SENSEI
Strategies towards an efficient future North Sea energy infrastructure

ESTRAC
Energy Systems Transition Centre

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Summary

System integration between the offshore gas infrastructure and offshore wind, can offer significant economic and ecologic benefits compared to separate development. These result from lower development and operational costs for both offshore wind and gas, a higher market value through increased flexibility, reduced greenhouse gas emissions and accelerated wind deployment. In order to realise these benefits strategic decisions need to be made that should be coordinated between the offshore wind, offshore gas sector, government and other stakeholders. Yet a systematic overview and evaluation of the available system integration options is lacking, as well as sufficient insight in which choices need to be made on the short and medium term what are possible consequences.

This project provides an overview of possible system integration options, with their main opportunities and challenges with a qualitative evaluation to form a basis for defining development strategies. The aim of this report is to produce an informative and well-balanced overview of the main options and evaluation aspects.

Challenges offshore gas and wind sector

The depletion of gas fields and the low gas price lead to early decommissioning of gas platforms, while operational platforms need additional investments in order to comply with more stringent emission limits in 2019. Gas platforms and infrastructure that reach the end of their lifetime are planned for decommissioning and abandonment. Plans and reservations for decommissioning are part of the development plans from the operator, but have appeared to be more expensive than previously thought and increase the stress on the commercial balance of offshore gas operations. The decreasing use of the gas infrastructure and pending decommissioning may pose a threat to future gas explorations: The removal of infrastructure can cause future gas discoveries or small fields to fall out of the commercial window, as they have to account for longer intra-platform pipelines. Despite the challenges for offshore gas, it is seen to play an important role in the transition towards a low-carbon energy system, as the demand for gas will remain and North Sea gas has significant lower footprint than imported gas and a higher security of supply. Gas can also provide additional flexibility to balance supply and demand with increased shares of intermittent renewables.

For offshore wind developments beyond 2023 in the Dutch zone of the North Sea no concrete plans exist, although a further expansion is expected in line with the ambitions to decarbonise the energy system. Although offshore wind energy costs have recently decreased it is still one of the main challenges, for which the scale of projects and also technology and market developments are major factors. More specific challenges for offshore wind are related to spatial planning of the offshore site, the cable routing up till the onshore grid feed-in location, considering the limited space and suitable connection points, the multiple stakeholders, the wind resource and environmental conditions. Also the offshore wind development should remain to be synchronized with the grid development to prevent under-used assets, taking into account the different planning procedures, different responsible parties and the different operational lifetime of the wind farm and the offshore grid. Furthermore, for the development and installation process challenges are to reduce risks related to the high investments, the complex organisation, Health Safety and Environmental (HSE) risks and tight time schedule with risks of delay due to the limited workability offshore. For the operational phase the main challenges are obtaining insight in and reducing of operation and maintenance costs and at the same time to maximize the revenues by accurate forecasting, strategic bidding and/or contracting of energy and flexible power.

System integration options – drivers and barriers

Several options for system integration between offshore wind and offshore gas are evaluated in this study that offer potential benefits for both sectors, which may partly resolve the challenges mentioned. The main drivers and barriers of the studied system integration options are summarized below.

Table 0-1: Main drivers and bottlenecks for studied system integration options

System int. option / Drivers & Barriers	Platform electrification	Power to gas Power to X	Carbon capture and storage	Gas to wire	Energy storage
Main drivers	• GHG & local emissions reduction • O&M costs reduced • Stable market for offshore renewable (wind) electricity • Optimal use of E-transport capacity • Increased sector /public revenues	• Green gas or chemical feed-stock reduce GHG emissions • High value of energy → feedstock • Energy balancing / flexibility • Optimal use of infra-structure(s)	• GHG emissions reduction • Low cost mitigation option • Re-use of existing infrastructure (wells, platforms, pipelines) • Experience with offshore CO_2 injection	• Energy balancing/ flexibility/ • Security of supply/ optimal use of resources • Sector and public revenues end-of-field sites and more remote undeveloped gas fields	• Energy balancing / flexibility • Security of supply • Reuse of infrastructure
Main Barriers	• Regulations until 2023 do not facilitate coupling • Uncertain public acceptance	• Investments vs. low gas prices • Efficiency improvements needed • Regulations limit H_2 admixing	• Absence of sustainable business case due to low CO_2 price • Regulatory framework sub-optimal • Uncertain public acceptance	• Offshore conversion technology development needed: high efficiency, low cost, low emissions • Uncertain political and public support	• Currently poor business case • Technology at low technology readiness level
Interlinkage between options	• Important stepping stone for offshore E-Grid and connection of energy infrastructures	• Linkage offshore E-grid with gas infrastructure	• Energy needed for CO_2 injection/compression calls for link with offshore E-grid	• Prerequisite: offshore E-grid connected or nearby Combinations possible with: ○ CCS ○ Energy storage (gas storage)	• Strong link with all other options: ○ Electricity storage on platforms ○ Gas storage in reservoirs and pipelines

Summarizing, all system integration options offer certain clear benefits to either GHG reduction or increased flexibility for the energy supply, cost reductions and the optimal (re)use of valuable infrastructure.

Fostering the benefits of system integration options, like GHG reduction or increased flexibility for the energy supply, cost reductions and the optimal (re)use of valuable infrastructure, requires removing or minimizing of a number of barriers. These include high investments of infrastructural developments; non-converging goals of stakeholders, political and public support; the short window of opportunity; and the diverse use, invested interests and spatial claims of the North Sea.

Possible development paths

Focusing on the strong developments in wind offshore, the short and long term energy transition challenges and the available Oil & Gas infrastructure the assessment identified a number of concrete options for investment on short to medium term. Considering the drivers and barriers and resulting feasibility of the studied options, both on the short-term, mid-term and long-term, a possible development strategy is indicated in table 0-2.

Table 0-2: Possible options for short-mid-long term

Time horizon / System integration options	Short-term <2023	Mid-term 2023 - 2030	Long-term 2030 - 2050
Electrification	Platform electrification near-shore	Platform electrification, far-offshore & stand-alone	Platform electrification, offshore grid
P2G / P2X	Power2Gas, onshore (demo)	Power2Gas, offshore	Power2X, offshore
CCS	CCS + electrification near-shore	CCS + electrification (depleted gas fields, aquifers, further offshore)	
GTW	GTW near shore (end-of-field)		GTW far offshore, through offshore electricity grid
Energy storage			Energy storage offshore (H_2, CAES)

Platform electrification and offshore CO_2 storage are the most realistic system integration options for the short term. The strategy shows that platform electrification could be an important stepping stone for a larger offshore electricity grid that could facilitate electrical CO_2 compression for injection, gas to wire, power to gas and energy storage facilities.

Another important conclusion is thus that system integration options are interlinked in space and time: for example, opportunities exist with the rise of renewable energy production and the abandonment of gas production platforms, but the time gap between them and geographic distances should not be unsurmountable. This makes solutions for system integration complex, but at the same time warrant strategic actions now as for the North Sea offshore energy sectors a window of opportunity exists. In the near future a significant share of hydrocarbon reservoirs will stop production and infrastructure will be abandoned.

It should be noted that the exact roll out of these options is very difficult to predict as they depend on many uncertain factors, including those of economic, technical and societal nature. Nevertheless, the screening of options has yielded interesting insights that benefit future research and development actions.

Research and development needs and comprehensive agenda

A comprehensive concerted action supported by an integral research program on energy transition questions in the North Sea region is recommended covering the following core components:

1. Technology development and specific demonstration projects of no/ low regret options; key technological development pathways for new and advanced options can be defined, with an emphasis on identification of clear business cases on short and medium term.

2. Integral scenario and energy system transition analyses and quantified road map(s) for the North Sea region and larger energy system. Such efforts should take into account different possible development pathways and key technological, policy and economic drivers and uncertainties. A long term perspective will also include energy demand projections, energy storage needs and advanced, energy supply and conversion technologies
3. Strategic spatial planning interlinked with the above system analysis with insight in competing claims and synergies in different utilization options over time.
4. Building on the previous activities, ecological impacts of large scale infrastructure changes in and around the North Sea should be better understood in order to allow for sustainable planning of activities and preferably achieve co-benefits in improving the North Sea ecosystem.
5. Socio-economic impacts and optimization of economic development pathways; also on regional level. Understanding the possible development pathways for the North Sea energy system is the basis for understanding the macro- and socio-economic implications of such energy transitions.
6. Societal aspects and governance issues can be analysed and tackled thoroughly with the above information and actions available. Policy choices, the impact of technology development, market design as well as society preferences and views and their implications on North Sea energy system developments.

This can serve as a basis for a detailed program to realize and study energy transition in the North Sea region. The contours of a national consortium including key market players, key knowledge institutions and academia, as well as stakeholder management are taking shape at the moment with the formulation of an innovation program on North Sea Energy. It is strongly recommended to establish a national program supported by the Topsector energy at large, industry, science foundation and national and regional government. On the medium term, research activities could be strongly coordinated in the EU, starting from a national R&D program and stakeholder organization in the Netherlands.

Concrete actions for the short term

1. **Set up an integral strategic vision and roadmap** on the possible transition pathways of the North Sea, following the EU targets to fulfil the Paris Agreement. The development of offshore energy production and related infrastructures are to be seen as part of the transformation of the energy system in the North Sea region at large.
2. **Identify a short list of clear business cases** that can lead to demonstration projects and development pathways for specific key technologies on the short term.
3. **Mobilise international coordination**, governance and policy; with a concerted action, preferably with heavy involvement of the European Commission. Part of this coordination effort should bring together different key efforts done already on EU level.
4. **Develop regional action plans and strategies** to facilitate and benefit from the larger transition. Clear alignment of efforts between the regions to avoid overlap and facilitate effective investment and development
5. **Engage with stakeholders** on the value of system integration to all relevant stakeholders in North Sea dominated value chains to manage and converge the wide range of spatial claims and secure an ecologically sound and beneficial development of the new energy system of the North Sea region, involving key stakeholders and governance bodies.

1 Introduction

1.1 Background

Large-scale offshore wind energy will play a crucial role in the transition towards a low-carbon energy system. For North-Western Europe the North Sea is one of the most suitable areas to deploy offshore wind, with already 10 GW in operation in 2015 and 45 GW expected for 2030 (EWEA, 2015)

The cost price of offshore wind energy development and operation, especially when located far offshore, is one of the main bottlenecks, as well as the large-scale integration of offshore wind and other intermittent renewable sources in the energy system. In order to minimize development costs of the wind farms and the offshore grids, wind farms are currently planned in large clusters located near shore and connected to the nearest available grid connection point.

Nearby or even in these development zones several gas production and transport infrastructure are in operation. Depletion of gas fields, low gas prices and more stringent ecological regulations put the business case of gas production under pressure and bring planned decommissioning forward.

System integration between the offshore gas infrastructure and offshore wind, can offer significant economic and ecologic benefits compared to separate development. These result from lower development and operational costs for both offshore wind and gas, a higher market value through increased flexibility, reduced greenhouse gas emissions and accelerated wind deployment.

In order to realise these benefits strategic decisions need to be made that should be coordinated between the offshore wind, offshore gas sector, government and other stakeholders. Yet a systematic overview and evaluation of the available options for system integration is lacking, as well as sufficient insight in which choices need to be made on the short and medium term what are possible consequences.

1.2 Project aim and approach

In the recently signed manifesto “Gas meets Wind” (Topsector Energie, 2016), a broad Dutch consortium agreed to explore possibilities of coordination and collaboration in the North Sea region. The project upon hand aims to provide, as a first step, insight in system integration options and development strategies of offshore wind with oil- and gas infrastructure.

This project provides an overview of possible system integration options, with their main opportunities and challenges with a qualitative evaluation to form a basis for defining development strategies. The inventory and evaluation are based on existing studies and well-recognized scenarios by the sounding board of this project. The aim of this report is to produce an informative and well-balanced overview of the main options and evaluation aspects. This approach does not provide firm conclusions on which system integration options to develop, but rather a range of favourable options to consider and to elaborate as elements of a development strategy and what are the main choices and their implications. This project is closely linked to the recently finalized project System integration Offshore Energy (TNO, Shell, Siemens, EBN, 2016), which has identified the main drivers of stakeholders for system integration and has outlined a broad innovation project on System Integration Offshore Energy.

1.2.1 Focus on the medium and long term

In this study the focus will be on a medium term perspective between 2023 and 2030 and a long term perspective between 2030 and 2050, which could look as follows: 1) Between 2023 and 2030, it is expected that large offshore wind farms both at near-shore and far offshore locations, such as IJmuiden Ver and Dogger Bank, co-exist with mainly larger gas platforms. Possibly part of these wind farms are connected to these platforms, providing renewable energy for production and transport of gas as well as energy conversion, such as power-to-gas to facilitate cost effective exploitation and integration into the onshore energy system; 2) Between 2030 and 2050, the deployment of far offshore wind at even a larger scale and also interconnected with all countries around the North Sea is envisioned, while abandoned gas platforms and gas fields could be re-used for large-scale energy conversion as well as hydrogen and CO_2 storage.

1.2.2 Based on energy transition scenarios and mitigation measures

The implications of the recent Paris climate agreement are reported by IEA in the "Intended Nationally Determined Contributions" scenario (IEA, 2016), where the development of the EU primary energy demand shows a strong growth in renewables and gas, replacing coal and oil generation, see Figure 1-1. The main technologies for CO_2 reduction are CCS, both in power generation and heavy industry, and renewables, as well as end-user fuel switching and energy efficiency measures according to IEA and OECD (OECD, 2011). Therefore, gas and CCS are considered to play an important role in the energy transition in this project and are included in the system integration options in the North Sea. To decide on which options to develop a broad range of aspects needs to be considered, like technical maturity, economic perspective, effects on ecology and climate change, spatial planning and social acceptance.

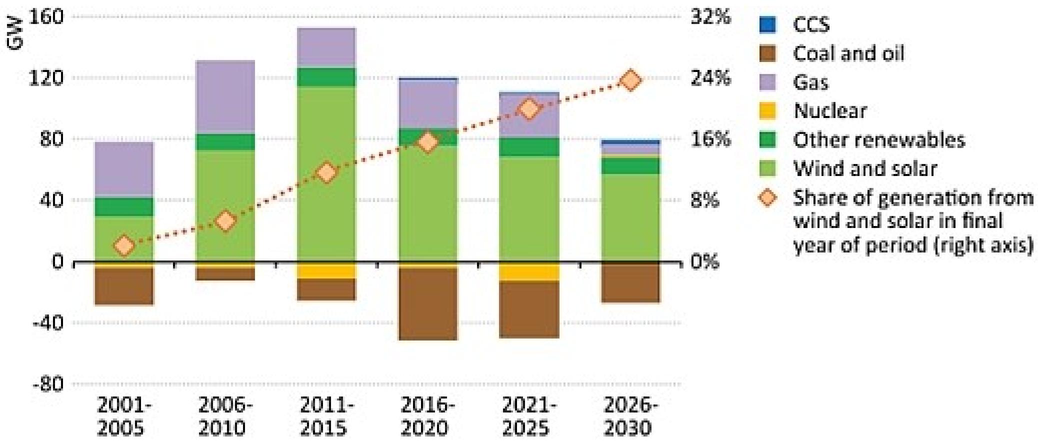


Figure 1-1: EU net capacity additions by type and share of electricity from variable renewables in the INDC scenario[1] (OECD, 2011)

1.3 Report structure

An overview of today's and expected future challenges for offshore gas and wind is provided in chapter 2. After, number of options for system integration is evaluated in chapter 3. Finally, chapter 4 states a number of conclusions and recommendations and also elaborates on possible development strategies, illustrating strategic choices and dilemmas, and issues such as critical timelines and knowledge gaps.

[1] For the EU the INDC is based on the EU's 2030 framework for energy and climate policies, stating a 27% renewables share and 40% CO_2 emission reduction compared to 1990 levels.

2 North Sea Energy System Description and Developments

2.1 Oil and gas platforms and infrastructure

2.1.1 Value chain and business model

The offshore oil and gas sector consists of a diverse landscape of actors which have their specific function and timing in the development of fossil resources at sea. The phases of offshore gas can be categorized by use of the value chain for offshore gas, as showed in Figure 2-1. An offshore gas company is present in all three phases, but is not necessary the executing party. Primarily they work with a broad range of specialized subcontractors, or service companies. For the purpose of strategic system integration focused is on specific elements of these three phases. The majority of the downstream activities are onshore and therefor this paper will not explicitly discuss this part of the value chain.

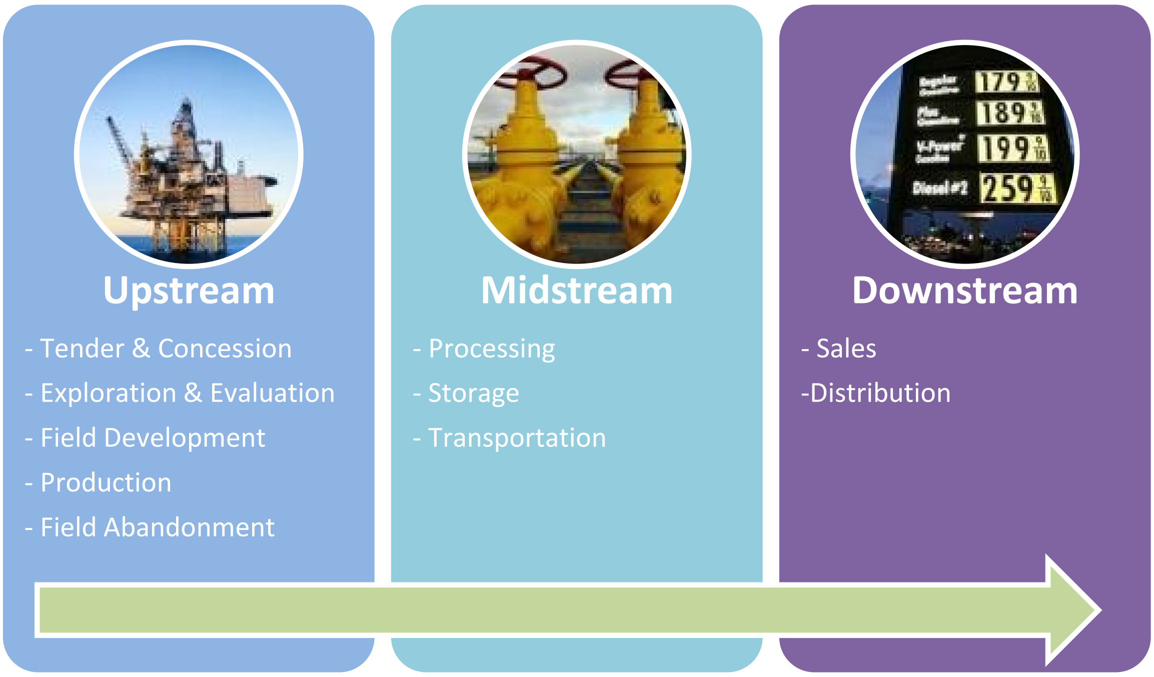
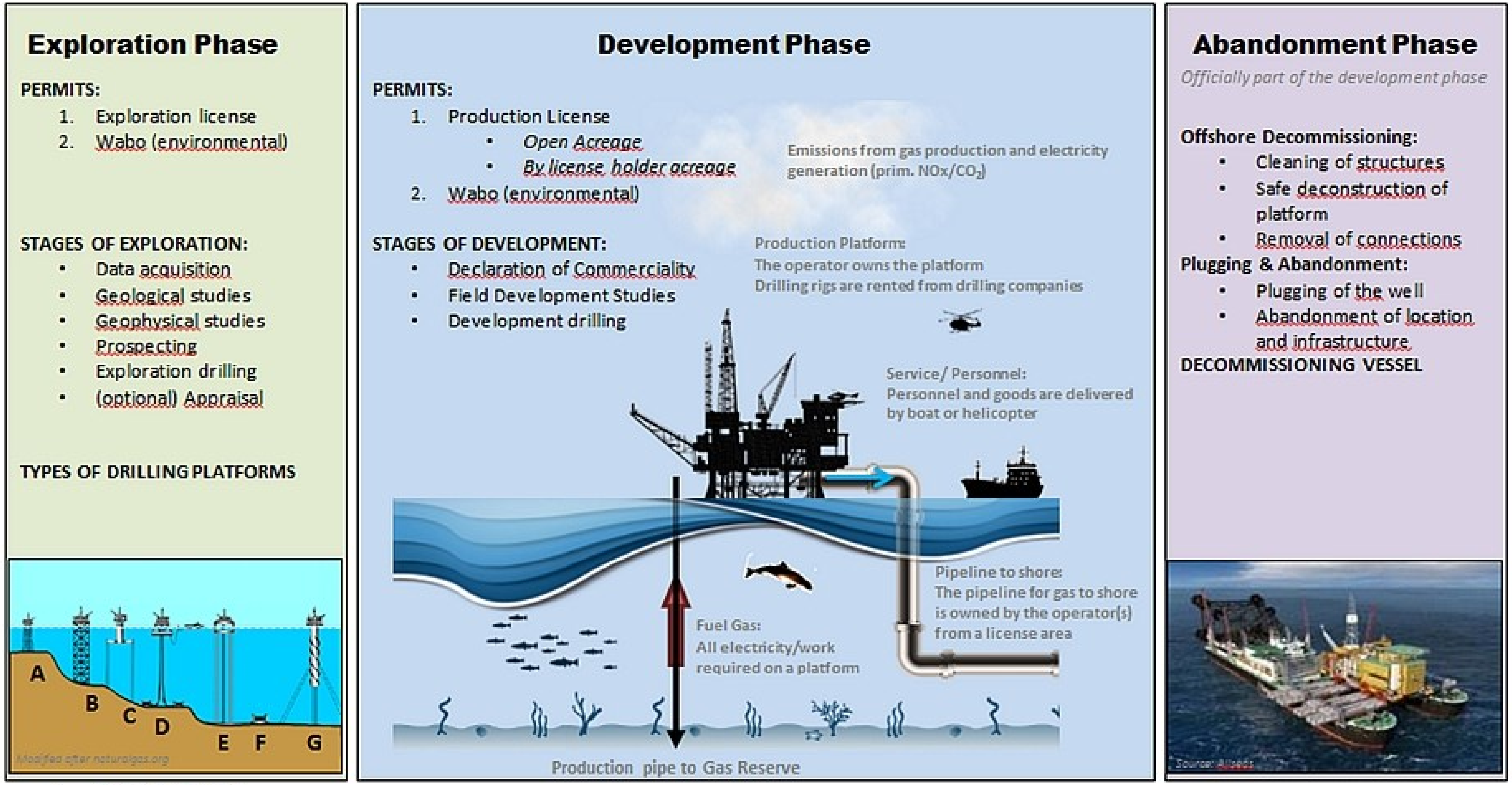


Figure 2-1: Value chain of offshore gas (and oil)

<u>Phase 1) Upstream</u>

To gain insight in the offshore business model for gas, at first a single operator within a license area with one owner is considered, after which the possible complexities will be discussed. The lifetime of an offshore gas project is displayed schematically in Figure 2-2. Each offshore gas project goes through from exploration to development to abandonment.



A. Fixed Platform (till 1.500 ft)
B. Compliant Tower (1.500 – 3.000 ft)
C. Sea Star (500 – 3.500 ft)
D. Floating Production System (1.500 – 6.000 ft)
E. Tension Leg Platform (1.500 – 7.000 ft)
F. Sub Sea System (to 7.000 ft)
G. SPAR Platform (2.000 – 10.000 ft)

Figure 2-2: Schematic overview of the lifetime of an offshore gas project

It all begins with the assessment of the potential of a certain area. When an gas company foresees potential in a certain area, it can opt for an exploration license at the Ministry of Economic Affairs. This can be either from an open acreage or from an already reserved area. How and at which requirements is described in the Mining Act. Having an exploration license gives a gas company the opportunity to do operate and invest without the risk of being outdone by another party and risking a lost investment. The licensing is both required for the exploration phase as for the production phase, see Figure 2-2.

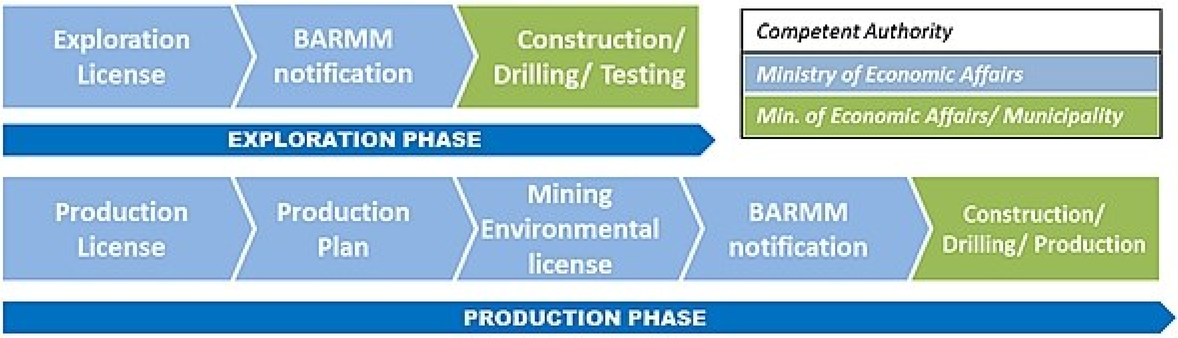


Figure 2-2: License to Operate (modified after (EBN, 2015))

In the exploration phase a gas company will acquire data, which includes existing data from nearby of previous activities or new data when required. Based on this acquisition phase it will start geological studies to gain insight in the subsurface and in the likelihood of finding a gas play: a set of characteristics which combined might host a natural gas entrapment. If required addition geophysical studies (e.g. seismic surveys) can be done to pinpoint the prolific areas within the licensed area. Based on the acquired data and insights it will do prospecting to get an estimate of the GIIP (short for: Gas Initially In Place) and whether or not shows sufficient potential to drill an exploration well. An exploration well will target the top of the natural gas entrapment and will serve as a proof of concept and the gathering of detailed knowledge. If necessary a gas company can opt for a second well in case the exploration well shows disappointing results or insufficient insight in the reservoir characteristics. This well is called an appraisal well.

The exploration phase is a – by license – protected investment done by the operator (or gas company, which is by default the same party). It is partly unaccounted for investments in house for coordination, collecting and reviewing of the different stages, but for a large part dominated by subcontracted activities, of which:

- Geologists ((geo-technical) consultants or researchers): assistance with data acquisition, geological studies, interpretation or re-evaluation of seismic, on site evaluation, etc.
- Geo-technical Engineers: Geophysical data acquisition, processing of raw data, prospecting
- Drilling Company: organization and execution of drilling activities for exploration and/or appraisal well.
- Service companies: testing equipment, transport of materials, etc.

There are several parties and actors involved in the upstream part of the value chain. The operator (by law the owner of the license) has the leading role. But the operator requires specialized techniques and services which are provided by a subcontractor or service company. During the exploration phase seismic surveys and processing and interpretation from a seismic service provider are possibly required. In case of drilling the exploration well, a drilling company will provide the platform and execute the operations. Also these actors require suppliers.

If the exploration phase gave sufficient trust in the potential for gas production, the operator will opt for a production license. In line with the exploration license, the procedure and requirement is described in chapter 2 of the mining act. In addition the operator also has to meet the environmental requirements which are described in the so called Wabo (Dutch: Wet Algemene Bepalingen Omgevingsrecht | English: Legislation General Provision Environment). The first step on the development phase is the formulation of the 'Declaration of Commerciality' (short: DoC). Following the DoC, the operator will conduct field development studies to define the optimal development scenarios, well placements, production strategies, etc. This will give the operator insight in scale and location of the surface facilities, which is direct input for drilling the development wells. This can be more than one from one location or multiple locations within one license area.

As soon as we move from the exploration phase to the production phase, a production platform needs to be installed. Drilling companies usually can provide production platforms, which can be installed by an actor in the maritime sector (e.g. shipyards). Depending on the specific offshore conditions (water depth, sea roughness, etc.) a design for a platform is chosen. The inter-platform pipelines are required to be placed by the license holder. When the platform and pipelines are in place, the production well can be drilled by a drilling company. For the production phase a large pool of services is required for operations, maintenance, transport and logistics for supplies and personnel and stand-by services for urgent situations (e.g. helicopter pilots). The final phase is the plugging of the well(s) and abandonment of the platform and infrastructure. For plugging of the well(s) a drilling company can provide the service. Specific companies from the maritime sector can provide the decommissioning. Over the whole span of operations, the Ministry of Economic Affairs is the competent authority. For compliance with the Dutch law on mining 'Staatstoezicht op de Mijnen' (short: SodM). The SodM is the ministerial department responsible to ensure that all oil companies operate according to the legal provisions. This includes the exploration, production, transportation and storage of natural resources.

Phase 2) Midstream

Midstream gas consists of processing, storage and transportation. Since processing is mainly done onshore, it is considered not relevant for the current state of play, yet it can be an opportunity in the coupling of infrastructure. The produced gas is for a small part used as fuel gas for the platform facilities: e.g. compression of gas or electricity generation. The majority of the gas is compressed and transported onshore via pipelines. To store strategic or excess amounts of gas, storage in the subsurface is possible. Currently there are only gas storages onshore in depleted gas fields (e.g. Bergermeer) or in Salt Caverns. Figure 2-3 shows the offshore infrastructure in use, in future use and licensed.

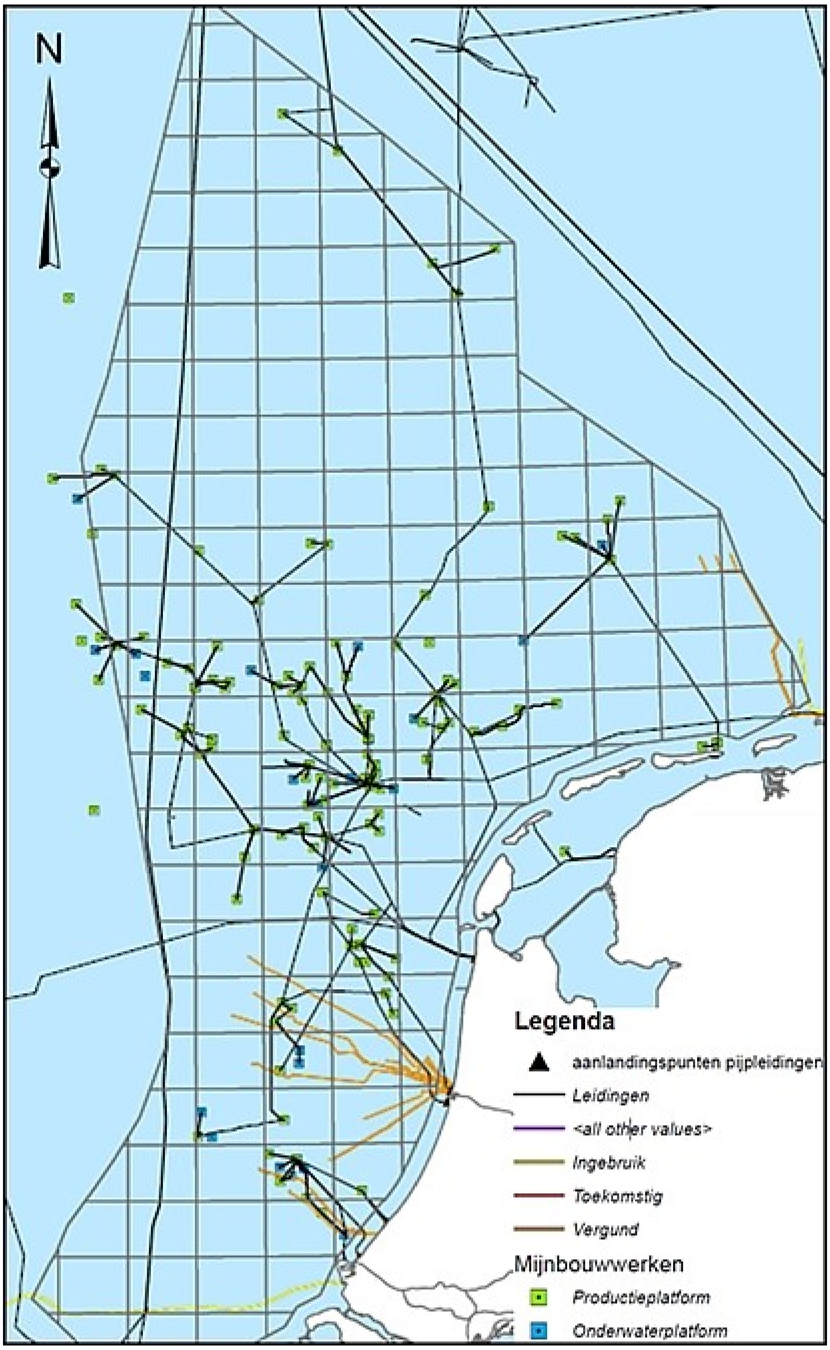


Figure 2-3: Offshore Infrastructure - Pipe Lines (in use, planned or licensed)

Phase 3) Downstream

The majority of the downstream activities are onshore. Therefore, this paper will not explicitly discuss this part of the value chain.

At the end of a life time of a gas field, all installations and structures need to be decommissioned and the field needs to be abandoned. This means that all elements need to be cleaned, deconstructed and taken away: the offshore installation, the interfiled pipelines and the well (production or exploration). The abandonment of installations and pipelines adds up to almost 90% of the total abandonment costs (EBN, 2015), as can be seen in Figure 2-4.

