DECARBONISATION OPTIONS FOR THE DUTCH OFFSHORE NATURAL GAS INDUSTRY

Adrian Serna Tamez, Stijn Dellaert

08 April 2020

MIDDEN

Manufacturing Industry Decarbonisation Data Exchange Network

Decarbonisation options for the Dutch offshore natural gas industry
© PBL Netherlands Environmental Assessment Agency; © TNO
The Hague, 2020
PBL publication number: 4161
TNO project nr. 060.33956 / TNO 2020 P10086

Authors
A. Serna Tamez and S. Dellaert

MIDDEN project coordination and responsibility
The MIDDEN project (Manufacturing Industry Decarbonisation Data Exchange Network) was initiated and is also coordinated and funded by PBL and ECN part of TNO (named TNO Energy Transition after 1 January 2020). The project aims to support industry, policymakers, analysts, and the energy sector in their common efforts to achieve deep decarbonisation. Correspondence regarding the project may be addressed to:
D. van Dam (PBL), Dick.vanDam@pbl.nl, K.M. Schure (PBL), Klara.Schure@pbl.nl, or A.W.N. van Dril (TNO), Ton.vanDril@tno.nl.

Production coordination
This publication is a joint publication by PBL and TNO Energy Transition and can be downloaded from: www.pbl.nl/en. Parts of this publication may be reproduced, providing the source is stated, in the form: Serna Tamez, A., and Dellaert, S. (2020), Decarbonisation options for the Dutch offshore natural gas industry. PBL Netherlands Environmental Assessment Agency & TNO Energy Transition, The Hague.

PBL Netherlands Environmental Assessment Agency is the national institute for strategic policy analysis in the fields of the environment, nature and spatial planning. We contribute to improving the quality of political and administrative decision-making by conducting outlook studies, analyses and evaluations in which an integrated approach is considered paramount. Policy relevance is the prime concern in all of our studies. We conduct solicited and unsolicited research that is both independent and scientifically sound.

TNO Energy Transition has a twofold mission: to accelerate the energy transition and to strengthen the competitive position of the Netherlands. TNO conducts independent and internationally leading research and stands for an agenda-setting, initiating and supporting role for government, industry and NGOs.

This report was reviewed by TAQA Offshore B.V. and NOGEPA. PBL and TNO Energy Transition remain responsible for the content. The decarbonisation options and parameters are explicitly not verified by the companies.

Contents

FINDINGS

Summary

The offshore production of natural gas (NG) in the Netherlands has significantly decreased over the last years due to the depletion of the existing reserves and the lack of feasible economic prospective locations against an environment of low NG prices. Therefore, operators have focused their efforts on lowering their operating costs in order to secure sufficient profit margins. These efforts, together with covenants made with public bodies, have encouraged energy efficiency and methane reduction measures that have lowered their greenhouse gases emissions in recent years. This report intends to give an overview of the options that the sector could adopt to further decrease the emissions related to their regular operations during the production lifetime of a platform. For each option the technical and economic implications are analysed and discussed.

In 2017, the offshore NG sector produced 29% of the total NG (onshore and offshore) extracted in the Netherlands. This represented approximately 2.8% (1,350 $ktCO_2$) and 65% (8.9 $ktCH_4$) of the total CO_2 and methane emissions from the Dutch energy sector[1] respectively. The CO_2 emission figure corresponds to a total consumption of 24.8 PJ (6.89 TWh) of NG, required for the operation of the offshore production platforms.

In August 2019, a covenant was signed between the Dutch offshore operators and the Ministry of Economic Affairs and Climate Policy to reduce the methane emissions with at least 50% by the end of 2020 compared to the emissions in 2017.

This report focusses on measures applicable to the 15 platforms with the highest CO_2 emissions in the Dutch continental shelf, which represent more than 50% of the total greenhouse gas emissions from the offshore sector. The options considered in this report are divided in three different categories: i) energy generation and use; ii) flaring, venting and fugitive emissions and iii) other (e.g. optimization of the pipeline system).

The options include three different concepts of platform electrification: i) electrification from shore; ii) electrification from wind energy and iii) electrification from a dedicated Natural Gas Combined Cycle (NGCC) equipped with a Carbon Capture and Storage (CCS) unit. These measures can offer a large reduction of CO_2 but each may require a high initial capital of investment, if taken individually by the operator of each single platform.

References show that options to decrease methane emissions may require a lower cost of investment and a favourable business case as operators have already introduced some of them. Among these measures, flaring, vapour recovery units, emission free dehydrators, and the implementation of a leak detection and repair program are discussed.

For the retrofit of existing platforms there are important technical and economic limitations to be considered such as the weight, space and balancing restrictions and the short remaining lifetime of some of these offshore facilities. These aspects make the implementation of most of the measures considered here very challenging.

---

[1] According to CBS, the Dutch energy sector includes the extraction of crude petroleum and natural gas, the manufacture of refined petroleum products, and the electricity, gas, steam and air conditioning supply.

The development of effective policy instruments and frameworks integrating NG platforms in an offshore energy system, cooperation among operators, authorities and industries, a comprehensive planning of new developments, the assessment of possibilities to repurpose existing facilities for synergies between different sectors after their end-of-life, and an upward development of the NG price are all important factors that will influence the degree to which the sector adopts measures to reduce the CO_2 and methane emissions.

FULL RESULTS

Introduction

This report describes the current situation for offshore natural gas (NG) production in the Netherlands and the options and preconditions for its decarbonisation. Furthermore, options for its "demethanisation[2]" are included specifically for this sector. The study is part of the MIDDEN project (Manufacturing Industry Decarbonisation Data Exchange Network). The MIDDEN project aims to support industry, policymakers, analysts, and the energy sector in their common efforts to achieve deep decarbonisation. The MIDDEN project will update and elaborate further on options in the future, in close connection with the industry.

Scope

Production locations:
- The 15 NG production platforms in the Dutch continental shelf with highest CO_2 emissions as reported under the EU Emissions Trading System (EU ETS). Together, these platforms have a share larger than 50% of gas consumption and production within the offshore NG industry.

Production processes include:
- Separation of NG, compression, dehydration and power generation

Products include:
- NG and condensate.

The main options for decarbonisation and 'demethanisation' are:
- Electrification from shore, wind, and a dedicated platform with CCS
- The use of vapour recovery units, flaring stacks, and emission free dehydrators for the reduction of methane emissions.

Timeframe of the study:
- Production lifetime of the platforms without considering repurposing options of the facilities after their end-of-life.

Data reference year: 2017.

---

[2]   The reduction of methane emissions.

Table 1 Overview of the report scope

Production platform	Operator	Main product output (NLOG, 2019b)	Expected decommission year (Nexstep, 2018)
K14-FA-1C	Nederlandse Aardolie Maatschappij B.V.	L-cal gas, H-cal gas and condensate	>2027
K5 Complex	Total E&P Nederland B.V.	H-cal gas and condensate	>2027
J6-A-Markham	Spirit Energy Nederland B.V.	H-cal gas and condensate	2023-2027
P15-D	TAQA Offshore B.V.	H-cal gas and oil/condensate	2023-2027
A12	Petrogas E&P Netherlands B.V.	H-cal gas	>2027
L9-FF-1W	Nederlandse Aardolie Maatschappij B.V.	H-cal gas and condensate	2023-2027
L10-AD	Neptune Energy Netherlands B.V.	H-cal gas and condensate	2023-2027
Ameland-Westgat-1W	Nederlandse Aardolie Maatschappij B.V.	H-cal gas and condensate	>2027
K6 Complex	Total E&P Nederland B.V.	H-cal gas and condensate	2023-2027
P06-A*	Wintershall Noordzee B.V.	H-cal gas and condensate	2023-2027*
G17d-A	Neptune Energy Netherlands B.V.	H-cal gas and condensate	2023-2027
F3-FB-1P	Neptune Energy Netherlands B.V.	H-cal gas and condensate	>2027
L08-P4	Wintershall Noordzee B.V.	H-cal gas	>2027
F16-A*	Wintershall Noordzee B.V.	L-cal gas	2023-2027*
D15-FA-1	Neptune Energy Netherlands B.V.	H-cal gas	2023-2027

Note: L-cal gas = Low-calorific gas. H-cal gas = High-calorific gas.

* Platforms left out from the study after the operator notified an earlier cease of activities.

Reading guide

Section 1 introduces the Dutch NG industry. Section 2 describes the current situation for NG production processes in the Netherlands, and Section 3 describes the relevant products of these processes, while options for decarbonisation and 'demethanisation' are systematically quantified and evaluated in Section 4. The feasibility of and requirements for those decarbonisation options are discussed in Section 5.

1 Offshore NG production in the Netherlands

The Netherlands is the second largest producer of natural gas (NG) among the countries belonging to OECD[3] Europe, just behind Norway (IEA, 2017). Despite the climate change policies and the efforts to shift towards renewables and a low CO_2 economy, NG has been and remains the backbone of energy supply and power generation in the Dutch market. In 2017, NG accounted for 41% of the total primary energy supply (TPES) in the Netherlands (CBS, 2018b).

1.1   History and Future of the NG Production in NL

The history of NG exploration and production (E&P) in the Netherlands dates back to the discovery of the Groningen gas field in 1959. Since its start of production in 1963, the Netherlands exploited this field becoming a major producer of NG and an important supplier for North-Western Europe (Honore, 2017).

After the oil crisis of 1973, however, the Dutch government decided to slow down the gas production from the Groningen field as it was considered a strategic source of NG worth preserving to secure future energy supply (Mulder et al., 2018). This led to the introduction of the Kleineveldenbeleid ("small fields policy") in 1974. This policy encouraged the E&P of NG from smaller fields in order to compensate for the reduction of gas production from the Groningen field. Since then, the role of the Groningen field became more strategic. Annual caps were imposed on its production levels and its production flexibility was used to secure NG during periods of winter peak demands (Mulder et al., 2018).

The damage caused to properties and social confidence, caused by a series of NG production related earth tremors, including the notorious earthquake of magnitude 3.6 on the Richter scale in 2012 at Huizinge, led to further actions to limit the production of this field. The Ministry of Economic Affairs requested an amended plan to reduce the yearly extraction levels, which in 2019 resulted in an ultimate decision to cease the production of NG in the Groningen field by 2022 (Rijksoverheid, 2019). Because of these events, extraction of NG in smaller fields including offshore became more important.

In 1975, the first offshore NG facility started production from the L10-A gas field (Ruoff, 2016). From that moment on and until the first decade of the 2000-s, the Dutch offshore infrastructure quickly developed (Honore, 2017).

Yet, in recent years the investments in small fields have slowed down as a result of the advanced maturation state of many of the existing fields and the lack of prospective and economical production locations together with the low NG prices (EBN, 2017). In 2016 for

---

[3]   Organisation for Economic Cooperation and Development

instance, only 5 new NG fields were brought into production, compared to 14 brought in 2015 (EBN, 2017).

The development of the NG prices will continue influencing the future level of investments in the small gas fields and therefore investments in offshore infrastructure (EBN, 2017). With higher NG prices, more investments in E&P offshore could be expected and current production rates could be maintained. This would in turn extend the lifespan of platforms and positively impact the time window needed to successfully implement decarbonization options. With lower NG prices, however, the E&P of NG and the options to reduce the CO_2 and methane emissions could become less profitable for operators (EBN, 2017). This could result in an earlier decommission of the platforms, which would decrease the possibility to their reuse in possible synergies with other energy sectors (e.g. hydrogen production and transport, carbon dioxide storage)[4], and reduce the benefits related to decarbonization measures.

Despite the ambition to increase the use of renewable energies, EBN (2016) and the Ministry of Economic Affairs (2016) in the Netherlands foresee that NG will play an important role in the energy transition.

1.2   Present

NG revenues have dropped significantly together with the decline of the NG price and NG production in the Netherlands. While total state revenues were 15.4 billion euros (2.3% of the GDP) in 2013, in 2017 revenues went down to 2.8 billion euros (0.4% of the GDP) (CBS, 2019c). Exploration and extraction of the NG provided around 7,000 jobs in 2018 (Mulder et al., 2018).

The offshore NG industry in the Netherlands is characterized by approximately 150 production platforms located in the North Sea (see Figure 1) (NLOG, 2019d). The extracted NG is transported to the onshore NG grid via three main pipeline systems: West Gas Trunk (WGT), North Gas Trunk (NGT) and Northern Offshore Gas Trunk (NOGAT).

The platforms are operated by the following 9 companies (NLOG, 2019c, 2019a):
- Nederlandse Aardolie Maatschappij B.V.
- Neptune Energy Netherlands B.V.
- Spirit Energy Nederland B.V.
- TAQA Offshore B.V.
- Wintershall Noordzee B.V.
- Total E&P Nederland B.V.
- Dana Petroleum Netherlands B.V.
- ONE-Dyas B.V.
- Petrogas E&P Netherlands B.V.

Figure 1 Location of NG production platforms in the North Sea (North Sea Energy, 2018).

Offshore platforms can be classified into two main types: satellites and main central platforms (Nexstep, 2017). Satellite platforms are located in remote areas and connected through subsea cables and/or infield pipelines to main central platforms. The latter are

---

[4]   Options of repurposing already being investigated by different projects such as the North Sea Energy project.

energy intensive facilities used to extract and/or collect, process and transport NG, and provide housing to workers. Main central platforms usually accommodate gas turbines for the generation of electricity and power for compression. On the other hand, satellite platforms utilize gas or diesel engines for electricity generation.

In 2017, offshore platforms consumed approximately 767 million normal cubic meters (nm^3) of NG, representing 6.1%[5] of the total NG produced offshore in the same year (NLOG, 2019d). The electricity and mechanical work required for the operation of platforms is mostly generated using single-cycle gas turbines and engines with low efficiency. Typically, more than 80% of the total energy used in large platforms is used in gas turbines to drive compressors for the transportation of NG (Devold, 2015). The remaining energy requirements are met by gas or diesel engines (generally used for generation of electricity for utilities and as a back-up in emergency situations) (Devold, 2015).

The CO_2 emissions related to offshore NG activities are mainly due to the combustion of gas fuel in the gas turbines that drive the compressors and to a much lesser extent from flaring activities. CH_4 emissions are released primarily from venting practices.

In 2017, the total CO_2 and CH_4 emissions associated with offshore NG activities amounted to 1,350 kilotons and 8.9 kilotons respectively (Ministerie van Economische Zaken en Klimaat, 2018; Tacoma, 2019). The latter representing 249.6 CO_{2-eq} kilotons if considering a methane global warming potential of 28 on a 100 year time-span (IPCC, 2013). The emissions from the offshore NG industry accounted for about 3.3% of the total CO_2 emissions from the Dutch energy sector in 2017 (CBS, 2019b).

In the same year, 15 platforms consumed 50% of the total NG consumed by the offshore NG industry, and subsequently emitted around the same proportion of CO_2. Table 2 shows the NG production, consumption, and emissions of CO_2 of these platforms during 2017. Figure 2 shows the location of these facilities in the North Sea (NLOG, 2019d). This study focuses on these 15 platforms[6] since these have the highest energy consumption and Greenhouse Gas (GHG) emissions of the Dutch offshore facilities registered in the European Emission Trading System (ETS) and are a good representation of the offshore NG industry in the Netherlands.

---

[5]   The share between consumed and produced NG in the sector has increased from 4.1% in 2012 to 6.1% in 2017 (NLOG, 2019d). This increase can be explained by the maturity of the NG fields.
[6]   During the course of the research, Wintershall Noordzee B.V. notified the cease of production of platforms P06-A and F16-1 in the short term. For this reason, these platforms were no longer included in this study.

Table 2. Top 15 energy and emission intensive platforms (2017)

Facility	Operator	Gas production (1000nm³) (NLOG, 2019d)	Gas consumption (1000nm³) (NLOG, 2019d)	CO₂ emissions EU ETS (Tonnes) (NEA, 2019)
K14-FA-1C	Nederlandse Aardolie Maatschappij B.V.	897,953	58,373	122,742
K5 Complex	Total E&P Nederland B.V.	*1,173,519	*47,623	108,962
J6-A-Markham	Spirit Energy Nederland B.V.	87,807	33,098	86,742
P15-D	TAQA Offshore B.V.	*536.936	*33,103	75,045
A12	Petrogas E&P Netherlands B.V..	*1,095,994	*34,571	68,273
L9-FF-1W	Nederlandse Aardolie Maatschappij B.V.	493,444	27,918	64,511
L10-AD	Neptune Energy Netherlands B.V.	387,701	30,118	63,024
Ameland-Westgat-1W	Nederlandse Aardolie Maatschappij B.V.	2,384,220	32,212	60,959
K6 Complex	Total E&P Nederland B.V.	*452,092	*26,903	58,046
P06-A	Wintershall Noordzee B.V.	96,050	3,146	50,530
G17d-A	Neptune Energy Netherlands B.V.	1,054,449	24,252	47,106
F3-FB-1P	Neptune Energy Netherlands B.V.	174,122	14,708	45,753
L08-P4	Wintershall Noordzee B.V.	*464,058	*21,472	43,322
F16-A	Wintershall Noordzee B.V.	141,498	18,432	37,845
D15-FA-1	Neptune Energy Netherlands B.V.	34,164	12,334	24,109
Totals		**6,248,346**	**418,263**	**956,969**

*NG production and consumption data validated by the operator.

