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Low carbon power generation for offshore oil and gas production

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ABSTRACT

Emission reductions in power generation for offshore oil and gas activities are key in order to reach climate targets in regions with this industry. This study presents a review of both established and immature low carbon power generation concepts, an analysis of their potential for greenhouse gas (GHG) emission reduction, and an evaluation of their offshore applicability. The potential for GHG emission reduction is quantified by estimating CO_2 equivalent intensity for implementation on the Norwegian Continental Shelf. The offshore applicability is evaluated with emphasis on weight, infrastructure requirements, process heat availability, technical maturity, as well as health, safety, and environment (HSE). It is shown that power from shore is the only technically mature concept with potential for very high emission reductions (>95 %, provided that low GHG electric power is available). There are several alternative concepts under development that also can give significant emission reductions (>70 %), including fuel switching, CO_2 capture and storage, and renewable power combined with energy storage. Combined cycle gas turbines and offshore wind power combined with gas turbines are technically mature and can achieve partial emission reductions (around 15–50 %, with the assumed system configurations). Other concepts offering partial emission reductions are under development, but do not show clear advantages over those already mentioned. It is pointed out that, to enable reaching the net zero emission targets, only efficiency improvements and power from shore are not enough, and there is a need to develop additional low emission technologies not yet on the market. The present study has compiled a large database of specifications for assessing low carbon power production concepts and proposes a methodology that is valuable in screening a large number of commercial and immature technologies.

1. Introduction

Since signing the Paris Agreement in 2015, the participating countries are committed to fulfil stringent emission reduction targets, and large efforts must be made within all sectors to realize this. Emissions from the oil and gas industry are responsible for a considerable part of overall greenhouse gas (GHG) emissions in some countries. Such activities were in 2020 responsible for yearly emissions of 316 Mt CO_2eq in the United States [1] and 16.0 Mt CO_2 in the United Kingdom [2], corresponding to approximately 5 % of the total emissions in both these countries [3,4]. In Norway, oil and gas extraction was responsible for emissions of 13.3 Mt CO_2eq in 2020, corresponding to 27 % of the country's overall emissions [5]. Consequently, several of the oil and gas industry actors have set and are striving to achieve ambitious emission reduction targets [6].

To reduce emissions in the oil and gas industry, several measures

Abbreviations: AC, Alternating Current; ASU, Air Separation Unit; CCR, CO_2 Capture Ratio, defined as carbon captured divided by carbon in feed; CCS, CO_2 Capture and Storage; CCUS, CO_2 Capture and Utilisation or Storage; CO_2eq, CO_2 equivalent; DC, Direct Current; EGR, Exhaust Gas Recirculation; EU, European Union; FPSO, Floating Production Storage and Offloading unit; GHG, Greenhouse Gas; GT, Gas Turbine; GWP-20, Global Warming Potential evaluated over 20 years; GWP-100, Global Warming Potential evaluated over 100 years; HAT, Humid Air Turbine; HP, High Pressure; HRSG, Heat Recovery Steam Generator; HSE, Health, Safety, and Environment; HVAC, High Voltage Alternating Current; HVDC, High Voltage Direct Current; HVO, Hydrogenated Vegetable Oil; KPI, Key Performance Indicator; LCA, Life Cycle Assessment; LH_2, Liquid Hydrogen; LHV, Lower Heating Value; LP, Low Pressure; MCFC, Molten Carbonate Fuel Cells; NCS, Norwegian Continental Shelf; NG, Natural Gas; PEMFC, Polymer Electrolyte Membrane Fuel Cells; PV, Photovoltaic; SCR, Selective Catalytic Reduction; SMR, Small Modular Reactors; SNCR, Selective Non-Catalytic Reduction; SOFC, Solid Oxide Fuel Cells; WHRU, Waste Heat Recovery Units.

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have already been implemented, such as limiting flaring, energy efficiency measures in the production process, CO_2 capture and storage (CCS), and alternative solutions for power generation [7]. Limitation of flaring is practiced on a wide scale, e.g., by installing gas transport infrastructure or gas injection systems. So far, CCS is only practised for natural gas sweetening processes related to the Sleipner and Snøhvit fields in Norway [8]. Energy efficiency measures in the production process are mainly related to optimum operation of the installed equipment and installation of more efficient compressors and pumps [7], and have been systematically assessed by several oil and gas companies and in literature [9]. To reduce emissions from power generation, combined cycle solutions are installed at the Oseberg, Snorre, and Eldfisk facilities on the Norwegian Continental Shelf (NCS) [10], and at the Appomattox field in the Gulf of Mexico [11]. In addition, implementation is ongoing on the Bacalhau FPSO and planned for two other fields under development in Brazil and Canada [12]. Implementation of offshore wind is ongoing at the Hywind Tampen project, where eleven floating wind turbines are being installed offshore and are estimated to provide about 35 % of the annual electric power demand of five oil and gas facilities [13]. Import of power from shore is an alternative to power generation offshore and is relevant in regions where the onshore grid is associated with low emissions. It has been implemented on eight existing fields and is currently planned for eight additional ones on the NCS [14].

In countries where large-scale, routine flaring of natural gas is avoided, power supply is currently responsible for the bulk part of the sector's CO_2 emissions. For instance, power generation with gas turbines was responsible for approximately 85 % of the Norwegian oil and gas sector's CO_2 emissions in 2020 (Fig. 1) [7]. Furthermore, around 30 % of global oil and gas extraction takes place offshore [15], and in some countries, like Norway and the United Kingdom, offshore oil and gas extraction is predominant. This motivates the focus on low carbon power generation for offshore oil and gas production.

Decarbonisation of the *onshore* electric power sector has received a lot of attention during the last decades, and scenarios suggested to decarbonise this sector include, among others, increased efficiency, fuel switch (e.g. from coal to natural gas), introduction of renewable energy (in particular wind and solar energy), introduction of nuclear power (although this has in reality been phased down in some countries), and CO_2 capture and utilisation or storage (CCUS) [16,17]. The typical onshore energy system has the benefit of being part of a large grid that facilitates frequency balancing, and constraints on weight and space are normally not critical, so large and heavy equipment can be utilized.

Offshore energy systems have quite different characteristics compared to onshore systems. Normally each offshore facility operates in island mode with its own small power grid, or several facilities located close to each other share a small grid. The electrical power demands of offshore facilities vary significantly between fields and over field

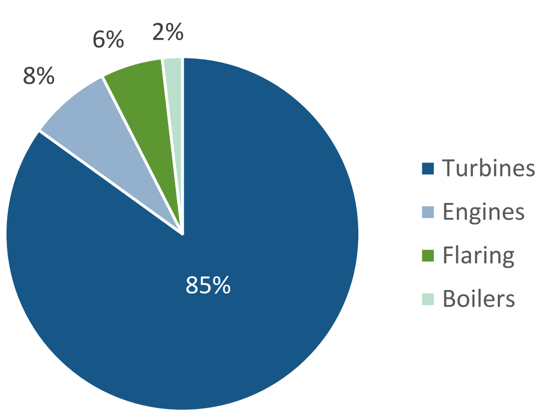

Fig. 1. Main CO_2 emissions sources from petroleum activities in Norway in 2020 [7].

lifetime but are typically ~30 MW or more. The power is traditionally generated with gas turbines running on natural gas produced at the site, since this is a convenient and inexpensive fuel normally available in large quantities. Space and weight capacity is very limited offshore, and installation of large and heavy equipment is associated with high costs. Hence, aeroderivative gas turbine models are typically installed and, when needed, waste heat recovery units (WHRU) are added to extract heat from the exhaust to cover process heat demands. The nominal capacities of the gas turbines used in these applications are typically in the 20–40 MW range.

In addition to the concepts for low carbon power supply already being implemented offshore, solutions from other sectors or technologies under development could be of interest. An overview and critical review of the most relevant options and their applicability to the offshore oil and gas facilities can help the industry, policy makers, and the research community to prioritise their efforts, funding, and attention. Few studies on this topic are currently available. Itiki et al. [18] made a general review on offshore power systems for all types of offshore applications (e.g., ships and submarines in addition to oil and gas facilities) where the focus was on conceptualisation of the whole power system. They listed relevant power generation technologies but did not analyse them in the context of GHG emission reductions. Grainger et al. [19] presented a selection of technologies for emissions reduction offshore (both power generation technologies and others) and their approximate CO_2 abatement potential. However, there is no comprehensive review available in the literature that gives an overview of all options for offshore power supply, including immature ones, and analyses their potential for emission reductions as well as their applicability offshore, while presenting all the underlying assumptions.

The abovementioned gap is covered in this study. The key contribution of this paper is that a wide range of power supply concepts is systematically reviewed and analysed in the context of offshore oil and gas production, using defined key performance indicators (KPIs). The thirty most promising options are evaluated considering GHG emissions reduction potential and applicability offshore in terms of process heat availability, weight, infrastructure requirements, technical maturity, as well as health, safety, and environment (HSE). All underlying assumptions are made available in the supplementary material, allowing critical reassessment and updates as immature concepts are further developed. GHG emission reduction potential is for some technologies dependent on location, and in this work implementation on the NCS is assumed. This study gathers a database of information that can be used for benchmarking concepts against major KPIs. The methodology is useful to shortlist concepts by weighting these KPIs according to a desired application (offshore power generation in this case), before further pursuing the assessment with a more in-depth analysis tool, like LCA and techno-economic analysis, not feasible on a large set of concepts and particularly for immature technologies lacking detailed quantification of specifications.

This article is structured along three working sections. Section 2 first defines the notion of a power generation concept for offshore application in this study, describing all the energy sources, power generation technologies and supporting technologies considered. Section 3 defines KPIs for assessing the GHG reduction potential and offshore applicability and evaluates the selected concepts accordingly. Section 4 provides a discussion and insights regarding the potential for partial or close to full decarbonization of offshore power generation by use of the evaluated concepts. Section 5 concludes the paper.

2. Power generation concepts

2.1. Definition of a power generation concept

Concepts for low carbon power generation can differ in many aspects, e.g., from the use of an unconventional source of energy or by an innovative power generation technology. For clarity, the use of the term *power generation concept* in this article is illustrated in Fig. 2. One power generation concept is a combination of one or several energy sources and one or several power generation technologies, that further may be combined with a supporting technology, such as energy storage or CO_2 capture technologies.

