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Analysing long-term opportunities for offshore energy system integration in the Danish North Sea

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ABSTRACT

This study analyzes future synergies between the Oil and Gas (O&G) and renewables sectors in a Danish context and explores how exploiting these synergies could lead to economic and environmental benefits. We review and highlight relevant technologies and related projects, and synthesize the state of the art in offshore energy system integration. All of these preliminary results serve as input data for a holistic energy system analysis in the Balmorel modeling framework. With a timeframe out to 2050 and model scope including all North Sea neighbouring countries, this analysis explores a total of nine future scenarios for the North Sea energy system. The main results include an immediate electrification of all operational Danish platforms by linking them to the shore and/or a planned Danish energy island. These measures result in cost and CO_2 emissions savings compared to a BAU scenario of 72% and 85% respectively. When these platforms cease production, this is followed by the repurposing of the platforms into hydrogen generators with up to 3.6 GW of electrolysers and the development of up to 5.8 GW of floating wind. The generated hydrogen is assumed to power the future transport sector, and is delivered to shore in existing and/or new purpose-built pipelines. The contribution of the O&G sector to this hydrogen production amounts to around 19 TWh, which represents about 2% of total European hydrogen demand for transport in 2050. The levelized costs (LCOE) of producing this hydrogen in 2050 are around 4 €$_{2020}$/kg H_2, which is around twice those expected in similar studies. But this does not account for energy policies that may incentivize green hydrogen production in the future, which would serve to reduce this LCOE to a level that is more competitive with other sources.

1. Introduction

With the Green Deal, the EU aims to be climate neutral by 2050, meaning a reduction in emissions of at least 55% by 2030 compared to 1990 levels [1]. All European countries are designing strategies to comply with these objectives with increased energy efficiency and renewable energies. Renewable electricity promises to provide the means to decarbonize key sectors of the economy, but especially heating and transport. Exploiting increasing amounts of Variable Renewable Electricity (VRE) from wind and solar relies on diverse integration measures such as sector coupling, storage, network extension/densification and energy system integration.

Currently, there are about 22 GW of offshore wind installed in Europe, of which 77% is located in the North Sea. According to ENTSOE [2], such capacity is expected to reach 70 GW by 2030 and 112 GW by 2040. Amongst other things due to rapid cost reductions in this technology, the Green Deal indicates a potential need of more than 200 GW of offshore wind by 2050. In addition, future wind farms will be placed farther offshore and into deeper waters due to both better, stable wind resources far from shore and the depletion of near-shore locations [3]. This means that future wind farms will probably be installed closer to existing Oil and Gas (O&G) platforms, which in the Danish Underground Consortium (DUC) case study of this paper are around 230 km from shore.

In this context, indirect greenhouse gas (GHG) emissions from O&G operations amount to around 15% of the energy sector's total GHG emissions [4]. On the one hand, O&G operators are under pressure from shareholders and the public to reduce their carbon footprint and there is a growing need for O&G companies in taking on strategies to adapt to the energy transition [5–7]. On the other hand, O&G companies are expecting an End of Production (EOP) for most existing offshore assets within the same timeframe to 2050 mentioned above. In addition, the relatively low recent global demand and price for crude oil has rendered many operations uneconomical. Whatever the primary reason that EOP

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is reached, large decommissioning costs are expected in order to conform with regulations. Hence an extension of life and/or repurposing of the existing O&G infrastructure may be one option to reduce these costs and simultaneously support energy system decarbonisation.

O&G platforms are energy-intensive systems with a constant power demand between a few and several hundred MW [8]. O&G platforms are usually powered by Simple-Cycle Gas Turbines (SCGT) which burn natural gas. To ensure an energy supply at all times, multiple redundant gas turbines are used which run at partial load conditions thus leading to more fuel usage and lower efficiency operations [9]. The electrification of the platform would replace or reduce the use of the gas turbines and thereby reduce the overall operational energy consumption, CO_2 and NO_x emissions. In addition, a cabled connection to an offshore power hub or to shore could provide a reliable power supply, thus improving the security of supply. Moreover, an electrified platform could increase offshore energy system integration and enable the development of other system integration concepts, such as carbon capture and storage and Power-to-Hydrogen [10].

Against this background, the present study aims to analyze future synergies between the O&G and renewables sectors and explore how exploiting these synergies could lead to economic and environmental benefits. The focus is on the 13 fields under the management of Total E&P DK and within the Danish Underground Consortium. These fields include 52 platforms, with data taken from the OSPAR database [11]. The name of the fields, together with the year of production start, the field age and the mean platform age within a field is provided in Table A.1 in the Appendix. By firstly reviewing and highlighting relevant technologies and related projects, this paper synthesizes the state of the art in offshore energy system integration, by focusing on key technologies in electrification, floating wind, electrolysis and hydrogen production.. Both existing O&G assets and these renewable technologies are techno-economically analysed with relevant technical and economic criteria. This results in an overview of the interconnected system of O&G assets within the DUC along with operational data and retirement schedules, as well as techno-economic characteristics of floating offshore wind and electrolysis. All of these preliminary results serve as input data for a holistic energy system analysis in the Balmorel modeling framework. With a timeframe out to 2050 and model scope including all North Sea neighbouring countries, this analysis explores a total of nine future scenarios for the North Sea energy system.

The remainder of the paper is structured as follows. Section 2 discusses previous research relating to synergies between offshore O&G and renewables sectors. Section 3 then explains the methodology, firstly for the techno-economic analysis and secondly for the energy system modeling. Section 4 then presents and discusses the results, and is organized according to the defined scenarios. The paper then closes with a summary and conclusion in section 5.

2. State of art and literature review

The synergies between the O&G sector and renewable energy have been examined from technical, economical and environmental perspectives. A common element among the studies in the literature is the objective to reduce O&G platforms' greenhouse gas emissions. This objective can be achieved in multiple ways, but all relate closely to the gas turbines as the main source of CO_2 emissions on the platforms [12]. This section provides an overview of relevant studies in terms of their approaches and key findings and summarizes them in Table 1.

The literature shows *different approaches*. Among the 12 manuscripts analyzed, 5 perform a technical analysis, 4 a techno-economic analysis, 2 an energy system modeling analysis and 1 techno-economic and environmental analysis.

The *technical analyses* involve a transient stability analysis of the voltage and frequency on the platform [13], a feasibility study of the integration of renewable energy sources [12–14] and the optimization of the operational design of the gas turbine [8].

The *techno-economic analyses* include Riboldi & Nord [15], who conclude that the gas and the CO_2 prices need to be favourable in order to repay the wind farm investment. In particular, for gas prices of $9\$_{2015}$/Mbtu (*i.e.* 25% higher than the study's assumed market price) the break-even point is found at a rather high CO_2 price between 124 $\$_{2015}$/t and 141 $\$_{2015}$/t according to the different scenario considered in their analysis. Furthermore, when the gas price is lowered by 25%, a CO_2 price around $200\$_{2015}$/t is needed to reach break-even. Riboldi et al. [16] involves an energy system model approach, which models the power production and demand capacities of several countries (Norway, Sweden, Finland, Denmark, Germany and the Netherlands) and the platforms to find the optimal energy flow to minimizes total system costs (from a socio-economic perspective). The authors demonstrate that platform electrification can lead to an increase in the total system CO_2 emissions due to the additional demand included in the model when electricity is produced by high CO_2 content energy sources.

Environmental aspects are included only in Leporini et al. [17], where a life cycle assessment is conducted on the repurposing of a decommissioning platform for hydrogen production.

Similar to the present paper, Riboldi et al. [16] consider a long *timeframe* of 2022–2058 and 2025–2050 respectively. Such a long-term scenario analysis is only found in 3 studies: Riboldi et al. [16,18] use a long timeframe to include the influence of the increasing penetration of renewables in the generation mix towards 2050 on the CO_2 content of electricity produced in the grid. Riboldi & Nord [15] includes a cost development overtime for natural gas and CO_2 emissions.

The literature shows that the *geographical area* studied most is the Norwegian continental shelf – in 8 of 12 manuscripts. Norway has required the operators to evaluate electrification with power from shore for all new offshore platforms on the Norwegian shelf since 2007 [19], thus it drew attention to the concept of electrifying the platform. Other studies are performed in the Gulf of Mexico [9,14], the UK continental shelf [20], the West coast of Africa [9] and the Adriatic Sea [17].

The geographical area of study in turn influences the *renewable energy sources* included in the studies. The integration of a renewable energy source is considered in 8 of 12 studies, where the wind power is present in 6 of these, of which 4 consider only wind energy and 2 either wave or solar beside it. Other energy sources are thus wave and solar that are in most cases not studied as standalone energy sources but coupled with other energy sources and energy from shore. Only in Azimov and Birkett [20] is wave power considered but it is not used to supply the platform but to produce electricity which is then injected to the grid.

In terms of *commodities*, the majority of the studies consider only the electricity demand of the platforms. Only in 4 studies is a heat production system included in the analysis [8,16,18,21]. Furthermore, the electricity produced is either consumed or injected into the onshore grid – if possible – while only in 2 studies, it is transformed into another energy vector and the feasibility of hydrogen production offshore from a techno-economic perspective is [17,22] evaluated.

Synergies between the oil and gas sector and renewable energy sources have been studied mainly during the *operational life of the platforms.* However, the integration of renewables during the lifetime can be a driver for an alternative use of the platforms when the O&G production ceases. For example, Leporini et al. [17] evaluate several configurations for the production of hydrogen on an offshore platform where production has ceased.

Generally, there is a *lack of literature regarding the repurposing* of O&G platforms for renewable energy production. The decommissioning of O&G platforms and thus the possible reuse of the existing infrastructure is a relatively new concern for O&G operators in the North Sea, which is drawing attention due to the increasing concerns about climate change.

The *contribution of this analysis* in the context of the reviewed literature is therefore threefold. Firstly, it provides insights and develops a roadmap for the possible integration of wind energy with the Danish O&G sector according to the current and future development of the Danish offshore wind sector. It analyzes a large number of platforms (*i.e.* the

Table 1
Collection of manuscripts analyzed in the literature review.