Note: Diesel consumption not publicly available.
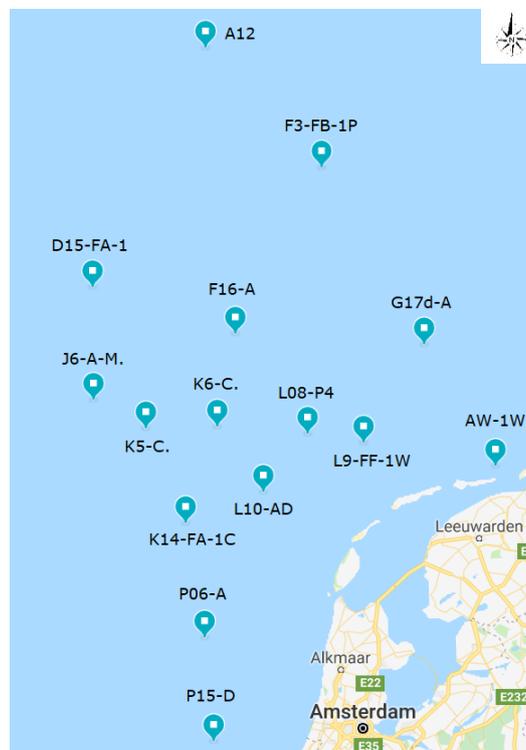
Figure 2. Location in the North Sea of the top 15 platforms selected for this study (NLOG, 2019d)

2 Offshore NG production processes

After its extraction, NG undergoes some processing steps before it is transported to shore through a high pressure pipeline system. Depending on the sales contract and the specifications of gas required from the end users, the NG processing installations and pipelines are designed to meet transport and user requirements.

2.1 Processing of NG

Although the process of NG production differs among facilities due to different field characteristics (e.g. gas/condensate/water ratios; well pressure and temperature levels; well lifetime) and different platform design setups (e.g. number of compression trains, export specifications), the majority of the platforms have overall similar design as shown in Figure 3 (Ertesvåg et al., 2015).
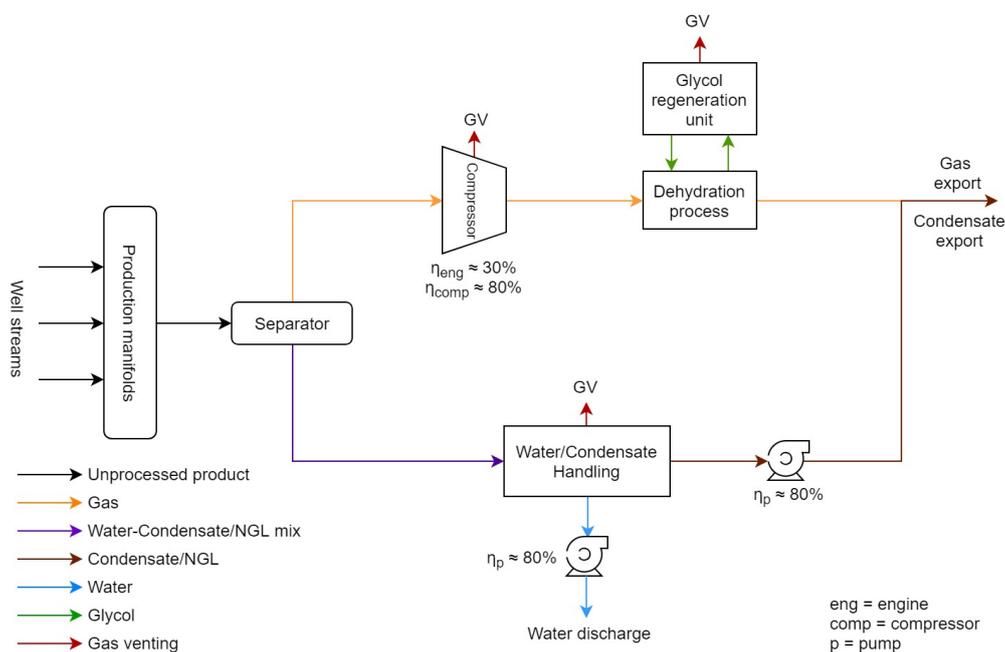
Figure 3. Overall process design of an offshore NG platform

2.1.1 NG extraction

The extraction of NG begins with the drilling and completion of a well. Although most of the drills start vertically close the Earth's surface, directional drilling (i.e. deviating from the vertical) is often used to extend the reach of a platform to various nearby NG fields and to increase the recovery from complex reservoirs (Devold, 2015). In conventional wells, NG

generally flows up to the surface without the need of any lifting technique during the build-up and mature phase of production (Mokhatab et al., 2006).

2.1.2   Separation

The gas is brought to the process facility through a series of pipelines and manifold systems. Some wells produce pure dry gas which do not require any separation process before further treatment and compression, but more often they produce a combination of gas, oil, condensate, water and/or various contaminants that need to be separated (Bahadori, 2014).

There are different types of separators but the most commonly used for large volumes of gas and/or liquids are gravity separators (Devold, 2015). Gravity separators are classified in "two phase" separators, if they separate gas and liquids as a whole from the stream, and "three phase" separators if they further separate the liquids into water and oil or condensate (Devold, 2015).

In two phase separators, the product is retained in a horizontal or vertical vessel for a period of time to allow the gas to escape out, and the liquids to settle at the bottom. In three phase separators the difference of densities makes the water settle at the bottom and the oil or condensate at the middle as shown in Figure 4. (Callaghan et al., 1985; Lung et al., 2005).

Additionally, separators can be classified in low and high pressure types. Low-pressure separators operate from 230 to 700 psi (16-48 bar); high pressure separators from 975 to 1500 psi (67-103 bar) (Mokhatab et al., 2006). The pressure is reduced in stages to allow controlled separation of volatile components and to prevent flash vaporizations that lead to instabilities and safety risks (Mokhatab et al., 2006).
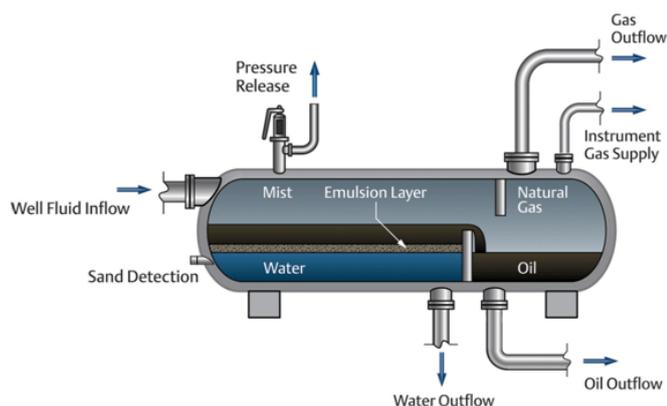
Figure 4. 3-Phase horizontal gravity separator (Rumbles, 2014)

Moreover, a good separation of gas and liquids can be achieved by arranging the separators in series and in different pressure stages. In some cases, however, a booster compressor is needed to bring the pressures of the NG fractions produced in low pressure separators to the levels of the high-pressure separator in order to avoid major energy loses in the compression process.

After the separation process, the liquid fraction of the product can be sent to a water/condensate processing unit, where the water is further treated for its reinjection into the sea and the condensate pumped for its exportation (Nouri, 2016). The gas fraction on the other hand is sent to the compressor unit for additional processing.

2.1.3   Compression

The NG is compressed to compensate for any pressure drop in the separation process and to comply with the specifications of the transportation pipeline systems. Transport of sales gas[7] is performed at high pressures (e.g. >80 bar in the Dutch offshore pipeline systems) to use efficiently the pipeline diameter (SodM, 2018). Compression can be set up in different stages

---

[7]   Sales gas is equivalent to the wellhead gas minus the gas consumed by the platform.

to allow cooling, using heat exchangers between each stage, and save work in the compression process. Moreover, multistage compressors allow the compression of streams with different pressures (IPIECA, 2013). Compression often requires two or three stages to attain the high pressures of transportation systems (Ward, 2011).

Two type of compressors are used in gas transmission applications: i) reciprocating compressors and ii) centrifugal compressors (IPIECA, 2013). Reciprocating compressors are often driven by electric motors or gas engines and are used for low volume flows and high-pressure product ratios (IPIECA, 2013). Centrifugal compressors are generally driven by gas turbines or electric motors and are ideal for high volume flows and low heads (IPIECA, 2013).
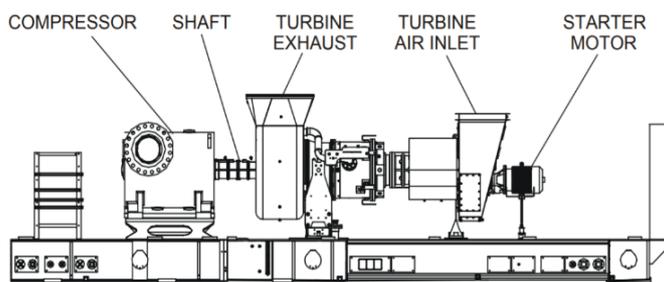
Figure 5. Solar Taurus 70 gas turbine compressor package (Solar Turbines, 2009)

When used on the platform, gas turbines and engines typically use a proportion of the NG produced as fuel. Electric motors require a reliable source of electricity, which in offshore environments is hard to find. For this reason, gas turbine/compressor packages are frequently used for the compression of NG in offshore facilities (See Figure 5).

These gas turbine driven compressors typically have low thermal efficiencies of around 25-35% at rated load (Wall et al., 2006). Yet, gas turbines are usually designed for plateau conditions (i.e. maximum capacity of production). Over time, as the wells are depleted, the capacity of production decreases, resulting in oversized gas turbines operating far from their best efficiency point (BEP) that need to be restaged to optimize their performance. As a result, the operating efficiencies of the gas turbines and compressors are usually lower than their rated values (Mazzetti et al., 2014).

The Dutch offshore industry is characterized by gas turbine driven centrifugal compressors with installed capacities of up to 70 MW$_{th}$ input, with typical shares of 70-85% from the total energy used in the platforms (NLOG, 2019d).

2.1.4   Dehydration

After the compression of NG, a dehydration process takes place to remove the remaining water from the gas. This process is performed to meet the limits for water content in the pipeline system established by gas transport and sales contracts, and/or to comply with pipeline specifications to prevent water condensation, which can result in corrosion and the formation of hydrates (Bahadori, 2014).

Although there are different processes available to carry out such dehydration, absorption with glycol is the most common method because of its economics and low energy consumption (Kinigoma et al., 2016). This method utilizes mass transfer of the water molecule into a liquid solvent. Triethylene glycol (TEG) is frequently used as desiccant in this type of dehydration (Devold, 2015).

The TEG dehydration process starts with the NG entering an inlet separator that removes all the liquid hydrocarbons from the stream. Next, the gas flows into an absorber where it is

counter flowed and dried by the TEG. From one side dry NG exits the absorber. From the other, the rich TEG exits through a coil where it is preheated by hot lean glycol. After the glycol-glycol heat exchanger, the rich glycol enters a stripping column and flows down the packed bed section into the reboiler where the absorbed water is steamed. The water vapours are then vented from the top of the stripper. The lean glycol flows in from the reboiler, usually heated by a NG open flame and into an accumulator (surge tank) where it is cooled via cross exchange with the returning rich glycol and pumped back to the top of the absorber in a regeneration process. (See Figure 6).
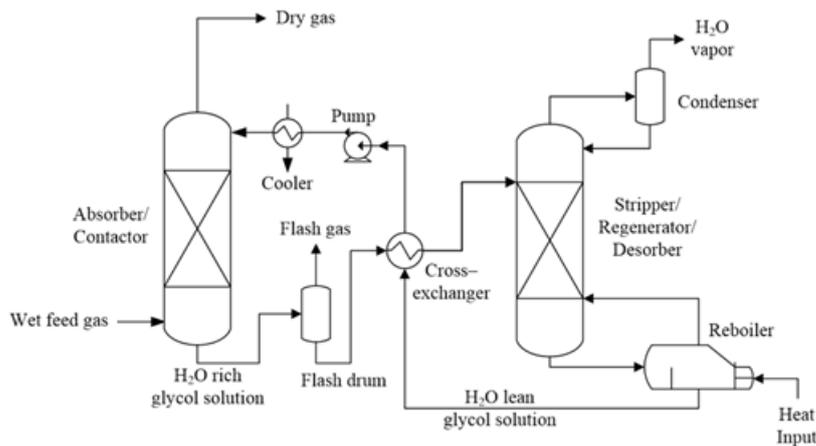
Figure 6. TEG dehydration process (Abdulrahman et al., 2013)

2.1.5   Metering and further transport

After the gas is dried, a metering station either at the platform or onshore allows the measurement and management of the exported NG and condensate/oil from the platform to shore.

2.2   Flaring and Venting

Flaring refers to the combustion of NG in an open flame. Venting to the controlled or uncontrolled release of gas directly into the atmosphere (Bahadori, 2014).

Even though it is in the interest of oil and gas (O&G) industries to avoid flaring and venting activities when possible, there are various circumstances that make these activities necessary due to economic, practical or safety reasons. Among these, lack of process infrastructure, start up, maintenance, periods of overproduction and emergency events cause the flaring and venting of NG (Emam, 2015).

Regulations imposed by countries can also limit the amount of NG being flared or vented. In the Netherlands, the flaring and venting activities in NG offshore facilities are ruled by the Mining Decree ('Mijnbouwbesluit') implemented on the 6th of December of 2002. In its article 38, Section 5.1.3, the venting and flaring activities are prohibited, unless unforeseen operations in the production process require it. In that case, all actions are to be taken to prevent and minimize any damage to the environment (Mijnbouwbesluit, 2002).

Flaring and venting activities can be classified as routine and non-routine (Bylin et al., 2010). Routine activities occur during normal operations in the platforms. Sources of routine vents

include compressors, separators and glycol dehydrators. Non-routine venting emissions occur occasionally in components such as valves, seals, flanges, etc. Routine and non-routine venting and flaring activities occur due to the lack of infrastructure to collect, store and direct the NG back to the processing system (Bylin et al., 2010).

As methane (main component of uncombusted NG) has a global warming potential 28 times higher than CO_2 (emitted when NG is combusted in flare), the global warming impact caused when a certain amount of NG is vented is higher than when it is flared. Nevertheless, concerns were raised in the past regarding the adverse effects of flaring activities to the environment, especially the danger to migrating birds. This led the facilities on the Dutch continental shelf to prefer venting instead of flaring (Juez-Larré et al., 2018).

There are two types of flare burners utilized in flaring activities: elevated open flares and enclosed flares (Bader et al., 2011). The first are mostly used in offshore platforms and are installed at a considerable height and isolated from the main operational area (Bader et al., 2011). The second flare type, used onshore, encloses the flare in a chamber and is installed at ground level. With enclosed systems, the flare light is eliminated, and the noise and thermal radiation are reduced (Bader et al., 2011).

2.3   Emissions

The CO_2 emissions from the Dutch offshore O&G sector are directly related to the fuel combustion and therefore are primarily caused by the use of NG in gas turbines to drive compressors, and from flaring activities.

The methane emissions of the Dutch offshore O&G sector as result of its activity was reported to the Ministry of Economic Affairs and Climate in 2017, as shown in Table 3. These numbers were determined using, among other data, standard emission factors established by the American Petroleum Institute (API) (See Table 4) (Steller, 2018). It is important to note that gas motors typically have much higher methane emissions than turbines and diesel engines per unit of fuel consumed, however, gas engines are less often used in the sector.

Table 3. Methane emissions from the Dutch offshore O&G industry in 2017 (Ministerie van Economische Zaken en Klimaat, 2018)

Activity	Methane emissions (tons/year)
Drilling	1.0
Flaring	12.7
Production testing	18.9
Combustion installations	648.5
Venting	7,915.6
Other	316.5
Total	**8,913.2**

Table 4. Emission factors for methane emissions from combustion installations in the O&G sector utilized by NOGEPA and established by the American Petroleum Institute (API) (Steller, 2018)

Combustion installation	API emission factor (gCH_4/ton of fuel consumed)
Gas Turbines	168
Gas motors	28000
Diesel motors	178
Natural gas-fired furnace	47
OVC (Overhead Vapor Combustor), fuelled by residual gas	47

Venting activities, high and low pressure vents, as well as the glycol regeneration and the condensate flash and stabilization processes, are the main sources of methane emissions (NOGEPA, 2019b). Data from 4 of the top 15 platforms validated by operators showed that the total methane emissions are in the range of 20-1500 tons CH_4/year/platform, with emissions from high and low pressure vents on the range of 500-1500 tons CH_4/year/platform, and diffuse emissions on the range of 3-20 tons CH_4/year/platform. These ranges are however skewed and do not suggest a proportional relationship with the quantities of gas produced in the platforms. Little information could be derived from the data validation process regarding the amount of CH_4 emissions from the other sources.

Compared to the international energy and emission intensities of offshore O&G facilities, Dutch platforms performed as shown in Table 5 (IOGP, 2018).