The relevant energy sources are either in the form of chemically bound energy in a fuel or local renewable energy. An alternative to offshore power generation is power from shore, where electricity is generated from energy sources onshore and transferred offshore through subsea cables. The various options for energy supply to offshore oil and gas facilities are illustrated in Fig. 3. Most renewable technologies are non-dispatchable, e.g., wind power or solar power. Due to its decentralized nature and for reasons of safety and production efficiency, an offshore asset can only use non-dispatchable technologies if combined with dispatchable technologies or energy storage.

2.2. *Energy sources*

The different types of chemical fuels can be utilised by several different power generation technologies. These are linked with direct or indirect CO_2 emissions which significantly affect the CO_2 equivalent intensity of the power generation concepts, or other issues affecting the applicability offshore. Nuclear fuel and renewable energy are tightly connected with the power generation technology and are therefore discussed in Section 2.3.

2.2.1. *Natural gas*

Natural gas (NG) is currently the most common energy source offshore. It is a product or a by-product from most oil and gas production facilities and therefore readily available at relatively low cost. The CO_2 equivalent intensity of natural gas is related to the direct emissions from combustion, and around 2.8 kg CO_2/kg NG (0.057 kg CO_2/MJ_{LHV}) [20], depending on its actual composition.

2.2.2. *Hydrogen*

Hydrogen is a completely carbon free fuel, but it does not exist in a natural minable state on Earth and must be produced through chemical processes. Low carbon hydrogen can be produced either by natural gas reforming with CCS or electrolysis of water using low carbon electricity [21]. For the former, supply chain GHG emissions are around 0.8–1.1 kg CO_2eq/kg H_2 (0.007–0.009 kg CO_2eq/MJ_{LHV}), assuming the hydrogen is produced with ATR and CO_2 capture ratio (CCR) of 94 % or SMR with CCR of 91 % [22,23]. This includes upstream CO_2 and methane emissions related to natural gas production on the NCS and the production related emissions. A recent study shows that supply chain GHG emissions of hydrogen produced by natural gas reforming with CCS in Norway will be even lower (0.005–0.006 kg CO_2eq/MJ_{LHV}) [24], and several actors claim that hydrogen production processes with CCR of at least 95 % are required and planned. Natural gas reforming will most likely be located onshore due to the weight and size of reforming equipment as well as the scale dependency of the natural gas reforming cost. For hydrogen from electrolysis, the supply chain emissions depend largely on the GHG emission factor of the electric power mix. This option based on power from the onshore grid is less relevant since it will compete with power from shore which has a much higher overall energy efficiency, whereas hydrogen produced by locked in power from renewables (e.g., offshore wind turbines) may become important in the future.

Hydrogen can be transported to the offshore facility either by pipeline, which requires compression, or by ship, which requires liquefaction (cooling to −253 °C). The power needed for compression is around 1 kWh/kg H_2 depending on the feed and target pressure [25], giving a negligible contribution to the supply chain GHG emissions. Current industrial hydrogen liquefiers are for low capacities and typically use 10–12 kWh/kg liquid hydrogen (LH_2) [26–28]. For larger plants, overall energy- and cost optimisation has indicated power consumption of around 6.5 kWh/kg LH_2 [29,30]. Liquefaction then adds 0.1 kg CO_2/kg LH_2 (0.0009 kg/MJ_{LHV}) to the supply chain GHG emissions assuming Norwegian electricity mix (11 g CO_2/kWh [31]).

The use of hydrogen offshore introduces several new safety aspects compared to natural gas, including lower minimum ignition energy, challenging leak potential due to its high diffusivity, material compatibility, higher flame propagation velocity, and lower flame visibility [32]. The combustion of hydrogen is more prone to generate NO_x than combustion of NG, including N_2O which has a global warming potential of 265–298 over 100 years (GWP-100) [33,34].

2.2.3. *Ammonia*

Ammonia is an alternative energy carrier that is already available at large scale due to its use in the fertilizer industry. It has a higher energy density than both liquid and gaseous hydrogen, but a lower heating value on mass basis. Ammonia can be seen as a hydrogen carrier that requires synthesis before transport and may require cracking into hydrogen and nitrogen before use, depending on the power generation

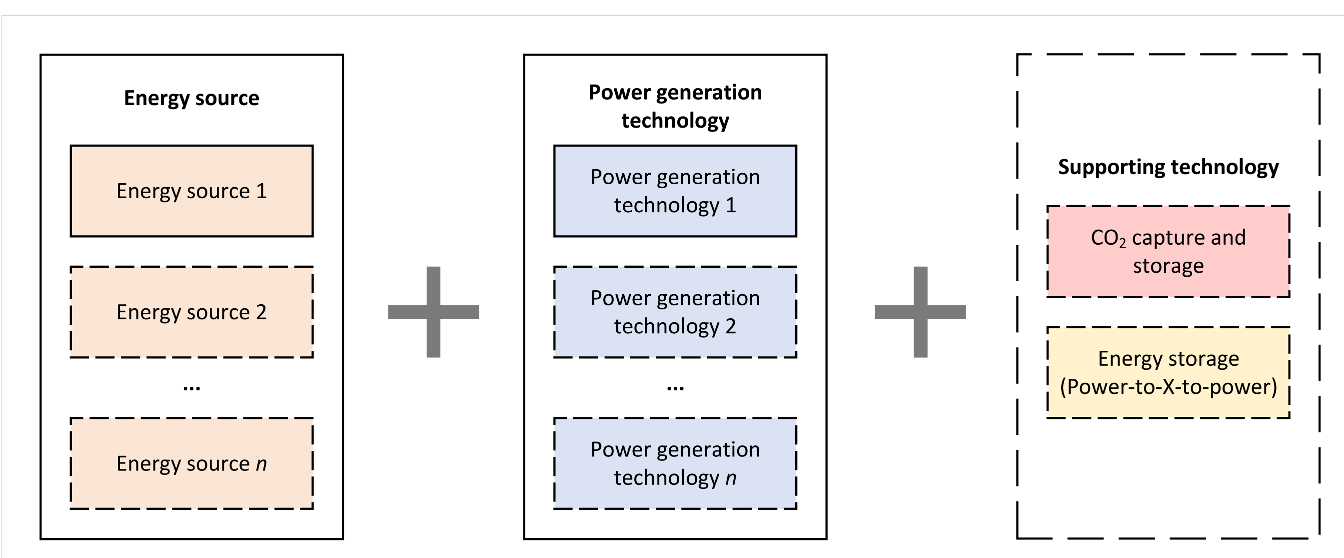

Fig. 2. Elements composing a power generation concept.

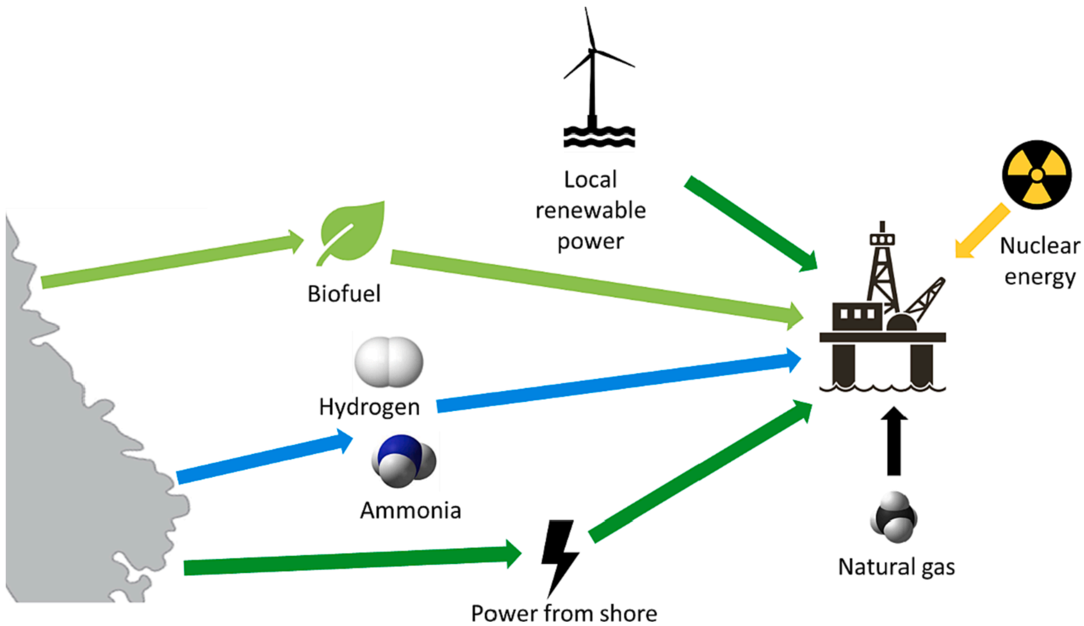

Fig. 3. Possible options for energy supply to offshore oil and gas facilities.

technology. Ammonia is also carbon free, but there are supply chain emissions depending on the ammonia synthesis process and feedstock [35–39]. When produced based on natural gas from the NCS with CCS, the supply chain GHG emissions are around 0.2 kg CO_2eq/kg NH_3 (0.011 kg CO_2eq/MJ_{LHV}) considering the same assumptions as for hydrogen [23,40].

Anhydrous ammonia is routinely transported in large tonnage by truck, tank car, barge, ship, rail, and pipeline [36,41]. Its vapor pressure at 25 °C is 10 bara and it can be stored as pressurized liquid [42,43], but for large quantities and improved safety it is normally stored and transported fully refrigerated (–33 °C) in thermally insulated containers and atmospheric pressure [44]. Use and transport of ammonia are related to risks due to its toxicity, and it has some practical drawbacks such as its corrosive nature and that it is susceptible to generate NO_x, including N_2O, when combusted [36]. The nitrogen content in ammonia makes NO_x generation an even higher challenge than for hydrogen combustion.

