The North Seas Countries' Offshore Grid Initiative

- Initial Findings -

Final Report
Working Group 1 – Grid Configuration

16th November 2012

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Executive Summary

Recognising the important contribution the resources of the North Seas could make towards achieving renewable targets up to 2020 and carbon targets beyond, the North Seas Countries' Offshore Grid initiative was formed as the responsible body to evaluate and facilitate coordinated development of a possible offshore grid that maximises the efficient and economic use of those renewable resources and infrastructure investments. The Memorandum of Understanding (MoU) was signed on 3 December 2010 by the 10 countries around the North Seas represented by their energy ministries, supported by their Transmission System Operators (TSOs, organised in the European Network of Transmission System Operators for Electricity ENTSO-E), their regulators (organised in the Agency for the Cooperation of Energy Regulators ACER) and the European Commission, together forming the "North Seas Countries' Offshore Grid Initiative (NSCOGI)".

The MoU breaks down the overarching objective into a set of deliverables to be taken forward, initially for a two year period, by three Working Groups (WGs): WG1 - grid implementation, WG2- market and regulation and WG3 - permissions and planning. Each WG is chaired by representatives of two countries' energy ministries and coordinated by a programme board. This report sets out the initial findings of the TSOs' study within WG1 supporting the NSCOG1 final report.

Go it alone, or do it together?

The information contained in this report aims to evaluate the long-term development of an offshore grid structure in the North Seas. While some coordination already exists, nationally with the integrated connection of a number of offshore wind parks (e.g. Germany and Great Britain) and between nations in the development of interconnectors, this report seeks to answer the question of how best to exploit future offshore generation resources – by continuing to 'go it alone', or by 'doing it together'? It therefore provides a view on how a meshed offshore grid might develop over the period 2020 to 2030 as the countries in the North Seas region advance towards a low carbon energy future. It is based on the governments' best view of energy generation and demand in 2030 as expressed in summer 2011.

The designs presented in this report are shown to illustrate possible electricity transmission system designs. They do not represent a physical construction programme or the investment decisions of the involved Governments, TSOs or offshore generator developers. Actual development of the transmission systems in each of the North Seas countries may differ significantly to those presented by this study, due to necessary assumptions around perfect functioning markets, absence of regulatory barriers and common assumptions on fuel / CO_2 prices being made for this study.

The illustrative designs consider the possible development of an offshore grid by utilising two different design strategies, thus enabling comparison between the different approaches (and associated technology assumptions as analysed in [5])

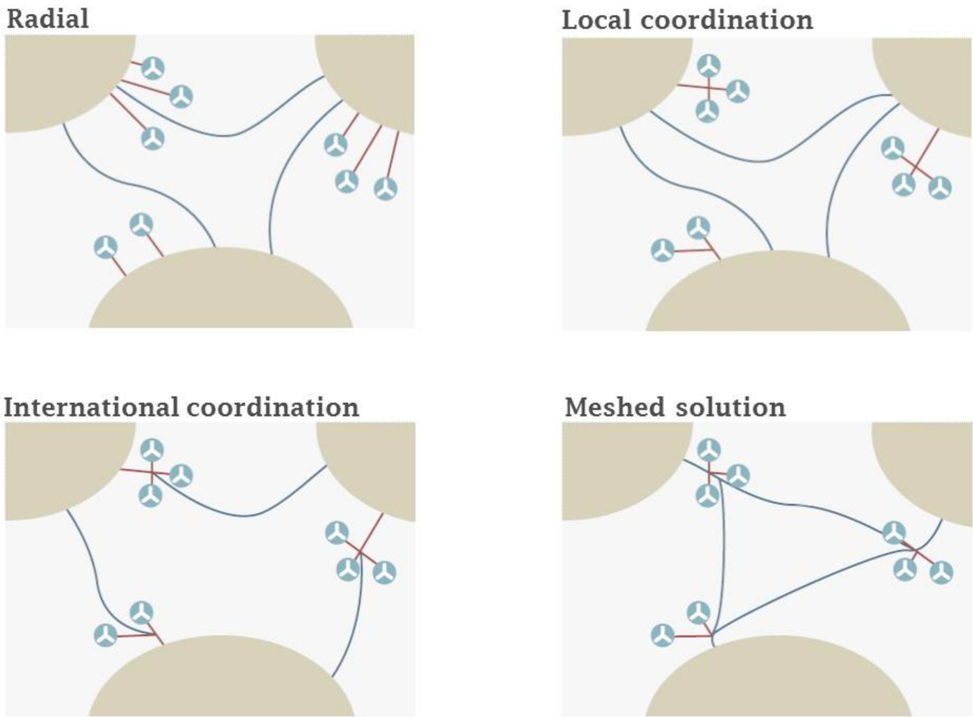


Figure 0-1 Assumed general pattern of the Offshore Grid Development

Radial -point-to-point connection of offshore wind farms and shore-to-shore interconnectors (with necessary onshore development) utilising existing and anticipated future transmission technology [5].

Meshed -coordinated onshore, offshore and interconnected design using anticipated technology [5], interconnecting offshore platforms, offshore development zones and countries

It should be recognised that the radial and meshed design strategies represent extreme ends of the spectrum of approaches. Any integrated offshore grid is likely to develop in a stepwise manner with coordinated near-shore wind connections and point-to-point interconnectors an essential first step. In reality therefore a regional solution could be expected to include some or all of the elements shown in Figure 0-1above. At today's stage any future offshore grid is expected to be developed gradually based on robust business cases for individual projects rather than being built from any blueprint for the future.

Approach adopted

The process adopted by WG1 to develop the grid designs is essentially the same as the one used by TSOs to plan their own internal grid enhancements, although it may differ in some of the detail. This is best shown by the figure below:

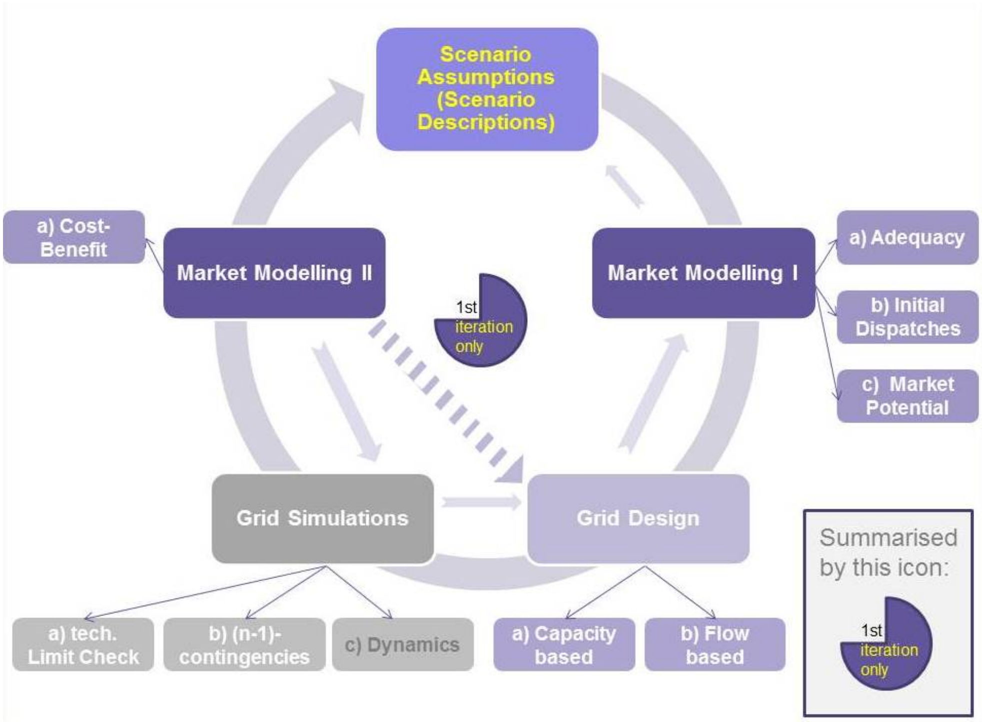


Figure 0-2 General Procedure divided into logical steps

The NSCOGI study presented a unique opportunity to collect the ten countries' views of generation and load in the year 2030 to create a Reference scenario (the details of which are set out in Appendix A 2). This data was combined with technical parameters and IEA fuel and CO_2 prices to carry out market analysis to simulate the expected amount of generation produced by each fuel type and investigate the expected import/export position of each country and associated CO_2 emissions. In this way the potential for increasing trading capacity between countries can be investigated, although this investigation only assesses the additional cross border capacity that might be supported by market analysis alone, and therefore does not yet represent an investment plan.

Network design and analysis were then carried out to investigate the physical behaviour of the grids, based on the technical parameters of the region's electricity grid. Selection of candidate investments was optimised to reinforce the grid to meet the market needs derived from the 2030 generation and load scenario (including connection of new offshore generation). Optimised outline grid designs were confirmed as viable and refined with more targeted grid and market simulations.

A final market analysis explored and what benefits might arise in terms of reduced 2030 production costs as a result of the grid expansion strategies proposed in the previous stages. A comparison of the costs and benefits is also carried out at this stage.

Resulting grid designs

While the illustrative grid designs emerging from this process focus on integration of offshore RES, they also meet the needs of the other pillars of energy policy: integration of energy markets (IEM), integration of renewable energy sources (RES) and security of supply (SoS).

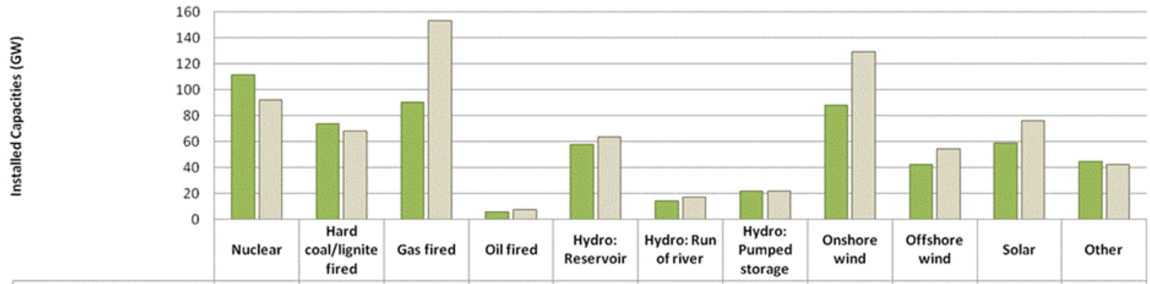
Both the radial and meshed designs provide access to all of the offshore wind parks assumed in the 2030 scenario and therefore facilitate the renewable energy ambitions of the 10 Governments as set out in the Reference scenario.

Because of the relatively small volumes of offshore RES expected between 2020 and 2030 in the Reference scenario, the designs have limited opportunity for ‘meshing’ with the resulting radial and meshed strategies costing both approximately 30 €bn respectively. They provide relatively equivalent “results/benefits” in terms of market integration with little difference between the radial and meshed configurations for net import and export positions, production cost savings and CO_2 emissions, , which is not a surprise due to only a limited amount of meshing resulting from the analysis of the reference scenario. This is a result of a relatively small amount of offshore wind and their location being added to the system.

The expansion of the grids out to 2030 involves building a significant amount of new interconnection capacity in addition to those foreseen in the TYNDP 2012 [3] (which focuses on the perspective 2020 and was the starting position of the study). The new interconnectors connect market areas with different prices (driven by the different fuel mixes presented in the Reference scenario).

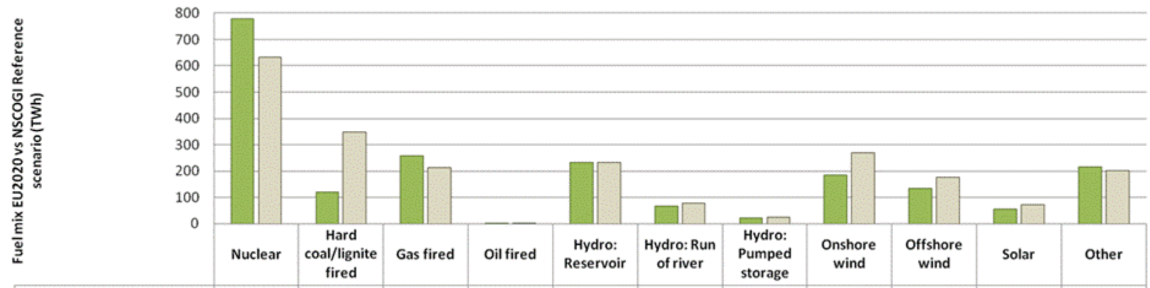
The Reference Scenario used in this analysis was the result of a joint exercise by Governments and TSOs in the summer of 2011 and represents the considered views of the 10 Governments of the North Seas region at that time. Although PRIMES was used as a starting point for generation and load data, each Government made adjustments taking account of their own national policies, planning considerations etc. The assumptions underpinning those national contributions were quite different, resulting in different fuels emerging as dominant in different countries. This clearly has a significant impact on the infrastructure needs emerging from the market studies. In addition to the new offshore wind installations these market differences were the key drivers for increased interconnection and reinforcements in 2030.

In general it makes a significant difference if a scenario is based on collected national information rather than a modelled vision based on an implicit consistent regional or European generation policy. In a collected scenario different countries will inevitably take different decisions with individual assumptions concerning the neighbours’ decisions (on their generation planning and prices for fuel and CO2) and assumptions to achieve a similar target and these different individual decisions have a direct impact on the modelled results, and infrastructure recommendations that follow:



	Nuclear	Hard coal/lignite fired	Gas fired	Oil fired	Hydro: Reservoir	Hydro: Run of river	Hydro: Pumped storage	Onshore wind	Offshore wind	Solar	Other
EU2020	111	74	90	6	58	14	22	88	42	59	45
NSCOGI Reference Scenario	92	68	153	7	64	17	21	129	55	76	43
Change [GW]	- 19	- 6	+ 63	+ 1	+ 6	+3	- 1	+ 41	+ 13	+ 17	- 2
Change [%]	- 17	- 8	+ 70	+ 17	+ 10	+21	- 5	+ 47	+ 31	+ 29	- 4

Figure 0-3 Comparison of installed capacities (in GW) in the NSCOGI perimeter in the years 2020 (Scenario EU2020) and 2030 (NSCOGI Reference scenario)



	Nuclear	Hard coal/lignite fired	Gas fired	Oil fired	Hydro: Reservoir	Hydro: Run of river	Hydro: Pumped storage	Onshore wind	Offshore wind	Solar	Other
EU2020	779	120	259	0	232	66	21	184	133	55	216
NSCOGI Reference Scenario	633	348	212	1	234	77	23	270	176	71	202
Change [TWh]	- 146	+ 228	- 47	+ 1	+ 2	+ 11	+ 2	+ 86	+ 43	+ 16	- 14
Change [%]	- 19	+ 190	- 18		+ 0,9	+ 17	+ 10	+ 47	+ 32	+ 29	- 7

Figure 0-4 Comparison of energy fuel mix (in TWh) in the NSCOGI perimeter in the years 2020 (Scenario EU2020) and 2030 (NSCOGI Reference scenario)

Although gas capacity increases by 70%, and coal capacity decreases by 8%, the energy production behaves inversely with an 18% decrease for gas, but 190% increase for coal due to the impact of the assumed merit order. By implication, this will play a major role in the countries' import / export positions and related infrastructure requirements.

Clearly running this amount of coal will also have an impact on CO_2 emissions, which according to the results stay constant between 2020 and 2030. It therefore follows that, without large-scale CCS integration, countries with significant coal generation (e.g. Germany, Great Britain and the Netherlands) are and stay also the largest emitters of CO_2, although some movement between them can be observed between 2020 and 2030.

In an energy only market and under this scenario it is doubtful whether gas-fired plant would have sufficient utilisation hours to be profitable with the assumed CO2 price and fuel prices of gas and coal.

Thus, the resulting infrastructure for the Reference scenario should be re-evaluated, if the underlying production mix assumptions are changed in the light of the results presented in this study.

This study emphasises the importance of studying scenarios developed against common foundations to avoid distortions created by differences within the scenario rather than genuine market need. Both the radial and meshed approaches produce similar levels of interconnection, with similar associated production cost savings, although there are significant differences in how they were achieved (e.g. Norway-Great Britain link in the radial design is replaced by Norway-Germany and flows through Continental Europe in the meshed design). These differences need to be further investigated.

The addition of new offshore wind park connections and new interconnectors require reinforcement of the onshore grids to accommodate the increased power flows through the onshore networks. The onshore reinforcements are, with the exception of very small differences in Great Britain, of the same order in both the meshed and radial cases.

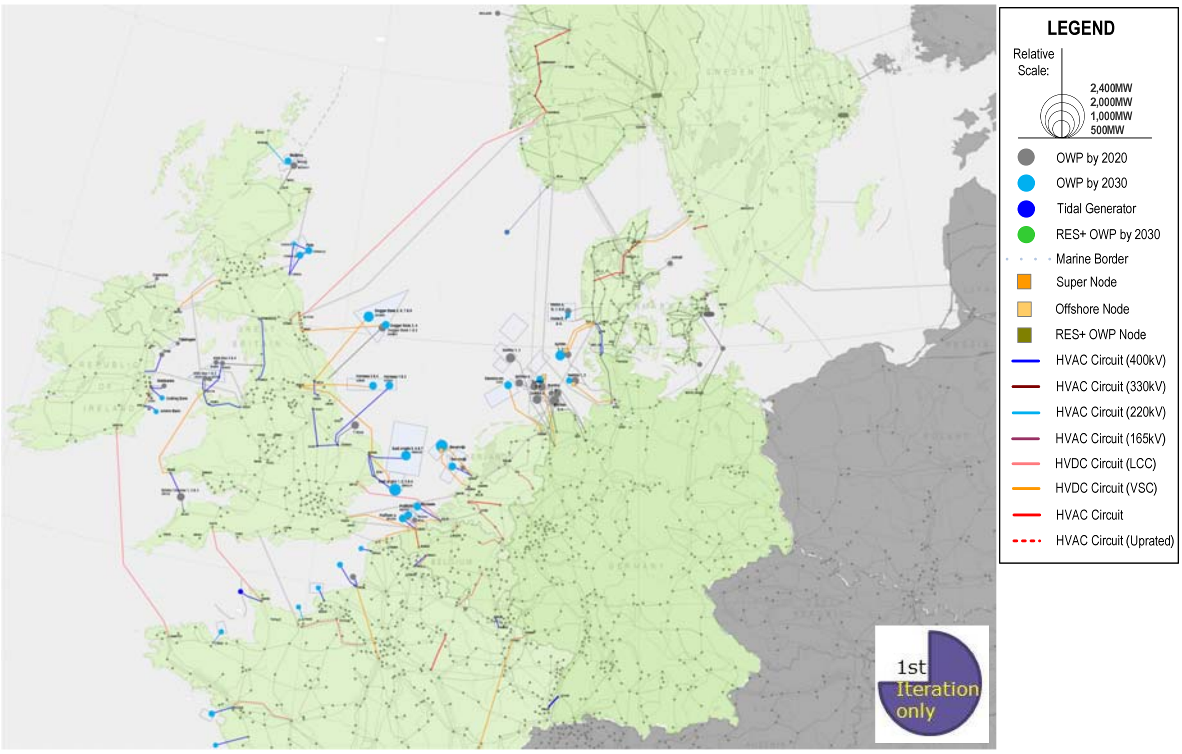


Figure 0-5 Radial Grid Design for 2030, Reference Scenario[1]

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[1] For bigger maps, see chapter 5

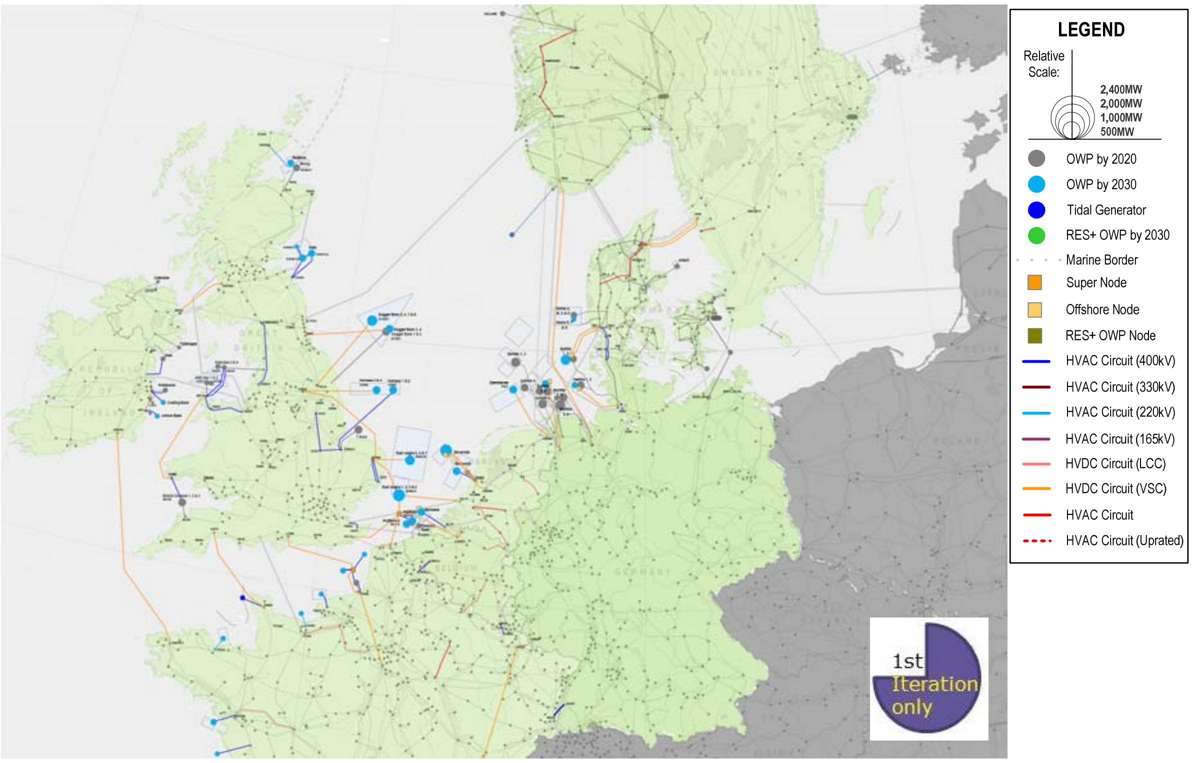

Figure 0-6 Meshed Grid Design for 2030, Reference Scenario

Based on the NSCOGI 2011 forecasts of generation and demand in the Reference scenario, the analysis carried out for this study showed that there may be slight a preference for adopting a meshed approach to grid design by 2030.

The radial and meshed designs generate an annual saving in overall production costs across the NSCOGI region of 1,449 M€ at annual costs of 1,488 M€ for the radial design, and of 1,456M€ at annual costs of 1,418 M€ for the meshed design. Thus, the meshed design provides economically the slightly better solution for the region on the basis of the assumptions made. However, the significance of these differences has to be tested with further analysis and other generation mix scenarios.

In addition, there are other less quantifiable implications of both approaches including challenges and possible advantages of a meshed grid:

- Challenges: the added complexity associated with designing and building a meshed grid, increased technology and operational risk and the need for regulatory clarification, which has already been started within NSCOGI WG2 .

- Possible advantages: the increased operational flexibility provided by the meshed network with greater resilience for individual Offshore wind power plant (OWPP). In addition, reduced environmental impact should be expected with the potential for larger cables and fewer landing points.

Sensitivity Analysis: Increasing the amount of offshore RES

Work has been initiated to test the extent to which the design topology might change as the volume of offshore RES increases by carrying out a sensitivity analysis - the RES+ sensitivity. In this analysis, only the amounts of offshore RES were changed, with volumes provided by the TSOs to reflect the most ambitious RES volumes for 2030 in their scenarios. These numbers are therefore not generally consistent with any Governments' predictions. Being only a sensitivity analysis, it is not a fully studied scenario and therefore the results of the Reference scenario and the RES+ sensitivity are not directly comparable. They do however provide a useful indication regarding the influence an increasing amount of offshore wind has on the design topology and therefore provides a motivation for further investigations in this area.

Although the RES+ analysis did not go through the same rigour as the reference scenario (only half way round the process shown in Figure 0-2), the increased volumes of wind do create a more complex, meshed offshore network in the North Sea between Great Britain, Norway and Germany, with simpler meshed networks emerging in the Irish Sea and English Channel. Indicative cost comparisons suggest that a meshed approach results in higher interconnector costs but lower national reinforcements. Overall costs for the meshed design for this RES+ sensitivity analysis are approximately 7 per cent lower than for the radial design. The benefit in terms of production cost reduction has not been assessed for this sensitivity (half way around the circle).

Therefore, if future targets are likely to involve significantly increased volumes of offshore RES over those assumed in the Reference scenario, there may be substantial benefits in adopting a more integrated, meshed approach to grid design. This hypothesis should be further examined with the in-depth analysis of an additional scenario covering this outcome.

Continued cooperation needed

Going forward additional scenarios should be developed assessing each corner of the 'future kite' described in Chapter 1. These should be developed on common underlying assumptions, which is a different scenario building approach than the one used in this study. ENTSO-E are currently developing four 2030 consulted visions to be considered in the next TYNDP (2014). These scenarios will be subject to extensive consultation, and it is important that all NSCOGI stakeholders agree to them being used as an appropriate foundation also for further NSCOGI work. In addition TSOs, alongside the relevant NRAs and Governments, should study in more detail the projects where early 'meshings' are suggested, assessing them against additional sensitivities to test the effects of fuel price assumptions and alternative connection regimes.

The North Seas Countries' Offshore Grid Initiative has shown the importance of cooperation between Governments, the European Commission, Regulatory institutions and TSOs for the development of a common understanding of future requirements and possible routes / barriers. Continuation of the Initiative is therefore recommended in order to further investigate the requirements of a 2030 grid.

1 Background and Context (Programme of work)

1.1 Introduction

In order to achieve its energy policy goals as described in the European Commission's draft Energy Infrastructure Package [1] (affordable by integration of energy markets (IEM), sustainably integration of renewable energy sources (RES) and secure by ensuring security of energy supply (SoS)) – it is necessary that the relevant electricity system is adapted in a coordinated and collaborative manner.

Generation from renewable sources has increased significantly over the last few years and will continue to do so in the short to medium term to achieve 2020 RES targets. Beyond 2020, increasing RES production is expected to continue to make a significant contribution to 2050 decarbonisation.

The North Seas[2] are recognised in the infrastructure package[1] as being one of the priority corridors and expected to supply a significant volume of RES up till 2030 and onwards. The Political Declaration launching the North Seas Countries' Offshore Grid Initiative (NSCOGI)[2]was initiated to support the development of this priority corridor, and is the background of this report.

The NSCOGI was formed as the responsible body to first investigate barriers and propose solutions to the 10 countries' ministers, who will then decide on the way forward. Offshore generation and grid development has a major impact on onshore grid expansion. Nevertheless, the three pillars of the policy goals (RES, SoS and IEM) cannot be separated when planning grid development, as the cost of additional assets has to be balanced by the expected socio-economic benefit for European citizens. This study has therefore involved a much broader perspective than just the sole task of connecting offshore renewable generation.

1.1.1 NSCOGI Working Structure and Tasks

In December 2010, a Memorandum of Understanding (MoU) was signed by the 10 countries around the North Seas, represented by their Energy Ministers, supported by their TSOs (organised in the European Network of Transmission System Operators for Electricity ENTSO-E) and their regulators (organised since March 2011 in the Agency for the Cooperation of Energy Regulators ACER), and the European Commission, forming the "North Seas Countries' Offshore Grid Initiative"[2]. This is the first time that these different

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[2]The "North Seas" in this document refers to the North Sea, the Irish Sea, the English Channel, Skagerrak and Kattegat.

stakeholders have joined forces, which indicates the topic's importance on the European agenda.

The initiative aims at coordinating all efforts towards necessary investigations on a) technical and grid planning questions, as well as b) identifying market and regulatory barriers and c) proposing measures to streamline the permitting process, in order to assess the economic interest of offshore grid development.

The MoU breaks down the overarching objective into a set of deliverables to be taken forward by three Working Groups, see Figure 1-1, each investigating the different issues a) to c) mentioned above, needing different experts. This structure was chosen to ensure fast information flows and commonly agreed results.

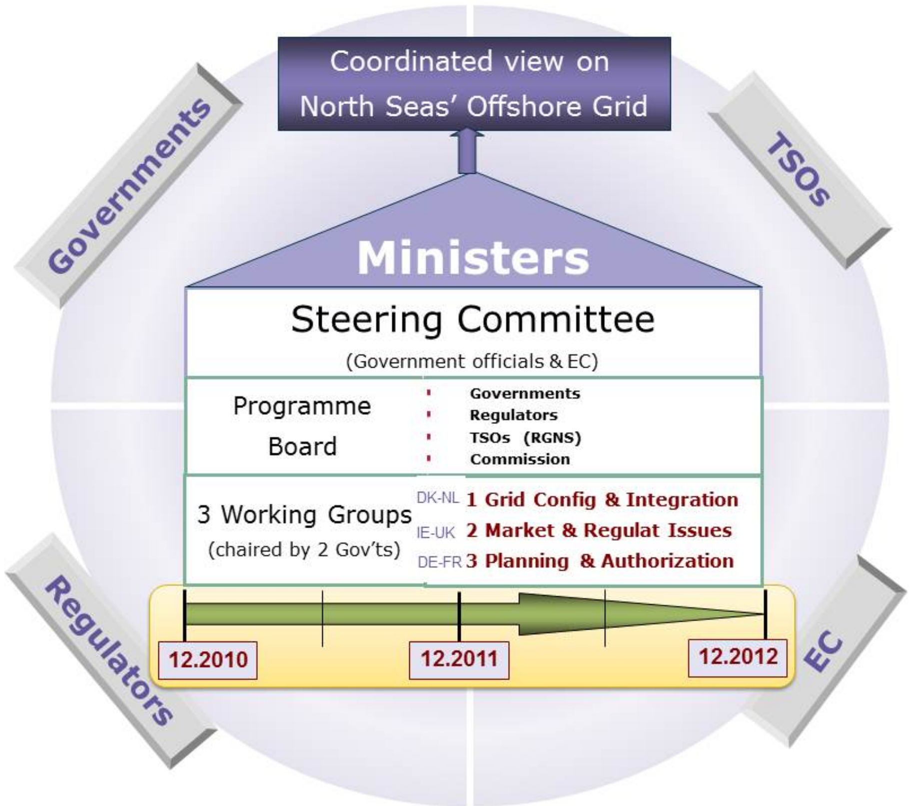

Figure 1-1 NSCOGI Working Structure

Each Working Group is composed of members representing the ten countries' energy ministries, the regulatory authorities, the TSOs and the European Commission. Two ministerial representatives chair each Working Group. A programme board consisting of the Working Group leads, representatives of ENTSO-E, ACER and the Commission coordinate the work of the Working Groups.

1.1.2 Statement of Aims and Objectives of the NSCOGI Working Groups

Figure 1-2 Study Area (Violet)

The aim of the NSCOGI is to establish a strategic and coordinated approach to improve current and future energy infrastructure development in the North Seas.

The initiative seeks to evaluate and facilitate coordinated development of a possible offshore grid that maximises the efficient and economic use of the renewable resources and infrastructure investments in the North Seas, focusing on the connection of offshore wind, onshore grid reinforcements and cross border capacity.

The objectives of the three Working Groups are summarised below:

Working Group 1 (WG1) - Grid Configuration and Integration
a. North Seas offshore and onshore grid study, based on Government policies and grid conditions, simulated in market and grid models b. Identification of needs, costs and benefits
Working Group 2 (WG2) - Market and Regulatory Issues
a. Identification of incompatibilities of national markets and regulatory regimes as barriers to an offshore grid b. Proposal on cost-benefit sharing and investment incentives c. Proposal for a common regulatory approach to anticipatory investments, risk sharing →cost efficient grid development d. Develop proposal for market mechanisms for both increase RES and combination of offshore wind + interconnectors, taking national support schemes into account
Working Group 3 (WG3) - Planning and Authorisation procedures
a. Identify incompatibilities in national regimes on authorisation as barriers to an offshore grid b. Develop recommendations to accelerate decision-making procedures both for on- and offshore grid planning at regional or sub-regional level

This report focuses on the tasks and results from WG1 – grid configuration and integration, chaired jointly by representatives from Denmark and the Netherlands. The methodology, assumptions concerning generation portfolio, load situation, available technology and results are presented.

1.1.3 Aims and objectives of this report

Aim
• This report presents the WG1 Offshore Grid Study that supports the NSCOGI final report. • The information contained in this report aims to evaluate the long-term development of an offshore grid structure in the North Seas by providing a view on how such a grid may possibly develop in the future, based on the assumptions made for this study. • The report aims to compare and evaluate the possible advantages and disadvantages of the long term development of an optimised, integrated (or meshed) offshore grid in the North Seas by providing a view of how that possible grid might develop in the future against changes to the electricity energy requirements. • To evaluate basic variants, different transmission design topologies (radial and meshed) were compared and analysed with respect to various aspects, such as cost/ benefits, import and export levels and the systems' CO_2 emissions.

Scope

The information contained within this report:

- **Does** analyse the possible effects of the development of meshed grid versus a radial approach
- **Does** compare the costs of building the different grid designs against the measureable benefits
- **Does** provide a view on how a meshed offshore grid might possibly develop over the period 2020 to 2030 as the countries in the North Seas region advances towards a low carbon energy future
- **Does** evaluate how a future transmission grid (on- and offshore) may possibly evolve in the future against the studied best view on generation and load (G/L) assumptions for 2030 and a variation of these
- **Does** identify electricity transmission technology available for deployment (incorporating advancements in research and development)
- **Does** assume perfect market and no regulatory barriers and smooth consenting

The information contained in this report:

- **Does not** represent a plan or programme of physical construction of how possible grids in the North Seas will develop in future years
- **Does not** represent the investment decisions and/or programme of the Governments and the Transmission System Owners
- **Does not** represent development/construction of offshore generation projects
- **Does not** dictate the actual connection routes for new electricity transmission infrastructure
- **Does not** consider delivery vehicles or ownership/operation issues, focusing exclusively on design
- **Does not** elaborate on the question whether an offshore grid is the best solution for the region to solve its future electricity supply

The maps presented in this report are shown to **illustrate possible** electricity transmission system designs. The actual development of the transmission systems in each of the North Seas' countries will probably be **different** due to the points above.

This study is only the first step of a process: completion of further, more detailed, analyses will be required to agree electricity transmission grid connections for individual projects which can and may be different from those which are shown in this document.

Some coordination in the development of offshore infrastructure already exists both nationally with the integrated connection of a number of offshore wind parks (e.g.

Germany and Great Britain) and between nations in the development of interconnectors. However, in showing the potential benefits of the development of a meshed grid over a radial approach, this report seeks to answer the question of how best to exploit future offshore generation resources – by continuing to ‘go it alone’, or by ‘doing it together’?

Table 1-1 below presents a generally accepted hypothesis that motivated this offshore grid study. The cost indications in the table refer only to offshore assets. While the results of this study may not have conclusively proven the points in the table, the hypothesis remains sound.

Table 1-1 Exploitation of offshore generation resources

How to exploit offshore generation resources		
Scenarios (Note: both meet renewables targets, but in different ways)	**“Do-it-alone”** Each MS has own regulatory regime, and works alone to connect offshore generation radially or in national integrated hubs	**“Do-it-together”** MSs work together to build a shared / integrated network offshore
High offshore deployment (High levels of new RES deployed offshore)	More expensive, less efficient, leading to possible unnecessary redundancy compared to coordinated approach	Relatively less expensive than do-it-alone Opportunity to optimise international network
Low offshore deployment (CCS, nuclear, onshore wind and less offshore generation than above)	Less expensive than for high deployment, as less generation connected	Benefits from coordination is smaller as fewer resources to be connected. May be some benefits on a project-by-project basis

1.1.4 The development of plausible grid configuration designs by 2030

In the NSCOGI MoU of December 2010, Ministers asked Working Group 1 (WG1) to identify plausible grid scenarios for onshore and offshore grid infrastructure in 2030. These were to be based on the simultaneous consideration of baseline overviews of Government policies and grid conditions. In this context, ‘scenarios’ are understood as conceptual offshore grid designs based on plausible market modelling simulations.

Grid cables have a very long life (40 to 50 years) and the location and placement of offshore wind farms should also be expected to last for a long time, as other generation facilities using other primary resources do. Investment decisions therefore need to be made for the long term and should be thoroughly prepared and planned. The conceptual offshore grid designs contained in this report are intended to prepare the market and decision makers for the possible future grid development that could be needed between now and 2030.

The grid designs should potentially contribute to identify and potentially mitigate bottlenecks in the onshore grid system and facilitate the greater integration of electricity markets in the region. The grid designs take account of the envisioned developments in new technology and make assumptions on the price of technology as elaborated in [5].

The generation and load assumptions for the Reference scenario were based on the EU's latest available PRIMES scenario, which were adapted by each Government to present their best view on 2030. This status of best views was collected in summer 2011 and so may have changed since then.

In general it makes a difference if a scenario is based on collected national information or on a modelled vision based on an implicit consistent European policy, which might even include an investment model for electricity production facilities. In a collected scenario the different countries might take different decisions for reaching a similar target – or even the different national targets. Although each national contribution may be the result of sophisticated government modelling, it is always hard to estimate the neighbours' decisions and behaviour due to lack of information.

Associated technical characteristics was added to the collected national data and processed in the TSO's various models.

1.1.5 Stepwise development of an offshore grid

The future-looking assessment of the possible developments of an offshore grid is based on a number of principles that impact the electricity system designs included in this document.

In its publication on the North Seas Grid development in February 2011[3] ENTSO-E assumed that the pattern of offshore grid development would follow interim steps, under which current radial approaches would be followed by concentration patterns ('local coordination' and 'international coordination') before (fully) meshed designs were adopted, Figure 1-3. This same evolution of an offshore grid is also assumed in this report.

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[3] ENTSO-E: Offshore Grid Development in the North Sea - ENTSO-E views – Feb 2011 https://www.entsoe.eu/fileadmin/user_upload/_library/position_papers/110202_NSOG_ENTSO-E_Views.pdf

Grid design strategies – visual illustration

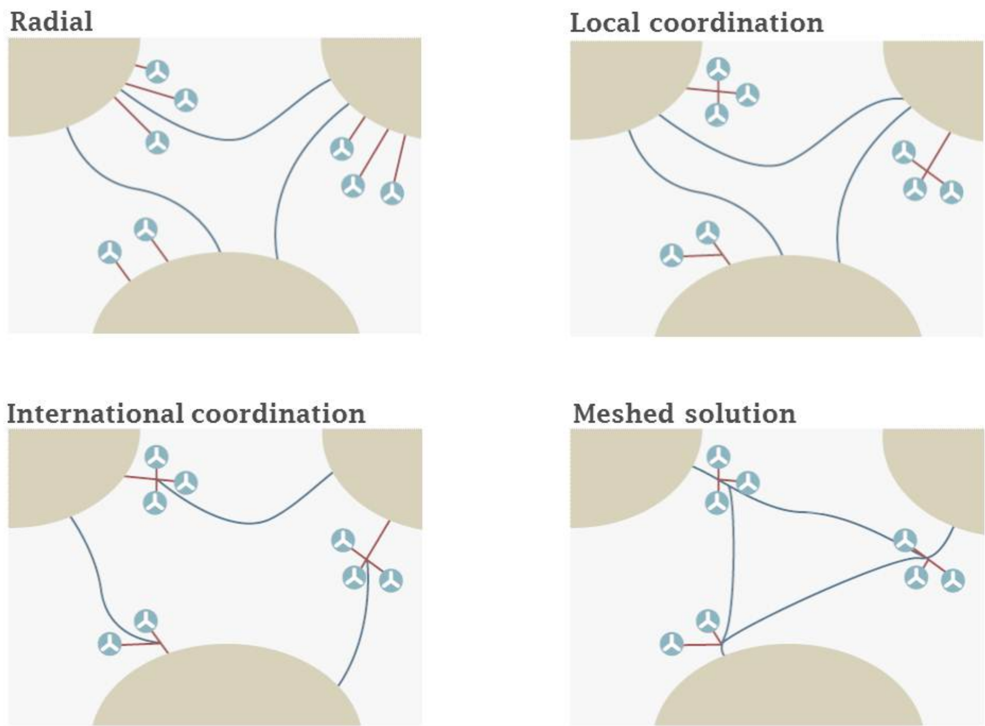


Figure 1-3 Assumed General Pattern of Offshore Grid Development

Subsequently, ENTSO-E's Regional Group North Sea developed a report outlining the likely development of new grid technology, when it is expected to be ready for the market and at what prices. This comprehensive piece of work was commented on by stakeholders through the 'Adamowitsch group' which includes industry and research representatives, and informed the work of ENTSO-E serving NSCOGI's WG1[4].