Title	Authors	Year	Method	Area	Time Period	Num. Platforms	Technologies	Commodities	Platform Status	Repurposing
Assessment of the potential of combining wave and solar energy resources to power supply worldwide offshore oil and gas platforms	Oliveira-Pinto et al. [9]	2020	Techno-econ	North Sea/Gulf of Mexico/West Coast Africa	–	1	Wave, Solar	Electricity	Operational	No
Reconversion of offshore oil and gas platforms into renewable energy sites production: Assessment of different scenarios.	Leporini et al. [17]	2019	Techno-econ-env	North Sea /Adriatic Sea	2020–2040	2/1	Electrolysis, Methanation, Wind, Solar,	Hydrogen, electricity, Methane, Natural Gas	Not operational	Yes but not modelled
An Integrated Assessment of the Environmental and Economic Impact of Offshore Oil Platform Electrification	Riboldi et al. [16]	2019	Energy System modeling	Norway /European Power system	2015–2060	4	Gas turbine, el from shore	Electricity, Heat	Operational	No
Offshore Power Plants Integrating a Wind Farm: Design optimisation and Techno-Economic Assessment Based on Surrogate Modeling	Riboldi and Nord [15]	2018	Techno-econ	Norway	2016–2034	1	Gas turbine, Wind	Electricity	Operational	No
Assessment of the potential of energy extracted from waves and wind to supply offshore oil platforms operating in the gulf of Mexico	Haces-Fernandez et al. [14]	2018	Technical	Gulf of Mexico	–	Not stated	Wind, Wave, el from shore	Electricity	Operational	No
Effective concepts for supplying energy to a large offshore oil and gas area under different future scenarios	Riboldi et al. [18]	2017	Energy System modeling	Norway/ 6 countries power model	2022–2058	4	el from shore	Electricity, Heat	Operational	No
Concepts for lifetime efficient supply of power and heat to offshore installations in the North Sea	Riboldi and Nord [21]	2017	Technical	Norway	2022–2034	2	Gas turbine, el from shore	Electricity, Heat	Operational	No
Feasibility study and design of an ocean wave power generation station integrated with a decommissioned offshore oil platform in UK waters	Azimov et al. [20]	2017	Techno-econ	United Kingdom	2025	1	Wave	Electricity	Not operational	Yes
Energy efficiency measures for offshore oil and gas platforms	Van Nguyen et al. [8]	2016	Technical	Norway	–	4	Gas turbine	Electricity, Heat	Operational	No
Hydrogen production with sea water electrolysis using Norwegian offshore wind energy potentials	Meier [22]	2014	Techno-econ	Norway	–	1	Wind, Electrolysis	Hydrogen, electricity, Methane, Natural Gas	not stated	not stated
Electrification of offshore petroleum installations with offshore wind integratio	Marvik J et al. [13]	2013	Technical	Norway	–	4	Wind, el from shore	Electricity	Operational	No
Case Study of Integrating an Offshore Wind Farm with Offshore Oil and Gas Platforms and with an Onshore Electrical Grid	He et al. [12]	2010	Technical	Norway	–	5	Gas turbine,Wind, el from shore	Electricity	Operational	No

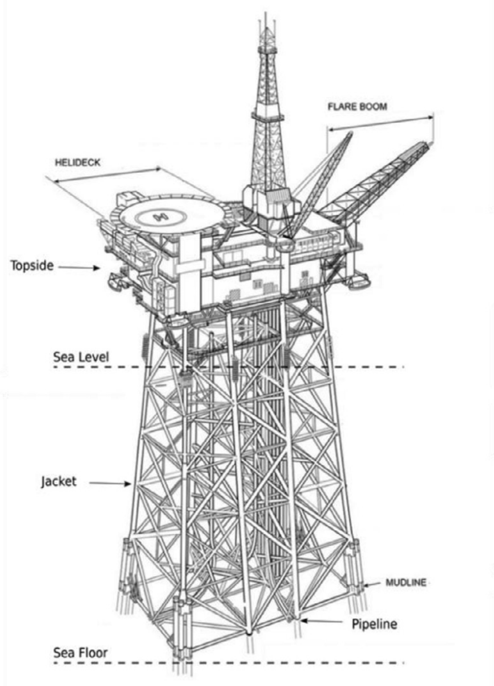

Fig. 1. Schematic of an offshore platform [25].

whole sector) compared to the average in literature of three. Secondly, it evaluates the influence of platform electrification on the power system of northern Europe which is modelled in the Balmorel model. Thirdly, it assesses the possibility of repurposing the O&G platforms to produce hydrogen offshore.

3. Methodology

This section provides the methodologies applied in the techno-economic analysis and the energy system modeling. The techno-economic assumptions are presented in section 3.1; these are the backbone for the energy system modeling described in section 3.2. A more comprehensive description of the aforementioned methodologies is given in D'Andrea et al. [23].

3.1. Techno-economic analysis

3.1.1. The Danish oil and gas sector

The O&G offshore platforms have different infrastructure based on the operations carried out. Firstly, platforms can be divided between manned and unmanned, whereby the latter are often called satellite platforms. Secondly, the platforms can be distinguished by the type of foundations and the operation performed (*e.g.* processing, flaring). An offshore platform typically consists of several key elements as displayed in Fig. 1. These are:

- a topside, the above-water structure, where the offshore activities take place;
- a jacket, which is a steel structure that supports the topside. Alternatively, the foundations can be made of concrete or floating;
- footings, the heaviest section of the jacket, which anchors it to the seabed;
- pipelines for the export of oil and gas.

Currently, the Danish O&G sector in the North Sea consists of 62 platform operating in 19 fields [11]. Total E&P DK is the operator in charge of production from 15 fields, while Ineos and Hess operate the remainder [24]. In the present study, we focus on the 13 fields under the management of Total E&P DK and within the Danish Underground Consortium (DUC). These fields include 52 platforms, with data taken from the OSPAR database [11].

The platforms are located in the western area of the Danish North Sea, at around 230 km from shore. This area, called *Doggerbank*, is a large sandbank with shallow waters (~35 m deep) that is rich in hydrocarbons. Oil and gas pipelines are connected to Tyra, Gorm and Harald facilities. The pipelines' landing point is in the area of *Nybro* for gas and *Fredericia* for oil (see Fig. 2 for details).

The platforms have been aggregated according to the field they are operating on, and small fields aggregated to larger ones which receive and process O&G. The cluster name refers to the main field within the aggregated ones. Five clusters of platforms have been identified as presented in Table A. 2 in the Appendix. In order to simplify further analysis, it is carried out at the cluster level.

Gas turbines are the platforms' only source of energy. The energy consumption on the platform is estimated based on the mean yearly consumption of the last 5 years [24]. A constant hourly demand is assumed, while the heat demand on the platform has not been considered. This study only considers the CO_2 emissions related to the consumption of natural gas for fuel purposes or gas flaring processes provided by DEA [24]. Table 2 presents the gas turbine capacity, a breakdown of natural gas consumption and the related CO_2 emissions on a field level.

3.1.2. Decommissioning process and timeline

The decommissioning process starts when the O&G field ceases production. In this study, we assume two possible decommissioning methods. In the first, the platform topside and whole substructure are removed and brought to shore (conventional decommissioning). Alternatively, the platform's topside is removed and replaced. The latter method assumes that the platform is going to be used for other purposes such as Power-to-Hydrogen (P2H). The decommissioning process is assumed to last 5 years.

The decommissioning timeline is presented in Table 3, based on the platforms' age. Specifically, it considers the mean cluster age and the age of specific platforms in the cluster. Regarding Tyra's facilities, since these are currently under renovation, it is assumed to be operational until 2042. In this year, the concession for drilling given by the Danish Government to the DUC expires and so all operations are assumed to cease. The decommissioning methodology is provided more in depth in section 3.1.4 in D'Andrea et al. [23].

3.1.3. O&G cost and repurposing assumptions

Each cluster of platforms has decommissioning costs, operational and maintenance costs, repurposing costs and operational costs related to the production of hydrogen offshore. These costs are provided in Table 4. The techno-economic assumptions behind these costs are provided in detail in section 3.1.7 in D'andrea et al. [23].

The O&G platforms have a complex design to minimize the space and the weight of the topside. A complete refurbishment of a platform for alternative uses could be challenging. Therefore, it is assumed that the platform topside is substituted with a new one – often the preferred solution, as was done for [27] Tyra . The maximum weight allowance of the jackets is another criteria but Catrinus & Jepma [28] demonstrate that the availability of space is a tighter constraint than the weight. It is also assumed that 50% of the platforms in each cluster may have the topside replaced and the new topside has the same weight as the old one so the jackets will be able to support it. Furthermore, due to uncertainty in the sizes of the hydrogen plants, any capacity limitations are neglected.

3.1.4. Floating wind turbines

Floating Wind turbines (FW) are a relatively new technology that is especially suited to locations where the sea is too deep or the seabed is not suitable for fixed-bottom offshore foundations. Europe has 70% (45 MW) of the world's floating wind fleet, with projects up to 30 MW

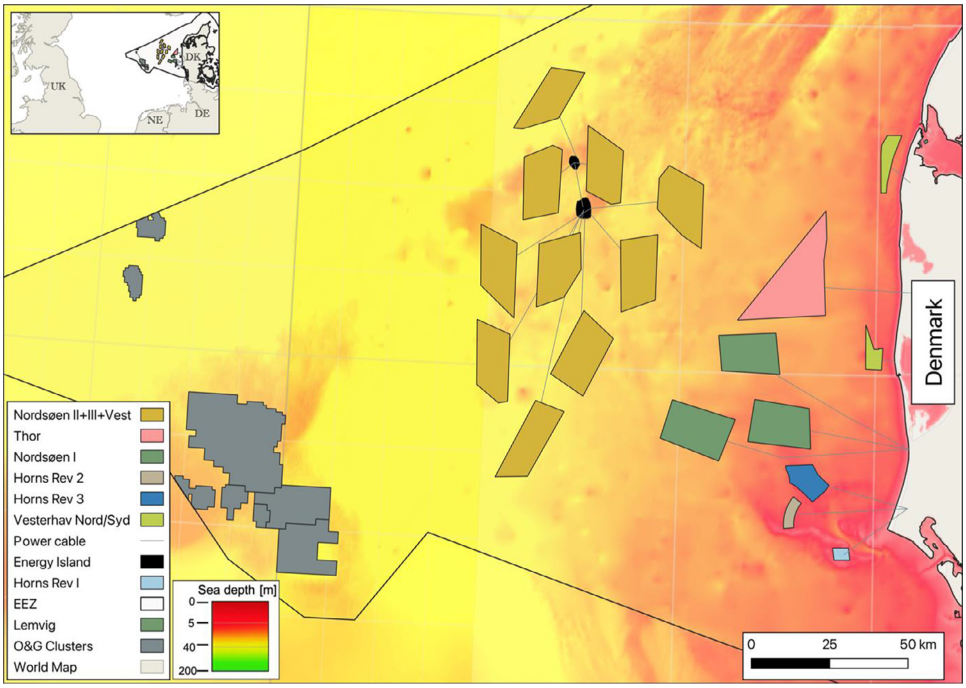

Fig. 2. Schematic of the Danish North Sea region showing existing wind farms and O&G Clusters (for interpretation of the references to color in this figure, the reader is referred to the web version of this article).