Table 5. Energy and emission intensities of the International and Dutch offshore O&G industry (IOGP, 2018; NLOG, 2019d)

	Global 2017	NL 2017	Difference
Energy intensity (GJ/t-hydrocarbon produced)	1.21	2.8	+1.6
CO_2 emissions (tCO_2/1000t-hydrocarbon produced)	116	158	+42
Flaring intensity (tNG/1000t-hydrocarbon produced)	12.07	1.0	-11.1
CH_4 emission intensity (tCH_4/1000 t-hydrocarbon produced)	0.63	0.90	+0.3

The differences in energy intensity can be explained by both the dominance of NG exploration and production in the Netherlands, which is more energy intensive than oil (NEA, 2016), and the maturity of the NG wells in the Dutch continental shelf which increase the energy required for production. Additionally, a tendency for venting instead of flaring in the Dutch offshore industry could explain a lower flaring and slightly higher CH_4 emission intensity compared to the global average values. This relatively small difference in CH_4 emission might furthermore be explained by the efforts of the Dutch sector to minimize the CH_4 losses.

The Dutch O&G sector has experienced a reduction of about 67% of its methane emissions since 1990 (Juez-Larré et al., 2018). Furthermore, the Netherlands Oil and Gas Exploration and Production Association (NOGEPA), which represents the 13 companies that explore and produce O&G in the Netherlands, signed a covenant in August 2019 with the Ministry of Economic Affairs and Climate to draw a reduction plan and halve the methane emissions from offshore activities by the end of 2020 compared to 2017 (Savelkouls, 2019).

In this covenant, the operators agreed on carrying out this plan by applying the Best Available Technologies (BAT) as a starting point and weighting the proposed measures according to their reduction potential and cost effectiveness (NOGEPA, 2019a). The cost

effectiveness criterion of the measures was set at a maximum of the price of the CO_2 in the EU ETS at the time the inventory of the measures was made (NOGEPA, 2019a). To achieve additional emission reductions beyond the cost effectiveness criterion, the potential of electrification is considered. For electrification to be economically and practically feasible, the sector has identified several conditions that need to be met, namely:

- A generic allowance of the investment of 40%.
- A legal framework for the connection of the offshore production platforms to the offshore power grid.
- The setting of connection conditions and tariffs.
- Financial compensation of the unprofitable costs of electrification.
  (NOGEPA, 2019a).

3 Offshore NG products and application

The total production of NG in the Netherlands amounted to 45.7 billion nm^3 in 2017. Offshore production contributed 26% to this production. Figure 7 shows the trends in onshore and offshore production during the last decade (NLOG, 2019d).
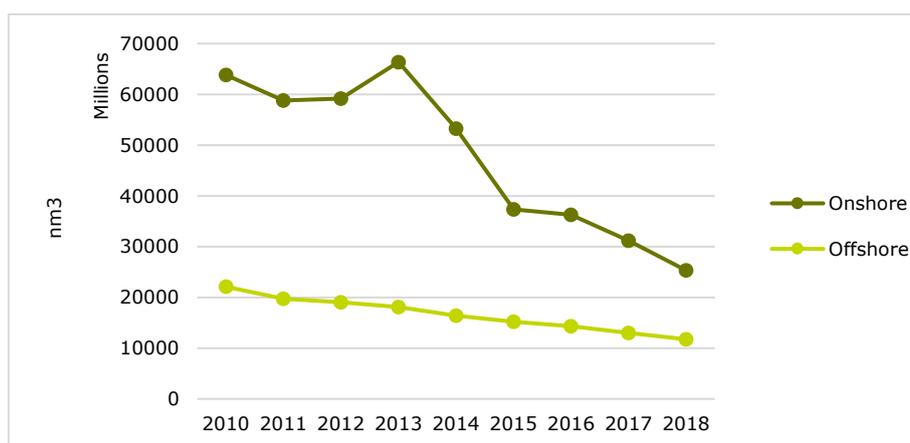
Figure 7. Onshore and offshore NG production in the Netherlands per year (NLOG, 2019d)

The Netherlands produces and commercializes two types of NG: low-calorific gas (L gas) and high-calorific gas (H gas). This qualification depends on the percentage of methane and other gases such as nitrogen and CO_2. The methane content relative to other gases (e.g. N_2, CO_2) determines the gross heating value (GHV) as indicated by the the Wobbe-Index (Mulder et al., 2018).

In the Netherlands, NG defined as L gas has a lower Wobbe-index and contains a higher percentage of nitrogen (approximately 14%) and a lower percentage of methane than H gas (NAM, 2016). Therefore, the amount of thermal energy content in a (volumetric) unit of L gas (43.46 - 44.41 MJ/nm^3) is lower than in the same unit of H gas (49.9-55.7 MJ/nm^3) (De Minister van Economische Zaken, 2016; B. Van Eeckhout et al., 2009).

L gas is used by virtually all households and buildings. This gas is mainly produced from the Groningen gas field (G gas)[8]. Additional G gas, known as pseudo-Groningen gas, is manufactured by mixing H gas from small fields or from imports, with nitrogen captured from the air (Correljé et al., 2003).

H gas is used to satisfy the demands of approximately 80 large industries (Van Den Berg et al., 2006). H gas is produced from small fields both onshore and offshore, and has been supplemented with imported gas via pipeline from Russia and Norway, and via the port of Rotterdam from the United States, Qatar and Algeria as liquefied NG (LNG) (Van Den Berg et al., 2006).

---

[8]   The term G gas owes its name to gas from the Groningen field.

For the first time since the commissioning of the Groningen field, and occurring earlier than expected, the Netherlands became a net importer of NG in 2018 (See Figure 8) (CBS, 2019e, Van Geuns et al., 2017). With the expected reduction of NG extraction in the coming years, large quantities of nitrogen and a number of processing facilities will be needed to facilitate the conversion of future imports of H gas to L gas (Van Geuns et al., 2017).
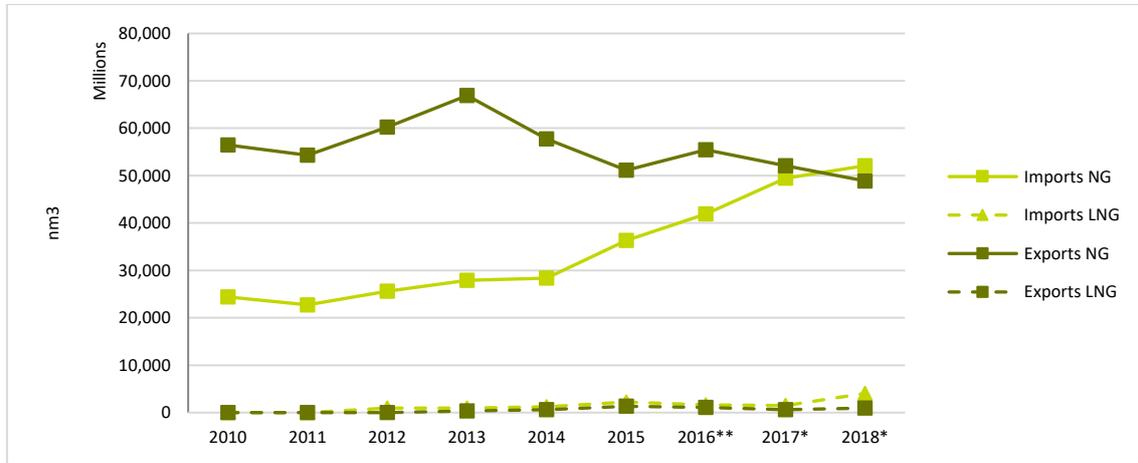
Figure 8. Import and exports of NG in the Netherlands

Note:
*Provisional figure.
**Revised provisional figure (but not definite). (CBS, 2019e).

The NG price is a function of different factors (e.g. seasonality, weather, storage of NG, disruptions in supply) that define the market supply and demand (Brown et al., 2008). Increases in gas supply and decreases in demand result in lower NG prices. Decreases in supply and increases in demand tend to lead to higher prices. Cold temperatures in winter seasons for example, contribute to higher prices of NG due to the high heating demands by residential and commercial users. The NG and oil prices have been found to not be strongly linked together anymore (Hulshof et al., 2016).

As shown in Table 6, the selling prices of domestic oil and NG industries in the Netherlands dropped since 2012 and recovered in 2016. Because of the low gas prices and lower production rates over the past few years, operators have focused in decreasing the operating costs (OPEX), including energy efficiency measures, to secure appropriate profit levels (EBN, 2017). If the recovery trend continues to develop upwardly, an increase of investments offshore could be expected in the coming years, potentially leading to a rise in the production amounts.

Although both oil and NG products are included in the Producer Price Index (PPI) shown in Table 6, the NG extraction and production dominance in the Netherlands gives a strong indication that these are similar to the actual selling price indexes of NG (Consumer price index, CPI). For reference, Table 6 also shows the change in the CPI for NG and its specific taxes applied during the same years. In 2016, the producers selling price of NG was of approximately 0.135 €/nm^3 (EBN, 2017).

Table 6. Oil and gas extraction producer price index in the Netherlands. Consumer price index (CPI) of NG and town gas. Consumer price index of specific taxes on gas. Reference year: 2015. (CBS, 2019).

Year	PPI O&G extraction	CPI NG	CPI Specific taxes on gas
2012	134.1	103.4	82.9
2013	130.1	105.6	95.0
2014	113.5	104.3	97.7
2015	100.0	100.0	100
2016	74.8	101.0	132.5
2017	82.9	103.1	135.2
2018	101.2*	110.8	145.3

Note: *Provisional figure.

4 Options for decarbonisation

The measures investigated in this study are categorized as shown in Figure 9.
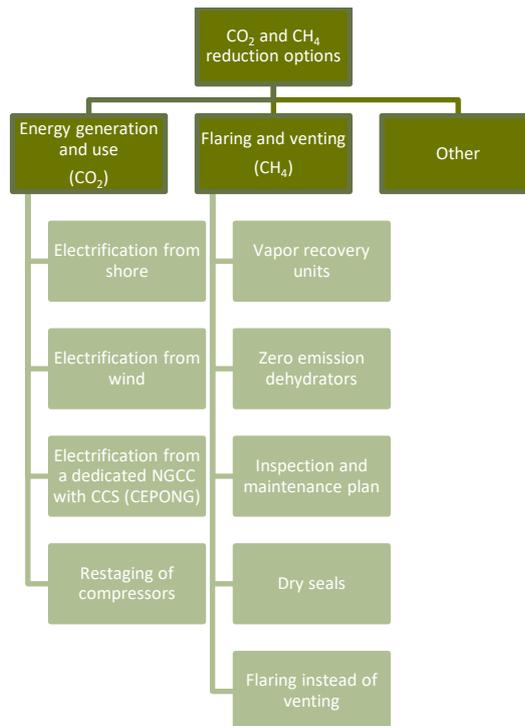
Figure 9. Categorization of option to reduce CO$_2$ and CH$_4$ in offshore NG platforms

Since process-related energy efficiency measures are very specific and applicable only to particular locations, the options for decarbonizing offshore NG platforms investigated in this study were limited to measures that could apply generally to the top 15 platforms. Examples of such energy efficiency measures that were not included in this report are (Nguyen, Voldsund, et al., 2016):

- Multi-level production manifolds
- Reduction of anti-surge recirculation.

Because heat demands in NG platforms are low (compared to oil platforms), waste heat recovery systems were not included (Zhang et al., 2019). Similarly, because of what it would imply to switch operations to produce hydrogen from NG, and to store the recovered CO$_2$ (i.e. blue hydrogen) as a way to decarbonize the operations of the NG industry, this option was excluded in the report (De Alegría et al., 2009). Nevertheless, the production of green hydrogen is being considered as an option to repurpose O&G platforms after their end of life (TNO, 2019).

4.1   Energy generation and use

4.1.1   Electrification from shore

Description

Electrification refers to the centralisation of power supply of offshore O&G facilities. Electrification from shore involves the connection of platforms to the onshore electricity grid (See Figure 10). Platforms can be partly or fully electrified depending on whether any existing heating demand can be met by electric or combustion equipment, and on the reliability of the power from shore (ABB, 2014; Nguyen, Tock, et al., 2016).
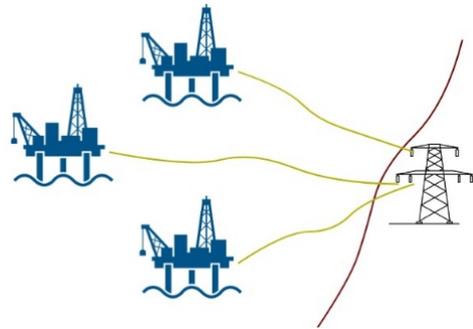
Figure 10. Electrification from shore

Benefits

Electrification from shore allows an overall reduction of both fuel consumption and emissions of CO_2 by replacing the low-efficient gas turbines and diesel motors with the efficiency of the power from shore and the electrical equipment. The emission savings will however depend on the CO_2 footprint of the power mix from land and on the quantity of purchased green electricity certificates (if available and applicable).

As a general reference, assuming the gas turbines have an overall thermal efficiency of 30%, the CO_2 emission intensity of delivering one kWh of energy with a gas turbine would be of 0.67 $kgCO_2$/kWh, compared to the CO_2 intensity of the Dutch electricity grid of 0.45 $kgCO_2$/kWh in 2017 (CBS, 2018a). This difference represents a 33% reduction of CO_2 emissions[9].

Additional benefits from electrifying NG platforms include (ABB, 2014; Greenblatt, 2015):
* Increased NG deliveries to shore
* Safer operations by eliminating a source of gas ignition[10]
* Reduction of noise levels and vibrations caused by gas turbines[10]
* Lower maintenance and repairs costs
* Higher reliability and availability of electrical systems compared to gas turbines and diesel engines
* Elimination of the methane and NO_x emissions released by NG and diesel combustion installations (See Table 5).

Technical implications

Electrification can be considered as a retrofit of existing platforms or in the design of new developments. It implicates the partial or complete substitution of gas turbines by variable frequency drives (VFD's) and electric motors, depending on the reliability of power from land.

Fully electrified platforms have already proven to be reliable enough to depend completely on the power from shore. This is the case of the Valhall platform in Norway where the gas turbine was removed, and the power supply relies solely on the power from mainland. Over the years 2013-2015, the power availability achieved an average of 98.5%, compared to the

---

[9]   These savings do not consider losses due to electricity transmission and the efficiency losses of VFD's and electric motors in the case of electrification.
[10]   If the gas turbine is removed from the platform.

availability of a gas turbine driven compressor set of about 97.9% (Kurz et al., 2006; Myklebust et al., 2017).

Although electrical systems usually require less space than gas turbines, they have a larger weight (Kurz et al., 2006; Schwarz et al., 2017). For this reason, whether gas turbines are removed or left as a backup, the weight and space required to accommodate the electrical equipment make its installation very challenging in retrofit projects.

Depending on the distance of the platforms to shore and on the power required offshore, high voltage alternate current (HVAC) or high voltage direct current (HVDC) can be used as the type of transmission technology to deliver the electricity from land.

A HVAC transmission system consists of a transformer substation (onshore), used to raise the voltage and decrease the transmission losses, the power transmission cables, and another transforming substation (offshore) used to adjust the voltage to the platform requirement levels (De Alegría et al., 2009). A HVDC transmission system consists of a converter station (onshore), where the AC voltage from the onshore power grid is converted into DC voltage, a power transmission line, and an inverter converter station (offshore) where DC voltage is converted back into AC (Elliott et al., 2015). Additional filters may be required in an HVDC system to deal with the harmonics generated by the switching techniques converting DC to AC (De Alegría et al., 2009). The offshore inverter or transformer substations can be located either on the platform that is being electrified or on a dedicated platform to connect a group of facilities.

Although case specific circumstances dictate the optimal transmission option, Green et al. (2007) concluded generally that HVAC offers better transmission capabilities and lower losses in distances up to 50 km from shore. Between 50 and 80 km both technologies present similar technical characteristics, and HVDC offers reduced cabling requirements and lower transmission losses at increasing powers and distances longer than 80 km.

It is important to mention that in case of a retrofit project, where no redundant gas turbine is present in the facility, the cease of operations demanded by this type of retrofits could bring a considerable amount of operations downtime, and hence an important cost element, for such a critical and non-stop production environment.

Finally, in order to be able to connect offshore oil and gas platforms to shore, the utility company has to be able to accommodate the additional power demand required by the platforms. For this reason, reinforcement of the local distribution grid onshore might be required prior the electrification of platforms.

Economic implications
Different facilities have demonstrated the economic feasibility and benefits of electrifying offshore platforms from shore. The first ever platform to be electrified was the Norwegian platform Troll A in 2005 (ABB, 2013). Valhall, Gjoa and Goliat are other examples of facilities that have been electrified from land in Norway (ABB, 2014). In the Netherlands, the only platform electrified to date is the oil platform Q13-Amstel, located approximately 12 km from the coast of Scheveningen (EBN, 2015).

The cost of electrification depends on the distance of the platform to shore, the power capacity, the type of transmission, the environmental conditions and other safety and regulatory requirements, as well as the electricity price. New developments present more favourable economic conditions than existing platforms due to the full time span of the

platform lifetime to recover the investment and due to the unneeded retrofitting works (Chokhawala, 2008). Therefore, the life expectancy and furtherly the electricity demand of the wells and platforms, respectively, play a big role in the business case of electrification.

The investment cost of electrifying a platform consists of the cost of connecting the platform to shore, the cost of the electrical equipment, civil works, installation costs and the gas turbine dismantling, if applicable. An exhaustive investment analysis requires very specific data. Nevertheless, the following paragraphs give an indication of what are the main costs of electrification from shore.