This WG1 deliverable takes the development of the existing and expected new technologies and the interplay with the geographical location of offshore wind farm developments into account. The objective being to provide some assessment of the cost and overall benefits expected from higher integration of the offshore grid (i.e. comparison of 'radial' design with more integrated designs incorporating 'meshed' solutions). The projected phasing out of some existing power plants in the region is also taken into account according to Governments' view at the beginning of the study.

[4] ENTSO-E Offshore Transmission Technology. Bruxelles, November 2011 https://www.entsoe.eu/fileadmin/user_upload/_library/publications/entsoe/SDC/European_offshore_grid_-_Offshore_Technology_-_FINALversion.pdf

The results of this study compare two reference years – 2020 and 2030; no phasing of interim steps is reflected. In reality the development of the offshore grid will be the result of individual business cases for each individual offshore project. The outcome of such business cases will be critically dependant on decisions taken elsewhere in the scope of the whole area, and also on the order of sequence of their development.

1.1.6 Grid designs – key principles

Grid designs – key principles
The illustrative grid designs are based on an assessment of: • possible generation and demand backgrounds assumed for 2030; • development and deployment of different types of generation (including those applicable offshore); • transmission electricity technology which may be available for deployment over the time period considered[5]; • resilience and integrity of the transmission systems which is reflected in the different transmission design topologies utilised in this document; and • holistic design requirements of transmission systems which is reflected in the different transmission design strategies utilised in this document.

Grid design strategies
The illustrative electricity transmission system designs consider the possible development of an offshore grid by utilising two different design strategies which enables a comparison between the different approaches and associated technology assumptions, described in [5], which was written to gather the assumptions for this study: • **Radial** Point-to-point connection of offshore wind farms from offshore substation to a suitable onshore substation and shore-to-shore interconnectors utilising anticipated future transmission technology e.g. 2GW capacity converter stations and high capacity offshore cables. Necessary onshore development is considered as well. • **Meshed** A coordinated onshore, offshore and interconnected design approach using anticipated technology (2GW cables etc), but also interconnecting offshore platforms, offshore development zones and countries. Optimised for an overall economic and efficient design. This means that the meshed design for the whole of the North Seas region could include some or all of the solution types shown in Figure 1-3, as for some offshore wind parks a fully meshed solution may not be economic. • **Gradual development** For simulation of the meshed variant, a gradual transition from radial via local coordination and internal coordination has been assumed. **Working Hypothesis** The study's basic hypothesis is that a meshed grid provides a series of quantifiable and non-quantifiable benefits against the radial design. This is to be tested utilising the Reference scenario.

1.1.7 Scenario based planning and TYNDP perspective

Under the third energy package (especially Regulation (EC) 714/2009) ENTSO-E must publish a Ten-Year Network Development Plan (TYNDP) every two years. The production of each TYNDP is a long process requiring strong cooperation between the European TSOs and involves many resources within each of them. As a result, the TYNDP is a valuable reference that presents the best available common view of European grid development in the coming ten years.

The recently published TYNDP 2012[3], focusing on the time horizon to 2020, has been used as the starting point for this NSCOGI study with respect to grid development. Going forward the TYNDP 2014 (published July 2014) will present scenarios for load and generation evolution for the period 2015-2030.

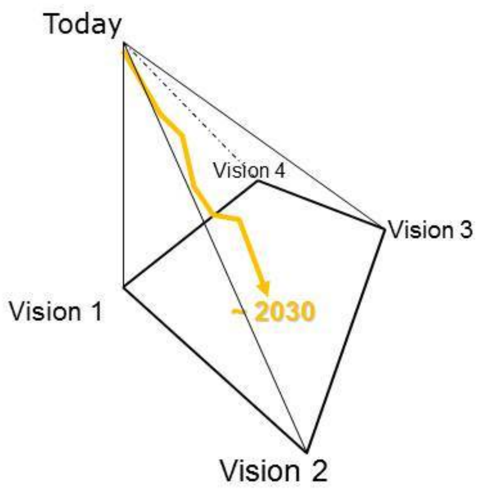


Figure 1-4: "Future Kite": Four Visions spanning an area containing the best view on 2030 [5]

Figure 1-4 illustrates potential development paths from now to 2030. As it is not possible to predict future developments to 2030 with any degree of accuracy, ENTSO-E is developing four contrasting 2030 visions (i.e. scenarios) that differ enough from each other to capture a realistic range of possible future pathways as well as result in different future challenges for the grid development [3].

The framework for these visions consists of two main axes indicating the level of European integration on the horizontal axis and on the vertical axis the level of being on track for the 2050 Energy Roadmap [9].

The 2014 TYNDP will therefore depict the investment needs (boundaries) stemming from these scenarios and corresponding projects with an assessment of their expected benefits under at least one top-down scenario.

[5] A quantified vision is called "Scenario" in NSCOGI terminology:
Therefore, a vision is a set of macro-economic assumptions, and the associated scenario reflects the consequences in terms of electricity generation/load data

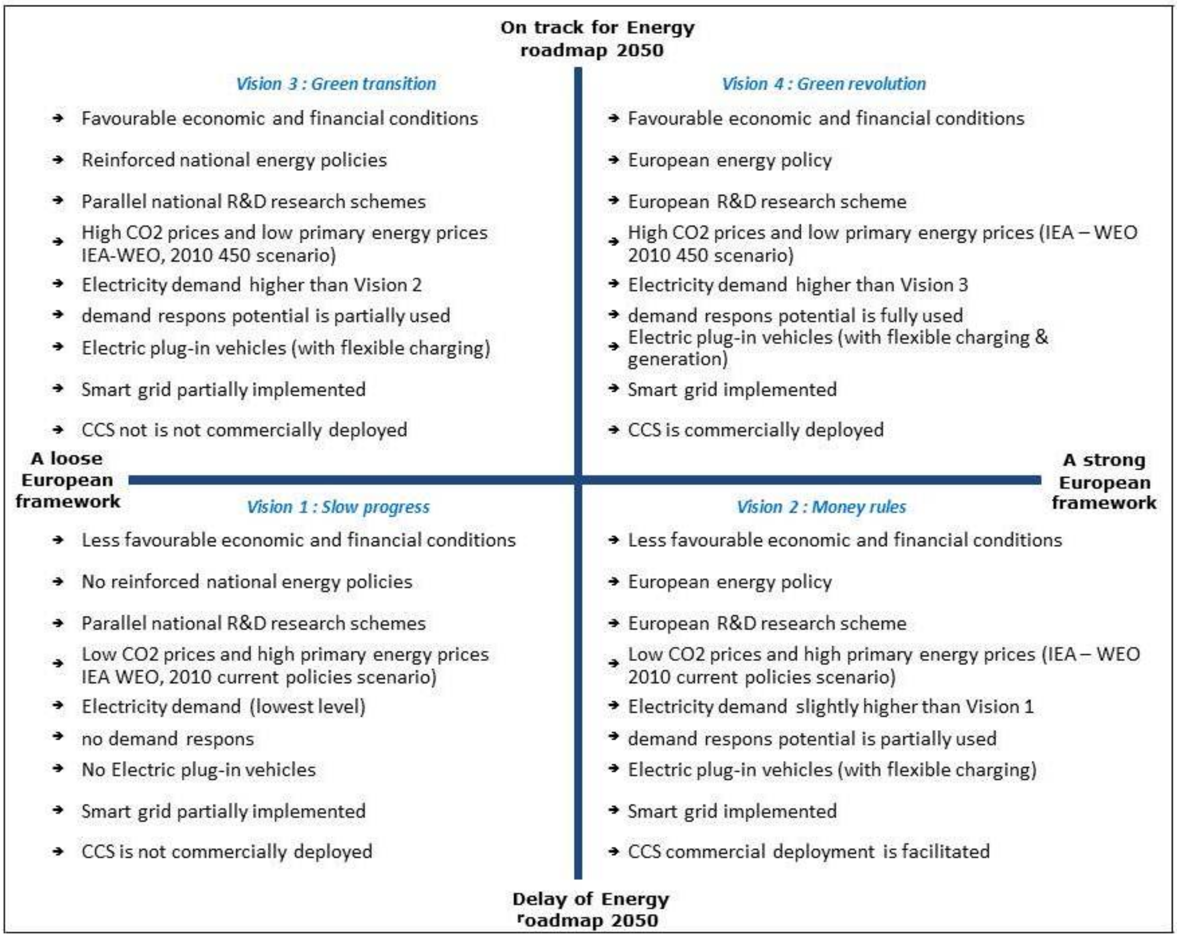


Figure 1-5: ENTSO-E's Visions

In parallel to building up these scenarios on load and generation, the TSOs are also working jointly on multilateral grid studies in order to define possible new projects for developing the grid where it will be needed. In the 2014 TYNDP these projects will be assessed for the 2030 time-horizon and the scenarios mentioned above, using the principles set up in the Cost Benefit Analysis methodology currently adopted by ENTSO-E under the Energy Infrastructure Package (EIP) [9].

This NSCOGI WG1 study can serve as a main contribution from the involved TSOs to the TYNDP Multilateral Studies.

In contrast to this general and broad approach, the present NSCOGI study used the opportunity to collect the 10 countries' best view on the future in the year 2030, see Appendix A 2, while preparing the models for the scenario based approach being used in the next TYNDP edition, and balancing appropriate level of detail versus computational feasibility as well.

2 Methodology Overview

2.1 Overview

The process adopted by Working Group 1 of NSCOGI to develop grid designs is essentially the same as that used by TSOs to plan their own internal grid enhancements, though differing in some of the details of the various activities.

The general procedure from Figure 7-1in Appendix A 1is divided into a number of logical steps as illustrated in Figure 2-1 below. Each activity enhances the knowledge about investment requirements and adds to the refinement of the grid designs. Although the process flows sequentially through each activity, there are checks at each stage built into the process that allow for a step back to the previous activity with modified inputs and assumptions to improve the quality of the outputs.

It is important to state that for this study there was only a single run through the overall process – although comprising several micro-iterations between the activities. Due to the nature of the study, dynamic investigations have not been executed. It is therefore possible that the maps and figures would change when continuing with additional iterations. The addition of a small icon on all of the maps included in this report serves as a reminder of this fact.

While the Reference scenario included several micro-iterations, the RES+ sensitivity described later in the report, did not. A reminder of this fact is made by the use of another icon on the respective maps, preventing the reader from making a direct comparison of the results from the sensitivity analysis with those from the scenario itself.

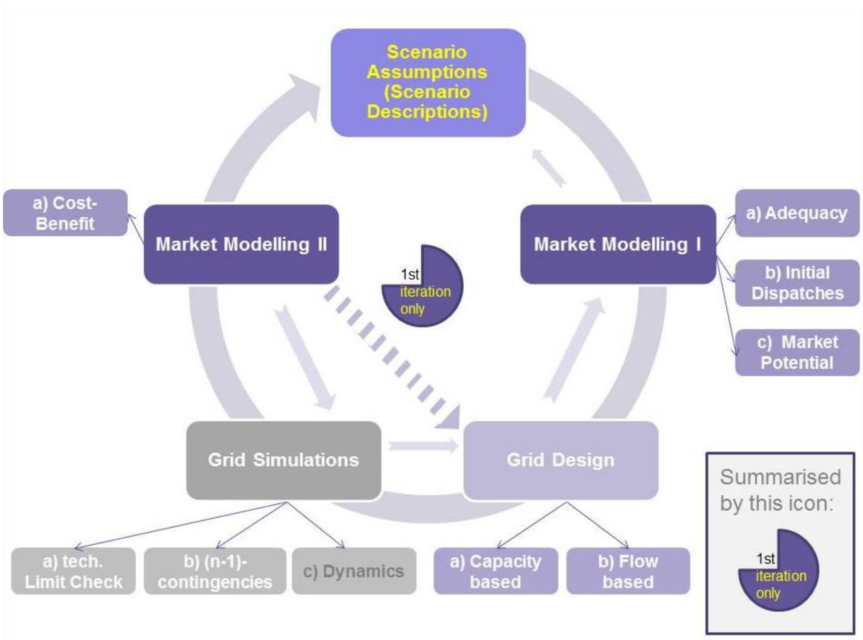


Figure 2-1: Logical Steps of the General Procedure

2.2 Scenario Assumptions

This describes the essential parameters relating to demand, generation sources and network on which the study is carried out

The national views of the 10 countries' generation and load situation were collected in summer 2011, based on the PRIMES data on 2030 and adjusted by the considered views of the national authorities, in the absence of common European 2020+ targets. Generation and load data were then combined with IEA scenario fuel and CO_2 prices (WEO 2010, New policies scenario). Correlated wind time series and solar time series were scaled up to year 2030 values. The generation data was grouped into power plant types with start-up times and other technical operating parameters added.

This study took the 2020 grid situation (including interconnectors), as fixed by the TYNDP 2012 scenario, and examined the impact of the changes from 2020 to 2030, see Figure 2-2. The scenario development is described in Chapter 3 and Appendix A 1.

Two conceptual interconnector projects, France-Ireland and Great Britain-Ireland, were included in the 2012 TYNDP based on positive results from studies carried out for the TYNDP. By exception these were not fixed in this study so that the case for their inclusion could be further tested against the 2030 scenario.

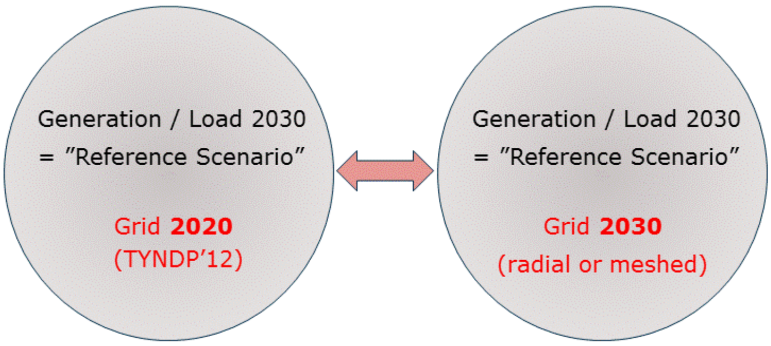


Figure 2-2 Basecase (left) and Study Cases (right).

This study examined a Reference scenario for 2030 using official Government forecasts based on their modelling of firm and funded national policies, taking account of planning constraints and a sensitivity analysis using data available to the TSOs reflecting their most optimistic offshore wind development. In the future, if more scenarios are considered, each scenario should initiate a cycle through the sequence of study activities as illustrated in Figure 2-1, resulting in separate and potentially different grid configurations for each scenario.

Note - This is a feasibility study, not a business case to support investment decisions – which would require a more detailed study examining intermediate years between the start and the horizon year to get an understanding of the phasing requirements of investments.

2.3 Market Modelling I

System Adequacy check to examine whether there is sufficient generation in the scenario to meet projected demand (regardless of price) and the simulation of the expected electricity market characteristics based on the scenario assumptions

a. **Adequacy** - The chosen scenario is loaded into a **market model** to examine the adequacy of the generation portfolio to meet the projected demands. If the generation capacity is too great or too low, there is an option at this stage to return to the scenario development to correct the details of the scenario – to adjust assumptions, or introduce more interconnectivity between imbalanced regions.

b. **Initial dispatches** - The market models simulate electricity market behaviour for a one year period in hourly steps and calculates the expected amount of generation produced by each type of fuel and generation (and therefore CO_2) and investigates the expected import / export position of each country with any curtailment. This information on the initial despatch solution (utilisation of units) and marginal costs is the first input into the grid design phase.

c. **Market potential** – This final step assesses the market potential for increasing interconnection capacity between the countries by considering the impact on overall production costs as interconnectors between different markets are added. Note that this stage assesses additional cross border capacity that might be supported by market analysis alone. It therefore does not represent an investment plan, which requires additional investigation steps as described below.

2.4 Grid Design

Network analysis and grid modelling investigate the physical behaviour of the grids, based on the technical parameters of the region's electricity grid. Selection of optional ("candidate") investments is optimised to reinforce the grid to meet the market needs derived from the 2030 generation and load scenario (including connection of new offshore generation).

a. **Capacity based** - The market model will identify the potential for further trading capacity. This is an important element of the offshore **grid design** that must meet the needs of integrating markets as well as integrating renewable generation and ensuring security of supply. The grid design is carried out using an optimisation procedure that tries combinations of investment options ("candidates") chosen to connect new generation facilities, to create new interconnection capacities and to ensure security of supply. The objective of the design procedure is to minimise overall grid investment and energy system operational costs. These costs comprise fuel costs, CO_2 emission costs and variable operation and maintenance (VOM) costs. The process is based on simplified market and grid models. This provides an initial outline grid configuration that will result in additional trading capacity between countries.

b. **Flow based** optimisation, using both an optimisation tool and iterations with local experts and decentralised flow based simulations challenging and reviewing the outputs of the optimisation tool to create revised cross border capacities. These new capacities are loaded into the **market model** to identify the trading benefits resulting from the additional investment. Some refinement of the configurations can be carried out at this stage to take account of the detailed benefit calculations.

2.5 Grid Simulations

Optimised outline grid designs are confirmed as viable and refined with more targeted network and market simulations.

While the outline grid designs have been optimised based on combined on and off shore grid costs, the configurations must then be checked in detail by local grid experts to identify in more detail the impacts of the new power flows on the internal grids including e.g. lower voltage levels of each country. This is done to ensure that the grids adhere to transmission standards as outlined in Appendix 3 of TYNDP 2012 [3], among these the requirement for power flows not to violate thermal limits of any part of the grid, with all circuits in service (i.e. the "n" condition) or with any one circuit out of service (i.e. the "n-1" condition). At this stage the requirement for some additional internal reinforcements may be identified.

Other more complex and time consuming tests, such as testing the dynamic stability of the proposed networks, are normally done to support real investment decisions and to ensure that the selected solution will be operable. In the case of this study, where general concepts are being tested but no investment decisions are being made, these additional analyses are not necessary or justified, instead some expert assessment was deemed sufficient.

2.6 Market Modelling II

Explores how the market would be expected to evolve and what benefits arise as a result of the grid expansion strategies proposed in the previous stages.

Once all modifications to the grid design, both onshore and offshore, have been completed, a further market model analysis is carried out to validate and review the level of interconnection and assess how the market behaviour might evolve as a result of the grid expansion strategies proposed in the previous stages. Any changes in the cross border capacities as a result of this investigation are fed back into the grid analysis for further investigation.

Once this is finalised – a comparison of costs and benefits is carried out, delivering the quantifiable part of the benefits. A set of non-quantifiable benefits is mentioned in Chapter 5.1.4

A detailed description of the process is presented in Appendix A 1, including statistics on the model parameters, technologies and the candidates used for both designs.

3 Development of the 2030 Hypothesis

3.1 Starting point – the development of scenarios

The aim of the study is to assess offshore grid development under two different concepts – radial and meshed, as introduced in the previous chapters, and to compare them from a socio-economic point of view, as described in chapter 5, on the assumption that technically they both meet the same requirements.

The year 2030 was chosen as an appropriate time horizon for this assessment. This timeframe was on the one hand deemed far enough in the future to be able to set up different assumptions for grid development, and on the other hand close enough to be able to make reasonable assumptions on generation and load development.

A consistent macro-economic framework for 2030 had to be developed and a set of more specific assumptions. Not only the offshore generation, but also the composition and characteristics of the region’s whole power system were to be agreed. While consistency of these assumptions on a pan-European scale is important, otherwise the results could be biased by divergent forecasts for the same parameters and the economic assessment would not make sense, such a study should also reflect expected trends in energy policies of each of the participating countries, for example the national objectives (e.g. the National Renewables Action Plans).

In the absence of common European 2030 energy targets, the first step of the study was to set up a common consistent starting point (“scenario”). The NSCOGI WG1, where Governments, Regulators, TSOs and the EC are involved, offered a unique opportunity to develop and discuss this scenario and to achieve a general consensus on the basis for the study.

As a starting point for generation and load development the EC provided two consistent PRIMES scenarios to each TSO (“Reference” and “Decarbonisation”) [6], under a Non Disclosure Agreement. Each Government reviewed and validated their data in summer 2011 to update and reflect national ambitions and policy goals for 2030. At this stage some regional inconsistencies may have been introduced into the scenario due to possible differences in the national focus of energy policies for the year 2030. However, although these characteristics coloured the results, the Reference Scenario provided an important starting position and has been used to understand and develop the best views of the 10 Governments.

[6] In the follow up of the process, the difference between the revised PRIMES decarbonisation scenario and the reference scenario was not deemed significant and as a result the latter was no longer considered.

During the review process, national administrations were also asked to provide approximate locations of new conventional and renewable generation (RES), especially new offshore capacity and also, to the extent available, possible landing points. Furthermore, potential environmental or other constraints for development were described where possible.

The Reference Scenario was fixed in summer 2011; it therefore does not take account of later changes regarding future energy mix made since that time.

The locations of the new offshore wind power plants (OWPP) contained in the Reference Scenario are represented by blue dots on the map in Figure 3-1: the size of the dot representing the capacity of wind generation at the location. For clarity, the wind parks assumed to exist by 2020 are shown by grey dots.

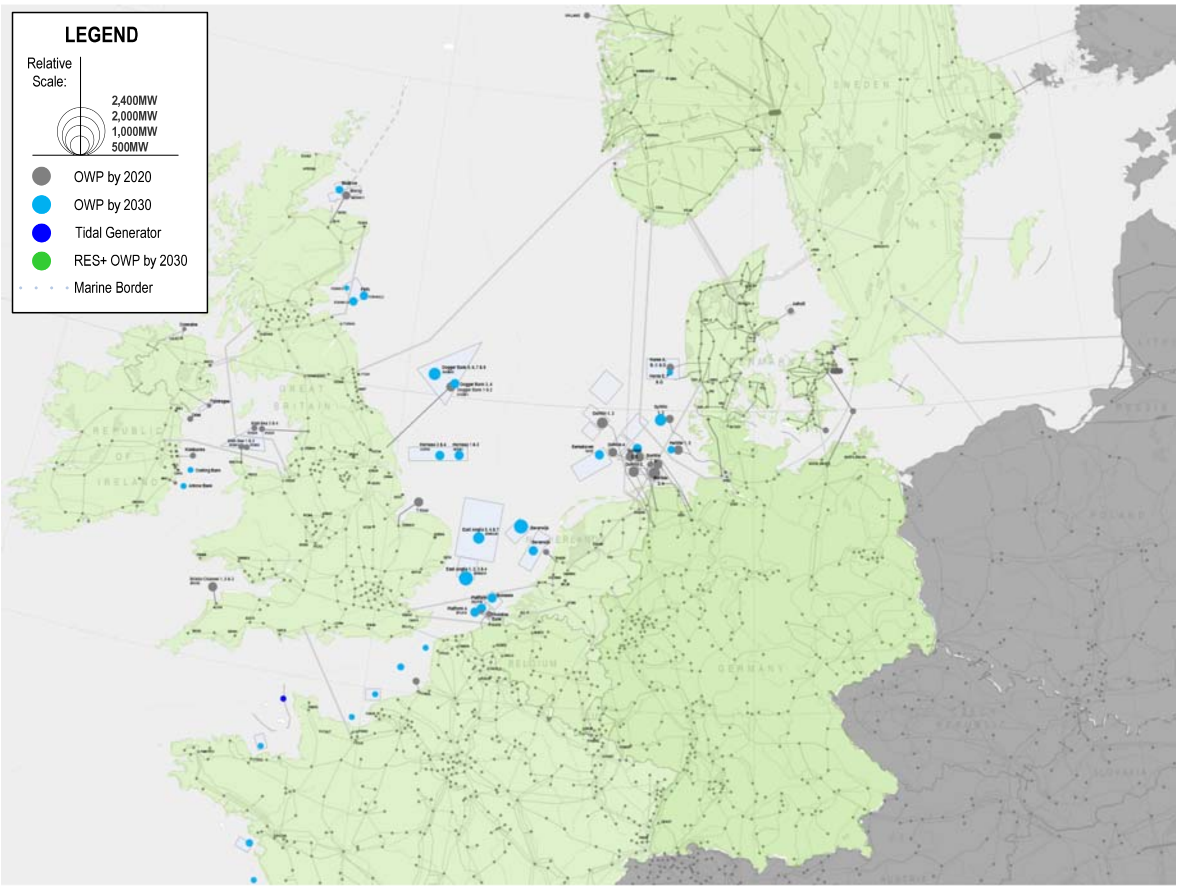


Figure 3-1 Assumed Location of Offshore Wind Power Plants (OWPP) by 2030 (due to readability reasons the scale in the legend does not match the map)

In the use of data it is important to recognise that:

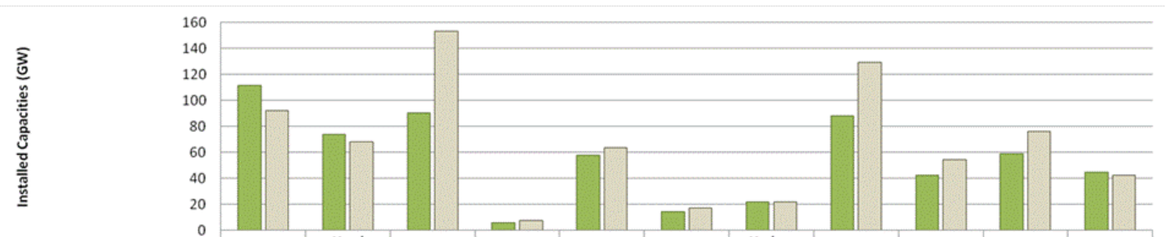
1. The level of renewable generation, in particular, the level and location of offshore renewables in projections, is likely to be the parameter with the most significant impact in determining which offshore grid configuration design best serves the region's socio-economic interests. Other parameters that change that impact on market flows are also likely to influence future grid development; of these, the assumed level of CO2 costs is probably one of the most important variables.

2. The North Seas Countries are committed to addressing climate change and reducing emissions in the longer term. Although there are EU-wide RES targets up to 2020, there are none beyond this point. There is therefore significant uncertainty over the level of renewable generation in the North Seas Countries in the period 2020 – 2030, as there are various possible pathways to decarbonisation.

The reviewed and updated data was further developed for use in market modelling tools by the TSOs (see Appendix A 1).

As the updated Reference and Decarbonisation scenarios did not differ significantly with respect to the overall RES share for the region, it was decided to proceed with just one scenario for the year 2030 which is referred to as the NSCOGI dataset of summer 2011 or "Reference Scenario" in this text. Key figures for this scenario are described in more detail in Appendix A 2.

The evolution of the system in terms of installed generating capacities between the year 2020 and 2030 is shown in Figure 3-2. The year 2020 is based on scenario EU2020 from the TYNDP 2012. This scenario, in which the 2020 targets are met, is based on the National Renewable Energy Action Plans (NREAPs) of the European Member states. This scenario is compared here with the situation in 2030, represented by the NSCOGI Reference Scenario.



	Nuclear	Hard coal/lignite fired	Gas fired	Oil fired	Hydro: Reservoir	Hydro: Run of river	Hydro: Pumped storage	Onshore wind	Offshore wind	Solar	Other
EU2020	111	74	90	6	58	14	22	88	42	59	45
NSCOGI Reference Scenario	92	68	153	7	64	17	21	129	55	76	43
Change [GW]	- 19	- 6	+ 63	+ 1	+ 6	+3	- 1	+ 41	+ 13	+ 17	- 2
Change [%]	- 17	- 8	+ 70	+ 17	+ 10	+21	- 5	+ 47	+ 31	+ 29	- 4

Figure 3-2 Comparison of installed capacities (in GW) in the NSCOGI perimeter in the years 2020 (Scenario EU2020) and 2030 (NSCOGI Reference Scenario)

The electricity production capacity in the region increases in total by 19%. Figure 3-2 shows the changes for each fuel type in absolute and percentage figures as well:

- Installed nuclear capacities reduce by 17% from 111 GW in 2020 to 92 GW in 2030
- Installed hard coal and lignite-fired capacities decrease by 8% from 74GW in 2020 to 68 GW in 2030
- There is a remarkable 70% increase in gas-fired capacity from 90 GW in 2020 to 153 GW in 2030
- Overall there is a net 14% increase in the installed thermal generating capacities (increasing by 40 GW from 281 GW to 320 GW), while variable RES (wind, solar and hydro) is expected to increase by about twice as much (29% or 79 GW).
- Of the RES production capacity increase, the most significant is from wind generation, which increases by 41% (54 GW). However, most of this increase is assumed to occur onshore (+ 41GW) with just a 13 GW (31%) increase offshore, bringing the offshore capacity from 42 GW in 2020 to 55 GW in 2030.
- Solar PV has a development of about 30% from 59 GW to 76 GW; total hydro capacities increase by 9% from 94 GW to 102 GW.

The demand during the period 2020 – 2030 increases by 9% from 1,922 TWh to 2,101 TWh. If the demand and supply side developments defined in the scenario are compared it becomes clear that there is greater excess capacity in the 2030 Reference Scenario than in 2020. As a result, the average utilisation of the installed thermal capacities will decrease significantly unless thermal generation is used to meet additional demand outside the region.

3.2 The Reference Scenario in the context of future work

The approach used in the study – starting with the best view of the future, is shown in Figure 3-3 with the yellow arrow representing the 10 countries' best view on the year 2030. The development of this Reference Scenario was a unique opportunity ensuring consensus of the input data used for this study.

For future development, a so called "scenario-based approach" would use a number of scenarios representing possible pathways e.g. with respect to green versus carbon development on the one axis and national development versus international cooperation on the other axis as shown in Figure 3-4. This kind of approach is currently under preparation inside ENTSO-E for the TYNDPs to come, see chapter 1, to address the fact that there are no common EU policies available for the year 2030.

Thus, for the present study the detailed data and tools used have been prepared towards a later adaptation of a scenario-based approach, which is more comprehensive and robust, than a best view approach. A scenario-based approach looks at the extremes – the "corners" of possible futures spanning an area in which the used best guess should be found (Figure 3-3).

For this study a balance between an appropriate level of detail and computational feasibility in general had to be found having re-usability of the general procedure for future ENTSO-E purposes in mind.

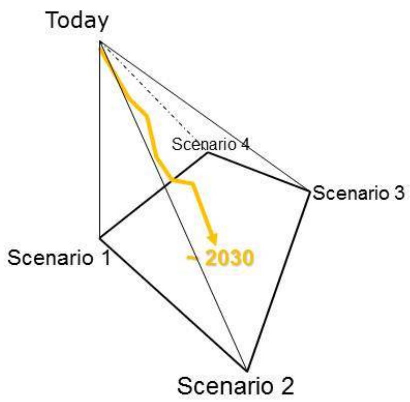


Figure 3-3: Best View approach (yellow arrow)

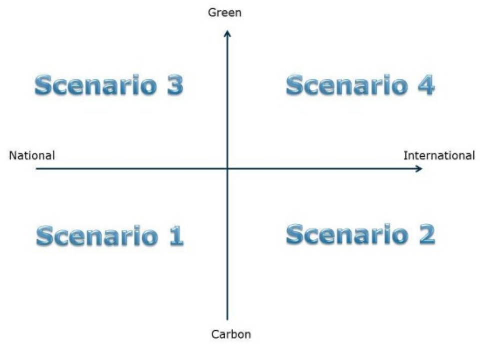


Figure 3-4: Scenario based approach

3.3 Scenario Adequacy and Security of Electricity Supply

The Security of Electricity Supply in the Region will be a function of the available generation capacities and demand curves: there should always be enough generation resources to cover the demand with a sufficient degree of certainty. Therefore, as a first step in the overall process, the generation adequacy of the provided NSCOGI Reference Scenario was assessed, with the possibility to increase the generation capacities in the event of shortages being identified.

As a start, the reserve margins in each individual country (and the margin for the entire NSCOGI region) were checked using a simplified shallow adequacy assessment method. The reserve margin is defined as the ratio between installed thermal and hydro capacity and annual peak load. Sufficient reserves are necessary in a system to cope with unavailability of production capacity arising from the unforeseen outages and the maintenance of generating units. It should be noted that for this preliminary scan the capacity of variable sources of generation, i.e. wind and solar PV, are not taken into account. In reality both types of resources do contribute to some extent to system adequacy, so the assessment presented can be considered conservative.

It should be noted that reserve margin should only be used as a preliminary indicator. Final adequacy judgements should be done with detailed models.

The required reserve margin is very system dependant and can vary by country, but typically for self-sufficiency a reserve margin of about 1.15 to 1.25 is usually necessary for thermal systems. National standards on self-sufficiency differ within the region – with some countries requiring self-sufficiency, while others rely to some extent on the regional market to meet their adequacy requirements. For hydro-dominated systems, energy margin indicators are generally required in addition to capacity-based reserve margins. Because of the diverse requirements within the region, judgement on the adequacy of the Reference Scenario was made based on a reserve margin with the help of TSOs' expertise from all countries. This confirmed that regional adequacy was met.

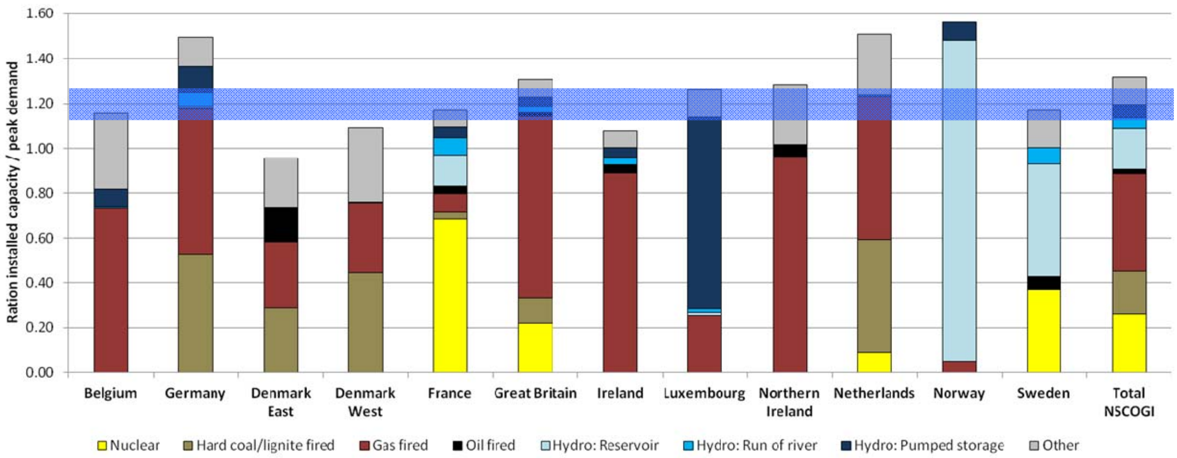


Figure 3-5: Installed capacity as a ratio of the peak demand by country and for the total NSCOGI Region (2030). The horizontal blue line represents the typical target reserve margin of 1.15 to 1.25.

NB: These results are based on a hypothesis on future capacities by fuel type, validated by administrations in summer 2011. They do not take account of any changes in energy mix that may have been decided since that time.

The result of the assessment is presented in Figure 3-5. It shows that reserve margin in the region varies between 0.95 and 1.55 with margins smaller than 1.1 occurring in Denmark and Ireland. For the entire Region a margin of 1.32 is reached.

Based on these results it can be concluded that the Reference Scenario includes enough resources in the Region to guarantee security of supply from a generation adequacy point of view. Some countries with low reserve margins may have to rely on resources outside their national borders or on their own wind or solar resources to guarantee security of energy supply. However sufficient cross border capacity is available to facilitate this.

The market simulations made later on in the process, in which generation adequacy was assessed in much more detail, have confirmed these preliminary adequacy assessment results.

3.4 Assumptions

In addition to the Reference Scenario data provided, assumptions on some further parameters are required to complete the 2030 data set necessary to carry out the grid design conceptual study.

1. No legal obligations were considered in order to get some view of the economically optimised design of the grid (e.g. in Germany and Denmark the TSO is in charge of connecting the offshore wind, but this is not the case in all other countries).

2. No regulatory barriers were assumed: energy may flow according to an integrated market. The scope of NSCOGI WG2 is to identify regulatory barriers and propose measures to overcome them.

3. The market was assumed to be perfect: prices reflect generation costs and no market power are assumed to be exerted by any producer.

4. Price driven demand-side management or policies are not modelled.

5. The study considered one year for the simulations (2030). Two grid designs, radial and meshed, were compared with the grid status as of 2020, Figure 2-2. The benefits arising from the grid enhancements, in terms of reduced electricity production costs for the region, were calculated for 2030. To enable a meaningful comparison of the grid investment costs with the calculated 2030 benefits, investment annuities were calculated using a 6% discount rate and a 40-year useful asset lifetime. Interim steps (timing of individual investments) were not considered due to the feasibility character of this study (in contrast to a business case study which would need to consider the costing implications of phasing investments).

6. Installed capacity for wind generation in 2030 was defined in the Reference Scenario. Capacity factors and wind speeds for these wind generators were derived from correlated European wind power time series from 2006, scaled as appropriate to match defined 2030 capacities.

7. A set of correlated profiles for solar and other non-dispatchable units was used.

8. The locations and capacities of generation plants (all types, both on-shore and off-shore) were provided by Governments with support of TSOs.

9. The different behaviour of reservoir-based hydro, run-of-river production facilities and pumped water storage were assumed to continue unchanged.

10. As a zero-operational cost was assumed for RES generation plant, they achieve priority access to the market.

11. Fuel prices were taken from the IEA World Energy Outlook 2010, New Policies scenario (Real Terms) and agreed in NSCOGI WG1. Standard CO_2 emission factors were assumed for each fuel type. These are described further in Section 3.4.1below. An exchange rate from $ to € of 0.74 has been used. The CO_2 price was taken from PRIMES,

12. Thermal plants within each country were grouped into categories according to fuel type, age, must-run obligations, etc. and parameters assigned for each category:

    a. Technical characteristics such as start-up costs, minimum stable generation, and maximum stable generation.

    b. Operational flexibility characteristics e.g. minimum run/downtime, ramp rates etc of each generator group were assigned based on the power plant type in order to assess secure system operation on the one hand and to facilitate curtailment of surplus flexible production on the other.

13. Must-run obligations for each of these categories were defined according to their current market behaviour or known obligations. These were intended to represent operational constraints forcing the need to run a specific plant outside of the merit order because of security criteria which could not be modelled in the simulation tools.

14. The 2020 grid status as shown in the TYNDP 2012, amounting to 77 bn€ of regional investments until 2020 was taken as fixed with all of its projects assumed to be in operation (with the exception of the France-Ireland and Great Britain-Ireland conceptual interconnectors). The TYNDP 2012 [3] was the best available common denominator for use as a starting position for this study. The TYNDP 2012 projects are illustrated in Figure 3-6 and Figure 3-7.

15. The Base Case Net Transfer Capabilities (NTCs) were based on an assessment of the capacities of the planned grid in 2020 (consistent with TYNDP 2012). Seasonal values of transfer capacities between market nodes were used. The NTCs between market nodes were subsequently adjusted to take account of new interconnection capacities included in the grid configurations being analysed.

Figure 3-6TYNDP Projects 2012 – 2016 [from [3])

Figure 3-7 TYNDP Projects 2017 – 2022 [from [3])

3.4.1 Fuel and CO_2 Prices – Merit Order

The fuel and CO_2 prices employed are critical to the decision as to which generators are committed and dispatched, with a consequent impact on both overall production costs as well as flows between connected market nodes. The fuel prices were taken from the IEA World Energy Outlook, New Policies scenario for 2030, and a CO_2 price of 36€/MWh was employed [7]. The variable costs of operating and maintaining generation plant excluding production costs, (VOM costs), were also taken into account in the study.

Table 3-1 shows the thermal economic merit order for 2030 for several sample generator types. The costs have been derived from the assumed generator efficiencies and the short-run marginal costs for fuel, CO_2 emissions and VOM. Capital costs of generation plant, revenues and other imperfections in market behaviour, namely different fuel contracts, are not considered.

The table shows that nuclear generation is the cheapest followed by coal/lignite generation, which in turn are cheaper than gas and oil-fired generation. Newer plant is assumed to be more efficient than older plant, so that production from older plant is more expensive than from newer plant of the same fuel type. As stated under the assumptions section, RES is assumed to have a price of 0 €/MWh.