Table 2
Natural Gas consumption and related CO_2 emissions. The emission factor of natural gas is 2.28 tCO2/1000 Nm^3 [24,26]. The turbine capacities for each platform are reported in the Environmental and Social Impact Statement (ESIS) of the field [24].

Cluster	Total gas turbine capacity		Natural gas consumption			CO_2 emissions	
	Total [MW]	Total [M Nm3]	For fuel purposes [M Nm^3]	For flaring purposes [M Nm^3]	Total [kt CO_2]	From fuel purposes [kt CO_2]	From flaring purposes [kt CO_2]
Dan	453	205	148	17	468	429	39
Gorm	311	114	76	33	260	185	75
Tyra	255	177	155	19	404	361	43
Harald	50	19	14	2	43	39	5
Halfdan	164	80	70	6	183	169	14
Total	1233	595	463	77	1359	1183	176

Table 3
Clusters' decommissioning timeline.

Cluster	Start of production year	Mean cluster age [a]	Assumed Cease of Production year [a]
Gorm	1981	36	2025
Harald	1997	23	2030
Dan	1972	34	2035
Halfdan	2000	15	2040
Tyra	1984	28*	2042

*The mean age of Tyra's cluster doesn't consider the latest renovation on the field [11].

already operational, and in the next few years, wind farms of 250 MW are planned to be tendered [3].

Despite some very optimistic projections for the cost developments of FW, this analysis adopts a more conservative approach, with a cost of 60 €$_{2020}$/MWh in 2030 and 40 €$_{2020}$/MWh in 2050 (Table 5).

3.1.5. Hydrogen production with electrolysis

Hydrogen is currently most commonly produced by steam methane reforming. Only a very small percentage is produced by water electrolysis due to its higher production costs [34]. The single largest cost for water electrolysis is the operating expenditure (OPEX) associated with the electricity that is used to drive this endothermic reaction. Hydrogen is defined as "green hydrogen" if is produced by electrolysis or biomass gasification with renewable electricity and the emissions are less than 8 kg CO_2 per kgH_2 [35].

In the present study, the techno-economic data of the hydrogen plant are taken from the case study of DNV-GL [35], which evaluates the repurposing of two platforms in the Dutch North Sea to produce hydrogen. Electricity is provided by wind farms and the hydrogen produced is transported via pipelines to shore with a stackable electrolyser unit of 200 MW.

The data provided by the case study (cf. Table 9 in D'Andrea et al. [23]) are projected to 2050 based on the cost developments estimated by the IEA (see Table 6). The hydrogen transportation costs in newly dedicated pipelines (36″Ø) is 179 k€$_{2020}$/GW.km [36]. Furthermore, in one scenario it is assumed that existing gas pipelines can be used for 10% costs of new pipelines.

3.2. Energy system modeling with Balmorel

The techno-economic assumptions are applied in a whole system analysis with Balmorel model, as presented in this section. Section 3.2.1 first gives an introduction to the Balmorel model, before section 3.2.2 defines the scenarios employed in this analysis.

3.2.1. Implementation of the analysis in Balmorel

Balmorel (BALtic Model Of Regional Electricity Liberalized) is an open-source, bottom-up, partial equilibrium energy system capacity development and dispatch model that employs linear programming, originally developed by Ravn [37] and subsequently extended and employed

Table 4
Clusters' weights [11], decommissioning costs [29] and operational costs [24], repurposing costs and repurposed platform's operational costs [23].

Cluster	Total Weight [kt]	Topside Weight [kt]	Decommissioning costs [M€$_{2020}$]	OPEX [M€$_{2020}$/a]	Repurposing costs* [M€$_{2020}$/a]	OPEX repurposed [M€$_{2020}$/a]
Dan	60	43	1820	264	108	26
Gorm	49	34	1495	217	88	22
Tyra	68	45	2073	300	54	30
Harald	13	7	388	56	20	5
Halfdan	37	20	1115	162	116	16
	227	150	6892	999	386	100

*Based on the method presented in section 3.1.7 of [23].

Table 5
Floating wind turbines unit costs towards 2050 [30–32]. The operational costs follow the cost assumptions in Balmorel [33].

	Unit	2025	2030	2035	2040	2045	2050
Tender size	MW	250	1000	1000	1000	1000	1000
LCOE	M€$_{2020}$/MWh	100	60	55	50	45	40
Capex	M€$_{2020}$/MW	3.85	2.35	2.14	1.96	1.77	1.58
Opex fixed	k€$_{2020}$/MW.a	41	27	25	24	23	22
Opex variable	€$_{2020}$/MW.a	3.0	3.0	3.0	2.7	2.5	2.4

Table 6
Techno-economic data for hydrogen production by electrolysers. All costs are in €$_{2020}$.

Source	Parameter	Units	2020	2030	Long Term
IEA	Capex	€/kW	~800	~620	~400
	Opex	%/year Capex	1.5	1.5	1.5
	Efficiency (LHV)	%	64	69	74
	LCOE	€/kg H_2	2.6 – 6.4	–	1 – 2.7
	El. Price	€/MWh	–	–	~40
DNV-GL	Capex	€/kW	1170	–	400*
	Opex	%/year Capex	2	–	2*

*The cost development of DNV-GL is based on the IEA's projections. LHV: Lower Heating Value. HHV: Higher Heating Value.

in many national and international applications [38]. Balmorel minimizes total system costs for a combined electricity and district heating system in an international context in the long term, but on an hourly basis, including investment in new generation plants, operational costs and in some cases additional transmission line capacities.

As for many similar energy system models [39], the starting point in Balmorel is the exogenously-defined regional demands for electricity and heat, which are provided as inputs alongside macroeconomic developments in energy and carbon prices. The model meets these predefined demands by employing existing generation technologies, as long as technically and/or economically feasible, as well as new generation plants. Geographically, the model is divided into three categories: countries (C), regions (R) and areas (A). Each country is divided into a number of regions and the regions are divided into areas. The model allows for electric power transmission between regions via interconnectors. Within areas, the heat demand is balanced by district heating.

The version of Balmorel employed in this research includes the Nordics and neighbouring countries around the North Sea, a total of 10 countries as shown in Fig. 3 below. The temporal analysis involves 5 years steps towards 2050 (*i.e.* 2025–2030, etc.). A rolling horizon approach was considered in the analysis. It consists of optimizing two years together; for example, both 2030 and 2025 are considered when optimizing 2025.

In the model the O&G offshore installations, the clusters of platforms – Gorm, Tyra, Halfdan, Dan, and Harald – are defined as Regions. Each Region is assumed to have a natural gas turbine installed and a constant annual electricity demand that needs to be satisfied. The techno-economic assumptions of the clusters are provided in section 3.1.1. The

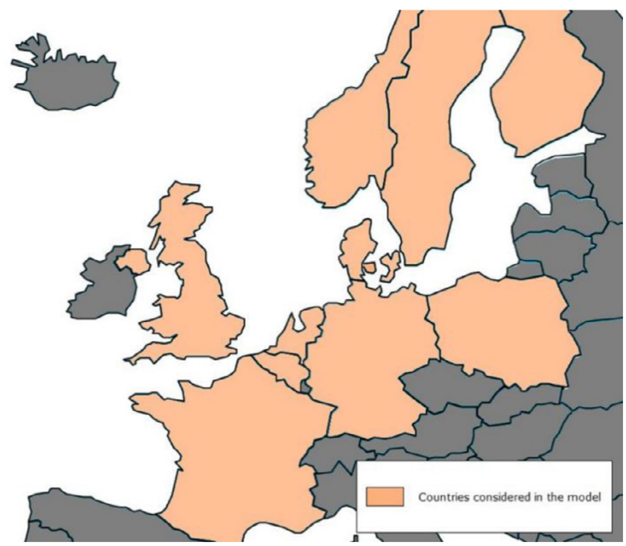

Fig. 3. Countries considered in the Balmorel model.

model can then invest on the platform electrification or the repurposing of the platforms according to the scenarios described in 3.2.2. Furthermore, the model includes price development for natural gas and CO_2 towards 2050 which are provided in section 8.2 in the Appendix.

Hydrogen is assumed to be pivotal for the production of e-fuels to support the decarbonisation of the transport sector. E-fuels could account for a significant share of the total electricity demand in the future [40]. In the model, part of the electricity demand refers to the e-fuels production which can be satisfied indirectly by any low-carbon electricity source. However, the demand allocation is restricted to avoid large investments in individual countries. The ratio between the additional transport demand and the annual average demand of each region is also restricted. On the O&G platforms, the hydrogen plant's electricity input equals the electricity demand for the decarbonisation of the transport sector allocated from the model on the platform.

3.2.2. Scenario analysis

This section gives an overview of the analysed scenarios employed in this analysis:

Table 7
Sensitivity analysis scenarios based on the E&R scenario. All costs are in €$_{2020}$.

Scenario	Element	Unit	Variation
FW-high	Floating Wind turbines LCOE	€/MWh	+25%
FW-low	Floating Wind turbines LCOE	€/MWh	−25%
TL-25, TL-50	Electricity transmission line	€/MWh	+25%, +50%
CO_2-low	CO_2 Tax	€/tCO	Linear increase from 8 to 65 €/tCO in 2050.
CO_2-mod	CO_2 Tax	€/tCO	Linear increase from 8 to 98 €/tCO in 2050.
H_2-low	Reuse of existing gas pipeline to transport hydrogen	€/MW.km	H_2 pipelines costs 10% of a new pipeline.