Although the cost of transmission technologies depend on many factors which are difficult to define precisely, B. Van Eeckhout et al. (2009) gives an indication and a comparison of the prices of installing HVAC and HVDC for connecting a 300 MW wind park 50 km away from land. The summary of these costs are shown in Table 7.

Table 7. Prices of HVAC and VSC HVDC transmission system for 300 MW offshore wind farm (B. Van Eeckhout et al., 2009)

Item	HVAC	VSC HVDC
Substation (M€)	10	45
Cable (k€/km)	1500	600
Cable installation (k€/km)	340	215
Offshore substation (M€)	13	24
Onshore land use (k€)	50	125

Roussanaly et al. (2019) also present a calculation method to estimate the investment costs of an offshore HVDC system through Eq. 1 and Eq. 2, where the prices are even higher than the ones given by B. Van Eeckhout for a reference system of 300 MW (See Table 8).

Table 8. Cost parameters for scaling of cable and converters investment cost. Roussanaly et al. (2019)

Parameter	Value	Unit	Related item
B_{dp}	0.47	k€/(km·MW)	HVDC Cables
B_d	680	k€/km	HVDC Cables
B_0	5 000	k€	HVDC Cables
C_p^L	118.3	k€/MW	Onshore converter
C_O^L	20 280	k€	Onshore converter
C_p^S	758	k€/MW	Offshore converter (including platform)
C_O^S	129 900	k€	Offshore converter (including platform)

Equation 1. Cable investment cost for a HVDC system.

$$I_{cable} = P_{cableinlet} \cdot L \cdot B_{dp} + L \cdot B_{dp} + B_0$$

Equation 2. Converters investment cost for a HVDC system.

$$I_{converters} = (P_{trans} \cdot C_P^L + C_O^L) + (P_{trans} \cdot C_P^S + C_O^S)$$

Where:
- *P_{trans} is the designed transmission power (MW)*
- *L is the length of the export cable (km)*
- *B_{dp}, B_0, C_P^L, C_O^L, C_P^S, C_O^S are the cost parameters for scaling of cable and converters investment costs in Table 9.*

Operating costs for transmission systems include the energy losses and the maintenance costs (Raza et al., 2017). Losses occur in the cables and in the substation or converter units on both HVAC and HVDC. These losses vary greatly as they depend on parameters such as the cable diameter, transmission distance, load levels, etc. A reference for these values can be found in the paper of Lazaridis (2005) where the losses of HVAC and HVDC transmission systems for different power capacities and distances are presented.

HVAC and HVDC transmission lines require limited maintenance unless unexpected damage occurs. Little information is available for the indication of maintenance costs in offshore substations. However, scientific literature (e.g. Elliott et al., 2015; Hur, 2012; Bram Van Eeckhout, 2008), usually utilizes lifetime maintenance costs of 15% of the total capital costs for HVAC systems and annual costs of 0.5% of the total capital costs for HVDC in their calculations.

The price of medium voltage (MV)[11] drives and motors replacing the gas turbines depends mainly on the rated power. For reference, the list price of a Siemens VFD of the line SINAMICS Perfect Harmony of 3.73 MW is €631,700$_{2017}$ (Siemens, 2019). The cost of a Siemens motor of the line SIMOTICS HV series H-compact of 3.6 MW is of €191,200$_{2017}$ (Siemens, 2019). It is important to mention that these prices are of the individual equipment and do not include additional equipment required for its installation (e.g. filters and reactors to improve power quality, cabinets suitable for offshore environments, etc.).

The conversion of gas and diesel motors (if existing) by low voltage (LV)[12] electric motors would incur an extra expenditure. In order to increase the efficiencies, VFD's would be needed to control such equipment. The costs of low voltage equipment, similarly as with medium voltage motors and drives, depend mostly on the rated power. De Almeida et al. (2003) gives an indication of the cost of LV VFD's and Siemens AG (2015) of LV motors for different power ranges and characteristics. For reference, the cost of a LV VFD and an electric motor of 250 kW in the mentioned citations is estimated to be of €35,000$_{2017}$ and €46,400$_{2017}$, respectively.

Although the introduction of VFD's and electric motors add new elements to maintenance, requiring specialized staff, the maintenance of VFD's reduces to yearly checks to minor components such as air filters, in air cooled VFD's, and back-up batteries in water cooled VFD's, making maintenance costs very low (Scheuer et al., 2007).

The costs of civil work and labour time for the installation of the equipment on the platform and the dismantling of the gas turbines if necessary, is very variable and rather hard to estimate, but may be substantial, as it might require the use of heavy lifting vessels. As a general indication, the costs of labour in offshore environments are usually 3 times the costs of onshore labour (Bendiksen et al., 2015).

In a hypothetical case, at a gas production cost and electricity purchase price of 20 c€/nm^3 and 0.068 €/kWh respectively (CBS, 2019a; EBN, 2017), savings in fuel costs of only 0.3% could be achieved per platform from substituting gas consumption with electricity from

---

[11] MV includes voltages between 1000 V and 35 kV and typically covers powers between .4MW and 40MW (IEC, 2009).
[12] LV includes voltages of up to 1000 V and typically covers powers up to 375 kW (IEC, 2009).

shore. Alternately, at a gas production cost of 25 c€/nm^3 and the same electricity price, these cost savings would increase to around 20.0%.

For the platform with largest consumption of NG in the Dutch continental shelf (K14-FA-1C), this would represent annual savings of approximately €30,000-M€2.95[13] at the end of 2017, for the two cases. However, the liability costs of the emitting CO_2 would transfer to the power generation company and therefore, additional costs benefits from the reduction of emissions could be obtained. Benefits other than energy savings (e.g. maintenance costs, productivity benefits, safety, etc.) which are often hard to quantify could also improve the economics of a business case.

Although the calculated savings in fuel costs are very speculative because of their sensitivity to the costs of NG and electricity, they suggest that the costs of electrifying single offshore facilities are very high and may not be fully compensated by the monetary benefits. Exploring the possibility of creating platform hubs to electrify a cluster of facilities that are close to each other can decrease individual expenditures. Furthermore, assessing opportunities to reutilize offshore O&G platforms where the electrification could be beneficial after their end of life (e.g. CO_2 injection, hydrogen production and transport), and considering these benefits in a business case, could improve the economics of electrification from shore.

Due to the relatively short remaining lifetime in many of the offshore NG platforms on the Dutch continental shelf, the implementation of this measure should be explored also in new developments.

Policy instruments such as subsidies or CO_2 taxes can also improve the cost-effectiveness of electrification from shore. In Norway for instance, a CO_2 tax applied to the oil and gas sector since 1991, in addition to the regulation of emissions through the EU ETS, has favoured the realization of energy efficiency projects and the electrification of offshore O&G platforms from shore (Gavenas et al., 2015; Nguyen, Voldsund, et al., 2016).

Lastly, in addition to the economic implications, political constraints have to be addressed. A development of a legal framework that includes O&G facilities in the realization of a transmission grid in the North Sea could favour the implementation of this measure and the cooperation between different industries (e.g. transmission system operators [TSO's], wind energy companies, O&G operators).

For reference of the technical and economic implications in the top 15 platforms, Table 9 shows their maximum power capacity[14] and the approximate linear distance to Den Helder port or Scheveningen and Ameland harbours, depending on the closeness of these facilities to shore. These numbers do not however reflect joint infrastructure uses or offshore grid developments that could possibly result to optimize the electrification from shore in platforms around the same geographical area.

---

[13] Savings assuming a gas turbine overall efficiency of 30% and the consumption levels of 2017, without considering the efficiency losses of the electrical equipment.
[14] The maximum capacity was calculated considering the maximum primary energy consumption (excluding diesel fuel) during the last 5 years and considering an annual capacity factor of 8000 hours.

Table 9. Maximum capacities and distances to shore for the top 15 platforms (NLOG, 2019d)

Facility	Operator	Maximum capacity (MW$_{th}$)	Approximate distance to shore (km)	Onshore connection point (Den Helder = DH Scheveningen = SC Ameland = AM)
K14-FA-1C	Nederlandse Aardolie Maatschappij B.V.	90	85	DH
K5 Complex	Total E&P Nederland B.V.	58	125	DH
J6-A-Markham	Spirit Energy Nederland B.V.	75	155	DH
P15-D	TAQA Offshore B.V.	52	35	SC
A12	Petrogas E&P Netherlands B.V.	50	280	DH
L9-FF-1W	Nederlandse Aardolie Maatschappij B.V.	40	55	AM
L10-AD	Neptune Energy Netherlands B.V.	58	50	DH
Ameland-Westgat-1W	Nederlandse Aardolie Maatschappij B.V.	44	10	AM
K6 Complex	Total E&P Nederland B.V.	32	100	DH
P06-A	Wintershall Noordzee B.V.	8	65	DH
G17d-A	Neptune Energy Netherlands B.V.	55	70	AM
F3-FB-1P	Neptune Energy Netherlands B.V.	26	210	DH
L08-P4	Wintershall Noordzee B.V.	5	80	DH
F16-A	Wintershall Noordzee B.V.	30	140	DH
D15-FA-1	Neptune Energy Netherlands B.V.	38	195	DH

4.1.2 Electrification from wind

Description

An alternative to electrification from shore, is the connection of platforms to an offshore substation from a wind park in the proximity (i.e. "plug-in" option) or directly to dedicated wind turbines (i.e. "stand-alone" option) (See Figures 11 & 12).
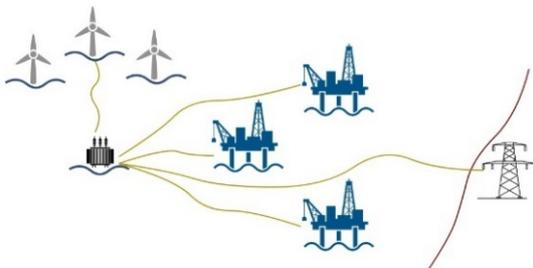
Figure 11. Electrification from wind. Plug-in option
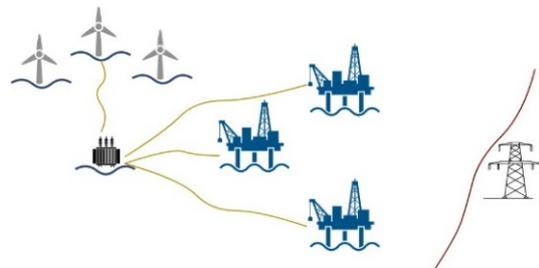
Figure 12. Electrification from wind. Stand-alone option

In plug-in connections, the electrification is similar to that of electrification from shore, with possibly shorter distances to the power source. In stand-alone connections, because of the intermittence of the wind power generation, platforms would require a back-up source of power either from local gas turbines or from power onshore (Ardal et al., 2014). For these reasons, electrification from wind power offers a reduction and not an elimination of fuel consumption and emissions (Marvik et al., 2013).

Benefits

Electrification from wind offers the same operational benefits as electrification from shore. In a plug-in connection, the CO_2 emissions are similarly dependant on the carbon footprint of the onshore grid, and on the quantity of purchased green electricity certificates (if available and applicable).

In stand-alone connections however, larger savings in CO_2 emissions can be achieved as wind energy is accounted as emission free. These savings will be equivalent to the amount of wind energy supplied to the platform(s).

Compared to electrification from shore, plug-in wind electrification can offer reduced investments as the costs of laying down transmission cables can be shorter to a wind park offshore substation than to the onshore grid. Additionally, the power drawn by the offshore O&G platforms can help to alleviate the congestion of the onshore high-voltage grid, brought by the increasing offshore wind capacity (Ericson et al., 2019).

Technical implications

If considered as a stand-alone, the type of offshore wind technology required is defined by the water depth and the distance of the wind park development to shore. Depending on the depth, different foundations might be needed (e.g. gravity, mono-pile, jacket pile, floating, etc,) and depending on the distance to the platform HVAC or HVDC has to be selected as transmission technology (Legorburu et al., 2018). The distance of the wind development will be defined by the potential wind resource in the area surrounding the platform(s).

With a stand-alone option without backup of energy from shore, a control system for rapid power balance between the fluctuating wind power and the local backup source of energy is needed to ensure the reliability of supply to the platform, adding costs and complexity to the system (Ericson et al., 2019). Additionally, an energy storage system might be required during periods when the wind energy production is surplus. Cases where non-critical and flexible loads are available and can be powered by wind energy present the best potential for a stand-alone wind electrification.

When wind electrification is considered as a plug-in option, no balancing regime is needed to compensate the variability of wind power, as the connection to an offshore substation automatically enables the backup source of energy from shore. However, the feasibility of physically connecting to an existing wind park offshore substation needs to be assessed, as this installation may not be prepared to enable a connection of an extra cable to the production platform (Koornneef, 2019).

As in electrification from shore, the retrofit of existing platforms is a difficult task due to the weight and space restrictions to accommodate the electrical equipment needed to electrify the platform. Especially in stand-alone options where a gas turbine is left as backup, and no extra space becomes available on the platform.

Although the concept of electrifying oil and gas platforms from wind power has been researched and determined to be technically feasible (Ardal et al., 2014), to the best of the authors knowledge, its implementation has not yet taken place in the present.

Economic feasibility

Stand-alone electrification involves the same investment and Operation and Maintenance (O&M) costs as electrification from shore (electrical equipment, civil works, installation costs and the gas turbine dismantling if applicable) and adds up the investment and O&M costs of installing wind turbines, depending on the power required by the platform (See Table 9), and a power balancing system.

The capital costs of wind power developments includes the turbine costs, civil works, grid connection costs, and other capital costs including the cost of control systems, project consultancy, etc. (IRENA, 2012). The costs of laying down transmission cables to the powered platform(s) substitute the grid connection costs and are those costs of transmission as per in Section 4.1.1, considering shorter distances.

The total investment costs of offshore wind energy developments (excluding the costs of laying down transmission cables) calculated by Lensink et al. (2019) for 5 open wind farm zones on the Dutch continental shelf are shown in Table 10.

Table 10. Dutch offshore wind energy cost (Lensink et al. 2019)

Wind Farm	Investment costs ($€_{2017}$/kW)	Operation and Maintenance Costs* ($€_{2017}$/kW/year)
Hollandse Kust (Zuid) (III&IV)	1,575	40.4
Hollandse Kust (West)	1,720	43.3
Hollandse Kust (Noord) (V)	1,670	40.4
IJmuiden Ver	1,820	55.1
Boven de Wadden Eilanden	1,870	63.0

*Operational and maintenance costs do not include decommissioning costs.

No reference regarding the cost of the control system to balance the power between the wind power and a local gas turbine was found publicly available. As an alternative, a connection to land could be implemented to enable the export and backup of energy to/from shore, without the need of a power control/energy storage system. Nonetheless, this option would significantly increase the investment costs.

If considered as a plug-in option, the costs of developing and installing wind turbines and of the control system for power balance can be neglected. The same investment for the transmission system, electrical equipment, civil works, installation costs and the gas turbine dismantling (if applicable) are considered, but the costs of the transmission lines to connect the wind park transformer station to the platform might be lowered, if a wind development is in the proximity of the facility.

For a stand-alone options, the fuel and emission savings by integrating wind energy are hard to quantify due to the sizing of the wind development, the variability of the wind energy in a specific location[15], and the decrease of efficiencies of the gas turbine and compressor at partial loads if left as back-up source of power (Ardal et al., 2014). In any case, the costs

---

[15] For reference, the average offshore capacity factor of wind energy production in 2017 was of 44.1% in the Netherlands (IEA, 2018a).

and emissions savings will be proportional to the wind energy generated and introduced in the platform.

For a plug-in option, the same fuel costs savings can be considered as in 4.1.1.

Similarly as with electrification from shore, clustering and cooperation with different operators to integrate wind turbines and/or transmission systems in platforms proximate to each other, the creation of regulatory frameworks to allow the distribution and commercialization of energy offshore, and the flexibility to cope with the variability of production of wind energy could allow the implementation of electrification from wind and decrease the costs of investments (Ardal et al., 2014).

4.1.3 Electrification from a dedicated NGCC offshore with CCS (CEPONG)

Description
The concepts Sevan GTW (gas-to-wire) and Clean Energy Production Offshore Natural Gas (CEPONG) introduced by Hetland et al. (2009) and Roussanaly et al. (2019), respectively, refer to the installation of an offshore NG combined cycle (NGCC) power plant integrating a post-combustion CO_2 capture unit dedicated to supply the power to offshore O&G platforms located nearby. This concept can also include the export of surplus power to mainland (See Figure 13).
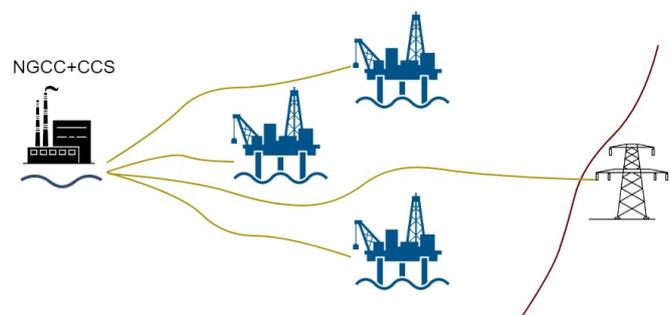
Figure 13. Electrification from a dedicated NGCC offshore with carbon capture.

Benefits
These concepts offer an increase in the overall energy generation efficiency by recovering the heat of the flue gases of single-cycle gas turbines in a heat recovery system intended to drive an additional steam turbine. The exhaust flue gases are then sent to a CO_2 capture unit for its further treatment before its transportation to a permanent storage site.