Table 3-1: Thermal Economic Production Order for 2030 (taking account of the short-run marginal costs of fuel, CO_2 emissions and VOM) –based on IEA World Energy Outlook, New Policies scenario for 2030 [7]

Unit Type	Unit Efficiency at full capacity (%)	Fuel Type	Production Cost €/MWh
Nuclear	33	UOX – MOX	12.9
Coal CCS	35	Coal	40.0
Lignite New	43	Lignite	46.5
Coal New	46	Coal	53.3
Lignite Old	36	Lignite	54.9
Coal Old	35	Coal	69.1
CCGT New	58	Gas	77.0
CCGT Old	48	Gas	92.7
OCGT New	40	Gas	110.9
Conventional Gas Old	35	Gas	126.0
Oil	35	LSFO	144.5
OCGT Old	30	Gas	147.3

Note: CCS = Carbon Capture Storage; CCGT = Combined Cycle/Gas Turbine; OCGT = Open Cycle/Gas Turbine

3.5 Sensitivities

Sensitivity analyses allow the influence of certain parameters on study outcomes to be investigated, creating a picture of the robustness of any solution in the event of a changing environment.

The Reference Scenario includes an additional 13 GW of offshore wind capacity for the NSCOGI region between 2020 and 2030.

A sensitivity was studied significantly increasing the amount of installed offshore wind capacity (called “RES+”) to establish whether the benefit of meshing would increase with increasing offshore wind volumes. This was considered the most important parameter to investigate due to the probable impact increasing offshore wind capacity is expected to have on the offshore grid design and to allow comparability with other offshore grid or RES integration studies (e.g. [12]; [13]; [17];[18];[21]; [23]) that consider significantly higher offshore development than reflected in the Reference Scenario. It was also expected that higher volumes of offshore RES would reveal potential benefits of an integrated offshore grid in a more illustrative way.

The RES+ sensitivity figures for offshore RES, presented in 'Table 3-2, were based on the most ‘green’ national scenarios available to TSOs in early 2012, see also list of

References. All other generation / load data remains the same as the Reference Scenario. It should be noted that the figures for offshore RES in this scenario were not necessarily validated by Government authorities and may therefore not be consistent with published Government projections.

Other sensitivity analyses, like a 'Merit order Shift' and 'Smart Dimensioning of Offshore Wind Farm connections' were identified as appropriate sensitivity analyses to be conducted in the next stage of NSCOGI.

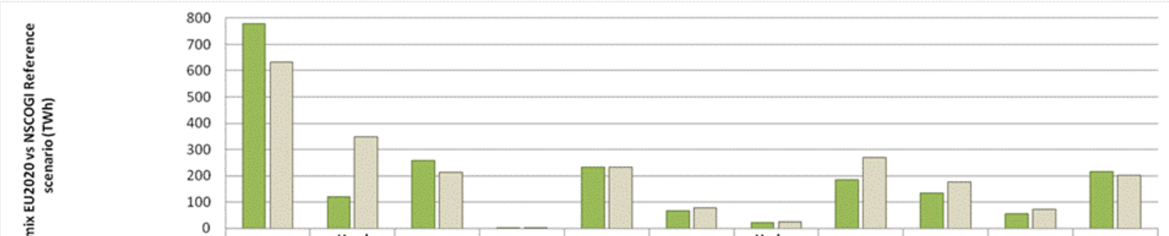
'Table 3-2: Study Assumptions on Offshore Generation Installed in 2030

Offshore Wind Capacity(GW)	NSCOGI Reference Scenario	RES+ sensitivity
Belgium	3.1	4.0
Germany	16.7	25.0
Denmark W	0.9	3.4
Denmark E	0.3	1.0
France	6.5	13.0
Great Britain	17.7	49.0
Ireland and N.Ireland	2.3	7.0
Netherlands	6.0	12.0
Norway	0.7	1.0
Sweden	0.7	2.0
TOTAL	55.5	117.4

4 Market Based Potential for Further Interconnection

4.1 System Evolution between 2020 and 2030

As part of the process described in Chapters 2and 3, an assessment was made of the potential for further interconnection capacities between the 10 countries of NSCOGI over and above the planned links in the TYNDP. The assessment uses market modelling tools to evaluate the changes up to 2030 in the fuel mix of energy production, import and export positions, CO_2 emissions and production costs. The market models calculate the energy produced by every generator during the study year. By amalgamating the generation output by fuel-type, a view of the total amount of generation produced by each fuel can be obtained for each market node and for the NSCOGI region as a whole.



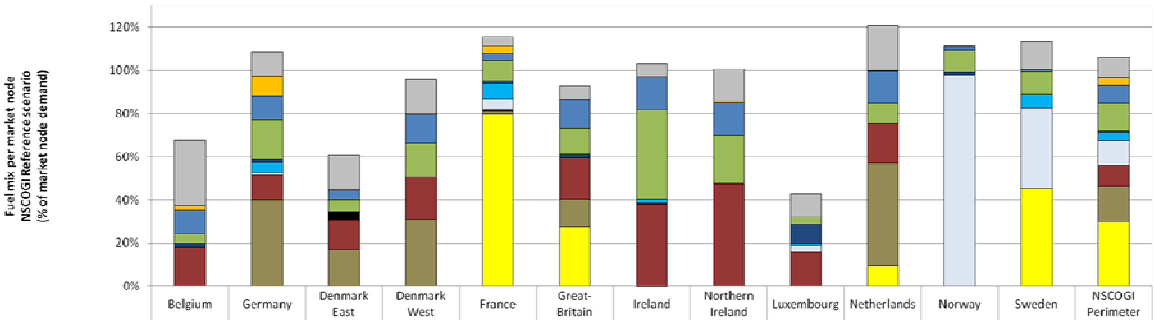
	Nuclear	Hard coal/lignite fired	Gas fired	Oil fired	Hydro: Reservoir	Hydro: Run of river	Hydro: Pumped storage	Onshore wind	Offshore wind	Solar	Other
EU2020	779	120	259	0	232	66	21	184	133	55	216
NSCOGI Reference Scenario	633	348	212	1	234	77	23	270	176	71	202
Change [TWh]	- 146	+ 228	- 47	+ 1	+ 2	+ 11	+ 2	+ 86	+ 43	+ 16	- 14
Change [%]	- 19	+ 190	- 18		+ 0,9	+ 17	+ 10	+ 47	+ 32	+ 29	- 7

Figure 4-1 Comparison of fuel mix in energy (in TWh) in the NSCOGI perimeter in the years 2020 (Scenario EU2020) and 2030 (NSCOGI Reference scenario) calculated with grid 2020 capacities

In Figure 4-1, the fuel mix in terms of TWh electricity production of the EU2020 and the NSCOGI Reference scenario are compared. The graph shows that, although coal/lignite fired capacity decreases between 2020 and 2030 and gas fired capacity significantly increases, the electricity production behaves inversely: production from coal and lignite fired capacities increases by almost 190%, while production from gas fired capacity decreases. This can be explained by the different assumptions made for fuel and CO_2 prices in the EU2020 and NSCOGI Reference scenarios. These differences lead to a shift in the merit order of the generating capacities. In scenario EU2020 new CCGT gas fired capacity is dispatched before coal fired capacity, as required by the EC's assumptions on 2020. The NSCOGI Reference Scenario is a coal before gas scenario, resulting in maximum utilisation of coal and lignite capacity. This would suggest that scenario development for future work should consider a gas before coal pricing order to match the ambitions of countries building gas capacity before coal capacity more closely.

Figure 4-2 details the 2030 fuel mix as a percentage of total demand for each market node. A combined fuel mix greater than 100% for a market node means that generation exceeds demand at that node and electricity is therefore exported to a neighbouring country. Similarly, a combined fuel mix of less than 100% means that the market node meets some portion of its demand using imported electricity from neighbouring countries. More detailed information on import/export balances is provided in section 4.2 ‘Import and Export Positions’.

The last bar of Figure 4-2 shows the fuel mix for the entire NSCOGI region. Due to the economic production order derived from the IEA prices (coal before gas), gas-fired generation provides just 10% of production even though it makes up 21% of total installed capacity in the region. Conversely, generation from hard coal and lignite plant provides 16% of production despite making up just 9% of total installed capacity. Wind has a 20% share of the regional fuel mix; with another 19% covered by hydro and solar energy. The total renewable share of energy consumption is about 40%.



	Belgium	Germany	Denmark East	Denmark West	France	Great-Britain	Ireland	Northern Ireland	Luxembourg	Netherlands	Norway	Sweden	NSCOGI Perimeter
Other	30%	11%	16%	16%	4%	7%	6%	15%	11%	20%	0%	13%	10%
Solar	2%	9%	0%	0%	3%	0%	0%	1%	0%	0%	0%	0%	3%
Offshore wind	11%	11%	5%	14%	3%	13%	15%	15%	0%	15%	2%	1%	8%
Onshore wind	4%	18%	5%	16%	10%	12%	42%	22%	3%	10%	10%	11%	13%
Hydro: Pumped storage	1%	1%	0%	0%	1%	1%	0%	0%	9%	0%	2%	0%	1%
Hydro: Run of river	0%	4%	0%	0%	7%	0%	2%	0%	1%	0%	0%	6%	4%
Hydro: Reservoir	0%	1%	0%	0%	5%	0%	0%	0%	3%	0%	98%	37%	11%
Oil fired	0%	0%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Gas fired	18%	12%	14%	20%	1%	19%	38%	48%	16%	18%	0%	0%	10%
Hard coal/lignite fired	0%	40%	17%	31%	2%	13%	0%	0%	0%	48%	0%	0%	16%
Nuclear	0%	0%	0%	0%	80%	28%	0%	0%	0%	9%	0%	45%	30%

Figure 4-2 Fuel Mix, as percentage of the TWh demand, by country in the NSCOGI Reference Scenario for the year 2030 with grid 2020 capacities

NB : The scenario has been validated by administrations in summer 2011 and does not take account of any changes in energy mix strategy decided since then.

4.2 Import and Export Positions

Figure 4-3 shows the anticipated gross export, gross import and net export balances in energy terms by market node while Figure 4-4 shows the same data as a percentage of demand. The gross export and gross import balances were calculated as follows. For each hour, the imports to and exports from a market node were netted off to provide an hourly net import/export balance. For all the hours with a resulting net hourly import balance, the net imported energy was summed to provide the overall gross import balance for the year. Similarly, for all the hours with a resulting net hourly export balance, the net exported energy was summed to provide the overall gross export balance for the year. As a result, the gross import and gross export balances reported for each market node exclude transit flows. Transit flows are power transfers between two market nodes that are hosted by, and pass through, a different market node. The annual net export balance for each market node was calculated by subtracting gross imports from gross exports.

By energy, Belgium and Great Britain are the largest importers in this scenario due to the assumption that coal is ahead of gas in the merit order and the high proportion of gas-fired generators in their systems. Germany, France, the Netherlands, Norway and Sweden are large exporters. The region as a whole is exporting approximately 110 TWh towards its neighbouring countries outside the region, which is about 5% of the region's annual demand Figure 4-4.

Luxembourg, Denmark East and Belgium are the largest importers in terms of percentage of their own demand. The Netherlands is a large exporter in terms of percentage of its demand.

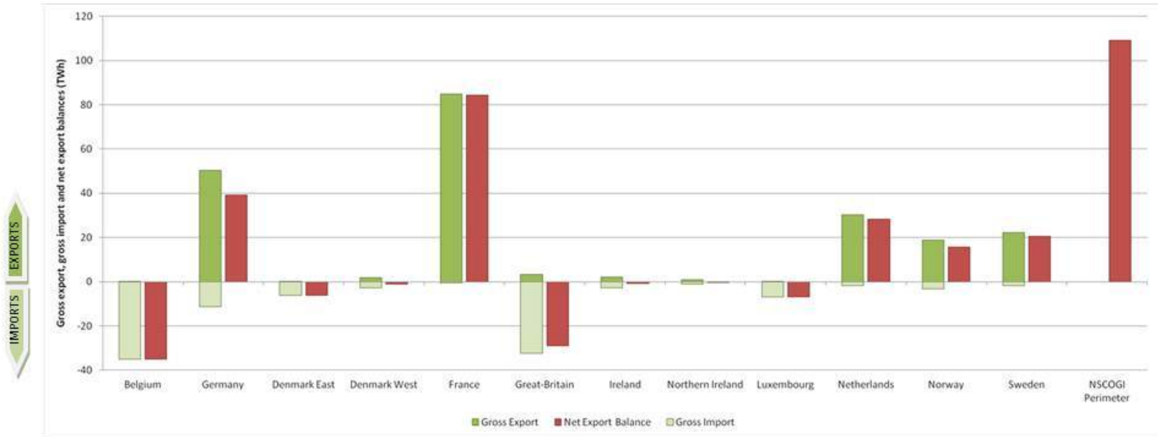


Figure 4-3 Import/Export Balance in TWh by NSCOGI Country and for the Region as a Whole[7] in the NSCOGI Reference Scenario for the year 2030 with grid 2020 capacities

Overall the NSCOGI region is a net exporter, with about 110 TWh produced in the NSCOGI countries for export to meet demands outside the region. This represents an addition 5% production over the region's own demand as shown in Figure 4-4. The figure also presents each country's import/export position in relation to its own demand. France is by far the biggest exporter, but in terms of the size of its system, Netherlands is the greatest exporter. Similarly while Great Britain and Belgium import more energy than any other country, Denmark East and Luxembourg import the highest percentages of their demand from neighbouring countries. It should be noted that this does not suggest that they rely on other countries. For these countries the simulations show that the prices of neighbouring markets are lower making it more economic to import than to produce electricity with their more expensive national generators.

[7] While the gross import, gross export and net export balances are provided for each market node, only the net export balance is provided for the NSCOGI region as a whole.

Figure 4-4 Import/Export Balance as percentage of the TWh demand by NSCOGI Country and for the Region as a whole in the NSCOGI Reference Scenario for the year 2030 with grid 2020 capacities

4.3 CO_2 emissions

Figure 4-5 shows the anticipated CO_2 emissions by market node. The carbon emissions produced are dependent on the fuel used, which is determined by the generation portfolio in each country and the fuel/carbon costs employed. The fuel and CO_2 emission prices employed are consistent with the IEA World Energy Outlook 2010, New Policies scenario for 2030. As a coal before gas merit order was assumed, it can be seen in the results that countries with the largest amounts of coal generation such as Germany, Great Britain and the Netherlands are also the largest emitters of CO_2.

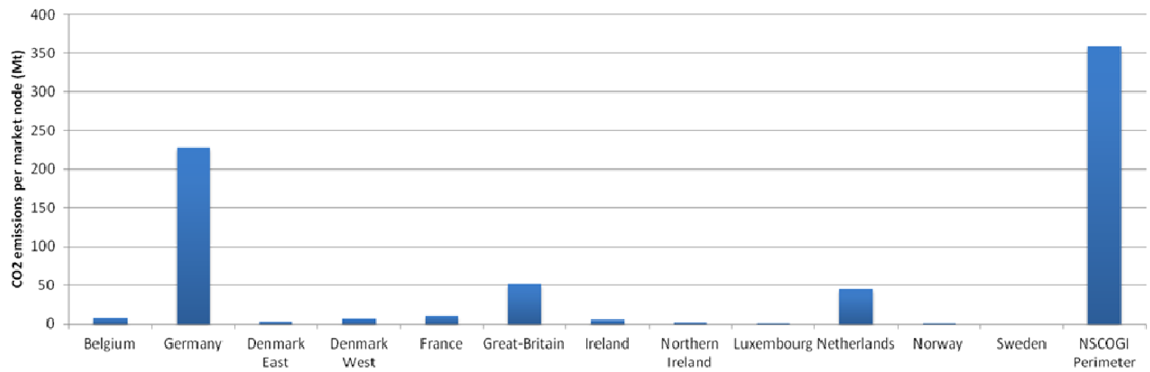


Figure 4-5 CO_2 emissions in Mton by NSCOGI Country for the year 2030 with the NSCOGI Reference Scenario and with 2020 grid capacities

4.4 Production Costs

The models calculate the variable cost of production comprising fuel costs, Variable Operation and Maintenance (VOM) costs and CO_2 emissions costs. In order to compare the different benefits of a radial and a meshed grid design in an appropriate manner, a common starting point is required for the analysis. This common starting point is found in the grid of the year 2020, which should accommodate the generation mix calculated for the year 2030, see Figure 2-2. The variable production costs of this fuel mix 2030 are then compared with those that result from the model runs under the radial grid design and the meshed grid design for the year 2030. These comparisons can be found in chapter 5.1.5 Because of the difference in fuel mix, there is a wide spread in the specific average production cost in €/MWh between the countries of the Region. This is illustrated by Figure 4-6, which also shows the average regional cost making it easy to see which countries' costs are above and below the regional average.

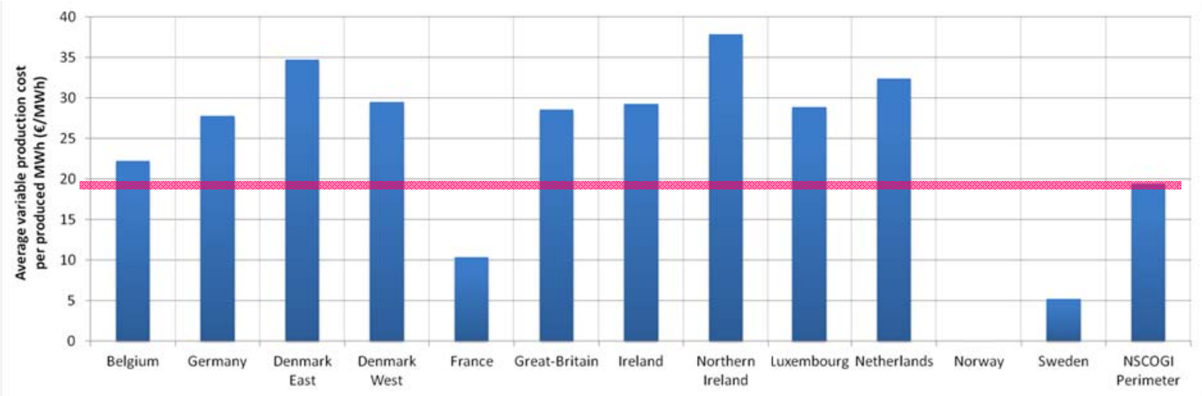


Figure 4-6 Average Variable Production Costs per produced MWh by NSCOGI Country and for the Region as a whole for the year 2030 with the NSCOGI Reference Scenario and with 2020 grid capacities

5 Grid designs

5.1 Grid Configuration Options for Reference Scenario

Two grid designs, one radial and one meshed, have been developed to meet the requirements of the 2030 Reference Scenario. These were designed through the grid expansions studies described in Chapter 2 and Appendix A 1. The results of the grid expansion exercise have been benchmarked against the results of the initial assessment by market modelling and were further fine-tuned where necessary with the methodology described in the Appendix A 1 to arrive at a more balanced outcome.

The radial design connects offshore wind farms directly to the host country's grid; new interconnections are from onshore grid points in both countries. In the meshed design, integrated offshore grid options are considered and selected where economically preferable to a radial option. In this way the meshed design could include a variety of connection types from radial to fully meshed, as illustrated in Figure 2-3.

The radial and mesh network designs are illustrated in Figures 5-1 and 5-2 respectively.

In both configurations, radial and meshed, all offshore wind farms are connected to the grid. The grid developments therefore facilitate the renewable energy ambitions of the 10 governments for 2030 as set out in the Reference Scenario. The method of connection is largely the same in both grid designs with the exception of a more meshed connection in the Channel and the southwest part of the North Sea and a changed overall flow pattern from Scandinavia to the Continent.

The Base case model is the starting point for the grid expansion study. The model includes existing interconnections and those foreseen in the TYNDP 2012. An exception was made for the two new interconnectors from Ireland – one to France and the other to Great Britain. These two were conceptual projects identified in the TYNDP 2012 studies. They have been omitted in the Base case in order to test again the justification for their inclusion against this 2030 Reference Scenario.

The expansion of the grids out to 2030 involves the building of a significant amount of new interconnection capacity in addition to those foreseen in the TYNDP 2012. These new interconnections connect market areas with different prices generating a saving in overall production costs across the NSCOGI region.

A number of interconnectors are common to both configurations. The two TYNDP 2012 interconnectors omitted from the Base Case, France-Ireland and Great Britain-Ireland, were selected in both the radial and meshed grids, although interestingly, the Great Britain – Ireland interconnector is located further north than assumed in the TYNDP. A third France – Great Britain interconnector is also included in both radial and meshed configurations.

There are, however, a number of differences in interconnections between the two configurations. The meshed configuration has the same number of interconnections as the radial, but has an overall greater length of offshore interconnection circuits. The meshed case provides an opportunity to use the circuits that are required to connect offshore wind parks as a part of offshore interconnectors. This type of development is seen emerging in the Channel where a number of offshore nodes allow multiple meshed offshore connections between Great Britain and its continental neighbours.

In particular, the links between Great Britain and Belgium and between Great Britain and Netherlands in the radial case are replaced with a meshed structure between Great Britain and Netherlands via an offshore node off the south east coast of Great Britain named here as East Anglia. In addition, the connection of a number of offshore wind parks off the north coast of France is extended to create a fourth interconnector between France and Great Britain.

In the radial design, the Belgian onshore 380 kV substation Zeebrugge is a central node enabling the connection of offshore wind parks and new interconnections with France, Great Britain and The Netherlands. This central substation needs to be secured by new onshore reinforcements towards inland regions. In the meshed structure, this central role is beneficially moved to an offshore hub in the Belgian territorial waters, to connect offshore wind parks and new interconnections toward France and the Netherlands (via the Belgian substation Doel). The offshore hub in this structure is connected to Great Britain via the East Anglia offshore wind development. An additional link between the Belgian offshore hub and the Thames Estuary enables the energy from East Anglia to be transmitted towards the London area. As a result of this arrangement, wind energy produced in the East Anglia area can be transmitted in multiple directions, avoiding stresses on the onshore network and so decreasing the need for onshore reinforcements.

A new Great Britain – Norway link is included in the radial case. This is replaced in the meshed case by the inclusion of additional links from the continent to Great Britain, meaning that the link between Norway and Great Britain is achieved indirectly through the continental system, with the second end of the Norwegian link ending in Germany. An additional interconnector between Sweden and Western Denmark, in addition to the one included in the radial design is also required to accommodate the flows from Scandinavia to the continent. These designs demonstrate how the potential for meshing of the transmission grid impact the overall regional or system-wide network design. Hence, the optimisation of the network configuration, in respect to either radial or meshed configurations, necessitated a regional scope rather than a localised focus.

The addition of new offshore wind park connections and new interconnectors require reinforcement of the onshore grids to accommodate the increased power flows through the onshore networks. The onshore reinforcements are, with the exception of very small differences in Great Britain, of the same order in both the meshed and radial cases.

Figure 5-1 Radial Grid Design for 2030 Reference Scenario (for readability reasons the scale in the legend does not match the map)

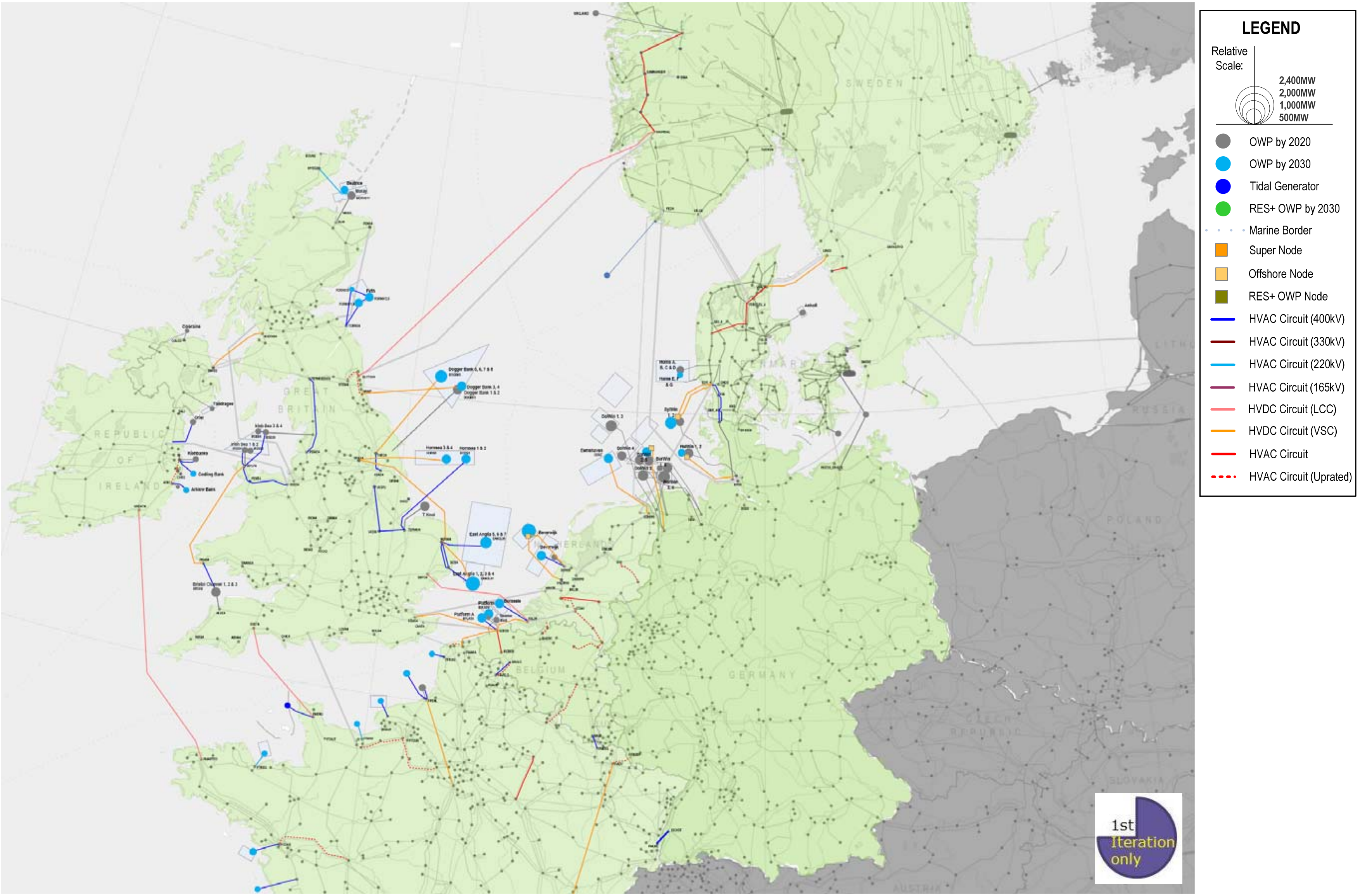
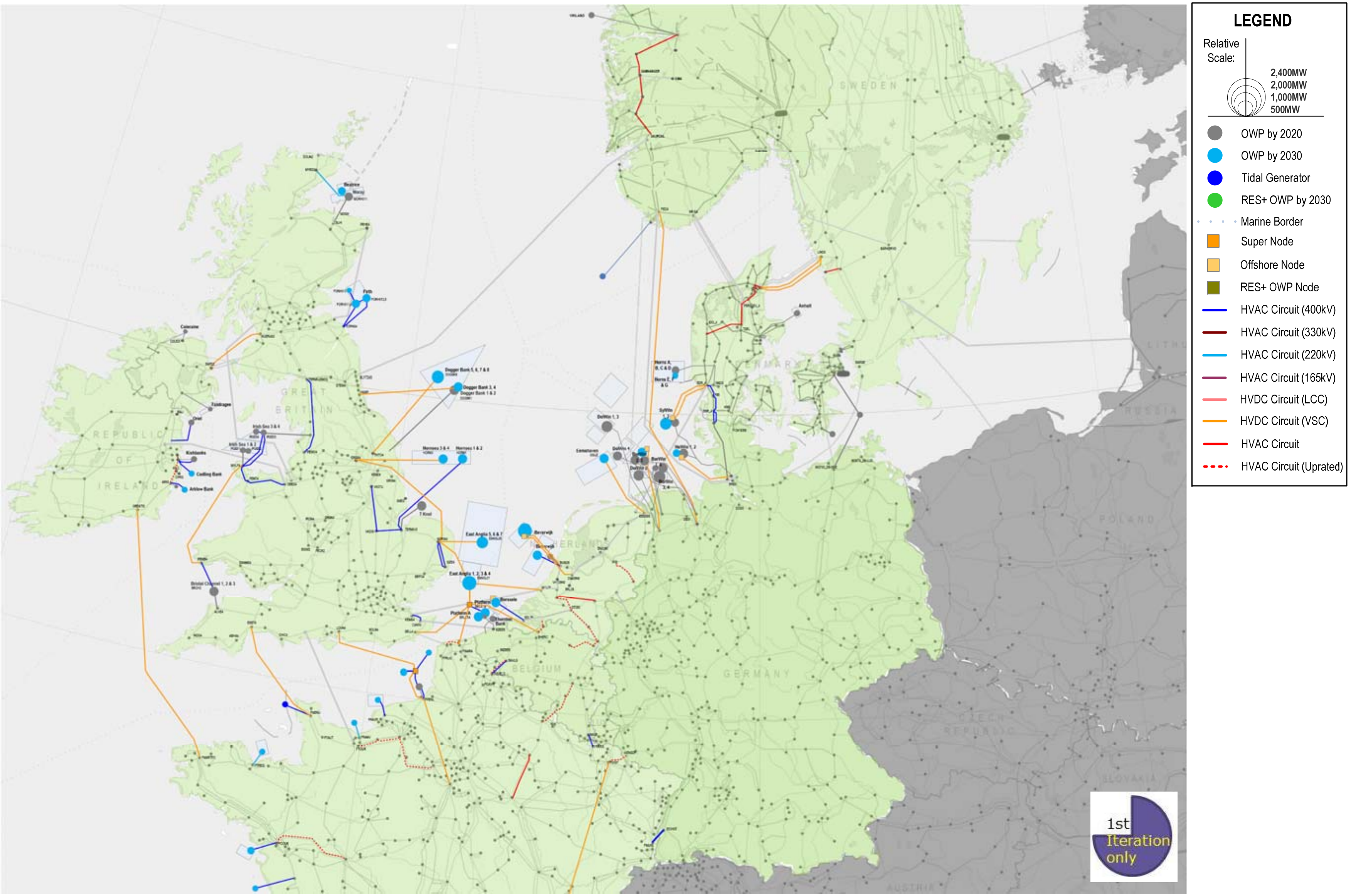
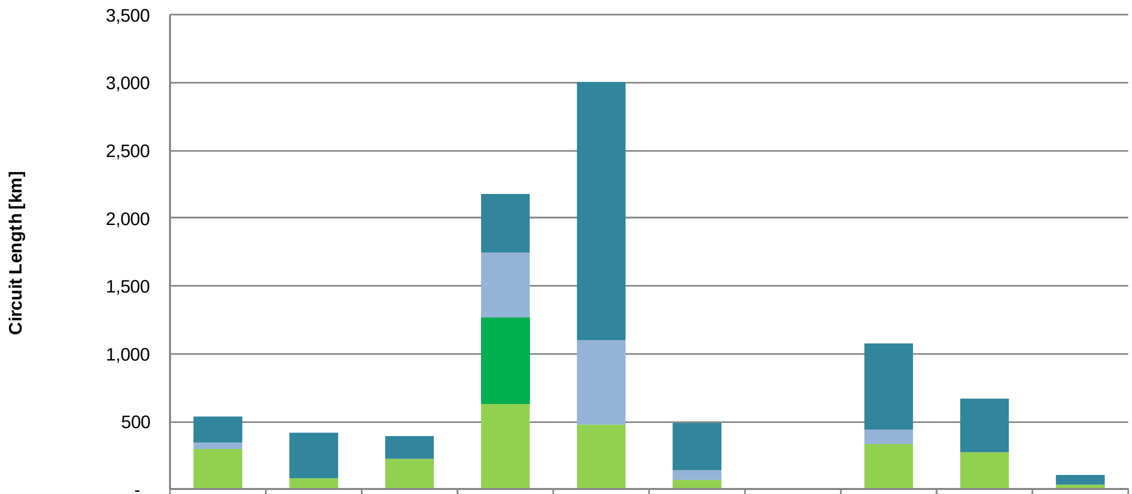


Figure 5-2 Meshed Grid Design for 2030 Reference Scenario (for readability reasons the scale in the legend does not match the map)



5.1.1 Statistics for Grid Design Options

The tables below show the total amount of new circuit lengths added by each country between 2020 and 2030 for the two designs. In the case of offshore interconnections, whether connected directly to shore or to an offshore node, it is assumed that 50% of the length is allocated to each country. For interconnections fully onshore an estimate has been made as to the length of new asset in each territory. In addition to the new circuits, the designs include new AC substations, HVDC converter stations and upgrades of existing equipment.

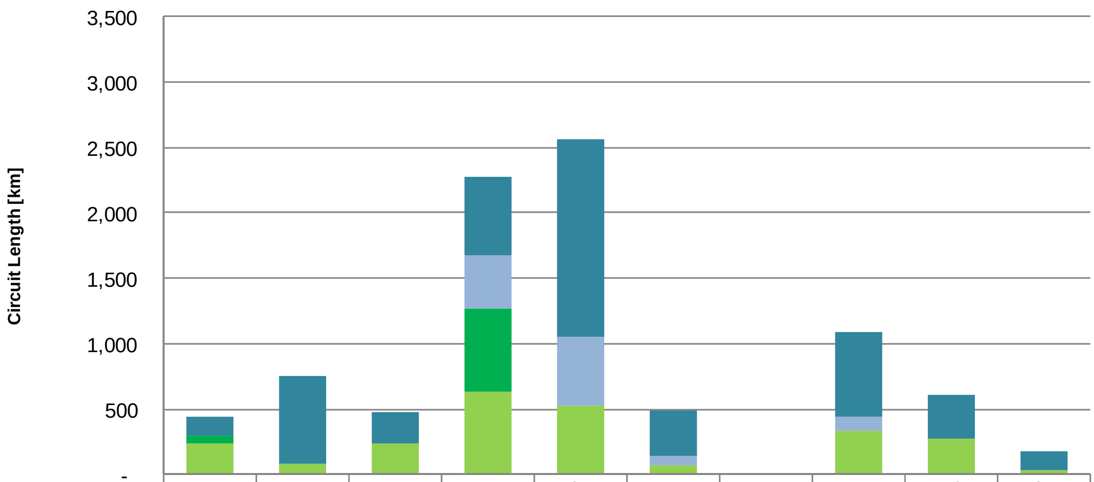


	BE	DE	DK	FR	GB	IE	LU	NL	NO	SE
Line HVDC OFFshore	190	346	160	435	1,903	343	-	640	392	75
Line AC OFFshore	55	-	-	473	617	73	-	110	-	-
Line HVDC ONshore	-	-	-	634	-	-	-	-	-	-
Line AC ONshore	294	78	229	638	484	75	-	331	276	30

Figure 5-3 Radial Grid Design - New Circuit Lengths for 2030 Reference Scenario (additional to TYNDP projects)

Figure 5-3 shows that most of the offshore assets in the radial design are connected to Great Britain. This is driven by the number and distance from shore of its new offshore wind parks, but to a much greater degree by the details of the scenario which makes coal-fired generation more economic than gas-fired generation. Great Britain is assumed to increase its gas-fired capacity and reduce its coal-fired capacity out to 2030 and therefore becomes a major importer from other lower price markets (see Figure 4-4). As a result there are five new interconnectors to Great Britain in this design.

France also requires significant new build both offshore and onshore to manage new power flows. It should be noted that Germany, which has the second highest offshore wind capacity, has developed a network plan for 2030 to reinforce the German grid [12]. The reinforcements set out in its plan are assumed to be in the Base case and therefore the new circuit lengths shown here for Germany are relatively small.



	BE	DE	DK	FR	GB	IE	LU	NL	NO	SE
Line HVDC OFFshore	135	681	235	600	1,512	343	-	651	335	149
Line AC OFFshore	1	-	-	406	527	73	-	110	-	-
Line HVDC ONshore	60	-	-	634	-	-	-	-	-	-
Line AC ONshore	244	78	243	638	521	75	-	331	276	30

Figure 5-4 Meshed Grid New Circuit Lengths for 2030 Reference Scenario ((additional to TYNDP projects)

In comparison to the radial design, the meshed design shows a big reduction in Great Britain's offshore circuit lengths. This is due to the replacement of the long Great Britain-Norway interconnection to a development of a power corridor from Scandinavia to Germany, through the continental systems and a meshed grid in the south west corner of the North Sea and Channel to Great Britain.

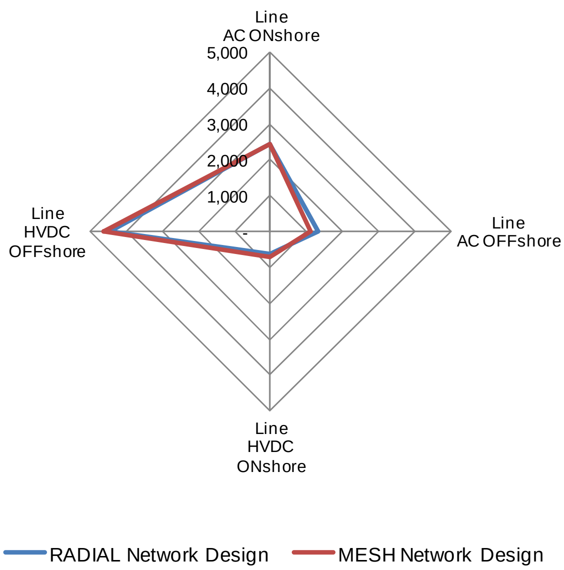


Figure 5-5 Comparison in New Circuit Lengths between Radial and Meshed Designs

The spider diagram in Figure 5-5 presents the differences in circuit lengths between the two designs in terms of each asset type. It shows that some of the AC offshore connections in the radial case are replaced in the meshed design by Offshore HVDC links.

5.1.2 Investment Costs for Grid Design Options

The costs of both radial and meshed grid options were estimated based on information provided in the ENTSO-E Technology Report (2011)[5]. These costs are in addition to the investments costs for the region of 77 bn€ for projects included in the TYNDP [3] which were taken as a starting point for this evaluation. The grids have been designed to connect new conventional and renewable generation, to increase interconnection between markets and to provide the necessary reinforcement of the national onshore grids.