- **The Business As Usual (BAU) scenario** represents the current conditions on the platforms and assumes no modification or investments on the platforms until decommissioning. Hence this scenario is also referred to as the Decommissioning scenario. The platforms' energy supply is provided by gas turbines at all times representation of this scenario is provided Fig. 12 in D'Andrea et al. [23].
- **The Electrification & Repurposing (E&R) scenario** is the main scenario, where the model can invest in several technologies on the platform to reduce the total system cost. The platforms can be interconnected to the onshore grid or to the energy hub and can invest in floating wind to satisfy the demand. The gas turbines can be decommissioned or used in parallel to other energy sources. As an alternative to a complete decommissioning, the existing infrastructure can be reused for hydrogen production and transportation. Alternatively, a new hydrogen pipeline can be built. The repurposing of the platforms relies on the removal and replacement of the topside, based on costs and assumptions set out in 3.1.3. A representation of this scenario is provided in Fig. 13 in D'Andrea et al. [23].
- **Sensitivity analyses:** the impact of uncertain input data on the results is evaluated through a sensitivity analysis which includes seven additional scenarios. From the *E&R* scenario, each variable is modified one at a time according to Table 7. Floating wind costs are highly uncertain due to the early stage of market development thus FW-high and FW-low asses their influence on the model. The H_2-low scenario allows the model to use existing pipelines for the hydrogen transportation which results in large cost savings. The CO_2 tax development described in Fig. A.1 is reduced in two more moderate scenarios *CO_2-low* and *CO_2-mod*.

4. Results and discussion

This section presents and discusses the results from the Balmorel model. It is broadly structured according to the scenarios as presented in 3.2.2.

4.1. Decommissioning (BAU)

The decommissioning scenario provides the platform's costs according to the current operational settings. The cluster's annual energy related expenses are presented in Fig. 4. CO_2- and fuel-related expenses represent the highest share of costs among all clusters. On average, they account for 17% and 79% of annual expenses in 2025, respectively.

The increasing costs of natural gas and CO_2 emissions towards 2050 (cf. Fig. A.1) lead to an increase in the yearly costs as shown in Fig. 4. Across all clusters, the yearly average growth is at least 9%; the peak is observed in 2030 with an average growth of 33%. The differences in the growth between natural gas and CO_2 costs influence the cluster's share of costs. CO_2 related costs almost double between 2025 and 2030 among all cluster at the expenses of the fuel costs. In 2025 the energy-related OPEX of all platforms is 798 M€$_{2020}$. In addition to the energy related costs, there are the operational costs of the platform, namely the expenses related to drilling and processing the hydrocarbons fuels. These range from 74% to 144% of the cumulative energy related yearly costs among the different clusters. The aggregated cost for all platforms is 201 M€$_{2020}$. Furthermore, the total decommissioning costs sum up to 6891 M€$_{2020}$.

Table 8
Installed capacities of floating wind and electrolyser in 2050 for all clusters.

Technology	Unit	Dan	Gorm	Halfdan	Harald	Tyra	Total
Floating wind	GWel	1.7	0.9	1.0	0.2	2.0	5.8
	%	29%	16%	17%	3%	34%	100%
Electrolyser	GWel	1.3	0.5	0.3	0.1	1.3	3.6
	%	37%	15%	8%	3%	37%	100%

4.2. Electrification & repurposing (E&R)

In 2025 – the first model year – the model decommissions the gas turbines due their high operational costs and electrifies the platform through connections to the shore or the energy island (rather than to offshore wind plants, for example). In Fig. 8, these interconnections are presented with a blue solid line. Due to the decommissioning of the gas turbines, there are large savings in terms of Costs and CO_2 emissions as reported in Fig. 5. On average, the reduction in Costs and CO_2 emissions through electrification is 72% and 85%, respectively. This results in aggregated savings of 140 M€$_{2020}$ and 1 Mt of CO_2 emissions in 2025. Due to electrification, the electricity price on the platforms decreases from 174 to 47 €$_{2020}$/MWh (in the case of the gas turbines the former represents a shadow price). Moreover, due to the electrification, the O&G sector accounts for just 2% of Denmark's total CO_2 emissions in 2025, compared to around 15% in the *BAU* scenario. The aggregated costs across the cluster in 2025 for the *E&R* scenario are 62 M€$_{2020}$ (excluding operational costs of the platform) and the CO_2 emissions are 176 ktons.

In this scenario, the platforms which cease production are repurposed (cf. Section 3.2.2). On each cluster there can be hydrogen production which is then transported to shore via pipelines. Also, floating wind farms can be used to power the platforms while excess energy is exported. In Fig. 6, the average breakdown of the cluster's yearly costs is shown.

Noteworthy is that the largest cost shares are related to the hydrogen plant and the floating wind farm, with 60% and 22%, respectively. In absolute terms, the average yearly expenses are 464 M€$_{2020}$/year and 168 M€$_{2020}$/year, respectively. The remaining part of the costs consists in repurposing and operating the platforms; it accounts for 14% (98 M€$_{2020}$/year).

In Table 8 the floating wind farms and the electrolyser plants capacities in 2050 are presented for each cluster. The cumulative capacities are 5.8 GW and 3.6 GWel, respectively, whereby the ratio of electrolyser to wind capacity is capped at a maximum of 80%. The distribution of the capacity among the clusters shows a correlation between the two technologies. The availability of relatively inexpensive electricity from floating wind is a driver for the model to allocate electricity demand for the decarbonization of the transport sector on the platforms. The hydrogen LCOE in 2050 is 3.9–7.4 €$_{2020}$/kg H_2 (average 4.9 €$_{2020}$/kg H_2), which is higher than the expected price of renewable hydrogen of 0.7–1.5 €$_{2020}$/kg H_2 already in 2030 [41,42]. However, the hydrogen plant costs, and the expenses related to repurposing the platform are highly uncertain. Therefore, the LCOE alone does not indicate the feasibility of the hydrogen production offshore. The aggregated hydrogen production is about 505 kt of H_2, which is far below the hydrogen demand of 4.4 million tons assumed in 2030 by the "2 × 40 GW Green Hydrogen" initiative drafted in [44].

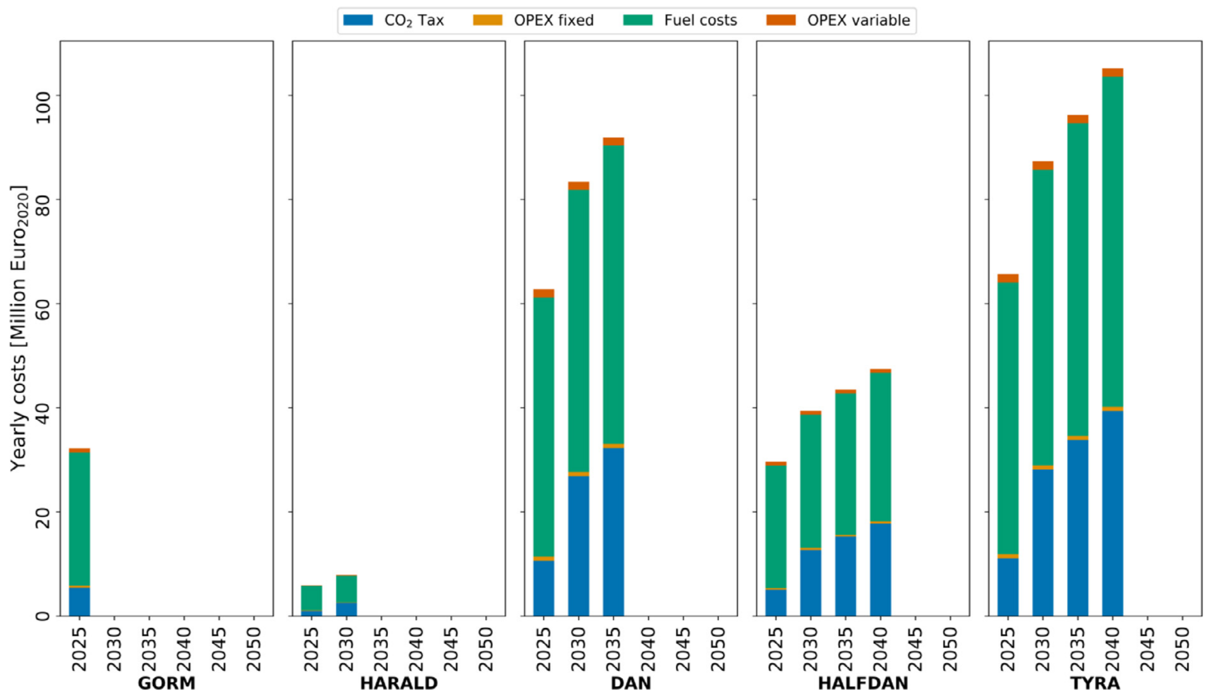

Fig. 4. Yearly energy related expenses breakdown for each cluster towards 2050. The figure does not take into account the operational costs of the producing the oil & gas (*e.g.* drilling, oil & gas processing). The years without any costs thereby represent years in which the platform is no longer operational. (For interpretation of the references to color in this figure, the reader is referred to the web version of this article.)