2.2.4. Biofuels

Biofuels are alternative fuels for reciprocating engines and gas turbines. The direct GHG emissions of biofuels are potentially zero as the CO_2 produced in the combustion process can be reabsorbed for feedstock plant growth. Supply chain GHG emissions reported for these fuels vary significantly depending on the specific fuel type, production method, and feedstock. As an example, hydrogenated vegetable oil (HVO), which has fuel characteristics similar to fossil diesel [45], has supply chain GHG emissions varying in the range 0.0081–0.0566 kg CO_2eq/MJ, depending on the feedstock and production pathway [46]. Bio-methanol, which has been proposed as a fuel for internal combustion engines [47–49], has supply chain GHG emissions in the range 0.0066–0.070 kg CO_2eq/MJ, and this is heavily depending on the electricity mix [46,48,50]. Supply chain emissions reported for biofuels typically include emissions associated with cultivating the crop and processing it into finished fuels. Although the emissions from land use change may be large in some cases, these are usually not considered [51,52]. The cost of feedstock is a major component of overall costs [53], which also vary widely and typically increase with lower supply chain GHG emissions.

Potential technical challenges vary between different fuel types; e.g. for methanol the high electrical conductivity may increase corrosion, it can cause swelling in some materials typically used for gaskets and seals [54], and it is more volatile than diesel. Production of certain fuels from biomass may lead to loss of natural habitat and compete with food production, raising issues related to sustainability. The availability of (and competition for) the vast quantities of biofuels that would be needed to decarbonise offshore facilities is also a challenge. Comprehensive reviews on biofuels and bioliquids for power generation are available in literature [55–57].

2.3. Power generation technologies

Power generation technologies relevant for low carbon power generation offshore range from simple cycle natural gas fired turbines to technologies with decarbonized fuels, or completely different solutions based on nuclear or renewable energy.

2.3.1. Gas turbine based technologies

Natural gas fired simple cycle gas turbines. The most common technology for offshore power generation is simple cycle gas turbines using natural gas as fuel. Offshore gas turbines are typically aeroderivative, because of their high power density, low weight, and high availability. The main components in natural gas fired simple cycle gas turbine generator packages are the gas turbine itself, the generator, and sometimes a gearbox. A general drawback with these engines is their low part-load efficiencies, which is a challenge because part load operation will often be required offshore. Typical design thermal efficiencies for aeroderivative gas turbines with power output around 30 MW are 36–40 % [58], while thermal efficiency at 50 % load may drop below 30 % [59]. Industrial type gas turbines can be relevant in some cases, and their design efficiencies are generally in the same range as for aeroderivative gas turbines with comparable power output. Process heat demand can be covered by heat recovered from the gas turbine exhaust gas, and can potentially result in combined heat and power energy utilization as high as 70 % [19].

Combined cycles. In a combined cycle, the thermal efficiency is increased by adding a Rankine cycle, also called bottoming cycle, which recovers heat from the gas turbine exhaust gas and converts it into additional power output. Steam is the most common working fluid in bottoming cycles, but other working fluids such as supercritical CO_2 and organic fluids can also be used. Several steam bottoming cycles are in operation offshore (on the Oseberg, Snorre, Eldfisk, and Appomattox fields [10,11]). While natural gas fired combined cycle power plants on shore can reach > 60 % efficiency, the more compact offshore solutions are typically in the 45–50 % range [10,19,60].

The main challenges for the implementation of combined cycles offshore are their size and weight, mainly due to the large heat recovery steam generator (HRSG). There is a trade-off between efficiency and weight, and the offshore solutions have been optimised to minimize weight [10]. However, heavier and more efficient solutions for floating applications at shore also exist, e.g. the Siemens Seafloat concept [61]. There is ongoing research and development to reduce weight, and a recent study has found that weight reductions of up to 50 % can be achieved with new solutions [11], such as unconventional equipment geometries and reducing the tube diameters of the heat recovery steam generator [60].

Alternative cycles. Alternative gas turbine cycles have been proposed for the purpose of improving the cycle thermal efficiency, with strategies like intercooling, steam injection, or alternative working media [62]. One such concept that has received a lot of attention is the humid air turbine (HAT) cycle. This concept is based on humidifying the air and increasing the mass flow of working fluid in the turbine to increase the power output. Various configurations have been proposed e.g. steam injection into the combustor, water injection into the compressor, and saturation in a direct contact column [63]. Similar thermal efficiencies to gas turbine combined cycles (50–63 %), and potentially lower weight have been reported [64]. However, the concepts are more complex and less technically mature than combined cycles. Furthermore, for offshore applications it is challenging to produce the large amount of fresh water needed for humidification and the related additional equipment required. Another concept that has attracted considerable attention recently is the Allam cycle, which is an oxyfuel concept where the generated CO_2 and water serve as the working medium and gives increased efficiency compared to air-based cycles. The concept has been proposed primarily for the purpose of CO_2 capture and is further discussed in Section 2.4.1.2.

Hydrogen fired gas turbines. Hydrogen can in principle replace natural gas as fuel in gas turbines and there are ongoing efforts to develop this technology. The main technical challenges to overcome are related to emissions of NO_x and heat management of combustion systems [65]. Hydrogen is characterized by a higher adiabatic flame temperature than natural gas, and a small increase in the higher range of flame temperature results in an exponential increase in NO_x emissions, which can double or more when switching a low NO_x burner designed for methane to pure hydrogen [66,67]. One strategy to overcome that issue is to partially replace natural gas by hydrogen. Gas turbine manufacturers currently offer systems that can operate with a concentration of 40–70 vol% hydrogen, depending on the models and manufacturers [68–70]. Mixing hydrogen into natural gas only gives a partial decarbonisation and due to its lower volumetric energy density, utilising fuel with 40–70 % hydrogen in volume only corresponds to approximately 16–41 % CO_2 emission reduction. A strategy allowing full decarbonization is to control temperature, hence NO_x formation, through dilution with an inert like steam, water, or nitrogen. However, this has an impact on cycle efficiency and the penalty is reported to be around 1.5 %-points with nitrogen dilution [71,72] and 3.5 %-points with steam dilution [71]. Another proposed strategy is based on modifying the plant layout by forcing exhaust gas recirculation (EGR) into the compressor to dilute the inlet air instead of the hydrogen. By decreasing the oxygen content of the air, the combustion temperature is intrinsically limited and NO_x emissions are kept low without significant efficiency penalty [72,73]. A higher steam content in the flue gas from hydrogen combustion may increase heat transfer to the turbine blades, increasing material degradation, reducing component lifetime and maintenance intervals [74], and may potentially reduce efficiency if turbine blade cooling needs to be increased. There are ongoing efforts by all manufacturers to develop gas turbines to operate with 100 % hydrogen within current NO_x emissions standards by 2030 [65].

Ammonia fired gas turbines. Ammonia is also being considered as a fuel for gas turbines, but ammonia has unfavourable combustion properties (high minimum ignition energy and auto-ignition temperature, low combustion speed compared to hydrocarbon fuels, low flammability, and low radiation intensity) and an even stronger propensity to NO_x formation than hydrogen. Therefore, current developments are mainly focusing on blending it with other fuels, such as natural gas or hydrogen [36], or decomposing (cracking) ammonia fully or partially [75]. Laboratory testing of combustion of ammonia-methane mixtures has shown that flame stability could be maintained with mixtures with a high concentration of ammonia in methane (e.g. up to 70 vol% [76]). When reducing the amount of natural gas as fuel to the gas turbine, it must be replaced by a larger volume of ammonia to conserve the turbine inlet temperature and power output, as a result of lower heating value and lower adiabatic flame temperature [77]. A 50 vol % ammonia-natural gas mixture would only represent a 25 % reduction in CO_2 emissions compared to pure natural gas. As for hydrogen fuel, the higher steam content in the combustor exhaust gas may increase heat transfer to the turbine blades leading to possible impacts on lifetime, maintenance, and efficiency.

With today's combustion technology, the level of ammonia substitution to natural gas without need for post-combustion NO_x abatement may be < 1 % [77]. Therefore, for ammonia fired gas turbines with existing combustion technology, addition of a NO_x abatement unit needs to be considered [78]. Several studies (e.g., [75,77,79–81]) indicate that staged combustion is a possible path towards controlled NO_x ammonia combustion, and it has been shown that high pressure combustion in the gas turbine has a strong impact on reducing NO_x formation from ammonia [75]. It is however unlikely that ammonia combustion meeting NO_x regulatory limits can be achieved in the short term without any form of exhaust gas post-treatment such as selective catalytic, or non-catalytic, reduction (SCR/SNCR).

Biofuel fired gas turbines. Biofuels can in principle be used as fuel in gas turbines with some modifications of the turbine system. HVO can achieve comparable performance to the jet fuel used in aviation gas turbines [56], which are similar to the aeroderivative gas turbines used on offshore installations. Compared to liquid fossil fuel, HVO can reduce overall emissions of particulate matter (soot), incomplete combustion products, and NO_x [82]F. Methanol was considered as a substitute for natural gas as early as 1971 [47,54], and since it does not contain sulfur or nitrogen and burns at a lower temperature, stack gas quality is improved [54]. Compared to natural gas, the main differences are lower heating value, lower lubricity, and lower flash point [47]. It may be necessary to remove bottlenecks to enable doubling the fuel volumetric flowrate through the liquid fuel injectors to compensate for the lower heating value of methanol. Further, the low flash point of methanol requires explosion proofing and start-up to be performed with a secondary fuel [83]. Testing and qualification of some gas turbine models for certain types of biofuels is ongoing (e.g. [84]).

2.3.2. Reciprocating engines

Natural gas fired reciprocating engines. Natural gas fired reciprocating engines, or gas engines, is an established technology in the marine sector for a wide range of power capacities. Compared to gas turbines, reciprocating engines have higher thermal efficiencies, typically in the range 47–50 % [85–88]. However, reciprocating engines cannot run on natural gas alone and require spark ignition or a diesel pilot flame for stable operation. The diesel pilot flame typically accounts for 1–2 % of the LHV of the fuel [85,86,88]. A known challenge with low pressure (LP) reciprocating engines is methane slip, typically in the range 2.5–5.5 g/kWh [88]. Methane released through the exhaust may, due to its high global warming potential, counteract the climate effect of the engines' high thermal efficiency. This challenge is avoided with high pressure (HP) reciprocating engines. One major drawback for both HP and LP reciprocating engines is that they are large and heavy units with relatively low power outputs compared to gas turbines. In addition, they require more frequent maintenance than gas turbines, and due to their size and weight they cannot be transported to shore, so overhauls need to be performed on site. Several major vendors offer or are developing engines that can run on alternative fuels, such as methanol, ethanol, liquefied petroleum gas, hydrogen, and ammonia [89,90].