Each country's investment requirements were defined based on the additional assets that were identified as being necessary for each network design (i.e. radial and meshed). The capital cost estimates of investments for each case and for each country are categorised in the charts below by asset types, namely:

- Terminal HVDC costs relate to the investment in offshore HVDC hubs to connect offshore wind farms together and to interconnectors; costs of terminals of on-shore HVDC links are also included ;

- Station AC costs relate to the investments in new AC substations, both onshore and offshore, and to enhancements of existing AC substations;

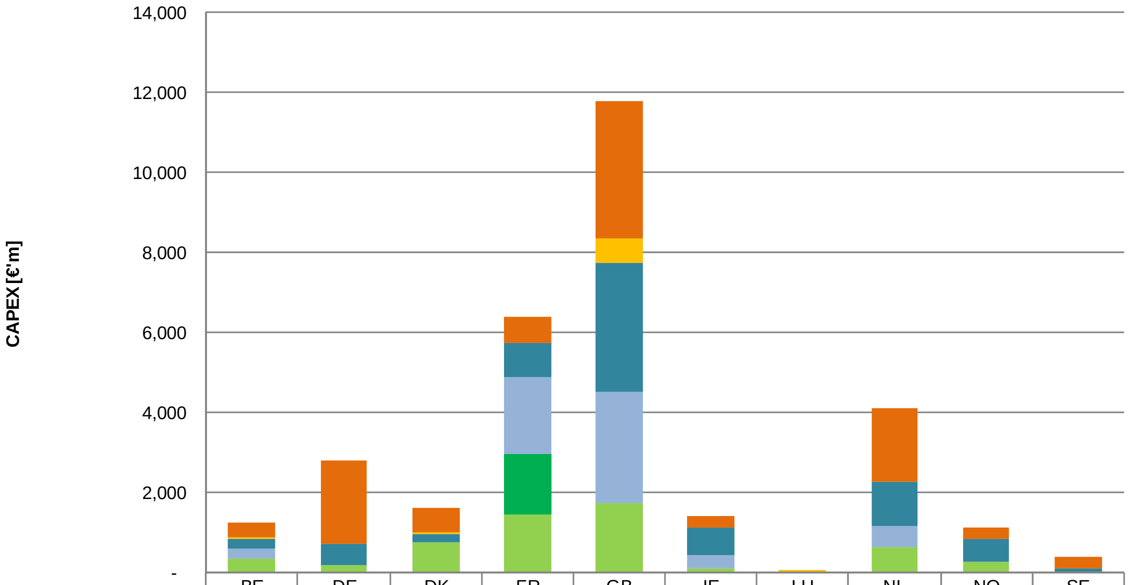
- LINE HVDC Offshore costs relate to new HVDC offshore cable links, but exclude costs of HVDC converter stations and offshore hubs; the cost of the onshore part of a mainly offshore cable is included here;

- LINE HVDC Onshore costs relate to new HVDC cables installed completely onshore, but exclude termination costs;

- LINE HVAC Offshore costs relate to new HVAC offshore cable links, but exclude substation termination costs; the cost of the onshore part of a mainly offshore cable is included here;

- LINE HVAC Onshore costs relate to new HVAC overhead lines and underground cables installed completely onshore, but exclude substation termination costs;

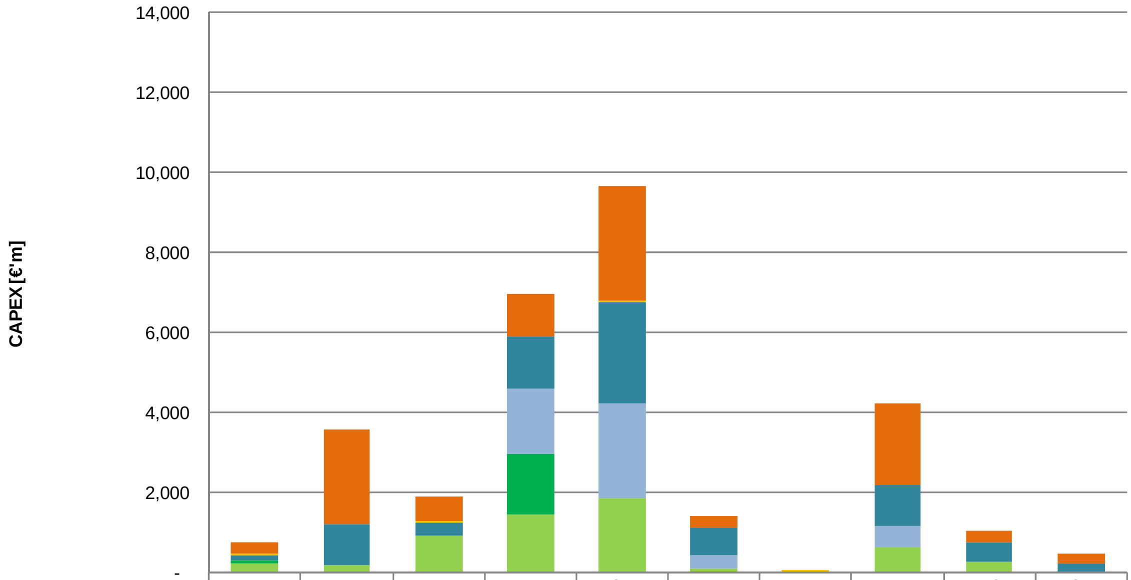
The total investment cost of the optimised 2030 radial grid design is 30.9 € bn. These are displayed by country and asset type in Figure 5-6. As with the circuit length charts above, a simple assumption was made that the costs of offshore interconnectors are split 50:50 between the two connecting countries. Almost 40% of the cost of the radial design is related to new build in and around Great Britain. The French share is also high, especially due to the need for onshore internal grid development between the Normandy Coast and Paris area and from the north-eastern border to the south-eastern part.



	BE	DE	DK	FR	GB	IE	LU	NL	NO	SE
Terminal HVDC	362	2,096	623	637	3,440	271	-	1,835	272	259
Station AC	58	-	10	-	630	20	13	-	-	-
Line HVDC OFFshore	245	535	220	875	3,227	682	-	1,112	579	93
Line AC OFFshore	244	-	-	1,915	2,764	335	-	532	-	-
Line HVDC Onshore	-	-	-	1,486	-	-	-	-	-	-
Line AC ONshore	343	176	751	1,461	1,736	99	-	620	276	20

Figure 5-6 Radial Grid New Circuit Investment Costs for 2030 Reference Scenario (additional to TYNDP projects)

The total of the investment costs of the optimised 2030 meshed grid design is 30 €bn. These costs are displayed by country and asset type in Figure 5-7. In this case the Great Britain share of the costs is reduced to about 33%, while the German and French investment costs have increased. The changes in total cost for each country are displayed in Figure 5-8. While the positions of individual countries change between the two designs, the important point to note is that the overall costs are somewhat lower for the meshed case indicating a potential benefit to the region of such meshed design. However, the difference in overall costs is relatively small compared to the overall capital costs reflecting the limited amount of meshing proposed in the meshed case for this Reference Scenario.



	BE	DE	DK	FR	GB	IE	LU	NL	NO	SE
Terminal HVDC	273	2,375	623	1,075	2,852	271	-	2,014	279	259
Station AC	58	-	13	-	64	20	13	-	-	-
Line HVDC OFFshore	118	1,031	331	1,306	2,511	682	-	1,052	497	203
Line AC OFFshore	-	-	-	1,628	2,366	335	-	532	-	-
Line HVDC Onshore	59	-	-	1,486	-	-	-	-	-	-
Line AC ONshore	233	176	933	1,461	1,869	99	-	620	276	20

Figure 5-7 Meshed Grid New Circuit Investment Costs for 2030 Reference Scenario (additional to TYNDP projects)

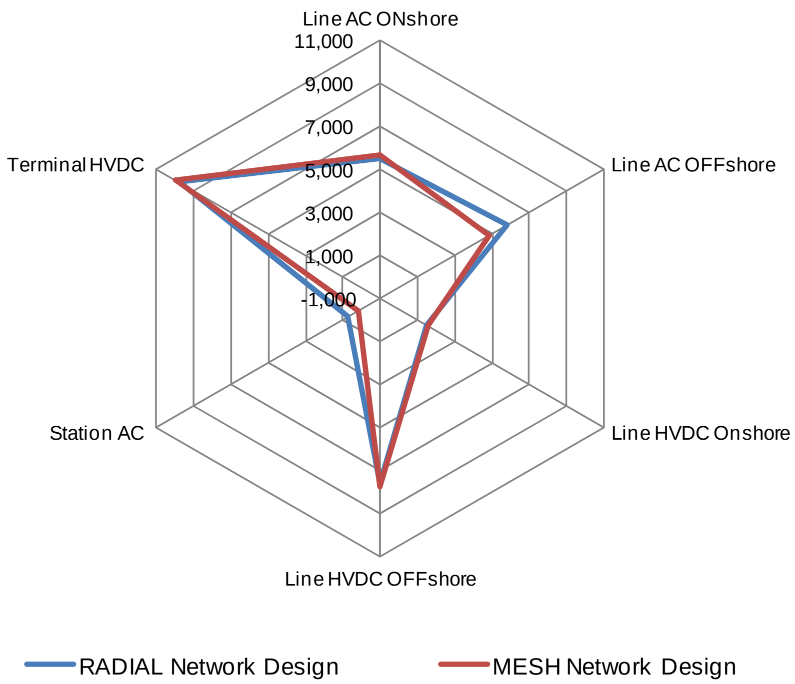
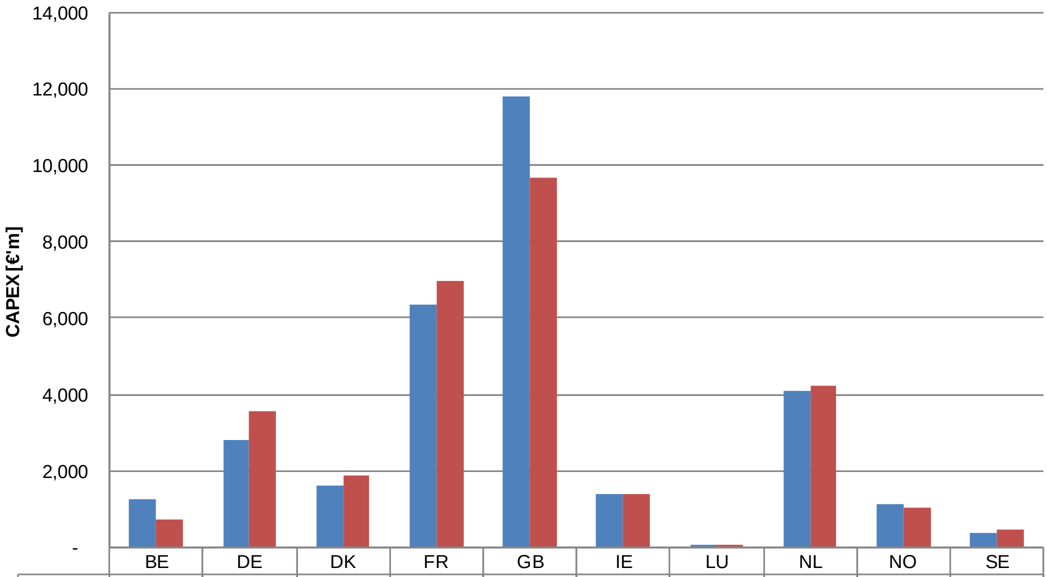


Figure 5-8 Comparison of Radial and Meshed Grid Costs by Asset Class for 2030 Reference Scenario

Figure 5-8 shows cost differences across the different types of asset. The chart shows that the two designs have similar costs across most asset types, but AC offshore and substation costs are somewhat higher for the radial design.



	BE	DE	DK	FR	GB	IE	LU	NL	NO	SE
RADIAL Network Design	1,252	2,807	1,604	6,374	11,797	1,408	13	4,099	1,127	372
MESH Network Design	741	3,582	1,900	6,956	9,661	1,408	13	4,218	1,051	483

Figure 5-9 Comparison of Radial and Meshed New Investment Costs by Country for 2030 Reference Scenario (additional to TYNDP projects)

A comparison of the total capital cost per country for both the radial and meshed network designs are shown in Figure 5-9. From the figure it can be seen that the meshed network design results in a reduction in capital costs in Great Britain, Belgium and Norway which is sufficient to offset the increase in capital costs for the other North Sea countries. In the case of Ireland and Luxembourg, the capital costs remain unchanged.

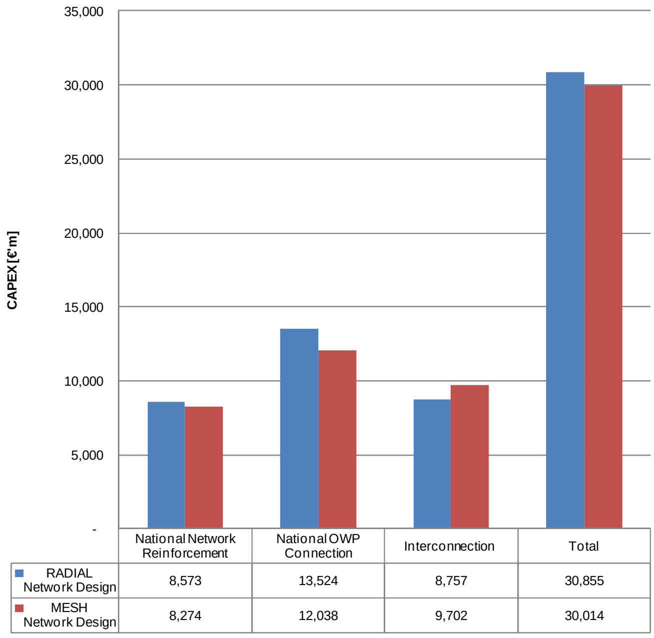


Figure 5-10 Comparison of Radial and Meshed New Investment Costs by Country for 2030 Reference Scenario (additional to TYNDP projects)

Figure 5-10 shows the breakdown of the investment costs into national reinforcements, the connection of the additional 13 GW of offshore wind park and new interconnections for both designs. This categorisation of capital costs into investment areas or types allows the concentration of spend to be assessed.

In total, the meshed design has a capital cost of around 800 M€ (2,7%) less than that of the radial design. Both designs have similar requirements as to the national reinforcements; as may have been expected, the radial design has higher costs connecting offshore wind parks back to shore; while meshed has slightly higher offshore costs to accommodate some of the output from the offshore wind parks, reducing the requirement for direct connections of the offshore wind parks back to shore.

The total capital costs for the radial and meshed network designs are represented in their corresponding annualised capital cost values in Table 5-1.The annuity values are based on the average real net discount rate of 6% and an assumed useful asset life of 40 years. The rate and the period were seen to be comparable with those used by most of the TSOs across the North Seas countries. The discount rate is in real values (i.e. excludes inflation) and therefore allows constant values to be used.

Table 5-1: Total and Annualised Investment Costs for Radial and Meshed Designs (additional to TYNDP projects)

Investment Costs	Radial Design	Meshed design
Total Investment Costs [M€]	30,855	30,014
Annualised Investment Costs [M€ p.a.]	2,051	1,995

5.1.3 VOM Costs for Grid Design Options

In order to include all measurable costs in a comparison of costs and benefits, the variable costs associated with operating and maintaining the new grid assets are calculated for each design.

Table 5-2: Variable O&M Costs for Radial and Meshed Designs (additional to TYNDP projects)

Variable O&M Costs p.a. (M€)	Radial Design	Meshed design
National network Reinforcements	180	180
National OWP Connections	180	141
Interconnections	157	181
Total	516	502

5.1.4 Production Cost Savings Resulting from Grid Expansions

Developing the grid delivers benefits, some quantifiable and others non-quantifiable. This section presents the quantifiable benefits – the reduction in 2030 variable production costs in the region - that arise thanks to the grid expansion strategies discussed in the previous section.

In assessing the benefits of new grid build, it is essential to remove other influences in the analysis. The approach to calculating the reduction in production costs was to model the production in year 2030 with the demand and generation assumptions derived from the Reference Scenario, firstly with the initial 2020 grid and then with the two 2030 grid designs. To model the 2030 Reference Scenario it was necessary to assume that all new generation and demand in the Reference Scenario is connected, and in the case of new offshore wind parks, that these are connected to their host countries. The benefits derived therefore relate to the removal of congestions both internally in national grids and between markets of different price characteristics.

There are other benefits of grid enhancements that were not analysed but include the lower production costs arising from the connection of new efficient generation (already assumed in the base case) and enhanced security of supply. A meshed grid provides more paths for offshore wind farms to transmit their power, meaning that an outage of one cable to shore does not completely block their access to the grid.

5.1.4.1 Annual Production Cost Savings

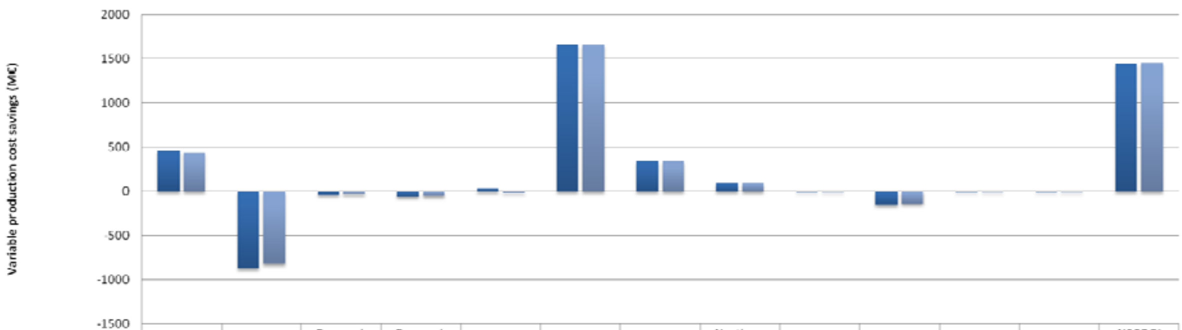
The main measureable benefits calculated in this study relate to the savings in electricity generation production costs. The variable cost of production comprises fuel costs, VOM costs and CO_2 emissions costs. Figure 5-11 shows the savings in the 2030 production costs within each country for the radial and meshed designs over the initial 2020 grid. It is important to know that these are changes in <u>production</u> costs within each country, and not <u>energy</u> costs. The impact of imported energy it therefore not included.

The most significant savings arise in Great Britain where higher cost (gas fired generation) is replaced with generation in other countries, thereby reducing the overall production in Great Britain. The costs of production in Belgium and Ireland also fall with the 2030 grid designs.

Germany and Netherlands see the largest increases in production costs, as they generate more to export to the higher price countries.

In the other countries there are only small differences.

The total savings for the NSCOGI region are also presented in the graph. As can be seen, the total production costs savings are very similar (around 1450 M€ per year) for both radial and meshed configurations. This means that the total production costs have come down from 43.6 billion € to 42.1 billion €.



	Belgium	Germany	Denmark East	Denmark West	France	Great Britain	Ireland	Northern Ireland	Luxembourg	Netherlands	Norway	Sweden	NSCOGI Perimeter
2030 radial design	458	-875	-36	-60	36	1669	336	91	-5	-156	-2	-10	1449
2030 meshed design	439	-820	-32	-55	-16	1660	339	92	-4	-140	-2	-5	1456

Figure 5-11 Difference in the variable production costs by NSCOGI country for the Reference Scenario in 2030, between the Grid2030 Radial case and the Grid2020 case, and between the Grid2030 Meshed case and the Grid2020 case

The additional grid build therefore reduces average production costs in formerly high price countries and increases prices in formerly lower priced countries by virtue of their additional exports.

The following sections provide more insight into the production cost results.

5.1.4.2 Marginal cost changes

Figure 5-12shows the impact of extra grid capacity on marginal cost differences (base for electricity price differences) between countries. Marginal cost differences are a driver for the market to realize interconnections.

The blue area indicates the spread of short run marginal cost (SRMC) between countries if grid 2020 interconnectivity is available. The figure shows that the spread is significantly reduced with grid 2030 connectivity (the green area).

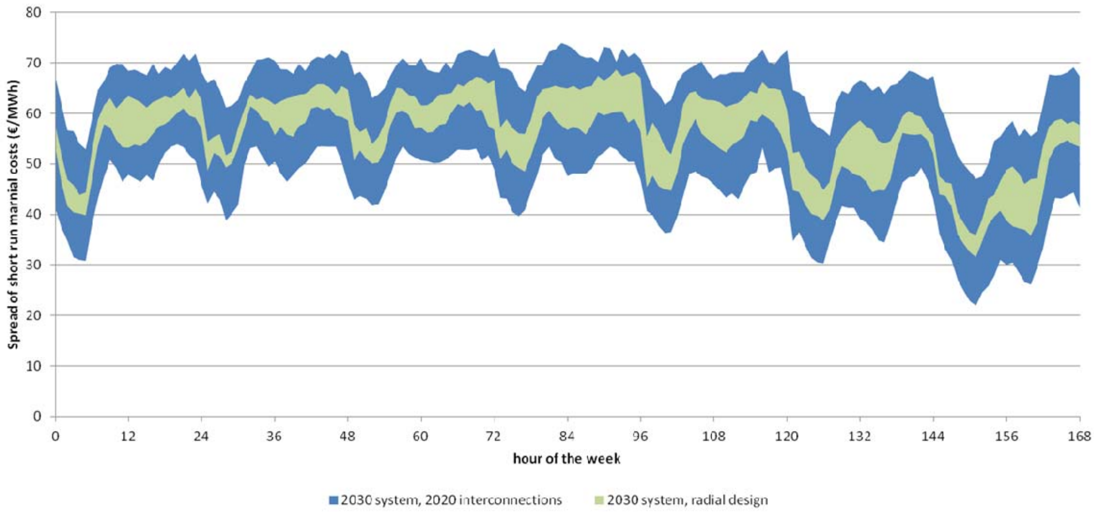


Figure 5-12: Spread of short run marginal cost for the Reference Scenario in the year 2030 for grid 2020 and grid 2030/radial design

5.1.4.3 Fuel Mix in Energy

The fuel mix has been calculated for each NSCOGI market node based on the Reference Scenario for the two 2030 grid designs, with the 2020 grid as a reference point. Figure 5-13 compares these three sets of results for each node; the left column represents the fuel mix with the grid as planned in 2020 (Grid2020), the middle column represents the fuel mix with the radial expansion in 2030 (Grid2030Radial), and the rightmost column represents the fuel mix with the meshed expansion in 2030 (Grid2030Meshed).

A summed fuel mix greater than 100% for a market node means that generation exceeded demand at that node and electricity was therefore exported to a neighbouring country. Similarly, a summed fuel mix of less than 100% means that the market node met some portion of its demand using imported electricity from neighbouring countries.

Comparing the results for the meshed and radial designs it can be observed that there is little difference in the fuel mix between the radial and meshed configurations. Nuclear generation benefits from the increase in interconnection in the 2030 configurations. However, the greatest changes are in coal and gas generation. As mentioned previously, coal generation is more economic in general to gas generation in this scenario. With increased interconnection, coal-fired generation increases substantially and gas-fired generation decreases by even more.

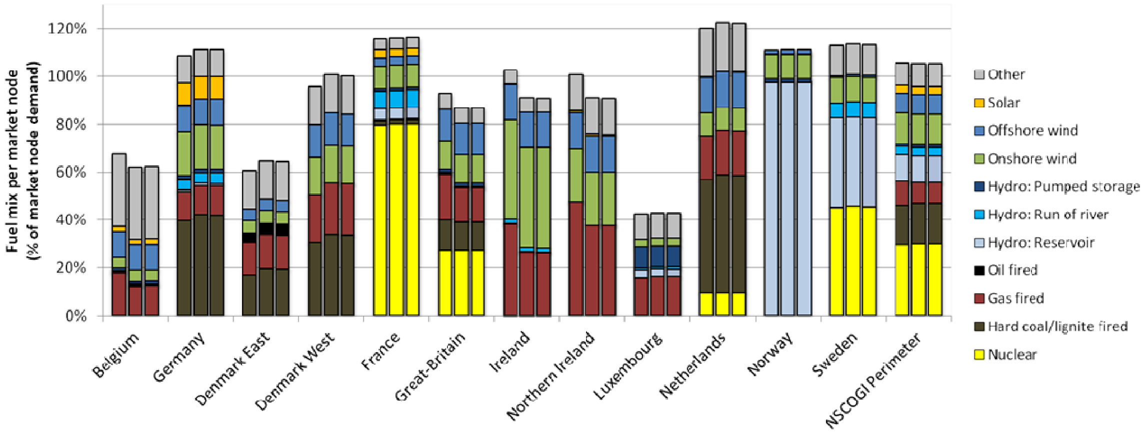
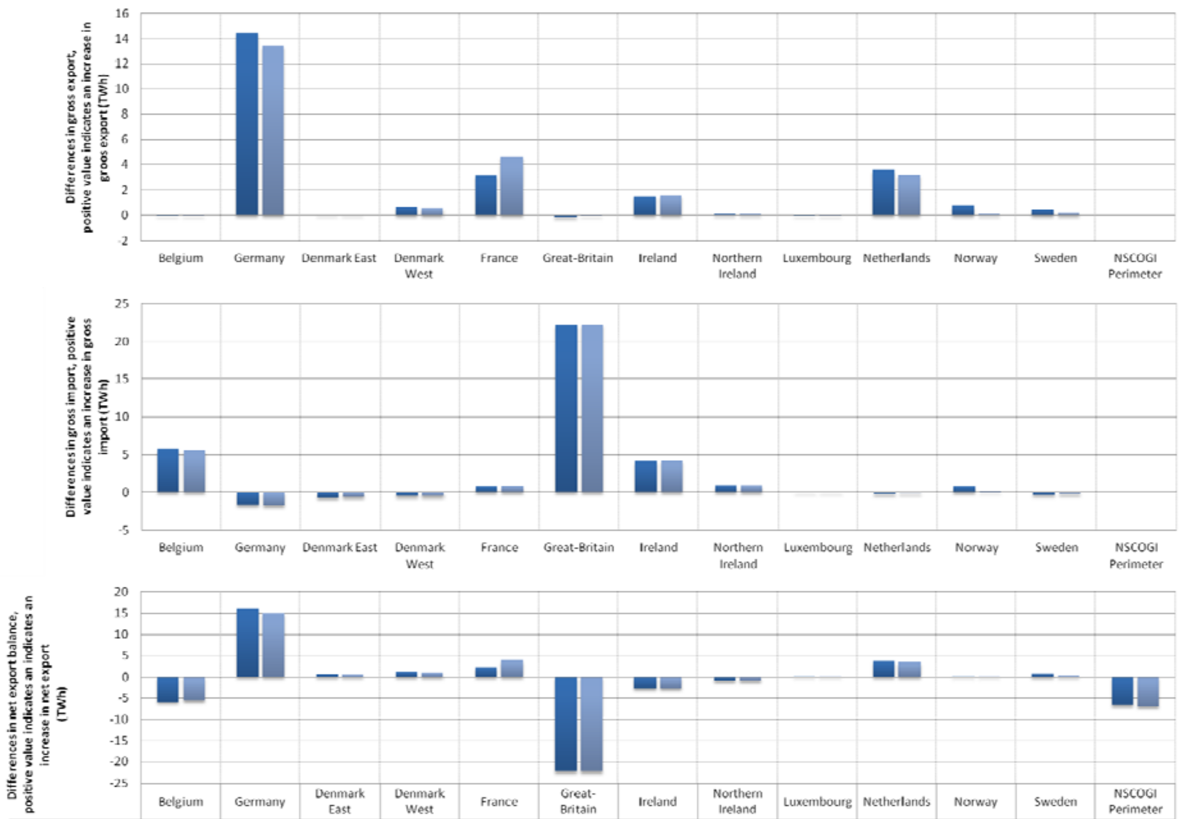


Figure 5-13 Fuel mix by NSCOGI country for the Reference Scenario in the year 2030 for the Grid2020, Grid2030 Radial, and Grid2030 Meshed grid scenarios.

5.1.4.4 Import and Export Positions



	Belgium	Germany	Denmark East	Denmark West	France	Great-Britain	Ireland	Northern Ireland	Luxembourg	Netherlands	Norway	Sweden	NSCOGI Perimeter
2030 radial design	-6	16	1	1	2	-22	-3	-1	0	4	0	1	-7
2030 meshed design	-6	15	1	1	4	-22	-3	-1	0	3	0	0	-7

Figure 5-14 Differences in: the gross export (top), gross import (middle) and net export balance(bottom) by NSCOGI country for the Reference Scenario in 2030, between the Grid2030 Radial case and the Grid2020 case, and between the Grid2030 Meshed case and the Grid2020 case

Figure 5-the change in gross imports, export and net position, relative to 2020 grid connectivity for each market node as a result of the additional interconnections in the 2030 radial and meshed grid expansions strategies. The changes in gross import and export reported for each market node exclude transit flows, see chapter 4.2. Positive values mean that there is an increase relative to case with the 2020 connectivity. Conversely, negative values mean that there is a reduction.

There is little difference in gross imports, export and net position between the radial and meshed configurations.

Comparison of both Radial and Meshed against the grid 2020 connectivity shows the following:

- There is a large increase in gross imports for Belgium, Ireland and especially Great Britain. These are countries with large amounts of gas-fired generation, which is being replaced by cheaper imported electricity from hard coal, lignite, nuclear and wind generators.

- There is a large increase in gross exports for France, Ireland, Netherlands and especially Germany. These are countries that have large amounts of cheaper generation such as hard coal, lignite, nuclear and wind generation, which the additional interconnections allow to be exported. For example, Germany has large amounts of hard coal and lignite generation. In the case of Ireland, the increase in gross exports is from wind generation that was previously curtailed but which can now be exported.

- As for the export balance, Great Britain, Belgium and to a lesser extent Ireland have the biggest increases in net imports, while Germany, France and the Netherlands see the largest increases in net exports.

5.1.4.5 CO_2 Emissions

Figure 5-15 shows the changes in the CO_2 emissions at each market node as a result of the additional interconnections in the 2030 radial and meshed grid expansions strategies.

As previously mentioned, the fuel and CO_2 emission prices employed in the study result in hard coal and lignite generators generally being cheaper than gas generators. The additional interconnection capacity in the 2030 grid design facilitates better utilisation of cheaper generating resources, including the coal and lignite fired generators. Consequently there is an increase in the CO_2 emissions of countries with significant coal generation such as Germany and the Netherlands. This increase is offset by a decrease in CO_2 emissions mainly in Belgium, Great Britain and Ireland. There is very little change in CO_2 emissions for the NSCOGI region as a whole. This is mainly caused by the decrease of the net export of the region as a whole.

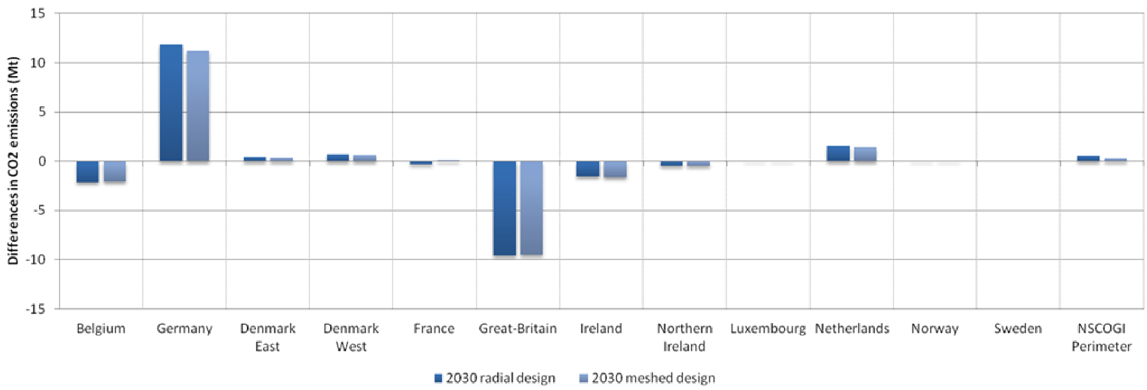


Figure 5-15 Difference in the CO_2 emissions by NSCOGI country for the Reference Scenario in 2030, between the Grid2030 Radial case and the Grid2020 case, and between the Grid2030 Meshed case and the Grid2020 case

5.1.5 Comparison of Costs and Calculated Benefits of both Grid Designs

The comparison of costs and benefits between the radial and meshed grid designs is carried out using readily quantifiable values and as such is seen to be a narrow assessment of the relative merits of the options considered. The value associated with the non-quantifiable or less readily available costs and benefits are, for the purposes of this discussion, not considered.

In accordance with the assumptions used and the agreed scope of the study, the level of wind generation and their geographical locations in 2030 have been stipulated and the evaluation is therefore focused on the comparison of network design options.

The separate assessment of whether it is economic to connect the OWPPs as specified in the Reference Scenario for 2030, or what level of offshore wind generation is optimum, is not addressed in this evaluation. The starting position for this economic assessment is therefore that the specified OWPPs are deemed connected and costs associated with providing the OWPPs with connections need to be excluded from this assessment. The default design configuration for the integration of the OWPPs was assumed using a radial design configuration. Under the exercise the simple approach was chosen to assume that the connection costs of the offshore wind parks in the radial case are the reference costs for connections applicable in both cases. These costs are therefore subtracted from the totals of both designs.

In reality, some wind parks in the meshed design will be connected partly through direct links to shore and partly through interconnectors, resulting in a possible reduction of connections to shore. By choosing to subtract the higher reference connection costs from the overall meshed design costs, the analysis takes account of this optimisation.

As stated in Section 5.1.4, the benefits that were derived relate to all new grid build other than the connections of new generation and demand.

The annualised values (annuities) associated with the two network designs are used to carry out the evaluation. This method is appropriate for the comparison of the relative economic position of competing alternatives. Given that the way the individual network designs will be developed is not known at this stage, this method allows the comparison of economic merits without addressing the issue of the phased development of the individual networks and the associated phasing of capital expenditure. As such, the method is suitable to compare competing alternatives, but should not be interpreted as a means of conducting an investment appraisal.

In order to compare the capital investment costs of each grid design, presented in Section 5.1.3, with the annual production cost savings calculated for 2030, it is necessary to express the costs as annuities. Full amortisation with an asset life of 40 years and a discount rate of 6% were assumed for this purpose.

The costs and the benefits for the radial and mesh network designs are summarised in the Table 5-3 below. The differences are presented with reference to the radial case.

The capital costs account for the majority of the total costs with the meshed capital costs being 5% lower than the radial capital costs. The variable operating and maintenance costs (VOM) show a similar result with Meshed VOM costs being 4% lower than the Radial VOM costs. Together, the total costs differ by 5%.

The Production cost savings for both the Radial and Meshed scenarios are almost the same, differing by just under 0.5%. Consequently, the analysis of the costs and the benefits of the proposed network designs will be dictated by the differences in the total costs of the two network designs and not by the differences in the production cost savings.

Table 5-3 Summary of Costs (excluding OWP connection costs) and Benefits for Radial and Meshed Designs

	A	B	C = A+B	D	E = D-C	F = E/C
	Annualised Investment Cost excluding the radial OWPP connection costs M€ p.a.	Annual VOM Costs M€ p.a.	Total Costs M€ p.a.	Production Cost Savings M€ p.a.	Net benefits M€ p.a.	Net benefit related to total costs [%]
Radial	1,152	336	1,488	1,449	-39	-2,6
Meshed	1,096	322	1,418	1,456	38	+2,7
Difference Radial vs Meshed	**-56**	**-14**	**-70**	**7**	**77**	

Based on the scenario considered and the assumptions made, the meshed network design has an annual net benefit of 38 M€ compared to the radial network design that has an annual net loss of 39 M€, representing 77 M€ per annum difference between them. These net benefit or net loss values individually represent approximately 2.6% of the total costs and as such may not necessarily be seen as significant enough to distinguish the results from a net break-even result for either design.

The difference between the two alternatives is relatively small and on a purely comparative basis - using the assumptions, data, methodologies and tools available - the meshed network design would be ranked ahead of the radial network design.

5.1.6 Sensitivity Analysis – the RES+ case

Section 3.11 describes the selection of a sensitivity study referred to as RES+. In this case, the volume of offshore wind parks was increased to 117 GW from the 56 GW in the Reference Scenario[8], without changing any other study parameters. The most significant changes were in Great Britain offshore volumes that increased from 17.7 GW to 49 GW. The higher French figure includes 4 GW tidal plants. All other increases are offshore wind parks.

Table 5-4: Offshore wind changes for the RES+ Sensitivity

GW	BE	DE	DK W	DK E	FR	GB	IE+NI	NL	NO	SE
Ref	3.1	16.7	0.9	0.3	6.5	17.7	2.3	6.0	0.7	0.7
RES+	4.0	25.0	3.4	1.0	13.0	49.0	7.0	12.0	1.0	2.0
Change	+0.9	+8.3	+2.5	+0.7	+6.5	+31.3	+4.7	+6.0	+0.3	+1.3

The sensitivity analysis has been studied to obtain an indication of the impact of an increased offshore renewable generation capacity - some located further offshore - on the overall designs arrived at in the Reference Scenario. The approach was less thorough than that adopted for the Reference Scenario, and can be illustrated, from a process perspective, by considering the circle shown in Figure 2-2 showing the TSOs' method for this type of study. The sensitivity analysis can be assumed to have progressed half way around the first circle.

The maps in Figures 5-17 and 5-18 show the offshore grids for the radial and meshed grid designs, respectively, for the RES+ sensitivity. The onshore details are not shown as they have not been through the same rigorous analysis as the Reference Scenario cases, and therefore could be considered misleading.

Although a proper comparison with the reference scenario is not valid, it is possible to observe that the radial design for RES+ involves many more radial links to shore than in the Reference Scenario because of the additional offshore wind parks and the tidal plant. There are also more interconnectors in the RES+ case, some of which are common with the Reference scenario.