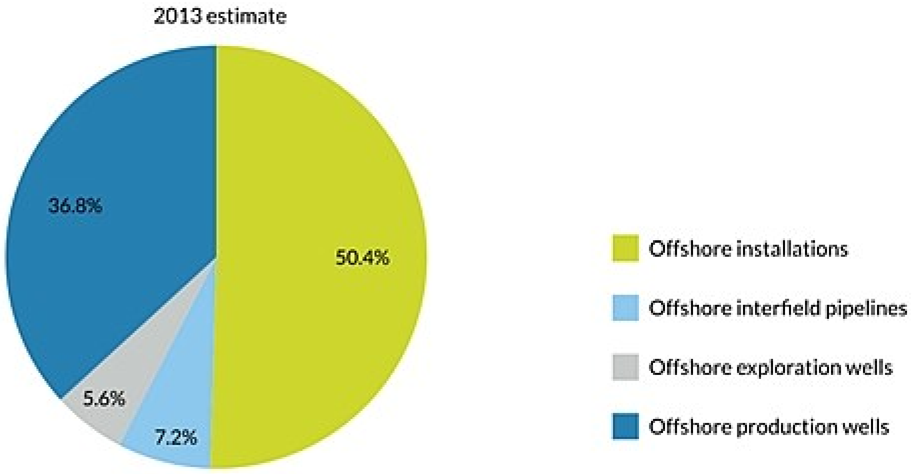
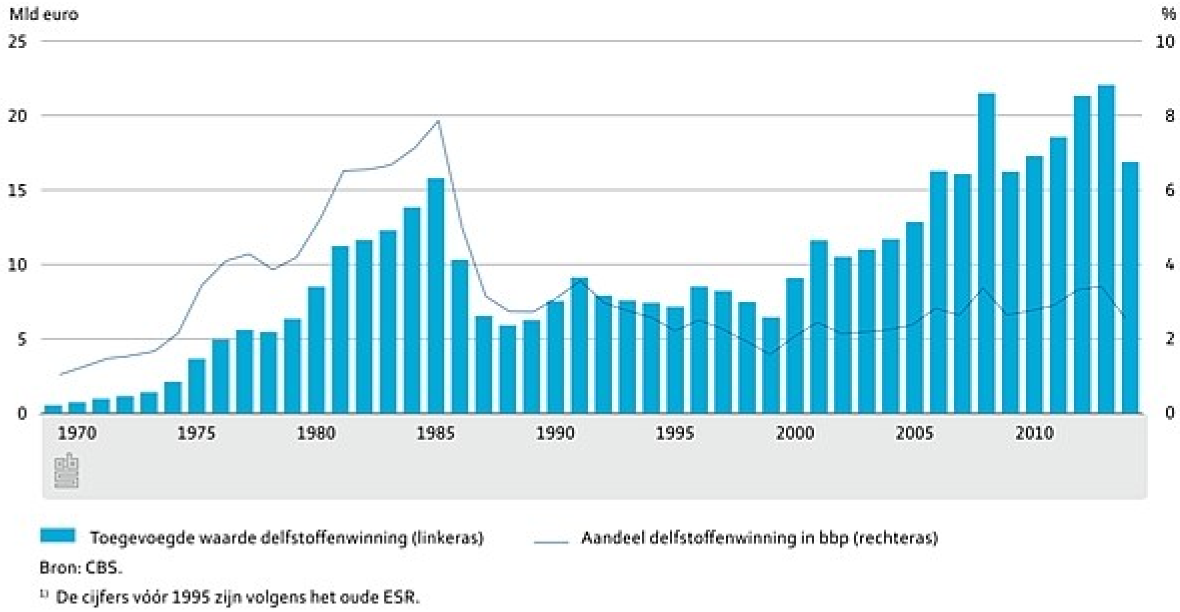


Figure 2-4: Estimated abandonment costs offshore installations (EBN, 2015)

2.1.2 Current state of play

Since the first production of gas with a satellite platform in the Dutch part of the North Sea in 1974, the construction of offshore platforms grew in number and size. There were about 140 structures at the Dutch part of the North Sea in 2015.

There are currently about 230 gas fields in production, planned for production and ceased production (not yet abandoned) in the Dutch part of the North Sea (Dutch Ministry of Economic Affairs, 2016). These fields are divided among more than 190 offshore licenses, of which almost 120 production licenses. For the situation at January 1st 2016, Figure 2-6 displays the production for all Dutch gas fields, both onshore ('territoir') and offshore ('continentaal plat') (Dutch Ministry of Economic Affairs, 2016). In 2014, in total more than 15 billion Nm^3 of gas was produced from the Dutch part of the North Sea. For reference, the gas production from land used to be little more than 50 billion Nm^3, which is for a large part coming from the Groningen gas field. Over 2014, the direct and indirect benefits from gas production account for about 16.9 bn Euro, or 2.6% of the gross domestic product (bbp), and the income from mineral reserves, including dividends, taxes and concession rights, account for 10.3 bn Euro, or 6.4% of the total state income (CBS, 2016), as stated in Figure 2-5.



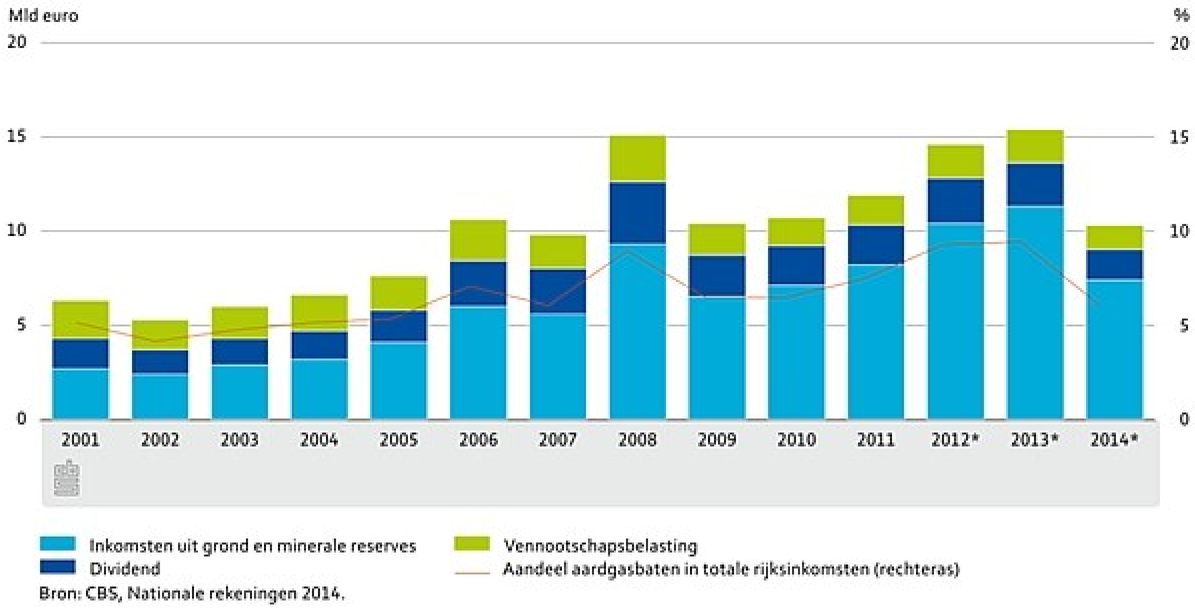


Figure 2-5: (upper) Contribution of minerals extraction to Dutch economy, (lower) Contribution of minerals reserves to the Dutch economy, with in red gas benefit (CBS, 2016)

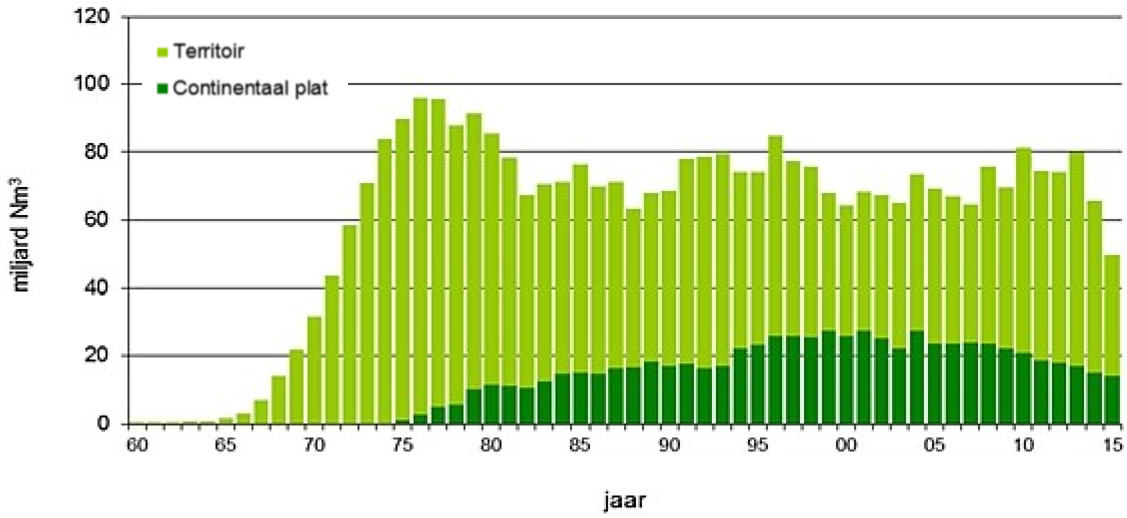


Figure 2-6: Production of Dutch gas fields (Dutch Ministry of Economic Affairs, 2016)

2.1.3 Challenges and developments in the offshore Oil and Gas sector

In the transition towards a low-carbon power generation sector in the Netherlands, it is expected that gas will play an important role in the transition towards a low-carbon energy system based on renewable generation. Also most scenarios foresee an important role for CCS, looking at the relative costs and potential for abatement of CO_2 emissions from power generation and industry, as shown in section 2.3.1 of (EBN, 2014) and in (World Energy Council, 2013), while (Natuur & Milieu, 2016) foresees an accelerated decline of all fossil production through energy efficiency, electrification in the heat in mobility sector, growth of renewables and cross-border trade.

Meanwhile the Dutch offshore gas sector faces a number of serious challenges, as shown in Figure 2-7. These challenges will be discussed in the part below.

Figure 2-7: Challenges for offshore oil and gas sector

Challenge 1/6) Social license to operate

The social license to operate for the O&G industry is currently under debate by public and politicians. The sector faces the challenge to regain and strengthen the trust that the sector can operate safely and with care for the environment. Important here is that the sector strengthens trust in being a reliable partner in decision making processes regarding the energy transition together with public stakeholders.

Figure 2-8: The beach of Ameland (Ameland Tegen Gas, 2016)

Challenge 2/6) Economics

The Dutch offshore O&G sector faces some economic challenges:

- Prices for gas have been highly fluctuating over the last decade (see Figure 2-9) between 10 and 30 €/MWh (Heeswijk van, 2012). The fluctuations and certainly the low market prices have a profound impact on the business case, the production strategy and the willingness to invest for offshore operators. At the moment the gas price is very low (TTF spot market shows around 14 euro/MWh, see Figure 2-10 and approaches the lowest levels found in the period 2006 -2010 (The ICE, 2016). At this level the margins of operators are under high pressure.
- Reservoir depletion results in lower production and higher operational costs (e.g. for compression).
- More difficult recoverable gas reserves (small fields, tight gas or tail-end production) in increasingly challenging conditions (deeper waters, more stringent requirements, etc.) results in higher costs
- The availability of capital to finance investments is sub-optimal
- Uncertainties on the fiscal regime related to O&G production influence the economics
- The newly discovered gas field are further away from the coast and therefore the transport costs increase

These factors together have a strong negative impact on the economics of producing gas and oil in the North Sea offshore sector.

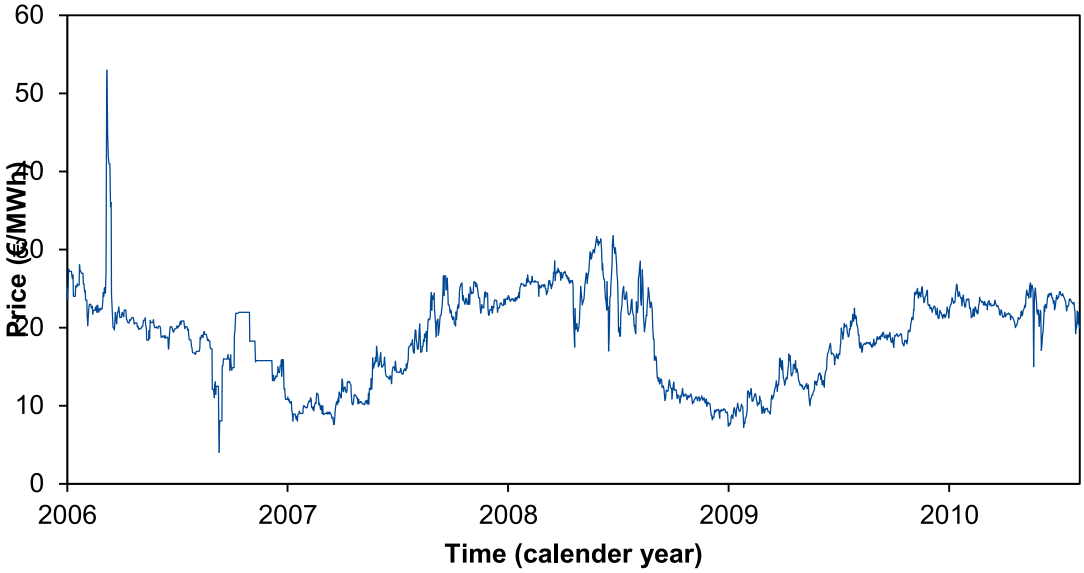


Figure 2-9: Gas prices 2006-2011 (Heeswijk van, 2012)

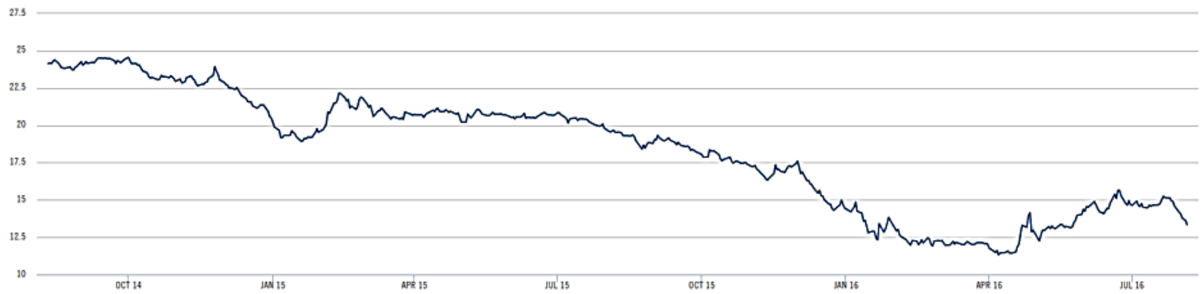


Figure 2-10: Dutch Gas TTF spot prices in €/MWh over the last two years (The ICE, 2016)

Challenge 3/6) Declining and more difficult production activities

Exploration for O&G offshore still results in finding and developing new resources. However, the new found resources are not enough to compensate for the declining production. This trend could result in potential withdrawal of operators from the Dutch North Sea, which reduces new investments in offshore infrastructure and innovative production techniques. This infrastructure is in turn a very important prerequisite for facilitating new exploration and production initiatives and optimizing the use of natural resources. The expected developments in gas production in volume are decreasing (Dutch Ministry of Economic Affairs, 2016), as can be seen in Figure 2-11. The coming years a large amount of North Sea fields are at the end of their life time (Atlantic Marine and Offshore, 2016), as can be seen in Table 2-1. Furthermore, the sector moves more and more towards increasingly difficult recoverable gas reserves (small fields, tight gas or tail-end production) in increasingly challenging conditions (deeper waters, more stringent requirements, etc.).

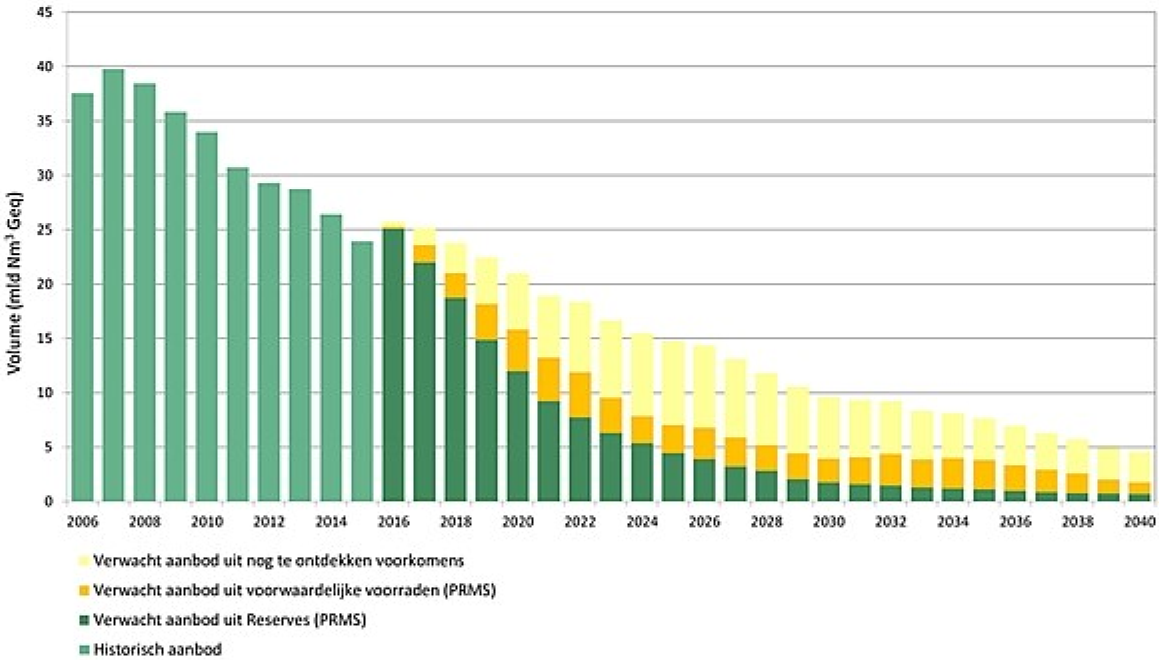


Figure 2-11: Expected developments in gas production

Table 2-1: Overview of North Sea fields aby status and estimated end of life

End of field life	Netherlands	Norway	United Kingdom	North Sea
<2000	0	6	0	6
2000 - 2005	1	5	15	21
2005 - 2010	9	1	47	57
2010 - 2015	22	14	84	120
2015 - 2020	68	12	124	204
2020 - 2025	47	9	55	111
2025 - 2030	35	18	45	98
2030- 2035	1	6	12	19
after 2035	0	10	5	15
No data	2	0	4	6
Total	**185**	**81**	**391**	**657**

The decline in production activities results in a prospective phase-out of current infrastructure. In the North Sea dozens of platforms are planned to be decommissioned on the near term (Altantic Marine and Offshore, 2016). This trend will continue, but has different impacts on different areas in the North Sea. A possible phase-out scenario is shown in Figure 2-12. It shows that in the short term (2016 – 2020) the red areas will be ceasing production and infrastructure is to be decommissioned. These areas are in front of the west coast (North-Holland, South-Holland) and northwest of the Wadden islands. In the longer term (2026 – 2035) the light green highlighted area north of Vlieland will be ending production followed by a large cluster in the east of the Dutch economic zone (2036-2050) highlighted in darker green.

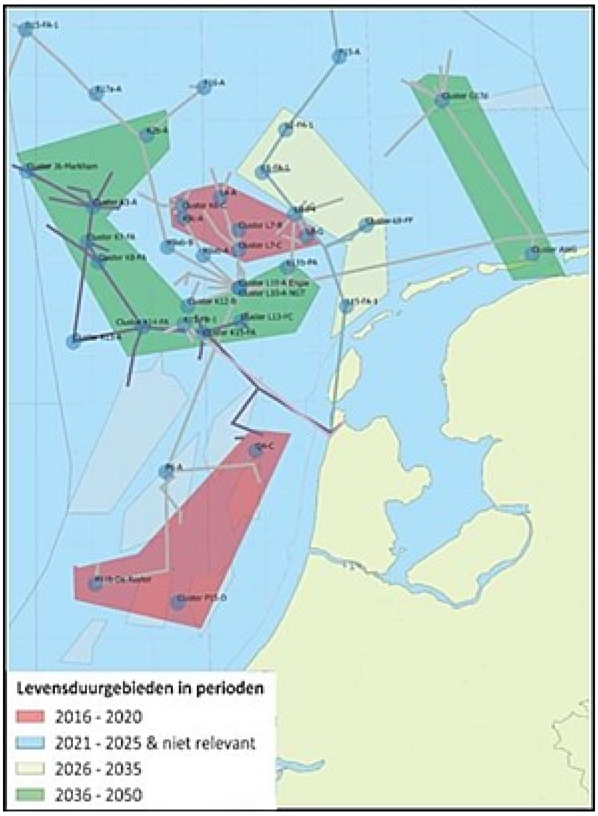


Figure 2-12: Possible phase out scenario of offshore O&G infrastructure op cit. (TNO, Shell, Siemens, EBN, 2016)

Challenge 4/6) Sustainability (environmental performance)

The offshore O&G sector faces strengthened environmental regulation to improve environmental performance related to emissions to air and water, and reduce the use of energy and resources. Given the existing challenge that O&G will be more difficult to produce in the future this poses challenges and urges the sector to grasp opportunities such as 'green' solutions with acceptable cost. In all operations and decisions the three p's should be considered (people, planet, profit).

The most important challenge for the offshore O&G sector is to reduce Greenhouse Gasses (GHG) emissions. With the Emission requirements for medium sized combustion plants (BEMS) setting strict NOx emission limits, the sector faces investments costs for retrofitting power supply on offshore platforms before 1 January 2019. ECN has calculated the retrofit and new investments at 25 million euro and annual costs of 8.5 million euro as can be seen in Table 2-2 (Kroon, 2012).

Table 2-2: Effecten van de afschaffing van NOx- emissiehandel

	Voldoet in 2010 nog niet aan eis	NO_x-emissie reductie [ton/jr]	Totaal investering [mln euro]	Totale kosten per jaar [mln euro/jr]	Kosten in euro/kg NO_x-reductie
Gasketel	4	2	0	0,0	1,5
Gasmotor	17	273	4	1,2	4,4
Dieselmotor[19]	19	484	3	1,0	2,0
Gasturbine	32	857	17	5,9	6,9
Gasturbine onshore	3	78	1	0,5	6,3
Totaal	75	1694	25	8,5	5,0

Reducing the amount of CO_2 emissions during O&G production is an important challenge for the sector. Climate change is an important indicator for measuring the environmental performance of Dutch O&G production and is therefore an important factor to include when comparing sourcing options for oil and gas consumers, now and in the future (IEA, 2012). The CO_2 performance of Dutch O&G operations is already better than other sourcing options for the Netherlands (i.e. Russian import, LNG import) but can be improved further by reducing emissions from platform operations. An estimate for the current offshore O&G CO_2 emissions is estimated at approximately 1.5 Mton of CO_2 (TNO, Shell, Siemens, EBN, 2016), as can be seen in Figure 2-4. This is likely to decline to below 0.5 Mton of CO_2, moving towards 2050, because of declining production operations offshore. It should be noted that CO_2 emissions per unit are expected to increase significantly when production levels decline because of field depletion (Statistics Norway Research department, 2015). Reducing methane emission is another challenge (US Environmental protection Agency, 2015).

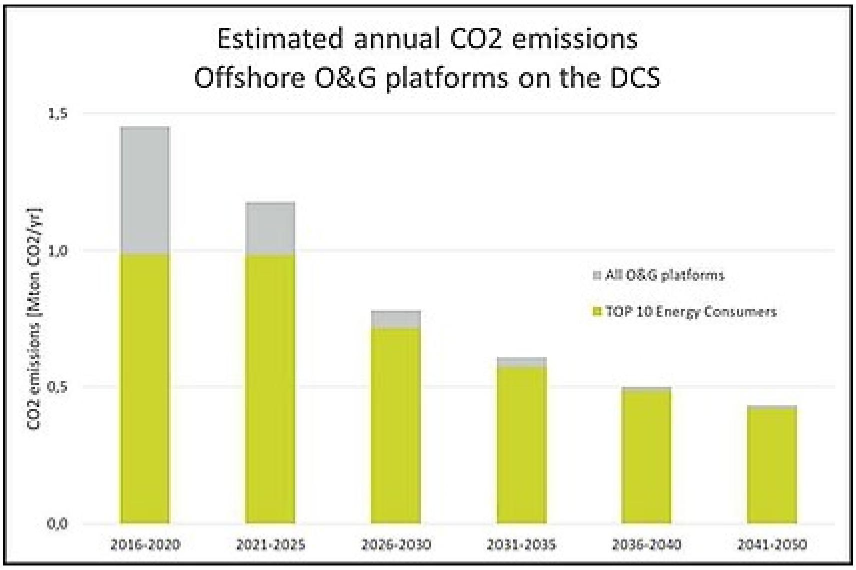


Figure 2-13: Estimated annual CO_2 emissions (EBN 2016 op cit (TNO, Shell, Siemens, EBN, 2016))

Both NOx as CO_2 emissions (and other environmental effects) can be reduced significantly by electrification of offshore energy supply on the platforms. This energy could be supplied by offshore energy solutions (wind and others) or from supply options on land. However, electrification comes with its own challenges:

- The CAPEX for the electrification of gas platforms is high and the CAPEX and installation costs for the cable to make this possible can also be expensive, depending on the distance and power demand.
- The BEMS regulation sets strict NOx emission limits per platform. Electrification of a couple of platforms therefore does not help the O&G sector as a whole.
- The supply of electricity through wind energy is intermittent. However, the production of oil and gas cannot be intermittent. Usually the wind farms are connected to the onshore grid, which provides power to the gas platform when the wind farm production is insufficient.
- The available room for conversion on existing platforms is limited. Furthermore, the spatial requirements of the oil and gas infrastructure are expanded by a 500-metre zone around each platform within which no other activities are permitted.

- Each platform is unique and asks for a different solution for electrification. However, it gives opportunities for an integrated plan on optimization.
- A challenge for the electrification of platforms could be the public opinion. It can be seen as a way of greenwashing the activities of the O&G sector. People would see a SDE subsidy for electrification of platforms as not justified. On the other hand, direct consumption offshore will reduce the amount of SDE subsidy required for offshore wind.

This is discussed in more detail in chapter 3 in this report.

Challenge 5/6) Human capital
Human capital is one of the most, if not the most, important assets of the industry. Education and training of new personnel is high on the agenda for the O&G sector as are providing clear perspective for new generations joining the O&G sector. Human capital can make the difference in developing and applying new products and services. The competitiveness of exploration and operation in the North Sea will strongly depend on how stakeholders renew, build and leverage their human capital.

Challenge 6/6) Decommissioning strategies
The existing offshore infrastructure needs to be removed when production has ceased. This is costly and can be complex from a technical and environmental perspective. Plans and cost reserves (ABEX) are part of the development plans from the operator, but have appeared to be more challenging and cost intensive than previously thought and increase the stress on the commercial balance of offshore gas operations.

Existing infrastructure (platforms, cables, pipelines) and (near) empty reservoirs can also suit a new purpose, for example for production of hydrogen or biofuels powered by offshore wind, CO_2 storage, energy storage or as artificial sanctuary for maritime ecosystems. However, due to the low market prices operators need to bring forward the decommissioning, which leaves little time to consider such options. Therefore it is important to obtain in the optionality for system integration of existing O&G infrastructure with offshore electricity generation (EBN, 2016). This will be discussed in the next section of this paper. Figure 2-14 shows an impression of an offshore masterplan for the North Sea.

Figure 2-14: Artist impression offshore masterplan (OMA for Natuur en Milieu, 2009)

Recently, EBN has presented a masterplan on decommissioning and re-use, which elaborates on how the Dutch O&G infrastructure can be decommissioned or re-used in a safe, efficient and effective way (EBN, Masterplan Decommissioning and Re-use , 2016)

2.1.4 Conclusion

In a society where the urgency increases to make the transition to a clean and sustainable energy supply, there can be an important role for natural gas to facilitate, support and accelerate this transition. Considering to the downsides of onshore gas and the associated opposition, it is worthwhile to look at the opportunities offshore.

Offshore gas is developed since 1974, where the first developments were the easiest: relatively shallow, permeable reservoirs and moderate offshore conditions. Currently the sector moves more and more towards increasingly difficult recoverable gas reserves (small fields, tight gas or tail-end production) in increasingly challenging conditions (deeper waters, more stringent requirements, etc.). Whilst the cost per cubic meter of gas produced increases, the gas price is going down, see Figure 2-10. This results in a narrowing of the commercial space at both the cost and benefit side. In addition, the gas sector is also facing changing regulations with the BEMS as the most dominant directive. This requires a drastic adaptation of the energy system on existing platforms or new ways of electricity supply to platforms. Next to NOx emissions, also the emissions of CO_2 and methane emissions are a challenge for the sector, although emissions from domestically produced gas are lower than alternatives. Currently emissions of CO_2 from production and transport of domestically produced gas are nine times less than the CO_2 emissions from imported gas from e.g. Russia (Royal Haskoning DHV, 2013). Looking at the CO_2 emissions for electricity production, these are about a factor two lower compared to coal fired power plants (DOE - NETL, 2015)

Within the ambition to create an as clean as possible transition to a fully sustainable energy system, reduction and limitation of CO_2 emissions play an important role, if not commercially for the operator, then for the society (as represented by the government) in tackling the climate goals as agreed in the Climate Act 2016. Next to the role of gas as an transition fuel, another societal aspect of ongoing gas development in The Netherlands are the direct and indirect benefits from gas production, which account for about 16.9 bn Euro, or 2.6% of the gross domestic product (bbp), and from mineral reserves, including dividends, taxes and concession rights, which account for 10.3 bn Euro, or 6.4% of the total state income (CBS, 2016).

Gas platforms and gas infrastructure which reach the end of their lifetime are planned for decommissioning and abandonment. Plans and cost reserves (ABEX) are part of the development plans from the operator, but have appeared to be more challenging and cost intensive than previously thought and increase the stress on the commercial balance of offshore gas operations. The decreasing use of the gas infrastructure and pending decommissioning may pose a threat to future gas explorations: The removal of infrastructure can cause future gas discoveries or small fields to fall out of the commercial window, as they have to account for longer intra-platform pipelines.

Effectuated legislations, decommissioning of structures and infrastructure and potential collaborations together define a window of opportunity for offshore natural gas. A window which can only be open for a limited period of time, since alternative solutions for urgent challenges (e.g. NOx reduction on platforms) may cause a lock-in for other integrated solutions which might benefit the energy transition on a longer term.

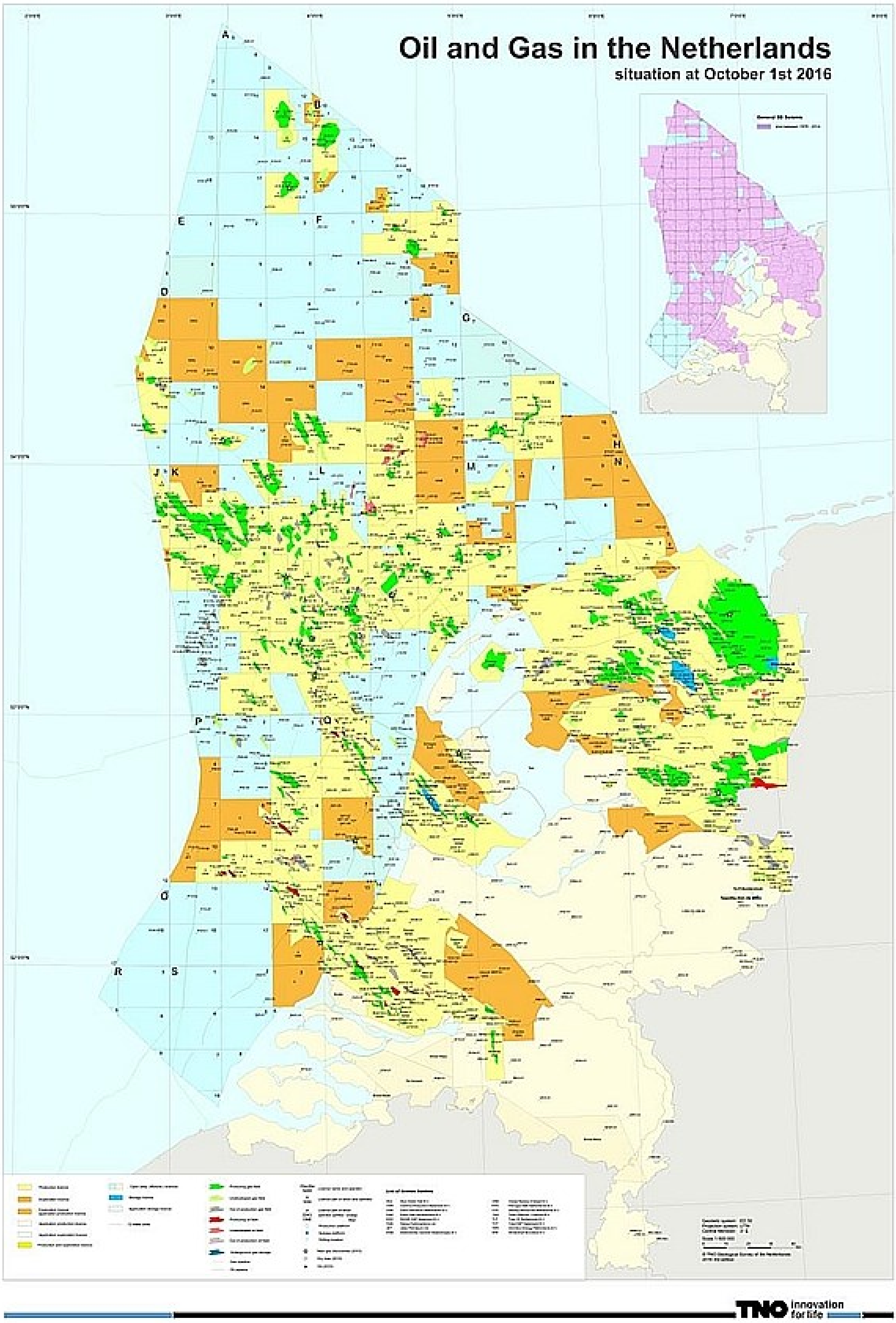


Figure 2-15: Oil & Gas in the Netherlands - situation at January 1st 2016

2.2 Offshore wind farms and infrastructure

2.2.1 The role of offshore wind energy

Reduction of greenhouse gas emissions and the desire to become less dependent from foreign energy suppliers are the main drivers for the transition to a sustainable energy. The share of renewables in the energy mix is still small, but solar PV and wind energy are expanding rapidly. In the last decade the first large-scale offshore wind farms have been put in operation, with currently 10GW of offshore wind in operation in Europe, see Figure 2-16. This growth is expected to continue, with an estimated 45GW of offshore wind capacity predicted in the North Sea for 2030 (EWEA, 2015).

Conditions for offshore wind energy in the North Sea are excellent: shallow waters, significant wind resource, adequate harbour facilities and robust supporting industry. At the moment, the Netherlands occupy the fourth place in the European offshore wind ranking with almost 1GW, which is a relatively small amount compared to United Kingdom, Denmark and Germany. In the coming years another 3.5GW of offshore wind capacity will be installed, as well as other renewable energy generation and energy savings measures under the 'Energieakkoord' framework in order to achieve the required 16% renewable electricity share in 2023 (SER, 2016).