Ammonia fired reciprocating engines. There has been high focus on development of ammonia fired reciprocating engines for deep sea maritime applications recently [91,92]. The main challenge related to use of ammonia in reciprocating engines is its combustion characteristics [91,93], which makes pure ammonia combustion challenging (see Section 2.3.1). There has been successful testing with full-scale engines with up to 70 vol% ammonia mixed with natural gas [92], and vendors are aiming to reach close to 100 % ammonia. However, it is expected that there will be a diesel pilot flame required, as for natural gas fired engines. Other challenges are also the same as for natural gas fired engines: similar size and weight, maintenance frequency at site, with the addition of offshore ammonia storage/loading and NO_x reduction units.

2.3.3. Fuel cells

Fuel cells convert chemical energy to electrical energy without combustion and can have high efficiencies as they are not heat engines and are not subject to Carnot cycle limitations. NO_x emissions are either non-existent or, in the case of fuel cells with afterburners, lower than for combustion-based technologies [94]. There are several types of fuel cells with different electrolyte, ion, fuel, and operating temperature. The main technologies in Europe are polymer electrolyte membrane fuel cells (PEMFC) and solid oxide fuel cells (SOFC), and these are already commercial at capacities lower than 1 MW_e [95]. PEMFCs require high purity hydrogen and operate at low temperatures (60–100 °C), their use being currently focused on transportation. SOFCs are fuel-flexible, as long as the fuel is sulfur-free [96], and can run on e.g. hydrogen, natural gas, or ammonia [94,97,98]. Molten carbonate fuel cells (MCFC) are also fuel-flexible and have been deployed in stationary installations in the United States and Asia [99], but have lower power density than SOFCs and PEMFCs [100]. Alkaline fuel cells and phosphoric acid fuel cells have not been much adopted and commercialised for large-scale stationary applications [99]. It is thus the PEMFCs and SOFCs that are the most likely candidates for offshore applications.

In the current stage of development, stationary fuel cells in the ~200 kW_e range, which would be very low for offshore power generation requirements, are sometimes considered to have "large capacity" [99]. However, as most fuel cells are modular, capacity can be increased by stacking, and performance and operating costs per power output are almost not dependent on scale. Still, capital costs can be affected by scale [95] and scaling-up by stacking fuel cells not designed for large-scale power generation may result in low power density. In addition to the fuel cell modules, a DC/AC converter is required for offshore applications. There is ongoing research to improve the power density and scalability, increase lifetime and reliability, and reduce costs of fuel cell systems [101–104]. This is in part driven by marine energy propulsion applications, e.g. the FCwave concept by Ballard [105] and the Toshiba 1 MW fuel cell module [106].

Hydrogen-based fuel cells. Most fuel cell types can operate using pure hydrogen, but for offshore applications PEMFCs seem most relevant. PEMFCs can operate only with high purity hydrogen, but they are lightweight and have a quick start-up process compared to other fuel cells [107]. Such fuel cells are proposed for electric grids and provide frequency support, but the configuration of the electric system may need to be further studied [108]. Typical efficiencies range between 53 and 60 % [109]. Contrary to gas turbines, the efficiency of PEMFCs at part-load may be the same or higher than at nominal power since the voltage is higher at lower power levels. This effect may be seen for partial loads higher than ~20 %, but in practice it may be set off due to lower efficiencies of the auxiliary equipment, such as temperature regulation [32].

Natural gas-based fuel cells and hybrid systems. The use of natural gas as fuel is made possible by internal reforming and electrochemical conversion of carbon monoxide in some high and medium-temperature fuel cells, including SOFCs [110]. Efficiency of natural gas based SOFCs ranges between 35 and 65 % [109,111,112]. Like PEMFCs, the electrical efficiency of the SOFCs at part-load tends to be higher than at full-load. However, if surplus heat is recovered, thermal efficiency is lower at part-load [113]. Natural gas based SOFCs are subject to relatively quick degradation, which may reduce efficiency by 8–10 %-points in the first five years [111,112], and current median time to stack replacement for state-of-the-art SOFCs is 4–5 years [111,114]. SOFCs have been proposed in various hybrid systems, e.g. combined with CCS, which can be simple since the flue gas is composed of mainly CO_2 and water [94], or combined with a gas turbine, like the Megamie technology under development by Mitsubishi Hitachi Power Systems with thermal efficiency potentially between 55 and 70 % [115–119]. In an offshore context, SOFCs are large compared to competing power generation concepts. Typically, 25 % of the volume of a SOFC system is made up of the cell stack and the rest is the balance of plant, which includes thermal insulation, pipework, pumps, heat exchangers, heat utilisation plant, fuel processors, control system, start-up heater and power conditioning [120]. Another disadvantage is slow start-up times and limited capabilities for dynamic operation compared to PEMFCs.

2.3.4. Renewable technologies

Renewable power generation technologies relevant for offshore power generation include wind power, solar power, and wave power. All these technologies are non-dispatchable, meaning that they cannot generate power on demand and must thus be combined with energy storage and/or dispatchable power generation, or power from a dispatchable grid, to make the overall system dispatchable. Geothermal power is a potentially dispatchable power generation technology that has been suggested for offshore facilities due to potential synergies with production wells but is not considered relevant at the NCS due to low well stream temperatures.

The expected power output profile of a non-dispatchable renewable technology is of key importance for the design of the overall system. Important factors are (i) the capacity factor of the renewable system, i.e., the actual power generated over a time period divided by the maximum power generation given 100 % availability of the energy source, and (ii) the time of autonomy required for energy storage, i.e., the time period an energy storage system is able to meet the load demand during a non-availability period of the primary energy source. These factors are site-specific.

Non-dispatchable renewable technologies are often considered in combination with gas turbines. Challenges related to this are (i) to limit frequent starts and stops of gas turbines, which may significantly reduce gas turbine lifetime, (ii) to allow for quick ramp up rate of gas turbine power when required, and at the same time (iii) limit off-design operation and operation on idle. These challenges require good operation strategies and advanced process control, also considering weather forecasts [19,121].

Wind power. Wind power is the most technically mature renewable technology relevant for offshore use. New generation floating wind power is applicable in deep water sites and can thus potentially utilize wind resources nearby offshore platforms [122]. Pioneer applications of floating wind are Equinor's Hywind Scotland where a 30 MW park is installed [123] and Hywind Tampen where a 88 MW park is under installation [13]. Wind turbines can only generate power when the wind speed is above a certain cut-in value and must shut down to prevent damages above a cut-out speed. The capacity factor is therefore highly site specific, but depends also on turbine size and technology [124]. The average annual capacity factor for offshore wind turbines was in 2018 in the range 29–52 % globally [125], and in 2020 around 42 % in Europe [126]. Optimal integration of wind farms and gas turbine combined cycles for offshore applications has been investigated by e.g., Riboldi et al [59].

Solar power. The most relevant solar power technology for offshore is based on photovoltaics (PV) where the sunlight is absorbed and converted into power by solar panels. The cost of PV systems has been considerably reduced in the past few years and is for onshore applications close to the cost of fossil-based power. Solar power for offshore applications has a low maturity compared to onshore applications. However, several floating PV systems on lakes and reservoirs have been tested, and more than one year operation of a pilot high-wave offshore PV plant has been reported in the Dutch North Sea [127]. Solar energy availability is linked to the variation in sunlight over one day and fits well with onshore power demand in cities. However, solar PV plants have a considerably lower capacity factor than wind power, with an average annual capacity factors in the range 10–21 % globally in 2018 [125]. The efficiency of PV cells is enhanced by a cold climate, but application far north also implies long periods with limited or no availability during the winter and would require large energy storage capacity or long periods with alternative power supply.

Wave power. Wave energy resources are more consistent and have higher predictability than wind and solar resources [128,129]. They are also highly available in certain areas with offshore oil and gas production, such as the NCS. Wave power technology is less technically mature than both wind and solar power, and a major issue for reaching commercialisation has been the survivability and cost of the technologies [130]. Many different wave energy converter designs have been developed (an overview over some of the working principles is given in Babarit et al. [131]). Many vendors of wave power technologies focus on designs requiring shallow waters, which is of less relevance for power generation for offshore oil and gas facilities. There are however concepts that with further development could be applied in deeper waters, for instance a concept based on heaving buoys that are connected to the seabed with cables [132]. Due to the low maturity, less statistical data is available on capacity factors compared to solar and wind power, but annual average capacity factors of 2–66 % are reported [130,133,134], indicating that the capacity factor can be expected to be in a range similar to offshore wind. Combination of wind and wave power has been proposed and may, depending on the site, give up to a 15 %-points higher capacity factor than for a purely wind-based system [135].

2.3.5. Nuclear technologies

Nuclear power is a thermal power generation technology where heat is generated from a nuclear reaction and converted to power in a Rankine cycle, normally with steam as working fluid. Nuclear fuel has the highest energy density of all practical fuel sources and is associated with no direct GHG emissions. Nuclear power has traditionally been used for large civil power stations or in military applications. Small modular reactors (SMRs) represent a new generation of nuclear reactors designed to generate electric power in small scale [136] that have potential to be used in new applications. Their components and systems can be shop fabricated and then transported as modules to the sites for installation. The general lifecycle of SMRs includes building at the factory, transport to the location for the duration of the (long) fuel cycle and return transport to the factory where the nuclear core is replaced with a new core containing fresh fuel.

Nuclear power presents some challenges related to the long-term handling of waste, and introduction of new HSE aspects very different from what is normally handled offshore. In addition, the regulatory framework for international trade of nuclear material would have to be adapted. For application on the NCS, nuclear based power generation is expected to be very challenging due to the potential consequences of an accident and barriers both in Norwegian laws and public perception. Hence, implementation of this concept would probably not be possible within a time scale matching the short to medium terms climate targets.

Power from shore

Power from shore is technically mature for many applications and the currently most used technology for emission reductions from offshore oil and gas production. The emission reduction depends on the GHG emission factor of the power available from the grid and, for existing assets, on the degree of electrification (partial or full). An important precondition for implementation is that the onshore power system can supply the offshore power demand, without negative effects on security of supply for onshore consumers. Calculated impact of power from shore on overall GHG emissions is strongly affected by the approach chosen. The GHG emission factor of the electric power can be based on the CO_2 emissions related to the physically delivered power. This factor depends on the selected system boundaries. For instance, the emission factor for electricity physically delivered to consumers in Norway is 11 g CO_2/kWh (2021) [31], but the Norwegian grid is connected with the EU grid with 229 g CO_2/kWh (2020) [137]. An alternative approach is to assign the marginal GHG emissions to the electric power consumption offshore, and this approach can in some cases indicate a GHG emission factor even higher than for the physical power in the EU grid [138].