[8] The RES+ sensitivity figures were based on the most "green" national scenarios available to TSOs in early 2012

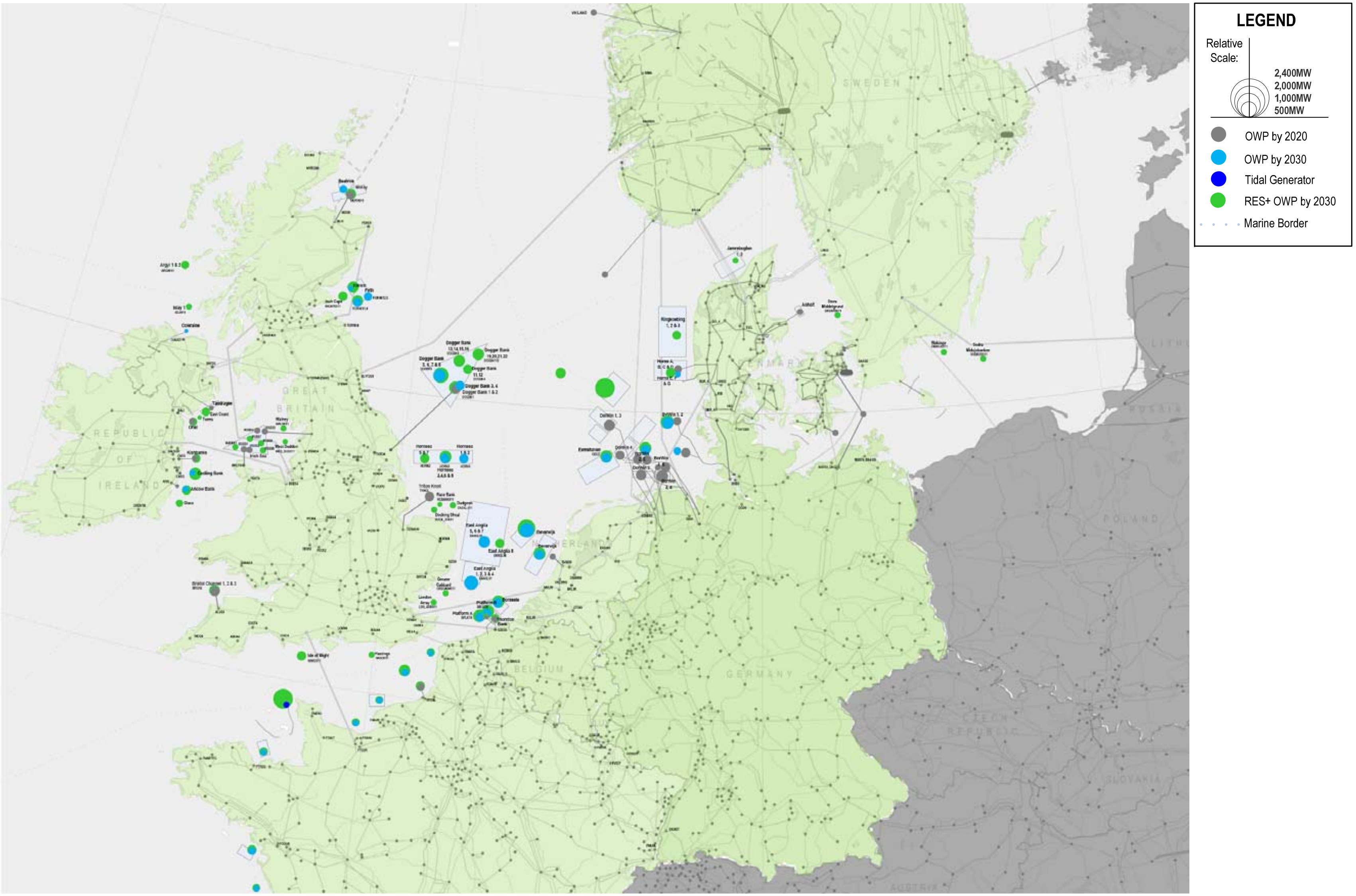


Figure 5-16 : Map of OWP locations for RES+ sensitivity on the Reference Scenario (for readability reasons the scale in the legend does not match the map)

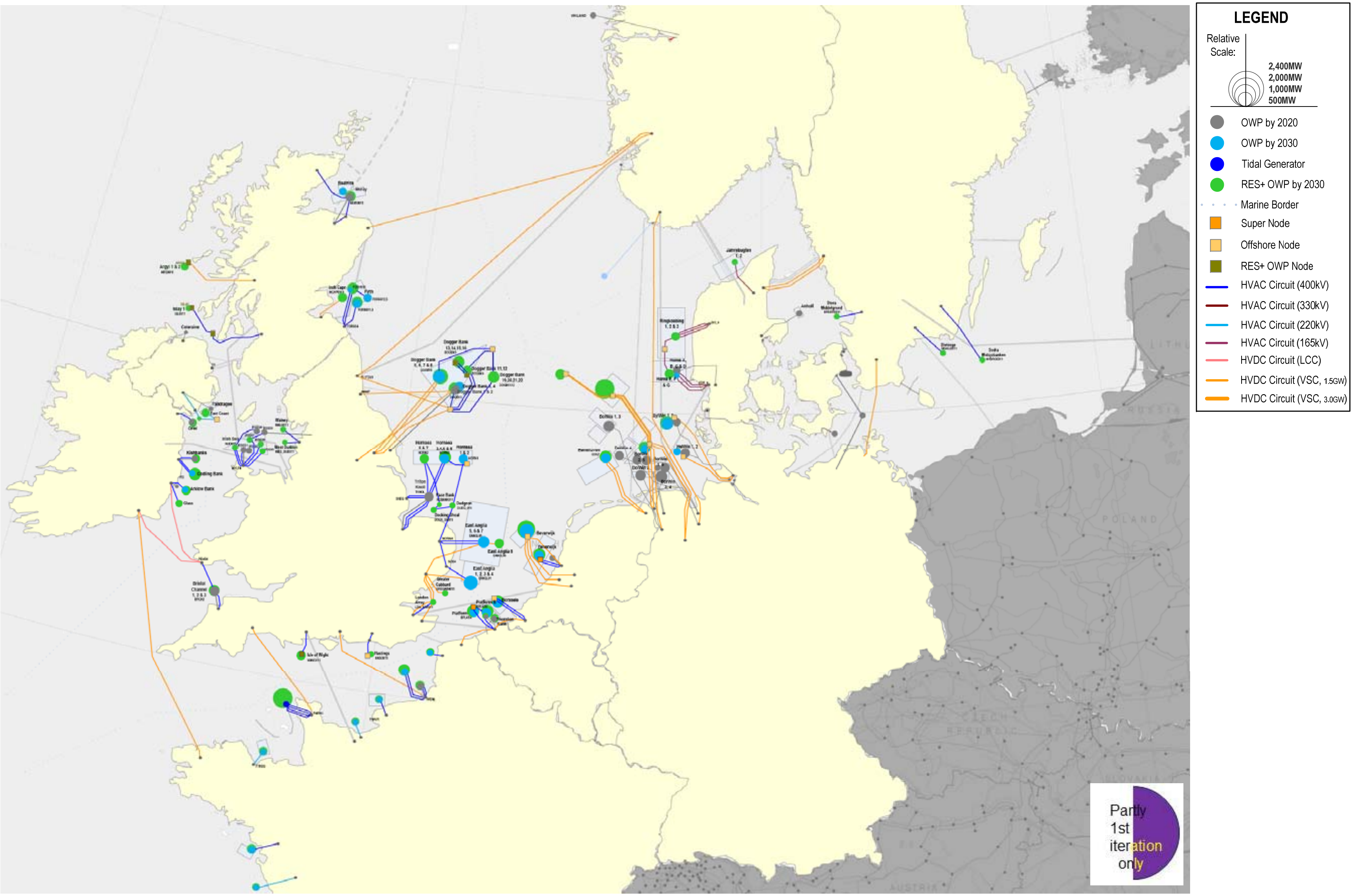


Figure 5-17 : Map of radial grid design for RES+ sensitivity on the Reference Scenario (for readability reasons the scale in the legend does not match the map)

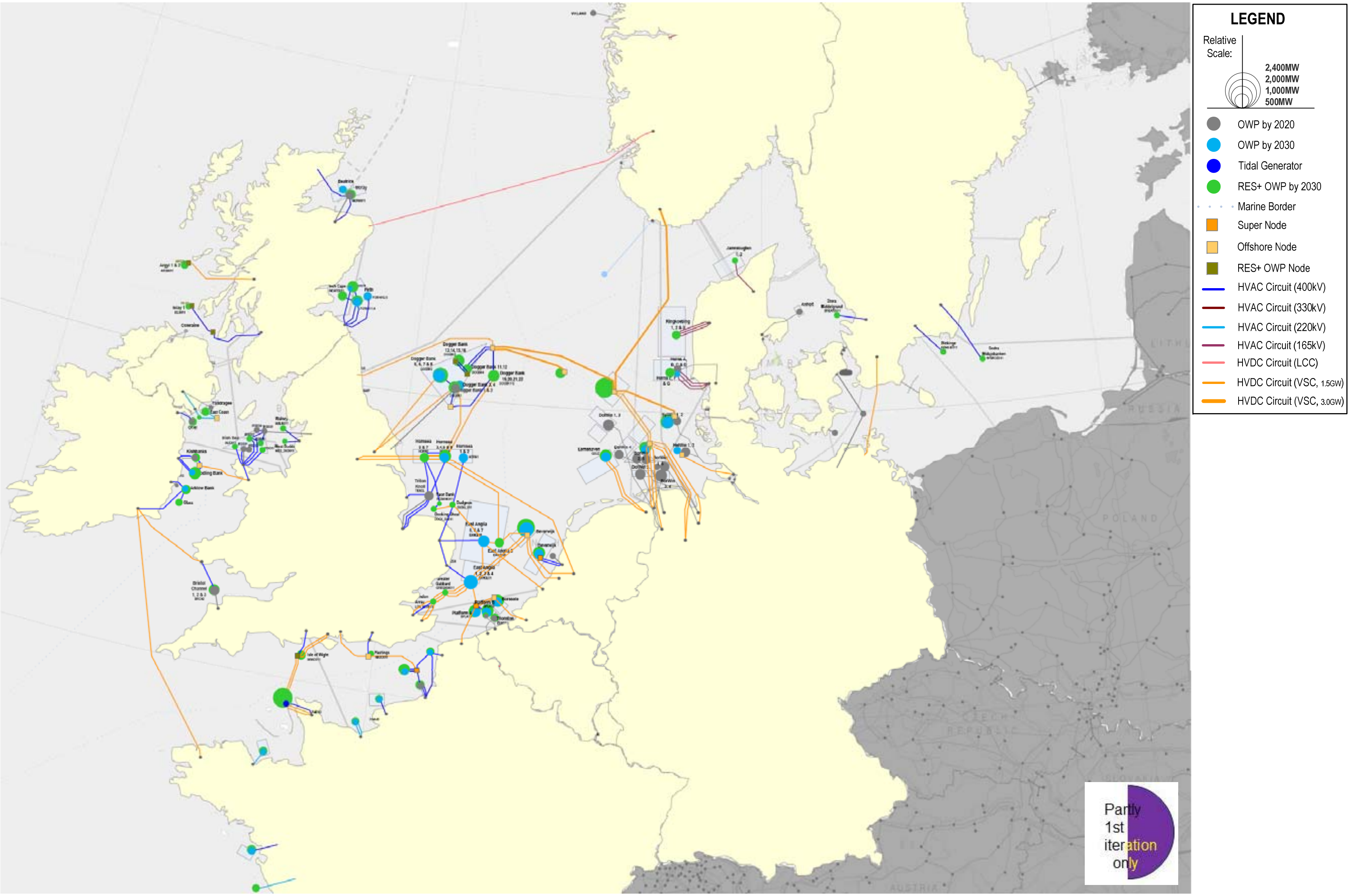


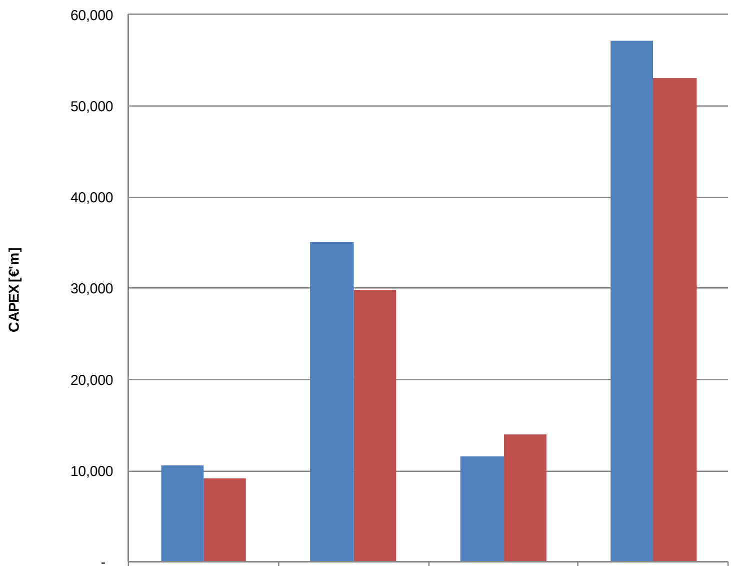
Figure 5-18 : Map of meshed grid design for RES+ sensitivity on the Reference Scenario (for readability reasons the scale in the legend does not match the map)

The principle benefit of this sensitivity study is to compare the radial and meshed designs for the increased volumes of offshore wind. The meshed design for the RES+ case involves a significant amount of complex offshore meshed network in the North Sea, with simpler meshed networks emerging in the Irish Sea and in the Channel.

The location of large wind parks further from the coasts of Great Britain, the Netherlands and Germany provide an opportunity to create offshore interconnected hubs. One of the two direct Great Britain-Norway interconnectors and a Germany-Norway interconnector in the radial designs are replaced in the meshed with a shorter higher capacity interconnector from Norway to a hub at a large German offshore wind park that is connected also to a Great Britain offshore hub. This reduces the length of new circuit required to achieve the interconnection.

The offshore grid in the south-west corner of the North Sea displays a high degree of meshing with multiple links to Great Britain, the Netherlands, Belgium and France.

The chart in Figure 5-19 presents a comparison of the capital costs of the radial and meshed network designs. These capital costs should be viewed as indicative only as the sensitivity analysis has not been as thoroughly studied as the Reference Scenario. Notwithstanding these precautions, the graph shows that the meshed design results in higher capital costs of interconnections but lower capital costs for national reinforcements and offshore wind park connections. The meshed grid provides more alternative paths for power flows from offshore wind parks thereby requiring fewer connections to shore and fewer onshore reinforcements. Overall, the capital costs of the meshed design are lower than the radial design by about 7 per cent.



	National Network Reinforcement	National OWP Connection	Interconnection	Total
RADIAL Network Design	10,579	35,026	11,547	57,153
MESH Network Design	9,209	29,893	13,988	53,090

Figure 5-19 : Comparison of Investment Costs for radial and meshed grid design for RES+ sensitivity on the Reference Scenario

To provide an indication of total costs, the annual VOM costs are also included. The capital costs were represented as annualised values in the same manner as used in the Reference Scenario, and are summarised in Table 5-5 below.

Table 5-5 : Comparison of Annualised Investment and VOM Costs for radial and meshed grid design for RES+ sensitivity on the Reference Scenario

	RADIAL Network Design			MESH Network Design		
	Capital Cost [M€p.a.]	VOM [M€p.a.]	Total [M€p.a.]	Capital Cost [M€p.a.]	VOM [M€p.a.]	Total [M€p.a.]
National Network Reinforcement	703	195	**898**	612	194	**806**
National OWPP Connection	2,328	591	**2,919**	1,987	456	**2,443**
Interconnection	767	215	**982**	930	287	**1,216**
Total	**3,798**	**1,001**	**4,799**	**3,528**	**937**	**4,465**
Total Costs excluding radial OWPP connection costs			**1,880**			**1,546**

Excluding the costs of connecting the OWPPs (assuming the default is the radial network design), the annual costs for the radial design are 1,880 M€, whereas the meshed design costs are 1,546 M€.

5.1.7 Operational Aspects

Although not within the scope of this study, the operational aspects of an integrated meshed grid have to be considered. A number of studies have concluded that the operation of a meshed DC system is more complex than the known and proven radial design for connection of offshore wind farms and shore-to-shore interconnections. [30], [35].

Although not necessarily necessary for the meshed designs presented in this report, new technologies, such as the commercial availability of a DC breaker should improve the operational challenge [36].

5.2 Comparison of the results to the study „OffshoreGrid“

In October 2011, the study “OffshoreGrid: Offshore Electricity Infrastructure in Europe” was published [12]. The project was funded by the EU’s intelligent Energy Europe (IEE) programme. Under the coordination of 3E, a team of seven project partners[9] worked on the study. In this section, the results concerning different grid designs and calculated benefits are compared shortly.

In the Reference Scenario, the NSCOGI-study shows only limited difference between the radial and the meshed grid design approach (cf. chapter5.1.5); the main differences occur in the Channel, where the meshed version leads to integrated designs between British offshore wind farms on the one hand and Dutch, Belgian and French offshore generation on the other hand. Hence, the total costs of the system[10] do not vary considerably when comparing a potential radial or meshed infrastructure. A slight advantage for the meshed solution can be found though.

The advantage in favour of a meshed design increases in the RES+ sensitivity. In RES+, the assumed installed offshore capacities in the NSCOGI-region increases to from 55 GW to 117 GW and more complex offshore structures occur. The meshed design shows lower grid investment and VOM costs than the radial case (by approx. 7%). An evaluation of the benefit by reduced production costs has not been carried out yet.

This confirms the results of the Offshore Grid study. Taking 126 GW offshore wind volumes into account, the OffshoreGrid study finds a relevant benefit of a meshed grid approach compared to a radial design including hubs (“hubs” connect two or more offshore wind farms to shore using a shared line). The first benefit, (lower investment costs), shows when deploying these hubs in contrast to single connections for each wind farm. The second benefit (lower VOM costs) appears when more meshed approaches are investigated. In this case, the grid infrastructure costs increase further, but the production costs decrease even more resulting in 10 to 15% lower total system costs.

Another common feature can be found when comparing the NSCOGI study to the OffshoreGrid-study: The “Teeing-In” of wind farms, i.e. connection of an OWPP to a nearby interconnector forming a T-joint is part of the NSCOGI design assumptions (see Figure 1-3) and was selected in certain cases. The OffshoreGrid shows it to be beneficial for some examples saving on total costs: A German wind farm is integrated into the so-called COBRA-cable [20] and also into NordLink, though with less benefit for the latter.

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[9]Dena, EWEA, ForWind, IEO, NTUA, Senergy, SINTEF

[10]Grid investment annuities, annual VOM and production costs of the generators

6 Conclusions and Outlook

6.1 Discussion on Results

NSOCGI has proved to be an important platform for collaboration between the European Commission, Governments, NRAs and TSOs. It has considered two different regional design approaches concerning the offshore part of the infrastructure necessary to meet the 10 Governments' energy mix ambitions, including the accommodation of expected volumes of offshore wind energy to achieve targets in 2020 and beyond

The North Seas' Countries are committed to addressing climate change and reducing emissions in the longer term [8]. Although there are EU-wide renewable targets to 2020, there are none beyond this point. There is therefore considerable uncertainty over the generation mix, including the predicted level of renewable generation in the North Seas, for the period 2020 to 2030, because each country might follow individual 2030 targets or has an individual approach to deliver the EU's 2050 decarbonisation objective with individual assumptions concerning the neighbours' decisions [8].

In summer 2011 the Governments provided their individual generation and load forecasts for 2030. The TSOs applied their knowledge and expertise to develop plausible grid designs to accommodate the expected generation mixes at optimal grid investment cost.

6.1.1 Initial findings

Based on the NSCOGI 2011 forecasts of generation and demand in 2030, the analysis carried out in this study showed that the meshed solution is slightly better (by 77 M€ p.a.) than the radial one, in terms of variable electricity production costs, investment cost into grid assets and related variable operation and maintenance costs. However, the significance of this difference in the context of a 30 bn€ investment in the grid has to be tested with further analysis using other scenarios and executing some risk assessment.

The volume of new offshore RES between 2020 (the base year) and the studied year (2030) in the Reference scenario was relatively small, with only 13 GW predicted for new connections across the region. This is in contrast to the expected developments for other fuel types e.g. gas capacity increasing by 63GW during the same period. The findings of this study should therefore be considered against this background.

6.1.2 The scenario is fundamental to results

The development of the Reference scenario was the result of a joint exercise by Governments and TSOs in the summer of 2011. The Reference scenario was built up from Governments' best views taking into account national policies at that time and planning considerations. Governments are well placed to make such forecasts given their role in supporting specific technologies and making planning decisions.

However, although PRIMES was used as a common basis, the governments each adapted it with their own best view. The assumptions underpinning those national contributions were quite different, resulting in different fuels emerging as dominant in different countries This is to be expected, with different countries having different technology preferences. This clearly has a significant impact on the infrastructure needs emerging from the market studies. In addition to the new offshore wind installations these market differences were the key drivers for increased interconnection and reinforcements in 2030.

The impact of these market differences is particularly evident in those countries presenting a gas-focussed portfolio, like Great Britain and Belgium. The assumed and agreed IEA fuel prices result in an economic production order of coal ahead of gas across the region. As a result, gas-fired generation units provide just 10% of electric energy (2030) even though they constitute over 20% of the installed capacity in the region. Conversely, coal-fired generation units provide 16% of electric energy despite making up just 9% of the total capacity installed. So, although gas capacity increases by 70%, and coal capacity decreases by 8%, the energy production behaves inversely with an 18% decrease for gas, but 190% increase for coal due to the impact of the assumed merit order. By implication, this will play a major role in the countries' import / export positions and related infrastructure requirements.

Clearly running this amount of coal will have an impact on CO_2 emissions, which according to the results stay constant between 2020 and 2030. It therefore follows that, without large-scale CCS integration, countries with the largest amounts of coal generation (e.g. Germany, Great Britain and the Netherlands) are and stay also the largest emitters of CO_2, although some movement between them can be observed between 2020 and 2030.

In an energy only market and under this scenario it is doubtful whether gas-fired plant would have sufficient utilisation hours to be profitable with the assumed CO2 price and fuel prices of gas and coal.

Thus, the resulting infrastructure for the Reference scenario should be re-evaluated, if the underlying production mix assumptions are changed in the light of the results presented in this study.

Even though there may be differing assumptions underpinning the Reference scenario it provided an important insight to understand and evaluate the ten NSCOGI Governments' best views. Through this exercise, NSCOGI has made it possible to combine unique national knowledge with regional modelling capability. With this newly established regional cooperation with key stakeholders, NSCOGI is better prepared to provide future regional studies of this nature.

The results show clearly that the region can benefit from 'talking-to-the-neighbours' or even cross-border cooperation on questions concerning both energy production unit planning and the associated infrastructure development.

Going forward, additional scenarios should be developed assessing each corner of the 'kite' described in Figure 1-4. In the absence of agreed national/ Regional/ European 2030 energy targets, these should be developed with key stakeholders. based, as far as possible, on common underlying assumptions

6.1.3 Grid designs

Under the grid expansion methodology special attention was given to the integration of offshore RES, but it also met the requirements under the other pillars of energy policy, as defined in the European Energy Infrastructure Package, i.e. Integration of Energy Markets (IEM), Implementation of Renewable Energy Resources (RES) and Security of Supply (SoS). An important finding of this study is that, under the Reference Scenario, further market integration is facilitated through the development of additional cross-border links. The analysis also shows that it is essential to take the impact of offshore grid developments on the onshore network into account. These impacts provide a critical element in the future grid designs.

Two main offshore grid structures were considered:

- A radial design with offshore RES independently and radially connected to the onshore grid, separately from the establishment of point-to-point interconnectors
- An integrated (meshed) design where offshore RES and interconnectors can be connected to the onshore grid or to offshore hubs.

Both designs provide access to all of the offshore wind parks assumed in the Reference scenario and therefore facilitate the renewable energy ambitions of the 10 Governments as set out in the Reference scenario.

Because of the relatively small volumes of offshore RES expected between 2020 and 2030, there are limited opportunities for 'meshing' with only small differences between the costs (annuitised investment cost and annual VOM for the grid) and benefits (reduction in production costs, including CO_2 impact and VOM for the generation) between the radial and meshed designs. The results show an annual difference between radial and meshed of 77 M€ p.a. in favour of a meshed approach. This difference may not necessarily be seen as significant enough to distinguish the results from a net break-even result for either design. Further investigation would be needed before taking project decisions based on these results.

Any future offshore grid will not be built from blueprints or NSCOGI impressions for the future. It will be developed gradually based on robust business cases for individual projects The optimisation of candidate reinforcements does identify some opportunities for meshing in the reference scenario (in particular in the English Channel and between Belgium, the Netherlands and Great Britain). This is a contrast to other studies, e.g. [12],which found meshing opportunities for long-distance offshore assets – but used much higher offshore wind volumes (126 GW) than in the Reference Scenario (56 GW) as basis for the study, as further studies on future RES integration did [15] -[18], [21]; [23].

Although the benefits of the emerging meshing opportunities found in this study may be marginal for the region, there may be more significant benefits for the involved countries. There may be added value for TSOs to investigate these opportunities, in close collaboration with relevant NRAs and Government authorities. It should be noted in this respect that this study optimised investments for the region; in other words, actions on specific projects may have implications for neighbouring countries as a result of discrete decisions taken by its regional neighbours.

This study emphasises the importance of studying scenarios developed against common foundations to avoid distortions created by differences within the scenario, rather than genuine market need. Although the radial and meshed approaches produced similar levels of interconnection, with similar associated production cost savings, there were significant differences in how they were achieved (e.g. Great Britain-Norway link in the radial design is replaced by Norway-Germany and flows through Continental Europe in the meshed) which need to be further investigated.

6.1.4 The benefits of meshing

It should be expected that there are quantifiable costs and benefits associated with adopting a meshed approach to grid design, and these have been assessed as part of this study. However, there are other less quantifiable implications which include the added complexity associated with designing and building a meshed grid, increased technology risk, challenges of operating an integrated DC grid and the need for significant regulatory adaptation. These may be offset by increased operational flexibility provided by the meshed network with greater resilience for individual offshore wind developments. In addition reduced environmental impact should be expected with the potential for larger cables and fewer landing points.

6.1.5 Sensitivity with increased amount of offshore RES

The RES+ sensitivity analysis was used to test whether the benefits of meshing would increase if the volume of offshore RES were to increase significantly. The increased volumes of offshore RES included in the RES+ sensitivity reflect the most ambitious offshore RES numbers available to each of the TSOs. As such, they may not be consistent with formal and/or published Government predictions.

Although the RES+ analysis did not go through the same rigour as the reference scenario (only half way round the circle), the increased volumes of wind do create a more complex offshore network in the North Sea, with simpler meshed networks emerging in the Irish Sea and the English Channel and between Great Britain, Norway and Germany as well. Indicative cost comparisons suggest that meshing results in higher interconnector costs but lower national reinforcements. Overall costs of the offshore grid in the meshed design are approximately 7 per cent lower than the radial design. The benefit in terms of production cost reduction has not been assessed for this sensitivity (half way around the circle).

Therefore, if future targets are likely to involve increased volumes of offshore RES that those assumed in the Reference scenario, there may be significant benefit in adopted a more integrated, meshed approach to grid design. This result was also found in [12] These two and also other studies on future RES integration [15] -[18], [21]; [23] usually assume an absence of regulatory barriers, which is not yet the case in reality. The findings of the RES+ sensitivity reinforce the requirement for NSCOGI to further cooperate on pathways to mitigating existing barriers.

6.1.6 Future Work Stream

It is proposed to continue work in NSCOGI with special focus on assessing scenarios produced with a common foundation, analysing additional sensitivities and considering the barriers as far as possible, on real life characteristics.

6.1.6.1 Development of common scenarios

As described in Chapter 1.1.7 ENTSO-E will continue to work on the scenario-based approach where four scenarios are being developed in the framework of the next TYNDP(s) to come. These scenarios are discussed with external stakeholders.. The NSCOGI forum could serve as a valuable forum for consultation already at an early stage and during developing the scenarios. It would increase the value of the TYNDP even further, if the scenarios are understood and as far as possible agreed by all NSCOGI stakeholders as an appropriate foundation also to be considered for future NSCOGI work.

This scenario based approach differs from the collection of best views used in this study and takes the uncertainty around a common Regional / European target for 2030 into account.

6.1.6.2 Possible sensitivities on a scenario

To investigate the robustness of a scenario, single parameters can be changed. For this study, the amount of offshore RES has been significantly increased, as described in 6.1.5. Other possible sensitivities, which could be worth investigating on a next scenario are described below, - in case they are not already being taken into account as part of the four scenarios to be developed (see 6.1.6.1).

CO_2 prices

CO_2 prices have substantial influence on the eventual fuel mix. A sensitivity analysis on the assumed CO_2 prices may address the mismatches between the merit order (fuel mix) presently observed in some countries with those of the Reference Scenario. A 'gas before coal' merit order would require substantially higher CO_2 prices. A sensitivity analysis on CO_2 prices may also address the mismatch between CO_2 prices in the Reference Scenario and those observed over the past period on the ETS-market. In order to substantially reduce the workload of this 'Merit Order Change' sensitivity analysis, some limitation in scope of the analysis is required.

'Smart Dimensioning'

Previous work within ENTSO-E has pointed at the potential for increased cost efficiency by a smarter dimensioning of the connection to shore capacities. The socio-economic benefits from some 10-15% capacity reduction would – at the expense of some curtailment during a relatively limited number of hours – result in important overall cost reductions. The regional benefit would have to be investigated (loss of cheap production vs. saving of investment cost). This sensitivity analysis would require some agreement with ENTSO-E on how work on this substantial exercise would draw on the limited resources available for the TYNDP2014 work.

Other sensitivity analyses were considered (like extensive underground cabling in the onshore tracks of new offshore connections), but are currently not proposed with a high priority for further work.

Benefits and barriers to meshing

The future offshore grid will gradually be developed through specific individual grid reinforcement projects with a positive business case. With the findings of the NSCOGI Offshore Grid Study and the insights obtained on Market and Regulatory Issues, further work could be carried out in order to identify the benefits and barriers for integration of offshore wind and trading across a virtual grid facility combining the two. The purpose of such work is to identify options for common future regulatory approaches for such joint cross border assets. Issues to be considered will include anticipatory investment, allocation of costs and benefits and the impact of national renewables support schemes on trade and investment. Analysis of this topic will not be possible without sufficient resources from stakeholders involved. Resources for assistance by external consultancy will be required.

6.1.7 Recommendation for Future collaboration

During the last couple of years the European institutional electricity landscape has changed considerably. National approaches, prevailing less than a decade ago, have been replaced by approaches under which the European dimension is becoming more obvious. The challenges for the future coordinated European electricity system are enormous. In the next few years internal procedures and specific ways of operational cooperation between the Commission, the Government authorities, TSOs, regulating Agencies and industry will further be developed.

In this respect the constructive cooperation within NSCOGI has proved its added value. In the absence of further developed settled institutional behaviour including also the governments beside the settled cooperation between ENTSO-E, ACER and the EC, NSCOGI has provided a platform for analysis, exchange of views and information; within the group and, at appropriate moments, also with industry. The existence of such a platform may therefore help the development of further analysis, planning and regulatory considerations before these will be considered in policy discussions in more formalised settings.

Continuing this initiative will help design the optimal grid development for the entire region and, working closely with WG2 (regulatory and market issues), facilitate the evolution of regulatory mechanisms required to deliver it.

In summary, the NSCOGI collaboration involving four critical stakeholders – Governments, National Regulatory Institutions, Transmission System Operators and the European Commission - offers a unique and beneficial forum for the development of a common understanding of future energy related requirements, possible barriers and routes around them. It is therefore recommended to encourage continuation of NSCOGI for another limited period, as far as it aligns with the envisaged works programmes of each of the TSO, NRA and Government stakeholders in order to further investigate the requirements of future regional energy issues.

7 APPENDICES

A 1 Detailed Description of Methodology

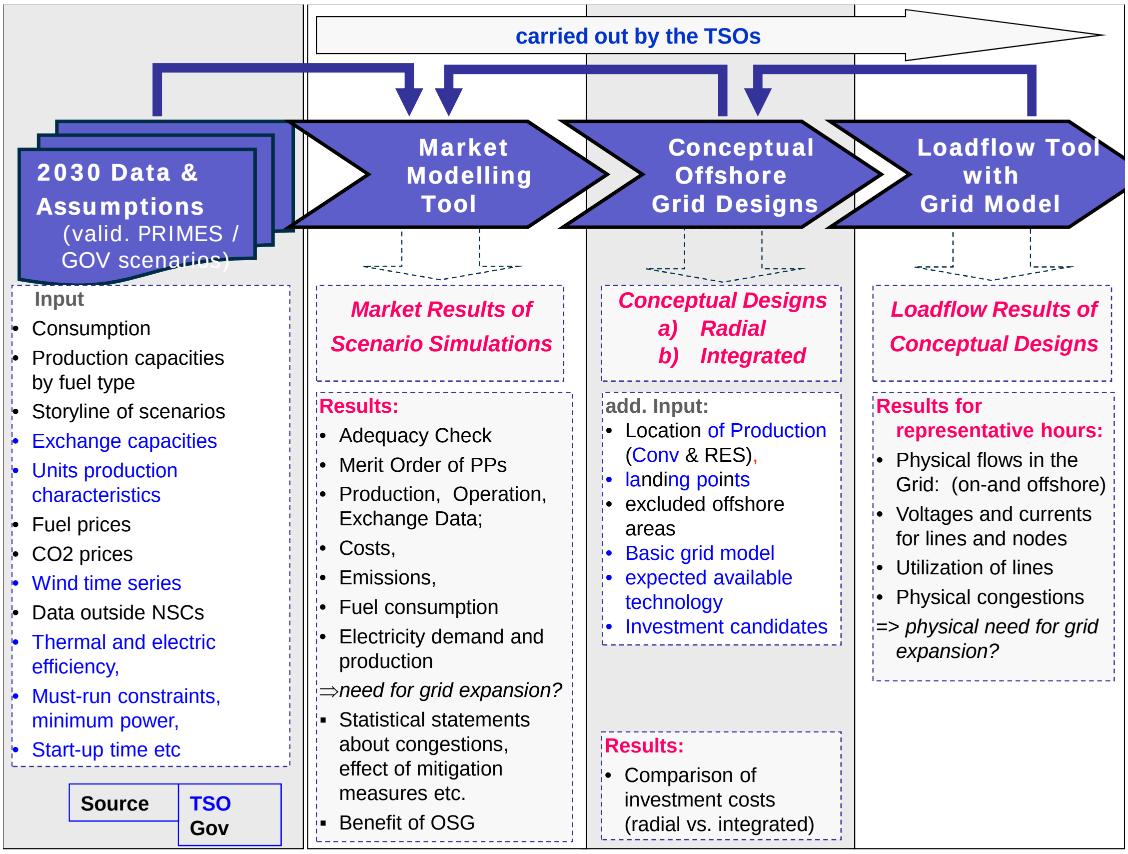

Figure 7-1: General Procedure for NSCOGI WG1 Grid Study

Figure 7-1shows the high level approach that was conducted for assessing the potential benefits from the offshore grid in the North Seas, using market and grid modelling. The numbers refer to the columns in Figure 7-1.

1. First, the dataset elaborated in a joint exercise between Government authorities and TSOs served as necessary input data for the market models. These data (e.g. country wise installed MW by fuel type) were translated by the TSOs into input data for the market models. This means e.g. that the information on the MW coal power plant installed in a country has to be broken down into a number of units with specific characteristics (e.g. thermal and electric efficiency, ‘must-run’ constraint, minimum power, time to start-up. etc) with possible differences between single coal plant types (see first column in Figure 7-1).

2. Based on the developed scenario framework, market simulations were run to assess the economic use of the generation, the direction of major power flows and potential cross border bottlenecks triggering needs for grid development.

   At this stage, most countries are represented by one node where all the load and generation is connected, with a detailed description of the generation system (at unit level). These nodes are connected by interconnectors with limited transfer capacities.

The market models delivered results on the "market flows", i.e. the electricity flows across Europe caused by market signals and the merit order (as well as the aggregated production of each primary resource, CO_2 emissions, imports/ exports, marginal production costs etc.).

3. From these "market flows", market needs for grid expansion were developed, both, on- and offshore. This information, together with the countries' offshore wind power production developments was used order to develop the "conceptual offshore grid designs". Two designs were developed: a radial and an integrated ("meshed") one (see high level principle). These conceptual designs were developed based on the expected available technology, as described in the "Offshore Transmission Technology Report[11]".

4. After developing the conceptual offshore grid designs, the resulting physical flows and the effect on the onshore systems was investigated by grid calculations. At this stage the location of both the conventional power plants as well as the renewable power input must be taken into account because the location of a power plant in the grid defines the physical flow and thus, the physical need for grid expansion.

Several iterations were needed in the course of the study, for example if the impact on the on-shore grid leads to reconsider the offshore grid design.

At the end of this process, an overall socio-economic cost-benefit analysis of the grid designs was carried out, including a new assessment of benefits from the market model. The grid development obtained for the radial and meshed configurations were compared.

The details of this procedure are described below.

11 https://www.entsoe.eu/fileadmin/user_upload/_library/publications/entsoe/SDC/European_offshore_grid_-_Offshore_Technology_-_FINALversion.pdf

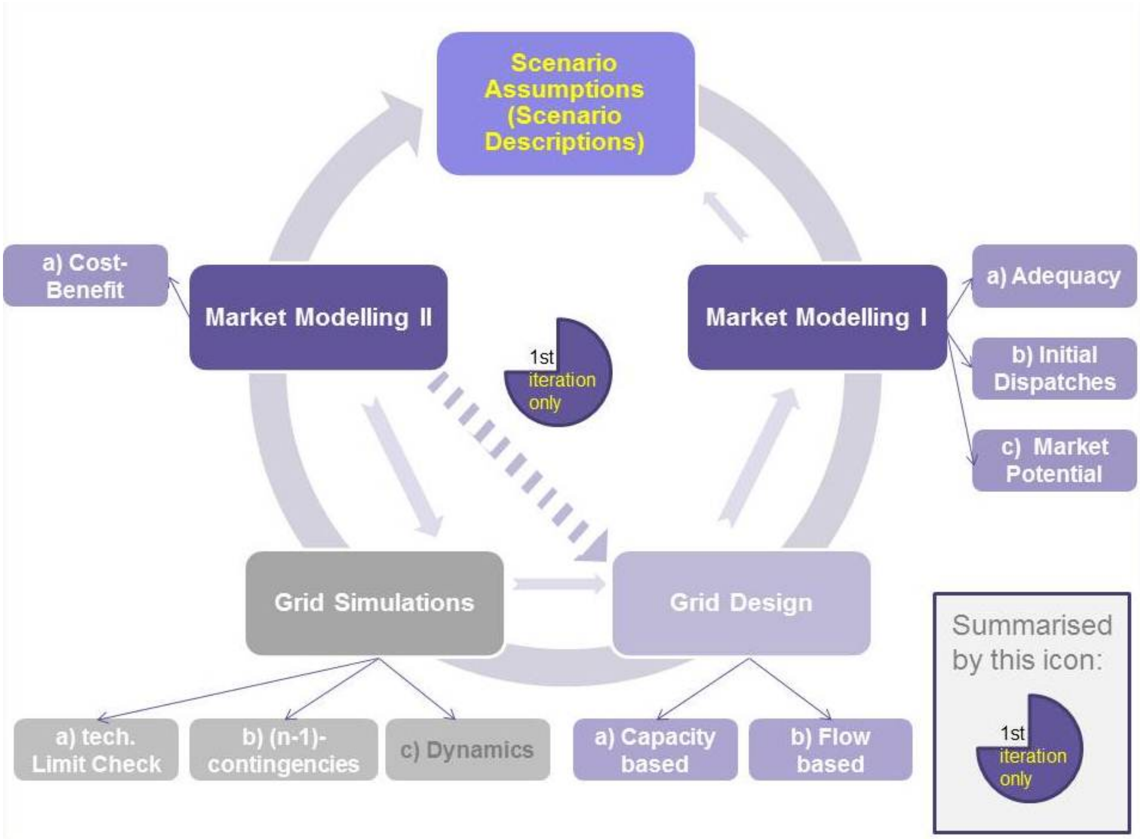

Figure 7-2 High level Process overview

A 1.1 Market Modelling I -a) Adequacy

The Security of Supply in the Region will be a function of the available generation capacities and the demand profiles: there should always be enough generation resources to cover the demand with a sufficient degree of certainty. Therefore, as a first step in the overall process, the generation adequacy of the provided NSCOGI Reference Scenario was assessed, with the goal of having the possibility to increase the generation capacities in case of shortages.

As a start a simplified shallow adequacy assessment method was used, by checking the reserve margins in each individual country as well as the margin for the entire NSCOGI Region. The reserve margin is defined as the ratio between installed capacity and annual peak load. Sufficient reserves are necessary in a system to cope with for instance unforeseen outages and maintenance of generating units.

It should be noted that reserve margin can only be used as a preliminary indicator. Final adequacy judgements should be done with detailed models.

A 1.2 Market Modelling I - b)Initial Dispatches

A 1.2.1 Overview of Market Modelling

The market modelling tools used in the NSCOGI studies simulate the electricity market behaviour for a one year period in hourly time steps. The modelling tools schedule the production of electricity by generators to meet demand at least cost while satisfying operational and security constraints. In general, each country is represented as a single market node (with some exceptions) with its generation portfolio and hourly electricity demand. The market models optimise the production of electricity across all market nodes taking into account economic trading of electricity across interconnections. The hourly production values for each generation category and hourly commercial exchanges between the market nodes within the modelled perimeter are output from the model. The models calculate the variable cost of production comprising fuel costs, CO_2 emissions costs and the variable operational and maintenance costs (VOM) of operating generation plan (excluding fuel and CO_2 costs).

The Net Transfer Capacities (NTCs) set the limit for commercial exchanges between market nodes in the market model and these are not exceeded in the model.

For this study, the TSOs used three market simulation tools in parallel (Antares, PowerSym4 and PROMOD IV). For the studied scenario, the results of the three simulation tools were compared in depth enabling the TSOs to verify the results and to increase the quality of the market analysis.

A 1.2.2 Market Model Setup

A regional database, containing detailed 2030 generation and load data submitted by the TSOs in each of the NSCOGI member countries (shaded in blue in Figure 7-3), was used to model the power system within the NSCOGI geographic perimeter. This model matched the details of the scenario and additional assumptions described in Chapter 3.

ENTSO-E's 2020 Pan European Market Modelling Database (PEMMDB), collated during preparation of ENTSO-E's Ten Year Network Development Plan (TYNDP) 2012, was used to model the European power system outside the North Sea Region as follows:

1. Generation and load data for neighbouring countries, shaded orange in the map in Figure 7-3, were included in the market model in detail similar to the PEMMDB to address market behaviour across the boundaries with NSCOGI countries.

2. The market beyond the neighbouring countries was modelled using fixed hourly commercial flows between the neighbouring countries and those beyond. These commercial power flows were derived for each scenario from the PEMMDB Europe-wide market analysis.

In particular, PEMMDB generation and load data consistent with the EU2020 Scenario was used to model the neighbouring countries. This scenario is based on the 2020 National Renewable Energy Action Plan (NREAP) targets set by governments of the member states and represents a context in which all the European Union 20-20-20 objectives are met.

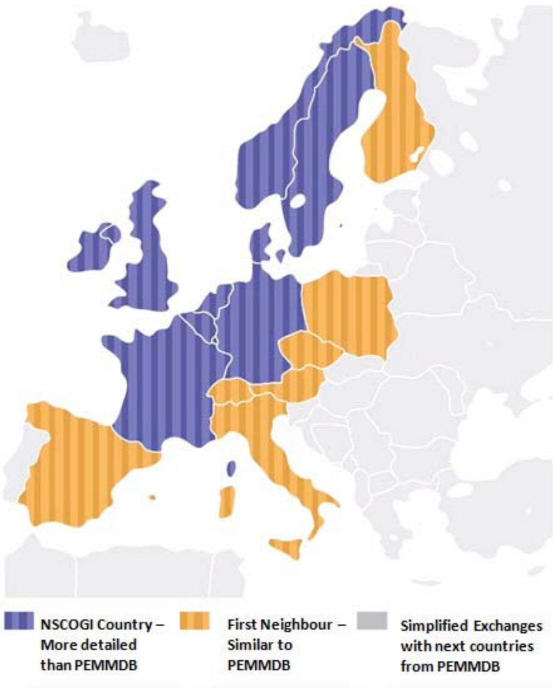

Figure 7-3: Market Modelling Perimeters in the NSCOGI Study

Each country is modelled as one market node, neglecting the internal bottlenecks, except for Denmark and Luxembourg where, due to the grid design, the market areas are split. Northern Ireland and Ireland are modelled together as they form a single wholesale market. All these nodes are connected with each other with specified cross-border transfer capacities.

A 1.2.3 Market Integration Potential (2020 Grid)

An important element in the process, facilitated by market modelling, is the assessment of possibilities of increasing interconnection capacity between the countries. Market modelling can be used to assess the reduction of the overall variable generating costs in the system when an extra interconnector is added connecting high and low price areas.. The outcome shows a combined benefit of connecting RES and facilitating the market.

A methodology has been developed to get a first impression of additional economically feasible interconnections by comparing the calculated market benefits with the investment cost.

The process inside the market models can be summarised as follows:

1. Run market simulations for the 8760 hours in the year. The initial simulation is done with 2020 interconnections as included in the TYNDP 2012.

2. Calculate actual system cost savings: This can only be performed after the first iteration. The system cost savings resulting from additional interconnections consist of two parts. First, the production cost savings as additional interconnections allow a more cost efficient electricity generation. Second, the investment costs of the interconnections.

3. Estimate benefit from additional interconnections by calculating the remaining congestion rents on all existing and possible offshore interconnectors.

4. Estimate costs from additional interconnections based on the cost of converter stations and cables. Assumptions are made about the landing points of possible additional interconnectors and the resulting cable distance. Also, to limit the number of possibilities only a selected number of technologies are considered.

5. Estimated benefits minus estimated costs gives the estimated potential economical feasibility of additional interconnections. A resulting ranking was used to decide on which interconnection to add to the system.