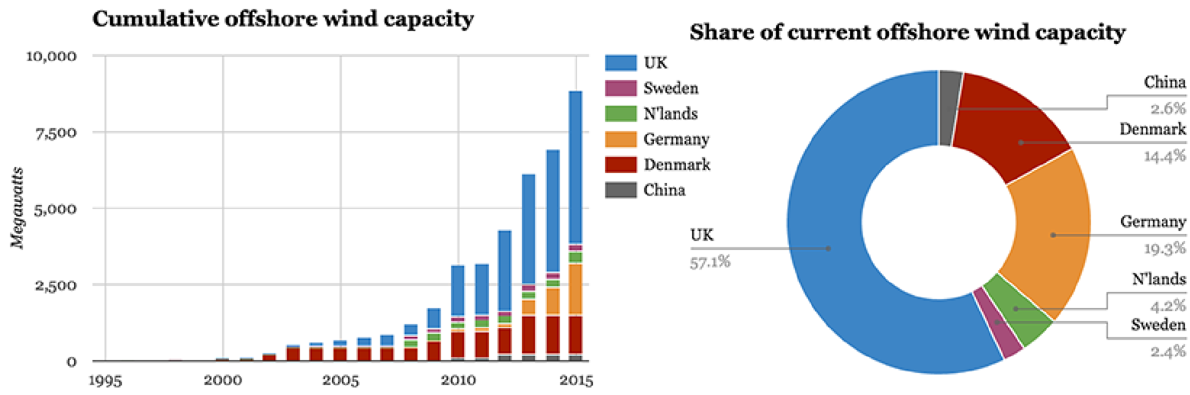


Figure 2-16: Cumulative offshore wind capacity between 1995 and 2015 (left) and share of the current 8.9GW total (right) (carbonbrief.org, 2016)

2.2.2 Business Model

Offshore wind farm development is driven by national government planning with respect to the selection of development areas and the issuing and managing tenders for specific locations and with respect to the support schemes and regulations. For the North Sea countries these plans and regulations are based on long-term CO_2 reduction targets and other EU regulations, e.g. on spatial planning and energy markets.

In general we can distinguish between the following phases: Consenting, Development, Operation, with possible repowering and decommissioning, as illustrated in Figure 2-17.

Main challenge for offshore wind is the need for cost reduction, which is addressed in section 2.2.6. Specific challenges and opportunities for each development phase have been briefly described in the following paragraphs.

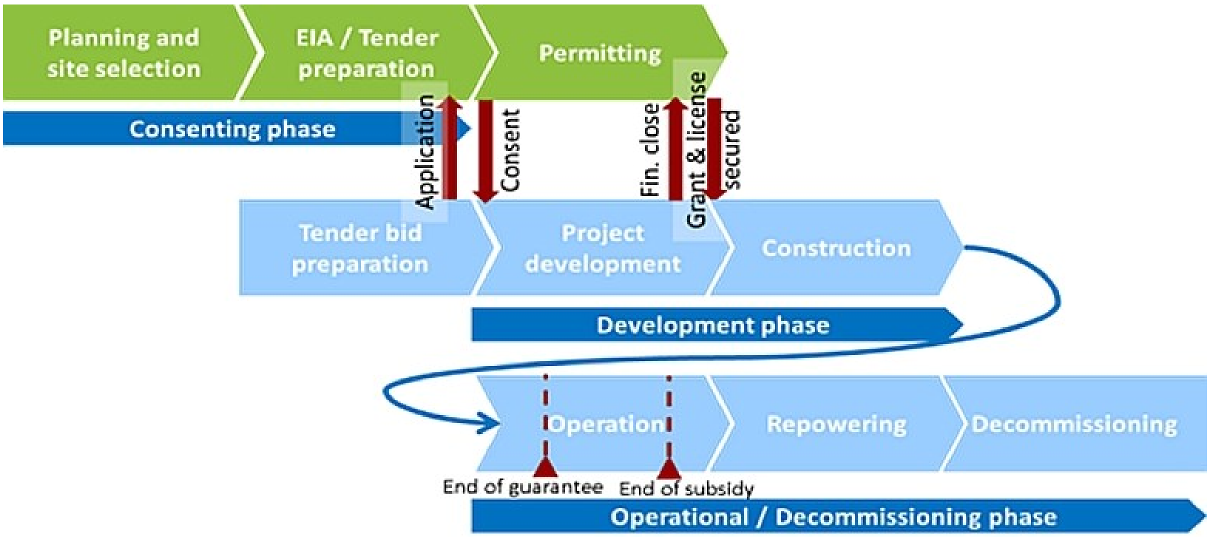


Figure 2-17: Illustration of offshore wind development process in the Netherlands

1. *Planning and consenting phase*

Usually the planning and selection of development sites is done by the national government, who also sets the permitting requirements and the subsidy level to facilitate economic development and operation. In the current tender procedures the Dutch government provides an information package with site and wind resource data. The Dutch government also takes care of the offshore grid connection, by having appointed TenneT TSO to develop and operate the offshore transmission system. Please note that the processes for planning, tendering and grid connection as well environmental regulations and support schemes differ per country.

A challenge is to organise this consenting phase to attract investors and at the same time minimize the required subsidy levels and limit (financial, HSE, etc.) risks and time delays.

Second challenge is to streamline the planning of different processes, e.g. the transmission grid planning and the planning for different offshore wind farms. For the current offshore wind tenders in the Netherlands this process has been streamlined well, which is said to be one of the factors for the progress that was made as well as for the low kWh price of the winning bid. On the contrary, recent offshore wind development in Germany has led to serious cost increase and time delays.

Third challenge is that, due to the rapid growth in number and size of offshore wind farms, the least expensive development locations and grid connection points will be occupied at some point. This does not mean that after 2023 no additional offshore wind can be connected, but roughly above 6GW of offshore wind additional measures are needed, like grid reinforcements or development of new feed-in at locations further in land. Also spatial planning of these development sites with many other users and exclusion zones becomes more challenging, which is also addressed in section 2.2.10. Insufficient development space and scattered plots due to exclusion zones and crossings of pipelines or cables lead to an increase of the levelized cost of energy due to higher investments and higher cost of capital of smaller projects.

Regional cooperation between countries in project planning, development and grid connection is considered for a more rapid and economic development, for instance through sharing costs of grid development. However this is not yet possible due to the differences in national regulations and because current national and EU regulations do not allow this. For example, it should be arranged that national support schemes apply to renewable generation irrespective of its location. Second example is a conflict that prevents feeding in offshore wind energy through interconnectors as a result of different EU regulations, as one prioritizes renewable electricity feed in but the other requires maximizing the available interconnector trading capacity. Options for regional collaboration or system integration should be considered already in the early consenting phase to have a chance of success. As adapting national and EU regulations to allow this is a time consuming process, this is seen as a short-term priority. This will also create a sound market perspective, which is a prerequisite for necessary industrial development.

2. *Development phase*

When after a successful accepted application the project developer receives the consent to develop the project, a project organisation is built up in parallel with the financing structure, the technical design and the permit preparation. All this has to be put in place to be able to seal the project in a so-called financial closure. When after financial closure the license to build and the grant have been secured, contracts with suppliers and subcontractors need to be detailed, with special attention for long lead items, such as the wind turbines, substructures, maritime cables, harbour facilities and installation vessels.

Challenges are the complexity of this development process and the uniqueness of almost every new project. As offshore wind projects are extremely capital-intensive and relatively new technology is applied, so financing conditions and risk insurances are very important. Moreover, in order to be eligible to receive subsidies this development phase is limited, currently to four years, so care should be taken to assure sufficient capacity in the supply chain.

Then the actual installation also imposes many challenges due to unknown environmental conditions, uncertain weather conditions and HSE risks. With the expected growth the availability of trained personnel for installation as well as for O&M is becoming a bottleneck, as shown in Figure 2-18: Skill gap for offshore wind (Windplatfom, 2016). Wind farm installation is also known to have negative effects on sea mammals, especially related to pile hammering, which needs mitigating measured or alternative foundation techniques (RoyalHaskoningDHV, 2014).

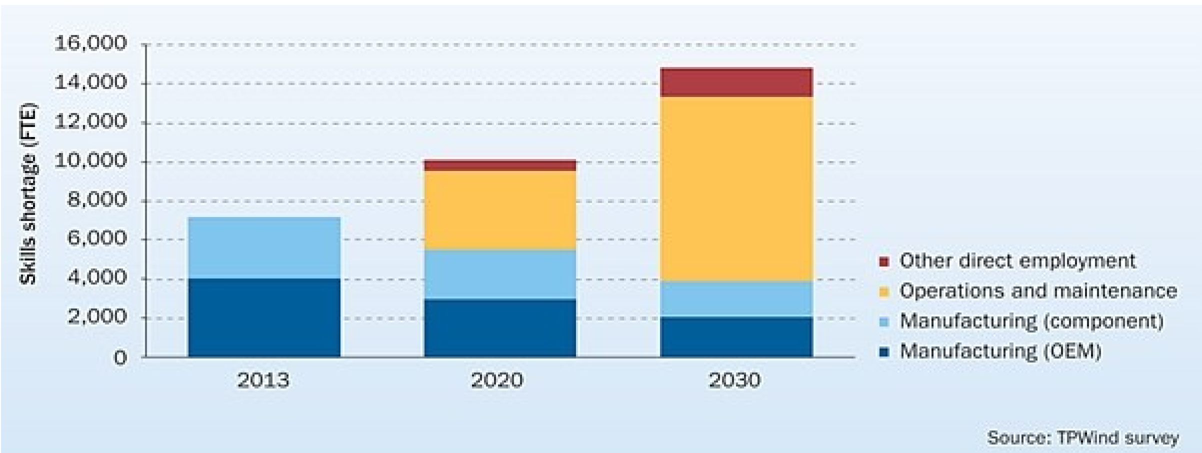


Figure 2-18: Skill gap for offshore wind (Windplatfom, 2016)

Like any other large generation, offshore wind farms need to comply with the grid connection requirements. As modern wind turbines with power-electronic converters can fulfil these requirements, this requirement is covered as standard practice in wind farm design. It is foreseen that in the future there will be additional demands on flexibility and grid support by offshore wind farms due to the increase in the share of renewables in the generation mix and the increased size of wind farm power in relation to the limited transport capacity of the grid at the feed in locations. These demands can lead to additional costs for offshore wind or may require new developments.

3. *Operation / decommissioning phase*

For large wind farms the commissioning process will be performed in phases, so that the wind farm production will increase stepwise until all wind turbines are fully operational. During the first period, usually 5 years, the wind turbines operate under guarantee of the supplier with respect to maintenance and a guaranteed minimum availability. This is followed by operation under a maintenance contract in which O&M costs. Although these O&M costs are already foreseen at the project start, the actual costs and conditions are not fully known by then and also the risk of failures is expected to increase in time because of component wear.

Then after the end of the subsidy period, which is 15 years with a possibility of a 1-year extension under the Dutch SDE+ scheme, the grey electricity price should cover the O&M costs and any remaining financial obligations. If so, operation can continue until the technical end-of-life is near and a steep increase of the O&M costs is expected. One option is to decide on repowering the wind farm and apply for a new subsidy, or to start decommissioning. Re-use of some components in the wind farm, such as substructures, may be considered and also the offshore transmission system design lifetime is 40 years.

Therefore the main challenge is to obtain insight in O&M costs, in order to set up a sound O&M strategy already during the project design phase. During operational phase the prediction of O&M costs over shorter periods is important in order to arrange O&M contracts with a suitable service level and to optimize O&M planning.

HSE issues linked to O&M are a main challenge, as well as in the installation and decommissioning phase. With a large fleet of wind farms located far offshore travel times become significant and working conditions, including the traveling and access, become more uncertain.

At the income side uncertainties exist in the long-term wind resource, including wake losses inside and in between wind farms, which are not yet fully understood. The full-load hour subsidy mechanism that is applied in the Netherlands reduces these risks to some extent. Then the large uncertainty and volatility in the electricity market price and the negative economic effects of the wind intermittency and limited forecast accuracy further reduce the revenues.

2.2.3 Regulatory framework for offshore wind energy in the Netherlands

The regulatory framework to facilitate offshore wind energy employment in the Netherlands is established in the Offshore Wind Energy Law (“Wet Windenergie op Zee”), of July 2015. The main points of this framework are the designation of wind farm zones and the definition of wind farm sites (“kavelbesluiten”) by the government, the site data (e.g. wind resource, geotechnical) provision to investors and developers by the government and the granting of offshore wind energy investments through the corresponding governmental subsidy scheme (SDE+). In April 2016 TenneT TSO was made responsible for the realization and operation of the offshore grid for the connection of wind farms and the approval procedure by the Dutch regulator ACM is ongoing.

The national support scheme SDE+ (“Stimulering Duurzame Energieproductie”) category “Wind op Zee” indicates a separate budget to compensate energy producers and make offshore wind investments more attractive. The maximum grant to which an applicant is entitled through this subsidy scheme is equal to the difference between the tender energy price bid, up to a maximum price, and the actual electricity price, with a floor price of 29euro/MWh. The maximum price decreases from 125euro/MWh for the current tender to 105euro/MWh for the final tender in 2019. The grant is further limited by a maximum number of kWh/year, so-called full-load hours, over a 15 year period. In some cases a one-year extension is allowed in case when the number of full-load hours could not be reached.

2.2.4 Existing and planned offshore wind farms in the Netherlands

At the moment, three near shore wind farms are in operation of which the first demonstration wind farm OWEZ (“Offshore Wind park Egmond aan Zee”) of 108MW, is located within the 12-miles zone while the wind parks “Princess Amalia” of 120MW and the “Luchterduinen” of 129MW, are located just outside the 12-mile zone. Gemini is the first far offshore wind farm, built in the twin locations Buitengaats and Zee-energie, located 85 km off the coast. At the moment, half of the 150 wind turbines of 4MW have been installed and the park is expected to be fully operational in 2017. Table 2-3 and Figure 2-18 provide an overview existing and planned offshore wind farms according to the roadmap of the Energieakkoord.

Table 2-3: Existing and planned offshore wind farms in the Netherlands

Offshore wind farm	Capacity [MW]	Distance to shore [km]	Number of WTs [-]	Operational status	Owner/Developer
OWEZ	108	10-18	36	2007	Noordzeewind (NUON, Shell)
Princess Amalia	120	23	60	2008	Eneco
Luchterduinen	129	23	43	2015	Eneco and Mitsubishi
Gemini	600	85	150	2017	Northland Power, Siemens, Van Oord, HVC
Borssele I & II	700*	28 – 45	Unknown	2019	DONG
Borssele III & IV	700*			2020	Shell, Van Oord, Enerco, Mitsubishi/DGE
South Holland I&II	700*	22 – 30	Unknown	2021	Tenders 2017-2018
South Holland III & IV	700*			2022	
North Holland	700*	28	Unknown	2023	Tender 2019
Total capacity	4457				

*700MW is the guaranteed transport capacity, while a wind farm capacity of 760MW is allowed (except for Borssele IV and Borssele V it is 740MW and 20MW respectively)

2.2.5 Future developments

Developments in offshore wind development after 2023 are not yet concrete, although a substantial further growth is foreseen in the medium term following from the 40% CO_2 reduction target and the 27% renewables share for 2027, as agreed by the European Commission. Long-term developments aim at a 100% sustainable energy supply and 80-95% CO_2 reduction in 2050. However, the Nationale Energieverkenning 2015 (ECN, 2015), which includes an investigation study on the Dutch energy policy, highlights the uncertainty with respect to offshore wind energy planning after 2023.

Besides the uncertainty for the offshore wind planning after 2023, the status of existing offshore wind farms is also uncertain after 15 years of operation when no subsidy is provided anymore. The decision to continue operation depends on the electricity market energy at the time, the O&M costs and the alternatives, such as repowering or early decommissioning. In case of repowering of the wind farm owner should take into account that the offshore transmission system of TenneT is designed to operate for 40 years.

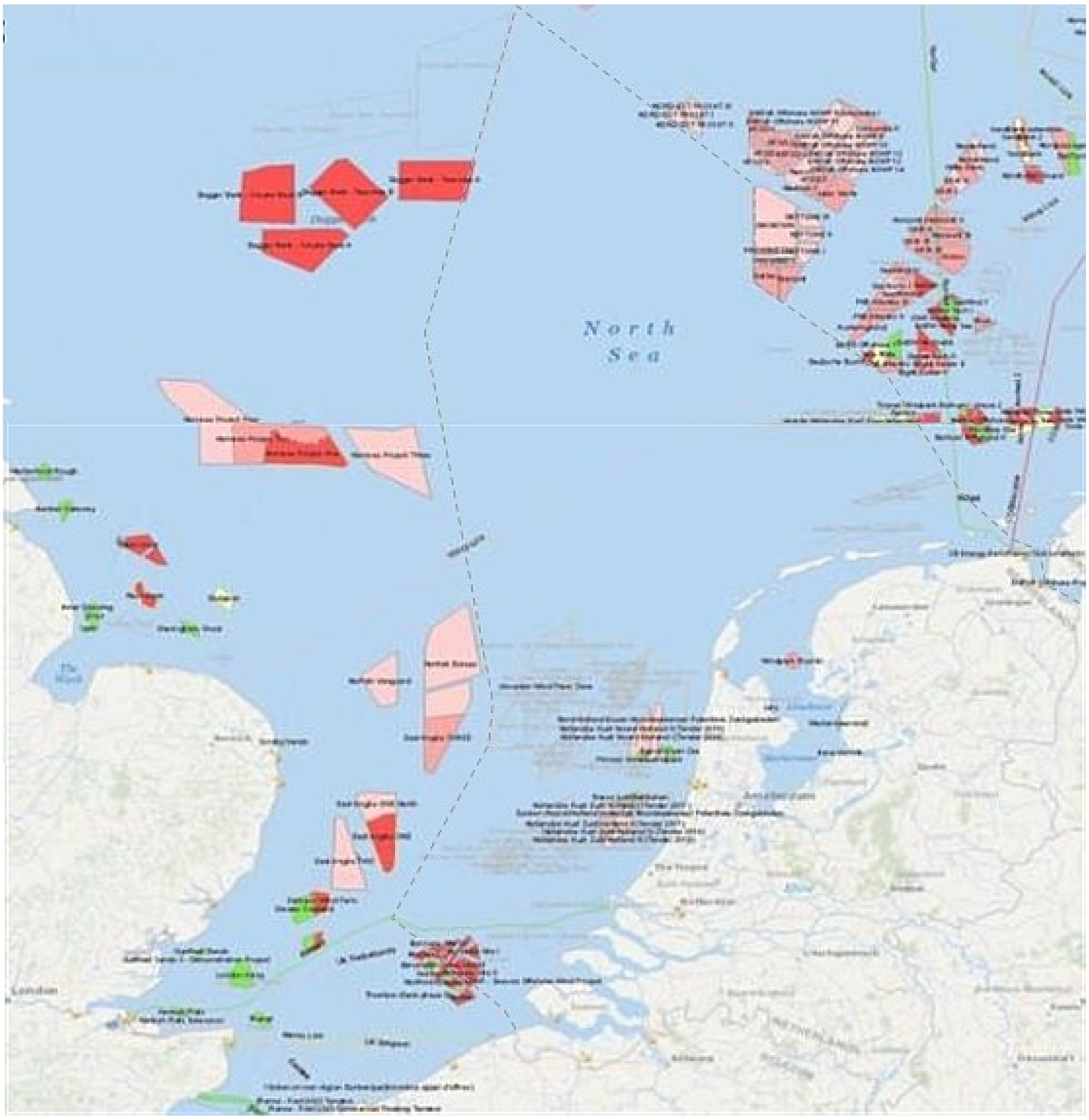


Figure 2-18: North Sea offshore wind farms (green: operational, yellow: construction, red: consented/pre-construction, pink: early planning) (4C-Offshore, 2016)

The Dutch government has already defined candidate locations for future construction sites for offshore wind projects. In Government Structural Vision for Offshore Wind ("Rijksstructuurvisie Windenergie op Zee"), besides "Hollandse Kust" and Borssele that had already been planned for ongoing and future tenders, the locations of 'IJmuiden Ver' (75 km off the coast, 5-6 GW expected offshore wind capacity) and 'To the North of the Wadden Islands' were also considered. Taking into account that great part of the North Sea is already allocated to fisheries, shipping, sand, oil and gas extraction and military activities, it can be concluded that the option for defining offshore wind locations tend to be limited.

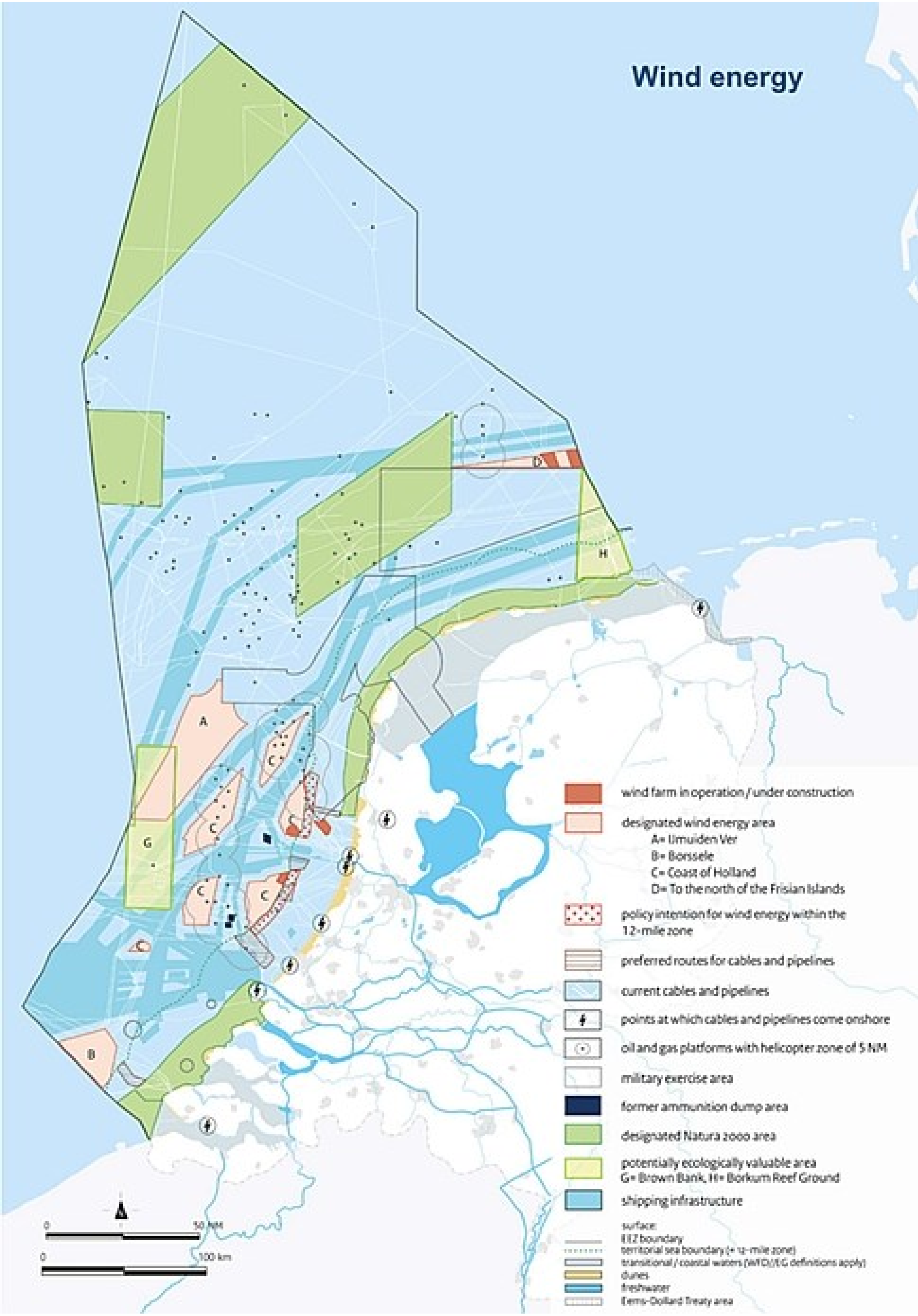


Figure 2-19: Designated areas for offshore wind energy in the Dutch EEZ (Noordzeeloket, 2015)

Dogger Bank is a sea location that is spread among the national exclusive zones of UK, Denmark, Germany and the Netherlands with shallow waters and high average wind speeds. Due to the long distance to shore and harsh environment of Dogger Bank earlier UK initiatives for offshore wind farms have been abandoned, but for the longer term, say after 2030, it remains an interesting area to develop large-scale offshore wind.

TenneT TSO recently presented their vision for cost-effective deployment of far offshore wind farms in Dogger Bank with a total capacity of 30 GW (roughly 40.000 km^2) through an artificial island of roughly 6 km^2 that also facilitates installation and O&M. The central location in between several North Sea countries is used to create additional interconnection capacity.

Figure 2-20: Artist impression of TenneT's vision for a concept for large scale wind energy at the North Sea (Tennet, 2016)

This vision fits in the more general way of thinking that combining offshore wind farm connection with cross-border trade and coordinated development by the North Sea countries, which is supported by the EU (European Union, 2011), North Sea countries (benelux.int, 2016) and NWEA (NWEA, 2016). Compared to separate developments per country, the socio-economic benefits outweigh the costs. Coordinated planning and regulation, such as allocating costs and benefits, should be established to enable such development, as mentioned in the case study #5 in (World Energy Council (b), 2016), a comprehensive study on economics and policies (Decker & et_al, 2015) and an overview report (Clingendael, 2015).

2.2.6 Cost reduction

Cost reduction and stimulating green jobs are main ambitions of the Dutch government related to offshore wind and the energy transition in general, with a 40% cost reduction target in 2020 compared to the 2010 price level of 175 Euro/MWh. This is effectuated by a gradual decrease in the maximum SDE+ subsidy level, the choice for near-shore locations and by appointing TenneT as offshore grid developer and operator.

After several years of very limited cost reduction, the price of offshore wind projects have recently dropped with a bid of Vattenfall on Horns Rev 3 early 2016 of 104Euro/MWh and a bid of 72.7Euro/MWh by DONG on Borssele lot 1 and 2 in July 2016, excluding 14Euro/MWh for the offshore transmission system. Main factors in cost reduction are considered to be (1) increased scale of offshore wind farm projects, (2) increase wind turbine size, (3) gained experience, in particular for installation and O&M and (4) streamlined planning and risk management (Renewable Energy World, 2016).

In line with previous national and European R&D programs, the new Dutch industry-led RD&D program GROW aims at further cost reduction, so that phase subsidies can be phased out, and strengthening the Dutch offshore wind sector (Grow Offshore Wind, 2016).

2.2.7 Offshore wind electrical infrastructure

2.2.7.1 Functional overview

The infrastructure needed to transport the electricity generated by the offshore wind turbines and to feed this in to the onshore grid is described in terms of its structure, costs and technology.

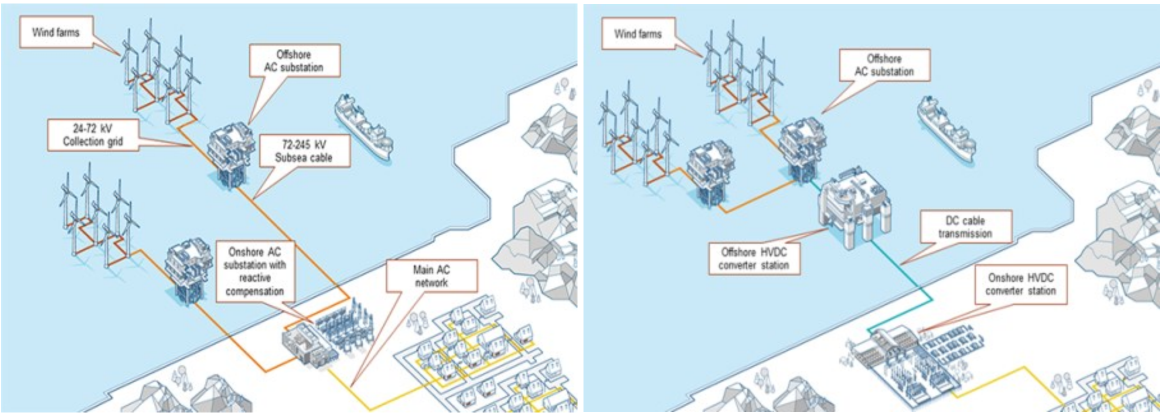


Figure 2-21: Illustration of offshore wind electrical infrastructure for AC and DC transmission (New Abb, 2016)

2.2.7.2 Collection grid

The collection grid interconnects strings of wind turbines with a central collection platform, called an offshore high-voltage station. The collection grid is developed and operated as an integral part of the wind farm.

The choice of cable layout and type is project specific, depending on the power rating and locations of the turbines and on the bathymetry, e.g. water depth, soil characteristics and obstacles, and on regulations. In most cases a radial layout is selected, but sometimes so-called end loops are introduced to be able to re-route the power flow in case of cable failures and thereby reduce the loss of production.

Along each string the transported power increases towards the collection platform. Therefore larger core diameters, or even parallel cables, are used near the collection platform, although the number of different cable types is limited to facilitate O&M.

Recently the industry standard was set to a higher nominal voltage level of 66kV, which enables a higher power throughput and thereby reduces the total cable length in the wind farm.

2.2.7.3 Offshore high-voltage stations

The offshore high-voltage stations, together with the onshore high-voltage station and the export cable system in between, form the transmission system for the offshore wind farm.

At the offshore high voltage stations all incoming cables from the wind turbines are connected to a bus that is connected to a transformer that raises the 66kV medium voltage to a high voltage level, to enable the transport of large power levels through only a limited number of cables.

Depending on the maximum power level and distance to the onshore connection point, different solutions are possible, depending on the costs and technical limitations. For example at higher power levels and longer distances high voltage dc (HVDC[2]) transmission becomes attractive compared to high voltage ac (HVAC) transmission, because it has no limitations for the transmission distance and the lower cable costs outweigh the additional costs for the AC/DC converter stations. This is elaborated in section 3.4.

Figure 2-22: Offshore high voltage substations: (upper) 300MW HVAC platform installed at Gemini wind farm (Gemini, 2015), (lower) 800MW HVDC BorWin beta platform of TenneT TSO (Siemens, 2014)

[2] Here HVDC based on Voltage Source Converter technology is meant, while the so-called classical HVDC, based on Line Commutated thyristor Converters) is not suitable for application offshore

Other functions of the offshore high voltage station are:

- protection against short-circuit and overvoltage, both at medium and high voltage side
- other switching operations, e.g. re-routing of the power flow in case of component failure
- reactive power compensation (only for HVAC transmission)
- voltage control
- data communication for wind farm and HV station monitoring and control
- auxiliary power provision (e.g. by diesel generator or by redundant power lines)
- energy metering from the connected wind farm(s), power quality monitoring, in particular when the offshore station is operated by the offshore transmission system operator
- O&M access facilities (optional), e.g. helideck, hotel facility

2.2.7.4 Transmission grid

Both for HVAC and HVDC transmission the cable systems design is project-specific, based on power level, distance, soil conditions and regulations. The choice of the HVAC cable voltage is a trade-off between the amount of copper needed and the limitations for reactive currents and inrush currents, as illustrated in Figure 2-23 (solid lines). Also different ampacity ratings, i.e. cable core diameters, are chosen along the route, depending on soil thermal characteristics and the reactive current distribution over the cable length.

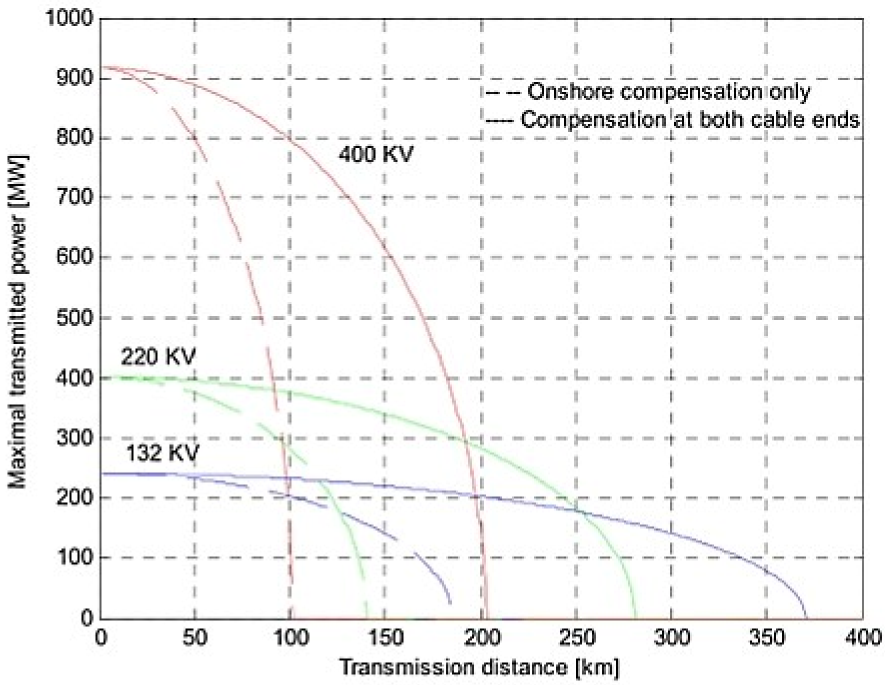


Figure 2-23: Transmission capacity as a function of the transmission length for AC cables (Barberis, Todorovic, & Ackerman, 2006)

For HVDC the trend is towards higher cable voltages to achieve higher power levels, with 300kV to 320kV as current standard for polymer (XLPE) cables and 600kV introduced recently (Prysmian Group, 2016). For HVDC the main limitations are the size and weight, complexity and costs of the HVDC offshore substation.