Power from shore can be transmitted either with high voltage alternating current (HVAC) or direct current (HVDC) cables. Solutions with AC transmission are associated with larger losses per distance and higher cable costs compared to DC, while DC solutions require larger, heavier, and more expensive equipment at the facility and on shore due to the necessary DC/AC conversions. HVAC is therefore preferred for short distances from shore, while HVDC is preferred for longer distances. The world's longest AC cable is connecting the Martin Linge field to shore, and measures 163 km [139]. Meanwhile there are DC cables on the NCS measuring 200–300 km [14].

Power from shore offers an improvement in work environment compared to gas turbine solutions since noise and vibrations from such rotating equipment are eliminated. Another benefit compared to gas turbine solutions is reduced maintenance requirements. Partial instead of full electrification is normally preferrable for existing assets, having the benefit to avoid conversion from mechanical to electrical drive for compressors, which would require significant modifications with long downtime and production loss.

2.4. Supporting technologies

2.4.1. Carbon dioxide capture and storage

Carbon dioxide capture and storage (CCS) has the potential to eliminate close to all CO_2 emissions at the expense of some additional energy demand (heat, power, or both). CCS for natural gas sweetening has been in use since 1996 in offshore installations, 20 years before implementation of CCS in other industries, with >19 million tonnes of CO_2 captured and stored from the Sleipner, Utgard, and Snøhvit fields by the end of 2020 [8]. Offshore CCS from power generation has not been implemented yet, but has been evaluated in several studies (e.g. [140,141]), and vendors are currently developing solutions targeted for offshore use [142]. Capture of CO_2 can be performed with a wide range of fundamentally different technologies at different technical maturity levels. Capture technologies are normally categorized as pre-combustion, oxyfuel combustion or post-combustion technologies. Hydrogen and ammonia-based power generation are examples of pre-combustion capture processes if the hydrogen or ammonia is produced from fossil feedstock with CO_2 capture. Post-combustion capture implies treatment of the flue gas after combustion, while oxyfuel combustion capture is based on combustion in pure oxygen instead of air, to facilitate simpler separation of CO_2 from the exhaust.

Post-combustion CO_2 capture. Post-combustion CO_2 capture is suitable for retrofit to existing plants, as most post-combustion technologies do not interact with the power generation except by increased heat and/or power demand. Types of post-combustion capture include solvent absorption, adsorption, calcium looping, and membrane separation. Certain solvent absorption processes are technically mature. The potential for emission reductions depends on the CO_2 capture ratio (CCR), and the amount of heat and/or power required to drive the capture process. Achievable CCR depends on the technology and can be higher than 90 %, while the economically optimal CCR depends on the use case. Post-combustion CO_2 capture typically involves installation of large and heavy process equipment, which is a challenge for offshore application and operation. However, several companies are developing more compact solutions, e.g. by absorption and desorption using gravitational forces like Prospin Rotating Packed Bed [143] and Compact Carbon Capture (3C) [144,145]. Other potentially compact solutions are on the conceptual stage, like exhaust gas recirculation, which gives higher CO_2 concentration in the flue gas and thus more compact CO_2 capture [146].

Oxyfuel combustion CO_2 capture. In oxyfuel combustion CO_2 capture, the combustion in high purity oxygen generates a flue gas mainly consisting of steam and CO_2. Depending on the specific technology, further purification of the flue gas may or may not be necessary before transport and storage. The technology relies on supply of oxygen, so oxygen storage or an air separation unit (ASU) would be required at site, and this is a safety challenge for a congested offshore facility with combustible inventories. The Allam cycle is an oxyfuel combustion technology that has been reported to be both energy efficient and cost effective when being applied for CO_2 capture [147]. It utilizes supercritical CO_2 produced in the process as the working fluid in a power cycle [148]. Natural gas and pure oxygen are burned in nearly stoichiometric ratio so that pure CO_2 (required for supercritical conditions) is ideally produced without oxygen and other impurities. A portion of the produced CO_2 is recycled into the combustor, while the remaining portion can be stored. The thermal efficiency of the Allam cycle can be comparable to natural gas combined cycles without CO_2 capture. An obvious advantage of the Allam cycle is that CO_2 can be inherently captured at high purity and high pressure with a CCR close to 100 %. For offshore platforms, challenges such as increased size and weight e.g., related to the ASU, the recuperative heat exchanger, and the water separator will apply.

2.4.2. Energy storage

Non-dispatchable technologies can be combined with energy storage to make the overall concept dispatchable. For combination with intermittent renewable energy sources, it is necessary with systems that can provide at least 30 MW electric power with several days, even weeks, of autonomy, such as hydrogen energy storage or compressed air. Hydrogen energy storage is preferable due to the energy density. Batteries have high round-trip efficiency and quick response times, but pure battery systems are less suitable for long-term and large-scale energy storage [149]. A hydrogen energy storage system requires (i) a power-to-hydrogen unit (electrolyzers), that converts electric power to hydrogen, (ii) a hydrogen conditioning process (compression or liquefaction), (iii) a hydrogen storage system, and (iv) a hydrogen-to-power unit (e.g., fuel cells or hydrogen fired gas turbines). Hydrogen can be stored in gaseous form in tanks or as liquid in insulated tanks. Gaseous hydrogen storage is considered as more suitable than liquified storage for offshore applications, provided that the gaseous hydrogen can be stored subsea for instance as envisioned in the Deep Purple project [150]. Gaseous hydrogen storage requires approximately 20 times larger volume than liquid hydrogen tanks for the same amount of hydrogen, but a relatively simple compressor system placed on the platform can be used to condition the hydrogen before it is sent to the subsea tanks, whereas liquid hydrogen storage systems would require a more complex and more spacious liquefaction unit. The round-trip efficiency of a gaseous hydrogen energy storage system with fuel cell as hydrogen-to-power unit is around 42 % considering typical efficiency values of 60 % for the fuel cell and 70 % for the electrolyzer [151] and neglecting the penalty for the hydrogen conditioning.

3. Evaluation of selected concepts for low carbon power generation offshore

Six properties considered critical for low GHG power generation concepts for offshore oil and gas facilities have been defined as Key Performance Indicators (KPIs), and NG fired aeroderivative gas turbine has been selected as the reference concept. The KPIs are described in Table 1, together with their values for the reference concept.

Initially a database of more than 100 power generation concepts, as outlined in Section 2.1, was built. Out of these, the thirty most promising concepts for application at the NCS were selected for evaluation. These concepts are listed in Table 2. For the sake of completeness, local nuclear power which has interesting technical features but is considered not relevant for the NCS for non-technical reasons, is also evaluated against the same criteria. This concept is however not discussed in detail. All the assumptions used in the evaluation of the quantitative KPIs are provided

Table 1
Key performance indicators (KPI).

KPI	Definition	Reference concept
CO_2 equivalent intensity (g/kWh)	CO_2 equivalent emitted per delivered kWh electric power at design load. Sum of: (i) direct CO_2 emissions due to combustion of fossil fuels, (ii) CO_2 equivalent emissions of methane slip* (for reciprocating engines), (iii) supply chain CO_2 equivalent emissions for production of the fuel, e.g., hydrogen, ammonia, or biofuels, and (iv) GHG emission factor of electric power.	540 g/kWh
Process heat availability	"Yes": heat above 100 °C is continuously available. "No": otherwise.	Yes
Weight-to-power ratio at facility (tonne/MW)	Weight of power generation equipment per MW delivered power at full load. Only the weight of key equipment located at the facility is included.	3.3 tonne/MW
Infrastructure requirement outside facility	"Yes": significant infrastructure is required outside the offshore facility. "No": no significant infrastructure is required outside the offshore facility.	No
HSE risk	"Yes": new risks** are introduced compared to technologies already applied offshore. "No": no new risks** are introduced.	No
Technical maturity	"Qualified": the technology is sufficiently mature for first use offshore. "Under development": otherwise.	Qualified

* When calculating CO_2 equivalent intensity due to methane slip, one GWP-20 and one GWP-100 case were included. The values were taken to be 82.5 and 29.8 respectively, as used in the Assessment Report 6 of the IPCC [152].

** From qualitative evaluation of HSE risk.

Table 2
Power generation concepts selected for evaluation.

Concept group	Concept	Comment
NG fired gas turbine (GT)	NG fired aeroderivative GT – reference	~30 MW unit
	NG fired industrial GT	~40 MW unit
NG fired combined cycle	NG fired combined cycle (offshore)	
NG fired alternative cycles	NG fired humid air turbine	
	NG fired Allam cycle (without CCS)	Included to show impact of efficiency only
40 % alternative fuel fired GT	H_2 + NG fired GT – 40 vol% H_2	
	NH_3 + NG fired GT – 40 vol% NH_3	
H_2 fired GT	H_2 fired GT	100 % H_2
	H_2 fired combined cycle (offshore)	100 % H_2
Biofuel fired GT	Bio fired GT – 100 % HVO	
	Bio fired GT – 100 % bio-methanol	
NG fired reciprocating engines	NG fired LP reciprocating engine	4-stroke, with diesel pilot fuel
	NG fired HP reciprocating engine	2-stroke, with diesel pilot fuel
NH_3 fired reciprocating engines	NH_3 + NG fired reciprocating engine – 70 vol% NH_3	4-stroke, with diesel pilot fuel
	NH_3 fired reciprocating engine	4-stroke, 100 NH_3, with diesel pilot fuel
NG based SOFC	NG based SOFC	
H_2 based PEMFC	H_2 based PEMFC	100 % H_2
Renewable + GT	Wind power + GT	
	Wave power + GT	
	Wind and wave power + GT	
	Solar power + GT	
Renewable + energy storage	Wind power + energy storage	H_2 energy storage
	Wave power + energy storage	H_2 energy storage
	Wind and wave power + energy storage	H_2 energy storage
	Solar power + energy storage	H_2 energy storage
Power from shore	Power from shore – HVACPower from shore – HVDC	
CCS based technologies	NG fired Allam cycle with CCS	
	NG fired GT with amine-based CCS	
	NG fired CC with amine-based CCS	

in the supplementary material.