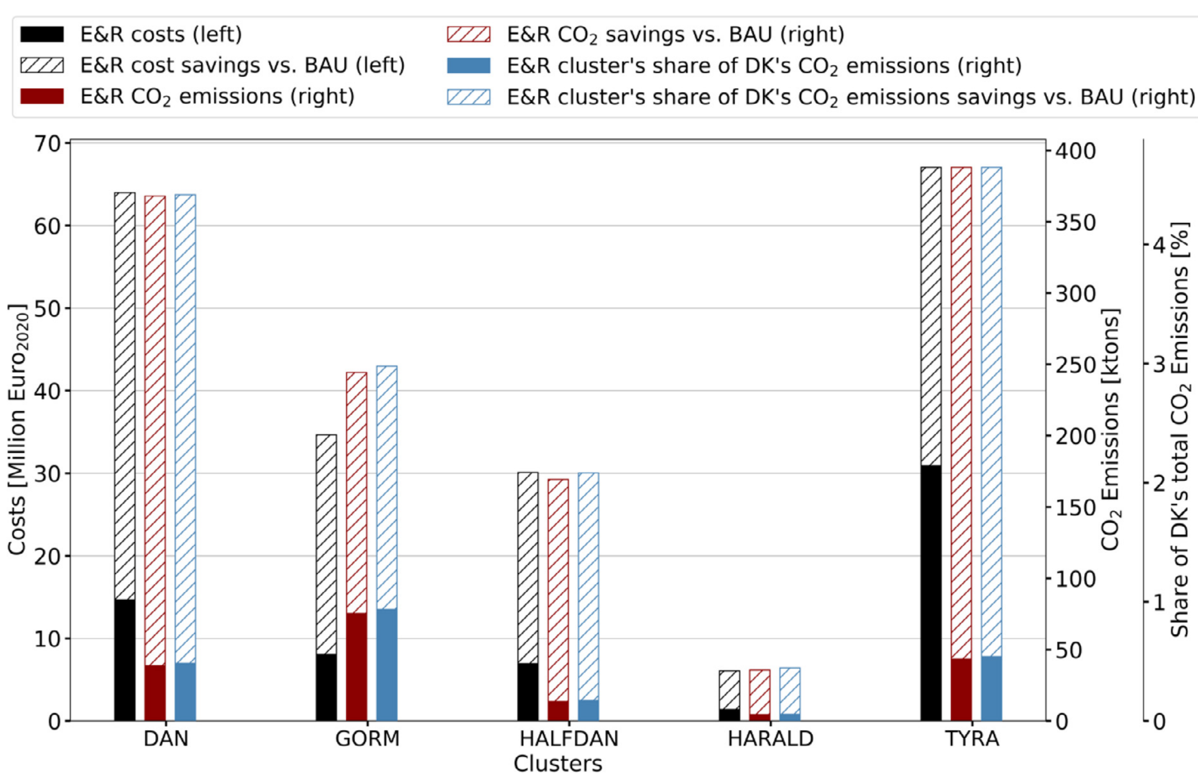

Fig. 5. Cost and CO_2 emissions savings in 2025 for each cluster of platforms in the E&R scenario. The left-hand side y-axis shows the costs while on the right-hand side the y-axes show the CO_2 emissions and the share of the cluster's emission in Denmark's total CO_2 emissions. (For interpretation of the references to color in this figure, the reader is referred to the web version of this article.)

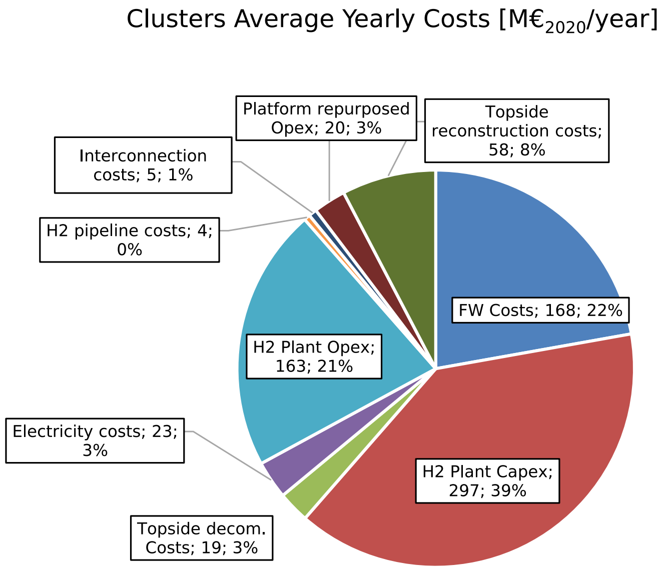

Fig. 6. Clusters' average annual costs in E&R scenario. (For interpretation of the references to color in this figure, the reader is referred to the web version of this article.)

4.3. Roadmap for offshore energy system integration

The performed analysis has highlighted a possible roadmap for the Danish Oil & Gas sector towards 2050 as presented in Fig. 7. The clusters of platforms cease operation according to the timeline provided in Fig. 7, while Balmorel, the optimization model, can choose to invest on the platforms (*e.g.* floating wind farms, electrification) and decommission existing infrastructure on the platform (*e.g.* gas turbines). It is important to emphasize that the model optimizes only two adjacent years, *i.e.* the current year and the future one (*e.g.* 2025 and 2030), as returned to in the discussion.

Firstly, in 2025 all platforms are electrified through a connection from shore or the energy island which can be interconnected to other countries. In Fig. 8, these interconnections are graphically represented by a solid blue line. Between 2025 and 2035 the layout is unchanged, there aren't new interconnections. In 2040, the platforms are interconnected within each other and a secondary cable is connected to the energy island which is now also connected to shore. In 2045, Harald, Halfdan and Tyra invest in floating wind farms; the cumulative capacity is 2.5 GW. In addition, there is hydrogen production on all platforms except for Gorm. The aggregated capacity is 0.71 GWel, where Tyra and Halfdan account for 98% of it. The hydrogen produced is transported to shore by pipelines, which are connected to all producing platforms. Furthermore, in this year, the energy island has 10 GW of installed wind capacity therefore there is a large availability of green energy offshore which benefits the production of hydrogen offshore. Finally, in 2050, the layout changes slightly from 2045. In terms of interconnections, there is no change but an increase in capacity. Floating wind capacity doubles and reaches 5.8 GW. Hydrogen is produced on all platforms and the aggregated electrolyser capacity increases to 3.56 GW, more than 5 times compared to 2045. Overall, it can be noticed that the energy island works as a bridge between the platforms and the Danish shore which are interconnected with a 1.6 GW power cable.

In Balmorel a demand for the decarbonisation of the transport sector as discussed in section 3.2 was included. The model can allocate the demand in any of the countries included in the model up a total capacity. The total demand for each year is equal in both scenarios since it is an exogenous variable. The demand increases by more than 20 times from 48 TWh in 2025 to about 1000 TWh in 2050. France is the first country to satisfy the demand and its share is the largest across all years. Furthermore, the demand allocation among the countries is quite similar between the two scenarios except in 2050 where Denmark's share doubles from 2% (18 TWh) to 4% (37 TWh). This is due to the large investments in floating wind which provides electricity at a competitive price for hydrogen production through electrolysis.

4.3.1. LCOEs of electricity on the platform

This analysis evaluates the development of the costs of powering the platforms from different energy sources: the gas turbine, the floating wind farm or through an interconnection to shore. The levelized cost of electricity (LCOE) is used to compare the energy sources' production costs. For each of these sources, the LCOE has been calculated based on three scenarios. Note, each energy source has been sized to satisfy the platform's energy demand only. Also, for the sake of the analysis, the platforms are assumed to be operational during the whole period.

In Fig. 9 the results from the analysis based on Tyra and Halfdan are presented. From an overall perspective, one can notice a defined trend in the cost development of each energy source. This is due to the underlying cost assumptions which are the same for both clusters. However, on Tyra, which is under renovation, a gas turbine is installed that is twice as efficient as the gas turbine on Halfdan, hence the large difference in the range of gas turbines' LCOEs.

Comparing the energy sources between each other, one can notice that except for Tyra in 2025, the gas turbine is always the most expensive option. For both clusters, until 2045, delivering electricity is the best solution. From that year, floating wind become cost-competitive. If its costs are reduce by 25% (*FW-low scenario),* floating wind is the best solution at the earliest in 2030, for both cases. This analysis helps to explain the trends seen in the results in terms of the LCOEs of the competing options.

4.3.2. Investments in floating wind and hydrogen

A sensitivity analysis was performed to evaluate the drivers for the investment in floating wind and hydrogen plant. The results are presented in Figs. 10 and 11. In the figures, for each modeling year (*e.g.* 2025, 2030…), the cumulative installed capacity and the share of capacity on each cluster is provided for the core scenarios plus the *E&R* scenario as a reference.

Comparing the two figures reveals a correlation between the installed capacity of the two technologies, as floating wind is a driver for the production of hydrogen offshore. In the *FW-low* scenario, where floating wind costs are reduced by 25%, hydrogen is already produced

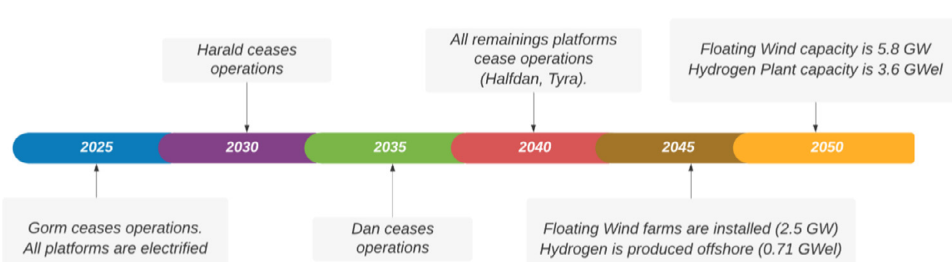

Fig. 7. Timeline of the electrification and repurposing (E&R) scenario.

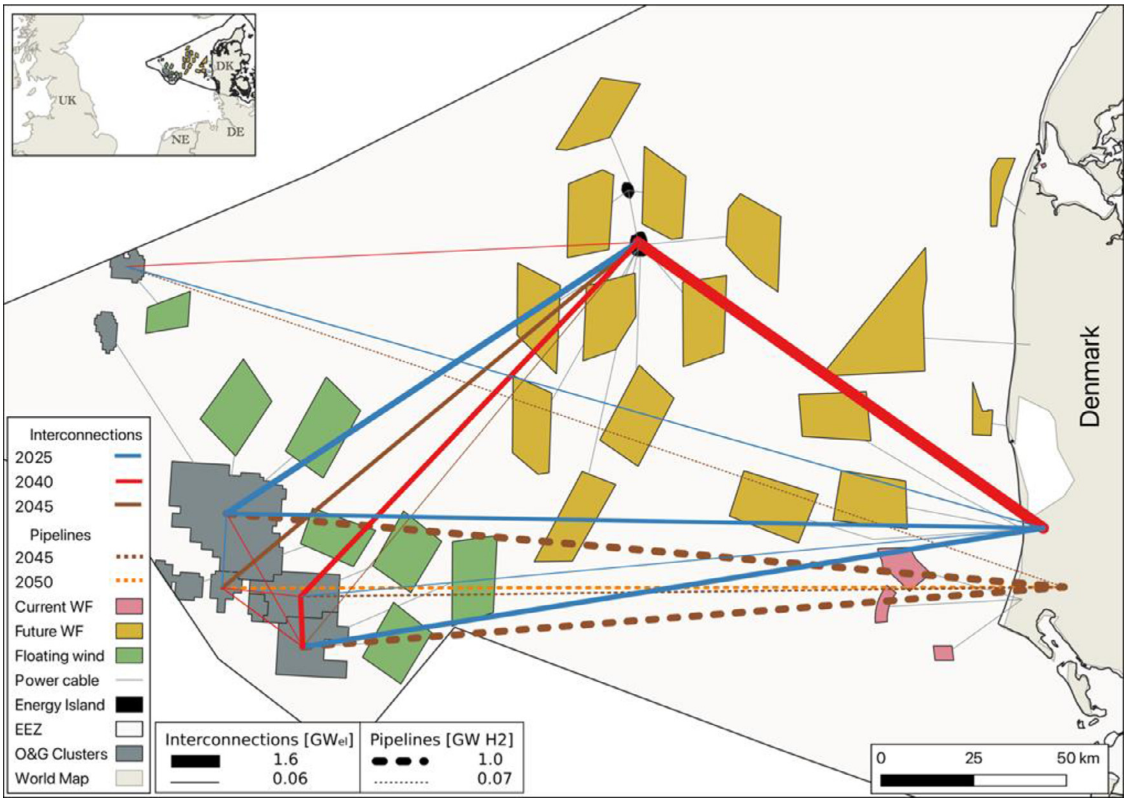

Fig. 8. Overview of Danish offshore region with developed energy system infrastructure to 2050 in E&R scenario (for interpretation of the references to color in this figure, the reader is referred to the web version of this article).