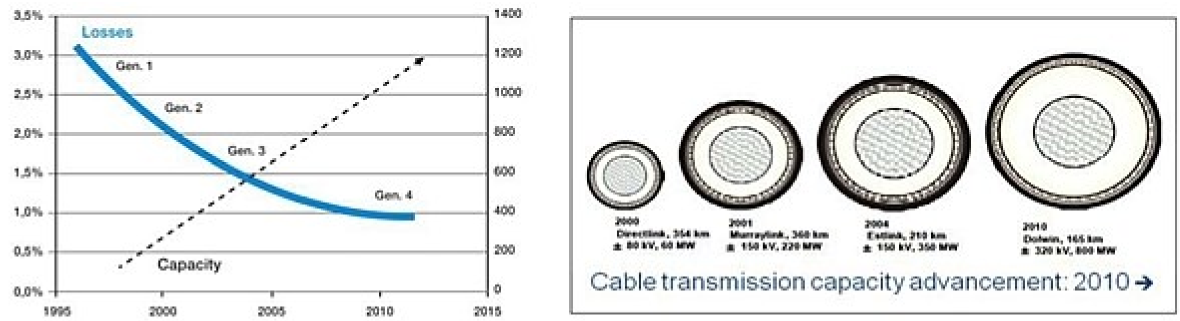


Figure 2-24: (left) Evolution of converter station losses and power handling capacity for a HVDC Light® station from 1997 until today; (right) Extruded DC cable development since 2000 with project references included showing voltage and power ratings (Callavik, Lundberg, Bahrman, & Rosenqvist, 2012)

2.2.7.5 Grid connection

The landfall, onshore cable routing and location of the onshore station require careful planning because of the limited space and preserving nature, as the recent planning study for connecting the Borssele offshore wind farms show (RoyalHaskoning DHV, 2014). Because of the many stakeholders involved, the planning process is often lengthy and difficult. Examples exist where relatively expensive solutions, e.g. offshore cable routes, have been chosen because of the difficulties with the onshore planning and permitting. After realization of the near shore wind farms the remaining capacity to connect additional large-scale offshore wind farms and transport the electricity to the load centres is limited, requiring substantial onshore grid reinforcements or alternative solutions.

For HVAC the space requirements are modest, especially when compact gas-insulated switchgear is applied, but for the HVDC option the onshore converter station is huge. As there are no technical limitations with respect to cable length, this station may also be located far inland, as is the case in Northern Germany.

2.2.7.6 Design concepts

So far offshore high-voltage substations designs were project-specific. Since the Dutch government has set out plans for five near shore development zones of equal size and made TenneT responsible for the offshore transmission grid planning, realisation and operation, standardization of the offshore transmission system concept has become achievable. The TenneT solution consists of standardized 700MW HVAC platforms, called hubs that can be interconnected, thereby providing redundancy. Each platform also consists of two parallel transmission systems, each connected to a single 220kV export cable.

With 700MW capacity the planned TenneT high voltage platforms are the largest HVAC platforms designed so far, although for HVAC technology it is common to scale up the power by putting several systems in parallel, such as is applied in the Gemini wind farm with two 300MW HVAC offshore stations that are interconnected.

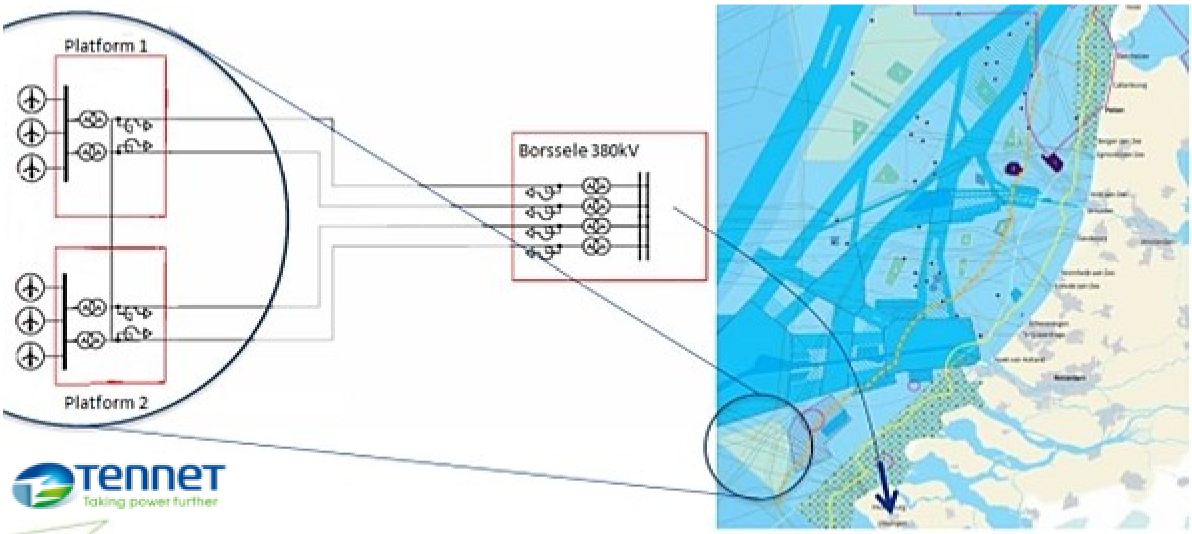


Figure 2-25: Technical design concept of TenneT for offshore wind farm grid connection

For HVDC the maximum platforms size is now 900MW, but the technology for constructing 1200MW offshore platforms is already available and in the near future platforms up to 2000MW are expected, based on the 525kV cable voltage. Unlike HVAC systems, which is rather a combination of standardized components and have a modular structure, HVDC systems are more designed as a complete system, which limits their modularity and inter-operability. An extensive technical and economical assessment and analysis of an HVDC based offshore grid can be found at (ECN, TU-Delft, 2014), (NUON, ECN, TU-Delft, al, 2015)

2.2.8 Offshore wind farm Operation

2.2.8.1 Metering and tariffs

Metering of the wind farm production at the grid feed-in point is located at the TenneT offshore substation and conducted by an independent party. The metering is used to determine the market revenues, the required subsidy and possible balancing fees. For the existing offshore wind farms this metering is at the onshore TenneT stations while for the planned farms this will be at the medium voltage connection of the TenneT offshore substation.

2.2.8.2 Program responsibility and forecasting

The variable nature and limited predictability has several impacts on the utilization of the electricity transport infrastructure, the electricity market and the grid stability.

For offshore wind farms the average power level is about 50% of the rated capacity. This figure can be influenced by the wind turbine design (larger slender rotors), the wind farm location and design (e.g. wind turbine inter-spacing and overplanting), depending on where the economic optimum lies. This means a low utilisation of the electricity transport infrastructure, from the offshore substation up till the onshore grid connection.

The inherent intermittency of wind power and other renewable generation requires additional flexibility from the electricity system, which is partly available already in order to respond to load changers and extreme events, such as grid faults or outages of large production or load units. This flexibility can mean starting or ramping up less economic power plants in case of low wind speeds and low utilisation of conventional power plants and low electricity prices on case of high wind speeds, both leading to negative economic effects. Figure 2-26 (left) shows that significant power variations already occur over a 4-hour time period, although these can be predicted with reasonable accuracy (right) in order to prepare the dispatching scheme.

In case of fast production variations, even when well-predicted, the electricity system should be able to absorb or counteract these variations, in order to preserve balance between supply and demand and also to maintain safe operational voltage limits. This requires fast response of production or load units, which is supported by fast power flow control and congestion management strategies in the onshore transmission grid.

Offshore wind farm control strategies exist to limit extreme variations, e.g. high wind ride-through and power reserve control, e.g. delta control. Also significant improvements in the power forecasting quality help reducing these variations or at least the negative effects.

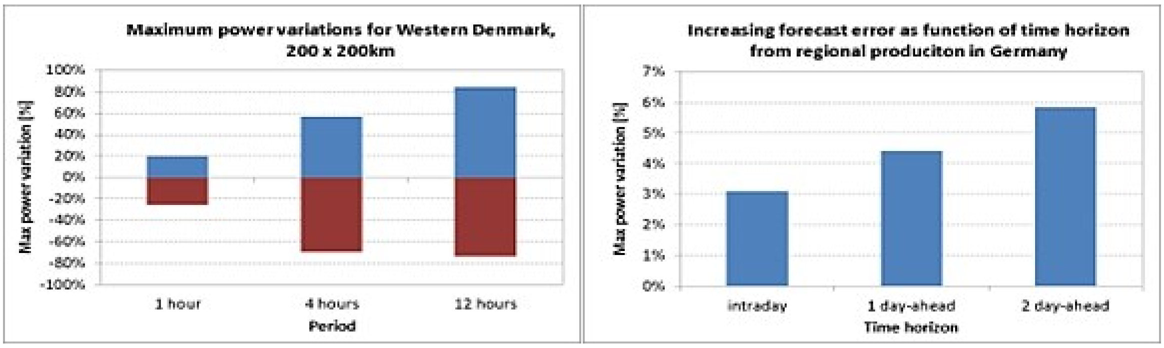


Figure 2-26: (left) Extreme power variations; (right) Average forecast error (ieawind.org, 2016)

2.2.9 Expected technology development

For wind farms located relatively close to shore that are connected through HVAC, modular offshore substations, sometimes integrated with offshore wind turbines, have been presented in order to reduce costs (Catapult, 2016). This solution would also facilitate that wind farm clusters are located at some longer distances from a large central offshore substation.

For large far-offshore wind farms HVAC is beyond the economic and technical limits of HVAC, so that other (new) solutions will be applied instead. HVDC technology is one of the likely solutions and for this technology the following main developments are expected:

- Increased power rating to 1200MW and possibly 2000MW and at the same time reduction of the costs per MW installed
- Interoperability of different HVDC systems, standardisation of main parameters, e.g. DC-voltage
- Advancement of control and protection schemes of HVDC transmission in order to support the inshore grid and prevent black-outs in case of DC faults
- Development of multi-terminal HVDC networks, enabling to create larger meshed DC-grids
- Alternative technologies, e.g. the Siemens modular HVDC concept or Low-Frequency AC

With respect to wind farm operation expected developments are increased wind farm control capabilities and power forecasting accuracy in order to cope with the intermittency.

2.2.10 Conclusion

Offshore wind developments in the Dutch zone of the North Sea until 2023 are clear, with 4.5GW of offshore wind farms operational at the time, mostly near shore. Beyond 2023 no concrete plans exist, although a further expansion is expected in line with the ambitions to decarbonise the energy system, to start at IJmuiden Ver with 5 to 6 GW and later at other far offshore locations above the Wadden Sea and at Dogger Bank, summing up to several tens of GW.

Although offshore wind energy costs have recently decreased it is still one of the main challenges, for which the scale of projects and also technology and market developments are major factors.

More specific challenges for offshore wind are related to spatial planning of the offshore site, the cable routing up till the onshore grid feed-in location, considering the limited space and suitable connection points, the multiple stakeholders, the wind resource and environmental conditions. Also the offshore wind development should remain to be synchronized with the grid development to prevent under-used assets, taking into account the different planning procedures, different responsible parties (wind farm developer and TenneT) and the different operational lifetime of the wind farm (typically 25 years, of which 15 years subsidized) and the offshore grid (financed for 27 years but the technical lifetime is probably much longer).

Further, for the development and installation process challenges are to reduce risks related to the high capital costs, the complex organisation, HSE risks and tight time schedule with risks of delay due to the limited workability offshore. For the operational phase the main challenges are obtaining insight in and reducing of O&M costs and at the same time to maximize the revenues by accurate forecasting, strategic bidding and/or contracting of energy and flexible power.

2.3 Strategic spatial planning

The Dutch North Sea is a hotbed of economic activity including renewable energy generation, oil and gas production, fishing, sand and shell extraction and recreational activities. The same region also contains some of the busiest shipping lanes in the world. All these activities are in constant development, and compete for a limited space. The available space is furthermore decreased by protected environmental areas and areas reserved for military use. Most activities are subject to legislation and require permits, according to the most important laws governing use of the Dutch North Sea: the Water Act (Waterwet), the Shipping Traffic Act (Scheepvaartverkeerwet), EU Common Fisheries Policy (Gemeenschappelijk Visserijbeleid), the Mining Act (Mijnbouwet), the Flora and Fauna Act (Flora- en faunawet), The Nature Conservation Act (Natuurbeschermingswet) and the Earth Removal Act (Ontgrondingenwet).

Balancing the competing interests and optimizing the long-term development of this region requires strategic spatial planning. One recent example are the recent changes to the Dutch shipping lanes enacted in 2013. It is the explicit ambition of the Dutch government to increase the amount of control it exerts on the spatial planning in the Dutch North Sea, as stipulated in the National Spatial Strategy formulated in 2006 which included the Dutch North Sea area (Netherlands, 2006). Since the various activities fall under different ministries, cooperation and coordination is achieved through the institutions such as the Interdepartmental Director's Consultative Committee North Sea, or IDON, in which representatives of various stakeholders such as the ministries and the Royal Dutch Navy debate North Sea policy and governance. This institution also published the Integrated Management Plan for the North Sea 2015 ((IDON, 2015)

> "To enhance the economic importance of the North Sea and maintain and develop the international ecological and landscape features by developing and harmonising sustainable spatial economic activities in the North Sea, taking into account the ecological and landscape features of the North Sea."
>
> - Primary objective of the Integrated Management Plan for the North Sea 2015

In order to further facilitate transparency and coordination between users, the Dutch North Sea Office intends to make available a spatial planning tool including relevant maps on its website (Noordzeeloket, 2016). Many individual maps can already be found on this website. Nevertheless, improved communication and cooperation between different users of the North Sea holds a vast potential for improved use of construction, operation and optimal spatial planning synergies.

The North Sea Commission strategy (northseacommission.info, 2016)has listed "Managing Maritime Space" as one of five priority strategic areas, with focus areas: Marine spatial planning, Exploitation of marine resources and North Sea Stakeholder Forum.

The following section will briefly expand on the five most important uses of the North Sea and their current trends.

2.3.1 Users of the North Sea

Figure 2-27: (left) Offshore wind park (Pettersen & Statoil)

User 1: Renewable Energy

Trend: Strong increase of activity

Large offshore wind farms are attractive for two main reasons: high offshore wind speeds yielding high efficiency and low public resistance against landscape impact in comparison with placing them onshore. However, they require higher construction costs and longer transport distances to the onshore grid. In 2013, the Dutch government and more than 40 Dutch organizations have signed The Agreement on Energy for Sustainable Growth which outlines ambitious goals for a reduction of energy consumption and an increase of the fraction of renewable energy to 14% in 2020 and 16% in 2023 (SER, 2016). To realize these goals, an additional offshore wind capacity of about 3500 MW will have to be installed until 2023.

Therefore, the Dutch government has assigned certain regions for the development of wind energy parks, which are outlined in Figure 2-27 .

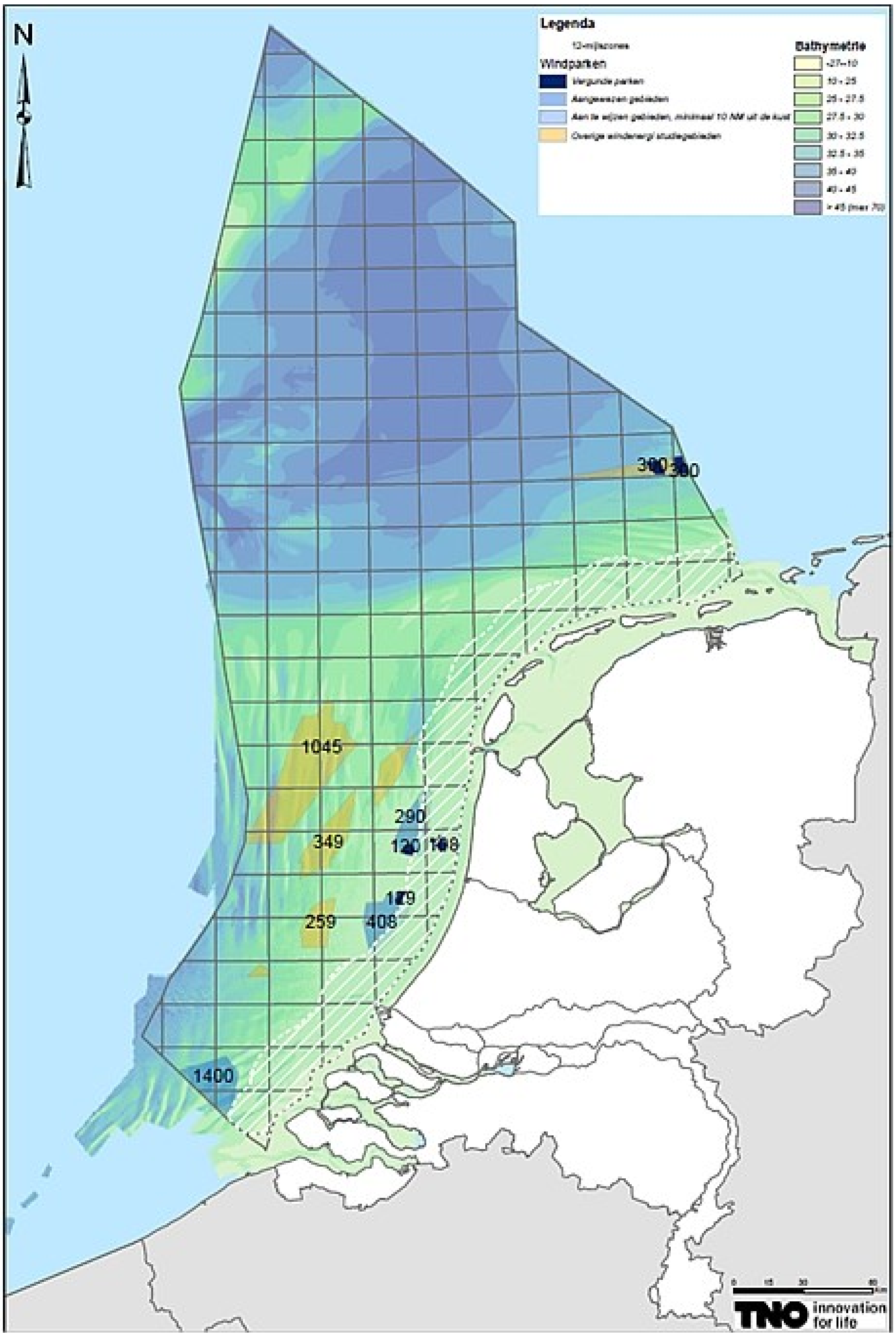


Figure 2-28: Regions assigned for the development of wind parks in the Dutch North Sea

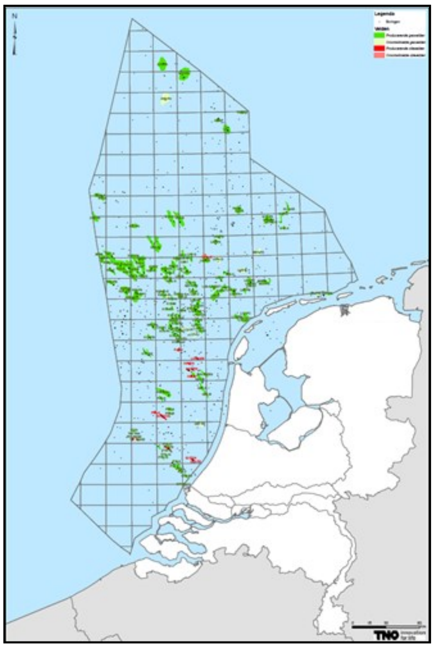
In July 2016, the two prospective wind park areas Hollandse Kust (noord) and Hollandse Kust (zuid) were officially announced (SER, 2016). Overall, it is expected that this development continues and the demand for space for wind energy in the Dutch North Sea increases.

Figure 2-29: North Sea gas production platform L10-A of ENGIE (ENGIE, 2016)

User 2: Oil and Gas production

Trend: Decreasing activity. Abandonment of majority of current wells expected until 2035, large amount of decommissioning or re-fit activities expected.

The Netherlands is the largest European producer of natural gas. The Dutch North Sea contains around 160 production locations, which are connected by a network of pipelines, see Figure 2-31. Most of the fields are nearing the end of their lifetime, with offshore natural gas production peaking at 30 billion m³ in 2001 and having halved since then. The spatial requirements of the oil and gas infrastructure are expanded by a 500-metre zone around each platform within which no other activities are permitted (EBN, 2016).



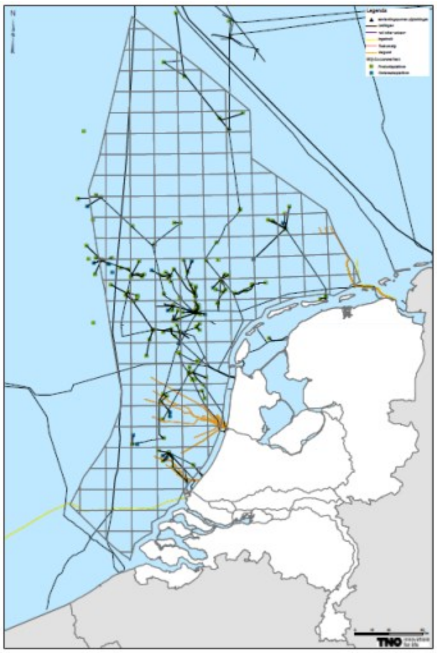


Figure 2-30: (left) Current offshore oil and gas production platforms, (right) current offshore oil and gas pipelines.

Figure 2-31 Container ship (Pixabay, 2016)

User 3: Shipping

Trend: Increasing activity.

The North Sea receives more than 400,000 ship movements a year and contains some of the world's most busy shipping lanes. Most of the largest ports in the European Union are situated at the North Sea coast, including Hamburg, Amsterdam, Rotterdam and Antwerp (Europese Commissie, 2016). The entrance route to Europort Rotterdam (Eurogeul) allows for vessels of up to 400,000 tonnes, and the port of Rotterdam has recently been expanded by the construction of Maasvlakte 2 in 2013, the largest civil engineering project since construction of the Delta Works.

Shipping has been of crucial importance to the Dutch economy for hundreds of years. In the world's most intensive route change at sea, the Dutch government modified the distribution of the 3600 km^2 of sea routes in 2013 to improve both the efficiency of the shipping lanes and the potential development of other offshore infrastructure. The new shipping lanes are shown in Figure 2-32.

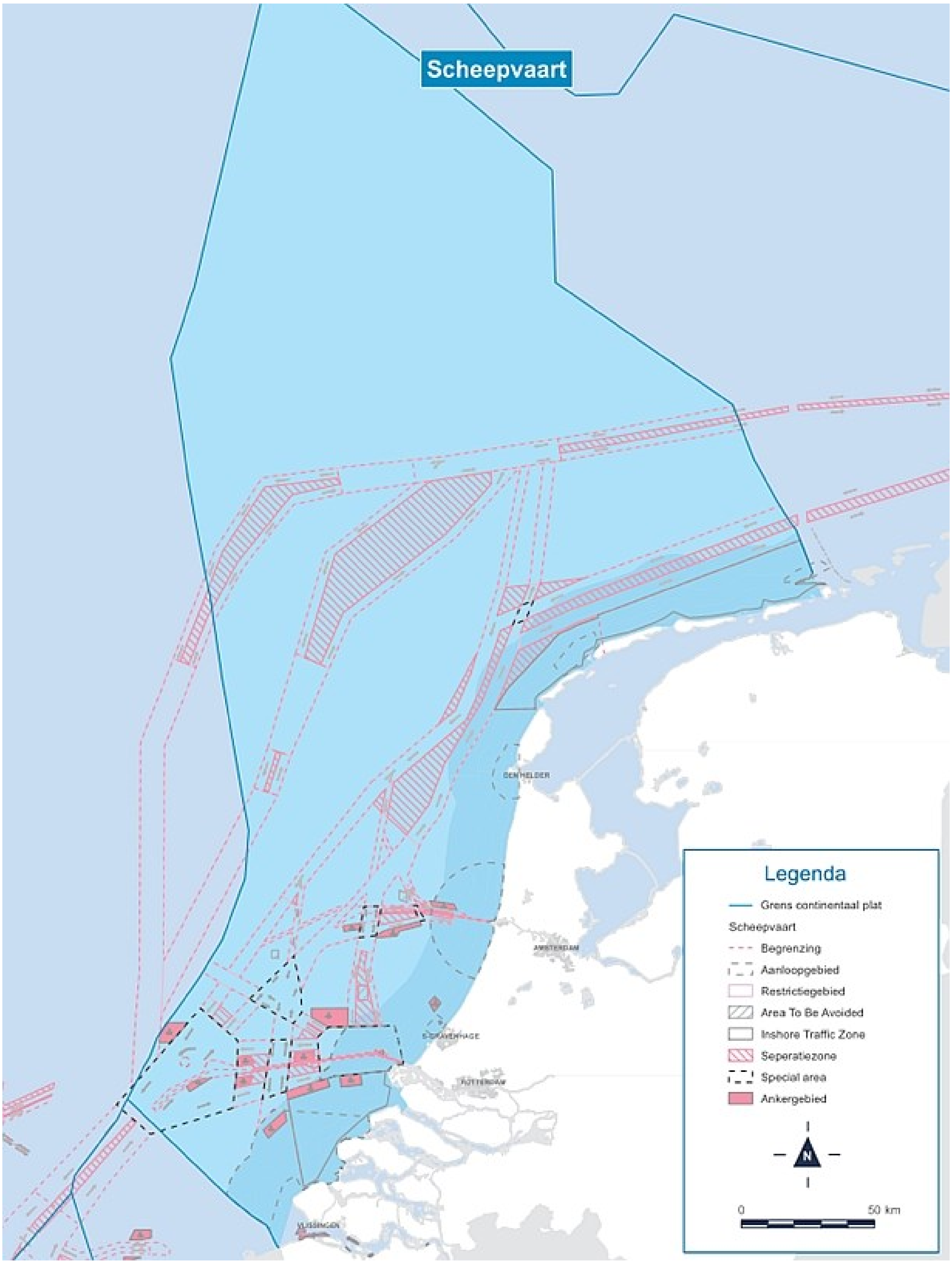


Figure 2-32: Shipping lanes, regions reserved for military use and nature reserves in the Dutch North Sea.

User 4: Fishing

Trend: Sector facing decrease of available terrain

The Dutch North Sea is divided in zones based on shore distance (Figure 2-33). Within three miles of the coast, only Dutch fishermen are allowed to fish. In the other zones, fishermen from Belgium, Germany, Denmark and France are selectively permitted to fish, with specific restrictions in terms of fish species in place for each zone and nationality combination.

The Dutch fishing industry is facing a steady decrease of available North Sea area, since fishing is forbidden in wind turbine farms, within 500 meters of oil and gas infrastructure, in shipping routes or approach areas, in certain nature reserves, in areas reserved for military exercises and in areas containing a large amount of sunk ammunition.

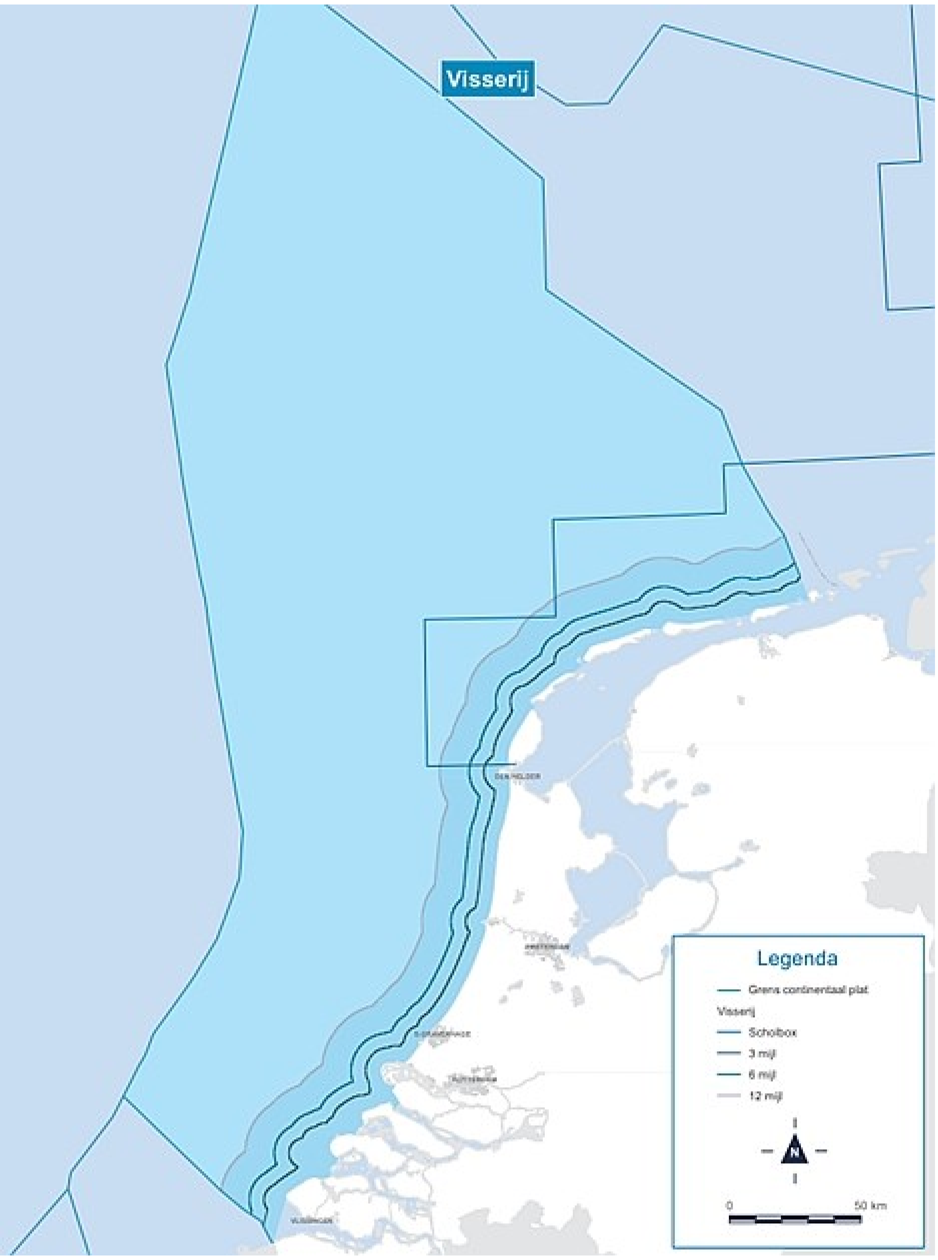


Figure 2-33: Fishing zones based on distance to shore

User 5: Sand and shell extraction

Trend: Increasing with potential strong increase of demand for sand for civil construction projects and coastal maintenance with rising sea levels.

Regular yearly sand extraction from the North Sea amounts to around 25 million m³ per year, with about half going to coast maintenance and half to use as onshore filling material (Noordzeeloket, 2016). The area between 12-mile line and the ongoing NAP -20 m isobath has been reserved for sand extraction (5134 km2), with sand extraction enjoying highest priority in this area. However, within this region, extraction depths are limited to 2 metres. Beyond 2 km of the NAP -20 m isobath large-scale sand extractions is permitted. Shell extraction is also restricted to a reserved area and is limited to natural accumulation, see Figure 2-34.

Figure 2-34: Sand extraction strategy in the Dutch North Sea (Noordzeeloket, 2015)

2.3.2. Excluded areas

Some areas in the North Sea are excluded for environmental protection and defense.

Environmental protection areas

The Netherlands strives for a sustainable use of a clean North Sea, while protecting valuable habitats. As part of the European Natura 2000 initiative, large areas along the Dutch coast have been designated as nature reserve areas in 1992. In these areas, fishing is permitted only very selectively, which most construction and exploration activity is forbidden.

The restricted areas are outline in green in Figure 2-34 in the 'shipping' section.

Area for defense

Various regions in the Dutch North Sea are restricted areas on military grounds. These areas consist of artillery, mine disposal and flight exercise areas and two former (British and German) ammunition dumps. Most exercise areas are restricted during all times. However, a potential usage optimization strategy for these areas would be restricting them only during exercises. Furthermore, extracting oil and gas can potentially be permitted using mobile extraction infrastructure. The current reserved areas are outlined in Figure 2-35.

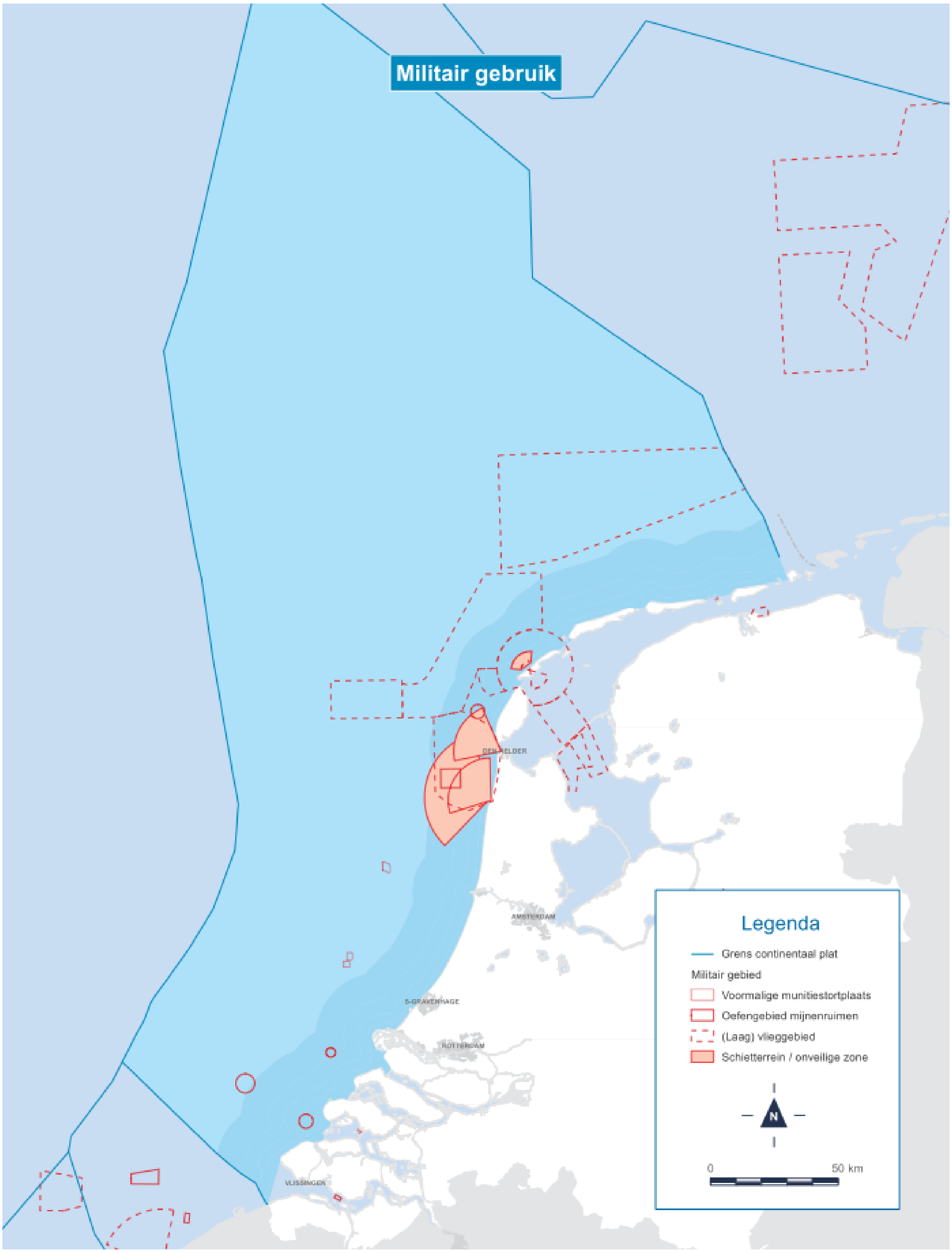


Figure 2-35: Military exclusion zones in the Dutch North Sea (Noordzeeloket, 2016)

2.4 Environmental considerations

The North Sea is an invaluable ecological ecosystem and represents to one of the richest animal habitats in the world. Its coast lines include a multitude of different habitats, from the rocky fjords of Norway to mud flats of Wadden Sea along the northern Dutch coast. More than 280 species of fish, birds, and sea mammals are found in the North Sea, of which at least 15 are currently classified as vulnerable or endangered.