CEPONG brings the same operational benefits as the electrification from shore and wind but with it, a larger CO_2 emissions reduction can be achieved due to the capture and storage process. These CO_2 emission savings will depend on the capture ratio from the capture unit, typically around 85-90% (Leung et al., 2014).

Additionally, the construction of a power plant offshore allows the use of non-commercial NG, a reduction in the transport distances of CO_2 to the storage reservoir and lower power transmission losses by reducing the distance from the power source to the powered platforms (Rousannaly, 2017; Roussanaly et al., 2019).

Technical implications
To date, no NGCC power plant has ever been constructed offshore, but a contract to construct a floating power plant near to shore was awarded by Siemens and ST Engineering in the Dominican Republic to start operations in 2021 (Siemens, 2018). Nonetheless, a project in the Netherlands storing over 100 kt of CO_2 in the K12-B platform showed the technical feasibility of storing CO_2 offshore (Vandeweijer et al., 2018). This project, however, separated the CO_2 from the production stream and not in a post-combustion process, due to

the relatively high content of CO_2 of approximately 13% in the produced gas (Vandeweijer et al., 2018).

The most common method to capture CO_2 is through chemical absorption (NRC, 2013). With this method, the CO_2 is separated from the flue gases in an absorber column using chemical solvents. Generally, amine is used as solvent. After the absorption process, the rich solvent containing the CO_2 is desorbed in a desorbing column by a change in temperature or pressure. The lean solvent is then pumped back and recycled in the absorber column in a process similar to the dehydration of NG. The resulting CO_2 stream is further compressed and transported to a permanent storage site.

For reference of the transport capacity required for the NG platforms in the Netherlands, the total amount of CO_2 emitted by the top 15 platforms in 2017 was of 957 kt. The estimated practical offshore storage capacity in the Dutch continental shelf is 1,678 Mt (North Sea Energy, 2018). Figure 14 shows the map of the CO_2 storage potential and the pipeline transport network that could be used in the North Sea (North Sea Energy, 2018). As it can be seen, the central area presents the largest potential for CO_2 storage.

The energy required for this capturing process is obtained from the power plant itself, resulting in an energy penalty. For a reference NGCC of 288 MW_{th}, Roussanaly et al. (2019) calculate a 16% efficiency penalty from the total power plant electric efficiency of 54% without CCS.

Figure 14. Storage potential and pipeline transport network in the North Sea (North Sea Energy, 2018)

Even though Hetland et al. (2009) and Roussanaly et al. (2019) present a conceptual but realistic design of the offshore plant integrating CCS (See Figure 15), the lack of experience in this type of facilities on offshore environments adds high uncertainty on the reliability and operational risks that the CEPONG concept can encounter. Moreover, the weight and space restrictions to accommodate the electrical equipment in platforms makes the technical possibility of connecting existing platforms to a dedicated offshore NGCC with a CCS unit very challenging.

Figure 15. Layout of the offshore power production platform with CCS in the CEPONG concept. (a) deck views (b) lateral view (Roussanaly et al., 2019)

Economic implications
The same costs of the electrical connections from the platform(s) to the offshore power plant, and of the electrical equipment apply to the electrification from a CEPONG as for electrification from offshore and from wind (See Section 4.1.1). Additionally, the costs of

constructing an offshore medium/large-scale[16] power plant with a CCS unit and the possible infrastructure to transport the NG fuel to the power plant have to be considered.

The U.S. EIA gives an indication of the construction and operating costs of both an inland NGCC and an advanced generation (AG-NGCC) using a more efficient combustion turbine (See Table 11).

Table 11. Associated CAPEX and OPEX of onshore NGCC plants *(U.S. EIA, 2016)*

Technology	Fuel	Net Nominal Capacity (kW)	Net Nominal Heat Rate (BTU/kWh)	Capital Cost ($€_{2017}$/kW)	Fixed O&M ($€_{2017}$/kW-yr)	Variable O&M ($€_{2017}$/MWh)
NGCC	Gas	702,000	6,600	895	10.0	3.2
AG-NGCC	Gas	429,000	6,300	1,011	9.1	1.8

These values do not consider the cost of an offshore platform and other equipment that might be required to operate and maintain the power plant in offshore environments and that could result into a considerable increase in the investment and operating costs.

The costs of the capture, transport and storage of CO_2 also need to be considered. The investment costs of capturing CO_2 depend on the type of process plant, the capture technology, the operating conditions and the location of the facility. According to Budinis et al. (2018), the average cost of capturing CO_2 excluding transport and storage for a NGCC is of €78$_{2017}$/tCO_2. Similarly, the Global CCS Institute compiles the estimation of the investment cost of NGCC plants with a post-combustion capture units from different studies, resulting in an average cost of €1,502$_{2017}$ per kW of installed capacity (Global CCS Institute, 2009a).

The costs of CO_2 transport for offshore pipelines and different capacities, and the costs of offshore storage in different sites according to Budinis et al. (2018) are shown in Table 12 and Table 13 respectively.

Table 12. Cost of CO_2 transport for offshore pipelines with different capacities (Budinis et al., 2018)

Method	Capacity (MtCO_2/yr)	Transport costs ($€_{2017}$/tCO_2/250 km)[17]	
Offshore pipelines	3	6.7	13.8
	10	3.2	4.5
	30	1.7	2.2

Table 13. Cost of CO_2 storage for various storage sites (Budinis et al., 2018)

Methods	Storage costs ($€_{2017}$/tCO_2)	
Depleted oil and gas field – reusing wells offshore	2.8	12.9
Depleted oil and gas field –no reusing wells offshore	4.3	20.0
Saline formations offshore	8.6	28.7

---

[16] See Table 7 for the calculated maximum capacities required by the top 15 platforms.
[17] Prices would, in the most likely case, need to be scaled down as the distance between the carbon capture unit and the storage site be the minimum as possible.

The fixed and variable O&M for a NGCC with post-combustion capture given by the Global CCS Institute are on average €47.9[2017] per kW of installed capacity and of €1.1[2017] per kWh produced per year, accordingly (Global CCS Institute, 2009b).

Although the investment costs for the CEPONG are expected to be very high, the technoeconomic analysis carried out by Roussanaly et al. (2019) resulted in a levelized cost of electricity (LCOE)[18] of €113[2017]/MWh for the CEPONG concept without CCS and €190[2017]/MWh with CCS, versus €152[2017]/MWh of a reference case with electrification from shore, located 160km away from Den Helder. This suggests the economic advantage of the CEPONG concept over the electrification from shore.

4.1.4   Compressor restaging

Description

Over time, with the change of operational conditions in NG wells, the operation of centrifugal compressors deviates from the initial optimal design (i.e. Best Operating Point [BEP]). The performance of the compressor can increase or decrease with the change of well pressure, flow, temperature, speed and gas composition. Usually the compressor efficiency drops over the years as the flow from the well reduces in volume and pressure. The restaging of compressors is carried out by

Figure 16. Components of a typical rotating assembly in a centrifugal compressor (Brun et al., 2018)

adding/removing or replacing the existing impellers of the compressor to meet new operational conditions and optimize the efficiency to consume less power (See Figure 16) (Brun et al., 2013).

Benefits

Restaging compressors increases the compressor efficiency, increasing the gas production and reducing the fuel consumption and emissions, and extends the lifetime of the equipment, reducing the life cycle costs and the risk of downtimes (Solar Turbines, 2004).

Figure 17. Assembly of a centrifugal compressor (Turbomachinary International, 2016)

The increase in compressing efficiencies depend on the type of restaging that is performed (e.g. by adding new stages to compensate reduced speeds, by removing stages to increase speeds, replacement of smaller flow stages by larger flow stages or vice versa to adapt to changing flows). Therefore the potential energy benefits of restaging have to be studied for a particular application.

---

[18]   The LCOE includes the lifetime fixed and variable costs of generating technologies divided by the unit of electricity produced. It is used to compare the economic performance of different technologies. (Ueckerdt et al., 2013),

Technical implications

Compressor constructions can have either a "fixed" or modular design. In a fixed design impellers are shrink-fitted into a shaft (Garcia et al., 2015). In a modular design, components (including impellers) are bolted together allowing the interchange of components from the same compressor family (Garcia et al., 2015). The later are naturally easier and cheaper to restage.

As indicated by Garcia et al. (2015), the restaging of compressors is recommended when the efficiency decreases by more than 6% compared to its rated value. Furthermore, experiences with 379 compressors restaged by Solar Turbines, showed the percentage of operators that performed a restaging of compressors accordingly to the change of 4 performance parameters: i) inlet flow coefficient (Φ) ii) isentropic head coefficient (Ψ) iii) inlet pressure (P1) iv) and the required power (HP) (See Table 14) (Garcia et al., 2015).

Table 14. Percentage of compressors restaged at specific parameters change (Garcia et al., 2015)

Parameter percent change	<25%	25%-50%	>50%
Φ	<15%	15%-31%	>31%
Ψ	<5%	5%-19%	>19%
P	<5%	5%-15%	>15%
HP	<3%	3%-13%	>13%

Most of the times, restaging can be planned ahead as changes in the operational conditions occur gradually. Therefore, the impact of the downtimes in operations for restaging the compressors can be reduced. Moreover, impellers that are replaced can be stocked for future restages in case the operational conditions return to the previous ones.

Economic implications

Little information is available regarding the costs of restaging centrifugal compressors. However, from conversations with O&G operators in the Netherlands, it became clear that this is a measure that is often taken as part of their strategy to decrease the operating costs, suggesting that the restaging of compressors is a cost-effective measure.

4.2 Flaring, Venting and Fugitive Emissions

The processing of NG offshore represented 36% of the total methane emissions from the Dutch O&G sector in 2015 (Juez-Larré et al., 2018). The O&G sector itself was responsible of approximately 3.5% of the total CH_4 emissions in the country in the same year and has experienced a reduction of about 67% of its methane emissions since 1990 (Juez-Larré et al., 2018).

Bylin et al. (2010) estimate that 85% of methane emissions in the Gulf of Mexico could be reduced by: i) using vapor recovery units to recover gas from routine vents; ii) replacing wet seals for dry seals in compressors, and iii) implementing an inspection and maintenance plan to contain fugitive sources of emissions. The main sources of methane in the Dutch sector suggest that a considerable reduction of methane emissions can be achieved by these options (NOGEPA, 2019b). Therefore, the measures to reduce the flaring and venting of methane focus on the aforementioned options.

4.2.1   Vapor recovery units

Description

Vapor recovery units (VRU's) are used to compress and store vapor hydrocarbons that normally are vented from crude oil or condensate storages (Bylin et al., 2010). This recovered gas can be used for injection at the suction side of a compressor, at the inlet of a low pressure separation system or as fuel in local power systems. Additionally to storage tanks, other sources of vent gas such as glycol dehydrators can be piped to a VRU (Bylin et al., 2010) .

VRU's include NG engines or electric motors to provide power to the compressor pressurizing the NG. Other systems, such as the EVRU™ (Eductor Vapor Recovery Unit) developed by the company
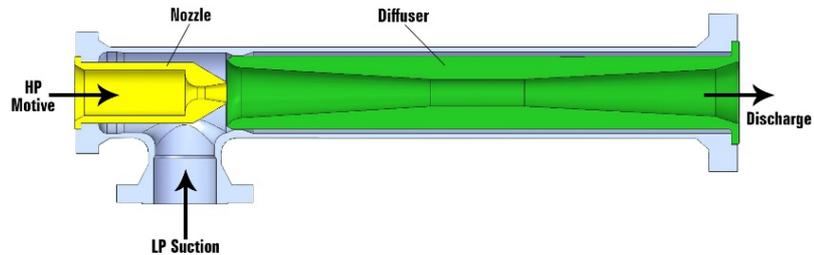
Figure 18. Ejectors principle design (Transvac, 2018)

COMM Engineering, utilize a non-mechanical ejector to pressurize low pressure NG. Ejectors use a motive fluid at high pressure to discharge a low pressure gas at an intermediate pressures suitable for its reinjection in compressors or other parts of the process system (See Figure 18).

Another ejector system, that utilizes water as a motive fluid, is the Vapor Jet developed by the Hy-Bon company. This system utilizes a pump to pressurize water to entrain the low pressure gas.

Benefits

Vapor recovery units reduce the methane and volatile organic compounds VOC's emissions that otherwise are vented or flared, reducing gas losses.

Comparing to traditional VRU's and the Vapor Jet, the EVRU™ does not require any rotating compressor or pump, lowering the O&M costs. Furthermore, according to a study by US EPA, the EVRU™ and the Vapor Jet present a better operational availability compared to traditional VRU's, which usually have 90-95% of availability (U.S. EPA, 2006a).
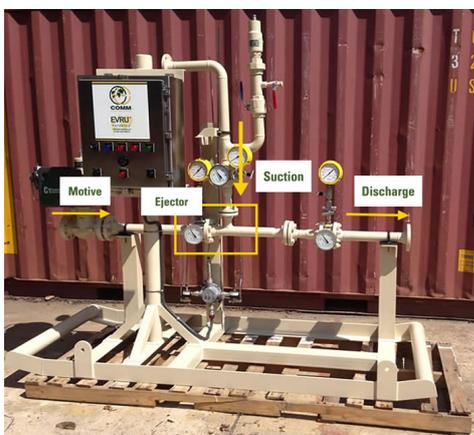
Figure 19. EVRU™ system (COMM Engineering, 2019)

Technical implications

The U.S. EPA (2009) suggests the use of the EVRU™ when a high pressure compressor with excess capacity is available, the use of the Vapor Jet when there is a stream of produced water available to be used as a motive fluid, and a traditional VRU when the previous conditions do not apply.

The installation of platforms with a VRU has different requirements depending on the technology used. For traditional VRU's and the Vapor Jet, the installation of either compressors or pumps and a rerouting of pipes from the gas vent sources to the VRU's is required. Moreover, space and weight availability is needed to allocate the equipment in the deck.

The EVRU™ does not need any power or fuel to operate, therefore it is suitable for offshore locations (Greenhouse Gas Tehnology Center, 2002). Furthermore this system is compact in space and weight compared to traditional VRU's and the Vapor Jet, which require additional equipment (See Figure 19).

Economic implications
The economics of VRU's depend on the amounts of available recoverable gas from the sources of gas vents.

In the verification program carried out by the EPA, the EVRU™ system recovered around 5,000 m^3 per day in an onshore storage tank at a O&G exploration and production facility (U.S. EPA, 2007b). The total installed costs were of €90,400$_{2017}$, bringing payback periods of less than 3 months (U.S. EPA, 2007b).

Similarly, installation and capital costs of traditional VRU's in storage tanks onshore range from €33,140-€96,500$_{2017}$, O&M costs between €6,880-€15,600$_{2017}$/yr, and payback periods from 19 to 3 months for design capacities of 700-14,200 m^3, respectively (U.S. EPA, 2006a). These savings were estimated assuming that the average recovery rate is half of the design capacity.

4.2.2 Zero emissions dehydrators

Description
Zero emission dehydrators can virtually eliminate methane emissions from the dehydration process. These type of systems reuse the non-condensable products recovered in the glycol dehydration and that otherwise are vented or flared in typical systems, as a fuel in the reboiler regenerating the glycol (U.S. EPA, 2011a). Zero emission dehydrators have been installed in onshore facilities. An example of such dehydrators is the Emission Free Dehydrator (EFD) system developed by the company Engineering Solutions LLC. in the United States (See Figure 20).

Figure 20. EFD system (Kirchgessner et al., 2004)

Benefits
The EFD system eliminates the methane and VOC's emissions by condensing or using all hydrocarbons as a fuel (Kirchgessner et al., 2004). It incorporates an effluent condenser and a vacuum separator where condensable hydrocarbons are separated and sent to a storage tank, and hydrocarbons vapours are directed to the reboiler to be used as a fuel to heat glycol (Kirchgessner et al., 2004).

Additionally, an improved burner system in the EFD achieves a reduction in CO_2 emissions compared to traditional thermal oxidizers or flare systems used to destroy unrecovered hydrocarbons (Engineered Concepts, n.d.).

The EFD system can also incorporate an electric pump in facilities where a reliable source of electricity is available, to replace the gas-assisted (i.e. Kimray) pump that is often used to circulate the glycol in the dehydration process (Kirchgessner et al., 2004). This can enable lower maintenance costs and a reduced fuel usage.

Technical implications

It is possible to configure the EFD either as a retrofit or as a replacement of existing conventional dehydrators. A TEG dehydrator incorporating the EFD system is easy to retrofit and would essentially be the same dimensions and weight as a conventional TEG system (U.S. EPA, 2011a).

Although this system has not yet been employed in an offshore facility, Engineering Solutions LLC. states that there are no limitations that would prevent the use of this dehydrator in an offshore environment (Heath, 2019). A similar system recovering vented gas from the dehydration process has been installed in the platform L08-P4 operated by Wintershall Noordzee B.V., proving the technical feasibility of such concept (Steller et al., 2019).

Economic feasibility

The installation of the EFD system has demonstrated to be economically attractive onshore. An example of a positive business case was the retrofit occurring in the Kerr-McGee Corp (Kirchgessner et al., 2004). The costs of implementation were estimated to be around €290,000$_{2017}$. The total gas savings were of approximately 117 m^3 per hour, translating into overall savings of €167,300$_{2017}$ per year. In this retrofit project, where the costs of the replaced equipment were recovered, a payback period lower than of 6 months was obtained (Kirchgessner et al., 2004).