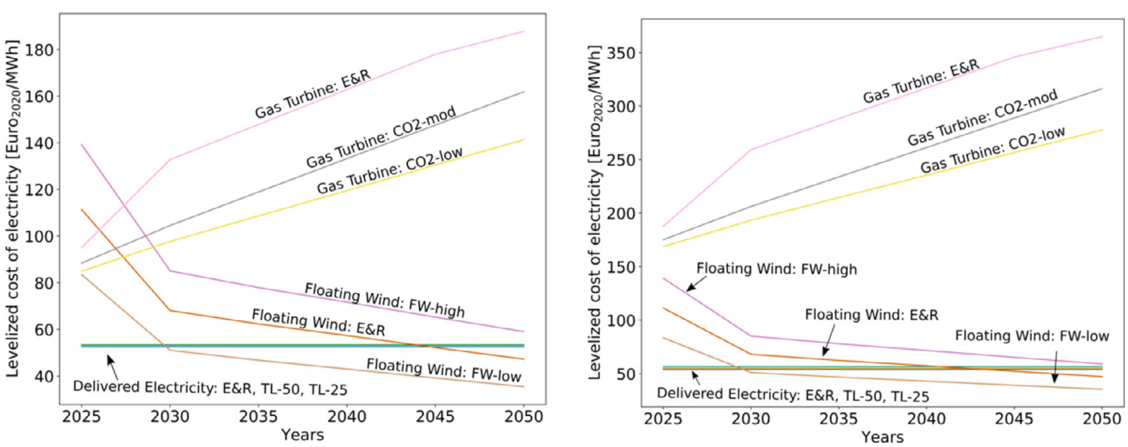

Fig. 9. Levelized Cost of Electricity analysis for Tyra (left) and Halfdan (right). (For interpretation of the references to color in this figure, the reader is referred to the web version of this article.)

in 2035. Moreover, the distribution of the technologies' capacity among the clusters highlights the correlation between the two technologies. In 2045, in all scenarios but *FW-low*, Tyra and Halfdan clusters have the largest share of capacity of both technologies.

Focusing on floating wind, it is interesting to notice that in 2050 the cumulative capacity and its distribution among the cluster is the same for all scenarios. Therefore, it can be concluded that floating wind is a very competitive energy source in 2050 while it less competitive earlier in time, except if its costs are reduced as in *FW-Low*.

On the other hand, the cumulative capacity of the hydrogen plant in 2050 varies between the scenarios. On average about 3 GW are installed across all scenarios. However, the share of capacity is highly dependent on the scenario. Dan and Tyra account for the largest shares of capacity in 2050, but Dan has the lowest share in 2045 among three scenarios. Moreover, in the *FW-low* scenario, in 2050, Gorm does not produce any hydrogen. From these results, it can be concluded that the production of hydrogen from electricity produced on the platform is not strongly competitive. Therefore, the variations performed on the variables of the sensitivity scenarios have a high influence on the allocation of the electricity for the hydrogen production.

4.3.3. LCOEs of hydrogen in 2050 for each platform

The repurposing of the platform for alternative uses involves large investments which can be offset by the sale of the energy produced on the platform. The LCOE shows the price of energy to break-even with the investments. Table 9 shows the hydrogen LCOE in €$_{2020}$/kg H_2 that is

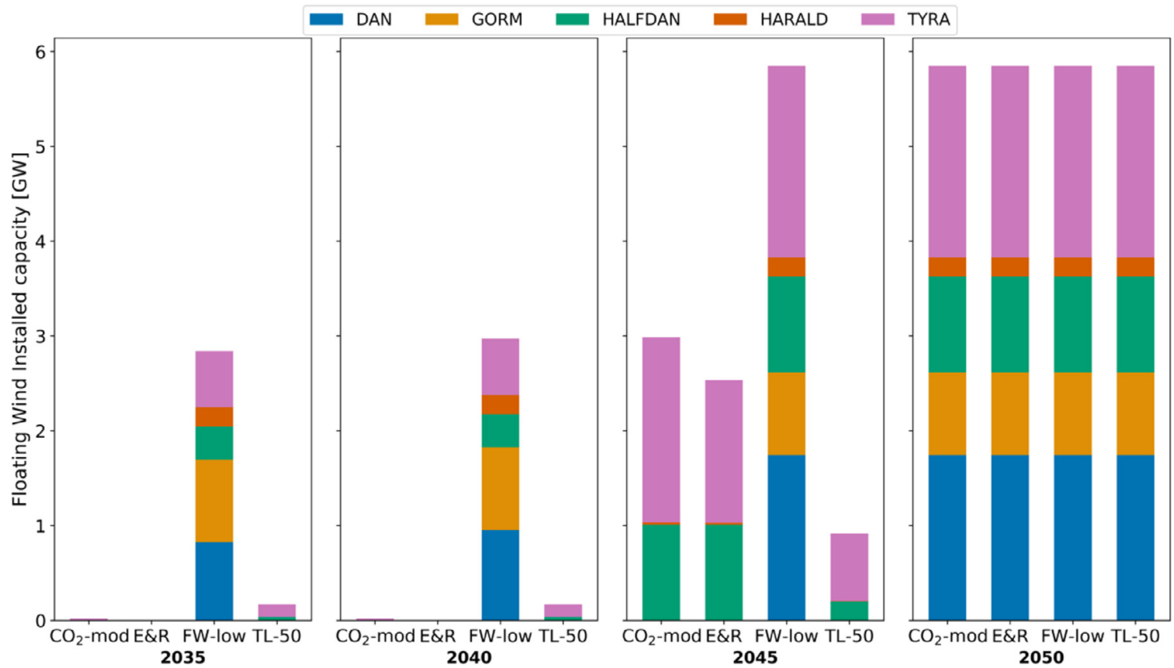

Fig. 10. Floating wind capacity for each modeling year and cluster for the core scenarios. (For interpretation of the references to color in this figure, the reader is referred to the web version of this article.)

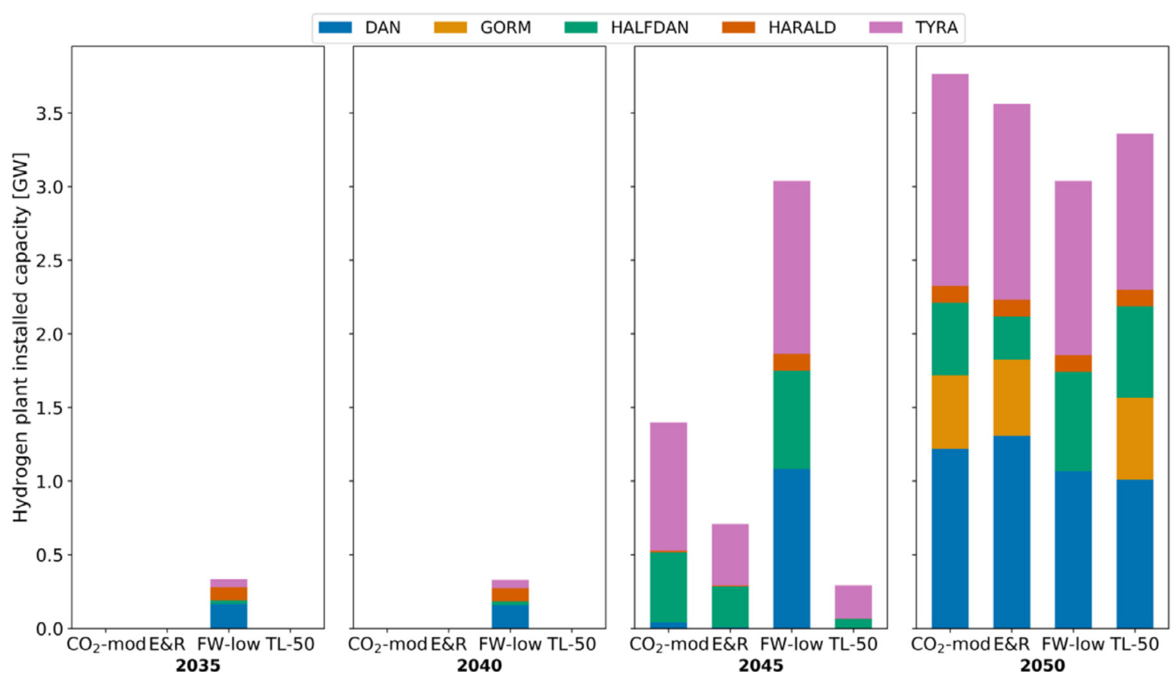

Fig. 11. Electrolyser capacity for each modeling year and cluster in the core scenarios. (For interpretation of the references to color in this figure, the reader is referred to the web version of this article.)

required to offset the yearly expenses of each cluster in 2050 – minus the income from the sale of electricity. The analysis was performed on all scenarios and for each cluster. The *E&R* scenario represents the reference while the other scenarios were used to identify the range of variations of the LCOE which is provided in the last two columns of Table 9.

The analysis shows that the LCOE on average is 4.9 €$_{2020}$/kg H_2, which is significantly higher than the expected price of renewable hydrogen of 0.7–1.5 €/kg H_2 already in 2030 [41, 42]. The LCOEs range is relatively small among all clusters except for Halfdan. On this cluster, there is a low income from the electricity sale and a low hydrogen production. The combination of these two conditions increases the LCOE highly.