Figure 2-36: Seals in the North Sea

At the same time, the North Sea harbours a great amount of economic activity, which puts considerable pressure on the ecosystem. Environmental awareness is comparatively high in the North Sea community, with most adjacent countries being at the global top in terms of environmental regulation (Yale Environmental Performance Index 2016[3]). Nevertheless, many coastal ecosystems remain vulnerable, and considerable effort and cooperation has been extended and will continue to be required to continue the sustainable exploitation of the rich resources the North Sea has to offer. Human activity can threaten the North Sea environment in various ways (European Environment Agency, 2002) (Interreg IVM North Sea Region Programme, 2014) (Miljodirektorat, 2012) (Noordzeeloket, 2016):

- **Physical impact** on seafloor through trawling, dredging sand/shell extraction and offshore construction or decommissioning, decreasing habitat size through activities on breeding and feeding grounds, disturbance of migration patterns above and below the surface
- **Pollution** of both air and water, oil and gas spills, human-induced eutrophication (i.e. unnatural, excessive increase of nutrient density), marine pollution with potentially toxic litter and other hazardous substances.
- **Noise** from shipping and construction activity
- **CO_2 emissions** lead to rising sea temperature and ocean acidification
- **Overfishing** and the introduction of non-native species

[3] http://epi.yale.edu/country-rankings

2.5 Markets

2.5.1 Electricity market

The wholesale electricity market enables purchases, sales, and trading of electricity. Prices result from the intersection of supply and demand. Not only supply and demand in the Netherlands determine the Dutch electricity prices, but also cross-border electricity infrastructure which allows for imports and exports.

Figure 2-37 shows the development of generation capacity for the period 2015-2030. The capacity prediction is based upon model calculations. In the short term capacity is given, while in the long term investors will adjust their generation capacities to market circumstances.

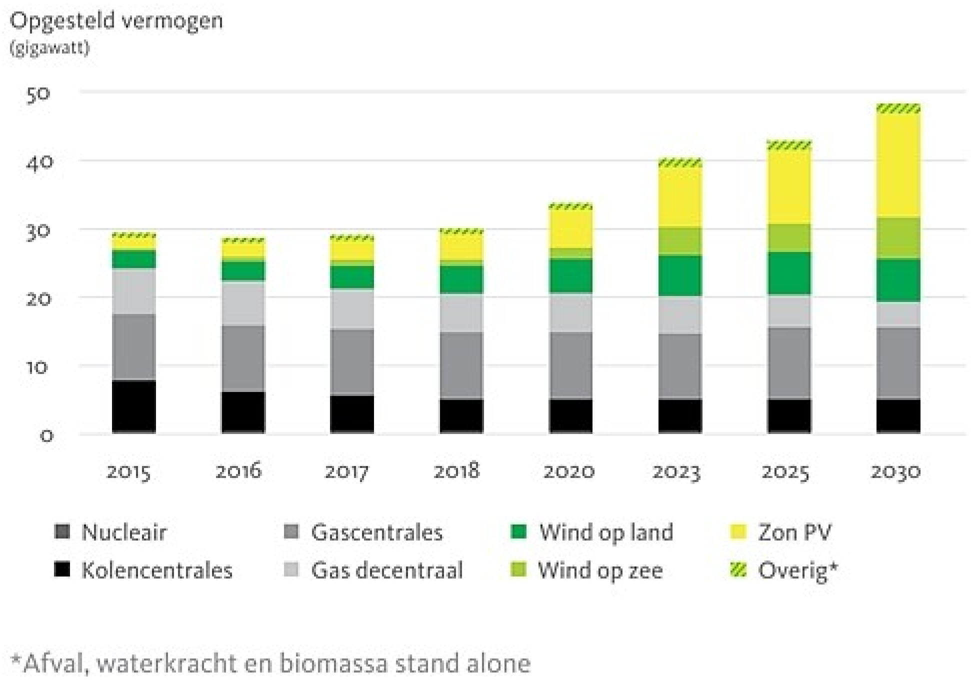


Figure 2-37: Development of generation capacity in the Netherlands for the period 2015-2030 (projection for fixed policy variant) (Schoots & Hammingh, 2015)[4] (in Dutch

Figure 2-38 shows the development of the electricity production for the period 2015-2030. Electricity production by onshore and offshore wind turbines plays an important role in the overall increase of electricity production from less than 90 TWh in 2016 towards more than 130 TWh in the year 2030. The production of gas-fired power plants increases, especially after 2020 when the Netherlands becomes a net exporter given the development of demand and production capacity in neighbouring countries according to ENTSO-E scenarios. However, after 2020 the electricity production of gas fired power plants decreases due to the increasing production of solar PV and wind turbines.

[4] Two policy variants exist. The fixed policies variant assumes concrete, officially published or mainly binding measures, for instance the European emission trading system or the subsidies for renewable energy.

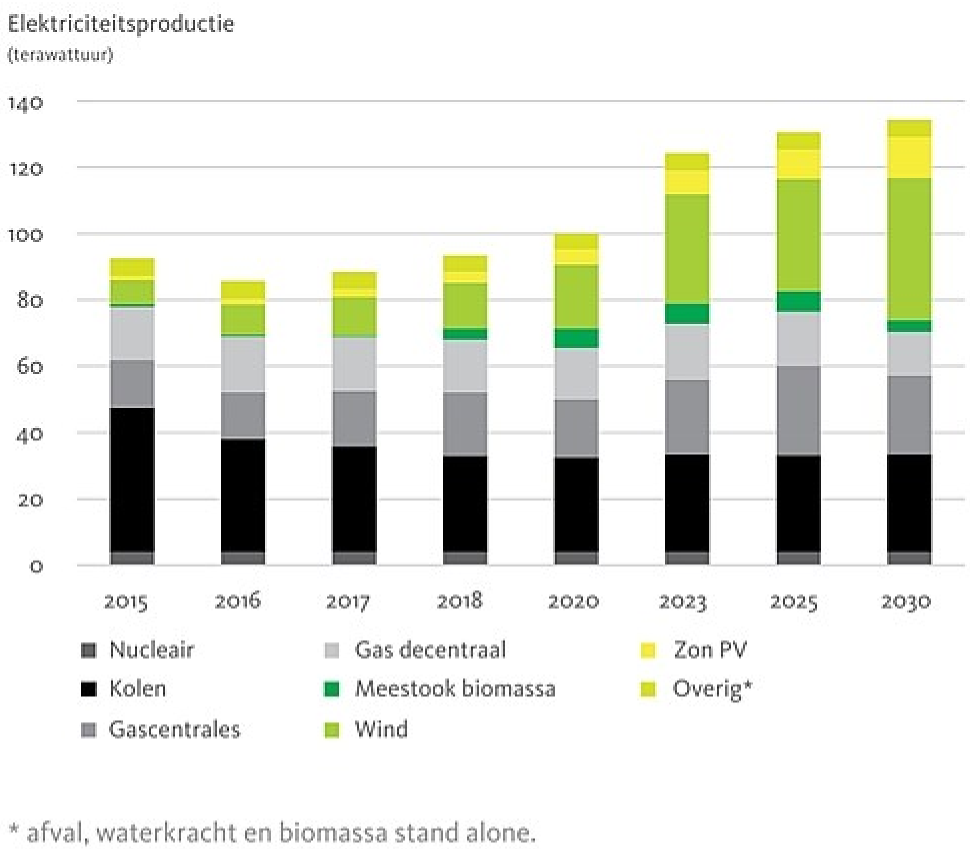


Figure 2-38: Development of electricity production for the period 2015-2030 (projection for fixed policy variant)) (Schoots & Hammingh, 2015) (in Dutch

The development of the electricity demand for different sectors for the period 2015-2030 is shown in Figure 2-39, while Figure 2-40 shows the development of the overall (final) electricity demand. In the latter figure it can be seen that in case of the policy variant fixed policies[5] a slight increase is visible up to the year 2030, while in the variant proposed policies a slight decrease up to 2020 is followed by a slight increase of electricity demand up to 2030. Apart from that, gross energy consumption is expected to decline slightly until 2030 in the proposed policy variant, especially due to a lower energy consumption in the built environment.

The main reason for the limited rise of the electricity demand in the Netherlands is that there is no strong policy for large-scale electrification. Also energy efficiency measures will temper the growth of the electricity demand.

[5] In addition to the fixed policies variant, the proposed policies variant assumes officially proposed measures which were not yet fixed at the time of analysis but concrete enough to take into account in calculations. Examples are a large number of measures from the national energy agreement.

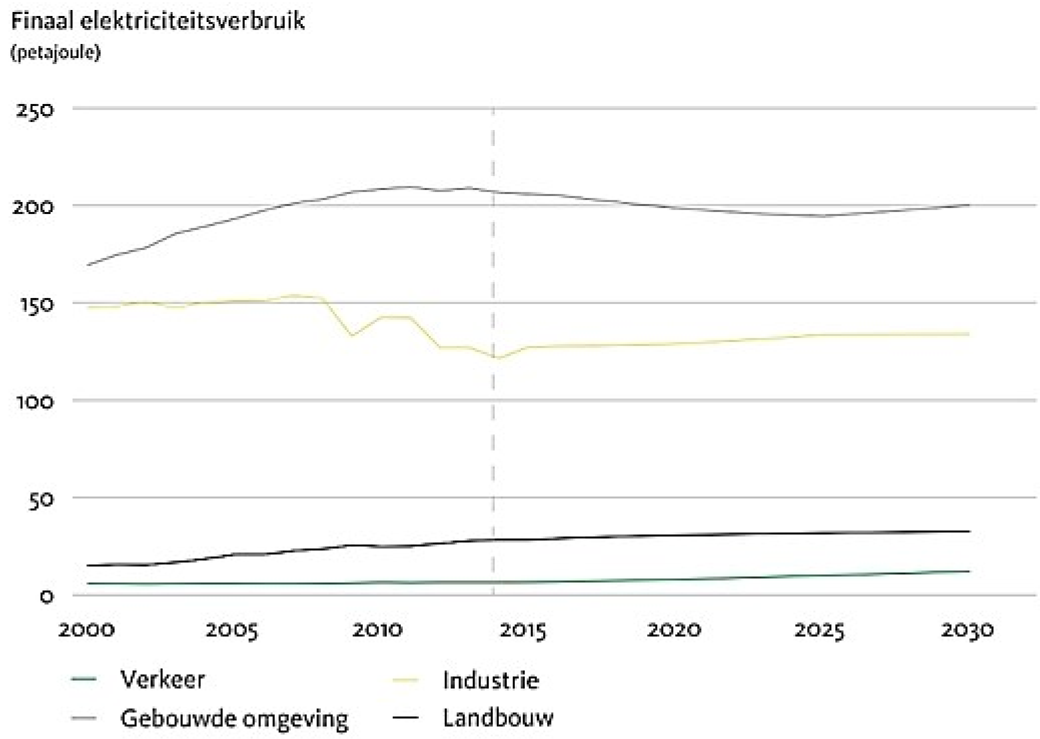


Figure 2-39: Development of final electricity demand for different end user categories, source: K. Schoots and P. Hammingh (eds) (2015) (in Dutch)

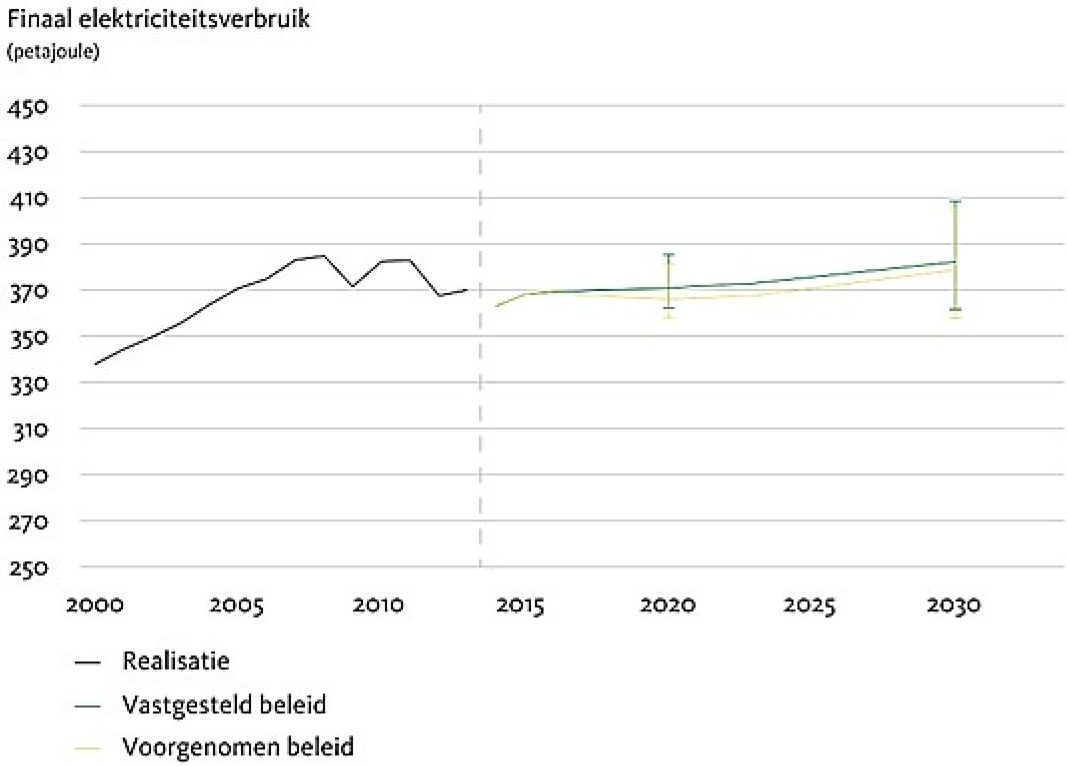


Figure 2-40: Development of the total final electricity demand of end users, source: K. Schoots and P. Hammingh (eds) (2015) (in Dutch)

The described developments of supply and demand affect electricity prices. Figure 2-41 below shows the electricity wholesale price projections.

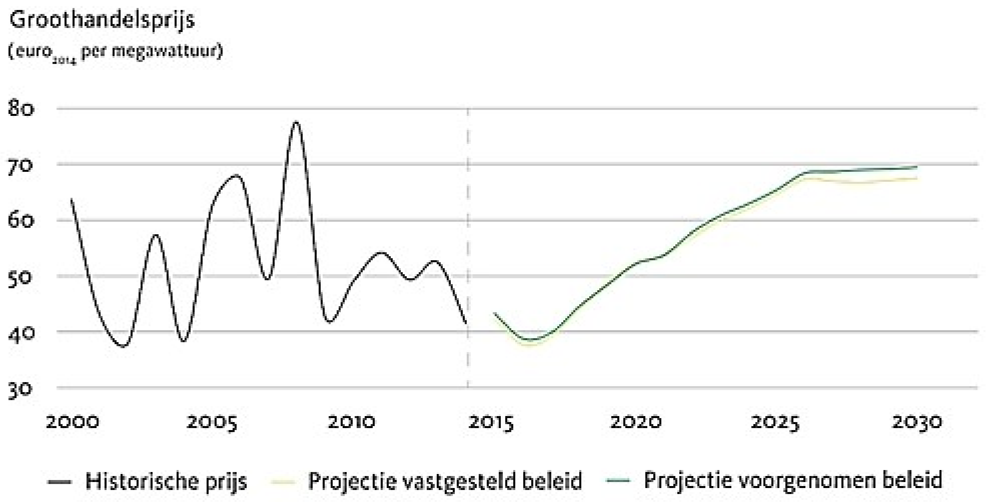


Figure 2-41: Development of the average wholesale electricity prices, source: Source: APX (historical price figures) (Schoots & Hammingh, 2015) (APX, 2016) (in Dutch)

Electricity prices are expected to remain low in the coming years due to low gas prices on future markets and the increase of electricity imports from Germany given the new interconnection between Doetinchem and Wesel and market convergence. However, it is expected that prices will increase afterwards due to both the increase of fuel prices, the increase of electricity demand outside the Netherlands (given ENTSO-E scenario projections) which increases scarcity on the North West European market and the diminishing of the overcapacity of conventional generation in the Netherlands. The rising share of renewables with its low marginal production costs will decrease the average electricity prices, although it also increases the price volatility with high peak process during periods of low wind and solar production. Consequently, the Dutch electricity price will increase as well.

However, it should be kept in mind that electricity price predictions are surrounded with uncertainties. These uncertainties relate to the following factors;

- Prices for coal, gas and CO_2; 30% lower coal and gas prices, while keeping remaining conditions unchanged lead to a 20% lower wholesale electricity market price.
- Future development of renewable production in the Netherlands and neighbouring countries such as Germany. Higher shares of installed wind power and solar PV capacity are an important factor that depresses electricity prices. The resulting electricity price obviously depends on many more factors, e.g. fuel prices, CO_2 prices or the costs of reserve capacity.
- Future development of conventional generation capacity, e.g. the current situation of overcapacity that will end at some point in time, and the share of coal and gas in the electricity generation mix, as coal fired plants operate at lower costs than gas fired plants.
- Development of electricity interconnections with neighbouring countries. When the markets coupling improves, developments in neighbouring countries will become more decisive for the electricity price in the Netherlands.

Finally, it is important to note that prices for electricity produced by solar PV and wind turbines will decrease compared to the average wholesale electricity price. If the wind is blowing, it does so in the majority of the country and there is a strong wind correlation with neighbouring countries.

Consequently, at those hours that supply is large, wind turbines operators will face lower prices. This is the so-called profile effect. The profile effect increases with the higher share of weather-dependent renewables such as wind in the power system. For example, the average price for wind turbines investors in 2030 is about 57 euro per MWh, while the average wholesale market price is well over 67 euro per MWh, implying that the profile effect is about 11 euro per MWh, see Figure 2-42.

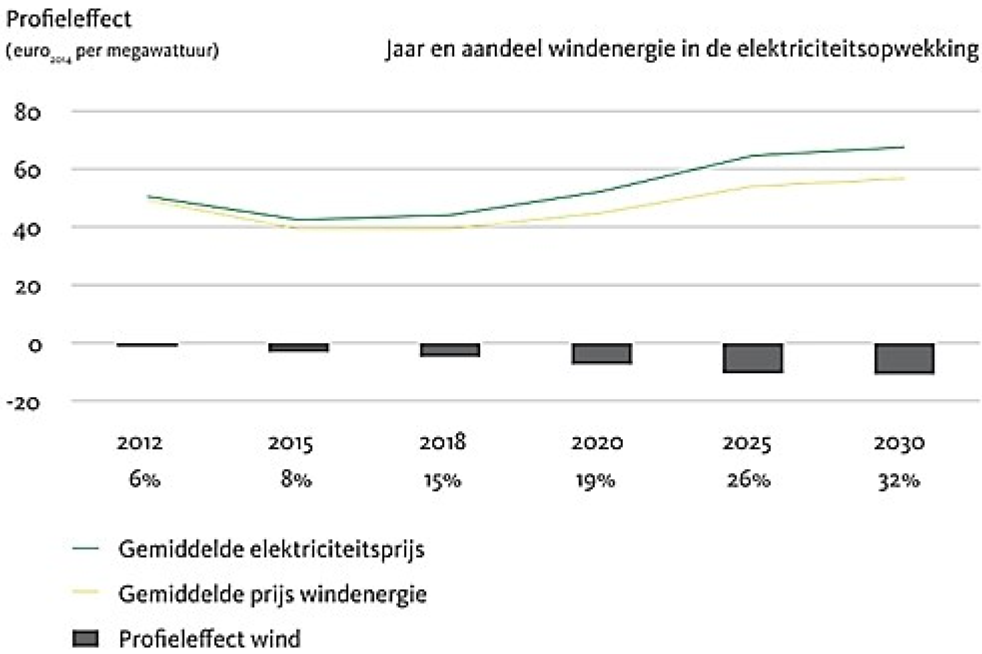


Figure 2-42 Development of the profile effect on the electricity price for wind energy (projection for fixed policy variant) (Schoots & Hammingh, 2015) (in Dutch)

This negative correlation between intermittent renewables production and market prices increases the price volatility and affects their competitiveness. To mitigate these effects a proper market designs is needed that takes into account the intermittent nature and limited predictability (World Energy Council, 2016). The increasing share of renewables will also lead to increased costs for grid integration, due to the need for grid reinforcements and additional flexibility such as additional balancing reserve. This advocates taking a system integration perspective, where the broader advantages and costs of renewables for the power system are accounted for in the comparison of technologies. The IEA recently coined this System Value approach; which is also suitable to value system integration options (IEA, 2016). An example of the impact of different integration options in terms of the “value factor” of wind power, which is defined as the wind-weighted electricity price (wind market value) over the time-weighted electricity price (base price), please see figure Figure 2-43 (Hirth, 2016)

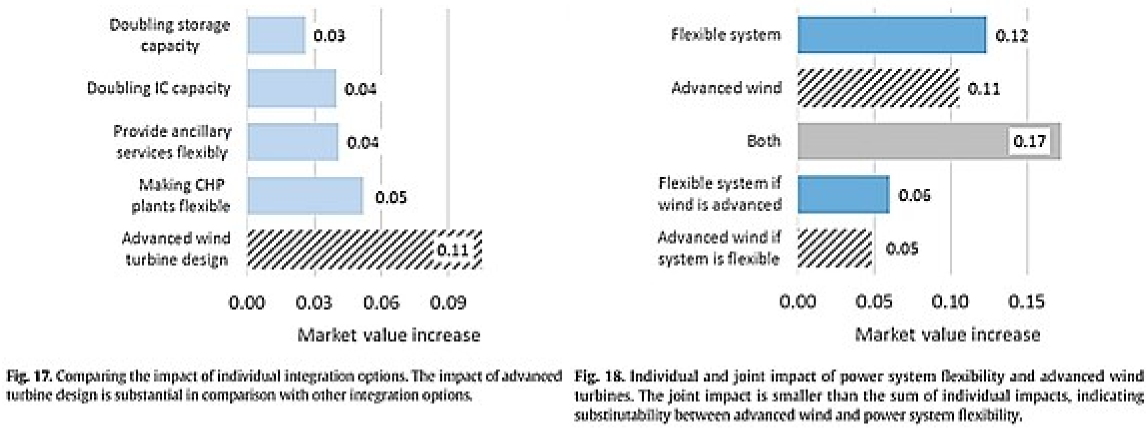


Figure 2-43: Advanced wind technology and flexibility options compared (left: individual options), (right: combined options), figures are in percentage-point (Hirth, 2016)

To indicate the importance of energy prices, the Regional Energy Issues map – Europe 2016 considers commodity prices and the climate framework as the most important macro-economic issues, which are closely linked to the key, see Figure 2-44.

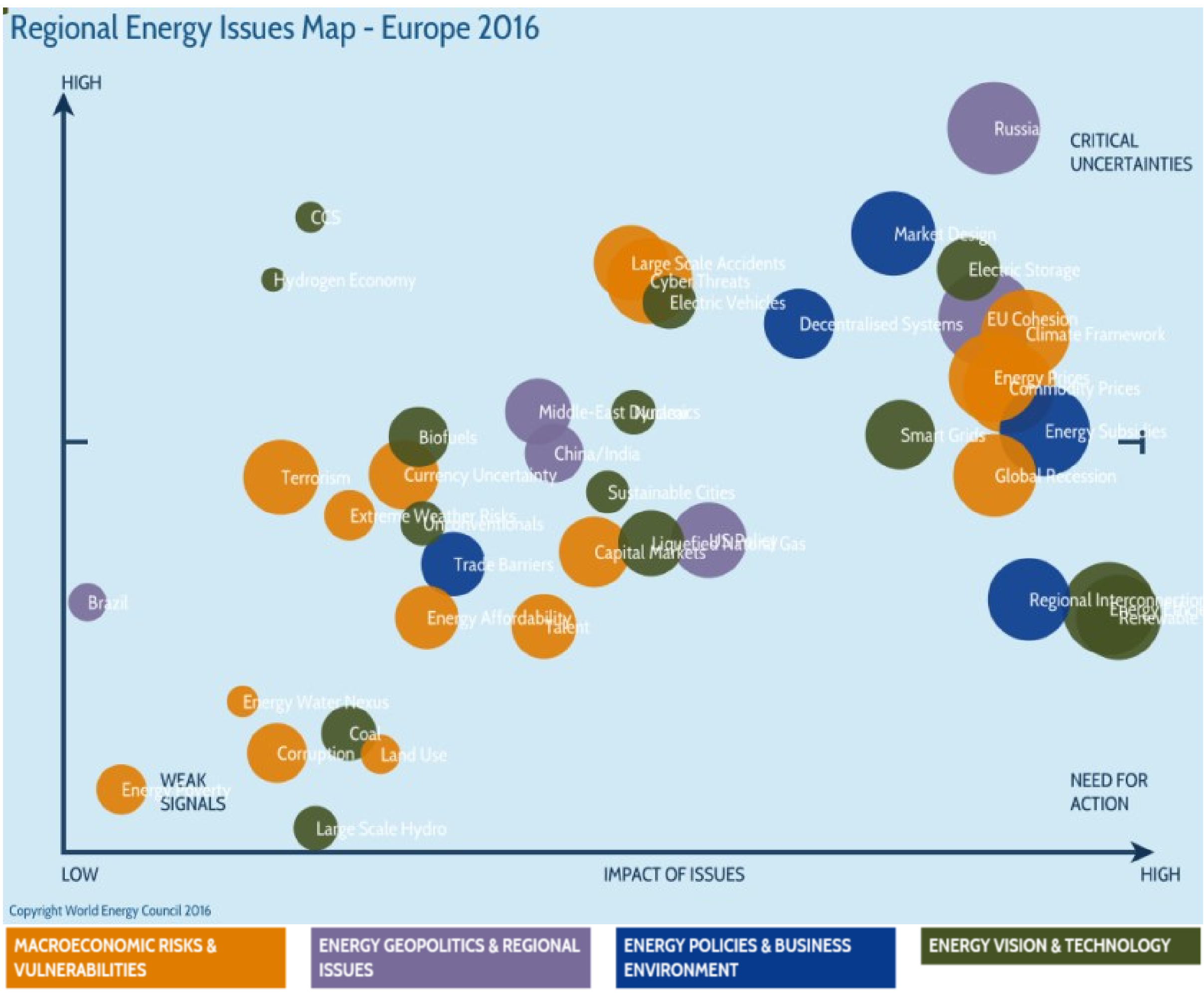


Figure 2-44: Regional Issues Map – Europe 2016 (World Energy, 2016)

2.5.2 Natural gas market

Price projections shown in Figure 2-45 are based upon future prices of ICE Endex (TTF) (first years of projection) and the Current Policies scenario in the World Energy Outlook (WEO) of the IEA (IEA, 2014). This scenario assumes an increasing import dependency of Europe as a whole, resulting in imports from sources that are located further away as well as from relative more expensive gas fields. The wide bandwidth for the future gas price is mainly based on the extent of international climate policies. In the Current Policies Scenario no international climate policy exists, causing an increase of gas demand. The lower boundary is based on the WEO scenario with effective international climate policy i.e. limiting the temperature increase by 2100 to maximum two degrees Celsius. Moreover, it is assumed that international markets function well and geopolitical tenses are absent. The latter scenario results thus in a significantly lower gas demand and therefore gas prices.

Please note that the gas prices in 2016 have dropped well below the indicated bandwidth, which emphasizes the large uncertainties of future projections of gas prices, and also to the future energy mix, which is closely linked to these prices.

As indicated in section 2.1.3 prices for gas have been fluctuating over the last decade and it should be expected to fluctuate in the coming years as well.

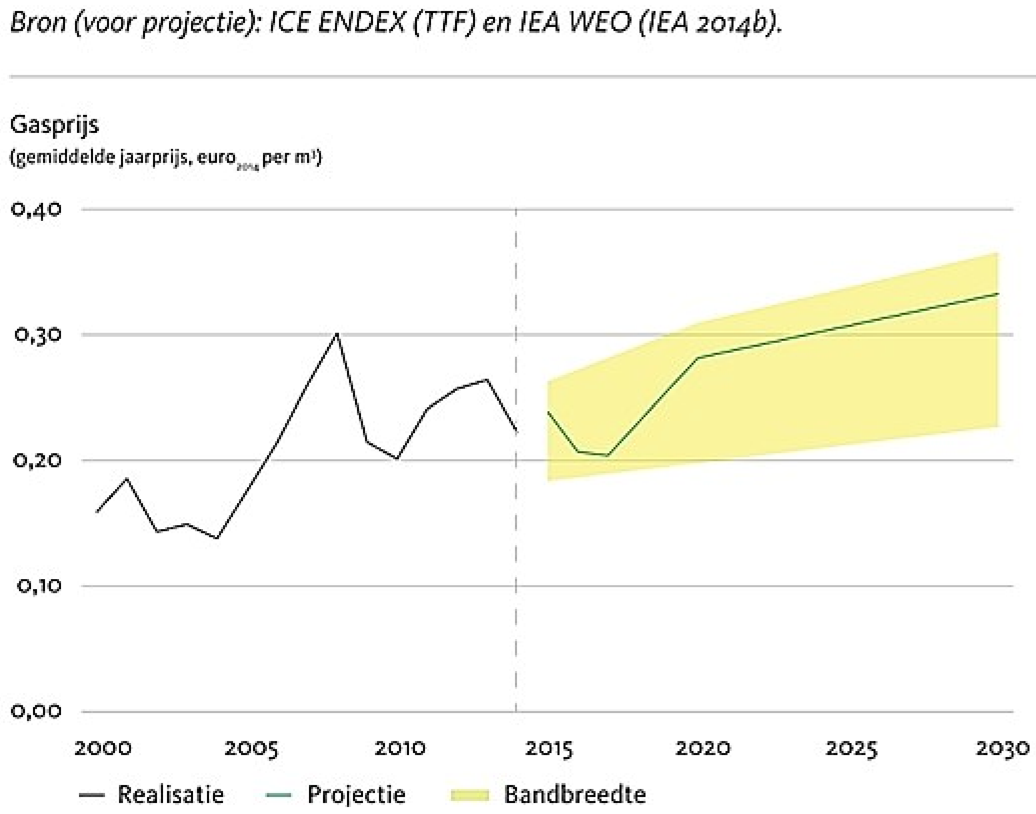


Figure 2-45: Historical and assumed future gas prices in the Netherlands[6] (Schoots & Hammingh, 2015)

[6] The historical gas price is the price for wholesale consumers in the Netherlands. The future gas price is the expected average import price for gas from outside Europe.

2.5.3 CO_2 market

CO_2 prices are considered as the main measure by the EU to reduce GHG emissions of energy intensive industry and the electricity sector. The CO_2 prices result from a market mechanism, although political decisions play a large role in the market functioning.

As of 2005 GHG emissions of firms in the sectors mentioned above are part of the European system for emission trading (ETS). For each tonne CO_2, these firms are obliged that hand in one emission right. The ETS results in an overall cap for the total emissions, since it restricts the quantity of emission rights. Emission rights are tradable and the market price is the result of the interaction between supply and demand of rights. The supply is fixed and decreasing in course of time, while the demand for rights is affected by the economic situation, energy prices, and the deployment of renewable energy. Because rights can be transferred to following years ('banking'), not only the actual but also the expected situation determines the value of CO_2 emission rights.

The CO_2 price projections are summarized in Figure 2-46. At the start of 2014 the European Commission issued a proposal to limit the excess of emission rights by introduction of a market stability reserve. Besides, in October 2014 an ETS reduction target for 2030 was agreed. Since then prices have slightly increased to around 8 euro per tonne CO_2 at the end of July 2015. CO_2 prices are expected to rise further, the increase being dependent on the policy variant considered; the fixed policies variant does not yet take into account de accentuating of the reduction factor and the establishment of the market stability reserve, while the proposed policies variant does so. The fixed and proposed policies variants therefore result in prices of 8.4 euro and 11.2 euro per tonne CO_2 in 2020 respectively, and 15.0 euro and 20.1 euro per tonne CO_2 in 2030 respectively. The wide bandwidth illustrates the considerable uncertainty about the development of the price of emission rights.

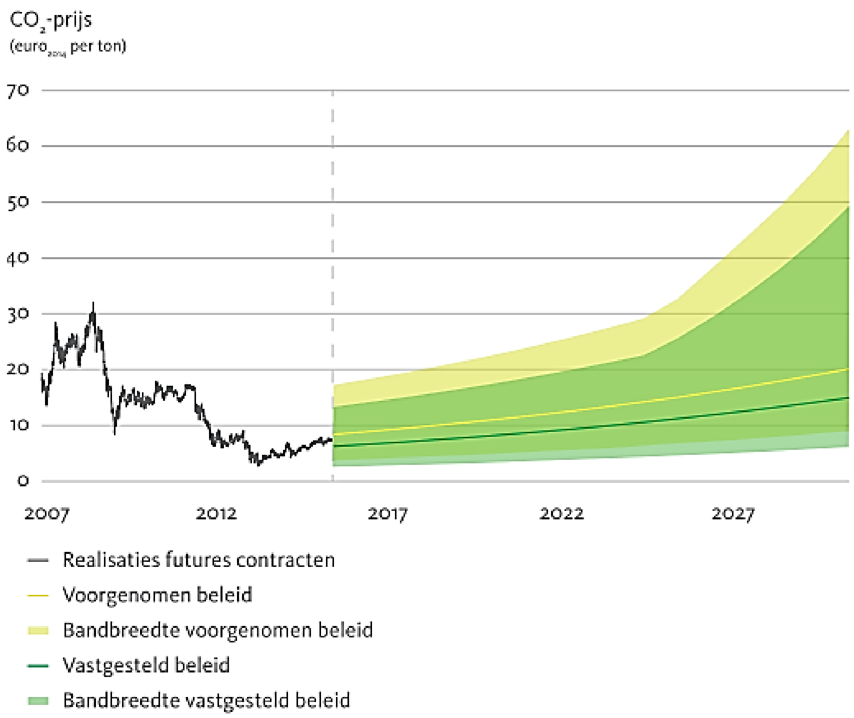


Figure 2-46: Historical and projected future prices for CO_2 emission rights (Schoots & Hammingh, 2015)

2.5.4 Hydrogen markets

One hydrogen market covering different hydrogen applications does not exist at the moment, instead there are submarkets, mainly for industrial, mobility and power-to-gas purposes.