A high-level summary of the KPIs for the concepts outlined in Table 2 is presented in Table 3 together with local nuclear power. In this overview the CO_2 equivalent intensity is defined as:

- *Low:* <150 g/kWh,
- *Medium:* 150–450 g/kWh,
- *High:* >450 g/kWh,

and the weight-to-power-ratio at facility is defined as:

- *Low:* <10 tonne/MW,
- *Medium:* 10–30 tonne/MW,
- *High:* >30 tonne/MW.

It can be observed that most groups of concepts with reduced CO_2 equivalent intensity compared to the reference case have one or several challenges related to other KPIs, illustrating the general statement that GHG emission reductions come at the expense of other critical aspects.

Table 3
Summary of KPIs for concept groups.

	NG fired gas turbine (GT)	NG fired reciprocating engines	40 % alternative fuel fired GT	NG fired combined cycle	NG fired alternative cycles	Renewable + GT	NG based SOFC	Biofuel fired GT	H_2 fired GT	H_2 based PEMFC	NH_3 fired reciproc. engines	CCS based technologies	Power from shore	Renewable + energy storage	Nuclear power*
CO_2 equivalent intensity	High	Medium to high	Medium	Medium to high	Medium	Medium to high	Medium to high	Low to high	Low	Low	Low to medium	Low	Low to medium	Low	Low
Process heat availability	Yes	Yes	Yes	Yes	Yes/No	No	Yes	Yes	Yes	No	Yes	Yes/No	No	No	Yes
Weight-to-power ratio at facility	Low	Medium to high	Low to medium	Low	Uncertain	Low	High	High	Low to medium	Low to medium	Medium to high	Uncertain	Low to medium	High	Uncertain
Infrastructure requirement outside facility	No	No	Yes	No	No	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
New HSE risks	No	Yes	Yes	No	No/Yes	No/Yes	No	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes
Technical maturity	Qualified	Qualified/ Under development	Under development	Qualified	Under development	Qualified/ Under development	Under development	Under development	Under development	Under development	Under development	Under development**	Qualified	Under development	Under development

*Not considered relevant at the NCS for non-technical reasons.
**Offshore post combustion amine-based CCS is close to being ready for first use in Equinor.

This is in fact not surprising and illustrates the complexity of decarbonizing the offshore sector.

3.1. CO_2 equivalent intensity and technical maturity

The CO_2 equivalent intensity of all the evaluated power generation concepts is presented in Fig. 4 with the level for the reference technology (natural gas fired simple cycle gas turbine) indicated with a dashed line. The more technically mature concepts classified as *qualified* are grouped on the left-hand side of the figure and the less technically mature classified as *under development* on the right-hand side. The CO_2 equivalent intensity is dependent on several parameters, e.g., efficiency, GHG emissions related to the energy source, and capacity factor. The maximum CO_2 equivalent intensity of each concept is calculated based on a combination of conservative assumptions, while the minimum is calculated based on optimistic assumptions (see supplementary material).

The concepts classified as *qualified* are gas turbines, power from shore, and combined cycle, which are already implemented offshore, offshore wind combined with gas turbines, under construction in the Hywind Tampen project [13], and natural gas fired LP 4-stroke reciprocating engines that are available from vendors. The remaining concepts are classified as *under development* and this category covers a very wide range of technical maturity levels, ranging from pilot scale to qualified for other applications. Among the technologies with relatively high maturity in this category are offshore post combustion amine-based CCS that is close to being ready for first use in Equinor. Fuel cells are also technically mature for some applications, but not available at the scale required in this context and are associated with uncertainties regarding response time. Natural gas fired HP 2-stroke reciprocating engines are available for ship propulsion but not for electricity generation offshore. Some categories of hydrogen fired gas turbines are claimed to be ready from vendors, but all hydrogen-based concepts are classified as *under development* due to challenges related to transport and handling of hydrogen offshore.

Power from shore is the only concept among the *qualified* concepts with potential for *low* CO_2 equivalent intensity, i.e., CO_2 equivalent intensity below 150 g/kWh, corresponding to >70 % reduction compared to the reference. However, this alternative has a large span in CO_2 equivalent intensity depending on the origin of the power. For the low bound in Fig. 4, the GHG emission factor of the Norwegian grid (2021), which is largely dominated by renewable power, is assumed, resulting in CO_2 equivalent intensity of 11.6 g/kWh for this concept, corresponding to >95 % GHG emission reduction compared to the reference. For the high bound the average GHG emission factor of the European grid (2020) is assumed, resulting in CO_2 equivalent intensity of 241 g/kWh. The GHG emission factors of the electricity in these regions are under continuous change, influenced by aspects such as introduction of more renewables, increased electric power demand due to electrification of society and industry (including the offshore sector), and import and export between regions. These changes are to a large extend driven by societal and political evolution.

The two *qualified* concepts with the second largest potential for reduction in CO_2 equivalent intensity are wind power combined with natural gas fired gas turbines and natural gas fired combined cycle. These concepts have CO_2 equivalent intensity in the higher end of the *medium* range and can potentially reduce GHG emissions by 29–52 % and 16–24 % compared to the reference. The exact CO_2 equivalent intensity of wind power combined with natural gas fired gas turbines is dependent on local conditions driving the utilisation factor of the wind turbines, but also on the design and operation of the system (design capacity of wind park versus the power demand of the facility). It is here assumed that the wind park can supply exactly 100 % of the power when operated at full capacity, but systems with larger wind parks will have lower CO_2 equivalent intensity at the expense of higher capital expenses. The performance of the combined cycle system is directly linked to the thermal efficiency of the system, which is a trade-off with weight. The range in combined cycle efficiency assumed here is representative of light-weight solutions developed for offshore application (45–50 %), which is lower than for heavier systems where thermal efficiency can exceed 60 %. The optimal trade-off between efficiency and weight offshore will depend on the specific case, and more efficient but heavier

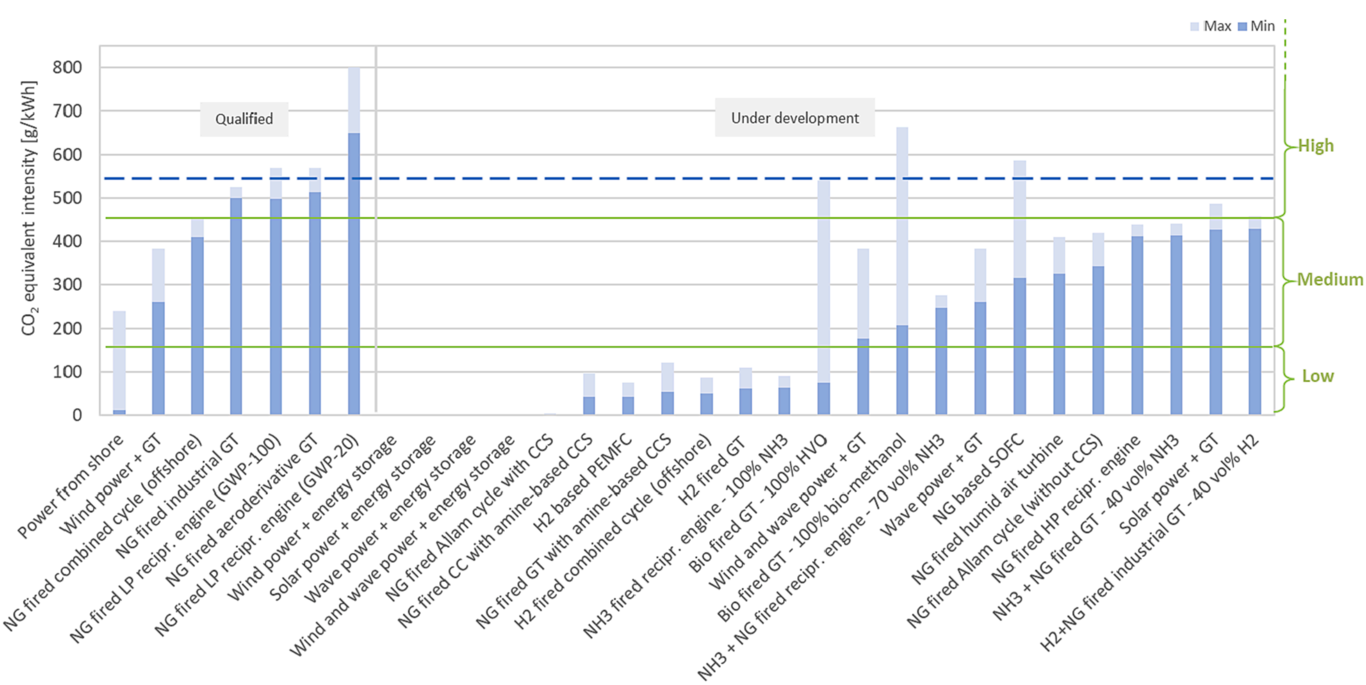

Fig. 4. CO_2 equivalent intensity of offshore low carbon power generation concepts at design load, with low and high bounds shown as dark and light bars respectively. The blue dotted line indicates the level of the reference gas turbine concept, while the green lines indicate low, medium, and high CO_2 equivalent intensity. Hydrogen-based concepts that are identical except for different transport options are merged. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

solutions may in some cases be preferred.

The highest CO_2 emitter among the *qualified* power generation concepts is natural gas fired LP reciprocating engine, although having higher efficiencies than gas turbines. For LP reciprocating engines the high efficiency is outweighed by methane slip, that depending on the amount and assumed GWP may result in higher CO_2 equivalent intensity than the reference.

All the concepts with *low* CO_2 equivalent intensity, except power from shore, are in the *under development* category. It can be seen that achieving near-zero emissions (lower range of *low*) is only possible by using renewables combined with an innovative form of energy storage. Other concepts with low CO_2 equivalent intensity are either based on fuel switch or CO_2 capture solutions. The two concepts representing biomass sourced fuel, 100 % HVO and bio-methanol fired gas turbines, have a large range in CO_2 equivalent intensity depending on the origin of the fuel. These concepts show potential for large emission reductions, but also the possibility to end up with as high or higher emissions than the reference technology if a fuel with large supply chain GHG emissions is used. For technologies based on hydrogen, the variation in CO_2 equivalent intensity due to the origin of the fuel is low, because it is assumed that the hydrogen relevant for utilisation will be produced from natural gas with CO_2 capture (with CCR in the range 91–94 %) or by electrolysis with a high share of renewable power. Similarly, for CCS based technologies high capture ratios (80–90 %) are assumed.