4.3.4. Sensitivity analysis of the hydrogen LCOE

A sensitivity analysis on the LCOE of the hydrogen was performed. It is considered that the hydrogen plant is installed in the *E&R* scenario on Tyra in 2050. In the analysis, each cost component of the LCOE was changed by +/- 20% at a time and the variation of the LCOE was recorded. Fig. 12 provides the list of cost components and the corre-

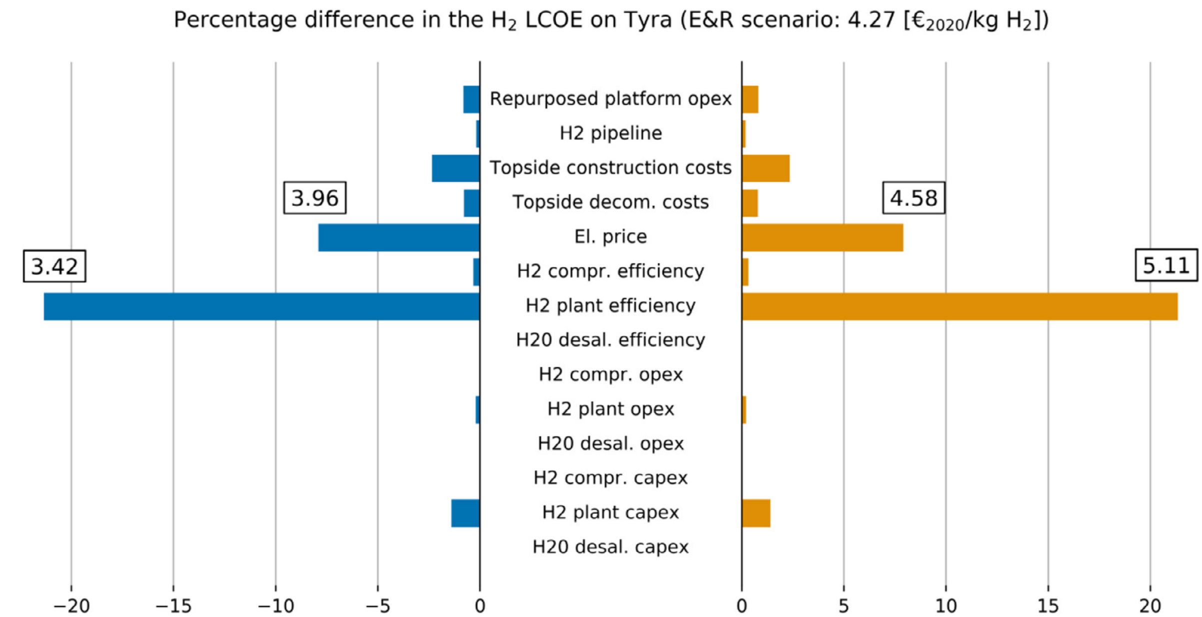

Fig. 12. Sensitivity analysis of the H_2 LCOE on Tyra in 2050.

Table 9
H_2 LCOEs in 2050 for each platform in the E&R scenario. The last two columns show the minimum and maximum LCOE observed in the sensitivity scenarios.

	LCOE [$€_{2020}$ / kg H_2]		
Cluster	**E&R**	**min**	**max**
Dan	3.85	3.85	4.48
Gorm	4.29	3.44	4.43
Halfdan	7.32	4.10	64.62
Harald	4.86	4.30	5.08
Tyra	4.27	3.63	4.88

sponding positive and negative percentage variation of the LCOE compared to the reference case, 4.27 $€_{2020}$/kg H_2.

The sensitivity analysis demonstrated that the electrolyser efficiency has the highest influence on the LCOE with a correlation close to 1. The LCOE reaches 5.11 and 3.42 $€_{2020}$/kg H_2 when the negative and positive variation of the electrolyser efficiency, respectively.

Between the other cost components, the electricity price has the second highest influence followed by the electrolyser capex. This is in line with the findings of Hydrogen Europe which estimate the electricity price to account for 60–80% of the hydrogen cost [11]. All the other cost components result in a variation of the LCOE lower than 2.5%.

It is important to mention that the costs of repurposing and keeping the platform operational are independent from the costs of the hydrogen plant. Therefore, the possible influence of these costs on the hydrogen LCOE cannot be evaluated fully. Furthermore, performing the sensitivity analysis on the Tyra cluster provides useful insights but cannot represent the situation on all platforms. However, we can see that the LCOE is influenced the most strongly by the electrolyser's efficiency which is an exogenous variable equal for all platforms. Therefore, any difference in the sensitivity analysis would result from differences in the electricity prices among the platforms, which are very similar.

4.4. Discussion of results

The electrification of all O&G platforms in the first years of analysis is an interesting result, especially as the platforms are connected to the shore and energy islands rather than being electrified with floating offshore wind. This electrification results in significant cost and emissions reduction for energy supply to the platforms. Even with substantially higher transmission line costs (*i.e. TL-25* and *TL-50*, see Fig. 9), this remains the cheaper option for electrification compared to offshore wind, especially once the offshore energy island with up to 10 GW of connected offshore wind is established by 2030. Electrifying the platforms provides a large degree of flexibility, as this electricity can be used for multiple applications, including motive power, light as well as space and process heating. The connection of these platforms to the Danish and North Sea electricity transmission grid could also prepare them for future alternative uses and provides many opportunities in this regard. Some of these are explored in this study, but others might include offshore O&M, logistics and/or shipping hubs.

The second major noteworthy result relates to the repurposing of the O&G platforms as an alternative to decommissioning. In all cases, these platforms are connected to up to 5.8 GW of floating offshore wind and repurposed with new topsides and up to 3.6 GW of electrolysers to serve as hydrogen generators. Seen in the context of expected total electrolyser capacity of 40 GW in Europe by 2030, which requires the realization of up to 80 GW of additional renewable electricity production, these results seem reasonable [43]. This hydrogen is assumed to be transported to the Danish shore through existing and/or new purpose-built pipelines and there stored/transported for use in the transport sector. In the context of the system-level analysis carried out in this study, with all North Sea neighbouring countries and more included in the model, the Danish share of overall hydrogen demand in the *E&R scenario* is 37 TWh compared to just 18 TWh in the *BAU scenario*. In other words, the repurposing of the Danish O&G infrastructure is instrumental in providing an extra 2% of the total future demand for hydrogen in the transport sector by 2050. This means that it is more economical to exploit these offshore wind resources in the North Sea alongside the repurposing of existing O&G infrastructure, compared to utilizing renewable technologies such as wind and solar PV in other locations onshore.

Whilst this study focusses on the Danish part of the North Sea, the method and results are applicable more generally to other regions with O&G infrastructure. Both the challenges faced by this sector in decarbonizing existing operations and decommissioning infrastructure, and the potential benefits of exploiting synergies with future offshore renewable (especially wind) developments are common around the world. The results from this study should be understood in this context, as highlighting a large potential for economic and environmental benefits through repurposing existing O&G infrastructure. Whilst this study makes some important methodological simplifications (as discussed in section 4.5), it does suggest a very large global opportunity in the context of the current energy transition.

These results are clearly significant, but they should be understood in the wider context of the method employed and assumptions made in this study. For example, the levelized costs (LCOEs) of hydrogen in this analysis in 2050 at around 4 $€_{2020}$/kg H_2 are significantly above other studies and expectations for the hydrogen price within this timeframe. This calculation does not take into account the support policies that renewable energy technologies benefit from, however. For green hydrogen, such policies would most likely be required and could serve to narrow this gap with other studies of about 2 $€_{2020}$/kg H_2, cf. Table 6 and [4], if not making it disappear altogether. In addition, the economic results are very sensitive to the assumed gas and CO_2 prices, as was found elsewhere in the similar study of [16]. In that cited study, for gas prices of 9$€_{2020}$/Mbtu (*i.e.* 25% higher than the study's assumed market price) the break-even point is found at a rather high CO_2 price between 120 $€_{2020}$/t and 135 $€_{2020}$/t according to the different scenarios considered in their analysis.

A related point that should be noted is the lack of consideration of markets in this analysis. Both for electricity and hydrogen, current and future markets provide a framework within which any business model needs to operate. For electricity, this currently means operating on one or more of a variety of markets for energy (kWh) and/or power (kW) at different temporal and spatial scales. In the context of hydrogen generation through electrolysis, optimizing the operation within these different markets – and especially combining the participation on several markets simultaneously, known as stacking [45, 46] – could provide added economic incentives leading to higher full load hours and reduced levelized costs. One salient example involves the use of otherwise curtailed or excess renewable electricity to drive the electrolysis process, which was not assessed here. The inclusion of the market dimension in future analyses could therefore substantially improve the case for generating offshore hydrogen by indicating extra revenue streams and reducing the identified range of break-even costs.

Another important result relates to the costs of decommissioning versus repurposing. Whilst the results indicate that the high costs of decommissioning can in most cases be avoided by repurposing the existing infrastructure, in some cases these repurposing costs are actually higher than the decommissioning costs. The difference is compensated by the additional value that the infrastructure has once repurposed, especially (as analysed here) in terms of serving the future low-carbon energy system, but also (not analysed) possibly as a hub for logistics, O&M and/or shipping activities. On the one hand, there are obvious role(s) of offshore O&M infrastructure in the development of an offshore renewable power system. On the other hand, the uncertainty around the costs and benefits of these roles is very high, especially beyond 2030 which is a crucial timeframe for hydrogen in these results. These uncertainties, as well as some other important aspects of the adopted approach, are discussed in the following section.

4.5. Discussion of method

This section highlights some of the main weaknesses and uncertainties in the employed method, starting by addressing economic and technical aspects in turn, before discussing some general points.