The main segments of the industrial hydrogen market are: chemical (63% of market share), refineries (30%), metal processing (6%), and others (1%). The chemical sector uses hydrogen mainly as feedstock for the production of ammonia and methanol. Refineries use hydrogenation processes in order to produce lighter crudes. The European industrial hydrogen consumption currently covers about 90% of the total hydrogen consumption and amounts to about 7 Mton. It is expected that industrial use will grow with 3.5% per annum until 2025 (CertifHy (a), 2015). Although industrial prices are not transparent, also because trading is taking place bilaterally with individualized contracts rather than in organized exchange type of markets with standardized contracts, current prices are estimated to be around 10-60 €/kg depending on the purity level and the location of consumption (CertifHy (a), 2015).

Given GHG emission reduction targets it is expected that hydrogen use in the mobility sector will develop. According to Hinicio, and based on national H_2 mobility scenarios, by 2030 EU could reach 786,000 H_2 tons of consumption. Prices will gradually decrease as markets become more mature and the technology further develops. The current retail price is around 10 €/kg, while prices could be 5-7 €/kg by 2030 (CertifHy (a), 2015)

Currently, hydrogen is mainly produced using steam methane reforming of natural gas (NG). In a future with GHG emission reduction goals, green hydrogen produced from electricity produced by wind turbines might play a role. Some state that green hydrogen may receive a higher price e.g. because of renewable energy targets or specific low-carbon regulations to be met. It is expected that about 15% of all hydrogen produced i.e. about 1.4 million tons per year could originate from renewable and/or low-carbon sources by 2030. However, the added value of CO_2 neutral H_2 is estimated to be below 0.5 €/kg even if CO_2 prices are seven times higher than today (CertifHy (b), 2015).

The discussed market price projections for electricity, gas, CO_2, and hydrogen in this section have considerable uncertainties. Therefore, the business cases for system integration options should be evaluated along several different price scenarios, rather than only using an average prices scenario.

3 Options for system integration

3.1 Background

In a recent study by TNO, EBN, Shell and Siemens (2016) drivers and barriers for system integration are identified. The report proposes innovation themes that are relevant for offshore energy system integration.

- **Strategic spatial planning** “To balance competing commercial, ecological and societal interests and open opportunities for smart coupling of infrastructure”.
- **Society and Governance** “To understand and mitigate public perception issues, regulatory hurdles and human capital shortages”.
- **Physical network** “To achieve an integrated energy network in the Dutch North Sea.”
- **Health, Safety and Environment** ”To maintain and strengthen the trust that offshore activities can be performed safely and with care for the environment.”

Figure 3-1: Innovation themes identified for offshore energy system integration (TNO, Shell, Siemens, EBN, 2016)

Drivers for system integration

The study identified further the most important offshore energy challenges and drivers for system integration from the perspective of offshore wind sector, offshore gas sector and society using the following categories: *Policy and regulation, Optimisation for lowest social (system) cost, Geographic limitations, Short and long term grid integration, Public and environmental impacts, Shortage of human capital*.

For the wind energy community, the most important driver is lowering the cost of wind energy. This can be achieved by cost reduction through synergies in construction, operation and maintenance, and the optimal use of space through strategic planning. A jointly developed offshore grid including offshore demand for electricity can lower the costs of the investments required to transport power from windfarms.

For the gas community the most important driver is maintaining a security of supply with as little emissions as possible. This can be achieved through electrification of platforms, which could potentially reduce the GHG emissions, increase energy efficiency lower the operational costs of E&P installations. Infrastructure lifetime extension would mean more time to explore opportunities for the reuse of installations and reservoirs for innovations like system integration, CO_2 storage, power to gas and balancing of the offshore energy grid.

For society at large, the main driver is a transition to clean energy at acceptable cost for society while moving towards a low-carbon system that remains at least as reliable as our current energy system.

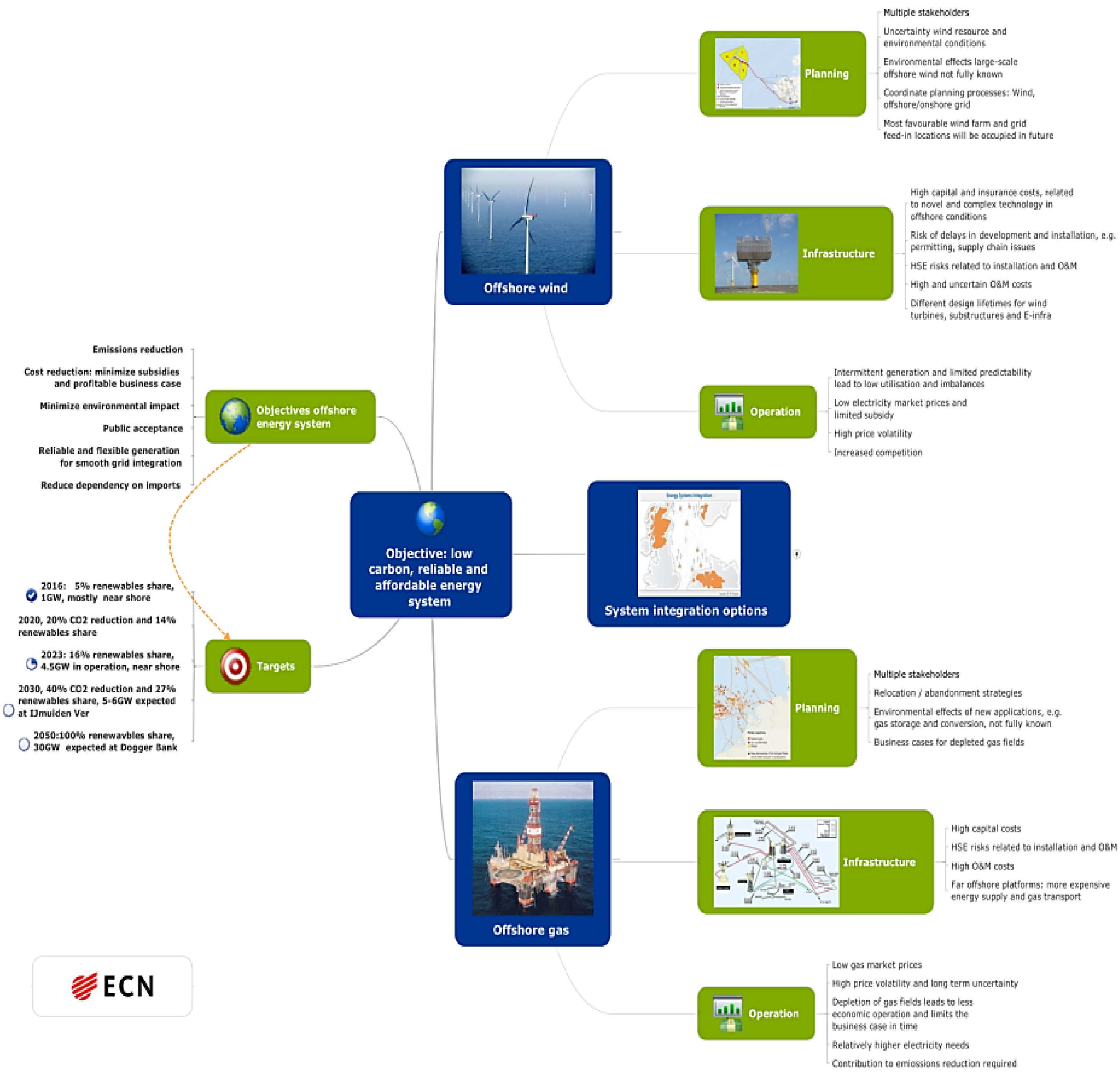


Figure 3-2: Drivers and barriers for offshore energy

It is important to translate these drivers and challenges into concrete examples of possible synergies through system integration in the offshore energy domain. These are listed below and provide a wide array of options. Some of which are selected in this report to explore further.

- Reduce GHG emissions to the atmosphere to – virtually – zero through electrification of hydrocarbon production platforms;
- Reduce the costs of wind farms (and grids) and other offshore renewable energy technologies by combining maintenance staff, connecting to other existing structures in the North Sea and decreasing installation and transportation distances;
- Provide a future infrastructure for far-shore offshore wind farms;
- Increase biodiversity in the North Sea by lowering the environmental impact and creating new biotopes;
- Maximise economic revenues of subsurface natural gas resources by smart development of resources and longer tail-end production (e.g. through gas-to-power at lower gas pressures);
- Maintain a strong workforce for offshore operations by integrating activities by the experienced offshore natural gas workforce with those of the potentially understaffed offshore wind workforce;
- Minimise the negative externalities of a changing energy system, e.g. increasing public participation and guaranteeing energy supply levels;
- Provide gas operators a future license to operate, by, for example, reducing OPEX and ABEX (abandonment costs);
- Provide energy storage and balancing options (offshore underground gas storage (UGS), Power-to-gas (P2G), Compressed air energy storage (CAES), H_2 for a resilient and robust energy grid;
- Reuse infrastructure to enable offshore storage and buffering of CO_2;
- Optimise the use of existing offshore infrastructure by developing power-to-fuels technology options, which potentially enable an efficient transfer of offshore renewable power into high value products and fuels, and using the infrastructure for the transport of gaseous and liquid products to shore;
- Providing offshore feed-in locations for future energy generation options (offshore algae, tidal, wave, non-platform wind, etc.);
- Optimise the implementation of innovative technologies, e.g. offshore (or subsea) Wi-Fi, the use of robotics and drones and unmanned/autonomous ships.

3.2 System integration overview

A considerable number of options for system integration thus exist. In order to limit the complexity of this study only a limited set of main options is identified and assessed. The criteria for the assessment of these options are related to the main objectives for energy and climate change and to the main challenges for wind offshore energy and offshore gas, which these options can help to resolve.

In subsection 0 these generic system integration options are further specified to typical applications that can more clearly illustrate the benefits, challenges and other implications.

The following map illustrates a number of generic system integration options and the opportunities these are expected to offer.

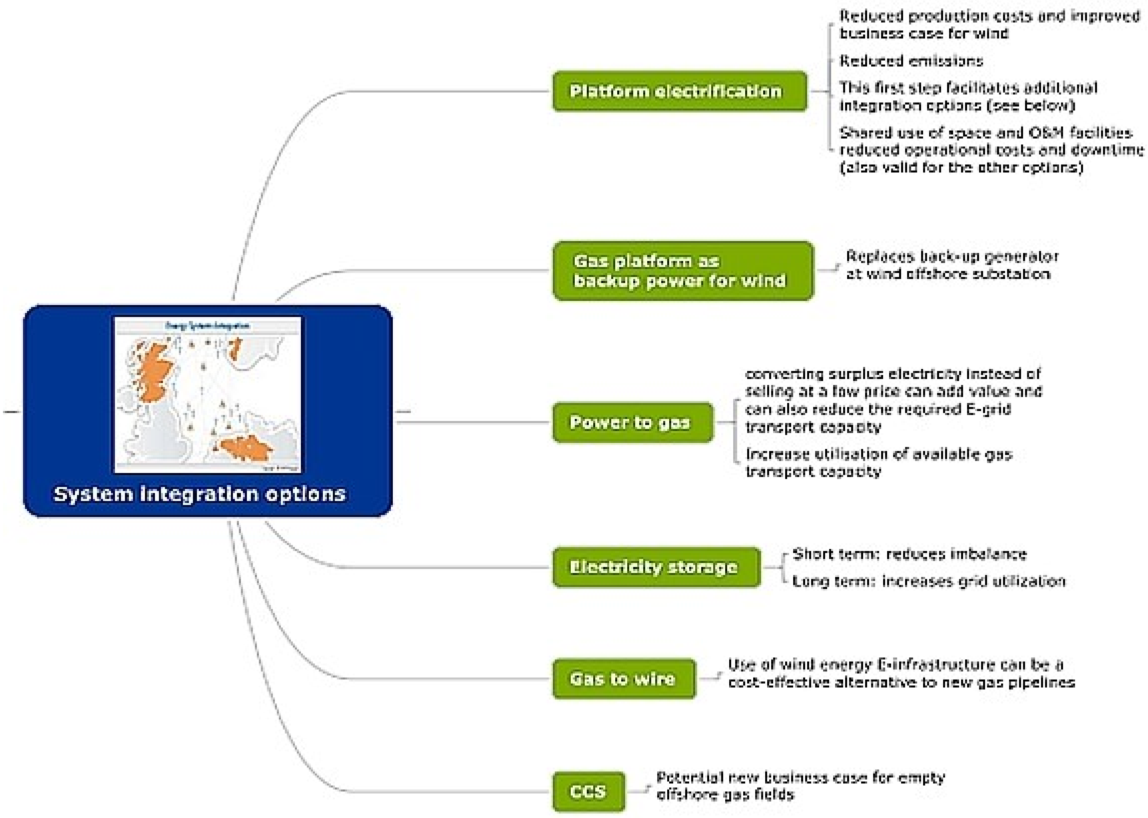


Figure 3-3: short list of system integration options and their opportunities

Alternative solutions to the ones described exist, but are not included in this assessment, e.g.:

- Hybrid platforms, a recently proposed concept by DNV, promises to increase the efficiency of gas-powered compression systems, mainly by compensating production variations (DNVGL, 2016)
- Wind-powered water injection (WIN WIN) (DNVGL, 2016) Joint Industry Project, by DNV-GL, Statoil, ExxonMobil and ORE Catapult
- Multi modal platforms for offshore aquaculture, wind and gas production, and
- For more examples see The Ocean of Tomorrow Projects (Europese Commissie, 2016)

3.3 Characterisation of typical system integration options

3.3.1 Electrification of gas platforms

Electrification of gas platforms considers the power required by these platforms to be supplied by an alternative onshore or offshore power supply system and to be transmitted to the offshore platform via subsea cables, instead of the power supply by a fuel gas turbine or engine installed on the platform. Electrification significantly reduces GHG emissions and increases the energy efficiency which reduces the operational costs and reduces the amount of gas burned offshore and allows this unburned gas to be usefully applied in the economy. The importance of such an option is increased by the fact that in the depleting offshore wells will require more power generation capacity to keep up production.

Regarding electrification of existing gas platforms there are in principle three technology options. The first option is connecting existing gas platforms directly to the onshore electrical grid via subsea power cables, which has already been implemented on platforms in the Norwegian part of the North Sea. Depending on the maximum power consumption and the distance to the onshore feed-in point, different feasible transmission technologies are chosen, as shown in Figure 3-4.

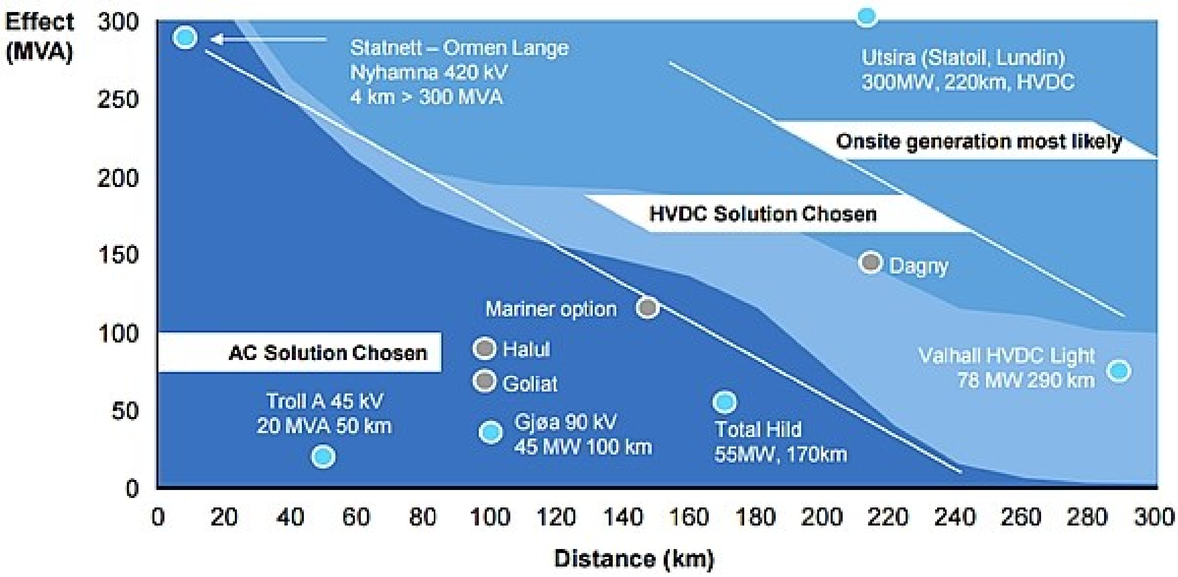


Figure 3-4: Technology selection for electrification of offshore platforms with respect to power demand and distance. (Devold, 2012)

The second option is connecting an existing platform to a wind farm. In the periods of low wind backup power from onshore is provided to the gas platform using the wind farm transmission system. The alternative would be to omit the windfarm connection to shore and provide local backup power, but this is seen to be less reliable, limits the scale of the wind farm and requires additional measures for stable operation, in particular in contingency situations (He, Uhlen, & et_al, 2013). For selecting the technology for interconnecting the offshore gas platform and the offshore wind farm the same rules apply as in Figure 3-4, with the difference that the distance is measured from the wind farm offshore substation. The maximum power demand of most gas platforms is well below 100MW, which can be supplied through a single medium voltage subsea cable.

The third option that addresses electrification of large far offshore gas platforms, for which Figure 3-4 mentions "Onsite generation most likely" would be to connect these platforms, as well as large far offshore wind farms, to a North Sea meshed offshore grid. By using the same infrastructure for offshore gas, offshore wind and cross-border trade, the costs for development and O&M, as well as the benefits, can be shared by different users, thereby making this solution affordable.

3.3.2 Power-to-Gas (P2G)

Power-to-gas is the functional description of the conversion of the electrical power into a gaseous energy carrier, such as hydrogen, syngas or methane. Regarding the conversion of power to gas (P2G), two main technologies can be considered.

Electrolysis or water splitting is the crucial step which uses electricity to split water into its basic elements hydrogen and oxygen. Polymer electrolyte membrane (PEM) and alkaline electrolysis are the two most common technologies for electrolysis. PEM uses a solid polymer electrolyte membrane and alkaline electrolysis uses a liquid potassium hydroxide (KOH) electrolyte. Due to technical reasons, electrolyzers using alkaline technology require significantly more plot space as well as a water desalination system, therefore the PEM technology is the preferred technology. An overview of the technology and trends for hydrogen and fuel cells is provided in the IEA Technology Roadmap Hydrogen and Fuel Cells (IEA, 2015). A detailed cost study of current and future H_2 production through PEM electrolysis is available from (DOE, 2014), incl. the sensitivity to the electricity price.

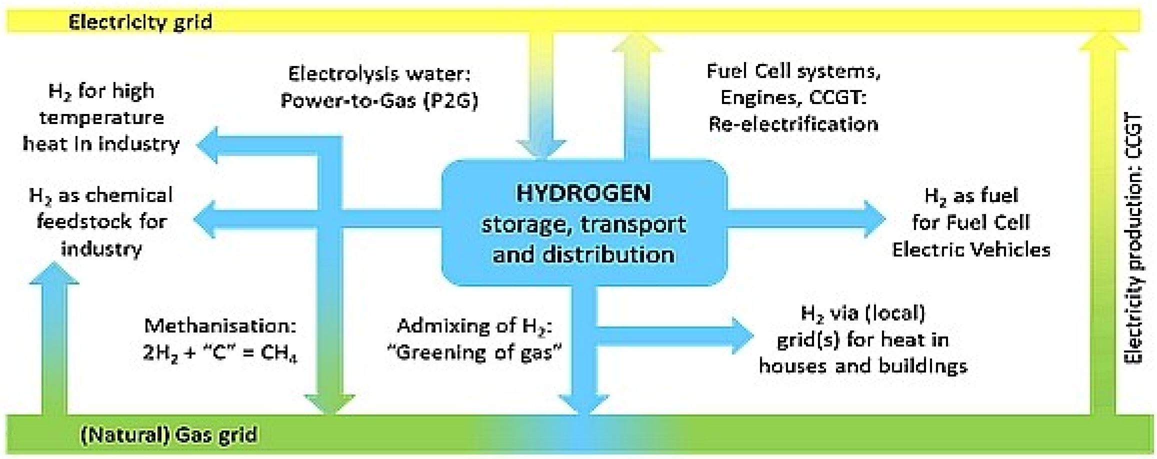


Figure 3-5: Options for gas and electricity grid integration (ECN and DNV GL, 2014).

A possible second step is to convert the hydrogen with CO_2 into methane, that can be fed in seamlessly in the existing gas infrastructure can be used. This additional conversion is from an energy efficiency point of view not attractive due to the fact that the required intermediate process step that couples hydrogen with CO_2, requires additional costs, lowers the system efficiency. Moreover, methanisation units require additional space on the platform, as well as price of methane is lower than that of hydrogen. The technology yet needs to be proven offshore at sufficient scale, for example regarding a 50kW pilot plant onshore that is planned in 2017 (Fraunhofer IWES, 2016).

Hydrogen can be transported to land in two ways. First by admixing hydrogen with natural gas and transporting the mix using the existing gas pipelines to an onshore station for separation of natural gas and hydrogen or co-firing. This requires that neighboring platforms are still producing gas.

Second by a dedicated (piece of) hydrogen pipeline, either when a whole cluster of platforms does not produce natural gas anymore.

A possible third step is to convert electricity (in)directly to a liquid fuel or feedstock such as formic acid, Ammonia, Methanol or Dimethyl Ether. Currently these possible technology streams are still in an early stage of development. The indirect, via water electrolysis and thermo-catalytic conversion of Hydrogen and CO_2 to CH_3OH (Methanol) might be most interesting option to be considered. Liquid fuels might be easily transported via existing infrastructure.

3.3.3 Carbon capture and storage (CCS)

Carbon dioxide capture and storage (CCS) entails the capture of carbon dioxide from facilities in the energy intensive sectors followed by transport and storage of CO_2 in geological formations (IPCC, 2005). CO_2 storage in these geological formations encompasses the injection of CO_2 into porous rocks that may hold or have held gas and or liquids. In literature, several storage media are proposed, such as deep saline formations (aquifers), (near) empty oil reservoirs, possibly with enhanced oil recovery (EOR), (near) empty gas reservoirs, possibly with enhanced gas recovery (EGR) and deep unminable coal seams combined with enhanced coal bed methane production (ECBM).

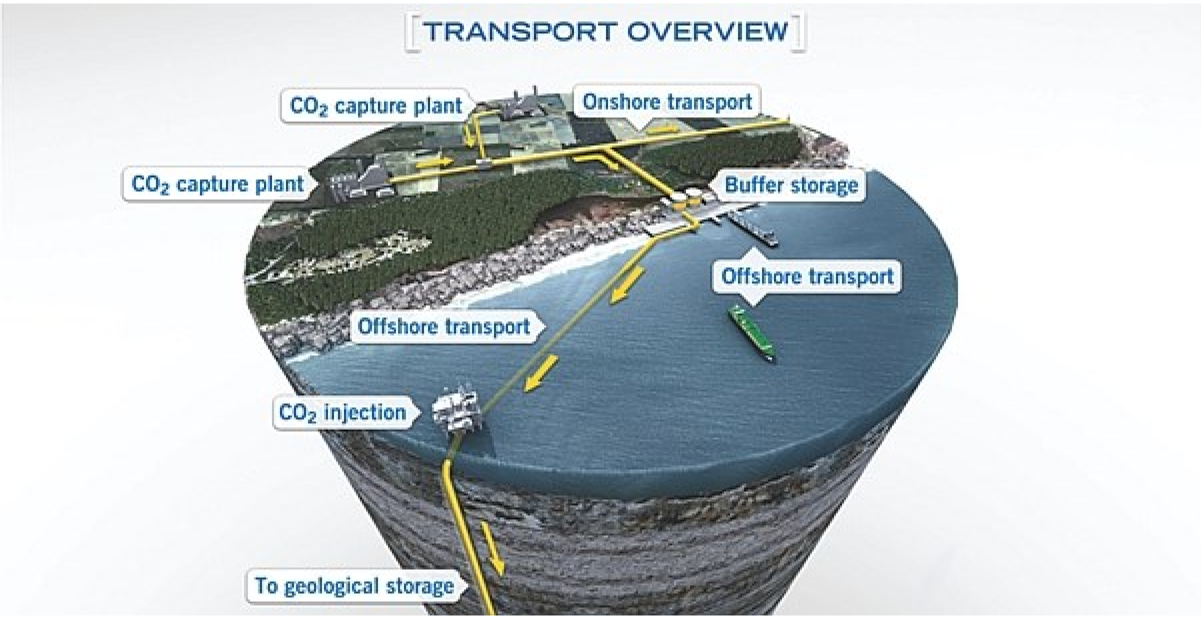


Figure 3-6: Graphical impression of CO_2 transport and storage as part of CCS value chain (GCCSI, 2015)

According to IEA scenarios (IEA, 2013), CCS application can contribute to about one-sixth of CO2 emission reductions required in 2050, not only from electricity generation, but also from industrial applications (steel, cement, chemicals).

For the Netherlands earlier scenarios studies suggested (Damen, Faaij, & Turkenburg, 2009) that already 50 Mt CO_2/year could be avoided in 2020, and 80–110 Mt CO_2/ year by 2050. A more recent overview of scenarios suggest a wide range of futures for CCS ranging between very low deployment to 332 Mt CO_2/year in 2050.

The greatest potential for CO_2 emission reductions is identified in the power sector, industry and fuel conversion sectors (e.g. refineries). Deployment has been delayed but the Netherlands clearly has vast potential for CCS deployment. Several gigatonnes of (offshore) CO_2 storage potential, clustered point sources and first building blocks of a CO_2 infrastructure. Offshore storage is an important part of CCS in the Netherlands.

The offshore storage of CO_2 can be either permanent or intermediate. In the first case, $CO_2$2 from onshore and offshore emission sources is stored which helps reducing the greenhouse gas footprint for carbon intensive sectors. Intermediate storage of CO_2 can act as a buffering alternative in order to provide a source for synthetic natural gas production through methanisation of hydrogen, as shown in Figure 3-7. Also other energy carriers or chemicals can be produced using CO_2 as a feedstock. Decarbonisation of energy carriers and chemicals is in this variant obviously more limited compared to permanent storage of CO_2.

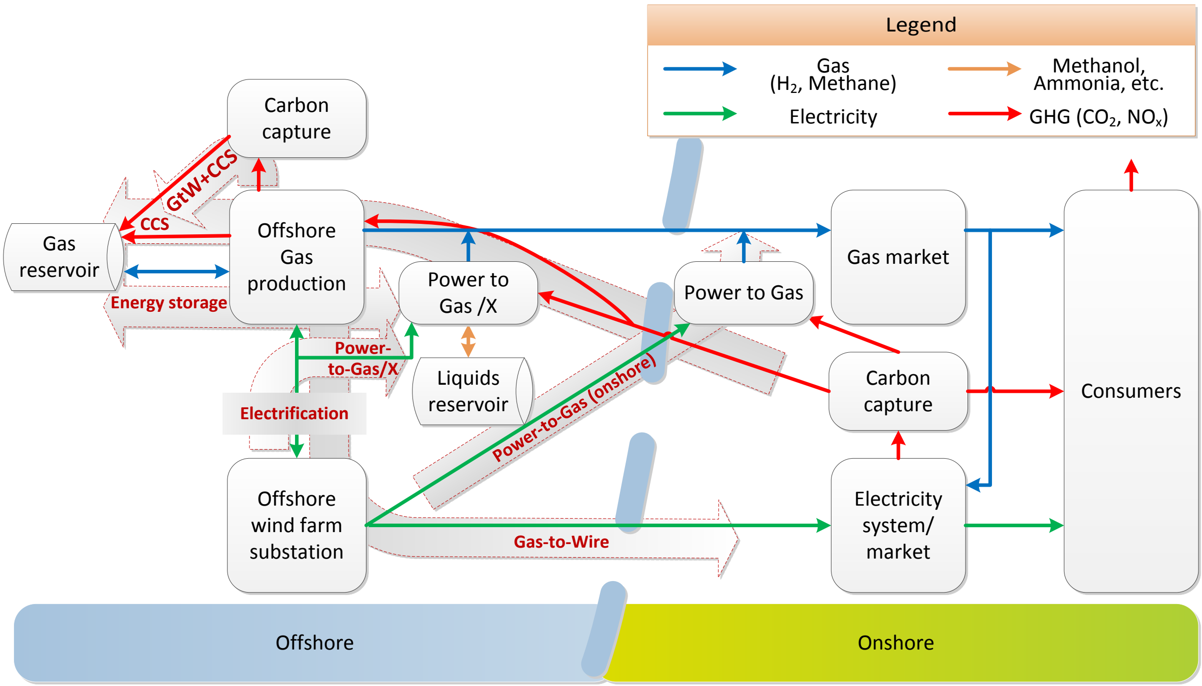


Figure 3-7: Offshore system integration options that could include CO_2 (buffer) storage. Adapted from Jepma et al. 2015 (Jepma, 2015)

In their vision on energy transition, the Dutch government considers development of CCS in the Dutch North Sea as an important aspect (Dutch Ministry of Infrastructure and Environment, Economic affairs, 2016).

The Netherlands already has a strong position and experience in developing and demonstrating CCS. Already since 2004, CO_2 is being injected (annual 20 kilotonnes of CO_2) captured from the locally produced natural gas, into the same gas field in sector K12-B at the North Sea. At larger scale offshore CO_2 storage is already in operation in Norway since 20 years: the Sleipner project with ~1 million tonnes of CO_2 stored per year. This scale is also foreseen for the Netherlands where the (ROAD, The Rotterdam Capture and Storage Demonstration Project, 2016) project of Uniper Benelux and ENGIE Energie aims at demonstrating subsea CO_2 storage captured form the coal plant of Uniper at Maasvlakte. ROAD plans to capture 1.1 million tonnes of CO_2 per year and store this in a depleted hydrocarbon reservoir under the North Sea.

This project could be an important stepping stone for a larger scale CO_2 infrastructure; together with the existing onshore OCAP CO_2 transport network for enhance crop production in west Netherlands.

Graphical sketches of how such an infrastructure could evolve are shown below based on work by EBN (2010) and the Rotterdam Climate Initiative (RCI, 2010).

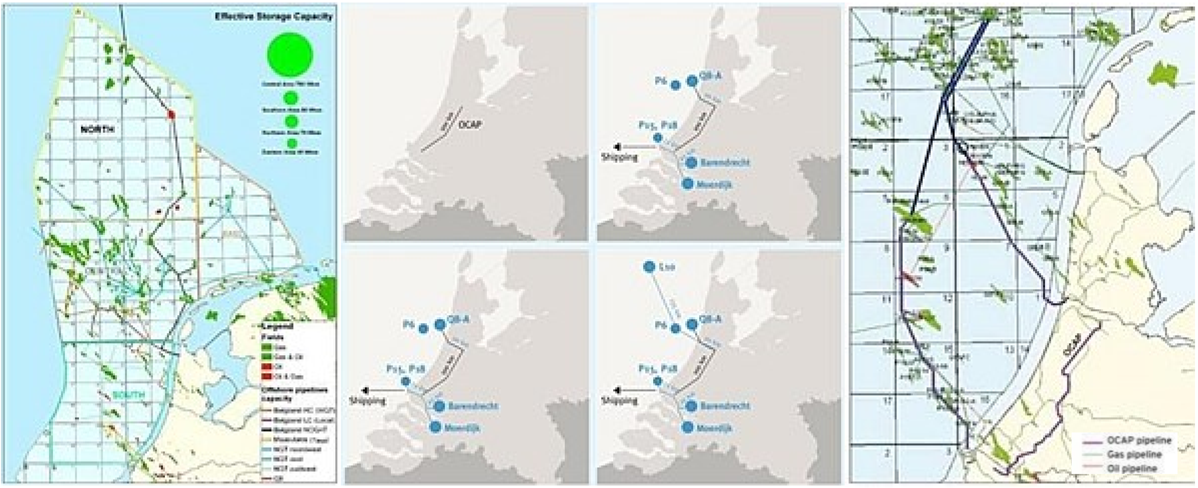


Figure 3-8: Offshore storage scenarios by EBN (2010) and the Rotterdam Climate Initiative (2010)

More information on the history of CCS in the Netherland can be read in the book Linking the Chain (CATO2, 2014). The recent CCS report from IEA provides a comprehensive overview of the status of CCS from an international perspective (IEA, 2015).Dutch specific information can most easily be obtained via the CATO programme (CATO, 2016).

CCS: a viable option offshore?

Whether CCS could be viable in offshore system integration, the following needs to be considered when developing an offshore storage strategy (Ecofys, 2015):

- Geological characterization and suitability of the reservoir for CO_2 storage based on existing or new data
- Type of offshore storage option (saline aquifer, near empty gas/oil reservoir)
- Competing use options for the storage reservoir (e.g. gas/hydrogen storage)
- Location of offshore storage site
- Storage capacity of the reservoir
- Typical power demand for pressurizing the CO_2
- Availability over time (i.e. especially related to stop production of hydrocarbon and possible mothballing of offshore infrastructure)
- Possibility to re-use existing infrastructure (platform structure, space available, pipelines, wells).

3.3.4 Gas-to-wire (GTW)

Gas-to-wire (GTW), also referred to as Gas-to-Power is the conversion of gas into electrical power. In the case of offshore gas platforms, this process requires the conversion of gas on the platform by gas turbines, fuel cells or combustion technologies using oxygen for combustion (oxyfuel combustion). These options are in principle possible to combine with CO_2 capture technologies to reduce GHG emissions of GTW facilities.

