of cross-border lines but also by the ratings of so-called 'critical' domestic components. Thus the GTC value is generally not equal to the sum of the capacities of the physical lines represented by this branch; it is represented by a typical value across the year.
Internal Energy Market	IEM	Since 1996, in order to harmonise and liberalise the EU's internal energy market, measures have been adopted to address market access, transparency and regulation, consumer protection, supporting interconnection, and adequate levels of supply. These measures aim to build a more competitive, customer-centred, flexible and non-discriminatory EU electricity market with market-based supply prices.
Investment (in the TYNDP)		Individual equipment or facility, such as a transmission line, a cable or a substation.
Mid-term adequacy forecast	MAF	ENTSO-E's annual pan-European monitoring assessment of power system resource adequacy, spanning a timeframe from one to ten years ahead.
Net transfer capacity	NTC	The maximum total exchange programme between two adjacent control areas compatible with security standards applicable in all control areas of the synchronous area and taking into account the technical uncertainties on future network conditions.

N-1 criterion		The rule according to which elements remaining in operation within a TSO's responsibility area after a contingency from the contingency list must be capable of accommodating the new operational situation without violating operational security limits.
National Energy and Climate Plan	NECP	National Energy and Climate Plans are the new framework within which EU Member States have to plan - in an integrated manner - their climate and energy objectives, targets, policies and measures for the European Commission. Countries will have to develop NECPs on a ten-year rolling basis, with an update halfway through the implementation period. The NECPs covering the first period from 2021-30 will have to ensure that the Union's 2030 targets for greenhouse gas emission reductions, renewable energy, energy efficiency and electricity interconnection are met.
North Seas offshore grid	NSOG	One of the four priority corridors for electricity identified by the TEN-E Regulation. Integrated offshore electricity grid development and related interconnectors in the North Sea, Irish Sea, English Channel, Baltic Sea and neighbouring waters to transport electricity from renewable offshore energy sources to centres of consumption and storage and to increase cross-border electricity exchange.
North-south electricity interconnections in central eastern and south eastern Europe	NSI East Electricity	One of the four priority corridors for electricity identified by the TEN-E Regulation. Interconnections and internal lines in north-south and east-west directions to complete the EU internal energy market and integrate renewable energy sources.
North-south electricity interconnections in western Europe	NSI West Electricity	One of the four priority corridors for electricity identified by the TEN-E Regulation. Interconnections between EU countries in this region and with the Mediterranean area, including the Iberian peninsula, in particular to integrate electricity from renewable energy sources and reinforce internal grid infrastructures to promote market integration in the region.
Power to gas	P2G	Technology that uses electricity to produce hydrogen (Power to Hydrogen – P2H2) by splitting water into oxygen and hydrogen (electrolysis). The hydrogen produced can then be combined with CO2 to obtain synthetic methane (Power to Methane – P2CH4).
Project (in the TYNDP)		Either a single investment or a set of investments, clustered together to form a project, in order to achieve a common goal.
Project of common interest	PCI	A project which meets the general and at least one of the specific criteria defined in Article 4 of the TEN-E Regulation, and which has been granted the label of PCI project according to the provisions of the TEN-E Regulation.
Put IN one at the Time	PINT	Methodology that considers each new network investment / project (line, substation, PST or other transmission network device) on the given

		network structure one by one and evaluates the load flows over the lines with and without the examined network reinforcement.
Reference grid		The existing network plus all mature TYNDP developments, allowing the application of the TOOT approach.
Reference capacity		Cross-border capacity of the reference grid used for applying the TOOT/PINT methodology in the assessment according to the CBA.
Scenario		A set of assumptions for modelling purposes related to a specific future situation in which certain conditions regarding electricity and gas demand and supply, infrastructures, fuel prices and global context occur.
Take Out One at the Time	TOOT	Methodology that consists of excluding investment items (line, substation, PST or other transmission network device) or complete projects from the forecasted network structure on a one-by-one basis and to evaluate the load flows over the lines with and without the examined network reinforcement.
Ten-Year Network Development Plan	TYNDP	The Union-wide report carried out by ENTSO-E every other year as part of its regulatory obligation as defined under Article 8, para 10 of Regulation (EC) 714 / 2009.
Top-Down		The “Top-Down Carbon Budget” scenario-building process is an approach that uses the “bottom-up” model information gathered from the gas and electricity TSOs. The methodologies are developed in line with the Carbon Budget approach.
Trans-European Networks for Energy	TEN-E	Policy focused on linking the energy infrastructure of EU countries. It identifies nine priority corridors (including four for electricity) and three priority thematic areas.

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