Most if not all of the **economic assumptions** employed in this study are subject to varying degrees of uncertainty. In general, there is high confidence about the economic characterization of current technologies, as employed in the Balmorel model. These assumptions are based on widely-recognized and authoritative sources such as the Danish Energy Agency's Technology Catalogue [33]. Larger uncertainties relate to the economic assumptions for the O&G platforms, for which data was largely based on third-party studies from other contexts outside the DUC. This was inevitable given the fact that few Danish platforms have been decommissioned, and there is arguably a strong similarity between the infrastructure in the UK and Danish sectors, for example. But the fact that platform decommissioning in the North Sea in general is still in its infancy, means that any economic assumptions used here for decommissioning and repurposing are uncertain. In addition, the platform operational costs are indirect estimates based on the aggregated operational costs for the whole O&G sector, which are provided by the Danish Energy Agency [24]. Finally, the uncertainty relating to all of these economic assumptions clearly increases with time into the future, including the gas and CO_2 prices as well as the retirement schedules for O&G platforms. For example, the latter assumptions lead to a cease of operation on Gorm in 2025 but hydrogen production first in 2045, which is probably unrealistic. Estimating economic parameters three decades in advance is obviously a very challenging task and the approach taken here overlooks any potential 'shock' impacts on the energy system, such as the ongoing COVID-19 pandemic.

From a **technical perspective**, this study also has several weaknesses, especially but not only relating to the O&G infrastructure. As mentioned above, the repurposing of the O&G platforms is largely based on third party data from other sectors/countries, so also the technical details are uncertain. For example, the space availability on existing/new topsides, the structural integrity of existing jackets and the energy management aspects of the platform were all at least partly overlooked. The latter could be important for meeting both heat and power demand on the platform, whereby the heat demand in this context was completely neglected. In terms of the structural integrity, corrosion of offshore O&G [47] and wind [48] structures is a major challenge for man-made structures, which tends to reduce the serviceable lifespan of materials and requires an over-specification (*e.g.* material thickness) at the design stage. In addition, technical challenges relate to the transportation of hydrogen in pipelines to shore. To account for the problem of hydrogen embrittlement in existing/old oil/gas pipelines [49], the scenario with the new pipelines alongside the one with the existing ones was considered. But other options for transporting this hydrogen to shore, or elsewhere, were overlooked. The same applies to alternative energy carriers such as ammonia, which could be produced directly on the platform and either transported to shore or directly used as a fuel for ships. Finally, the focus on offshore wind was justified based on the advanced development stage of this technology and the good wind resources in the North Sea, which meant excluding less mature technologies such as salinity gradients, wave energy, ocean thermal energy, geothermal energy etc. All of these aspects should be addressed in future work.

Finally, there are some **general aspects of the methodology** that should be mentioned here. Probably most important is the macroeconomic perspective adopted, *i.e.* that of the omnipotent central planner, which does not reflect reality with a mixture of operators and assets. The implication of this is that some of the results in this study may not be economically attractive from the perspective of individual operators – whereby this relates less to the electrification and more to the latter repurposing activities. The issue lies in the apportioning of costs between different fields and platforms, which may be influential for the overall economics. It is therefore recommended to analyze the business case for these measures from an operator's microeconomic perspective in further work. In addition, the spatial resolution employed to include the O&G sector in the Balmorel model is relatively low, such that whole fields with several platforms are aggregated into one cluster. This obviously overlooks any connections between the platforms and related space or energy system constraints. Another general limitation with this method is the simplified way in which hydrogen is modelled, indirectly as electricity demand. Whilst this has advantages in terms of modeling simplicity, it does overlook some important aspects of hydrogen demand and competition (especially markets, see above), which could also be decisive for the business case. Despite there not yet being an established market for hydrogen, this is likely to change within the long timeframes considered here. It is therefore also recommended that an integrated energy system analysis, with hydrogen as a separate energy carrier, is carried out in future work. A more holistic analysis could also include other sectors such as marine transport and thereby also assess synergy effects with alternative uses of repurposed offshore O&G infrastructure as refueling stations, for example.

5. Summary and conclusions

Against the background of depleting oil and gas fields and retiring infrastructure alongside developments in offshore renewable energies, this paper has analysed potential future synergies between the two in a Danish (DUC) context. It starts with a techno-economic characterization of key technologies in this field and a review of the state of the art offshore energy system integration. All of these preliminary results serve as input data for a holistic energy system analysis in the Balmorel modeling framework. With a timeframe out to 2050 and model scope including all North Sea neighbouring countries, this analysis explores a total of nine future scenarios for the North Sea energy system. The main results include an immediate electrification of all operational DUC platforms by linking them to the shore and/or a planned Danish energy island. These measures result in cost and CO_2 emissions savings compared to a BAU scenario of 72% and 85% respectively. When these platforms cease production, this is followed by the repurposing of the platforms into hydrogen generators with up to 3.6 GW of electrolysers and the development of up to 5.8 GW of floating wind. The generated hydrogen is assumed to power the future transport sector, and is delivered to shore in existing and/or new purpose-built pipelines. The contribution of the O&G sector to this hydrogen production amounts to around 19 TWh, which represents about 2% of total European hydrogen demand for transport in 2050. The levelized costs (LCOE) of producing this hydrogen in 2050 are around 4 €$_{2020}$/kg H_2, which is around twice those expected in similar studies. But this does not account for energy policies that may incentivize green hydrogen production in the future, which would serve to reduce this LCOE to a level that is more competitive with other sources.

The very limited scope of this research means that the analysis presented here is relatively high-level, requiring many simplifying assumptions and resulting in some important technical details being overlooked and left for future research. In particular there remain significant uncertainties relating to the technical feasibility and future economic developments of most of the technologies analysed. For this reason, this paper should be understood as a starting point for further and more detailed analysis, rather than a definitive roadmap for the sector.

Given the explorative nature of this research, recommendations mainly relate to areas where future work should focus:

- **The business case** for the results reported here should be analysed from the operator's perspective, in order to provide a clear indication of possible value opportunities in repurposing existing assets.
- **Collaborative research with offshore O&G engineers** should clarify the technical constraints on electrification and repurposing, especially but not only relating to the space availability, structural integrity, and energy system integration aspects. This analysis would involve assessing challenges and opportunities for repurposing individual, exemplary platforms.
- **A more holistic energy system analysis** should be performed, which is at a higher spatial resolution and thereby includes details of individual platforms (rather than only clusters), includes hydrogen (and possibly other electro-fuels) as a distinct energy carrier and considers demand and markets for this alongside electricity (which is already included), reflects the energy management system on the platforms and the heat demand, and alternative transportation means for the generated fuels as well as alternative use cases such as refueling stations.
- **A wider policy, regulation and market analysis** needs to build on the above system analysis in order to assess the required framework conditions for a future integrated North Sea energy system, which maximises social utility by providing adequate incentives for operators and investors. This analysis would provide clear recommendations for national and international policymakers relating to the future development of existing and new North Sea energy infrastructure.

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Appendix

This section provides some of the necessary data to support the analysis performed in this paper. Additional information is available in [23].

Danish O&G sector

The Danish O&G fields included in the analysis are presented in Table A.1 below. Further, Table A. 2 provides the cluster composition and the assumed decommissioning date for each cluster.

Natural gas and CO_2 price developments

The assumed price developments for natural gas and CO_2 are shown in Fig. A.1 Natural gas and CO_2 tax evolution through the years considered in the model. (DEA 2021b) below, which represents typical expected future scenarios based on previous work and Danish Energy Agency projections.

The natural gas price increase from 22 €$_{2020}$/GJ in 2020 to 42 €$_{2020}$/GJ in 2050. The gas price used in the gas turbines on the platforms is considered as an opportunity cost, *i.e.* the forgone cost of selling this gas. For the CO_2 tax, the *E&R* curve shows the default trend assumed in the *E&R* scenario (see section 3.2.2), which rises to about 87 €$_{2020}$/tCO_2 and 141 €$_{2020}$/tCO_2 in 2030 and 2050 respectively, and reflects the progressive tightening of CO_2 allowances in the EU ETS. In addition, two

Table A.1
Fields under management of Total E&P DK and the DUC considered in the analysis (OSPAR 2017).

Field	First year of prod.	Field Age [a]	Mean platform age [a]
Dan	1972	48	36
Gorm	1981	39	37
Skjold	1982	38	30
Tyra	1984	36	31
Rolf	1986	34	34
Dagmar	1991	29	29
Kraka	1991	29	29
Valdemar	1993	27	18
Roar	1996	24	24
Svend	1996	24	24
Harald	1997	23	23
Lulita	1998	22	22
Halfdan	2000	20	15

Table A.2
Assumed clusters of fields composition and cease of production date.

Cluster	Number of platforms assigned	Assigned fields
Gorm	11	Gorm, Rolf, Dagmar, Skjold
Harald	2	Harald, Lulita
Dan	13	Dan, Kraka
Halfdan	8	Halfdan
Tyra	18	Tyra, Valdemar, Svend, Roar

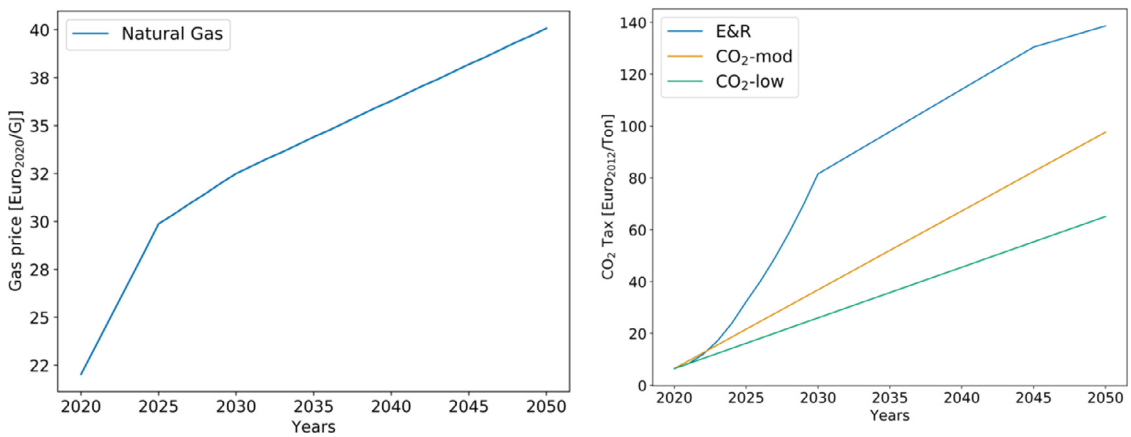

Fig. A.1. Natural gas and CO_2 tax evolution through the years considered in the model. (DEA 2021b). (For interpretation of the references to color in this figure, the reader is referred to the web version of this article.)

alternative scenarios CO_2-mod and CO_2-low assume a linear development to 87 €$_{2020}$/tCO_2 and 65 €$_{2020}$/tCO_2 in 2050 respectively.

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