The remaining concepts classified as *under development* have CO_2 equivalent intensity in the *medium* or *high* range. The most promising of these concepts in terms of GHG reduction potential, is the combination of wind power, wave power, and gas turbines, which potentially can have lower CO_2 equivalent intensity than wind combined with gas turbines. The rest have similar or higher CO_2 equivalent intensity compared to wind combined with gas turbines and combined cycle solutions, which are already qualified technologies. This includes concepts with partial substitution of natural gas (up to 70 %), other renewable technologies combined with gas turbines, and technologies with higher efficiencies than gas turbines, but still based on natural gas as fuel (fuel cells, reciprocating engines, and the alternative gas turbines cycles HAT and Allam cycle without CCS).

3.2. Process heat availability

Process heat is required at most offshore platforms, and normally supplied by surplus heat recovery from gas turbine exhaust gas. If surplus heat is not available from the power generation technology, it must be provided by other means such as by electric heaters or heat pumps or directly from combustion of natural gas. Surplus heat is typically available at different temperature levels and various amounts depending on technologies. Some power generation concepts will have surplus heat continuously available, while other concepts may have surplus heat available only part of the time. In Table 3, process heat availability is categorized as *yes* if any heat above 100 °C is continuously available. However, it should be noted that the required temperature level and amount of heat needed will vary among offshore facilities, and not all concepts categorised as *yes* can cover all heat demands at all offshore applications.

Simple cycle gas turbines always produce surplus heat, independently of fuel type. For combined cycle solutions process heat is available, but at the expense of some power generation in the steam cycle. Reciprocating engines are also combustion-based technologies, and surplus heat above 100 °C can be recovered from the flue gas, but the amount of heat and the temperature level is lower than for gas turbines. For the natural gas fired alternative cycles, surplus heat is available in the HAT concept, but not in the Allam cycle, where low temperature heat is converted to power and excess heat is recuperated and utilised in the process. In CCS based technologies, surplus heat availability depends on the capture process. With amine-based capture, lower amounts are available because some heat is used in the CO_2 capture process. For fuel cell-based concepts the surplus heat availability depends on the fuel cell type: SOFCs operate at high temperatures and surplus heat may be available, while PEMFCs operate at low temperatures and do not produce heat above 100 °C. For combinations of gas turbines and non-dispatchable renewable technologies, surplus heat is only available while the gas turbines are operating. When renewable technologies are combined with energy storage, surplus heat may be available part of the time but not continuously, while for power from shore solutions surplus heat is never available.

3.3. Weight-to-power ratio at facility

Low weight is essential for all types of equipment to be installed offshore due to the impact on costs of construction and operation. The weight-to-power ratios of gas turbines, combined cycles, and reciprocating engines with different types of fuel were calculated including only the key equipment installed at the facility, like the gas turbine, reciprocating engine, steam turbine, generator, HRSG, and fuel storage tanks fully loaded. These power generation concepts are similar in the sense that they consist of similar type of equipment, and they are relatively technically mature, which makes this kind of weight estimates and comparison possible. The estimated weight is not equivalent to installed weight which would include weight of support structures and utilities, that are very case specific as these structures are adapted to fit into each specific facility. In Fig. 5 the calculated weight-to-power ratios of these concepts are plotted against CO_2 equivalent intensity. The middle CO_2 equivalent intensity value (see Fig. 4) is used on the horizontal axis for all concepts, except for the two bio-based fuels where the range in CO_2 equivalent intensity is very wide, so high/low cases are shown instead.

Fig. 5 shows, as expected, that natural gas fired gas turbine is the technology with best power to weight ratio. The geometry and dimensions of alternative fuel fired gas turbines are similar to conventional gas turbines which makes them candidates to retrofit to solutions where modification to the combustion system is possible. However, the new fuel would require installation of fuel storage tanks and for ammonia-based solutions also a NO_x abatement unit, at least in the short to medium terms. It can be seen in Fig. 5 that for any change in fuel which requires ship fuel supply, the offshore storage requirement has a significant weight impact that more than doubles the weight to power ratio for partial decarbonization compared to the reference case. To reach near full decarbonization, one must tackle an increase by a factor of minimum eight. In the examples shown here, tanks with capacity to store fuel for three days of operation were assumed, while the optimum tank size is dependent on factors such as the type of fuel and the fuel transport distance. The alternative to fuel storage tanks is the installation of pipeline network, with its corresponding capital costs. It can be noted that the weight of the ammonia fired technologies is more influenced by the fuel storage than the other technologies, due to the high weight of ammonia compared to the other fuels for the same energy content. For instance, the (weight based) LHV of ammonia is 16 % that of the LHV of hydrogen. On the other hand, ammonia has high energy density, which is an advantage compared to hydrogen that is not visible in this evaluation. Note that in the case of the 40 vol% ammonia fired gas turbines, the NO_x abatement unit represents approximately 40 % of the weight. There is therefore a significant improvement potential if a breakthrough technology for combustion of ammonia containing fuels emerges. It would however only bring the weight-to-power ratio to the same levels as the 40 vol% hydrogen fired gas turbines with ship transport. The potential is far lower for corresponding reciprocating engine concepts which are heavier than gas turbines.

The weight of reciprocating engines is high compared to gas turbines and cannot be justified from a CO_2 emission reduction perspective due to the small and sometimes negative potential for emission reductions they offer when operated with natural gas. With ammonia as fuel, the weight is still a major drawback, but further development may be justified by the potential for emission reductions. However, hydrogen fired gas

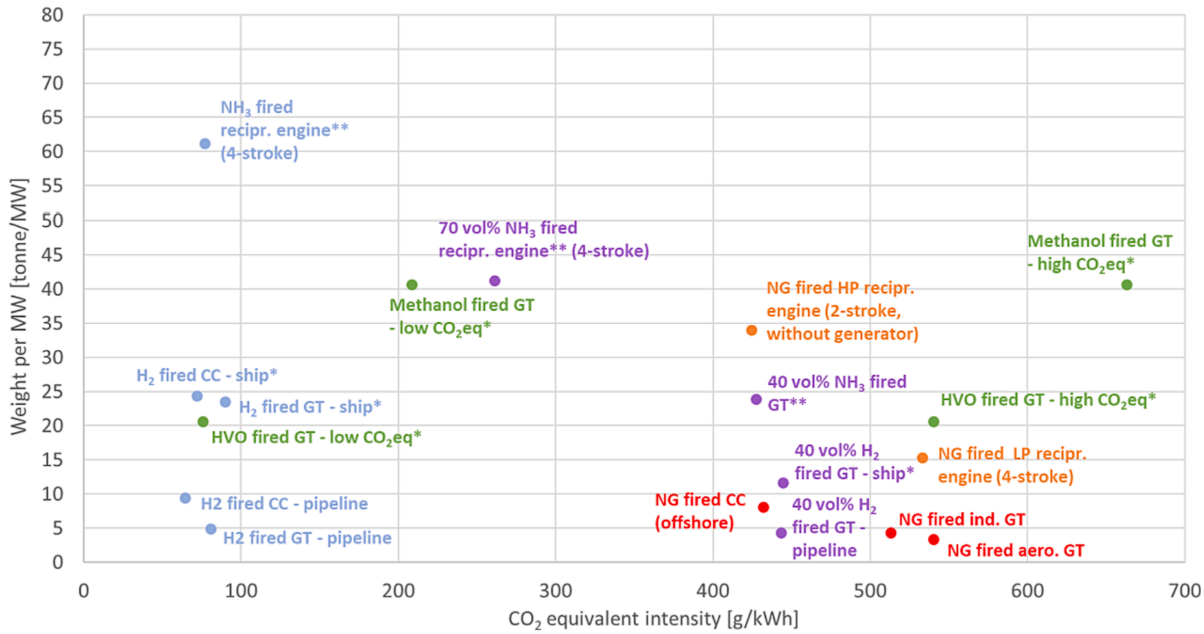

Fig. 5. Weight-to-power ratio at facility for key equipment vs CO_2 equivalent intensity of gas turbines (GT), combined cycles (CC), and reciprocating engines with different types of fuel. Concepts marked with * include fuel storage tanks (with fuel for three days of operation). Concepts marked with ** include fuel storage tanks (with fuel for three days of operation) and NO_x abatement unit.

turbines perform much better in terms of weight, so ammonia fired reciprocating engines would need to provide other benefits to be relevant.

Other evaluated concepts have significant differences compared to the concepts discussed above. For this reason, and in some cases due to low technical maturity and lack of data, it is challenging to make reliable weight estimates that are directly comparable to the estimates presented in Fig. 5. Instead, the weight-to-power ratio at facility is classified as *low*, *medium*, or *high*, and in some cases *uncertain*, as presented in Table 3 based on the literature review and a qualitative assessment (see supplementary materials). Renewables combined with gas turbines and power from shore with AC power transmission have low weight at the facility. Power from shore with DC transmission is significantly heavier and is categorised with medium weight-to-power ratio at facility. It should be noted that as these technologies do not produce surplus heat, the weight will be increased if process heat is required at the facility. Hydrogen based PEMFCs may end up either in the low or medium category while natural gas based SOFCs are among the technologies with high weight at the facility. Renewable power with energy storage is heavy due to the weight of the equipment required for conversion between electric and chemical energy. Public data is lacking on weight both for natural gas fired alternative cycles and CCS based technologies.