6. The last step covers the actual adding of the selected interconnection to the simulation model and loop back to step I for the next iteration.

It is important to remark that only the offshore grid is currently considered. This is a result of the assumption that (from a market perspective) the onshore grid is considered within a market node as a copperplate (i.e. unlimited capacity), therefore internal bottlenecks are not identified. Furthermore, onshore AC interconnections are not assessed at this stage as physical flows play an important role in investments in AC interconnections. The market model used for this study did not estimate these physical flows. Ongoing work is performed to enhance the market model and methodology in order to improve the results of this stage of future studies.

The described process allowed for an initial assessment of a plausible offshore grid and offered a framework for the grid expansion explained in the next section.

A 1.3 Grid Expansion Approach (Grid Design and grid simulations)

The development of an optimised transmission network to accommodate further market integration and the integration of the specified offshore wind parks (OWP) - in both their capacity and planned locations - involves the exploration of various designs of the bulk transmission network. For this study, the objective is to define plausible radial and meshed network designs.

The geographical scope of the study area and the consequential scale of the transmission network that is required to be considered for augmentation are exceptionally large. This, together with the resulting magnitude of network reinforcement options (choice of locations, choice of technologies, choices of capacities etc.), and combinations of options to consider, conspire to make a numerically ***complex problem*** for which few systematic or automated problem-solving tools are readily available.

The decision-making aspect of testing competing reinforcement candidates lends itself to a optimisation solution. A ***linear-programming tool*** has been chosen to support the process

- the line-capacity shortages and the necessary new circuits to relieve those shortages in the existing transmission networks; and
- The combination of network components and technologies that would represent the plausible network configurations to facilitate further market integration and to appropriately integrate the proposed OWPs with the existing power systems.

A 1.3.1 Capacity-Based Grid Expansion

The optimisation of power system capacities is done by using Mixed Integer Programming. An optimisation tool has been used to develop the outline designs for both the radial and meshed, or integrated, network designs. The tool has been used to perform other studies in the region [11].

Linear flow estimation is used to simulate the maximum steady state power flow through the onshore and offshore transmission network. Candidates for new grid links are made available by national experts to be selected by the optimisation routine in order to meet the future grid requirements which come from the market studies. The objective is to minimise the overall production cost, capital cost of new investments (selected from the large list of candidates) and operational losses while satisfying all the supply and demand restrictions.

The addition of any new onshore or offshore transmission link to the model will change the technical and economic performance of all other candidates such that the optimisation process must consider all possible combinations of candidate reinforcements. The selection of the optimum candidates is made using the Branch and Bound method. The method is used to address this combinatorial nature of the problem in order to identify the optimum combination of reinforcements for the overall transmission network. Using this method, a feasible network design (based on radial and meshed or integrated, design configurations) is created that selects the most cost-effective solution which provides the best power system performance among several possible combinations of candidate alternatives. The objective function comprises two parts, namely:

- Continuous costs composed of generation production costs, reliability and energy not delivered penalties; and
- Discrete costs (capital and incremental operating costs) related to candidate infrastructure, depending on whether it is selected for the chosen simulation.

A 1.3.1.1 Load and Generation Modelling

The method requires a series of 'planning cases' to represent the changing states of load and generation over the year (i.e. 8,760 hours) to build an expansion planning scenario (e.g. reference scenario and RES+ sensitivity). In such a way, the year is divided into a number of representative planning cases, also called snapshots, across which the market integration, RES integration and Security of Supply issues can be optimised by appropriate network development.

The planning cases are a simplification of an hourly representation in which the generation-load balance (magnitude, location and fuel mix) are sufficiently similar for them to be grouped together. This approach allows a balance to be achieved between accuracy and speed of computation. For the purposes of these simulations, the year of 8,760 hours was reduced to 65 planning cases.

Reducing the total number of hours that are considered makes further simplifications. Truncating those planning cases that account for the least number of hours and would, by definition, represent the less likely generation-load combinations does this. For the purposes of the studies discussed in this report, the planning cases were reduced from 65 to 40 snapshots, which represented a small reduction in the hours accounted for in the studies from 8,760 to 8,700.

Market-based economic generation dispatching is accounted for in each planning case, where the source of the individual planning case is the simulations produced by the initial market studies for the chosen year2030.

A summary of the model parameters is contained in Table7-1.

Table 7-1: Summary of the Model Parameters.

Summary of Model Parameters			
Years	1(2030)	Generation areas	21
Planning case	40	Existing links	22,343
Busses	18,984	Contingencies	3,127
Generators	5,725		

A 1.3.1.2 Overview of Available Technologies

The electricity transmission technologies that are assumed to be available in 2030 to design the on- and offshore grid architectures are primarily based on the ENTSO-E's report on transmission technology [5]. The report summarises each technology, its current state, potential development and unit cost.

Two main technologies are commercially available and proven for the development of the onshore and offshore grids, namely alternating current (i.e. AC), and high voltage direct current (i.e. HVDC) transmission technologies.

AC technology is widely used and therefore all current AC grid functionality is assumed to be readily available in the long term. Therefore, the present study includes design options such as AC overhead lines (OHL) and underground or under-sea cables, which are listed in Table 7-2.

Table 7-2: Summary of available technologies for AC Links.

	Number of circuits	Capacity [MVA]
400 kV OHL	Single	Up to 2,790
400 kV OHL	Double	Up to 5,500
220 kV OHL	Single	518
220 kV OHL	Double	1,036
220 kV onshore cable		Up to 600
220 kV offshore cable		Up to 600
400 kV onshore cable		Up to 1,400
400 kV offshore cable		Up 920

The AC cables have some limitations, especially with respect to offshore applications due to the need for reactive power compensation to maintain voltages within acceptable levels. This is due to the physical characteristics of cables where the cable capacitance increases significantly as the cable length and the rated voltage increases.

With regard to HVDC technologies, both Current Source Converter (CSC) and Voltage Source Converter (VSC) technologies were considered in the study.

The CSC HVDC technology is considered to be a mature technology with recent applications achieving capacities of up to 3,000 MW for underground links.

By comparison, VSC HVDC is relatively newer with the expectation within the electricity supply industry being that a ±500kV, 2,000MW capacity underground system could be procured, installed and commissioned within a decade.

The development of VSC HVDC systems, which are not constrained by the need for polarity switches like CSC multi-terminals, has opened opportunities to develop multi-terminal systems that behave more like today's known AC system. No operating VSC multi-terminal HVDC system has been demonstrated in real operation to date yet, and DC circuit breakers are not yet commercially available at transmission voltages, although development has started [36]. Nevertheless, the technology is developing rapidly and is evaluated in the present study as not being a fundamental barrier to the implementation of VSC multi-terminals.

Table 7-3; Summary of available technologies for DC Links.

	Number of circuits	Capacity [MVA]
OHL CSC HVDC	Single	2,382
OHL CSC HVDC	Double	4,763
OHL VSC HVDC	Single	1,429
OHL VSC HVDC	Double	2,858
Underground VSC HVDC		Up to 2,000
Underground CSC HVDC		Up to 3,000

Offshore platforms are required to house offshore equipment. The weight of the equipment influences the size and construction of platforms. Considering the know-how in the gas and oil industry to build such platforms, there would be no perceived technical barrier to constructing offshore platforms capable of accommodating a 3 GW HVDC converter.

A 1.3.1.3 Description of the investment candidates

The approach that has been adopted allows for a wide range of options for new transmission connection links, both onshore and offshore, to be tested by the optimisation tool. These link options are referred to as candidates. In fact the wider the set of candidate transmission links the more refined the network design selected can be.

The onshore candidates were provided by each of the TSOs, while offshore candidates were defined jointly by the TSOs to ensure that all plausible (and less plausible) options were represented. Offshore candidates accommodate alternative connection points and the full range of technologies available and hence permit an objective selection of the most appropriate technology. In such a way, the final design would permit observations regarding the most appropriate technology solution for a specific application or area.

Technology choices that were considered are based on those contained within the Offshore Transmission Technology report [5] prepared by the ENTSO-E Regional Group North Sea for the NSCOGI[12] and briefly described in the previous section.

In the case of the meshed network design, the potential for points of common coupling (referred to as supernodes) to be selected was also considered at strategic points across the North Seas region. The supernodes permit the meshing of the offshore grid to best optimise the offshore grid development and may involve the integration of multiple technologies at those points.

The number of reinforcement candidates for the radial and the mesh network designs has similar numbers of candidates to consider. The differences in the candidate sets were primarily in the offshore area, as the mesh configuration allowed for the inclusion of supernodes and hence the opportunity to couple offshore reinforcements at sea, whereas the radial variant did not allow these options.

The statistics associated with both the radial and meshed network designs are summarised in the Tables below. The large number of candidates, particularly in the largely undeveloped offshore grid space, allows for consideration of the widest range of possibilities thus ensuring selection of the most economic connection points and technologies for each link.

Table 7-4: Number of Candidates Considered for the Radial Network Design

Description	Technology	Number of Candidates	Length [km]
Offshore Candidates	HVDC	1,865	435,759
	HVAC	830	40,294
Onshore Candidates	HVDC	265	55,928
	HVAC	552	28,763
TOTAL		3,512	560,744

[12] Offshore Transmission Technology, ENTSO-E, 24.11.2011

Table 7-5: Number of Candidates Considered for the Meshed Network Design

Description	Technology	Number of Candidates	Length [km]
Offshore Candidates	HVDC	2,687	680,175
	HVAC	754	37,584
Onshore Candidates	HVDC	354	55,928
	HVAC	566	29,146
TOTAL		4,361	802,832

A 1.3.1.4 Design Optimisation

The results of the simulations, using the abovementioned methodology, reduces the almost limitless combinations of individual candidate reinforcements to a structurally well optimised outline design for the integration of the proposed OWPs and for the reinforcement of the existing networks in order to accommodate them. This structural outline design is then confirmed as viable and refined with more targeted network and market simulations.

A 1.3.2 Flow -Based Grid Expansion

A 1.3.2.1 Approach

The output of the capacity-based grid expansion process consists of two main parts:

- The first part is the grid design. In the radial design, this contains connections from the OWPs (or other offshore sources) to the onshore grid and separate point-to-point interconnectors between countries. In the meshed design, the design connections that apply to the radial design can be inter-linked and interconnections can form links between three or more countries via offshore nodes; and

- The second part is a detailed list of loads per node in the network, the generation by each individual power plant and the flows on each modelled AC or HVDC-link.

The above outputs, together with the pre-existing reference network model, are used to define the expected power flows through the transmission networks, especially onshore. The transmission network, particularly the onshore transmission network, is predominantly an AC grid which means that the flow of power through the grid from generation sources to loads is the direct consequence of the impedances of the grid and, as such, cannot be imposed.

The expected power flows are typically simulated using load flow tools. Load flow simulations are used to estimate the steady state power flows for prescribed network configurations that typically consider an intact network (i.e. N state) as well as single outages on the grid (i.e. N-1 contingencies). The purpose of such simulations is to assess the adequacy of the network in accommodating the plausible power flows without exceeding the rated capacity of the equipment while remaining within acceptable performance (e.g. voltage) limits. If contingency simulations identify cases where the available capacity of transmission equipment is exceeded or where performance levels fall outside of acceptable ranges, it is necessary for the network to be reinforced. In such cases, the affected TSO(s) design, test and evaluate additional mitigating reinforcements for all relevant cases. Thanks to the variety of planning cases selected very different dispatch situations are studied, both frequent ones and rare ones which result in particularly extreme flow patterns.

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A 1.3.3 Network Reliability Assessment

From a transmission network planning perspective, a **planning case** represents a particular situation that may occur within the framework of a planning scenario, and typically feature:

- One specific point-in-time (e. g. winter / summer, peak hours / low demand conditions, year), with its corresponding demand and environmental conditions,
- A particular realisation of random phenomena, generally linked to climatic conditions (such as wind conditions, hydro inflows, temperature etc.) or availability of plants (forced and planned outages),
- The corresponding dispatch (coming from a market simulator or a merit order) of all generating units (and international flows),
- Detailed location of generation and demand,
- Power exchange forecasts with regions neighbour to the studied region and
- Assumptions on grid development.

In the context of this study the planning cases (or snapshots) are defined by the outputs of the capacity-based network expansion studies for which the generation-load relationship (mix, magnitude and location) and grid development assumptions are already prescribed.

Evaluating the grid's performance in response to contingencies assesses the reliability of the transmission network for each snapshot. A contingency is the loss of one or several elements of the power transmission system. A differentiation is made between normal, rare and out-of-range contingencies:

- A normal contingency is the (not unusual) loss of one of the following elements: generator, transmission circuit; transformer, shunt device (i.e. capacitors, reactors), etc. This is referred to as the N-1 contingency. The N-1 security criterion is satisfied if the network is within acceptable limits for expected transmission and supply situations as defined by the planning cases, following a temporary (or permanent) outage of one of the elements of the normal contingency list.

- A rare contingency is the (unusual) loss of one of the following elements: a line with two or more circuits on the same towers, a single busbar, a common mode failure with the loss of more than one generating unit or plant, etc. These contingencies are referred to as N-1-1, N-2 or N-G-1 contingencies, amongst others.

- An out-of-range contingency includes the (very unusual) loss of one of the following: two lines or generation units independently and simultaneously, a total substation with more than one busbar.

If the network is outside of acceptable limits in response to the abovementioned contingencies for expected transmission and supply situations, then reinforcement of the grid is planned. These measures can include, but are not limited to, the following:

- Reinforcement of overhead circuits to increase their capacity (e.g. increased distance to ground, replacing of circuits);

- Duplication of cables to increase rating;

- Replacing of network equipment or reinforcement of substations (e.g. based on short-circuit rating);

- Extension of substations and construction of new ones;

- Installation of reactive-power compensation equipment (e.g. capacitor banks);

- Addition of network equipment to control the active power flow (e.g. phase shifter, series compensation devices);

- Additional transformer capacities; or

- Construction of new circuits (overhead and cable).

Initial assessment and detailed grid expansion were then benchmarked against each other and further fine-tuned. No dynamic investigations have been carried out. Finally, the Market modelling II step assessing a Cost-Benefit Analysis was carried out.

A 2 NSCOGI reference scenario – details by country

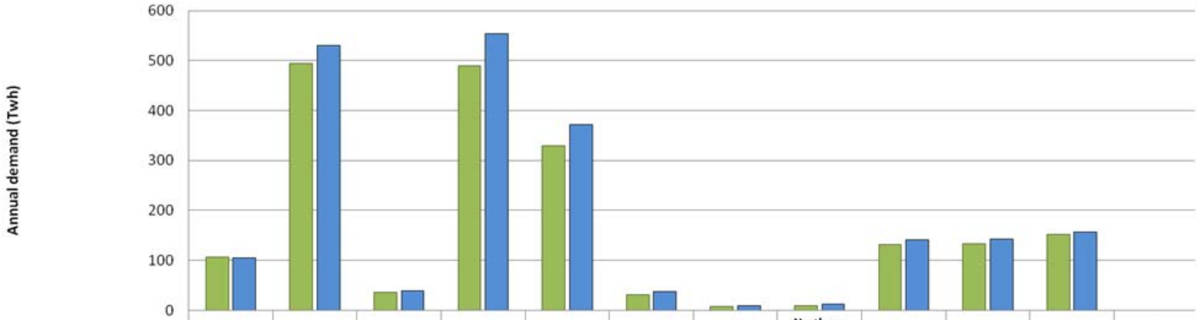
Details by country

- Installed capacities by country in the years 2020 (Scenario EU2020) and 2030 (NSCOGI Reference scenario)
- Fuel mix in the years 2020 (Scenario EU2020) and 2030 (NSCOGI Reference scenario, both Radial and Meshed design)
- Annual load

Development of the 10 countries'

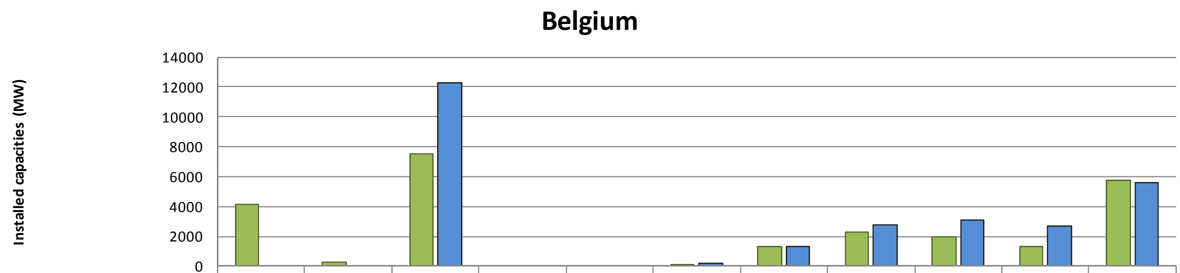
1. Belgium
2. Denmark
3. France
4. Germany
5. Great Britain
6. Ireland
7. Luxembourg
8. Northern Ireland
9. The Netherlands
10. Norway
11. Sweden
12. Total NSCOGI perimeter

A 2.1 Development of the 10 countries' demand

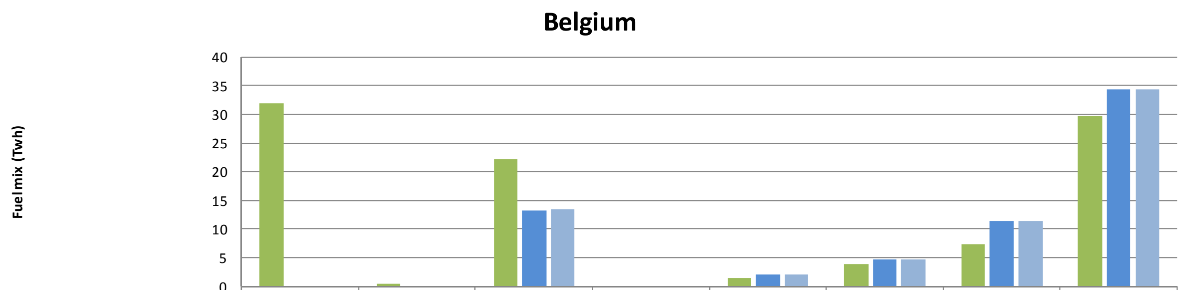


	Belgium	Germany	Denmark	France	Great Britain	Ireland	Luxembourg	Northern Ireland	Netherlands	Norway	Sweden	Total NSCOGI
Year 2020: EU2020	106	494	36	490	329	32	7	10	132	134	152	1922
Year 2030: NSCOGI Ref. Scen.	105	530	39	554	372	37	10	12	141	143	157	2099

A 2.2 Details by country- Belgium

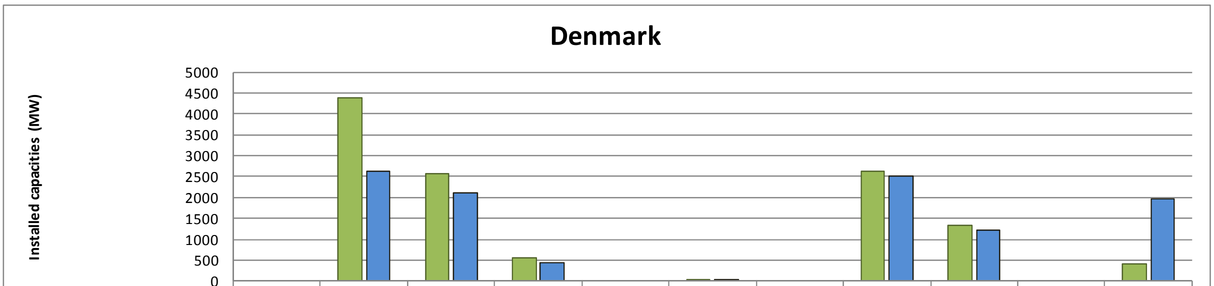


	Nuclear	Hard coal/lignite fired	Gas fired	Oil fired	Hydro: Reservoir	Hydro: Run of river	Hydro: Pumped storage	Onshore wind	Offshore wind	Solar	Other
EU2020	4120	235	7554	0	0	140	1308	2320	2000	1340	5736
NSCOGI Reference Scenario	0	0	12267	0	0	150	1308	2754	3087	2672	5612

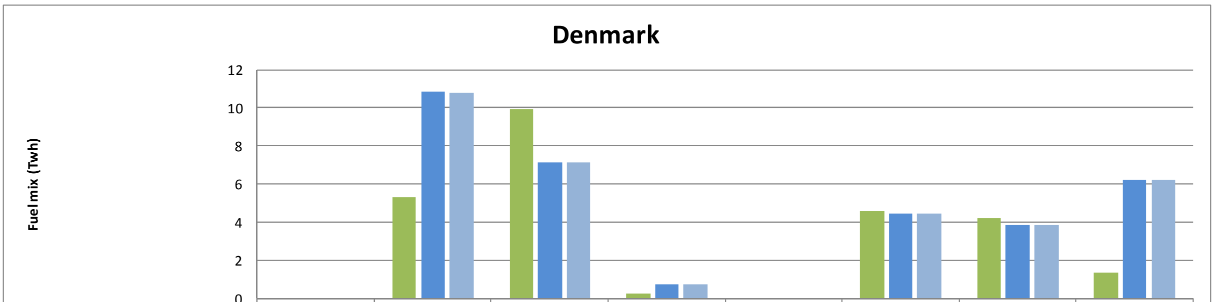


	Nuclear	Hard coal & lignite fired	Gas fired	Oil fired	Hydro (Reservoir, Run of River & Pump Storage)	Onshore wind	Offshore wind	Other (including solar)
EU2020	32	0	22	0	1	4	7	30
NSCOGI Reference 2030 Radial	0	0	13	0	2	5	11	34
NSCOGI Reference 2030 Meshed	0	0	14	0	2	5	11	34

A 2.3 Details by country- Denmark

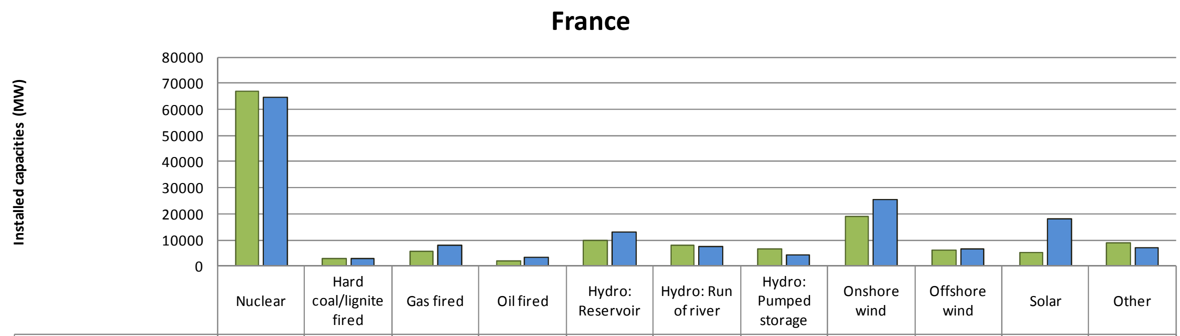


	Nuclear	Hard coal/lignite fired	Gas fired	Oil fired	Hydro: Reservoir	Hydro: Run of river	Hydro: Pumped storage	Onshore wind	Offshore wind	Solar	Other
EU2020	0	4395	2570	568	0	10	0	2621	1339	0	418
NSCOGI Reference Scenario	0	2630	2115	436	0	10	0	2512	1208	0	1959

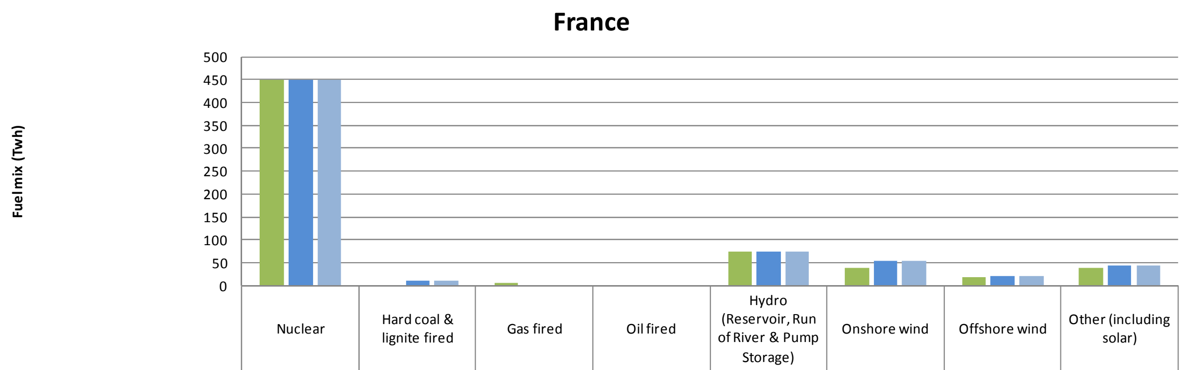


	Nuclear	Hard coal & lignite fired	Gas fired	Oil fired	Hydro (Reservoir, Run of River & Pump Storage)	Onshore wind	Offshore wind	Other (including solar)
EU2020	0	5	10	0	0	5	4	1
NSCOGI Reference 2030 Radial	0	11	7	1	0	4	4	6
NSCOGI Reference 2030 Meshed	0	11	7	1	0	4	4	6

A 2.4 Details by country- France

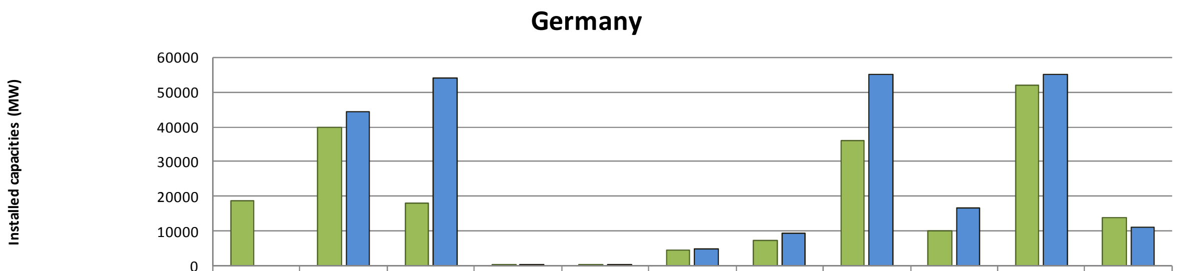


	Nuclear	Hard coal/lignite fired	Gas fired	Oil fired	Hydro: Reservoir	Hydro: Run of river	Hydro: Pumped storage	Onshore wind	Offshore wind	Solar	Other
EU2020	66760	2900	5810	1889	10000	8000	6800	19000	6000	5400	8800
NSCOGI Reference Scenario	64830	2900	7830	3231	13000	7500	4300	25500	6500	18000	7100

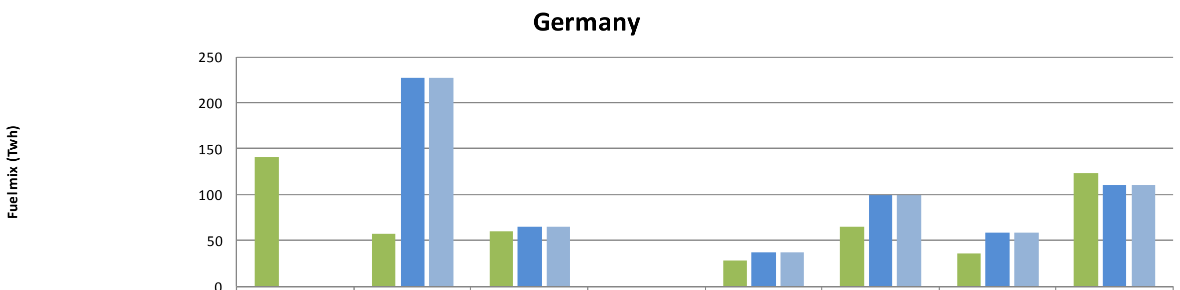


	Nuclear	Hard coal & lignite fired	Gas fired	Oil fired	Hydro (Reservoir, Run of River & Pump Storage)	Onshore wind	Offshore wind	Other (including solar)
EU2020	448	0	5	0	73	40	18	39
NSCOGI Reference 2030 Radial	449	9	2	0	74	53	19	43
NSCOGI Reference 2030 Meshed	450	10	2	0	74	53	19	43

A 2.5 Details by country- Germany

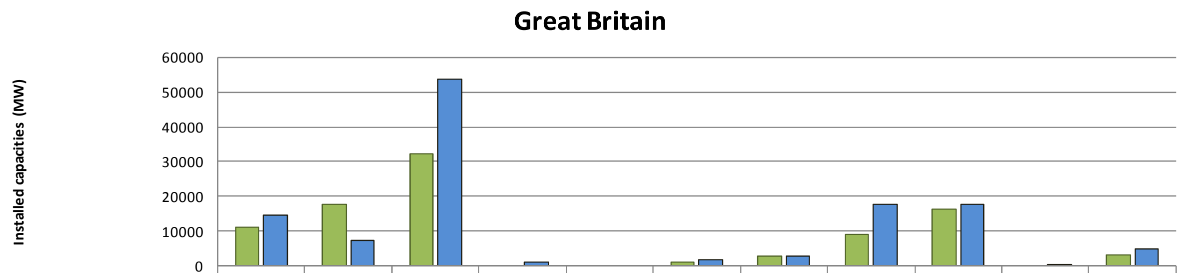


	Nuclear	Hard coal/lignite fired	Gas fired	Oil fired	Hydro: Reservoir	Hydro: Run of river	Hydro: Pumped storage	Onshore wind	Offshore wind	Solar	Other
EU2020	18848	39734	18031	145	200	4700	7300	36000	10000	52000	14000
NSCOGI Reference Scenario	0	44331	54129	400	417	5012	9500	55000	16700	55000	11000

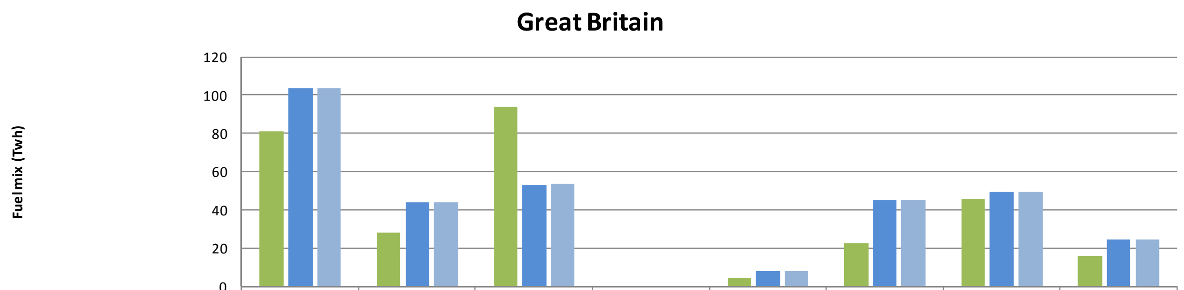


	Nuclear	Hard coal & lignite fired	Gas fired	Oil fired	Hydro (Reservoir, Run of River & Pump Storage)	Onshore wind	Offshore wind	Other (including solar)
EU2020	141	57	59	0	28	65	35	124
NSCOGI Reference 2030 Radial	0	227	65	0	37	99	59	111
NSCOGI Reference 2030 Meshed	0	227	65	0	37	99	59	111

A 2.6 Details by country- Great Britain

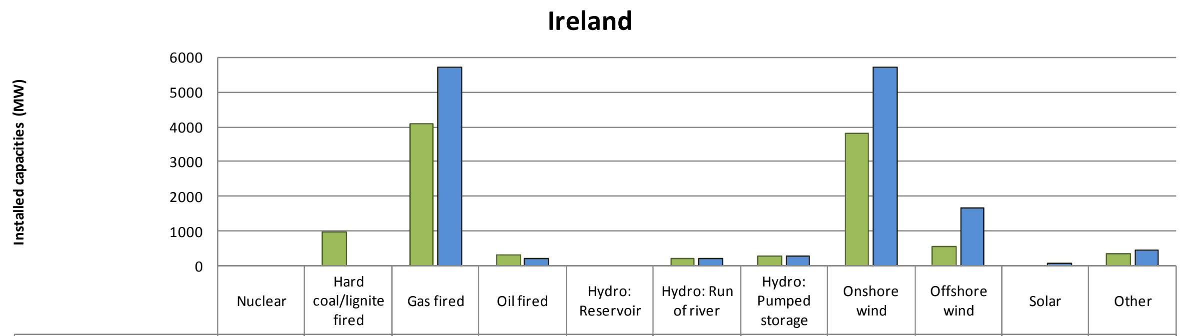


	Nuclear	Hard coal/lignite fired	Gas fired	Oil fired	Hydro: Reservoir	Hydro: Run of river	Hydro: Pumped storage	Onshore wind	Offshore wind	Solar	Other
EU2020	11228	17750	32291	0	0	1132	2744	8975	16374	0	3109
NSCOGI Reference Scenario	14663	7414	53688	1157	0	1953	2744	17723	17661	33	5087

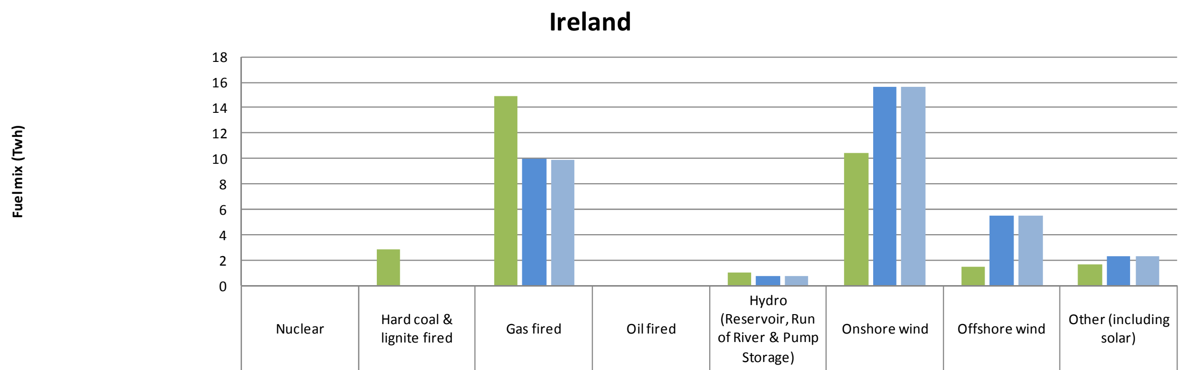


	Nuclear	Hard coal & lignite fired	Gas fired	Oil fired	Hydro (Reservoir, Run of River & Pump Storage)	Onshore wind	Offshore wind	Other (including solar)
EU2020	81	28	94	0	4	23	46	16
NSCOGI Reference 2030 Radial	104	44	53	0	8	45	49	25
NSCOGI Reference 2030 Meshed	104	44	53	0	8	45	49	25

A 2.7 Details by country- Ireland

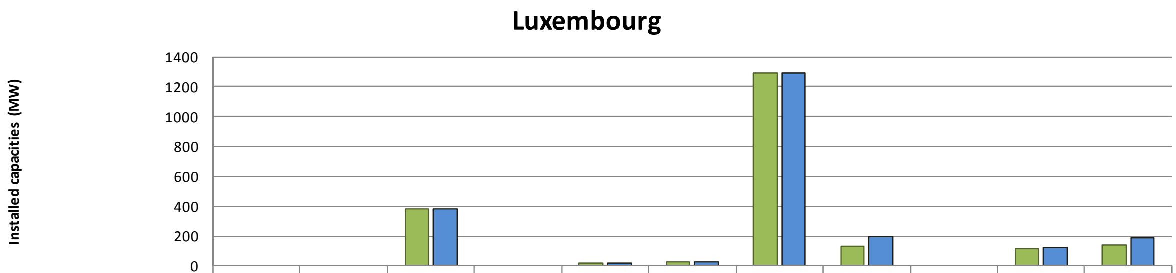


	Nuclear	Hard coal/lignite fired	Gas fired	Oil fired	Hydro: Reservoir	Hydro: Run of river	Hydro: Pumped storage	Onshore wind	Offshore wind	Solar	Other
EU2020	0	965	4100	323	0	216	292	3800	555	0	361
NSCOGI Reference Scenario	0	0	5709	232	0	216	292	5698	1668	64	472

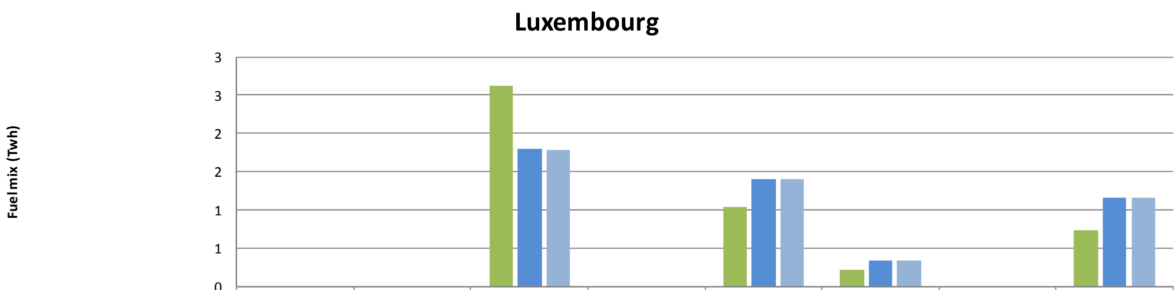


	Nuclear	Hard coal & lignite fired	Gas fired	Oil fired	Hydro (Reservoir, Run of River & Pump Storage)	Onshore wind	Offshore wind	Other (including solar)
EU2020	0	3	15	0	1	10	2	2
NSCOGI Reference 2030 Radial	0	0	10	0	1	16	6	2
NSCOGI Reference 2030 Meshed	0	0	10	0	1	16	6	2

A 2.8 Details by country- Luxembourg

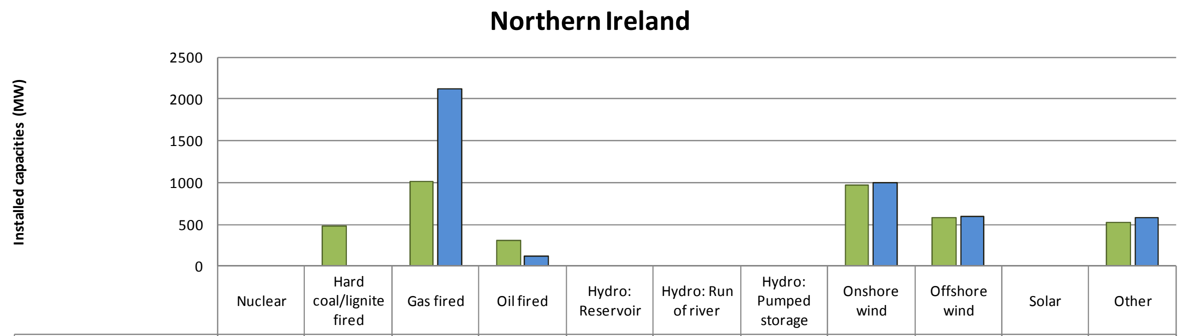


	Nuclear	Hard coal/lignite fired	Gas fired	Oil fired	Hydro: Reservoir	Hydro: Run of river	Hydro: Pumped storage	Onshore wind	Offshore wind	Solar	Other
EU2020	0	0	385	0	17	27	1296	131	0	113	137
NSCOGI Reference Scenario	0	0	385	0	17	27	1296	200	0	120	190

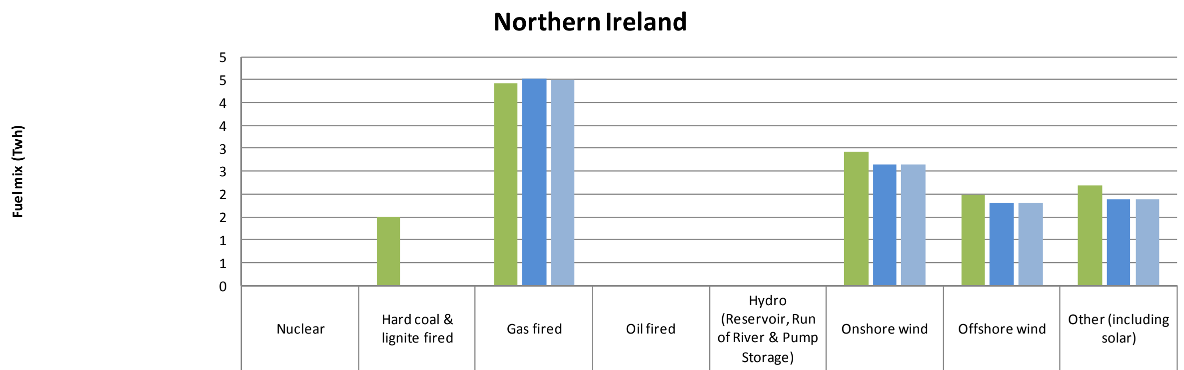


	Nuclear	Hard coal & lignite fired	Gas fired	Oil fired	Hydro (Reservoir, Run of River & Pump Storage)	Onshore wind	Offshore wind	Other (including solar)
EU2020	0	0	3	0	1	0	0	1
NSCOGI Reference 2030 Radial	0	0	2	0	1	0	0	1
NSCOGI Reference 2030 Meshed	0	0	2	0	1	0	0	1