However, the installation and logistics costs in offshore environments could considerably increase the total cost of implementation if considered as a retrofit option.

4.2.3 Dry seals

Description

Seals are used to prevent the leakage of NG from the rotating shaft of centrifugal compressors to the environment. In a typical system, high pressure seal oil acts as a liquid barrier (i.e. wet seals) to prevent gas leaks. The gas absorbed in the oil is then separated with heating or flash tank techniques, and the oil recirculated back to the seal. Although very little gas leaks occur directly through the oil seals, most of the times the methane absorbed by the recirculating oil is vented into the atmosphere (U.S. EPA, 2006b).

Figure 21. Tandem dry seal in a centrifugal compressor *(U.S. EPA, 2006b).*

Dry seals on the other hand, mechanically prevent gas leakages by creating a gap between a stationary and a rotating ring and filling it with a sealing gas (See Figure 21) (Stahley, 2001).

Benefits

Dry seals reduce the gas leakage compared to traditional wet seals. According to the EPA (2006) wet seals typically emit 1.1-5.7 sm^3/min. Single dry seals 0.17 sm^3/min.

Dry seals consume less energy as they do not require any fluid recirculation equipment. Because of this reason, an increased reliability and consequent reduction of unscheduled downtimes can be obtained in comparison to wet seal systems.

Additionally, the elimination of oil consumption and oil leakages into the compressor due to the operating fluid in wet seals bring a further reduction of operating and maintenance (O&M) costs and a safer operation.

Technical implications
The sealing gas in dry seals requires a clean and dry gas to operate. Therefore, a conditioning system to supply pressured, clean and dry gas may be required in case the processing gas does not meet these conditions.

Dry seals are available in different configurations, but the tandem type is the most used in gas processing facilities and consists of two or more dry seals in series (Sahadevan et al., 2018). Tandem dry seals have less than one percent leakages than wet seal systems (U.S. EPA, 2006b).

Economic feasibility
The economics of a dry seal system needs to be considering the benefits (reduction of power consumption by the elimination of pump and fans in wet seal systems, reduction of power loss in the shaft rotation, reduced vented gas, process improvements, reduced O&M's) versus all the cost implications.

Even though most of the new and installed compressors in the Dutch continental shelf have dry seals installed, the change to dry seals proves to be economically feasible in a short time period for existing compressors with wet seals.

Albeit savings on a specific retrofit are not representative to other installations (Ross et al., 2003), according to the EPA (2006) the investment costs of replacing wet seals by dry seals are of €301,000$_{2017}$ with payback periods ranging from 13 to 29 months depending on the price of the NG. These numbers are obtained by considering typical emission rates of 170m^3/h for wet seals and 10m^3/h for single dry seals, on a compressor that operates with 2 seals and assuming a capacity factor of 8,000 hours per year.

While annual maintenance costs for wet seals are estimated in the range of €73,620-€147,300$_{2017}$ per compressor, maintenance costs of dry seals are of €7,350$_{2017}$ (Sears et al., 2000).

4.2.4 Flaring instead of venting

Description
In the 1980´s, a request from the Dutch State Supervision of Mines (SodM), supporting fauna protection, recommended to halt the flaring of NG when birds could be endangered (Juez-Larré et al., 2018). This led to the preference of venting unrecoverable gases instead of flaring in offshore operations.

As mentioned before, the methane released from venting activities has a larger global warming potential per kilogram than the CO_2 emitted from burning NG in flaring activities. For this reason, flaring might be an alternative to decrease the global warming impact from venting activities in the Dutch industry.

Benefits
To illustrate the environmental benefits from flaring instead of venting, in a hypothetical case where all the gas vented in the Dutch offshore sector in 2017 from routine activities would

have been flared, the global warming impact would be reduced by approximately 85%[19] on a 100 years horizon. These savings represent a theoretical reduction of 6,430 tCH_4 or 180,030 tCO_{2-eq} per year.

Technical implications

The installation of flare systems on existing platforms (where a flare was not included in the original design) is challenging. The balancing, space and weight restrictions of platforms make it very difficult and expensive to install new equipment, especially for the structures needed in flare systems, which often require to be at a considerable distance from the main operational area (See Figure 22) (Oonk et al., 1995). For platforms that already have a flaring system installed, piping from the sources of vented gas to the flare stack is required if not yet present.

Figure 22. Typical flare system in an O&G platform (Zenith, 2016)

Figure 23. Enclosed flaring system (Callidus Technologies, 2014)

To reduce the endangerment and misguidance of migrating birds, enclosed flaring systems might be considered to eliminate the light irradiance from the flames (See Figure 23). Although no reference to the installation of such systems was found for an offshore facility, Callidus Technologies (A Honeywell company) offers a totally enclosed flare system which the company states is suitable for offshore applications (Callidus Technologies, 2014).

Economic feasibility

The cost of a flaring system varies greatly depending on the size of the flare, the height of the flare stack, the pressure characteristics, the number of pilot burners needed and the type of ignition system preferred (manual or automated) (PetroWiki, 2015).

Because no economic gains are associated with the burning of NG in a flare stack, the installation of a flare system on existing platforms is unlikely to be initiated for economic reasons (Emam, 2015). In addition, the combustion of NG can increase any incurring cost of emitting CO_2.

Due to these reasons, government support together with dialogue and consultation with environmental conservation organizations is necessary to decrease the global warming impact of venting activities.

4.2.5   Inspection and maintenance plan

Fugitive emissions are considered as one of the main sources of methane emissions in the NG production and transport chain (U.S. EPA, 2007a). Fugitive emissions exist of the

---

[19]   Calculation of savings considering a combustion efficiency of 98%, a methane global warming potential 28 times greater than the CO_2, and a content of 80% of methane in the NG (U.S. EPA, 2011b).

emissions occurring accidentally in equipment such as pumps, compressors, and components such valves, seals, pipeline connectors, etc. (Bylin et al., 2010).

A leak detection and repair (LDAR) program is recommended to contain this type of emissions and consists of a survey to identify and measure sources of fugitive emissions in a facility to repair them (Bylin et al., 2010). This type of practice must be carried out at regular intervals to ensure the prevention of leaking components during operations.

Different methods of leak detection can be used (e.g. infrared cameras, radars, fluorescence sensors, ultrasonic equipment, soap bubble screening, etc.). In the Dutch O&G industry, the localization and classification of methane leaks is carried out in compliance to the EPA method 21, which determines the leaks from process equipment (Steller, 2018). After detection, a quantification of the emission levels considering the gas composition is done to quantify the emission levels and analyse cost, benefits and outcomes of mitigation options. Such quantification can be made through bagging techniques or with the use of flow meters (Bylin et al., 2010).

In addition to the recovery of saleable gas, an LDAR program increases the safety of an installation and helps to avoid any possible emission enforcement action imposed by regulation bodies.

4.3   Other

Another option to reduce the energy required for the compression of NG is the optimization of the pipeline system. According to Janssen (2016) the offshore pipeline systems in the Netherlands are operating at less than 30% of their nameplate capacity. This means that the pressure specification in the pipeline system can be lowered, reducing the compression work carried out in the platforms, by further increasing gas pressures onshore to levels required by gas treatment facilities using more efficient compressors.

Nonetheless, equal mass flows at lower pressures increase the volumetric flow and consequently the pipeline losses. This could in turn offset the savings brought by the reduction of compression work brought in principle by the decrease in pressures (González Díez, 2019). Moreover, a restaging of the compressor might be required to further optimize the compressor efficiency at different working conditions.

The energy savings are hard to estimate due to limited publicly available information regarding the existing pipeline systems in the Netherlands, and the specific data of the compressors on the platforms. However, this option could enhance savings in energy without large required investments besides the restaging of compressors to optimize their efficiency with the changing operating parameters.

Although the implementation of this option could benefit all platforms, the conversations with the operators indicated that the application of this measure is hindered by political and contractual barriers regarding the operation of the pipeline system.

4.4 Summary of measures

Table 15 shows an overview of the capital and operational expenditures (CAPEX/OPEX) with ranges[20] of the costs related to the top 15 platforms according to Table 9 (if applicable and available) for the reviewed measures. It is important to mention that these figures are for reference only, and that values might differ greatly from location to location, depending on the characteristics of a specific platform. Furthermore, specific business cases should be performed to assess the cost and benefit values of the stated measures. Lastly, the table shows the category of measures according to the classification of CO_2 reduction categories by PBL, shown in Figure 24.

Table 15. Overview of the related expenditures for the reviewed measures

Measure	Category	CAPEX	OPEX
Electrification from shore	1	**Transmission technology (300MW, 50km ref.)** *HVAC* Substation: 11.1 M€$_{2017}$ Cable: 1,670 k€$_{2017}$/km Cable installation: 378 k€$_{2017}$/km Offshore substation rig: 14.5 M€$_{2017}$ Onshore land use: 55.6 k€$_{2017}$ [Total costs: 97-599 M€$_{2017}$] *HVDC* Substation: 50 M€$_{2017}$ Cable: 667 k€$_{2017}$/km Cable installation: 239 k€$_{2017}$/km Offshore substation rig: 26.7 M€$_{2017}$ Onshore land use: 139 k€$_{2017}$ [Total costs: 108-331 M€$_{2017}$] **Electrical equipment (reference)** MV drives: €631,700$_{2017}$ (3.73 MW) MV motors: €191,200$_{2017}$ (3.6 MW) LV drives: €35,000$_{2017}$ (250 kW) LV motors: €46,400$_{2017}$ (250 kW) **Civil and dismantling works** NPA	**Transmission technology** *Power losses* NPA *Substations* HVAC: 15% of CAPEX/lifetime HVDC: 0.5% of CAPEX/yr **Electrical equipment** NPA
Electrification from wind	1	**Transmission technology (300MW, 50km ref.)** *HVAC* Substation: 11.1 M€$_{2017}$ Cable: 1,670 k€$_{2017}$/km Cable installation: 378 k€$_{2017}$/km Offshore substation rig: 14.5 M€$_{2017}$ Onshore land use: 55.6 k€$_{2017}$ *HVDC* Substation: 50 M€$_{2017}$ Cable: 667 k€$_{2017}$/km Cable installation: 239 k€$_{2017}$/km Offshore substation rig: 26.7 M€$_{2017}$ Onshore land use: 139 k€$_{2017}$ **Electrical equipment (reference)** MV drives: €631,700$_{2017}$ (3.73 MW) MV motors: €191,200$_{2017}$ (3.6 MW) LV drives: €35,000$_{2017}$ (250 kW) LV motors: €46,400$_{2017}$ (250 kW) **Civil and dismantling works** NPA	**Transmission technology** *Power losses* NPA *Substations* HVAC: 15% of CAPEX/lifetime HVDC: 0.5% of CAPEX/yr **Electrical equipment** NPA **Wind turbines (average)** €48.4$_{2017}$/kW/yr [Total costs: .242-4.35 M€$_{2017}$/yr]

---

[20] Ranges of the total costs for the top 15 platforms indicated in [].

Measure	Category	CAPEX	OPEX
		Wind turbines (average) €1,730$_{2017}$/kW [Total costs: 8.7-158 M€$_{2017}$] **Power balancing system** NPA	
Electrification from a dedicated platform	1, 7	**Transmission technology (300MW, 50km ref.)** *HVAC* Substation: 11.1 M€$_{2017}$ Cable: 1,670 k€$_{2017}$/km Cable installation: 378 k€$_{2017}$/km Offshore substation rig: 14.5 M€$_{2017}$ Onshore land use: 55.6 k€$_{2017}$ *HVDC* Substation: 50 M€$_{2017}$ Cable: 667 k€$_{2017}$/km Cable installation: 239 k€$_{2017}$/km Offshore substation rig: 26.7 M€$_{2017}$ Onshore land use: 139 k€$_{2017}$ **Electrical equipment (reference)** MV drives: €631,700$_{2017}$ (3.73 MW) MV motors: €191,200$_{2017}$ (3.6 MW) LV drives: €35,000$_{2017}$ (250 kW) LV motors: €46,400$_{2017}$ (250 kW) **NGCC power plant** €895$_{2017}$/kW [Total costs: 4.5-81 M€$_{2017}$] **CCS** Capture €1502$_{2017}$/kW$_{(NGCCinstalledcapacity)}$ [Total costs: 7.5-135 M€$_{2017}$] Transport €6.7-€13.8$_{2017}$/tCO$_2$/250 km Storage €2.8-12.9$_{2017}$/tCO$_2$ **Civil works** NPA	**Transmission technology** *Power losses* NPA *Substations* HVAC: 15% of CAPEX/lifetime HVDC: 0.5% of CAPEX/yr **Electrical equipment** NPA **NGCC** FO&M: €10.0$_{2017}$/kW/yr [Total costs: 50-900 k€$_{2017}$/yr] VO&M: €3.2$_{2017}$/MWh [Total costs: 16-288 k€$_{2017}$/yr] **CCS** FO&M €47.9$_{2017}$/kW$_{(NGCCinstalledcapacity)}$/yr [Total costs: 240-4320 k€$_{2017}$/yr] VO&M €1.1$_{2017}$/kWh/yr
Compressor restaging	3	NPA	NPA
Vapor recovery units	3	**EVRU™** €90,400 USD$_{2017}$ **Conventional VRU's (700-14,200 m^3)** €33,140-€96,500$_{2017}$	**EVRU™** NPA **Conventional VRU's (700-14,200 m^3)** €6,880-€15,600$_{2017}$/yr
Zero emission dehydrators	3	**EFD system** €290,000$_{2017}$	NPA
Dry seals	3	€301,000$_{2017}$	€7,350$_{2017}$/yr
Leaking detection and repair programs	-	NPA	NPA
Flaring instead of venting	3	NPA	NPA

Note: NPA = not available

CO₂ reduction categories

1	**Fuel substitution**
2	**Feedstock substitution**
3	**Process design** a. Energy efficiency b. Process substitution
4	**Recycling**
5	**Product design** a. Reduced use b. Substitution with product with smaller CO_2 footprint
6	**Use of residual energy**
7	**CO_2 capture and storage or re-use**
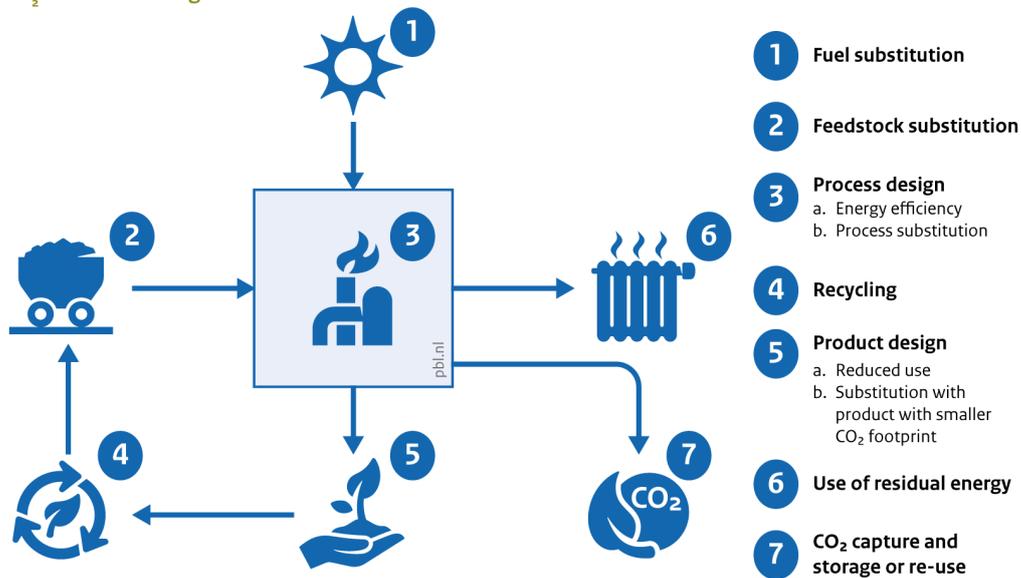
Figure 24. CO₂ reduction categories *(PBL, 2019)*

5 Discussion

In recent years, offshore gas operators have actively focused on reducing their OPEX to ensure sufficient margins after the drop of the NG prices (EBN, 2017). These efforts, together with covenants signed with public bodies, have enhanced energy efficiency in the sector, but have not generally included larger scale emission reduction options, such as electrification. This study attempted to identify and highlight the technical and economic implications of such and other measures that can be applicable to the 15 platforms with the highest CO_2 emissions in the Dutch continental shelf to lower their GHG emissions.

Electrification measures have significant emission savings potential but come at a high investment cost (CAPEX). In order to curtail the large costs of implementation, collaboration between different operators and different industries (e.g. wind energy, TSO's), together with possible repurposing options and support from regulatory frameworks and policy instruments are necessary.

Cooperation between different operators in the development of offshore hubs can increase the likelihood of implementing electrification options as individual investments may be unprofitable. The possible sharing of infrastructure costs among different operators and different industries can enable a reduction in individual expenditures. Moreover, possible future system integrations and repurposing of facilities after the end of NG production can increase the cost effectiveness and allow a smoother shift to future technologies. Lastly, regulatory frameworks to facilitate a fair and effective interconnection of offshore systems including O&G platforms, and policy instruments such as subsidies or carbon taxes as the ones implemented in Norway, can have a positive effect on the electrification of offshore facilities.