In the case of Netherlands, this option could be seriously considered as there are currently potential gas fields that are not exploited yet due to their long distance from existing gas infrastructure. The required installation of new pipelines makes these gas fields too costly to develop at this moment.

A second option is to apply GTW in marginal or nearly depleted offshore gas fields, where high fuel consumption for compression leads to uneconomic operation, or where gas transport infrastructure that remains is uneconomical to exploit for the small remaining assets.

A third possibility is to use marginal or nearly depleted offshore gas fields as offshore gas storage in combination with power-to-gas and gas-to-wire functionalities. The option would use electricity in high wind periods and convert this to synthetic gas offshore using PtG technologies. In low wind periods the gas to wire facility could use natural gas and injected synthetic gas for a more stable electricity supply from the offshore energy sectors. In this way infrastructure is used optimally and potentially storage costs can be reduced. This concept has however not been studied in detail.

All three options require a smart integration with imbalance power market dispatch system and control algorithms. A combination with offshore CCS to reduce CO_2 emissions is proposed and evaluated in (Winden, Chen, & et_al, 2013). Gas-to-wire using fuel cells are regarded as more expensive, while the required investments for grid connection and for reengineering the platform are already considerable. This application only showed to be economically feasible over longer periods of time and for relatively short connection distances. Feeding power into existing (offshore wind) electrical transmission systems could be beneficial, in the sense that the connection distance and related costs are reduced. Costs could also be reduced potentially if relocation of the GTW equipment will be made easier. Relocation of GTW equipment could also be done using floating platforms that could be relocated, shown in Figure 3-9. The technology readiness of this application is however pre-commercial, but could play a role in the longer term.

Further technology improvement is needed to increase offshore conversion efficiency, lower cost of conversion and minimize emissions from conversion.

Figure 3-9: Graphical impression of a floating Gas-to-Wire platform (source: Fameline O&G)

3.3.5 Energy storage

This option has not yet been elaborated on, as the application and technology choices are not yet clear. Gas or electrochemical storage would require that least the same set-up as has the power to gas application, but with extended gas storage, either hydrogen and oxygen, or other chemicals, e.g. ammonia, such as applied by NUON onshore (NUON, 2016). Mechanical Energy Storage including compressed air or gas (CAES) or pumped hydro (Energiesystemtechnik, 2016) is regarded as a more mature and efficient technology, although these offshore application at a large scale still needs significant time and investments. The storage capacity and power that is needed will largely depend on the type of application, such as short-term grid support, e.g. balancing, frequency recovery, or long-term storage in terms of hour or even weeks.

Jepma et al (2015) includes several scenarios (medium and long term) for offshore surplus wind energy conversion to gas (hydrogen and SNG). Forms of energy storage are also part of these scenarios. The authors suggest for example small scale gas buffer on the platform, storage of gas in salt caverns and storage of gas in depleted gas fields. As the study entails a pre-feasibility study the detailed technical and economic challenges of offshore storage are not yet sorted out.

3.4 Assessment of options

3.4.1 Assessment framework

The different system integration options are assessed qualitatively along the following criteria, categorized in four categories, as pictured in Figure 3-10. For this assessment of the each system integration options will be compared to a business as usual scenario as a base case, which considers that the development of offshore wind will be separate from the developments in offshore gas.

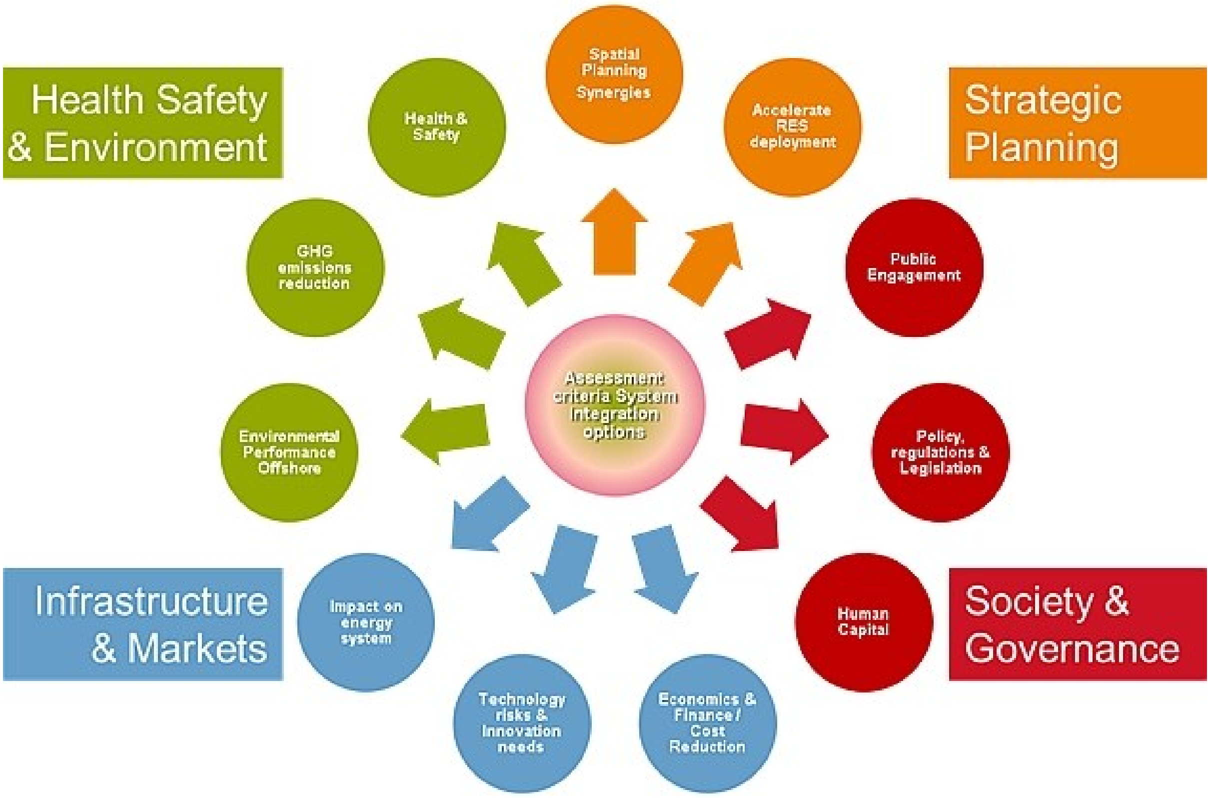


Figure 3-10: Criteria as elaborated during the first stakeholder workshop at 2 September 2016:

Also a general assessment is made on the feasibility of the system integration options for the short term (until 2023), medium term (2023-2030) and long term (2030-2050), aiming to define possible development strategies and critical time paths.

Most of the assessment criteria contain many aspects, of which need some more explanation:

- Spatial Planning Synergies: includes efficient use of space at sea, both at the production locations and the transmission infrastructure, including landfall
- Accelerated RES deployment: impact on achieving the mandatory EU targets on renewables shares on the short term, as well as on accelerated emission reduction on the longer term
- Public engagement: includes public support for specific system integration options and developments in renewables and the gas sector in general, looking at economic and ecological effects, as well as possible intrusion of nature or recreational zones
- Policy, regulations & legislation: includes the level of policy support as well as the time and effort needed to put in place a suitable legal and regulatory framework to enable and support system integration and to coordinate the developments between wind and gas.
- Human capital: includes potential for new employment as well as bottlenecks in the availability of sufficient qualified personnel
- Economics & finance / cost reduction: includes the business case from installation, (continued) operation to decommissioning or repowering for both gas and wind, focusing on potential reduction of costs and risks and on additional benefits
- Technology risks & innovation needs: includes an assessment on the maturity of the technology required and perceived risk level as a result of this, as well as an identification of technology needs to reduce these risks and thereby costs.
- Impact on energy system: includes a wide range of aspects, such as potential efficiency increase of the energy system, either by a decrease of the production from onshore power plants, or by reducing the need for balancing reserve and reducing ramp rates. Another effect is the decrease of gas imports. A third aspect is the possible impact on market prices level and volatility. A forth aspect contains possible effects on the electricity transmission system, such as on grid frequency and voltage stability and on the risk of congestion. Linked to these effects are: fuel and infrastructure costs, GHG emissions and security of supply.
- Environmental performance offshore: includes effects on the local eco system
- GHG emission reduction: includes the contribution to national and global climate targets
- Health and safety: includes the amount and risk of (mainly) offshore operations for installation, O&M and decommissioning, including transport. Another aspect is the level of experience, which can possibly be increased by sharing knowledge between sectors.

3.4.2 Assessment of electrification of gas platforms

Electrification of existing offshore gas platforms has clear benefits such as fuel savings and reduction of NOx and CO_2 emissions. For instance, in the case of Norway six projects (Troll A, Valhall, Gjøa, Goliat and Martin Linge) of electrification of offshore facilities represent a reduction or elimination of CO_2 emissions around 1.2 million tons per year between 2008 and 2020 (Statoil, 2015). The emissions reduction when integrating 20MW wind power with an offshore gas platform with two gas turbines of 23MW each (and a third as backup) is estimated as 55.6 ktonnes CO_2 and 379 tonnes NO_x (He, Jacobsen, & et_el, The Potential of Integrating Wind Power with Offshore Oil and Gas Platforms, 2010). For the Netherlands EBN has estimated that electrification of the ten largest offshore production platforms saves 1 Mton of CO_2 per year over the coming 10 years (TNO, Shell, Siemens, EBN, 2016), while electrification of the K-14 platform of NAM, near the planned IJmuiden Ver site, is said to save 0.8 TWh per year (De Ingenieur, 2016), while the total energy consumption is estimated at 7TWh per year (Maritiem Nederland, 2016).

Since the efficiency of current offshore gas turbines is quite low, roughly between 20% and 30%, significant fuel savings can be achieved by electrification, while also the reliability increases, leading to increased availability of gas with added value for operators and tax income for the Netherlands. From an operational perspective, the electrification of offshore platforms indicates fewer personnel on board, improve health and safety on the platform, less space required on the platform and fewer reinforcement structures by eliminating the gas turbine, saving operational costs. Moreover, the reduction of CO_2 emissions will also avoid CO_2 emission costs as less CO_2 emission rights need to be bought by offshore facilities operators. The power supply even from onshore can be performed by renewable energy sources, which further increases the environmental benefits.

On the other hand, electrification of platforms and establishing the electrical connection requires significant investments. A comparison could be made between only replacing equipment, building a completely new platform or replacing the topside of the platform. Electricity connection costs are likely to be substantially higher for gas platforms further from shore and when electricity infrastructure cannot be shared with neighboring gas platforms. For these cases connecting an existing gas platform with a wind farm and maintaining existing gas turbines on platforms for back-up can be a viable alternative. The same trade-off needs to be made in case of new gas platforms which are already designed fully electrical.

The electrification is considered to be most beneficial for the larger hubs, as the main energy demand is located in the main compressor and smaller satellites will be decommissioned sooner.

Onshore power can be generated more efficiently and any operational issues can be resolved very quickly. In case of onshore electrification, the platform connection is part of the national power grid and this indicates high security of supply.

Furthermore, main driver of electrification seems the national legislation (in Dutch 'Activiteitenbesluit milieubeheer', section 3.2.1) which requires that all combustion plants < 50 MWth, both existing and new ones, should fulfill the NOx and SO_2 emission requirements as of 1 January 2017. For offshore platforms a transitional period holds until 1 January 2019. Furthermore, regarding gas turbines only NOx emission requirements are applicable. Gas turbines that operate for maximum 500 hours a year are exempted from the emission requirements and therefore they can still operate as back-up power supply[7].

Offshore wind farms can profit from the provision of backup power, replacing the need for backup capacity at the offshore substation in the wind farm. Also, the power that is consumed offshore reduces the capacity rating of the offshore transmission system to shore. In other words, given a certain transmission system rating, the capacity of the offshore wind farm can be larger, provided that there are enough feed-in tubes and switch bays available at the offshore platform.

[7] [reference=P2G externalities project]

Considering other system integration, like the ones that are considered in this study, most options require electrification of the gas platform, so that electrification can be regarded as a first step, enabling additional system integration.

In the long term, large and far offshore wind energy requires substantial investments in the offshore transmission infrastructure, which will probably lead to coordinated planning and deployment of a North Sea offshore grid. Connection of far offshore gas platforms to such a North Sea offshore grid can lead to even more significant operational cost reductions than for near shore platforms.

Despite the obvious advantages of electrification, the implementation should be assessed on a case-by-case basis taking into account a number of factors, such as the distance of the platform(s) from shore, marine conditions, technology requirements and the capacity of onshore or offshore power generation.

With TenneT as offshore grid developer and operator, connecting offshore consumers like gas platforms is possible from regulatory perspective, and leads to the opportunity to undersize the electrical connection with respect to the offshore wind farm maximum power production. Main bottleneck is the limited space and time to plan the cable that that interconnects the gas platform and the TenneT offshore substation.

As rough estimation the K-14 platform with an energy consumption of 0.8TWh/yr would require roughly 0.25 TWh/yr of electricity after electrification, assuming an initial and final energy efficiency of 30% and 95% respectively. This is equivalent to the production of about 70 MW, assuming 4000 full load hours and a combined wake and electrical efficiency loss of 10%.

3.4.3 Assessment of Power-to-Gas

The P2G option can act as an effective energy balancing option to deal with wind energy intermittency, both at short and longer timescales. In particular, the gas infrastructure can accommodate large volumes of electricity converted into gas in case that the supply of wind power is larger than the grid capacity or than the electricity demand. As a result, P2G can increase the value of offshore wind and reduce the costs offshore grid connections and for balancing power reserve elsewhere in the electricity system. Another main advantage is that this option can provide gas with a lower CO_2- footprint and, through methanisation and further conversion steps, also chemical feedstock, which will replace natural oil and gas. In this way P2G can facilitate the energy transition, towards higher shares of renewable electricity, gas and chemicals in the energy mix, making this innovation an important topic in achieving a carbon-neutral energy system in 2050. The study reported in (Brouwer & Broek, 2016) found a 12% reduction of the total costs when increasing the share of RES from 40% to 80% (resp. 22% to 59% intermittent RES) through natural gas-fired power plants. Cost reductions found for other options were: Demand response (2–3% reduction), RES curtailment (2% reduction in 80% RES scenario, compared to no curtailment); increased interconnection capacity (0–1% decrease) and storage (0.1 to 3% *in*crease), considering CAES with 40% cost reduction and batteries with 70% cost reduction.

From an economic perspective, savings on electricity infrastructure can be achieved as new offshore wind farms with P2G conversion require no electricity connection, and extension of wind power plants together with P2G does not need an extension of the electricity infrastructure. This is important as the locations to connect new offshore wind farms to the electricity grid are limited and also the onshore transport grid can only handle limited additional offshore wind after 2023, requiring grid reinforcements or other adjustments.

For P2G to be economic it needs sufficient scale, which is only available far offshore, e.g. IJmuiden Ver. One of the reasons is that the costs for hydrogen transport decrease with the transport capacity (larger diameter). These scale benefits are much larger than for electricity transport infrastructure.

On the other hand P2G requires adjustment of the existing gas infrastructure in order for hydrogen transport. In case that hydrogen is transported onshore admixed with natural gas, additional costs should be considered for gas separation facilities and the actual separation process, while the case that hydrogen is transported by a dedicated hydrogen pipeline may require substantial pipeline investments, see also fig. 24 in (Deutscher Verein des Gas- und Wasserfaches e.V., 2013). Furthermore, the efficiency loss of conversion to hydrogen is still considerable; the production of 1 kg hydrogen (which is equivalent to 33 kWh) requires currently more than 50 kWh of electricity, although conversion efficiency is expected to increase to 65-70% in the next decade. Although the research has not yet been finished, it seems that these efficiencies and additional costs required for conversion, compression and gas separation do not outweigh the benefits of not having to construct an electricity infrastructure to transport the offshore wind energy to shore. Two important determinants of this preliminary result are the distance to shore and the market for (green) hydrogen. First, the case for platforms further away from shore may be more favorable due to larger avoided electricity infrastructure costs. Second, currently a market for green hydrogen is lacking, hence produced green hydrogen needs to compete with grey hydrogen which can still be produced from natural gas against low prices.

3.4.4 Assessment of Carbon Capture and Storage (CCS)

Offshore transport and storage of CO_2 provides the opportunity to large emitters in reducing their carbon footprint. Offshore storage could be done in saline aquifers in (near) empty oil and gas reservoirs, possibly with enhanced hydrocarbon production. Moreover, offshore transport and storage could make use of existing O&G reservoirs and infrastructure (platforms, pipelines).

An overview of offshore and onshore CO_2 storage locations is provided in (Ramirez, Hagendoorn, Kramers, Wildenborg, & Hendriks, 2010), see figure below.

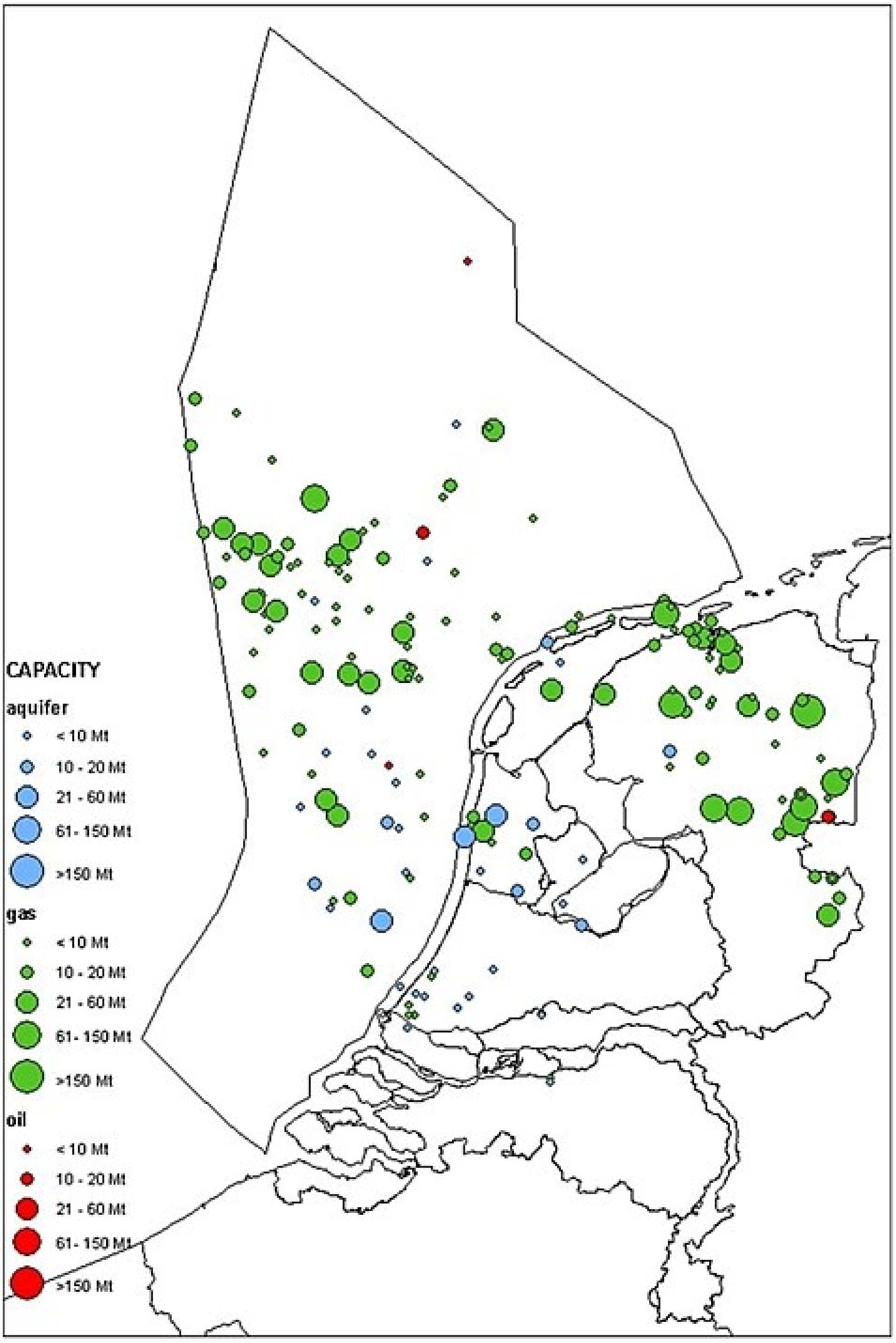


Figure 3-11: Map of potential storage locations by CO_2 capacity of storage, type of field. Source: (Ramirez, Hagendoorn, Kramers, Wildenborg, & Hendriks, 2010).

An offshore CO_2 storage strategy for these locations would be of high value when bringing CCS to the commercial phase. A follow-up assessment of the offshore storage potential, see below, yielded a short list of high-capacity storage sites for CO_2. Blue indicates saline formations and green shows depleted gas fields. Larger green discs represent clusters of gas fields. The numbers correspond to storage reservoirs which are not further detailed here.

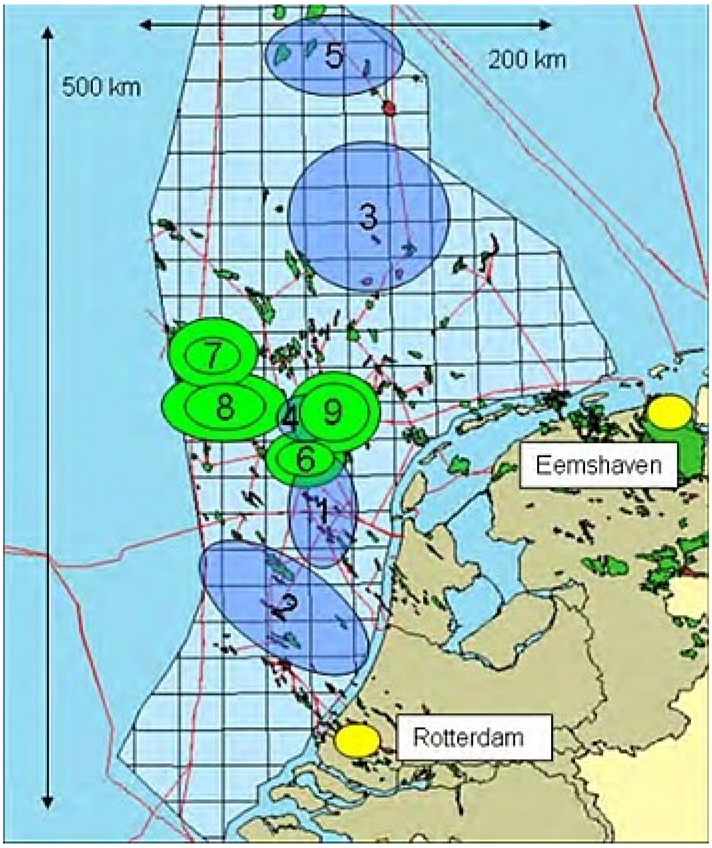


Figure 3-12: Offshore storage options. Source: (TNO, 2012)

Loeve et al (2013) performed an analysis for the short and medium term development of offshore CCS in the Netherlands. Scenarios for CCS development were constructed by combining the most recent estimates of offshore storage capacity, for both depleted gas fields and saline formations, with expected timing and volumes of captured CO_2 from two industrialised regions, the Rotterdam harbour area and the Eemshaven area. The cost of transport and offshore storage (excluding capture) of CO_2 were explored, yielding estimates between 5.5 and 7 euro/tonne (incl pipeline transport and offshore storage).

National scenarios (SER, 2016) indicate that CCS can contribute substantially to the emission reduction target in 2050. The Netherlands has a strategic position for CCS with respect to geographical, geological, and economic aspects, as well as the country is considered suitable for CCS taking into account the vast amounts of storage locations both onshore and offshore. Large CO_2 sources are located near offshore storage locations, e.g. in Rotterdam port area in possible connection with Antwerp; IJmuiden with possible connection to Amsterdam and the North of the Netherlands near the Eemshaven. In addition, the Netherlands' geographical position near the North Sea provides opportunities to collaborate in a future CO_2 infrastructure with the surrounding countries, like UK, Germany and Denmark (Ecofys, 2016). Consequently, the offshore CO_2 infrastructure could establish strategic connections with infrastructure in other North Sea countries like Norway and UK that are active in the area of CCS. For example, a feasibility study of a CO_2 trunkline from the Netherlands to the Utsira formation in the Norwegian part of the North Sea (Broek, Ramirez, & et_al, 2010) shows that an offshore pipeline to the Utsira formation as part of a regional solution (transporting CO_2 from the Netherlands, Belgium and Germany) appears a cost-effective option in the medium term (after 2020), provided that the CO_2 price (now between 3 and 9 Euro/ton), will be at least 43 Euro/ton in 2020 and 60 Euro/ton in 2030.

In addition, the region sees strongly increasing biomass trading and investments in bioenergy facilities and bio-refining that utilize both regional and imported biomass resources. On medium term, new biomass capacity can be combined with CCS infrastructure offering opportunities for large scale negative emission facilities, which are now deemed necessary to limit the increase of global mean temperature 20C or 1.50 C as recently agreed at COP-21 in Paris.

Timewise, CCS and especially CCS-EOR options on short to medium term can provide another key opportunity for continued use of exisiting O&G infrastructure in the North Sea area. Enhanced Gas Recovery poses more challenges, but may develop later on when more experience is gained. Such early schemes could kick-off CCS infrastructure on shorter term, while on longer term the CO_2 capture on land can be connected to new biobased conversion capacity and industry, partly to realize negative emissions in the energy system

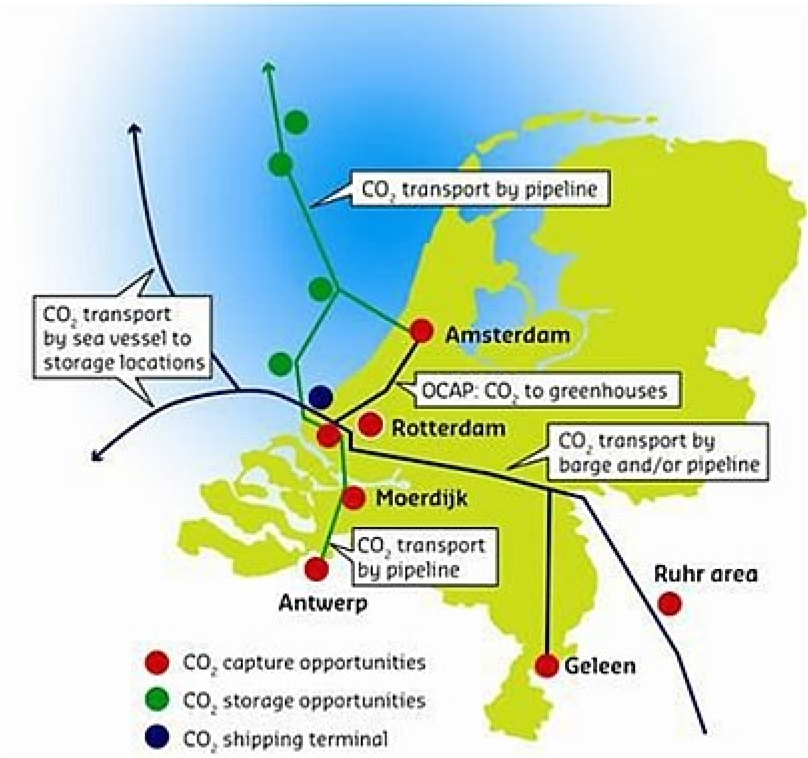


Figure 3-13: Possible future for Rotterdam as CCS hub. Source: RCI

An important barrier is that there is currently no strong economic incentive to implement commercial CCS projects. The most important incentive in Europe is the price of CO_2 under the EU Emission Trading Scheme which is currently too low to justify commercial CCS project investments.

The technology is ready to be implemented in pre-commercial projects. For the Dutch offshore a window of opportunity exists. In the near future a significant share of hydrocarbon reservoirs will stop production and infrastructure will be abandoned. Platforms and wells can be re-used for CO_2 storage. Costs are entailed in bridging the time gap between stopping production and commencing with CO_2 storage. These mothballing costs are considerable and the window between stop production and CO_2 injection should ideally be as short as possible.

3.4.5 Assessment of Gas-to-Wire

Implementing GTW, uneconomical exploitation of gas infrastructure could be avoided and could be decommissioned. The platforms depending on these pipelines could be retrofitted to convert gas to power and use the electricity grid to transport energy to shore. This could lower the costs and could improve the revenues for both oil and gas sector, offshore electricity transport grid and the national treasury. On the other hand, there is a need for investing in the retrofit of power technology (and CCS) on the platform, as well as space should be available for this. For undeveloped gas fields the investments of new platforms with green field gas to wire technology installed requires also very high investments.

The business case for gas fields that are currently not exploited due to their distance from gas infrastructure can positively change in case these fields could be connected to an existing and nearby electricity grid. Therefore, platforms could produce power converted from gas and transported to shore through the power grid.

Improving the ultimate recovery of resources and integrating more gas fields into production will enhance the turnover of Dutch oil and gas sector while generating revenues for the national treasury and public. Gas to wire also presents an option for improving the security of energy supply. A pre-requisite is that gas to wire should fit into a low carbon energy sector and should, depending on future policy and regulations, be equipped with CCS to minimize the environmental footprint.

The business case hinges on several factors. Power vs gas price: if the power price is higher than the gas price, it is more viable to produce power than gas. The higher power price could be an effect of an unbalanced power market with more demand than supply. The produced power by the gas platforms would in that way help balance the market. This could for example be the case during days that wind conditions will not favor wind farms to generate significant power. Generating power during these days and transporting this power onshore will make sure that the electricity grid is better used and security of supply could be improved. However, it is in doubt whether such a variable production of gas versus a more baseline production is desirable for the producers. It could be only viable if the power price is very high during unbalance periods. Besides, it depends on the regulation and the view of the national government on holding strategic gas reserves. In any case, the technology is viable depending on gas and power price, as well as the costs of the conversion, the reduction of costs from maintaining the gas infrastructure and if necessary the costs of CCS and the development of and/or connection to the electricity grid.

A feasibility study in 2012 by TNO explored the potential of GtW of onshore and offshore Netherlands. The study included a portfolio of 318 gas fields currently in production but expected to become available for alternative development within 15 years. Stranded fields where also included. The cost breakdown for the various development options considered the average Capex/Opex estimates from various operators. A minimum gas deliverability (plateau rate and duration) specific for the GtW development was defined for and Unit Technical Cost (UTC) below 20 €ct/Nm^3. A total of 68 candidate fields were identified onshore with a potential production of 35 billion Nm^3 of gas while offshore only 35 candidate fields with a potential of 53 billion Nm^3. However, for offshore the availability of a future offshore electricity infrastructure is needed. In case an E-grid connection is not nearby, offshore G2W development does not appear as a viable economical option. In addition, a study by Van Heeswijk indicates that Gas-to-Wire becomes much more viable with higher power prices (actually the spread between power and gas prices) and higher conversion efficiencies (Heeswijk van, 2012).

It is definitely critical whether this technology is supported by laws and regulatory framework. It could be the case that in time of effect, production of power by gas is only of value together with carbon capture and storage (CCS), because of regulations or a higher CO_2 price than the current one. It has also been shown by Winden (Windén B., 2013) that the GTW concept can increase merit if CCS is introduced for thermal power generation by removing two transportation needs (transportation of CO_2 for storage and transportation of natural gas onshore for power generation). The uncertainty in this concept lies in operating large facilities offshore and exposing of expensive equipment to challenging offshore conditions. The experience of operating offshore wind farms of ever increasing complexity, experience with offshore CCS and offshore platform conversion can make this concept an option in the future.

3.4.6 Assessment of Energy Storage

Energy storage offshore is one of several options to enable reliable and efficient operation of a future electricity system that is dominated by intermittent renewables. A number of different technologies have been proposed, such as gas or chemical storage, Compressed Air (or gas) Energy Storage (Energiesystemtechnik, 2016), although these are all still in an early development stage. Therefore economic deployment is only foreseen at the medium to longer term.

3.5 Main opportunities and bottlenecks

The main drivers and bottlenecks of the studied system integration options have been summarized in Table 3-1

Summarizing, all system integration options offer certain clear benefits to either GHG reduction or increased flexibility for the energy supply, cost reductions and the optimal (re)use of valuable infrastructure.

Further, system integration options are interlinked in space and time. As an example, platform electrification could be an important stepping stone for a larger offshore electricity grid that could facilitate electrical CO_2 compression for injection, gas to wire, power to gas and energy storage facilities. Clearly this requires extensive coordination between the stakeholders in the wind sector, gas sector and government and as a start need more open communication about their plans, goals, limitations, needs, etc.

Important barriers are the high investment costs of the needed infrastructural developments and not always converging goals of stakeholders, including political and public support. This together with a relative short window of opportunity and diverse use, invested interests and spatial claims of the North Sea makes offshore system integration a challenging and complex endeavor.

Table 3-1: Main drivers and bottlenecks for studied system integration options

System int. option / Drivers & Barriers	Platform electrification	P2G/P2X	CCS	GTW	Energy storage
Main drivers	• GHG & local emissions reduction • O&M costs reduced • Stable market for offshore renewable (wind) electricity • Optimal use of E-transport capacity • Increased sector and public revenues	• Green gas or chemical feed-stock reduce GHG emissions • High value of energy → feedstock • Energy balancing / flexibility • Optimal use of infra-structure(s)	• GHG emissions reduction • Low cost mitigation option • Re-use of existing infrastructure (wells, platforms, pipelines) • Experience with offshore CO_2 injection	• Energy balancing/ flexibility/ • Security of supply/ optimal use of resources • Sector and public revenues end-of-field sites and more remote undeveloped gas fields	• Energy balancing / flexibility • Security of supply • Reuse of infrastructure
Main Barriers	• Regulations until 2023 do not facilitate coupling • Uncertain public acceptance	• Investments vs. low gas prices • Efficiency improvements needed • Regulations limit H_2 admixing	• Absence of sustainable business case due to low CO_2 price • Regulatory framework sub-optimal • Uncertain public acceptance	• Offshore conversion technology development needed: high efficiency, low cost, low emissions • Uncertain political and public support	• Currently poor business case • Technology at low technology readiness level
Interlinkage between options	• Important stepping stone for offshore E-Grid and connection of energy infrastructures	• Linkage offshore E-grid with gas infrastructure	• Energy needed for CO_2 injection/compression calls for link with offshore E-grid	• Prerequisite: offshore E-grid connected or nearby Combinations possible with: ○ CCS ○ Energy storage (gas storage)	• Strong link with all other options: ○ Electricity storage on platforms ○ Gas storage in reservoirs and pipelines

In order to consider integration options on the short-term arrangements between the stakeholders to facilitate spatial planning, such as reconsidering safety zones around gas platforms, cables and pipelines, need to start as soon as possible. In particular, consensus on and adaptation of legal and regulatory aspects requires significant time and effort.