A 2.9 Details by country- Northern Ireland

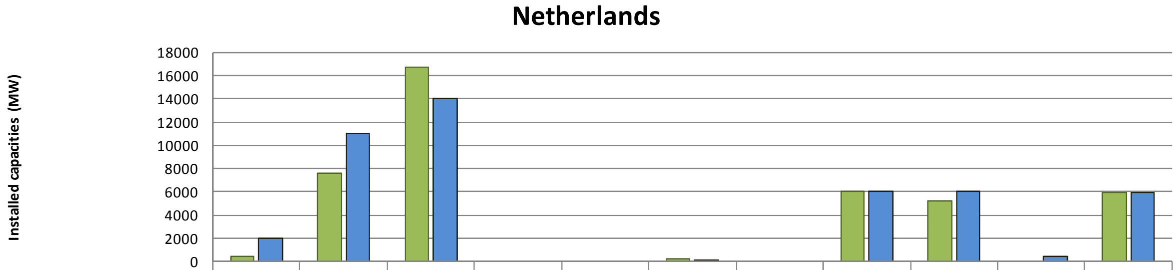


	Nuclear	Hard coal/lignite fired	Gas fired	Oil fired	Hydro: Reservoir	Hydro: Run of river	Hydro: Pumped storage	Onshore wind	Offshore wind	Solar	Other
EU2020	0	476	1009	310	0	0	0	967	580	0	518
NSCOGI Reference Scenario	0	0	2115	124	0	0	0	1000	600	0	580

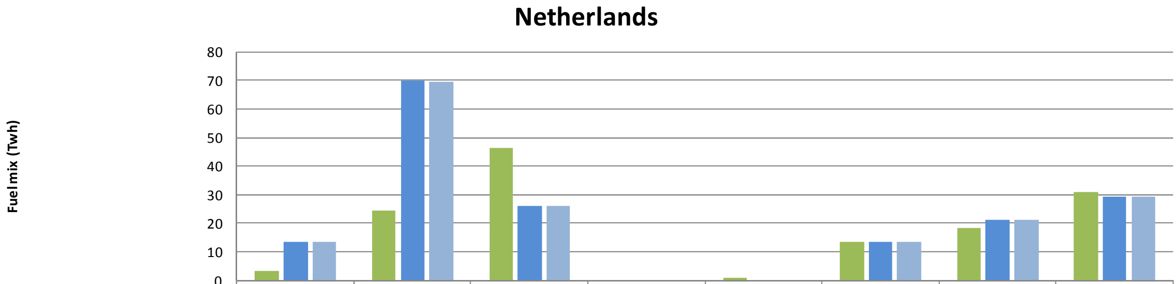


	Nuclear	Hard coal & lignite fired	Gas fired	Oil fired	Hydro (Reservoir, Run of River & Pump Storage)	Onshore wind	Offshore wind	Other (including solar)
EU2020	0	2	4	0	0	3	2	2
NSCOGI Reference 2030 Radial	0	0	5	0	0	3	2	2
NSCOGI Reference 2030 Meshed	0	0	5	0	0	3	2	2

A 2.10 Details by country- Netherlands

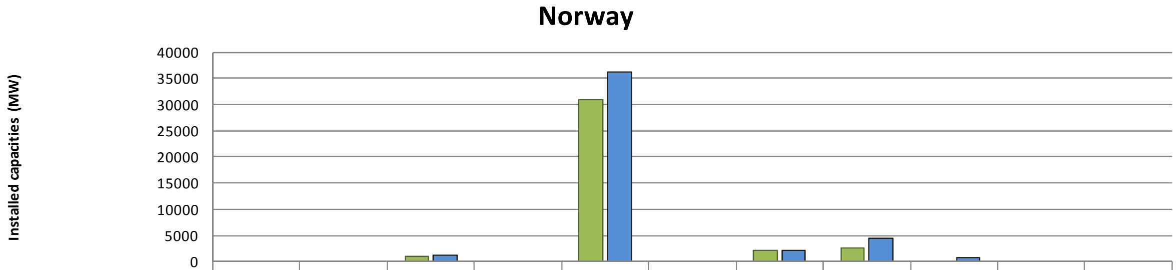


	Nuclear	Hard coal/lignite fired	Gas fired	Oil fired	Hydro: Reservoir	Hydro: Run of river	Hydro: Pumped storage	Onshore wind	Offshore wind	Solar	Other
EU2020	480	7573	16722	0	0	203	0	6000	5178	0	5960
NSCOGI Reference Scenario	2000	11000	14000	0	0	100	0	6000	6000	500	5960

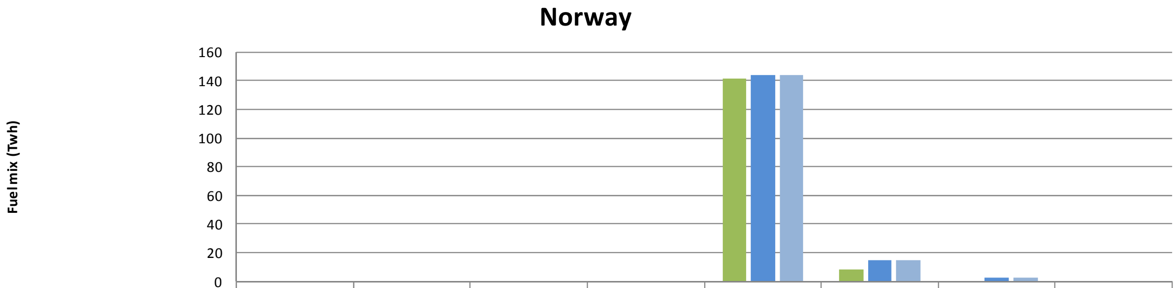


	Nuclear	Hard coal & lignite fired	Gas fired	Oil fired	Hydro (Reservoir, Run of River & Pump Storage)	Onshore wind	Offshore wind	Other (including solar)
EU2020	3	24	46	0	1	13	18	31
NSCOGI Reference 2030 Radial	13	70	26	0	0	13	21	29
NSCOGI Reference 2030 Meshed	13	70	26	0	0	13	21	29

A 2.11 Details by country- Norway

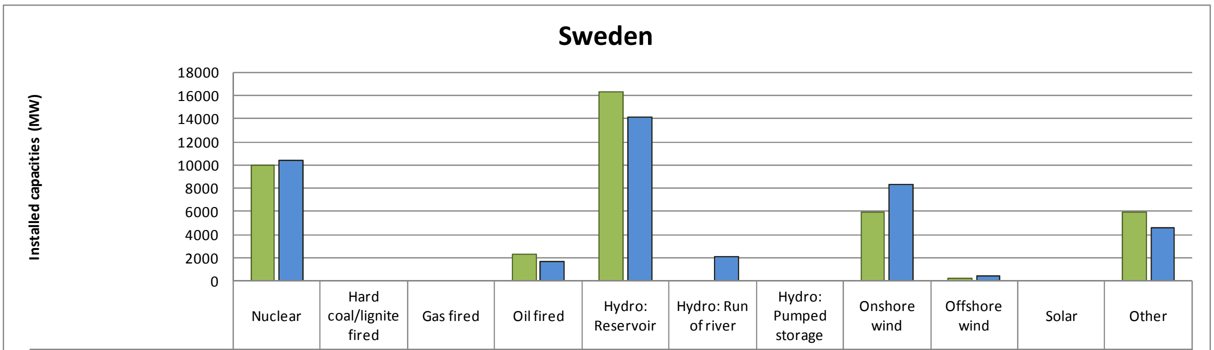


	Nuclear	Hard coal/lignite fired	Gas fired	Oil fired	Hydro: Reservoir	Hydro: Run of river	Hydro: Pumped storage	Onshore wind	Offshore wind	Solar	Other
EU2020	0	0	915	0	31000	0	2054	2500	0	0	0
NSCOGI Reference Scenario	0	0	1250	0	36200	0	2054	4472	739	0	0

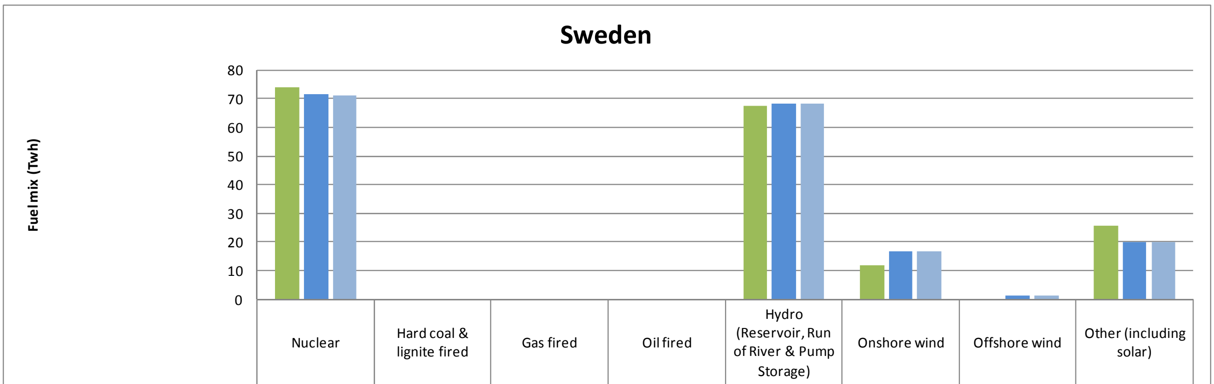


	Nuclear	Hard coal & lignite fired	Gas fired	Oil fired	Hydro (Reservoir, Run of River & Pump Storage)	Onshore wind	Offshore wind	Other (including solar)
EU2020	0	0	1	0	141	8	0	0
NSCOGI Reference 2030 Radial	0	0	0	0	144	15	3	0
NSCOGI Reference 2030 Meshed	0	0	0	0	144	15	3	0

A 2.12 Details by country- Sweden

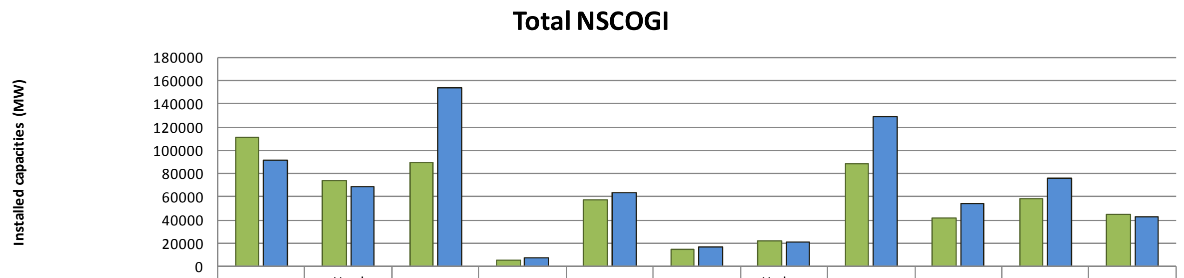


	Nuclear	Hard coal/lignite fired	Gas fired	Oil fired	Hydro: Reservoir	Hydro: Run of river	Hydro: Pumped storage	Onshore wind	Offshore wind	Solar	Other
EU2020	10008	0	0	2310	16351	0	0	5990	200	0	5895
NSCOGI Reference Scenario	10432	0	0	1700	14136	2064	0	8362	500	0	4623

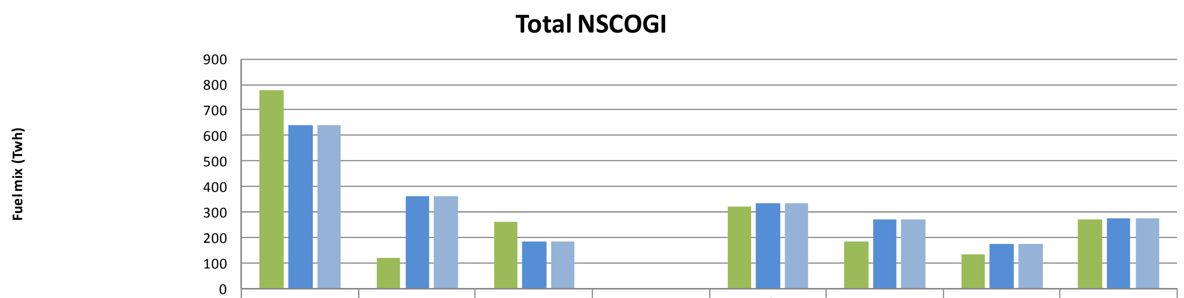


	Nuclear	Hard coal & lignite fired	Gas fired	Oil fired	Hydro (Reservoir, Run of River & Pump Storage)	Onshore wind	Offshore wind	Other (including solar)
EU2020	74	0	0	0	68	12	0	25
NSCOGI Reference 2030 Radial	72	0	0	0	68	17	1	20
NSCOGI Reference 2030 Meshed	71	0	0	0	68	17	1	20

A 2.13 Total NSCOGI perimeter



	Nuclear	Hard coal/lignite fired	Gas fired	Oil fired	Hydro: Reservoir	Hydro: Run of river	Hydro: Pumped storage	Onshore wind	Offshore wind	Solar	Other
EU2020	111444	74028	89387	5545	57568	14428	21794	88304	42226	58853	44934
NSCOGI Reference Scenario	91925	68275	153488	7280	63770	17032	21494	129221	54663	76389	42583



	Nuclear	Hard coal & lignite fired	Gas fired	Oil fired	Hydro (Reservoir, Run of River & Pump Storage)	Onshore wind	Offshore wind	Other (including solar)
EU2020	779	120	259	0	318	183	133	271
NSCOGI Reference 2030 Radial	638	362	184	1	335	270	176	274
NSCOGI Reference 2030 Meshed	638	361	184	1	335	270	176	274

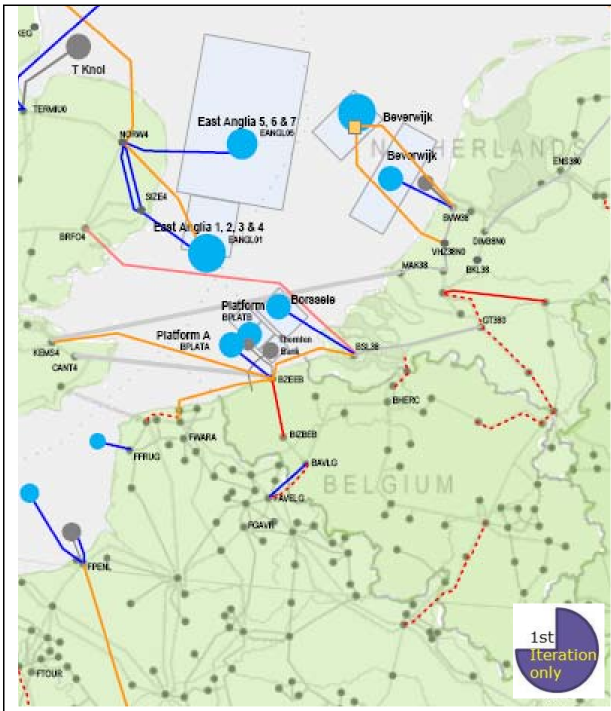
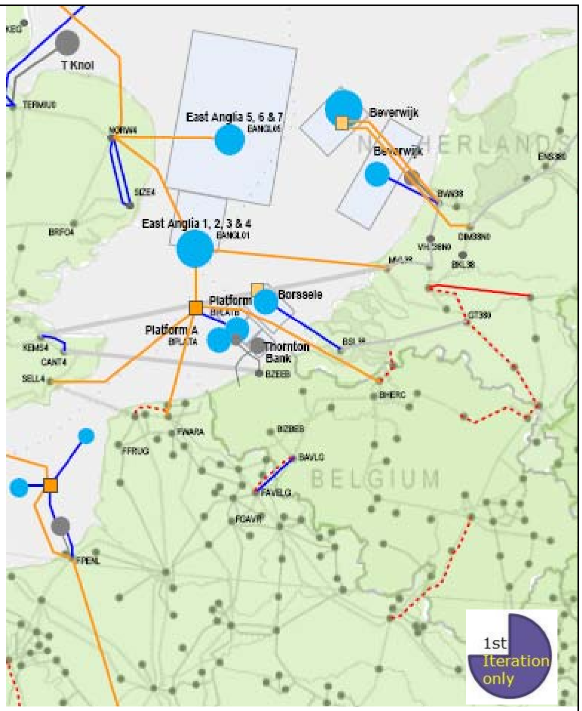
A 3 Country specific comments

The following sections provide country-specific comments on the impact of the various designs on the grid infrastructure of each country in turn.

1. Belgium
2. Denmark
3. France
4. Germany
5. Great Britain
6. Ireland and Northern Ireland
7. Luxembourg
8. The Netherlands
9. Norway
10. Sweden

A 3.1 Country-specific comments – Belgium

Reference Scenario

	
Reference Scenario Radial Design Map	Reference Scenario Meshed Design Map

Interconnectors

Due to market opportunities in the Reference Scenario, an additional 1 GW interconnector with Great Britain is included in the radial design. The creation of a DC hub in the Belgian territorial waters in the meshed design enables a new interconnection between the hub and another hub in the East Anglia area. In this design, another link from the DC-hub towards the Thames Estuary increases the market exchange capacity and a path to transfer wind energy out of the East Anglia area towards English demand centres without congesting the onshore grid.

Offshore connections

In the radial design, the offshore wind farms are connected radially to the coastal 400 kV substation Stevin at Zeebrugge, requiring new undersea cables towards that substation. In the meshed design, the new offshore wind farms are connected to the Belgian offshore DC hub.

Onshore reinforcement

Power flows from the Netherlands to Belgium are higher than 4,000 MW for some 2,600 hours, with less than 100 hours of flows higher than 6,000 MW. Power flows from Belgium to the Netherlands are much lower, at a maximum of 2500 MW. The existing phase shifting transformers are used to moderate these flows, but important reinforcements are still needed over and above the proposed 2020 GTC of ~3500MW.

The physical cross-border grid capacity between the Netherlands and Belgium can be increased to a target of +/- 6000 MW by upgrading both the Maasbracht – VanEyck and the Kreekrak – Zandvliet overhead lines to 2635MVA. To avoid the phase shifters being the new bottlenecks following N-1 contingencies, additional phase shifters are needed in both Zandvliet (PST 5) and VanEyck (PST 6), with new substations. Inside the Belgian grid additional reinforcements are needed from Zandvliet to Doel (upgrade to 2x2635 MVA) and from VanEyck to Meerhout (second circuit on existing towers).

Further reinforcements for the onshore grid from Borssele in the Netherlands to, for example, Stevin/Zeebrugge in Belgium could in fact be implemented offshore, with an additional HVDC link of 1000 MW between Borssele and Stevin/Zeebrugge.

On the French-Belgian border, for both radial and meshed grid designs, the load flow simulations showed high power flows from France to Belgium, reaching above 7000 MW in some instances. As a comparison, the present day (2012) grid transfer capacity between France and Belgium is +/- 3000 MW. Unsurprisingly, this level of power flow leads to overloading at the border and further into the Belgian grid even in the intact network, i.e. without any grid outages. Apart from the overloads on the 400 kV network, part of the power flow causes overloading on the France-Belgium-Luxembourg-Germany 220 kV corridor. Power flows in the Belgium to France direction are much lower, only reaching 2600 MW.

The French-Belgian Border has to be reinforced to accommodate these very high flows. The following reinforcements are foreseen in the Reference scenario, other scenarios, leading to less important flows, could request only a part of them to be implemented.

- Phase shifting transformers on the Moulaine (FR) – Aubange (BE) – Bascharage (LU)220 kV link;

- Upgrade of all the following existing 400 kV lines : Mastaing-Avelgem, Avelin-Avelgem (and further to Horta in Belgium),Lonny-Achene-Gramme.

- Options with HVDC-links, with a preference for a connection as much to the West as possible. The most westerly option is to create a link between Warande in France and Stevin (Zeebrugge) in Belgium. Both substations are close to the North Sea coast. This link could actually be created as an offshore link. In the meshed offshore design, the link could interconnect with the Belgian offshore hub and connected via the Belgian offshore windfarms to Zeebrugge/Stevin.

All the above reinforcement possibilities are currently being investigated in a bilateral RTE-Elia study.

These reinforcements could achieve a physical cross-border capacity of some 6000 MW between Belgium and France. In a first analysis, higher flows continue to cause overloads on both the border (notably on the 220 kV connections) and deeper into the Belgian grid (mainly on the already reinforced Horta-Doel/Mercator corridor). Further reinforcements may be needed if the highest power flows are confirmed in a sensitivity analysis, but would probably require an overlaying grid to be studied in more detail in the TYNDP 2014 process or the e-Highways 2050 project.

In the radial design, the links from the Netherlands and France to Stevin/Zeebrugge, are required to reinforce the onshore grid at the borders, but they also increase the need for an onshore reinforcement inside the Belgian AC grid to Stevin/Zeebrugge. This might consist of a link from Izegem to Zeebrugge, but permitting will be very difficult.

In the meshed design, a HVDC link could be proposed from the offshore hub to Doel, as an appropriate node deeper inside the Belgian grid. This creates a meshed offshore France-Great Britain-Belgium-Netherlands structure which helps with the onshore flows.

RES+ commentary

In the RES+ sensitivity radial design, power flows from the Netherlands to Belgium are greater than 4000 MW for some 2000 hours; and greater than 6000 MW for 1200 hours, compared with only 100 hours in the Reference Scenario.

The prevailing power flow direction on the south border remains France to Belgium, with flows often above the 7000MW range. Unlike the Reference Scenario results, the RES+ sensitivity results show some high flows from Belgium to France of between 3000 and 5000 MW for 1200 hours.

In comparison with the Reference Scenario, some further reinforcements between the Netherlands and Belgium may be needed to accommodate the flows between 6000 and 7000 MW. For the France-Belgium border the same need for further reinforcements remains to achieve an increase in cross-border capacity of 6000-7000 MW to 9000 MW. As already mentioned, the highest power flows would need to be confirmed in a sensitivity analysis, and would probably require an overlaying grid to be studied in more detail in the TYNDP 2014 process or the e-Highways 2050 project.

Next to the cross-border flows, the additional RES+ Sensitivity generation leads to additional overloads on the onshore grid, even in the intact network. Reinforcements still need to be studied, but again may require an overlaying grid.

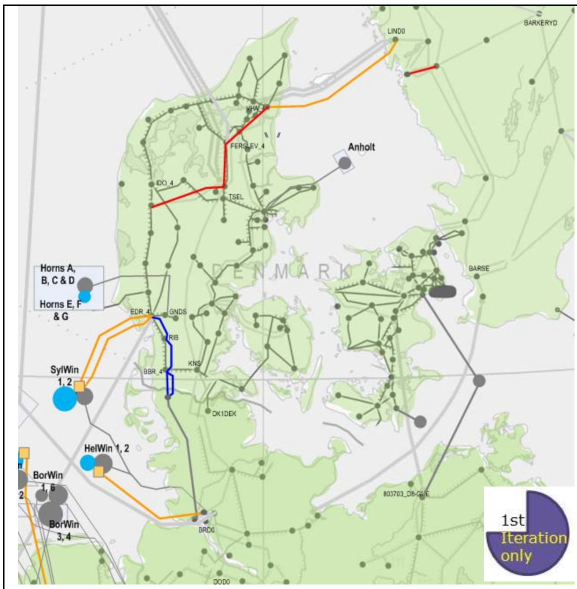
For the meshed design, the DC link from the offshore hub to Doel is diverted to the offshore park “Borsele” and the Dutch substation Borsele before reaching Doel.

Towards England, the link from the Belgian offshore hub to the Thames Estuary is replaced by various links between East Anglia, the zones “Greater Gabbard” and “London Array” and towards the Thames Estuary.

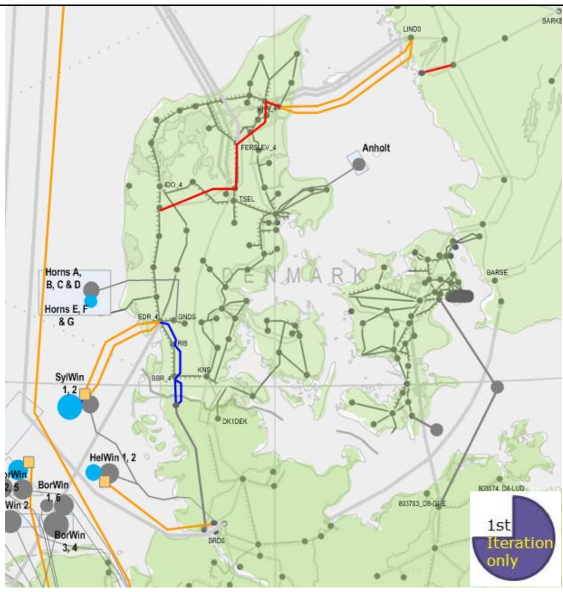
A 3.2 Country-specific comments – Denmark

Reference Scenario

The Reference Scenario for Denmark assumed the connection of 937 MW of offshore wind power in the North Sea, located at Horns Rev and Anholt.



Reference Scenario Radial Design Map



Reference Scenario Meshed Design Map

Interconnectors

For the radial design, the grid simulations indicated three new interconnectors: a single 700 MW HVDC VSC interconnector between Denmark-West and Sweden, a 1400 MW HVDC VSC interconnection to a German offshore wind park (divided into two 700 MW circuits), and a 4740 MW 400 kV AC interconnection to Germany.

For the meshed design, the grid simulations indicated an additional (second) 700 MW HVDC VSC connector between Denmark-West and Sweden, i.e. in addition to the interconnectors of the radial design.

Offshore connections

All Danish offshore wind farms – and even a single German offshore wind farm - are connected radially to the onshore network with no offshore connections, i.e. offshore platform to platform connections.

Both the radial and meshed designs connect a German windfarm to the Danish system, which, based on the input scenario seems to be socio-economically better for the region. This is as a result of the strong Danish system, which already has plans for the future Danish offshore windfarms, but these windfarms have not been part of the investigated scenario assumptions.

In reality, this international offshore wind park connection would require bilateral negotiations on the regulatory schemes between the Danish and the German regulator in order to facilitate this solution.

Onshore reinforcement

The grid simulations have shown risks of overloading of the Denmark-West transmission system between Idomlund (in the Western part) through Tjele and Ferslev and further to VesterHassing (in the northern part of the Danish peninsula of Jutland). Risks of overloading are as a result of increased energy transports via the enforced connections to Sweden. The tables below provide the proposed onshore reinforcements and asset costs.

Substation		Type	Rated Voltage [kV]	Power Rating [MW]	Systems	Length [km]	Lifetime [y]	Price [M€]
From	To							
Idomlund	Tjele	Cable	400	1400	1	73	40	307
Ferslev	Tjele	Cable	400	940	1	62	40	222
Ferslev	Vester Hassing	Cable	400	940	1	22	40	81
Total:								**610**

Table 1: Radial design - estimation of the onshore reinforcement asset costs

Substation		Type	Rated Voltage [kV]	Power Rating [MW]	Systems	Length [km]	Lifetime [y]	Price [M€]
From	To							
Idomlund	Tjele	Cable	400	1400	1	73	40	307
Ferslev	Tjele	Cable	400	1400	1	62	40	261
Ferslev	Nordjylland	Cable	400	1400	1	14	40	62
Ferslev	Vester Hassing	Cable	400	940	2	22	40	163
Total:								**792**

Table 2: Meshed design - estimation of the onshore reinforcement asset costs

Specific comments relating to existing national plans

In 2012, the commissioning of the 400 MW Horns Rev-3 offshore wind park, scheduled for2014/2015, has been announced. Together with the existing offshore wind parks in the Denmark-West transmission system, the total power capacity of the offshore wind power will reach 1167 MW assuming the Horns Rev-3 is commissioned as scheduled. Thus, the Reference Scenario assumes a lower offshore generation portfolio than that which is scheduled in Denmark, which explains the connection of a German park instead. Such larger offshore wind volume in Denmark should not introduce significant changes to the grid study results; however, the German park would presumably then be connected to Germany. The results shall be taken with precautions.

RES+ commentary

For the radial design, as in the Reference Scenario, two HVDC interconnectors link Sweden to the Denmark-West onshore transmission system, as well as the interconnectors to the Danish OWPP in the North Sea, which are connected with each other. The grid simulations identified risks of overloading and congestions in the Northern and Eastern parts of Jutland. The onshore reinforcement between the Tjele, Trige and Malling 400 kV stations as well as between Tjele, Ferslev and VesterHassing, are proposed. Additionally, a 400 kV AC line is included between Endrup and Ribe to connect Endrup through Ribe (Denmark) to the German transmission system. The reinforcement asset cost is estimated to an amount of 701 M€.

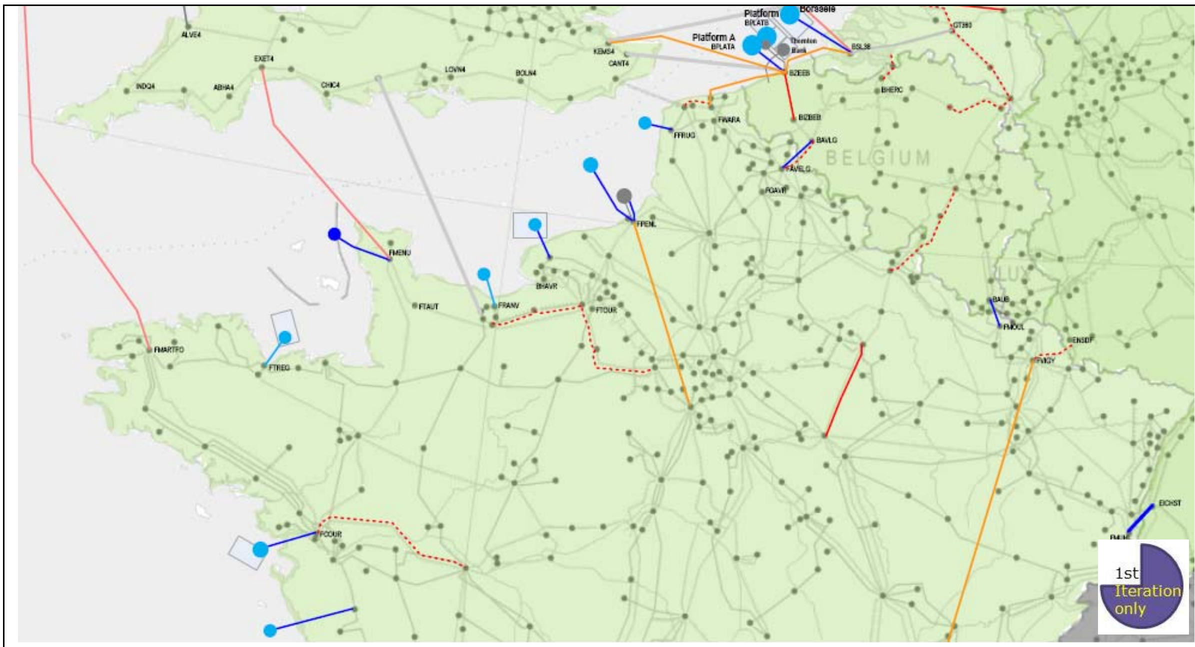
For the meshed design, only the interconnectors to the Danish OWPP link with the Western Danish onshore system, i.e. no non-Danish offshore network is linked with Denmark West which thus can be evaluated as Denmark being bypassed. This difference in the overall grid topology implies different reinforcement needs for the Western Danish onshore grid infrastructure. The grid simulations did not identify any overloading or congestions in the Western Danish onshore transmission system, which can be explained by the bypassing of Denmark and no non-Danish offshore network being linked with Denmark West. Therefore no additional investment needs have been found.

In general, further detailed studies based on internationally coordinated 2030 scenarios are required to determine robust reinforcement and investment needs into the Danish grid and interconnection needs to other countries. As shown with this study, the results are highly sensitive to investment decisions in other countries.

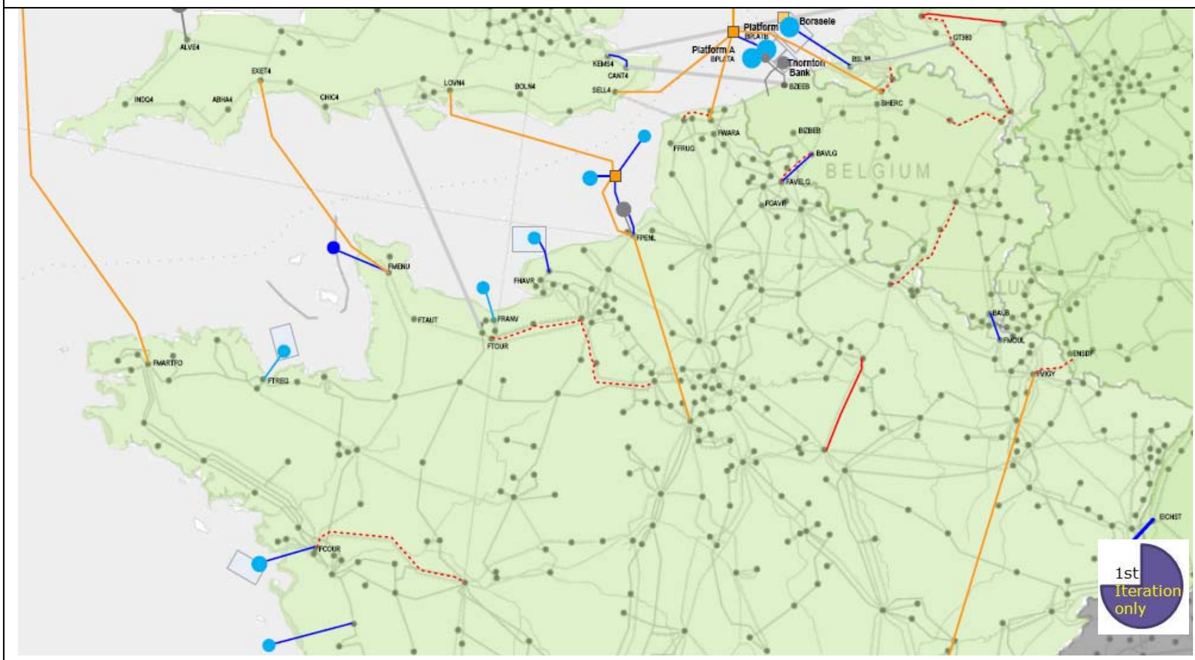
A 3.3 Country-specific comments – France

Reference scenario

The scenario was fixed with the French administration in summer 2011; it therefore does not take account of later changes regarding future energy mix made since that time.



Reference Scenario Radial Design Map



Reference Scenario Meshed Design Map

Interconnectors

The total France - England interconnections reach 4 GW (including, IFA and IFA2 which were assumed in the base grid). One additional 1 GW interconnector is included between the Cotentin and England.

A new France - Ireland interconnector (1GW) connected in West Brittany is included. A bilateral EirGrid-RTE study is currently being carried out to assess other constraints (i.e. voltage constraints)

On the French-Belgian border, for both the Reference Scenario radial and meshed designs, the grid simulations showed high power flows from France to Belgium, reaching 7000 MW. As a comparison, present day (2012) grid transfer capacity for France-Belgium is +/- 3000 MW. Unsurprisingly, this level of power flow leads to overloads at the border - even in the intact network, i.e. without any grid outages. The internal grid would also be impacted by such a level of exchange. Next to the overloads at 400 kV, part of the flow uses the 225 kV link France-Belgium-Luxembourg-Germany, causing overloads on this axis as well. Flows in the Belgium-France direction are much lower, only reaching 2600 MW.

Several reinforcements are considered, always taking the feasibility of actually achieving these reinforcements into account:

- Phase shifting transformers on the Moulaine (FR) – Aubange (BE) – Bascharage (LU)220 kV link;
- Upgrade of existing 400 kV lines Mastaing-Avelgem and Avelin-Avelgem using high-temperature conductors;
- Reinforcement of 400 kV existing axis Lonny-Achene-Gramme;
- options with HVDC links, with a preference for a connection as much to the West as possible. The most westerly option is to create a link between Warande in France and Stevin (Zeebrugge) in Belgium. Both substations are close to the North Sea coast. This link could actually be created as an offshore link. In the meshed offshore design, the link could interconnect with the planned offshore hub and connected via the Belgian offshore windfarms to Stevin.

The above reinforcement possibilities are currently being studied in a bilateral RTE-Elia study.The exact capacity that is needed, the impact on the internal grid and the cost/benefit viability of the solution will be carefully checked.

These reinforcements could achieve a physical cross-border capacity of about 6000 MW. Further reinforcements may be needed if the highest flows are confirmed in a sensitivity analysis, but would probably require an overlaying grid to be studied in more detail in the TYNDP 2014 process or the e-Highways 2050 project.

With regard to the France – Germany cross-border interconnections, the results show that additional transfer capacities between Germany and France are necessary. An additional need of cross-border capacity of approximately 2 GW was identified in the study. The solution favours the reinforcement of the existing high voltage corridors, while not excluding interconnectors on new routes. The representation on the map is an example of possible reinforcement, but a bilateral Germany-France study, currently being carried out, should further optimise the required reinforcements.

Compared with the radial design, the meshed grid solution proposes mainly the following additional offshore HVDC structure:

- The creation of an offshore node off the Normandy coast, collecting French wind in the area and providing, through an additional interconnection to England, an increase by 1 GW of the total France-Great Britain exchange capacity that reaches 5 GW.
- The creation of an offshore node off the Belgium coast connected to three countries (France, Belgium and Great Britain), allowing a flexible 1 GW exchange capacity between these three countries.

Offshore connections

In the Reference Scenario, the 6,5 GW of offshore generation capacity in France was distributed along the coast of France, corresponding to possible future projects listed in recent years. The consequence is a geographical repartition of the French offshore generation as specified below, which leads to reduced grid constraints with respect to concentrated offshore generation in other countries (i.e. Belgium or Germany).

- A Northern France area with about 4.3 GW wind and 0.5 GW installed tidal capacity;
- A Southern France area (south of Loire River) with about 1.7 GW installed offshore wind capacity.

Onshore reinforcement

The grid simulations identified very high flows on two main transmission corridors:

- The England–Normandy–Paris corridor;
- The Belgium-Luxembourg-Germany to Lyon-Geneva corridor;

The reinforcement projects within France concern mainly two transmission corridors:

- The Great Britain-Normandy-Paris corridors, through upgrade of existing lines and creation of a new HVDC connection;
- The North-South corridor from the Germany/Lorraine area to the Rhone area, consisting mainly of a new HVDC connection.

These onshore reinforcement projects for the radial design align with those required for the meshed design. The power flows remain concentrated on the same corridors. The main reasons are that the offshore grid structures between the radial and meshed designs are similar in the France area.

RES+ commentary

The RES+ Scenario consists in a doubling of the offshore generation with respect to the Reference Scenario, to reach 13 GW installed capacity for France.

- 9 GW offshore wind generation (3 GW more than the Reference Scenario) distributed in the same regional areas as for the Reference Scenario;
- 4 GW tidal generation located in the Channel area, mainly between Cherbourg (FR) and Alderney Island.

The offshore interconnection structure in the Channel remains globally similar to the Reference Scenario.