Measures to decrease methane emissions present a similar outlook. Because methane emissions are not taxed, their reduction has little or no economic returns beyond avoiding the loss of marketable gas. These measures will therefore require higher leverage of policy instruments and/or the constant commitment of the Dutch sector, which has continuously reduced their methane emissions since 1990 and has signed a covenant to draw a reduction plan to halve the methane emissions from offshore activities by the end of 2020 compared to 2017. Moreover, consultation with nature conservation organizations might be needed to reconsider practices such as flaring versus venting.

Not only energy savings, but also operational and safety benefits (i.e. non-energy benefits), which are of major importance in O&G facilities, might be highlighted to increase the profitability and attractiveness of the measures and to create a link to the core business of the operators.

One important factor that can influence the realization of decarbonization options in the offshore NG sector is the gas price. If it develops upwardly, it can help to increase the investments in new developments offshore, increase the lifetime of existing production sites and consequently increase the timespan available to make the implementation of measures more cost-effective. If it develops downwardly, however, the benefits related to fuel savings could be reduced, hindering the adoption of measures for economic reasons.

The weight and space restrictions on platforms, together with the relatively short and rather uncertain remaining lifetime of the existing facilities in the Dutch continental shelf adds complexity to the realization of decarbonization and "demethanisation" projects. For these

reasons, some of the measures can be easily questioned from an economic and technical point of view for existing facilities. Therefore, with new developments, these options should be considered from an early stage. Yet, thorough analyses of specific locations including business cases should be made to obtain conclusive results regarding the cost-effectiveness of the measures for existing platforms.

To conclude, cooperation between operators, authorities and different industries, effective policy instruments and frameworks, comprehensive planning of new developments of conventional and renewable sources of energy, the consideration of repurposing options of the offshore facilities, and an upward development of the NG price can influence the degree to which the offshore NG industry implements larger scale measures to decarbonize and "demethanise" their operations and contribute to the energy transition.

References

ABB. (2013). Troll A - The energy company Statoil awarded ABB a second contract to supply subsea HVDC Light® transmission systems to the Troll A platform in the North Sea. Retrieved from https://new.abb.com/systems/hvdc/references/troll-a

ABB. (2014). *Electrification of petroleum installations. Commercially justifiable and necessary for the climate*. Retrieved from https://library.e.abb.com/public/1239733f013ac1c485257ddc004d0246/PT0147 BR ABB og elektrifisering_A4_engelsk_3mm.pdf

Abdulrahman, R., & Sebastine, I. (2013). Natural Gas Dehydration Process Simulation and Optimization: A Case Study of Khurmala Field in Iraqi Kurdistan Region. *Journal of Natural Gas Science and Engineering*, *78*. https://doi.org/10.1016/j.jngse.2013.06.005

Ardal, A. R., Sharifabadi, K., Bergvoll, O., & Berge, V. (2014). Challenges with integration and operation of offshore oil gas platforms connected to an offshore wind power plant. *2014 Petroleum and Chemical Industry Conference Europe*, 1–9. https://doi.org/10.1109/PCICEurope.2014.6900054

Bader, A., Baukal, C. E., & Bussman, W. (2011, July). Selecting the Proper Flare Systems. *CEP Magazine. An AlChe Publication*. Retrieved from www.aiche.org/cep45

Bahadori, A. (2014). *Natural gas processing: technology and engineering design* (1st ed.). Gulf Professional Publishing.

Beatrix, Wine, J., & Donner, J. (2002). Mijnbouwbesluit. Retrieved June 6, 2019, from https://wetten.overheid.nl/BWBR0014394/2017-04-01

Bendiksen, T., & Young, G. (2015). *Commissioning of Offshore Oil and Gas Projects: The Manager's Handbook* (2nd ed.). AuthorHouse.

Brown, S. P. A., & Yucel, M. K. (2008). What drives natural gas prices? *The Energy Journal 29(2):45-60*. https://doi.org/10.5547/ISSN0195-6574-EJ-Vol29-No2-3

Brun, K., & Kurz, R. (2018). *Compression Machinery for Oil and Gas* (1st ed.). Gulf Professional Publishing.

Brun, K., Kurz, R., & Nored, M. G. (2013). Gas Turbine Packaging Options and Features. *Turbosymposium 2016*. Retrieved from https://oaktrust.library.tamu.edu/bitstream/handle/1969.1/172641/METS2Tutorial6.pdf?sequence=1&isAllowed=y

Budinis, S., Krevor, S., Dowell, N. Mac, Brandon, N., & Hawkes, A. (2018). An assessment of CCS costs, barriers and potential. *Energy Strategy Reviews*, *22*, 61–81. https://doi.org/10.1016/j.esr.2018.08.003

Bylin, C., Schaffer, Z., Goel, V., Robinson, D., do N. Campos, A., & Borensztein, F. (2010). *Designing the Ideal Offshore Platform Methane Mitigation Strategy*. https://doi.org/10.2523/126964-ms

Callaghan, I. C., McKechnie, A. L., Ray, J. E., & Wainwright, J. C. (1985). Identification of Crude Oil Components Responsible for Foaming. *Society of Petroleum Engineers Journal*, *25*(02), 171–175. https://doi.org/10.2118/12342-PA

Callidus Technologies. (2014). *Callidus Flares: Flares for the Petrochemical and Petroleum Industry*. Retrieved from https://www.uop.com/wp-content/uploads/2014/06/Callidus-General-Flares-Brochure.pdf

Centraal Bureau voor de Statistiek (CBS). (2018a). *CBS Rendementen en CO2-emissie elektriciteitsproductie 2017*. Retrieved from https://www.cbs.nl/nl-nl/maatwerk/2018/04/rendementen-en-co2-emissie-elektriciteitsproductie-2017

Centraal Bureau voor de Statistiek (CBS). (2018b). Energy - Figures - Economy | Trends in the Netherlands 2018. Retrieved May 31, 2019, from https://longreads.cbs.nl/trends18-eng/economy/figures/energy/

Centraal Bureau voor de Statistiek (CBS). (2019a). CBS StatLine - Aardgas en elektriciteit, gemiddelde prijzen van eindverbruikers. Retrieved June 4, 2019, from https://statline.cbs.nl/StatWeb/publication/?DM=SLNL&PA=81309NED&D1=0-1,5,8,12,15&D2=0&D3=0&D4=4,9,14,(l-6)-l&HDR=T&STB=G2,G3,G1&VW=T

Centraal Bureau voor de Statistiek (CBS). (2019b). CBS StatLine - Emissions of greenhouse

gases according to IPCC guide-lines. Retrieved June 6, 2019, from
https://opendata.cbs.nl/statline/#/CBS/en/dataset/70946eng/table?dl=BADE

Centraal Bureau voor de Statistiek (CBS). (2019c). CBS StatLine - Government Finance
Statistics; key figures. Retrieved May 31, 2019, from
https://opendata.cbs.nl/statline/#/CBS/en/dataset/84114eng/table?ts=155352325124
7

Centraal Bureau voor de Statistiek (CBS). (2019d). CBS Statline - Producer Price Index;
output prices by economic activity SIC 2008, 2015=100. Retrieved June 3, 2019, from
https://opendata.cbs.nl/statline/#/CBS/en/dataset/83936eng/table?ts=155955112496
0

Centraal Bureau voor de Statistiek (CBS). (2019e). Natural gas trade deficit for the first time
in 2018. Retrieved May 31, 2019, from https://www.cbs.nl/en-
gb/news/2019/11/natural-gas-trade-deficit-for-the-first-time-in-2018

Chokhawala, R. (2008). Powering paltforms. *ABB Review*. Retrieved from
https://library.e.abb.com/public/aab4c01eb564adf3c1257427002e53a5/52-56
1M811_ENG72dpi.pdf

COMM Engineering. (2019). EVRU™ – COMM Engineering. Retrieved July 3, 2019, from
http://www.commengineering.com/products/evru/

Correljé, A., Van Der Linde, C., & Westerwoudt, T. (2003). *Natural Gas in the Netherlands -
From Cooperation to Competition?* (1st ed.). Retrieved from
https://www.clingendaelenergy.com/inc/upload/files/Book_Natural_Gas_in_the_Netherl
ands.pdf

De Alegría, I. M., Martín, J. L., Kortabarria, I., Andreu, J., & Ereño, P. I. (2009).
Transmission alternatives for offshore electrical power. *Renewable and Sustainable
Energy Reviews*, *13*(5), 1027–1038. https://doi.org/10.1016/J.RSER.2008.03.009

De Almeida, A. T., Ferreira, F. J. T. E., Fonseca, P., Chretien, B., Falkner, H., Reichert, J. C.
C., … Both, D. (2003). VSDs for Electric Motor Systems. *Coimbra: University of
Coimbra, Portugal.* https://doi.org/10.1002/14651858.CD007938.pub2

De Minister van Economische Zaken. (2016). Regeling gaskwaliteit. Retrieved July 9, 2019,
from https://wetten.overheid.nl/BWBR0035367/2016-04-01#Bijlage1

Devold, H. (2015). *Oil and gas production handbook. An introduction to oil and gas
production, transport, refining and petrochemical industry*. Retrieved from
www.wikimedia.org.

Elliott, D., Bell, K. R. W., Finney, S. J., Adapa, R., Brozio, C., Yu, J., & Hussain K. (2015). A
comparison of AC and HVDC options for the connection of offshore wind generation in
Great Britain. *IEEE Transactions on Power Delivery 31(2):1-1*, *31*.
https://doi.org/10.1109/TPWRD.2015.2453233

Emam, E. A. (2015). Gas Flaring in Industry: An Overview. *Petroleum & Coal*, *57*(5), 532–
555. Retrieved from www.vurup.sk/petroleum-coal

Energie Beheer Nederland (EBN). (2015). Focus on Dutch Oil and Gas 2015. Retrieved
November 25, 2019, from https://www.ebn.nl/wp-content/uploads/2014/11/EBN-
Focus-on-Dutch-Oil-and-Gas.pdf

Energie Beheer Nederland (EBN). (2016). Knowledge partner Dutch oil and gas - EBN.
Retrieved July 5, 2019, from https://www.ebn.nl/en/knowledge-partner-dutch-oil-and-
gas-2/

Energie Beheer Nederland (EBN). (2017). *Focus on Energy - The full potential of the Dutch
subsurface*. Retrieved from https://www.ebn.nl/wp-content/uploads/2017/06/Focus-on-
Energy-2017.pdf

ENGIE. (2017). Natural gas at the heart of energy transition. Retrieved July 8, 2019, from
https://www.engie.com/en/businesses/gas/natural-gas-energy-transition/

Engineered Concepts, L. (n.d.). *Key Features and Benefits of the Emissions Free Dehydration
(EFD) System*.

Ericson, S., Engel-Cox, J., & Arent, D. (2019). *Approaches for Integrating Renewable Energy
Technologies in Oil and Gas Operations*. https://doi.org/10.2172/1491378

Ertesvåg, I. S., Voldsund, M., Elmegaard, B., Kjelstrup, S., & Nguyen, T.-V. (2015).
Thermodynamic Performance Indicators for Offshore Oil and Gas Processing:
Application to Four North Sea Facilities. *Oil and Gas Facilities*, *3*(06), 051–063.
https://doi.org/10.2118/171565-pa

Garcia, D., Singh, A., Kurz, R., Zhang, D., Walls, K., & Stork, M. (2015). Restage of Centrifugal Gas Compressors for Changing Pipeline Landscapes. *Symposium of the Industrial Application of Gas Turbines Committee*. Retrieved from https://www.eiseverywhere.com/file_uploads/212a89c24a7ab9c8ae16c174295edd2e_204finalpaper.pdf

Gavenas, E., Rosendahl, K. E., & Skjerpen, T. (2015). CO2-emissions from Norwegian oil and gas extraction. *Energy*, *90* part *2*, 1956–1966. https://doi.org/10.1016/j.energy.2015.07.025

Global CCS Institute. (2009a). 3.1 Review of capital costs | Global CCS Institute. Retrieved July 2, 2019, from https://hub.globalccsinstitute.com/publications/cost-carbon-capture-and-storage-demonstration-projects-europe/31-review-capital-costs

Global CCS Institute. (2009b). 3.2 Review of operating costs and efficiencies of CCS power plants | Global CCS Institute. Retrieved July 2, 2019, from https://hub.globalccsinstitute.com/publications/cost-carbon-capture-and-storage-demonstration-projects-europe/32-review-operating-costs-and-efficiencies-ccs-power-plants

González Díez, N. (2019). *Program Manager Offshore Production Systems at TNO. June 6th. Personal Communication Email*.

Green, J., Bowen, A., Fingersh, L. J., & Wan, Y. (2007). Electrical Collection and Transmission Systems for Offshore Wind Power. *Offshore Technology Conference,*. https://doi.org/10.4043/19090-MS

Greenblatt, J. B. (2015). *LBNL-6990E Opportunities for Efficiency Improvements in the U.S. Natural Gas Transmission, Storage and Distribution System*. Retrieved from https://www.energy.gov/sites/prod/files/2015/05/f22/QER Analysis - Opportunities for Efficiency Improvements in the U.S. Natural Gas Transmission Storage and Distribution System.pdf

Greenhouse Gas Tehnology Center. (2002). *Environmental Technology Verification Report - COMM Engineering, USA Environmental Vapor Recovery Unit (EVRU^{TM})*. Retrieved from https://books.google.nl/books?id=4lSoIyNB4j4C&printsec=frontcover&source=gbs_ge_summary_r&cad=0#v=onepage&q&f=false

Heath, G. (2019). *Representative at Engineered Concepts, LLC. May 15th. Personal Communication Email*.

Hetland, J., Kvamsdal, M., Haugen, G., Kårstad, V., & Tjellander, G. (2009). Integrating a full carbon capture scheme onto a 450 MWe NGCC electric power generation hub for offshore operations: Presenting the Sevan GTW concept. *Applied Energy*, *86*, 2298–2307. https://doi.org/10.1016/j.apenergy.2009.03.019

Honore, A. (2017). *The Dutch Gas Market: trials, tribulations and trends*. Retrieved from Oxford Institute for Energy Studies website: https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/05/The-Dutch-Gas-Market-trials-tribulations-and-trends-NG-118.pdf

Hulshof, D., van der Maat, J.-P., & Mulder, M. (2016). Market fundamentals, competition and natural-gas prices. *Energy Policy*, *94*, 480–491. https://doi.org/10.1016/J.ENPOL.2015.12.016

Hur, D. (2012). Economic Considerations Underlying the Adoption of HVDC and HVAC for the Connection of an Offshore Wind Farm in Korea. *Journal of Electrical Engineering & Technology*, *7*(2), 157–162. https://doi.org/10.5370/JEET.2012.7.2.157

Intergovernmental Panel on Climate Change (IPCC). (2013). *Climate Change 2013: The Physical Science Basis*. Cambridge University Press.

International Association of Oil and Gas Producers (IOGP). (2018). *Environmental performance indicators – 2017 data*.

International Electrotechnical Comission (IEC). (2009). *IEC 60038 Standard - Standard Voltages*. Retrieved from www.iec.ch/searchpub/cur_fut-f.htm

International Energy Agency (IEA). (2016). *Natural Gas Information 2016*. Retrieved from www.iea.org/t&c/

International Energy Agency (IEA). (2018a). *IEA Wind Technology Collaboration Programmel - 2017 Annual Report*. Retrieved from https://community.ieawind.org/HigherLogic/System/DownloadDocumentFile.ashx?DocumentFileKey=dd7c47c2-b19d-00bf-6c38-970494257e43&forceDialog=0

International Energy Agency (IEA). (2018b). *Outlook for Natural Gas 2017*. Retrieved from www.iea.org/t&c/

International Petroleum Industry Environmental Conservation Association (IPIECA). (2013). Compressors/drivers | IPIECA. Retrieved June 5, 2019, from http://www.ipieca.org/resources/energy-efficiency-solutions/efficient-use-of-power/compressorsdrivers/

International Renewable Energy Agency (IRENA). (2012). *Renewable Energy Technologies: Cost Analysis Series*. Retrieved from www.irena.org/Publications

Janssen, H. (2016). *Dutch Offshore infrastructure optimization Project (DOMINO)*. Retrieved from https://www.loyensloeff.com/media/7323/domino-presentation-ll.pdf

Juez-Larré, J., Denier van der Gon, H., Dellaert, S., Griffioen, J., Nepveu, M., & Peters, R. (2018). *Emissie van het broeikasgas methaan gerelateerd aan de olie- en gassector in Nederland met nadruk op exploratie en productie*. Retrieved from https://www.tweedekamer.nl/kamerstukken/plenaire_verslagen/kamer_in_het_kort/ga svondst-

Kinigoma, B. S., & Ani, G. O. (2016). Comparison of gas dehydration methods based on energy consumption. *Journal of Applied Sciences and Environmental Management*, *20*(2), 253–258. Retrieved from https://www.ajol.info/index.php/jasem/article/view/140385

Kirchgessner, D. A., Richards, R. G., Heath, F., & Smith, R. D. (2004). *QLD - Oil and Gas Journal*. Retrieved from http://www.engineeredconcepts.com/images/QLT_-_Oil_and_Gas_Journal_article.pdf

Koornneef, J. (2019). *Strategy Consultant - Sustainable Geo Energy at TNO. May 28th. Personal Communication Meeting*.