3.4. Infrastructure requirement outside facility

The requirement for infrastructure outside the facility varies significantly between the various concepts and may have a large impact on cost. Some technologies have a low weight at the facility but require extensive infrastructure. Natural gas based power generation concepts do not require any infrastructure outside the facility, neither related to the power generation technology nor to the fuel, with the exception of CCS based technologies that require transport and storage solutions for the captured CO_2. Even so, solutions where the captured CO_2 is mixed into the injection water can save dedicated equipment and wells for CO_2 injection and storage. For renewable based concepts, the actual power generation technologies are installed outside the facility, as fixed or floating wind turbines, wave power buoys, or floating solar panels. These concepts also require a system for transmission of the produced electricity to the facility, and cases with energy storage imply installation of large hydrogen storage facilities on the seabed. Alternatively, storage could be avoided by transferring the generated renewable power to the onshore grid and supplying dispatchable power from the grid to the offshore installation. The concepts based on alternative fuel require onshore synthesis of the fuel and fuel transport either in pipelines or by ship. In a similar manner, power from shore solutions imply installation of subsea cables. One important difference between solutions with ship transport versus pipelines and cables is that ships are flexible, i.e., the number of ships can be scaled up and down according to the demand and used in other projects after the end of a field's life (although the local fuel tanks at the facilities would be fixed). Pipelines and power cables are fixed and thus less flexible, although e.g., power cables can potentially be used to send renewable power *from* offshore *to* shore when there is no more need for power from shore for the offshore oil and gas facility. Also, solutions depending on cables and pipelines are less attractive for facilities located far from shore.

3.5. HSE risk

Offshore oil and gas facilities handle a huge amount of energy and are often subject to harsh environments. Their conception and operation must therefore meet extremely stringent specifications to ensure the safety of personnel and operations and minimize impact to the environment. Most power generation concepts do imply some potential HSE issues in one form or another, and suitable mitigation measures add extra costs or complexity levels to the technologies. Natural gas fired gas turbines involve high temperatures, utilisation of flammable fuel, and emissions to air, but these risks are well-known and have been handled and mitigated at offshore facilities for decades. New power generation concepts may introduce new HSE risks, which must be properly understood and mitigated before implementation. Among the concepts not already qualified for offshore use, the HAT technology and SOFCs do not introduce new HSE risks compared to installed natural gas fuelled gas turbines and steam based combined cycles. All other concepts under development are linked to new HSE risks, but the consequences and likelihood of these risks vary significantly among the concepts. Reciprocating engines are associated with high levels of noise and vibrations that exceed that of gas turbines, while the Allam cycle requires handling of pure oxygen and supercritical CO_2 as working fluid. CCS based technologies may introduce new risks depending on the selected technology. For instance, some types of solvents may be hazardous for health and environment in case of accidental spillage or leaks. Concepts based on fuel switch introduce new risks related to the new fuel. Hydrogen has high flammability and explosibility, and is more prone to leak than other fuels, while ammonia is toxic and corrosive. Biofuels are linked with risks related to its impact on biodiversity due to land use and use of water resources (depending on origin), and some types are more flammable than conventional diesel already used offshore. The concepts including renewables present risks related to the impact on ecosystems by wind turbines, wave buoys, and floating solar panels.

4. Discussion

4.1. Limitations of the study

The evaluation presented in Section 3 is based on various literature sources ranging from research articles describing technologies under development to datasheets with vendor data for mature technologies. Research articles describing technologies under development tend to give optimistic performance estimates that can be looked upon as targets for further development or performance under controlled conditions, while datasheets are more realistic as they are based on performance tests of finished products available in the market. This means that the estimated CO_2 equivalent intensity is expected to be more accurate for the qualified technologies, while the estimates for the technologies under development may be on the optimistic side.

In general, the availability of literature with focus on offshore application is limited. A few research papers are available on integration of wind power, combined cycle, and CCS in offshore power systems (e.g., [59,121,138,141]), but apart from these the offshore aspect is normally not included. Thus, the focus is mainly on performance data in terms of efficiency or emission reductions, and less on the remaining properties relevant offshore. In particular, obtaining consistent data on weight has proven to be challenging due to the lack of available data and the different system boundaries for which the available data has been prepared. Furthermore, research studies are normally focused on technologies under development where weight is still uncertain and seldom the main point of concern. The focus is normally only on the core part of the technology, and if information on weight is included, this does not include the whole system with auxiliary equipment. Datasheets for commercial technologies may report weight or volume only including the core technology (e.g., gas turbine and generator), or including the whole package (e.g., fuel cell system with auxiliary equipment inside an ISO container). These limitations in available data only allowed for direct comparison of a selection of technologies in terms of weight-to-power ratio (Fig. 5).

It should be mentioned that some of the technologies evaluated are subject to continuous development, and the current evaluation and recommendations represent a snapshot of the situation at the time of publication. The evaluation can be extended and updated as concepts are matured, and if new competing concepts appear.

4.2. Main findings

Despite the limitations mentioned above, the main findings of this work are clear. A wide range of concepts that have the potential for partial or close to full decarbonization of offshore power generation exists. However, all concepts that can reduce emissions have one or several drawbacks compared to natural gas fired gas turbines in terms of the KPIs related to applicability offshore. All alternative concepts will either introduce heavy equipment at the facility or require significant infrastructure outside the facility, or both. Several concepts rely on the use of alternative fuels, which are more expensive than natural gas, and these concepts are therefore also associated with higher operational costs. If unused fuel gas has export value this can help the economy of these cases, but the CO_2 impact of this also needs to be considered in a broader assessment. A few concepts do not have process heat availability, implying that other solutions must be implemented to cover process heat demand, thus increasing costs, and likely reducing the potential for emission reductions. Most concepts under development introduce new HSE risks, and development of strategies and solutions for mitigation of these risks will need to be a part of the technology development and qualification path. It can also be highlighted that the concepts requiring modification or exchange of the existing power system are associated with risk for unwanted production loss, with potentially large economic consequences. All these points illustrate that GHG emission reductions come with challenges. Solving these challenges is typically more difficult for existing (brownfield) installations with limited space and weight allowances compared to new (greenfield) installations in the planning stage.

Power from shore is a qualified technology for many applications and can significantly reduce emissions (potentially $>$ 95 %) and contribute to reaching both intermediate and ultimate climate goals, given that power is available and that the GHG emissions related to the utilised power mix are low. This concept is less suitable for facilities far from shore. Offshore combined cycles and wind power combined with gas turbines are qualified technologies that can partially reduce emissions in a short time frame. These concepts have GHG emission reduction potential around 15–50 % with the assumed system designs and can give important contributions to reaching intermediate climate targets on the way to net zero. Deeper emission cuts for these concepts can be achieved by switching to alternative fuel or implementing CCS at a later stage. Wind power can have synergies with power from shore, since power from shore can provide the dispatchable power initially covered by gas turbines, and cables used to supply power from shore can in the future be used to transport power produced by offshore wind *to* shore. These already qualified concepts may thus be suitable as part of a stepwise emission reduction strategy. They are ready for relatively fast implementation to help achieving 2030 climate goals and can, in combination with other concepts, also support net zero 2050 goals.

However, the already qualified concepts are not enough to reach net zero. There is not one solution for all installations. The most appropriate solution will depend on various factors such as location, brownfield/greenfield, remaining lifetime, type of installation (e.g., FPSOs), power demand, and heat demand. Power from shore is the only qualified concept with potential for deep emission reductions and with today's technology it is not suitable for all cases. The attractiveness of power from shore in terms of emission reductions is also dependent on the onshore power mix, which is outside the control of single oil and gas operators. Therefore, introduction of new concepts that are under development is needed to meet the ultimate target of net zero emissions. The concepts under development with similar or slightly higher GHG reduction potential compared to offshore combined cycles and wind power combined with gas turbines face various challenges regarding applicability offshore and demonstrate no clear benefits compared to the existing solutions. Given their limited potential for emission reductions, and thus low added value compared to qualified concepts, it does not seem reasonable to focus on research and development of these solutions for offshore application. Due to the ultimate goal of net zero emissions and lack of other qualified concepts than power from shore that can help achieving this, it is recommended to rather focus on concepts that can give significant cuts ($>$70 %), i.e., concepts with renewable power combined with energy storage, CCS based concepts, and concepts based on alternative fuels. All these concepts require further development, and face challenges in terms of weight, HSE risks, or infrastructure requirement, but they have the potential to play important roles in the net zero scenario. Although significant emission reductions from power generation offshore are possible, it is clear that costs will be high for development, qualification, and operation of such concepts. Further technology development might also reveal technical or commercial showstoppers for some of the technologies in this application area.

4.3. Recommendations

The current study can support policy makers and oil and gas companies in developing roadmaps for reaching climate targets. Furthermore, public funding agencies and industries can use this study to direct funding towards concepts having potential for the offshore sector. One general recommendation is that research and development should be directed to solutions offering deep emission cuts. Solutions for medium cuts are already qualified and in the process of being implemented. It is evident that reaching climate goals will be expensive, and it is important that national and international climate goals are reflected in the policies for public funding of the research, development, and implementation of offshore low carbon power generation technologies.

5. Conclusion

In this study a wide range of offshore power generation concepts are reviewed and analysed with respect to their potential for emission reductions and their applicability offshore. The concepts analysed include alternative power generation technologies, alternative energy sources, and alternative energy carriers. It is shown that several different power generation concepts that potentially can reduce emissions compared to standard natural gas fired gas turbines exist. However, their emission reduction potential and their technical maturity for implementation offshore vary and they all have various drawbacks compared to the current and well proven natural gas fired gas turbine technology.

Power from shore is a qualified technology which can be used for many applications and can contribute to reaching both intermediate and ultimate climate goals when power is available and the GHG emission factor of the utilised power mix is low. For partial emission reductions (around 15–50 %) combined cycle solutions and wind power combined with gas turbines are technically mature concepts that already have been implemented or are in the process of being implemented offshore. Other natural gas fired technologies with improved efficiency compared to gas turbines and other renewable technologies combined with gas turbines, show negligible potential for emission reductions compared to these, and face significant challenges in terms of low technical maturity or high weight at the facility. On the other hand, concepts based on fuel switch to hydrogen or ammonia have the potential for significant emission reductions provided that 100 % fuel switch can be safely achieved. The same holds for concepts based on CCS with high CO_2 capture rate. Renewable technologies combined with energy storage also have the potential for near zero emissions. All the concepts under development with potential for significant emission reductions face different types of challenges and require more research and development before implementation.

As technologies suitable to partly reduce emissions already exist and are technically mature, it is recommended that further research and development focuses on technologies enabling significant emission reductions, i.e., fuel switch, CCS, and energy storage solutions. To reach the net zero emission targets, efficiency improvements and power from shore only are not enough, and there is a need to develop safe, reliable, and cost-efficient low emission power generation technologies not yet on the market.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

A supplementary information file with the used data and assumptions is available.

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Appendix A. Supplementary data

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