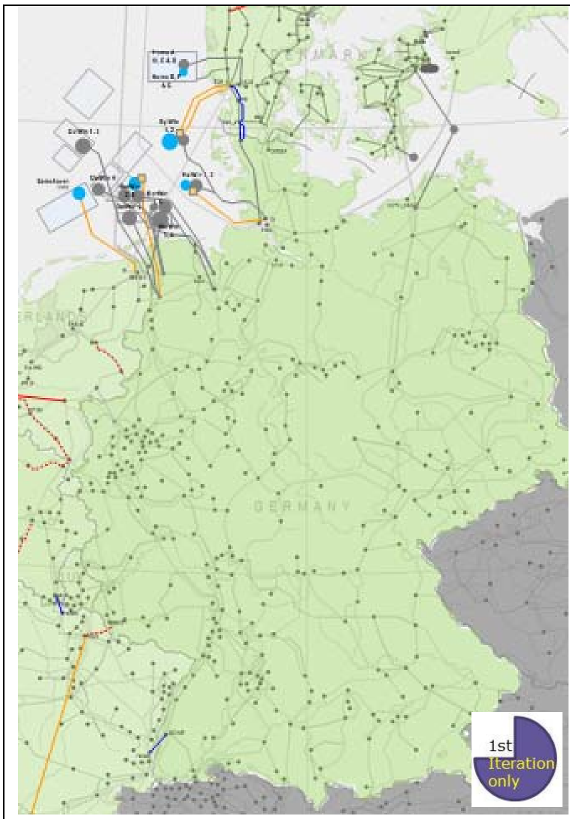
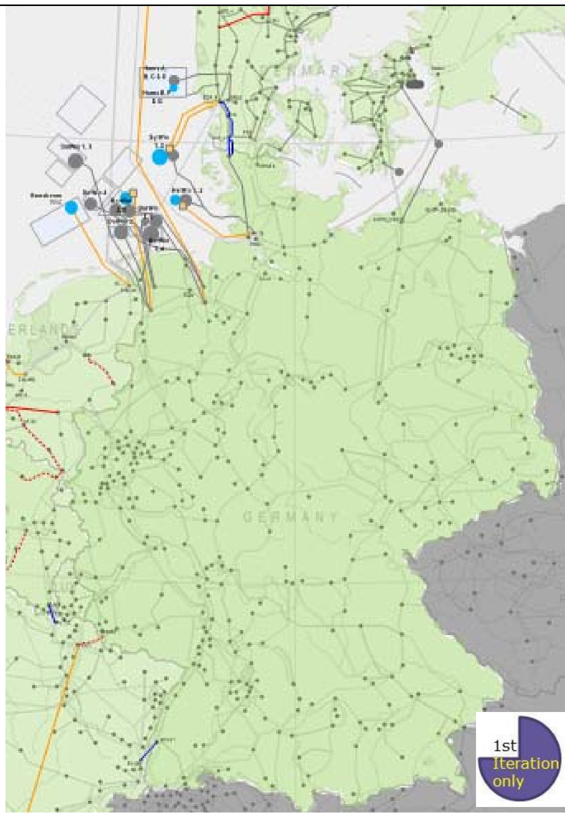
The main RES+ Scenario challenge for France is the concentration of 4 GW of tidal generation in a local area off the Cotentin coast. These tidal plants are, for meshed grid, integrated within a France-Great Britain interconnector.

Regarding the onshore grid in France, all the reinforcements projects proposed for the Reference Scenario are the same as those identified for the RES+ Sensitivity. One additional corridor with about 3GW capacity is needed between Cotentin and the Loire Valley.

As RES+ was only a sensitivity scenario, these results should be taken as a trend for grid reinforcement need. Further market studies and load flow calculations would be necessary for a better assessment of these reinforcements.

A 3.4 Country-specific comments – Germany

Reference Scenario

	
Reference Scenario Radial Design Map	Reference Scenario Meshed Design Map

Interconnectors

Compared to the radial approach, the meshed grid shows one additional connection between Norway and Germany (Elsfleth/West) in order to link German wind farms and Norwegian hydro reservoirs and pumped storage plants. In both cases, the connection to Denmark is significantly reinforced.

With regard to the interconnections, the results of the grid simulations show that additional transfer capacity is needed between Germany and France. The additional need of cross-border capacity of approximately 2 GW was identified. The solution favours the reinforcement of the existing high voltage corridors, while not excluding interconnectors on new routes. The representation on the map is an example of possible reinforcement, but a bilateral Germany-France study, currently being carried out, should further optimise the required reinforcements.

Offshore connections

For Germany an installed offshore wind capacity of 16700 MW was assumed in the Reference Scenario. In both the radial and meshed designs, the German wind farms are connected directly to the shore. One German offshore wind farm is connected to the Danish system – see country specific comments on Denmark.

A comparison of the radial and meshed network design configurations shows no large differences. For this reason the impact on the German transmission grid is similar and therefore the assessment of these two grid configurations can be merged.

In order to connect the developed offshore-grid as well as the offshore-windfarms to the existing German transmission grid, different onshore substations are chosen as follows:

- Diele,
- Elsfleth/West and
- Büttel.

In both grid configurations the offshore wind farms BorWin 2,5 and HelWin 1,2 are connected to the substations Diele and Büttel.

Specific comments relating to existing national plans

The German Grid Development Plan [24] is based on results of the national investigations made in parallel to the NSCOGI study, during 2012. The German plan covers the time between 2012 to 2032 and includes lines which are part of the NSCOGI starting point, (compare Figure 3-7).

The national plan found that, in order to achieve the targets of the German energy policy – especially the nuclear phase out until 2022 and the changeover to renewable energies – additional grid reinforcements are necessary. A significant impact is caused by the high increase of onshore and offshore wind farms in the North of Germany and solar power in the South of Germany. This results in high energy North-South transmission corridors (e.g. HVDC) which connect the wind farms in the North with the consumption centres in the Mid and South of Germany and further onwards to the pump storage facilities in the Alps. A transmission capacity of approximately 26-28 GW is intended for these four corridors.

A big part of these investments are already planned until the year 2020, as shown in the TYNDP [3] and Figure 3-7 respectively. Although the new connections of the German grid development plan 2012 are not shown on the NSCOGI-maps, the NSCOGI study confirmed their necessity. Their invisibility on the NSCOGI maps results from the fact that the NSCOGI study-process stopped after the first iteration, (see Figure 2-1).

RES+ commentary

For the RES+ Scenario an installed offshore capacity of 25000 MW is assumed. Due to this increase of renewable energy, further German onshore connection points are necessary in both grid configurations, not only in order to connect additional wind farms, but also to implement additional interconnectors. Following this in the meshed grid design, German and Great Britain offshore wind farms are linked and are connected to Norway. As a consequence these three countries are linked in a meshed grid structure.

In comparison to the Reference Scenario, the following additional onshore connections points are chosen:

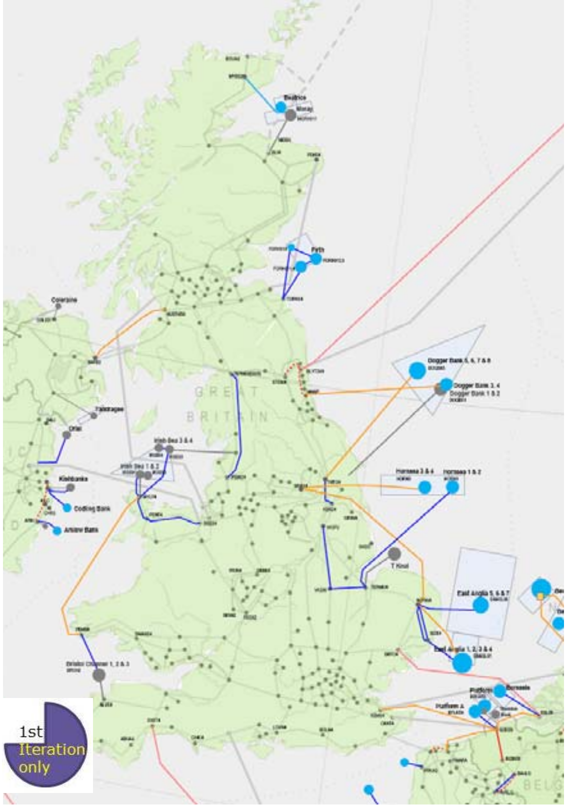
- Emden/Ost,
- Cloppenburg, and
- Bentwisch.

Due to the fact that these substations are also connection points for the German North-South high energy transmission corridors, incoming power flows can be integrated into the German power system. According to the results of grid analysis the additional incoming power flows lead to North-South transit flows, whereby German grid reinforcements are confirmed. In addition the interaction of the offshore grid and the internal grid expansion measures facilitate pan-European power exchanges, especially between Scandinavian countries and Central/South European countries.

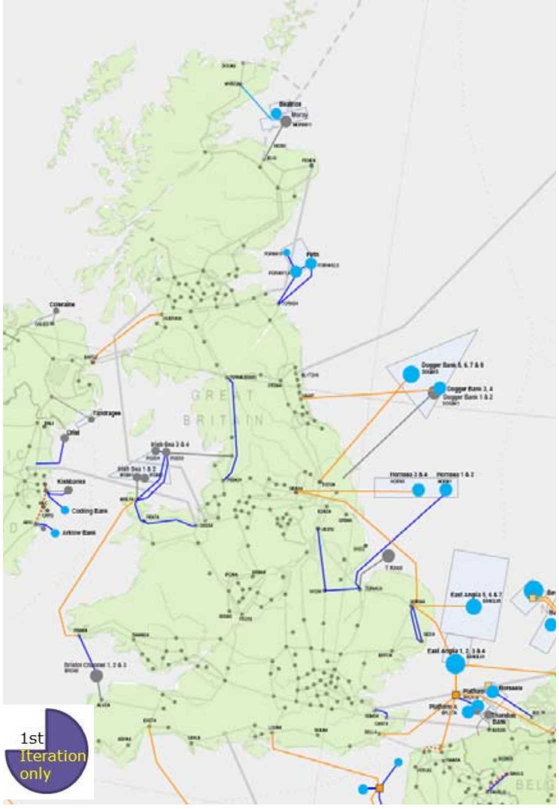
In conclusion, offshore wind production and an offshore grid can be connected to the German power system. However both require a significant investment in the onshore infrastructure to enable the evacuation of the power from the coast sites to the southern consumptions centres.

A 3.5 Country-specific comments – Great Britain

Reference Scenario



Reference Scenario Radial Design Map



Reference Scenario Meshed Design Map

The NSCOGI Reference Scenario has three main characteristics that drive the need for investments in Great Britain:

(i) There is very limited growth in offshore wind farm development from the 16GW assumed to be connected by 2020 (TYNDP 2012) to 17.7GW in 2030. It should however be noted that the Reference Scenario used in the study was derived from mid-2011 data, based on policies that were sufficiently advanced at the time to be incorporated. Policy developments since then have not been taken into account, nor have potential future reductions in the costs of offshore wind. In this Scenario, the study therefore only assesses the most economic and efficient way of connecting the additional 1.7GW of offshore wind, the majority if which is situated along the east coasts of England and Scotland and in the Irish Sea. The connection of these wind farms is by new offshore AC cables and HVDC circuits to multiple onshore connection sites.

(ii) RES targets are achieved through a significant increase in onshore wind generation (from 9.1GW in 2020 to 17.7GW by 2030). The majority of this onshore generation is expected to be sited in Scotland, significantly increasing north to south flows.

(iii) The pricing assumptions place gas fuelled generation, which forms much of the Great Britain generation base in the scenario (55GW), low in the economic merit order. As a result, Great Britain is seen to have a shortfall of low cost (in merit) generation. This results in additional interconnection to other North Seas countries being identified to allow for the import of energy from lower cost generation. In all of the planning cases selected for the 2030 analysis, Great Britain is importing from the central European countries. Ireland and Northern Ireland are in a similar situation and therefore an additional interconnector has been triggered from Scotland to Northern Ireland to export power from the Great Britain system.

(iv) Alternate pricing assumptions (merit order shift to consider gas ahead of coal) and additional scenarios will undoubtedly produce different results and should therefore be considered as next step.

Interconnectors

In both the radial and mesh designed networks there is additional interconnector capacity included from Great Britain to most of the surrounding countries including Northern Ireland, Norway, Netherlands, Belgium and France. The radial design has a new 1.5GW HVDC circuit to Norway which is not present in the meshed design, but instead the meshed design has higher interconnection capacity through the meshed nodes to France, Belgium and Netherlands.

Offshore connections

In the radial solution all offshore windfarms are connected to nearest possible substation. The ones closer to the coast are connected via AC connections and the ones further away are connected using HVDC VSC technology.

The larger wind farms such as Dogger Bank and the Irish Sea development have connections which are split across more than one connection point to avoid overloading. As north to south power flows on the Great Britain transmission system can be high and cause limitations, it can be advantageous to connect the wind farms as far south as possible to reduce onshore system requirements. Due to existing generation and limited transmission capacity at the coastal substations, some of the offshore connections have had to be brought deep onshore.

Onshore reinforcement

In the Reference Scenario the predominant power flow across the Great Britain transmission system is inwards from the periphery and north to south from Scotland and the northern counties of England. The installed CCGT generation is out of merit (i.e. uneconomic in a regional context) and does not provide its usual support to the south of the country. To cater for this, reinforcement is required along the north to south corridors and regions close to the new connections such as North Wales, Teesside and Humber.

In the Reference Scenario the North Wales, East Anglia and South West areas also have to provide for new nuclear generation connections which drive many of the reinforcement needs.

Specific comments relating to existing national plans

Most of the generation within the Reference Scenario already has connection agreements to the Great Britain transmission network and has been accounted for in the Great Britain national strategies. The new interconnectors from this study are different from current agreements and would require further consideration before being considered as feasible.

RES+ commentary

The RES+ sensitivity differs from the Reference Scenario in that it assumes a larger growth in offshore wind generation at an accelerated rate. For Great Britain, the total installed capacity in the RES+ sensitivity in 2030 is 49.8GW compared with 17.7GW in the Reference Scenario. The amount of Offshore RES is based on National Grid's consulted Accelerated Growth scenario and is therefore not consistent with Government's projections [25]. The installed capacity of the other generator types remains the same along with the assumed merit order.

With the radial design for the RES+ sensitivity there are many more connections from offshore wind farms that of the Reference Scenario design. As with the Reference Scenario results there are system reinforcements required along the north to south transmission routes to cater for the power flows at the time of high wind farm output.

To accommodate the Dogger Bank and Norwegian interconnector to the north east of England there is a requirement for an additional HVDC circuit spanning from the northeast of England to the Humber area.

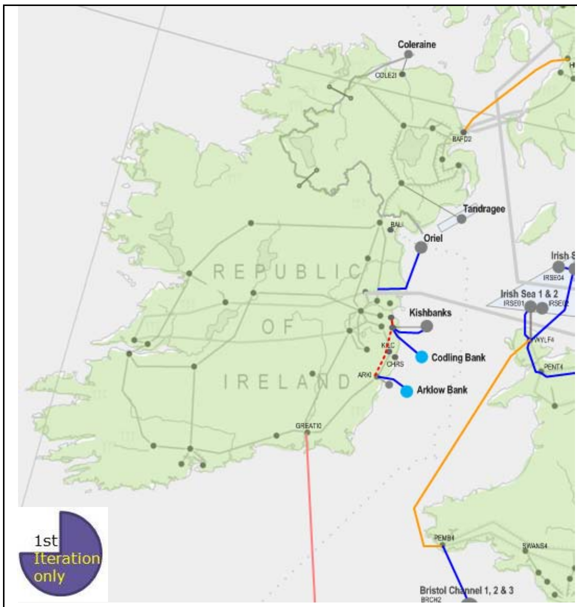
With the larger capacity of installed wind generation in this scenario there are several instances of the interconnectors exporting to the continent. Of interest is the predominant import to Great Britain from France in all of the selected planning cases while other interconnectors to the east and west of Great Britain regularly change flow direction.

With the meshed design there is additional interconnection to Germany, Belgium and the Netherlands that was not in the radial design. This meshed interconnection shares transmission capacity with the connections of the offshore windfarms but as interconnection capacity is significantly increased the periods of contention should not be minimal.

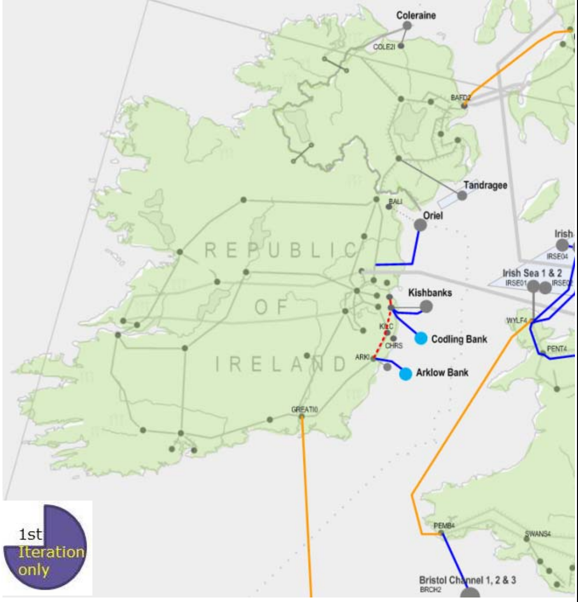
Within Great Britain the interconnection of the wind farms on the English east coast helps support the north to south power flows and the direct HVDC circuit linking the northeast of England to the Humber area is not required in the meshed design.

A 3.6 Country-specific comments – Ireland and Northern Ireland

Reference Scenario



Reference Scenario Radial Design Map



Reference Scenario Meshed Design Map

Interconnectors

The existing Moyle Interconnector between Northern Ireland and Scotland and the recently commissioned East West Interconnector between Ireland and Wales were assumed to have import and export capacities of 500 MW. The Reference Scenario analysis identified the need for a 1 GW HVDC interconnector between Northern Ireland and Great Britain (Scotland) and another between Ireland and France. The main drivers were high imports from Great Britain and France, particularly when renewable generation levels were low and thermal plant was out of merit on the island. In Ireland the interconnection termination location was determined to be at the Great Island 400 kV station and in Northern Ireland at the Ballylumford 275 kV station. The interconnectors were accommodated without additional network reinforcement beyond what is already planned.

In relation to the France- Ireland interconnector (1GW), a bilateral EirGrid-RTE study is currently being carried out to assess other constraints (i.e. voltage constraints)

Offshore Connections

The assumed offshore generation levels and locations for the Ireland and Northern Ireland Reference Scenario were as outlined in the table below. Due to the relatively small size of the wind farms assumed in the scenario and the short distances from the existing onshore network, the optimisation analysis produced the same result for the radial and meshed network configurations. In summary, for the levels of offshore generation assumed in the Reference Scenario, all the offshore wind farm network connections could be realised with single HVAC radial connections.

Table 7-6 Offshore Generation level and locations

Offshore Wind Farms	Reference Scenario	RES+ Sensitivity
	Capacity (MW)	Capacity (MW)
Arklow (Ireland)	400	1,100
Codling (Ireland)	578	2,000
Kish (Ireland)	360	884
Oriel (Ireland)	330	700
Glassgorman (Ireland)	-	600
East Coast (Northern Ireland)	-	800
Tunes (Northern Ireland)	-	200
Coleraine (Northern Ireland)	200	200
Tandragee (Northern Ireland)	400	400
Totals	**2,268**	**6,884**

In the Reference Scenario, a meshed option could be considered by connecting the Kish and Codling offshore wind farms with the addition of an offshore HVAC circuit and connecting to the onshore network via HVAC circuits. However to ensure N-1 compliance and to accommodate the full capacity of this group of wind farms (978 MW), two to three HVAC circuits could be required and hence, in this instance, would make the radial configuration a more favourable option in comparison due to significantly less reinforcement requirements.

Onshore Reinforcement

In Ireland the need for onshore network reinforcement was identified in the part of the network south of Dublin, the main demand centre, due to the connections of the Kish, Codling and Arklow offshore wind farms. In particular, planning cases with high wind generation, and low thermal generation, resulted in high power flows into the south Dublin network necessitating the reinforcement of the Arklow-Carrickmines-Poolbeg 220 kV circuit. The Oriel wind farm was looped into the Louth – Woodland 220 kV circuit without the need for additional reinforcement. In the north west of the island, the cross border Renewable Integration Development Project (RIDP) was assumed in place. In Northern Ireland, and the Coleraine and Tandragee offshore wind farms could be accommodated without additional network reinforcements.

Specific Comments Relating to Existing National Plans

A number of TYNDP projects were significant in realising the connection of high levels of offshore generation:

- RIDP: This project allowed for the connection of onshore wind generation in the northwest of the island and offshore wind generation, particularly off the north coast of Northern Ireland.

- North South Interconnector: This project allowed for high north-south power flows resulting from, in particular, the connection of offshore wind generation off the east coast of Northern Ireland.
- Grid Link: This project facilitated the Ireland – France interconnector termination location in the south east of Ireland and enabled the high transfers of renewable power from the South of Ireland to Dublin.
- Dublin 'Ring' Reinforcement: This group of 400 kV projects helped facilitate the high power flows into this large demand area and the connection of offshore generation at the Carrickmines station.

Two separate studies have recently examined network designs to facilitate the development of offshore generation for Ireland and Northern Ireland:

- The Irish-Scottish Links on Energy Study (ISLES) Project (2011), and
- EirGrid's Offshore Grid Study (2011).

These other studies were conducted with a local focus whereas the NSCOGI study has been conducted on a regional basis and hence they differ in some aspects of findings.

RES+ Commentary

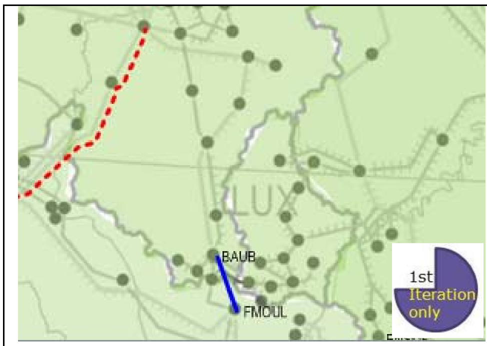
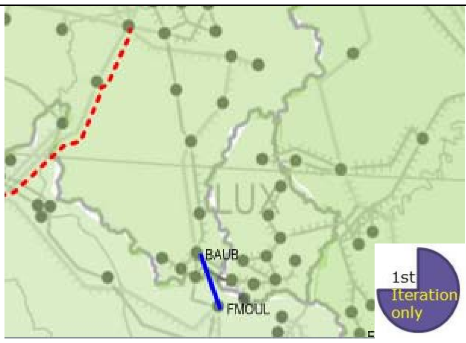
The assumed offshore generation levels for the Ireland and Northern Ireland RES+ Sensitivity were as outlined in the table above. This sensitivity involved a significant increase of 4.6 GW to the offshore generation levels that were assumed in the Reference Scenario. More planning cases with high interconnector exports were identified due to high levels of wind generation. The optimisation analysis therefore identified further interconnection and additional onshore and offshore reinforcement, in addition to that identified in the Reference Scenario.

The radial configuration consisted of the offshore generation connected back to the onshore network but close to an onshore interconnection termination location, in some instances enabling the export of offshore generation and minimising the need for onshore network reinforcement, e.g. the placement of an interconnector at Arklow where the offshore Arklow generation was also connected.

The meshed configuration consisted of the offshore generation connected by both onshore connections and offshore interconnection, e.g. the Kish and Codling offshore wind parks were grouped and connected to Ireland via AC links and to the east with interconnection to Great Britain. All configurations identified the need for additional interconnection and further reinforcement of the south Dublin network due to the high power flows resulting from the large offshore generation.

A 3.7 Country-specific comments – Luxembourg

Reference Scenario

 Reference Scenario Radial Design Map	 Reference Scenario Meshed Design Map

Interconnectors

Due to the central location of Luxembourg in Western Europe, in between Germany, Belgium and France, the direct impact of the offshore grid structure is limited. Nevertheless the results for both radial and meshed grid designs show that the power flows generated by offshore generation have a high impact on the existing Germany-Luxembourg and planned Belgium/France–Luxembourg interconnections.

The planned Luxembourg – Belgium interconnection will provide 700 MW of transmission capacity. The Aubange (BE) – Bascharage (LU) 220 kV link will be operated by phase shifting transformers.

The ongoing reinforcements of the German grid will increase the existing capacities on the Germany–Luxembourg border.

The load flow simulations show high power flows on the Germany-Luxembourg-Belgium transmission corridor. The studies show that these power flows exceed the 400 KV AC cross-border capabilities.

Onshore reinforcement

The study showed very high flows on the Germany-Luxembourg-Belgium transmission corridor.

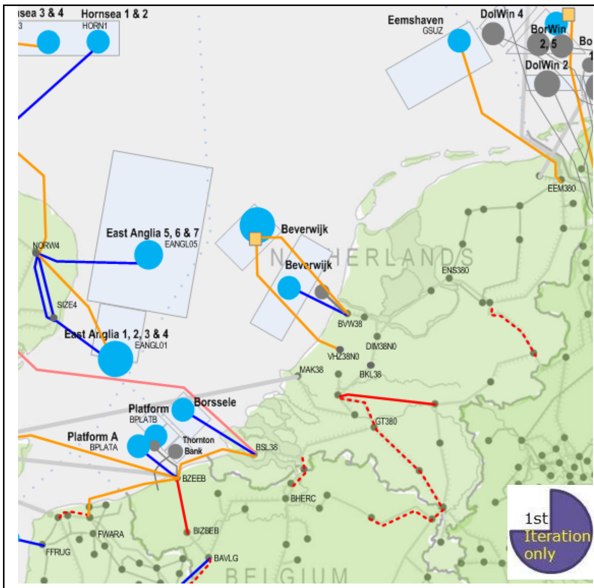
Further reinforcements from Luxembourg towards Belgium and France may be needed if the high power flow transfers are confirmed in the ongoing studies for additional France-Germany and France-Belgium grid transfer capacity.

RES+ commentary

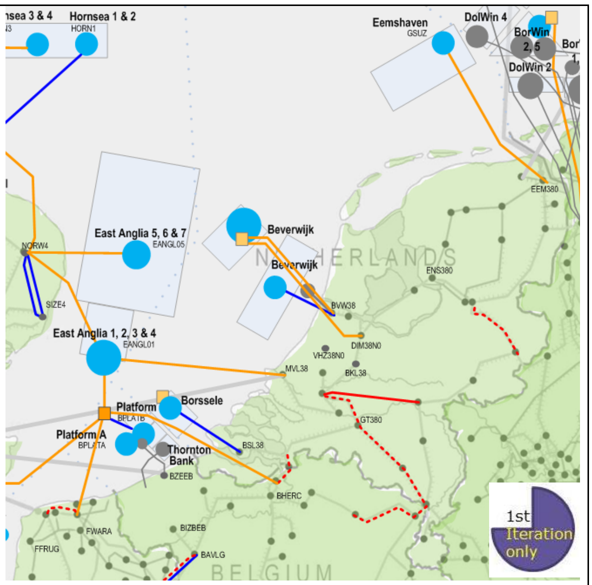
The RES+ Scenario consists in an increase of installed onshore capacity generation for Luxembourg from 131 MW in EU 2020 to 200 MW.

A 3.8 Country-specific comments – the Netherlands

Reference scenario



Reference Scenario Radial Design Map



Reference Scenario Meshed Design Map

The Reference Scenario shows an installed offshore wind capacity for the Netherlands of 6000MW. This capacity is divided between four new areas:

- Eemshaven 1000MW
- Beverwijk1 1000MW
- Beverwijk2: 2500MW
- Borssele 1000MW
- And one existing offshore windfarm of 500 MW connected at Velsen.

Interconnectors

The cross-border connections between the Netherlands and Belgium are heavily overloaded:

- Kreekrak – Zandvliet, and
- Maasbracht – VanEijck

Upgrading both Maasbracht –VanEijck and Kreekrak – Zandvliet to 2635MVA can increase the cross-border capacity between the Netherlands and Belgium. In the Belgian grid additional reinforcements are required to accommodate this upgrade as described previously. In addition to the reinforcement of existing cross-border connections an offshore HVDC link of 1000 MW between Borssele and Zeebrugge is introduced.

There are no overloads on the cross-border connections between the Netherlands and Germany.

Offshore connections

In the radial design all the offshore windfarms are connected to the nearest substation. Those closer to the coast are connected via AC connections while those further away are connected using HVDC VSC technology. To achieve a more dispersed grid in-feed, the largest windfarm, Beverwijk, is split in two parts and connected to the substations of Beverwijk and Vijfhuizen.

In addition to the offshore wind connections, the need for a new interconnector between the Netherlands (Borssele) and Great Britain was identified. In the Reference Scenario the prices in Great Britain are high compared to the prices in continental Europe, resulting in several additional interconnectors to Great Britain.

In the meshed design some changes can be seen in the offshore grid structure. The windfarms are still connected to the closest onshore substation with a minor change in the Beverwijk windfarm, which is connected to Diemen instead of to Vijfhuizen. This change is caused by the fact that an additional offshore connection to Maasvlakte is introduced, causing an additional in-feed in the area. The East Anglia 1,2,3,4 windfarm is now connected in a meshed way to the Netherlands and Great Britain via a HVDC VSC connection.

Onshore reinforcement

The locations and amounts of offshore wind power in the Reference Scenario are very similar to the data used in the national TenneT ten year grid development plan (Quality and Capacity Plan 2011).

Overloads in the internal grid that were observed in this scenario are therefore not new. They have been identified on the following lines:

- Geertruidenberg – Krimpen,
- Hengelo – Zwolle, and
- Eindhoven – Maasbracht.

To mitigate these overloads several grid reinforcements are proposed. Internally in the Dutch grid it can be seen that overloads larger than 20% appear in the intact network already for a significant number of hours per year. Since the overloads are more than 20% (especially under N-1 conditions) upgrading of these lines (reconductoring) to 4 kA (2635MVA) is required. Furthermore, the need for a new connection between the Western and Eastern part of the main 380kV ring was identified to be able to transport all offshore wind power and conventional generation at the coastal locations.

The impact of the meshed solution on the onshore grid is very similar to the impact of the radial solution; therefore the exact same possible reinforcements are introduced. The main change in the reinforcements is the offshore connection between Borssele and Zeebrugge that has been replaced by the offshore meshed solution via East Anglia and BOFF.

Specific comments relating to existing national plans

In the Reference Scenario there are no new overloads in the Dutch grid that were not yet identified in the national capacity plan. The possible solutions chosen to mitigate these overloads are therefore in line with the ones proposed in the TenneT Quality and Capacity Plan 2011, except the bottlenecks for the cross-border reinforcements with Belgium.

RES+ commentary

In the RES+ sensitivity the installed offshore wind capacity for the Netherlands is doubled to 12000MW compared with the Reference Scenario. This capacity is again divided between the same four areas:

- Eemshaven 2000MW
- Beverwijk1 2000MW
- Beverwijk2 5000MW
- Borssele 2000MW
- And the existing offshore location at Velsen is also doubled to 1000 MW.

The RES+ sensitivity radial design shows an offshore grid configuration that is very similar to the radial design of the Reference Scenario. Since the offshore installed wind power has been doubled, it can be seen that the number of connections to the shore has also been doubled. The windfarms connections near Beverwijk are, in this scenario, divided between four instead of two different substations to account for a more dispersed in-feed. The additional interconnector from the Netherlands to Great Britain is not included in this scenario.

In the RES+ sensitivity, overloads appear on the same internal Dutch lines as in the Reference Scenario, with one additional overload in the line Breukelen - Krimpen. However, the overloads in the RES+ sensitivity are significantly higher than in the Reference Scenario. The cross-border overloads between the Netherlands and Belgium have also increased in the RES+ sensitivity. These overloads are now at such a level that the proposed reinforcements for the Reference Scenario would probably not be sufficient. Therefore, when taking into account this specific scenario with extremely high cross-border flows, additional reinforcements are required. Further studies are required to determine the impact of the RES+ sensitivity in more detail and identify possible additional reinforcements. With the high wind power penetration level as assumed in the RES+ sensitivity, the step towards an overlaying HVDC grid connection in the Netherlands might become an effective solution.

In general the results from the different scenarios and offshore grid designs show that the offshore grid design (whether meshed or radial) does not impact the bottlenecks that occur in the Dutch onshore grid. Proposed possible grid reinforcements are therefore the same for the radial and meshed designs.

Table 7-7 Bottlenecks in the Dutch Netherlands' onshore grid

Overload		Reference		RES+	
		Radial	Meshed	Radial	Meshed
Geertruidenberg – Krimpen	Internal	X	X	X	X
Hengelo – Zwolle	Internal	X	X	X	X
Eindhoven – Maasbracht	Internal	X	X	X	X
Breukelen - Krimpen	Internal	-	-	X	-
Kreekrak – Zandvliet	NL-BE	X	X	X	X
Maasbracht – VanEijck	NL-BE	X	X	X	X

Note: X means that the bottleneck is present

A 3.9 Country-specific comments - Norway

Reference scenario

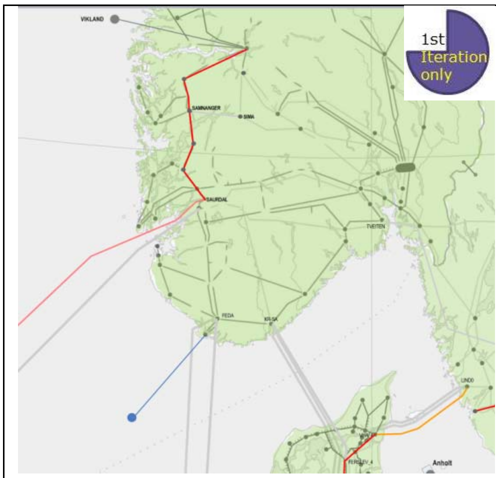
In both the meshed and radial designs Norway is connected to the rest of Europe by one additional direct HVDC link in addition to those outlined in the TYNDP 2012. The effects on the onshore grid may in periods be challenging, this because both links are connected in the southern part of Norway.

The internal power flows are mainly from the north to the south due to the demand centre and interconnectors in the south, and this triggers the reinforcement needs on the west coast.

The total HVDC capacity by 2030 could be 8100MW. This includes:

- Norway-Netherlands: 700MW
- Norway-Denmark: 1700 MW
- Norway-Germany: 1400MW
- Norway-Great Britain: 1400 MW
- Norway-Germany or Norway-Great Britain: 1500MW
- Norway – Sweden 1400 MW

With this large amount of HVDC interconnection the onshore grid will in periods experience great stress. The number of hours at which the interconnectors will be at maximum utilisation will be reduced, and therefore the total benefit derived from the links may be reduced in some periods. The possible future need for pump storage solutions may play a role here as well.

	
Reference Scenario Radial Design Map *One additional interconnector to Great Britain*	Reference Scenario Meshed Design Map *One additional interconnector to Germany*

Interconnectors

The radial design includes a 1500MW HVDC interconnector from Norway to Great Britain, connected in Norway at Saurdal.

In the meshed design there is a 1500MW HVDC Norway-Germany interconnector, connected to Feda instead.

Onshore reinforcement

Sauda-Samnanger-Sogndal 420kV. The total reinforcement costs will be approximately 280M€.

The suggested reinforcements are in the national grid development plan, implemented after 2020.

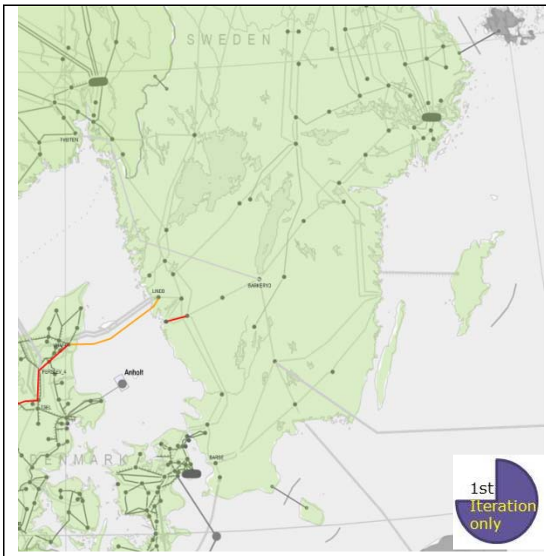
RES+ commentary

In both the radial and the meshed designs for the RES+ sensitivity one of the additional HVDC-links will need to be connected to Samnanger in order to ease the pressure on the grid on the west coast (south of Samnanger). In the radial design the second link is connected directly from Feda in Norway to Germany. In the meshed design the second link is connected to an offshore node instead. Both designs require reinforcements along the west coast from Sauda to Sogndal. There will probably also be some minor reinforcement needs for upgrades in the southern part. This is triggered by the combination of two additional HVDC links, one connected in Fedaand one connected in Samnanger. The total reinforcement costs will be approximately 400M€

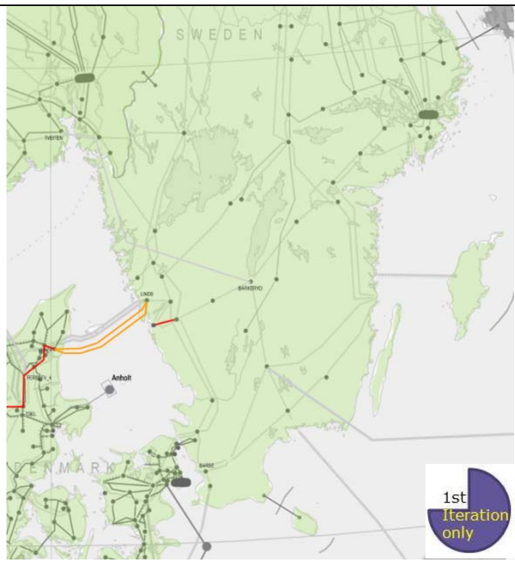
The generation dispatch in Norway in the RES+ sensitivity is very similar to the one in the reference scenario. Due to the increase in wind generation in the North Sea Norway will experience more import over the year and thereby making the system more volatile compared to the reference scenario. In all of the scenarios approximately 22% of Norwegian power production comes from the generators in the south. This corresponds to 4500MW-7000MW and will be the possible capacity for import and export using the reservoirs as storage.

A 3.10 Country-specific comments - Sweden

Reference scenario



Reference Scenario Radial Design Map



Reference Scenario Meshed Design Map

Interconnectors

Sweden’s interconnector in the radial design for the offshore grid design consists of a 700 MW link connecting Sweden to Denmark. This connection is mainly used to export hydro power.

The meshed design for the offshore grid is very similar to the radial design for Sweden, but with an additional 700 MW DC link to Denmark.

Onshore reinforcement

Both the radial and meshed designs require onshore reinforcement in Sweden. A short line on the west coast relieves stress on the system. The estimated cost of this reinforcement is approximately 20 M€(170 million SEK).

RES+ commentary

The RES+ sensitivity suggested an increase in interconnections from Sweden; however some of these have not been included due to onshore constraints.

In the radial design, extra reinforcements on top of those for the reference scenario, are required manage the extra renewables as well as the import from Denmark along two 740 MW DC links. The additional cost of this line is approximately 65 M€(550 million SEK), bringing the total cost of reinforcements to 85 M€. A 1440 MW DC link to Germany is also connected in this design, but this does not require any reinforcements, as it can be connected directly to the South West Link.

In the meshed design the connections to Denmark have not been selected, so the only link remaining is the link to Germany. National market studies have shown that such a connection would be beneficial for Sweden in most of the scenarios which have been studied.No internal reinforcements are required in this design.

A 4 Resources

Comparing the resources used for this NSCOGI study with the European Wind Energy Study (EWIS) study [14], a considerable increase in efficiency of regional cooperation can be observed:

While the first common TSO-study on Wind Energy (EWIS) used ~4 M€ financed by the EC plus the same amount own financing, this NSCOGI study built on the existing ENTSO-E's Regional Group North Sea (RGNS), providing the necessary resources and experience from recent regional studies. Via this NSCOGI study coming common investigations to be delivered for the next edition of ENTSO-E's Ten-Year-Network-Development Plan (TYNDP) are prepared.

While in EWIS 15 TSOs were involved, the NSCOGI study team comprises 16 TSOs. Both studies involved 50-60 persons from the different companies delivering part of their time during the project phase.

While EWIS had a one-year preparatory phase (March 2006 – January 2007) and a three year project phase (June 2007 – April 2010 = 34 months), this NSCOGI study had half a year preparatory phase (data gathering) and ~1,5 years of simulating and reporting.

	EWIS	**NSCOGI**
Financing - by EC - by TSOs	 ~4 M€ ~same amount	 not specified
Resources - TSOs involved - persons involved	 15 ~60	 16 ~50
Time preparatory phase simulation/ reporting phase	 11 months 34 months	 6 months 17 months

A 5 Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
BTC	Boundary Transfer Capacity
CCS	Carbon Capture and Storage
DSM	Demand side management
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
EU2020 targets	…
EU2020 Scenario	…
GHG	Greenhouse Gas
G/L	Generation / Load
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IEA	International Energy Agency
IEM	Integrated Energy Markets
LCC	Line Commutated Converter
MOS	Merit Order Shift
MOU	Memorandum of Understanding signed by NSCOGI members on 3 December 2010
MS	Member State
N state	System condition with all circuits and equipment in service
N-1	System condition with any one circuit or piece of equipment out of service
NDA	Non- Disclosure Agreement
NREAP	National Renewable Energy Action Plan
NSCOGI	North Seas Countries' Offshore Grid Initiative
NTC	National Transfer Capacity
OWP	Offshore Wind Park
OWPP	Offshore Wind Power Plant
PEMMDB	Pan European Market Modelling Data Base
PRIMES	…
RES	Renewable Energy Source
SoS	Security of Supply
SRMC	Short Run Marginal Cost
TSO	Transmission System Operator

TYNDP	Ten Year Network Development Plan
VSC	Voltage Source Converter
VOM	Variable Operation and Maintenance Cost
WG1	Working Group 1 of the NSCOGI

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