Kurz, R., & Sheya, C. (2006). Electric drive vs gas turbines. *Turbomachinery International*, *47*(1), 20–21. Retrieved from https://www.scopus.com/inward/record.uri?eid=2-s2.0-33645162852&partnerID=40&md5=b31b128a9e29fbe4d9cc2ab131c80bd5

Lazaridis, L. P. (2005). *Economic Comparison of HVAC and HVDC Solutions for Large Offshore Wind Farms under Special Consideration of Reliability* (Royal Institute of Technology Department). Retrieved from http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.66.4595&rep=rep1&type=pdf

Legorburu, I., Johnson, K. R., & Kerr, S. A. (2018). Multi-use maritime platforms - North Sea oil and offshore wind: Opportunity and risk. *Ocean & Coastal Management*, *160*, 75–85. https://doi.org/10.1016/j.ocecoaman.2018.03.044

Lensink, S., & Pisca, I. (2019). *Costs of offshore wind energy 2018*. Retrieved from www.pbl.nl/en.

Leung, D. Y. C., Caramanna, G., & Maroto-Valer, M. M. (2014). An overview of current status of carbon dioxide capture and storage technologies. *Renewable and Sustainable Energy Reviews*, *39*, 426–443. https://doi.org/10.1016/J.RSER.2014.07.093

Lung, R. B., McKane, A., Leach, R., & Marsh, D. (2005). Ancillary Savings and Production Benefits in the Evaluation of Industrial Energy Efficiency Measures. *Proceedings ACEEE Summer Study on Energy Efficiency in Industry*.

Marvik, J. I., Øyslebø, E. V., & Korpås, M. (2013). Electrification of offshore petroleum installations with offshore wind integration. *Renewable Energy*, *50*, 558–564. https://doi.org/10.1016/J.RENENE.2012.07.010

Mazzetti, M. J., Nekså, P., Taxt Walnum, H., & Hemmingsen, A. K. T. (2014). Energy-Efficient Technologies for Reduction of Offshore CO2 Emmissions. *Society of Petroleum Engineers*, *3*(1), 8. https://doi.org/https://doi.org/10.2118/169811-PA

Ministerie van Economische Zaken en Klimaat. (2018). *Voortgang op het dossier methaanemissies in de olie- en gassector. NOGEPA 25 juni 2018*. 1–5.

Ministry of Economic Affairs. (2016). Energy Report - Transition to sustainable energy. *IEEE Spectrum*. https://doi.org/10.1109/MSPEC.1982.6501937

Mokhatab, S., Poe, W. A., & Speight, J. G. (2006). *Handbook of natural gas transmission and processing* (3rd ed.). Gulf Professional Pub.

Mulder, M., & Perey, P. (2018). Gas production and earthquakes in Groningen reflection on economic and social consequences. *CEER Policy Papers. Centre for Energy Economics Research, University of Groningen*, *3*. Retrieved from http://www.rug.nl/feb/

Myklebust, H., Eriksson, K., Westman, B., & Persson, G. (2017). Valhall power from shore after five years of operation. *2017 Petroleum and Chemical Industry Conference Europe (PCIC Europe)*, 1–4. https://doi.org/10.23919/PCICEurope.2017.8015056

Natural Resources Canada (NRC). (2013). Post Combustion CO2 Capture | Natural Resources Canada. Retrieved July 1, 2019, from https://www.nrcan.gc.ca/energy/energy-sources-distribution/coal-and-co2-capture-storage/carbon-capture-storage/post-combustion-co2-capture/4321

Nouri, N. (2015). *Practical Engineering Management of Offshore Oil and Gas Platforms* (1st ed.). Elsevier.

Nederlandse Aardolie Maatschappij (NAM). (2016). Gaskwaliteit. Retrieved July 9, 2019, from https://www.nam.nl/gas-en-oliewinning/het-winnen-van-aardgas/gas-kwaliteit.html

Nederlandse Emissieauthoriteit (NEA). (2019). *Emissiecijfers 2013-2018-plaats inrichtingen.ods*.

Nederlandse Olie en Gas Exploratie en Productie Associatie (NOGEPA). (2019a). *Olie en gasindustrie halveert methaanuitstoot op zee.* Retrieved January 6, 2019, from https://www.nogepa.nl/olie-en-gasindustrie-halveert-methaanuitstoot-op-zee/.

Nederlandse Olie en Gas Exploratie en Productie Associatie (NOGEPA). (2019b). *REDUCING OFFSHORE METHANE EMISSIONS IN THE NETHERLANDS*. (March).

Nexstep. (2017). *OFFSHORE RE-USE & DECOMMISSIONING INVENTORY*. Retrieved from www.nexstep.nl

North Sea Energy. (2018). North Sea Energy Atlas - story map BETA. Retrieved May 31, 2019, from http://tno.maps.arcgis.com/apps/MapSeries/index.html?appid=a71489bb089640588ea395264f0e42ff

Nguyen, T.-V., Tock, L., Breuhaus, P., Maréchal, F., & Elmegaard, B. (2016). CO2-mitigation options for the offshore oil and gas sector. *Applied Energy*, *161*(October), 673–694. https://doi.org/10.1016/j.apenergy.2015.09.088

Nguyen, T.-V., Voldsund, M., Breuhaus, P., & Elmegaard, B. (2016). Energy efficiency measures for offshore oil and gas platforms. *Energy*, *117*, 325–340. https://doi.org/10.1016/j.energy.2016.03.061

NLOG. (2019a). Infrastructure | NLOG. Retrieved July 8, 2019, from https://www.nlog.nl/en/infrastructure

NLOG. (2019b). Keuzelijst velden | NLOG. Retrieved July 8, 2019, from https://www.nlog.nl/keuzelijst-velden

NLOG. (2019c). Oil and gas overview NLOG. Retrieved May 31, 2019, from https://www.nlog.nl/olie-en-gas-overzicht

NLOG. (2019d). Selectiescherm productie | NLOG. Retrieved June 3, 2019, from https://www.nlog.nl/selectiescherm-productie

Norwegian Environment Agency (NEA). (2016). *Oil and gas activities*. Retrieved from http://www.environment.no/topics/marine-and-coastal-waters/oil-and-gas-activities/

Oonk, J., & Vosbeek, M. E. J. P. (1995). *Methane emissions due to oil and natural gas operations in The Netherlands*.

PetroWiki. (2015). Flare and vent disposal systems - PetroWiki. Retrieved June 25, 2019, from https://petrowiki.org/Flare_and_vent_disposal_systems

Planbureau voor de Leefomgeving (PBL). (2019). *CO2 reduction categories.jpg*.

Raza, A., Shakeel, A., Tahzeeb ul Hassan, H., Jamil, M., & Omer Gillani, S. (2017). Economic Analysis for HVDC Transmission System in Pakistan. *International Journal of Control and Automation*, *10*(11), 29–38. https://doi.org/10.14257/ijca.2017.10.11.03

Rijksoverheid. (2019). Gaswinning Groningen komend jaar onder 12 miljard Nm3. Retrieved from 2019: https://www.rijksoverheid.nl/actueel/nieuws/2019/09/10/gaswinning-groningen-komend-jaar-onder-12-miljard-nm3

Ross, S. L., & Beckinger, R. F. (2003). Compressor seal selection and justification. *Turbomachinery and Pump Symposia*. https://doi.org/https://doi.org/10.21423/R14944

Rousannaly, S. (2017). Clean Electricity Production from Offshore Natural Gas - #SINTEFblog. Retrieved June 28, 2019, from https://blog.sintef.com/sintefenergy/gas-technology/clean-electricity-production-from-offshore-natural-gas/

Roussanaly, S., Aasen, A., Anantharaman, R., Danielsen, B., Jakobsen, J., Heme-De-Lacotte,

L., … Dreux, R. (2019). Offshore power generation with carbon capture and storage to decarbonise mainland electricity and offshore oil and gas installations: A techno-economic analysis. *Applied Energy*, *233–234*(October 2018), 478–494. https://doi.org/10.1016/j.apenergy.2018.10.020

Rumbles, L. (2014). Importance of Flow Measurement for Separators - Emerson Automation Experts. Retrieved June 5, 2019, from https://www.emersonautomationexperts.com/2014/industry/oil-gas/importance-of-flow-measurement-for-separators/

Ruoff, M. (2016). *The future of the Dutch offshore oil and gas infrastructure - Relevance and role in a carbon emission neutral energy system*. Oranje-Nassau Energie B.V.

Sahadevan, R., & Al Menhali, B. (2018). Enhancement of Dry Gas Seal Reliability. *Society of Petroleum Engineers*. https://doi.org/https://doi.org/10.2118/192804-MS

Savelkouls, J. (2019). Offshore-industrie wil methaanuitstoot halveren | Energeia. Retrieved September 12, 2019, from https://energeia.nl/energeia-artikel/40084210/offshore-industrie-wil-methaanuitstoot-halveren

Scheuer, G., Schmager, T., Krishnan, L. C., Khaleej, A., & Refinery, S. (2007). Medium Voltage Drives in the Sugar Industry. *International Sugar Journal*, *109*, 1–11.

Schwarz, G., & Keller, H. (2017). *TURBINE REPLACEMENT BY ELECTRIC DRIVE SYSTEMS PROVIDES SIGNIFICANT BENEFITS*. Retrieved from https://w3.siemens.com/markets/global/en/oil-gas/Documents/downloads/technical-papers/Turbine-Replacement-PCIC-2017.pdf

Sears, J., & Hosking, D. (2000). Economic Justification of Mechanical Dry Seals for Centrifugal Compressors. *Volume 2: Integrity and Corrosion; Offshore Issues; Pipeline Automation and Measurement; Rotating Equipment*. https://doi.org/10.1115/IPC2000-272

Siemens. (2018). *Siemens and ST Engineering secure major order for floating power plant in Dominican Republic - Press release*. Retrieved from https://www.siemens.com/press/en/pressrelease/?press=/en/pressrelease/2018/power-gas/pr2018120095pgen.htm&content[]=GP

Siemens. (2019). SinaSave. Retrieved June 3, 2019, from https://www.automation.siemens.com/sinasave#/en/pump

Siemens AG. (2015). *SIMOTICS Low-Voltage Motors. Price List D 81.1 P*. Retrieved from https://www.industry.usa.siemens.com/drives/us/en/electric-motor/nema-motors/Literature-and-technical-resources/Documents/Pricelist-D81.1-P-March-2015 Update.pdf

Solar Turbines. (2004). *Compressor Restaging For Maximum Performance and Profit*. Retrieved from http://s7d2.scene7.com/is/content/Caterpillar/C10547484

Solar Turbines. (2009). *Solar Turbines Taurus 70 - Turbomachinery Package Specification*. Retrieved from https://www.manualslib.com/manual/539711/Taurus-60.html

Staatstoezicht op de Mijnen (SodM). (2018). *Toekomstbeelden van de energietransitie*. 1–78.

Stahley, J. S. (2001). Design, Operation, and Maintenance Considerations for Improved Dry Gas Seals Reliability in Centrifugal Compressors. *Turbomachinery and Pump Symposia*, 203–208. https://doi.org/https://doi.org/10.21423/R1SQ11

Steller, R. (2018). *e-MJV Bepalingsprotocol methaan emissies*.

Steller, R., & Baars, M. (2019). *HSE-engineer Environment at Wintershall. June 25th. Personal Communication Meeting.*

Tacoma, A. (2019). *Secretary Environmental Matters, NOGEPA. December 17th. Personal Communication Email*.

The Dutch Ministry of Infrastructure and the Environment, & The Dutch Ministry of Economic Affairs. (2015). *Policy Document on the North Sea 2016-2021*.

TNO. (2019). World first: an offshore pilot plant for green hydrogen | TNO. Retrieved July 31, 2019, from https://www.tno.nl/en/focus-areas/ecn-part-of-tno/roadmaps/towards-co2-neutral-fuels-and-feedstock/hydrogen-for-a-sustainable-energy-supply/world-first-an-offshore-pilot-plant-for-green-hydrogen/

Transvac. (2018). Transvac | How do Ejectors work? Retrieved June 26, 2019, from https://www.transvac.co.uk/howanejectorworks.php

Turbomachinary International. (2016). *Components of centrifugal compressors in oil and gas*

| *Turbomachinery Magazine*. Retrieved from https://www.turbomachinerymag.com/centrifugal-compressors-in-upstream-and-midstream-sectors/

Ueckerdt, F., Hirth, L., Luderer, G., & Edenhofer, O. (2013). System LCOE: What are the costs of variable renewables? *Energy*, *63*, 61–75. https://doi.org/10.1016/J.ENERGY.2013.10.072

United States Energy Information Administration (U.S. EIA). (2016). *Capital Cost Estimates for Utility Scale Electricity Generating Plants*. Retrieved from www.eia.gov

United States Environmental Protection Agency (U.S. EPA). (2006a). *Lessons Learned from Natural Gas STAR Partners - Installing Vapor Recovery Units on Storage Tanks*. Retrieved from https://www.epa.gov/sites/production/files/2016-06/documents/ll_final_vap.pdf

United States Environmental Protection Agency (U.S. EPA). (2006b). *Lessons Learned from Natural Gas STAR Partners Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. Retrieved from https://www.epa.gov/sites/production/files/2016-06/documents/ll_wetseals.pdf

United States Environmental Protection Agency (U.S. EPA). (2007a). *Leak Detection and Repair - A Best Practices Guide*. Retrieved from https://www.epa.gov/sites/production/files/2014-02/documents/ldarguide.pdf

United States Environmental Protection Agency (U.S. EPA). (2007b). *U.S. Environmental Protection Agency. Environmental Technology Verification Program - Eductor Vapor Recovery Unit (EVRU™)*. Retrieved from http://www.epa.gov/etv/vt-ggt.html#ogi

United States Environmental Protection Agency (U.S. EPA). (2009). *Installing Vapor Recovery Units - Lessons Learned from the Natural Gas STAR Program*. Retrieved from https://www.epa.gov/sites/production/files/2017-07/documents/05_vru_billings_2009.pdf

United States Environmental Protection Agency (U.S. EPA). (2011a). *Partner Reported Opportunities (PROs) PRO Fact Sheet No. 206 for Reducing Methane Emissions Zero Emissions Dehydrators*. Retrieved from https://www.epa.gov/sites/production/files/2016-06/documents/zeroemissionsdehy.pdf

United States Environmental Protection Agency (U.S. EPA). (2011b). *Partner Reported Opportunities (PROs) PRO Fact Sheet No. 904 for Reducing Methane Emissions Install Flares*. Retrieved from https://www.epa.gov/sites/production/files/2016-06/documents/installflares.pdf

Van Den Berg, P., Denys, F., & Bos, M. (2006). *Dutch gas sector - Overview of research and collaboration*. Retrieved from https://www.rvo.nl/sites/default/files/Overview of research and collaboration Dutch Gas Policy.pdf

Van Der Velde, R., Mieog, J., Breunese, J., & Remmelts, G. (2008). *Potential for CO2 storage in depleted gas fields on the Dutch Continental Shelf Phase 1: Technical assessment*. Retrieved from https://www.nlog.nl/sites/default/files/c000f8a7-cc15-468e-8556-9b5046bb5d11_dhv tno ccs offshore final 30-06-08.pdf

Van Eeckhout, B., Van Hertem, D., Reza, M., Srivastava, K., & Belmans, R. (2009). Economic comparison of VSC HVDC and HVAC as transmission system for a 300 MW offshore wind farm. *European Transactions on Electrical Power*, n/a-n/a. https://doi.org/10.1002/etep.359

Van Eeckhout, Bram. (2008). *The economic value of VSC HVDC compared to HVAC for offshore wind farms* (Katholieke Universiteit Leuven). Retrieved from http://homes.esat.kuleuven.be/~dvherten/eindwerk_vsc_hvdc_bram_van_eeckhout.pdf

Van Geuns, L., Juez-Larré, J., & De Jong, S. (2017). Van Exporteur Naar Importeur. De Verander(en) de Rol Van Aardgas in Nederland. TNO White Paper, 19-9022, , pp. 28.

Vandeweijer, V., Hofstee, C., & Graven, H. (2018). 13 Years Of Safe CO_2 Injection At K12-B. *Fifth CO_2 Geological Storage Workshop*, (November 2018). https://doi.org/10.3997/2214-4609.201802995

Vlek, C. (2019). Rise and reduction of induced earthquakes in the Groningen gas field, 1991-2018: statistical trends, social impacts, and policy change. *Environmental Earth Sciences*, *0*, 59. https://doi.org/10.1007/s12665-019-8051-4

Wall, M., Lee, R., & Frost, S. (2006). *Offshore gas turbines (and major driven equipment)*

integrity inspection guidance notes. Retrieved from
http://www.hse.gov.uk/research/rrpdf/rr430.pdf

Ward, M. (2011). Understanding Natural Gas Compressor Stations. *Marcellus Education Fact Sheet*, 1–5. Retrieved from extension.psu.edu

Zenith. (2016). Offshore flare tip replacement - Zenith. Retrieved July 11, 2019, from http://www.zenithstructural.com/2016/offshore-flare-tip-replacement/

Zhang, A., Zhang, H., Qadrdan, M., Yang, W., Jin, X., Wu, J., … Wu, J. (2019). Optimal Planning of Integrated Energy Systems for Offshore Oil Extraction and Processing Platforms. *Energies*, *12*(4), 756. https://doi.org/10.3390/en12040756.