Given the national scope of this study the international component of system integration has until thus far been underexplored. Considering this international component may improve the business case for system integrations by allowing larger scales and access to international markets, although a longer development is foreseen due to higher regulatory and technical complexity.

For example, the offshore wind development zone IJmuiden Ver is already close to the UK border and interconnection with UK wind farms in the East Anglia development zones can offer significant economic benefits and increase the reliability of the electricity grid. Plans for the longer term to expand such regional interconnections between wind farms towards a North Sea super grid have already been proposed and studied. Currently several large Interconnectors between North Sea countries -most of these having the status of Projects of Common Interest (PCI) (Europese Commissie, 2016) - are operational, such as NorNed and BritNed, or are being built or planned, such as COBRA cable, NordLink and Viking Link. Together with integrating electricity market regulations, these projects will enhance the flexibility and efficiency of the electricity system in Europe and facilitate the integration of renewables.

Gas networks in the North Sea are already coupled (BBL pipeline), which can also create opportunities for cost-efficient and flexible transport of renewable energy between countries and regions.

Clearly such large scale infrastructural developments in the North Sea are optimally realised in strong collaboration with neighbouring countries that also face equal challenges. Sharing lesson learned and concerted actions towards developing and reshaping offshore infrastructure is a priority for offshore system integration.

4 Conclusions and Recommendations

4.1 Main developments and longer term projections

The North Sea region can be considered as the biggest 'living lab' on energy transition in the world. The oil and gas industry is in decline and creates challenges on removing existing infrastructure or find ways to reuse the infrastructure for new purposes. At the same time, the North Sea region offers major possibilities for deployment of renewable energy sources, energy storage and conversion options, and CO_2 storage.

Investments in wind offshore capacity and grid integration have reached impressive levels, but nevertheless are only at the start of far larger deployment levels. New energy options such as large scale aquaculture (macro algae), ocean thermal energy conversion (OTEC), wave & tidal energy, and even geothermal energy create more opportunities for the North Sea region. First demonstrations may be deployed on the short to medium term and deployment can then be integrated in further developments of the North Sea energy systems after 2030.

These developments coincide with the vast task to abandon or reshape offshore infrastructure for oil & gas production and at the same time identify options how the existing infrastructure can, partly, be used to support and develop and facilitate the new investments and energy system over time. This applies to new use of pipelines, platforms, and off-shore pore space in the subsurface to store energy carriers and CO_2. The latter offers decarbonisation options for offshore and onshore CO_2 point source in the energy intensive industries of NW Europe, but certainly also offering opportunities for large scale negative emission when CCS infrastructure is combined with biomass conversion and refining capacity.

Further intermittent capacity deployment (PV and wind, but also bioenergy and biogas) on land and ambitious targets on increasing energy efficiency in the built environment and industry with changing energy demand patterns as result, implies that the North Sea region is a frontrunner in the (global and European) energy transition. All this is driven by innovation, European ambitions on energy security and mitigation of climate change and national policies, aiming for a decarbonized energy system around 2050 at acceptable societal costs.

The process of energy transition results in complex questions on energy system integration to manage the rising share of fluctuating renewable energy production through a combination of flexible technologies, including demand side management, more use of energy storage, flexible generation, more interconnection between networks, more market coupling and integration of renewable energy policies while meeting social, legal and economic feasibility conditions.

Many challenging questions are to be addressed in many areas: investments, infrastructure, spatial planning, policies and legal issues. The competing claims on space in the North Sea for different renewable energy options, shipping, fisheries, nature protection, extraction of resources, military use, etc. require careful planning with a long term timeframe in mind. Furthermore, developments and changes in the energy system on different spatial levels (from the European to the regional) are strongly interlinked and need to be better understood, for example with respect to robust investments in harbors as key hubs and onshore versus offshore infrastructure developments.

This report has provided an overview of key ongoing and expected energy transition developments in and around the North Sea on short to longer term and identifies the key elements of a development strategy, possible key choices and their implications. While doing so, key options for offshore energy system integration, projects and investments have been identified and discussed.

4.2 Key system integration options identified; favourable options and development paths

Focusing on the strong developments in wind offshore, the short and long term energy transition challenges and the available Oil & Gas infrastructure the assessment identified a number of concrete options for investment on short to medium term. Considering the drivers and barriers and resulting feasibility of the studied options, both on the short-term, mid-term and long-term, a possible development strategy is indicated in Table 4-1.

Table 4-1: Possible options for short-mid-long term

Time horizon / System integration options	Short-term <2023	Mid-term 2023 - 2030	Long-term 2030 - 2050
Electrification	Platform electrification near-shore	Platform electrification, far-offshore & stand-alone	Platform electrification, offshore grid
P2G / P2X	Power2Gas, onshore (demo)	Power2Gas, offshore	Power2X, offshore
CCS	CCS + electrification near-shore	CCS + electrification (depleted gas fields, aquifers, further offshore)	
GTW	GTW near shore (end-of-field)		GTW far offshore, through offshore electricity grid
Energy storage			Energy storage offshore (H_2, CAES)

Platform electrification and offshore CO_2 storage are the most realistic system integration options for the short term. The strategy shows that platform electrification could be an important stepping stone for a larger offshore electricity grid that could facilitate electrical CO_2 compression for injection, gas to wire, power to gas and energy storage facilities.

Another important conclusion is thus that system integration options are interlinked in space and time: for example, opportunities exist with the rise of renewable energy production and the abandonment of gas production platforms, but the time gap between them and geographic distances should not be unsurmountable. This makes solutions for system integration complex, but at the same time warrant strategic actions now as for the North Sea offshore energy sectors a window of opportunity exists. In the near future a significant share of hydrocarbon reservoirs will stop production and infrastructure will be abandoned.

Fostering the benefits of system integration options, like GHG reduction or increased flexibility for the energy supply, cost reductions and the optimal (re)use of valuable infrastructure, requires removing or minimizing of a number of barriers. These include high investments of infrastructural developments; non-converging goals of stakeholders, political and public support; the short window of opportunity; and the diverse use, invested interests and spatial claims of the North Sea.

It should be noted that the exact roll out of these options is therefore very difficult to predict as they depend on many uncertain factors, including those of economic, technical and societal nature. Nevertheless, the screening of options has yielded interesting insights that benefit future research and development actions.

4.3 Research and development needs and comprehensive agenda

A comprehensive concerted action supported by an integral research program on energy transition questions in the North Sea region is recommended covering the following core components:

1. Technology development and specific demonstration projects of no/ low regret options; key technological development pathways for new and advanced options can be defined, with an emphasis on identification of clear business cases on short and medium term. Such business cases will cover the options assessed in this report as well as additional ones.
2. A good quantified understanding of the potential developments of the North Sea energy system, based on integral scenario and energy system transition analyses can help to underpin the selection of good business cases, related risk management and sound planning over time. Such efforts should take into account different possible development pathways and key technological, policy and economic drivers and uncertainties. A long term perspective will also include energy demand projections, energy storage needs (among other flexibility needs) and advanced, non-commercial energy supply and conversion technologies like large scale seaweed production for biobased applications, OTEC, geothermal and possibly wave energy technologies and related infrastructure.
3. Strategic spatial planning interlinked with the above system analysis with insight in competing claims and synergies in different utilization options over time. This work also provides the basis for detailed infrastructure design (electricity networks, siting of energy production, gas (CH4, CO_2, H2) networks) and planning.
4. Building on the previous activities, ecological impacts of large scale infrastructure changes in and around the North Sea should be better understood in order to allow for sustainable planning of activities and preferably achieve co-benefits in improving the North Sea ecosystem. Modeling, mapping and monitoring activities are required.
5. Socio-economic impacts and optimization of economic development pathways; also on regional level. Understanding the possible development pathways for the North Sea energy system is the basis for understanding the macro- and socio-economic implications of such energy transitions. This work can lay the basis for maximizing the economic benefits of energy system transitions, and provides detailed insights in specific regional impacts for various parts of the energy sector (e.g. off-shore operations, harbors, energy infrastructure). This activity also includes the underpinning of the human capital agenda by understanding expected (and desired) changes in workforce and capabilities over time. This allows for pro-active policies and strategies.
6. Societal aspects and governance issues can be analysed and tackled thoroughly with the above information and actions available. Policy choices (e.g. national governance versus multilateral collaboration), the impact of technology development, market design (especially for the power

market, but also CO_2 and green gases) as well as society preferences and views will have major implications for how the North Sea energy system develops. The total program allows for delivering science based policy (as well as business) choices over time.

The agenda set in this report can serve as a basis for a detailed program to realize and study energy transition in the North Sea region. The contours of a national consortium including key market players, key knowledge institutions and academia, as well as stakeholder management are taking shape at the moment with the formulation of an innovation program on North Sea Energy. It is strongly recommended to establish a national program supported by the Topsector energy at large, industry, science foundation and national and regional government.

On the medium term, research activities could be strongly coordinated and realized by means of a so called Joint Undertaking (Europese Commissie, 2016)on the North Sea. Starting from a national R&D program and stakeholder organization in the Netherlands, the initiative could be taken from such a consortium, like the existing R&D network NSON (Energiesystemtechnik, 2016), to initiate a Joint Undertaking on managing the energy system transition in the North Sea.

4.4 Concrete actions for the short term

1. **Set up an integral strategic vision and roadmap** on the possible transition pathways of the North Sea, following the EU targets to fulfil the Paris Agreement. The development of offshore energy production and related infrastructures are to be seen as part of the transformation of the energy system (integral offshore-onshore solutions) in the North Sea region at large.
2. **Identify a short list of clear business cases** (as also highlighted by this report) that can lead to demonstration projects and development pathways for specific key technologies on the short term.
3. **Mobilise international coordination**, governance and policy; with a concerted action, preferably with heavy involvement of the European Commission. Part of this coordination effort should bring together different key efforts done already on EU level, such as gas and electricity infrastructure priority planning and project of common interests (PCIs), wind offshore, CCS, wave and tidal, and efforts with respect to development of legal and regulatory frameworks.
4. **Develop regional action plans and strategies** to facilitate and benefit from the larger transition pathways (investment in energy infrastructure, harbours and offshore sector, production & maintenance facilities, etc.). Clear alignment of efforts between the regions to avoid overlap and facilitate effective investment and development
5. **Engage with stakeholders** on the value of system integration to all relevant stakeholders in North Sea dominated value chains (fishery, ecology, energy, defense, mining, shipping, aquaculture, etc.) to manage and converge the wide range of spatial claims and secure an ecologically sound and beneficial development of the new energy system of the North Sea region, involving key stakeholders and governance bodies.

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Appendix A Schemes of system integration options

Schematic overview of system integration options

The following simplified schemes illustrate the setup and indicative energy flows for a typical far offshore wind development zone, comparable to IJmuiden Ver. The sizing of equipment, such as electrolyzers, has been kept equal for the different options wherever possible. The figures include the intermittency of the wind production and the estimated efficiencies for electricity and gas transport and conversion. These figures are only meant to indicate the order of magnitude of the energy flows. These figures are highly dependent on the system sizing and technology choices. For offshore CO_2 storage efficiency indications were unknown.

In the first scheme, illustrating the base case with separate development of offshore wind and offshore gas, the main challenges for offshore wind and offshore gas are stated in red. In the schemes with the different system integration options the main drivers are stated in green and the main barriers in red.

Table A-1: Assumed sizing and indicative losses

Subsystem	Rated power	Losses	Outage loss	CO_2 Emission
Wind farm	6 GW	8% (wake & infield)	3%	-
Electricity transmission	HVDC-VSC + 90km cable	2% (conv.& 90km)	3%	-
Gas compression & transport	80% of 5TWh/yr.			13,5 kton/TWh
Electrolyzer[8]	2 GW	35%		-
Methanisation	Equals gas production	20%		8.8 kg/kg H2
Storage	2 GW (max. cons.)	65% (round trip)		-
Gas motor (CCT)[9]	2 GW	65%	10%	13,5 kton/TWh
CO_2 compression	Assumed low compared to gas compression			-

[8] Experiences and Results from the RWE Power-to-Gas-Projekt at Niederaußem site, RWE Power AG, 2013
[9] Efficiencies for power generation from selected offshore gas turbines from: http://www.energy.siemens.com/hq/pool/hq/power-generation/gas-turbines/downloads/gas-turbines-siemens.pdf

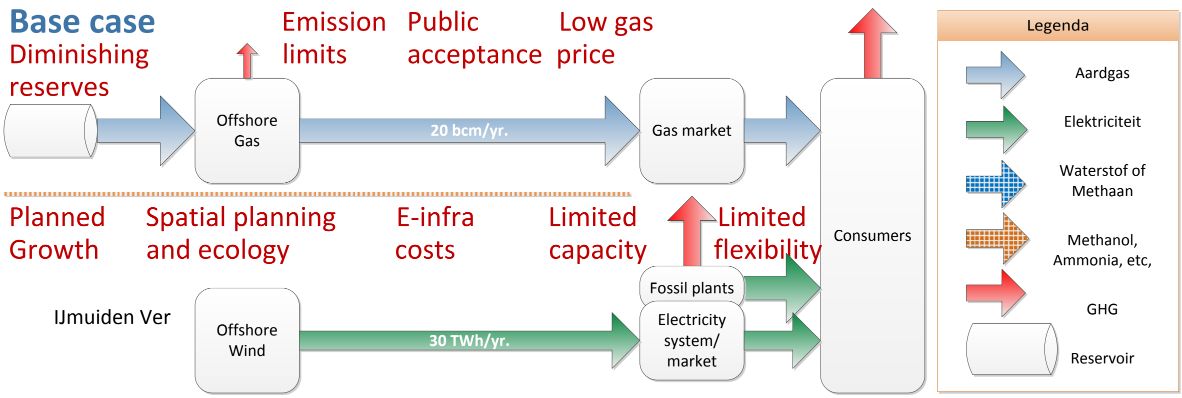

Figure A-1: Separate offshore wind and offshore gas development

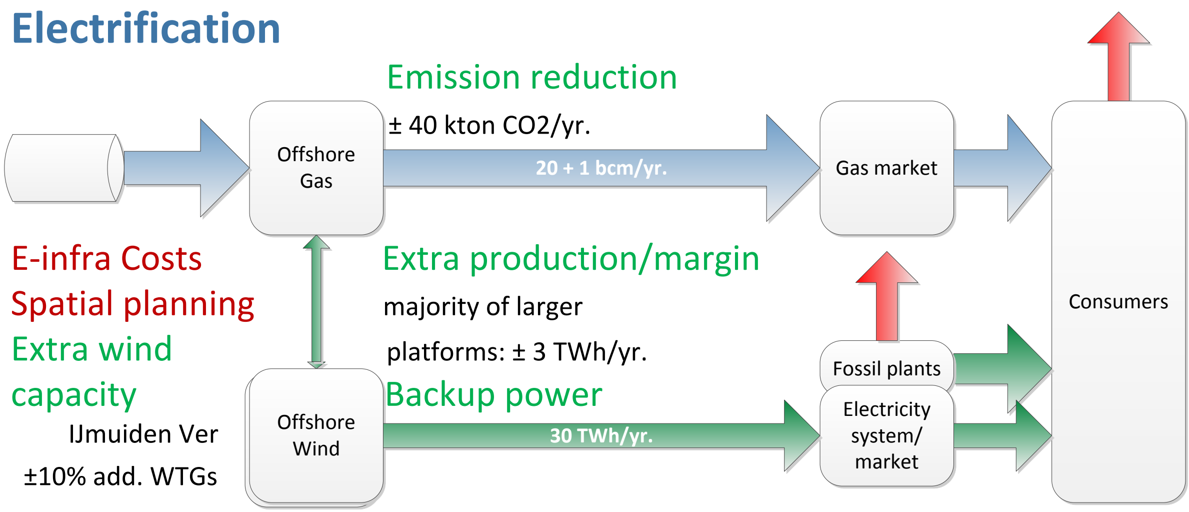

Figure A-2: Electrification of offshore gas platforms

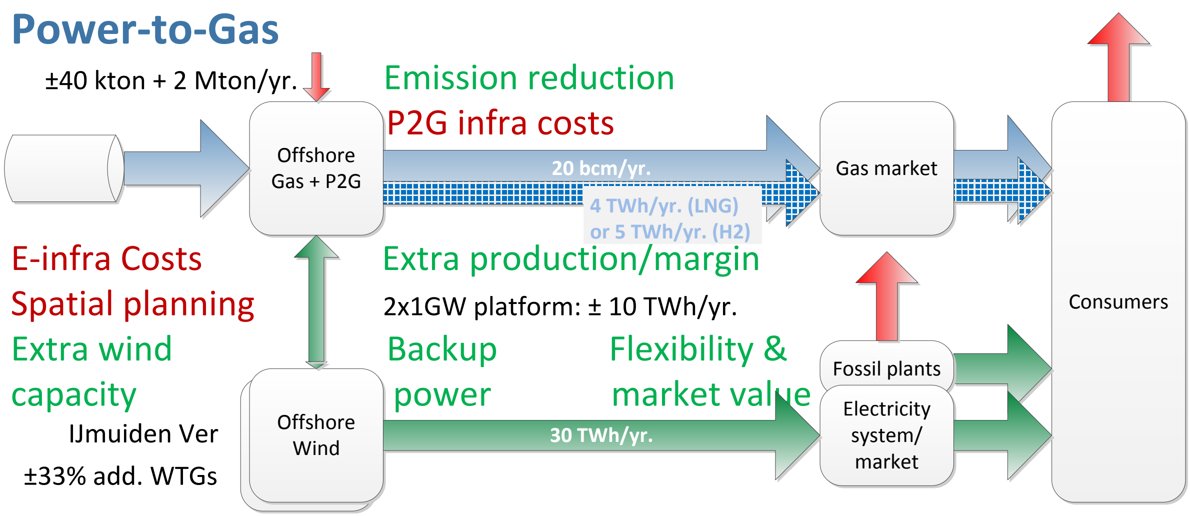

Figure A-3: Offshore power-to-gas

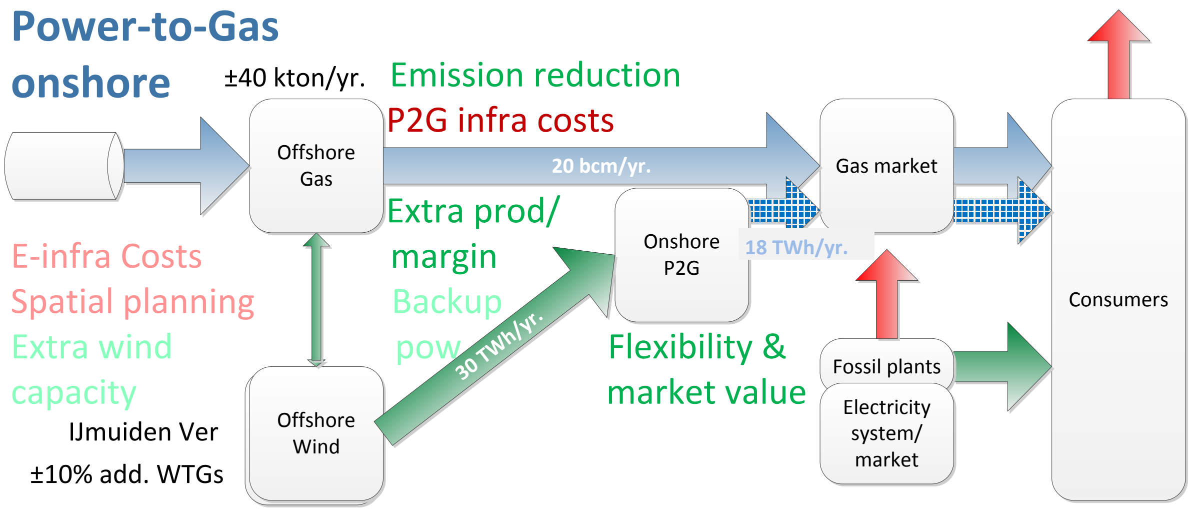

Figure A-4: Onshore power-to-gas

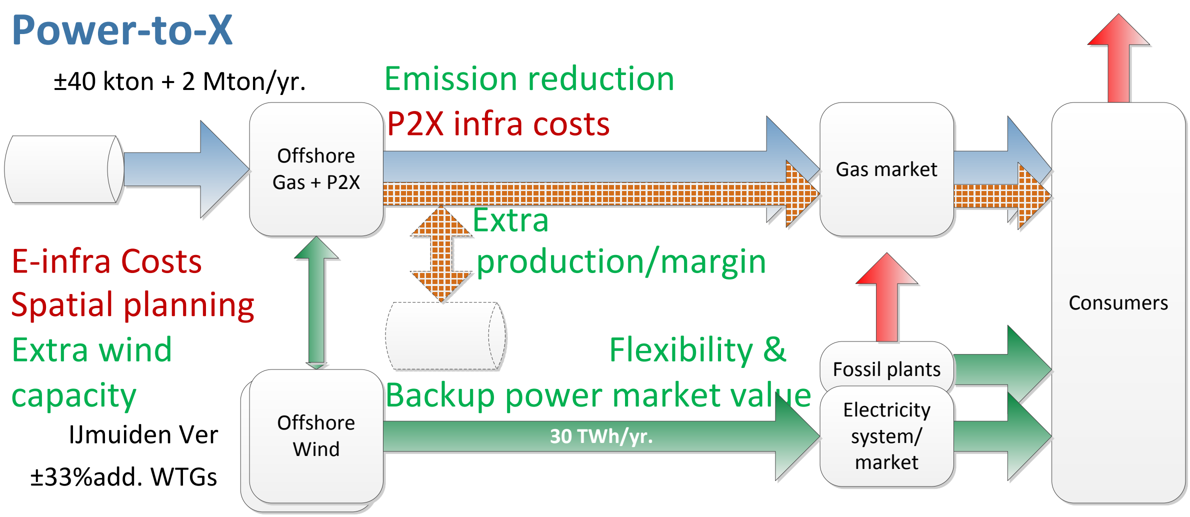

Figure A-5: Offshore power-to-X

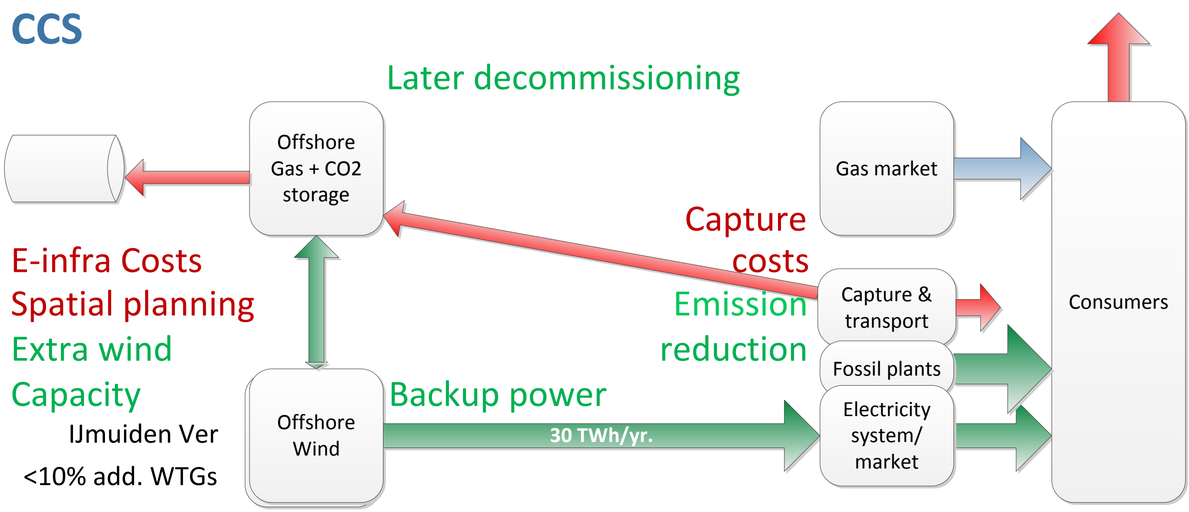

Figure A-6: Offshore CCS in depleted gas fields

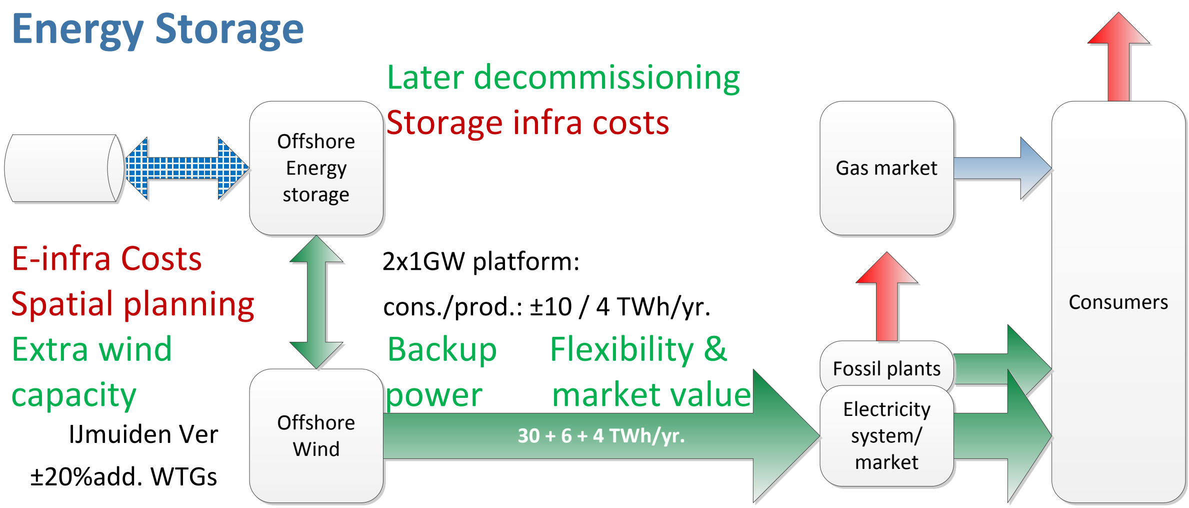

Figure A-7: Offshore CCS in depleted gas fields

Possible development paths

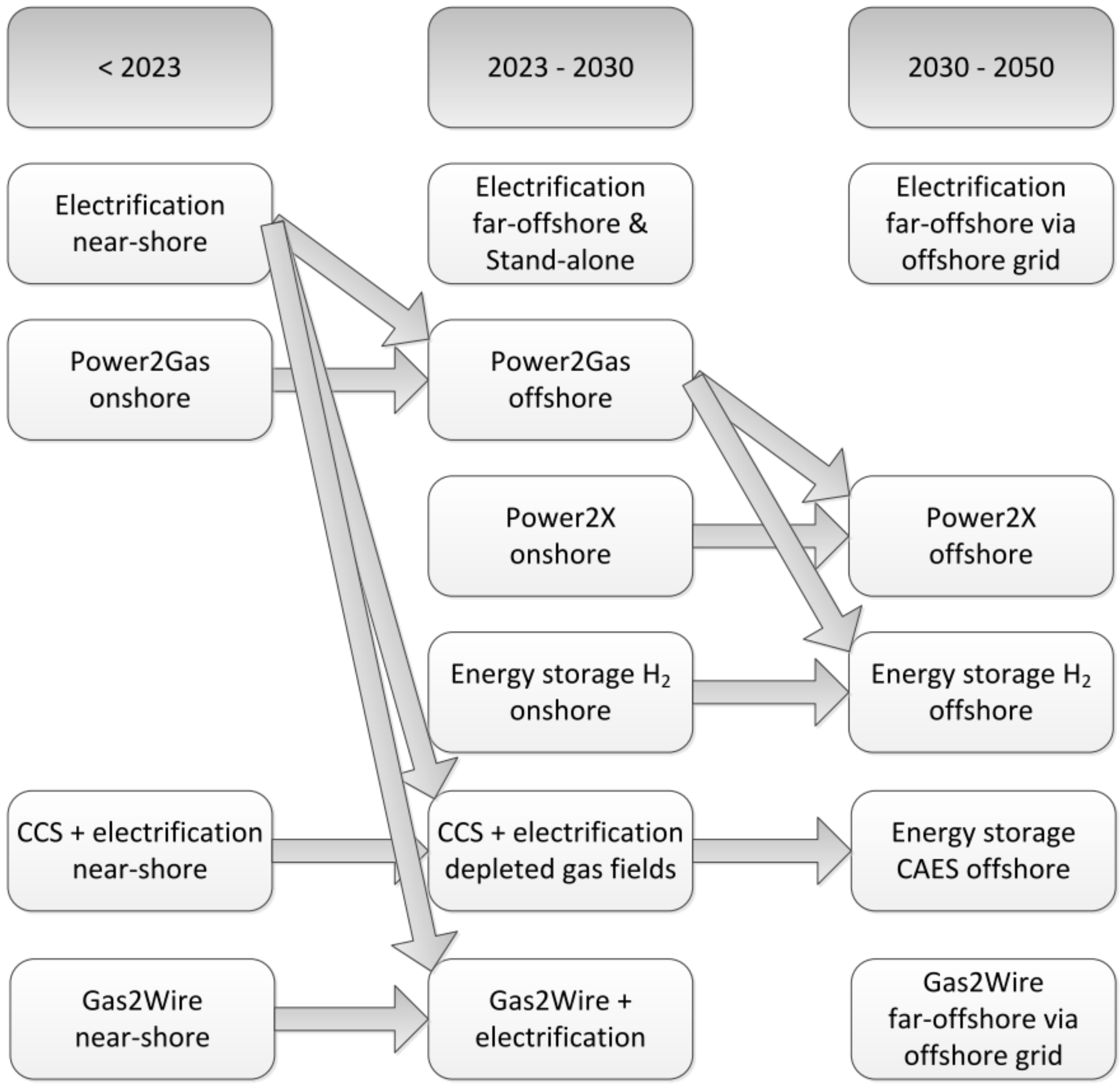

Figure A-8: Possible development paths for the short-, mid-, and long-term

Development of optimization framework

As part of developing possible strategies for system integration of offshore wind and offshore gas the following generic framework is proposed, see figure below. In this stage the key aspects are to define specific goals and Key Performance Indicators, in line with the already identified drivers and barriers.

A coordinated action plan set up by a broad group of stakeholders from different sectors is proposed to: (1) develop solutions to solve the barriers and to exploit the benefits through R&D, (2) initiate pilot projects to demonstrate these solutions so to enable implementation at a larger scale, and (3) communicate the why these solutions for system integration are developed and deployed and how these actually have worked out.

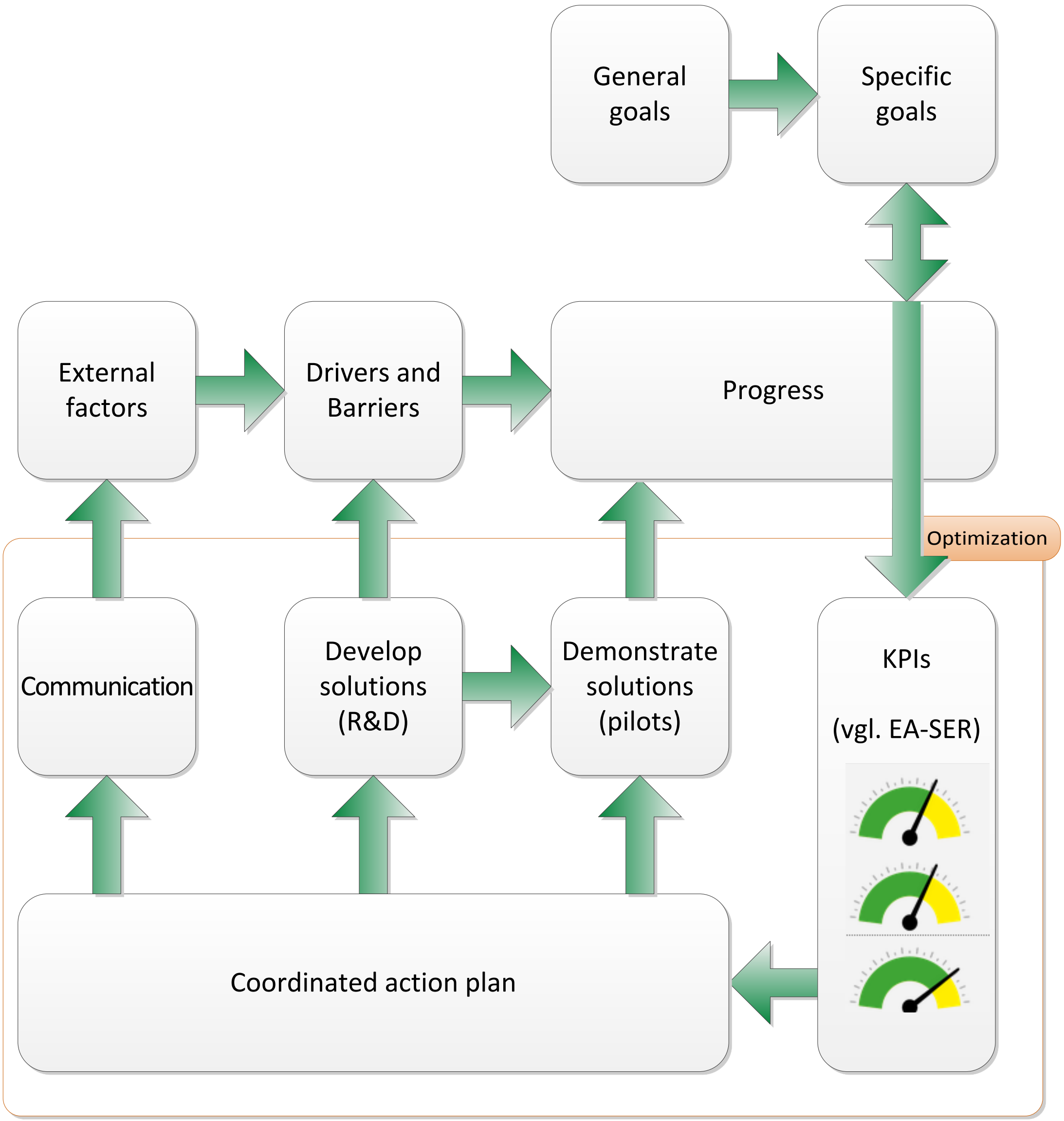

Figure A-9: Proposed optimisation framework